Glen Canyon Dam

Long-Term Experimental and Management Plan Environmental Impact Statement

PUBLIC DRAFT

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GLEN CANYON DAM LONG-TERM EXPERIMENTAL AND MANAGEMENT PLAN DRAFT ENVIRONMENTAL IMPACT STATEMENT

Joint-Lead Agencies
Bureau of Reclamation
National Park Service

Cooperating Agencies

Department of the Interior
Bureau of Indian Affairs
U.S. Fish and Wildlife Service
U.S. Department of Energy
Western Area Power Administration
Arizona Game and Fish Department
Colorado River Board of California
Colorado River Commission of Nevada
Upper Colorado River Commission
Havasupai Tribe
Hopi Tribe
Hualapai Tribe
Kaibab Band of Paiute Indians
Navajo Nation
Pueblo of Zuni
Salt River Project
Utah Associated Municipal Power Systems

ABSTRACT

The U.S. Department of the Interior (DOI), through the Bureau of Reclamation and National Park Service (NPS), proposes to develop and implement a Long-Term Experimental and Management Plan (LTEMP) for operations of Glen Canyon Dam. The LTEMP would provide a framework for adaptively managing Glen Canyon Dam operations over the next 20 years, consistent with the Grand Canyon Protection Act of 1992 (GCPA) and other provisions of applicable federal law. The LTEMP would determine specific options for dam operations, non-flow actions, and appropriate experimental and management actions that will meet the GCPA's requirements and minimize impacts on resources within the area impacted by dam operations, including those of importance to American Indian Tribes.

The Draft Environmental Impact Statement (DEIS) draws on the scientific information that has been collected under the Glen Canyon Dam Adaptive Management Program over the last 20 years to identify the potential environmental effects associated with taking no action, as well as a reasonable range of alternatives to no action for implementing the proposed federal action. The alternatives addressed in this DEIS include a broad range of operations and actions that would meet the purpose, need, and objectives of the proposed federal action. The primary resources that could be affected by the proposed action include sediment resources, aquatic and terrestrial ecological resources, recreational resources, socioeconomic resources, hydropower resources, resources of importance to American Indian Tribes, and historic and cultural resources in the vicinity of the Glen and Grand Canyons. The DEIS has been developed in accordance with the National Environmental Policy Act of 1969, as amended (NEPA), and follows the implementing regulations developed by the President's Council on Environmental Quality in Title 40 *Code of Federal Regulations* (CFR) Parts 1500 to 1508 and DOI regulations

implementing NEPA in 43 CFR Part 46. Based on the impact analyses conducted, DOI has chosen Alternative D as the preferred alternative.

The review period for this DEIS will end 90 days after publication of the U.S. Environmental Protection Agency Notice of Availability in the *Federal Register*. During the 90-day comment period, comments will be accepted electronically through the NPS Planning, Environment, and Public Comment website (http://parkplanning.nps.gov/LTEMPEIS) and in hard copy delivered by the U.S. Postal Service or other mail delivery service. Written comments will also be accepted during public meetings on the DEIS. Comments will not be accepted by fax, by e-mail, or in any format other than those specified above. Bulk comments in any format (hard copy or electronic) submitted on behalf of others will also not be accepted.

For additional information, visit http://ltempeis.anl.gov or contact:

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ACRONYMS AND ABBREVIATIONS

ac	acre(s)
ac-ft	acre-foot (feet)
ACHP	Advisory Council on Historic Preservation
AML	abandoned mine land
AMSL	above mean sea level
AMWG	Adaptive Management Work Group
AOP	Annual Operation Plan for Colorado River Reservoirs
APE	Area of Potential Effect
Argonne	Argonne National Laboratory
ASMR	Age-Structured Mark Recapture Model
AZGFD	Arizona Game and Fish Department
AZ-SGCN	Arizona Species of Greatest Conservation Need
BA	Balancing Authority (in Chapter 3 only)
	Biological Assessment (in all other sections)
BGEPA	Bald and Golden Eagle Protection Act of 1940
BIA	Bureau of Indian Affairs
BO	Biological Opinion
C	Celsius
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CAEDYM	Computational Aquatic Ecosystem Dynamics Model
CCC	Civilian Conservation Corps
CEQ	Council on Environmental Quality
CFMP	*Comprehensive Fisheries Management Plan*
CFR	*Code of Federal Regulations*
cfs	cubic feet per second
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPUE	catch per unit effort
CRBC	Colorado River Board of California
CRCN	Colorado River Commission of Nevada
CRD	Colorado River Discovery
CREDA	Colorado River Energy Distributors Association
CRMP	Colorado River Management Plan
CRSP	Colorado River Storage Project
CRSPA	Colorado River Storage Project Act of 1956
CRSS	Colorado River Simulation System
CSU	Colorado Springs Utilities

DEIS	Draft Environmental Impact Statement
Deseret	Deseret Generation and Transmission Cooperative
DFC	desired future condition
DO	dissolved oxygen
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DPS	Distinct Population Segment
EA	Environmental Assessment
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
ELCOM	Estuary, Lake and Coastal Ocean Model
EMS	emergency medical services
E.O.	Executive Order
EPA	U.S. Environmental Protection Agency
EPT	Ephemeroptera, Plecoptera, and Trichoptera
ESA	Endangered Species Act of 1973, as amended
F	Fahrenheit
FCPP	Four Corners Power Plant
FES	Firm Electric Service
FONSI	Finding of No Significant Impact
FR	*Federal Register*
ft	foot (feet)
FWS	U.S. Fish and Wildlife Service
FY	fiscal year
GCDAMP	Glen Canyon Dam Adaptive Management Program
GCM	general circulation model
GCMRC	Grand Canyon Monitoring and Research Center
GCNP	Grand Canyon National Park
GCNRA	Glen Canyon National Recreation Area
GCPA	Grand Canyon Protection Act of 1992
GHG	greenhouse gas
GMP	General Management Plan
GW	gigawatt(s)
GWh	gigawatt-hour(s)
GWP	global warming potential
H_2S	hydrogen sulfide
HBC	humpback chub
HFC	hydrofluorocarbon
HFE	high-flow experiment
hr	hour(s)

HRR	Hualapai River Runners
in.	inch(es)
IPM	Integrated Pest Management
IRP	integrated resource plan
ISM	Indexed Sequential Method
kaf	thousand acre-feet
kWh	kilowatt-hour(s)
lb	pound(s)
LCRMSCP	Lower Colorado River Multi-Species Conservation Program
LMM	Lake Mead Model
LMNRA	Lake Mead National Recreation Area
LROC	Long-Range Operating Criteria
LTEMP	Long-Term Experimental and Management Plan
LTEP	Long Term Experimental Plan
LTF	long-term firm
maf	million acre-feet
MAMB	miscellaneous algae, macrophytes, and bryophytes
MBTA	Migratory Bird Treaty Act
MCL	maximum contaminant level
mi	mile(s)
MLFF	Modified Low Fluctuating Flow
MMt	million metric tons
MOA	Memorandum of Agreement
MT	metric ton(s)
MW	megawatt(s)
MWh	megawatt-hour(s)
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAU	Northern Arizona University
NC	no change
NEPA	National Environmental Policy Act of 1969, as amended
NERC	North American Electric Reliability Corporation
NEV	net economic use value
NGO	nongovernmental organization
NHPA	National Historic Preservation Act
NM	national monument
NO_2	nitrogen dioxide
NO_3	nitrate-nitrogen
NOI	Notice of Intent
NO_x	nitrogen oxides
NPS	National Park Service

NPV	net present value
NRHP	*National Register of Historic Places*
NTUA	Navajo Tribal Unit Authority
O&M	operation and maintenance
O_3	ozone
OPAC	Office of Planning and Compliance
OSMRE	Office of Surface Mining Reclamation and Enforcement
PA	Programmatic Agreement
Pb	lead
PEPC	Planning, Environment, and Public Comment
PFC	perfluorocarbon
P.L.	Public Law
PM	particulate matter
$PM_{2.5}$	particulate matter ≤2.5 μm in aerodynamic diameter
PM_{10}	particulate matter ≤10 μm in aerodynamic diameter
POM	particulate organic matter
PSAR	preventative search and rescue
PSD	Prevention of Significant Deterioration
RA	resource available
Reclamation	Bureau of Reclamation
RM	river mile
RMP	Resource Management Plan
ROD	Record of Decision
RSG	Reserve Sharing Group
SAAQS	State Ambient Air Quality Standards
SBM	Sand Budget Model
SCP	Salinity Control Project
SD	standard deviation
SDA	Structured Design Analysis
SE	standard error
Secretary, the	Secretary of the Interior
SF_6	sulfur hexaflouride
SHPO	State Historic Preservation Officer
SLCA/IP	Salt Lake City Area Integrated Projects
SO	Secretarial Order
SO_2	sulfur dioxide
SPC	Southern Paiute Consortium
SRP	Salt River Project
SRSG	Southwest Reserve Sharing Group
TCD	temperature control device
TCP	traditional cultural property

TDS	total dissolved solids
THPO	Tribal Historic Preservation Officer
TL	total length
TMF	trout management flow
Tri-State	Tri-State Generation and Transmission Association
TWG	Technical Working Group
UAMPS	Utah Associated Municipal Power Systems
UBWR	Utah Board of Water Resources
UCRC	Upper Colorado River Commission
UMPA	Utah Municipal Power Agency
USC	*United States Code*
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	volatile organic compound
WACM	Western Area Colorado-Missouri Region
WALC	Western Area Lower Colorado Region
WAUW	Western Area Upper Great Plains West Region
WECC	Western Electricity Coordinating Council
Western	Western Area Power Administration
YOY	young-of-year
yr	year(s)
ZHHPO	Zuni Heritage and Historic Preservation Office

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APPENDIX A:

ADAPTIVE MANAGEMENT WORKING GROUP DESIRED FUTURE CONDITIONS

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APPENDIX A:

ADAPTIVE MANAGEMENT WORKING GROUP DESIRED FUTURE CONDITIONS

The Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) Draft Environmental Impact Statement (DEIS) joint lead agencies have used the 2012 Glen Canyon Dam Adaptive Management Program (GCDAMP) Desired Future Conditions (DFCs) as a basis for the resource goals and objectives of the DEIS as presented in Section 1.4 of the DEIS. The resource goals and objectives are based on and consistent with the DFCs, but are more concise and direct relative to the LTEMP purpose and need of the proposed action. The following text is based on the document *Desired Future Conditions for the Colorado River Ecosystem in Relation to Glen Canyon Dam* (DFC Ad Hoc Committee 2012).

The DFCs were intended to be used within the GCDAMP to help guide the development of recommendations concerning management of Glen Canyon Dam operations and related activities and dam impacts on Grand Canyon National Park (GCNP) and Glen Canyon National Recreation Area (GCNRA). The DFCs focus on those conditions that can be accomplished through dam operations and also identify those conditions that might be achieved through non-operational measures.

The Secretary of the Interior (the Secretary) is authorized to consider and implement both operational and non-operational measures to address downstream effects of Glen Canyon Dam if those measures meet the Grand Canyon Protection Act's (GCPA's) goal of protecting, mitigating adverse impacts on, and improving the resources downstream of the dam. Section 1802 of the GCPA provides the following:

a. *In General*—The Secretary shall operate Glen Canyon Dam in accordance with the additional criteria and operating plans specified in Section 1804 and exercise other authorities under existing law in such a manner as to protect, mitigate adverse impacts on, and improve the values for which GCNP and GCNRA were established, including, but not limited to, natural and cultural resources and visitor use.

b. *Compliance with Existing Law*—The Secretary shall implement this section in a manner fully consistent with and subject to the Colorado River Compact, the Upper Colorado River Basin Compact, the Water Treaty of 1944 with Mexico, the decree of the Supreme Court in Arizona v. California, and the provisions of the Colorado River Storage Project Act of 1956 and the Colorado River Basin Project Act of 1968 that govern allocation, appropriation, development, and exportation of the waters of the Colorado River basin.

c. *Rule of Construction*—Nothing in this title alters the purposes for which the GCNP or the GCNRA were established or affects the authority and

> responsibility of the Secretary with respect to the management and administration of the GCNP and GCNRA, including natural and cultural resources and visitor use, under laws applicable to those areas, including, but not limited to, the Act of August 25, 1916 (39 Stat. 535), as amended and supplemented.

The Bureau of Reclamation (Reclamation) is charged with balancing a complex set of interests in operating the dam. Those interests include not only the endangered species below the dam, but also Tribes in the region, the seven Colorado River basin states, large municipalities that depend on water and power from Glen Canyon Dam, agricultural interests, GCNP, GCNRA, and national energy needs at a time when clean energy production is becoming increasingly important. The DFCs will assist the AMWG in providing recommendations to the Secretary of the Interior for future decision-making. The DFCs have evolved from discussions during the entire 16-year history of the AMWG, and were generated in the following form from the concerted work of the DFC Ad Hoc Group and the federal agency regional leadership during 2010 and 2011.

The vision and mission of the AMWG (adopted on July 21, 1999) was developed to guide adaptive management of Glen Canyon Dam, and helps explain how and why definition of desired conditions is important:

> *The Grand Canyon is a homeland for some, sacred to many, and a national treasure for all. In honor of past generations, and on behalf of those of the present and future, we envision an ecosystem where the resources and natural processes are in harmony under a stewardship worthy of the Grand Canyon.*
>
> *We advise the Secretary of the Interior on how best to protect, mitigate adverse impacts to, and improve the integrity of the Colorado River ecosystem affected by Glen Canyon Dam, including natural biological diversity (emphasizing native biodiversity), traditional cultural properties, spiritual values, and cultural, physical, and recreational resources through the operation of Glen Canyon Dam and other means.*
>
> *We do so in keeping with the federal trust responsibilities to Indian Tribes, in compliance with applicable federal, state, and Tribal laws, including the water delivery obligations of the Law of the River, and with due consideration to the economic value of power resources.*
>
> *This will be accomplished through our long-term partnership utilizing the best available scientific and other information through an adaptive ecosystem management process.*

The DFCs are intended to be statements of qualitative goals and objectives for the GCDAMP, realistic and achievable through the operation of Glen Canyon Dam and related activities, subject to the Law of the River and other laws and authorities and consistent with the GCPA. These DFCs may not be entirely or collectively achievable; there will be tradeoffs and

inherent limitations. This fact does not diminish their value. These DFCs of the affected resources have been identified by the stakeholders as appropriate goals for the AMP and are based on information available at this time. As new information develops, the DFCs may need further revision and refinement. Therefore, these DFCs are neither fixed nor final. This is intended to be a "living document" that reflects advances in learning and understanding. This is consistent with the process—and application—of adaptive management.

The Colorado River Ecosystem (CRE) is defined as the Colorado River mainstream corridor and interacting resources in associated riparian and terrace zones, located primarily from the fore bay of Glen Canyon Dam to the western boundary of GCNP. It includes the area where the dam operations impact physical, biological, recreational, cultural, and other resources. The scope of GCDAMP activities may include limited investigations into some tributaries (e.g., the Little Colorado and Paria Rivers).

The majority of the CRE exists within the boundaries of two national parks and proposed wilderness areas. Despite these protections, the CRE could be considered "a human-dominated ecosystem, one whose aesthetic appeal, goods and services, and spiritual services are widely used and appreciated and needed by a broad cross-section of society. Adaptive management of the CRE has been adopted to ensure the sustainability of the natural environment with the least impact on the goods and services the CRE provides to society. As such, and as information about the CRE has increased, its stewardship is moving toward an ecosystem perspective, fully recognizing the role of humans, and this approach is reflected in the structure of this document." (DFC Ad Hoc Committee 2012)

The DFCs are divided into four categories, including the CRE, Power, Cultural Resources, and Recreation. There are many direct, indirect, short-term, and long- term ecosystem responses to dam existence and operations. The DFCs are directly or indirectly linked to each other on short- and long-term bases through dam-related flows, sediment retention and distribution, hydropower production, fish and wildlife populations, recreation, and visitor experience. The following sections are excerpted from the 2012 DFC document.

A.1 DESIRED FUTURE CONDITIONS: COLORADO RIVER ECOSYSTEM

A.1.1 DFC Description

The term "ecosystem" refers to the combined physical and biological components of an environment. An ecosystem is generally an area within the natural environment in which physical (abiotic) factors and processes of the environment, such as geology, climate, and soil development, function along with interdependent (biotic) organisms, such as plants and animals, in the same habitat and create a dynamic and interconnected system. Ecosystems usually encompass a number of food webs. An ecosystem is a functional unit within a given area consisting of living things and the nonliving chemical and physical factors of their environment, linked together through nutrient cycle and energy flow.

A.1.2 DFC Background and Legislation

Glen Canyon Dam has had a profound impact on the aquatic and terrestrial domains of the CRE from lower Lake Powell downstream to Lake Mead. The CRE DFCs are designed to be consistent with the GCPA, Law of the River, and other appropriate laws and mandates. The CRE DFCs apply the requirements of the GCPA, and are the goals that AMWG members will consider when making recommendations to the Secretary.

A.1.3 Why the Colorado River Ecosystem DFCs Are Important

These CRE DFCs address the natural resource values for which the GCNP and the GCNRA were established. The DFCs aim to comply with the GCPA and describe the individual resource objectives sought with the realization that they may not be achievable in the process of finding the most desirable mix of resources in the CRE and the natural habitats, and natural ecosystem processes. Native and nonnative species are to be managed in accord with federal regulations, policies, and guidelines. The CRE described herein includes most of the native natural resources found in the Colorado River. Those resources are managed, consistent with the Law of the River, described in part in Section 1802(b) of the GCPA, under the National Park Service (NPS) Organic Act, the Redwoods Amendment, NPS 2006 Management Policies, the Wilderness Act, the Antiquities Act, the Endangered Species Act (ESA), the GCPA, the Fish and Wildlife Coordination Act, and other federal legislation. The health of the river ecosystem and the protection of the resource values of GCNP and GCNRA are important to the nation, many Native American Tribes, the economy of the Southwest, and the millions of visitors to the parks and the region.

The CRE DFCs will provide a foundation for and help define the components of the Core Monitoring Program under development by the Grand Canyon Monitoring and Research Center (GCMRC). The Core Monitoring Program ultimately will be essential to quantifying, measuring, and reporting the status of the natural resources, allowing the Secretary and the GCDAMP to track progress toward desired outcomes. DFCs will also provide foundation support in the development of other planning and management assignments associated with the GCDAMP.

A.1.4 Colorado River Ecosystem DFCs

A.1.4.1 Sediment-Related Resources DFCs

High-elevation open riparian sediment deposits along the Colorado River in sufficient volume, area, and distribution so as to provide habitat to sustain native biota and desired ecosystem processes include the following:

- Nearshore habitats for native fish,
- Marsh and riparian habitat for fish (food chain maintenance),

- Cultural resource preservation, and

- Maintenance of camping beaches.

A.1.4.2 Water Quality DFCs

Water quality with regard to dissolved oxygen, nutrient concentrations and cycling, turbidity, temperature, and so forth, is sufficient to support natural ecosystem functions, visitor safety, and visitor experience to the extent feasible and consistent with the life history requirements of focal aquatic species including the following:

- Ecosystem-sustaining nutrient distribution, flux, and cycling.

- Hydro-physical conditions and characteristics of the CRE necessary to sustain aquatic biota.

- Acceptable water quality for human health and visitor experience.

A.1.4.3 Colorado River Ecosystem Aquatic Resource DFCs

Aquatic Food Base DFCs

- The aquatic food base will sustainably support viable populations of desired species at all trophic levels.

- Assure that an adequate, diverse, productive aquatic food base exists for fish and other aquatic and terrestrial species that depend on those food resources.

Native Species DFCs

- Native fish species and their habitats (including critical habitats) sustainably maintained throughout in each species' natural ranges in the CRE.

- Healthy, self-sustaining populations of other remaining native fish with appropriate distribution (flannelmouth sucker, bluehead sucker, speckled dace) so that listing under the ESA is not needed.

Humpback Chub DFCs

- Achieve humpback chub recovery in accord with the ESA and the humpback chub comprehensive management plan, and with the assistance of collaborators within and external to the GCDAMP.

- A self-sustaining humpback chub population in its natural range in the CRE.

- An ecologically appropriate habitat for the humpback chub in the mainstem.

- Spawning habitat for humpback chub in the Lower Little Colorado.

- Establish additional humpback chub spawning habitat and spawning aggregations within the CRE, where feasible.

- Adequate survival of young-of-year or juvenile humpback chub that enter the mainstem to maintain reproductive potential of the population and achieve population sizes consistent with recovery goals.

Rainbow Trout DFCs

A high-quality trout fishery in GCNRA, as further described in the Recreation DFC that does not adversely affect the native aquatic community in GCNP:

- Minimize emigration of nonnative fish from the Lees Ferry reach in GCNRA to downstream locations.

- Minimize emigration of nonnative warm water fish to the mainstem Colorado River.

Extirpated Species DFC

Re-establish fishes extirpated from Grand Canyon, where feasible and consistent with recovery goals for humpback chub and the recovery goals of those extirpated fishes. See the linkages that follow for further information.

Nonfish Biotic Communities DFCs

Native non-fish aquatic biota and their habitats are sustainably maintained with ecologically appropriate distributions:

- Populations of native non-fish species (invertebrates and vertebrates, including northern leopard frog).

- GCDAMP support, actions, and funding are limited to incorporation of dam operations that are conducive to restoration of extirpated species.

- Minimize the abundance and distribution of nonnative species in the CRE.

- Sustainable dam-influenced aquatic, wetland, and springs plant communities and associated biological processes, including those supporting threatened and endangered species and their habitats.

A.1.4.4 Colorado River Ecosystem Riparian Resource DFCs

Native riparian systems in various stages of maturity are diverse, healthy, productive, self- sustaining, and ecologically appropriate, as indicated by the following:

- Native, self-sustaining riverine wetlands, and riparian vegetation and habitat, with appropriate mixture of age classes.

- Healthy, self-sustaining populations of native riparian fauna (both resident and migratory).

- Habitat for sensitive species within the CRE.

- Encourage the resolution of the taxonomic status of the Kanab ambersnail (e.g., completely describe the taxa and subspecies).

- Habitat for neotropical migratory birds, waterfowl, and other appropriate native bird species.

- Ecological functions of tributary mouths and riverside springs, including habitat for native species.

A.1.5 Colorado River Ecosystem DFCs Additional Information

A.1.5.1 Colorado River Ecosystem Linkages

Physical characteristics, including climate, site-specific geomorphology, dam-related discharge and flow, and tributary flows, generally predominate over biological processes. The aquatic and riparian components of the CRE are linked to fluvial habitat distribution and the collection, composition, structure, and population dynamics of living organisms. “Lateral” bio-ecological processes, such as competition, and “top-down” processes, such as predation, parasitism, and decomposition, can influence some elements of these linkages over time.

In addition to physical and biological interactions, the CRE is linked to Native American cultural resources such as archeological and cultural properties. Recreation benefits have resulted from both dam operations and healthy ecosystem conditions.

A.1.5.2 Colorado River Ecosystem Metrics

These DFCs are intended to guide the gathering and analysis of data pertinent to the CRE in GCNP and GCNRA. The CRE DFCs and the related documents will be used to provide direction toward development of the core monitoring program under development by the GCMRC. Through diligent and consistent monitoring, GCMRC may inform the Secretary as to whether as to what degree these DFCs are being achieved. Such monitoring may include the following:

- Percentage of critical habitat lost or gained;
- Condition of species variability (native population, abundance, distribution);
- Carrying capacity thresholds; and
- Population estimates.

A.2 POWER DESIRED FUTURE CONDITIONS

A.2.1 Power DFC Description

Hydroelectric power is generated by the release of stored water through Glen Canyon Dam. The dam's eight generators can produce up to 1,320 megawatts: enough electricity to serve 1.3 million residential customers. The integration of hydropower and other resources provides an efficient and flexible operation of this region's electrical resources. Releases of water from Glen Canyon Dam are adjusted in part to follow customer loads.

A.2.2 Power DFC Background and Legislation

Glen Canyon Dam is an important component of the Colorado River Storage Project (CRSP), which stores water, the Western United States' most vital resource, during wet years for use in times of drought, much like a bank account. As part of the nation's critical infrastructure, the water stored by Glen Canyon Dam is vital to the growing water needs of the Western United States. More than 30 million people depend on the water stored behind the dam for drinking, irrigation, and other municipal and industrial uses.

Revenues from the sale of hydropower generation from Glen Canyon Dam and other CRSP facilities are used to repay reimbursable costs and interest on the interest-bearing costs of

the federal investment in the CRSP, and are also used to repay over 85% of the irrigation costs of CRSP federal irrigation projects. These revenues are also used, instead of annual federal appropriations, to pay for the yearly operation, maintenance, and replacement costs of Glen Canyon Dam and other CRSP facilities.

The Reclamation Project Act of 1939 provides that hydropower produced by Glen Canyon Dam and other CRSP facilities be offered for sale first to municipalities, other public corporations and cooperatives, and other nonprofit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936. Customers include rural electric associations, federal facilities, state agencies, universities, and 57 Native American entities.

A.2.3 Why the Power DFC Is Important

- Hydropower is an authorized purpose of Glen Canyon Dam.
- Hydropower produced by Glen Canyon Dam is under long-term contract to not-for-profit entities and 57 Tribal entities.
- Power revenues are a significant funding source (providing an estimated $20 million/year) for the GCDAMP, Upper Colorado River and San Juan River Endangered Fish Recovery Programs, and the Colorado River Salinity Control Program.
- Hydropower is a renewable resource that is an important component in the Western Electricity Coordinating Council (WECC). Hydropower production is a national objective to help meet the nation's needs for reliable, affordable, and environmentally sustainable electricity.
- Glen Canyon generation has the ability to "ramp up" to meet system reliability obligations that are important when regional power shortages or power/transmission system disruptions occur.

A.2.4 Power DFCs

- Glen Canyon Dam capacity and energy generation is maintained and increased, so as to produce the greatest practicable amount of power and energy, consistent with the other DFCs.
- Ensure continued delivery of Glen Canyon Dam hydropower to the existing customers who have entered into long-term firm power contracts with the Western Area Power Association (WAPA).
- Ensure sufficient and efficient production of Glen Canyon Dam hydropower in order to provide the revenues to support the CRSP facilities and purposes.

- Maintain the operational flexibility (including but not limited to load following capability, ramp rates, and emergency operations allowances) that enable Reclamation and WAPA to meet the system operating and other regulatory requirements of WECC, North American Electric Reliability Corporation, and the Federal Energy Regulatory Commission, as well as emergency operating criteria for safety and human health situations.

- Maximize the environmental benefits of hydropower generation at Glen Canyon Dam.

- Minimize carbon emissions through hydropower generation at Glen Canyon Dam.

A.2.5 Power DFC Additional Information

A.2.5.1 Power Linkages

- Operational changes, including experimentation and management actions, which include changes to volumes; release limitations (minimum and maximum); ramp rates; and hourly, daily, monthly, and seasonal variability, all potentially impact this resource.

- The above-identified parameters could have impacts to the CRE resources as well as recreational and cultural resources, depending on the operational design.

A.2.5.2 Power Metrics

- Valuation (measurement characterization for an average year):
  - Electric generating capacity (MW);
  - Electric generating energy (MWH);
  - Load following capability (MW/hr);
  - Ramp rate capability (MW/hr);
  - CO_2, SO_2, and NO_X emissions (tons);
  - Power plant water consumption (acre-feet); and
  - Costs ($ millions).

A.3 CULTURAL RESOURCES DESIRED FUTURE CONDITIONS

A.3.1 Cultural Resources DFC Description

Preservation and appropriate management of cultural resources are vital at many levels. At the most basic level, cultural resources are our history; they define and reaffirm us, and provide a tangible record of who we are and where we have been. Their importance may be to the nation as a whole, to a local community, or to a group traditionally associated with the area. This includes resources within the Grand Canyon region, such as resources along the river corridor in Glen and Grand Canyons.

A.3.2 DFC Background and Legislation

Recognition of the importance of cultural resources is codified through numerous statutes and executive orders that mandate protection, consideration, and preservation of cultural resources. Because of the structure of federal law, particularly the National Historic Preservation Act of 1966 (NHPA), cultural resources will be considered below in two broad groupings: (1) those that fall within the purview of the NHPA (*National Register of Historic Places* [NRHP] eligible historic properties); and (2) all other resources of traditional cultural importance. This is done for purely pragmatic reasons; there are specific legal requirements for cultural resources that fall under the NHPA umbrella that do not apply to the second class of cultural resources. The Cultural Resources DFCs apply the requirements of the Grand Canyon Projection Act to "protect, mitigate adverse impacts to, and improve the values for which GCNP and Grand Canyon National Recreation Area (GCNRA) were established," including cultural resources, and are the goals that AMWG members will consider when making recommendations to the Secretary.

A.3.3 Why the Cultural Resources DFCs Are Important

The cultural resources of the Grand Canyon provide a record of human history in the area. They also encompass the traditional cultural use and significance of the Grand Canyon. Maintaining these resources is important to the nation as a whole so we can better understand the long history of the people who came before us and to the traditional groups that consider this area to have traditional significance to them. A number of Native American groups believe the Grand Canyon is their place of origin. These DFCs will help to maintain compliance with relevant cultural resource laws, maintain traditional cultural linkage with the Grand Canyon, and maintain traditional cultural access to and use of resources in the Grand Canyon in accordance with applicable law.

A.3.4 NRHP Eligible (or Potentially Eligible) Historic Properties DFCs

These resources are historic properties that are eligible or potentially eligible for inclusion in the NRHP. The criteria for inclusion are defined in the NHPA, and are described in more detail in *National Register* Bulletins 15 and 38. Resources in the Grand Canyon include the following:

- Prehistoric archaeological sites (including trails, petroglyphs, and pictographs);
- Historic sites (boats, mining, European exploration, river running); and
- Traditional Cultural Properties—for the Grand Canyon, these include:
  - Archaeological sites,
  - Traditional resource use areas,
  - Sacred sites,
  - Landmarks/geographic features,
  - Springs,
  - The Colorado River,
  - Ethno-ecological resources,
  - Significant event locations, and
  - The Grand Canyon itself.

A.3.4.1 Prehistoric Archaeological Sites and Historic Sites

To the extent feasible, maintain significance and integrity through preservation in place:

- If preservation in place is not feasible or reasonable, then implementation of appropriate preservation treatments will be implemented to ensure reduction or elimination of threats consistent with NPS management policies, Tribal traditional values, and historic preservation law.
- Public access to historic properties on Tribal lands is managed by the respective Tribes. On lands administered by the NPS, access to some sites for users of the river corridor is maintained as long as integrity of the sites is not compromised.

A.3.4.2 Traditional Cultural Properties (TCPs)

- Attributes are maintained; for example, NRHP eligibility is not compromised. These attributes will be specific to traditionally associated peoples and will need to be identified by the federal agencies in consultation with those groups. Attributes may include aspects of location or physical integrity, and may be

intangible elements that link the resource to ongoing traditional cultural practices.

- The ability of traditionally associated people to maintain access to and use of the resources is preserved, in accordance with applicable law.

- Culturally appropriate conditions of resources are maintained based on traditional ecological knowledge; integration of the desired condition is included in relevant monitoring and management programs.

- Maintain ongoing consultation with the groups for whom the resource has traditional value. Because the desired condition of a TCP needs to be determined by the group for whom it has the traditional value, ongoing consultation is necessary to assess the condition of the resource.

- Mitigate impacts that affect the integrity of the TCPs. How and if effects can be mitigated will need to be determined in conjunction with the traditionally associated peoples for whom the resource holds value.

A.3.5 NRHP Eligible (or Potentially Eligible) Historic Properties DFC Additional Information

A.3.5.1 NRHP Eligible (or Potentially Eligible) Historic Properties Linkages

The goals for the following all have the potential to directly or indirectly affect the condition of the NRHP eligible properties (including some examples of effects):

- Flow
  - Direct inundation
  - Levels of sediment deposition
  - Fluctuation frequency and range

- Sediment
  - Distribution (laterally and vertically)

- Vegetation
  - Species composition
  - Density

- Recreation
  - Camping locations
  - Recreational visitation
  - Trailing

In addition, management and research actions have the potential to directly or indirectly impact these resources.

A.3.5.2 NRHP Eligible (or Potentially Eligible) Historic Properties Metrics

- Erosion (or deposition) rates of substrates in which the sites are contained, and
- Impacts at sites that will affect eligibility.

A.3.6 Resources of Traditional Cultural Significance but Not NRHP Eligible

These are resources of cultural significance to traditional peoples, often Native American Tribes, that do not meet some aspect for eligibility for inclusion in the NRHP. A common reason that a resource does not meet NRHP eligibility requirements is that the resource lacks a clearly defined boundary or does not remain in a fixed location.

Resources that have the potential to be considered of traditional cultural significance in the Grand Canyon include the following:

- Animal resources,
- Geologic materials,
- Landscapes,
- Plant resources,
- Soundscapes,
- Viewscapes, and
- Water.

A.3.7 Resources of Traditional Cultural Significance DFCs

- Maintain the ability of traditionally associated peoples to access and use the resource in accordance with applicable law.
- Maintain culturally appropriate resource conditions based on traditional ecological knowledge and integrate this desired condition into monitoring and management programs.

- Maintain effective consultation with the groups for whom the resource has traditional cultural significance.

A.3.8 Resources of Traditional Cultural Significance Linkages

The goals for the following resources all directly or indirectly affect the condition of resources with traditional cultural significance:

- Flow,
- Sediment,
- Vegetation, and
- Recreation.

In addition, management and research actions have the potential to directly impact these resources.

A.3.9 Resources of Traditional Cultural Significance Metrics

Because culture defines the roles resources play in that culture, only members of that culture can assess the status or health of the resources. Therefore, measures for resource status or health and appropriate management will need to be determined individually by federal agencies in consultation with the traditionally associated peoples.

A.4 RECREATION DESIRED FUTURE CONDITIONS

A.4.1 Recreation DFC Description

The Recreation DFCs are meant to describe goals and objectives for human use of the CRE through GCNRA and the GCNP. They are intended to include not only traditional recreational activities such as whitewater rafting, camping, and fishing, but also such things as educational activities, spiritual engagement, and other appropriate activities and values. Grand Canyon and Glen Canyon offer many ways for people to experience, appreciate, and learn from them, even to those who never visit in person.

A.4.2 DFC Background and Legislation

Recreational use on the Colorado River began before there were any dams there, although its exact beginnings are unknown. Recreational and other activities and values in the Grand

Canyon and Glen Canyon have increased greatly since the construction of Glen Canyon Dam. The Recreation DFC applies the requirements of the GCPA to "protect, mitigate adverse impacts to, and improve the values for which GCNP and Grand Canyon National Recreation Area (GCNRA) were established," including visitor use/recreation, and the goals that AMWG members will consider when making recommendations to the Secretary.

A.4.3 Why the Recreation DFC Is Important

A.4.3.1 Grand Canyon National Park

The Grand Canyon is a unique place in the world. Its natural beauty, challenging environment, fascinating history, wilderness character, biodiversity, and sheer size offer a rare and valuable experience. The river corridor is at the heart of the Grand Canyon. The river corridor and the canyon are worthy of the greatest possible respect, treatment, and protection that can be afforded them. They must be kept vital and intact for future generations.

A.4.3.2 Glen Canyon National Recreation Area

The river corridor through the GCNRA provides opportunity to enjoy outdoor beauty with relatively easy access. It supports a valuable and high-quality trout fishery and offers excellent outdoor opportunities that are more accessible and less demanding than those of the Grand Canyon. It is deserving of respect and protection, while also providing the recreational opportunities for which it was established.

A.4.4 Recreation DFCs

The recreation DFCs have been divided in to four subcategories, each corresponding to a different section of the overall ecosystem or type of use.

A.4.4.1 River Recreation in Grand Canyon National Park

- Stewardship worthy of the Grand Canyon so that it can be passed from generation to generation in as natural a condition as possible.

- Provide maximum opportunity to experience the wilderness character of the canyon.

- Wilderness experiences and benefits available in the canyon include solitude, connection to nature, personal contemplation, joy, excitement, the natural sounds and quiet of the desert and river, and extended time periods in a unique environment outside the trappings of civilization.

- A river corridor landscape that matches natural conditions as closely as possible, including extensive beaches and abundant driftwood.

- A river corridor ecosystem that matches the natural conditions as closely as possible, including a biotic community dominated in most instances by native species.

- A dynamic river ecosystem characterized by ecological patterns and processes within their range of natural variability.

- Numerous campable sandbars distributed throughout the canyon.

- Recreational and wilderness experiences minimally affected by research and management activities.

- River flows that continue to be within a range that is reasonably safe, given the inherent risks involved in river recreation.

A.4.4.2 River Recreation in Glen Canyon National Recreation Area

- A quality recreation experience in Glen Canyon.

- Camping beaches suitable for recreational use.

- A setting and ecosystem that is as close to natural conditions as possible.

- Quality river running and angling recreation opportunities.

A.4.4.3 Blue Ribbon Trout Fishery in Glen Canyon National Recreation Area

- A high-quality sustainable recreational trout fishery in the river corridor in GCNRA, while minimizing emigration of nonnative fishes.

- Operate Glen Canyon Dam to achieve the greatest benefit to the trout fishery in GCNRA without causing excessive detriment to other resources.

A.4.4.4 River Corridor Stewardship

- Management of Glen Canyon Dam that is significantly driven by concern for the cultural values and ecological integrity of the river corridor through the Grand Canyon, with preservation and protection considered over the long term (multiple generations).

- A well-informed public, confident that high-quality scientific information is being used for best stewardship practices in the CRE.

A.4.5 Recreation DFC Additional Information

A.4.6 Recreation Linkages

- A natural, healthy, and protected ecosystem is a fundamentally key element to the recreation experience and wilderness character of the river corridor.

- Cultural resources within and near the river corridor:
  - The history of human habitation and use is an important part of the recreation experience. Individual sites are valuable whether they are open for visitation or designated off-limits.
  - Outfitters and guiding opportunities.
  - Local businesses.

A.4.7 Recreation Metrics

- Socioeconomic value of river recreation in GCNP.

- Socioeconomic value of the river corridor visitation and the Grand Canyon itself, as a whole.

- Economic effects of Grand Canyon tourism.

- Factors that make up the "wilderness character" of the river corridor.

- Number and size of campable beaches, safe flows for an optimal recreation experience.

- Socioeconomic value of river recreation in GCNRA.

- Socioeconomic value of the river corridor itself in GCNRA.

- Socioeconomic value of the fishery in GCNRA.

- Effect of the trout on the ecosystem in GCNP and the social and economic costs of mitigation.

- Characteristics most valued for the fishery; for example, the number, condition, and size of fish, and the ease or challenge of catching them.

- River running visitation metrics.
- Water quality variables that influence river recreation.
- Other river running safety issues.

A.5 REFERENCE

DFC Ad Hoc Committee, 2012, *Desired Future Conditions for the Colorado River Ecosystem in Relation to Glen Canyon Dam.* Available at http://www.usbr.gov/uc/rm/amp/amwg/pdfs/recltr_12April30.pdf. Accessed July 24, 2015.

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APPENDIX B:

PERFORMANCE METRICS USED TO EVALUATE ALTERNATIVES

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APPENDIX B:

PERFORMANCE METRICS USED TO EVALUATE ALTERNATIVES

This appendix describes a set of scientifically based performance metrics that were used by the Draft Environmental Impact Statement (DEIS) team to evaluate the impacts of alternatives on key resources in the Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) DEIS. The metrics were also used in a structured decision analysis process to objectively evaluate how alternatives perform relative to stakeholder values and in the face of critical uncertainties (Appendix C). The metrics were developed in a series of workshops among subject matter experts working on the LTEMP DEIS and were revised to incorporate feedback from Cooperating Agencies and other stakeholders. The performance metrics are intended to be objective measures of the performance of alternatives relative to goals for each affected resource evaluated in the DEIS.

Evaluation of these metrics represents only a component of the impact analysis performed for the DEIS. Other sources of both quantitative and qualitative information, in addition to the metrics described below, were used to assess the overall and relative performance of alternatives and their constituent elements.

The affected resources, associated goals, and performance metrics are described below.

B.1 AQUATIC ECOLOGY

B.1.1 Humpback Chub

Resource Goal: Meet humpback chub recovery goals including maintaining a self-sustaining population, spawning habitat and aggregations in its natural range in the Colorado River and its tributaries below the Glen Canyon Dam.

Performance Metrics

- **Number of Adult Humpback Chub.** This metric provides the estimated number of adult (200 mm+) humpback chub in the Little Colorado River population over the LTEMP period relative to the estimated adult population size in September 2011.

  The modeled number of humpback chub adults was calculated using a size-structured model that considers both the Little Colorado River and mainstem components of the Little Colorado River aggregation and used empirically derived estimates of growth and survival that differ for these two areas. In addition, the size structure of the modeled humpback chub population at the end of the 20-year traces was compared to evaluate possible differences

among alternatives. Growth and survival rates in the mainstem are based on inputs related to monthly water temperature for each of the Colorado River Simulation System (CRSS) traces (modeled using the Wright et al. 2008 model) and estimated annual trout abundance in the Little Colorado River reach occupied by humpback chub. Trout abundance was estimated using a trout emigration submodel that models the numbers of trout that leave the Glen Canyon reach (see description of trout fishery metrics below) and subsequently pass through Marble Canyon to the Little Colorado River reach.

- **Potential for Self-Sustaining Aggregations of Humpback Chub.** The potential for a self-sustaining aggregation of humpback chub to be supported at each of eight locations (RM30, 61 [Little Colorado River], 88, 108, 119, 125–128, 157, 213) was based on the output of a temperature suitability model that considers how well water temperatures under a particular alternative meet temperature requirements for important humpback chub life history aspects (spawning, egg incubation, and growth) at each aggregation area. It was assumed that mainstem spawning and egg incubation would be required to support self-sustaining aggregations at each location except for the aggregation at the confluence of the mainstem and the Little Colorado River (RM 61), where successful tributary spawning is known to occur. At each location, the potential for successful spawning, egg incubation, and rearing for juvenile humpback chub at various temperatures was calculated using triangular probability functions based on the reported ranges of suitable temperatures and the reported optimal temperatures for each life history need as presented in Valdez and Speas (2007). A temperature suitability score for each life history need was generated for each day of the modeled LTEMP period using modeled predictions of water temperatures for the aggregation location (modeled using the Wright et al. 2008 model).

  Annual mean temperature suitability scores for each life history need were calculated by averaging daily suitability scores that occur during the appropriate portion of each water year (i.e., April–June for spawning and egg incubation and year-round for growth). The annual potential for an aggregation to be self-sustaining at a particular location was calculated as the geometric mean of the annual temperature suitability scores for each life history event within a particular water year (a value between 0 and 1), and the overall means of the annual scores for each hydrologic trace was used to statistically compare the potential for self-sustaining aggregations to be supported by the various alternatives.

  For each hydrologic trace, the number of aggregation locations where the estimated annual temperature suitability score is $\geq$0.5 was determined for each alternative. The mean number of aggregations with temperature suitability values $\geq$0.5 for all traces was used as an indicator of overall humpback chub temperature suitability for each alternative.

B.1.2 Other Native Fish

Resource Goal: Maintain self-sustaining native fish species populations and their habitats in their natural ranges on the Colorado River and its tributaries.

Performance Metrics

- **Temperature Suitability for Warmwater Native Fish.** The potential for self-sustaining populations of native warmwater fish (other than humpback chub) to be supported at each of five locations (RM 15, 0, 61, 157, and 225) was based upon the output of a temperature suitability model (similar to the modeling approach for humpback chub aggregation evaluations) that evaluates the suitability of water temperatures under a particular long-term (e.g., 20 years) operational regime for meeting identified needs for major life history aspects (spawning, egg incubation, and growth) of a group of native fish species. The model generates individual temperature suitability scores for four species of native fish (flannelmouth sucker, bluehead sucker, razorback sucker, and speckled dace) at each location. Modeled monthly temperatures at different locations under different alternatives (modeled using the Wright et al. 2008 model) were the primary input needed to generate the temperature suitability scores for this metric.

  The relative suitability of conditions under each alternative to support native fish was represented by the mean of the temperature suitability scores for these four species, calculated for each location and also by an overall metric for each alternative that combined the temperature suitability scores for the four species at all locations.

B.1.3 Trout Fishery

Resource Goal: Achieve a healthy high-quality recreational trout fishery in Glen Canyon National Recreation Area and reduce or eliminate downstream trout migration consistent with National Park Service fish management and ESA compliance.

Performance Metrics

- **Lees Ferry Trout Abundance Index.** For age 1+ fish.

- **Catch Rate Index (number/hr).** For age 2+ fish.

- **Emigration Estimate.** Number of age-0 trout moving into Marble Canyon from Glen Canyon.

- **Number of Trout >16 in. Total Length.** These metrics were estimated using a trout-humpback chub model developed specifically for the LTEMP DEIS by

Lew Coggins (U.S. Fish and Wildlife Service), Josh Korman (Ecometrics), and Charles Yackulic (Grand Canyon Monitoring and Research Center). The model uses inputs related to annual water volumes, water temperatures, and specifics of the release patterns (e.g., occurrence of high-flow experiments [HFEs], implementation of trout management flows, amount of daily flow fluctuation) to estimate recruitment and survival of trout within the Glen Canyon reach. Emigration of trout into Marble Canyon was based on statistical relationships to the abundance of trout in Glen Canyon. Size structure of trout within the Glen Canyon reach was modeled for age 1+ trout and the calculated number of trout that exceed 16 in. total length was calculated as an estimate of the quality of the fishery. Angling catch rate was calculated for age 2+ trout based on estimated vulnerability of different age classes.

B.1.4 Nonnative Aquatic Species

Resource Goal: Minimize or reduce presence and expansion of aquatic nonnative invasive species.

Performance Metrics

- **Potential for Establishment and Expansion of Nonnative Fish.** The potential for self-sustaining populations of nonnative warmwater and coldwater fish to be supported at each of five locations (RM –15, 0, 61, 157, and 225) was based upon the output of a temperature suitability model that considers how well water temperatures under a particular alternative meet identified needs for required life history aspects (spawning, egg incubation, and growth) of warmwater and coldwater groups of nonnative fish species. The model generates individual temperature suitability scores for four species of warmwater nonnative fish (channel catfish, green sunfish, smallmouth bass, and striped bass) and two species of coldwater fish (brown trout and rainbow trout) at each location.

  The relative suitability of temperature conditions under each alternative to support the two groups of nonnative fish was represented by the mean of the temperature suitability scores for the species within the groups, calculated for each location and also by an overall metric composed of the temperature suitability scores for the groups at all locations. Modeled monthly temperatures at different locations under different alternatives (modeled using the Wright et al. 2008 model) were the primary input needed to generate the temperature suitability scores for this metric.

- **Potential for Establishment and Expansion of Aquatic Parasites.** A similar temperature suitability model was used to evaluate temperature suitability for the selected fish parasite species (Asian tapeworm, anchor worm, trout

nematode, and whirling disease) based on the suitability of specific temperatures to meet the requirements for host species activity and the development of infestations at each of five locations (RM 15, 0, 61, 157, and 225). As with the nonnative fish modeling, temperature suitability for the parasite species under each alternative was evaluated for the five identified locations using modeled water temperature regimes.

The relative suitability of temperature conditions under each alternative to support the parasite species was represented by the mean of the temperature suitability scores for the species group, calculated for each location and also by an overall metric composed of the temperature suitability scores for the group at all locations.

B.2 ARCHAEOLOGICAL AND CULTURAL RESOURCES

Resource Goal: Maintain the integrity of potentially affected *National Register of Historic Places* eligible or listed historic properties in place, where possible, with preservation methods employed on a site specific basis.

Performance Metrics

- **Wind Transport of Sediment Index.** This metric evaluated the availability of fine sediment for wind transport and potential deposition on historic properties at higher elevations (i.e., those properties located at stages above 45,000 cfs). Deposited sediment would serve to protect those resources from erosion. Optimal conditions for wind transport of sediment occur when (1) there is deposition of fine sediment by flows above the stage of normal operations, which represents the availability of sand at higher elevations and (2) there are low flows which expose more sand during the windy season, which would make more dry sand available for redistribution by the wind. This criterion accounts for the two processes using the equation:

$$Wind\ Transport\ Index = FF \times SLI$$

  where *FF* is the flow factor and *SLI* is the Sand Load Index produced by the Sand Budget Model.

  The flow factor represents the relative amount of exposure of sand deposits on a 0–1 scale that occurs for each day of the windy period (March–June). The daily flow factor was calculated as follows:

  FF = 1 for maximum daily flows less than or equal to 8,000 cfs, indicating maximum exposure of sand to wind transport;

FF = 0 for maximum daily flows greater than 31,500 cfs, indicating minimum exposure of sand to wind transport;

FF = 1.34 – (0.00004255×maximum daily flow), for flows between 8,000 and 31,500 cfs. This equation represents the linear decrease in flow factor from 1 at flows of 8,000 cfs to 0 for flows of 31,500 cfs.

The yearly flow factor was calculated by averaging the daily flow factors for the March–June period.

The *SLI* is the ratio of the cumulative sand load transported by high flows (i.e., flows >31,500 cfs) to total cumulative sand load transported by all flows for the alternative (range 0–1; higher index indicates greater likelihood of sediment deposition for wind transport).

Wind Transport Index is a value of 0–1, where a value of 1 has the most exposure to possible movement of sediment by the wind and is therefore the most desirable.

The mean annual Wind Transport Index value for the 20-year modeling period was used as the performance metric for each alternative.

The metric reflects when alternatives create the conditions for movement of sediment by wind, and therefore the potential for cultural resources to be protected, under each alternative. Although wind-blown sand deposited from sandbars created by dam operations may provide some benefit to archaeological site preservation in Grand Canyon, both the extent to which this occurs and the extent to which wind-deposited sand provides long-term preservation of archaeological sites are not known.

- **Flow Effects on Historic Properties in Glen Canyon Index.** Within Glen Canyon, there is concern that significant archeological sites could be negatively affected by flow levels of certain magnitudes.

  Ninemile Terrace, which is considered representative of other archeological sites situated on terraces within Glen Canyon, is potentially affected by higher flows, which inundate and could erode the slope of the terrace. The toe of the slope begins to be inundated at flows above 23,200 cfs. Consequently, the flow metric is calculated as the mean number of days/year the maximum daily flow is greater than 23,200 cfs.

- **Time Off River Index.** In the Grand Canyon, higher flow levels increase the potential for discretionary time off the river for visitors. There is concern that there may be a greater potential for archaeological sites to be visited and possibly affected, if visitors have more time to explore during the day because of increased travel rates at higher flows.

  The calculated index is a yearly value ranging from 0 to 1, where 1 indicates the most potential for discretionary time for visitors (and the highest potential for increased visitation of archaeological sites).

  Calculation of the index involved computing mean daily flow from the hourly flow data and using this value to calculate an off river flow factor. The off river flow factor (ORFF) was calculated as follows:

  – *ORFF* = 0 for mean daily flows less than or equal to 10,000 cfs, indicating the increased time visitors would spend on the river.

  – *ORFF* = 1 for mean daily flows greater than 31,500 cfs, indicating faster river travel times and potentially increased time spent off the river.

  – *ORFF* = (0.0000465× mean daily flow) – 0.465, for flows between 10,000 and 31,500 cfs. This equation represents the linear increase in the metric from 0 at flows of 10,000 cfs (lease negative effect) to 1 for flows of 31,500 cfs (greatest negative effect). Flows greater than 31,500 cfs are assigned flow metric values of 1 because of the increased potential for visitation of cultural sites that occur at elevations above normal operating flows.

  ORFF values for each season were summed and weighted to reflect the uneven use of the river throughout the year; 0.15 for winter months (Nov., Dec., Jan., Feb.), 0.31 for spring and fall months (Mar, Apr, Sep, Oct), and 0.54 for summer months (May, June, July, Aug.) and normalized by the number of days in each season as shown in the following equation.

$$TOR = \{0.15\left(\frac{\sum_{winter} ORFF}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{\frac{spring}{fall}} ORFF}{\sum Days_{\frac{spring}{fall}}}\right) + 0.54\left(\frac{\sum_{summer} ORFF}{\sum Days_{summer}}\right)\}$$

B.3 HYDROPOWER AND ENERGY

Resource Goal: Maintain or increase Glen Canyon Dam electric energy generation, load following capability and ramp rate capability, and minimize emissions, and costs to the greatest extent practicable consistent with improvement and long-term sustainability of downstream resources.

Performance Metrics

- **Combined Value of Hydropower ($).** This composite performance metric combined (1) the value of energy production, (2) the value of capacity, and (3) the value of operational flexibility, to provide a mean annual and total value estimate for Glen Canyon Dam hydropower under each of the alternatives. Performance metrics were developed that quantify the potential value of hydropower production under the limitations imposed by each alternative. These components were estimated using the GTMax-Lite power systems modeling and post-processing analysis, based on monthly and hourly release estimates for the LTEMP period:

  - **Value of Energy Production ($).** Results show mean annual and total quantities of energy production (MWh) and corresponding energy values ($), based on market price estimates ($/MWh) for the time periods generated. (Market price estimates were used to characterize the economic value of energy delivered to the grid.) This metric was obtained directly from GTMax-Lite hourly results and market price estimates.

  - **Value of Capacity ($).** Results show mean annual and total quantities of capacity available (MW) and corresponding capacity values ($), based on market price estimates ($/MW) for the relevant time periods. This metric, derived from GTMax-Lite results and market price estimates, represents an initial proxy for detailed capacity replacement analyses completed in other stages of the LTEMP analysis.

B.4 NATURAL PROCESSES

Resource Goal: Restore, to the extent practicable, ecological patterns and processes within their range of natural variability, including the natural abundance, diversity, and genetic and ecological integrity of the plant and animal species native to those ecosystems.

This resource goal incorporates many different physical and biological processes and ecological components of the river system. As a consequence, the goal does not lend itself to expression in a quantitative metric. Instead of a quantitative metric, alternatives were compared in the DEIS by qualitatively evaluating each alternative's performance relative to this goal considering impacts on various natural processes such as flow, sediment transport, water temperature, riparian vegetation, aquatic organisms, and terrestrial wildlife. This resource goal was not included in the structured decision analysis process.

B.5 RECREATIONAL EXPERIENCE

Resource Goal: Maintain and improve the quality of recreational experiences for the users of the Colorado River ecosystem. Recreation includes, but is not limited to, flatwater and whitewater boating, river corridor camping, and angling in Glen Canyon.

B.5.1 Grand Canyon Metrics

- **Camping Area Index.** It is important to develop and retain adequate medium (16–25 people) and large (>25 people) campsites to meet the visitor capacities established in the National Park Service (NPS) Colorado River Management Plan. The availability of camping area above the stage of normal operations (25,000 cfs) is considered as part of the index.

  Camping area and campsite size are a function of the amount of sand deposited and retained. The output from the Sand Load Index, which simulates sediment conditions between RM 0 and 61 provides a proxy for indicating whether the alternatives are likely to create the conditions conducive to creating/retaining adequate campsite area.

  Camping area and campsite size also are a function of flow level. Lower flows provide more camping area (i.e. there is more camping area at 8,000 cfs than at 25,000 cfs.

  The index was calculated as follows:

  $$Camping\ Area\ Index = SLI \times SWFF$$

  where *SLI* is the Sand Load Index and *SWFF* is the seasonally weighted flow factor.

  SLI is a ratio of the cumulative sand load transported by high flows (i.e., flows >31,500 cfs) to the total cumulative sand load transported by all flows for an alternative (range 0–1; higher index indicates greater likelihood of sediment deposition for campsites).

  SWFF consists of a seasonal weighting (*SW*) and a flow factor (*FF*) component.

  SW is as follows: 0.15 for winter months (Nov., Dec., Jan., Feb.); 0.31 for spring and fall months (March, April, Sept., Oct.), and 0.54 for summer months (May, June, July, Aug.).

  FF is as follows: 1 for daily maximum flows that are less than or equal to 8,000 cfs, 0 for daily maximum flows greater than 31,500 cfs, and 1.34 – (0.00004255 × maximum daily flow), for flows between 8,000 and 31,500 cfs. This equation represents the linear decrease in flow factor from 1 at flows of 8,000 cfs to 0 for flows of 31,500 cfs.

  The computation of the *SWFF* involved taking hourly flow data and computing daily maximum flows resulting in a time series of daily maximum flows. The next step was to assign these daily maximum flows into seasonal

compartments defined by *SW* for each year. *FF* values for each season were summed and normalized by the number of days in each season. The *SWFF* was then calculated as:

$$SWFF = 0.15\left(\frac{\sum_{winter} FF}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{spring/fall} FF}{\sum Days_{spring/fall}}\right) + 0.54\left(\frac{\sum_{summer} FF}{\sum Days_{summer}}\right)$$

SWFF is a yearly value ranging from 0 to 1, where 1 is better for camping.

The Camping Area Index (*CAI*) is a yearly value that ranges from 0 to 1, where 1 is better for camping area.

- **Visitor Experience Indices.** Visitor experience in Grand Canyon is related to navigational safety, the magnitude of within-day flow fluctuations, and the amount of time visitors can spend off river. These factors are affected by flow levels and fluctuation regimes. This relationship is based on studies documenting difficulties of motor rigs navigating rapids at lower flows, and with oar boats having their travel time and time for off-river activities affected at lower flows. The highest level of recreational impacts occurs when flows are low.

  – **Navigational Risk Index.** The Navigational Risk Index (*NRI*) was calculated in a similar fashion to the *SWFF* component of the camping area index. The *NRI* was a yearly value ranging from 0 to 1, where 1 indicates the least risk, and 0 the most.

  The seasonal weighting for *NRI* was the same as the *SW* component of the *CAI*, specifically: 0.15 for winter months (Nov., Dec., Jan., Feb.); 0.31 for spring and fall months (March, April, Sept., Oct.), and 0.54 for summer months (May, June, July, Aug.).

  The main parameter involved with the calculation of the *NRI* was the number of days where the daily minimum flow was less than 8,000 cfs.

  The computation of the *NRI* involved taking hourly flow data and computing daily minimum flow resulting in a time series of daily minimum flows. The next step was to assign these daily minimum flows into seasonal compartments defined by *SW* for each year. Then days where daily minimum flow was less than 8,000 cfs ($Days_{min}$) were identified for each season and the *NRI* was then calculated as:

$$NRI = 1 - \left\{0.15\left(\frac{\sum_{winter} Days_{min}}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{spring/fall} Days_{min}}{\sum Days_{spring/fall}}\right) + 0.54\left(\frac{\sum_{summer} Days_{min}}{\sum Days_{summer}}\right)\right\}$$

– **Fluctuation Index.** The Fluctuation Index (*FI*) examined the daily range in flow fluctuations relative to a defined threshold, and is a yearly value ranging from 0 to 1, where 1 indicated a desirable recreational and wilderness experience.

The daily range was the difference between the daily maximum and daily minimum flows.

Daily flow fluctuations were described as whether they are "tolerable" for recreational river use (as identified by river guides) (Table B-1) in the pertinent study by Bishop et al. (1987).

We made two assumptions in using this table of fluctuation thresholds: (1) the river flow ranges shown in the left-hand column above were determined based on the mean daily flow and (2) that the maximum fluctuation (in italics) given in the range of tolerable fluctuations in the right-hand column serves as the daily range threshold ($DR_{threshold}$) condition, above which fluctuations become increasingly more unacceptable to river users. At daily fluctuation levels greater than 10,000 cfs, fluctuations are clearly noticeable and have strong adverse effects on river users.

Fluctuations that are less than or equal to the threshold fluctuation ranges shown in the table above were assigned a value of 1 indicating an optimal condition. As daily fluctuations increased above those thresholds, the Fluctuation Index (*FI*) decreased linearly until it reached 0 when fluctuations were at or above 10,000 cfs. The equations used to calculate

TABLE B-1 Tolerable Flow Fluctuations for Recreational River Use

River Flow (cfs)	"Tolerable Fluctuation" (cfs)
5,000–8,999	2,400–*3,400*
9,000–15,999	3,900–*4,800*
16,000–31,999	6,400–*7,200*
32,000 and up	7,200–*9,800*

the fluctuation index when daily fluctuations exceeded the threshold flows shown in the table above were as follows:

- For mean daily flows between 5,000 cfs and 8,999 cfs: (–0.00015 × daily fluctuation) + 1.5151)
- For mean daily flows between 9,000 cfs and 15,999 cfs: (–0.00019 × daily fluctuation) + 1.923)
- For mean daily flows between 16,000 cfs and 31,999 cfs: (–0.00036 × daily fluctuation) + 3.5714)
- For mean daily flows at or above 32,000 cfs: (–0.005 × daily fluctuation) + 50.000)

Calculation of the *FI* involved computing mean daily flow, minimum daily flow, maximum daily flow, and daily range from the hourly flow data.

The seasonal weighting for *FI* was the same as the *SW* component of the *CAI*, specifically: 0.15 for winter months (Nov., Dec., Jan., Feb.), 0.31 for spring and fall months (March, April, Sept. Oct.), and 0.54 for summer months (May, June, July, Aug.).

The daily flow values and daily ranges were defined by seasonal use. Then for each day, mean daily flow was examined to set the value of $DR_{threshold}$ (italicized flow values in the table). The *FI* then identified days that $DR_{threshold}$ was exceeded ($Days_{exceed}$) according to:

$$FI = \left\{0.15\left(\frac{\sum_{winter} Days_{exceed}}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{spring/fall} Days_{exceed}}{\sum Days_{spring/fall}}\right) + 0.54\left(\frac{\sum_{summer} Days_{exceed}}{\sum Days_{summer}}\right)\right\}$$

- **Time Off River Index.** The Time Off River Index examined the amount of time visitors were able to engage in onshore activities such as hiking or visiting attractions, and was a yearly value ranging from 0 to 1, where 1 indicated the most available time off river for visitors. Calculation of the Time Off River Index involved computing mean daily flow from the hourly flow data and using this value to calculate an off river flow factor (*ORFF*).

The *ORFF* was determined as follows: 1 for mean daily flows that are greater than 31,500 cfs, 0 for flows less than 10,000 cfs, and a linear

function for flows between 10,000 and 31,500 cfs ([0.0000465 × mean daily flow] – 0.465).

The seasonal weighting for *TOR* was the same as the *SW* component of the camping area index, specifically: 0.15 for winter months (Nov., Dec., Jan., Feb.), 0.31 for spring and fall months (March, April, Sept., Oct.), and 0.54 for summer months (May, June, July, Aug.).

ORFF values for each season were summed and normalized by the number of days in each season. The Time Off River Index was then calculated as:

$$0.15\left(\frac{\sum_{winter} ORFF}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{spring/fall} ORFF}{\sum Days_{spring/fall}}\right) + 0.54\left(\frac{\sum_{summer} ORFF}{\sum Days_{summer}}\right)$$

B.5.2 Glen Canyon Metrics

- **Glen Canyon Rafting Use Metric.** This metric represents the amount of recreational use lost in average number of visitors affected by HFEs. The metric is a single value for the 20-year analysis period (note that the range is not 0-1, but some value that is larger than 1 representing the number of lost visitor-days), where a higher value means greater adverse impact. The Glen Canyon rafting use metric uses an estimate of the average daily visitor (*ADV*) use for the months in which HFEs occur (March, April, May, Oct., Nov.). The number and duration of individual HFEs (T_{HFE}) are modeled as a part of the Sand Budget Model.

  The number of days lost for rafting because of an HFE (D_{lost}) is the duration of the HFE plus 2 days prior and 2 days post HFE ($D_{lost} = T_{HFE}$ + 2 days + 2 days) that represent the amount of time required to de-mobilize and re-mobilize rafting operations.

  The Glen Canyon rafting use metric is calculated as follows:

$$\sum_{20\ years} (ADV_{of\ HFE\ month}\left[\frac{visitors}{day}\right] \times D_{lost\ from\ HFE}[days])$$

  The units of the Glen Canyon rafting use metric are in number of visitor-rafting days lost.

- **Glen Canyon Inundation Metric.** The Glen Canyon inundation metric represents the percentage of time that flow is above critical flow elevations that affect recreational experiences. The Glen Canyon inundation metric is a

yearly value ranging from 0 to 1, where 1 indicates an optimal recreational experience.

The flow metric is calculated daily such that:

- Flow metric = 0 for daily maximum flows less than 3,000 cfs, indicating flows below 3,000 cfs are poor for boating and fishing.

- The flow metric between 3,000 cfs and 8,000 cfs was calculated using the linear function, (0.0002 × maximum daily flow) – 0.60, and flow metric values between 0 and 1. Fishing is better above 5,000 cfs, and flows for boating get progressively better up to 8,000 cfs.

- Flow metric = 1 for daily maximum flows between 8,000 and 20,000 cfs, indicating optimal conditions for boating, fishing, and shoreline access.
- The flow metric between 20,000 cfs and 31,500 cfs was calculated using the linear function, 2.739 – (0.00008695 × maximum daily flow), and flow metric values between 1 and 0. Flows above 20,000 cfs get progressively worse for boating, fishing, and shoreline access.

- Flow metric = 0 for daily maximum flows greater than 31,500 cfs. Flows above 31,500 cfs are poor for rafting, campable area, shoreline access, and fishing, and can adversely impact onshore recreational facilities.

B.6 RIPARIAN VEGETATION

Resource Goal: Maintain native vegetation and wildlife habitat, in various stages of maturity that is diverse, healthy, productive, self-sustaining, and ecologically appropriate.

Performance Metrics

- **Riparian Native States and Diversity Index.** The Riparian Native States and Diversity Index considers predicted changes over the 20-year LTEMP period in the relative cover of native vegetation community types and the relative diversity of community types. This metric was developed using a state-and-transition model developed by the Grand Canyon Monitoring and Research Center (GCMRC) (Ralston et al. 2014), which uses characteristics of annual operations to predict transitions from one vegetation type to another on different geomorphic features of the riparian zone. The model evaluates the effects of five operations (extended low flow, extended high flow, HFE, pre-dam flow, and default operation) on transitions among seven vegetation states (bare sand, common reed/cattail, horsetail/coyote willow, tamarisk, Baccharis/coyote willow, arrowweed, and mesquite). The model divides operations into growing (April–September) and non-growing seasons

(October–March) and incorporates upper and lower bar submodels, using stage elevation as a division.

Operational characteristics of each alternative were used as input to the riparian model. Output from the model was used to calculate the following component indices, which together were used to develop the overall Riparian Native States and Diversity Index:

- Relative change in cover of native vegetation community types (PM_1) (other than arrowweed) on sandbars and channel margins using the total % increase in native states predicted by an existing state and transition model for riparian vegetation communities.

$$PM_1 = \text{cover}_{\text{final}}/\text{cover}_{\text{initial}}$$

- Relative change in diversity of native vegetation community types (PM_2) (other than arrowweed) on sandbars and channel margins using the Shannon Weiner Index for richness/evenness using the results of the state and transition model.

$$PM_2 = \text{diversity}_{final}/\text{diversity}_{initial}$$

- Relative change in the ratio of native (other than arrowweed)/nonnative dominated vegetation community types (PM_3) on sandbars and channel margins using the ratio of native/nonnative communities predicted by the state and transition model.

$$PM_3 = \text{ratio}_{\text{final}}/\text{ratio}_{\text{initial}}$$

- Relative change in the arrowweed state (PM_4) on sandbars and channel margins using the total % decrease in arrowweed states predicted by the state and transition model.

$$PM_4 = \text{arrowweed}_{initial}/\text{arrowweed}_{final}$$

These individual components were combined as follows:

$$PM_n = (\Sigma w_i PM_i)$$

Where: PM_n = the performance score for Alternative n
PM_i = the score for Performance Metric i

Therefore:

$$PM_n = (PM_1 + PM_2 + PM_3 + PM_4)$$

B.7 SEDIMENT

Resource Goal: Increase and retain fine sediment volume, area, and distribution in the Glen, Marble and Grand Canyon reaches above the elevation of the average base flow for ecological, cultural, and recreational purposes.

Performance Metrics

Two metrics were used to reflect sandbar area in Marble and Grand Canyons above 8,000 and 25,000 cfs using existing sediment modeling tools:

- **Sand Load Index.** The Sand Load Index was defined as the cumulative sand load transported by high flows (flows > 31,500 cfs) divided by cumulative sand load for entire alternative (range 0–1; higher index means a greater likelihood of larger sandbars).

- **Sand Mass Balance Index.** The Sand Mass Balance Index was defined as the mean annual sand mass balance between RM 0 and RM 61 (sand mass value, thousand metric tons; higher index means larger mass of sand in the river on average).

B.8 TRIBAL RESOURCES

A large number of resource goals have been identified in discussions with stakeholder Tribes. Although all of these goals are important to the Tribes, not all of the resources were affected by the alternatives being considered in the LTEMP DEIS. In the discussion below, resource goals that are likely to differ across LTEMP alternatives (and so matter in the selection of a preferred alternative) are listed separately from resource goals that are not likely to differ across LTEMP alternatives.

For those resource goals that are likely to distinguish LTEMP alternatives, performance metrics are identified. Performance metrics are ways that the achievement of the resource goal might be measured; these were the metrics used to evaluate the alternatives in the DEIS. For some of these resource goals, specific metrics that were amendable to quantifying differences among alternatives were not identified. Instead, the Tribes developed narrative evaluations of alternatives that were included in the DEIS. Resource goals that would be evaluated in this way in the DEIS are identified below.

1. *Increase the health of the ecosystem in Grand, Marble, and Glen Canyons*. The ecosystems in the Canyons is more than the sum of its parts, and should be healthy as a whole. Historically, in the Glen Canyon Dam Adaptive Management Program (GCDAMP), the overall health of the ecosystem has been determined by evaluating the status of each part, but this reductionist approach might possibly miss some important aspects. There are a variety of indicators of ecosystem health, including, but not limited to: the health of the

river and its ability to sustain life; the color of the water; the absence of contaminants, pollutants, and disease in the water; the potability of the water; the quality of the water that reaches Lake Mead; and the viability and health of wildlife and plants in the Canyons. It is important to understand that for many Tribes the Colorado River is a sentient being and the spiritual center of the ecosystem, as it has the capability of giving and taking life; and is prone to anger if mistreated, the health of the ecosystem depends on the health of the River.

This resource goal requires consideration of traditional ecological knowledge (TEK) and an evaluation of alternatives applying TEK was included in the narrative DEIS analysis, but not the structured decision analysis.

2. *Protect and preserve sites of cultural importance*. There are specific sites within the Canyons that are important for cultural reasons and for preservation of Tribal/religious society/kiva group/clan history (e.g., shrines, sacred sites, ancient burial sites, springs, plant collection areas, mineral collection areas, offering places, and other elements). These sites can be threatened by erosion, loss of sediment inputs, and intrusive human use (especially, non-Tribal, outside visitors). Both flow and non-flow actions (for example, education, permitting, research/monitoring, and interpretation) may affect these sites.

    a. Performance metric: *Wind Transport of Sediment Index* (see Section B.2). This index focuses on the availability of fine sediment for wind transfer to protect *National Register of Historic Places* eligible or listed sites (see Archaeological and Cultural Resources).

        It should be noted that the sites and resources that are individually *National Register of Historic Places* eligible or listed do not represent a full set of Tribal concerns. Tribal input was necessary to identify impacts to other culturally important sites or resources, and to develop an appropriate measure of their protection and preservation.

    b. Performance Metric: *Flow Effects on Historic Properties in Glen Canyon Index* (see Section B.2). In Glen Canyon, flow levels could affect resources through inundation (see Archaeological and Cultural Resources).

    c. Performance Metric: *Time Off River Index* (see Section B.2). In Grand Canyon, flow levels could increase the potential for discretionary time off the river for visitors, which could in turn result in an increased potential for archaeological sites to be visited and possibly adversely affected (see Archaeological and Cultural Resources).

    d. Performance metric: *Riparian Diversity Index*. Using results from the "Riparian Vegetation" state and transition model, this metric employed the

Shannon-Weiner Index for richness and evenness to compare relative changes in diversity of six vegetation states found on sandbars and channel margins. The equation for the Shannon-Weiner Index is:

$$-\sum_{i=1}^{n}(p_i)(\log_2 p_i)$$

where p_i is the proportion of the *i*th state of the total bar-years. The Riparian Diversity Index was the proportion of model run diversity divided by the initial diversity found on sandbars and channel margins.

e. Performance metric: *Marsh Habitat.* Using results from the "Riparian Vegetation" state and transition model, this metric modeled change in marsh habitat. This metric compared the modeled change in marsh vegetation states (clonal wet marsh and perennial marsh) for each alternative.

f. Performance metric: *Native Fish*. Temperature suitability reflects protection and preservation of a resource important to Tribes (see Section B.1.2).

g. Assessment: *Access to Springs.* For most Tribes, all springs and seeps are sacred. Access to culturally important springs may be affected by flow levels. Springs were evaluated in the DEIS to determine if alternatives differ in terms of the ability of Tribes to access them under varying flow conditions.

3. *Preserve and enhance respect for life*. The Tribes see life itself as sacred and believe that human activities should protect and promote life, not destroy life. There are two aspects to this objective: first, minimize the taking of life; and second, encourage the expansion and proliferation of life forms. These are both complex concepts. The Tribes recognize that it is appropriate for humans to take other life in some circumstances, especially when it promotes other life (particularly our own consumption for survival), but this taking needs to be minimal and respectful because there are spiritual consequences associated with the taking of life. The promotion of life does not necessarily imply a return to historical or "natural" conditions—the Glen Canyon Dam has encouraged new life in Glen, Marble, and Grand Canyons, so a return to pre-Dam conditions is not necessarily implied by this objective, nor is there a strong distinction between native and nonnative species among all Tribes.

a. Performance metric: *The average number of years in which trout mechanical removal trips occur.* As a coarse measure of the impact of killing trout, this allows a distinction between alternatives that minimize mechanical removal. But the nature of the take, the purpose behind it, the

methods of take, the disposition of the trout taken, and the mindset of those killing the fish also affect the sacred treatment of living beings. This performance metric was calculated from the coupled trout-humpback chub models.

b. Performance metric: *The average number of years in which trout management flows occur*. Trout management flows, designed to reduce reproduction or survival of juvenile trout, are considered to be killing by some Tribes, and should be minimized. Alternatives that include trout management flows are likely to differ in how often the flows are triggered, so this performance metric might ultimately help to distinguish the alternatives. This performance metric was calculated from the coupled trout-humpback chub models.

4. *Preserve and enhance the sacred integrity of Grand, Marble, and Glen Canyons*. Grand, Marble, and Glen Canyons are sacred to many Tribes, and the preservation of their sacred integrity is important. The sanctity of the Canyons may be threatened by human impacts and behaviors, development, and the presence of artificial structures and activities. An important aspect of the sanctity is the intentionality of visitors: when outsiders enter the Canyons (on boat or hiking trips), the respect they show to the Canyons and Colorado River can affect the spiritual integrity. There are many consequences of the disturbance of this sanctity, including but not limited to: a reduction of the spiritual strength of plants gathered and used by the Navajo for medicinal and cultural purposes; an inability to retire Navajo sacred objects into the Colorado River, when they have become too old for continued use; weakening of the sacred role the Canyons play as a final resting place for Hopi; and an overall disruption of the state of mind and spirit of Zuni religious leaders and their experience of being within a very sacred place that embodies the Zuni emergence, migrations, creation of medicine bundles, and the communion with the spirits of Zuni ancestors.

a. Assessment: This resource goal, while of profound importance to the Tribes, is not thought to differ measurably across the alternatives under consideration in the LTEMP DEIS, because it is not driven by flow operations from the dam or currently envisioned attendant activities. Future science plans could include activities that are objectionable to the Tribes. Future science planning should include meaningful consultation with the Tribes. This goal was evaluated in the narrative DEIS analysis, but not the structured decision analysis.

5. *Maintain and enhance healthy stewardship opportunities*. Several of the Tribes have been given a sacred stewardship responsibility for the preservation and harmony of the world. For example, the Hopi have a covenant with *Ma'saw* to be stewards of the earth; other Tribes have similar stewardship ethics grounded in spiritual traditions. To maintain these

stewardship responsibilities, the Tribes need to be an active part of stewardship of the Canyons. This stewardship includes: ceremonial activities, whether performed in the Canyons or in the villages; participation in management of the Canyons, including water management, both through traditional practices and Western management activities; and education, to maintain cultural knowledge and connection with the Canyons. The Tribes note that the Federal Government also has stewardship responsibilities that arise out of federal legislation; because this federal involvement has sometimes taken stewardship responsibility from the Tribes, it is critical that the Federal Government be accountable for its stewardship. At times, the colonial presence of the Federal Government has made it more difficult for Tribes to carry out their stewardship responsibilities; the Tribes need the autonomy to undertake their responsibilities. Successful development of joint stewardship among the Tribes and Federal Government will require continued building of mutual respect and trust between those entities.

a. Assessment: Tribal stewardship opportunities are not tied to individual alternatives being considered in the LTEMP DEIS, but could be crafted to apply to any of the alternatives. Thus, this resource goal, while of critical importance to the Tribes individually, as well as to the ongoing relationship between the Tribes and the Federal Government, may not help distinguish among the alternatives. This goal was evaluated in the narrative DEIS analysis, but not the structured decision analysis.

6. *Maintain and enhance the Tribal connections to the Canyons*. The spiritual, historical and cultural connections that Tribes have to the Canyons require the protection of sacred sites and the integrity of the Canyons as a whole, but protection alone is not enough. The Tribes also need opportunities for access, education, and stewardship to keep their connections vibrant. Access can be undermined by physical barriers, by the requirement of permits from a colonial authority, and by the effects of human activity that decrease the power of those sites and the experience when at them (e.g., lack of privacy, disturbance of the soundscape and viewshed).

a. Assessment: Like the sacred integrity and stewardship resource goals, this resource goal is not thought to differ across the alternatives. The flow operations of Glen Canyon Dam are not likely to affect Tribal access, education, spiritual ceremonies, or other connections to the Canyons. This resource goal may be more appropriately addressed through government-to-government consultation in other forums. This goal was evaluated in the DEIS, but not the structured decision analysis.

7. *Increase economic opportunity*. The Canyons, the Colorado River, and the dam are sources of economic benefit for the Tribes in the area. The Canyons provides tourism and other opportunities that enhance the economic well-being of Tribes. (As an important note, tourism can also undermine the well-

being of Tribes in aspects other than economic; see the other Tribal resource goals.) Glen Canyon Dam provides affordable electricity for Tribal needs, as well as for development projects.

a. Assessment: *projected annual economic benefit for the Hualapai Tribe associated with river-running tourism.* During discussions with Tribal representatives, one particular economic concern was raised by Hualapai river runners, namely, the effect on tourism operations of extensive sediment deposition downstream of Diamond Creek. There is a narrative analysis of the effect of dam operations on Hualapai River running in the DEIS.

b. Assessment: Note that the economic benefit directly associated with hydroelectric power is measured through the hydroelectric performance metrics. A recreation economics model was used to determine the value of recreational use of Lake Powell, Lake Mead, and the Colorado River downstream of Glen Canyon Dam.

8. *Maintain Tribal water rights and supply*. Tribes in the area depend on the Colorado River for many of their water needs, so the preservation of established, traditional, and desired water rights, both now and into the future, is important. There are a number of claims to water rights that have been asserted by the Tribes, but for which there are not yet quantified rights through decree or negotiated settlement; these water rights are as important as the established water rights.

   a. Sidebar for LTEMP DEIS alternatives: based on its purpose and need, the LTEMP DEIS is not intended to include any alternatives that violate agreed-upon Tribal water rights.

   b. Performance metric: *Lake Powell water elevation.* This metric evaluates the frequency with which Lake Powell elevations drop below critical levels where existing or proposed intakes are.

9. *Process objectives*. There are several important process objectives—objectives that govern *how* the LTEMP decision is made, rather than what decision is made. The first of these is the genuine incorporation of Tribal input to the LTEMP process, as a reflection of Federal trust responsibilities. The second is the importance of incorporating learning, to improve management over time; in this spirit, an experimental approach that can result in adaptive management is favored.

   a. Assessment: (a) It is the intention of the Department of the Interior and the joint-lead Federal agencies to genuinely incorporate Tribal input into the LTEMP process, and this has been undertaken through face-to-face meetings with individual Tribes who have requested such meetings, as

well as regular conference calls with Tribal representatives. The Tribes are included in all Cooperating Agency and stakeholder meetings. Continued involvement of Tribes in the LTEMP process will occur. (b) The evaluation of experimental alternatives and the development of a long-term monitoring program associated with the LTEMP DEIS will occur in a later stage of analysis. The purpose and need for the DEIS includes the appropriate incorporation of learning. Thus, this resource goal is an important part of how the process was designed for LTEMP, but it does not help distinguish among the alternatives (because the alternatives do not differ in this regard).

B.9 WATER DELIVERY

Resource Goal: Ensure that water delivery continues in a manner that is fully consistent with and subject to the Colorado River Compact, the Upper Colorado River Basin Compact, the Water Treaty of 1944 with Mexico, the decree of the Supreme Court in *Arizona v. California*, and the provisions of the Colorado River Storage Project Act of 1956 and the Colorado River Basin Project Act of 1968 that govern allocation, appropriation, development, and exportation of the waters of the Colorado River Basin.

Calculated Metrics (not used in the structured decision analysis process)

- Frequency of deviation from the Alternative A (No Action Alternative) to Lake Powell Annual Operating Tier as specified by the 2007 Interim Guidelines (Reclamation 2007). The Operating Tier was predicted using the CRSS RiverWare model.

- Probability over time of Lake Powell being in each Operating Tier as specified in the 2007 Interim Guidelines (Reclamation 2007). The Operating Tier was predicted using the CRSS RiverWare model.

- Frequency and volume of exceptions to meeting the annual release target volumes specified by the 2007 Interim Guidelines (Reclamation 2007). The target and actual annual release volumes were predicted using the CRSS RiverWare model.

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APPENDIX C:

DECISION ANALYSIS TO SUPPORT DEVELOPMENT OF THE GLEN CANYON DAM LONG-TERM EXPERIMENTAL AND MANAGEMENT PLAN

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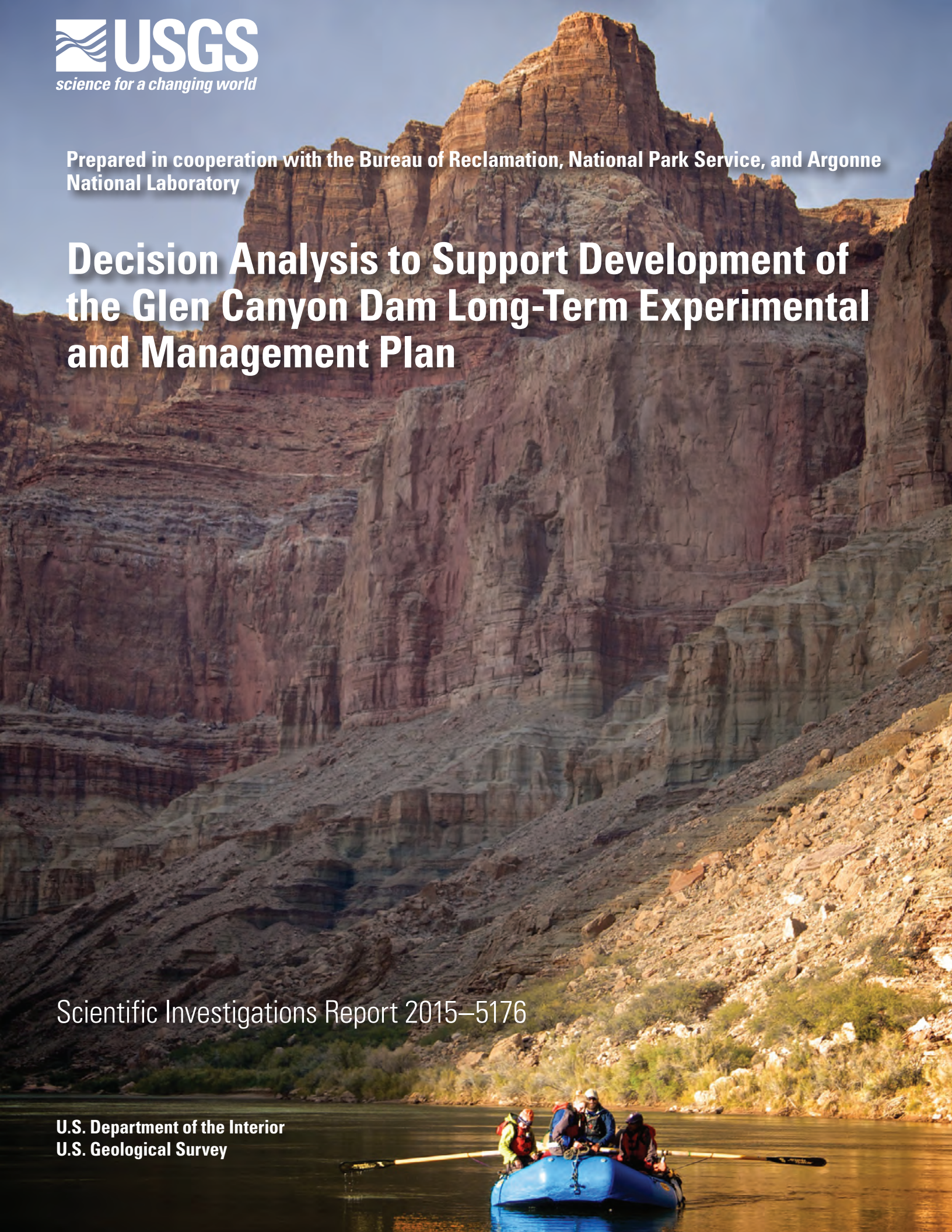
Prepared in cooperation with the Bureau of Reclamation, National Park Service, and Argonne National Laboratory

Decision Analysis to Support Development of the Glen Canyon Dam Long-Term Experimental and Management Plan

Scientific Investigations Report 2015–5176



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Covers. Front: An oar boat with university students from Northern Arizona University's Grand Canyon Semester passes river mile 61 near the confluence of the Little Colorado River and the Colorado River. This area is known for its biological and cultural significance, as the stronghold of the endangered humpback chub, and a place of importance in many tribal histories. Photograph taken by Amy S. Martin, Northern Arizona University, November 2014.

Back: Lower Beaver Falls lies approximately 4 miles up Havasu Creek from its confluence with the Colorado River at river mile 157 and is the site of ongoing endangered humpback chub translocations. Photograph taken by Amy S. Martin, National Park Service, October 2013.

Decision Analysis to Support Development of the Glen Canyon Dam Long-Term Experimental and Management Plan

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Conversion Factors

[Inch/Pound to International System of Units]

Multiply	By	To obtain
	Length	
inch (in.)	2.54	centimeter (cm)
inch (in.)	25.4	millimeter (mm)
foot (ft)	0.3048	meter (m)
mile (mi)	1.609	kilometer (km)
	Area	
acre	4,047	square meter (m^2)
acre	0.4047	hectare (ha)
	Volume	
acre-foot (acre-ft)	1,233	cubic meter (m^3)
acre-foot (acrea-ft)	0.001233	cubic hectometer (hm^3)
	Flow rate	
cubic foot per second (ft^3/s)	0.02832	cubic meter per second (m^3/s)

Vertical coordinate information is referenced to the North American Vertical Datum of 1988 (NAVD 88).

Horizontal coordinate information is referenced to the North American Datum of 1983 (NAD 83).

Altitude, as used in this report, refers to distance above the vertical datum.

Abbreviations

ADWR	Arizona Department of Water Resources
AGFD	Arizona Game and Fish Department
AMWG	Adaptive Management Working Group
Argonne	Argonne National Laboratory
Aurora	AURORAxmp
AZGFD	Arizona Game and Fish Department
BIA	Bureau of Indian Affairs
CMIP3	Coupled Model Intercomparison Project Phase 3
CREDA	Colorado River Energy Distributors Association
CRSP	Colorado River Storage Project
CRSS	Colorado River Simulation System
DEIS	Draft Environmental Impact Statement
DFC	desired future condition
DOI	U.S. Department of the Interior
DT	Decision-Theoretic school of adaptive management
EIS	Environmental Impact Statement
ESA	Endangered Species Act of 1973
EVPI	expected value of perfect information
EVXI	expected value of partial information
FWS	U.S. Fish and Wildlife Service
GCDAMP	Glen Canyon Dam Adaptive Management Program
GCMRC	Grand Canyon Monitoring and Research Center
GCPA	Grand Canyon Protection Act of 1992
GCRG	Grand Canyon River Guides
GTMax-Lite	Generation and Transmission Maximization model, spreadsheet version
HBC	humpback chub (*Gila cypha*)
HFE	high-flow experiment
IFFF	International Federation of Fly Fishers
LTEMP	Long-Term Experimental and Management Plan
MCDA	multicriteria decision analysis
MLFF	Modified Low Fluctuating Flow
NEPA	National Environmental Policy Act
NPCA	National Parks Conservation Association
NPS	National Park Service

NPV	net present value
O&M	operating and maintenance
RBT	rainbow trout (*Onchorhynchus mykiss*)
RE	Resilience-Experimentalist school of adaptive management
Reclamation	Bureau of Reclamation
RM	river mile
ROD	Record of Decision
SDA	structured decision analysis
SDM	structured decision making
SLI	sand load index
SMART	Simple Multi-attribute Rating Technique
SME	subject-matter expert
SRP	Salt River Project
TMF	trout management flow
UAMPS	Utah Associated Municipal Power Systems
WAPA	Western Area Power Administration
WTSI	wind transport of sediment index

Decision Analysis to Support Development of the Glen Canyon Dam Long-Term Experimental and Management Plan

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1 Abstract

The U.S. Geological Survey, in cooperation with the Bureau of Reclamation, National Park Service, and Argonne National Laboratory, completed a decision analysis to use in the evaluation of alternatives in the Environmental Impact Statement concerning the long-term management of water releases from Glen Canyon Dam and associated management activities. Two primary decision analysis methods, multicriteria decision analysis and the expected value of information, were used to evaluate the alternative strategies against the resource goals and to evaluate the influence of uncertainty.

A total of 18 performance metrics associated with 8 out of 12 resource goals (fundamental objectives) were developed by the Bureau of Reclamation and National Park Service in partnership with subject-matter teams composed of Federal, State, tribal, and private experts. A total of 19 long-term strategies associated with 7 alternatives were developed by the Bureau of Reclamation, National Park Service, Argonne National Laboratory, U.S. Geological Survey, and Cooperating Agencies. The 19 long-term strategies were evaluated against the 18 performance metrics using a series of coupled simulation models, taking into account the effects of several important sources of uncertainty. A total of 27 Federal, State, tribal, and nongovernmental agencies were invited by the Assistant Secretary of Interior to participate in a swing-weighting exercise to understand the range of perspectives about how to place relative value on the resource goals and performance metrics; 14 of the 27 chose to participate. The results of the swing-weighting exercise were combined with the evaluation of the alternatives to complete a multicriteria decision analysis. The effects of uncertainty on the ranking of long-term strategies were evaluated through calculation of the value of information.

The alternatives and their long-term strategies differed across performance metrics, producing unavoidable tradeoffs; thus, there was no long-term strategy that was dominated by another across all performance metrics. When the performance of each alternative was weighted across performance metrics, three alternatives (B, D, and G) were top-ranked depending on the set of weights proposed: Alternative B was favored by those stakeholders that placed a high value on hydropower; Alternative G was favored by those stakeholders that placed a high value on the restoration of natural processes, like beach-building and natural vegetation; and Alternative D was favored by the remaining stakeholders. Surprisingly, these rankings were not sensitive to the critical uncertainties that were evaluated; that is, the choice of a preferred long-term strategy was sensitive to the value-based judgment about how to place relative weight on the resource goals but was not sensitive to the uncertainties in the system dynamics that were evaluated in this analysis. The one area of uncertainty that did slightly affect the ranking of alternatives was the long-term pattern of hydrological input; because of this sensitivity, some attention to the possible effects of climate change is warranted.

The results of the decision analysis are meant to serve as only one of many sources of information that can be used to evaluate the alternatives proposed in the Environmental Impact Statement. These results only focus on those resource goals for which quantitative performance metrics could be formulated and evaluated; there are other important aspects of the resource goals that also need to be considered. Not all the stakeholders who were invited to participate in the decision

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analysis chose to do so; thus, the Bureau of Reclamation, National Park Service, and U.S. Department of Interior may want to consider other input.

2 Introduction

The Glen Canyon Dam is on the Colorado River in Arizona, United States, within the boundaries of Glen Canyon National Recreation Area and upstream from Grand Canyon National Park (fig. 1) and is managed by the Bureau of Reclamation (hereinafter referred to as "Reclamation"). The Glen Canyon Dam Adaptive Management Program (GCDAMP) was established in 1997 to provide research and monitoring of downstream resources to Reclamation and the U.S. Department of the Interior (DOI). The GCDAMP project area stretches along the Colorado River from the forebay of Glen Canyon Dam to the westernmost boundary of Grand Canyon National Park. Locations along the Colorado River are indexed by river miles (RM) with a reference point at Lees Ferry (RM 0). The Glen Canyon Dam is at RM -15.5 (15.5 mi upstream from Lees Ferry). Other important locations that are referenced in this report include the following: Paria River (RM 1.0), Little Colorado River (RM 61.4), and Bright Angel Creek (RM 87.8) (fig. 1). The reach from Glen Canyon Dam to Lees Ferry is known as Glen Canyon, the reach from Lees Ferry to the Little Colorado River is known as Marble Canyon, and Grand Canyon proper begins at the Little Colorado River.

In October 1996, the Secretary of the Interior signed a Record of Decision (ROD) documenting the selection of operating criteria for Glen Canyon Dam (Bureau of Reclamation, 1996) as analyzed in the 1995 Final Environmental Impact Statement (Bureau of Reclamation, 1995). The preferred alternative, known as Modified Low Fluctuating Flow (MLFF), has governed the operation of Glen Canyon Dam for the last 19 years (1996 to present) with important modifications described in "Final Environmental Impact Statement—Colorado River interim guidelines for lower basin shortages and the coordinated operations for Lake Powell and Lake Mead" (Bureau of Reclamation, 2007), "Environmental Assessment—Development and implementation of a protocol for high-flow experimental releases from Glen Canyon Dam" (Bureau of Reclamation, 2011a), "Environmental Assessment—Non-native fish control downstream from Glen Canyon Dam" (Bureau of Reclamation, 2011b), and many other regulatory documents. The Bureau of Reclamation (1996) also established the GCDAMP and Grand Canyon Monitoring and Research Center (GCMRC), which has led extensive monitoring and research aimed to improve the management of the Colorado River and its environs below Glen Canyon Dam.

In July 2011, the Secretary of the Interior announced the intent to develop a Long-Term Experimental and Management Plan (LTEMP) and Environmental Impact Statement (EIS) for Glen Canyon Dam as the first comprehensive review of dam operations in 15 years and as an opportunity to integrate the considerable scientific information collected since the GCDAMP began in 1996. The Bureau of Reclamation and National Park Service (NPS) are serving as joint-lead agencies for the EIS. The following agencies are participating as Cooperating Agencies in development of the EIS: Arizona Game and Fish Department (AGFD), Bureau of Indian Affairs (BIA), Colorado River Board of California, Colorado River Commission of Nevada, the Havasupai Tribe, the Hopi Tribe, the Hualapai Tribe, the Kaibab Band of Paiute Indians, the Navajo Nation, the Pueblo of Zuni, Salt River Project (SRP), U.S. Fish and Wildlife Service (FWS), Upper Colorado River Commission, Utah Associated Municipal Power Systems (UAMPS), and Western Area Power Administration (WAPA).

The purpose of the LTEMP is to provide a comprehensive framework for adaptively managing Glen Canyon Dam over the next 20 years consistent with the Grand Canyon Protection Act of 1992 (GCPA) and other provisions of federal law (Bureau of Reclamation and National Park Service 2015); thus, the preferred alternative ultimately selected for the LTEMP will govern the management of water releases at Glen Canyon Dam for the next 20 years, specifying condition-dependent seasonal, weekly, and daily patterns of release, as well as nonflow actions, including vegetation management and the potential for mechanical removal of nonnative fish. The goals for the LTEMP are to meet the requirements of the GCPA; and to minimize, consistent with the law, adverse effects on the downstream natural, recreational, and cultural resources in Glen Canyon National Recreation Area and Grand Canyon National Park, including resources of importance to American Indian Tribes, while ensuring water delivery and maintaining or increasing hydroelectric capacity and generation. The need for the LTEMP arises from scientific information developed since the 1996 record of decision (Bureau of Reclamation, 1996), the use of which will better inform DOI decisions on dam operations and other management and experimental actions so that the Secretary of the Interior may continue to meet statutory obligations to protect resources downstream from Glen Canyon Dam for future generations, conserve species listed under the Endangered Species Act of 1973 (ESA), avoid or mitigate effects on National Register eligible properties, and protect tribal interests, while meeting water delivery obligations and providing hydropower generation. The list of resources of concern in the analysis of alternatives includes the following: tribal resources and interests, sediment deposition and retention, riparian vegetation, humpback chub (HBC) (*Gila cypha*) and other native fish, historic properties, recreation, the rainbow trout fishery in Glen Canyon, water delivery, and hydropower. There is uncertainty about how management actions in this system affect the resources of concern, which complicates the analysis of alternatives. There is an acknowledged need for adaptive management (Walters, 1986), perhaps even for experimental actions chosen to accelerate learning for the benefit of selecting future management actions. The decision problem, therefore, can be characterized as one of multiple objective tradeoffs in the face

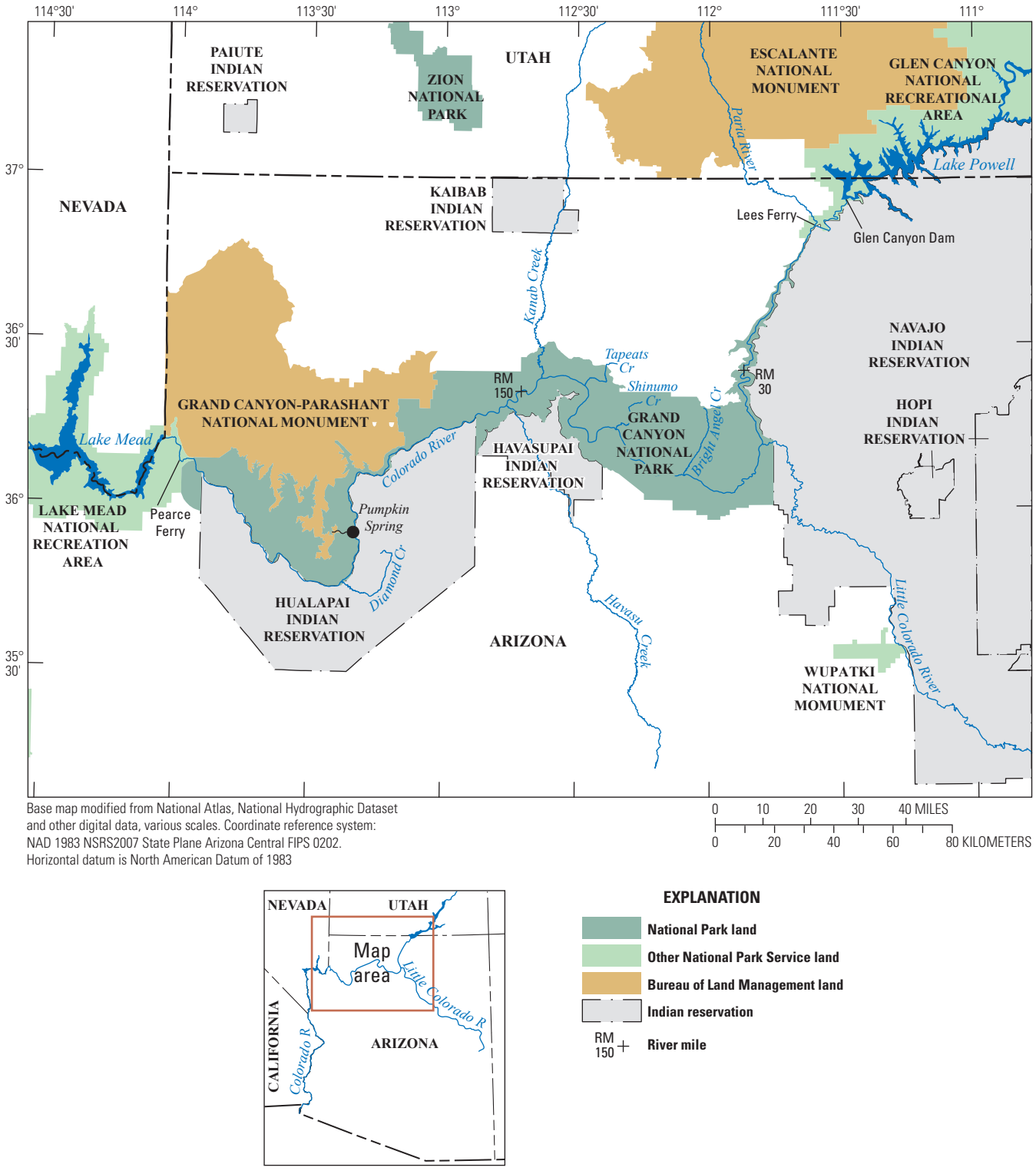

Figure 1. The Colorado River ecosystem below Glen Canyon Dam, depicting the Glen Canyon Dam Adaptive Management Program project area.

of uncertainty, where the management actions themselves are condition-dependent, information-dependent, and complex; and where there is the opportunity to reduce uncertainty early on to improve later actions through adaptive implementation.

In July 2012, the Assistant Secretary of the Interior for Water and Science, Reclamation, and NPS embraced the idea of using structured and formal decision analysis as one of several tools to evaluate alternatives in this EIS. Formal decision analysis was seen as a way to address multiple objectives, engage stakeholders, and evaluate the degree to which uncertainty is an impediment to the selection of management actions.

The purpose of this report is to document the formal decision analysis completed by the U.S. Geological Survey, in cooperation with the Bureau of Reclamation, National Park Service, and Argonne National Laboratory, as one component of the evaluation of alternatives for the LTEMP EIS. This report is a stand-alone document and an appendix to the Draft EIS (Bureau of Reclamation and National Park Service, 2015); it is also anticipated to be an appendix to the Final EIS. The emphasis in this report is on the decision analysis; the reader is referred to the Draft EIS (DEIS) and its appendixes for many other details, including the following: the legal, ecological, and cultural context of the LTEMP; an indepth description of the alternatives; the details of the quantitative models used to evaluate the alternatives; and a comprehensive comparison of the alternatives and their effects on resources of concern, including qualitative assessments that were not included in the decision analysis.

3 Decision Analysis

The DOI is including formal decision analysis tools to accompany more traditional qualitative tools to evaluate alternatives in the Glen Canyon Dam LTEMP EIS. The LTEMP EIS concerns the management of a very complex system with many, possibly competing, resources of interest and considerable uncertainty about the relations between management strategies and the responses of resources of interest to management strategies; furthermore, there are multiple stakeholder viewpoints to consider, and the DOI wants to use a structured process as one of the tools for better evaluating and understanding stakeholder viewpoints. This section provides an overview of decision analysis and describes the quantitative methods the DOI used to analyze the alternatives.

3.1 Structured Decision Making

"Structured decision making" (SDM) is a term of art, used by a community of practitioners in the United States, Canada, and Australia, to refer to the application of a broad array of decision analysis tools to natural resource management (Gregory and others, 2012). The analytical tools used in any application will depend on the specific needs of that decision setting, so SDM can look quite different from case to case. The set of analytical tools that might be used include the following: multicriteria decision analysis (MCDA), decision trees, expert elicitation, objectives hierarchies, value of information, stakeholder involvement, predictive modeling, utility theory, dynamic optimization, portfolio analysis, and many others. The common features in any application of decision analysis are (1) an attention to value-focused thinking (Keeney, 1996), recognizing that any decision is an attempt to achieve something of value to the decision maker; and (2) decomposing the decision problem into basic elements (objectives, alternatives, consequences, and tradeoffs) (Runge, 2011). The goal of SDM is to provide a transparent process for articulating objectives, developing alternatives, and evaluating those alternatives against the objectives. Note, however, that SDM does not substitute for a decision maker, and the application of the SDM process does not make a decision; rather, SDM only serves to aid the decision maker in understanding and organizing the complexities of the problem. The DOI prefers to use the term "structured decision analysis" or simply "decision analysis" for the LTEMP EIS process because the Secretary of the Interior retains the responsibility and authority to make a decision. In the context of the LTEMP EIS, two key decision analysis tools are used to evaluate the alternatives: MCDA and the expected value of perfect information (EVPI).

3.2 Multicriteria Decision Analysis

Many objectives associated with management of Glen Canyon Dam are important to stakeholders, including tribal cultural and spiritual values, endangered species, hydropower generation, sediment conservation, and recreation. It is possible that some of these objectives compete; if so, no single strategy will be best at achieving all the objectives. One of the difficulties the decision maker faces, then, is the value judgment regarding how to weight this host of objectives based on the many statutes governing Glen Canyon Dam operation and resource protection. Multicriteria decision analysis is a formal decision analysis tool designed to help evaluate the competing objectives and explore how to weight them within the context of the statutes (Figueira and others, 2005), and has been applied to a wide variety of natural resource management problems (Herath and Prato, 2006). Considerable literature advocates the use of MCDA in National Environmental Policy Act (NEPA) processes (Gregory and others, 1992; Kulkarni and others, 1993; Prato, 1999; Sheehy and Vik, 2002; Kiker and others, 2005; Linkov and others, 2006a, 2006b, 2006c; Stich and Holland, 2011; Marcot and others, 2012). Although not common, a few examples of NEPA documents explicitly incorporate MCDA methods (National Oceanic and Atmospheric Administration, 1995a, 1995b; Kimbrough and others, 2008; Nobrega and others, 2009; Bureau of Reclamation, 2011b; Runge and others, 2011a). Notably, the value of using MCDA for evaluation of management alternatives for Glen Canyon Dam has been argued by Flug and others (2000).

One of the key advantages of MCDA in the context of the LTEMP EIS is that it provides a structured and transparent method for receiving detailed stakeholder input about the resource goals, ways to evaluate performance of the alternatives against the resource goals, and the value of resource goals relative to each other. Stakeholders have legitimate differences in viewpoint about the relative importance of the objectives affected by the LTEMP alternatives, differences that stem from policy judgments rather than scientific judgments. Multicriteria decision analysis provides a way for stakeholders to articulate those judgments. By clearly understanding those different viewpoints, Reclamation and NPS (hereinafter referred to as the "joint-lead agencies") were better able to analyze and compare the alternatives and ultimately advise the Secretary of the Interior regarding her choice of a preferred alternative. In selecting a preferred alternative, the Secretary of the Interior needed to consider the appropriate suite of laws, regulations, agency guidance, and policies; the language in the purpose and need statement; stakeholder input; and the public input at various points in the process. The MCDA helped organize at least part of that complex input.

3.2.1 A Full Articulation of Resource Goals

The first step in a MCDA is a full articulation of the resource goals important to the decision maker, stakeholders, and the public. The set of resource goals should be (1) complete because it should cover the full range of concerns relevant to the decision; (2) concise because it should not contain redundant or irrelevant resource goals; (3) sensitive so that the resource goals are able to distinguish the performance of the alternatives under consideration; (4) understandable so that the resource goals directly communicate what matters; and, if possible, (5) independent so that the resource goals describe unique aspects of the problem (Gregory and others, 2012). The completeness of the set of resource goals is often very important because it provides objectivity and transparency to otherwise invisible values (Turner and others, 2008).

In an MCDA, the focus of the resource goals should be should be on objectives that are fundamental (called "fundamental objectives") to the decision maker, stakeholders, and public. Fundamental objectives, as distinguished from means objectives, are objectives that are important in their own right—they are the desired outcomes of the decision, not because they lead to something else of importance but because of their inherent value. Means objectives are pursued as a pathway to fundamental objectives but are not themselves of inherent value to the decision maker; for example, a high juvenile survival rate of HBC is important as a means to achieving a sustainable population of HBC in the Colorado River below Glen Canyon Dam, but juvenile survival is not itself the objective that the decision maker fundamentally cares about. Achieving population sustainability with low or moderate juvenile survival rates of HBC, if possible, would be acceptable; thus, the fundamental objective concerns population sustainability.

The joint-lead agencies, in consultation with the tribes and Cooperating Agencies and with input from public scoping comments, developed a set of resource goals, which represent the fundamental objectives to be pursued in the LTEMP EIS. Some of these resource goals are closely aligned with the desired future conditions (DFCs) developed by the Adaptive Management Working Group (AMWG); and are grounded in the laws, regulations, and policies relevant to the joint-lead agencies. In a few instances, the resource goals differ from the DFCs to more clearly identify a set of fundamental objectives for the specific context of the LTEMP EIS that meet the characteristics described previously in this section (complete, concise, sensitive, understandable, and independent). In a parallel effort, the joint-lead agencies worked directly with interested tribes to develop resource goals that are specific to tribal perspectives.

3.2.2 Performance Metrics

Performance metrics are scales of measurement on which the fundamental objectives (resource goals) can be evaluated. By developing performance metrics that are closely tied to the resource goals, the assessment of alternatives can include a quantitative, rather than solely narrative, analysis. Also, articulation of performance metrics forces considerable clarity about the resource goals; thus, using performance metrics encourages a high degree of transparency in the analysis of alternatives. It is difficult, however, to express all the resource goals in quantitative form. The use of performance metrics, therefore, does not preclude use of narrative analyses to evaluate additional resource goals in a NEPA process.

Ideally, performance metrics should directly reflect the resource goals, but this is often very difficult to achieve because the resource goals can be subtle, nuanced, complex, and difficult to quantify. There are also cases where a desired performance metric can be articulated, but the scientific tools do not exist to predict the performance of alternatives on that scale; thus, development of performance metrics is a very important science-policy interface. For the management agency, the desire is to have performance metrics that closely track the corresponding resource goals, but for the scientists, the desire is to have performance metrics that can be predicted with high confidence. When the difference between these desires is large, the question is how far the quantitative assessment can stretch toward the desired performance metric while maintaining a robust scientific foundation. There is, of course, a tendency to want to use proxy metrics that can be reliably predicted (for example, temperature as a proxy for HBC recruitment), but this only shifts a difficult burden to the decision maker who has to then make invisible judgments about how closely the proxy aligns with the underlying resource goal. The performance metrics developed for this decision analysis span the gamut from direct, natural measures of resource goals to distant proxies, depending on the science available to support their assessment. An effort has been made

to transparently articulate the relation between each performance metric used and the resource goal it represents.

The joint-lead agencies in conjunction with subject-matter expert (SME) teams from all relevant disciplines developed performance metrics corresponding to the resource goals that were used as the scales on which alternatives were quantitatively evaluated. During the course of development, the joint-lead agencies sought feedback on draft performance metrics from the Cooperating Agencies, tribes, and other stakeholders.

3.2.3 Transparent and Quantitative Evaluation of Alternatives

As part of the effects analysis for the LTEMP EIS, and as a supplement to the traditional narrative analysis, Argonne National Laboratory (hereinafter referred to as "Argonne") and collaborators completed quantitative analyses of the alternatives against the performance metrics. These quantitative analyses are an exercise in forecasting—predicting the relative performance of the alternatives against the resource goals using the best available science. In some cases, existing models were available for this task; in other cases, new predictive models were developed; and in still other cases, formal methods of expert elicitation (Martin and others, 2012) were needed. But, in all cases, the methods for assessing the alternatives provide transparency to the evaluation.

The ecological, economic, and social systems being evaluated in the LTEMP EIS are complex, and even though the systems are some of the best studied systems in the world, they are nevertheless incompletely understood; thus, the models used to predict performance of the alternatives were necessarily simplifications of the real world and had to account for uncertainty. Specific details about how uncertainty was handled in the decision analysis are described in section 3.3, "Uncertainty, Value of Information, and Adaptive Management."

A traditional, narrative evaluation of alternatives has to make all the same assumptions as a quantitative evaluation does. The use of a quantitative approach raises the degree of transparency about these assumptions and allows better inspection by interested parties. Also, quantitative analysis of the alternatives provides the raw material for later steps in a decision analysis.

3.2.4 Tradeoff Analysis

The outcome of the assessment phase can be viewed as a "consequence table"—a summary of how each alternative is expected to perform against each resource goal (as expressed by the corresponding performance metric). That assessment phase is a scientific endeavor—an evaluation of the current knowledge of the system to forecast how the system will respond to any proposed alternative. The consequence table provides a visual way to compare the alternatives and is an important analytical and communication step. Selection of a preferred alternative involves a policy choice based on sound science, which requires a values judgment about how to comply with the laws applicable to the proposed action while achieving a multitude of fundamental objectives, particularly if there are tradeoffs among the objectives. Some fundamental objectives, because of legal and policy considerations, may take precedence over other objectives; the remaining objectives need to be balanced appropriately. The joint-lead agencies, in evaluating the alternatives and providing a recommendation to the Secretary of the Interior, wanted to understand how Cooperating Agencies and other stakeholders would individually value the range of resource goals. This structured input was not the only consideration; in the NEPA process, decisions are also informed by the legal and policy framework, including relevant laws, regulations, agency policies and guidance, court cases, consultation with tribes, and public comment at various points in the process.

Multicriteria decision analysis provides tools for eliciting and investigating the values judgments associated with balancing tradeoffs. There are a variety of MCDA methods; we used the Simple Multi-Attribute Rating Technique (SMART) (Edwards, 1971; Goodwin and Wright, 2004) with swing weighting (Winterfeldt and Edwards, 1986). Stakeholders were asked to individually complete a swing-weighting exercise to express how they valued the resource goals relative to one another, while accounting for the range in performance across alternatives. The weights derived were combined with the consequence table to rank the alternatives from the viewpoint of each participating stakeholder. These individual viewpoints were provided as input to the joint-lead agencies and are documented in this report.

3.3 Uncertainty, Value of Information, and Adaptive Management

The second major set of tools from decision analysis that were used in the development and assessment of alternatives for the LTEMP EIS concern how to articulate, evaluate, and address uncertainty in an adaptive design. The primary analytical tool that informed this process is the expected value of information (Raiffa and Schlaifer, 1961; Howard, 1966). In a decision analysis context, the value of information is the best method for sensitivity analysis (Felli and Hazen, 1998). Runge and others (2011b) describe how the value of information can be used to design an adaptive management program that focuses on finding the best management strategy (rather than reducing the most uncertainty).

3.3.1 Adaptive Management Versus Experimental Management

Several different schools of adaptive management, which differ in their emphasis on various decision analysis tools and approach to experimental design, exist (McFadden and others, 2011). All the schools trace their lineage back to Walters

(1986), but their current approaches can look very different. In the Resilience-Experimentalist (RE) school of adaptive management, emphasis is placed on experimental design focused on policy choices (management alternatives) as the elements of uncertainty. To some extent, the RE school is most focused on "unknown unknowns"—uncertainty that cannot be anticipated in advance—and, therefore, advocates robust experimental designs composed of management alternatives to provide accelerated learning about the system dynamics in response to management. This accelerated learning might not be formally linked to subsequent long-term management planning because of a sense that there is too much hubris in making long-term plans when so much surprise is expected. The RE school perhaps draws more inspiration from Walters and Holling (1990) than from the seminal text (Walters, 1986). Examples of adaptive management that are often associated with the RE school include management in the Columbia River Basin, water management in the Everglades, and past management in the GCDAMP (McFadden and others, 2011).

In the Decision-Theoretic (DT) school of adaptive management, the emphasis is placed on a priori articulation of uncertainty through alternative hypotheses about system response to management and derivation of optimal strategies that solve the "dual-control problem" of achieving long-term management objectives by balancing the benefits and costs of learning in the short term. The DT school is most focused on known unknowns—uncertainty that can be explicitly articulated—and, therefore, advocates adaptive design that seeks resolution of this uncertainty but only to the degree that such resolution will improve future management. Learning is explicitly linked to future management decisions by associating particular courses of action with the degree of evidence in support of the alternative hypotheses; in this way, long-term management is articulated as part of the adaptive program, so the natural transition from experimentation to implementation is specified up front. The tenets of the DT school are arguably a more direct expression of Walters (1986) than other schools of adaptive management. The example most commonly associated with the DT school is the adaptive harvest management of mallards in North America (Johnson and others, 1997).

It seemed appropriate that the 1995 Glen Canyon Dam Final EIS and the GCDAMP embraced an RE school approach to adaptive management. At the time, there was very significant uncertainty about the dynamics of the Colorado River system below Glen Canyon Dam, so an approach that emphasized learning about unknown unknowns made sense. Several policy experiments have been completed, and a great deal has been invested in research; together these have greatly advanced the state of knowledge. It would have been difficult in 1995 to anticipate all the discoveries and specify clearly how and when management of Glen Canyon Dam would move from an experimental phase to a long-term implementation phase. The current question for the joint-lead agencies is if the last two decades of research and experimentation have generated enough knowledge to allow the articulation of uncertainty as known unknowns and pursue a DT school approach to adaptive management. The joint-lead agencies believe this is the case, and approached the development of the LTEMP EIS with this philosophy in mind.

3.3.2 Articulating Uncertainty as Competing Hypotheses

For many, if not all, of the resource goals, the performance of the alternatives is uncertain. Some of that uncertainty can be captured simply by including estimates of variance around the forecasts, but some uncertainty is pervasive enough that it could change the ranking of the alternatives relative to a particular resource goal and, thus, could impede the identification of a preferred alternative. For these critical uncertainties, the SME teams characterized the uncertainty in the predictive models as a set of competing hypotheses. The focus of the uncertainty was on the mechanisms or parameters in the models, not on a holistic statement of uncertainty about whether a particular management intervention will work or not; thus, for example, rather than state the uncertainty as whether or not a particular management alternative will build and sustain beaches, the uncertainty was expressed as competing hypotheses about the long-term rate of sediment input from the Paria River. Likewise, whether trout management flows (TMFs) work or not was expressed as competing hypotheses about the rate of recruitment of juvenile rainbow trout when TMFs are used.

Development of competing hypotheses to capture critical uncertainty is challenging. It requires very deliberative thought about the limits of knowledge and the nature of uncertainty that would affect the ranking of management alternatives. To do so with a small number of discrete hypotheses requires a simplification of the full degree of uncertainty. But careful thought along these lines allows a transparent and explicit statement of the uncertainty that is the focus of experimental and adaptive design. In a NEPA context, such explicit articulation of critical uncertainty allows full disclosure of the motivation for experimental design and explanation of how subsequent management will respond to newfound knowledge.

3.3.3 Deconstructing Complex Alternatives

Several of the alternatives under consideration in the DEIS (especially Alternatives C, D, and E; see explanations of each in the "Alternatives" sections 5.4, 5.5, and 5.6) include, either explicitly or implicitly, complex experimental or adaptive designs (see, for example, figs. 2–13 and 2–14 in Bureau of Reclamation and National Park Service, 2015). These strategies prescribe different management interventions depending on state and information conditions. It is particularly important to distinguish state-dependent triggers from information-dependent triggers. State-dependent triggers are conditions of the state of the system that would lead to implementation of a different management action, primarily in recognition that the Colorado River is a stochastic ecosystem, and it is important

to be able to respond to natural variation. Most obviously, all the alternatives contain state-dependent triggers under the Bureau of Reclamation (2007) guidelines that specify, among other parameters, the annual volume for water release from Glen Canyon Dam. Other state-dependent triggers are designed to guard against chance reductions in HBC or other resources of concern. State-dependent triggers are in contrast to information-dependent triggers, which are indications that the state of knowledge has changed substantially and a new approach to management is warranted; for example, Alternatives C and E propose experimental implementation of TMFs, and it is at least implicit in both that if those TMFs are ineffective in reducing downstream migration of rainbow trout from Lees Ferry, they would be discontinued. This is an information-dependent trigger. To the extent possible, information-dependent triggers should be explicit in that they specify the weight of evidence that would be needed on one hypothesis or another to induce a change in management strategy.

A complex experimental or adaptive strategy can be viewed as a portfolio of simpler strategies combined and implemented in a manner to reduce critical uncertainty, with the ultimate intention to implement one of the simpler strategies as the operational standard in the long term. The information-dependent triggers govern the switch between these simpler strategies. To evaluate such a complex design, the first step is to understand what the simpler strategies are; thus, the complex strategies were deconstructed into simpler long-term strategies, each of which might have state-dependent triggers but not information-dependent triggers. In other words, an experimental or adaptive strategy can be viewed as a set of simpler, operational strategies arrayed against a set of competing hypotheses. Resolution of the competing hypotheses would lead to identification of a long-term strategy, but of course, in the short term, an experimental design is needed to achieve that resolution. The first step in development of such a complex strategy is the articulation of the simpler component strategies and the attendant competing hypotheses; the development of the experimental design is a later step.

3.3.4 Value of Information

The essence of the DT school of adaptive management is a focus on uncertainty that is an impediment to the decision maker; that is, resolution of the uncertainty could affect the choice of the long-term management strategy. To evaluate the importance of a source of uncertainty, we used a technique known as the value of information (Raiffa and Schlaifer, 1961; Howard, 1966; Runge and others, 2011b), which was also advocated by Walters (1986) as the motivation for adaptive management. The idea behind the value of information is to compare the expected performance if a decision has to be made in the face of uncertainty with the expected performance if uncertainty can be resolved before committing to a decision. This contrast, known as the EVPI, sets an upper bound on the value of experimental or adaptive management measured on the scale of the management objective(s). To make a decision in the face of uncertainty, a decision maker chooses to implement an action that achieves the highest expected performance against the uncertainties, but that decision carries the risk of being wrong (because some other action could have performed better); the value of information measures how important it is to eliminate that risk. There are two related methods: (1) the expected value of partial information (EVXI) allows calculation of the value of reducing some component of uncertainty, while remaining uncertain about the rest; and (2) the expected value of sample information takes into account the noise in the monitoring.

To calculate the value of information, uncertainty must be explicitly articulated (as competing hypotheses with evidentiary weights or as a probability distribution on a set of parameters). With a small set of competing hypotheses, the calculations involve several steps: (1) forecasting the performance of each long-term strategy under each hypothesis, (2) calculating a weighted performance across hypotheses to identify an optimal decision in the face of uncertainty, (3) calculating the expected performance if uncertainty could be fully resolved before the management alternative was chosen, and then (4) comparing the expected values in steps 2 and 3.

In a single-objective setting, the EVPI is measured on the scale of that objective; thus, it could be expressed, for example, as the expected increase in the probability of persistence of HBC if uncertainty could be resolved before committing to a long-term management strategy. In a multiple-objective setting, EVPI is calculated on the composite utility scale (in which the full array of objectives is weighted); thus, an evaluation of the importance of uncertainty cannot be calculated without first completing a MCDA to understand the value weights on the resource goals. The sequence of assessment matters; the LTEMP EIS process was crafted to accommodate this series of steps. First, the long-term strategies (the elements of the full alternatives broken down into their constituent parts) were analyzed against the array of performance metrics under all the competing hypotheses. Second, using the expected value across hypotheses, MCDA (with input from stakeholders) was used to generate a preliminary weighting of fundamental objectives. Third, with those weights, the individual competing hypotheses were investigated, and the expected value of information (perfect and partial) was calculated.

3.3.5 Experimental and Adaptive Design

The motivation for the EVPI analysis was to provide guidance useful for developing an experimental or adaptive design for implementing management actions, taking into account their value as long-term strategies and the value of reducing uncertainty. This report only describes the results from the decision analysis, with a brief discussion of the implications of the results for experimental design (section 9.2, “Motivation for Adaptive Management”); the development of the experimental design is described in the DEIS.

4 Resource Goals and Performance Metrics

In February 2010, the Assistant Secretary of the Interior asked an ad hoc group of the AMWG to develop a set of DFCs, which were outcomes of fundamental importance that were "achievable through the operation of Glen Canyon Dam, subject to the Law of the River and consistent with the Grand Canyon Protection Act" (Castle, 2010, p. 2) During the next 2 years, this ad hoc group worked with the AMWG and DOI to develop the set of DFCs, which were adopted by the AMWG and recommended to the Secretary of the Interior in February 2012. The set of DFCs formed the basis for the development of the resource goals for the LTEMP EIS. The resource goals express the fundamental objectives for the LTEMP EIS and are described in the nine subsections that follow (4.1 through 4.9).

Associated with the resource goals, the joint-lead agencies developed metrics to evaluate the relative performance of the LTEMP alternatives. These scientifically based performance metrics were developed in a series of workshops among SMEs working on the LTEMP EIS and were revised to incorporate feedback from Cooperating Agencies and other stakeholders. The performance metrics are intended to be objective measures of the performance of alternatives relative to goals for each affected resource being evaluated in the LTEMP EIS. Note that these performance metrics are not the full impacts analysis for the LTEMP EIS. Other sources of quantitative and qualitative information, in addition to the performance metrics, were used to assess the overall and relative performance of alternatives and their constituent elements for the LTEMP EIS. A summary of the performance metrics used in the decision analysis is given in table 1.

4.1 Aquatic Ecology

The resource goals associated with aquatic ecology focused on the persistence of HBC and other native fish, the quality of the rainbow trout (RBT) (*Oncorhynchus mykiss*) fishery, and absence or containment of nonnative aquatic species.

4.1.1 Humpback Chub

Resource Goal.—Meet HBC recovery goals including maintaining a self-sustaining population, spawning habitat, and aggregations in the natural range of the HBC in the Colorado River and its tributaries below the Glen Canyon Dam.

Performance Metric 1.—Expected minimum number of adult (greater than or equal to [≥] 200 millimeters [mm]) HBC in the Little Colorado River population during the LTEMP planning period (20 years).

Performance Metric 2.—Average temperature suitability index (scale 0–1) for HBC at RM 157 (Havasu Creek) and RM 213 (Pumpkin Spring) (fig. 1). The potential for a self-sustaining aggregation of HBC at each of these locations was based on a temperature suitability model that considered how well water temperatures met requirements for important HBC life-history stages (spawning, egg incubation, and growth) using triangular probability functions based on the reported ranges of suitable temperatures for each life-history stage (Valdez and Speas, 2007). The composite temperature suitability index was the geometric mean of the suitability indices for each of the life-history stages.

4.1.2 Other Native Fish

Resource Goal.—Maintain self-sustaining native fish species populations and their habitats in their natural ranges on the Colorado River and its tributaries.

In the analysis for the EIS, temperature suitability indexes for other native fish, similar to the one for HBC, were developed. They did not, however, show much differentiation among alternatives, and they did not differ much from each other and from the HBC temperature suitability metric. These metrics were not, subsequently, used in the decision analysis; the HBC temperature suitability metric was assumed to stand in for other native fish as well.

4.1.3 Rainbow Trout Fishery

Resource Goal.—Achieve a healthy high-quality recreational RBT fishery in the Glen Canyon National Recreation Area and reduce or eliminate downstream RBT migration consistent with NPS fish management and ESA compliance.

Performance Metric 3.—Rainbow trout catch rate in Glen Canyon National Recreation Area (age 2+ fish per angler-hour).

Performance Metric 4.—Rainbow trout emigration rate (number of age-0 RBT moving into Marble Canyon from Glen Canyon per year).

Performance Metric 5.—Abundance of high-quality RBT (greater than [>] 16 inches total length) in the Glen Canyon reach.

4.1.4 Nonnative Aquatic Species

Resource Goal.—Minimize or reduce the presence and expansion of aquatic nonnative invasive species.

In the analysis for the EIS, temperature suitability metrics for nonnative warm-water and cold-water fish and aquatic parasites, similar to the one for HBC, were developed. They did not, however, provide much differentiation among the alternatives. These metrics are reported in the EIS but were not used in the decision analysis.

Table 1. Summary of the 18 performance metrics used in the decision analysis.

[The range for each performance metric captures the amount of variability in the metric because of the effects of the different alternatives, the hydrological and sediment traces, and structural and parametric uncertainty. The range shown was used in the swing-weighting elicitation. HBC, humpback chub; RBT, rainbow trout; #, number; >, greater than]

Number	Resource goal	Performance metric	Units	Desired direction	Range
1	Humpback chub	Minimum number of adult HBC	# adults	Increase	3,000–8,500
2		HBC temperature suitability	Index (0–1)	Increase	0.0–0.2
3	RBT fishery	RBT catch rate	Fish/angler-hour	Increase	1.0–5.0
4		RBT emigration rate	Trout/year	Decrease	15,000–125,000
5		Abundance of high-quality RBT	# fish > 16 inches	Increase	400–1,200
6	Archaeological and cultural resources	Wind transport of sediment index	Index (0–1)	Increase	0.0–0.5
7		Glen Canyon flow index	Days/year	Decrease	0–75
8		Time-off-river index	Index (0–1)	Increase	0.60–0.95
9	Hydropower and energy	Hydropower generation	Million $/year	Increase	120–200
10		Hydropower capacity	Million $/year	Increase	10–50
11	Recreation	Camping area index	Index (0–1)	Increase	0.0–0.5
12		Fluctuation index	Index (0–1)	Increase	0.0–1.0
13		Rafting use index	Visitor-days/year	Decrease	0–1,300
14	Riparian vegetation	Riparian vegetation index	Sum of ratios	Increase	2.0–6.0
15	Sediment	Sand load index	Proportion (0–1)	Increase	0.0–0.6
16	Tribal resources	Marsh vegetation ratio	Ratio	Increase	0.0–1.5
17		Mechanical removal	Years (out of 20)	Decrease	0–5
18		Trout management flows	Years (out of 20)	Decrease	0–20

4.2 Archaeological and Cultural Resources

Resource Goal.—Maintain the integrity of potentially affected National Register of Historic Places eligible or listed historic properties in place, where possible, with preservation methods used on a site-specific basis.

Performance Metric 6.—Wind transport of sediment index (WTSI). This WTSI metric captures the availability of fine sediment for movement by wind. The potential settlement of such sediment over historic properties may provide protection from erosion. The WTSI is the product of the sand load index (SLI; see section 4.7, "Sediment"), which is a proxy for the availability of sediment, and a flow factor, which is higher when low flows happen during the windy season. The WTSI can range between 0 and 1, with higher values indicating more opportunity for transport of sediment.

Performance Metric 7.—Glen Canyon flow index (number of days per year that the maximum daily flow is greater than 23,200 cubic feet per second [ft^3/s]). There are a number of archaeological sites within the Glen Canyon National Recreation Area that could be negatively affected by high flows. Ninemile Terrace is considered representative of other archaeological sites on terraces within the Glen Canyon National Recreation Area; the toe of its slope is at an elevation that corresponds to flows from Glen Canyon Dam of 23,200 ft^3/s.

Performance Metric 8.—Time-off-river index. This metric reflects the availability of discretionary time off river for rafting parties, which allows for greater visitation of archaeological sites. From the standpoint of protection of archaeological and cultural sites, such discretionary time is not desirable. The time-off-river index is calculated from the mean daily flow levels in the river: daily flows less than 10,000 ft^3/s receive a score of 1 (because rafting progress is slow and there is little discretionary time); daily flows greater than 31,500 ft^3/s receive a score of 0 (because rafting progress is fast, allowing the most discretionary time); and daily flows between 10,000 and 31,500 ft^3/s receive a score based on linear interpolation. The daily scores are averaged within seasons: summer (May–August), winter (November–February), and spring and fall (March–April and September–October, respectively). An annual value is calculated using a weighted average across seasons, with higher weight (0.54) given to summer than to spring and fall (0.31) or winter (0.15). The final metric ranges between 0 and 1, with higher values indicating better potential to protect archaeological resources.

4.3 Hydropower and Energy

Resource Goal.—Maintain or increase Glen Canyon Dam electric energy generation, load following capability, and ramp rate capability; and minimize emissions and costs to the greatest extent practicable, consistent with improvement and long-term sustainability of downstream resources.

Performance Metric 9. —Value of hydropower generation (million dollars per year). The value of hydropower energy production over a 20-year trace is discounted at 3.375 percent per year. The total net present value of energy production is divided by 20 to provide an annualized measure.

Performance Metric 10.—Value of hydropower capacity (million dollars per year). The WAPA enters into long-term firm contracts that obligate them to deliver firm electric service to their customers. For the purpose of the LTEMP EIS, the value of these contracts is estimated by first calculating the amount of power (megawatt [MW]) that can be contracted, then multiplying by the replacement cost for that capacity (dollars per MW-year). The capacity itself is calculated by finding the 90-percent exceedance value (10th percentile) for the daily maximum generation in August (August is the month with the highest demand) during a 20-year trace. The replacement cost used was $50,100/MW-year based on a natural gas combustion turbine.

Additional metrics associated with hydropower generation, including the retail rate effects on residential and nonresidential consumers, are examined in the LTEMP EIS but were not available in time to be included as part of the decision analysis.

4.4 Natural Processes

Resource Goal.—Restore, to the extent practicable, ecological patterns and processes within their range of natural variability, including the natural abundance, diversity, and genetic and ecological integrity of the plant and animal species native to those ecosystems.

A quantitative performance metric to capture this resource goal was not developed because of its multifaceted complexity. In the EIS, the alternatives are compared qualitatively against this resource goal, but it was not used in the decision analysis.

4.5 Recreational Experience

Resource Goal.—Maintain and improve the quality of recreational experiences for the users of the Colorado River ecosystem. Recreation includes, but is not limited to, flatwater and whitewater boating, river corridor camping, and angling in Glen Canyon.

Performance Metric 11.—Camping area index. This metric captures the availability of medium (16–25 people) and large (>25 people) campsites on beaches along the Colorado River. The camping area index is the product of the SLI (see section 4.7, "Sediment"), which measures the availability of sediment for beach forming, and a flow factor, which reflects exposure of the beaches. The flow factor is calculated from the maximum daily flows. A score of 1 is given to flows less than 8,000 ft^3/s (because the lower flow means a lower elevation of the water and hence more beach exposure); a score of 0 is given to flows greater than 31,500 ft^3/s; and an intermediate score is determined by linear interpolation for flows between 8,000 and 31,500 ft^3/s. The flow factor is averaged over days within each season, and then over seasons, with higher weight given to the summer season (0.54) than the spring and fall (0.31) or winter (0.15) seasons. The camping area index can range between 0 and 1, with higher values indicating greater availability of medium and large campsites.

Performance Metric 12.—Fluctuation index. This index measures the fraction of time that the daily fluctuations in flow are within a tolerable range; tolerable is defined based on the study by Bishop and others (1987). As the mean daily flow increases, greater fluctuations are tolerable. For mean daily flow in the range from 5,000 to 8,999 ft^3/s, the daily fluctuation index is 1 if the daily fluctuation is less than 3,400 ft^3/s; for daily flow in the range from 9,000 to 15,999 ft^3/s, the fluctuation index is 1 if the daily fluctuation is less than 4,800 ft^3/s; for daily flow in the range from 16,000 to 31,999 ft^3/s, the fluctuation index is 1 if the daily fluctuation is less than 7,200 ft^3/s; and for daily flow greater than 32,000 ft^3/s, the fluctuation index is 1 if the daily fluctuation is less than 9,800 ft^3/s. In all cases, the daily fluctuation index is 0 if the daily fluctuation is greater than 10,000 ft^3/s. For fluctuation index values between 1 and 0, the index is determined by linear interpolation between the tolerable threshold and 10,000 ft^3/s. The daily values for the fluctuation index are averaged within seasons, then averaged across seasons with higher weight (0.54) given to summer months than to spring and fall (0.31) or winter months (0.15). The fluctuation index can range between 0 and 1, with higher values indicating a better visitor experience as influenced by fluctuation in water levels.

Performance Metric 13.—Glen Canyon rafting use metric (average boat seats lost per year because of high-flow experiments [HFEs]). During HFEs and for 2 days before and after, Glen Canyon day-rafting operators cannot take recreational passengers. This metric calculates the average number of boat seats lost per year.

Several other metrics reflecting the recreational experience were analyzed in the LTEMP EIS. In some cases, these did not help to discriminate among the alternatives, and in other cases, these metrics were highly correlated with other metrics. For these reasons, the metrics were not included in the decision analysis and are not described here.

4.6 Riparian Vegetation

Resource Goal.—Maintain native vegetation and wildlife habitat, in various stages of maturity, such that they are

diverse, healthy, productive, self-sustaining, and ecologically appropriate.

Performance Metric 14.—Riparian vegetation index. This index summarizes predicted changes during the 20-year LTEMP period in the relative cover of native vegetation community types and the relative diversity of community types, as described by a seven-state state-and-transition model (Ralston and others, 2014). The index is calculated as the sum of four component ratios: the ratio of final to initial native vegetation cover, the ratio of final to initial vegetation state diversity, the ratio of final to initial native to nonnative dominant vegetation state, and the ratio of initial to final cover of arrowweed. An index value of 4.0 indicates an unchanged vegetation condition; values greater than 4.0 indicate improved vegetation conditions; values less than 4.0 indicate degraded vegetation conditions.

4.7 Sediment

Resource Goal.—Increase and retain fine sediment volume, area, and distribution in the Glen, Marble, and Grand Canyon reaches above the elevation of the average base flow for ecological, cultural, and recreational purposes.

Performance Metric 15.—The SLI (the cumulative sand load transported by high flows [greater than 31,500 ft^3/s] divided by the cumulative sand load transported in total). The range of this metric is 0–1, with higher values reflecting the potential for larger sandbars because more of the sediment is transported at higher river volumes and hence higher elevations. A number of other metrics that summarize the transportation and deposition of sediment were analyzed in the LTEMP EIS. They were all fairly highly correlated; only the SLI was used in the decision analysis.

4.8 Tribal Resources

Resource Goal.—Maintain the diverse values and resources of traditionally associated tribes along the Colorado River corridor through Glen, Marble, and Grand Canyons.

In discussions with tribal representatives during the course of the development of the LTEMP EIS, a large number of important resource goals were identified. A concerted effort was made to understand these goals as clearly as possible, but it was challenging to express some of them in terms amenable to measurement. Although all these goals are important aspects of the importance to the tribes of the Grand Canyon, the Colorado River, and their management, not all of them will be affected by the alternatives being considered in the LTEMP EIS. All of these resource goals are discussed and evaluated in the LTEMP EIS. The full set of goals is described in this section, but only those for which performance metrics were identified are included in the decision analysis.

4.8.1 Health of the Ecosystem

The ecosystem in Glen, Marble, and Grand Canyons is more than the sum of its parts and, in the view of the tribes, should be healthy as a whole. Historically, in the GCDAMP, the overall health of the ecosystem has been examined by evaluating the status of each part, but this reductionist approach might possibly miss some important aspects. There are a variety of indicators of ecosystem health that could be considered including, but not limited to, the following: the health of the river and its ability to sustain life; the color of the water; the absence of contaminants, pollutants, and disease in the water; the potability of the water; the quality of the water that reaches Lake Mead; and the viability and health of wildlife and plants in Glen, Marble, and Grand Canyons. It is important to understand that, for many tribes, the Colorado River is a sentient being and the spiritual center of the ecosystem because it has the capability of giving and taking life and is prone to anger if mistreated. The health of the ecosystem depends on the health of the Colorado River.

Because of the holistic nature of this resource goal, it was difficult to find a single performance metric that summarized it. A narrative analysis of this resource goal is found in the LTEMP EIS, but it was not included in the decision analysis.

4.8.2 Sites of Cultural Importance

There are specific sites within Glen, Marble, and Grand Canyons that are important for cultural reasons; and for preservation of tribal, religious society, kiva group, and clan history (for example, shrines, sacred sites, ancient burial sites, springs, plant collection areas, mineral collection areas, offering places, and other elements). These sites can be threatened by erosion, loss of sediment inputs, and intrusive human use (especially nontribal, outside visitors). Flow and nonflow actions (for example, education, permitting, research and monitoring, and interpretation) may affect these sites.

Performance Metric 16.—Marsh vegetation ratio (ratio of frequency of wetland states during the course of 20 years to frequency of wetland states if the initial abundance remained unchanged). Wetlands are a rare and important habitat type along the Colorado River; within Glen, Marble, and Grand Canyons, there are currently approximately 4.6 acres of such habitat. Maintenance and increase of marsh vegetation is important from a tribal perspective. The metric is calculated by looking at the marsh and shrub wetland states in the riparian state-and-transition model (Ralston and others, 2014) during the course of a 20-year projection and comparing that to the current abundance. The metric is a ratio; thus, a value of 1.0 indicates an unchanged abundance of marsh (on average), a value greater than 1.0 indicates an average increase, and a value less than 1.0 indicates an average decrease.

A number of aspects of this resource goal are also reflected in other performance metrics described in previous sections. The WTSI (performance metric 6) focuses on the availability of fine sediment for transfer to protect National

Register eligible or listed sites. Such sites, however, do not represent the full set of places of tribal concern, so other metrics must also be considered. The Glen Canyon flow index (performance metric 7) reflects the protection of some important sites in Glen Canyon. The time-off-river index (performance metric 8) measures the degree to which the discretionary time off river of rafters might affect cultural resources, including those of tribal importance.

In additions to these performance metrics, a number of other considerations are evaluated narratively in the LTEMP EIS, including riparian vegetation diversity, native fish diversity, and access to springs.

4.8.3 Respect for Life

To many of the tribes associated with the Colorado River and Glen, Marble, and Grand Canyons, life itself is sacred. Human activities should protect and promote life, not destroy it. There are two aspects to this resource goal: first, minimize the taking of life; and second, encourage the expansion and proliferation of life. These are both complex concepts. The tribes recognize that it is appropriate for humans to take other life in some circumstances, especially when it promotes other life (particularly, our own consumption for survival), but this taking needs to be minimal and respectful because there are spiritual consequences associated with the taking of life. The promotion of life is also important but does not necessarily imply a return to historical or "natural" conditions. The Glen Canyon Dam has encouraged new life in Glen, Marble, and Grand Canyons, so a return to predam conditions is not necessarily implied by this objective. It is worth noting that many of the tribes do not make a strong distinction between native and nonnative species.

Performance Metric 17.—Frequency of mechanical removal, as measured by the average number of years in which trout mechanical removal trips happen. Several of the alternatives considered in the LTEMP EIS include the use of electrofishing and removal of nonnative trout at the confluence of the Colorado River with the Little Colorado River in an effort to reduce the piscivory of juvenile HBC by trout. A number of tribes, especially Hopi and Zuni, have raised concerns about this taking of life. As a coarse measure of the cultural, spiritual, and ethical effects of killing trout, this performance metric allows distinctions among alternatives, favoring those that make an effort to minimize mechanical removal. But the nature of the take, the purpose behind it, the methods of the take, the disposition of the trout taken, and the mind set of those killing the fish all also affect the sacred treatment of living beings.

Performance Metric 18.—Frequency of trout management flows, as measured by the average number of years in which TMFs happen. Several of the alternatives considered in the LTEMP EIS include the potential for use of TMFs. The TMFs, designed to reduce reproduction or survival of juvenile trout, are considered to be killing by some tribes and should be minimized. Alternatives that include TMFs are likely to differ in how often the flows are triggered, so this performance metric helps to distinguish among the alternatives.

4.8.4 Sacred Integrity of Grand, Marble, and Glen Canyons

Glen, Marble, and Grand Canyons are sacred to many tribes, and the preservation of their sacred integrity is important. The sanctity of Glen, Marble, and Grand Canyons may be threatened by human activities and behaviors, development, and the presence of artificial structures and activities. An important aspect of the sanctity is the intentionality of visitors: when outsiders enter Glen, Marble, and Grand Canyons (on boat or hiking trips), the respect they show to the canyons and Colorado River can affect the spiritual integrity. There are many consequences of the disturbance of this sanctity, including, but not limited to, the following: a reduction of the spiritual strength of plants gathered and used by the Navajo for medicinal and cultural purposes; an inability to retire Navajo sacred objects into the Colorado River when they have become too old for continued use; weakening of the sacred role the canyons play as a final resting place for Hopi; and an overall disruption of the state of mind and spirit of Zuni religious leaders and of their experience of being within a very sacred place that embodies the Zuni emergence, migrations, and communion with the spirits of Zuni ancestors.

This resource goal, although of profound importance to the tribes, is not thought to differ measurably across the alternatives under consideration in the LTEMP EIS because it is not driven by flow operations from Glen Canyon Dam or currently envisioned attendant activities. This goal is evaluated in the narrative EIS analysis but not in the formal decision analysis.

4.8.5 Stewardship

According to their traditions, several of the tribes understand that they have been given a sacred stewardship responsibility for the preservation and harmony of the world; for example, the Hopi have a covenant with the caretaker of this world, Masaw, to be stewards of the earth; other Tribes have similar stewardship ethics grounded in spiritual traditions. To maintain these stewardship responsibilities, the tribes need to be an active part of stewardship of the Glen, Marble, and Grand Canyons. This stewardship includes the following: ceremonial activities, whether performed in the canyons or in the villages; participation in management of the canyons, including water management, through traditional practices and western management activities; and education to maintain cultural knowledge and connection with the canyons. The tribes note that the Federal government also has stewardship responsibilities that arise out of Federal legislation; because Federal involvement has sometimes taken stewardship responsibility from the tribes, it is critical that the Federal government be accountable for its stewardship. At times, some tribes believe

the presence of the Federal government has made it more difficult for them to carry out their stewardship responsibilities. Successful development of joint stewardship among the tribes and Federal government will require continued building of mutual respect and trust between those entities.

Tribal stewardship opportunities are not tied to individual alternatives being considered in the LTEMP EIS but could be crafted to apply to any of the alternatives; thus, this resource goal, although of critical importance to the tribes individually and to the ongoing relationship between the tribes and Federal government, may not help distinguish among the alternatives. This goal is evaluated in the narrative EIS analysis but not in the formal decision analysis.

4.8.6 Tribal Connections to the Canyons

The spiritual, historical, and cultural connections that tribes have to Glen, Marble, and Grand Canyons require the protection of sacred sites and the integrity of the canyons as a whole, but protection alone is not enough. The tribes also need opportunities for access, education, and stewardship to keep their connections vibrant. Access can be undermined by physical barriers and by the effects of human activity that decrease the power of those sites and the experience when at them (for example, lack of privacy, disturbance of the soundscape, and viewshed).

Like the sacred integrity and stewardship resource goals, this resource goal is not thought to differ across the alternatives. The flow operations of Glen Canyon Dam are not likely to affect tribal access, education, spiritual ceremonies, or other connections to Glen, Marble, and Grand Canyons. This resource goal may be more appropriately addressed through government-to-government consultation in other forums. This goal is evaluated in the narrative EIS analysis but not in the formal decision analysis.

4.8.7 Economic Opportunity

The Glen, Marble, and Grand Canyons, Colorado River, and Glen Canyon Dam are sources of economic benefit for the tribes in the area. The canyons provide tourism and other opportunities that enhance the economic well-being of tribes. (As an important note, tourism can also undermine the well-being of tribes in aspects other than economic; see the other tribal resource goals.) The Glen Canyon Dam provides affordable electricity for tribal needs and for development projects.

The hydroelectric performance metrics (especially hydroelectric generation, performance metric 9) may reflect one aspect of economic opportunity in that provision of affordable hydroelectricity is a component of economic development. Other economic effects are evaluated in the narrative EIS but were not included in the formal decision analysis.

4.8.8 Tribal Water Rights and Supply

Tribes in the area depend on the Colorado River for many of their water needs; so the preservation of established, traditional, and desired water rights, now and into the future, is important to them. There are a number of claims to water rights that have been asserted by the tribes but for which there are not yet quantified rights through decree or negotiated settlement; some Tribes have indicated that these claims to water rights are as important as established water rights.

Based on its purpose and need, the LTEMP EIS was not intended to include any alternative that violated agreed-upon water rights. The effect of the Lake Powell water elevation on Navajo access to water was examined and was not determined to differ across alternatives.

4.8.9 Process Objectives

The tribes also expressed several important process objectives—objectives that govern how the LTEMP decision is made, rather than what decision is made. The first of these is the genuine incorporation of tribal input to the LTEMP process as a reflection of Federal trust responsibilities. The second is the importance of incorporating learning to improve management with time; in this spirit, an experimental approach that can result in adaptive management is favored.

Because these were process objectives, they were not evaluated in the formal decision analysis, which focused on objectives that could help discern among the alternatives.

4.9 Water Delivery

Resource Goal.—Ensure that water delivery continues in a manner that is fully consistent with and subject to the Colorado River Compact, Upper Colorado River Basin Compact, Water Treaty of 1944 with Mexico, decree of the Supreme Court in *Arizona* v. *California*, and provisions of the Colorado River Storage Project Act of 1956 and the Colorado River Basin Project Act of 1968 that govern allocation, appropriation, development, and exportation of the waters of the Colorado River Basin; and consistent with applicable determinations of annual water release volumes from Glen Canyon Dam made pursuant to the Long-Range Operating Criteria for Colorado River Basin Reservoirs, which are currently implemented through the 2007 interim guidelines (Bureau of Reclamation, 2007).

The scope and need of the LTEMP EIS was designed to preserve existing agreements concerning water delivery; thus, none of the alternatives considered were meant to differ with regard to aspects of water delivery. A number of water delivery metrics were evaluated to make certain that this part of the purpose and need was upheld. None of the alternatives were determined to differ with regard to these metrics; thus, they were not included in the decision analysis.

5 Alternatives

Seven alternatives were considered in the LTEMP EIS. Each of these alternatives is a complex combination of flow and nonflow actions, often with condition-dependent and information-dependent triggers for various components. Four of the alternatives (B, C, D, and E) also contain variants (called long-term strategies) to represent different combinations of actions that would be taken once critical uncertainties were resolved. In total, 19 long-term strategies were evaluated. A brief summary of these alternatives is given here to provide context for the decision analysis with an emphasis on those elements that differ across alternatives. A full description of these alternatives, with the rationale for each, is given in chapter 2 of the LTEMP EIS.

5.1 Action Elements

The alternatives are composed of flow actions, which govern how water flow through Glen Canyon Dam is to be managed on hourly, daily, and monthly scales, as well as nonflow actions, which govern other activities meant to complement the flow actions to achieve the resource goals.

5.1.1 Monthly Release Pattern and Other Base Operations

The seven alternatives differ in the operational characteristics that govern flow through Glen Canyon Dam (table 2). All alternatives follow the 2007 interim guidelines (Bureau of Reclamation, 2007), which specifies the annual volume of water to be passed through Glen Canyon Dam. The alternatives differ in how they apportion the annual volume to monthly volumes, ranging from patterns that match releases under the previous EIS to patterns that match monthly demand for electricity to patterns that approximate the unregulated flow in the Colorado River. The minimum flow at any time differs across alternatives, with a range from 5,000 to 8,000 ft^3/s. The maximum flow for base operations is the same for all alternatives (25,000 ft^3/s). The daily range specifies the limit to how much variation there can be between the minimum and maximum flow on a given day and ranges between 0 and 12,000 ft^3/s across alternatives. The ramp rates limit how quickly the flow can change; for all alternatives the ramp rate for increasing flow is 4,000 cubic feet per second per hour (ft^3/s-h); the ramp rate for decreasing flow is lower, ranging from 1,500 to 4,000 ft^3/s-h.

5.1.2 High-Flow Experiments

Since 1996, there have been a number of experimental high-flow releases of water through Glen Canyon Dam, designed to mimic natural high flows and deposit sediment at higher elevations, in an effort to rebuild sandbars and restore other ecosystem processes in Glen, Marble, and Grand Canyons. High-flow releases exceed the operational maximum daily flow and can be as high as 45,000 ft^3/s depending on the number of generation units available. The Bureau of Reclamation (2011a) established a protocol for determining when HFE releases were warranted and how they should be implemented. To date, the HFEs that have been implemented under the 2011 HFE protocol have happened in the fall, although the HFE protocol allows them to happen in the spring after 2015. The LTEMP EIS alternatives differ in if, when, and how they allow fall HFEs and spring HFEs (table 3). In addition, some of the alternatives allow proactive spring HFEs; these are HFE releases designed to protect sand supply in years when the annual guidelines call for high annual volumes (>10 million acre-feet). Most of the HFEs are limited to a maximum duration of 96 hours, but some of the alternatives allow extended-duration HFEs if adequate sediment supply is available (table 3).

5.1.3 Trout Management Flows

High flows, whether through high annual volumes or HFEs, have been determined to increase RBT production in the Glen Canyon reach. Because of the concern about the effect of RBT on HBC, methods have been sought to manage RBT populations. One proposed method is TMFs. These are patterns of high-water release (for example, 20,000 ft^3/s) for 2–7 days to encourage young-of-the-year trout to move to higher elevation shallow-water habitats followed by a rapid drop to a low flow (for example, 5,000 to 8,000 ft^3/s) during the day to strand young trout and expose them to sunlight and heat. The intention is to reduce RBT production and, hence, reduce emigration of trout from Glen to Marble Canyon, lowering the risk to HBC farther downstream. The TMFs have not previously been implemented at Glen Canyon Dam. They are considered an experimental element in several of the alternatives (table 3).

5.1.4 Other Flow Manipulations

A variety of other flow manipulations are built into the alternatives. Low summer flows are designed to produce warmer conditions for juvenile HBC growth in the Colorado River at the confluence with the Little Colorado River by reducing flows from July through September. These flows would be implemented experimentally in those alternatives that allow them (table 3).

Sustained low flows for benthic invertebrate production ("bug flows") are an experimental action considered under Alternative D for restoring mayflies, stoneflies, and caddisflies to Glen and Marble Canyons. If implemented, steady minimum flows would be provided every weekend from May through August, to ensure that eggs laid during weekends would not be subject to drying because of lower water levels during egg development. Demand for electricity is lower on

Table 2. Operational characteristics of Long-Term Experimental and Management Plan alternatives.

[maf,, megaacre-foot; kaf, kiloacre-foot; ft^3/s, cubic foot per second; >, greater than]

Elements of base operations	Alternative						
	A	B	C	D	E	F	G
Monthly pattern in release volume	Historic monthly release volumes.	Same as Alternative A	Highest volume in high electric demand months; February–June volumes proportional to contract rate of delivery; lower volumes August–November	Comparable to Alternative E, but August and September volume increased, with additional volume taken from January through July	Monthly volumes proportional to the contract rate of delivery, but with a targeted reduction in August–October volumes; volume released in October, November, and December=2.0 maf in > 8.23-maf years	Relative to Alternative A, higher release volumes in April–June; lower volumes in remaining months	Equal monthly volumes, adjusted with changes in runoff forecast.
Minimum flows (ft^3/s)	8,000 during day; 5,000 during night	Same as Alternative A	Same as Alternative A	Same as Alternative A	Same as Alternative A	5,000	5,000
Maximum flows (ft^3/s)	25,000	Same as Alternative A	Same as Alternative A	Same as Alternative A	Same as Alternative A	Same as Alternative A	Same as Alternative A.
Daily range (ft^3/s)	5,000, 6,000, or 8,000 depending on monthly volume	December and January: 12,000 February, July, and August: 10,000 October, November, March, June, and September: 8,000 April and May: 6,000	Equal to 7 × monthly volume in kaf in all months; 2,000 ft^3/s following significant sediment input in summer or fall	Equal to 10 × monthly volume in kaf in June–August, and 9 × monthly volume in kaf in other months; not to exceed 8,000 ft^3/s	Equal to 12 × monthly volume in kaf in June–August, and 10 × monthly volume in kaf in other months; 2,000 ft^3/s following significant sediment input in summer or fall	0	0
Ramp rates (ft^3/s-hr)	4,000 up 1,500 down	4,000 up 4,000 down November–March 3,000 down in other months	4,000 up 2,500 down	4,000 up 2,500 down	4,000 up 2,500 down	4,000 up 1,500 down	4,000 up 1,500 down.

Table 3. Triggered and experimental elements of the Long-Term Experimental and Management Plan long-term strategies.

[A filled circle (●) indicates the element in question is implemented fully in the long-term strategy; an open circle (○) indicates the element in question is implemented in some partial degree; and -- indicates that element is not part of that long-term strategy. HFE, high-flow experiment]

Element	Alternative																	
	A	B		C				D				E						F	G
	A	B1	B2	C1	C2	C3	C4	D1	D2	D3	D4	E1	E2	E3	E4	E5	E6	F	G
Fall HFEs	○	○	○	●	●	--	●	●	●	●	●	●	●	--	●	--	--	●	●
Spring HFEs	○	○	○	●	●	--	--	○	○	○	○	○	○	--	--	--	--	●	●
Proactive spring HFEs	--	--	--	●	●	--	--	●	●	●	●	--	--	--	--	--	--	--	●
HFEs longer than 96-hour duration	--	--	--	●	●	--	●	○	○	○	○	--	--	--	--	--	--	--	●
Trout management flows	--	●	●	●	--	--	--	●	●	--	●	●	--	--	--	--	●	--	●
Low summer flows	--	--	--	--	●	--	--	○	○	○	--	--	●	--	--	●	--	--	--
Bug flows	--	--	--	--	--	--	--	--	●	--	--	--	--	--	--	--	--	--	--
Hydropower improvement flows	--	--	●	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Steady flows before HFEs	--	--	--	●	●	--	●	●	●	●	●	●	●	--	●	--	--	●	●
Steady flows after HFEs	--	--	--	●	●	--	●	●	●	●	●	--	--	--	--	--	--	●	●
Mechanical trout removal	●	●	●	--	--	●	●	●	●	●	●	--	--	●	●	--	--	--	●

weekends, so timing the benthic invertebrate production flows during the weekends minimizes the effect on the value of hydropower generation.

Hydropower improvement flows are an experimental action considered under Alternative B to increase hydropower generation during high-demand months (December–February and June–August) in years when the annual volume is less than or equal to (≤) 8.23 million acre-feet. These flows work largely by allowing a greater daily range and higher ramp rates.

Some of the alternatives use steady flows before an HFE to conserve sediment for the high-flow release, after an HFE to reduce erosion of newly built sandbars, or both (table 3). These steady flows stop the load-following patterns of hourly releases and are sometimes called "load-following curtailment."

5.1.5 Nonflow Actions

Under a 2011 assessment (Bureau of Reclamation, 2011b), experimental methods of controlling trout populations were evaluated and implemented. These methods include mechanical removal of brown trout (*Salmo trutta*) and RBT at the Little Colorado River through electrofishing, selective removal, and beneficial use of the fish removed. Many of the LTEMP EIS alternatives allow for continued use of mechanical removal with specific requirements for when such removal would be triggered (table 3).

Under all alternatives except Alternative A (no-action alternative), the NPS would implement experimental vegetation restoration to modify the cover and distribution of plant communities along the Colorado River. This restoration would include removal of nonnative species, prevention of new introductions, planting of native species, management of vegetation at campsites, and removal of windrows that block wind transport of sediment.

5.1.6 Long-Term Strategies

Four of the seven alternatives (Alternatives B, C, D, and E) were conceived as experimental and adaptive strategies, with elements that would be deployed experimentally to allow resolution of uncertainty and subsequent adaptation of the strategy in response to the information acquired; thus, within each of these alternatives are a number of implicit long-term strategies that might result after resolution of uncertainty. Not all of those possible long-term strategies were analyzed, but a representative set from each alternative was articulated and analyzed to capture the possible range of environmental effects and evaluate the importance of resolving the underlying uncertainty; thus, for example, under Alternative C, whether or not to implement fall HFEs, spring HFEs, TMFs, low summer flows, or mechanical removal will depend on the efficacy of those actions in achieving their intended purpose, the strengths of undesirable side effects of those actions, and the underlying effect of RBT on HBC. The long-term strategies C1, C2, C3, and C4 represent a range of possible solutions once such uncertainty is resolved; if, for instance, spring HFEs have a beneficial effect on sediment deposition and only a small effect on RBT production, TMFs are ineffective, but low summer flows benefit HBC, then long-term strategy C2 might be the best version of Alternative C to use. All of the 19 long-term strategies (table 3) were evaluated against the critical uncertainties described in sections 6.2.1, 6.3.1, and 6.5.1.

5.2 Alternative A (No Action)

Alternative A, the no-action alternative, represents continued operation of Glen Canyon Dam under the existing guidelines in Bureau of Reclamation (1996), interim guidelines in Bureau of Reclamation (2007), and the two 2011 EAs (Bureau of Reclamation, 2011a, 2011b), as well as other applicable guidance. This alternative has a base operation pattern that was called MLFF in Bureau of Reclamation (1996). Both of the 2011 EAs expire after 2020, so the elements specified in them (HFEs and mechanical removal) would cease at that point (Bureau of Reclamation 2011a, 2011b). Beyond the actions discussed in Bureau of Reclamation (2011a, 2011b), there are limited experimental options that can be tested under this alternative.

5.3 Alternative B

Alternative B was designed to increase the value of hydropower generation while limiting negative effects to other resources. This alternative was submitted by the Colorado River Energy Distributors Association (CREDA), a member of AMWG. The base operations are designed to generate more valuable power than Alternative A by increasing the daily range and ramp rates to allow power generation to more closely follow power demand. This alternative limits the implementation of HFEs to one every other year because HFEs release water without generating power and require water volumes to be shifted from months when the value of power is potentially higher to other months. To moderate some of the negative effects of this water-release pattern on other resources, Alternative B includes mechanical removal, evaluation of TMFs, and experimental implementation of vegetation restoration.

5.3.1 Alternative Long-Term Strategies

Alternative B includes two long-term strategies, one with its base operations (B1) and one that includes hydropower improvement flows (B2), maximum power plant capacity flows implemented as many as four times during the LTEMP period, in years when the annual volume is ≤8.23 million acre-feet (table 3). Such years, because of their lower volume of release, typically require the most purchases by WAPA to meet contractual demand, so the higher flows could mitigate costly purchases in high-demand months. Whether B1 or B2 is a better long-term strategy, when the effects across all resource goals are taken into account, depends on the strength of negative effects of greater power generation on other resources. Specific hypotheses for these negative effects, which are uncertain, were not explicitly articulated when Alternative B was submitted. The long-term strategies B1 and B2 were evaluated, however, against the set of uncertainties developed in the context of other alternatives.

5.4 Alternative C

Alternative C was developed by the joint-lead agencies to maintain or improve multiple resources, with some priority placed on HBC, sediment, and hydropower. Called the "condition-dependent adaptive strategy" in interim public documents during the preparation of the EIS (Bureau of Reclamation and National Park Service, 2014), Alternative C has information-dependent and condition-dependent triggers, seeks to test critical hypotheses, and contains explicit instructions for how new insights will affect subsequent implementation of action elements.

Compared to many of the other alternatives, the base operations for Alternative C shift monthly volumes from the monsoon months (August through November) to high-demands months (December, January, and July) to reduce sediment transport during the monsoonal high-sediment-input period and limit effects on the value of power generation. The reduced volume in late summer is also intended to provide warmer river temperatures for the benefit of HBC and other native fish.

Alternative C includes a number of condition-dependent (triggered) elements; among them are fall HFEs, spring HFEs, proactive spring HFEs, extended duration HFEs, TMFs, low summer flows, load-following curtailment, and mechanical removal of trout. The specific details of the triggers for these events are found in chapter 2 of the EIS. Most of these elements are experimental, and so there are information-dependent triggers as well; that is, monitoring and evaluation of all these elements would be completed, and elements would be dropped or retained depending on if the evidence supported their retention.

5.4.1 Alternative Long-Term Strategies

Four long-term strategies (C1, C2, C3, and C4) were developed to capture the range of possible outcomes from adaptive implementation of Alternative C (table 3). The motivation for the creation of these long-term strategies was the recognition that there are critical uncertainties that impede identification of the best long-term strategy. The key questions concerned the following: the magnitude of increase in RBT production in the Glen Canyon reach caused by fall HFEs, the relative effects of temperature and trout density on survival and growth of juvenile HBC at the Little Colorado River, and the effectiveness of TMFs in reducing RBT production. The relevance of these uncertainties arises because of the possible tradeoffs among the objectives of supporting the HBC population, maintaining a strong rainbow trout fishery, increasing sediment deposition and sandbar building, and affirming tribal values concerning the respect for life (especially aquatic life). Each of the action elements under consideration (HFEs, TMFs, low summer flows, and mechanical removal) is meant to increase achievement of one or more of those objectives, but the question is if the benefits to one objective come at the expense of others. Alternative C was designed under the

assumption that the best mix of action elements (the best long-term strategy) depends on resolution of the critical uncertainties.

Long-term strategy C1 allows use of all the triggered elements from Alternative C except for low summer flows and mechanical removals; such a strategy has been hypothesized to be warranted, for instance, if the effect of spring HFEs on trout production was weak, TMFs were effective, and low summer flows were not effective. Long-term strategy C2 is similar to C1 except that it calls for low summer flows but not TMFs. Long-term strategy C3 does not allow HFEs and might be called for if HFEs are determined to cause a very strong increase in trout recruitment and other actions are ineffective at mitigating the effect of trout on HBC. Long-term strategy C4 allows fall HFEs but not spring HFEs and manages the effect of trout on HBC through mechanical removal.

Whether or not the resolution of the critical uncertainties actually matters to the ranking of the long-term strategies is one of the central questions in section 8.3, "Expected Value of Information."

5.5 Alternative D

Alternative D was developed by the joint-lead agencies after a full analysis of the other six LTEMP alternatives had been completed. The initial analysis suggested that there were strong characteristics of Alternatives C and E that contributed to achievement of resource goals and motivated creative thinking about how to achieve more of those benefits in a single alternative. Alternative D adopts characteristics of Alternatives C and E.

The base operations for Alternative D are in many respects a compromise between those of Alternatives C and E (table 2). The monthly pattern of release is most similar to that of Alternative E, with an increase in the August and September volumes (and a corresponding decrease in the January through June volumes). The daily range for flows is about midway between the ranges from Alternatives C and E.

The experimental and adaptive options for Alternative D include all the elements considered in the any of the alternatives, except for hydropower improvement flows (table 3). The experimental implementation calls for early testing of TMFs in the first 2–5 years without having to meet the condition-dependent triggers and delayed consideration of spring HFEs until the third year of implementation.

5.5.1 Alternative Long-Term Strategies

Four long-term strategies (D1, D2, D3, and D4) were developed to capture the range of possible outcomes from adaptive implementation of Alternative D (table 3). The long-term strategies in this set look more similar than in the sets for Alternatives C and E because they were created after an initial analysis of the other six alternatives and, thus, reflect insights from that analysis. For instance, long-term strategies D1 through D4 are all similar with regard to implementation of HFEs because the initial analysis suggested that the benefits of HFEs outweighed the costs, even in the face of the uncertainties tested. There remain, however, other long-term strategies implicit in Alternative D; for example, if spring, proactive, or extended HFEs are determined to have very strong negative effects on resources of importance that cannot be mitigated by other actions, they could be removed from long-term implementation. The four long-term strategies for Alternative D, however, are thought to capture the most important differences that might arise in long-term implementation.

Long-term strategy D4 might be considered the base strategy under Alternative D because all action elements except low summer flows and bug flows are in operation (table 3). Long-term strategy D1 adds low summer flows. Long-term strategy D2 adds implementation of bug flows and would be supported if early experimental tests of bug flows determined they had the intended effects in restoring important native benthic invertebrate communities without having adverse effects on other resources. Under this long-term strategy, low summer flows would only be implemented in the second 10 years. Long-term strategy D3 is similar to D1 but removes TMFs.

The motivations for the different long-term strategies in Alternative D are the same critical uncertainties that motivate the long-term strategies in Alternative C, with a specific focus on the effectiveness of TMFs, the influence of temperature on juvenile HBC growth and survival, and the effect of bug flows on other resources.

5.6 Alternative E

Alternative E was developed by representatives of the seven states in the Colorado River Basin to provide for recovery of HBC while protecting other important resources, including sediment, the RBT fishery at Lees Ferry, aquatic food base, and hydropower resources. Called the "resource-targeted condition-dependent" strategy in interim public documents during the preparation of the EIS (Bureau of Reclamation and National Park Service, 2014), Alternative E has information-dependent and condition-dependent triggers, seeks to test critical hypotheses, and contains explicit instructions for how new insights will affect subsequent implementation of action elements.

The base operations for Alternative E seek greater value of hydropower production than Alternatives C and D (table 2). The monthly volumes largely follow hydropower demand and are proportional to the contract rate of delivery but with a reduction in August through October volumes to conserve sediment during the monsoon period. The daily range is large compared to the other alternatives. The ramp rates are the same as in Alternative C and D.

Alternative E includes a number of condition-dependent (triggered) elements; among them are fall HFEs, spring HFEs, TMFs, low summer flows, load-following curtailment

(before but not after HFEs), and mechanical removal of trout (table 3). Implementation of spring HFEs is delayed until the second 10 years to allow testing of TMFs in the early years (with long-term implementation of spring HFEs conditional on TMFs being an effective tool). An important experimental element of Alternative E is early testing of the response of RBT populations to TMFs and fall HFEs in a 2x2 factorial design, replicated two to three times (in hopes of experiencing both cold and warm water temperatures). The specific details of the triggers for these events are found in chapter 2 of the EIS. Most of these elements are experimental, and so there are information-dependent triggers as well; that is, monitoring and evaluation of all these elements would be completed, and elements would be dropped or retained depending on if the evidence supported their retention.

5.6.1 Alternative Long-Term Strategies

Six long-term strategies (E1, E2, E3, E4, E5, and E6) were developed to capture the range of possible outcomes from adaptive implementation of Alternative E (table 3). The motivation for the creation of these long-term strategies was the recognition that there are critical uncertainties that impede identification of the best long-term strategy. The key questions concerned the following: the magnitude of increase in RBT production in the Glen Canyon reach caused by fall HFEs, the relative effects of temperature and trout density on survival and growth of juvenile HBC at the Little Colorado River, the effectiveness of TMFs in reducing RBT production, and the effect of high flows on sediment retention.

Long-term strategy E1 uses spring and fall HFEs when triggered, along with TMFs to manage the trout populations; this long-term strategy would be favored, for example, if HFEs are determined to be beneficial to sediment conservation and TMFs are effective in controlling trout populations. Long-term strategy E2 also uses spring and fall HFEs but uses low summer flows instead of TMFs; this strategy might be favored if temperature is a more important factor in HBC survival than trout predation and TMFs are ineffective. Long-term strategy E3 does not allow HFEs, TMFs, or low summer flows and uses mechanical removal to manage trout density at the Little Colorado River when needed; such a strategy might be favored if HFEs greatly increase production of trout, TMFs are ineffective in managing trout populations, HBC are strongly affected by trout predation, and low summer flows do not provide enough advantage to HBC to warrant use. Long-term strategy E4 allows fall HFEs but not spring HFEs and relies on mechanical removal to manage trout at the Little Colorado River. Long-term strategy E5 is like E3 in not allowing HFEs but uses low summer flows rather than mechanical removal to support HBC population growth. Long-term strategy E6 also does not use HFEs and uses TMFs when needed to manage trout. As with Alternatives C and D, these long-term strategies are not meant to be a comprehensive set of the possible permutations of Alternative E that might arise from adaptive implementation but, rather, are meant to represent a broad range of possible outcomes, effectively bracketing the strategies that might arise.

As with Alternative C and D, whether or not the resolution of the critical uncertainties actually matters to the ranking of the long-term strategies is one of the central questions in section 8.3, “Expected Value of Information.”

5.7 Alternative F

Alternative F was designed to follow a more natural pattern of flows, limiting sediment transport and providing warmer temperatures in the summer months. The base operations provide higher release volumes in April–June (to mimic spring runoff), including a May 1 high-flow spike of 45,000 ft^3/s (essentially an untriggered HFE) and lower volumes the remainder of the year. The daily flows are steady with no daily fluctuations (no hydropeaking). The only modification to base operations would be sediment-triggered HFEs (fall and spring). In keeping with the desire to have this alternative better match predam conditions than the other alternatives, it does not use TMFs or mechanical removal.

5.8 Alternative G

Alternative G was designed to maximize the conservation of sediment by providing year-round steady flows. The base operations provide equal monthly volumes and steady daily flows. In practice, the monthly volumes would have to be adjusted as the forecasts for annual volume change through the year, but the intent is to keep flows quite steady. This alternative does allow all forms of HFEs to be used to maximize sandbar building and sediment conservation.

6 Quantitative Methods

The 19 long-term strategies were evaluated against the 18 performance metrics and 5 sources of uncertainty: the hydrology during the 20-year LTEMP period of performance, the sediment inputs during the 20-year LTEMP period of performance, the relative effects of temperature and trout predation on juvenile HBC survival and growth, the effectiveness of trout management flows, and the effect of fall HFEs on trout recruitment. A total of 10 modeling teams built a linked set of analyses to simulate the performance of the long-term strategies; the performance metrics were calculated from the simulation outputs. This section describes the methods used to complete these analyses.

6.1 Modeling Overview

The basis of the analysis of the alternatives was a large, linked set of simulation models that were meant to represent the Colorado River ecosystem below Glen Canyon Dam (fig. 2).

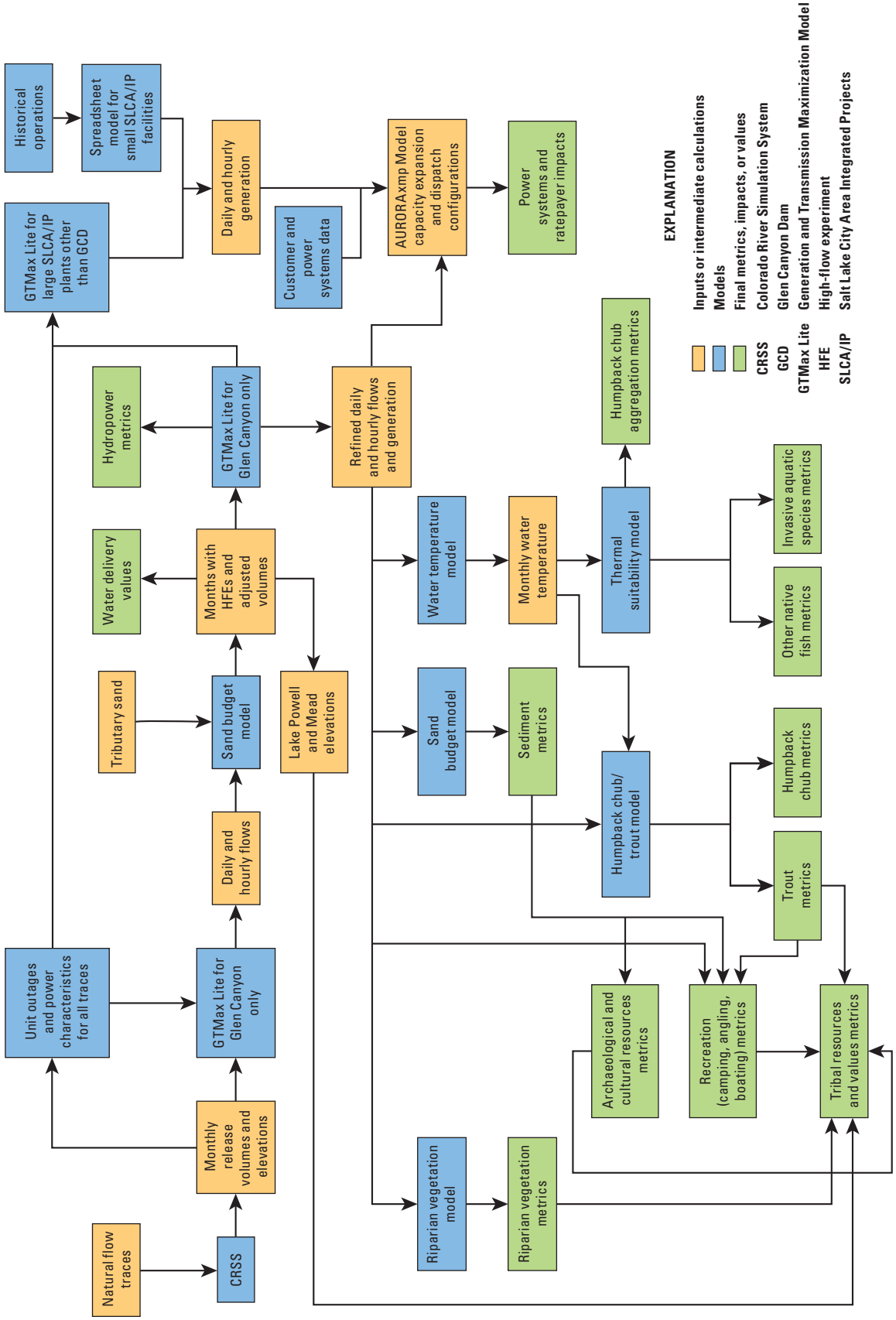

Figure 2. Model flow for the analysis of the Long-Term Experimental and Management Plan long-term strategies against the performance metrics.

Each long-term strategy encoded a set of rules that governed annual, monthly, daily, and hourly flow through the dam, as well as mechanical removal of nonnative fish from the Colorado River at its confluence with the Little Colorado River and vegetation treatments along the river corridor. The long-term strategy, coupled with 21 hydrological traces and 3 sediment traces (to represent environmental variation), determined the flows through the Glen Canyon Dam. The daily and hourly flows then were sent to models for vegetation, sediment, and temperature. The temperature and flow outputs then informed models for RBT, HBC, and other aquatic organisms. The outputs of all these models were collected and used to calculate performance metrics under all the resource goals. The details of all these modeling methods are provided in the technical appendixes to the LTEMP EIS; a synopsis is provided here.

6.2 Hydrology

The hydrological modeling requires three sets of input: a time series of hydrological flow into Lake Powell, a time series of sediment input into the Colorado River from the Paria River and the Little Colorado River, and the operational rules determined by a long-term strategy. The output of the hydrological modeling is the monthly, daily, and hourly flows through Glen Canyon Dam for the 20-year LTEMP period of performance. This requires three modeling systems. First, the Colorado River Simulation System (CRSS), built with the commercial software package RiverWare™ (Zagona and others, 2001), generates monthly volumes and lake elevations taking into account the operations of the 12 primary reservoirs on the Colorado River. Second, the Generation and Transmission Maximization model (GTMax-Lite) generates daily and hourly flows taking into account patterns of demand and supply of electric power in the Colorado River Storage Project (CRSP) region. Third, a sand budget model tracks sediment in Glen, Marble, and Grand Canyons; and is used to indicate when sediment conditions warrant high-flow experiments (if the long-term strategy in question allows them). After the HFEs are identified, a second pass through GTMax-Lite is required to refine the daily and hourly flows. Note that the effect of TMFs on hydrology were not modelled because this would have required a full coupling of the hydrology and fish models (with feedback from the fish models to the hydrology models), which was a computing task that was beyond the resources available.

6.2.1 Critical Uncertainty

To model uncertainty in future inflow, the indexed sequential method (Ouarda and others, 1997) was used to resample the historical record of natural flow in the Colorado River system during the 105-year period from 1906 through 2010. Every fifth trace was selected from this series to produce 21 hydrological traces; every long-term strategy was evaluated against all 21 hydrological traces.

To investigate the possible effects of climate change on the performance of the long-term strategies, CRSS was run with 112 natural flow traces developed from downscaled general circulation model projected hydrological traces (Bureau of Reclamation, 2012). These climate scenarios were based on 16 general circulation models from the Coupled Model Intercomparison Project Phase 3 (CMIP3) using three forcing scenarios (A2, high; A1b, medium; and B1, low) (Maurer and others, 2007). The LTEMP models were not run with the 112 hydrological traces; rather, the 112 hydrological traces from the climate-change scenarios were used to place weights on the 21 index sequential historical traces. The model results are compared using historical (equal) and climate-change weights on the 21 hydrological traces.

6.3 Sediment Dynamics

A sand budget model (Russell and Huang, 2010; Wright and others, 2010) was used to track sand storage and transport from Lees Ferry (RM 0) to Bright Angel Creek (RM 87) (fig. 1). The sand budget model takes as input hourly hydrographs at the reach boundaries (RM 30, RM 61, and RM 87) developed based on release schedules from Glen Canyon Dam and hourly sand delivery from the Paria and Little Colorado Rivers. The model tracks sand storage and movement through three reaches (Upper Marble Canyon, RM 0 to 30; Lower Marble Canyon, RM 30 to 61; and Eastern Grand Canyon, RM 61 to 87) using empirically-based rating curves formulated on a particle-size-specific basis. The outputs of the model include hourly time series of the sand transported at the downstream border of each reach, and the sand budget for each reach. From these outputs a variety of performance metrics, including the SLI (performance metric 15), can be calculated.

6.3.1 Critical Uncertainty

Sediment input to the Colorado River between Lees Ferry and Bright Angel Creek comes primarily from the Paria River and the Little Colorado River (fig. 1). Variation in sediment input is driven by spatial and temporal variation in precipitation. To capture uncertainty about the time series of future sediment input, three 20-year traces of sediment input were created from historical records using an index sequential method. For Paria River input, 49 reconstructed historical traces were available (index years 1964–2012). For Little Colorado River input, 18 reconstructed historical traces were available (index years 1995–2012). The cumulative 20-year sediment delivery for each trace was calculated; and the traces corresponding to the 10th, 50th, and 90th quantiles of cumulative sediment delivery were selected to represent the range of possible uncertainty. The traces from corresponding quantiles for the Paria River and Little Colorado River delivery were coupled in the simulations. Weights were placed on the three sediment traces so that the weighted mean and standard deviation of the 20-year Paria River sediment delivery for the three

traces matched the mean and standard deviation for the full set of index sequential Paria River traces.

6.4 Temperature

The average monthly water temperatures along the river corridor from Glen Canyon Dam to Lake Mead were forecast using the monthly flow and air temperatures forecasts. The release temperature from Glen Canyon Dam was simulated with the CE–QUAL–W2 model (Cole and Wells, 2006). This served as an input to a river temperature model that calculated the gains and losses of heat as the water moved downstream (Wright and others, 2009). For the purposes of the decision analysis, water temperature was an intermediate variable used as input to the fish models but not used directly as a performance metric.

6.5 Coupled Rainbow Trout-Humpback Chub Dynamics

A coupled RBT–HBC model was used to simulate the population dynamics of RBT in the Glen Canyon reach, movement of RBT from Lees Ferry to the Little Colorado River confluence, and the population dynamics of HBC in the Little Colorado River reach. The RBT population dynamics were simulated with an age-structured population model that accounted for the effects of water flow on recruitment, survival, growth, and downstream emigration (Korman and others, 2012). The RBT performance metrics are calculated from this model. The RBT catch rate (performance metric 3) was calculated from the age-specific abundances, age-specific vulnerabilities, and a catchability coefficient. The abundance of RBT greater than 16 inches (considered high-quality RBT; performance metric 5) was calculated from the age-specific abundances and size-at-age characteristics. The annual emigrants (performance metric 4) were computed as a fraction of the recruitment.

The RBT movement model predicts the monthly abundance of RBT in each 1-mile segment of the Colorado River from RM 0 to RM 150 taking into account movement rates, natural mortality, and implementation of mechanical removal. Movement and survival were density independent and were not affected by flow or temperature.

A size- and location-structured population model was used to predict the adult population size of HBC at monthly intervals (Yackulic and others, 2014). The HBC population size in two locations, the Colorado River and the Little Colorado River (a tributary of the Colorado River), was accounted for in the model. Survival of juvenile HBC in the Colorado River depended on the abundance of RBT in the Little Colorado River reach of the Colorado River; their growth depended on RBT abundance and temperature. Growth rates in other size classes in the Colorado River depended on water temperature. From this model, the minimum number of adult HBC during each 20-year trace was calculated, and the expected minimum value (performance metric 1) was calculated by taking the mean across traces.

6.5.1 Critical Uncertainties

A number of critical uncertainties concerned parameters in the RBT and HBC models. Each of these uncertainties was expressed as alternative sets of model parameters. All long-term strategies, with all sediment and hydrology traces, were run separately against the combinations of model parameters. The alternative sets of model parameters were assigned weights to represent their empirical support, and weighted averages of the performance metrics were calculated across them.

Uncertainty about the effect of fall HFEs on recruitment of RBT in the Glen Canyon reach was expressed as two hypotheses: one that there is no effect on recruitment, and another that proposed recruitment would increase at the same rate as seen with spring HFEs (Korman and others, 2011) but for only 1 year instead of 2 years. An expert panel consisting of four fish biologists who were familiar with RBT dynamics in the Colorado River was convened in March 2014. A modified Delphi process with four-point elicitation (Speirs-Bridge and others, 2010) was used to estimate the likelihood of the two hypotheses; the resulting individual estimates were aggregated by simple averaging.

Uncertainty about the effect of TMFs in reducing RBT recruitment in the Glen Canyon reach was expressed as two hypotheses by the expert panel: TMFs reduce recruitment by 10 percent, and TMFs reduce recruitment by 50 percent. The two levels of effectiveness were chosen to represent equally plausible extremes.

The final area of uncertainty concerned the effects of RBT abundance and temperature on the growth and survival of juvenile HBC in the Little Colorado River reach of the main stem Colorado River. Four hypotheses were generated (fig. 3*A* and 3*B*): a strong effect of temperature on growth and a strong effect of RBT on growth and survival (f1), a weak effect of temperature on growth and a weak effect of RBT on growth and survival (f2), a weak effect of temperature and a strong effect of RBT (g1), and a strong effect of temperature and a weak effect of RBT (g2). The parameter values for the four hypotheses were chosen from the ends of diameters on the 90-percent confidence ellipsoid for the joint parameter likelihood (Yackulic and others, 2014) and, thus, were equally weighted.

6.6 Fish Habitat Suitability

Temperature suitability for HBC and other native and nonnative fish at a number of sites between Lees Ferry (RM 0) and Diamond Creek (RM 225) (fig. 1) was evaluated with species-specific models for the effect of temperature on survival, reproduction, and growth (Valdez and Speas, 2007). The details of all these methods and results are in the LTEMP EIS.

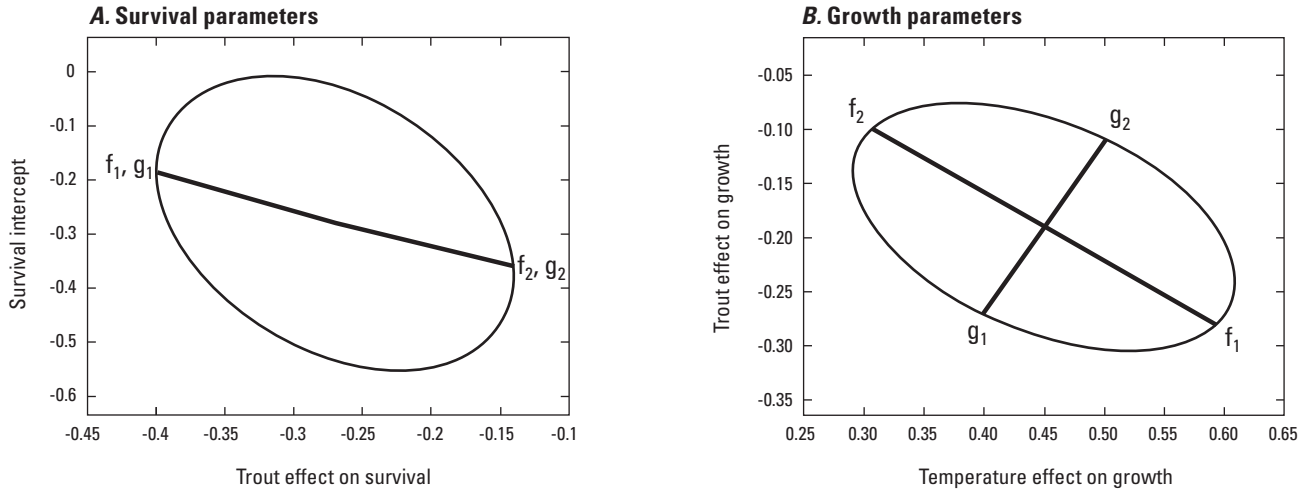

Figure 3. Uncertainty in the humpback chub population dynamics as represented by four alternative sets of parameters. *A*, survival parameters; and, *B*, growth parameters

The only one of those metrics that was retained for the decision analysis was the average temperature suitability for HBC at Havasu Creek (RM 157) and Pumpkin Spring (RM 213) because most of the other metrics exhibited very little difference across alternatives. Monthly water temperatures in the main stem Colorado River at the various sites under each long-term strategy were used to calculate the suitability for spawning, incubation, and growth during critical periods of the annual cycle. The overall temperature suitability at a site was the product of the suitability for the three component processes during the course of the year and could theoretically vary between 0 and 1 (performance metric 2).

6.7 Archaeological and Cultural Resources

The performance metrics associated with archaeological and cultural resources (performance metrics 6–8; table 1) did not require separate models but, rather, were calculated from intermediate sediment and flow variables.

6.8 Hydropower

As noted above in the "Hydrology" section (section 6.2), CRSS, the sand budget model, and GTMax-Lite are used in combination to simulate the water release and, therefore, hydropower generation on an hourly basis for each long-term strategy (fig. 2). The GTMax-Lite optimized the economic value of hourly energy produced at Glen Canyon Dam. This model determined an hour-by-hour pattern of generation (in megawatt hours) and water releases (in cubic feet per second) that satisfied the operating constraints imposed by each alternative, such as upramp and downramp rates, maximum change in the release during a rolling 24-hour period, maximum hourly release, and others. Hourly electricity market prices during the 20-year LTEMP period were determined using the AURORAxmp (Aurora) model to simulate the operation of the Western Interconnection of which Glen Canyon Dam is one of several thousand generating plants. Hourly prices determined by Aurora for 2013 were benchmarked against 2013 day-ahead market prices published by the Intercontinental Exchange. Prices forecast by Aurora for 2013 were compared against historical Intercontinental Exchange prices, and future electricity prices were adjusted accordingly.

For a given long-term strategy, the value of hydropower generation (performance metric 9) was calculated by combining the forecasts of the hourly generation profile and electricity market price. The net present value (NPV) of this 20-year time series was calculated assuming a 3.375 percent discount rate, and then divided by 20 to present the results on an annualized scale.

Hydropower capacity from Glen Canyon Dam is also marketed in the form of long-term firm contracts to provide power up to a given level. Energy demand is highest in August, so to calculate the marketable capacity (in megawatts), the peak daily generation was tabulated for each day in August across the 20 years of a trace (for each long-term strategy). From these 620 daily values (20 years x 31 days in August), the 90-percent exceedance value (10th quantile) was calculated, representing the marketable capacity for that trace. In 90 percent of August days (and much more often in other months), WAPA can be confident of being able to deliver that amount of power without having to purchase it. The net present value of that capacity (performance metric 10) was calculated by multiplying by the levelized cost of capacity plus fixed annual operating and maintenance (O&M) expenses of a thermal power plant constructed to replace capacity lost at Glen Canyon Dam. The selection of the replacement technology was based on insights obtained from the power systems economic analysis. The Aurora model runs made for this analysis determined that a natural gas combustion turbine would be the type of generating unit most likely constructed

as a replacement for lost Glen Canyon Dam capacity. The cost to construct that type of unit, spread over its book life, was determined to be $50,100/MW-year, including capital investment costs, allowance for funds during construction, and fixed O&M costs. The source of cost data for replacement power plant capacity was U.S. Energy Information Administration (2014). In the analysis in the LTEMP EIS (chapter 4 and appendix K), the daily August generation values for all traces were combined before the exceedance value was calculated; this results in some slight differences in the median values presented but not systematic bias.

6.9 Recreation

The performance metrics associated with recreation (performance metrics 11–13; table 1) did not require separate models but, rather, were calculated from intermediate sediment and flow variables.

6.10 Riparian Vegetation

The effects of the long-term strategies on riparian vegetation were simulated with a state-and-transition model for Colorado River riparian vegetation downstream from Glen Canyon Dam (Ralston and others, 2014). The model tracks seven vegetation communities (bare sand, marsh, shrub wetland, tamarisk, cottonwood-willow, arrowweed, and mesquite) on channel margins and sandbars in the New High Water Zone and Fluctuation Zone as affected by the depth, timing, and duration of inundation. Six geomorphic submodels are included: lower separation bar, upper separation bar, lower reattachment bar, upper reattachment bar, lower channel margin, and upper channel margin; only four of these are unique (the parameters for the upper separation bar, upper reattachment bar, and upper channel margin are all equal). The model starts in 1 of 25 possible states (the 7 vegetation communities crossed with the 6 geomorphic submodels; not all of the 42 combinations are possible) and then tracks the vegetation state in each subsequent year as affected by the alternative-specific flows. The output is the number of years spent in each vegetation state during the 20-year LTEMP period of performance. These results are summed across the 25 starting states and then compared to the results that would have happened if the starting state was maintained for the 20-year period. In comparing the native to nonnative states, and in calculating the native diversity, the results are weighted by the current estimated area of each vegetation state.

Four component ratios are calculated as intermediate results: the ratio of cumulative to initial native vegetation cover, the ratio of cumulative to initial vegetation state diversity, the ratio of cumulative to initial native to nonnative dominant vegetation state, and the ratio of initial to cumulative cover of arrowweed. The final value (riparian native states and diversity index; performance metric 14) is the sum of the four component ratios; thus, an index value of 4.0 indicates an unchanged vegetation condition, values greater than 4.0 indicate improved vegetation conditions, and values less than 4.0 indicate degraded vegetation conditions.

7 Consequence Analysis Results

In this section, the results for the individual performance metrics are presented. In most cases, these results are reported as means over all sources of uncertainty with boxplots used to show the variance induced by uncertainty. Unless otherwise noted, the historical weighting of hydrological traces was used; the sensitivity of the results to climate change (as captured by weighting of the hydrological traces) is discussed in section 8.4, “Effects of Climate Change.”

7.1 Humpback Chub Results

Across alternatives, the expected (mean) minimum number of adult HBC during the 20-year LTEMP period of performance differed by about 500 from Alternative A (fig. 4, bottom panel). The variation across hydrological traces within an alternative was greater than the magnitude of variation across alternatives. Many of the long-term strategies were demonstrably better than Alternative A; the biggest exceptions (C2 and F) were long-term strategies that increased RBT recruitment (through HFEs) without tools to manage RBT populations (TMFs and mechanical removal). The best-performing long-term strategy (E6) did not allow HFEs of any type and included triggered use of TMFs if needed. The benefit of low summer flows to HBC (compare D1 to D4) is not discernible, likely because of their infrequent use.

The set of 16 scenarios that captured critical uncertainty did not affect the dominance of long-term strategy E6 (table 4); that is, if the only desired outcome is to maximize the HBC metric, the best long-term strategy is E6 regardless of the effect of fall HFEs or TMFs on RBT recruitment or the relative effects of temperature and RBT on juvenile HBC growth and survival. For the purpose of the HBC objective, therefore, the expected value of information across the critical uncertainties that were articulated is 0.

Across the uncertainty represented by the hydrological traces, there is a small value of information (table 5). For most hydrological traces, the best long-term strategy for HBC was E6; but long-term strategies B2, C3, D1, and E5 were also favored in some traces. In the face of uncertainty, the best strategy is E6 with an expected (mean) minimum adult population size of 5,708. If the hydrological trace could be known in advance of choosing an action, the appropriate strategy (B2, C3, D1, E5, or E6) would be chosen; the expected minimum adult population size would be 5,725, which is an increase of 0.30 percent. Of course, the hydrological trace cannot be known in advance of choosing an action because it represents environmental variation during the next 20 years, but the inclusion of these results is helpful in understanding the value

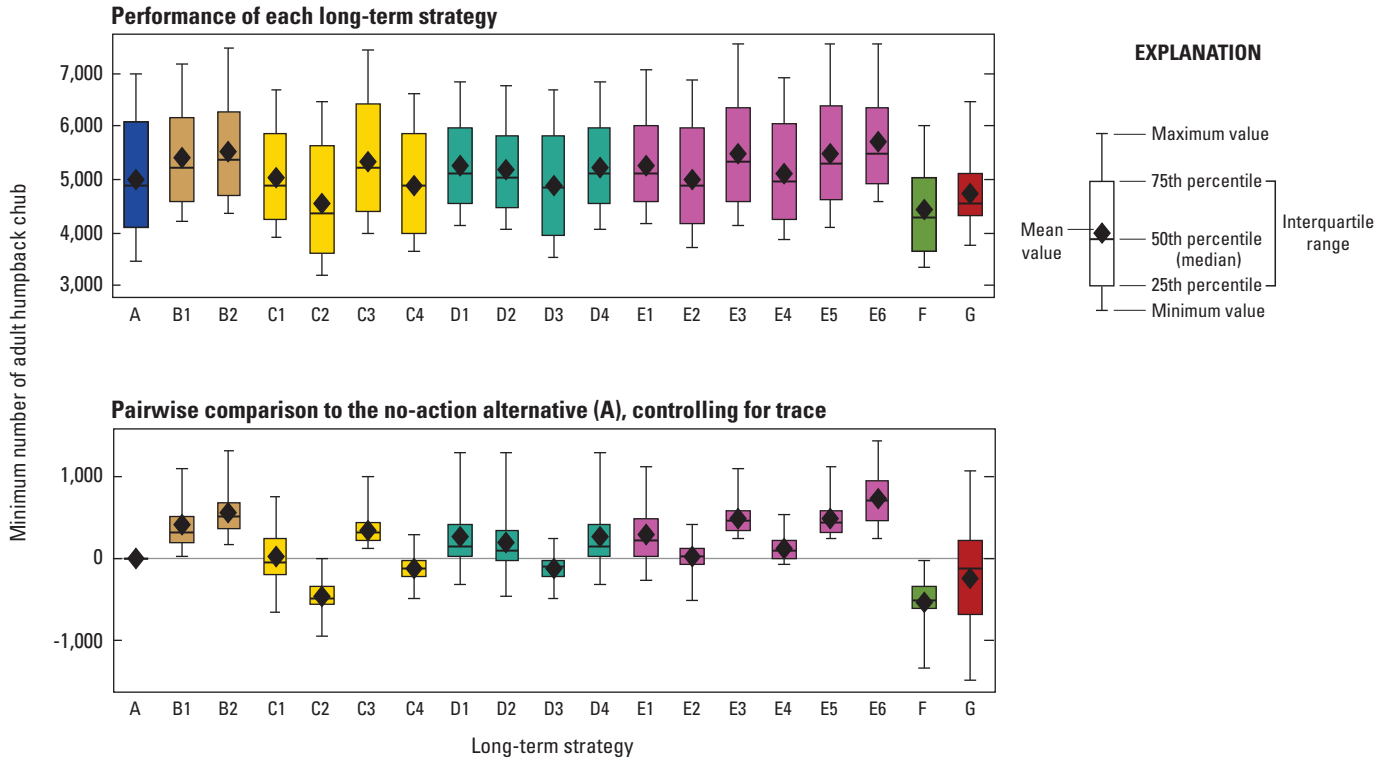

Figure 4. Minimum number of adult humpback chub (performance metric 1) forecast for 19 long-term strategies with equal weighting of traces.

of information for resolvable uncertainty (the 16 scenarios) relative to the value of information for background environmental variation.

The value of information depends on the set of long-term strategies evaluated. The calculations just described assume the decision maker is choosing from the entire set of 19 long-term strategies. In practice, it is more likely that one of the alternatives would be chosen, and the long-term strategy would be chosen from within the set associated with that alternative. The value of information in resolving the critical uncertainties is 0 for all alternatives except Alternative C, which has a value of information of 8.5 adult HBC (table 6).

Temperature suitability for HBC was forecast at a number of locations in the main stem Colorado River, and in most cases the suitability was low (less than 0.03 on a scale of 0 to 1). At the two locations farthest downstream (Havasu Creek, RM 157; Pumpkin Spring, RM 213; fig. 1), the average suitability was around 0.1 (on a scale of 0 to 1). The temperature suitability for HBC was affected more by hydrology than by the long-term strategy; only Alternative F stood out from the other alternatives (fig. 5). Alternative G, with its year-round steady flows, provided the best suitability (mean 0.102); its ranking above the other long-term strategies was not affected by any of the critical uncertainties (table 6). There was a small effect of the hydrological trace on the ranking of alternatives based on temperature suitability (EVXI; 0.77 percent; table 6).

7.2 Rainbow Trout Fishery Results

The RBT performance metrics differed substantially across long-term strategies (figs. 6–8). The RBT catch rate (performance metric 3) and RBT emigration rate (performance metric 4) were highly correlated with one another because both were driven by the RBT population size. Catch rate and emigration rate were highest for those long-term strategies that implemented many HFEs but did not allow TMFs (C2, C4, D3, E2, and F) or that provided steady flows that supported RBT recruitment (G) (figs. 6–7). The abundance of high-quality RBT (greater than 16 inches in length, performance metric 5) was negatively correlated with RBT population size; the best long-term strategies were those that restricted or did not allow HFEs (B1, B2, C3, E3, E5, E6) (fig. 8).

Apart from the HBC metric when only the strategies under Alternative C were considered, the RBT performance metrics were the only ones affected by the critical uncertainties; the fall HFE hypothesis had an EVXI of 0.26 percent, 3.50 percent, and 0.98 percent for the three performance metrics, respectively (table 6). Across all performance metrics and all uncertainties, the strongest effect was the effect of the combined hydrological/sediment trace on the RBT catch rate with an EVXI of 7.53 percent (table 6). The uncertainty about the effectiveness of TMFs did not affect the top ranked long-term strategy for any of the trout or other performance metrics (table 6).

Table 4. Effect of critical uncertainty on minimum adult humpback chub population size (performance metric 1).

[The cell entries show the expected minimum humpback chub population size for each long-term strategy in each combination of hypotheses. The hypotheses are if high-flow experiments increase rainbow trout recruitment (N, no; Y, yes), how effective rainbow trout management flows are (H, high effectiveness; L, low effectiveness), and the relative effects of temperature and rainbow trout on juvenile humpback chub survival and growth (f1, f2, g1, and g2). A solid dot (●) indicates the result is averaged over this uncertainty. The highlighted long-term strategy is the best performing alternative in each row. HFE, high-flow experiments; TMF, trout management flow; RBT, rainbow trout]

Fall HFE	TMF	Model	A	B1	B2	C1	C2	C3	C4	D1	D2	D3	D4	E1	E2	E3	E4	E5	E6	F	G
N	H	f1	5,204	5,712	5,858	5,463	4,766	5,408	5,402	5,655	5,576	5,174	5,645	5,839	5,500	5,580	5,574	5,572	5,900	4,409	5,082
N	H	f2	5,116	5,413	5,520	5,268	4,772	5,253	5,246	5,324	5,275	5,050	5,318	5,482	5,298	5,357	5,352	5,351	5,521	4,545	5,028
N	H	g1	5,195	5,774	5,941	5,430	4,632	5,377	5,372	5,655	5,556	5,116	5,646	5,874	5,500	5,597	5,593	5,582	5,947	4,184	5,042
N	H	g2	5,135	5,396	5,486	5,324	4,901	5,303	5,295	5,368	5,329	5,125	5,359	5,493	5,327	5,375	5,369	5,376	5,527	4,773	5,078
N	L	f1	5,204	5,653	5,799	5,251	4,766	5,408	5,402	5,439	5,367	5,003	5,432	5,790	5,500	5,580	5,574	5,572	5,857	4,409	4,803
N	L	f2	5,116	5,382	5,487	5,132	4,772	5,253	5,246	5,214	5,168	4,959	5,209	5,457	5,298	5,357	5,352	5,351	5,500	4,545	4,855
N	L	g1	5,195	5,710	5,877	5,189	4,632	5,377	5,372	5,420	5,332	4,931	5,415	5,822	5,500	5,597	5,593	5,582	5,902	4,184	4,739
N	L	g2	5,135	5,367	5,457	5,206	4,901	5,303	5,295	5,265	5,228	5,036	5,257	5,470	5,327	5,375	5,369	5,376	5,507	4,773	4,922
Y	H	f1	4,803	5,340	5,538	4,824	4,210	5,408	4,365	5,266	5,179	4,781	5,258	4,936	4,608	5,580	4,727	5,572	5,900	4,352	4,603
Y	H	f2	4,870	5,193	5,327	4,878	4,412	5,253	4,559	5,104	5,051	4,820	5,100	4,948	4,715	5,357	4,808	5,351	5,521	4,494	4,709
Y	H	g1	4,748	5,349	5,578	4,720	4,038	5,377	4,232	5,214	5,111	4,680	5,208	4,861	4,496	5,597	4,643	5,582	5,947	4,126	4,549
Y	H	g2	4,916	5,201	5,317	4,974	4,571	5,303	4,679	5,168	5,124	4,914	5,161	5,019	4,814	5,375	4,886	5,376	5,527	4,726	4,762
Y	L	f1	4,803	5,280	5,475	4,639	4,210	5,408	4,365	5,015	4,939	4,575	5,010	4,880	4,608	5,580	4,727	5,572	5,857	4,352	4,364
Y	L	f2	4,870	5,159	5,291	4,755	4,412	5,253	4,559	4,972	4,924	4,702	4,969	4,913	4,715	5,357	4,808	5,351	5,500	4,494	4,557
Y	L	g1	4,748	5,282	5,509	4,521	4,038	5,377	4,232	4,950	4,860	4,472	4,947	4,801	4,496	5,597	4,643	5,582	5,902	4,126	4,292
Y	L	g2	4,916	5,170	5,285	4,864	4,571	5,303	4,679	5,042	5,001	4,793	5,036	4,988	4,814	5,375	4,886	5,376	5,507	4,726	4,621
Grand mean																					
●	●	●	4,991	5,392	5,541	5,016	4,527	5,335	4,874	5,247	5,181	4,876	5,241	5,269	5,015	5,477	5,103	5,470	5,708	4,450	4,741
Effect of fall HFE hypotheses																					
N	●	●	5,162	5,551	5,678	5,283	4,768	5,335	5,328	5,417	5,354	5,049	5,410	5,653	5,406	5,477	5,472	5,470	5,708	4,478	4,943
Y	●	●	4,835	5,247	5,415	4,772	4,308	5,335	4,459	5,091	5,024	4,717	5,086	4,918	4,658	5,477	4,766	5,470	5,708	4,424	4,557
Effect of TMF hypotheses																					
●	H	●	4,991	5,415	5,565	5,098	4,527	5,335	4,874	5,337	5,268	4,950	5,330	5,290	5,015	5,477	5,103	5,470	5,724	4,450	4,847
●	L	●	4,991	5,368	5,516	4,933	4,527	5,335	4,874	5,157	5,094	4,801	5,152	5,248	5,015	5,477	5,103	5,470	5,691	4,450	4,636
Effect of temperature and RBT hypotheses																					
●	●	f1	4,995	5,488	5,660	5,030	4,475	5,408	4,859	5,334	5,256	4,874	5,327	5,340	5,034	5,580	5,131	5,572	5,878	4,379	4,702
●	●	f2	4,987	5,281	5,402	5,000	4,584	5,253	4,887	5,148	5,099	4,877	5,144	5,188	4,993	5,357	5,067	5,351	5,510	4,518	4,780
●	●	g1	4,961	5,519	5,718	4,949	4,322	5,377	4,776	5,299	5,204	4,789	5,293	5,316	4,975	5,597	5,096	5,582	5,925	4,154	4,645
●	●	g2	5,021	5,279	5,382	5,084	4,728	5,303	4,972	5,206	5,166	4,962	5,199	5,232	5,059	5,375	5,117	5,376	5,517	4,748	4,839

Table 5. Effect of hydrological trace on minimum adult humpback chub population size (performance metric 1).

[The cell entries show the expected minimum adult humpback chub population size for each long-term strategy, under each hydrological trace, averaged over the sediment traces and critical uncertainties. The bottom row shows the mean over the hydrological traces. The highlighted long-term strategy is the best performing alternative in each row. The best strategy in the face of uncertainty has an expected minimum population size of 5,708; the expected minimum population size if the hydrological trace could be known before the strategy was selected is 5,725 (average of the highlighted cells). Thus, the expected value of information, for resolving uncertainty about the future hydrology, is an increase of 17 adults in the minimum humpback chub population.]

Trace	A	B1	B2	C1	C2	C3	C4	D1	D2	D3	D4	E1	E2	E3	E4	E5	E6	F	G
h00	3,680	4,570	4,575	4,258	3,286	4,113	3,772	4,616	4,574	3,732	4,617	4,615	3,875	4,252	3,986	4,182	4,887	3,419	4,326
h01	3,789	4,804	4,812	4,279	3,284	4,050	3,670	4,692	4,613	3,740	4,692	4,708	3,779	4,182	3,892	4,136	5,038	3,357	4,519
h02	3,742	4,403	4,406	3,991	3,304	3,964	3,656	4,372	4,325	3,609	4,370	4,344	3,820	4,131	3,936	4,085	4,592	3,391	4,155
h03	4,035	4,325	4,434	4,007	3,476	4,307	3,959	4,306	4,206	3,909	4,287	4,402	4,197	4,576	4,266	4,610	4,837	3,493	4,208
h04	5,047	5,443	5,591	4978	4,401	5,345	4,892	5,083	5,026	4,930	5,071	5,147	4,944	5,455	5,076	5,450	5,639	4,430	4,674
h05	6,386	6,619	6,901	6,166	5,940	6,873	6,164	6,234	6,152	6,126	6,236	6,318	6,335	6,998	6,433	7,008	6,998	5,767	5,226
h06	4,200	4,497	4,794	4,048	3,726	4,563	4,102	4,324	4,258	4,097	4,292	4,242	4,240	4,735	4,330	4,739	4,735	3,664	3,918
h07	4,206	4,386	4,555	4,274	3,972	4,618	4,207	4,445	4,347	4,245	4,445	4,535	4,448	4,857	4,518	4,857	4,918	3,765	4,421
h08	5,176	5,303	5,378	4,988	4,733	5,364	5,064	5,317	5,278	5,165	5,323	5,262	5,274	5,523	5,304	5,543	5,523	4,364	4,831
h09	5,435	5,561	5,726	5,297	5,193	5,580	5,269	5,746	5,704	5,528	5,730	5,486	5,414	5,714	5,453	5,703	5,713	4,864	4,953
h10	6,053	6,160	6,258	6,036	5,913	6,413	6,049	6,035	5,970	5,900	6,030	5,984	5,976	6,362	6,048	6,377	6,362	5,792	5,433
h11	6,788	7,118	7,349	6,630	6,365	7,433	6,577	6,710	6,646	6,551	6,735	6,792	6,802	7,544	6,867	7,553	7,544	6,003	5,526
h12	6,310	6,560	6,677	5,854	5,580	6,628	5,879	6,048	5,930	5,906	6,040	6,242	6,200	6,967	6,314	6,998	6,970	5,035	5,052
h13	4,511	4,965	5,111	4,567	4,005	4,868	4,372	4,657	4,614	4,350	4,673	4,791	4,565	5,080	4,643	5,071	5,340	4,026	4,107
h14	4,120	5,185	5,313	4,644	3,663	4,391	4,045	5,029	4,986	3,931	4,991	4,828	4,151	4,513	4,236	4,479	5,166	3,713	4,436
h15	4,130	4,543	4,715	4,097	3,601	4,368	3,981	4,256	4,160	4,024	4,186	4,342	4,011	4,458	4,124	4,442	4,745	3,668	4,202
h16	5,013	5,313	5,674	5,172	4,716	5,772	5,186	5,229	5,159	4,966	5,218	5,292	5,135	5,682	5,201	5,679	5838	4,761	4,568
h17	4,994	5,213	5,375	4,948	4,615	5,210	4,942	5,347	5,281	5,079	5,347	5,221	5,036	5,317	5,099	5,309	5,471	4,638	4,938
h18	6,419	6,586	6,692	6,192	5,814	6,653	6,201	6,476	6,432	6,328	6,489	6,503	6,457	6,803	6,505	6,818	6,857	5,905	6,009
h19	6,678	7,055	7,339	6,506	5,895	7,076	6,354	6,540	6,468	6,242	6,555	6,880	6,511	7,210	6,674	7,202	7,570	5,832	5,801
h20	4,098	4,617	4,678	4,395	3,590	4,450	4,004	4,721	4,675	4,027	4,725	4,710	4,150	4,659	4,254	4,629	5,117	3,559	4,267
Mean	**4,991**	**5,392**	**5,541**	**5,016**	**4,527**	**5,335**	**4,874**	**5,247**	**5,181**	**4,876**	**5,241**	**5,269**	**5,015**	**5,477**	**5,103**	**5,470**	**5,708**	**4,450**	**4,741**

Table 6. Expected value of information, by performance metric, for resolving critical uncertainty.

[See table 1 for a list of performance metrics. The best performance is the expected value of the performance metric across all uncertainties for the long-term strategy that maximized or minimized the performance metric. The value of perfectly resolving uncertainty across the 16 formal hypotheses about critical parameters is shown when all 19 long-term strategies are considered; only the two long-term strategies of alternative B are considered; and only the four, four, or six long-term strategies of alternatives C, D, and E are considered, respectively. Partial values of information are shown for resolving only the uncertainty about the effects of fall high-flow experiments on rainbow trout recruitment, efficacy of trout management flows, and effects of temperature and rainbow trout on humpback chub. Finally, the partial values of information are shown for resolving uncertainty about the combined hydrological-sediment trace, just the sediment trace, and just the hydrological trace. For the performance metrics not shown, all values of information were 0. min, minimum; HBC, humpback chub; TempSuit, temperature suitability index; Qual, quality; RBT, rainbow trout; WTSI, wind transport of sediment index; GC flow, Glen Canyon flow index; TOR, time-off-river index; CAI, camping area index; Veg, riparian vegetation index; SLI, sand load index; max, maximum; EVPI, expected value of perfect information; EVXI, expected value of partial information; HFE, high-flow experiment; TMF, trout management flow; ~, value less than 0.01 percent]

Performance metric	1	2	3	4	5	6	7	8	9	11	14	15	16
	minHBC	TempSuit	RBT Catch	Emigrate	Qual RBT	WTSI	GC flow	TOR	Power	CAI	Veg	SLI	Marsh
Desired direction	max	max	max	min	max	max	min	max	max	max	max	max	max
Best performance	5,708	0.102	3.367	22,415	956	0.465	18.4	0.840	150.41	0.451	3.954	0.576	1.101
Best action	E6	G	F	E6	E6	G	E3	G	B2	G	D4	G	E6
EVPI (16, all)	0.0	0.000	0.009	785	9.3	0.000	0.0	0.000	0.00	0.000	0.000	0.000	0.000
EVPI (16, B)	0.0	0.000	0.000	0	0.0	0.000	0.0	0.000	0.00	0.000	0.000	0.000	0.000
EVPI (16, C)	8.5	0.000	0.000	237	0.8	0.000	0.0	0.000	0.00	0.000	0.000	0.000	0.000
EVPI (16, D)	0.0	0.000	0.000	0	0.0	0.000	0.0	0.000	0.00	0.000	0.000	0.000	0.000
EVPI (16, E)	0.0	0.000	0.000	0	0.0	0.000	0.0	0.000	0.00	0.000	0.000	0.000	0.000
EVXI (fall HFE)	0.0	0.000	0.009	785	9.3	0.000	0.0	0.000	0.00	0.000	0.000	0.000	0.000
EVXI (TMF)	0.0	0.000	0.000	0	0.0	0.000	0.0	0.000	0.00	0.000	0.000	0.000	0.000
EVXI (HBC)	0.0	0.000	0.000	0	0.0	0.000	0.0	0.000	0.00	0.000	0.000	0.000	0.000
EVXI (traces)	19.0	0.001	0.254	1,033	8.4	0.003	0.9	0.001	0.35	0.007	0.224	0.021	0.035
EVXI (sediment)	0.0	0.000	0.000	37	0.0	0.000	0.0	0.000	0.00	0.000	0.012	0.000	0.000
EVXI (hydrology)	17.0	0.001	0.198	636	5.5	0.002	0.9	0.001	0.35	0.004	0.212	0.015	0.032
As a percent of the best performance													
EVPI (16, all), in percent	~	~	0.26	3.50	0.98	~	~	~	~	~	~	~	~
EVPI (16, B)	~	~	~	~	~	~	~	~	~	~	~	~	~
EVPI (16, C), in percent	0.15	~	~	1.06	0.09	~	~	~	~	~	~	~	~
EVPI (16, D)	~	~	~	~	~	~	~	~	~	~	~	~	~
EVPI (16, E)	~	~	~	~	~	~	~	~	~	~	~	~	~
EVXI (fall HFE), in percent	~	~	0.26	3.50	0.98	~	~	~	~	~	~	~	~
EVXI (TMF)	~	~	~	~	~	~	~	~	~	~	~	~	~
EVXI (chub)	~	~	~	~	~	~	~	~	~	~	~	~	~
EVXI (traces), in percent	0.33	1.39	7.53	4.61	0.88	0.59	4.78	0.10	0.23	1.63	5.66	3.57	3.20
EVXI (sediment), in percent	~	~	~	0.17	~	~	~	0.03	~	~	0.30	~	~
EVXI (hydrology), in percent	0.30	0.77	5.89	2.84	0.58	0.44	4.77	0.08	0.23	0.96	5.36	2.58	2.91

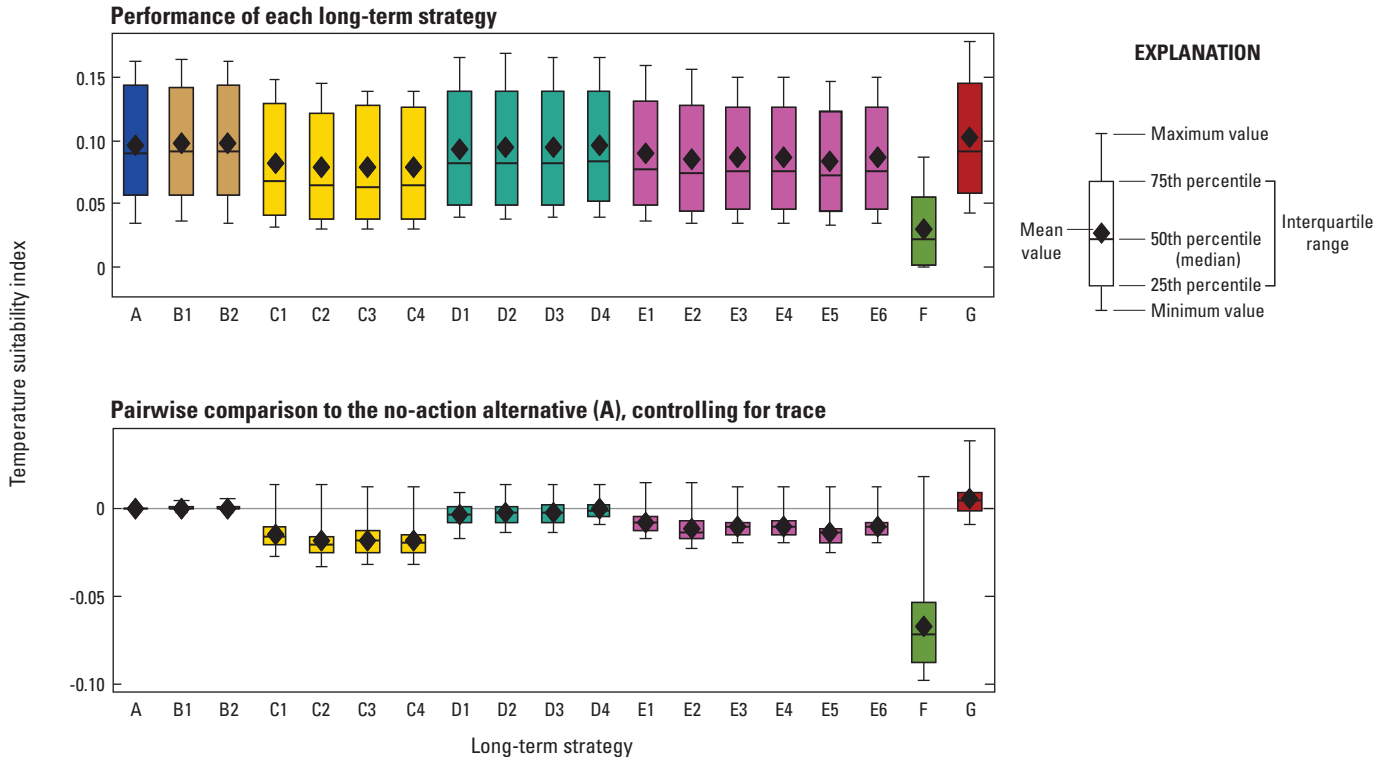

Figure 5. Temperature suitability index for humpback chub at river mile 157 and 213 (performance metric 2) forecast for 19 long-term strategies with equal weighting of traces.

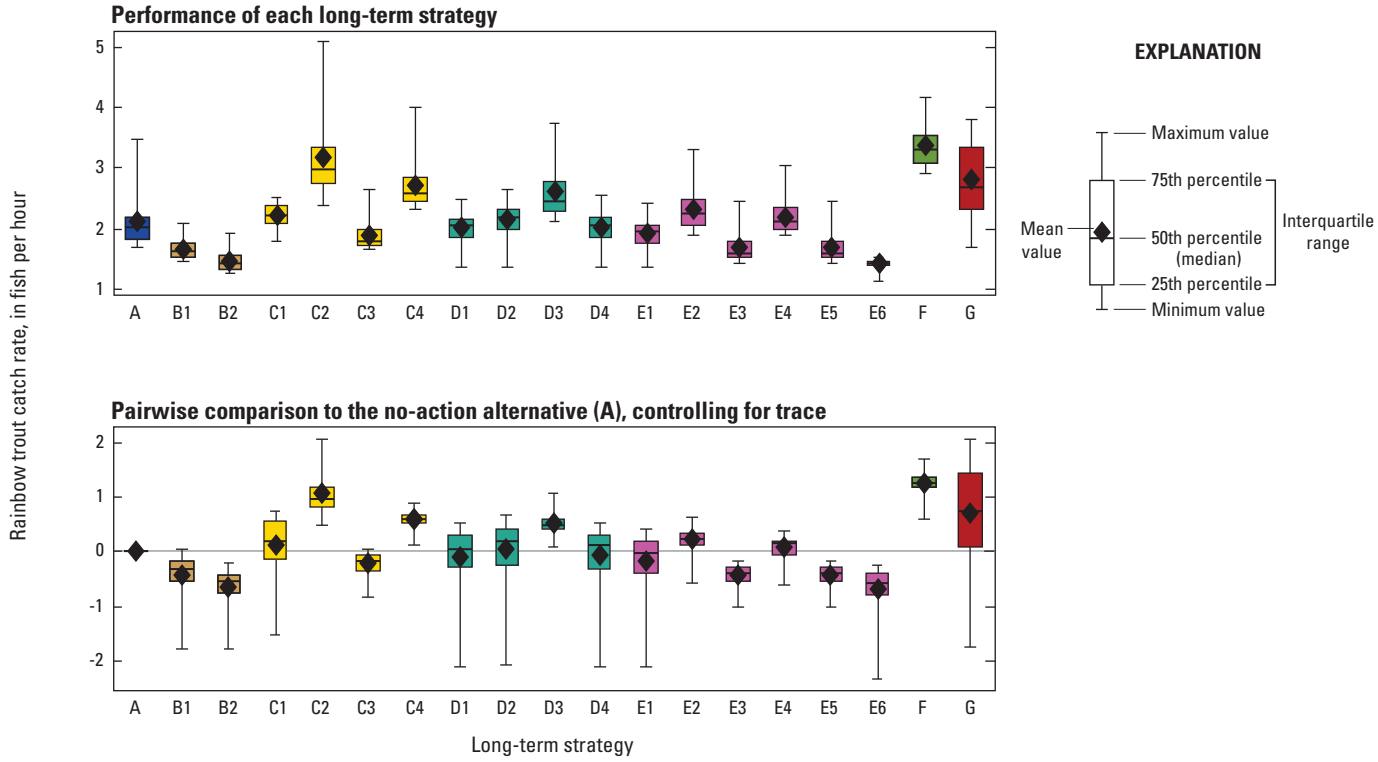

Figure 6. Rainbow trout catch rate (performance metric 3) forecast for 19 long-term strategies with equal weighting of traces.

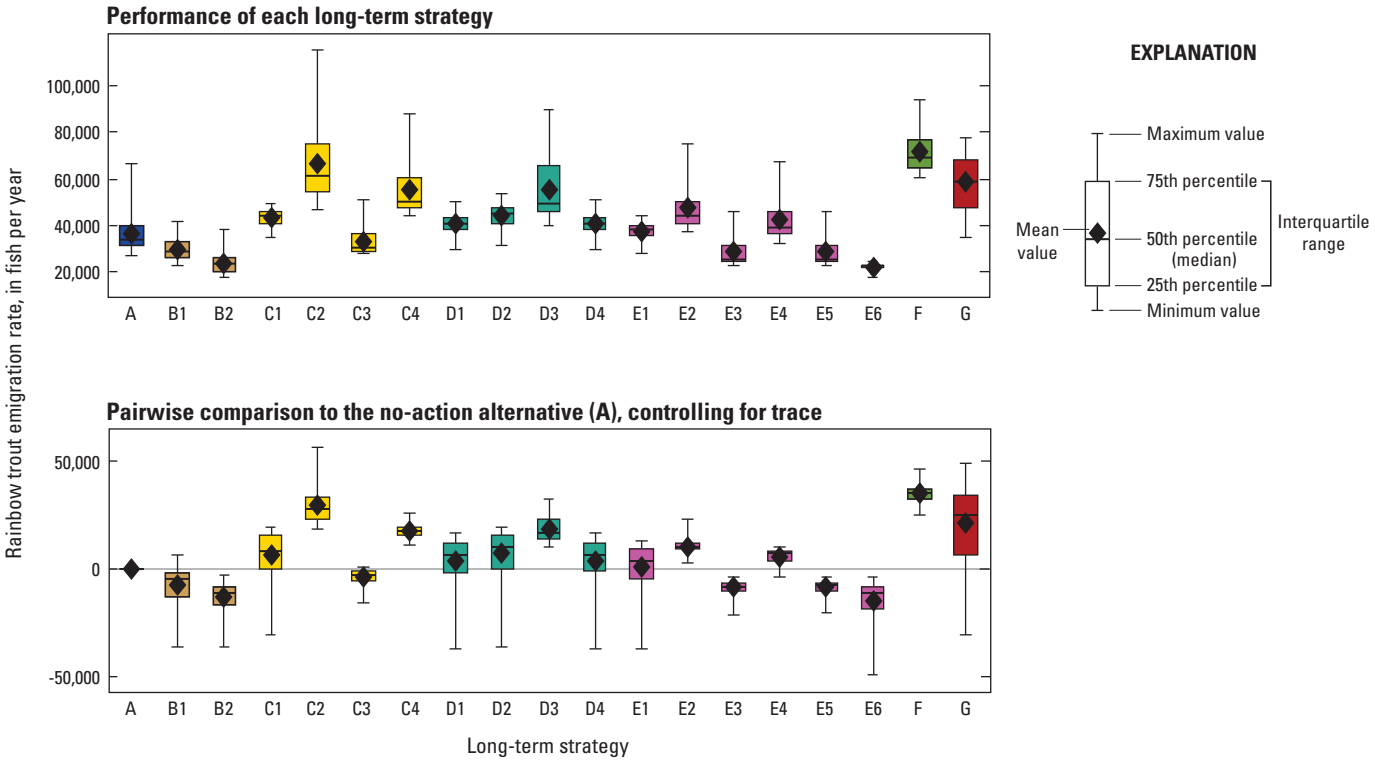

Figure 7. Rainbow trout emigration rate from Glen Canyon (performance metric 4) forecast for 19 long-term strategies with equal weighting of traces.

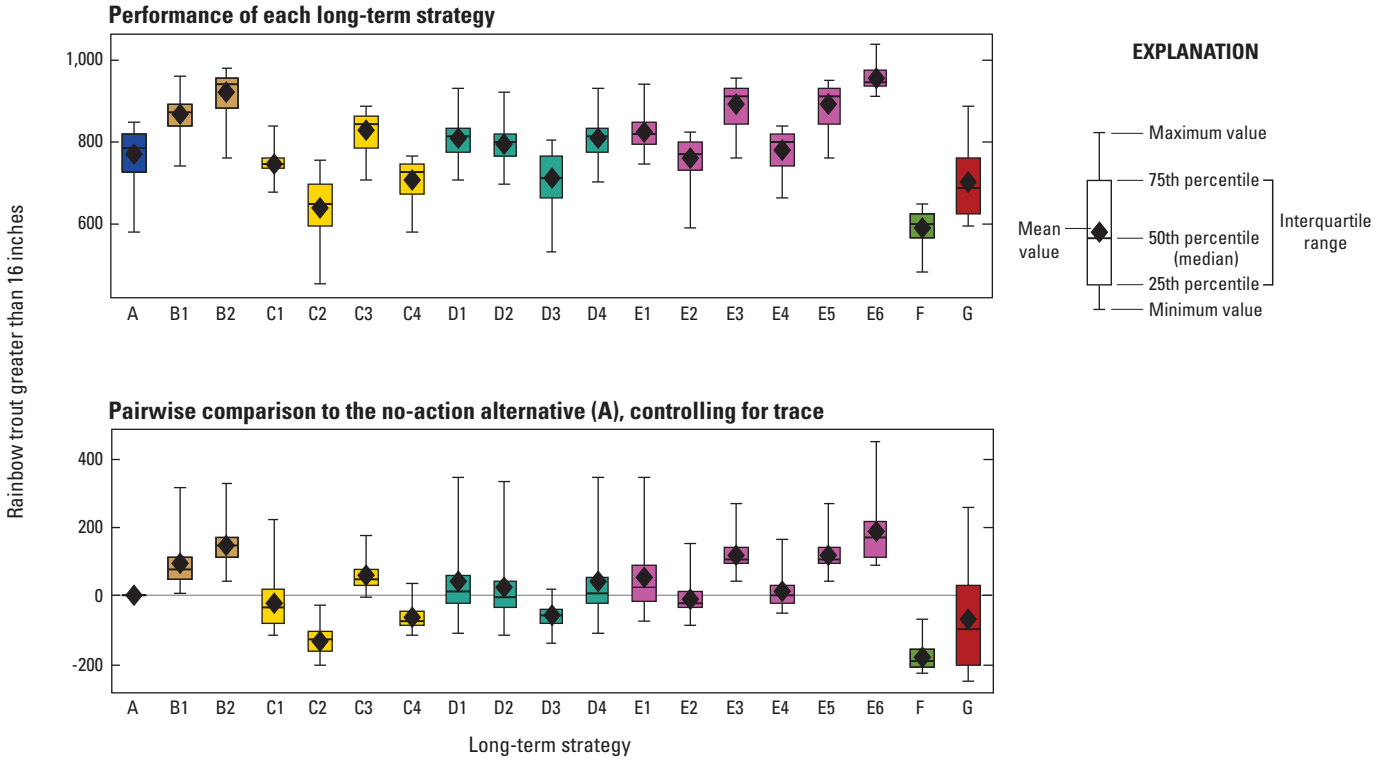

Figure 8. Abundance of high-quality rainbow trout (performance metric 5) forecast for 19 long-term strategies with equal weighting of traces.

7.3 Archeological and Cultural Resources Results

The protection of archeological and cultural resources was reflected in three performance metrics. The WTSI (performance metric 6) was largely driven by the SLI (performance metric 15) and was highest for those long-term strategies that implemented HFEs often (fig. 9). The best-performing alternative for WTSI was Alternative G (mean WTSI, 0.465); this ranking was not affected by any of the critical uncertainties or uncertainty in the sediment input (table 6). For some hydrological traces, long-term strategy C1 outperformed G, but the value of information related to hydrological uncertainty was small (0.44 percent).

The Glen Canyon flow index (performance metric 7) differed little among alternatives with a mean of around 20 days per year in which the flow exceeded 23,200 ft^3/s (fig. 10). Only Alternative F differed from the other long-term strategies (mean 36.8 days/year). The long-term strategies that did not allow HFEs (C3, E3, E5, and E6) had the best performance (smallest Glen Canyon flow index). The top ranking long-term strategy was not affected by critical uncertainty or sediment trace (table 6) but did vary depending on the hydrological trace (EVXI, 4.77 percent).

The time-off-river index (performance metric 8) was affected most strongly by the hydrological trace but was also weakly affected by the long-term strategy (fig. 11). Alternatives B and C were indistinguishable from Alternative A; Alternatives D, E, and G performed slightly better than Alternative A; and Alternative F performed noticeably worse because high flows during the peak rafting season allow quicker trips and more discretionary time at camping stops. Long-term strategies E1 and G were the best-performing strategies across hydrological and sediment traces, with only a small value of information associated with the trace uncertainty and no value of information associated with the critical uncertainties (table 6).

7.4 Hydropower Generation and Capacity Results

The best-performing long-term strategy for hydropower generation (performance metric 9) was B2, a long-term strategy designed to match power generation more closely to demand (fig. 12). For most of the long-term strategies, the annual value of hydropower generation is within $3 million of the value from Alternative A, except for Alternatives F and G for which annual generation is $6 million to $8 million less than Alternative A (fig. 12). The effect of hydrology on hydropower generation is much greater than the effect of the alternatives, with the average annual power generation over 20 years varying more than $60 million across hydrological traces (fig. 12). The dominance of B2 as the best long-term strategy for hydropower generation, however, is robust to uncertainty in hydrology with a value of information of only $350,000 per year (EVXI, 0.23 percent, table 6); for 4 out of 21 hydrological traces, long-term strategy E3 outranked B2.

The value of hydropower capacity (performance metric 10) was more sensitive to the choice of long-term strategy than hydropower generation with long-term strategies differing by nearly $20 million per year (fig. 13). Long-term strategy B2 was the best-performing strategy across all uncertainties, including hydrological trace. The long-term strategies in Alternative B outperformed Alternative A; all the remaining long-term strategies had a lower value of hydropower capacity than Alternative A (fig. 13). The value of capacity was somewhat sensitive to hydrological trace (the range of performance within a long-term strategy varied by $8 million to $17 million per year across hydrological traces), but the identification of the best-performing alternative was not (EVXI, 0).

7.5 Recreational Experience Results

The camping area index (performance metric 11), a metric composed from the SLI to represent beach formation and a flow factor to represent beach exposure, was highly correlated with the SLI (performance metric 18). The best-performing long-term strategies (especially C1, F, and G) include frequent implementation of HFEs; the worst-performing long-term strategies (for example, C3, E3, E5, and E6) do not permit HFEs (fig. 14). The identification of the top-ranked long-term strategy was affected by the combination of hydrological and sediment trace (EVXI, 1.96 percent) but not by any other uncertainties (table 6).

The fluctuation index (performance metric 12), which reflects the fraction of time the daily flow fluctuations are in a tolerable range for recreation, was highest for Alternatives F and G and lowest for Alternative B (fig. 15). Alternative D was comparable to Alternative A. The effect of the long-term strategies within an alternative was small compared to the effect of the base operations within each alternative. The fluctuation index was not strongly affected by any of the uncertainties, including hydrological trace.

The Glen Canyon rafting use metric (performance metric 13), which reflects the visitor-days lost per year because of HFEs, was best for those long-term strategies that did not permit HFEs (for example, C3, E3, E5, and E6) and worst for Alternative F (fig. 16). Under Alternative F, nearly 1,000 boat seats per year in Glen Canyon are expected to be lost because of HFEs. The rafting use metric showed variation as a result of hydrological trace, but the identification of the best-performing long-term strategies was not affected by any of the uncertainties.

7.6 Riparian Vegetation Results

The riparian vegetation index (performance metric 14) was the sum of four ratios that represented measures of different aspects of the vegetation community with a score of 4 indicating maintenance of current conditions.

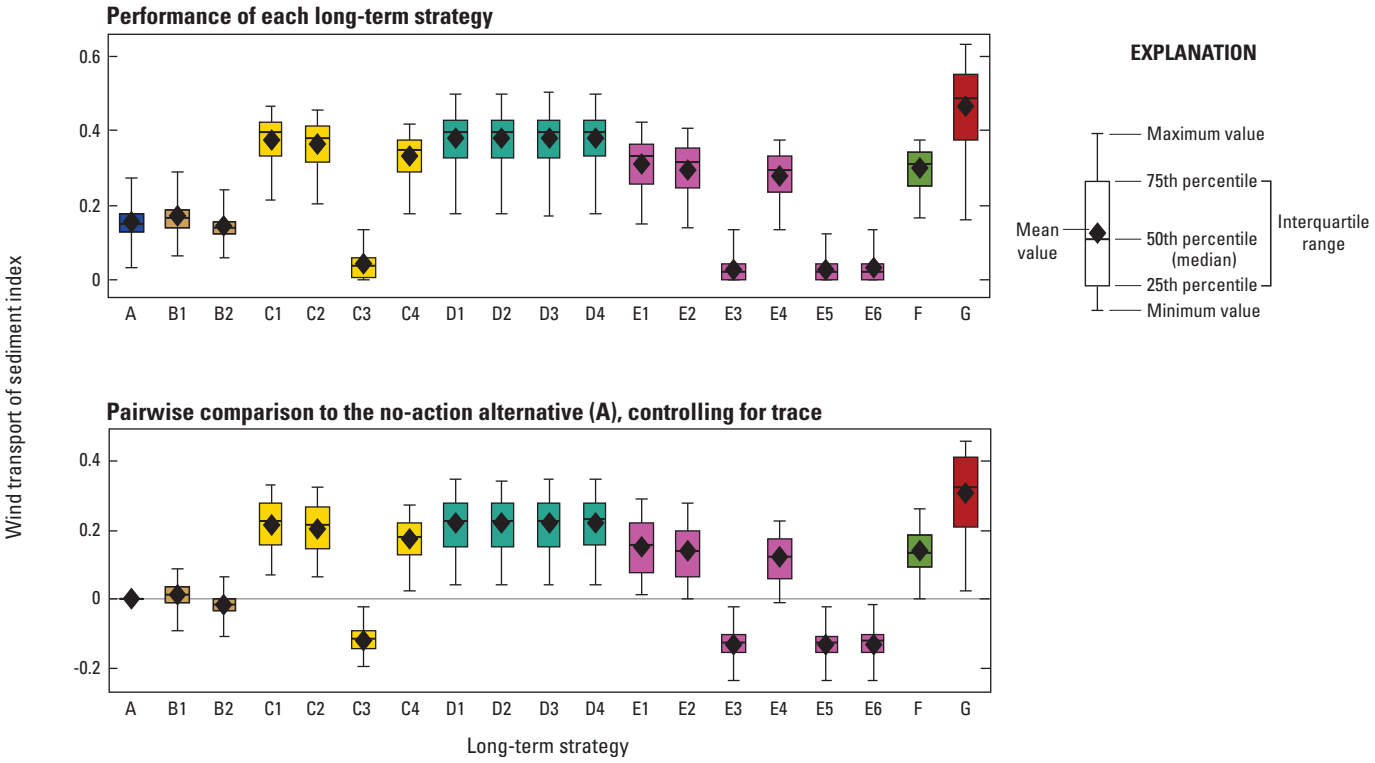

Figure 9. Wind transport of sediment index (performance metric 6) forecast for 19 long-term strategies with equal weighting of traces.

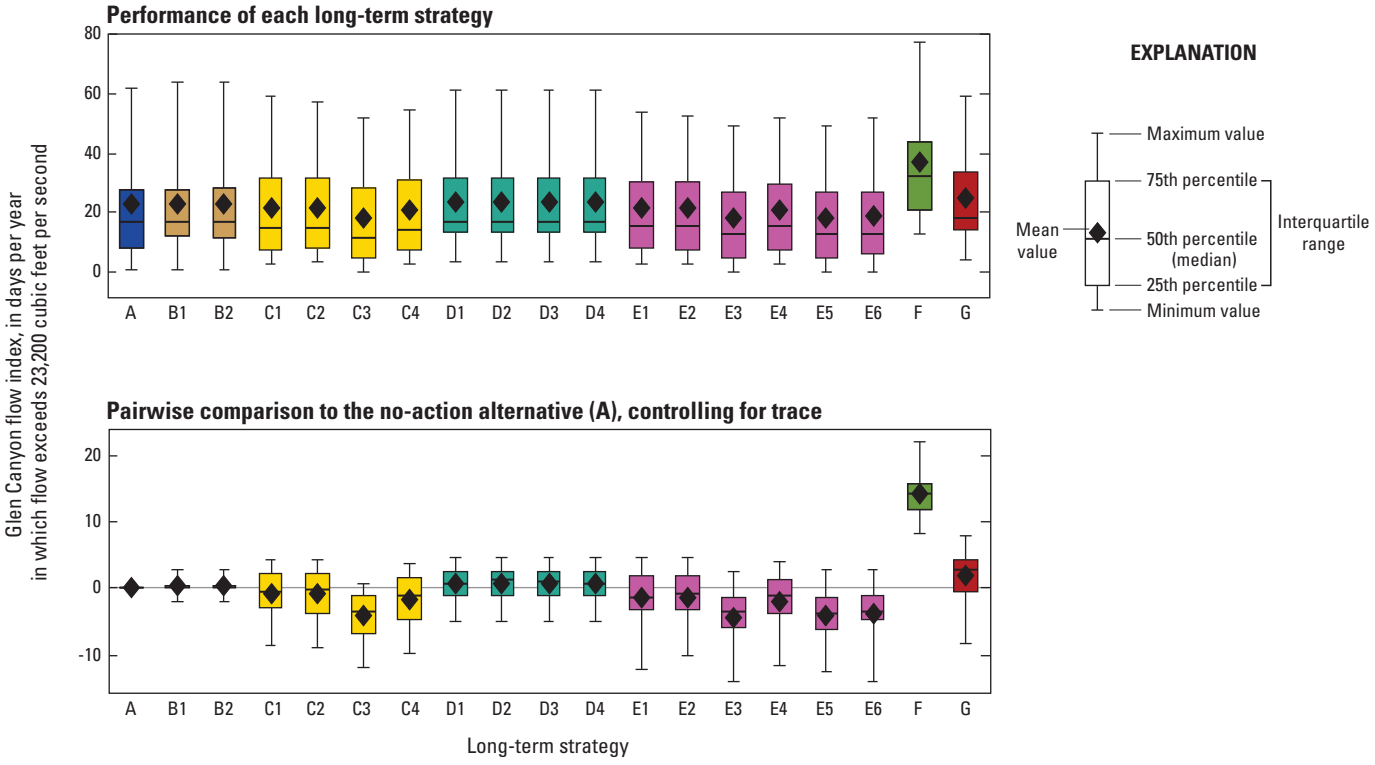

Figure 10. Glen Canyon flow index (performance metric 7) forecast for 19 long-term strategies with equal weighting of traces.

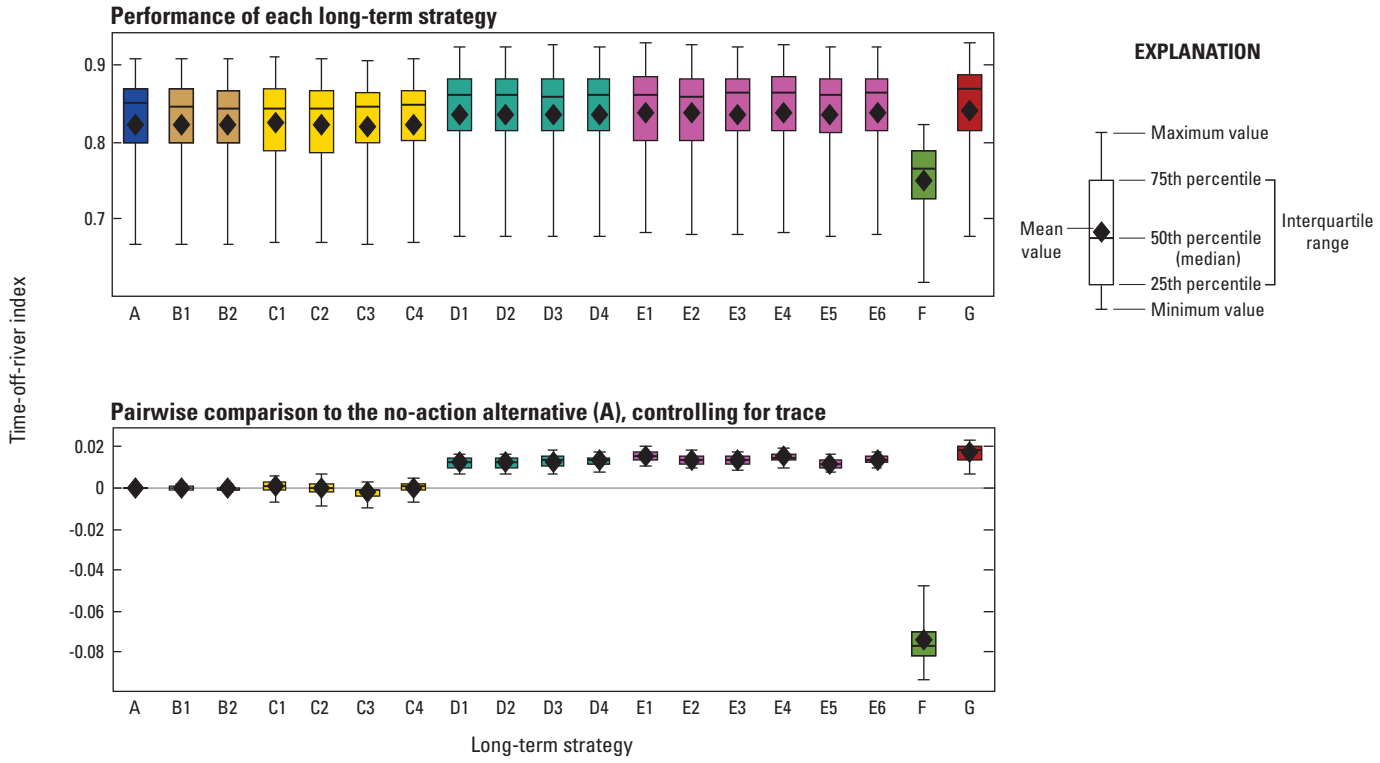

Figure 11. Cultural resources time-off-river index (performance metric 8) forecast for 19 long-term strategies with equal weighting of traces.

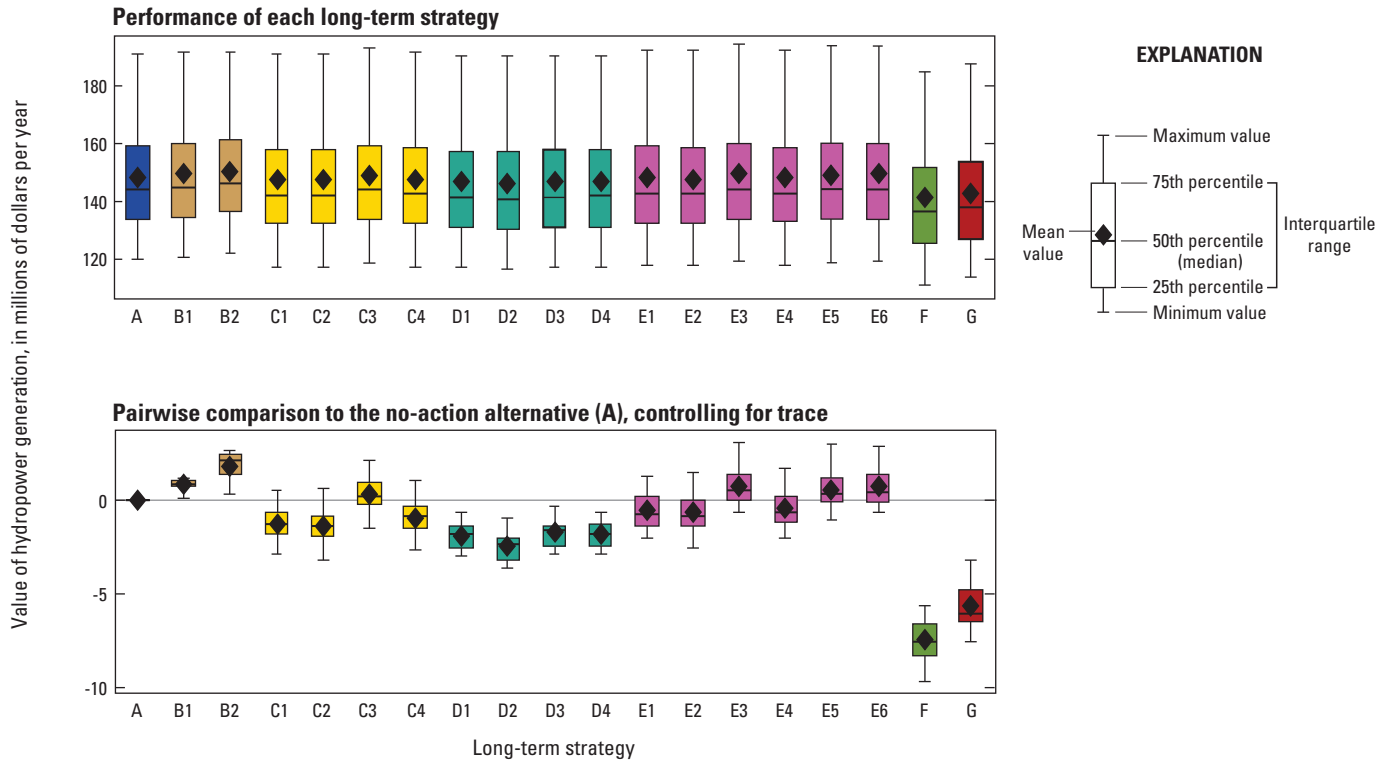

Figure 12. Annualized net present value of hydropower generation (performance metric 9) forecast for 19 long-term strategies with equal weighting of traces.

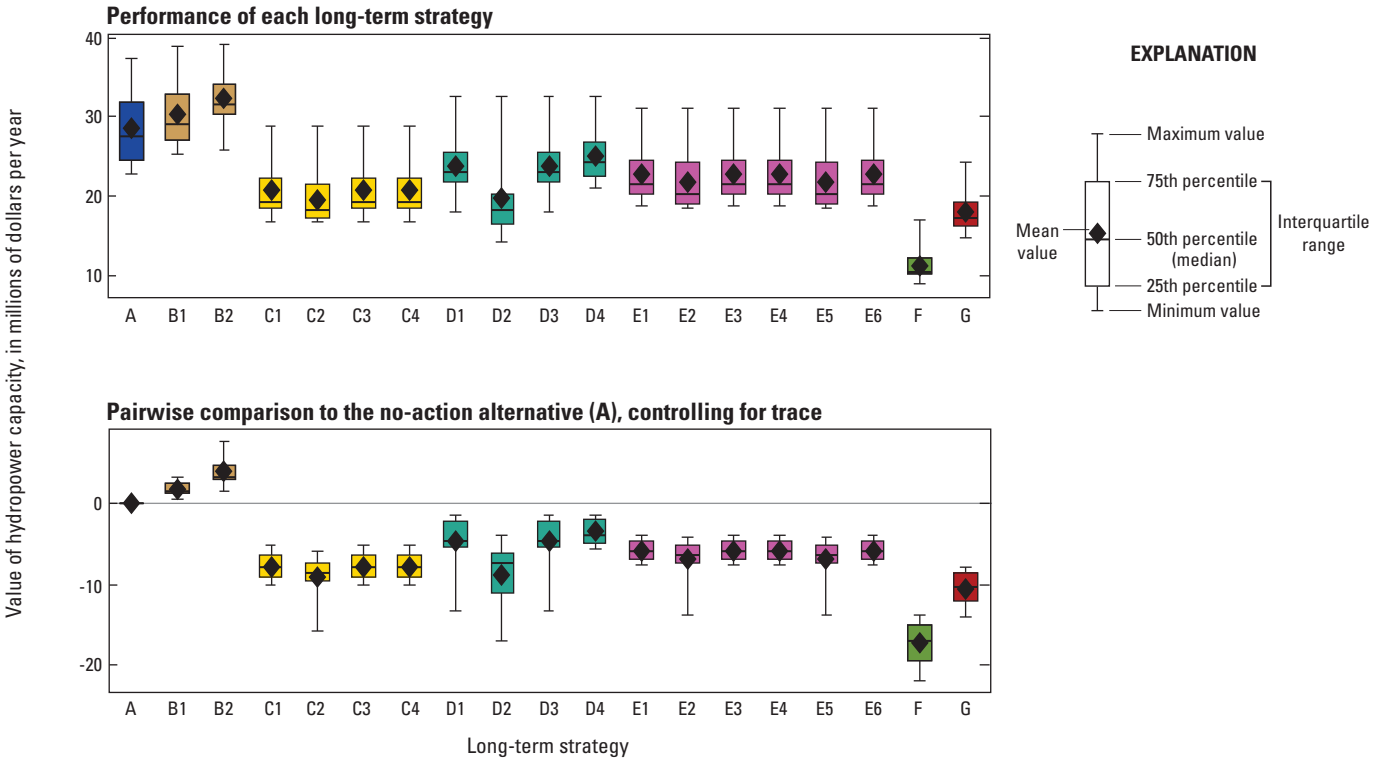

Figure 13. Annualized net present value of hydropower capacity (performance metric 10) forecast for 19 long-term strategies with equal weighting of traces.

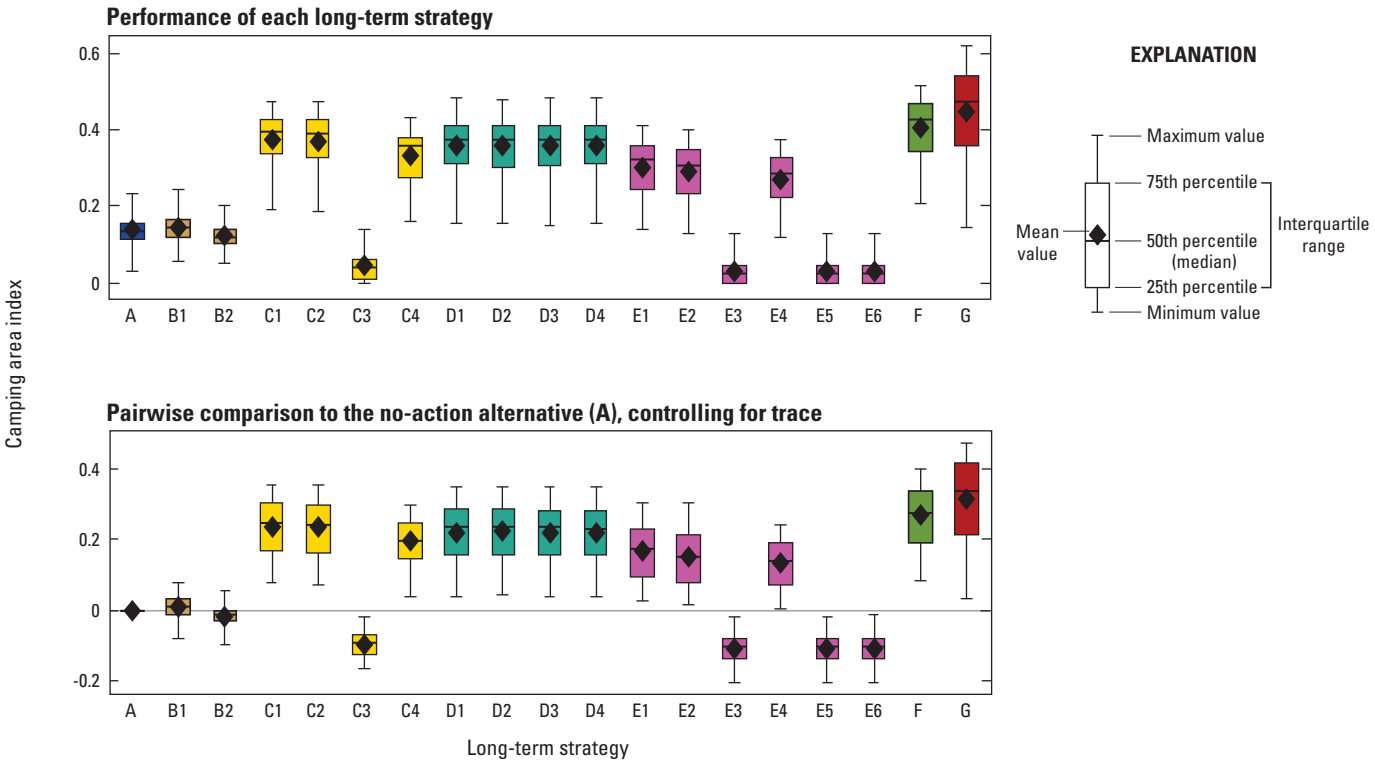

Figure 14. Camping area index (performance metric 11) forecast for 19 long-term strategies with equal weighting of traces.

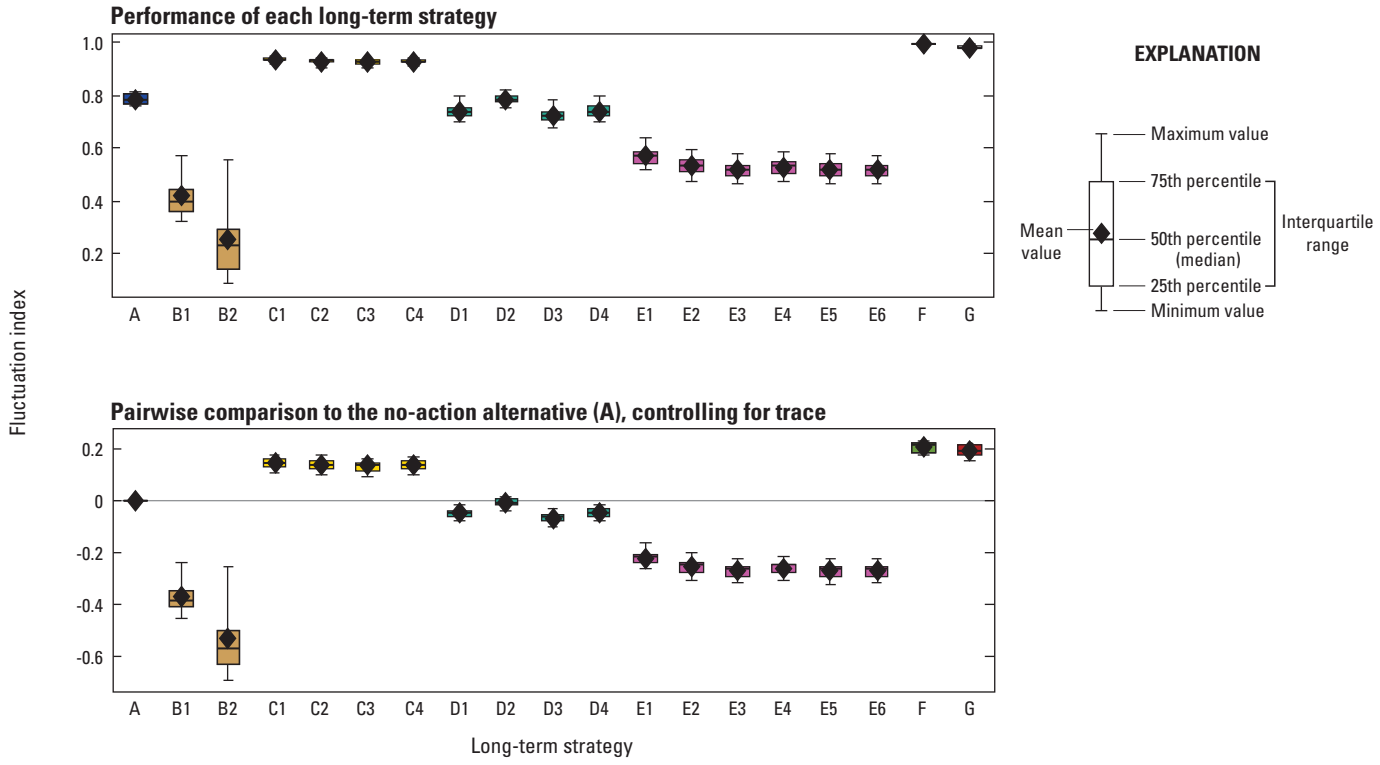

Figure 15. Fluctuation index (performance metric 12) forecast for 19 long-term strategies with equal weighting of traces.

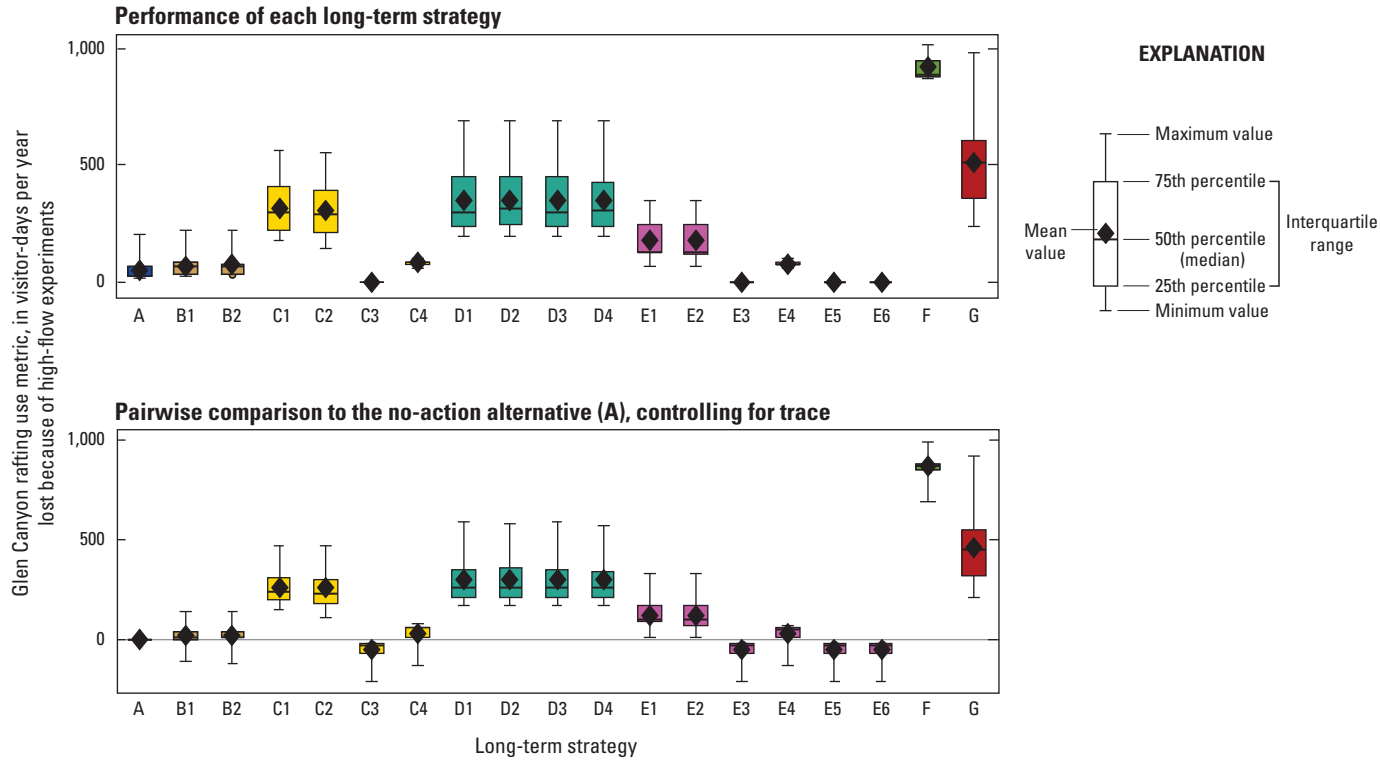

Figure 16. Glen Canyon rafting use metric (performance metric 13) forecast for 19 long-term strategies with equal weighting of traces.

The index ranged between 2 and 6 across alternatives and traces (fig. 17), indicating a 50-percent degradation or a 50-percent improvement in vegetation conditions, respectively. The highest mean vegetation index was associated with long-term strategy D4 (riparian vegetation index, 3.954), but 13 of the 19 long-term strategies were ranked first depending on the hydrological and sediment trace. The value of information for resolving uncertainty about the hydrological and sediment trace before committing to a long-term strategy was 0.224 (an improvement of 5.66 percent; table 6). The choice of the long-term strategy was not affected, however, by any of the critical uncertainties (table 6).

7.7 Sediment Results

The SLI (performance metric 15) measured the potential for sand bar formation by reporting the proportion of sand transported during flows greater than 31,500 ft^3/s. The SLI was most strongly affected by the frequency of HFEs; the long-term strategies with the highest SLI (especially C1, C2, D1, D2, F, and G) allowed frequent HFEs, and the long-term strategies with the lowest SLI (C3, E3, E5, and E6) did not permit HFEs (fig. 18). Uncertainty in the combination of hydrological and sediment trace did affect the ranking of the alternatives (EVXI, 3.57 percent; table 6) with 6 of the 19 long-term strategies favored in at least 1 trace.

7.8 Tribal Resources Results

Several performance metrics were developed to evaluate resources of specific importance from a tribal perspective. The marsh vegetation ratio (performance metric 16) forecast the preservation or expansion of the wetland vegetation communities along the Colorado River (fig. 19). For context, the current extent of marsh vegetation is 4.6 acres. The long-term strategy with the highest mean marsh vegetation ratio was E6 (mean marsh vegetation ratio, 1.101), representing about a 10-percent increase in marsh community area, but long-term strategy E3 was most commonly ranked first among the 63 traces. Alternatives C, F, and G exhibited consistent losses of marsh vegetation compared to Alternative A, whereas Alternatives D and E exhibited modest increases (fig. 19). The variance in the index induced by variation in hydrology was larger than the variance across alternatives (fig. 19). The value of information for resolving hydrological and sediment uncertainty before committing to a long-term strategy was 3.20 percent (table 6).

The frequency of mechanical removal (performance metric 17) was 0 for those long-term strategies that do not permit this management tool (C1, C2, E1, E2, E5, E6, and F) and varied between 0 and 6 years out of 20 for the other long-term strategies (fig. 20). For those long-term strategies that permitted mechanical removal, the frequency was influenced by the emigration rate of RBT from Glen Canyon (performance metric 4), which in turn was influenced by the frequency of HFEs. Because the long-term strategies with the lowest frequency were determined simply by whether mechanical removal was allowed or not, the identification of the top-ranked strategy was not influenced by any of the uncertainties.

The frequency of trout management flows (performance metric 18) was 0 for those long-term strategies that did not allow their use (10 out of the 19 long-term strategies) and varied between 0 and 20 years out of 20 for the remaining strategies (fig. 21). Under Alternative G, TMFs were triggered on average more than one-half of the years, and sometimes in all 20 years, depending on the hydrological trace. For the strategies that allowed TMFs, the frequency of their use was correlated with RBT abundance and, hence, with the RBT catch rate (performance metric 3) and emigration rate (performance metric 4). Again, because the long-term strategies with the lowest frequency of TMFs were determined by the admissible tools in the strategy, the value of information associated with the various uncertainties was 0.

7.9 Full Consequence Table

A summary of the performance of the 19 long-term strategies against the 18 performance metrics is represented in a consequence table (table 7). There is neither a single long-term strategy that performs best for all performance metrics (such a strategy would be shaded in yellow across the corresponding row), nor a single long-term strategy that performs worst for all performance metrics (such a strategy would be shaded dark blue across the row); furthermore, no long-term strategy is either consistently better or consistently worse than Alternative A across all performance metrics. Interestingly, the strategies that are worst for a number of performance metrics (for example, B2, C3, E5, F, and G) are also best for other performance metrics. Other long-term strategies are neither best nor worst on any performance metrics (for example, B1, C4, D1, D2). This pattern of performance indicates that there are important tradeoffs among the long-term strategies, and the best alternative cannot be identified without considering the relative value of the resource goals and performance metrics.

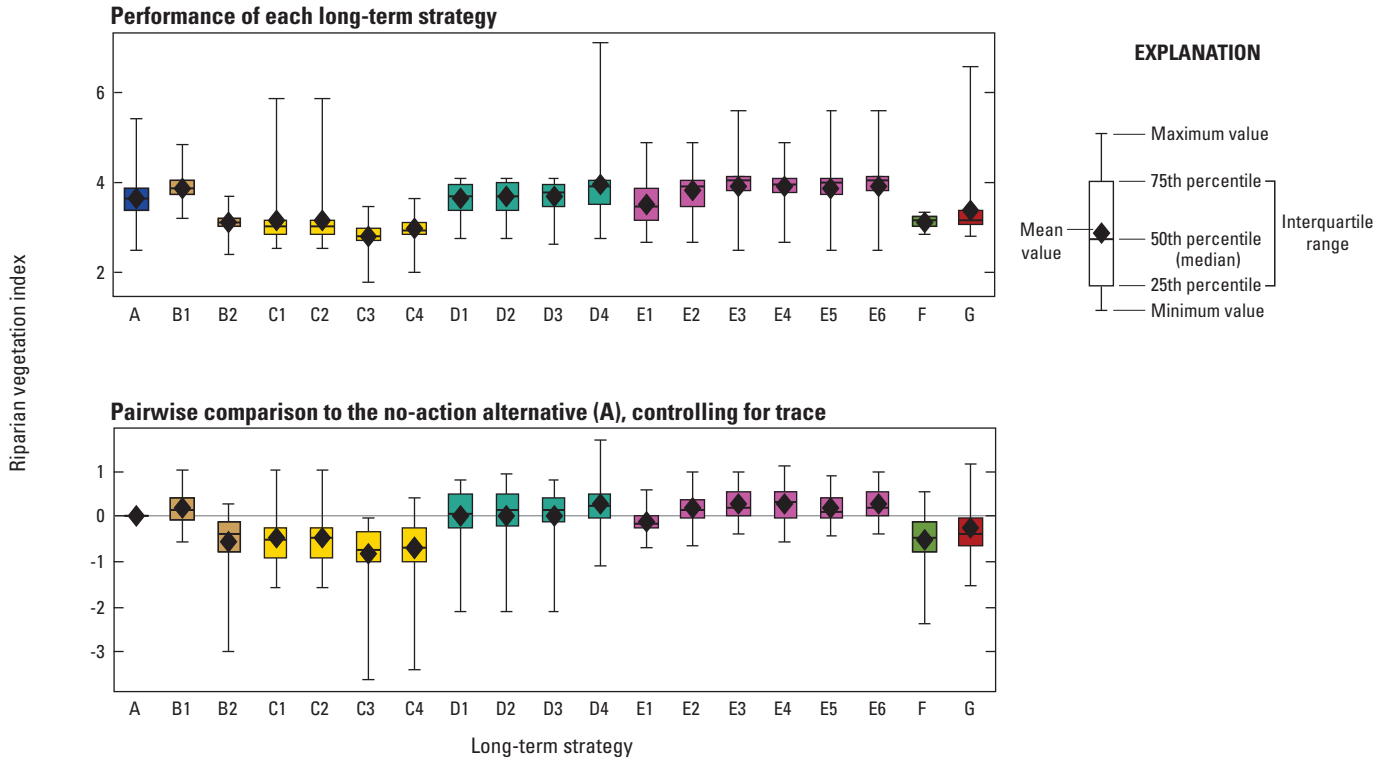

Figure 17. Riparian vegetation index (performance metric 14) forecast for 19 long-term strategies with equal weighting of traces.

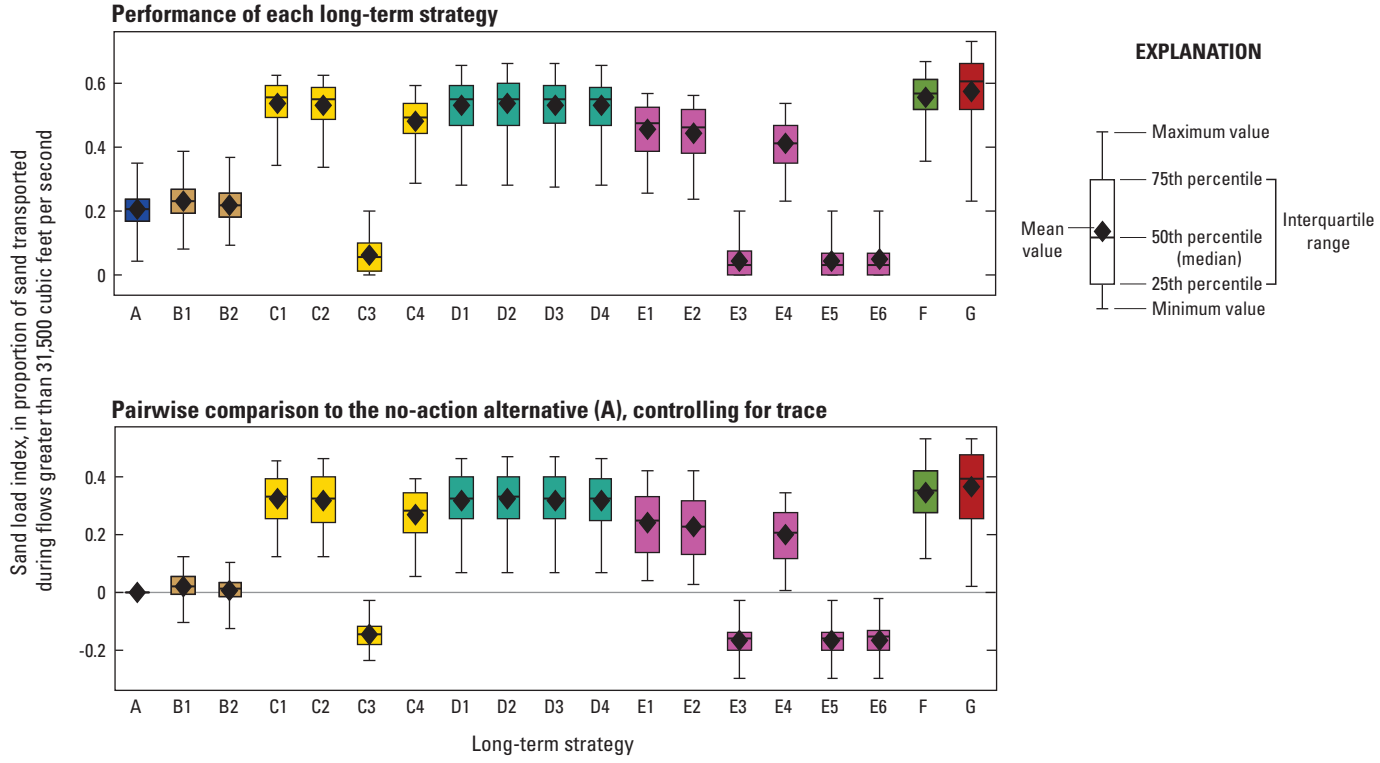

Figure 18. Sand load index (performance metric 15) forecast for 19 long-term strategies with equal weighting of traces.

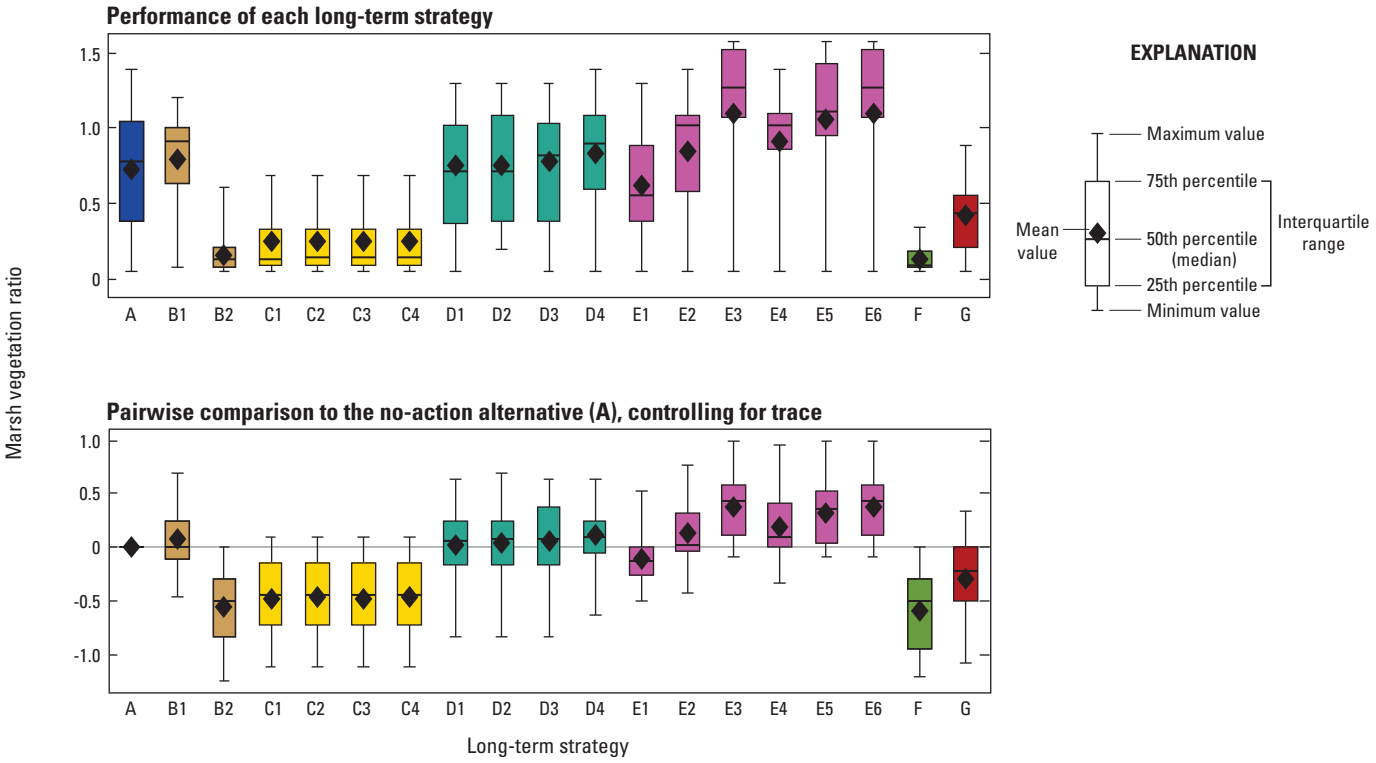

Figure 19. Marsh vegetation ratio (ratio of average marsh cover over 20-year period to current marsh cover, performance metric 16) forecast for 19 long-term strategies with equal weighting of traces.

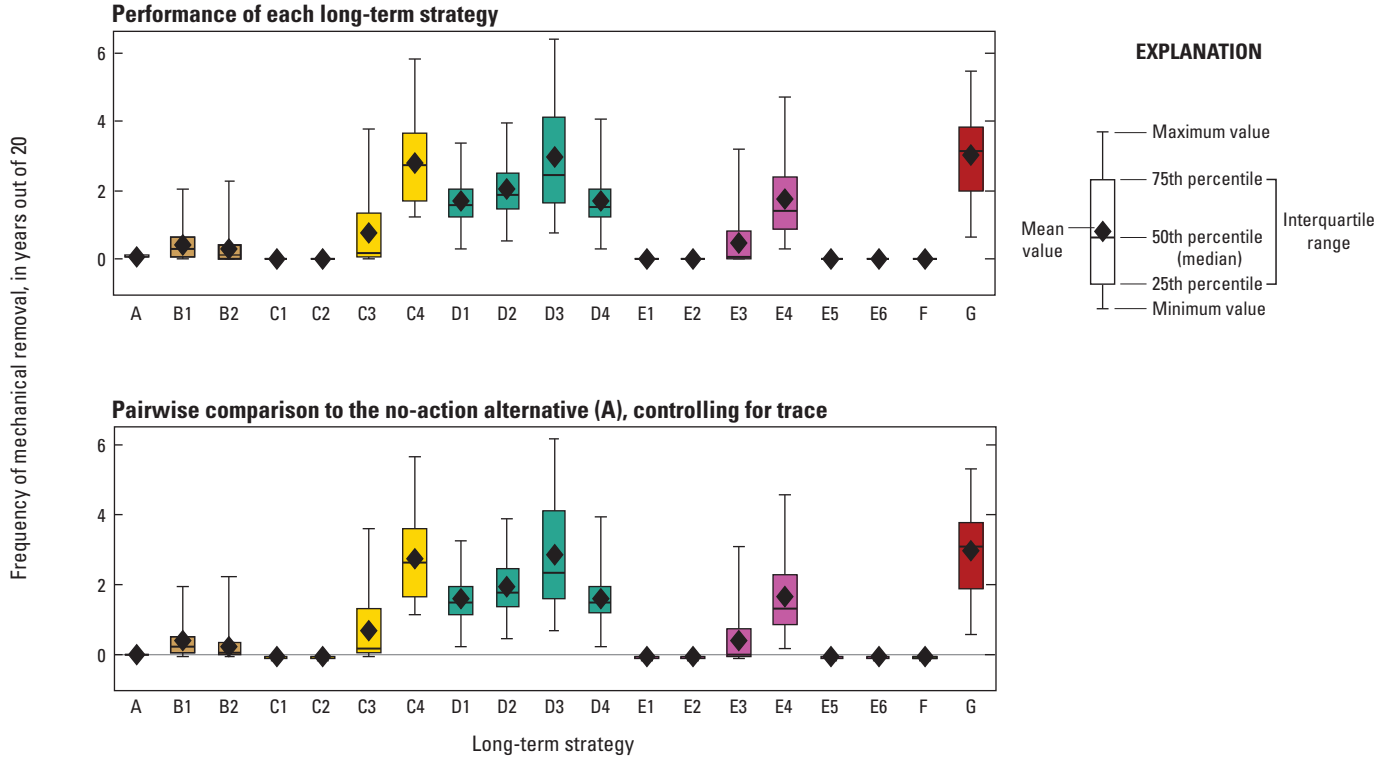

Figure 20. Frequency of mechanical removal (performance metric 17) forecast for 19 long-term strategies with equal weighting of traces.

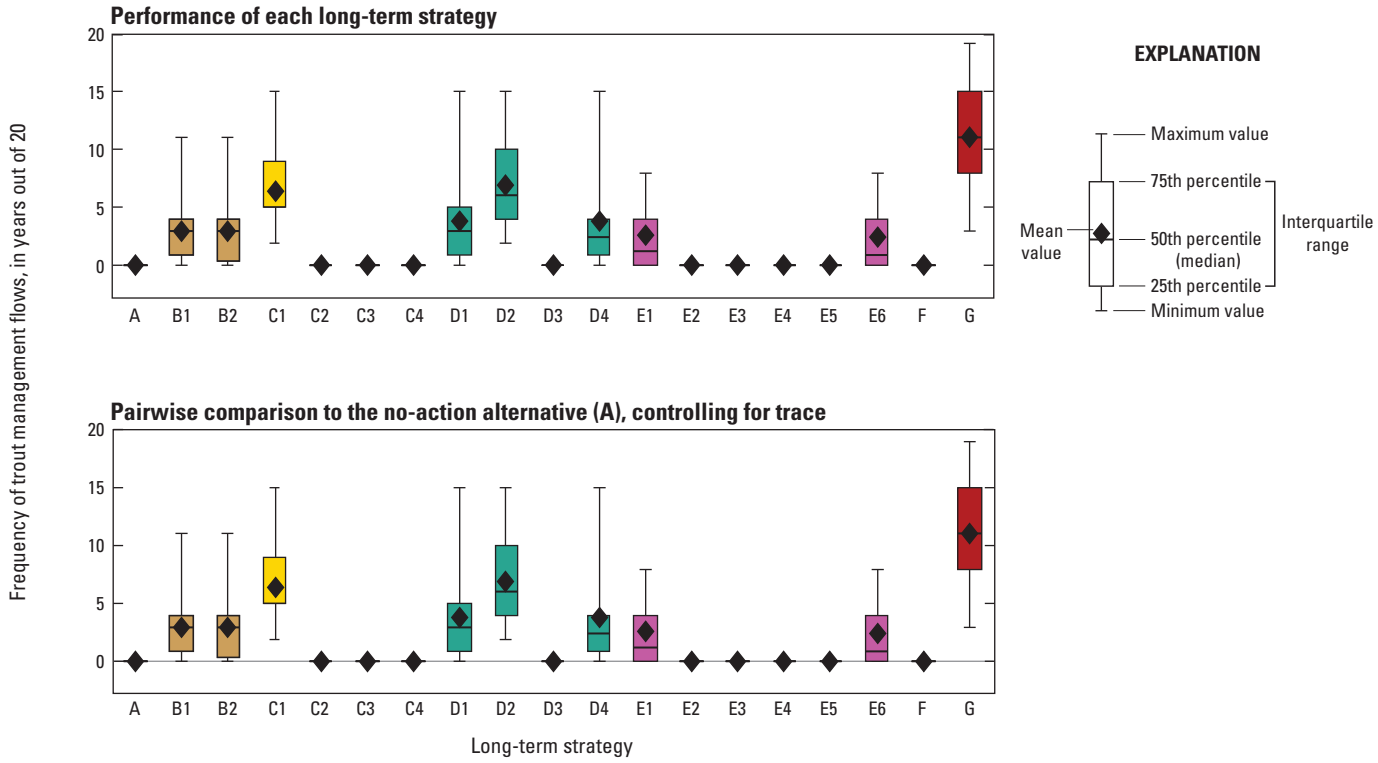

Figure 21. Frequency of trout management flows (performance metric 18) forecast for 19 long-term strategies with equal weighting of traces.

Table 7. Full consequence table showing the mean value of each performance metric for each long-term strategy.

[The columns are the performance metrics, numbered as in table 1. For most performance metrics, higher values are desired (yellow), but for five metrics, lower values are desired (pink). The rows are the long-term strategies. The values in each column are color-coded, with the best-performing long-term strategy shaded in yellow, the worst-performing long-term strategy shaded in dark blue, strategies that perform better than status quo (Alternative A) shaded in orange, and strategies that perform worse than status quo shaded in turquoise. HBC, humpback chub; TempSuit, temperature suitability index; RBT, rainbow trout; WTSI, wind transport of sediment index; GC flow, Glen Canyon flow index; TOR, time-off-river index; CAI, camping area index; FI, fluctuation index; GC raft, Glen Canyon rafting use metric; Veg, riparian vegetation index; SLI, sand load index; MR, mechanical removal; TMF, trout management flow]

Long-term strategy	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
	HBC	Temp Suit	RBT Catch	RBT Emigrate	Quality RBT	WTSI	GC flow	TOR	Power	Cap.	CAI	FI	GC raft	Veg	SLI	Marsh	MR	TMF
	High	High	High	Low	High	High	Low	High	High	High	High	High	Low	High	High	High	Low	Low
A	4,991	0.097	2.11	36,699	769	0.159	22.7	0.823	148.5	28.5	0.139	0.786	49	3.66	0.211	0.72	0.07	0.0
B1	5,392	0.097	1.67	29,586	867	0.171	23.1	0.823	149.4	30.4	0.146	0.420	71	3.87	0.234	0.80	0.44	3.0
B2	5,541	0.097	1.46	24,172	920	0.144	23.1	0.823	150.4	32.4	0.122	0.256	72	3.12	0.222	0.17	0.30	3.1
C1	5,016	0.082	2.23	43,683	748	0.377	21.8	0.824	147.3	20.8	0.376	0.935	315	3.18	0.536	0.25	0.00	6.5
C2	4,527	0.079	3.18	66,890	640	0.365	21.8	0.823	147.2	19.5	0.371	0.929	307	3.18	0.534	0.25	0.00	0.0
C3	5,335	0.079	1.90	33,559	830	0.043	18.5	0.821	148.9	20.8	0.043	0.924	0	2.83	0.065	0.25	0.74	0.0
C4	4,874	0.079	2.72	55,076	707	0.334	21.0	0.823	147.6	20.8	0.335	0.928	83	2.98	0.483	0.25	2.80	0.0
D1	5,247	0.094	2.02	40,784	811	0.379	23.5	0.835	146.6	23.8	0.359	0.741	348	3.67	0.531	0.75	1.67	3.9
D2	5,181	0.095	2.15	43,981	796	0.378	23.6	0.835	146.1	19.6	0.360	0.784	351	3.69	0.535	0.76	2.02	6.9
D3	4,876	0.095	2.63	55,811	711	0.378	23.5	0.836	146.8	23.8	0.359	0.724	348	3.70	0.533	0.78	2.95	0.0
D4	5,241	0.097	2.03	40,936	810	0.380	23.5	0.836	146.7	25.1	0.358	0.741	348	3.95	0.529	0.84	1.69	3.8
E1	5,269	0.090	1.93	37,614	826	0.311	21.3	0.839	148.0	22.8	0.303	0.568	177	3.54	0.456	0.62	0.00	2.6
E2	5,015	0.086	2.33	47,450	761	0.297	21.3	0.837	147.9	21.8	0.292	0.534	174	3.84	0.443	0.85	0.00	0.0
E3	5,477	0.087	1.68	28,499	891	0.030	18.4	0.836	149.3	22.8	0.028	0.517	0	3.93	0.046	1.10	0.47	0.0
E4	5,103	0.087	2.19	42,806	781	0.281	20.9	0.838	148.1	22.8	0.272	0.529	79	3.93	0.415	0.91	1.73	0.0
E5	5,470	0.083	1.68	28,561	890	0.029	18.5	0.835	149.1	21.8	0.028	0.517	0	3.87	0.046	1.05	0.00	0.0
E6	5,708	0.087	1.42	22,415	956	0.032	18.8	0.837	149.3	22.8	0.030	0.518	0	3.93	0.049	1.10	0.00	2.4
F	4,450	0.030	3.37	71,869	592	0.299	36.8	0.749	141.0	11.2	0.406	0.997	919	3.14	0.558	0.14	0.00	0.0
G	4,741	0.102	2.81	58,533	702	0.465	24.7	0.840	142.9	18.0	0.451	0.981	512	3.40	0.576	0.42	3.05	11.0

8 Decision Analysis Results

The purposes of completing a formal decision analysis as a component of the evaluation in the LTEMP EIS was to explicitly examine the influence of the relative importance assigned to the resource goals on the ranking of the alternatives and long-term strategies, and to understand the effect of uncertainty on this same ranking. As described in section 3, "Decision Analysis," the two primary tools used to support this investigation were MCDA and the expected value of information.

8.1 Swing-Weighting Method and Results

The swing-weighting method (Winterfeldt and Edwards, 1986) was used to develop weights for the performance metrics, reflecting individual stakeholder expressions of the relative importance of those metrics. In April 2014, a 2-day workshop was held to present a preliminary analysis of the long-term strategies against the performance metrics to interested stakeholders. After discussion of the meaning and interpretation of each of the performance metrics, the stakeholders were given a swing-weighting response form with instructions (table 8) to complete within several weeks. The swing-weighting method asks a decision maker or stakeholder to consider each resource goal, the performance metric that reflects it, and the range over which the performance metric varies; and to compare the relative importance of the performance metrics by evaluating how valuable it would be to change the performance of an alternative from the worst score for a performance metric to the best score. The stakeholders were first asked to rank the performance metrics in this manner and then to assign a score between 0 and 100 to each metric to reflect a more nuanced interpretation of the ranking. Because it is difficult to evaluate 18 performance metrics simultaneously, and because there were natural groupings of the metrics, the swing-weighting exercise used a two-level structure. The 18 performance metrics were assigned to 8 higher-level groups (table 8). The stakeholders first ranked and scored the metrics within each group. Then, to rank and score the higher-level groups, the stakeholders were asked to think about the importance of changing the scores of all the metrics within a group for their worst levels to their best levels at the same time. While completing this exercise, the stakeholders had access to a preliminary consequence table (similar to table 7) and a spreadsheet that automatically calculated the weights on the performance metrics as the swing-weighting sheet was filled in.

A total of 27 Federal, State, tribal, and private agencies and organizations were invited to participate in the decision analysis by expressing their view of the relative importance of the performance metrics using the swing-weighting method (Winterfeldt and Edwards, 1986). The invitations were sent to agencies that were either members of AMWG or Cooperating Agencies for the LTEMP EIS; 14 agencies, including the 2 joint-lead agencies, elected to participate (table 9).

From the responses to the swing-weighting exercise, weights were calculated for the 18 performance metrics separately for each participating stakeholder. To compare these vectors of weights, principal components analysis was used to reduce the dimension of the comparison from 18 to 2. The first two principal components explained 52.6 percent of the variation in weights across stakeholders. The first principal component was positively correlated with the weight on the frequency of mechanical removal, SLI, WTSI, fluctuation index, and riparian vegetation index; and negatively correlated with hydropower generation and capacity (fig. 22*A*). The second principal component was positively correlated with HBC population size, Glen Canyon rafting use, and the camping area index; and negatively correlated with RBT emigration and the Glen Canyon flow index (fig. 22*A*). The differences among the participating stakeholders can then be plotted with these two components (fig. 22*B*). Representatives from the utility industry (CREDA, UAMPS, and SRP) tended to put more weight on the hydropower generation and capacity metrics than other stakeholders. The agencies concerned with management of the RBT fishery (International Federation of Fly Fishers [IFFF] and Arizona Game and Fish Department [AZGFD]) were in the middle of the spectrum on the first component but had strong positive values for the second component, reflecting an emphasis on HBC, high-quality RBT, and RBT catch rate. The FWS, Arizona Department of Water Resources (ADWR) and the Hopi, Hualapai, and Navajo Tribes placed relatively more emphasis on increasing vegetation and minimizing RBT emigration than other stakeholders. The principal components for two of the nongovernment organizations (Grand Canyon River Guides [GCRG] and National Parks Conservation Association [NPCA]) placed an emphasis on camping area index, SLI, and WTSI. Note that the joint-lead agencies (Reclamation and NPS) separately completed the swing-weighting exercise, and their separate weights were used as input to the principal components analysis, but they elected to average their weighting vectors for presentation and discussion. The joint-lead principal components fall near the center of the spectrum of stakeholders. Although some of these patterns compare well with the expressed views of the stakeholder agencies, others are harder to explain; it is important to note that the higher-order principal components still contained explanatory power, so not all the differences among agencies can be summarized with the first two components.

8.2 Multicriteria Decision Analysis

The weights on the performance metrics, unique to each agency, tribe, or organization, were combined with the consequence table to generate a weighted performance metric for each long-term strategy, allowing a comparison of the long-term strategies that integrates the differences in response across performance metrics and the relative value

Table 8. Swing-weighting response form.

[Stakeholder agencies were invited to share their perspectives on the relative importance of the resource goals and performance metrics using this swing-weighting exercise. The results were compiled to generate agency-specific weights on the performance metrics; GLCA, Glen Canyon National Recreation Area; GRCA, Grand Canyon National Park; min, minimum; M, million; B, billion; >, greater than; yr, year; hr, hour; #, number; TMF, trout management flow]

Agency:	
Participants:	

						Higher level		Sublevel	
Goal	Performance metrics	Units	Desired direction	Worst case	Best case	Rank	Score	Rank	Score
Humpback chub									
	Number of adult humpback chub (20-yr min)	# of adults	High	3,000	8,500				
	Temperature suitability index (river mile 157 and 213)	index (0–1)	High	0	0.20				
Rainbow trout fishery									
	Angler catch rate index	fish/angler-hr	High	1.0	5.0				
	Lees Ferry trout emigration estimate	trout/yr	Low	125,000	15,000				
	Number of trout > 16 inches total length	# fish	High	400	1,200				
Archaeological and cultural resources									
	Wind transport of sediment index (WTSI)	index (0–1)	High	0	0.50				
	GLCA flow effects of historic properties	days flow > 23.2k	Low	75	0				
	Time-off-river index (TOR)	index (0–1)	High	0.60	0.95				
Hydropower									
	Value of energy generation (mean annual)	Million $/yr Billion $/20-yr	High	120M/ 2.4B	200M/ 4B				
	Value of capacity (mean annual)	Million $/yr Billion $/20-yr	High	10M/ 0.2B	50M/ 1B				
Recreation									
	GRCA camping area index (average of 3)	index (0–1)	High	0	0.50				
	Fluctuation index	index (0–1)	High	0	1.0				
	GLCA rafting use index	boat seats lost/yr	Low	1,300	0				
Riparian vegetation									
	Vegetation index (sum of four ratios)	sum of ratios	High	2.0	6.0			1	100
Sediment									
	GRCA sand load index (sand transported > 31,500)	proportion	High	0	0.6			1	100
Tribal									
	Change in marsh vegetation	ratio	High	0	1.5				
	Mechanical removal (years out of 20)	yrs	Low	5	0				
	Frequency of TMF (years out of 20)	yrs	Low	20	0				

Table 9. Agencies participating in the swing-weighting exercise.

[Representatives from 27 Federal, State, tribal, and private agencies were invited to participate in the swing-weighting exercise. The set of invited agencies included the Adaptive Management Working Group and cooperating agencies for the Long-term Experimental and Management Plan Environmental Impact Statement. Of the 27 agencies invited, 14 participated. AMWG, Adaptive Management Working Group; CA, cooperating agency; NGO, non-governmental organization]

Agency	Affiliation	AMWG	CA	Participant
Bureau of Indian Affairs	Federal	Yes	Yes	No
National Park Service	Federal	Yes	Yes	Yes
Bureau of Reclamation	Federal	Yes	Yes	Yes
U.S. Fish and Wildlife Service	Federal	Yes	Yes	Yes
Western Area Power Administration	Federal	Yes	Yes	No
Havasupai Tribe	Tribe	No	Yes	No
Hopi Tribe	Tribe	Yes	Yes	Yes
Hualapai Tribe	Tribe	Yes	Yes	Yes
Navajo Nation	Tribe	Yes	Yes	Yes
Pueblo of Zuni	Tribe	Yes	Yes	No
Southern Paiute Consortium	Tribe	Yes	No	No
Fort Mojave Indian Tribe	Tribe	No	Yes	No
National Parks Conservation Association	NGO	Yes	No	Yes
International Federation of Fly Fishers	NGO	Yes	No	Yes
Grand Canyon River Guides	NGO	Yes	No	Yes
Arizona Department of Water Resources	State	Yes	No	Yes
Arizona Game and Fish Department	State	Yes	Yes	Yes
Colorado River Board of California	State	Yes	Yes	No
Colorado Water Conservation Board	State	Yes	No	No
Colorado River Commission of Nevada	State	Yes	Yes	No
New Mexico Interstate Stream Commission	State	Yes	No	No
Wyoming State Engineer's Office	State	Yes	No	No
Utah Division of Water Resources	State	Yes	No	No
Salt River Project	Public power utility	No	Yes	Yes
Upper Colorado River Commission	State and Federal	No	Yes	No
Colorado River Energy Distributors Association	Power purchase contractor	Yes	No	Yes
Utah Associated Municipal Power Systems	Power purchase contractor	Yes	Yes	Yes

the particular agency places on those performance metrics. For the joint-lead agencies, using their average set of weights, Alternative D (and specifically, long-term strategy D4) performed better than the other alternatives (fig. 23). Alternatives C, D, E, F, and G all substantially outperformed Alternative A (status quo), provided HFEs were implemented. The long-term strategies that did not implement HFEs (C3, E3, E5, and E6) were all demonstrably poorer than Alternative A, as measured by the weighted performance. The weighted performance of Alternative B was similar to that of Alternative A, with long-term strategy B1 slightly better than long-term strategy B2.

Alternative D was created after a preliminary analysis of the other alternatives. In the April 2014 preliminary analysis, the results of which were discussed by the joint-lead agencies and the Cooperating Agencies, Alternative C and E exhibited roughly equivalent performance with some differences in ranking across stakeholders. Alternative D was created as a hybrid between Alternative C and E, taking features of each that had contributed to positive performance in the preliminary analysis. One of the advantages of separating objective weighting from alternative evaluation in MCDA is that the weights only depend on the ranges of the performance metrics, not on the alternatives under consideration, so new alternatives can be evaluated without having to re-elicit the swing weights. Because Alternative D was created from the insights gained in the preliminary analysis of alternatives, it stands to reason that Alternative D outperformed Alternatives C and E. It is interesting, however, that the gain in performance is fairly small, suggesting that only marginal gains in performance remain with the management tools available, against the backdrop

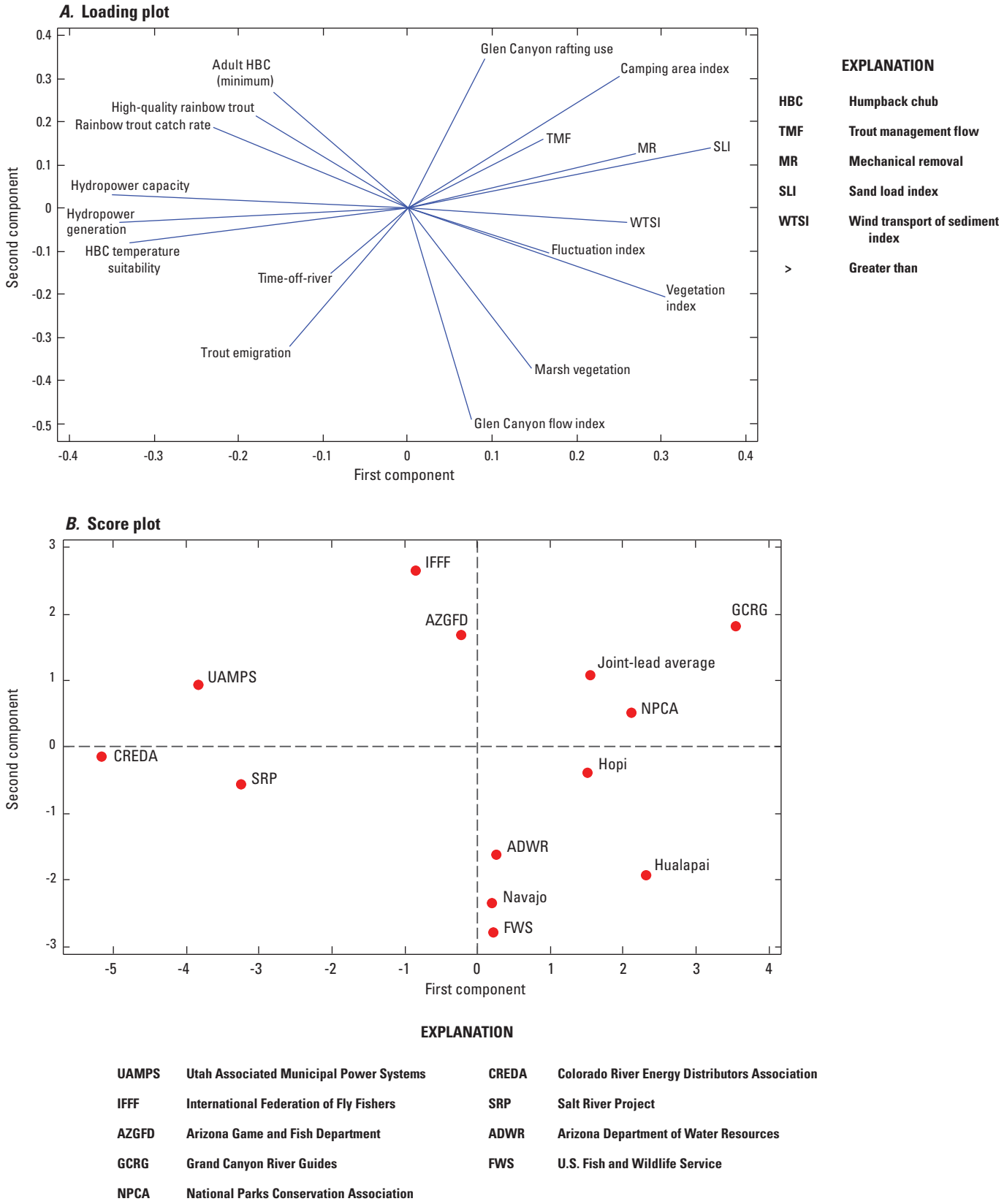

Figure 22. Principal components analysis of the weights on the performance metrics across stakeholder agencies. *A*, loading plot; and, *B*, score plot.

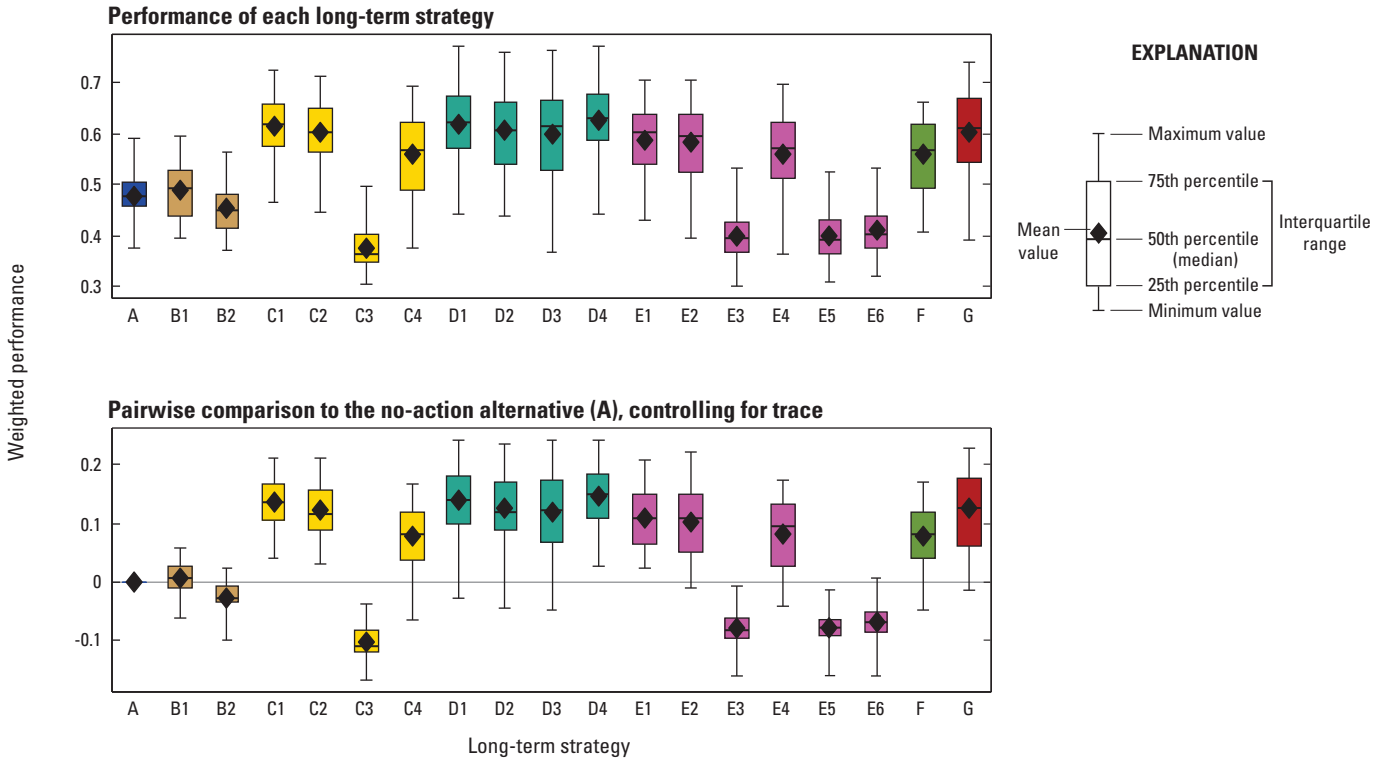

Figure 23. Joint-lead agency weighted performance across 18 metrics forecast for 19 long-term strategies using equal weighting of hydrological traces.

of uncertainty in hydrology and the complex set of tradeoffs among the resource goals.

One of the important motivations for MCDA was the opportunity to include and analyze differing viewpoints from stakeholder agencies regarding the importance of the various resource goals and their performance metrics. The agency-specific weightings did affect the ranking of alternatives (table 10). For most of the participating agencies, long-term strategy D4 had the highest mean-weighted performance (with the mean taken over hydrology and sediment traces and critical uncertainties). For two of the agencies (UAMPS, CREDA), long-term strategy B2 had the highest weighted score, and for one organization (GCRG), Alternative G had the highest weighted score. For all participating agencies except CREDA, long-term strategy D4 outperformed Alternative A. For all agencies, long-term strategy C3 performed worse than Alternative A, and for most of those agencies, it was the worst-performing long-term strategy. Alternative F was a polarizing strategy: for three agencies it was the worst-performing strategy, whereas for four others, it performed better than the status quo. Most of the differences across stakeholders in the MCDA ranking of the long-term strategies can be explained by the first principal component in the weighting (fig. 22). For those agencies that placed more weight on the performance metrics on the left side of the diagram (fig. 22*A*), Alternative B performed very well because it performs best for power generation and capacity; for those agencies that placed more weight on the performance metrics on the right side of the diagram (fig. 22*A*), Alternative B was outperformed by Alternative D. Across all participating stakeholders, the mean values for the long-term strategies in Alternative D were greater than those for Alternatives C and E, suggesting that the improvements made in crafting Alternative D are robust to the weights on the performance metrics.

Across stakeholders, the top-ranked long-term strategy was effectively tied with a number of other long-term strategies, against the backdrop of uncertainty induced by the hydrology and sediment traces; for example, using the joint-lead agency weights on the objectives, Alternative D4 had the highest mean performance, but the differences between D4 and next nine long-term strategies (D1, C1, D2, G, C2, D3, E1, E2, and E4) had ranges that included zero (fig. 24, bottom panel); that is, based on the results of the MCDA, alternatives C, D, E, and G were nearly indistinguishable using the joint-lead agency weights. This pattern held for the weights from most stakeholders as well (fig. 25), with between 2 and 11 long-term strategies effectively tied. For all stakeholders except CREDA, long-term strategies D4 and D1 were either the best-performing or effectively tied with the best-performing long-term strategy.

The differences among the long-term strategies within Alternative D are difficult to discern (fig. 23). The tradeoffs associated with using TMFs are marginal (compare D1 to D3). Similarly, the tradeoffs associated with “bug flows” do not

Table 10. Weighted performance for 19 long-term strategies using the weights on the performance metrics expressed by 14 participating agencies.

[The aggregate scores across performance metrics, weighted using the agency-specific swing-weighting results, are shown for each long-term strategy. For each participating agency, the best-performing long-term strategy is shaded in yellow, the worst-performing strategy is shaded in dark blue, strategies that perform better than Alternative A are shaded in orange, and strategies that perform worse than Alternative A are shaded in turquoise. The 21 hydrological traces were weighted equally. Thirteen additional stakeholder agencies were invited but declined to participate. JL, joint-lead agency average; FWS, U.S. Fish and Wildlife Service; ADWR, Arizona Department of Water Resources; AZGFD, Arizona Game and Fish Department; SRP, Salt River Project; UAMPS, Utah Associated Municipal Power Systems; CREDA, Colorado River Energy Distributors Association; IFFF, International Federation of Fly Fishers; NPCA, National Parks Conservation Association; GCRG, Grand Canyon River Guides]

	JL	FWS	ADWR	AZGFD	SRP	UAMPS	CREDA	Hopi	Hualapai	Navajo	IFFF	NPCA	GCRG
A	0.479	0.508	0.483	0.448	0.472	0.448	0.459	0.515	0.530	0.477	0.508	0.450	0.429
B1	0.488	0.504	0.511	0.450	0.493	0.485	0.474	0.512	0.538	0.495	0.511	0.474	0.443
B2	0.454	0.434	0.447	0.402	0.491	0.495	0.484	0.457	0.477	0.446	0.504	0.416	0.384
C1	0.615	0.539	0.484	0.508	0.458	0.410	0.410	0.574	0.599	0.521	0.544	0.604	0.637
C2	0.602	0.515	0.465	0.518	0.426	0.376	0.391	0.570	0.591	0.511	0.549	0.589	0.631
C3	0.376	0.433	0.378	0.369	0.418	0.400	0.412	0.411	0.410	0.374	0.445	0.315	0.280
C4	0.559	0.507	0.452	0.497	0.441	0.392	0.405	0.532	0.544	0.488	0.529	0.555	0.573
D1	0.619	0.573	0.542	0.540	0.489	0.450	0.436	0.596	0.630	0.559	0.553	0.634	0.648
D2	0.607	0.574	0.526	0.535	0.470	0.424	0.414	0.581	0.615	0.547	0.534	0.630	0.642
D3	0.599	0.557	0.526	0.540	0.472	0.425	0.428	0.584	0.614	0.550	0.544	0.621	0.637
D4	0.628	0.590	0.560	0.553	0.500	0.460	0.445	0.610	0.646	0.574	0.559	0.647	0.662
E1	0.589	0.535	0.522	0.506	0.475	0.447	0.430	0.572	0.607	0.535	0.550	0.587	0.592
E2	0.583	0.539	0.533	0.515	0.459	0.428	0.418	0.579	0.616	0.542	0.547	0.588	0.594
E3	0.400	0.488	0.482	0.411	0.450	0.445	0.434	0.463	0.483	0.445	0.461	0.373	0.319
E4	0.560	0.543	0.532	0.509	0.468	0.436	0.427	0.563	0.597	0.536	0.534	0.575	0.569
E5	0.401	0.482	0.476	0.407	0.442	0.438	0.426	0.461	0.482	0.440	0.461	0.370	0.318
E6	0.412	0.498	0.492	0.415	0.460	0.462	0.440	0.469	0.491	0.451	0.467	0.382	0.326
F	0.559	0.465	0.396	0.484	0.311	0.269	0.293	0.509	0.536	0.431	0.475	0.535	0.622
G	0.605	0.559	0.478	0.532	0.456	0.385	0.397	0.563	0.588	0.524	0.514	0.634	0.669

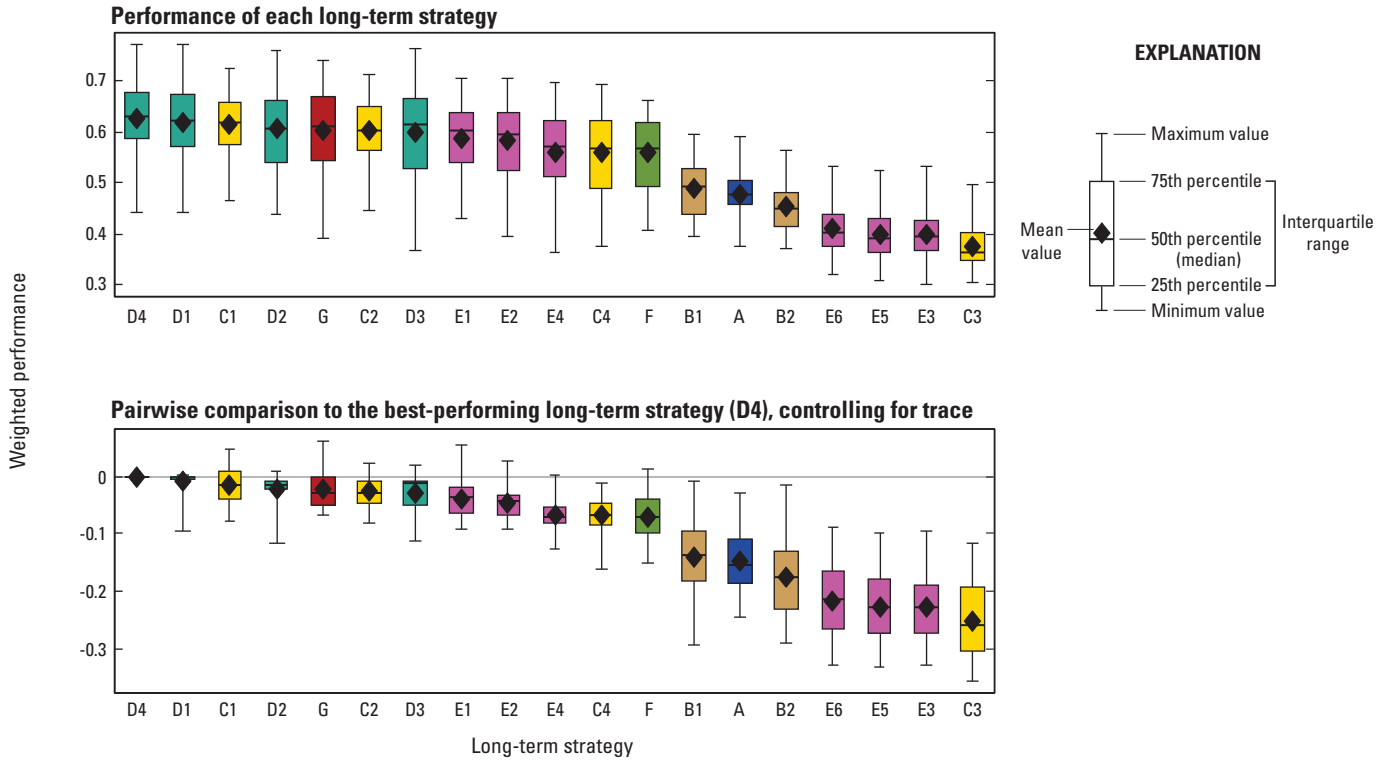

Figure 24. Joint-lead agency weighted performance across 18 metrics, sorted by mean performance, forecast for 19 long-term strategies using equal weighting of hydrological traces.

produce a clear favorite (compare D1 to D2). Finally, although there is the suggestion that the costs of low summer flows outweigh the benefits (compare D1 to D4), the difference is small against the backdrop of the variation driven by hydrology. The patterns within Alternative D are shown for the joint-lead agency weighting (figs. 23–24) but hold for the other stakeholder weightings as well (fig. 25).

8.3 Expected Value of Information

A second important purpose for the use of formal decision analysis tools was to examine the effect of uncertainty on the ranking of the alternatives. Although the effect of uncertainty on the ranking of alternatives based on single performance metrics was generally small (table 6), it is conceivable that the weighted performance could be more sensitive to uncertainty if the effects of the uncertainties affect the subtle balancing of tradeoffs. The analysis of the value of information on the weighted performance, however, revealed that the effect of the uncertainties was nearly 0 (table 11). For the joint-lead agency weighting and all but two of the participating stakeholders, the best-performing long-term strategy was the same across the 16 hypotheses that represented critical uncertainty (table 11); for example, long-term strategy D4 was preferred in the joint-lead agency weighting regardless of whether fall HFEs have an effect on RBT recruitment or not, regardless of whether TMFs are 10 or 50 percent effective in reducing RBT recruitment, and regardless of the relative influence of temperature and RBT on juvenile HBC survival and growth. For two stakeholders, there was a very small effect of the critical uncertainty: for IFFF, C2 was preferred more than D4 in 2 of the 16 hypotheses; and for GCRG, D4 was preferred more than G in 1 of the 16 hypotheses (table 11). Even in these two cases, however, the expected value of information for resolving the uncertainty represented by the 16 hypotheses was less than 0.1 percent.

At first glance, these results may seem puzzling. Many intense discussions within AMWG through the years have focused on concern that uncertainty about the response of the system to management prevents the identification of a best management strategy, and differences concerning recommendations for management have been explained as differences in interpretation of the scientific evidence. The uncertainties examined in this analysis (effect of fall HFEs, effectiveness of TMFs, and relative influence of temperature and RBT on juvenile HBC) have been central to previous discussions. But the results of this analysis do not support the conclusions that resolution of this uncertainty is important in choosing among the long-term strategies examined. There are several explanations for these results. First, there is less uncertainty than informal conversations imply. After several decades of intense study of the resources affected by the operation of Glen Canyon Dam, the AMWG partners have learned a great deal. Uncertainty remains, of course, but it is bounded; for

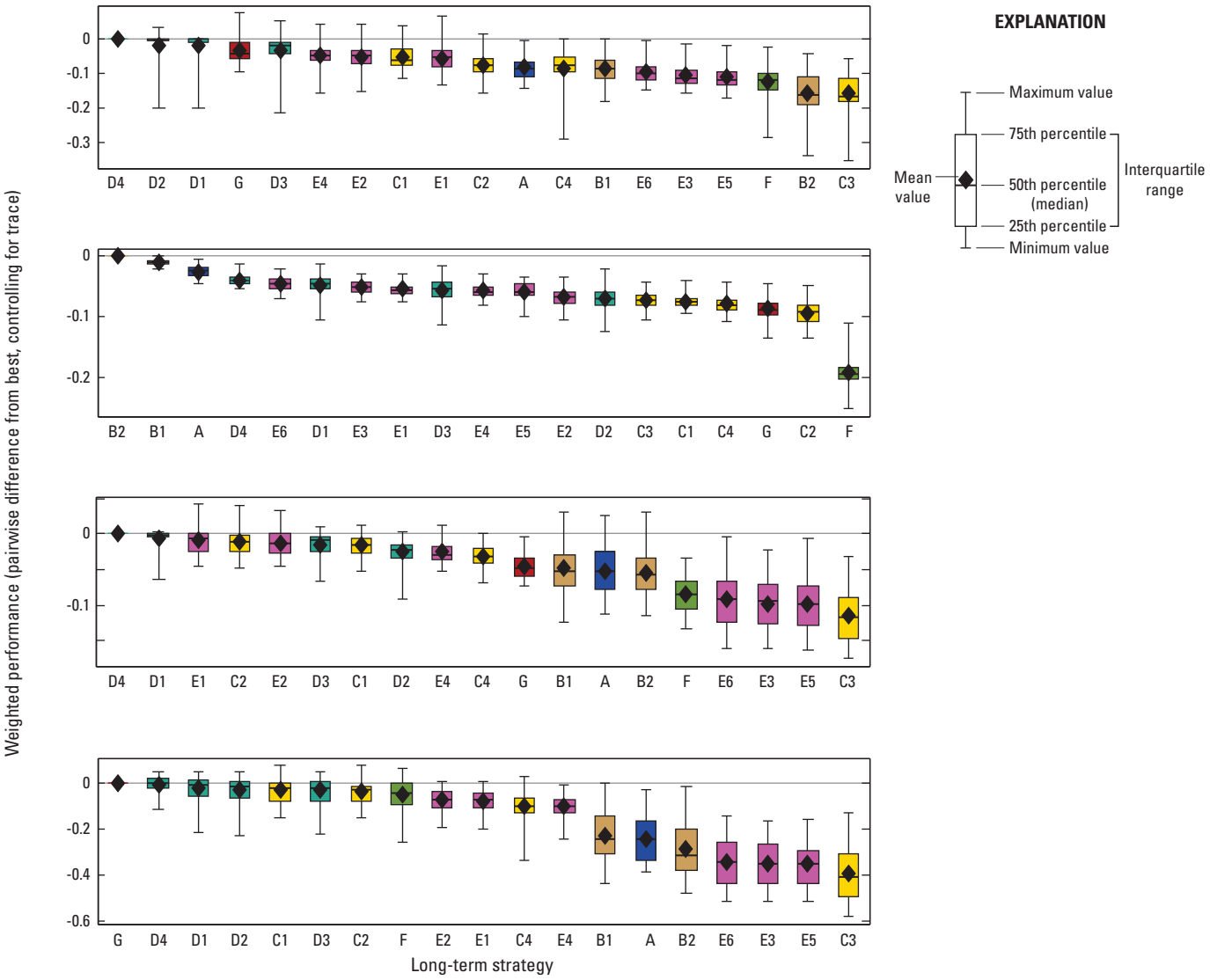

Figure 25. Weighted performance across 18 metrics, for four stakeholder agencies, sorted in descending order of mean performance. The four panels show the results for the stakeholders at the outer boundary of the score plot (fig. 22B; U.S. Fish and Wildlife Service, Colorado River Energy Distributors Association, International Federation of Fly Fishers, and Grand Canyon River Guides).

Table 11. Expected value of perfect information for resolving various uncertainties, as a function of the agency-specific weights.

[For each of the 16 combinations of hypotheses that describe the critical uncertainties, the best-performing long-term strategies are listed, using the agency-specific weights on the performance metrics. The shading of each cell is associated with the alternative from which the best-performing long-term strategy comes. See table 4 for a description of the critical uncertainties. The expected value of information for resolving critical uncertainty is zero for all the stakeholders except IFFF and GCRG. The expected value of partial information for resolving uncertainty about the combination of sediment and hydrology trace, sediment trace alone, and hydrology trace alone is shown. JL, joint-lead agency average; FWS, U.S. Fish and Wildlife Service; ADWR, Arizona Department of Water Resources; AZGFD, Arizona Game and Fish Department; SRP, Salt River Project; UAMPS, Utah Associated Municipal Power Systems; CREDA, Colorado River Energy Distributors Association; IFFF, International Federation of Fly Fishers; NPCA, National Parks Conservation Association; GCRG, Grand Canyon River Guides; HFE, high-flow experiment; TMF, trout management flow; EV, expected value; EVPI, expected value of perfect information; EVXI, expected value of partial information]

Critical uncertainties			Stakeholder											
Fall HFE	TMF	Temp trout	Federal		State					Tribe			NGO		
			JL	FWS	ADWR	AZGFD	SRP	UAMPS	CREDA	Hopi	Hualapai	Navajo	IFFF	NPCA	GCRG
No	High	f1	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
No	High	f2	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
No	High	g1	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
No	High	g2	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
No	Low	f1	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
No	Low	f2	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
No	Low	g1	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
No	Low	g2	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
Yes	High	f1	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
Yes	High	f2	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
Yes	High	g1	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
Yes	High	g2	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
Yes	Low	f1	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
Yes	Low	f2	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	C2	D4	G
Yes	Low	g1	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	D4
Yes	Low	g2	D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	C2	D4	G
Average best			D4	D4	D4	D4	D4	B2	B2	D4	D4	D4	D4	D4	G
EV			0.628	0.590	0.560	0.553	0.500	0.495	0.484	0.610	0.646	0.574	0.559	0.647	0.669
EVPI			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000
EVPI, in percent			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.01
EVXI (trace), in percent			1.50	1.39	1.54	1.84	0.89	0.10	0.00	1.06	1.32	1.00	1.23	1.87	2.50
EVXI (sediment), in percent			0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.14	0.00
EVXI (hydrology), in percent			1.10	0.93	1.27	1.58	0.75	0.09	0.00	0.87	1.12	0.80	0.91	1.53	1.89

example, the uncertainty in the effect of temperature and RBT on juvenile HBC is large, in the sense that the parameters governing those relations are uncertain by a factor of two (fig. 3*A* and 3*B*); the trout effect on survival could be as small as -0.15 or as large as -0.4. But, the decades of study of the interactions of RBT and HBC have indicated conclusively that there is an effect of RBT on juvenile HBC survival, and there are effects of both RBT and temperature on juvenile HBC growth. Second, the value of information is strongly affected by the set of alternatives considered. It only asks if the uncertainty impedes the choice of a best alternative from among the set evaluated. It does not ask if there could be another alternative, not yet identified, that would be sensitive to the uncertainty. So, for example, it was thought that the value of low summer flows would be sensitive to the effect of temperature on HBC growth; therefore, C2, for example, might be favored compared to C1 if model f1 holds, but C1 might be favored compared to C2 if model f2 holds. This presumes, though, that low summer flows are triggered in enough years and involve flows low enough to lead to substantial changes in the temperature in the Colorado River at the confluence with the Little Colorado River to produce a demonstrable difference between models f1 and f2; this was not the case. But, if there were another alternative that could produce large differences in temperature (for example, a temperature control device on Glen Canyon Dam), these uncertainties may have played a greater role. Third, in a multiple-objective decision, the influence of the weights on the objectives might override the effect of uncertainties; for example, the costs associated with low summer flows (on recreation and hydropower, for example) may override the potential benefits (to HBC) enough that the effect of the uncertainty does not matter.

8.4 Effects of Climate Change

Although the value of information associated with resolving critical uncertainty was small, there was an indication that the uncertainty associated with hydrological input had some influence on the ranking of the long-term strategies (table 11). For the joint-lead agency weighting, foreknowledge of the hydrological and sediment trace could lead to a 1.5 percent improvement in the weighted performance across objectives (table 11). Such knowledge is not possible because it would require accurate prediction of the monthly precipitation in the Colorado Basin over the next 20 years. But in demonstrating that hydrological input might be important in the selection of a long-term strategy, it raises the question about the potential influences of climate change.

The 21 reconstructed historical hydrological traces that were used in the LTEMP analysis represent possible 20-year sequences if the future is like the recent past (1906-2010). The 112 hydrological traces generated as part of the Basin Study (Bureau of Reclamation, 2012) represent the best current understanding of what might happen because of climate change. Mean annual inflow to Lake Powell is quite different under these two sets of traces (fig. 26). The median flow over the climate-change traces is lower than for the historical traces, although it is within the interquartile range of the historical traces. About 30 percent of the potential future distribution of flows, however, is not captured by the distribution of the historical traces. The historical 20-year trace with the lowest mean inflow has an annual flow of about 8.5 million acre-feet; 30 percent of the climate-change traces fall below this point, suggesting that the set of historical traces may not be representative of future conditions.

To examine part of the potential influence of climate change, a reweighting of the historical traces was calculated to better match the mean and variance of Lake Powell inflow seen in the climate-change traces. The climate-change weighing put about 18 percent of the weight on the single hydrology trace with the lowest input to Lake Powell. This reweighting of the hydrological traces was then used in all the MCDA calculations to examine the effect of those weights on the performance of the long-term strategies. For the joint-lead agency weights on the performance metrics, the weights on the hydrological traces had a small effect on the aggregate performance but did not change the rankings of alternatives (fig. 27). A similar pattern was seen for other stakeholder weightings. Although this result suggests the ranking of alternatives is robust to uncertainty about climate change, it is important to

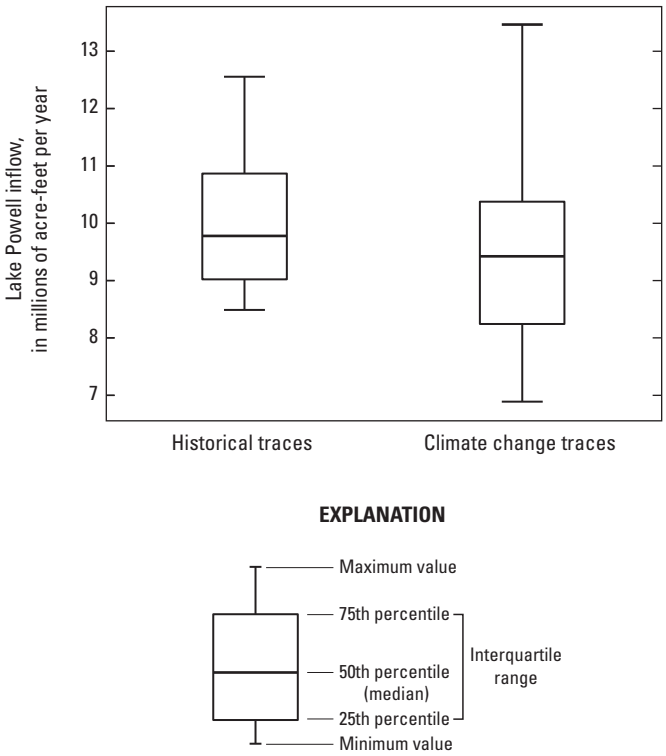

Figure 26. Mean annual inflow to Lake Powell during the 20-year period of the Long-Term Experimental and Management Plan for 21 historical hydrological traces and 112 climate-change-influenced hydrological traces.

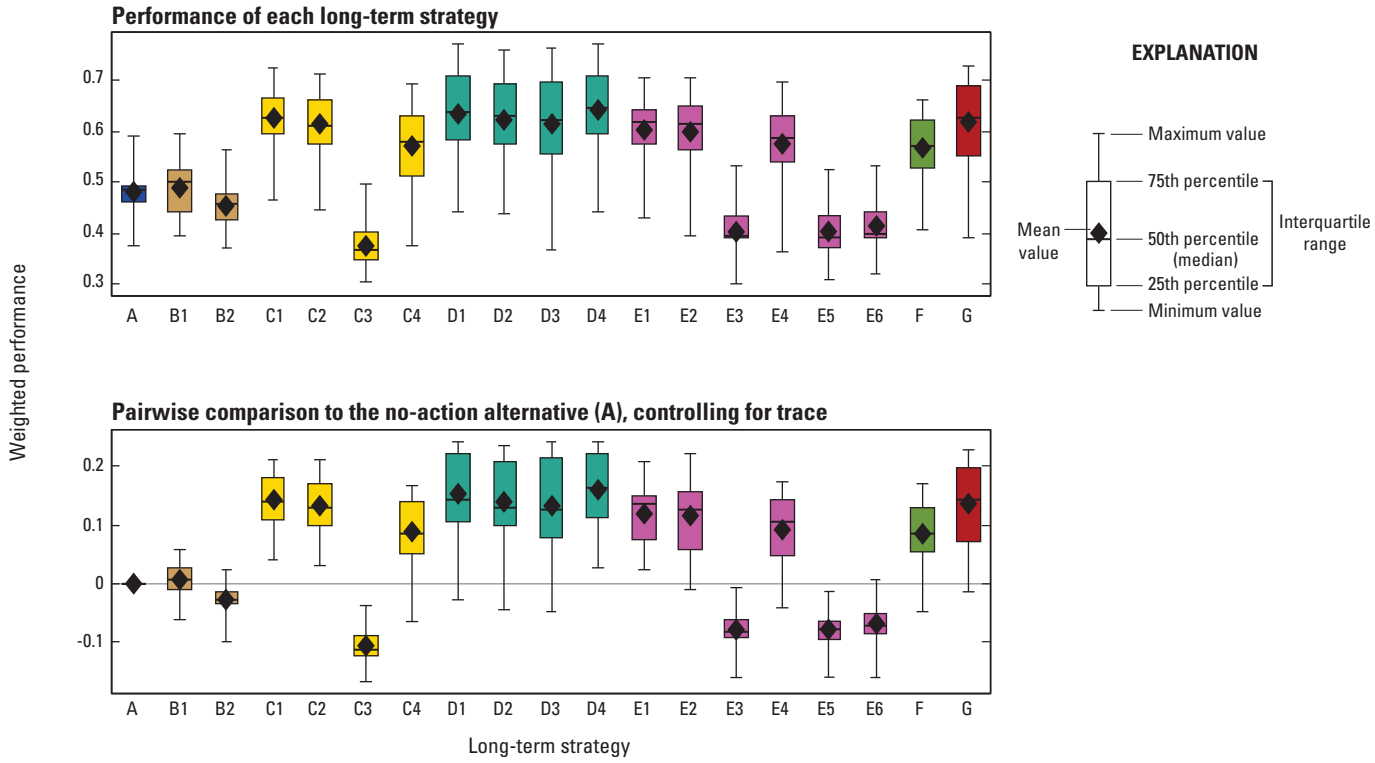

Figure 27. Joint-lead agency weighted performance across 18 metrics forecast for 19 long-term strategies using the climate-change weighting of hydrological traces.

keep in mind that the traces that were run through the modeling did not include plausible scenarios from the low end of the climate-change distribution.

9 Discussion

The analysis in this report is meant to add to the analysis in the LTEMP EIS itself. For those resource goals that could be evaluated with quantitative performance metrics, the tools of decision analysis allowed us to integrate the consequence analysis with the value judgments of stakeholders to formally evaluate the tradeoffs among the resource goals and to examine the influence of uncertainty on the performance of the long-term strategies. It is important to note, however, that not all the resource goals of importance could be evaluated quantitatively. The LTEMP EIS contains a narrative analysis of a greater number of resource goals than were included in the decision analysis, and this greater set of goals may be influential for the stakeholders and joint-lead agencies.

9.1 Evaluation of Alternatives

The alternatives examined in the LTEMP EIS and their long-term strategies differed in performance across the metrics considered. The full consequence table (table 7) shows strong tradeoffs: long-term strategies that perform well on any one performance metric may not perform well on others; thus, the choice of a preferred alternative will require the Secretary of Interior to weigh the importance of the various resource goals. The MCDA was designed as one way to provide input to the Secretary in her decision, by allowing the joint-lead agencies and stakeholders to express their interpretation of the importance of those resource goals and trace that interpretation through to the rankings of the alternatives. The best-performing long-term strategy did depend on the weights given to the performance metrics. Among the participating agencies, three alternatives rose to the top: Alternatives B, D, and G. Alternative B (especially long-term strategy B2) was favored by those agencies that emphasized the importance of the hydropower resource. Alternative G was the top- or second-ranked alternative for those agencies that emphasized restoration of natural processes, like beach building and native vegetation. For the remainder of the participating agencies, the analysis ranked Alternative D (especially long-term strategy D4) the highest. Alternative D was created after preliminary analysis revealed the strengths and weaknesses of the other alternatives and performs marginally better than the alternatives from which it was designed (C and E).

A number of other suggestions arise from the decision analysis regarding the long-term strategies. For most of the stakeholders, the benefits of HFEs seem to outweigh the costs, even in the face of uncertainty about their effects, at least as

measured by the performance metrics included in this analysis. The other modifications (for example, TMFs, mechanical removal, low summer flows, and bug flows) produce equivocal results; their inclusion is neither convincingly demonstrated nor precluded by the decision analysis.

Several caveats are warranted in interpreting this report. First, the performance metrics evaluated represent only a subset of the resource goals that might be influenced by the alternatives. The LTEMP EIS provides a fuller discussion of other goals, and the stakeholders and decision makers will need to judge if the formal decision analysis represents a sufficient degree of completeness. Second, not all stakeholders with an interest in the LTEMP EIS chose to participate in the decision analysis; thus, the array of viewpoints represented (for example, fig. 22 and table 10) may not capture the full range or appropriate distribution of viewpoints. Third, even for those stakeholders that participated, it may be difficult to express a nuanced set of values through the swing-weighting process. The set of MCDA methods used assumes the resource goals can be traded against each other in a linear, additive, and independent fashion. In fact, the value a stakeholder places on one objective might depend on how well an alternative is also performing on another objective; such dependencies require other decision analysis methods that were not used here. Fourth, some of the performance metrics may not have directly captured the resource goals they were meant to represent. For instance, the SLI is a proxy for sediment deposition and retention but not necessarily directly correlated with it. Fifth, some of the performance metrics (like hydropower generation) were expressed on natural scales that can be readily understood, but some of the performance metrics were expressed on proxy scales (for example, SLI) or constructed scales (for example, fluctuation index) that are difficult to understand; this mixture of scales makes the swing-weighting judgments challenging.

The structuring of objectives and the development of appropriate performance metrics are critical steps in MCDA and require diligence to meet the assumptions of a linear, additive value model (the form of MCDA used in this analysis). One of the concerns is the possible inclusion of means objectives, leading to possible double counting in the weighting process; for example, there was considerable discussion about the inclusion of the RBT emigration rate (performance metric 4)—was it fundamental or merely a means to conserving native fish populations? For some stakeholders, it was fundamental as an expression of the conservation of natural processes. But for other stakeholders, weight may have been placed on this objective as an expression of the effect of trout on native fish, thus, leading to possible double counting. Another concern is the possible inclusion of preferentially dependent objectives; for example, were RBT catch rate (performance metric 3) and abundance of high-quality RBT (performance metric 5) treated as independent in the swing-weighting exercise, or did the participants assume that if you had one, you would have the other and so assign weight based on simultaneous achievement? The two-stage swing-weighting may have helped reduce this concern, but with the large number of performance metrics being evaluated, cognitive mistakes in the swing-weighting exercise could still have happened. When applying decision theory to real problems, with all their subtleties and complexities, it is difficult to achieve perfect adherence to the assumptions of the analysis, but diligence toward those assumptions is needed.

All these caveats are fair, and the interpretation of the results should account for them. But the analysis also represents an effort to use the best available science to explicitly examine the ranking of alternatives as influenced by an analysis of consequences and the relative values placed on the resource goals.

9.2 Motivation for Adaptive Management

The purpose of doing the EVPI calculation was to understand the importance of resolving uncertainty (and the relative importance of resolving the different sources of uncertainty) before beginning experimental design. This puts the focus of uncertainty on its value to the decision maker, rather than its value as a point of scientific discovery. Although much has been written about the many scientific uncertainties about how the Colorado River ecosystem responds to management, less has been documented about how resolution of those uncertainties would explicitly affect and improve management decisions. The value of information analysis identifies the following: what long-term management alternative is best assuming each of the competing hypotheses, what long-term management alternative is best in the face of uncertainty (if uncertainty cannot be resolved), how much long-term management can improve through resolution of uncertainty, and which components of uncertainty contribute most to the value of information. Of course, what constitutes “best” depends on how the decision maker values the multiple resource goals within their statutory framework, so the analysis includes the sensitivity of the value of information to the weights on the objectives.

The results presented in this report (including the MCDA and EVPI analyses) provide valuable information for the construction of an experimental or adaptive design that is targeted to the most importance sources of uncertainty and has the best chance of resolving that uncertainty. The design of an adaptive strategy needs to consider three important elements: the value of the information being sought, the power of any experimental or adaptive design to resolve that uncertainty, and the short-term costs to the resource goals of pursuing the reduction of uncertainty. Although there are optimization algorithms to derive adaptive strategies taking these factors into account, for example, active adaptive stochastic dynamic programming (Williams, 1996), such tools are difficult to use in such a complex system.

Interestingly, the EVPI analysis suggests that there is not much advantage in an experimental approach because the resolution of the uncertainties articulated is not expected to alter the choice of long-term strategy. This suggestion, however,

hinges on the assumption that the uncertainties examined are a complete set. What about the "unknown unknowns," the uncertainties that we cannot yet articulate, but which we might nevertheless discover? We cannot analyze their importance, without being able to estimate their effect, and we also cannot design a monitoring system to detect them reliably. But, ongoing monitoring of the important resource goals, coupled with experimental implementation of the novel elements of any chosen alternative, is likely to reveal any surprises that would affect the achievement of the resource goals.

9.3 Decision Analysis and the National Environmental Policy Act

A typical analysis under the NEPA looks quite a bit like a formal decision analysis: resource goals (objectives) are articulated, alternatives are designed and described, and alternatives are evaluated against the individual resources of concern. These analyses are often qualitative, but a mix of qualitative and quantitative tools is also common. What is often missing from such analyses is a formal way to synthesize the results across the resources of concern. To the extent that NEPA is meant as a way to disclose to the public the environmental effects of the considered actions, such a synthesis is not needed. What decision analysis adds is a formal, quantitative way for the decision maker to consider and express the relative importance of the various resource goals in choosing a preferred alternative. In our view, then, decision analysis provides a useful companion to the analyses completed in an EIS.

The use of formal decision analysis in the context of a NEPA process was unfamiliar to a number of the Cooperating Agencies and other stakeholders, and several noted their discomfort with its use in comments to the joint-lead agencies. One-half of those stakeholders invited to participate in the swing-weighting exercise chose not to do so (table 9). They cited a number of concerns: skepticism that all the resources could be evaluated quantitatively, distrust of the methods of MCDA generally, a preference for providing input in a format they felt comfortable with, and a desire not to be forced to make an explicit value judgment on all the resource goals. Underlying the concerns was a stated fear that the decision analysis methods would be used to make the decision rather than just support an understanding of the alternatives. At all points, the joint-lead agencies and DOI leadership assured the stakeholders that the decision analysis was an effort to explore the performance of the proposed alternatives as deeply as possible with quantitative tools but was being used as only one of many sources of input in the transparent, deliberative process sought under NEPA. The effective use of decision analysis tools in the context of future NEPA processes will benefit from the insights of additional case studies, and from improved communication and training with regard to the theory, practice, justification, and benefits of decision analysis.

10 Summary

This report describes a formal decision analysis led by the U.S. Geological Survey, in cooperation with the Bureau of Reclamation, National Park Service, and Argonne National Laboratory, to support the development and evaluation of alternatives for the Glen Canyon Dam Long-Term Experimental and Management Plan. A set of 12 resource goals formed the basis of this evaluation, with 18 performance metrics used to provide quantitative measures of the resource goals. A total of 19 long-term strategies associated with 7 alternatives were evaluated against the performance metrics using a series of linked simulation models. Stakeholder input was elicited using the swing-weighting method, and this input was coupled with the quantitative evaluation of the alternatives in a multicriteria decision analysis. For 10 out of 13 stakeholder weightings presented, Alternative D (in particular, long-term strategy D4) outperformed the other alternatives. For the remaining stakeholder weightings, Alternatives B and G were the top performers. These rankings were robust to the uncertainties examined; the value of resolving uncertainty was never greater than 7.5 percent for any performance metric, and never greater than 2.5 percent for any stakeholder-weighted performance. This analysis is not a substitute for the full qualitative analysis found in the Long-Term Experimental and Management Plan Environmental Impact Statement, but does provide a transparent way to synthesize the analyses that could be quantified.

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12 Appendix 1. Disclaimers

In preparatory discussions with the Adaptive Management Working Group (AMWG) stakeholders and Cooperating Agencies, the joint-lead agencies and U.S. Department of the Interior (DOI) wanted to be clear about the role of the decision analysis in the Long-Term Experimental and Management Plan (LTEMP) Environmental Impact Statement (EIS) process. The following disclaimer is to be included in the EIS when describing the use of formal decision analysis. (Note that during the discussions with the stakeholders, the term "structured decision analysis" was used as shorthand for the process being used. In this report, we follow the common practice in the literature and simply refer to the process as "decision analysis." The disclaimers below are reproduced verbatim, and so retain the use of the term "structured decision analysis"). A number of the participating stakeholders added disclaimers of their own when they submitted their swing-weighing results; these are also included below.

12.1 Standard Disclaimer

In an effort to provide multiple opportunities for interested stakeholders to provide input in the LTEMP process, the National Park Service (NPS) and Bureau of Reclamation (hereinafter referred to as "Reclamation") have decided to incorporate facilitated structured decision analysis (SDA) into the LTEMP EIS process. The SDA has been used previously for one aspect of the Glen Canyon Dam Adaptive Management Program (GCDAMP), the "Environmental Assessment for Non-Native Fish Control below Glen Canyon Dam." The use of SDA in the LTEMP process is not required by the National Environmental Policy Act (NEPA), nor does it replace the NEPA impact analysis.

Participation in the SDA process is a voluntary opportunity for stakeholder input. The NPS and Reclamation recognize that any input provided during the SDA effort does not replace the need and opportunities for formal public comment that are required steps in the NEPA process. Such formal comments on the Draft and Final EISs will be regarded as the formal and official positions of any commenting entity.

The use of SDA is an effort to cast a complex decision setting into a transparent, comprehensive but compressed form to help the decision makers and stakeholders see the essential elements; it may not, however, capture all nuances perfectly. The NPS and Reclamation recognize that the metrics for identified resource goals in the SDA do not necessarily reflect consensus or agreement among participants; moreover, the swing-weighting values to be applied to the metrics for identified resource goals may not reflect the broader policies or the importance of issues for any participant or agency. Stakeholders have had and will have formal opportunities to express their values through standard steps in the NEPA process, especially the submission of alternatives and public comments; for some stakeholders, these steps may allow them more flexibility to express their values in a familiar form than the decision analysis.

For these and other reasons, neither the co-leads nor the swing-weighting participants are bound by any outcomes or results of the SDA process. The NPS and Reclamation will use the results of the SDA process as one of multiple sources of information to inform the NEPA process, but the SDA process itself will not be used in isolation from other input to select the preferred alternative; rather, the NPS and Reclamation will choose a preferred alternative based on their statutory missions and responsibilities, giving consideration to legal, economic, environmental, technical, and other factors, as well as formal public input.

12.2 Arizona Department of Water Resources Disclaimer

The Arizona Department of Water Resources (ADWR) understands that the use of SDA in the LTEMP process is not required by NEPA, nor does it replace the NEPA impact analysis; furthermore, the ADWR recognizes that any input provided during the SDA effort does not replace the need and opportunity for formal public comment that are required steps in the NEPA process. Such formal comments on the Draft and Final EISs, in addition to the attached swing-weight exercise input, will be regarded as the formal and official positions of the ADWR.

The ADWR further recognizes that the swing-weighting values that have been applied to the metrics for identified resource goals do not reflect the broader policies or the importance of issues for the State of Arizona. The importance and priority of the values of ADWR are more accurately reflected within the "Resource Targeted Condition-Dependent" alternative, being necessarily incorporated during alternative creation. For these and other reasons, the ADWR is not bound by any outcomes or results of the SDA process.

Moreover, ADWR understands that the NPS and Reclamation will not solely rely on the results of the SDA process to select a preferred alternative; rather, the NPS and Reclamation will choose a preferred alternative based on their statutory missions and responsibilities, giving consideration to legal, economic, environmental, technical formal public input and other factors.

12.3 Arizona Game and Fish Department Disclaimer

The Arizona Game and Fish Department (AGFD) understands that the use of SDA in the LTEMP process is not required by NEPA, nor does it replace the NEPA impact analysis; furthermore, the AGFD recognizes that any input provided during the SDA effort does not replace the need and opportunity for formal public comment that are required steps in the NEPA process. Such formal comments on the Draft and Final EISs will be regarded as the formal and official positions of the AGFD, in addition to the attached swing-weight exercise.

The AGFD further submits that the swing-weighting values that we have provided for the metrics for identified resource goals do not reflect the broader policies or the importance of issues for the State of Arizona as a whole; rather, they represent AGFD values as they relate to our specific statutory authority and mission. For these and other reasons, the AGFD is not bound by any outcomes or results of the SDA process.

The AGFD understands and expects that the NPS and Reclamation will not solely rely on the results of the SDA process to select a preferred alternative; rather, the NPS and Reclamation will choose a preferred alternative based on their statutory missions and responsibilities, giving consideration to legal, economic, environmental, technical, formal public input and other factors.

12.4 Salt River Project Explanatory Letter

The Salt River Project (SRP) submits the attached swing-weighting exercise response under the following conditions:

- that this letter entitled "SRP's SDA Evaluation" remain attached to the SRP swing-weighting response table, and
- that the information submitted herein is not authorized for use, or attribution, beyond the purposes of this specific exercise in the current LTEMP EIS process.

1. *Hydropower (100).*—The SRP believes that the hydropower resource goal is the only one that represents both societal and environmental benefits. Greater quantities of hydropower provide cost effective service to people who value electricity to support many aspects of their lives. Greater quantities of this renewable, carbon-free resource also serve to avoid emissions and water use by other electric generating facilities. In the initial round of swing weighting, energy and capacity are valued equally.
    1. The energy metric does not appear to function in a consistent, intuitive manner; for example, a more flexible alternative with more energy production in higher-value months sometimes performs worse than a less flexible alternative with less energy production in higher-value months.
    2. While the capacity metric currently looks at July, SRP's peak demand requirement most often occurs in August, and our understanding from the Western Area Power Administration (WAPA) is that August is a better choice for peak planning purposes from their perspective as well. The SRP believes that utilizing August for peak demand planning would produce more credible capacity metric results.
2. *Humpback Chub (75).*—The SRP recognizes the environmental significance of the endangered humpback chub (HBC) (*Gila cypha*). The SRP supports the assembly of scientific evidence that establishes clear cause and effect relationships between flow regimes and a recovery of this endangered species. The "Number of Adult Humpback Chub" metric looks specifically at chub population, so the SRP places more emphasis on this metric than the "Temperature Suitability Index" metric.
3. *Archaeological and Cultural Resources (60).*—The Archeological and Cultural Resources goal represents an important societal benefit that the SRP supports; furthermore, SRP's perception is that, as presently crafted, the Archeological and Cultural Resources goal contains a more accurate representation of tribal interests than the "Tribal" resource goal. The SRP supports alternatives that science shows will preserve these resources.
    1. At the April Workshop, it was mentioned that the Time-off-river index was the issue that could lead to degradation of archeological and cultural resources; thus, this metric was scored highest.
    2. There has been some discussion about the wind transport of sediment index (WTSI). Specifically, some LTEMP representatives indicated that they would not want architectural and cultural sites buried by sand. This metric was, therefore, scored less highly.
    3. Based on new data from high-flow experiments (HFEs), it is unclear how HFEs and sediment affect downstream architectural and cultural sites. Because there are some winners and some losers, it is uncertain how the single "GLCA flow effects of historic properties (Ninemile)" metric can be representative of all sites; for example, science shows that HFEs will not increase sand bars before river mile (RM) 30 since there is no silt inflow. Even below RM 30, some sandbars cannot be built up to previous levels because even the maximum output of GCD cannot push sand high enough; thus, the SRP is not weighing this option as heavily as the others.
4. *Trout Fishery (40).*—The SRP recognizes the recreational value of the trout fishery and weighs the benefits against the environmental dangers of trout migration on downstream resources in the Grand Canyon ecosystem.

Since science appears to show that trout stay relatively close to Lees Ferry, SRP would not weigh "Lees Ferry trout emigration estimate" metric as heavily as if trout emigrated more through the canyon. As long as trout are not affecting downstream resources, the other metrics are also important to the trout fishery; thus, the "Angler Catch Rate Index" and "Number of trout > 16 inches total length" sublevel metrics are scored lower than the emigration metric but are still valued.

5. *Recreation (20).*—The SRP recognizes the societal value of recreation and believes Glen and Grand Canyons should be enjoyed by anyone who visits. While most visitors who visit the Grand Canyon do not raft down the canyon, the subset of people who do so should be considered.

    1. The "GRCA camping area index" is an important metric because people need safe areas to camp for the night. This is the highest rated metric.

    2. The fluctuation index is less highly rated because it does not take the time of day of the fluctuation into account.

    3. The GLCA rafting use index does not appear to have enough swing from low to high values to be rated highly. The swing of 600 people per year that could not take a trip down the river is not the same scale of an impact as a 1,000 fish population increase for HBC or a $9 million per year increase in hydropower energy value.

6. *Riparian Vegetation (20).*—The SRP recognizes the effect of riparian vegetation on the ecosystem of the Grand Canyon and believes it is has valuable environmental impacts. The aggregation of all metrics into this single metric hides some of the complexities; for example, CDAS and SASF perform worst for native/nonnative ratio but best for arrowweed. These are not able to be considered separately, which makes specific value judgments difficult.

7. *Sediment (0).*—The SRP observes that the effects of sediment are accounted for in the HBC, Archaeological & Cultural, Recreation, and Riparian Vegetation metrics. The SRP's perception is that sediment is a means to an end. We believe that a separate sediment metric does not make sense in the same manner that a separate temperature or HFE metric does not make sense.

8. *Tribal (0).*—The SRP believes that tribal interests should be recognized as a valued dimension of the LTEMP EIS process; however, as presented assembled and stated, the Tribal Resource goal does not appear to effectively represent tribal interests. The results for "Change in Marsh Vegetation" were questioned at the April Workshop and were not changed before this swing weighting. Trout should only be removed when they are endangering HBC, and the decision of how to remove them would preferably comply with tribal interests.

12.5 Utah Associated Municipal Power Systems Explanatory Letter

Utah Associated Municipal Power Systems (UAMPS) representing over 30 UAMPS members contracting for power generating output of Glen Canyon Dam is pleased to submit our response to the swing-weight exercise related to the LTEMP EIS process. The UAMPS is both an LTEMP EIS Cooperating Agency, a member of Glen Canyon Dam Adaptive Management Workgroup, and has been involved with most activities related to the operation of Glen Canyon Dam since environmental studies began in the mid-1980s. The UAMPS is grateful for the opportunity to participate in the EIS process as a member of the AMWG and as a Cooperating Agency contributor. We are appreciative of the great amount of work performed by both Federal government employees and contractors performing studies and assembling vast amounts of reporting documents, as well of those interested parties who have been following this LTEMP process.

We continue to be concerned with the valuation of the electric generation from Glen Canyon Dam and the reduction of power capacity and see this loss will be required to be replaced by resources using fossil fuels emitting carbon dioxide, which create other environmental problems and considerations. Thus far, we have not seen any expression of impacts of capacity switching except for some costs of capacity data for natural gas generation. In that regard, we wish to support the comment submitted by the Colorado River Energy Distributors Association (CREDA) that the cost estimates for natural gas combined-cycle generation in today's costs included in the performance metrics are way undervalued and should be corrected. We also hope additional cost analysis will eventually be included to address the lost power generating flexibility at Glen Canyon Dam needed for the western power grid. The flexibility provided by this hydropower is not free and will need to be made-up by some other power generating resource paid for by all utilities connected to the WECC power grid. Thus far, this loss of generating flexibly and the environmental impacts resulting from the shift to fossil fuels has only been casually addressed. We see the environmental objectives in this EIS seem to have priority over the far reaching climate change impacts that the electric industry in the west faces more and more as it struggles meet electric demands.

12.6 Colorado River Energy Distributors Association Submittal Letter

This letter [dated April 18, 2014] is an integral part of CREDA's SDA swing-weighting exercise submittal. CREDA members are all non-profit wholesale customers of the Salt

Lake City Area Integrated Projects (SLCA/IP) firm electric and transmission resources, of which Glen Canyon Dams is the largest generating facility. Although all members are non-profit entities, CREDA membership is diverse. Therefore, responses provided on the attached exercise cannot be ascribed to any individual CREDA member, as individual members did not have the ability to participate in the 5 days of workshop nor complete the exercise individually. Further, the responses are submitted with the understanding that the results will be reported with participant attribution and included in the draft/final Long-Term Experimental and Management Plan (LTEMP) Environmental Impact Statement (EIS). Further, it is not clear to CREDA in what other forums this submittal is intended for use or attribution. Given those assumptions, CREDA submits its SDA swing-weighting response under the conditions that a) this letter shall remain attached to the SDA swing-weighting response table, and 2) the information submitted herein is not authorized for use or attribution beyond purposes of this specific exercise in the LTEMP EIS processes and documents.

SDA AND LTEMP: Having participate fully in the August and March-April SDA workshops, it has become clear to CREDA this this process may not lend itself readily to a system and resources as complex and interdependent as we see in the resources of interest in the LTEMP. As the performance metrics and models have been developed and evolved, CREDA still has concerns about some of the underlying Resource Goals, and their inconsistency with the AMWG-approved Desired Future Conditions. Although many comments and concerns have been expressed on some of the Goals in various forums and through various medium, the Goals have remained unchanged since LTEMP scoping, As we were advised on April 1, if a participant still has concerns with a Resource Goal, or if the participant believes the elements of a metric are contradictory, inappropriately "linked" to a Resource Goal, or a create a potential legal or policy conflict, the participant should value the metric with a very low or 0 value. We appreciate the time and effort involved in developing and facilitating the SDA process, but suggest that it may be more applicable and useful for either determining stakeholder values of individual attributes of a resource, or analyzing a reduced number of alternatives (particularly when many of the LTEMP alternatives were "split up" for this exercise). We commend the stakeholders who devoted a significant amount of time and effort to the August 2013 and this year's process.

SDA, HYDROPOWER ANALYSIS AND LTEMP: As you are aware, CREDA is participating in this process as a member of the Glen Canyon Dam Adaptive Management Work Group (AMWG), representing "contractors for the purchase of Federal power produced at Glen Canyon Dam". As such representative, CREDA's submittal of the Balanced Resource Alternative represents the value we ascribe to the hydropower resource, notwithstanding we have some outstanding questions about how this alternative was ultimately modeled for the SDA process. Participants in the April workshop were advised that the hydropower performance metric was incomplete, and that a key component of the metric, capacity, had to be developed by Argonne in an inordinately short period of time (April 1–8), further, that the "ratepayer analysis" portion of the hydropower analysis was noted as "still under discussion" in the Performance Metrics document provided to the workshop participants. CREDA offers detailed comment herein on the energy, capacity and ratepayer analysis components of the hydropower resource, as we were invited to do as soon as possible after the April 1 workshop. We understand and expect that the electric resource flexibility component of the metric will be assessed as part of the draft/full EIS process, and that air quality impacts, such as carbon offsets will also be a part of the overall hydropower analysis. We offer the following comments and suggestions for use in assessing hydropower resources going forward in the LTEMP process.

ENERGY: The information provided to the SDA workshop participants on April 1 has results that are unintuitive. For example, one can compare RTCD4 with BR1. Both have Fall HFEs. BR1 has an average output of 14,500 cfs during July and August, while RTCD4 has an average output of 12,000 cfs and 11,000 cfs respectively. Furthermore, BR1 has an average fluctuation range that is 140% of MLFF, while RTCD4 has an average fluctuation range that is 114% of MLFF. Based on common knowledge, BR1 should perform better for energy than RTCD4. However, based on modeling results, RTCD4 performed better. This example, along with others discussed during the April 4 meeting, call the energy results into question. *We urge the LTEMP co-leads to utilize the expertise of the cooperating agency utility experts in energy analysis. We would also like to see more detailed energy results, as was agreed in the April 4 conference call.*

CAPACITY: The information provided to the SDA workshop participants on April 10 indicates that the capacity metric uses July as its peak month. CREDA reaffirms its suggestion on March 31 that August be used as the peak month to reflect actual utility peak demand experience, both past and as projected for the period of the LTEMP EIS. Also included in the April 10 information is a capacity value of $65,000/MW-yr to be used in the swing-weighting process, based upon the following factors:

- 620-MW natural gas combined cycle plant
- Capital cost of $917/kW
- Fixed operation and maintenance cost of $13.17/kW
- 30-year lifetime
- Discount rate of 3.8%

CREDA believes, based on discussion with its utility members who are also cooperating agencies in the LTEMP, that a more accurate estimate of the capacity value for a large, natural gas combined cycle facility is in the range of $82,000/MW-yr–$132,000/MW-yr.

As a consulting service to the electric utility industry, the Electric Power Research Institute (EPRI) regularly

prepares estimates of the costs associated with developing various types of energy resources, including gas-fired combined cycle facilities. EPRI's publicly available Generation Technology Options Report (published 2/19/2013) can be accessed at the linked site. EPRI information provided below can be found in Table 1-2 of their report.

Having worked with EPRI for a number of years with respect to resource characteristics and cost information for various electric resource technologies, a CREDA member's experience suggests that EPRI's valuations often do not fully account for the generally higher elevations and harsher ambient conditions that exist in CREDA member service regions relative to the assumptions used in EPRI's technology assessment efforts. Consequently, the CREDA member's internal cost estimates are higher. A comparison of key factors is provided below.

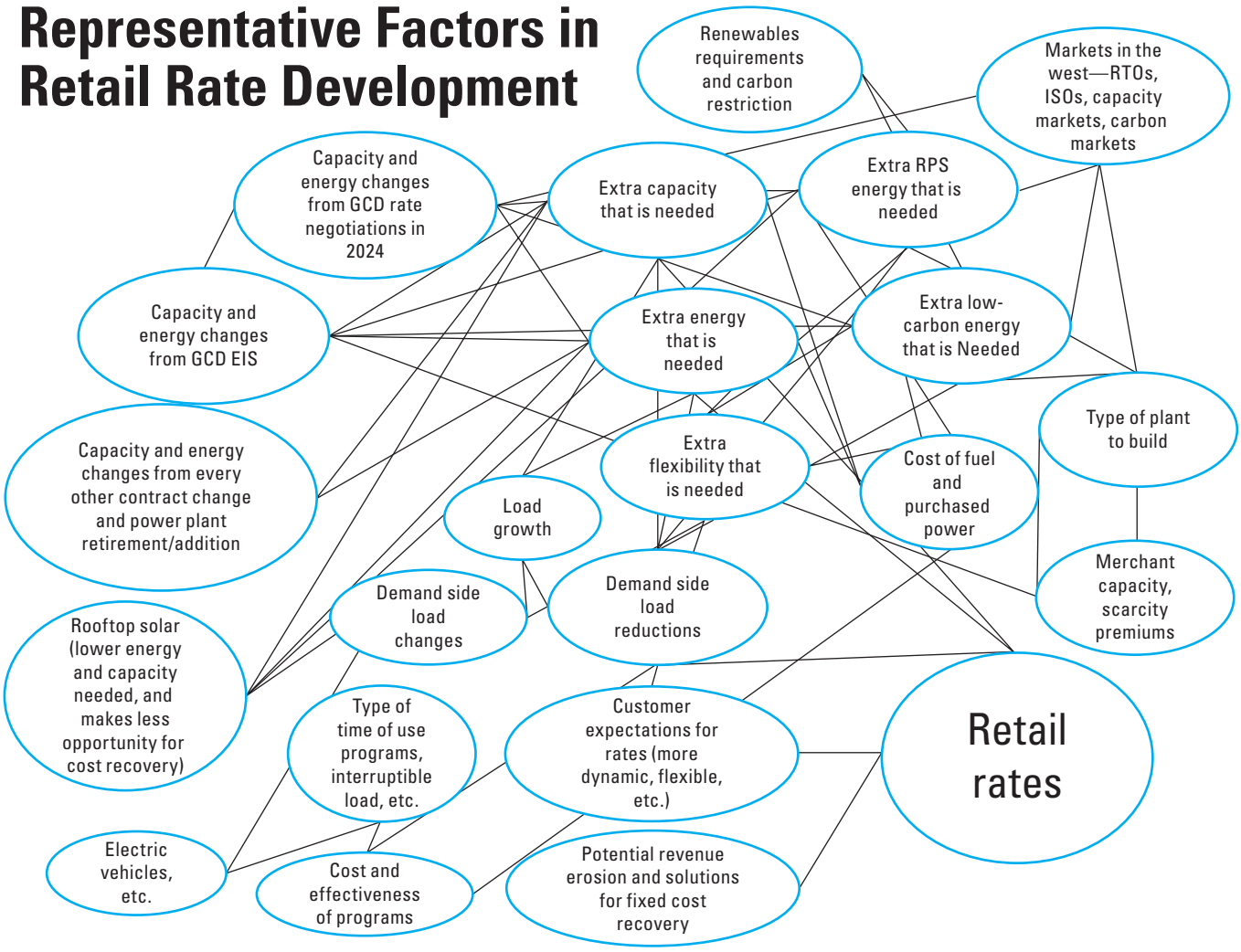
In summary, CREDA believes that the currently proposed values for LTEMP capacity valuation result in an understatement of Glen Canyon hydropower capacity value on the basis of a credible, publicly available, industry standard source for such information (EPRI) as well as on the basis of utility specific information and experience. *We urge the LTEMP co-leads to utilize the expertise of the cooperating agency utility experts in capacity analysis.*

RATEPAYER ANALYSIS: As was recently communicated to Ass't. Secretary Castle, CREDA and its electric utility members believe that this analysis must be based on and reflect impacts to the product/resource produced through the operation of Glen Canyon Dam, which is *wholesale* electric power and energy. On 4/1/14, we again objected to an attempt to develop and include a *retail* rate analysis, which is not required by NEPA, and which will likely be incorrect and misleading because it will not be possible to obtain sufficient and credible data given the time constraints and budget dollars associated with the LTEMP process. The chart below provides some perspective about the complexities involved in electric utility retail rate development. *Consistent with the scope of federal agency responsibility, to the extent any ratepayer analysis is required (which we don't believe is the case under NEPA), we urge the LTEMP co-leads to focus on the wholesale level, and consider utilizing cooperating agency utility expertise.*

Finally, CREDA recognizes the time and effort spent by all the SDA participants and believes that a key outcome from the workshops and exercises is the opportunity afforded the AMWG stakeholders, LTEMP co-leads, Argonne National Labs and GCMRC personnel and contractors to learn more about and appreciate the complexities and interdependencies of the resources addressed through the Adaptive Management Program, as well as the challenges faced by the Secretary of the Interior in balancing the resources associated with the operation of Glen Canyon Dam. It has also become clear through the model development and results supporting the SDA process that the resources of concern are "performing well" under the current operational and management parameters. The LTEMP co-lead and cooperating agencies should strongly consider this information.

	Factor	LTEMP	EPRI	CREDA
1	Capital Cost	$917/kw	$1,025/kw–1,325/kw	$1,130/kw–$1,426/kw
2	Fixed O&M Cost	$13.17/kw-yr	$15/kw-yr	$23/kw-yr–$25/kw-yr
3	Discount Rate (1)	3.8%	5%	Higher than 5%
4	Resulting Capacity Cost (2)	$65,000/MW-yr	$82,000/MW-yr–$101,000/MW-yr	$108,000/MW-yr–$132,000/MW-yr

(1) The discount rates of CREDA members are proprietary and confidential information.
(2) Lower cost represents wet cooling, higher cost represents dry cooling.



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APPENDIX D:

HYDROLOGY TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX D:

HYDROLOGY TECHNICAL INFORMATION AND ANALYSIS

D.1 ANALYSIS METHODS

The Colorado River Simulation System (CRSS) is the modeling tool used to assess the effects of the Long-term Experimental and Management Plan (LTEMP) alternatives on water resources and to provide relevant information to other models used to assess other resources. This section provides a background on CRSS, all relevant modeling assumptions used in CRSS, and a description of any changes that were made to CRSS, specifically for the LTEMP modeling.

D.1.1 Background

The CRSS, the Bureau of Reclamation's (Reclamation's) long-term planning model that covers the Colorado River Basin (Basin) from the natural inflow points in the Upper Basin (see Figure D-3) to Imperial Dam, was the first model used in LTEMP Draft Environmental Impact Statement (DEIS) analysis process. CRSS simulates future system conditions based on different hydrologic inflow scenarios and assumed reservoir operations for the evaluation period (2013–2033). The model framework used for this process is a commercial river modeling software called RiverWare™ (Zagona et al. 2001), a generalized river basin modeling software package developed by the University of Colorado through a cooperative arrangement with Reclamation and the Tennessee Valley Authority. CRSS was originally developed by Reclamation in the early 1970s and was implemented in RiverWare™ in 1996.

CRSS simulates the operation of the major reservoirs on the Colorado River and provides information regarding the projected future state of the system on a monthly basis in terms of output variables including the amount of water in storage, reservoir elevations, releases from the dams, the amount of water flowing at various points throughout the system, and the diversions to and return flows from the water users throughout the system. The basis of the simulation is a mass balance (or water budget) calculation that accounts for water entering the system, water leaving the system (e.g., from consumptive use of water, trans-basin diversions, evaporation), and water moving through the system (i.e., either stored in reservoirs or flowing in river reaches). The model was used to project the future conditions of the Colorado River system on a monthly time-step for the period 2013 through 2033.

The input data for the model includes monthly natural inflows,[1] various physical process parameters such as the evaporation rates for each reservoir, initial reservoir conditions on January 1, 2013, and the future diversion and depletion schedules for entities in the Basin States and for the United Mexican States (Mexico). These future schedules were based on the Current

[1] Calculated as gaged flow corrected for the effects of upstream reservoirs and depletions. Natural flow data and supporting documentation are available at http://www.usbr.gov/lc/region/g4000/NaturalFlow/index.html.

Projected demand scenario (Schedule A) from the Colorado River Basin Water Supply and Demand Study (Basin Study [Reclamation 2012b]).

The rules of operation of the Colorado River mainstream reservoirs including Lake Powell and Lake Mead are also provided as input to the model. This set of operating rules describes how water is released and delivered under various hydrologic conditions and aims to reflect actual operations. However, limitations inherently exist in the model's ability to reflect actual operations, particularly when responding to changing hydrological conditions and other operational constraints such as dam maintenance.

The future hydrology used as input to the model consisted of samples taken from the historical record of natural flow in the river system over the 105-year period from 1906 through 2010 and the "Downscaled GCM Projected" water supply scenario from the Basin Study (Reclamation 2012a). Each sequence is input as natural flow at 29 individual inflow points (or nodes) on the system. The future hydrology is merely a projection of what future conditions might be based upon the 105-year record, and is not a prediction of the likelihood of these future hydrologic conditions occurring.

The following sections describe the CRSS modeling assumptions and configuration associated with the modeling undertaken for the LTEMP DEIS process. The version of CRSS used for the LTEMP modeling started from the version of CRSS used for the Basin Study and was updated with more recent initial conditions and other changes necessary to reflect the different alternatives, as described below.

D.1.2 Initial Conditions

The model was initialized with the observed 2012 end-of-calendar-year (EOCY) reservoir conditions shown in Table D-1.

D.1.3 Reservoir Operations

D.1.3.1 Upper Basin Reservoirs above Lake Powell

The Taylor Park, Fontenelle, and Starvation reservoirs are operated in accordance with their existing rule curves (Reclamation 2007), although Fontenelle's operating rules in CRSS have been updated since the 2007 Interim Guidelines (DOI 2007). Aspinall Unit operations do not reflect the *Record of Decision* (ROD) *for the Aspinall Unit Operations Final Environmental Impact Statement* (Reclamation 2012c) because the modeling for the LTEMP DEIS began before the latest Aspinall ROD could be reflected in CRSS. Instead, Aspinall Unit operations are also operated in accordance with their previous rule curves as documented in the *Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations of Lake Powell and Lake Mead Final Environmental Impact Statement* (2007 Interim Guidelines Final EIS [Reclamation 2007]).

TABLE D-1 Initial Reservoir Conditions
(2012 Observed End-of-Calendar-Year Values)

Reservoir	Elevation (ft AMSL)	Storage (ac-ft)
Fontenelle	6,485.19	196,963
Flaming Gorge	6,020.63	3,001,912
Starvation	5,734.92	255,000
Taylor Park	9,301.09	56,647
Blue Mesa	7,452.65	327,537
Morrow Point	7,146.50	106,381
Crystal	6,749.11	15,830
Navajo	6,024.73	956,630
Powell	3,609.82	12,712,205
Mead	1,120.36	13,636,479
Mohave	638.30	1,572,110
Havasu	446.41	550,689

Navajo and Flaming Gorge operations reflect the recent RODs (Reclamation 2006a and 2006b, respectively). In general, both RODs contain downstream flow targets that the reservoirs attempt to meet according to the rules within the RODs. In summary, Flaming Gorge operations are governed by the April through July unregulated inflow into the reservoir, which determines which downstream flow targets should be met; for example, in a wet year (larger inflow into the reservoir), higher downstream flows are targeted. The flow targets are specified at the sub-monthly time step, which historically could not be reflected within CRSS. In order to capture the sub-monthly component of the flow targets, and thus Flaming Gorge's operations, the model was programmed to determine typical daily operations before summing to a monthly release (Butler 2011).

Similarly, Navajo's ROD contains multiple downstream flow targets, specified at sub-monthly time intervals. In this case, a September 30 storage target guides Navajo's operations. A release pattern is selected to bring Navajo as close as possible to the September 30 storage target while helping meet the downstream flow targets stated in the ROD (Butler 2011).

D.1.3.2 Lake Powell and Lake Mead

For 2013 through 2026, Lake Powell and Lake Mead would be operated according to the 2007 Interim Guidelines (DOI 2007). For modeling purposes, after the expiration of the 2007 Interim Guidelines in 2026, operations are assumed to conform to those specified in the No-Action Alternative from the 2007 Interim Guidelines Final EIS (Reclamation 2007). Both operations are briefly described below.

Lake Mead flood control procedures are in effect for the entire simulation period. In addition, if Lake Mead elevation falls below 1,000 feet above mean sea level (AMSL), deliveries to the Southern Nevada Water Authority (SNWA) are assumed to continue.

If Lake Mead is sufficiently low such that after the maximum shortage (per the 2007 Interim Guidelines or No-Action Alternative post 2026) is applied and water is still unavailable to meet the remaining deliveries, the remaining deliveries were shorted hydrologically with respect to their physical location on the river.

Operations during the Interim Guidelines (2013–2026)

Operations of Lake Powell and Lake Mead are coordinated as specified in the 2007 Interim Guidelines (DOI 2007). Figure D-1 summarizes the different operating tiers at both reservoirs. Based on rules programmed in the model, CRSS determines which tier Powell is operating in, and simulates releases consistent with the selected tier. Similarly, CRSS is configured to simulate normal, shortage, and surplus deliveries in the Lower Basin, consistent with the Interim Guidelines.

Operations after the Interim Guidelines Expire (2027–2033)

The operating rules reverted to the rules of the 2007 Interim Guidelines Final EIS No-Action Alternative for simulations starting in 2027 and continuing through 2033. The No-Action Alternative assumed the following for shortage, surplus, and coordinated operations. There was no intentionally created surplus (ICS) assumed in the No-Action Alternative, however; consistent with the 2007 Interim Guidelines, ICS deliveries would be permissible through 2036. See Appendix A of the 2007 Interim Guidelines Final EIS (Reclamation 2007) for additional details regarding the No-Action Alternative.

Three factors that affect Lake Powell's release are (1) the minimum objective release of 8.23 maf, (2) equalization, and (3) spill avoidance. For equalization to occur, the 602(a) storage requirement must be met.[2]

Stage 1 shortage is triggered to prevent Lake Mead from declining below 1,050 feet AMSL. Stage 1 shortages range in volume from approximately 350 to 500 kaf. If Lake Mead's elevation continues to decline, a Stage 2 shortage is imposed to keep Lake Mead above 1,000 feet AMSL. Stage 2 shortages can be up to 3.0 maf.

[2] See Appendix A of the 2007 Interim Guidelines Final EIS (Reclamation 2007) for the full 602(a) storage requirement computation.

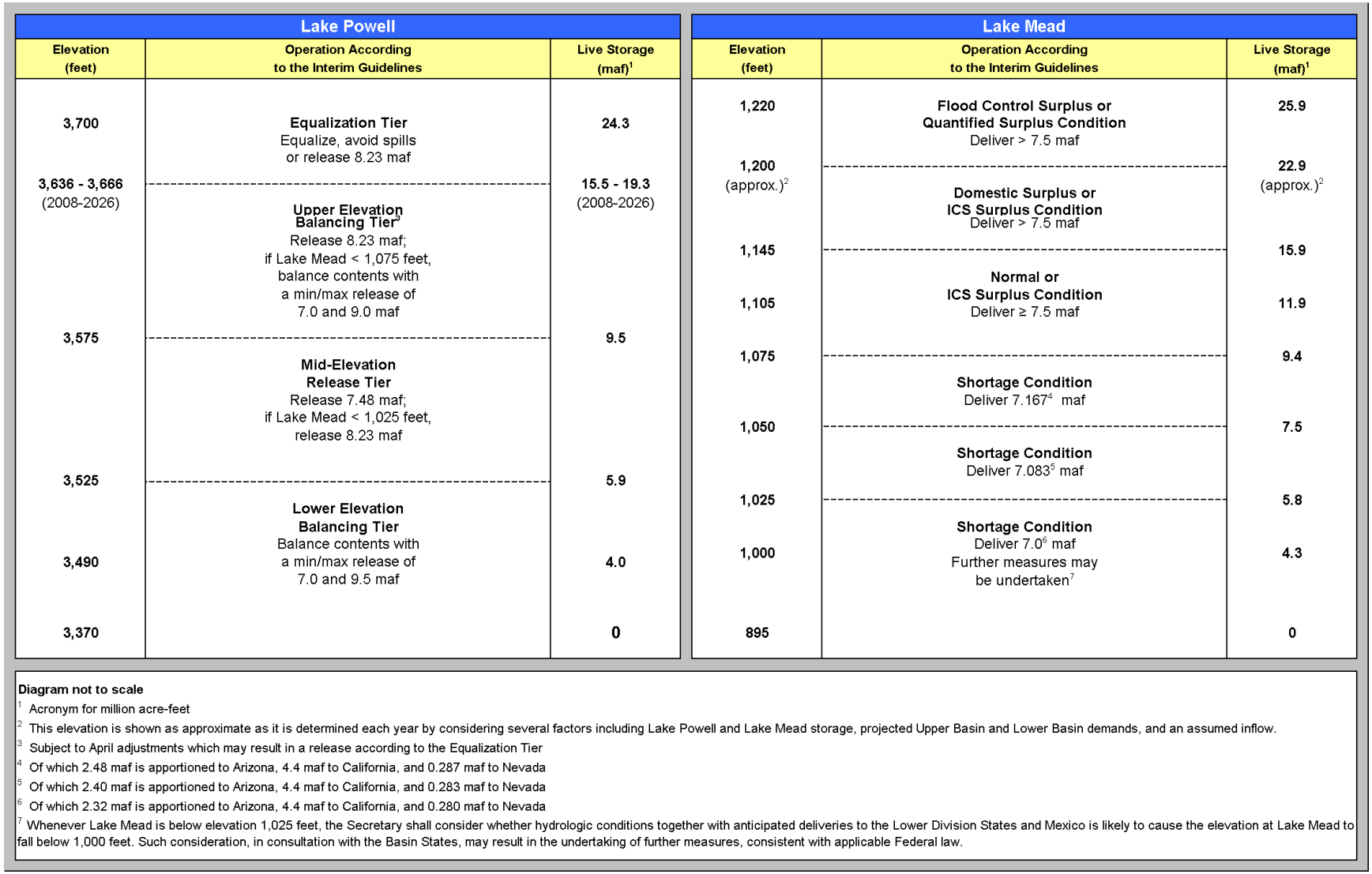

Diagram not to scale

[1] Acronym for million acre-feet

[2] This elevation is shown as approximate as it is determined each year by considering several factors including Lake Powell and Lake Mead storage, projected Upper Basin and Lower Basin demands, and an assumed inflow.

[3] Subject to April adjustments which may result in a release according to the Equalization Tier

[4] Of which 2.48 maf is apportioned to Arizona, 4.4 maf to California, and 0.287 maf to Nevada

[5] Of which 2.40 maf is apportioned to Arizona, 4.4 maf to California, and 0.283 maf to Nevada

[6] Of which 2.32 maf is apportioned to Arizona, 4.4 maf to California, and 0.280 maf to Nevada

[7] Whenever Lake Mead is below elevation 1,025 feet, the Secretary shall consider whether hydrologic conditions together with anticipated deliveries to the Lower Division States and Mexico is likely to cause the elevation at Lake Mead to fall below 1,000 feet. Such consideration, in consultation with the Basin States, may result in the undertaking of further measures, consistent with applicable Federal law.

FIGURE D-1 Operating Tiers as Specified by the 2007 Interim Guidelines (DOI 2007) for the Operations of Lake Powell and Lake Mead

Surplus determinations are per flood control surplus conditions or the 70R Strategy.[3]

Modeling Assumptions for Annual Releases Extending Beyond the Water Year

Modeling assumptions for equalization operations need to be performed for a full analysis of monthly and annual operations in this DEIS. These assumptions are for analytical purposes only and do not, and cannot, modify the Secretary's approach to operations of equalization releases that are made pursuant to the Colorado River Basin Project Act of 1968. Modeled equalization release volumes can be affected by the annual pattern of monthly volumes. Alternatives that have higher releases earlier in the water year are able to release more water in years when the maximum release through the powerplant becomes a potential limiting factor to equalizing within the water year, which is consistent with the objectives of the Law of the River. A limitation of the current modeling assumptions is that they cannot fully mimic or predict operator judgment or actions to achieve full equalization within the relevant timeframe. Reclamation will continue to operate Glen Canyon Dam to achieve equalization releases in a manner fully consistent with the Law of the River and in consultation with the Colorado River Basin States.

For LTEMP modeling, logic was added to CRSS to handle instances when Powell could not meet annual release requirements by the end of the water year. If the computed remaining release in September is greater than Powell's power plant capacity, then the volume above powerplant capacity necessary meet annual release requirements is released in the subsequent months. Releases, beginning in October, are increased above the normal release requirements (e.g., 600 kaf in an 8.23-maf release year of Alternative A, the no-action alternative) up to power plant capacity, for as many months as necessary to release the remaining equalization volume. The volume of annual releases extending beyond the water year and the frequency at which these releases would be necessary were reported as one of the calculated water resource metrics.

Setting Powell's Monthly Release Volumes

In order to more efficiently model the different alternatives being evaluated in the LTEMP DEIS, CRSS logic was modified to use an input release table, and to allow minimum release constraints to vary among alternatives. The tables include monthly release volumes for water year releases of 7.0, 7.48, 8.23, 9.0, 9.5, 10.5, 11.0, 12.0, 13.0, and 14.0 maf. In fixed release volume years (e.g., 8.23-maf release years), the monthly volumes used were directly from the input release tables presented in Section D.1.4, subject to other constraints such as ensuring Powell stays at a safe operating capacity. In years with computed release volumes

[3] Under the 70R Strategy, a surplus condition is based on the system space requirement at the beginning of each year. Based on the 70th percentile historical runoff, a normal 7.5-maf delivery to the Lower Division states, the Upper Basin scheduled use, and Lake Powell and Lake Mead volumes at the beginning of the year, the volume of water in excess of the system space requirement at the end of the year is estimated. If that volume is greater than zero, a surplus is declared. See Appendix A of the 2007 Interim Guidelines Final EIS (Reclamation 2007) for the full 70R computation.

(e.g., equalization releases), the necessary water year release volume is computed, and the monthly release is interpolated between the two closest water year releases. For example, if the equalization release is computed to be 12.5 maf, then the monthly release would be interpolated between the 12.0- and 13.0-maf monthly release volumes.

The minimum release constraints were also incorporated into CRSS because there are certain instances when the release from Powell may be computed to be less than the alternative's minimum release constraints. In these cases, the alternative's minimum release constraint is used, subject to the physical ability to release the water. Furthermore, the implementation of these constraints does not result in a modification of the annual release volume.

D.1.3.3 Lake Mohave and Lake Havasu

Lake Mohave and Lake Havasu are operated in accordance with their existing rule curves.

D.1.4 Representation of the Different Alternatives in CRSS

For each alternative, tables were developed that include the monthly release volumes that are modeled to occur under differing water year release volumes. In most cases, the volumes in the tables represent some desired aspect of the alternatives and were developed by proportionally scaling monthly volumes to the water year volume. However, in the minimum (7.0-maf) water release years and in the higher water release years, the proportionally scaled monthly volumes in the tables were sometimes adjusted up to meet minimum release constraints or down to powerplant capacity. All alternatives met the minimum release constraints and were within powerplant capacity in an 8.23-maf release year. However, in some months for some alternatives the proportionally scaled monthly volumes in the tables required adjustment to meet these constraints.

For example, the proportionally scaled monthly volumes in a 7.0-maf year were not always adequate to meet the minimum release requirement, as computed by the minimum hourly releases and ramping constraints. In these instances, the monthly release volume was set to the volume necessary to maintain minimum flow throughout the entire month. Similarly, in high-volume water release years, the proportionally scaled monthly volumes in the tables were sometimes greater than the physical capacity of Glen Canyon Powerplant. In these instances, the monthly release volume in the table was set to powerplant capacity, reallocating the excess into other months of the water year. The annual release volume was not affected by these modifications.

In addition to the physical capacity of the powerplant represented in the monthly tables input to CRSS, the maximum release capacity of Glen Canyon Dam (powerplant and bypass volume) can also affect modeled monthly release volumes, particularly in years with an annual release volume greater than 14.0 maf. The maximum release was modeled explicitly in CRSS as a function of reservoir head. Generally speaking, the maximum release was computed as

45,000 cfs; this flow was converted to a daily volume and then multiplied by the number of days in the month to determine the monthly maximum release volume. In months when the monthly release prescribed by the alternative was greater than the maximum capacity for the month, the monthly volume was capped at the physical capacity, and the remaining volume was released in the following month(s).

Monthly release volume can also be affected by high-flow experiments (HFEs). For HFEs that required more water than was already allocated for the given month of the HFE, water was reallocated from later months to ensure the water year release volume remained the same. For this DEIS, the monthly reallocation of water for HFEs was modeled as a post-process to the sand-budget model (i.e., after the model determined the magnitude and duration of the HFE). Reservoir mass balance was computed for the affected months and the resulting monthly releases and reservoir elevations were then passed to the hydropower model.

The monthly reallocation of releases to support a HFE does not affect the Lake Powell operating tier (and thus did not need to be explicitly modeled in CRSS). Operationally, the magnitude and duration of a HFE would be determined in either October–November or March–April. Because the Lake Powell annual operating tier is determined based on the August projection of the January 1 elevation, it is not yet known whether an HFE will take place that water year. Therefore, a modeled reallocation of water into November, for example, should not be considered when determining the annual operating tier because, operationally, this information would not be known until after the operating tier was already set.

Tables D-2 through D-11 include the monthly release tables used for all alternatives in CRSS, and Table D-12 summarizes the minimum release constraints used for each alternative. Figure D-2 shows the 8.23-maf release year pattern for all alternatives. In addition, the experimental components of LTEMP that are modeled in CRSS are also discussed.

Long-term strategies (various implementations of the seven LTEMP alternatives; described in Appendix C) that would not affect monthly or annual releases from Powell were not simulated in CRSS. These long-term strategies are labeled in the figures in this appendix as identical to another long-term strategy. For example, the only difference between long-term strategies D1 and D3 is that D1 includes trout management flows. Because trout management flows were not included in CRSS, results for D1 and D3 are identical and labeled as such in the water delivery results.

TABLE D-2 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative A

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	480,000	480,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
November	500,000	500,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
December	600,000	600,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000
January	600,000	800,000	800,000	800,000	850,000	950,000	950,000	1,000,000	1,000,000	1,000,000
February	600,000	600,000	600,000	650,000	650,000	650,000	700,000	800,000	800,000	900,000
March	500,000	600,000	600,000	650,000	650,000	650,000	700,000	900,000	950,000	1,100,000
April	500,000	500,000	600,000	600,000	650,000	750,000	900,000	1,000,000	1,100,000	1,413,000
May	500,000	600,000	600,000	650,000	800,000	1,100,000	1,100,000	1,100,000	1,250,000	1,537,000
June	600,000	600,000	650,000	800,000	900,000	1,100,000	1,150,000	1,200,000	1,400,000	1,488,000
July	800,000	800,000	850,000	1,000,000	1,050,000	1,150,000	1,250,000	1,400,000	1,537,000	1,537,000
August	800,000	800,000	900,000	1,050,000	1,100,000	1,200,000	1,250,000	1,500,000	1,537,000	1,537,000
September	520,000	600,000	630,000	800,000	850,000	950,000	1,000,000	1,100,000	1,426,000	1,488,000

TABLE D-3 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative B

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	480,000	480,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
November	500,000	500,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
December	600,000	600,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000
January	600,000	800,000	800,000	800,000	850,000	950,000	950,000	1,000,000	1,000,000	1,000,000
February	600,000	600,000	600,000	650,000	650,000	650,000	700,000	800,000	800,000	900,000
March	500,000	600,000	600,000	650,000	650,000	650,000	700,000	900,000	950,000	1,100,000
April	500,000	500,000	600,000	600,000	650,000	750,000	900,000	1,000,000	1,100,000	1,413,000
May	500,000	600,000	600,000	650,000	800,000	1,100,000	1,100,000	1,100,000	1,250,000	1,537,000
June	600,000	600,000	650,000	800,000	900,000	1,100,000	1,150,000	1,200,000	1,400,000	1,488,000
July	800,000	800,000	850,000	1,000,000	1,050,000	1,150,000	1,250,000	1,400,000	1,537,000	1,537,000
August	800,000	800,000	900,000	1,050,000	1,100,000	1,200,000	1,250,000	1,500,000	1,537,000	1,537,000
September	520,000	600,000	630,000	800,000	850,000	950,000	1,000,000	1,100,000	1,426,000	1,488,000

TABLE D-4 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative C

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	436,260	436,260	480,000	480,000	480,000	480,000	480,000	480,000	480,000	480,000
November	436,260	436,260	480,000	480,000	480,000	480,000	480,000	480,000	480,000	480,000
December	754,360	754,360	830,000	830,000	830,000	830,000	830,000	830,000	830,000	830,000
January	692,498	754,360	830,000	929,239	993,680	1,122,562	1,187,003	1,315,885	1,444,767	1,537,189
February	609,215	663,640	730,180	817,484	874,175	987,557	1,044,248	1,157,630	1,271,012	1,388,429
March	643,264	700,730	770,990	863,174	923,033	1,042,752	1,102,611	1,222,330	1,342,049	1,474,882
April	572,129	623,240	685,730	767,719	820,959	927,439	980,679	1,087,159	1,193,639	1,311,782
May	592,562	645,500	710,220	795,138	850,279	960,562	1,015,703	1,125,985	1,236,268	1,358,631
June	619,811	675,180	742,880	831,703	889,380	1,004,734	1,062,411	1,177,765	1,293,119	1,421,109
July	692,498	754,360	830,000	929,239	993,680	1,122,562	1,187,003	1,315,885	1,444,767	1,537,189
August	550,661	599,850	660,000	738,913	790,155	892,640	943,882	1,046,366	1,148,851	1,262,562
September	400,482	436,260	480,000	537,391	574,659	649,192	686,460	760,995	835,528	918,227

TABLE D-5 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative C with Low Summer Flows

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	436,260	436,260	480,000	480,000	480,000	480,000	480,000	480,000	480,000	480,000
November	436,260	436,260	480,000	480,000	480,000	480,000	480,000	480,000	480,000	480,000
December	754,360	754,360	830,000	830,000	830,000	830,000	830,000	830,000	830,000	830,000
January	692,498	754,360	830,000	929,239	993,680	1,122,562	1,187,003	1,315,885	1,444,767	1,537,189
February	609,215	663,640	730,180	817,484	874,175	987,557	1,044,248	1,157,630	1,271,012	1,388,429
March	643,264	700,730	770,990	863,174	923,033	1,042,752	1,102,611	1,222,330	1,342,049	1,474,882
April	708,598	771,899	849,296	950,842	1,016,781	1,148,660	1,214,599	1,346,477	1,478,355	1,487,603
May	733,905	799,467	879,628	984,801	1,053,095	1,189,683	1,257,977	1,394,566	1,531,154	1,537,189
June	767,648	836,224	920,070	1,030,079	1,101,513	1,244,381	1,315,815	1,458,684	1,488,000	1,487,603
July	410,410	447,074	491,901	550,715	588,906	665,288	703,479	779,862	894,506	1,110,981
August	410,410	447,074	491,901	550,715	588,906	665,288	703,479	779,862	894,506	1,110,981
September	397,172	432,652	476,034	532,951	569,911	643,829	680,789	754,704	865,651	1,075,143

TABLE D-6 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative D

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	480,000	480,000	642,583	642,583	642,583	642,583	642,583	642,583	642,583	642,583
November	500,000	500,000	641,532	641,532	641,532	641,532	641,532	641,532	641,532	641,532
December	600,000	600,000	715,885	715,885	715,885	715,885	715,885	715,885	715,885	715,885
January	664,609	723,467	763,000	858,351	919,662	1,042,283	1,103,594	1,226,216	1,348,837	1,471,459
February	587,262	639,271	675,000	758,457	812,632	920,983	975,159	1,083,510	1,191,860	1,300,211
March	620,206	675,132	713,000	801,004	858,219	972,648	1,029,863	1,144,292	1,258,721	1,373,150
April	552,170	601,070	635,000	713,134	764,072	865,949	916,887	1,018,763	1,120,640	1,222,516
May	571,506	622,119	657,000	738,108	790,830	896,274	948,996	1,054,440	1,159,884	1,265,328
June	598,005	650,965	688,000	772,331	827,497	937,830	992,997	1,103,330	1,213,663	1,323,996
July	651,718	709,434	749,000	841,702	901,823	1,022,067	1,082,188	1,202,431	1,322,674	1,442,918
August	652,434	710,214	750,000	842,627	902,814	1,023,190	1,083,377	1,203,753	1,324,128	1,444,503
September	522,090	568,328	600,000	674,286	722,451	818,776	866,939	963,265	1,059,593	1,155,919

TABLE D-7 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative D with Low Summer Flows

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	480,000	480,000	642,583	642,583	642,583	642,583	642,583	642,583	642,583	642,583
November	500,000	500,000	641,532	641,532	641,532	641,532	641,532	641,532	641,532	641,532
December	600,000	600,000	715,885	715,885	715,885	715,885	715,885	715,885	715,885	715,885
January	664,609	723,467	763,000	858,351	919,662	1,042,283	1,103,594	1,226,216	1,348,837	1,471,459
February	587,262	639,271	675,000	758,457	812,632	920,983	975,159	1,083,510	1,191,860	1,300,211
March	620,206	675,132	713,000	801,004	858,219	972,648	1,029,863	1,144,292	1,258,721	1,373,150
April	730,640	795,346	840,007	943,631	1,011,033	1,145,837	1,213,239	1,348,044	1,482,848	1,487,603
May	756,226	823,198	869,423	976,676	1,046,439	1,185,964	1,255,726	1,395,252	1,534,777	1,537,189
June	791,289	861,367	909,735	1,021,961	1,094,958	1,240,952	1,313,949	1,459,944	1,487,603	1,487,603
July	427,856	465,748	491,901	552,582	592,052	670,992	710,463	789,403	908,217	1,126,373
August	427,856	465,748	491,901	552,582	592,052	670,992	710,463	789,403	908,217	1,126,373
September	414,056	450,723	476,033	534,756	572,953	649,349	687,544	763,936	878,920	1,090,039

TABLE D-8 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative E

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	480,000	480,000	642,583	642,583	642,583	642,583	642,583	642,583	642,583	642,583
November	500,000	500,000	641,532	641,532	641,532	641,532	641,532	641,532	641,532	641,532
December	600,000	600,000	715,885	715,885	715,885	715,885	715,885	715,885	715,885	715,885
January	683,468	747,279	781,296	883,660	950,130	1,083,070	1,149,540	1,282,480	1,415,420	1,548,360
February	604,808	661,275	691,377	781,960	840,780	958,420	1,017,240	1,134,880	1,252,520	1,370,160
March	638,457	698,066	729,843	825,465	887,558	1,011,743	1,073,835	1,198,020	1,322,205	1,446,390
April	568,537	621,618	649,915	735,065	790,357	900,942	956,235	1,066,820	1,177,405	1,287,990
May	588,202	643,119	672,394	760,490	817,695	932,105	989,310	1,103,720	1,218,130	1,332,540
June	615,733	673,220	703,866	796,085	855,967	975,732	1,035,615	1,155,380	1,275,145	1,394,910
July	670,795	733,423	766,809	867,275	932,513	1,062,988	1,128,225	1,258,700	1,389,175	1,519,650
August	560,700	599,148	659,223	720,900	760,950	841,050	881,100	961,200	1,041,300	1,121,400
September	489,300	522,852	575,277	629,100	664,050	733,950	768,900	838,800	908,700	978,600

TABLE D-9 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative E with Low Summer Flows

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	480,000	480,000	642,583	642,583	642,583	642,583	642,583	642,583	642,583	642,583
November	500,000	500,000	641,532	641,532	641,532	641,532	641,532	641,532	641,532	641,532
December	600,000	600,000	715,885	715,885	715,885	715,885	715,885	715,885	715,885	715,885
January	683,468	747,279	781,296	883,660	950,130	1,083,070	1,149,540	1,282,480	1,415,420	1,537,189
February	604,808	661,275	691,377	781,960	840,780	958,420	1,017,240	1,134,880	1,252,520	1,381,331
March	638,457	698,066	729,843	825,465	887,558	1,011,743	1,073,835	1,198,020	1,322,205	1,446,390
April	714,353	775,725	823,598	922,047	985,976	1,113,833	1,177,761	1,305,618	1,433,475	1,487,603
May	739,062	802,556	852,085	953,940	1,020,080	1,152,359	1,218,499	1,350,778	1,483,058	1,537,189
June	773,654	840,120	891,967	998,589	1,067,825	1,206,296	1,275,531	1,414,002	1,487,603	1,487,603
July	426,654	463,308	491,901	550,701	588,883	665,246	703,428	779,792	878,014	1,052,213
August	426,654	463,308	491,901	550,701	588,883	665,246	703,428	779,792	878,014	1,052,213
September	412,890	448,363	476,032	532,937	569,885	643,787	680,738	754,638	849,691	1,018,269

TABLE D-10 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative F

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	444,800	444,800	493,860	493,860	493,860	493,860	493,860	493,860	493,860	493,860
November	430,450	430,450	477,930	477,930	477,930	477,930	477,930	477,930	477,930	477,930
December	444,800	444,800	493,860	493,860	493,860	493,860	493,860	493,860	493,860	493,860
January	399,780	444,800	493,860	566,090	587,333	697,737	762,803	849,488	1,127,401	1,405,315
February	491,970	541,610	599,950	679,580	713,503	847,624	926,667	1,388,429	1,388,429	1,388,429
March	701,570	767,290	848,690	954,120	1,009,323	1,199,050	1,310,865	1,537,189	1,537,189	1,537,189
April	830,780	904,790	999,830	1,118,560	1,189,069	1,412,584	1,487,603	1,487,603	1,487,603	1,487,603
May	1,101,480	1,170,880	1,279,340	1,390,680	1,521,482	1,576,859	1,576,859	1,576,859	1,576,859	1,576,859
June	1,123,140	1,176,360	1,259,500	1,344,870	1,487,603	1,487,603	1,487,603	1,487,603	1,487,603	1,487,603
July	347,480	388,920	432,370	498,850	514,205	610,863	667,828	743,719	987,030	1,230,340
August	347,480	388,920	432,370	498,850	514,205	610,863	667,828	743,719	987,030	1,230,340
September	336,270	376,380	418,440	482,750	497,627	591,167	646,294	719,741	955,206	1,190,672

TABLE D-11 Monthly Release Volumes (in ac-ft) by Water Year Release for Alternative G

	Water Year Release (maf)									
Month	7	7.48	8.23	9	9.5	10.5	11	12	13	14
October	635,300	635,300	699,000	699,000	699,000	699,000	699,000	699,000	699,000	699,000
November	635,300	635,300	699,000	699,000	699,000	699,000	699,000	699,000	699,000	699,000
December	615,305	615,305	677,000	677,000	677,000	677,000	677,000	677,000	677,000	677,000
January	580,721	635,300	699,000	786,355	843,132	956,685	1,013,462	1,127,015	1,240,568	1,354,121
February	524,523	614,396	676,000	710,256	761,538	864,103	915,385	1,017,949	1,120,513	1,223,077
March	580,721	635,300	699,000	786,355	843,132	956,685	1,013,462	1,127,015	1,240,568	1,354,121
April	561,988	635,300	699,000	760,989	815,934	925,824	980,769	1,090,659	1,200,549	1,310,440
May	580,721	573,497	631,000	786,355	843,132	956,685	1,013,462	1,127,015	1,240,568	1,354,121
June	561,988	635,300	699,000	760,990	815,934	925,824	980,768	1,090,659	1,200,549	1,310,440
July	580,721	614,396	676,000	786,355	843,132	956,685	1,013,462	1,127,015	1,240,568	1,354,120
August	580,721	635,300	699,000	786,355	843,132	956,685	1,013,462	1,127,015	1,240,568	1,354,120
September	561,991	615,306	677,000	760,990	815,934	925,824	980,768	1,090,658	1,200,549	1,310,440

TABLE D-12 Minimum Release Constraints (cfs) Used for Each Alternative

Alternative	Minimum Release (cfs)
A	6,562.50
B	6,500.00
C	6,520.83
D[a]	6,520.83
E	6,520.83
F	5,000.00
G	8,000.00

[a] For Alternative D, with steady weekend flows for invertebrate production, the May–August minimum release constraint is 8,000 cfs.

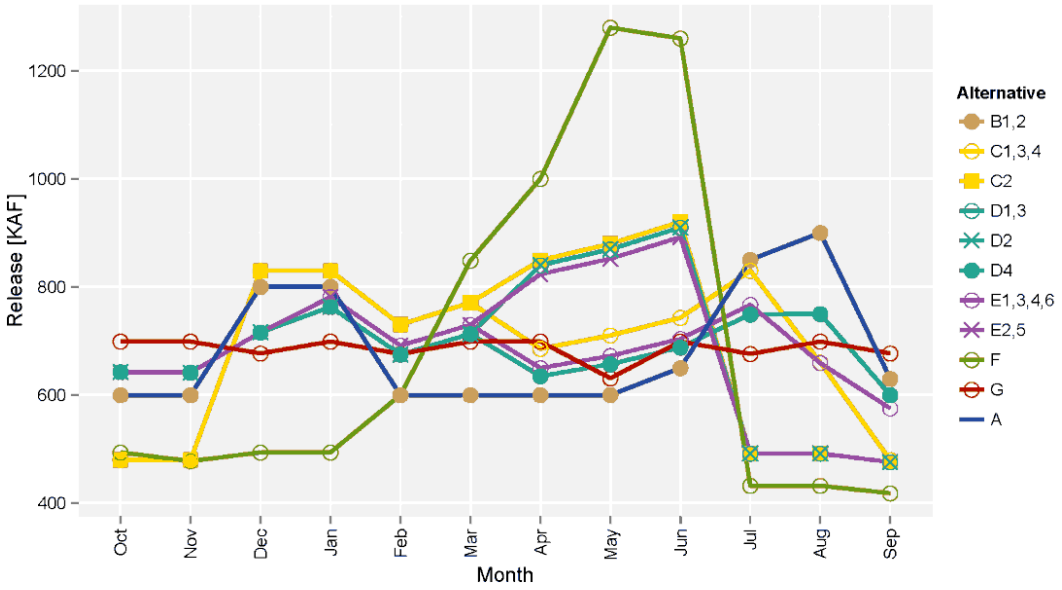

FIGURE D-2 Monthly Releases in kaf for Each Alternative in an 8.23-maf Release Year (Note that long-term strategies C2, D1, D2, D3, E2, and E5 are shown with the monthly distributions when low summer flows are implemented. Low summer flows would not be implemented in all years.)

D.1.4.1 Experimental Components Modeled in CRSS

Specific to the LTEMP DEIS, both experimental treatments—low summer flows and May through August steady weekend flows for invertebrate production—were incorporated into CRSS. The following sections discuss how these experimental components were modeled in CRSS.

Low Summer Flows

Low summer flows were implemented in CRSS as an experimental component under Alternatives C, D, and E. The objective of low summer flows is to produce warmer temperatures (i.e., greater than 13°C [55°F] for Alternatives C and E and greater than 14°C [57°F] for Alternative D) at the confluence with the Little Colorado River (T_{LCR}) in July, August, and September. In May, these alternatives would switch to a low summer flow pattern, releasing less water during these months, if all three of the following conditions are true: (1) the projected annual water year release is <10 maf, (2) projected T_{LCR} is cold[4] in any of the three target months using the base release pattern, and (3) switching to the low summer flow pattern would result in warm[5] temperatures in all three of the target months. Alternatives that have low summer flows as an experimental component would use the base release tables, unless these three conditions were met. For example, Alternative E (long-term strategy 2) would use release volumes from Table D-8, but would switch to the release volumes in Table D-9 if the above conditions were met. Note that Alternatives C and E were modeled with low summer flows during the entire 20-year LTEMP period, whereas Alternative D was modeled with implementation of low summer flows only during the second 10 years of the LTEMP period.

The projected temperature conditions were calculated using regression equations that considered monthly elevations and releases and the calendar year inflow at Lake Powell, and were empirically developed from observed conditions. The regression equations[6] to solve for T_{LCR} in July, August, and September were as follows:

July: $T_{LCR} = T_o + 3.791 / (0.000461 \times \textit{Apr Projected Release}_{JUL})^{0.63} \times (36.31 - T_o)$,
where: $T_o = 249.4 - (0.0668 \times \textit{Apr Projected EOM Elev}_{JUL}) + (3.766\text{E-}7 \times \textit{Apr Projected CY Inflow})$

4 Cold is defined as <13°C (55°F) for long-term strategies C2, E2, and E5 and <14°C (57°F) for long-term strategies D1, D2, and D3.

5 Warm is defined as >13°C (55°F) for long-term strategies C2, E2, and E5 and >14°C (57°F) for long-term strategies D1, D2, and D3.

6 Regression equations were log-transformed for inclusion into CRSS.

August: $T_{LCR} = T_o + 3.791 / (0.000461 \times Apr\ Projected\ Release_{AUG})^{0.63} \times (34.81 - T_o)$,
where: $T_o = 297.2 - (0.0802 \times Apr\ Projected\ EOM\ Elev_{AUG}") + (4.915E\text{-}7 \times Apr\ Projected\ CY\ Inflow)$

September: $T_{LCR} = T_o + 3.791 / (0.000476 \times Apr\ Projected\ Release_{SEP})^{0.63} \times (30.01 - T_o)$,
where: $T_o = 327.9 - (0.0886 \times Apr\ Projected\ EOM\ Elev_{SEP}) + (5.342E\text{-}7 \times Apr\ Projected\ CY\ Inflow)$

where:

T_{LCR} = temperature at the Little Colorado River Confluence, °C

T_o = Lake Powell release temperature, °C

EOM Elev = Lake Powell projected end-of-month elevation, ft

CY Inflow = Lake Powell projected calendar year inflow, ac-ft

Release = Lake Powell projected monthly release volume, ac-ft

Steady Weekend Flows For Invertebrate Production

Steady weekend flows for invertebrate production were an experimental component of Alternative D. For the long-term strategy that included these flows, the May–August minimum release constraint was increased to 8,000 cfs.

D.1.5 Input Hydrology

The future hydrology used as input to the model consisted of samples taken from the historical record of natural flow in the river system over the 105-ear period from 1906 through 2010, from 29 individual inflow points (or nodes) on the system. The locations of the hydrologic input sites are shown in Figure D-3.

Typically, CRSS is run with the full suite of available natural flow traces created using a resampling technique known as the Indexed Sequential Method (ISM) (Ouarda et al. 1997). Using the ISM on a 105-year record (1906–2010) results in 105 inflow traces (i.e., plausible inflow sequences). For this DEIS, however, due to the complexity, resource and timing constraints, and number of loosely coupled models used to analyze other resource impacts, every fifth trace from the 105 natural flow traces was selected, resulting in 21 traces.

Figures D-4 and D-5 compare the differences between using 105 traces versus 21, and indicate that the distribution of 21 traces is very similar to the distribution of the full 105 traces for Lake Powell annual inflow, annual and monthly releases, and end of December pool elevation.

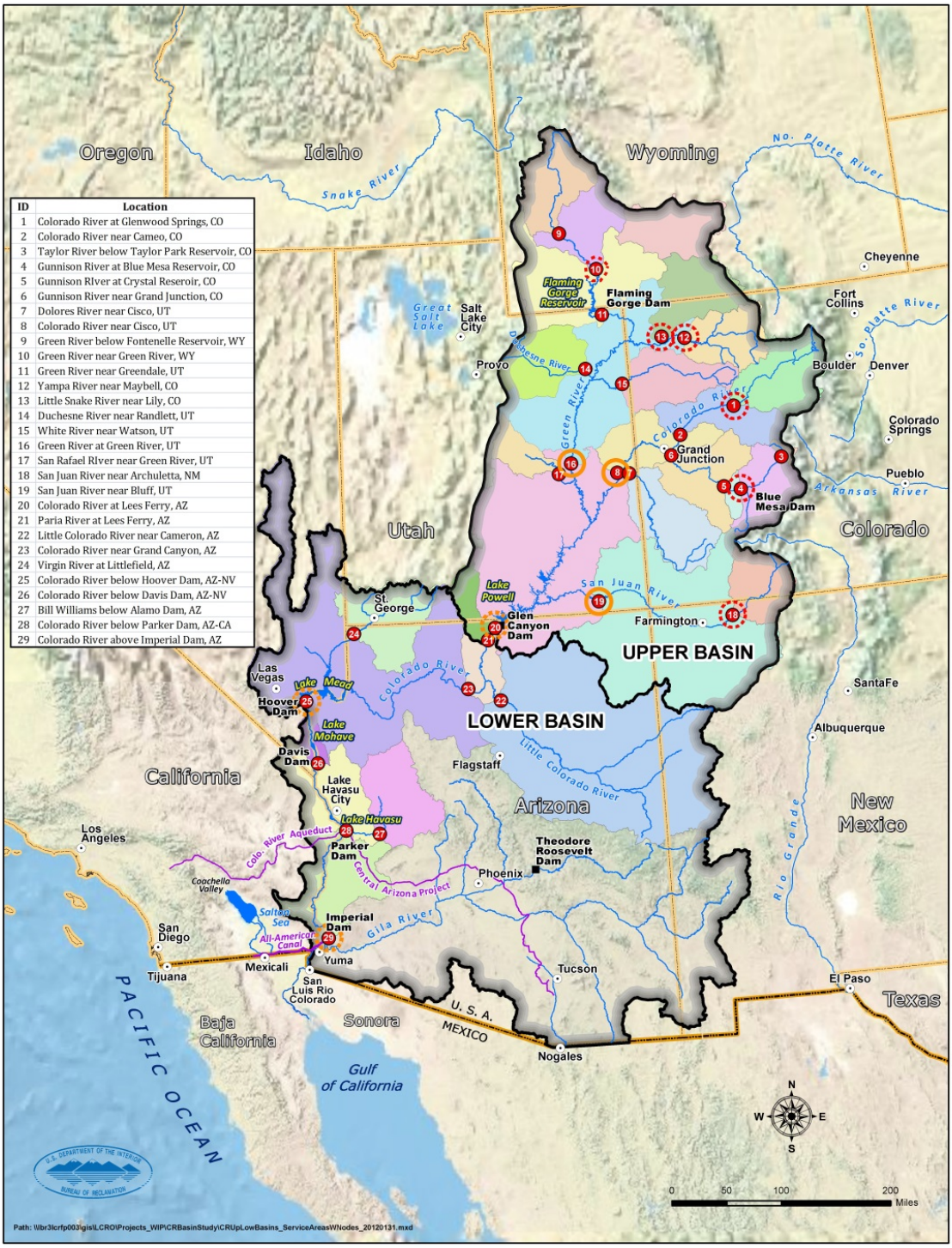

FIGURE D-3 Locations of CRSS 29 Natural Flow Nodes

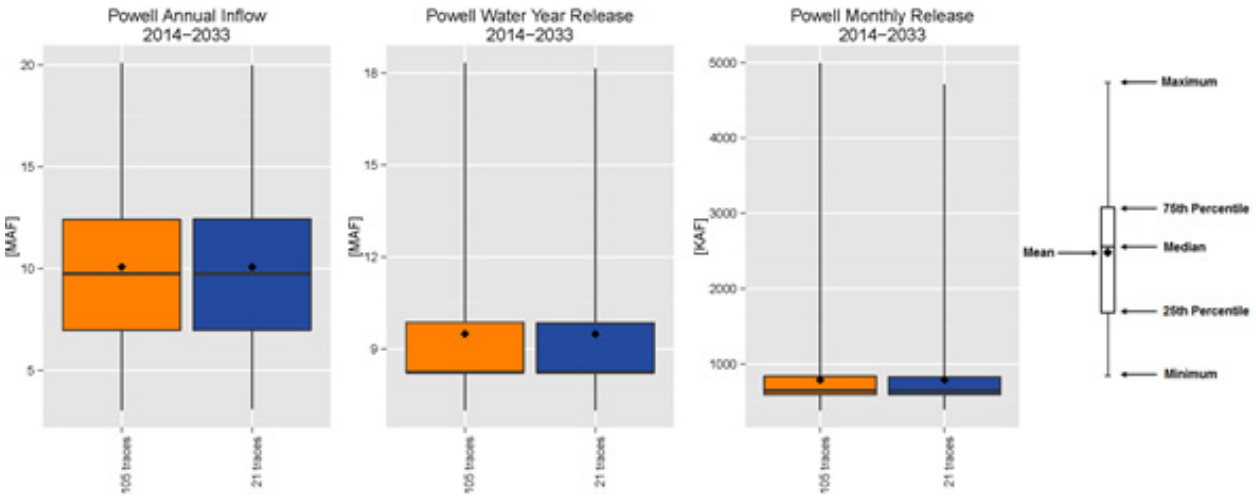

FIGURE D-4 Comparison of CRSS Results Generated Using 105 Traces (orange) and 21 Traces (blue) for Lake Powell Annual Inflow (left), Lake Powell Water Year Release Volume (center) and Lake Powell Monthly Release Volume (right)

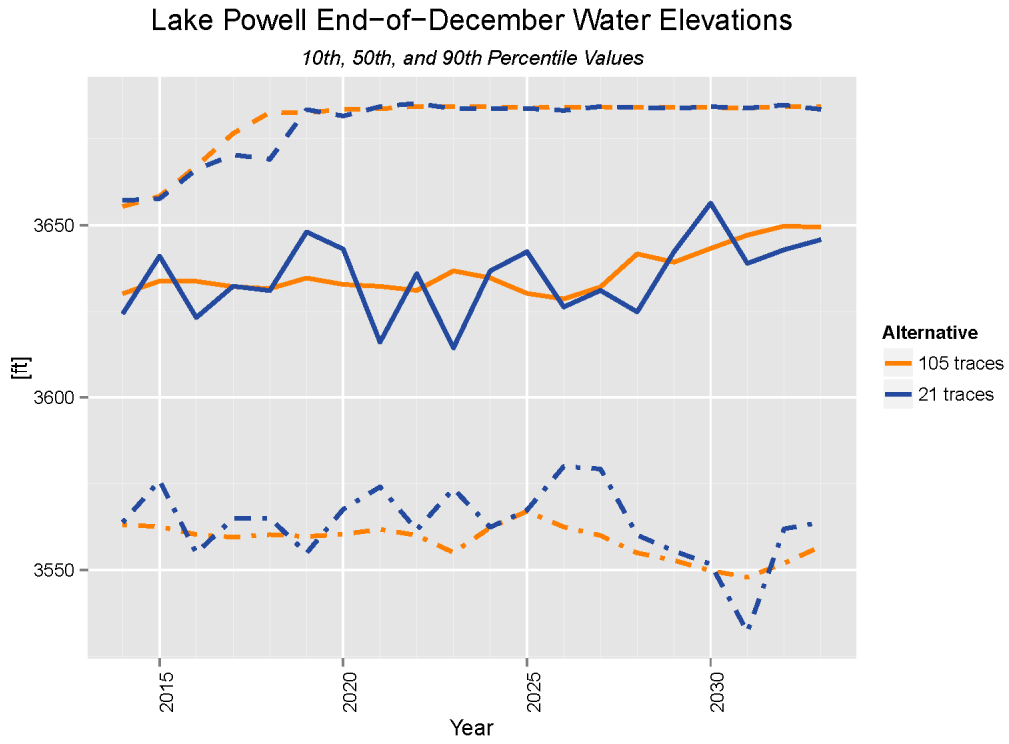

FIGURE D-5 Comparison of CRSS Results Generated Using 105 Traces (orange) and 21 Traces (blue) for Lake Powell End of December Water Elevations at the 10th (dashed and dotted lines), 50th (solid lines), and 90th (dashed lines) Percentiles

D.1.6 Input Demands

The LTEMP modeling utilized the Basin Study Current Projected demand scenario (Reclamation 2012b) for the input demands into CRSS. Table D-13 summarizes the demands by state.

D.1.7 Other Key Assumptions

A number of changes to CRSS were described in the Basin Study (Appendix G-2) including how the model treats implementation of Upper Colorado River water rights and intentionally created surplus.

Future water deliveries to Mexico were modeled as follows:

1. The model accounts for the entire delivery to Mexico at the Northerly International Boundary (NIB).

2. Water deliveries to Mexico are pursuant to the requirements of the 1944 Treaty. This provides annual deliveries of 1.5 maf to Mexico and up to 1.7 maf during Lake Mead flood control release conditions.

3. For modeling purposes, it is assumed that during shortage conditions, Mexico shares shortage in proportion to U.S. users in the Lower Basin (16.67 percent). This assumption is consistent with that used in the modeling supporting 2007 Interim Guidelines Final EIS (Reclamation 2007).[7]

4. Minute No. 318 and Minute No. 319 were not modeled as part of the LTEMP DEIS because modeling began before they could be incorporated into CRSS.

The Warren H. Brock Reservoir was assumed to operate every year beginning in 2013 and is assumed to conserve approximately 90 percent of non-storable flows. This reduces the average annual volume of non-storable flows delivered to Mexico from 73 kaf/yr (historical average from 1964 through 2010, excluding flood years on the Gila or flood control releases) to 7 kaf/yr.

Bypass of return flows from the Welton-Mohawk Irrigation and Drainage District to the Cienega de Santa Clara in Mexico was assumed to be 109 kaf/yr (historical average from 1990 through 2010) and was not counted as part of the 1944 Treaty delivery to Mexico.

The Yuma Desalting Plant was assumed to not operate during the LTEMP period.

[7] Allocation of Colorado River water to Mexico is governed by the 1944 Treaty. Reclamation's modeling assumptions are not intended to constitute an interpretation or application of the 1944 Treaty or to represent current United States policy or a determination of future United States policy regarding deliveries to Mexico.

TABLE D-13 Input Demands, by State (in ac-ft)

	Upper Division States				Lower Division States		
Year	CO	NM	UT	WY	AZ[a]	CA	NV
2013	2,524,327	592,772	1,017,031	539,545	2,800,000	4,400,000	300,000
2014	2,524,552	601,496	1,018,144	539,755	2,800,000	4,400,000	300,000
2015	2,524,776	610,220	1,019,258	539,965	2,800,000	4,400,000	300,000
2016	2,536,669	618,944	1,020,371	542,900	2,800,000	4,400,000	300,000
2017	2,548,562	627,668	1,021,485	545,835	2,800,000	4,400,000	300,000
2018	2,560,455	636,392	1,022,599	548,769	2,800,000	4,400,000	300,000
2019	2,572,347	645,116	1,023,712	551,704	2,800,000	4,400,000	300,000
2020	2,584,240	653,840	1,029,826	554,639	2,800,000	4,400,000	300,000
2021	2,596,133	658,483	1,033,820	557,574	2,800,000	4,400,000	300,000
2022	2,608,026	663,126	1,037,813	560,509	2,800,000	4,400,000	300,000
2023	2,619,919	667,769	1,041,807	563,443	2,800,000	4,400,000	300,000
2024	2,631,812	672,412	1,045,801	566,378	2,800,000	4,400,000	300,000
2025	2,643,705	677,055	1,049,794	569,313	2,800,000	4,400,000	300,000
2026	2,655,597	681,698	1,053,788	572,248	2,800,000	4,400,000	300,000
2027	2,667,490	686,341	1,057,781	575,183	2,800,000	4,400,000	300,000
2028	2,679,383	690,984	1,061,775	578,117	2,800,000	4,400,000	300,000
2029	2,691,276	695,627	1,065,769	581,052	2,800,000	4,400,000	300,000
2030	2,703,169	700,270	1,074,762	583,987	2,800,000	4,400,000	300,000
2031	2,715,062	702,863	1,080,156	586,922	2,800,000	4,400,000	300,000
2032	2,726,954	705,456	1,085,550	589,857	2,800,000	4,400,000	300,000
2033	2,738,847	708,049	1,090,943	592,791	2,800,000	4,400,000	300,000

[a] There are an additional 50,000 ac-ft/yr of Arizona demands within the Upper Basin, represented in CRSS.

D.2 SUPPLEMENTAL INFORMATION ON IMPACT MODELING

The following sections provide more detailed information on the impacts of the different LTEMP alternatives, particularly for low summer flows, the carryover equalization release metric, and alternative-specific comparisons to Alternative A (no-action alternative). These results supplement those covered in Section 4.1 of this DEIS.

D.2.1 Low Summer Flows

During years with low summer flows, releases would be lower than typical in July, August, and September and proportionally higher in May and June, in order to maintain the same annual release volume. In years when the required annual release volume is not known until the end of the water year (e.g., during balancing or equalization), the low summer flows monthly volumes may end up being higher or lower than those originally projected in April, due to changing hydrologic conditions. Figure D-6 shows the modeled frequency of occurrence of low summer flows. Note that Alternatives C and E were modeled with implementation of low summer flows during the entire 20-year period, whereas Alternative D was modeled with low

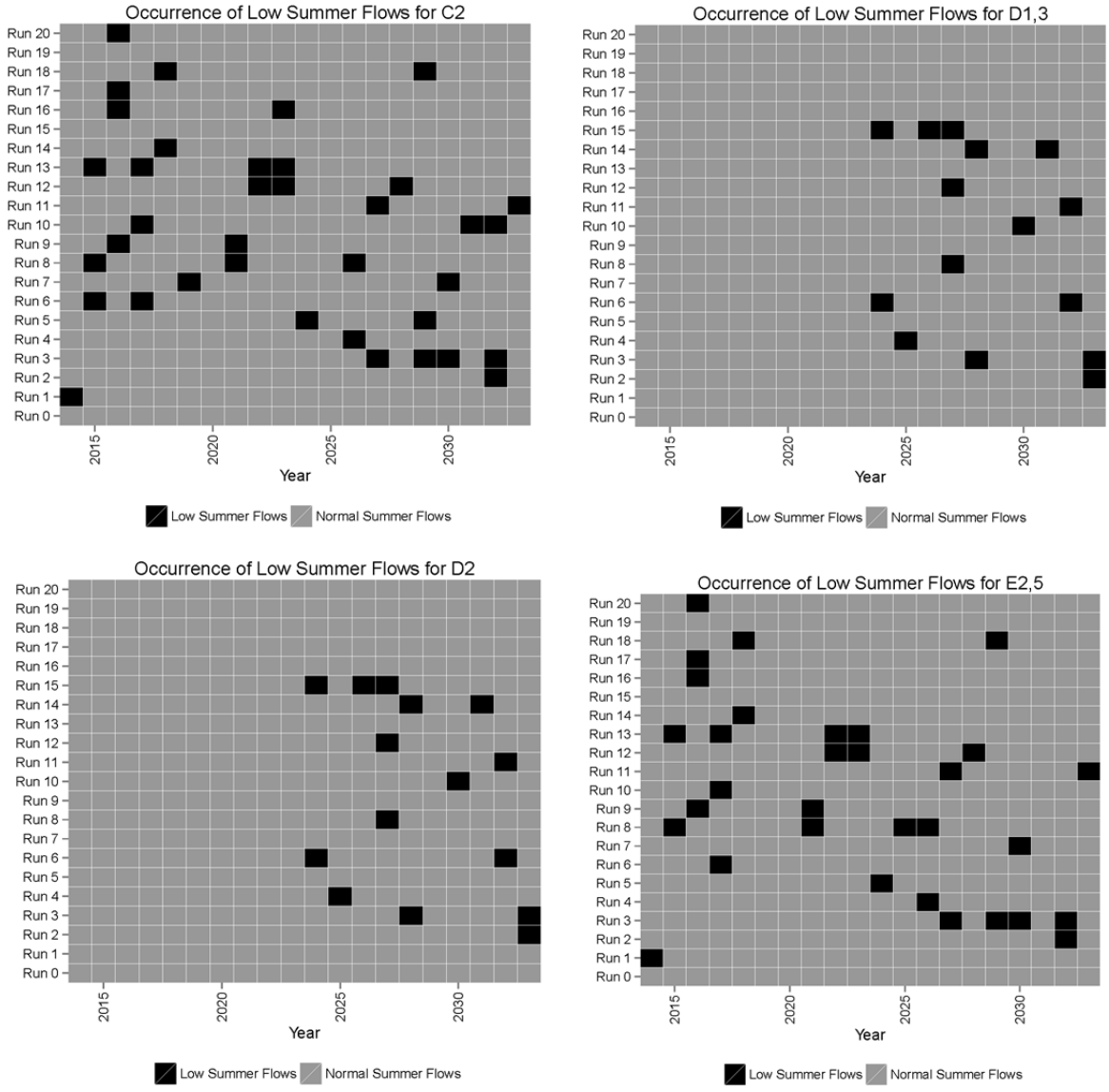

FIGURE D-6 Occurrences of Low Summer Flows in Applicable Alternatives (Numbers after alternative letter designations represent the long-term strategies that would implement low summer flows.)

summer flows only during the second 10 years of the LTEMP period. For those alternatives with low summer flows, the modeled number of low summer flows in the 20-year period ranged from zero to four occurrences per trace. Depending on the alternative, the average ranged from 0.7 to 1.8 low summer flows per 20-year run.

D.2.2 Modeled Annual Releases Extending Beyond the End of the Water Year

The frequency (Figure D-7) and volume (Figure D-8) of exceptions to meeting the annual release target volumes specified by the Interim Guidelines were one of the calculated water

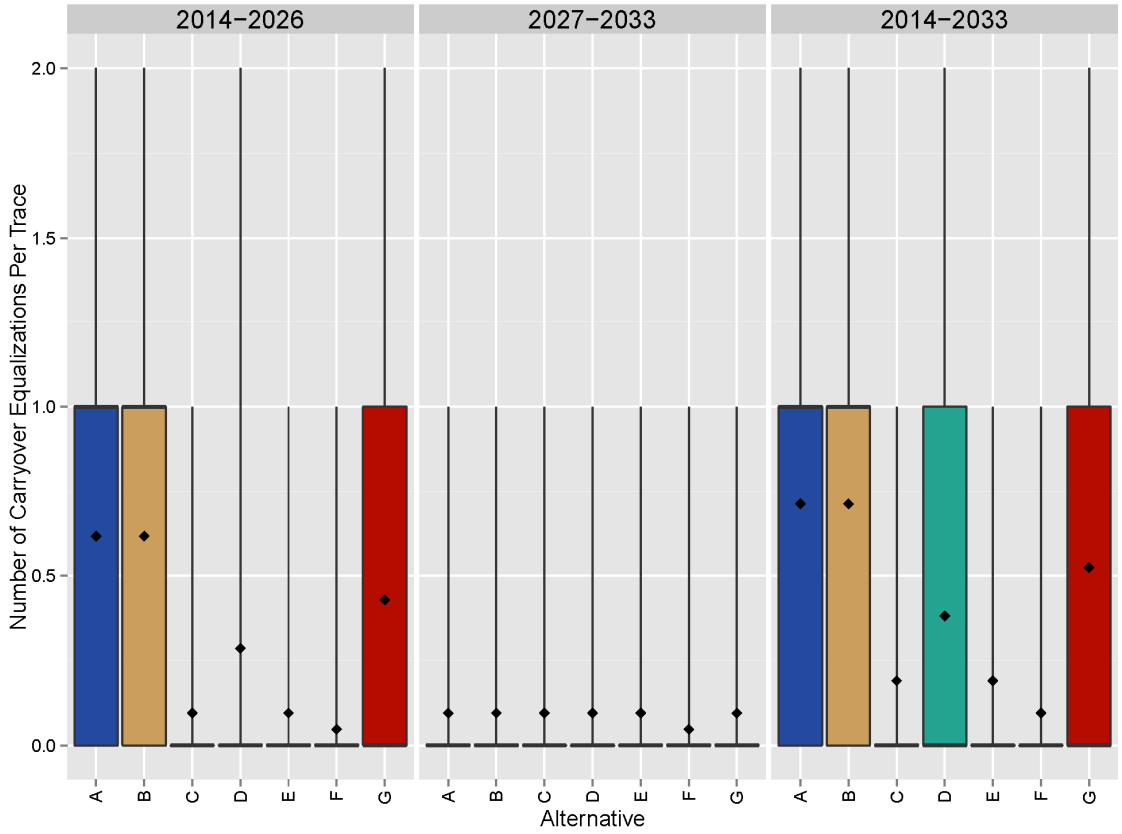

FIGURE D-7 Frequency of Occurrence of Modeled Annual Releases Extending beyond the End of the Water Year per 20-Year Trace for Each of the Alternatives (See Figure 4-2 for an explanation of how to interpret this graph. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

resource metrics. Note that there is the possibility of exceptions occurring under all alternatives, including Alternative A (the no-action alternative).

D.2.3 Lake Elevation

The following figures present end-of-December elevations for Lake Powell (Figures D-9 through D-14) and percent of traces below Lake Powell's minimum power pool (Figures D-15 through D-20) for each alternative, and compares them to Alternative A. These graphs show different implementations of each alternative (referred to here as long-term strategies). These are given the letter designation of the alternative (A–G), and a number designating the long-term strategy for the alternative. See Section 4.1 and Appendix C for descriptions of the experiments included in each long-term strategy. For both of these parameters, only very small differences between Alternatives B-G and Alternative A were found.

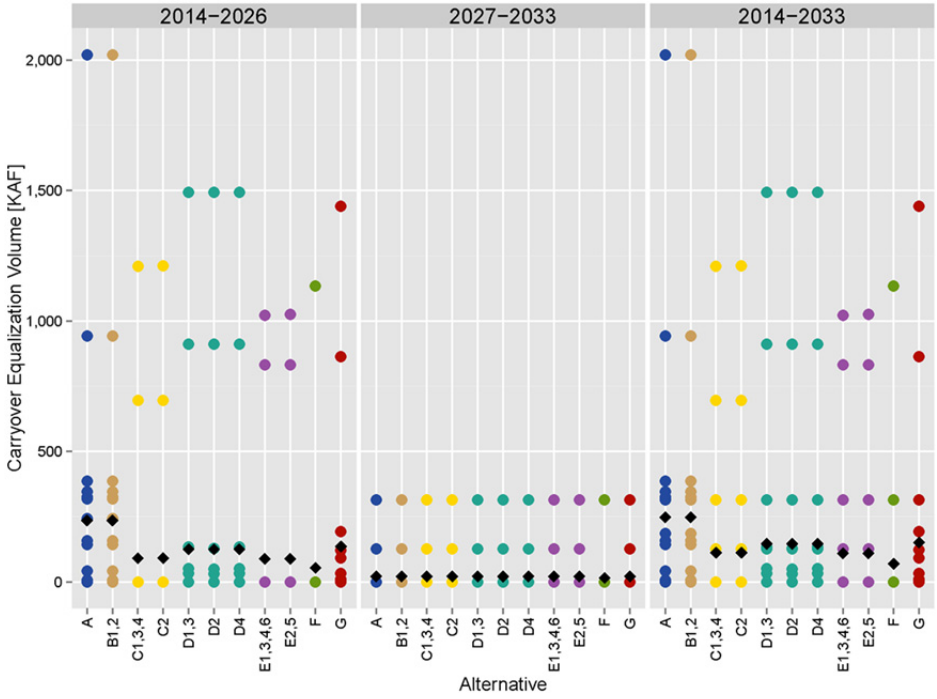

FIGURE D-8 Median Volume of Modeled Annual Releases Extending beyond the End of the Water Year Releases by Trace for Each of the Alternatives (Each value represents the median carryover equalization volume for one trace. Because there are few traces with more than one occurrence, the median value typically represents the only nonzero instance. For each alternative there are 21 possible carryover equalization values for each period and alternative combination [21 traces].)

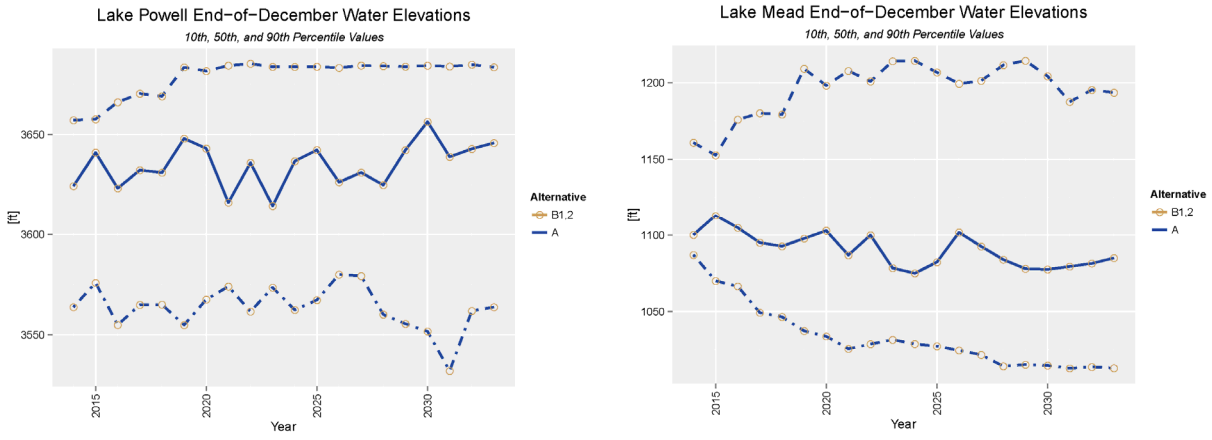

FIGURE D-9 Lake Powell (left) and Lake Mead (right) End-of-December Pool Elevation for 21 Hydrology Traces under Alternatives A and B

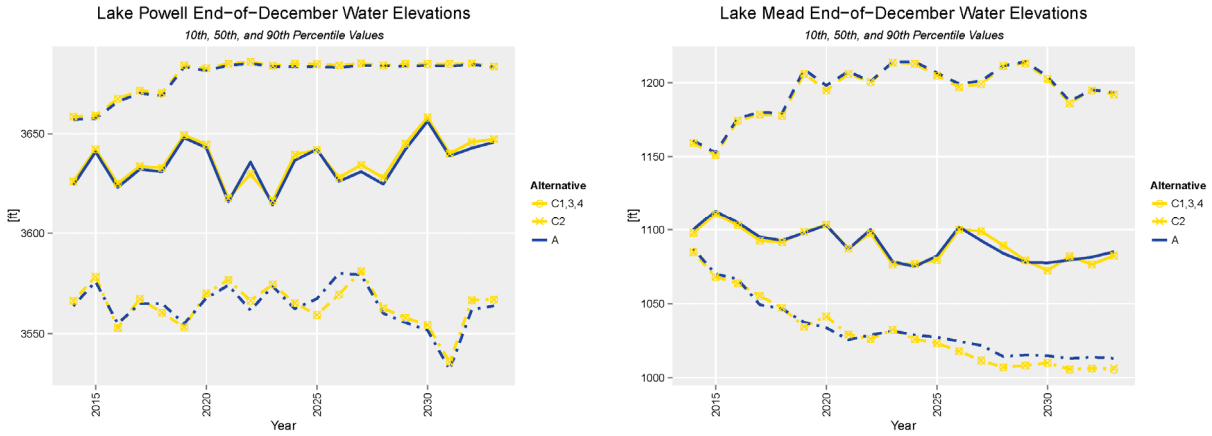

FIGURE D-10 Lake Powell (left) and Lake Mead (right) End-of-December Pool Elevation for 21 Hydrology Traces under Alternatives A and C

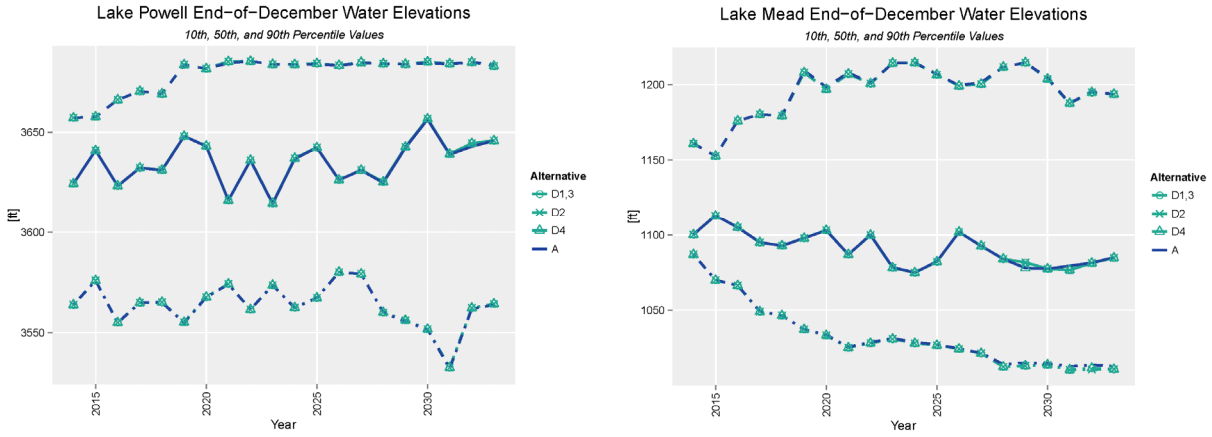

FIGURE D-11 Lake Powell (left) and Lake Mead (right) End-of-December Pool Elevation for 21 Hydrology Traces under Alternatives A and D

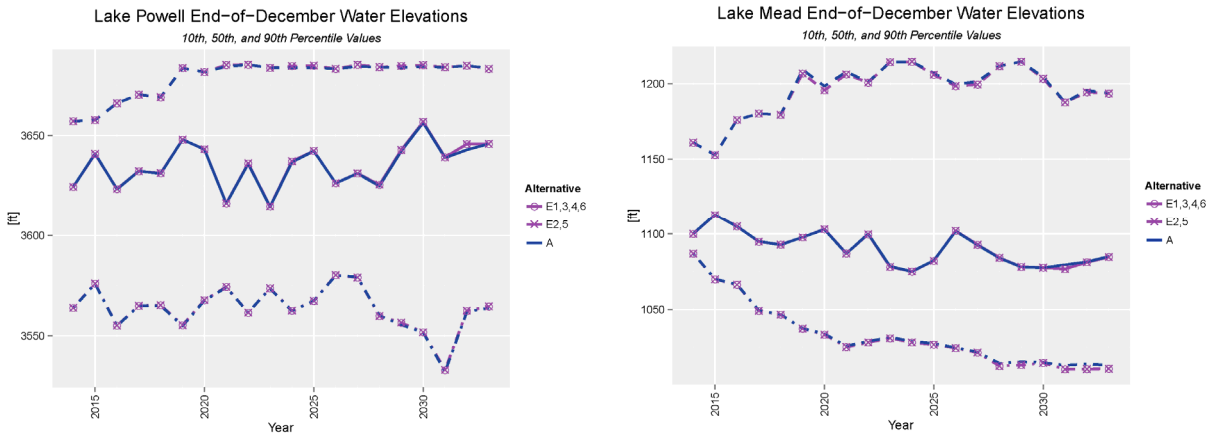

FIGURE D-12 Lake Powell (left) and Lake Mead (right) End-of-December Year Pool Elevation for 21 Hydrology Traces under Alternatives A and E

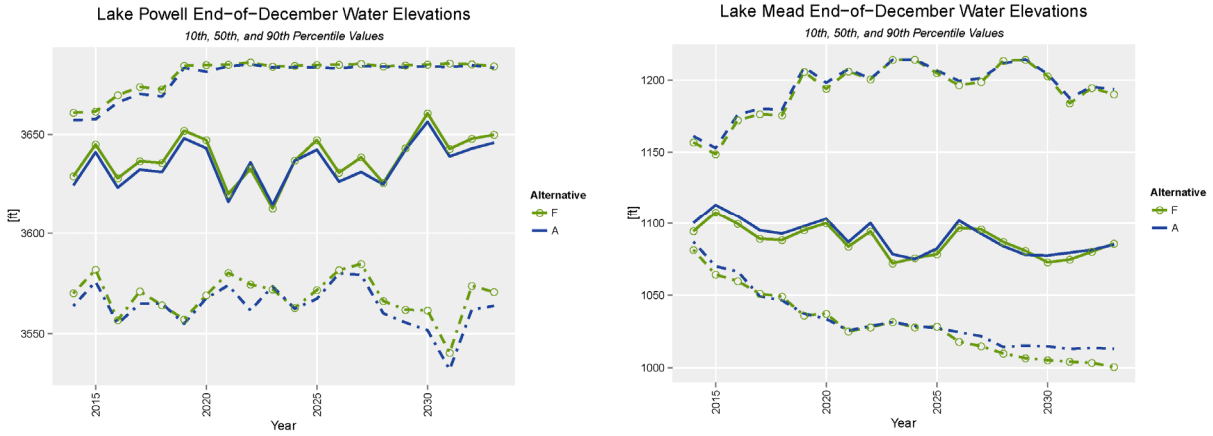

FIGURE D-13 Lake Powell (left) and Lake Mead (right) End-of-December Pool Elevation for 21 Hydrology Traces under Alternatives A and F

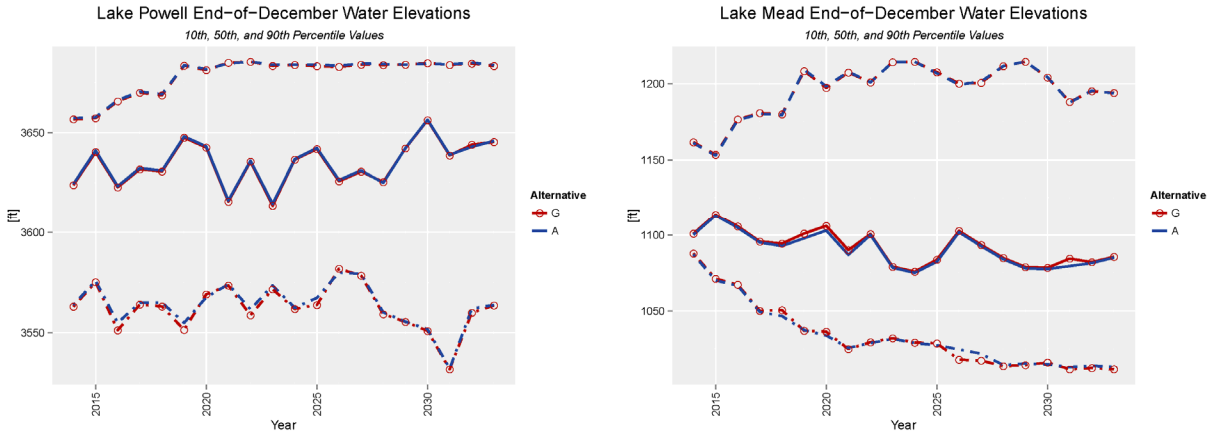

FIGURE D-14 Lake Powell (left) and Lake Mead (right) End-of-December Pool Elevation for 21 Hydrology Traces under Alternatives A and G

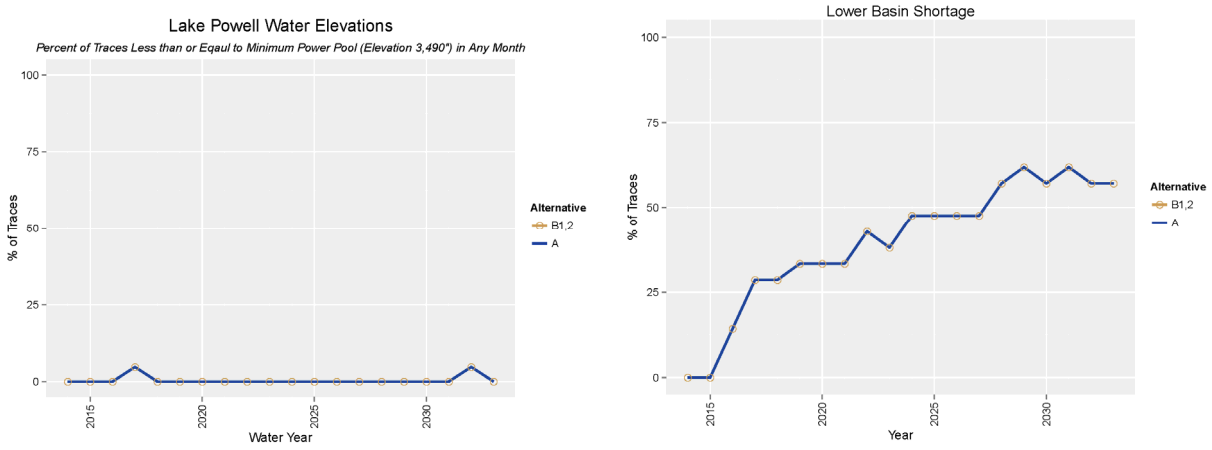

FIGURE D-15 Percent of Traces below Lake Powell's Minimum Power Pool (elevation 3,490 ft) (left) and Percent of Traces with a Lower Basin Shortage (any tier) (right) for 21 Hydrology Traces under Alternatives A and B

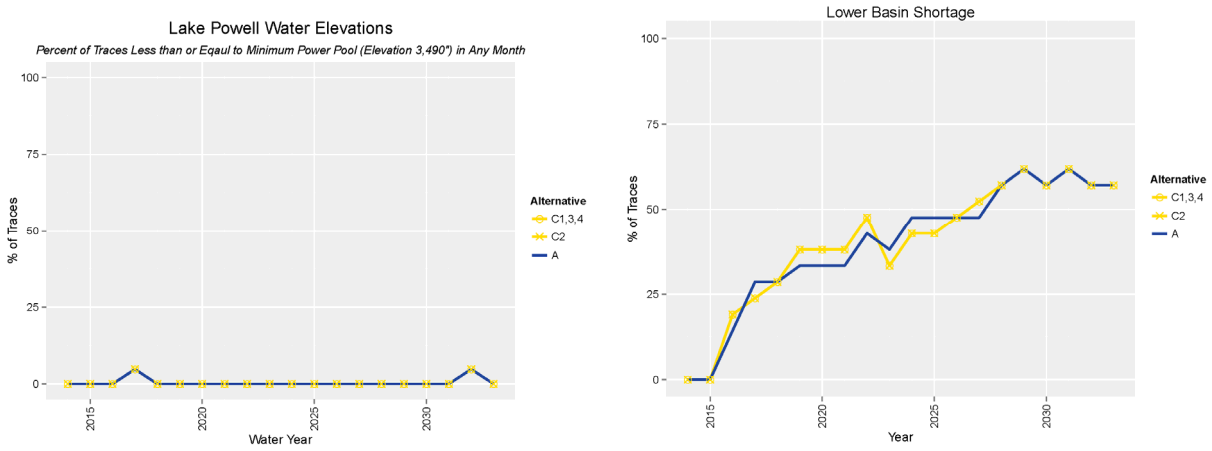

FIGURE D-16 Percent of Traces below Lake Powell's Minimum Power Pool (elevation 3,490 ft) (left) and Percent of Traces with a Lower Basin Shortage (any tier) (right) for 21 Hydrology Traces under Alternatives A and C

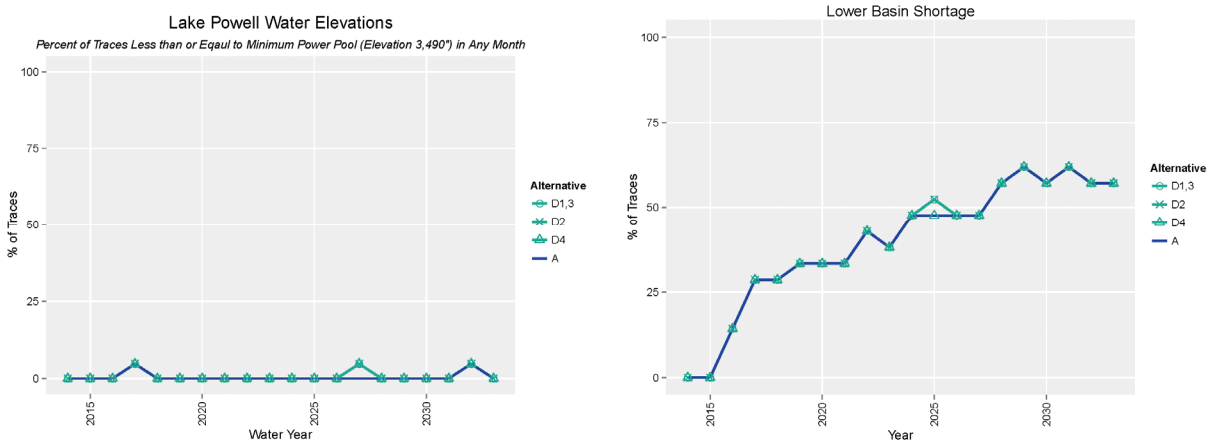

FIGURE D-17 Percent of Traces below Lake Powell's Minimum Power Pool (elevation 3,490 ft) (left) and Percent of Traces with a Lower Basin Shortage (any tier) (right) for 21 Hydrology Traces under Alternatives A and D

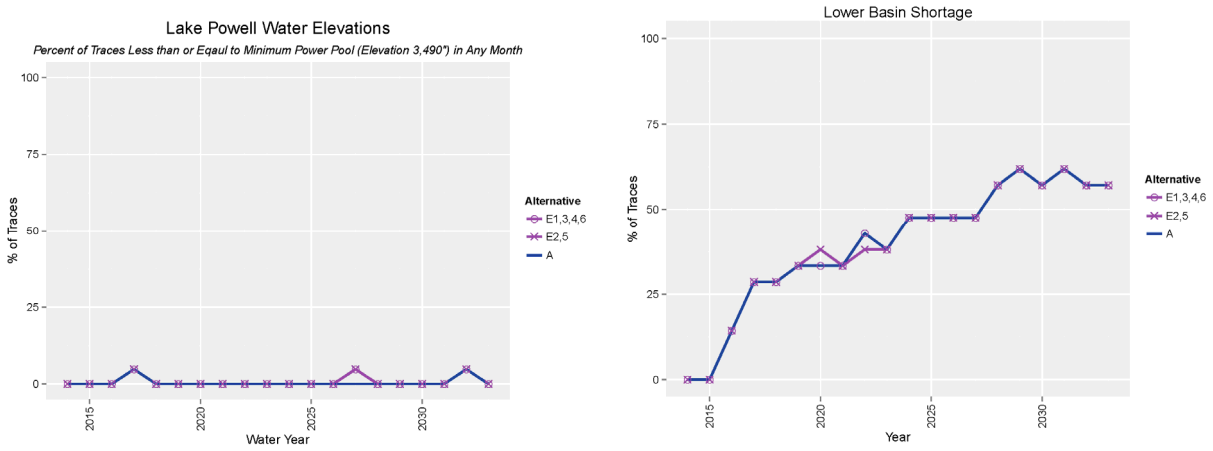

FIGURE D-18 Percent of Traces below Lake Powell's Minimum Power Pool (elevation 3,490 ft) (left) and Percent of Traces with a Lower Basin Shortage (any tier) (right) for 21 Hydrology Traces under Alternatives A and E

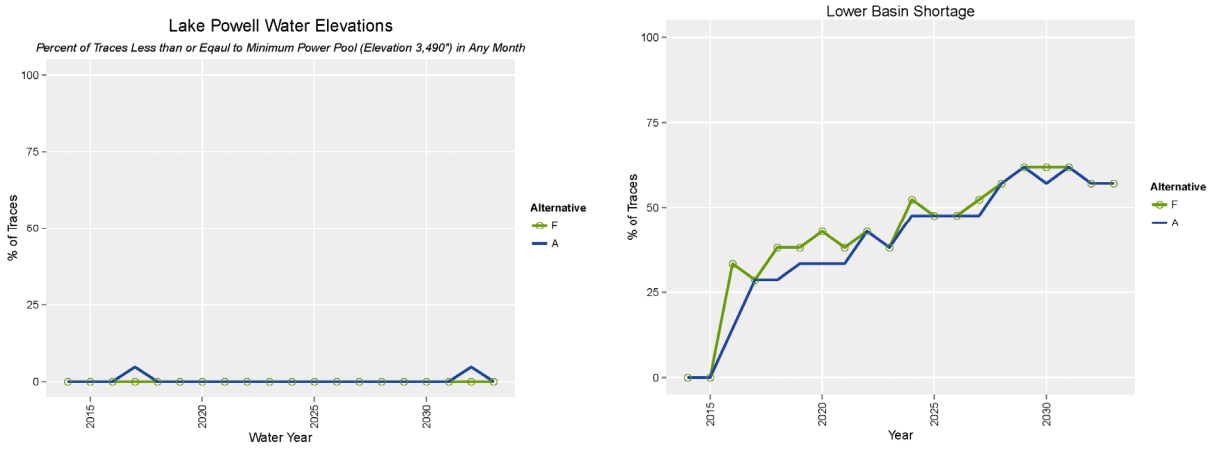

FIGURE D-19 Percent of Traces below Lake Powell's Minimum Power Pool (elevation 3,490 ft) (left) and Percent of Traces with a Lower Basin Shortage (any tier) (right) for 21 Hydrology Traces under Alternatives A and F

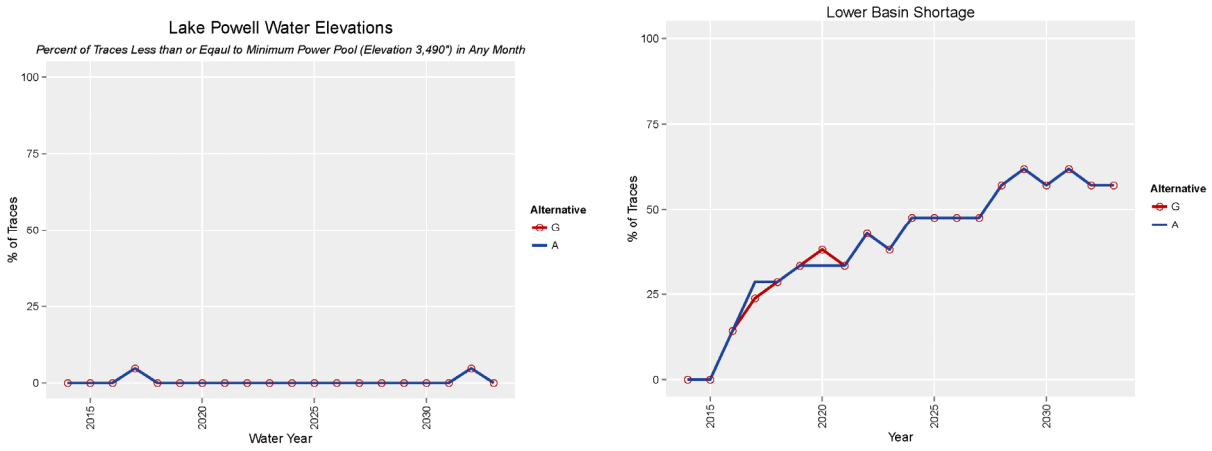

FIGURE D-20 Percent of Traces below Lake Powell's Minimum Power Pool (elevation 3,490 ft) (left) and Percent of Traces with a Lower Basin Shortage (any tier) (right) for 21 Hydrology Traces under Alternatives A and G

D.3 REFERENCES

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APPENDIX E:

SEDIMENT RESOURCES TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX E:

SEDIMENT RESOURCES TECHNICAL INFORMATION AND ANALYSIS

E.1 INTRODUCTION

This technical appendix focuses on sediment resources. The sediment resource goal is to increase and retain fine sediment volume, area, and distribution in the Glen, Marble, and Grand Canyon reaches above the elevation of the average base flow for ecological, cultural, and recreational purposes. One interpretation of this goal is to promote and maintain sandbars downstream of Glen Canyon Dam for the benefit of other resources. Currently, there is no peer-reviewed model or program that can simulate or predict sediment bar response to Glen Canyon Dam operations. Until such a model is available, other information and analyses were used in this draft environmental impact statement (DEIS) to analyze the effects alternatives would have on sediment resources. The sand budget model, which is peer reviewed and was used in the 2011 high-flow experiment (HFE) protocol environmental assessment (EA) (Reclamation 2011), provides the best available modeling method to estimate the effects of different flows on the potential for sandbar growth.

Seven alternatives were analyzed. Some of these alternatives would use condition-dependent or experimental elements that would be implemented under an adaptive management framework that would allow modification of flow and non-flow actions as new information is obtained. Critical uncertainties were identified that could lead to changes in flow and non-flow actions; these were used to identify multiple long-term strategies for those alternatives with condition-dependent actions (Alternatives B, C, D, and E). These long-term strategies were essentially different versions of the analyzed alternatives. The condition-dependent experimental elements included in the 19 strategies that were analyzed are presented in Appendix C; a full description of the alternatives can be found in Chapter 2 of this DEIS.

E.1.1 Analysis Period

Sediment analysis spanned water years 2014 through 2033 (i.e., October 1, 2013, to September 30, 2033) (Figure E-1). However, the hourly dam release data developed for the hydropower analysis (GTMax-Lite) followed a calendar year framework (i.e., January 1, 2013, through December 31, 2033). Development of sediment data for simulation input were analyzed in terms of sediment years (i.e., July 1, 2013, through June 30, 2033), which coincides with the accounting periods currently used by the Bureau of Reclamation (Reclamation) for determining whether or not a high-flow experiment (HFE) should be conducted (Russell and Huang 2010).

E.1.2 General Scope

In order to address uncertainty, the analysis conducted for this DEIS covered a range of hydrology scenarios and tributary sediment delivery scenarios. Hydrologic futures were

developed using the Colorado River Simulation System (CRSS) (Appendix D). One-hundred and five 20-year hydrologic traces were developed from the 105-year period of record; for modeling (Section 4.1.1.1 of this DEIS), every fifth hydrologic trace was used, yielding 21 potential hydrologic futures to be analyzed.

Three sediment input time series were developed to address uncertainty in the future delivery of sand to the Colorado River from tributaries. Two main tributaries—the Paria River and the Little Colorado River—deliver sand to the Colorado River downstream of Glen Canyon Dam and upstream of Lake Mead. Three 20-year sediment traces were developed for the two tributaries (Section E.2.1.3), spanning the available historical data.

In summary, there were 19 long-term strategies, 21 hydrology traces per long-term strategy, and three sediment traces per hydrology trace. This produced 63 simulations per long-term strategy, 1,197 simulations in all.

E.2 METHODS

Resource models were used to evaluate and compare the impacts of alternatives. Figure E-2 illustrates the inputs, intermediate calculations, and output of the models. This appendix will describe and discuss those parts of the flowchart circled in red: the modified sand budget model (including development of model inputs) and the sediment metrics.

E.2.1 Sand Budget Model

E.2.1.1 Model Description

A reach-based sediment budget model for the Colorado River from Lees Ferry (river mile [RM] 0) to approximately Bright Angel Creek (RM 87) was developed by the U.S. Geological Survey (USGS) (Wright et al. 2010). Using gage data at RM 30, RM 61, and RM 87, the model was calibrated and validated to the time period of 2002–2009. The model uses empirically based rating curves, which are formulated on a particle-size-specific basis. On the basis of observed transport rates, the transport function changes when flows exceed 25,000 cfs. Initial sand bed size and thickness are user-specified for each reach (RM 0–RM 30, RM 30–RM 61, and RM 61–RM 87), and a budget is developed by tracking the incoming and outgoing suspended sand flux for each reach. The incoming sand flux for RM 0–RM 30 consists mainly of Paria River inputs, and ungaged tributaries in the reach are assumed to be 10% of Paria River inputs. The ungaged tributaries for RM 30–RM 61 are assumed to be negligible, so the flux into the reach equals the flux out of RM 0–RM 30. The flux into RM 61–RM 87 consists of the flux out of RM 30–RM 61, contributions from the Little Colorado River, and ungaged tributaries, which are assumed to be negligible. Figure E-3 provides a schematic of the sand budget model.

E.2.1.2 Sand Budget Model Modifications

The sand budget model has been updated to meet the specific analytical needs since its inception. During analysis for the 2011 High Flow Experiment (HFE) Environmental Assessment (EA) (Reclamation 2011), a protocol was developed to determine whether a HFE could be implemented to improve/maintain the sandbar sediment resource (Russell and Huang 2010). The model was updated to include the HFE protocol and to identify the largest HFE that could be implemented within each sediment accounting period without causing the Marble Canyon sediment balance to be negative for that period. Marble Canyon is the focus of the sediment balance because (1) the sand budget model was calibrated and validated for the first 87 mi downstream of Lees Ferry; and (2) the gage record for the Little Colorado River is relatively short, and therefore there is less confidence in using the data for predictive purposes. The protocol in the model assumes that the implementation of an HFE occurs on April 1 for the spring accounting period and on November 1 for the fall accounting period.

For the LTEMP DEIS, the water volumes used by each HFE were accommodated by adjusting monthly volumes in the rest of the water year instead of simply adjusting the releases for the remainder of the implementation month as was done for the HFE EA. One of two different reallocation schemes is implemented depending on the alternative: a sequential reallocation scheme or an average reallocation scheme.

The sequential reallocation scheme was applied to Alternatives A and B (because they have the same monthly release volume allocations). The months from which to reallocate water were specified in order, along with the minimum release volume for each month and the minimum release flow rate. Water was reallocated from the months, in order, until the water volume needed for an HFE was achieved. If the volume needed for an HFE could be borrowed from the first month in the list, then no water was borrowed from the following listed months. If the necessary HFE volume could not be taken from the first month without violating either the minimum monthly volume or the minimum release discharge, then the next month in the list was accessed for additional volume.

The average reallocation scheme was applied to the rest of the alternatives because their monthly release volume distributions differed from Alternative A. This method borrowed a percentage of the monthly volume from each month specified. The volume of water borrowed was not the same across months, but the percentage borrowed from each month was consistent; a higher monthly volume before reallocation means more water taken and applied to the HFE volume. There is a user-specified minimum release discharge that cannot be violated for the average reallocation scheme.

Another modification made to the sand budget model (which did not affect the triggering of an HFE) was to track the necessary parameters to determine whether a trout management flow (TMF) would be triggered for a water year. For a description of TMFs, see Chapter 2 of this DEIS. A simple binary file was developed to identify water years meeting the requirement for a TMF; parameters indicating trout recruitment and the triggering of a TMF are all flow related.

The primary results from the first iteration of the modified sand budget model are two files per simulation: one identifying the timing and size of HFEs, and one identifying timing of TMFs. This information is fed back to the GTMax-Lite model (Figure E-2) for refined hourly dam release hydrographs.

E.2.1.3 Modified Sand Budget Model Inputs

Primary model inputs to the sand budget model are (1) flow hydrographs and (2) tributary sand inputs. The initial conditions of sand bed thickness and average bed grain size were also specified; these values are constant across simulation and are not alternative dependent.

Flow Hydrographs

The model-predicted suspended sand transport rates were calibrated and validated (as part of the model development; Wright et al. 2010) at gage measurement locations, namely the gages at RM 30, RM 61, and RM 87. The flow hydrograph at these locations needs to be specified for the sand budget model and are developed using the Colorado River Flow, Stage, and Sediment (CRFSS) model. The CRFSS model has a one-dimensional unsteady-flow model component that routes a dam-release flow hydrograph and provides hydrographs at locations requested by the user. The CRFSS model uses average channel geometry based on previously measured cross-sections in Marble and Grand Canyons (Wiele and Smith 1996; Wiele et al. 2007). For each dam release hydrograph provided by GTMax-Lite (Figure E-2), there were three hydrographs developed by the CRFSS model (at RM 30, RM 61, RM 87) for use in the modified sand budget model.

Tributary Sand

Both the Paria River and the Little Colorado River have sediment records that were used to develop a time series of sand load (a sediment trace). Although the Little Colorado River record is for only 18.5 years, it is the best available data set. Three sediment traces were developed for each tributary to address uncertainty in future tributary sand delivery. Sediment data were obtained from two sources: published data from the Grand Canyon Monitoring and Research Center (GCMRC 2015) and from D. Topping (Topping 2014). The period of record for the two tributaries and the sources of the data are presented in Table E-1.

The model simulation period covers 21 calendar years, which corresponds to 41 sediment accounting periods, or ~20.5 sediment years (Figure E-2). An index sequential approach was used to develop statistics for each record. In general, an index sequential method cycles through each year in a historic record and generates time series (or traces) for a specific duration; for years toward the end of the record, the requisite time period is achieved by "wrapping around" to the beginning of the record. This technique is typically used for hydrologic data cycling through water years (Reclamation 2007; Ouarda et al. 1997), whereas the method is employed here for sediment data and cycles through sediment years. The "wrap around" for the sediment analysis

means that for the Paria River, the fall 2013 accounting period is followed by the spring 1964 accounting period; likewise, for the Little Colorado River the fall 2013 accounting period is followed by the spring 1994 accounting period. The record for the Little Colorado River is short enough relative to the 21-year period that every index sequential sediment trace covers the entire period of record.

Paria River. Because fall 2013 is the first full accounting period for which an HFE would be considered in the simulation, only index sequential segments beginning with fall accounting periods are used in the statistical analysis. The three traces selected were approximately the 10%, 50%, and 90% non-exceedance traces from the index sequential statistics. The three selected traces for the Paria River also cover the entire period of record. Figure E-4 presents the sand input from the Paria River for the historical record grouped into accounting periods, along with the index sequential 41-accounting period (20.5-year) sand loads. Only the 20.5-year sand load sequences beginning with a fall accounting period are presented in Figure E-4; these are the data from which the statistics are developed for identifying three representative traces. Figure E-5 presents the cumulative sand load for the three traces that were identified for the use in the DEIS modeling. Again, these traces were identified based on cumulative sand load and to ensure the entire historical record is represented in the modeling.

These three traces are not consistently low, medium, and high relative to each other throughout the 20-year period. Moving from beginning to end of the simulation period, s1 (sediment trace 1) is not always less than s2, and s2 is not always less than s3. In fact, s3 is comparable to s2, except in the last couple of years when the s3 trace jumps significantly; this jump corresponds to the fall 1980 accounting period. In addition, s1 has the most sediment contributions for approximately the first 3 years. These are three different sediment traces that were selected to be representative of the historical record.

Once the three sets of 41 accounting periods were identified for use in the simulation, the necessary simulation records (traces) were completed by applying the appropriate sections of the historical record. The periods of record used for s1, s2, and s3 are presented in Table E-2.

Little Colorado River. The record for the Little Colorado River is shorter than the simulation period, so every trace covers the entire period of record. In addition, the HFE protocol as implemented in the modified sand budget model assesses the balance of sand in Marble Canyon to determine whether an HFE is simulated. The balance of sand in Eastern Grand Canyon—and therefore the sediment input from the Little Colorado River—is less critical to the simulations and analysis performed for this DEIS.

The index sequential method for the Little Colorado River was performed on a calendar year basis, and the simulation periods for s1, s2, and s3 are presented in Table E-3. Figure E-6 presents the sediment traces used as input for the modified sand budget model.

Initial Conditions

The initial conditions to be specified in the sand budget model for each reach are bed thickness and median bed sediment grain size, D_{50}. The initial conditions specified for the DEIS analysis come from the best available data nearest the simulation start date of January 1, 2013. Wright et al. (2010) found that varying initial bed D_{50} by ±10% from the initial estimated values (0.4, 0.3, and 0.3 mm for UMC, LMC, and EGC, respectively) yielded between 3 and 7% difference in total flux for the three reaches; varying initial bed thickness from the initial estimated values (0.4, 0.5, and 0.5 m for UMC, LMC, and EGC, respectively) by ±10% yielded a difference in total sand flux of less than 0.5%. The simulations conducted for this analysis used initial condition values for UMC, LMC, and EGC of 0.46, 0.38, and 0.43 mm, respectively, for grain size and 0.30, 0.37, and 0.27 m, respectively, for bed thickness.

High Flow Events

The modified sand budget model identified the largest HFE that would not violate water and sediment availability rules. The HFEs that the model considered are user specified. Eighteen HFEs that are specified for this analysis (Table E-4), and HFEs 1–13 are consistent with the HFEs considered for the HFE EA (Reclamation 2011). Longer-duration HFEs (A–E in Table E-4) were suggested for consideration in the DEIS, and two alternatives consider HFEs lasting longer than 96 hours: Alternative D and Alternative G. HFE C in Table E-4 was originally defined as lasting 240 hours at 45,000 cfs for Alternative G. Alternative D was crafted after seeing the results of the Alternatives A, B, C, E, F, and G (Section 2.2.4 of this DEIS), and HFE C in Table E-4 was defined as 250 hours for this alternative.

Proactive spring HFEs would be triggered based on hydrology. Conceptually, a large snowpack in the mountains leads to a prediction of a wet year, and if the predicted annual runoff volume is great enough (greater than 10 million ac-ft, or 10 maf) then a proactive spring HFE would be implemented. The purpose of this HFE is to redistribute the available bed sediment onto sandbars and channel margins so that it would be stored at elevations above those of the subsequent large runoff volume. The proactive spring HFE implemented in the model is identical to HFE 6 in Table E-4 in terms of peak discharge and duration at peak discharge.

E.2.2 Sediment Metrics

Prior to modeling for the LTEMP DEIS, a number of metrics were crafted to evaluate the alternatives in terms of their performance with regard to the sediment resource goal. The metrics developed prior to modeling were surrogates intended to be representative of sediment resource response; it was assumed that if the surrogate performed well, the sediment resource also would respond well. The metrics developed were the sand load index (SLI), the standard deviation of high flows (SDHF), and the sand mass balance index (SMBI).

E.2.2.1 Sand Load Index (SLI)

The potential for building sandbars was estimated using the SLI, which is a comparison of the mass of sand transported at RM 30 when river flows ≥31,500 cfs relative to the total mass of sand transported at all flows, as shown in equation 1:

$$SLI = \frac{Q_{s,Q>31.5}}{Q_{s,total}} \quad (1)$$

where:

SLI = sand load index

$Q_{s,Q>31.5}$ = sand flux at RM 30 when river flows at RM 30 are greater than 31,500 cfs

$Q_{s,total}$ = total sand flux at RM 30 during analysis period.

The index varies from 0 (no sand transported at flows ≥31,500 cfs) to 1 (all sand transported at flows ≥31,500 cfs). An SLI of 0 would indicate that there are no flows above 31,500 cfs during a simulation; the alternative that there are flows above 31,500 cfs but no sediment flux occurring is for all practical purposes impossible.

The larger the SLI for an alternative, the more potential there is for bar growth. The SLI only estimates the potential for (and not actual) bar growth, because all sandbars have a maximum potential deposition volume; the closer any given bar is to full, the less deposition will occur (Wiele and Torizzo 2005).

E.2.2.2 Standard Deviation of High Flows (SDHF)

This index was intended to represent a greater likelihood of more robust sandbars. Historical sandbar surveys indicate that individual bars respond differently to different HFEs (Hazel et al. 2010). Some sandbars are smaller after a 45,000 cfs event. Equation 2 shows how this value is calculated for each water year, and the metric is averaged across the 20-water-year analysis period.

$$SDHF = \sqrt{\frac{1}{N-1}\sum_{i=1}^{N}(x_i - \bar{x})^2} \quad (2)$$

where:

SDHF = standard deviation of high flows

N = sample size (in this case, 63 per alternative)

x_i= individual observed peak discharge, cfs

$\bar{x}$ = sample mean of peak discharges, cfs.

E.2.2.3 Sand Mass Balance Index (SMBI)

This index quantifies the amount of sand that is left in storage in Marble Canyon (RM 0 to RM 61) at the end of a simulation relative to the amount of sand that is present at the beginning of the simulation. This is the most direct application of the modified sand budget model; it tracks the amount of sand that comes into the individual reaches compared to the amount of sand that leaves the individual reaches (Figure E-7). This index is not directly representative of the resource goal. However, this metric does provide insight into how the amount of sediment in Marble Canyon is affected by dam operations. If more sand comes into Marble Canyon than leaves Marble Canyon, there will be an increase in stored sand, and a positive SMBI. Conversely, a greater amount of sand leaving Marble Canyon than entering will yield a negative SMBI.

E.3 RESULTS

Two iterations of the modified sand budget model were completed for each simulation (Figure E-2). The first iteration determined the timing and size of triggered HFEs, as well as identifying whether TMFs would be triggered. This information was passed back to GTMax-Lite where the hourly dam release hydrographs were refined based on the HFE schedule and TMF schedule.

The second iteration of the modified sand budget model did not allow additional HFEs to be implemented because the refined GTMax-Lite dam releases already include the HFEs and TMFs. The second iteration was used to obtain sediment-related data for sediment metrics to be calculated for each alternative.

E.3.1 HFEs Determined by Alternative

The sediment metrics for each alternative are closely related to the number of HFEs that occur for the alternative. The number of HFEs is not a sediment metric itself, but understanding the HFEs that occur under an alternative helps to clarify the sediment metrics discussed in the following sections. The average number of HFEs that occur (across 63 simulations per alternative) is compared, along with the number of HFEs that occur based on sediment trace (average across 21 simulations). Results for long-term strategies C3, E3, E5, and E6 are not presented in this section, because HFEs are not included in these long-term strategies.

Figure E-8 presents the breakdown of the average number of HFEs for each long-term strategy (across 21 hydrology and 3 sediment traces) by HFE type (Table E-4). Only Alternatives D and G allow for HFEs longer than 96 hours, and Alternative G has the most HFEs on average. Alternatives A and B have the fewest HFEs on average. Under Alternative A (no-action alternative) the HFE protocol would expire in 2020, so a little more than half of the

simulation period does not have HFEs simulated. Alternative B stipulates that HFEs would not be implemented more often than once every 2 years. This limits the number of HFEs to one-fourth of the simulation period. Alternative F has a 24-hour 45,000-cfs flow at the beginning of the spring peak period (e.g., on May 1) as part of the alternative definition. Those events are not captured in Figure E-8; this figure represents the sediment-triggered and hydrology-triggered HFEs identified from the modified sand budget model. More information on the alternative definitions can be found in Chapter 2 of this DEIS.

Figure E-9 compares the average number of HFEs simulated (not by HFE type) for the three different sediment traces. Remember that s1, s2, and s3 do not equate to low, medium, and high; they are three sediment traces intended to be representative of the historical sediment records in terms of exceedance probability, as well as ensuring that the entire period of record is represented by the three traces. Figure E-9 shows some variability among the sediment traces, although the general trends between alternatives as shown in Figure E-8 are maintained. Sediment trace s2 commonly has the lowest number of simulated HFEs. Sediment trace s1 has the most simulated HFEs for Alternatives A, B, and F. Sediment trace s3 has the most simulated HFEs for Alternatives C (except long-term strategy C4), D, and G. Sediment traces s1 and s3 are very similar for Alternatives E (except long-term strategy E4) and F with regard to the number of HFEs triggered.

The majority of HFEs are triggered in the fall, because sediment from the Paria is related to monsoonal precipitation and the majority of the sediment delivery occurs in the fall. Fall HFEs account for 77% of all HFEs simulated; the remaining 23% of HFEs that occur in the spring include proactive spring HFEs, which are triggered by hydrology (wet years) and not by sediment delivery.

E.3.2 Metrics

Plots have been developed for each metric to statistically describe the alternative performance from the 63 different simulations for each long-term strategy. The statistics represented in these plots include a weighting scheme based on each sediment trace's exceedance probability. The weighting scheme for the box and whisker plots is as follows: s1 = 0.1754, s2 = 0.6313, s3 = 0.1933. In addition, a different set of weights was used for a climate change analysis to represent the fact that future hydrology in the Upper Colorado River Basin is expected to be drier than the historical hydrology (Section 4.16.1.2 of this DEIS). Plots using climate change weighting are provided for each sediment resource metric in Section E.3.3.

The box and whisker plots provide information on the following statistical representations of the distribution of performance across 63 simulations per long-term strategy: minimum, maximum, mean, median, 25th percentile, and 75th percentile, as described in Figure E-10.

E.3.2.1 Sand Load Index (SLI)

The SLI as described in Section E.0 reflects the potential for sandbar growth. Figure E-11 presents SLI values for all long-term strategies. Overall, Alternative G has the highest SLI values, followed by Alternatives F, D, C and E. Alternatives A and B have the lowest SLI values, which is consistent with the number of HFEs that can be triggered under each alternative.

Figure E-11 matches the general pattern of the number of HFEs shown in Figure E-8. One notable exception is Alternative F; Figure E-8 represents the sediment-triggered and hydrology-triggered HFEs, whereas Figure E-11 includes data from the alternative-defined spring events that occur each year under Alternative F regardless of sediment availability.

There is a nonzero SLI for long-term strategies C3, E3, E5, and E6, even though there are no HFEs simulated for these long-term strategies. Some hydrologic years are wet enough to necessitate flows above 31,500 cfs being released from Glen Canyon Dam as normal (non-HFE) operations. The sand transported while flows are above 31,500 cfs under these conditions contributes to a nonzero SLI.

E.3.2.2 Standard Deviation of High Flows (SDHF)

As described in Section E.2.2.2, this metric was intended to reflect variability in flow, which was thought to be positively related to the ability to build more robust sandbars. Figure E-12 presents the statistical distribution of SDHF values for the long-term strategies, which is similar to the general pattern shown for the SLI in Figure E-11.

The SDHF mean is plotted against the SLI mean in Figure E-13. A strong correlation exists between the SDHF and the SLI. Therefore, the SDHF was not considered with the SLI for alternative comparison in this DEIS.

E.3.3 Sand Mass Balance Index (SMBI)

This metric does not represent the sediment metric directly (Section E.2.2.3); however, it does provide an index to relative changes in sediment balance that would result under different alternatives. If an alternative reduces the overall sediment balance (the amount of sediment in the sandbars and eddies, and on the channel bed) then this net depletion will result in less sediment being available for bar building during future HFEs.

The only long-term strategies that do not significantly reduce the sediment balance over the duration of the simulation period are those that do not have HFEs (long-term strategies C3, E3, E5, and E6), as shown in Figure E-14. The mass balance of sediment is affected by high flows. HFEs have been called a “double-edged sword” by Rubin et al. (2002) because they necessarily export relatively large volumes of sand in order to transfer sand to high-elevation portions of sandbars (Wright et al. 2008). There is an inverse relationship between sandbar building potential and sediment balance; more sandbar building potential reduces the sediment

remaining within the channel. Figure E-15 plots the mean SMBI relative to the mean SLI. Although there is variation among the alternatives, a higher SLI tends to create a larger net deficit of sand (lower SMBI value) in Marble Canyon. Two exceptions are Alternatives B and D. Alternative B would produce a large net deficit in SMBI but has a relatively low SLI; the relatively low SLI is a result of the limited number of HFEs under this alternative, but this does not produce a correspondingly low SMBI because the larger daily fluctuations during intervening flows transport more sediment. Alternative D has relatively high SMBI and SLI values; more HFEs (including longer duration HFEs) yields the higher SLI value and the combination of relatively even monthly distributions along with relatively small daily fluctuations contributes to a higher SMBI.

E.3.4 Alternative Performance under Climate Change Scenarios

Weights were applied to hydrology traces to reflect expected changes in hydrology under climate change. This weighting scheme was intended to represent future hydrology in the basin, which is expected to be drier than the historical hydrology (Section 4.16.1.2 of this DEIS). Figure E-16 presents SLI values calculated under the long-term strategies using the climate change weights. Figure E-17 shows that there is little difference in long-term strategy performance in terms of SLI when comparing the climate change weights to the historical weights. The small difference that does exist could be described as a slight improvement in performance under the climate change weighting.

Figure E-18 presents SDHF values under long-term strategies when the climate change weights were used. Figure E-19 shows that there was little difference between SDHF values calculated using the climate change weights and those calculated using the historical weights. The most notable difference is a slight reduction in the 75th percentile, which indicates less variability in the metric when climate change weights are used.

Figure E-20 presents SMBI values under long-term strategies when the climate change weights were used. Figure E-21 shows that there was some difference between SMBI values calculated using the climate change weights and those calculated using the historical weights. When climate change weights were used, the interquartile ranges and the means were higher, which indicates less net depletion. Interestingly, the minima and maxima do not change appreciably, meaning these extremes are likely due to specific simulations (combination of hydrology and sediment traces).

E.3.5 Relative Impacts of Dam Operations and Hydrology on Performance

Modeling results were evaluated to determine the effect of the following management actions on sediment resources: proactive spring HFEs, spring HFEs, fall HFEs, TMFs, daily fluctuations and intervening flows, load-following curtailment, low summer flows, and general hydrology (wet vs. dry). These evaluations were made using the model runs of the various long-term strategies, which included some, but not necessarily all, elements. Additional modeling did not take place to answer these questions.

HFEs, whether they are proactive spring HFEs, spring HFEs, or fall HFEs, are the most influential management action in terms of sediment resources. Whether a given HFE type (magnitude and duration) occurs in the fall or the spring does not affect the sediment resource differently. The timing of sediment delivery from the Paria River (during the summer-fall monsoon season) leads to larger and more frequent fall HFEs, but that is due to input, not management actions.

TMFs did not show a significant impact on the sediment resource. This is due in part to the fact that one of the primary factors in triggering a TMF is a spring HFE, which, in the model, increased trout recruitment (Section 4.4.1.2 of this DEIS). Spring HFEs have a relatively large effect on the SLI and SMBI that tends to mask a TMF's impacts on sediment. Another reason TMFs have little impact on sediment because of their effect on release volume. In order to provide the flow for TMFs, the average flow in the remainder of the late spring/early summer period tends to be lower than if there were no TMF. The effect of higher flows for the TMFs and the lower flows means a very minor difference in net sediment transport.

Figure E-22 shows the time series of flow (Q) at RM 30, the SLI, and the SMBI for the simulation hydrology trace 1/sediment trace 3 (t01s3) for the period March 1, 2021, to August 1, 2021. Long-term strategies C1 and C2 are plotted for comparison; both simulations have the same HFE triggered in spring 2021, but TMFs are implemented under C1 but not C2. In the figure, the TMF flows can be seen in early May, June, and July in the top graph. Notice the time series of SLI and SMBI show a strong signal response in early April due to the HFE, and practically no signal response from the TMF flows.

Alternatives C and E differ in daily fluctuation levels, as well as monthly volume allocations; this is the best comparison we can make (without performing targeted modeling) on the effects of daily fluctuations. Alternative C has lower daily fluctuations than Alternative E, but has relatively high spring volume compared to the more even monthly pattern of Alternative E. Although lower daily fluctuations reduce sediment transport, higher monthly volumes increase transport. It was not possible to reconcile the relative importance of daily fluctuations and monthly volume allocations without additional modeling. However, a comparison of Alternative C and Alternative E using the long-term strategy where no HFEs are allowed (long-term strategies C3 and E3) was made. This comparison takes into account both daily fluctuations and monthly volume allocations. There was no difference in SMBI values between long-term strategies C3 and E3 (Figure E-23), and there was a minor difference in SLI values (Figure E-24). Because there are no HFEs in long-term strategies C3 and E3, all of the values for SLI are below 0.2 and any differences between these alternatives are minor.

Load-following curtailment is a management action intended to retain sediment for HFEs by reducing daily fluctuations before and/or after the HFE for a period of weeks or months. Load-following curtailment is specified as fluctuations being limited to ±1,000 cfs about the mean daily flow (a 2,000 cfs range of fluctuation). This management action does not appear to make a difference in the modeled metric values, because an HFE will necessarily reduce the non-HFE mean flow around which daily fluctuations occur; the daily fluctuations associated with lower means tend to have fluctuation ranges not much greater than the ±1,000 cfs specified for load-following curtailment. Figure E-25 shows the smaller fluctuation range leading up to a fall

HFE and the associated impact on SLI and SMBI (hydrology trace 6, sediment trace 3). Long-term strategies E1 and E2 are compared here, but the same comparison could be made using other long-term strategies (C1 and C2 or D1 and D2) with similar trends. Although there are differences in metric values between E1 and E2 for the months following the HFE, the SMBI is different by only 9 ktons at the end of the water year, and the SLI is the same by the end of the water year.

Low summer flows are a management action intended to provide warmer water for humpback chub during the summer. These lower flows would also be expected to conserve sediment inputs during the monsoon period. Implementing low summer flows in the summer requires increasing average monthly release volumes in other non-summer months (especially in the spring), thereby counteracting, in the long term, any short-term increase in sediment conservation (Figure E-26).

Annual inflow volume that reflects annual variation in precipitation and runoff is the main driving force on sediment processes. Release volumes are governed by legal release requirements (Section 1.9 of this DEIS). For the SLI, wetter hydrology means a lower metric value (Figure E-27). This is true for the long-term strategies that do not have limitations on the number of HFEs that can be triggered. The trend lines with a positive slope in Figure E-22 are Alternative A (no HFEs after 2020), Alternative B (long-term strategies B1 and B2; not more than one HFE every 2 years), and long-term strategies C3, E3, E5, and E6 (no HFEs). Based on modeled SMBI values, wetter hydrology is expected to transport more sediment downstream under all long-term strategies (Figure E-28).

E.4 LAKE DELTAS

The impact of sediment delta formation due to different alternatives must be inferred, because there are no models for this physical process. The following discussion and conclusions are based on existing data and on some of the modeling data for the sediment resource alternative analysis.

Lake deltas are formations that occur when sediments transported in high-energy riverine flow fall out of the water column as the river enters a lake and loses energy. The Colorado River, along with a number of smaller rivers (that used to be tributaries to the Colorado River but are now emptying directly into Lake Powell or Lake Mead) have deltas that form in locations determined by reservoir elevation. As the elevations of the lakes change, the locations of the deltas will also change (Figure E-29).

Lake Powell and Lake Mead deltas can be grouped into two categories: those deltas whose size and location would be affected by dam operations, and those whose location, but not size, would be affected by dam operations.

Only the Colorado River delta in Lake Mead can be affected in terms of both location and size; all other deltas' positions are affected by reservoir elevation (and their delta size is unaffected by dam operations). Using historical data from the GCMRC data portal

(http://www.gcmrc.gov/discharge_qw_sediment/stations/GCDAMP), less than half (approximately 46%) of the suspended sand load reaching the gage above Diamond Creek (USGS gage 09404200) since October 2002 can be accounted for as suspended sand leaving Marble Canyon (USGS gage 09383100). The other half of the suspended sand reaching Diamond Creek comes from tributaries downstream of Marble Canyon, most notably the Little Colorado River. Figure E-30 compares the cumulative sand load above Diamond Creek (RM 225) to the cumulative sand load at Desert View (RM 61). This figure demonstrates that the amount of sediment passing RM 225 is approximately 22,000 ktons in the approximately 12.5-year time span since October 2002; this can be extrapolated to about 35,200 ktons of sand for a 20-year period (the same duration as the LTEMP analysis period). Similarly, the approximately 10,000 ktons of sand that have passed RM 61 since October 2002 can be extrapolated to approximately 16,200 ktons of sand for a 20-year period.

The mean SMBI resulting from the 20-year simulations indicates that there may be anywhere from 1,000 to 3,300 ktons of net loss in Marble Canyon sand, depending on the alternative. This decrease in Marble Canyon sand increases the amount of sand going past RM 61 by approximately 6% for Alternative A and 20% for Alternative F, as compared to historical data. Assuming all of the sand leaving Marble Canyon eventually passes Diamond Creek, these increased fluxes leaving Marble Canyon represent less than a 10% change in sand flux at RM 225 compared to the historical data.

The alternatives considered will have minimal impacts on the size of the Colorado River delta in Lake Mead, which is the only delta that could be affected in terms of size and location by Glen Canyon dam operations.

The positions of deltas in Lake Powell and Lake Mead are directly affected by reservoir elevation (Figure E-29). Changes to reservoir elevations are calculated in the CRSS model (Section 4.1 and Appendix D of this DEIS). The elevation of the lakes is compared to full pool elevations of 3,700 ft for Lake Powell and 1,229 ft for Lake Mead. The lake elevations from the alternatives are compared on a monthly basis and minima, means, and maxima were determined for the 63 simulations under each alternative. Figure E-31 presents the pool elevation for Lake Powell and Figure E-32 presents the pool elevation for Lake Mead. There is more variability related to differences in hydrology (compare the minimum and maximum for a given month) than there is related to different alternatives (compare colors across months). Pool elevations are ultimately controlled by regional hydrologic conditions and will not be affected by the alternatives. Alternative F is slightly different than the other alternatives because the monthly release volumes are low through winter. This small difference is not as pronounced as the variability due to annual inflow.

E.5 LIMITATIONS AND KNOWN ISSUES

E.5.1 Geographic Scope

The geographic scope of this DEIS includes the Colorado River from Glen Canyon Dam downstream, and west, to Lake Mead (Section 1.5.1 of this DEIS). This geographic scope in terms of Colorado River Mile is from RM 15 (Glen Canyon Dam; RM 0 is at Lees Ferry) to RM 347 (Hoover Dam). The numerical model upon which the sediment resource analysis is based extends from RM 0 to RM 87, although uncertainty in sand load from the Little Colorado River limited the analysis to Marble Canyon (RM 0 to RM 61).

E.5.2 Modeling Improvements

The average reallocation scheme (Section E.2.1.2) requires specification of a minimum flow rate about which fluctuations occur. The modeling for alternatives that use the average reallocation scheme and that allowed for daily fluctuations (Alternatives C, D, and E) have a fluctuation range specified at 5,000 cfs to 8,000 cfs. Due to differing up- and down-ramp rates, the average discharge is not 6,500 cfs but is closer to 6,521 cfs. Alternatives C and E used a specified flow rate of 6,500 cfs, but this error was found before modeling of Alternative D, and 6521 cfs was used for this alternative. Fixing the minimum flow rate for Alternatives C and E may result in a small adjustment to the results, but should not change relative rankings among alternatives.

Load-following curtailment was not implemented for all long-term strategies of Alternatives C and E. Fixing this issue is not expected to affect modeling results.

In a few cases during the modified sand budget modeling, sufficient water volume was identified to sustain an HFE; however, the water surface elevation in Lake Powell was below the minimum power pool intake elevation. This did not allow GTMax-Lite to develop refined hourly flows. In such cases, the sand budget model for the appropriate simulation(s) was run again without allowing an HFE to occur during the problem accounting period. A potential fix for this issue could result in the occurrence of a small HFE. This fix is expected to affect results for a given simulation; however, when considering the averaging across 63 simulations, the net effect is expected to be small.

Initial conditions for bed thickness and bed material size may not have been consistent between the first and second runs of the modified sand budget model for all long-term strategies. Wright et al. (2010) found that varying initial conditions by ±10% made less than a 7% difference in model results, so this fix is not expected to make a difference in alternative analysis.

One of the long-term strategies for Alternative D (D2) included sustained low flows for benthic invertebrate production (Section 2.2.4 of this DEIS). The set of months from which water is reallocated to support an HFE is not the same set of months when these sustained low

flows are implemented, and implementing this in the model proved iterative and perhaps not as representative as it could be. Further modification to the sand budget model may improve the implementation of this flow management action; anticipated effects of this effort are unknown.

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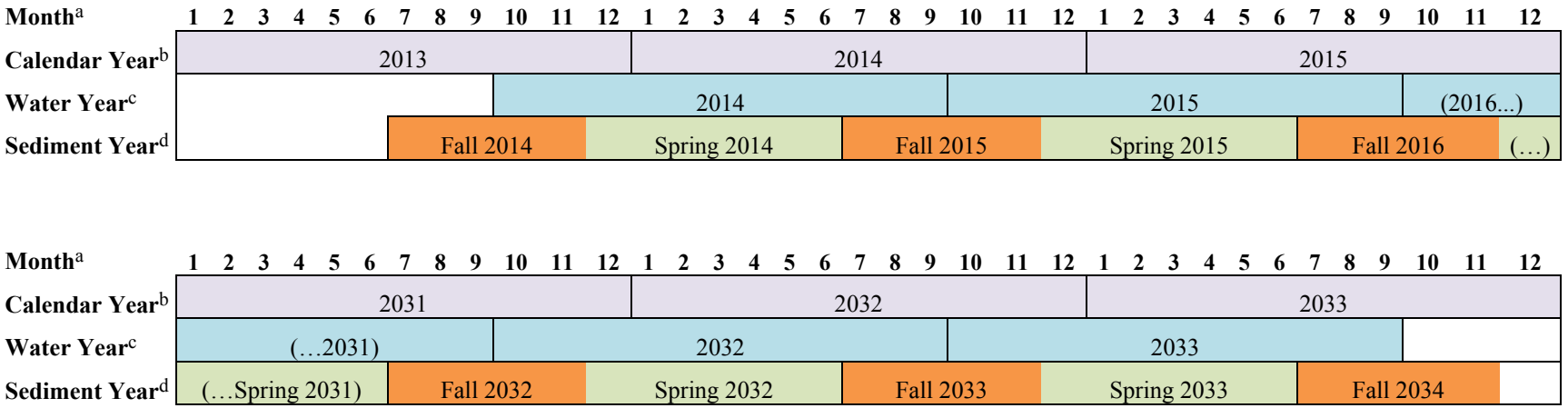

[a] 1 = January; 2 = February; 3 = March; 4 = April; 5 = May; 6 = June; 7 = July; 8 = August; 9 = September; 10 = October; 11 = November; 12 = December.

[b] Model simulations run for 21 calendar years.

[c] Analysis of alternatives covers 20 water years.

[d] Two accounting periods (spring/fall) per sediment year.

FIGURE E-1 Comparison of Calendar, Water, and Sediment Years

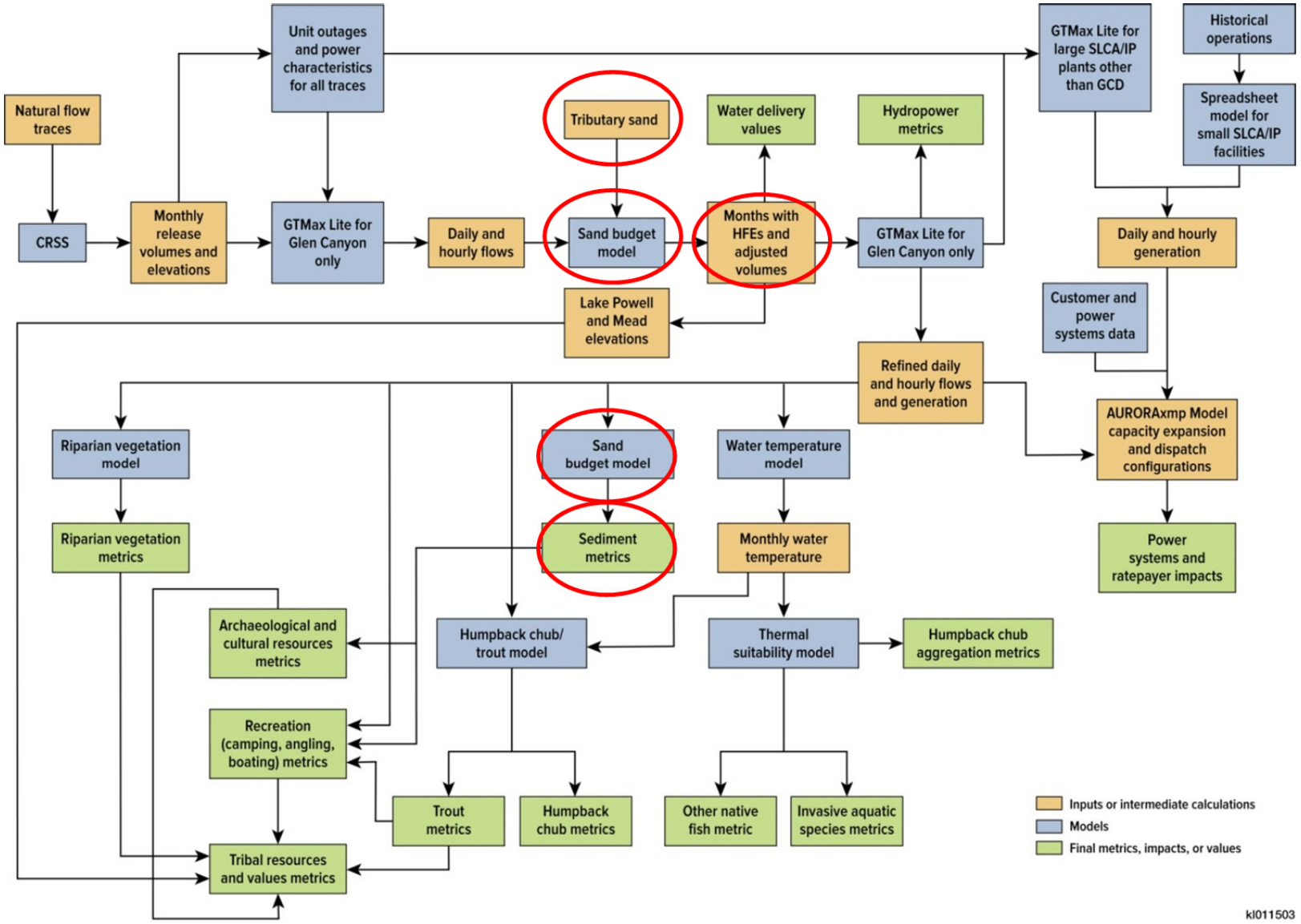

FIGURE E-2 Model Flow Diagram for Analyses Showing Inputs, Intermediate Calculations, and Output

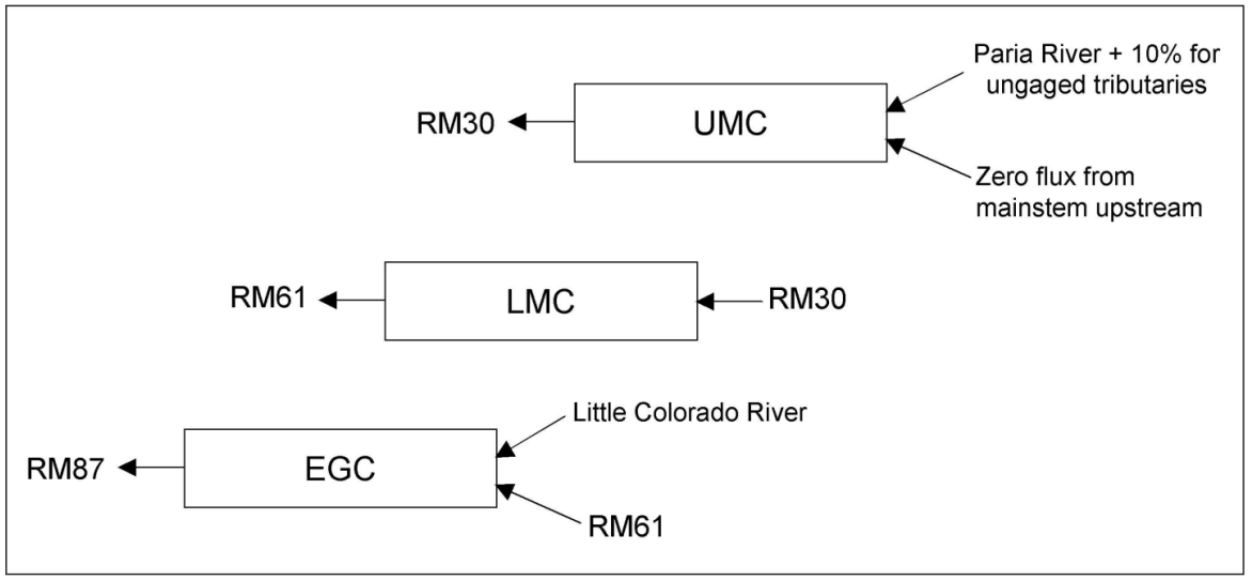

FIGURE E-3 Conceptual Schematic of the Sand Budget Model (UMC = Upper Marble Canyon; LMC = Lower Marble Canyon; EGC = Eastern Grand Canyon)

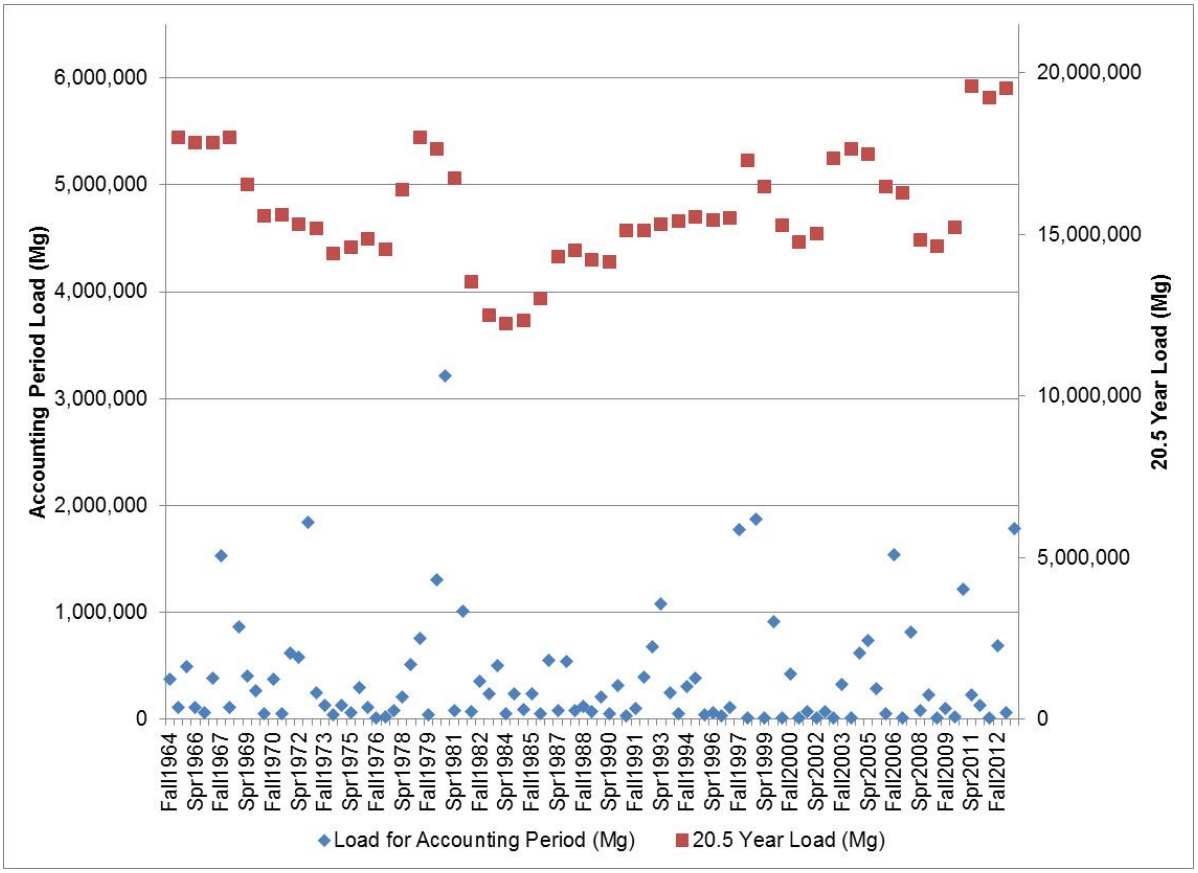

FIGURE E-4 Historical Paria Sediment Load per Accounting Period and the 20.5-year Load for the Trace That Begins in Each Fall Accounting Period

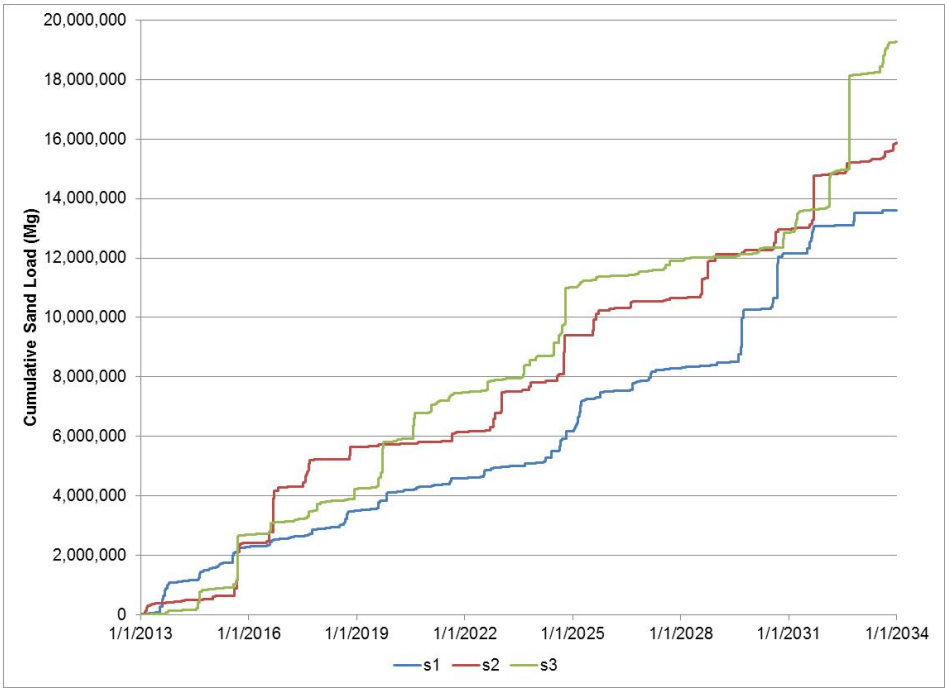

FIGURE E-5 Sediment Traces s1, s2, and s3 for the Paria River (presented as cumulative load) Used in the Modeling to Account for Uncertainty in Future Delivery

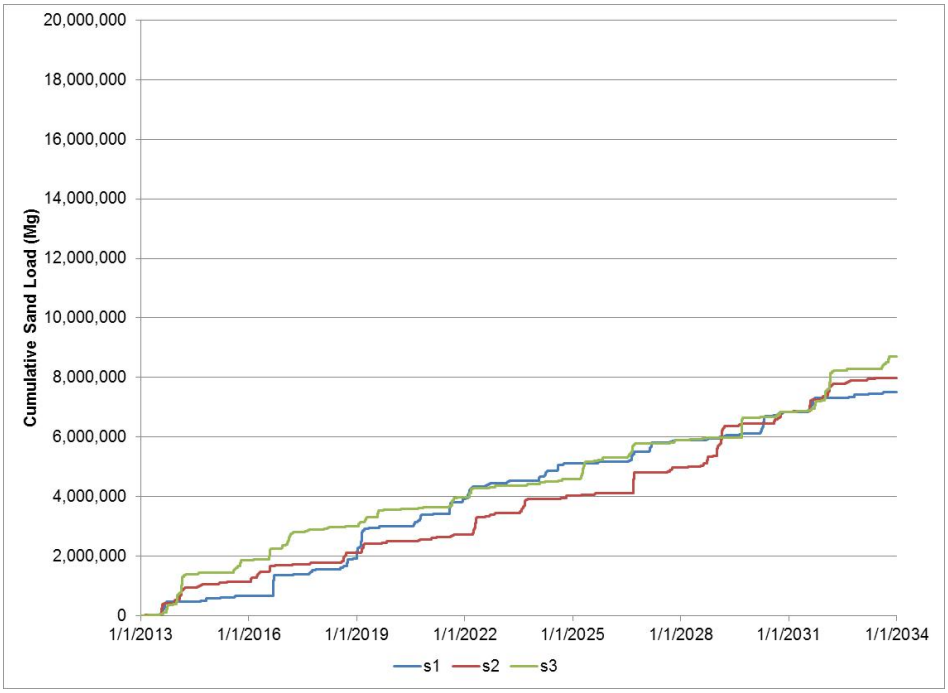

FIGURE E-6 Little Colorado River Sediment Traces (presented as cumulative loads) for s1, s2, and s3 Used in the Modeling to Account for Uncertainty in Future Delivery

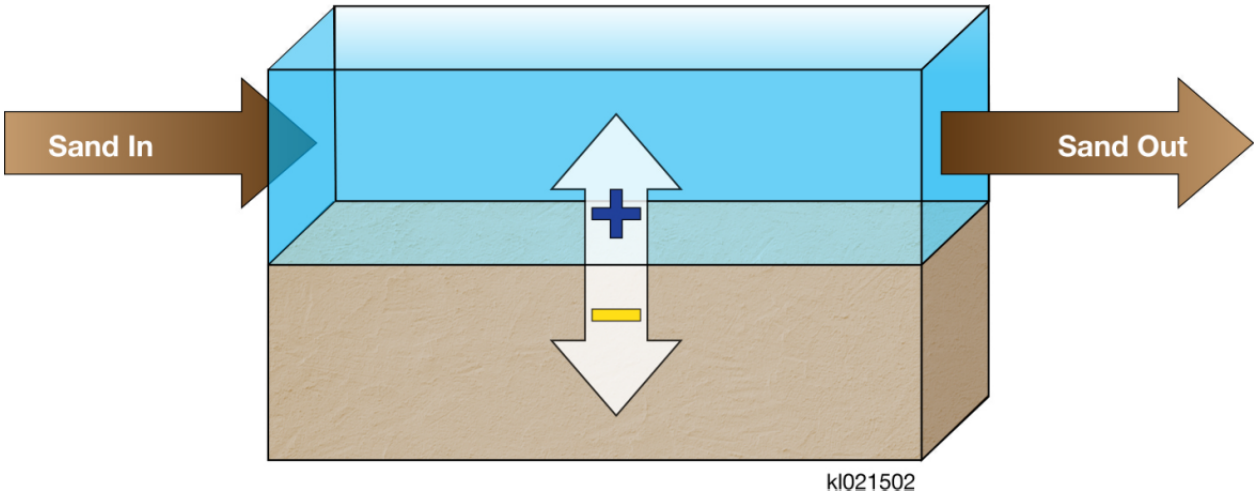

FIGURE E-7 Conceptual Representation of the Sand Mass Balance Index

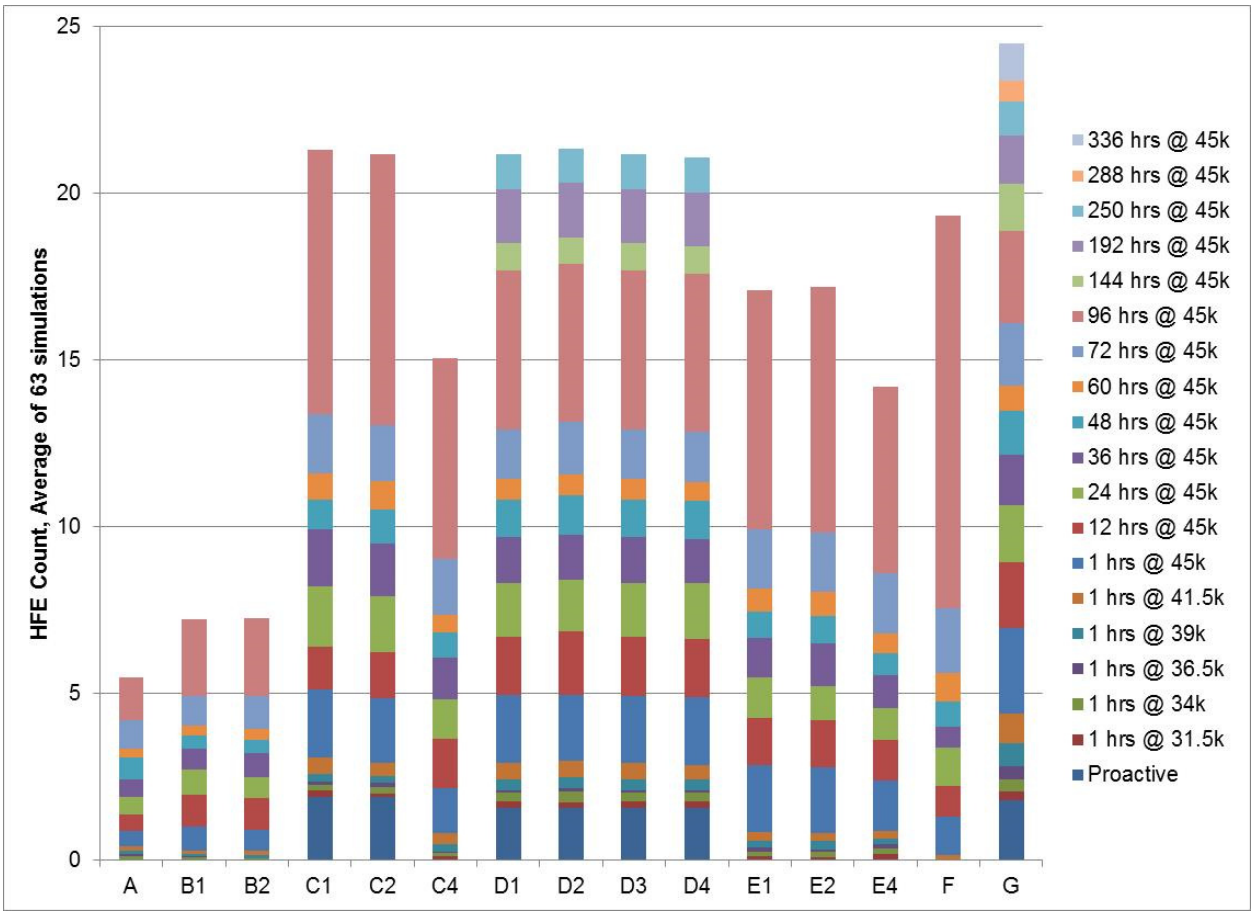

FIGURE E-8 Average Sediment and Hydrology Triggered HFE Count by Type for Each Long-Term Strategy (long-term strategies C3, E3, E5, and E6 by definition have no HFEs)

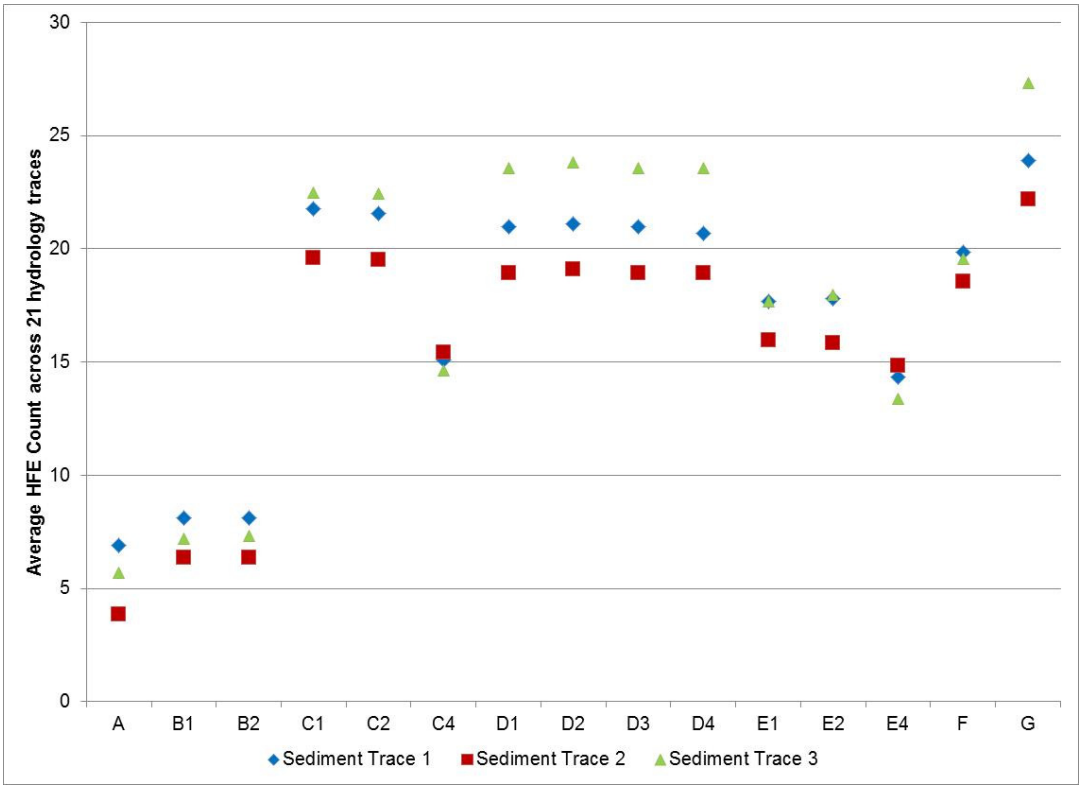

FIGURE E-9 Average HFE Count for Sediment Traces s1, s2, s3 for Each Long-Term Strategy (long-term strategies C3, E3, E5, and E6 by definition have no HFE)

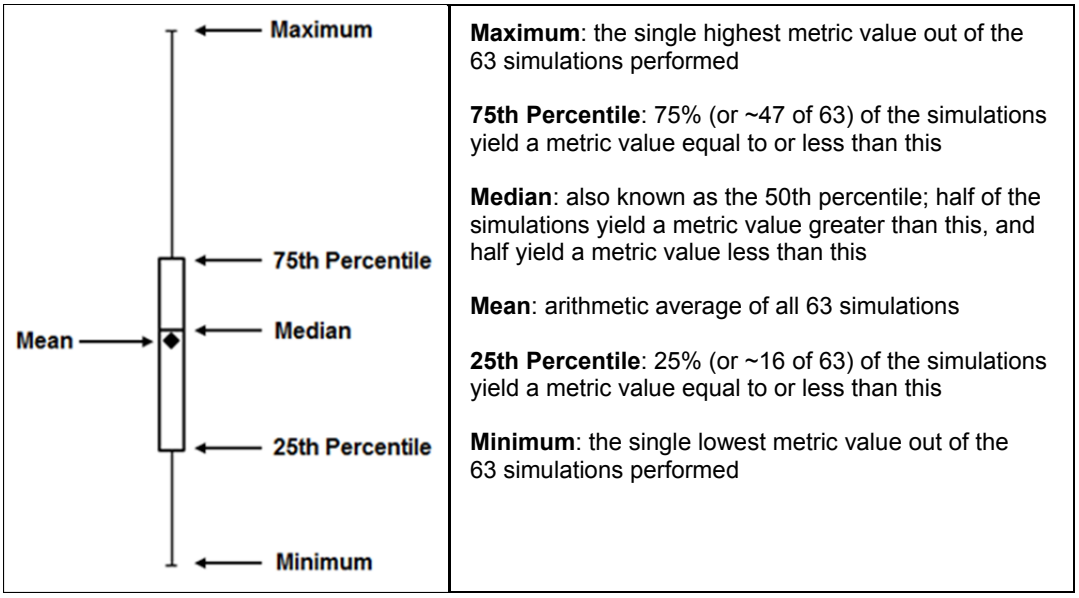

FIGURE E-10 Definition of the Statistics Represented by the Box and Whisker Plots Used in This Analysis

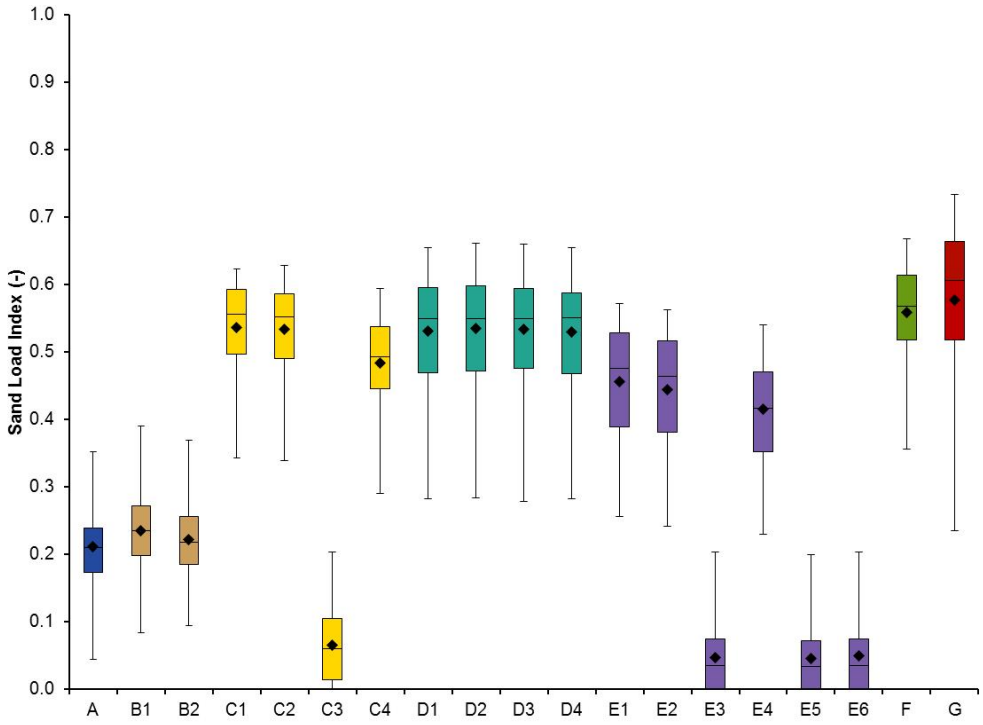

FIGURE E-11 Sand Load Index Statistics from 63 Simulations for Each Long-Term Strategy

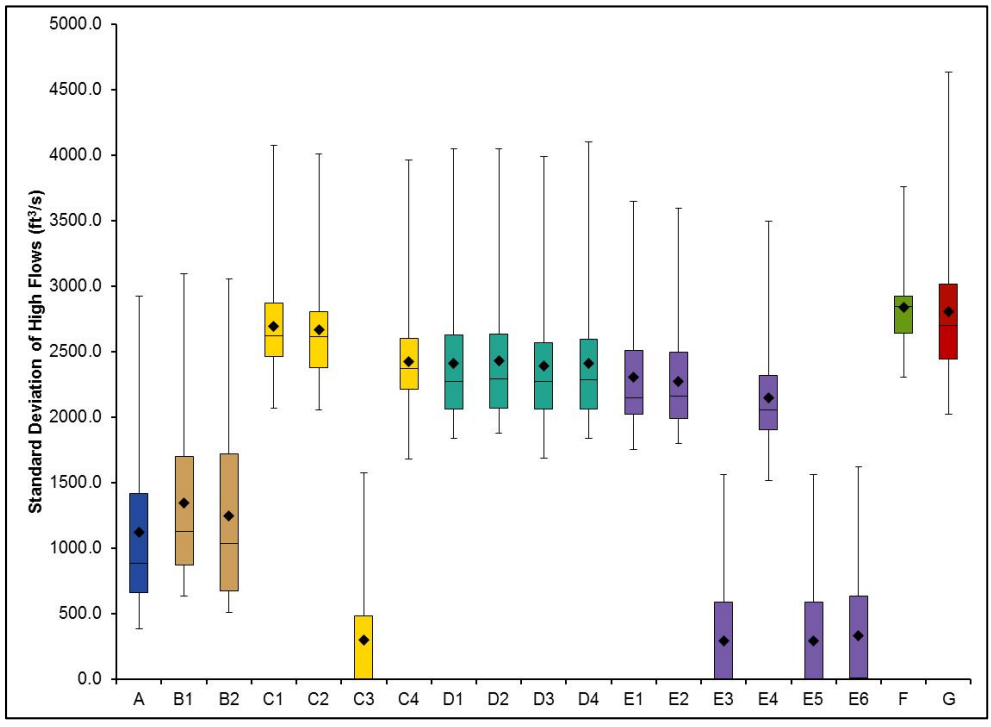

FIGURE E-12 Standard Deviation of High Flows Statistics from 63 Simulations for Each Long-Term Strategy

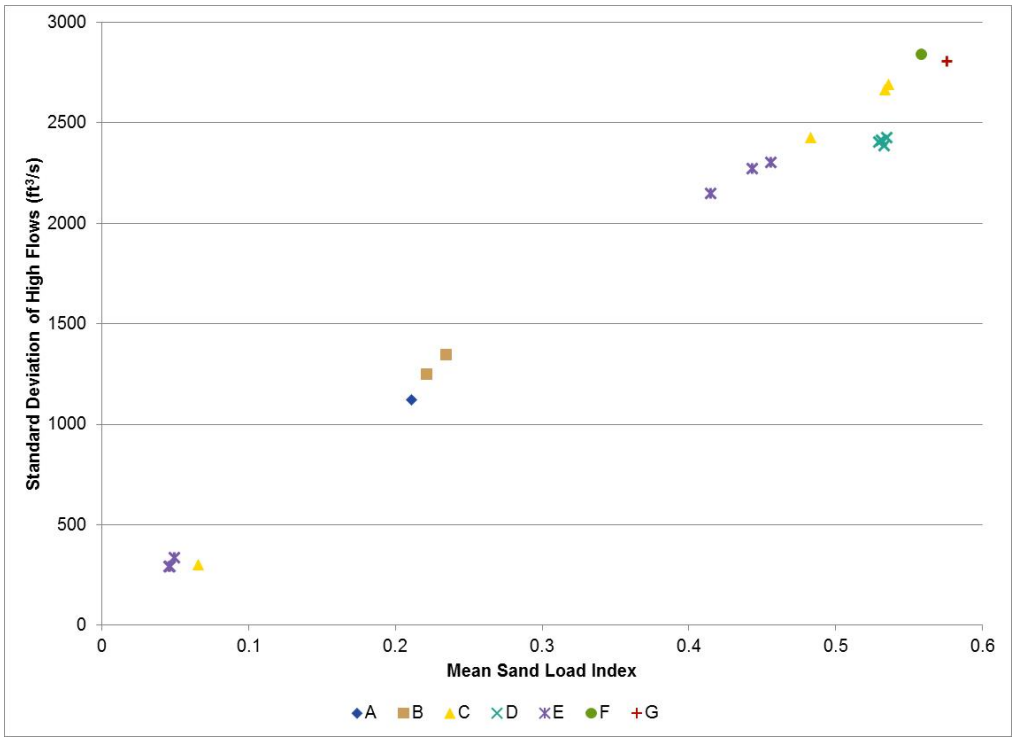

FIGURE E-13 Correlation between SDHF and SLI (r = 0.99, *P* < 0.001)

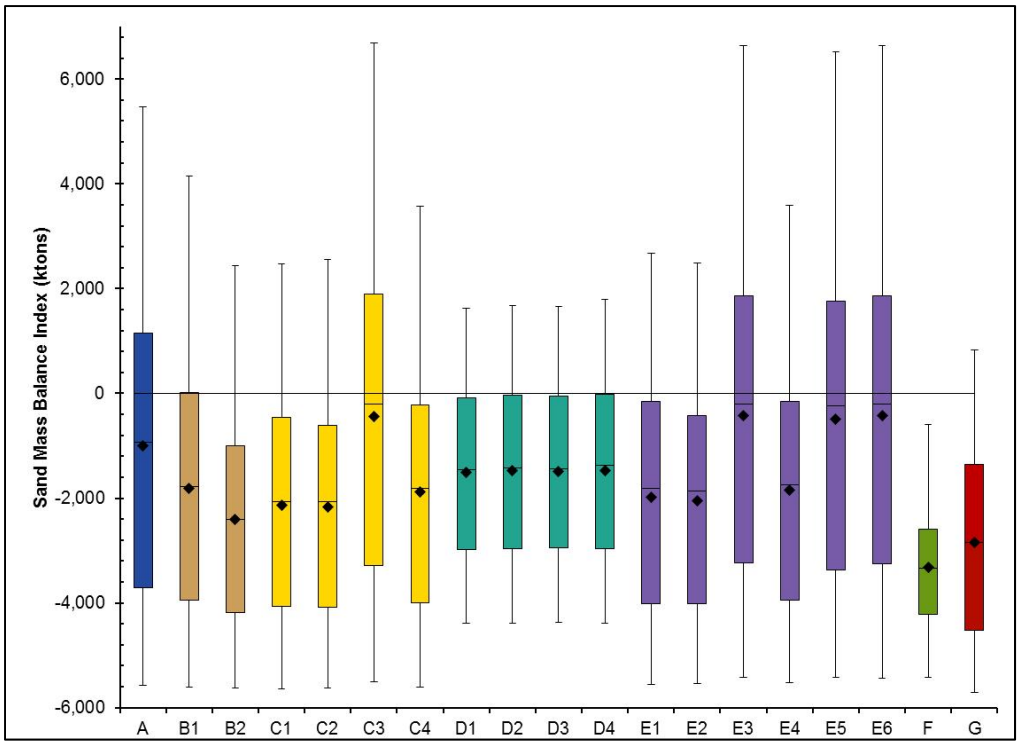

FIGURE E-14 Sand Mass Balance Index Statistics from 63 Simulations for Each Long-Term Strategy

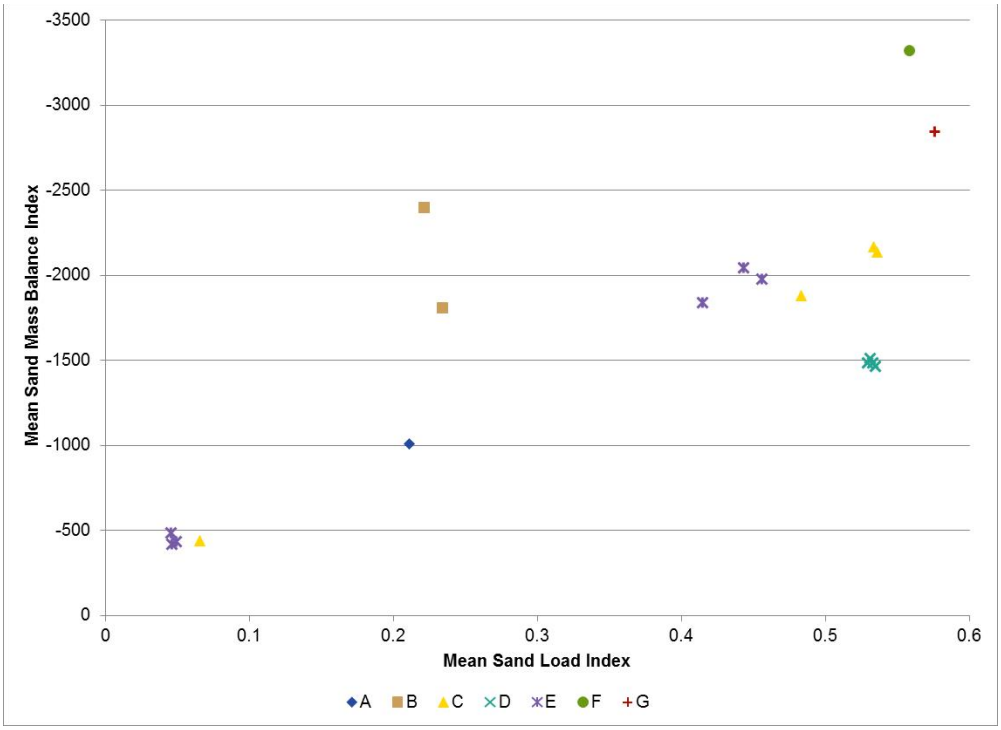

FIGURE E-15 Correlation between SMBI and SLI (r = 0.75, *P* < 0.001) (Note that the *y*-axis values are negative and in reverse order.)

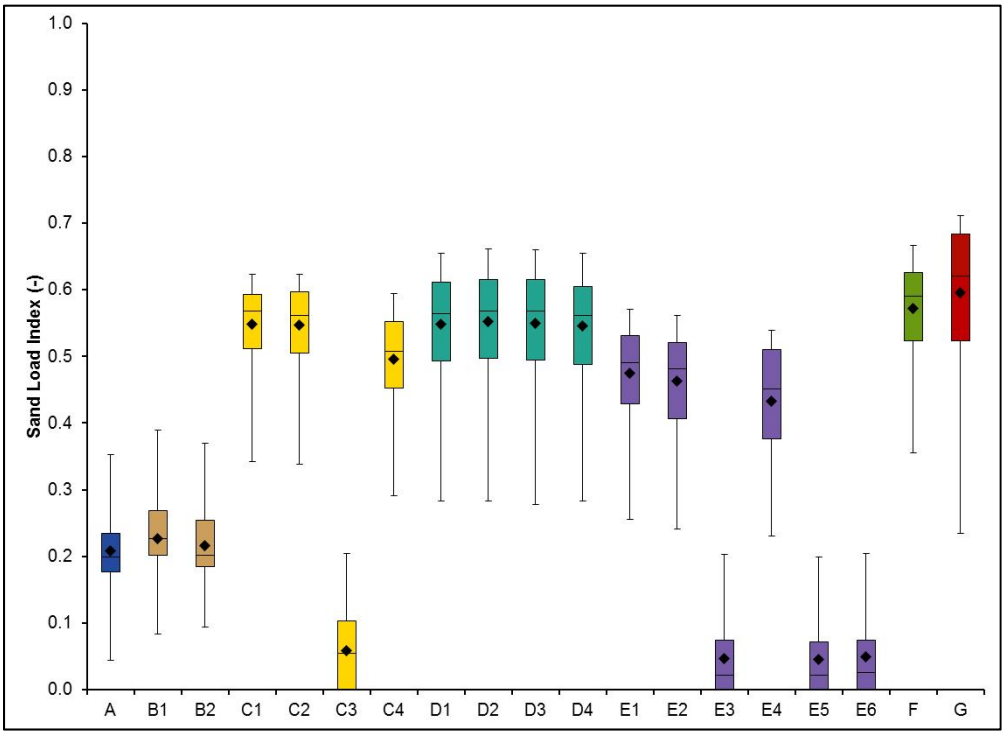

FIGURE E-16 Sand Load Index for Long-Term Strategies Using Climate Change Weights (Compare to Figure E-11, which uses historical weights.)

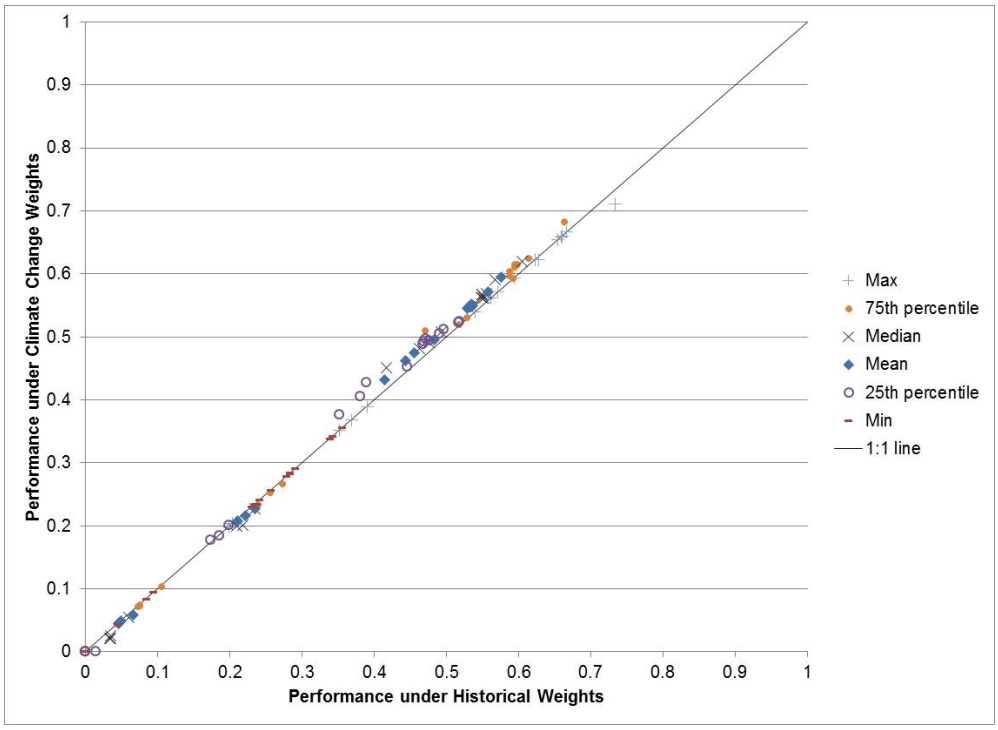

FIGURE E-17 Comparison of the Sand Load Index between Climate Change and Historical Weights

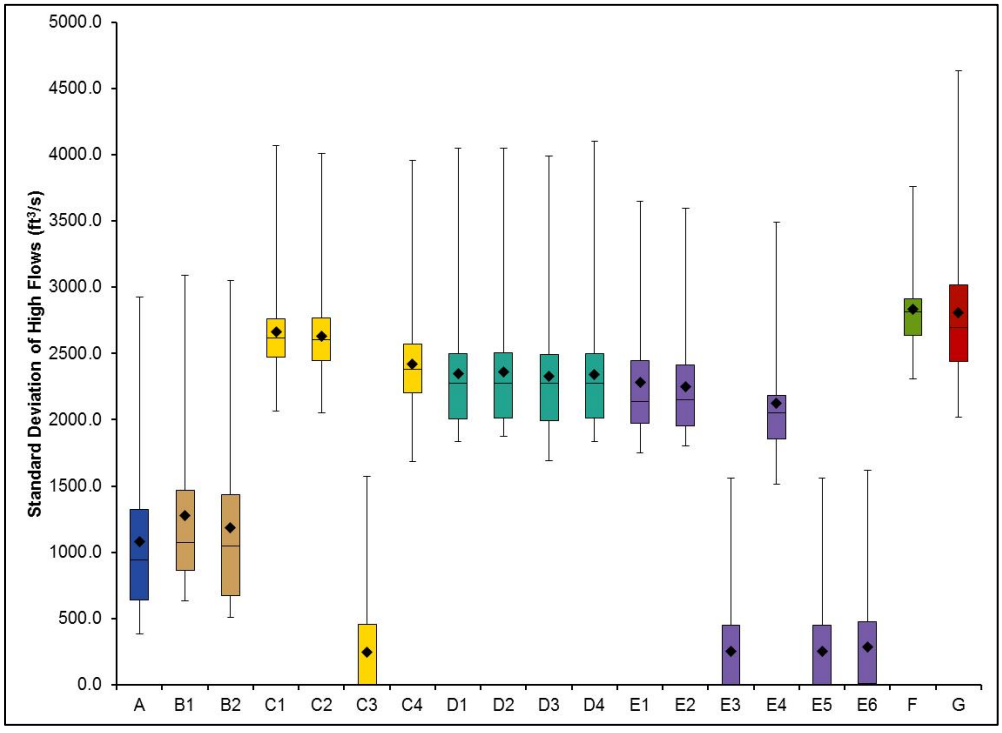

FIGURE E-18 Standard Deviation of High Flows Using Climate Change Weights (Compare to Figure E-12, which uses historical weights.)

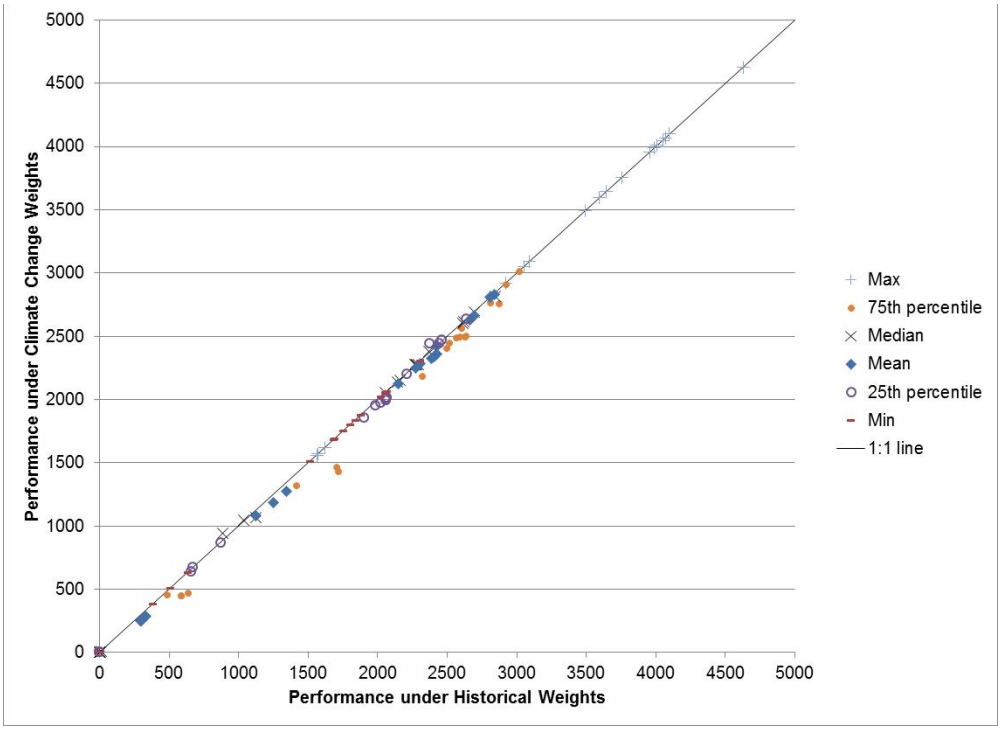

FIGURE E-19 Comparison of the Standard Deviation of High Flows between Climate Change and Historical Weights

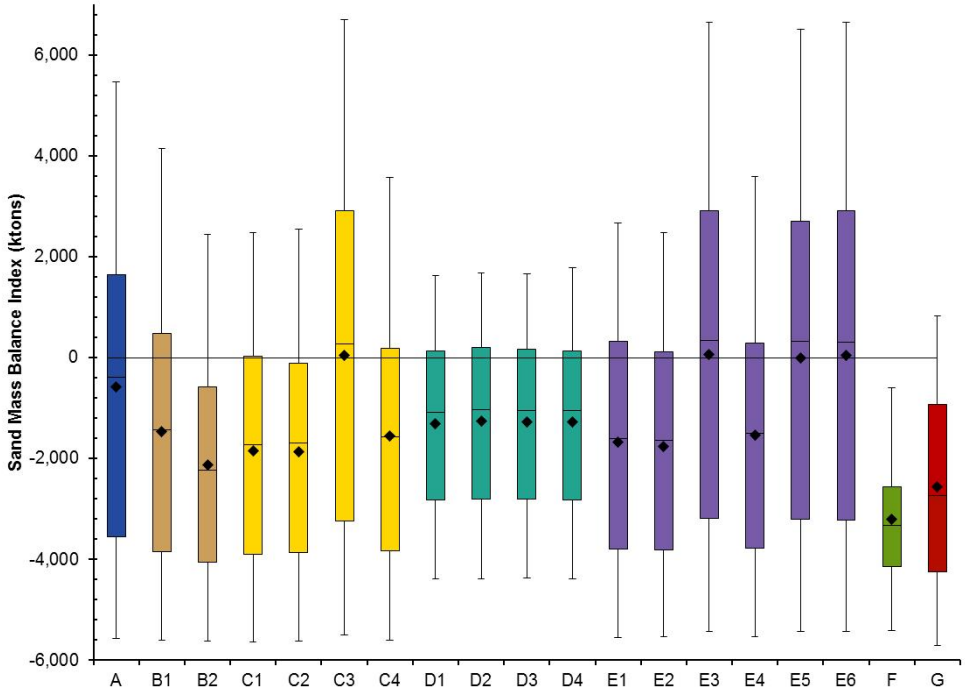

FIGURE E-20 Sand Mass Balance Index Using Climate Change Weights (Compare to Figure E-14, which uses historical weights.)

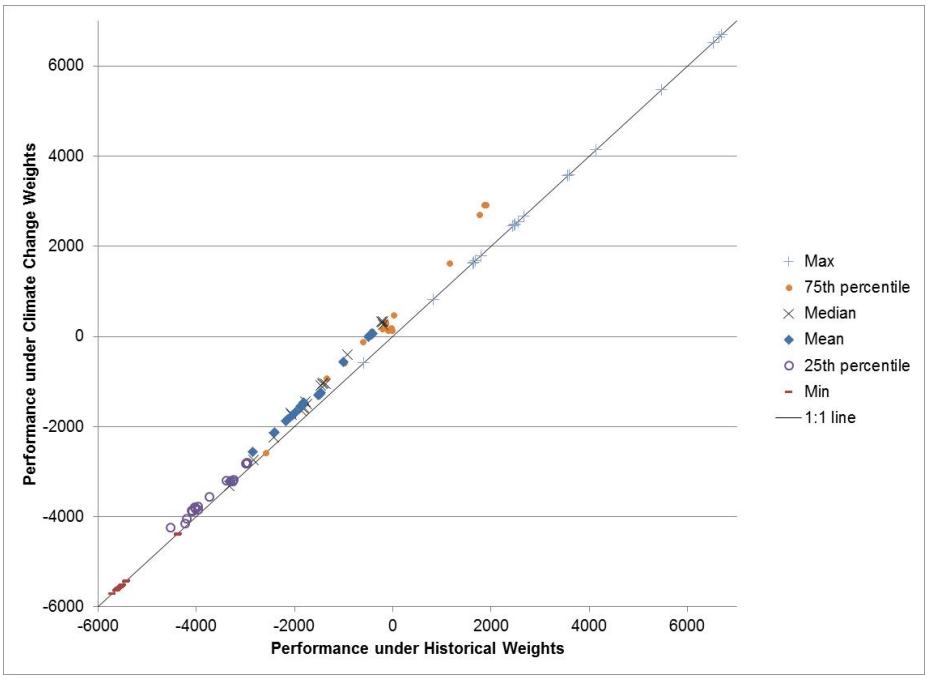

FIGURE E-21 Comparison of the Sand Mass Balance Index between Climate Change and Historical Weights

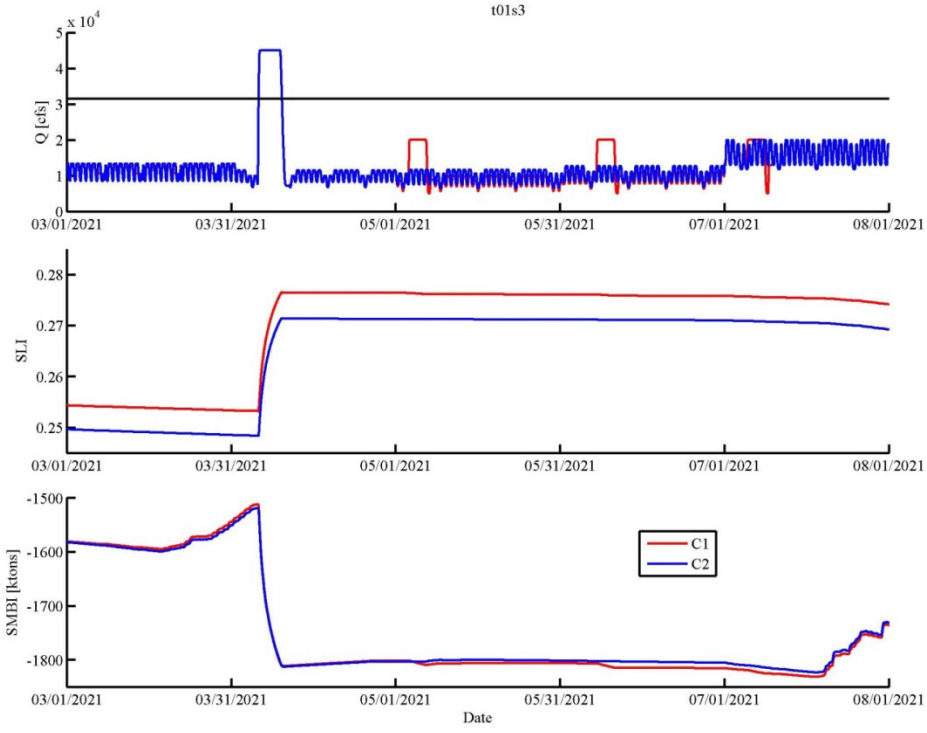

FIGURE E-22 Comparison of Long-Term Strategies C1 and C2 for Hydrology Trace 1, Sediment Trace 3 (TMF flows have very little effect on SLI or SMBI.)

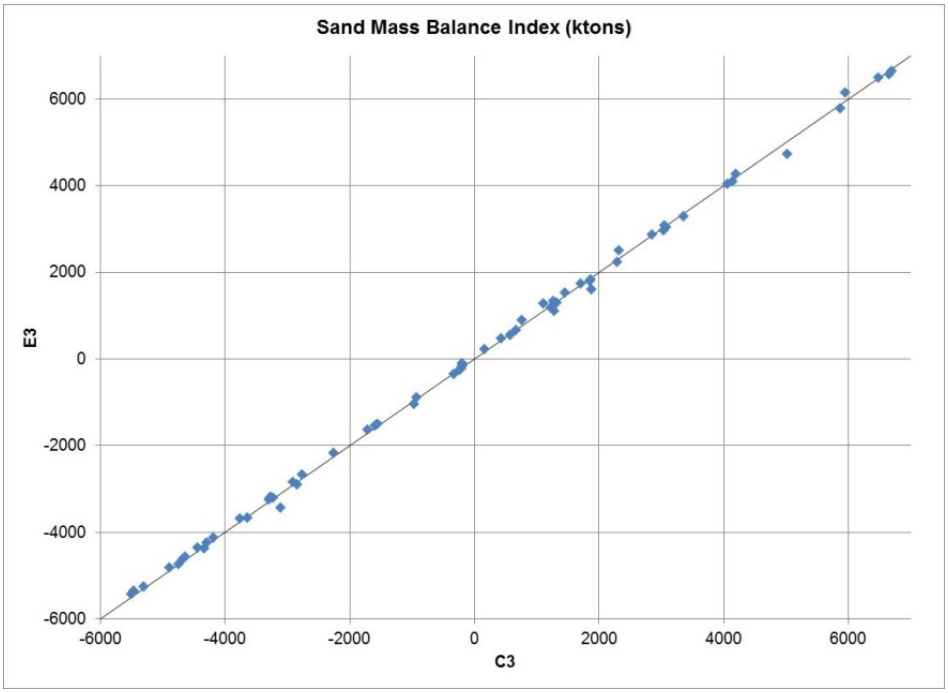

FIGURE E-23 SMBI for Alternative E Plotted against Alternative C (The combination of intervening flows and monthly volumes yields no difference in SMBI.)

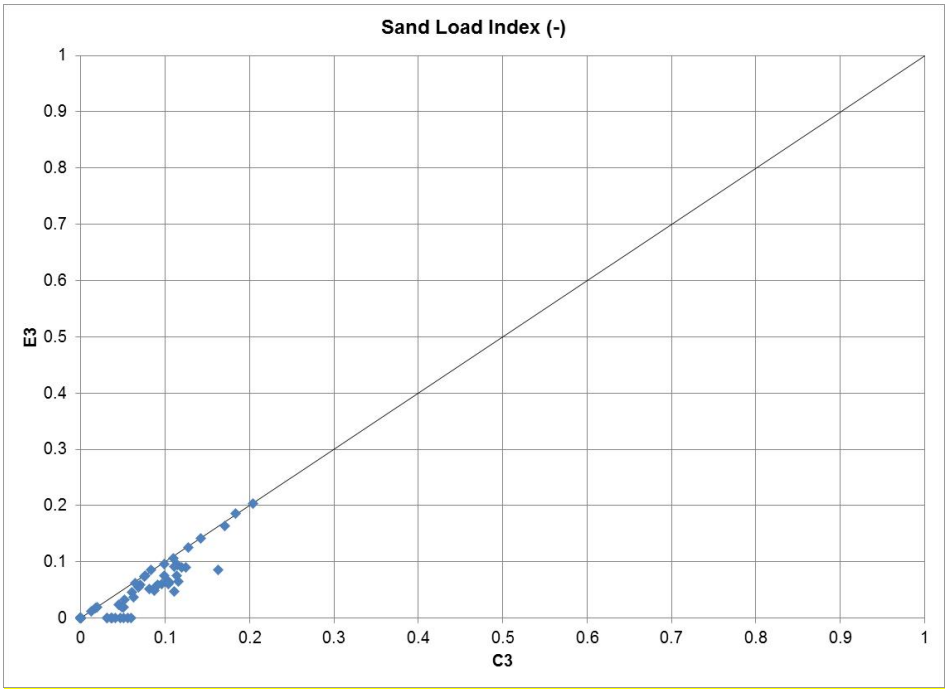

FIGURE E-24 SLI for Alternative E Plotted against Alternative C (The combination of intervening flows and monthly volumes yields small differences in SLI.)

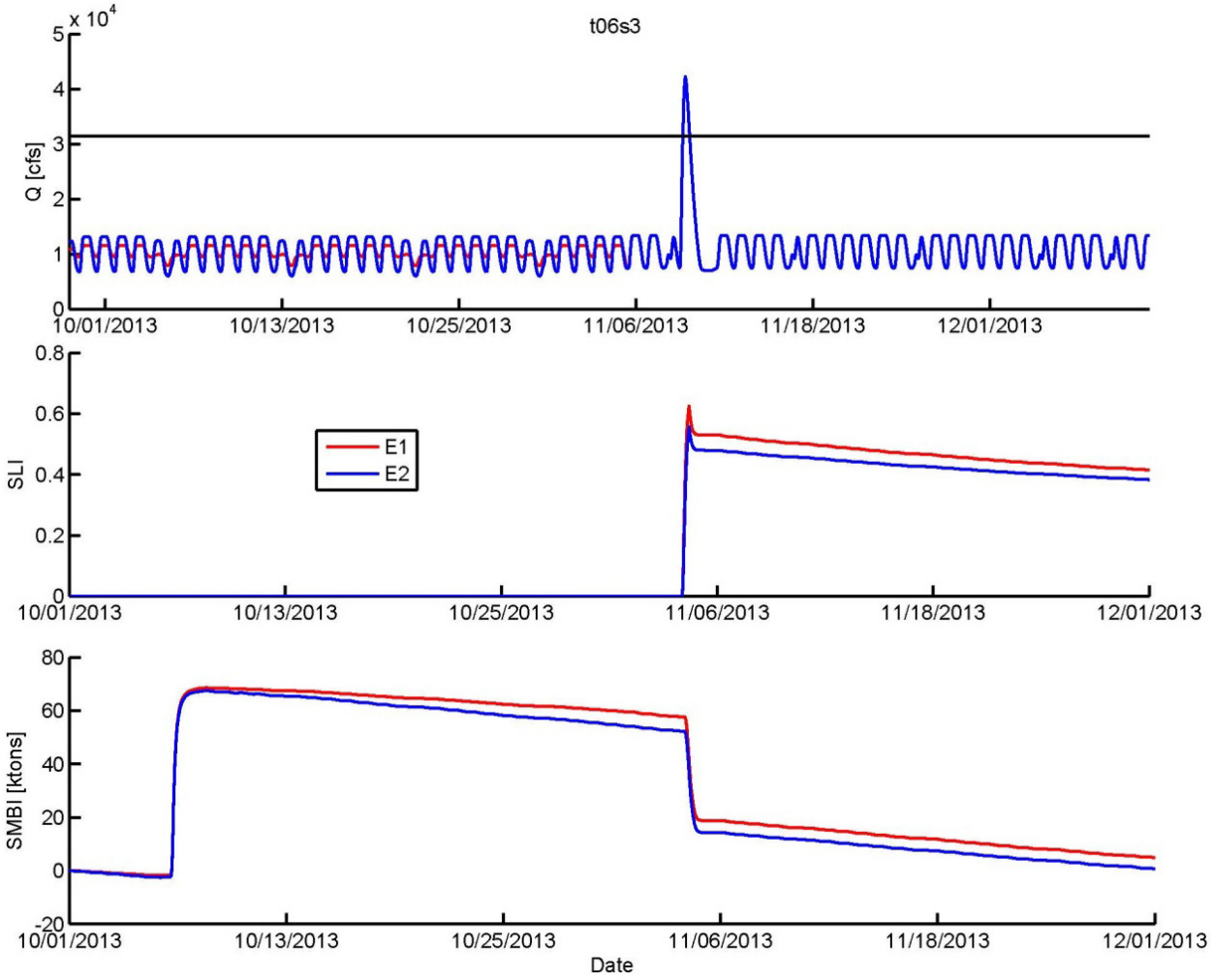

FIGURE E-25 Load-Following Curtailment Effects on SLI and SMBI (Although small effects are noticeable for the month after an HFE, by the end of the calendar year there is no difference in SLI and the difference in SMBI is 9 ktons.)

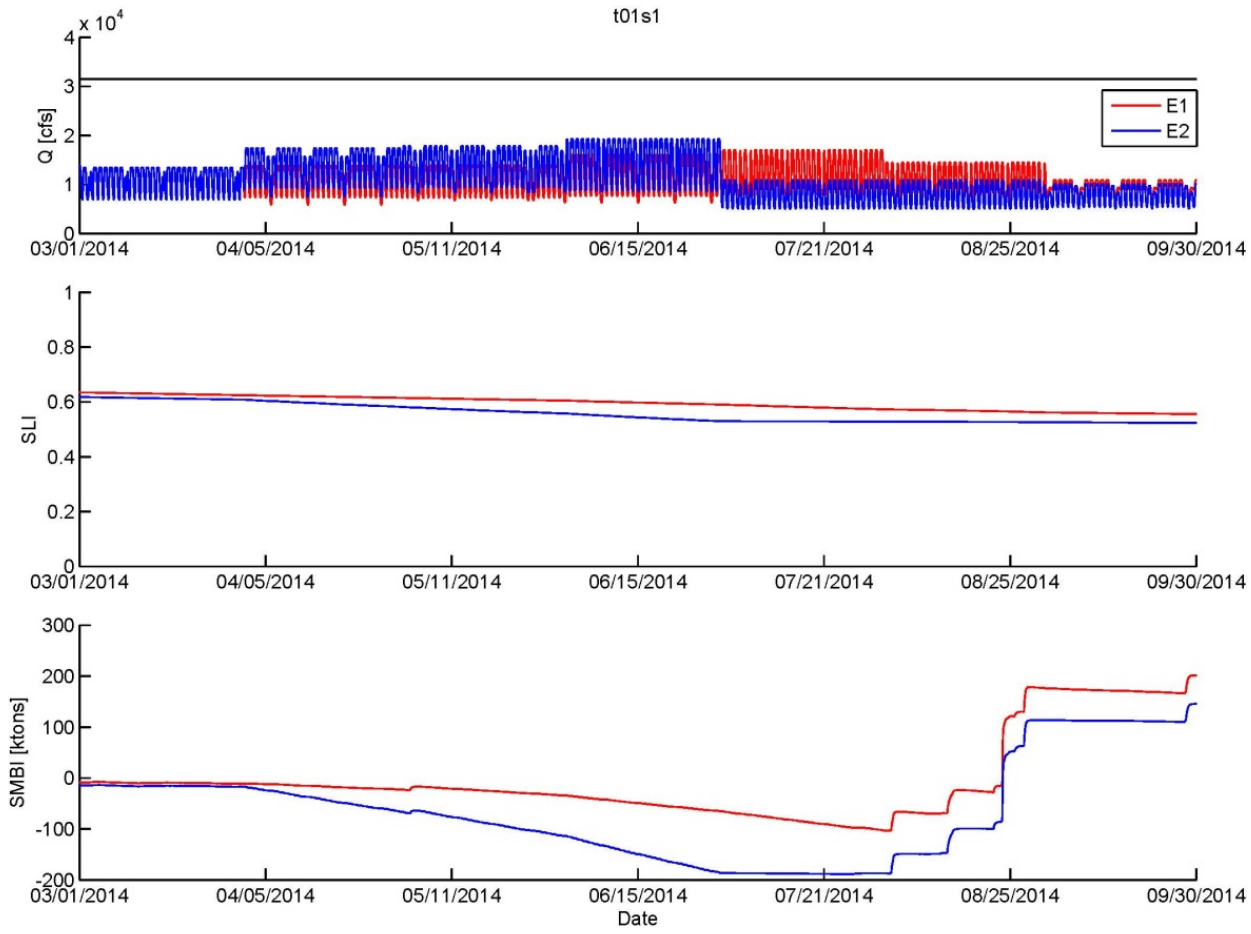

FIGURE E-26 Low Summer Flows for WY 2014, Hydrology Trace 1, Sediment Trace 1 (Long-term strategy E2 has low summer flows starting in July; this necessitates higher flows in April–June. Both SLI and SMBI are higher for alternative strategies without low summer flows [long-term strategy E1] than for those with low summer flows [long-term strategy E2].)

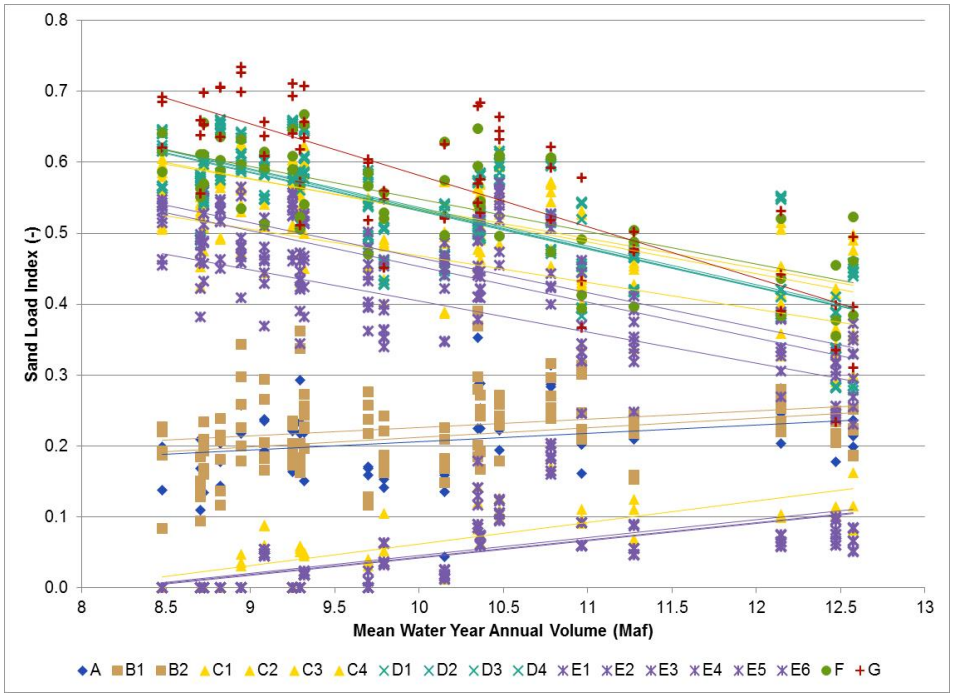

FIGURE E-27 Hydrology Impacts on the Sand Load Index (Wetter hydrological conditions tend to reduce SLI for long-term strategies without defined restriction on the number of HFEs that can be triggered [C1, C2, D1, D2, D3, D4, E1, E2, F, G]. Wetter hydrological conditions tend to increase SLI for long-term strategies with defined restrictions on the number of HFEs that can be triggered [A, B1, B2, C3, C4, E3, E4, E5, E6].)

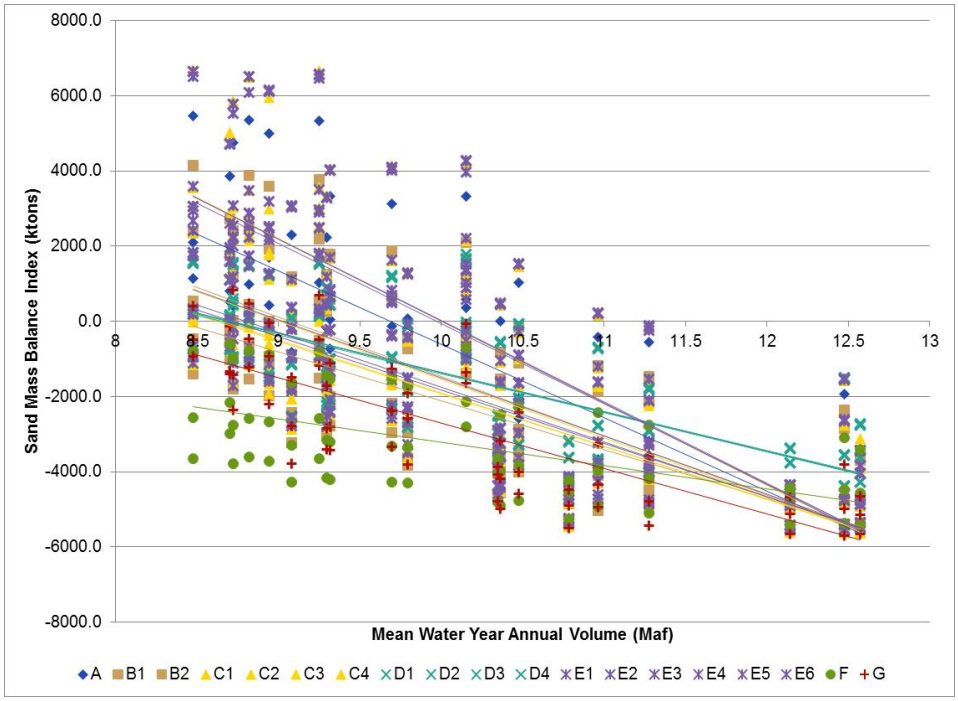

FIGURE E-28 Hydrology Impacts on the Sand Mass Balance Index (Wetter hydrological conditions create lower Sand Mass Balance Index values.)

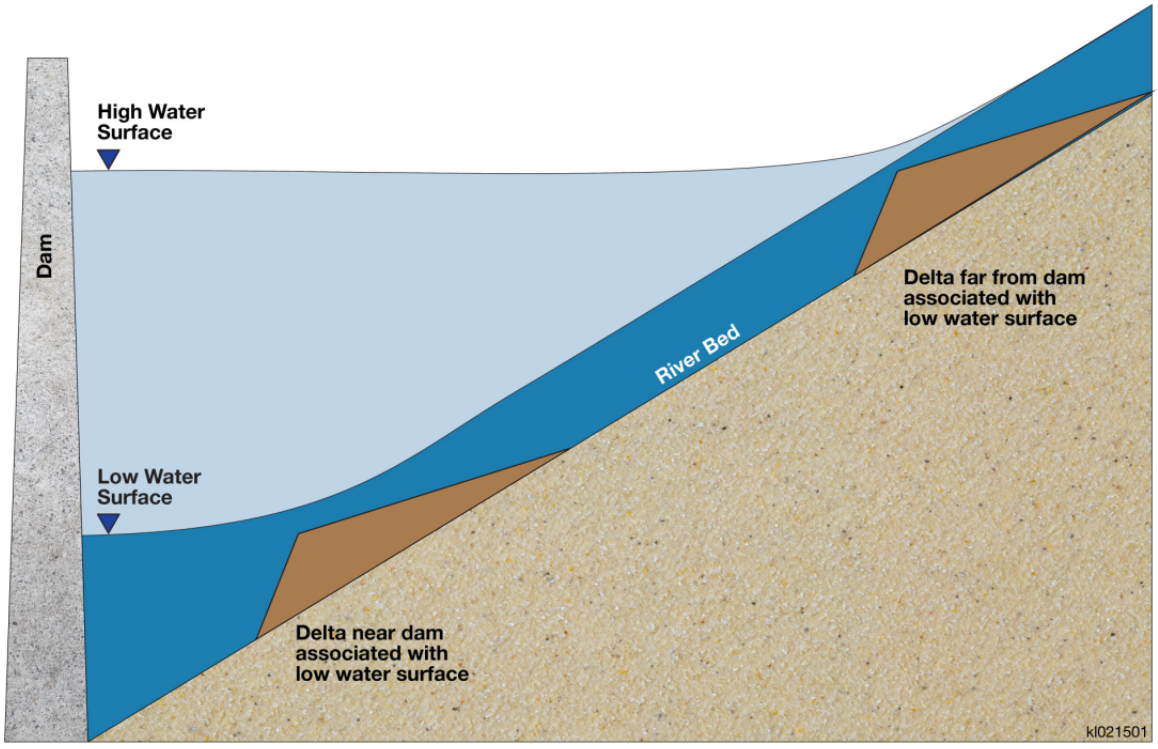

FIGURE E-29 Conceptual Diagram of Water Surface Elevation Affecting Delta Location

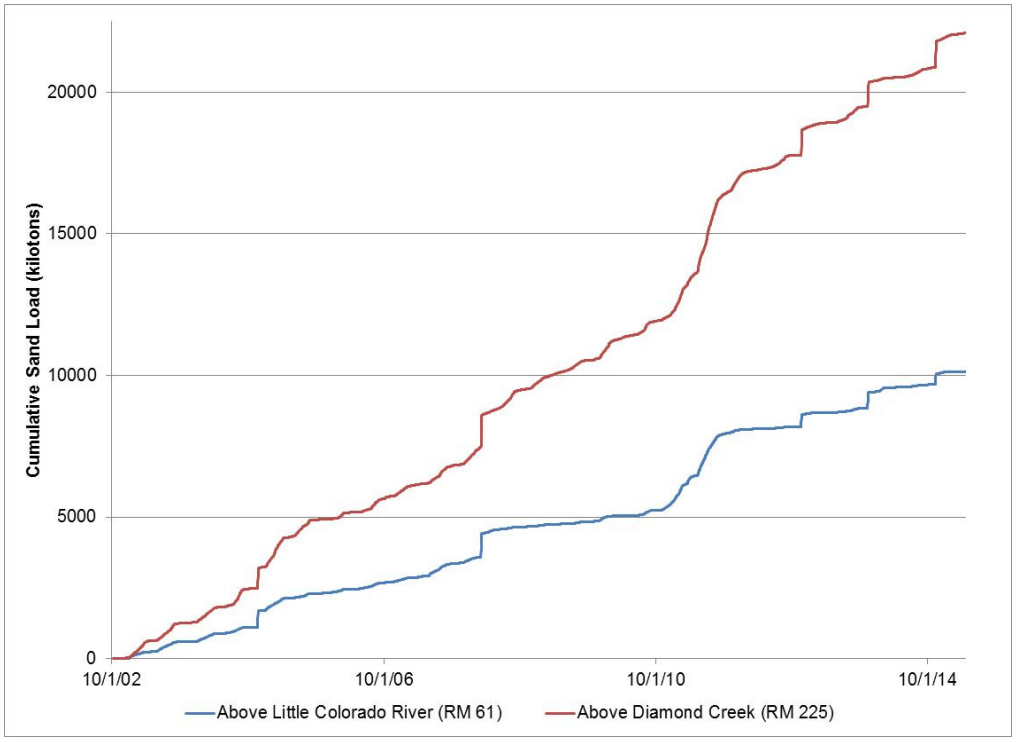

FIGURE E-30 Historical Cumulative Sand Load Leaving Marble Canyon (RM 61) and Reaching the Gage above Diamond Creek (RM 225) (Source: GCMRC 2015)

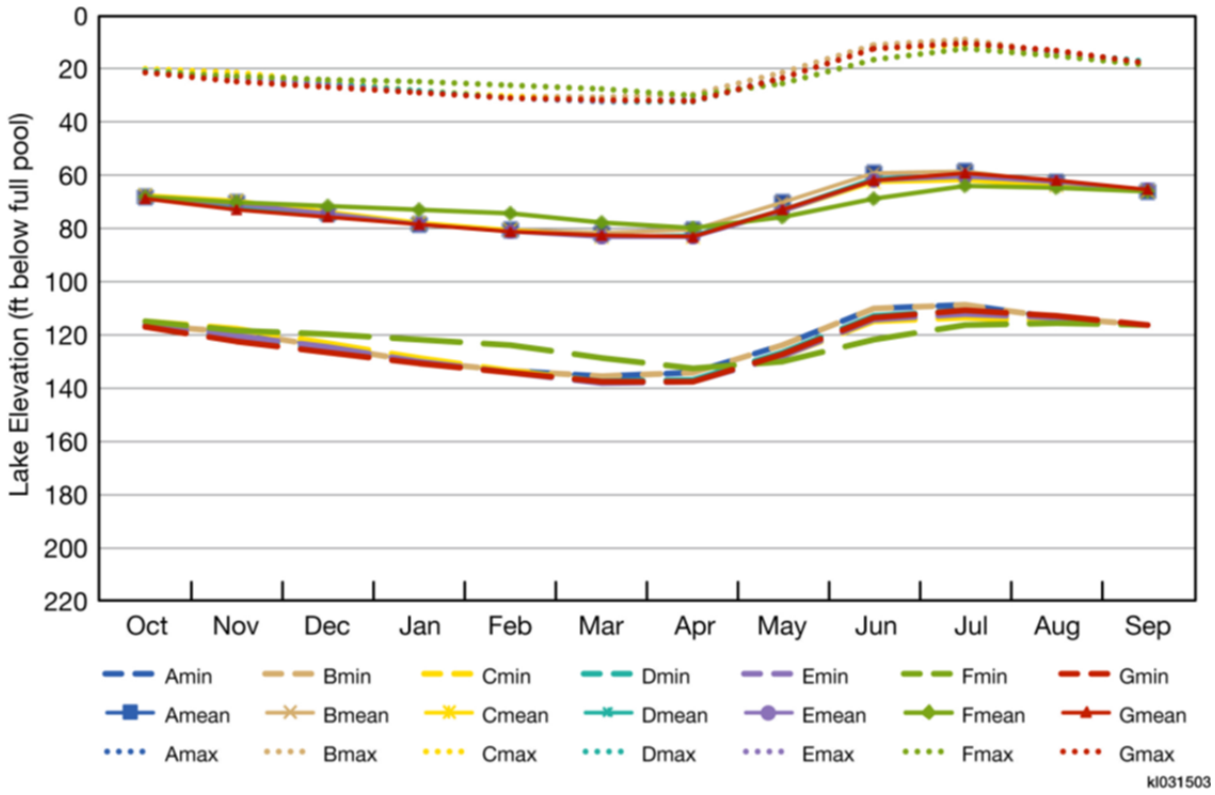

FIGURE E-31 Hydrology Impacts of Lake Powell Pool Elevations by Month across Alternatives

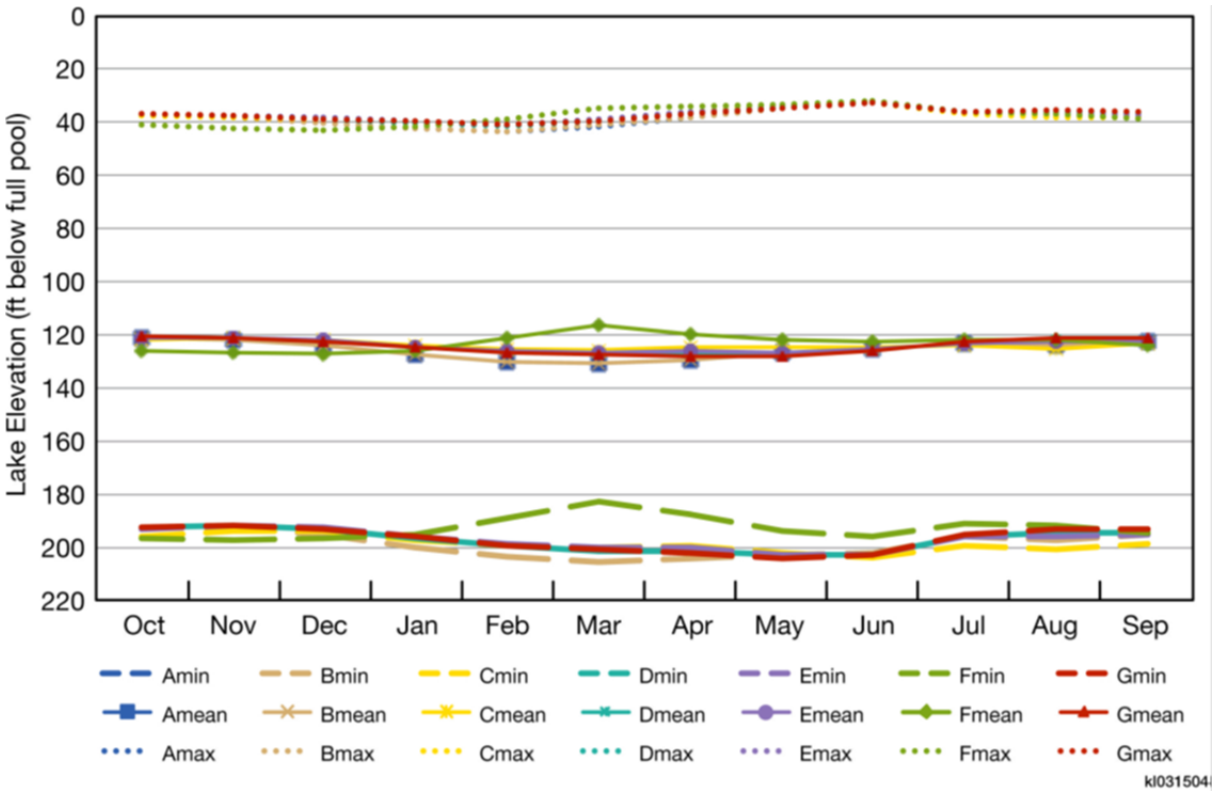

FIGURE E-32 Hydrology Impacts of Lake Mead Pool Elevations by Month across Alternatives

TABLE E-1 Sources for Historical Tributary Sediment Load Data

Tributary	Period of Record, by Source: Topping (2014)	Period of Record, by Source: GCMRC (2015)	Record Length
Paria River	10/1/1963 to 10/1/1996	10/1/1996 to 1/1/2014	50.3 years
Little Colorado River	10/1/1994 to 3/27/2013		18.5 years

TABLE E-2 Historical Periods Used for Paria Sediment Traces s1, s2, and s3

Sediment Trace	Sediment Accounting Periods	Simulation Period
s1	Fall 1981–Fall 2001	1/1/1981–12/31/2001
s2	Fall 1995–Fall 2013 : Spring 1964–Fall 1965	1/1/1995–11/30/2013 : 12/1/1963–12/31/1965
s3	Fall 2011–Fall 2013 : Spring 1964–Fall 1981	1/1/2011–11/30/2013 : 12/1/1963–12/31/1981

TABLE E-3 Historical Periods Used for Little Colorado River Sediment Traces s1, s2, and s3

Sediment Trace	Simulation Period
s1	1/1/1999–12/31/2012 : 1/1/1995–12/31/2001
s2	1/1/2007–12/31/2012 : 1/1/1995–12/31/2009
s3	1/1/2004–12/31/2012 : 1/1/1995–12/31/2006

TABLE E-4 List of HFEs Available for Sediment-Triggered Events (fall and spring)

HFE ID	Peak Discharge (cfs)	Duration at Peak (hours)
A	45,000	336
B	45,000	288
C	45,000	240 (Alternative G) 250 (Alternative D)
D	45,000	192
E	45,000	144
1	45,000	96
2	45,000	72
3	45,000	60
4	45,000	48
5	45,000	36
6	45,000	24
7	45,000	12
8	45,000	1
9	41,500	1
10	39,000	1
11	36,500	1
12	34,000	1
13	31,500	1

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APPENDIX F:

AQUATIC RESOURCES TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX F:

AQUATIC RESOURCES TECHNICAL INFORMATION AND ANALYSIS

F.1 INTRODUCTION

This technical appendix provides information pertaining to analyses of effects on aquatic ecological resources for the Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) Draft Environmental Impact Statement (DEIS), including the aquatic food base, native and nonnative fishes, and fish parasites. It is intended to supplement the information presented in Sections 3.5 and 4.5 of the DEIS.

Methods used to evaluate resources, including modeling methods, are described and results regarding effects of alternatives and associated long-term strategies are presented. Analysis of effects on the aquatic food base is based upon a review of literature pertaining to past studies and extrapolation of those results to qualitatively evaluate effects of alternatives and the associated long-term strategies. The evaluation of impacts on rainbow trout (*Oncorhynchus mykiss*), endangered humpback chub (*Gila cypha*), other native fish, nonnative fish, and fish parasites is based upon reviews of the scientific literature and upon the evaluation of performance metrics that were developed for the LTEMP assessment process. The values for the performance metrics were calculated using models developed to examine effects of alternatives on the various aquatic resources.

The potential effects of six action alternatives are compared to the no action alternative (Alternative A), which describes how the dam is currently operated. Operations under Alternative A employ a release pattern established in the 1996 Record of Decision (ROD) (Reclamation 1996) associated with the 1995 Environmental Impact Statement (EIS) on operations of Glen Canyon Dam (Reclamation 1995). This operational release pattern, referred to as Modified Low Fluctuating Flows, moderated the releases relative to operations practiced in the 1960s through 1980s. As described in Chapter 2 of the DEIS, Alternative A also includes various operational decisions and non-flow actions that have been established since the 1996 ROD.

Some of the alternatives under consideration in the DEIS (especially Alternatives C, D, and E) are complex experimental or adaptive designs. These alternatives prescribe different management interventions depending on resource conditions. Various condition-dependent triggers govern the implementation of experiments. To understand effects of alternatives that incorporate multiple adaptive components, especially components that might be considered experimental, the complex alternatives were decomposed into nineteen versions referred to as long-term strategies, with specific experimental elements included or excluded in each long-term strategy. Table 4.1-1 identifies the experimental elements included in each of the long-term strategies associated with the LTEMP alternatives. Descriptions of each alternative, including the elements included in the long-term strategies, are presented in Sections 2.2 and 4.1 of the DEIS. Modeling to evaluate potential effects on aquatic resources was conducted similarly for each long-term strategy and results were compared using various performance metrics to evaluate how

inclusion of experimental elements as part of an alternative affected the modeled outcome for the resources of concern. As discussed in Section 4.1 of the DEIS, the long-term strategies used to represent the alternatives in Section 4.5 are A, B1, C1, D4, E1, F, and G.

A full range of potential hydrologic and sediment conditions were modeled for a 20-year period (water years 2013–2033) that represented the 20 years of the LTEMP. Twenty-one potential Lake Powell inflow scenarios (known as hydrology traces) for the 20-year LTEMP period were sampled from the 105-year historic record (water years 1906 to 2010) using the Index Sequential Method and selecting every fifth sequence of 20 years. Using this approach, the first 20-year period considered was 1906–1925, the second was 1911–1930, and so forth. As the start of traces reach the end of the historic record, the years needed to complete a 20-year period are obtained by wrapping back to the beginning of the historical record. For instance, the trace beginning in 1996 consists of the years 1996–2010 and 1906–1910, in that order. This method produced 21 hydrology traces for analysis that represented a range of possible conditions from dry to wet.

In addition to these 21 hydrology traces, three 20-year sequences of sediment inputs from the Paria River sediment record (water years 1964–2013) were analyzed that represented low (water years 1982 to 2001), medium (water years 1996 to 1965), and high (water years 2012 to 1981) sediment input conditions. In combination, the 21 hydrology traces and 3 sediment traces resulted in an analysis that considered 63 possible hydrology-sediment conditions for each alternative and long-term strategy.

Section F.2 of this appendix describes analyses conducted to evaluate impacts of alternatives on the aquatic food base. Section F.3 presents methods, results, and conclusions from modeling conducted to evaluate population-level effects of alternatives on rainbow trout and humpback chub. Section F.4 presents methods, results, and conclusions for modeling conducted to evaluate how alternatives would affect the suitability of mainstem water temperatures for sustaining populations of humpback chub and other native fish species, nonnative fish species, and fish parasites.

F.2 AQUATIC FOOD BASE ASSESSMENT

This section provides information on flow and temperature effects of LTEMP alternatives on the aquatic food base. It serves as the basis for descriptions and conclusions provided in Sections 3.5.1 and 4.5 of this DEIS.

F.2.1 Description of the Aquatic Food Base Downstream from Glen Canyon Dam

Determining the impacts of LTEMP alternatives on the aquatic food base requires an evaluation of changes in the aquatic food base from pre-dam years through various post-dam operations, changes in the food base that occur with increasing distance from the dam, and the effects of intentional and unintentional species introductions. The following discussion provides this information and supplements the aquatic food base information presented in Section 3.5.1.

F.2.1.1 The Aquatic Food Base Prior to Construction of Glen Canyon Dam

Prior to the construction of Glen Canyon Dam, the productivity of the Colorado River was low due to scouring and high turbidity levels that limited the colonization and growth of benthic macroalgae and invertebrates (Woodbury 1959; Stevens et al. 1997; Ward et al. 1986). Generally, the more productive habitats for algae and invertebrates occurred at the lower edge of deltas formed at the mouths of tributaries, on and behind boulders, and on woody debris carried by flood waters (Woodbury 1959). A pre-dam survey of 171 mi of the Colorado River between Dirty Devil River, Utah, and Lees Ferry, Arizona (collections made along the banks of the Colorado River and in tributaries or side canyons), included 28 species of green algae, 5 species of cyanobacteria, 20 species of diatoms, and 91 species of insects including mayflies, dragonflies, true bugs, fishflies, caddisflies, aquatic snout moths, beetles, and true flies (Woodbury 1959). Sixteen insect species were collected from sites along the river bank while 77 species were collected from tributary streams. From a sample of fish stomachs, it appeared that organisms derived from tributaries and terrestrial habitats played an important role in the diet of river fishes (Woodbury 1959). Pre-dam reports of invasive aquatic food base species in the Grand Canyon are limited. In 1932, 50,000 amphipods (*Gammarus lacustris*) were introduced into Bright Angel Creek. They apparently washed into the mainstem of the Colorado River where they became abundant (Carothers and Minckley 1981), particularly within the Glen Canyon reach, where they are associated with *Cladophora* beds (Blinn and Cole 1991; Blinn et al. 1992; Hardwick et al. 1992).

Stanford and Ward (1986) suggested that the lower Green and Colorado Rivers in Canyonlands National Park, Utah, may provide the best examples of the pre-regulated Colorado River, as these reaches retain similar hydrographs to pre-dam conditions and are the farthest downstream from the large dams in the upper Colorado River basin. High suspended sediment concentrations limited the growth of primary producers; thus, the primary carbon source for benthic invertebrates was terrestrial organic matter. The invertebrate community was composed of 49 taxa, mostly mayflies, caddisflies, and true flies. Stoneflies and dragonflies comprised a smaller portion of the community (Haden et al. 2003).

F.2.1.2 The Aquatic Food Base of the Colorado River Downstream from Glen Canyon Dam

Section 3.5.1 of the DEIS provides an overview of the aquatic food base of the mainstem of the Colorado River following installation of Glen Canyon Dam. The following supplements that information. Glen Canyon Dam altered the primary carbon source from terrestrial (e.g., leaf litter) to aquatic (e.g., algae and detritus), the temperature regime from seasonally warm to stenothermically cool, and discharge patterns from low daily variations to high daily variations (Benenati et al. 2002). Nevertheless, riparian and upland vegetation still contribute energy to the impounded river system, particularly during flood events (Blinn et al. 1998, 1999). The large quantity of driftwood that occurred in the pre-dam river is now replaced by lower quantities of woody debris derived from tributaries during floods, or from occasional scouring flows of the vegetated post-dam shoreline (Stevens et al. 1997). Benthic detrital standing mass is generally low and variable, increasing through the more turbid downstream reaches (Shannon et al. 1996).

The Paria and Little Colorado Rivers, the primary sediment delivery systems downstream from Glen Canyon Dam, divide the Colorado River into three distinct turbidity zones that have a significant impact on mainstem aquatic food base communities (Stevens et al. 1997). The first 16 mi downstream from Glen Canyon Dam account for 60% of the total phytobenthic standing biomass throughout the remaining 242 mi of the river corridor (Blinn et al. 1995). Algae production decreases from Glen to Marble Canyon and is even lower in the Grand Canyon (Hall et al. 2010) because of the increasing suspended sediment loads that reduced light availability (Kennedy et al. 2013). *Cladophora* grows best in continuously submerged clear-water stable habitats, whereas *Oscillatoria* forms dense mat-like matrices of filaments and sand in the varial zone and other habitats with high suspended sediments that are more typical of many southwestern streams (Shaver et al. 1997).

Oscillatoria tends to colonize relatively early in disturbed or newly inundated zones, while colonization by *Cladophora* is reduced or occurs more slowly (McKinney et al. 1997). As *Oscillatoria* supports ten-fold fewer invertebrates than *Cladophora*, the input of terrestrially derived carbon has become vital to support the aquatic food base organisms. However, the leaves of the common nonnative *Tamarix ramosissima* along the river are an inferior food source for macroinvertebrates due to their high tannin content and slower decomposition rate compared to leaves of native cottonwoods and willows (Bailey et al. 2001).

Zooplankton is an important food resource for larval and juvenile native fish in the Colorado River system. The zooplankton found in regulated rivers is composed of both plankton derived from the reservoir (lentic species) and those derived from the streambed, backwaters, and tributaries of the river (lotic species) (Haury 1986). Lotic zooplankton and detritus are positively correlated with distance downriver from Glen Canyon Dam, increased discharge, and near-shore versus mid-channel locations. Lentic zooplankton abundance also increases at higher discharges and in near-shore habitats but are negatively correlated with distance downriver. It is possible that lentic zooplankton cannot survive and reproduce under the cold temperatures in the mainstem, although near-shore habitats provide a more stable environment than the mainstem, which may enhance rearing and development of lentic zooplankton (Benenati et al. 2001). Copepods are the most abundant zooplankton species in the Colorado River (AZGFD 1996). The biomass, productivity, and abundance of zooplankton (cladocerans, copepods, and ostracods originating primarily from Lake Powell) are highest in the Glen Canyon reach and drop sharply downstream (Tables F-2 through F-4).

There is evidence that Lake Powell zooplankton can survive downstream passage to Diamond Creek with only a small mortality rate due to abrasion. Thus, the zooplankton derived from Lake Powell has the potential of contributing to the aquatic food base throughout the river system to Lake Mead (Haury 1986). However, the Colorado River between Lake Powell and Lake Mead has a highly constricted channel and for the most part lacks backwaters of any significant area, which may account for the limited importance of zooplankton drift in the river (Blinn et al. 1995). Zooplankton may also have an affinity for *Cladophora* and other algae in the Glen Canyon reach, and are consumed by macroinvertebrates and fish in that reach (Benenati et al. 2001). These factors may also account for the diminished importance of zooplankton in the Marble and Grand Canyon reaches.

Generally, the responses of macroinvertebrates downstream of dams depend largely on the depth of the reservoir, the depth from which water is drawn, and on the ratio of low to high discharges (Jones 2013). Information on macroinvertebrates collected before and after closure of the Flaming Gorge Dam on the Green River in northeastern Utah is applicable to events that may have occurred in the Colorado River below Glen Canyon Dam (Blinn and Cole 1991; Pearson et al. 1968). Following closure of the Flaming Gorge Dam, macroinvertebrate genera declined from >70 to <30, while the mean macroinvertebrate abundance increased from 1,000 to 10,000/m^2 (Vinson 2001). Mayflies declined from 30 species to a single common species and two rare species. Midges and blackflies were the only other common post-dam insect taxa (Vinson 2001). Colonization of tailwaters by insects can be somewhat limited by lack of drift and small downstream insect population sizes that may limit recruitment from upstream flying adults (Vinson 2001).

River regulation by Glen Canyon Dam decreases turbidity in the tailwaters and permits increased algae growth on bottom substrates (Angradi 1994; Shannon et al. 1994), leading to an increased expansion of macroinvertebrate populations in the tailwater reach of Glen Canyon Dam (Blinn et al. 1992; Stevens et al. 1997). Algae biomass and production decrease downstream as water clarity decreases (Carothers and Brown 1991; Stevens et al. 1997; Hall et al. 2010). As is evident in Table F-1, this drives a downstream decrease in aquatic invertebrate biomass (e.g., *Gammarus*, midges, snails, and aquatic worms) (Carothers and Brown 1991; Stevens et al. 1997; Kennedy and Gloss 2005; Rosi-Marshall et al. 2010).

Various studies in the 1990s demonstrated that over 80% of the invertebrate biomass below Glen Canyon Dam was composed of *Gammarus*, midges, aquatic worms, and snails, many of which graze on epiphytes and other fine particulate matter (Blinn et al. 1998). Predation on insect eggs (e.g., by *Gammarus*) may contribute to the absence of mayflies and stoneflies below dams (Vinson 2001). In Glen Canyon, blackflies and midges support more than half of rainbow trout (*Oncorhynchus mykiss*) production but represent under 10% of total invertebrate production and abundance (Tables F-3 and F-4) (Kennedy et al. 2013). Midges and blackflies dominate invertebrate production in Marble and Grand Canyons (Table F-2); cobble bars are "hotspots" for midge and blackfly production (e.g., 2 to 10 times higher than other habitat types) (Kennedy et al. 2013). New Zealand mudsnails (*Potamopyrgus antipodarum*), *Gammarus*, aquatic worms, and midges dominate the current composition of the benthic community at Lees Ferry (Table F-3). In cobble substrates, New Zealand mudsnails and aquatic worms dominate the benthic biomass. They also dominate depositional habitats, although these areas tend to support lower benthic biomass (Cross et al. 2013). *Gammarus* dominates talus slopes and cliff faces, but these habitats generally have the lowest benthic biomass in the Lees Ferry reach. Blackflies (*Simulium arcticum*) are present in the Lees Ferry reach, but their biomass and abundance are generally low (Tables F-2 and F-4).

The absence of leaf litter and woody debris is probably largely responsible for the decreased biodiversity and density of invertebrates the Colorado River downstream from the Paria River (Purdy 2005). Clear and cool stenothermic releases and highly variable discharges from the dam and seasonal turbidity from tributary inputs also adversely impact macroinvertebrates (Shannon et al. 2001). The decrease in stream clarity lowers primary production and favors the growth of the less nutritious *Oscillatoria* in the lower reaches of the

TABLE F-1 Average Mean Habitat-Weighted Invertebrate Biomass at Select Sites in the Colorado River, July 2006–June 2009

Taxon	Habitat-Weighted Biomass (mg AFDM/m^2)[a]					
	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6
Acari (water mite)	<1	1	<1	<1	1	<1
Blephariceridae (net-winged midge)	0	0	0	2	<1	0
Ceratopogonidae (biting midge)	<1	<1	0	<1	<1	<1
Chironomidae (midge or chironomid)	163	113	58	30	43	45
Cladocera (water flea)	5	<1	<1	0	<1	0
Collembola (springtail)	0	<1	0	0	<1	0
Copepoda (copepod)	4	<1	<1	<1	<1	<1
Corixidae (water boatman)	0	0	0	<1	<1	0
Elmidae (riffle beetle)	0	<1	<1	6	3	3
Empididae (dagger or balloon fly)	0	<1	2	<1	1	<1
Ephemeroptera (mayfly)	0	0	0	0	<1	0
Gammarus (scud)	1,053	30	5	2	3	5
Hydropsychidae (net-spinning caddisfly)	0	0	2	3	2	<1
Hydroptilidae (microcaddisfly)	0	16	30	0	8	9
Molophilus (crane fly)	0	0	0	<1	<1	0
Nematoda (roundworm)	15	13	2	<1	<1	<1
New Zealand mudsnail	3,170	45	3	35	8	7
Oligochaetes (earthworm/bloodworm)	2,077	218	65	28	42	25
Ostracoda (seed shrimp)	25	<1	0	<1	<1	0
Physidae (bladder snail)	122	<1	0	1	<1	<1
Planariidae (planarian or flatworm)	114	9	<1	<1	<1	<1
Pyralidae (snout moth)	0	<1	0	<1	<1	3
Rhyacophilidae (free-living caddisfly)	0	42	0	0	<1	0
Simuliidae (blackfly)	100	858	35	50	49	44
Sphaeriidae (pea or fingernail clam)	14	<1	0	0	0	0
Zygoptera (damselfly)	0	0	0	0	<1	0
Total	6,862	1,345	202	155	160	141

[a] AFDM = ash-free dry mass. Site 1 is 16 mi downstream of Glen Canyon Dam (GCD, upstream of Paria River confluence), Site 2 is 45 mi downstream of GCD (downstream of Little Colorado River confluence), Site 3 is 78 mi downstream of GCD, Site 4 is 142 mi downstream of GCD, Site 5 is 180 mi downstream of GCD, and Site 6 is 240 mi downstream of GCD (upstream of Diamond Creek confluence).

[b] Biomass values <0.1 mg AFDM/m^2 for a taxon not included in total productivity value.

Source: Cross et al. (2011, 2013).

TABLE F-2 Average Mean Habitat-Weighted Invertebrate Production at Select Sites in the Colorado River, July 2006–June 2009

Taxon	Habitat-Weighted Productivity (mg AFDM/m^2/yr)[a]					
	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6
Acari (water mite)	0.3	5.0	4.9	3.7	7.0	4.5
Blephariceridae (net-winged midge)	0.0	0.0	0.0	12.4	1.6	0.0
Ceratopogonidae (biting midge)	0.3	4.1	1.4	0.2	1.1	3.6
Chironomidae (midge or chironomid)	717.6	1,103.2	549.0	437.8	634.6	575.7
Cladocera (water flea)	45.2	0.3	<0.1	0.0	<0.1	0.0
Collembola (springtail)	0.0	<0. 1	0.0	0.0	<0.1	0.0
Copepoda (copepod)	33.8	2.2	0.7	<0.1	1.6	0.5
Corixidae (water boatman)	0.0	0.0	0.0	<0.1	<0.1	0.0
Elmidae (riffle beetle)	0.0	2.3	2.6	24.9	17.7	18.3
Empididae (dagger or balloon fly)	0.0	7.3	11.7	4.4	12.2	6.7
Ephemeroptera (mayfly)	0.0	0.0	0.0	0.0	0. 7	0.0
Gammarus (scud)	6,113.8	129.1	18.1	13.5	36.7	68.9
Hydropsychidae (net-spinning caddisfly)	0.0	0.0	15.3	0.0	11.5	0. 7
Hydroptilidae (microcaddisfly)	0.0	134.0	159.2	17.9	41.9	58.6
Molophilus (crane fly)	0.0	0.0	0.0	0. 5	2.2	0.0
Nematoda (roundworm)	152.6	133.5	24.9	6.6	11.6	8.1
New Zealand mudsnail	8,637.0	74.4	8.3	27.8	32.1	27.5
Oligochaetes (earthworm/ bloodworm)	6,019.5	753.3	249.3	86.0	158.6	121.6
Ostracoda (seed shrimp)	124.9	0.3	0.0	<0.1	<0.1	0.0
Physidae (bladder snail)	690.2	4.0	0.0	8.2	0.6	4.6
Planariidae (planarian or flatworm)	571.2	45.9	1.2	0.1	4.2	0.8
Pyralidae (snout moth)	0.0	11.0	0.0	<0.1	0.5	19.0
Rhyacophilidae (free-living caddisfly)	0.0	316.4	0.0	0.0	3.8	0.0
Simuliidae (blackfly)	539.4	5,240.8	266.3	367.2	540.2	488.0
Sphaeriidae (pea or fingernail clam)	69.0	<0.1	0.0	0.0	0.0	0.0
Zygoptera (damselfly)	0.0	0.0	0.0	<0.1	0.0	0.0
Total[b]	23,714.8	7,967.1	1,312.9	1,011.2	1,520.4	1,407.1

[a] AFDM = ash-free dry mass. Site 1 is 16 mi downstream of Glen Canyon Dam (GCD, upstream of Paria River confluence), Site 2 is 45 mi downstream of GCD (downstream of Little Colorado River confluence), Site 3 is 78 mi downstream of GCD, Site 4 is 142 mi downstream of GCD, Site 5 is 180 mi downstream of GCD, and Site 6 is 240 mi downstream of GCD (upstream of Diamond Creek confluence).

[b] Productivity values <0.1 mg AFDM/m^2/yr for a taxon not included in total productivity value.

Source: Cross et al. (2011, 2013).

TABLE F-3 Average Mean Habitat-Weighted Invertebrate Abundance at Select Sites in the Colorado River, July 2006–June 2009

Taxon	Habitat-Weighted Abundance (number/m^2)[a]					
	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6
Acari (water mite)	20	455	423	324	562	318
Blephariceridae (net-winged midge)	0	0	0	<1	<1	0
Ceratopogonidae (biting midge)	2	52	11	1	25	31
Chironomidae (midge or chironomid)	6,814	9,814	4,602	2,929	3,716	3,172
Cladocera (water flea)	2,497	13	2	0	3	0
Collembola (springtail)	0	<1	0	0	<1	0
Copepoda (copepod)	4,973	404	118	2	174	62
Corixidae (water boatman)	0	0	0	<1	<1	0
Elmidae (riffle beetle)	0	48	38	41	41	19
Empididae (dagger or balloon fly)	0	5	21	11	25	5
Ephemeroptera (mayfly)	0	0	0	0	1	0
Gammarus (scud)	2,930	50	11	8	20	33
Hydropsychidae (net-spinning caddisfly)	0	0	5	0	1	<1
Hydroptilidae (microcaddisfly)	0	42	81	17	22	20
Molophilus (crane fly)	0	0	0	<1	<1	0
Nematoda (roundworm)	1,199	1,846	276	67	113	62
New Zealand mudsnail	74,033	382	110	229	187	120
Oligochaetes (earthworm/bloodworm)	32,988	7,270	2,774	533	1,117	922
Ostracoda (seed shrimp)	1,023	4	0	<1	3	0
Physidae (bladder snail)	279	<1	0	4	4	2
Planariidae (planarian or flatworm)	987	81	5	<1	21	2
Pyralidae (snout moth)	0	<1	0	<1	1	5
Rhyacophilidae (free-living caddisfly)	0	15	0	0	3	0
Simuliidae (blackfly)	419	3,180	316	327	476	352
Sphaeriidae (pea or fingernail clam)	122	<1	0	0	0	0
Zygoptera (damselfly)	0	0	0	0	<1	0
Total[b]	128,286	23,661	8,793	4,493	6,515	5,125

[a] AFDM = ash-free dry mass. Site 1 is 16 mi downstream of Glen Canyon Dam (GCD, upstream of Paria River confluence), Site 2 is 45 mi downstream of GCD (downstream of Little Colorado River confluence), Site 3 is 78 mi downstream of GCD, Site 4 is 142 mi downstream of GCD, Site 5 is 180 mi downstream of GCD, and Site 6 is 240 mi downstream of GCD (upstream of Diamond Creek confluence).

[b] Abundance values <0.1/m^2 for a taxon not included in total productivity value.

Source: Cross et al. (2011, 2013).

TABLE F-4 Distribution, Ecological Importance, and Favorable Temperature Range for Select Primary Producers

Taxa	Distribution	Ecological Importance	Favorable Temperature Range
Upright epiphytic diatoms	Throughout the river, but most abundant in the Glen Canyon Dam–Paria River reach	High, easily consumed by grazers	10–15°C (50–59°F)
Adnate epiphytic diatoms	Throughout the river, but most abundant in the Glen Canyon Dam–Paria River reach	Medium, not as easily consumed by grazers	15–20°C (59–68°F)
Cladophora glomerata	Throughout the river, but most abundant in the Glen Canyon reach	High, substrate for epiphytic diatoms	13–17°C (55–63°F)
Oscillatoria spp.	Throughout the river, but most abundant below Little Colorado River	Low, not generally consumed directly, poor substrate for diatoms	18–21°C (64–70°F)
Egeria densa	Glen Canyon reach	Medium-high, substrate for epiphytic diatoms, cover for fish	15–21°C (59–70°F)
Potamogeton spp.	Throughout the river, but most abundant in the Glen Canyon reach	Medium-high, substrate for epiphytic diatoms, cover for fish	20–22°C (68–72°F)
Fontinalis spp.	Glen Canyon reach	Medium-high, secondary substrate for epiphytic diatoms	10–15°C (50–59°F)
Chara spp.	Throughout the river, but most abundant in the Glen Canyon reach	Medium-high, substrate for epiphytic diatoms, cover for fish	18–25°C (64–77°F)

Source: Valdez and Speas (2007) and references cited therein.

Colorado River (Blinn et al. 1999). Macroinvertebrates are not generally associated with *Oscillatoria* because it is very compact, has little surface area for colonization, and largely lacks epiphytic diatoms (Blinn et al. 1995). For example, *Gammarus*, a major food source for trout and other fishes, prefers *Cladophora* due to its epiphytic diatoms. This relationship is strong from Glen Canyon Dam to Lees Ferry and weak from Lees Ferry to Diamond Creek (Patten 1998). This relationship does not exist between *Gammarus* and *Oscillatoria*. If *Cladophora* declines, then the contribution of *Gammarus* to the aquatic food base also declines, except perhaps in the drift (Patten 1998).

Drifting macroinvertebrates provide an important food resource for rainbow trout and other native and nonnative fish species. Flow regime, discharge, and distance from the dam influence drift of macroinvertebrates in the Colorado River (Shannon et al. 1996; Stevens et al. 1998; Sublette et al. 1998; McKinney et al. 1999). In general, a positive correlation exists between stream drift and discharge; however, reduced flows can increase stream drift through behavioral factors such as crowding, reduced oxygen concentrations, and avoidance of desiccation (Blinn et al. 1995). Kennedy et al. (2014) concluded that benthic density is the primary control on drift concentrations over long timescales (e.g., weeks to months), because increased benthic production will also increase drift. In contrast, changes in flow such as those

occurring from hydropeaking have an important control on drift concentrations, but primarily on a shorter timescale (e.g., days) (Kennedy et al. 2014).

Tributary and terrestrial insects comprise a small portion of the stream drift in the Colorado River (Shannon et al. 1996), even though Minckley (1991) reported that terrestrial insects commonly occur in stomachs of humpback chub (*Gila cypha*). It is possible that terrestrial invertebrate drift increases during and immediately after rainstorms and is therefore an uncommon but locally important resource for river fishes through Grand Canyon (Shannon et al. 1996). Terrestrial and tributary insects contribute <0.001 and <0.1% of the total invertebrate biomass in the mainstem drift, respectively (Blinn et al. 1995). Fish production throughout Glen and Grand Canyon appears to be limited by the availability of midges and blackflies, and fish may exert top-down control over them (Carlisle et al. 2012). While blackflies and midges support between 43 and 50% of trout production, they only comprise a small percentage of total invertebrate secondary production and abundance in the Glen Canyon reach (Tables F-3 and F-4) (Cross et al. 2011).

Generally, physical, chemical, and biological attributes in the lower reaches of the Colorado River peak at or immediately downstream of tributaries. The connection between tributaries and the mainstem is important for the flow of nutrients, sediment, and wood that contribute to habitat heterogeneity and biodiversity in the mainstem (Kiffney et al. 2006). However, tributary sediment inputs can limit light availability and reduce algal production, thereby reducing food for aquatic invertebrates. High sediment loads may also limit the ability of fish to see their prey (Coggins and Yard 2011).

The Colorado River between Glen Canyon Dam and Lake Mead contains more than 400 ephemeral and 40 perennial tributaries; however, as many of the Colorado River tributaries are dry except during heavy summer rains, they contribute little to the mainstem aquatic food base (Haury 1986). All of the tributary streams have a natural seasonal range of temperatures and discharges unaffected by Glen Canyon Dam (NPS 2005). Oberlin et al. (1999) indicated that primary productivity and detritus, the major food resource for macroinvertebrates, are higher overall in clear-water tributaries and highest in those originating inside the Grand Canyon. Phytoplankton species richness also increases in clear-water tributaries (Crayton and Sommerfield 1979; Oberlin et al. 1999), increasing primary productivity and food quality in those environments (Henery 2005).

Common macroinvertebrates in the tributary streams include caddisflies, mayflies, stoneflies, midges, and blackflies. Drift of tributary macroinvertebrates into the mainstem contributes, at least locally, to the aquatic food base in the Colorado River. Macroinvertebrate productivity and diversity in the tributaries are lowest in the spring and summer, as flash floods in these seasons disrupt the benthic invertebrate communities (Oberlin et al. 1999). Tributaries provide ≤25% of the total organic stream drift in the Colorado River through Grand Canyon National Park (Blinn et al. 1995).

Tributary streams with travertine deposits (e.g., Havasu Creek) or dominated by bedrock (e.g., Matkatamiba Creek) have little inhabitable substrates for macroinvertebrates. Steep channel gradients and erosional habitat also limit benthos in some tributaries (Lawson 2007).

Overall, standing biomass of the Little Colorado River macroinvertebrate community was an order of magnitude lower (0.056 g/m^2 ash-free dry mass [AFDM]) than at the confluence with the Colorado River (0.25 g/m^2 AFDM). A high discharge with increased suspended sediment loads negatively affects macroinvertebrate biomass (Haden et al. 1999). Even extended periods of base flow (which tends to increase macroinvertebrates and algae) do not increase productivity for the areas of the Little Colorado River that contain most of the river's humpback chub population (Haden et al. 1999).

Some of the tributaries also contain New Zealand mudsnails, probably spread by recreationists (NPS 2005). Shannon et al. (2003a) reported the New Zealand mudsnail in cobble bars of 5 of 18 tributaries they sampled, but the snail did not extend more than 32 m upstream in those streams. Since New Zealand mudsnails prefer habitats with constant temperatures and flows and high primary productivity, flash floods may diminish their long-term establishment in tributaries (Shannon et al. 2003a). The risk of quagga mussel (*Dreissena rostriformis bugensis*) introduction to tributaries also appears low. Reservoirs on the upper reaches of the Little Colorado River may eventually support the quagga mussel. Establishment of the quagga mussel in many of the tributaries is unlikely due to high summer water temperatures above the mussel's upper lethal limit (Kennedy 2007).

F.2.1.3 Influence of New Zealand Mudsnail on the Aquatic Food Base

In addition to changes brought about by Glen Canyon Dam, the loss of native species and the addition of numerous nonnative species modified the aquatic ecosystem of the Colorado River within Grand Canyon (Johnson and Carothers 1987). This applies to the aquatic food base and fish species. Nonnative species, including those intentionally introduced, are often better competitors in the homogeneous habitats of regulated rivers (Stanford et al. 1996). To date, nonnative periphyton and rooted aquatic macrophytes have not caused adverse impacts to the aquatic food base in the Colorado River below Glen Canyon Dam. Section 4.17.3.4 discusses potential impacts that could occur if the diatom *Didymosphenia geminata* ("didymo") becomes established in the Colorado River.

The New Zealand mudsnail can tolerate a wide range of water temperatures (except freezing), salinity, and turbidity. It can also withstand short periods of desiccation. Densities of New Zealand mudsnail are usually highest in systems with high primary productivity, constant temperatures, and constant flow. It occurs in all types of aquatic habitats from eutrophic mud bottom ponds to clear rocky streams (USGS 2002; Sorensen 2010). Fitness of the New Zealand mudsnail peaks at 18°C (64°F), declining at cooler and warmer temperatures (NZMMCPWG 2007).

Numerous adaptations of the New Zealand mudsnail aid its spread within watersheds. For instance, adults can pass live through the digestive systems of some fish species, adults can float on masses of algae, and juveniles can float freely on the water surface (Kerans et al. 2005; NZMMCPWG 2007). While the New Zealand mudsnail is not common in streams prone to periods of sediment-moving flood flows, its tough shell, small size, and hydrodynamic shape make it likely to survive scouring flows (Holomuzuki and Biggs 1998; NZMMCPWG 2007).

Most New Zealand mudsnails in North America are asexually reproducing females that are born with developing embryos already present in their reproductive system (Sorensen 2010). Clonal reproduction increases the probability of success of introduction as only a single female can establish a new population (NZMMCPWG 2007). One female can carry up to 20 embryos and under proper conditions may account for over one million snails within one year (Shannon et al. 2003a).

Vinson et al. (2007) suggest that the New Zealand mudsnail introduction into the Green River below Flaming Gorge Dam may have led to a decline of total invertebrate abundance by over 25%. They concluded that decreases in mayflies due to competition from New Zealand mudsnails may jeopardize mayfly recolonization of the Green River following implementation of a more natural springtime flood flow regime. Where the New Zealand mudsnail dominates invertebrate production, it could become the dominant forage base for fishes that prey on macroinvertebrates (Vinson and Baker 2008). Field survey data in the Green River below Flaming Gorge Dam showed a sharp annual increase in the number of brown trout (*Salmo trutta*) and rainbow trout that consumed New Zealand mudsnail between 2001 and 2005 (Vinson and Baker 2008). Bioenergetic simulations suggest that fish diets high in New Zealand mudsnail would not meet energy requirements of fish, resulting in reduced growth and weight loss (Vinson et al. 2007; Vinson and Baker 2008) as discussed previously. For example, when the New Zealand mudsnail comprised between 71 and 81% of brown trout diet, the trout did not gain weight, and when the diet consisted of more than 81% New Zealand mudsnails, brown trout lost weight. Rainbow trout fed a diet of 42% New Zealand mudsnail began losing weight over the course of the experimental study (Harju 2007).

The presence of the New Zealand mudsnail is altering (e.g., causing a decline in) the entire food web in the Grand Canyon (Purdy 2005). The New Zealand mudsnail represents a trophic dead end in Glen Canyon because it has a high production and consumption of primary producers, but it does not support a substantial amount of production for higher trophic organisms. Minnows and suckers that possess pharyngeal teeth may be capable of consuming and crushing the shells of New Zealand mudsnails (NZMMCPWG 2007). However, the New Zealand mudsnail offers little or no energy compared to other common food items in those fish successful in crushing its shell (Ryan 1982).

F.2.2 Impacts of LTEMP Alternatives on the Aquatic Food Base

The Desired Future Conditions (DFCs) for the Colorado River Ecosystem Domain (Appendix A of the DEIS) include these two DFCs for the aquatic food base goals:

- The aquatic food base will sustainably support viable populations of desired species at all trophic levels.

- Assure that an adequate, diverse, productive aquatic food base exists for fish and other aquatic and terrestrial species that depend on those food resources.

Attaining these DFCs while meeting existing water delivery requirements is complex. Biological resources in regulated rivers are subject to a number of spatial and temporal changes in conditions downstream from a dam: reductions in seasonal flow variability, alterations in the timing of extreme flow events, pulses in flow during periods of peak power demands, reduced turbidity and increased water clarity, diel and seasonal constancy of water temperatures, armoring of substrates in the tailwaters, modified nutrient regimes, and the appearance of lentic plankton below the reservoir (Blinn and Cole 1991; Blinn et al. 1995; McKinney and Persons 1999). Flow and temperature are the two major factors that influence the condition and availability of the aquatic food base in the Colorado River between Glen Canyon Dam and Lake Mead. The following discussion supplements the analyses presented in Sections 4.5.2.1 and 4.5.3 of the DEIS.

F.2.2.1 Flow Effects on the Aquatic Food Base

Hydropeaking is the mode of hydroelectric generation that most alters the quantity and quality of habitats available to aquatic organisms. Effects can be direct (e.g., stranding, mortality, and habitat loss) or indirect (e.g., downstream displacement, depleted food production, increased stress) (Clarke et al. 2008). Impacts of flow fluctuations are typically greatest within the tailwaters of a dam and decline with distance downstream due to flow attenuation and the increasing influence of tributaries (Clarke et al. 2008; Patterson and Smokorowski 2011). Flow attenuation occurs downstream of Glen Canyon Dam, however, because of the constrained nature of the channel through most of Marble Canyon and the Grand Canyon, flow fluctuations from dam releases are still apparent in the lower Grand Canyon near Lake Mead (see Section 3.2.1.2 of the DEIS). The following provides discussion of flow effects on the aquatic food base with respect to the elements of base operations, adjustments of base operations, and trout management actions for the LTEMP alternatives.

Effects of Base Operations

Potential alternative-specific effects of base operations (i.e., operations in those years when no condition-dependent or experimental actions are triggered) on the aquatic food base depend on the differences in the monthly pattern in release volumes, minimum and maximum flows, daily flow ranges, and ramp rates. Monthly increases in release volumes may increase the permanently wetted zone, which could increase benthic production, if the increased monthly flows last long enough for benthic development to occur (e.g., weeks to months). Months of higher release volumes would also improve hydraulic connectivity with and maintenance of backwater habitats. Backwaters with more permanency potentially support increased planktonic and benthic communities. A decrease in the permanently wetted zone would occur when decreases in monthly release volumes occur (Reclamation 1995; Hoffnagle 2001; Melis et al. 2006; Behn et al. 2010). Pools of water left after high spring or summer flow months potentially provide habitat for mosquitoes (Blinn et al. 1995). While mosquitoes may contribute to the aquatic and terrestrial food base, they pose a potential health concern to humans.

Daily minimum flow is an important determinant of benthic standing crop because of the strong negative effects of desiccation on algae and invertebrates (Melis et al. 2006). Periods of low steady summer/fall releases (e.g., 5,000 to 8,000 cfs) are expected to result in warmer and more stable nearshore and backwater habitats and longitudinal river warming; while similar flows in winter are likely to produce greater overwinter algal and macroinvertebrate production (Blinn et al. 1995; Valdez et al. 2000). Wet channel area in low-angle habitats within the Glen Canyon reach is reduced by about 10% at 5,000 cfs compared to 8,000 cfs. This area reduction consists of about 16 ha; however, the effects on the aquatic food base from this habitat reduction may not be detectable (Melis et al. 2014).

Restricted minimum and maximum flows and reduced ramping rates of the Modified Low Fluctuating Flow regime adopted in the Glen Canyon Dam Record of Decision (Reclamation 1996) were intended to stabilize the area available for colonization by benthic algae, thereby decreasing losses through desiccation or freezing while increasing primary and secondary production (Blinn et al. 1995). Midges, blackflies, and *Gammarus* were not observed in the varial zone above the 10,600-cfs stage (Blinn et al. 1995).

The interactions between cycles of inundation and dewatering in varial zones play a major role in structuring algal communities in regulated desert rivers (Blinn et al. 1998). Periodic exposure of nearshore and backwater habitats can result in loss of invertebrates and primary producers through desiccation, while inundation can impact the aquatic food base through sediment deposition (Valdez et al. 1998). Atmospheric exposure of benthos can be more severe than flooding because organisms are directly killed rather than displaced or buried (Blinn et al. 1995). Fluctuating flows (>10,000 cfs/day) can fragment *Cladophora* from its basal attachment and increase its occurrence in the drift. Consuming drifting *Cladophora* (with its attached epiphytes and any invertebrates) allows rainbow trout to expend less energy in searching for food (Leibfried and Blinn 1987). Daily range in flows >10,000 cfs only occur during December and January (12,000 cfs) for Alternative B.

A stabilized discharge regime could increase algae production downstream of Glen Canyon Dam. In turn, this may have positive effects on invertebrate and fish production (Kennedy et al. 2013). Basal holdfasts of *Cladophora* can dry following periods of exposure as short as four hours in summer (Pinney 1991). Exposure to subzero winter air temperatures for only one night resulted in ≥50% loss of chlorophyll a and mass of *Cladophora* (Blinn et al. 1995). Recovery time may take several months (Blinn et al. 1992). Since algal communities provide the dominant food resource below dams, restricting the extent of the varial zone and maintaining wetted perimeter can be important to maintaining the overall food base (Blinn et al. 1998). Potential differences among alternatives based on daily range in flows are provided in Section 4.5.3 of the DEIS.

Warm or sub-freezing air temperatures could cause mortality of invertebrates stranded in the varial zone (Gislason 1985). The varial zone probably provides poor habitat for species with multiple life history stages (Jones 2013) by dewatering of emergence and oviposition sites (Vinson 2001). High rates of egg mortality due to exposure may partially explain the rarity of mayflies in the Colorado River. For example, adult female *Baetis* species land on rocks protruding from the water surface and then crawl underwater to lay their eggs on the underside of

the rocks. These rocks may become dry for possibly 12 hours during the hydropeaking cycle, causing egg mortality (Kennedy 2013). The fact that midges and blackflies are broadcast spawners may explain why they are the predominant insects in the mainstem. Nevertheless, hydropeaking could still limit egg survival and thus recruitment for these species in the mainstem (Kennedy 2013). In the Glen Canyon Dam tailwaters, *Gammarus* standing stock and fecundity are lower, seasonal recruitment of young is briefer, and fewer young are recruited into the population in the varial zone compared to the permanently wetted zone. Also, *Gammarus* mortality increases in the varial zone (Angradi and Kubly 1993; Ayers and McKinney 1996; Ayers et al. 1998).

Invertebrates are continually moving and drifting to different positions in the river, thus stranding of a significant number of invertebrates in the varial zone would reduce the overall abundance in the river including that in the permanently wetted zone (Smokorowski 2010). However, there may be little colonization of shoreline areas during daily high flows, and as discharge decreases, large numbers of insects may not be present to enter the drift from areas being dewatered (Perry and Perry 1986). Nevertheless, reduction in the amplitude and duration of power peaking flow fluctuations may be an effective management strategy for enhancing aquatic insect biomass with the potential for increasing the survival and growth of fishes dependent on them (Gislason 1985).

Conversely, daily flow fluctuations may benefit the aquatic food base, if they have a strong negative impact on New Zealand mudsnails. In laboratory experiments, there was an average mudsnail survival of 50% from 1 to 7 hours of exposure, while 8 to 9 hours of exposure killed 88% of the mudsnails with none surviving a 14-hour exposure (Shannon et al. 2003b). However, New Zealand mudsnails occur on both stable and unstable habitats, so they can quickly colonize newly submerged habitats (Melis et al. 2006). Flow fluctuations may also increase the amount of organisms available to drift-feeding fish, although this may only occur for a short period (e.g., a few days or less) depending on the density and replacement capacity of benthic invertebrates. For example, a twofold daily variation in discharge resulted in a >10-fold increase in drift concentrations of *Gammarus* and New Zealand mudsnails while blackfly drift concentrations decreased by over 80% as discharge doubled. Midge drift concentrations increased proportional to discharge (Kennedy et al. 2014).

As the daily range in flows increases, there is greater divergence in habitat conditions between low and high flows, and there will likely be fewer taxa that can withstand such variability. Consequently, the ratio of the regulated high and low flows may become as important as the base flow as an influencing factor determining biotic composition (Jones 2013). Ramping rate restrictions may allow sufficient time for aquatic macroinvertebrates to respond to daily flow fluctuations (Patterson and Smokorowski 2011). Rapid up-ramping can result in rapid increases in shear stress, potentially causing catastrophic drift or the large scale displacement of invertebrates from the sediment (Gibbins et al. 2007). Perry and Perry (1986) observed a greater number of aquatic invertebrates stranded when the down ramping rate was rapid; indicating that unlimited down ramping is a potential cause of increased invertebrate mortality (Smokorowski 2010). Also, high ramping rates potentially favor adnate diatom species over the more upright species, the latter of which macroinvertebrates and fishes more readily consumed (Hardwick et al. 1992; Pinney 1991; Biggs 1996).

Miller and Judson (2014) observed that, during a daily hydropeaking schedule, macroinvertebrate drift biomass below Flaming Gorge Dam in the Green River increased during the rising limb of the daily hydrograph and declined prior to the cessation of the peak. Macroinvertebrate drift increases were correlated with the biomass of drifting vegetation. As the study by Miller and Judson (2014) occurred over winter, the rate of vegetation export declined over time due to senescence caused by decreased light levels and cooler temperatures. This at least partly accounted for the observed declines in macroinvertebrate drift after 30 to 60 days (Miller and Judson 2014).

During base operations, up-ramping rates are the same at 4,000 cfs for all alternatives except for Alternatives F and G that would not have a daily range in flows. Down-ramping rates would be highest for Alternative B (4,000 cfs for November through March and 3,000 cfs in the other months), followed by the Alternatives C, D, and E (2,500 cfs) and Alternative A (1,500 cfs). Alternatives F and G both feature steady flows in all months.

Experimental Treatments

High-Flow Experiments. Most experimental adjustments of base operations relate to high-flow experiments (HFEs). The existing HFE protocol calls for spring HFEs to occur in March–April and fall HFEs to occur in October–November with magnitudes ranging from 31,500 to 45,000 cfs (Reclamation 2011a). Most HFEs would last from less than one hour to 96 hours, although HFEs longer than 96 hours could occur under Alternatives C, D, and G. There is a potential for more than one HFE to occur within the same year or between years, with a potential for up to 40 HFEs during the LTEMP period (Alternatives C, F, and G). Food webs close to Glen Canyon Dam are more energy inefficient and are expected to exhibit lower resistance to experimental flood perturbations compared to food webs downstream of major tributaries (Cross et al. 2013).

HFEs conducted in the spring and fall represent contrasting conditions, particularly with regard to light, temperature, and invertebrate biomass. Plant and macroinvertebrate recovery times may be shorter for spring HFEs than for fall HFEs as a result of longer day lengths and warmer river temperatures in spring and summer. Spring HFEs can cause ponding of tributary flows that enter the Colorado River, creating temperature refuge areas within the mainstem (Valdez et al. 2000). Spring HFEs can also re-suspend organic material stored along the shoreline and redistribute it into the mainstem (Valdez et al. 2000). The majority of the aquatic food base taxa would recover within 1 to 4 months after a spring HFE as observed for the spring 1996 and 2008 HFEs (Blinn et al. 1999; Rosi-Marshall et al. 2010), although some taxa may recover more slowly (Cross et al. 2011). Shannon et al. (2001) reported high rates of invertebrate drift for two months after the spring 1996 HFE. A post-flood increase in production and drift of midges and blackflies is expected after a spring HFE (Cross et al. 2011) likely due to the flushing of fines in the interstitial spaces between gravel and around macroalgae holdfasts used by these invertebrates for cover. *Gammarus* is expected to be slower to recover because of its greater susceptibility to being exported by river currents than most invertebrate species (Reclamation 2011a). Also, slow-growing taxa such as *Gammarus* take longer to recover to pre-flood levels

relative to faster growing taxa with aerial life stages such as blackflies and midges (Robinson and Uehlinger 2008).

Fall HFEs precede winter months of minimal insolation, low temperatures, and reduced gross primary productivity. Thus, recovery times for aquatic food base organisms take longer than for spring HFEs (Melis et al. 2006). Following the fall 2004 HFE, *Gammarus* was extremely scarce for many months in Lees Ferry (Melis et al. 2006). Even longer recovery times could occur if a fall HFE is followed by a spring HFE. The 4 to 5 months between a fall and spring HFE could preclude full recovery of most benthic invertebrate assemblages. The following spring HFE could scour the remaining primary producers and susceptible invertebrates and further delay recovery. A spring HFE followed by a fall HFE may not have as great an impact because of the rapid recovery of the food base expected over the summer (Reclamation 2011a).

The 2008 spring HFE reduced annual invertebrate production in the Lees Ferry tailwater by >50%, driven primarily by significant reductions in production of New Zealand mudsnails and *Gammarus*. Large numbers of *Gammarus* dislodged during high flows are transported considerable distances downstream, making them available to fishes. Windrows of stranded *Gammarus* carcasses along some shorelines following the spring 1996 controlled flood (Valdez 1999) became available to terrestrial consumers such as shorebirds, lizards, and spiders. Reductions in mudsnails and *Gammarus* persisted at least 15 months after the HFE (when the study concluded) and coincided with a significant decline in the annual production of these taxa (e.g., New Zealand mudsnail production declined from 11 to 13 g AFDM/m^2/yr to 2 g AFDM/m^2/yr and *Gammarus* production from 7 to 8 g AFDM/m^2/yr to 3 g AFDM/m^2/yr). Reductions in aquatic worms recovered in about 4 to 6 months (Rosi-Marshall et al. 2010). However, midges and blackflies increased by 30 and 200%, respectively, in the year following the HFE, and they supported a 200% increase in rainbow trout production (Cross et al. 2011). During the flood, the concentrations of invertebrate prey available in the drift increased from an average of 0.093 mg/m^3 AFDM before the flood to an average 0.163 mg/m^3 after the flood (Rosi-Marshall et al. 2010; Cross et al. 2011).

The concentrations of midges and blackflies in the drift increased 400 and 800%, respectively, after the 2008 HFE, and this effect persisted for at least 15 months. Biomass and production of both groups also increased after the HFE (Rosi-Marshall et al. 2010; Cross et al. 2011). The March 2008 HFE resulted in an increase in the area of backwater habitat that persisted for at least two months, but returned to conditions similar to those before the HFE by about 6 months after the HFE (Melis 2011). In addition to scouring benthic algae and invertebrates, high flows can capture large quantities of terrestrial organic matter that may temporarily increase the amount of food base available for drift-feeding fish (Valdez and Hoffnagle 1999; Gloss et al. 2005).

Generally, more frequent HFEs may cause a shift to more resistant taxa or to new taxa that would colonize the river. However, if such taxa are not present, more frequent HFEs may reduce macroinvertebrate diversity and possibly abundance, resulting in a reduction in the aquatic food base (Reclamation 2011a). Any benefits from HFEs along downstream segments of the Colorado River (particularly the lower portion of the Grand Canyon reach) will likely be

smaller in magnitude than in the Lees Ferry reach (Melis 2011; Kennedy et al. 2013). The average number of HFEs during the LTEMP period would be 39.3 under Alternative F; range from 17.1 to 24.5 under Alternatives C, D, E, and G; and be only 7.2 under Alternative B and 5.5 under Alternative A.

The most notable differences among the alternatives is for Alternative A, which would not have HFEs after 2020; Alternative B, which would not exceed one spring or fall HFE every other year; and Alternative E, which would not have spring HFEs during the first 10 years (Table 2-2 of the DEIS).

A comprehensive study on the ecological effects of repeated HFEs in the River Spöl in Switzerland indicated that one or two high-flow events per year can enhance and sustain long-term ecological integrity (Scheurer and Molinari 2003) and that such releases must be repeated on a regular basis (annually) to maintain their benefits (Robinson and Uehlinger 2008). The first experimental flood in the River Spöl reduced macroinvertebrate abundance by about 50%. However, subsequent experimental floods had less effect, indicating that a new assemblage had established that was more resilient to flood disturbance. The response of macroinvertebrates to experimental floods occurs over a period of years, rather than months, as species composition adjusts to the new flow conditions (Robinson and Uehlinger 2008). Robinson et al. (2003) observed that the abundance of amphipods and planarians decreased while the abundance of baetid mayflies, blackflies and midges increased. Some mayfly, stonefly, and caddisfly taxa initially decreased in abundance but subsequently increased. The results of experimental floods in the River Spöl imply that the experimental flood regime needs maintaining to sustain the development of a more natural macroinvertebrate assemblage (Robinson et al. 2003). While three to five consecutive HFEs from Glen Canyon Dam may alter the aquatic food base composition, the absence of an HFE for one or more seasons might reset the current aquatic food base community (Reclamation 2011a). It is anticipated that, regardless of the HFE regimen, midges and blackflies would remain important components of the aquatic food base downstream of Glen Canyon Dam.

A large portion of the aquatic food base in the Lees Ferry reach would likely be scoured by an HFE of 41,000 to 45,000 cfs regardless of the time of year. The initial hydrostatic wave produces the scouring effect, and the duration of the flow is an important factor in transporting the material downstream (Rosi-Marshall et al. 2010). The HFE conducted in March 1996 (7-day discharge of 45,000 cfs) resulted in benthic scour and entrainment of both primary and secondary producers at all study sites along the 239-mi river corridor. Over 90% of the benthos was removed by the hydrostatic wave or within 24 hr from the start of the test flood. Also, drift mass reached highest levels during the first 2 days of the HFE (an order of magnitude higher than under normal dam operations) and subsided after that period (Shannon et al. 2001). Recovery rates to pre-flood levels were fast for benthic algae (1 month) and invertebrates (2 months) (Blinn et al. 1999). Recovery of the macrophytes *Chara*, *Potamogeton*, and *Elodea* to pre-flood conditions took 1 to 7 months (Shannon et al. 2001).

It is hypothesized that mucilaginous algae found in miscellaneous algae, macrophytes, and bryophytes (MAMB) can outcompete *Cladophora* under the combination of reduce nutrient conditions and elevated discharge regimes of about 25,000 cfs. However, if discharge increases

to 45,000 cfs or more, MAMB will scour, allowing *Cladophora* to recolonize regardless of nutrient conditions because of strong holdfast attachment and lack of competition (Benenati et al. 2000). HFEs up to 45,000 cfs may occur under Alternatives C, D, and G.

HFEs longer than 96 hours may also occur under Alternatives C, D, and G. These longer-duration HFEs could scour much of the aquatic food base, especially within the Glen Canyon reach, and reduce the standing crop of benthic invertebrates. The extended-duration HFEs may increase the aquatic food base available for drift-feeding fishes, particularly during the initial hours of the flood. An extended-duration HFE may also help to control the abundance of New Zealand mudsnails in the Glen Canyon reach, but possibly contribute to their downstream abundance. Potential effects of sustained spring flows include:

- High, turbid main-channel flow and a surge of increased macroinvertebrate drift, increased feeding opportunities for non-sight feeders, and increased density of terrestrial invertebrates washed from shoreline.

- Rebuilt backwater habitats and increased primary and secondary production in backwaters following redistribution of organics (Valdez et al. 1998).

Steady Flows. Steady flows (or nearly steady flows with some instantaneous fluctuations associated with ancillary services) would occur prior to or following spring and/or fall HFEs (prior to spring and fall HFEs under Alternative C and before fall HFEs only for Alternatives D and E; Alternatives F and G already feature steady flows). Potential effects of steady flows include: (1) warmer shoreline and backwaters and an increase in backwater production; (2) warmer main channel and an increase in primary and secondary production and potential for parasite maturation and proliferation; and (3) stable main channel and less turbidity and an increase in shoreline primary and secondary production and reduced macroinvertebrate drift as food for fish (Valdez et al. 1998). However, mainstem warming, particularly in the Glen Canyon and Marble Canyon reaches, would be limited. Ralston et al. (2007) observed that biological and physical parameters were unaffected by daily fluctuations in flow of 2,700 cfs and steady-flow releases. Reduced flow fluctuations prior to an HFE could increase production of primary producers and consumers. The HFE could increase drift biomass. Reduced flow fluctuations following an HFE could hasten benthic recolonization.

Low Summer Flows. Low summer flows may be tested for two or three years under Alternatives C, D, and E; and are an annual component of Alternative F. The low summer flow tests would involve flows between 5,000 and 8,000 cfs to warm the Colorado River at the confluence with the Little Colorado River to at least 13°C (55°F). This would necessitate increasing mean daily flows in other months relative to base operations. Low summer flow tests may increase primary and secondary benthic production but reduce macroinvertebrate drift. In particular, the density of New Zealand mudsnails may increase under low summer flows. However, the opposite conditions, compared to base operations without low summer flow tests, may occur in non-summer months. Potential impacts on the aquatic food base from low summer flows under Alternative F are described in Section 4.5.3.6 of the DEIS.

Hydropower Improvement Flows. Hydropower improvement flows (increased fluctuation levels proposed as an experiment under Alternative B) would entail a daily change from a minimum flow of 5,000 cfs to a maximum flow of 15,000 to 25,000 cfs (depending on season). This could decrease primary and secondary production, although macroinvertebrate drift may increase. Down ramp rates of 5,000 cfs/hr may increase stranding of organisms in the varial zone compared to base operations that range from 1,500 cfs/hr (Alternatives A, F, and G) to 4,000 cfs/hr (Alternative B from November through March). Conversely, higher up-ramp rates of 5,000 cfs/hr coupled with sustained high flows may flush increased amounts of terrestrial invertebrates (and other items such as leaf litter) from shoreline areas into the drift compared to base operations for all alternatives (up-ramp rates of 4,000 cfs/hr).

Sustained Low Flows for Benthic Invertebrate Production. An aquatic resource-related experiment unique to Alternative D would be to test the effects of sustained low weekend flows in May through August on benthic invertebrate production and diversity. It has been hypothesized that the large varial zone created by fluctuating flows limits recruitment of mayflies (order Ephemeroptera), stoneflies (order Plecoptera), and caddisflies (order Trichoptera), collectively referred to as EPT, due to high egg mortality. If EPT deposit eggs principally along the shallower shoreline areas, then eggs laid during stable low flows over the weekend would not be subjected to drying prior to hatching. Depending on the findings from the first test, this experiment may be conducted two to three times during the LTEMP period, but not during the first 2 years. In addition to potentially increasing EPT, sustained low weekend flows may benefit other aquatic food base organisms that have terrestrial adult life stages such as dragonflies and true flies (including midges and blackflies). Some loss of benthic production is possible in the shoreline areas that remain dewatered over the weekend. If this results in an unacceptable risk (e.g., decreased benthic production), the experiment would not be repeated. There is also the strong possibility that this experimental procedure may result in confounding interactions with trout management flow (TMF) experiments, also expected to be conducted during the LTEMP period.

Trout Management Flows. The 2003 Ecological Restoration Flows that began on January 1, 2003, consisted of daily fluctuations between 5,000 and 20,000 cfs in an attempt to disadvantage nonnative fish, particularly trout, during their winter spawning period. Overall, the 2003 Ecological Restoration Flows caused a drop in benthic biomass at cobble bars in Glen Canyon during the January to March flows followed by recovery through the summer (Shannon et al. 2003b). The flows did not have a long-term adverse impact on New Zealand mudsnail biomass and densities throughout the river. For example, at –3 Mile Bar, mudsnail biomass dropped by 70% between December and January collections; however, by June, New Zealand mudsnails had recovered to 90% of the December estimate (Shannon et al. 2003b).

TMFs conducted in spring and summer months (May–July), featured in all alternatives but Alternative A, would consist of several days at relatively high sustained flows (e.g., 20,000 cfs) followed by a rapid drop to low flows (e.g., 5,000 cfs) which would be held for a brief period (e.g., <24 hr). This pattern would be repeated for a number of cycles. Conditions for primary production should decrease slightly with increased turbidity during the higher

discharge portion of TMFs (Reclamation et al. 2002). Although a temporary increase in total wetted area would occur under TMFs, areas would not be inundated for sufficient time to allow for benthic colonization (Benenati et al. 1998; Blinn et al. 1995). Thus, desiccation losses due to substrate exposure from dewatering of the varial zone would be minimal. Aquatic food base drift may increase during up-ramping to 20,000 cfs/hr associated with TMFs. Drift biomass has been observed to increase during the rising limb of the hydrograph (Miller and Judson 2014).

F.2.2.2 Temperature Effects on the Aquatic Food Base

One of the primary effects of dams, particularly those with hypolimnetic releases, is the change in water temperatures, which is primarily responsible for the decline in invertebrate biodiversity. Warmer winter water temperatures can impact invertebrates in a number of ways including loss of physiological signals; disruption of normal growth, fecundity, and emergence; lack of winter chill to break insect egg or larval diapause; and early emergence. Cooler summer water temperatures can also impact invertebrates. For example, water temperatures high enough to complete development may not occur. Other impacts may include decreased fecundity, temporal separation of male and female emergence, delayed emergence, and prolonged emergence. The greater thermal constancy in annual and diel stream water temperatures downstream from dams also tends to decrease food base biodiversity (Vinson 2001).

Seasonal variation in water temperatures decreased gradually from Glen Canyon Dam closure in 1963 until about 1971, when water began to be drawn from the hypolimnion of Lake Powell. Main channel temperatures are now relatively isothermal at 7.2 to 10°C (45 to 50°F), but warm somewhat downstream in summer. There is an estimated maximum warming of the Colorado River mainstem of about 1°C (1.8°F) for every 35 mi, and water released at 10°C (50°F) from Glen Canyon Dam is expected to warm to about 17°C (62.6°F) near Diamond Creek (RM 225) in May or June (Benenati et al. 2002; Valdez 1994). Backwater habitats near the channel margins are one of the few aquatic habitats that warm above these levels. Backwater temperatures tend to warm with distance downstream from the dam (Valdez et al. 1998).

In winter, the mainstem water temperature near Diamond Creek is only about 1°C (1.8°F) higher than at Glen Canyon Dam (Cross et al. 2013). From 1988 to 2005, the average temperature of water released from Glen Canyon Dam was 9°C (48.2°F), and annual high temperatures at Diamond Creek between 1990 and 2002 were about 18°C (64.4°F). A drought that began in 2003 reduced water levels in Lake Powell and resulted in water temperatures that reached an annual high of 21°C (69.8°F) at Diamond Creek in 2005 (Hamill 2009).

In a two-week laboratory study, epiphytic diatom communities from the cold tailwaters of Glen Canyon Dam (12°C [54°F]) were incubated at 18 and 21°C. No change occurred in diatom composition between 18 and 21°C (64 and 70°F), but a significant change occurred between 12 and 18°C (54 and 64°F). At the higher water temperatures, smaller and closely adnate taxa became more important numerically than larger, upright diatoms (Blinn et al. 1989). This shift in diatom species composition may affect macroinvertebrates that feed on diatoms (Lechleitner 1992). Table F-4 provides the distribution, ecological importance, and favorable temperature range for select primary producers in the Colorado River, while Table F-5 provides temperature requirements for common zooplankton taxa.

TABLE F-5 Temperature Requirements for Common Zooplankton

Species	Temperature, °C (°F)		
	Minimum	Maximum	Optimum
Daphnia pulex (cladoceran)	10 (50)	28 (82)	20 (68)
Daphnia galeata (cladoceran)	10 (50)	25 (77)	20 (68)
Daphnia lumholtzi (cladoceran)	10 (50)	30 (86)	25 (77)
Leptodora sp. (cladoceran)	15 (59)	30 (86)	20 (68)
Bosmina sp. (cladoceran)	6 (43)	28 (82)	20 (68)
Diaphanosoma sp. (cladoceran)	10 (50)	30 (86)	25 (77)
Rotifers	15 (59)	30 (86)	25 (77)
Calanoid copepods	10 (50)	30 (86)	25 (77)
Cyclopoid copepods	10 (50)	30 (86)	25 (77)

Source: Valdez and Speas (2007).

If stream temperatures are raised by only a few degrees in winter, many aquatic insects that normally emerge in May or June may emerge in February or March and face death by freezing or will be prevented from mating because they are inactivated by low air temperatures. In addition, increases in stream temperatures may exaggerate the separation between the emergence of males and females (e.g., males may emerge and die before females emerge) (Nebeker 1971). Overall, temperatures above or below the optimum can lead to the production of small adults and lower fecundity (Vannote and Sweeney 1980). Slower warming of streams throughout the summer can reduce fecundity of emerging adults, exaggerate the separation of male and female emergence, prolong the emergence period of individual generations (which reduces the number of insects emerging at any given time, which may increase the individual risk of predation by trout or other fish), and reduce the growth rate such that emergence might occur later in the year when air temperatures are suboptimal for mating (Rader et al. 2008; Vinson 2001).

The lack of temperature variability in the Colorado River downstream of Glen Canyon Dam has selected for macroinvertebrates that do not require temperature cues to complete their development. This may at least partially account for the low levels of mayflies and caddisflies and the absence of stoneflies in the mainstem of the Colorado River (Oberlin et al. 1999). Fecundity of *Gammarus* in the tailwaters of Glen Canyon Dam is lower than that reported for it in other locations, probably due to water temperatures being well below the optimum of 18°C (64°F) for reproduction (Ayers et al. 1998). Table F-6 provides the distribution, importance to higher trophic levels, and temperature range for common benthic macroinvertebrates that occur in the Colorado River.

There is the possibility of an increase in the distribution and prevalence of fish diseases and parasites from river warming (Hoffnagle 2001; Valdez et al. 2000). Warmer, more stable backwaters could provide additional habitats for the Asian tapeworm (*Bothriocephalus acheilognathi)* and anchor worm (*Lernaea cyprinacea*) to substantially increase in abundance,

TABLE F-6 Distribution, Importance to Higher Trophic Levels, and Temperature Range for Common Benthic Macroinvertebrates Downstream of Glen Canyon Dam

Taxa	Distribution in Project Area	Importance to Higher Trophic Levels	Temperature Range in Project Area[a]	Favorable Temperature Range[a]
Gammarus lacustris (amphipod)	Glen Canyon Dam–Paria River (also important component of drift below this reach)	High	7–10 (45–50)	7–29 (45–84)
Simulium (blackfly)	RM 1.0 to Lake Mead and various tributaries	Medium-high	5–31 (41–88)	10–26 (50–79)
Cricotopus (midge)	Glen Canyon Dam–Paria River (also important component of drift below this reach)	Medium	7–10 (45–50)	15–21 (59–70)
Eukiefferiella (midge)	Glen Canyon Dam–Paria River (also important component of drift below this reach)	Medium	7–10 (45–50)	12–18 (54–64)
Orthocladius (midge)	Glen Canyon Dam–Paria River (also important component of drift below this reach)	Medium	7–10 (45–50)	8–18 (46–64)
Chironomus (midge)	River Mile 1.0 to Lake Mead	Medium	4–23 (39–73)	9–25 (48–77)
Aquatic worms	Glen Canyon Dam–Paria River (also important component of drift below this reach)	Low	4–23 (39–73)	8–25 (46–77)
Aquatic snails	Glen Canyon Dam–Paria River	Low	7–10 (45–50)	7–39 (45–102)
Potamopyrgus antipodarum (New Zealand mudsnail)	Glen Canyon Dam–Paria River	Low	4–23 (39–73)	7–28 (45–82)
Pisidium (pill clam)	Glen Canyon Dam–Paria River	Low	7–10 (45–50)	2–20 (36–68)
Dugesia (planarian)	Glen Canyon Dam–Paria River	Low	7–10 (45–50)	5–16 (41–61)
Baetis (mayfly)	Various tributaries	High	3–31 (37–88)	4–18 (39–86)
Hydropsyche (caddisfly)	Various tributaries	High	3–3 (37–88)	7–30 (45–86)
Megaloptera: Corydalidae (dobsonflies)	Various tributaries	High	5–28 (41–82)	5–30 (41–86)

[a] Temperature in °C (°F).

Source: Valdez and Speas (2007) and references cited therein.

resulting in their spread along the mainstem and into additional warmwater tributaries. Reported maximum temperature warming above those in the main channel for nearshore habitats range from 2.2°C (4.0°F) in eddies to 13°C (23.4°F) in backwaters (Vernieu and Anderson 2013). Warming of nearshore areas is somewhat ephemeral (e.g., decreases at night and during day under windy or cloudy conditions) (Vernieu and Anderson 2013). Temperatures greater than 20°C (68°F) would allow maturation of the Asian tapeworm, while temperatures greater than 15°C (59°F) would allow maturation of the anchor worm (Valdez et al. 1998). Section 4.5.2.4 of the DEIS discusses fish parasite and disease incidence for mainstem locations. Table F-7 presents temperature requirements of the Asian tapeworm, anchor worm, and trout nematode. Whirling disease infection prevalence and disease severity reaches its highest levels at 10–15°C (Steinbach Elwell et al. 2009).

As analyzed in Section 4.5.3 of the DEIS, temperature differences among alternatives would be minimal. Therefore, no significant changes in the aquatic food base due to elements of the base or condition-dependent operations are expected.

F.2.3 Conclusion

Table 4.5-1 of the DEIS summarizes the impacts from the alternatives on the aquatic food base, while Section 4.5.3 of the DEIS presents the impacts of each alternative in more detail. Under Alternative A, existing conditions and trends in the composition, abundance, and distribution of the aquatic food base are expected to persist over the LTEMP period. The cessation of HFEs after 2020 may result in a shift to a food base community not dominated by midges and blackflies (important contributors to the diet of trout). Water temperatures, and their resultant influences on species composition, diversity, and production of the aquatic food base, would be similar to current temperatures in the Colorado River downstream of Glen Canyon Dam.

TABLE F-7 Temperature Requirements for the Asian Tapeworm, Anchor Worm, and Trout Nematode

	Host Activity Temperature Requirements[a]			Infestation Temperature Requirements[a]		
Species	Minimum	Maximum	Optimum	Minimum	Maximum	Optimum
Asian tapeworm	18 (64)	20 (68)	19 (66)	20 (68)	30 (86)	25 (77)
Anchor worm	20 (68)	30 (86)	25 (77)	18 (64)	30 (86)	25 (77)
Trout nematode	16 (61)	20 (68)	18 (64)	16 (61)	20 (68)	18 (64)

[a] Temperature in °C (°F)

Source: Valdez and Speas (2007).

Under Alternative B, benthic food base production would be similar to Alternative A. HFEs conducted less often than annually may lower the potential to establish a food base adaptable to flood conditions (i.e., one dominated by midges and blackflies). Hydropower improvement flows could decrease benthic food base production, which over the long term may also decrease drift (Kennedy et al. 2014). Over the short term, TMFs could also cause short-term increases in drift rates and slightly decreased primary production compared to Alternative A. Temperature impacts on the aquatic food base under Alternative B would be similar to those under Alternative A.

Under Alternative C, benthic food base productivity may be higher in December through June compared to Alternative A due to higher volumes and larger wetted area, but lower from August through November compared to Alternative A due to lower volumes and smaller wetted area. The more frequent HFEs compared to Alternative A would favor midge and blackfly production. Low summer flows are expected to lower food base production compared to higher flow conditions. Over the short term, TMFs could increase drift rates and slightly decrease primary production compared to Alternative A. Slightly warmer water temperatures for August and September at RM 225 under Alternative C may slightly increase food base production compared to Alternative A, although this could be offset by changes in diatoms from stalked to adnate forms and favoring *Oscillatoria* over *Cladophora*.

The relatively consistent monthly release volumes under Alternative D compared to Alternative A would produce a more consistent and stable aquatic food base. The more frequent HFEs under Alternative D are expected to favor midge and blackfly production compared to Alternative A. Low summer flows are expected to lower food base production compared to higher flow conditions. Over the short term, TMFs could increase drift rates and slightly decrease primary production compared to Alternative A. Sustained low weekend flows in May through August under Alternative D would be tested to determine if they increase benthic food base production and diversity including the recruitment of mayflies, stoneflies, and caddisflies (important food base organisms currently rare to absent throughout much of the mainstem below Glen Canyon Dam). Temperature impacts on the aquatic food base under Alternative D would be similar to those under Alternative C.

Under Alternative E, relatively consistent monthly release volumes would favor aquatic food base productivity, but this effect would be offset by larger daily fluctuations. The frequent HFEs under Alternative E will favor midge and blackfly production, though the number of HFEs would be less than under Alternative C, D, F, and G. Temperature impacts on the aquatic food base for Alternative E would be similar to those under Alternative C and D.

Under Alternative F, food base biomass from July through the following March would be potentially less compared to all other alternatives due to comparatively lower flow volumes. Flow stabilization may allow for high benthic densities of New Zealand mudsnails. Over the long term, increased benthic production from flow stabilization may increase drift rates of food base organisms (Kennedy et al. 2014). Higher flow volumes in April through June may increase benthic food base biomass compared to Alternative A. The frequent HFEs will favor blackfly and midge production. The warmer water temperatures for August and September at RM 225 under Alternative F may slightly increase food base production even more than Alternative D,

although this could similarly be offset by changes in diatoms from stalked to adnate forms and favoring *Oscillatoria* over *Cladophora*.

Under Alternative G, consistent and stable aquatic food base conditions would persist throughout the year. Benthic food base biomass would probably be greater under Alternative G compared to Alternative F, because flows from July through the following February would be higher. However, stable flows may favor dominance by the New Zealand mudsnail. Potentially higher drift rates from spring flows under Alternative F would not occur under Alternative G. However, increased benthic production may increase drift rates over the long term (Kennedy et al. 2014). The frequent HFEs are expected to favor blackfly and midge production. Temperature impacts on the aquatic food base for Alternative G would be similar to those under Alternative C, D, and E.

F.3 MODELING EFFECTS OF LTEMP ALTERNATIVES ON RAINBOW TROUT AND HUMPBACK CHUB

This section describes the methodology, results, and conclusions from a model developed in support of the LTEMP DEIS by Yackulic (Grand Canyon Monitoring and Research Center [GCMRC]), Coggins (U.S. Fish and Wildlife Service [FWS]), and Korman (EcoMetrics) to evaluate effects of alternatives on rainbow trout and humpback chub populations. Although other models were considered for use, the combined rainbow trout-humpback chub model described here was developed to incorporate recent information from the Natal Origins, Juvenile Humpback Chub Monitoring, and Near-Shore Ecology projects being conducted by GCMRC and to utilize newer approaches to modeling humpback chub population demographics. Additionally, there was a need to develop the model in a software environment in which batch processing of model runs for multiple hydrologic and sediment input scenarios for each alternative would be feasible and computationally efficient. The model used existing data to inform parameter estimates whenever possible.

F.3.1 Model Overview

The trout-chub model consists of three combined submodels: (1) a model of rainbow trout population dynamics in the Lees Ferry reach, (2) a model of rainbow trout movement and survival downriver from Lees Ferry (trout routing model), and (3) a model of the response of humpback chub population dynamics in the Little Colorado River and Colorado River to monthly mainstem temperatures and monthly trout abundances. The model of the Lees Ferry rainbow trout population dynamics is similar to previous models used for the Glen Canyon reach. The trout movement and humpback chub models, on the other hand, were developed for this application to reflect recent advancements, with an emphasis on deriving parameter values from data. The following paragraphs give a brief overview of the three submodels, with more detailed descriptions of each submodel available in subsequent sections (Sections F.3.1.1, F.3.1.2, and F.3.1.3).

Output from a flow model drives the Lees Ferry rainbow trout submodel. This model can be run independently from the trout routing and humpback chub submodels, as it does not include any feedbacks. Simulations include interannual variability in recruitment, outmigration, and growth based both on regression-derived predictions and variation around these predictions. Simulations also include parameter uncertainty, which includes a critical uncertainty related to the effectiveness of TMFs. The parameter associated with the critical uncertainty was fixed at two values (0.10 and 0.50) encompassing a hypothesized range of effectiveness, while all other parameters were drawn from the multivariate distribution estimated from data. Outputs from this submodel include four performance metrics, including simulated outmigration, which was used as an input to the trout routing submodel.

The trout routing submodel includes a single biological parameter describing movement, as well as multiple inputs related to implementation of mechanical removal, all of which are fixed. The trout routing submodel model is run a year at a time, after which it passes monthly rainbow trout abundances to the humpback chub submodel.

The humpback chub submodel simulates the impacts of rainbow trout and temperature (forecasted by a temperature model) on humpback chub population dynamics at a monthly time step. It returns the adult population abundance at the end of the year, which is used as one of the performance metrics and is also used by the trout routing model to determine if mechanical removal would be triggered in the next year. The humpback chub submodel includes parametric uncertainty including levels for a critical uncertainty related to the effect of rainbow trout on humpback chub survival and growth, as well as variation in other parameters. The humpback chub submodel also includes interannual variability in recruitment and outmigration.

More detailed information about each of the submodels is provided in the following sections.

F.3.1.1 Glen Canyon Trout Submodel

An age-structured population dynamics model was used to predict the abundance and growth of rainbow trout in Glen Canyon and the number of those fish that migrate into Marble Canyon. The model makes predictions on an annual time step for ages 1–6 yr. Annual recruitment, which was defined as the number of age-0 fish (i.e., fish hatched in the current year) that enter the population in a given year, is predicted based on flow statistics, and growth is predicted as a decreasing function of overall rainbow trout abundance. Abundance, in combination with age-specific angling vulnerabilities, is used to make predictions of angler catch per hour of effort. Predicted abundance and size distributions are used to compute the number of high-quality fish (trout ≥16 in. total length) potentially available for capture. The number of fish migrating from the Glen Canyon reach into Marble Canyon each year (out-migrants) is predicted as a proportion of the previous year's recruitment, and is used to determine the potential number of fish that eventually migrate down to the confluence of the Little Colorado River (RM 61), where their effects on humpback chub are simulated. Basic simulation parameters and those for key functional relationships were derived or fitted to values from the Korman et al. (2012) stock synthesis model. This model used 21 years of electrofishing-based catch-per-effort data for Glen

and Marble Canyons, in conjunction with length frequencies and other information, to estimate annual recruitment, survival rate, von Bertalanffy growth parameters, and outmigration patterns (numbers, size, and timing). Specifics of the Glen Canyon trout simulation model are provided below.

Recruitment

The annual recruitment of age-0 trout in Glen Canyon was predicted based on a multiple linear regression driven by flow-derived independent variables. The model predicted log annual recruitment as a function of annual Glen Canyon Dam release volume, the range in mean daily flows during the critical early life history rearing period (May–August), and the presence of a spring HFE in each year or in the previous year (Korman et al. 2011c; Avery et al. 2015). The model explained 55% of the annual variation in the recruitment estimates from the Korman et al. (2012) stock synthesis model between 1990 and 2010 (Figure F-1). The flow-dependent regression model predicted that recruitment would be higher in years with greater annual volumes, reduced daily variation in flow between May and August, and when spring HFEs occur. In the simulation model, log recruitment each year is predicted from a random normal distribution, with the mean determined by linear regression parameters and hydrologic statistics, and the extent of error determined by the residual error in the regression model.

Recruitment for a given year was predicted to be higher if a spring HFE occurred in that year or in the previous year, based upon empirical relationships reported by Korman et al. (2011c). However, there is insufficient information to draw a conclusion about whether HFEs that occur in the fall would have a similar effect on recruitment of trout. The model considered this uncertainty about the effect of fall HFEs on recruitment of rainbow trout in the Glen Canyon reach by examining two hypotheses: (1) fall HFEs would have no effect on recruitment and (2) recruitment would increase at the same rate as seen with spring HFEs, but for only one year instead of two.

As described in Section 2.3.3.2 of the DEIS, TMFs are a special type of fluctuating flow designed to reduce the recruitment of trout by disadvantaging young-of-the-year (YOY) trout. TMFs have been proposed and developed on the basis of research described in Korman et al. (2005). TMFs are included as elements of some alternatives evaluated in the LTEMP DEIS, and the Glen Canyon trout submodel incorporated the ability to consider the effects that occurrence of TMFs could have on trout resources. For alternatives and associated long-term strategies that included TMFs, these flows were triggered in the model during years in which the initial production of YOY rainbow trout (based on hydrologic characteristics) in the Glen Canyon reach was anticipated to be greater than 200,000 individuals. Because there is uncertainty regarding how effective TMFs would be at disadvantaging YOY trout, the model was used to evaluate two different levels of effectiveness by reducing the number of YOY trout surviving to age-1 by either 10% or 50% for each 20-year simulation period.

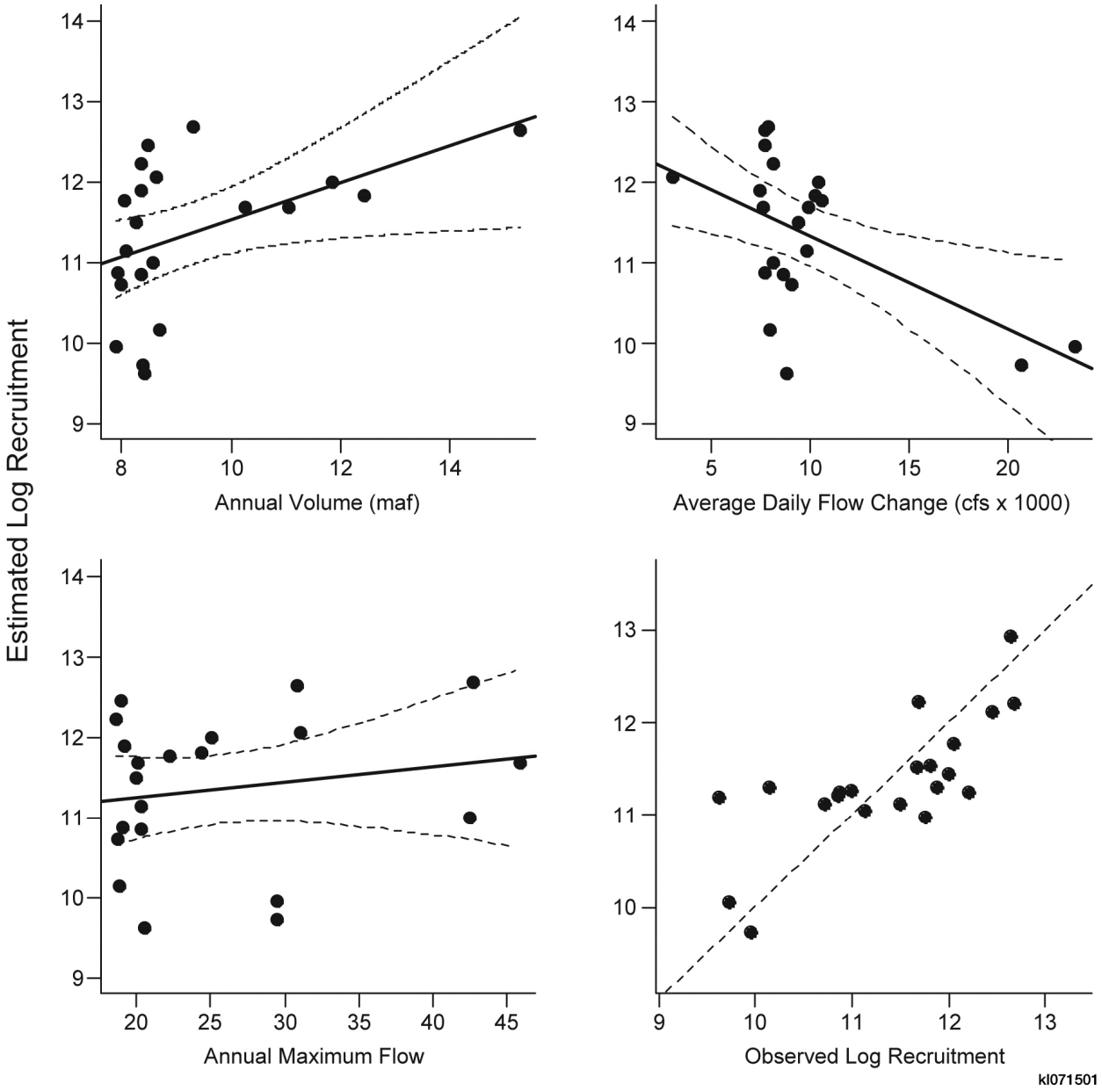


FIGURE F-1 Fit of Regressions Predicting the Log of Recruitment of Rainbow Trout in the Glen Canyon Reach Estimated by the Korman et al. (2012) Stock Synthesis Model as a Function of the Annual Release Volume from Glen Canyon Dam (million acre-feet), the Range of Mean Daily Flows during May–August (thousand cfs), and the Maximum Flow (cfs) Each Year (The bottom-right plot compares the overall fit of a multiple regression model with annual volume and range of mean daily flows during May–August as independent variables, and with the maximum annual flow independent variable replaced with a dummy variable with values of 1 for years prior to or with spring HFEs. The dashed line in the bottom-right graph indicates the 1:1 relationship and the 95% confidence interval in other graphs. The multiple regression model explained 55% of the variation in log recruitment and was statistically significant [p = 0.002].)

Growth

Length-at-age was calculated assuming a von Bertalanffy relationship that depends on the Brody growth coefficient ($vbK = 0.55$), the asymptotic length (L_{inf}, size at the terminal age), the coefficient of variation in length-at-age ($cvLen = 0.1$), and the mean size at age 1 ($L_0 = 130$ mm). Parameter estimates were derived from the stock synthesis model, which was fit to length-frequency and supplemental growth data (Korman et al. 2012, 2011a,b). Annual variation in asymptotic length was predicted as a linear function of the abundance of trout >150 mm. This model predicts only 18% of the annual variation in the annual asymptotic length estimates from the stock synthesis model (Figure F-2). To simulate interannual variation in L_{inf} in the model, annual deviates of L_{inf} in log space were added to a base value (5.89). In the simulation, predicted deviates from the $L_{inf} - N > 150$ regression model were added to the base value, and these formed the mean of a random normal distribution with a standard deviation equal to the residual error of the regression model.

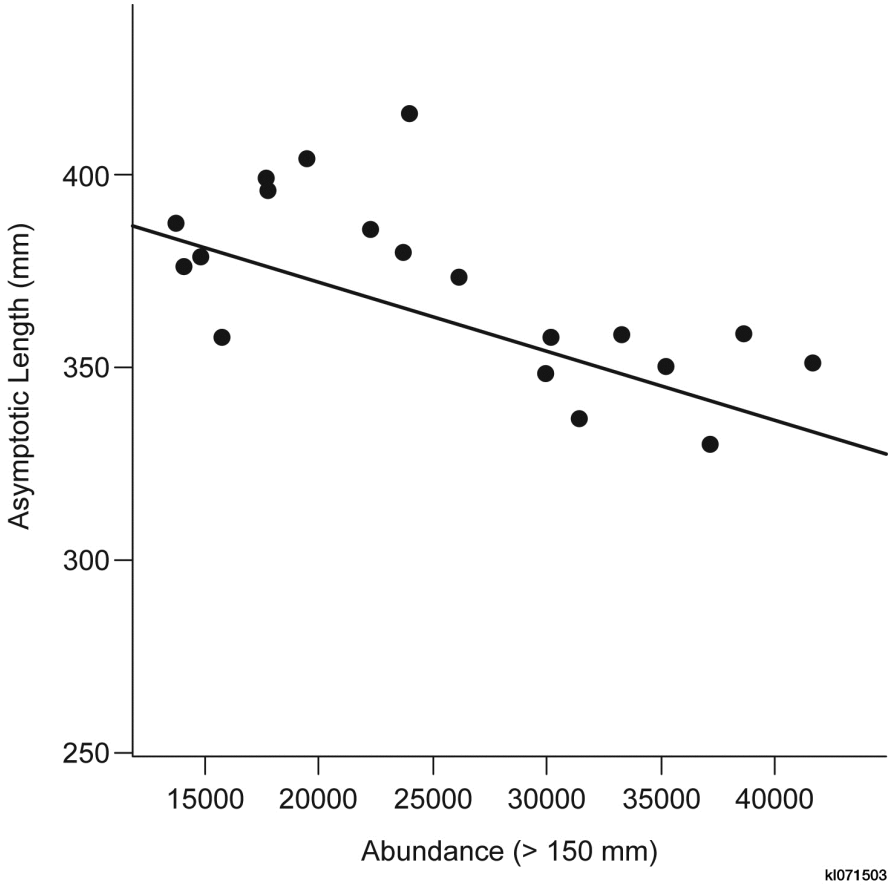


FIGURE F-2 Relationship between Annual Estimates of the Asymptotic Length of Rainbow Trout in Lees Ferry Predicted by the Stock Synthesis Model as a Function of the Estimated Abundance for Fish >150 mm (approximately age 1+) Each Year (The solid line is the best-fit relationship. This relationship explained 18% of the annual variation in asymptotic length and was not statistically significant [p = 0.056].)

Performance Metrics from Glen Canyon Trout Submodel

Four performance metrics were derived from the trout submodel in order to evaluate the relative degree to which the various alternatives would achieve a healthy high-quality recreational trout fishery in Glen Canyon National Recreation Area and reduce or eliminate downstream trout migration consistent with National Park Service fish management and Endangered Species Act (ESA) compliance needs. These four trout performance measures were:

1. Glen Canyon trout abundance index (for age 1+ fish)

2. Catch rate index (#/hr) for age 2+fish

3. Number of trout >16 in. total length

4. Trout emigration estimate (number of age-0 trout moving into Marble Canyon from Glen Canyon)

The Glen Canyon trout abundance index was calculated as the average of modeled annual abundance of trout that were 1 year of age or older during each 20-year simulation period. The model used an age-structured population dynamics model to calculate the annual abundance for age classes 1 through 6 based upon annual recruitment rates and density-dependent survival rates.

The catch rate index was calculated as the average annual angling catch per unit of effort (number of fish per hour) during the 20-year simulation period. Only fish 2 years of age or older were considered vulnerable to angling. The annual angling catch per effort in the fishery (CPE_{yr}) was predicted as the sum of products of an overall catchability coefficient ($q = 4.25e^{-05}$), age-specific vulnerabilities ($V_1 = 0$, $V_2 = 0.5$, and V_3 *to* $V_6 = 1$), and the predicted age-specific abundance for the year ($N_{yr,a}$):

$$CPE_{yr} = \sum_{a=0}^{6} \left(q \times V_a \times N_{yr,a} \right)$$

To estimate q, the simulation model was run using the recruitment estimates from the stock synthesis model to predict age-specific abundance between 1990 and 2010. The value for q was then calculated from the back-transformed average of the log of the ratio of the observed CPEs to the estimates of the vulnerable population each year. Thus, q represents the average scalar required to convert predicted vulnerable abundance to the observed CPE.

In order to evaluate the potential for large trout to be present in the population under a given alternative, a performance metric was calculated as the average of the annual modeled number of fish equal to or greater than 16 in. that would be present in the Glen Canyon reach. The number of trout in the population with total lengths equal to or greater than 16 in. during a given year was predicted as the sum of the products of the abundance-at-age and the proportion of the age with lengths greater than or equal to 16 in. That proportion meeting the length

criterion is predicted based on a normal distribution (*pnorm*) with a mean predicted by expected length-at-age ($Len_{yr,a}$) determined using the von Bertalanffy relationship and a standard deviation determined by the coefficient of variation in length-at-age (*cvLen*):

$$N_{qual,yr} = \sum_{a=0}^{6} \left(N_{yr,a} \times pnorm\left(16, Len_{yr,a}, cvLen \times Len_{yr,a}\right)\right)$$

The trout emigration performance metric was calculated as the average of the annual modeled number of trout migrating from Glen to Marble Canyon during a 20-year simulation period. The Glen Canyon Trout submodel computes the number of trout migrating to Marble Canyon as a fraction of the recruitment estimate from the previous year (Figure F-3). A linear model with a zero intercept explained about 70% of the estimated outmigration from Korman et al. (2012). The model predicts that on average, the number of out-migrants is 42% of the recruitment value from the previous year; however, there is considerable interannual variation in this percentage (95% of values are between 0 and 91%). A normal distribution (*rnorm*) with a mean equal to the mean of the logit-transformed annual proportions and a standard deviation equal to the standard deviation of the transformed proportions was used to simulate the proportion of fish out-migrating in each year of the simulation. The back-transformed proportions were then multiplied by the previous year's recruitment ($Rec_{\text{yr-1}}$) to calculate the out-migration each year:

$$Out_{yr} = Rec_{yr\text{-}1} \times \text{logit}(rnorm(\text{mean} = -0.35, \text{sd} = 1.65))$$

Parameter estimates for the key linear models (recruitment-flow, out-migration-recruitment, asymptotic length-abundance) were estimated by linear regression. The variance-covariance matrices for these models, which represent the extent of uncertainty in parameter estimates and their covariation, were used to generate 1,000 different parameter values for each relationship. The simulation model integrated over these values to incorporate uncertainty in key functional relationships when making predictions for any long-term strategy and hydrologic trace.

In addition to the performance metrics that were used to evaluate the potential effects of alternatives and long-term strategies on the trout fishery and downstream migration of trout, the trout submodel also kept track of the number of TMFs expected to be triggered during each 20-year simulation period. The number of TMFs during a 20-year period was used as one indicator of how American Indian Tribes, some of which consider lethal actions to fish an adverse effect if there is no beneficial use, could be affected by alternatives and long-term strategies (see Appendix I) rather than a measure of effects on the trout fishery itself.

Evaluation of Trout Submodel

Annual flow statistics for Glen Canyon Dam were computed from the historical record between 1990 and 2010 and used as input to the Glen Canyon trout model to compare predictions with observations and best estimates of key state variables such as recruitment,

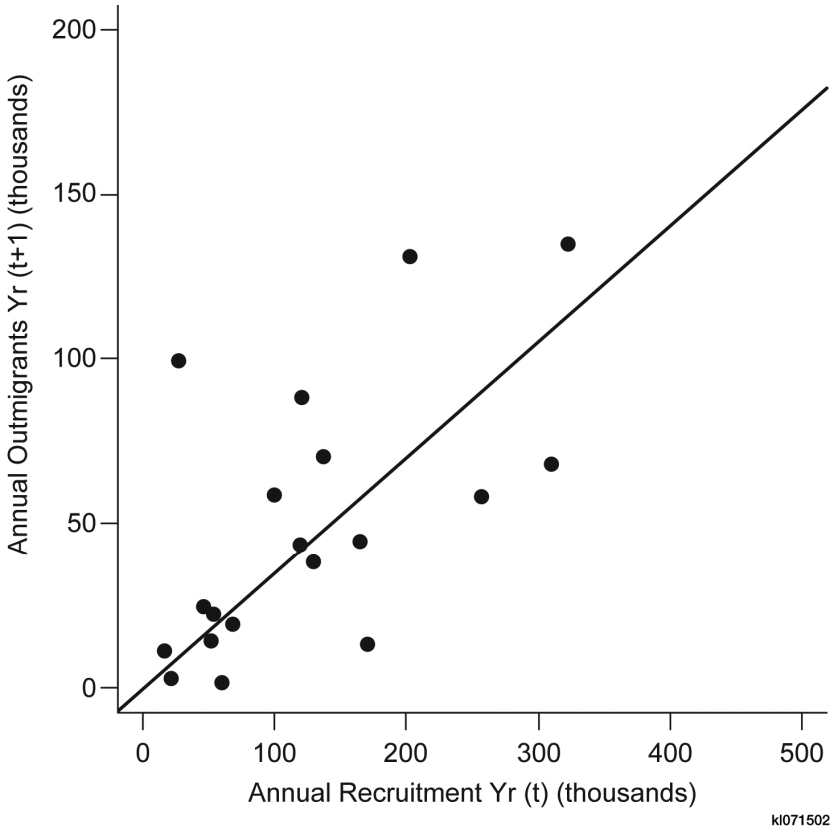


FIGURE F-3 The Relationship between Annual Recruitment of Rainbow Trout in Lees Ferry Estimated by the Korman et al. (2012) Stock Synthesis Model and the Number of Trout That Emigrate from Lees Ferry into Marble Canyon the Following Year (The solid line represents the best-fit relationship, which assumes no out-migration when there is no recruitment in the previous year [i.e., the line is forced through the origin]. This relationship predicted 72% of the annual variation in estimated out-migration and was statistically significant [p < 0.001].)

out-migration, and size at the terminal age. Predictions of angler CPE were compared to estimates of annual CPE from the Arizona Game and Fish Department (AZGFD) creel survey (Makinster et al. 2011). Simulations were based on most likely parameter estimates from the key regression models (recruitment-flow, outmigration-recruitment, asymptotic length-abundance) and did not include interannual variation in predictions to facilitate comparisons of predictions and data. Predictions of abundance were compared to the interannual trend in AZGFD electrofishing surveys. Other predictions (recruitment, asymptotic length, and out-migration) were compared to best-fit estimates from the Korman et al. (2012) stock synthesis model.

The historical flow-driven predictions of recruitment made by the simulation model produced an interannual trend quite similar to the estimates produced by Korman et al. (2012; Figure F-4, top-left panel). However, the model substantially over-predicted recruitment in 1996 and under-predicted recruitment in 2007–2009. The effects of high annual volumes and spring

floods on recruitment may be confounded with other variables in the multiple regression model due to the low frequency of these events in the period of record.

The trend in predicted abundance from the model generally matched the trend in electrofishing-based CPE (Figure F-4, middle-left panel). The model over-predicted abundance in 2005–2007, perhaps because it did not account for a number of unusual events in earlier years that likely affected recruitment and adult mortality (e.g., a sudden change in minimum flow due to an emergency shutdown of Glen Canyon Dam generators, very few spawners in 2006, mortality of adults due warm water and low dissolved oxygen in releases during the fall of 2004). The trend in asymptotic length predicted by the model did not provide a good fit to the trend from the Korman et al. (2012) stock synthesis model. This is not surprising, as trout abundance was a relatively poor predictor of asymptotic length (Figure F-3), especially in years when other factors (e.g., low food availability, high mud snail abundance) appeared to have strong effects. Factors such as food availability and quality and long-term trends in reservoir productivity are likely more important drivers of growth than abundance.

The model was only partially able to reproduce the observed trend in angling CPE (Figure F-4, top-right). It correctly predicted an increase with abundance between 1992 and 1997. However, observed CPE for the following 3 years was relatively stable, while model predictions indicated that CPE increased by about 3-fold. As the model provided a relatively good fit to the observed trend in electrofishing CPE over the majority of the historical period, this likely indicates that catchability (q) declined beginning in 1999. Possible mechanisms include a reduction in q at higher trout densities, as a greater fraction of fish use less vulnerable habitats, or reduced q at lower flows (which began in 1999). The predicted number of quality-sized fish in the population (dashed line, top-right) has been low over the entire historical period (<1000) and declined from maximum values at the start of the period due to increasing abundance (top-left), which reduced asymptotic length (bottom-left).

The trend in simulated out-migration estimates was reasonably close to the historic trend estimated by the stock synthesis model (Figure F-4, lower-right). The proportion of recruitment that out-migrates each year is not constant (Figure F-2), and this simplification in the application of the simulation model to historical data leads to some of the error in out-migration estimates. Departures between the best recruitment estimates (Korman et al. 2012) and those derived from the flow regression (Figure F-4, top-left) increases the extent of error in out-migration estimates.

F.3.1.2 Trout Movement Submodel

One component of the LTEMP trout/humpback chub simulation model is the movement of rainbow trout from Glen Canyon to near the confluence of the Little Colorado River. The trout movement model predicts the monthly abundance of trout within each mile segment of the Colorado River from RM 0 to RM 150 and reports monthly abundance over broader river reaches as required for the humpback chub population dynamics model. While the LTEMP Rainbow Trout-Humpback Chub model is not focused on locations below approximately RM 66, the trout movement model extends below this location to avoid problems with modeling boundary conditions near the Little Colorado River. Key inputs to the trout movement model

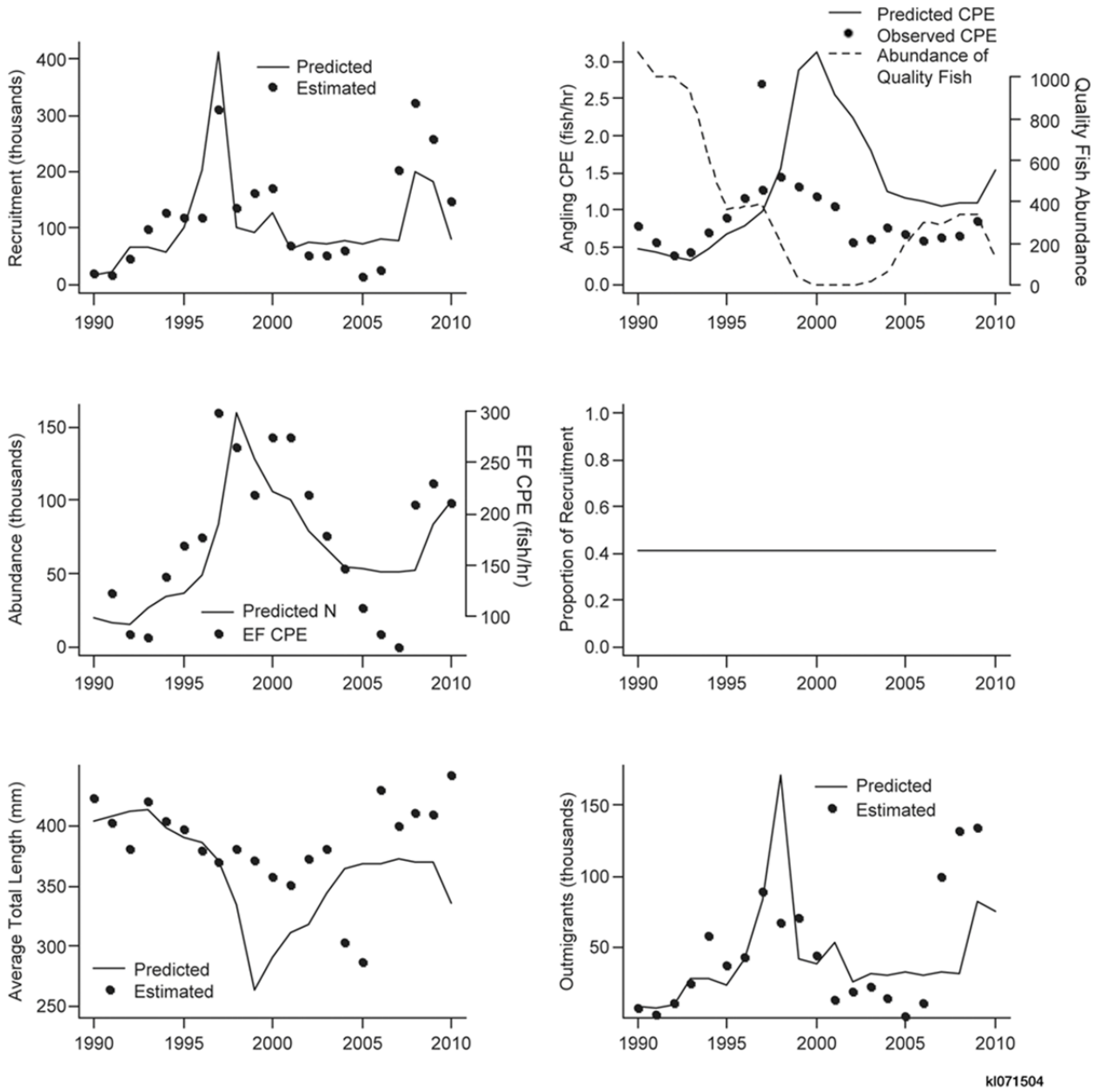


FIGURE F-4 Fit of the Glen Canyon Rainbow Trout Simulation Model to Predictions of Recruitment (top left), Asymptotic Length (bottom left), and the Number of Out-migrants (bottom right) Predicted by the Korman et al. (2012) Stock Synthesis Model (Also shown is the predicted abundance relative to catch per effort [CPE] from AZGFD electrofishing surveys [middle left], the predicted angling CPE compared to AZGFD creel survey estimates [top right], and the average proportion of recruitment that migrates from Glen to Marble Canyon each year [middle right].)

include the monthly number of age-0 trout out-migrating from the Glen Canyon reach, parameters that control the movement and dispersion of rainbow trout in Marble/Grand Canyons, the natural mortality rate of rainbow trout, and the number, intensity, and timing of nonnative mechanical removal trips conducted each year. The rules governing the implementation of

mechanical removal were specified based on the Biological Opinion on nonnative fish control (Reclamation 2011b). Monthly movement and dispersion do not depend on trout density and are modeled as a random process following a Cauchy distribution of movement distances. To allow parameter estimation and to evaluate the ability of the model to reconstruct historic trout abundance patterns, model-predicted catch of rainbow trout from sampling efforts in 2000–2009 was compared to the observed catch.

The trout movement model accounts for the abundance of rainbow trout at a monthly time step and in one-mile-long river segments (RM segments) from RM 0 to RM 150. The age and size structure of the population was not modeled, although all immigrants from Glen Canyon are assumed to be YOY. At the end of each month, trout within each RM segment are diminished by some survival rate and then distributed to other RM segments according to a RM segment-specific movement distribution. This calculation is accomplished via matrix operations as:

$$n(t+1) = MSn(t),$$

where n is a vector containing the abundance of rainbow trout within each RM segment, M is the movement matrix specifying how the abundance at a particular RM segment is distributed to other segments, S is the survival matrix where the diagonal contains the survival of fish within each RM segment and all other elements are zero, and t is the month of the year.

Number of Trout from the Glen Canyon Reach

The number of fish entering the upstream-most RM segment in the model (RM 1) each month equals the number of annual emigrants calculated by the Glen Canyon trout submodel. The monthly number of trout entering the reach was assumed to be 1/12 of the annual total emigrants, as migration timing was assumed to be uniform across months.

Survival

Instantaneous natural mortality rate (M = 0.49/year) was assumed to be temporally and spatially constant and corresponded to a monthly survival rate of 0.96 based on mark recapture-based methods from the Natal Origins project (Korman et al. 2015). In the RM segments RM 56 to RM 66, monthly survival is also potentially influenced by mechanical removal operations. Survival rate associated with mechanical removal was modeled as:

$$MR_{surv} = (1-p),$$

where MR_{surv} is survival from mechanical removal, p is the electrofishing capture probability, and D is the number of times fish are removed from each RM segment (number of passes). Thus monthly survival rate in RM segments where mechanical removal is not conducted was 0.96, and in RM segments where mechanical removal was conducted, it was $0.96 \times MR_{surv}$. The diagonal elements of the survival matrix S contained these RM segment survival rates and non-diagonal

elements were zero. Capture probability (p) was assumed to be 0.10, based on recent work from the Natal Origins project (Korman et al. 2015).

Mechanical Removal

Mechanical removal in RM 56–66 was triggered in a particular year when three conditions were simultaneously met: (1) mechanical removal was authorized under the alternative being modeled, (2) the estimated abundance of rainbow trout in the trigger reach (RM 63–64.5) during September of the previous year was greater than 760 individuals, and (3) the estimated number of adult humpback chub (from humpback chub submodel, see Section F.3.1.3) was less than 7,000 individuals. When the triggering conditions were met, mechanical removal was implemented as 6 removal trips that occurred from February through July. Occurrence of removal trips reduced the number of trout in the vicinity of the Little Colorado River during the month, based upon the abundance of trout and electrofishing capture probability estimated from past removal efforts.

Trout Movement

The movement of fish between RM segments was assumed to be a diffusion process in which the probability of a fish moving from each RM segment to every other RM segment followed a truncated Cauchy distribution. The distribution is said to be truncated as movement upstream of the RM 0 segment or downstream of the RM 150 segment was disallowed. The probability distribution for each RM segment was assumed to represent the proportions of fish that would move to every other segment and formed a row vector in a movement matrix.

Performance Metrics from Trout Movement Submodel

The principal purpose of the trout movement submodel was to provide inputs to the humpback chub population submodel pertaining to monthly estimates of the number of rainbow trout that would be present in the vicinity of the Little Colorado River and to calculate the number of trout that would be removed by mechanical removal efforts. Although there were no aquatic ecology performance metrics generated, the trout movement submodel was used to calculate the numbers of years in which mechanical removal trips were triggered for each 20-year simulation, and that calculation was used as an indicator of how Tribal resources could be affected by alternatives and long-term strategies (see Appendix I).

Two factors must coincide to trigger mechanical removal trips in the submodel: (1) there must be more than 760 adult rainbow trout projected for the test reach in the vicinity of the Little Colorado River confluence (RM 63–RM 64.5) and (2) the projected adult humpback chub population must be less than 7,000 individuals. The number of adult humpback chub is calculated by the humpback chub population submodel and provided as input to the trout movement submodel. Once triggered, the model assumes that 6 mechanical trip passes would occur during the year.

Estimating Model Parameters and Evaluating Model Predictions

Rainbow trout electrofishing catch data from 2000 through 2009 and between RM 0 and RM 65.7 were used to estimate the Cauchy scale distribution parameter and the catchability coefficient (q). These data were composed of the annual electrofishing catch and effort by the 10-mi reaches between RM 0–50 and by the reaches RM 50–61.5 and RM 61.5–65.7 (Makinster et al. 2011). The annual predicted catches (C_i) for each reach (i) were computed as:

$$C_i = n_i \times E_i \times q,$$

where n_i is the model-predicted abundance of rainbow trout within reach *i* during the month of June and E_i is AZGFD electrofishing effort in June.

The observed catch was assumed to be distributed as a Poisson random variable with mean equal to the model-predicted catch. Estimation of the Cauchy scale (γ = 3.38) parameter and the catchability coefficient ($q = 3.4e^{-06}$) was accomplished via the method of maximum likelihood and the function "optim" within R (R Core Team 2013). These estimates provided a reasonably good fit to the data (Figure F-5), providing confidence that the simulation model would accurately portray movement dynamics of rainbow trout. A more complex parameterization of the Cauchy distribution was tested, where the location parameter (which specifies the most probable movement distance) was estimated as a free parameter. The maximum likelihood estimate of the location parameter was approximately $5.0\ e^{-03}$ confirming that most fish do not change location on a monthly basis. A normal distribution also was considered to describe movement distance, but there was a better fit to the data using the Cauchy distribution. Additionally, the Cauchy distribution of movement implies a smaller probability of fish moving long distances within a month than the normal distribution (Figure F-6) and is more biologically reasonable, considering the observed movement of tagged trout (unpublished data, GCMRC database).

F.3.1.3 Humpback Chub Population Submodel

A size- and location-structured population dynamics model was used to predict the size of the adult population of humpback chub over time. The model assumes five size classes of humpback chub (40–99 mm; 100–149 mm; 150–199 mm; 200–249 mm; and >250 mm, which are named size class 1–5, respectively) and two locations (Little Colorado River and Colorado River) for a total of 10 "states" (where a state is a unique combination of size and location; for example, a fish in the Little Colorado River that is 40–99 mm is in state 1; Figure F-7). The structure of this model is based on recent modeling work (Yackulic et al. 2014) as well as a new set of candidate models developed specifically to address the effects of temperature and rainbow trout on humpback chub survival (see "Model Selection and Development" below). The model uses a monthly time step and assumes constant survival for all states except for state 6, corresponding to juveniles in the Colorado River. Survival for this state depends on rainbow trout abundance. Growth of size class 1 (40–99 mm) humpback chub depends on both water temperature and rainbow trout abundance. Growth for all other size classes in the Colorado River is temperature-dependent, while Little Colorado River growth is assumed constant. Movement

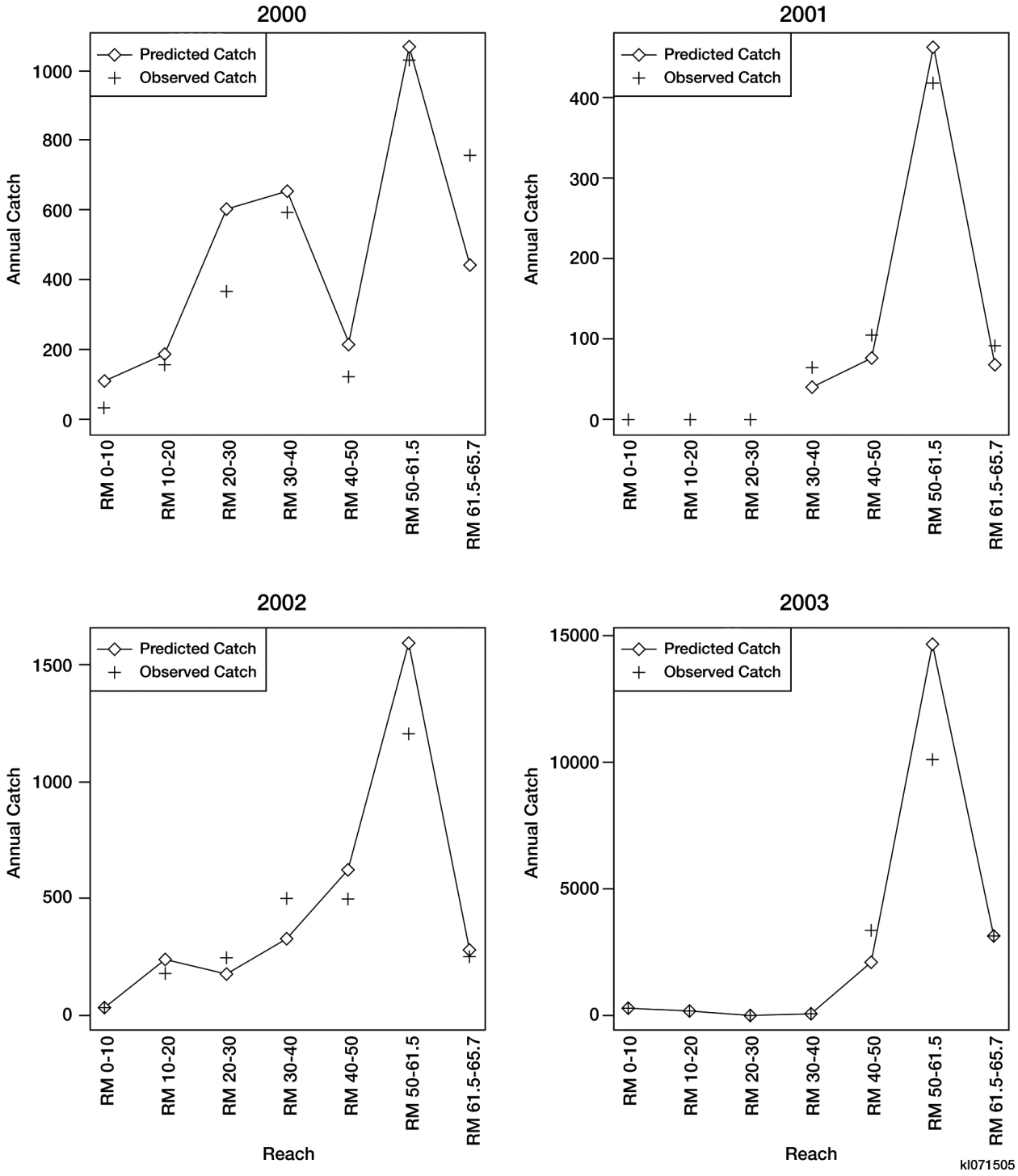


FIGURE F-5 Predicted and Observed Annual Catch of Rainbow Trout by Year and River Reach

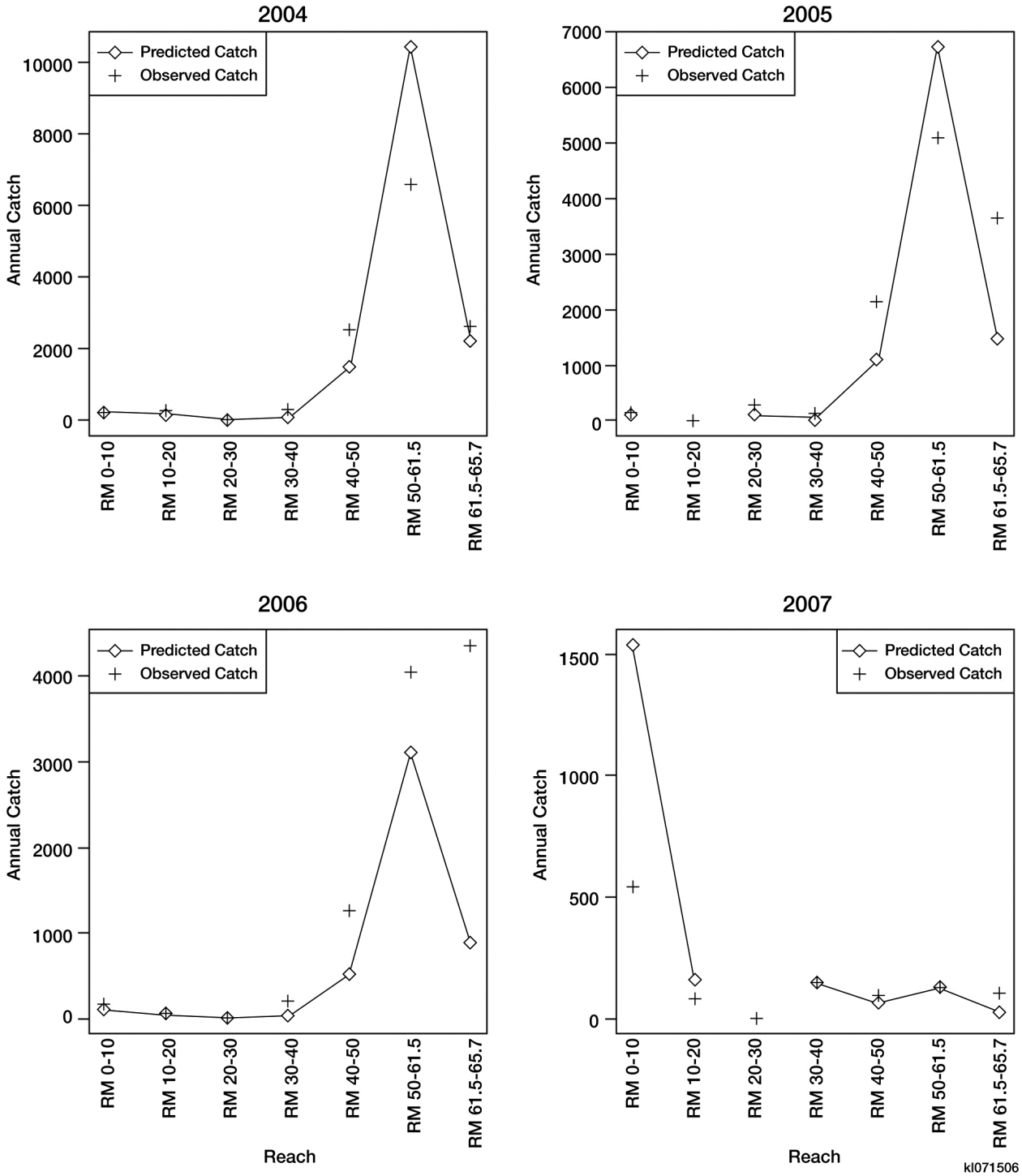


FIGURE F-5 (Cont.)

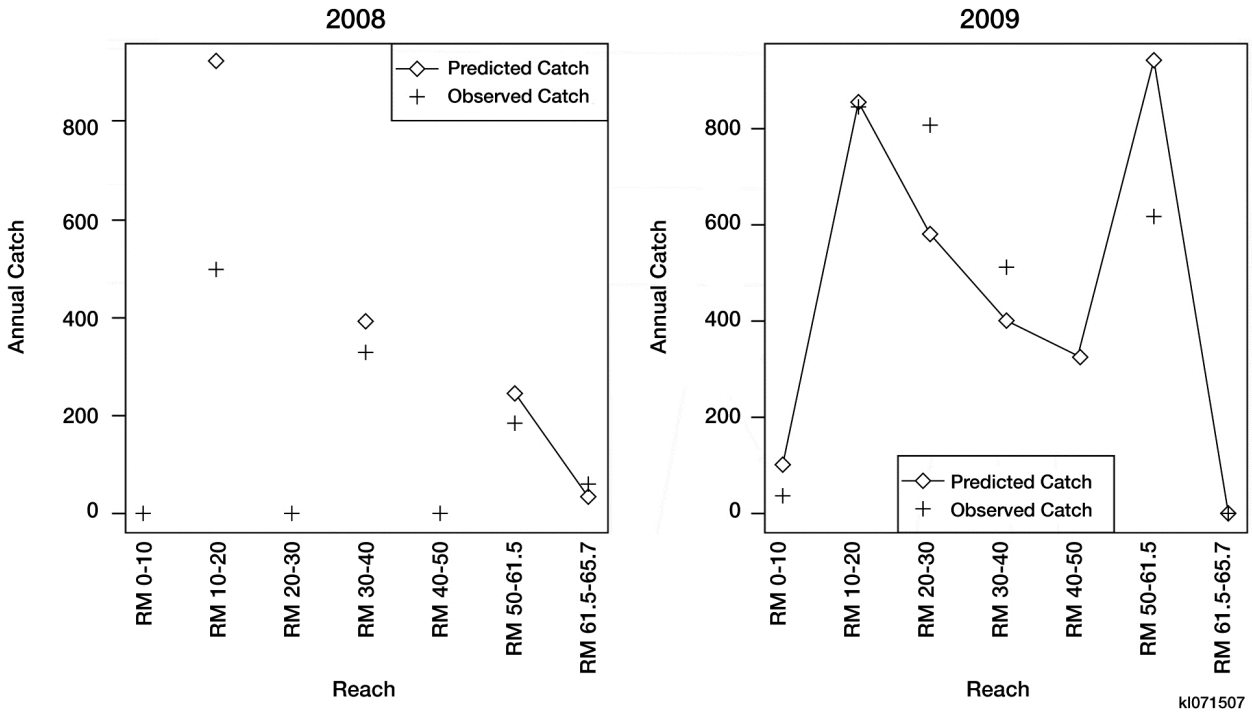


FIGURE F-5 (Cont.)

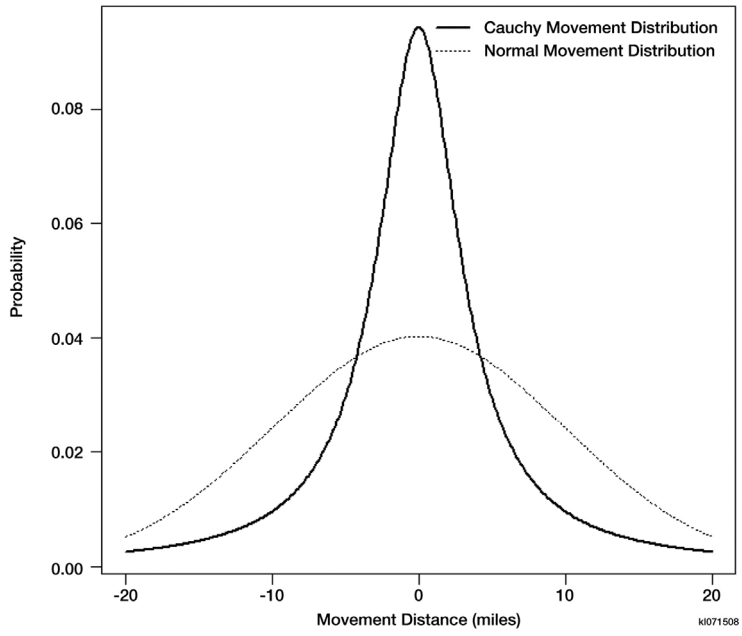


FIGURE F-6 Best-Fitting Distributions Describing Monthly Movement of Rainbow Trout in Marble Canyon Assuming Either a Normal or Cauchy Distribution (The Cauchy distribution implies a lower probability of large monthly movements and agrees better with movement observations from tagging data.)

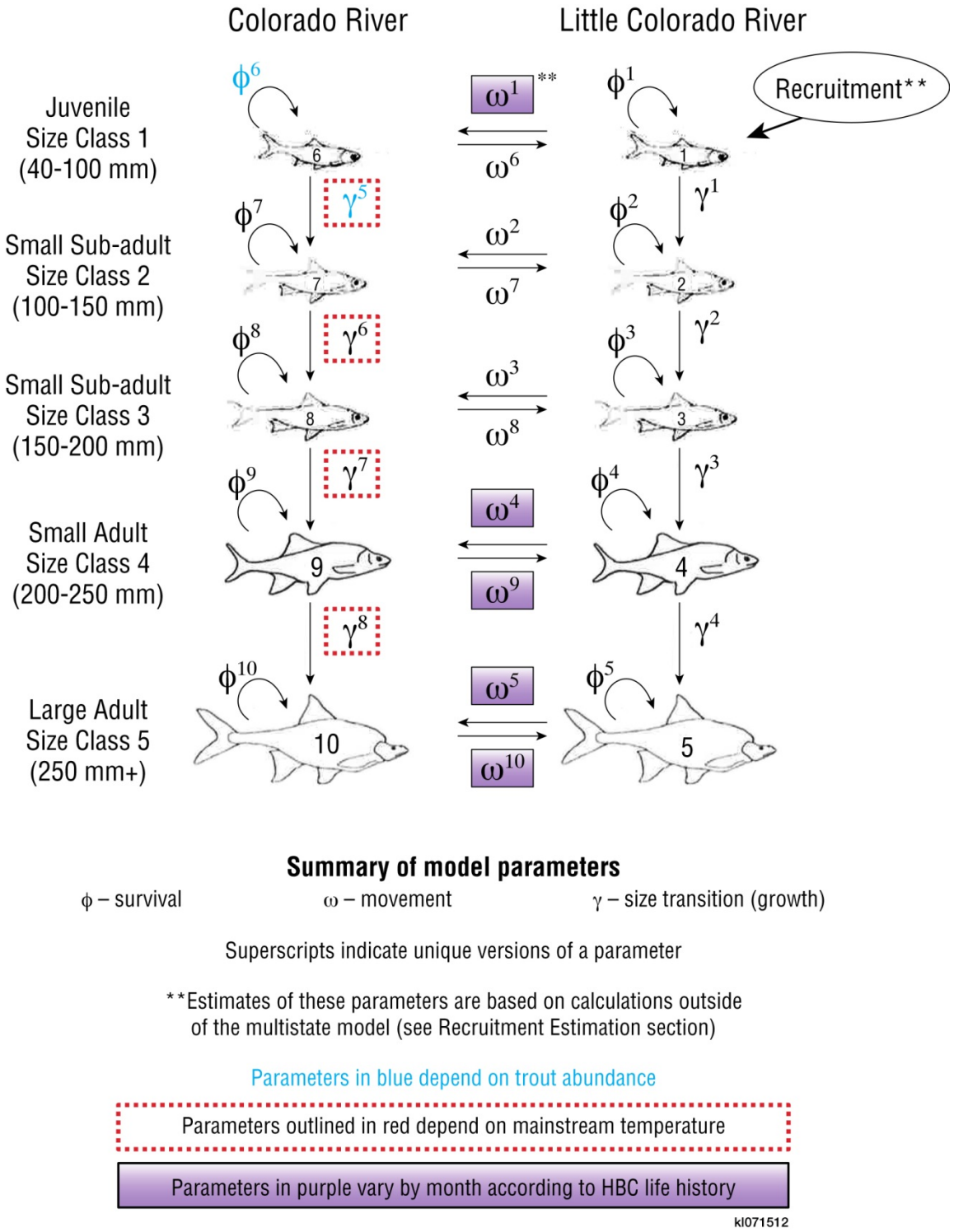


FIGURE F-7 Visual Summary of Humpback Chub Population Model Structure (The number on each fish represents its state number. Modified from Yackulic et al. [2014].)

between the Little Colorado River and Colorado River is modeled via movement parameters that vary depending on the month and size class (see Yackulic et al. 2014, for more details regarding movement parameters). In addition to parameters describing survival, movement, and growth, the simulation model also relies on estimates of the starting abundance in each of the 10 states, as well as assumed annual recruit abundance.

All YOY fish recruit to state 1 (i.e., size class 1 fish in the Little Colorado River) in July. Most parameters were estimated directly from data collected during 2009–2013 in the Colorado River and 2009–2012 in the Little Colorado River. Recruitment was approximated by comparison of estimated juvenile abundances in the Colorado River and Little Colorado River between 2009 and 2012. This analysis also led to modification of the value for the movement parameter associated with juvenile out-migration from the Little Colorado River (see "Recruitment Estimation" below). Yackulic et al. (2014) had previously speculated that this parameter might be biased, since July marking of juveniles has, until recently, been limited to a small section of the Little Colorado River proximate to the Colorado River that is likely to experience higher overall out-migration than the Little Colorado River as a whole. Recruitment estimates were also influenced by recent research suggesting severely diminished recruitment in years with little winter runoff in the Little Colorado River (Van Haverbeke et al. 2013).

Having estimated the maximum likelihood ("best") values of parameters based mainly on data collected from 2009 to 2013, the simulation model was run using a 20-year sequence of observed temperatures near the Little Colorado River between 1990 and 2009, as well as predictions of rainbow trout abundance for this period from the Glen Canyon and trout movement submodels. These outputs were compared to trends reported in Coggins and Walters (2009), as discussed in "Evaluating Model Predictions," below. Potential uncertainties in model predictions are discussed in "Model Uncertainties" below.

Model Selection and Development

The primary objective for the humpback chub population model was to estimate the effects of mainstem temperature and trout abundance on humpback chub population dynamics (i.e., growth and survival). Six candidate models that represent different *a priori* hypotheses concerning potential effects were evaluated:

- Model A: Rainbow trout and temperature have no effect on growth and survival.

- Model B: Survival of size class 1 humpback chub in the Colorado River is a logit linear function of rainbow trout abundance. Growth of all size classes in the Colorado River are logit linear functions of temperature with independent intercepts for each size class and a shared slope (a model with different slopes for each size class was considered, *a posteriori*, but this did not improve the fit considerably). Model B was based on the hypotheses that temperature is a primary control on growth rates and that rainbow trout mainly affect humpback chub by lowering the survival of juvenile humpback chub. This

does not mean that rainbow trout effects are solely predatory, as competition with trout could lead to lowered survival if humpback chub were forced to forage longer or in suboptimal habitat, leading to increased predation risk by species other than rainbow trout.

- Model C: As in Model B, but growth of size class 1 fish is a function of rainbow trout abundance in addition to temperature. Rainbow trout are hypothesized to affect humpback chub growth by forcing them into suboptimal habitats and directly consuming food resources that might otherwise be consumed by young humpback chub. This effect is likely to be greatest in young fish because they are frequently found in nearshore environments that rainbow trout also prefer.

- Model D: As in Model C, but growth of size class 2 humpback chub is also a logit linear function of rainbow trout abundance in addition to temperature.

- Model E: As in Model B, but survival of size class 1 fish is a function of temperature in addition to rainbow trout abundance. Increased temperature is expected to increase the swimming ability of juvenile humpback chub, which should in turn aid them in avoiding predation by a variety of fish species in the system.

- Model F: A combination of Models C and E.

A general model structure modified from Yackulic et al. (2014) was used to fit a series of mark-recapture multistate models using maximum likelihood. For more technical details, see Yackulic et al. (2014). Yackulic et al. (2014) suggested three important features of humpback chub movement between the Little Colorado River and Colorado River:

1. Juveniles out-migrate from the Little Colorado River at a different and higher rate during July through September as opposed to the rest of the year,

2. Smaller and larger adults spawn at different rates, and

3. There is evidence for a resident Little Colorado River population.

The models that were considered include the first two of these elements, but ignore the third element. The third element is ignored because it would make simulations more difficult and is likely to only apply to a relatively small portion of the adult population (about 15%). Moreover, since the model only considers those fish that move into the mainstem, the movement dynamics of the system can be well represented without this detail.

Monthly temperatures were calculated using data from U.S. Geological Survey (USGS) gage 09383100 located on the Colorado River above the confluence with the Little Colorado River. Rainbow trout abundance in 2012 and 2013 was calculated by averaging trip estimates from the Natal Origins project within each year. Rainbow trout estimates for 2009–2011 were

back-calculated based on the relationship between the catch between RM 63.4 and RM 64.8 and the estimated abundance in the same area.

Models were fit using general-purpose optimization algorithms provided by "optim" in R (version 3.0.2) using the BFGS (Broyden, Fletcher, Goldfarb and Shanno) method[1] and were run until convergence of all models was obtained. The variance inflation factor (c-hat) was calculated based on model F, and models were compared using the quasi-Akaike's Information Criterion (qAIC) calculation.[2] Model selection based on qAIC favored model C (summarized in Figure F-7), and estimates from this model were used for further steps. Figure F-8 illustrates the estimated relationships between temperature and trout and various survival and growth parameters. The maximum likelihood estimates from these relationships were used for backcasting, while combinations of the draws from the multivariate normal and critical uncertainties were used to characterize these relationships in simulations conducted for the comparison of LTEMP alternatives.

Recruitment Estimation

The one value needed for simulation that was not estimated in the model selection section is the mean annual recruitment, along with the variability around this mean. Annual recruitment is defined here as the number of YOY humpback chub present in the Little Colorado River in July. By July, most YOY are typically above 40 mm in total length. While some YOY will have left the Little Colorado River before this, several lines of evidence suggest that fish that leave the Little Colorado River before July do not contribute appreciably to population growth, given the temperature typically found in the Colorado River during May and June (Robinson and Childs 2001). Unfortunately, direct estimates of July YOY abundance in the Little Colorado River are not available. However, estimates from the Little Colorado River during September–October are available for 2001 through 2012 in Van Haverbeke et al. (2013), and were used here. The parameters estimated in the model should allow back-calculation of July YOY abundance in the Little Colorado River from the September abundance using the following formula:

$$N_J^1 = \frac{N_S^1}{\left[\emptyset^1\left(1-\omega_{JS}^1\right)\right]^2}$$

where N_J^1 is recruitment to state 1 in July, N_S^1 is recruitment to state 1 in September, ϕ^1 is the probability of survival during state 1 in the Little Colorado River, and ω_{JS}^1 is the probability of moving from the Little Colorado River to the mainstem Colorado River during the July-to-September period.

[1] For details regarding the "optim" function in the "stats" package for Program R, see http://www.inside-r.org/r-doc/stats/optim.

[2] For additional information, refer to http://www.inside-r.org/packages/cran/MuMIn/docs/QAIC.

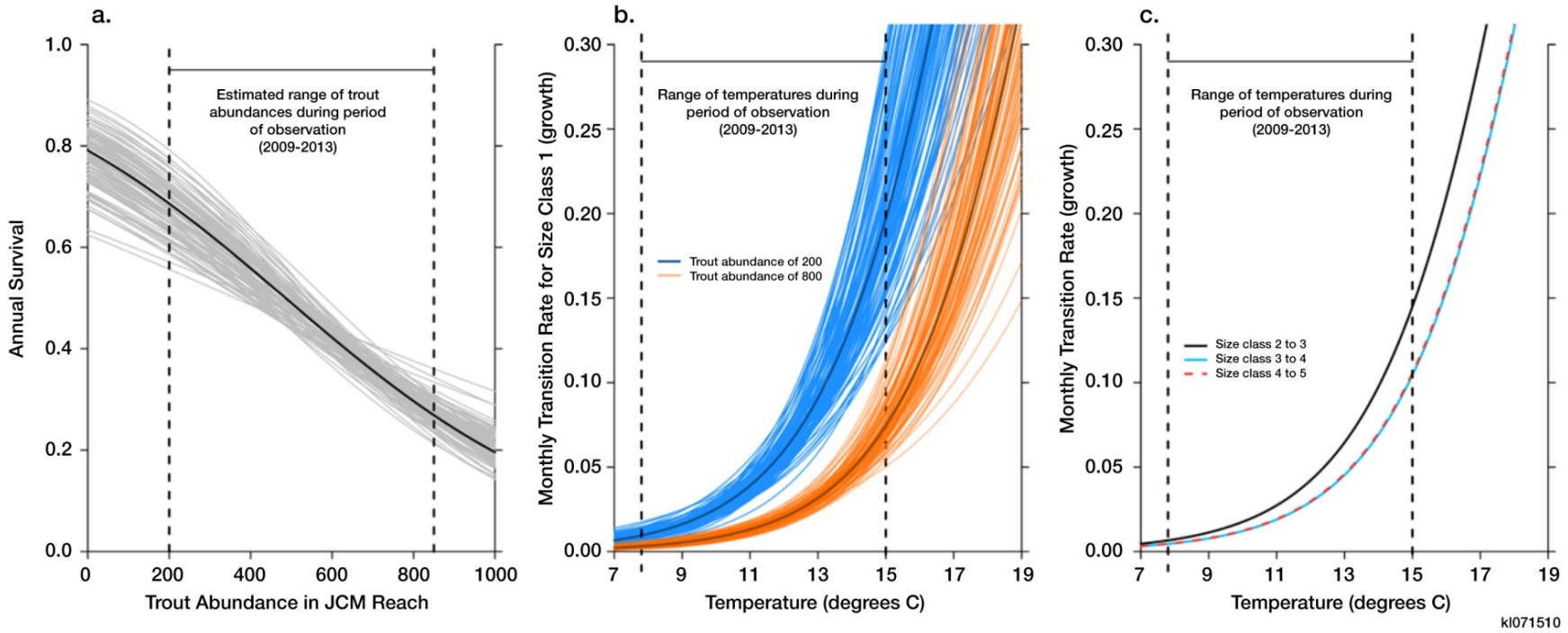


FIGURE F-8 Modeled Effects of Trout Abundance and Temperature on Humpback Chub Survival and Growth ([a] Annual survival of juvenile humpback chub [40–99 mm] declines relative to estimated trout abundance in the Colorado River; gray lines are based on 100 draws from a multivariate normal distribution based on maximum likelihood estimates and associated covariance matrix and give an indication of uncertainty around the maximum likelihood estimates in black. [b] Monthly size transition rates [proportional to growth] as a function of temperature with trout abundance set at either 200 or 800; as in panel [a], dark lines indicate best estimates and lighter lines are draws from a multivariate normal distribution giving an indication of uncertainty. [c] Dependence of size transition rates [growth] for larger fish on temperature. Note that relationships have a common slope but different intercepts. Uncertainty in these rates is comparable to the uncertainty around either of the curves in panel [b], with slightly more uncertainty around the intercept associated with the transition from size class 4 to size class 5.)

However, this approach is based on estimates of the monthly probability of size class fish moving from the Little Colorado River during the July–August and August–September intervals, ω_{JS}^1. Unfortunately, this is the parameter in the multistate model that is most likely to be biased because of details of sampling. In short, up until 2013, all July and August marking of humpback chub at the Little Colorado River was limited in its spatial extent to an area near the confluence, which is likely to have a higher rate of export than the Little Colorado River as a whole. Moreover, over two-thirds of the marked fish were marked in 2011 and 2012, years that exhibited large increases in the abundance of size class 1 humpback chub in the juvenile chub monitoring (JCM) reach, thereby suggesting higher export (see Yackulic et al. 2014, for a full discussion). Lastly, both July recruitment, N_J^1, and movement out of the Little Colorado River, ω_{JS}^1, may exhibit substantial interannual variability (in comparison to, say, adult survival), even though the limited number of marked fish released in July and August into the Little Colorado River in 2009 through 2012 does not allow us to estimate interannual variability in our models.

Therefore, a different approach was taken that is based on the estimated increase in size class 1 abundance in the JCM reach between July and September, as well as the estimated proportion of humpback chub in the JCM reach, τ, and survival rates in both the Little Colorado River, ϕ^1, and Colorado River, ϕ^6. (Note that humpback chub in size class 1 in the Colorado River are frequently two or more years old, whereas almost all size class 1 fish caught in the Little Colorado River in the fall are YOY fish). This approach involved solving the following equations for N_J^1 and ω_{JS}^1 for each year:

$$N_J^1 = \frac{N_S^1}{\left[\emptyset^1\left(1-\omega_{JS}^1\right)\right]^2}$$

and

$$N_J^1 = \frac{N_S^6 - N_J^6 \times \emptyset^6 \times \emptyset^6}{\left(\emptyset^1 \times \omega_{JS}^1 \times \emptyset^6 + \emptyset^1 \times \left(1-\omega_{JS}^1\right) \times \emptyset^1 \times \omega_{JS}^1\right) \times \tau}$$

This approach was applied to abundance estimates from 2009 to 2012 and resulted in estimated values of ω_{JS}^1 of 0.15, 0.28, 0.45, and 0.52 (mean, 0.35), with associated values of N_J^1 of 5,000, 17,000, 45,000, and 35,000 (mean, 25,000). Another aspect of recruitment highlighted in Van Haverbeke et al. (2013) is that in years with low runoff between January 1 and May 31, there appears to be weak recruitment, at least in terms of the number of YOY remaining in the Little Colorado River in the fall. Six years between 1990 and 2013 meet this criterion (1990, 1996, 1999, 2000, 2002, and 2006).

When backcasting historical trends, the mean values across years for both ω_{JS}^1 and N_J^1 were used, with the exception of "weak recruitment years" in which recruitment was assumed to be 2,500, based on an examination of estimates in Van Haverbeke et al. (2013). For forecasting, "weak" versus "strong" recruitment years were modeled as a Bernoulli process in which weak years occur with a probability of 0.25 (based on the observed frequency of these hydrologic conditions in the Little Colorado River from 1990 to 2013). For "strong" years, annual

recruitment values were drawn from a uniform distribution between 0 and 50,000. For both "strong" and "weak" years, out-migration was chosen randomly from a uniform distribution between 0.15 and 0.55.

Performance Metrics from Humpback Chub Population Submodel

The resource goal identified for humpback chub is to "meet humpback chub recovery goals including maintaining a self-sustaining population, spawning habitat, and aggregations in the humpback chub's natural range in the Colorado River and its tributaries below the Glen Canyon Dam" (DEIS Section 1.4). The humpback chub population submodel was used to calculate an estimate of the number of adult (i.e., >200 mm total length) humpback chub that would be present in the aggregation associated with the Little Colorado River for each year of a 20-year simulation period. In order to evaluate and compare the potential for alternatives and long-term strategies to lead to extinction or improvement of the humpback chub population in the Grand Canyon, the modeled minimum number of adult humpback chub that would occur during each 20-year simulation period was used as the performance metric.

Evaluating Model Predictions

Humpback chub population dynamics were backcasted using maximum likelihood estimates of parameters (see "Model Selection and Development" section), with the exception of the parameters related to recruitment and juvenile out-migration from the Little Colorado River (see "Recruitment Estimation" section) and an initial vector of abundances by state. Initially dynamics were simulated using a monthly time step; however, based on concerns expressed by C. Walters, the time scale was coarsened to six-month intervals so as to minimize potential issues related to numerical diffusion. This was accomplished by calculating a six-month transition matrix and then removing any transitions of more than one size class and adding these to the cells corresponding to a one size class transition. The initial structure of the population was based roughly on estimates from 2009 to 2012. For the Little Colorado River, abundance by size classes 1–5 was 4,000, 2,500, 1,800, 1,200, and 800, respectively, while corresponding Colorado River abundances by size were 20,000, 7,000, 5,500, 4,000, and 5,000. The simulation model was also provided a 20-year sequence of observed temperature near the Little Colorado River between 1990 and 2009, as well as predictions of trout abundance for this period that resulted from the Glen Canyon trout and trout movement submodels (Sections F.3.1.1 and F.3.1.1, respectively). While the backcasted simulation (Figure F-9) suggests a later decline than the Age-Structured Mark Recapture (ASMR) estimates (Coggins and Walters 2009), followed by a quicker recovery, the patterns are remarkably similar, given that parameters from the simulation model were derived primarily from a more recent period (2009–2013). Moreover, the ASMR estimation method is known to have some biases (Coggins and Walters 2009), so minor discrepancies are expected.

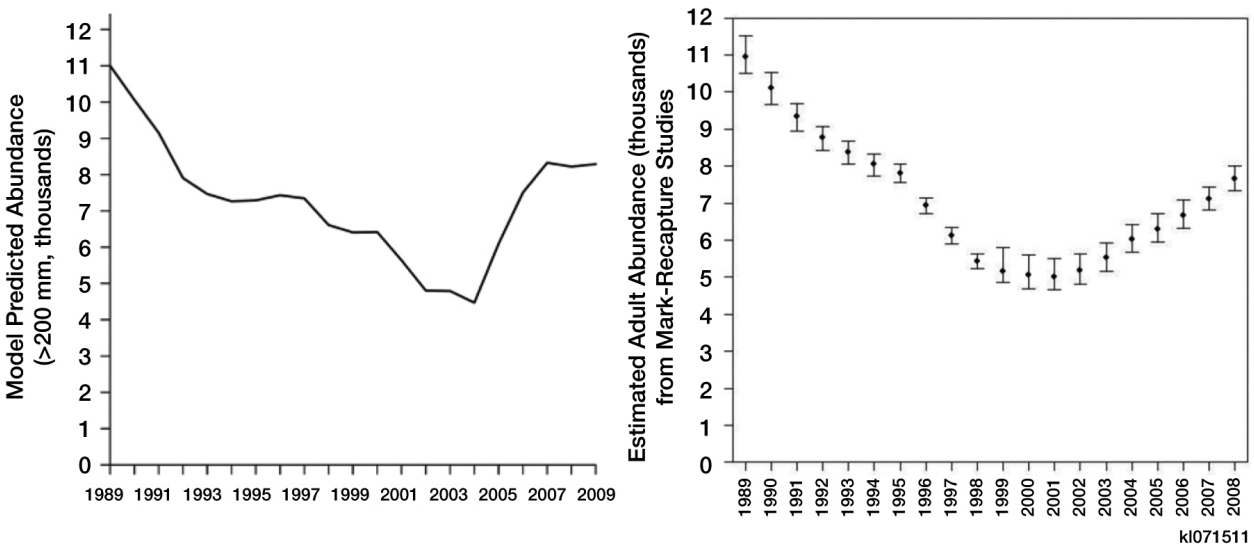


FIGURE F-9 Simulated Adult Abundances from Backcasted Model (left) Compared to Patterns Reported in Coggins and Walters (2009) (right)

Model Uncertainties

The model described here is based on the best available information and does a good job of backcasting the dynamics of humpback chub populations for a period of time (1990–2008) that is separate from the period of time (2009–2012) over which most parameters were estimated. However, like all models, it is only a representation of the actual system it seeks to describe. There are a number of conditions that could lead to dynamics in humpback chub populations that are different from those predicted with the model. Some of these conditions are listed here, in no particular order:

- No portion of this model explicitly models short- or long-term impacts of flows or temperature on the aquatic food base. Flow, particularly an increased frequency of flooding, has the potential to permanently change the composition of the invertebrate assemblage, as has been observed in other regulated rivers (Robinson 2012; see Section F.2). This shift could be beneficial for both rainbow trout and humpback chub resources, positive for one and negative for the other, or detrimental to both, and initial impacts may differ from long-term consequences. Similar, unpredictable shifts in the invertebrate assemblage could also occur because of long-term changes in release temperatures associated with climate change and lower Lake Powell reservoir elevations.

- Temperature–growth relationships estimated here are based on a relatively short period of record and do not consider seasonal patterns in food availability, light, and turbidity. As such, the humpback chub submodel assumes a temperature of 11°C (52°F) observed in clear water in June during

midge emergence will lead to the same growth as a temperature of 11°C (52°F) in August in turbid water. Moreover, monthly mean temperatures at the Little Colorado River confluence from 2009 to 2013 peaked at roughly 15°C (59°F), suggesting that modeling the effects of substantially warmer temperatures on humpback chub populations represents an extrapolation. On the other hand, the model did a reasonable job of backcasting dynamics during the 1990–2009 era, even though monthly temperatures reached 16.7°C (62°F) in one year (2005).

- The humpback chub model does not consider the potential effects of other fish species besides rainbow trout that are already relatively common in the system and known to eat humpback chub (e.g., brown trout and various catfish species), nor does it attempt to account for the negative effects of other warmwater nonnative fishes that could become prevalent if temperatures above 16°C (61°F) become common. Potential effects of cannibalism by humpback chub are also not directly considered by the model.

- Climate change could lead to increases in the proportion of "weak" recruitment years in the Little Colorado River, particularly if winter precipitation in the Little Colorado River watershed becomes less frequent.

F.3.2 Results for LTEMP Alternatives

The results for the Rainbow Trout-Humpback Chub Model for each of the alternatives (including associated long-term strategies) are summarized in the following sections. Values for the means of the six metrics resulting from the model are summarized in Table F-8. The magnitude of effects to rainbow trout and humpback chub populations are estimated using the performance metrics identified in Sections F.3.1.1, F.3.1.2, and F.3.1.3.

F.3.2.1 Rainbow Trout Performance Measures

This section summarizes the results for the performance measures for rainbow trout that were derived from the Rainbow Trout-Humpback Chub Model.

Rainbow Trout Population Estimates

The rainbow trout population estimates for the 19 LTEMP alternatives and associated long-term strategies are summarized in Figure F-10. Among all of the long-term strategies evaluated, the modeled average abundance of age-1 (i.e., individuals that are 1 year old) and older rainbow trout during the simulations of 20-year LTEMP periods ranged from about 48,000 to 242,000 individuals in the Glen Canyon reach. Overall means (i.e., mean abundance for all simulations) for the various long-term strategies ranged from approximately 61,000 individuals under long-term strategy E6 to approximately 160,000 individuals under Alternative F

(Table F-8; Figure F-10). The differences among the modeled population levels for rainbow trout reflect the estimated levels of annual recruitment based on the empirically derived flow-dependent regressions in the model that predict that annual recruitment of rainbow trout will increase as a function of greater annual volumes, reduced daily variation in flow between May and August, the occurrence of spring HFEs, and implementation of management actions (i.e., TMFs) that would decrease annual survival of YOY trout (see "Recruitment" in Section F.3.1.1) in high-recruitment years. Table 4.1-1 identifies the experimental elements included in the various long-term strategies, and Appendix E of the DEIS describes the number and duration of HFEs that would be expected under the various long-term strategies.

Although there is a considerable amount of overlap in the ranges of the estimates for some long-term strategies, the overall modeled average rainbow trout abundance in the Glen Canyon reach was greatest under long-term strategies C2, C4, D3, F, and G. With the exception of long-term strategy G, all of these long-term strategies implement spring HFEs and would have steadier flows (at least for the May–August portion of the year) than Alternative A and would not include implementation of TMFs. Although Alternative G would include implementation of TMFs, the annual production of trout would be expected to be very high due to a high proportion

TABLE F-8 Summary of Metrics Values from the Rainbow Trout-Humpback Chub Model[a]

Alternatives and Long-Term Strategies	Trout Abundance	Number of Trout ≥16 in. Total Length	Catch Rates (fish/hr)	Number of Out-migrants (fish/year)	Number of Years with Trout Management Flows	Number of Years with Mechanical Removal	Minimum Humpback Chub Population
A	94,667	769	2.11	36,699	0.0	0.07	4,991
B1	74,078	867	1.67	29,586	3.0	0.44	5,392
B2	62,822	920	1.46	24,172	3.1	0.30	5,541
C1	102,342	748	2.23	43,683	6.5	0.00	5,016
C2	150,285	640	3.18	66,890	0.0	0.00	4,527
C3	85,181	830	1.90	33,559	0.0	0.74	5,335
C4	127,129	707	2.72	55,076	0.0	2.80	4,874
D1	92,854	811	2.02	40,784	3.9	1.67	5,247
D2	99,452	796	2.15	43,981	6.9	2.02	5,181
D3	123,448	711	2.63	55,811	0.0	2.95	4,876
D4	93,312	810	2.03	40,936	3.8	1.69	5,241
E1	87,812	826	1.93	37,614	2.6	0.00	5,269
E2	108,046	761	2.33	47,450	0.0	0.00	5,015
E3	73,727	891	1.68	28,499	0.0	0.47	5,477
E4	100,330	781	2.19	42,806	0.0	1.73	5,103
E5	73,848	890	1.68	28,561	0.0	0.00	5,470
E6	60,600	956	1.42	22,415	2.4	0.00	5,708
F	160,297	592	3.37	71,869	0.0	0.00	4,450
G	131,816	702	2.81	58,533	11.0	3.05	4,741

[a] Mean values for 63 modeled hydrology–sediment conditions.

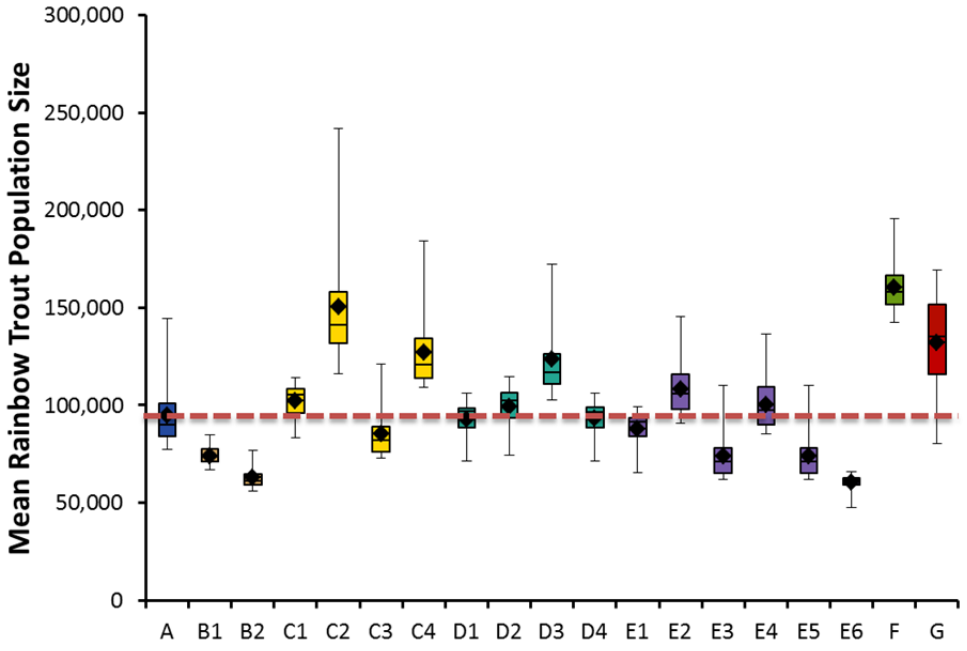


FIGURE F-10 Modeled Average Population Size of Age-1 and Older Rainbow Trout in the Glen Canyon Reach during the 20-year LTEMP Period under LTEMP Alternatives and Long-Term Strategies (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

of years with HFEs and the steady pattern of flows that would be maintained throughout the year without monthly differences in flow (other than those needed to adjust operations in response to changes in forecast and other operating requirements such as equalization); even at the highest evaluated levels of effectiveness for TMFs (50% reduction in age-0 trout), average annual recruitment would be expected to be quite high under Alternative G.

The overall modeled average rainbow trout abundance in the Glen Canyon reach was lowest under long-term strategies B1, B2, E3, E5, and E6. These long-term strategies generally would not allow spring HFEs (e.g., E3, E5, E6) or would be expected to have considerably fewer HFEs during the LTEMP period (e.g., B1, B2) than other long-term strategies, would maintain levels of fluctuations in flow similar to or greater than Alternative A, and (with the exception of long-term strategies E3 and E5) would implement TMFs. Thus, average annual recruitment levels would be expected to be lowest under these alternatives.

Modeled levels of trout abundance were intermediate and similar to Alternative A under long-term strategies C1, C3, D1, D2, D4, E1, E2, and E4. These long-term strategies generally included implementation of combinations of flow actions that would be expected to result in

intermediate levels of trout recruitment (e.g., no spring HFEs in all or a portion of the LTEMP period together with higher levels of fluctuation) or included TMFs that would function to control recruitment in years with high levels of trout production (e.g., years with HFEs).

Abundance of Rainbow Trout >16 in. Total Length

The modeled abundance of large rainbow trout in the Glen Canyon reach (i.e., trout that would be larger than 16 in. total length) under LTEMP alternatives are summarized in Figure F-11. Among all the long-term strategies evaluated, the modeled abundance of these larger trout during the simulations of 20-year LTEMP periods ranged from 480 to 1,039 individuals (Figure F-11). Overall modeled means (i.e., mean number of large trout for all simulations) for the various long-term strategies ranged from 592 large fish under Alternative F to 956 large fish under long-term strategy E6 (Table F-8; Figure F-11). Compared to Alternative A, the model suggested that long-term strategies C2, C4, D3, F, and G would have fewer large trout; long-term strategies D1, D4, E1, and E4 would have similar numbers of large

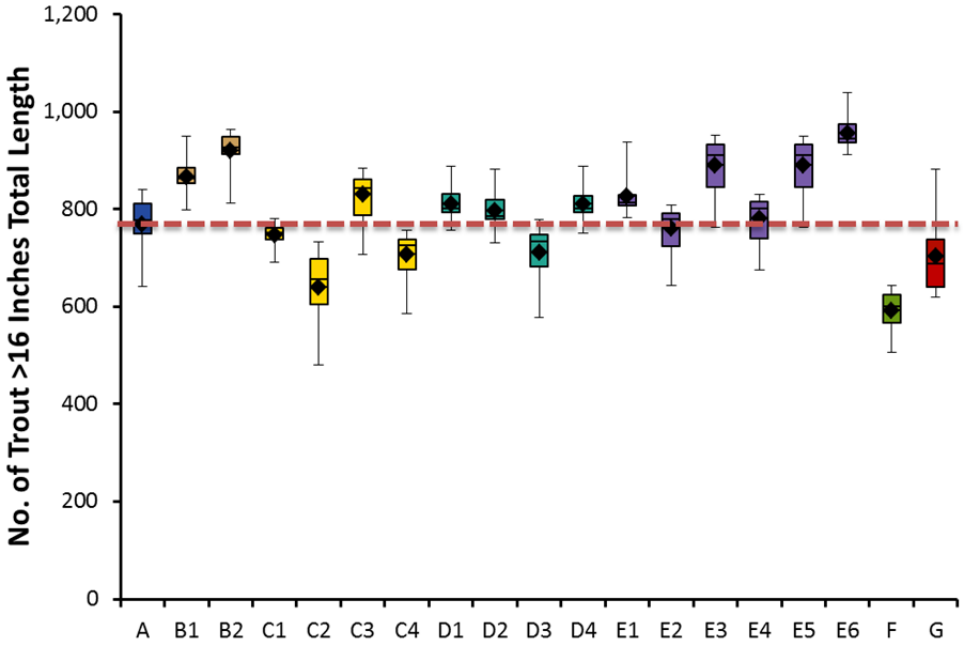


FIGURE F-11 Modeled Mean Annual Number of Rainbow Trout in the Glen Canyon Reach Exceeding 16 in. Total Length during the 20-year LTEMP Period under the LTEMP Alternatives and Long-Term Strategies (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

trout; and the remaining long-term strategies would have greater numbers of large trout (Figure F-11). It is generally expected that the average size of rainbow trout in the population would be inversely proportional to the average population size because of the effects of trout density on growth rates due to competition for food and other resources, and this was supported when comparing the modeled results for average number of large trout to the average number of trout in the Glen Canyon reach (Figure F-12). Because of their effect on lowering recruitment levels and population size, long-term strategies (such as long-term strategies B2 and E6) that have fewer HFEs, higher daily fluctuations, and that implement TMFs are expected to have a greater number of large trout. Table 4.1-1 identifies the experimental elements included in the various long-term strategies, and Appendix E of the DEIS describes the number and duration of HFEs that would be expected under the various long-term strategies.

Trout Catch Rates

The modeled angler catch rates for rainbow trout in the Glen Canyon reach under the LTEMP alternatives and long-term strategies are shown in Figure F-13. Modeled average catch rates during the simulations of 20-year LTEMP periods ranged from approximately 1.1 fish/hr to

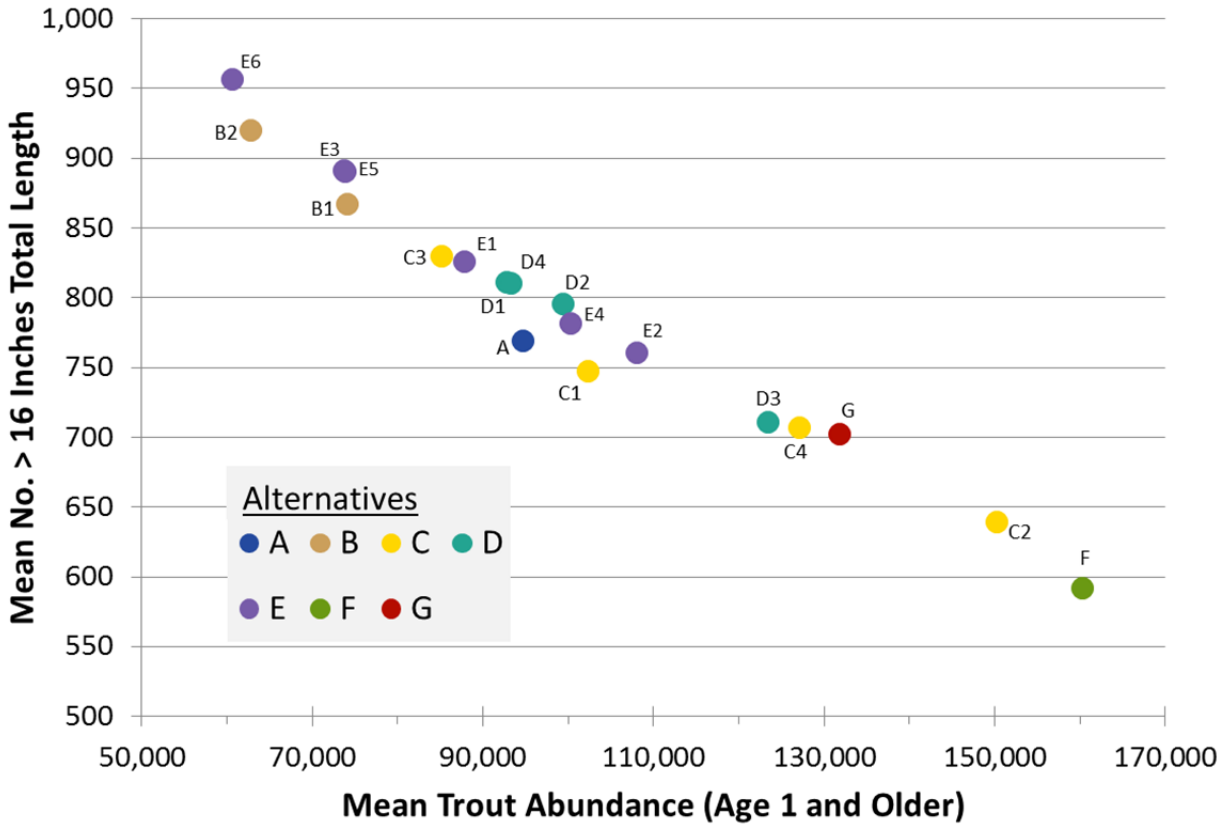


FIGURE F-12 Relationship between Modeled Mean Rainbow Trout Abundance in the Glen Canyon Reach and the Mean Number of Rainbow Trout Exceeding 16 in. Total Length during the 20-year LTEMP Period under the LTEMP Alternatives and Long-Term Strategies

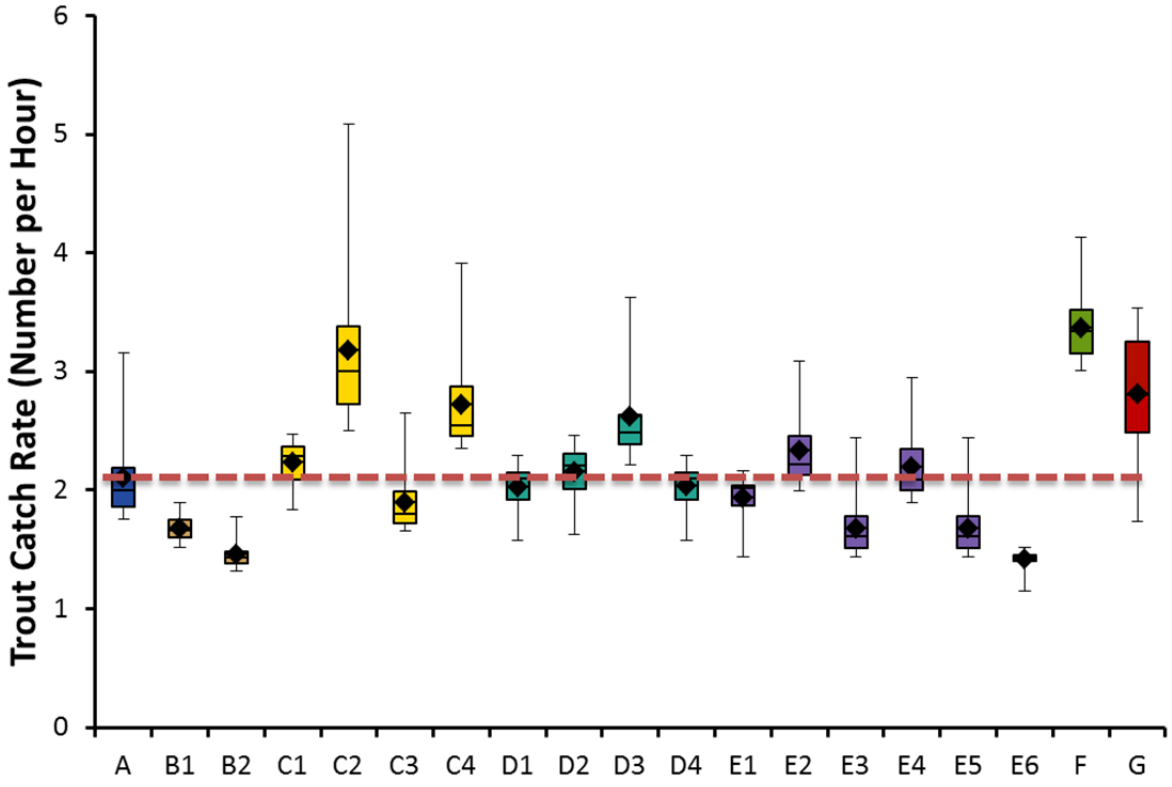


FIGURE F-13 Modeled Mean Annual Angler Catch Rate for Rainbow Trout in the Glen Canyon Reach during the 20-year LTEMP Period under the LTEMP Alternatives and Long-Term Strategies (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

5.1 fish/hr (Figure F-13).Modeled mean catch rates (i.e., mean catch rates for all simulations) ranged from 1.4 fish/hr under long-term strategy E6 to 3.4 fish/hr under long-term strategy F (Table F-8; Figure F-13). Compared to Alternative A, the model indicated that long-term strategies B1, B2, C3, E1, E3, E5, and E6 would have lower catch rates; long-term strategies C1, D1, D2, D4, and E4 would have similar catch rates; and long-term strategies C2, C4, D3, E2, F, and G would have higher catch rates (Figure F-13). Although the modeled vulnerability of individual trout to angling varies depending on the age of the trout, modeled average angler catch rates are highly correlated with average population levels of the long-term strategies, as shown in Figure F-14.

For this reason, the same combinations of experimental elements that drive recruitment levels and affect rainbow trout abundance would be expected to drive angler catch rates (see "Recruitment" in Section F.3.1.1 and "Rainbow Trout Population Estimates" in Section F.3.2.1). Thus, long-term strategies that result in more frequent HFEs (especially spring HFEs) have steadier flows and do not include TMFs (e.g., Alternatives F and G and long-term strategies C2

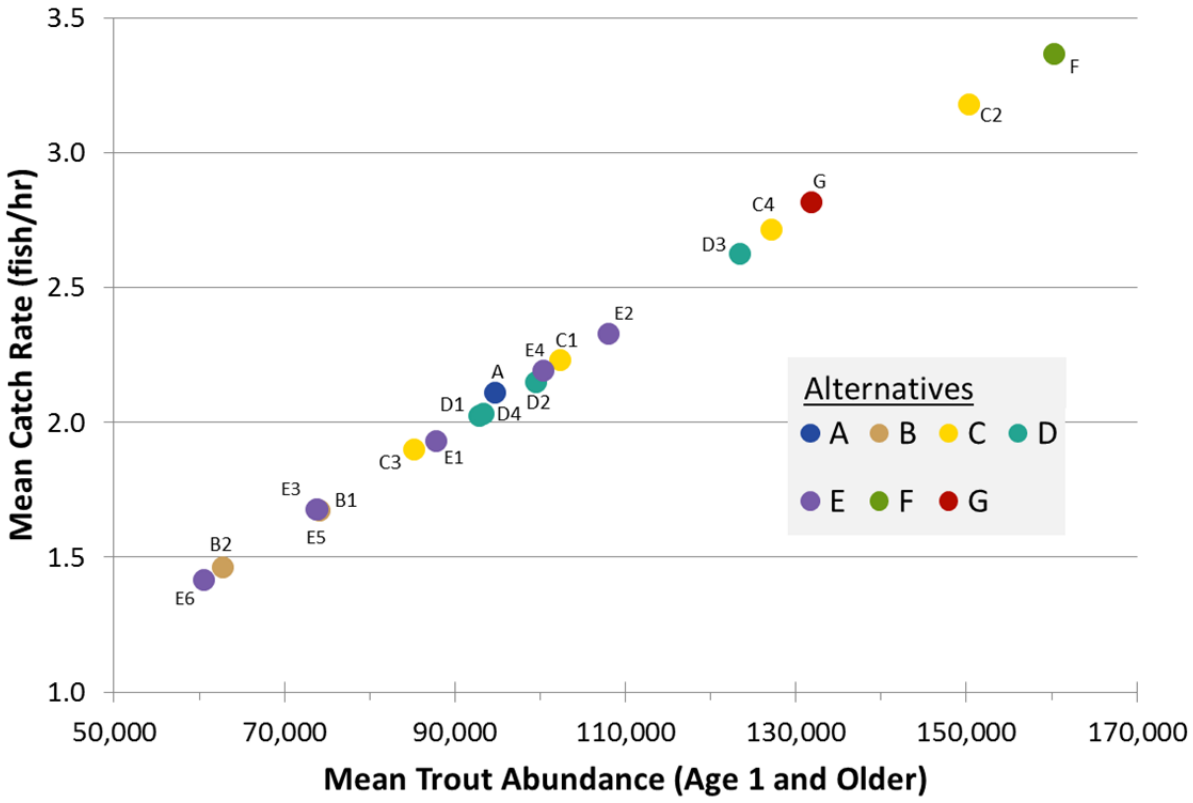


FIGURE F-14 Relationship between Modeled Mean Rainbow Trout Abundance in the Glen Canyon Reach and Mean Angler Catch Rates during the 20-year LTEMP Period under the LTEMP Alternatives and Long-Term Strategies

and D3) would be expected to have higher trout numbers and would lead to greater angler catch rates for rainbow trout, while long-term strategies that have fewer HFEs, more variable flows, and include TMFs (e.g., long-term strategies B1, B2, and E6) would be expected to have lower trout abundance and lower mean angler catch rates. Table 4.1-1 identifies the experimental elements included in the various long-term strategies, and Appendix E of the DEIS describes the number and duration of HFEs for each.

Trout Emigration

The modeled number of trout emigrating (i.e., number of out-migrants) from the Glen Canyon reach into the Marble Canyon reach of the Colorado River under the LTEMP alternatives and long-term strategies are summarized in Figure F-15. Modeled annual number of out-migrants ranged from approximately 18,200 fish/year to 114,900 fish/year (Figure F-15). Modeled mean annual number of out-migrants (i.e., mean number of out-migrants for all simulations) ranged from 22,415 fish/year under long-term strategy E6 to 71,869 fish/year under Alternative F (Table F-8; Figure F-15). Compared to Alternative A, the model indicated that long-term strategies B1, B2, E3, E5, and E6 would have lower numbers of out-migrants; long-term strategies C3 and E1 would have similar numbers of out-migrants; and long-term strategies

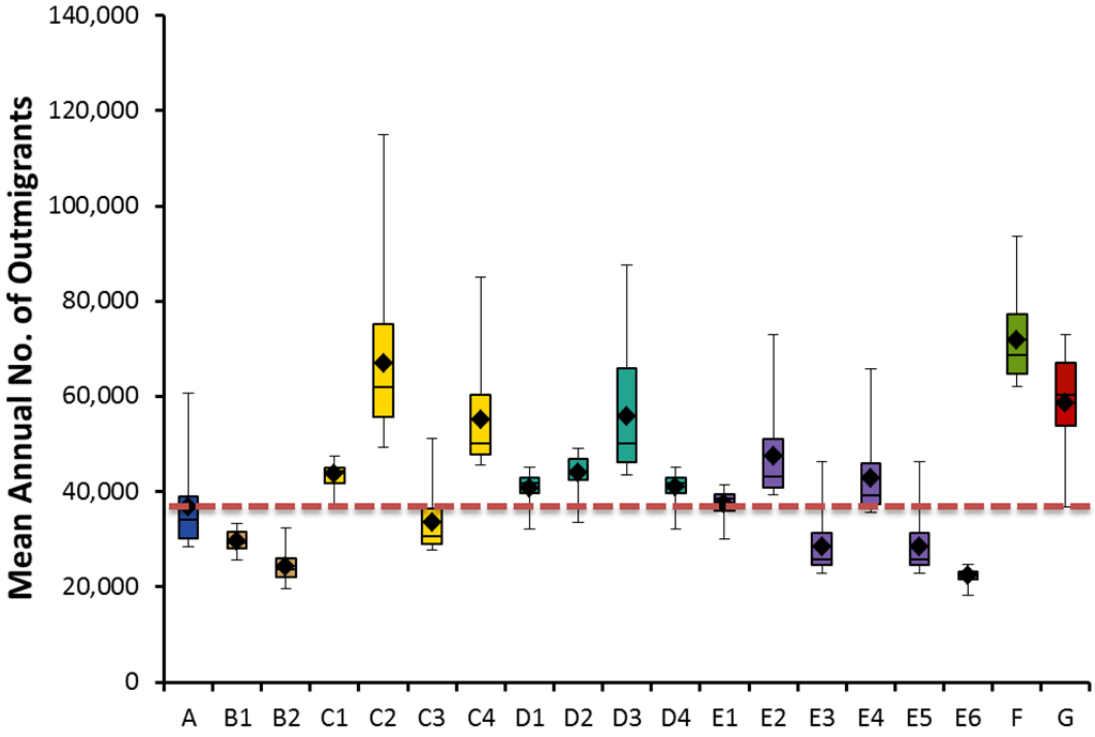


FIGURE F-15 Modeled Annual Average Number of Rainbow Trout Emigrating into the Marble Canyon Reach from the Glen Canyon Reach during the 20-year LTEMP Period under the LTEMP Alternatives and Long-Term Strategies (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

C1, C2, C4, D1, D2, D3, D4, E2, E4, F, and G would have higher numbers of out-migrants (Figure F-13).

As described in Section F.3.1.1, the annual number of trout emigrating from Glen Canyon into Marble Canyon was calculated as a function of the level of trout recruitment during the previous year. Thus, long-term strategies that result in more HFEs (especially spring HFEs), less variability in flows, and do not include TMFs (e.g., Alternatives F and G and long-term strategies C2, C4, D3, and E2) had higher modeled levels of trout emigration than long-term strategies with fewer HFEs, more variable flow regimes, and included TMFs (e.g., long-term strategies B1, B2, and E6). Table 4.1-1 identifies the experimental elements included in the various long-term, and Appendix E of the DEIS describes the number and duration of HFEs that would be expected under each.

Mechanical Removal of Trout in the Little Colorado River Reach

The modeled frequency of years in which mechanical removal of trout would be triggered in the Little Colorado River reach under the LTEMP alternatives and long-term strategies are summarized in Figure F-16. Mechanical removal is not included under long-term strategies C1, C2, E1, E2, E5, E6, and Alternative F. Among the remaining long-term strategies, the average number of years in which mechanical removal was triggered ranged from approximately 0.1 under Alternative A to approximately 3.1 under Alternative G (Table F-8; Figure F-16). The average maximum number of years in which mechanical removal would be triggered is 6.3 out of 20 years under long-term strategy D3. In general, long-term strategies that result in more frequent HFEs (especially spring HFEs), have steadier flows, and do not include TMFs (e.g., Alternatives F and G and long-term strategies C2, C4 and D3) have higher levels of recruitment, increase the number of trout that move downstream to the Little Colorado River reach, and meet conditions in the model that trigger mechanical removal of trout with a greater frequency. Long-term strategies that result in fewer HFEs and more variable flow levels (e.g., long-term strategies B1, B2, and E6) have lower levels of trout recruitment on average; inclusion of TMFs acts to further decrease the potential for large recruitment events. As a consequence, these long-term strategies result in lower numbers of trout entering the Little Colorado River reach and fewer years when mechanical removal is triggered. Table 4.1-1 identifies the experimental elements included in the various long-term strategies, and Appendix E of the DEIS describes the number and duration of HFEs that would be expected under each.

F.3.2.2 Humpback Chub Performance Measures

The modeled minimum population sizes for humpback chub adults under the LTEMP alternatives and long-term strategies are summarized in Figure F-17. Modeled minimum adult population sizes ranged from 1,433 to 13,478 fish (refer to upper and lower whiskers in Figure F-17). Overall modeled means (i.e., mean minimum number of adult humpback chub for all simulations) ranged from 4,450 individuals under Alternative F to 5,708 individuals under long-term strategy E6 (Table F-8; refer to diamonds in Figure F-17). The lowest modeled minimum adult population size (1,433 fish) was observed under long-term strategy C2, and the highest modeled minimum adult population size was observed under long-term strategy E6, although the lowest minimum adult population values were relatively similar among all long-term strategies (refer to lower whiskers in Figure F-17). Compared to Alternative A, the model indicated that long-term strategy C2 and Alternative F would have somewhat lower mean minimum adult population sizes; long-term strategies C1, C4, D1, D2, D3, D4, E1, E2, E4 and Alternative G would have similar mean minimum adult population sizes; and long-term strategies B1, B2, C3, E3, E5, and E6 would have higher mean minimum adult population sizes (Figure F-17). These results indicate that although there are small differences among the long-term strategies with regard to the predicted minimum number of adult humpback chub in the Little Colorado River aggregation, all long-term strategies would likely maintain the population above at least 1,000 adults throughout the 20-year LTEMP period.

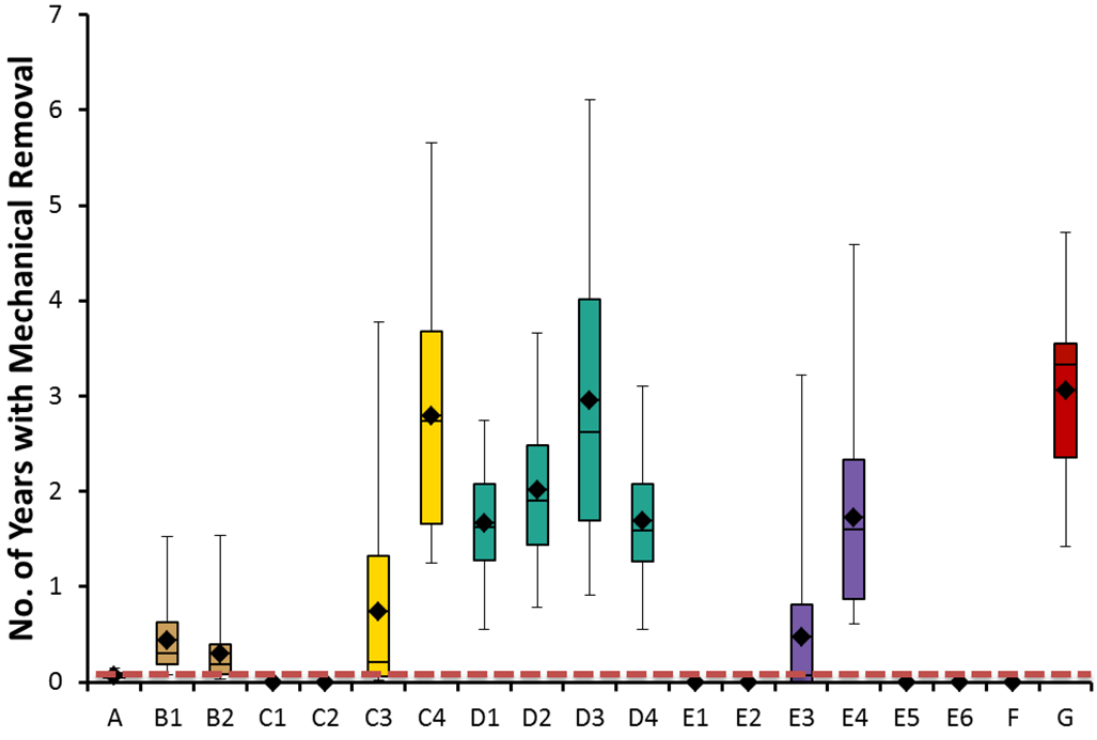


FIGURE F-16 Modeled Frequency of Triggered Mechanical Removal for Rainbow Trout in the Little Colorado River Reach during the 20-year LTEMP Period under the LTEMP Alternatives and Long-Term Strategies (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

In the humpback chub submodel, the factors that affect annual recruitment and survival of humpback chub are mainstem water temperatures and the number of trout in the Little Colorado River reach (Section F.3.1.3). Because there is little variation among the long-term strategies in modeled mainstem water temperatures at the confluence with the Little Colorado River, the differences in modeled numbers of adult humpback chub among the long-term strategies were primarily affected by the estimated abundance of trout in the Little Colorado River reach where survival of age-0 and juvenile humpback chub and subsequent recruitment of adult humpback chub could be affected by increased competition and predation (e.g., Yard et al. 2011). Because the modeled abundance of trout in the Little Colorado River reach is driven by modeled emigration of rainbow trout from the Glen Canyon reach, there is a strong relationship between the average adult humpback chub population size and the average number of trout emigrating from the Glen Canyon reach for the various long-term strategies (Figure F-18). Refer to the section above entitled "Trout Emigration" for information about the experimental elements of long-term strategies that affect the levels of trout emigration. Although the model predicts that

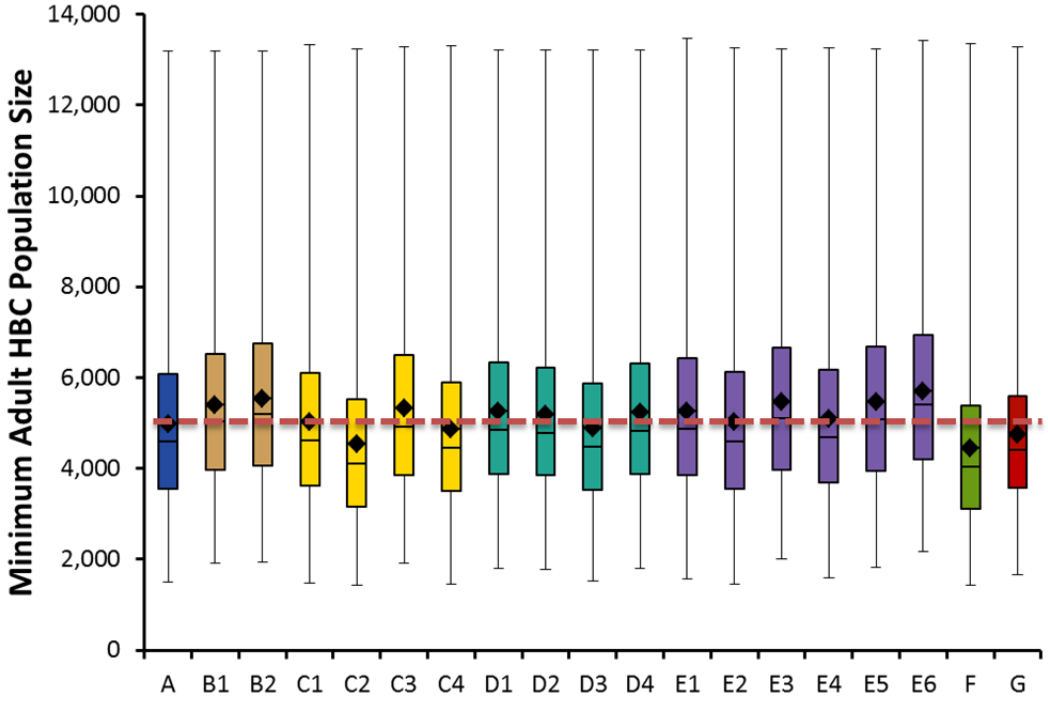


FIGURE F-17 Modeled Minimum Population Size for Humpback Chub (HBC) during the 20-year LTEMP Period under the LTEMP Alternatives and Long-Term Strategies (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum annual value for all simulations; upper whisker = maximum annual value for all simulations; horizontal dashed line identifies mean value for Alternative A.)

the number of trout at the confluence with the Little Colorado River is related to trout recruitment in the Glen Canyon reach, the actual relationship is unclear and still under investigation.

F.4 MODELING THE EFFECTS OF LTEMP ALTERNATIVES ON TEMPERATURE SUITABILITY

This section describes the modeling approach used to evaluate the effects of LTEMP EIS alternatives on temperature suitability for fishes and invertebrate parasites in the mainstem Colorado River downstream of Glen Canyon Dam. The goal of the temperature suitability modeling was to evaluate the potential for each of the alternatives to result in temperature conditions that would promote maintenance and/or establishment of various fish and invertebrate

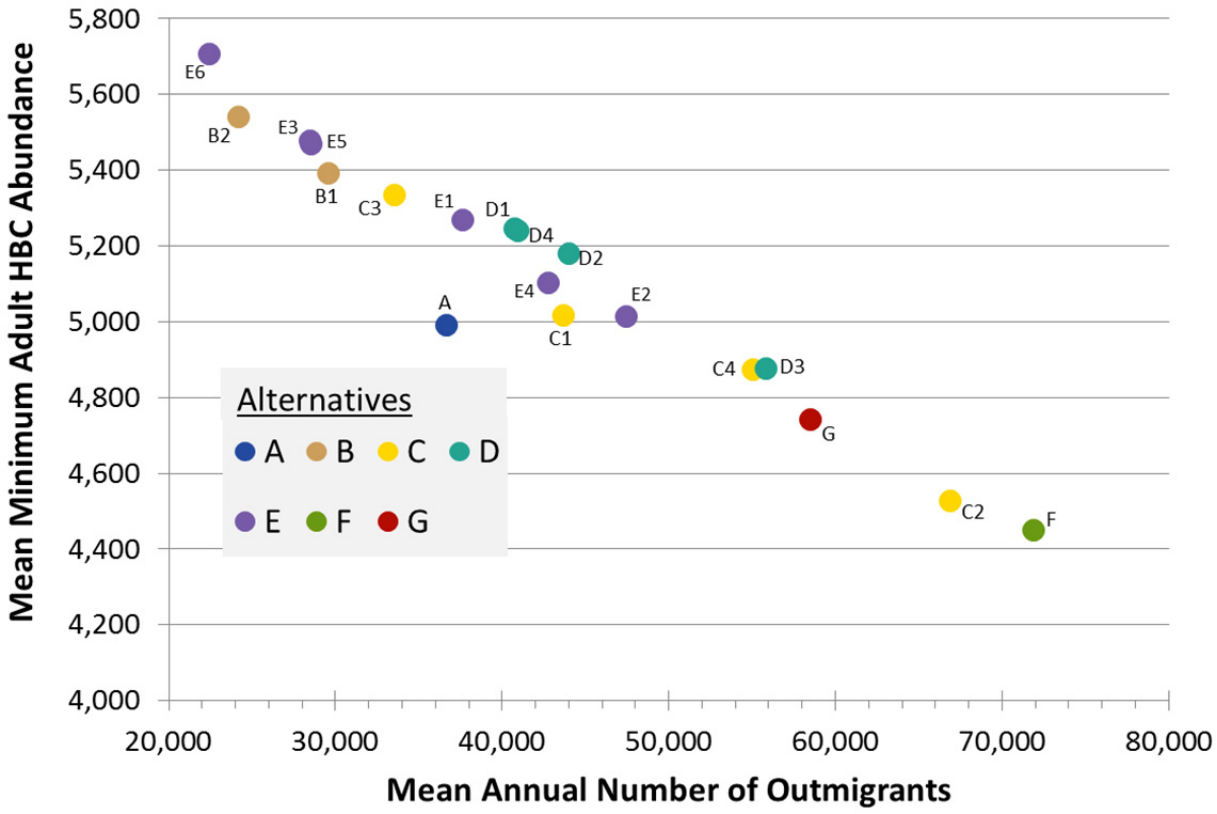


FIGURE F-18 Relationship between Modeled Mean Numbers of Rainbow Trout Out-migrants from the Glen Canyon Reach and the Modeled Mean Minimum Abundance of Adult Humpback Chub during the 20-year LTEMP Period under the LTEMP Alternatives and Long-Term Strategies

species of management concern. In particular, the temperature suitability modeling is intended to evaluate effects of alternatives on temperature suitability for four species groups:

1. Temperature suitability for establishment and maintenance of self-sustaining aggregations of humpback chub at various river locations in the Colorado River downstream of Glen Canyon Dam;

2. Temperature suitability for establishment and maintenance of self-sustaining populations of native warmwater fish other than humpback chub at various locations in the Colorado River downstream of Glen Canyon Dam;

3. Temperature suitability for establishment and maintenance of self-sustaining populations of nonnative fish species at various locations in the Colorado River downstream of Glen Canyon Dam; and

4. Temperature suitability for establishment and maintenance of self-sustaining populations of parasitic invertebrate species at various locations in the Colorado River downstream of Glen Canyon Dam.

The following sections describe the general modeling approach for evaluating temperature suitability, specific modeling considerations applied in order to implement the modeling approach for each of the species groups to be evaluated, the input data needs and sources for each of the ecological components, and the approach for statistically evaluating the output of the models in order to compare the effects of the various operational alternatives on temperature suitability for each species group.

F.4.1 Model Overview

In general, the temperature suitability modeling considers how well mainstem water temperatures at selected locations downstream of Glen Canyon Dam would meet the temperature requirements for three life history components—spawning, egg incubation, and growth—for each species group evaluated. To accomplish this, monthly water temperature values in a multi-year time series were compared to temperature suitability profiles for life history components of each species group considered. The seasonal timing or period of the year during which the temperature needs for each life history component must be met is taken into account by the model. Possible values for temperature suitability can theoretically range from 0 (completely unsuitable for one or more life history component) to 1 (magnitude and timing of temperatures would be optimal for all life history components). However, since optimal conditions for all life history components cannot be simultaneously met in many cases (due to different optimal temperatures during overlapping time frames, the maximum attainable value for a given species would generally be less than one.

The temperature suitability modeling evaluates the potential for all life history components to be met in the mainstem river, even though some species are known to sometimes use tributaries to accomplish particular needs. Thus, the model can predict relatively low temperature suitability for some areas even though species populations appear to be abundant and self-sustaining. In addition, modeled water temperatures used as inputs do not consider the potential for warming near tributary mouths, backwater habitats, or in shallow nearshore areas. Thus, the results of temperature suitability modeling are used to compare relative effects of alternatives on species-specific temperature needs in the mainstem Colorado River, rather than as an exact predictor of the potential for the presence or absence of fish or parasite species at particular locations.

For fish species, the model considers the suitability of each day's water temperature for three life history components (spawning, egg incubation, and growth). The model bases the potential for self-sustaining populations of fish species being successful on the combined temperature suitability scores for spawning, incubation, and growth, and it is assumed that some level of both mainstem spawning and egg incubation would be required to support self-sustaining populations of fish species. The annual potential for successful spawning and egg incubation is assumed to be related to the suitability of the annual temperature regimes for

spawning and egg incubation during the spawning and egg incubation periods. It was assumed that the potential for successful rearing and survival of fish species within the mainstem at each evaluation location was related to the suitability of temperatures throughout the year for growth. The suitability of various temperatures for meeting spawning, egg incubation, and growth needs of fish was calculated using triangular probability functions[3] based upon reported suitable ranges and optimal temperatures for each life history aspect of each species (Valdez and Speas 2007).

For parasite species, the model bases the potential for unacceptable parasite conditions on the temperature suitability scores for host activity and infestation. It is assumed that both elevated host activity and infestation rates would be needed to result in unacceptable infestations of the parasite species and the annual potential for unacceptable infestations is assumed to be related to the suitability of the temperature regimes for host activity and infestation throughout the year. The suitability of various temperatures for host activity and infestation needs of a group of four parasite species was calculated using triangular probability functions based on the reported range of suitable temperatures and the reported optimal temperature for each species (Valdez and Speas 2007). The model calculates daily temperature suitability scores for the life history components based on the triangular suitability relationships and the seasonal time periods during which the temperature needs for each life history component must be met.

Annual temperature suitability for each life history component is calculated as the mean of the daily suitability values that fall within the specified seasonal time period during a given water year. The overall annual temperature suitability for each species is calculated as the geometric mean of the annual temperature suitability scores for the applicable species-specific life history components. Temperature suitability over a 20-year period is based on the mean of the annual temperature suitability values. Evaluations were conducted for each river location to be assessed or using the overall annual means for combinations of downstream locations. The mean of the annual suitability scores for multiple fish or parasite species was used as an indication of the overall suitability of each year's temperature regime for groups of native fish, nonnative fish, or parasite species.

The LTEMP temperature suitability model requires inputs pertaining to daily water temperatures for each of the downstream locations to be assessed and requires identification of temperature requirements for the life history aspects of each species to be evaluated. Species-specific temperature requirement information includes the minimum, optimal, and maximum suitable temperatures for important life history components and information describing the appropriate months of the year during which conditions for each life history component should be met. Table F-9 summarizes the input data needs and the anticipated sources of the input values. The model is formulated to consider daily water temperatures for multi-year periods. The daily water temperature input values were derived from external modeling (i.e., not calculated within the LTEMP temperature suitability model) following formulas developed by Wright et al. (2009) to predict mean monthly water temperatures at various locations downstream of Glen

[3] With the triangular functions used, the temperature suitability value rises linearly from 0 at the minimum suitable temperature to 1 at the optimum temperature, then falls linearly from 1 at the optimum to 0 at the maximum suitable temperature). Each of these functions was based on species-specific temperature requirements as reported by Valdez and Speas (2007). See Figure F-19 for example functions.

TABLE F-9 Description of Input Parameters for the LTEMP Temperature Suitability Model

Input Parameter	Description of Input Data	Comments
$TW_{x, y}$	Mean daily water temperature (°C) for a specific day (*x*) in a given year (*y*)	Provided by water temperature modeling. Although daily water temperatures are used as inputs into the model, modeled mean monthly water temperatures were used to provide the mean daily temperatures to be used within the months for each year. The model is formulated to accommodate multi-year traces of daily temperature data. A water temperature time series covering the same time period was developed for each downstream location.
$T_{Min\ (s,l)}$	The minimum suitable temperature (°C) to meet a given life history need (*l*) for a given species (*s*)	Values obtained from Valdez and Speas (2007).
$T_{Max\ (s,l)}$	The maximum suitable temperature (°C) to meet a given life history need (*l*) for a given species (*s*)	Values obtained from Valdez and Speas (2007).
$T_{Opt\ (s,l)}$	The optimum suitable temperature (°C) to meet a given life history need (*l*) for a given species (*s*)	Values obtained from Valdez and Speas (2007).
$MonthStart_{(s,l)}$	The beginning month of the water year during which a given life history need (*l*) for a given species (*s*) should be met	Used to identify the beginning of the appropriate time period for meeting each species–life history component combination.
$MonthEnd_{(s,l)}$	The ending month of the water year during which a given life history need (*l*) for a given species (*s*) should be met	Used to identify the end of the appropriate time period for meeting each species–life history component combination.

Canyon Dam based on assumed meteorological conditions, the expected magnitude of water releases, and the temperature of the water being released from Lake Powell for each of the LTEMP alternatives. The temperature suitability for each alternative/long-term strategy was evaluated using a total of 63, 20-year temperature input scenarios generated from conditions expected during operations for a range of hydrology–sediment trace combinations. The temperature suitability model was implemented using R (R Core Team 2013; see http://www.r-project.org/about.html).

The following sections provide specific information regarding implementations and results of the temperature suitability modeling approach to evaluate suitability for (1) self-sustaining aggregations of humpback chub; (2) self-sustaining populations of native warmwater fish species other than humpback chub; (3) self-sustaining populations of coldwater and warmwater nonnative fish species; and (4) establishment and maintenance of invasive parasitic invertebrate species.

F.4.2 Humpback Chub Aggregations

The temperature suitability model evaluates how well alternatives would provide mainstem water temperatures suitable for spawning, egg incubation, and growth of humpback chub at reported aggregation locations. The model based the potential for a self-sustaining aggregation of humpback chub becoming successfully established at each location on the combined potential for successful spawning, successful incubation, and successful growth of humpback chub. The time series of water temperatures was based upon estimated water temperatures for eight mainstem Colorado River locations (Table F-10) where humpback chub aggregations have been reported to occur. As described in Section F.4.1, the water temperatures used as inputs for these locations were modeled using a water temperature model developed by Wright et al. (2009).

It was assumed that mainstem spawning would be required to support self-sustaining aggregations at all locations except for the aggregation at the confluence of the mainstem and the Little Colorado River (RM 61), where successful tributary spawning is known to occur. Thus, except for the Little Colorado River aggregation, the annual potential for successful spawning is assumed to be related to the suitability of temperature regimes in the mainstem Colorado River for spawning. The potential for successful spawning at various temperatures was calculated using a triangular probability function based upon the reported range of suitable spawning temperatures (16–22°C) (61–72°F) and the reported optimal spawning temperature (18°C) (64°F) for humpback chub (Valdez and Speas 2007). The calculated suitability of various water temperatures for successful humpback chub spawning is shown in Figure F-19.

April, May, and June were identified as encompassing the possible spawning period for humpback chub aggregations (Figure F-20), based on observations of fish in spawning condition reported by Valdez and Ryel (1995) for aggregations and by Gorman and Stone (1999) for spawning in the Little Colorado River. The annual suitability values for spawning were set to a value of 1 for the Little Colorado River aggregation, since water temperature in the Little

TABLE F-10 Humpback Chub Aggregation Locations

Aggregation Location	River Mile (RM)[a]
30-mile	RM 30
Little Colorado River confluence	RM 61
Bright Angel Creek	RM 88
Shinumo Creek	RM 108
Stephen Aisle	RM 119
Middle Granite Gorge	RM 125
Havasu Creek	RM 157
Pumpkin Spring	RM 213

[a] River mile distances are calculated as the distance downstream from the Lees Ferry gage.

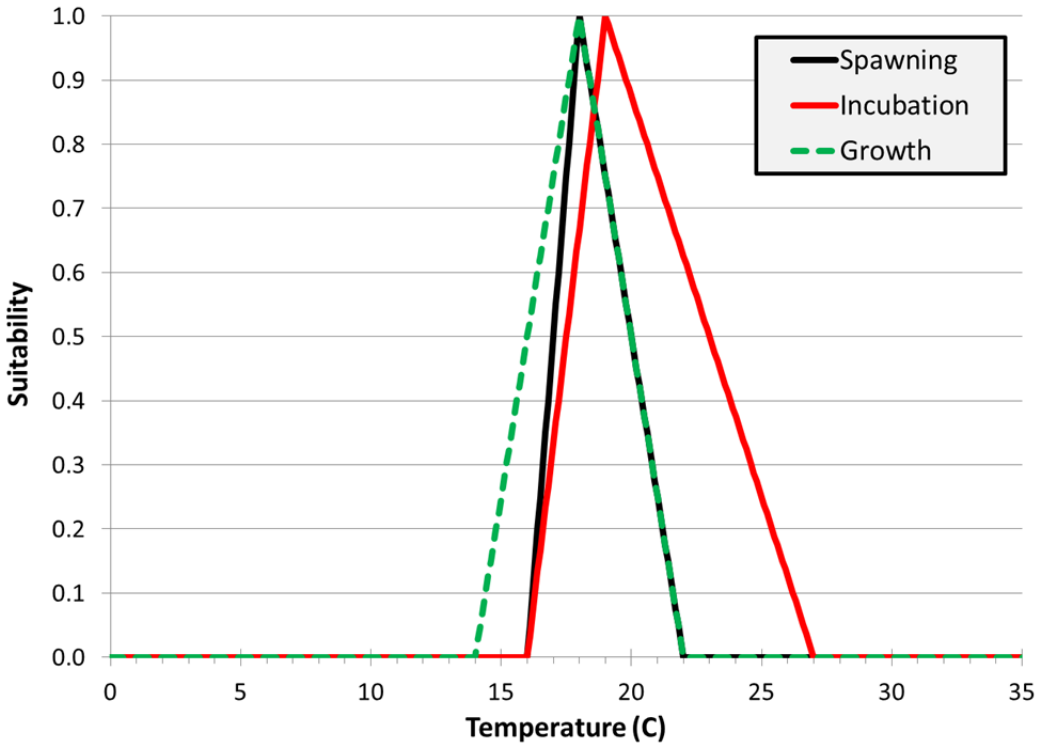


FIGURE F-19 Suitability for Spawning, Egg Incubation, and Growth of Humpback Chub as a Function of Water Temperature (based on minimum, maximum, and optimum temperature values presented in Valdez and Speas 2007)

Species	Life History Aspect	Month											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Humpback Chub	Spawning				■	■	■						
	Incubation				■	■	■						
	Growth	■	■	■	■	■	■	■	■	■	■	■	■

FIGURE F-20 Months for Which Annual Temperature Suitability for Specific Life History Aspects of Humpback Chub Were Calculated

Colorado River is known to support spawning needs for this aggregation. The potential for successful spawning during a given water year for each aggregation was calculated as the average of the estimated suitability scores during April through June (Figure F-20).

It was assumed that mainstem egg incubation would be required to support self-sustaining aggregations at all locations except for the aggregation at the confluence of the mainstem and the Little Colorado River (RM 61), where successful tributary spawning is known to occur. The suitability for incubation in the Little Colorado River (RM 61) aggregation was assumed to be 1. At other aggregation locations, the annual potential for successful egg incubation was assumed to be related to the suitability of mainstem temperature regimes for incubation during the spawning period, because incubation of humpback chub eggs may require as little as 3 days at optimal temperatures. Thus, it was assumed that the spawning period of April, May, and June also encompassed the egg incubation period for aggregations (Figure F-20). The suitability of various temperatures for egg incubation was calculated using a triangular probability function based upon the reported range of suitable egg incubation temperatures (16–27°C) (61–81°F) and the reported optimal egg incubation temperature (19°C) (66°F) for humpback chub (Valdez and Speas 2007;Figure F-19).

It was assumed that the potential for successful rearing of humpback chub within the mainstem at each aggregation location is related to the suitability of temperatures throughout the year for humpback chub growth. The suitability of various temperatures for growth of humpback chub was calculated using a triangular probability function based upon the reported range of suitable temperatures (16–22°C) (61–72°F) and the reported optimal temperature (18°C) (64°F) for growth (Valdez and Speas 2007; Figure F-19). The annual suitability of daily temperatures for growth was calculated as the mean of daily suitability values during the entire water year (Figure F-20).

The geometric mean of the annual temperature suitability values for spawning, egg incubation, and growth was used as an indicator of the annual potential for an aggregation to be successful (and self-sustaining) at a particular location. The arithmetic mean of the annual suitability scores for each of the eight aggregation locations was used as an indication of the overall relative suitability of each year's temperature regime for supporting humpback chub aggregations in the mainstem Colorado River downstream of Glen Canyon Dam.

F.4.2.1 Historic Temperature Suitability for Humpback Chub

Historic temperature suitability of mainstem water temperatures for humpback chub aggregations was examined using modeled water historic temperatures at the aggregation locations for a 23-year period from October 1, 1989, through September 30, 2012 (water years 1990–2012), as the temperature inputs (Figure F-21). The annual values of the modeled historic temperature suitability for the various aggregation locations are summarized in Figure F-22.

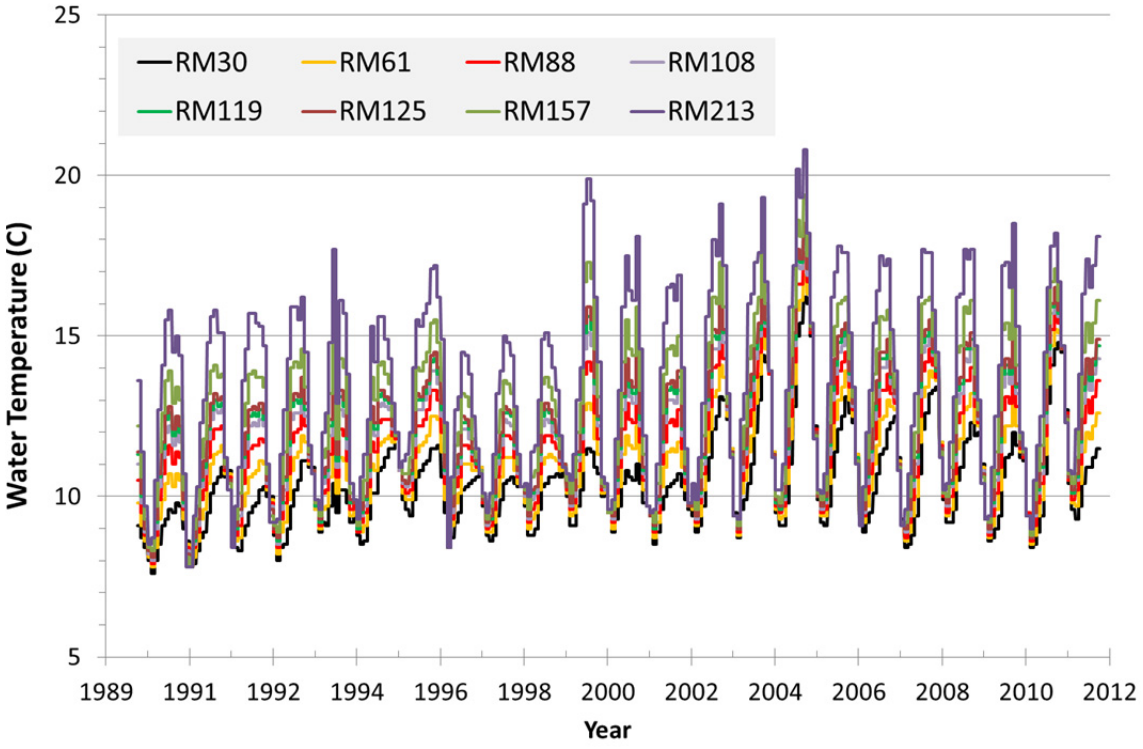


FIGURE F-21 Modeled Historic Water Temperatures in the Colorado River at Humpback Chub Aggregation Locations, Water Years 1990–2012 (Source: Williams 2013)

F.4.2.2 Results for LTEMP Alternatives

The temperature suitability for humpback chub at aggregation locations under the LTEMP alternatives and long-term strategies is summarized in Figure F-23. Modeled main channel water temperature suitability for humpback chub was relatively low and similar to Alternative A under all the long-term strategies for most aggregation locations. Modeled mean annual main channel temperature suitability for humpback chub at RM 61 (the Little Colorado River confluence) was slightly higher under Alternative F than under the other long-term strategies (Figure F-23), because the lower summer and fall flows of this alternative resulted in warmer water that would benefit growth during those seasons; note that the overall suitability score for RM 61 reflects temperature suitability for growth in the main channel, but optimal spawning and egg incubation temperatures in the Little Colorado River where the species spawns. Because the water warms as it travels downstream from the dam (for spring through fall months), temperature suitability improves with increasing distance. At RM 213, mean annual temperature suitability for humpback chub was similar to Alternative A under all long-term strategies except for C1, C2, C3, C4, and Alternative F. Compared to Alternative A, long-term strategies C1, C2, C3, and C4 were slightly lower, although differences were small (Figure-F-23). Modeled temperature suitability at RM 213 was lowest under Alternative F (Figure F-23), reflecting the higher, colder flows expected to occur under this alternative during spawning and egg incubation periods (April through June). Based on these results, the combined suitability of mainstem temperatures for spawning, egg incubation, and growth by humpback

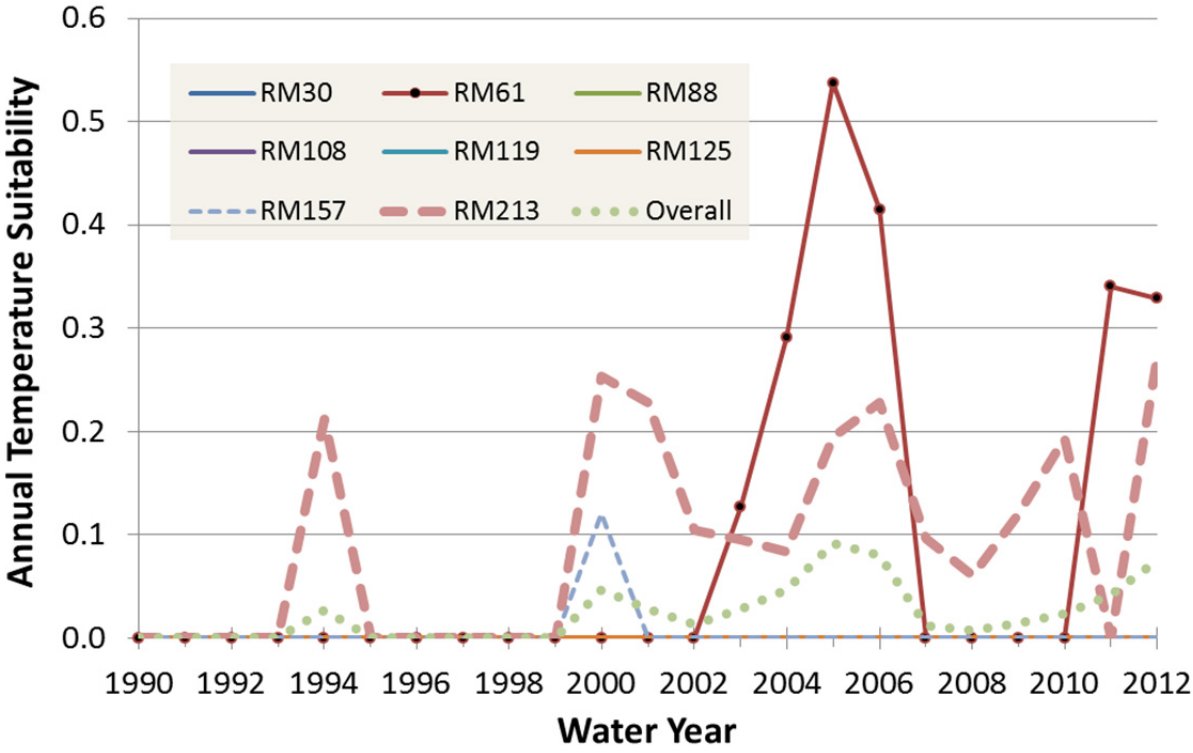


FIGURE F-22 Output from the Temperature Suitability Model for Humpback Chub Aggregation Locations Based on Modeled Water Temperatures for Water Years 1990–2012

chub in the downstream-most aggregation sites is anticipated to be negatively affected compared to current conditions under Alternative F; however, for the other long-term strategies, suitability would remain similar to the low historic levels, as represented by the suitability under Alternative A (the no-action alternative). It should be noted that, historically, there have been years where the magnitude and timing of mainstem water temperatures have likely coincided to allow spawning and egg incubation to occur in some of the downstream aggregation areas; however, the overall average suitability has likely been low (Figure F-22).

F.4.3 Other Native Fish

The temperature suitability model for native fish evaluates how well alternatives provide mainstem water temperatures suitable for spawning, egg incubation, and growth of four species of warmwater native fish other than humpback chub (speckled dace [*Rhinichthys osculus*], razorback sucker [*Xyrauchen texanus*], flannelmouth sucker [*Catostomus latipinnis*], and bluehead sucker [*C. discobolus*]). In order to account for changes in water temperatures as water released from Glen Canyon Dam travels downstream, evaluations of temperature suitability were conducted for five mainstem Colorado River locations (Table F-11). As described in Section F.4.1, the time series of water temperatures used as inputs for these locations are generated using a water temperature model developed by Wright et al. (2009).

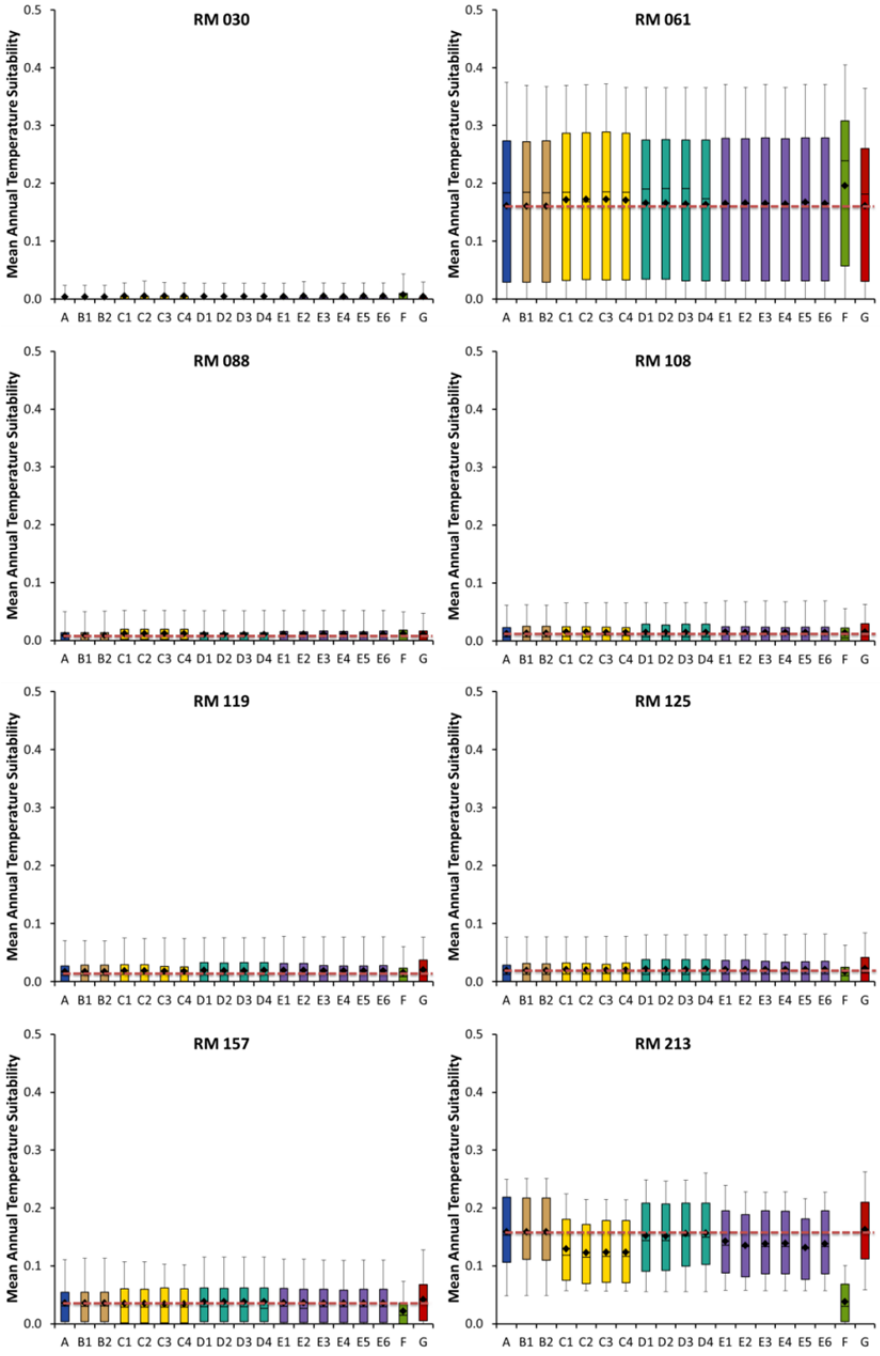


FIGURE F-23 Mainstem Temperature Suitability for Humpback Chub Aggregation Locations under LTEMP Alternatives and Long-Term Strategies (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

TABLE F-11 Locations Used for Temperature Suitability Modeling of Native Fish, Nonnative Fish, and Parasites

Aggregation Location	River Mile (RM)[a]
Glen Canyon Dam	RM –15
Paria River/Lees Ferry	RM 0
Little Colorado River confluence	RM 61
Havasu Creek	RM 157
Diamond Creek	RM 225

[a] River mile distances are calculated as the distance downstream from the Lees Ferry Gage. Glen Canyon Dam is indicated as being at RM –15, since it is located upstream of Lees Ferry.

The calculated suitability of various water temperatures for successful spawning, egg incubation, and growth of the four native species is depicted in Figure F-24. The months encompassing the spawning, egg incubation, and growth periods for each of the four native fish species are indicated in Figure F-25.These time periods were identified by reviewing the scientific literature pertaining to each of the species.

F.4.3.1 Historic Temperature Suitability for Native Fish

Historic temperature suitability of mainstem water temperatures for the four native fish species was examined using modeled water historic temperatures at five evaluation locations for a 23-year period from October 1, 1989, through September 30, 2012 (water years 1990–2012) as the temperature inputs (Figure F-26). Figure F-27 presents the annual temperature suitability scores for spawning, incubation, and growth of the four native fish species based upon the modeled historic temperatures for water years 1990–2012 at RM 225 (Diamond Creek). The annual temperature suitability scores for the five river locations and a combined overall score for all locations based on the modeled historic temperature suitability for the various assessment locations are presented in Figure F-28. The overall means of annual suitability scores at each river location for native fish over the 1990–2012 water years are presented in Figure F-29.

F.4.3.2 Results for LTEMP Alternatives

The temperature suitability for the four native fish at multiple downstream locations under the LTEMP alternatives and long-term strategies is summarized in Figure F-30. Modeled main channel water temperature suitability for native fish species was relatively low and similar to Alternative A under all long-term strategies at RM 61, reflecting the prevalence of coldwater releases from Glen Canyon Dam throughout the year and the limited effect that the long-term strategies would have on mainstem water temperature regimes at RM 61. Because the water

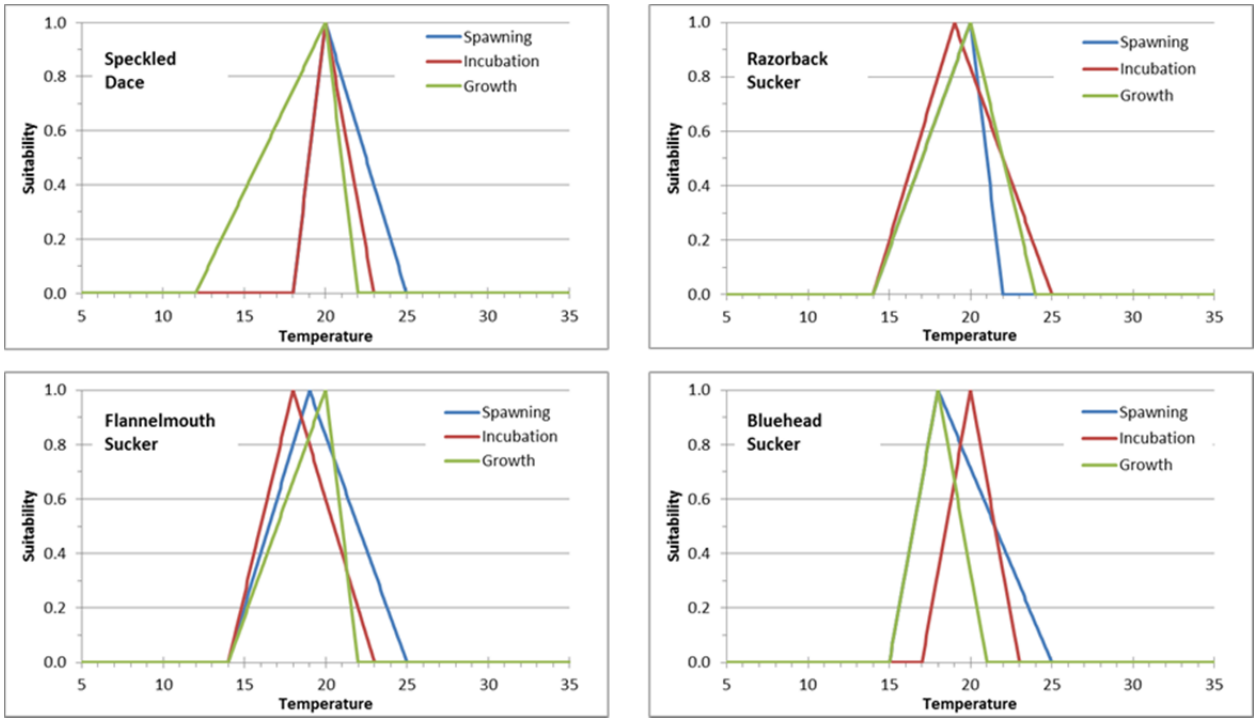


FIGURE F-24 Suitability of Water Temperatures (°C) for Spawning, Egg Incubation, and Growth of Native Fish Species (Source: Valdez and Speas 2007)

Species	Life History Aspect	Month											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Speckled Dace	Spawning												
	Incubation												
	Growth												
Razorback Sucker	Spawning												
	Incubation												
	Growth												
Flannelmouth Sucker	Spawning												
	Incubation												
	Growth												
Bluehead Sucker	Spawning												
	Incubation												
	Growth												

FIGURE F-25 Months for Which Temperature Suitability for Specific Life History Aspects Were Considered for Native Fish Species

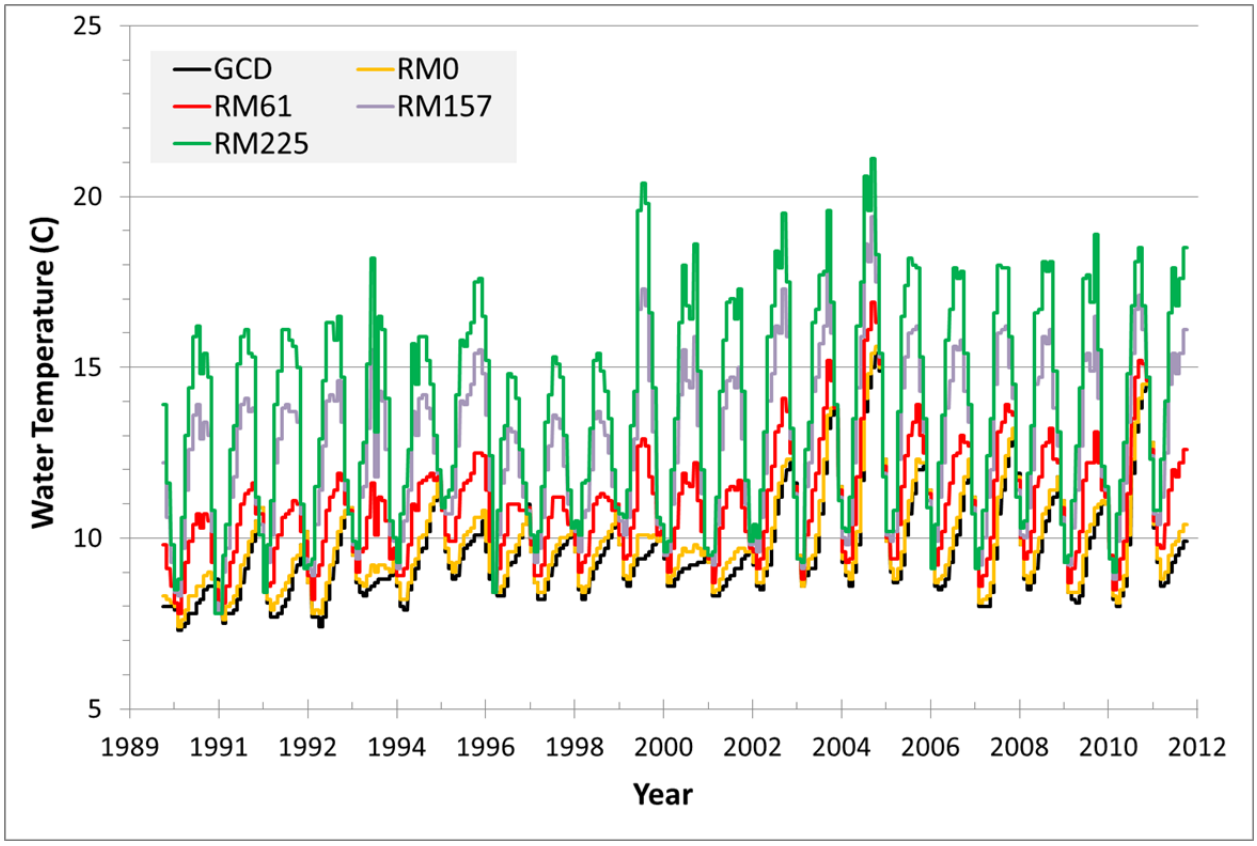
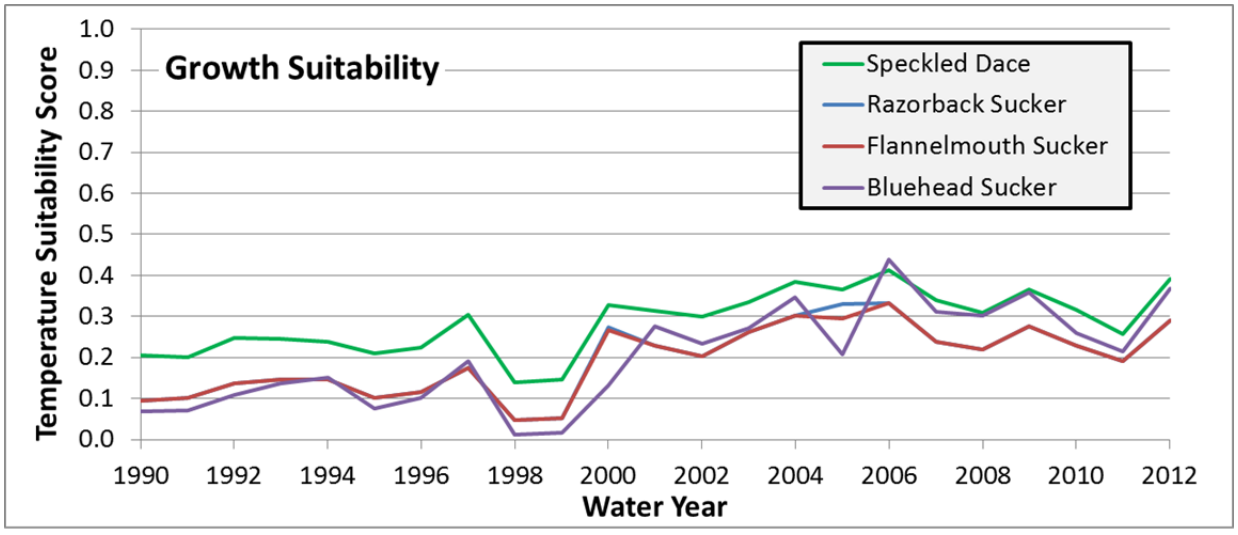
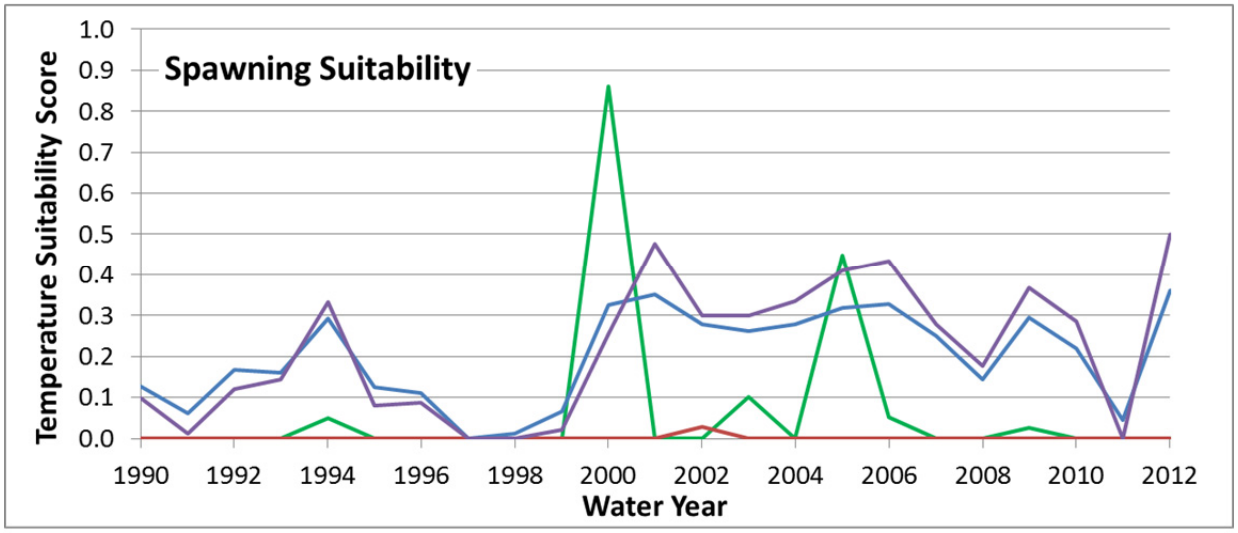


FIGURE F-26 Modeled Historic Water Temperatures in the Colorado River Downstream of Glen Canyon Dam, Water Years 1990–2012 (Source: Williams 2013)

warms as it travels downstream from the dam (for spring through fall months), temperature suitability improves with increasing downstream distance, and differences in suitability among the long-term strategies begin to appear. Whereas suitability for most long-term strategies remain similar to, or lower than, the modeled suitability under Alternative A at these downstream locations, temperature suitability for native fish improves somewhat under long-term strategies D1, D2, D3, and D4 (Figure F-30). It should be noted that there is little difference in temperature suitability among the long-term strategies specific to Alternatives B, C, D, and E, suggesting that experimental elements identified in Table 4.1-1 such as HFEs, low summer flows, TMFs, and hydropower improvement flows would have little effect on mainstem water temperature regimes during periods of the year considered most important for spawning and egg incubation by native species. Rather, differences in temperature suitability for native fish under the various long-term strategies appear to be more related to differences in the seasonal patterns of releases and the effects of those patterns on seasonal temperatures. Thus, the reduction in modeled temperature suitability under Alternative F at RM 225 reflects the higher flows expected to occur under this alternative during spring and early summer months when native fish are expected to spawn; those higher flows would result in temperatures less suitable for spawning and egg incubation.





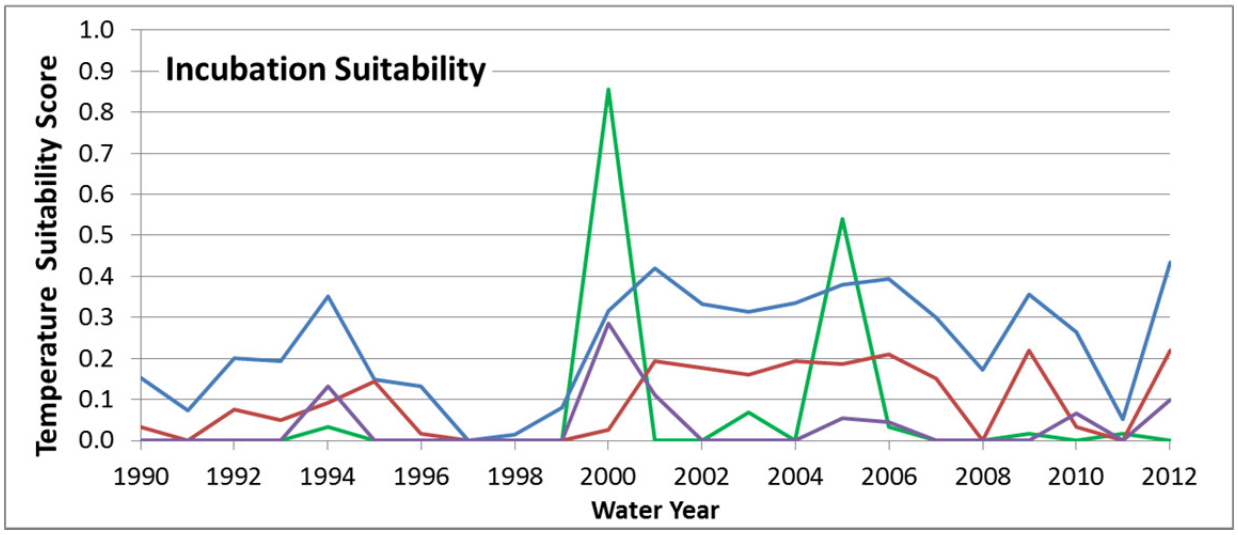


FIGURE F-27 Annual Temperature Suitability Scores for Growth, Spawning, and Egg Incubation of Native Fish Species at RM 225 Based on Modeled Water Temperatures for Water Years 1990–2012

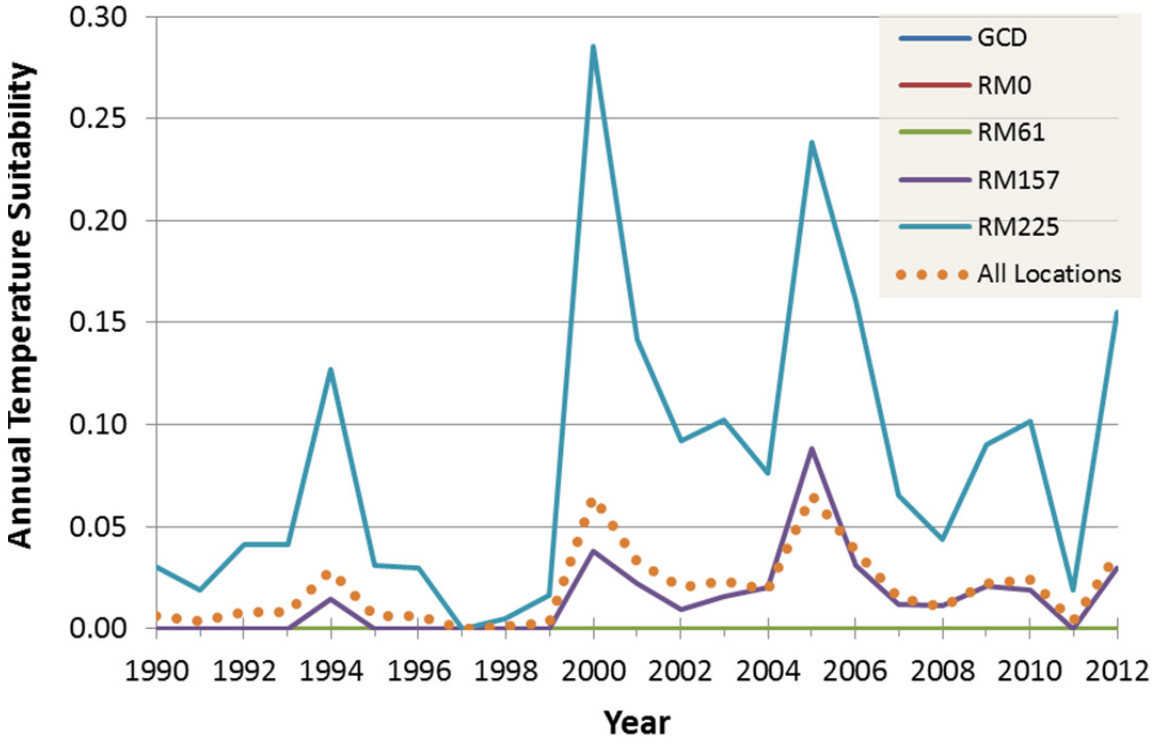


FIGURE F-28 Annual Temperature Suitability Scores for Native Fish by Assessment Location Based on Modeled Water Temperatures for Water Years 1990–2012

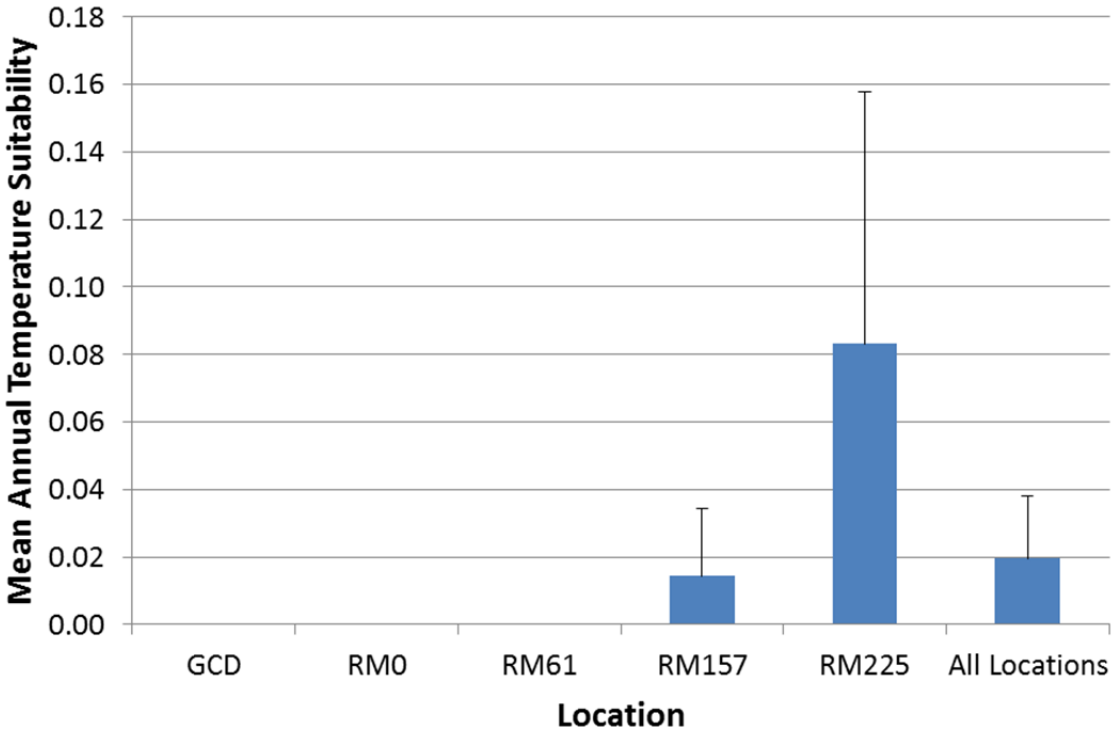


FIGURE F-29 Mean (±SD) Annual Overall Temperature Suitability for Native Fish by Assessment Location Based on Modeled Water Temperatures for Water Years 1990–2012

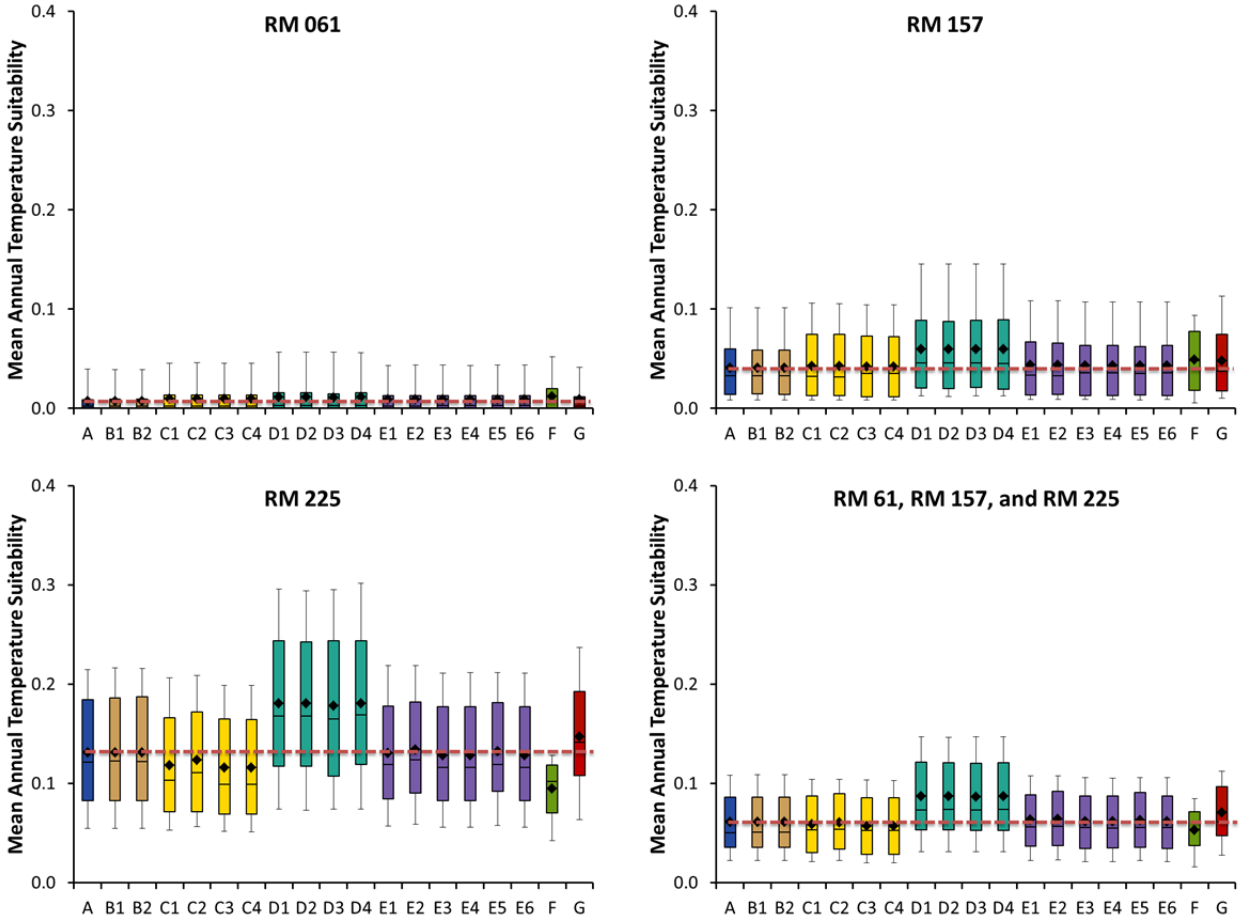


FIGURE F-30 Mean Annual Mainstem Temperature Suitability for Native Fish under LTEMP Alternatives and Long-Term Strategies at RM 61, RM 157, and RM 225, and Overall Mean for RM 61–225 (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

F.4.4 Nonnative Fish

The temperature suitability model for nonnative fish evaluates how well alternatives provide mainstem water temperatures suitable for spawning, egg incubation, and growth of six species of coldwater (brown trout [*Salmo trutta*], rainbow trout) and warmwater (channel catfish [*Ictalurus punctatus*], green sunfish [*Lepomis cyanellus*], smallmouth bass [*Micropterus dolomieu*], and striped bass [*Morone saxatilis*]) nonnative fish. In order to account for changes in water temperatures as water released from Glen Canyon Dam travels downstream, evaluations of temperature suitability were conducted for the five mainstem Colorado River locations identified in Table F-11. As described in Section F.4.1, the time series of water temperatures used as inputs for these locations were generated using a water temperature model developed by Wright et al.

(2009). The calculated suitability values for various water temperatures for successful spawning, egg incubation, and growth of the six nonnative fish species are depicted in Figure F-31. The months encompassing the spawning and egg incubation periods for each of the six nonnative fish species are indicated in Figure F-32. The annual suitability of daily temperatures for growth is calculated as the mean of daily suitability values for the entire water year (October through September). The overall means of temperature suitability values for the coldwater and warmwater nonnative species groups were examined separately.

F.4.4.1 Historic Temperature Suitability for Nonnative Fish

Historic temperature suitability of mainstem water temperatures for the six nonnative fish species was examined using modeled water historic temperatures at the five evaluation locations for a 23-year period from October 1, 1989, through September 30, 2012 (water years 1990–2012), as the temperature inputs (Figure F-26). Figure F-33 presents the annual temperature suitability scores for spawning, incubation, and growth of the six nonnative fish species based upon the modeled historic temperatures for water years 1990–2012 at RM 225 (Diamond Creek). The mean annual temperature suitability scores for each species and temperature group for the five river locations are presented in Figure F-34. The overall means of annual suitability scores for the coldwater and warmwater nonnative fish species groups across all river locations during the 1990–2012 water years are presented in Figure F-35.

F.4.4.2 Results for LTEMP Alternatives

In general, temperature suitability for coldwater nonnative species (i.e., brown and rainbow trout) would be similar among most of the long-term strategies at most locations downstream of Glen Canyon Dam and would be remain similar to current conditions based on comparisons to Alternative A (Figure F-36). Because of the effects of the timing and magnitude of peak and base flow releases on water temperatures, temperature suitability would be slightly greater under Alternative F than other long-term strategies at the confluence with the Little Colorado River (RM 61) and lower under Alternative F than other long-term strategies for locations farther downstream; however, those differences are very small and may not be biologically significant. Although main channel temperature regimes at and downstream of RM 61 appear to become more suitable for trout species than at locations closer to the dam (Figure F-36), the abundance of trout is known to be lower at those locations (based on sampling), suggesting that other habitat characteristics (e.g., substrate composition and water clarity) may be less suitable at these downstream locations. Because inclusion of flow actions such as HFEs, TMFs, and low summer flows had only minor influences on modeled monthly mainstem water temperatures during periods of the year considered most important for spawning and egg incubation by trout, these flow actions have little effects on modeled mainstem temperature suitability and would not alter relative suitability for coldwater nonnative species among the long-term strategies (Figure F-36).

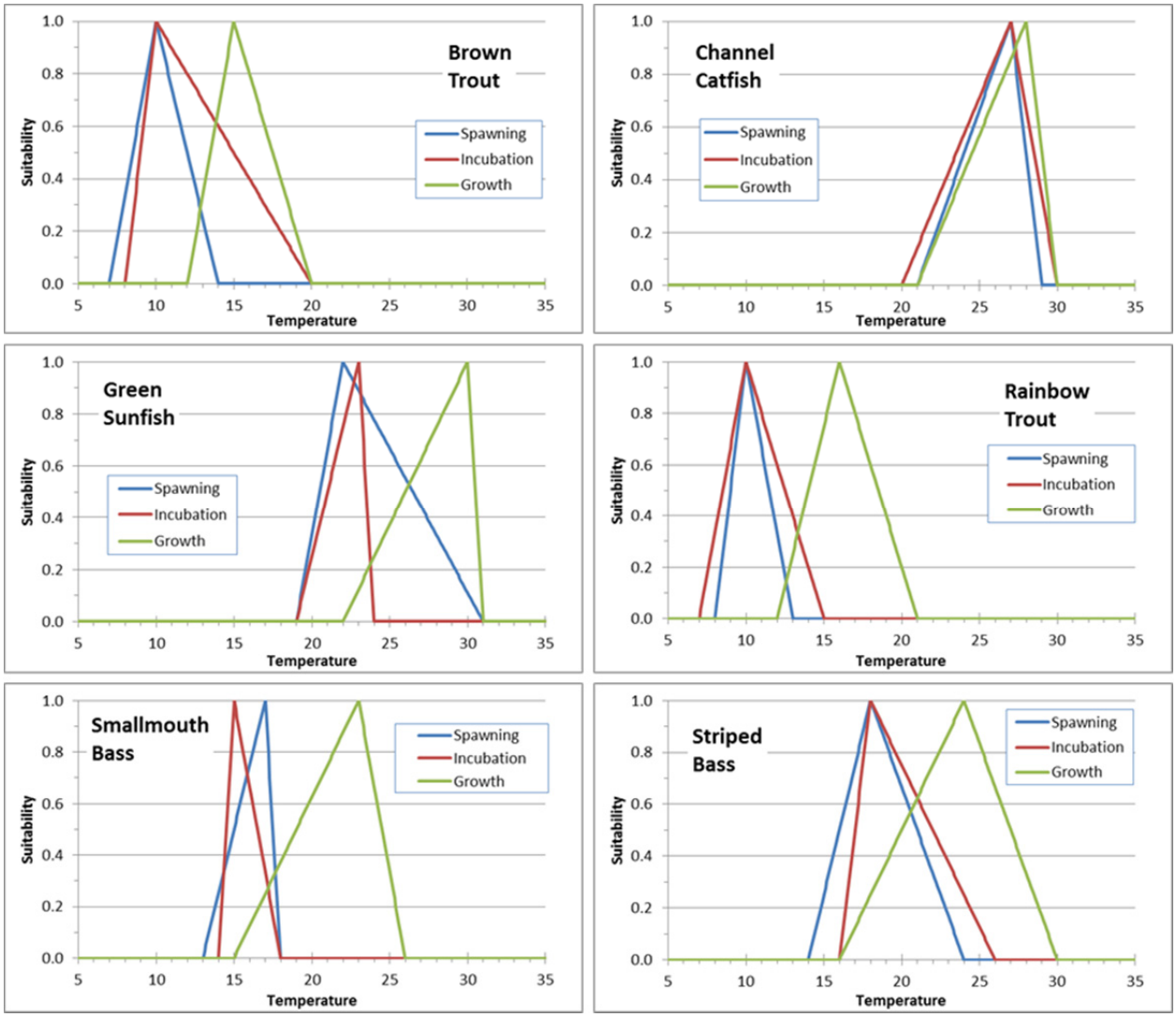


FIGURE F-31 Suitability of Water Temperatures (°C) for Spawning, Egg Incubation, and Growth of Nonnative Fish Species (Source: Valdez and Speas 2007)

Temperature suitability at the various main channel locations was modeled for the four nonnative warmwater species considered to be representative of the warmwater nonnative fish community (smallmouth bass, green sunfish, channel catfish, and striped bass). In general, the estimated average main-channel temperature suitability for these nonnative fish did not differ greatly among the long-term strategies, and was low under all long-term strategies (Figure F-37). The modeled temperature suitability indicated that temperature conditions would be most suitable for warmwater nonnative species at locations farther downstream from Glen Canyon Dam (e.g., RM 157 and RM 225) compared to upstream locations (e.g., RM 0 and RM 61); this agrees with past surveys that have found more warmwater nonnative fish species in those areas. Relative to current conditions (as exemplified by Alternative A), the temperature suitability model indicated that the long-term strategies for Alternative C (i.e., C1, C2, C3, and C4) and Alternative F have the greatest potential to improve conditions for warmwater nonnative fish at

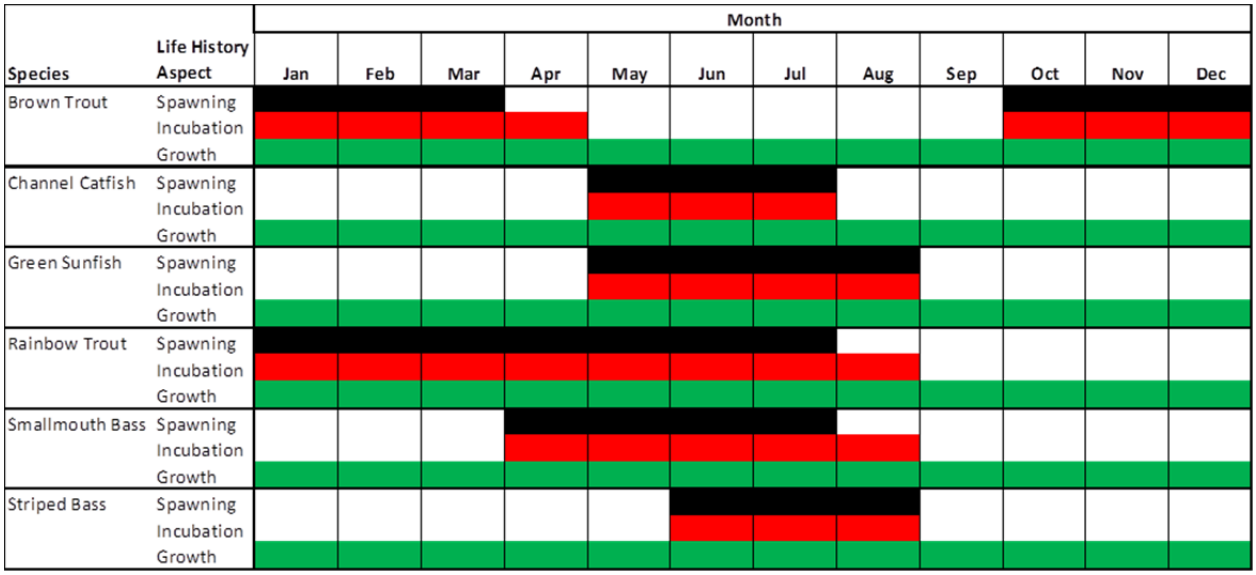


FIGURE F-32 Months during Which Temperature Suitability for Specific Life History Aspects Were Calculated for Nonnative Fish Species

locations downstream of RM 157, which could result in increased numbers and a greater potential for upstream spread of warmwater nonnative fish species. As described above for coldwater fish species, inclusion of flow actions such as HFEs, TMFs, and low summer flows had only minor influences on modeled monthly mainstem water temperatures during periods of the year considered most important for spawning and egg incubation by nonnative warmwater species. As a consequence, the various experimental elements associated with the long-term strategies (Table 4.1-1) would be expected to have little effect on mainstem temperature suitability for warmwater nonnative species (Figure F-37). Rather, as identified for native fish in Section F.4.3.2, differences among alternatives appear to be more related to differences in the seasonal patterns of releases and the effects of those patterns on seasonal temperatures.

F.4.5 Aquatic Parasites

The temperature suitability model for aquatic parasite species evaluates how well alternatives provide mainstem water temperatures suitable for host activity for and infestation by four species (Asian tapeworm [*Bothriocephalus acheilognathi*], anchor worm [*Lernaea cyprinacea*], trout nematode [*Truttaedacnitis truttae*], and whirling disease [*Myxobolus cerebralis*]) that could parasitize fish in the Colorado River downstream of Glen Canyon Dam. In order to account for changes in water temperatures as water released from Glen Canyon Dam travels downstream, evaluations of temperature suitability were conducted for the mainstem Colorado River locations identified in Table F-11. As described in Section F.4.1, the time series of water temperatures used as inputs for these locations were generated using a water temperature model developed by Wright et al. (2009).

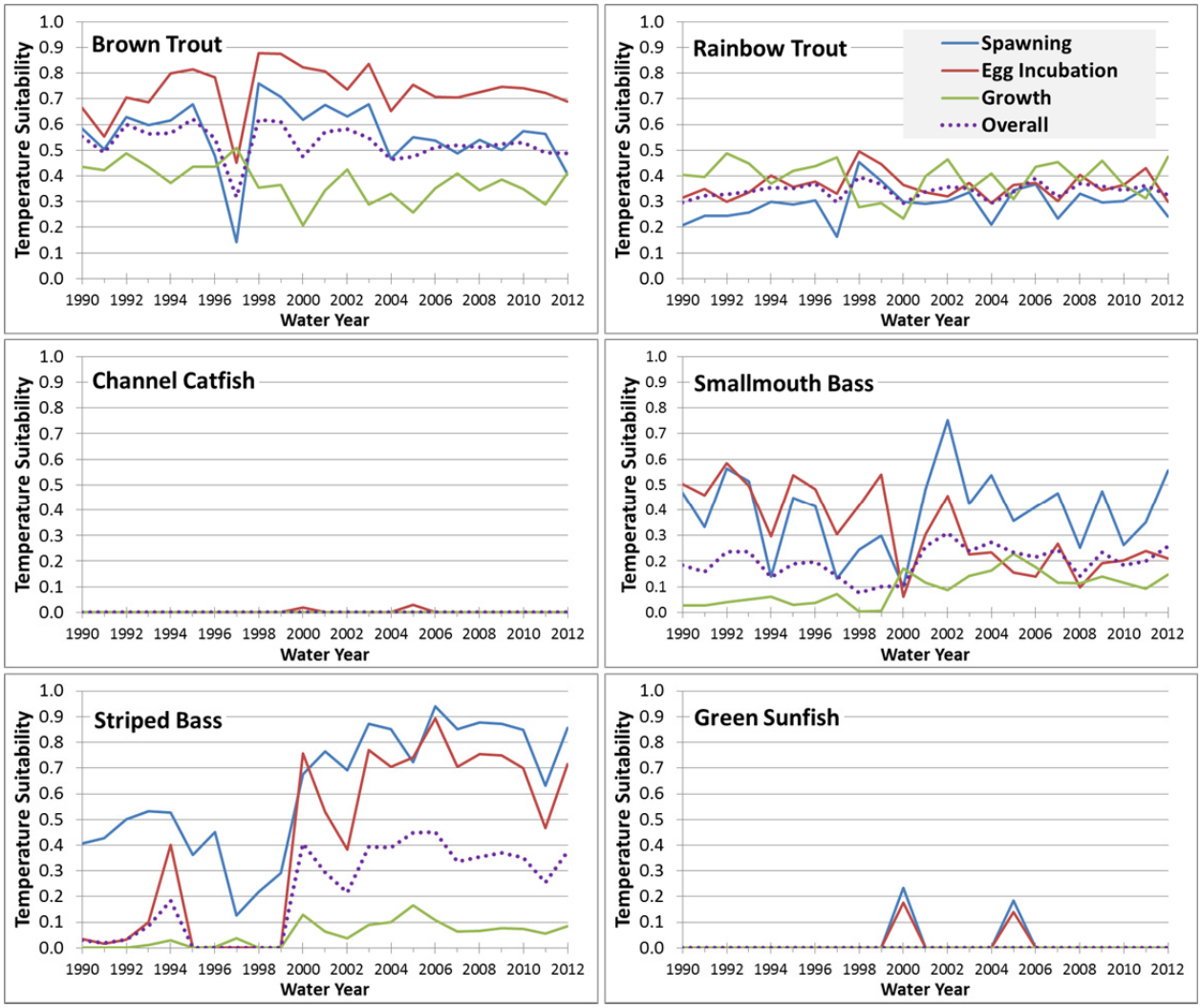


FIGURE F-33 Annual Temperature Suitability Scores for Spawning, Incubation, and Growth of Nonnative Fish Species at RM 225 (Diamond Creek) Based on Modeled Temperatures for Water Years 1990 to 2012

The calculated suitability values at various water temperatures for host activity and infestation rates of the four parasite species is depicted in Figure F-38. It was assumed that evaluation of temperature suitability across the entire water year (rather than just a portion of the year) was relevant for both of the parasite life history components. The geometric mean of the annual temperature suitability values for host activity and infestation was used as an indicator of the annual overall suitability for each parasite species and served as the indicator of the potential for each of the parasite species to become problematic at a particular downstream location. The combined mean of the annual suitability scores for all four parasite species was used as an indication of the overall suitability of each year's temperature regime for the group of parasite species at each downstream location. The mean of the group means for all of the downstream locations was calculated as an indication of overall relative suitability of the temperature regime

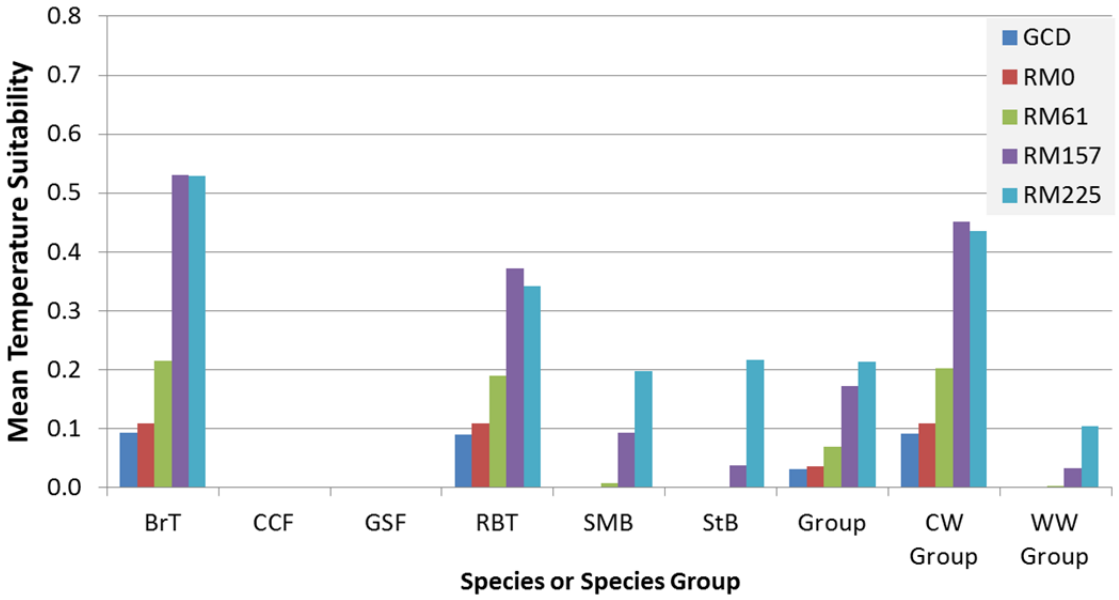


FIGURE F-34 Mean Annual Temperature Suitability Scores for Nonnative Fish Species and for Temperature Groups by River Location Based on Modeled Water Temperatures for Water Years 1990–2012 (BrT = brown trout; CCF = channel catfish; GSF = green sunfish; RBT = rainbow trout; SMB = smallmouth bass; StB = striped bass; Group = combined coldwater and warmwater; CW = coldwater; WW = warmwater)

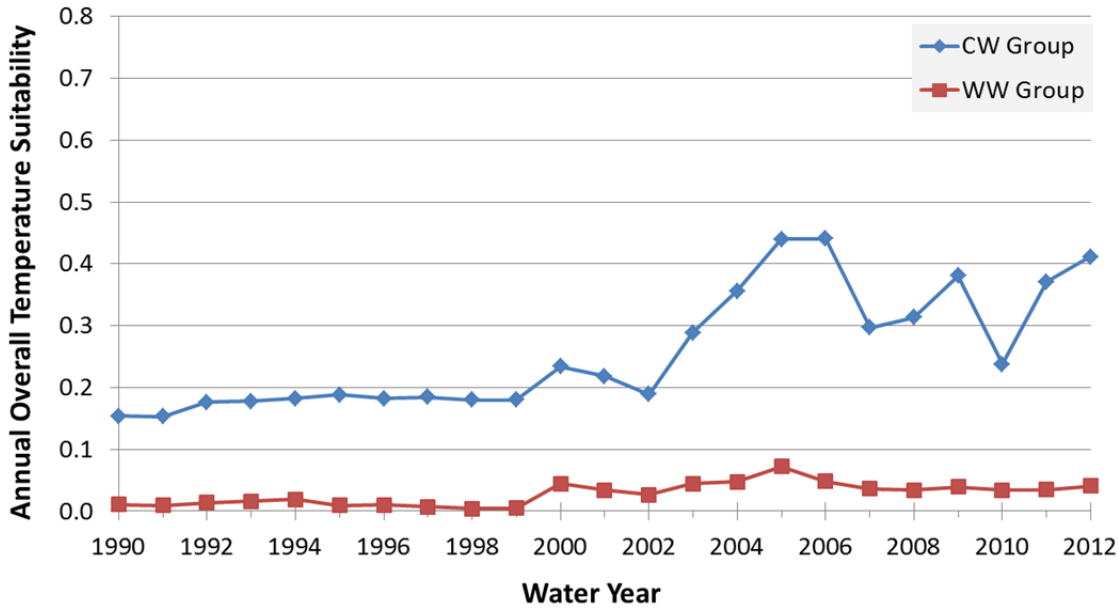


FIGURE F-35 Mean Annual Overall Temperature Suitability Scores for Coldwater (CW) and Warmwater (WW) Nonnative Fish Species Groups Based on Modeled Historic Temperatures for Water Years 1990–2012

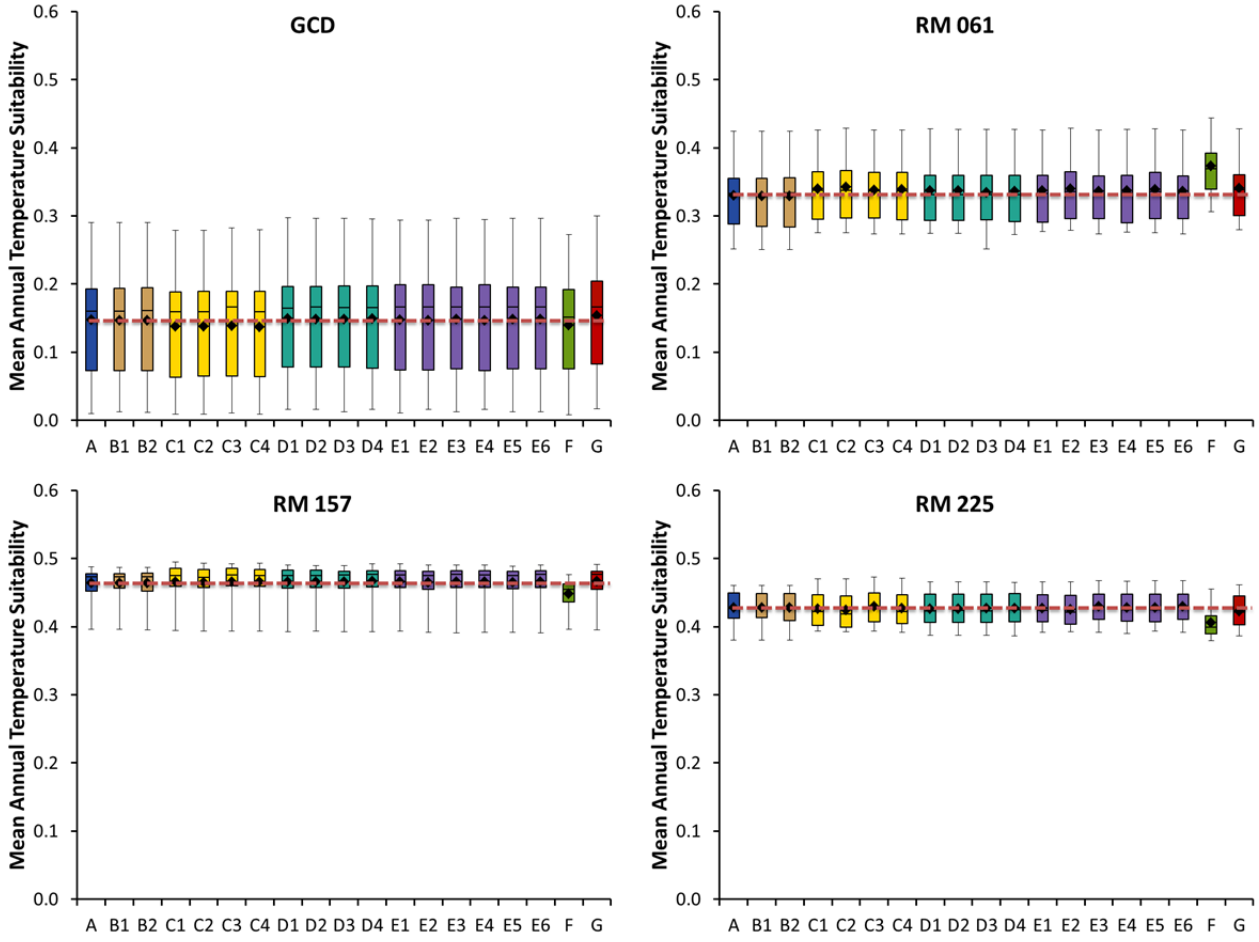


FIGURE F-36 Mean Annual Mainstem Temperature Suitability for Coldwater Nonnative Fish (brown trout and rainbow trout) under LTEMP Alternatives and Long-Term Strategies at RM –15 (Glen Canyon Dam, GCD) RM 61, RM 157, and RM 225 (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

within a particular year for parasite species in the mainstem Colorado River downstream of Glen Canyon Dam.

F.4.5.1 Historic Temperature Suitability for Aquatic Parasites

Historic temperature suitability of mainstem water temperatures for the four aquatic parasite species was examined using modeled water historic temperatures at the five evaluation locations for a 23-year period from October 1, 1989, through September 30, 2012 (water years 1990–2012), as the temperature inputs (Figure F-26). Figure F-39 presents the annual

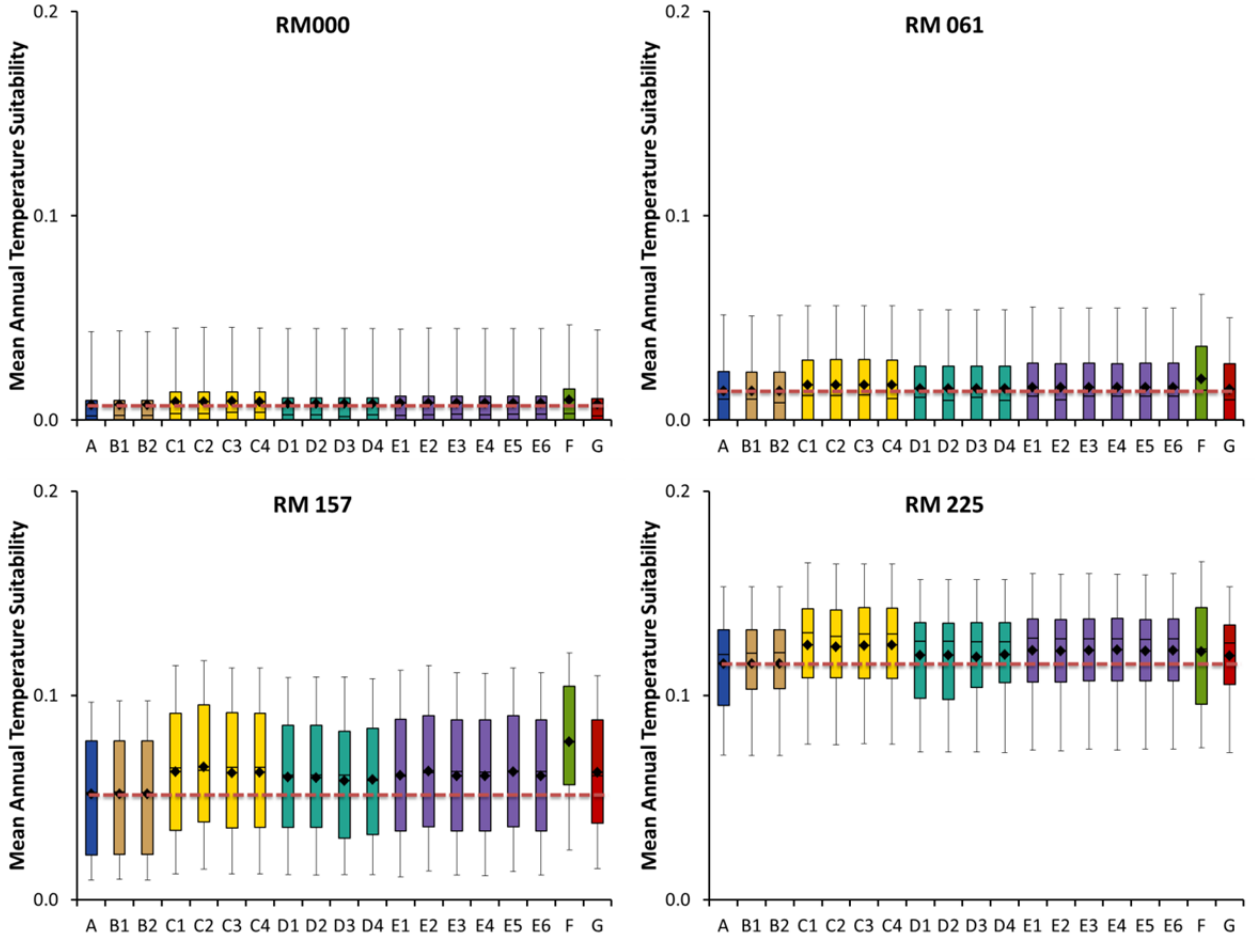


FIGURE F-37 Mean Annual Mainstem Temperature Suitability for Warmwater Nonnative Fish (channel catfish, green sunfish, smallmouth bass, and striped bass) under LTEMP Alternatives and Long-Term Strategies at RM 0, RM 61, RM 157, and RM 225 (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

temperature suitability scores for host activity and infestation rates of the parasite species based upon the modeled historic temperatures for water years 1990–2012 at RM 225 (Diamond Creek). The mean annual temperature suitability scores for each species and temperature group for the five river locations are presented in Figure F-40. The overall means of modeled annual suitability scores for the coldwater and warmwater nonnative fish species groups across all river locations during the 1990–2012 water years are presented in Figure F-41.

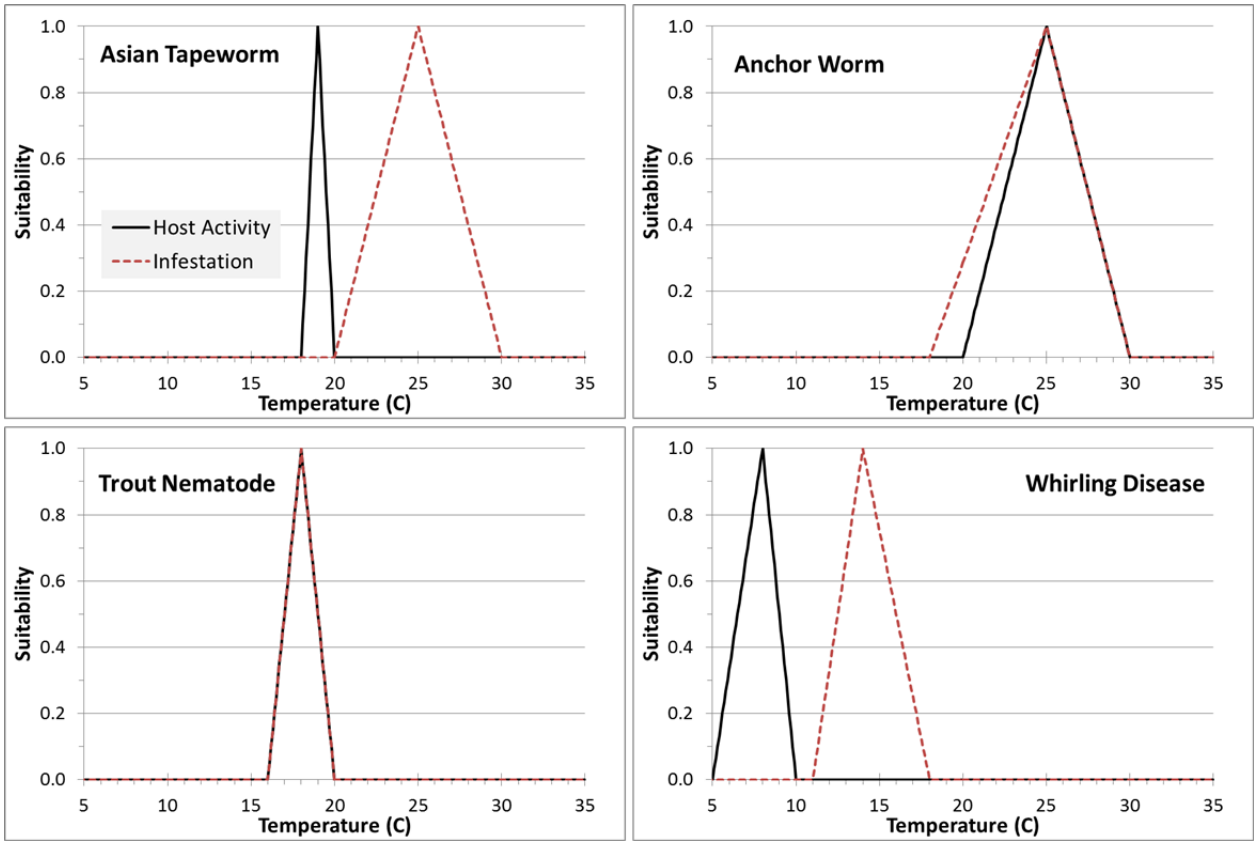


FIGURE F-38 Suitability of Various Water Temperatures for Host Activity and Infestation Rates of Parasite Species (Source: Valdez and Speas 2007)

F.4.5.2 Results for LTEMP Alternatives

Temperature suitability for the four aquatic parasite species (Asian tapeworm, anchor worm, trout nematode, and whirling disease) under the LTEMP alternatives and long-term strategies was modeled for various locations downstream from Glen Canyon Dam. Modeling indicated that temperature suitability for the aquatic parasite species would generally be very low under all long-term strategies and would be comparable to the suitability under current operations as represented by Alternative A (no-action alternative; Figure F-42). As a consequence, the relative distributions of aquatic parasites or the effects of aquatic parasites on survival and growth of native fish or trout species would not be expected to change relative to current conditions under any of the long-term strategies. Under current conditions, population-level effects of parasites on survival and growth of native fish or trout have not been observed. Inclusion of flow actions such as HFEs, TMFs, and low summer flows had only minor influences on modeled monthly mainstem water temperatures during periods of the year considered most important for spawning and egg incubation by native fish. As a consequence, these flow actions are expected to have minor effects on temperature suitability for the parasite species group and would not alter the relative suitability among the long-term strategies.

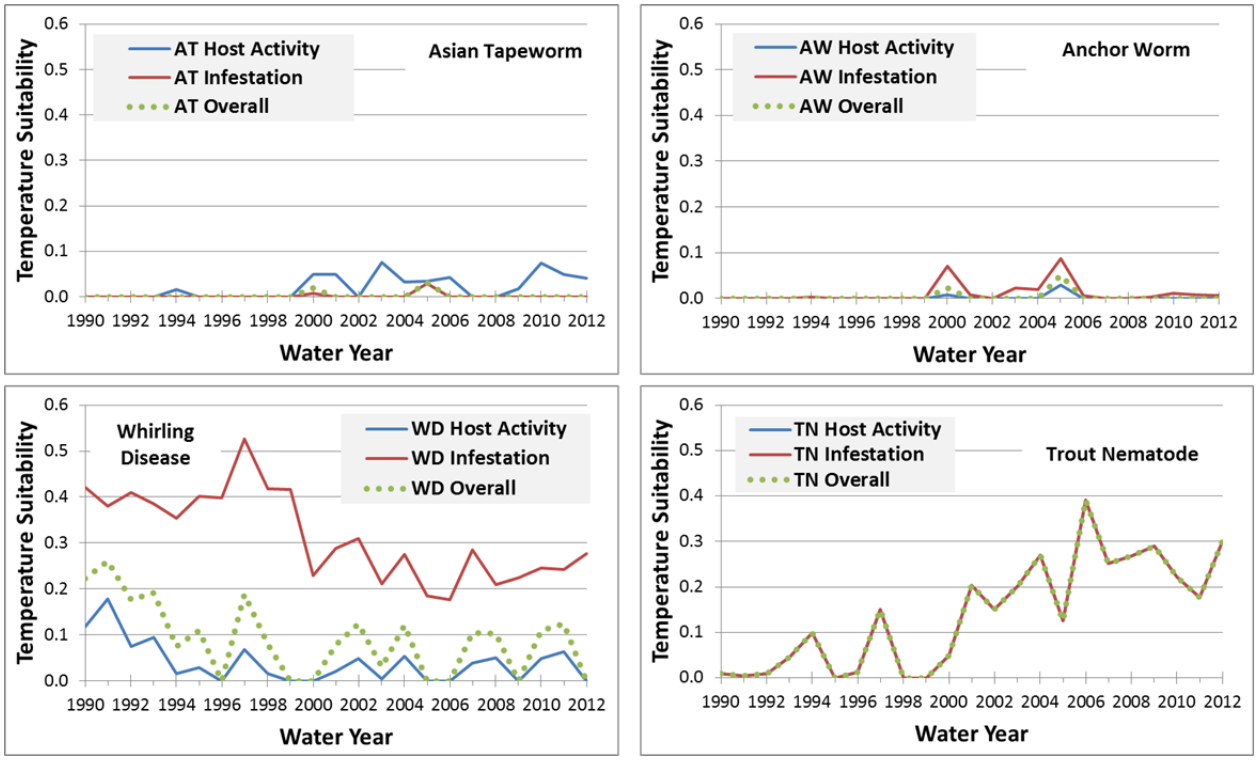


FIGURE F-39 Annual Temperature Suitability Scores for Parasite Species at RM 225 (Diamond Creek) Based on Modeled Water Temperatures for Water Years 1990–2012 (AT = Asian tapeworm; AW = anchor worm; TN = trout nematode; and WD = whirling disease)

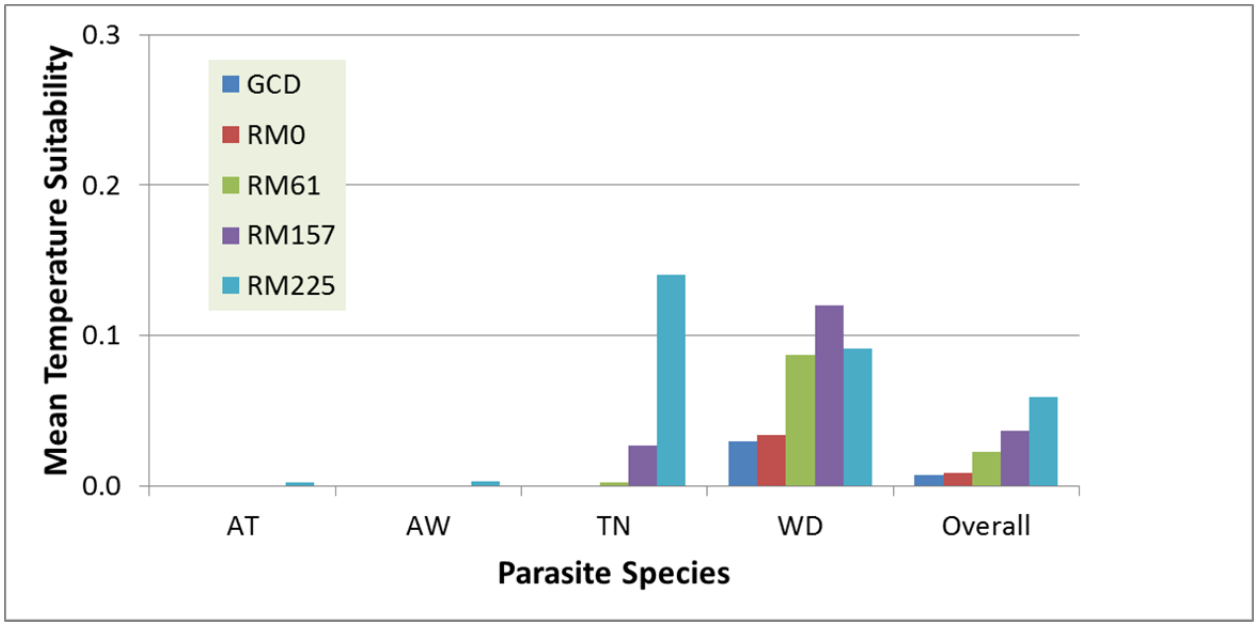


FIGURE F-40 Mean Annual Temperature Suitability Scores for Parasite Species by River Location Based on Modeled Water Temperatures for Water Years 1990–2012 (AT = Asian tapeworm; AW = anchor worm; TN = trout nematode; and WD = whirling disease)

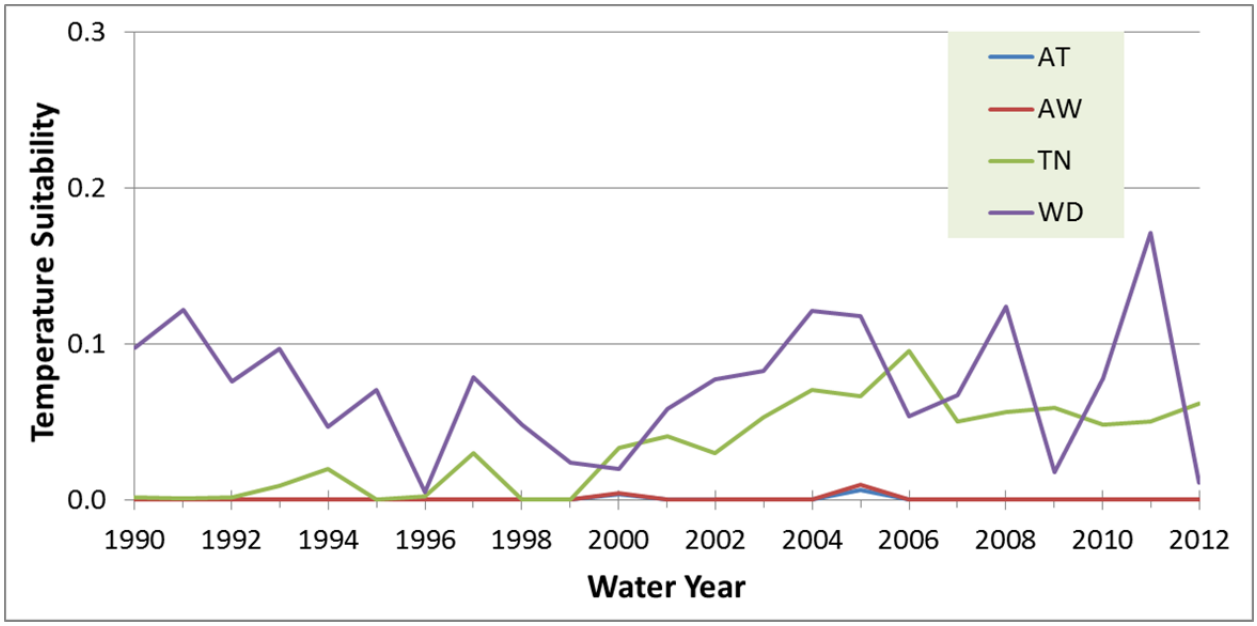


FIGURE F-41 Overall Means of Annual Suitability Scores for Parasite Species Across All River Locations during the 1990–2012 Water Years (AT = Asian tapeworm; AW = anchor worm; TN = trout nematode; and WD = whirling disease)

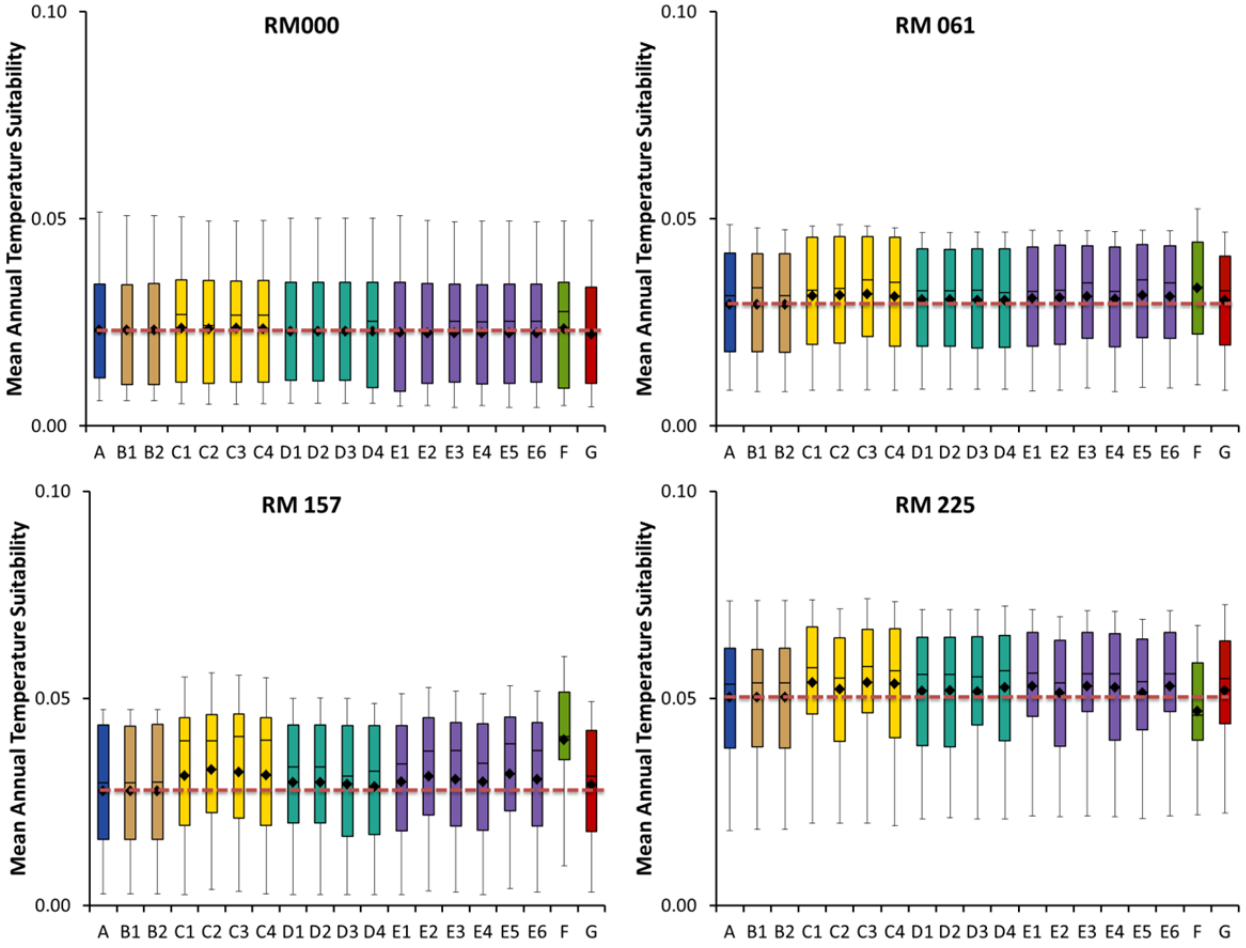


FIGURE F-42 Overall Modeled Mean Annual Temperature Suitability under LTEMP Alternatives and Long-Term Strategies for Aquatic Fish Parasites (Asian tapeworm, anchor worm, trout nematode, and whirling disease) at Four Locations Downstream of Glen Canyon Dam (The graph shows the mean, median, 75th percentile, 25th percentile, minimum, and maximum values for 21 hydrology scenarios and three sediment scenarios. Means were calculated as the average for all years within each of the 21 hydrology runs. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum; horizontal dashed line identifies mean value for Alternative A.)

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APPENDIX G:

VEGETATION TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX G:

VEGETATION TECHNICAL INFORMATION AND ANALYSIS

G.1 ANALYSIS METHODS

The analysis of impacts on plant communities is primarily based on the evaluation of four performance metrics that were developed for the Long-Term Experimental and Management Plan (LTEMP) assessment process. The metrics are calculated using the results of an existing state and transition model for Colorado River riparian vegetation downstream from Glen Canyon Dam. Model details are described in Ralston et al. (2014). The four metrics are as follows:

- Relative change in cover of native vegetation community types (other than arrowweed[1]) on sandbars and channel margins using the total percent increase in native states (change in native cover = $cover_{final}/cover_{initial}$).

- Relative change in diversity of native vegetation community types (other than arrowweed) on sandbars and channel margins using the Shannon-Weiner Index for richness/evenness (change in diversity = $diversity_{final}/diversity_{initial}$).

- Relative change in the ratio of native (other than arrowweed)/nonnative dominated vegetation community types on sandbars and channel margins (change in native/nonnative ratio = $ratio_{final}/ratio_{initial}$).

- Relative change in the arrowweed state on sandbars and channel margins using the total percent decrease in arrowweed states (Change in arrowweed = $arrowweed_{initial}/arrowweed_{final}$).

These performance metrics were developed from the resource goal for riparian vegetation downstream from Glen Canyon Dam: *Maintain native vegetation and wildlife habitat, in various stages of maturity that is diverse, healthy, productive, self-sustaining, and ecologically appropriate*.

The state and transition model was developed to compare the effects of various flow regimes on Colorado River riparian vegetation. Seven vegetation states are used in the model to represent plant community types found along the river on sandbars and channel margins in the new high-water zone and fluctuation zone. Species associated with a state respond similarly to Colorado River hydrologic factors such as depth, timing, and duration of inundation. These states and the plant species associated with each are given in Table G-1. The model and data used to calculate performance metrics are based on vegetation studies conducted within Grand Canyon National Park and may have limited application to riparian vegetation communities within Glen

[1] This species was selected to be excluded from the native species metrics and to be a fourth metric. It is managed differently than other native species because of its tendency to rapidly establish on sandbars to the exclusion of other species.

Canyon. The model consists of six submodels based on landforms: lower separation bar, upper separation bar, lower reattachment bar, upper reattachment bar, lower channel margin, and upper channel margin. Upper and lower bars are divided at the 25,000 cfs flow stage.

The model uses the daily maximum flow from the GTMax-Lite 2 hydrograph (GTMax-Lite 2 includes hourly flows for the entire 20-year flow period); it does not include daily fluctuations (the range in flows within a day). A total of 63 hydrology-sentiment trace combinations were included in the analysis of each alternative and long-term strategy. Within each run of each alternative, the model identifies the occurrence of hydrologic events, such as spill flows, spring and fall high-flow experiments (HFEs), extended low flows, extended high flows, and growing or non-growing seasons without extended high or low flows, occurring during the growing season (May–September) or non-growing season (October–March) (see Table G-2). The model then records transitions between vegetation states, based on a set of rules developed for each submodel, driven by these hydrologic events. The model includes a subset of states and transition rules for each bar type and channel margin type. The transition rules for the upper portions of the bars and channel margin are the same because of the similarity of plant community types and responses to flow characteristics. The transition rules are based on the effects of scouring, drowning, desiccation, and sediment deposition on riparian plant species. The interrelationships among vegetation states were developed primarily from published vegetation studies based on data collected in Grand Canyon National Park (see Ralston et al. 2014 and citations therein). A subject matter expert team refined the transitions based on extensive field experience in the Colorado River riparian system. Transition rules for the submodels are given in Table G-3. Although the model is a simplification of the complexities of the riparian ecosystem, it is a valuable tool in estimating the changes in riparian vegetation under a variety of flow regimes.

Model results include the total number of years each state occurs for the 20-year period of the model run, according to each potential starting state in each submodel (i.e., the number of years each feature is in each state, based on the transition rules). Each model run starts with each potential state of each submodel, shown in Table G-1. For example, the lower Reattachment Bar submodel uses five different starting states for each hydrologic trace: bare sand, *Phragmites australis* Temperate Herbaceous Vegetation, *Equisetum hyemale* Herbaceous Vegetation, Tamarisk Temporarily Flooded Shrubland, and *Pluchea sericea* Seasonally Flooded Shrubland. Therefore, five model runs, each with a different starting state, are made with the Reattachment Bar submodel for each trace.

G.1.1 Old High-Water Zone Analysis

Plant communities of the old high-water zone are not included in the riparian state and transition model. Therefore, a qualitative assessment was conducted to evaluate impacts of alternatives. The old high-water zone vegetation is located at high flow stage elevations (above 60,000 cfs, but primarily from about 100,000 to approximately 200,000 cfs), well above the level of current dam operations. Dam operations, other than HFEs, are limited to 31,500 cfs flows (generally will not exceed 25,000 cfs), and HFEs do not exceed 45,000 cfs.

None of the alternatives considered would include flows sufficient to maintain these pre-dam plant communities. HFEs could potentially provide occasional soil moisture to some older deep-rooted plants located in the old high-water zone. Dam releases can affect water availability for plants at elevations up to approximately 15,000 cfs above discharge levels (Melis et al. 2006; Ralston 2005). Alternatives with more frequent spring HFEs—such as Alternative F, with annual spring HFEs, or Alternative G; Alternative C, long-term strategies C1 and C2; and Alternative D, long-term strategies D1–D4, all with considerably more spring HFEs than Alternative A—may result in higher survival rates of plants at lower elevations of the old high-water zone than under Alternative A. Spill flows (between 45,000 and 85,000 cfs) would provide soil moisture to old high-water zone plants; however, these have not occurred since the mid-1980s. Periodic spill flows could occur within the 20-year period of this evaluation, but would likely be infrequent and would occur equally under all alternatives. Because of a lack of sufficiently high flows and nutrient-rich sediment, mortality of pre-dam plants within this zone has been occurring for decades, along with a lack of seedling establishment for some species, such as mesquite and hackberry (Kearsley et al. 2006; Anderson and Ruffner 1987; Webb et al. 2011). Because of generally continued low soil moisture and lack of recruitment opportunities under all alternatives, the upper margins of this zone would be expected to continue moving downslope, with a continued narrowing of this zone. Desert species occurring on the pre-dam flood terraces and aeolian deposits above the Old High-Water Zone would increasingly establish within this zone.

G.1.2 New High-Water Zone

The four metrics, (1) relative change in cover of native vegetation community types, (2) relative change in diversity of native vegetation community types, (3) relative change in the ratio of native/nonnative dominated vegetation community types, and (4) relative change in the arrowweed state, were calculated from the model results for each alternative and long-term strategy. The four native-dominated states are *Phragmites australis* Temperate Herbaceous Vegetation, *Salix exigua-Baccharis emoryi* Shrubland/*Equisetum laevigatum* Herbaceous Vegetation, *Populus fremontii*/*Salix exigua* Forest, and *Prosopis glandulosa* var. *torreyana* Shrubland. Two of these states, both of which represent wetland community types, are further discussed below. Although arrowweed is a native species, because of its invasive characteristics and tendency to form monocultures, the *Pluchea sericea* Seasonally Flooded Shrubland state is excluded from the native states in the performance metrics.

Model results were used to calculate the performance metrics for each alternative/long-term strategy using the sum of years of each of the states for all six models. This value is then compared to the number of years each state would have accumulated if the current condition was maintained (i.e., if no transitions occurred and each of the seven states remained the same for the full 20 years of the model run). This proportion was then multiplied by the acreage of mapped cover types from the NPS Vegetation Map of Grand Canyon National Park (Table G-4) corresponding to the seven model states (Table G-5). This final acreage and the initial mapped acreage were then used to calculate the performance metrics.

The results for the four metrics were then summed to derive a final score for each alternative long-term strategy. Alternatives with higher scores were considered to have come closer to achieving the resource goal.

The 63 hydrology-sediment trace combinations used in the model runs were developed from the historical record (see Section 4.1 of the DEIS for a detailed description). Twenty-one potential Lake Powell inflow scenarios for the 20-year LTEMP period were sampled from the 105-yr historic record (water years 1906–2010), producing 21 hydrology traces for analysis. In addition, three 20-year sequences of sediment input from the Paria River sediment record (water years 1964–2013) were analyzed. In combination, the analysis considered 63 possible hydrology-sediment scenarios. An assumption underlying the model results is that future river flows will be similar to past flows. To examine the effect of potential climate change, each of the traces used in the model runs was then differentially weighted (see Section 4.17.1.2). Weights were developed based on climate change projections of the 2012 Colorado River Basin Water Supply and Demand Study (Reclamation 2012). These assigned weights thus reflect the likelihood of occurrence of each hydrology trace under potential future climate change, emphasizing the drier scenarios. The model result for each trace was then multiplied by the assigned weight.

G.1.2.1 Native Cover Metric

Relative change in cover of native vegetation community types (other than arrowweed) on sandbars and channel margins using the total percent increase in native states (change in native cover = $cover_{final}/cover_{initial}$).

The results for the Native Cover metric based on historical flows are shown in Figure G-1. The two highest-scoring long-term strategies, E6 and E3, are significantly different from the others (differences between means of the 63 traces based on a three-factor ANOVA followed by Tukey's Studentized Range [HSD] Test) but not from each other. Results under projected climate change are similar to those for historical flows (all alternatives score slightly higher) and are shown in Figure G-2; thus the relative performance of each alternative under climate change would be similar to that modeled under historical conditions.

To illustrate the relative change in native cover, the modeled acreage changes for several alternative/long-term strategies are shown in Table G-6.

Native states tend to increase with growing and non-growing seasons without extended high or low flows. Bare Sand, Tamarisk Temporarily Flooded Shrubland, and *Pluchea sericea* Seasonally Flooded Shrubland tend to increase with extended high and extended low flows. The effect of differences between hydrologic traces is greater than the effect of differences between alternatives.

G.1.2.2 Native Diversity Metric

Relative change in diversity of native vegetation community types (other than arrowweed) on sandbars and channel margins using the Shannon-Weiner Index for richness/evenness (change in diversity = $diversity_{final}/diversity_{initial}$).

The Native Diversity metric is calculated using the Shannon-Weiner Index for richness/evenness: $-\Sigma(p_i)(\log_2 p_i)$ where p_i is the proportion of the *i*-th state of the total native cover. The calculations use the initial mapped cover and final (modeled) cover of each of the four native-dominated states. The results for the Native Diversity metric based on historical flows are shown in Figure G-3; the two highest scoring alternatives—Alternative E, long-term strategy E4, and Alternative B, long-term strategy B1—are not significantly different from each other (differences between means based on a three-factor ANOVA followed by Tukey's Studentized Range [HSD] Test); long-term strategy B1 is not significantly different from long-term strategies D3 and D2. Results under projected climate change are similar to those for historical flows, with 11 alternatives showing a slight increase and eight with a slight decrease, and are shown in Figure G-4; thus the performance of each alternative under climate change would be similar to that modeled under historical conditions. The results for all alternatives include all states. Therefore, there is no difference in the number of states between alternatives; diversity is increased by the evenness of states. For example, long-term strategy B2 and Alternative F, which are somewhat lower scoring, have a low representation of the *Phragmites australis* Temperate Herbaceous Vegetation state, while long-term strategies B1 and E4, somewhat higher scoring, have a relatively high representation of that state. The transition to the *Phragmites australis* Temperate Herbaceous Vegetation state from the bare sand state in the lower reattachment bar is slowed by growing season extended high flows, and growing season extended low or high flows contribute to transitions of the *Phragmites australis* Temperate Herbaceous Vegetation state to other states. The effect of differences between alternatives is greater than the effect of differences between hydrologic traces.

G.1.2.3 Native/Nonnative Ratio Metric

Relative change in the ratio of native (other than arrowweed)/nonnative dominated vegetation community types on sandbars and channel margins (change in native/nonnative ratio = $ratio_{final}/ratio_{initial}$).

The Native/Nonnative Ratio metric is calculated using the ratio of the cover of each of the four native-dominated states to the cover of the tamarisk state. The ratio of the final (modeled) cover is then divided by the ratio of the initial mapped cover. The results for the Native/Nonnative Ratio metric based on historical flows are shown in Figure G-5; the three highest-scoring long-term strategies, E6, E3, and E5, are not significantly different from each other (between means based on a three-factor ANOVA followed by Tukey's Studentized Range [HSD] Test); long-term strategy E5 is not significantly different from long-term strategy B1. Results under projected climate change are similar to those for historical flows (all alternatives score slightly higher) and are shown in Figure G-6; thus the performance of each alternative under climate change would be similar to that modeled under historical conditions.

Native states tend to increase with growing and non-growing seasons without extended high or low flows. The tamarisk state tends to increase with extended high flows followed by extended low flows, as well as spring HFEs with an extended low or high flow. Under Alternative C, long-term strategy C1, and Alternative F, high flows shift all states to sand, which then shifts to tamarisk (e.g., lower reattachment bar, growing season extended low).

G.1.2.4 Arrowweed Metric

Relative change in the arrowweed state on sandbars and channel margins using the total percent decrease in arrowweed states (change in arrowweed = $\text{arrowweed}_{initial}/\text{arrowweed}_{final}$). The results for the arrowweed metric based on historical flows are shown in Figure G-7; the two highest-scoring long-term strategies, C1 and C2, are not significantly different from each other (between means based on a three-factor ANOVA followed by Tukey's Studentized Range [HSD] Test); long-term strategy C2 is not significantly different from Alternatives F and G. Results under projected climate change are similar to those for historical flows (all alternatives score slightly lower) and are shown in Figure G-8; thus the performance of each alternative under climate change would be similar to that modeled under historical conditions (Alternative F would be the highest scoring, however).

To illustrate the relative change in arrowweed, acreage changes for several alternatives/long-term strategies are shown in Table G-7.

The arrowweed state tends to increase with extended high and extended low flows, but this increase can be slowed by fall HFEs. The effect of differences between hydrologic traces is greater than the effect of differences between alternatives.

G.1.2.5 Overall Score

The results for the overall score based on historical flows are shown in Figure G-9; The six highest-scoring long-term strategies, D4, E4, E6, E3, E5, and B1, are not significantly different from each other (between means based on a three-factor ANOVA followed by Tukey's Studentized Range [HSD] Test); long-term strategies E5 and B1 are not significantly different from long-term strategy E2. These alternatives included the five highest scores in the Native Cover metric and Native/Nonnative Ratio. The lowest scoring is long-term strategy C3, which is the lowest in the arrowweed metric and consistently low scoring in the other metrics. Results under projected climate change are similar to those for historical flows, with four alternatives showing a slight decrease and all others with a slight increase, and are shown in Figure G-10; thus the performance of each alternative under climate change would be similar to that modeled under historical conditions.

For the overall score, the effects of the differences between alternatives are greater than the effects of differences between hydrologic traces; sediment traces 1 and 2 are significantly different.

In reviewing the components of the overall score:

- Native Cover Index: long-term strategies E6 and E3 are the highest scoring; native states tend to increase with growing and non-growing seasons without extended high or low flows.

- Native Diversity Index: long-term strategies E4 and B1 are the highest scoring. The transition to the *Phragmites australis* Temperate Herbaceous Vegetation state from the bare sand state in the lower reattachment bar is slowed by growing season extended high flows, reducing diversity, and growing season extended low or high flows contribute to transitions of the *Phragmites australis* Temperate Herbaceous Vegetation state to other states.

- Native/Nonnative Ratio: long-term strategies E6, E3, and E5 are the highest scoring; the tamarisk state tends to increase with extended high flows followed by extended low flows, as well as spring HFEs with an extended low or high flow.

- Arrowweed Index: long-term strategies C1and C2 are the highest scoring; the arrowweed state tends to increase with extended high and extended low flows.

G.1.3 Wetlands

Two of the model states discussed above represent wetland community types: *Phragmites australis* Temperate Herbaceous Vegetation, a marsh community; and *Salix exigua-Baccharis emoryi* Shrubland/*Equisetum laevigatum* Herbaceous Vegetation, a shrub wetland community. These occur on the lower reattachment bar and lower channel margin (as well as lower reattachment bar), respectively (Table G-1), and occupy 4.4 and 0.2 ac, respectively (Table G-5). The relative change in cover of these wetland community types was calculated from the model results using the method described for metric 1 above. The results for the 19 alternatives/long-term strategies are presented in Figure G-11 (a score of 1.0 means no change from initial conditions). Only Alternative E long-term strategies E3, E5, and E6 show an increase in wetland community cover (based on mean scores); all others show a decrease. Decreases of greater than 50% occur under Alternative B, long-term strategy B2; Alternative C; Alternative F; and Alternative G. Results under projected climate change are similar to those for historical flows (all alternatives score slightly higher; however, Alternative F shows only a minimal increase), and are shown in Figure G-12; thus the performance of each alternative under climate change would be similar to that modeled under historical conditions.

G.2 ALTERNATIVE-SPECIFIC IMPACTS

This section provides additional information related to the impacts of alternatives, specifically the impacts associated with the long-term strategies that were analyzed for

condition-dependent alternatives (Alternatives B, C, D, and E). This analysis supplements the information presented in Section 4.6 of the DEIS.

G.2.1 Alternative A (No Action Alternative)

Alternative A includes sediment-triggered spring and fall HFEs through 2020 (no spring HFEs until 2015). Alternative A has higher monthly volumes in the high electricity demand months of December, January, July, and August. This alternative has fewer spring and fall HFEs than other alternatives, occasional extended low flows, and more frequent extended high flows than most other alternatives, the latter being particularly frequent in the growing season. The model results for each of the metrics as well as the overall score are presented in Table G-8.

G.2.2 Alternative B

Alternative B includes spring and fall HFEs (the number of HFEs not to exceed one every other year). This alternative lacks low summer flows, and has higher monthly volumes December–January and July–August. Alternative B has few spring HFEs, similar to Alternative A, but it also has more fall HFEs than Alternative A. The expected number of HFEs would be lower under this alternative than under any other. This alternative has the same monthly pattern in release volume as the Alternative A; however, Alterative B has no extended low flows; long-term strategy B1 has a slightly greater frequency of extended high flows compared to Alternative A, and long-term strategy B2 has considerably more extended high flows than long-term strategy B1—far more than any other alternative long-term strategy. The results for this alternative are presented for long-term strategy B1 (Table G-9), followed by long-term strategy B2 (Table G-10).

G.2.3 Alternative C

Alternative C includes spring and fall HFEs in long-term strategies C1 and C2, fall HFEs only in long-term strategy C4, and no HFEs in long-term strategy C3; proactive spring HFEs are tested in April, May, or June in high-volume years. This alternative features low summer flows in some years in long-term strategy C2, and has highest monthly release volumes December–January and July, and lower volumes from August through November. Long-term strategies C1–C4 have more extended low flows and fewer growing season extended high flows than Alternative A (although long-term strategies C2–C4 have more growing season extended high flows than long-term strategy C1); long-term strategy C3 has slightly more non-growing season extended high flows than the other Alternative C long-term strategies. Long-term strategies C1 and C2 have considerably more spring and fall HFEs than Alternative A; the number of long-term strategy C4 fall HFEs is similar to those of long-term strategies C1 and C2. The model results for each of the metrics, as well as the overall score for this alternative, are presented for long-term strategy C1 (Table G-11), followed by long-term strategies C2 (Table G-12), C3 (Table G-13), and C4 (Table G-14).

G.2.4 Alternative D (Preferred Alternative)

Alternative D includes spring (March–April) and fall (October–November) HFEs; proactive spring HFEs (24 hours, 45,000 cfs) would be tested (April, May, or June) in high-volume years; no spring HFEs the first 2 years; and extended-duration fall HFEs (up to 250-hour duration, up to 45,000 cfs), up to four in a 20-year period. As a result, Alternative D has a greater frequency of fall and spring HFEs compared to the Alternative A. Monthly water volumes would be similar to Alternative E but August and September would have higher volumes and January through July would be slightly lower than Alternative E. A 2- or 3-year test for invertebrate production would reduce flows to the minimum flow for the month on Saturdays and Sundays in May through August starting the third year of the LTEMP period; if successful, these flows would be implemented for the remainder of the LTEMP period (up to 18 years total), resulting in few, if any, growing season extended high flows during those years. Low summer flows (July, August, September) would be tested in two or three of the second 10 years. This alternative has very few growing season extended low flows, as well as slightly fewer non-growing season extended low or high flows, due to the monthly pattern of flows as well as the amount of daily fluctuations. Alternative D has frequent growing season extended high flows but not as many as under Alternative A. Seasons, especially non-growing seasons, without extended low or high flows are frequent. The model results for each of the metrics as well as the overall score for this alternative are presented for long-term strategy D1 (Table G-15) followed by long-term strategies D2 (Table G-16), D3 (Table G-17), and D4 (Table G-18).

G.2.5 Alternative E

Alternative E includes spring and fall HFEs; no spring HFEs in first 10 years; rapid response is tested every fourth HFE matching Paria flood; spring and fall HFEs in long-term strategies E1 and E2; fall HFEs only in long-term strategy E4; and no HFEs in long-term strategies E3, E5, and E6. This alternative has lower monthly water volumes in August, September, and October. Low summer flows occur in some years (triggered) of the second 10 years in long-term strategies E2 and E5. Long-term strategies E1–E6 have fewer growing season extended high flows than Alternative A, (long-term strategies E2 and E5 have slightly more than the other Alternative E long-term strategies); and more HFEs than Alternative A. Long-term strategies E1 and E2 have similar numbers of HFEs; the number of long-term strategy E4 fall HFEs is similar to long-term strategies E1 and E2. The model results for each of the metrics as well as the overall score for this alternative are presented for long-term strategy E1 (Table G-19), followed by long-term strategies E2 (Table G-20), E3 (Table G-21), E4 (Table G-22), E5 (Table G-23), and E6 (Table G-24).

G.2.6 Alternative F

Alternative F includes spring and fall HFEs; peak flows in May and June; base flows from July through January; and a 168-hour (7-day) 25,000 cfs flow at the end of June. This alternative also features higher volumes than Alternative A April–June, and lower volumes than Alternative A in the other months. This alternative has more extended low flows, slightly fewer

extended high flows, and considerably more HFEs than Alternative A (more than any other alternative). The model results for each of the metrics as well as the overall score for this alternative are presented in Table G-25.

G.2.7 Alternative G

Alternative G includes spring and fall HFEs; HFEs can extend for up to 336 hours (2 weeks); proactive spring HFEs are tested in high-volume years; and monthly volumes vary only in response to runoff forecast and other requirements. This alternative has more extended low flows and fewer extended high flows than Alternative A. The model results for each of the metrics, as well as the overall score for this alternative, are presented in Table G-26.

G.3 SUMMARY

Transitions between plant community types, or to bare sand, are driven by specific flow events that vary among the alternatives. Spring HFEs, fall HFEs, spill flows, extended low flows, extended high flows, and seasons without extended high or low flows occurring during the growing or non-growing season result in changes in the distribution and cover of New High Water Zone plant communities.

HFEs result in sediment deposition, but scouring is minor and limited to low-elevation wetland species. HFEs transport seeds of nonnative as well as native species. Repeated extended high flows result in removal of vegetation by drowning and scouring, primarily on lower elevation surfaces. Increased soil moisture at upper elevations from extended high flows can increase vegetation growth and seedling establishment. The germination of seeds transported by HFEs or extended high flows is promoted by extended low flows (e.g., elevated base flows) that reduce disturbance, expose lower elevation surfaces, and maintain soil moisture at lower elevations, all of which are conducive to seedling growth. Extended low flows also can result in the lowering of groundwater levels, thus increasing the depth to groundwater and the reduction of soil moisture, creating conditions that favor the growth of more drought-tolerant species.

Repeated seasons of extended high flows, extended high flows above 50,000 cfs, or spill flows transition native communities to bare sand through the processes of drowning, scouring, and burial. All the alternatives would result in a decrease in native plant community cover. Wetland communities generally transition only from bare sand or other wetlands; they can transition back to bare sand or to arrowweed, tamarisk, or cottonwood-willow communities. Alternatives that include frequent extended low flows, such as annually for Alternative F, or extended high flows followed by extended low flows tend to result in transitions of wetlands to other plant community types. All the alternatives are expected to result in a decrease in wetland cover, with particularly large decreases for Alternative F.

The overall cover of tamarisk-dominated communities would be expected to increase under Alternatives C, F, and G, each of which is expected to produce frequent transitions to tamarisk communities, in large part because they frequently have extended high flows, extended

low flows, and spring HFEs. This combination of flows encourages transitions to tamarisk because tamarisk increases when high flows coincide with seed release during spring and early summer, followed by lower flows, all of which results in establishment of seedlings above the elevation of subsequent floods. Also, under these alternatives, various community types frequently shift to bare sand, which then shifts to tamarisk. Each of these alternatives has more extended low flows and more spring HFEs than the other alternatives. The overall cover of the tamarisk is expected to decrease under Alternatives A, B, D, and E. Each of these alternatives has frequent extended high flows, which result in consecutive seasons and consecutive years of extended high flows. Two or more years of extended high flows are required for tamarisk to be removed by drowning, leaving a bare sand lower reattachment bar, or two consecutive seasons on a lower separation bar.

The overall cover of the arrowweed community would be expected to increase under Alternatives A, B, and E; under these alternatives, bare sand would transition to arrowweed rather than tamarisk because there are few spring HFEs and/or few growing-season extended high flows, both of which promote the establishment of tamarisk on bare sand, and, except in Alternative B, arrowweed would transition from marsh because of growing-season extended low flows. Once established, arrowweed would tend to remain for many years under these alternatives. HFEs alone are not effective at reducing arrowweed as burial typically results in resprouting from roots, buried stems, and rhizomes, and subsequent vegetative growth occurs. Arrowweed would decrease under Alternatives C, D, F, and G, usually by transitioning to bare sand with repeated extended high flows, but often by transitioning to tamarisk.

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TABLE G-1 Vegetation States, Plant Associations, and Corresponding Submodels

Vegetation States	Primary Plant Species	Additional Species	Submodel/Landform
Bare Sand	<1% vegetation		All submodels
Phragmites australis Temperate Herbaceous Vegetation[a]	Common reed (*Phragmites australis*), cattail (*Typha domingensis*, *T. latifolia*)	Common tule (*Schoenoplectus acutus*), creeping bent grass (*Agrostis stolonifera*)	Lower Reattachment Bar
Salix exigua–Baccharis emoryi Shrubland/ *Equisetum laevigatum* Herbaceous Vegetation[a]	Horsetail (*Equisetum laevigatum*), coyote willow (*Salix exigua*), *Baccharis emoryi*, *Schoenoplectus pungens*	*Eleocharis palustris, Muhlenbergia asperifolia*	Lower Channel Margin, Lower Reattachment Bar
Tamarix spp. Temporarily Flooded Shrubland[b]	Tamarisk (*Tamarix* spp.)		All submodels
Populus fremontii/Salix exigua Forest[a]	Coyote willow, cottonwood (*Populus fremontii*)	*Salix gooddingii, Baccharis salicifolia, Distichlis spicata, Muhlenbergia asperifolia, Phragmites australis*, *Equisetum* spp., *Juncus spp.*, *Carex* spp., *Elaeagnus angustifolia, Tamarix* spp., *Poa pratensis, Melilotus* spp.	Lower Channel Margin, Lower Separation Bar
Pluchea sericea Seasonally Flooded Shrubland	Arrowweed (*Pluchea sericea*)	*Baccharis* spp., *Mesquite* (*Prosopis glandulosa*), coyote willow	Lower Reattachment Bar, Upper Separation Bar, Upper Reattachment Bar, Upper Channel Margin
Prosopis glandulosa var. *torreyana* Shrubland[a]	Mesquite (*Prosopis glandulosa* var. *torreyana*)	*Baccharis* spp., *Pluchea sericea*,	Lower Channel Margin, Upper Separation Bar, Upper Reattachment Bar, Upper Channel Margin

[a] Native-dominated states used in the metric calculations.

[b] Nonnative-dominated state used in the metric calculations.

Source: Ralston et al. (2014).

TABLE G-2 Hydrologic Events Considered in the Riparian Vegetation Model

Event	Flow Range	Timing
Spill flow[a]	>45,000 cfs one day or more	Any month
Spring HFE	>31,500 cfs to ≤45,000 cfs, less than 30 days[b]	March–June
Fall HFE	>31,500 cfs to ≤45,000 cfs, less than 30 days[b]	October–December
Extended low flow	≤10,000 cfs for at least 30 consecutive days	Growing season; non-growing season
Extended high flow	≥20,000 cfs to ≤45,000 cfs for at least 30 consecutive days	Growing season; non-growing season
Growing or non-growing seasons without extended high or low flows	Flows that can fluctuate up to 25,000 cfs (i.e., the absence of spill flows or extended high or extended low flows)	Growing season; non-growing season

[a] Spill flows (i.e., flows that include releases through the spillway, and total >45,000 cfs) are not a function of the alternatives, but rather a function of annual hydrology. These do not differ among the alternatives.

[b] A peak or spike in flow between 31,500 cfs and 45,000 cfs that begins or ends below 31,500 cfs is considered an HFE.

TABLE G-3 Riparian Vegetation Model Transition Rules

Transition	From	To	Trigger	Notes
Upper Separation Bar				
T1	Bare Sand	*Pluchea sericea* Seasonally Flooded Shrubland	*Pluchea* cover[a] = 30%	*Pluchea* growth variable (before T1 transition): cover starts at 1% in bare sand frame; non-growing season extended low flow or season without extended high or low flow + growing season extended low flow or season without extended high or low flow same year = 5%; non-growing season extended low flow or season without extended high or low flow + growing season extended high flow same year = 7.5%; non-growing season extended high flow + growing season extended low flow or season without extended high or low flow same year = 7.5%; non-growing season extended high flow + growing season extended high flow same year = 10%; fall HFE same year = increase × 0.5
T2	Bare Sand	Tamarisk Temporarily Flooded Shrubland	Spring HFE + growing season extended high flow same year	*Pluchea* cover must be ≤10%
T3	Tamarisk Temporarily Flooded Shrubland	*Prosopis glandulosa* var. torreyana Shrubland	*Prosopis* cover = 25%	*Prosopis* growth variable (before T3 transition): cover starts at 0% in tamarisk frame; spring HFE + growing season without extended high or low flow same year = +2%; spring HFE + growing season extended high flow same year = +2%; growing season extended low flow = -0.5%
T4	Tamarisk Temporarily Flooded Shrubland, *Pluchea sericea* Seasonally Flooded Shrubland, or *Prosopis glandulosa* var. *torreyana* Shrubland	Bare Sand	Spill flow; OR any season extended high flow > 50K cfs	Extended high flow must be >50K cfs

TABLE G-3 (Cont.)

Transition	From	To	Trigger	Notes
Lower Separation Bar				
T1	Bare Sand	*Populus fremontii/Salix exigua* forest	*Populus/Salix* cover = 20%	*Populus/Salix* growth variable (before T1 transition): cover starts at 1% in S1 frame; non-growing season without extended high or low flow + growing season without extended high or low flow same year = +3%; non-growing season extended high flow + growing season without extended high or low flow same year = cover × 0.5
T2	Bare Sand	Tamarisk Temporarily Flooded Shrubland	Non-growing season extended high flow + growing season extended low flow same year; OR spring HFE + growing season extended low flow same year	
T3	Tamarisk Temporarily Flooded Shrubland or *Populus fremontii*/*Salix exigua* Forest	Bare Sand	Non-growing season or growing season spill flow; OR non-growing season extended high flow + growing season extended high flow same year; OR growing season extended high flow + non-growing season extended high flow next year	
Lower Reattachment Bar				
T1	Bare Sand	*Phragmites australis* Temperate Herbaceous Vegetation	*Phragmites* cover = 20%	*Phragmites* growth variable (before T1 transition): growing season without extended high or low flow = +10%; growing season extended high flow set to 0

TABLE G-3 (Cont.)

Transition	From	To	Trigger	Notes
Lower Reattachment Bar (Cont.)				
T2	*Phragmites australis* Temperate Herbaceous Vegetation	*Salix exigua-Baccharis emoryi* shrubland/*Equisetum laevigatum* Herbaceous Vegetation	Growth variable = 4 (see "Notes" column of this table for growth variable calculation)	*Salix-Baccharis/Equisetum* growth variable (before T2 transition): non-growing season without extended high or low flow + growing season without extended high or low flow same year = +1; fall HFE or spring HFE = -1; any season extended high flow sets to 0. Values are not additive within a year; e.g., fall HFE + spring HFE in same year is still -1. Non-growing season extended low flow = season without extended high or low flow.
T3	*Salix exigua-Baccharis emoryi* Shrubland/*Equisetum laevigatum* Herbaceous Vegetation	Tamarisk Temporarily Flooded Shrubland	Non-growing season extended high flow + growing season extended low flow same year; OR growing season extended high flow + next year growing season extended low flow	
T4	*Phragmites australis* Temperate Herbaceous Vegetation, or *Salix exigua-Baccharis emoryi* Shrubland/*Equisetum laevigatum* Herbaceous Vegetation, or *Pluchea sericea* Seasonally Flooded Shrubland	Bare Sand	Non-growing season extended high flow + growing season extended high flow same year; OR growing season extended high flow + non-growing season extended high flow next year; OR growing season extended high flow + growing season extended high flow next year; OR any spill flow	
T5	*Phragmites australis* Temperate Herbaceous Vegetation	Tamarisk Temporarily Flooded Shrubland	Non-growing season extended high flow + growing season extended low flow same year OR growing season extended high flow + growing season extended low flow next year	

TABLE G-3 (Cont.)

Transition	From	To	Trigger	Notes
Lower Reattachment Bar (Cont.)				
T6	Tamarisk Temporarily Flooded Shrubland	Bare Sand	Growing season extended high flow + non-growing season extended high flow in sequence of 4; OR growing season extended high flow in sequence of 4; OR any season spill flow	Does not have to be same year
T7	Bare Sand	Tamarisk Temporarily Flooded Shrubland	Growing season extended low flow	
T8	*Pluchea sericea* Seasonally Flooded Shrubland	Tamarisk Temporarily Flooded Shrubland	Growing season extended high flow + growing season extended low flow the next year OR non-growing season extended high flow + growing season extended low flow same year	
T9	*Phragmites australis* Temperate Herbaceous Vegetation	*Pluchea sericea* Seasonally Flooded Shrubland	Growing season extended low flow	NOT if non-growing season extended high flow same year (then *Phragmites* transitions to tamarisk).
Lower Channel Margin				
T1	Bare Sand	*Salix exigua-Baccharis emoryi* Shrubland/*Equisetum laevigatum* Herbaceous Vegetation	Growth variable = 4 (see *Notes* for growth variable calculation)	*Salix-Baccharis/Equisetum* growth variable (before T1 transition): non-growing season without extended high or low flow + growing season without extended high or low flow same year = +1; growing season extended low flow = -1; fall HFE or spring HFE = -1; any season extended high flow sets to 0. Values are not additive within a year; e.g., fall HFE + growing season extended low flow in same year is still -1.

TABLE G-3 (Cont.)

Transition	From	To	Trigger	Notes
Lower Channel Margin (Cont.)				
T2	*Salix exigua-Baccharis emoryi* Shrubland/*Equisetum laevigatum* Herbaceous Vegetation	*Populus fremontii/Salix exigua* Forest	Non-growing season extended high flow + growing season extended low flow same year; OR growing season extended high flow + next year growing season extended low flow	
T3	Bare Sand	Tamarisk Temporarily Flooded Shrubland	Non-growing season extended high flow + growing season extended low flow	*Salix-Baccharis/Equisetum* must be ≤2.
T4	Tamarisk Temporarily Flooded Shrubland	*Prosopis glandulosa* var. *torreyana Shrubland*	*Prosopis* cover = 25%	*Prosopis* growth variable (before T4 transition): cover starts at 0% in woody riparian tamarisk frame; spring HFE + growing season without extended high or low flow same year = 2%; spring HFE + growing season extended high flow = 2%; growing season extended low flow = -0.5%
T5	Tamarisk Temporarily Flooded Shrubland, *Populus fremontii*/*Salix exigua* Forest, *Prosopis glandulosa* var. *torreyana* Shrubland	Bare Sand	Any season spill flow; OR any season extended high flow >50K cfs	Extended high flow must be >50K cfs
T6	*Salix exigua-Baccharis emoryi* Shrubland/*Equisetum laevigatum* Herbaceous Vegetation	Bare Sand	Any season extended high flow >25K cfs	Extended high flow must be >25K cfs

[a] Percent cover refers to the overall percentage of a hypothetical geomorphic feature (e.g., lower reattachment bar) beneath a vertical projection of the vegetation canopy.

TABLE G-4 New High-Water Zone and Old High-Water Zone Vegetation Classes Mapped from Lees Ferry to Diamond Creek[a]

Vegetation Class	Dominant Species	Area (ac)
New High-Water Zone		
Phragmites australis Western North America Temperate Semi-natural Herbaceous Vegetation	Cattail, common reed	4.4
Tamarix spp. Temporarily Flooded Semi-natural Shrubland	Tamarisk	273.7
Baccharis spp.–*Salix exigua–Pluchea sericea* Shrubland Alliance	*Baccharis* spp., coyote willow, arrowweed	354.7
Prosopis glandulosa var. *torreyana* Shrubland	Western honey mesquite	137.1
Abronia elliptica Herbaceous Dune Vegetation	Fragrant white sand verbena	4.0
Acacia greggii Shrubland	Catclaw acacia	30.4
Arctostaphylos–Quercus turbinella Shrubland Alliance	Bearberry, live oak	2.2
Artemisia bigelovii Shrubland Alliance	Bigelow sagebrush	1.1
Artemisia tridentata Shrubland Alliance	Big sagebrush	2.4
Brickellia longifolia–Fallugia paradoxa–Isocoma acradenia Shrubland	Longleaf brickellbush, Apache plume, goldenbush	65.5
Encelia (*farinosa, resinifera*) Shrubland Alliance	Brittlebush, sticky brittlebush	401.0
Ephedra (*torreyana, viridis*) Mixed Semi-desert Grasses Shrubland	Mormon tea, green ephedra	29.0
Ephedra fasciculate Mojave Desert Shrubland Alliance	Arizona joint-fir	103.6
Ephedra torreyana–Opuntia basilaris Shrubland	Mormon tea, beavertail cactus	64.0
Gutierrezia (*sarothrae, microcephala*)–*Ephedra* (*torreyana, viridis*) Mojave Desert Shrubland Alliance	Snakeweed, broom snakeweed, Mormon tea, green ephedra	14.5
Larrea tridentata–Encelia spp. Shrubland Alliance	Creosote, brittlebush	15.3
Sparsely Vegetated Slickrock	–[b]	5.4
Other[c]	–	5.0

TABLE G-4 (Cont.)

Vegetation Class	Dominant Species	Area (ac)
Old High-Water Zone		
Abronia elliptica Herbaceous Dune Vegetation	Fragrant white sand verbena	5.7
Acacia greggii Shrubland	Catclaw acacia	56.1
Artemisia tridentata Shrubland Alliance	Big sagebrush	1.1
Baccharis spp.–*Salix exigua–Pluchea sericea* Shrubland Alliance	*Baccharis* spp., coyote willow, arrowweed	200.2
Brickellia longifolia–Fallugia paradoxa–Isocoma acradenia Shrubland	Longleaf brickellbush, Apache plume, goldenbush	78.5
Encelia (*farinosa, resinifera*) Shrubland Alliance	Brittlebush, sticky brittlebush	438.1
Ephedra (*torreyana, viridis*) Mixed Semi-desert Grasses Shrubland	Mormon tea, green ephedra	41.4
Ephedra fasciculata Mojave Desert Shrubland Alliance	Arizona joint-fir	120.1
Ephedra torreyana–(*Atriplex canescens, Atriplex confertifolia*) Sparse Vegetation	Mormon tea, four-wing saltbush, shadscale	2.1
Ephedra torreyana–Opuntia basilaris Shrubland	Mormon tea, beavertail cactus	109.7
Great Basin and Intermountain Ruderal Dry Shrubland and Grassland Group	–	1.1
Gutierrezia (*sarothrae, microcephala*)–*Ephedra* (*torreyana, viridis*) Mojave Desert Shrubland Alliance	Snakeweed, broom snakeweed, Mormon tea, green ephedra	24.0
Larrea tridentata–Encelia spp. Shrubland Alliance	Creosote, brittlebush	41.4
Pleuraphis rigida Herbaceous Vegetation	Big galleta	1.3
Prosopis glandulosa var. *torreyana* Shrubland	Western honey mesquite	315.9
Sparsely Vegetated Slickrock	–	1.4
Tamarix spp. Temporarily Flooded Semi-natural Shrubland	Tamarisk	224.6
Unvegetated Surfaces and Built-up Areas	–	32.1
Other[c]	–	6.4

Footnotes on next page.

TABLE G-4 (Cont.)

[a] The New High-Water Zone and Old High-Water Zone were separated at the 45,000 cfs stage elevation.

[b] – = No dominant species identified.

[c] Includes all vegetation classes with less than 1 ac mapped within the zone.

Source: Kearsley et al. (2015).

TABLE G-5 Vegetation States and Corresponding Mapped Vegetation Types

Vegetation States	Mapped Vegetation Classes[a]	Area (acres)
Bare Sand	Unvegetated Surfaces and Built Up Areas	112
Phragmites australis Temperate Herbaceous Vegetation	*Phragmites australis* Western North America Temperate Semi-natural Herbaceous Vegetation	4.4
Salix exigua Baccharis emoryi shrubland/*Equisetum laevigatum* Herbaceous Vegetation	Arid West Emergent Marsh	0.2
Tamarisk Temporarily Flooded Shrubland	*Tamarix* spp. Temporarily Flooded Semi-natural Shrubland	273.7
Populus fremontii/Salix exigua Forest	*Baccharis* spp.–*Salix exigua–Pluchea sericea* Shrubland Alliance	177.3[b]
Pluchea sericea Seasonally Flooded Shrubland	*Baccharis* spp.–*Salix exigua–Pluchea sericea* Shrubland Alliance	177.3[b]
Prosopis glandulosa var. *torreyana* Shrubland	*Prosopis glandulosa* var. *torreyana Shrubland*	137.1

[a] Kearsley et al. (2015), which mapped river miles 0–278; vegetation classes and area are based on 2007 and 2010 aerial photography and do not necessarily reflect current conditions.

[b] The *Baccharis* spp.–*Salix exigua–Pluchea sericea* Shrubland Alliance (354.7 ac) was divided equally between the *Populus fremontii/Salix exigua* forest state and *Pluchea sericea* Seasonally Flooded Shrubland state.

TABLE G-6 Example Results for the Native Cover Metric[a]

Alternative/ Long-Term Strategy	Final Acres	Change
E6	307	−12
D4	280	−39
A	264	−55
B2	169	−150

[a] Initial acres: 319 (based on Kearsley et al. 2015).

TABLE G-7 Example Results for the Arrowweed Metric[a]

Alternative/ Long-Term Strategy	Final Acres	Change
C1, C2	152	−25
D4	160	−17
A	222	45
C3	235	58

[a] Initial acres: 177 (based on Kearsley et al. 2015).

TABLE G-8 Results for Alternative A

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.827	0.983	1.051	0.799	3.661
Change	17.3% reduction in cover of native states	1.7% reduction in diversity of native states[a]	5.1% increase in the native/ nonnative ratio	25.1% increase in the arrowweed state cover	Overall movement away from the resource goal
Modeled values	263.8 ac, all four native states (initial cover 319.0 ac)	Modeled diversity 1.065, all four native states (initial diversity 1.083)	Modeled ratio 1.226 (initial ratio 1.166)	221.8 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 55.2 ac	NA	Tamarisk state decrease of 58.4 ac[b]	Arrowweed state increase of 44.5 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-9 Results for Alternative B, Long-Term Strategy B1

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.849	1.027	1.148	0.842	3.865
Change	15.1% reduction in cover of native states	2.7% increase in diversity of native states[a]	14.8% increase in the native/ nonnative ratio	18.8% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	270.7 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.113, all four native states (initial diversity 1.083)	Modeled ratio 1.338 (initial ratio 1.166)	210.6 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 48.3 ac	NA	Tamarisk state decrease of 71.4 ac[b]	Arrowweed state increase of 33.3 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-10 Results for Alternative B, Long-Term Strategy B2

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0. 529	0.913	0. 869	0. 809	3.120
Change	47.1% reduction in cover of native states	8.7% decrease in diversity of native states[a]	13.1% decrease in the native/ nonnative ratio	23.6% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	168.9 ac, all four native states (initial cover 319 ac)	Modeled diversity 0.988, all four native states (initial diversity 1.083)	Modeled ratio 1.013 (initial ratio 1.166)	219.2 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 150.1 ac	NA	Tamarisk state decrease of 107.0 ac[b]	Arrowweed state increase of 41.9 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-11 Results for Alternative C, Long-Term Strategy C1

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.631	0.924	0.457	1.165	3.177
Change	36.9% reduction in cover of native states	7.6% decrease in diversity of native states[a]	54.3% decrease in the native/ nonnative ratio	14.2% decrease in the arrowweed state cover	Movement away from the resource goal
Modeled values	201.3 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.001, all four native states (initial diversity 1.083)	Modeled ratio 0.533 (initial ratio 1.166)	152.2 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 117.7 ac	NA	Tamarisk state increase of 104.0 ac[b]	Arrowweed state decrease of 25.1 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-12 Results for Alternative C, Long-Term Strategy C2

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.632	0.925	0.463	1.163	3.183
Change	36.8% reduction in cover of native states	7.5% decrease in diversity of native states[a]	53.7% decrease in the native/ nonnative ratio	14.0% decrease in the arrowweed state cover	Movement away from the resource goal
Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Modeled values	201.5 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.001, all four native states (initial diversity 1.083)	Modeled ratio 0.540 (initial ratio 1.166)	152.4 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 117.5 ac	NA	Tamarisk state increase of 99.3 ac[b]	Arrowweed state decrease of 24.9 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-13 Results for Alternative C, Long-Term Strategy C3

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.626	0.923	0.529	0.755	2.834
Change	37.4% reduction in cover of native states	7.7% decrease in diversity of native states[a]	47.1% decrease in the native/ nonnative ratio	32.5% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	199.8 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.000, all four native states (initial diversity 1.083)	Modeled ratio 0.617 (initial ratio 1.166)	234.9 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 119.2 ac	NA	Tamarisk state increase of 50.1 ac[b]	Arrowweed state increase of 57.6 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-14 Results for Alternative C, Long-Term Strategy C4

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.632	0.925	0.533	0.892	2.981
Change	36.8% reduction in cover of native states	7.5% decrease in diversity of native states[a]	46.7% decrease in the native/ nonnative ratio	12.1% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	201.5 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.001, all four native states (initial diversity 1.083)	Modeled ratio 0.621 (initial ratio 1.166)	198.8 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 117.5 ac	NA	Tamarisk state increase of 50.9 ac[b]	Arrowweed state increase of 21.5 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-15 Results for Alternative D, Long-Term Strategy D1

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.840	1.017	0.910	0.905	3.671
Change	16.0% reduction in cover of native states	1.7% increase in diversity of native states[a]	9.0% decrease in the native/ nonnative ratio	10.5% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	267.8 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.101, all four native states (initial diversity 1.083)	Modeled ratio 1.061 (initial ratio 1.166)	196.0 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 51.2 ac	NA	Tamarisk state decrease of 21.2 ac[b]	Arrowweed state increase of 18.7 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-16 Results for Alternative D, Long-Term Strategy D2

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.845	1.019	0.919	0.903	3.686
Change	15.5% reduction in cover of native states	1.9% increase in diversity of native states[a]	8.1% decrease in the native/ nonnative ratio	10.7% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	269.5 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.103, all four native states (initial diversity 1.083)	Modeled ratio 1.072 (initial ratio 1.166)	196.2 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 49.5 ac	NA	Tamarisk state decrease of 22.2 ac[b]	Arrowweed state increase of 18.9 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-17 Results for Alternative D, Long-Term Strategy D3

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.859	1.019	0.930	0.889	3.697
Change	14.1% reduction in cover of native states	1.9% increase in diversity of native states[a]	7.0% decrease in the native/ nonnative ratio	12.5% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	274.0 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.104, all four native states (initial diversity 1.083)	Modeled ratio 1.084 (initial ratio 1.166)	199.5 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 45.0 ac	NA	Tamarisk state decrease of 21.0 ac[b]	Arrowweed state increase of 22.2 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-18 Results for Alternative D, Long-Term Strategy D4

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.876	1.017	0.954	1.107	3.954
Change	12.4% reduction in cover of native states	1.7% increase in diversity of native states[a]	4.6% decrease in the native/ nonnative ratio	9.6% decrease in the arrowweed state cover	Movement away from the resource goal
Modeled values	279.5 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.101, all four native states (initial diversity 1.083)	Modeled ratio 1.112 (initial ratio 1.166)	160.2 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 39.5 ac	NA	Tamarisk state decrease of 22.4 ac[b]	Arrowweed state decrease of 17.1 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-19 Results for Alternative E, Long-Term Strategy E1

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.801	0.979	0.961	0.801	3.541
Change	19.9% reduction in cover of native states	2.1% decrease in diversity of native states[a]	3.9% decrease in the native/ nonnative ratio	24.8% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	255.5 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.060, all four native states (initial diversity 1.083)	Modeled ratio 1.120 (initial ratio 1.166)	221.3 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 63.5 ac	NA	Tamarisk state decrease of 45.7 ac[b]	Arrowweed state increase of 44.0 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-20 Results for Alternative E, Long-Term Strategy E2

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.875	1.019	1.067	0.881	3.842
Change	12.5% reduction in cover of native states	1.9% increase in diversity of native states[a]	6.7% increase in the native/ nonnative ratio	13.5% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	279.3 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.103, all four native states (initial diversity 1.083)	Modeled ratio 1.244 (initial ratio 1.166)	201.2 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 39.7 ac	NA	Tamarisk state decrease of 49.2 ac[b]	Arrowweed state increase of 23.9 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-21 Results for Alternative E, Long-Term Strategy E3

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.961	0.977	1.227	0.768	3.932
Change	3.9% reduction in cover of native states	2.3% decrease in diversity of native states[a]	22.7% increase in the native/ nonnative ratio	30.3% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	306.5 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.058, all four native states (initial diversity 1.083)	Modeled ratio 1.430 (initial ratio 1.166)	231.0 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 12.5 ac	NA	Tamarisk state decrease of 59.4 ac[b]	Arrowweed state increase of 53.7 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-22 Results for Alternative E, Long-Term Strategy E4

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.899	1.027	1.124	0.884	3.934
Change	10.1% reduction in cover of native states	2.7% increase in diversity of native states[a]	12.4% increase in the native/ nonnative ratio	13.2% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	286.8 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.113, all four native states (initial diversity 1.083)	Modeled ratio 1.311 (initial ratio 1.166)	200.6 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 32.2 ac	NA	Tamarisk state decrease of 54.9 ac[b]	Arrowweed state increase of 23.3 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-23 Results for Alternative E, Long-Term Strategy E5

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.941	0.977	1.187	0.769	3.875
Change	5.9% reduction in cover of native states	2.3% decrease in diversity of native states[a]	18.7% increase in the native/ nonnative ratio	30.0% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	300.2 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.058, all four native states (initial diversity 1.083)	Modeled ratio 1.384 (initial ratio 1.166)	230.5 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 18.8 ac	NA	Tamarisk state decrease of 56.9 ac[b]	Arrowweed state increase of 53.2 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-24 Results for Alternative E, Long-Term Strategy E6

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.961	0.977	1.227	0.768	3.933
Change	3.9% reduction in cover of native states	2.3% decrease in diversity of native states[a]	22.7% increase in the native/ nonnative ratio	30.3% increase in the arrowweed state cover	Movement away from the resource goal
Modeled values	306.7 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.058, all four native states (initial diversity 1.083)	Modeled ratio 1.431 (initial ratio 1.166)	231.0 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 12.3 ac	NA	Tamarisk state decrease of 59.4 ac[b]	Arrowweed state increase of 53.7 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-25 Results for Alternative F

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.702	0.909	0.381	1.143	3.136
Change	29.8% reduction in cover of native states	9.1% decrease in diversity of native states[a]	61.9% decrease in the native/ nonnative ratio	12.5% decrease in the arrowweed state cover	Movement away from the resource goal
Modeled values	224.0 ac, all four native states (initial cover 319 ac)	Modeled diversity 0.985, all four native states (initial diversity 1.083)	modeled ratio 0.444 (initial ratio 1.166)	155.1 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 95.0 ac	NA	Tamarisk state increase of 230.7 ac[b]	Arrowweed state decrease of 22.2 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

TABLE G-26 Results for Alternative G

Parameter	Metric 1: Change in Native Cover, Final Cover/ Initial Cover	Metric 2: Change in Diversity, Final Diversity/ Initial Diversity	Metric 3: Change in Native/ Nonnative Ratio, Final Ratio/ Initial Ratio	Metric 4: Change in Arrowweed, Initial Arrowweed/ Final Arrowweed	Overall Score
Mean score (weighted mean for all sediment traces)	0.706	0.967	0.604	1.128	3.405
Change	29.4% reduction in cover of native states	3.3% decrease in diversity of native states[a]	39.6% decrease in the native/ nonnative ratio	11.3% decrease in the arrowweed state cover	Movement away from the resource goal
Modeled values	225.3 ac, all four native states (initial cover 319 ac)	Modeled diversity 1.047, all four native states (initial diversity 1.083)	Modeled ratio 0.704 (initial ratio 1.166)	157.2 ac arrowweed state (initial cover 177.3 ac)	NA
Change in cover (acres)	Native states decrease of 93.7 ac	NA	Tamarisk state increase of 46.4 ac[b]	Arrowweed state decrease of 20.1 ac	NA

[a] Because the results for each modeled run include the same number of states (each state is a different starting condition for model runs), a reduction in diversity indicates a reduction in evenness among the vegetation states.

[b] A relative increase in native cover or decrease in nonnative cover can increase the ratio.

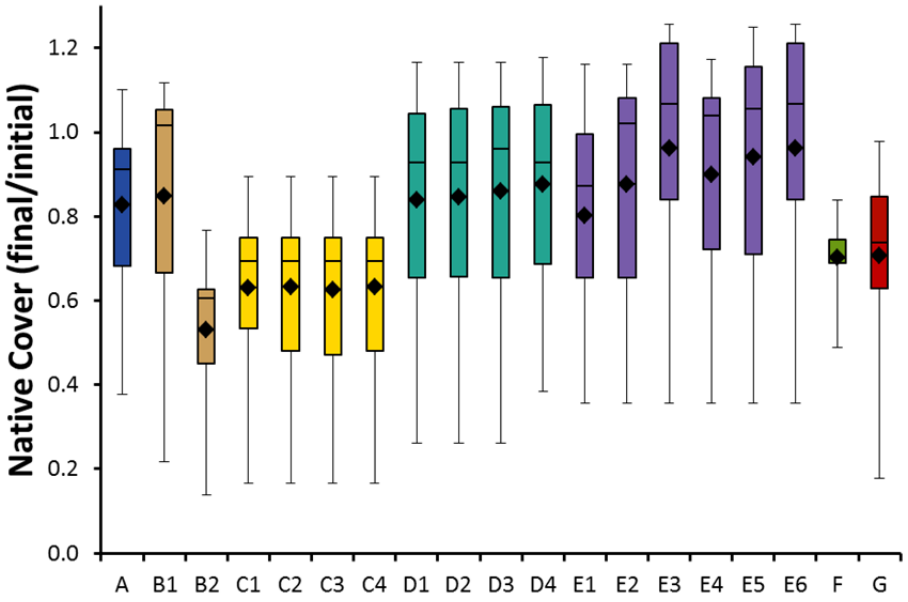

FIGURE G-1 Native Cover Metric for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

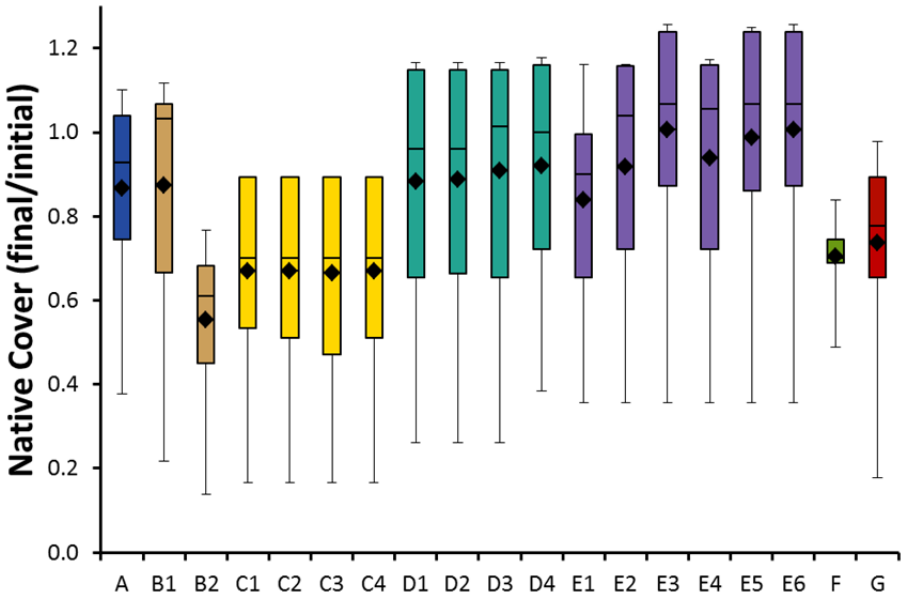

FIGURE G-2 Native Cover Metric under Climate Change for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

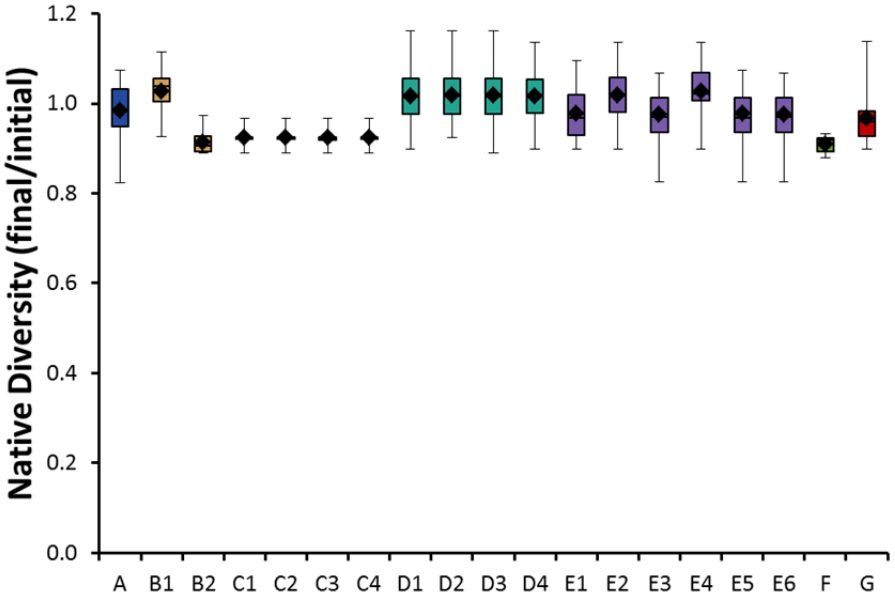

FIGURE G-3 Native Diversity Metric for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

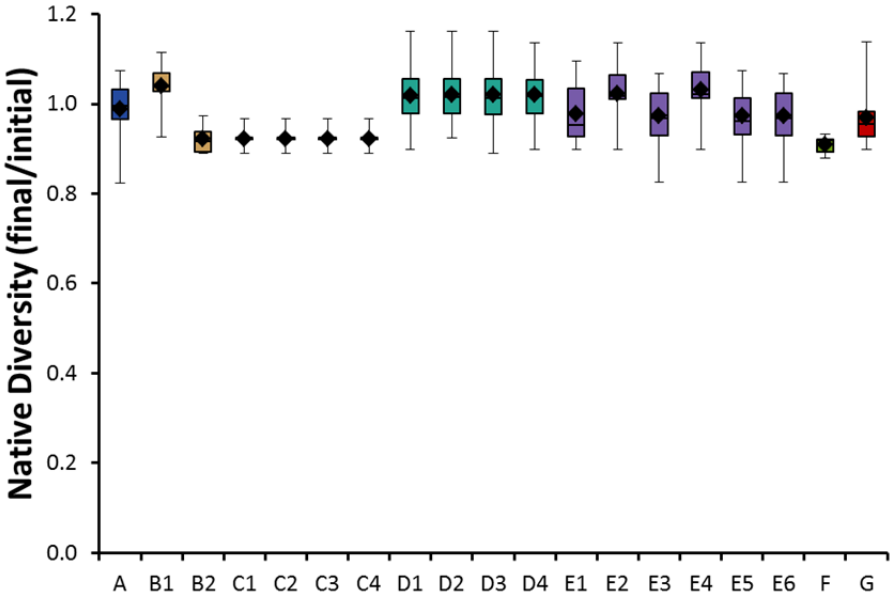

FIGURE G-4 Native Diversity Metric under Climate Change for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

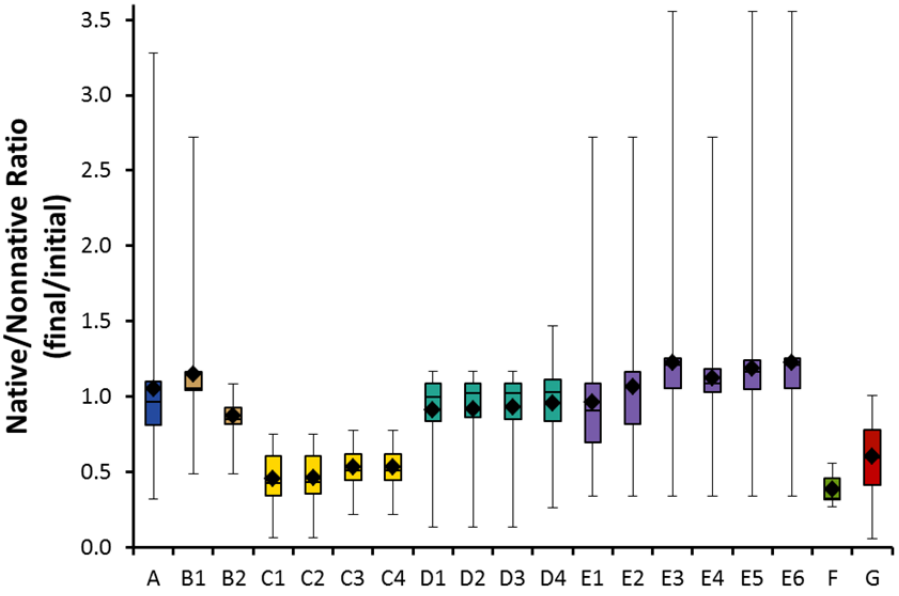

FIGURE G-5 Native/Nonnative Ratio Metric for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

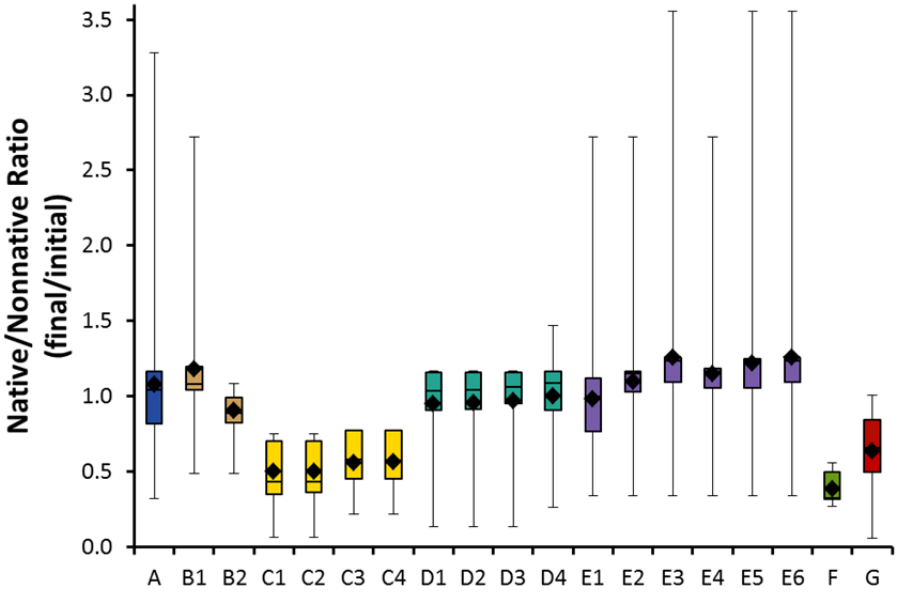

FIGURE G-6 Native/Nonnative Ratio Metric under Climate Change for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

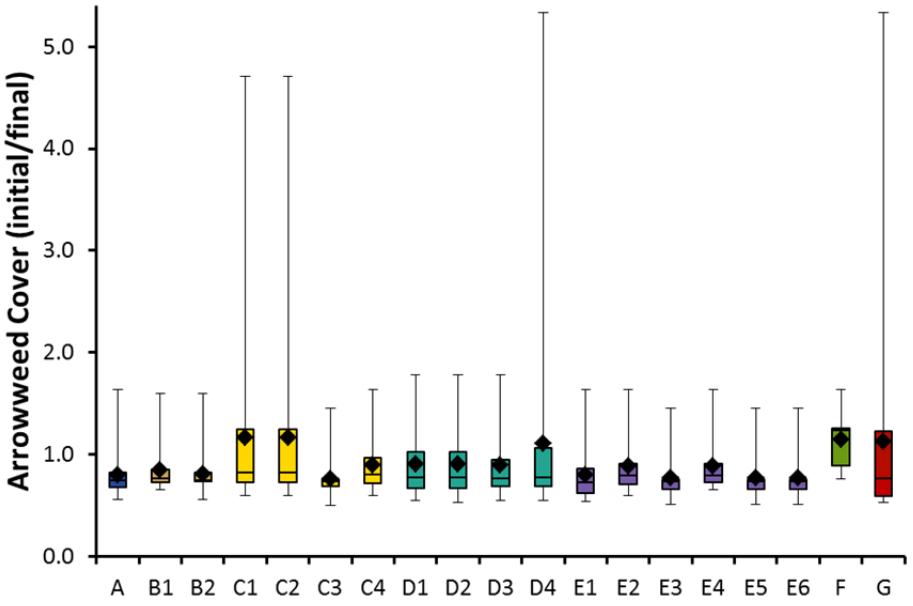

FIGURE G-7 Arrowweed Metric for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

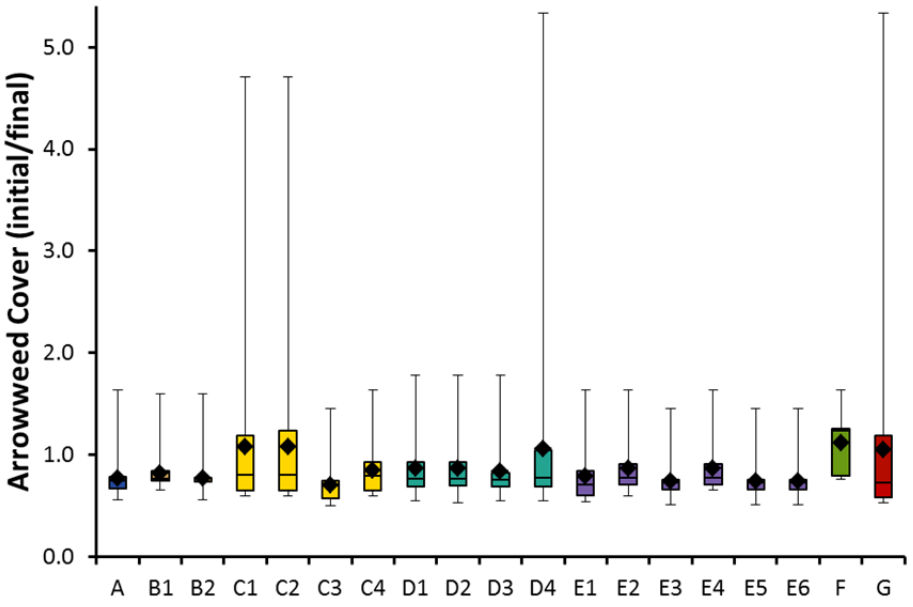

FIGURE G-8 Arrowweed Metric under Climate Change for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

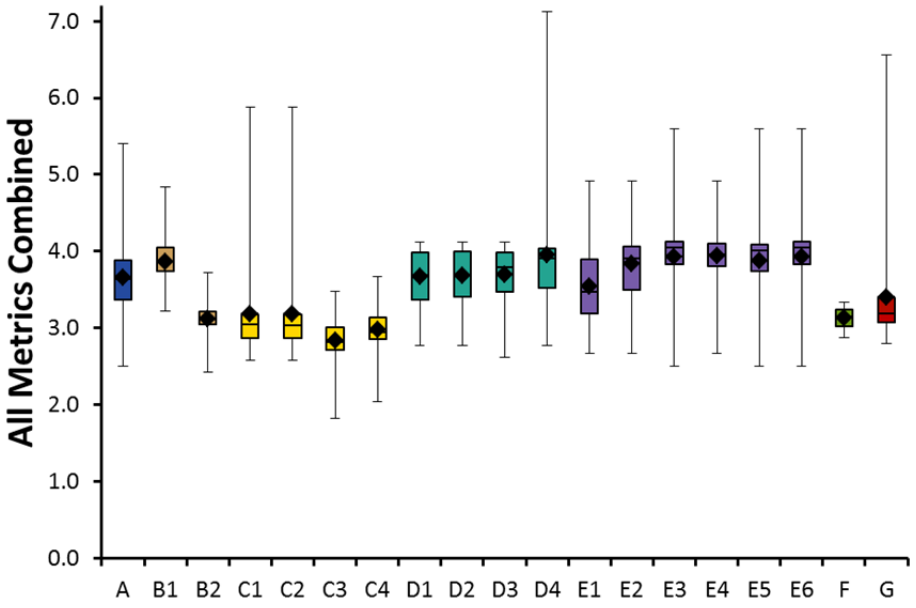

FIGURE G-9 Overall Combined Score for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

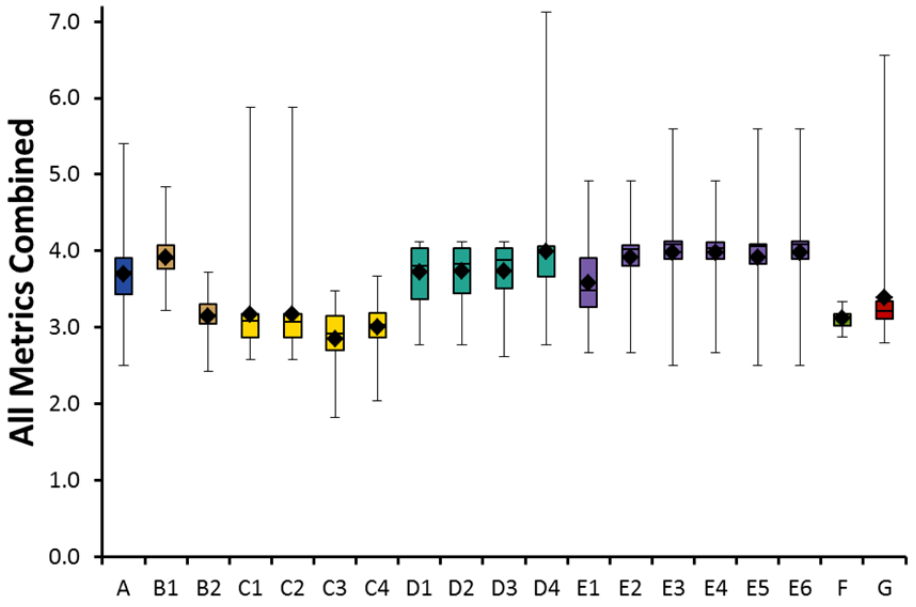

FIGURE G-10 Overall Combined Score under Climate Change for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

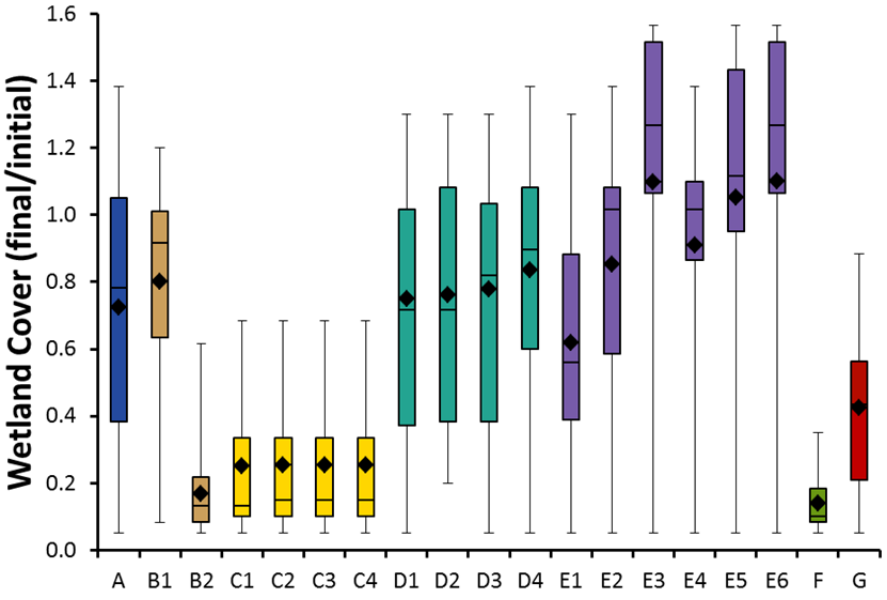

FIGURE G-11 Relative Change in Wetland Cover for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

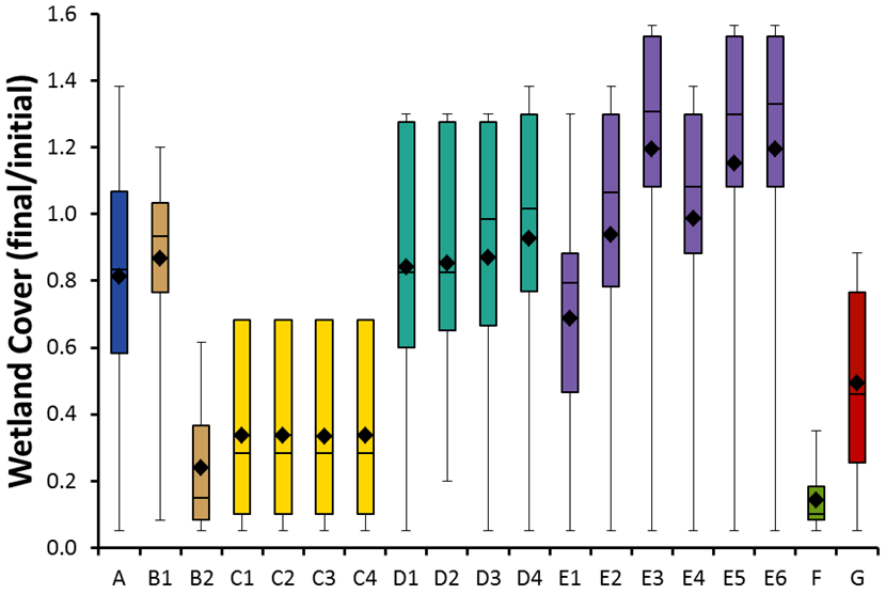

FIGURE G-12 Relative Change in Wetland Cover under Climate Change for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum of the values for the 63 traces analyzed.)

APPENDIX H:

CULTURAL RESOURCES TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX H:

CULTURAL RESOURCES TECHNICAL INFORMATION AND ANALYSIS

The assessment of potential impacts on cultural resources relied on three factors identified during the Long-Term Experimental and Management Plan (LTEMP) assessment process as the primary factors affecting the stability of historic resources in the canyons: (1) erosion (Thompson and Potochnik 2000; Damp et al. 2007; Spurr and Collette 2007), (2) inundation (Baker 2013), and (3) visitor effects (Bulletts et al. 2008, 2012; Jackson-Kelly et al. 2013). Metrics were formulated for these factors to quantitatively analyze the effects on cultural resources of the LTEMP alternatives based on modeling of discharge and sediment loads. The metrics are:

- Wind Transport of Sediment Index
- Flow Effects on Cultural Resources in Glen Canyon Index
- Time Off River Index

This appendix discusses the modeling of each metric and presents a detailed discussion of the modeling results. The metrics were developed through consultation with subject matter experts, findings in published papers and reports, and consideration of comments from cooperating agencies. See Section 3.8 for a more detailed description of Grand Canyon cultural resources and Chapter 2 for a detailed description of the LTEMP alternatives.

H.1 WIND TRANSPORT OF SEDIMENT

Prior to the construction of Glen Canyon Dam, periodic large-magnitude storm events would flood the Colorado River and deposit fluvial sediment onto high-elevation terraces. The deposited sediment buried and protected evidence of past human activity within the floodplain of the river. However, the dam's closure in 1964 trapped most of the sand that would have been transported into the Glen Canyon and Grand Canyon reaches of the Colorado River, and operations reduced the magnitudes of annual peak flows, which determine the elevation of the area scoured by high flows and at which new sand can be deposited. These changes decreased the renewal of sediment to high-elevation terraces downstream of the dam. With limited rejuvenation of sand, erosion can expose archaeological sites found along the riparian zone of the river.

In 2008, researchers found that, under the right conditions, sediment deposited along the riverbank above the elevation of normal operational flows can be transported by the wind and deposited on high-elevation terraces, many of which contain archaeological sites. This wind-blown sediment is thought to help stabilize archaeological sites on these high-elevation terraces. It was observed that this transfer of sediment occurred primarily in the spring months, when a reduced amount of rainfall and strong winds create optimal conditions for wind-blown sediment

transport (Draut and Rubin 2008). A wind transport metric was developed based on principles identified by Draut and Rubin (2008). It is noted that the extent to which this process could stabilize cultural resources is unknown.

H.1.1 Wind Transport of Sediment—Methods

The Wind Transport of Sediment Index (WTSI) evaluates the availability of fine sediment for wind transport to cover cultural resources at higher elevations (i.e., those properties located at stages above 31,500 cfs). Optimal conditions for wind transport of sediment occur when (1) fine sediment is deposited by flows above the stage of normal operations and (2) low flows occur during the windy season, which exposes more sand for redistribution by the wind. These two conditions are accounted for by the Wind Transport of Sediment Index (WTSI) using the following equation (Eq. H1), where SLI is the Sand Load Index and FF is the Flow Factor*:*

$$WTSI = SLI \times Average(FF)_{2014-2033} \quad \text{(H.1)}$$

Both of the inputs for the metric (SLI and FF) are indices ranging from 0 to 1. The resulting Wind Transport of Sediment Index is a value from 0 to 1, where a value of 1 corresponds to the most potential movement of sediment by the wind, and therefore has the highest likelihood to contribute to the preservation of cultural resources. Both elements of the equation (SLI and FF) are limiting factors in the sense that the highest value between the two is the highest possible output. This mirrors the occurring environmental limitations—no more sediment can be transported than available, while, regardless of availability, wet sand is not likely to be easily transported by the wind.

The WTSI is calculated for a total of 63 scenarios representing different hydrologic (20 traces) and sediment conditions (3 traces), and weighted by the historical exceedance percentage of the sediment traces included in the scenario. Because of modeling limitations, environmental factors such as erosion of sandbars due to fluctuations in water level, rainstorm events which may further saturate soil, and vegetation barriers which could prevent sediment transport by the wind were not incorporated into the metric. Complex parameters like these would require more assumptions, which could result in less confidence in the model.

The SLI is an index of the potential sand deposited on sandbars along the river channel in Marble and Grand Canyons above normal stage elevations (31,500 cfs). The SLI is calculated as the ratio of the cumulative sand load at flows greater than 31,500 cfs relative to the total cumulative sand load at all flows. The sand load, or the mass of sand in transport by the river, is calculated at RM 30 and is computed by a version of the Sand Budget Model (Wright et al. 2010) for the 20-year LTEMP modeling period. A larger SLI (on a scale of 0 to 1) indicates a greater potential for sediment deposition. The SLI is described in more detail in Appendix E. The SLI was calculated using Equation H.2:

$$SLI = \frac{\sum_{2014-2033} Sand\ Load\ at\ dam\ discharges > 31{,}500\ cfs}{\sum_{2014-2033} Sand\ Load\ at\ all\ dam\ discharges} \quad \text{(H.2)}$$

The FF represents the relative exposure of dry, fluvial sand along the banks of the river available for wind transport. An increase or decrease in dam discharge will increase or decrease the downstream river elevation, respectively. Therefore, a lower discharge will expose a greater amount of sediment. For this metric, maximum daily flows above normal river stage (8,000 cfs) are considered increasing worse for sediment exposure. The maximum daily discharge (Q_{max}) modeled by GTMax-Lite represents the maximum discharge released from Glen Canyon Dam in cubic feet per second (cfs) and thus the extent of dry sand for each day. The yearly FF is the average of FF_{Daily} (Eq. H.3) for the spring months of March through June.

$$FF_{Daily} = \begin{cases} \text{if } Q_{max} \leq 8{,}000; & 1 \\ \text{if } 8{,}000 < Q_{max} < 31{,}500; & 1.34 - 0.0000425 \times Q_{max} \\ \text{if } Q_{max} \geq 31{,}500; & 0 \end{cases} \qquad \text{(H.3)}$$

Note that although the FF only takes into account the months of March through June, the SLI incorporates the entire year. This is because the exposure of sand is most prominent during the windy season, but the sediment transported during those months is continuously built up throughout the year.

H.1.2 Wind Transport of Sediment—Results

WTSI values calculated for the LTEMP alternatives under historical flow and sediment inputs are shown in Figure H-1. The metric values represent the *potential* for sand to be transported to cultural sites rather than the actual transport that would occur or the level of protection that transport may provide to cultural sites. This results in some uncertainty with regard to actual differences in impact among the alternatives based on this metric. Our conclusions on relative impact are based on comparisons of the metric values calculated for Alternatives B, C, D, E, F, G and their long-term strategies, against Alternative A (the no-action alternative), which has the same basic operational discharge pattern as current operations under Modified Low Fluctuation Flows (MLFF). Although there is no published research for the direct impact of wind transport of sediment under MLFF on archaeological sites within the river corridor, recent research has shown that, under MLFF, approximately 1–3% of the gullies studied within reaches of the Colorado River between Glen Canyon Dam and the headwaters of Lake Mead showed obvious indication of filling by wind-blown sand (Sankey and Draut 2014).

Of the long-term strategies analyzed, one for each alternative was selected as most representative of the alternative as fully implemented. These representative long-term strategies were A, B1, C1, D4, E1, F, and G. All of the representative long-term strategies B1, C1, D4, E1, F, and G scored greater than Alternative A because they have more frequent high-flow experiments (HFEs). Long-term strategies B2, C3, E3, E5, and E6 rank below Alternative A. With the exception of B2, HFEs are not conducted for these strategies, and flows above 31,500 cfs would occur rarely, if at all. Recall that one of the primary assumptions for this metric is that flows above 31,500 cfs are the primary mechanism for sediment deposition at higher elevations. If there are no high flows to deposit sand at higher elevations along the banks of the river, there is no new sediment to be moved by the wind. Increased flow fluctuations in long-term strategy B2 cause it to rank below Alternative A.

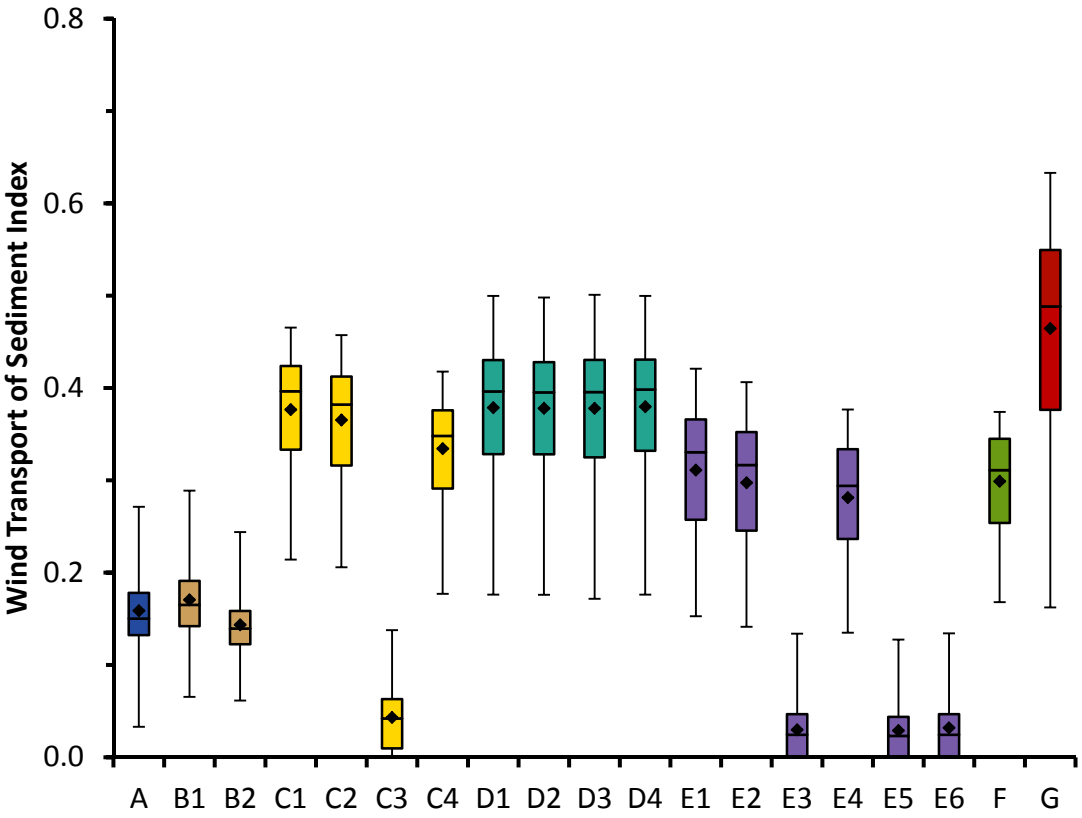


FIGURE H-1 Wind Transport of Sediment Index Values for the LTEMP Alternatives (letters) and Associated Long-Term Strategies (numbers) (Index values of 1 are considered optimal. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

Alternative G scores the highest of all the alternatives, with an average WTSI nearly three times greater than Alternative A. With the highest number of HFEs and the lowest maximum daily flows during the windy months (Figure H-2), this alternative has parameters ideal for wind-transport of fluvial sediment to high-elevation terraces that contain cultural resources. The second highest scoring long-term strategy, D4, is not significantly different from D1, D2, D3, and C1 (statistical differences between means based on a three-factor analysis of variance (ANOVA) followed by Tukey's Studentized Range Test).

On the whole, the WTSI is highly correlated with the number of HFEs and the corresponding SLI. The relationship between SLI and HFEs is discussed in Appendix E. The similarity between WTSI and HFEs can be seen by comparing Figure H-1 with the average number of HFEs in Figure H-2. The WTSI is highly correlated with the SLI because the average maximum discharge between March and June for each of the alternatives is within 5,000 cfs (standard deviation of 0.05). With minimal difference in flow, the amount of sediment for distribution becomes the determining factor for the index. The exception to this is Alternative F. Figure H-3 shows a sample trace of the typical 8.23 million acre feet (maf) release year. In April,

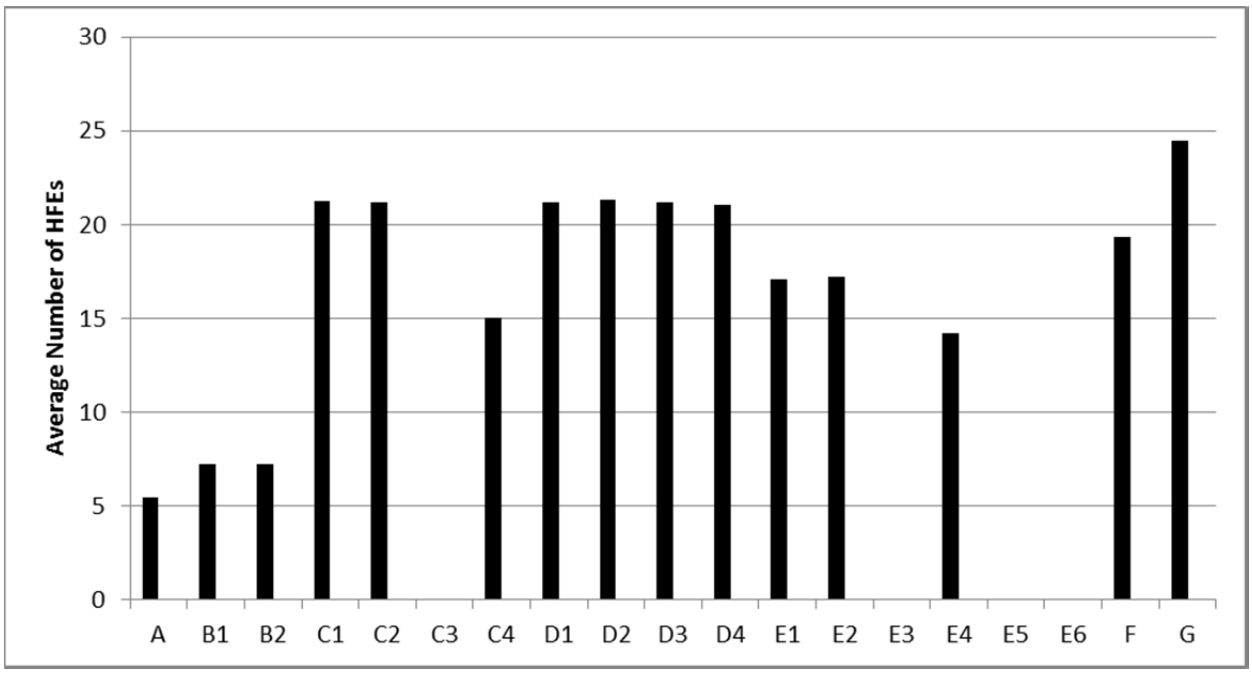


FIGURE H-2 Average Number of HFEs in the 20-Year LTEMP Period

May, and June, the discharge of Alternative F is higher than that of all other alternatives. Although Alternative F was determined to have the second highest potential sand deposition (highest SLI), it ultimately has an average WTSI value lower than Alternatives C, D, E, and G, as larger discharges of water create less ideal conditions for wind transport.

Long-term strategies C2 and E2 feature low summer flows and trout management flows (TMFs) when conditions trigger them. Reallocation of water volume from low summer flows can cause increased discharge in other portions of the water year. This reallocation combined with the high-flow portion of TMFs causes C2 and E2 to rank lower than their base alternatives. Similarly, the exclusion of spring HFEs in C4 and E4 decrease their WTSI in comparison to C1 and E1.

The WTSI is useful for understanding the interplay between the components of the alternatives. Alternatives that incorporate strategies for enhancing sediment retention (i.e., C, D, E, and G, which have reduced fluctuations or more even monthly volumes) have higher WTSI values. The metric also illustrates through Alternative F the effect that flow operations can have on wind transport. Index values are lower for Alternative F because the alternative features higher flows in the windier periods of the spring and summer, which negates some of the benefits of the higher sediment retention indicated in the SLI. Although the metric is beneficial for comparative and theoretical purposes, it reflects idealized conditions for wind transport of sediment that cannot be easily translated into actual site preservation. The extent to which wind transport of sediment can mitigate the erosion occurring to cultural sites on high elevation terraces remains unknown.

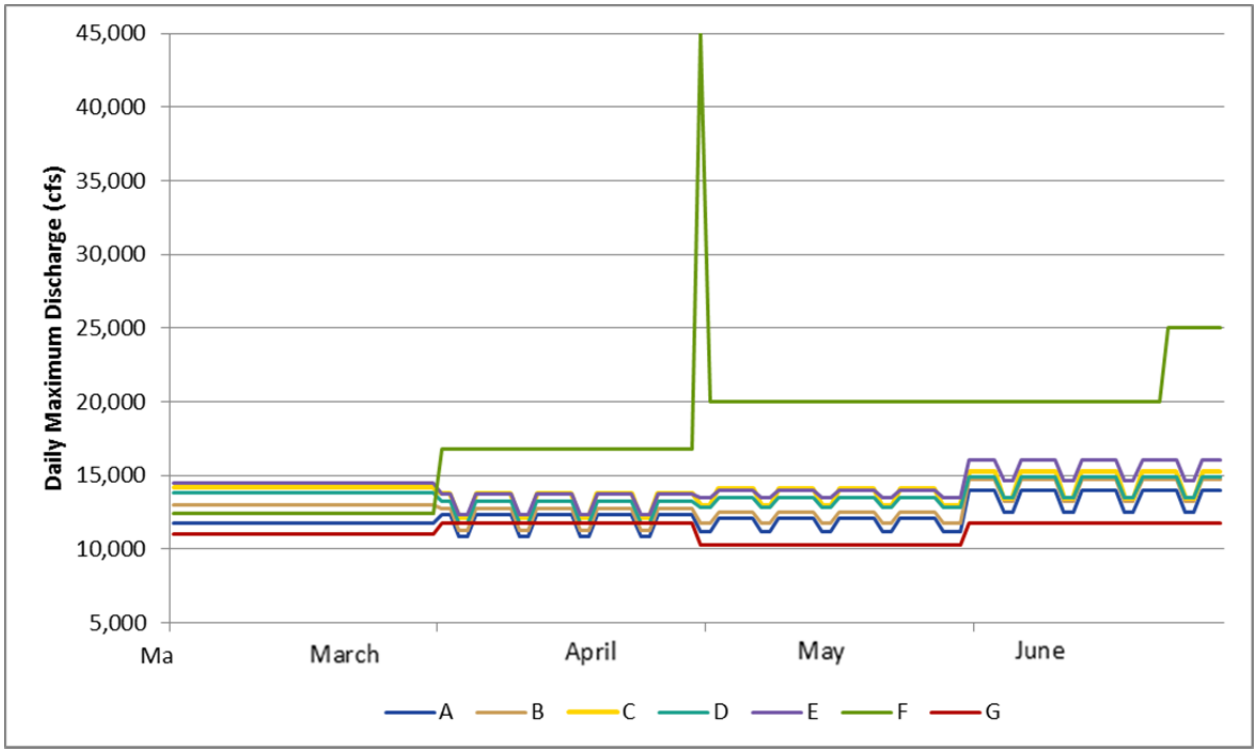


FIGURE H-3 Daily Maximum Discharge in a Typical 8.23-maf Water Volume Release Year from the Glen Canyon Dam during the Windy Season of March–June

H.2 FLOW EFFECTS ON CULTURAL RESOURCES IN GLEN CANYON

The construction of Glen Canyon Dam significantly scoured the immediate downstream Glen Canyon reach of the Colorado River and cut off nearly all of the sediment supply from upstream. Unlike further downstream sections of the river, a lack of significant tributaries in Glen Canyon results in very little sediment deposition on river banks of the canyon. In fact, high flows meant to distribute sediment have been shown to degrade terraces in the Glen Canyon reach (Grams et al. 2007). Archaeological sites located in Glen Canyon are also not associated with significant wind deposition of sediment (Anderson 2006). Without the rejuvenation of sediment, higher flows can increase erosion within the Glen Canyon, which is of concern for significant archeological sites.

Anderson (2006) identified 14 archaeological sites within Glen Canyon that were being affected by river-based arroyos or gullies. However, only one of these sites, commonly referred to as Ninemile Terrace, was determined to have erosional features that are unequivocally related to direct impacts of river operations. Bank stability at Ninemile Terrace, and other terraces having the potential to contain cultural resources, is partially dependent on the accumulation of material at the base of the slope. Removal of this protective material through erosion leaves the lower-bank material prone to a continuing cycle of undercutting, collapse, and removal. This, in turn, contributes to slumping of the upper-bank material, whether dry or saturated. The flow at which the base of the slope begins to erode serves as the "flow elevation threshold." Flows at or

above this threshold have the potential to adversely affect cultural resources through bank erosion and destabilization (Baker 2013). Time-lapse photography from the November 2012 HFE shows that the inundation of the existing base of the slope at Ninemile Terrace occurs at a flow of 23,200 cfs.

Ninemile Terrace reflects many characteristics of other sites in Glen Canyon and was considered representative of other Glen Canyon terrace sites for determining the effects of water flow on high-elevation terraces. In the absence of direct field measurements to further clarify a flow elevation threshold, the flow rate of 23,200 cfs was selected by Grand Canyon Monitoring and Research Center (GCMRC) staff as an approximate measure to represent the flow elevation above which erosional processes could contribute to impacts that have the potential to adversely affect cultural resources.

H.2.1 Flow Effects on Cultural Resources in Glen Canyon—Methods

Impacts on cultural resources in the Glen Canyon reach were determined by calculating the number of days per year that the maximum daily flow would be >23,200 cfs. Therefore, a higher number represents the increased potential of erosion of terraces that contain cultural resources. The maximum daily flow is used to capture all instances where flow is high enough to contribute to erosional processes. As with the WTSI, a total of 63 scenarios of different hydrologic and sediment conditions were analyzed.

This metric determines the relative difference among alternatives for the potential impacts of flow on cultural resources. Research would be needed to determine the number of days of high flow that would produce noticeable or extensive impacts on cultural sites.

H.2.2 Flow Effects on Cultural Resources in Glen Canyon—Results

The number of days per year flows would be >23,200 cfs under each alternative are shown in Figure H-4. The average number of days flows would be >23,200 cfs ranges from 18 to 36 days among the alternatives. High maximum values of 50–77 days would occur under all alternatives (as noted by the upper whisker) and would occur in years with abnormally high water volumes released from Glen Canyon Dam.

Alternative A has the highest number of days per year flows would be >23,200 cfs. Alternative A most closely represents the current conditions of MLFF. Long-term strategies C3, E3, E5, and E6 (long-term strategies with no HFEs) have average values that are lower than under Alternative A, but by no more than 3 days. Alternative F would have the highest number of days per year flows would be >23,200 cfs with an average of 14 days per year more than under Alternative A. Alternative F, therefore, has the highest potential for impacts on terraces that contain cultural resources in Glen Canyon. The higher number of days under Alternative F results from the relatively high spring flows between May and June (Section 2.2.6). The remaining alternatives have an average number of days per year flows would be >23,200 cfs within 4 days of those under Alternative A.

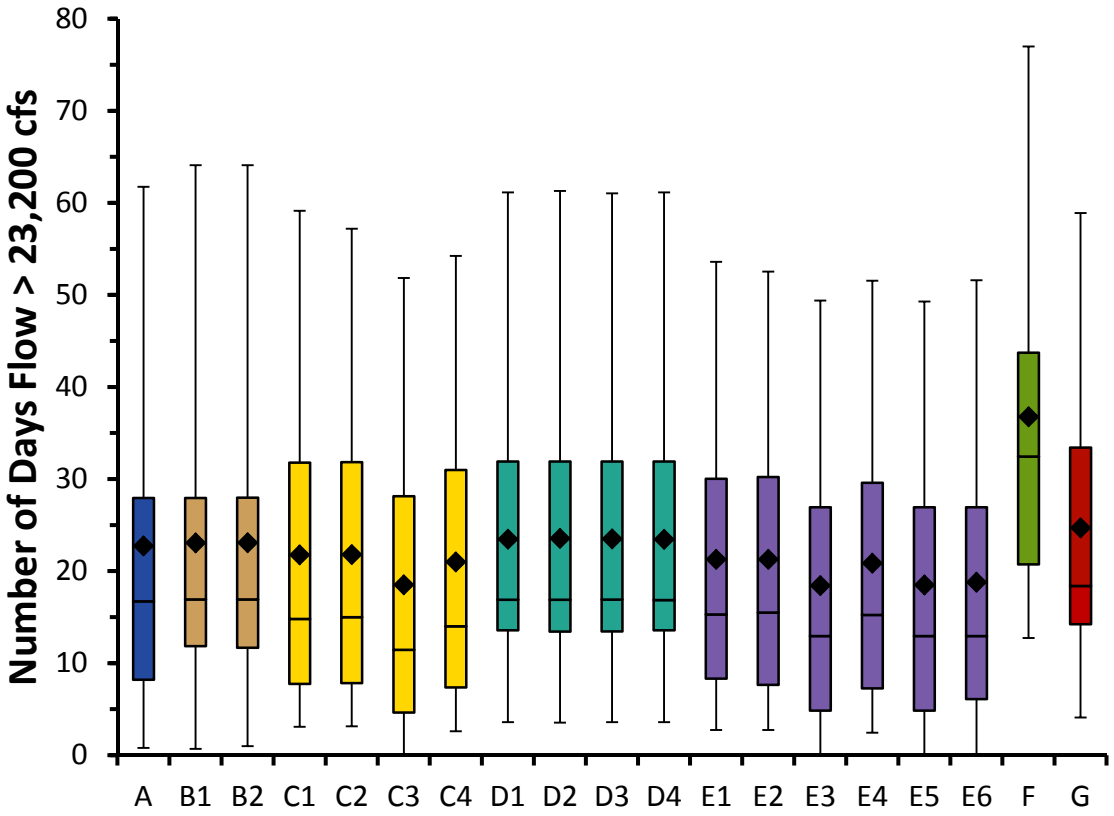


FIGURE H-4 Number of Days per Year Flows Would Be >23,200 cfs under LTEMP Alternatives (Letters) and Long-Term Strategies (Numbers) (Flows of this magnitude have the potential to affect cultural resources in Glen Canyon. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

Besides the high spring flows of Alternative F and HFEs under all alternatives, operational changes within long-term strategies seem to have minimal effect on the number of days per year flows would be >23,200 cfs. Long-term strategy B2 includes tests of hydropower improvement flows (i.e., operations with wider water release fluctuations in high electrical demand months than the base operations of B1). Although hydropower improvement flows increase within-day flow fluctuations, in most cases, the altered maximum flow does not exceed 22,000 cfs. Therefore, long-term strategies B1 and B2 have nearly identical values and are not significantly different. Long-term strategies C2, D3, E2, and E5 all have low summer flows. Low summer flows result in higher flows at other times of year, but do not affect the number of days per year flows would be >23,200 cfs, and these long-term strategies will not have any effect on this metric. TMFs would also have minimal effect on this metric.

Although there are differences among alternatives in the number of HFEs (Figure H-2), these differences have little effect on the number of days per year flows would be >23,200 cfs. This occurs because HFEs are relatively short (Figure H-5), and the large volume released under the HFE must be compensated by releasing less water at other times of the year (Figure H-6).

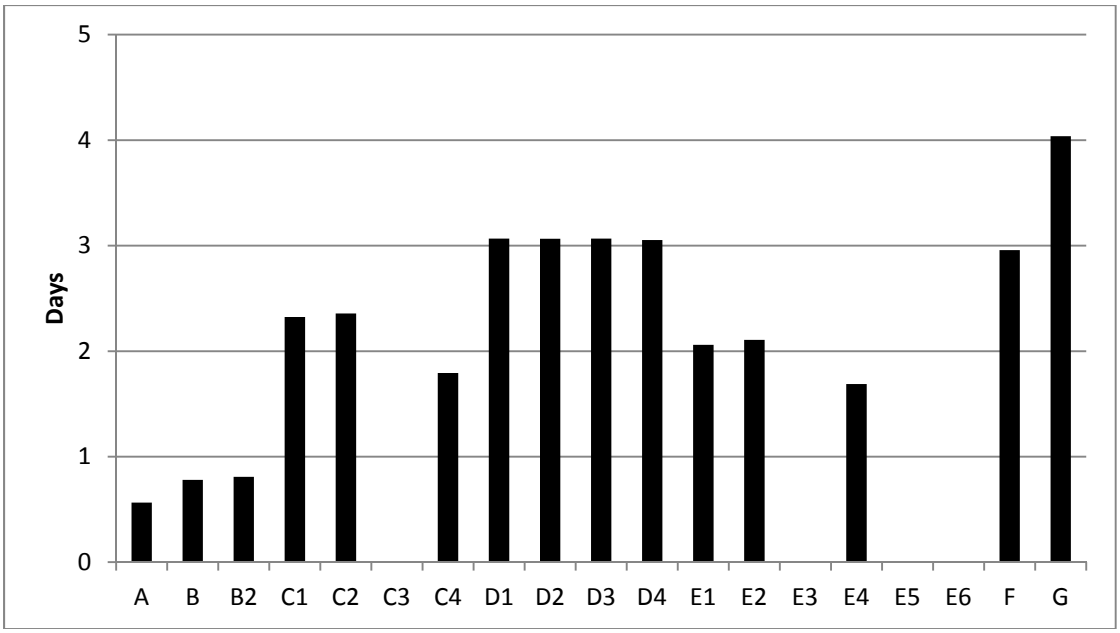


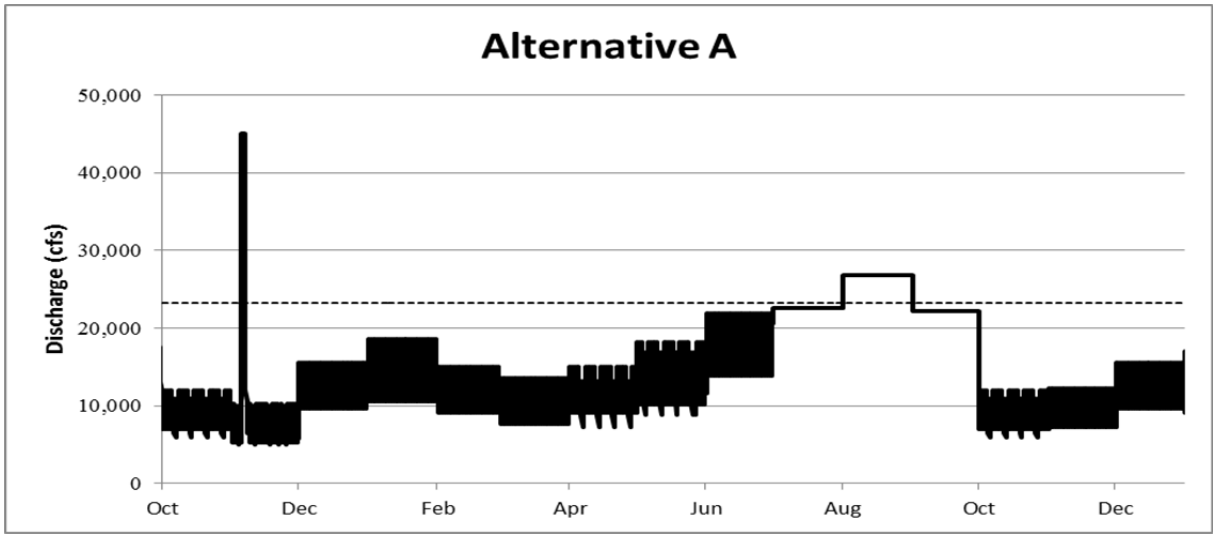
FIGURE H-5 Average Number of Days of an HFE Event per Year

Since all alternatives must release the same annual volume of water, alternatives with HFEs may have lower releases at other times of years than those without. The effect on the metric would be greater in years of high volume (≥10 maf) when equalization flows would be implemented according to the Interim Guidelines (Reclamation 2007).

This explains why Alternative A and B, with minimal HFE events, have nearly the same metric value as alternatives like Alternative C with more than four times the number of HFEs (Figure H-2). Although Alternative C has two HFEs in Figure H-6 and Alternative A has only one, Alternative A must release more water in August to compensate. Historically, precipitation was higher than conditions in recent years; therefore, equalization flows may be triggered less frequently and days above 23,200 cfs might be less than those based on historical flows. The 50th and 25th percentile values are more applicable to recent climate conditions seen in the Glen Canyon region. It is also noted that the variability (noted by the length of box) in the value is a result of the variability in the release volume between water years, HFEs, and the interaction between the two for a particular alternative.

H.3 TIME OFF RIVER

Greater discretionary time for whitewater rafters to explore the canyons downstream of Glen Canyon Dam increases the likelihood that they could have an impact on archaeological sites by creating trails to sites or looting or vandalizing sites. When the river is moving at a faster pace and boat travelers arrive at their destination earlier, their discretionary time off river increases. It is therefore hypothesized that higher flows may increase the potential for adverse human contact with archeological sites.



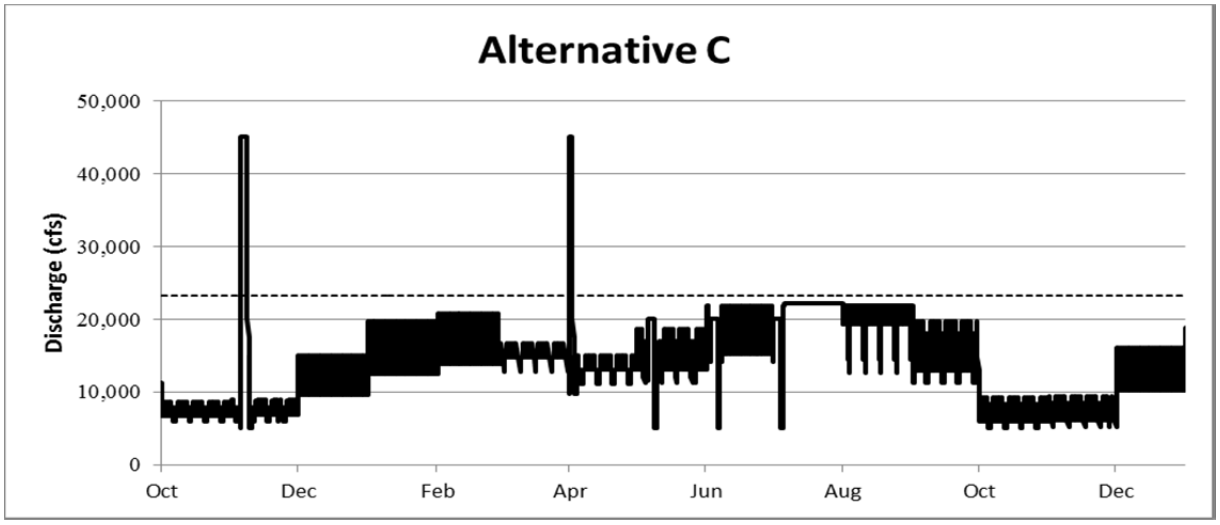


FIGURE H-6 Modeled Glen Canyon Dam Discharge for the Same Year (the line represents 23,200 cfs)

H.3.1 Time Off River—Methods

The Time Off River Index (TORI) represents the degree to which flows could affect visitor potential to interact and disturb cultural sites. Grand Canyon visitor numbers vary depending on the time of the year. Recreational activity is more common in the warmer summer months, less so in the spring and fall months, and even less in the colder winter months. The yearly TORI (Eq. H.4) is the ratio of the sum of seasonal ratios which designate flows ideal for minimal visitor-site interaction. Summer has the highest weight (0.54) while winter has the lowest (0.15) and spring and fall are in between (0.31). The TORI is a 0–1 value, where 1 equals the least discretionary time for visitors to access archaeological sites, and, therefore, the lowest potential for impacts on cultural sites.

$$TORI = \{0.15\left(\frac{\sum_{winter} ORFF}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{\frac{spring}{fall}} ORFF}{\sum Days_{\frac{spring}{fall}}}\right) + 0.54\left(\frac{\sum_{summer} ORFF}{\sum Days_{summer}}\right)\} \quad \text{(H.4)}$$

An overall annual mean TORI value for the 20-year modeling period was developed for each alternative and used as the performance metric (Eq. H.5).

$$TORI = Average\ (TOR_{annual})_{2014-2033} \quad \text{(H.5)}$$

The Off River Flow Factor (ORFF) represents the potential for discretionary time off river. The discharge level at which boats begin to exceed typical river travel times is 10,000 cfs. However, once flows reach above 31,500 cfs, visitors are more likely to stay at campsite areas rather than travel in a turbulent river. Daily average flows (Q_{avg}) represent the average release from Glen Canyon dam in cfs. Average daily discharge from the dam was modeled in GTMax-Lite. The ORFF is a 0–1 value, where 1 indicates the lowest potential for discretionary time off river and therefore the lowest potential for increased visitation of archaeological sites. Specifically, the average daily ORFF is assigned as follows (Eq. H.6), where the value within the brackets in the right column is assigned to $ORFF_{Daily}$ if the equation in the left column is satisfied:

$$ORFF_{Daily} = \begin{cases} \text{if } Q_{avg} \leq 10{,}000; & 1 \\ \text{if } 10{,}000 < Q_{avg} < 31{,}500; & 1.465 - 0.0000465 \times Q_{avg} \\ \text{if } Q_{avg} \geq 31{,}500; & 0 \end{cases} \quad \text{(H.6)}$$

As with the WTSI, a total of 63 scenarios of different hydrologic and sediment conditions were analyzed.

H.3.2 Time Off River—Results

TORI does not specify how much additional discretionary time off river a visitor may experience. Instead, TORI is intended to determine the potential for visitors to spend more time off of the river exploring, which could result in more cultural resources being visited and possibly affected, by examining the flows under the various alternatives as compared to Alternative A.

A summary of TORI results is provided in Figure H-7. All of the alternatives and their long-term strategies performed similarly within this metric. Values of TORI under long-term strategies B1, B2, C2, and C4 were not significantly different than those under Alternative A. Although Alternatives D, E, and G rank the highest with regard to this value (and thus would be expected to have the lowest impact), the minimal differences in the metric values from Alternative A would likely indicate that they would not have noticeable impacts on visitor-site interactions.

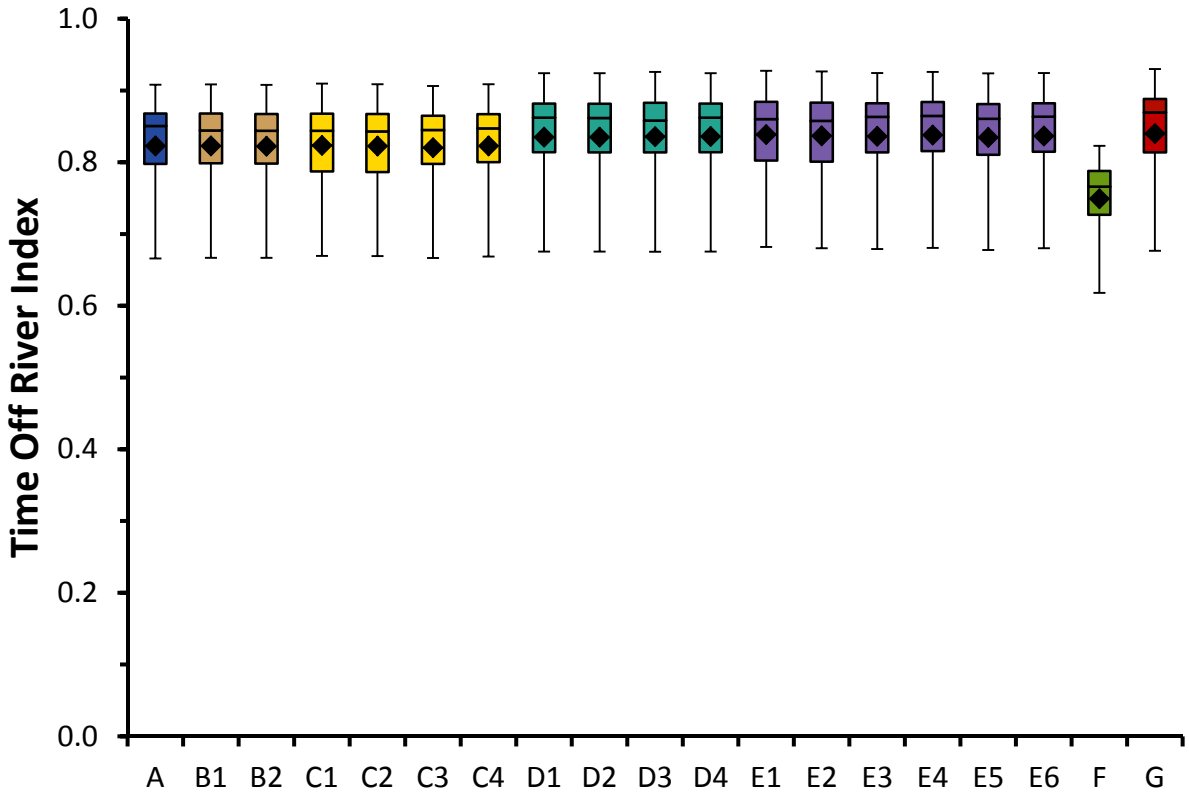


FIGURE H-7 Time Off River Index Values for All LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers) (Index values of 1 are considered optimal. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

The difference between the TORI for Alternative F and the other alternatives is largely due to flows during the spring and early summer that are generally at or above 20,000 cfs, while all other alternatives have daily flows that average between 8,000 and 12,000 cfs. Figure H-8 shows the difference in average discharge between Alternative F and the other alternatives. Although Alternative F has very low flows in December and January, the alternative has flows that are more than 7,000 cfs higher than other those under other alternatives in spring and early summer months.

TORI values would be higher in years of high volume (>10 maf) when relatively high equalization flows would be implemented according to the Interim Guidelines (Reclamation 2007). However, these relatively high releases result from high inflow volumes in wet years, are unavoidable, and differ little among alternatives.

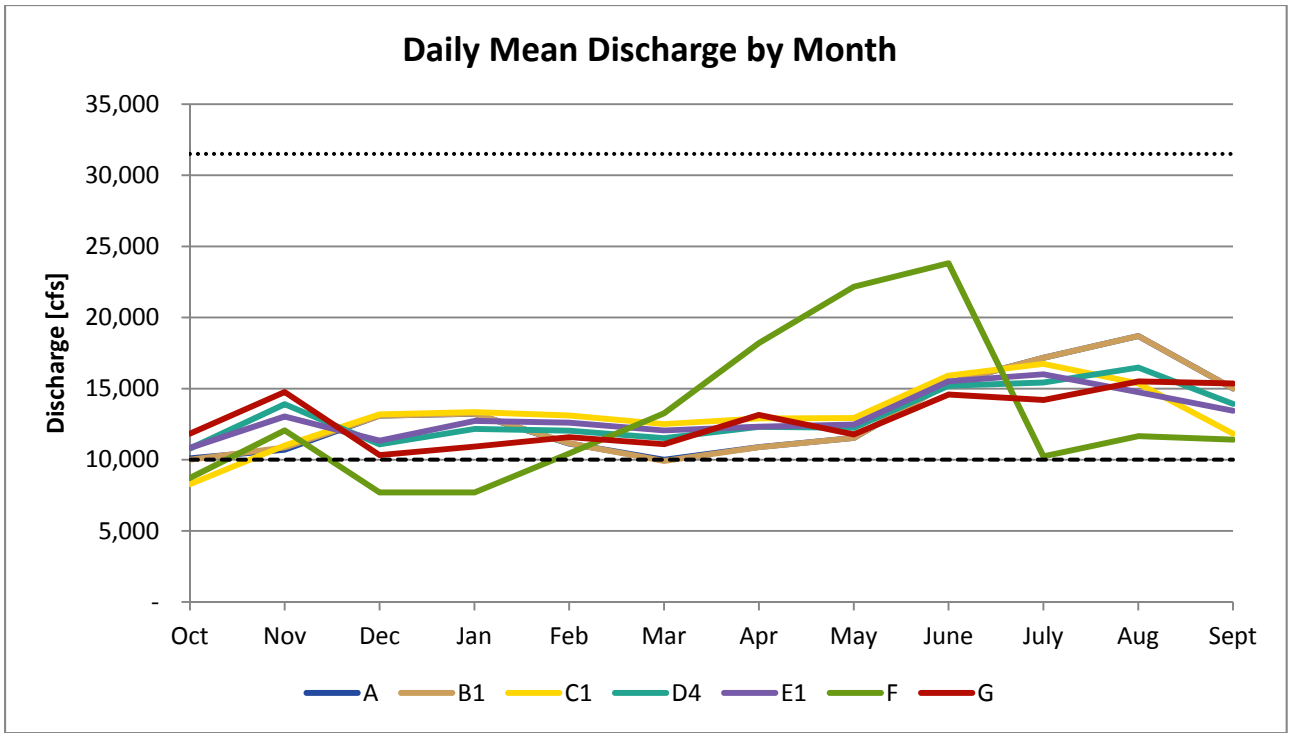


FIGURE H-8 Daily Average Discharge for Representative Long-Term LTEMP Strategies

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APPENDIX I:

TRIBAL RESOURCES TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX I:

TRIBAL RESOURCES TECHNICAL INFORMATION AND ANALYSIS

Section 4.9 of the Draft Environmental Impact Statement (DEIS) assesses and compares the potential impacts Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) alternatives could have on resources important to federally recognized Tribes. Indian Tribes have been recognized by the courts as "domestic dependent nations." They were sovereign entities before the arrival of Euro-American colonizers and continue to exercise that sovereignty within their reserved lands. Consultation between Tribes and the federal government is consultation between sovereign entities. Even when they have been removed from their ancestral lands, Tribes often retain strong ties to culturally important resources in their traditional homelands. When those resources are located on federal lands or could be affected by federal or federally licensed undertakings, federal agencies are required to take into account those potential impacts in their decision-making (see Table I-1).

The nature and degree of impacts that an undertaking could have on resources important to Tribes is best evaluated with significant input from the Tribes themselves. To this end, the Bureau of Reclamation (Reclamation) and National Park Service (NPS) have sought to include input from all federally recognized Tribes that have traditional, historical, cultural, or religious ties to the canyons. Forty-three Tribes with potential ties to the canyons were notified of the LTEMP EIS project by mail with telephone follow-up and invited to participate. Of these, six chose to become cooperating agencies; two Tribes chose to consult, but not as cooperating agencies; and nine chose not to actively consult, but to be kept informed of project developments. Thirteen Tribes chose not to participate. There was no response from the remaining twelve Tribes (see Appendix N).

Assessing the comparative impacts of the LTEMP alternatives on Tribal resources presents a challenge both (1) because of the holistic view of the canyons that Tribal members tend to take, in which all elements of the environment are interconnected, so that effects on one part of the environment affects the whole, because there is no single "Tribal view" held by all members of all Tribes, and (2) because knowledge of the location of some of the most sacred places is not shared with outsiders. Not all Tribes agree with each other on all issues, but some common themes and issues did emerge from discussions with Tribal representatives, review of canyon monitoring reports produced by the Tribes, and ethnographic sources produced by or for

TABLE I-1 Federal Regulations and Executive Orders Pertaining to Consultation with Tribes

40 CFR 1506.6 *Cooperating Agencies*
43 CFR 46.225 *How to Select Cooperating Agencies*
E.O. 13175 *Consultation and Coordination with Indian Tribal Governments*
Section 106 of the *National Historic Preservation Act (1966 as amended)*
36 CFR 800.2 (c) (2) *Participants in the Section 106 Process*

the Tribes. For many Tribes, environmental features considered inanimate in Western cultures are seen as imbued with life; in some cases, such as with the Colorado River and the Little Colorado River, they are considered deities. Various Tribes regard the canyons as sacred space, the place where their people emerged into this world, the home of their ancestors, the residence of the spirits of their dead, and the source of many culturally important plant, animal, and mineral resources. Many Tribes view themselves as connected to the Colorado River and its canyons and as stewards over the living world around them including water, earth, plant life, and animal life. This holistic view encompasses subject areas considered in this DEIS, and Tribal perspectives on these resources are found throughout the document. The values the Tribes place on the river and its canyons are significant and real, but often intangible; therefore, they are not easily or are only partially quantifiable. In addition, many of the values and resources that are most important to the Tribes are not directly affected by differences in the patterns of release of water from the Glen Canyon Dam.

Knowledge of some of the most sacred and sensitive places and resources in the canyons is esoteric, known chiefly by elders and initiated religious practitioners. Only they can provide information on what is most sacred and what can be revealed in a public format such as an EIS. Funding was provided to support Tribes in obtaining and providing these important perspectives on the river and the canyons. Appendix N details the efforts undertaken to obtain Tribal input regarding resources important to Tribes that could be affected by the operation of Glen Canyon Dam and proposed associated actions. These efforts included face-to-face meetings, webinars, and conference calls. The Tribes that chose to act as cooperating agencies also were afforded the opportunity to provide text for the DEIS, and to review and comment on the draft document before it was released to the public.

Although many aspects of the effects on Tribal resources are not quantifiable, quantifiable measures of effects on the canyon environment were found that reflect important Tribal values and could stand as proxies for those values. These include effects on the diversity of riparian vegetation, effects on marshes and other wetlands, effects of large-scale taking of nonnative fish for fish management purposes, effects on Tribal water rights, and factors that could affect Tribal economics. Tribes are concerned with natural resources beyond plant and aquatic life in the canyons. Bighorn sheep, songbirds, and butterflies are among the indicators of canyon health mentioned by Tribal members. Many of these resources are considered qualitatively in the wildlife section of the DEIS (Sections 3.7 and 4.7) and can be reviewed and considered by Tribal specialists and representatives.

I.1 QUANTIFIABLE MEASURES USED TO ASSESS IMPACTS ON TRIBAL RESOURCES

I.1.1 Riparian Diversity

Among the quantifiable projected impacts are those on riparian vegetation, the plant life likely to be most directly affected by flow management at the Glen Canyon Dam. The Western concept of "ecosystem" comes close to Tribal views of interconnectedness. Plant life is a

fundamental part of most ecosystems. The state of riparian vegetation is a good indicator of the state of the canyon ecosystem as a whole. Thriving, diverse vegetation communities indicate a healthy ecosystem. Models of future plant diversity along the river provide a quantitative indicator of ecosystem health. Many Tribes give native species and nonnative plant species equal value as forms of life to be respected. Therefore the measure presented here includes plant communities dominated by both native and nonnative plants. For a discussion of diversity in native plant communities, see the Native Diversity Index in Appendix G.

A metric for vegetation community diversity in the riparian zone has been developed based on the results of a state and transition model for Colorado River riparian vegetation downstream of Glen Canyon Dam. This model has been developed to compare the effects of alternative flow regimes on Colorado River riparian vegetation. The model is discussed in Section 4.6.1. For a more detailed discussion of the model, see Ralston et al. (2014) and Appendix G. The model uses characteristics of annual dam operations to predict transitions from one plant community type to another on sandbars and channel margins in the riparian zone. The model projects transitions over a 20-year period for each alternative and long-term strategy analyzed. Relative change in the diversity of vegetation community types on sandbars and in channel margins is projected using the Shannon-Weiner Index for richness/evenness[1] and a diversity score calculated by comparing the final (modeled) diversity to the initial diversity (change in diversity = $diversity_{final}/diversity_{initial}$). A healthy ecosystem is characterized by a high degree of species diversity, represented here by diversity in vegetation community types. A total diversity score was calculated that included nonnative (primarily tamarisk) as well as native communities including the invasive arrowweed. Table I-2 shows the seven vegetation states, or plant community types, that were considered. The species associated with a state all respond similarly to Colorado River hydrologic factors such as depth, timing, and duration of inundation.

The model consists of six submodels based on the following landforms: lower separation bars, upper separation bars, lower reattachment bars, upper reattachment bars, lower channel margins, and upper channel margins. Upper and lower landforms are divided at the 25,000 cfs

TABLE I-2 Vegetation States

Vegetation States
Bare Sand
Marsh (Common Reed Temperate Herbaceous Vegetation)
Shrub Wetland (Coyote Willow-Emory Seep Willow Shrubland/Horsetail Herbaceous Vegetation)
Tamarisk (Tamarisk Temporarily Flooded Shrubland)
Cottonwood-Willow (Fremont Cottonwood/Coyote Willow Forest)
Arrowweed (Arrowweed Seasonally Flooded Shrubland)
Mesquite (Mesquite Shrubland)

[1] For a discussion of the Shannon-Weiner Index, see Appendix G.

flow stage (see Section 3.3.1.1 for a description of these landforms). The model projects transitions between vegetation states, based on a set of rules developed for each submodel, driven by hydrologic events. The model includes a subset of states and transition rules for each submodel. The states and transition rules for the upper portions of the bars and channel margin are the same because of the similarity of plant community types and responses to flow characteristics. The transition rules are based on the effects of scouring, drowning, desiccation, and sediment deposition on riparian plant species. Transition rules are presented in Table G-3 in Appendix G.

Figure I-1 shows the weighted diversity scores for the seven LTEMP alternatives and their associated long-term strategies (described in Appendix C). The higher the score, the greater the diversity of plant community types. A score of 1.0 indicates that the current degree of plant community diversity is projected to be maintained. A score greater than 1.0 indicates increased diversity, less than 1.0 a loss of diversity. The mean scores for each alternative fall into a somewhat wider range than the Native Diversity scores presented in Appendix G. They range from 0.70 under Alternative F to 0.97 under long-term strategy B1. Alternative A (no action alternative) scored 0.95. Alternatives D and E scored above 0.90 under all of their associated long-term strategies.

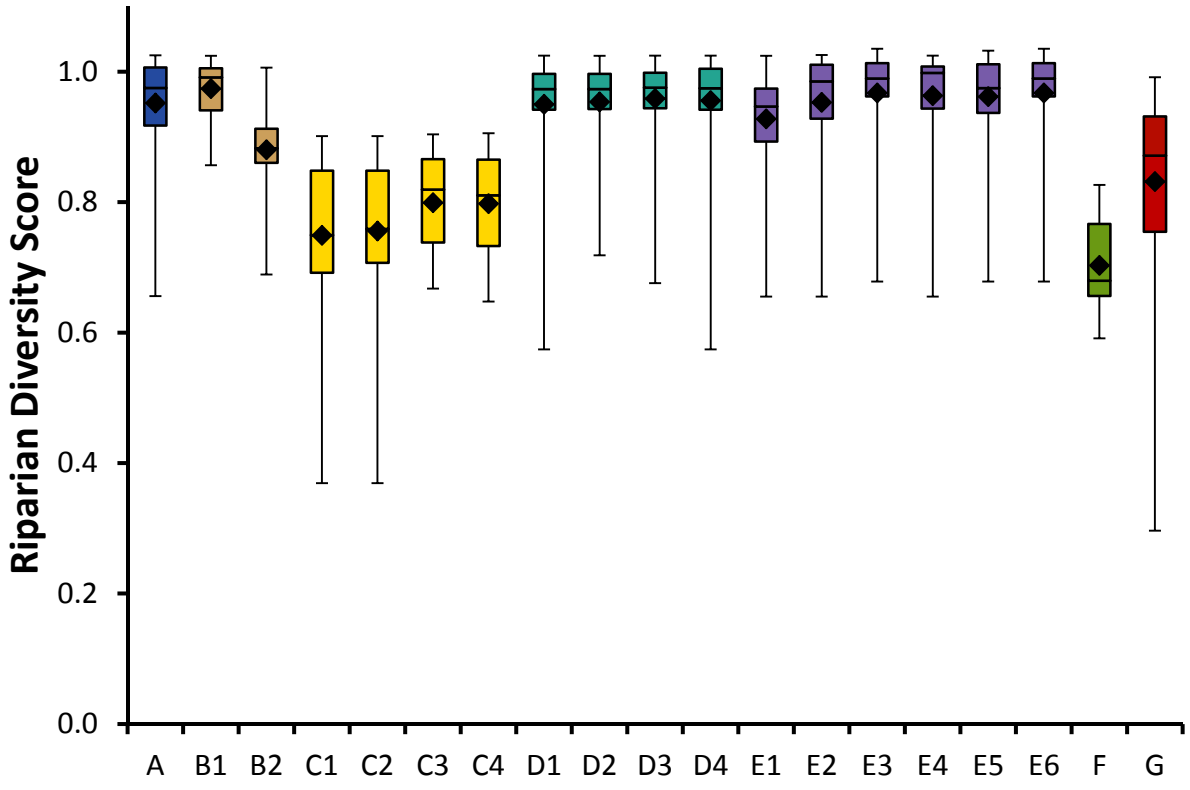

FIGURE I-1 Riparian Diversity for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

The results indicate that on average all alternatives would result in a small decrease in total vegetation state diversity over the 20-year LTEMP modeling period. The loss in diversity would be greatest under those long-term strategies where there is an increase in the area covered by the tamarisk community type (see Table 4.8-3). Alternatives where tamarisk[2] would increase are characterized by high flows (high-flow experiments [HFEs] or ≥30 days with flows >20,000 cfs), which serve to distribute seed, and/or low flows in the growing season (May–September) that allow seedlings to establish themselves. Once established, tamarisk is tenacious. When it does transition, it is most often to bare sand.

Under climate change assumptions, the modeled pattern shows very little difference from the historical-based assumptions (Figure I-2). There is a minimal overall increase in mean diversity scores, suggesting that the difference would be barely perceptible on the ground.

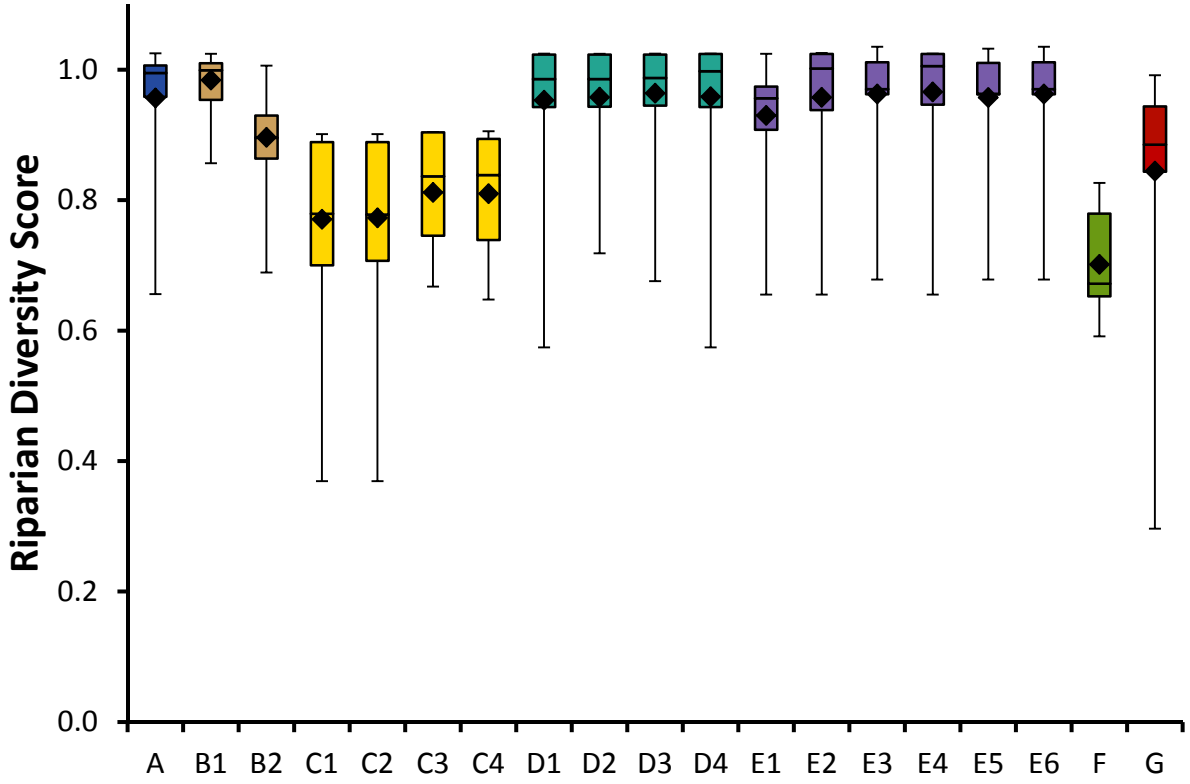

FIGURE I-2 Riparian Diversity under Climate Change Assumptions for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

[2] The model takes into account the effects of scouring, drowning, desiccation, and sediment deposition, but does not account for the effects of the tamarisk leaf beetle or tamarisk weevil. These two insect species may result in a reduction in the amount of live tamarisk in the river corridor.

I.1.2 Wetland Abundance

Some Tribes (e.g., the Hopi) see the health of canyon wetlands as an indicator of canyon health (Yeatts and Huisinga 2013). Assessments of the projected state of wetland cover over the next 20 years can be derived from the state and transition model discussed above. Two of the model states listed in Table I-2 are wetland community types: Common Reed Temperate Herbaceous Vegetation, a marsh community; and Coyote Willow-Emory Seep Willow/Horsetail Herbaceous Vegetation, a shrub wetland community.

Wet marsh communities of flood-tolerant herbaceous species that occur on low-elevation areas of reattachment bars have developed in response to frequent inundation. Wet marsh communities (with common reed and cattail the dominant species) occur on fine-grained silty loam soils in low-velocity environments on lower areas of eddy complex sandbars; although they are easily scoured by high flows, they can redevelop quickly. Shrub wetland communities (with coyote willow, Emory seep willow, and horsetail the dominant species) occur on sandy soils of reattachment bars and channel margins, below the 25,000 cfs stage, that are less frequently inundated.

Wetland communities generally transition only from bare sand or other wetlands; they can transition back to bare sand or to arrowweed, tamarisk, or cottonwood-willow communities. An increased occurrence of transitions from bare sand to wetlands and/or maintenance of wetlands (lack of transitions to other community types) would result in greater wetland cover. Large daily fluctuations increase the area of saturated soil and thus the sandbar area available for wetland species establishment. The reduction of daily fluctuations may increase the establishment of wet marsh species at lower elevations and promote the transition of higher elevation marshes to woody species such as tamarisk or arrowweed. Periodic flooding and drying tends to increase diversity and productivity in wetland communities. Although low-elevation plants in marshes in Marble Canyon and Grand Canyon, such as cattail, common reed, and willow, may become buried with coarse sediment, recovery generally occurs within 6 to 8 months. Low steady flows can cause some wetland patches to dry out, resulting in considerable plant loss. Sustained high releases reduce wetland vegetation cover to less than 20% on lower reattachment bars. Extended high flows typically scour herbaceous vegetation; however, most woody plants often remain. Thus, extended high flows followed by extended low flows in the following growing season result in a transition from shrub wetland to a cottonwood-willow community on channel margins. A transition from marsh to shrub wetland occurs on lower reattachment bars with 4 years of consecutive seasons of low fluctuating flows or non-growing season sustained low flows (Ralston et al. 2014).

The relative change in cover of these wetland community types was calculated from the state and transition model results. The number of years each of the wetland states occur in each submodel is projected for the 20-year LTEMP modeling period. The results for the seven alternatives and their long-term strategies are presented in Figure I-3. A mean score of 1.0 indicates no change from initial conditions is expected. A score greater than 1.0 indicates an increase in wetland cover; a score of less than 1.0 indicates a loss in wetlands. Alternative F scored the lowest (0.14), and long-term strategy E6 scored the highest (1.10). Alternative A scored 0.72.

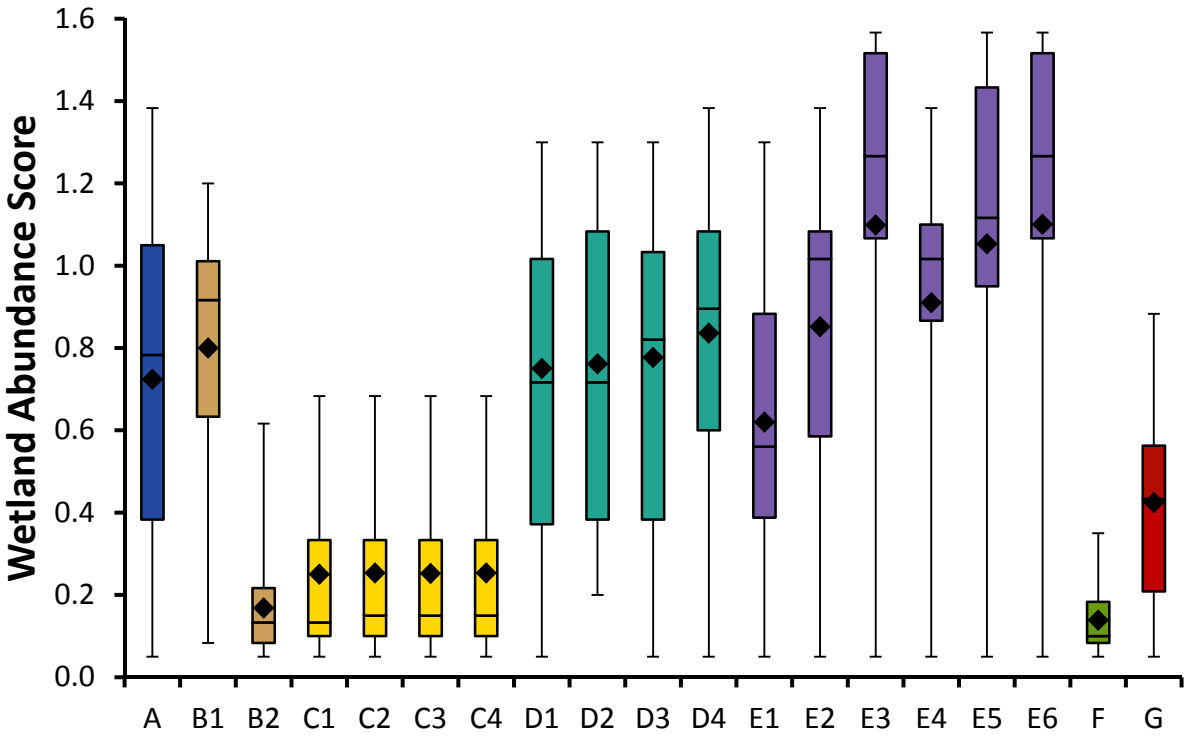

FIGURE I-3 Wetland Abundance for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

Only Alternative E, long-term strategies E3, E5, and E6—none of which have HFEs—show an increase in wetland cover (based on mean scores); all others show a decrease. However, long-term strategies B1, D1, D2, D3, D4, E2, E3, E4, E5, and E6 all scored higher than Alternative A. The alternatives with high scores are characterized by fewer extended high flows (greater than 20,000 cfs) and fewer extended low flows (less than 10,000 cfs) than Alternative A. There is enough water to sustain wetlands, but not too much inundation to support them over time. A large decrease in wetland community cover occurs under B2, all Alternative C long-term strategies, Alternative F, and to a lesser extent Alternative G. Frequent extended low flows or extended high flows followed by extended low flows tend to result in the transition of wetlands to other plant community types. Repeated seasons of extended high flows, or sufficiently high flows during one season, can remove wetlands, resulting in bare sand landforms.

Under climate change assumptions, the overall pattern remains the same for all alternatives, except that the Alternative F score increases slightly, as seen in Figure I-4. On average, scores increased by 0.08, with Alternative F showing only a negligible increase in the mean score (0.0017).

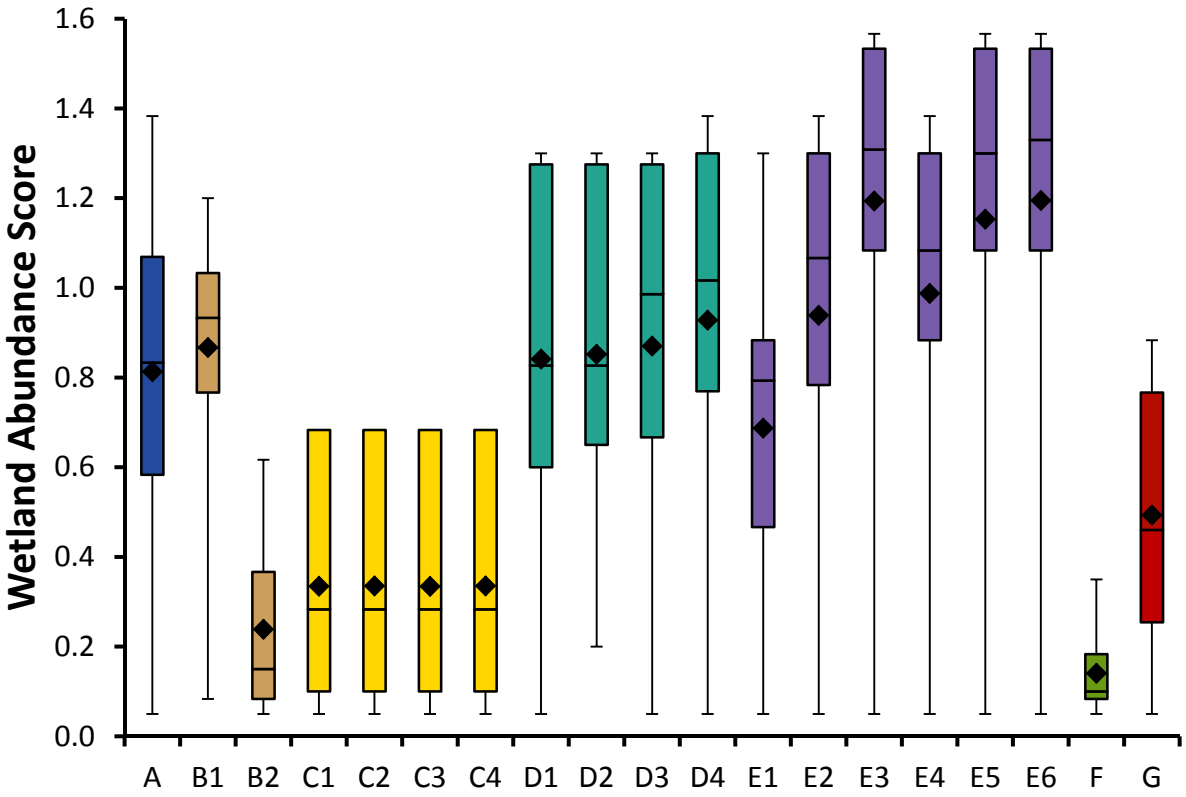

FIGURE I-4 Wetland Abundance under Climate Change Assumptions for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

I.1.3 Trout Management Flows

Reclamation and NPS are required under the U.S. Fish and Wildlife Service (FWS) biological opinion related to the *Non-native Fish Control Downstream from Glen Canyon Dam Environmental Assessment* (Reclamation 2011) to take steps to protect and encourage the recovery of endangered humpback chub (*Gila cypha*) populations in the canyons. The Little Colorado River is the home of a significant population of chub, which interact with rainbow trout at the confluence of the Colorado River and the Little Colorado River. Past and proposed methods for encouraging chub population growth involve reducing the number of nonnative trout, which prey on and compete with the chub. Large-scale killing of trout brings Reclamation and NPS into conflict with the value placed on all forms of life held by some Tribes. Although Tribes differ as to whether they consider the removal of nonnative fish species positively or negatively, many Tribes place a high value on the sanctity of life throughout the ecosystem and see themselves as its stewards. For them life, including fish and animal life, must not be wasted and must not be taken except to sustain human life. The Zuni in particular have important cultural ties to aquatic life in the canyons. The confluence of the Colorado River and the Little Colorado River is particularly sacred.

Aquatic resources models allow the comparison of the number of years trout management flows designed to strand trout larvae and fry would be triggered, and the number of years in which mechanical removal of trout would be triggered across the alternatives and their associated long-term strategies. Details of the models are presented in Appendix F.

A trout management flow is a highly variable flow pattern of water releases at Glen Canyon Dam intended to control the number of young-of-the-year trout in the Glen Canyon reach of the Colorado River. Reducing the number of trout in the Glen Canyon reach would reduce the number of trout emigrating downstream to the confluence with the Little Colorado River and other downstream areas. A typical trout management flow would consist of several days of a relatively high sustained flow (e.g., 20,000 cfs) that would prompt young fish to move into the shallows along the channel margins and, depending on the time of year, would prompt spawning fish to construct redds and lay eggs in nearshore shallow areas. The high flows would be followed by a rapid drop to a low flow (e.g., 5,000 cfs), stranding and killing young-of-the-year trout and, depending on the time of year, possibly exposing eggs in shallow redds, thus preventing them from hatching. Management flows would be triggered during years in which the production of young-of-the-year rainbow trout in the Glen Canyon reach is anticipated to be high (more than 200,000 individuals.).

Figure I-5 shows the projected number of years in which trout management flows would be triggered under each alternative and long-term strategy. Trout management flows are not elements of all alternatives and may not occur in many years, even under alternatives that allow them. Under each of the alternatives and long-term strategies in which trout management flows are included, they would first be conducted as tests and then implemented only if they prove to be effective in reducing the trout population in the Glen Canyon reach and emigration to downstream sections of the Colorado River. Trout management flows are not included as elements of nine alternatives/strategies: Alternative C long-term strategies C2, C3, and C4; Alternative D long-term strategy D3; Alternative E long-term strategies E2, E3, E4, and E5; and Alternative F. They would be only tested under Alternative A. In long-term strategies D1, D2, and D4, trout management flow experiments would be implemented without triggers during the first 5 years of the LTEMP period. Figure I-5 assumes experiments in the first 5 years of the LTEMP period. In general, trout management flows would most likely be triggered when spring HFEs, which stimulate the food base, are followed by relatively steady summer flows (May–August). These factors are associated with higher production of young-of-the-year trout and would result in conditions that would trigger trout management flows more often. Where the number of HFEs is limited, as in Alternative B, it is expected that there would be fewer years in which trout management flows would be triggered. Modeling indicates trout management flows would be triggered most often under Alternative G and long-term strategy D2. The mean number of years in which trout management flows would occur are relatively high under long-term strategies D1, D2, and D4 because of the experimental flows that would be implemented, whether trout management flows are triggered or not. If trout management flows prove successful, they would reduce the number of times mechanical removal near the Little Colorado River confluence would be triggered.

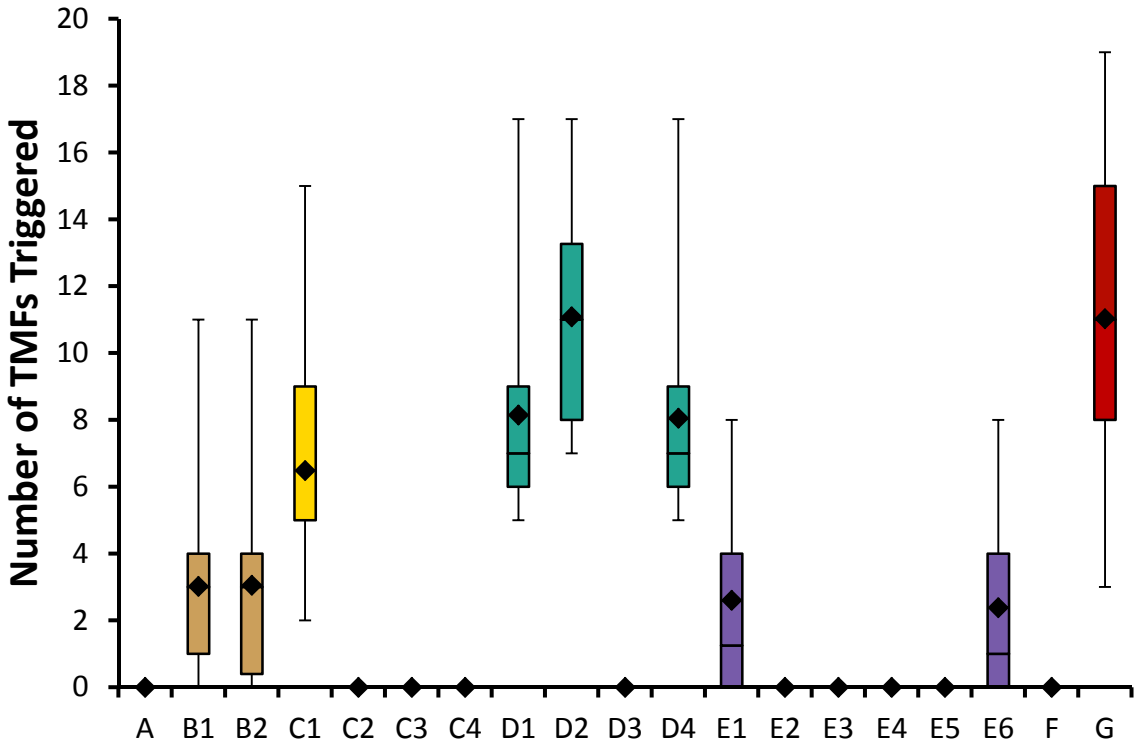

FIGURE I-5 Frequency of Trout Management Flows for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

As shown in Figure I-5, trout management flows would be triggered in just under half the alternative long-term strategies. Among the alternative long-term strategies that include trout management flows, the mean number of years during the 20-year LTEMP period in which trout management flows would occur ranges from 2.4 under E6 to 11.0 under Alternative G; the average number ranges between 2 and 4 years under six out of the nine alternative/long-term strategies where trout management flows are allowed.

Figure I-6 shows the frequency of trout management flows under climate change assumptions. A comparison of Figures I-5 and I-6 shows that the frequency distribution pattern is virtually the same for historical and climate change assumptions. On average, the mean value for each alternative/long-term strategy is 0.49 years less under climate change assumptions; this suggests that there would be somewhat fewer trout in the Glen Canyon reach, perhaps a reflection of a drier, warmer future climate.

I.1.4 Mechanical Removal of Trout

Mechanical removal would be implemented by using electrofishing to stun and remove nonnative fish.

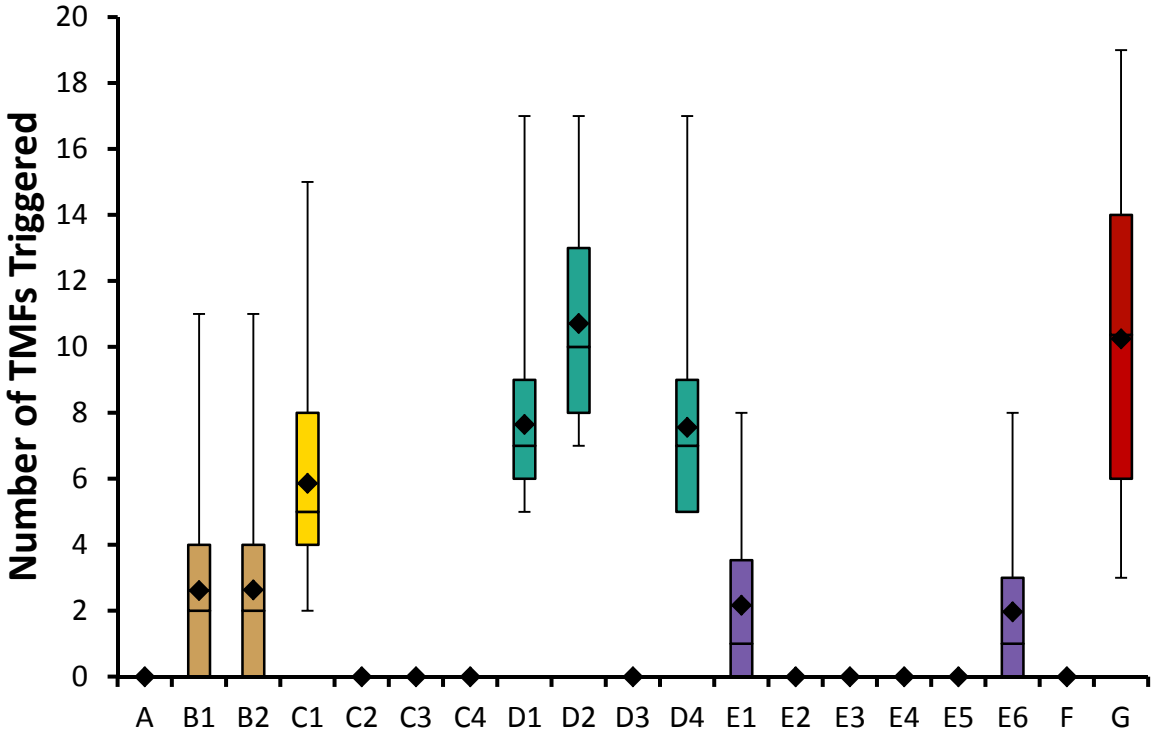

FIGURE I-6 Frequency of Trout Management Flows under Climate Change Assumptions for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

Although this does not kill the fish, usually the removed fish would be euthanized (killed) and put to some beneficial use. For example, in one mechanical removal test, the trout were emulsified and used as fertilizer in the Hualapai tribal gardens (Reclamation 2011). Grand Canyon Monitoring and Research Center (GCMRC) has modeled the number of years in which mechanical removal would be triggered under various alternatives. In the model two factors must coincide to trigger mechanical removal trips: (1) there must be more than 760 adult rainbow trout projected for the test reach in the vicinity of the Little Colorado River confluence (RM 63–RM 64.5), and (2) the projected adult humpback chub population for the canyons must be less than 7,000 individuals.

Figure I-7 shows the projected number of years in which mechanical removal from the Little Colorado River reach would be undertaken. Mechanical removal is not an allowed element of seven alternatives/strategies: Alternative C long-term strategies C1 and C2; Alternative E long-term strategies E1, E2, E5, and E6; and Alternative F. The mean number of years in which mechanical removal is modeled to occur ranges from 0.07 under Alternative A to 3.05 under Alternative G. In general, mechanical removal would be triggered in far fewer years than trout management flows. Modeling indicates that the average maximum number of years in which mechanical removal would be triggered is 6.3 out of 20, the projected maximum under D3. The overall pattern of mechanical removal events would be similar to the pattern of trout management flow occurrences and for similar reasons. Conditions that favor trout production

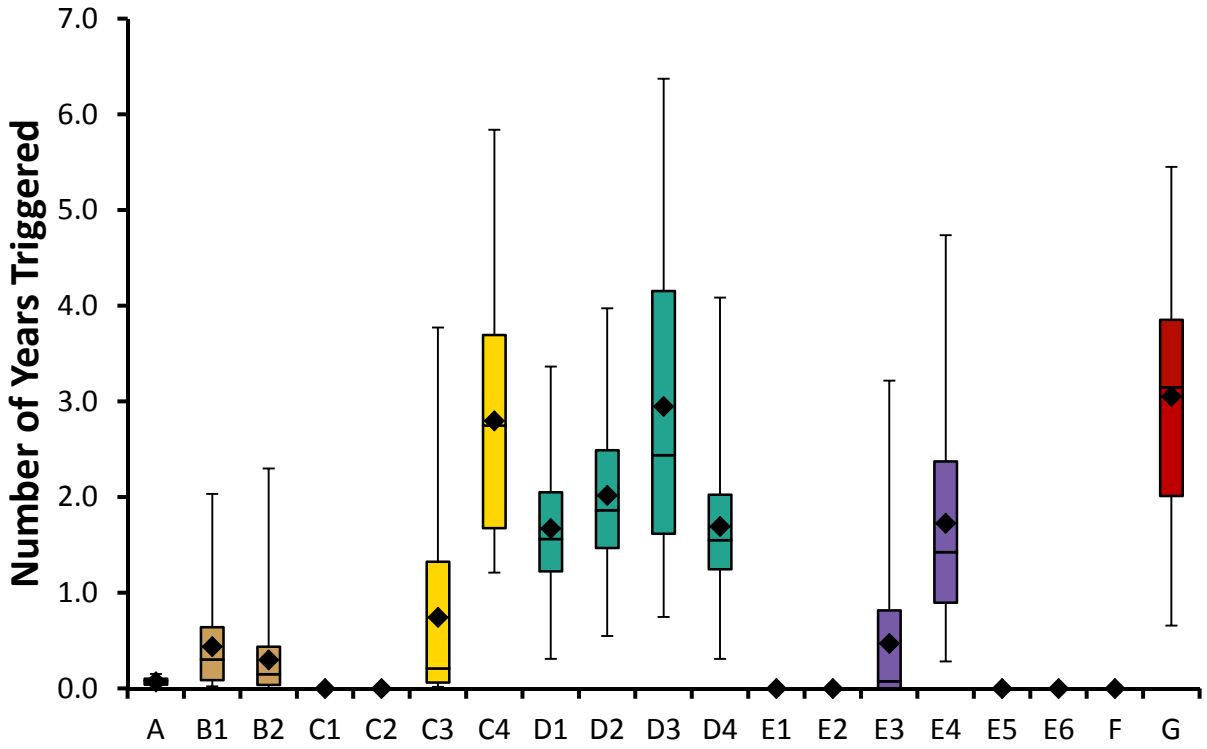

FIGURE I-7 Frequency of Mechanical Removal for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

(spring HFEs and steady summer flows) result in trout population increases in the Glen Canyon reach, thereby increasing the number of trout that move downstream to the Little Colorado River reach and triggering mechanical removal more often.

Figure I-8 shows the frequency of mechanical removal under climate change assumptions. As with trout management flows, the distribution pattern varies very little between the two plots. In all cases except Alternative G there is a slight decline in the mean number of years in which mechanical removal would be triggered. On average, those that score lower under climate change assumptions score 0.13 years less, while Alternative G scores 0.06 years more. This suggests that with the exception of Alternative G, river conditions would be slightly less favorable for trout production under climate change conditions.

I.1.5 Water Levels at Lake Powell

The domestic water supply for the LeChee Chapter of the Navajo Nation is obtained from Lake Powell through pumping and conveyance facilities that were first constructed at the time Glen Canyon Dam was built between 1957 and 1964 (NPS 2009). The current system relies on either an intake on the face of the dam at 3,480 ft above mean sea level (AMSL), or an intake off the penstocks, which are at an elevation of 3,470 ft AMSL at Lake Powell. Therefore, 3,470 ft

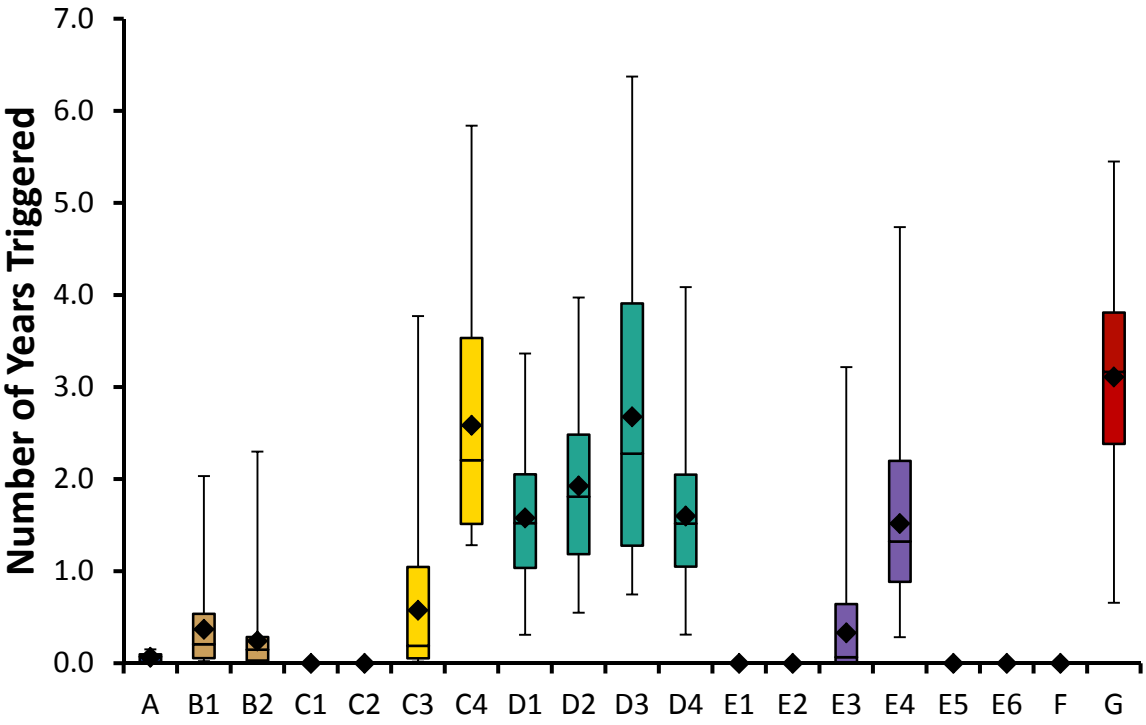

FIGURE I-8 Frequency of Mechanical Removal under Climate Change Assumptions for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

AMSL is the minimum elevation necessary for the LeChee Chapter to draw water from Lake Powell, even while penstock units are down or are undergoing maintenance.

An environmental assessment (EA) done in 2009 addresses possible future construction to provide a backup water supply to the area (NPS 2009). Three designs for new water supply systems from Lake Powell for the City of Page and the LeChee Chapter were evaluated. The EA eliminated two of the designs and narrowed the options to either no action or an entirely new pumping system which calls for six 48-in. intake pipes reaching the lake at an elevation of 3,373 ft AMSL.

The Colorado River Simulation System (CRSS) model was used for the LTEMP process to project future river and reservoir system conditions on a monthly time-step.

Because there are no known restrictions within the model for the intake pipes, an analysis was conducted to identify modeled minimum Lake Powell elevations in order to address concern regarding the LeChee Chapter's ability to draw water under LTEMP. End-of-the-month Lake Powell elevations were created as part of the LTEMP analysis (see Appendix E) for all the different hydrologic and sediment inputs (see Section 4.1 for a presentation of the overall modeling approach). A script within the MATLAB® scripting program was created to retrieve the minimum elevation possible within each alternative.

As shown in Figure I-9, there is little variation projected for Lake Powell water levels among the LTEMP alternatives. The mean water level for Lake Powell under all alternatives and long-term assumptions falls between 3,540 ft AMSL and 3,560 ft AMSL, well above intake elevations. More importantly, the minimum elevation of the lake modeled for all different input combinations and alternatives was 3,480 ft AMSL. This is the same elevation as the intake on the dam face and 10 ft above the elevation of the penstock intakes and well above elevations for any planned future intakes. Although there is always potential for modification of dam operations based on circumstantial conditions, the LeChee Chapter is projected to retain its water supply from Lake Powell under all LTEMP alternatives, with average levels slightly higher under Alternative F than the other alternatives.

As seen in Figure I-10, with the exception of Alternative F, climate change assumptions mean lake elevations are projected to fall just below 3,540 ft AMSL. Mean lake levels under Alternative F would be just above 3,540 ft AMSL. Even under climate change assumptions, minimum lake elevations are never projected to fall below 3,480 ft AMSL and are project to remain at least 10 ft above the minimum required to supply the LeChee Chapter with water. Only under Alternative F would the minimum projected Lake Powell elevation be above 3,490 ft AMSL.

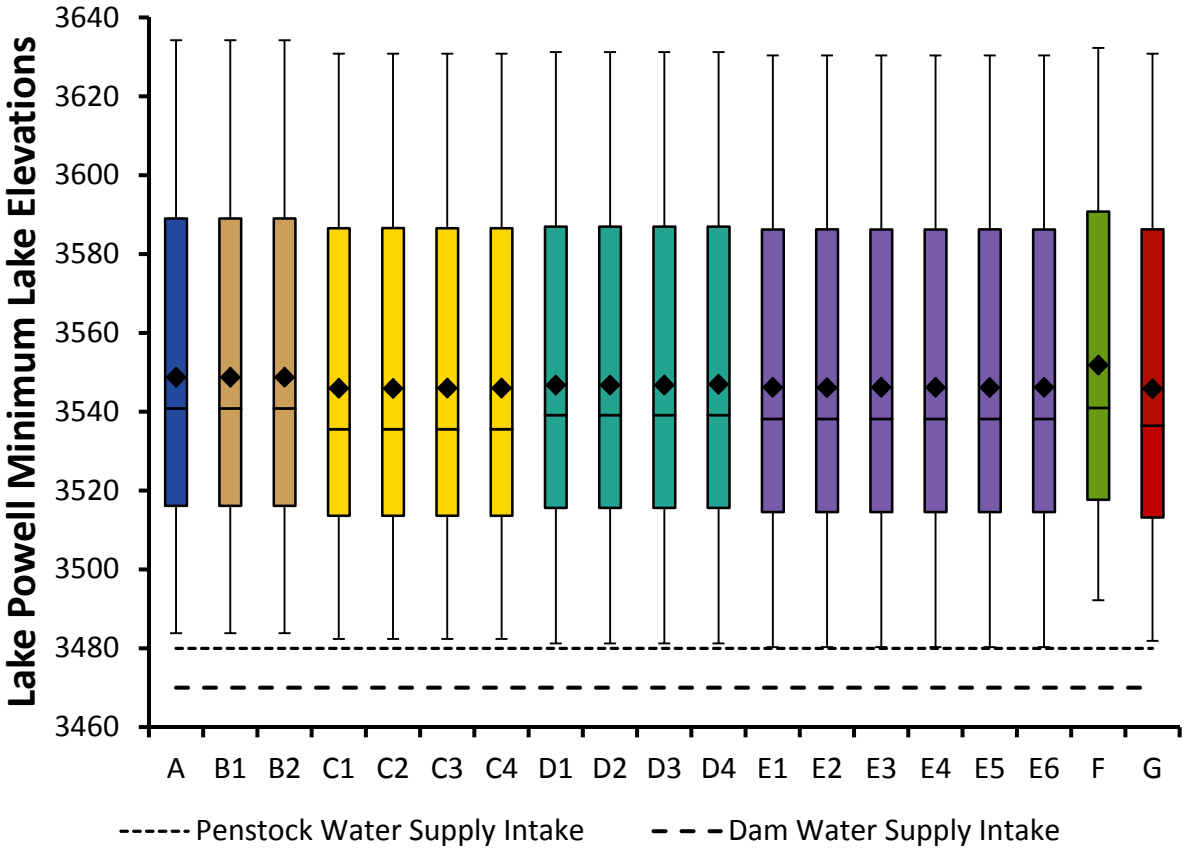

FIGURE I-9 Lake Powell Water Levels for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

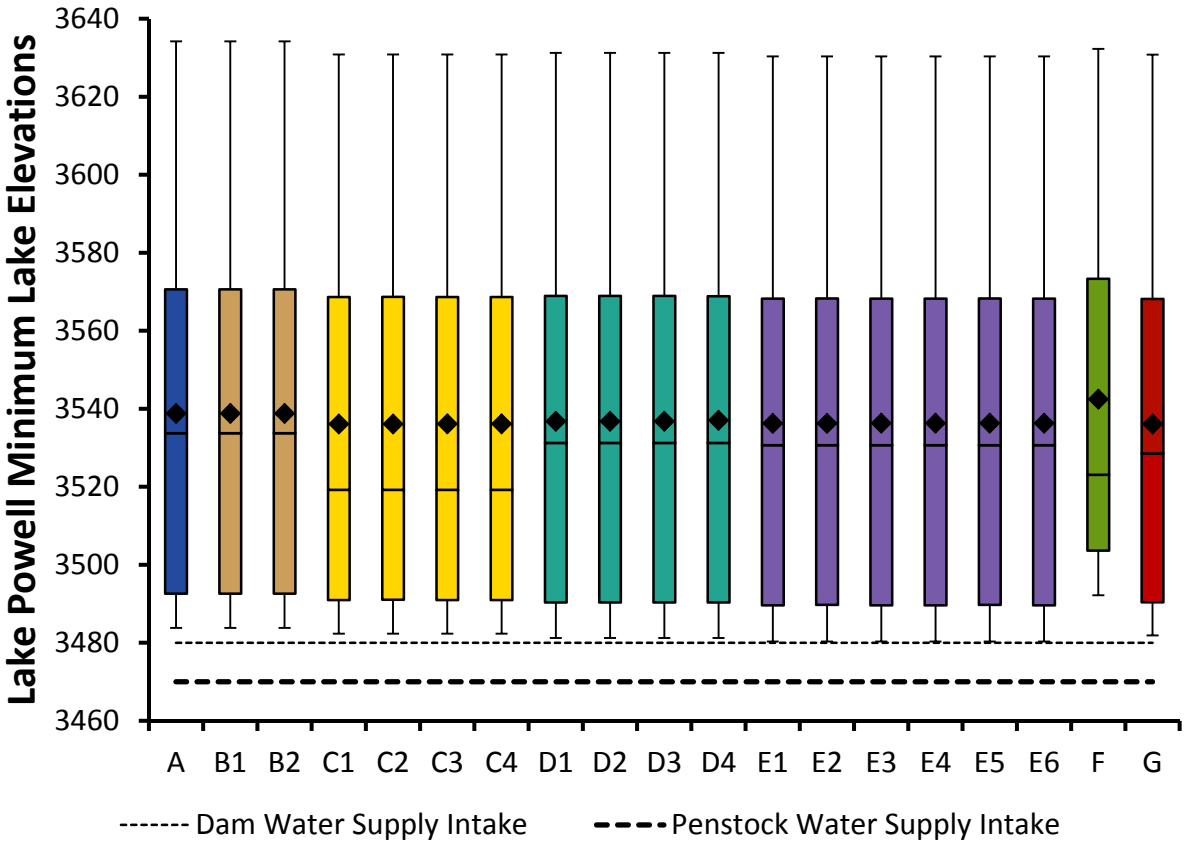

FIGURE I-10 Lake Powell Water Levels under Climate Change Assumptions for the LTEMP Alternatives (Letters) and Associated Long-Term Strategies (Numbers)

I.1.6 Access to Resources

Access to culturally important sites and resources has the potential to be a significant factor in assessing impacts from the alternatives. Resources important to the Tribes include plant resources important for food, medicinal, and ritual purposes; minerals including salt and pigments that are ritually important; and sacred places including springs and offering sites. Potential access interruption is tied to the frequency of HFEs. HFEs could cause temporary loss of access to culturally important resources through inundation of the resources or trails leading to them. These temporary interruptions can be mitigated by communication between Reclamation and the Tribes so that Tribes have notice of impending HFEs. Of the LTEMP alternatives, Alternative F and Alternative G have the most HFEs. Under the latter alternative, there are HFEs that last as long as 2 weeks. Alternative C long-term strategies C1 and C2 have a similar number of HFEs as the steady flow alternatives. Alternative C long-term strategy C4 and Alternative E long-term strategies E1, E2, and E4 have a moderate number of HFEs. Alternative A and Alternative B long-term strategies are projected to have a small number of HFEs (seven or fewer over 20 years). No HFEs are projected for Alternative C long-term strategy C3 or Alternative E long-term strategies E3, E5, and E6.

Potential impacts on archeological sites important to Tribes are discussed in technical Appendix H.

I.2 REFERENCES

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APPENDIX J:

RECREATION, VISITOR USE, AND EXPERIENCE TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX J:

RECREATION, VISITOR USE, AND EXPERIENCE TECHNICAL INFORMATION AND ANALYSIS

The Glen and Grand Canyons of northern Arizona provide a unique experience of extraordinary geologic landscapes, diverse wildlife and vegetation, and over 12,000 years of human history for visitors from across the globe. The area offers a variety of recreational activities including flatwater and whitewater boating, hiking, and angling. This Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) Draft Environmental Impact Statement (DEIS), developed by the Bureau of Reclamation (Reclamation) and the National Park Service (NPS), has identified the recreational experience goal as being to "maintain and improve the quality of recreational experiences for the users of the Colorado River ecosystem. Recreation includes, but is not limited to, flatwater and whitewater boating, river corridor camping, and angling in Glen Canyon" (Section 1.4). Past recreational studies have shown that Glen Canyon Dam operations can affect the experience of recreationalists in the downstream Glen and Grand Canyons (Bishop et al. 1987; Hall and Shelby 2000; Stewart et al. 2000; Roberts and Bieri 2001). In an effort to quantitatively assess the downstream impacts on recreational activities of the LTEMP alternatives, six performance metrics were created to address recreational concerns. This appendix explains the metrics and compares the performance of the LTEMP alternatives as indicated by the metrics.

The alternatives encompass 19 long-term strategies, which include various combinations of experimental components (Appendix C). A full range of potential hydrologic and sediment conditions were modeled for the 20-year LTEMP period. Twenty-one potential Lake Powell in-flow scenarios (known as hydrology traces) for the 20-year LTEMP period were used to generate twenty-one 20-year hourly release patterns for each alternative and long-term strategy. In addition to these twenty-one hydrology traces, three 20-year sequences of sediment inputs from the Paria River sediment record were analyzed that represented low, medium, and high sediment conditions. In combination, the twenty-one hydrology traces and three sediment traces resulted in an analysis that considered sixty-three possible hydrology-sediment conditions.

In the presentation of results below, LTEMP alternatives are identified by the alternative letter designation (Alternatives A through G) and, if the alternative includes multiple long-term strategies, a number designation (1 through 6, depending on the number of long-term strategies for an alternative) that denotes a particular long-term strategy within an alternative. See Appendix C for descriptions of the long-term strategies.

J.1 RECREATIONAL EXPERIENCE METRICS

The analysis of potential impacts on recreational experience is based primarily on the evaluation of six quantitative metrics that were developed for the assessment, but also on more qualitative information and experience of GCNRA and GCNP staff and on the studies that served as the basis for quantitative metrics. The metrics were developed through consultation with

subject matter experts, findings in published papers and reports, and with consideration of comments from the Cooperating Agencies.

J.1.1 Grand Canyon Metrics

Of the six evaluation metrics, four address issues important to visitor use and experience in Grand Canyon National Park (GCNP) downstream of Lees Ferry, while the remaining two metrics address the Glen Canyon reach between the dam and Lees Ferry. The metrics are:

- *Camping Area Index:* Accounts for optimal campsite area building and maintenance flows and sediment load (also used as input to the assessment of campsite crowding).

- *Navigational Risk Index:* Measure of navigation difficulty based on the number of days during which the daily minimum flow was less than 8,000 cfs (also used as input to the assessment of campsite crowding and encounters with other groups).

- *Fluctuation Index:* Measures the degree to which combinations of flows and fluctuations are within a range identified as preferable by experienced boat guides.

- *Time Off River Index:* Relates the level of flows to visitors being able to spend time ashore visiting attractions.

J.1.2 Glen Canyon Metrics

- *Glen Canyon Rafting Metric:* Estimates the number of visitors unable to participate in day rafting in Glen Canyon due to high flows.

- *Glen Canyon Inundation Metric:* Accounts for flows that impact recreational sites and recreational uses within the Glen Canyon reach.

Some of the metrics evaluate non-tangible, qualitative aspects of the recreational experience. Such metrics may be based on results of recreational surveys of visitor experience under various flow and fluctuation conditions, which overlap dam operations under LTEMP alternatives (Hjerpe and Kim 2001). These and other metrics used in the analyses and described elsewhere in this DEIS (see Appendices B and C) based on relative performance are expressed as an index having values from 0 to 1, where increasing values indicate increasing performance with respect to the associated resource goal. Metrics employing an index include the Camping Area Index (CAI), Navigational Risk Index (NRI), the Fluctuation Index (FI), the Time Off River Index (TORI), and the Glen Canyon Inundation Metric (GCIM). The Glen Canyon Rafting Metric (GCRM) is the only metric that uses an absolute scale. It is the number of potential lost

visitor trips for day-use rafts in Glen Canyon due to high flows during high-flow experiments (HFEs).

The metrics all rely on the hourly Glen Canyon Dam discharge computed by the GTMax-Lite model (Reclamation 2007) with the incorporation of a sediment analysis (Russell and Huang 2010) to account for HFE implementation (Appendix E). GTMax-Lite produces a trace (20 years of hourly discharge) for each combination of hydrology and tributary sediment traces input into the model. For each metric, all 7 alternatives and any associated long-term strategies were analyzed for all 63 traces (see Section 4.1 for more detail). The following sections explain the calculation of recreation metrics for an individual trace.

In all metrics but the GCRM, the index value is weighted to emphasize seasons with greater recreational use over the course of a year. Percent of annual recreation use was determined to be 15% in the winter months of November, December, January, and February; 31% in the spring and fall months of March, April, September, and October; and 54% in the summer months of May, June, July, and August (based on monthly visitation statistics presented in https://irma.nps.gov/Stats/Reports/Park/GRCA).

J.2 METRIC DEFINITIONS, ANALYSIS METHODS, AND RESULTS

J.2.1 Camping Area Index

Campsites are primarily located on sandbars along the shoreline of the river, and they provide open, flat areas ideal for camping. Crucial for multi-day trips, campsites can limit the visiting capacity (the number of people to maintain a desired natural visitor experience) for high-demand downstream rafting trips (Kearsley et al. 1994). The management of campsites is therefore of particular concern to river managers (NPS 2006). To meet the visitor capacities established in the NPS Colorado River Management Plan, it is necessary to develop and retain medium (16–25 people) and large (>25 people) campsites, which maintain and potentially improve visitor experience based on preferences expressed in surveys of visitors. Commercial and private trip leaders preferred large beaches for camping compared to smaller beaches (Stewart 2000). A study by Kaplinski and others monitoring campsites from 1998 to 2012 reported a decrease of average campsite area by 36% with any decrease in area noted at 29 out of the 37 study sites (Kaplinski et al. 2014).

Dam operations have been shown to have significant effects on campsite area. HFEs have proven to temporarily increase campsite area due to sandbar deposition (Grams et al. 2010; Hazel et al. 2010). In the Grand Canyon Monitoring and Research Center (GCMRC) *Fiscal Year 2014 Annual Project Report* (GCMRC 2015), Kaplinski and others concluded, “sandbar deposition associated with high flows results in increases in campsite area, while post-HFE erosion causes decreases in campsite area.” Currently, it is perceived that lower discharge reduces erosion to campsites, while also exposing campsites that are covered at higher discharges. A decrease of discharge from 25,000 cfs to 15,000 cfs during normal flows increased

campable area by 73%; a further increase of 46% in campable area was seen when discharges further decreased to 8,000 cfs (Kearsley and Warren 1993).

J.2.1.1 Camping Area Index—Methods

The Camping Area Index (CAI) evaluates the conditions conducive to increased camping area in the Grand Canyon, which is a function of the amount of sand deposited and retained and campsite area exposure as a function of river level (flow rate). The output from the Sand Load Index (SLI), which simulates sediment conditions between RM 0 and 30 provides a proxy for indicating whether the alternatives are likely to create the conditions conducive to creating/retaining campsite area (Appendix E). The CAI is the product of the SLI and a Seasonally Weighted Flow Factor (SWFF):

$$CAI = Average(SWFF)_{2014-2033} \times SLI$$

Both the SLI and SWFF are indices ranging from 0 to 1, as is the resulting CAI, where a value of 1 indicates the greatest potential to increase camping area. As the metric output is a generalization of sediment conditions throughout the canyon, it does not predict conditions at any particular site. Erosion is not taken into account in the CAI. Daily flow level is accounted for in the SWFF, as discussed below. Lower flows provide more camping area (i.e., there is more camping area at 8,000 cfs than at 25,000 cfs because more sand is exposed at lower flows [Kearsley and Warren 1993]). The minimum flow within the daytime period (7 am to 7 pm) is 8,000 cfs under most LTEMP alternatives.

The SLI is an index of the potential sand deposited on sandbars along the river channel in Marble and Grand Canyons above normal stage elevations (31,500 cfs). The SLI is calculated as the ratio of the cumulative sand load at flows greater than 31,500 cfs relative to the total cumulative sand load at all flows modeled (Appendix E). The sand load, or the mass of sand in transport by the river, is calculated at RM 30 and is computed by a version of the Sand Budget Model (Wright et al. 2010) for the 20-year LTEMP period. A larger SLI (on a scale of 0–1), indicates a greater potential for sediment deposition. The SLI was calculated using the following equation:

$$SLI = \frac{\sum_{2014-2033} Sand\ Load\ at\ dam\ discharges > 31{,}500\ cfs}{\sum_{2014-2033} Sand\ Load\ at\ all\ dam\ discharges}$$

The SWFF is a yearly value representing the relative amount of river bank exposure available for camping areas dependent on the Glen Canyon discharge. Low river flows will expose more campsite area while higher flows will submerge campsite area and potentially cause erosion (Kearsley and Warren 1993). Flows above 8,000 cfs are considered to increasingly reduce camping area and to submerge most campsite areas at 31,500 cfs. Camps above 25,000 cfs are considered high campsites in Kaplinski (2014). With no data on the exact location of all campsites relative to the river, an informed assumption is made here. The daily maximum flow is used to evaluate the extent to which flows may cover campsites at any point in the day.

Modeled daily flows are assigned a 0–1 index value, referred to as the daily flow factor (FF_{Daily}):

$$FF_{Daily} = \begin{cases} \text{if } Q_{max} \leq 8{,}000 \text{ cfs}; & 1 \\ \text{if } 8{,}000 < Q_{max} < 31{,}500\ cfs; & 1.34 - 0.0000425 \times Q_{max} \\ \text{if } Q_{max} \geq 31{,}500 \text{ cfs}; & 0 \end{cases}$$

where Q_{max} refers to the daily maximum discharge released from the Glen Canyon Dam in cfs and FF_{Daily} is equal to the value in the right column if the equation in the left column is satisfied.

The yearly index value (SWFF) is the ratio of the index values for each season:

$$\text{SWFF} = \left\{0.15\left(\frac{\sum_{\text{winter}} FF_{daily}}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{\text{spring\&}fall} FF_{daily}}{\sum Days_{spring\&fall}}\right) + 0.54\left(\frac{\sum_{\text{summer}} FF_{daily}}{\sum Days_{summer}}\right)\right\}$$

J.2.1.2 Camping Area Index—Results

CAI values for all 19 LTEMP long-term strategies are shown in Figure J-1. All of these have higher CAI values than Alternative A (no-action alternative). Long-term strategies B2, C3, E3, E5, and E6 rank below Alternative A. With the exception of B2, HFEs are not conducted for these long-term strategies, and therefore flows above 31,500 cfs, the primary mechanism for sediment deposition, occur rarely, if at all. Experimentally increased flow fluctuations (hydropower improvement flows) under B2 cause it to rank below Alternative A.

The CAI is fairly insensitive to SWFF because SWFF values typically range only between 0.55 and 0.77. Consequently, the CAI is strongly dependent on the SLI, and therefore to the number of HFEs under a given alternative or long-term strategy (see Appendix E). The strong dependence of CAI on SLI can be seen by comparing Figure J-1 and Figure J-2.

Alternative G has the highest CAI, a value 3.2 times that of Alternative A. This result is attributed to the highest number of HFEs and relatively even year-round daily flows under Alternative G, conditions conducive to conserving sediment and increasing camping area through deposition and retention of sediment. Ranking second-highest, Alternative F, with a CAI 2.9 times that of Alternative A, has low flows in non-summer months and more 96-hour HFEs than other long-term strategies.

Long-term strategy B2 has a slightly reduced CAI compared to B1 attributable to testing of hydropower improvement flows under B2, which reduces CAI through reductions in both SLI and SWFF. The CAI for long-term strategy C4 is reduced relative to that for C1 and C2 due to the absence of spring HFEs and proactive spring HFEs under C4, which reduces its SLI value. C3 is much reduced owing to the absence of spring or fall HFEs, as noted above.

The CAI for long-term strategy D4 is not significantly different from D1, D2, D3, or C1, based on a test of differences between means using a three-factor analysis of variation (ANOVA)

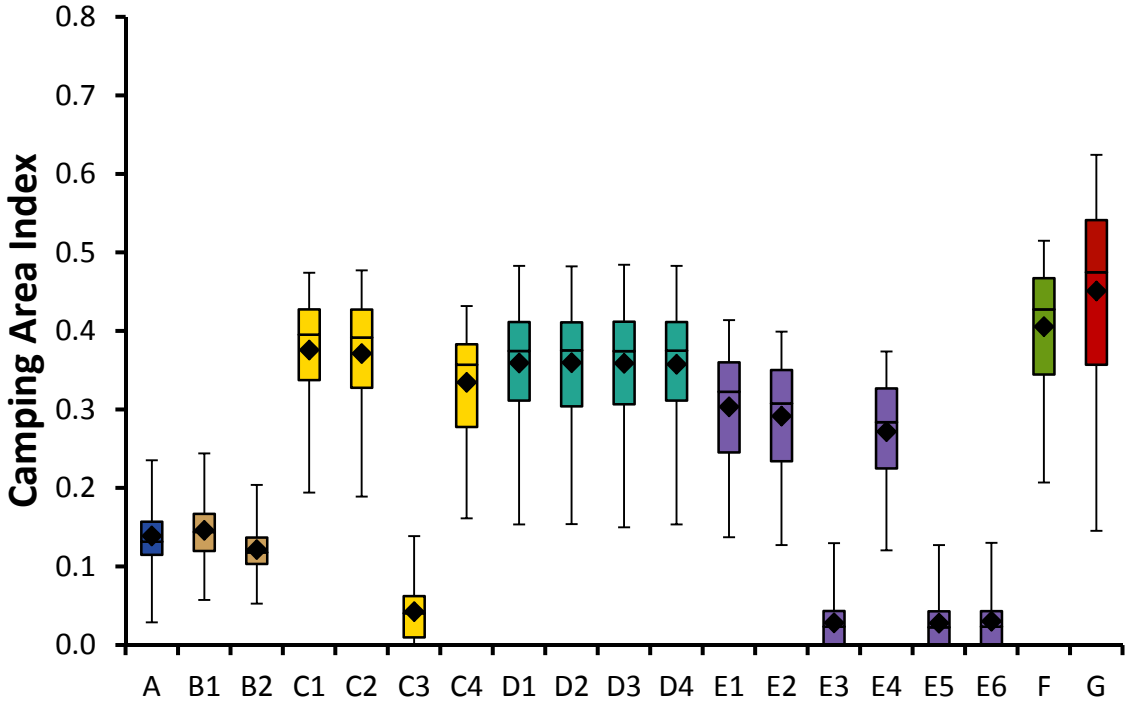

FIGURE J-1 Camping Area Index for LTEMP Long-Term Strategies (Increasing values indicate increasing camping area. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

followed by Tukey's Studentized Range Test. This indicates that low summer flows under D1, D2, and D3 have no effect on CAI, nor does sustained low flows for benthic invertebrate production under D2 or the absence of trout management flows under D3.

The CAI for long-term strategy E4 is slightly lower than that for E1 and E2, indicating a small reduction in sediment retention for E4 due to the absence of spring HFEs in the second 10 years of the LTEMP period, which are conducted under E1 and E2. As noted above, E3, E5, and E6 do not include spring or fall HFEs, explaining their low CAI values.

J.2.2 Navigational Risk Index

Navigating the Colorado River downstream of Glen Canyon Dam at low flows, especially at rapids, can cause difficulties for oar and motor trips. A survey conducted by Bishop et al. (1987) of commercial oar and motor guides indicated that flow levels below 9,200 cfs and 8,400 cfs, respectively, began to compromise boater safety. In the Bishop et al. (1987) study, guides were simply asked for minimum levels of flow for running safely with passengers. Survey respondents noted that at these flows, boat accidents related to exposed rocks are much more probable. A similar survey by Shelby et al. (1992) reported nearly the same

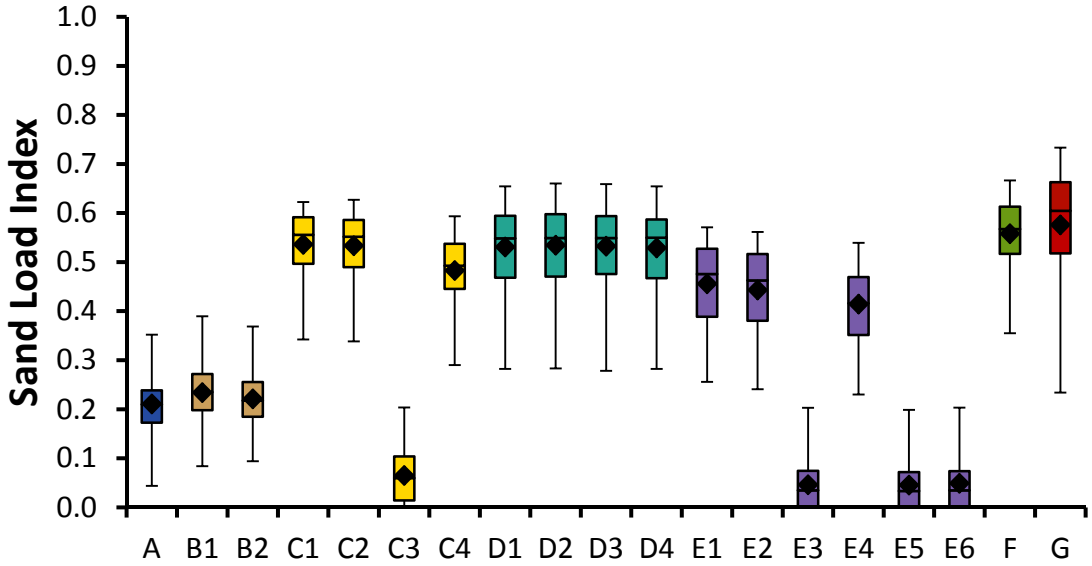

FIGURE J-2 Sand Load Index (see Appendix E) for LTEMP Long-Term Strategies (Increasing values indicate more sediment deposited along river banks. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

values as Bishop et al. (1987), and a more recent survey by Stewart et al. (2000) had similar findings with oar and motor river guides identifying approximately 8,100 cfs and 7,800 cfs, respectively, as minimum flows for what they considered safe river trips. Exposures to experimental low flows of 8,000 cfs in the summer of 2000 further supported the guides' perceptions of potentially dangerous flows, with double the number of boating accidents reported than the previous year, mostly associated with hitting exposed rocks (Ralston 2011).

J.2.2.1 Navigational Risk Index—Methods

To assess the risk due to difficulties of motor rigs navigating rapids at lower flows, the risk (frequency) of daily minimum discharges that are ≤8,000 cfs was determined for each season. To account for the variance in use between the seasons, the yearly value is averaged with weights corresponding to recreational use as used above for SWFF in calculating the CAI. The annual risk was calculated as:

$$Risk = \left\{ 0.15 \left(\frac{\sum_{\text{winter}} Days_{min}}{\sum Days_{winter}} \right) + 0.31 \left(\frac{\sum_{\frac{\text{spring}}{\text{fall}}} Days_{min}}{\sum Days_{\frac{spring}{fall}}} \right) + 0.54 \left(\frac{\sum_{\text{summer}} Days_{min}}{\sum Days_{summer}} \right) \right\}$$

where $Days_{min}$ is the number of days when flows were <8,000 cfs, $Days_{winter}$ is the number of days in the winter, $Days_{spring/fall}$ is the number of days in the spring and fall, and $Days_{summer}$ is the number of days in the summer.

The index is the complement of the risk, where 1 indicates 100% of minimum daily flow above 8,000 cfs and is therefore the least risk to river navigators. Thus, the NRI for a single input trace for the LTEMP period of 2014–2033 is as follows:

$$NRI = Average(1 - Risk)_{2014-2033}$$

While Alternatives A through E restrict minimum flows to 8,000 cfs during day hours (7 am to 7 pm), flows during night hours (7 pm to 7 am) can drop to 5,000 cfs, and these low flows can affect downstream boaters during daylight hours well after the change in discharge rate occurs at the dam due to the transit time required for the change to reach downstream locations. The calculation of daily minimum flow was therefore inclusive of the entire 24-hour period.

J.2.2.2 Navigational Risk Index—Results

NRI values for each alternative are shown in Figure J-3. Long-term strategies C1–C4, D2, F, and G have higher values than Alternative A, while D1, D3, and D4 are only slightly lower than Alternative A. Long-term strategy B2 has the lowest NRI value owing to high flow fluctuations and low minimum flows, while B1 and E1–E6 are also lower than Alternative A.

Alternative G has year-round steady flows of approximately 11,000 to 13,000 cfs, rarely dipping below 8,000 cfs, resulting in an NRI approaching 1 (lowest risk). Alternative F, which also has steady daily flows, has high flows in the months of February through June and lower flows running near or below 8,000 cfs in July through January. However, for the historic water volumes modeled (typically greater than 8.23 maf), higher releases would sometimes occur for equalization purposes at the end of the water year. Primarily for this reason, the average days with flows above 8,000 cfs actually outnumber the days below it for Alternative F. On average, Alternative F has an NRI almost 1.5 times that of Alternative A.

For alternatives with fluctuating flows, the size of daily fluctuations generally differentiates between alternatives, while experimental features drive differences between long-term strategies within alternatives. Daily fluctuations under Alternative C are lower than those under Alternatives A, D, E, and B, resulting in fewest occurrences of flows less than 8,000 cfs and the highest NRI value (lowest risk) of the fluctuating-flow alternatives. The relative ranking of these alternatives in Figure J-3 generally reflects the size of daily fluctuations, which determines the frequency of flows less than 8,000 cfs.

Within alternatives, long-term strategy B2 has a lower NRI (higher risk) than B1 due to high fluctuations and flows less than 8,000 cfs associated with experimental hydropower improvement flows not included in B1. For the same reasons, B2 has the lowest NRI (highest risk) of all long-term strategies. C2 has a slightly lower NRI than C1, C3, and C4 due to the

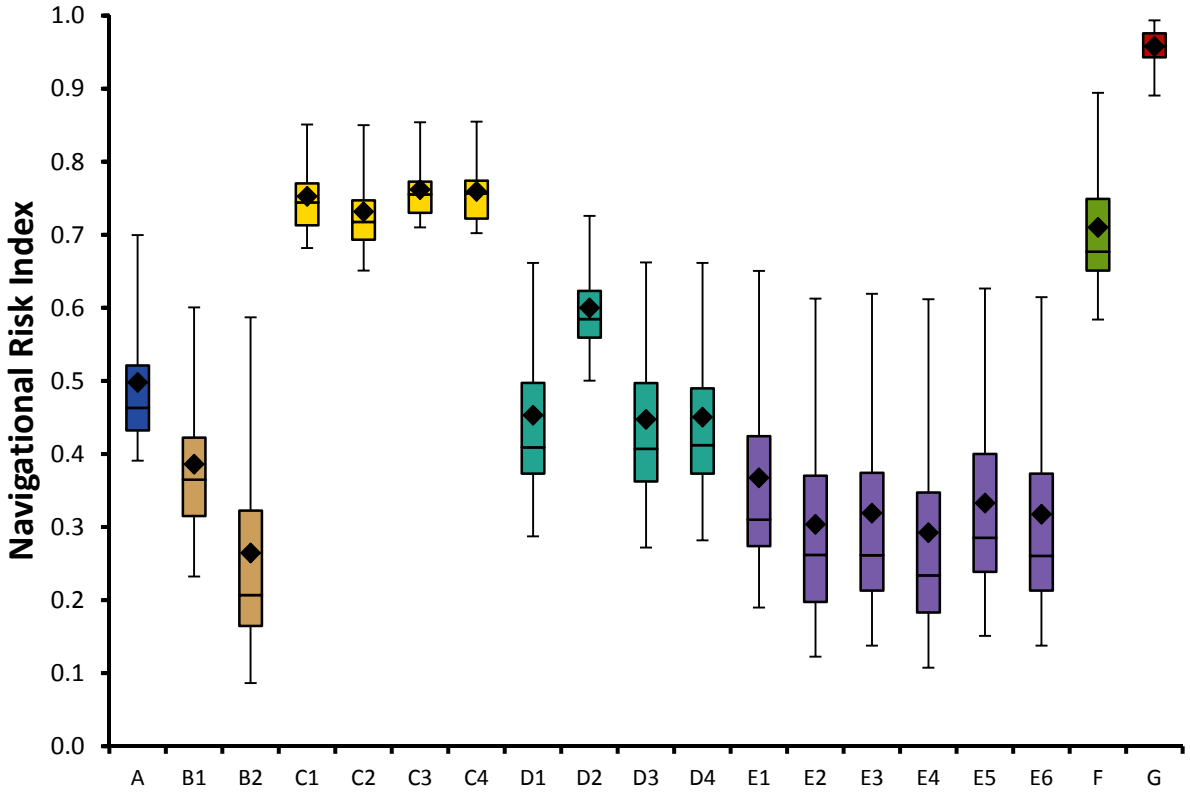

FIGURE J-3 Navigational Risk Index Values for the LTEMP Long-Term Strategies (Increasing values indicate improving navigation conditions. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

inclusion of low summer flows, which allows minimum daily flows as low as 5,000 cfs. Low weekend flows to promote benthic invertebrate production during May–August under long-term strategy D2 increase the overall minimum flow during those months, elevating the NRI relative to D1, D3, and D4. Absence of low summer flows under E1, E3, E4, and E6 elevates the NRI for these long-term strategies slightly compared to E2 and E5.

J.2.3 Fluctuation Index

Whitewater rafting guides surveyed by Bishop et al. (1987) indicated that moderate (8,000–25,000 cfs) and severe (1,000–33,500 cfs) daily fluctuations are potentially problematic for rafting trips. Fluctuations can complicate mooring at campsites, and running rapids, and can increase the unpredictability of flows. Bishop et al. surveyed guides and private trip leaders with experiences of both large fluctuations (greater than 15,000 cfs) and steady flows and documented the ranges of tolerable fluctuations at various river flow levels, as shown in Table J-1.

TABLE J-1 Reported Mean Tolerable Daily Changes in Flow Levels for Commercial Motor Guides, Commercial Oar Guides, and Private Trip Leaders[a]

River flow (cfs)	Tolerable Fluctuations (cfs)
5,000–8,999	2,400–*3,400*[b]
9,000–15,999	3,900–*4,800*
16,000–31,999	6,400–*7,200*
32,000 and up	7,900–*9,800*

[a] Table modified from Table 4-7 of Bishop et al. 1987.

[b] Italicized values indicate the maximum tolerable fluctuation threshold used in the Fluctuation Index.

J.2.3.1 Fluctuation Index—Methods

Table J-1 is the basis for the Fluctuation Index (FI). It is assumed that (1) the river flow ranges shown in the left-hand column of Table J-1 are based on the mean daily flow and that (2) the maximum tolerable fluctuation threshold (italicized flow values in Table J-1) serves as the level above which fluctuations become increasingly more unacceptable to river users.

A daily flow factor (FF) value of 0–1 was computed using Table J-1 and the mean flow for a given day. The daily flow factor is 1 if the fluctuations are within the acceptable range. Above the threshold, daily FF goes linearly to zero as the fluctuation increases to 10,000 cfs. Daily fluctuation levels greater than 10,000 cfs are clearly noticeable and have strong adverse effects on river users (Bishop et al. 1987). The daily FF is computed as follows, where Q_{avg} is the daily mean flow, Q_{range} is the daily fluctuation, and Q_{tol} is the tolerable fluctuation threshold:

$$FF_{daily} = \begin{cases} \text{if } Q_{range} \leq Q_{tol} & 1 \\ \text{if } Q_{range} > Q_{tol} & \\ \quad where\ 5{,}000 < Q_{avg} < 8{,}999 & 1.515 - (0.00015 \text{ x } Q_{range}) \\ \quad where\ 9{,}000 < Q_{avg} < 15{,}999 & 1.923 - (0.00019 \text{ x } Q_{range}) \\ \quad where\ 16{,}000 < Q_{avg} < 31{,}999 & 3.571 - (0.00036 \text{ x } Q_{range}) \\ \quad where\ Q_{avg} > 32{,}000 & 50 - (0.005 \text{ x } Q_{range}) \end{cases}$$

The annual FI is the sum of daily FFs weighted by season according to recreational use, with seasonal weights being the same as for the NRI:

$$FI_{annual} = \left\{0.15\left(\frac{\sum_{winter} FF_{Daily}}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{spring/fall} FF_{Daily}}{\sum Days_{spring/fall}}\right) + 0.54\left(\frac{\sum_{summer} FF_{Daily}}{\sum Days_{summer}}\right)\right\}$$

An overall annual mean index value for the 20-year modeling period was calculated as follows:

$$FI = Average\ (FI_{annual})_{2014-2033}$$

J.2.3.2 Fluctuation Index—Results

The results of the FI are shown in Figure J-4. Differences between alternatives reflect differences in levels of daily flow fluctuations under the respective operational regimes. Alternatives F and G have FIs approaching 1 due to the absence of daily fluctuations; G is slightly lower, as it includes trout management flows in years when trout recruitment is high. Alternatives C, A, D, E, and B have rankings in order of increasing levels of daily fluctuations.

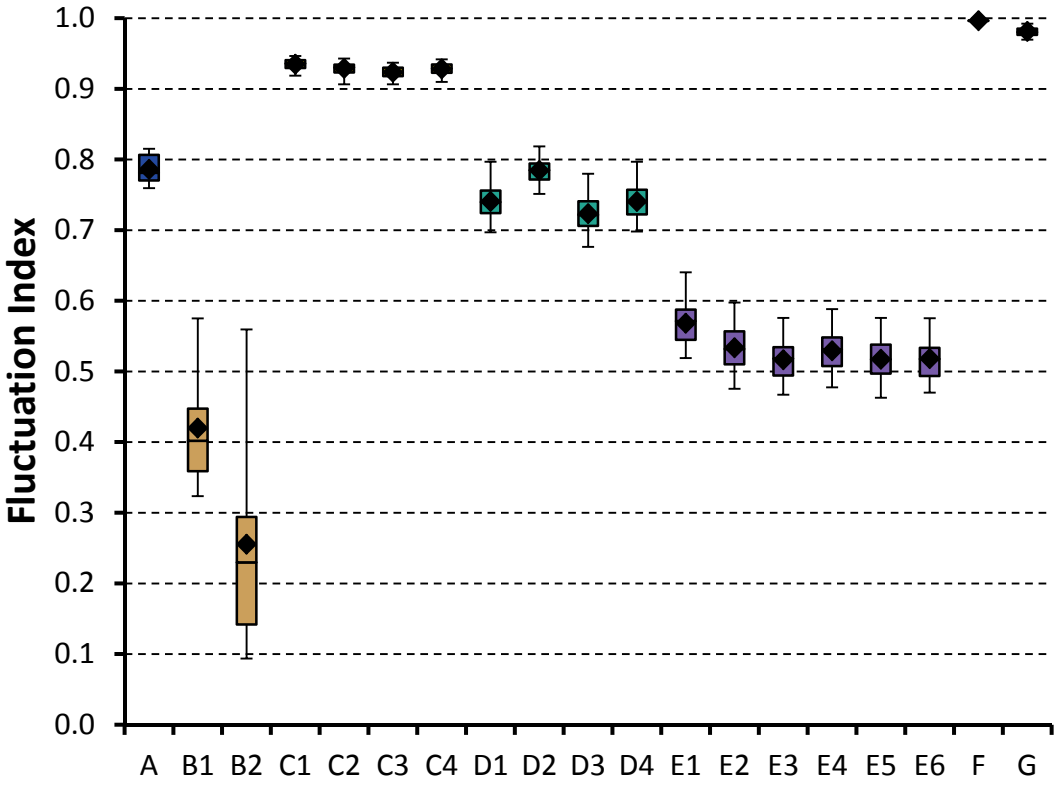

FIGURE J-4 Fluctuation Index for LTEMP Long-Term Strategies (Increasing values indicate more days have tolerable fluctuation levels. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

Alternative A and all long-term strategies under Alternatives C, D, and E have average index values above 0.5, indicating a high proportion of daily fluctuations that are within the tolerable range. Long-term strategy B1 has an annual FI value roughly half that of Alternative A, while B2 has a value roughly a third of Alternative A. Tests of hydropower improvement flows, particularly during highly weighted summer months, reduce B2 relative to B1, while high fluctuation levels overall contribute to low FI values for B1 and B2. Steady, low weekend flows to promote benthic invertebrate production during May through August elevate the FI for D2 relative to D1, D3, and D4. The slightly higher FI values for long-term strategies E1 and E2 relative to E3–E6 can be attributed to the inclusion of both spring and fall HFEs in EI and E2. Water released for HFEs is not available for load following, thus reducing fluctuations and raising the FI. Likewise, E4, which includes fall but no spring HFEs, has a slightly elevated FI compared to E3, E5, and E6, which have no HFEs.

J.2.4 Time Off River

For rafting visitors, time off river to visit attractions and for other activities is important to the recreational experience (Stewart et al. 2000). Low river flows reduce travel speed for boats. Below a flow of about 10,000 cfs, there may be problems getting to camp on time and not enough time for stops at scheduled locations (Shelby et al. 1992).

J.2.4.1 Time Off River Index—Methods

The Time Off River Index (TORI) is computed using a daily flow factor (FF), which is an index from 0 to 1 that uses a flow threshold of 10,000 cfs. The daily FF is computed as follows, where the value within the brackets in the right column is assigned to the FF if the equation in the left column is satisfied, and where Q_{avg} is the average daily discharge:

$$FF_{Daily} = \begin{Bmatrix} \text{if } Q_{avg} \leq 10{,}000; & 0 \\ \text{if } 10{,}000 < Q_{avg} < 31{,}500; & 0.0000465 \times Q_{avg} - 0.465 \\ \text{if } Q_{avg} \geq 31{,}500; & 1 \end{Bmatrix}$$

The annual TORI is the sum of the weighted seasonal index values. The seasonal index is the mean of the FF for all days within a given season, as above for NRI and FI:

$$TORI_{annual} = \{0.15\left(\frac{\sum_{winter} FF_{Daily}}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{spring/fall} FF_{Daily}}{\sum Days_{\frac{spring}{fall}}}\right) + 0.54\left(\frac{\sum_{\text{summer}} \text{FF}_{\text{daily}}}{\sum Days_{summer}}\right)\}$$

An overall annual mean index value for the 20-year modeling period was calculated as follows:

$$TORI = Average\ (TORI_{annual})_{2014-2033}$$

J.2.4.2 Time Off River Index—Results

Figure J-5 shows the TORI results for all long-term strategies. TORI values for all of the long-term strategies have similar mean and quartile values, due to similar average flows among the alternatives. The exception is the TORI for Alternative F, which is notably higher than for other alternatives. This difference is largely due to elevated flows during March–June under Alternative F, which falls within moderately to highly weighted seasons in the annual TORI computation. Figure J-6 shows elevated average daily discharge rates during March–June for Alternative F relative to the other alternatives. For all other long-term strategies, there would be negligible differences in time off river from current conditions.

J.2.5 Glen Canyon Rafting Use

Day-rafting trips in Glen Canyon are a popular visitor attraction of Glen Canyon National Recreation Area. These day-rafting trips regularly run as full-day, half-day, and rowed trips during March 1 to December 1. Glen Canyon rafting trips are not sensitive to flow levels (Bishop et al. 1987) and can generally operate during all releases up to powerplant capacity

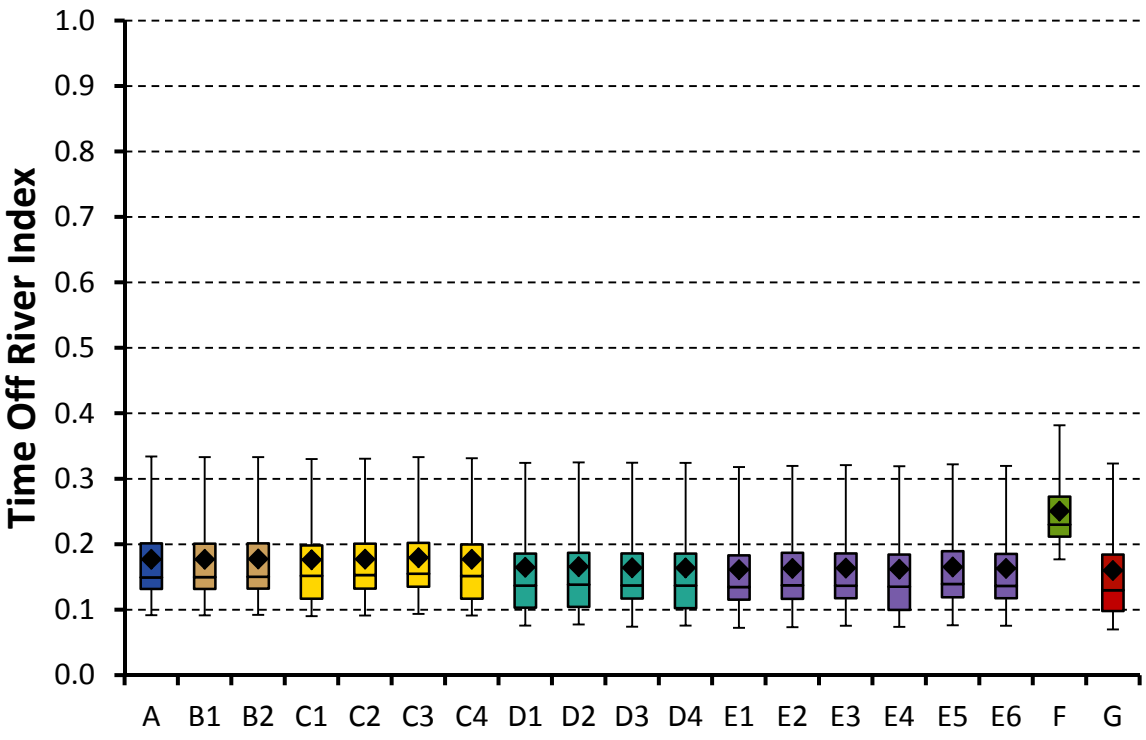

FIGURE J-5 Time Off River Index for LTEMP Long-Term Strategies (Increasing values indicate more time off river. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

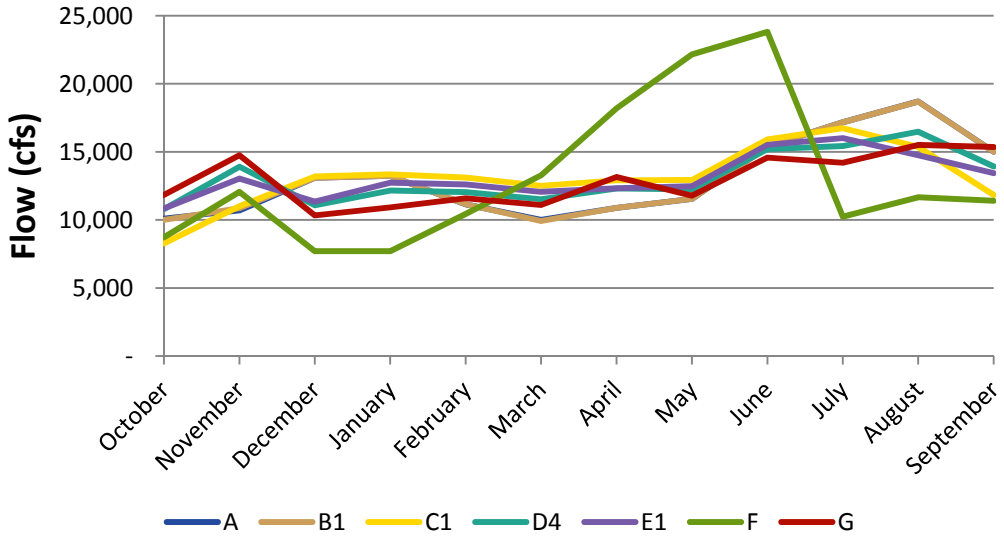

FIGURE J-6 Average Daily Discharge for All Modeled Traces and Years under LTEMP Alternatives

(31,500 cfs). However, when HFEs are run and the bypass tubes are activated, the turbulence at the loading dock is too great to safely load passengers and the commercial operator, Colorado River Discovery, ceases day-use rafting operations (Grim 2012).

J.2.5.1 Glen Canyon Rafting Use Metric—Methods

The Glen Canyon Rafting Use Metric (GCRM) represents the number of visitors unable to take day-rafting trips due to HFEs. Monthly passenger logs for Colorado River Discovery from 2011 to 2012 (Blais 2014) were used to estimate the number of daily passengers (*ADV*) for the months in which HFEs occur (March, April, May, October, and November). Data from 2013 was available but was not included because roadway closures that year potentially impacted visitor numbers. HFEs in spring and fall are possible each year. Estimates of the average daily rafting visitor count for lost trips from spring and fall HFEs are approximately 155 and 68, respectively. Thus, spring HFEs would have a much greater impact than fall HFEs due to higher rafting use in spring (more than double the passengers affected for a given HFE duration).

HFEs require day-raft concessioners to pull the boats from the water or relocate them. Therefore, the number of days lost for Glen Canyon rafting because of an HFE (*D*) is equal to the HFE duration plus 2 days prior and 2 days post HFE ($D = T_{HFE} + 4$ days) required to de-mobilize and re-mobilize rafting operations. The total number of lost rafting days (*D*) is multiplied by the estimated visitors per day (*ADV*) to calculate the number of passengers unable to raft due to an HFE. Note that, unlike the other recreation metrics in this appendix, the Glen Canyon Rafting Use Metric (GCRM) is a measure of an absolute effect, the actual number of annual lost visitor trips, as opposed to a relative index.

The operational 24-hr, 45,000 cfs spring high flow under Alternative F is taken into account in this analysis. No other high flows, such as equalization flows, except those distinctly defined as HFEs are considered. For each modeled year, there is the potential for a spring HFE, a fall HFE, or both to occur. The GCRM is calculated as follows for each HFE event.

$$GCRM_{HFE} = ADV\left[\frac{visitors}{day}\right] \times D\ [days]$$

If there are two HFEs within a single year, the number of passengers unable to raft is summed as in the following equation:

$$GCRM_{annual} = \sum_{yearly} GCRM_{HFE}$$

The final metric value is the average number of passengers unable to raft the Glen Canyon reach for the 20-year LTEMP modeling period (2014 to 2033) due to HFEs:

$$GCRM = Average\ (GCRM_{annual})_{2014-2033}$$

J.2.5.2 Glen Canyon Rafting Use Metric—Results

Figure J-7 shows GCRM values for LTEMP alternatives and long-term strategies. As the metric is based on the number of HFEs, the GCRM closely resembles the pattern of HFEs under each alternative. This can be seen by comparing the GCRM values in Figure J-7 with the average HFE count in Figure J-8. Not shown for Alternative F is the annual 24-hr high flow that occurs in years without a spring HFE. This further contributes to increases the GCRM, resulting in the highest number of lost visitor trips for Alternative F. As spring trips have a higher number of passengers than fall trips, spring HFEs have a larger impact on lost visitor trips than do fall HFEs.

As they do not include HFEs, long-term strategies C3, E3, E5, and E6 incur no lost visitor rafting trips. With few HFEs and mostly fall HFEs, long-term strategies A and B1 and B2 have the next fewest lost trips on average, while C4 and E4 have only slightly more, due mainly to the absence of spring HFEs under these long-term strategies. E1 and E2 have more lost trips than E4 due to spring HFEs in the second 10 years of the LTEMP period that do not occur under E4. Long-term strategies C1–C2 and D1–D2 have similar numbers of lost visitor trips owing to similar numbers and durations of HFEs. Alternative G has the second highest number of lost trips at roughly 500 annually, due to a high number of HFEs, an estimated 24.5 over the 20-year LTEMP period, including HFEs of 96 hr or longer duration. Finally, Alternative F has the highest number of lost visitor trips, on average over 900 annually, due to the highest number of HFEs, an estimated 38.1 over the 20-year LTEMP period, including the annual 24-hr release in all summers of years without a spring HFE. In addition, roughly two-thirds of HFEs under Alternative F are of 96-hr duration, representing a large number of days closed to rafting.

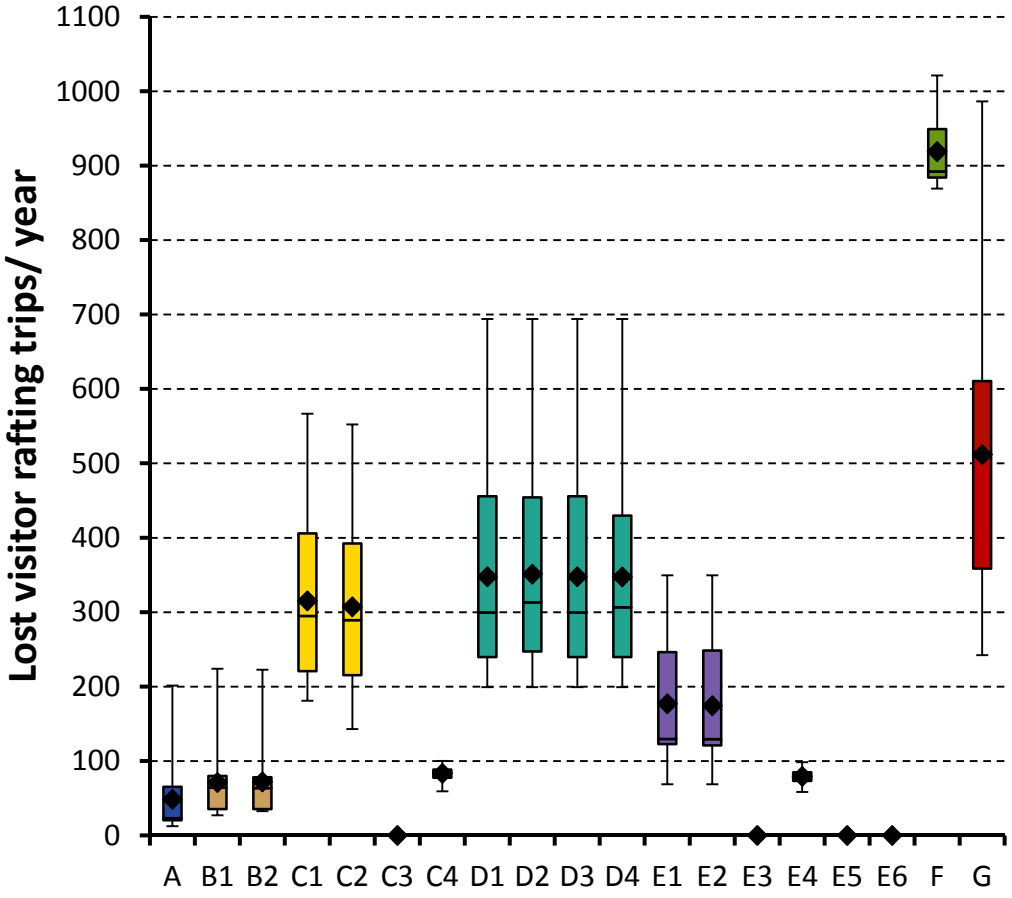

FIGURE J-7 Glen Canyon Rafting Metric for All LTEMP Long-Term Strategies (Values are estimated annual lost visitor rafting trips. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

J.2.6 Glen Canyon Inundation Metric

The 15-mi stretch of Glen Canyon, from the Glen Canyon Dam to Lees Ferry, along the Colorado River is a hub for recreation within Glen Canyon National Recreation Area. Due to its unique geography, Lees Ferry is the only place directly accessible by car to visitors in hundreds of miles of canyon country. It is therefore an ideal location for boating, fishing, swimming, kayaking, camping, and hiking activities by visitors. However, these activities are directly downstream of the Glen Canyon Dam, and can be impacted by dam operation.

Surveys of users have indicated that the most ideal recreational conditions for Glen Canyon are flows from 8,000 to 20,000 cfs. Bishop et al. (1987) and Stewart et al. (2000) reported that anglers preferred a constant flow of about 10,000 cfs, while more recent information indicated Lees Ferry anglers preferred constant flows from 8,000 to 16,000 cfs

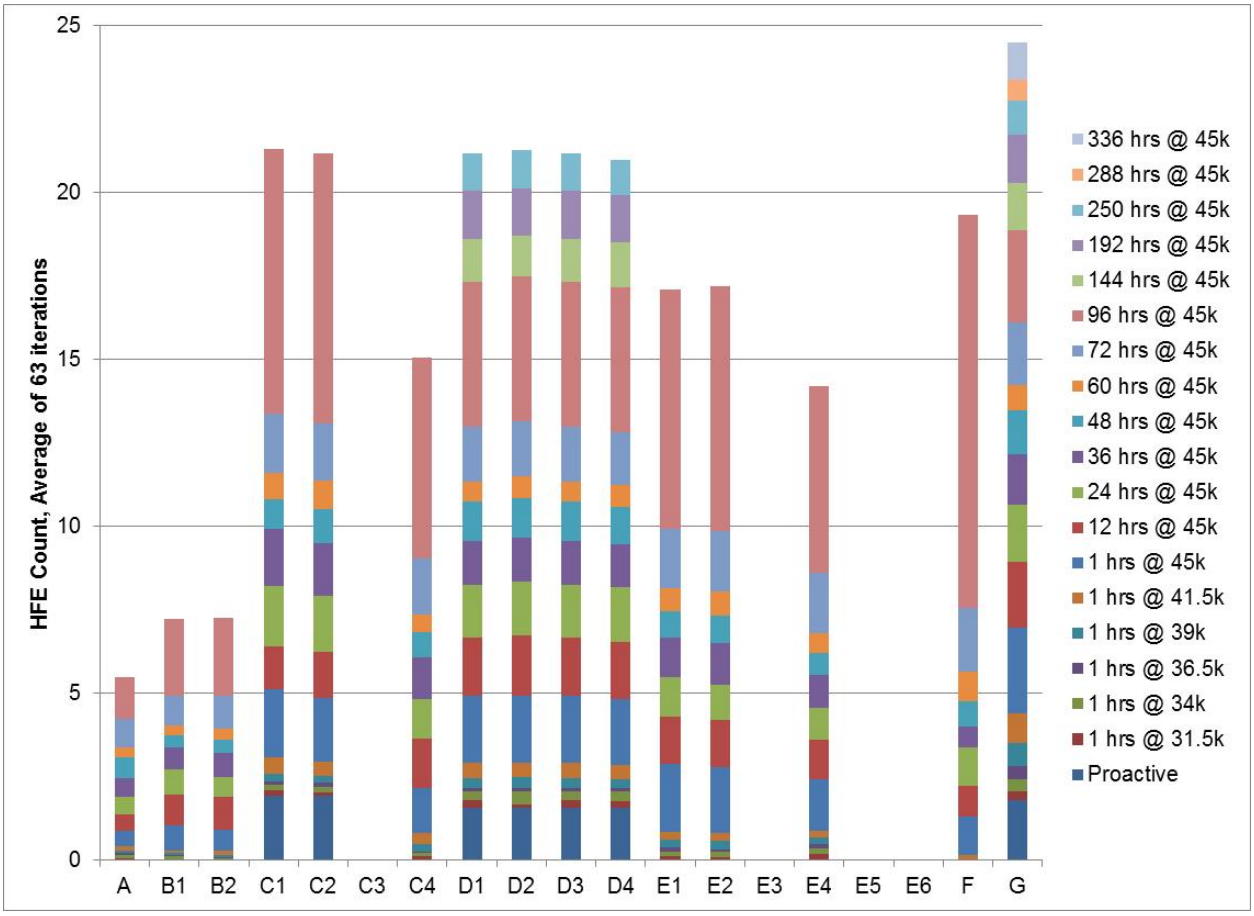

FIGURE J-8 Average Number of HFEs in the 20-Year LTEMP Period for LTEMP Long-Term Strategies

(Gunn 2012). Flows within the 8,000 to 20,000 cfs range are ideal for shoreline access for boaters, who primarily only report poor conditions or water level issues with extremely high or low flows. For example, the Colorado River Discovery day rafting service reported operating issues with flows below 3,000 cfs and inoperable conditions when bypass tubes are in operation (above 31,500 cfs), as they create too much turbulence below the dam (Grim 2012). Flows at or below 8,000 cfs may allow tamarisk tree growth and, as observed in the low summer flows of 2000 (Hjerpe and Kim 2001), may make prime angling spots impenetrable. At flows above 20,000 cfs, reduced participation in upstream fishing has been observed (McGinnis 2014).

J.2.6.1 Glen Canyon Inundation Metric—Methods

The Glen Canyon Inundation Metric (GCIM) represents the percentage of time that flow is at preferred levels for recreational experiences within the canyon, 8,000 to 20,000 cfs. Table J-2 presents a summary of recreational response to various discharge rates. This information was used in the computation of the Glen Canyon Inundation Metric as follows. A flow factor (FF) value from 0 to 1 is computed as a function of daily maximum discharge and

TABLE J-2 Recreation Response to Daily Maximum Flow

Flow (cfs)	Recreational Response
<3,000	Flows below 3,000 cfs are poor for boating and fishing.
3,000–8,000	Flows for fishing and boating get progressively better up to 8,000 cfs.
8,000–20,000	Flows are optimal for boating, fishing, and shoreline access.
20,000–31,500	Flows above 20,000 cfs get progressively worse for fishing and shoreline access.
>31,500	Flows above 31,500 cfs are poor for rafting, campable area, shoreline access, and fishing, and can adversely impact onshore recreational facilities.

the noted recreation responses, with higher values representing improved recreational experience. Daily FF values for discharges of 3,000 to 8,000 cfs and 20,000 to 31,500 cfs ranges were assigned values based on linear interpolation from 0 to 1 and 1 to 0, respectively. The daily FF is assigned as shown below, where the value in the right column within the brackets is assigned to FF if the equation in the left column is satisfied. Q_{max} refers to the daily maximum discharge released from the Glen Canyon Dam in cfs:

$$FF_{Daily} = \begin{Bmatrix} \text{if } Q_{max} \leq 3{,}000 \text{ cfs}; & 0 \\ \text{if } 3{,}000 < Q_{max} < 8{,}000\ cfs; & (Q_{max} \times 0.0002) - 0.60 \\ \text{if } 8{,}000 < Q_{max} < 20{,}000\ cfs & 1 \\ \text{if } 20{,}000 < Q_{max} < 31{,}500\ cfs; & 2.74 - (0.0000870 \times Q_{max}) \\ \text{if } Q_{max} \geq 31{,}500 \text{ cfs}; & 0 \end{Bmatrix}$$

An overall annual mean index value for the 20-year modeling period was computed for each alternative and used as the performance metric.

$$GCIM_{annual} = \{0.15\left(\frac{\sum_{winter} FF_{Daily}}{\sum Days_{winter}}\right) + 0.31\left(\frac{\sum_{spring/fall} FF_{Daily}}{\sum Days_{\frac{spring}{fall}}}\right) + 0.54\left(\frac{\sum_{\text{summer}} \text{FF}_{\text{daily}}}{\sum Days_{summer}}\right)\}$$

An overall annual mean index value for the 20-year modeling period was calculated as follows:

$$GCIM = Average\ (GCIM_{annual})_{2014-2033}$$

J.2.6.2 Glen Canyon Inundation Metric—Results

Results for the GCIM for LTEMP long-term strategies are shown in Figure J-9. Results are similar for all of the long-term strategies, except for Alternative F and, to a lesser extent, B2. Overall, index values are all high, above 0.9 for all but Alternative G, which has a mean value of about 0.85. Such high values indicate that discharge rates are in a range preferred for a variety of recreational activities most of the time under all alternatives and long-term strategies. The index value for Alternative F is reduced due to the large number of HFEs overall and to the high percentage of 96-hr HFEs, which together produce a relatively high number of days annually with flows above preferred levels. Similarly, high flows during hydropower improvement tests under B2 reduce its index value relative to B1 and most other long-term strategies. Other long-term strategies have values very close to that for Alternative A, with small deviations both higher and lower.

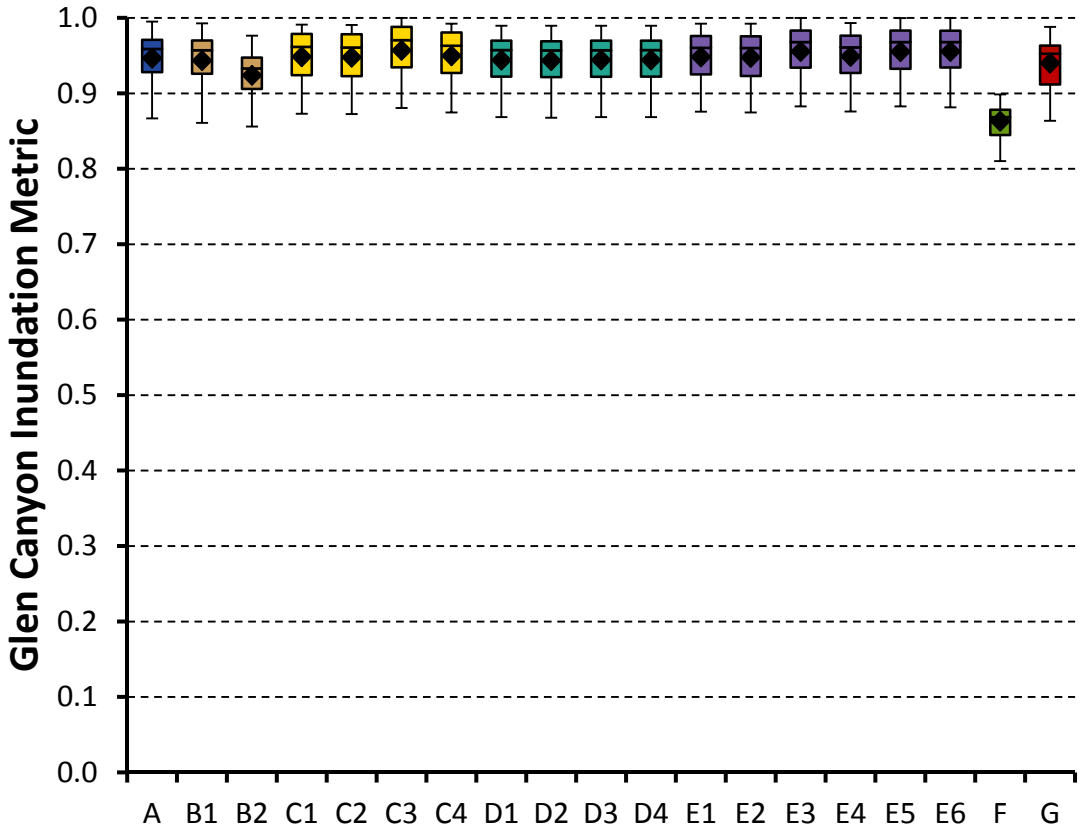

FIGURE J-9 Glen Canyon Inundation Metric for All LTEMP Long-Term Strategies (Increasing values indicate increasing frequency of flow levels preferred for recreation. Note that diamond = mean; horizontal line = median; lower extent of box = 25th percentile; upper extent of box = 75th percentile; lower whisker = minimum; upper whisker = maximum.)

J.3 LAKE POWELL AND LAKE MEAD DOCK ACCESS

Lower-than-normal lake levels have been occurring in Lake Powell upstream of the Glen Canyon Dam and in Lake Mead, which lies at the end of the 277-mi stretch of the Colorado River through GCNP. At Lake Powell, low lake elevation has rendered some boat launch sites inaccessible, and, in October 2005, NPS completed a General Management Plan (GMP) Amendment for Low Water Conditions and Finding of No Significant Impact (NPS 2005), which identified a strategy for low-water operations. This amendment ensured the maintenance of the boat launch sites at Lake Mead despite low water levels by either extending or relocating existing launch ramps and marinas so as to be functional down to an elevation of 1,050 feet above mean sea level (AMSL). Similarly, at Lake Powell, a connection channel called Castle Rock Cut, located directly across from Wahweap Bay from the Stateline launch ramp, became inaccessible at lake levels below an elevation of 3,580 ft AMSL in 2014 (Elleard 2014).

Modeled end-of-month lake elevations from 63 historical traces were compared against these two elevations (1,050 ft AMSL for Lake Mead and 3,580 ft AMSL for Lake Powell) to determine the percentage of time that lake levels would potentially fall below these critical levels. The percentage of traces where monthly lake elevation fell below critical elevation for any month within a season over the 20-year LTEMP period for Lake Powell is shown in Figure J-10 for the recreational summer seasons of May, June, July, and August and in Figure J-11 for the recreational fall and spring months of March, April, September, and October. Figures J-12 and J-13 show the analogous percentages for Lake Mead. Note that since these figures were generated by recasting past hydrology, they show the potential future variability and range of lake elevation conditions relative to the access reference elevations, but they do not predict conditions for any particular future year or year-to-year trends. Thus, the year dates on the *x* axis have meaning only in the sense that they show a hypothetical future 20-year period.

These graphs show that monthly lake elevations fall on or below critical elevations during spring and summer months for roughly 22% of historical trace simulations for Lake Powell and roughly 25% of historical trace simulations for Lake Mead for all alternatives and long-term strategies over the LTEMP period. Table J-3 shows the percentages for all alternatives. While rates of access issues are substantial, the difference among alternatives is small, indicating overall impacts at the launch sites of Lake Mead or the Castle Rock Cut connection channel in Lake Powell are driven mainly by hydrology. At Lake Powell, on average over all seasons, all alternatives have slight increases in access impacts relative to Alternative A. Conversely, at Lake Mead, all alternatives exhibit slight decreases in access issues compared to Alternative A. It is not clearly the case, but this behavior might be the result of Alternative A having the lowest number of HFEs of all alternatives. Large volumes of water taken from Lake Powell for an HFE might temporarily drop the lake level below the access threshold when the lake level is near the threshold, while similarly reducing the frequency of access issues at Lake Mead, which receives an input pulse from an HFE.

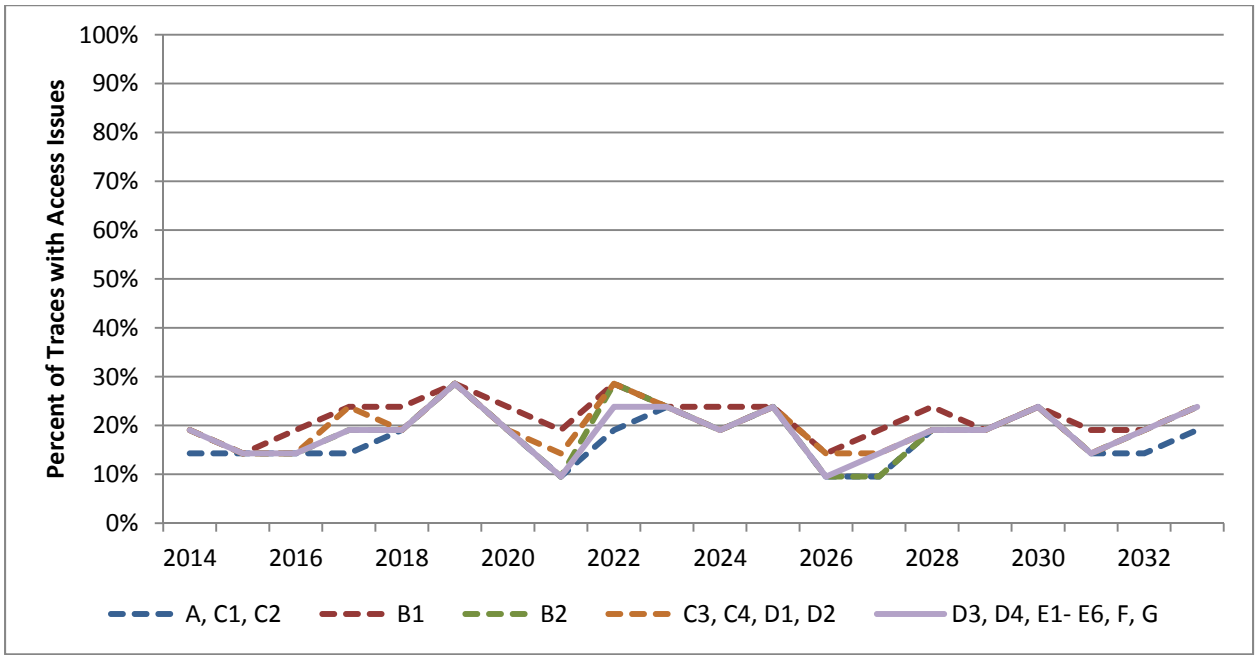

FIGURE J-10 Percentage of Traces Lake Powell Elevation Equal to or below 3,580 ft AMSL for the Summer Season

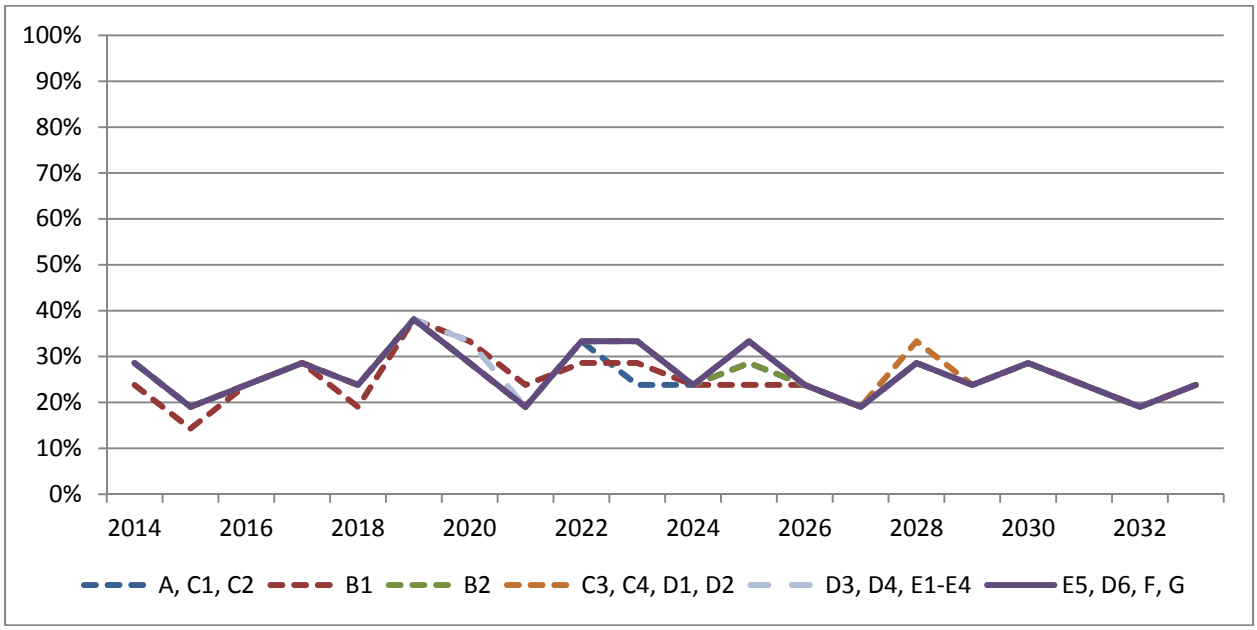

FIGURE J-11 Percentage of Traces Lake Powell Elevation Equal to or below 3,580 ft AMSL for the Fall and Spring Seasons

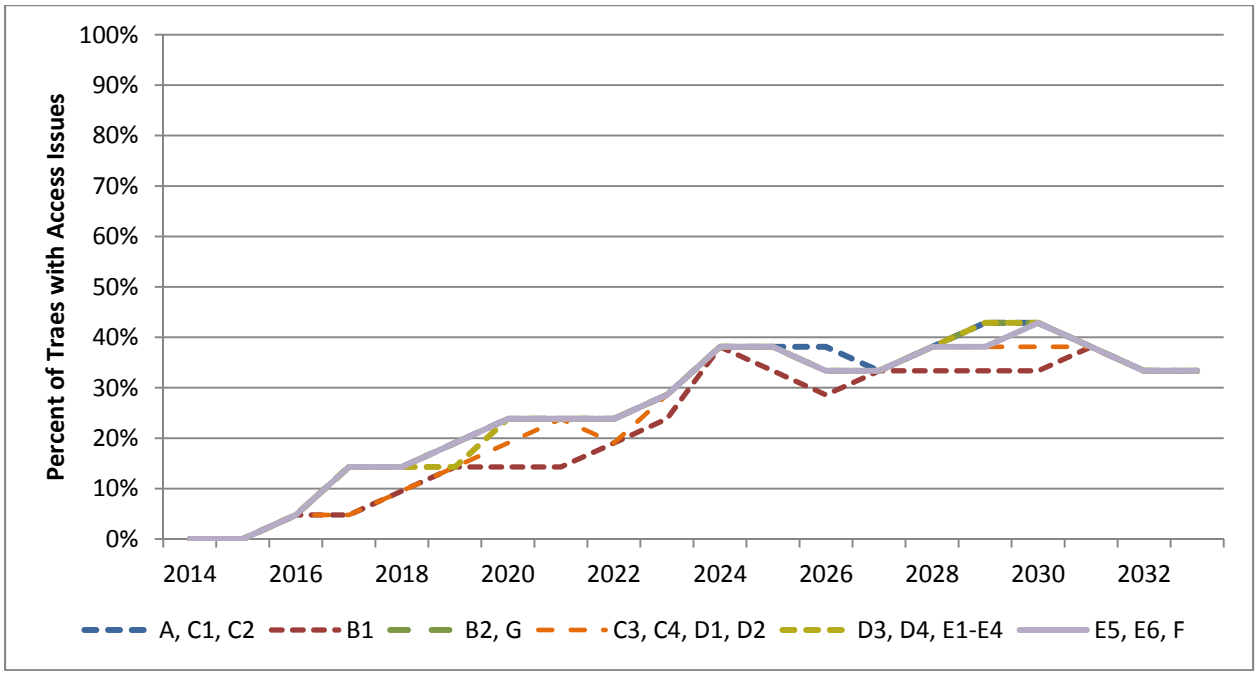

FIGURE J-12 Percentage of Traces Lake Mead Elevation Equal to or below 1,050 ft AMSL for the Summer Season

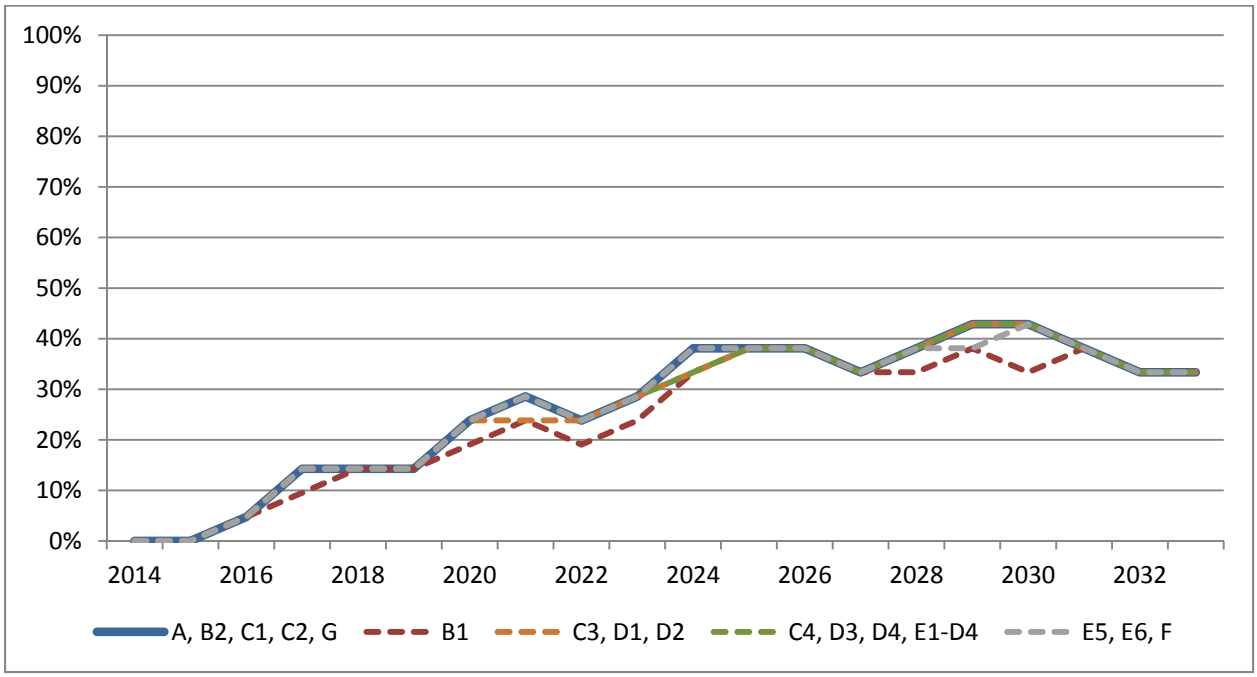

FIGURE J-13 Percentage of Traces Lake Mead Elevation Equal to or below 1,050 ft AMSL for the Fall and Spring Seasons

TABLE J-3 Summary of Recreation, Visitor Use, and Experience Metrics

Alternative/ Long-Term Strategy	CAI	NRI	FI	TORI	GCRM	GCIM	Lake Powell[a]	Lake Mead[a]
A	0.14	0.50	0.79	0.18	49	0.95	0%	0%
B1	0.15	0.39	0.42	0.18	71	0.94	2.5%	-10.6%
B2	0.12	0.26	0.26	0.18	72	0.92	4.4%	-3.5%
C1	0.38	0.75	0.93	0.18	315	0.95	0.37%	-0.31%
C2	0.37	0.73	0.93	0.18	307	0.95	0.37%	-0.31%
C3	0.04	0.76	0.92	0.18	0	0.96	5.5%	-4.4%
C4	0.33	0.76	0.93	0.18	83	0.95	5.5%	-4.1%
D1	0.36	0.45	0.74	0.16	347	0.94	4.7%	-3.5%
D2	0.36	0.60	0.78	0.16	351	0.94	5.5%	-4.1%
D3	0.36	0.45	0.72	0.16	347	0.94	5.1%	-2.5%
D4	0.36	0.45	0.74	0.16	347	0.94	5.1%	-2.5%
E1	0.30	0.37	0.57	0.16	177	0.95	5.1%	-1.3%
E2	0.29	0.30	0.53	0.16	174	0.95	5.1%	-2.5%
E3	0.03	0.32	0.52	0.16	0	0.96	5.1%	-1.3%
E4	0.27	0.29	0.53	0.16	79	0.95	5.1%	-1.3%
E5	0.03	0.33	0.52	0.17	0	0.96	4.7%	-2.5%
E6	0.03	0.32	0.52	0.16	0	0.96	4.7%	-2.5%
F	0.41	0.71	1.00	0.25	919	0.86	4.7%	-2.5%
G	0.45	0.96	0.98	0.16	512	0.94	4.7%	-1.9%

[a] Percentage difference from Alternative A in frequency of access issues; Alternative A has predicted access issues in 21.75% of future seasons for Lake Powell and 25.48% of future seasons for Lake Mead based on historical hydrology.

J.4 SUMMARY

Values for the means of the six metrics and frequency of Lake Powell and Lake Mead access issues discussed above are summarized in Table J-3. An index of 0 to 1 is used for CAI, NRI, FI, TORI, and GCIM, while GCRM is the estimated number of actual visitor trips lost due to HFEs. Access issues for Lake Powell and Lake Mead are the percent differences from Alternative A in the expected frequency of traces in which lake elevation falls below access thresholds in at least one month in either the spring–fall or summer seasons. The values shown in the table are mean values for 63 modeled hydrology–sediment conditions. Quartile values and minimum and maximum values for the six metrics can be seen in the respective box-and-whisker plots (Figures J-1 to J-9).

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APPENDIX K:

HYDROPOWER SYSTEMS TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX K:

HYDROPOWER SYSTEMS TECHNICAL INFORMATION AND ANALYSIS

This appendix provides details on three analyses that are related to hydropower system electricity production, powerplant capacity, costs, and electricity service charge rates and that are conducted for the Glen Canyon Dam Long-Term Experiment and Management Plan (LTEMP) Draft Environmental Impact Statement (DEIS). The first analysis (presented in Section K.1) evaluated the impacts of changes in Glen Canyon Dam operations associated with LTEMP alternatives on the economic value of the powerplant's capacity and energy production. The impacts were measured in terms of changes in the value of regional power system capacity (the power system comprised of Western's long-term firm (LTF) customers) and overall system-level electricity production costs (the entire Western Interconnection). The second analysis (presented in Section K.2) studied how system resources and operations under LTEMP alternatives affect the wholesale electricity rates paid by utility entities that receive federal preference power produced by Glen Canyon Dam. The third analysis (presented in Section K.3) studied the effects of alternatives on electricity rates paid by retail customers.

K.1 ECONOMIC VALUE OF GLEN CANYON DAM POWERPLANT CAPACITY AND ENERGY PRODUCTION

This first analysis studied the impacts of changes in Glen Canyon Dam Powerplant operations associated with LTEMP alternatives on the economic value of its capacity and energy production. Power system impacts are measured in terms of increases in capacity expansion expenditures and overall electricity production costs that would result from changing current Glen Canyon Dam operating criteria to different operating criteria as defined under LTEMP alternatives.

K.1.1 Power Systems Background

The Glen Canyon Dam Powerplant generates large amounts of energy that yield economic benefits to the grid. It also provides the grid with firm capacity that contributes to system reliability. Argonne National Laboratory (Argonne) staff conducted a power systems analysis of Glen Canyon Dam's economic benefits under each of the main alternatives defined by the LTEMP DEIS. These alternative-specific operating criteria are summarized in Table 2-1 of the DEIS.

The total water release volume from Lake Powell during each water year (WY) is nearly identical under all alternatives (see Section 4.2). However, at varying restriction levels, alternative criteria define the daily and hourly operational flexibility at Glen Canyon Dam, and affect Lake Powell reservoir elevations and monthly water release volumes. LTEMP alternatives also differ in their inclusion of various experimental releases such as high flow experiments

(HFEs) and trout management flows (TMFs). The frequencies of these experimental releases differ among the alternatives.

Glen Canyon Dam energy production serves the electricity demands (loads) of a dynamic system that responds to its operations. Therefore, economic impacts of changes in Glen Canyon Dam operations are measured for the system as a whole. Some of the responses to changes in Glen Canyon Dam operating criteria, such as system unit dispatch adjustments, would occur very quickly. System dispatch refers to the amount of generation that each powerplant unit produces over time to match system loads plus system energy losses. In contrast, other system responses are much slower. For example, Glen Canyon Dam operating criteria affect its maximum output at times of peak load, and therefore system-wide capacity expansion pathways; that is, the timing and type of new units that will be built in the future. This methodology measures the spectrum of system economic impacts from hourly time intervals to multi-year processes.

The system modeled consists of 11 hydropower plants (including the Glen Canyon Dam Powerplant) marketed and scheduled by the Colorado River Storage Project (CRSP) Management Center of the Western Area Power Administration (Western), the loads of all LTF power customers, and the resources owned and operated by the eight LTF power customers that have the largest allocations of capacity and energy (see Section K.1.3.2 for more detail). The combined loads and resources of these entities are referred to at the Salt Lake City Area Integrated Projects (SLCA/IP) market system.

Each aspect of an LTEMP alternative affects the economic value of this system. This analysis focuses on the total differences in the economic value of SLCA/IP federal hydropower resource among alternatives benchmarked to existing operating criteria (Alternative A, the no action alternative). This difference is referred to as the economic cost of an alternative and is quantified as the net present value (NPV) of the cost that would be accrued during the 20-year LTEMP period. System interactions with the broader Western Interconnection are also represented. It should be noted that this is an economic analysis that measures the net cost difference for the system as a whole, not a financial analysis of individual entities (e.g., a utility company) that operate within the system.

Operating criteria impact power economics because they affect the timing and routing of water releases through the dam. From a system dispatch perspective, power produced by Glen Canyon Dam yields the highest economic benefits when the limited amount of water released during a WY is routed through the powerplant's generating turbines to produce power during seasons of the year and times of the day when it displaces either energy generation or demand curtailment from expensive grid resources. For example, Glen Canyon Dam has a high economic value when the energy it produces either reduces or eliminates the operation of a generating unit with a high production cost. On the other hand, it has a much lower value when it displaces lower-cost power generation.

During most HFEs, water release rates from Glen Canyon Dam are greater than the maximum flow rate of the powerplant's turbines. Therefore, some water is released through the dam's hollow jet tubes, bypassing powerplant turbines. Non-power water releases such as these produce no electricity and therefore yield no energy value. Because water is limited, the bypass

water reduces the overall economic value of power because this water could have otherwise been stored in Lake Powell and released to produce energy at another time to displace the dispatch of more costly system resources.

Glen Canyon Dam capacity also has considerable value because the powerplant can generate power during times of peak demand. Without the Glen Canyon Dam Powerplant, other resources would need to be constructed or acquired in order to ensure that the system had adequate generating capabilities available to reliably meet system loads. The Glen Canyon Dam power resource therefore avoids investments and fixed operating and maintenance (O&M) costs. Alternative operating criteria affect peak Glen Canyon Dam Powerplant operations and therefore the amount of capacity the system can rely upon to meet system peak loads.

The methodology used for power systems analysis mimics decisions that could be made by system entities based on contractual and financial considerations that affect economic outcomes. For example, the borrowing rate for capital may impact both capacity expansion decisions and therefore economic outcomes. Economic costs include the following components: (1) energy production costs for the entire system and (2) capital investment plus fixed O&M costs for constructing and operating units built for system capacity expansion. Energy production costs are comprised of fuel expenditures, variable O&M costs, and unit startup expenses. All costs are estimated over the 20-year LTEMP period starting at the beginning of calendar year (CY) 2015 and extending through the end of CY 2034. To be consistent with the analyses performed for other resource areas, the start of the study period was adjusted to CY 2015. Please refer to Section K.1.9 for a description of how the adjustment was made. Emphasis is placed on accurately estimating the cost of an alternative compared to Alternative A in terms of both economic ranking and the relative magnitude of cost differences. Therefore, costs such as fixed O&M costs are not computed for existing units that remain unchanged across all alternatives.

K.1.2 Glen Canyon Dam, Reservoir, and Powerplant Background

Glen Canyon Dam is a U.S. federal resource that was built by the Bureau of Reclamation (Reclamation) between 1956 and 1964 as part of the CRSP that was authorized by the Colorado River Storage Project Act on April 11, 1956. The Act authorized the Secretary of the Interior to develop the water resources of the Upper Colorado River Basin by constructing, operating, and maintaining the CRSP and other participating reclamation projects. The dam is a 710-foot–high concrete arch structure with a crest length of 1,560 ft, containing 4,901,000 yd^3 of concrete. The thickness of the dam at the crest is 25 ft, and its maximum base thickness is 300 ft. The reservoir formed by the dam, Lake Powell, has a total water storage capacity of 27 million acre-feet (maf), with an active capacity of approximately 20.9 maf when full. Under normal water surface elevation levels, the reservoir has a length of 186 mi and a surface area of 161,390 ac. The dam controls a drainage basin approximately 108,355 mi^2 (Harpman and Rosekrans 1996).

Currently, there are eight generating units at Glen Canyon Powerplant with a total sustained operating capacity of approximately 1,320 megawatts (MW). The first two Glen Canyon units began generating power in September 1964, and the eighth and final unit came online in February 1966, as recorded in Power Operations and Maintenance Form 59 (Form

PO&M-59). When water is released from the reservoir through power plant turbines, the energy generated serves the electricity demands of consumers located in the SLCA/IP market system.

Lake Powell was filled for the first time in 1980, when it reached a maximum reservoir water elevation of 3,700.6 feet (ft). Displacing power generation and associated air emissions mainly from powerplants that burn fossil fuels such as coal, oil, and natural gas, the average annual gross electricity generation from the Glen Canyon Dam Powerplant between CY 1980 and 2013 was about 4,716.5 GWh. This statistic does not include generation production for years prior to 1980, because a portion of water inflows into Lake Powell were used to fill the reservoir prior to that time. From 1980 through 2013, annual generation has varied by more than a factor of 2.6. Generation was at a low of 3,299 GWh in CY 2005 and at a high of 8,703 GWh in CY 1984. The high level of annual generation variability of the Glen Canyon Dam Powerplant since 1980 is mainly attributable to variations in Lake Powell inflow levels, which are strongly influenced by precipitation. Hydropower variability and uncertainty reduce its value because at times these resources have reduced energy production and peak output capabilities. Therefore, other resources need to be made available to serve system loads and reliability requirements.

Operational limitations at Glen Canyon Dam were minimal from 1964 through May 1990. Minimum releases from Lake Powell were 1,000 cfs from Labor Day to Easter and 3,000 cfs during the rest of the year. These minimums are only a small fraction, approximately 3% to 9%, of the physical maximum turbine flow rate of 33,000 cfs at full reservoir. There were no institutional limitations on maximum flow rates, hourly ramping, or daily changes in flow. The relatively low minimum release rate requirement, combined with limits that were only constrained by the physical powerplant and dam characteristics, allowed for flexible operations that maximized the economic or financial value of hydropower generation.

Many interested parties became increasingly concerned about the effects of rapid changes in Glen Canyon Dam water releases on the downstream riverine environment, including the impacts they could have on endangered species. Legislation was introduced in Congress in 1990 addressing dam operations after the Glen Canyon Environmental Studies Program published its report in 1987 describing the impacts of dam operation on the national and recreational resources of the Grand Canyon. Reclamation began to restrict operations on June 1, 1990, when it conducted research discharges as part of the Glen Canyon Environmental Studies. Numerous test flows were conducted during a 14-month period that concluded at the end of July 1991. The purpose of these research releases was to collect and analyze data at different flow levels in order to investigate the effects of flow patterns on the riverine environment downstream of Glen Canyon Dam. Interim flow operating constraints were imposed at Glen Canyon Dam on August 1, 1991, and were in effect until February 1997, when new operational rules and project management goals were adopted to comply with the 1996 Glen Canyon Dam Environmental Impact Statement Record of Decision (ROD).

The 1996 ROD requires releases from Lake Powell to be at least 8,000 cfs between the hours of 7:00 a.m. and 7:00 p.m., and 5,000 cfs or more during all other hours of the day. The maximum allowable release is limited to 25,000 cfs. In very high release months, the maximum limit can be exceeded, but the release rate must be constant during the entire month. The 1996 ROD operating criteria also limits release fluctuations during all rolling 24-hour periods.

The fluctuation level permitted depends on the amount of water that will be released from Glen Canyon Dam during a month. The allowable daily fluctuation is 5,000 cfs/24 hours when the monthly scheduled water release is less than or equal to 600 kaf. Daily fluctuations are restricted to 6,000 cfs/24 hours for those months in which the scheduled release is equal to or greater than 600 kaf but less than 800 kaf, and at 8,000 cfs/24 hours for months with releases equal to or greater than 800 kaf. Finally, the 1996 ROD operating criteria also limited the rate at which Lake Powell water release are allowed to ramp up and down. The maximum ramp rate is 4,000 cfs/hr when increasing, and 1,500 cfs/hr when decreasing. Operating criteria reduced the flexibility of operations, diminished dispatchers' ability to respond to market price signals, and decreased the economic power benefits of the Glen Canyon Dam. Between 1997 and 2005, this decrease in economic benefit was estimated to range from $38 million to $50 million per year (in 2009$) (Veselka et al. 2010). This range may not be indicative of future economic costs due to a number of factors including changes in power market structures and utility fuel prices.

The 1996 ROD operating criteria include "emergency exception criteria" that recognize the fact that the Glen Canyon Dam Powerplant is an important grid resource. When emergency exception criteria are invoked, normal operations are suspended until the emergency has ended or Western has been cleared of its North American Electric Reliability Corporation (NERC) emergency operation responsibilities. Emergency exception criteria allow Glen Canyon Dam to dispatch up to all of its available capacity at Glen Canyon Powerplant, depending on the severity of the system emergency, by rapidly increasing generation output in response to events such as insufficient system generating capacity, transmission system problems, and system restoration.

In addition, Glen Canyon Dam generators provide system regulation to Western as the operator of the Western Area Colorado Missouri (WACM) balancing authority (BA) area. The Glen Canyon Dam Powerplant responds to a regulation signal developed and electronically transmitted to the dam by Western for continuous response to power system load and frequency changes. Western is required to react to moment-by-moment changes in system frequency, time error, and tie-line loading within the WACM BA via powerplant automatic generation control (AGC) equipment at Glen Canyon Dam and some of the other SLCA/IP federal hydropower plants to adjust the power output of the generators to match variations in system load in accordance with prescribed NERC criteria. The degree to which Western responds to these system changes is computed by an area control error (ACE) equation.

The ACE signal that is sent to Glen Canyon Dam adds to or subtracts from the existing scheduled hourly generation set point. Therefore, at any instant in time, the powerplant is typically producing more or less power than the current hourly scheduled set point. Deviations from the set point typically fluctuate from negative to positive values many times during any hour. However, the resulting output from Glen Canyon generators on average approximates the hourly scheduled level. Because post-ROD operating criteria specify release restrictions in terms of hourly average levels, Glen Canyon Dam can provide regulation services while scheduling set point levels at minimum and maximum allowable flow limits. It can also ramp set points within up and down limitations (see http://www.wapa.gov/crsp/planprojectscrsp/gcopswhite.html).

The 1996 ROD operating criteria currently restrict Glen Canyon Dam operations in terms of both the operational range of water releases and the rate at which water releases are permitted to change over time. It also provides the operating criteria for Alternative A.

K.1.3 Power Systems Geographic Scope

The Glen Canyon Dam Powerplant is part of a large dynamic power grid that responds to its operations. It is also a component of Western's SLCA/IP, which is comprised of 11 federal hydropower facilities marketed and scheduled by the CRSP Management Center. Western markets these facilities as a bundled resource. Therefore, power economic impact analyses are based on a systems approach that measures the collective responses of system components to changes in Glen Canyon Dam operating rules and experimental releases. The focus area is on SLCA/IP federal hydropower resources, and the utilities operated by Western's SLCA/IP LTF power customers. For the purpose of this appendix, this primary impact area is referred to as the SLCA/IP market system (or SLCA/IP system). However, as described in more detail below, the methodology also recognizes that this system does not operate in isolation. Instead, it interacts with the much larger Western Interconnection power grid.

The power systems method uses a three-tiered approach. All simulate the system on an hourly basis over the 20-year LTEMP period. The top tier models the loads and resources of the entire Western Interconnection to gain a broad perspective on the future development of the larger overall system. Both Western Interconnection system capacity expansion and economic system dispatch are modeled.

The middle tier models SLCA/IP LTF customer utility loads and resources along with future Western Interconnection interactions via non-firm bilateral energy transaction. It also projects SLCA/IP market system future capacity additions, determines day-ahead unit commitments, and performs economic dispatch. It focuses on SLCA/IP customer resources at a higher level of fidelity than the Western Interconnection tier. The top and middle tiers both rely on projections found in the *Annual Energy Outlook* (EIA 2014) published by the U.S. Energy Information Administration (EIA). The *Annual Energy Outlook* uses an even broader perspective that incorporates overall U.S. and global macroeconomic drivers into the projection of U.S. energy futures.

The bottom tier focuses on SLCA/IP federal hydropower resources. It models the long-term management and routing of water resources within the Colorado River Basin, including those river reaches below Glen Canyon Dam. Future water management is compliant with all applicable laws and water rights. Given this projection of long-term water management, simulation of powerplant dispatch is performed based on market price drivers projected by the Western Interconnection tier and key physical and institutional constraints on reservoir operations and powerplant dispatch. Hourly dispatch is subject to numerous physical and institutional constraints, including those specified under an LTEMP alternative.

The top tier represents a large geographical area, but at a relatively low level of fidelity. Increasing attention to detail and accuracy is paid as the geographical coverage becomes more

focused. By using this approach, power systems comparative analyses are able to determine how changes in Glen Canyon Dam Powerplant operations affect its economic value. This top-down modeling approach is further described below. More details about the selection of the power system's geographical scope and detail are provided in Attachment K-1.

K.1.3.1 Top Tier: General Western Interconnection Perspective Modeling

North America is comprised of two major and three minor alternating-current power grids. The Western Interconnection is the major power grid that stretches from Western Canada south to Baja California in Mexico, and eastward from the Pacific Ocean to the Rockies and the Great Plains. All of the electric utilities in the Western Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency that averages 60 Hz. The Western Electricity Coordinating Council (WECC) region of NERC facilitates regional transmission expansion planning for the interconnection, and the Western Governors' Association acts as a state/provincial steering committee. These entities work collaboratively to develop long-term electricity supply futures, estimate transmission requirements, and prepare long-term interconnection-wide transmission plans (see http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act-0).

Argonne power system analysts modeled the long-term capacity expansion, unit commitments, and hourly unit dispatch of Western Interconnection resources using the AURORAxmp model (referred to as AURORA). The Western Interconnection topology and supporting model inputs were provided by EPIS, Inc., the AURORA model developers. A depiction of this topology is shown in Figure K.1-1. Each "bubble" in the diagram roughly represents groups of utilities, single BAs, or combinations of BAs. Bidirectional limits on the links that connect bubbles restrict network energy transfers. User-defined limits can vary hourly. The location of SLCA/IP federal hydropower resources in the AURORA Western Interconnection topology is indicated in the figure. The Glen Canyon Dam Powerplant is labeled "GC," and the Flaming Gorge and Fontenelle Powerplants are labeled "FG" and "FN," respectively. The location of powerplants in the Wayne D. Aspinall Cascade and all other SLCA/IP hydropower plants is labeled "Aspinall & Others."

The primary driver of many variables that define Western Interconnection future developments were based on projections published in EIA's 2014 *Annual Energy Outlook* (hereafter 2014 AEO; EIA 2014) for the reference scenario that was released in April 2014. Model results are consistent with state integrated resource plans (IRPs). A more detailed description of AURORA is provided in Section K.1.5.9.

In addition to estimating the capacity expansion pathways and system production costs, AURORA also projects future locational marginal prices (LMPs) throughout the Western Interconnection. The LMPs measure the incremental cost to serve an additional 1 MW of load at a specific point in the grid; that is, the cost to change the dispatch of system resources to serve a slightly higher load. This typically involves increasing the power generation at one of more units or reducing loads via a demand response management (DSM) agreement.

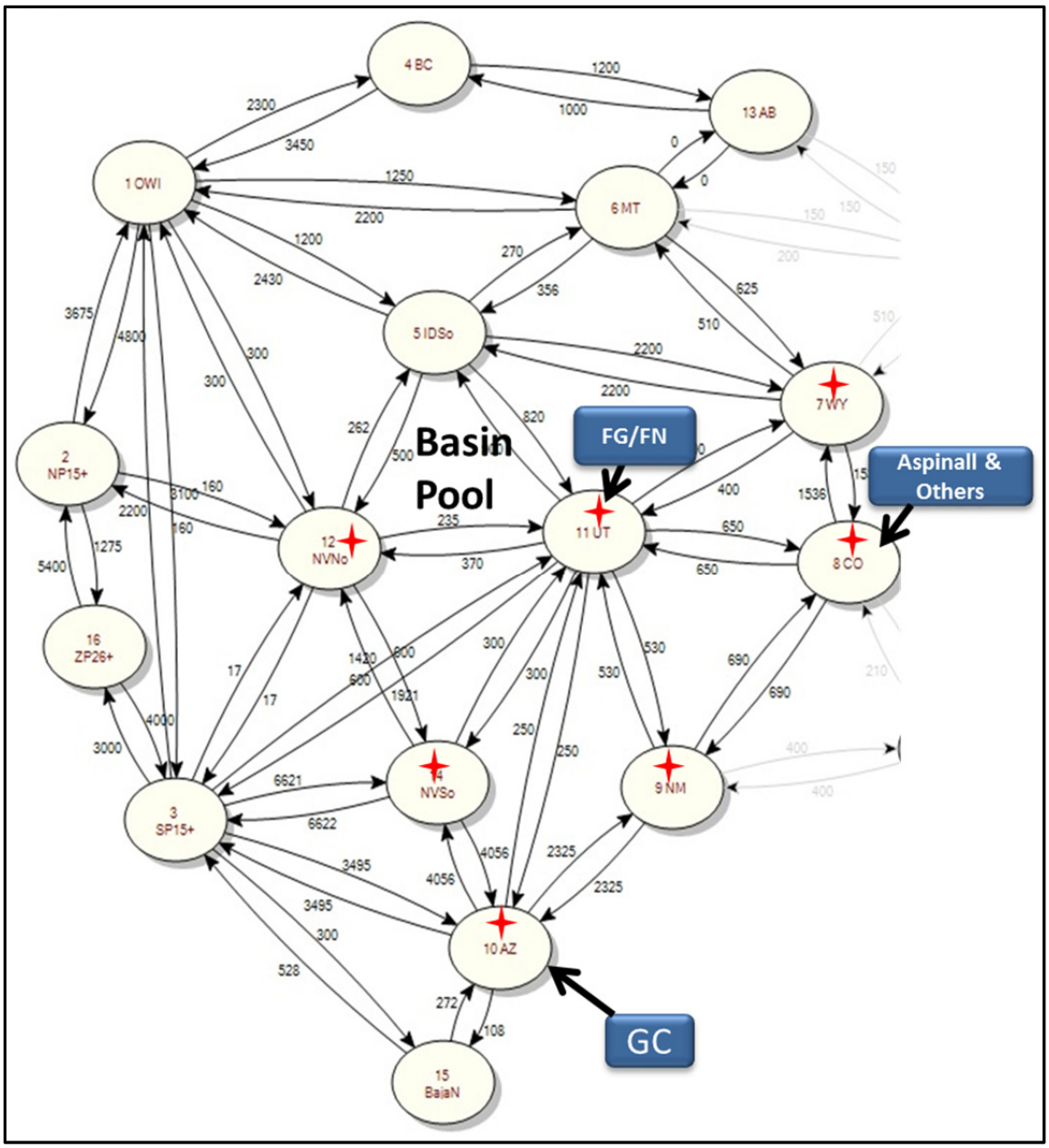


FIGURE K.1-1 Network Topology Used by the AURORA Western Interconnection Model

AURORA Western Interconnection projections of hourly LMPs at the Palo Verde marketing hub are used by the LTF customer and Western SLCA/IP federal resource tiers (i.e., middle and bottom tiers). This hub was selected as a representative point for LTEMP EIS modeling because prices at this location are often used by schedulers at the Western's Montrose Energy Management and Marketing Office (EMMO) as a benchmark for short-term bilateral transactions. Palo Verde hub prices have also been used extensively in the past for other economic and financial analyses of SLCA/IP hydropower resources (see http://www.usbr.gov/lc/region/programs/strategies/FEIS/AppO.pdf and http://www.usbr.gov/uc/envdocs/eis/

AspinallEIS/Vol2-Appdx-D.pdf). As discussed in Attachment K-1, investigations by Argonne indicate that alternative operations at Glen Canyon Dam will have a negligible impact on Western Interconnection LMP levels and patterns outside of the SLCA/IP market system, and are therefore assumed to be static (i.e., given values) and identical under all alternatives.

LTEMP alternatives will have a relatively small impact on bilateral market interactions between the SLCA/IP market system and the rest of the Western Interconnection; that is, a maximum decrease of about 4.3% for power sales and decrease of 1.4% for power purchases. The use of LMPs to measure the economic impact of changes in Western Interconnection transactions yields a very good approximation because the LMP represents the system resource cost to serve the marginal load at a specific point. Therefore, a SLCA/IP market system sale to the Western Interconnection displaces higher cost generation in the interconnection. Likewise, a power purchase by the SLCA/IP market system displaces higher cost generation in the SLCA/IP system by increasing production in the interconnection at a cost that approximately equals the LMP at the Palo Verde hub minus transmission costs.

K.1.3.2 Middle Tier: LTF Customer Utility Systems

The primary focus of the power systems analysis is the SLCA/IP federal hydropower resources and the utilities operated by its LTF power customers. The SLCA/IP federal hydropower resources that the CRSP Management Office markets and the Montrose EMMO schedules are described in more detail in Section K.1.3.3. This section describes the approximately 138 customer entities that have SLCA/IP LTF contractual agreements with Western.

Western sells power to wholesale power customers on both a firm and non-firm basis, including cities and towns, rural electric cooperatives, public utility and irrigation districts, federal and state agencies, investor-owned utilities, power marketers, and American Indian Tribes (Tribes). In total, these entities provide retail electric service to millions of consumers in the Western Interconnection. However, others are end-use customers, including federal and state agencies, and irrigation districts that use power directly for their own purposes. Various laws, including the Reclamation Project Act of 1939 and the Federal Power Act, require Western to give preference to certain types of nonprofit organizations seeking to purchase federal power. Those entitled to preference status include cities and towns, state and federal agencies, irrigation districts, public utility districts, rural electric cooperatives, and Tribes (see https://www.wapa.gov/About/Pages/customers.aspx).

For economic analysis purposes, the system modeled in the middle tier includes LTF customers that are categorized as either large or small. Accounting for about 75% of Western's LTF energy and capacity sales, the eight largest customers, in terms of capacity and energy allocation, are Deseret Generation and Transmission Cooperative (Deseret), the Navajo Tribal Utility Authority (NTUA), Salt River Project (SRP), Utah Associated Municipal Power Systems (UAMPS), Utah Municipal Power Agency (UMPA), Platte River Power Authority (PRPA), Tri-State Generation and Transmission Association (Tri-State), and Colorado Springs Utilities (CSU). Except for NTUA, all large LTF customers own and operate generating resources. About

130 remaining customers were aggregated for the analysis into two "small customer" entities accounting for the remaining 25% of LTF sales. Individually, each small customer receives less than 2.5% of Western's total SLCA/IP LTF capacity and energy sales. Last, Western has LTF contracts to serve project use loads such as pumping for irrigation. Serving these loads has the highest priority for delivery.

In CY 2013, the eight large SLCA/IP LTF power customers owned and contracted for the use of specific physical resources. Based on data contained in EIA Form-860 and information obtained from both IRPs and the EPIS AURORA database, the total firm capacity of these resources was approximately 12,670 MW. As discussed in more detail in Section K.1.7.5, firm capacity in this power systems study is based on the maximum output level that a resource is expected to reliably produce during the time of peak demand. For some generating units, the firm capacity is significantly different from the nameplate capacity.

As shown in Figure K.1-2, over 50% of this capacity is owned by SRP and another 19% is owned by Tri-State. The remaining six large customers account for the remainder. In addition to these supply resources and the aforementioned SLCA/IP LTF contracts, additional firm capacity for is secured through other federal power purchases from Western's Loveland Area Projects and the Desert Southwest Offices and through non-federal power contracts. In addition, DSM measures are credited as firm capacity resources. Based on data contained in Federal Energy Regulatory Commission (FERC) Form-714 and utility IRPs, these resources and non-firm energy transactions were used to serve combined service territory loads of almost 61 TWh in CY 2013.

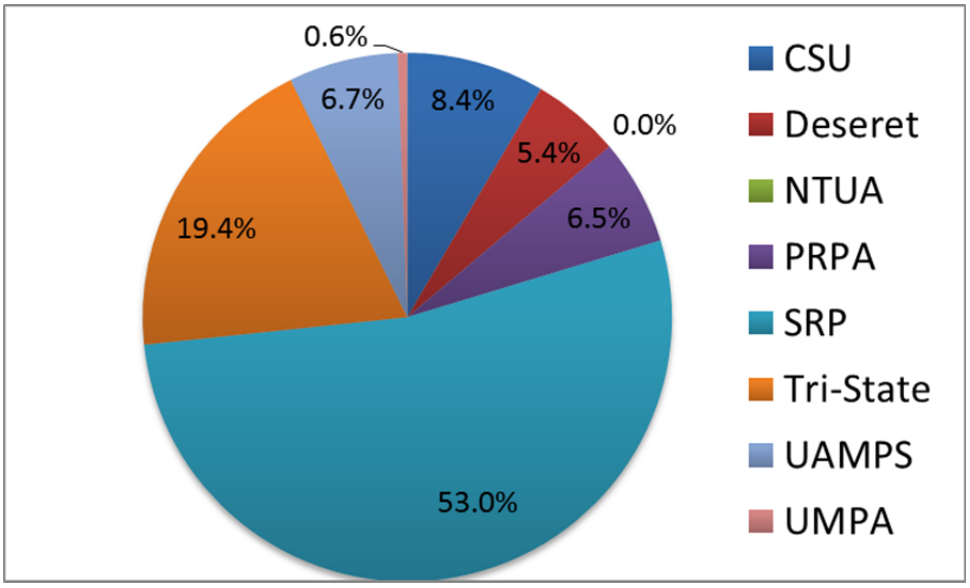


FIGURE K.1-2 SLCA/IP LTF Customer Capacity Ownership Percentages

Figure K.1-3 shows a simplified topology for the SLCA/IP market systems that was used by the AURORA model. It contains both large and small LTF customers. Where applicable, bubbles for large customers (shown as Pool A in Figure K.1-3) contain both loads and resources. Depending on the customer's location, loads and resources are designated as east or west regional entities. In the figure, small customer and project use bubbles only contain loads that have been aggregated by location. Energy flows among entities via system linkages. Some links have limitations and/or associated costs. More details about the SLCA/IP market system topology are described in Section K.1.6.

It should be noted that the Glen Canyon Dam Powerplant and all other federal hydropower plants are modeled as resources that are directly available to Western's customers. In reality, energy and capacity from these resources are sold by the CRSP Management Center to customers through LTF contracts. Argonne staff, in consultation with Western, Reclamation, and the NPS, decided not to include a representation of these contracts in the modeling process because the vast majority of the SLCA/IP federal resource ultimately serves LTF customer loads and capacity needs. Financial complications associated with covering short-term and hourly long and short energy positions would have made the modeling process significantly more expensive and time consuming. It was also judged to have little impact on the assessment of the relative impacts of LTEMP alternatives. Given the time and budget constraints, it was decided that the more direct approach of modeling hydropower resources was sufficient.

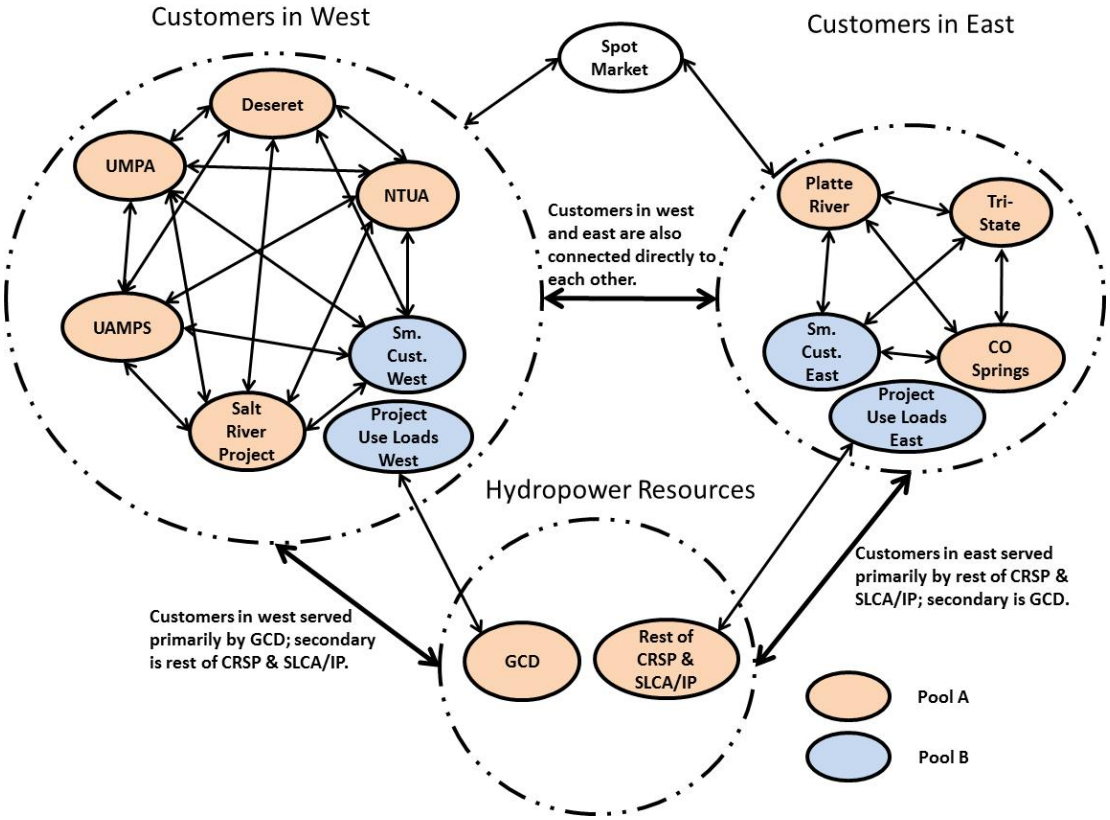


FIGURE K.1-3 Simplified Network Topology of the SLCA/IP Market System

Power systems modeling of the SLCA/IP market system assumes a very high level of cooperation and coordination among Western and its LTF power customers. Capacity expansion planning, unit commitment schedules, and least-cost hourly dispatch for the entire system were based on a "single operator/decision maker" model. This is a higher level of cooperation and coordination than what actually occurs. However, Western and its customers do cooperate on a number of different levels. For example, several large LTF customers jointly own capacity of some of the same facilities. They also buy and sell energy through long-term, day-ahead, and hour-ahead bilateral agreements using various market signals. The SLCA/IP market system topology also includes energy transfer costs that dampen power transfers relative to a "single-decision maker" model that does not incur these costs.

The AURORA topology of the SLCA/IP market system does not model physical transmission constraints. It does, however, limit flows on some links between bubbles. Energy flows on links connecting SLCA/IP federal hydropower resources to LTF customer loads are limited by contract rate of delivery (CROD) allocations (Western 2015). CROD is the firm capacity the CRSP Management Center agrees to have available for delivery. It may or may not be accompanied by energy supplied by Western (see https://www.wapa.gov/crsp/opsmaintcrsp/dictionary.htm#c). When not all of the CROD is being utilized for Western power deliveries, a customer can use the remainder to schedule the delivery of other energy transactions. In addition, 5% of the energy that flows on these links is lost between the point of injection and the delivery point. This represents EMMO current transmission losses for SLCA/IP federal hydropower deliveries. Under wet hydrological conditions in which SLCA/IP total federal hydropower generation exceeds the total CROD, the excess energy flows on links that represent shorter term Western energy transactions with its LTF customers.

Regardless of the amount of firm capacity that is available from SLCA/IP federal hydropower resources, Western's CROD is assumed to be identical under all alternatives. Currently, some customers voluntarily use the difference between the CROD and sustainable hydropower (SHP) on Western's transmission system for customer displacement power (CDP). The SHP is the minimum amount of power and energy the EMMO must deliver to its LTF customers regardless of SLCA/IP federal hydropower conditions. The CDP replacement option is specified under an amendment to the SLCA/IP firm electric service contract to accommodate replacement power decisions. Therefore, it is assumed that any loss in firm capacity under an alternative will free up transmission capacity for CDP transactions (Loftin et al. 1998).

Transfers of energy among LTF customers are virtually unconstrained, which may at times lead to an overestimation of the amount of energy transfers among LTF customer utilities. However, there are significant on- and off-peak costs for energy flows on lines that connect customers to each other. These costs tend to dampen bulk power transactions among the bubbles. Information from Western regarding hourly transmission rates for five of Western's large customers and six other investor-owned utilities in the surrounding area (Wicks 2014) was used to set transfer costs on links between any two firm electric service customers to $6.5/MWh and $3.5/MWh for peak and off-peak, respectively.

Lastly, it is assumed that new capacity built as a result of any losses at Glen Canyon Dam will be located near load centers freeing up transmission at peak times between remotely located Glen Canyon Dam and major loads. This would also result in a somewhat lower energy loss on the transmission lines since more heavily loaded lines during peak hours have higher losses than during cooler off-peak periods. For example, lost capacity from SRP would be built near the Phoenix load center. This will free up transmission between Glen Canyon Dam and Phoenix. These potential advantages were not quantified in this analysis.

Assumptions and simplifications associated with the topology and representation of the SLCA/IP market system may produce modeling errors in some situations. However, the intent of the power systems analysis is to perform a comparative economic study to identify the relative ranking and magnitude of alternative impacts using Alternative A as a benchmark. Because these inaccuracies are present in the evaluation of all alternatives, errors in differences among alternatives may be somewhat muted. Despite the simplifying assumptions and potential inaccuracies, the AURORA dispatch model does provide reasonable results for LTEMP power systems analyses. As discussed in more detail in Section K.1.6.2, a 2013 benchmark analysis of utility-level generation by fuel type for the eight large customers modeled by AURORA were very similar to values reported by each utility in EIA Form-923. This result gave Argonne modelers some degree of assurance that, from a production cost standpoint, the modeling approach captured the essence of the dispatch.

K.1.3.3 Bottom Tier: Western SLCA/IP Hydropower Resources

Of the three analysis tiers, the bottom tier is modeled at the finest level of granularity. It simulates the hourly operation of Western's 11 SLCA/IP powerplants that are marketed and scheduled by the CRSP Management Center. For this study, six of these facilities are classified as large plants. The largest is at Glen Canyon Dam. Its powerplant consists of eight generating units with a combined capacity of about 1,320 MW. As shown in Figure K.1-4, Glen Canyon Dam accounts for about 72% of Western's total SLCA/IP federal hydropower nameplate capacity. Other SLCA/IP federal hydropower plants in the system that are classified as large SLCA/IP federal hydropower facilities include powerplants contained in the CRSP and the Seedskadee Project. All large plants except Fontenelle are in the CRSP. The Blue Mesa Powerplant has two generators, the total capacity of which is 86.4 MW. Located 12 mi downstream from Blue Mesa on the Gunnison River, the Morrow Point Power Plant has two units with a combined capacity of 165 MW; another 6 mi farther downstream, the Crystal Powerplant has an installed capacity of approximately 32 MW from one unit. Blue Mesa, Morrow Point, and Crystal are part of the Wayne D. Aspinall Cascade (also referred to as the Aspinall Cascade). The Fontenelle Powerplant has a nameplate capacity of 10 MW and it is the only powerplant associated with the Seedskadee Project. Flaming Gorge Dam is located on the Green River downstream of Fontenelle Dam. The Flaming Gorge Powerplant has three generating units. Each unit has a nameplate capacity of 50.65 MW for a total of approximately 152 MW. However, because of turbine limitations, the operable capability of the powerplant is approximately 141 MW.

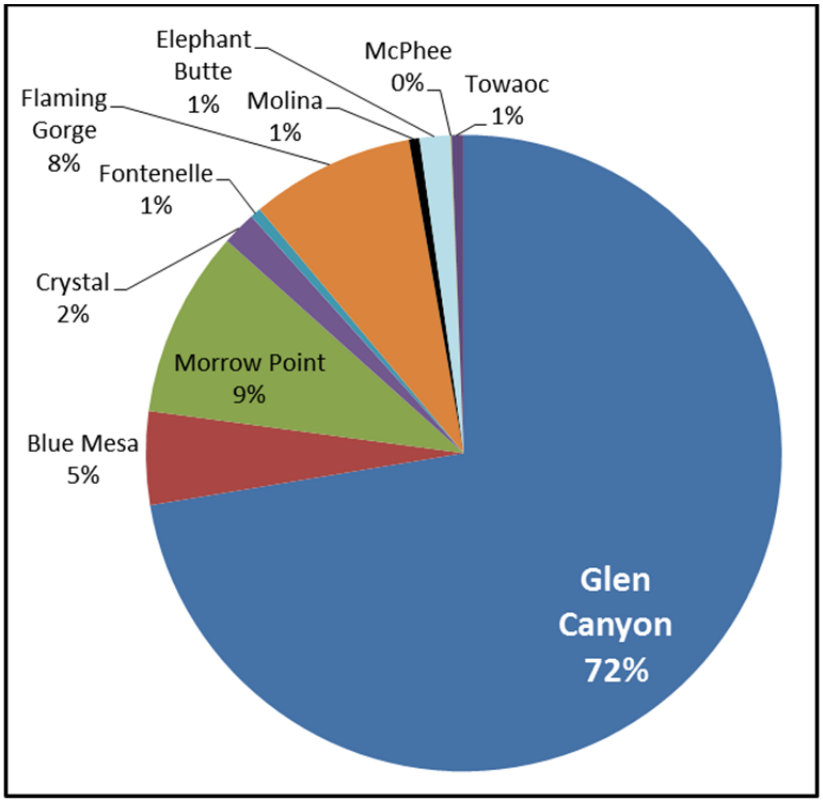


FIGURE K.1-4 Percent of SLCA/IP Federal Hydropower Nameplate Capacity by Facility

The SLCA/IP hydropower facilities that are classified as small include the Upper and Lower Molina complex in the Collbran Project with a combined nameplate capacity of 13.5 MW, the Elephant Butte Powerplant in the Rio Grande Project with 28 MW, and in the Dolores Project, the McPhee and Towaoc Powerplants with total of 11.5 MW. Combined, these small facilities account for less than 3% of Western's SLCA/IP hydropower resources.

Modeled hourly energy production from federal hydropower resources are input into the SLCA/IP market system as a time series of power injections and from bubbles indicated in Figure K.1-3 as "Hydropower Resources." As discussed in more detail in Section K.1.5, both the middle and bottom tier models use a consistent set of LMP projected by the Western Interconnection model (top tier).

K.1.4 Overview of Power Systems Methods

The Argonne team of power system analysts and modelers developed a collection of tools that are linked together to evaluate the economic costs of LTEMP EIS alternatives. The processes by which these tools were used and information flows among them are summarized in this section. The next section describes each tool in more detail, and the ones that follow provide more information on model input data and applications.

Incorporating all aspects of the three tiers discussed earlier, Figure K.1-5 shows the modeling sequence and data flows for the power systems analysis. Using Western Interconnection topology depicted in Figure K.1-1, the AURORA model models the top tier. Palo Verde market hub LMPs produced for CY 2013 are calibrated to closely match observed levels. LMP calibration factors are discussed in more detail in Attachment K-2 and are applied to future years through the end of the study period.

The bottom tier, which represents Western's SLCA/IP federal hydropower plants, is modeled next. Due to the complexities of SLCA/IP hydropower operating criteria and mandates unrelated to power production, AURORA could not directly model either the firm capacity or the hourly operations of the larger and more complex SLCA/IP federal hydropower resources. Therefore, the Colorado River Simulation System (CRSS) model, the Sand Budget Model (SBM), a simplified version of the Generation and Transmission Maximization (referred to as GTMax-Lite) model, and spreadsheet tools were used to project powerplant-specific hourly production levels over the study period at a level of detail sufficient for estimating power economic impacts that would potentially occur from alternative Glen Canyon Dam operations.

The CRSS model developed by Reclamation models the future operations of water-related resources on the Colorado River. Power systems analysis utilized 21 CRSS projected monthly hydrological futures for large Western SLCA/IP federal hydropower plants including Glen Canyon Dam. Separate CRSS model runs are made for each alterative, resulting in unique projections of monthly reservoir elevation and water volume releases for Glen Canyon Dam. The monthly operations of all other SLCA/IP dams are unaffected by an alternative.

A simplified version of the Generation and Transmission Maximization model (called GTMax-Lite) developed by Argonne optimizes the economic value of hourly energy produced by both Glen Canyon Dam and all other large SLCA/IP federal hydropower facilities. The dispatch depends on unit availability as simulated by an outage model, LTEMP EIS operating criteria, SBM monthly water releases, and a time series of energy market prices.

For each alternative, the GTMax-Lite configuration that represents Glen Canyon Dam was run for all traces under two different conditions. The first condition assumes that no distinctive release events such as HFEs will occur in the future; that is, CRSS monthly results and Western Interconnection calibrated LMPs drive hourly SLCA/IP operations. No TMFs or HFE are conducted in this first set of model runs. Using these initial results from CRSS and GTMax-Lite, the Reclamation SBM schedules various HFEs that differ in terms of peak water release rate, duration, and timing. The SBM also reallocates CRSS monthly water release volumes among the months of a single WY in order to enable higher water releases during months with experiments. Due to the reallocation of monthly water releases and the scheduled TMFs and HFEs, the GTMax-Lite model that represents Glen Canyon Dam must be run a second time using the SBM results. It is this second GTMax-Lite run that is used for Glen Canyon Dam for all power systems economic analyses.

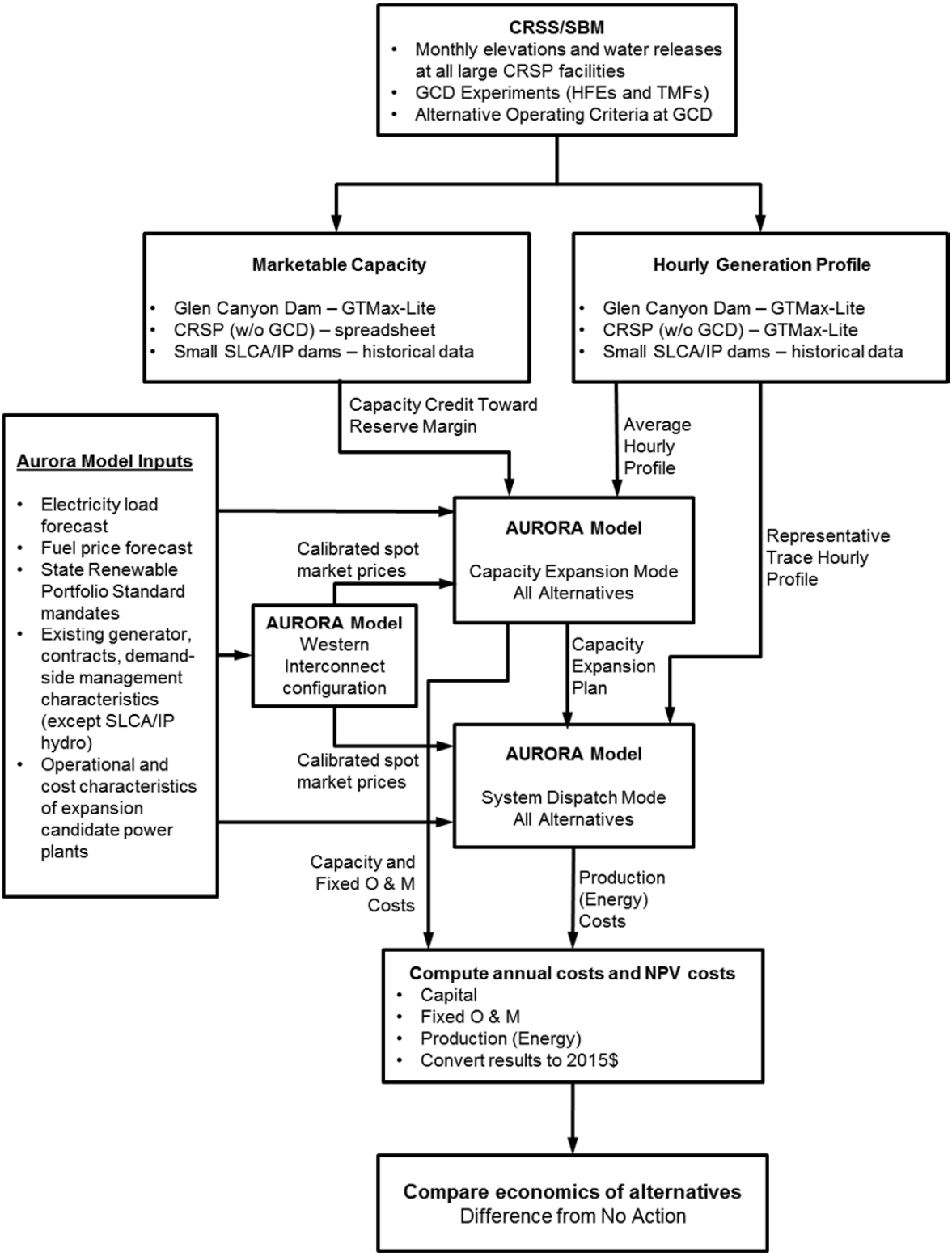


FIGURE K.1-5 Flow Diagram of the Power Systems Methodology Used in the LTEMP DEIS

A second configuration of GTMax-Lite configuration simulates the operation of other large SLCA/IP powerplants. It also uses input data from the CRSS model and calibrated Western Interconnection LMPs. The Glen Canyon Dam LTEMP DEIS alternative operating criteria and experimental releases conducted at Glen Canyon Dam do not impact the operations of these upstream resources; therefore, the SBM does not consider these resources in the determination of when HFE events will occur. GTMax-Lite optimization for these plants was performed for a condition that represents an average hydrological condition as projected by CRSS and for the CRSS projection, also known as a trace, which was judged by Argonne staff to be "representative" of the 21 projections. The selection of this representative trace is described in Attachment K-3.

The firm capacity of Western's SLCA/IP federal hydropower resources is computed by spreadsheet tools that estimate the maximum potential output of these resources during the time of peak system load. Depending on an alternative's operating criteria, the maximum output level at the Glen Canyon Dam Powerplant is suppressed. For example, flat flow alternatives are associated with relatively low firm capacity levels, while higher firm capacity levels are attained under less stringent operating criteria such as under Alternative B. As described in more detail in Sections K.1.5 and K.1.7, determination of Glen Canyon Dam Powerplant capacity is based on GTMax-Lite hourly results for all 21 projected futures. Other large SLCA/IP hydropower plant firm capacities are based on CRSS projected futures and power equations that estimate maximum output levels.

The middle tier is modeled by the SLCA/IP market system configuration of AURORA. This configuration contains all of the loads and resources that are in the utilities operated by SLCA/IP LTF wholesale customers and a point that represents a connection to the rest of the Western Interconnection. At this interconnection point, energy is bought and sold at the calibrated Palo Verde market hub price. Hour-by-hour energy injections into the system from Western's hydropower resources are prescribed as determined by GTMax-Lite.

For each alternative, AURORA was used for two major purposes: (1) to determine the cost of capacity expansion pathway over time during the study period for the SLCA/IP market system; and (2) to compute production costs associated with a least-cost unit commitment and system dispatch for a given expansion pathway and a single representative hydrology future or trace. Therefore, AURORA is run in two modes. The first, or "expansion," mode is used to determine the type of technologies that will be built in the SLCA/IP market system and the time when system capabilities will be expanded. It also considers scheduling the retirement of existing generating units. The second, or "dispatch," mode determines unit commitments and performs a system dispatch of a static set of both existing and new resources. This static resource set was determined by previous AURORA capacity expansion runs.

As shown in Figure K.1-5, calibrated market prices are used by both the capacity expansion and system dispatch modes for all alternatives. However, the AURORA capacity expansion model runs use the hourly energy production from Western's SLCA/IP hydropower resources, based on an average hydropower condition, while AURORA dispatch runs use generation level projected by the representative trace.

Results of the AURORA dispatch model consist of costs to produce the electrical energy to meet the system load demand. Production costs are the sum of powerplant fuel costs, variable O&M costs, unit startup costs, and the cost of power purchased from the spot market minus spot market sales revenues. Results from the AURORA expansion and dispatch models (namely capital, fixed O&M, and production or energy costs) were combined to determine the total annual costs for each alternative. The NPV stream of costs was also calculated to facilitate comparisons among alternatives. This single lump-sum value was based on a discount rate of 3.375%, a rate that is used by Reclamation for cost-benefit studies of projects. The use of this discount rate was in part based on information contained in Attachment K-4, which was provided by Reclamation staff. At the recommendation of Western staff, a second discount rate of 1.4% was used in a sensitivity study.

K.1.5 Description of Individual Power System Models

As described in the previous section, Argonne used several tools and models of varying levels of detail and complexity to estimate the economics of LTEMP DEIS alternatives. Additional information on each of these tools and models, along with a description of other supporting algorithms, is provided below.

K.1.5.1 Colorado River Simulation System Model (Bottom Tier)

The CRSS model was developed by Reclamation to model future operations of water-related resources on the Colorado River, including both the upper and lower portions of the basin. The Glen Canyon Dam is the lowest reservoir in the upper basin. For the LTEMP EIS, CRSS projected 105 monthly hydrological futures over a 48-year time period from 2013 through 2060, inclusive. Each future or trace is based on a historical time series of hydrological conditions. Power system analyses utilize the first 21 years of CRSS projections of reservoir elevations and water release volumes for CRSP and the Seedskadee project; that is, the set of large plants. Of the 105 traces projected by CRSS, a common set of 21 was used by all DEIS research areas including power systems analyses.

For the initial structured decision-making exercises, all of the simulation cases included three separate options for sediment conditions (high, moderate, and low), effectively multiplying the number of simulations required by a factor of three. Once the detailed results were generated, the three sets of findings were assigned relative weightings in order to combine and condense the findings into weighted averages. For expediency in the power systems analysis, all of the simulation runs will be based on a single sediment option (the moderate case, also designated "s2" in previous treatments), which was weighted by 63.1% for combining the detailed results. This greatly reduces the number of cases to be examined, and based on previous findings it does not affect comparisons or conclusions regarding impacts of the alternatives.

Separate CRSS model runs are made for each alterative, resulting in a unique projection of monthly reservoir elevation and water volume releases for Glen Canyon Dam. However, monthly operations of all other SLCA/IP dams are identical under all alternatives. Therefore,

operations for all Large SLCA/IP federal hydropower plant model runs of GTMax-Lite used CRSS results for the Alternative A. In addition, Reclamation staff determined that LTEMP DEIS alternatives have negligible impacts on reservoir, and hence, power operations in the Lower Colorado River Basin, including those at Hoover Dam. Therefore, operations downstream of Glen Canyon Dam were not included in power systems analyses.

K.1.5.2 Representative Trace Tool (Bottom Tier)

The Representative Trace Tool contains supplemental software written by Argonne specifically for the LTEMP DEIS. It assists in the selection of a single hydrological trace for the detailed hourly dispatch of Western's large SLCA/IP hydropower plants. The trace chosen best meets a set of criteria for being "representative." The representative trace must have annual variations in hydrological conditions at Glen Canyon Dam that are similar to the hydrological distribution of the entire population of the 21 common trace set for sediment condition 2. The mean Glen Canyon Dam annual water release of the representative trace must also be approximately equal to the mean of all 21 traces. For consistency, the selected trace is also applied to the other five large SLCA/IP federal hydropower plants.

K.1.5.3 Hydropower Outage Model (Bottom Tier)

The Hydropower Outage model and supporting spreadsheets are used to simulate unit outages at all six large SLCA/IP federal hydropower powerplants. This includes both scheduled outages and forced outages that are caused by random mechanical and electrical events. Designed and written by Argonne, a methodology was developed to incorporate the number, cause, and duration of forced outages that may potentially occur during the 20-year study period. The model uses a random number generator to simulate the timing and cause of forced outages using data contained in the NERC Generating Availability Data System (GADS). Several instances of the model were run. The time series of random outage selected for LTEMP analyzes was the one that closely matched GADS statistical averages. The outage methodology is discussed in more detail later in Section K.1.7.3 and in Attachment K-5. The same time sequence of representative outages was used under all alternatives.

Reclamation provided Argonne with maintenance schedules over the study period for large SLCA/IP facilities. The timing and length of outages at large SLCA/IP powerplants is in general the same under all DEIS alternatives. However, during HFEs and TMFs, it was assumed that a scheduled maintenance outage would not be conducted.

K.1.5.4 Generation and Transmission Maximization-Lite (Bottom Tier)

GTMax-Lite is a simplified version of the full GTMax model. Both were developed by Argonne. GTMax-Lite has limited scope and data requirements compared to the full version of GTMax. The two versions of GTMax-Lite used for the LTEMP DEIS represent only the physical characteristics of hydropower plants, downstream flow requirements, and both water release and

reservoir operating criteria. The primary modeling objective of the lite version is to maximize the economic value of hydropower resources. This differs from the full GTMax model, in which the full model represents other factors such as customer power delivery requests sent to the EMMO, short-term purchase and sale commitments, and non-economic EMMO dispatch goals and guidelines. Although full GTMax and GTMax-Lite differ, they share many of the same features and in general produce similar generation patterns and estimates of hydropower economic value.

The GTMax-Lite model configuration used for LTEMP power systems analyses optimizes the economic value of hourly energy produced at both Glen Canyon Dam and all other large SLCA/IP federal hydropower facilities. Operations depend on both unit availability as simulated by the outage model and a set of operating criteria. For the LTEMP DEIS, two configurations of the model were constructed. One represents the operation of only Glen Canyon Dam, and the other optimizes the operation of the remaining large hydropower facilities.

GTMax-Lite was used because many thousands of weekly runs with hourly time steps need to be performed rapidly. It was customized to address a specific problem by tailoring the objective function, the input and output routines, and the model constraints to be consistent with LTEMP modeling needs; that is, it models federal hydropower resources without LTF contractual obligations. Multiple model runs and data handling are controlled by a Microsoft Excel® spreadsheet, and the objective function is optimized using the Lingo software, which simultaneously identifies the best pattern of hourly energy production over time that satisfies all operational constraints.

Glen Canyon Dam Configuration

The Glen Canyon Dam GTMax-Lite model was run thousands of times in support of the structure decision analysis (SDA) process. This includes nearly 1,000 LTEMP scenario optimizations (combinations of 15 alternatives, 21 hydrology traces [based on 105 years of historical data], and three sediment traces) that optimize water releases (each run consisting of 180,000 hours of Glen Canyon Dam flows). The GTMax-Lite hourly water release results are used by analysts of each resource area, such as sediment, fish, recreation, and riparian vegetation. Analyses of power systems economics leverages the outputs produced by this process.

Initial SDA exercises used all of the simulation cases, including three separate options for sediment conditions (high, moderate, and low), effectively multiplying the number of simulations required by a factor of three. Once the detailed results were generated, the three sets of findings were assigned relative weightings in order to combine and condense them into weighted averages. For expediency in the power systems analysis, all of the simulation runs were based on a single sediment option (the moderate case), which was weighted by 63.1% for combining the detailed results. It should be noted that for any given hydrology, variations in sediment level had only minor impacts on SDA power outcomes. This greatly reduces the number of cases to be examined and, based on previous findings, does not affect comparisons or conclusions regarding impacts of the alternatives.

GTMax-Lite simulated operations at Glen Canyon Dam were made for all 21 projected hydrological futures over the entire study period. As described below, all runs were performed twice. The Glen Canyon Dam configuration uses hourly AURORA calibrated prices projected by the Western Interconnection configuration to maximize the economic power value of operations during representative 1-week periods for each month during the study period. Hourly prices input into the model are average values based on weekday, Saturday, and Sunday/holiday Palo Verde hub LMP projections. Model results for hourly Glen Canyon Dam generation are greatly influenced by the hourly LMP profile, a weekly water release requirement, Lake Powell Reservoir elevation, and LTEMP alternative operating criteria.

To achieve more accurate/realistic results, both GTMax-Lite configurations explicitly model scheduled and forced outages. Reclamation provided a maintenance schedule for all six CRSP facilities over the study period (Clayton 2013). A methodology was developed to incorporate the number, cause, and duration of forced outages that would be expected during the study period. Data on forced outages for hydroelectric turbines were obtained from GADS, which is a database of operating data on electric generating equipment maintained by the NERC. This information was input into an algorithm that produced a plausible series of random outages for units at the Glen Canyon Dam Powerplant. For large SLCA/IP federal hydropower facilities, based on the cause of forced outages and associated average down times using data contained in the NERC GADS for hydropower plants that had capacities greater than 30 MW.

Market prices input to LTEMP power system models represent the economic value of hydropower generation at hourly intervals. These prices directly influence the generation schedule produced by the models when optimizing SLCA/IP hydropower resources. To the extent possible, the GTMax-Lite model uses its limited-energy/water resource stored in a reservoir (i.e., Lake Powell at the Glen Canyon Dam) to first generate electricity during on-peak hours when it has the highest economic value. Any remaining energy is scheduled during lower-priced hours.

Model-generated operations comply with any operating constraints and downstream flow targets placed upon the hydropower system for environmental or institutional reasons. Operating constraints include limits on water release up- and down-ramp rates, limits on reservoir water release rate changes over a rolling 24-hour period, ancillary service requirements, and others.

Figure K.1-6 illustrates a typical Glen Canyon Dam GTMax-Lite result for a 24-hour period. The green bars represent hourly Glen Canyon Dam Powerplant production, the total of which is highly influenced by the mandated monthly water release volume. The light green line shows hourly market prices. In general, energy production is the highest when it has the most value. Note that the production levels are such that the total of hourly generation multiplied by the market price (i.e., energy production value) over the day is as large as possible. The production pattern adheres to all operating criteria such that the power output pattern complies with minimum and maximum flow rate constraints, ramp-rate limits, and daily change restrictions. Also note in this example that some of the constraints are binding. In this case, the minimum and maximum generations do not bind the solution; that is, generation levels do not operate at either of these levels. Generation pattern is bound or limited by daily change and both up and down hourly ramp rate constraints. However, when more water is released for power

generation, the maximum limit becomes binding because peak generation levels are possible within the daily change constraint. On the other hand, when hydropower generation is low, the minimum constraint becomes binding. Therefore, hydropower conditions often dictate when a constraint is either binding or not binding.

More operational flexibility at Glen Canyon Dam always translates into higher or equal economic value. For example, if there was no daily change constraint, powerplant output in Figure K.1-6 would have been at the minimum during the nighttime, when prices are lower, and ramped up over a few more hours to reach the maximum output level when prices are the highest. A further relaxation of operating criteria by removing hourly ramping constraints, lowering the minimum, and increasing the maximum would have resulted in a higher concentration of Glen Canyon Dam generation in the hours with the highest demand. The daily maximum generation level would have also been higher. Therefore, limits not only constrain the economic value of energy, but also impact the maximum output that Glen Canyon Dam produces during system peak loads and therefore reduce its firm capacity.

The Glen Canyon Dam version of GTMax-Lite compresses the full 8760 hours per year into 12 "typical week" periods of 168 hours for each month. Outputs include hourly turbine and non-turbine water release and power generation schedules for a series of representative 1-week time periods (i.e., sequence of 168-hour time periods) that maximize the economic value of hydropower energy resources. The Glen Canyon Dam GTMax-Lite configuration utilizes a "wrap" technique that significantly reduces model end-effects associated with running typical

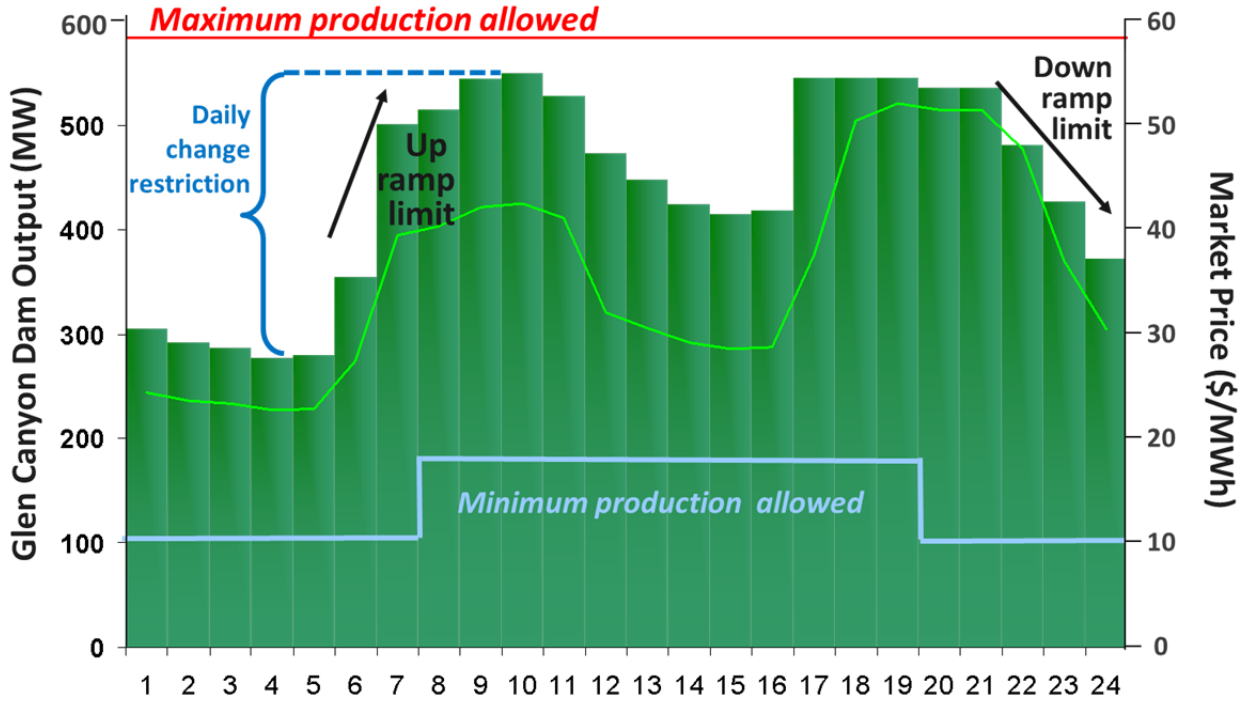


FIGURE K.1-6 Illustration of a Typical GTMax-Lite Result for a 24-Hour Period

weeks. The technique essentially connects the modeled beginning hours to those at the end of the optimized week. Because the model mathematically repeats the same weekly pattern infinitely, ending model solutions are positioned such that it is starting in a good position for operations during the following week.

Because the GTMax-Lite model only simulates operations for one representative week in each month, the results are repeated to reflect full months of hourly operations for each year of the study. This is accomplished by assigning the typical water and generation release pattern estimate by GTMax-Lite for specific day types to each day of the month. For example, the Sunday optimized pattern is assigned to all Sundays and holidays that occur in a month. It should also be noted that GTMax-Lite is provided with the number of day types that occur in each simulated month. Using this information, GTMax-Lite produces a weekly result such that the repeated daily results over a month release the exact amount of specified monthly water release.

The GTMax-Lite configuration that represents Glen Canyon Dam was run under two different of assumptions. The first assumes that no distinctive release events such as HFEs will occur in the future, in which case CRSS data are used to drive operations. This information was input into the SBM in order for the model to schedule HFEs and adjust CRSS monthly water release volumes and Glen Canyon Dam reservoir elevations. This intermediate solution was only used by the SBM.

For a second run of the Glen Canyon Dam GTMax-Lite model, it is assumed that HFEs will occur as scheduled by the SBM. The LTEMP DEIS defines several different types of HFE, each with a unique specified hourly water release pattern. GTMax-Lite models operations when an HFE is *not* scheduled. A separate routine is used to compute Glen Canyon Dam Powerplant generation based on the prescribed HFE water release pattern. This pattern depends on the type of HFE that would be conducted. Under most HFEs, there are time periods when water release requirements exceed the combined maximum flow rate of Glen Canyon Dam Powerplant turbines. Therefore, the routine tracks both turbine water and non-turbine water releases. It also computes power production levels based on Lake Powell's water elevation. During days in a month in which an HFE is not scheduled, Glen Canyon Dam hourly generation simulated by GTMax-Lite accounts for the SBM monthly water release volume, the amount of water that was released during the HFE, and the number of normal operating days (i.e., day without the HFE) in the month.

Other Large Federal SLCA/IP Hydropower Resources Configuration

Because Western markets power from combined SLCA/IP facilities, of which Glen Canyon Dam is the single largest component, a second GTMax-Lite configuration was developed. It represents the remaining CRSP hydropower powerplants, including Blue Mesa, Morrow Point, Crystal, and Flaming Gorge, and the Fontenelle Powerplant of the Seedskadee Project. Although Fontenelle is not technically part of CRSP, it is included in this configuration because it is operated as a cascade with Flaming Gorge and the CRSS model projects both monthly reservoir elevations and releases for these facilities. This GTMax-Lite configuration and

its key operating constraints, shown in Figure K.1-7 below, were developed specifically for the LTEMP DEIS.

GTMax-Lite is a scaled-down version of the full GTMax model. Both represent all the physical CRSP and Seedskadee powerplants and downstream flows at gages in the Green River. However, the lite version omits the representation of SLCA/IP firm contracts. Instead, large SLCA/IP hydropower plant operations are driven directly by electricity market price signals—not contracts. This streamlined process involves far fewer model operator steps and solves the problem considerably faster than the full GTMax model. The GTMax-Lite configuration that represents these five large SLCA/IP powerplants was run once for an average hydrological condition to support AURORA capacity expansion model runs, and a second time using the representative trace to support SLCA/IP detailed system dispatch runs. It optimizes operations during all hours of the study period, based on input data from the CRSS model and AURORA Western Interconnection calibrated market prices for the Palo Verde market hub. LTEMP DEIS alternative and experimental releases conducted at Glen Canyon Dam, such as HFEs and TMFs, do not affect the operations of these five upstream resources. Therefore, this configuration uses CRSS results for Alternative A. Therefore, the SBM did not adjust CRSS results.

As shown in the figure, GTMax-Lite contains two water cascades. The first consists of the Fontenelle and Flaming Gorge Reservoirs and the second consists of the Aspinall Cascade, which includes the Blue Mesa, Morrow Point, and Crystal reservoirs. Operationally, reservoirs in

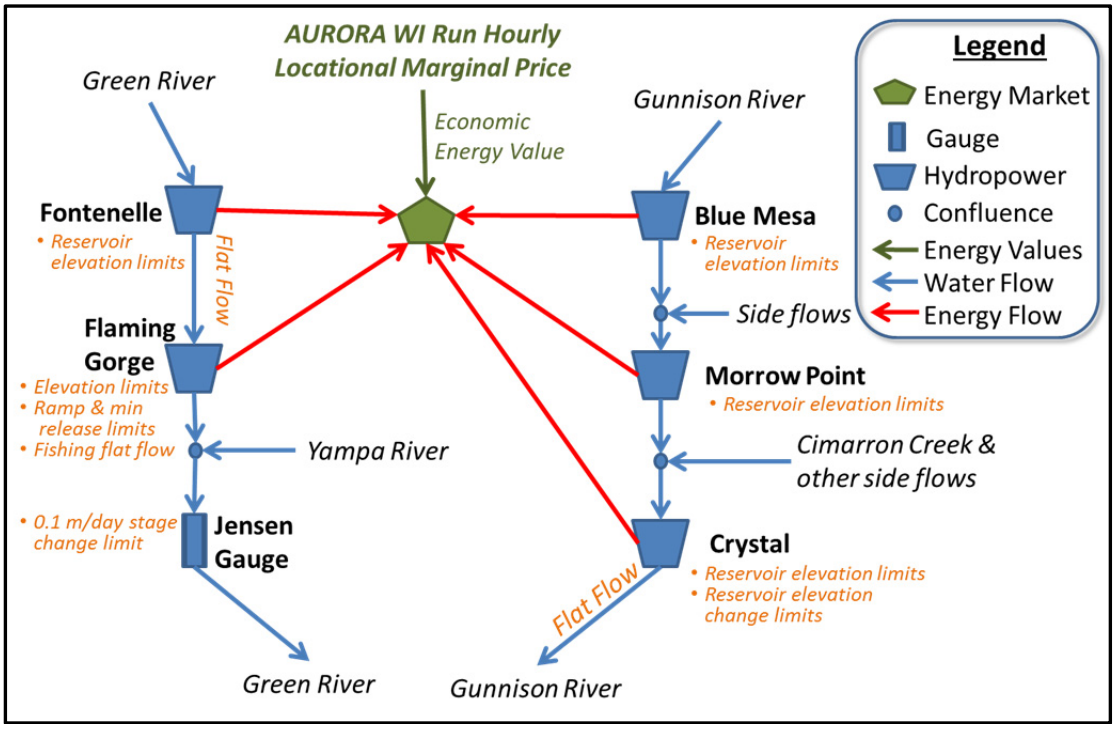


FIGURE K.1-7 GTMax-Lite Network Topology for the Large SLCA/IP Hydropower Resources Other Than Glen Canyon Dam

the first cascade are very loosely connected, but reservoirs in the Aspinall Cascade are very tightly coupled.

Monthly releases and reservoir elevations were obtained from CRSS model results for Alternative A. CRSS also provides information about water inflows into reservoirs, side flows that occur between connected reservoirs, and reservoir evaporation. Other inputs included operating constraints placed on the facilities, such as restrictions on water release ramp rates and flow requirements at the Jensen Gage downstream of Flaming Gorge. The objective function simultaneously maximizes the economic value of the hydropower resource at these five large facilities. The output is an hourly schedule of water releases and electric generation that maximizes the economic value of hydropower resources within the bounds of all operating constraints.

Operating constraints include maximum and minimum limits imposed on all reservoirs and a complex set of restrictions at the Crystal Reservoir that bound the rate of elevation changes over time. In order to ensure that water releases do not violate reservoir operating constraints, the GTMax-Lite model computes hourly water mass balances and reservoir elevations using reservoir elevation-volume functions. Water balancing equations account for water inflows, side flows, evaporation, upstream reservoir water releases, and all releases from the reservoir of interest.

Flows at the Jensen Gage are restricted to daily stage changes of 0.1 meters/day. Because gage flows are directly affected by upstream water releases from the Flaming Gorge Reservoir, GTMax-Lite models gage flows that comply with the daily gage constraint. To optimize Flaming Gorge operations, water travel time distribution (WTTD) functions are used to estimate the time it takes water to flow through Green River reaches, and the attenuation of releases as water travels downstream. For this study, two reaches are defined. The first is from the Flaming Gorge Dam to the confluence of the Green and Yampa Rivers and the second is from this confluence down to the gage. Although WTTD can vary by hydrological condition, for this study a typical WTTD function was derived from Streamflow Synthesis and Reservoir Regulation (SSARR) model outputs. SSARR was written by the Army Corps of Engineers. In general, it takes about 24 hours for the first fractional amount (less than 1%) of a Flaming Gorge release to reach the gage. Typically, all of the water passes the gage 48 hours after the release. Gage readings are computed using a function that relates the flow rate at the gage to the gage stage. Yampa River water flows into the Green River are based on historical monthly data. Based on historical records, for this study a monthly 50% flow exceedance was input into GTMax-Lite.

The temporal modeling methods used by GTMax-Lite for the five large hydropower plants differ from the Glen Canyon Dam configuration because it simulates operations for all hours during every study period day. It was structured and configured differently from Glen Canyon Dam GTMax-Lite because the operating constraints at powerplants and reservoirs in the Aspinall Cascade are fundamentally different from those at Glen Canyon Dam. The imposition of gage constraints at Jensen is also unique. The five-plant configuration of GTMax-Lite needs to be run far fewer times than the Glen Canyon Dam configuration, and therefore it is computationally more affordable to model all days.

As shown in Figure K.1-8, time in the five large plant configuration of GTMax-Lite is separated into three periods that include history, primary optimization, and extension. The historical period is required because operations in the past affect future operation. These include operations in the Aspinall Cascade that constrain Crystal Reservoir elevation changes over 1-day and 3-day periods. In addition, operations at the Flaming Gorge Dam need to comply with gage flow constraints. Note that the water travel time from the Dam to the gage is about 2 days. For the first model run, actual historical operations are input into the model. However, for all subsequent optimizations, "history" is obtained from the previous model run. For this study, hourly results for the last 3 days of the primary optimization period are used.

To reduce model end effects and place operations at the end of the simulated period in a good position for the following days, a 1-week extension period is included in each model run. This differs from Glen Canyon Dam GTMax-Lite model runs that apply the previously described wrap technique to reduce model end effects. Results for the extension period are not used by AURORA or in any economic calculations. Instead, results for the extension period are erased and replaced with primary optimization period results from a subsequent model run.

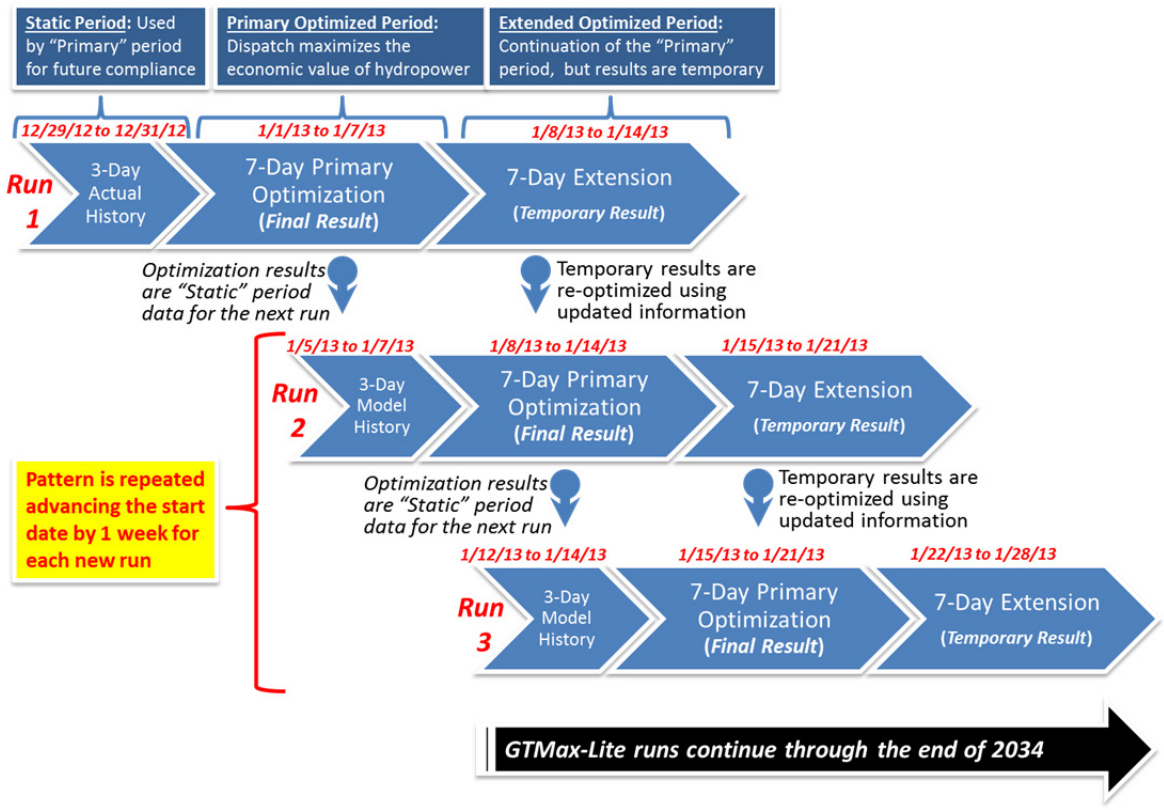


FIGURE K.1-8 Illustration of Temporal Modeling Method Used in the GTMax-Lite Five Large SLCA/IP Plant Configuration

K.1.5.5 Sand Budget Model (Bottom Tier)

The Reclamation SBM schedules various HFEs that differ in terms of peak water release rate, duration, and timing. It uses results from the CRSS model and the intermediate Glen Canyon Dam GTMax-Lite solution. The model is run for each alternative using alternative specific triggers to schedule future HFEs under all 21 hydrological futures and three sediment futures.

SBM maintains the annual WY release volumes specified by CRSS, but reallocates monthly volumes in order to enable higher water releases during months with experiments. Due to the reallocation of water releases, the Glen Canyon Dam GTMax-Lite model is run a second time using the SBM results. It is this second GTMax-Lite run that is used for all economic analyses.

K.1.5.6 Large SLCA/IP Powerplant Spreadsheets (Bridges Bottom and Middle Tiers)

Several spreadsheets were written by Argonne in support of the LTEMP DEIS power system analyses. These large SLCA/IP powerplant spreadsheets perform the following functions:

- Create alternative-specific hourly Glen Canyon Dam generation input data for the SLCA/IP market system configuration of AURORA. One set of generation data contains average hourly values computed from GTMax-Lite results for the 21 SBM traces. These values are used for SLCA/IP capacity expansion simulations. The second set of Glen Canyon Dam generation is based on GTMax-Lite results for the representative trace and used for AURORA dispatch model runs.

- Determine the amount of Glen Canyon Dam capacity will be reserved and available for ancillary services for each day of the simulation period. If these services cannot be entirely fulfilled by the Glen Canyon Dam Powerplant, the amount that needs to be supplied by Aspinall Cascade powerplants is computed. Computations for Glen Canyon Dam and the Aspinall Cascade are performed for each alternative.

- Find and store the maximum daily generation level contained in Glen Canyon Dam GTMax-Lite outputs for all alternatives and traces. These data are used by the Firm Capacity Spreadsheet that computes aggregate firm capacity level for SLCA/IP federal hydropower resources.

- Create alternative-specific hourly generation input data for AURORA that represents the five large SLCA/IP powerplants. One set of generation data is based on GTMax-Lite that models these five large plants based on average monthly releases and reservoir information that is derived from CRSS trace results. These values are used for SLCA/IP capacity expansion simulations.

The second set of large SLCA/IP hydropower generation values is based on GTMax-Lite results for the representative trace and used for AURORA dispatch model runs.

- Determine the maximum potential output level from the five large SLCA/IP powerplants. Maximum output levels are computed for all combinations of unit outages at each powerplant based on operating criteria, turbine capacities, forebay elevation, tailwater elevation calculations, and water-to-power conversion factors as a function of head. Except for minor adjustments that account for Aspinall spinning reserve and regulation service duties, maximum output levels are identical across all alternatives. Based on user-defined risk level, spreadsheet results are also used by the Firm Capacity Spreadsheet to set the aggregate firm capacity level for Western's SLCA/IP federal hydropower resources.

K.1.5.7 Small SLCA/IP Powerplant Spreadsheet (Bridges Bottom and Middle Tiers)

The capacity and dispatch of relatively small SLCA/IP federal hydropower resources including Deer Creek, Elephant Butte, Towaoc, McPhee, and Molina are estimated using the Small SLCA/IP Powerplant spreadsheet. Estimates of future hourly plant-level generation are on based on historical Form PO&M-59 data and powerplant duty cycle (i.e., baseload or peaking). This spreadsheet is also used to estimate maximum output levels for use in computations of Western's SLCA/IP hydropower firm capacity. The same hourly generation and maximum output values are used for all alternatives for both AURORA capacity expansion and dispatch model runs.

K.1.5.8 Loads Shaping Algorithm (Middle Tier)

In order to project hourly customer loads for LTF large and small customers, Argonne analyzed several years of historical load data for the eight large customers that was contained in the FERC Form-714. Normalized loads for CY 2006 were selected to serve as a representative profile and used as the basis for projecting future chronological hourly loads for all LTF customers. The basis for selecting this year is described in more detail in Section K.1.6.3. Normalized profiles cannot simply be multiplied by a constant value (e.g., monthly peak load) to scale loads for a future year, because load factors are projected to change over time. Therefore, the Loads Shaping Algorithm is used to compute hourly scaling factors that, when applied to the normalized profile, produce a time series of chronological hourly loads that simultaneously match both a projected monthly peak load and monthly total load.

The Loads Shaping Algorithm uses a quadratic programming technique that minimizes differences between a normalized load duration curve (LDC) constructed from historical data and a reshaped LDC generated by the model. Figure K.1-9 shows the original LDC, constructed from historical loads for one of the large customers and the reshaped LDC. The reshaped curve is

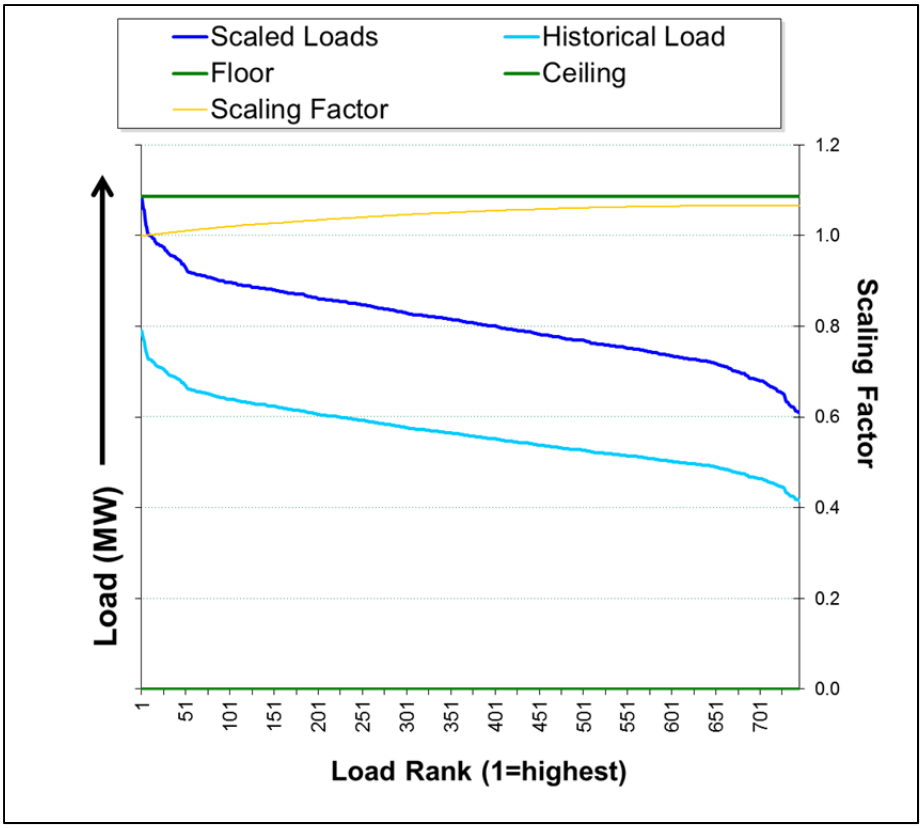


FIGURE K.1-9 Example of the Load Scaling Algorithm LDC

consistent with a projected monthly load factor. Upper and lower load constraints may be specified by the user to bind the model's solution. For each point in the LDC, a scaling factor, shown on the secondary y-axis, is then computed as the ratio of the reshaped load to the original load. Finally, the algorithm constructs a scaled chronological hourly profile based on the load scaling factors and an associated original hourly load. The end product, as shown in Figure K.1-10, is a chronological load time series that exactly matches the monthly projected peak and total load.

K.1.5.9 AURORA (Top and Middle Tiers)

The AURORA model is at the core of the methodology used to identify SLCA/IP federal hydropower interactions with the power grid. It was developed by EPIS, Inc., and it is used by utilities throughout the United States to model capacity expansion pathways, simulate unit commitments, and perform hourly unit dispatch. Based on information contained in the EPIS, Inc., Web page (http://epis.com/AURORA_xmp/long_term_expansion.php), one of the primary uses of AURORA is for lifecycle analysis and resource capacity expansion optimization studies.

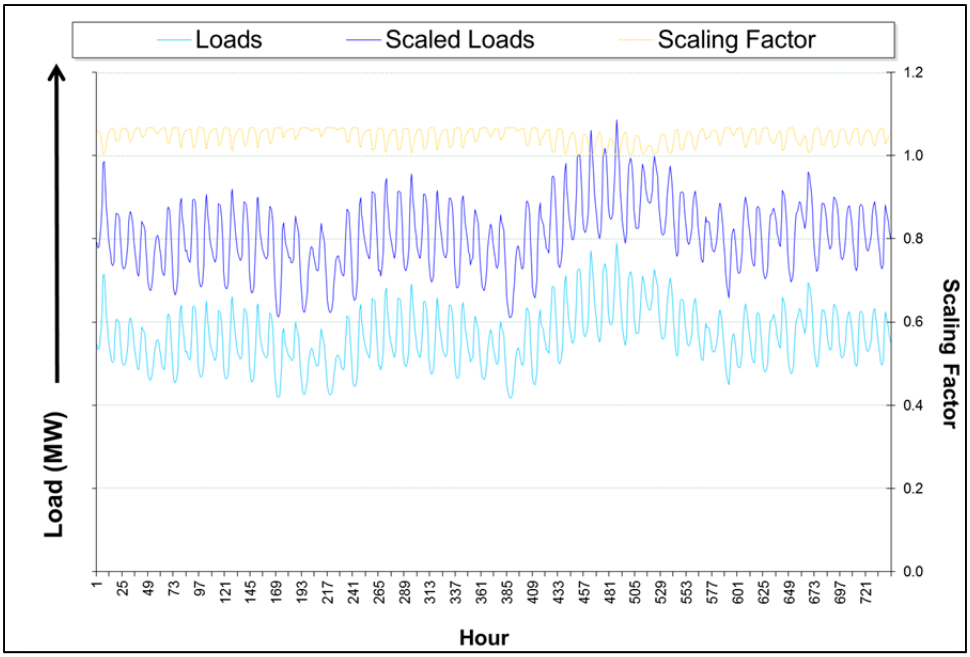


FIGURE K.1-10 Example of the Load Scaling Algorithm Chronological Hourly Loads

AURORA uses hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. This algorithm also models the deployment of curtailments at market price trigger points. LMPs projections are made in user-defined market bubbles over long-term planning horizons. For the LTEMP DEIS, it computes LMPS at each of the bubble shown in Figure K.1-1.

A recursive modeling process identifies the set of resources among existing and potential future resources with the highest and lowest market values to produce economically consistent capacity expansion and retirement schedules. Based on the NPV of hourly market prices, it chooses to build one or more technologies contained in a user-defined list of new resource candidates. AURORA compares those values to existing resources in an iterative process to create a capacity expansion path of new units over time. The end result is a coordinated forecast of capacity expansion schedules for multiple market areas that meet planning reserve margin targets. State renewable portfolio standards (RPSs) under the future conditions are also simulated and incorporated into the expansion pathway.

Capital investment decisions made in AURORA use levelized capital investment costs that spread the cost of building a new unit into payments that are made at set time intervals (i.e., weekly, monthly, annually) over the book life of the project, similar to home mortgage payments. In this study, these payments are made and accounted for from the time a new unit comes online through the end of the LTEMP study period. This reduces modeling end-effects because new units contained in the AURORA expansion path will operate long beyond the end of the LTEMP period. For example, if a new unit is brought online during the last year in the study, only 1 year of capital payments are included in the economic cost calculations, not the

entire cost of the project. This reduces issues associated with evaluating technologies that have disparate capital costs and operational characteristics on timelines that do not cover the entire life of the candidate resources.

This levelized cost methodology is equivalent to incurring all capital cost expenditures when the unit comes online and later receiving a salvage value payment at the end of the study period. The salvage value represents the economic value of the resource at the end the study. This approach is used in the Wien Automatic System Planning (WASP) Package. Developed in 1972 by the Tennessee Valley Authority and the Oak Ridge National Laboratory, it has long been in continuous use by many utilities around the world for power generation expansion planning. When using the WASP sinking fund depreciation accounting method, WASP mathematics are equivalent to NPV results used by Argonne in this study (IAEA 1980).

For the LTEMP DEIS, AURORA is used in the order listed below for the following purposes:

1. Project Palo Verde market hub prices/LMPs (top tier),

2. Determine construction schedules for new units in the SLCA/IP market system (middle tier), and

3. Simulate unit commitments and perform SLCA/IP market system dispatch (middle tier).

Modeling for the top tier is performed once—the results are used across all LTEMP DEIS alternatives. The middle tier of AURORA is run for each alternative.

AURORA is first used to project future hourly energy market prices throughout the Western Interconnection during the study period; that is, for top tier modeling. Without alteration, it uses a Western Interconnection topology and dataset that were provided by EPIS. It should be noted that EPIS derived model input data for load growth, utility fuel price projections, and the cost and performance for new candidate units for system capacity expansion based primarily on information contained in EIA's 2014 AEO (EIA 2014).

For the LTEMP DEIS, LMPs at the Palo Verde marketing hub were selected as a representative hourly time series. These market prices are the primary economic driver that shape SLCA/IP hydropower operations in both versions of the GTMax-Lite model and the Small SLCA/IP Power Plant Spreadsheet. The same price set was used for all alternatives. As discussed in Attachment K-1, Argonne assumes that alternative operations at Glen Canyon Dam will have a negligible impact on Western Interconnection LMPs outside of the SLCA/IP market system.

The second purpose of the AURORA model was to project system capacity expansion paths and unit retirement schedules for utilities in the SLCA/IP market system based on the assumption that customers will engage in cooperative agreements that are mutually beneficial; that is, middle tier modeling. It uses detailed unit-level information about existing powerplant units owned and operated by Western and its LTF customers. The model also includes

information about candidate units that could be built in the future. Projected power demands consist of Western project use loads (which are described later) and loads for SLCA/IP LTF customers as described above. Capacity is constructed such that the reserve margin of the aggregate eight large customers never drops below 15%.

The firm capacity credit assigned to SLCA/IP federal hydropower resources in AURORA is estimated by the Western Firm Capacity Spreadsheet. The firm capacity logic used in this tool is in part based on a risk level consistent with a dry (i.e., low) hydropower condition such that the CRSP Management Center and the EMMO will be able to meet its LTF contractual capacity obligations with SLCA/IP federal hydropower resources 90% of the time. This is consistent with the level of risk to which Western has been exposed in the past.

SLCA/IP utility system energy transactions with the rest of the Western Interconnection are assumed to be priced at levels projected by the AURORA Western Interconnection model run. For the purpose of determining capacity expansion paths, it was assumed that the SLCA/IP market system would only make power purchases. This assumption was made to ensure that the SLCA/IP market system would not construct capacity on a speculative basis for the purpose of selling energy to the Western Interconnection; that is, it constructs capacity primarily for internal purposes. Because the Western Interconnection prices tend to be more expensive than production costs in the SLCA/IP market system, purchases from the Western Interconnection tend to be small. However, the Western Interconnection energy was made available for purchase in situations where internal SLCA/IP production costs became expensive. In addition, reserve margin requirements were configured to exclude Western Interconnection purchases as a source of firm capacity. Therefore, the SLCA/IP market system is prevented from leaning on the Western Interconnection for capacity during times of peak load.

The third purpose of the AURORA model was to perform a detailed dispatch analysis of the SLCA/IP market system which consists of the SLCA/IP hydropower facilities and Western's SLCA/IP LTF customers. Resources available for hourly dispatch are based on a previous capacity expansion run made by AURORA.

K.1.5.10 LMP Calibration Spreadsheet (Top Tier)

Spot market prices were modeled for CY 2013 through CY 2033 by the Western Interconnection AURORA model. Prices from the first year of this run, 2013, were compared against actual day-ahead market (DAM) prices published by the Intercontinental Exchange (ICE) and the California Independent System Operator to determine model accuracy. The Palo Verde market hub was chosen for the LTEMP analysis to represent prices for the spot market in the AURORA network topology because it is a major hub relatively close to Glen Canyon Dam and is often used as the benchmark price for Western energy transactions.

In general, AURORA prices differed significantly from both ICE and California independent system operator day-ahead market (CAISO DAM) historical prices for 2013. Therefore, the LMP Calibration Spreadsheet was written to scale AURORA hourly LMPs to more closely match actual nominal values in terms of 2013 dollars. The ICE publishes day-ahead

weighted average peak, off-peak, and Sunday off-peak electricity prices for each day. Sunday off-peak hours are the 16 daytime hours that have the highest loads; they correspond to the 16 hours classified as peak in the other 6 days of the week. Hourly prices generated by the AURORA model were subdivided into seven categories: holiday, Sunday daytime, Sunday nighttime, Saturday peak, Saturday off-peak, weekday peak, and weekday off-peak. AURORA 2013 monthly averages were computed for each category and compared against the monthly average ICE prices in these categories.

A scalar (ratio of the ICE to AURORA prices) was generated for each month and each category. Prices generated by the AURORA model were generally lower than the ICE prices. Prices in off-peak hours were lower by about 5 to 15%, and prices in peak hours were lower by as much as 20 to 50%. To adjust prices, both AURORA 2013 and projected LMPs for Palo Verde were multiplied by the aforementioned scalar.

LMPs at the Palo Verde hub were projected by applying AURORA model price growth rates to the calibrated 2013 price. Future spot market prices are difficult to accurately forecast because they are dependent on many factors, each of which cannot be projected with certainty. Therefore, many future scenarios are possible. For the power systems analysis, the 2014 AEO (EIA 2014) reference case was used to supply AURORA with variable inputs that drive future prices. One of the most important of these is natural gas prices. Figure K.1-11 shows a very strong correlation between historical on and off-peak prices at the Palo Verde hub and natural gas prices. This correlation is due the fact that the resources that are on the margin (i.e., last ones dispatch and determine the LMP) frequently burn natural gas. This strong correlation is expected to continue in the future. AURORA model results support this expectation. Figure K.1-12 shows that the 2014 AEO (EIA 2014) forecasted annual average delivered natural gas price to increase in the future. By 2033, natural gas prices are expected to be about 83% more expensive than prices in 2013. Calibrated LMPs follow this same basic trend. By 2033, Palo Verde price projections, which are based on the aforementioned methodology, are expected to increase by 78%. Factors that lead to a slightly slower growth in LMPs include the emergence of more-efficient gas-fired electricity generating technologies that burn less fuel per MWh of fuel consumed and a projected increase in the penetration of variable energy resources (VERs).

K.1.5.11 Firm Capacity Spreadsheet (Bridges Bottom and Middle Tiers)

The Firm Capacity Spreadsheet uses maximum daily output levels from the Large and Small SLCA/IP Powerplant spreadsheets and an assumed risk preference to estimate the amount of firm capacity that is available to the SLCA/IP market system for credit toward the system reserve margin. It also applies outage results produced by the Hydropower Outage model the five large SLCA/IP federal hydropower plants. GTMax-Lite runs of Glen Canyon Dam incorporate outages into estimated daily peak powerplant operations under all 21 hydrological traces.

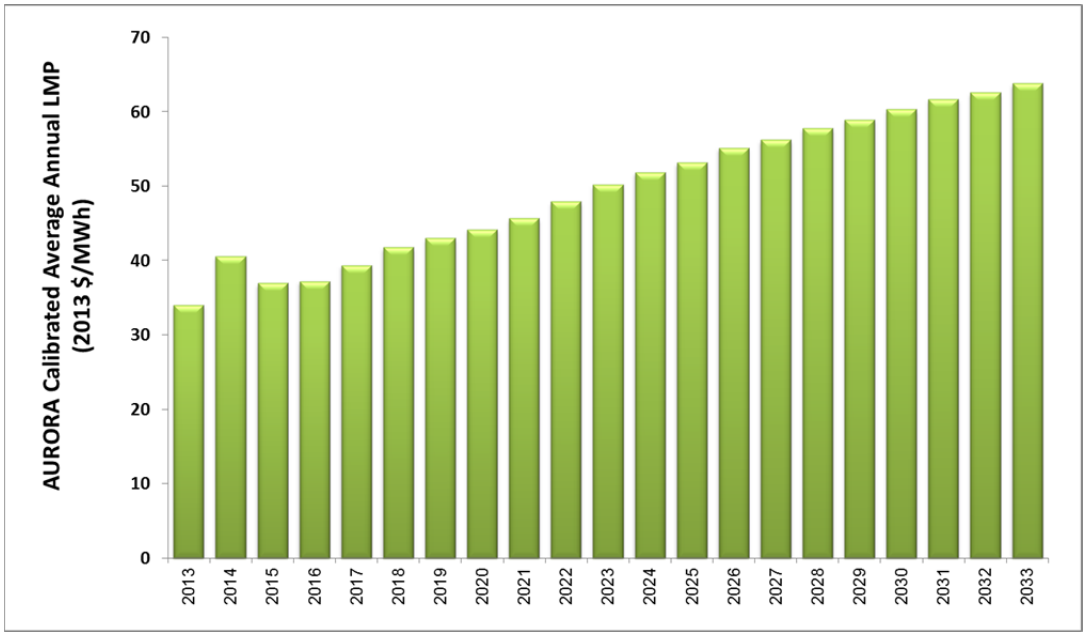


FIGURE K.1-11 Projected Annual Average Calibrated AURORA LMPs at the Palo Verde Market Hub

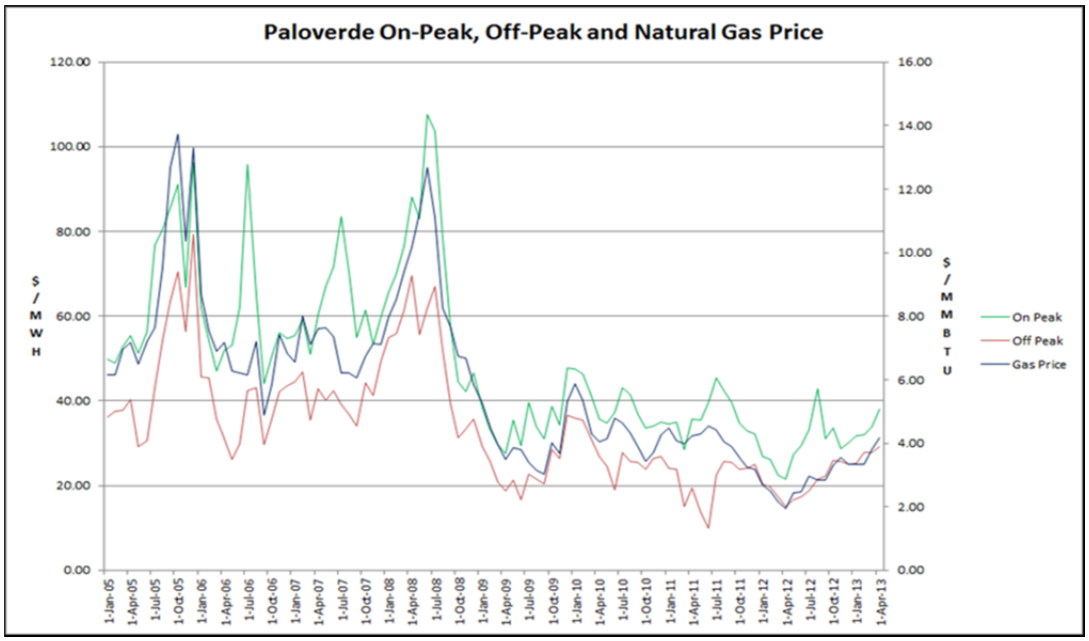


FIGURE K.1-12 Historical Palo Verde On- and Off-Peak Electricity Prices Compared to Natural Gas Prices

In addition to outages, the spreadsheet incorporates a large number of factors in the determination of firm capacity. As explained in more detail in Section K.1.7, these factors include the following:

- The time of the year the system peak load is projected to occur;
- The probability distribution of the coincidental hydropower peak output potential from SLCA/IP hydropower facilities that consist of all SLCA/IP large and small federal hydropower plants as computed by Glen Canyon Dam GTMax-Lite and the Large SLCA/IP Powerplant Spreadsheet tools;
- Projected ancillary service obligations;
- Projected capacity levels that will be reserved to for project use obligations;
- Expected future system transmission losses; and
- The risk tolerance level associated with SLCA/IP federal hydropower having a lower production capability than the declared firm capacity level during the time of the system peak load.

Firm capacity results vary significantly by alternative and are sensitive to both assumptions regarding the selected risk tolerance level and the month in which the peak load is projected to occur in the future. For the LTEMP DEIS, the capacity that is available to the SLCA/IP market system is a fixed amount over the entire study period. Spreadsheet firm capacity results are input into the AURORA SLCA/IP market system runs that simulate capacity expansion.

K.1.6 SLCA/IP Market System, Data Sources, and Model

The power systems methodology assesses the economic impacts of changes in Glen Canyon Dam Powerplant operations at the systems level using the three-tiered approach briefly described in the Power Systems Geographic Scope section. The middle tier represents SLCA/IP federal hydropower resources marketed and scheduled the CRSP Management Center and all of the utility systems that receive LTF SLCA/IP energy and capacity.

Previous sections described federal hydropower resources and hourly prescribed energy injections into the SLCA/IP market system based on GTMax-Lite model results. This section provides additional information about modeling the loads and resources of CRSP Management Center LTF power customers. There are approximately 129 LTF SLCA/IP wholesale customer entities that are categorized as either large or small. Accounting for about 75% of Western's LTF energy and capacity sales, the eight largest customers are Deseret, the Navajo NTUA, SRP, UAMPS, UMPA, PRPA, Tri-State, and CSU. Except for NTUA, all large LTF customers own and operate generating resources. There are about 130 remaining customers, which are aggregated into east and west "small customer" entities, accounting for the remaining 25% LTF

sales. Energy received by a few customers under Western LTF contracts are used to serve project use loads such as pumping for irrigation. Figure K.1-3 shows a simplified topology for the SLCA/IP systems that was used by the AURORA model to simulate the capacity expansion pathways and dispatch under each alternative. The following sections describe key model input and modeling assumptions for the SLCA/IP system.

The AURORA model is used to simulate unit commitment scheduling, for resources dispatch, and for capacity expansion in the SLCA/IP market system. Details on model inputs for initial historical conditions and for simulating future operations are provided below.

K.1.6.1 Historical Data Sources

The first year simulated by AURORA is CY 2013. It set initial model conditions based on historical information and serves as a starting point for modeling the future. A considerable amount of data is needed for AURORA to model SLCA/IP market system operations including hourly load data, characteristics of existing powerplants, and firm hydropower contracts that Western's customers have with offices other than the CRSP Management Center. Primary data sources for this information include the following:

- EPIS—AURORA database containing general/default power systems data;
- EIA—existing powerplant ownership, capacity, technology type, primary mover, historical delivered fuel prices, plant fuel consumption, historical annual generation;

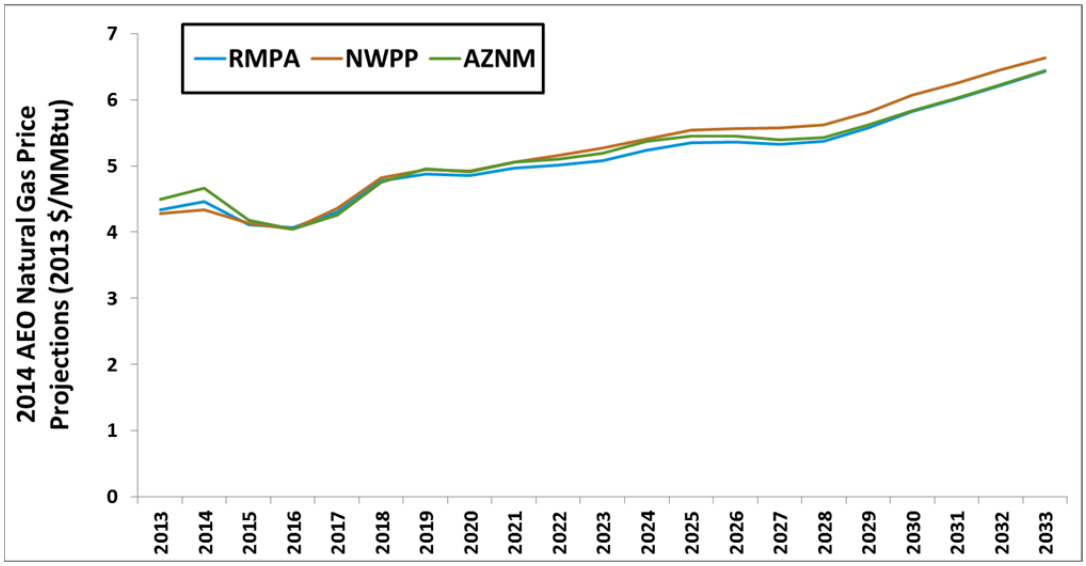


FIGURE K.1-13 2014 AEO (EIA 2014) Projected Delivered Utility Natural Gas Prices

- ICE and CAISO Web sites—sources of historical day-ahead peak and off-peak electricity prices;

- NERC—power plant maintenance and forced outage characteristics from GADS,

- FERC—historical hourly load data for utilities and BAs;

- Large customer IRPs—a report filed by each of Western's customers and contains characteristics of existing power plants, utility system loads, and DSM programs; and

- Western—data and information on hydropower contracts from the CRSP Management Center and other regional offices from which Western customers' receives federal hydropower and detailed information on federal hydropower plant and WACM BA operations, including factors related to ancillary services and the transmission system.

The AURORA model uses a database constructed by EPIS that contains Western Interconnection-wide powerplant characteristics, fuel price projections, and hourly load profiles. These data were compared to the aforementioned data sources to verify their accuracy and consistency. Because the methodology calls for Western's eight large customers to be modeled in detail, Argonne staff constructed hourly load profiles for SLCA/IP system entities and carefully examined power plant characteristics data contained in the AURORA inventory and benchmark them against data on powerplant characteristics compiled by EIA.

Historical 2013 Loads

SLCA/IP market system loads were generated for three types of LTF customers: large, small, and project use. Project use loads are based on information provided by CRSP Management Center staff. These loads are aggregated into east and west groups and are assumed to be constant over each month. Project use loads are projected to increase over the study period, but are relatively small, ranging from a total project use monthly peak load of 4.15 to 51.42 MW. Project use loads are higher in the summer and lower in the winter.

The power systems modeling effort began at a time when historical FERC Form-714 load data for CY 2013 were not yet available. Argonne staff therefore constructed a time series of CY 2013 hourly loads for each of the eight large customers and for each of the two small customers groups classified as east and west.

Loads for 2013 were constructed by the Loads Shaping Algorithm. For the eight large customers, the algorithm scaled representative nominal hourly shapes to CY 2013 levels such that hourly loads were consistent with projected monthly peak and total load targets. As described previously, CY 2006 hourly load profiles were used as the basis for constructing these

nominalized shapes. CY 2013 load targets were based primarily on information contained in large customer IRPs.

Aggregate small customer loads in the west were based on the UAMPS load profiles that was scaled to match 2013 small customer energy data used for retail rate analyses. UAMPS projected growth rates were also applied to the west small customer group. An identical method was used for the small customer group in the east, except in this case load profiles and growth rates for CSU were scaled to match small customer energy targets.

Although Western almost exclusively sells LTF capacity and energy to utilities in its service territory, special arrangements were made to enable Tribal entities to receive SLCA/IP federal hydropower capacity and energy. For 48 Tribes that do not operate their own electric utilities, Western made an administrative change to allow them to receive an allocation of power and the associated financial benefits. In this benefit crediting arrangement, Western delivers the Tribe's allocation to their electric service supplier. Because the SLCA/IP rate is lower than the supplier's production cost, the supplier provides the Tribe with a payment that is equal to the Tribe's electric allocation from Western multiplied by the difference in rates. The payment received by the Tribe is the financial equivalent of a direct delivery of electricity. Through this arrangement, Tribes ultimately receive the same services, pay the same rates for both capacity and energy, and abide by the same terms as all other customers. For power systems economic modeling, these financial transactions are not explicitly simulated because the effects on overall system-level economics are insignificant and not appreciably different among alternatives.

2013 Powerplant Characteristics and Fuel Prices

Recent data (from 2012 and 2013) on thermal power plant characteristics were obtained from EIA Form-860. This information was coupled with monthly cost and quality fuel deliveries from EIA Form-923 to estimate delivered 2013 fuel prices for each of the thermal powerplants in the unit inventory of Western's large customers. Fuel prices for 2013 are typically used. However, when this information is not available, 2012 prices are used as a surrogate. AURORA model generating unit capacity levels vary by month, with generally higher capacities in the winter than in summer months.

In AURORA, delivered fuel prices are not directly assigned to each powerplant in its database. Instead, AURORA applies unit-specific fuel price multipliers to a common price. Henry Hub is used as a price reference point for natural gas, and state-level coal prices are used as coal reference points. The EPIS-supplied representation of the Western Interconnection uses actual and projected monthly natural gas prices at Henry Hub for the year 2010 in terms of nominal 2010 dollars. For power systems analysis, AURORA unit-level delivered natural gas prices are converted to 2013 dollars. Prices at points of delivery are typically higher than the Henry Hub price. Therefore, prices are adjusted to account for delivery costs by applying unit-specific price multipliers in the model. Natural gas prices for 2013 are based on plant delivery costs reported in FERC Form-923. Similarly, 2013 coal prices in 2013 nominal dollars are computed in AURORA by applying unit-level multipliers to state-level prices.

Natural gas prices in AURORA differ by month; generally, prices are higher in the winter as compared to the spring and autumn. These same seasonal trends were used for the LTEMP power systems study. No seasonal changes in coal or distillate fuel prices were assumed; that is, coal and distillate fuel prices are constant throughout 2013.

Only one small oil-fired unit is owned by Western's large customers. It is rarely dispatched. No adjustments were made to the EPIS default nuclear fuel price. Only one nuclear plant is partially owned by SRP. It is dispatched as a base load unit, and production levels do not vary significantly among alternatives. Therefore, production cost differences for this plant do not have a significant bearing on economic cost differences among alternatives.

O&M Costs for Existing and Committed Units

Real variable O&M costs for existing units and ones that are committed to be constructed are held static at 2013 levels throughout the study period.

Fixed O&M costs only factor into LTEMP DEIS economic calculations for capacity expansion units because the retirement schedule of existing units and online dates for committed units do not change among alternatives; therefore the economic difference of these "fixed" costs between Alternative A, which serves as a reference point, and other alternatives is equal to zero.

2013 Unit-Level Heat Rates

Documentation in the AURORA model acknowledges shortcomings in the default heat rate data in the EPIS-provided database. It recommends that EIA sources of historical generation data, like Form-923, be consulted to confirm plant-specific heat rates. This information was coupled with monthly powerplant generation and the cost and quality fuel deliveries from EIA Form-923 to generate heat rates and delivered fuel prices for each of the thermal powerplants in the unit inventory of Western's large customers. AURORA default heat rates differed by as much as 60% from levels calculated from current EIA data. Therefore, in this analysis heat rates calculated from EIA data replaced AURORA default values. However, EIA data was not reported for some thermal powerplants; in those cases, default AURORA values or surrogate values based on similar type plants were used. Some differences were also found when comparing AURORA default delivered fuel prices with those calculated from recent EIA data. When discrepancies were found, calculated fuel prices were used in this analysis. However, AURORA defaults were used for plants that either had no EIA data or where fuel prices were outside of a reasonable range.

2013 Firm Power Contracts

The eight large SLCA/IP power utilities both buy and sell power under various LTF contracts. As described previously, contracts between the CRSP Management Center and its LTF customers are not directly modeled. Instead, power systems economic analyses assume that

federal SLCA/IP hydropower plants are supply resources for meeting SLCA/IP system (i.e., large and small customer utility) loads. In addition to SLCA/IP capacity and energy, some customers also receive federal hydropower from other regional offices within the Western organization. Information on these non-SLCA/IP LTF contracts was supplied by Western. These contracts are modeled in AURORA as virtual hydropower plants, the operation of which is constrained by contract monthly minimum and maximum hourly contract limits and total monthly energy bounds.

In addition to federal contracts, some customers have contracts with entities that are either within the modeled SLCA/IP system and/or other Western Interconnection entities that are outside of the SLCA/IP market system. Information on these contracts was ascertained from customer IRPs. Details on these non-federal firm contracts were typically not available. Therefore, Argonne power system modelers created simple representations of these contracts in AURORA using the information that was available in the IRPs. Contracts are modeled in AURORA as virtual thermal power plants with operating limits.

2013 Renewable Energy Resources (Water, Wind, and Solar)

The AURORA model also includes a representation of existing renewable energy resources. These resources include SLCA/IP system non-federal hydropower and wind and solar Variable Energy Resources (VERs) that produce power and serve system loads. Non-federal hydropower plant resources were modeled as AURORA hydropower plants based on the operating characteristics of the resource (i.e., run-of-river or peaking). For 2013 operations, monthly generation levels were benchmarked to actual levels recorded in EIA Form-923. Power production from VERS is represented as a fixed time series of hourly power injections into the grid using locational profiles provided by EPIS in the AURORA Western Interconnection database.

K.1.6.2 AURORA Model Dispatch Results for 2013

Initial model AURORA model runs of CY 2013 produced results that significantly differed from historical monthly generation levels. Model runs were mainly driven by EPIS input data that was supplied with the model. However, after system representation and input data refinements were made, the model results more closely mimicked historical production patterns. Figure K.1-14 shows that the 2013 AURORA generation profile by fuel type for Western's eight large LTF customers is similar to actual 2013 levels as found in EIA Form-923. Generation for hydropower plants by LTF customer utilities exactly match prescribed historical levels.

K.1.6.3 SLCA/IP Market System Projections

SLCA/IP market system supply and demand attributes, time value of money assumptions, and projections driving variables such as load growth, delivered utility fuel prices, and new unit technology characteristics play a major role in the development of the system and LTEMP DEIS

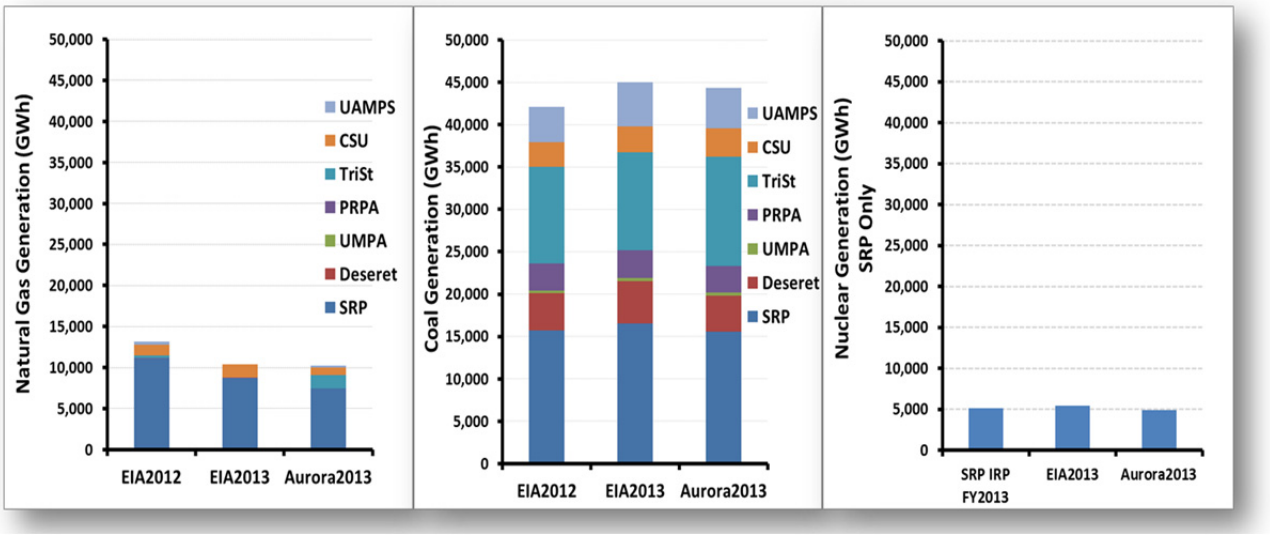


FIGURE K.1-14 Comparison of Modeled and Actual Annual Aggregated Generation Levels (from the EIA) for Natural Gas, Coal, and Nuclear Powerplants under the No Action Alternative

power system results. Projected future developments in the SLCA/IP market system rely on several information sources that include the following:

- Large customer IRPs—future fossil, and VER power plant additions and DSM initiatives;
- EIA announced (or committed) new unit additions, 2014 AEO (EIA 2014) candidate technology characteristics, utility fuel price, and load projections as driven by broader forces such as overall U.S. and global macroeconomic developments;
- State RPS—future RPS requirements; and
- Western—changes in project use loads and outlooks for future ancillary service requirements.

Western LTF customers are required to submit IRPs in order to receive federal hydropower capacity and energy. Information contained in these IRPs was used as a principal source of model inputs for future developments in terms of load growth and resource capacity expansion. However, not all IRPs cover the entire timeframe of the LTEMP DEIS study period. Therefore, projections found in the 2014 AEO (EIA 2014) were used to supplement LTF customer IRPs and provide projections that were based on a common and consistent basis.

Load Growth Projections

This section will describe in detail how the hourly loads for the eight large customers and the two groups of aggregate small customers were developed for the years in the LTEMP study period. As noted earlier, small customers were aggregated into an east group or bubble and a west group or bubble.

Developing hourly loads was a three-step process. First, historical hourly load data was gathered for each utility to be modeled. Second, a historical year was selected that best represented the load profiles of all years for which data was collected. The year selected had the best matches to both the average weekly load factor and the average annual load factor across all years. Third, the Hourly Load Forecast Algorithm was used to generate hourly load profiles for all future years for each utility. The model scaled hourly loads so they followed the profile of the representative year and at the same time also match forecasted monthly peak and total monthly energy for each utility modeled.

To find the representative historical year, hourly loads were collected from each large customer for the years 2006 to 2009. The data were compiled by FERC in Form-714 and are publicly available via software downloaded from the FERC Web site (available at http://www.ferc.gov/docs-filing/forms/form-714/view-soft.asp). These years were chosen because they were the only recent set of years for which complete annual datasets were available for all eight customers. Data for 2010, 2011, and 2012 were not available for NTUA and Deseret. We could only choose a year for which data was available for all utilities. For more details on load data collection see Attachment K-7.

Small Customer Loads. As noted earlier, small customers were aggregated into an east bubble and a west bubble. Staff from Western assisted Argonne in classifying whether small customers should be placed into the east or west bubble. In general, small customers in Colorado, New Mexico, and Wyoming were put into the east bubble, while small customers in Arizona, Nevada, and Utah were put into the west bubble. Small customer load shapes were based on the representative year from one of the eight large customers. For small customers in the east bubble, the profile from CSU was used; for small customers in the west bubble, UAMPS was used. UAMPS is in the western part of the CRSP Management Center customer territory and is comprised of many cooperating small customers. Therefore, it was judged that UAMPS load shape was representative of small customers in the west bubble. CSU is a relatively small municipal utility in the eastern part of Western's service territory; therefore, its load shape was used to represent small customers in the east bubble. These load shapes were scaled to match their estimated historical total load based on information that was collected for the retail rate payer analysis described in Section K.3.

Representative Load Shape. After collecting the historical data, total hourly coincidental loads were computed for the eight large utilities for the 2006 through 2009 time period. A weekly load factor (WLF) was calculated for each week in each year for which FERC Form-714 data were available. An average weekly load factor (AWLF) across all years was also

calculated. Then the sum of the squared differences (SSD) between the WLF and the AWLF was calculated using the equation SSD (WLF) = $\sum$ (WLF-AWLF)^2. A similar calculation was performed to find the SSD between the annual load factor (ALF) for each year and average annual load factor (AALF) across all years or SSD (ALF) = $\sum$ (ALF-AALF)^2. The sum of the squared differences for both the WLF and ALF were then summed. CY 2006 had the smallest sum and was therefore selected as the representative year for all customer loads. Using a common year for all utilities correctly captures load diversity among the utilities, including those resulting from large-scale weather patterns.

After selecting the representative year, the Hourly Load Forecast Algorithm was used to generate hourly load profiles for future years for each of the eight large LTF utilities and for each small customer bubble. Inputs into the algorithm were the utility's hourly load profile for the representative year and the forecasted monthly peak load and energy for each future year. Based on the data that were available, a load forecast was generated using a customized method for each utility. The following describes the method used to generate each load forecast.

Salt River Project

1. Historical hourly load profile for 2006 was used. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from 2006.

2. Total annual energy for 2012 was specified in the 2013 IRP (SRP et al. 2012). From 2013 to 2033, the annual energy was assumed to grow at the same annual rate as the total electricity sales forecast for the Southwest region of the Western Electricity Coordinating Council in the 2014 AEO (namely, Table 91 in EIA 2014)).

3. Annual peak loads for 2012 to 2016 were specified in the 2013 IRP (SRP et al. 2012). From 2017 to 2033, the peak load was assumed to grow at the same annual rate as used for the total annual energy shown above (namely, the data from Table 91 of the early release of EIA 2014).

Navajo Tribal Utility Authority

1. The historical hourly load profile for 2006 was used. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from 2006.

2. Annual peak loads and energy for 2012 to 2030 were obtained from the October 2012 IRP (NTUA 2012).

3. Annual peak loads and energy for 2031 to 2033 were calculated using the same growth rate as 2030.

UMPA

1. The historical hourly load profile for 2006 was used. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from 2006.

2. Annual peak loads and energy for 2012 to 2033 were obtained from the IRP 5-year plan (UMPA 2013).

UAMPS

1. The historical hourly load profile for 2006 was used. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from 2006.

2. UAMPS staff provided historical monthly energy and peak demand data for 2011 to 2013 (Anderson 2014).

3. There were no growth forecasts in the UAMPS IRP (UAMPS 2013), so the same growth rates were assumed for annual peak and energy as those provided in the UMPA IRP for 2014 to 2033. Members of UAMPS were assumed to have similar energy demand profiles as members of UMPA.

Deseret

1. The historical hourly load profile for 2006 was used. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from 2006.

2. Annual peak loads and energy for 2012 to 2018 were obtained from the IRP update (Deseret 2012).

3. From 2019 to 2033, the annual peak load and energy were assumed to grow at the same rate as the total electricity sales forecast for the Rocky Mountain region of the Western Electricity Coordinating Council in the 2014 AEO (namely, Table 94, in EIA 2014).

Tri-State Generation and Transmission Association

1. The historical hourly load profile for 2006 was used. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from 2006.

2. Annual peak loads and energy for 2012 to 2029 were obtained from the IRP (Tri-State 2010).

3. Annual peak loads and energy for 2030 to 2033 were assumed to grow at the same rate as 2029.

Colorado Springs Utility

1. The historical hourly load profile for 2006 was used. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from 2006.

2. Annual peak loads and energy for 2012 to 2031 were obtained from the IRP (CSU 2012).

3. Annual peak loads and energy for 2032 to 2033 were assumed to grow at the same rate as 2031.

Platte River Power Authority

1. The historical hourly load profile for 2006 was used. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from 2006.

2. Annual peak loads and energy for 2012 to 2020 were obtained from the IRP (PRPA undated).

3. Annual peak loads and energy for 2021 to 2033 were assumed to grow at the 5-year average growth rate from 2016 to 2020.

Small Customer—West

1. The historical 2006 hourly load profile for UAMPS selected as representing small customers in this bubble.

2. Data was collected for 2012 on retail energy sales from EIA Form-861 and summed for all small customers in this bubble.

3. The annual load factor for UAMPS was assumed to be representative of this small customer group. The annual peak load for 2012 was computed from the retail energy sales in 2012 and the UAMPS load factor.

4. Annual peak loads and energy for 2013 to 2033 were assumed to grow at the same rate as for UAMPS.

5. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from the 2006 UAMPS load profile.

Small Customer—East

1. The historical 2006 hourly load profile for CSU selected as representing small customers in this bubble.

2. Data for 2012 was collected on retail energy sales from EIA Form-861 and summed for all small customers in this bubble.

3. The annual load factor for CSU was assumed to be representative of this small customer group. The annual peak load for 2012 was computed from the retail energy sales in 2012 and the CSU load factor.

4. Annual peak loads and energy for 2013 to 2033 were assumed to grow at the same rate as for CSU.

5. The monthly peak loads and energy were based on the ratios of monthly peak to annual peak and monthly energy to total annual energy from the 2006 CSU load profile.

Figures K.1-15 and K.1-16 show stacked bar charts of customer non-coincidental monthly peak load and total monthly load projections, respectively. As described in sections that follow, projections of the eight large customer system summer peak load is particularly significant. Any reduction in Glen Canyon Dam Powerplant capacity as a result of more stringent operating criteria does not incur an economic cost until all of the excess capacity in the system is fully depleted. The year in which this occurs is heavily dependent on large customer utility system load growth. Attachment K-6 contains more detailed results for individual large customers and for the two aggregate small customer bubbles.

Capacity Expansion Candidate Unit Characteristics

To reliably meet the forecasted increases in electricity demand and to replace powerplants that will be retired during the study period, new powerplants will be constructed in the SLCA/IP market system.

Argonne staff used the AURORA model to create system capacity expansion paths and unit retirement schedules for utilities in the SLCA/IP system for each of the DEIS alternatives. As described previously, AURORA uses detailed unit-level information about existing and

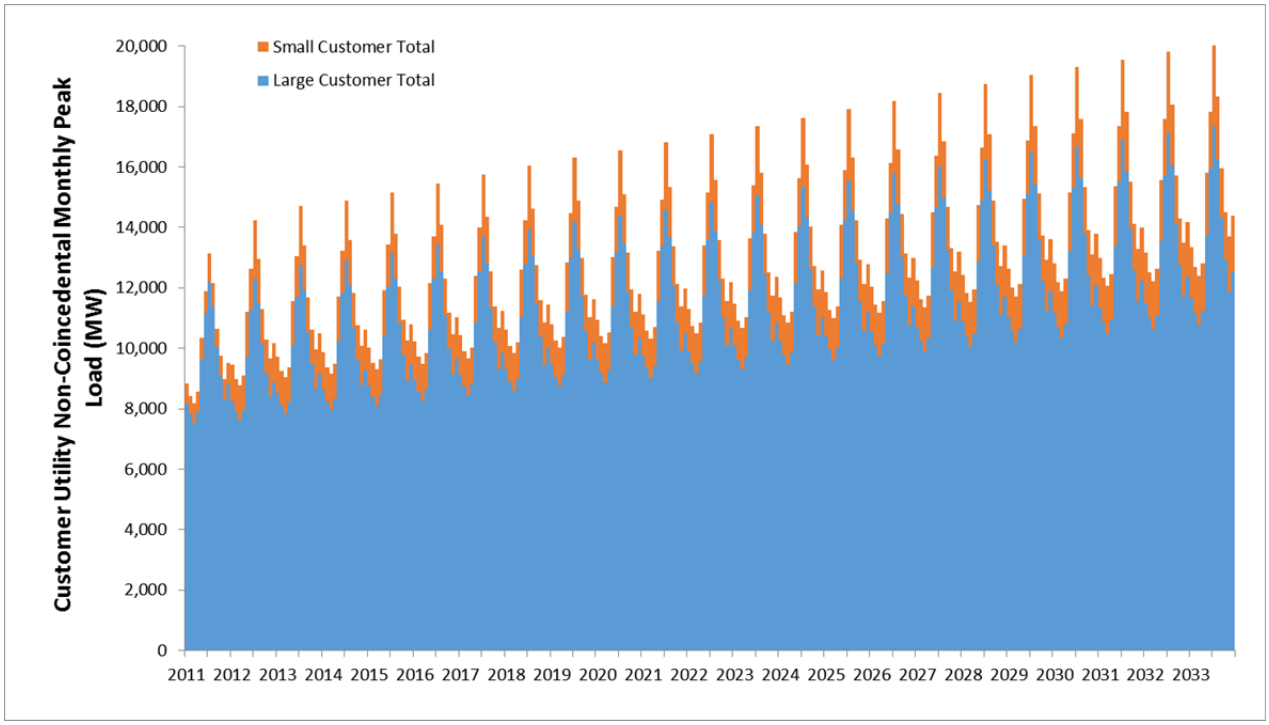


FIGURE K.1-15 Total Non-coincidental Peak Loads for the SLCA/IP Market System

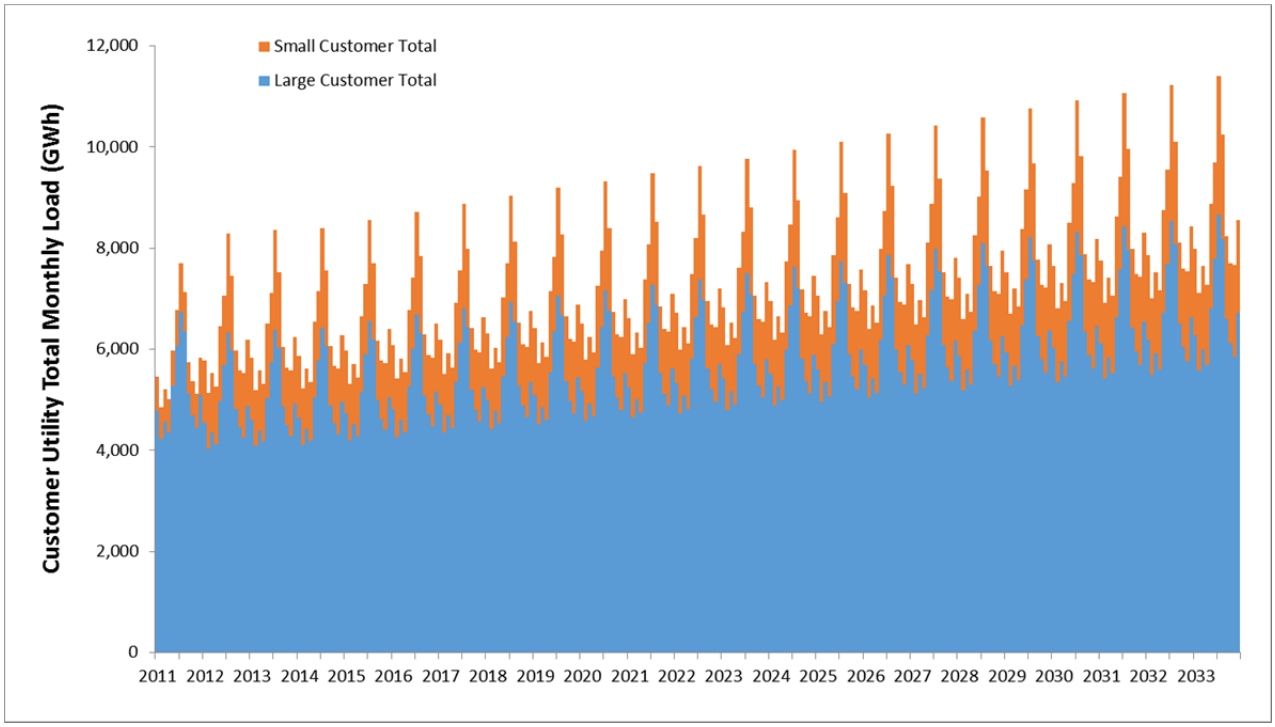


FIGURE K.1-16 Total Monthly Loads for the SLCA/IP Market System

committed generating units owned and operated by Western's LTF customers. The model also includes information about candidate units that could be built in the future. The type and number of new technologies added over time was determined by Argonne staff by tunneling AURORA model capacity expansion runs. In this context, "tunneling" refers to restricting the number of possible model solutions to a smaller set of capacity expansion possibilities (e.g., restricting the number of possible new gas-turbines built in a specific year and location [i.e., bubble], to one to three units instead of the model default of zero to unlimited new units). This technique is often used in capacity expansion planning when the number of combination of expansion technologies is otherwise enormous. It often requires multiple iterative model runs as the user explores different tunnel boundaries such that the solution is not bounded by the user-defined limits. Capacity is constructed such that the capacity reserve margin of the aggregate eight large customers never drops below 15%. Table K.1-1 shows the cost, in terms of 2013 dollars, and performance characteristics of a suite of candidate plants from which the AURORA model could choose to expand capacity of the power system.

Expansion candidates were selected from the suite of new central station electricity generating technologies in the 2014 AEO (EIA 2014). The suite includes conventional and advanced thermal units and renewables. Performance characteristics in the table include unit capacity, heat rate, and fuel type, and cost characteristics include capital costs, fixed and variable O&M costs, book life of the unit, and number of years it takes to construct. Costs are shown as a range because Western's customers are located in three different geographic regions identified by the EIA 2014 AEO (EIA 2014) electricity market module; each has powerplant-specific labor multipliers. Different labor multipliers were factored into the powerplant costs from EIA depending upon where the plant would be located. Labor costs vary by region where the plant is constructed; a regional multipliers table is located on the EIA Website (http://www.eia.gov/forecasts/capitalcost).

Overnight capital expenses and fixed O&M costs are based on 2014 AEO (EIA 2014) data and expressed in 2012 dollars. AEO documentation indicates that these costs are applicable to new units built in 2014 and later. It is assumed that these costs will not change in real terms; therefore, capital costs for a specific technology in real terms do not change as a function of online date. The AEO cost values were converted to 2013 dollars using the "Powerplants" index contained in the "Bureau of Reclamation Construction Cost Trends" table (Reclamation undated). The values for January were used because it was assumed that new plants came online at the beginning of the year. Fixed O&M costs were converted to 2013 nominal dollars using this same table, except in this case the "Powerplant Accessory elect. & misc. equip" index was used. Variable O&M costs for new construction are converted to 2013 nominal dollars based on the producer price index (PPI) for "Electric power transmission, control, and distribution energy production" (series ID code pcu22112-22112-) (BLS undated).

In the AEO, capital costs are shown as an "overnight" cost, which is an estimate of the cost at which a powerplant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. However, in reality a plant takes several years to construct. Money borrowed or committed to a project during its construction must be repaid with interest. The term for this expenditure is allowance for funds during construction (AFUDC). Because capital costs from the 2014 AEO (EIA 2014) for expansion

TABLE K.1-1 Cost and Performance Characteristics of Capacity Expansion Candidates

Expansion Candidate Technology	Capacity (MW)	Heat Rate (Btu/kWh)	Fuel Type	Unit Book Life (yr)	Construction Lead Time (yr)	AFUDC (% of overnight cost)	Levelized Capital Cost (2013$/MW/yr)		Fixed O&M Cost (2013$/MW/yr)		Variable O&M Cost (2013$/MWh)	
							Min	Max	Min	Max	Min	Max
Scrubbed Pulverized Coal	600	8,800	Coal	30	4	9.83	194,080	197,146	31,491	31,982	4.51	4.59
Integrated Gasification Combined Cycle	550	8,700	Coal	30	4	9.83	250,755	253,980	52,015	52,684	7.31	7.40
Conventional Combined Cycle	300	7,050	Natural Gas	30	3	7.26	59,953	60,429	13,456	13,563	3.68	3.71
Advanced Combined Cycle	400	6,430	Natural Gas	30	3	7.26	66,931	67,407	15,708	15,825	3.34	3.37
Conventional Combustion Turbine	120	10,850	Natural Gas	30	2	4.76	62,438	62,755	7,544	7,578	15.87	15.95
Advanced Combustion Turbine	230	9,750	Natural Gas	30	2	4.76	43,722	44,304	7,297	7,392	10.75	10.89
Advanced Nuclear	2,236	10,452	Uranium	30	6	15.19	385,516	386,997	94,873	95,243	2.18	2.19
Wind	50	0	Wind	30	3	7.26	105,631	106,900	40,996	41,350	0.00	0.00
Solar Thermal	50	0	Solar	30	3	7.26	240,921	253,715	65,452	68,112	0.00	0.00
Photovoltaic	50	0	Solar	30	2	4.76	217,553	225,801	24,055	24,966	0.00	0.00

Source: Reclamation (undated)

candidates were overnight costs, they did not include AFUDC. Therefore, these additional expenditures were added to the overnight capital cost before the capital costs are levelized. Calculation of AFUDC assumes that a certain percent of the total overnight cost is borrowed at regular intervals during construction. The time series of expenditures is often referred to as an "S curve" of capital spending. The time series of expenditures from the S curve coupled with the interest rate of the borrowed money and the time period over which it is borrowed yields the amount of interest paid per dollar or as the amount of AFUDC as a percent of the overnight cost.

AFUDC is estimated for each technology using a spreadsheet model. For this study, a Weibull distribution was used to represent the S curve of capital spending and the interest rate assumed was 4.28%. Table K.1-1 shows the amount of AFUDC as a percent of the overnight cost. It estimates interest payments monthly using a blended average of long-term taxable and municipal bond rates, which are estimated using information from several sources including the following:

1. WM Financial Strategies (undated)

2. Bloomberg Business (undated)

3. BondsOnline (undated)

Assumed construction times used for the study period were also obtained from the 2014 AEO (EIA 2014). The average projected bond rate in real terms (i.e., actual quoted levels less projected inflation) is expected to vary slightly over time. As a simplification, an annual average bond rate of 4.28% was used regardless of when construction begins. This is the average rate over the 2017 through 2033 time period. It should be noted that during this time period the weighted average annual bond rate fluctuates between 4.16% in 2033 and 4.39% in 2019; that is, a range of only 0.23%.

It should be noted that in order for the power systems analysis to be consistent with other LTEMP resource study areas, the analysis period and assumed implementation date of all alternatives is assumed to occur retroactively. Therefore, in order to best capture the economic impacts of an alternative, capacity replacement for lost Glen Canyon Dam Powerplant capacity may be brought online in the model sooner than what may be physically possible.

Capital costs used for this analysis are similar to those recommended by Energy and Environmental Economics, Inc. (E3), for WECC 10- and 20-year planning studies (E3 2014). Similar to this study, E3 used AEO new powerplant construction cost information as the basis for its recommendations to WECC. However, E3 used data from the 2013 AEO, while this analysis used more recent data contained in the 2014 AEO (EIA 2014). The costs between the two sources were slightly different. Overnight capital costs for the two key technologies selected by AURORA for SLCA/IP market system expansion are somewhat lower in the 2014 AEO (EIA 2014) compared to the 2013 AEO; costs are 5.2% less for advanced combustion turbines and 7.6% less for advanced natural gas combined cycle plants.

E3 also used a method similar to that used in this study by adjusting overnight capital costs to account for additional expenditures like AFUDC. The AFUDC multipliers applied by Argonne are slightly greater than those used by E3. For example, Argonne used an IDC multiplier of 1.0476 for advanced combustion turbines, while E3 used a multiplier of 1.035. For advanced natural gas combined cycle technologies, Argonne used a multiplier of 1.0983 while E3 used a multiplier of 1.068.

Finally, the levelized cost of capital plus fixed O&M cost used in Reclamation's (2007a) *Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lake Powell and Lake Mead* (a.k.a. Interim Guidelines EIS) is consistent with levels used in this study. For a natural gas combined cycle plant, the total cost presented in that EIS was $75,800/MW-yr (in 2007$; i.e., approximately $83,400/MW-yr in 2013$). In comparison, this study uses a levelized capital cost of capital plus fixed O&M that, depending on location, ranges between $82,639/MW-yr and $83,232/MW-yr. No other technologies were considered in the Interim Guidelines EIS; therefore, a comparison cannot be made for the combustion turbine technology.

In an email response (James 2014) sent to LTEMP co-lead agencies following the March/April 2014 Stakeholder Workshop, the Colorado River Energy Distributors Association (CREDA) suggested using capital cost data from a document published by the Electric Power Research Institute (EPRI 2013). In this document, the overnight capital cost of a natural gas-fired combined cycle plant was shown to have a range of 900 to 1,150 $/kW (in 2011$); the lower cost unit used wet cooling and the higher cost dry cooling. The wet cooling value was similar to the value from the 2014 AEO (EIA 2014), which also assumed wet cooling. When AFUDC was added, the cost range became 1,025 to 1,325 $/kW, which equates to an AFUDC multiplier of about 15% above the overnight cost. This multiplier is substantially more than AFUDC multipliers used by either Argonne or the E3 report. The EPRI report did not provide a rationale for using such a high multiplier. The discount rate assumed by the EPRI study was also greater than the one used by Argonne (i.e., 5% vs. 4.28%, respectively).

CREDA supplied their own capital cost estimate for a natural gas–fired combined cycle plant because they felt that the EPRI data did not fully account for higher elevations and harsher ambient conditions that exist in CREDA member service regions. The capital cost given by CREDA ranged from 1,130 to 1,426 $/kW. It was assumed that AFUDC was included in these capital costs, but assumptions about calculating the AFUDC were not given. Therefore, we were unable to compare Argonne's and E3's assumptions to CREDA's.

CREDA also supplied an estimate of levelized cost for the natural gas–fired combined cycle plant; the cost range was 108,000 to 132,000 $/MW-yr. Although CREDA did not state the exact discount rate used to determine the levelized cost, they did acknowledge it was greater than 5%. However, based on the capital cost range in units of $/kW that CREDA supplied, their discount rate would be approximately 6.25%, which is substantially higher than the discount rate used by Argonne.

Generating Unit Operating Cost and Fuel Price Projections

This section will describe how fixed O&M costs of expansion candidates generating plants were projected into the future and will also describe how fuel prices for both existing and new generating plants were projected.

Variable O&M Costs for Existing and Committed Units. The AURORA model default database currently contains unit-level estimates of variable O&M costs for the year 2010 in terms of nominal 2010 dollars. These costs are converted to 2013 nominal dollars based on the PPI for "Electric power transmission, control, and distribution energy production" (series ID code pcu22112-22112-) (BLS undated). This equates to an increase in nominal cost of approximately 6.9%, which is reflected in AURORA inputs, thereby affecting unit-level total power production cost.

Future Natural Gas Prices for Existing Units. Unit delivery multipliers are adjusted for future time periods to be consistent with anticipated real price projection changes forecasted regionally by the 2014 AEO (EIA 2014). The cumulative percent increase in natural gas prices are provided in Table K.1-2. Note that all multipliers in the table are relative to the 2013 price.

TABLE K.1-2 Cumulative Annual Percent Increase in Natural Gas Prices at the Henry Hub

Year	Percent Increase
2014	3.7
2015	3.9
2016	14.9
2017	22.2
2018	33.2
2019	29.3
2020	21.5
2021	29.5
2022	33.9
2023	37.6
2024	42.1
2025	45.3
2026	48.8
2027	52.3
2028	55.3
2029	60.4
2030	67.5
2031	71.3
2032	76.5
2033	82.8

Future Natural Gas Prices for New Expansion Units. Future natural gas prices for new units constructed by AURORA model expansion plans are specified by bubble and duty cycle. These prices are linked to the absolute real 2013 price levels and price changes over time that are consistent with the 2014 AEO (EIA 2014) prices shown in Figure K.1-17. Prices can also vary by technology type. The 2014 AEO (EIA 2014) price projections are specified in terms of 2012 dollars. These were converted to 2013 dollars using the GNP IPD based on the GNP IPD for January 2013 relative to January 2012 GNP IPD (see http://research.stlouisfed.org/fred2/data/GDPDEF.txt).

Natural gas prices in AURORA differ by month; generally, prices are higher in the winter as compared to the summer. In the AURORA EPIS default database, this monthly price pattern is most distinct (i.e., relatively large price range during the year) in early forecast years and gradually diminishes over time. These same seasonal trends were used for the LTEMP power systems study.

Future Coal Prices for Existing Units. AURORA base coal prices are entered at the state level and change annually. Unit delivery coal price multipliers are adjusted for future time

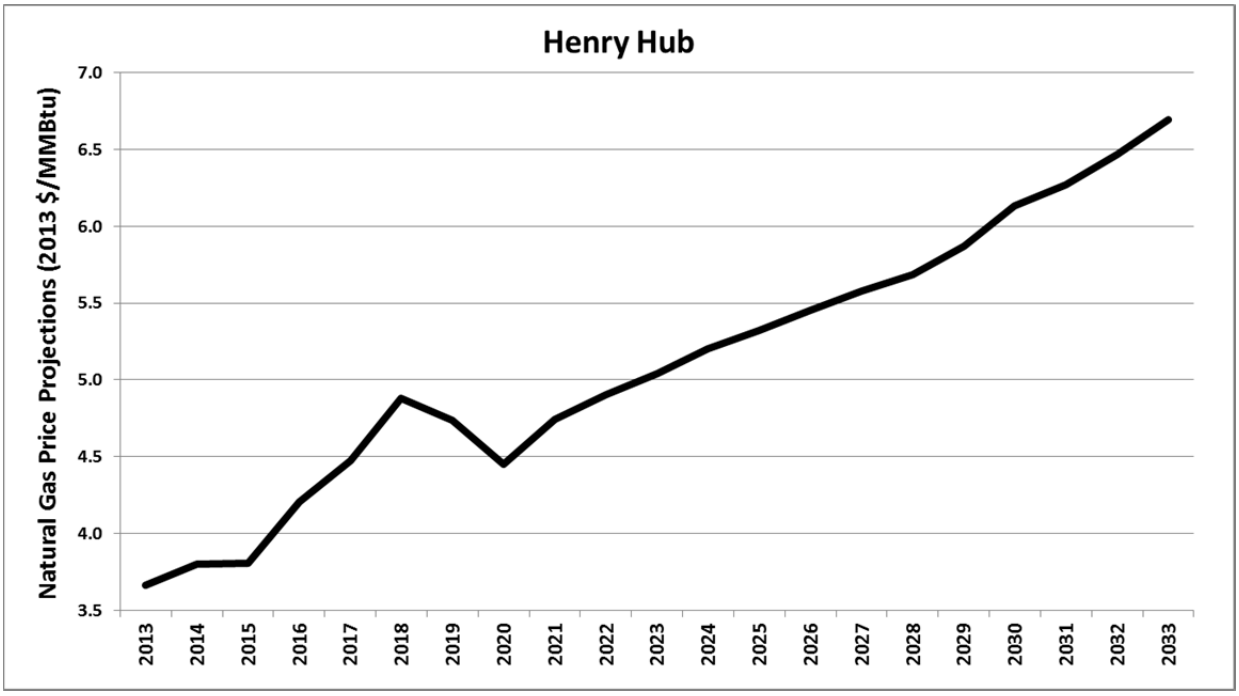


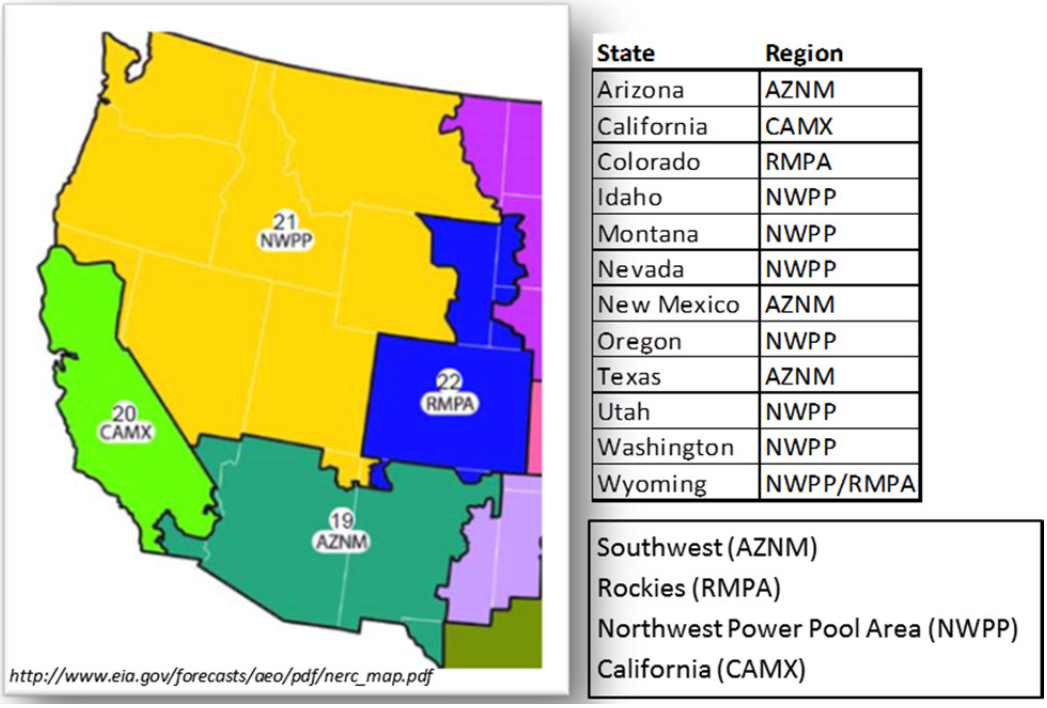
FIGURE K.1-17 Projected 2014 AEO (EIA 2014) Natural Gas Prices at the Henry Hub

periods to be consistent with anticipated real price projection changes forecasted regionally by the 2014 AEO (EIA 2014) electricity market module shown in Figure K.1-18. Regional multipliers are shown in Table K.1-3 below.

Multipliers are applied at the unit level, depending on the state in which it resides. Therefore, as shown in Figure K.1-18, states were paired with the AEO regions. Because Wyoming is split between two regions, an average of the two was used.

Future Coal Prices for New Expansion Units. Future coal prices for new units constructed by the AURORA model expansion plan are specified by bubble (i.e., large customer) and duty cycle. These are consistent with absolute real-price levels and changes over time projected by 2014 AEO (EIA 2014), as shown in Figure K.1-19. The 2014 AEO (EIA 2014) price projections are specified in terms of 2012 dollars which are converted to 2013 dollars using the GNP IPD.

Future Distillate Fuel Oil for Existing Units. Future delivered price multipliers are adjusted for future time periods to be consistent with anticipated real price projection changes forecasted regionally by the 2014 AEO (EIA 2014). Regional multipliers are shown in Table K.1-4.



State	Region
Arizona	AZNM
California	CAMX
Colorado	RMPA
Idaho	NWPP
Montana	NWPP
Nevada	NWPP
New Mexico	AZNM
Oregon	NWPP
Texas	AZNM
Utah	NWPP
Washington	NWPP
Wyoming	NWPP/RMPA

FIGURE K.1-18 2014 AEO (EIA 2014) Electricity Market Module Regions and the Mapping of States to Regions

Future Nuclear Fuel Price for Existing Units. EPIS-supplied nuclear fuel prices and projections were used for power systems modeling. As previously noted, there is only one nuclear plant in the SLCA/IP market system whose production levels do not vary significantly among alternatives.

Renewable Resource Projections

Future renewable resource additions are built by the model such that each utility complies with minimum requirements specified in state RPSs. Each utility fulfills the requirements specified by the state(s) where the utility serves load. If a state where a utility has load requires that 20% of the electric energy be satisfied by renewables, then the utility must have sufficient renewable capacity to serve 20% of its electric generation in the state. In cases such as Tri-State, which has loads in more than one state, RPS compliance is attained within each state. One simplification is that a utility employs a single type of renewable generation to serve future load in each state (namely, solar for Arizona and New Mexico and wind for Utah and Colorado). Any renewable generation source that a utility currently utilizes is credited toward meeting a future RPS goal.

TABLE K.1-3 Cumulative Annual Percent Increase in Regional Coal Prices

	Year																			
Region	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
RMPA	–1.6	2.7	6.5	8.8	11.6	13.7	15.8	17.7	20.0	22.1	24.4	26.8	28.7	30.3	29.3	30.0	30.1	30.9	31.7	33.8
NWPP	0.6	4.5	10.0	11.9	14.7	17.1	19.4	20.5	23.0	26.4	28.7	31.2	33.2	35.1	32.6	32.3	31.2	31.5	30.6	34.4
AZNM	–1.7	5.1	8.6	11.6	8.9	9.2	9.6	10.8	12.2	13.7	14.7	15.9	16.8	17.6	18.1	19.2	20.2	21.3	22.3	23.3
CAMX	–4.0	2.7	4.3	5.8	7.8	9.6	11.6	13.1	15.1	17.0	19.1	21.2	22.7	23.9	24.9	26.9	28.7	30.5	31.8	33.1

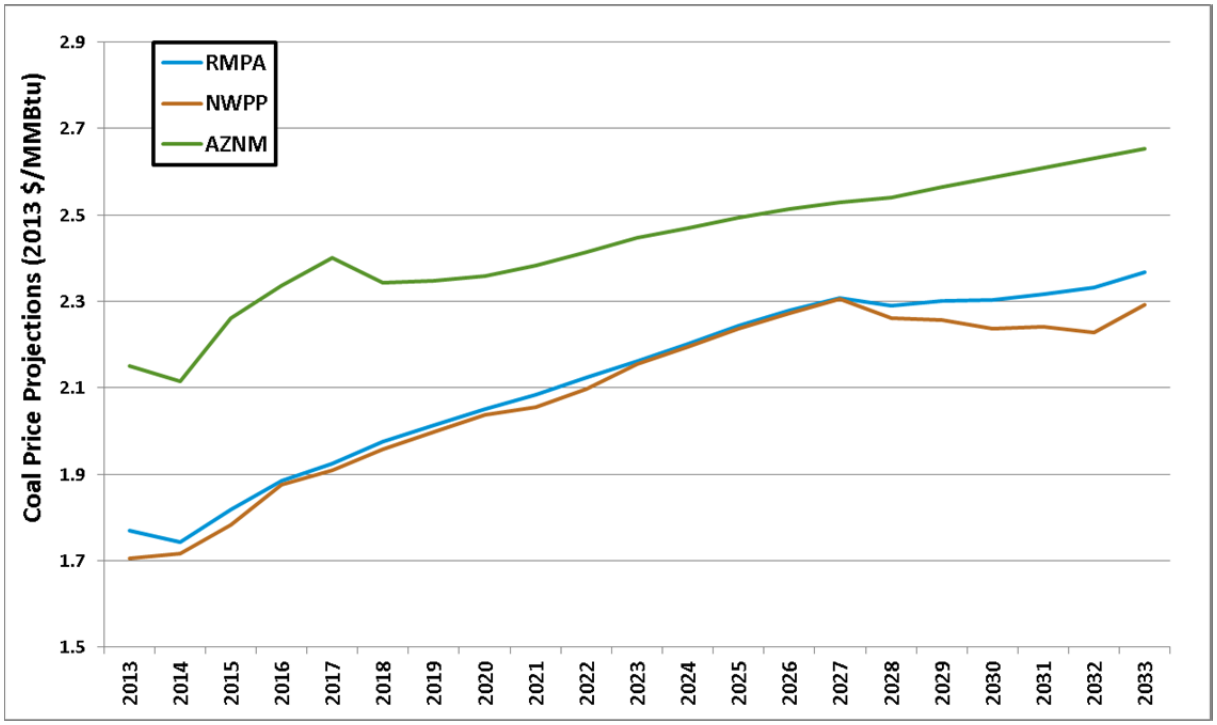


FIGURE K.1-19 Projected AEO 2014 (EIA 2014) Coal Prices by Electricity Market Module Region

K.1.7 Glen Canyon Dam Powerplant Capacity Cost and Benefit Methodology

The difference between the firm capacity level of Alternative A and the firm capacity level under a specific alternative is the amount of additional capacity that will eventually need to be built. It is referred to as lost Glen Canyon Dam capacity and will be replaced at some point in the future by one or more entities in the SLCA/IP market system, which consists of Western and the utilities operated by its LTF customers. The economic costs of this lost firm capacity is based on the capital and fixed O&M costs that would be expended to construct and operate new units that replace it. The amount of replacement capacity that would need to be built is dependent on several factors, including the level of current and committed system resources, future annual system peak loads, and system reliability criteria. Economic impacts are measured for the system as a whole, where system-wide capacity expansion pathways are simulated and associated costs are computed for each alternative. A time series of costs differences relative to Alternative A is then computed and expressed as a single NPV for each alternative. Capacity replacement costs include capital investment for new capacity plus fixed O&M costs for operating the newly constructed units.

TABLE K.1-4 Cumulative Annual Percent Increase in Regional Distillate Fuel Prices

	Year																			
Region	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
RMPA	–5.6	–10.2	–13.0	–13.9	–13.0	–11.1	–9.3	–7.3	–5.2	–3.3	–1.5	0.3	1.7	3.5	4.9	6.4	7.6	9.0	10.6	12.2
NWPP	–5.6	–10.4	–13.3	–14.2	–13.2	–11.3	–9.5	–7.5	–5.3	–3.5	–1.5	0.3	1.8	3.4	4.8	6.4	7.6	9.0	10.6	12.2
AZNM	–5.6	–10.2	–13.0	–13.9	–13.0	–11.1	–9.3	–7.3	–5.2	–3.3	–1.5	0.3	1.7	3.5	4.9	6.4	7.6	9.0	10.6	12.2
CAMX	–5.6	–10.4	–13.1	–14.0	–13.1	–11.2	–9.4	–7.4	–5.3	–3.4	–1.5	0.3	1.8	3.5	4.8	6.4	7.6	9.0	10.6	12.2
NWPP/RM	–5.6	–10.3	–13.1	–14.0	–13.1	–11.2	–9.4	–7.4	–5.3	–3.4	–1.5	0.3	1.7	3.4	4.8	6.4	7.6	9.0	10.6	12.2

K.1.7.1 Treatment of Glen Canyon Dam Capital and Fixed O&M Costs

The Glen Canyon Dam and Powerplant was constructed between June 1960 and September 1966. Preceding the construction of the dam, diversion tunnels were dug and a coffer dam was built upstream to divert water from the main dam construction site (see http://www.usbr.gov/uc/rm/crsp/gc/history.html). All of the capital costs to build the dam and powerplant were incurred in past. Therefore, the economic costs of these past expenditures are treated as sunk investments under all alternatives; that is, economic costs for building the dam and powerplant are set equal to zero because past expenditures cannot be altered. Furthermore, it is assumed that any additional capital investment in the dam and powerplant that will be incurred in the future is unaffected by an alternative. It therefore follows that capital investment differences among alternatives is also zero. Similarly, Glen Canyon Dam fixed O&M costs are assumed to be unaffected by all of the alternatives. It is also assumed that the total physical 1,320 MW of nameplate capacity at Glen Canyon Dam is identical under all LTEMP DEIS alternatives and that the capacity of all powerplant units will not change over the study period.

Past Glen Canyon Dam construction costs and interest expenses are paid by Western SLCA/IP LTF customers through Western's firm energy and capacity rates. Revenues from the sale of CRSP power are deposited in the U.S. Treasury. These power revenures also pay for irrigation assistance, O&M costs, salinity control, and environmental programs through Western's firm energy and capacity rate. CRSP power revenues have funded over $298 million of costs associated with environmental programs in the Grand Canyon. Since 2000, Glen Canyon Dam environmental experiments recommended through the Glen Canyon Dam Adaptive Management Program cost an additional $44.3 million (see http://www.gcdamp.gov/faq.html). Firm power customer rates are assumed to have no impact on the economic costs of LTEMP DEIS alternatives. However, as discussed in the Wholesale Rate section, energy and capacity rates have a financial impact on Western's CRSP Management Center Office, the EMMO, and firm customer finances.

K.1.7.2 Western's SLCA/IP LTF Obligations and Glen Canyon Dam Replacement Capacity

Although construction expenditures that occurred a long time ago are assumed to be a sunk economic cost, Glen Canyon Dam Powerplant capacity and energy currently reap economic benefits for the electric utility sector. The economic benefits of Glen Canyon Dam capacity will continue far into the future at a level that, in part, depends on the operating criteria that govern future power operations. Under most hydrological conditions, current operating criteria and those specified by LTEMP DEIS alternatives affect the ability of Western staff to schedule and Reclamation powerplant operators to deploy the entire Glen Canyon Dam nameplate capacity at times of peak system load. This deployment level differs by alternative. Therefore, the firm capacity of the Glen Canyon Dam Powerplant is less than its physical nameplate capacity.

Currently, Glen Canyon Dam capacity primarily benefits SLCA/IP LTF customers. Through its marketing program, Western currently sells customers bundled SLCA/IP federal hydopower resources, not individual plants. For power systems analysis, firm capacity is

therefore determined for the entire system, based on the coincidental sum of maximum daily energy outputs from all SLCA/IP federal hydropower facilities and other factors such as those described in the Firm Capacity Spreadsheet section (Section K.1.5.11). For the LTEMP DEIS, Argonne conducted a study of Western's SHP commitment levels over the last 10 years; the study is described later in this appendix, in the Firm Capacity Risk Level section. The study found that capacity has historically been marketed such that 90% of the time Western's 11 SLCA/IP federal hydropower plants had sufficient maximum operating capabilities to meet customers' total peak requests for energy within the bounds specified by SLCA/IP LTF contracts. This same 90% level is used to determine the firm capacity under all of the alternatives. However, in the future Western may choose to market capacity at either a higher or a lower risk level.

Operating criteria differ by alternative in terms of the distribution of monthly water release volumes during a WY and the level of operating flexibility that is allowed at Glen Canyon Dam. Both affect the maximum output level that the Glen Canyon Dam Powerplant is allowed to deliver during times of SLCA/IP market system peak load. The difference between the Alternative A capacity and the capacity under another specific alternative is the amount of additional capacity that will eventually need to be built above the Alternative A capacity expansion plan. This lost capacity will be replaced at some point in the future by one or more large SLCA/IP LTF customer utilities. For the purposes of economic impacts, it is assumed that the identification of the entities that replaces this lost capacity is inconsequential. As stated previously, this is an economic analysis that measures the net cost difference for the system as a whole, not a financial analysis of individual entities (e.g., a utility company) that operate within the system.

The wholesale rate and retail rate studies that are presented in Sections K.2 and K.3, respectively, discuss potential impacts on individual entities within the SLCA/IP market system. The wholesale rate study also discusses rates under a scenario in which Western replaces lost capacity, as well as another scenario in which Western makes capacity and energy obligations based on the chronological capabilities of SLCA/IP federal hydropower resources. The latter scenario requires that SLCA/IP LTF customers replace the lost capacity.

K.1.7.3 Western SLCA/IP Firm Hydropower Capacity

Argonne used several tools and models of varying levels of detail and complexity to estimate SLCA/IP federal hydropower plant firm capacity levels; that is, the maximum power output that system operators can usually, but not always, rely upon to meet peak loads. Argonne also developed capacity expansion paths for each alternative and associated costs for the SLCA/IP market system. An expansion path describes the timing and type of new units that will be built in the future. It is based on a host of factors such as CRSP Management Center firm capacity, the system capacity reserve margin goal, projected fuel prices, the characteristics of existing powerplants, and peak load growth.

Firm capacity is based on the coincidental sum of maximum daily energy outputs for all SLCA/IP federal hydropower facilities. The method used varies by powerplant size and

operating criteria. Figure K.1-20 lists SLCA/IP federal hydropower facilities grouped by size. The figure also provides information on the models, parameters, and data used for estimating firm capacity.

The entire physical capacity of SLCA/IP federal hydropower resources is not available to meet LTF customer loads. Instead capacity is reserved for other purposes. As shown in Figure K.1-21, some of these purposes include capacity set aside to serve project use loads such as pumping for irrigation, replacing transmission losses, providing spinning reserves, and performing regulation services. A more detailed description of these components is provided next.

From an operational standpoint, the capacity that is reserved for these purposes is known with a relatively high degree of certainity. However, at any single point in the future, the impacts of unit outages, reservoir elevation, and enviromental operating critera on hydropower resource capacity are highly variable and cannot be predicted without forecast error. Therefore, SLCA/IP federal hydropower resources are exposed to risks because the future of both reservoir conditions and the operating state of generating units are not known with certainty. This risk level is directly related the amount of firm capacity that is assumed (that is, the lower the amount of firm capacity, the lower the risk). The power systems methodology uses a probabilistic approach to quantify this risk.

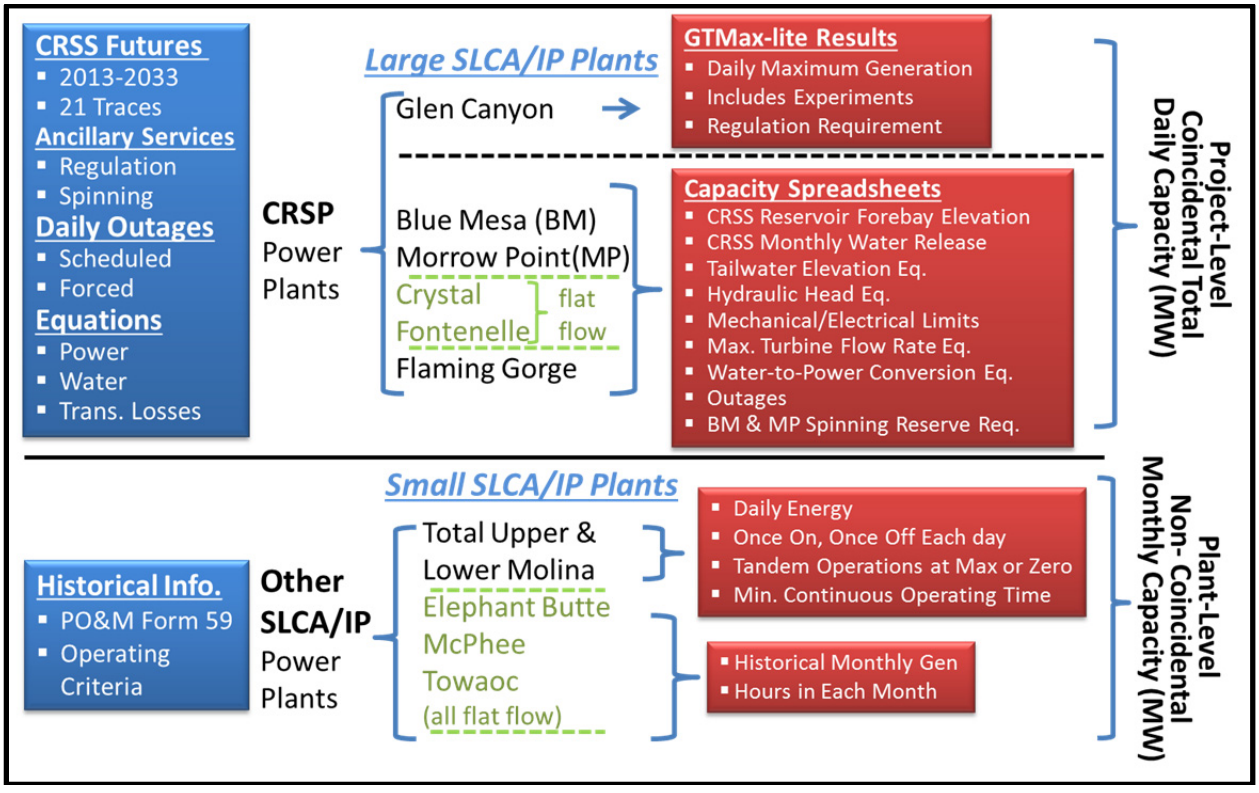


FIGURE K.1-20 Western SLCA/IP Hydropower Powerplants

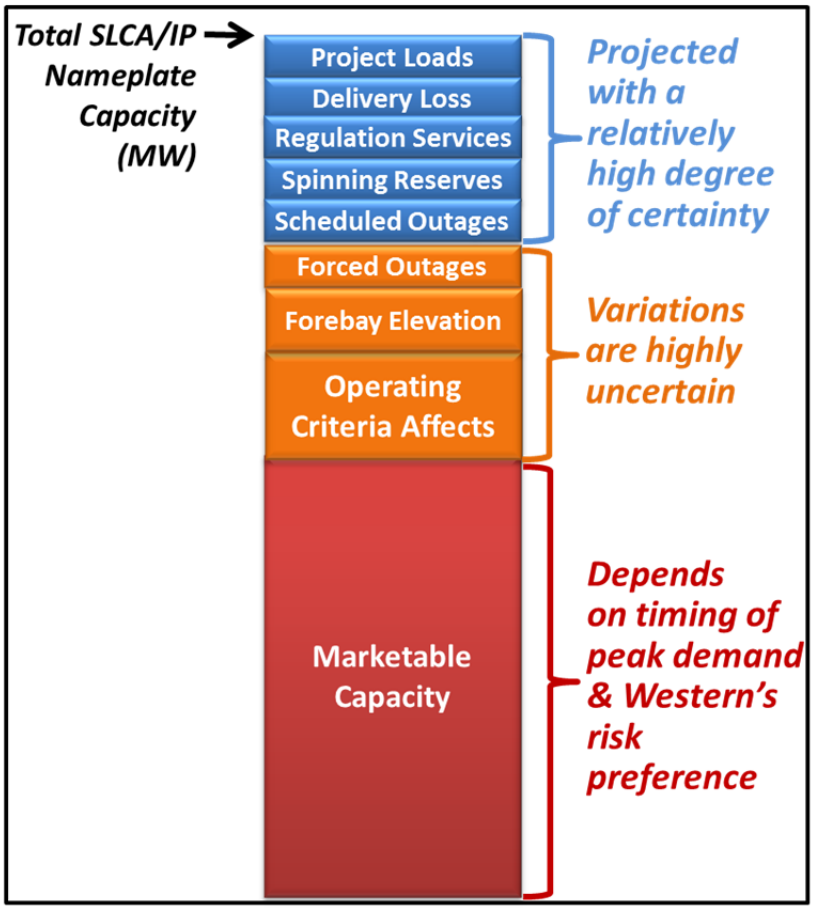


FIGURE K.1-21 SLCA/IP Federal Hydropower Capacity Uses and Variability Factors

Project Use Loads

Western has an obligation to serve project use loads such as pumping for irrigation. These loads are also given a high priority in LTEMP power system models; that is, these loads must be satisfied before other SLCA/IP market system loads are served. Summary data that describes project use obligations was obtained from the CRSP Management Center. These obligations were transformed into hourly "flat" load vectors. During the study period, one new project use load will come online: the Navajo-Gallup Water Supply Project. From discussions with CRSP Management Center staff, it was determined that there would be additional project use loads from this project of 5 MW load in 2018, 2023, 2024, and 2029, for a total increase of 20 MW. Loads are assumed to be identical for both capacity and energy economic analyses. In addition, these loads are assumed to be unaffected by alternative.

Delivery Losses

Energy is lost in the process of transporting energy from SLCA/IP federal hydropower generation points to points of energy delivery. Under current accounting practices, which were established after system consolidation measures were implemented, transmission system losses are set to 5% (Scheid 2015). Therefore, it is assumed that marketable capacity that is delivered to customers is reduced by this same percentage. For example, when the Fontenelle Powerplant produces its maximum output of 10 MW, it is assumed that only 9.5 MW is delivered to demand points; that is, for accounting purposes, 0.5 MW is lost during the transmission process.

Ancillary Services

As part of its power pool agreements, Western has an obligation to provide ancillary services. SLCA/IP resources provide regulation reserves and fast spinning reserves. As shown in Table K.1-5, both of these ancillary services are projected to increase by up to 80 MW. The maximum requirement is reached in 2025 for regulation reserves and in 2030 for fast spinning reserves. A total of 160 MW of ancillary will then be maintained from 2030 into the foreseeable future. Estimates of future ancillary service levels were provided by Reclamation based on a discussion with Western staff in May 2013.

Figure K.1-22 shows how the methodology used for this study explicitly reduces the operating range of plants that provide one or more ancillary services. A plant's hourly maximum output is reduced by the level of regulation service and spinning reserve provided. In addition, when providing regulation services, the minimum generation level is also increased by the level of regulation service provided. Note that under current power pooling agreements, a powerplant simultaneously provides identical levels of up and down regulation. Based on discussions with power system operators, the priority for ancillary services provided by SLCA/IP federal hydropower resources is as follows. The first priority is to serve both regulation services and spinning reserves at Glen Canyon Dam. However, if the Glen Canyon Dam Powerplant has insufficient capacity to serve both or doing so would increase Glen Canyon Dam non-power water releases, spinning reserves will be off-loaded to powerplants located in the Aspinall Cascade and, if absolutely necessary, followed by regulation services.

TABLE K.1-5 Assumed Ancillary Services Provided by SLCA/IP Hydropower Facilities from 2013 to 2030

	Ancillary Services (MW)		
Year	Fast Spinning Reserves	Regulation Reserves	Total
2013	43	60	103
2014	45	62	107
2015	47	63	111
2016	50	65	115
2017	52	67	118
2018	54	68	122
2019	56	70	126
2020	58	72	130
2021	60	73	134
2022	63	75	138
2023	65	77	141
2024	67	78	145
2025	69	80	149
2026	71	80	151
2027	73	80	153
2028	76	80	156
2029	78	80	158
2030+	80	80	160

When Glen Canyon Dam serves regulation services, it instantaneously fluctuates above and below a fixed generation set point. For example, when the hourly set point is 500 MW and regulation services is 60 MW, generation will go to a minimum of 440 MW when regulating down and go up to a maximum of 560 MW when regulating up. Based on conversations with EMMO staff, the net energy generated to provide regulation over a 1-hour time period is very close to zero; that is, instantaneous fluctuations in generation above and below the generation set point sum to zero. In the example above, 500 MWh of generation would be generated during the hour.

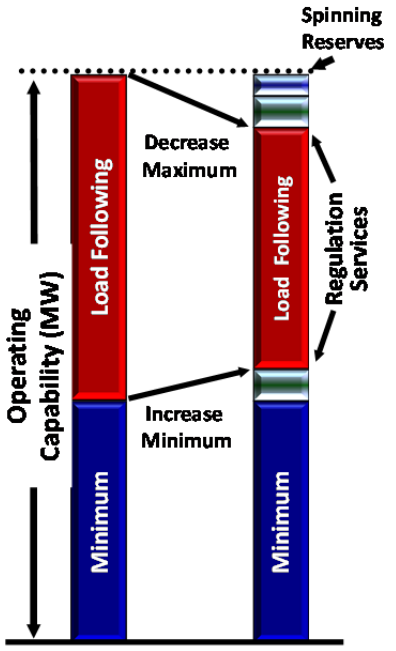


FIGURE K.1-22 Reductions in Operating Range when Providing Ancillary Services

Because water release restrictions at Glen Canyon Dam are specified in terms of average hourly flow rates, and not instantaneous limits, regulation services can continue to be provided when releases are at an environmental flow rate limit. For example, a powerplant's generation can be set for an hour to a level that exactly releases the minimum water flow rate requirement. When providing regulation services during this hour, instantaneous flow rate will sometimes be lower than the environmental "hourly rate" minimum (regulating down), but these low flows will be offset by instances when it is higher than the minimum flow (regulating up).

Regulation services will affect the operating range at Glen Canyon Dam. The sum of the regulation service plus the operational set point cannot exceed the physical maximum MW output of the *entire* powerplant. The maximum physical output of the plant is dependent on the number of units that are operational and Lake Powell's water elevation. At the other extreme, the set point operation minus regulation service cannot be less the minimum operating limit of a *single* Glen Canyon Dam unit.

Spinning reserves only affect the maximum set point at Glen Canyon Dam. Under normal operating conditions, this spare or reserved capacity is not utilized. However, events such as a unit forced outage or downed power lines may result in a sudden grid energy imbalance; that is, there is not enough energy production to serve load. To overcome this deficiency, spinning reserves are deployed and one or more powerplants increase output to return the system to a balanced state as quickly as possible.

When spinning reserves are deployed at Glen Canyon Dam, the powerplant very quickly ramps up production by a maximum of 60 MW. Under these conditions, the water release up-ramp is allowed to exceed environmental operating limits. Glen Canyon Dam "emergency exception criteria," which are stipulated under all alternatives, allows Glen Canyon Dam to operate outside of minimum and maximum flow limits, daily changes constraints, and both maximum hourly up- and down-ramp rates in the event of a power system emergency (e.g., grid energy imbalance events). However, similar to regulation services, the set point generation level

plus the spinning reserve service cannot exceed the physical maximum MW output of the *entire* plant. As shown in Figure K.1-22, when both ancillary services are being served, the sum of set point, regulation, and spinning reserves cannot exceed then maximum output capability of the plant.

The economic cost of providing ancillary services at Glen Canyon Dam varies by alternative, such that the greater the operational flexibility is, the higher the cost of serving regulation and spinning reserves will be. Under flat flow alternatives, ancillary services do not typically affect the operating range because there is no flexibility in the system. On the other hand, ancillary services at times bind (i.e., lower) the maximum output level at Glen Canyon Dam. These binding events occur when the monthly water release volume allows for a relatively large daily operating range and a higher base flow. Glen Canyon Dam unit outages and lower reservoir elevations exacerbate the economic impacts of this constraint by essentially lowering the maximum physical output of the plant.

The time series of ancillary service projections shown in Table K.1-5 will be used in GTMax-Lite model runs that determine differences in capacity and energy value among LTEMP DEIS alternatives. However, in December 2014, Western indicated that ancillary services were no longer expected to increase as anticipated in May 2013. Glen Canyon Dam currently supplies a total of 67 MW of ancillary services, and this is not expected to increase during the LTEMP study period. Therefore, a sensitivity study was performed to determine how firm capacity levels will change if a different ancillary services schedule is used. The sensitivity study and results are reported in Section K.1.10.8.

Outage

All of the SLCA/IP hydropower resources undergo both scheduled and forced unit outages, during which times a unit either produces no output or produces at a level that is lower than its full capability; that is, the capacity is temporarily de-rated. Maintenance is normally performed during a scheduled outage, while forced outages typically occur at random, and are precipitated by the failure of one or more unit/plant components.

For the LTEMP study, the Reclamation provided Argonne with unit-level maintenance schedules for the six largest SLCA/IP facilities over the study period. When a unit is taken out of service for maintenance, the maximum output of that unit is set to zero in all pertinent modeling processes, including both versions of GTMax-Lite and spreadsheet tools that estimate maximum physical output levels at large SLCA/IP hydropower resources other than Glen Canyon Dam.

To represent unit forced outages at large SLCA/IP powerplants, a methodology was developed to incorporate the number, cause, and duration of forced outages that may potentially occur during the study period. Data on forced outages for hydroelectric turbines were obtained from the GADS. This database is maintained by NERC and contains operating information on electric generating equipment. GADS data were input into an algorithm that produces a plausible series of random outages for units at the Glen Canyon Dam Powerplant. Using a different set of random draws for each run, the forced outage model performed numerous simulations. The run

that produced the most representative time series of outages in terms of matching overall GADS statistical averages was selected. It should be noted that the forced outage model only represents full unit outages. It therefore does not directly represent partial outages. However, the model uses equivalent outage statistics that implicitly account for these types of outages. For example, if a unit is de-rated by 25% over a 6-month time period, the equivalent outage rate would be 12.5%. Details of the forced outage algorithm and methodology are described in Attachment K-5.

Scheduled and forced outages are not explicitly modeled for small SLCA/IP federal hydropower resources. However, outages are reflected in the model to the extent that unit down time is reflected in Form PO&M-59 data, which is ultimately used to model small federal hydropower facilities. For example, if the McPhee unit was down for an entire month, a zero generation level would be reported by Form PO&M-59 for that month, which would affect the results produced by the Small SLCA/IP Powerplant Spreadsheet model. Although this methodology is not the most accurate modeling approach, it should be noted that the total small facilities capacity is less than 3% of the entire SLCA/IP federal hydropower capacity. Therefore, modeling errors were judged by Argonne staff to be negligible.

Maximum Power Plant Output, Forebay Elevations, and Monthly Releases

The surface water elevation in a reservoir affects both hydropower maximum possible output level and the amount of water that needs to be released through a turbine to produce a unit (MWh) of energy. For the large SLCA/IP hydropower resources, end of the month reservoir elevations, also referred to as forebay elevations, were projected using Reclamation's CRSS and the SBM models.

Because DEIS alternative operating criteria affect monthly Glen Canyon Dam water releases, and therefore Lake Powell water elevations, CRSS and SBM make separate projections for each alternative. Future hydrology conditions are not known with certainty; therefore, the CRSS model projected 105 possible outcomes at the end of each month throughout a 2013 through 2060 time period, inclusive. Although 48 years of monthly outcomes were projected, only the first 21 calendar years (20 water years) were used for analysis in the DEIS. Each outcome, also known as a "trace," is based on a unique historical series of hydrological conditions. Therefore, hydrological conditions are deterministic and it is extremely unlikely that any one trace will ever be repeated. Of these 105 traces, a common set of 21 was used by all DEIS research areas.

Using this information, the GTMax-Lite model is used to optimize the hourly operations of the Glen Canyon Dam such that is maximizes the economic value of energy. As described previously, GDC GTMax-Lite runs were performed twice. The first provides input to the SBM and the second run accommodates experimental releases using altered SBM monthly water release volumes and reservoir elevations. Hourly operations are projected over the entire time period for all 21 traces for each alternative. Daily maximum daily generation levels from Glen Canyon Dam GTMax-Lite output for all alternatives and traces are stored for use by the Firm Capacity Spreadsheet.

The maximum monthly physical output levels for the other five large SLCA/IP hydropower resources were computed over the entire study period for all 21 CRSS traces. Each powerplant's maximum possible output level is based on the following set of conditions, limits, and equations;

1. Mechanical/electrical turbine capacity limit;

2. Unit operating status (either operating or out of service);

3. Reservoir elevation as a function of water storage;

4. Maximum turbine water release as a function of head (forebay minus tailwater elevations);

5. Tail-water elevation as a function of maximum flow rate; and

6. The water-to-power conversion factor that is a function of reservoir forebay elevation.

In order to solve for the above set of relationships, an iterative process is used to converge all interdependent relationships to a consistent set of values. Interdependencies occur because the tailwater elevation is a function of the turbine flow and the turbine flow is a function of the system head, which is the difference between the tailwater and reservoir forebay elevations. In addition, the total turbine flow rate, and therefore tailwater and head, depend on the number of units that are operating. End-of-month reservoir forebay elevation levels that are used in the dispatch process for the other five large SLCA/IP hydropower plants are obtained from the CRSS model.

The physical maximum output level for the small SLCA/IP federal hydropower plants was set to the nameplate capacity. However, for small run-of-river hydropower plants, historical maximum output levels are based on the MWh of energy that a plant produced during a month divided by the number of hours that occurred during the month. The maximum output is typically achieved only at the Molina units.

Operating Criteria Effects on the Maximum Output Level

In addition to physical limitations, operations at all SLCA/IP hydropower plants are required to remain within a set of institutional and environmental limitations. For power systems analysis, SLCA/IP modeled operations are restricted by three types of limitations. These include (1) reservoir operating restrictions, (2) reservoir water release constraints, and (3) downstream gage stage and water flow limitations. Each of these affects the maximum daily output level. Depending on the situation, operating criteria do not allow a powerplant to reach its maximum physical output potential.

Glen Canyon Dam. The impact of operating criteria on Glen Canyon Dam maximum output levels is both complex and situational, involving not only the criteria, but also other factors such as the ancillary service requirements, monthly water release volumes, Lake Powell Reservoir elevation, and the number of operational units. End-of-month Lake Powell Reservoirs were obtained from the SBM.

To provide accurate estimates of the operating criteria on Glen Canyon Dam maximum output levels, Argonne optimized its hourly dispatch using a configuration of the GTMax-Lite model that only models Glen Canyon Dam. The GTMax-Lite model incorporates all environmental constraints imposed on Glen Canyon Dam from the current operating regime, such as restrictions on reservoir water release up/down ramp rates, minimum and maximum hourly release rates, and flow rate changes over a rolling 24-hour period. It also includes a projected maintenance schedule provided by Reclamation and a set of random unit forced outages. When physically possible and economically advantageous, the Glen Canyon Dam Powerplant also has ancillary service requirements, which, as discussed above, can impact Glen Canyon Dam's operational range.

For Glen Canyon Dam, the daily capacity level is set to the maximum output level that was modeled each day by GTMax-Lite. Although all operating criteria at Glen Canyon Dam potentially affect the maximum output potential, the daily change constraints in combination with water availability typically are the most binding. In addition to the aforementioned operating criteria, HFEs also affect capacity.

Aspinall Cascade: Blue Mesa, Morrow Point, and Crystal Dams. The Aspinall Cascade is operated as a tightly coupled, multipurpose system with a total nameplate capacity of approximately 283.4 MW. Plants in the cascade include Blue Mesa, Morrow Point, and Crystal. At the top of the cascade (i.e., highest elevation), the Blue Mesa Powerplant operates in a peaking mode. Located 12 mi downstream from Blue Mesa, the Morrow Point Power Dam is in the middle of the cascade. When tour boats operate in the Morrow Point Reservoir, there is a minimum reservoir elevation requirement of 7,151 ft. In addition, the Morrow Point Reservoir cannot be drawn down by more than 3 ft per rolling 24-hour period if the surface elevation is below an elevation of 7,144 ft. When tour boats are not operating, the minimum reservoir elevation is 7,125 ft.

The Crystal Powerplant is at the bottom of the cascade. In addition to functioning as a power generation unit, its operations stabilize the flow of water through Gunnison National Park. The flat flow requirement precludes it from rapidly changing its power output from one hour to the next. Operating criteria for the Crystal Reservoir are season specific. During the wet season (March 1 to June 30), the operating criteria limit reservoir drawdown to no more than 4 ft in a 24-hour rolling period, 5 ft over a 48-hour rolling period, or 6 ft over a 72-hour rolling period, and so on. In addition, once an elevation of 6,748 ft is reached, the reservoir level may not drop by more than 0.5 ft per 24-hour rolling period. During the remainder of the year, there is a 10-ft-per-24-hr-period fluctuation limit, with a maximum 3-day drawdown of 15 ft. If the reservoir elevation is below 6,733 ft, there is a 5-ft-per-24-hr-period drawdown limit, with a maximum drawdown of 20 ft per 7-day period.

Cascade reservoir restrictions can at times affect the hourly dispatch of powerplant units. However, for the LTEMP DEIS, it is assumed that these operating criteria do not affect the maximum output level that can be achieved at the Blue Mesa and Morrow Point. Generation at both of these powerplants can be ramped up or down from a zero output level to maximum capability in a matter of minutes without adverse effects on the power equipment. In addition, the plants are scheduled in advance, so reservoirs can usually accommodate water releases associated peak powerplant output levels without violating reservoir operating criteria. Therefore, it is assumed that Blue Mesa and Morrow Point maximum output levels are limited only by the reservoir level and the number of units that are in service as described in the Forebay Elevation section above.

The Crystal Dam however has a flat flow requirement that precludes it from rapidly changing its power output from one hour to the next. Therefore, the maximum output level from this plant is assumed to equal the monthly generation at the plant divided by the number of hours in the month.

Green River: Fontenelle Dam and Flaming Gorge Dam. The Fontenelle Powerplant also releases water at a constant rate (or flat flow), and output levels are nearly constant during daily operations. Therefore, maximum output level from this plant is assumed to equal the monthly generation at the plant divided by the number of hours in the month.

Operations at Flaming Gorge Dam are subject to set of complex limitations that affect maximum daily capacities. These include a minimum flow rate of 800 cfs, a maximum up-ramp rate of 800 cfs/hr, and a down-ramp rate limit of 1,000 cfs/hr. Water releases are further constrained to a constant rate (i.e., flat flow) in the summertime during the hours of the day when people are likely to be fishing below the dam. In keeping with current practices, the computation of Flaming Gorge capacity assumes the following:

1. The daily water release volume is the same for all days of a month;

2. The hourly water release pattern is identical each day of the week;

3. There is a one-hump release pattern during the summer; and

4. There is flat flow in summer between the hours of 6:00 AM and 7:00 PM (i.e., a duration of 13 hours every day).

The trapezoidal methodology utilized in the Large Plant Capacity Spreadsheet is illustrated in Figure K.1-23. It applies simple geometric equations to estimate Flaming Gorge base and peaking capacities using daily water release volumes and reservoir elevations derived from CRSS model results. The base capacity is computed by multiplying the 800 cfs minimum flow requirement by a water-to-power conversion factor that is a function of hydraulic head. It requires a significant volume of base load water to be released each day (i.e., constant 800 cfs release over a 24-hour period).

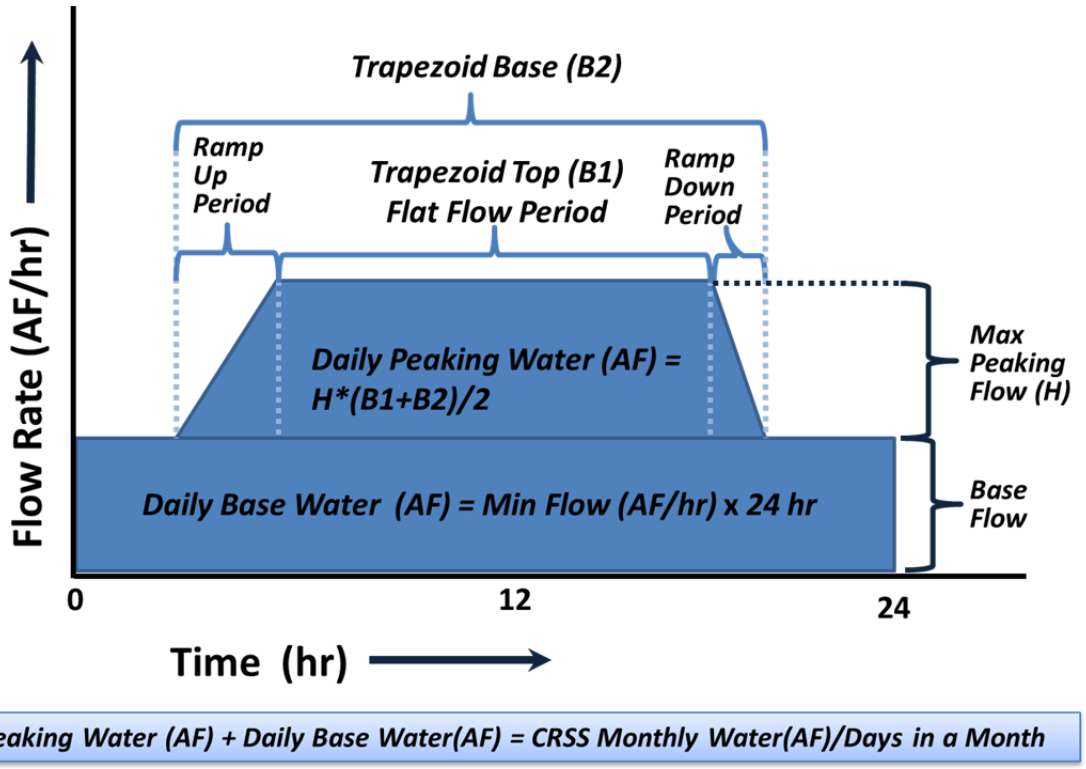


FIGURE K.1-23 Illustration of the Trapezoidal Method Used to Compute Capacity at Flaming Gorge Dam

The water volume that remains after sustaining the daily base release is used to estimate peaking capacity as the height of a trapezoid. The length of the top of the trapezoid is 13 hours (i.e., fishing duration) and length of its bottom/base is equal to 13 hours plus the up and down ramping times. As shown in Figure K.1-24, these ramping times increase as a function of peaking water volume and subjected to a total time limit of 11 hours (i.e., 24 hours less the 13 hour flat flow period).

Furthermore, the sum of the base load and peaking capacities cannot exceed the total physical turbine flow limit multiplied by the water-to-power conversion factor, as described in more detail in the Forebay Elevation section; both the maximum turbine flow limit and the power conversion factor are a function of the hydraulic head. The total turbine water release, and therefore the maximum output level, is reduced when turbines are taken offline due to a scheduled or forced unit outage at Flaming Gorge. The results of performing trapezoidal computations over a large range of daily water volumes are shown in Figure K.1-25. This relationship between daily water volume and maximum turbine flow rate is fairly accurately described by a sixth order polynomial. Multiplying the maximum flow rate by the water to power conversion factor yields a capacity estimate.

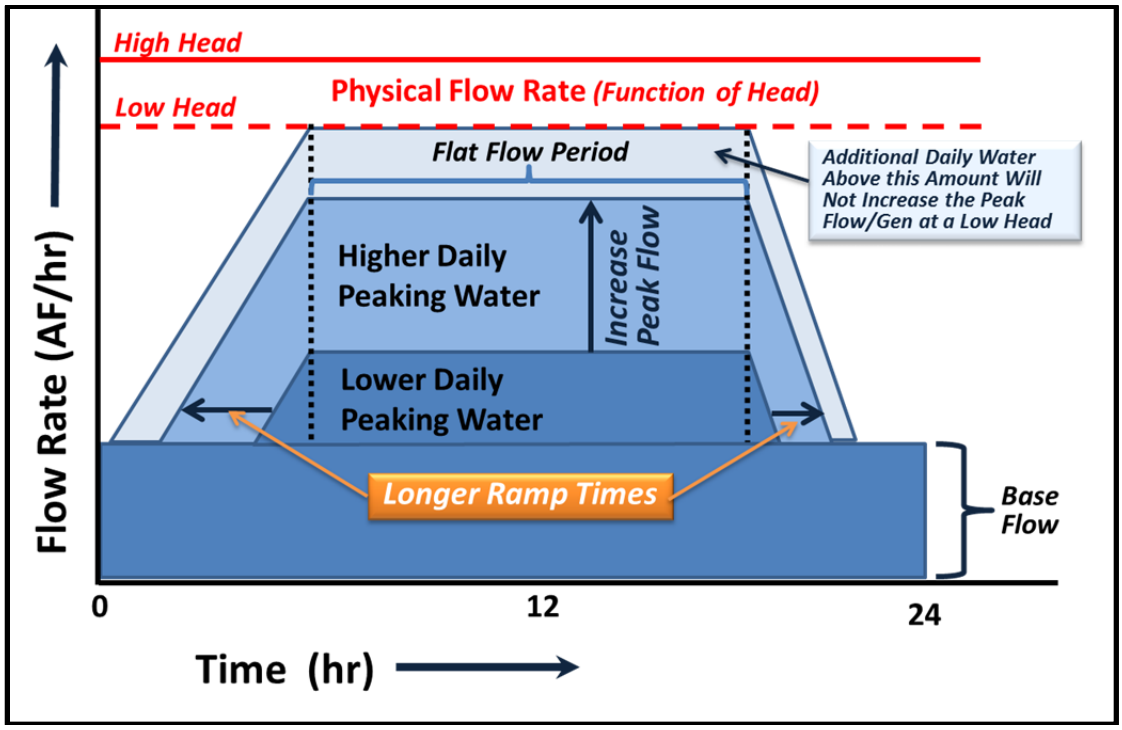


FIGURE K.1-24 Illustration of Ramping Time Increase as a Function of Increasing Water Volumes at Flaming Gorge Dam

To protect endangered native fish in the Green River basin, the U.S. Fish and Wildlife Service released a biological opinion (FWS 1992) designed to protect the Colorado Squawfish and Razorback Sucker. The overall intent of the opinion was to structure releases from the Flaming Gorge reservoir so that they resemble natural hydrograph and water temperature conditions. A final set of restrictions was implemented in WY 2006 following completion of a final EIS on the operation of Flaming Gorge Dam (Reclamation 2005) and issuance of its ROD (Reclamation 2006) in February 2006.

High spring release volumes are being structured to enhance river flows during spring spawning periods. Flow volumes include full powerplant output (approximately 4,500 cfs or 141 MW) to full plant output plus bypass tubes and spillways combined. The high release period could be held for as long as 4 weeks. The actual volume and duration of release from Flaming Gorge is determined by the river volume desired on the Green River below the Jensen measurement gage at Jensen (or Jensen Gage) and inflow support from the Yampa River. The high spring release is patterned around the peak runoff period, which varies each year based on weather conditions and endangered fish spawning activities. High peak spring releases transfer water that historically was released during summer and winter peak months to spring months. This shifting of water among months of the year is factored into CRSS model runs that provide input data into the Large Plant Capacity Spreadsheet.

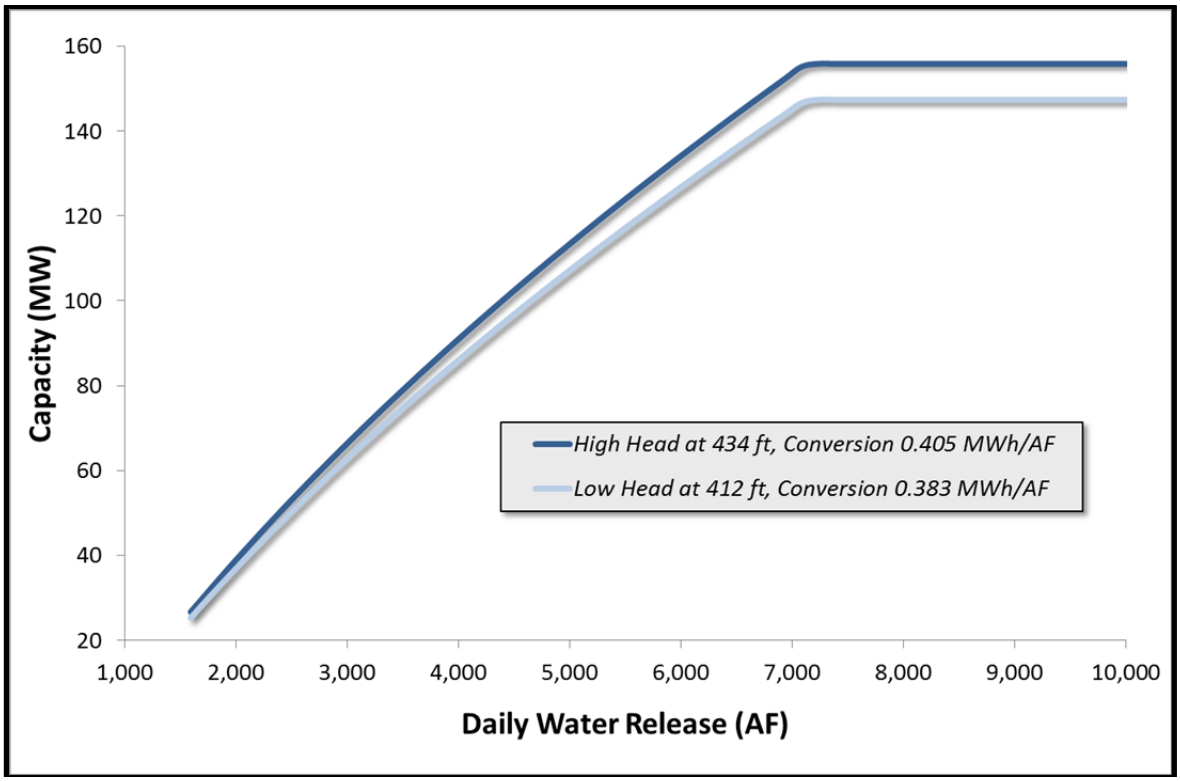


FIGURE K.1-25 Capacity Values at Flaming Gorge Dam Calculated over a Wide Range of Daily Water Releases Using the Trapezoidal Method

After the high spring release is completed, flows on the Green River below the Jensen Gage are held to an average of 1,600 cfs, if possible. The gage is about 94 mi downstream of the reservoir, receiving water not only from Flaming Gorge but also from the uncontrolled Yampa River, which joins the Green River approximately 65 mi downstream of the dam. This means that releases from the Flaming Gorge power plant are held to a minimum of 800 cfs (25 MW) until a time when the combined average flows on the Green and Yampa rivers below Jensen fall below the desired level of 1,600 cfs average. This powerplant restriction can last from 3 to 8 weeks, depending on snowpack conditions.

Flaming Gorge operations must also be patterned such that daily stage readings at the Jensen Gage do not fluctuate by more than 0.1 m. These stage readings are a function of hourly water releases from Flaming Gorge, inflows into the Green River from the Yampa River (105 km [65 mi] downstream of the dam), downstream flow rate attenuations, and water travel times. Although the influence of Jensen Gage constraints are not factored into the capacity estimate, at low daily water release volumes the daily range of Jensen Gage flow rates are also low.

Small SLCA/IP Resources. Relatively small SLCA/IP hydropower plants including Towaoc, McPhee, Elephant Butte, Upper Molina, and Lower Molina power plants. In total, these facilities contribute a relatively small amount of capacity and all but the Molina power plants are

flat flow facilities. Powerplant capacities for small powerplants are computed in a spreadsheet based on historical monthly generation data as archived in Form PO&M-59. For the small powerplants that are run at flat flow, the firm capacity credit is primarily a function of monthly estimates of total energy production divided by the number of hours in a month.

However, Molina powerplants are dispatchable and operated in unison. The spreadsheet algorithm evenly divides Form PO&M-59 monthly generation among all days in the month. The spreadsheet then operates Molina at maximum output continuously until the entire daily generation is exhausted; that is, the units start and stops once per day and no power is produced in any other hours. The block of operating hours is based on market prices such that the economic value of Molina resources is maximized.

Risk-Based Firm Capacity Operating Criteria

As discussed previously, numerous factors influence the amount of firm capacity that is credited toward reserve margin computations for SLCA/IP system. Two of these factors are discussed in this section. These include (1) the month when system peak load occurs and (2) the percentage of time that the entire firm capacity or more will be available to meet the system peak load.

System Peak Load Month. The month in which the system peak load occurs and upon which firm capacity calculations would be based was debated and ultimately jointly decided upon by staff from Reclamation, Western, National Park Service (NPS), and Argonne. August was chosen as the month when the system peak load occurs. This decision was made after examining historical FERC Form-714 data for CY 2006 through CY 2012, inclusive. Hourly load data were available for all eight large customer utilities. However, NTUA and Deseret data was only available for the first 4 of the 7 years. No hourly load data were available for any of the small LTF customers.

An examination of large LTF customer historical peak loads over this time period showed that individual customer peaks almost always occurred during the summer. A few exceptions occurred. CSU experienced one annual peak load in April 2006 and another peak in December 2009. In addition, NTUA, which has the lowest peak load of the eight large customers, experiences its peak load in either December or January. Figure K.1-26 shows that the NTUA peak load is about 1% of the non-coincidental sum of the eight large customer average annual historical peak loads. The sum of these annual non-coincidental peaks changed very little during the 2006 to 2012 time period, and averaged approximately 11,800 to 11,900 MW.

When the peak occurs in the summertime, it almost always occurs in either July or August. Only CSU experienced a different summer peak; it occurred in June of 2012 and was merely 2 MW greater than the highest load in July. A close examination of when the peak occurred also revealed that, for several utilities, there was no clear pattern of which month the peak occurs in. For example, SRP, which accounts for a majority of the non-coincidental total,

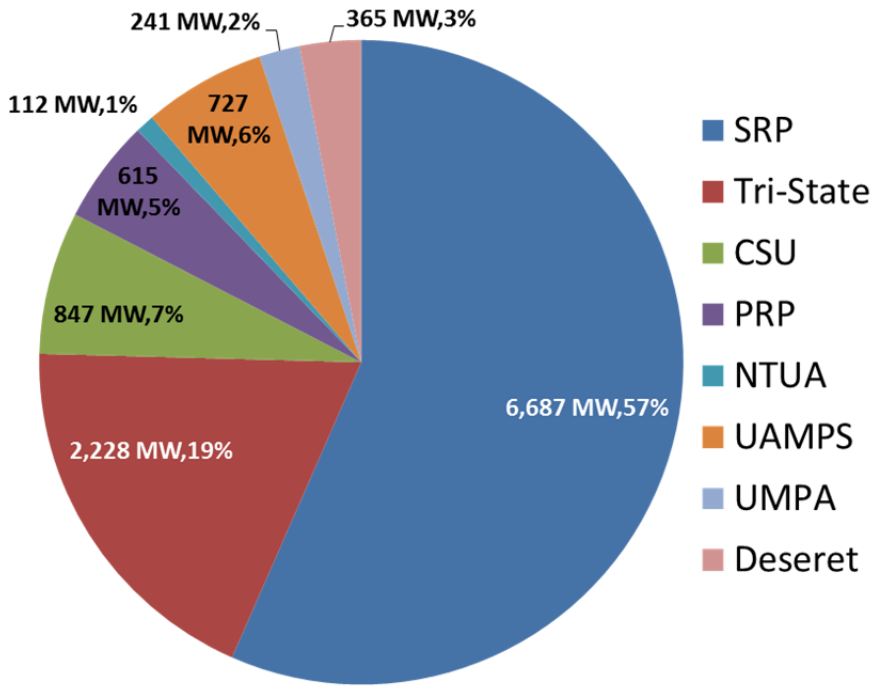


FIGURE K.1-26 Average Historical Non-coincidental Annual Peak Loads (in MW) for the Eight Large Customers and Percentages Relative to the Total

experienced 3 years during which the annual peak occurred in July and 3 years during which the peak occurred in August. In 2007, the maximum load in July equaled the maximum in August. In addition, July and August maximum loads tend to be very similar across all systems.

Coincidental annual peak loads were also examined. The coincidental peak was determined by first summing up the available loads for the eight large customers on an hourly basis and then identifying the month in which the maximum total hourly load occurred. Results of this exercise also showed that, historically, July and August both had very similar maximum loads. Figure K.1-27 shows annual coincidental monthly maximum loads for 4 years (CY 2006 through CY 2009), based on data for all eight large SLCA/IP customers. In chronological order, the bars show annual peaks and the line shows the average. Figure K.1-28 shows the same information, except it is for an additional 3 years (CY 2010 through CY 2012) and is based on only six utilities. Information is presented in two separate figures because all load data were not available for all 7 years. As mentioned previously, FERC hourly data were not available for NTUA and Deseret during this time period. It should be noted that, for CY 2011 and CY 2012, the August peaks were markedly higher than those in July. The representative lead profile for the large customers has a coincidental peak load of about 12,370 MW.

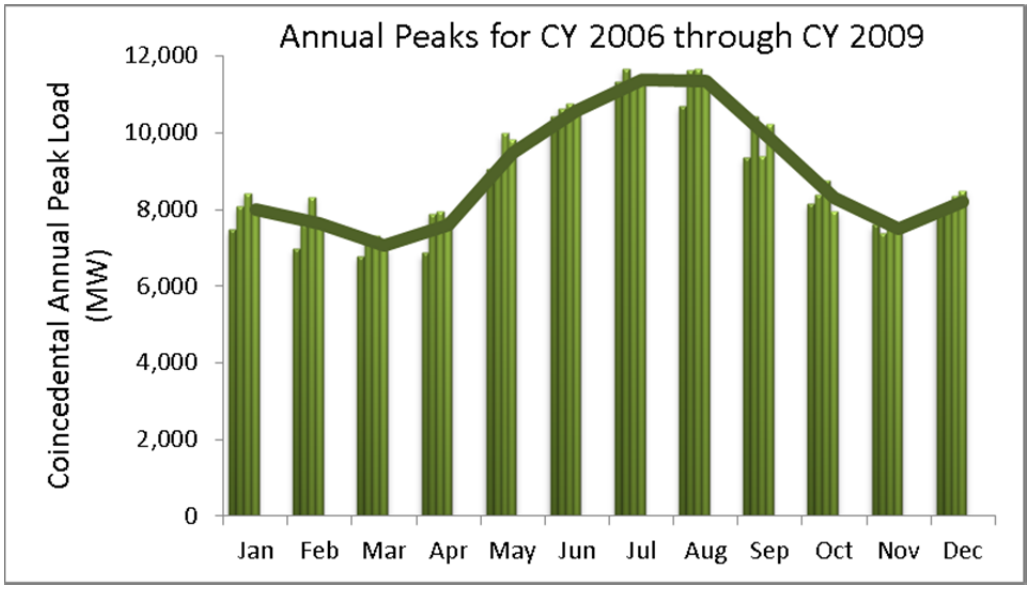


FIGURE K.1-27 Historical Coincidental Annual and Average Peak Loads for the Eight Large Customers during the CY 2006 through CY 2009 Time Period

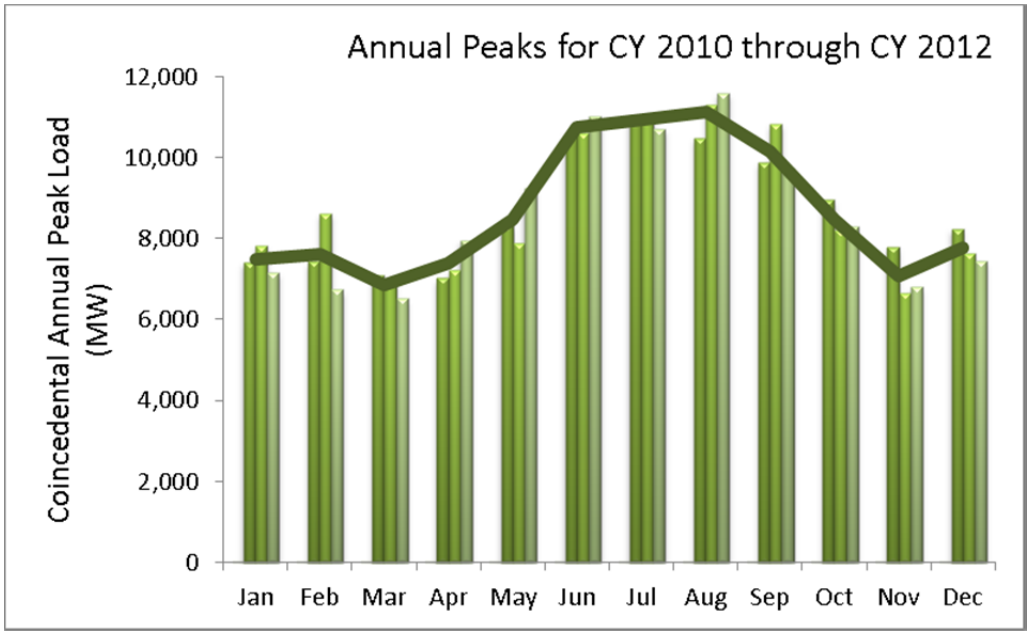


FIGURE K.1-28 Historical Coincidental Annual and Average Peak Loads for Six Large Customers during the CY 2010 through CY 2012 Time Period

Firm Capacity Risk Level. Assumptions regarding the level of risk that would be used in the LTEMP power systems analyses to determine firm capacity levels under each alternative were debated and jointly decided upon by staff from Reclamation, Western, NPS, and Argonne. Again, historical information was used to help in the decision-making process. However, unlike the process that was used to determine the timing of the peak load, which primarily relied on historical data, these methods also required the use of modeling tools—most of which were previously described in the Modeling Tools section.

Under terms of the SLCA/IP 2004 LTF contracts, Western's CRSP Management Center Office is obligated to provide its LTF customers with a minimum capacity level (SHP). The SHP level must be supplied regardless of the state or condition of SLCA/IP hydropower resources. These non-contingent contracts became effective on October 1, 2004, and will continue to be binding until September 30, 2024. When SLCA/IP resources are incapable of fulfilling Western's entire obligation, Western must make power purchases to cover any shortfalls. Therefore, Western is exposed to market risks because the future of both reservoir conditions and the operating state of generating units are not known with certainty. Argonne conducted an analysis to roughly approximate risk levels to which Western is exposed under its current SHP obligation. For this analysis, risk exposure is measured as the probability that Western will not be able to meet its daily SHP obligations during peak summer load months. Argonne staff estimate this probability by computing daily SLCA/IP hydropower powerplant capacity under many possible hydrological futures while accounting for the impacts of unit-level outages and environmental operating limits. This analysis is merely a retrospective study of Western's SHP level using current hydrological data. The methodology used in this analysis was not necessarily used by Western to determine its current SHP obligations.

SLCA/IP hydropower facilities span a large range of powerplant sizes and operational flexibility. For this analysis, Western's SLCA/IP hydropower resources are divided by size as shown in Figure K.1-20.

The capacity from the Western SLCA/IP system is estimated using the models and method shown in Figure K.1-29, which leverages LTEMP tools and methods. A brief overview of capacity computations is as follows:

1. Glen Canyon Dam Powerplant resource capacity under many plausible futures is based on Reclamation's CRSS and SBM models, along with maximum daily production levels projected by the Argonne GTMax-Lite model;

2. Other CRSP and Fontenelle daily capacities under many plausible futures are estimated by the Large Powerplant spreadsheets that compute unit-level maximum output based on CRSS model results and unit-level outages;

3. Flaming Gorge capacity is further reduced under most hydrological conditions because operating criteria and other agreements further constrain its maximum daily output; and

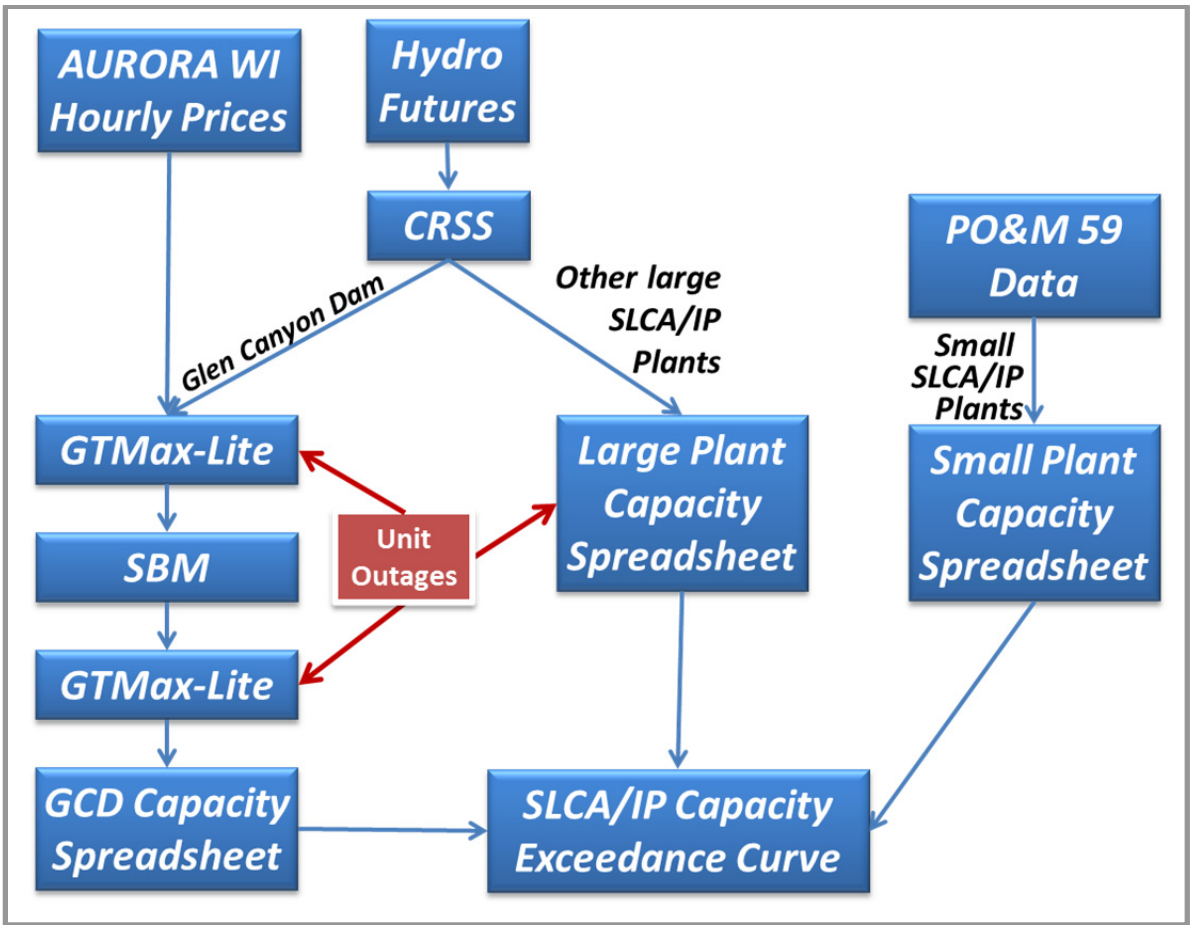


FIGURE K.1-29 SLCA/IP Models Used for Estimating SHP Capacity

4. For the remaining SLCA/IP resources (i.e., Towaoc, McPhee, Elephant Butte, Upper Molina, and Lower Molina), monthly capacity computations are based on historical monthly operating information contained in Form PO&M-59.

After trace-specific time series of plant-level capacities are computed, the Firm Capacity Spreadsheet creates SLCA/IP hydropower capacity exceedance curves. For each day in a month, the routine totals the daily coincidental peak capacities of all large powerplants. To this sum the routine adds monthly capacities for all small powerplants and subtracts capacity that is reserved for other purposes as described in previous sections.

After a time series of plant-level capacities was computed for all facilities and all traces over the 20-year study period, the data were processed further in a separate routine to determine exceedance levels for the peak loads months of July and August. For each day in a month, the routine totals the daily coincidental peak capacities for both Glen Canyon Dam and the other large SLCA/IP federal facilities for 21 hydrology traces over the 20-year study period. The resulting values are used to create SLCA/IP hydropower marketable capacity exceedance curves.

Western's current sustainable hydropower (SHP) commitment level was located on these exceedance curves to determine how much of the time SLCA/IP resources would be able to meet all of Western's current contractual and operating obligations. SHP is the minimum aggregate level of LTF capacity and energy that will be provided by Western to all SLCA/IP customers through the contract period, regardless of the hydropower condition. The location of the Western's SHP commitment on the exceedance curve will determine the level of capacity risk to which Western is currently exposed.

From Western's data over at least the last 10 years, its SHP commitment for July has been about 750 MW. As shown on the SLCA/IP capacity exceedance curve in Figure K.1-30, this level is exceeded about 89.5% of the time; in other words, there is a 10.5% probability that Western will need to make purchases to fulfill its entire SHP. In August the risk is somewhat lower. Figure K.1-31 shows that Western has enough SLCA/IP hydropower capacity to meet its SHP capacity obligation of 721.4 MW about 91% of the time. Therefore, Western's current capacity risk is at about the 90% exceedance level.

K.1.7.4 Firm Capacity Curves for LTEMP Power Systems Analyses for the Peak Month of August

Similar to the above assessment of risk for the CRSP Management Center, exceedance curves were constructed to analyze risk levels associated with firm capacity used for SLCA/IP system reserve margin calculations. The left panel of Figure K.1-32 shows the marketable capacity for the seven primary alternatives at exceedance levels ranging from 10% to 99% for

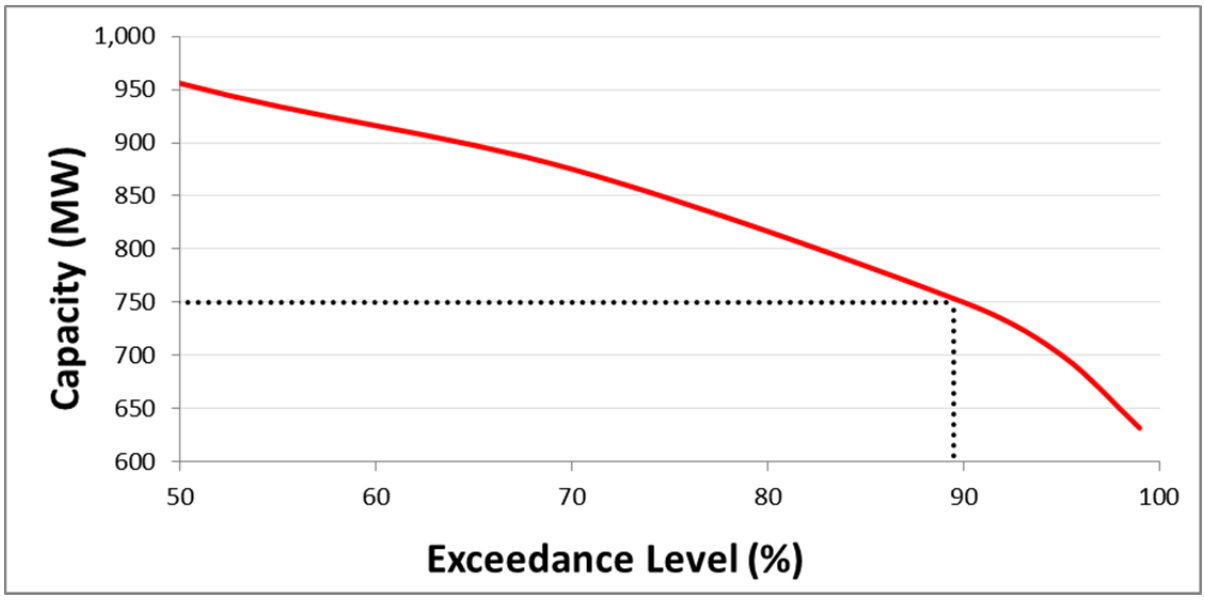


FIGURE K.1-30 Historical SHP Capacity Obligation and Western Estimated Risk Level in July

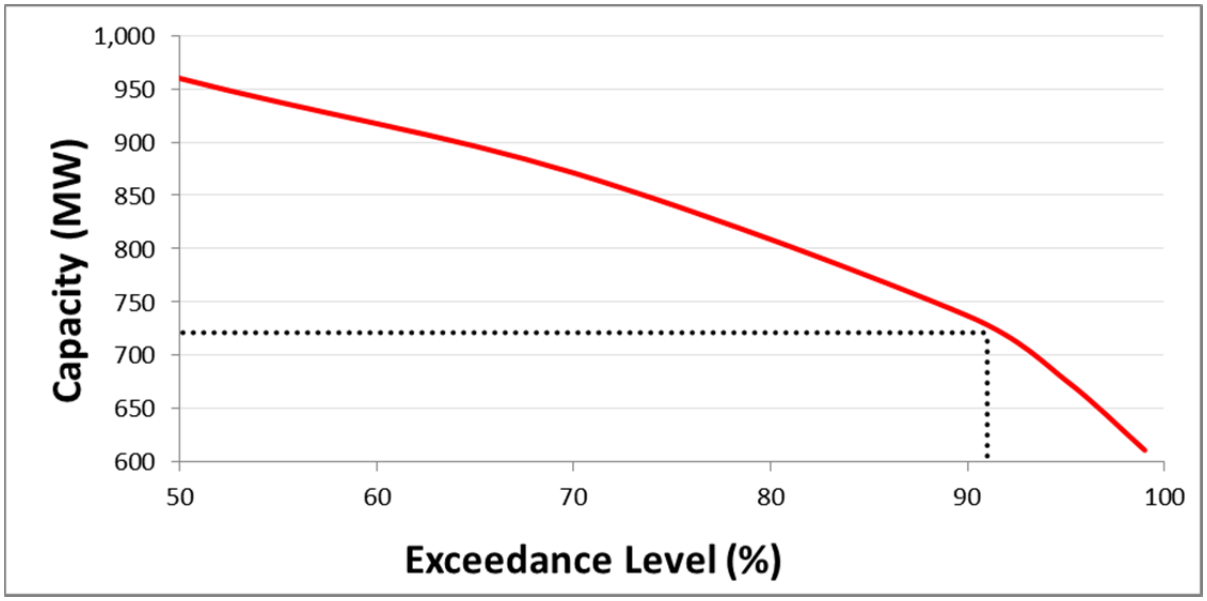


FIGURE K.1-31 Historical SHP Capacity Obligation and Western Estimated Risk Level in August

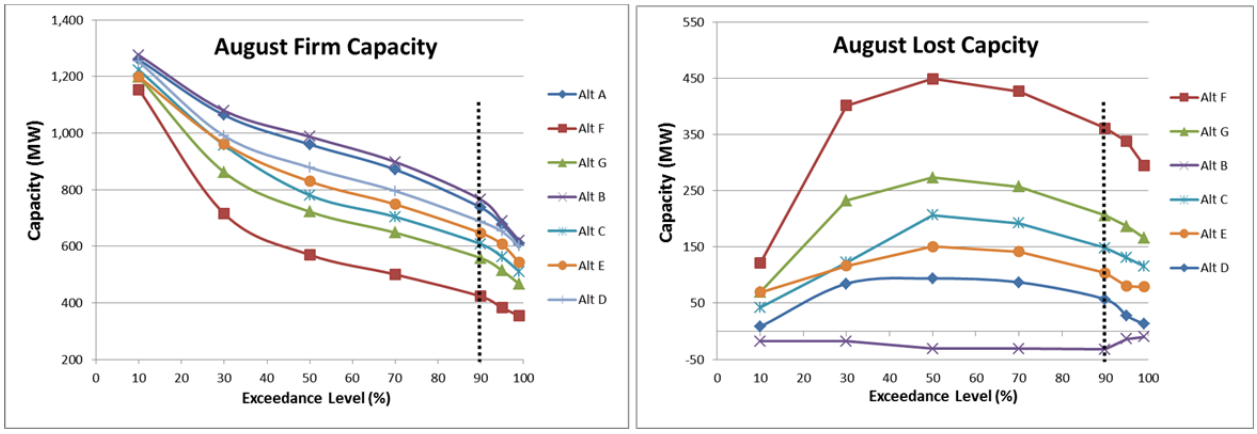


FIGURE K.1-32 Comparison of Firm Marketable Capacity Determinations across Alternatives, Exceedance Levels, and Summer Peak Months

combined SLCA/IP federal hydropower resources. These results assume that the peak system load will occur in August. All alternatives have less firm capacity at all exceedance levels than Alternative A, except for Alternative B, but this is expected because it has the least restrictive environmental constraints of any alternative.

Under the assumption that the peak load occurs in August, the right panel of Figure K.1-32 shows the difference in firm capacity compared to Alternative A. The graphs show that the greatest difference in capacity occurs at the 50% exceedance level and the smallest at the 99% exceedance level. Based on the current CRSP Management Center risk exposure of

10%, the determination of firm capacity for all LTEMP alternatives will also be based on this risk level. Note that the results reported in Chapter 4 of the main document also assume a 10% risk level (90% exceedance level) for a peak load that is anticipated to occur in August.

However, Western CRSP Management Center staff point out that Western has no obligation to use this criteria when setting future LTF capacity offers to its preference customers. Western staff also noted that other offices within the Western organization use different critera to establish marketable capacity levels. For example, the Desert Southwest (DSW) Office sells its entire available Hoover Dam Powerplant capacity to its customers, and this capacity varies over time. As the Hoover Dam Power Resource changes, DSW staff modifies its commitment level accordingly. Therefore, Argonne staff encouraged a sensitivity analysis that uses a range of exceedance levels. The results of the analysis are presented in Section K.1.10.4.

The power systems methodology assumes that lost Glen Canyon Dam Powerplant capacity replacement costs due to more stringent operating criteria under an alternative will be assessed at the systems level.

Capital costs to build the dam and powerplant were incurred in past. Therefore, the economic costs of these past expenditures are treated as sunk investments under all alternatives; that is, economic costs for building the dam and powerplant are set equal to zero because past expenditures cannot be altered. Furthermore, it is assumed that any additional capital investment in the dam and powerplant that will be incurred in the future is unaffected by an alternative. It therefore follows that capital investment differences among alternatives is also zero. Similarly, Glen Canyon Dam fixed O&M costs are assumed to be unaffected by any of the alternatives. It is also assumed that the total physical 1,320 MW of nameplate capacity at Glen Canyon Dam is identical under all LTEMP DEIS alternatives and that the capacity of all powerplant units will not change over the study period.

Capital costs only factor into LTEMP DEIS economic calculations for capacity expansion units because the retirement schedule of existing units and the online date of committed units does not change among alternatives; therefore, the economic cost difference between Alternative A and other alternatives is equal to zero. Fixed O&M costs only factor into LTEMP DEIS economic calculations for capacity expansion units because the retirement schedule of existing units and online dates for committed units do not change among alternatives; therefore, the economic difference of these "fixed" costs between Alternative A, which serves as a reference point, and other alternatives is equal to zero.

K.1.7.5 AURORA Capacity Expansion Reserve Margin Targets and Capacity Additions

The AURORA model was used as a tool to aid power system modelers and analysts at Argonne in finding reasonable capacity expansion plans for each LTEMP alternative using the topology previously shown in Figure K.1-3 and described in Section K.1.5.9. This section provides more details on how it was used for capacity expansion. The network topology shown in Figure K.1-3 consists of two power pools. Pool A is made up of all SLCA/IP hydropower

resources and Western's eight large customers. Pool B consists of the aggregate of Western's small customers and all project use loads.

The network was modeled as two power pools for the purpose of calculating a system reserve margin. Western's eight large customers and hydropower resources were put into Pool A because these customers (except for NTUA) satisfy their loads from a combination of their own generation, generation owned jointly with another large customer(s), Western firm hydropower allocations, bilateral contracts, and market purchases. Customers in Pool B have no generation and serve loads only through Western firm hydropower allocations, bilateral contracts, and market purchases. It is assumed that customers in Pool A would satisfy their combined reserve margin by constructing new generation. Customers in Pool B would satisfy their reserve margin by making individual purchases from large Pool A customers and from the Western Interconnection market transactions.

The model builds new units when the capacity reserve margin of the aggregate SLCA/IP system, which includes Western and all of its LTF customers, would otherwise drop below 15%. Based on a review of utility IRPs in the Western Interconnection, it was found that a 15% reserve margin is a typical capacity expansion goal. This value was therefore used as a reserve margin goal for the LTEMP power systems analysis.

Capacity that is credited toward the reserve margin frequently differs from the rated nameplate capacity, because the maximum output from the powerplant may differ from the rated level. For example, a high atmospheric temperature typically reduced the maximum output from gas-turbine technologies. Therefore, the firm capacity that is used in the reserve margin calculation is less than the nameplate capacity if the system peak load is expected to occur during a hot summer afternoon. The firm capacity that is given to VERs can be very complicated. It is often based on system-level reliability calculations that determine an equivalent "100% reliable" capacity that yields the same loss-of-load probability as the VER.

The power system analysis uses an estimate of firm capacity for all existing and new units instead of the nameplate capacity. In some cases, this requires that sometimes the nameplate capacity is significantly derated. For example, it is assumed that the firm capacity credit of new solar and wind farms is only 10% of the nameplate capacity. This is the default used by AURORA. The firm capacity of Western's SLCA/IP hydropower resources that is credited toward this system reserve margin was described in Section K.1.7.4. In addition, as noted previously, only the daily capacity of Glen Canyon Dam differs among alternatives.

Figure K.1-33 provides a simplified illustration of the impact of the firm capacity credit at Glen Canyon Dam on the timing of new construction to meet future loads and the reserve margin target. Two cases are shown in this example for illustrative purposes only. Under Case 1, Glen Canyon Dam has a larger firm capacity and Case 2 has a smaller credit. The orange line shows the annual coincidental peak load for the system. Because Western's firm allocation is non-contingent, that capacity amount can be subtracted from the system peak load before calculating the reserve margin. The reserve margin is then applied to that resulting curve to obtain a revised load curve that includes the required reserve margin. This curve is then compared with the capacity in Pool A to determine where they intersect. The year in which they

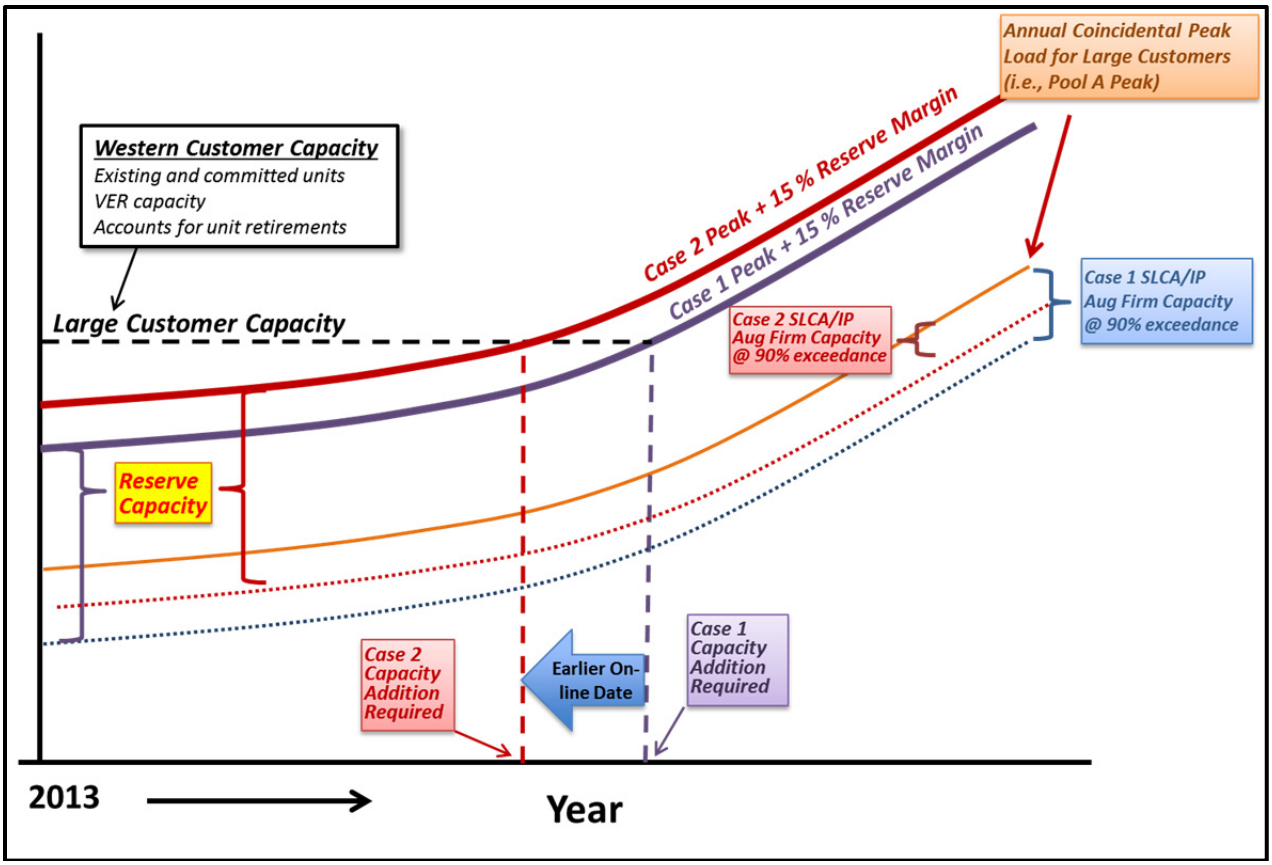


FIGURE K.1-33 Timing of Capacity Additions in AURORA

intersect is when new capacity is needed to meet the reserve margin. The graph shows that Case 2 needs new capacity before Case 1 because Western's firm capacity credit under Case A is smaller.

To reliably serve projected load growth, fossil and non-fossil generation units are constructed by AURORA. AURORA also sheds load at specified market price trigger points.

Capacity shortfalls that remain after complying with state RPSs are resolved by building new electric generating units from a list of candidates. The cost and characteristics of candidate technologies for future capacity expansion that were used for power systems analysis were provided in Table K.1-1. These technologies and associated attributes and costs were based for data found in EIA's 2014 AEO (EIA 2014).

The AURORA capacity expansion feature was used to guide the selection of a plausible capacity expansion plan for the SLCA/IP system. The methodology utilized models the expansion path for an aggregate eight large customer pool labeled "Pool A" in Figure K.1-3. The expansion plan determined under each alternative meets a 15% target reserve margin for pool A (large customers and SLCA/IP federal hydropower resources) plus additional capacity to replace lost Glen Canyon capacity that is allocated to small customers. Under an alternative, large

customers therefore replace the entire lost capacity even though only a portion (i.e., about 75% under current SLCA/IP LTF capacity allocations) of this lost capacity would contractually affect these larger utilities. Because small customers would most likely not build capacity in the future, it was assumed the lost capacity allocated to these small utilities (i.e., about 25%) would be replaced via the capacity expansion pathways of the aggregate eight large systems (Pool A). Small customers pay for this capacity by purchasing it from the large customers via LTF contracts.

The methodology implicitly assumes that a capacity shortfall in one customer utility system could be temporarily fulfilled by another utility that has excess. Conceptually, this could be achieved via a short-term firm bilateral capacity contract between the two systems, thereby delaying a physical capacity addition by the utility that is "short" capacity. The sharing of capacity resources differs from an approach in which the capacity requirements and goals of each large customer are met individually. Under the joint system model, new units are only constructed when the aggregate system is short. Because the methodology used in the analysis focuses on the economics of the entire system, financial transactions among individual utilities, such as short-term firm capacity purchases and sales, are not computed.

Although Western customers have a history of mutually beneficial arrangements, the "joint system" model assumes a level of cooperation and coordination that currently does not exist. Currently, there are no centralized energy or capacity markets in the region of the Western Interconnection where SLCA/IP federal hydropower resources and Western's LTF customers are located. Capacity expansion decisions and energy transactions in this area are done autonomously to meet the objectives of each independent utility. In addition, each utility has limited information about the entire grid and the independent actions/decisions made by other entities in the system. This is different than that used in the AURORA model, which makes units commitments and dispatches units with "perfect" information about the entire system to optimize a system-wide objective. AURORA also builds new powerplants to meet the pool-level reserve margins, not to serve the objectives of each independent utility. Because a utility may add capacity instead of making a short-term firm capacity purchase, this methodology will tend to underestimate capacity expansion costs under all alternatives. However, inaccuracies associated with cost differences among alternatives are most likely lower.

As discussed previously, new units are constructed when the capacity reserve margin of the aggregate system would otherwise drop below 15%. Additions are made in unit capacity increments resulting in a plan that has a "lumpy" reserve margin time series. The reserve margin requirement (i.e., modeled as a "hard" constraint) also produces a solution that almost always exceeds the 15% target. These relatively small excess capacities that fluctuate over time are beneficial to the system dispatch and production-cost economics. Although most analyses would assume that this excess capacity has no value, it could potentially be sold to a neighboring utility outside the SLCA/IP marketing area, thereby reducing expansion costs. A simple post-model sensitivity study was performed that assumed this capacity could be sold. The results of the study are reported later in this appendix.

Depending on AURORA model parameters and run settings, the expansion plans suggested by AURORA can be considerably different for Alternative A and in many instances

add significantly more generating units than the number required to maintain a 15% reserve margin. This in part stems from the fact that the optimization problem AURORA attempts to solve is extremely difficult to find. After discussion with EPIS staff and examinations of expansion results, Argonne concluded that new capacity addition decisions made by the model are based on financial objects rather than a single global economic objective. AURORA builds a new unit if it is financially attractive. The end result is a realistic expansion path. However, solutions that focus on local unit additions that are financially viable based on the NPV of costs and revenues over the study period result in expansion pathways that often differ from the one that costs the least over the entire multi-utility system.

Given the size of the modeled SLCA/IP area, the focus/capabilities of AURORA, and Argonne staff skill level in the use of the model, finding the global least-cost economic solution for Alternative A is intractable; that is, Argonne could not mathematically prove that any one of the many solutions produced by AURORA was the global least-cost solution. It was also judged that the mathematical optimum path would most likely not be found within a reasonable amount of time and effort (i.e., several weeks or months). Given this modeling limitation, however, the technologies selected by AURORA consistently indicated that combustion turbines (CTs) and natural gas-fired combined cycle units will be constructed in the future. This solution is consistent with available IRPs that Argonne reviewed for SLCA/IP large customers and several large systems (typically investor-owned utilities) that neighbor the SLCA/IP marketing area. A summary of these IRPs is shown in Table K.1-6 (see Table 2 of Attachment K-9 for additional information). More detailed information about these IRPs are provided in Attachment K-9.

It should be noted that the methodology only represents SLCA/IP physical assets and production levels. It does not reflect changes in SLCA/IP contract that may be implemented in October 1, 2024, or financial implications as they affect Western and individual customers. This topic will be discussed in the Wholesale Rate Analysis section.

K.1.7.6 Dispatch Performed by AURORA Model Capacity Expansion Runs

The methodology used represents all of SLCA/IP hydropower energy assets in the AURORA model to measure the economics of changes in Glen Canyon Dam operating criteria. GTMax-Lite and customized small SLCA/IP resource spreadsheet results provide AURORA with alternative-specific SLCA/IP dispatch and an hourly schedule of energy injections into the power grid. By doing so, AURORA recognizes the basic role of hydropower resources as they affect the dispatch of the SLCA/IP system and energy transactions with the Western Interconnection.

Due to the complexities of SLCA/IP hydropower operating criteria and non-power considerations, AURORA could not model the dispatch of these resources at the level of detail required for this study. Instead, powerplant-specific hourly production levels were projected over the study period using the previously discussed two GTMax-Lite model configurations and the Small SLCA/IP Powerplants Spreadsheet. Energy injections into the system from Glen Canyon Dam are based on average hourly GTMax-Lite results over all 21 hydrology traces from the SBM. Hourly energy injections from all other large SLCA/IP resources are based on

TABLE K.1-6 Summary of Utility IRPS for Four Large SLCA/IP Customers and Other Large Utilities in Areas Neighboring the SLCA/IP System

Utility	Utility Type	Type of Generation Added	When Added	Capacity Added (MW)
Public Service of CO	Investor	Gas Turbines	2018 to 2022	1,211
	Owned	Combined Cycle	2023 to 2032	1,929
Public Service of NM	Investor	Gas Turbines	2016 to 2033	736
	Owned	Solar PV	2015 to 2022	283
Rocky Mountain Power	Investor	Combined Cycle	2014, 2024	645, 423
	Owned	Wind	2024	432
Arizona Public Service	Investor	Natural Gas (unspecified)	2019 to 2029	4,200
	Owned	Renewable (unspecified)	2019 to 2029	425
Tucson Elect. Power	Investor	Natural Gas (unspecified)	2015 to 2028	1,214
	Owned	Renewable (unspecified)	2014 to 2028	529
Nevada Power Company	Investor	Combined Cycle	2018 to 2024	3,813
	Owned	Gas Turbines	2023 to 2032	2,043
		Solar PV	2016 to 2021	50
Sierra Pacific Power	Investor	Gas Turbines	2023 to 2029	1,975
	Owned	Combined Cycle	2025	571
Platte River Power	Western Customer	Gas Turbines	2021	Unspecified
Colorado Springs Utilities	Western	Gas Turbines	2029 to 2031	39
	Customer	Renewable (unspecified)	2018 to 2029	20
Tri-State G & T Assn.	Western	Combined Cycle	2019 to 2026	1,176
	Customer	Renewable (unspecified)	2016 to 2027	350
Salt River Project	Western Customer	Natural Gas (unspecified)	FY2018+	Projected 581-MW gap in 2017

GTMax-Lite results, which use average monthly hydrological conditions over the 21 hydrology traces produced by CRSS. Last, energy injections from small SLCA/IP hydropower plants are based on average historical conditions reported in Form PO&M-59.

Annual CY energy generation for Glen Canyon Dam and all other SLCA/IP hydropower resources combined are shown in Figure K.1-34 under Alternative A. Annual generation from the Glen Canyon Dam Powerplant averages about 4,114 GWh, and ranges from about 3,665 GWh to 4,338.2 GWh. The lowest generation value occurs in 2013 due to low initial reservoir elevations that were observed at the end of CY 2012. That is, because the simulation starts out at a point in time when the Glen Canyon Dam reservoir is low, water releases tend to be less since more water is retained in the reservoir in an attempt to increase the water storage level. On average, Glen Canyon Dam is expected to account for about 72% of the total annual SLCA/IP hydropower generation. Because annual WY releases are nearly the same under all alternatives, total CY annual generation levels for all alternatives are within about 1.7% of Alternative A. Those alternatives that have more HFEs tend to have somewhat lower annual average generation levels. This topic will be discussed in more detail in Section K.1.10.

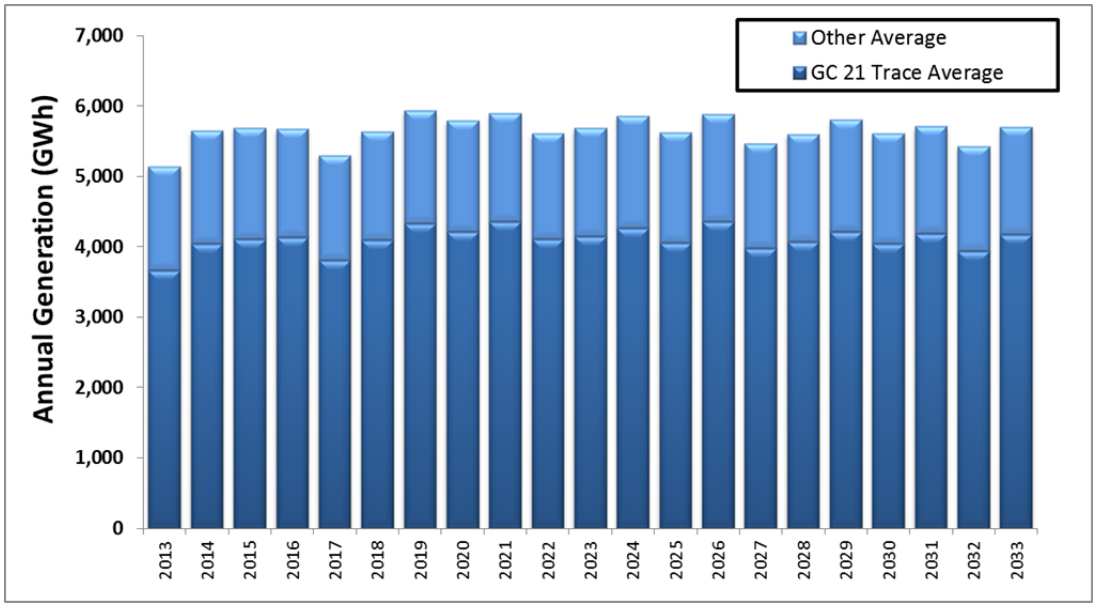


FIGURE K.1-34 Annual Average Hydropower Generation for the Glen Canyon Dam Powerplant and the Aggregate Generation for all other SLCA/IP Resources

Although annual Glen Canyon Dam generation levels are similar among alternatives, the monthly distribution of generation within a year is substantially different among alternatives. Projected monthly generation produced by other SLCA/IP hydropower resources is essentially identical under all alternatives. Figure K.1-35 shows that alternatives such as Alternatives A and B have high Glen Canyon Dam average daily generation levels during the peak summer months when marginal energy production costs are relatively expensive. These energy levels produce higher economic values than those with lower summertime generation levels, such as Alternative F.

Interactions between all entities in the SLCA/IP marketing area and the rest of the Western Interconnection are represented by a single point where non-firm hourly energy transactions occur. This point, labeled "Spot Market" in Figure K.1-3, contains an inelastic time vector of market prices for system energy purchase and sales.

Power transfers between utilities and the Western Interconnection node incur a charge that varies by on-peak and off-peak periods. All purchases and sales that a customer makes incur an additional transfer cost that also varies by on-peak and off-peak periods. The eight large customer utilities and small customers only purchase energy from the spot market node; spot sales are not possible. This assumption was made to ensure that the SLCA/IP system would not construct capacity on a speculative basis for the purpose of selling energy to the Western Interconnection; that is, it constructs capacity primarily for internal purposes. Because the Western Interconnection prices tend to be more expensive than production costs in the SLCA/IP system, purchases from the Western Interconnection tend to be small. However, the Western Interconnection energy was made available for purchase by the SLCA/IP systems in situations where internal production costs became expensive. In addition, reserve margin requirements

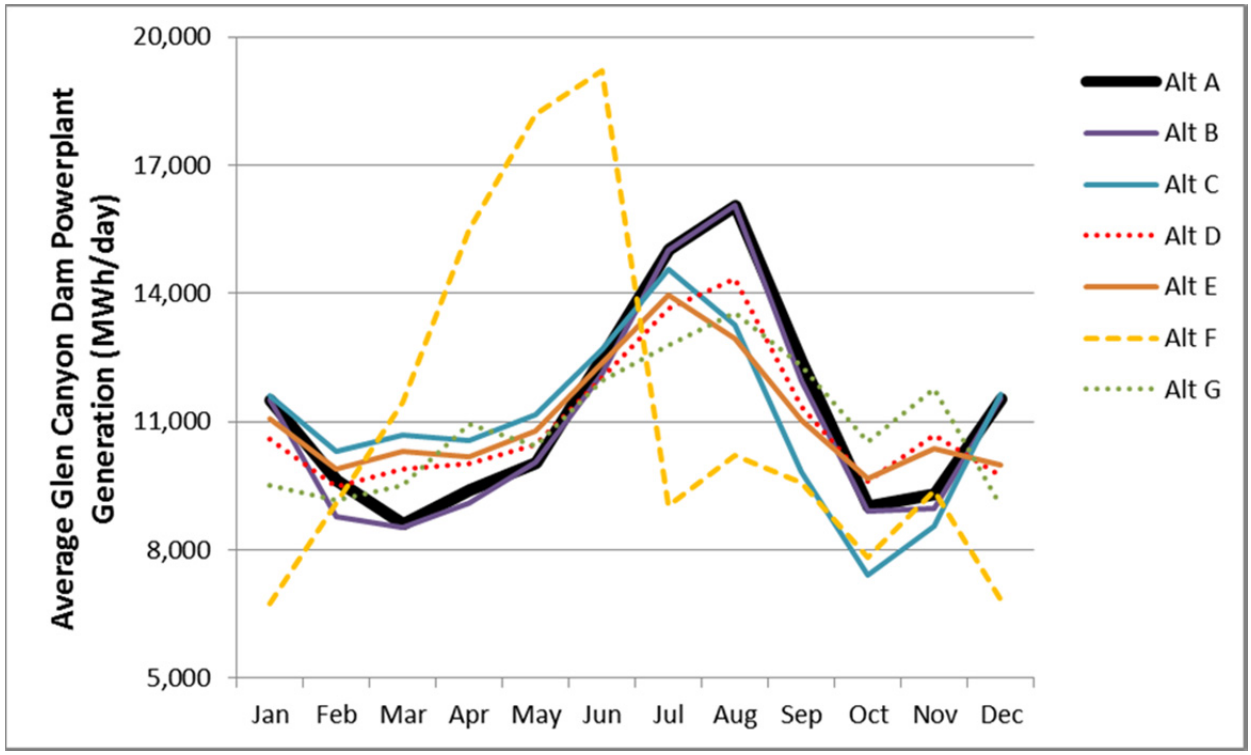


FIGURE K.1-35 Average Daily Glen Canyon Dam Powerplant Hydropower Generations by Month Based on the Average of All 21 CRSS/SBM Hydrology Traces

were configured to exclude Western Interconnection purchases as a source of firm capacity. Therefore, the SLCA/IP system is prevented from leaning on the Western Interconnection for capacity during times of peak load.

Depending on the customer's location, loads and resources are designated as east or west regional entities. Energy flows among entities via system linkages. Some links have limitations and/or associated costs. Energy flows on links connecting SLCA/IP resources to Western's customer loads. Limits on energy transfers on those links represent customer CROD allocations. Under hydrological conditions in which SLCA/IP total generation exceeds the total CROD, the excess energy flows on links that represent Western's shorter-term energy transactions with its LTF customers.

Very small cost premiums are placed on some connections to represent Western's service priorities and to roughly approximate energy flows. Energy generated by Glen Canyon Dam is transmitted to loads in the following priority order: (1) project use in the west region, (2) project use in the east region, (3) LTF customers in the west region, and (4) LTF customers in the east region. The higher the priority, the lower the power delivery cost; that is, the lower the assigned link cost. Energy flow priorities for other SLCA/IP resources mirror the Glen Canyon Dam pattern. The priority order for SLCA/IP resources other than Glen Canyon Dam is (1) project use in the east region, (2) project use in the west region, (3) LTF customers in the east region, and (4) LTF customers in the west region.

Figure K.1-3 also shows that an LTF customer has direct connections to all other LTF customers in the region where it resides. Energy transfers may also occur among customers located in different regions. In addition, "ballpark" energy transactions among LTF customers incur an energy transfer cost that varies by on-peak and off-peak periods. Power transmission costs of $3.5/MWh during off-peak hours and $6.5/MWh during on-peak hours was based on historical information provided by Western. Off-peak hours include all day on Sundays and holidays and 8 hours each night during all other days.

The AURORA topology/configuration assumes a very high level of cooperation and coordination among Western and its customers when modeling system dispatch. More specifically, given the transfer limits and costs discussed above, the model determines a unit commitment schedule and least-cost hourly dispatch for the entire SLCA/IP marketing area as if it were under the control of a single operator. This is a higher level of cooperation and coordination than what actually occurs. However, Western and its customers do buy and sell energy via both day-ahead and hour-ahead bilateral agreements using market signals, insights, and data such as that provided by ICE as a guide. The AURORA topology also includes energy transfer costs among LTF customers that dampen power transfers relative to a "single-owner" model that does not incur these costs.

K.1.7.7 Rationale for the Selection of Hydrology Conditions Used for Capacity Expansion Runs

The low hydropower condition of 90% exceedance used to select SLCA/IP hydropower capacity credits is fairly conservative because the system is slow to respond to capacity shortfalls. New units take a relatively long time (years) to plan/engineer, permit, construct, test, and eventually bring online. Therefore, if insufficient capacity is built, the system may experience years of unacceptably high reliability risks when hydrology/hydropower capacity is low.

On the other hand, average energy conditions are used for power injections into the grid for capacity expansion modeling because the system quickly adapts to various hydrological situations through system dispatch and short-term energy transactions (e.g., purchases when hydropower energy production is below normal). Although it does not provide an exact estimate of energy economics, given all of the other uncertainties involved with long-term projections, an average hydrological condition provides a good approximation of the *relative* economics among the enormous number of capacity expansion pathways that are theoretically possible for the SLCA/IP study area.

K.1.8 Glen Canyon Dam Energy Economic Benefits Methodology

The Glen Canyon Dam Powerplant generates large amount of energy that yields significant economic benefits to the grid. It serves SLCA/IP market system demands and this system responds/reacts to its powerplant operations. Therefore, the economic impacts of changes in Glen Canyon Dam operations are measured for the system as a whole by computing SLCA/IP

market system operating costs. On the production side, costs include energy production costs that are comprised of fuel expenditures, variable O&M costs, and unit startup expenses. Costs are also incurred to deploy price-sensitive loads. The AURORA model run in dispatch mode was used to estimate production levels and associated costs for each generating unit and DSM program in the SLCA/IP market system during the study period.

AURORA dispatch mode computations are based on a given set of resources, as previously determined by AURORA runs that were made in capacity expansion mode. Hourly SLCA/IP federal hydropower production input into AURORA is based on GTMax-Lite runs for Glen Canyon Dam and the other five large hydropower plants. These runs adhere to all physical and institutional operating criteria, including those needed to supply project use loads and fulfil ancillary service requirements. Energy costs for each LTEMP alternative are computed as the difference between the AURORA dispatch results for Alternative A and another alternative.

The LTEMP DEIS affects the system-level operating costs and therefore energy economics because operating criteria bind the timing and routing of water releases through Glen Canyon Dam. From a system dispatch perspective, power produced by the Glen Canyon Dam Powerplant yields the highest economic benefits when the limited amount of water it releases during a WY is routed through the powerplant's generating turbines to produce power that either displaces energy generation or demands curtailment from expensive grid resources. For example, Glen Canyon Dam has a high economic value when the energy it produces reduces or eliminates the operation of an old, inefficient gas turbine with high production costs. On the other hand, it has a much lower value when it displaces low-cost power generation. As discussed earlier, LMPs that are specified at the Western Interconnection spot market node interface represents Western Interconnection marginal cost production savings when it purchases power from the SLCA/IP market system. On the other hand, when the SLCA/IP market system buys from the Western Interconnection, operating costs of the system are reduced, but it pays for the purchase at the LMP price. For the LTEMP DEIS, these prices were determined by the Western Interconnection model run and a scaling algorithm applied to the Palo Verde market hub. Purchases are only made when the LMP is less expensive than the incremental cost of both power production and DSM deployment.

The average annual energy produced by the Glen Canyon Dam Powerplant varies by less than 2% among alternatives. However, at varying levels of stringency, alternative criteria bind the daily and hourly operational flexibility at Glen Canyon Dam and affect both Lake Powell monthly reservoir elevations and Glen Canyon Dam monthly water release volumes. One of the primary differences between the AURORA dispatch in capacity expansion mode and when AURORA is run in dispatch mode is the hydrological information used for SLCA/IP federal hydropower conditions. When run in dispatch mode, the AURORA model uses GTMax-Lite results for Glen Canyon Dam and the other five large SLCA/IP federal hydropower plants, based on hydrological information for the representative trace. As shown in Figure K.1-36, average annual SLCA/IP federal hydropower plant generation for the representative hydrology trace (i.e., trace 14) used for economic dispatch runs is significantly different from that used for AURORA capacity expansion runs, shown in Figure K.1-33. It should be noted that there is significantly more generation volatility in Glen Canyon Dam Powerplant energy production used for economic dispatch runs. The lowest annual Glen Canyon Dam generation level using trace 14

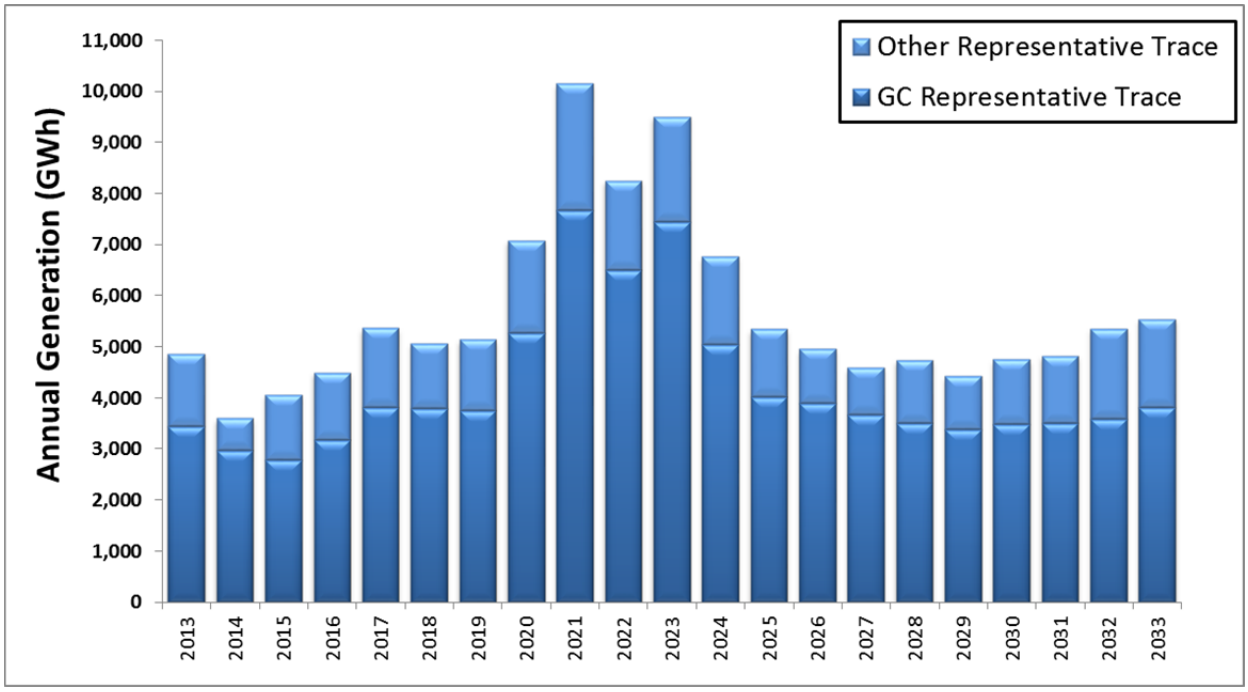


FIGURE K.1-36 Average Annual Glen Canyon Dam Powerplant Generation for the Representative CRSS/SBM Hydrology Trace

is 2,781 GWh, which occurs in CY 2015. Generation under that same trace is 7,677 GWh in CY 2021; therefore, those years differ by a factor of about 2.7. This is consistent with historical volatility levels. As described in Section K.1.2, Glen Canyon Dam Powerplant annual generation varied by a factor of 2.6 between CY 1980 and CY 2013.

Trace 14 average daily generation over the LTEMP period produced by the Glen Canyon Dam Powerplant by month is shown in Figure K.1-37. These values are similar to the ones used for the AURORA capacity expansion runs shown in Figure K.1-34. It is one of the attributes of trace 14 that make it "representative."

As described in more detail in Section K.1.10, the combination of LTEMP operating criteria, Glen Canyon Dam monthly water releases volumes, SLCA/IP market system loads, and spot market LMPs drive DEIS differences in economic dispatch cost among alternatives. The system-level dispatch methodology for computing energy economic costs captures the following key aspects of DEIS alternative operating criteria:

- Marginal dispatch costs at a location to serve loads increase as the system load-level increases. Resources with low costs are dispatched first. As the load increases, more expensive resources are dispatched to balance the supply and demand.

- The Glen Canyon Dam energy value is based on SLCA/IP market system cost reduction as a consequence of powerplant energy injections into the grid.

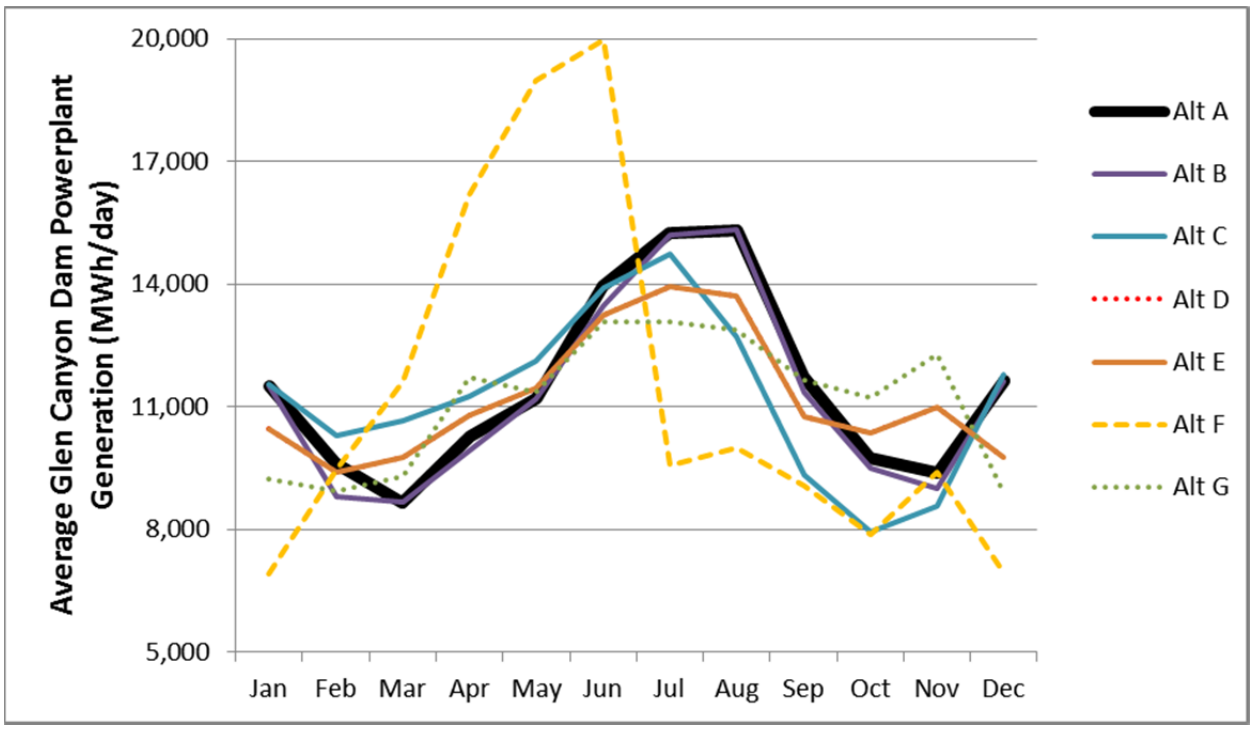


FIGURE K.1-37 Representative Trace Average Daily Glen Canyon Dam Powerplant Generations by Month

- Over short-term operations such as daily and weekly dispatch, energy economic differences among alternatives are highly dependent on operational flexibility allowed under the alternative and the marginal production cost and LMP spread between off- and on-peak periods. If costs and prices are always the same, operational criteria would have minimal impacts.

- On an annual timeframe, energy economic differences among alternatives are dependent on the correlation of monthly water release volumes to monthly marginal production costs and LMP. Alternatives with a positive correlation have a much higher energy economic value than those with a negative correlation. The larger the monthly price and cost spreads, the greater the economic cost of the alternative. If costs and prices are always the same, monthly water release volumes would have minimal impacts.

- Unlike daily, weekly, and monthly economic differences that are a function of price/cost spreads, economic differences from HFEs are a function of absolute energy price/cost levels. Some water bypasses the turbines because the required HFE flow rate can exceed the turbines' maximum flow capability. Water that bypasses the turbines does not generate electricity for sale to customers and therefore has zero power value.

K.1.9 Net Present Value Calculations and Study Period Adjustments

As described in previous sections, all costs input into GTMax-Lite and AURORA are expressed in 2013 dollars. For many of these inputs, this required that input values reported in the literature be converted to 2013 dollars. For example, the cost of candidate technologies for new construction was expressed in terms of 2012 dollars. The index used for dollar conversion is application specific. Attachment K-10 provides more information on the dollar year conversion process.

By expressing all present and future cost inputs in terms of real dollars, the effects of inflation are removed from all AURORA model calculations. Therefore, for each year all costs projected by the model are measured on a common and consistent basis. However, LTEMP DEIS alternatives incur different levels of cost at different times over the study period. Therefore, to account for the time value of money in which the present worth of money is typically, but not necessarily, higher today than the same amount of money in the future, the NPV of all costs are calculated to facilitate a common point in time for cost comparisons among alternatives. The process of discounting is used to make costs that occur at different points in time commensurate with each other.

The NPV computation takes a chronological stream of values over time and discounts each one to a specified point in time based on a defined discount rate. These values are then summed. Although the mechanics of the discounting process are very straightforward, the magnitude of the discount rate greatly influences the degree to which future costs and benefits "count" in the decision. As a result, the choice of discount rate is the subject of much debate. For the LTEMP DEIS, NPV calculations are based on a discount rate of 3.375%. The use of this discount rate was in part based on information contained in Attachment K-4, which was provided by Reclamation staff. At the recommendation of Western staff, a second discount rate of 1.4% was used in a sensitivity study.

Because of discounting, the NPV calculation places more importance on near-term economic costs as compared to those that occur in the more distant future. For example, a dollar cost incurred during the first year of the study period has a $1 NPV impact. However, at a 3.375% discount rate, the same dollar impact in the 20th year of the analysis has only a $0.5322 impact (i.e., slightly more than half) on the NPV. The selection of the representative trace does not consider the discount effect on NPV outcomes. It may be important, however, because the energy costs of an alternative are sensitive to hydrological conditions. The selected representative hydrology trace starts out dry, becomes very wet in the middle of the period, and by the last few years it returns to a dry condition. All other factors constant, the NPV calculation would yield a different value if the sequence of dry, average, and wet hydrological conditions differed from trace 14. A sensitivity analysis of the impacts of the sequence of hydrological conditions on DEIS energy NPVs would help quantify the range of possible outcomes.

All detailed model calculations were made and expressed in 2013 dollars. This was in part due to CRSS and SBM, which used the beginning of CY 2013 as a starting point. Cost was computed over the 20-year length of the long-term experiment: a period that begins at the start of CY 2013 and ends at midnight on the last day of CY 2032. However, to be consistent with other

DEIS disciplines, the power system analysis period was directed by project co-leads to cover CY 2015 through CY 2034 and express all costs in terms of 2015 dollars. The request was made at a point in the modeling process when all model runs, computations, and most aspects of the analysis had been completed. It was therefore necessary to make adjustments to the CY 2013 to CY 2032 results. The power systems team and co-leads agreed that the following adjustments were reasonable given time and budget constraints.

1. All energy costs were shifted by 2 years. That is, CY 2013 energy costs were assumed to take place in CY 2015 using trace 14 hydrology for CY 2013, energy costs in CY 2014 were assume to occur in CY 2016, and so on.

2. The energy costs were then adjusted to account for real changes in energy prices over time. This was accomplished in a two-step process. First, an energy price index benchmarked to 2013 dollars was computed. The index is based on the yearly average energy cost to serve load from the AURORA SLCA/IP market systems model. This index was then applied to the shifted energy costs from step 1 for all years. For example, because energy prices in real 2013 dollars decreased during CY 2013 to CY 2015 timeframe (according to AURORA and in actuality), the costs are adjusted downward using the AURORA-generated energy price index. The end result is chronological annual costs from CY 2015 through CY 2034 in beginning year 2013 dollars.

3. The energy cost time series is then converted to 2015 dollars using a general price index. For this analysis, the seasonally adjusted GNP IPD was applied to the 2013 dollars (see Table 1 in Attachment K-10).

4. The capital cost dollar for new unit construction from the EIA's 2014 AEO (EIA 2014) expressed in nominal 2012 was adjusted to beginning year 2015 dollars using the "Powerplants" index contained in Reclamation (undated). Fixed O&M costs were converted to 2015 dollars used the same table, except that the "Powerplant Accessory elect. & misc. equip" index was used.

5. No adjustments were made to the online dates of new units constructed to the study period, because the capacity reserve margin was greater than 15% in 2015 under all alternatives. However, because the analysis period is shifted, there were no AURORA capital or fixed O&M cost computations for the last 2 years. Therefore, average cost values over the last 5 years of the AURORA model run were assumed for CY 2033 and CY 2044.

6. The stream of all future costs are discounted to beginning year 2015 at an annual discount rate (i.e., 3.375%) specified by the Reclamation for cost-benefit studies of projects.

A final EIS and ROD will not be completed until after WY 2015. The reader should recognize that the economic analysis for electrical power systems is sensitive to the years that are modeled. Currently, the region affected by a change in the operation of Glen Canyon Dam is in

"capacity surplus." This means that generating capacity in the affected region currently exceeds peak electrical demand more than is necessary to achieve an acceptable level of reliability. However, a growing regional economy and population will soon cause electrical demand to catch up to supply. Depending on the actual ROD implementation date, the SLCA/IP market system and the Western Interconnection may need to build additional capacity above committed levels before completion of the ROD.

K.1.10 Power Systems Results

This section details the results of the power systems analysis, focusing primarily on total SLCA/IP market system costs under each alternative relative to Alternative A. It also describes the sensitivity studies that were performed to test the robustness of model results and analysis conclusions. One set of sensitivity studies was on the risk preference or exceedance level that is used to determine SLCA/IP federal hydropower firm capacity. The results in the main DEIS were based on a 90% exceedance level. This section presents power system results for exceedance levels of 50% and 99% to reflect the possibility of Western considering different risk levels in future marketing efforts.

Another sensitivity study was performed on discount rate. The discount rate used in the main EIS was 3.375% because the Bureau of Reclamation is required to employ an administratively determined discount rate known as the federal plan formulation and evaluation rate, when undertaking economic analyses of water resource and related matters pursuant to 42 U.S.C. 1962d–17. The plan formulation and evaluation rate for fiscal year (FY) 2015 is 3.375% (Reclamation 2014a,b). This section will show how power system results will change if a lower discount rate, namely, 1.4%, is used. This value was used to explore a "real" interest rate based on treasury notes and bonds, as determined by the Office of Management and Budget in Circular A-94 Appendix C.

Two other sensitivity studies were also performed. One studied the sensitivity of the baseline capacity expansion pathway used in Alternative A to different assumptions about the candidate plants that would be constructed. AURORA invariably chose a combination of advanced combustion turbines and advanced combined cycle plants as the preferred expansion path. However, to test the sensitivity of the results to different expansion pathways, we ran the AURORA model for two extreme expansion pathways for Alternative A: one allowed construction of only advance combustion turbines, and the other only natural gas combined cycle plants.

The next study determined the sensitivity of the AURORA results to the choice of hydrological conditions. The results of another hydrological condition were compared against the results of the representative trace (i.e., trace 14).

Finally, as described in Section K.1.7.3, ancillary services are no longer expected to increase as much and as rapidly as assumed in GTMax-Lite model runs. Therefore, a sensitivity study was performed to determine whether and by how much power system results would change if current ancillary service projection had been used. The results of the sensitivity study showed

that ancillary services assumptions under a range of plausible futures have little to no effect on firm capacity and energy value for the LTEMP alternatives (see Section K.1.10.8 for further detail).

K.1.10.1 Main Drivers of Differences among Alternatives

Among all alternatives, annual water release volumes differ by less than 1% and the total volume of water released from Glen Canyon Dam over the 20-year LTEMP period is nearly identical. Therefore, the economic cost of an LTEMP alternative is not caused by changes in long-term water release volumes, but rather from altering the routing and timing of water releases during monthly, daily, and hourly timeframes within a year.

Figure K.1-38 shows monthly average daily generation produced by water releases that are routed through the powerplant's turbines. Each alternative has a unique monthly water release pattern. For example, as compared to Alternative A, Alternative F turbine releases are much higher during March, April, May, and June and much lower during July and August. When water/generation is shifted from a month that has higher system production costs to a month with lower costs, the economic value of power produced by the Glen Canyon Dam Powerplant is reduced. Ultimately, this generation shift increases costs to the SLCA/IP market system, and therefore the cost of the alternative, because more expensive generation serves system electricity demand. Figure K.1-39 shows the average daily minimum, maximum, average, and range of electricity market prices by month forecasted for the Palo Verde market hub during the 20-year LTEMP period. In general, the more generation is produced in months with high electricity prices, the lower the alternative's cost will be relative to Alternative A. This allocation of limited water resources allows Glen Canyon Dam to serve system loads when the power it generates has the highest value.

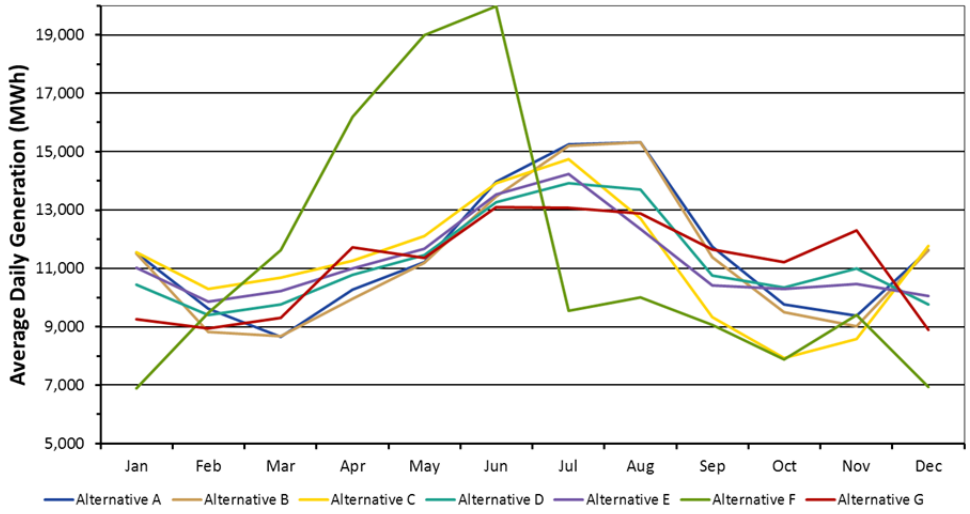


FIGURE K.1-38 Average Daily Generation by Month for Each Alternative

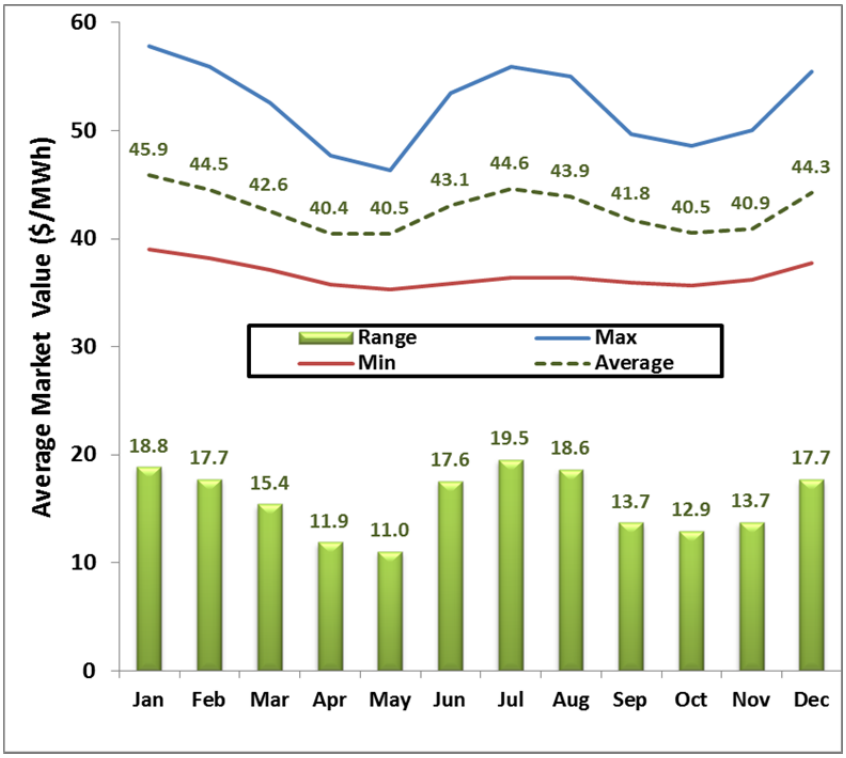


FIGURE K.1-39 Palo Verde Average Daily Electricity Market Price Statistics by Month during the 20-Year LTEMP Period

Alternatives also impact the daily profile of water releases. Changes in operating criteria, such as maximum and minimum release restrictions and mandates that limit water release changes over time, result in very different release patterns during most days. For example, except when transitioning between months or when HFEs are being conducted, Alternatives F and G require water releases from Glen Canyon Dam to be at a constant rate during each month. In contrast, other alternatives allow powerplant operators to change water release levels during a day in response to market price signals and system marginal production cost patterns. Alternatives that allow for only a small range between maximum and minimum releases and permit only minimal changes in water releases over time decrease the value of Glen Canyon Dam power production by shifting water releases from high price peak hours to low price off-peak hours. Figure K.1-40 shows typical Western Interconnection hourly electricity price patterns for winter and summer and the price spread between peak and off-peak hours.

Finally, alternatives affect the routing of water releases from the dam. Water is typically released through one or more of Glen Canyon Dam's eight turbines to produce electricity. However, depending on the pressure exerted by the water elevation in Lake Powell, only a limited amount of water can flow through turbines during an hour. In addition, the generating capacity of a unit indirectly limits the flow of water through it. Therefore, whenever a water release is required to exceed the combined flow capabilities of the generating units that are in operation, some of the water is released through hollow jet tubes and spillways. These non-power releases produce no energy and are referred to as spilled water. Each alternative has a

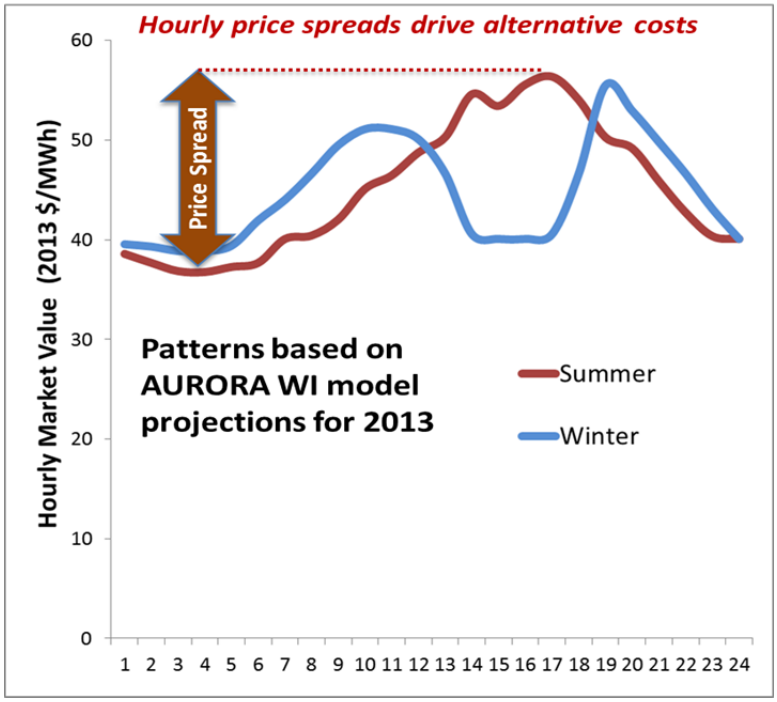


FIGURE K.1-40 Typical Hourly Winter/Summer Price Patterns in the Western United States

unique set of HFE specifications that affect the frequency and duration of Glen Canyon Dam water spill volumes. Figures K.1-41 and K.1-42 show the average number of HFEs and the average amount of water spilled by alternative over the LTEMP period, respectively. Averages shown are based on all 21 hydrology traces of sediment trace 2 and disaggregated by type of HFE. Alternative G has the highest number of HFEs; Alternatives C, D, E, and F have somewhat fewer HFEs; and Alternatives A and B have by far the fewest HFEs. Similarly, the greatest average volume of spilled water occurs under Alternatives D and G; a lower amount of water is spilled under Alternatives C, E, and F; and again by far the least water is spilled under Alternatives A and B.

Water is also spilled during very low (i.e., dry) hydropower conditions when the water elevation in Lake Powell is below the minimum turbine water intake level. During those times, it is assumed that all of the water released from Glen Canyon Dam produces no electricity until the water level rises to the minimum intake level. Figure K.1-43 shows the average annual number of hours, by alternative, the Lake Powell elevation is below the minimum penstock intake over the 20-year study period for all 21 traces of sediment trace 2. Alternative G averages the greatest number of hours when the elevation is too low, resulting in an average of 8.5 hours over the 8,760-hour year, or 0.1% of the time; Alternatives A, B, C, D and E have somewhat fewer hours; and Alternative F has no hours when the elevation is too low to produce electricity.

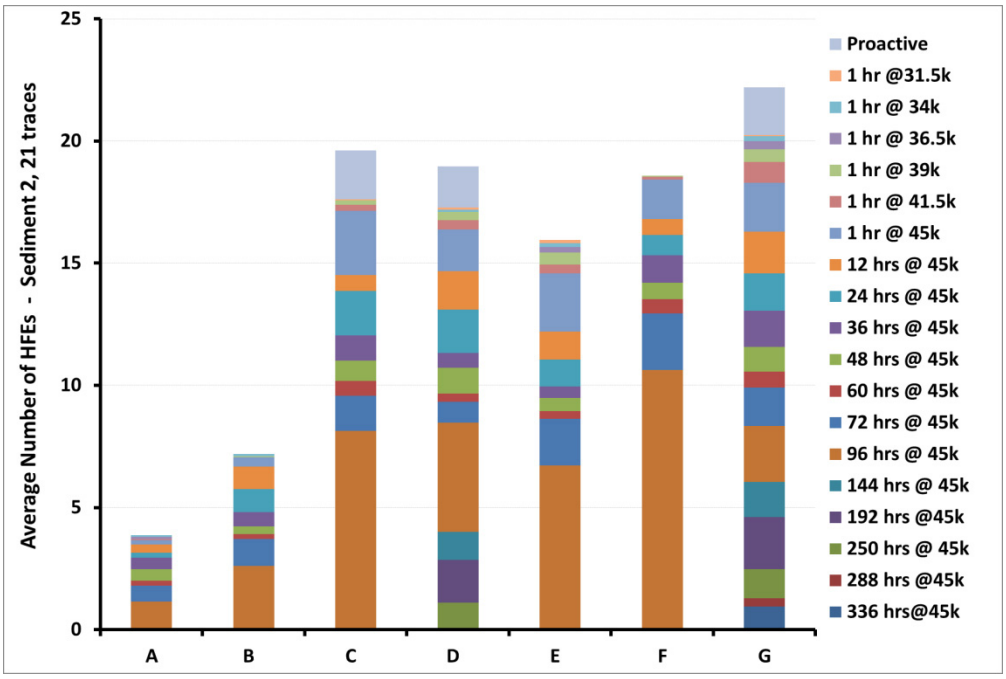


FIGURE K.1-41 Average Number of HFEs by Alternative for All 21 Hydrology Traces of Sediment Trace 2

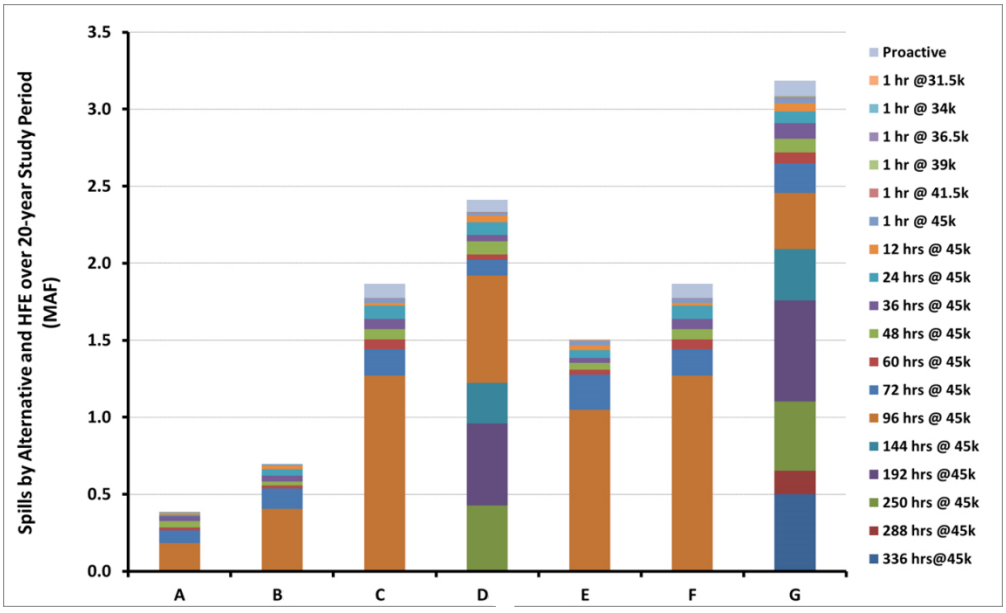


FIGURE K.1-42 Average Amount of Water Spilled by Alternative for All 21 Hydrology Traces of Sediment Trace 2

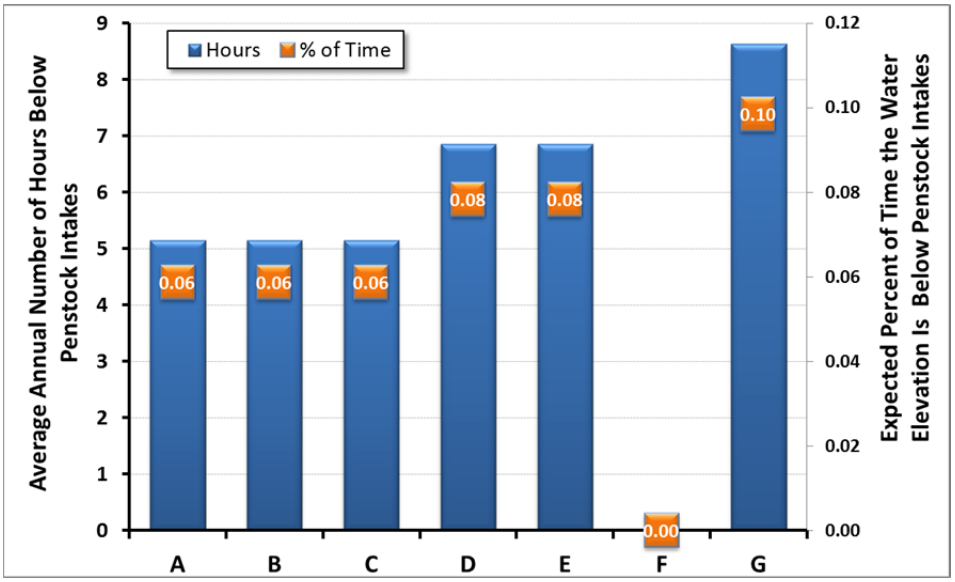


FIGURE K.1-43 Average Annual Number of Hours the Lake Powell Elevation Is below the Penstock Intake by Alternative for All 21 Hydrology Traces of Sediment Trace 2

Figure K.1-43 also shows that the percentage of time the reservoir at Glen Canyon Dam is expected to be below the penstock is very small (i.e., at most about one hourly occurrence out of every 1,000 hours). However, most of these occurrences are concentrated in fairly long, continuous periods of time. For example, under Alternative G, all hours with elevations below the penstocks occur during a continuous 3-month period starting in January 2018, under hydrology trace 19, and during the entire month of April 2024, under hydrology trace 8. Therefore, the risk of encountering zero generation periods is small, but when it does occur, the economic implications are very costly.

Finally, water spills can also occur as a result of inflow forecast error. High reservoir conditions in combination with unanticipated large water inflow volumes into Lake Powell will result in a spill if there is inadequate spare reservoir capacity to accommodate all of the water inflows minus maximum turbine flow rates.

K.1.10.2 Capacity Expansion Modeling

Capacity expansion plans for each alternative during the study period are determined by running the AURORA model in capacity expansion mode. The plans specify the type of technology built, unit capacity, and the year a new unit begins operation. The model also computed the annual capacity investment and O&M costs for all new units built over the study period except those previously committed and contained in the unit inventory. As noted in section K.1.6.3, the AURORA model was given a wide selection of technologies from which to choose for future capacity additions, including conventional and advanced natural gas combustion turbines, conventional and advanced gas/oil combined cycle units, scrubbed and

pulverized coal units, integrated gasification combined cycle units, nuclear units, wind farms, and solar thermal and photovoltaic projects.

The firm SLCA/IP federal hydropower capacity input to the AURORA expansion model is credited toward meeting the system reserve margin. The quantity input depends on the combined operating capabilities of these resources at the time of the system peak demand, and on a defined exceedance level. Table K.1-7 shows marketable capacity by alternative at the 90% exceedance level (i.e., a 10% risk of having a lower peak operating capability than the specified firm level at the time of system peak load). The table also shows the difference in firm capacity compared to Alternative A (referred to as lost capacity). Except for Alternative B, which has 28.1 MW more firm capacity than Alternative A, all other alternatives provide approximately 50 MW to 314 MW less firm capacity—that is, a reduction that ranges from 6.7 to 42.6% relative to Alternative A.

A retrospective study performed by Argonne on marketable capacity offered by CRSP Management Center over the last 10 years shows that it markets capacity at a 90% exceedance level. That is, Western has enough SLCA/IP federal hydropower resource capacity to meet its obligation 90% of the time. Therefore, the baseline LTEMP analysis used the same exceedance level to determine SLCA/IP federal hydropower firm capacity. However, in the future Western may choose another exceedance level to determine marketable capacity. Results are presented later in Section K.1.10.4 for exceedance levels of 50% and 99%; this range will bracket the risk preference level that the CRSP Management Center will likely, but not necessarily, choose to use when determining future LTF capacity commitment levels.

TABLE K.1-7 SLCA/IP Marketable Capacity at the 90% Exceedance Level

Capacity Type	Alternative A (No Action)	Alternative B	Alternative C	Alternative D (Preferred Alternative)	Alternative E	Alternative F	Alternative G
SLCA/IP Firm Capacity (MW)[a]	737.2 (no change from current condition)	765.3 (3.8% increase)	608.1 (17.5% decrease)	687.6 (6.7% decrease)	647.0 (12.2% decrease)	423.1 (42.6% decrease)	558.2 (24.2% decrease)
SLCA/IP Lost Capacity (MW)[b]	Not applicable	–28.1	129.1	49.6	90.2	314.1	179.0

[a] Marketable capacity is calculated based on all 21 hydrology traces with median sediment input (sediment trace 2), which has the highest likelihood of occurrence. It is calculated at the 90% exceedance level, using August as the peak load month. That is, combined SLCA/IP federal hydropower resources are able to attain peak output at the firm capacity level or higher 90% of the time during the August peak load.

[b] Lost capacity is the difference between the marketable capacity in Alternative A and the marketable capacity of another alternative; it represents the capacity that would need to be replaced somewhere in the power system if that alternative was implemented.

The AURORA expansion model only selected natural gas–fired technologies in its SLCA/IP market system plan to meet future demand; no other thermal or renewable technologies were chosen. Wind and solar plants were added in the expansion pathway, but only to meet the state RPS requirements as described in Section K.1.6.3. The natural gas–fired technologies chosen by AURORA were the 400-MW advanced combined cycle unit and 230-MW advanced combustion turbine.

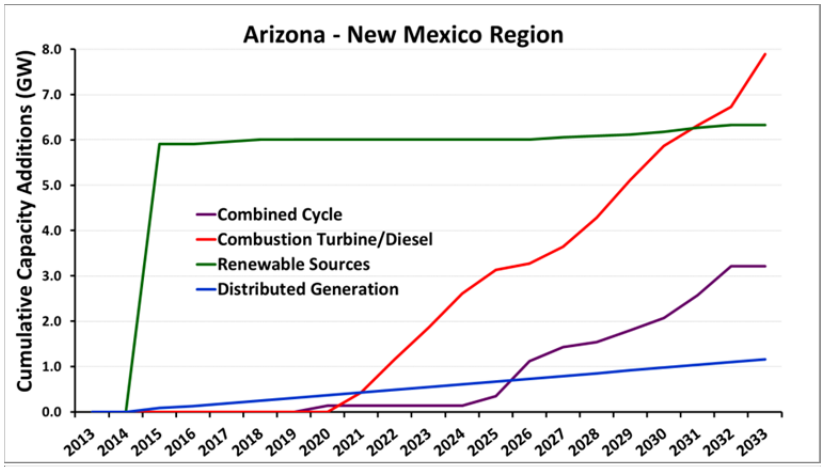
The expansion pathway chosen by AURORA was consistent with projections made in the 2014 AEO (EIA 2014), and with expansion plans reported in IRPs developed by utilities in the region. Figure K.1-44 shows the 2014 AEO projects of cumulative capacity additions for the three geographic regions in the Western Interconnection for the next 20 years. In the future, the AEO projects only renewable generation; natural gas combined cycle plants and combustion turbines; and distributed peaking generation, which is most often fueled by natural gas.

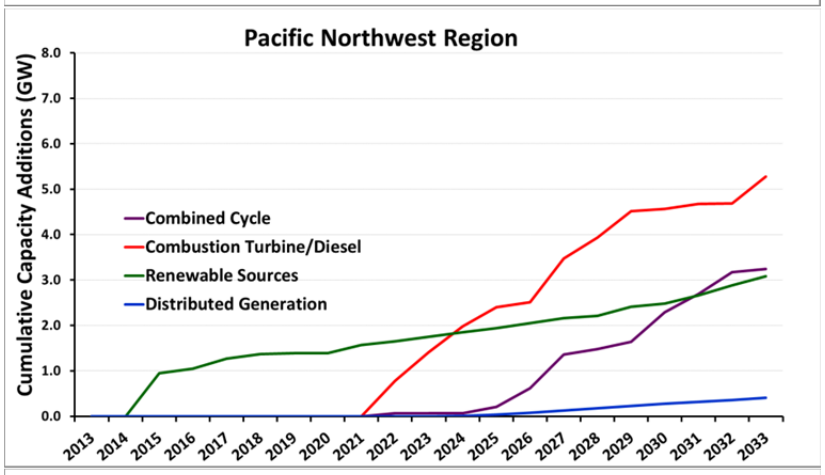
As noted in Section K.1.6.3, Argonne conducted a survey of the current IRPs available on the websites (which typically had publication dates of either 2013 or 2014) of Western's customers and investor-owned utilities in the geographic and "electrical" area of Western's customers to determine the timing and type of resources these utilities were planning to meet future electric demand. The results of that survey were shown in Table K.1-6. As in the 2014 AEO (EIA 2014), utilities are forecasting that future capacity additions to their systems will consist of renewables (mainly wind and solar) and natural gas–fired combined-cycle plants and combustion turbines. A conclusion that can be drawn from Table K.1-6 is that because new generators are forecasted to come online in the very near term (the next 2 to 3 years) there will be little or no excess capacity in the region that would be available to replace capacity lost at Glen Canyon Dam at the time when the ROD is issued.

Figure K.1-45 shows the cumulative capacity additions selected by the AURORA expansion model for Alternative A (combustion turbines are labeled CT and natural gas combined-cycle units are labeled NGCC). Because units are built in large increments, capacity expansion is often said to be "lumpy." The green line in the figure shows the amount of capacity in excess of the 15% reserve margin. Due to the lumpy expansion path, some years significantly exceed the 15% reserve margin target, while others have just enough to satisfy the reserve margin. However, the capacity above the reserve margin could be sold to utilities that are short of capacity at the market price, thereby reducing the total net cost to the SLCA/IP market system. Sales of excess capacity will be explored and quantified in the analysis of alternatives.

It should be noted that the first capacity addition under Alternative A comes online in 2018 under the current joint system analysis. Therefore, there will be very little or no excess capacity when operational changes at Glen Canyon Dam could possibly be implemented. Furthermore, lost capacity would need to be replaced soon after the ROD.

Although CRSP Management Center LTF customers typically engage in economical firm capacity and energy transactions, the joint planning approach assumes a higher level of coordination and cooperation among LTF customers than may currently exist. Results shown in Figure K.1-45 are based on a methodology that projects the expansion plan for the combined





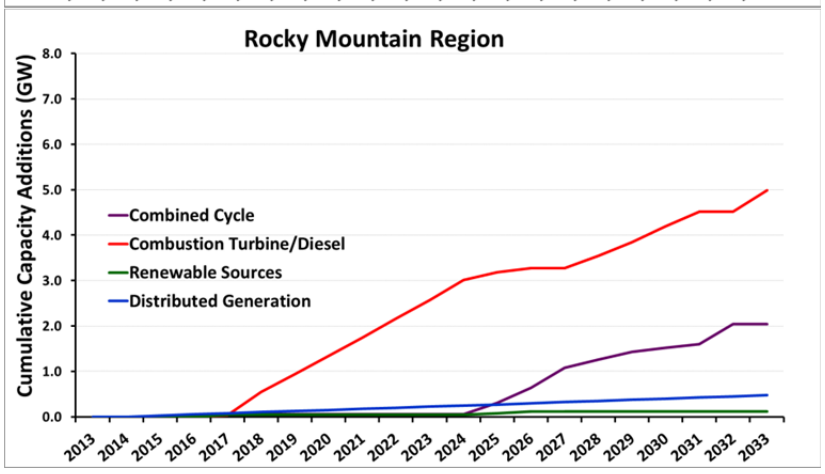


FIGURE K.1-44 2014 Annual Energy Outlook Projections of Capacity Additions in the Western Interconnection over the LTEMP Period

TABLE K.1-8 Difference in Cumulative Capacity Additions of Each Alternative Relative to Alternative A (90% Exceedance Level)

		Additional Capacity (MW) Needed Relative to Alternative A					
Year	Alternative A Expansion (MW)	Alternative B, Long-Term Strategy 1	Alternative C, Long-Term Strategy 1	Alternative D, Long-Term Strategy 4	Alternative E, Long-Term Strategy 1	Alternative F	Alternative G
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	230	0
2018	230	0	230	0	0	460	230
2019	630	0	230	0	0	460	230
2020	1,030	0	230	0	0	460	230
2021	1,030	0	230	230	230	460	230
2022	1,430	0	230	230	230	460	230
2023	1,830	0	230	230	230	460	230
2024	2,060	0	230	0	0	460	230
2025	2,290	0	230	0	0	460	230
2026	2,520	0	230	0	230	460	230
2027	2,750	0	230	230	230	460	230
2028	2,980	0	230	230	230	460	230
2029	3,440	–230	0	0	0	230	230
2030	3,670	0	0	0	0	230	230
2031	3,900	0	0	0	0	230	230
2032	4,590	0	230	230	230	460	230
2033	4,820	0	230	230	230	460	230
Average		–11	142	77	88	329	175
GC Reduction		–28	129	49	90	314	179
Difference		17	13	28	–2	15	–4

system in which the costs and benefits of new generating resources would be shared among both large and small customers. This approach has a number of advantages related to modeling efficiency while representing the general system response to changes in Glen Canyon Dam firm capacity. This joint planning approach indicates that numerous units would be constructed by the system. For example, by 2034, 14 new advanced combustion turbines and four advanced combined cycle units would be constructed under Alternative A (see Table K.1-9). Each unit could be operated by an individual utility or as a joint dispatch, whatever arrangement is more advantageous. If technical or institutional barriers did not allow joint unit dispatch, a new unit could be built by a single owner/operator. Furthermore, if the new unit created excess capacity in the owner's utility, it may be able sell capacity from other system resources that are more conducive to joint dispatch. Alternatively, the capacity-long system could sell the excess without specifying the individual supply resource.

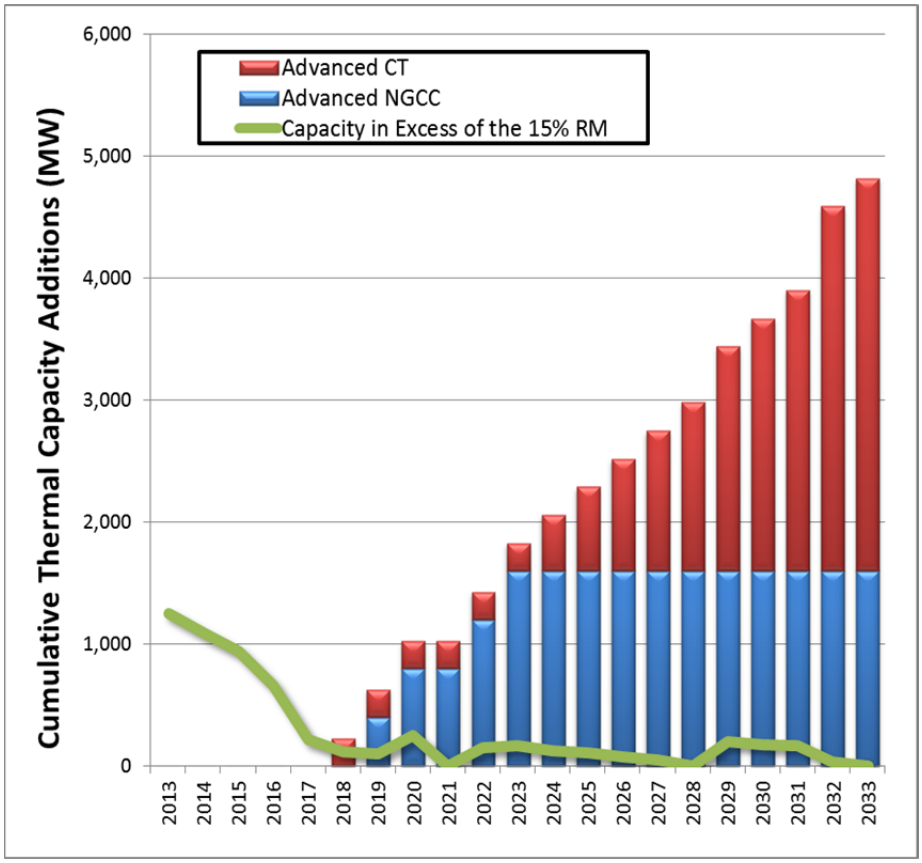


FIGURE K.1-45 Cumulative Capacity Additions for Alternative A (90% Exceedance Level)

The cost of capacity replacement in general would be higher if each individual utility were modeled as isolated entities (i.e., without mutually beneficial arrangements), which is how new units would actually be constructed. This model solution would, in many respects, be uneconomical and unrealistic because each utility that is capacity short would need to either (1) build a relatively large efficient unit to replace its allocation of the lost capacity, which in most cases is very small, or (2) build a very small unit that is typically less efficient and, because of economies of scale, is more costly per kilowatt of installed capacity to construct. Utilities that are capacity long may not need to construct any replacement capacity. The capacity expansion plan would also be very lumpy.

The capacity expansion pathway for Alternative A will replace existing powerplant capacity that will retire in the future and meet forecasted increases in electricity demand in the SLCA/IP market system. The expansion pathways for all other alternatives are a modification of this pathway. Differences in firm capacity among alternatives were evaluated in terms of the amount and timing of new generating units constructed in the future. All alternatives except Alternative B have a decrease in firm capacity compared to Alternative A. Alternatives that have less firm capacity would be expected to install capacity earlier and/or install more capacity than Alternative A. Conversely, Alternative B would be expected to have a delay in capacity additions

compared to Alternative A. Table K.1-9 compares the capacity expansion pathways for Alternatives A and F. Alternative F has the most lost capacity of all alternatives.

Table K.1-9 shows that Alternative F installs combustion turbines (labeled CT1, CT2, etc.) 1 to 7 years earlier than Alternative A. By the end of the LTEMP period Alternative F also installs more capacity, two more combustion turbines. Because the number and timing of natural gas combined cycle units (labeled NGCC1, NGCC2, etc.) is identical under both alternatives, lost Glen Canyon Dam capacity is replaced exclusively by advanced combustion turbines. This accelerated capacity addition schedule occurs because Alternative F has 314 MW less SLCA/IP federal hydropower firm capacity than Alternative A.

TABLE K.1-9 Comparison of the Amount and Timing of New Capacity Additions for Alternatives A and F (90% Exceedance Level)

On-Line Date	New Additions	
	Alternative A	Alternative F
2014		
2015		
2016		
2017		CTl
2018	CTl	CT2 & CT3
2019	NGCC1	NGCC1
2020	NGCC2	NGCC2
2021		
2022	NGCC3	NGCC3
2023	NGCC4	NGCC4
2024	CT2	CT4
2025	CT3	CT5
2026	CT4	CT6
2027	CT5	CT7
2028	CT6	CT8
2029	CT7 & CT8	CT9
2030	CT9	CT10
2031	CT10	CT11
2032	CT11–CT13	CT12–CT13
2033	CT14	CT16

Table K.1-8 shows a comparison of capacity additions for all alternatives. This table lists the cumulative additional capacity for Alternative A and then shows the difference in cumulative capacity between it and the other alternatives. The difference represents the capacity that is constructed to replace lost Glen Canyon Dam capacity. Note that the replacement capacity in the table are –230 MW, 230 MW, or 460 MW; capacity changes occur in increments of an advanced combustion turbine unit. At the bottom of the table are values showing the average annual amount of replacement capacity, the lost firm capacity, and the difference between those two values. As expected, the average annual amount of lost capacity and capacity replacement is very close.

Under Alternative A, an estimated 4,820 MW of new capacity is built in the SLCA/IP market system. Capacity additions are phased in over time, such that a minimum 15% capacity reserve margin is attained in each year of the 20-year LTEMP period. Under alternatives with less SLCA/IP federal firm capacity, more new generating capacity must be built and the capacity must also be built sooner. Like Alternative A, Alternative B adds 4,820 MW of new capacity by CY 2034; however, because Alternative B has slightly more firm capacity, one new generating unit would be constructed a year later than under Alternative A. All other alternatives have less firm capacity than Alternative A. Under Alternatives C, D, E, and G, 5,050 MW of new capacity additions would be required by CY 2034; this amounts to one more combustion turbine than Alternative A, which is an increase in capacity of 4.8%. Under Alternative F, 5,280 MW of new capacity is built by CY 2034, which is two more combustion turbines than Alternative A. This amounts to an increase in capacity of 9.5%.

In addition, it is noteworthy that because capacity is built in discrete sizes/increments that do not match the amount of lost capacity, system expansion differences among the alternatives do not typically match the amount of lost capacity. In some years, the replacement capacity is larger than the lost capacity, while in other years it is smaller. Again, this result shows the "lumpiness" of capacity expansion, which allows for possible sale of capacity above the 15% reserve margin to be sold at market price to reduce the total cost of an alternative.

K.1.10.3 Economic Impacts

When the capacity expansion pathways were determined for each alternative, the AURORA model was run in dispatch mode to simulate the operation of the system for every hour in the entire study period for hydrological trace 14, which is the representative trace. Selection of the representative trace was discussed in Section K.1.5.2, and Attachment K-3 of this appendix describes in detail how that trace was chosen.

The AURORA dispatch model computes all SLCA/IP market system costs associated with the production of electrical energy to meet the system load and to generate additional energy for power sales to the spot market. Production costs are the sum of powerplant fuel costs, variable O&M costs, and cost of power purchased from the spot market. Revenues from the power sales to the spot market are subtracted from these costs to compute the net economic cost. This technique was used to compute the production costs of serving only SLCA/IP market load. Results from the AURORA expansion and dispatch models (i.e., capital, fixed O&M, and production or energy costs) are combined to determine the total annual costs for each alternative. The net present value stream of costs is also calculated to facilitate comparison of each alternative to Alternative A. This single lump-sum value is based on a discount rate of 3.375%, a rate used by Reclamation for cost-benefit studies of projects pursuant to U.S.C. 1962d-17.

The total economic impacts at the 90% exceedance level by alternative are summarized in Table K.1-10. Costs are disaggregated by system-wide net production cost, which was obtained from AURORA dispatch model simulations, and by capital costs and fixed O&M costs, which were both obtained from AURORA expansion model simulations. This table also includes calculating a benefit from the sale of excess capacity above that required to satisfy the reserve margin. This benefit would reduce the total cost of each alternative.

All alternatives except for Alternative B have less firm SLCA/IP federal hydropower capacity than Alternative A. Therefore, the NPV of capital and fixed O&M costs are higher than under Alternative A. Alternative B had the same total amount of new capacity at the end of the LTEMP study period as Alternative A, but the construction of one combustion turbine was delayed by a year due to its slightly higher firm SLCA/IP federal hydropower capacity, which resulted in slightly lower capital and fixed O&M costs. Although Alternatives C, D, E, and G have the same amount of new capacity at the end of the LTEMP study period, they have different NPVs for capacity and fixed O&M because of the difference in the timing of the installation of the new capacity. The differences in timing are found in Table K.1-8.

TABLE K.1-10 Total Economic Impacts by Alternative at the 90% Exceedance Level

Economic Impact Measure	Alternative A (No Action Alternative)	Alternative B	Alternative C	Alternative D (Preferred Alternative)	Alternative E	Alternative F	Alternative G
System-level generating capacity additions (MW)[a]	4,820 (no change from current condition)	4,820 (no change from current condition)	5,050 (4.8% increase)	5,050 (4.8% increase)	5,050 (4.8% increase)	5,280 (9.5% increase)	5,050 (4.8% increase)
SLCA/IP system-wide production cost ($million)[b]	34,228 (no change from current condition)	34,221 (0.02% decrease)	34,255 (0.08% increase)	34,270 (0.1% increase)	34,249 (0.06% increase)	34,373 (0.4% increase)	34,345 (0.3% increase)
SLCA/IP Capital cost ($million) for capacity expansion[b]	1,643 (no change from current condition)	1,635 (0.5% decrease)	1,746 (6.3% increase)	1,696 (3.2% increase)	1,703 (3.7% increase)	1,882 (14.5% increase)	1,769 (7.7% increase)
Fixed O&M cost ($million) for capacity expansion[b]	345 (no change from current condition)	344 (0.3% decrease)	363 (5.2% increase)	354 (2.6% increase)	355 (2.9% increase)	385 (11.6% increase)	366 (6.1% increase)
Total cost ($million)[b]	36,216 (no change from current condition)	36,200 (0.04% decrease)	36,364 (0.41% increase)	36,320 (0.29% increase)	36,307 (0.25% increase)	36,640 (1.2% increase)	36,480 (0.73% increase)
Difference in Total Costs ($million) Relative to No Action	Not applicable	–16	148	104	91	424	264
Rank (lowest to highest total cost)	2	1	5	4	3	7	6
Potential capacity sales ($million)[b]	86	99	99	106	82	105	85
Adjusted total cost ($million)[b]	36,130 (No change from current conditions)	36,101 (0.08% decrease)	36,265 (0.37% increase)	36,214 (0.23% increase)	36,225 (0.26% increase)	36,535 (1.1% increase)	36,395 (0.73% increase)

TABLE K.1-10 (Cont.)

Economic Impact Measure	Alternative A (No Action)	Alternative B	Alternative C	Alternative D	Alternative E	Alternative F	Alternative G
Difference in Adjusted Total Costs ($million) Relative to No Action	Not applicable	–29	135	84	95	405	265
Adjusted Rank (lowest to highest total cost)	2	1	5	3	4	7	6

[a] Additional generation capacity required under the LTEMP alternatives for Western's customers over the 20-year LTEMP period to not only meet future load demand and replace unit retirements but also account for loss/gain in capacity at Glen Canyon Dam due to the alternative operating constraints.

[b] Net present value ($million 2015) of costs to meet total system electric demand over 20-year study period for all SLCA/IP customers under representative trace. Discount rate is 3.375%.

Table K.1-10 also shows the amount of potential sale of excess capacity of generating units constructed by Western's customers above that mandated by the reserve margin. As a result of the lumpy nature of capacity additions, there are short periods of time (i.e., typically less than 2 years) in which slightly more system capacity is built than is needed to meet the reserve margin target. It is assumed this small amount of capacity (i.e., less than the size of one generating unit) may have some value and could be sold to entities outside of the SLCA/IP system. Sales of this excess capacity lower the total cost of all alternatives, but do not substantially affect their relative ranking from lowest to highest cost alternative. If alternatives are ranked based on the difference in adjusted total cost, the order of alternatives from lowest to highest cost is as follows: Alternative B, Alternative A, Alternative D, Alternative E, Alternative C, Alternative G, and Alternative F. If the potential for sale of excess capacity is not factored into the total alternative cost, then the ranking of alternatives changes only slightly; Alternatives E and D change places in the ranking. All other alternatives remain in the same order.

Cost of Experimental Releases

LTEMP alternatives and associated long-term strategies are composed of operating criteria and several experimental elements, as shown in Table 4.1-1. Economic evaluations presented for the Structured Decision Analysis (SDA) (Appendix C) and detailed power systems analysis (Section 4.13 and Section K.1) bundle all of the costs associated with an alternative (including operational changes and experiments) into a single value (NPV). This section provides estimates of the "unbundled" economic cost of several types of experiments.

These estimates are computed by comparing the estimated effects of long-term strategies of alternatives that differ only in inclusion of a particular experiment.[1] The one element that differs between the two alternatives is the element for which the economic impacts are measured. For example, to measure the economic cost of low summer flows, two long-term strategies for Alternative D are compared (D1 and D4). Both have identical operating criteria and the same experimental elements except that under long-term strategy D1 low summer flows are included in the second 10 years of the LTEMP period, while under long-term strategy D4 low summer flows would not be conducted. Subtracting NPV results for D4 from D1 yields the NPV cost of conducting the experiments over the 20-year LTEMP period. Using this methodology, the approximate cost of conducting different types of experimental elements can be "unbundled" from the total aggregate costs previously reported.

Although the SDA modeling results do not include all possible combinations of operating criteria and experiments, a general estimate of the relative costs of each type of experiment can be gained by comparing selected pairs of SDA NPV model results as described in the example above. Using information provided in Table 4.1-1, the following pairs of alternatives were selected to approximate costs associated with individual experimental elements:

1. Low summer flows
    a. Long-term strategies D4 (without low summer flows) and D1 (with low summer flows)
    b. Long-term strategies E3 (without low summer flows) and E5 (with low summer flows)
2. TMFs
    a. Long-term strategies D3 (without TMFs) and D1 (with TMFs)
    b. Long-term strategies E3 (without TMFs) and E6 (with TMFs)
3. Steady weekend flows for macroinvertebrate production
    a. Long-term strategies D1 (without steady weekend flows) and D2 (with steady weekend flows)
4. Fall HFE
    a. Long-term strategies C3 (without HFEs) and C4 (with HFEs)
    b. Long-term strategies E3 (without HFEs) and E4 (with HFEs)

Consistent with both the SDA and detailed power system results, costs for each experiment are computed for both Glen Canyon Dam Powerplant energy production and replacement capacity. Figures 12 and 13 in Appendix C show annual average energy and capacity costs for four experimental elements described above. These estimates are based on 21 hydrology traces over the 20-year LTEMP study period. Note that the cost of a single element type differs by alternative pairing. For example, the annual average NPV energy costs difference between long-term strategies E3 and E5 is bigger than the difference between long-term strategies D4 and D1. In this case, the difference is due to several factors including interactions among the experimental element that is being measured (i.e., low summer flows), and both the

[1] Mechanical trout removal is not included in the comparison of elements because it not a factor in estimates of either SDA or power systems costs.

operating criteria and other experiments. Note that both E3 and E5 do not include other experiments while both long-term strategies D4 and D1 include TMFs and different types of HFEs. It is therefore apparent that operating criteria and other experiments have an impact on the incremental cost of conducting a specific experiment.

As discussed in more detail below, the cost of conducting an experiment is dependent not only on the water release specifications of the experiment but also the frequency of the experiments and the length of time that it takes to conduct an individual experiment. For example, the energy cost to conduct each steady weekend flow experiment is relatively low, while it is much more costly to conduct an individual low summer flow. However, as shown in the following discussion, steady weekend flows are much more costly than low summer flows because of the high frequency of steady weekend flows throughout the 20-year LTEMP period. Approximately seventeen 2-day steady flows would take place every year under the former scenario while on average over all 21 traces less than one low summer flow 92-day experiment is expected over the entire 20-year LTEMP period under the latter scenario.

Capital costs for experimental elements display a pattern that is distinctly different from energy costs. For example, among the experimental elements, fall HFEs are the most expensive while replacement capital costs are zero. Because these HFEs are conducted exclusively during the month of November, there are small impacts on Glen Canyon Dam Powerplant maximum output levels in August when firm capacity is measured. This is especially the case under dry hydrological conditions (e.g., 90% exceedance) under Alternative C and Alternative E operating criteria. There are also no firm capacity cost impacts associated with TMFs because these are conducted in May, June, and July and require no water reallocation among months of the year.

The following sections discuss in more detail each experimental element in terms of the cost to conduct an individual experiment, the frequency of experiments, and duration of each experiment.

Cost of Low Summer Flows. The average annual energy cost for low summer flow experiments is approximately $0.10 million for the long-term strategy D1 to long-term strategy D4 comparison (i.e., $1.97 million over 20 years) and about $0.17 million for the long-term strategy E3 to long-term strategy E5 comparison (i.e., $3.36 million over 20 years). These values are the difference in the averages of the annualized NPV of hydropower generation between long-term strategies D1 and D4 and long-term strategies E3 and E5, as computed from Figure C-12 of Appendix C. These costs are relatively low compared to both steady weekend flows and HFEs. This outcome is due to the timing and infrequent occurrence of low summer flow experiments. Among all 21 hydrology traces over the 20-year LTEMP period (i.e., 20 × 21 = 420 outcomes), only 15 low summer flow experiments were triggered; that is, on average there is only a 71.4% chance (15/21 × 100) that a single low summer flow will be conducted during the entire 20-year LTEMP period. On an annual basis, the chance that a low summer flow will be conducted is only 3.6% (15/420 × 100). Furthermore, all low summer flows occur during the last 10 years of the LTEMP period. Because the NPV calculation uses an annual discount rate, a low summer flow experiment in a later year has a lower weight in the NPV calculation compared to the same experiment conducted in an earlier year. Based on the total energy cost of a low

summer flow experiment and the frequency of occurrence, the average NPV energy cost of a single low summer flow experiment is about $2.76 million for Alternative D and about $4.70 million for Alternative E. Because a low summer flow experiment takes place during the entire months of June, July, and August (92 days), the average daily NPV cost to conduct a low summer flow experiment is about $30,000 for Alternative D and about $51,000 for Alternative E.

The average annual capacity replacement costs for low summer flows are approximately $1.25 million based on the long-term strategy D1 to long-term strategy D4 comparison ($24.94 million over 20 years) and about $0.99 million based on the long-term strategy E3 to long-term strategy E5 comparison ($19.77 million over 20 years). These values are the difference in the averages of the annualized NPV of hydropower capacity between long-term strategies D1 and D4 and long-term strategies E3 and E5, as computed from Figure C-13 of Appendix C. Because low summer flow experiments directly impact operations in the critical peak load month of August by reducing both monthly water release volumes and operational flexibility, there is an impact on firm capacity estimates and therefore the cost of lost capacity at the Glen Canyon Dam Powerplant. Based on the total capital cost of the low summer flow experiment and the frequency of occurrence, the average NPV capital cost of a single experiment is about $34.92 million for long-term strategies D1–D4 and about $27.67 million for Alternative E; that is, an average daily NPV costs of about $380,000 for long-term strategies D1–D4 and about $301,000 for long-term strategies E3–E5. Adding the low summer flow costs for energy and capacity yields a per experiment cost of $37.68 million and $32.37 million for Alternatives D and E, respectively.

In WY 2000, a low summer steady flow experiment was conducted and the financial energy cost of this experiment was estimated to be about $25 million in nominal dollars (Veselka et al. 2011). Because the low summer steady flow was a one-time experiment, it was assumed that there were no firm capacity impacts. The WY 2000 low summer steady flow experiment was several times more expensive than the projected energy costs of the low summer flow experiments considered for the LTEMP period, for which costs were estimated to be $2.76 million and $4.70 million for Alternatives D and E, respectively. Although both have similar-sounding names and are conducted in the summertime, there are several factors that make the historical low summer steady flow distinctly different from low summer flows under LTEMP. These include but are not limited to following:

1. The WY 2000 low summer steady flow lasted 6 months. In contrast, the low summer flow is only 3 months long.

2. The WY 2000 low summer steady flow had zero operational flexibility, whereby water and therefore power plant output was almost always constant. There is comparatively more operating flexibility allowed under the LTEMP low summer flow.

3. During WY 2000, energy prices were driven by the California market, which at that time experienced extraordinary price spikes due to the market design structure in place at that time (e.g., the <u>average</u> on-peak price in August was

approximately $114.29/MWh) and daily price spreads between on- and off-peak periods were up to $90/MWh.

4. The WY 2000 low summer steady flow required two "spike flows" (the predecessor of HFEs) in the spring and fall.

Cost of Trout Management Flows. The average annual energy costs of TMFs[2] are approximately $175,000 for the long-term strategy D1 to long-term strategy D3 comparison (i.e., $3.49 million over 20 years) and about $48,900 for the long-term strategy E3 to long-term strategy E6 comparison (i.e., $0.98 million over 20 years). These values are the difference in the averages of the annualized NPV of hydropower generation between long-term strategies D1 and D3 and long-term strategies E3 and E6, as computed from values in Figure C-12 of Appendix C. Like low summer flows, these costs are relatively low compared to both the steady weekend flow and the HFE experiments. The average number of TMFs conducted in a trace for Alternatives D and E is 3.48 and 2.38, respectively. On an annual basis, the chances that a TMF will be conducted for Alternatives D and E are 17.4% (3.48 per 20 years) and 11.9% (2.38 per 20 years), respectively. Based on the total energy cost of a TMF and the frequency of occurrence, the average NPV energy cost of a single TMF is about $1.0 million for Alternative D and about $410,000 for Alternative E. Because a TMF takes place for a period of 5 days in May, June, and July, or a total of 15 days, the average daily NPV cost to conduct a TMF is almost $67,000 for Alternative D and about $27,400 for Alternative E.

There is no capacity replacement cost for TMFs because these experiments only occur in the months of May, June, and July, and water is only reallocated within the same month to conduct the experiments; there is no water reallocation among other months of the year. Therefore, there is no capacity impact in the month of August when firm capacity is measured.

Cost of Steady Weekend Flows. The average annual energy cost for the steady weekend flows is approximately $533,000 (i.e., $10.6 million over 20 years). This value is the difference in the averages of the annualized NPV of hydropower generation between long-term strategies D2 and D1, as computed from values in Figure C-12 of Appendix C. As noted earlier, this is the highest cost of all experimental elements because of the large number of steady weekend flows conducted each year (i.e., there are approximately seventeen 2-day steady weekend flow experiments annually). Steady weekend flows are conducted each weekend in the months of May through August. Based on the total energy cost of a steady weekend flow and their frequency of occurrence, the average NPV energy cost of a single steady weekend flow is about $31,400 ($533,000/17). Each steady weekend flow lasts 2 days, so the average daily NPV cost of a steady weekend flow is about $15,700.

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[2] Trout management flows consist of repeated cycles of high and low flows over a season (see Section 2.2.3.2 for a description of TMFs). The modeling conducted for the LTEMP considered three cycles, one each in May, June, and July. In the cost of experiment analysis, a TMF experiment is assumed to be a single three-cycle implementation.

The average annual capacity replacement cost for steady weekend flows is about $4.2 million (i.e., $84 million over 20 years). This value is the difference in the averages of the annualized NPV of hydropower capacity between long-term strategies D2 and D1, as computed in Figure C-13 of Appendix C. Based on the total capital cost of the steady weekend flows and their frequency of occurrence, the average NPV capital cost of a single experiment is about $247,000 ($4.2 million/17), or an average daily cost of almost $124,000. Adding the costs for both energy and capacity yields a per-experiment cost of over $278,000.

Cost of Fall High Flow Experiments. The average annual energy cost for the fall HFEs is approximately $1.25 million for the long-term strategy C3 to long-term strategy C4 comparison (i.e., $24.98 million over 20 years) and about $1.23 million for the long-term strategy E3 to long-term strategy E4 comparison (i.e., $24.54 million over 20 years). These values are the difference in the averages of the annualized NPV of hydropower generation between long-term strategies C3 and C4 and long-term strategies E3 and E4, as computed from values in Figure C-12 of Appendix C. These costs are relatively high compared to the energy cost for other experiments. This outcome is due to the frequent occurrences of fall HFEs and the high energy cost associated with conducting each individual fall HFE. On an annual average basis, 19.6 HFE experiments per hydrology trace (nearly every November during the 20-year LTEMP period) are conducted under long-term strategy C4 and 16.0 HFE experiments (80% of Novembers; 16/20 × 100) are conducted under long-term strategy E4. Based on the total energy cost of the fall HFEs and the frequency of occurrence, the average NPV energy cost of a single fall HFE is about $1.27 million for Alternative C and about $1.53 million for Alternative E.

The number of days it takes to conduct a fall HFE experiment varies based on the type of HFE. An HFE can last from 2 to 16 days, including the up and down ramping periods. On average, a fall HFE lasts about 4.7 days under long-term strategy C4 and 4.6 days under long-term strategy E4. Therefore, the average daily NPV costs to conduct a fall HFE experiment in November is about $271,000 for Alternative C and about $337,000 for Alternative E. As discussed previously, there is no lost capacity cost associated with a fall HFE because November HFEs have little to no impact on maximum output levels at the Glen Canyon Dam Powerplant in August (i.e., the month with the highest peak load).

The cost for an individual HFE computed in this analysis is somewhat lower than the estimated cost of the fall HFE conducted in WY 2014, which ranged from $2.44 million to $2.59 million (Graziano et al. 2015). Several factors contributed to the higher historical costs and include (1) WY 2014 HFE was a longer 6-day event; (2) costs were not discounted; and (3) the WY 2014 HFE study was a financial analysis.

Experimental Element Summary. Table K.1-11 summarizes the results of the pairwise comparison of alternatives to determine the costs of individual experiments.

TABLE K.1-11 Estimated Cost of LTEMP Experiments

Experimental Element and Pair	Average NPV Cost over 20 Years ($ million)			Average NPV Cost Per Experiment ($ million)			Average Daily NPV Cost ($ million)		
	Energy	Capacity	Total	Energy	Capacity	Total	Energy	Capacity	Total
Low summer flows (long-term strategies D4, D1)	1.97	24.94	26.92	2.76	34.92	37.68	0.03	0.38	0.41
Low summer flows (long-term strategies E3, E5)	3.36	19.77	23.13	4.70	27.67	32.37	0.05	0.30	0.35
TMFs (long-term strategies D3, D1)	3.49	0.00	3.49	1.00	0.00	1.00	0.067	0.00	0.067
TMFs long-term strategies (E3, E6)	0.98	0.00	0.98	0.41	0.00	0.41	0.027	0.00	0.027
Steady weekend flows (long-term strategies D1, D2)	10.6	84.0	94.6	0.031	0.247	0.278	0.016	0.124	0.14
Fall HFEs (long-term strategies C3, C4)	24.98	0.00	24.98	1.27	0.00	1.27	0.27	0.00	0.27
Fall HFEs (long-term strategies E3, E4)	24.54	0.00	24.54	1.53	0.00	1.53	0.34	0.00	0.34

K.1.10.4 Sensitivity of Results to Exceedance Level

One sensitivity study investigated the effect of exceedance level on results. The previous section discussed results at the 90% exceedance level. This section will show results at the 50% and 99% exceedance levels and discuss how they compare to each other and to results at the 90% exceedance level. Table K.1-12 shows at each exceedance level and alternative the firm capacity, the capacity replacement requirement, and the system-level capacity additions at the end of the LTEMP study period.

Table K.1-12 shows that, compared the 90% exceedance level, the 99% exceedance level results in a lower firm capacity and the 50% exceedance level results in a higher firm capacity. A higher exceedance level means SLCA/IP federal hydropower resources will be able to supply the system with all of the computed firm capacity more often than when a lower exceedance level is used. In addition, in the 50 to 99% exceedance range, the higher the exceedance level, the lower the firm capacity difference among alternatives. Therefore, the higher the exceedance level, the smaller the difference in in capital and fixed O&M costs among alternatives.

The AURORA model was run both in capacity expansion and dispatch mode to determine the NPV costs of the new expansion pathways and the production costs for the 50% and 99% exceedance levels for the representative trace. Figures K.1-46, K.1-47, and K.1-48 show results for the 50%, 90%, and 99% exceedance levels, respectively. These figures also show the difference in cost between various alternatives and Alternative A for each of the three

TABLE K.1-12 Comparison of Marketable Capacity, Replacement Capacity, and Capacity Additions by Exceedance Level

Capacity Type	Alternative A (No Action Alternative)	Alternative B	Alternative C	Alternative D (Preferred Alternative)	Alternative E	Alternative F	Alternative G
99% Exceedance Level							
SLCA/IP Marketable Capacity (MW)[a]	611.2 (no change from current condition)	619.9 (1.4% increase)	510.7 (16.4% decrease)	599.8 (1.8% decrease)	542.2 (11.3% decrease)	354.5 (42.0% decrease)	466.8 (23.6% decrease)
SLCA/IP Replacement Capacity (MW)[b]	Not applicable	–8.8	100.5	11.3	68.9	256.7	144.3
System-Level Generating Capacity Additions (MW)[c]	5,050 (no change from current condition)	5,050 (no change from current condition)	5,050 (no change from current condition)	5,050 (no change from current condition)	5,050 (no change from current condition)	5,280 (4.6% increase)	5,280 (4.6% increase)
90% Exceedance Level							
SLCA/IP Firm Capacity (MW)[a]	737.2 (no change from current condition)	765.3 (3.8% increase)	608.1 (17.5% decrease)	687.6 (6.7% decrease)	647.0 (12.2% decrease)	423.1 (42.6% decrease)	558.2 (24.2% decrease)
SLCA/IP Lost Capacity (MW)[b]	Not applicable	–28.1	129.1	49.6	90.2	314.1	179.0
System-Level Generating Capacity Additions (MW)[c]	4,820 (no change from current condition)	4,820 (no change from current condition)	5,050 (4.8% increase)	5,050 (4.8% increase)	5,050 (4.8% increase)	5,280 (9.5% increase)	5,050 (4.8% increase)
50% Exceedance Level							
SLCA/IP Firm Capacity (MW)[a]	959.9 (no change from current condition)	987.0 (2.8% increase)	780.2 (18.7% decrease)	878.3 (8.5% decrease)	829.1 (13.6% decrease)	569.6 (59.3% decrease)	722.1 (24.8% decrease)
Lost Capacity (MW)[b]	Not applicable	–27.2	179.7	81.6	130.8	390.3	237.8
System-Level Generating Capacity Additions (MW)[c]	4,820 (no change from current condition)	4,590 (4.8% decrease)	5,050 (4.8% increase)	4,820 (no change from current condition)	4,820 (no change from current condition)	5,280 (9.5% increase)	5,050 (4.8% increase)

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TABLE K.1-12 (Cont.)

[a] Additional generation capacity required under the LTEMP alternatives for Western's customers over the 20-year LTEMP period to not only meet future load demand and replace unit retirements but also account for loss/gain in capacity at Glen Canyon Dam due to the alternative operating constraints.

[b] Lost capacity is the difference between the marketable capacity in Alternative A and the marketable capacity of another alternative; it represents the capacity that would need to be replaced somewhere in the power system if that alternative was implemented.

[c] Additional generation capacity required under the LTEMP alternatives for Western's customers over the 20-year LTEMP period to not only meet future load demand but also account for loss/gain in capacity at Glen Canyon Dam due to the alternative operating constraints

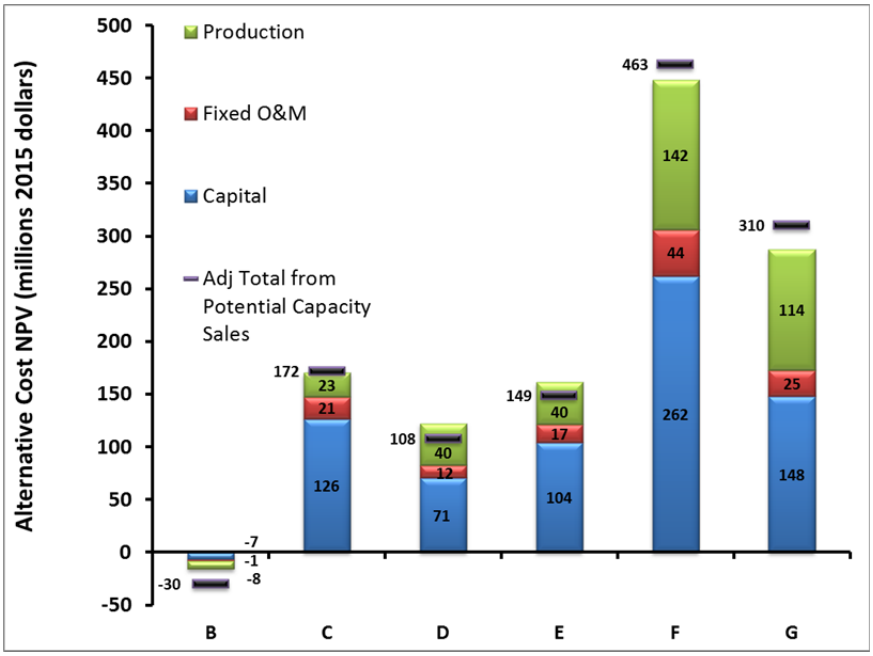

FIGURE K.1-46 Cost Difference of Alternatives Compared to Alternative A at 50% Exceedance Level and 3.375% Discount Rate

components that comprise the total cost of the alternative: capital, fixed O&M, and production or energy. The black bar for each alternative shows the total cost of the alternative if excess capacity above the amount required to satisfy the reserve margin is sold to the market. This sale of excess capacity could either raise or lower the total alternative cost compared to Alternative A. Results shown in all three figures are based on a 3.375% discount rate. The relative ranking of alternatives for these two sensitivity analyses are similar to the 90% exceedance level (that is, in order from highest to lowest, Alternatives B, A, D, E, C, F, and G). In addition, this ranking is identical whether excess firm capacity is either sold or not sold.

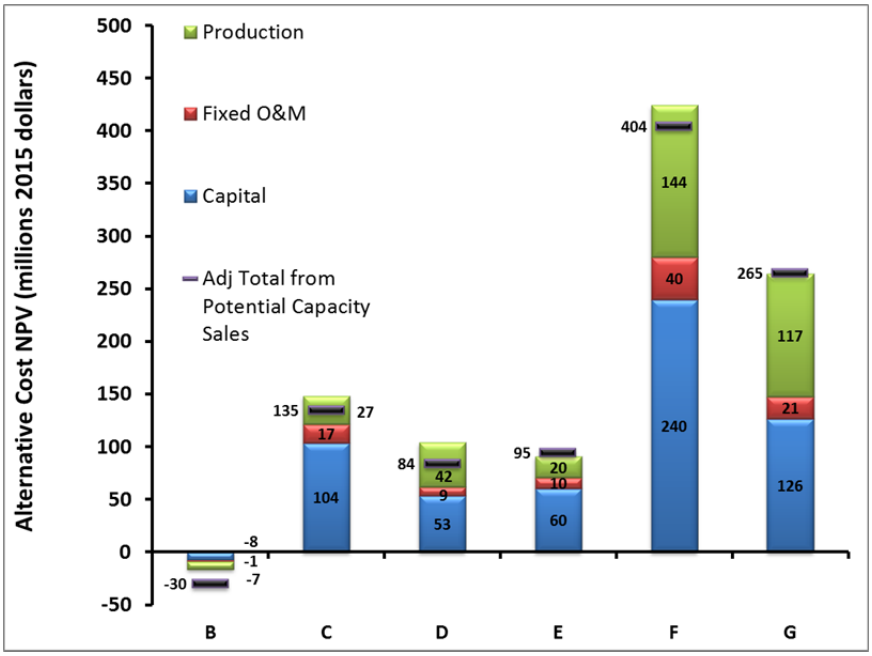

FIGURE K.1-47 Cost Difference of Alternatives Compared to Alternative A at 90% Exceedance Level and 3.375% Discount Rate

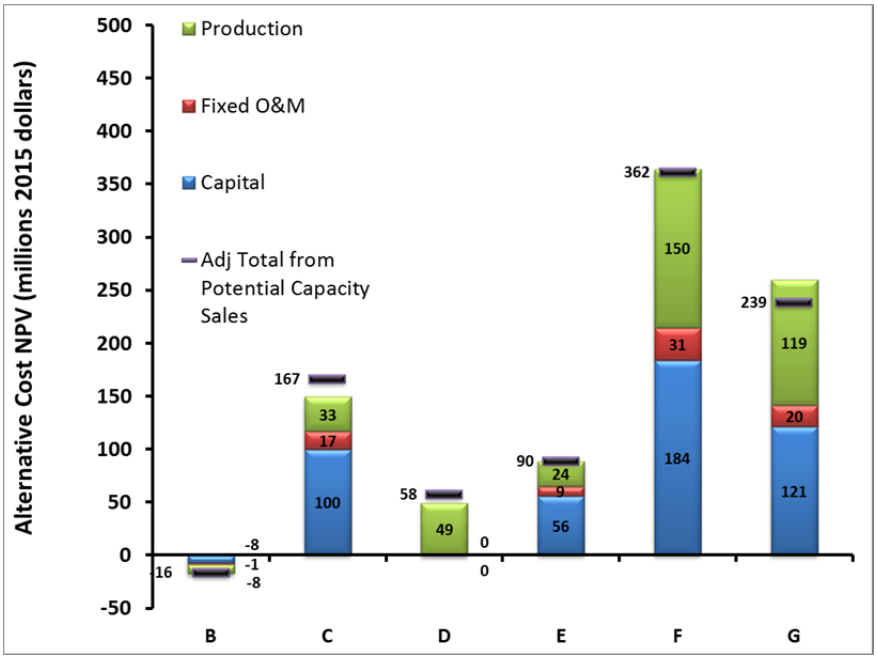

FIGURE K.1-48 Cost Difference of Alternatives Compared to Alternative A at 99% Exceedance Level and 3.375% Discount Rate

The figures show that as the exceedance level increases the difference in the cost of each component and the total cost compared to Alternative A decreases. The alternative cost differences are smaller because the difference in firm SLCA/IP federal hydropower capacity between the various alternatives and Alternative A is lower as the exceedance level increases. Because a smaller amount of new capacity is needed to replace capacity lost at Glen Canyon Dam compared to Alternative A, each cost component and the total cost of the alternative is reduced.

At all exceedance levels, the cost of Alternatives F and G, which both have steady flow operating requirements, have the highest costs of all alternatives because they have the lowest firm capacity and no operational flexibility. Therefore, both require the largest amount of new capacity additions to replace lost Glen Canyon Dam capacity. Alternative F is the highest cost because, unlike Alternative G, it has very high monthly water releases at a time of the year (i.e., spring) with relatively low marginal production costs, and low releases during the high-production-cost summer months of July and August. In contrast, Alternative B is always the lowest cost alternative because it has a higher firm capacity than Alternative A and slightly more operational flexibility. The other three alternatives also have approximately the same ranking across all three exceedance levels.

Note that in Figure K.1-48 (the 99% exceedance level), the capital and fixed O&M cost differences between Alternatives A and D are zero. This occurs because the capacity expansion schedule is identical in both alternatives; that is, the amount and type of capacity is brought online at exactly the same time. Table K.1-12 has examples of other alternatives that have the same amount of capacity additions at the end of the LTEMP period as Alternative A, but still have a difference in the capital and fixed O&M costs compared to Alternative A. This occurs because of the difference in timing of capacity additions. This result again illustrates the lumpy nature of capacity expansion due to the fact that plants used for capacity expansion have a discrete size; thus, adding one or a combination of several may exceed the capacity needed to just fulfill the reserve margin requirement.

Finally, the cost differences between an alternative and Alternative A are a very small percent of the total cost of the alternative across this wide range of exceedance levels. For example, Alternative F is the highest cost alternative at all three exceedance levels. At the 50% exceedance level, Alternative F costs more about $448 million more than Alternative A. However, this difference is only about 1.2% of the total cost of Alternative A, which is about $36.2 billion. This total cost excludes static expenditures that are not tracked because they are identical under all alternatives. These static expenditures include, but are not limited to, fixed O&M costs for existing powerplants and both transmission and distribution costs. If these other costs were included, the percent difference relative to the total cost of Alternative A would be lower than the aforementioned 1.2%.

K.1.10.5 Sensitivity of Results to Discount Rate

Up to this point NPVs have been calculated using an annual discount rate of 3.375%, which is a rate used by Reclamation for project cost-benefit studies. The LTEMP hydropower

subject matter expert team that helped guide this power systems study expressed concern that the 3.375% rate appears to be too high under current economic conditions. Therefore, a real annual discount rate of 1.4% was used for the sensitivity study. That value was obtained from the Office of Management and Budget Circular A-94, Appendix C (available at https://www.whitehouse.gov/omb/circulars_a094/a94_appx-c). That rate is the real interest rate on treasury notes and bonds with a maturity of 30 years.

Figure K.1-49 shows the 20-year NPV cost differences between each alternative and Alternative A for the representative trace at the 90% exceedance level using the 1.4% real discount rate. This figure should be compared to Figure K.1-47, which is the same exceedance level but for the baseline discount rate. When using a lower discount rate, the NPV costs of alternatives relative to Alternative A are larger because costs at the end of the study period have a larger contribution to the NPV. Note that the NPV cost difference between Alternatives F and A is approximately a half billion dollars ($508 million, if adjustment for potential excess capacity sales is not included). However, the relative ranking of alternatives from lowest to highest cost, and relative percent difference from Alternative A do not change for these two discount rates. Alternative B is the lowest cost alternative, followed by Alternatives A, D, E, C, G, and F. If it is assumed that excess capacity will be sold to an entity outside of the SLCA/IP market system, then Alternatives D and E change places in the alternative ranking.

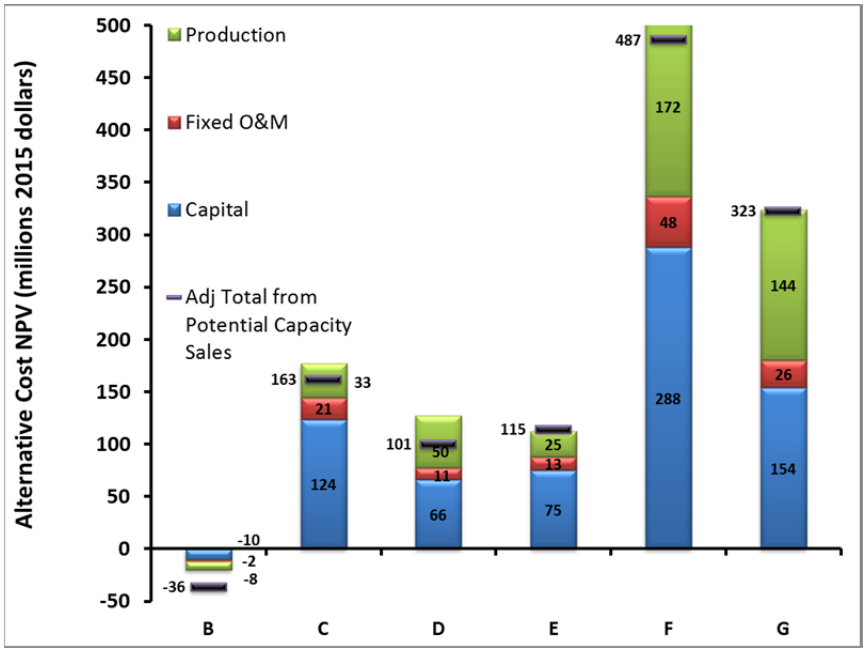

FIGURE K.1-49 Cost Difference of Alternatives Compared to Alternative A at 90% Exceedance Level and 1.4% Discount Rate

K.1.10.6 Sensitivity of Results to the Base Capacity Expansion Path

The new generating unit additions projected by the AURORA capacity expansion model run for Alternative A represents a reasonable and plausible outlook that is consistent with utility IRPs in the region and the 2014 AEO (EIA 2014) projections. However, as stated earlier, the AURORA model bases capacity expansion decisions more on local financial objectives than on economic ones. Argonne power systems analysts also discovered that small changes in some AURORA inputs would lead to substantial changes in capacity expansion pathways. This model behavior leads to uncertainty about the impact of Alternative A's expansion pathway on the final results and about the conclusions that could ultimately be made about power systems economic impacts.

Although pathways were different, it became apparent that the advanced combustion turbines and advanced combined cycle units were the two expansion candidates used almost exclusively by AURORA for new future additions. Therefore, additional model runs were made to measure the sensitivity of the base capacity expansion pathway on economic outcomes. Two extreme Alternative A pathways were tested. Both were based on a 90% exceedance level and a 3.375% discount rate. One pathway built exclusively advanced combustion turbines and the second pathway build only the advanced combined cycle plants. Under both pathways, combustion turbines replaced lost capacity at Glen Canyon Dam for all other alternatives. Results for these two extreme pathways are shown in Figures K.1-50 and K.1-51.

For both pathways, the comparative results show the same basic pattern as all of the previously discussed results. Alternative ranking is basically the same. However, under the advanced combustion turbine base expansion pathway, costs (stacked bars) are noticeably higher for Alternatives D and E as compared to the primary assumption set reported in Chapter 4 (i.e., mixed technology expansion, 90% exceedance, and a 3.375% discount rate shown in Figure K.1-47). Also under the advanced combined cycle base expansion pathway, costs for Alternatives C, D, and E are somewhat lower. This is due primarily to the lumpy nature of capacity additions. If excess capacity can be sold, the effects of this lumpy behavior are significantly reduced. Note that for each alternative the black bars for the three base expansion pathways are very similar.

K.1.10.7 Sensitivity of Results to the Assumed Future Hydrological Conditions

Hydrology trace 14 in combination with sediment trace 2, which was the most probably sediment condition, was used as the representative trace. However, as noted earlier, the impacts of an alternative are dependent on the hydrological conditions. Therefore, the timing of dry, average, and wet hydrological condition is important because discounting in the NPV computation gives a higher weight to near-term costs as compared to costs that are incurred in the more distant future.

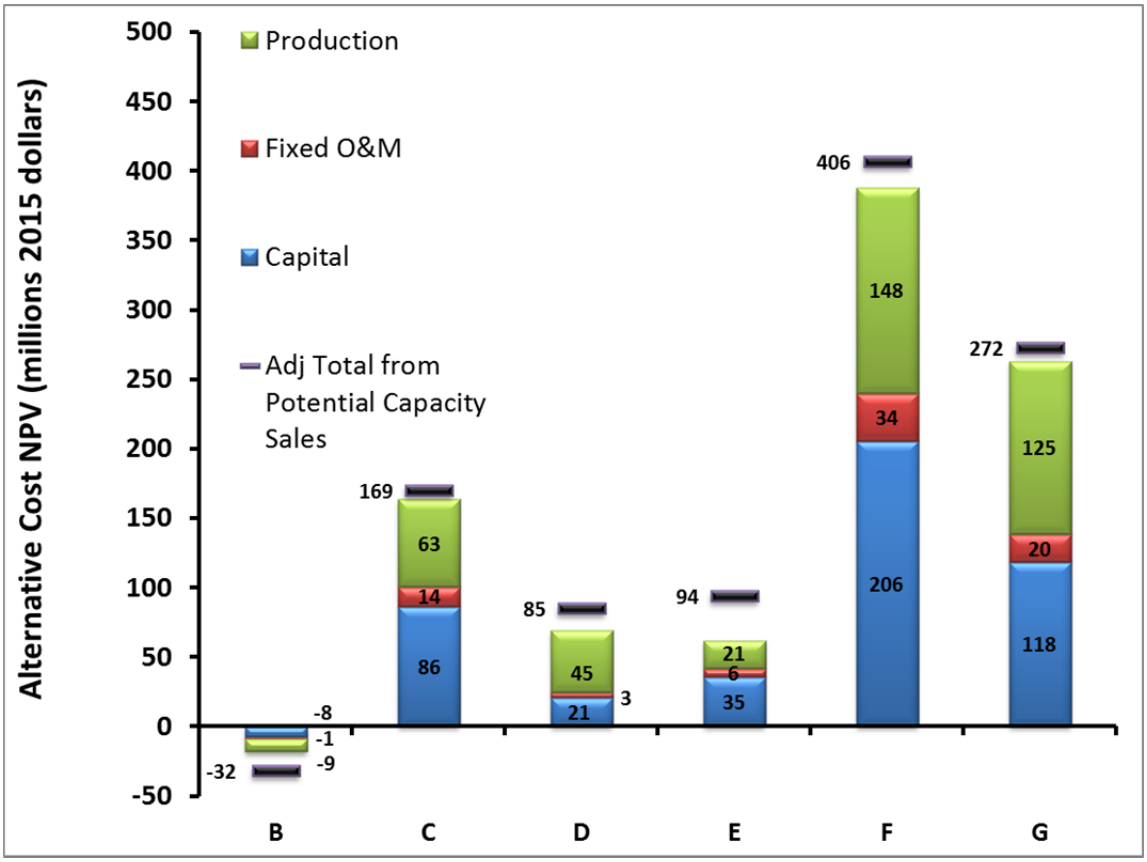

FIGURE K.1-50 Cost Difference of Alternatives Compared to Alternative A at 90% Exceedance Level and 3.375% Discount Rate, Assuming All Alternative A New Capacity Additions Are Advanced Combustion Turbines

This section is intended to provide insights into the economic results' sensitivity to the selected hydrological condition. Ideally, all possible combinations of the 21 hydrology traces and three sediment traces would be simulated with the AURORA model in dispatch mode over the 20-year study period. However, such an effort would be very time consuming. As a simplification, only one other hydrological condition was run. For each hour of the LTEMP study period, this condition uses the average hourly generation from all 21 traces under sediment trace 2 as projected by GTMax-Lite runs of Glen Canyon Dam. Results for this average hydropower condition are shown in Figure K.1-52.

Note that all capital and fixed O&M costs in Figure K.1-52, as shown by the blue and red bars, respectively, are identical to those shown in Figure K.1-47 for the primary assumption set. This occurs because capacity expansion decisions are made under uncertainty. For this power systems study, the expansion pathway for each alternative is based on a set of 21 plausible future hydrological conditions. It is also assumed that once the firm capacity level is determined and input into the AURORA model to determine an alternative-specific expansion path, the firm capacity level does not change regardless of the sequence of actual hydrological conditions that occur in the future. Therefore, the representative trace and the average trace use identical

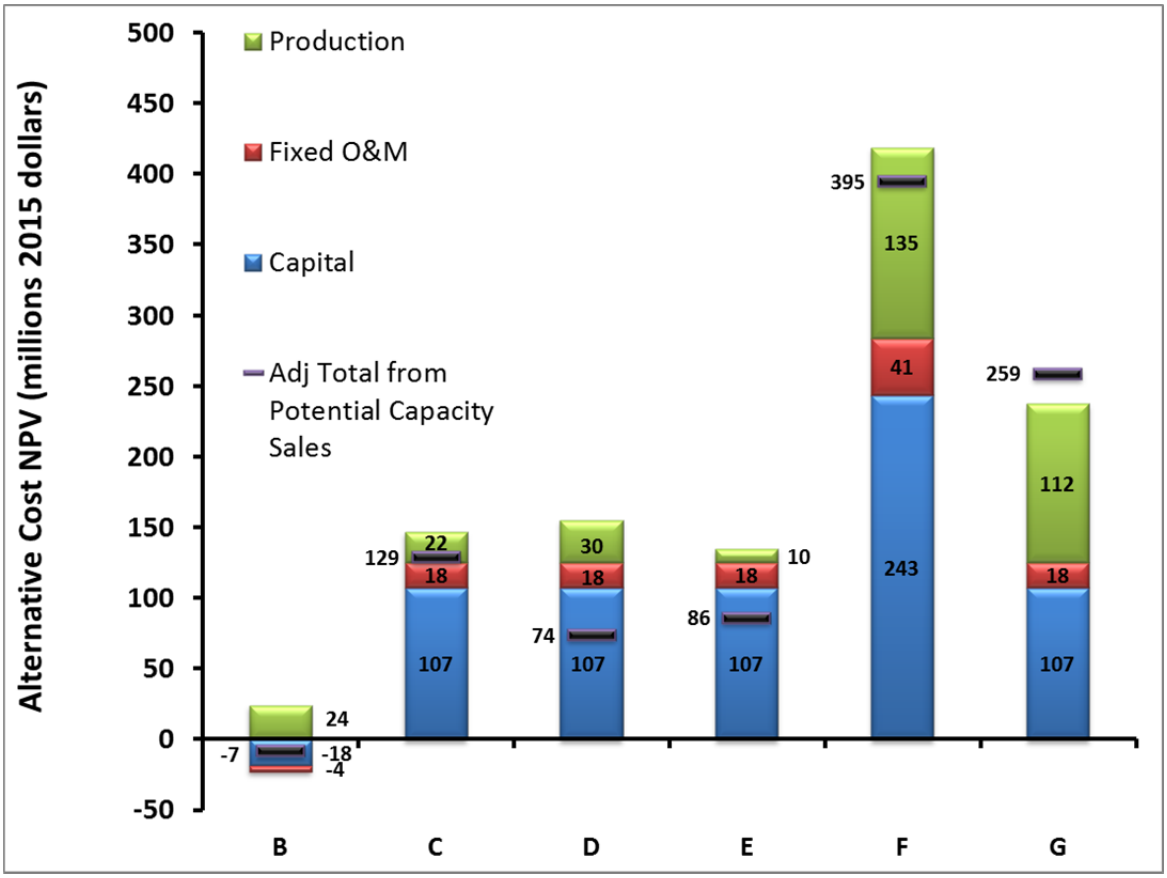

FIGURE K.1-51 Cost Difference of Alternatives Compared to Alternative A at 90% Exceedance Level and 3.375% Discount Rate, Assuming All Alternative A New Capacity Additions Are Advanced Combined Cycle

capacity expansion pathways. If other hydropower conditions were run, each one would use this fixed expansion path.

Although capital and fixed O&M costs are identical, production costs (green bars) are slightly different. This does not provide definitive proof that the selected trace does not have a substantial impact on economic outcomes, but it does show that the representative trace—which has a sequence of dry, average, wet, average, and dry conditions over the study period—produces a result that is very similar to a sequence of average hydropower conditions.

K.1.10.8 Sensitivity of Results to Changes in Ancillary Services

A sensitivity study was performed on the effect changes in ancillary services (AS), which is the sum of regulation and fast spinning reserves, would have on the value of energy and firm capacity from Glen Canyon Dam. It was performed because assumptions about ancillary service requirements changed from when the GTMax-Lite model was run for the swing-weighting exercise in March 2014 (swing-weighting described in Appendix C). For this modeling, ancillary

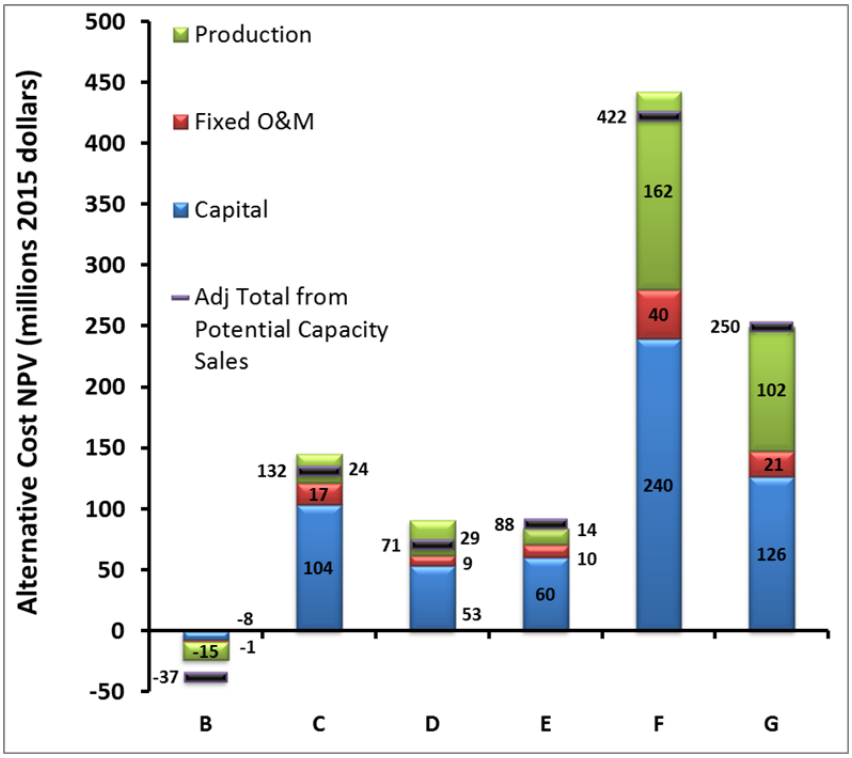

FIGURE K.1-52 Cost Difference of Alternatives Compared to Alternative A at 90% Exceedance Level and 3.375% Discount Rate Assuming Average Hydropower Conditions

service requirements at Glen Canyon Dam were projected to be 103 MW in 2013 and then to increase to 160 MW by 2030. This case was called the high AS scenario. However, subsequent to this modeling, a second scenario was determined by Western to be more likely (i.e., ancillary service requirements would remain at the same levels that exist today). Glen Canyon Dam currently supplies 67 MW of ancillary services and Western currently expects this not to increase during the LTEMP study period. This case was called the current AS scenario. This section reports the results of the study.

Using a lower ancillary service requirement will affect Glen Canyon Dam dispatch, firm capacity levels, and economic evaluations. In addition, alternatives that allow higher operational flexibility may be affected more than ones with very stringent limitations. Therefore, a sensitivity analysis was conducted to evaluate the magnitude of change that would occur in model results if the current AS scenario had been used.

Because it would have been very costly to repeat the entire analysis with current ancillary service requirements, the sensitivity analysis used a simpler methodology to gage differences in firm capacity and energy economics among Alternatives A, D, and F under two disparate ancillary service market assumptions. If differences in the marketable capacity and energy for these three alternatives were dissimilar under the two AS cases, a second phase analysis would be performed.

Alternatives A, D, and F were chosen because they span a wide range of firm capacities that the LTEMP alternatives exhibit. Alternative A is the current operating regime and has the second highest firm capacity; Alternative F is a steady flow alternative and has the lowest marketable capacity; and Alternative D represents a mid-range firm capacity level. To expedite the analysis, end-of-month elevations and monthly release values from the CRSS model for just trace 14 (i.e., the representative hydrology trace) was analyzed. Monthly releases input to the Glen Canyon Dam GTMax-Lite model were not adjusted for experiments (either HFEs or TMFs) because CRSS results did not account for them. Experiments are only added by the SBM and are assumed to have relatively small impacts on firm capacity at exceedance levels over 50%.

The GTMax-Lite model was run and results were stored for hourly generation over the entire study period. Firm capacity for several exceedance levels above 50% under the three alternatives were then estimated for both sets of ancillary service values. The value of generation was determined by multiplying hourly generation levels by corresponding hourly Palo Verde LMPs. Hourly values were then summed to determine the total economic energy value. Next, differences in firm capacity and energy value among the three alternatives were computed and results from the ancillary services cases were compared.

Ancillary services sensitivity analysis results are shown in Tables K.1-13 through K.1-15 below. Table K.1-13 shows the capacity at exceedance levels ranging from 0 to 100% for the three alternatives and the two ancillary service scenarios. At capacity exceedance levels of interest for the LTEMP analysis (namely, 50% to 99%), the capacity differs by less than 5% between the two ancillary services scenarios.

TABLE K.1-13 Firm SLCA/IP Federal Hydropower Capacity (MW) at Various Exceedance Levels at Glen Canyon Dam by Alternative and Ancillary Service Scenarios

	Alternative A (No Action Alternative)		Alternative D (Preferred Alternative)		Alternative F	
Exceedance	Current AS	High AS	Current AS	High AS	Current AS	High AS
100	519	495	458	458	191	191
99	519	495	458	458	191	191
90	550	549	484	481	212	212
80	575	575	525	511	232	232
70	630	623	546	544	241	241
60	647	647	564	564	251	251
50	673	673	591	584	259	259
40	694	694	595	595	267	267
30	716	716	620	607	276	276
20	890	830	887	827	692	692
10	975	967	987	967	985	985
1	1097	1097	1097	1097	1097	1097
0	1097	1097	1097	1097	1097	1097

Table K.1-14 shows capacity (MW), energy (GWh), spills (GWh), and the NPV of all cost components for the 3 alternatives. The capacity shown in Tables K.1-14 and K.1-15 is at the 90% exceedance level; it shows that there is a very small difference (less than 0.8%) in the capacity and energy, in terms of MW and GWh, respectively, between the high AS and current AS scenarios for Alternatives A and D. There is no difference between the ancillary service scenarios for Alternative F. The difference in total NPV between the two scenarios for Alternatives A and D is also very small; namely, $2.86 million (0.08%) for Alternative A and $4.71 million (0.14%) for D. There is no difference between the ancillary services scenarios for Alternative F.

Table K.1-15 compares the differences in firm capacity and energy in Alternatives D and F relative to Alternative A for both ancillary services scenarios. Again, the ancillary services scenario has only a very minor effect on the relative difference between each alternative and Alternative A.

These results show very little difference among ancillary services scenarios. The primary reason for this is that under all three alternatives operating criteria do not allow the Glen Canyon Dam Powerplant to utilize a significant amount of its capacity under most hydropower conditions; that is, the criteria almost always restrict the maximum Glen Canyon Dam output to a level that is significantly below the physical maximum capacity. This gap between maximum output and physical capacity can be used for ancillary services because all alternatives allow exception criteria and restrict hourly average flow rates, but not instantaneous rates. For example, under Alternatives A and D, daily change specifications typically limit maximum output levels far (more than 160 MW) below the maximum physical output of the plant. Therefore, ancillary services requirements do not usually bind operations. Note that the power systems analysis did not evaluate the value of any unused capacity (i.e., the differences between the physical powerplant capacity minus the sum of generation plus ancillary services).

TABLE K.1-14 Comparison of Capacity and Energy Values at Glen Canyon Dam by Alternative and Ancillary Services Scenarios at the 90% Exceedance Level

Ancillary Service Scenario and Alternative	Capacity (MW)	Energy (GWh)	Spills (GWh)	NPV ($millions)			Increase in Value Compared to Current AS
				Capacity	Energy	Total	
High AS Scenario							
Alternative A	548.9	88,754	1,824	422.77	3,054.06	3,476.82	Not Applicable
Alternative D	480.7	88,790	1,556	370.29	3,043.41	3,413.70	Not Applicable
Alternative F	212.3	88,081	1,918	163.53	2,916.39	3,079.92	Not Applicable
Current AS Scenario							
Alternative A	550.3	88,757	1,821	423.87	3,055.81	3,479.68	2.86
Alternative D	484.2	88,792	1,555	372.95	3,045.39	3,418.34	4.64
Alternative F	212.3	88,081	1,918	163.53	2,916.39	3,079.92	0.00

TABLE K.1-15 Difference Relative to Alternative A (value of Alternative A minus value of alternative)

Strategy	Capacity (MW)	Energy (GWh)	Spills (GWh)	NPV ($millions) Capacity	Energy	Total
High AS Scenario						
Alternative D	68.13	-36.64	267.90	52.48	10.64	63.12
Alternative F	336.55	672.59	-93.50	259.23	137.67	396.90
Current AS Scenario						
Alternative D	66.10	-34.67	265.93	50.92	10.42	61.34
Alternative F	337.98	676.04	-96.95	260.33	139.42	399.76
Difference (Current−High)						
Alternative D	-2.02	1.97	-1.97	-1.56	-0.22	-1.78
Alternative F	1.43	3.45	-3.45	1.10	1.76	2.86

Based on insights gained from this study, it was concluded that ancillary services assumptions under a range of plausible futures have little to no effect on firm capacity and energy value for the LTEMP alternatives. Therefore, it was not necessary to conduct more detailed analyses on ancillary services.

K.1.10.9 Summary of Economic Ranking

Power systems analysis results show that there are three distinct groups of outcomes. Alternatives A and B are clearly the most favorable for hydropower economics, while Alternatives F and G are the least favorable. Alternatives C, D, and E rank between these two extremes. As shown in Table K.1-16, the ranking of alternatives is very consistent regardless of changes in assumptions that were made in the sensitivity runs. Alternatives D and E switched ranking under only two sets of assumptions. This order switch between the third and fourth rank is mainly attributed to the lumpy nature of capacity expansion paths. Among the sensitivity analyses conducted the discount rate assumption had the largest impact on absolute economic costs, but in terms of percent changes in total system costs that were tracked, it had negligible effects.

It is noteworthy that as the exceedance level increased from 50% to 99% the cost of the alternatives decreased, but the rankings did not change except for the aforementioned switching of Alternatives D and E. Although cost differences among alternatives decrease, higher exceedance levels increase overall SLCA/IP market system costs for all alternatives; however, system reliability improves with higher exceedance levels since there is more capacity built in the system.

TABLE K.1-16 Summary of Economic Rankings for Baseline and All Sensitivity Scenarios

Assumptions					Alternative Rank (lowest to highest total cost)						
Exceedance Level (%)	Excess Capacity Sales	Hydrology	Base Expansion Path	Discount Rate (%)	A	B	C	D	E	F	G
90	No	Representative Trace	CT & NGCC	3.375	2	1	5	4	3	7	6
90	Yes	Representative Trace	CT & NGCC	3.375	2	1	5	3	4	7	6
50	No	Representative Trace	CT & NGCC	3.375	2	1	5	3	4	7	6
50	Yes	Representative Trace	CT & NGCC	3.375	2	1	5	3	4	7	6
99	No	Representative Trace	CT & NGCC	3.375	2	1	5	3	4	7	6
99	Yes	Representative Trace	CT & NGCC	3.375	2	1	5	3	4	7	6
90	No	Representative Trace	CT & NGCC	1.4	2	1	5	4	3	7	6
90	Yes	Representative Trace	CT & NGCC	1.4	2	1	5	3	4	7	6
90	No	Average Hydropower	CT & NGCC	3.375	2	1	5	3	4	7	6
90	Yes	Average Hydropower	CT & NGCC	3.375	2	1	5	3	4	7	6
90	No	Representative Trace	CT	3.375	2	1	5	3	4	7	6
90	Yes	Representative Trace	CT	3.375	2	1	5	3	4	7	6
90	No	Representative Trace	NGCC	3.375	2	1	5	3	4	7	6
90	Yes	Representative Trace	NGCC	3.375	2	1	5	3	4	7	6

Last, the rankings of alternatives are also in general agreement with those found in the structured decision analysis (SDA). The SDA report shows that the value of GCD hydropower production is the highest under Alternative B followed closely by Alternative A. Alternatives F and G have the least value, respectively, and the remaining alternatives are between these bookends.

K.2 WESTERN'S SLCA/IP FIRM ELECTRIC SERVICE RATE IMPACTS[3]

The SLCA/IP firm electric service (FES) rate is the price paid per unit of product sold by Western's CRSP Management Center to its SLCA/IP FES customers. Two SLCA/IP commodities are sold, namely firm capacity and firm energy. Each has a separate price. This section documents the methods and calculations used to determine the impact of the LTEMP DEIS alternatives on the SLCA/IP capacity and energy rates.[4] The analysis was performed by Western CRSP Management Center staff with assistance from Argonne.

[3] New terms and acronyms used in this section are defined at first use, and definitions of those terms are provided at the end of the section.

[4] The term "rate" will be used rather than "price." This is the standard convention for wholesale electrical commodities. Rate is the price charged for an energy unit, whether capacity or energy. Rate is often used to describe wholesale prices because it is the price of wholesale units and not necessarily the units used for retail sales.

The analysis in this section begins with the calculations of economic impact performed and described in Section K.1. Section K.1 describes the economic impact on electrical power production , which is the impact—measured in dollars—on the economy. It includes the system cost of changing the timing and routing of water releases at Glen Canyon Dam. It also includes the expense of constructing (or savings resulting from forgoing construction of) additional electrical generators because of changes in firm SLCA/IP hydropower capacity.

Several calculations were performed to determine the impact of the LTEMP DEIS alternatives on the SLCA/IP rates. Three rates were calculated for each of the seven alternatives: (1) a firm energy rate, (2) a firm capacity rate, and (3) a composite rate. This section describes the methods and assumptions used to determine these financial rate impacts.

This analysis is a financial study. It uses the economic estimates described in Section K.1 as input values to conduct a financial analysis. Because existing FES contracts are firm obligations to deliver electrical power, the economic impact described in Section K.1 will affect the SLCA/IP rates through the period specified under contract. This analysis describes how the economic impacts are "stepped down," through changes in the SLCA/IP rate, to utilities that purchase Glen Canyon Dam electrical power. The analysis assumes that Western's contractual obligation to deliver power to its current FES customers remains unchanged from current levels through the end of the marketing period.

K.2.1 Relationship between the Economic Impacts of LTEMP Alternatives and Impacts on SLCA/IP FES Rates

It is important that this analysis of the impacts of LTEMP alternatives on SLCA/IP FES rates be compatible with the economic analysis of the impacts of alternatives on Glen Canyon Dam power production and value (as presented in Section K.1). Economic impacts are changes in the value of power systems resources. The power system economic analysis described in Section K.1 determines the economic loss (or gain) of changing the operation of Glen Canyon Dam. The economic information resulting from the analysis presented in Section K.1 is used as input values for the SLCA/IP rate analysis. This financial analysis is a "step down" from the economic analysis described in Section K.1. It demonstrates how the economic impact of alternative-specific differences in Glen Canyon Dam electric power generation affects the per unit cost of electricity to FES customers through changes in the SLCA/IP rate.

K.2.2 Temporal Scope of the Analysis and Input Data

The SLCA/IP rate analysis is a 20-year analysis encompassing the CY 2015 through CY 2034 time period. It is assumed that the SLCA/IP rate associated with the alternative does not change throughout the power repayment study (PRS) repayment period, which extends beyond CY 2034.

As explained in Section K.2.3, the SLCA/IP rate is required to be sufficient to repay authorized irrigation projects, which have construction and repayment periods that extend for

another 50 years. Therefore, although the analysis includes LTEMP EIS alternative-specific costs that differ by alternative over the 20-year time frame of the LTEMP EIS, the rate study continues with other operations and repayment expenses for many years thereafter.

Rate changes as a result of alternative operating criteria for Glen Canyon Dam impact all FES customers.[5]

Data described in Section K.1 are key input data for the SLCA/IP rate impact analysis. These data include:

- The hourly SLCA/IP electrical production under each alternative for the representative 20-year trace[6] that is simulated by both the GTMax-Lite model and the Small SLCA/IP Powerplant Spreadsheet that is produced for the economic impact analysis;

- The hourly FES customer requests for energy under the terms of their contractual agreements with Western; and

- The estimated capacity cost for each alternative that is set equal to the AURORA model's capacity expansion plan multiplied by the technology-specific levelized cost of capital plus annual fixed O&M expenses.

K.2.3 SLCA/IP Rate Setting

A typical regulated electrical utility sets a rate based on a "test year" using a formula that recoups its estimated operations expenses and allows a fair return on its capital investment. For electrical utilities regulated by State Commissions, their rates are reviewed and approved by the Commission. This approach is quite different from the ratesetting process required of Western.

Western sets SLCA/IP rates in order to repay all costs associated with power generation. Western must establish power rates sufficient to recover operating, maintenance, and purchase power expenses. In addition, Western sets rates in order to repay the federal government's investment in building these generation and transmission facilities within 50 years. Outside of the 50-year repayment period, this is similar to a regulated electrical utility. The biggest difference lies in the requirement that Western's rates must also be set to cover certain non-power costs Congress has assigned to power users to repay. These are authorized irrigation costs in excess of water users' ability to repay. For the CRSP, authorized irrigation projects have repayment periods that extend for another 50 years. Western must demonstrate to the Federal Electrical Regulatory Commission (FERC) that its SLCA/IP rate is set appropriately to make required repayment of all authorized projects. Even though FERC approves a SLCA/IP rate that

5 "FES customers" and "SLCA/IP LTF customers" are used synonymously.

6 The basis for selection of a representative trace is described in Attachment K-3 of Appendix K.

expires in 5 years, it is a rate that has been demonstrated to make all required repayment of all authorized projects.

Another approach to this analysis would be to add LTEMP EIS alternative-specific expenses for 5 years, estimate a SLCA/IP rate based on that, do it again for another 5 years, and again and again. The LTEMP EIS alternative-specific impact would then show four SLCA/IP rates that cover the 20-year temporal scope of the EIS. We could then do a net present value calculation to 2015. This approach would have made the SLCA/IP rate analysis more comparable to the approach used in Sections K.1 and K.3. This would be a straight-forward calculation for a regulated utility that uses a "test year" to set rates. The expenses related to a "test year" would be available for each of the 20 years included in the LTEMP EIS time frame from the analysis in Section K.1. As explained in the previous paragraph, this approach would be significantly different from Western's required method of setting SLCA/IP rates. In addition, the schedule for completion of this analysis did not allow for the added time required.

K.2.4 Calculation of Net Electrical Energy Expense

Figure K.2-1 illustrates the method used to determine the yearly expense of electrical energy over the 20-year study period.

K.2.4.1 SLCA/IP Electrical Production

Data on the combined amounts of electrical energy produced by all of the SLCA/IP federal hydropower plants under each alternative were generated for the economic analysis described in Section K.1, and were used as input to the SLCA/IP wholesale rate analysis. The data are hourly over the 20-year study period. There is one set of these hourly data for each LTEMP DEIS alternative.

K.2.4.2 Sustainable Hydropower (SHP) and Available Hydropower (AHP) Capacity and Energy

Western's Energy Management and Marketing Office (EMMO) schedules electrical capacity and energy to serve FES customer energy requests. Each FES customer requests energy according to the terms and conditions of CRSP Management Center FES contracts. An FES customer can schedule an amount of energy to be delivered up to a specified capacity amount. This is known as the SHP capacity.[7] SLCA/IP FES customers also have a monthly amount of electrical energy that Western is obligated to deliver. A customer schedules the monthly allocation of electrical energy within the capacity limit mentioned above. This is known as the

[7] Specific descriptions of the terms and conditions of FES contracts will not be discussed here. The abbreviated descriptions provided here are intended only to explain the process of calculating the impact of the LTEMP DEIS alternatives on the SLCA/IP wholesale rate.

SHP energy allocation. Both capacity and energy amounts differ by customer and by month. Table K.2-1 shows CRSP Management Center current total SHP contractual obligations and project use required deliveries by month.

Because SLCA/IP FES customers are allowed to schedule SHP energy according to their individual needs, the hourly shaping of energy differs from day to day and from customer to customer. Therefore, it is necessary to estimate the aggregate daily shape of electrical energy schedules submitted to the EMMO by all FES customers. Western used average weekday, Saturday, and Sunday shapes for each month of WY 2014 to represent these schedules. When a holiday occurs, the load shape for Sunday is used. These SHP loads are provided in Table K.2-2.[8] In addition, the EMMO must serve project use loads that vary over time. Western used WY 2014 data, rather than averaging several years of loads or projecting different load shapes for future years, because the SHP daily shape does not differ substantially from year to year.

TABLE K.2-1 SHP Contractual Obligations and Project Use Required Deliveries by Month

	Firm Electric Service			Project Use		Total	
Month	Capacity (kW)	Energy (kWh)	CROD[a] (kW)	Capacity (kW)	Energy (kWh)	Capacity (kW)	Energy (kWh)
Jan.	863,726	463,462,717	1,403,777	7,639	4,200,824	871,365	467,663,541
Feb.	851,326	409,824,542	1,403,777	7,639	4,200,824	858,965	414,025,365
Mar.	765,761	422,665,276	1,403,777	42,539	21,916,824	808,300	444,582,100
April	638,196	365,283,663	1,317,779	52,634	23,184,158	690,830	388,467,820
May	623,515	378,216,775	1,317,779	52,634	23,184,158	676,149	401,400,933
June	646,035	397,635,769	1,317,779	52,634	23,184,158	698,669	420,819,927
July	740,916	434,536,678	1,317,779	52,634	23,184,158	793,550	457,720,836
Aug.	714,683	437,867,014	1,317,779	52,634	23,184,158	767,317	461,051,172
Sept.	618,576	380,082,095	1,317,779	52,634	23,184,158	671,210	403,266,253
Oct.	739,646	398,608,181	1,403,777	42,539	21,916,824	782,185	420,525,004
Nov.	775,589	408,041,232	1,403,777	7,639	4,200,824	783,228	412,242,055
Dec.	869,160	455,561,848	1,403,777	7,639	4,200,824	876,799	459,762,672

[a] CROD = Contract Rate of Delivery

[8] In some situations, it is difficult to separate customer SHP and project use loads that are submitted to Western's EMMO. For this analysis, it is conservatively assumed that the loads in Table K.2-2 are only SHP loads even though small amounts of project use loads are included. This assumption will have minimal impact on the results, since the same hourly loads are used for all alternatives.

TABLE K.2-2 SHP Hourly Load Shapes by Month and Type of Day

Month	Day of the Week	Hour of Day 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Oct.	Wkday	275	271	267	279	320	454	594	596	673	695	714	707	717	713	720	727	734	742	748	750	729	656	451	366
	Sat.	294	288	282	280	297	417	539	538	625	653	676	671	680	672	676	686	691	701	707	711	701	640	427	352
	Sun.	272	290	275	269	287	384	467	459	494	518	562	581	588	590	599	620	632	643	652	658	627	558	382	340
Nov.	Wkday	354	295	287	291	363	460	643	676	676	697	689	677	665	657	656	680	721	773	780	776	770	734	507	441
	Sat.	351	299	290	294	363	449	580	617	639	677	672	666	654	647	644	665	702	758	767	762	753	707	504	433
	Sun.	314	270	268	267	331	391	490	518	525	525	525	525	510	506	509	543	591	673	702	699	696	648	426	399
Dec.	Wkday	346	325	319	322	391	525	698	794	785	764	760	740	721	676	665	676	719	836	853	849	833	791	612	506
	Sat.	356	342	332	334	386	496	654	751	747	735	738	722	704	662	643	652	707	823	839	835	820	776	601	489
	Sun.	324	307	309	297	347	448	568	602	586	565	570	551	537	511	509	521	586	698	765	764	752	712	490	453
Jan.	Wkday	375	358	351	379	445	586	771	810	810	784	749	735	714	698	692	689	724	845	854	850	833	793	565	441
	Sat.	376	381	375	398	435	516	691	710	725	714	691	680	662	648	639	641	677	822	835	831	788	750	559	430
	Sun.	356	343	343	340	400	449	548	562	582	559	536	523	514	504	501	511	567	688	723	721	683	629	457	394
Feb.	Wkday	360	346	340	343	374	481	769	793	805	806	740	711	691	677	624	633	664	838	861	860	843	807	608	464
	Sat.	363	361	353	352	356	425	684	725	729	736	676	652	636	621	576	587	616	780	813	815	777	745	624	446
	Sun.	341	338	344	333	334	379	557	558	569	576	520	504	490	473	470	489	531	693	777	780	739	637	532	360
Mar.	Wkday	348	334	334	359	465	585	671	704	726	723	711	703	698	689	685	689	698	744	765	770	733	641	523	411
	Sat.	367	354	351	368	450	531	609	625	682	685	677	670	667	653	645	646	664	715	747	746	719	643	513	425
	Sun.	347	342	346	353	413	479	535	541	558	552	536	537	539	527	525	536	562	622	658	660	661	586	462	409
Apr.	Wkday	307	299	296	342	396	501	548	589	601	604	632	640	646	633	632	629	630	636	649	653	633	600	510	415
	Sat.	318	309	304	328	363	471	529	562	581	587	615	618	623	609	611	613	613	619	635	641	618	585	497	409
	Sun.	301	299	293	305	328	406	428	460	479	486	490	504	517	532	541	548	554	560	573	587	570	538	446	386
May	Wkday	379	339	335	345	412	513	552	593	609	630	632	641	640	637	633	642	644	657	647	645	641	615	528	452
	Sat.	392	358	348	354	397	488	510	523	560	595	600	607	607	607	605	619	622	639	636	638	631	602	524	467
	Sun.	373	333	323	326	368	449	463	469	480	506	557	580	582	584	584	589	593	613	609	612	604	573	509	413
Jun.	Wkday	475	435	398	422	438	519	605	634	672	681	681	685	691	691	691	696	695	692	682	681	673	666	632	511
	Sat.	474	442	420	404	401	473	549	606	640	658	667	675	679	680	681	687	686	681	675	675	662	648	626	507
	Sun.	410	395	410	403	375	396	446	457	471	501	521	571	576	592	599	612	608	604	599	607	594	572	548	491
Jul.	Wkday	478	428	425	421	443	553	582	617	649	675	685	711	747	751	752	756	755	771	762	761	736	693	609	554
	Sat.	489	443	428	423	441	520	562	576	605	653	669	700	738	739	741	745	743	758	754	748	723	678	598	532
	Sun.	449	418	442	438	442	509	526	526	542	610	624	635	683	702	707	710	708	721	714	695	671	629	577	528
Aug.	Wkday	499	433	413	412	438	531	644	678	667	667	679	696	727	763	764	768	766	761	757	745	736	700	663	571
	Sat.	490	446	431	414	429	510	594	638	631	640	662	680	720	760	762	767	764	759	753	740	728	691	656	572
	Sun.	472	402	425	421	402	424	484	491	511	552	616	633	677	683	683	686	687	688	683	674	665	609	589	561
Sep.	Wkday	428	394	391	399	440	500	549	576	608	616	621	623	637	663	666	668	667	663	661	657	652	646	577	512
	Sat.	446	392	382	378	408	467	502	548	594	605	612	613	628	652	653	656	654	653	653	648	639	629	567	501
	Sun.	400	383	375	375	395	436	471	476	492	521	564	605	620	638	640	643	653	650	649	645	641	629	546	478

When seasonal SLCA/IP federal hydropower resources are significantly greater than combined SHP commitments and project use loads plus the energy required to cover delivery losses,[9] the CRSP Management Center offers its FES customers capacity and/or energy above the SHP levels. These additional offers plus SHP are referred to as available hydropower (AHP). The methodology applied for the wholesale rate analysis offers a seasonal AHP, which is distributed monthly. The seasons that met the AHP offer criteria were largely a function of hydrological condition rather than of the alternative. Each of the seven alternatives had the same number of seasons that met the AHP criteria. The alternatives differed, however, in the amount of AHP that was offered.

Based on the sequence of hydrological conditions contained in the representative trace, AHP offers were calculated for any season that met the 20% excess AHP offer criterion; that is, an AHP offer is made only if hydropower resources in a season are at least 20% greater than the seasonal SHP level.

Western is required under its FES contracts to provide AHP, by season, when available. However, the contracts do not specify how much energy above SHP is required to make a seasonal AHP offer. There are no set criteria for offering AHP. It is the current practice of the CRSP Management Center to review and release information for the upcoming season and decide whether to offer AHP. CRSP Management Center power marketing managers confer with EMMO managers and consider anticipated release information, market prices, the amount of anticipated energy and capacity above SHP, and other factors in making an AHP offer for the upcoming season.

For the purposes of completing this analysis, CRSP Management Center managers and staff that are involved in the seasonal determinations were surveyed to establish a criterion based on past practices. The 20% trigger represents a reasonable amount of additional available hydropower that could be efficiently and equitably offered to Western's more than 135 customers. Offers to FES customers are made prior to the beginning of the season.[10] If the predicted energy production above AHP levels did not occur, and an AHP offer was made, the resulting short position must be resolved by energy market purchases. When available seasonal hydropower is less than 20% it is assumed that the excess energy would be offered to the market. The 20% trigger used for this analysis is for modeling purposes only and does not represent an established policy or practice.

The amount of AHP offered in a particular month was the smaller of the percent energy above the SHP energy and the percent capacity above the SHP capacity. Once this was determined, the SLCA/IP hourly energy delivery obligation (i.e., SHP load) was scaled by the

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9 Energy delivery losses were conservatively set equal to 8.5% of the total SLCA/IP hourly federal hydropower generation when computing FES rates and seasonal customer offers above AHP levels. This level is consistent with historical levels used for ratemaking, but somewhat higher than the 5% loss rate used for power systems economic analyses presented in Section K.1.

10 SLCA/IP power is marketing in two seasons: the "summer" season is April through September, the "winter" season is October through March.

appropriate percentage for each hour in the months that offer seasonal AHP. Project use loads were not adjusted.

AHP is sold to SLCA/IP FES customers at the FES energy rate. Since the FES energy rate is typically lower than the hourly spot market price, the addition of AHP tends to reduce CRSP Management Center revenues when compared to selling this excess (or long) energy to the spot market. There is typically a relatively minor (if any) financial impact on Western from offering AHP capacity. All SLCA/IP FES customers are billed monthly for the CROD capacity allocation, regardless of the particular SHP or AHP capacity allocation for the month. However, there is a financial impact on Western when SHP capacity offers exceed the amount available from SLCA/IP federal hydropower resources (due to, for example, the aforementioned forecast error), because Western must purchase capacity to fill the deficit.

Seasonal SLCA/IP federal hydropower generation is almost always either above or below the SHP obligation. The logic that is used to model this energy imbalance is shown in Figure K.2-1. If generation is below the SHP obligation, it is assumed that Western will be a net seasonal power purchaser and cover the short energy position via the spot market at spot market prices.[11] If generation is above the SHP obligation, the excess seasonal energy is sold to the spot market at spot market prices, unless it is a season in which the AHP offer criteria are met, in which case the seasonal excess energy is sold to SLCA/IP customers at the FES energy rate.

Although Western may be short during a specific season, on an hourly basis it may produce SLCA/IP federal hydropower in excess of FES SHP loads (i.e., FES customer energy requests). For example, during the middle of the night, under a steady flow alternative, loads may be less than generation. Likewise, there are some hours when hydropower resources produce less energy than loads when there is excess seasonal energy. Therefore, the wholesale rate analysis uses a methodology in which long and short positions along with associated costs and revenues are computed hourly under each alternative. Spot prices are the same scaled AURORA Western Interconnection LMPs at the Palo Verde hub that are used for power system economic analyses.

K.2.5 Calculation of Capacity Expenses and Total Net Costs

In addition to the annual net expense related to electrical energy for each alternative, Western will have a cost related to electrical capacity purchases or, in the case of Alternative B,

[11] Western's CRSP Management Center has several decades of experience with the vicissitudes of hydrological conditions in the Colorado River basin. There have been years in which electrical production from the SLCA/IP was inadequate to meet SHP commitment levels. Western once hedged its risk of dealing with this condition by making a long-term capacity and energy purchase. Outside of one instance, Western's firming purchases have only been on the day-ahead market or for a season when conditions were forecasted to require this.

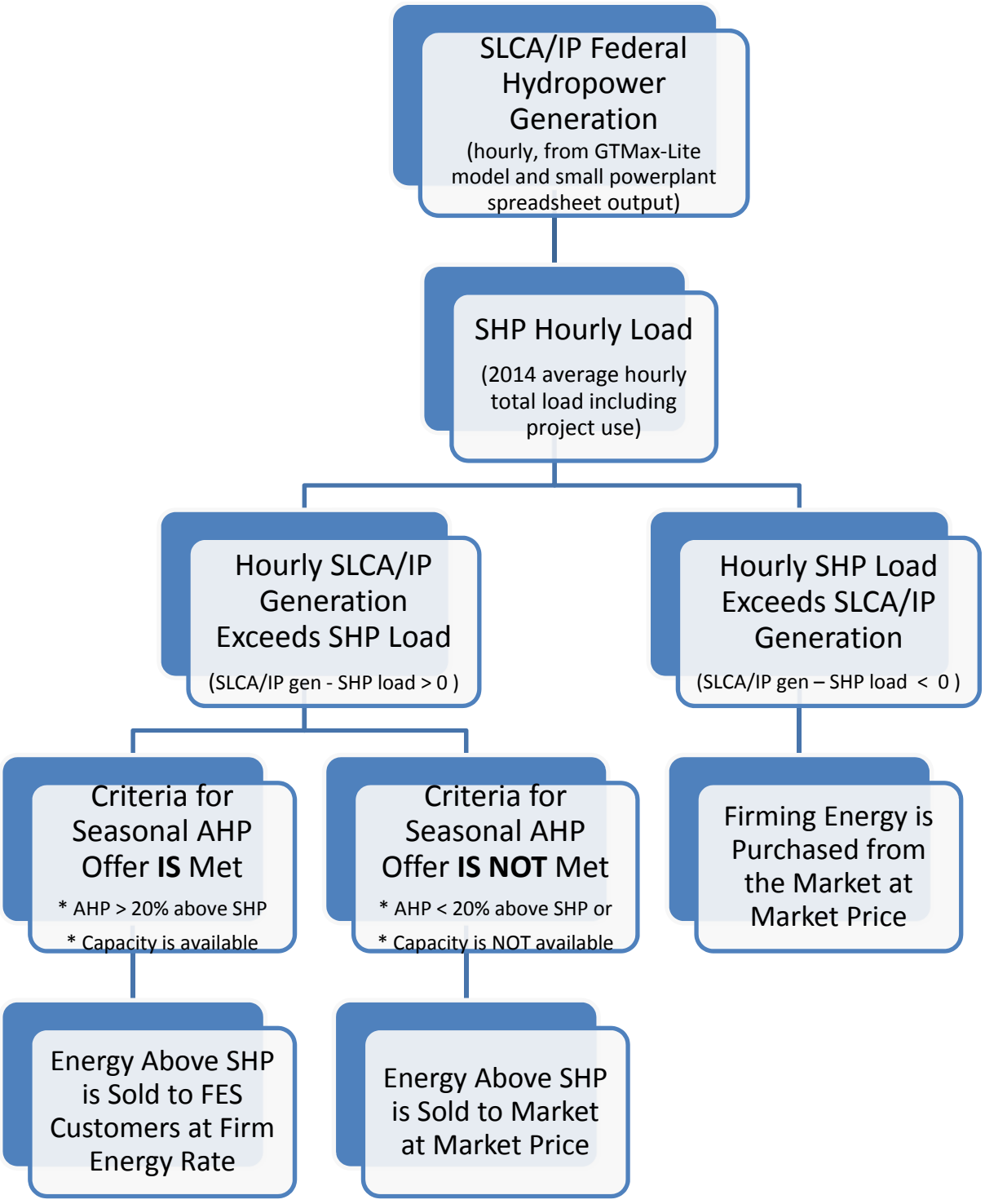

FIGURE K.2-1 Determination of Energy Hourly Expense or Revenue

capacity cost avoided.[12] As explained in Section K.2.1, an important requirement of this SLCA/IP wholesale rate analysis is to maintain compatibility with the economic analysis presented in Section K.1. The AURORA capacity expansion module applied in the analysis indicated that additional capacity facilities (construction of new generation) would be required over the 20-year LTEMP period. Table K.2-3 contains the same costs that were used in the power systems economic analysis described in Section K.1. It shows the capacity expense required over the 20-year period for each alternative.

The net energy expense for each alternative is computed as described above and illustrated in Figure K.2-2. Added to this figure is the capacity cost, by year, for each alternative. The sum of these two numbers is the total Western expense that is incorporated into the computation of wholesale rates (Figure K.2-2).

TABLE K.2-3 Total Levelized Capital and Fixed O&M Cost (million 2015$) for System Capacity Expansion by Alternative and Year

Year	Alternative A (No Action Alternative)	Alternative B	Alternative C	Alternative D (Preferred Alternative)	Alternative E	Alternative F	Alternative G
2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	0.0	0.0	0.0	0.0	0.0	12.2	0.0
2018	12.2	12.2	24.5	12.2	12.2	36.7	24.5
2019	46.7	46.7	58.9	46.7	46.7	71.2	58.9
2020	81.1	81.1	93.4	81.1	81.1	105.6	93.4
2021	81.1	81.1	93.4	93.4	93.4	105.6	93.4
2022	115.6	115.6	127.8	127.8	127.8	140.1	127.8
2023	150.0	150.0	162.2	162.2	162.2	174.5	162.2
2024	162.2	162.2	174.5	162.2	162.2	186.7	174.5
2025	174.5	174.5	186.7	174.5	174.5	199.0	186.7
2026	186.7	186.7	199.0	186.7	199.0	211.2	199.0
2027	199.0	199.0	211.2	211.2	211.2	223.5	211.2
2028	211.2	211.2	223.5	223.5	223.5	235.7	223.5
2029	235.7	223.5	235.7	235.7	235.7	248.0	248.0
2030	248.0	248.0	248.0	248.0	248.0	260.2	260.2
2031	260.2	260.2	260.2	260.2	260.2	272.5	272.5
2032	297.0	297.0	309.2	309.2	309.2	321.5	309.2
2033	309.2	309.2	321.5	321.5	321.5	333.7	321.5
2034	270.0	267.6	274.9	274.9	274.9	287.2	282.3

[12] Capacity in this context is LTF capacity that Western must acquire as a result of a reduction in Glen Canyon Powerplant output that is caused by a change in operating criteria specified under an LTEMP alternative. It is distinctly different from the short-term capacity discussed in the previous section that is dependent on natural short-term hydrological variability.

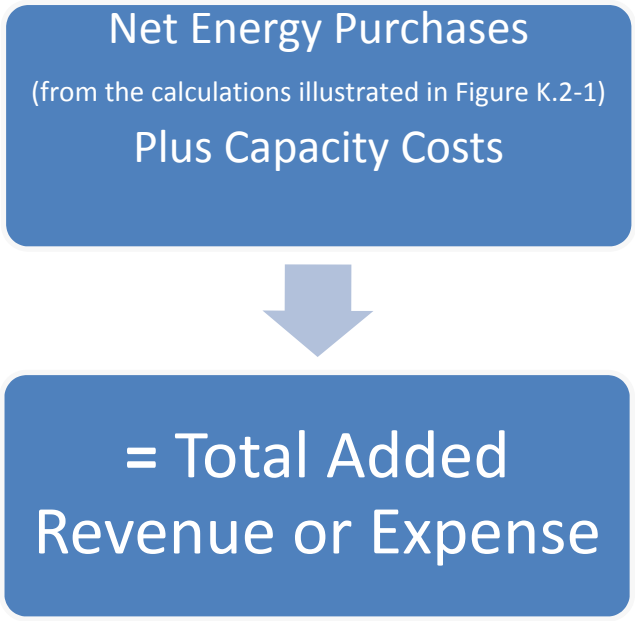

FIGURE K.2-2 Determination of Total Net Expense or Revenue by Year for Each Alternative

Table K.2-3 is a reproduction of a table from Section K.1. It is the estimated expense of capacity construction under each alternative. Alternative A includes capacity expenses, not because of a changed operation at Glen Canyon Dam or a change in SLCA/IP commitment levels by Western, but because of growth in electrical demand and the need for SLCA/IP customers to have to build new generating units to meet growing electrical demand. Based on the analysis described in Section K.1, existing generating units are sufficient to meet electrical demand until 2017.

The difference between the capacity expenses under Alternative A and the other alternatives is a function of how the LTEMP EIS alternatives affect the available capacity at Glen Canyon Dam. Differences in capacity expenses from Alternative A are a result of implementing the alternative. Table K.2-4 shows the differences in capacity expenses from Alternative A. The numbers in Table K.2-4 (differences from Alternative A) were used in this analysis. Notice that no capacity expense is required until 2018 under all alternatives except for Alternative F, which requires a capacity expense in 2017.

TABLE K.2-4 Total Levelized Capital and Fixed O&M Cost (in millions of 2015$) for System Capacity Expansion by Alternative and Year Expressed as the Difference from Alternative A

	Total Levelized Capital and Fixed O&M Cost (millions 2015$)—Difference from Alternative A					
Year	Alternative B	Alternative C	Alternative D	Alternative E	Alternative F	Alternative G
2015	0	0	0	0	0	0
2016	0	0	0	0	0	0
2017	0	0	0	0	12.2	0
2018	0	12.3	0	0	24.5	12.3
2019	0	12.2	0	0	24.5	12.2
2020	0	12.3	0	0	24.5	12.3
2021	0	12.3	12.3	12.3	24.5	12.3
2022	0	12.2	12.2	12.2	24.5	12.2
2023	0	12.2	12.2	12.2	24.5	12.2
2024	0	12.3	0	0	24.5	12.3
2025	0	12.2	0	0	24.5	12.2
2026	0	12.3	0	12.3	24.5	12.3
2027	0	12.2	12.2	12.2	24.5	12.2
2028	0	12.3	12.3	12.3	24.5	12.3
2029	-12.2	0	0	0	12.3	12.3
2030	0	0	0	0	12.2	12.2
2031	0	0	0	0	12.3	12.3
2032	0	12.2	12.2	12.2	24.5	12.2
2033	0	12.3	12.3	12.3	24.5	12.3
2034	-2.4	4.9	4.9	4.9	17.2	12.3

K.2.6 Western Replacement Resources

Using AURORA capacity expansion path modeling, the power systems analysis identified lost Glen Canyon Dam Powerplant capacity that would result from alternative-specific differences in operations and changed system capacity expansion paths. However, Western's FES power obligations are unaltered over the time period of this analysis, at least through FY 2024. Therefore, it is assumed for this analysis that Western purchases this capacity and incurs capacity firming costs.

When capacity in the region is in short supply, Western's firming purchases either include a capacity premium or Western makes a capacity purchase. For this analysis, it is assumed that Western purchases the electrical capacity projected by the AURORA capacity

expansion module. The capacity expenses included in this analysis are the differences from those for Alternative A.[13]

Western's purchase of electrical power to meet contractual obligations is a common occurrence. It is quite typical for Western to make these purchases during drier years with low release targets. Even in average years, Western purchases firming energy on some days or for some hours. Typically, Western purchases electrical energy on an hourly basis for the days or months ahead. However, Western's CRSP Management Center has also purchased firming energy for a future season or year. Western has also once contracted for electrical power and energy over a multi-year period.

It is also assumed that, when electrical capacity in the region is in short supply, utilities that buy electricity at a price that covers the average cost, including the cost of capital and fixed O&M. For this analysis, it is assumed that Western purchases the capacity needed to make up for losses in capacity that results from alternative-specific changes in Glen Canyon Dam operations (i.e., the difference between FES capacity and the alternative-specific SLCA/IP federal hydropower firm capacity that is based on a 90% exceedance level).

Electrical capacity additions by Western's FES customers are required under Alternative A over the 20-year analysis period, with existing SLCA/IP contractual obligations in place. These additions are required because of growth in electrical demand. However, if there is a change in the operation of Glen Canyon Dam that reduces the powerplant's firm capacity—as would occur under most of the LTEMP alternatives—additions to electrical capacity would be required.[14] The assumption used for this analysis is that Western purchases the capacity identified as the amount lost under each alternative, costing the amounts specified in Table K.2-3. The differences in total costs include levelized capital and fixed O&M between each alternative and Alternative A.

To be clear, Table K.2-3 is a duplication of the power economic analysis (Section K.1). Western would not incur the capacity expansion costs for Alternative A. Added capacity costs needed for load growth in Alternative A are not included. Only the differences in capacity costs between Alternative A and the other alternatives are included in the analysis.

K.2.7 Post-2024 Marketing Period

Western markets SLCA/IP electrical power under firm, long-term contracts. Under these contracts, Western is required to deliver this electrical power to federal points of delivery regardless of hydrological conditions or changes in the operational criteria of the SLCA/IP hydropower plants. The current FES marketing contracts expire on September 30, 2024. For the

[13] See Section K.1 for details on the generation types, years in which construction occurs, and pricing assumptions.

[14] This is not the case for Alternative B. Under Alternative B, Glen Canyon Dam marketable capacity is increased over that of Alternative A. Fewer capacity additions are required.

period following 2024, Western is currently engaged in developing a marketing plan. This requires a formal public process in compliance with applicable federal law.

For the purpose of completing this analysis, certain assumptions had to be made. First, it was assumed that Western will continue with its current SLCA/IP obligations until the current marketing period ends and the existing contracts expire.[15] This requires that Western deliver the same amount of electrical power and energy to SLCA/IP customers until the end of FY 2024, regardless of the alternative analyzed. Second, recognizing that there is a period of uncertainty between 2025 and 2034, net firming expenses for the post-2024 time period were analyzed under two sets of assumptions. These are as follows:

- A continuation of existing SLCA/IP FES contract commitments between FY 2025 and FY 2034 (no change); and

- A reduction in SLCA/IP FES contract commitments so that net firming expenses are equal to $0 between FY 2025 and FY 2034. This means, for the numbers included in the SLCA/IP power repayment study, zero dollars of firming expense and zero additional dollars of revenue from market sale or from AHP sales (resource available).

These two assumptions constitute "bookends" regarding the outcomes possible in the development of the post-2024 marketing plan.[16]

These bookends are for modeling purposes only. They represent a very broad range of possible FES obligations of electrical power in the post-2024 marketing period.

Obligations of electrical capacity under the current marketing plan were based on a 90% exceedance level (i.e., the amount of hydropower capacity available 90% of the time). This level of marketable capacity is consistent with marketing plans established by other Western regional offices. In establishing power obligations for the post-2024 marketing period, Western will consider the capacity and energy available from the SLCA/IP units including those at the Glen Canyon Dam Powerplant and will establish, through a public process, an appropriate and reasonable amount of marketable capacity and energy to provide to FES customers. The range of

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15 There is a provision in the existing SLCA/IP contracts to modify the FES obligations upon a 5-year notice to SLCA/IP customers. However, considering the probable timing of new operating criteria for the Glen Canyon Dam following the completion of the LTEMP DEIS and the issuance of a ROD, a 5-year notice would not be significantly different than the end of the current marketing period.

16 Western could choose a post-2024 SLCA/IP FES obligation of electric power that exceeds its current obligation. However, prior to completion of the required public process it would be difficult to determine what the higher obligation would be that could be considered a reasonable bookend. Moreover, the time-frame available to complete this analysis required that the analysis be simplified. The assumption that the post-2024 SLCA/IP FES obligation continues existing commitments was easier to accomplish since much of the data related to this assumption was produced in Section K.1.

SLCA/IP impacts described for these bookends will almost certainly encompass the actual rate impact, once the post-2024 marketing plan is completed.

It should be noted that the establishment of these bookends is not an attempt to predict or to anticipate Western's choice prior to the conclusion of the required public process. This is an analysis, not a description of policy or attempt to predict Western's post-2024 marketing plan. This set of bookends is intended to reflect the range of reasonable possibilities. It is reasonable that Western would continue existing commitment levels to ensure continued customer access to the transmission associated with the energy. Moreover, it is also reasonable to believe that Western would establish post-2024 marketing plan commitments that exactly follow the power resource available at the SLCA/IP power system.

K.2.8 Power Repayment Studies to Determine Rate Impacts

Western sets rates as low as possible consistent with sound business principles to repay the federal government's investment in generation and transmission facilities in addition to specific non-power costs that power users are legislatively required by Congress to repay, such as irrigation costs that are beyond the irrigators' ability to repay. Sales of federal electric power and transmission repay all costs (including interest) associated with generating and delivering the power. Western prepares a PRS for each specific power project to ensure the rates are sufficient to recover expenses, including O&M, transmission, interest, replacement/upgraded equipment, purchased power, and wheeling. The PRS consists of two parts: historical data and future forecasted data. The historical data is a record of project repayment from the beginning of the project to the most recent year for which audited financial data are available. The first future year in the PRS is the first year for which forecasts, rather than actual data, are used. The last future year in the PRS must cover the final year allowed for repayment of historical investment.

Although the tool used to calculate the PRS has changed many times in the past, the principles underlying project repayment have not. These principles are summarized in U.S. Department of Energy (DOE) Order RA 6120.2 that governs project repayment and financial reporting for the DOE Power Marketing Administrations. In addition to Order RA 6120.2, Western's PRSs must meet the Federal Energy Regulatory Commission's rate filing requirements and procedures in 18 CFR Part 300.

K.2.8.1 PRS Expenses

All annual costs that are to be repaid by power customers must be included in the PRS. These costs include O&M, purchased power, transmission and other expenses, and interest expense,. Interest expense is calculated by multiplying each investment's prior year unpaid balance by the appropriate interest rate.

Tables K.2-5 and K.2-6 show the total net purchase power costs for each year for each alternative. These tables show net purchase power expenses only. They do not include other O&M expenses, interest or principle payments. Positive numbers indicate net purchase power

TABLE K.2-5 Total Net Purchase Power Expenses (thousand 2015$) by Year and Alternative for the Continuous Current Obligations Scenario[a]

Year	Alternative A (No Action Alternative)	Alternative B	Alternative C	Alternative D (Preferred Alternative)	Alternative E	Alternative F	Alternative G
2015	31,200	29,800	35,300	32,000	31,600	44,100	34,800
2016	96,900	95,200	93,500	98,300	96,800	104,200	98,800
2017	68,600	68,800	70,500	69,700	70,300	89,920	73,800
2018	49,500	74,100	68,320	54,200	51,500	87,930	72,020
2019	17,700	13,300	30,820	22,900	18,000	49,730	38,220
2020	34,700	33,000	48,220	37,100	35,700	69,930	53,020
2021	31,400	29,900	48,420	47,920	46,920	70,630	52,620
2022	4,350	3,650	13,020	14,750	15,400	26,780	16,570
2023	–82,550	–79,810	–63,220	–67,640	–67,550	–59,290	–66,150
2024	–36,580	–33,010	–6,710	–43,190	–41,360	–20,400	–36,130
2025	–70,810	–69,840	–55,780	–64,110	–70,420	–47,120	–59,360
2026	11,480	11,990	24,340	9,370	24,860	45,600	11,620
2027	29,400	29,900	46,320	53,320	45,120	68,830	62,320
2028	52,200	50,100	69,820	69,820	68,920	89,930	80,920
2029	75,000	60,680	76,800	77,000	76,100	99,620	97,220
2030	66,800	66,000	67,700	67,700	66,800	91,120	86,620
2031	89,100	89,900	95,300	94,600	93,400	115,420	120,720
2032	70,900	70,200	84,320	84,120	83,420	108,630	91,520
2033	67,800	66,500	84,820	84,920	84,020	107,730	91,720
2034	35,900	31,240	48,130	46,830	46,230	71,540	72,020

[a] These numbers are compared to a condition in which generation is just equal to SHP obligations. Positive numbers indicate net firming purchases. Negative numbers indicate revenues collected above a condition in which generation is just equal to SHP obligations.

expenses. Negative numbers indicate that generation from SLCA/IP power plants is sufficient to meet SHP obligations and include additional sales of electricity to FES customers (AHP) or additional sales to the market. The numbers in these tables are net purchase power expenses compared to a condition in which electrical generation is just sufficient to meet SHP obligations without firming expenses and without sales of surplus electricity to FES customers or to the market. Note that the negative numbers occur in the years 2023-2025 and carry across all the alternatives in these years. These are the wettest years of the representative trace used for this analysis..

Table K.2-5 is purchase power for the scenario in which the existing SLCA/IP commitment levels for energy and capacity are maintained. Table K.2-5 is purchase power for the scenario in which Western reduces its commitment levels, post-2024, to just the amount of

TABLE K.2-6 Total Net Purchase Power Expenses by Year and Alternative for the Reduced Obligations to Match Resource Scenario[a, b]

Year	Alternative A (No Action Alternative)	Alternative B	Alternative C	Alternative D (Preferred Alternative)	Alternative E	Alternative F	Alternative G
2015	31,200	29,800	35,300	32,000	31,600	44,100	34,800
2016	96,900	95,200	93,500	98,300	96,800	104,200	98,800
2017	68,600	68,800	70,500	69,700	70,300	89,920	73,800
2018	49,500	74,100	68,320	54,200	51,500	87,930	72,020
2019	17,700	13,300	30,820	22,900	18,000	49,730	38,220
2020	34,700	33,000	48,220	37,100	35,700	69,930	53,020
2021	31,400	29,900	48,420	47,920	46,920	70,630	52,620
2022	4,350	3,650	13,020	14,750	15,400	26,780	16,570
2023	–82,550	–79,810	–63,220	–67,640	–67,550	–59,290	–66,150
2024	–36,580	–33,010	–6,710	–43,190	–41,360	–20,400	–36,130
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0

[a] These numbers are compared to a condition in which generation is just equal to SHP obligations. Positive numbers indicate net firming purchases. Negative numbers indicate revenues collected above a condition in which generation is just equal to SHP obligations.

[b] Zeroes indicate that no purchase power expenses are required to firm to contract obligations. Other expenses; operations, maintenance, repayment of investment and interest payments continue.

energy and capacity provided by the resource. These data were developed as described above and include the following:

- Purchase power expense net of additions to revenue from the sale of AHP, and
- Cost of capacity including capital and fixed O&M expenses relative to Alternative A.

K.2.8.2 PRS Revenue Distribution

The CRSP Management Center uses a balloon payment methodology for repayment of project costs. This means that principal payments for capital costs are not due until the end of

their repayment period. For example, if an investment has a repayment period of 50 years, the total principal payment can be made in the 50th year. The revenue distribution described in this section, and the PRS calculations described in the next section, pertain to the balloon payment methodology.

Within the PRS, electrical power revenues within the year must first be applied to the annual O&M costs. Interest expense is considered an operational cost, but it is the last in priority. After all annual costs are paid, capital costs must be repaid in the following order: (1) required principal payments, (2) deficits, and then (3) the highest interest-bearing investment. Required payments are payments on those investments that still have an unpaid balance at the end of their repayment period.

K.2.8.3 The SLCA/IP PRS

The SLCA/IP PRS includes the revenue requirements for the CRSP, Collbran, and Rio Grande projects, which were integrated for marketing and ratemaking purposes on October 1, 1987, in addition to two participating projects of the SLCA/IP system that have power facilities, the Dolores and the Seedskadee Projects. The CRSP Management Center forecasts 5 years of firming purchased power in the PRS. This reflects the firming purchase power requirements between projected generation and FES contract obligations. For the remaining future years, a forecast of $4 million per year is projected to cover operational purchase power costs for the EMMO located in Montrose, Colorado.

Western used the FY 2015 preliminary SLCA/IP PRS as the template to calculate the rate impacts for all the alternatives. The generation, project use, energy, and capacity values for each alternative were updated in the PRS, and the rate was computed for each alternative. The rate-setting period in the PRS is determined by calculating the revenue requirement from the first future year through the year with the highest revenue requirement, which is referred to as the pinch-point year. For this rate analysis, the first future year used in the template is FY 2018. The pinch point used in the template is FY 2025 and is driven by a multi-million dollar Aid-to-Participating-Projects required payment due that year. Consequently, the rate-setting period for the template, from the first future year to the pinch point, is FY 2018 through FY 2025. The revenue requirements are recovered through a 50/50 split between the energy and capacity rates. Three rates calculated in the PRS are energy, capacity, and composite.

The energy rate is the rate that sets forth the charges for energy. It is expressed in mills/kWh and is applied to each kilowatt-hour delivered to an FES customer. The energy rate is estimated by a rates specialist and manually entered in the PRS, and a study is run to determine if the rate is sufficient to cover costs without creating a deficit. If the study produces a deficit balance, a new rate is entered into the PRS and the study is run again. The estimated rate is increased until the study no longer produces a deficit.

The capacity rate is the rate that sets forth the charges for capacity. It is expressed in $/kW-month and applied to each kilowatt of the CROD. The formula for the capacity rate is linked to the energy rate and is simultaneously updated to ensure the revenue requirement is recovered through a 50/50 split between the capacity and energy rates.[17]

The composite rate is the rate for firm power, which is the total annual revenue requirement for capacity and energy divided by the total annual energy sales. It is expressed in mills/kWh and used for comparison purposes only. The composite rate is calculated after the energy rate is computed and the rate-setting period is established. The composite rate, in mills/kWh, is calculated as the ratio of the total revenue required during rate-setting period to the total projected sales during the rate-setting period.

K.2.8.4 Standard PRS Rate-Setting Method Versus the Method Used in This Analysis

In order to accurately compute the impact of each alternative in terms of energy and capacity rates, projected power purchases for the entire rate-setting period of 2015 through 2034 were used. This deviates from Western's normal 5-year forecast in order to accurately capture each alternative's rate impacts. Table K.2-4 shows power purchase costs, assuming that current FES obligations would continue after FY 2024, and Table K.2-5 shows results for the marketing structure that would incur zero firming expenses after 2024. Table K.2-6 shows the SLCA/IP rate impact for each alternative.

K.2.9 Results

Table K.2-6 shows the estimated SLCA/IP energy and capacity rates by alternative. This reflects Western's current method of billing. SLCA/IP FES customers are billed monthly for the amount of energy used and for their capacity allocation. A composite rate is an index number that includes the energy and capacity rates together and may be useful for comparison purposes.

Table K.2-7 shows that there is a significant difference between the "bookend" assumptions. Comparing the composite rate, the No Change condition results in higher SLCA/IP rates across all alternatives compared to the Resource Available condition. For the No Change condition, the highest rate occurs under Alternative G (38.75 mills/kWh). The lowest SLCA/IP

[17] The production of hydropower that Western markets requires the construction of a dam and water storage. The fuel for these hydropower facilities is water, which is costless. Under the law, Western is required to set "cost-based" rates. If Western used marginal cost to set capacity and energy rates, the energy rate would be zero or near zero. It has been Western's practice to set FES rates so that 50% of the revenues collected through the sale of power are through the capacity rate and 50% of the revenues collected are through the energy rate. Other Federal power marketing agencies use different rate-setting strategies, but their rates are also required to be cost-based. The "50/50 split" is not a legal requirement, but, rather, a common Western practice.

TABLE K.2-7 SLCA/IP Rate Impact by Alternative

	Alternative A (No Action Alternative)		Alternative B		Alternative C		Alternative D (Preferred Alternative)		Alternative E		Alternative F		Alternative G	
	NC[a]	RA[b]	NC	RA	NC	RA	NC	RA	NC	RA	NC	RA	NC	RA
Pinch-Point FY	2031	2055	2031	2055	2031	2055	2031	2055	2031	2055	2025	2057	2031	2055
Composite (mills/kWh)	32.64	25.19	32.69	25.07	33.77	25.65	33.65	25.22	33.41	25.16	37.79	27.53	38.75	26.65
Energy (mills/kWh)	13.52	13.40	13.54	13.22	13.99	14.55	13.94	13.78	13.84	14.01	15.67	16.86	16.07	15.22
Capacity ($/kW-month)	5.74	5.69	5.75	5.62	5.94	6.18	5.92	5.85	5.88	5.95	6.66	7.16	6.83	6.50

[a] NC = No change from current FES commitment levels.

[b] RA = Resource available. Commitment level equals available SLCA/IP federal hydropower resource.

rate occurs under Alternative A (32.64 mills/kWh), although Alternative B is almost the same rate (32.69 mills/kWh). The range is 6.11 mills/kWh, with Alternative G producing a rate that is 19% higher than Alternative A (the no action alternative). The Resource Available condition produces similar results. The lowest SLCA/IP rate occurs under Alternative B (25.07 mills/kWh), almost identical to Alternative A (25.19 mills/kWh). Under this condition, the highest SLCA/IP rate occurs under Alternative F (27.53 mills/kWh). The range is smaller under this condition with Alternative F producing a rate that is 2.46 mills/kWh or 10% higher than Alternative B.

It is worth noting that under either of the post-2024 "bookend" conditions, Alternatives A, B, C, D, and E produce similar SLCA/IP rates. Alternatives F and G produce significantly higher SLCA/IP rates.

As described previously, the no change and resource available bookends are used for modeling purposes only and do not represent estimates or indications of the post-2024 commitment levels that may result from the public process. Alternative impacts on SLCA/IP rates illustrated in Table K.2-7 are good indications of the rank order of the alternatives and the direction of impacts (positive or negative), and they encompass the range of the actual future rate impacts once the post-2024 marketing plan has been implemented. For the final LTEMP EIS, assumptions concerning post-2024 commitment levels may be revised to duplicate the range examined in the economic analysis described in Section K.1. This would be a SLCA/IP capacity obligation based on the 99th, 90th, and 50th percentile exceedance levels. The resulting range will likely be somewhat narrower than the results of the bookend analysis presented in this draft.

K.2.9.1 Pinch-Point Year

Table K.2-7 includes pinch-point year information. The pinch point is the year in which the largest revenue requirement occurs in the future and is influential in setting the SLCA/IP rate.

There were three common pinch points that occurred when determining alternative-specific rates:

- 2025, caused by a required Aid-to-Participating-Projects Payment (Duchesne);
- 2031, caused by purchase power expense; and
- 2055, caused by a required Aid-to-Participating-Projects Payment (Starvation Reservoir).

As described in Section K.2.3, Western's SLCA/IP rates are set to assure repayment of all authorized water projects. In the current PRS, repayment of existing projects and repayment of yet-to-be constructed water projects will be completed in 50 years. The pinch-point is the year in which the largest future revenue requirement occurs. These pinch-points occur when a large water project – or "block" of a large water project – requires a repayment. After this pinch-point year, revenues are sufficient to complete repayment of remaining water projects. Therefore, it is said that the pinch-point year drives the rate.

Higher purchase power requirements require increasing the revenue requirement in the pinch-point year. Because the amount of purchase power is not consistent across alternatives, neither is the revenue requirement. The pinch-point year varies among alternatives because of the variation of purchase power amounts by alternative. It is not possible to use a consistent pinch-point year because each alternative produces different annual revenue requirements, and therefore a different schedule for completing repayment. The only way to have a consistent pinch-point year is to have consistent revenue requirements across each alternative.[18] With a fixed rate, the lower the purchase power, the more revenue available for discretionary repayment of investments which reduces annual interest and ultimately the annual revenue requirements. Conversely, increases in purchase power reduce the amount available for repayment on investment which leads to higher interest payments and subsequently, higher annual revenue requirements.

[18] One could argue that the SLCA/IP rate analysis should "force" the SLCA/IP rate to have the same pinch-point year for each alternative so that the impact of the alternatives is a more "apples to apples" comparison. This was considered as an approach, but it was decided that forcing such a condition would require a significant change in the rate-setting process. Moreover, it may be useful to the reader to know how alternatives differ in terms of their effect on setting a pinch-point year.

K.2.10 Definitions Used in Section K.2

Available Hydropower (AHP): The amount of SLCA/IP electrical energy and/or capacity available to FES customers for either the summer or winter seasons. This is designated for each month of the season.

Aid to Participating Projects: This is the part of an authorized irrigation/water project that is assigned to power for repayment. There is an assigned amount in the PRS for each authorized project.

Composite Rate: This is not a rate that is used for billing purposes. It is for comparisons. One takes the capacity rate and the energy rate, assumes a load factor and calculates the average rate per kilowatt-hour.

Contract Rate of Delivery (CROD): the amount of capacity allocated to an FES customer, by season, for the marketing period. It represents the "ceiling" obligation. An FES customer can utilize AHP capacity up to this amount.

Colorado River Storage Project (CRSP): Federal hydropower facilities in the Upper Colorado River Basin including Glen Canyon, Flaming Gorge, Fontenelle and the Aspinall Units.

CRSP Management Center: Western's Colorado River Storage Project Management Center. This is the Western office that has the responsibility for marketing the SLCA/IP power resources and for setting SLCA/IP FES rates.

Federal Energy Regulatory Commission (FERC): A federal commission that regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines as well as licensing hydropower projects. The FERC has limited jurisdiction over Western's rates, but must ensure that Western's project rates are sufficient to repay authorized projects.

Load Factor: A proportion of average energy used over a specified time period compared to peak demand for the same time period.

No Change Scenario (NC): This scenario represents a post-2024 condition where Western continues its current obligations to provide capacity and energy from the SLCA/IP resources.

Pinch Point Year: In setting the SLCA/IP FES rate, this is the year in which the highest payment obligation exists. It is said to "drive" the rate.

Project Use: Electrical capacity and energy reserved to power authorized water projects.

Power Repayment Study (PRS): this is the name of the model used by Western to set rates. PRS models are project specific.

Resources Available Scenario (RA): This scenario represents a post-2024 condition where Western reduces its current commitment of SLCA/IP energy and capacity to exactly match the production of power from the SLCA/IP resources.

Sustainable Hydropower (SHP): The amount of SLCA/IP electrical energy and capacity available to FES customers over the course of the marketing plan. This is the "firm" commitment that Western, in low release conditions, must firm up. There is an SHP capacity and energy amount for each month of the season.

Salt Lake City Area Integrated Projects (SLCA/IP): The Collbran, Rio Grande, and the Colorado River Storage Projects were integrated by Western in 1986 for marketing and rate-setting purposes.

K.3 IMPACTS ON RETAIL ELECTRICITY RATES

This section documents effects of Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) alternatives on retail electricity rates and bills. Retail rate impacts measure how LTEMP alternatives affect electricity bills paid by household and business consumers who buy electricity from utility systems that directly or indirectly receive power from the Salt Lake City Area Integrated Projects (SLCA/IP) through Western Area Power Administration (Western). These impacts are documented in three sections that first explain the methodological approach then summarize results and finally present the impacts.

K.3.1 Analysis Approach

Retail rate and residential bill impacts are derived from the power systems analysis (described in Section K.1), SLCA/IP allocations, and publicly available retail rate and sales data using various allocation formulas. The foundation of the analysis is a database of retail sales, retail rates, and SLCA/IP energy allocations for utility systems that are given preference in power allocation from the SLCA/IP (referred to here as preference power). Rate impacts are based on the assumption that the capital, operating, and administrative costs of Glen Canyon Dam do not substantively change under different LTEMP alternatives when the energy output from the dam changes. Because these operating and administrative costs are not affected by the LTEMP alternatives, rate impacts result from changes in the cost associated with replacing capacity and/or energy with changes in dam operations. The wholesale power costs associated with changes in dam operations are labeled "grid costs" and include costs of replacement capacity, changed production costs (fuel costs, purchased power costs, and variable operation and maintenance [O&M] costs), and differential fixed O&M costs. Using the retail data along with aggregate grid costs, the retail rate impacts of the LTEMP alternatives were determined for the vast majority of municipal, cooperative, and other entities that directly or indirectly receive preference power from SLCA/IP. A separate analysis was made for American Indian Tribes using SLCA/IP allocations to the Tribes combined with contract price data for special arrangements that are made with Tribes for SLCA/IP energy and capacity. The special contract

arrangements imply that rate impacts for Tribes are generally greater than the rate impacts for non-Tribal systems. This analysis is presented in Section K.4.

The primary output from the rate impact analysis is a set of figures and tables that present the percent increase or decrease in electric rates and the changes in monthly electricity bills paid by residential consumers of municipal utilities, cooperative distribution utilities, Tribal authorities, and irrigation districts. (Retail consumers include businesses households and other institutions, while residential only includes households.) The rate impacts of different LTEMP alternatives are presented relative to Alternative A (the no action alternative). Rate impacts were estimated for all of the utility systems that have available retail energy sales data published by the Energy Information Agency (EIA) and incorporated more than 90% of entities that receive power from the SLCA/IP in terms of energy allocation. Entities for which rate impacts cannot be measured directly because of a lack of publicly available data include direct retail consumers such as military bases, universities, and the DOE Albuquerque office. In addition to computing rate impacts for companies with available data from the EIA, retail rate impacts for American Indian Tribes were calculated. This calculation used data from utility systems that serve the Tribes at a retail level combined with the effects of net benefit contracts between the Tribes and wholesale utility systems that directly compensate for wholesale power. Contracts between Tribes and wholesale systems to provide benefits are termed net benefit contracts. This analysis is presented in Section K.4.

Four primary tasks were undertaken to compute the rate impacts on retail consumers. These tasks were:

1. Compiling retail energy sales ($), rate ($/MWh), and residential bill ($/month) data for each utility system directly or indirectly receiving an allocation of SLCA/IP federal preference power;

2. Computing year-by-year grid costs under LTEMP alternatives from the power systems analysis and analyzing how the capital cost of new capacity is translated into retail revenue requirements (the capital recovery factor or carrying charge rate);

3. Allocating the aggregate grid cost impacts under LTEMP alternatives to individual retail utility systems; and,

4. Presenting the disparate retail rate and residential bill impacts over time for different systems.

Three information sources, as illustrated in Figure K.3-1, were used to compute the rate impacts of LTEMP alternatives. The first set of inputs for the analysis was a database of sales, rates, and SLCA/IP allocations for utility systems that receive federal preference power from the SLCA/IP. The second set of inputs consisted of the aggregate grid cost combined data from the power systems analysis with capital recovery charge analysis that represents the wholesale power costs. The third set was macroeconomic data from the Energy Information Administration (EIA) (EIA 2015b,c). These inputs were used to determine the relative rate impacts for individual

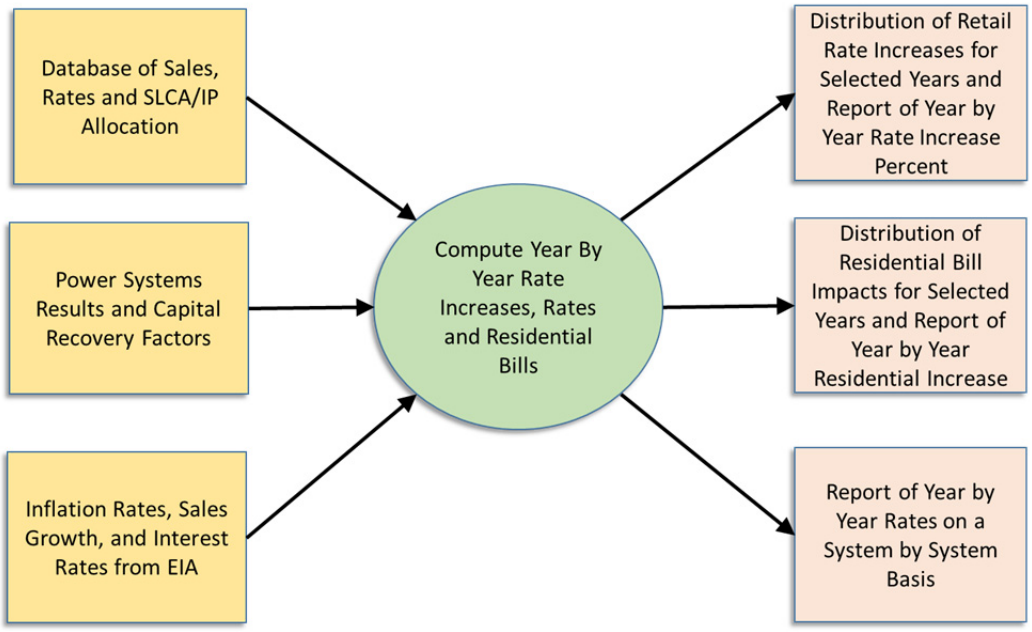

FIGURE K.3-1 Flowchart Diagram of Rate Impact Analysis Process

systems from different LTEMP alternatives. Varying impacts on individual systems were largely driven by (1) the amount of preference power allocated to each system relative to the total generation resources of the system, and (2) the current retail rate, which influences the percentage change calculation (a higher rate results in a smaller percent change).

Explanations of analytical methods for determining rate impacts are organized around Figure K.3-1. The next three sections explain the data input items listed on the left side of Figure K.3-1. Section K.3.1.4 describes details of the calculation process referenced in the middle of Figure K.3-1, and Sections K.3.2 and K.3.3 describe the rate impacts that are cited on the right side of the figure. Additional description of the process to compute rate impacts for American Indian Tribes appears in Section K.4.

K.3.1.1 Database of Sales, Rates, and SLCA/IP Allocation for Retail Utility Systems

The explanation of the database is separated into two parts that address: (1) how a list of utility systems that receive federal preference power from SLCA/IP and distribute power to retail residential, commercial, industrial and other consumers was compiled; and (2) how retail statistics are gathered for utility distribution systems from Form EIA-861 detailed data files (EIA 2015a).

List of Utility Systems that Distribute Power to Retail Consumers

Developing the database for retail rate analysis involved arranging a list of utility systems that sell electricity on a retail basis and that directly or indirectly receive SLCA/IP federal preference power allocations. The starting point for this list is tabulating utility systems that receive federal preference power from SLCA/IP. Western provided this information in a spreadsheet of allocations for the period October 1, 2008, through September 30, 2024 (Osiek 2014). The allocation data included information for 154 different systems that receive separate preference power allocations.

Some of the utility systems listed in the Allocation Report do not sell power on a retail basis to residential and business retail consumers. Five systems including (1) the Wyoming Municipal Power Agency (WMPA), (2) the Utah Municipal Power Agency (UMPA), (3) the Platte River Power Authority (Platte River), (4) the Colorado River Commission of Nevada (CRCN), and (5) Tri-State Generation and Transmission Cooperative (Tri-State) receive preference power allocations from SLCA/IP and then re-allocate power to distribution systems. Table K.3-1 shows that these five indirect systems comprise 47% of the total SLCA/IP federal preference power. Deseret Generation and Transmission Cooperative and the Utah Associated Municipal Power Systems are not included in the five indirect allocation entities because for these two systems, each of their member distribution systems receives distinct direct allocations.

For the systems with indirect allocation listed in Table K.3-1, it is necessary to compile retail sales and rate data on all of the individual systems that sell power to retail consumers because the larger wholesale systems do not sell to retail consumers. A list of retail entities that are members of indirect retail systems (e.g., distribution cooperatives [co-ops] that are members of Tri-State) have been obtained from Websites for the five indirect allocation utility systems (CRCN 2015; Platte River Power Authority 2015; Tri-State 2015; UMPA 2015; WMPA 2015).

TABLE K.3-1 Energy Allocations for Systems Receiving Indirect SLCA/IP Allocations

System	Annual SLCA Energy Allocation (MWh)	Percent of Total Allocation
Systems Receiving Indirect Allocation		
Wyoming Municipal Power Agency	24,753	0.50%
Utah Municipal Power Agency	290,604	5.87%
Platte River Power Authority	502,467	10.15%
Colorado River Commission of Nevada	88,212	1.78%
Tri-State Generation and Transmission	1,424,012	28.76%
Subtotal Systems with Indirect Allocation	2,330,048	47.05%
Systems Receiving Direct Allocation	2,621,739	52.95%
Total Energy Allocation	4,951,787	100.00%

After including the retail systems that are members of indirect allocation utilities, the total number of retail utility systems in the database increases from 154 to 226.

Retail Statistics for Distribution Utility Systems from the Form EIA-861 Database

Rate impact calculations for each entity required data for residential and nonresidential sales revenues and sales quantity. The primary source for the existing retail rates and retail residential, commercial, industrial, and other energy sales is the Form EIA-861 database (EIA 2015a). Data for direct retail consumers such as military bases and most American Indian Tribes are not included in the EIA database. After adjusting for complications associated with differences in system names, historical data availability, and systems the operate in multiple states, 91% of the preference power can be associated with retail sales data available in the EIA 861 database as shown in Table K.3-2. Additional data for American Indian Tribes is derived from utility companies that serve the Tribal Reservation along with wholesale utility systems that are the SLCA/IP benefit crediting partners (see Section K.4). Tribal entities that provide data to the EIA 861 database (representing the figure of 44.19% in Table K.3-2) included Ak-Chin, Tohono O'odham Reservation, and the Navajo Tribal Utility Authority. These three systems operate their own utilities and do not have special contracting arrangements to secure their SLCA/IP allocation. After accounting for special net benefit contracts used by Tribal Authorities combined with retail utilities that serve the Tribes, the coverage of Tribes is 100%.

TABLE K.3-2 Coverage of Retail Information from EIA Database Relative to SLCA/IP Preference Power Allocation[a]

System	SLCA Annual Energy Allocation (MWh)	Percent of Total Energy Allocation	SLCA Energy with Retail Sales	Percent of Energy With Retail Sales
WMPA, UAMPS, UMPA, CRCN, Platte River	1,231,926	24.87	1,229,054	99.77
Tri-State, Deseret	1,840,470	37.15	1,840,470	100.00
Co-ops not Included in Larger Entities	210,951	4.26	210,951	100.00
Electric Districts and Irrigation Districts	123,588	2.49	108,401	87.71
Municipalities not in JAAs (including SRP)	921,408	18.60	921,408	100.00
Military Bases	70,550	1.42	0	0.00
Tribal Authorities	464,030	9.37	205,051	44.19
Universities and DOE Office	91,401	1.84	0	0.00
Total	4,954,323	100.00	4,515,334	91.14

[a] Note: CRCN = Colorado River Commission of Nevada; JAA = Joint Action Agency; SRP = Salt River Project; UAMPS = Utah Associated Municipal Power Systems; UMPA = Utah Municipal Power Agency; WMPA = Wyoming Municipal Power Agency.

K.3.1.2 Incorporation of Power Systems Analysis and Capital Recovery Factors

The second category of information input to the rate impact analysis shown in Figure K.3-1 is projected grid cost data derived from the power systems analysis and capital recovery factors. The amount of annual aggregate capacity (in MW) that is added on an annual basis, the total annual variable production cost, and the fixed O&M costs for new capacity are obtained from the power systems analysis described in Section K.1. The amount of capacity that needs to be added under each LTEMP alternative due to changes in operations is converted to revenue requirements using a carrying charge analysis combined with the projected cost of constructing new generating plants.

To integrate power systems analysis with the rate impact calculations, selected results are summed together over the different systems that are simulated. Aggregating data from the power systems analysis across the large systems that were modeled and then allocating those costs to individual systems means that, in terms of the rate impact analysis, there is no difference in treatment between the small systems and the other eight utilities modeled in the power systems analysis. Equations used to convert the generation cost and capacity expansion data to aggregate grid cost impacts are listed below, where *t* represents the annual period, *i* represents the LTEMP alternative, and *c* represents the capacity type. The summation is over the new capacity type:

$$\text{Capacity Cost}_{t,i} = \sum \text{New Capacity}_{t,i,c} \times \text{Capacity Cost}_{t,i,c} \times \text{Carrying Charge Rate}_{t},$$

$$\text{Fixed O\&M}_{t,i} = \sum \text{Accumulated Capacity}_{t,i,c} \times \text{Fixed O\&M Cost/kW-yr}_{c}, \text{ and}$$

$$\text{Grid Cost}_{i,t} = \text{Production Cost}_{i,t} + \text{Capacity Cost}_{t,i} + \text{Fixed O\&M}_{t,i}.$$

Carrying Charge Factors Applied to New Capacity That Account for Ownership and Financing Structures of Municipal and Cooperative Systems

Rate impacts cannot be directly calculated from outputs generated by the power systems analysis because of the manner in which plants are financed. The annual cost of new capacity that is charged to consumers is established from dollar amounts that are paid to bondholders who lend money for constructing a new plant. Annual funds collected to compensate for the cost of building new capacity is termed the "capital recovery factor" or the "carrying charge rate." A detailed analysis has been made of carrying charges for individual municipal and cooperative systems as part of the rate impact analysis. The carrying charges used data from financial reports and derived revenue requirements from changes in the quantity of generating capacity. The analysis includes effects of municipally financed debt, debt service requirements, the tenor of debt, and other assumptions including the interest rate. Some of the considerations in deriving the carrying charge analysis include:

- The carrying charge for purposes of the rate impact depends on the debt structure used to finance the investment. If the bond repayment period is not the same as the plant life and/or the bond repayment does not increase with inflation (both of which are generally true) then the capital recovery for

purposes of the rate impact analysis is different than the economic carrying charge used in the power system analysis;

- The carrying charge for rate impact analysis does not reflect differences in risks associated with generating alternatives that are borne by consumers (for example, the capacity from Glen Canyon Dam already exists, while the ultimate cost of capacity from new generation plants has uncertain capital and operating costs);

- The carrying charge for rate impact analysis is affected by the debt service coverage and other specific features of bonds issued to finance construction for municipal and cooperative systems;

- The year-by-year carrying charge measured using actual interest rates relevant for measuring rate impacts is flat over the prospective tenor of the debt (by contrast, the real carrying charge used in economic analysis in the initial year of the plant life is lower than subsequent years);

- The carrying charge for generation and transmission cooperatives may be affected by patronage capital that is generally part of the financing of a new powerplant;

- The interest rate used in the calculation of carrying charges for rate impact analysis should reflect the credit rating and the tax status of entities that will finance the new construction; and

- The interest rate used for the carrying charge analysis changes over time when interest rates change (as projected by the EIA).

The carrying charge rates implemented in the rate impact analysis are shown on Figure F.3-2. The carrying charges applied in the rate impact simulation are a weighted average of the carrying charges for taxable (e.g., co-op) and municipal financing. The weighted average is derived from the energy allocations for (1) systems that issue taxable debt (co-ops and irrigation districts), and (2) systems for which the interest is exempt from federal income taxes (municipal systems). The weighted average carrying charge that converts one-time capital costs for construction of new capacity into projected annual revenue requirements begins at a level of 7.03% in 2015 and eventually increases to 8.50% (the middle line in Figure K.3-2). By contrast, if the same interest rate and inflation assumptions were applied to computing economic carrying charges, the real capital recovery factor would only be 4.38% in 2014. This higher carrying charge increases measured rate impacts.

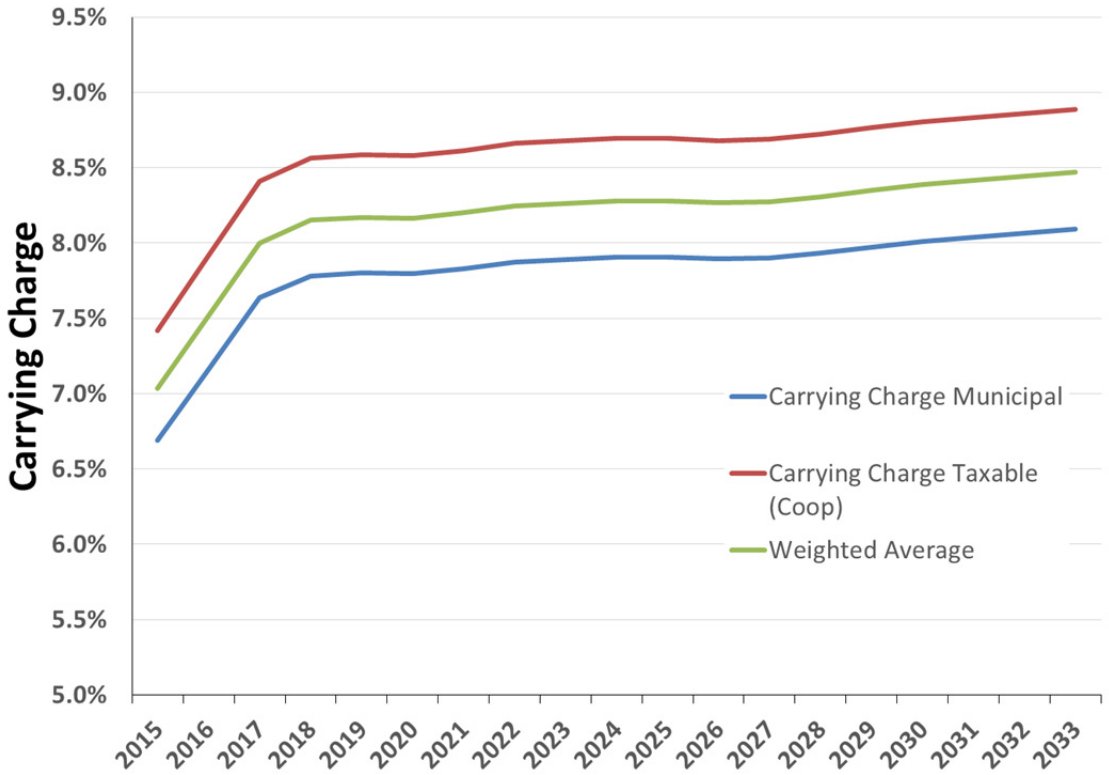

FIGURE K.3-2 Projected Carrying Charge Rates Used in Rate Impact Analysis

K.3.1.3 Inflation Rates, Sales Growth, and Interest Rates from EIA

The third set of input data presented on the left side of Figure K.3-1 consists of general macroeconomic variables that drive the prospective level of base retail rates for each utility system. Macroeconomic factors include the expected level of electricity rates and the expected level of retail sales growth in the southwest region, as well as future interest rates for the municipal and cooperative systems. Data for these items has been derived from information provided in EIA regional forecasts presented in the 2015 Annual Energy Outlook (EIA 2015b). Projections from the EIA annual outlook (EIA 2015c) are also used for macroeconomic data including prospective inflation rates and interest rates.

K.3.1.4 Calculation Process for Computing Rate and Bill Impacts

The middle of Figure K.3-1 represents calculations made for computing rate impacts after the inputs are established. The computations of rate impacts for individual systems involve a series of allocations under each LTEMP alternative. Figure K.3-3 shows three allocation procedures that were part of calculating rate impacts. The first allocation involved attributing total grid cost to individual utility systems using SLCA/IP allocation data (shown in red in Figure K.3-3). For the indirect allocation systems defined in "List of Utility Systems that Distribute Power to Retail Consumers" above, a second allocation involved attributing SLCA/IP

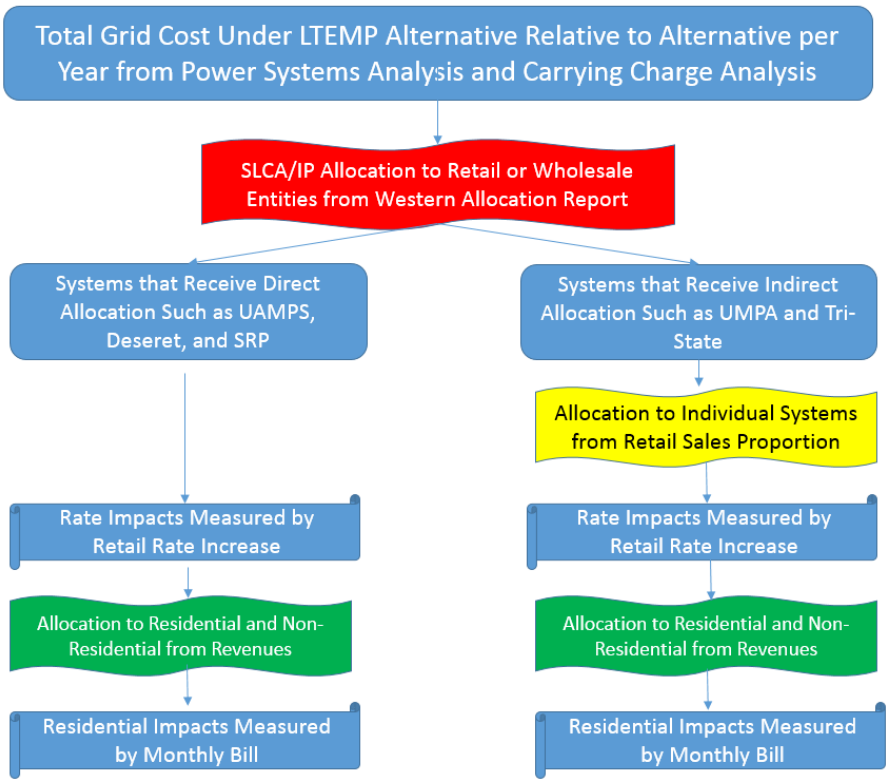

FIGURE K.3-3 Flowchart Diagram of Allocation Process

power from the Generation and Transmission Cooperative or the Joint Action Agency to individual members (shown in yellow in Figure K.3-2). These two allocations define impacts measured by the percent change in retail rates. The only allocation that involves assumptions with respect to utility-specific ratemaking processes is the computation of residential bill impacts. To compute the residential bill impact, costs must be allocated between residential and nonresidential consumers (shown in green in Figure K.3-2). For this allocation, the assumption is made that capacity and energy costs are allocated in the same proportion as existing overall rates.

Then next five sections describe the allocation process used to compute the rate impacts. The first section explains why wholesale rates were not needed in the allocation process and how the aggregate grid cost impacts can be compared to SLCA/IP wholesale revenues. The second section describes the allocation of aggregate grid costs to different systems, and the third section describes the allocation process for indirect systems. The fourth section explains the allocation process for residential rates, and the final section demonstrates the process with a case study.

Using Grid Costs Rather than SLCA/IP Wholesale Rates for Computing Retail Rate Impacts

A fundamental concept underlying the rate impact analysis is that rate impacts of LTEMP alternatives occur because of differences in alternatives with regard to capacity that is lost and

energy that must be purchased during different periods, not Western's cost structure. Western must collect the same amount of revenue to cover its costs under all of the LTEMP alternatives, even though marketable capacity has declined and timing of energy production has changed. For LTEMP alternatives that increase grid cost relative to Alternative A, retail consumers must in one way or another pay for replacing capacity and more expensive energy. This implies that rate impacts can be computed directly from grid costs rather than Western wholesale tariffs. For benchmarking purposes, the average annual real grid cost impacts are presented relative to the dollar amount of revenues collected by Western presented in Section K.3.2.2. Wholesale grid costs used as the basis for computing rate impacts are also compared to the aggregate wholesale amounts that would be paid under projected SLCA/IP rates described in Section K.2. This analysis is described in detail in Section K.3.6, where the aggregate incremental grid cost for each alternative is compared to the aggregate wholesale power cost that would be paid under wholesale SLCA/IP rates computed in Section K.2. Table K.3-15 (presented in Section K.3.6) demonstrates that for LTEMP alternatives other than Alternative G, the SLCA/IP wholesale rates would result in lower measured impacts than the aggregate grid costs.

The fact that retail rate impacts can be computed without separate calculations of Western wholesale rates can be demonstrated with a hypothetical example of three rate calculation approaches, the first of which does not include wholesale rate calculations, while the second and third apply different possible changes in wholesale tariffs that result from various LTEMP alternatives. All three of the wholesale rate techniques result in the same retail rate impact. The first method does not require measurement of SLCA/IP wholesale rates and is consistent with the approach illustrated in Figure K.3-3. Using this approach, rate impacts are computed by directly allocating grid costs under different LTEMP alternatives. The second method assumes that Western increases wholesale capacity charges to cover the fixed costs associated with lower amounts of capacity from changes in Glen Canyon Dam operations. This method assumes that the utility systems themselves procure the capacity and energy to make up for the changes in dam operations. The total amount of wholesale revenues received by Western does not change in this second method, and the utility systems themselves incur the increased grid costs in this scenario. Because Western's revenues do not change and utilities procure the capacity and energy deficits created from the LTEMP alternatives, the second scenario produces the same revenues as the first method, in which wholesale rates are not considered. The third approach assumes that Western, instead of the utility systems, procures the deficient capacity and energy. This means the grid cost impacts are included in the Western wholesale rates and, from the perspective of the utility systems, the capacity quantity does not change. The same amount of capacity and energy must be procured by Western as would be procured by the individual utility systems. Ultimately, SLCA/IP rates change in different LTEMP alternatives to cover changes in the cost of capacity and energy.

Allocation of Aggregate Grid Costs to Retail Systems

The primary allocation formula applied to compute rate impacts involves allocating total grid costs to different systems using the annual SLCA/IP energy as reported in Osiek (2015). This allocation process, illustrated in red in Figure K.3-3, is represented by the following

equation (recall that retail rates include rates to residential, business, and other consumers served by the utility system):

Retail Change for Individual System Relative to Alternative A ($) =
[SLCA/IP Energy Allocation to Individual System (MWH) /
Aggregate SLCA/IP Energy Allocation to All Systems (MWH)] ×
Aggregate Grid Cost Impact of LTEMP Alternative Relative to Alternative A ($).

SLCA/IP energy allocation in the above formula is applied by summing the summer and winter energy allocation for each system listed in Osiek (2015). The actual allocation that determines the amount each system pays for SLCA/IP power involves both energy and capacity and is differentiated by season. This raises the question of whether summer capacity, winter capacity, summer energy, and winter energy should be applied in a more complex allocation process. The question is resolved because the allocation shares to individual systems would be virtually identical if either the capacity or energy allocation were used. This is demonstrated by the fact that the annual load factor in SLCA/IP allocations is similar across different systems. If the load factor across systems is the same, then allocation of total grid costs using either capacity or energy will result in the same percentage of aggregate grid cost being attributed to each individual system. The similarity of annual load factors (average hourly energy for the winter and summer divided by the average summer and winter capacity) is illustrated in Figure K.3-4. Because the load factor is nearly identical for almost all distribution systems in Figure K.3-4, the use of capacity or energy does not influence the allocation process.

Given total retail revenues attributed to individual systems, the calculation of percent change in retail rates from LTEMP alternatives can be represented by the two formulas shown below. In these formulas, t is a subscript for the year and i represents the individual system. The term Retail $\text{Change}_{t,i}$ shown in the equation is the result of equation presented at the beginning of this section.

$\text{Rate Change Percent}_{t,i} = \text{Retail Change}_{t,i} / \text{Retail \$ Revenue under Alternative A}_{t,i}$

Retail Revenue under Alternative $A_{t,i}$ comes from retail revenue for each individual system that is part of the database. Increases in retail revenues from sales growth and from price increases after the base period are calculated from the EIA energy outlook for the Southwest region as represented by the following equation:

Retail Rate ($/MWh) under Alternative $A_{t,i}$ = Retail Rate under Alternative $A_{t-1,i}$ ×
(1 + Electricity Price Inflation from EIA_t) × (1+1 + Sales Growth from EIA_t).

SLCA/IP Energy for Indirect Allocation Systems

The second allocation issue highlighted in Figure K.3-3 involves allocation of SLCA/IP energy and capacity to individual retail entities from systems that receive indirect allocations. For the indirect allocation systems other than Tri-State (WMPA, UMPA, Platte River, and CRCN), the allocation of SLCA/IP energy to individual member utility systems is made on the

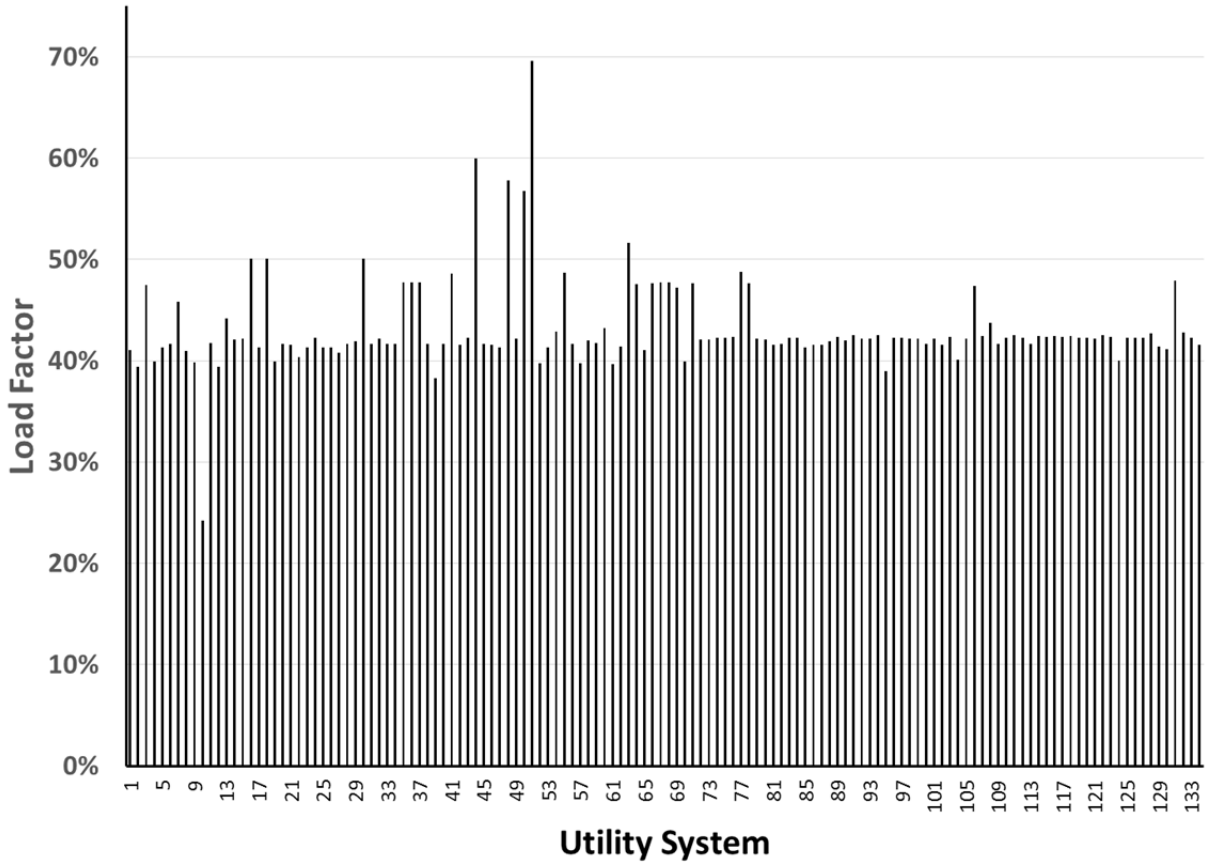

FIGURE K.3-4 Load Factors of SLCA/IP Power (Source: Osiek 2015)

basis of the retail sales proportion. Retail sales of the individual member system is divided by aggregate retail sales accumulated for the wholesale system (e.g., WMPA). The percentage of retail sales is multiplied by the aggregate SLCA/IP allocation to the large system reported in Osiek (2015). For Tri-State, the same general process was used, with the exception that distribution cooperatives in Nebraska are not assumed to receive any SLCA/IP preference power and are not included in the aggregate sales calculation. The method for allocating SLCA/IP energy to individual distribution systems that are part of the larger indirect allocation systems can be represented by the following equation:

Allocation of SLCA/IP to Distribution Entity (MWh) =
[Annual Retail Sales of Distribution Entity (MWh) /
Total Aggregate Retail Sales of Distribution Systems in Group (MWh)] ×
Total SLCA/IP Allocation to Group (MWh).

Allocation Process from Computing Residential Bill Impacts

The final allocation process illustrated in Figure K.3-3 is the allocation of overall retail revenues (residential and non-residential revenues) to residential consumers and computation of

residential bills. Calculation of residential bills involves two steps. The first step is to allocate a portion of the total retail increase for the system to residential consumers. This allocation is made with the ratio of residential revenues to total retail revenues for each system. Using the residential revenue percent, the dollar amount of change in residential revenue under LTEMP alternatives relative to Alternative A can be represented by the following equation:

$$\text{Residential Revenue Change } \$_{t,i} = \text{Change in Grid Cost}_{t,i} \times \text{Residential Percent}_{i}.$$

The second step is computing the monthly residential bill change from residential revenue change. The change in monthly residential bill relative to Alternative A is computed by dividing the total residential revenue change by projected residential consumers and then by 12. The number of residential consumers is projected through dividing the overall sales growth by 2 (implicitly assuming half of the growth is from increased use per customer). Calculation of monthly residential bills relative to the Alternative A is demonstrated in the equations below:

$$\text{Residential \$ Bill Increase}_{t,i} = \text{Residential \$ Increase}_{t,i} / \text{Residential Customers}_{it} / 12,$$

where:

$$\text{Residential Customers}_{it} = \text{Residential Customers}_{i,t-1} \times (1+\text{Sales Growth EIA}_{t}/2).$$

Case Study Illustration of the Allocation Process

The process of calculating rate impacts can be demonstrated by considering a case study. Tri-State is used to show how aggregate grid costs are allocated to determine rate impacts and why wholesale rates are not necessary in computing retail rate impacts. To demonstrate how rate changes are established, the grid cost impact under Alternative F in the highest impact year is used. On an aggregate basis, grid costs in this case increase by $41 million (in real 2015 dollars) relative to Alternative A. Tri-State members had retail revenues of $1.476 billion (computed from aggregating revenues for the Tri-State systems excluding the Nebraska members using the database).[20] Tri-State energy allocations represent 29.0% of the total SLCA/IP (derived from the allocation report and recorded in the database). The amount of grid cost increase allocated to Tri-State can be computed as 29.0% multiplied by the aggregate grid cost change of $41 million, or $11.89 million. Note this calculation is made without any wholesale rate calculations. This calculation implies that the increase in average retail rates for Alternative F in the high-impact year across Tri-State member systems is $11.89 million/$1,476 billion = 0.81%.

The same retail rate calculation can be made by first computing impacts on SLCA/IP wholesale rates. Using the current capacity and energy allocations, Western revenues collected from SLCA/IP power are current published rates multiplied by aggregate allocations. Total revenues from multiplying capacity charges by total SLCA/IP capacity and energy charges by

[20] By comparison, Tri-State's wholesale revenues were $1.019 billion in 2013, as reported in its Financial Report (Tri-State 2015).

total SLCA/IP energy sum to approximately $143 million. The total increase in wholesale rates would then be 28.67%, or $41 million/$143 million, if Western did not change capacity and energy allocations in the SLCA/IP tariff. Tri-State payments for wholesale power without the increase are the Tri-State allocation percent multiplied by total SLCA/IP revenues or 29.0% × $143 million = $41.47 million. For Tri-State, the increase in wholesale costs is 28.67% × $41.47 million = $11.89 million. Thus, the wholesale cost increase is the same whether it is calculated directly from aggregate grid costs as in the last paragraph or whether it is computed using wholesale rates as in this paragraph, and the $143 million of revenues collected from wholesale rates is not necessary for computing retail rate impacts. The wholesale impact of $11.89 million translates into the same retail impact of 0.81% discussed above. The example demonstrates that a large wholesale rate increase of 28.87% translates to a much smaller retail rate impact.

Rate Impact Measurement for American Indian Tribes

A detailed retail rate impact analysis has been prepared for American Indian Tribes. The analytical approach and results are described in Section K.4.

K.3.2 Results

Retail rate and residential bill changes are affected by the aggregate grid costs that occur under the various LTEMP alternatives relative to Alternative A. Once grid cost changes are established (that correspond to SLCA/IP wholesale rate changes), differential retail rate changes experienced by individual systems are affected by the amount of power that a system receives from SLCA/IP relative to total generation resource requirements of the system. The ratio of SLCA/IP allocation to retail sales for a particular system is termed the "preference ratio." Measurement of aggregate grid cost and the effect of SLCA/IP allocation guide presentation of the rate analysis in this section. The first part measures the aggregate grid cost change relative to wholesale revenues that are currently collected for SLCA/IP capacity and energy. Second, differential retail rates for individual systems are explained in the context of the preference ratio.

K.3.2.1 Grid Cost Changes Relative to Western Wholesale Revenues

Retail rate impacts of LTEMP alternatives relative to Alternative A are relatively small for individual utility systems. This is because grid cost impacts are spread over a wide consumer base and because SLCA/IP is only one out of a multitude of generating resources for the retail utility systems. Given the small rate impacts on retail systems, changes in annual grid costs relative to the total SLCA/IP revenues are introduced to provide a benchmark for comparing LTEMP alternatives. Table K.3-3 presents the average annual real grid cost increases per year from 2015 through 2035 (the LTEMP period) for LTEMP alternatives relative to Alternative A. (Grid costs that include capacity costs and production costs are defined in Section K.3.1.) Table K.3-3 shows that using the benchmark of wholesale revenues collected for SLCA/IP federal preference power, the increase in annual real grid costs divided by current wholesale

TABLE K.3-3 Average Annual Grid Cost Relative to SLCA/IP Wholesale Revenues Relative to Alternative A

Alternative	Average Annual Grid Cost Increase Relative to Alternative A (in thousands of 2015$)	Western Revenues from SLCA/IP Capacity and Energy Charges (in thousands of 2015$)	Percentage Change Relative to Western Revenues	Average Capacity Differential Relative to Alternative A After 2017 (MW)	Maximum Capacity Differential in Single Year Relative to Alternative A (MW)
A		143,000	0.00%		-
B	(976)	143,000	–0.68%	(13.53)	(230.00)
C	9,820	143,000	6.87%	189.41	230.00
D	6,831	143,000	4.78%	121.76	230.00
E	6,392	143,000	4.47%	135.29	230.00
F	28,751	143,000	20.11%	392.35	460.00
G	17,218	143,000	12.04%	230.00	230.00

revenues is as much as 20% for Alternative F. The grid cost increase is between 4% and 5% of current SLCA/IP wholesale revenues for Alternatives E and D. Capacity differences between the respective LTEMP alternatives and Alternative A, presented as the capital recovery of capacity costs, are the most important drivers of grid cost changes. The average annual capacity that is constructed under Alternative A that corresponds to the two right-most columns in Table K.3-3 is 2,701 MW.

K.3.2.2 Retail Rate Changes for Individual Systems and SLCA/IP Power Relative to Total Resources

Variation among retail rate changes for individual utility systems under different LTEMP alternatives are driven in large part by the ratio of SLCA/IP energy allocation compared to the total generation resources required for the system. Using the database described in Section K.2.1.2, the proportion of SLCA/IP power to total resources can be measured by computing the ratio of SLCA/IP annual energy allocation to total retail sales. If this preference ratio is low for a retail utility system, then even a relatively large increase in SLCA/IP costs will probably have a small rate impact. Figure K.3-5 displays the range in preference ratios for individual systems, together with the size of the systems, in a scatter plot. The size of the system on the x-axis is represented by annual retail sales. The y-axis of the graph demonstrates that the range in preference ratio varies from less than 1% to more than 60% for different systems in the database. Points in the upper left corner of Figure K.3-5 demonstrate that most of the systems with high preference ratios are small. This is likely due to the history of allocations for preference power. If a system was small when it originally received a preference power allocation, but has subsequently grown large, it will have a relatively lower ratio of SLCA/IP allocation to retail sales (sales have increased and the SLCA/IP allocation has remained the same). On the other hand, if a system has not grown much since the original allocation was made

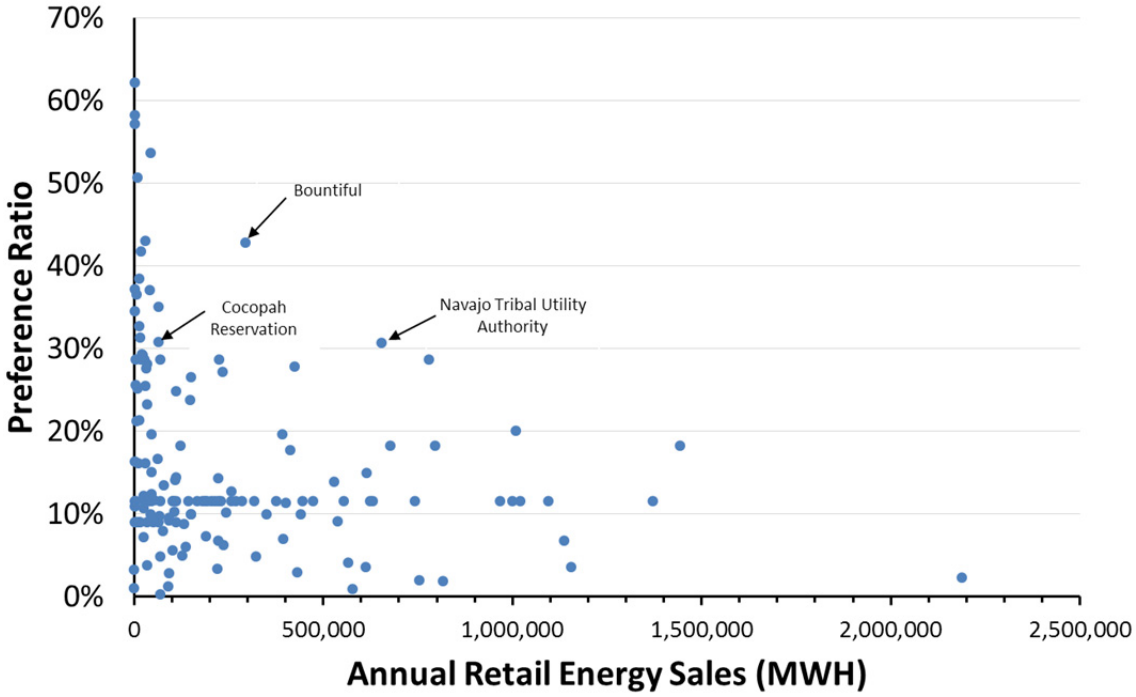

FIGURE K.3-5 Scatter Plot of Preference Ratio and Annual Retail Sales

(i.e., it is a small system with relatively low retail sales), the preference ratio could remain relatively high.

Two of the Tribes that provide data to the EIA 861 database are highlighted in Figure K.3-5 as background for the rate impacts that are discussed in Section K.3.4.[21] The Navajo Tribal Utility Authority represents a large proportion (about 40%) of the SLCA/IP allocation to Tribes.[22] Figure K.3-5 shows that the Tribes with EIA data do have relatively high preference ratios. The only other utility system with a relatively high preference ratio that is not a very small system is the City of Bountiful, a member of UAMPS (highlighted in Figure K.3-5).

The relationship between the preference ratio and rate changes for individual systems is demonstrated by scatter plots of the percentage retail rate change and the preference ratio. In the scatter plots, the retail rate change is measured relative to Alternative A, implying that a scatter plot for Alternative A is not meaningful. Figure K.3-6 presents scatter plots of the preference ratio and the percent rate change relative to Alternative A for Alternatives B through G. In

[21] Fifty-three different Tribal entities receive capacity and energy allocations from SLCA/IP, representing 8.85% of the total energy allocation. Because the Tribes do not report sales and revenues as part of Form EIA-861 database, accessing sufficient data to make individual rate impact assessments was not possible. Instead, the analysis focused on two Tribal systems: Navajo Tribal Utility Authority and the Cocopah Reservation.

[22] Retail data for the Navajo Tribal Utility Authority was derived from its Integrated Resource Plant (IRP) and Website (https://ww2.wapa.gov/sites/western/es/irp/Documents/NTUA2012.pdf) rather than from the EIA-861.

displaying the scatter plots for each LTEMP alternative relative to Alternative A, a single year is selected so that each system represents a single point. In each panel of Figure K.3-6, the year shown is the year with the highest rate impact for the respective LTEMP scenario. Because the highest rate changes do not occur in the same year for the various LTEMP alternatives, as explained in Section K.3.3.2, the scatter plots use different years.

The scatter plots shown in Figure K.3-6 demonstrate that much of the rate impact on individual systems is driven by the preference ratio. For each of the panels in Figure K.3-6, a regression equation of the percent retail rate change versus the preference ratio is displayed. The R^2 statistic displayed on each of the panels is 0.87. This indicates that 87% of the variation in percentage rate change can be explained by variation in the preference ratio. The 13% of variation in percentage retail rate changes that is not explained by the preference ratio represents other factors that include the level of retail rates, the load factor of the system, distribution costs, and the capacity and energy costs paid for non SLCA/IP power.

Scatter plots displayed in Figure K.3-6 have differently scaled y-axes. The y-axes represent the range in possible rate changes for the respective LTEMP alternative in the year with the highest (absolute value) percent change. The upper end of the y-axis therefore represents the absolute maximum retail rate percent increase for the LTEMP alternative across systems. Finally, regression equations are presented in each panel of Figure K.3-6 that shows the relationship between the preference ratio and the percent retail rate change in the year with the maximum change for each LTEMP alternative. These regression equations can be used to approximate rate impacts for systems that are not included in the database, as explained in the next section.

K.3.2.3 Using Regression Equations to Approximate Retail Rate Changes for Systems Not Included in the Database

For small Tribal systems and other entities that do provide retail sales and rate data to the EIA, the rate impacts can be approximated using the regression equations shown in Figure K.3-6. To compute rate impacts for systems that are not directly evaluated in the database, the preference ratio should be computed first through dividing annual SLCA/IP energy allocations by the retail electricity usage of consumers for the system. This preference ratio can then be multiplied by the coefficient shown in each of the panels of Figure K.3-6. For example, under Alternative F in the high-impact year, the coefficient is 0.074. If the ratio of SLCA/IP energy to total energy consumption is 50% for an entity such as a U.S. Air Force base or for a Tribe that does not report to the EIA, the estimated rate increase would be 3.7% (0.074 × 50%).

K.3.3 Summary of Impacts

Retail rate and residential bill impacts under the LTEMP alternatives were compiled for 147 different utility systems during the LTEMP period, 2015 to 2035, on an annual basis. The retail rate impacts and the residential bill impacts under Alternatives B–G are presented relative to Alternative A. Due to the large number of retail utility systems that receive federal preference

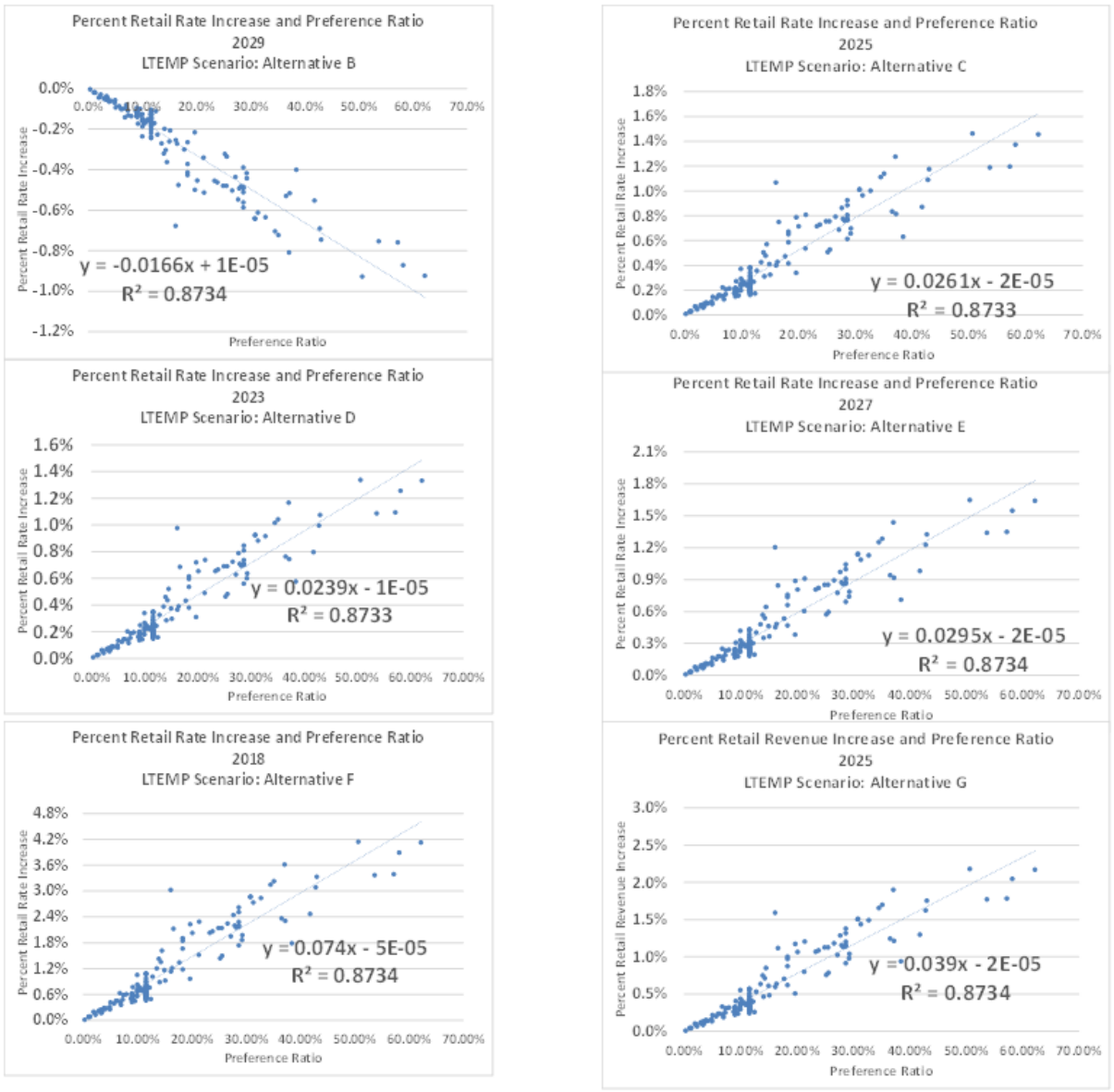

FIGURE K.3-6 Scatter Plots of Percent Retail Rate Change and the Preference Ratio

power and the number of LTEMP alternatives, various different techniques were used to summarize the rate impact results.

Rate and bill impacts are presented in four parts. First, the aggregate impacts are averaged across all systems and across the entire LTEMP period. Second, the impacts of LTEMP alternatives are presented on a year-by-year basis averaged across all systems. This section also includes a summary comparison of maximum-impact-year rate and bill impacts across different LTEMP alternatives. Third, rate and bill impacts for specific utility systems are listed under different LTEMP alternatives and the impacts under each LTEMP alternative are discussed. Fourth, the rate impacts on small systems and Tribes are explained.

K.3.3.1 Average Rate Impacts under LTEMP Alternatives over the 20-Year LTEMP Period

To demonstrate the general magnitude of rate impacts and evaluate the relative impact of different LTEMP alternatives on retail electricity rates, impacts are presented in terms of average impacts across utility systems and the LTEMP period. Before introducing the rate and bill impacts for Alternatives B, C, D, E, F, and G relative to Alternative A, retail rates and residential bills for Alternative A are described. The retail rates and residential bills under Alternative A provide a benchmark for gauging impacts of other alternatives. For example, a monthly residential bill increase of $1.00 under a particular LTEMP alternative relative to Alternative A can be evaluated relative to the average and median monthly residential bills in Alternative A.

Figures K.3-7 and K.3-8 display retail rates in $/MWh and residential bills in $/month under Alternative A. Note that none of the tables and figures in this section include the impacts on Tribes that have special net benefit contracts. Rate impacts for Tribes with net benefit contracts are addressed in Section K.3.4.2. Figure K.3-7 shows the distribution of retail rates across the utility systems. Retail rates are computed by dividing retail revenues collected from residential, business and other consumers by retail sales for the consumers. Rates and bills are represented in Figures K.3-7 and K.3-8 with distribution analyses. The increments on the x-axes demonstrate the highest and lowest ranges for rates and bills across different systems. The average and the median statistics, as well as the ranges, are shown in the graph titles. The range in retail rates under Alternative A varies from $55/MWh to $177/MWh, with an average rate of $104/MWh. The level of retail rates influences the reported rate increase percent in subsequent presentation of rate impacts. For example, a lower retail rate for a particular system results in a higher percent increase, all else being equal, because the allocated aggregated cost increase is

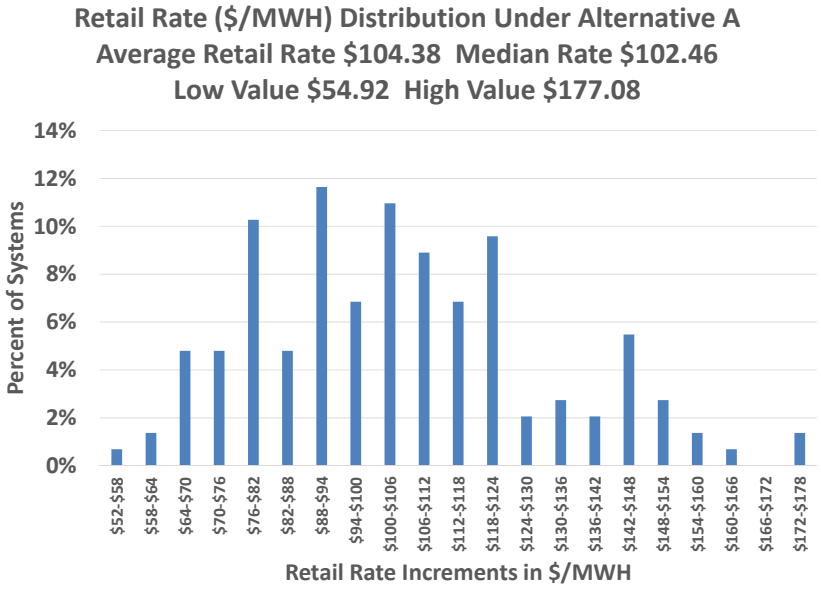

FIGURE K.3-7 Retail Rate Distribution under Alternative A

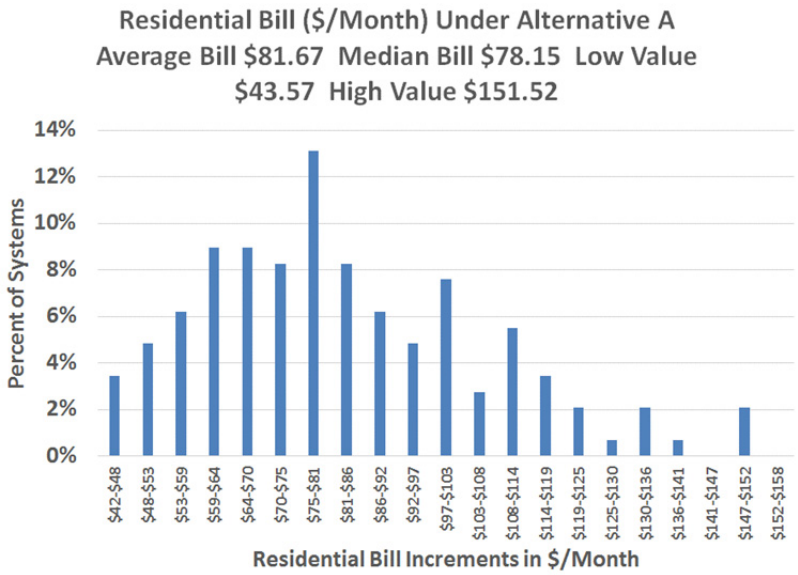

FIGURE K.3-8 Monthly Residential Bill Distribution under Alternative A

divided by the retail rate. On the other hand, a lower retail rate does not influence the residential bill calculation because bill impacts are measured on an absolute basis.

Figure K.3-8 presents monthly residential bills that are calculated by dividing annual residential revenues of a system by the number of residential consumers and then dividing the product by 12. Average monthly bills under Alternative A range between $44 and $151 per month, with an average of $82 per month. This implies that an increase of $1 from an LTEMP alternative other than Alternative A results in a typical percent increase in monthly bills of somewhat more than 1%.

Figures K.3-9 and K.3-10 illustrate the average impacts on retail rate changes and on monthly residential bills across different systems relative to Alternative A. Residential bill impacts in Figure K.3-10 and in the rest of the subsequent rate impact presentation are measured in real 2015 dollars. The graphs in Figures K.3-9 and K.3-10 display averages across systems that are not weighted by the size of the systems. This means that a small system with less than 1,000 consumers is given the same weight as a large system with hundreds of thousands of customers (such as SRP). Because rate impacts tend to be greater for small systems, evaluating impacts using averages weighted by the sales size results in lower increases (about half of the unweighted average). Weighted average impacts are discussed in Section K.3.3.3 and presented in Table K.3-4. Figure K.3-9 demonstrates that even the most extreme LTEMP alternative in terms of changing dam operations (Alternative F) results in rate changes for retail consumers below 1%. Under Alternative F, there is an average rate increase of 0.75% relative to Alternative A. Figure K.3-10 shows that the highest average residential bill impact is 69 cents per month. Alternatives E and D have much lower retail rate impacts that are approximately 20% of the rate impact under Alternative F. (Note that individual rate impacts on particular systems can be higher than the average impacts.)

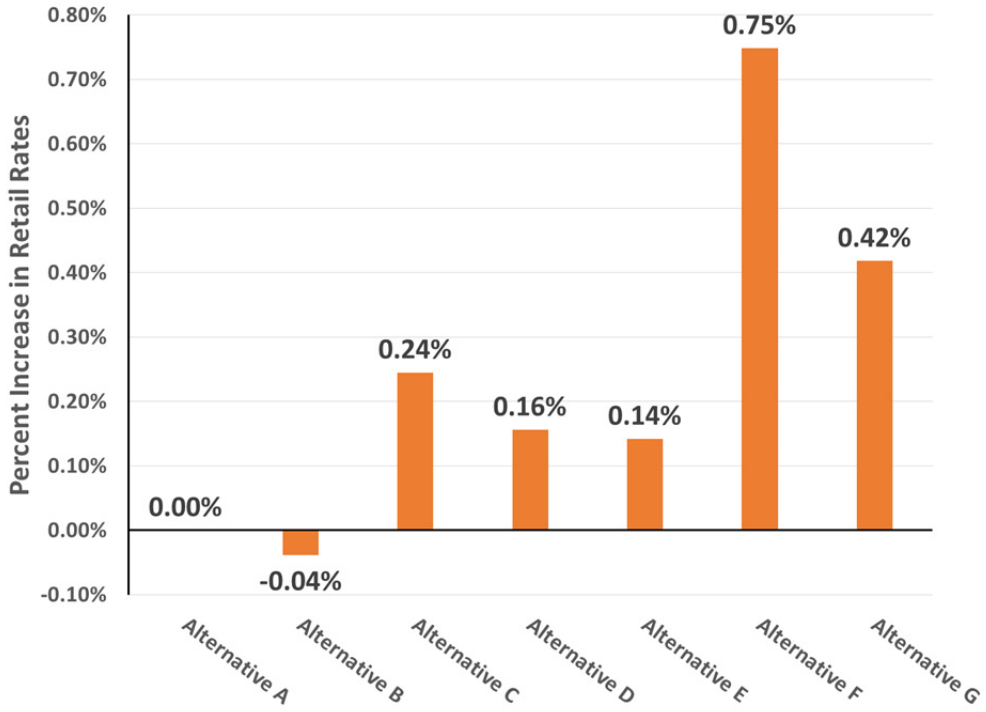

FIGURE K.3-9 Average Retail Rate Impacts under LTEMP Alternatives Relative to Alternative A

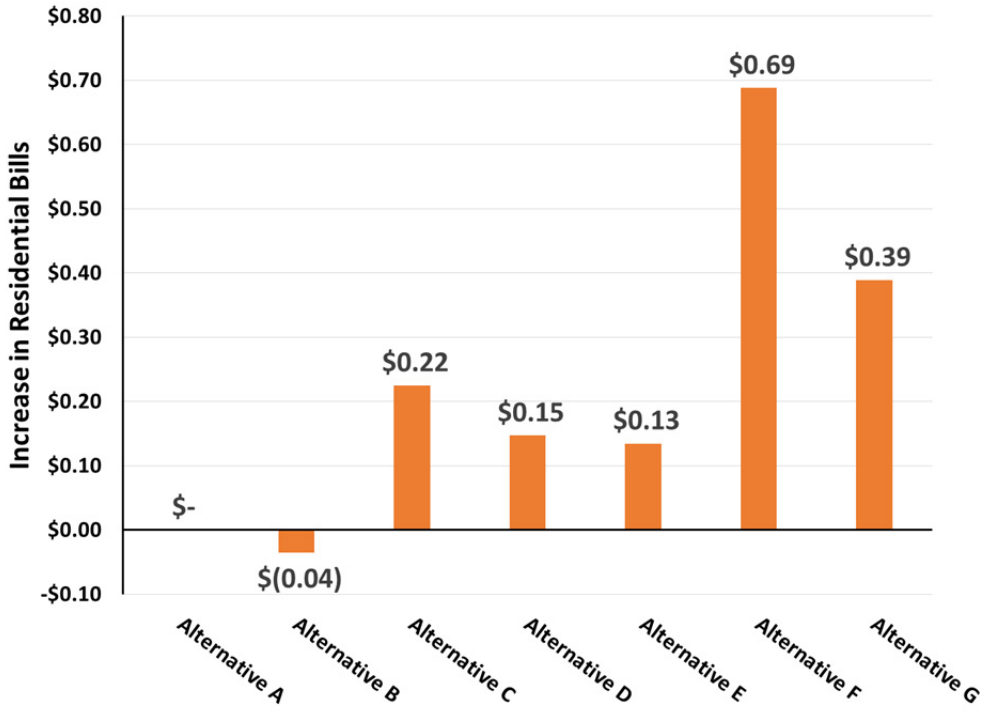

FIGURE K.3-10 Average Residential Bill Impacts under LTEMP alternatives Relative to Alternative A

K.3.3.2 Average Year-by-Year Rate Impacts

Rate impacts presented in the previous paragraphs, which average rate and bill changes across the entire LTEMP period, mask the year-to-year rate impacts. Impacts in a single year can be different than average impacts across years because of the manner in which capacity changes occur and the effects of dam operations on production costs. Maximum rate impacts in a single year may be of concern to stakeholders. Therefore, the average annual retail rate and bill impacts from year to year are presented in this section. Figures K.3-11 and K.3-12 show the year-by-year averages for the overall retail percent changes and residential bill changes under different LTEMP alternatives. Year-by-year impacts for LTEMP alternatives are measured relative to Alternative A and the averages are not weighted by system size. Figure K.3-11 demonstrates that in terms of average percent changes in retail rates across all of the utility systems, the changes are not constant from year to year. Retail rate impacts from Alternative F are above the other alternatives, except in 2 of the years. The largest percent changes other than under Alternative F are under Alternative G, which has relatively constant changes over the LTEMP period. The third-highest rate impacts are from Alternative C; these are constant until 2028, after which the impacts decline. Alternatives D and E have varying impacts from year to year that are driven by differences in construction of new capacity. Alternative B has impacts below zero (bill reductions relative to Alternative A), except in 2034, when construction of new capacity is accelerated relative to Alternative A. All of the tables and figures in this section include the

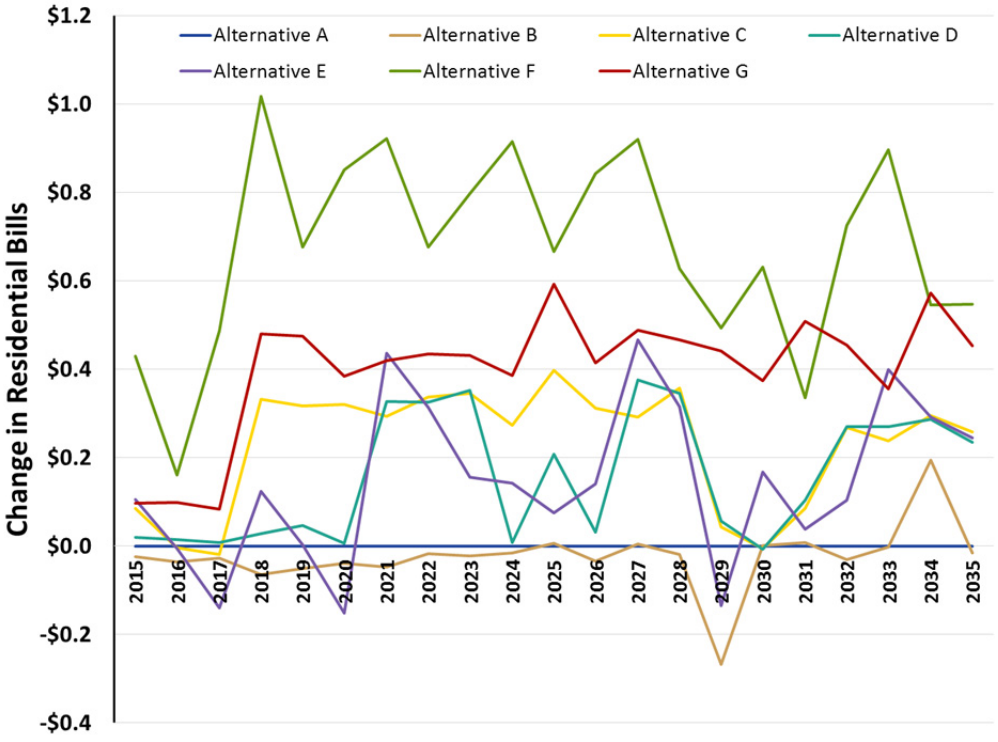

FIGURE K.3-11 Average Retail Percent Revenue Increase Relative to Alternative A

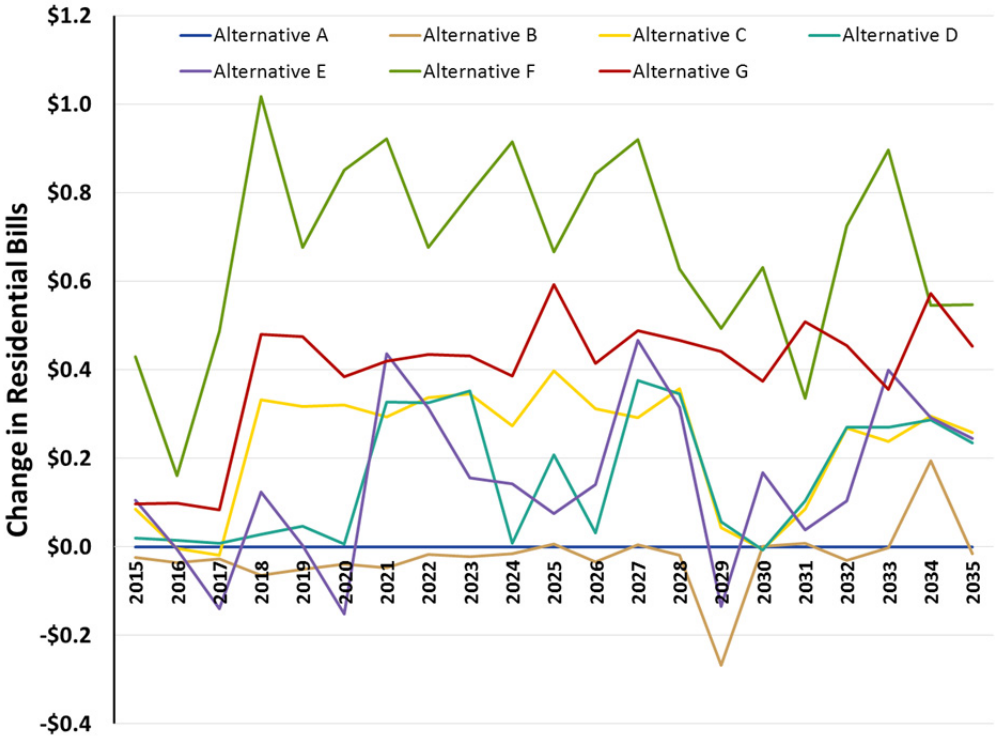

FIGURE K.3-12 Average Monthly Residential Bill Changes Relative to Alternative A

Ak-Chin, Tohono O'odham Reservation, and Navajo Tribal Utility Authority Tribes but do not include the impacts on Tribes that have special net benefit contracts. Rate impacts for Tribes with net benefit contracts are addressed in Section K.3.4.2.

Figure K.3-12 shows that in terms of monthly bill changes from year to year, the annual patterns are similar to the trends in retail bill changes. The highest monthly bill impact in a single year is just above $1.00 per month under Alternative F, relative to Alternative A in 2018. The year 2018 for Alternative F is termed the maximum impact year. For Alternative G, the maximum residential monthly impact is just below 60 cents per month in the year 2025. Impacts for the maximum year are presented in Table K.3-4. Figure K.3-11 also demonstrates that monthly bill impacts are more variable from year to year under Alternative E than other LTEMP alternatives. Alternative E has bill changes below zero in the years 2017, 2020, and 2029. The bill impacts are higher for Alternative E than Alternative D, but Alternative D does not have any impacts that are below zero.

Maximum and average rate and bill impacts are recorded in Table K.3-4, which summarizes the average impacts across systems in the maximum impact year and over the LTEMP period. Unlike the impacts presented up to this point, Table K.3-4 also presents the averages and maximum impacts using an alternative weighting method where the size of different systems is considered. The weighting method places a higher weight on larger systems

by multiplying all of the impacts by the ratio of retail sales for a system to aggregate retail sales across all systems. When averages are weighted by sales, the rate and bill impacts are approximately half of the amount without weighting. For example, the maximum monthly bill impact of $1.02 per month under Alternative F in 2018 is reduced to 50 cents when small systems are given lower weight and larger systems are given higher weight. The large reduction in impacts from weighting by sales comes about in part because SRP and the City of Colorado Springs have low rate impacts and a very high level of sales relative to other systems. The sales of these two systems alone represent 45% of the total sales for all systems in the analysis. When weighting by sales, the weighting calculation shown in Table K.3-4 excludes SRP and the City of Colorado Springs in the aggregate sales tabulation.

In addition to displaying average impacts across years and average rate impacts in the maximum change year, median impacts are also shown in Table K.3-4. Median statistics show the rate or bill change for which 50% of companies are above the value and 50% are below the value. The median values are less affected by extreme high values or low values and result in lower observed impacts because a few systems with high rate impacts skew the averages. The top half of Table K.3-4 shows data on an unweighted basis that have been shown above. The lower half shows weighted averages, including the median. The top part of Table K.3-4 demonstrates that the maximum impact is lower when measured by the median instead of the average. For example, under Alternative F, the maximum residential bill impact of $1.02 that is averaged for all systems is more than 20% less (78 cents) when the median is used to measure the typical impact. The impact is further reduced when the impacts are weighted by sales size, as shown at the bottom of the table. Weighting by sales reduces the measured rate impact. For example, under Alternative G, the average retail rate increase is reduced from 0.64% to 0.50% when the average is weighted by adjusted sales size. When the median sales weighted statistic is measured, the number for the maximum year under Alternative G falls to 0.39%.

K.3.3.3 Individual System Impacts and Summary Descriptions of LTEMP Alternatives

This section addresses individual rate and bill impacts on particular systems rather than presenting results in terms of averages. Detailed rate impacts on selected individual utilities are presented separately for systems that experience relatively large and relatively small impacts. Four tables, Table K.3-5 through Table K.3-8, demonstrate the large and small individual impacts on different systems. The tables show the year with the maximum retail rate and monthly bill impact for each alternative relative to Alternative A. Using the lists of systems with the highest rate impacts and the graphs and tables from previous sections, each alternative is summarized.

Lists of Individual Systems with Largest and Smallest Impacts

Table K.3-5 lists the 30 systems with the largest percentage retail rate impact (in absolute value) for the LTEMP alternatives. Given the aggregate grid cost change from an LTEMP alternative, the retail rate impact for a particular system depends on the SLCA/IP energy

TABLE K.3-4 Summary Table of Comparative Values

Impact	Alternative A (No Action Alternative	Alternative B	Alternative C	Alternative D (Preferred Alternative)	Alternative E	Alternative F	Alternative G
Percent change in average grid cost relative to Western revenues	No Change	–0.68	6.87	4.78	4.47	20.11	12.04
No Weighting by size							
Percent change in retail rates (average across years)	No Change	–0.04	0.25	0.15	0.14	0.75	0.42
Average percent change in retail rates (maximum impact year)	No Change	–0.27	0.43	0.39	0.50	1.21	0.64
Median percent change in retail rates (maximum impact year)	No Change	–0.20	0.27	0.25	0.30	0.76	0.40
Change in monthly residential bill (average across years)	No Change	–$0.04	$0.22	$0.15	$0.13	$0.69	$0.39
Average change in monthly residential bill (maximum impact year)	No Change	–$0.27	$0.40	$0.38	$0.47	$1.02	$0.59
Median change in monthly residential bill (maximum impact year)	No Change	–$0.23	$0.31	$0.27	$0.09	$0.78	$0.46
Weighting by size with adjustments for SRP and Colorado Springs							
Percent change in retail rates (average across years)	No Change	–0.03	0.19	0.12	0.11	0.59	0.33
Percent change in retail rates (maximum impact year)	No Change	–0.21	0.34	0.31	0.39	0.96	0.50
Median percent change in retail rates (maximum impact year)	No Change	–0.19	0.26	0.24	0.30	0.75	0.39
Change in monthly residential bill (average across years)	No Change	–$0.03	$0.18	$0.12	$0.11	$0.56	$0.32
Change in monthly residential bill (maximum impact year)	No Change	–$0.25	$0.32	$0.31	$0.38	$0.83	$0.48
Change in monthly residential bill (average across years)	No Change	–$0.22	$0.31	$0.27	$0.10	$0.79	$0.46

TABLE K.3-5 Individual Systems with the Largest Percent Retail Rate Impacts Relative to Alternative A

Number	Utility System	Preference Ratio	Number of Residential Consumers	Percent Rate Impact Relative to Alternative A					
				Alternative B 2029	Alternative C 2025	Alternative D 2023	Alternative E 2027	Alternative F 2020	Alternative G 2025
1	Beaver (UAMPS)	25.51	1,500	–0.48	0.76	0.69	0.85	2.14	1.13
2	Ephraim (UAMPS)	28.19	1,731	–0.48	0.76	0.70	0.86	2.15	1.13
3	Manti (UMPA)	28.65	1,274	–0.49	0.77	0.70	0.86	2.17	1.14
4	Murray (UAMPS)	27.89	13,977	–0.49	0.78	0.71	0.88	2.20	1.16
5	Spanish Fork (UMPA)	28.65	9,712	–0.49	0.78	0.71	0.88	2.20	1.16
6	Dixie Escalante R.E.A.	19.68	13,831	–0.50	0.79	0.72	0.89	2.23	1.17
7	Brigham City	26.57	6,643	–0.50	0.79	0.73	0.89	2.25	1.18
8	Provo (UMPA)	28.65	31,204	–0.51	0.81	0.74	0.91	2.29	1.20
9	Ocotillo I.D.	21.36	19	–0.51	0.81	0.74	0.91	2.29	1.21
10	Paragonah (UAMPS)	37.22	250	–0.52	0.82	0.75	0.92	2.31	1.22
11	Fairview (UAMPS)	36.53	714	–0.53	0.84	0.76	0.94	2.37	1.25
12	Flowell E.A., Inc. (Deseret)	27.66	194	–0.55	0.86	0.79	0.97	2.44	1.29
13	Morgan (UAMPS)	41.79	1,429	–0.55	0.87	0.80	0.98	2.47	1.30
14	Levan (UMPA)	28.65	317	–0.56	0.89	0.81	1.00	2.51	1.32
15	Nephi (UMPA)	28.65	1,890	–0.59	0.93	0.85	1.04	2.62	1.38
16	Parowan (UAMPS)	31.33	1,237	–0.61	0.97	0.88	1.09	2.73	1.44
17	Monroe (UAMPS)	32.73	916	–0.63	1.00	0.92	1.13	2.84	1.49
18	Navajo Tribal Authority	30.75	32,727	–0.64	1.01	0.92	1.14	2.86	1.51
19	Cocopah Reservation	30.83	3,334	–0.64	1.01	0.93	1.14	2.87	1.51
20	Helper	16.10	1,020	–0.68	1.07	0.98	1.20	3.03	1.59
21	Bountiful (UAMPS)	42.82	15,295	–0.69	1.09	1.00	1.23	3.09	1.62
22	Oak City (UAMPS)	34.51	260	–0.70	1.11	1.02	1.25	3.15	1.66
23	Gunnison	35.12	3,348	–0.72	1.14	1.04	1.29	3.23	1.70
24	Ak-Chin Municipal	43.03	282	–0.75	1.18	1.08	1.33	3.33	1.75
25	Truth or Consequences	53.69	3,572	–0.75	1.19	1.09	1.34	3.37	1.77
26	Holden (UAMPS)	57.22	215	–0.76	1.20	1.09	1.35	3.39	1.78
27	Maricopa MWCD	37.09	NA[a]	–0.81	1.28	1.17	1.44	3.62	1.90

TABLE K.3-5 (Cont.)

Number	Utility System	Preference Ratio	Number of Residential Consumers	Percent Rate Impact Relative to Alternative A					
				Alternative B 2029	Alternative C 2025	Alternative D 2023	Alternative E 2027	Alternative F 2020	Alternative G 2025
28	Kanosh (UAMPS)	58.20	284	–0.87	1.37	1.26	1.55	3.89	2.05
29	Meadow (UAMPS)	62.22	158	–0.92	1.46	1.33	1.64	4.13	2.17
30	Enterprise (UAMPS)	50.65	517	–0.93	1.46	1.34	1.65	4.14	2.18

[a] NA = Not applicable (i.e., the system does not sell to residential consumers).

TABLE K.3-6 Individual Systems with the Smallest Percent Retail Rate Impacts Relative to Alternative A

No	Utility System	Preference Ratio	Number of Residential Consumers	Percent Rate Impact Relative to Alternative A					
				Alternative B 2029	Alternative C 2025	Alternative D 2023	Alternative E 2027	Alternative F 2020	Alternative G 2025
1	Frederick	0.26	3,453	0.00	0.01	0.01	0.01	0.01	0.01
2	Salt River Project	1.09	867,846	–0.02	0.03	0.02	0.03	0.08	0.04
3	Los Alamos County	0.98	7,792	–0.02	0.03	0.03	0.03	0.09	0.05
4	Wellton-Mohawk I.D.	1.24	2,768	–0.02	0.03	0.03	0.04	0.09	0.05
5	Intermountain R.E.A.	2.27	130,075	–0.03	0.05	0.04	0.05	0.13	0.07
6	Grand Valley E.C.	3.33	14,021	–0.04	0.06	0.05	0.07	0.17	0.09
7	Central Valley E.C., Inc.	2.04	5,180	–0.04	0.07	0.06	0.07	0.19	0.10
8	Lea County E.C., Inc.	1.89	6,759	–0.04	0.07	0.06	0.08	0.20	0.10
9	ELECTRICAL DISTRICT 3	3.54	19,561	–0.05	0.07	0.07	0.08	0.21	0.11
10	Washington (UAMPS)	2.89	5,578	–0.05	0.07	0.07	0.08	0.21	0.11
11	Farmers E.C., Inc.	2.93	9,739	–0.05	0.08	0.07	0.09	0.23	0.12
12	Colorado Springs Utilities	3.29	180,928	–0.05	0.09	0.08	0.10	0.24	0.13
13	Holy Cross E.A.	3.59	45,196	–0.06	0.09	0.08	0.10	0.25	0.13
14	Safford	4.91	3,378	–0.06	0.09	0.08	0.10	0.25	0.13
15	Yampa Valley Rural	4.15	21,670	–0.06	0.10	0.09	0.11	0.27	0.14
16	Santa Clara (UAMPS)	3.84	1,973	–0.06	0.10	0.09	0.11	0.29	0.15
17	Mesa (APPA)	4.85	13,257	–0.07	0.11	0.10	0.12	0.31	0.16
18	Navopache E.C., Inc.	6.96	34,867	–0.08	0.13	0.12	0.14	0.36	0.19
19	Torrington (WMPA)	5.66	3,163	–0.09	0.14	0.12	0.15	0.39	0.20
20	Glenwood Springs	5.00	4,779	–0.09	0.15	0.13	0.17	0.42	0.22
21	Fort Laramie (WMPA)	8.98	210	–0.10	0.15	0.14	0.17	0.43	0.22
22	Gallup	6.83	8,509	–0.10	0.15	0.14	0.17	0.43	0.23
23	Lamar Utilities Board	9.53	4,219	–0.10	0.16	0.14	0.18	0.45	0.24
24	Lehi (UAMPS)	6.26	14,146	–0.10	0.16	0.15	0.18	0.45	0.24
25	Kaysville (UAMPS)	6.01	7,929	–0.10	0.16	0.15	0.18	0.45	0.24
26	Sierra Electric Cooperative	11.56	3,595	–0.10	0.16	0.15	0.18	0.46	0.24
27	Tohono O'odham	9.20	3,036	–0.11	0.17	0.15	0.19	0.47	0.25
28	Thatcher	7.26	1,072	–0.11	0.17	0.15	0.19	0.48	0.25
29	Raton	12.46	3,645	–0.11	0.17	0.16	0.20	0.49	0.26
30	Sangre de Cristo Electric	11.56	10,756	–0.11	0.18	0.16	0.20	0.50	0.26

allocation, the preference ratio, and the current retail rate. None of these three items change with different operations of the dam. This means the ranking of systems does not change under different alternatives and lists of systems with the largest and smallest impact can be presented on a single table. The percentage rate impact is shown under the letter of the respective alternative. The year of the maximum impact for which the retail rate impact is displayed is shown below the alternative title. Table K.3-6 displays the 30 systems with the smallest percentage retail rate impact in a similar format. The size of systems as measured by the number of residential consumers and the preference ratio is presented for each system. The year for which the impact is measured is also shown on Table K.3-5.

Many of the entities that experience the largest impacts are part of the UAMPS system and have a high ratio of preference power to sales. The systems with the highest rate impacts generally are relatively small, such as the City of Enterprise (with 517 consumers). The systems that experience the smallest impact are often large systems and have relatively low preference power ratios.

Tables K.3-7 and K.3-8 list the systems with the highest and lowest residential monthly retail bill impacts in a similar format to the percent retail rate change tables. As with Tables K.3-5 and K.3-6, the impacts are shown for Alternatives B–G relative to Alternative A. The ranking of residential bill impacts is not the same as the rank of the retail percent increase. One of the reasons for differences in ranking is due to residential use variation among individual systems. Systems with lower residential use have a higher bill impact because grid costs are spread over a smaller base, all else being equal. Differences in residential usage are evidenced by the fact that the median average usage across the different systems is 730 kWh per month, while the maximum use for a single system is 1,680 kWh per month, and the system with the lowest annual residential usage is 391 kWh per month.[23] The ranking of retail percent impacts and monthly residential bill impacts also differs because residential bills are measured in absolute rather than in percentage terms. If two utility systems have the same overall percentage rate increase, but one system has a higher level of prices and higher residential bills, that system will have a higher residential bill impact relative to the percentage impact. For example, Ak-Chin has a higher ranking for bill impacts than for retail rate change impacts. This utility system has a small number of residential customers and a relatively high level of consumer bills. In 2012, the average monthly bill of Ak-Chin was about $140, which is 69% higher than the average bill across all systems of $84 per month.

K.3.4 Impacts on Small Systems

Two groups of utilities that are allocated a large fraction of their generation resources from SLCA/IP projects are Tribes and some small utilities, implying that the rate and bill impacts on these two groups tend to be relatively large. Impacts on small systems are presented separately in this section. Impacts on Tribes are presented in Section K.4.

[23] These figures are averages for a system and do not account for the distribution of usage within the systems.

TABLE K.3-7 Individual Systems with the Largest Monthly Residential Bill Impacts Relative to Alternative A

No	Utility System	Preference Ratio	Number of Residential Consumers	Monthly Bill Impact (2015 $) Relative to Alternative A: Alternative B 2029	Alternative C 2025	Alternative D 2023	Alternative E 2027	Alternative F 2020	Alternative G 2025
1	Bridger Valley E.A., Inc.	23.82	5,262	–0.43	0.63	0.56	0.74	1.62	0.94
2	Murray (UAMPS)	27.89	13,977	–0.43	0.63	0.56	0.74	1.62	0.95
3	Paragonah (UAMPS)	37.22	250	–0.43	0.64	0.56	0.75	1.63	0.95
4	Provo (UMPA)	28.65	31,204	–0.43	0.64	0.57	0.75	1.63	0.95
5	Gunnison	35.12	3,348	–0.46	0.69	0.61	0.81	1.76	1.03
6	Monroe (UAMPS)	32.73	916	–0.46	0.69	0.61	0.81	1.76	1.03
7	Salem (UMPA)	28.65	1,793	–0.47	0.70	0.62	0.82	1.79	1.04
8	Parowan (UAMPS)	31.33	1,237	–0.47	0.70	0.62	0.82	1.79	1.04
9	Nephi (UMPA)	28.65	1,890	–0.49	0.73	0.65	0.85	1.86	1.09
10	Spanish Fork (UMPA)	28.65	9,712	–0.49	0.73	0.65	0.86	1.88	1.10
11	Truth or Consequences	53.69	3,572	–0.50	0.74	0.66	0.87	1.90	1.11
12	Garkane Power Assn., Inc.	27.18	10,520	–0.50	0.75	0.66	0.87	1.91	1.11
13	Manti (UMPA)	28.65	1,274	–0.50	0.75	0.66	0.88	1.92	1.12
14	Page (AZ) +	24.91	3,492	–0.51	0.76	0.67	0.89	1.94	1.13
15	Morgan (UAMPS)	41.79	1,429	–0.52	0.78	0.69	0.91	1.99	1.16
16	Dixie Escalante R.E.A., Inc.	19.68	13,831	–0.53	0.79	0.70	0.93	2.02	1.18
17	Willwood	16.37	49	–0.55	0.81	0.72	0.95	2.07	1.21
18	Levan (UMPA)	28.65	317	–0.55	0.82	0.72	0.96	2.09	1.22
19	Holyoke	29.24	937	–0.55	0.82	0.73	0.96	2.09	1.22
20	Electrical District 3 (APPA)	14.49	975	–0.56	0.82	0.73	0.97	2.11	1.23
21	Oak City (UAMPS)	34.51	260	–0.57	0.84	0.74	0.98	2.15	1.25
22	Kanosh (UAMPS)	58.20	284	–0.61	0.90	0.80	1.05	2.30	1.34
23	Ocotillo I.D.	21.36	19	–0.66	0.98	0.87	1.15	2.52	1.47
24	Electrical District 3, Maricopa County	16.62	93	–0.71	1.05	0.93	1.23	2.69	1.57
25	Bountiful (UAMPS)	42.82	15,295	–0.76	1.13	1.01	1.33	2.90	1.69
26	Meadow (UAMPS)	62.22	158	–0.78	1.15	1.02	1.35	2.95	1.72
27	Holden (UAMPS)	57.22	215	–0.78	1.16	1.03	1.36	2.96	1.72
28	Enterprise (UAMPS)	50.65	517	–0.84	1.24	1.10	1.46	3.18	1.86
29	Flowell E.A., Inc. (Deseret)	27.66	194	–0.92	1.37	1.22	1.61	3.51	2.05
30	Ak-Chin Municipal	43.03	282	–1.39	2.07	1.83	2.42	5.29	3.08

TABLE K.3-8 Individual Systems with the Smallest Monthly Residential Bill Impacts Relative to Alternative A

No	Utility System	Preference Ratio	Number of Residential Consumers	Monthly Bill Impact (2015 $) Relative to Alternative A: Alternative B 2029	Alternative C 2025	Alternative D 2023	Alternative E 2027	Alternative F 2020	Alternative G 2025
1	Maricopa County	37.09	NA[a]	0.00	0.00	0.00	0.00	0.00	0.00
2	Frederick	0.26	3,453	0.00	0.01	0.01	0.01	0.02	0.01
3	Los Alamos County	0.98	7,792	–0.02	0.02	0.02	0.03	0.06	0.03
4	Wellton-Mohawk I.D.	1.24	2,768	–0.03	0.04	0.03	0.05	0.10	0.06
5	Salt River Project	1.09	867,846	–0.03	0.04	0.04	0.05	0.11	0.06
6	Intermountain R.E.A.	2.27	130,075	–0.04	0.06	0.05	0.07	0.16	0.09
7	Washington (UAMPS)	2.89	5,578	–0.04	0.07	0.06	0.08	0.17	0.10
8	Lea County E.C., Inc.	1.89	6,759	–0.05	0.07	0.06	0.08	0.17	0.10
9	Central Valley E.C., Inc.	2.04	5,180	–0.05	0.07	0.06	0.08	0.18	0.11
10	Farmers E.C., Inc.	2.93	9,739	–0.05	0.08	0.07	0.09	0.20	0.12
11	Colorado Springs Utilities	3.29	180,928	–0.06	0.08	0.07	0.10	0.21	0.12
12	Grand Valley E.C.	3.33	14,021	–0.06	0.09	0.08	0.10	0.22	0.13
13	Glenwood Springs	5.00	4,779	–0.07	0.10	0.09	0.11	0.25	0.15
14	Yampa Valley Rural	4.15	21,670	–0.07	0.10	0.09	0.12	0.25	0.15
15	Gallup	6.83	8,509	–0.07	0.10	0.09	0.12	0.27	0.16
16	Navopache E.C., Inc.	6.96	34,867	–0.08	0.11	0.10	0.13	0.29	0.17
17	Safford	4.91	3,378	–0.08	0.12	0.10	0.14	0.30	0.17
18	Torrington (WMPA)	5.66	3,163	–0.08	0.12	0.11	0.14	0.31	0.18
19	Holy Cross E.A.	3.59	45,196	–0.08	0.12	0.11	0.14	0.31	0.18
20	Fort Laramie (WMPA)	8.98	210	–0.09	0.13	0.11	0.15	0.33	0.19
21	Price	7.93	4,460	–0.09	0.13	0.11	0.15	0.33	0.19
22	Mesa (APPA)	4.85	13,257	–0.09	0.13	0.12	0.15	0.33	0.19
23	Santa Clara (UAMPS)	3.84	1,973	–0.09	0.14	0.12	0.16	0.35	0.20
24	ELECTRICAL DISTRICT 3	3.54	19,561	–0.09	0.14	0.12	0.16	0.36	0.21
25	Lusk (WMPA)	8.98	931	–0.09	0.14	0.12	0.16	0.36	0.21
26	Mora-San Miguel	11.56	10,575	–0.10	0.15	0.13	0.18	0.38	0.22
27	Lehi (UAMPS)	6.26	14,146	–0.10	0.15	0.13	0.18	0.38	0.22
28	Farmington	6.73	34,037	–0.10	0.15	0.14	0.18	0.39	0.23
29	Cody (WMPA)	8.98	5,894	–0.10	0.15	0.14	0.18	0.39	0.23
30	Kit Carson Electric	11.56	24,309	–0.11	0.17	0.15	0.19	0.42	0.25

[a] NA = Not applicable.

To demonstrate the effect of system size on rate impacts, statistics were computed for the 20 systems with the largest impact and the 20 systems with the smallest impacts. Table K.3-9 demonstrates that, as measured by the number of residential consumers, the average size of systems with the largest rate impacts (1,680 consumers) is much smaller than the typical size of utility systems. Without adjusting for SRP and Colorado Springs, utilities with the smallest rate impacts are on average 38 times the size of the systems that have the largest rate impacts. When the two large systems are removed, the systems with the smallest impacts are still about 10 times larger than the systems with the largest percent rate increases.

The comparatively high retail rate increases on some small utility systems under the LTEMP alternatives are shown in Table K.3-10. This table shows average retail rate impacts under different alternatives relative to Alternative A for the selected groups of utility systems. In comparing rate impacts, the maximum impact year is used. The 20 systems with the largest impact have an average rate increase that is 2.52 times the average rate increase percent across all systems. On the other hand, the 20 systems with the smallest impact have an average rate increase that is a small fraction of the average rate increase for the entire population of systems. Finally, Table K.3-10 illustrates that the preference ratio is highly correlated to the rate increase.

K.3.5 Alternative-Specific Impacts

K.3.5.1 Alternative A

Under Alternative A, SLCA/IP marketable capacity is 737.2 MW using an assumed water flow rate that is low enough that one can be 90% confident that the rate will be exceeded. Average annual daily generation and hydropower value at Glen Canyon Dam and SLCA/IP

TABLE K.3-9 Size and Preference Ratio for Utility Systems with Large Rate Impacts

Statistics for Impact Analysis on Small Systems

Group of System	Rate Impact Relative to Average	Residential Customers	Size Relative to Large Impact Systems	Preference Ratio	Preference Ratio Relative to Average
Utilities with Largest Rate Impact[a]	2.52	1,680	1.00	38.83%	2.36
Utilities with Smallest Impact[b]	0.18	69,099	41.13	3.24%	0.20
Utilities with Smallest Impact Excluding SRP and CS	0.20	17,096	10.18	3.81%	0.23
Average of All Systems	1.00	16,567.69	9.86	16.43%	1.00

[a] Includes 20 systems with largest impact except Tribes.

[b] Includes 20 systems with smallest rate impact.

TABLE K.3-10 Rate Impacts for Selected Groups in Maximum Impact Year

Alternative	Largest Retail Rate Change Group in Maximum Impact Year (%)	Smallest Retail Rate Change Group in Maximum Impact Year (%)	Average Retail Rate Change Across All Systems in Maximum Impact Year (%)	Rate Impact for Largest Group/ Average Rate Impact ($)
A	0.00	0.00	0.00	–
B	–0.56	–0.09	–0.27	2.08
C	1.08	0.09	0.43	2.52
D	0.98	0.07	0.39	2.52
E	1.21	0.09	0.50	2.44
F	3.05	0.22	1.21	2.52
G	1.60	0.12	0.64	2.52

marketable capacity would not change under Alternative A. Rate impacts for each LTEMP Alternative are computed relative to this alternative, meaning that the difference between two cases must be used to evaluate the change in rates.

Retail rates and residential bills are computed for Alternative A using inflation rates and sales growth from EIA forecasts. Production costs, fixed operation and maintenance costs associated with new capacity, and the cost of new capacity from Alternative A are used as the basis for evaluating aggregate grid cost impacts for the other LTEMP scenarios.

K.3.5.2 Alternative B

Under Alternative B, rates and bills would be lower than under all other alternatives. Production costs are lower under Alternative B than under Alternative A, and there is a minor difference in the amount of capacity added for 1 year. Although the total amount of capacity added over the 20-year LTEMP period is the same as in Alternative A, a 1-year delay in constructing a new natural-gas-fired combustion turbine is projected in the power systems analysis for the year 2029. This delay in capacity additions and the difference in production cost accounts for the slightly lower annual average grid cost for Alternative B compared to Alternative A. The difference in annual grid costs averages $976 thousand per year (real 2015$).

When the annual grid cost reduction is translated to impacts on electric bills, the average retail rate decrease over the LTEMP period is -0.039%. The maximum rate decrease occurs in the year of the capacity deferral, 2029. The percent decrease in this year with the deferred capacity (the maximum impact year) is -0.27%. Table K.3-5 shows that the individual systems with the maximum impact have decreases that range between -0.48% and -0.93%. The average

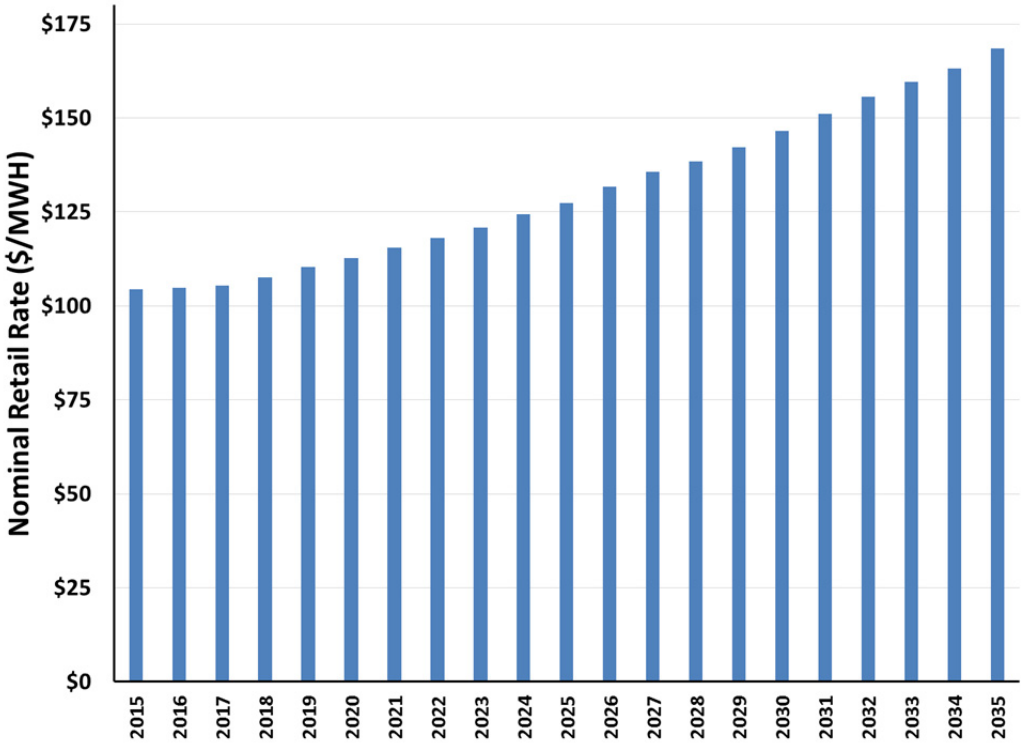

FIGURE K.3-13 Retail Rates under Alternative A

decrease in monthly residential bills over the LTEMP period is 4 cents per month, while the decrease in 2029 is 27 cents per month.

K.3.5.3 Alternative C

Retail rate increases under Alternative C relative to Alternative A are primarily driven by an increase in capacity of 230 MW that occurs for most years after 2018. This capacity increase is more than the reduction in marketable capacity of 129.1 MW. Replacement of the lost capacity and increased production costs results in varying grid cost impacts over the LTEMP period. Average grid impacts in real 2015 dollars are $9.8 million per year relative to Alternative A. These impacts are less than under Alternative F and Alternative G, but more than under Alternatives D, E, or B. The increase of $9.8 million in grid costs represents an increase of 6.87% relative to the annual wholesale revenues currently collected from SLCA/IP capacity and energy charges. When the wholesale grid cost of 6.87% is converted into retail rates, the averages across all systems and years range from a low of 0% to a high of 0.428% in 2025. The average percent retail rate increase across all systems for the LTEMP period is 0.245%. For the year 2025, which is the year with the maximum percent rate impact shown in Table K.3-5, individual systems experience percentage impacts ranging from less than 0% up to 1.46%.

Monthly residential bill impacts under Alternative C relative to Alternative A range from 0 to 40 cents for the LTEMP period. The average increase in residential bills is 22 cents per month. Detailed residential bill impacts under Alternative C for the maximum year are shown in Table K.3-6. Residential bill impacts in the highest impact year (2025) are not much higher than the results from Alternative D discussed in the next section. However, the average impacts under Alternative C are 43% greater than the impacts under Alternative D. For the maximum impact year 2025, the range in residential bill impacts ranges between approximately $0 (4 cents for SRP consumers) and $2.07 per month (Ak-Chin Electric Municipal).

K.3.5.4 Alternative D

Retail rate increases under Alternative D relative to Alternative A are primarily driven by a reduction in capacity of 230 MW in most years. Replacement of capacity and increased production costs result in varying grid cost impacts on a year-by-year basis. Average grid impacts in real 2015 dollars are $6.8 million per year. When translated to retail rates, the impacts as an unweighted average across all systems range from 0% to a high of 0.391% in 2023. The average retail rate increase across all systems for the LTEMP period is 0.156%. For the maximum impact year 2023, individual systems experience percentage impacts ranging from 0% to 1.38%, as shown in Tables K.3-5 and K.3-6. The maximum impact retail rate increase is lower for Alternative D than for any other alternative analyzed except Alternatives B and A.

The impacts measured in terms of residential bills for individual systems in the maximum impact year are shown in Tables K.3-6 and K.3-7. Residential bill impacts under Alternative D relative to Alternative A, measured in 2015 dollars per month, range from 0 to 38 cents over the LTEMP period. The bill increase of 38 cents per month in the high-impact year is less than the bill increase in the high-impact year of 47 cents under Alternative E. The average increase in residential bills over the LTEMP period is 15 cents per month. For the year 2023, with the maximum bill impact, the range in residential bill impacts is between 0 and $1.83 per month.

K.3.5.5 Alternative E

Retail rate increases under Alternative E relative to Alternative A are primarily driven by an increase in capacity of 230 MW that occurs in 10 out of the 20 years of the evaluation, the average of which is more than the reduction in marketable capacity change of 90.21 MW. Replacement of the lost capacity and increased production costs results in varying grid cost impacts over the LTEMP period, some of which are lower than rates and bills under Alternative A. Average grid impacts are $6.4 million per year, which is lower than any of the LTEMP alternatives except Alternatives A and B. When the grid cost is converted into retail rates, the average across all systems and years range from changes that are below zero in years with no capacity change, to a high of 0.497% in 2027. The average percent retail rate increase across all systems for the years 2015 to 2035 is 0.142%. When compared to Alternative D, the average increase across the LTEMP period is slightly less, but the impact in the maximum year is slightly more. For the year 2027, which is the year with the highest rate impact, individual systems experience percentage impacts ranging from 0.03% (SRP) to 1.65% (City of Enterprise).

Residential bill impacts under Alternative E relative to Alternative A range from amounts that are below zero to 47 cents over the LTEMP period. The average increase is 13 cents per month. For the year 2027 with the maximum bill impact, the range in residential bill impacts is between 5 (SRP) and $2.42 per month (Ak-Chin Municipal Electric).

K.3.5.6 Alternative F

Retail rate increases under Alternative F relative to Alternative A are driven by increases in capacity of either 230 MW or 460 MW in various years, as well as varying amounts of production cost increases. The increase in capacity compares to the reduction in marketable capacity of 314 MW. The average grid cost increase under Alternative F is $28.7 million per year. This is much higher than any of the other LTEMP alternatives and equates to 20.11% of the $143 million in SLCA/IP wholesale revenues. The average retail rate increase reaches a high of 1.21% in 2018 and the average percent retail rate increase over the LTEMP period is 0.75%. When compared to the next highest impact scenario, Alternative G, the average impact is almost double. For the year 2018, the year with the maximum rate impact, individual systems experience percentage impacts ranging from 0.08% (SRP) to 4.14% (City of Enterprise, a member of UAMPS), as shown in Tables K.3-5 and K.3-6.

Residential bills under Alternative F that result from the grid cost increases are higher than bills under Alternative A in all years and are $1.02 in the maximum impact year. The average increase in residential bills over the LTEMP period is 69 cents per month. For the year 2018, with the maximum bill impact, the range in residential bill impacts is between 11 cents (SRP) and $5.29 (Ak-Chin Municipal Electric) per month.

K.3.5.7 Alternative G

Retail rate increases under Alternative G relative to the Alternative A are driven by an increase in capacity of 230 MW that occurs from the year 2018 forward, as well as production cost increases. The increase in capacity of 230 MW is more than the reduction in marketable capacity of 179 MW. Average grid cost increases by $17.2 million per year, which is higher than any of the LTEMP alternatives except Alternative F. The average retail rate increase across all systems and years is above zero in all years and reaches a high of 0.638% in 2025. Across the LTEMP period and all systems, the rate increase is 0.418%. When compared to Alternative C, the average increase is almost double and the impact in the maximum year is also higher because of higher production costs. For the year 2025, which is the year with the highest rate impact in this scenario, individual systems experience percentage impacts ranging from 0.04% (SRP) to 2.18% (City of Enterprise).

Residential bill impacts under Alternative G have a high of 59 cents, while the average increase in residential bills is 39 cents per month over the LTEMP period. For the year 2025, with the maximum bill impact, the range in residential bill impacts is between 6 cents (SRP) and $3.08 (Ak-Chin Municipal Electric) per month as shown in Tables K.3-7 and K.3-8.

K.4 FINANCIAL IMPACTS OF LTEMP ALTERNATIVES ON AMERICAN INDIAN TRIBES

The purpose of this section is to estimate the financial impact of LTEMP alternatives on American Indian Tribes that receive an allocation of SLCA/IP electrical power. This section also compares the estimated financial impacts on these Tribes to the estimated financial impacts on other Western FES customers in the SLCA/IP marketing area to see how Tribal financial impacts compare with the financial impacts on others.

Western's post-2004 marketing plan purposely provided SLCA/IP power allocations to over 50 Tribes in its marketing area who historically had not been able to receive the financial benefits of federal hydropower. Western normally requires its customers to operate electric utilities, and most Tribes do not meet that requirement. Tribes are preference power customers, but historically have been underrepresented in Western's customer base. In order to encourage widespread use of federal hydropower, Western made administrative changes to allow numerous Tribes to receive an allocation of power and the associated financial benefits. Western developed a resource pool of sufficient size to target an allocation of 65% of total Tribal electrical use to eligible Tribes.[24] There are 57 Tribes or Tribal entities who currently receive an allocation of SLCA/IP power (directly or indirectly) from Western.

The impact of the alternatives ranges from almost no impact to over $3 million in financial costs for the Tribes, with the average financial impact of all the alternatives being $1.345 million per year. Tribes may be financially impacted in three ways by the LTEMP alternatives:

- Tribes that operate their own utilities may see a change in the rate they pay for SLCA/IP power.

- Tribes that do not operate their own electric utility and have entered into benefit crediting arrangements with another utility to take their allocation, and instead receive an economic benefit from that utility, may see a change in the economic benefit, essentially a change in payment received from that other utility.

- Tribes that have entered into an economic benefit with a utility that also receives SLCA/IP power may see their economic benefit crediting payments change and may experience changes in the retail rates charged to Tribal members.

There are currently 57 Tribes and Tribal entities that received a power allocation from the SLCA/IP resources. The analysis in this report assumes that each of these Tribes will continue to

[24] The final allocation of SLCA/IP power to Tribes was less than the 65% target. In addition, Western adjusted the target allocation to account for Tribes whose reservations were in electrical service areas served by existing SLCA/IP FES customers.

receive its current allocation under each alternative of the LTEMP DEIS. Nine of these Tribes operate electric utilities and receive power directly from Western. The remaining 48 Tribes are not electrical utilities but still receive the benefits of federal hydropower through benefit crediting arrangements with SLCA/IP customers or other electric utilities.

The purpose of benefit crediting is to provide a Tribe with the financial benefits associated with SLCA/IP power—a low-cost capacity and energy resource. This benefit is usually provided to the Tribe by an electrical service provider (supplier) that serves the area in which the Tribe is located. The benefit received by the Tribe is in lieu of a direct delivery of power by Western. It is intended to be the financial equivalent of a direct delivery. Because the SLCA/IP rate is generally lower than the supplier's production cost of electrical power, the difference between these costs is considered the benefit per megawatt-hour received by the Tribe. This cost difference is multiplied by the Tribe's megawatt-hour allocation of SLCA/IP power. The product of these two numbers is the dollar benefit to the Tribe for an SLCA/IP allocation. The supplier provides the Tribe with a dollar benefit. The equation used to determine the benefit is similar to the following:

$$Benefit = SLCA/IP\ Allocation \times (Supplier\ rate - SLCA/IP\ rate) \quad \text{(Eq. 1)}$$

Where:

Benefit = the financial benefit received by the Tribe from the electric service provider ($),
SLCA/IP Allocation = SLCA/IP allocation to the Tribe in the post-2004 marketing period (MWh),
Supplier rate = average production cost (i.e., large customer retail rate) or purchase cost of the electrical supplier ($/MWh), and
SLCA/IP rate = the composite SLCA/IP FES rate ($/MWh).

K.4.1 Contractual Requirements for Calculating and Delivering Benefits to Tribes

In order to accommodate the post-2004 allocations of SLCA/IP electrical power to Tribes, Western contracted with seven electrical wholesale utility customers (suppliers) to establish benefit crediting arrangements, which would allow the Tribes that did not operate electric utilities to benefit from a federal hydropower allocation. Western and the individual Tribes made arrangements with one of the following entities:

- Public Service Company of New Mexico,
- Navajo Tribal Utility Authority,
- Page Electric Utility,
- Tri-State Generation and Transmission Association,
- Salt River Project,
- Aha Macav, or
- Deseret Generation and Transmission.

Each of these suppliers calculates the financial benefit of a Tribe's SLCA/IP power allocation according to language in three-party contracts among Western, the supplier, and the Tribe. The contractual language varies somewhat for each supplier. Below is an excerpt from Western's contract with Public Service Company of New Mexico (PNM) and a Pueblo in New Mexico:

> "7.2 The Economic Benefit shall be calculated each month as follows: Economic Benefit ($) = (Cost A - Cost B)* (kWh scheduled and delivered as the Tribal Allocation). The values of A and B and the method for determining the amount of energy delivered by Western to PNM by month for the Economic Benefit of the Tribe are set forth in Exhibit A attached hereto.
>
> "7.2.1 Cost A is PNM's weighted average generation cost for the Pueblos in PNM's service area as delineated in Exhibit A. Cost A shall be revised as required by PNM to reflect changes in retail generation costs as set forth in Exhibit A attached hereto.
>
> "7.2.2 Cost B is the cost of the Tribal Allocation as delineated in Exhibit A attached hereto. Cost B shall be revised as required by Western to reflect changes in power supply costs as set forth in Exhibit A attached hereto."

Essentially, the benefit each Tribe receives is the difference between the market value of electrical energy and the SLCA/IP wholesale rate multiplied by the Tribe's SLCA/IP allocation. These benefit crediting arrangements are intended to capture the approximate benefit a Tribe would receive from an allocation of SLCA/IP power if it were able to receive it directly to serve its own electric load.

K.4.2 Calculation of Tribal Benefit Baseline under Alternative A (No Action Alternative)

Attachment K-11 lists the Tribes that receive an allocation of SLCA/IP electrical power, the amount of electrical capacity and energy the Tribe is currently allocated (by season), and the utility that serves the Tribal reservation or Tribal lands.

The Tribal benefit was calculated for Alternative A. Note that this benefit calculation differs somewhat from the benefit currently received by the Tribe for two reasons:

- The SLCA/IP rate developed by Western for Alternative A is marginally higher than the actual current SLCA/IP rate.
- The electrical rate of the supplier is estimated in several cases. Western's contracts may refer to "average generation cost" or to the "Class A rate," but the rate of the supplier is typically not quantitatively specified in the contract

language. Therefore, the published rates for the seven suppliers that best conformed to the current contract description were used.

With these data, the calculation of the Tribal economic benefit was determined by inputting the relevant rates and Tribal allocations into Equation 1. It includes both capacity and energy components. This calculation was performed for each Tribe that has entered into a benefit crediting contract. This was not done for the nine Tribes that operate utilities; they do not receive a benefit credit because they directly receive an SLCA/IP allocation.

K.4.3 Calculation of Change in Tribal Benefit as a Result of LTEMP EIS Alternatives

Figure K.4-1 illustrates the method that was used for evaluating the impacts of LTEMP alternatives on the benefit for each Tribe.

The power economic impacts for the DEIS are described in Section K.1. Western used these data to estimate the SLCA/IP FES rate for each alternative. The method used the results that are described in Section K.2. The financial benefit was computed for each Tribe for each alternative using the estimated SLCA/IP rate for each alternative, the estimated supplier's rate, and the Tribal allocations listed in Attachment K-11.

A simplifying assumption was used in this analysis. The Tribal allocations used for the analysis (and listed in Attachment K-11) are SLCA/IP commitment levels from the current marketing plan. This plan expires at the end of FY 2024. It was assumed that these commitment levels would continue through the LTEMP period, which extends through 2035. It should be emphasized that this is an analysis, not a description of policy or attempt to predict Western's post-2024 marketing plan. Although it is a reasonable assumption for the purposes of this analysis that Western will continue existing commitment levels after 2024, the reader should not assume that Western will or will not maintain these levels when the new marketing plan is finalized.

K.4.4 Impacts on Tribes through a Change in the Retail Rate of the Electrical Supplier to Tribal Lands

In addition to the economic impact of the LTEMP alternatives on Tribal benefits, some Tribes receive retail electric service from suppliers (such as rural cooperatives) that are SLCA/IP customers themselves. This means that Tribal households and commercial establishments on Tribal lands could pay a different retail rate for their electricity. If an alternative operating criterion at Glen Canyon Dam causes a change in the SLCA/IP rate, a utility supplying retail service to a Tribe could change its retail rate for electricity as a result of that alternative. Tribal members and commercial establishments on Tribal lands (households and businesses) could incur a change in their electrical utility bills as a result.

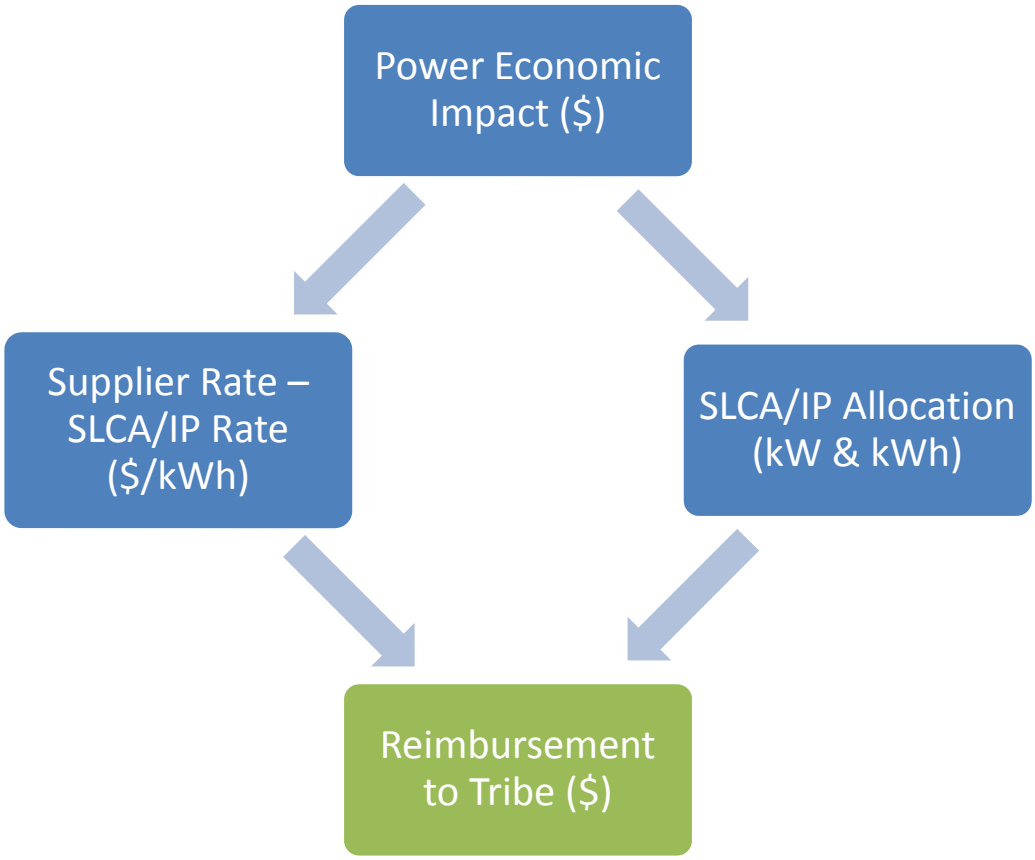

FIGURE K.4-1 Calculation of Change in Tribal Benefit Resulting from LTEMP DEIS Alternatives

Attachment K-11 includes the list of the Tribes receiving their SLCA/IP allocation from a supplier along with the name of the electrical supplier that serves the Tribal reservation or Tribal lands. Section K.3 includes the estimated retail rate change for SLCA/IP customers by alternative. The financial impacts on the Tribes based on changes in the SLCA/IP rate were calculated using the following equation:

$$\textit{Financial Loss/Gain} = \textit{Total Reservation Electricity Consumption}^{25} \times \textit{Change in Retail Rate}^{26} \quad \text{(Eq. 2)}$$

Attachment K-12 is a list of Tribes receiving SLCA/IP allocations and the estimated total electrical use by Tribe. These data were partly gathered and required by Western as part of the development of the post-2004 marketing plan. They are referred to as applicant profile data.

25 This estimate is for the year 2015. It is therefore an annual amount of electrical energy used. The financial loss or gain should be interpreted as an annual financial impact.

26 These estimated changes in retail rates by alternative are taken directly from Section K.3.

These applicant profile data are believed to be out of date because they are based on electrical use by Tribes in 1998. However, more current data on Tribal electrical use were not readily available or published. Therefore, the amounts of electrical energy shown in Attachment K-12 were escalated by 2.5% per year to 2015.[27] The estimated Tribal electricity use calculated with Equation 2 is therefore an escalated amount and represents an estimate of the current electrical use by Tribes.

The estimated 2015 total electrical use by Tribal households and commercial establishments on Tribal lands was multiplied by the change in the retail rate estimated for the electrical service supplier—which is an SLCA/IP FES customer—as derived from the analysis described in Section K.3. This results in an estimated increase (or decrease) in the retail electrical utility costs paid by each Tribe annually under each alternative (via the Tribal members who live on Tribal lands).

K.4.5 Calculation of Tribal Impacts for Tribes That Are Direct SLCA/IP Recipients

For the Tribes that operate electrical utilities and receive SLCA/IP power directly from Western, the impacts of LTEMP alternatives were calculated. This calculation is the difference in the SLCA/IP FES rate between each of the action alternatives and the No Action alternative multiplied by the total escalated electrical use for each Tribe. Multiplying the change in SLCA/IP rate (from Section K.2) by the escalated Tribal electrical use yields the estimated financial impacts for each of the LTEMP DEIS alternatives on each of the nine Tribes that receive SLCA/IP allocations directly from Western.

Table K.4-1 is the result of the retail-rate impact analysis for the average household on a Tribal reservation or on Tribal lands. The estimates, by Tribe, presented in Table K.4-1 describe how a residential household might be impacted by the LTEMP DEIS alternatives due to a changed retail rate. The numbers in Table K.4-1 are taken from the retail rate impact analysis described in Appendix K.3. That analysis computed the monthly change in an electric utility bill for an average residence across the SLCA/IP market footprint. Table K.4-2 shows this change. It is extracted from similar information in Section K.3. It assumes that residences on Tribal lands incur the same change in residential monthly electrical utility bills as other residences in the same electrical service area.

For example, the reservation of the Ute Tribe is electrically served by Moon Lake Electric. According to the estimate in Section K.3, Moon Lake Electric residences will pay slightly over a dollar a month more for electricity under Alternative F. It was assumed that the residences of the Ute Tribe on the Ute reservation, served by Moon Lake Electric, will also pay slightly over a dollar a month more for electricity under Alternative F. Remember that the information in Table K.4-1 is one of two financial impacts on the Tribes caused by the alternatives. The total financial impact on Tribes is presented in Table K.4-2.

[27] Based on data reported by the EIA, 2.5% is the approximate average annual increase in electrical energy use over the last decade in states where Tribal entities reside.

TABLE K.4-1 Monthly Change in Residential Electric Utility Bill for Tribes by Alternative

	Difference from Alternative A					
Tribal Entity	Alternative B	Alternative C	Alternative D	Alternative E	Alternative F	Alternative G
Tribes that Operate Their Own Utility						
Navajo Tribal Utility Authority	–0.035	0.339	0.234	0.211	1.011	0.591
Navajo Agricultural Products Industries	NA	NA	NA	NA	NA	NA
Ak-Chin Indian Community	–0.123	1.187	0.820	0.740	3.539	2.069
Tohono O'Odham Utility Authority	–0.013	0.122	0.084	0.076	0.362	0.212
Fort Mojave Indian Tribe	–0.032	0.309	0.214	0.193	0.922	0.539
Bureau of Indian Affairs Colorado River Agency	NA	NA	NA	NA	NA	NA
San Carlos Irrigation Project	NA	NA	NA	NA	NA	NA
Jicarilla Apache Tribe	NA	NA	NA	NA	NA	NA
Gila River Indian Community	NA	NA	NA	NA	NA	NA
Tribes That Have a Benefit Contracting Arrangement						
Alamo Navajo Chapter	–0.012	0.115	0.080	0.072	0.344	0.201
Canoncito Navajo Chapter	–0.014	0.134	0.092	0.083	0.399	0.233
Cocopah Indian Tribe	0.000	0.000	0.000	0.000	0.000	0.000
Colorado River Indian Tribes	0.000	0.000	0.000	0.000	0.000	0.000
Confederated Tribes of the Goshute Reservation	–0.015	0.145	0.100	0.091	0.433	0.253
Duckwater Shoshone Tribe	–0.015	0.145	0.100	0.091	0.433	0.253
Ely Shoshone Tribe	–0.015	0.145	0.100	0.091	0.433	0.253
Ft. McDowell Mojave-Apache Indian Community	–0.016	0.158	0.109	0.099	0.471	0.275
Havasupai Tribe	–0.123	1.187	0.820	0.740	3.539	2.069
Hopi Tribe	–0.007	0.065	0.045	0.041	0.195	0.114
Hualapai Tribe	0.000	0.000	0.000	0.000	0.000	0.000
Las Vegas Paiute Tribe	0.000	0.000	0.000	0.000	0.000	0.000
Mescalero Apache Tribe	–0.021	0.206	0.142	0.128	0.614	0.359
Nambe Pueblo	–0.026	0.246	0.170	0.153	0.733	0.429
Paiute Indian Tribe of Utah	0.000	0.000	0.000	0.000	0.000	0.000
Pascua Yaqui Tribe	–0.123	1.187	0.820	0.740	3.539	2.069
Picuris Pueblo	–0.018	0.170	0.118	0.106	0.508	0.297
Pueblo De Cochiti	0.000	0.000	0.000	0.000	0.000	0.000
Pueblo of Acoma	–0.014	0.134	0.092	0.083	0.399	0.233
Pueblo of Isleta	0.000	0.000	0.000	0.000	0.000	0.000
Pueblo of Jemez	–0.026	0.246	0.170	0.153	0.733	0.429
Pueblo of Laguna	–0.014	0.134	0.092	0.083	0.399	0.233
Pueblo of Pojoaque	–0.026	0.246	0.170	0.153	0.733	0.429
Pueblo of San Felipe	0.000	0.000	0.000	0.000	0.000	0.000
Pueblo of San Ildefonso	–0.026	0.246	0.170	0.153	0.733	0.429
Pueblo of San Juan	–0.026	0.246	0.170	0.153	0.733	0.429

TABLE K.4-1 (Cont.)

Tribal Entity	Difference from Alternative A: Alternative B	Alternative C	Alternative D	Alternative E	Alternative F	Alternative G
Tribes That Have a Benefit Contracting Arrangement						
Pueblo of Sandia	0.000	0.000	0.000	0.000	0.000	0.000
Pueblo of Santa Clara	–0.026	0.246	0.170	0.153	0.733	0.429
Pueblo of Santo Domingo	0.000	0.000	0.000	0.000	0.000	0.000
Pueblo of Taos	–0.018	0.170	0.118	0.106	0.508	0.297
Pueblo of Tesuque	0.000	0.000	0.000	0.000	0.000	0.000
Pueblo of Zia	–0.026	0.246	0.170	0.153	0.733	0.429
Pueblo of Zuni	–0.014	0.134	0.092	0.083	0.399	0.233
Quechan Indian Tribe	0.000	0.000	0.000	0.000	0.000	0.000
Ramah Navajo Chapter	–0.014	0.134	0.092	0.083	0.399	0.233
Salt River Pima-Maricopa Indian Community	–0.016	0.158	0.109	0.099	0.471	0.275
San Carlos Apache Tribe	0.000	0.000	0.000	0.000	0.000	0.000
Santa Ana Pueblo	0.000	0.000	0.000	0.000	0.000	0.000
Skull Valley Band of Goshute Indians	0.000	0.000	0.000	0.000	0.000	0.000
Southern Ute Indian Tribe	–0.011	0.106	0.073	0.066	0.317	0.185
Tonto Apache Tribe	0.000	0.000	0.000	0.000	0.000	0.000
Ute Indian Tribe	–0.009	0.086	0.059	0.054	0.256	0.150
Ute Mountain Ute Tribe	–0.035	0.338	0.234	0.211	1.009	0.590
White Mountain Apache Tribe	0.000	0.000	0.000	0.000	0.000	0.000
Wind River Reservation	–0.020	0.189	0.130	0.118	0.562	0.329
Yavapai Apache Nation	0.000	0.000	0.000	0.000	0.000	0.000
Yavapai Prescott Indian Tribe	0.000	0.000	0.000	0.000	0.000	0.000
Yomba Shoshone Tribe	0.000	0.000	0.000	0.000	0.000	0.000

TABLE K.4-2 Total Dollar Annual Impact on Tribes under LTEMP Alternatives Relative to Alternative A

Tribal Entity	SLCA/IP Allocation (MWh)	Difference from Alternative A ($)					
		Alternative B	Alternative C	Alternative D	Alternative E	Alternative F	Alternative G
Tribes That Operate Their Own Utility							
Navajo Tribal Utility Authority	183,625	9,090	205,442	183,625	139,991	936,304	1,110,839
Navajo Agricultural Products Industries	49,046	2,452	55,422	49,536	37,765	252,587	299,671
Ak-Chin Indian Community	11,356	562	12,705	11,356	8,658	57,905	68,699
Tohono O'Odham Utility Authority	7,765	384	8,687	7,765	5,920	39,592	46,973
Fort Mojave Indian Tribe	1,036	51	1,159	1,036	790	5,282	6,266
Bureau of Indian Affairs Colorado River Agency	2,451	121	2,742	2,451	1,868	12,497	14,826
San Carlos Irrigation Project	5,919	293	6,622	5,919	4,512	30,179	35,805
Gila River Indian Community	148,828	–13,860	206,171	148,828	128,785	705,437	564,644
Jicarilla Apache Tribe	2,464	122	2,757	2,464	1,879	12,566	14,909
Tribes That Have a Benefit Contracting Arrangement							
Alamo Navajo Chapter	1,222	–50	1,575	1,222	1,012	5,954	5,640
Canoncito Navajo Chapter	900	–37	1,159	900	745	4,382	4,151
Cocopah Indian Tribe	4,355	216	4,873	4,355	3,321	22,209	26,348
Colorado River Indian Tribes	18,072	895	20,219	18,072	13,778	92,150	109,327
Confederated Tribes of the Goshute Reservation	292	–7	367	292	238	1,432	1,418
Duckwater Shoshone Tribe	389	–10	490	389	318	1,912	1,892
Ely Shoshone Tribe	595	–15	749	595	486	2,923	2,895
Ft. McDowell Mojave-Apache Indian Community	8,895	380	10,065	8,895	6,825	45,202	52,851
Havasupai Tribe	887	29	1,021	887	687	4,484	5,124
Hopi Tribe	22,836	(1,580)	30,613	22,836	19,366	109,616	95,282
Hualapai Tribe	2,304	114	2,578	2,304	1,757	11,748	13,938

TABLE K.4-2 (Cont.)

Tribal Entity	SLCA/IP Allocation (MWh)	Difference from Alternative A ($)					
		Alternative B	Alternative C	Alternative D	Alternative E	Alternative F	Alternative G
Las Vegas Paiute Tribe	2,310	114	2,585	2,310	1,761	11,780	13,976
Mescalero Apache Tribe	6,322	–261	8,147	6,322	5,235	30,792	29,163
Nambe Pueblo	399	–16	514	399	330	1,942	1,840
Paiute Indian Tribe of Utah	583	29	652	583	445	2,973	3,527
Pascua Yaqui Tribe	4,754	153	5,472	4,754	3,684	24,035	27,463
Picuris Pueblo	312	–13	402	312	258	1,518	1,432
Pueblo De Cochiti	767	38	858	767	585	3,912	4,641
Pueblo of Acoma	2,669	–110	3,439	2,669	2,210	12,999	12,310
Pueblo of Isleta	4,123	204	4,612	4,123	3,143	21,021	24,940
Pueblo of Jemez	1,542	–63	1,986	1,542	1,276	7,510	7,117
Pueblo of Laguna	4,809	–199	6,197	4,809	3,982	23,422	22,183
Pueblo of Pojoaque	1,544	–63	1,989	1,544	1,278	7,523	7,130
Pueblo of San Felipe	1,406	70	1,573	1,406	1,072	7,168	8,504
Pueblo of San Ildefonso	409	–17	527	409	338	1,990	1,885
Pueblo of San Juan	1,935	–80	2,494	1,935	1,602	9,425	8,926
Pueblo of Sandia	3,278	162	3,668	3,278	2,499	16,717	19,833
Pueblo of Santa Clara	1,541	–63	1,986	1,541	1,276	7,507	7,115
Pueblo of Santo Domingo	1,662	82	1,859	1,662	1,267	8,472	10,051
Pueblo of Taos	1,811	–74	2,332	1,811	1,499	8,823	8,367
Pueblo of Tesuque	2,288	113	2,560	2,288	1,744	11,666	13,841
Pueblo of Zia	493	–20	635	493	408	2,402	2,277
Pueblo of Zuni	7,101	–293	9,148	7,101	5,879	34,587	32,771
Quechan Indian Tribe	2,319	115	2,595	2,319	1,768	11,825	14,029
Ramah Navajo Chapter	2,295	–94	2,956	2,295	1,899	11,178	10,597
Salt River Pima-Maricopa Indian Community	56,758	2,423	64,225	56,758	43,551	288,436	337,237

TABLE K.4-2 (Cont.)

Tribal Entity	SLCA/IP Allocation (MWh)	Difference from Alternative A ($)					
		Alternative B	Alternative C	Alternative D	Alternative E	Alternative F	Alternative G
San Carlos Apache Tribe	14,791	732	16,549	14,791	11,277	75,421	89,480
Santa Ana Pueblo	1,622	80	1,814	1,622	1,236	8,269	9,810
Skull Valley Band of Goshute Indians	56	3	63	56	43	286	339
Southern Ute Indian Tribe	7,391	–305	9,523	7,391	6,119	35,996	34,095
Tonto Apache Tribe	1,364	68	1,527	1,364	1,040	6,957	8,254
Ute Indian Tribe	4,835	(342)	6,495	4,835	4,105	23,190	20,060
Ute Mountain Ute Tribe	3,169	(131)	4,083	3,169	2,623	15,432	14,618
White Mountain Apache Tribe	22,090	1,094	24,715	22,090	16,841	112,639	133,636
Wind River Reservation	7,284	(823)	10,361	7,284	6,408	34,163	25,349
Yavapai Apache Nation	6,246	309	6,988	6,246	4,762	31,848	37,784
Yavapai Prescott Indian Tribe	2,877	142	3,219	2,877	2,193	14,670	17,404
Yomba Shoshone Tribe	116	6	129	116	88	589	699
Total	658,509	–336	738,872	609,463	486,660	3,030,857	3,204,513
Total for Systems that Operate Utility		10,503	237,357	212,151	161,739	1,081,759	1,283,408
Total for Systems with Benefit Contracts		–10,839	501,515	397,312	324,921	1,949,098	1,921,105

K.4.6 Total Impact of LTEMP DEIS Alternatives: Benefit Change and Rate Effect

Table K.4-2 lists the estimated Tribal financial impact by alternative relative to the impact under Alternative A. Table K.4-2 lists the total annual financial impact, which is (1) the change in Tribal benefit plus (2) the increase in the electrical utility bill of Tribal households and businesses due to a change in the SLCA/IP FES customers' retail rate.[28] Negative numbers indicate a positive financial benefit (this only occurs under Alternative B). Note that:

- Tribes whose electrical service is provided by a non-SLCA/IP FES customer have no retail rate change, but do experience a change in Tribal benefits;
- The Tribes that operate their own utility have no change in Tribal benefits, but do experience a change in retail rates; and
- Tribes whose lands are served by SLCA/IP customers are impacted by both a change in retail rate and a change in Tribal benefits.

Alternative impacts listed in Table K.4-2 include the sum of both types of financial impacts.[29] Alternative impacts included in Table K.4-2 are good indications of the rank order of the alternatives and the direction of impacts (positive or negative), and they describe an estimated financial impact under current contractual obligations. These financial impacts would continue beyond 2024 if contract commitments to all FES customers including Tribes and Tribal entities do not change. They represent one possible outcome of the post-2024 marketing plan. For the final EIS, assumptions concerning post-2024 commitment levels may be revised to duplicate the range examined in the economic analysis described in Section K.1.

K.4.7 Total Impact on Tribes and Tribal Members Versus Retail Rate Changes to Households

Figures K.4-2 through K.4-7 illustrate the difference between the total financial impact of the alternatives on Tribes as compared to the financial impact on non-Tribal households and businesses that receive retail service from utilities that are SLCA/IP customers.

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[28] Table K.4-2 shows the total financial impact. The separate financial impacts from a change in Tribal benefits and from a change in the electrical utility payments made by Tribal households and businesses were calculated but not shown here because of space limitations.

[29] The Tribal benefit calculation is the difference the Supplier's average production cost and the SLCA/IP rate multiplied by the Tribe's SLCA/IP allocation. For simplicity, the authors assume that the supplier's average production cost does not change as a result of an LTEMP DEIS alternative. It is more likely that an increase in a SLCA/IP rate will result in a lesser increase in the average production cost of a SLCA/IP FES customer. Therefore, the calculations of Tribal benefit change are overestimates for those Tribes that are served by SLCA/IP FES customers.

The financial impacts on non-Tribal households and businesses are, for illustrative purposes in this analysis, the percentage change in the electrical retail rate for the SLCA/IP FES customer (or their utility system member that provides retail electrical service in a service area). This information is a duplication of the analysis included in Appendix K.3, which is the retail rate analysis of the alternatives. In Figures K.4-2 through K.4-7, the blue lines illustrate non-Tribal SLCA/IP FES customers or member systems and are the same data that are included in Section K.3.

An increase (decrease) in the retail rates of an SLCA/IP FES customer or member system causes a financial effect (positive or negative) on households and businesses in the utilities' service area by increasing (decreasing) the electrical utility cost paid. This change in the utility bill and the resulting financial effect at the household/business level is approximately equivalent to the financial impact on Tribes and Tribal members.

Figures K.4-2 through K.4-7 present the percentage difference (compared to Alternative A) of financial impacts on Tribes and non-Tribes[30] for each alternative. Alternative B is the only alternative that results in a reduction in impacts relative to Alternative A (Figure K.4-3). The financial impacts of Alternatives C, D, and E are relatively similar (Figures K.4-3 through K.4-5), but greater than under either Alternative A or Alternative B. The financial impacts of Alternatives F and G are relatively similar to each other (Figure K.4-3), and higher than under any of the other alternatives. Alternative F has the highest financial impacts of any alternative.

K.4.8 Conclusions

Several conclusions can be drawn from this analysis:

- LTEMP alternatives are estimated to have a financial effect on Tribes that receive an SLCA/IP allocation. Compared to Alternative A, the impact is negative for Alternatives C, D, E, F, and G. These impacts are larger for Alternatives F and G. The financial impact on Tribes under Alternative B is largely positive.

- The financial impacts on Tribes are from two sources:

    - A change in the Tribal benefits provided to the Tribes under benefit crediting contracts; and

    - A change in the electrical utility bills paid by Tribal members and businesses that receive retail service from a supplier that receives an SLCA/IP allocation.

[30] The total percentage change is measured on the y-axis. For Tribal entities, this percentage change is the sum of the retail rate impact and the Tribal benefit impact. For non-Tribal SLCA/IP customers or members systems, it is the percentage change from the retail rate impact.

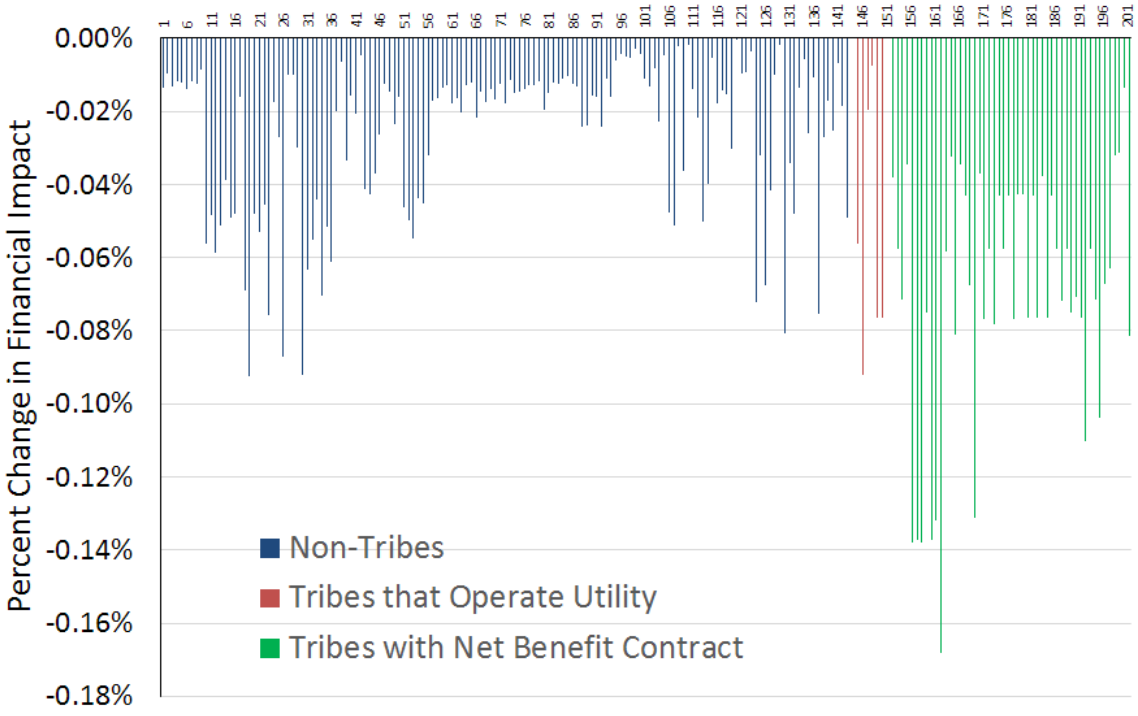

FIGURE K.4-2 Financial Impacts under Alternative B Relative to Alternative A for Tribal and Non-Tribal Entities

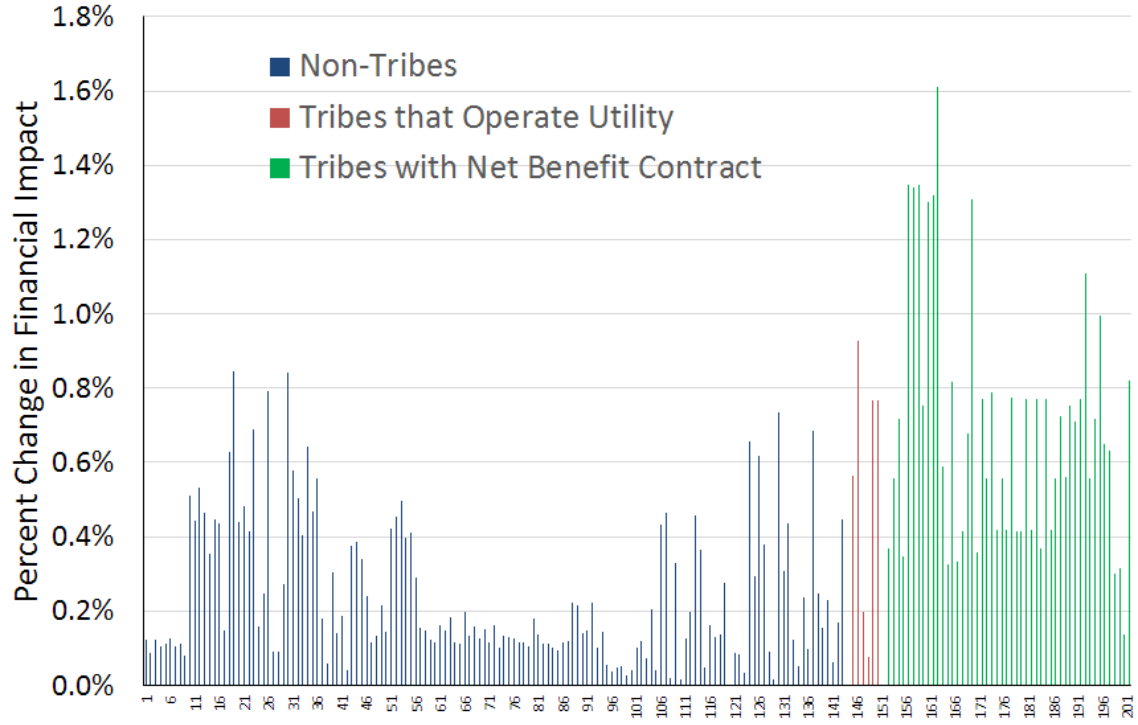

FIGURE K.4-3 Financial Impacts under Alternative C Relative to Alternative A for Tribal and Non-Tribal Entities

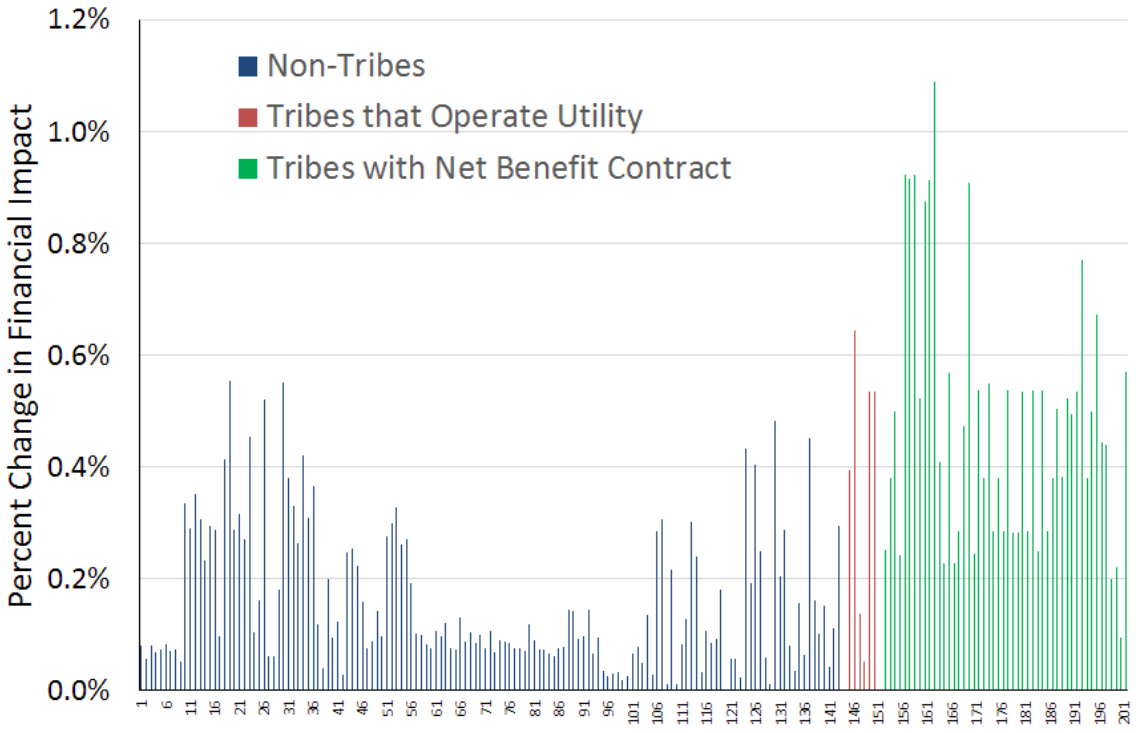

FIGURE K.4-4 Financial Impacts under Alternative D Relative to Alternative A for Tribal and Non-Tribal Entities

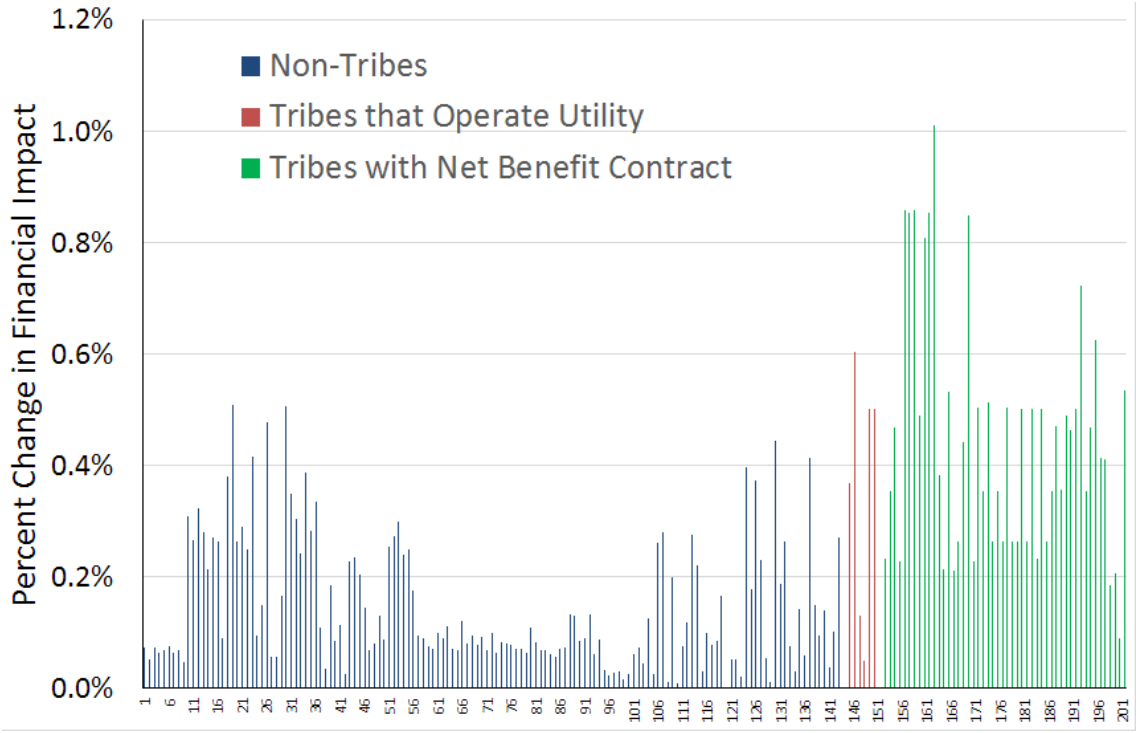

FIGURE K.4-5 Financial Impacts under Alternative E Relative to Alternative A for Tribal and Non-Tribal Entities

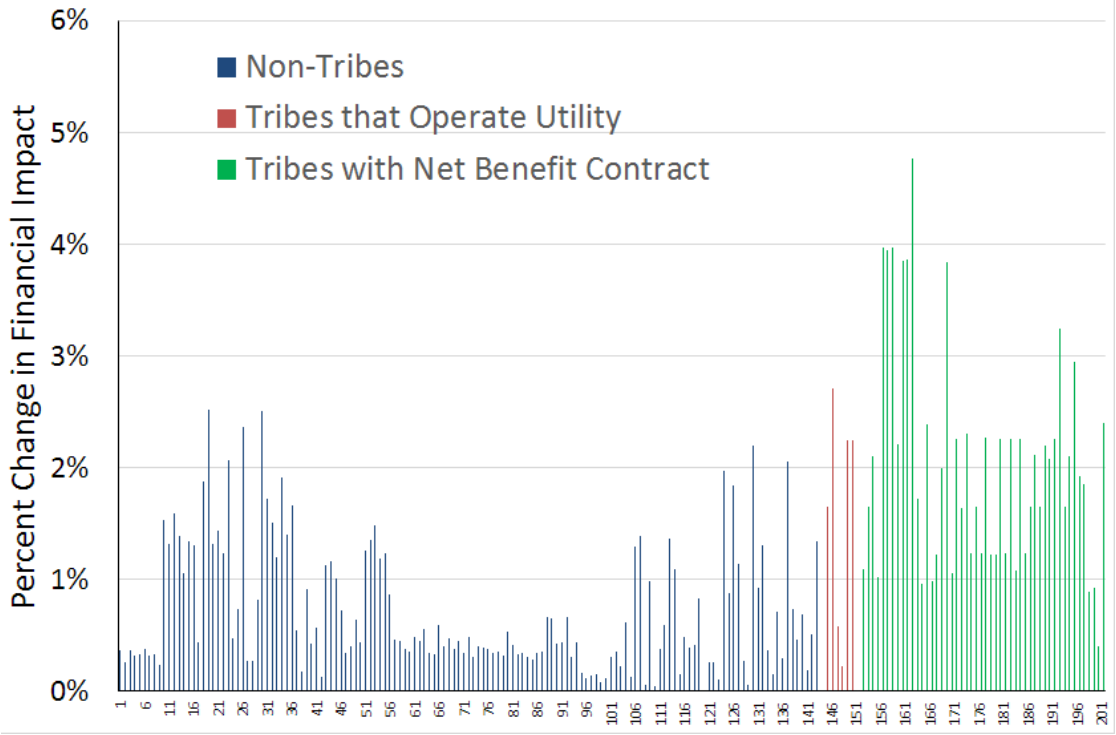

FIGURE K.4-6 Financial Impacts under Alternative F Relative to Alternative A for Tribal and Non-Tribal Entities

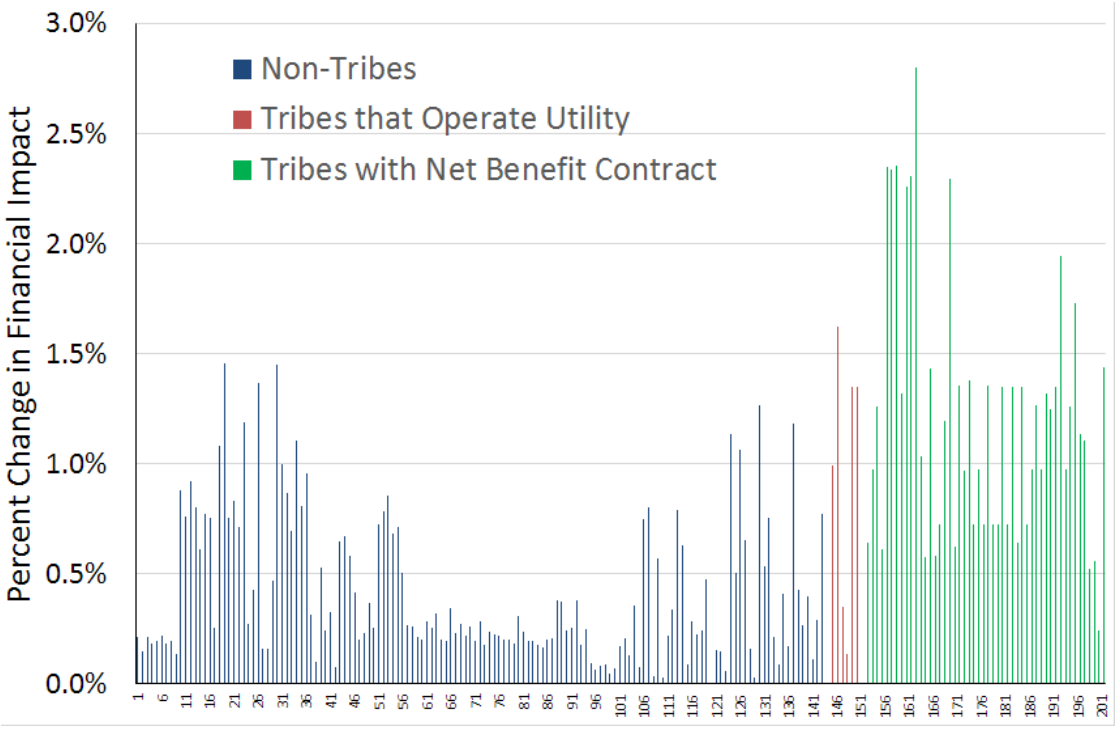

FIGURE K.4-7 Financial Impacts under Alternative G Relative to Alternative A for Tribal and Non-Tribal Entities

- These two sources of financial impact are additive for some Tribes—those who receive Tribal benefits and whose reservation or Tribal land is served by electrical utilities that are SLCA/IP FES customers.

- Tribal financial impacts for Alternatives C, D, E, F, and G, relative to Alternative A, are larger than the financial impacts on non-Tribes.

K.5 IMPACTS OF LTEMP ALTERNATIVES ON LAKE MEAD AND THE HOOVER DAM POWERPLANT

Water released from Lake Powell through the Glen Canyon Dam travels down the Colorado River through GCNP and then into the Lake Mead Reservoir. By the time the water travels the roughly 370 river miles from Lake Powell to Lake Mead, hourly water release fluctuations from the Glen Canyon Dam are almost completely attenuated. However, changes from Lake Powell current monthly water release volumes under LTEMP alternative operating criteria will impact pool elevations in Lake Mead. For example, under Alternative F Lake Powell monthly water releases from late winter through spring are higher than for Alternative A (Figure K.5-1), raising the pool elevation at Lake Mead above levels projected under Alternative A from April through November (Figure K.5-2). Because Glen Canyon Dam annual release volumes under all alternatives are nearly identical, the impacts of changed operations are within an annual time frame. Note that in Figure K.5-2 both alternatives have nearly the same average end-of-month (EOM) pool elevation in December.

Changes in Glen Canyon Dam monthly water release volumes have the greatest impact on Lake Mead, and therefore the Hoover Powerplant, when the pool elevation is low. Figure K.5-3 shows the Lake Mead Reservoir storage-elevation curve (primary y-axis) and the change in the Mead pool elevation as a function of change in the water storage volume (secondary y-axis). When the water storage (and therefore the pool elevation) is low, an additional million acre-feet (maf) of water increases the pool elevation substantially more than when the reservoir is nearly full. For example, when Lake Mead contains 4 maf (992.8 ft pool elevation) an additional 1 maf will increase the pool elevation by about 17.4 ft. At the other extreme, when Lake Mead contains 24 maf (1,205.6 ft pool elevation) an additional 1 maf of water increases the pool elevation by only 7.0 ft; that is, a rate of elevation change that is about 2.5 times less than at low pool.

A changed Lake Mead pool elevation in turn impacts Hoover Dam Powerplant firm capacity and energy generated by water releases through its turbines. When Lake Mead is full, the 17 France turbines and 2 Pelton Waterwheel station service units that are located in the Hoover Dam Powerhouse have a combined hydropower capacity of approximately 2,074 MW (http://www.usbr.gov/lc/hooverdam/faqs/powerfaq.html and https://www.wapa.gov/About/Pages/power-projects.aspx); that is significantly larger than the 1,356 MW nameplate capacity of the Glen Canyon Dam Powerplant. In addition, unlike operating criteria at Glen Canyon Dam, which does not typically permit powerplant schedulers and operators to realize its full output potential, the Hoover Powerplant is allowed to routinely generate up to its maximum output as dictated by the pool elevation of Lake Mead. Because the Parker Dam and the Davis Dam

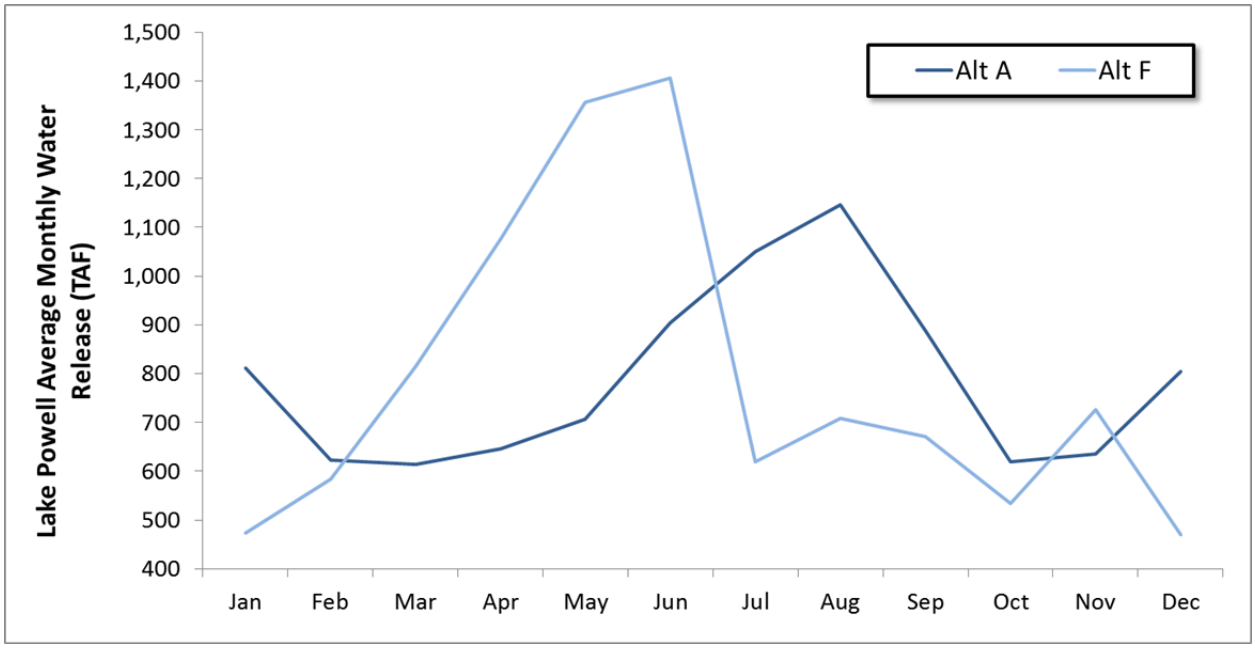

FIGURE K.5-1 Comparison of Alternative A and Alternative F Lake Powell Average Monthly Water Releases over the 20-Year Study Period and 21 Hydrology Traces

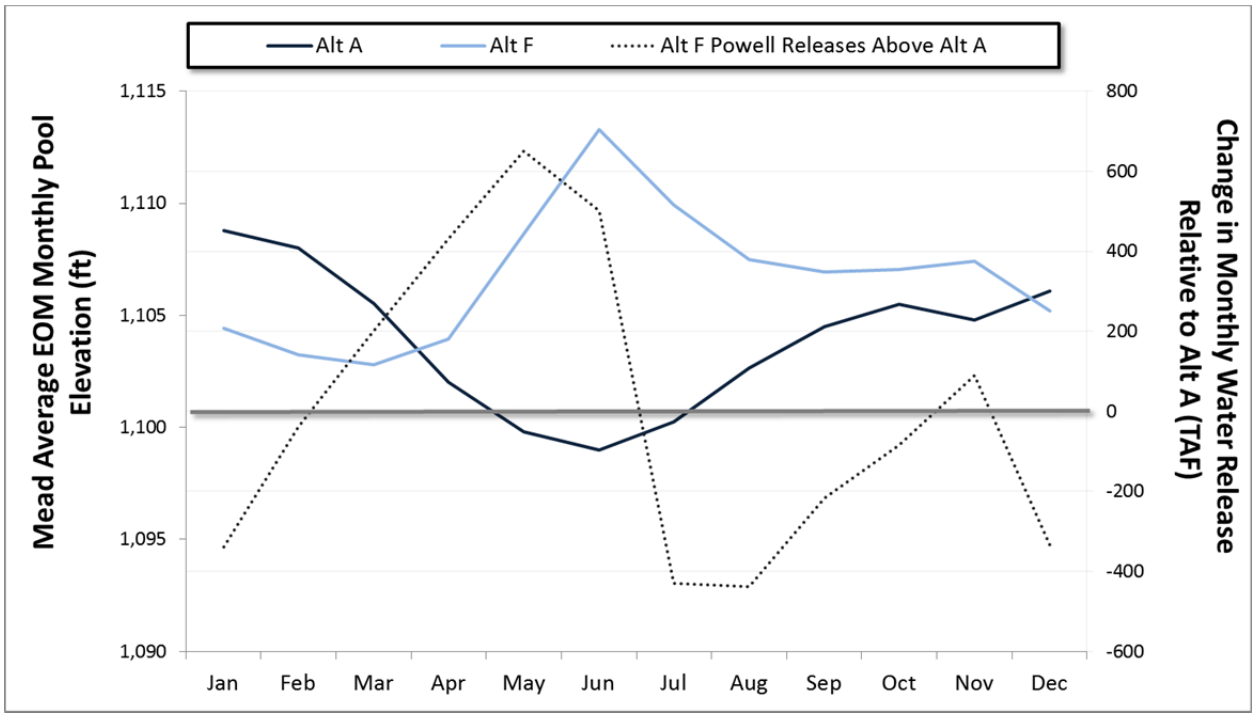

FIGURE K.5-2 Impact of Changed Lake Powell Month Water Release Volumes on Mead Average EOM Pool Elevations

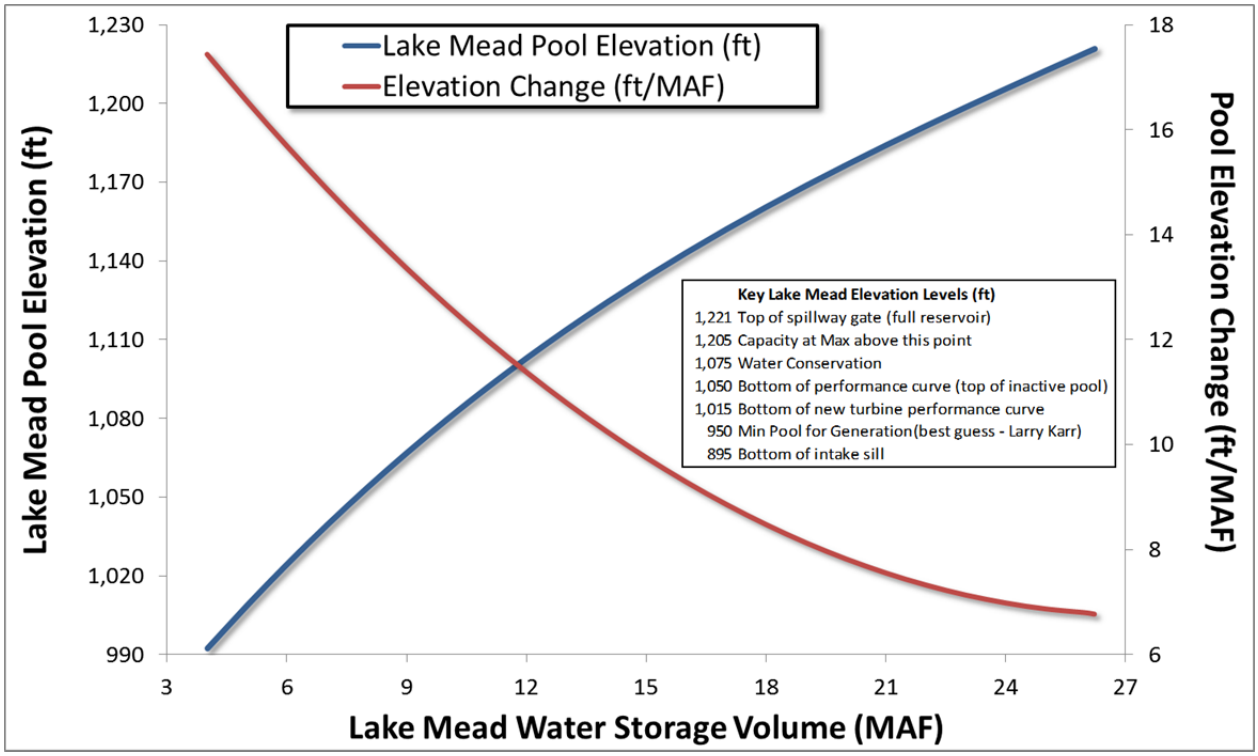

FIGURE K.5-3 Lake Mead Storage Elevation Curve and Change in Elevation as a Function of Lake Mead Water Storage

Projects provide re-regulation of the Colorado River downstream from Hoover Dam, powerplant hourly operations are allowed to fluctuate nearly unfettered by environmental operating criteria. On the other hand, Lake Mead monthly release volumes are largely dictated by downstream water delivery obligations.

Alternative Glen Canyon Dam operating criteria evaluated in the LTEMP DEIS will impact Hoover's Powerplant operation and therefore its economic value. The monthly allocation of annual releases from Lake Powell, and hence inflows into Lake Mead, affect several aspects of the Hoover Powerplant. The most significant factors impacting the Hoover Powerplant include changes in (1) the routing of Lake Mead's water releases[31]; (2) conversion of Lake Mead water releases into electricity (i.e., energy) production[32]; (3) maximum operating output capability[33] and firm capacity[34]; and (4) in some situations, but not all, monthly water release

31 For this analysis, a distinction is made between water that is routed through the powerplant turbines and water that bypasses the dam and powerplant.

32 Turbine water releases convert the kinetic energy of falling water into mechanical energy which is then converted to electricity by a generator. The volume of water needed to generate 1 MWh of electricity is a function of several factors.

33 For this analysis, we distinguish between the capacity of the powerplant and its output potential, which varies as a function of hydraulic head. It is assumed that the powerplant output potential decreases with lower Lake Mead pool elevations. The output potential or maximum output level is sometimes referred to as derated capacity.

volumes from Lake Mead. In terms of the economic impacts of alternatives on the Hoover Powerplant, the first two tend to be much larger than the latter two. As discussed in more detail below, Hoover Powerplant impacts are the greatest when Lake Mead has low water levels because the powerplant's maximum physical power output is significantly more sensitive at low pool as compared to high pool. This is exacerbated by the fact that when Lake Mead contains relatively little water, the pool elevation is more sensitive to change in storage volume (Figure K.5-3).

For the LTEMP DEIS, a model of Hoover Powerplant monthly operations was developed to provide approximations of LTEMP impacts on Hoover Powerplant economics; that is, to estimate the general magnitude and ranking of LTEMP alternative impacts on Hoover power. Two Hoover economic metrics, both in terms of net present value (NPV), were computed for each alternative; namely, firm capacity and energy. The following sections describe the methods, model, and comparative impacts of LTEMP alternatives on Lake Mead, Hoover Powerplant operations, and power system economics.

K.5.1 Hoover Methods, Model, and Supporting Data

The methods and the tool developed to estimate comparative impacts of LTEMP alternatives on Hoover Powerplant operations and economics use many of the same underlying assumptions and input data/information that were used for both the Glen Canyon Dam Structured Decision Analysis (SDA) and the SLCA/IP power systems economic analysis. However, this tool, referred to in this report as the "Hoover Powerplant Model," does not produce as rigorous an analysis.

The Hoover Powerplant Model utilizes monthly Lake Mead water release volumes and EOM reservoir pool elevations that are projected by the Sand Budget Model (SBM) for 21 hydrology traces over the 20-year LTEMP study period. The SBM relies on results from both the CRSS model and the lite version of the Generation and Transmission Maximization (GTMax-lite) model. For each alternative and hydrology trace, the SBM schedules HFEs at Glen Canyon Dam. Because an experiment typically requires a large water release volume, the SBM reallocates Glen Canyon Dam monthly water releases within a WY in order to provide the HFE with a sufficient amount of water. Note that the SBM only reallocates water within the same WY, not among WYs. The SBM does <u>not</u> alter Hoover Dam monthly water releases. It does, however, change CRSS Lake Mead monthly inflows, water storage volumes, and reservoir elevations in order to maintain a water mass balance in the Colorado River Basin.

The Hoover Powerplant Model uses monthly average market on-peak and off-peak prices computed from hourly prices for the Palo Verde hub. These are the same hourly prices used in the SDA and power systems economic analysis. In addition, as for the SDA approach, firm

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[34] Firm capacity in this study is based on the Hoover Powerplant's output potential during the time of system peak load at a specified probability level. For this analysis, the powerplant firm capacity is set to the output potential that is equal to or higher than the firm capacity level 90% of the time during the month of August.

hydropower capacity is based on a 90th percentile exceedance level during the month of August. Other factors such as unit random outage probabilities and unit maintenance schedules can also factor into powerplant maximum (potential) output levels and firm capacity computations, but were not included in this simpler model.

The economic value of Hoover firm capacity is based on the same replacement costs as those used for the SDA and very similar to the average costs used in the power systems economic analysis. It is based on the levelized cost of capital plus annual fixed O&M costs to construct a new advanced combustion turbine (CT), which amounts to $51,300/MW-yr. However, as discussed later, these capacity replacement costs are irrelevant to the final economic cost computation. The time series of Hoover economic costs are discounted at the same 3.375% annual rate used in the SDA and power systems analysis.

K.5.2 Hoover Monthly Energy Production and Water-to-Power Conversion

The Hoover Powerplant Model estimated powerplant monthly energy production over the 20-year LTEMP study period based on SBM monthly projections of Lake Mead EOM pool elevation and Hoover Dam monthly water releases for each of the 21 hydrology traces. A model-derived water-to-power conversion factor[35] was multiplied by the SBM monthly water release volume to project monthly Hoover Powerplant energy production. The operating characteristics of the Hoover Powerplant were based on and derived from information provided by Reclamation.

The Hoover Powerplant Model estimated future water-to-power conversion factors using an equation that relates both monthly EOM Lake Mead pool elevation and total Hoover plant-level turbine water releases to energy production. Argonne derived the form of the water-to-power conversion equation and its coefficients based on historical Mead and Hoover data, as recorded in Form PO&M-59, which was supplied by Reclamation. The equation is composed of two components. The first component is a linear relationship between the conversion factor and the pool elevation. The second component relates the conversion factor to monthly water release volumes in the form of a third-order polynomial function. To assess the accuracy of the derived equation, a back-casting exercise was conducted. Results of this exercise are shown in Figure K.5-4. Due to the implementation and application of new software at Hoover Dam that optimizes the powerplant unit dispatch to increase plant-level power conversion efficiency, equation coefficients in the period prior to March 2011 differ from the coefficients used after this date.[36]

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35 The water-to-power conversion factor, expressed in terms of MWh/ac-ft equals the monthly turbine water release (ac-ft) divided by monthly generation. Note that this conversion factor only includes turbine releases; that is, bypass water is excluded.

36 McManes (2014) discusses the change in Hoover Powerplant efficiency (3.4% improvement) that results from using unit dispatch software to guide power operations.

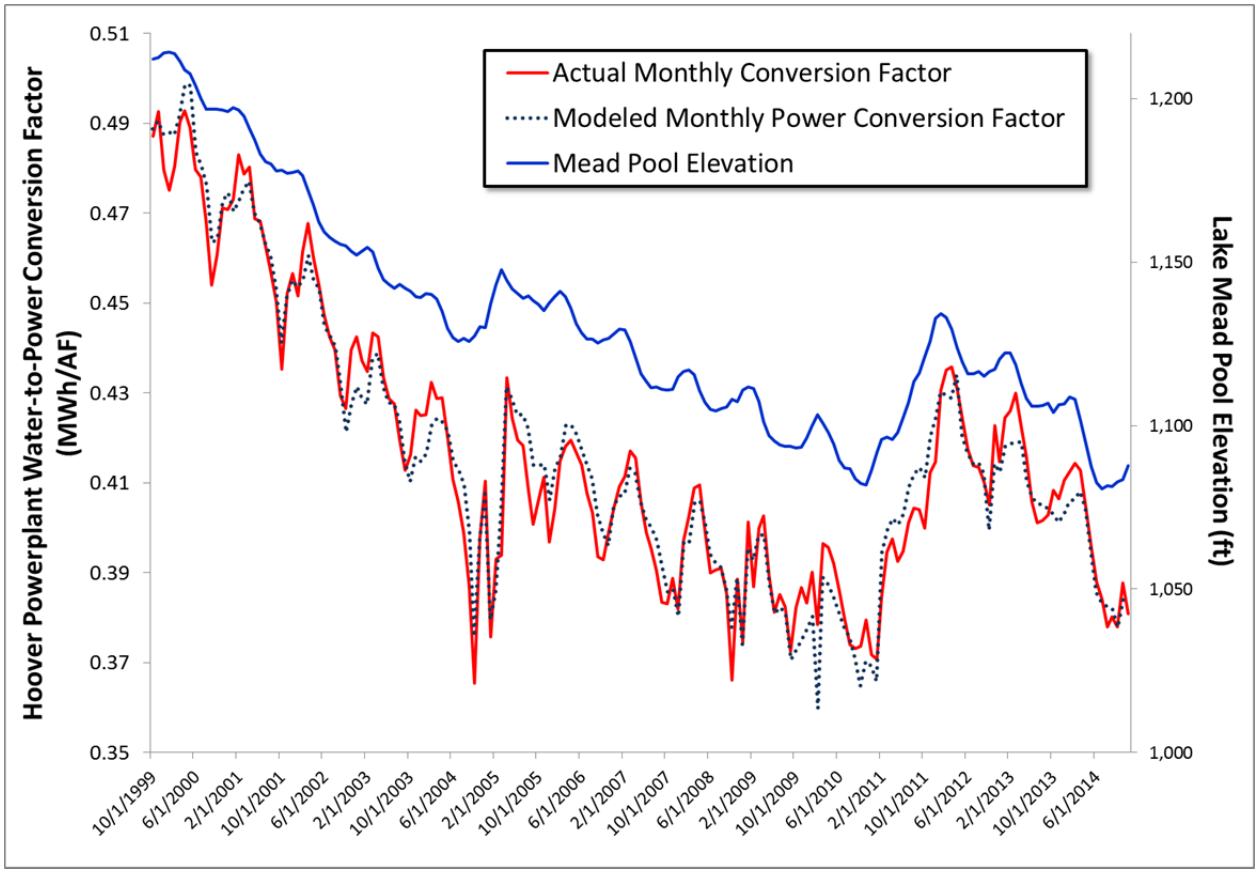

FIGURE K.5-4 Results of Water-to-Power Conversion Factor Back-casting Exercise

Figure K.5-4 shows that the Lake Mead pool elevation and water-to-power conversion factors have a similar pattern and can be used to explain most, but not all, of the changes in power conversion over time. Monthly turbine releases yield additional accuracy to the equations, but relatively small inaccuracies still exist. The average absolute error during both pre- and post-2011 periods is less than 0.005 ac-ft/MWh; that is, less than an average error of 1.2% of the average historical power conversion factor. The simple average of the errors equals zero. For comparative analyses such as this one, this level of accuracy was judged to be sufficient.

Projections of future monthly water-to-power conversion factors use equation coefficients derived for the post-2011 time period. In reality, conversion efficiencies (and therefore water-to-power conversion factors) will change in the future as equipment ages and changes are made to the powerplant. One such change that is partially implemented involves the replacement of old turbines with ones that can be operated over a wider range of hydraulic heads and have a narrower operating rough zone.

Based on information and guidance from Reclamation, this study conservatively assumes that the minimum pool elevation for energy production at the Hoover Powerplant is 1,050 ft above sea level. This elevation delineates the active and inactive pools. Hoover turbines may be mechanically and electronically operable below a pool elevation of 1,050 ft. This is in part

supported by turbine performance curves for new wide-head turbines that bottoms at approximately 1,015 ft (Harpman 2014a,b). However, none of the Hoover turbines have actually been operated at a pool elevation below 1,050 ft.

When the SBM projects that the Lake Mead elevation drops into the inactive pool, the Hoover Powerplant Model releases the entire SBM projected monthly water volume through one or more of the project's six outlets that are designed to bypass water around the Hoover Dam and Powerplant (http://www.usbr.gov/lc/hooverdam/faqs/tunlfaqs.html). Therefore, both the monthly maximum possible Hoover Powerplant output and generation are set equal to zero under this condition. These non-power water releases are referred to in this report as "bypass" water.

Figure K.5-5 shows Hoover model results for Alternative A average monthly water-to-power conversion factors (i.e., red line: plant-level generation/turbine water release) over the 20-year study period for all 21 SBM traces. Note that on average the power conversion factor changes little among months of the year. The blue line in the figure shows the ratio of Hoover Powerplant generation (in MWh) to total Lake Mead water releases that include both turbine and bypass releases. The difference between the two lines in the graph is due to water bypasses that occur when the pool elevation in Lake Mead is projected to be below 1,050 ft (i.e., the minimum power pool elevation). Under these circumstances, any required releases must be made through the outlet works rather than the turbines. Figure K.5-6 shows Hoover Powerplant average monthly turbine and Lake Mead bypass water releases for the 21 hydrology traces over the 20-year LTEMP period under Alternative A.

Monthly average turbine water releases at Hoover Dam differ by alternative, as shown in Figure K.5-7. The greatest difference among alternatives relative to Alternative A is about 81 kaf (thousand acre-feet) (roughly 11.7% more) in June under Alternative F. In almost all cases, the difference in turbine water release among alternatives is nearly counterbalanced by changes in bypass water releases. In the example above, 69 kaf more water is bypassed under Alternative A than under Alternative F. This is due to a higher occurrence of dead pool reservoir elevations under Alternative A. There is also a greater average total water release (turbine and bypass), about 12 kaf, in June under Alternative F. This is offset by lower water releases in the winter and early spring. On an average annual basis, there is very little difference in total Lake Mead water releases among alternatives.

The amount of water bypassed under each alternative is in part explained by the probability that the pool water drops into to the inactive zone. Figure K.5-8 shows the fraction of time the SBM projects that the pool elevation will be below 1,050 ft, thereby causing bypass release events. Alternatives A and B have the largest probability of a bypass event. Alternative F typically has the lowest, especially from late spring through the end of summer. This is primarily the result of changes in the monthly distribution of water releases from the Glen Canyon Dam relative to Alternative A. For example, as described previously, Alternative F has high Glen Canyon Dam releases during the late winter and early spring. These relatively high releases increase the pool level in Lake Mead, thereby reducing the probability that a low-pool bypass water release will occur. As shown in Figure K.5-9, the monthly bypass release probability pattern has a large impact on powerplant generation (in terms of megawatt-hours per ac-ft of

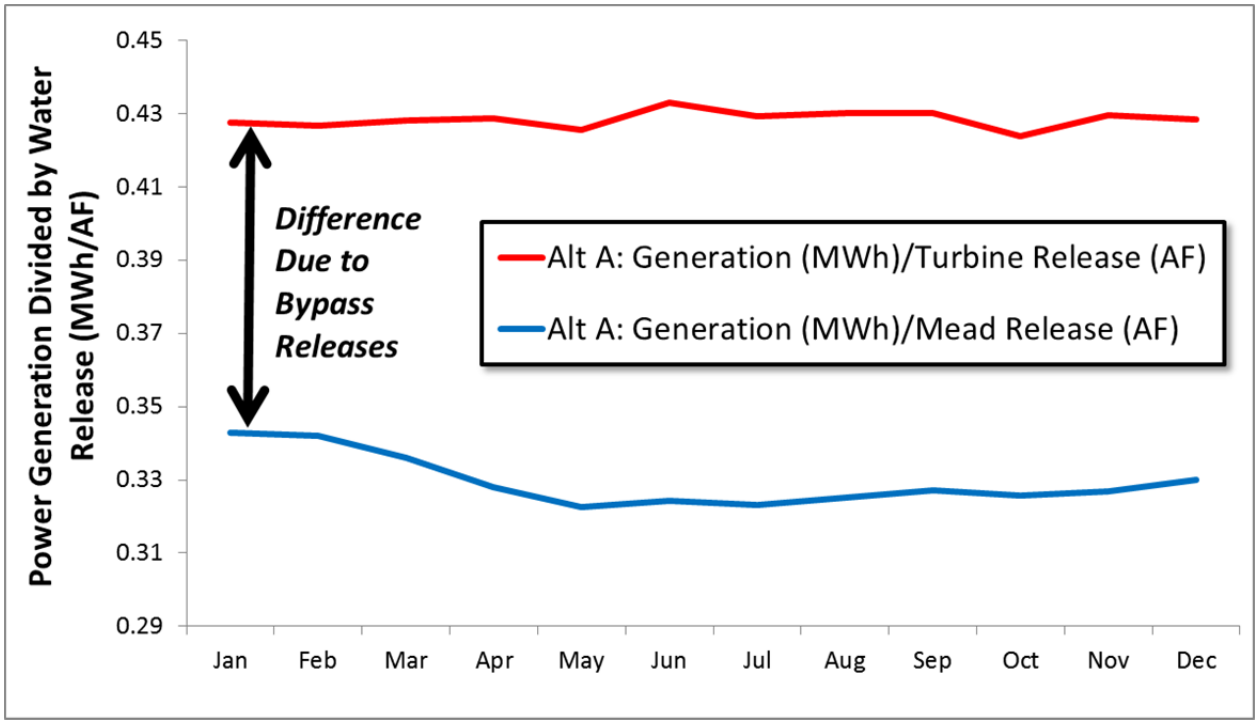

FIGURE K.5-5 Average Monthly Water-to-Power Conversion Factor and Energy Production per ac-ft of Total Mead Reservoir Release

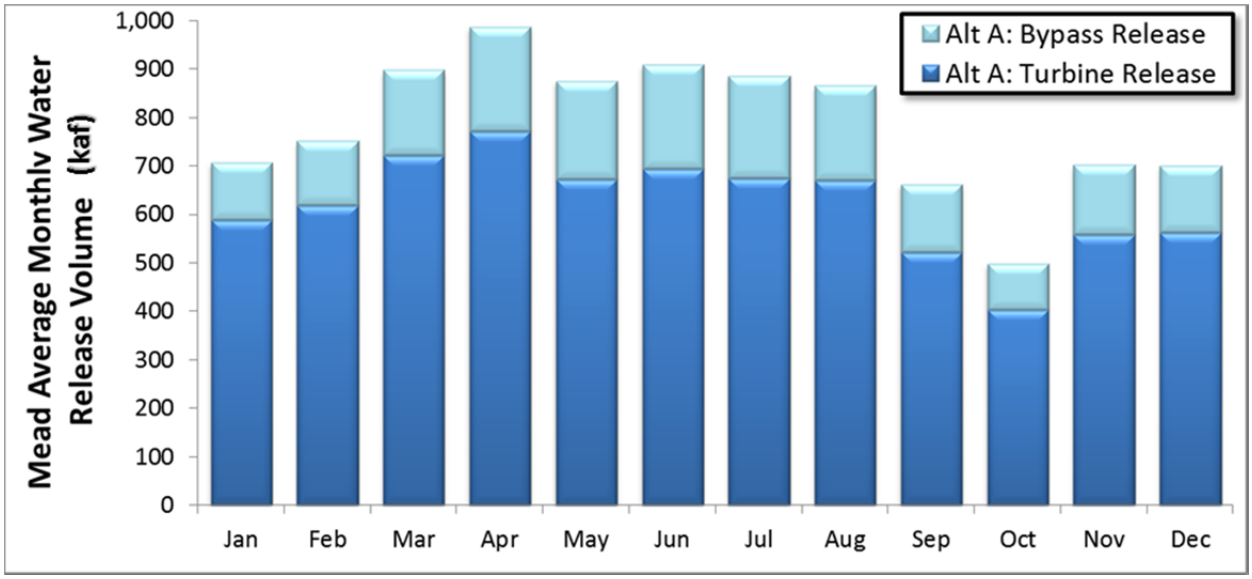

FIGURE K.5-6 Average Monthly Turbine and Bypass Water Releases

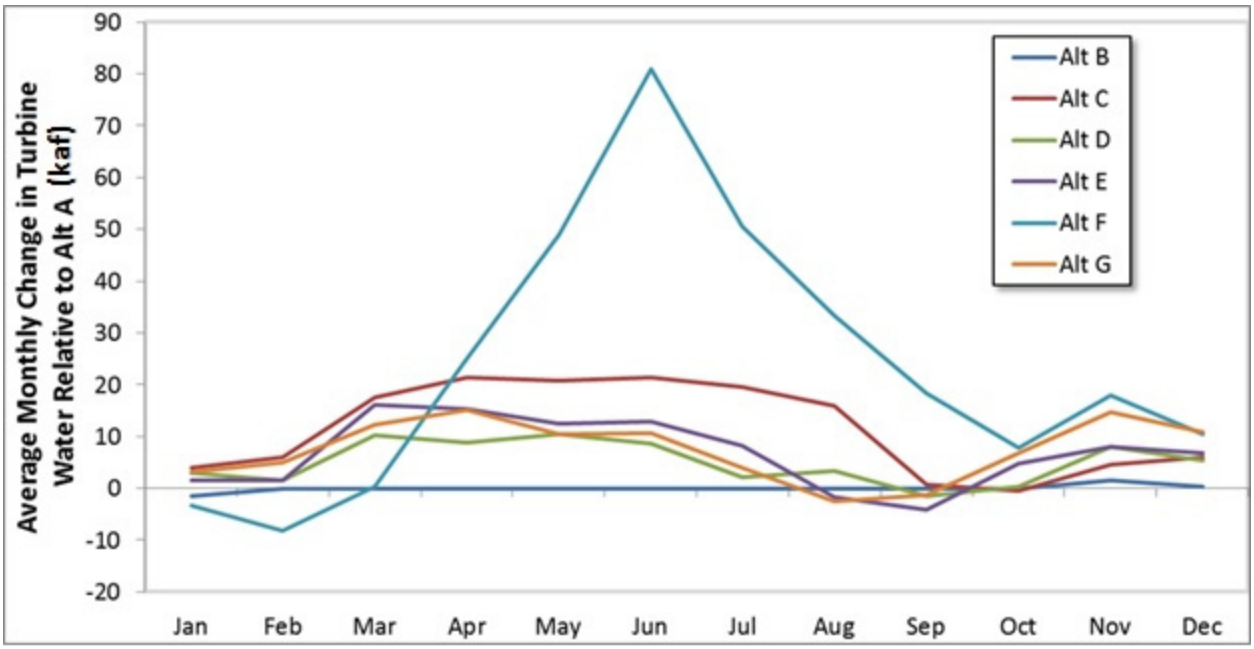

FIGURE K.5-7 Average Monthly Change in Turbine Water Releases

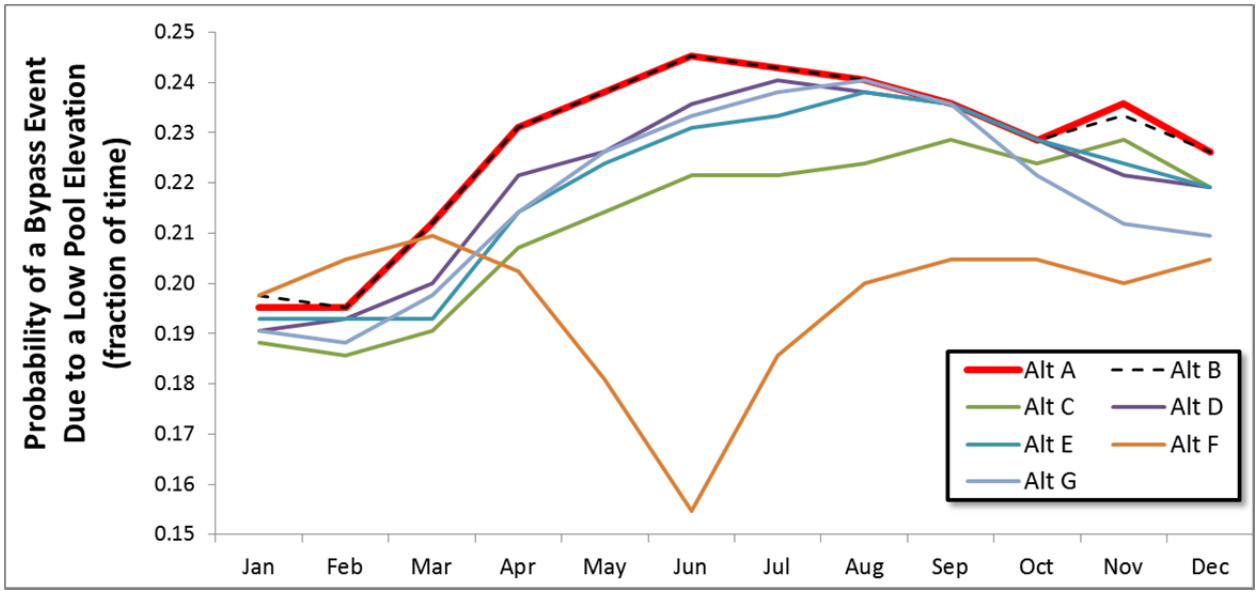

FIGURE K.5-8 Monthly Probability of a Water Bypass Event Due to a Low Mead Pool Elevation

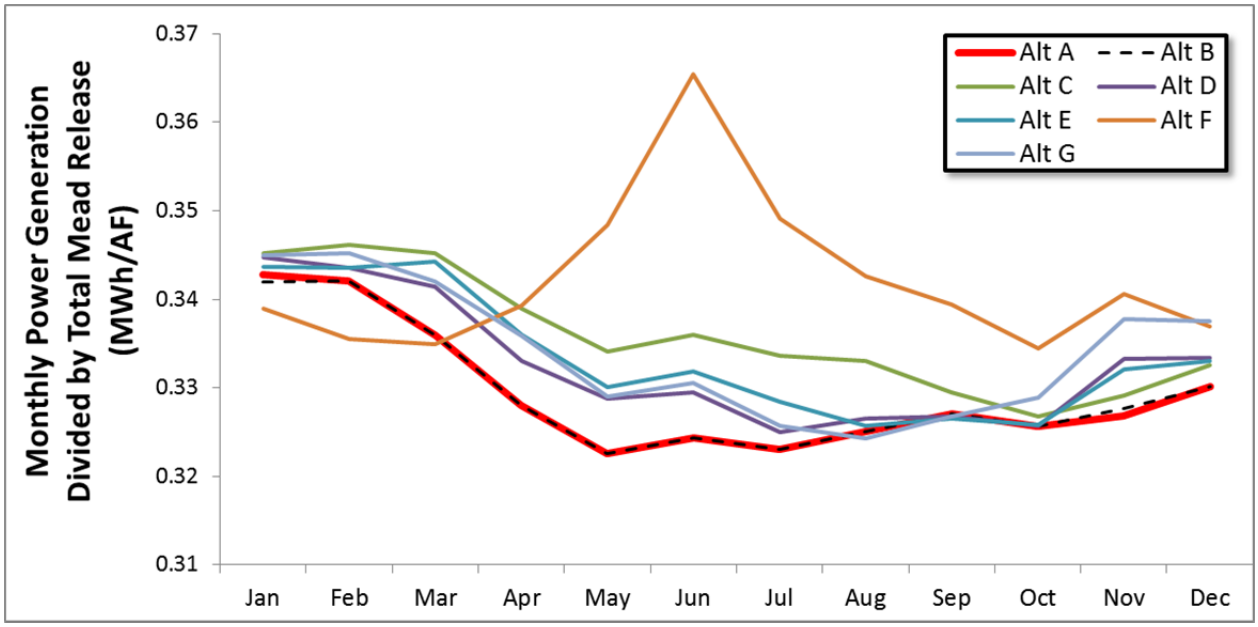

FIGURE K.5-9 Average Monthly Generation per ac-ft of Total Mead Reservoir Release for All Power Systems Primary LTEMP DEIS Alternatives

total Mead Reservoir release) during the summer months. Note that for each LTEMP alternative the pattern is the inverse of the one in Figure K.5-8.

As mentioned earlier, water releases that are made when Lake Mead is below 1,050 ft do not produce power. Therefore, for any alternative, Hoover Powerplant economics are not affected by water releases that are made from the dead pool, because all alternatives have zero power value at those elevations. It therefore follows that a change in water release from Alternative A also does not affect power economics at that point in time unless it raises the elevation above the power pool elevation. However, a changed monthly water release will indirectly affect the economics in other months of the year and Lake Mead's pool elevation in the month(s) that follow.

Differences in monthly water releases from Lake Mead are primarily caused by operating criteria that were established under the *Interim Guidelines for Operation of Lake Powell and Lake Mead* Record of Decision (ROD) that was signed on December 13, 2007 (Reclamation 2007b). The 2007 Interim Guidelines drive Hoover Dam releases, resulting in different Mead monthly total water releases among alternatives. Figure K.5-10 shows (1) Alternative F changes in Lake Mead monthly total water releases for hydrology trace 8 and (2) Lake Mead reservoir elevations under Alternatives A and F. Changes from Alternative A monthly water release are sometimes, but not always, triggered when elevations cross one of the shortage condition levels listed above (shown as dashed horizontal lines in Figure K.5-10). Because monthly water release decisions for the upcoming year are made at the beginning of the calendar year and forecasts of the future are uncertain, Hoover releases sometimes differ from the ones that would have occurred had the future been know with perfect foresight.

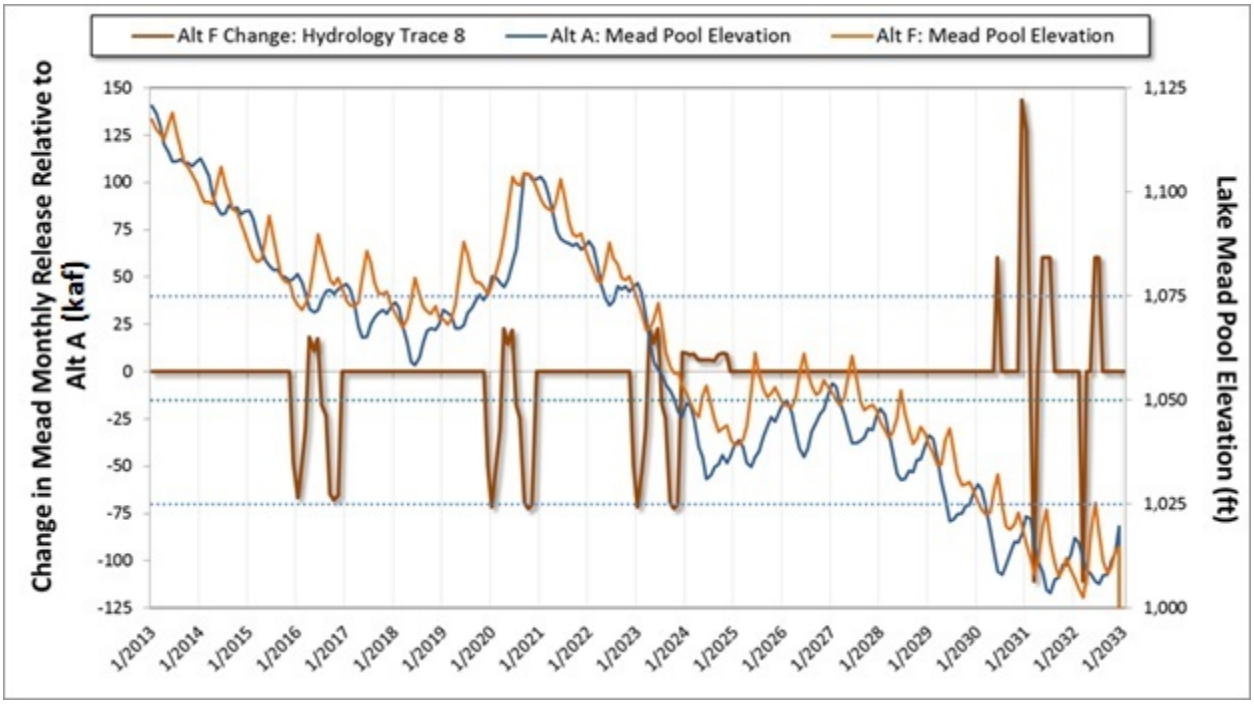

FIGURE K.5-10 Alternative F Changes in Monthly Hoover Powerplant Turbine Water Releases under Hydrology Trace 8

Multiplying monthly turbine water releases by the water-to-power conversion factor yields an estimate of the generation produced by the Hoover Powerplant. As shown in Figure K.5-11, Alternatives A and B have the lowest generation levels, while Alternative F typically has the most generation. The range of generation among alternatives is the largest from late spring through the end of summer, while the range in autumn and winter tends to be relatively small.

K.5.3 Hoover Maximum Physical Output and Firm Capacity

In addition to water-to-power conversion factors discussed in the preceding section, the maximum physical output of the Hoover Dam Powerplant is also affected by the pool elevation of Lake Mead. Figure K.5-12 shows the assumed relationship between pool elevation and maximum powerplant output. This curve is based on information provided by Reclamation. Note that below a pool elevation of 1,050 ft the maximum output is zero and above an elevation of 1,205 ft the maximum output remains constant at 2,075 MW (powerplant capacity).

The curve shown in Figure K.5-12 and SBM projections of Lake Mead pool elevations over the LTEMP study period were used to estimate monthly maximum physical output levels for the Hoover Powerplant for all 21 hydrological traces. Using the results for only August, the exceedance probability curve of the Hoover powerplant maximum output shown in Figure K.5-13 was constructed. To be consistent with other LTEMP power systems analyses,

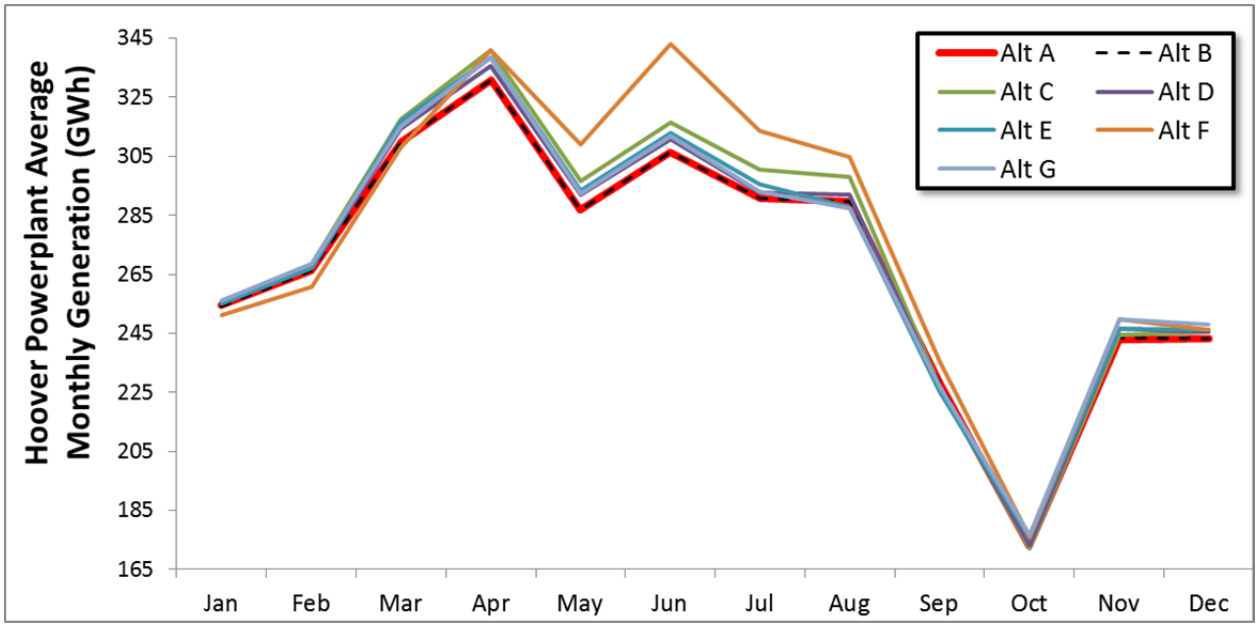

FIGURE K.5-11 Average Monthly Hoover Powerplant Generation for All Power Systems Primary LTEMP DEIS Alternatives

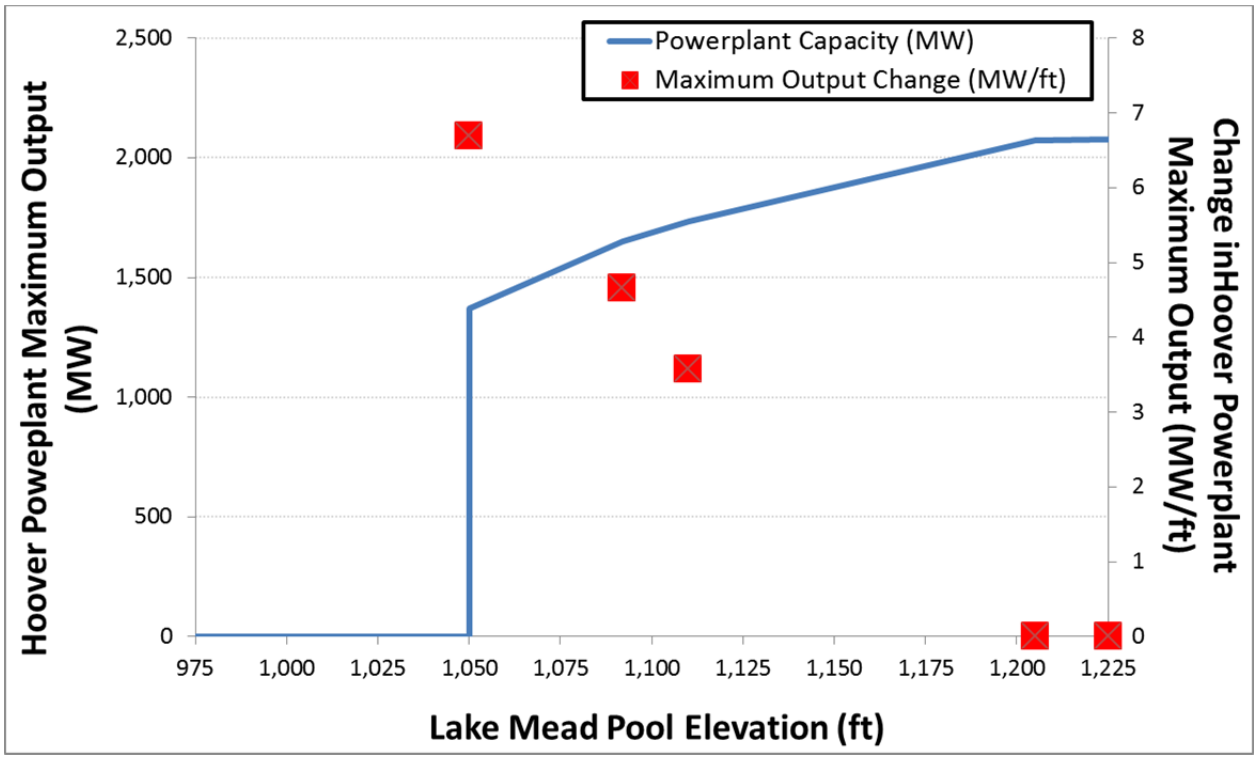

FIGURE K.5-12 Hoover Powerplant Maximum Physical Output as a Function of Lake Mead Pool Elevation

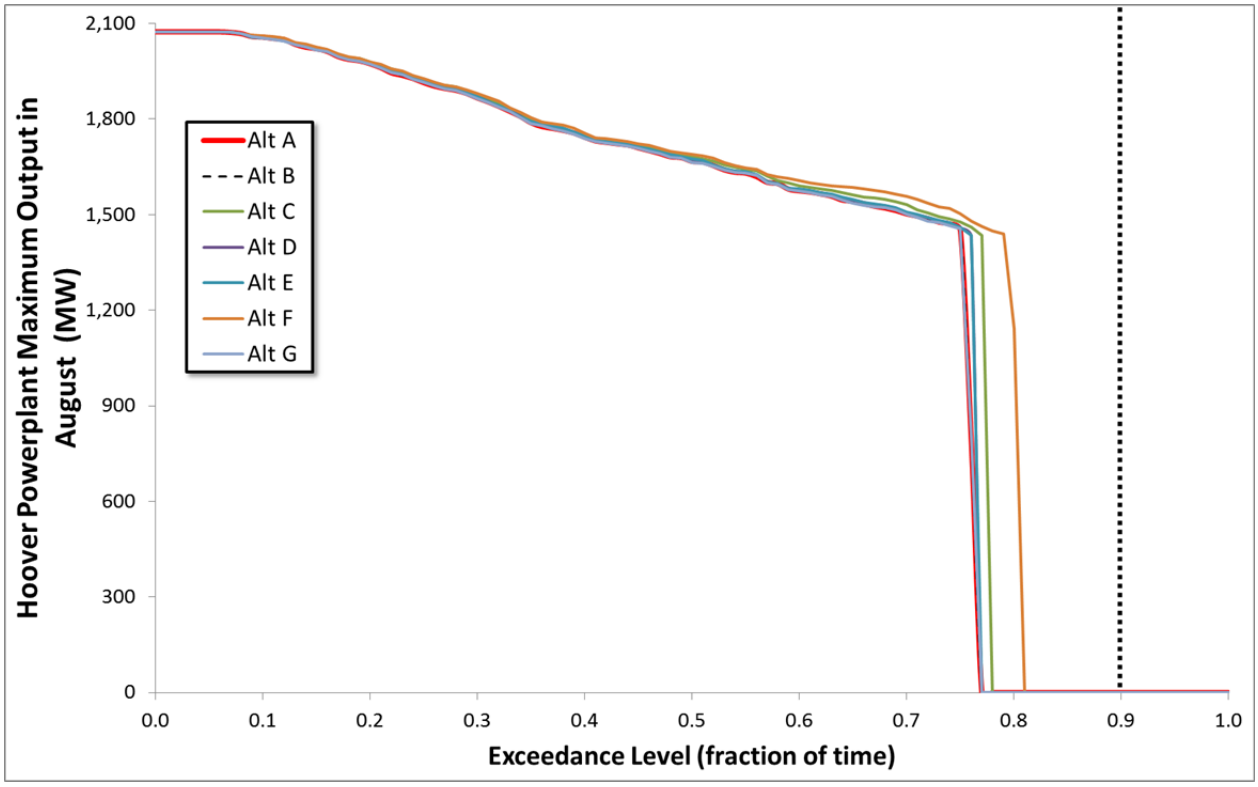

FIGURE K.5-13 Hoover Powerplant Maximum Output Exceedance Curve for the Month of August

this analysis assumed that the firm hydropower capacity of Hoover is based on a 90th percentile exceedance. Based on the analysis shown in Figure K.5-13, under all alternatives, Lake Mead's elevation in August would be below the active pool level (where no generation is possible) more than 10% of the time. Because the maximum output level is zero under all alternatives, the powerplant is credited with no firm capacity despite projections that indicate that the maximum output for the Hoover Powerplant is expected to be greater than zero most of the time. It therefore follows that LTEMP alternatives have no impact on Hoover Powerplant's firm capacity and economic value.

K.5.4 Hoover Powerplant Economic Energy Value

The change in the economic value of Hoover Powerplant energy production under each alternative is computed by multiplying the change in monthly energy production by monthly market prices of energy as projected by the AURORA model. Estimates are made for each month of the 20-year LTEMP period for all 21 hydrology traces. For this analysis, it was assumed that the powerplant generates 95% of its total energy production during hours of the

week that have relatively high market prices (16 hours per day, 7 days a week).[37] The remaining 5% is generated during times when prices are lower. Figure K.5-14 shows monthly average results of these calculations. Note that the values shown in the figure are average values over all 21 hydrology traces during the 20-year time period and are not discounted.

To compare the economic impact of alternatives on a consistent basis, the net present value (NPV) of Hoover Powerplant economic benefits were computed using a 3.375% annual discount rate, the same rate used for computing the NPV of SLCA/IP costs. The result of NPV calculations for the Hoover Powerplant is shown for each alternative in Figure K.5-15. The NPV benefit for Hoover ranges from nearly zero for Alternative B to about $89 million for Alternative F.

The economic benefits of alternatives at the Hoover Powerplant are lower than the economic costs of the alternatives in the SLCA/IP system that range from about –$30 million (a benefit) for Alternative B to roughly $420 million for Alternative F (see Table 4.14-1 for more details). Figure K.5-16 illustrates the difference between SLCA/IP costs and Hoover Powerplant benefits resulting from LTEMP alternatives. For example, Alternative F has a net cost that ranges from $315 million (without excess capacity sales) to $335 million (with excess capacity sales). Figure K.5-17 shows the net costs (SLCA/IP costs minus Hoover benefits) for all alternatives. When Hoover benefits are taken into account the net costs of LTEMP alternatives are less; however, the ranking among alternatives are identical to the case where Hoover benefits are not taken into account (green bars and dashes shown in Figure K.5-16).

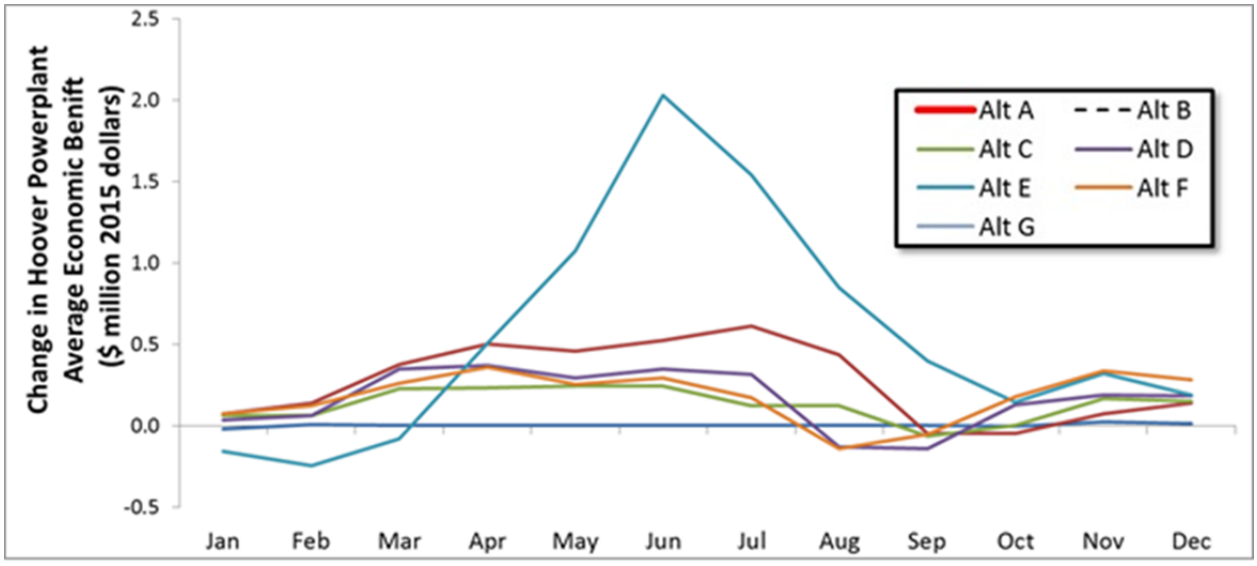

FIGURE K.5-14 Average Monthly Change in Hoover Powerplant Energy Economic Value (undiscounted) Relative to Alternative A for All Power Systems Primary LTEMP SEIS Alternatives

[37] The 95% assumption is based on discussions with Reclamation staff.

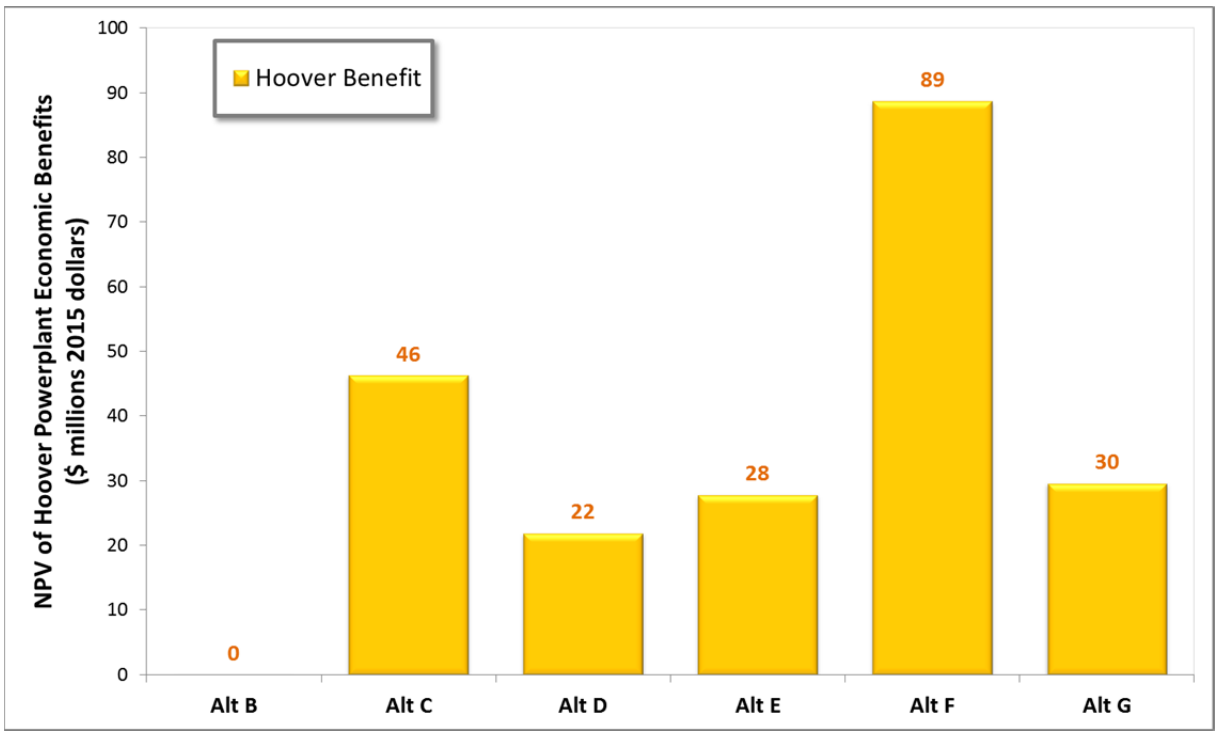

FIGURE K.5-15 NPV of Hoover Powerplant Benefits Relative to Alternative A Resulting from LTEMP Alternatives

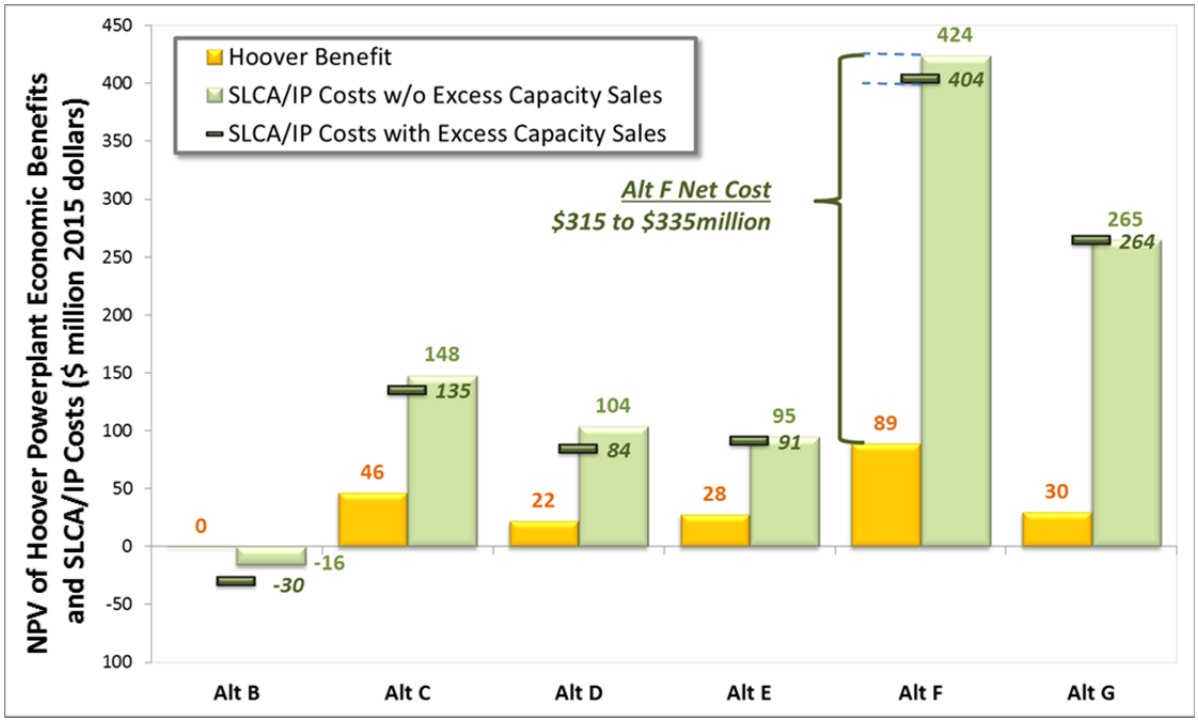

FIGURE K.5-16 NPV Comparison of SLCA/IP Costs and Hoover Powerplant Benefits Resulting from Changed Operating Criteria at Glen Canyon Dam

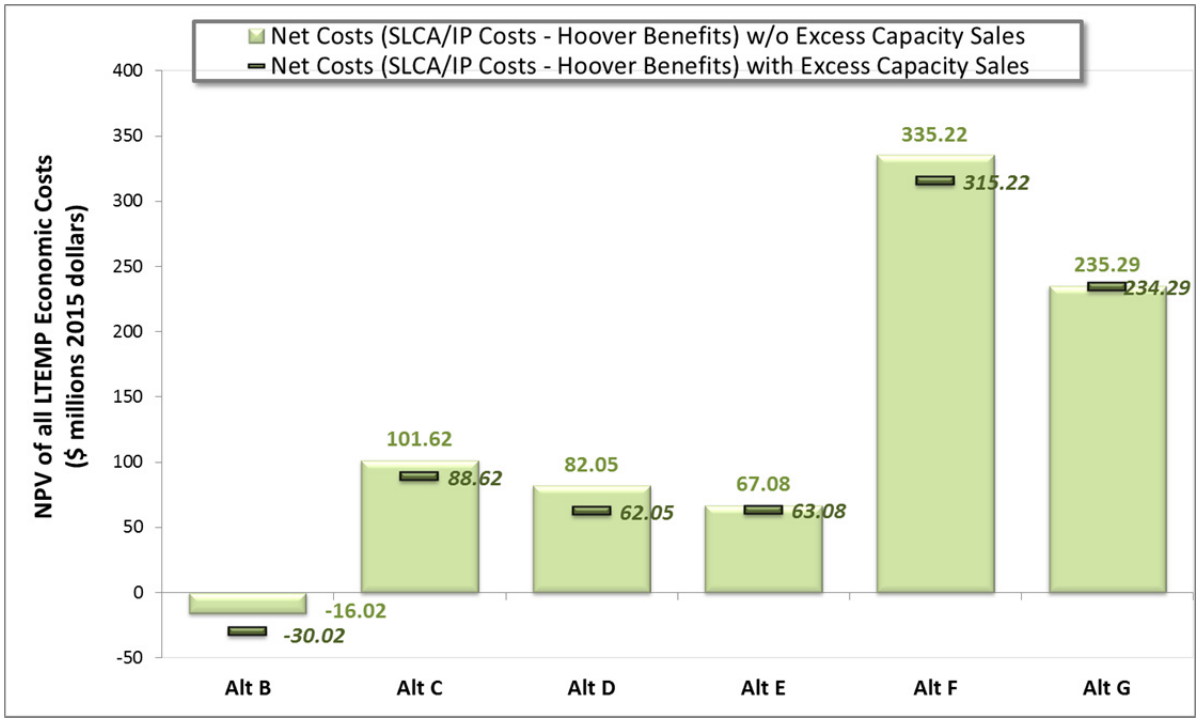

FIGURE K.5-17 NPV Comparison of SLCA/IP Costs and Hoover Powerplant Benefits Resulting from LTEMP Alternatives

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ATTACHMENT K.1:

GEOGRAPHIC SCOPE OF THE ANALYSIS

The geographic scope of the economic effects of the operations of Glen Canyon Dam has long been a topic of discussion among staff at the Western Area Power Administration (Western), Bureau of Reclamation (Reclamation), National Park Service (NPS), Grand Canyon Monitoring and Research Center (GCMRC), and Argonne National Laboratory (Argonne). The method described herein assumes that the effect of changes to the operation of the Glen Canyon Dam is limited to the Salt Lake City Area Integrated Projects (SLCA/IP) system; that is, SLCA/IP federal hydropower resources and Western's SLCA/IP long-term firm (LTF) customers. Figure 1 shows the extent of the study area considered in this analysis. This assumption became essential when the scope and timing of the Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) power systems analysis were re-evaluated in June 2014 as a result of funding and schedule considerations. Several proposed options for proceeding were developed at that time to offer different levels of analytical detail, costs, and completion dates. The option selected (middle ground relative to detail, funding, and timing) defined the geographic scope as Western's SLCA/IP marketing area with ties to the rest of the Western Interconnection (WI) for market transaction at the Palo Verde hub. This topology is the basis of analysis and results to be developed for the LTEMP Draft Environmental Impact Statement (DEIS). Initial assessments for the value of expanding the scope to all of the WI are discussed briefly in a section that follows, but those deliberations are no longer relevant to this initial stage of analysis. Budget and timing factors have determined the scope of this initial analysis.

This analysis assumes that there is little, if any, economic effect at electricity hubs outside the SLCA/IP system of hydropower plants and Western's firm customers in terms of changes in locational marginal prices (LMPs) as a result of alternative operations at Glen Canyon Dam. Recently, Argonne undertook a study verifying this limited regional influence. This is known as the WECCi-leaks study. The topology of the region in the WECCi-leaks study is shown in Figure 2. It models the entire extent of the U.S. portion of the WI and is the same topology used in the 2010 WECC Power Supply Assessment. A report documenting this study will be written and peer reviewed. A final, peer-reviewed version of this report will be available in time for reference in the final LTEMP EIS. Therefore, when simulating the operation of Glen Canyon Dam the region of detailed modeling is restricted to the SLCA/IP system. Spot market transactions conducted at points between this system and the rest of the WI will be represented as a static set of market prices for the Palo Verde hub.

WI Energy Transactions

The SLCA/IP system is directly connected with other private or invest-owned electric utilities (IOUs) in the geographic area. Among these are Rocky Mountain Power, Excel Energy, and Public Service Company of New Mexico. An electrical market exists such that the SLCA/IP system can exchange with these utilities and others to which they are indirectly connected in order to lower operating costs. To approximate these economic energy exchanges, the AURORA

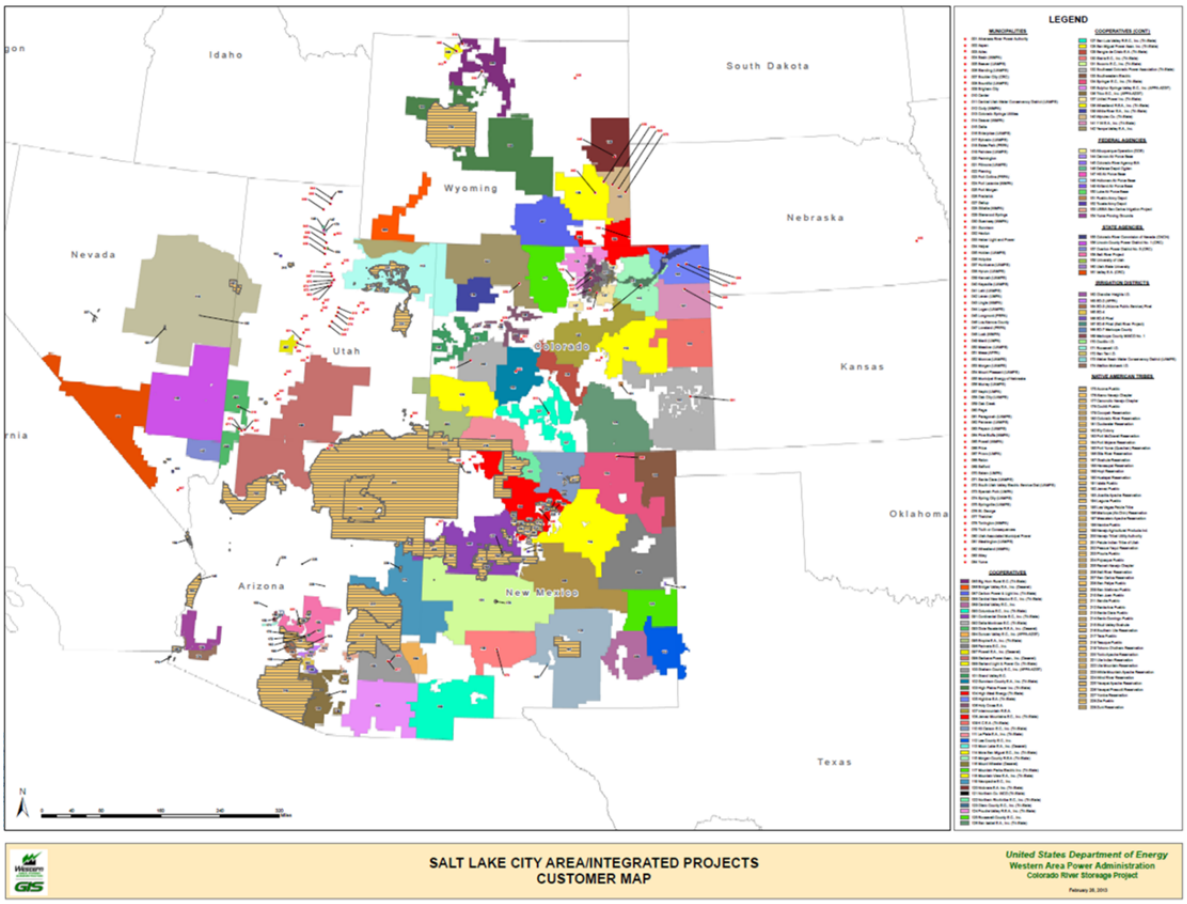

FIGURE 1 Study Area Considered in the LTEMP Power Systems Analysis

model was run to simulate the dispatch of the entire WI. Resulting prices from this run are then input into the more geographically limited, but more detailed, model of the SLCA/IP powerplants and its firm customers. It is assumed that these prices are static and do not change as a result of alternative operating criteria at Glen Canyon Dam. Glen Canyon Dam is a very small resource compared to the total WI generating capacity and is thought to have only a miniscule impact on WI market prices.

WI Capacity Transactions

For this analysis, we make the simplifying assumption that no capacity exchange or joint expansion planning occurs—economic impacts of changes in Glen Canyon Dam capacity are limited to Western's eight large SLCA/IP LTF customers. Note that smaller customers do not have significant supply resources. It is therefore assumed that small customers will not build capacity in the future. All lost Glen Canyon Dam capacity as a result of operational changes at Glen Canyon Dam would be replaced by the eight larger utility systems, and any resulting

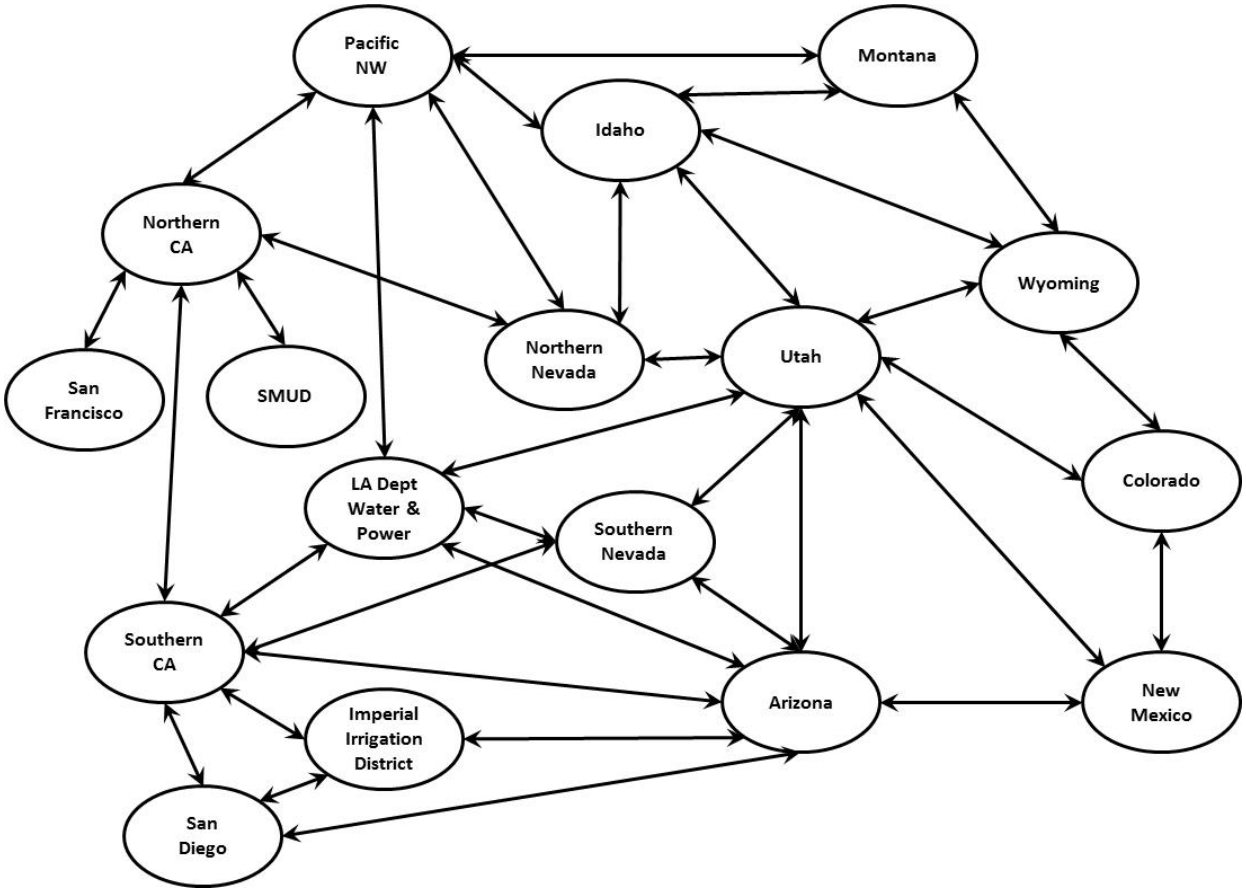

FIGURE 2 Topology Used in the WECCi-Leaks Study

capacity losses for the small customers would be replaced via LTF capacity agreements with the larger utilities.

This assumption that the SLCA/IP system will replace lost capacity through its own initiatives can be justified if there is no accessible excess capacity in the larger region. Therefore, a capacity loss at Glen Canyon Dam cannot be replaced via the purchase of excess capacity from a surrounding utility; for example, from IOUs with whom they are connected. If this assumption is true, the methodology described here will provide a very good approximation of the true economic impact, since the loss of Glen Canyon Dam capacity will require the construction of new capacity somewhere in the grid.

In order to properly assess the strength of this assumption, an examination of relevant regional data, such as integrated resource plans (IRPs) of Western's large customers that own generating facilities and large IOUs in the geographic and "electrical" area was conducted. In general, all IRPs examined revealed that utilities are expanding capacity with both renewable and thermal technologies in the near future. In addition, some utilities are increasing Demand Side Management programs to reduce the need for expanding capacity. It was also discovered that the loss of capacity in one large IOU (namely, NVEnergy) from a mandated shutdown of

coal-fired powerplants will be replaced with natural gas-fired generation about a year after the first group of coal-fired units are shut down (see Figure 7 in Attachment K-9). Summaries of key IRPs are provided in Attachment K-9. The conclusion drawn from the review of the IRPs is that there is very little, if any, excess capacity in the Balancing Authorities in which Western's customers are located and in the broader power pool areas that are defined in the AURORA "out-of-the-box" model configuration. Therefore, loss in capacity at Glen Canyon Dam would need to be replaced soon after the loss was incurred. This loss could be replaced by new capacity that is either built by Western's customers or alternatively by another utility and sold via LTF capacity contracts. In this analysis, it is assumed that the replacement capacity would be directly built by the customers. From a purely economic viewpoint, there is little difference if the pool of eight large customers builds the capacity or if it is built by another utility.

Analysis Fidelity

Although in reality Western and its customers operate in the WI, the approach used by Argonne power system analysts emphasizes performing high-fidelity analyses on a smaller network topology as opposed to analyzing system response of the entire WI to changes in operating criteria dictated by LTEMP DEIS alternatives. By accurately modeling a smaller system, it is possible to track and explain with a relatively high level of confidence both system- and component-level reactions to alternative operating criteria and to trout management flow (TMF) and HFE operation schedules. SLCA/IP system interactions with the broader WI are also represented, but in far less detail. As described in this attachment, power systems analysts were able to fairly closely match historical 2013 generation levels for the eight large utility systems.

It should also be noted that unit commitments, system dispatch, and capacity expansion decisions are not made by a single entity that makes decisions for the entire interconnect. Instead autonomous decisions under uncertainty are made by many entries in the WI using market price signals such as the ones reported by the Intercontinental Exchange (ICE) to take unit commitment, dispatch, and energy market transaction decisions. Therefore, the AURORA model of the WI tends to "over optimize" system operations. Low 2012 Palo Verde market prices computed by AURORA may be in part due to the "single decision maker" approach that is employed. Another difficulty in modeling WI operations is that hydropower operating constraints for the multitude of hydropower plants within the interconnection are extremely challenging. The approach used in this analysis represents a middle ground between simulating each utility individually and optimizing WI operations. It also allows the modeler to represent hydropower operations at a level of detail that cannot be simulated at an adequate level of fidelity by AURORA.

ATTACHMENT K.2:

AURORA WI SPOT MARKET ENERGY PRICES ADJUSTMENTS

The power systems analysis uses a representation of the spot market at the Palo Verde hub where SLCA/IP market system participants buy and sell energy at a set of given hourly prices. The methodology applied in this study uses this price set to represent the economic value of energy; that is, the marginal cost to produce energy that serves the last megawatt of load. This includes both fuel costs and variable operation and maintenance (O&M) expenses. Historical economic values are extremely difficult to accurately estimate because the Western Interconnection is comprised of numerous independent entities that operate in a geographically large and very complex grid. Difficulties associated with modeling the Western Interconnection for long-term analyses consist of but certainly not limited to the following (http://www.ipd.anl.gov/anlpubs/2012/04/73032.pdf):

1. The interconnection includes multiple U.S. states and three countries;

2. Part of the system operates in an organized central market (i.e., CAISO) and other portions operate in a bilateral market;

3. A large fraction of Western Interconnection loads are supplied by hydropower plants, many of which are subject to complicated and difficult to model environmental operating criteria (even on a site-specific level);

4. A lack of unit-specific information on fuel prices and heat rate curves ;

5. Insufficient data on bus-level loads;

6. A large and complicated transmission system;

7. Lack of information on resource availability (e.g., unit outage and transmission line outages);

8. Forecast errors associated with loads, hydropower inflows, and variable resource (wind/solar) output; and

9. Complex interactions among entities that make decisions under uncertainty based on limited information about the interconnection.

All power systems models, including AURORA, must therefore make many simplifying assumptions about the grid and the mathematical representation of each grid component. These assumptions lead to an imperfect representation of reality.

In the study, spot market prices modeled for 2013 by the default WI AURORA model were significantly different from day-ahead market (DAM) prices published by the ICE and the

CAISO. The Palo Verde hub was chosen to represent prices for the spot market in the AURORA network topology for the LTEMP analysis because it is the hub closest to Glen Canyon Dam and is often used as the benchmark price for Western energy transactions.

The ICE publishes day-ahead weighted average peak, off-peak, and Sunday off-peak electricity price for every day each year. Sunday off-peak hours are the 16 daytime hours that have the highest loads; they correspond to the 16 hours classified as peak in the other 6 days of the week. Hourly prices generated by the AURORA model were subdivided into 7 categories; namely, holiday, Sunday daytime, Sunday nighttime, Saturday peak, Saturday off-peak, weekday peak, and weekday off-peak. The monthly averages were computed for each category and compared against the monthly average of the ICE prices in these categories.

In order to bring AURORA model hourly prices in line with these ICE prices, AURORA model results were scaled to match ICE averages. A scalar (ratio of the ICE to AURORA prices) was generated for each month and each category. In this preliminary investigation, it was discovered that prices generated by the AURORA model were generally lower than the ICE prices. Prices in off-peak hours were lower by about 5 to 15% and prices in peak hours were lower by as much as 20 to 50%. To adjust for this discrepancy in prices, future AURORA model runs for the LTEMP network topology, AURORA prices at the Palo Verde hub were multiplied by the aforementioned scalar. The scalars derived from ICE prices are shown in Table 1.

TABLE 1 Scalars Used to Adjust Spot Market Prices in the AURORA Model

		Sunday		Saturday		Weekday	
Month	Holiday	Daytime	Nighttime	Peak	Off Peak	Peak	Off Peak
January	1.053	1.032	1.110	1.068	1.042	1.058	1.019
February	NA[a]	1.145	1.221	1.123	1.083	1.093	1.140
March	NA[a]	1.133	1.175	1.119	1.126	1.105	1.120
April	NA[a]	1.319	1.297	1.257	1.132	1.163	1.183
May	0.943	1.143	1.126	1.156	1.046	1.165	1.053
June	NA[a]	1.210	1.241	1.241	1.067	1.200	1.066
July	1.100	1.222	1.204	1.343	1.009	1.538	1.094
August	NA[a]	1.175	1.142	1.231	1.004	1.230	1.060
September	1.088	1.133	1.251	1.218	1.051	1.170	1.116
October	NA[a]	1.134	1.235	1.156	1.118	1.094	1.142
November	1.079	1.084	1.208	1.166	1.159	1.098	1.113
December	1.082	1.279	1.470	1.233	1.265	1.228	1.299

[a] NA = Not applicable.

The scaled AURORA prices were used as a surrogate for the economic value of energy based on the premise that the ICE data adequately reflects actual market prices and those market prices are a good measure of economic costs. In economic theory, a perfect market will produce prices that reflect economic costs. However, no market is perfect, including those in the Western Interconnect. Therefore, due to the complexities associated with modeling actual economic costs at the margin, power system modeler used the aforementioned scaling methodology. This not ideal, but it appears that market mechanisms in the Western Interconnection are working reasonably well and market monitors (such as those in the CAISO) help to ensure that participants do not unduly take advantage of market imperfections.

ATTACHMENT K.3:

SELECTION OF REPRESENTATIVE TRACE

Introduction

This paper briefly describes the process that was used for selecting a representative hydrology trace for use in the Long-Term Experiment and Management Plan (LTEMP) power systems modeling task. A single representative trace was required to balance the complexity and time requirements for power system simulations with task completion timelines. Goals in selecting a trace included considerations for (a) matching the probability distribution of annual water releases as exhibited in the full set of 21 hydrology traces developed by the Bureau of Reclamation, (b) representing the variability in monthly releases, (c) avoiding significant numbers of spill events (where monthly volumes and elevations lead to water releases not being fully utilized for power generation), and (d) providing reasonably close matches (across all six alternatives and long-term strategies) for end-of-year elevations and release volumes. The following sections describe several metrics that were developed to characterize these goals and provided the basis for selecting a representative trace.

Six alternatives and long-term strategies,[38] including a no action alternative, were originally proposed for study in the LTEMP Draft Environmental Impact Statement (DEIS). A seventh alternative was proposed after this analysis for choosing a representative trace was performed, and is not included in this analysis. The alternatives have been assigned a letter designation and will be referenced in this document by that letter: Long-Term Strategies B1, C1, and E1, and Alternatives F and G. Alternative A, the no action alternative, is the current operating regime and is known as modified low fluctuating flow (MLFF) as defined in the 1996 Record of Decision.

Annual Powell Outflows—Exceedance Curves

A priority in selecting a single representative 20-year hydrology trace for power modeling is to capture the range and distribution of water conditions that occur across all 21 of the original 20-year hydrology traces. To address that objective, we constructed time-independent exceedance curves (basically representing probability distributions) for the annual Powell outflows for each of the 21 traces and six alternatives and long-term strategies. As a metric for comparing the closeness of fit for those 21 distribution profiles as compared with the full set of traces, we calculated the least-squares differentials between each trace-specific

[38] It should be noted that at the time the representative trace was chosen, the LTEMP DEIS had only 6 alternatives and long-term strategies. A hybrid or 7th alternative was subsequently added. The hybrid is a combination of the C1 and E1 long-term strategies; however, the choice of the representative trace would not be affected by the addition of the hybrid alternative.

TABLE 1 Powell Outflow Exceedance: Rankings of Traces by Least-Squares Differentials as a Measure for Matching the Distribution of Releases for All Traces[a]

	Alternative A (No Action Alternative)		Long-Term Strategy B1		Long-Term Strategy C1		Long-Term Strategy E1		Alternative F		Alternative G	
Rank	Trace	Sq. Diff[b]	Trace	Sq. Diff.	Trace	Sq. Diff.	Trace	Sq. Diff.	Trace	Sq. Diff.	Trace	Sq. Diff.
1	Trace 14	710	Trace 14	710	Trace 13	636	Trace 13	637	Trace 14	533	Trace 13	872
2	Trace 19	836	Trace 19	836	Trace 19	906	Trace 14	1,130	Trace 13	832	Trace 14	940
3	Trace 13	1,024	Trace 13	1,024	Trace 14	1,055	Trace 19	1,401	Trace 19	930	Trace 19	1,133
4	Trace 12	1,208	Trace 12	1,208	Trace 12	1,241	Trace 12	1,448	Trace 12	1,257	Trace 12	1,337
5	Trace 15	2,353	Trace 15	2,353	Trace 15	2,548	Trace 15	2,620	Trace 15	2,639	Trace 15	2,590
6	Trace 3	2,594	Trace 3	2,594	Trace 3	3,811	Trace 3	3,945	Trace 3	3,003	Trace 3	3,746
7	Trace 18	3,509	Trace 18	3,509	Trace 18	4,249	Trace 7	4,661	Trace 7	4,150	Trace 18	3,833
8	Trace 7	3,962	Trace 7	3,962	Trace 7	4,641	Trace 18	4,835	Trace 18	4,394	Trace 7	4,362
9	Trace 4	4,096	Trace 4	4,096	Trace 4	5,110	Trace 4	5,106	Trace 4	4,642	Trace 4	4,676
10	Trace 17	4,541	Trace 17	4,541	Trace 2	5,406	Trace 17	5,392	Trace 17	5,129	Trace 17	5,028
11	Trace 16	5,245	Trace 16	5,246	Trace 17	5,420	Trace 2	5,846	Trace 2	5,440	Trace 2	5,631
12	Trace 2	5,325	Trace 2	5,325	Trace 6	7,051	Trace 16	6,429	Trace 6	6,467	Trace 16	5,919
13	Trace 6	5,648	Trace 6	5,648	Trace 20	7,258	Trace 6	7,047	Trace 16	6,669	Trace 6	6,460
14	Trace 20	7,399	Trace 20	7,399	Trace 16	7,572	Trace 20	7,359	Trace 20	7,511	Trace 20	7,390
15	Trace 8	9,687	Trace 8	9,688	Trace 0	10,979	Trace 8	10,992	Trace 0	10,858	Trace 8	10,202
16	Trace 10	10,446	Trace 10	10,446	Trace 1	11,068	Trace 0	11,008	Trace 10	11,016	Trace 0	10,865
17	Trace 0	10,868	Trace 0	10,868	Trace 8	11,350	Trace 1	11,332	Trace 8	11,255	Trace 10	11,111
18	Trace 1	11,249	Trace 1	11,249	Trace 10	11,557	Trace 10	11,601	Trace 1	11,491	Trace 1	11,408
19	Trace 5	11,262	Trace 5	11,262	Trace 5	12,662	Trace 5	12,816	Trace 5	12,712	Trace 5	12,113
20	Trace 9	13,003	Trace 9	13,003	Trace 9	14,797	Trace 9	14,807	Trace 9	13,982	Trace 9	14,046
21	Trace 11	14,321	Trace 11	14,321	Trace 11	16,284	Trace 11	16,349	Trace 11	15,433	Trace 11	15,501

[a] Trace 14, the selected representative trace, is highlighted in green.
[b] Note: Sq. Diff. = least squares differential between the trace-specific exceedance curve and the all-traces exceedance curve.

exceedance curve and the all-traces exceedance curve. These differentials were calculated separately for each of the six alternatives and long-term strategies.

Table 2 shows hydrology Trace 14 provides a distribution of annual water releases that closely mimics the full set of releases for all traces. We also observed that differences in the rankings when examining Powell outflows versus estimated power releases were minor and relatively insignificant to the selection of a single representative trace. Thus, the illustrations used in this summary focus primarily on Powell outflows.

Trace 13 also provides a good match with all-trace outflows, especially for Alternative G and Long-Term Strategies C1 and E1, where the least-squares differences are less than those for Trace 14. However, a large portion of the least-squares difference between Traces 13 and 14 is accredited to the closer match to near-peak releases for some alternatives in Trace 13 versus Trace 14, whereas Trace 14 exhibits a closer fit over other portions of the flow distributions (illustrated in figures that follow). Additionally, alternative-to-alternative inconsistencies in end-of-year Powell elevations and annual water releases were significantly greater for Trace 13 than Trace 14.

Trace 19 represents another possible contender with a good match to the all-trace variability. It is not considered further, though, because it includes numerous occurrences of Powell elevations below the top of the penstock within the 20-year modeling period (4 months for each alternative except Alternative F). The below-penstock occurrences across the 21 traces and 20 years are listed below:

- Alternative A—trace 8: 3 in 2032; trace 19: 12 in 2016 to 3 in 2017 inclusive.
- Long-Term Strategy B1—trace 8: 3 in 2032; trace 19: 12 in 2016 to 3 in 2017 inclusive.
- Long-Term Strategy C1—trace 8: 3 in 2032; trace 19: 12 in 2016 to 3 in 2017 inclusive.
- Long-Term Strategy E1—trace 8: 3 and 4 in 2032; trace 9: 3 in 2027; trace 19: 12 in 2016 to 3 in 2017 inclusive.
- Alternative F—none; all elevations above 3,490 ft.
- Alternative G—trace 8: 2 in 2032 to 4 in 2032 inclusive; trace 19: 12 in 2016 to 3 in 2017 inclusive.

Figures 1 through 5 illustrate the close match between Trace 14 and all-traces exceedance curves for annual Powell outflows. For comparison purposes, we also show: (1) Trace 14 exceedance curve for Long-Term Strategy C1, where Trace 14 ranked third instead of first in the distribution match (this represents the worst-case match for Trace 14); and (2) the Trace 19, 13, and 16 exceedance curves for the No Action Alternative (Alternative A) to illustrate the difference in fit between the top and middle-ranked traces (rankings for Alternative A are: Trace 19 = 2nd; Trace 13 = 3rd; and Trace 16 = 11th).

TABLE 2 Number of HFEs and Amount of Water Spilled during HFEs in Trace 14 and the All-Trace Average

Alternative/ Long-Term Strategy	Characteristic	Trace 14	21 Traces Average
A (No Action Alternative)	Number of HFEs	4	4
	Amount of water spilled during HFEs (kaf)	262	346
B1	Number of HFEs	6	7
	Amount of water spilled during HFEs (kaf)	472	553
C1	Number of HFEs	17	19
	Amount of water spilled during HFEs (kaf)	1,329	1,522
E1	Number of HFEs	15	16
	Amount of water spilled during HFEs (kaf)	1,236	1,211
F	Number of HFEs	18	19
	Amount of water spilled during HFEs (kaf)	1,734	1,853
G	Number of HFEs	22	22
	Amount of water spilled during HFEs (kaf)	3,188	2,591

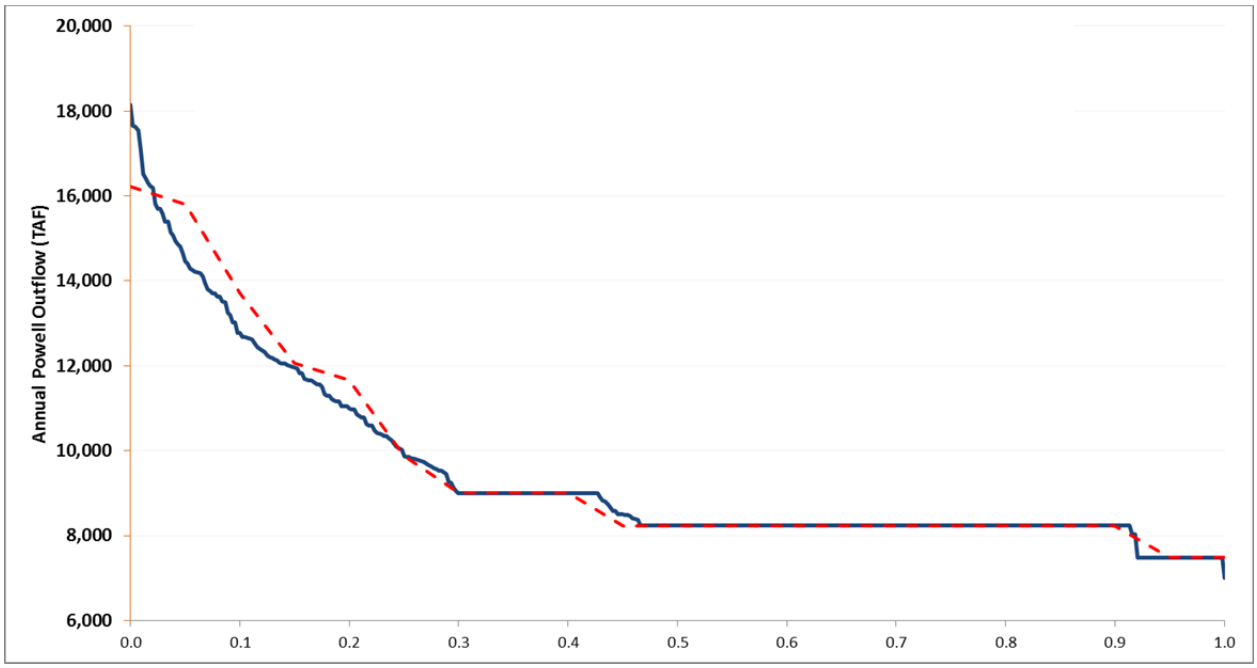

FIGURE 1 Exceedance Curve Comparing Outflows of Trace 14 (red dotted line) and the All-Trace Average (blue line) for the No Action Alternative

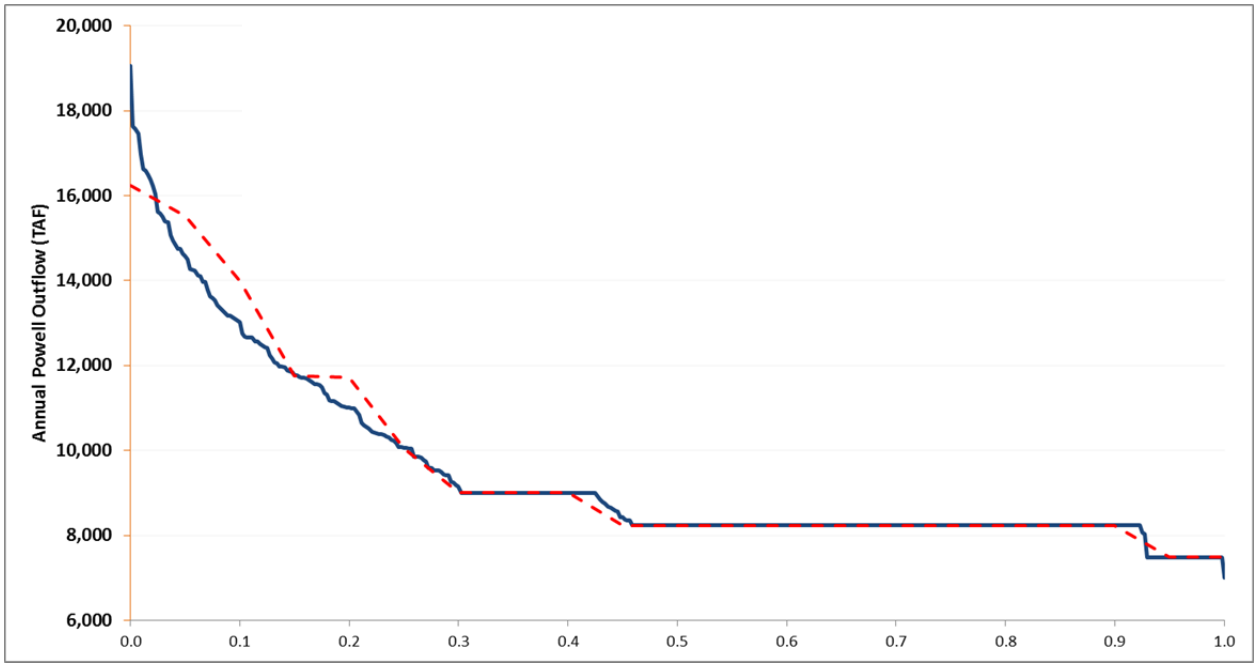

FIGURE 2 Exceedance Curve Comparing Outflows of Trace 14 (red dotted line) and the All-Traces Average (blue line) for Long-Term Strategy C1

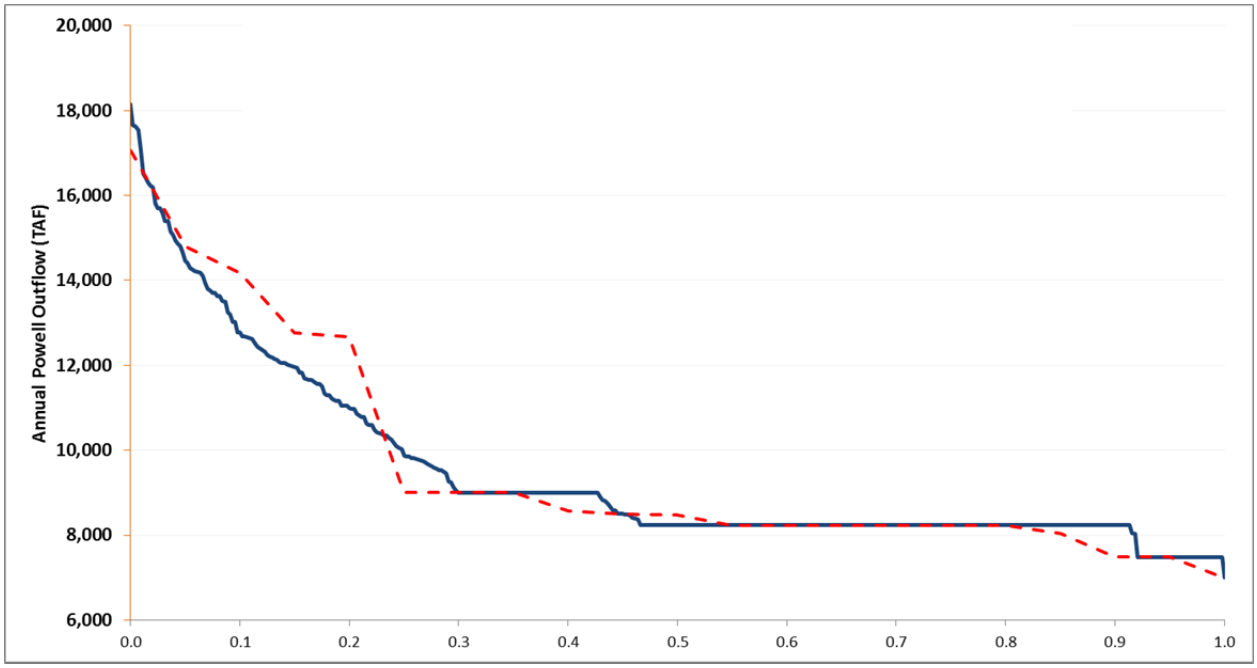

FIGURE 3 Exceedance Curve Comparing Outflows of Trace 19 (red dotted line) and the All-Traces Average (blue line) for the No Action Alternative

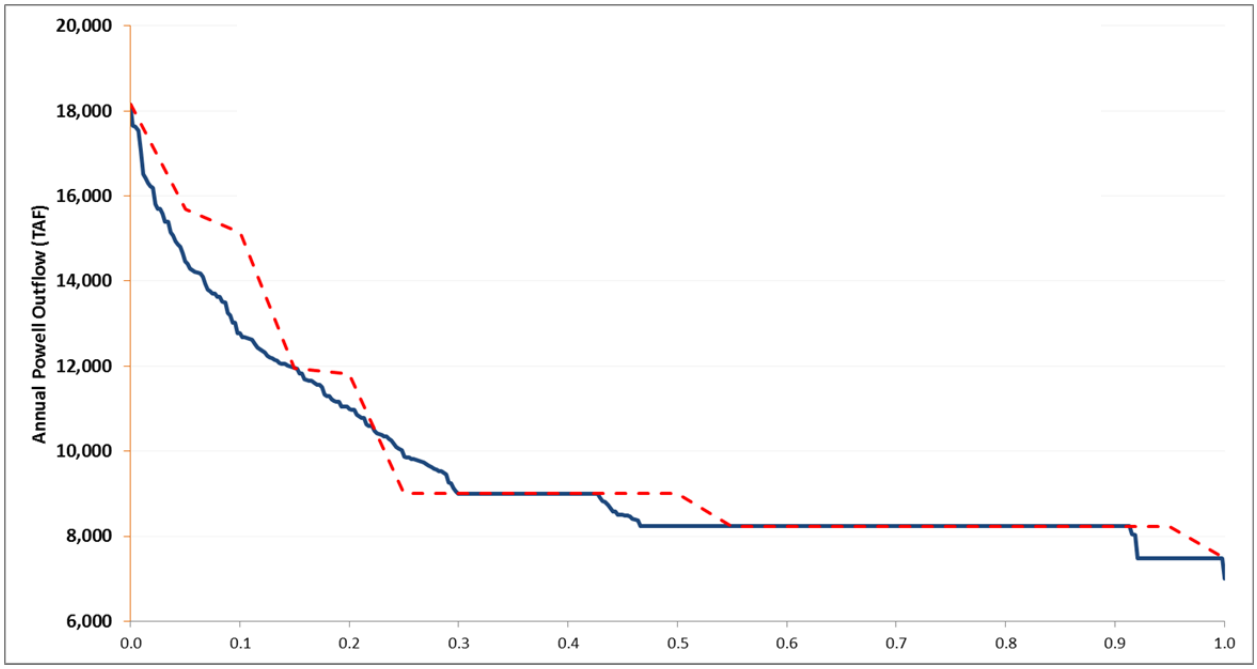

FIGURE 4 Exceedance Curve Comparing Outflows of Trace 13 (red dotted line) and the All-Traces Average (blue line) for the No Action Alternative

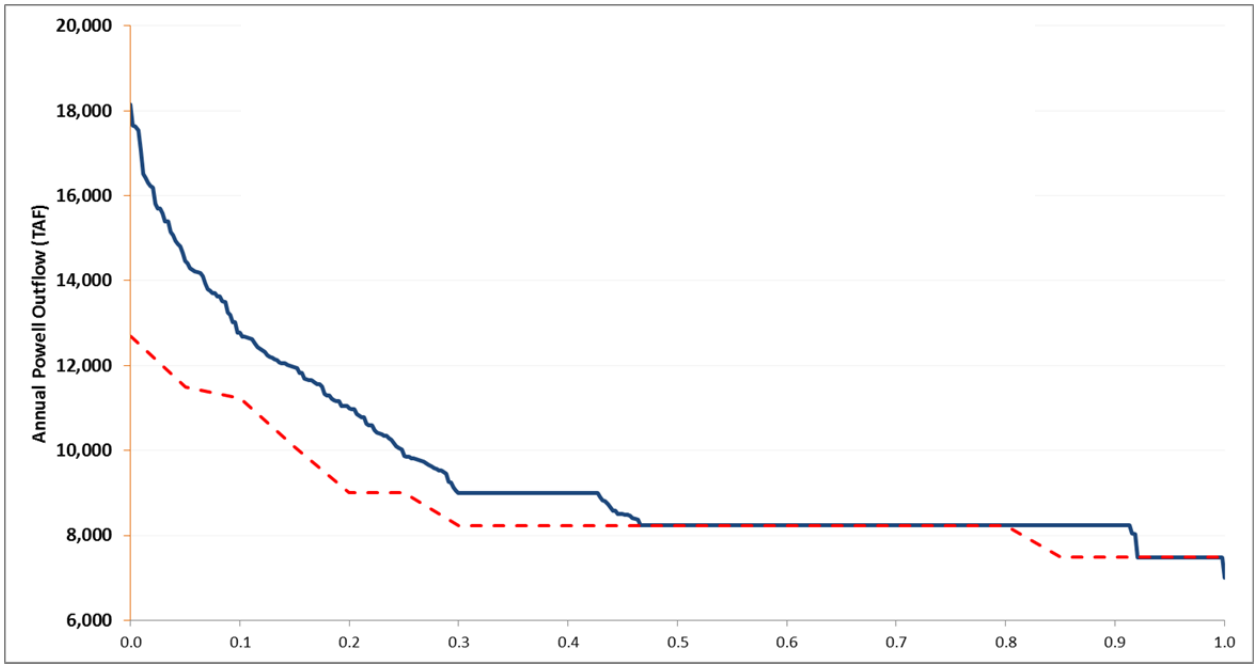

FIGURE 5 Exceedance Curve Comparing Outflows of Trace 16 (red dotted line) and the All-Traces Average (blue line) for the No Action Alternative

Comparison of Monthly Water Releases and Powell Elevations to Averages

Complementing the probability distribution analysis, monthly Powell elevations and water releases for each trace were compared to the associated averages for each month in the 20-year study period for all traces. Again, these comparisons were made separately for each alternative and long-term strategy. The objective in these examinations is to provide "representative variability" over the 20-year spans relative to average outcomes (i.e., the goal is to include conditions that are sometimes "wet," sometimes "dry," and sometime "average," rather than conditions that are uniformly "average" across the entire study period).

Results of monthly outflow and end-of-month elevations for Trace 14 and the all-trace averages are plotted in Figures 6 to 11. Table 3 shows the number of HFEs and the amount of water spilled during all HFEs for Trace 14 and the all-trace average. Trace 14 is characterized by lower-than-average water outflow through 2019, higher water outflow through 2026, followed by lower-than-average water outflow through 2033. As seen from these figures, the monthly Powell elevations and water releases averaged over the 21 traces are significantly less variable than observed for a single trace.

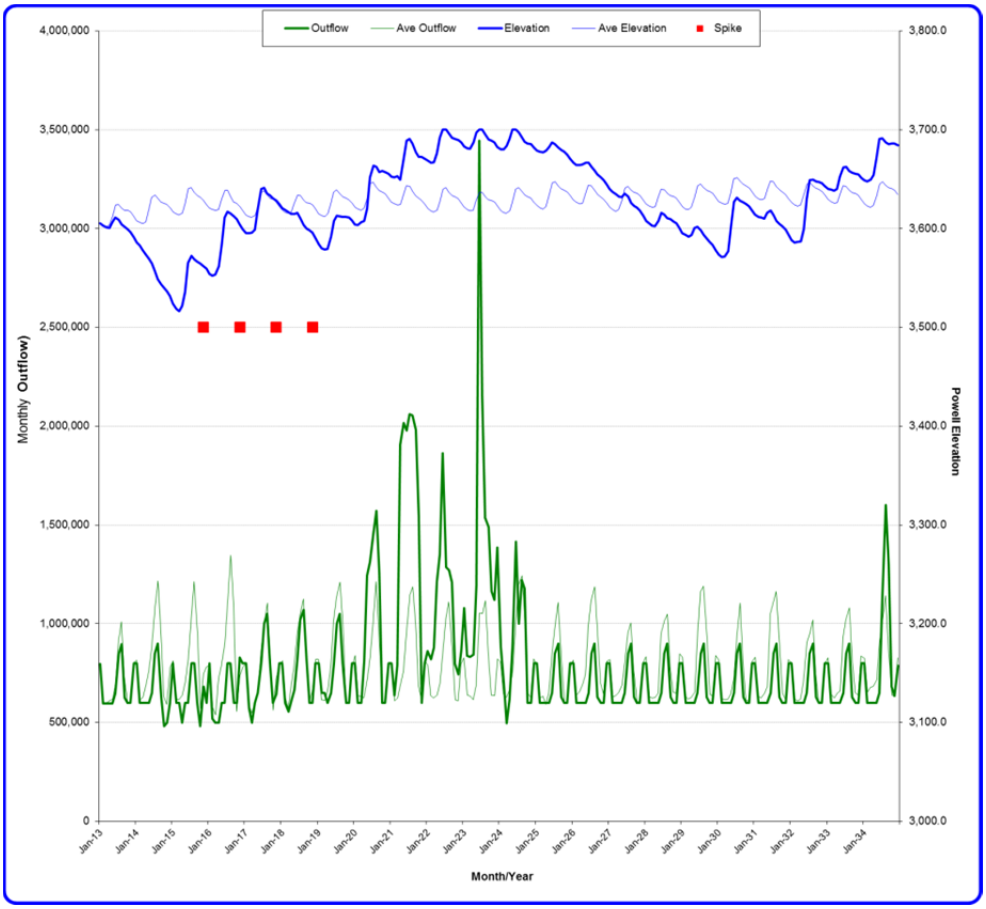

FIGURE 6 Comparison of Monthly Outflow and End-of-Month Elevation of Trace 14 and the All-Trace Average for the No Action Alternative

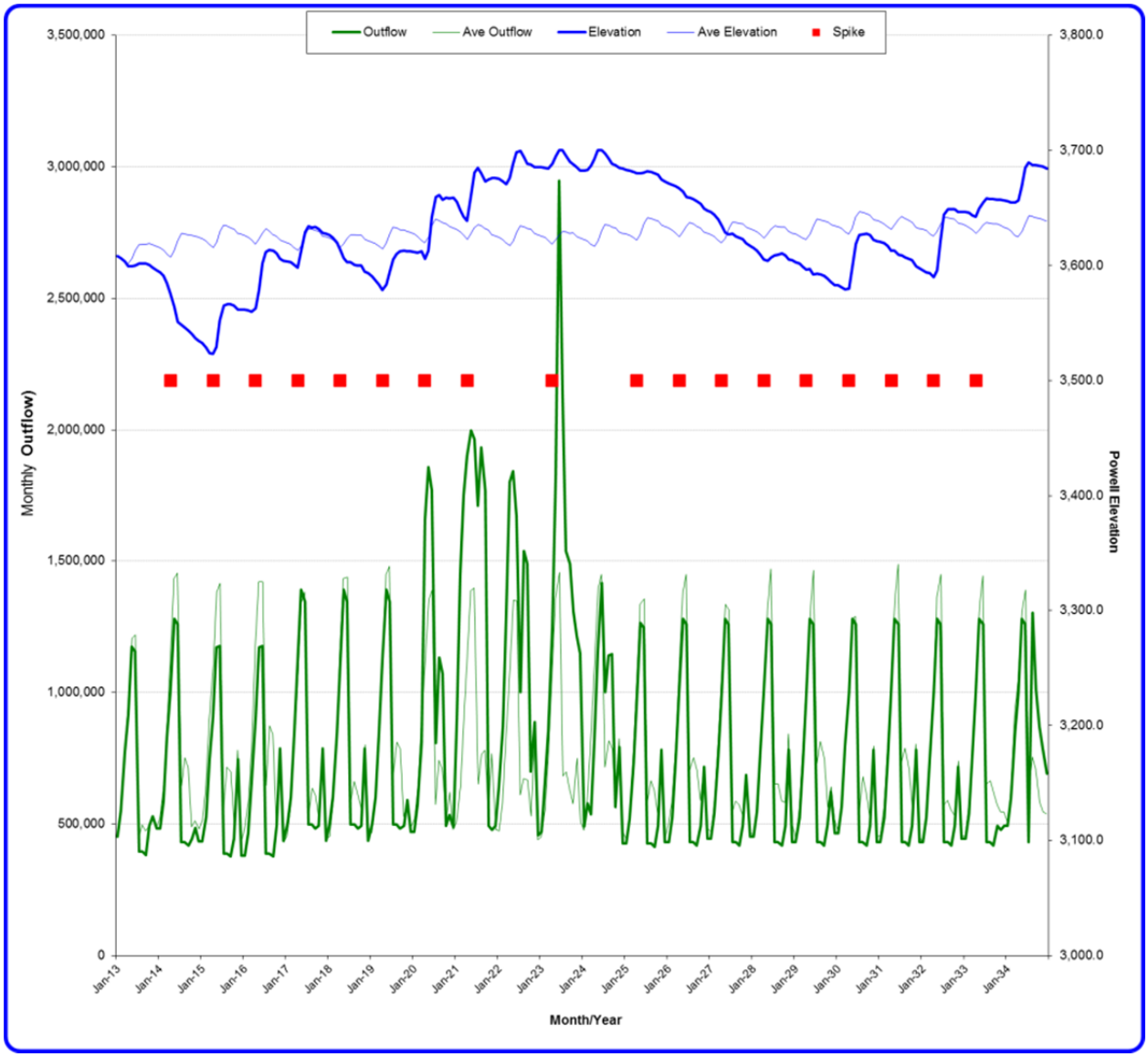

FIGURE 7 Comparison of Monthly Outflow and End-of-Month Elevation of Trace 14 and the All-Trace Average for Alternative F

FIGURE 8 Comparison of Monthly Outflow and End-of-Month Elevation of Trace 14 and the All-Trace Average for Alternative G

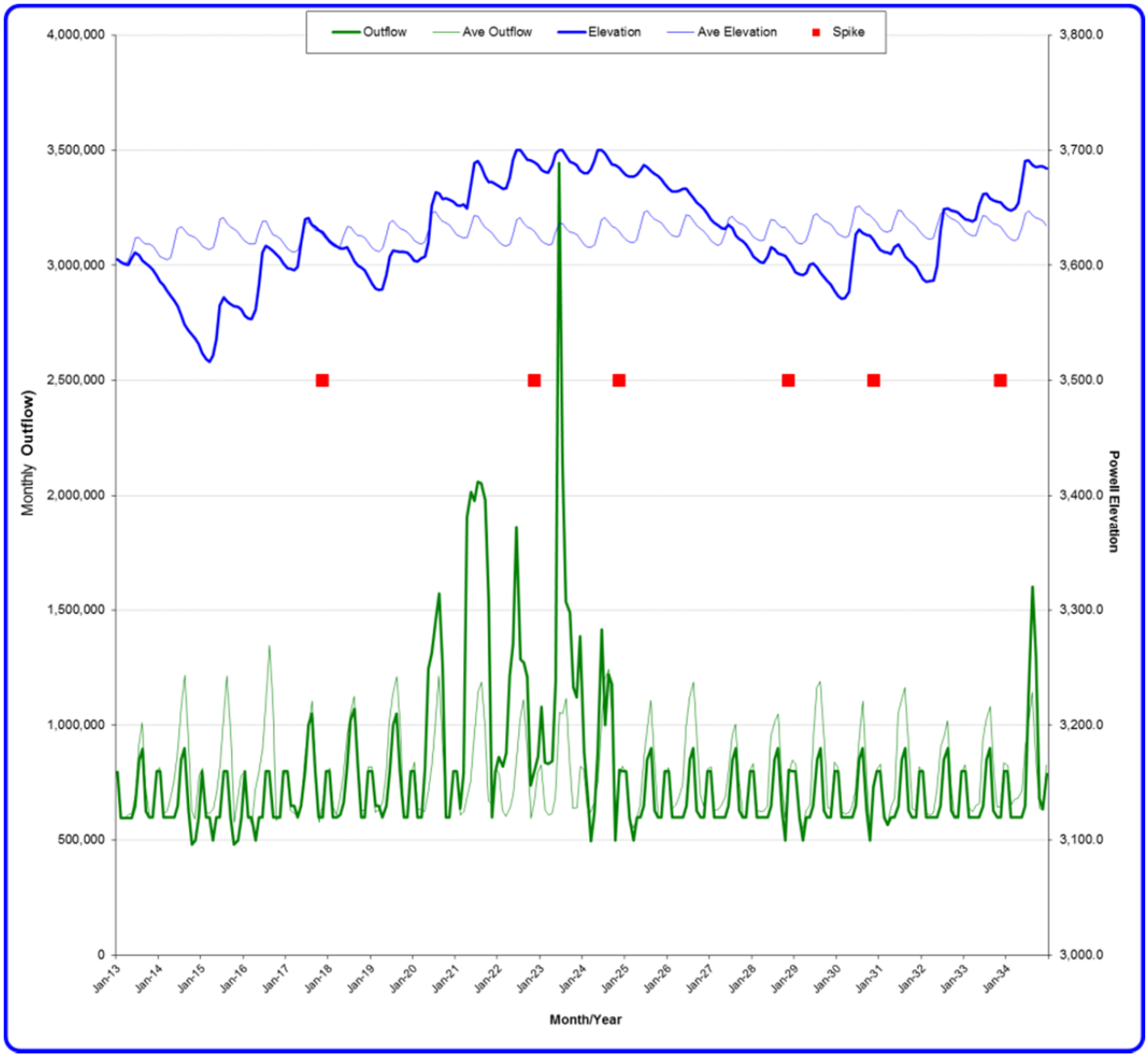

FIGURE 9 Comparison of Monthly Outflow and End-of-Month Elevation of Trace 14 and the All-Trace Average for Long-Term Strategy B1

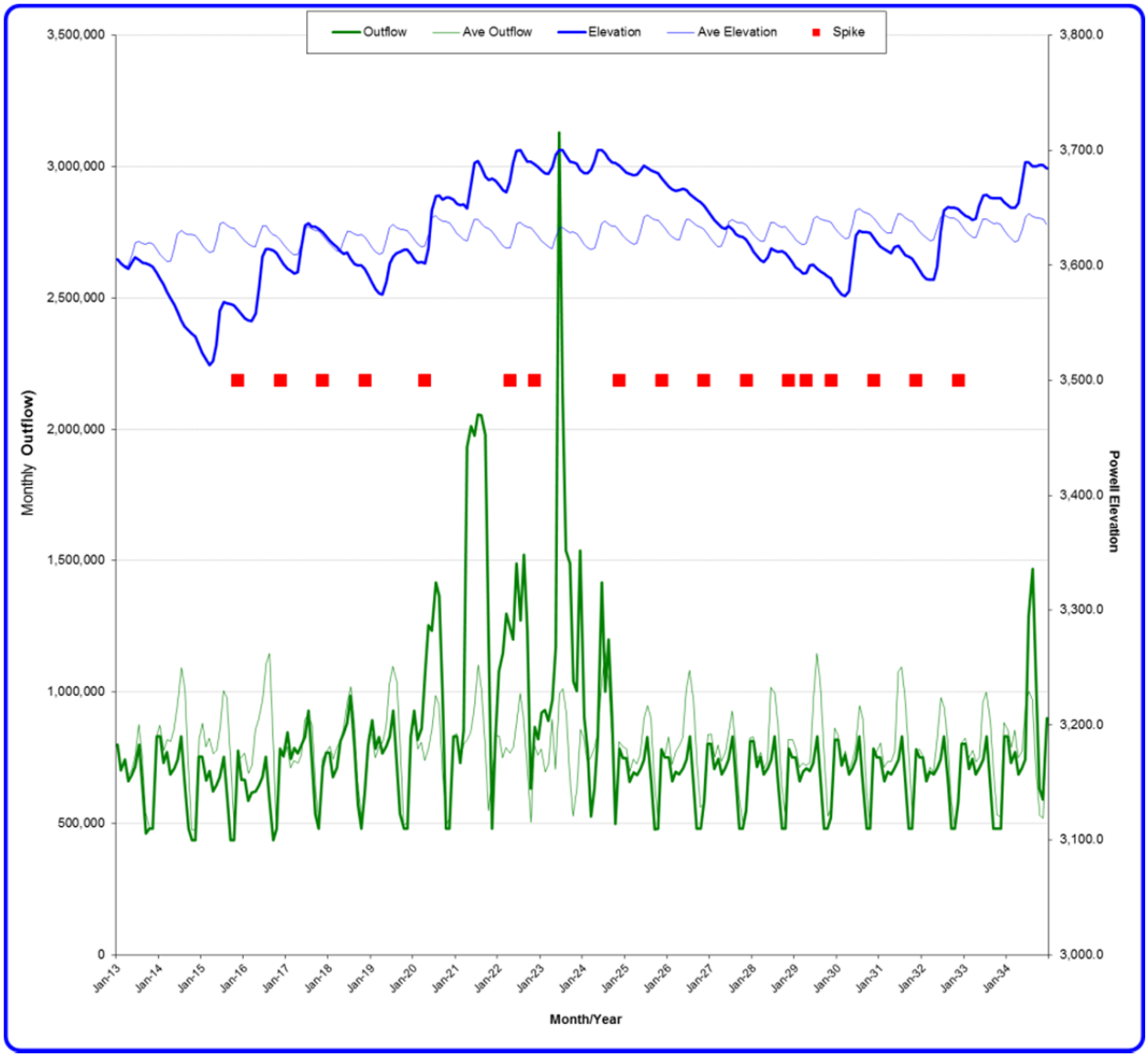

FIGURE 10 Comparison of Monthly Outflow and End-of-Month Elevation of Trace 14 and the All-Trace Average for Long-Term Strategy C1

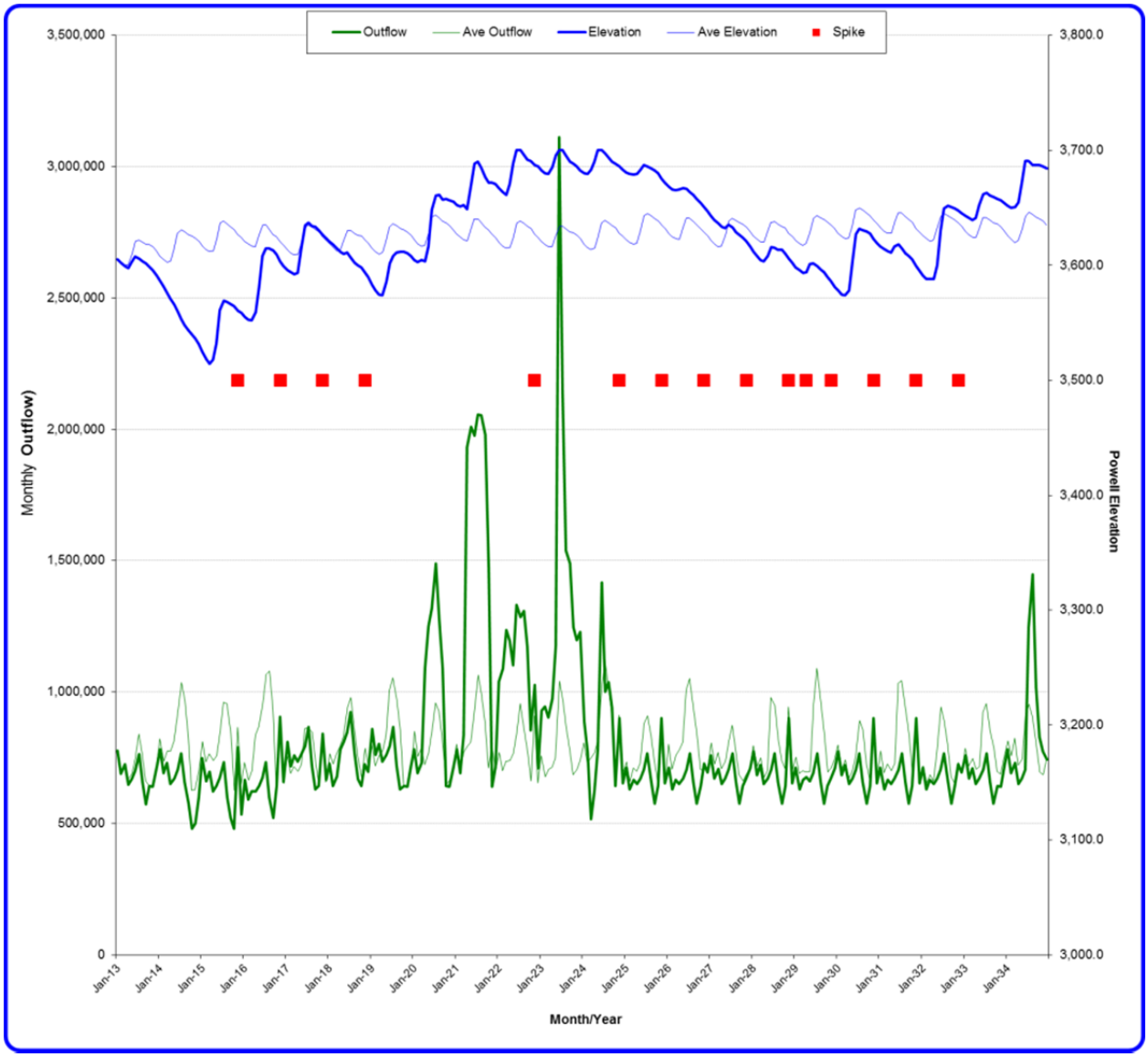

FIGURE 11 Comparison of Monthly Outflow and End-of-Month Elevation of Trace 14 and the All-Trace Average for Long-Term Strategy E1

TABLE 3 Rankings of Hydrology Trace 14 in Matching Average Elevations and Outflows Compared to the 21-Trace Average

Alternative/ Long-Term Strategy	Powell Elevation Trace 14 Rank	Powell Outflow Trace 14 Rank
A (No Action Alternative)	11	13
B1	11	13
C1	11	13
E1	10	13
F	12	13
G	10	13

Because capturing variability is an important objective for this study, an exact match to the 21-trace averages is not desirable. Table 4 illustrates how Trace 14 ranks near the middle of variability for all of the 21 traces; it is neither too close to the average during all years, nor the most extreme divergence from the average over all years.

To assess the 21 traces on a common metric, rankings were calculated based on the least-squares differences by rank relative to the monthly average of all 21 traces: Rank = 1 is the closest match to the average (smallest least-squares difference); Rank = 21 represents the largest difference relative to the average. Table 4 demonstrates that Trace 14 is in the mid-range for both elevation and outflow. The point of this comparison is to illustrate that the selected trace contains neither excessive variability, nor insufficient variability relative to all of the traces under consideration.

Evaluation of Differentials in End-of-Year Powell Elevations and Annual Water Releases

For the representative hydrology trace selection, we also examined how closely each trace's end-of-year Powell elevations and annual water releases match when compared across all six alternatives and long-term strategies. In theory, these values should match closely, but we found that this is not the case for a majority of the traces. To generate a common metric for trace-specific comparisons, we first calculated the differences in both end-of-year elevation and annual outflow between Alternatives A and F; A and G; A and Long-Term Strategy B1; A and Long-Term Strategy C1; and A and Long-Terms Strategy E1 for each of the 20 years and each hydrology trace (using Alternative A [no action alternative] as a reference point). Since these values should ideally all be zero, we calculated the least-squares differentials and ranked the traces according to the sum of the least-squares differences for the five comparisons listed above. Table 5 shows that for these criteria, Trace 14 ranks near the middle of all traces, indicating that it does not represent an extreme case for deviations in end-of-year elevations or annual water releases. In contrast, Trace 13 exhibits the worst match (21st) in annual outflows and ranks 18th in Powell end-of-year elevations.

TABLE 4 Rankings of Hydrology Traces Compared to All-Trace Average for End-of-Year Elevations and Annual Water Releases

Rank (1 = least differential)	Powell Elevation		Powell Outflow	
	Trace Number	Square Differential	Trace Number	Square Differential
1	Trace 4	6.51	Trace 9	0.000
2	Trace 9	20.05	Trace 4	0.000
3	Trace 11	26.91	Trace 11	0.000
4	Trace 6	32.63	Trace 6	0.001
5	Trace 0	43.05	Trace 8	0.003
6	Trace 20	47.32	Trace 12	0.006
7	Trace 3	47.95	Trace 15	0.006
8	Trace 1	54.64	Trace 14[a]	0.007
9	Trace 2	59.81	Trace 0	0.008
10	Trace 7	64.72	Trace 20	0.010
11	Trace 12	127.00	Trace 2	0.015
12	Trace 15	192.56	Trace 1	0.015
13	Trace 14[a]	235.30	Trace 3	0.016
14	Trace 17	326.53	Trace 17	0.018
15	Trace 19	354.81	Trace 7	0.019
16	Trace 16	458.47	Trace 5	0.029
17	Trace 8	583.18	Trace 19	0.060
18	Trace 13[a]	838.12	Trace 10	0.071
19	Trace 5	914.47	Trace 18	0.086
20	Trace 18	1085.39	Trace 16	0.099
21	Trace 10	2363.07	Trace 13[a]	0.112

[a] Traces 13 and 14 are highlighted to illustrate their relative rank with respect to end-of-year elevations and annual water releases.

Examining this same issue through graphical depictions, Figures 12 and 13 compare the differentials for Traces 14 and 13 side by side, in year-by-year plots of the pairwise end-of-year differentials. Trace 14 is preferred over Trace 13 because of the more consistent end-of-year Powell elevations and annual water releases across the six alternatives and long-term strategies.

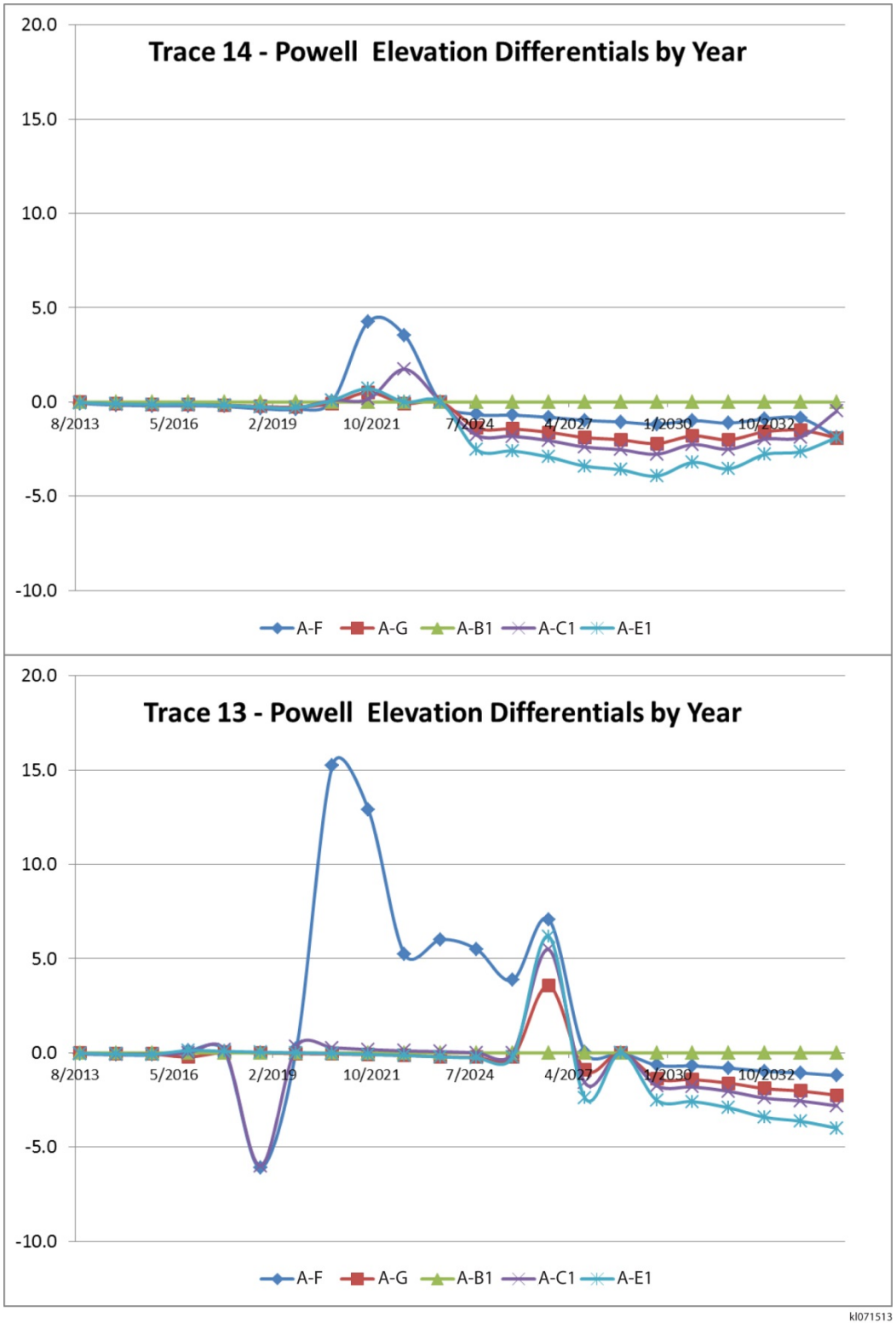

FIGURE 12 Pairwise Annual Lake Powell Elevation Differentials for Traces 14 and 13 (Alternative A is the reference case)

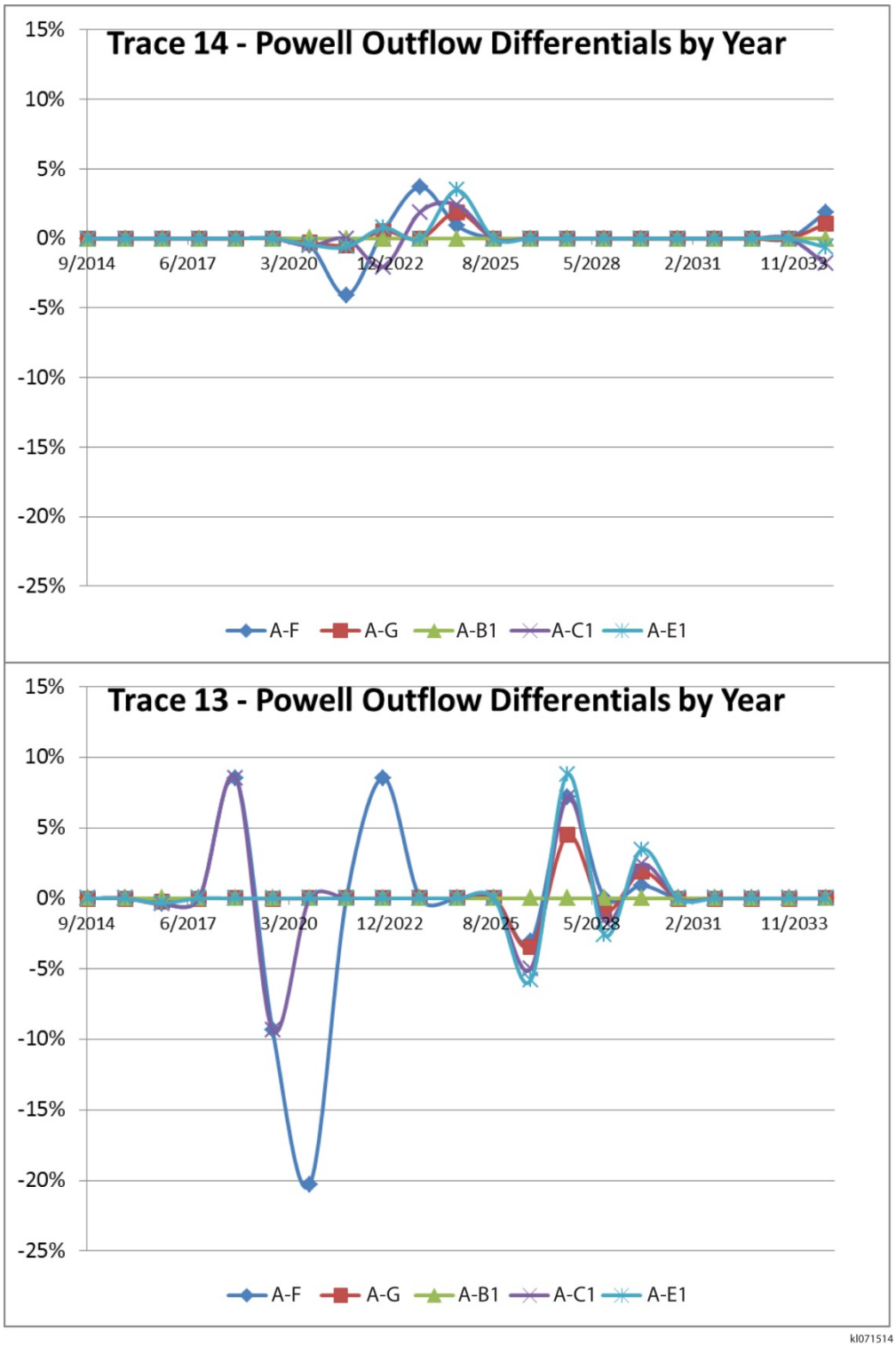

FIGURE 13 Pairwise Annual Lake Powell Outflow Differentials for Traces 14 and 13 (Alternative A is the reference case)

Evaluation of HFE Spills

As a final comparison, Figure 14 shows quantities of water spilled during the HFEs for Trace 14 (highlighted as enlarged red diamond) compared to other traces for each of the six alternatives. These comparisons show that Trace 14 exhibits outcomes that span the range of possible rankings relative to other traces. That is, Trace 14 exhibits HFE spill volumes that are low, medium, and high, for various alternatives, in comparison with other traces. These observations make Trace 14 a favorable candidate for representative spill characteristics across all alternatives.

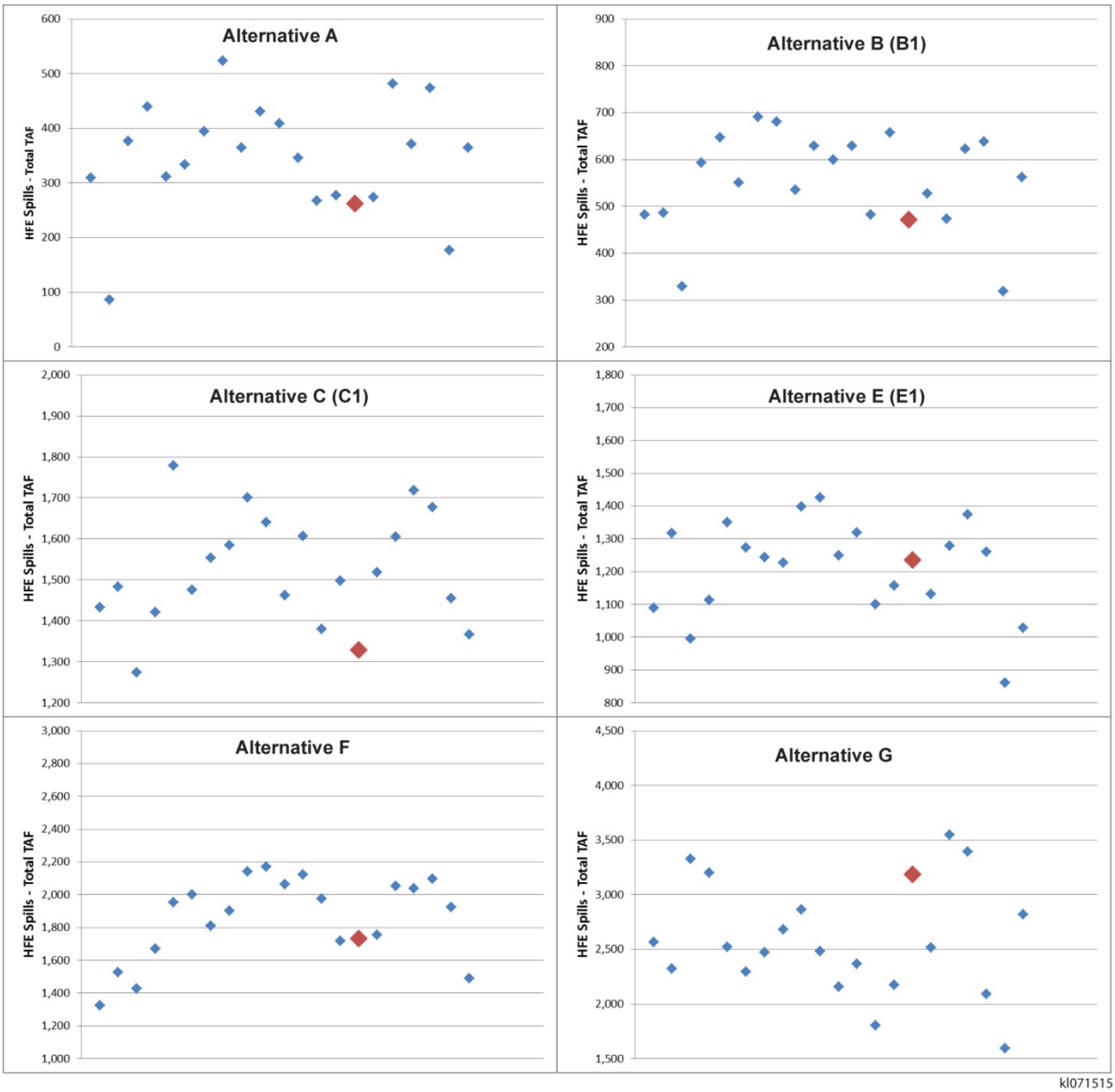

FIGURE 14 Quantity of Water Spilled during HFEs across All Hydrology Traces and All Six Alternatives

Summary

The observations and comparisons described above were used to select hydrology Trace 14 as the representative trace. Characteristics such as annual water release distributions, monthly water release variability, spill events, and end-of-year elevation/volume consistency were considered and a majority of these factors favor Trace 14. While a few other traces show comparable strengths in certain comparison categories, each of those candidate traces show less favorable rankings in other categories.

The power systems analysis will focus on Trace 14 for all six LTEMP alternatives. At some point in the study, sensitivity tests may be conducted to approximate the potential range of variation that might be expected to occur if other traces were used in the capacity expansion and unit dispatch simulations.

ATTACHMENT K.4:

DISCOUNTING PROCEDURES

The costs and benefits of most environmental policies are incurred at different times over what are frequently long time horizons. A fundamental concept in finance and economics is that the timing of benefits and costs makes a difference in the attractiveness of an investment. All other things being equal, one would prefer to receive the benefits of an investment as soon as possible and to pay the costs as far out in the future as possible. Given the choice between receiving $100 today or $100 a year from now, most people would prefer $100 today. Alternatively, if given the choice between paying out $50 today or one year from now, most of us would prefer the latter.

Because the timing of these costs and benefits differs across alternatives, the responsible policy choice requires the use of appropriate techniques to allow for commensurate comparisons. Typically, the present value of the future stream of costs and benefits for each alternative is computed and the results arrayed for decision-makers.

Discounting is the method used for identifying the present value of a cost or benefit that occurs at some time in the future. The process of "discounting" is used to make costs or benefits that occur at different points in time commensurate with each other.

Although the mechanics of the discounting process are very straightforward, the magnitude of the discount rate greatly influences the degree to which future costs and benefits "count" in the decision. As a result, the choice of discount rate is the subject of much controversy.

The literature on discounting and the choice of a discount rate is vast. Many modern economics texts contain synopses of this literature (e.g., Field 2008; Tietenberg and Lewis 2009). A more lengthy assessment can be found in the Environmental Protection Agency's, *Guidelines for Preparing Economic Analyses* (EPA 2010) and Burgess and Zerbe (2011).

Federal water resource agencies, including the Bureau of Reclamation (Reclamation), are required to employ an administratively determined discount rate known as the federal plan formulation and evaluation rate when undertaking economic analyses of water resource and related matters (see 42 U.S.C. 1962d–17, Public Law 93-251-March 7, 1974 Sec. 80 (a)). This requirement and more specific analysis procedures are described in the *Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies* (U.S. Water Resources Council 1983). This document is often referred to as the "P&Gs."

A new set of water resource planning guidelines have been announced which will ultimately supersede the P&Gs (Council on Environmental Quality 2014). In March 2013, the *Principles and Requirements for Federal Investments in Water Resources* (referred to as the P&Rs) were released and in December 2014 a set of *Interagency Guidelines* (IGs) were released by the President's Council on Environmental Quality. Reclamation is now drafting agency-

specific procedures. These ongoing efforts will lead to production of a consolidated document, the *Principles, Requirements and Guidelines* (PR&Gs). Finalization of this effort is slated for calendar year 2016.

Two procedural points are relevant to this analysis. First, the forthcoming PR&Gs do not alter the statutory requirement of federal water resource agencies to employ the federal plan formulation and evaluation rate in their water resource analyses. Second, this environmental impact study was initiated well-prior to completion of these new guidelines, and the PR&Gs are not applicable to the analysis reported here.

As prescribed by law and described in the P&Gs, federal water resource agencies must use an administratively determined discount rate for cost-benefit analysis. This rate is known as the federal discount rate for plan formulation and evaluation. The plan formulation and evaluation rate is calculated annually by the Secretary of the Treasury pursuant to 42 U.S.C. 1962d-1 (see the *Code of Federal Regulations* [CFR] at 18 CFR Part 704 for a description of the methodology) and then is officially transmitted to the water resource agencies. The plan formulation and evaluation rate for fiscal year (FY) 2015 is 3.375% (Reclamation 2014a,b).

TABLE 1 summarizes the inflation, escalation, and discounting procedures used in this analysis. As illustrated, the base year chosen for this economic analysis is 2015. The period of analysis is 21 calendar-years, spanning the period 2013 to 2033. All economic value estimates reported in this document are measured in 2015 dollars, unless otherwise stated.

The prices and values employed as input data for the economic modeling were reported at various times. To create a common input baseline, these prices and values were inflated from the year in which they were reported to 2014 dollars, using the annual Western Regional Consumer Price Index (CPI) (Bureau of Labor Statistics 2015).

TABLE 1 Discounting Procedures

Parameter	Value
Base year for reported results	2015
Period of analysis 2013 through 2033	21 years
Price escalation rate (2014 through 2015)	2.2126%
Price escalation rate (2015 through 2033)	0.0%
Discount rate[a]	3.375%

[a] Federal Water Resource plan formulation and evaluation rate for FY 2015.

Modeling output was inflated from 2014 to 2015 dollars for reporting purposes. The equivalent annual CPI rate during the most recent 10-year (2004 to 2014) period was calculated to be 2.2126 percent (rounded to 4 decimal places). Price inflation from 2014 to 2015 was assumed to be the same as it was during this 10-year period. All 2014 values and prices were escalated from 2014 to the base year of 2015 using an escalation rate of 2.2126 percent.

To summarize, consistent with applicable federal law, the procedures described in the *Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies* (U.S. Water Resources Council 1983), all costs and benefits that occur after 2015 are reported in constant 2015 dollars (they are not escalated). Costs and benefits that occur in 2015 are not discounted, given that 2015 is the base year for this analysis. All costs and benefits that occur after 2015 are discounted back to the 2015 base year using the FY 2015 federal discount rate for plan formulation and evaluation (3.375%).

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ATTACHMENT K.5:

FORCED OUTAGE SCENARIO GENERATION FOR HYDROELECTRIC POWER FACILITIES

The following is a description of the methodology used in creating a forced outage scenario for hydroelectric power facilities.

Requirement

1. Generate a reasonable forced outage scenario consistent with industry average for hydro units.

2. The forced outages should be multiple of 24 hours.

3. The forced outage always starts at the beginning of a day.

Inputs

1. Planned maintenance schedule for the hydroelectric power facility being modeled (from Reclamation)

2. Cause code statistics from the North American Electric Reliability Corporation (NERC)

3. Forced outage rate distribution from NERC

NERC publishes generating availability data system (GADS; http://www.nerc.com/page.php?cid=4|43|47). These reports contain aggregate statistics for various unit types. The cause code group statistics provides the number of forced outages and the number of hours under forced outage per unit per year. Tables 1 and 2 contain the relevant data extracted from GADS 2010.

Methodology

1. For each year and for each unit, randomly assign a forced outage rate (FOR) based on the distributions in Table 2.

2. Compute the forced outage hours based on the assigned FOR and service hours. Service hours are the number of hours the unit is not on planned maintenance schedule (i.e., available for generation).

3. Sum forced outage hours across all the units for a given year (TOTSYS)

TABLE 1 Cause Code Statistics for Hydro Plants >30 MW 2006–2010

Unit Type	Index	Cause Code	Description	Avg. No. of Outages per Unit Year	Avg. Hours Out per Unit Year
9	1	3600-3689	Electrical	0.31	25.28
9	2	3810-3899	AuxiliarySystems	0.06	2.71
9	3	3950-3999	Miscellaneous(BalanceOfPlant)	0.04	0.39
9	4	4500-4590	GENERATOR	0.17	45.18
9	5	4600-4609	Exciter	0.16	10.75
9	6	4610-4650	CoolingSystem	0.04	3.03
9	7	4700-4750	Controls	0.19	4.28
9	8	4800-4899	Miscellaneous(Generator)	0.1	9.92
9	9	7000-7099	Turbine	0.36	42.05
9	10	7100-7199	WaterSupplyDischarge	0.29	25.83
9	11	7200-7299	Miscellaneous(HydroTurbinePump)	0.23	11.25
9	12	9000-9040	Catastrophe	0.06	1.57
9	13	9135-9160	Economic	0.01	9.24
9	14	9300-9320	Miscellaneous(External)	0.26	1.4
9	15	9504-9590	Regulatory	0.01	0.01
9	16	9676-9696	OtherOperatingEnvironmentalLim	0.01	0.15
9	17	9700-9720	Safety	0	0
9	18	9900-9920	PERSONNELERRORS	0.05	0.22
9	19	9999-9999	PERFORMANCE	0.01	0.27

TABLE 2 Equivalent Forced Outage Rate Distribution

Unit Type	Index	FOR (Max)	Exceedance Curve
9	1	0	0.069
9	2	0.01	0.5727
9	3	0.02	0.7063
9	4	0.05	0.8238
9	5	0.1	0.8987
9	6	0.2	0.9383
9	7	0.3	0.9574
9	8	0.4	0.9721
9	9	0.5	0.9838
9	10	0.6	0.9883
9	11	0.7	0.9927
9	12	0.8	0.9956
9	13	0.9	0.9971
9	14	1	1

4. Using cause code statistics, calculate average outage length in hours for each cause code (column 6 divide by column 5 in Table 1).

5. Compute the total forced outage hours for each cause code across all units (column 6 * no. of units) and also the total forced outage hours across all units and all cause codes (TOTFOH).

6. Total outage hours based on cause codes are typically much lower than the hours out for units since cause codes outages are based on actual data and reflect only those hours that the unit is in service or called into service. Compute a "SCALE" as the ratio of TOTFH and TOTSYS.

7. Compute the total number of outages for each cause code across units using the "SCALE", column 5 from Table 1 and the total number of units.

8. For each cause code, loop through the number of outages. Randomly select a unit and a random start time that the unit is not on planned maintenance. Assign the forced outage for the duration of average outage length for the given cause code (from step 4 above).

9. Adjust the length of forced outage to be a multiple of 24 hours and move to the beginning of the day, if necessary.

ATTACHMENT K.6:

FORECAST OF MONTHLY PEAK LOADS AND ENERGY BY SLCA/IP LONG-TERM FIRM CUSTOMER

The development of hourly load projections over the study period is based on the 2006 representative nominal load profile and monthly projections of utility-level peak and total loads. Implementation of this method differs from utility to utility depending upon data availability. The primary source of forecast information was the utility's integrated resource plan (IRP). If these data are not available in the IRP, then generation and capacity projections from the Energy Information Administration's (EIA's) 2014 Annual Energy Outlook (EIA 2014) are used instead. The method for developing the hourly load forecast for each of the eight utilities plus Western's remaining small customers is described in more detail in Section K.1.6.3 of Appendix K.

Figures 1 and 2 show monthly peak loads and total monthly load projections, respectively, for each of the eight large customers and the two aggregate small customer groups. This data was used to generate the graphs shown in Figures K.1-15 and K.1-16 in Section K.1.6.3 of Appendix K.

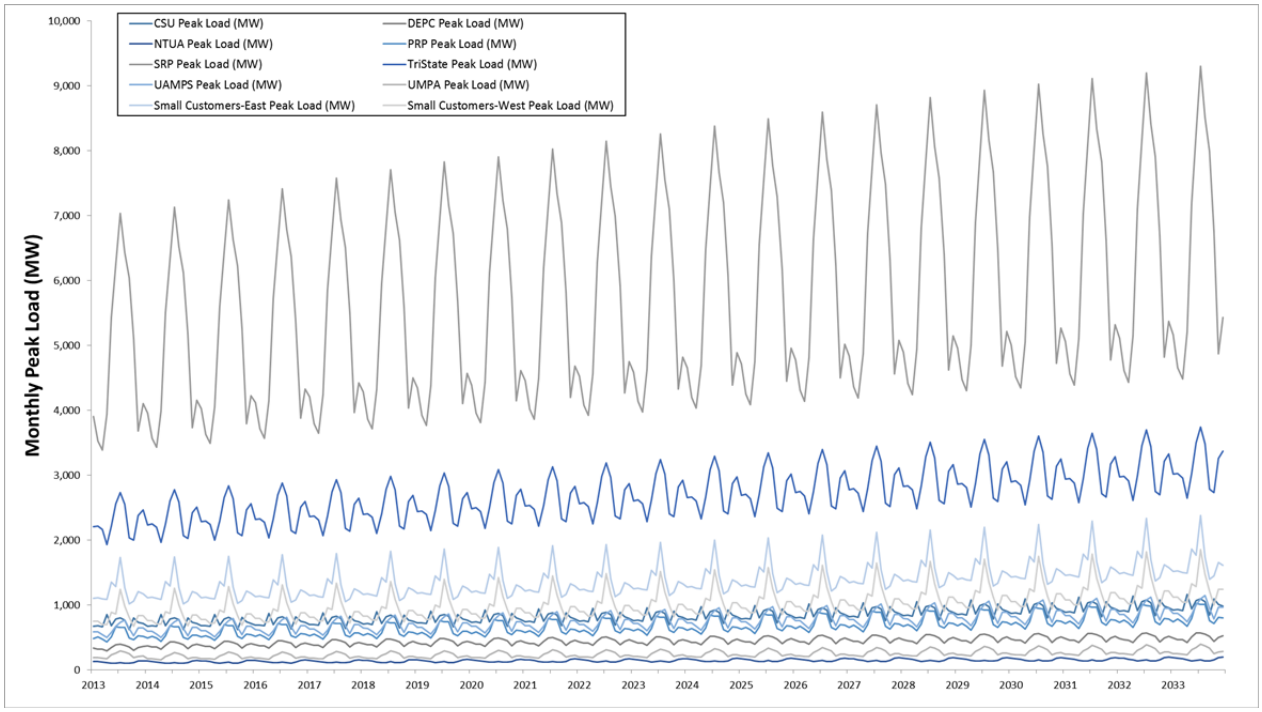

FIGURE 1 Projected Future Peak Loads by Each Large Customer and Small Customer Groups in the SLCA/IP Market System during the LTEMP Period

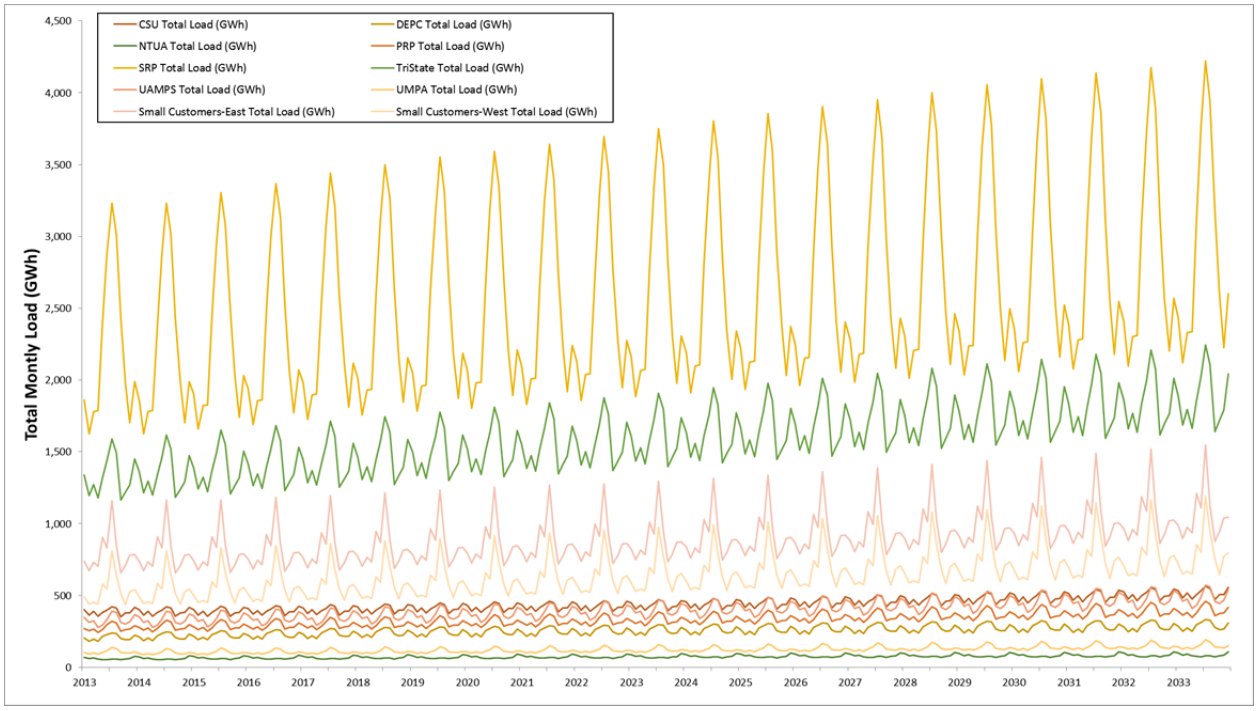

FIGURE 2 Projected Future Monthly Loads by Each Large Customer and Small Customer Groups in the SLCA/IP Market System during the LTEMP Period

Reference

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ATTACHMENT K.7:

ANALYSIS OF THE TIMING OF THE PEAK LOAD

In the recent past, Western's coincidental peak load has occurred in the summer, but it does not consistently occur in a specific month. A study was performed to determine the month in which the peak occurred in recent history.

Hourly load data was obtained for 2006 to 2012 from Federal Energy Regulatory Commission (FERC) Form 714 for Western's 8 largest customers; namely, SRP, Tri-State, CSU, Platte River, NTUA, UAMPS, UMPA, and Deseret. These customers account for 75% of Western's energy and capacity, so the aggregate load of these customers would determine when Western's peak occurs.

Table 1 shows the peak load in each month of the year from 2006 to 2012. Data was not available for NTUA and Deseret from 2010 to 2012, so those utilities were not included in those years. However, Figure 1 shows that NTUA and Deseret only account for 1% and 3% of the peak load from 2006 to 2009, respectively, so not having their data in the last 3 years of the study would not alter the occurrence of the coincidental peak.

The peak load occurs in July in 3 of the 7 years and in August in 4 of the 7 years (as indicated by the shaded areas in Table 1). Therefore, the peak occurs in either July or August with nearly equal frequency. For the LTEMP DEIS analysis, August was chosen as the peak month.

TABLE 1 Aggregate Monthly Peak Load of Western's Eight Large Customers for 2006 to 2012[a]

Month	2006	2007	2008	2009	2010	2011	2012
1	7,470	8,089	8,411	7,983	7,426	7,836	7,160
2	6,974	7,619	8,293	7,611	7,434	8,626	6,740
3	6,781	7,204	7,308	6,983	7,091	6,964	6,514
4	6,852	7,878	7,934	7,760	7,029	7,214	7,959
5	9,053	9,116	9,969	9,820	8,328	7,884	9,234
6	10,419	10,624	10,744	10,549	10,625	10,624	11,009
7	11,336	11,670	11,188	11,416	11,049	11,069	10,722
8	10,691	11,639	11,656	11,461	10,495	11,301	11,604
9	9,361	10,403	9,382	10,232	9,884	10,840	9,738
10	8,143	8,374	8,738	7,947	8,956	8,191	8,295
11	7,596	7,377	7,535	7,478	7,788	6,665	6,803
12	7,888	8,102	8,326	8,480	8,247	7,623	7,452
Total	11,336	11,670	11,656	11,461	11,049	11,301	11,604

[a] Missing NTUA and Deseret. Maximum values are highlighted in yellow.

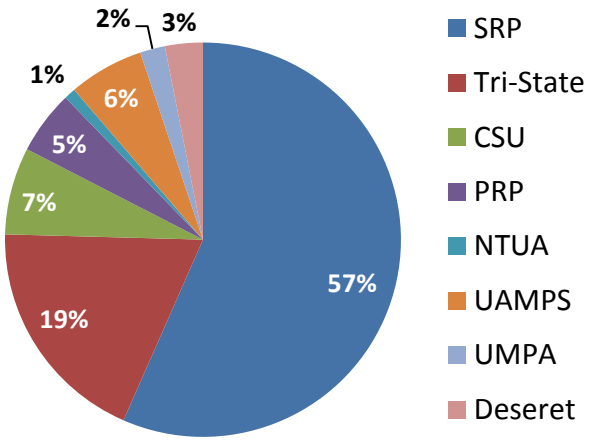

FIGURE 1 Breakdown of Non-coincidental Peak by Customer

Figures 2 through 9 show monthly peak loads for the eight large SLCA/IP LTF power customers. All customers except the NTUA peak in the summer months of either July or August. However, in one year, CSU reported an abnormally high peak load in April.

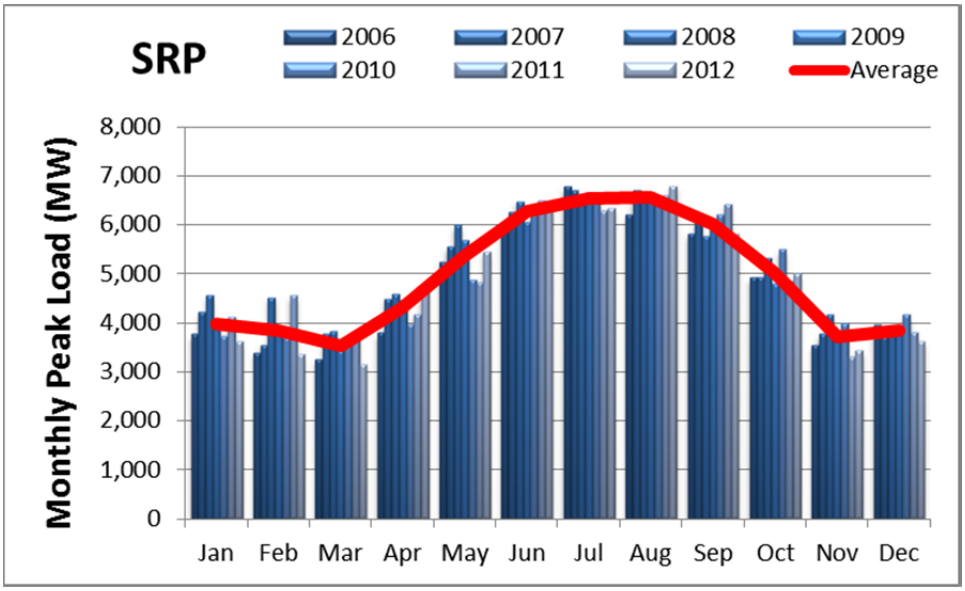

FIGURE 2 SRP Historical Monthly Peak Load

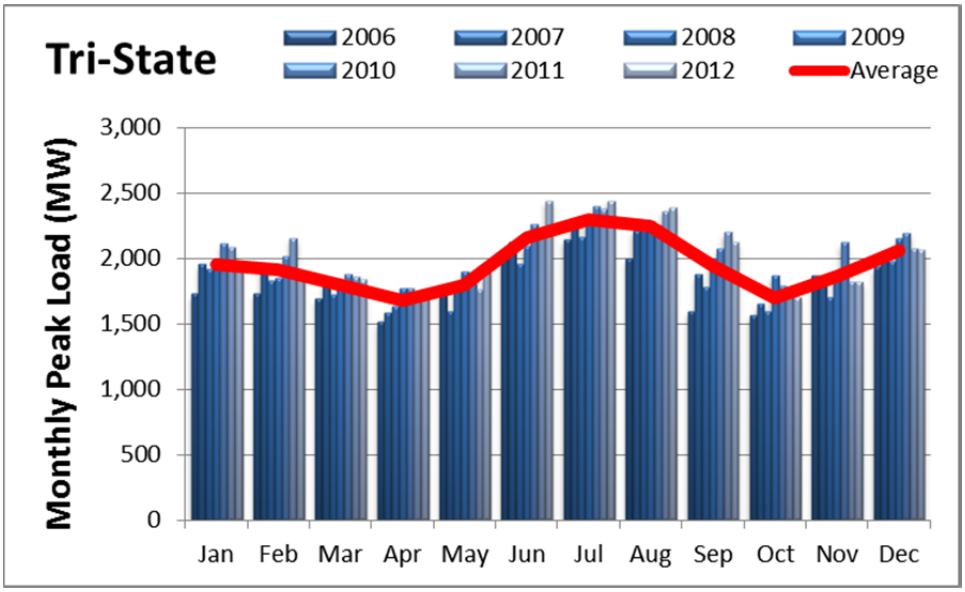

FIGURE 3 Tri-State Historical Monthly Peak Loads

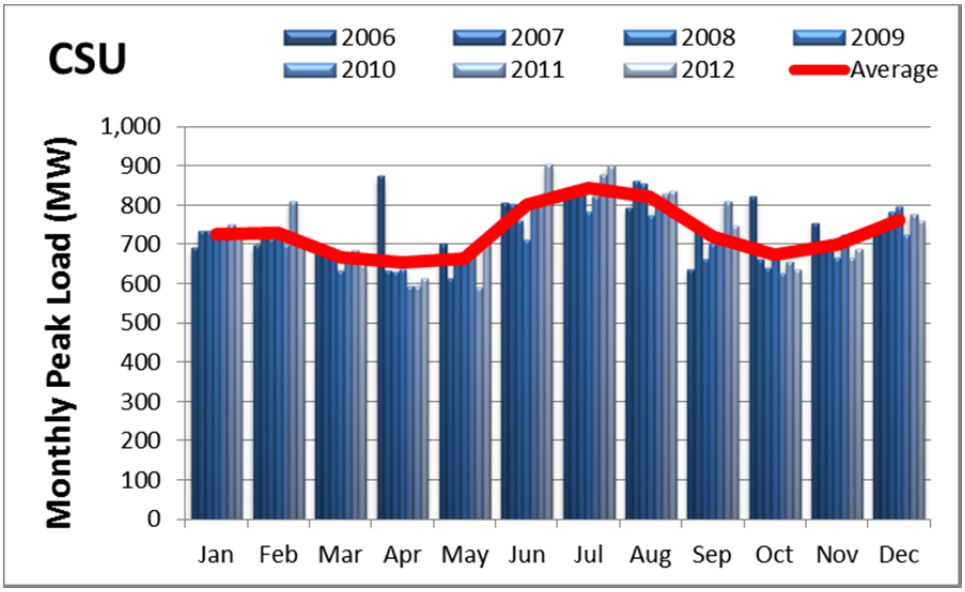

FIGURE 4 CSU Historical Monthly Peak Loads

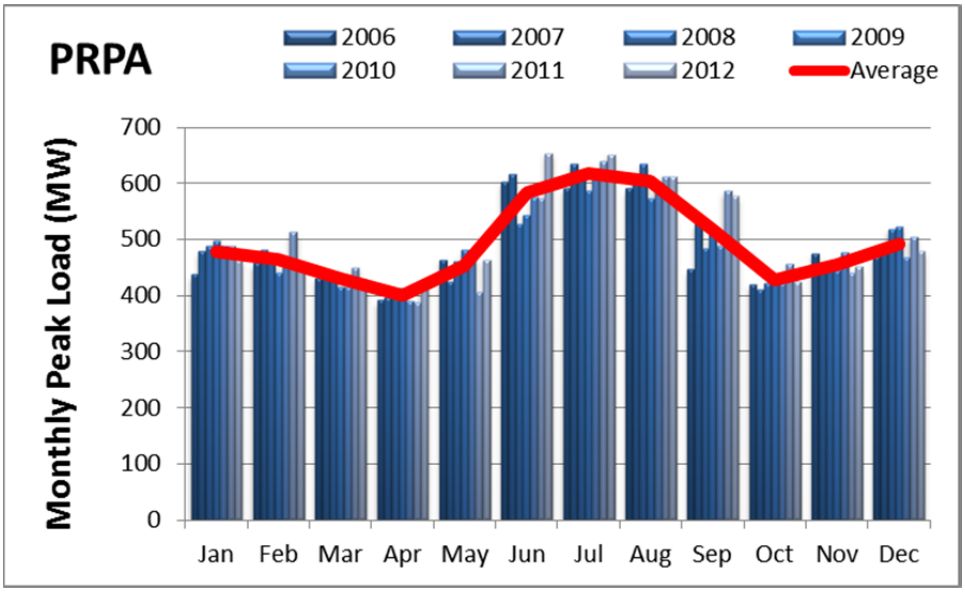

FIGURE 5 PRPA Historical Monthly Peak Loads

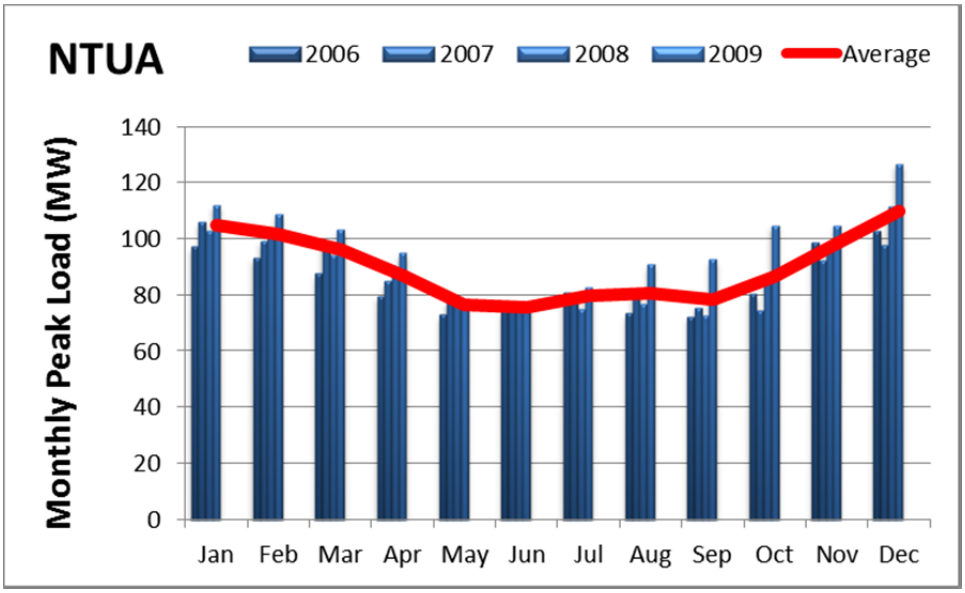

FIGURE 6 NTUA Historical Monthly Peak Loads

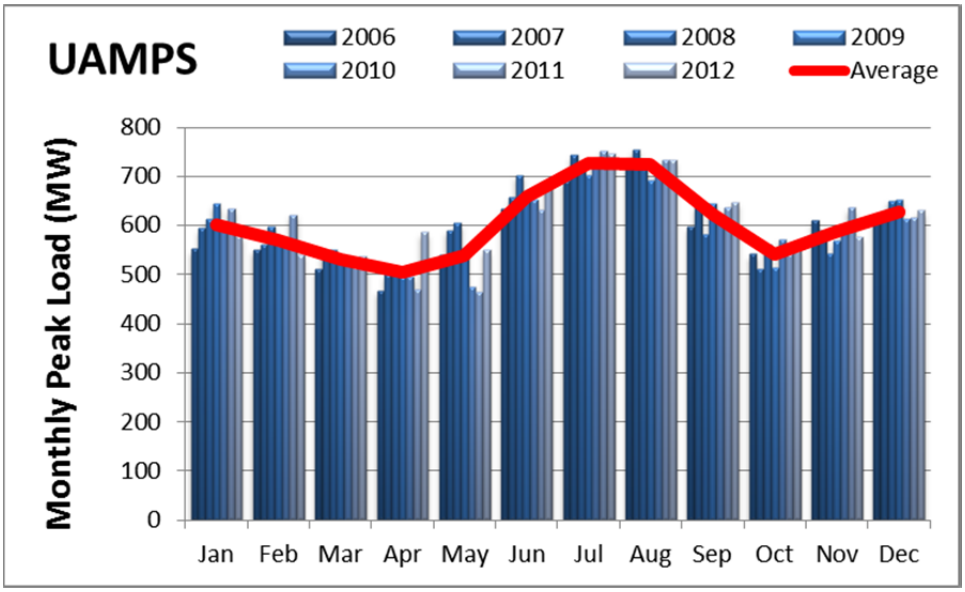

FIGURE 7 UAMPS Historical Monthly Peak Loads

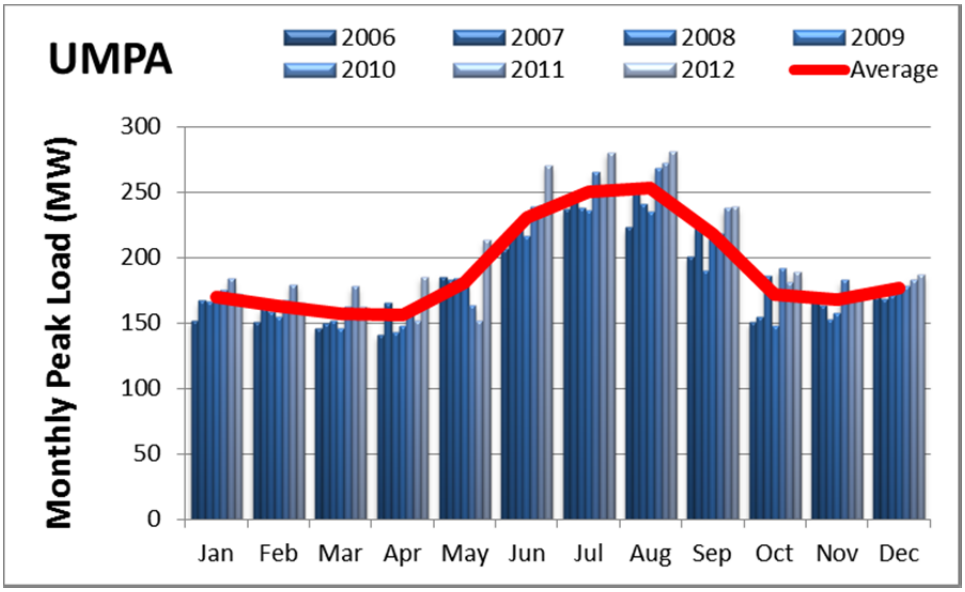

FIGURE 8 UMPA Historical Monthly Peak Loads

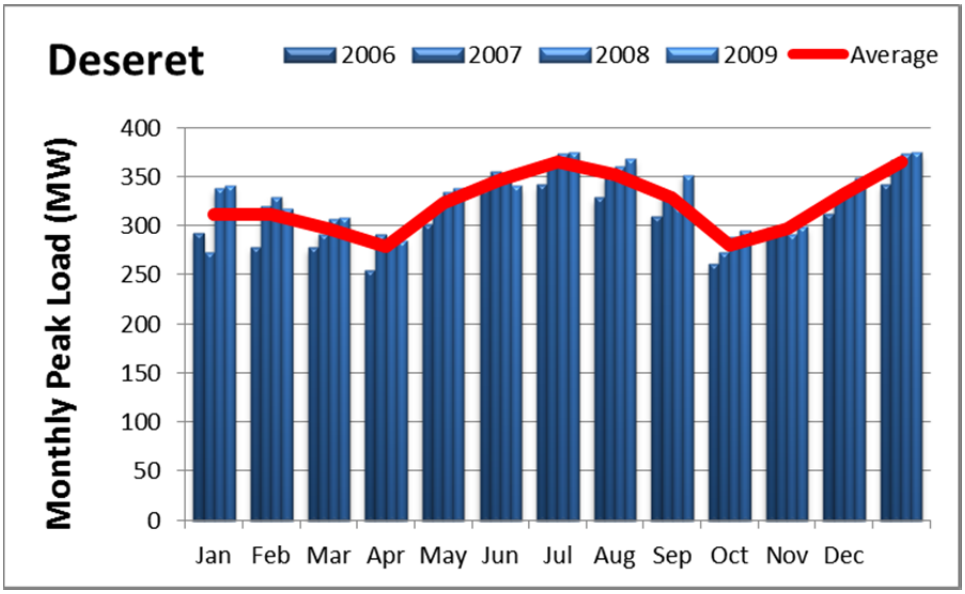

FIGURE 9 Deseret Historical Monthly Peak Loads

ATTACHMENT K.8:

ANALYSIS OF CAPACITY DETERMINATIONS— COMPARING RESULTS USING A RANGE OF EXCEEDENCE LEVELS AND TWO SUMMER PEAK MONTHS

Marketable capacity is very sensitive to the assumed exceedance level and the timing of the annual peak load. This attachment will describe that sensitivity. In the Western Interconnection (WI) annual peak loads almost always occur in either July or August; in fact, the study described in Attachment K-7 shows the peak occurs in either July or August with nearly equal frequency.

The graphs on the left side of Figure 1 show the marketable capacity for the six major alternatives and long-term strategies at exceedance levels from 10% to 99% for the three hydropower resource components combined. Marketable capacity was also shown for three different times when the peak load was assumed to occur, namely, July, August, and July/August combined. All alternatives have less marketable capacity at all exceedance levels than the no action alternative, except for Long-Term Strategy B1, which is expected because it has the least restrictive environmental constraints of any alternative.

The graphs on the right of Figure 1 show the difference in marketable capacity compared to Alternative A, which is the the no action alternative. The graphs show that the greatest difference in capacity occurs at the 50% exceedance level and the smallest at the 99% exceedance level.

There is also a noticeable difference in marketable capacity for some alternatives compared to the no action alternative depending upon the month chosen. Long-Term Strategies C1 and E1 have a much smaller difference in marketable capacity compared to Alternative A in July than in August at all exceedance levels.

The choice of the peak month and exceedence level used for Glen Canyon Dam capacity availability is a policy choice by Western and is related to the degree of risk Western chooses to take when marketing long-term capacity. There have been variations in level of risk chosen by Western when marketing long-term capacity from various projects. For the Long-Term Experimental and Management Plan (LTEMP) Draft Environmental Impact Statement (DEIS), an exceedance level of 90% and a peak month of August were selected. The exceedance level was chosen based on a retrospective study performed by Argonne on marketable capacity offered by the CRSP Management Center of Western. Over the last 10 years they marketed capacity at a 90% exceedance level. Results were presented in Section K.1.10.4 for exceedance levels of 50% and 99%; this range may bracket the risk preference level that the CRSP Management Center may choose to use when determining future LTF capacity commitment levels.

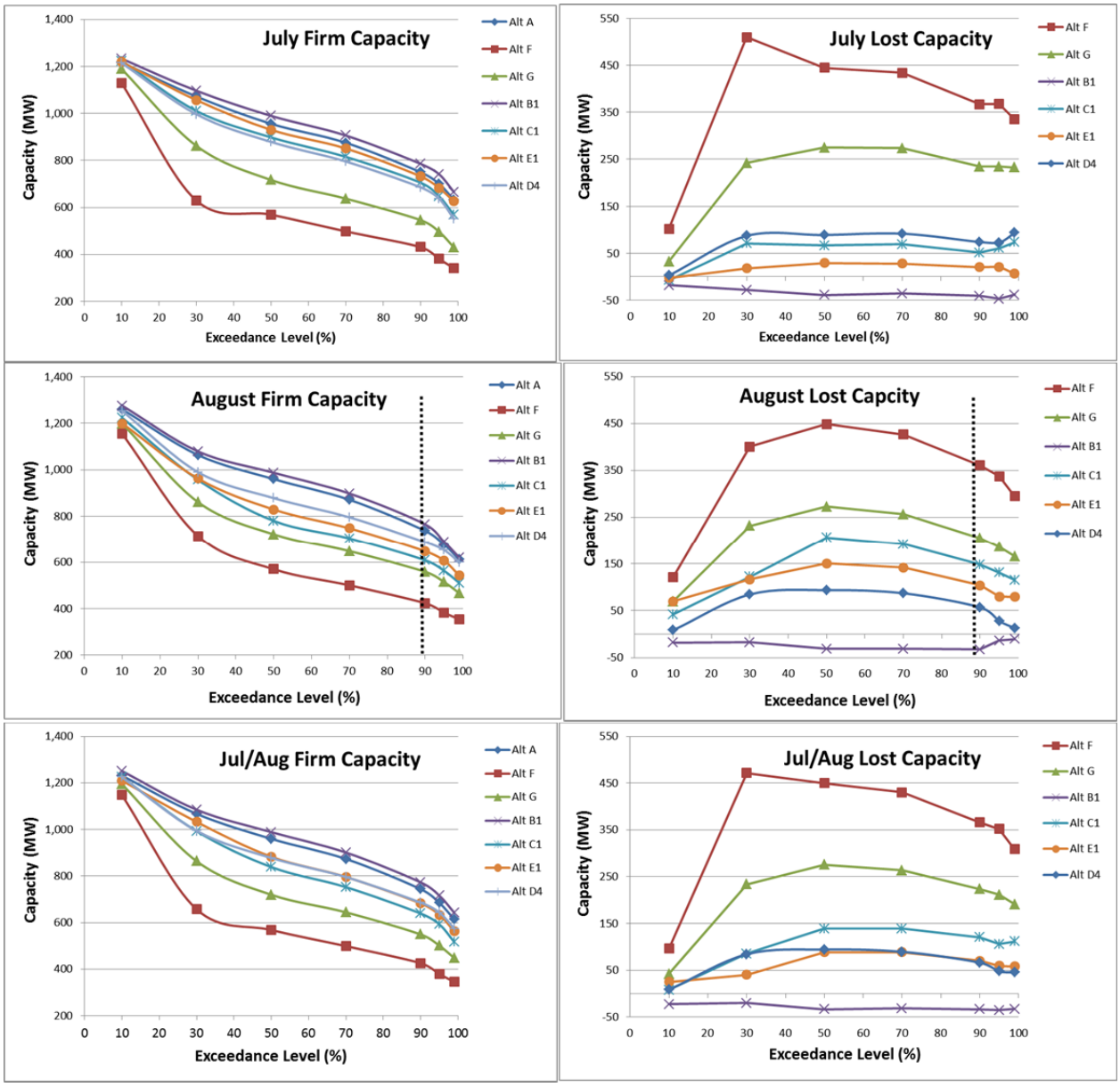

FIGURE 1 Comparison of SLCA/IP Federal Hydropower Firm and Lost Capacity Determinations across Alternatives, Exceedance Levels, and Summer Peak Months

ATTACHMENT K.9:

RESULTS OF A SURVEY OF ELECTRIC UTILITY INTEGRATED RESOURCE PLANS

An integrated resource plan (IRP) is a comprehensive decision support tool and roadmap for meeting an electric utility's objective of providing reliable and least-cost electric service to all of its customers. It is typically developed with considerable involvement from state agencies and regulators, customer and industry advocacy groups, project managers, and other stakeholders. Key elements of an IRP include determining the need for resources over a specific planning period, such as the next 10 to 20 years; the preferred portfolio of supply-side and demand-side resources to meet this need; and an action plan identifying the steps to implement the plan, such as the timing of bringing new resources online.

A survey of IRPs of Western's large customers that own generating facilities and large investor-owned utilities (IOUs) in the geographic and "electrical" area was conducted to determine the timing and type of resources these utilities were planning to reliably meet future electric demand. The results of this IRP survey could be compared to the results of the AURORA expansion model to see how well the AURORA prediction matched against the utility's best estimate. Western's customers surveyed included Platte River Power Authority (PRP), Colorado Springs Utilities (CSU), Tri-State Generation and Transmission Association (Tri-State), and Salt River Project (SRP).

Large IOUs surveyed included Public Service of Colorado (PSCO; now part of Xcel Energy), Public Service Company of New Mexico (PNM), Rocky Mountain Power (RMP; the eastern business unit of PacifiCorp or PACE), Arizona Public Service Company (AZPS), Tucson Electric Power Company (TEPC), Nevada Power Company (NEVP; the southern subsidiary of NV Energy), and Sierra Pacific Power Company (SPPC; the northern subsidiary of NV Energy). All IRPs were obtained from company websites and were all published between 2011 and 2014. These IOUs were chosen because they have contracts to supply generation to some of Western's customers and are also located in the same power pools in the AURORA model as Western's customers. Figure 1 shows the approximate service territories of these IOUs in the WI.

If the timing and type of new generation predicted by our AURORA expansion model runs are similar to what is planned in the IRPs, then the limited scope in our model is a good surrogate for modeling the larger system.

Figure 2 shows the least-cost baseline expansion plan for PSCO in its most recent IRP, which was published in October 2011. The plan predicts that several combustion turbine will come online between 2018 and 2022 followed by a combined-cycle gas turbine in 2023. Expansion plans from the 2014 PNM IRP shown in Figure 3 forecasts a small 40-MW gas turbine in 2016 followed by a 177-MW gas turbine in 2018. Rocky Mountain Power's expansion plans from its 2013 IRP are shown in Figure 4. A 645-MW combined-cycle unit was just brought online in 2014 as forecast by the IRP. RMP also plans to bring a combined-cycle combustion turbine and wind turbines online in 2024.

Figure 5 shows a future capacity addition plan from the APS IRP. The capacity it obtains from long-term contracts is steadily decreasing from over 2,800 MW in 2014 to less than 350 MW by 2029. ASP plans to bring over 1,000 MW of natural gas–fired generation online in 2019 followed by 2,000 MW more in 2024 and 1,000 MW in 2029. ASP also plans to rely more heavily on customer energy efficiency beginning in 2019. Additional generation from renewables will begin in 2019.

Figure 6 shows a future capacity addition plan from the TEP IRP. New natural gas generation of over 370 MW is planned for 2015 followed by another 640 MW in 2019. All short-term market resources will be phased out by 2019.

Figure 7 shows capacity addition plans from the NEVP IRP for four scenarios. To comply with a Nevada law phasing out certain coal-fired generation, a combination of new solar photovoltaic and natural gas-fired generation will be brought online between 2016 and 2021. To satisfy future demand, additional combined-cycle generation of 597 MW is planned to come online as early as 2020 and another 273 MW of capacity in 2022.

Figure 8 shows capacity addition plans from the SPP IRP for four scenarios. Depending upon the scenario, combustion turbines with a total capacity of from 273 MW to 536 MW are planned as early as 2022 and 2023. By 2025, an addition of over 570 MW of combined-cycle generation is planned followed by over 300 MW of combustion turbine capacity in 2029.

The IRPs of four of Western's large customers that own generation were also surveyed; namely, PRP, CSU, Tri-State, and SRP. The PRP IRP states that new peaking capacity may be needed as early as 2020 because that is when its reserve margin is forecast to drop below 15%. The CSU IRP shows capacity expansion plans for a number of future scenarios. Depending on the scenario, new renewables are expected to begin coming online beginning in 2017 to 2023. New combustion turbines of approximately 40 MW will start coming online from 2029 to 2031. The Tri-State IRP also examines numerous future scenarios. Depending on the scenario, new combined-cycle powerplants with a capacity of 588 MW will start coming online as early as 2019 to 2022; new renewable generation in multiples of 50 MW blocks will come online steadily from 2015 to 2029. Finally, SRP expects to bring new natural gas-fired peaking generation online between 2020 and 2022.

In conclusion, the survey of new capacity additions shown in IRPs for both Western's customers and large IOUs show that new capacity, both thermal and renewable generation, is scheduled to be brought online as early as 2017 to 2018. This means that there is very little excess capacity in the power pools in which Western's customers are located. Therefore, any capacity lost at Glen Canyon due to changes in operations from the Long-Term Experimental and Management Plan alternatives might cause new generation to be brought online earlier than the current IRPs indicate.

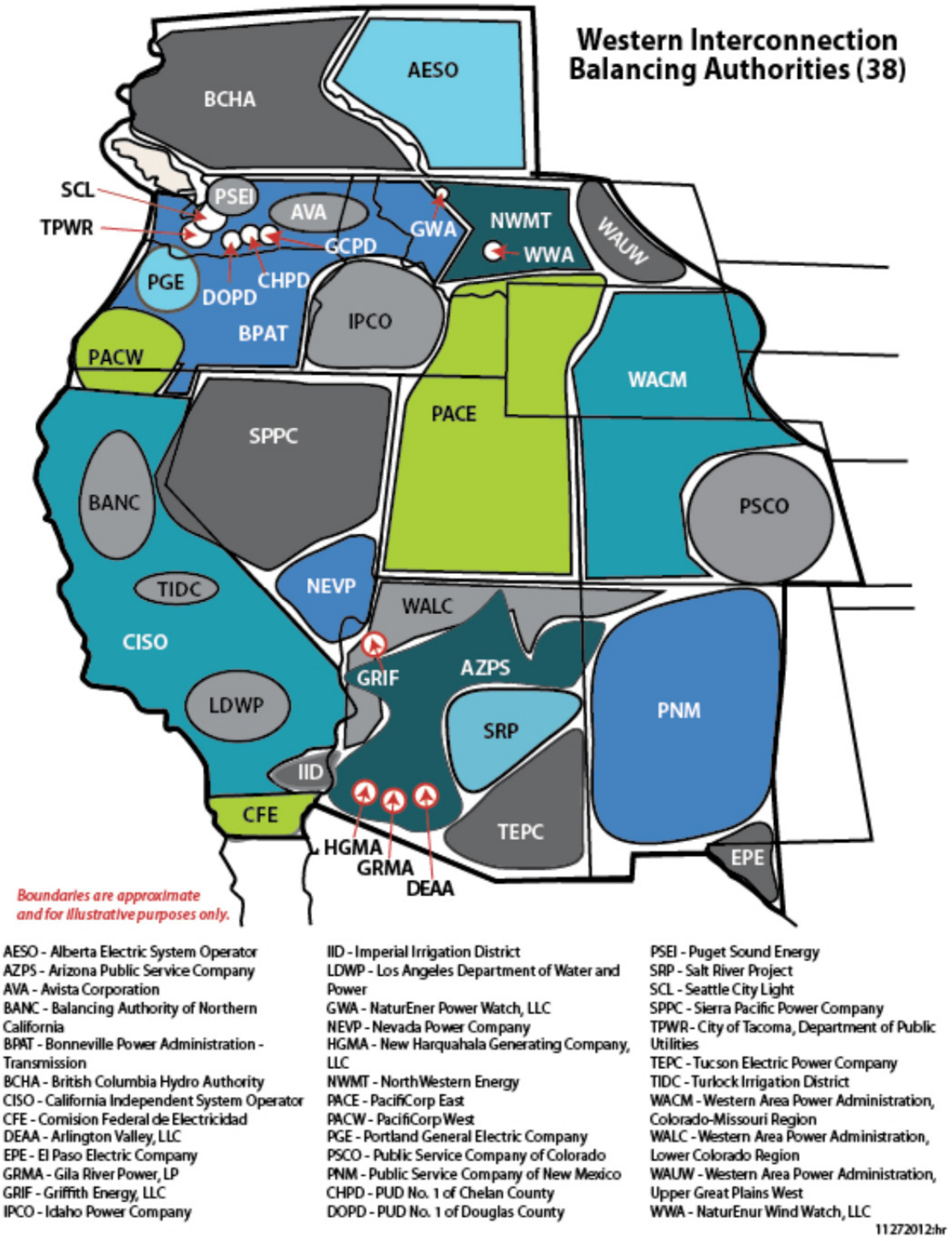

FIGURE 1 Balancing Authorities in the Western Interconnection (Source: WECC website: https://www.wecc.biz/Reliability/VGS_BalancingAuthorityCooperation Concepts_Intra-HourScheduling.pdf)

Year	Baseload[1]	2x1[1] Combined Cycle	1x1[1] Combined Cycle	Combustion Turbine[1]	Battery	Wind[2]	Solar PV[2]	Solar Thermal[2]
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018				346 MW				
2019				173 MW				
2020				173 MW				
2021				173 MW				
2022				346 MW				
2023		643 MW						
2024								
2025								
2026								
2027		643 MW						
2028								
2029				173 MW				
2030						200 MW		
2031				173 MW			100 MW	
2032		643 MW						
2033								
2034		643 MW						
2035								
2036		643 MW						
2037								
2038								
2039								
2040								
2041								
2042	485 MW	643 MW						
2043						200 MW	25 MW	
2044						200 MW	25 MW	
2045						100 MW		
2046						200 MW	25 MW	
2047						100 MW		
2048						100 MW		
2049				346 MW				
2050								

(1) Listed as summer accredited capacity rating
(2) Listed as nameplate capacity

Source: http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Exhibit-No-KJH-1-Volume-2.pdf

FIGURE 2 Least-Cost Baseline Expansion Plan from PSCO's Current IRP

Scenario Description	Revised SIP with PV3 78 MW Scenario	Revised SIP with PV3 132 MW Scenario
Load Forecast	Current	Current
Gas Pricing	PACE Reference Cas e	PACE Reference Case
CO2	PACE Reference Case ($11 in 2020)	PACE Reference Cas e ($11 in 2020)
San Juan Investment Recovery	$16,401,523	$16,401,523
SJ Retirements/Unit 4 Addition	Units 2 & 3 (Dec 2017) + 78 MW to SJ4	Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014		
2015	Red Mes a (102 MW)	Red Mesa (102 MW)
	2015 Solar (23 MW)	2015 Solar (23 MW)
2016	Aeroderivative (40 MW)	Aeroderivative (40 MW)
	Solar PV Tier 1 (40 MW)	Solar PV Tier 1 (40 MW)
2017	San Juan BART	San Juan BART
2018	Large GT (177 MW)	Large GT (177 MW)
	Palo Verde 3 (134 MW)	Palo Verde 3 (134 MW)
2019	Solar PV Tier 2 (60 MW)	
2020	Solar PV Tier 2 (20 MW)	Solar PV Tier 2 (20 MW)
	Solar PV Tier 3 (20 MW)	
2021	Solar PV Tier 3 (60 MW)	Solar PV Tier 2 (60 MW)
2022	Solar PV Tier 3 (60 MW)	Solar PV Tier 3 (40 MW)
2023	Large GT (177 MW)	Solar PV Tier 3 (60 MW)
		Wind (100 MW)
2024		Large GT (177 MW)
2025		
2026	Large GT (177 MW)	
	Wind (100 MW)	
2027		2nd Aeroderivative (40 MW)
2028		Large GT (177 MW)
2029		
2030	Reciprocating Engines (93 MW)	
2031	2nd Aeroderivative (40 MW)	Aeroderivative (40 MW)
		Solar PV Tier 3 (40 MW)
2032	Aeroderivative (40 MW)	Reciprocating Engines (93 MW)
2033	Small GT (85 MW)	

Source: https://www.pnm.com/documents/396023/396193/PNM+2014+IRP/bdccdd52-b0bc-480b-b1d6-cf76c408fdfc

FIGURE 3 Expansion Plan for PNM in Current IRP

	Preferred Portfolio (EG-2 Case-07a)	Capacity(MW)												
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bot	**Existing Plant Retirements/Conversions**													
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-
	Expansion Resources													
	CCCTFD 2d	-	-	-	-	-	-	-	-	-	-	-	-	-
	CCCTJ 1d	-	-	-	-	-	-	-	-	-	-	-	423	-
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	432	218
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3
	DSM, Class 2, UT	63	61	54	52	50	48	48	43	42	40	30	33	30
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7
	DSM, Class 2 Total	69	67	61	60	59	57	58	52	52	51	39	42	39
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4
	FOT Mona Q3	-	-	-	-	-	37	151	248	19	161	255	-	132

Source: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf *(see page 239)*

FIGURE 4 Rocky Mountain Power Expansion Plan from 2013 IRP

2014 IRP (VALUES IN MW AT PEAK)				
	2014	2019	2024	2029
TOTAL PROJECTED LOAD REQUIREMENTS (NEEDS)	8,124	9,543	11,276	12,982
EXISTING RESOURCES AS OF DEC. 31, 2013				
APS-Owned Generation	6,315	6,086	6,063	6,066
Long-Term Contracts	2,872	1,490	389	346
Total Existing Resources as of Dec. 31, 2013	**9,187**	**7,576**	**6,452**	**6,412**
FUTURE* PROJECTED CUSTOMER RESOURCES				
Energy Efficiency	109	877	1,230	1,447
Distributed Energy	45	109	203	261
Demand Response	0	0	150	275
Total Future* Customer Resources	**153**	**986**	**1,584**	**1,983**
FUTURE* PROJECTED GENERATION RESOURCES				
Natural Gas	0	1,010	3,030	4,205
Renewable Energy	0	57	295	425
Total Future* Projected Utility Resources	**0**	**1,067**	**3,325**	**4,630**
Total Future* Projected Resource Additions	**153**	**2,053**	**4,909**	**6,613**
Total Resources	**9,340**	**9,630**	**11,361**	**13,025**

*Future resources added after December 31, 2013 Source: http://www.aps.com/library/resource%20alt/2014_IntegratedResourcePlan.pdf

FIGURE 5 Capacity Expansion Plan for Arizona Public Service Company from 2014 IRP

Future Resources (Nameplate Capacity MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Natural Gas Resources	-	374	374	374	374	1,016	1,018	1,020	1,022	1,114	1,116	1,118	1,210	1,212	1,214
Utility Scale Renewables	208	258	258	258	258	258	258	258	326	326	475	529	529	529	529
Distributed Generation (DG)	71	78	94	110	125	141	157	173	190	210	229	250	254	259	265
Energy Efficiency (EE)	48	80	110	137	164	191	217	229	233	238	244	249	253	259	262
Demand Response (DR)	15	19	24	29	35	40	45	45	45	45	45	45	45	45	50
Total Nameplate Capacity	342	808	859	908	956	1,646	1,695	1,724	1,817	1,933	2,109	2,191	2,291	2,304	2,320
Short-Term Market Resources	400	250	200	200	570	-	-	-	-	-	-	-	-	-	-
Total System Resources	742	1,058	1,059	1,108	1,526	1,646	1,695	1,724	1,817	1,933	2,109	2,191	2,291	2,304	2,320

Source: https://www.tep.com/doc/planning/2014-TEP-IRP.pdf

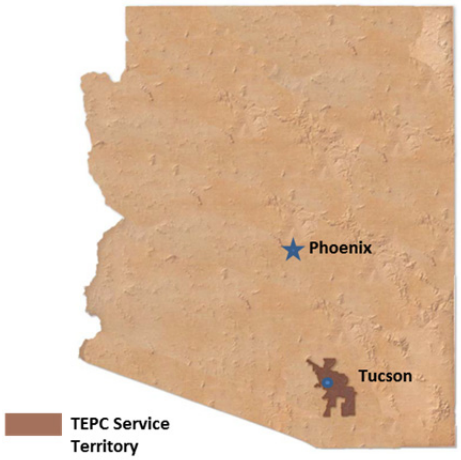

FIGURE 6 Capacity Expansion Plan for Tucson Electric Power Company from 2014 IRP

Nevada Power Company Expansion Plans - Base Load			
Case A	**Case B**	**Case C**	**Case D**
To replace retired coal plants in accordance with Nevada Law (SB 123)			
15 MW PV - 2016	15 MW PV - 2016	496 MW Merchant CC	274 MW Merchant CC
597 MW CC - 2018	568 MW CTs (8) - 2018	15 MW PV - 2016	15 MW PV - 2016
35 MW PV - 2021	35 MW PV - 2021	200 MW PV - 2016	200 MW PV - 2016
		35 MW PV - 2021	500 MW PV - 2018
Future conventional resource additions			
597 MW CC - 2020	597 MW CC - 2020	597 MW CC - 2020	597 MW CC - 2020
273 MW CC - 2022	273 MW CC - 2022	273 MW CC - 2022	273 MW CC - 2022
213 MW CTs (3) - 2023	213 MW CTs (3) - 2023	213 MW CTs (3) - 2023	213 MW CTs (3) - 2023
597 MW CC - 2024	597 MW CC - 2024	597 MW CC - 2024	597 MW CC - 2024
234 MW CTs (3) - 2030	234 MW CTs (3) - 2030	213 MW CTs (3) - 2027	234 MW CTs (3) - 2030
234 MW CTs (3) - 2032	234 MW CTs (3) - 2032	234 MW CTs (3) - 2030	234 MW CTs (3) - 2032
		234 MW CTs (3) - 2032	

Source: https://www.nvenergy.com/company/rates/filings/IRP/NPC_IRP/ERCR_NPC/Vol4-Narratives.pdf

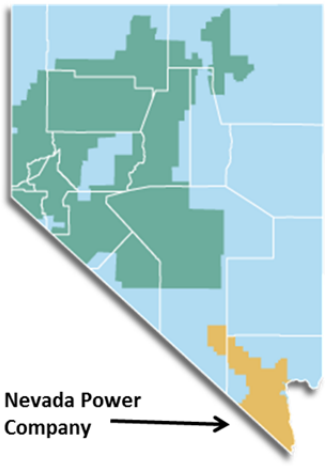

FIGURE 7 Capacity Expansion Plan for Nevada Power Company from 2014 IRP

Sierra Pacific Power Expansion Plans - Base Load			
Case 1 **ALL Market**	**Case 2** **Renewable**	**Case 3 - Alternative Plan** **CT's**	**Case 4 - Preferred Plan** **CC's**
	402 MW CTs (6) - 2022	536 MW CTs (6) - 2022	273 MW CC - 2022
237 MW CTs (3) - 2023			
571 MW CC - 2025	571 MW CC - 2025	571 MW CC - 2025	571 MW CC - 2025
316 MW CTs (4) - 2029	316 MW CTs (4) - 2029	316 MW CTs (4) - 2029	316 MW CTs (4) - 2029

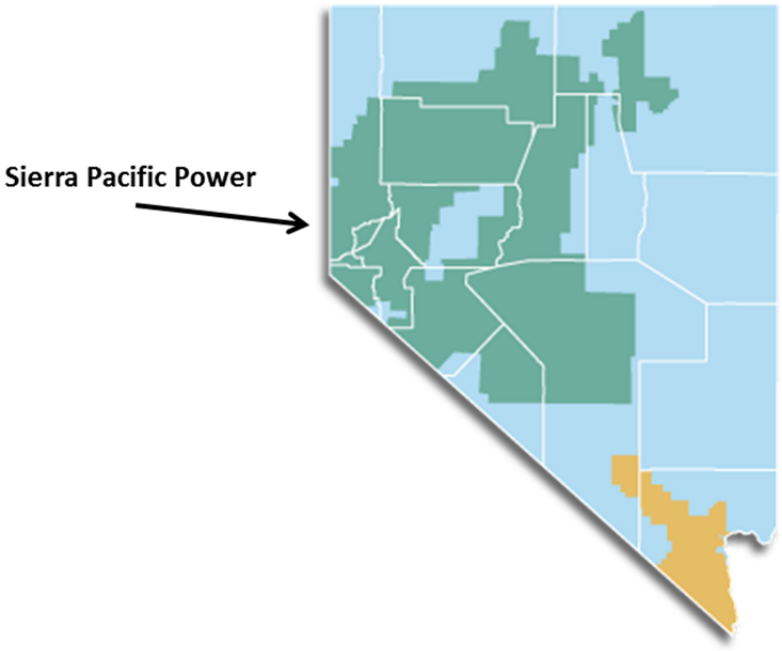

FIGURE 8 Capacity Expansion Plan for Sierra Pacific Power Company from 2014 IRP

ATTACHMENT K.10:

INDICES USED FOR CONVERTING DOLLARS FROM ONE YEAR TO ANOTHER

The Argonne National Laboratory Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) Draft Environmental Impact Statement (DEIS) power systems team has data that are expressed in terms of various nominal dollars. However, it is important that model runs and analysis be performed on a consistent dollar year basis. The range of nominal dollars that was used ranges from 2010 dollars to 2013 dollars. In addition, the LTEMP DEIS co-lead team has also decided that results presented to the public should be expressed in terms of 2015 dollars. For all power systems analyses, the gross national product (GNP) implicit price deflator (IPD) was used for converting nominal dollars from one year to another. Argonne staff used the Federal Reserve Economic Data (FRED) for the IPD with the series ID of the Gross Domestic Product: Implicit Price Deflator (GDPDEF) found on the St. Louis Federal Reserve Bank (Fed) website (http://research.stlouisfed.org/fred2/data/GDPDEF.txt).

The IPD is a good measure of the rate of price change in the economy as a whole. However, the last data point available from the St. Louis Fed is for October 2014. Therefore, the index was projected through January 2015. Based on a simple trend analysis using a third-order polynomial to fix the GNP price deflator over the January to October 2014 time period, the projected IPD was approximately 107.7 in January 2015 (January 2010 index = 100); that is a decline of about 0.3% from the October 2014 level. Figure 1 and Table 1 below show results of the trend analysis.

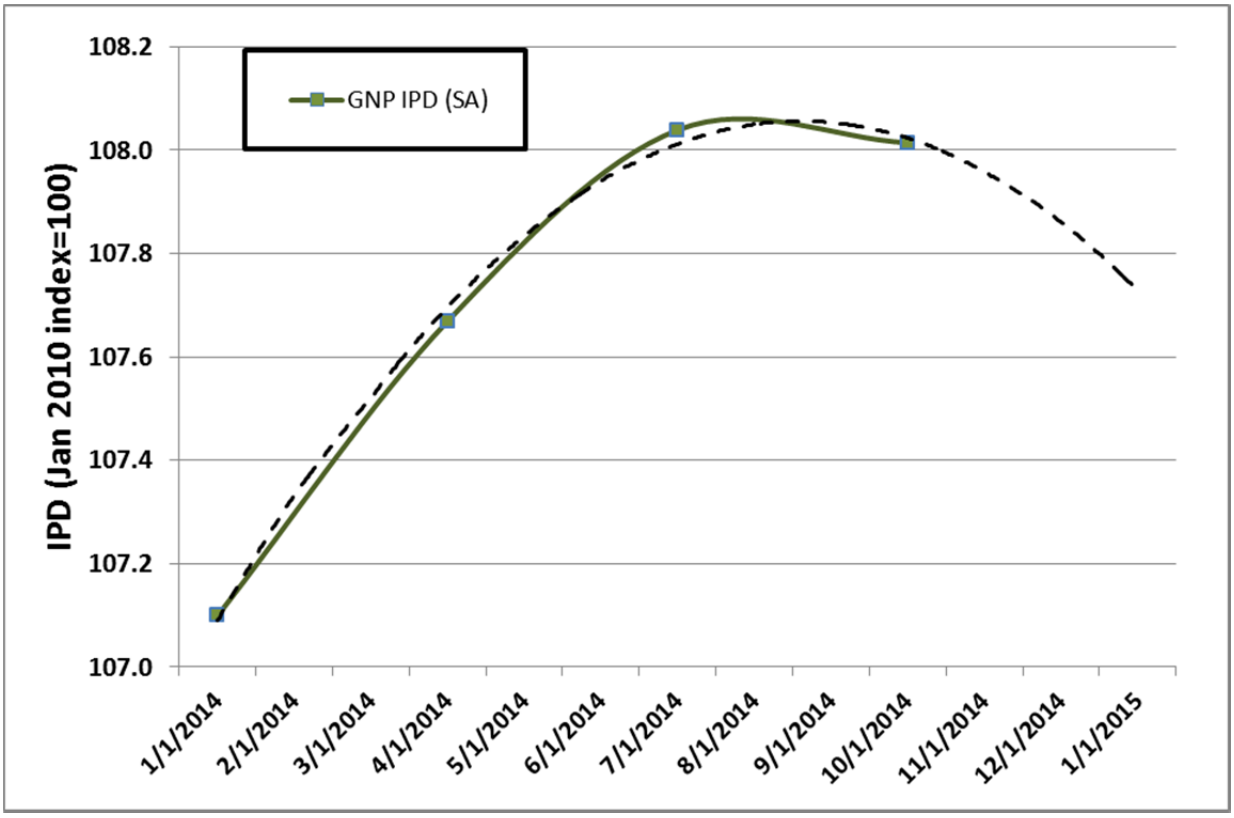

FIGURE 1 Results of Trend Analysis to Project Implicit Price Deflator (IPD) to January 2015 (SA = seasonally adjusted)

As shown in Figure 2, there is a similar, but somewhat more pronounced, decline when a trend analysis was conducted using monthly data for the seasonally adjusted (SA) consumer price index (CPI) for all U.S. cities/all items (series ID: CUSR0000SA0) (see http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems) and also for producer price index (PPI) data for total final demand (series ID: WPUFD4) from January 2014 through December 2015 (see http://www.bls.gov/news.release/ppi.nr0.htm). Both the CPI and PPI are about 1.0% lower in December 2014 relative to September 2014.

TABLE 1 Historical Quarterly Implicit Price Deflators and Projection for January 2015

Date	IPD
1/1/2010	100.0
4/1/2010	110.4
7/1/2010	100.9
10/1/2010	101.4
1/1/2011	101.9
4/1/2011	102.6
7/1/2011	103.2
10/1/2011	103.4
1/1/2012	103.9
4/1/2012	104.4
7/1/2012	104.9
10/1/2012	105.3
1/1/2013	105.7
4/1/2013	105.9
7/1/2013	106.4
10/1/2013	106.7
1/1/2014	107.1
4/1/2014	107.7
7/1/2014	108.0
10/1/2014	108.0
1/1/2015	107.7[a]

[a] Projected.

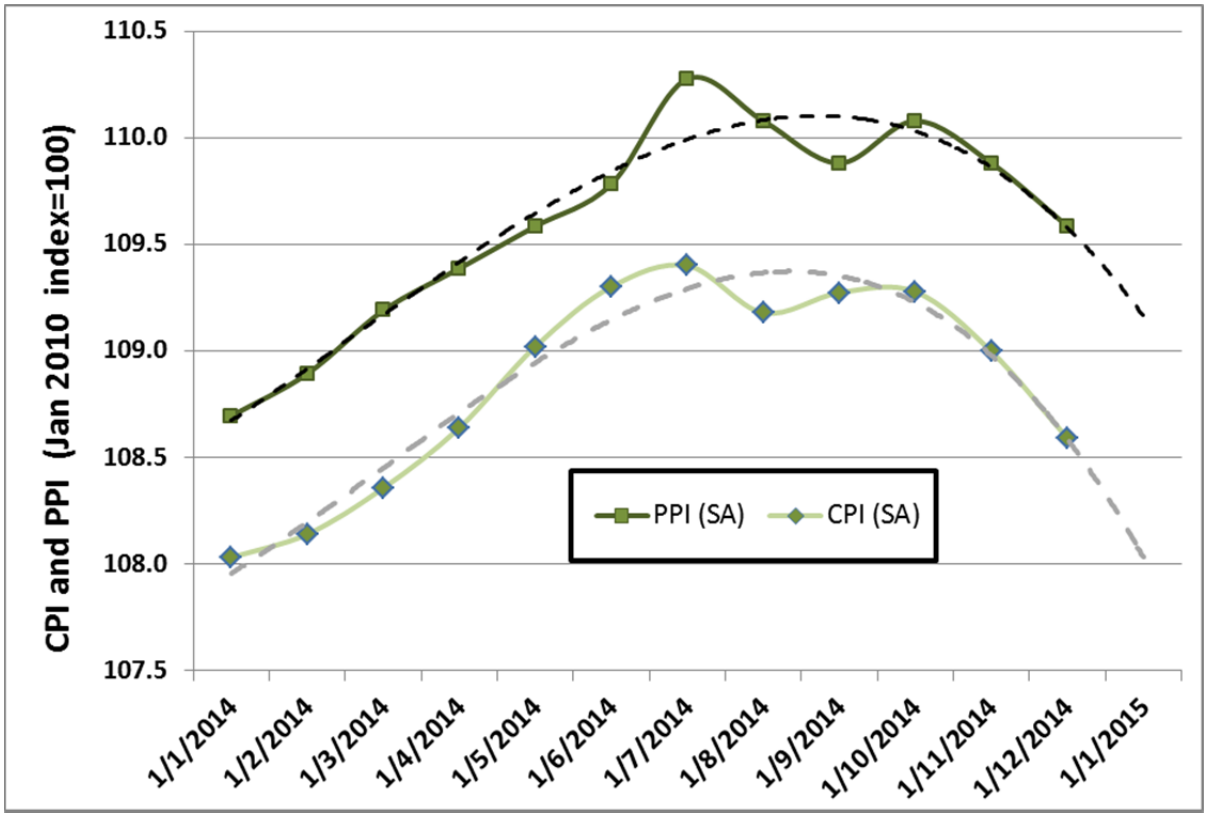

FIGURE 2 Comparison of Trend Analyses Projecting Produce Price Index (PPI) and Consumer Price Index (CPI) to January 2015 (SA = seasonally adjusted)

A downward trend in future producer prices through January 2015 is also in line with projections made by the Financial Forecast Center, which projects a 1% lower PPI for all commodities in January 2015 compared to December 2014 levels (see http://www.forecasts.org/ppi.htm).

The lower, but not as dramatic decrease in the IPD is further supported by Figure 3 below that shows both the CPI and PPI compared to the IPD. Both roughly follow the same trend in the January 2010 and October 2015 time period. However, the IPD tends to follow a smoother, less jagged track, implying that in general it may be somewhat less responsive to short-term economic drivers.

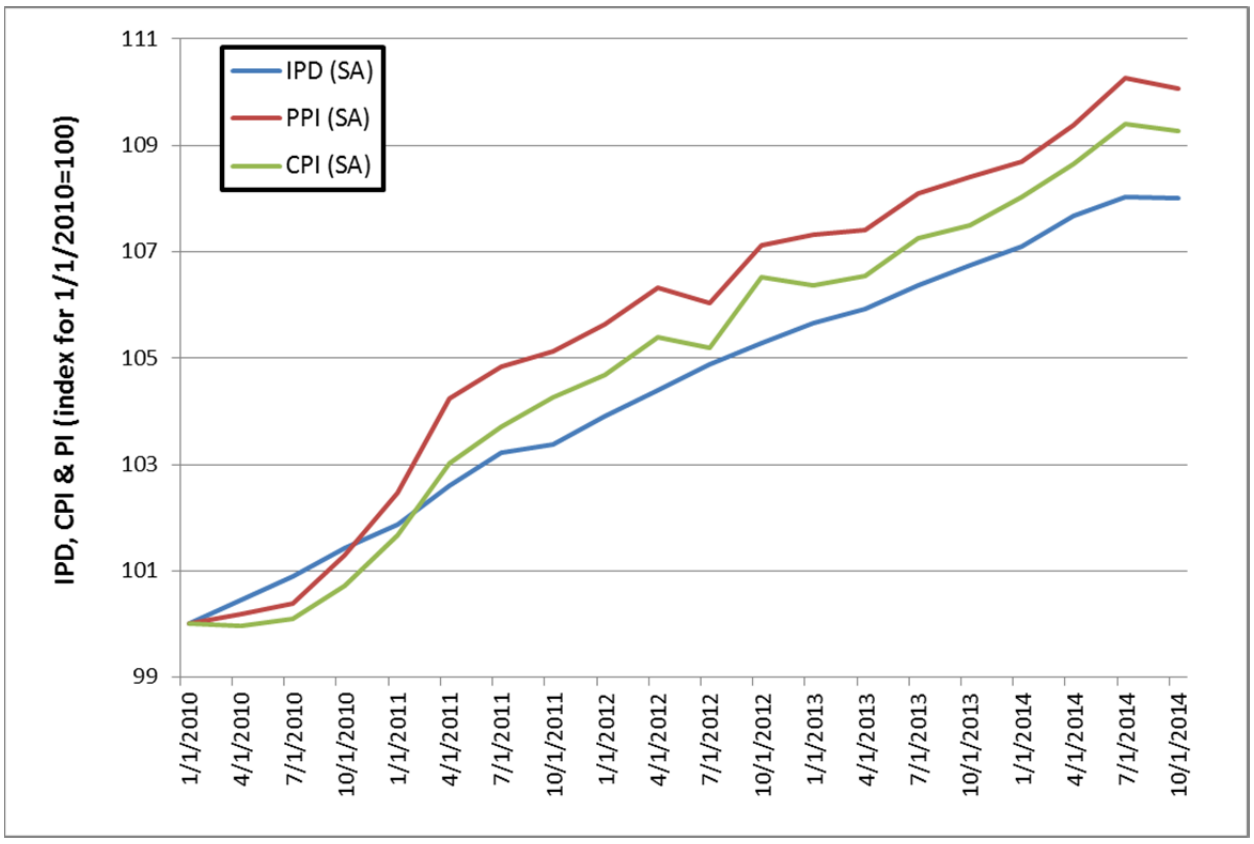

FIGURE 3 Comparison of Historical Trends for Implicit Price Deflator (IPD), Consumer Price Index (CPI), and Producer Price Index (PPI) from January 2010 to January 2014 (SA = seasonally adjusted)

ATTACHMENT K.11:

ANNUAL SLCA/IP ALLOCATIONS TO AMERICAN INDIAN TRIBES AND BENEFIT INFORMATION

Customer Name	Winter Season Capacity (kW)	Winter Season Energy (kWh)	Summer Season Capacity (kW)	Summer Season Energy (kWh)	Supplier Responsible for Benefit Crediting	Utility Serving Tribal Reservation
Ak-Chin Indian Community	1,920	3,520,881	4,244	7,722,879	N/A	Operate own utility
Bureau of Indian Affairs Colorado River Agency	881	1,593,277	442	883,290	N/A	Bureau of Indian Affairs operated utility
San Carlos Irrigation Project	1,840	3,373, 246	1,366	2,486,780	N/A	Bureau of Indian Affairs operated utility contracted with Gila River Indian Community Utility Authority (GRICUA)
Alamo Navajo Chapter	196	373,654	184	329,415	Tri-State	Socorro Electric Cooperative—Member of Tri-State
Canoncito Navajo Chapter	145	276,206	135	241,351	Tri-State	Continental Divide Electric Cooperative—Member of Tri-State
Cocopah Indian Tribe	1,058	2,022,535	1,281	2,289,809	NTUA	Arizona Public Service Company
Colorado River Indian Tribes	3,772	7,207,343	5,978	10,685,860	Page Electric Utility	Arizona Public Service Company
Confederated Tribes of the Goshute Reservation	62	118,806	39	69,992	Deseret/Mt. Wheeler	Deseret/Mt. Wheeler
Duckwater Shoshone Tribe	67	128,586	69	122,947	Deseret/Mt. Wheeler	Deseret/Mt. Wheeler
Ely Shoshone Tribe	129	246,599	78	138,741	Deseret/Mt. Wheeler	Deseret/Mt. Wheeler
Fort Mojave Indian Tribe	272	520,611	282	504,931	N/A	Operate own utility
Ft. McDowell Mojave-Apache Indian Community	2,270	4,336,951	2,346	4,192,957	SRP	Salt River Project
Gila River Indian Community	13,330	25,473,606	13,920	24,883,872	N/A	Operate own utility
Havasupai Tribe	237	452,237	199	356,282	NTUA	Provided by BIA—Truxton Canon Agency, but power is from Mohave Electric, Member of AEPCO, which has a SLCA/IP allocation—see APPA Contract No. 87-BCA-10001

Customer Name	Winter Season Capacity (kW)	Winter Season Energy (kWh)	Summer Season Capacity (kW)	Summer Season Energy (kWh)	Supplier Responsible for Benefit Crediting	Utility Serving Tribal Reservation
Hopi Tribe	2,810	5,369,665	2,716	4,854,810	NTUA	NTUA and Arizona Public Service Company (depends where on reservation)
Hualapai Tribe	609	1,163,130	625	1,118,127	NTUA	Mojave Electric Cooperative
Jicarilla Apache Tribe	735	1,403,805	580	1,036,264	N/A	Operate own utility/buy wholesale from PNM for supplemental
Las Vegas Paiute Tribe	523	999,427	721	1,288,008	NTUA	NV Energy
Mescalero Apache Tribe	990	1,890,996	976	1,743,837	Tri-State	Otero County Electric Cooperative—Member of Tri-State
Nambe Pueblo	65	124,829	59	104,627	Tri-State	Jemez Mountains Electric Cooperative—Member of Tri-State
Navajo Agricultural Products Industries	500	2,212,425	22,900	48,833,990	N/A	All Requirements Met by WAPA
Navajo Tribal Utility Authority	48,052	97,612,554	42,614	84,194,098	N/A	Operate own utility. Tucson Electric Power provides other wholesale power resources
Paiute Indian Tribe of Utah	154	294,452	158	282,873	NTUA	PacifiCorp, City of St. George, and Flowell Electric (Tribe fragmented geographically)
Pascua Yaqui Tribe	1,032	1,972,271	1,320	2,360,127	NTUA	TriCo Electric Cooperative—Member of AEPCO, which has a SLCA/IP allocation—see APPA Contract No. 87-BCA-10001
Picuris Pueblo	22	42,183	76	135,363	Tri-State	Kit Carson Electric Cooperative—Member of Tri-State
Pueblo De Cochiti	224	428,910	185	330,732	PNM-non-Western Area Power Administration customer	Public Service Company of New Mexico

Customer Name	Winter Season Capacity (kW)	Winter Season Energy (kWh)	Summer Season Capacity (kW)	Summer Season Energy (kWh)	Supplier Responsible for Benefit Crediting	Utility Serving Tribal Reservation
Pueblo of Acoma	410	783,229	420	750,759	Tri-State	Continental Divide Electric Cooperative—Member of Tri-State
Pueblo of Isleta	1,109	2,119,606	1,098	1,962,172	NTUA	Public Service Company of New Mexico
Pueblo of Jemez	265	505,513	214	382,418	Tri-State	Jemez Mountains Electric Cooperative—Member of Tri-State
Pueblo of Laguna	753	1,438,435	742	1,326,495	Tri-State	Continental Divide Electric Cooperative—Member of Tri-State
Pueblo of Pojoaque	271	517,903	208	371,891	Tri-State	Jemez Mountains Electric Cooperative—Member of Tri-State
Pueblo of San Felipe	422	805,473	328	586,285	PNM-non-Western Area Power Administration customer	Public Service Company of New Mexico
Pueblo of San Ildefonso	64	122,213	63	112,702	Tri-State	Jemez Mountains Electric Cooperative—Member of Tri-State
Pueblo of San Juan	303	579,114	298	533,433	Tri-State	Jemez Mountains Electric Cooperative—Member of Tri-State
Pueblo of Sandia	817	1,561,033	943	1,684,993	PNM-non-Western Area Power Administration customer	Public Service Company of New Mexico
Pueblo of Santa Clara	264	505,350	214	382,268	Tri-State	Jemez Mountains Electric Cooperative—Member of Tri-State

Customer Name	Winter Season Capacity (kW)	Winter Season Energy (kWh)	Summer Season Capacity (kW)	Summer Season Energy (kWh)	Supplier Responsible for Benefit Crediting	Utility Serving Tribal Reservation
Pueblo of Santo Domingo	438	837,643	452	807,426	PNM-non-Western Area Power Administration customer	Public Service Company of New Mexico
Pueblo of Taos	340	649,082	221	395,819	Tri-State	Kit Carson Electric Cooperative—Member of Tri-State
Pueblo of Tesuque	598	1,143,446	628	1,121,780	PNM-non-Western Area Power Administration customer	Public Service Company of New Mexico
Pueblo of Zia	85	161,712	68	122,326	Tri-State	Jemez Mountains Electric Cooperative—Member of Tri-State
Pueblo of Zuni	1,185	2,264,600	1,020	1,822,622	Tri-State	Continental Divide Electric Cooperative—Member of Tri-State
Quechan Indian Tribe	729	1,393,402	505	902,692	N/A	Arizona Public Service Company
Ramah Navajo Chapter	412	786,592	300	536,096	Tri-State	Continental Divide Electric Cooperative—Member of Tri-State
Salt River Pima-Maricopa Indian Community	13,380	25,569,197	16,144	28,858,050	SRP	Salt River Project
San Carlos Apache Tribe	3,780	7,222,993	4,152	7,421,915	NTUA	Arizona Public Service Company
Santa Ana Pueblo	410	783,525	460	822,045	PNM-non-Western Area Power Administration customer	Public Service Company of New Mexico
Skull Valley Band of Goshute Indians	15	28,290	15	27,269	N/A	PacifiCorp

Customer Name	Winter Season Capacity (kW)	Winter Season Energy (kWh)	Summer Season Capacity (kW)	Summer Season Energy (kWh)	Supplier Responsible for Benefit Crediting	Utility Serving Tribal Reservation
Southern Ute Indian Tribe	1,174	2,243,756	1,122	2,006,482	Tri-State	La Plata Electric Association—Member of Tri-State
Tohono O'Odham Utility Authority	3,044	5,816,784	1,047	1,871,035	N/A	Operate own utility
Tonto Apache Tribe	349	667,470	382	683,459	NTUA	Arizona Public Service Company
Ute Indian Tribe	688	1,315,260	457	816,884	Page Electric Utility	Deseret/Moon Lake Electric
Ute Mountain Ute Tribe	508	970,293	477	852,108	Tri-State	Empire Electric Association—Member of Tri-State
White Mountain Apache Tribe	5,999	11,463,994	5,822	10,407,621	Ak-Chin	Arizona Public Service Company
Wind River Reservation	491	938,332	484	865,612	Tri-State	High Plains Power—Member of Tri-State
Yavapai Apache Nation	1,465	2,800,451	1,893	3,383,533	NTUA	Arizona Public Service Company
Yavapai Prescott Indian Tribe	805	1,538,623	733	1,309,825	NTUA	Arizona Public Service Company
Yomba Shoshone Tribe	30	58,232	31	56,131	NTUA	NV Energy

ATTACHMENT K.12:

SLCA/IP AMERICAN INDIAN TRIBAL ALLOCATIONS ESTIMATED TOTAL ELECTRICAL USE BY TRIBE IN 1998

State	Benefit Credit Arrangement	Current Provider	Summer Estimated Load	Winter Estimated Load	Total Estimated Load
Arizona					
Hopi Tribe	NTUA	APS	10,681,912	11,388,535	22,070,447
Navajo Tribal Utility Authority	NTUA	Currently Files IRP	139,960,634	164,696,156	304,656,790
White Mountain Apache Tribe	Ak-Chin	Navopache	28,219,987	29,713,959	57,933,946
New Mexico					
Acoma Pueblo	Tri-State	Tri-State	3,724,900	3,583,590	7,308,490
Alamo Navajo Chapter	Tri-State	Tri-State	1,634,400	1,709,619	3,344,019
Canoncito Navajo Chapter	Tri-State	Tri-State	1,197,466	1,263,755	2,461,221
Cochiti Pueblo	PNM	PNM	727,700	909,677	1,637,377
Isleta Pueblo	NTUA	PNM	4,317,315	4,495,477	8,812,792
Jemez Pueblo	Tri-State	Tri-State	1,897,372	2,312,927	4,210,299
Jicarilla Apache Tribe	Tri-State	Tri-State	5,141,438	6,422,977	11,564,415
Laguna Pueblo	Tri-State	Tri-State	6,581,424	6,581,424	13,162,848
Mescalero Apache Tribe	Tri-State	Tri-State	8,652,073	8,652,073	17,304,146
Nambe Pueblo	Tri-State	Tri-State	519,108	571,141	1,090,249
Picuris Pueblo	Tri-State	Tri-State	671,608	193,005	864,613
Pojaque Pueblo	Tri-State	Tri-State	1,845,144	2,369,616	4,214,760
Ramah Navajo Chapter	Tri-State	Tri-State	2,659,850	3,598,976	6,258,826
San Felipe Pueblo	PNM	PNM	1,289,988	1,708,330	2,998,318
San Ildefonso Pueblo	Tri-State	Tri-State	559,175	559,175	1,118,350
San Juan Pueblo	Tri-State	Tri-State	2,646,684	2,649,680	5,296,364
Sandia Pueblo	PNM	PNM	3,707,446	3,310,798	7,018,244
Santa Ana Pueblo	PNM	PNM	1,808,724	1,661,781	3,470,505
Santa Clara Pueblo	Tri-State	Tri-State	1,896,628	2,312,183	4,208,811
Santo Domingo Pueblo	PNM	PNM	1,776,558	1,776,558	3,553,116
Taos Pueblo	Tri-State	Tri-State	1,963,860	2,969,811	4,933,671
Tesuque Pueblo	PNM	PNM	2,468,223	2,425,138	4,893,361
Zia Pueblo	Tri-State	Tri-State	606,921	739,899	1,346,820
Zuni Pueblo	Tri-State	Tri-State	9,042,967	10,361,462	19,404,429
Nevada/Utah					
Confederated Tribes Goshute	Deseret G&T	Deseret G&T	209,433	338,279	547,712
Duckwater Shoshone Tribe	Deseret G&T	Deseret G&T	367,885	366,124	734,009
Ely Shoshone Tribe	Deseret G&T	Deseret G&T	415,144	702,144	1,117,288

State	Benefit Credit Arrangement	Current Provider	Summer Estimated Load	Winter Estimated Load	Total Estimated Load
Nevada/Utah (Cont.)					
Las Vegas Paiute Tribe	NTUA	Nevada Power	2,833,971	2,119,688	4,953,659
Paiute Indian Tribe of Utah	NTUA	St. George/ DG&T/Pac	899,650	888,418	1,788,068
Skull Valley Band of Goshute	NTUA	UP&L	60,000	60,000	120,000
Ute Indian Tribe	Deseret G&T	Deseret G&T	4,052,985	6,017,847	10,070,832
Yomba Shoshone Tribe	NTUA	Sierra Pacific	123,504	123,504	247,008
Colorado/Wyoming					
Southern Ute Indian Tribe	Tri-State	Tri-State	9,955,191	10,266,092	20,221,283
Ute Mountain Ute Tribe	Tri-State	Tri-State	4,227,748	4,439,484	8,667,232
Wind River Reservation	Tri-State	Tri-State	11,884,905	23,766,810	35,651,715
Desert Southwest Region					
Arizona					
Cocopah Indian Tribe	NTUA	APS	5,038,208	4,289,600	9,327,808
Colorado River Indian Tribes	Colorado River Agency	Currently files Integrated Resource Plan	41,479,273	29,149,736	70,629,009
Fort Mojave Indian Tribe	Aha Macav	Aha Macav	12,348,324	8,991,679	21,340,003
Ft. McDowell Mojave-Apache	SRP	SRP	9,737,573	9,689,253	19,426,826
Gila River Indian Community	SRP	SRP	88,141,802	85,858,156	173,999,958
Havasupai Tribe	NTUA	Mohave	881,383	1,073,587	1,954,970
Hualapai Tribe	NTUA	Mohave	2,766,060	2,761,209	5,527,269
Pascua Yaqui Tribe	NTUA	AEPCO	5,838,562	4,682,066	10,520,628
Quechan Indian Tribe	NTUA?	IID	1,986,170	2,955,270	4,941,440
Salt River Pima-Maricopa	SRP	SRP	67,018,896	57,124,556	124,143,452
San Carlos Apache Tribe	NTUA	APS/SCIP/AEP CO	16,479,679	15,454,342	31,934,021
Tohono O'Odham Utility Authority	TOUA	TOUA	22,127,390	20,566,786	42,694,176
Tonto Apache Tribe	NTUA	APS	1,503,798	38	2,919,436
Yavapai Apache Nation	NTUA	APS	7,444,699	5,939,483	13,384,182
Yavapai Prescott Indian Tribe	NTUA	APS	12,529,338	13,975,168	26,504,506
Total			576,551,076	591,952,641	1,168,503,717

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APPENDIX L:

SOCIOECONOMIC TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX L:

SOCIOECONOMIC TECHNICAL INFORMATION AND ANALYSIS

The socioeconomic analysis of changes in Glen Canyon Dam operations included a number of parts:

- Analysis of changes in recreational activity in Lake Mead, Lake Powell, and the Colorado River in terms of recreation use values, non-use (passive use) values, and regional economic impacts; and

- Analysis of the regional economic impacts of changes in retail electricity prices resulting from changes in Western Area Power Administration (Western) wholesale electricity rates, and the analysis of the impacts of the construction and operation of additional Western customer utility generating capacity.

L.1 RECREATION ECONOMIC ANALYSES

L.1.1 Recreation Use Values

Estimation of use values associated with potential changes in recreational resources under each of the alternatives used benefits transfer methods; this involves applying existing use value data or estimates for a particular time period, site, level of resource quality, or combination thereof at an original or study site to a policy site for which data are not available. The benefits transfer method involves choosing study and policy sites with similar socioeconomic and environmental characteristics, similar recreational activities, and similar ranges of change in recreational quality.

Benefits transfer studies involve either the transfer of use values from a study site or the transfer of a statistical model used to estimate use values. The traditional benefits transfer approach to valuing recreation has been to employ existing use values from either travel cost or contingent valuation studies conducted at a study site, adjusting estimates to account for inflation by converting the original values to current dollars using the consumer price index (CPI) or some other price index, and applying them to analysis at the policy site. Given improvements in valuation techniques over time, however, the preferred approach is to employ statistical recreation models developed for a study site at a policy site. Proposed alternative-specific information about variables in the model can be gathered for the policy site. This information is used in conjunction with coefficients from the study site to estimate recreation visitation and/or value at the policy site, allowing the model transfer technique to improve the validity of the results compared to the use value transfer approach.

Benefits transfer methods present a reliable alternative to conducting original research when the analysis is not expected to be controversial, when time and budget constraints prevent the pursuit of original research, or when original research efforts have already been conducted at most of the geographic areas of interest. Because statistical models have been developed for estimating recreation value per trip for two of the three river reaches in the Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) study area—Glen Canyon and Upper Grand Canyon—and models estimating recreation use have been developed for Lake Powell and Lake Mead, while other studies have estimated values per trip for recreation use of Lake Powell and Lake Mead, the benefits transfer methods provides a useful and reliable approach to estimating river use values and lake visitation. More information on the background literature, data, and assumptions in applying the benefits transfer method to the analysis undertaken for the DEIS can be found in Reclamation (2014).

For the DEIS, the net economic value of recreation was estimated for Lake Powell, Lake Mead, and three reaches of the Colorado River—Glen Canyon (from Glen Canyon Dam to Lees Ferry), Upper Grand Canyon (from Lees Ferry to Diamond Creek), and Lower Grand Canyon(from Diamond Creek to Lake Mead)—using two utility programs:

- The Lake_Full program was used to estimate recreation economic value for Lake Powell and Lake Mead.

- The GCRec_Full utility program was used to estimate the economic value for recreation on the Colorado River.

L.1.1.1 Lake_Full Utility Model

The Lake_Full utility model incorporates the recreation-use relationships for Lake Powell and Lake Mead described in Neher et al. (2013). The model operates on a monthly time step and was designed to use all years and all traces of monthly data supplied by the Colorado River Storage Simulation (CRSS) model. The utility uses the end-of-month (EOM) reservoir contents to predict recreation use at the specified reservoir. The user supplies a unit economic value per trip and the utility employs the predicted recreation use in a given month and the unit economic value to calculate the monthly economic value of recreation. This calculation is repeated for each month in the period of analysis and for each hydrologic trace or sequence. The major analytical modeling steps are shown in Figure L-1.

The user also supplies appropriate inflation, escalation, and discount rates for the intended analysis. The Lake_Full utility program employs these economic inputs to compute the present economic value of recreation for each hydrologic trace present in the dataset. The results of these computations are reported for each reservoir as summary metrics computed from the distribution of trace present economic values. Current versions of the utility model output the 5% exceedance, 10% exceedance, 25% exceedance, mean, median (50% exceedance), standard deviation, 75% exceedance, 90% exceedance, and 95% exceedance.

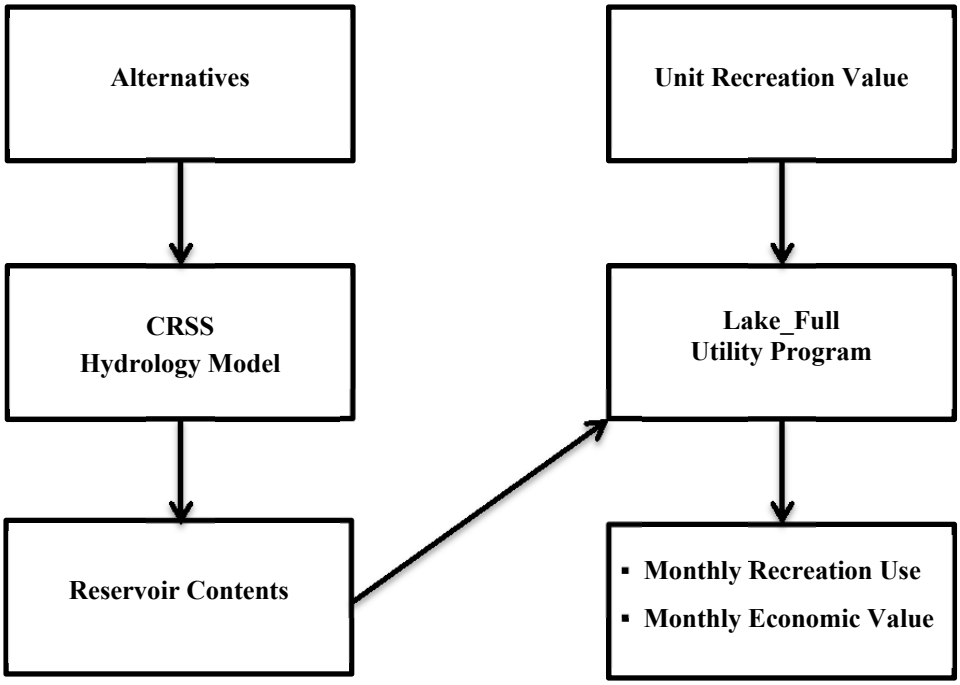

FIGURE L-1 Elements of the Lake_Full Utility Model

L.1.1.2 GCRec_Full Utility Model

The GCRec_Full utility model uses the recreation value relationships for Glen Canyon and Upper Grand Canyon estimated by Bishop et al. (1987). For purposes of this study, these relationships are extended to the Lower Grand Canyon. The model operates on a monthly time step and was designed to use all years and all traces of monthly data supplied by the CRSS model. The utility uses the mean monthly release from Glen Canyon Dam and the presence or absence of daily fluctuations exceeding 10,000 cfs per day during the month to predict the economic value of day-use rafting and angling in Glen Canyon and the economic value of commercial and private whitewater boating in the Upper Grand Canyon. The user also supplies the monthly recreation use, by activity. The utility employs the recreation use in a given month and the estimated economic value per trip to calculate the monthly net economic value of recreation for each activity. These calculations are repeated for each month in the period of analysis and for each hydrologic trace or sequence in the supplied dataset. The major analytical modeling steps are shown in Figure L-2.

The analyst also supplies appropriate inflation, escalation, and discount rates for the intended analysis. The GCRec_Full utility program employs these economic inputs for computing the present economic value of recreation for each hydrologic trace in the dataset. The results of these computations are aggregated and then reported as summary metrics computed from the distribution of trace present economic values. Current versions of the utility model output the 5% exceedance, 10% exceedance, 25% exceedance, mean, median (50% exceedance), standard deviation, 75% exceedance, 90% exceedance, and 95% exceedance levels.

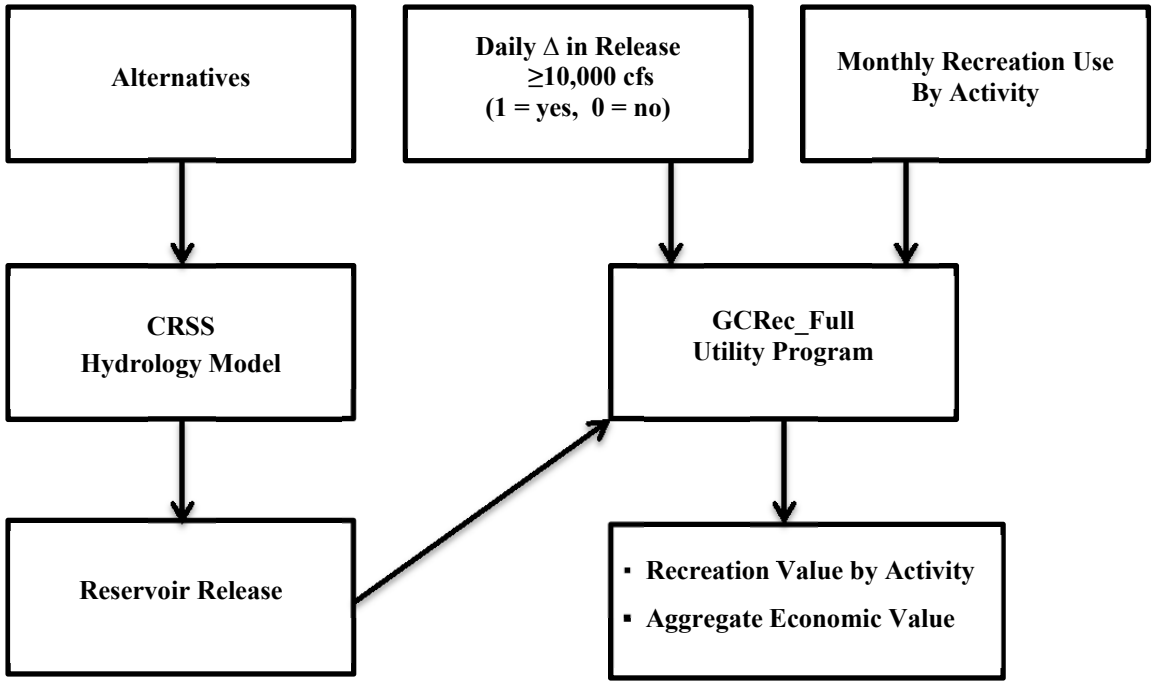

FIGURE L-2 Elements of the GCRec_Full Utility Model

More information on the background literature, data, assumptions, and output for these two models can be found in Reclamation (2014).

L.1.2 Recreation Non-Use Values

Non-use values are values that may be placed on the status of the natural or physical environment by non-users, or individuals who may never visit or otherwise use a natural resource that might still be affected by changes in its status or quality, and may assign a non-use or passive-use economic value to a resource. Although there are two approaches for measuring non-use values—revealed preference and stated preference methods—stated preference methods are typically used.

Stated preference valuation techniques include contingent valuation (CV), which is a means of eliciting the maximum dollar amount an individual would be willing to pay for a resource of a specified quantity and quality. CV methods use surveys to ascertain value by asking people about their willingness to pay (WTP) for a carefully specified change in environmental amenities. The dichotomous choice CV methodology is frequently employed in non-use valuation studies to estimate the net economic value for natural resource amenities. Respondents are presented with a hypothetical situation, including a price that they may be willing to pay for a change in an environmental condition, and they are then asked to respond to a dichotomous choice (yes or no) question. Using the data obtained from these surveys, the probability that an individual will respond "yes" is estimated using logistic regression analysis;

estimated regression coefficients are used to estimate the consumer surplus or net economic value associated with a particular resource.

Stated preference methods also include conjoint analysis, where respondents are presented with the characteristics or attributes of different hypothetical situations, and are then asked to either rank them or choose between them. Using the resultant survey data, the probability that an individual will rank or choose any particular scenario is then estimated, with data used to estimate households' total value for outcome changes associated with each alternative. There is a growing body of work that suggests that CV models and discrete choice methods can yield valid measures of willingness to pay (see, for example, Vossler and Evans [2009], and Vossler et al. [2012]).

Contingent valuation and conjoint methods have been applied widely in policy analysis, in particular in studies relating to measuring non-use values associated with river and lake resources associated with Grand Canyon National Park, Lake Mead National Recreation Area, and Glen Canyon National Recreation Area. Government agencies have also begun to use contingent valuation methods in benefit-cost analyses. The Bureau of Reclamation (Reclamation), for example, used contingent valuation to place a value on the impact of removing dams and restoring river habitat within the Klamath River Basin (RTI International 2012). The non-use values were used in a subsequent benefit-cost analysis (U.S. Department of the Interior 2012).

Contingent valuation surveys have been applied widely in the published economics literature to estimate passive-use values associated with preserving river and lake resources. Sanders et al. (1990), for example, estimated the total value of preserving 15 wild and scenic rivers in Colorado. They reported that Colorado residents expressed a use value of $19.15 and a non-use value of $81.96 per household per year. The total (use and non-use) value of protecting 15 Colorado rivers aggregated over these 12 million households was estimated at approximately $120 million annually, approximately four times the recreation use value. Welsh et al. (1995) estimated the willingness to pay to improve native vegetation, native fishes, game fish, river recreation, and cultural sites in Glen Canyon National Recreation Area and Grand Canyon National Park. Value estimates varied between $17.74 and $26.91 for a U.S. sample, and between $29.05 and $38.02 for a western U.S. sample.

Subsequent studies indicate that the range of values per household or respondent can be large, producing larger ranges in aggregated values. For example, Duffield and Patterson (1991) estimated a willingness to pay $2.24 per licensed angler to maintain fisheries resources, based on a one-time cash donation, while Hanemann et al. (1989) estimated $181 per California household per year. Large ranges in value have also been found in lake studies, with values ranging from about $45 per household annually for the preservation value of Flathead Lake in Montana (Sutherland and Walsh 1985) to about $60 per year for an increment of lake elevation at Mono Lake, California (Loomis 1989). In a 2010 survey, the annual value (in 2011 dollars) of Klamath River Basin restoration after the removal of dams, water sharing agreements, and improved fish habitat was estimated at $122 for households in a 12-county area, $213 by households in the rest of Oregon and California, and $213 in the rest of the United States (RTI International 2012).

The National Research Council (2005) has concluded that the results of studies using contingent valuation methods are of high quality; however, the results and findings of studies relating to the Colorado River Corridor are considerably outdated. Others have emphasized the need for additional or updated research on the sources and magnitudes of values associated with operational goals (see National Research Council 1999). To address these concerns, the National Park Service (NPS) has proposed to conduct a survey to determine non-use values associated with river-based amenities located in Lake Powell, Lake Mead, and the Upper and Lower Grand Canyon. The proposed survey, the results of which will not be available until after the Final EIS is published, closely follows the methodology developed by Welsh et al. (1995) by using stated preference methods to measure the changes in total value associated with the impacts on riparian areas caused by changes in operations of Glen Canyon Dam. If approved by the Office of Management and Budget, the survey will be conducted by the University of Montana, and will be administered to households selected from two samples, a national sample including all U.S. households, and a regional sample, consisting of all households receiving power from Western Area Power Administration, and including all utilities receiving power from the Glen Canyon Dam. The study will involve three phases.

The first phase will be a survey of a subsample (n = 200) of the total sample population. These responses will be used to conduct preliminary analysis on the data to determine whether the levels will be adjusted up or down to create greater differences between the LTEMP alternatives. If more than 80% (n = 160) of individuals in the subsample select the No Action Alternative, then the cost of the alternatives will be adjusted downward. The results from this sample will inform the choice of attribute levels in the final conjoint version of the survey mailed to the respondents in second phase of the study. Once the attributes have been evaluated and adjusted, the final mail survey will be used to collect data. Two survey instruments, both of which use identical sampling methods, will be used. All respondents will receive the same instructions and answer a series of common introductory questions to determine general socio-demographic background, visitation patterns, recreational preferences, values, and other information. Then 75% (n = 4,668) of individuals in the sample will receive Survey A with a section that will include conjoint questions. The remaining 25% (n = 1,500) will receive Survey B, which will include contingent valuation questions.

The final phase will include a short non-response phone survey that will be used to help test for any non-response bias. The results will be presented to the NPS in a report on the survey, including data collection, response rates, analysis, and non-response corrections if needed.

L.1.3 Regional Recreation Economic Impacts

Economic impacts of changes in recreational activity are measured by changes in visitor expenditures associated with various types of recreational activities, including angling, rafting, and boating. Visitor expenditures in the river corridor may include spending on food and beverages, fishing and boating equipment, gasoline for vehicles and boats, camping fees or motel expenses, guide services, and fishing license fees. Economic impacts also include the secondary effects of changes in expenditures that may occur on income, employment, and tax revenues. The major analytical modeling steps are shown in Figure L-3.

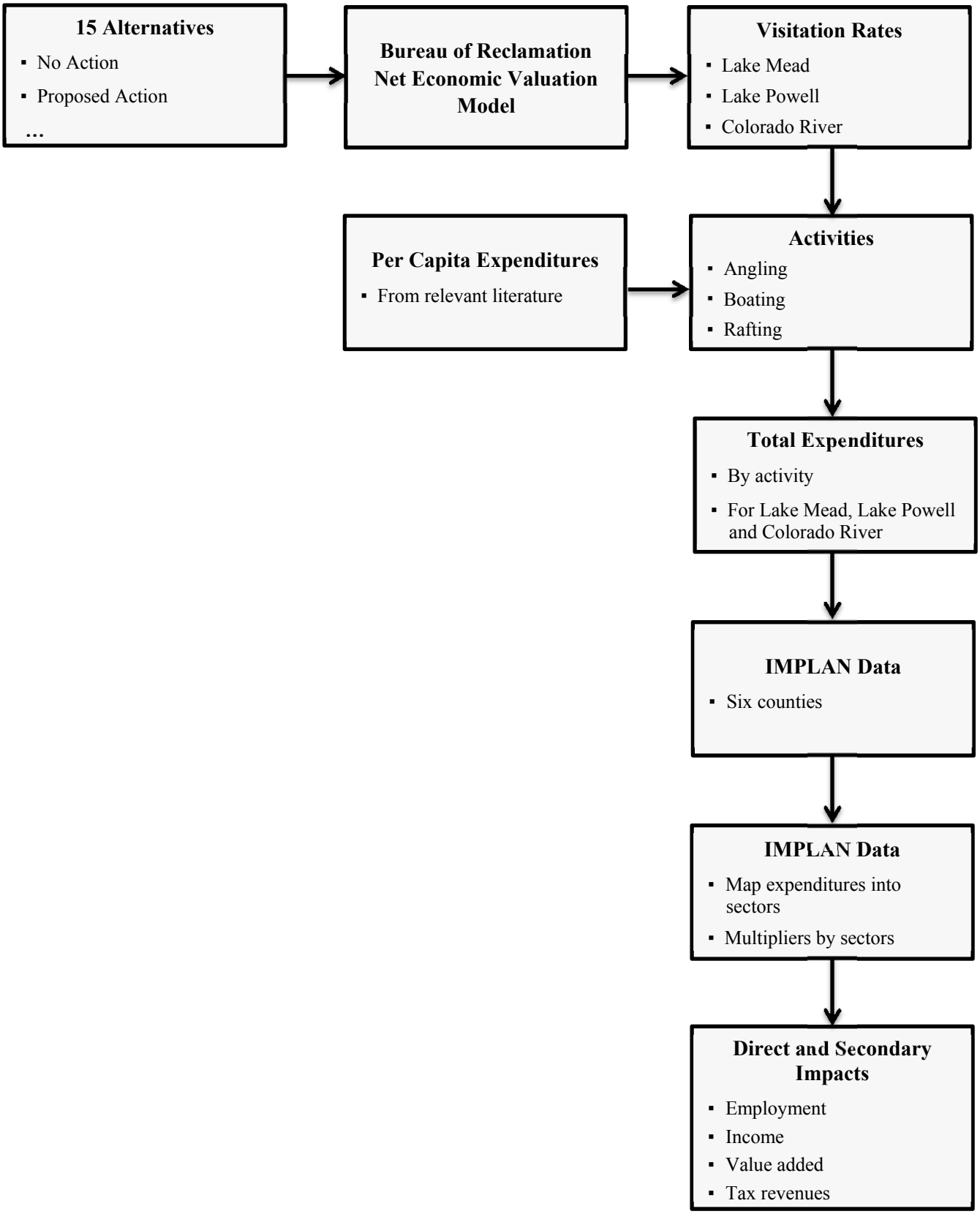

FIGURE L-3 Elements of the Regional Recreation Impacts Analysis

Analysis of these effects was undertaken in the six-county region in which the majority of current Glen Canyon, Grand Canyon, and Colorado River recreational expenditures occur:

- Coconino County and Mohave County, Arizona; and
- Garfield County, Kane County, San Juan County, and Washington County, Utah.

The following data were used in the analysis:

- Changes in visitation rates, by alternative and river reach, from the analysis of changes in activity resulting from changes in lake and river water levels for a range of river and lake segments using the Net Economic Valuation (NEV) model (see Section L.1), and
- Typical per-capita expenditure data by type of activity, based on studies of typical visitor spending patterns reported in existing technical and academic literature.

Data from these sources are combined to produce changes in expenditure by activity type, by year, and by alternative.

Two types of effects result from changes in recreational expenditures: (1) direct effects are employment and income effects in sectors of the economy in which recreational expenditures occur, while (2) indirect effects are employment and income effects in sectors providing materials, equipment, and services to sectors in which recreational expenditures occur. Indirect effects occur when suppliers to local businesses increase or decrease their purchases of equipment, materials, and services from other businesses, and those businesses in turn change their level of purchases. For food and beverages, for example, indirect effects occur when local food manufacturers purchase additional produce from local farmers, and the farmers then purchase additional supplies in order to grow products necessary to meet this demand. Additional, induced effects result from wages paid to households by both directly and indirectly affected businesses.

Input-output data and the associated multipliers can be readily used to determine the impact of changes in recreational expenditures through the estimation of multipliers for each sector in the multi-county region in which recreational expenditures occur. These multipliers typically give the total (direct plus indirect plus induced) benefits to the region in terms of employment, income, and taxes. Input-output data includes information for 440 separate North American Industry Classification System (NAICS) industries used by the U.S. Department of Commerce, Bureau of Economic Analysis. These accounts show the flow of commodities between industries and institutional consumers. Industries represented are those in agriculture, mining, construction, manufacturing, wholesale and retail trade, utilities, finance, insurance and real estate, and consumer and business services. Each industry is described in terms of its purchases from, and sales to, all other industries in the local economy.

Input-output accounts also provide information on value added by industry, and sales by industry, to final demand. Value added includes employee compensation (wages and salary payments, benefits, life insurance, retirement, etc.), proprietary income (payments received by self-employed individuals as income), other property-type income (payments received from royalties and dividends), and indirect business taxes (primarily excise and sales taxes paid by individuals to businesses). Final demands include personal consumption expenditures (payments by individuals/households to industries for goods and services used for personal consumption), federal government (military and nonmilitary) purchases and sales, state and local government (public education and non-education) purchases and sales, inventory purchases (unsold annual output), sales (where inventory reduction exceeds additions from production), capital formation (expenditures made to obtain capital equipment), and exports outside the region and nation.

Estimates of the regional economic impacts of changes in recreation expenditure came from the IMPLAN model, an "off-the-shelf" model produced by IMPLAN Group, LLC, that provides county-level and state-level input-output data. The model allows detailed analysis of the impacts of changes in recreation expenditures by mapping changes in expenditures by item (gas, food, lodging, etc.) into the appropriate sectors in the model, and then using IMPLAN multipliers to provide estimates of indirect effects and total effects, by alternative, activity type, and year in terms of employment (full-time equivalent staff, or ftes), income ($m), and the various components of value added ($m), including employment compensation, proprietor income, and tax revenues.

L.1.4 Estimates of Recreational Economic Impacts

Glen Canyon and Grand Canyon attract large numbers of visitors every year (see Section 3.10), and expenditures on gas, food and drink, lodging, guide services, and outdoor equipment are substantial. They produce direct income and employment both in sectors of the economy in which expenditures occur, and in the remainder of the economy; wages and salaries, and dollars spent on the purchases of goods and services, in these sectors circulate through the regional economy, producing indirect effects (effects in other industries) and induced effects (household effects). In 2011, spending by visitors to the Glen Canyon National Recreational Area, Grand Canyon National Park, and Lake Mead National Recreational Area produced 10,301 direct, indirect, and induced jobs and $373.7 million in total income (Table L-1).

As part of the overall impact of recreational visitation, various studies have attempted to estimate the regional economic impacts of specific recreational activities. Douglas and Harpman (1995) estimated that Glen Canyon and Grand Canyon recreational use in the region comprised of Coconino and Mojave Counties supported approximately 585 jobs. More recently, Hjerpe and Kim (2007) estimated that Grand Canyon boating recreation spending supported approximately 394 jobs in Coconino County, with commercial boating producing the majority (357) of the jobs created; Douglas (2005) found that whitewater boating in Grand Canyon National Park supported 438 jobs.

TABLE L-1 Total Regional Economic Impacts (Direct, Indirect, and Induced) of Non-Local Recreation Expenditures, 2013

Parameter	Glen Canyon National Recreation Area	Grand Canyon National Park	Lake Mead National Recreation Area	Total
Employment	1,435	6,238	2,628	10,301
Income ($m 2013 dollars)	39.3	235.9	98.5	373.7

Source: Thomas et al. (2014).

In addition to the economic impacts of recreational visitation in Glen Canyon and Grand Canyon, recreation in the region also provides employment and income for Navajo tradespeople selling jewelry and souvenirs to the traveling public along various routes in the region; jewelry production and sales provides 400 to 700 jobs (Reclamation 2011). Jobs held by the Navajo people are especially important because wage earners usually support extended families.

L.2 REGIONAL ELECTRICITY ANALYSES

L.2.1 Regional Electricity Price Impacts

The analysis of increases in electricity rates considered (1) changes in customer utility electricity prices resulting from changes in Glen Canyon Dam operations; and (2) impacts of constructing and operating additional power plants with customer utility capacity expansion plans to replace energy and capacity previously provided by Western

Analyses were conducted in the seven-state region in which Western markets power: Arizona, Colorado, Nebraska, Nevada, New Mexico, Utah, and Wyoming. This includes the service territories of the eight major Western customer utilities:

- Colorado Springs Utilities,
- Deseret Generation and Transmission Cooperative,
- Navajo Tribal Utility Authority,
- Platte River Power Authority,
- Salt River Project,

- Tri-State Generation and Transmission,

- Utah Municipal Power Agency, and

- Utah Associated Municipal Power Systems.

Separate analyses considered the following:

- The effects changes in Glen Canyon operations and changes in power marketing by the Colorado River Storage Project (CRSP) would have on wholesale electricity rates charged to customer utilities, by state and customer utility, from the GTMax/GTMax Lite models (see Appendix H); and

- The impacts changes in Glen Canyon and CRSP electricity rates would have on commercial, industrial, and residential electricity rates charged by the eight largest Western customer utilities, by state and customer utility, from the ratepayer analysis (see Appendix K).

Data used to analyze the regional economic impact of increases in electricity prices consisted of the following:

- Current and forecasted electricity prices, by state, from Energy Information Administration (EIA) data and other sources; and

- Estimates of the response in customer demand to changes in electricity prices (elasticities) for each customer class—commercial, industrial, and residential—taken from the technical and academic literature.

IMPLAN input-output models (see Section L.1), were used to estimate the regional economic impacts of changes in electricity prices, with a separate IMPLAN model representing each of the seven states in the Western marketing area. The analysis involved a number of steps:

- Aggregation of sectors in each state input-output models into the three customer classes: commercial, industrial, and residential;

- Calculation of electricity expenditure shares for each customer class; and

- Calculation of IMPLAN multipliers for each customer class.

These data, combined with changes in prices and price elasticities, give the total (direct plus indirect plus induced) impact of changes in aggregate electricity prices on the economy of each state, by alternative, state, and year, in terms of employment (ftes), income ($m), and the various components of value added ($m), including employment compensation, proprietor income, and tax revenues. The major analytical modeling steps are shown in Figure L-4.

FIGURE L-4 Elements of the Regional Electricity Price Impacts Analysis

L.2.2 Regional Electricity Generating Capacity Expansion Impacts

Analysis of the effects changes in Glen Canyon operations would have on electricity rates and capacity expansion required data on capital and operating expenditures, by alternative, including the following:

- Capacity expansion requirements, by state and customer utility, from the GTMax/GTMax Lite models (see Appendix K); and

- Expenditures on materials, equipment, services, direct and indirect labor, by year, from appropriate projects (similar in terms of fuel type, technology, size, and location), from the Jobs and Economic Development Impact (JEDI) model (NREL 2015).

Capacity expansion capital and operating expenditures were mapped into the appropriate sectors in an IMPLAN input-output model for each state, which were then used to estimate the appropriate multipliers to provide estimates of indirect effects and total effects, by alternative and year, in terms of employment (ftes), income ($m), and the various components of value added ($m), including employment compensation, proprietor income, and tax revenues. The major analytical modeling steps are shown in Figure L-5.

L.3 ADDITIONAL SOCIOECONOMIC DATA

Table L-2 contains data pertaining to population, median household income, and poverty in each community in the six-county affected environment forming the basis of the regional recreational economy.

L.3.1 Urban Population in the Six-County Region

Within the six counties in 2010, there were 86 places identified by the U.S. Census Bureau in the region of influence (ROI), including incorporated cities and Census Designated Places CDPs (unincorporated areas). The population of the ROI in 2010 was 83% urban; the largest town, St. George, Utah, had a 2010 population of 72,897; other places in the ROI with more than 10,000 inhabitants include Flagstaff (65,870), Lake Havasu City (52,527), Bullhead City (39,540), Kingman (28,068), New Kingman-Butler (12,134), and Sedona (10,031), all of which are in Arizona. There were 27 smaller towns in the ROI with 2010 populations of between 1,000 and 10,000, and an additional 50 places with populations of less than 1,000.

Urban population in the ROI grew at an average annual rate of 2.9% over the period from 2000 to 2010, although growth rates within the ROI varied considerably. Winslow West, Arizona, grew at an average annual rate of 12.8%; Spanish Valley, Utah, at 10.5%; and Arizona Village, Arizona, at 10.4% during this period, with higher than average growth also experienced in Washington, Utah (8.6%); Mesquite Creek, Arizona (7.3%); Mojave Ranch Estates, Arizona (6.4%); Golden Valley, Arizona (6.4%); Peach Springs, Arizona (6.2%); and Willow Valley,

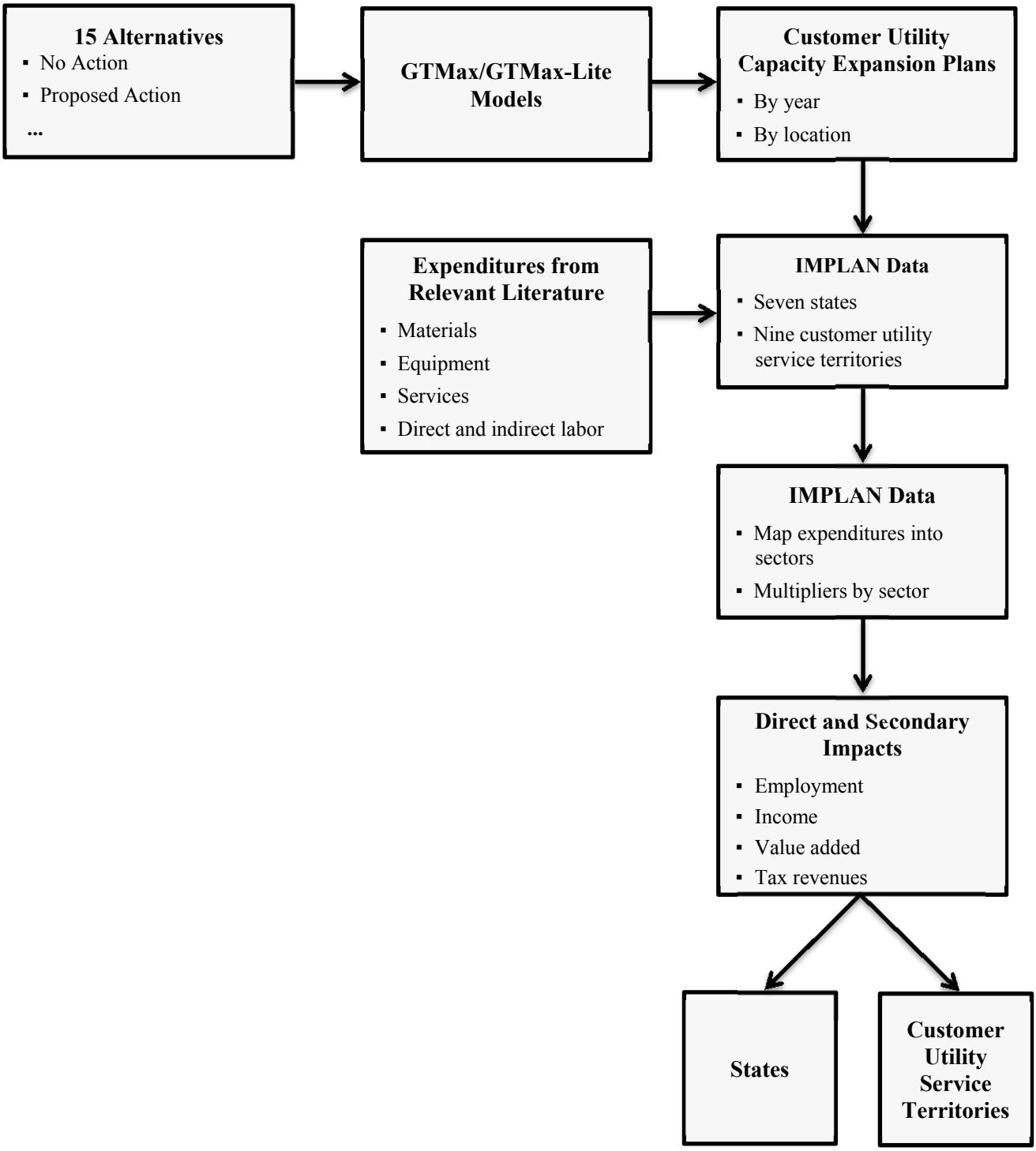

FIGURE L-5 Elements of the Regional Electricity Generating Capacity Expansion Impacts Analysis

TABLE L-2 Urban Population, Income, and Poverty in the Six-County Region

	Population			Median Household Income			
City	2000	2010	Average Annual Growth Rate, 2000–2010 (%)	2000 (2013 dollars)	2010 (2013 dollars)	Average Annual Growth Rate, 2000–2010 (%)	Percent of Individuals Living in Poverty, 2010
Alton	134	119	–1.2	41,712	51,414	2.1	31.4
Aneth CDP	598	501	–1.8	23,393	22,435	–0.4	54.2
Antimony	122	122	0.0	30,439	31,160	0.2	32.9
Apple Valley	NA	701	NA[a]	NA	67,365	NA	1.6
Arizona Village	351	946	10.4	35,723	44,549	2.2	25.6
Big Water	417	475	1.3	40,961	32,623	–2.3	19.9
Bitter Springs CDP	547	452	–1.9	33,666	44,350	2.8	33.5
Blanding	3,162	3,375	0.7	44,631	46,949	0.5	23.0
Bluff CDP	320	258	–2.1	32,341	38,801	1.8	35.4
Boulder	180	226	2.3	40,585	46,618	1.4	0.0
Bryce Canyon City	NA	198	NA	NA	36,724	NA	0.0
Bullhead City	33,769	39,540	1.6	40,884	39,047	–0.5	20.7
Cameron CDP	978	885	–1.0	33,514	23,916	–3.3	46.1
Cannonville	148	167	1.2	38,894	47,407	2.0	7.5
Central	NA	645	NA	NA	50,951	NA	6.0
Colorado City	3,334	4,821	3.8	44,408	43,115	–0.3	35.3
Dammeron Valley	NA	803	NA	NA	66,400	NA	6.4
Desert Hills	2,183	2,245	0.3	36,091	40,971	1.3	20.8
Dolan Springs	1,867	2,033	0.9	23,411	33,736	3.7	8.2
Doney Park CDP	NA	5,395	NA	NA	79,457	NA	7.2
Enterprise	1,285	605	–7.3				0.0
Escalante	818	797	–0.3	43,484	44,363	0.2	7.5
Flagstaff	52,894	65,870	2.2	50,252	52,852	0.5	19.4
Fredonia	1,036	1,314	2.4	40,974	45,168	1.0	7.0
Glendale	355	381	0.7	48,618	51,580	0.6	15.0
Golden Valley	4,515	8,370	6.4	37,686	36,477	–0.3	15.7
Grand Canyon Village CDP	1,460	2,004	3.2	56,931	49,731	–1.3	13.5
Halchita CDP	270	266	–0.1	13,359	12,383	–0.8	47.1
Halls Crossing CDP	89	6	–23.6	36,033	NA	NA	0.0
Hatch	127	133	0.5	50,167	48,576	–0.3	0.7
Henrieville	159	230	3.8	38,556	60,391	4.6	12.1
Hildale	1,895	2,726	3.7	44,209	32,623	–3.0	50.3
Hurricane	8,250	13,748	5.2	44,461	54,311	2.0	7.9
Ivins	4,450	6,753	4.3	55,868	53,417	–0.4	13.4
Kachina Village CDP	2,664	2,622	–0.2	61,828	50,975	–1.9	4.4
Kaibab CDP	275	124	–7.7	29,029	32,451	1.1	24.8
Kaibito CDP	1,607	1,522	–0.5	49,040	34,350	–3.5	31.6
Kanab	3,564	4,312	1.9	47,518	45,176	–0.5	6.5
Kingman	20,069	28,068	3.4	46,112	46,845	0.2	13.2
La Sal CDP	339	395	1.5	35,073	58,457	5.2	0.0

TABLE L-2 (Cont.)

City	Population 2000	Population 2010	Average Annual Growth Rate, 2000–2010 (%)	Median Household Income 2000 (2013 dollars)	Median Household Income 2010 (2013 dollars)	Average Annual Growth Rate, 2000–2010 (%)	Percent of Individuals Living in Poverty, 2010
La Verkin	3,392	4,060	1.8	48,633	47,997	–0.1	14.8
Lake Havasu City	41,938	52,527	2.3	49,377	46,630	–0.6	11.6
LeChee CDP	1,606	1,443	–1.1	65,443	59,912	–0.9	20.7
Leeds	547	820	4.1	55,804	54,936	–0.2	8.3
Leupp CDP	970	951	-0.2	29,029	30,848	0.6	29.8
Mesquite Creek	205	416	7.3	44,812	46,206	0.3	23.7
Mexican Hat CDP	88	31	-9.9	77,999	NA	NA	0.0
Moenkopi CDP	901	964	0.7	52,368	56,229	0.7	33.5
Mohave Valley	13,694	2,616	–15.3	46,430	57,353	2.1	11.8
Mohave Ranch Estates	28	52	6.4	NA	43,179	NA	0.0
Montezuma Creek CDP	507	335	–4.1	39,739	32,851	–1.9	23.4
Monticello	1,958	1,972	0.1	48,606	42,026	–1.4	8.8
Mountainaire CDP	1,014	1,119	1.0	55,804	67,333	1.9	3.5
Munds Park CDP	1,250	631	–6.6	56,050	59,620	0.6	3.8
Navajo Mountain CDP	379	354	–0.7	19,205	46,473	9.2	24.1
New Harmony	190	207	0.9	46,785	45,071	–0.4	3.1
New Kingman-Butler	14,810	12,134	–2.0	35,061	31,765	–1.0	23.0
Oljato-Monument Valley CDP	864	674	–2.5	43,545	47,742	0.9	40.6
Orderville	596	577	–0.3	48,389	34,357	–3.4	16.0
Page	6,809	7,247	0.6	63,495	53,787	–1.6	17.2
Panguitch	1,623	1,520	–0.7	45,320	43,910	–0.3	14.0
Parks CDP	1,137	1,188	0.4	53,959	66,850	2.2	8.4
Peach Springs	600	1,090	6.2	24,613	45,636	6.4	40.0
Pine Valley	NA	186	NA	NA	81,015	NA	0.0
Rockville	247	245	–0.1	51,295	44,069	–1.5	6.5
Santa Clara	4,630	6,003	2.6	71,389	73,078	0.2	3.4
Sedona	10,192	10,031	–0.2	59,581	53,149	–1.1	10.8
Spanish Valley CDP	181	491	10.5	67,923	74,055	0.9	0.0
Springdale	457	529	1.5	56,287	38,727	–3.7	2.6
St. George	49,663	72,897	3.9	49,385	51,815	0.5	11.1
Supai CDP	0	208	NA	0	40,063	NA	48.0
Tonalea CDP	562	549	–0.2	43,370	15,357	–9.9	46.5
Toquerville	910	1,370	4.2	46,048	48,648		12.2
Tropic	508	530	0.4	57,495	64,354	1.1	7.6
Tselakai Dezza CDP	103	109	0.6	63,921	144,726	8.5	7.5
Tuba City CDP	8,225	8,611	0.5	52,160	49,509	–0.5	24.5
Tusayan CDP	562	558	–0.1	47,237	53,468	1.2	6.6
Valle CDP	NA	832	NA	NA	31,511	NA	36.4
Veyo	NA	483	NA	NA	31,511	NA	4.6
Virgin	394	596	4.2	NA	52,160	NA	4.5
Washington	8,196	18,761	8.6	47,810	55,407	1,5	11.7

TABLE L-2 (Cont.)

City	Population 2000	Population 2010	Average Annual Growth Rate, 2000–2010 (%)	Median Household Income 2000 (2013 dollars)	Median Household Income 2010 (2013 dollars)	Average Annual Growth Rate, 2000–2010 (%)	Percent of Individuals Living in Poverty, 2010
White Mesa CDP	277	242	–1.3	18,601	21,100	1.3	37.7
Williams	2,842	3,023	0.6	43,906	46,072	0.5	19.3
Willow Valley	585	1,062	6.1	53,099	37,577	–3.4	23.5
Winslow West CDP	131	438	12.8	11,161	35,122	12.1	45.9

[a] NA = data not available.

Source: U.S. Census Bureau (2013).

Arizona (6.1%). The remaining places experienced lower growth rates between 2000 and 2010, with 29 places experiencing negative growth rates during this period. Rural population in the ROI grew at an annual average rate of 7.5% between 2000 and 2010.

L.3.2 Urban Income in the Six-County Region

Median household incomes in 2010 varied considerably across places in the ROI. Ten places in the Arizona portion of the ROI had median incomes that were higher than the average for the state ($50,991); these included Doney Park ($79,457), Mountainaire ($67,333), Parks ($66,850), LeChee ($59,912), Munds Park ($59,620), Mohave Valley ($57,353), and Moenkopi ($56,229). Twenty-eight places in the Arizona portion of the ROI had median incomes lower than the state average, and two places, Cameron ($23,916) and Tonalea ($15,357), had incomes that were less than half that of the state average. In 21 places, more than 20% of individuals were living in poverty, with poverty particularly marked in four communities, Supai (48.0% of individuals), Tonalea (46.5%), Cameron (46.1%), and Winslow West (45.9%).

Nine places in in the Utah portion of the ROI had median incomes higher than the state average ($59,014) in 2010; these included Tselakai Dezza ($144,726), Enterprise ($104,585), Pine Valley ($81,015), Spanish Valley ($74,055), and Santa Clara ($73,078). Thirty-six places had median incomes lower than the state average, and three places, Aneth ($22,435), White Mesa ($21,100), and Halchita ($12,383), had incomes that were less than half the state average. In 11 places, more than 20% of individuals were living in poverty, with higher poverty levels in four communities, Aneth (54.2% of individuals), Hildale (50.3%), Halchita (47.1%), and Oljato-Monument Valley (40.6%).

Median income growth rates within the ROI varied considerably over the period from 2000 to 2010. In the Arizona portion of the ROI, 39 places had annual average growth rates

higher than the state rate (–0.7%), with high growth rates in Winslow West (12.1%) and Peach Springs (6.4%) during this period. The remaining places experienced lower growth rates between 2000 and 2010, with 15 places experiencing negative growth rates. In the Utah portion of the ROI, 24 places had annual average growth rates higher than the state rate (–0.6%), including Navajo Mountain (9.2%), Tselakai-Dezza (8.5%), and Enterprise (8.0%). The remaining places experienced lower growth rates between 2000 and 2010, with 16 places experiencing negative growth rates.

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APPENDIX M:

AIR QUALITY AND CLIMATE CHANGE TECHNICAL INFORMATION AND ANALYSIS

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APPENDIX M:

AIR QUALITY AND CLIMATE CHANGE TECHNICAL INFORMATION AND ANALYSIS

This appendix provides a description of the analysis used to evaluate the impacts of the alternatives considered in the Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) Draft Environmental Impact Statement (DEIS). Glen Canyon Dam hydropower generation does not generate air emissions. However, dam operations can affect air emissions and ambient air quality over the 11-state Western Interconnection, comprising Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming, because hydropower generation offsets generation from other non-hydropower generating facilities in the SLCA/IP and in the Western Interconnection via the spot market. Differences among alternatives in the amount of Glen Canyon Dam generation at peak demand hours could affect regional air emissions, through differences in the technology mix of compensating generating facilities within SLCA/IP and, if SLCA/IP generation is insufficient to meet Western's long-term firm contract obligations, through generation from combustion sources in the greater Western Interconnection accessed via the spot market..

Air quality issues within the study area include visibility degradation in Federal Class I areas. Coal, natural gas, and oil units emit SO_2 and NO_x, which are precursors to sulfate and nitrate aerosols, respectively. These aerosols play an important role in visibility degradation by contributing to haze. Among anthropogenic sources, sulfate is a primary contributor to regional haze in the Grand Canyon, and nitrate is a minor contributor. Effects on visibility are analyzed through a comparison of regional SO_2 and NO_x emissions under the various alternatives.

Differences among alternatives in the amount and timing of Glen Canyon Dam generation directly affect the generation needed from coal, natural gas, or oil units within the 11-state Western Interconnection region of which the SLCA/IP system is a part, from the wholesale power market. As described in Section M.2, changes in generation from facilities within this interconnected system under various LTEMP alternatives result in small changes in total emissions due to similarly small differences in emissions from the contributing facilities.

Effects on visibility were analyzed through a comparison of SO_2 and NO_x emissions under the various alternatives. SO_2 and NO_x are also criteria air pollutants with limits on ambient concentrations under the National Ambient Air Quality Standards (NAAQS). Alternatives were compared on the basis of total emissions of these two pollutants from the contributing generation facilities in the interconnected system.

Electricity generation of combustion facilities in the system produces CO_2 and other greenhouse gases (GHGs). LTEMP alternatives can affect GHG emissions through changes in Glen Canyon Dam operations and related changes in GHG emissions of interconnected combustion facilities, as for SO_2 and NO_x. For the purpose of this analysis, the principal GHG of concern is CO_2, which accounts for over 99% of GHG emissions related to power generation.

However, facility- or technology-specific GHG emission factors also consider other GHGs, such as methane (CH_4) and nitrous oxide (N_2O), which may be emitted during facility operations.

M.1 ANALYSIS METHODS

To compute total air emissions under the LTEMP alternatives, emissions were summed from all generating facilities in the SLCA/IP system. This analysis was tiered off the power systems analysis (Section 4.13 of the DEIS and Appendix K), which estimated electrical power generation for the same facilities under each of the alternatives, including base operations and experimental flows such as high-flow experiments (HFEs), trout management flows, and low summer flows. Emissions were estimated using emission factor and corresponding generation level along with emission control efficiency for facilities equipped with a control system. Emission factors (either lb/MWh for power output or lb/MMBtu for heat input) were taken from standard references (EIA 2013; EPA 2014). Generation levels (either MWh/yr or MMBtu/yr) were the estimated electricity generation of each facility and the electricity traded on the spot market under each alternative by calendar year, which were obtained from the AURORA model outputs described in Appendix K. Emissions were then estimated by multiplying emission factors by electrical power generation. Emission controls were reflected in the emission factors used. Table M-1 presents emission factors used for SO_2, NO_x, and GHGs by plant for individual plants in the SLCA/IP system and the spot market. Table M-2 presents annual-average power generation for the same plants and for the spot market.

M.1.1 System Power Generation

Table M-1 presents emission factors by power generation type for (1) specific existing powerplants, (2) specific generating stations with multiple generating units under long-term contract, (3) power generation under long-term contract where no generating units are specified, and (4) future plants needed to provide additional capacity employing advanced gas technologies. For specific powerplants in the SLCA/IP system, pollutant emission factors (in lb/MWh) available in the *Emissions and Generation Resource Integrated Database* (eGRID)[1] with year 2010 data (EPA 2014) were used to estimate air emissions (Table M-1).

For advanced natural gas-fired simple cycle and combined cycle generating units to be built in the future, emission factors for advanced combustion turbine (ACT) and advanced generation natural gas combined cycle (AG-NGCC) in EIA (2013) were used with the following values: 0.001 lb/MMBtu for SO_2 for both simple cycle (0.0098 lb/MWh) and combined cycle (0.0064 lb/MWh); 0.03 lb/MMBtu (0.29 lb/MWh) for simple cycle and 0.0075 lb/MMBtu

[1] eGRID is a comprehensive inventory of environmental attributes of electric power systems. The preeminent source of air emissions data for the electric power sector, eGRID is based on available plant-specific data for all U.S. electricity generating plants that provide power to the electric grid and report data to the U.S. Government. eGRID plant-level emissions reflect monitored data, estimated data, or a combination of both.

(0.048 lb/MWh) for NO_x for combined cycle; and 117 lb/MMBtu for CO_2 for both simple cycle (1,141 lb/MWh) and combined cycle (752 lb/MWh).

Since emission factors for future plants and plants under long-term contract (Coolidge and Fort Lupton generating stations) are based on emissions per heat energy input (lb/MMBtu), conversion to lb/MWh is needed to produce the values shown in Table M-1 for these entities. Conversion factors were taken from the AURORA model outputs described in Appendix K and had the following values (in units of MWh/MMBtu): 6.43 for advanced combined cycle; 9.75 for advanced simple cycle; 9 for Coolidge; and 9.19 for Fort Lupton. For Brush 2 under long-term contract, emission factors in the eGrid database were used.

The Coolidge Generating Station under long-term contract has 12 simple-cycle natural gas-fired peaking units with a total capacity of 575 MW, which began service in 2011. For this station, emission factors in lb/MMBtu for a conventional combustion turbine (CT) are assumed, which are the same as those for ACT (EIA 2013). The Fort Lupton Cogeneration Powerplant is a 272-MW combined-cycle natural gas-fired station. For this station, emission factors in lb/MMBtu for conventional natural gas combined cycle (NGCC) are assumed, which are the same as those for AG-NGCC (EIA 2013).

For unspecified powerplants under long term-contract, composite emission factors were employed that are representative of all types of powerplants (such as fossil fuel-fired, hydroelectric, nuclear, and renewable resources) currently in operation over the 11-state Western Interconnection region. Composite emission factors were estimated to be 0.74, 1.07, and 963 lb/MWh for SO_2, NO_x, and GHGs in units of CO_2 equivalents (CO_2e),[2] respectively. Note that three plants (Kyrene, Rawhide, and Ray D. Nixon) have more than one generation type, but only one plant-wide composite emission factor for each pollutant is given in the EPA's eGRID database (EPA 2014). The available emission factors were applied to all generation at these three plants.

M.1.2 Spot Market

For spot market purchases and sales, composite emission factors in Table M-1 were used that are representative of power generation from gas powerplants currently in operation over the Western Interconnection, based on the assumption that spot market generation is primarily to serve peak loads. Composite emission factors were estimated to be 0.0083, 0.266, and 888 lb/MWh for SO_2, NO_x, and GHGs, respectively (EIA 2013).

[2] Emission factors for GHGs are expressed in CO_2 equivalent (CO_2e) for the long-term contract (unspecified generation type) and power stations available in the EPA's eGrid database. CO_2e is a measure used to compare the emissions from various GHGs on the basis of their global warming potential, defined as the ratio of heat trapped by one unit mass of the GHG to that of one unit mass of CO_2 over a specific time period (usually 100 years).

M.1.3 Generation Type

Tables M-1and M-2 group plants and other generation entities according to the type of generation technology used. Such grouping is for the purpose of understanding the differences in emissions under various LTEMP alternatives due to differences in generation from contributing generation technologies. Different operating regimes of Glen Canyon Dam under the various LTEMP alternatives supply different proportions of baseload or peaking power. Peaking power produced at the dam is assumed to displace power that would otherwise be produced by plants using gas turbine technologies, while baseload power produced at the dam is assumed to displace power produced by plants employing steam turbine technologies, most typically coal-fired plants. Gas- and coal-fired technologies have distinctly different emission profiles and levels. Gas plants emit far less SO_2 and NO_x than do coal-fired plants per unit of energy produced. Different mixes of these two types of technologies under various alternatives is related to the total levels of emissions. The technology groupings shown in Tables M-1 and M-2 are used below in the reporting and interpretation of results.

M.2 RESULTS

M.2.1 SO_2 and NO_x

The potential effects on visibility from emissions of SO_2 and NO_x, which are precursors of sulfate and nitrate aerosols, respectively, and which contribute to haze, are shown in Table M-3 for LTEMP alternatives. The geographic area of potential visibility impacts corresponds to the location of contributing powerplants in the SLCA/IP system and, to a small degree, the 11-state Western Interconnection and includes Grand Canyon National Park. Because the sources are geographically dispersed, effects would be similarly dispersed and low at any particular location. Further, due to very small differences in SO_2 and NO_x precursor emissions, negligible differences are expected among the alternatives with regard to visibility and haze in the region.

Emissions of SO_2 and NO_x under various LTEMP alternatives are compared with respect to air quality effects under NAAQS. Tables M-4 and M-5 show emissions of SO_2 and NO_x, respectively, under each LTEMP alternative, from contributing plants (35 primary facilities) and other contributing entities in the SLC/IP system, and presents subtotals of emissions by generation technology type. These tables also show contributions from the spot market computed according to the level of electrical power generated at each plant and entity, using the emission factors in Table M-1.

Table M-6 presents a summary of total system emissions by generation technology type drawn from Tables M-4 and M-5 for the generation facilities within the SCLA/IP system and from contributions from the spot market. The 35 generating facilities within the SLCA/IP system are categorized according to generation technology type, such as gas turbine or steam turbine (usually coal-fired), so that contributing emissions can be summed by technology type across the system to evaluate emissions from different technology mixes under alternatives. With respect to

the spot market entries in these tables, "sales" refers to sales of power by system utilities to non-system utilities within the Western Interconnection. Sales result in a net credit to total Western Interconnection emissions, because the sales result in a reduction in emissions from those non-system utilities that are purchasing the power. "Purchases" refers to purchases by system utilities from non-system utilities within the Western Interconnection. Emissions related to these purchases are added to the total emissions in the Western Interconnection.

Total SO_2 and NO_x emissions in the system averaged over the 20-year LTEMP period under Alternative A are estimated to be about 42,465 tons/yr and 78,496 tons/yr, respectively, while emissions under other LTEMP alternatives are similar to those under Alternative A. Differences in emissions of SO_2 and NO_x under LTEMP alternatives relative to those under Alternative A are very small, at most -0.04% and correspond to average annual emission differences that range from –18 to 5 tons/yr for SO_2 and -10 to 6 tons/yr for NO_x, compared to those under Alternative A.

With respect to generation technology type, SO_2 and NO_x emissions within the SLCA/IP system are dominated by steam turbine technologies, mainly coal-fired powerplants. Estimated differences among alternatives reflect slight differences in the contributions from various powerplant technologies; these are attributed to small differences in baseload and peaking energy generated by Glen Canyon Dam. As noted above, gas turbine peaking plant technologies produce lower SO_2 and lower NO_x emissions than baseload coal-fired plants. Thus, offsetting gas turbine peaking power with hydropower from Glen Canyon Dam has a potentially lower effect on total system emissions than does offsetting coal-fired baseload with baseload energy from Glen Canyon Dam.

Table M-6 shows levels of electricity generation at Glen Canyon Dam in MWh/day that would be produced under each LTEMP alternative. Differences in generation at the dam affect the amount of power needed by other contributing generators in the system. Little difference exists in generation at the dam among alternatives, which ranges from 11,438 MWh/day to 11,650 MWh/day. Alternative A produces the most energy, while Alternatives F and G produce roughly 2% less hydropower energy than Alternative A (98.3% and 98.2%, respectively). This reduction in generation is a consequence of the more frequent HFEs under these alternatives in which a portion of flows bypass the powerplant turbines.

Despite the fact that the steady-flow Alternatives F and G generate less power at Glen Canyon Dam than do the fluctuating-flow Alternatives A–E, and this lost generation must be made up by additional generation at other facilities in the system, Alternatives F and G have the lowest total emissions of all alternatives. This result may be explained by the operational regime of the dam under these alternatives with respect to baseload or peaking power. Under steady-flow Alternatives F and G, the dam produces baseload power which would displace baseload power from other facilities in the system, mainly coal-fired (steam turbine) facilities with relatively high emissions, while under fluctuating-flow Alternatives A–E, the dam produces a portion of peaking power, which offsets gas-fired peaking plants in the system, with relatively low emissions. See a more detailed discussion of this interpretation of results in Section 4.14.2 of the DEIS.

M.2.2 Greenhouse Gas Emissions

Table M-7 presents emissions in CO_2e for contributing plants (approximately 35 primary facilities) and other contributing entities in the SLC/IP system described above under each LTEMP alternative and presents subtotals of emissions by generation technology type and for contributions from the spot market. The spot market reflects the effects of Glen Canyon Dam operations on the larger Western Interconnection region and represents an offset of about 1% of system emissions. Emissions are computed from the level of electrical power generated at each plant and entity under each alternative using the emission factors in Table M-1.

Table M-8 summarizes emissions in Table M-7 by technology type and presents total emissions under the LTEMP alternatives. Total CO_2e emissions in the system averaged over the 20-year LTEMP period under Alternative A are estimated to be 55,177,668 MT/yr (60,822,967 tons/yr), while emissions under other LTEMP alternatives are similar to those under Alternative A. Differences in emissions of CO_2e from Alternative A are very small, and would range from an increase of 0.011% (Alternative B) to 0.081% (Alternative F) and corresponds to average emission increases that would range from 5,900 MT/yr (6,503 tons/yr) (Alternative B) to 44,522 MT/yr (49,077 tons/yr) (Alternative F), considering total emissions (system generation plus spot market sales and purchases) compared to that under Alternative A. Alternatives C, D, E, and G would have intermediate increases in CO_2e emissions of 18,161; 22,908; 16,503; and 40,960 MT/yr (0.033%, 0.042%, 0.030%, and 0.074%), respectively, compared to Alternative A.

With respect to generation technology type, CO_2e emissions are dominated (about 87%) by steam turbine technologies within the system, mainly coal-fired powerplants, as is the case for SO_2 and NO_x (about 98%). Estimated differences among alternatives reflect slight differences in the contributions from various powerplant technologies providing baseload and peaking energy in conjunction with Glen Canyon Dam, as discussed above for SO_2 and NO_x. Since gas turbine peaking plant technologies produce about half the CO_2e emissions as baseload coal-fired plants per unit of energy produced (Table M-1), offsetting gas turbine peaking power with hydropower from Glen Canyon Dam has a potentially lower effect on total system emissions than does offsetting coal-fired baseload with baseload energy from Glen Canyon Dam.

As shown in Table M-8, total CO_2e emissions are expected to be slightly higher for steady-flow Alternatives F and G than for the fluctuating-flow alternatives A–E. These increases in total emissions result mainly from relatively higher gas turbine emissions under Alternatives F and G. Higher gas turbine emissions are, in turn, attributable to the lack of peaking power from Glen Canyon Dam under the steady-flow alternatives, which require compensating peaking power from gas turbine peaking plants within the system. As for SO_2 and NO_x, Alternatives F and G have lower CO_2e emissions from steam turbine technologies than Alternative A and other fluctuating-flow alternatives, reflecting relatively greater offsets of baseload coal-fired plants from the steady-flow alternatives. However, total CO_2e emissions are greatest overall for Alternatives F and G due to a more than compensating increase in the gas turbine contribution under these alternatives. Alternatives F and G rank highest for CO_2e, but lowest for SO_2 and low for NO_x. This reversal in rank is due to smaller differences in emission factors between gas turbine and stream turbine technologies for CO_2e than for SO_2 and NO_x. CO_2e emission factors are lower for gas turbine technologies by roughly a factor of 2, while SO_2 is lower by almost two

orders of magnitude, and NO_x is lower by roughly a factor of 5 for gas turbines than for (coal-fired) steam turbines, as reflected in emission factors shown in Table M-1.

As shown in Table M-8, total system CO_2e emissions are a small fraction of total United States GHG emissions, totaling about 0.81% for all LTEMP alternatives.

M.3 REFERENCES

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TABLE M-1 Emission Factors by Plant for System Power Generation and Spot Market

Generation Type	Plant Name	EIA Plant No.	Emission Factor (lb/MWh) SO_2	NO_x	CO_2e[a]
System Power Generation					
Combined cycle	Advanced Combined Cycle Gas Turbine[b]	-[c]	0.006	0.048	752
	Desert Basin	55,129	0.005	0.094	1,001
	Front Range	55,283	0.005	0.264	975
	Kyrene #KY7 & #KY7Ae	147	0.005	0.141	932
	Long-Term Contract (Fort Lupton)[b]	-[c]	0.009	0.069	1,075
	Mesquite	55,481	0.004	0.064	879
	Nebo	56,177	0.005	0.135	890
	Rifle	10,755	0.021	1.026	716
	Santan	8,068	0.004	0.112	843
Composite	Long-Term Contract (Unspecified)[d]	-[c]	0.744	1.068	963
Gas turbine	Advanced Simple Cycle Gas Turbine[b]	-[c]	0.010	0.293	1,141
	Frank Knutson	55,505	0.033	0.394	1,500
	Kyrene KY4-KY6[e]	147	0.005	0.141	932
	Limon	55,504	0.111	0.794	1,714
	Long-Term Contract (Brush 2)	10,683	0.040	1.950	1,429
	Long-Term Contract (Coolidge)[b]	-[c]	0.009	0.270	1,053
	Pyramid	7,975	0.042	1.045	1,308
	Rawhide #A-#F[e]	6,761	0.775	1.616	2,049
Internal combustion	Payson	7,408	1.313	19.637	1,473
	Provo	3,686	0.257	17.719	1,493
Steam turbine	Bonanza	1	0.803	3.769	2,099
	Coronado	6,177	3.755	4.044	2,353
	Craig	6,021	0.694	3.035	2,216
	Escalante	87	1.449	3.721	2,449
	Four Corners	2,442	1.588	5.586	2,083
	George Birdsall	493	0.058	3.138	1,948
	Hayden	525	1.495	4.259	2,357
	Hunter	6,165	1.038	3.689	2,248
	Intermountain	6,481	0.765	3.999	2,011
	Kyrene 1 & 2[e]	147	0.005	0.141	932
	Laramie River 1	6,204.1	1.258	2.164	2,461
	Laramie River 2 & 3	6,204.2	1.627	2.890	2,332
	Martin Drake	492	7.428	4.205	2,435
	Navajo	4,941	0.621	2.974	2,179
	Nucla	527	3.859	4.874	2,625
	Rawhide #1[e]	6,761	0.775	1.616	2,049
	Ray D Nixon 1[e]	8,219	4.878	2.391	2,282
	San Juan	2,451	0.847	3.113	2,330
	Springerville	8,223	1.211	1.174	2,026

TABLE M-1 (Cont.)

Generation Type	Plant Name	EIA Plant No.	Emission Factor (lb/MWh) SO_2	NO_x	CO_2e[a]
Spot Market					
	Sales and purchases[f,g]	-[c]	0.0083	0.266	888

[a] Greenhouse gas (GHG) emissions are expressed in carbon dioxide equivalent (CO_2e), except for advanced combined cycle, advanced simple cycle, and long-term contract emissions (Coolidge and Fort Lupton), which are expressed as CO_2 and shaded for clarity.

[b] Emission factors were originally given in lb/MMBtu but were converted into lb/MWh using conversion factors (MMBtu/MWh) from the AURORA model outputs described in Appendix K: 6.43 for advanced combined cycle; 9.75 for advanced simple cycle; 9 for Coolidge; and 9.19 for Fort Lupton.

[c] A hyphen denotes "not applicable."

[d] Generation type was not specified, so composite emission factors representative of all types of powerplants currently in operation over the 11 Western Interconnect states were used.

[e] These plants have more than one generation type and only one plant-wide emission factor for each pollutant were given in the EPA's 2010 eGrid database.

[f] Composite emission factors representative of gas powerplants currently in operation over the 11 Western Interconnection states were used.

[g] "Sales" refers to sales of power by system utilities to non-system utilities within the Western Interconnection. Sales result in a net credit to total Western Interconnection emissions, because the sales result in a reduction in emissions from those non-system utilities that are purchasing the power. "Purchases" refers to purchases by system utilities from non-system utilities within the Western Interconnection. Emissions related to these purchases are added to the total emissions in the Western Interconnection.

Source: EIA (2013); EPA (2014).

TABLE M-2 Power Generation (in MWh per Year) Averaged over the 20-Year LTEMP Period by Alternative

Generation Type	Plant Name	EIA Plant No.	Alternative A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
System Power Generation									
Combined cycle	Advanced combined cycle gas turbine	-[a]	7,620,301	7,623,594	7,617,489	7,620,763	7,622,969	7,605,136	7,609,471
	Desert Basin	55,129	585,800	586,934	590,663	589,933	589,238	588,298	594,677
	Front Range	55,283	919,790	914,735	921,585	924,406	919,148	930,841	925,349
	Kyrene #KY7 & #KY7A	147	46,112	45,923	46,315	47,042	46,657	47,749	46,933
	Long-term contract (Fort Lupton)	-[a]	123,898	121,375	121,530	122,814	120,978	121,286	127,739
	Mesquite	55,481	4,637,436	4,639,304	4,637,048	4,637,704	4,637,659	4,639,378	4,636,160
	Nebo	56,177	205,798	204,042	206,783	206,287	206,392	210,230	209,969
	Rifle	10,755	145,808	145,812	145,755	145,838	145,754	146,621	146,144
	Santan	8,068	1,409,562	1,404,660	1,416,449	1,417,293	1,418,136	1,423,356	1,430,155
	Combined Cycle Subtotal		**15,694,506**	**15,686,380**	**15,703,618**	**15,712,080**	**15,706,930**	**15,712,895**	**15,726,598**
Composite	**Long-term contract (unspecified)**	-[a]	**1,628,526**	**1,629,588**	**1,628,457**	**1,630,110**	**1,629,858**	**1,632,176**	**1,627,328**
Gas turbine	Advanced simple cycle gas turbine	-[a]	597,114	587,362	672,023	639,175	647,159	774,061	702,516
	Frank Knutson	55,505	62,101	60,909	62,752	63,133	62,638	70,930	67,843
	Kyrene KY4-KY6	147	938	940	932	936	938	950	962
	Limon	55,504	37,077	36,889	36,664	36,912	36,575	41,589	38,986
	Long-term contract (Brush 2)	10,683	35,169	33,873	34,940	35,592	34,641	36,379	38,201
	Long-term contract (Coolidge)	-[a]	249,994	248,005	247,539	249,364	248,463	248,981	252,243
	Pyramid	7,975	162,140	156,957	163,256	164,392	162,204	172,688	178,097
	Rawhide #A-#F	6,761	4,280	4,267	4,306	4,354	4,278	4,796	4,548
	Gas Turbine Subtotal		**1,148,814**	**1,129,201**	**1,222,411**	**1,193,859**	**1,196,895**	**1,350,374**	**1,283,395**
Internal combustion	Payson	7,408	1,717	1,713	1,678	1,691	1,679	1,670	1,714
	Provo	3,686	854	850	825	882	869	844	828
	Internal Combustion Subtotal		**2,571**	**2,563**	**2,503**	**2,573**	**2,548**	**2,514**	**2,542**

TABLE M-2 (Cont.)

Generation Type	Plant Name	EIA Plant No.	Alternative A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
System Power Generation (Cont.)									
Steam	Bonanza	7,790	3,589,525	3,589,527	3,589,525	3,589,524	3,589,525	3,589,364	3,589,525
turbine	Coronado	6,177	5,764,907	5,767,009	5,764,236	5,764,829	5,764,453	5,762,531	5,761,006
	Craig	6,021	8,061,885	8,061,806	8,061,979	8,061,745	8,061,885	8,061,388	8,061,713
	Escalante	87	1,783,864	1,783,312	1,782,293	1,783,100	1,783,539	1,775,851	1,781,911
	Four Corners	2,442	1,145,170	1,145,639	1,145,109	1,145,343	1,145,548	1,143,803	1,144,356
	George Birdsall	493	116	115	116	116	114	141	121
	Hayden	525	989,044	989,196	989,115	989,115	989,327	989,267	989,196
	Hunter	6,165	1,514,296	1,514,296	1,514,296	1,514,296	1,514,296	1,514,296	1,514,296
	Intermountain	6,481	5,491,131	5,491,122	5,491,139	5,491,139	5,491,139	5,491,139	5,491,137
	Kyrene 1 & 2	147	1,028	1,034	1,023	1,034	1,027	1,053	1,053
	Laramie River 1	6,204.1	1,039,808	1,039,810	1,039,806	1,039,789	1,039,805	1,039,800	1,039,774
	Laramie River 2 & 3	6,204.2	2,079,620	2,079,620	2,079,620	2,079,620	2,079,620	2,079,620	2,079,620
	Martin Drake	492	1,920,235	1,920,236	1,920,225	1,920,234	1,920,236	1,920,231	1,920,225
	Navajo	4,941	3,741,478	3,741,640	3,741,240	3,741,369	3,741,359	3,740,851	3,740,803
	Nucla	527	753,249	753,276	753,462	753,462	753,504	752,312	752,981
	Rawhide #1	6,761	2,108,554	2,108,554	2,108,554	2,108,554	2,108,554	2,108,554	2,108,554
	Ray D Nixon 1	8,219	1,663,200	1,663,200	1,663,200	1,663,200	1,663,200	1,663,200	1,663,200
	San Juan	2,451	571,214	571,347	571,264	571,231	571,344	570,592	570,934
	Springerville	8,223	6,131,532	6,133,174	6,130,698	6,130,759	6,131,637	6,121,038	6,126,970
	Steam Turbine Subtotal		**48,349,855**	**48,353,913**	**48,346,900**	**48,348,459**	**48,350,114**	**48,325,031**	**48,337,375**
System Subtotal			**66,824,271**	**66,801,645**	**66,903,888**	**66,887,081**	**66,886,345**	**67,022,991**	**66,977,238**
Spot Market									
	Sales (emissions subtracted)[b]	-[a]	−3,753,513	−3,707,051	−3,830,282	−3,784,783	−3,812,913	−3,915,541	−3,872,321
	Purchases (emissions added)[b]	-[a]	2,823,573	2,816,937	2,848,706	2,836,661	2,848,870	2,865,526	2,861,183
Spot Market Subtotal			**−929,940**	**−890,114**	**−981,576**	**−948,122**	**−964,043**	**−1,050,015**	**−1,011,139**
Total (System + Spot Market)			**65,894,331**	**65,911,531**	**65,922,312**	**65,938,959**	**65,922,302**	**65,972,976**	**65,966,099**

Footnotes on next page.

TABLE M-2 (Cont.)

[a] A hyphen denotes "not applicable."

[b] "Sales" refers to sales of power by system utilities to non-system utilities within the Western Interconnection. Sales result in a net credit to total Western Interconnection emissions, because the sales result in a reduction in emissions from those non-system utilities that are purchasing the power. "Purchases" refers to purchases by system utilities from non-system utilities within the Western Interconnection. Emissions related to these purchases are added to the total emissions in the Western Interconnection.

Data source: AURORA model outputs described in Appendix K.

TABLE M-3 Summary of Potential Impacts of LTEMP Alternatives on Visibility and Regional Air Quality

	Alternative						
Air Quality	A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
Overall summary of impacts	No change from current conditions	Negligible increase in SO_2 and NO_x emissions compared to Alternative A	Negligible decrease in SO_2 emissions and no change in NO_x emissions compared to Alternative A	No change in SO_2 emissions and negligible increase in and NO_x emissions compared to Alternative A	Negligible increase in SO_2 and NO_x emissions compared to Alternative A	Negligible decrease in SO_2 and NO_x emissions compared to Alternative A	Negligible decrease in SO_2 emissions and negligible increase in NO_x emissions compared to Alternative A
Visibility[a]	No change from current conditions	No change from Alternative A	No change from Alternative A	No change from Alternative A	No change from Alternative A	No change from Alternative A	No change from Alternative A
Air Quality in 11-State Western Interconnection Region							
SO_2 emissions (tons/yr)	42,465[b]	42,471[b]	42,463[b]	42,465[b]	42,466[b]	42,448[b]	42,453[b]
	No change from current conditions	Negligible increase (0.01%)[c]	Negligible reduction (−0.01%)[c]	No change from current conditions	Negligible increase (<0.005%)[c]	Negligible reduction (−0.04%)[c]	Negligible reduction (−0.03%)[c]
NO_x emissions (tons/yr)	78,496[b]	78,501[b]	78,496[b]	78,503[b]	78,500[b]	78,487[b]	78,498[b]
	No change from current conditions	Negligible increase (0.01%)[c]	No change from current conditions	Negligible increase (0.01%)[c]	Negligible increase (<0.005%)[c]	Negligible reduction (−0.01%)[c]	Negligible increase (<0.005%)[c]

[a] Visibility effects are estimated from expected changes in the emissions of sulfate and nitrate precursors, SO_2 and NO_x.

[b] Total air emissions from combustion-related powerplants in the Western Interconnection averaged over the 20-year LTEMP period.

[c] Changes in air emissions compared to Alternative A.

Source: EPA (2014).

TABLE M-4 Annual SO_2 Emissions (in tons per Year) Averaged over the 20-Year LTEMP Period by Alternative

Generation Type	Plant Name	EIA Plant No.	Alternative A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
System Power Generation									
Combined cycle	Advanced combined cycle gas turbine	-[a]	24	25	24	25	25	24	24
	Desert Basin	55,129	1	1	1	1	1	1	1
	Front Range	55,283	2	2	2	2	2	2	2
	Kyrene #KY7 & #KY7A	147	0	0	0	0	0	0	0
	Long-term contract (Fort Lupton)	-[a]	1	1	1	1	1	1	1
	Mesquite	55,481	10	10	10	10	10	10	10
	Nebo	56,177	0	0	0	0	0	0	0
	Rifle	10,755	2	2	2	2	2	2	2
	Santan	8,068	3	3	3	3	3	3	3
	Combined Cycle Subtotal		**44**	**44**	**44**	**44**	**44**	**44**	**44**
Composite	**Long-term contract (unspecified)**	-[a]	**606**	**607**	**606**	**607**	**607**	**608**	**606**
Gas turbine	Advanced simple cycle gas turbine	-[a]	3	3	3	3	3	4	3
	Frank Knutson	55,505	1	1	1	1	1	1	1
	Kyrene KY4-KY6	147	0	0	0	0	0	0	0
	Limon	55,504	2	2	2	2	2	2	2
	Long-term contract (Brush 2)	10,683	1	1	1	1	1	1	1
	Long-term contract (Coolidge)	-[a]	1	1	1	1	1	1	1
	Pyramid	7,975	3	3	3	3	3	4	4
	Rawhide #A-#F	6,761	2	2	2	2	2	2	2
	Gas Turbine Subtotal		**13**	**13**	**13**	**13**	**13**	**15**	**14**
Internal combustion	Payson	7,408	1	1	1	1	1	1	1
	Provo	3,686	0	0	0	0	0	0	0
	Internal Combustion Subtotal		**1**	**1**	**1**	**1**	**1**	**1**	**1**

TABLE M-4 (Cont.)

Generation Type	Plant Name	EIA Plant No.	Alternative A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
System Power Generation (Cont.)									
Steam turbine	Bonanza	7,790	1,441	1,441	1,441	1,441	1,441	1,441	1,441
	Coronado	6,177	10,822	10,826	10,821	10,822	10,821	10,818	10,815
	Craig	6,021	2,795	2,795	2,795	2,795	2,795	2,795	2,795
	Escalante	87	1,293	1,292	1,291	1,292	1,292	1,287	1,291
	Four Corners	2,442	909	910	909	910	910	908	909
	George Birdsall	493	0	0	0	0	0	0	0
	Hayden	525	739	739	739	739	740	739	739
	Hunter	6,165	786	786	786	786	786	786	786
	Intermountain	6,481	2,099	2,099	2,099	2,099	2,099	2,099	2,099
	Kyrene 1 & 2	147	0	0	0	0	0	0	0
	Laramie River 1	6,204	654	654	654	654	654	654	654
	Laramie River 2 & 3	6,204	1,692	1,692	1,692	1,692	1,692	1,692	1,692
	Martin Drake	492	7,132	7,132	7,132	7,132	7,132	7,132	7,132
	Navajo	4,941	1,161	1,161	1,161	1,161	1,161	1,161	1,161
	Nucla	527	1,453	1,453	1,454	1,454	1,454	1,451	1,453
	Rawhide #1	6,761	817	817	817	817	817	817	817
	Ray D Nixon 1	8,219	4,056	4,056	4,056	4,056	4,056	4,056	4,056
	San Juan	2,451	242	242	242	242	242	242	242
	Springerville	8,223	3,712	3,713	3,712	3,712	3,712	3,706	3,710
	Steam Turbine Subtotal		**41,805**	**41,810**	**41,802**	**41,804**	**41,805**	**41,785**	**41,792**
System Power Generation Total			**42,469**	**42,474**	**42,467**	**42,469**	**42,470**	**42,452**	**42,457**
Spot Market									
	Sales (emissions subtracted)[b]	-[a]	−16	−15	−16	−16	−16	−16	−16
	Purchases (emissions added)[b]	-[a]	12	12	12	12	12	12	12
Spot Market Subtotal			**−4**	**−4**	**−4**	**−4**	**−4**	**−4**	**−4**
Total (System + Spot Market)			**42,465**	**42,471**	**42,463**	**42,465**	**42,466**	**42,448**	**42,453**

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TABLE M-4 (Cont.)

[a] A hyphen denotes "not applicable."

[b] "Sales" refers to sales of power by system utilities to non-system utilities within the Western Interconnection. Sales result in a net credit to total Western Interconnection emissions, because the sales result in a reduction in emissions from those non-system utilities that are purchasing the power. "Purchases" refers to purchases by system utilities from non-system utilities within the Western Interconnection. Emissions related to these purchases are added to the total emissions in the Western Interconnection.

1 **TABLE M-5 Annual NO_x Emissions (in tons per Year) Averaged over the 20-Year LTEMP Period by Alternative**

Generation Type	Plant Name	EIA Plant No.	Alternative A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
System Power Generation									
Combined cycle	Advanced combined cycle gas turbine	-[a]	184	184	184	184	184	183	183
	Desert Basin	55,129	28	28	28	28	28	28	28
	Front Range	55,283	122	121	122	122	121	123	122
	Kyrene #KY7 & #KY7A	147	3	3	3	3	3	3	3
	Long-term contract (Fort Lupton)	-[a]	4	4	4	4	4	4	4
	Mesquite	55,481	147	147	147	147	147	147	147
	Nebo	56,177	14	14	14	14	14	14	14
	Rifle	10,755	75	75	75	75	75	75	75
	Santan	8,068	79	79	80	80	80	80	80
	Combined Cycle Subtotal		**655**	**654**	**656**	**657**	**656**	**658**	**658**
Composite	**Long-term contract (unspecified)**	-[a]	**869**	**870**	**869**	**870**	**870**	**871**	**869**
Gas turbine	Advanced simple cycle gas turbine	-[a]	87	86	98	93	95	113	103
	Frank Knutson	55,505	12	12	12	12	12	14	13
	Kyrene KY4-KY6	147	0	0	0	0	0	0	0
	Limon	55,504	15	15	15	15	15	17	15
	Long-term contract (Brush 2)	10,683	34	33	34	35	34	35	37
	Long-term contract (Coolidge)	-[a]	34	33	33	34	34	34	34
	Pyramid	7,975	85	82	85	86	85	90	93
	Rawhide #A-#F	6,761	3	3	3	4	3	4	4
	Gas Turbine Subtotal		**271**	**265**	**282**	**278**	**277**	**307**	**300**
Internal combustion	Payson	7,408	17	17	16	17	16	16	17
	Provo	3,686	8	8	7	8	8	7	7
	Internal Combustion Subtotal		**24**	**24**	**24**	**24**	**24**	**24**	**24**

TABLE M-5 (Cont.)

Generation Type	Plant Name	EIA Plant No.	Alternative A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
System Power Generation (Cont.)									
Steam	Bonanza	7,790	6,764	6,764	6,764	6,764	6,764	6,764	6,764
turbine	Coronado	6,177	11,656	11,661	11,655	11,656	11,655	11,652	11,648
	Craig	6,021	12,236	12,235	12,236	12,235	12,236	12,235	12,235
	Escalante	87	3,319	3,318	3,316	3,318	3,318	3,304	3,315
	Four Corners	2,442	3,199	3,200	3,198	3,199	3,200	3,195	3,196
	George Birdsall	493	0	0	0	0	0	0	0
	Hayden	525	2,106	2,107	2,106	2,106	2,107	2,107	2,107
	Hunter	6,165	2,793	2,793	2,793	2,793	2,793	2,793	2,793
	Intermountain	6,481	10,979	10,979	10,979	10,979	10,979	10,979	10,979
	Kyrene 1 & 2	147	0	0	0	0	0	0	0
	Laramie River 1	6,204.1	1,125	1,125	1,125	1,125	1,125	1,125	1,125
	Laramie River 2 & 3	6,204.2	3,005	3,005	3,005	3,005	3,005	3,005	3,005
	Martin Drake	492	4,037	4,037	4,037	4,037	4,037	4,037	4,037
	Navajo	4,941	5,563	5,563	5,562	5,562	5,562	5,562	5,562
	Nucla	527	1,836	1,836	1,836	1,836	1,836	1,833	1,835
	Rawhide #1	6,761	1,704	1,704	1,704	1,704	1,704	1,704	1,704
	Ray D Nixon 1	8,219	1,989	1,989	1,989	1,989	1,989	1,989	1,989
	San Juan	2,451	889	889	889	889	889	888	889
	Springerville	8,223	3,600	3,601	3,600	3,600	3,600	3,594	3,598
	Steam Turbine Subtotal		**76,800**	**76,806**	**76,796**	**76,799**	**76,801**	**76,766**	**76,781**
System Power Generation Total			**78,620**	**78,620**	**78,626**	**78,629**	**78,628**	**78,626**	**78,632**
Spot Market									
	Sales (emissions subtracted)[b]	-[a]	−499	−492	−509	−503	−506	−520	−514
	Purchases (emissions added)[b]	-[a]	375	374	378	377	378	381	380
Spot Market Subtotal			**−124**	**−118**	**−130**	**−126**	**−128**	**−139**	**−134**
Total (System + Spot Market)			**78,496**	**78,501**	**78,496**	**78,503**	**78,500**	**78,487**	**78,498**

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TABLE M-5 (Cont.)

[a] Ahyphen denotes "not applicable."

[b] "Sales" refers to sales of power by system utilities to non-system utilities within the Western Interconnection. Sales result in a net credit to total Western Interconnection emissions, because the sales result in a reduction in emissions from those non-system utilities that are purchasing the power. "Purchases" refers to purchases by system utilities from non-system utilities within the Western Interconnection. Emissions related to these purchases are added to the total emissions in the Western Interconnection.

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TABLE M-6 Summary of Impacts of LTEMP Alternatives on SO_2 and NO_x Emissions

Generation Type	Alternative A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
Total Glen Canyon Dam power generation relative to Alternative A (MWh/day) (% of Alternative A)	11,650 (100%)	11,616 (99.7%)	11,566 (99.3%)	11,525 (98.9%)	11,571 (99.3%)	11,449 (98.3%)	11,438 (98.2%)
SO_2 Emissions (tons per year)							
System Power Generation							
Combined cycle	44	44	44	44	44	44	44
Composite[a]	606	607	606	607	607	608	606
Gas turbine	13	13	13	13	13	15	14
Internal combustion	1	1	1	1	1	1	1
Steam turbine	41,805	41,810	41,802	41,804	41,805	41,785	41,792
System Subtotal	**42,469**	**42,474**	**42,467**	**42,469**	**42,470**	**42,452**	**42,457**
Spot Market[b]							
Sales (emissions subtracted)	−16	−15	−16	−16	−16	−16	−16
Purchases (emissions added)	12	12	12	12	12	12	12
Spot Market Subtotal	**−4**	**−4**	**−4**	**−4**	**−4**	**−4**	**−4**
Total (System + Spot Market)	**42,465**	**42,471**	**42,463**	**42,465**	**42,466**	**42,448**	**42,453**
NO_x Emissions (tons per year)							
System Power Generation							
Combined cycle	655	654	656	657	656	658	658
Composite[a]	869	870	869	870	870	871	869
Gas turbine	271	265	282	278	277	307	300
Internal combustion	24	24	24	24	24	24	24
Steam turbine	76,800	76,806	76,796	76,799	76,801	76,766	76,781
System Subtotal	**78,620**	**78,620**	**78,626**	**78,629**	**78,628**	**78,626**	**78,632**
Spot Market Sales[b]							
Sales (emissions subtracted)	−499	−492	−509	−503	−506	−520	−514
Purchases (emissions added)	375	374	378	377	378	381	380
Spot Market Subtotal	**−124**	**−118**	**−130**	**−126**	**−128**	**−139**	**−134**
Total (System + Spot Market)	**78,496**	**78,501**	**78,496**	**78,503**	**78,500**	**78,487**	**78,498**

[a] Unspecified generation type.

[b] "Sales" refers to sales of power by system utilities to non-system utilities within the Western Interconnection. Sales result in a net credit to total Western Interconnection emissions, because the sales result in a reduction in emissions from those non-system utilities that are purchasing the power. "Purchases" refers to purchases by system utilities from non-system utilities within the Western Interconnection. Emissions related to these purchases are added to the total emissions in the Western Interconnection.

TABLE M-7 Annual Greenhouse Gas Emissions (in metric tons per year CO_2e)[a] under LTEMP Alternatives

Generation Type	Plant Name	EIA Plant No.	Alternative A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
System Power Generation									
Combined cycle	Advanced combined cycle gas turbine	-[b]	2,600,367	2,601,491	2,599,408	2,600,525	2,601,278	2,595,192	2,596,672
	Desert Basin	55,129	265,937	266,452	268,144	267,813	267,498	267,071	269,967
	Front Range	55,283	406,591	404,356	407,384	408,631	406,307	411,476	409,048
	Kyrene #KY7 & #KY7A	147	19,494	19,414	19,580	19,887	19,724	20,186	19,841
	Long-term contract (Fort Lupton)	-[b]	60,427	59,216	59,291	59,907	59,026	59,174	62,270
	Mesquite	55,481	1,849,137	1,849,882	1,848,983	1,849,244	1,849,226	1,849,912	1,848,629
	Nebo	56,177	83,114	82,405	83,512	83,312	83,354	84,904	84,799
	Rifle	10,755	47,363	47,364	47,345	47,372	47,345	47,627	47,472
	Santan	8,068	539,188	537,313	541,823	542,146	542,468	544,465	547,066
	Combined Cycle Subtotal		**5,871,619**	**5,867,894**	**5,875,470**	**5,878,837**	**5,876,226**	**5,880,006**	**5,885,763**
Composite	**Long-term contract (unspecified)**	-[b]	**711,604**	**712,068**	**711,574**	**712,296**	**712,186**	**713,199**	**711,081**
Gas turbine	Advanced simple cycle gas turbine	-[b]	308,968	303,922	347,729	330,732	334,863	400,526	363,507
	Frank Knutson	55,505	42,240	41,430	42,683	42,942	42,605	48,246	46,146
	Kyrene KY4-KY6	147	396	397	394	396	396	402	407
	Limon	55,504	28,833	28,686	28,511	28,704	28,442	32,341	30,317
	Long-term contract (Brush 2)	10,683	22,800	21,960	22,651	23,074	22,458	23,585	24,766
	Long-term contract (Coolidge)	-[b]	119,405	118,455	118,233	119,105	118,674	118,921	120,479
	Pyramid	7,975	96,184	93,109	96,845	97,520	96,222	102,441	105,650
	Rawhide #A-#F	6,761	3,979	3,966	4,003	4,047	3,977	4,458	4,227
	Gas Turbine Subtotal		**622,805**	**611,925**	**661,049**	**646,520**	**647,637**	**730,920**	**695,498**
Internal combustion	Payson	7,408	1,147	1,145	1,121	1,130	1,122	1,116	1,145
	Provo	3,686	579	576	559	597	588	572	561
	Internal Combustion Subtotal		**1,726**	**1,721**	**1,680**	**1,728**	**1,711**	**1,688**	**1,706**

TABLE M-7 (Cont.)

Generation Type	Plant Name	EIA Plant No.	Alternative A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
System Power Generation (Cont.)									
Steam turbine	Bonanza	7,790	3,418,218	3,418,220	3,418,218	3,418,217	3,418,218	3,418,064	3,418,218
	Coronado	6,177	6,153,123	6,155,366	6,152,407	6,153,039	6,152,639	6,150,587	6,148,959
	Craig	6,021	8,102,872	8,102,792	8,102,966	8,102,731	8,102,872	8,102,372	8,102,699
	Escalante	87	1,981,912	1,981,299	1,980,168	1,981,064	1,981,551	1,973,010	1,979,743
	Four Corners	2,442	1,081,762	1,082,205	1,081,704	1,081,925	1,082,120	1,080,471	1,080,993
	George Birdsall	493	103	101	103	103	101	124	107
	Hayden	525	1,057,553	1,057,715	1,057,628	1,057,628	1,057,855	1,057,791	1,057,715
	Hunter	6,165	1,544,335	1,544,336	1,544,335	1,544,335	1,544,336	1,544,335	1,544,335
	Intermountain	6,481	5,009,462	5,009,453	5,009,469	5,009,469	5,009,469	5,009,469	5,009,467
	Kyrene 1 & 2	147	435	437	432	437	434	445	445
	Laramie River 1	6,204.1	1,160,583	1,160,585	1,160,581	1,160,562	1,160,580	1,160,574	1,160,546
	Laramie River 2 & 3	6,204.2	2,199,501	2,199,501	2,199,501	2,199,501	2,199,501	2,199,501	2,199,501
	Martin Drake	492	2,120,585	2,120,587	2,120,574	2,120,585	2,120,587	2,120,581	2,120,575
	Navajo	4,941	3,697,248	3,697,409	3,697,013	3,697,141	3,697,131	3,696,629	3,696,581
	Nucla	527	896,805	896,837	897,059	897,059	897,108	895,690	896,486
	Rawhide #1	6,761	1,960,118	1,960,118	1,960,118	1,960,118	1,960,118	1,960,118	1,960,118
	Ray D Nixon 1	8,219	1,721,687	1,721,687	1,721,687	1,721,687	1,721,687	1,721,687	1,721,687
	San Juan	2,451	603,661	603,801	603,714	603,679	603,799	603,004	603,365
	Springerville	8,223	5,634,678	5,636,188	5,633,913	5,633,969	5,634,776	5,625,035	5,630,487
	Steam Turbine Subtotal		**48,344,640**	**48,348,638**	**48,341,590**	**48,343,248**	**48,344,880**	**48,319,488**	**48,332,026**
System Power Generation Total			**55,552,395**	**55,542,246**	**55,591,363**	**55,582,629**	**55,582,640**	**55,645,301**	**55,626,074**
Spot Market									
	Sales (emissions subtracted)[c]	-[b]	−1,512,509	−1,493,787	−1,543,444	−1,525,109	−1,536,444	−1,577,799	−1,560,383
	Purchases (emissions added)[c]	-[b]	1,137,782	1,135,108	1,147,910	1,143,056	1,147,975	1,154,687	1,152,937
Spot Market Subtotal			**−374,727**	**−358,679**	**−395,534**	**−382,053**	**−388,469**	**−423,112**	**−407,447**
Total (System + Spot Market)			**55,177,668**	**55,183,567**	**55,195,829**	**55,200,576**	**55,194,171**	**55,222,189**	**55,218,627**

Footnotes on next page.

TABLE M-7 (Cont.)

[a] To convert from metric tons to tons, multiply by 1.023.

[b] A hyphen denotes "not applicable."

[c] "Sales" refers to sales of power by system utilities to non-system utilities within the Western Interconnection. Sales result in a net credit to total Western Interconnection emissions, because the sales result in a reduction in emissions from those non-system utilities that are purchasing the power. "Purchases" refers to purchases by system utilities from non-system utilities within the Western Interconnection. Emissions related to these purchases are added to the total emissions in the Western Interconnection.

TABLE M-8 Summary of Impacts of LTEMP Alternatives on CO_2e Emissions

	CO_2e Emissions by Alternative (MT/yr)[a,b]						
CO_2e Emissions Source	A (No Action Alternative)	B	C	D (Preferred Alternative)	E	F	G
System Power Generation							
Combined cycle	5,871,619	5,867,894	5,875,470	5,878,837	5,876,226	5,880,006	5,885,763
Composite[c]	711,604	712,068	711,574	712,296	712,186	713,199	711,081
Gas turbine	622,805	611,925	661,049	646,520	647,637	730,920	695,498
Internal combustion	1,726	1,721	1,680	1,728	1,711	1,688	1,706
Steam turbine	48,344,640	48,348,638	48,341,590	48,343,248	48,344,880	48,319,488	48,332,026
System Subtotal	**55,552,395**	**55,542,246**	**55,591,363**	**55,582,629**	**55,582,640**	**55,645,301**	**55,626,074**
Spot Market[d]							
Sales (emissions subtracted)	−1,512,509	−1,493,787	−1,543,444	−1,525,109	−1,536,444	−1,577,799	−1,560,383
Purchases (emissions added)	1,137,782	1,135,108	1,147,910	1,143,056	1,147,975	1,154,687	1,152,937
Spot Market Subtotal	**−374,727**	**−358,679**	**−395,534**	**−382,053**	**−388,469**	**−423,112**	**−407,447**
Total Emissions (System + Spot Market)	**55,177,668**	**55,183,567**	**55,195,829**	**55,200,576**	**55,194,171**	**55,222,189**	**55,218,627**
	No change from current conditions	0.011% increase	0.033% increase	0.042% increase	0.030% increase	0.081% increase	0.074% increase
Difference from Alternative A (MT/yr)	0	5,900	18,161	22,908	16,503	44,522	40,960
Total Emissions as % of Total U.S. GHG Emissions[e]	No change from current conditions	0.011% increase	0.033% increase	0.042% increase	0.030% increase	0.081% increase	0.074% increase

[a] GHG emissions are expressed in carbon dioxide equivalent (CO_2e).

[b] GHG emissions (metric tons) from combustion-related powerplants in the Western Interconnect averaged over the 20-year LTEMP period.

[c] Unspecified generation type.

[d] "Sales" refers to sales of power by system utilities to non-system utilities within the Western Interconnection. Sales result in a net credit to total Western Interconnection emissions, because the sales result in a reduction in emissions from those non-system utilities that are purchasing the power. "Purchases" refers to purchases by system utilities from non-system utilities within the Western Interconnection. Emissions related to these purchases are added to the total emissions in the Western Interconnection.

[e] U.S. total GHG emissions at 6,810.3 million MT/yr CO_2e in 2010 (EPA 2013).

APPENDIX N:

GOVERNMENT-TO-GOVERNMENT AND NATIONAL HISTORIC PRESERVATION ACT CONSULTATION

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APPENDIX N:

GOVERNMENT-TO-GOVERNMENT AND NATIONAL HISTORIC PRESERVATION ACT CONSULTATION

This appendix presents the correspondence pertaining to government-to-government and National Historic Preservation Act of 1966 (NHPA) Section 106 consultation for the Long-Term Experimental Management Program (LTEMP) Draft Environmental Impact Statement (DEIS). Attachment 1 provides copies of signed Memorandums of Understanding (MOUs), Attachment 2 provides official correspondence with Tribes, and Attachment 3 contains a copy of the letter to the Arizona State Historic Preservation Officer.

N.1 GOVERNMENT-TO-GOVERNMENT CONSULTATION

As detailed in Chapter 5 of the DEIS, both the Bureau of Reclamation (Reclamation) and the National Park Service (NPS) coordinate and consult with all Tribal governments, American Indian communities and organizations, and Tribal individuals whose interests might be directly and substantially affected by activities within their jurisdiction. Both agencies strive to provide Indian Tribes with sufficient opportunities for productive participation in planning and resource management decision-making. In addition, Section 106 of the NHPA requires federal agencies to consult with Indian Tribes on undertakings on Tribal lands and on historic properties of significance to the Tribes that may be affected by an undertaking (36 CFR 800.2 (c)(2)) (see Section 4.8.1). Agency-specific guidance provides additional direction for American Indian consultations (see Section 5.2.3).

On January 21, 2011, an e-mail was sent to Tribes that were previous cooperators on the Glen Canyon Dam EIS (Reclamation 1995)—the Southern Paiute Consortium, the Hopi Tribe, the Hualapai Tribe, the Navajo Nation, and the Pueblo of Zuni—with an invitation to attend the initial "kickoff" meeting for the LTEMP EIS on February 11, 2011. Representatives from the Navajo Nation and the Pueblo of Zuni attended this meeting.

On October 17, 2011, an e-mail was sent to the Southern Paiute Consortium, the Hualapai Tribe, the Hopi Tribe, the Navajo Nation, and the Pueblo of Zuni indicating that Reclamation published in the *Federal Register* a Notice of Intent (NOI) to develop a LTEMP and prepare a LTEMP EIS. In this NOI, the public was notified of upcoming public scoping meetings and were provided information on how to participate in the LTEMP public scoping process. A link to the project website and project lead contact information was provided.

On November 4, 2011, an e-mail was sent to the Hopi Tribe, the Southern Paiute Consortium, the Las Vegas Tribe of Paiute Indians, the Moapa Band of Paiute Indians, the Paiute Indian Tribe of Utah, the Havasupai Tribe, the Hualapai Tribe, the Navajo Nation, and the Pueblo of Zuni with an update on the LTEMP process. The e-mail summarized NOI publications and provided contact information for project leads. The e-mail also stated that several Tribes had already indicated their desire to participate as cooperating agencies and the joint leads would

soon be formally contacting all potentially interested American Indian Tribes to initiate consultation.

On November 30, 2011, 43 Tribes, bands, and organizations were formally invited to enter into government-to-government consultation on the LTEMP EIS. A letter, sent by the joint-lead agencies, provided notification of the intent to prepare the LTEMP EIS, initiated government-to-government consultation, and invited the Tribes to identify concerns related to historic properties, including traditional cultural properties and archaeological sites; natural resources; relevant Indian Trust assets; and other issues of importance.

On December 8, 2011, in accordance with 40 CFR (Code of Federal Regulations) 1501.6, concerning the Council on Environmental Quality (CEQ) regulations for implementing the procedural provisions of the National Environmental Policy Act (NEPA), and 43 CFR 46.225 concerning the Department of the Interior's (DOI's) regulations for implementing NEPA, Reclamation and NPS invited 11 Tribes to participate as Cooperating Agencies in the development of the EIS.

A total of 31 Tribes responded to the invitations. Six Tribes agreed to participate as Cooperating Agencies (the Havasupai Tribe, the Hopi Tribe, the Hualapai Tribe, the Kaibab Band of Paiute Indians, the Navajo Nation, the Pueblo of Zuni); three Tribes (the Fort Mojave Tribal Council, Pueblo of Zia, and the Gila River Indian Community) agreed to participate as Consulting Tribes; eight Tribes (Pueblo of Santa Clara, Ute Indian Tribe, Ute Mountain Ute, Pueblo of Nambe, Yavapai Apache, Paiute Indian Tribe of Utah, the Pueblo of Santa Ana, and the Fort Yuma Quechan) declined participation, but asked to remain on the mailing list; and 11 Tribes (Ak Chin Indian Community, Cocopah Indian Tribe, Fort McDowell Yavapai Tribal Council, Jicarilla Apache Nation, Ohkay Owingeh, Southern Ute Tribal Council, the Pueblo of Laguna, the Pueblo of Sandia, Yavapai-Prescott Indian Tribe, Tohono O'odham Nation, and the White Mountain Apache) declined participation in the LTEMP EIS. The joint-leads have yet to receive a response to the request for consultation from the remaining 15 Tribes (Colorado River Indian Tribes, Chemehuevi Tribal Council, Las Vegas Tribe of Paiute Indians, Moapa Band of Paiute Indians, Salt River Pima-Maricopa Indian Community, San Carlos Apache Tribe, San Juan Southern Paiute Tribe, the Pascua Yaqui Tribe, the Pueblo of Acoma, the Pueblo of Cochiti, the Pueblo of Jemez, the Pueblo of Pojoaque, the Pueblo of San Felipe, the Pueblo of Tesuque, and the Tonto Apache Tribe) despite follow-up phone calls and e-mails.

Although the Pueblo of Zia agreed to participate as a Consulting Tribe, there was little participation from the Pueblo. On February 11, 2014, an e-mail was sent to a Tribal representative asking if the Pueblo of Zia would like to remain a Consulting Tribe or be moved to the mailing list. A hard copy of this letter was also sent to the Tribe. No response was received and the joint-leads agreed to move the Pueblo of Zia to the mailing list. A summary of Tribal Participation Status is provided in Table N-1 and a summary of follow-up inquiries is provided in Table N-2.

Beginning in February 2012, the Tribes participating as Cooperating Agencies were invited to monthly conference calls to review progress and to reach agreement on major issues during the preparation of the DEIS. Prior to these meetings, Tribes were sent an invitation to

TABLE N-1 Summary of Tribal Participation Status

Participating Tribes	Declined Participation	No Response
Cooperating Agencies	Ak Chin Indian Community	Chemehuevi Tribal Council
The Havasupai Tribe	Chemehuevi Tribal Council	Colorado River Indian Tribes
The Hopi Tribe	Cocopah Indian Tribe	Las Vegas Tribe of Paiute Indians
The Hualapai Tribe	Fort McDowell Yavapai Tribal Council	Moapa Band of Paiute Indians
The Kaibab Band of Paiute Indians	Jicarilla Apache Nation	Salt River Pima-Maricopa Indian Community
The Navajo Nation	Ohkay Owingeh	San Carlos Apache Tribe
The Pueblo of Zuni	Southern Ute Tribal Council	San Juan Southern Paiute Tribe
	The Pueblo of Laguna	The Pascua Yaqui Tribe
Consulting Tribes	The Pueblo of Sandia	The Pueblo of Acoma
The Fort Mojave Tribal Council	Tohono O'odham Nation	The Pueblo of Conchiti
Gila River Indian Community	White Mountain Apache	The Pueblo of Jemez
	Yavapai-Prescott Indian Tribe	The Pueblo of Pojoaque
Mailing List		The Pueblo of San Felipe
Fort Yuma Quechan		The Pueblo of Tesuque
Paiute Indian Tribe of Utah		Tonto Apache Tribe
The Pueblo of Nambe		
The Pueblo of Santa Ana		
The Pueblo of Santa Clara		
The Pueblo of Zia		
Ute Indian Tribe		
Ute Mountain Ute		
Yavapai-Apache		

each meeting as well as a meeting reminder with an agenda, call-in number, and password. Monthly Cooperating Agency meetings are ongoing and will continue to be held throughout the length of the LTEMP.

Cooperating Agency Tribes were invited to sign a MOU defining the relationship and duties of the joint-lead and cooperating agencies in completing the NEPA compliance for LTEMP. A draft copy of the MOU was sent to all Cooperating Agency Tribes on March 6, 2012, and Tribes were encouraged to make revisions and provide comments. Final copies of the MOU were distributed to each Tribe after revisions and comments were returned and incorporated into each MOU. Signed copies were returned to the joint-leads by all Cooperating Agency Tribes. Copies of the MOUs are provided in Attachment 1.

In addition to Cooperating Agency meetings, more than 30 meetings, workshops, and webinars were conducted with stakeholders and Cooperating Agencies to assist in the development of alternatives and performance criteria, explain the Structured Decision Analysis (SDA), conduct swing-weighting exercises, and provide general status updates. A series of Tribal-specific workshops, conference calls, and webinars were also held to identify Tribal resource goals and ways to measure the relative performance of alternatives against those goals. Prior to these meetings, inquiries were sent to Tribes to find a meeting time that would best suit

TABLE N-2 Summary of Tribal Correspondence

Tribe	Reclamation and NPS Communications with Tribes	Tribal Comment/Response
Ak Chin Indian Community	February 2012: Steve Daron, Lake Mead National Recreation Area (LMNRA), attempted phone contact with the Ak Chin Indian Community three times in February. He was unable to reach anyone. May 4, 2012: Steve Daron spoke with Carol Antone and re-sent the November 30 letter. Phone call follow-up, but no response.	July 31, 2012: Letter from Louis J. Manuel, Jr., Chairman indicating that the Ak Chin Indian Community is not interested in participating in the LTEMP process at this time.
Chemehuevi Tribal Council	February 2012: Steve Daron, LMNRA, attempted to call the Chemehuevi Tribal Council three times in February. He was unable to reach anyone.	No response.
Cocopah Indian Tribe	January 23, 2012: John Halliday, DOI, called and was referred from the Chair Office to Tribal Administrator Christopher Nunez. John left him a message regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	January 25, 2012: Tribal staff member Barbera Mathias called Mr. Halliday and informed him that the Cocopah did not wish to participate in the LTEMP process.
Colorado River Indian Tribes	February 2012: Steve Daron, LMNRA, attempted to call CRIT three times in February and received no response. September 24, 2012: Jennifer Abplanalp, Argonne, called and left a message for Mr. Buma requesting an e-mail or mailing address to send LTEMP information.	August 10, 2012: Consulting and Cooperating Tribes meeting was held in Tempe, Arizona. Grant Buma, Acting Director of Water Resources Department, was in attendance. September 24, 2012: Mr. Buma called back with his e-mail address.
Fort McDowell Yavapai Tribal Council	January 23, 2012: John Halliday, DOI, called and left a message for Karen Ray regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday left a message with Ms. Ray asking if the Tribe wished to participate in the LTEMP process. January 27, 2012: Mr. Halliday left a message with Ms. Ray asking if the Tribe wished to participate in the LTEMP process. February 6, 2012: Mr. Halliday called and spoke to Tribal Cultural Representative Gary Loutenhizer. February 14, 2012: Mr. Halliday called and spoke to Mr. Loutenhizer.	February 6, 2012: Mr. Loutenhizer said that he would check with Karen Ray regarding participation in LTEMP and would get back to John soon. February 14, 2014: Mr. Loutenhizer indicated that the Ft. McDowell Yavapai did not want to participate in LTEMP process.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Fort Mojave Tribal Council	December 6, 2013: Steve Daron, LMNRA, spoke with Nora McDowell-Antone and asked if the Fort Mojave were still interested in participating as a consulting Tribe for the LTEMP EIS. January 30, 2014: Mr. Daron spoke with Ms. McDowell-Antone regarding the Fort Mojave participation as a consulting Tribe for the LTEMP EIS.	February 2012: Linda Otero, Director of the Aha Makav Cultural Society, called Steve Daron and indicated that the Fort Mojave were interested in participating in government-to-government consultation. April 24, 2012: Ms. Otero called Mr. Daron to schedule a meeting with the joint-lead agencies for an overview of the project. December 6, 2013: Ms. McDowell-Antone indicated that the Tribe is still interested. January 30, 2014: Ms. McDowell-Antone informed Mr. Daron that Ms. Otero had been temporarily assigned for 3 to 6 months but the Tribe would like to stay in the loop and receive information. Ms. Ms. McDowell-Antone requested the most recent documents.
Fort Yuma Quechan Tribe	February 2012: Steven Daron, LMNRA, spoke with John Bathke, Tribal Historic Preservation Officer (THPO), regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. Steve also sent Mr. Bathke an e-mail with information on the LTEMP website. May 8, 2012: Mr. Daron spoke with John Bathke, THPO, regarding LTEMP consultation. May 14, 2012: Mr. Daron sent Mr. Bathke an e-mail with some potential dates for a meeting. May 29, 2012: Mr. Daron informed Mr. Bathke that the LTEMP representatives would be available for a meeting on June 22, as requested. May 30, 2012: Mr. Daron spoke with Mr. Bathke regarding the LTEMP. April 4, 2013: Bruce Verhaaren, Argonne, called the new THPO, Arlene Kingery, Mr. Bathke's replacement, regarding the Tribe's continued involvement in the LTEMP process.	February 15, 2012: John Bathke, THPO, called and left a message for Steven Daron requesting LTEMP consultation. May 8, 2012: Mr. Bathke indicated that the Cultural Committee would like a presentation on the LTEMP project and asked Mr. Daron to provide dates when LTEMP Representatives could come give a presentation. May 29, 2012: Mr. Bathke e-mailed Mr. Daron to request a meeting with LTEMP representatives on June 22, 2012, to discuss the LTEMP process. May 30, 2012: Mr. Bathke indicated that the Quechan are more interested in the impacts the project would have on cultural resources because the Tribe has heard that previous releases from Glen Canyon Dam have had impacts on sites. April 4, 2013: Ms. Kingery informed Bruce Verhaaren that the Quechan Cultural Committee had decided that they would no longer like to consult on the LTEMP but would like to remain on the mailing list.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Gila River Indian Community Council (GRIC)	January 9, 2012: Janet Cohen confirmed receipt of the Tribe's interest in consultation. February 2012: Steven Daron, LMNRA, attempted contact with the GRIC May 14, 2012: Mr. Daron spoke with Larry Benallie, Archaeology Compliance Specialist, regarding the Tribe's participation in the LTEMP process. June 20, 2012: Bruce Verhaaren, Argonne, sent the draft copy of *American Indian Perspectives and Values Related to the Glen Canyon Dam Long-Term Experimental and Management Plan Environmental Impact Statement.*	January 3, 2012: Barnaby Lewis, THPO, sent a letter to John Wessels, NPS, and an e-mail to Ms. Cohen, NPS, indicating the Tribe's interest in consultation. May 14, 2012: Mr. Benallie informed Mr. Daron that the GRIC did not want to schedule a meeting at this time, but would re-evaluate the decision after the alternatives have been chosen. Mr. Benallie also requested a copy of the draft copy of *American Indian Perspectives and Values Related to the Glen Canyon Dam Long-Term Experimental and Management Plan Environmental Impact Statement* and indicated that the Tribe would like to remain on the mailing list.
Havasupai Tribe	January 23, 2012: E-mail from Janet Cohen, NPS, to Chair and Vice Chair asking the Havasupai what their level of interest is in the project. Ms. Cohen attached a copy of the November and December 2011 letters and asked if they could get back to her by the end of the week regarding their involvement. January 27, 2012: Ms. Cohen tried to call Chairman Watahomigie and the Vice Chair regarding the November and December 2011 LTEMP letters asking if the Tribe wished to participate in the LTEMP process but was unable to reach anyone. January 30, 2012: Ms. Cohen called and spoke to Chairman Watahomigie regarding the November and December 2011 LTEMP letters asking if the Tribe wished to participate in the LTEMP process. Ms. Cohen resent the November and December 2011 letters and asked Chairman Watahomigie to return the Cooperating Agency form. February 7, 2012: Ms. Cohen sent copies of the November and December 2011 letters to the Tribal Secretary as per the Tribe's request. April 8, 2012: Sarah Rinkevich called and spoke with Margaret Vick, Attorney for the Havasupai, asking if they would like to submit a funding proposal and if they were still interested in participating in the LTEMP. July 2012: MOU signed by joint-leads.	January 30, 2012: Chairman Watahomigie said the Tribe is interested in participating but did not specify whether they wanted to be a Cooperating Agency or not. Chairman identified the Tribal secretary (Jaycee Manakaja) as the point of contact to send meeting information, etc. February 27, 2012: Cooperating Agency form returned indicating the Tribe would like to participate as a Cooperating Agency. July 6, 2012: MOU signed. April 8, 2013: Ms. Vick indicated that the Havasupai have not submitted any funding proposal for LTEMP, but she would ask the Chairman if the Havasupai were interested in funding. Ms. Vick indicated that the Havasupai may not be interested in sharing Grand Canyon cultural connections with the Federal Government but that the engineering and water quality departments may be interested in reviewing the alternatives. September 30, 2015: Havasupai Tribe submitted comments on LTEMP DEIS.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Havasupai Tribe (Cont.)	December 17, 2014: Preliminary Chapters 1 and 2 sent to Havasupai Tribe for review. April 15, 2015: Preliminary Chapter 3 sent to Havasupai Tribe for review. July 1, 2015: LTEMP DEIS sent to Havasupai Tribe for review.	
Hopi Tribe	January 13, 2012: Janet Cohen, NPS, spoke with Mike Yeatts regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process February 15, 2012: Ms. Cohen spoke with Mr. Yeatts regarding Hopi participation as a Cooperating Agency in the LTEMP process. She asked him to return the Cooperating Agency form to Argonne as soon as possible. She e-mailed another copy of the November 2011 letter and the form to Mr. Yeatts. October 2014: MOU signed by joint-leads December 17, 2014: Preliminary Chapters 1 and 2 sent to Hopi Tribe for review. April 15, 2015: Preliminary Chapter 3 sent to Hopi Tribe for review. July 1, 2015: LTEMP DEIS sent to Hopi Tribe for review.	February 15, 2012: Mr. Yeatts indicated that he will follow up with Leigh Kuwanwiswima, THPO, to see if the Cooperating Agency form had been sent in. June 7, 2013: MOU signed. January 23, 2015: Mr. Yeatts submitted Hopi comments on Chapters 1 and 2 to the joint leads. January 23, 2015: Hopi Tribe submitted comments on preliminary Chapters 1 and 2. September 30, 2015: Hopi Tribe submitted comments on LTEMP DEIS.
Hualapai Tribe	November 16, 2012: Rob Billerbeck, NPS, called and spoke with Kerry Christiansen regarding the LTEMP project. January 5, 2012: The November 30, 2011, letter of invitation to become a cooperating agency letter was returned to Argonne. The letter was resent via e-mail to Loretta Jackson-Kelly, THPO. Ms. Jackson-Kelly was informed that the deadline for informing the lead-agencies if the Hualapai wished to be a cooperating agency was Friday January 6, 2012, and asked Ms. Jackson-Kelly to let her know if the Hualapai needed more time.	November 16, 2012: Mr. Christiansen expressed that the Hualapai Tribe may be interested in having LTEMP representatives meet with the Hualapai Tribal Council as they felt this has not happened enough on past processes. January 6, 2012: Ms. Jackson-Kelly returned the Cooperating Agency form via fax. The Hualapai would like to be a Cooperating Agency.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Hualapai Tribe (Cont.)	December 16, 2013: Jim May, Argonne, spoke with Peter Bungart and Earlene Havatone, Exec. Director of Grand Canyon West, about the impacts of Glen Canyon Dam releases on the Hualapai's river-running businesses. Mr. May encouraged Ms. Havatone to try to quantify the impacts and to include pictures of the kinds of damage and concerns that the Hualapai have. October 2014: MOU signed by joint-leads. December 17, 2014: Preliminary Chapters 1 and 2 sent to the Hualapai Tribe for review. April 15, 2015: Preliminary Chapter 3 sent to the Hualapai Tribe for review. July 1, 2015: LTEMP EIS sent to the Hualapai Tribe for review.	October 4, 2012: MOU signed. April 8, 2013: Mr. Bungart informed Ms. Rinkevich that the Hualapai already submitted their request for funding. Ms. Jackson-Kelly and he requested a presentation by LTEMP representatives at an open house at the next council meeting on May 3, 2013. August 16, 2013: Mr. Bungart sent a follow-up e-mail in response to a discussion held at the Tribal Values Workshop on Tuesday August 6, 2013, with suggested performance metrics that would be both practical and useful for Hualapai resources of concern. December 16, 2013: Major concerns expressed by Ms. Havatone include bank erosion, difficulty accessing docks, tougher navigation in a narrowing channel, difficulty in accessing the shoreline up steep banks and excessive wear and tear on outboard motors. Ms. Havatone indicated that she had not tried to quantify the effects of the impacts before, but she thought she could. April 16, 2015: The Hualapai Tribe submitted comments on preliminary Chapters 1, 2, and 3. September 30, 2015: The Hualapai Tribe submitted comments on the LTEMP DEIS.
Jicarilla Apache Nation	January 26, 2012: John Halliday, DOI, called Jeffrey Blythe regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	January 26, 2012: Mr. Blythe indicated that the Jicarilla Apache Nation did not wish to participate in the LTEMP process.
Kaibab Band of Paiute Indians	May/June/July 2012: MOU signed by joint-leads. December 17, 2014: Preliminary Chapters 1 and 2 sent to Kaibab Band of Paiute Indians for review. April 15, 2015: Preliminary Chapter 3 sent to Kaibab Band of Paiute Indians for review.	February 15, 2011: The Cooperating Agency form as signed and returned. May 2, 2012: MOU signed. January 6, 2015: Mr. Bulletts inquired as to when Chapter 3 would be available for review by Tribal Representatives.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Kaibab Band of Paiute Indians (Cont.)	May/June/July 2012: MOU signed by joint-leads. December 17, 2014: Preliminary Chapters 1 and 2 sent to Kaibab Band of Paiute Indians for review. April 15, 2015: Preliminary Chapter 3 sent to Kaibab Band of Paiute Indians for review. July 1, 2015: LTEMP DEIS sent to Kaibab Band of Paiute Indians for review. November 2, 2015: Reclamation informed Charley Bulletts that the joint-leads had not received comments from the Kaibab Band of Paiute Indians as referenced in the September 29, 2015, letter and requested that Mr. Bulletts resend the comments.	February 15, 2011: The Cooperating Agency form as signed and returned. May 2, 2012: MOU signed. January 6, 2015: Mr. Bulletts inquired as to when Chapter 3 would be available for review by Tribal Representatives. September 29, 2015: Kaibab Band of Paiute Indians submitted comments on the LTEMP DEIS. References a letter dated April 8, 2015, regarding comments on preliminary Chapters 1 and 2 that were never received by the joint-lead agencies. November 3, 2015: Mr. Bulletts sent comments on Chapters 1 and 2. Comments received by joint-lead agencies.
Las Vegas Tribe of Paiute Indians	January 23, 2012: Janet Cohen, NPS, sent an e-mail to Kenny Anderson with a copy of the initial November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 27, 2012: Ms. Cohen called Kenny Anderson to follow up on an e-mail containing copies of letters sent on January 23, 2012. February 15, 2012: Ms. Cohen sent an e-mail to Mr. Anderson with a copy of the initial November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. February 22, 2012: Ms. Cohen called Mr. Anderson and left a voicemail indicating that the NPS will have to assume that the Las Vegas Paiute are not interested in this project since they have not indicated otherwise.	January 27, 2012: Mr. Anderson indicated that the Las Vegas Tribe of Paiute Indians are likely interested in some level of consultation and would like to review the letters before saying for sure.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Moapa Band of Paiute Indians	January 23, 2012: Janet Cohen, NPS, sent an e-mail to Chairman Anderson containing copies of the initial November 2011 and December 2011 LTEMP letters asking if the Tribe wished to participate in the LTEMP process. January 27, 2012: Ms. Cohen called Chairman Anderson to follow-up on the e-mail sent out on January 23, 2012. Ms. Cohen asked Chairman Anderson to look at the e-mail and the letters and let the NPS know if the Moapa Band of Paiute Indians is interested in consultation or not.	January 27, 2012: Chairman Anderson indicated he was very backed up on reviewing incoming e-mail and he wasn't sure if he had seen the letters or the e-mail.
)	February 15, 2012: Janet Cohen, NPS, sent an e-mail to Chairman Anderson with the November 2011 and December 2011 LTEMP letters attached and asked if the Tribe was interested in consultation. The letter also indicated that if the NPS does not receive a response, the NPS will assume that the Moapa Band of Paiute Indians is not interested in consultation. February 22, 2012: Ms. Cohen called Chairman Anderson and left a voicemail indicating the NPS will have to assume the Moapa are not interested in the project since they have not indicated otherwise.	
Navajo Nation	January 13, 2012: Janet Cohen, NPS, spoke with Jason John regarding the proper contact person for LTEMP. It was confirmed that The Department of Water Resources will represent the Tribe in its Cooperating Agency status. Ms. Cohen will follow up with the Historic Preservation Department in regards to Section 106 and cultural resources. Ms. Cohen provided the web address for the LTEMP project. May 20, 2013: Bruce Verhaaren, Argonne, spoke with Jason John, Navajo Department of Water and Power (NDWP). Bruce advised Mr. John to call Sarah Rinkevich, DO,I to request a meeting. February 11, 2014: Mr. Verhaaren e-mailed a letter to Jason John, NDWP, and Tony Joe, Supervisory Anthropologist, from the joint-leads of the LTEMP EIS concerning the pending MOU between the Navajo Nation, the Bureau of Reclamation, and the National Park Service regarding the participation of the Navajo Nation as a cooperating agency for the EIS.	February 28, 2011: Letter from Tony Joe of the Navajo Nation with comments on the preliminary draft outline distributed at the kickoff meeting. January 9, 2012: Cooperating Agency form was submitted indicating the Navajo Nation would like to participate in the LTEMP as a Cooperating Agency. May 20, 2013: Mr. John requested a meeting or teleconference to discuss the LTEMP. February 21, 2014: Return receipt confirmation for the February 11, 2014, letter to Mr. John. February 21, 2014: Mr. John sent the joint-leads a letter from the Navajo Nation President Ben Shelly requesting government-to-government consultation.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Navajo Nation (Cont.)	February 13, 2014: A hardcopy of the February 11, 2014, letter was sent to Tony Joe and Jason John.	February 24, 2014: Return receipt confirmation for the February 11, 2014, letter to Tony Joe.
	February 28, 2014: Rob Billerbeck, NPS spoke with Mr. John regarding government-to-government consultation.	February 28, 2014: Mr. John indicated that there may have been a misunderstanding. The Navajo Nation would like LTEMP representatives to explain the LTEMP process before signing the MOU. The Navajo Nation will likely wait until summer for formal government-to-government consultation.
	March 17, 2014: Mr. Billerbeck sent an e-mail to Mr. John in reply to the February 21, 2014, e-mail and attached letter requesting to meet with the project managers of LTEMP. Mr. Billerbeck apologized for not being able to meet on the requested dates and proposed new dates for a meeting and attached some additional information on the LTEMP project for the Navajo to review in advance.	March 17, 2014: Mr. John requested a meeting at 2 p.m. on April 10, 2014, in Window Rock, Arizona.
	October 2014: MOU signed by joint-leads	June 9, 2014: MOU Signed.
	December 17, 2014: Preliminary Chapters 1 and 2 sent to the Navajo Nation for review.	October 6, 2015: Navajo Nation submitted comments on the LTEMP DEIS.
	April 15, 2015: Preliminary Chapter 3 sent to the Navajo Nation for review.	
	July 1, 2015: LTEMP DEIS sent to the Navajo Nation for review.	
Ohkay Owingeh	January 23, 2012: John Halliday, DOI, called and left a message for Anthony Moquino regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	January 27, 2012: Mr. Moquino indicated that the Tribe did not wish to participate in the LTEMP process.
	January 26, 2012: Mr. Halliday left a message with Mr. Moquino asking if the Tribe wished to participate in the LTEMP process.	
	January 27, 2012: Mr. Halliday spoke with Mr. Moquino and asked if the Tribe would like to participate in the LTEMP process	
Paiute Indian Tribe of Utah	No follow-up needed. Tribe returned form and requested to be added to mailing list.	January 9, 2012: The Cooperating Agency form was returned. The Paiute Indian Tribe of Utah is not interested in being a Cooperating Agency, but would like to remain updated on the LTEMP.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Pascua Yaqui Tribe	January 24, 2012: John Halliday, DOI, called and left a message for Chairperson Peter Yucupicio regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday called and left another message for Chairman Yucupicio. January 27, 2012: Mr. Halliday called and left another message for Chairman Yucupicio. February 6, 2014: Mr. Halliday called and left another message for Chairman Yucupicio. February 14, 2014: Mr. Halliday called and left another message for Chairman Yucupicio.	No response.
Pueblo of Acoma	January 23, 2012: John Halliday, DOI, called and left a message for Theresa Pasquale regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday left another message for Ms. Pasquale. January 27, 2012: Mr. Halliday left another message for Ms. Pasquale. February 14, 2012: Mr. Halliday left another message for Ms. Pasquale.	No response.
Pueblo of Cochiti	January 23, 2012: John Halliday, DOI, called and left a message for Jacob Pecos, Director, Department of Natural Resources, regarding the LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday left another message for Mr. Pecos. January 27, 2012: Mr. Halliday left another message for Mr. Pecos. February 14, 2012: Mr. Halliday left another message for Mr. Pecos.	No response.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Pueblo of Jemez	January 23, 2012: John Halliday, DOI, called and left a message for Natural Resources Director Christopher Toya regarding the LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	No response.
	January 26, 2012: Mr. Halliday left another message for Mr. Toya.	
	January 27, 2012: Mr. Halliday left another message for Mr. Toya.	
	February 14, 2012: Mr. Halliday left another message for Mr. Toya.	
Pueblo of Laguna	January 23, 2012: John Halliday, DOI, called and was referred from the Governor's Office to Tribal Staff Member Adam Ringia and left a message for him regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	January 26, 2012: Mr. Ringia indicated that the Pueblo of Laguna does not wish to participate in the LTEMP process.
	January 26, 2012: Mr. Halliday called Mr. Ringia regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	
Pueblo of Nambe	January 23, 2012: John Halliday, DOI, called and left a message for Steve Romero regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	January 27, 2012: Ms. Carnevale informed Mr. Halliday that she is the new Tribal Environmental Officer. She indicated that the Tribe would like to schedule a consultation meeting.
	January 27, 2012: Mr. Halliday spoke with Nichole Carnevale regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	May 3, 2012: Mary Barger received an e-mail from Ms. Carnevale indicating that the Tribe would not like to actively participate in LTEMP but would like to remain on the mailing list.
Pueblo of Pojoaque	January 24, 2012: John Halliday, DOI, called and left message for Vernon Lujan, THPO, regarding the LTEMP letter asking if the Tribe wished to participate in the LTEMP process	March 29, 2012: Mr. Halliday received a message from Mr. Lujan indicating that the Tribe would like to participate in the LTEMP process.
	January 26, 2012: Mr. Halliday called and left another message for Mr. Lujan.	May 03, 2012: The Pueblo of Pojoaque indicated that they were interested in setting up a meeting and would get back to Ms. Barger, Reclamation, with a date to meet.
	January 27, 2012: Mr. Halliday called and left another message for Mr. Lujan.	
	February 14, 2012: Mr. Halliday called and left another message for Mr. Lujan.	May 14, 2012: Linda was not familiar with the project and gave Ms. Barger Mr. Lujan's cell phone.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Pueblo of Pojoaque (Cont.)	May 14, 2012: Ms. Barger called Mr. Lujan to schedule a meeting time and spoke with Linda, a member of his staff. Ms. Barger left Mr. Lujan a message on his cell phone. May 16, 2012: Ms. Barger called and left a voicemail for Mr. Lujan. She offered to put them on the mailing list or schedule a meeting. May 17, 2012: Ms. Barger left another voicemail with Mr. Lujan. May 21, 2012: Ms. Barger called and spoke with Mr. Lujan. May 22, 2012: Adrianne Carr, Argonne e-mailed a copy the November 2011 LTEMP letter and the Draft Tribal Consultation Plan to Mr. Lujan for review. May 29, 2012: Ms. Barger called Mr. Lujan to follow-up on the documents sent on May 22 and see if the Pueblo was interested in participating in LTEMP. June 09, 2012: Ms. Barger spoke to Mr. Lujan regarding LTEMP participation. June 19, 2012: Ms. Barger left a message with Mr. Lujan regarding participation in the LTEMP. June 25, 2012: Ms. Barger left a message with Mr. Lujan. She stated that since she has not heard from him, the joint-leads are assuming that the Pueblo of Pojoaque is not interested in meeting on the EIS, and to contact her by June 29 if her assumption was incorrect.	May 21, 2012: Mr. Lujan requested more information so he could decide if the Pueblo of Pojoaque should consult. May 29, 2012: Mr. Lujan indicated that he did not have time to review the project information that Ms. Barger sent. June 9, 2012: Mr. Lujan indicated that he forwarded the information to the Governor's office and was awaiting a recommendation.
Pueblo of San Felipe	January 23, 2012: John Halliday, DOI called and was referred from the Governor's Office to Tribal Administrator Daryl Candelaria. Mr. Halliday left him a message regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday called and left another message with Mr. Candelaria. January 27, 2012: Mr. Halliday called and left another message with Mr. Candelaria.	No response.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Pueblo of San Felipe (Cont.)	February 14, 2012: Mr. Halliday called and left another message with Mr. Candelaria.	No response.
Pueblo of Sandia	January 23, 2012: Mr. Halliday, DOI, called and left a message for Environmental Director Frank Chavez regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday called and spoke with Mr. Chavez regarding Pueblo of Sandia participation in the LTEMP process.	January 26, 2012: Mr. Chavez indicated the Pueblo of Sandia did not want to participate
Pueblo of Santa Ana	January 24, 2012: John Halliday, DOI, called and spoke with Tribal Liaison Ben Robbins regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 25, 2012: Mr. Halliday e-mailed copies of the November 2011 letter to Ben. February 06, 2012: Mr. Halliday called and left a message for Mr. Robbins regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. February 14, 2012: Mr. Halliday called and spoke with Mr. Robbins regarding Pueblo of Santa Ana participation in the LTEMP process.	January 24, 2012: Mr. Robbins asked Mr. Halliday to e-mail him another copy of the letter and he would ask the council and get back to John. February 14, 2012: Mr. Robbins indicated that the Tribe did not wish to participate in the LTEMP process, but would like to continue receiving information and updates.
Pueblo of Santa Clara	January 23, 2012: John Halliday, DOI, called to speak with Ben Chavarria, NAGPRA Contact, regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 24, 2012: Mr. Halliday called and left a message for Mr. Chavarria regarding the Tribe's participation in the LTEMP process. January 26, 2012: Mr. Halliday called and left a message for Mr. Chavarria regarding the Tribe's participation in the LTEMP.	January 23, 2012: Mr. Halliday spoke with a Tribal staff member who informed John that the Tribe was closed for the day and he should call back the next day. January 26, 2012: Mr. Chavarria returned Mr. Halliday's phone call. He informed Mr. Halliday that the Tribe does not wish to participate, but would like to remain on the mailing list.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Pueblo of Tesuque	January 23, 2012: John Halliday, DOI, called and spoke with Governor Mark Mitchell regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. February 6, 2012: Mr. Halliday left a message for Governor Mitchell regarding the Pueblo's participation in the LTEMP process. February 14, 2012: Mr. Halliday left a message for Governor Mitchell regarding the Pueblo's participation in the LTEMP process.	January 23, 2012: Governor Mitchell informed Mr. Halliday that he would ask the council and get back to him.
Pueblo of Zia	January 23, 2012: John Halliday, DOI, called and left a message for Peter Pino regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday called and left a message for Peter regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 27, 2012: Mr. Halliday called and left a message for Mr. Pino regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. February 6, 2012: Mr. Halliday called and left a message for Mr. Pino regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. February 14, 2012: Mr. Halliday called and left a message for Mr. Pino regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. May 3, 2012: Mary Barger spoke with the Pueblo of Zia. They will get back to her on a date for a meeting. May 14, 2012: Ms. Barger spoke with Tribal Administrator Peter Pino and a meeting was scheduled for May 23.	February 29, 2012: Mr. Pino called Mr. Halliday. He said that the Pueblo of Zia would like LTEMP Representatives to come out to the Pueblo and make a presentation on this subject. February 18, 2014: Delivery Confirmation of February 13 letter signed by Tammy L. Pino.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Pueblo of Zia (Cont.)	April 8, 2013: Sarah Rinkevich, Tribal Liaison, left a message for Peter regarding the Tribe's participation in LTEMP. February 11, 2014: Bruce Verhaaren, Argonne, sent an e-mail to Governor David Pino regarding the Pueblo of Zia participation in the LTEMP process. The letter indicated that despite many attempts, Argonne and the joint-leads have not received a response from the Pueblo of Zia since January 2013 and advised that they would be moved to the mailing list unless otherwise instructed by February 28, 2014. February 13, 2014: Argonne sent a hardcopy of the above-referenced letter to Governor Pino.	
Pueblo of Zuni	November 10, 2011: Janet Cohen, NPS, presented information about the LTEMP to Kurt Dongoske and members of the Zuni Cultural Resources Advisory Team (ZCRAT). December 13, 2011: Ms. Heffernan met with the Zuni about another matter, but was advised by Mr. Dongoske that the Pueblo of Zuni will be a cooperating agency. January 9, 2012: Ms. Cohen confirmed the receipt of the Zuni's request to be a Cooperating Agency with Kurt Dongoske. August/September 2012: MOU signed by joint-leads. April 17, 2014: Bruce Verhaaren, Argonne, informed Mr. Dongoske that a draft copy of Chapter 3 should be available for Tribal review the week of April 21. April 30, 2014: Mr. Verhaaren informed Mr. Dongoske that Chapter 3 is still undergoing review by the joint-leads and he is not sure when the Tribes will be able to view it. May 5, 2014: Verhaaren informed Mr. Dongoske that text submitted by the Pueblo of Zuni was incorporated into the various technical areas of Chapter 3 and that the chapter will be ready for review upon approval of project management.	November 4, 2011: Mr. Dongoske called Beverly Heffernan, Reclamation, with some questions on the general LTEMP process. He asked why there was no public meeting in New Mexico and asked that Ms. Cohen provide info about the project. He indicated that Zuni would want a presentation sooner rather than later by John Wessels, NPS, and Larry Walkoviak, Reclamation. December 22, 2011: Governor Arlen Quetawki, Sr., sent a letter indicating that the Zuni would like to be a cooperating agency on the LTEMP. Mr. Quetawki advised that Mr. Dongoske is the primary representative of the Zuni for the LTEMP. The Cooperating Agency form was signed and enclosed. July 26, 2012: MOU signed. March 25, 2014: Mr. Dongoske requested a copy of Chapter 3 so that the ZCRAT could review how the Zuni information had been included. February 7, 2015: Pueblo of Zuni submitted comments on preliminary Chapters 1 and 2. June 24, 2015: Pueblo of Zuni submitted comments on preliminary Chapter 3.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Pueblo of Zuni (Cont.)	December 17, 2014: Preliminary Chapters 1 and 2 sent to Pueblo of Zuni for review. April 15, 2015: Preliminary Chapter 3 sent to Pueblo of Zuni for review. July 1, 2015: LTEMP DEIS sent to Pueblo of Zuni for review.	September 29, 2015: Pueblo of Zuni submitted comments on LTEMP DEIS.
Salt River Pima-Maricopa Indian Community	February 2012: Steve Daron, LMNRA, called the Salt River Maricopa Indian Community three times, but there was no response. May 14, 2012: Mr. Daron left a few messages with Shane Antone in the Cultural Resource Department but there was no response.	No response.
San Carlos Apache Tribe	January 24, 2012: John Halliday, DOI, called the Tribal Administration staff regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. Mr. Halliday informed Reclamation about the name and address change of the Tribe. January 26, 2012: A copy of the November 2011 letter was sent to the new address. January 30, 2012: A copy of the November 2011 letter was sent via e-mail. February 14, 2012: Mr. Halliday called Chairman Terry Rambler regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. As requested, Mr. Halliday sent an e-mail to Chairman Rambler with the LTEMP letter attached.	January 24, 2014: A staff person informed Mr. Halliday that a new letter should be sent to the correct name and address. February 14, 2012: Chairman Rambler requested that Mr. Halliday re-send the LTEMP letter via e-mail and he would get back to Mr. Halliday. No further response.
Southern Ute Tribal Council	January 23, 2012: John Halliday, DOI, called and left a message for Native American Graves Protection and Repatriation Act (NAGPRA) Coordinator Neil Cloud regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday called and left a message for Mr. Cloud regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	January 27, 2012: Mr. Naranjo informed Mr. Halliday that the Southern Ute Tribal Council did not wish to participate in the LTEMP process.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Southern Ute Tribal Council (Cont.)	January 27, 2012: Mr. Halliday called and was referred to Mr. Alden Naranjo who was serving as the Acting Tribal NAGPRA representative. Mr. Halliday spoke to Mr. Naranjo regarding the LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	
Tohono O'odham Nation	January 24, 2012: John Halliday, DOI, called and left a message for Dr. Ned Norris, Jr., regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday left another message for Dr. Norris regarding the Tribe's participation in the LTEMP process. January 27, 2012: Mr. Halliday left another message for Dr. Norris regarding the Tribe's participation in the LTEMP process. February 06, 2012: Mr. Halliday left another message for Dr. Norris regarding the Tribe's participation in the LTEMP process.	May 03, 2014: Mary Barger, Reclamation, received an e-mail from Peter Steere, THPO, indicating that the Tribe does not wish to participate in the LTEMP process.
Tonto Apache Tribe	January 24, 2012: John Halliday, DOI, called and left a message for Chairman Ivan Smith regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday called and left a message for Chairman Smith regarding the Tribe's participation in the LTEMP process. January 27, 2012: Mr. Halliday called and left a message for Chairman Smith regarding the Tribe's participation in the LTEMP process. February 06, 2012: Mr. Halliday called and left a message for Chairman Smith regarding the Tribe's participation in the LTEMP process.	No response

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Ute Indian Tribe	January 23, 2012: John Halliday, DOI, called and left a message for Betsy Chapoose in the Cultural Rights and Protection Office regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday called and left a message for Ms. Chapoose, regarding the Tribe's participation in the LTEMP process. January 27, 2012: Mr. Halliday called and left a message for Ms. Chapoose, regarding the Tribe's participation in the LTEMP process.	February 1, 2012: Ms. Chapoose returned Mr. Halliday's phone call and informed him that the Tribe did not wish to participate in the LTEMP process, but would like to remain on the mailing list.
Ute Mountain Ute Tribe	February 29, 2012: Rosemary Sucec, Glen Canyon National Recreation Area (GCNRA), called and spoke with Lynn Hartman regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	February 29, 2012: Ms. Hartmann indicated that the Tribe did not wish to participate in the LTEMP process, but would like to remain on the mailing list.
White Mountain Apache	January 23, 2012: John Halliday, DOI, called and left a message for Chairman Ronny Lupe regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process. January 26, 2012: Mr. Halliday called and spoke with Chairman Lupe regarding the Tribe's participation in the LTEMP process. May 3, 2012: Mary Barger, Reclamation, spoke with Mark Altaha, THPO, about a consultation meeting. She also sent a follow-up e-mail to Mr. Altaha with the November 2011 LTEMP letter and requested Mr. Altaha let her know what kind of follow-up would be needed.	January 26, 2012: Mr. Lupe requested that LTEMP representatives meet with the Tribe to talk about the project and asked Mr. Halliday to coordinate the meeting with the Tribal Hydrologist, Cheryl Pailzot. May 3, 2012: Mr. Altaha informed Mary that it was not clear why the Chairman told Mr. Halliday that he wanted a meeting since the project was so far away. Mr. Altaha indicated he would look into the matter and get back to Ms. Barger. May 12, 2012: Mr. Altaha responded to Ms. Barger's e-mail and indicated he would forward her request to Ms. Pailzot as she was scheduled to meet with Chairman Lupe regarding the project. May 15, 2012: Ms. Pailzot e-mailed Ms. Barger and informed her she will recommend to Chairman Lupe that the White Mountain Apache do not need to be cooperators on the EIS.

TABLE N-2 (Cont.)

Tribe	Additional Joint Lead/Argonne Follow-up	Tribal Comment/Responses
Yavapai-Apache Nation	May 15, 2012: Jan Balsom, GCNP, called Christopher Coder regarding the Yavapai-Apache Nation's interest in a meeting to discuss the LTEMP process. September 27, 2012: Bruce Verhaaren, Argonne, sent Christopher an e-mail asking him to confirm that the Yavapai-Apache Nation no longer wished to function as a cooperating agency due to the changing circumstances and only a peripheral interest, as stated in an earlier conversation. October 10, 2012: Mr. Verhaaren sent a follow-up e-mail to Christopher Coder asking him to confirm that the Tribe no longer wishes to act as a cooperating agency for LTEMP. October 23, 2012: Mr. Verhaaren sent a follow-up e-mail to Christopher Coder asking him to confirm that the Tribes no longer wishes to act as a cooperating agency for LTEMP.	January 9-2012: Mr. Coder, Tribal Archaeologist, returned the Cooperating Agency form indicating that the Yavapai-Apache would like to be a Cooperating Agency. May 15, 2012: Mr. Coder returned Ms. Balsom's call and left a voicemail indicating that the Yavapai-Apache Nation would like to see the final set of alternatives before determining if they would like to have a meeting. October 10, 2012: Mr. Coder responded to Mr. Verhaaren's e-mail and indicated that he will confirm the position of the Yavapai-Apache Nation in regard to LTEMP participation at their next meeting and get back Mr. Verhaaren. October 24, 2012: Mr. Coder sent Mr. Verhaaren an e-mail confirming that the Tribe did not wish to participate as a Cooperating Agency anymore.
Yavapai-Prescott Indian Tribe	February 1, 2012: Steve Daron, LMNRA, called the Tribe and was directed to Greg Glassco. Mr. Daron left a message for Greg regarding the November 2011 LTEMP letter asking if the Tribe wished to participate in the LTEMP process.	February 1, 2012: Greg Glassco sent an e-mail to Mr. Daron indicating that the Tribe does not need to be consulted for LTEMP.

everyone. Every effort was made to hold a meeting when everyone was available; however, due to schedule conflicts there were instances when individuals could not attend and make-up meetings were held for these individuals. Tribes were sent an e-mail invitation prior to each meeting, as well as a meeting reminder with an agenda, call-in number, password, and any pertinent materials needed for review before the meeting. Meeting notes and presentations were distributed shortly after the meetings when requested. Meeting notes and other important documents related to the LTEMP EIS development process were also sent to those Tribes who wished to remain on the mailing list. Reclamation and NPS will continue to provide consultation opportunities for interested Tribes and keep all Tribal entities informed about the NEPA process for the EIS. A list of major face-to-face meetings, webinars, and conference calls involving Tribes is provided in Table N-3.

To date, the joint-leads have held individual Tribal consultation meetings with the Fort Mojave Indian Tribe, the Fort Yuma Quechan, the Havasupai Tribe, the Hualapai Tribe, the Hopi Tribe, the Kaibab Paiute Indian Tribe, the Navajo Nation, the Pueblo of Zia, and the Pueblo of Zuni. During these meetings, the background and overview of LTEMP process and was discussed as well as specific Tribal concerns related to the LTEMP EIS. A summary of these meetings is provided in Table N-4.

Throughout the early stages of EIS development, many Tribes indicated the need for monetary assistance to be able to fully contribute Tribal knowledge to the EIS. The joint-leads recognized that in some cases it was appropriate to pay a fee for professional services to address the travel costs of Tribal representatives who possess special cultural knowledge or may experience a potential loss of income by being away from their regular jobs to attend a consultation meeting. At the March 14, 2013, Tribal Workshop, the joint-leads requested from the Tribes funding proposals detailing the cost of travel and compensation of Tribal Representatives for their participation in the LTEMP. The joint-leads agreed to fund—to the extent possible—reimbursement of Tribal representatives (elders, or experts not already being paid salaries by the Tribe) to participate LTEMP meetings by invitation and agreement in advance and the cost of deliverables for editing/preparing specific information such as the Affected Environment section of the EIS or requested data or reports regarding affected sites, if those materials are not already publically available. Tasks not funded included review of EIS chapters or drafts and fees for Tribal representatives (such as THPOs) who are being paid by the Tribes to participate in the cooperating agency meetings. Tribes submitted proposals and were funded as appropriate.

Throughout the course of developing the EIS, Cooperating Agency Tribes were asked to review and provide comments on the *Tribal Consultation Plan for the Glen Canyon Dam Long-Term Experimental and Management Plan Environmental Impact Statement, Draft Performance Criteria and Draft Objectives for the Glen Canyon Dam Long-Term Experimental and Management Plan, and the Preliminary Draft Alternatives*. Tribes submitted comments and suggestions and the joint-leads incorporated them as appropriate. Cooperating Agency Tribes were also afforded the opportunity for preliminary review of select chapters of the preliminary DEIS prior to distribution to other Cooperating Agencies. They were also sent revised copies of the DEIS when it was distributed to Cooperating Agencies. The joint-lead agencies also sent responses to the Tribes who submitted comments.

TABLE N-3 Summary of Major Face-to-Face Meetings, Webinars, and Conference Calls Involving Tribes

Date	Meeting	Meeting Type	Location
February 11, 2011	LTEMP EIS Kickoff Meeting	Face-to-Face	Tempe, AZ
February 24, 2011	First Cooperating Agency Meeting	Face-to-Face	Tempe, AZ
April 4–5, 2012	Public Meeting to Discuss Alternatives Development	Face-to-Face	Flagstaff, AZ
August 10, 2012	Meeting with Consulting and Cooperating Tribes	Face-to-Face	Tempe, AZ
January 25, 2013	Tribal Workshop	Face-to-Face	Phoenix, AZ
March 14, 2013	Tribal Participation Workshop	Face-to-Face	Flagstaff, AZ
April 12, 2013	Tribal Representatives Meeting	Conference Call	
April 24, 2013	Tribal Consultation Meeting	Conference Call	
July 11, 2013	Tribal Values Webinar	Webinar	
July 25, 2013	Tribal Values Webinar (make-up)	Webinar	
August 1, 2013	Stakeholder Webinar—Preparation for the August 5 Stakeholder Workshop	Webinar	
August 5, 2013	Stakeholder Workshop—Structured Decision Analysis	Face-to-Face	Flagstaff, AZ
August 21, 2013	Stakeholder Workshop—Follow-up with Tribes	Conference Call	
November 5, 2013	Tribal Values Workshop	Face-to-Face	Flagstaff, AZ
November 19, 2013	Stakeholder Webinar—Alternatives, Performance Metrics, and Modeling	Webinar	
December 3, 2013	Stakeholder Webinar—Socioeconomics	Webinar	
March 18, 2014	Stakeholder Webinar—Swing Weighting	Webinar	
March 31–April 1, 2014	Stakeholder Workshop—Modeling Results, Structured Decision Analysis, and Swing-weighting Exercise	Face-to-Face	Phoenix, AZ
June 23, 2014	Meeting—Discussion of LTEMP EIS hybrid alternative components	Conference Call	
August 12, 2014	Meeting—Update on the LTEMP EIS	Conference Call	
October 6, 2014	Meeting—Discussion of Tribal input to LTEMP EIS	Conference Call	
October 16, 2014	Meeting—Discussion of the LTEMP Programmatic Agreement	Conference Call	
January 23, 2015	Meeting to discuss Tribal Input on Chapters 1 and 2	Conference Call	
March 27, 2015	Technical Webinar on LTEMP Power Systems and Rate Payer Analyses	Webinar	

TABLE N-4 Summary of Individual Tribal Consultation Meetings to Date

Tribe	Date	Attendees	Location
Fort Mojave Indian Tribe	May 4, 2012	Reclamation, NPS, Representatives of the Fort Mojave Indian Tribe	Needles, CA
Fort Yuma Quechan	June 22, 2012	Reclamation, NPS, Representatives of the Fort Yuma Quechan	Near Yuma, AZ
The Havasupai Tribe	November 8, 2013	Reclamation, NPS, DOI Tribal Liaison, Havasupai Tribal Council	Supai Village, AZ
The Hualapai Tribe	March 5, 2012	Reclamation, Hualapai Tribal Council	Peach Springs, AZ
	May 3, 2013	DOI, Argonne, Hualapai Tribal Council	Peach Springs, AZ
	July 30, 2014	Reclamation, NPS, GCMRC, DOI, Hualapai Tribal Council	Peach Springs, AZ
The Hopi Tribe	May 16, 2013	DOI, Argonne, Hopi Cultural Resources Advisory Team	Kykotsmovi Village, AZ
Kaibab Paiute Indian Tribe	April 19, 2012	Reclamation, NPS, Kaibab Paiute Indian Tribe Tribal Council	Fredonia, AZ
	July 22, 2013	DOI, Representatives of the Southern Paiute Consortium	Pipe Springs, AZ
	October 22, 2013	DOI, Director of the Southern Paiute Consortium, University of Arizona's Anthropology Department	Tucson, AZ
Navajo Nation	April 17, 2013	DOI, Representatives from the Navajo Nation	Conference Call
	April 10, 2014	Reclamation, NPS, DOI, Representatives of the Navajo Nation	Flagstaff, AZ
	November 4, 2015	Reclamation, NPS, DOI, Representatives of the Navajo Nation	Window Rock, AZ
Pueblo of Zia	May 23, 2012	Reclamation, NPS, Representatives from the Pueblo of Zia	Zia Pueblo, NM
Pueblo of Zuni	June 12, 2012	Reclamation, NPS, Pueblo of Zuni Tribal Council	Zuni Pueblo, NM
	May 17, 2013	DOI, Zuni Cultural Resources Advisory Team (ZCRAT)	Zuni Pueblo, NM
	October 25, 2013	NPS, DOI, Kurt Dongoske	Conference Call
	October 10, 2014	NPS, DOI, Pueblo of Zuni ZCRAT	Zuni Pueblo, NM
	August 18, 2015	DOI, NPS, FWS, Pueblo of Zuni ZCRAT	Zuni Pueblo, NM

At the start of the LTEMP, a document entitled *American Indian Perspectives and Values Related to the Glen Canyon Dam Long-term Experimental and Management Plan Environmental Impact Statement* was developed for inclusion as a chapter in the LTEMP EIS and distributed to the Cooperating and Consulting Tribes for review. After considering a number of comments received on the document and expressed at Tribal meetings, it was determined that Tribal concerns would best be incorporated throughout the EIS and would not be limited to one section. Instead, a Tribal Resources section (Section 3.9) was added to Chapter 3 (Affected Environment) and Tribal views and concerns were expressed here and incorporated into various resource areas throughout the chapter. Tribes were invited to contribute their own text to Chapter 3 and the Tribal Lands section (Section 1.5.2.3) of Chapter 1. For those Tribes who did not wish to write or did not have the resources to write the section themselves, Argonne National Laboratory (Argonne) provided text that was reviewed by a Tribal representative. To best incorporate Tribal views and concerns, Argonne reviewed meeting notes, ethnographic reports published for the 1995 LTEP EIS, and monitoring reports prepared for Tribal monitoring programs in the Canyon. Argonne requested additional relevant sources from Tribes that would be useful in the preparation of the chapter and information from these sources was incorporated into the EIS. Argonne communicated with Tribes through e-mail and phone during the preparation of Chapter 3 in order to ensure that Tribal views and concerns were being presented correctly.

On April 2, 2014, after a stakeholder workshop presenting modeling results and explaining SDA, Mike Runge (DOI), sent the LTEMP swing-weighting exercise and a summary consequence table to Stakeholders, including Tribes, to complete and be used as input to be considered in the EIS. A follow-up webinar where Stakeholders could ask questions regarding swing-weighting was held on April 4, 2014, but there were no Tribal representatives in attendance. Participation in the swing-weighting exercise was voluntary and some Tribes chose not to participate. Others returned their results and the results were incorporated into the EIS.

Chapters 1 and 2 of the preliminary LTEMP DEIS were sent to Tribes for review in December 2014. Chapter 3 of the LTEMP DEIS was sent to Tribes in for review in April 2015. A full copy of the LTEMP DEIS was sent to all Cooperating Agencies, including Tribes, in June 2015. Tribes were encouraged to provide comments during all three comment periods. Comments were received from the Havasupai Tribe, Hopi Tribe, Hualapai Tribe, Kaibab Band of Paiute Indians, Navajo Nation, and Pueblo of Zuni.

A listing of individual Tribal consultation meetings is provided in Table N-4, and an index of Tribal government consultation and coordination is provided in Table N-5. Table N-5 includes a page number reference to copies of correspondence that are located in Attachment 2.

N.2 CONSULTATION WITH THE STATE HISTORIC PRESERVATION OFFICE (SHPO)

This section presents the interactions that occurred as part of the NHPA Section 106 review for the LTEMP EIS. A brief overview of the consultation process with State Historic Preservation Officers (SHPOs) is provided below.

TABLE N-5 Index of Project Tribal Government Consultation and Coordination Correspondence

Date	Originating Agency/ Tribal Government	Recipient Organization	Page[a]
Multiple Tribes			
November 30, 2011	NPS, Reclamation	Various Tribes	N-74
December 8, 2011	NPS, Reclamation	Various Tribes	N-79
Ak-Chin Indian Community			
July 31, 2012	Louis Manuel Jr., Chairman, Ak-Chin Indian Community	John Wessels, Regional Director, NPS	N-83
Gila River Indian Community			
January 3, 2012	Barnaby Lewis, THPO, Gila River Indian Community	John Wessels, Regional Director, NPS	N-84
Havasupai Tribe			
February 27, 2012	Havasupai Tribe	NPS/Reclamation	N-85
June 21, 2012	Don Watahomigie, Chairman Havasupai Tribe	Kirk LaGory, Argonne	N-86
August 9, 2012	Adrianne Carr, Argonne; NPS; Reclamation	Don Watahomigie, Chairman Havasupai Tribe	N-88
August 29, 2012	Margaret Vick, Attorney for Havasupai	Kirk LaGory, Argonne	N-90
August 30, 2012	Kirk LaGory, Argonne	Margaret Vick, Attorney for Havasupai	N-95
Hopi Tribe			
August 27, 2013	Mike Yeatts, Hopi Cultural Preservation Office (HCPO)	Kirk LaGory, Argonne; NPS; Reclamation	N-96
Hualapai Tribe			
January 6, 2012	Hualapai Tribe	NPS/Reclamation	N-99
June 28, 2012	Peter Bungart, Hualapai Dept. of Cultural Resources	Kirk LaGory, Argonne	N-100
August 9, 2012	Adrianne Carr, Argonne on behalf of NPS/Reclamation	Loretta Jackson-Kelly, Director, Dept. of Hualapai Cultural Resources and Peter Bungart, Hualapai Dept. of Cultural Resources	N-103
Navajo Nation			
February 28, 2011	Tony Joe, Jr., Historic Preservation Department, Navajo Nation	NPS/Reclamation	N-106
January 9, 2012	Navajo Nation	NPS/Reclamation	N-108
July 17, 2012	Adrianne Carr, Argonne on behalf of NPS/Reclamation	Jason John, Navajo Department of Water and Power and Alan Downer, THPO	N-109
August 28, 2013	Tony Joe, Jr., Historic Preservation Department, Navajo Nation	Kirk LaGory, Argonne	N-111
February 11, 2014	Bruce Verhaaren, Argonne on behalf of NPS/Reclamation	Jason John, Navajo Department of Water and Power and Tony Joe, Jr., Historic Preservation Department, Navajo Nation	N-114

TABLE N-5 (Cont.)

Date	Originating Agency/ Tribal Government	Recipient Organization	Page
February 21, 2014	Delores Martinez and Laurinda M., Navajo Nation	Bruce Verhaaren, Argonne	N-117
	Jason John, Navajo Department of Water and Power and Ben Shelly, President Navajo Nation	Glen Knowles, Reclamation; Rob Billerbeck, NPS; and Bruce Verhaaren, Argonne	N-118
February 28, 2014	Rob Billerbeck, NPS	Jason John, Navajo Department of Water and Power	N-120
March 17, 2014	Rob Billerbeck, NPS	Jason John, Navajo Department of Water and Power	N-121
June 2, 2014	Rob Billerbeck, NPS and Glen Knowles, Reclamation	Walter Phelps, Council Delegate, Navajo Nation	N-125
June 3, 2014	Walter Phelps, Council Delegate, Navajo Nation	Rob Billerbeck, NPS and Glen Knowles, Reclamation	N-125
Paiute Indian Tribe of Utah			
January 9, 2012	Paiute Indian Tribe of Utah	NPS/Reclamation	N-126
Pueblo of Zuni			
December 22, 2011	Arlen Quetawki, Sr., Governor, Pueblo of Zuni	Larry Walkoviak, Regional Director, Reclamation and John Wessels, Regional Director NPS	N-127
White Mountain Apache			
May 15, 2012	Cheryl Pailzote, Water Resources Director, White Mountain Apache Tribe	Mary Barger, Reclamation	N-129
Yavapai-Apache Nation			
January 9, 2012	Yavapai-Apache Nation	NPS/Reclamation	N-130
October 10, 2012	Bruce Verhaaren, Argonne	Chris Coder, Tribal Archaeologist, Yavapai-Apache Nation	N-131
	Chris Coder, Tribal Archaeologist, Yavapai-Apache Nation	Bruce Verhaaren and Adrianne Carr, Argonne	N-132
October 23, 2012	Bruce Verhaaren, Argonne	Chris Coder, Tribal Archaeologist, Yavapai-Apache Nation	N-133
October 24, 2012	Chris Coder, Tribal Archaeologist, Yavapai-Apache Nation	Bruce Verhaaren, Argonne	N-134

[a] Page number in Appendix N, Attachment 2.

On June 12, 2014, the joint-leads sent a letter to the Arizona State SHPO notifying him of the intent to complete the LTEMP EIS. The letter provided a review of the LTEMP to date with a draft description of the proposed Area of Potential Effect. The letter also indicated the desire to consult with the SHPO pursuant to Section 106 of the NHPA. A copy of this letter was also sent to the Advisory Council on Historic Preservation and all Cooperating Agencies. The SHPOs office responded on July 18, 2014, indicating they look forward to working with the joint-leads on the Programmatic Agreement. A copy of these letters is provided in Attachment 3.

N.3 REFERENCE

Reclamation (Bureau of Reclamation), 1995, *Operation of Glen Canyon Dam: Colorado River Storage Project, Arizona, Final Environmental Impact Statement*, U.S. Department of the Interior, Bureau of Reclamation, Salt lake City, Utah, March. Available at http://www.usbr.gov/uc/library/envdocs/eis/gc/gcdOpsFEIS.html. Accessed February 19, 2015.

ATTACHMENT N.1

(a) Havasupai Tribe

Memorandum of Understanding
Between
the Bureau of Reclamation and the National Park Service
and
the Havasupai Tribe
for the Environmental Impact Statement for Adoption of a Long Term Experimental and Management Plan for the Operation of Glen Canyon Dam

I. Introduction and Purpose

Pursuant to the National Environmental Policy Act (NEPA), the Department of the Interior (Department), through the Bureau of Reclamation (Reclamation) and the National Park Service (NPS), is preparing an environmental impact statement (EIS) for a Long Term Experimental and Management Plan (LTEMP) for the operation of Glen Canyon Dam. Reclamation and the NPS are the joint lead or "joint-lead agencies" for the completion of this EIS. The Havasupai Tribe hereafter "the cooperating agency", in addition to other parties, has agreed to serve as a cooperating agency for the completion of the LTEMP EIS. The purpose of this Memorandum of Understanding (MOU) is to outline the roles and responsibilities of the joint-lead and the cooperating agency (hereinafter collectively referred to alternatively as "agencies" or "parties") in accordance with 43 CFR § 46.225(d).

II. Background

The LTEMP process is intended to develop and implement a structured, long term experimental and management plan, to determine the need for potential future modifications to Glen Canyon Dam operations, and to determine whether to establish an Endangered Species Act (ESA) Recovery Implementation Program for endangered fish species below Glen Canyon Dam. Revised dam operations and other actions under the jurisdiction of the Secretary of the Interior will be considered within alternatives of the EIS, in keeping with the scope of the Grand Canyon Protection Act (GCPA). The NEPA process will document and evaluate impacts of the alternatives described in the EIS.

III. Purpose of this MOU

This MOU defines the relationship and duties of the joint-lead and the cooperating agency in completing NEPA compliance for the LTEMP, and how the parties will cooperate during the NEPA process.

By signing this MOU, the parties agree that this MOU provides the framework to fulfill compliance requirements for NEPA.

IV. Agency Designee

The cooperating agency will designate a primary point of contact (and alternate if desired) for the EIS by sending correspondence at the time of signing of this agreement to the joint-lead agencies with the contacts name and information. The cooperating agency may change its point

of contact at any time by providing written notice to the joint-lead agencies and the other cooperating agencies.

V. Authority

The authority of the joint-lead and the cooperating agency to participate in this agreement is provided by the National Environmental Policy Act, 42 U.S.C. §§ 4321 *et seq.* NEPA allows agencies to be designated as a cooperating agency when that agency has jurisdiction by law or special expertise (40 CFR § 1501.6 and 40 CFR§ 1508.5). Activities contemplated under this MOU are specifically authorized under:

A. Title I of NEPA;

B. "Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act," 40 CFR §§ 1500-1508, Council on Environmental Quality (in particular 40 CFR § 1501.6, Cooperating Agencies);

C. Department of the Interior NEPA Implementing Procedures in the Departmental Manual at 43 CFR § Part 46, Cooperating Agencies (40 CFR §1501.6).

VI. Joint-lead Agency Responsibilities

Reclamation and the NPS will be joint-leads for this effort because Reclamation has primary responsibility for operation of Glen Canyon Dam and the NPS has primary responsibility for managing Grand Canyon National Park, Glen Canyon National Recreation Area, and Lake Mead National Recreation Area.

The NPS and Reclamation, as joint-leads for the completion of the LTEMP EIS, shall:

A. Jointly be responsible for the preparation, quality, content and overall direction of the EIS and for ensuring the appropriate participation of cooperating agencies in developing the EIS.

B. Jointly be responsible for identifying the purpose and need for the project, scope of analysis, and decisions to be made. In coordination with the Department, the joint-lead agencies will make the final decision on the content of all EIS-related documents, including the preferred alternative and the Record of Decision to be signed by the Secretary of the Interior.

C. Jointly oversee the execution and administration of contracts or cooperative agreements with mutually agreed upon federal, state or local agencies, or tribal governments or mutually agreed upon private contractors to develop information for inclusion in the EIS.

D. Jointly conduct cooperating agency meetings, and provide advance information for discussions at these meetings, as necessary during the preparation of the EIS. Meeting dates and locations will be jointly agreed upon and may be chosen to coincide with the

dates of Adaptive Management Working Group meetings to minimize travel costs and maximize collaboration.

E. Ensure that cooperating agency proposals and substantive comments (including divergent views) within their jurisdiction or technical expertise are appropriately documented and considered in the EIS.

F. Provide advance copies (normally 30 days) of the preliminary draft and preliminary final EIS and related compliance documents for review by cooperating agencies.

VII. Cooperating Agency Responsibilities

Federal, state, and local agencies, and tribal governments with appropriate expertise or jurisdiction have been invited to participate as cooperating agencies. Reclamation and NPS may, at any time during the course of the EIS project, invite additional agencies to participate in the process.

The cooperating agency, subject to sufficient appropriations to carry out the following responsibilities, shall:

A. Participate in the NEPA process at the earliest possible time.

B. Participate in the scoping process.

C. Assume, on request of the lead agencies, responsibility for developing information and preparing environmental analyses including portions of the environmental impact statement concerning which the cooperating agency has special expertise.

D. Make available staff support at the lead agencies' request to enhance the latter's interdisciplinary capability.

E. Normally use their own funds.

F. The cooperating agency may in response to a lead agencies' request for assistance in preparing the environmental impact statement reply that other program commitments preclude any involvement or the degree of involvement requested in the action that is the subject of the environmental impact statement.

G. Provide comments in a timely manner (normally within 30 days of receipt) of draft documents when requested. One consolidated set of comments for the cooperating agency will be provided in the format specified by the joint-lead agencies.

H. As appropriate and practicable, attend cooperating agency meetings and public meetings and hearings on the EIS process.

I. Retain the right to comment on all issues related to the EIS through the normal EIS public review and comment process.

expand, or substitute for those provisions or regulations. This MOU does not impose legally-binding requirements on the Parties, nor does it create a legal right of action for the Parties or any third party.

J. **AGENCY AND PARTNERSHIP.** Unless expressly provided by law, personnel or volunteers of one party shall not be considered to be agents, partners or employees of the other party for any purpose, and no joint venture or principal-agent relationship shall be deemed to exist. The personnel and volunteers of one party are not entitled to any of the benefits that any other party provides for its employees or volunteers.

K. **LIABILITY.** To the extent authorized by law, on behalf of itself, its officers, directors, members, employees, agents, and representatives, each party agrees that it will be responsible for its own acts and omissions and the results thereof and that it shall not be responsible for the acts or omissions of other parties, nor the results thereof. To the extent authorized by law, each party therefore agrees that it will assume the risk and liability to itself, its agents, employees, and volunteers for any injury to or death of persons or loss or destruction of property resulting in any manner from the conduct of the party's own operations and/or the operations of its agents, employees, and/or volunteers under this MOU. To the extent authorized by law, each party further releases and waives all claims against the other party for compensation for any loss, cost, damage, expense, personal injury, death, claim, or other liability arising out of the performance of this MOU.

L. **NONDISCRIMINATION.** This MOU is subject to all Federal statutes relating to nondiscrimination. These include, but are not limited to: (a) Title VI of the Civil Rights Act of 1964 (P.L. 88-352); and (b) Title IX of the Education Amendments of 1972 (20 U.S.C. 1681-1683 and 1685-1686).

XI. Effective Dates, Amendment and Termination

A. This MOU will become effective on the date of the last signature and may be subsequently amended through written agreement of all signatories. The joint-lead agencies or the cooperating agency may terminate their cooperative status by providing 30 days written notice of termination to the other party. Otherwise, the cooperative status will terminate when a Record of Decision is issued or the EIS is terminated.

XII. Signatures

The parties hereto have executed this Memorandum of Understanding as of the dates shown below.

BUREAU OF RECLAMATION

Date July 9, 2012

Larry Walkoviak
Regional Director
Upper Colorado Region
Bureau of Reclamation

NATIONAL PARK SERVICE

Date 7/11/2012

Herbert C. Frost
Associate Director for Natural Resources, Stewardship and Science
National Park Service

for

Date 7/20/12

John Wessels
Regional Director
Intermountain Region
National Park Service

Date 7/25/12

Christine Lehnertz
Regional Director
Pacific West Region
National Park Service

THE HAVASUPAI TRIBE

Date 7-6-12

Don E. Watahomigie, Chairman

(b) Hopi Tribe

Memorandum of Understanding
Between
the Bureau of Reclamation and the National Park Service
and
the Hopi Tribe
for the Environmental Impact Statement for Adoption of a Long Term Experimental and Management Plan for the Operation of Glen Canyon Dam

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of contact at any time by providing written notice to the joint-lead agencies and the other cooperating agencies.

V. Authority

The authority of the joint-lead and the cooperating agency to participate in this agreement is provided by the National Environmental Policy Act, 42 U.S.C. §§ 4321 *et seq.* NEPA allows agencies to be designated as a cooperating agency when that agency has jurisdiction by law or special expertise (40 CFR § 1501.6 and 40 CFR§ 1508.5). Activities contemplated under this MOU are specifically authorized under:

A. Title I of NEPA;

B. "Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act," 40 CFR §§ 1500-1508, Council on Environmental Quality (in particular 40 CFR § 1501.6, Cooperating Agencies);

C. Department of the Interior NEPA Implementing Procedures in the Departmental Manual at 43 CFR § Part 46, Cooperating Agencies (40 CFR §1501.6).

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Reclamation and the NPS will be joint-leads for this effort because Reclamation has primary responsibility for operation of Glen Canyon Dam and the NPS has primary responsibility for managing Grand Canyon National Park, Glen Canyon National Recreation Area, and Lake Mead National Recreation Area.

The NPS and Reclamation, as joint-leads for the completion of the LTEMP EIS, shall:

A. Jointly be responsible for the preparation, quality, content and overall direction of the EIS and for ensuring the appropriate participation of cooperating agencies in developing the EIS.

B. Jointly be responsible for identifying the purpose and need for the project, scope of analysis, and decisions to be made. In coordination with the Department, the joint-lead agencies will make the final decision on the content of all EIS-related documents, including the preferred alternative and the Record of Decision to be signed by the Secretary of the Interior.

C. Jointly oversee the execution and administration of contracts or cooperative agreements with mutually agreed upon federal, state or local agencies, or tribal governments or mutually agreed upon private contractors to develop information for inclusion in the EIS.

D. Jointly conduct cooperating agency meetings, and provide advance information for discussions at these meetings, as necessary during the preparation of the EIS. Meeting dates and locations will be jointly agreed upon and may be chosen to coincide with the

dates of Adaptive Management Working Group meetings to minimize travel costs and maximize collaboration.

E. Ensure that cooperating agency proposals and substantive comments (including divergent views) within their jurisdiction or technical expertise are appropriately documented and considered in the EIS.

F. Provide advance copies (normally 30 days) of the preliminary draft and preliminary final EIS and related compliance documents for review by cooperating agencies.

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Federal, state, and local agencies, and tribal governments with appropriate expertise or jurisdiction have been invited to participate as cooperating agencies. Reclamation and NPS may, at any time during the course of the EIS project, invite additional agencies to participate in the process.

The cooperating agency, subject to sufficient appropriations to carry out the following responsibilities, shall:

A. Participate in the NEPA process at the earliest possible time.

B. Participate in the scoping process.

C. Assume, on request of the lead agencies, responsibility for developing information and preparing environmental analyses including portions of the environmental impact statement concerning which the cooperating agency has special expertise.

D. Make available staff support at the lead agencies' request to enhance the latter's interdisciplinary capability.

E. Normally use their own funds.

F. The cooperating agency may in response to a lead agencies' request for assistance in preparing the environmental impact statement reply that other program commitments preclude any involvement or the degree of involvement requested in the action that is the subject of the environmental impact statement.

G. Provide comments in a timely manner (normally within 30 days of receipt) of draft documents when requested. One consolidated set of comments for the cooperating agency will be provided in the format specified by the joint-lead agencies.

H. As appropriate and practicable, attend cooperating agency meetings and public meetings and hearings on the EIS process.

I. Retain the right to comment on all issues related to the EIS through the normal EIS public review and comment process.

J. Promptly advise the joint-lead agencies of concerns related to the EIS process.

VIII. Shared Responsibilities of all Parties

A. Reclamation and NPS may meet separately with any one or more cooperating agencies to discuss specific topics.

B. It is understood that the respective agencies are normally responsible for their own costs with regard to completion of tasks outlined herein, such as attendance at meetings, assembling data, analyzing effects, and providing input with regard to sections of the EIS subject to section VII.F. Funding requests from tribal governments with a demonstrated need will be considered on a case by case basis by the joint-lead agencies.

C. All parties agree that because of the need for timely completion of NEPA compliance, work will proceed as expeditiously as possible, including data gathering, analysis, and document review. However, all parties agree that sufficient time must be allowed to ensure thorough document review. It is anticipated that the parties will be given a minimum of 30 days to review the preliminary draft EIS and a minimum of 30 days to review the draft final EIS.

IX. Resolution of Disputes

Reclamation and NPS are responsible for all decisions involving the EIS and will make all final decisions on disputes arising during the NEPA process. The joint-lead agencies will document the nature of any dispute and the resolution of the dispute. Documentation of resolution will be made available to appropriate parties.

X. Standard Conditions:

A. AUTHORITIES. Nothing in this MOU shall be construed to extend the jurisdiction or decision-making authority of any party to this MOU beyond that which exists under current laws and regulations. Nothing in this MOU shall be construed as limiting or affecting the authority or legal responsibility of any party, or as binding any party to perform beyond the respective authority of each, or to require any party to assume or expend any specific sum of money. The provisions of this MOU are subject to the laws of the United States; and the regulations of the Department of the Interior, as they may be applicable. Nothing in this MOU shall be construed as affecting the decision-making requirements of any party or impairing the independent judgment of each party regarding policy decisions.

B. RELEASE OF INFORMATION. Except as required by court order or ruling, the joint - lead agencies and the cooperating agency will not release any pre-decisional material or working information or documents to the public other than through an approved Freedom of Information Act request or comparable tribal or state law-based process, or unless the agency or agencies have already disseminated the specific materials or documents to the public. The

agencies agree to inform each other if it is determined that there is a legal requirement to release any such information, and that information will include expected release date of the information.

C. **LEGAL RIGHTS AND REMEDIES.** Nothing in this MOU shall be construed to alter the legal rights and remedies that each party would otherwise have. No party waives any legal rights or defenses by entering into this MOU or participating in the process contemplated hereby. This MOU is not a Federal contract, rule, or regulation. This MOU shall not be construed as or interpreted to be final Federal agency action.

D. **SEVERABILITY.** Should any portion of this MOU be judicially determined to be illegal or unenforceable, the remainder of the MOU shall continue in full force and effect, and any party may renegotiate the terms affected by the severance.

E. **THIRD PARTY BENEFICIARY RIGHTS.** The parties do not intend to create in any other individual or entity the status of third party beneficiary, and this MOU shall not be construed so as to create such status. The rights, duties and obligations contained in this MOU shall operate only among the parties to this MOU, and shall inure solely to the benefit of the parties to this MOU. The provisions of this MOU are intended only to assist the parties in determining and performing their obligations under this MOU.

F. **NON-FUND OBLIGATION DOCUMENT.** This MOU is neither a fiscal nor a funds obligation document. Any endeavor or transfer of anything of value involving reimbursement or contribution of funds between the parties to this instrument will be handled in accordance with applicable laws, regulations, and procedures including those for Government procurement and printing. Such endeavors will be outlined in separate agreements that shall be made in writing by representatives of the parties and shall be independently authorized by appropriate rules, policies, and statutory authority. This MOU does not provide such authority. Specifically, this MOU does not establish authority for noncompetitive award to the cooperator of any contract or other agreement. Nothing herein constitutes a binding commitment to fund any of the proceedings encompassed by the MOU. Any specific cost sharing or funding shall be executed separately through other funding mechanisms, as deemed necessary and appropriate by each of the signatories.

G. **PARTICIPATION IN SIMILAR ACTIVITIES WITH OTHER ENTITIES.** This MOU in no way restricts any of the parties from participating in similar activities with other public or private agencies, organizations, and individuals.

H. **ENDORSEMENT.** Nothing in this MOU may be interpreted to imply that the United States, the Department of the Interior, the NPS, the Bureau of Reclamation, or the cooperating agency endorses any product, service or policy of the other parties. No party will take any action or make any statement that suggests or implies such an endorsement.

I. **STATUTES AND REGULATIONS.** The provisions of any statutes and/or regulations cited in this MOU contain legally binding requirements. The MOU itself does not alter, expand, or substitute for those provisions or regulations. This MOU does not impose legally-

binding requirements on the Parties, nor does it create a legal right of action for the Parties or any third party.

J. **AGENCY AND PARTNERSHIP.** Unless expressly provided by law, personnel or volunteers of one party shall not be considered to be agents, partners or employees of the other party for any purpose, and no joint venture or principal-agent relationship shall be deemed to exist. The personnel and volunteers of one party are not entitled to any of the benefits that any other party provides for its employees or volunteers.

K. **LIABILITY.** To the extent authorized by law, on behalf of itself, its officers, directors, members, employees, agents, and representatives, each party agrees that it will be responsible for its own acts and omissions and the results thereof and that it shall not be responsible for the acts or omissions of other parties, nor the results thereof. To the extent authorized by law, each party therefore agrees that it will assume the risk and liability to itself, its agents, employees, and volunteers for any injury to or death of persons or loss or destruction of property resulting in any manner from the conduct of the party's own operations and/or the operations of its agents, employees, and/or volunteers under this MOU. To the extent authorized by law, each party further releases and waives all claims against the other party for compensation for any loss, cost, damage, expense, personal injury, death, claim, or other liability arising out of the performance of this MOU.

L. **NONDISCRIMINATION.** This MOU is subject to all Federal statutes relating to nondiscrimination. These include, but are not limited to: (a) Title VI of the Civil Rights Act of 1964 (P.L. 88-352); and (b) Title IX of the Education Amendments of 1972 (20 U.S.C. 1681-1683 and 1685-1686).

XI. Effective Dates, Amendment and Termination

A. This MOU will become effective on the date of the last signature and may be subsequently amended through written agreement of all signatories. The joint-lead agencies or the cooperating agency may terminate their cooperative status by providing 30 days written notice of termination to the other party. Otherwise, the cooperative status will terminate when a Record of Decision is issued or the EIS is terminated.

XII. Signatures

The parties hereto have executed this Memorandum of Understanding as of the dates shown below.

BUREAU OF RECLAMATION

Date 7/21/14

Larry Walkoviak
Regional Director
Upper Colorado Region
Bureau of Reclamation

NATIONAL PARK SERVICE

Date 10/10/2014

Raymond M. Sauvajot
Acting Associate Director for Natural Resources, Stewardship and Science
National Park Service

Date 10/1/14

Sue E. Masica
Regional Director
Intermountain Region
National Park Service

Date 03 October 2014

Christine Lehnertz
Regional Director
Pacific West Region
National Park Service

THE HOPI TRIBE

Date 6.7.13

Leroy Ned Shingoitewa, Chairman

(c) Hualapai Tribe

Memorandum of Understanding
Between
the Bureau of Reclamation and the National Park Service
and
the Hualapai Tribe
for the Environmental Impact Statement for Adoption of a Long Term Experimental and Management Plan for the Operation of Glen Canyon Dam

I. Introduction and Purpose

Pursuant to the National Environmental Policy Act (NEPA), the Department of the Interior (Department), through the Bureau of Reclamation (Reclamation) and the National Park Service (NPS), is preparing an environmental impact statement (EIS) for a Long Term Experimental and Management Plan (LTEMP) for the operation of Glen Canyon Dam. Reclamation and the NPS are the joint lead or "joint-lead agencies" for the completion of this EIS. The Hualapai Tribe hereafter "the cooperating agency", in addition to other parties, has agreed to serve as a cooperating agency for the completion of the LTEMP EIS. The purpose of this Memorandum of Understanding (MOU) is to outline the roles and responsibilities of the joint-lead and the cooperating agency (hereinafter collectively referred to alternatively as "agencies" or "parties") in accordance with 43 CFR § 46.225(d).

II. Background

The LTEMP process is intended to develop and implement a structured, long term experimental and management plan, to determine the need for potential future modifications to Glen Canyon Dam operations, and to determine whether to establish an Endangered Species Act (ESA) Recovery Implementation Program for endangered fish species below Glen Canyon Dam. Revised dam operations and other actions under the jurisdiction of the Secretary of the Interior will be considered within alternatives of the EIS, in keeping with the scope of the Grand Canyon Protection Act (GCPA). The NEPA process will document and evaluate impacts of the alternatives described in the EIS.

III. Purpose of this MOU

This MOU defines the relationship and duties of the joint-lead and the cooperating agency in completing NEPA compliance for the LTEMP, and how the parties will cooperate during the NEPA process.

By signing this MOU, the parties agree that this MOU provides the framework to fulfill compliance requirements for NEPA.

IV. Agency Designee

The cooperating agency will designate a primary point of contact (and alternate if desired) for the EIS by sending correspondence at the time of signing of this agreement to the joint-lead agencies with the contacts name and information. The cooperating agency may change its point

of contact at any time by providing written notice to the joint-lead agencies and the other cooperating agencies.

V. Authority

The authority of the joint-lead and the cooperating agency to participate in this agreement is provided by the National Environmental Policy Act, 42 U.S.C. §§ 4321 *et seq*. NEPA allows agencies to be designated as a cooperating agency when that agency has jurisdiction by law or special expertise (40 CFR § 1501.6 and 40 CFR§ 1508.5). Activities contemplated under this MOU are specifically authorized under:

A. Title I of NEPA;

B. "Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act," 40 CFR §§ 1500-1508, Council on Environmental Quality (in particular 40 CFR § 1501.6, Cooperating Agencies);

C. Department of the Interior NEPA Implementing Procedures in the Departmental Manual at 43 CFR § Part 46, Cooperating Agencies (40 CFR §1501.6).

VI. Joint-lead Agency Responsibilities

Reclamation and the NPS will be joint-leads for this effort because Reclamation has primary responsibility for operation of Glen Canyon Dam and the NPS has primary responsibility for managing Grand Canyon National Park, Glen Canyon National Recreation Area, and Lake Mead National Recreation Area.

The NPS and Reclamation, as joint-leads for the completion of the LTEMP EIS, shall:

A. Jointly be responsible for the preparation, quality, content and overall direction of the EIS and for ensuring the appropriate participation of cooperating agencies in developing the EIS.

B. Jointly be responsible for identifying the purpose and need for the project, scope of analysis, and decisions to be made. In coordination with the Department, the joint-lead agencies will make the final decision on the content of all EIS-related documents, including the preferred alternative and the Record of Decision to be signed by the Secretary of the Interior.

C. Jointly oversee the execution and administration of contracts or cooperative agreements with mutually agreed upon federal, state or local agencies, or tribal governments or mutually agreed upon private contractors to develop information for inclusion in the EIS.

D. Jointly conduct cooperating agency meetings, and provide advance information for discussions at these meetings, as necessary during the preparation of the EIS. Meeting

dates and locations will be jointly agreed upon and may be chosen to coincide with the dates of Adaptive Management Working Group meetings to minimize travel costs and maximize collaboration.

E. Ensure that cooperating agency proposals and substantive comments (including divergent views) within their jurisdiction or technical expertise are appropriately documented and considered in the EIS.

F. Provide advance copies (normally 30 days) of the preliminary draft and preliminary final EIS and related compliance documents for review by cooperating agencies.

VII. Cooperating Agency Responsibilities

Federal, state, and local agencies, and tribal governments with appropriate expertise or jurisdiction have been invited to participate as cooperating agencies. Reclamation and NPS may, at any time during the course of the EIS project, invite additional agencies to participate in the process.

The cooperating agency, subject to sufficient appropriations to carry out the following responsibilities, shall:

A. Participate in the NEPA process at the earliest possible time.

B. Participate in the scoping process.

C. Assume, on request of the lead agencies, responsibility for developing information and preparing environmental analyses including portions of the environmental impact statement concerning which the cooperating agency has special expertise.

D. Make available staff support at the lead agencies' request to enhance the latter's interdisciplinary capability.

E. Normally use their own funds.

F. The cooperating agency may in response to a lead agencies' request for assistance in preparing the environmental impact statement reply that other program commitments preclude any involvement or the degree of involvement requested in the action that is the subject of the environmental impact statement.

G. Provide comments in a timely manner (normally within 30 days of receipt) of draft documents when requested. One consolidated set of comments for the cooperating agency will be provided in the format specified by the joint-lead agencies.

H. As appropriate and practicable, attend cooperating agency meetings and public meetings and hearings on the EIS process.

I. Retain the right to comment on all issues related to the EIS through the normal EIS public review and comment process.

J. Promptly advise the joint-lead agencies of concerns related to the EIS process.

VIII. Shared Responsibilities of all Parties

A. Reclamation and NPS may meet separately with any one or more cooperating agencies to discuss specific topics.

B. It is understood that the respective agencies are normally responsible for their own costs with regard to completion of tasks outlined herein, such as attendance at meetings, assembling data, analyzing effects, and providing input with regard to sections of the EIS subject to section VII.F. Funding requests from tribal governments with a demonstrated need will be considered on a case by case basis by the joint-lead agencies.

C. All parties agree that because of the need for timely completion of NEPA compliance, work will proceed as expeditiously as possible, including data gathering, analysis, and document review. However, all parties agree that sufficient time must be allowed to ensure thorough document review. It is anticipated that the parties will be given a minimum of 30 days to review the preliminary draft EIS and a minimum of 30 days to review the draft final EIS.

IX. Resolution of Disputes

Reclamation and NPS are responsible for all decisions involving the EIS and will make all final decisions on disputes arising during the NEPA process. The joint-lead agencies will document the nature of any dispute and the resolution of the dispute. Documentation of resolution will be made available to appropriate parties.

X. Standard Conditions:

A. AUTHORITIES. Nothing in this MOU shall be construed to extend the jurisdiction or decision-making authority of any party to this MOU beyond that which exists under current laws and regulations. Nothing in this MOU shall be construed as limiting or affecting the authority or legal responsibility of any party, or as binding any party to perform beyond the respective authority of each, or to require any party to assume or expend any specific sum of money. The provisions of this MOU are subject to the laws of the United States; and the regulations of the Department of the Interior, as they may be applicable. Nothing in this MOU shall be construed as affecting the decision-making requirements of any party or impairing the independent judgment of each party regarding policy decisions.

B. RELEASE OF INFORMATION. Except as required by court order or ruling, the joint - lead agencies and the cooperating agency will not release any pre-decisional material or working information or documents to the public other than through an approved Freedom of

Information Act request or comparable tribal or state law-based process, or unless the agency or agencies have already disseminated the specific materials or documents to the public. The agencies agree to inform each other if it is determined that there is a legal requirement to release any such information, and that information will include expected release date of the information.

C. **SOVEREIGNTY.** Participation by a tribe in this National Environmental Policy Act process does not diminish the Tribe's rights to protect its sovereignty under their constitutional authorities and in consideration of applicable law.

D. **LEGAL RIGHTS AND REMEDIES.** Nothing in this MOU shall be construed to alter the legal rights and remedies that each party would otherwise have. No party waives any legal rights or defenses by entering into this MOU or participating in the process contemplated hereby. This MOU is not a Federal contract, rule, or regulation. This MOU shall not be construed as or interpreted to be final Federal agency action.

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cooperating agency endorses any product, service or policy of the other parties. No party will take any action or make any statement that suggests or implies such an endorsement.

J. **STATUTES AND REGULATIONS.** The provisions of any statutes and/or regulations cited in this MOU contain legally binding requirements. The MOU itself does not alter, expand, or substitute for those provisions or regulations. This MOU does not impose legally-binding requirements on the Parties, nor does it create a legal right of action for the Parties or any third party.

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L. **LIABILITY.** To the extent authorized by law, on behalf of itself, its officers, directors, members, employees, agents, and representatives, each party agrees that it will be responsible for its own acts and omissions and the results thereof and that it shall not be responsible for the acts or omissions of other parties, nor the results thereof. To the extent authorized by law, each party therefore agrees that it will assume the risk and liability to itself, its agents, employees, and volunteers for any injury to or death of persons or loss or destruction of property resulting in any manner from the conduct of the party's own operations and/or the operations of its agents, employees, and/or volunteers under this MOU. To the extent authorized by law, each party further releases and waives all claims against the other party for compensation for any loss, cost, damage, expense, personal injury, death, claim, or other liability arising out of the performance of this MOU.

M. **NONDISCRIMINATION.** This MOU is subject to all Federal statutes relating to nondiscrimination. These include, but are not limited to: (a) Title VI of the Civil Rights Act of 1964 (P.L. 88-352); and (b) Title IX of the Education Amendments of 1972 (20 U.S.C. 1681-1683 and 1685-1686).

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XII. Signatures
The parties hereto have executed this Memorandum of Understanding as of the dates shown below.

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Regional Director
Upper Colorado Region
Bureau of Reclamation

NATIONAL PARK SERVICE

Date 10/10/2014

Raymond M. Sauvajot
Acting Associate Director for Natural Resources, Stewardship and Science
National Park Service

Date 10/1/14

Sue E. Masica
Regional Director
Intermountain Region
National Park Service

Date 03October 2014

Christine Lehnertz
Regional Director
Pacific West Region
National Park Service

THE HUALAPAI TRIBE

Date 10/3/12

Sherry J. Counts
Chairwoman
The Hualapai Tribe

Date 10.04.2012

Loretta Jackson-Kelly
Director for the Department of Cultural Resources
The Hualapai Tribe

(d) Kaibab Band of Paiute Indians

Memorandum of Understanding
Between
the Bureau of Reclamation and the National Park Service
and
the Kaibab Band of Paiute Indians
for the Environmental Impact Statement for Adoption of a Long Term Experimental and Management Plan for the Operation of Glen Canyon Dam

I. Introduction and Purpose

Pursuant to the National Environmental Policy Act (NEPA), the Department of the Interior (Department), through the Bureau of Reclamation (Reclamation) and the National Park Service (NPS), is preparing an environmental impact statement (EIS) for a Long Term Experimental and Management Plan (LTEMP) for the operation of Glen Canyon Dam. Reclamation and the NPS are the joint lead or "joint-lead agencies" for the completion of this EIS. The Kaibab Band of Paiute Indians hereafter "the cooperating agency", in addition to other parties, has agreed to serve as a cooperating agency for the completion of the LTEMP EIS. The purpose of this Memorandum of Understanding (MOU) is to outline the roles and responsibilities of the joint-lead and the cooperating agency (hereinafter collectively referred to alternatively as "agencies" or "parties") in accordance with 43 CFR § 46.225(d).

II. Background

The LTEMP process is intended to develop and implement a structured, long term experimental and management plan, to determine the need for potential future modifications to Glen Canyon Dam operations, and to determine whether to establish an Endangered Species Act (ESA) Recovery Implementation Program for endangered fish species below Glen Canyon Dam. Revised dam operations and other actions under the jurisdiction of the Secretary of the Interior will be considered within alternatives of the EIS, in keeping with the scope of the Grand Canyon Protection Act (GCPA). The NEPA process will document and evaluate impacts of the alternatives described in the EIS.

III. Purpose of this MOU

This MOU defines the relationship and duties of the joint-lead and the cooperating agency in completing NEPA compliance for the LTEMP, and how the parties will cooperate during the NEPA process.

By signing this MOU, the parties agree that this MOU provides the framework to fulfill compliance requirements for NEPA.

IV. Agency Designee

The cooperating agency will designate a primary point of contact (and alternate if desired) for the EIS by sending correspondence at the time of signing of this agreement to the joint-lead agencies with the contacts name and information. The cooperating agency may change its point

of contact at any time by providing written notice to the joint-lead agencies and the other cooperating agencies.

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The authority of the joint-lead and the cooperating agency to participate in this agreement is provided by the National Environmental Policy Act, 42 U.S.C. §§ 4321 *et seq.* NEPA allows agencies to be designated as a cooperating agency when that agency has jurisdiction by law or special expertise (40 CFR § 1501.6 and 40 CFR§ 1508.5). Activities contemplated under this MOU are specifically authorized under:

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B. "Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act," 40 CFR §§ 1500-1508, Council on Environmental Quality (in particular 40 CFR § 1501.6, Cooperating Agencies);

C. Department of the Interior NEPA Implementing Procedures in the Departmental Manual at 43 CFR § Part 46, Cooperating Agencies (40 CFR §1501.6).

VI. Joint-lead Agency Responsibilities

Reclamation and the NPS will be joint-leads for this effort because Reclamation has primary responsibility for operation of Glen Canyon Dam and the NPS has primary responsibility for managing Grand Canyon National Park, Glen Canyon National Recreation Area, and Lake Mead National Recreation Area.

The NPS and Reclamation, as joint-leads for the completion of the LTEMP EIS, shall:

A. Jointly be responsible for the preparation, quality, content and overall direction of the EIS and for ensuring the appropriate participation of cooperating agencies in developing the EIS.

B. Jointly be responsible for identifying the purpose and need for the project, scope of analysis, and decisions to be made. In coordination with the Department, the joint-lead agencies will make the final decision on the content of all EIS-related documents, including the preferred alternative and the Record of Decision to be signed by the Secretary of the Interior.

C. Jointly oversee the execution and administration of contracts or cooperative agreements with mutually agreed upon federal, state or local agencies, or tribal governments or mutually agreed upon private contractors to develop information for inclusion in the EIS.

D. Jointly conduct cooperating agency meetings, and provide advance information for discussions at these meetings, as necessary during the preparation of the EIS. Meeting dates and locations will be jointly agreed upon and may be chosen to coincide with the

dates of Adaptive Management Working Group meetings to minimize travel costs and maximize collaboration.

E. Ensure that cooperating agency proposals and substantive comments (including divergent views) within their jurisdiction or technical expertise are appropriately documented and considered in the EIS.

F. Provide advance copies (normally 30 days) of the preliminary draft and preliminary final EIS and related compliance documents for review by cooperating agencies.

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Federal, state, and local agencies, and tribal governments with appropriate expertise or jurisdiction have been invited to participate as cooperating agencies. Reclamation and NPS may, at any time during the course of the EIS project, invite additional agencies to participate in the process.

The cooperating agency, subject to sufficient appropriations to carry out the following responsibilities, shall:

A. Participate in the NEPA process at the earliest possible time.

B. Participate in the scoping process.

C. Assume, on request of the lead agencies, responsibility for developing information and preparing environmental analyses including portions of the environmental impact statement concerning which the cooperating agency has special expertise.

D. Make available staff support at the lead agencies' request to enhance the latter's interdisciplinary capability.

E. Normally use their own funds.

F. The cooperating agency may in response to a lead agencies' request for assistance in preparing the environmental impact statement reply that other program commitments preclude any involvement or the degree of involvement requested in the action that is the subject of the environmental impact statement.

G. Provide comments in a timely manner (normally within 30 days of receipt) of draft documents when requested. One consolidated set of comments for the cooperating agency will be provided in the format specified by the joint-lead agencies.

H. As appropriate and practicable, attend cooperating agency meetings and public meetings and hearings on the EIS process.

I. Retain the right to comment on all issues related to the EIS through the normal EIS public review and comment process.

J. Promptly advise the joint-lead agencies of concerns related to the EIS process.

VIII. Shared Responsibilities of all Parties

A. Reclamation and NPS may meet separately with any one or more cooperating agencies to discuss specific topics.

B. It is understood that the respective agencies are normally responsible for their own costs with regard to completion of tasks outlined herein, such as attendance at meetings, assembling data, analyzing effects, and providing input with regard to sections of the EIS subject to section VII.F. Funding requests from tribal governments with a demonstrated need will be considered on a case by case basis by the joint-lead agencies.

C. All parties agree that because of the need for timely completion of NEPA compliance, work will proceed as expeditiously as possible, including data gathering, analysis, and document review. However, all parties agree that sufficient time must be allowed to ensure thorough document review. It is anticipated that the parties will be given a minimum of 30 days to review the preliminary draft EIS and a minimum of 30 days to review the draft final EIS.

IX. Resolution of Disputes

Reclamation and NPS are responsible for all decisions involving the EIS and will make all final decisions on disputes arising during the NEPA process. The joint-lead agencies will document the nature of any dispute and the resolution of the dispute. Documentation of resolution will be made available to appropriate parties.

X. Standard Conditions:

A. **AUTHORITIES.** Nothing in this MOU shall be construed to extend the jurisdiction or decision-making authority of any party to this MOU beyond that which exists under current laws and regulations. Nothing in this MOU shall be construed as limiting or affecting the authority or legal responsibility of any party, or as binding any party to perform beyond the respective authority of each, or to require any party to assume or expend any specific sum of money. The provisions of this MOU are subject to the laws of the United States; and the regulations of the Department of the Interior, as they may be applicable. Nothing in this MOU shall be construed as affecting the decision-making requirements of any party or impairing the independent judgment of each party regarding policy decisions.

B. **RELEASE OF INFORMATION.** Except as required by court order or ruling, the joint - lead agencies and the cooperating agency will not release any pre-decisional material or working information or documents to the public other than through an approved Freedom of Information Act request or comparable tribal or state law-based process, or unless the agency or agencies have already disseminated the specific materials or documents to the public. The

agencies agree to inform each other if it is determined that there is a legal requirement to release any such information, and that information will include expected release date of the information.

C. **LEGAL RIGHTS AND REMEDIES.** Nothing in this MOU shall be construed to alter the legal rights and remedies that each party would otherwise have. No party waives any legal rights or defenses by entering into this MOU or participating in the process contemplated hereby. This MOU is not a Federal contract, rule, or regulation. This MOU shall not be construed as or interpreted to be final Federal agency action.

D. **SEVERABILITY.** Should any portion of this MOU be judicially determined to be illegal or unenforceable, the remainder of the MOU shall continue in full force and effect, and any party may renegotiate the terms affected by the severance.

E. **THIRD PARTY BENEFICIARY RIGHTS.** The parties do not intend to create in any other individual or entity the status of third party beneficiary, and this MOU shall not be construed so as to create such status. The rights, duties and obligations contained in this MOU shall operate only among the parties to this MOU, and shall inure solely to the benefit of the parties to this MOU. The provisions of this MOU are intended only to assist the parties in determining and performing their obligations under this MOU.

F. **NON-FUND OBLIGATION DOCUMENT.** This MOU is neither a fiscal nor a funds obligation document. Any endeavor or transfer of anything of value involving reimbursement or contribution of funds between the parties to this instrument will be handled in accordance with applicable laws, regulations, and procedures including those for Government procurement and printing. Such endeavors will be outlined in separate agreements that shall be made in writing by representatives of the parties and shall be independently authorized by appropriate rules, policies, and statutory authority. This MOU does not provide such authority. Specifically, this MOU does not establish authority for noncompetitive award to the cooperator of any contract or other agreement. Nothing herein constitutes a binding commitment to fund any of the proceedings encompassed by the MOU. Any specific cost sharing or funding shall be executed separately through other funding mechanisms, as deemed necessary and appropriate by each of the signatories.

G. **PARTICIPATION IN SIMILAR ACTIVITIES WITH OTHER ENTITIES.** This MOU in no way restricts any of the parties from participating in similar activities with other public or private agencies, organizations, and individuals.

H. **ENDORSEMENT.** Nothing in this MOU may be interpreted to imply that the United States, the Department of the Interior, the NPS, the Bureau of Reclamation, or the cooperating agency endorses any product, service or policy of the other parties. No party will take any action or make any statement that suggests or implies such an endorsement.

I. **STATUTES AND REGULATIONS.** The provisions of any statutes and/or regulations cited in this MOU contain legally binding requirements. The MOU itself does not alter, expand, or substitute for those provisions or regulations. This MOU does not impose legally-

binding requirements on the Parties, nor does it create a legal right of action for the Parties or any third party.

J. **AGENCY AND PARTNERSHIP.** Unless expressly provided by law, personnel or volunteers of one party shall not be considered to be agents, partners or employees of the other party for any purpose, and no joint venture or principal-agent relationship shall be deemed to exist. The personnel and volunteers of one party are not entitled to any of the benefits that any other party provides for its employees or volunteers.

K. **LIABILITY.** To the extent authorized by law, on behalf of itself, its officers, directors, members, employees, agents, and representatives, each party agrees that it will be responsible for its own acts and omissions and the results thereof and that it shall not be responsible for the acts or omissions of other parties, nor the results thereof. To the extent authorized by law, each party therefore agrees that it will assume the risk and liability to itself, its agents, employees, and volunteers for any injury to or death of persons or loss or destruction of property resulting in any manner from the conduct of the party's own operations and/or the operations of its agents, employees, and/or volunteers under this MOU. To the extent authorized by law, each party further releases and waives all claims against the other party for compensation for any loss, cost, damage, expense, personal injury, death, claim, or other liability arising out of the performance of this MOU.

L. **NONDISCRIMINATION.** This MOU is subject to all Federal statutes relating to nondiscrimination. These include, but are not limited to: (a) Title VI of the Civil Rights Act of 1964 (P.L. 88-352); and (b) Title IX of the Education Amendments of 1972 (20 U.S.C. 1681-1683 and 1685-1686).

XI. Effective Dates, Amendment and Termination

A. This MOU will become effective on the date of the last signature and may be subsequently amended through written agreement of all signatories. The joint-lead agencies or the cooperating agency may terminate their cooperative status by providing 30 days written notice of termination to the other party. Otherwise, the cooperative status will terminate when a Record of Decision is issued or the EIS is terminated.

XII. Signatures

The parties hereto have executed this Memorandum of Understanding as of the dates shown below.

BUREAU OF RECLAMATION

Larry Walkoviak — Date 5/22/2012
Regional Director
Upper Colorado Region
Bureau of Reclamation

NATIONAL PARK SERVICE

Herbert C. Frost — Date 7/11/2012
Associate Director for Natural Resources Stewardship and Science
National Park Service

John Wessels — Date 6/21/12
Regional Director
Intermountain Region
National Park Service

Christine Lehnertz — Date 07/05/12
Regional Director
Pacific West Region
National Park Service

THE KAIBAB BAND OF PAIUTE INDIANS

Manuel Savala, Chairman — Date May 2, 2012

(e) Navajo Nation

Memorandum of Understanding
Between
the Bureau of Reclamation and the National Park Service
and
the Navajo Nation
for the Environmental Impact Statement for Adoption of a Long Term Experimental and Management Plan for the Operation of Glen Canyon Dam

I. Introduction and Purpose

Pursuant to the National Environmental Policy Act (NEPA), the Department of the Interior (Department), through the Bureau of Reclamation (Reclamation) and the National Park Service (NPS), is preparing an environmental impact statement (EIS) for a Long Term Experimental and Management Plan (LTEMP) for the operation of Glen Canyon Dam. Reclamation and the NPS are the joint lead or "joint-lead agencies" for the completion of this EIS. The Navajo Nation hereafter "the cooperating agency", in addition to other parties, has agreed to serve as a cooperating agency for the completion of the LTEMP EIS. The purpose of this Memorandum of Understanding (MOU) is to outline the roles and responsibilities of the joint-lead and the cooperating agency (hereinafter collectively referred to alternatively as "agencies" or "parties") in accordance with 43 CFR § 46.225(d).

II. Background

The LTEMP process is intended to develop and implement a structured, long term experimental and management plan, to determine the need for potential future modifications to Glen Canyon Dam operations, and to determine whether to establish an Endangered Species Act (ESA) Recovery Implementation Program for endangered fish species below Glen Canyon Dam. Revised dam operations and other actions under the jurisdiction of the Secretary of the Interior will be considered within alternatives of the EIS, in keeping with the scope of the Grand Canyon Protection Act (GCPA). The NEPA process will document and evaluate impacts of the alternatives described in the EIS.

III. Purpose of this MOU

This MOU defines the relationship and duties of the joint-lead and the cooperating agency in completing NEPA compliance for the LTEMP, and how the parties will cooperate during the NEPA process.

By signing this MOU, the parties agree that this MOU provides the framework to fulfill compliance requirements for NEPA.

IV. Agency Designee

The cooperating agency will designate a primary point of contact (and alternate if desired) for the EIS by sending correspondence at the time of signing of this agreement to the joint-lead agencies with the contacts name and information. The cooperating agency may change its point

of contact at any time by providing written notice to the joint-lead agencies and the other cooperating agencies.

V. Authority

The authority of the joint-lead and the cooperating agency to participate in this agreement is provided by the National Environmental Policy Act. 42 U.S.C. §§ 4321 *et seq.* NEPA allows agencies to be designated as a cooperating agency when that agency has jurisdiction by law or special expertise (40 CFR § 1501.6 and 40 CFR§ 1508.5). Activities contemplated under this MOU are specifically authorized under:

A. Title I of NEPA;

B. "Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act," 40 CFR §§ 1500-1508. Council on Environmental Quality (in particular 40 CFR § 1501.6, Cooperating Agencies);

C. Department of the Interior NEPA Implementing Procedures in the Departmental Manual at 43 CFR § Part 46. Cooperating Agencies (40 CFR §1501.6).

D. Section 106 of the National Historic Preservation Act, as amended. 16 U.S.C. §§ 470 *et seq.*

E. Applicable tribal consultation policies of the joint-lead agencies and the Department of the Interior, and Executive Order 13175 (Nov. 6, 2000).

F. Resolution No. NABIMY-33-14_ of the Naabik'kyati' Committee. Navajo Nation Council, pursuant to 2 N.N.C. § 301(B)(15).

VI. Joint-lead Agency Responsibilities

Reclamation and the NPS will be joint-leads for this effort because Reclamation has primary responsibility for operation of Glen Canyon Dam and the NPS has primary responsibility for managing Grand Canyon National Park, Glen Canyon National Recreation Area, and Lake Mead National Recreation Area.

The NPS and Reclamation, as joint-leads for the completion of the LTEMP EIS, shall:

A. Jointly be responsible for the preparation, quality, content and overall direction of the EIS and for ensuring the appropriate participation of cooperating agencies in developing the EIS.

B. Jointly be responsible for identifying the purpose and need for the project, scope of analysis, and decisions to be made. In coordination with the Department, the joint-lead agencies will make the final decision on the content of all EIS-related documents,

including the preferred alternative and the Record of Decision to be signed by the Secretary of the Interior.

C. Jointly oversee the execution and administration of contracts or cooperative agreements with mutually agreed upon federal, state or local agencies, or tribal governments or mutually agreed upon private contractors to develop information for inclusion in the EIS.

D. Jointly conduct cooperating agency meetings, and provide advance information for discussions at these meetings, as necessary during the preparation of the EIS. Meeting dates and locations will be jointly agreed upon and may be chosen to coincide with the dates of Adaptive Management Working Group meetings to minimize travel costs and maximize collaboration.

E. Ensure that cooperating agency proposals and substantive comments (including divergent views) within their jurisdiction or technical expertise are appropriately documented and considered in the EIS.

F. Provide advance copies (normally 30 days) of the preliminary draft and preliminary final EIS and related compliance documents for review by cooperating agencies.

VII. Cooperating Agency Responsibilities

Federal, state, and local agencies, and tribal governments with appropriate expertise or jurisdiction have been invited to participate as cooperating agencies. Reclamation and NPS may, at any time during the course of the EIS project, invite additional agencies to participate in the process.

The cooperating agency, subject to sufficient appropriations to carry out the following responsibilities, shall:

A. Participate in the NEPA process at the earliest possible time.

B. Participate in the scoping process.

C. Assume, on request of the lead agencies, responsibility for developing information and preparing environmental analyses including portions of the environmental impact statement concerning which the cooperating agency has special expertise.

D. Make available staff support at the lead agencies' request to enhance the latter's interdisciplinary capability.

E. Normally use their own funds.

F. The cooperating agency may in response to a lead agencies' request for assistance in preparing the environmental impact statement reply that other program commitments preclude any involvement or the degree of involvement requested in the action that is the subject of the environmental impact statement.

G. Provide comments in a timely manner (normally within 30 days of receipt) of draft documents when requested. One consolidated set of comments for the cooperating agency will be provided in the format specified by the joint-lead agencies.

H. As appropriate and practicable, attend cooperating agency meetings and public meetings and hearings on the EIS process.

I. Retain the right to comment on all issues related to the EIS through the normal EIS public review and comment process, as well as through the independently required tribal consultation process.

J. Promptly advise the joint-lead agencies of concerns related to the EIS process.

VIII. Shared Responsibilities of all Parties

A. Reclamation and NPS may meet separately with any one or more cooperating agencies to discuss specific topics.

B. It is understood that the respective agencies are normally responsible for their own costs with regard to completion of tasks outlined herein, such as attendance at meetings, assembling data, analyzing effects, and providing input with regard to sections of the EIS subject to section VII.F. Funding requests from tribal governments with a demonstrated need will be considered on a case by case basis by the joint-lead agencies.

C. All parties agree that because of the need for timely completion of NEPA compliance, work will proceed as expeditiously as possible, including data gathering, analysis, and document review. However, all parties agree that sufficient time must be allowed to ensure thorough document review. It is anticipated that the parties will be given a minimum of 30 days to review the preliminary draft EIS and a minimum of 30 days to review the draft final EIS.

IX. Resolution of Disputes

Reclamation and NPS are responsible for all decisions involving the EIS and will make all final decisions on disputes arising during the NEPA process. The joint-lead agencies will document the nature of any dispute and the resolution of the dispute. Documentation of resolution will be made available to appropriate parties.

X. Standard Conditions:

A. AUTHORITIES. Nothing in this MOU shall be construed to extend the jurisdiction or decision-making authority of any party to this MOU beyond that which exists under current laws and regulations. Nothing in this MOU shall be construed as limiting or affecting the authority or legal responsibility of any party, or as binding any party to perform beyond the

respective authority of each. , or to otherwise violate any applicable law, regulation or policy or to require any party to assume or expend any specific sum of money. The provisions of this MOU are subject to the laws of the United States; and the regulations of the Department of the Interior, as they may be applicable. Nothing in this MOU shall be construed as affecting the decision-making requirements of any party or impairing the independent judgment of each party regarding policy decisions.

B. **RELEASE OF INFORMATION.** Except as required by court order or ruling, the joint - lead agencies and the cooperating agency will not release any pre-decisional material or working information or documents to the public other than through an approved Freedom of Information Act request or an approved request made under the Navajo Nation Privacy Act, or unless the agency or agencies have already disseminated the specific materials or documents to the public. The agencies agree to inform each other if it is determined that there is a legal requirement to release any such information, and that information will include expected release date of the information.

C. **LEGAL RIGHTS AND REMEDIES.** Nothing in this MOU shall be construed to alter the legal rights and remedies that each party would otherwise have. No party waives any legal rights or defenses by entering into this MOU or participating in the process contemplated hereby, including that nothing herein shall be construed as a waiver, express or implied, of any party's sovereign immunity. This MOU is not a Federal contract, rule, or regulation. This MOU shall not be construed as or interpreted to be final Federal agency action.

D. **SEVERABILITY.** Should any portion of this MOU be judicially determined to be illegal or unenforceable, the remainder of the MOU shall continue in full force and effect, and any party may renegotiate the terms affected by the severance.

E. **THIRD PARTY BENEFICIARY RIGHTS.** The parties do not intend to create in any other individual or entity the status of third party beneficiary, and this MOU shall not be construed so as to create such status. The rights, duties and obligations contained in this MOU shall operate only among the parties to this MOU, and shall inure solely to the benefit of the parties to this MOU. The provisions of this MOU are intended only to assist the parties in determining and performing their obligations under this MOU.

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K. LIABILITY. To the extent authorized by law, on behalf of itself, its officers, directors, members, employees, agents, and representatives, each party agrees that it will be responsible for its own acts and omissions and the results thereof and that it shall not be responsible for the acts or omissions of other parties, nor the results thereof. To the extent authorized by law, each party therefore agrees that it will assume the risk and liability to itself, its agents, employees, and volunteers for any injury to or death of persons or loss or destruction of property resulting in any manner from the conduct of the party's own operations and/or the operations of its agents, employees, and/or volunteers under this MOU, in accordance with applicable law, including the Navajo Sovereign Immunity Act, as amended. To the extent authorized by law, each party further releases and waives all claims against the other party for compensation for any loss, cost, damage, expense, personal injury, death, claim, or other liability arising out of the performance of this MOU.

L. NONDISCRIMINATION. This MOU is subject to all Federal statutes relating to nondiscrimination, as applicable to the parties. These include, but are not limited to: (a) Title VI of the Civil Rights Act of 1964 (P.L. 88-352); and (b) Title IX of the Education Amendments of 1972 (20 U.S.C. 1681-1683 and 1685-1686).

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notice of termination to the other party. Otherwise, the cooperative status will terminate when a Record of Decision is issued or the EIS is terminated.

B. This MOU may be executed in separate counterparts, and such counterparts when executed shall constitute an original.

XII. Signatures

The parties hereto have executed this Memorandum of Understanding as of the dates shown below.

BUREAU OF RECLAMATION

Date June 18, 2014

Larry Walkoviak
Regional Director
Upper Colorado Region
Bureau of Reclamation

NATIONAL PARK SERVICE

Date 10/10/2014

Raymond M. Sauvajot, Ph.D.
Acting Associate Director
Natural Resource Stewardship and Science
National Park Service

for

Date July 16, 2014

Sue Masica
Regional Director
Intermountain Region
National Park Service

Date 03 October 2014

Christine Lehnertz
Regional Director
Pacific West Region
National Park Service

THE NAVAJO NATION

Date JUN 09 2014

Ben Shelly, President

(f) Pueblo of Zuni

Memorandum of Understanding
Between
The Bureau of Reclamation and the National Park Service
And
The Pueblo of Zuni
For the Environmental Impact Statement for Adoption of a Long Term Experimental and Management Plan for the Operation of Glen Canyon Dam

I. Introduction and Purpose

Pursuant to the National Environmental Policy Act (NEPA), the Department of the Interior (Department), through the Bureau of Reclamation (Reclamation) and the National Park Service (NPS), is preparing an environmental impact statement (EIS) for a Long Term Experimental and Management Plan (LTEMP) for the operation of Glen Canyon Dam. Reclamation and the NPS are the joint lead or "joint-lead agencies" for the completion of this EIS. The Pueblo of Zuni hereafter "the cooperating agency", in addition to other parties, has agreed to serve as a cooperating agency for the completion of the LTEMP EIS. The purpose of this Memorandum of Understanding (MOU) is to outline the roles and responsibilities of the joint-lead and the cooperating agency (hereinafter collectively referred to alternatively as "agencies" or "parties") in accordance with 43 CFR § 46.225(d).

II. Background

The LTEMP process is intended to develop and implement a structured, long term experimental and management plan, to determine the need for potential future modifications to Glen Canyon Dam operations, and to determine whether to establish an Endangered Species Act (ESA) Recovery Implementation Program for endangered fish species below Glen Canyon Dam. Revised dam operations and other actions under the jurisdiction of the Secretary of the Interior will be considered within alternatives of the EIS, in keeping with the scope of the Grand Canyon Protection Act (GCPA). The NEPA process will document and evaluate impacts of the alternatives described in the EIS.

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A. Title I of NEPA;

B. "Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act," 40 CFR §§ 1500-1508, Council on Environmental Quality (in particular 40 CFR § 1501.6, Cooperating Agencies);

C. Department of the Interior NEPA Implementing Procedures in the Departmental Manual at 43 CFR § Part 46, Cooperating Agencies (40 CFR §1501.6).

VI. Joint-lead Agency Responsibilities

Reclamation and the NPS will be joint-leads for this effort because Reclamation has primary responsibility for operation of Glen Canyon Dam and the NPS has primary responsibility for managing Grand Canyon National Park, Glen Canyon National Recreation Area, and Lake Mead National Recreation Area.

The NPS and Reclamation, as joint-leads for the completion of the LTEMP EIS, shall:

A. Jointly be responsible for the preparation, quality, content and overall direction of the EIS and for ensuring the appropriate participation of cooperating agencies in developing the EIS.

B. Jointly be responsible for identifying the purpose and need for the project, scope of analysis, and decisions to be made. In coordination with the Department, the joint-lead agencies will make the final decision on the content of all EIS-related documents, including the preferred alternative and the Record of Decision to be signed by the Secretary of the Interior.

C. Jointly oversee the execution and administration of contracts or cooperative agreements with mutually agreed upon federal, state or local agencies, or tribal governments or mutually agreed upon private contractors to develop information for inclusion in the EIS.

D. Jointly conduct cooperating agency meetings, and provide advance information for discussions at these meetings, as necessary during the preparation of the EIS. Meeting dates and locations will be jointly agreed upon and may be chosen to coincide with the

dates of Adaptive Management Working Group meetings to minimize travel costs and maximize collaboration.

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H. As appropriate and practicable, attend cooperating agency meetings and public meetings and hearings on the EIS process.

I. Retain the right to comment on all issues related to the EIS through the normal EIS public review and comment process.

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B. RELEASE OF INFORMATION. Except as required by court order or ruling, the joint - lead agencies and the cooperating agency will not release any pre-decisional material or working information or documents to the public other than through an approved Freedom of Information Act request or comparable tribal or state law-based process, or unless the agency or agencies have already disseminated the specific materials or documents to the public. The

agencies agree to inform each other if it is determined that there is a legal requirement to release any such information, and that information will include expected release date of the information.

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D. **SEVERABILITY.** Should any portion of this MOU be judicially determined to be illegal or unenforceable, the remainder of the MOU shall continue in full force and effect, and any party may renegotiate the terms affected by the severance.

E. **THIRD PARTY BENEFICIARY RIGHTS.** The parties do not intend to create in any other individual or entity the status of third party beneficiary, and this MOU shall not be construed so as to create such status. The rights, duties and obligations contained in this MOU shall operate only among the parties to this MOU, and shall inure solely to the benefit of the parties to this MOU. The provisions of this MOU are intended only to assist the parties in determining and performing their obligations under this MOU.

F. **NON-FUND OBLIGATION DOCUMENT.** This MOU is neither a fiscal nor a funds obligation document. Any endeavor or transfer of anything of value involving reimbursement or contribution of funds between the parties to this instrument will be handled in accordance with applicable laws, regulations, and procedures including those for Government procurement and printing. Such endeavors will be outlined in separate agreements that shall be made in writing by representatives of the parties and shall be independently authorized by appropriate rules, policies, and statutory authority. This MOU does not provide such authority. Specifically, this MOU does not establish authority for noncompetitive award to the cooperator of any contract or other agreement. Nothing herein constitutes a binding commitment to fund any of the proceedings encompassed by the MOU. Any specific cost sharing or funding shall be executed separately through other funding mechanisms, as deemed necessary and appropriate by each of the signatories.

G. **PARTICIPATION IN SIMILAR ACTIVITIES WITH OTHER ENTITIES.** This MOU in no way restricts any of the parties from participating in similar activities with other public or private agencies, organizations, and individuals.

H. **ENDORSEMENT.** Nothing in this MOU may be interpreted to imply that the United States, the Department of the Interior, the NPS, the Bureau of Reclamation, or the cooperating agency endorses any product, service or policy of the other parties. No party will take any action or make any statement that suggests or implies such an endorsement.

I. **STATUTES AND REGULATIONS.** The provisions of any statutes and/or regulations cited in this MOU contain legally binding requirements. The MOU itself does not alter, expand, or substitute for those provisions or regulations. This MOU does not impose legally-

XII. Signatures

The parties hereto have executed this Memorandum of Understanding as of the dates shown below.

BUREAU OF RECLAMATION

Larry Walkoviak — Date August 3, 2012
Regional Director
Upper Colorado Region
Bureau of Reclamation

NATIONAL PARK SERVICE

Herbert C. Frost — Date 9/6/2012
Associate Director for Natural Resources, Stewardship and Science
National Park Service

John Wessels — Date 8/13/12
Regional Director
Intermountain Region
National Park Service

for Christine Lehnertz — Date 8/29/12
Regional Director
Pacific West Region
National Park Service

THE PUEBLO OF ZUNI

For: Arlen Quetawki Sr., Governor — Date 07-26-12

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ATTACHMENT N.2

(a) Multiple Tribes

United States Department of the Interior

BUREAU OF RECLAMATION
Upper Colorado Regional Office
125 South State Street
Salt Lake City, UT 84138

NATIONAL PARK SERVICE
Intermountain Region Office
12795 Alameda Parkway
Denver, CO 80225

November 30, 2011

Bernadine Jones, Chairwoman
The Havasupai Tribe
PO BOX 10
Supai, AZ 86435

Dear Ms. Jones,

The Department of the Interior, through the Bureau of Reclamation (Reclamation) and the National Park Service (NPS) as co-lead agencies, intend to prepare an Environmental Impact Statement (EIS) under the provisions of the National Environmental Policy Act (NEPA) for a Long-Term Experimental and Management Plan (LTEMP) for Glen Canyon Dam operations. A primary function of the LTEMP, which will be developed based on tribal and public input and the latest science, will be to review the results of experiments that have been successfully completed and use this information to guide development of future experimental and management actions. Through the LTEMP EIS, alternatives will be developed and evaluated that consider potential future modifications to Glen Canyon Dam operations and other resource management and protection actions.

The Department's decision to develop the LTEMP is a component of its efforts to continue to comply with the ongoing requirements and obligations established by the Grand Canyon Protection Act of 1992 (Pub. L. 102-575) (GCPA) to protect, mitigate adverse impacts to, and improve the conditions for which Grand Canyon National Park and Glen Canyon National Recreation Area were established, while continuing to comply with the Law of the River. Although the GCPA does not apply to the Lake Mead National Recreation Area, effects to the resources at Lake Mead will be considered in the LTEMP EIS. Enclosed please find a map of the project area.

The purpose of this letter is to initiate government-to-government consultation on the LTEMP under Section 106 of the National Historic Preservation Act of 1966 (NHPA), as amended, and other relevant authorities. Through consultation, you will have opportunities to identify concerns related to historic properties, including traditional cultural properties and archaeological sites, natural resources, Indian trust assets as appropriate, and other issues of importance to your tribe. The NPS and Reclamation intend to follow 36 CFR 800.8(c), and use the process and documentation required for the preparation of all NEPA documents to comply with Section 106 in lieu of the procedures set forth in Sections 800.3 through 800.6.

The NPS and Reclamation began the NEPA Public Scoping process for this EIS with publication of the Notice of Intent in the Federal Register on July 6, 2011. We recently completed seven initial public scoping meetings; the deadline for receiving public comments on the scope of the EIS is January 31, 2012. More information can be found on the project website at http://ltempeis.anl.gov/.

Effects of the operations of Glen Canyon Dam have been evaluated for more than 20 years. The 1995 EIS for Glen Canyon Dam operations and the subsequent Glen Canyon Dam Adaptive Management Program have allowed us to better understand the relationship of water releases and downstream effects. The LTEMP EIS will draw on the research and knowledge we have acquired, and continue to acquire, to determine how the dam is operated for the next 20 years.

If you are interested in consulting on the LTEMP, please contact us at your earliest convenience and identify a point of contact for communication. If you would like to schedule meetings with us, please let us know as we plan to schedule these meetings by the end of January 2012, and conduct them as soon as is practicable. We will provide opportunities to meet and consult with you throughout the EIS process. Please contact Jan Balsom at (928) 638-7758 or Janet Cohen at (928) 638-7445, Grand Canyon National Park, or Keith Waldron, Bureau of Reclamation, at (801) 524-3816 at your earliest convenience.

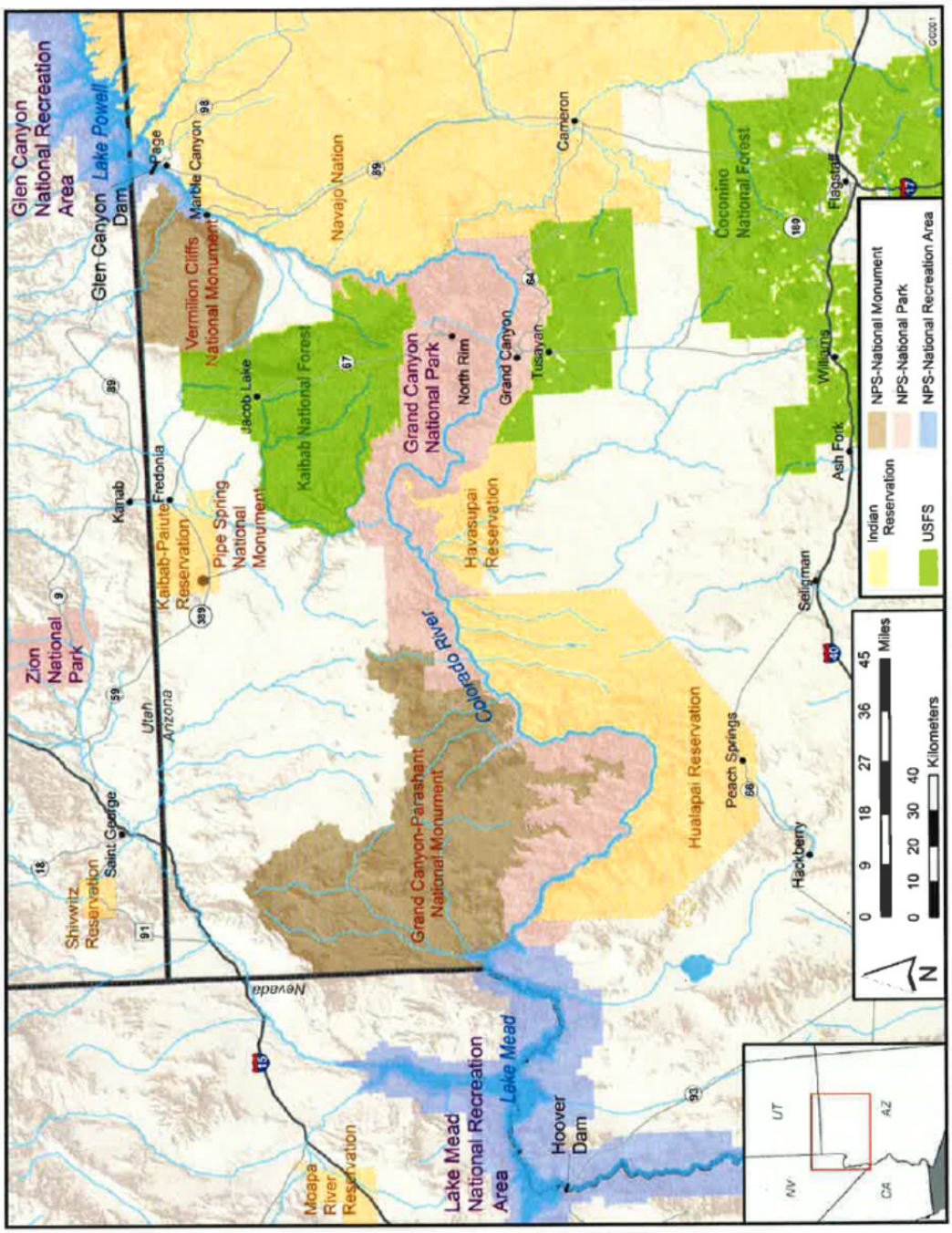
Sincerely,

Larry Walkoviak
Regional Director
Upper Colorado Region
Bureau of Reclamation

John Wessels
Regional Director
Intermountain Region
National Park Service

Enclosure: Project area map

cc: GRCA: Superintendent Uberuaga, Martha Hahn, Jan Balsom, Janet Cohen
LAKE: Superintendent Dickenson, Kent Turner, Steve Daron
GLCA: Superintendent Brindle, Brian Carey, Chris Hughes, Rosemary Sucec
IMR/WASO: Rob Billerbeck, Tammy Whittington, Karen Breslin, Chris Turk, Bert Frost, Pat Walsh
BOR: Beverley Heffernan, Glen Knowles, Keith Waldron
DOI: Jane Lyder, Lori Caramanian
Travis Hamidreek, Natural Resources


Glen Canyon National Recreation Area
Lake Powell
Glen Canyon Dam
Page
Marble Canyon
Vermilion Cliffs National Monument
Navajo Nation
Cameron
Coconino National Forest
Flagstaff
Jacob Lake
Kaibab National Forest
Grand Canyon National Park
North Rim
Grand Canyon
Tusayan
Williams
Ash Fork
Kanab
Fredonia
Kaibab-Paiute Reservation
Pipe Spring National Monument
Havasupai Reservation
Zion National Park
Utah
Arizona
Colorado River
Seligman
Peach Springs
Hualapai Reservation
Hackberry
Saint George
Shivwitz Reservation
Grand Canyon-Parashant National Monument
Nevada
Lake Mead National Recreation Area
Lake Mead
Hoover Dam
Moapa River Reservation
NPS-National Monument
NPS-National Park
NPS-National Recreation Area
Indian Reservation
USFS
Miles
Kilometers
N
UT
AZ
NV
CA

List of Recipients

Name	2ndName	Tribe	Add1	Add2	City	Cc1	Cc2	Cc3
Louis Manuel, Jr., Chairperson		Ak Chin Indian Community	42507 W. Peters & Nail Road		Maricopa, AZ 85138			
Charles Wood, Chairperson		Chemehuevi Tribal Council	PO BOX 1976		Chemehuevi Valley, CA 92362			
Cara MacDonald	Director of Cultural Resources	Chemehuevi Tribal Council	PO BOX 1976		Chemehuevi Valley, CA 92363			
Sherry Cordova, Chairperson		Cocopah Indian Tribe	County 15th & Avenue G		Somerton, AZ 85350			
H. Jill McCormick	Cultural Resources Manager	Cocopah Indian Tribe	Co. 15th St. & Ave. G		Somerton, AZ 85350			
Eldred Enas, Chairman		Colorado River Indian Tribes	26600 Mohave Road		Parker, AZ 85344			
Clinton Pattea, President		Fort McDowell Yavapai Tribal Council	PO BOX 17779		Fountain Hills, AZ 85268			
Karen Ray	Cultural Development Office		PO BOX 17779		Fountain Hills, AZ 85268			
Timothy Williams, Chairperson		Fort Mojave Tribal Council	500 Merriman Avenue		Needles, CA 92363			
William R. Rhodes, Governor		Gila River Indian Community Council	PO BOX 97		Sacatone, AZ 85147			
Bernadine Jones, Chairwoman		The Havasupai Tribe	PO BOX 10		Supai, AZ 86435			
Travis Hamidreek	Natural Resources	The Havasupai Tribe	PO BOX 10		Supai, AZ 86435			
Leroy Ned Shingoitewa, Chairman		The Hopi Tribe	PO BOX 123		Kykotsmovi, AZ 86039			
Leigh Kuwanwisiwma	Cultural Preservation Officer	The Hopi Tribe	PO BOX 123		Kykotsmovi, AZ 86039			
Mike Yeatts	Tribal Archaeologist	The Hopi Tribe	PO BOX 123		Kykotsmovi, AZ 86039			
Louise Benson, Chairwoman		The Hualapai Tribe	PO BOX 179		Peach Springs, AZ 86434			
Loretta Jackson-Kelly	Tribal Historic Preservation Officer	The Hualapai Tribe	PO BOX 300		Peach Springs, AZ 86434			
Lee Pasata, President		Jicarilla Apache Nation	PO BOX 507		Dulce, NM 87528			

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Manuel Savala, Chairman		Kaibab Band of Paiute Indians	Tribal Affairs Building	HC-65, Box 2	Pipe Spring, AZ 86022			
Charley Bullets	Cultural Resource Director	Kaibab Band of Paiute Indians	Tribal Affairs Building	HC-65, Box 2	Pipe Spring, AZ 86022			
Tonia Means, Chairperson		Las Vegas Tribe of Paiute Indians	One Paiute Drive		Las Vegas, NV 89106			
Ramona Salazar		Las Vegas Tribe of Paiute Indians	One Paiute Drive		Las Vegas, NV 89106			
Kenny Anderson		Las Vegas Tribe of Paiute Indians	One Paiute Drive		Las Vegas, NV 89106			
William Anderson, Chairman		Moapa Band of Paiute Indians	PO BOX 340		Moapa, NV 89025			
Deanna Domingo	Cultural Committee	Moapa Band of Paiute Indians	PO BOX 340		Moapa, NV 89025			
Ben Shelly, President		The Navajo Nation	PO Box 7440		Window Rock, AZ 86515			
Alan Downer	Historic Preservation Officer	The Navajo Nation	PO BOX 4950		Window Rock, AZ 86515			
Tony Joe	Supervisory Anthropologist	The Navajo Nation	Division of Natural Resources	PO BOX 4950	Window Rock, AZ 86515			
Jeff Cole	Navajo Fish and Game Department	The Navajo Nation	PO Box 1480		Window Rock, AZ 86515			
Stanley M. Pollack	Assistant Attorney General	Department of Justice	The Navajo Nation	P.O. Drawer 2010	Window Rock, AZ 86515			
Ron Lovato, Governor		Ohkay Owingeh	PO BOX 1099		San Juan Pueblo, NM 87566			
Jeannine Borchardt, Chairperson		Paiute Indian Tribe of Utah	440 North Paiute Drive		Cedar City, UT 84720			
Dorena Martineau		Paiute Indian Tribe of Utah	440 North Paiute Drive		Cedar City, UT 84720			
Peter Yucupicio, Chairperson		The Pascua Yaqui Tribe	7474 S. Camino de Oeste		Tucson, AZ 85746			
Randall Vicente, Governor		The Pueblo of Acoma	PO BOX 309		Acoma, NM 87034			

Robert B. Pecos, Governer		The Pueblo of Cochiti	PO BOX 70		Cochiti, NM 87072			
Michael Toledo, Jr., Governor		The Pueblo of Jemez	PO BOX 100		Jemez Pueblo, NM 87024			
Richard B. Luarkie, Governor		The Pueblo of Laguna	PO BOX 194		Laguna, NM 87026			
Ernest Mirabel, Governor		The Pueblo of Nambe	Route 1	Box 117-BB	Santa Fe, NM 87501			
George Rivera, Governor		The Pueblo of Pojoaque	7800 Cities of Gold Road		Santa Fe, NM 87506			
Raymond Sandoval, Jr., Governor		The Pueblo of San Felipe	PO BOX 4339		San Felipe, NM 87001			
Malcolm Montoya, Governor		The Pueblo of Sandia	481 Sandia Loop		Bernalillo, NM 87004			
Lawrence Montoya, Governor		The Pueblo of Santa Ana	2 Dove Road		Santa Ana Pueblo, NM 87004			
Walter Dashend, Governor		The Pueblo of Santa Clara	PO BOX 580		Espanola, NM 87532			
Mark Mitchell, Governor		The Pueblo of Tesuque	RR 42	Box 360-T	Santa Fe, NM 87506			
Marcellus Medina		The Pueblo of Zia	135 Capitol Square Drive		Zia Pueblo, NM 87053			
Arlen P. Quetawki, Sr., Governor		The Pueblo of Zuni	PO BOX 339		Zuni, NM 87327			
Kurt Dongoske	Zuni Heritage and Historic Preservation Office	The Pueblo of Zuni	PO BOX 339		Zuni, NM 87327			
Mike Jackson, Sr., President		Fort Yuma Quechan Tribe	PO BOX 1899		Yuma, AZ 85366			
Pauline Jose	Cultural Preservation Committee	Fort Yuma Quechan Tribe	PO BOX 1899		Yuma, AZ 85366			
Keeney Escalanti Sr.	Vice President	Fort Yuma Quechan Tribe	PO BOX 1899		Yuma, AZ 85366			
Diane Enos, President		Salt River Pima-Maricopa Indian Community	10005 E. Osborn		Scottsdale, AZ 85256			
Shane Anton	Cultural Resources Dept.	Salt River Pima-Maricopa Indian Community	10005 E. Osborn		Scottsdale, AZ 85256			

Mary Kim Titla, Chairwoman		San Carlos Apache Tribe	PO BOX 1240		San Carlos, AZ 85550			
Lee Choe	Interim Chair	San Juan Southern Paiute Tribe	PO Box 1989		Tuba City, AZ 86045			
Kelly Youngbear, Superintendent		Southern Paiute Agency	BIA	PO BOX 720	St. George, UT 84771			
Matthew J. Box, Chairman		Southern Ute Tribal Council	PO BOX 737		Ignacio, CO 81137			
Neil Cloud	NAGPRA Coordinator	Southern Ute Tribal Council	PO BOX 737		Ignacio, CO 81137			
Ned Norris, Jr.		Tohono O'odham Nation	PO BOX 837		Sells, NM 85634			
Ivan Smith, Chairman		Tonto Apache	Tonto Apache Reservation #30		Payson, AZ 85541			
Richard Jenks, Chairman		Ute Indian Tribe	PO BOX 190		Ft. Duchesne, UT 84026-0190			
Ms. Betsy Chapoose	Cultural Rights and Protection Office	Ute Indian Tribe	PO BOX 190		Ft. Duchesne, UT 84026-0190			
Gary Hayes, Chairman		Ute Mountain Ute Tribe	P. O. Box JJ		Towaco, CO 81334			
Terry Knight, Sr.		Tribal Historic Preservation Officer	Ute Mountain Ute Tribe	PO BOX 468	Towaco, CO 81334			
Ronnie Lupe, Chairman		White Mountain Apache	PO BOX 700		Whiteriver, AZ 85941			
Mark T. Altaha	Historic Preservation Office	White Mountain Apache	PO BOX 507		Fort Apache, AZ 85926			
David Kwail, Chairman		Yavapai-Apache Nation	2400 W. Datsi Street		Camp Verde, AZ 86322			
Chris Coder		Yavapai-Apache Nation	2400 W. Datsi Street		Camp Verde, AZ 86322			
Ernest Jones, Sr., President		Yavapai-Prescott Indian Tribe	530 E. Merritt		Prescott, AZ 86301			
Linda Ogo	Cultural Research Committee	Yavapai-Prescott Indian Tribe	530 E. Merritt		Prescott, AZ 86301			

United States Department of the Interior

BUREAU OF RECLAMATION
Upper Colorado Regional Office
125 South State Street
Salt Lake City, UT 84138

NATIONAL PARK SERVICE
Intermountain Region Office
12795 Alameda Parkway
Denver, CO 80225

December 8, 2011

Bernadine Jones
Chairwoman
The Havasupai Tribe
PO BOX 10
Supai, AZ 86435

Dear Chairwoman Jones:

The Department of the Interior, through the Bureau of Reclamation (Reclamation) and the National Park Service (NPS) as co-lead agencies, intends to prepare an Environmental Impact Statement (EIS) under the provisions of the National Environmental Policy Act (NEPA) for a Long-Term Experimental and Management Plan (LTEMP) for Glen Canyon Dam operations. A primary function of the LTEMP, which will be developed based on cooperator, tribal, and public input and the latest science, will be to review the results of experiments that have been successfully completed and use this information to guide development of future experimental and management actions. The LTEMP is intended to develop and implement a structured, long-term experimental and management plan, to determine the need for potential future modifications to Glen Canyon Dam operations, and to determine whether to establish an Endangered Species Act Recovery Implementation Program for endangered fish species below Glen Canyon Dam.

The Department's decision to develop the LTEMP is a component of its efforts to continue to comply with the ongoing requirements and obligations established by the Grand Canyon Protection Act of 1992 (Pub. L. 102-575) (GCPA) to protect, mitigate adverse impacts to, and improve the conditions for which Grand Canyon National Park and Glen Canyon National Recreation Area were established, while continuing to comply with the Law of the River. Although the GCPA does not apply to the Lake Mead National Recreation Area, effects to the resources at Lake Mead will be considered in the LTEMP EIS. Enclosed, please find a map of the project area.

Effects of the operations of Glen Canyon Dam have been evaluated for more than 20 years. The 1995 EIS for Glen Canyon Dam operations and the subsequent Glen Canyon Dam Adaptive Management Program have allowed us to better understand the relationship of water releases and downstream effects. The LTEMP EIS will draw on this existing research and knowledge to determine how the dam will be operated in the future.

In accordance with 40 CFR 1501.6 of the Council on Environmental Quality's (CEQ) regulations for implementing the procedural provisions of NEPA, and 43 CFR 46.225 of the Department of

the Interior's regulations for implementation of NEPA, the NPS and Reclamation are inviting the Havasupai Tribe to be a cooperating agency in the LTEMP EIS process. Your participation in the LTEMP EIS process will assist us in making a more informed decision. Participation as a cooperating agency does not imply that your agency supports the proposed project.

The scope of your agency's involvement as a cooperating agency should include those areas, resources, or issues under its jurisdiction or within its area of expertise. Should your agency choose to assume cooperating status, your specific responsibilities as a cooperating agency will include:

- Participation in the NEPA scoping and environmental review process including draft document review.
- Providing comments on the project's purpose and need, goals and objectives, methodologies, and range of alternatives.
- Providing comment on project coordination and project schedule.
- Providing (upon request of the co-lead agencies) information and assistance with the preparation of environmental analyses (portions of the NEPA documents relevant to your agency's jurisdiction or area of special expertise).
- Providing staff support at the lead agencies' request to enhance the agencies' interdisciplinary capability.
- Using your agency's own funds for participation.

An email was sent from Anne Castle, Assistant Secretary of the Department of the Interior, on January 21, 2011, to determine preliminary interest from potential cooperating agencies. An initial meeting with potential cooperators was held on February 11, 2011, to address questions and concerns related to this process. To follow up on these initial contacts, we now ask that you formally let us know if you would like to participate as a cooperating agency in the development of the LTEMP EIS. Should the Havasupai Tribe choose to decline cooperating agency status in part or in whole, we ask that you confirm this in writing. We have enclosed a form to facilitate your response to this cooperating agency invitation and ask that you complete and return this form, or otherwise respond in writing, not later than Friday, January 6, 2012.

At this time we are tentatively planning cooperator meetings in Phoenix sometime in February 2012. We will arrange for phone-in capability for all cooperating agency meetings. If you have any questions, please contact the EIS project managers, Beverley Heffernan, Bureau of Reclamation, at (801) 524-3712, or Rob Billerbeck, National Park Service, at (303) 987-6789. We look forward to working with you in developing the LTEMP EIS.

Sincerely,

Larry Walkoviak
Regional Director
Upper Colorado Region
Bureau of Reclamation

John Wessels
Regional Director
Intermountain Region
National Park Service

Enclosures: Response Form and Project Area Map

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cc: GRCA: Superintendent Uberuaga, Martha Hahn, Jan Balsom,
LAKE: Superintendent Dickenson, Kent Turner,
GLCA: Superintendent Brindle, Brian Carey, Chris Hughes,
IMR/WASO: Rob Billerbeck, Tammy Whittington, Karen Breslin, Chris Turk, Bert Frost, Pat Walsh
BOR: Beverley Heffernan, Glen Knowles
DOI: Jane Lyder, Lori Caramanian

List of Recipients

Name	2ndName	Tribe	Add1	Add2	City	Cc1	Cc2	Cc3
Bernadine Jones, Chairwoman		The Havasupai Tribe	PO BOX 10		Supai, AZ 86435			
Leroy Ned Shingoitewa, Chairman		The Hopi Tribe	PO BOX 123		Kykotsmovi, AZ 86039			
Louise Benson, Chairwoman		The Hualapai Tribe	PO BOX 179		Peach Springs, AZ 86434			
Manuel Savala, Chairman		Kaibab Band of Paiute Indians	Tribal Affairs Building	HC-65, Box 2	Pipe Spring, AZ 86022			
Tonia Means, Chairperson		Las Vegas Tribe of Paiute Indians	One Paiute Drive		Las Vegas, NV 89106			
William Anderson, Chairman		Moapa Band of Paiute Indians	PO BOX 340		Moapa, NV 89025			
Ben Shelly, President		The Navajo Nation	PO Box 7440		Window Rock, AZ 86515			
Jeannine Borchardt, Chairperson		Paiute Indian Tribe of Utah	440 North Paiute Drive		Cedar City, UT 84720			
Arlen P. Quetawki, Sr., Governor		The Pueblo of Zuni	PO BOX 339		Zuni, NM 87327			
Lee Choe	Interim Chair	San Juan Southern Paiute Tribe	PO Box 1989		Tuba City, AZ 86045			
David Kwail, Chairman		Yavapai-Apache Nation	2400 W. Datsi Street		Camp Verde, AZ 86322			

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Glen Canyon Dam
Long Term Experimental and Management Plan (LTEMP)
Cooperating Agency Interest

Please return this form by January 6, 2012, to indicate your interest in participating as a cooperating agency in the development of a Long-Term Experimental and Management Plan and Environmental Impact Statement for the Glen Canyon Dam.

A cooperating agency agreement will be developed to identify the specific roles and responsibilities of each agency. In general, cooperating agencies provide information in their areas of special expertise, which will assist the Bureau of Reclamation and the National Park Service in making a more informed decision.

_____ Yes, we are interested in participating as a cooperating agency.

_____ No, we are not interested in participating as a cooperating agency.

Agency: _____

Contact: _____

Title: _____

Office: _____

Address: _____

_____

_____

Direct Phone: _____

Office Phone: _____

Mobile Phone: _____

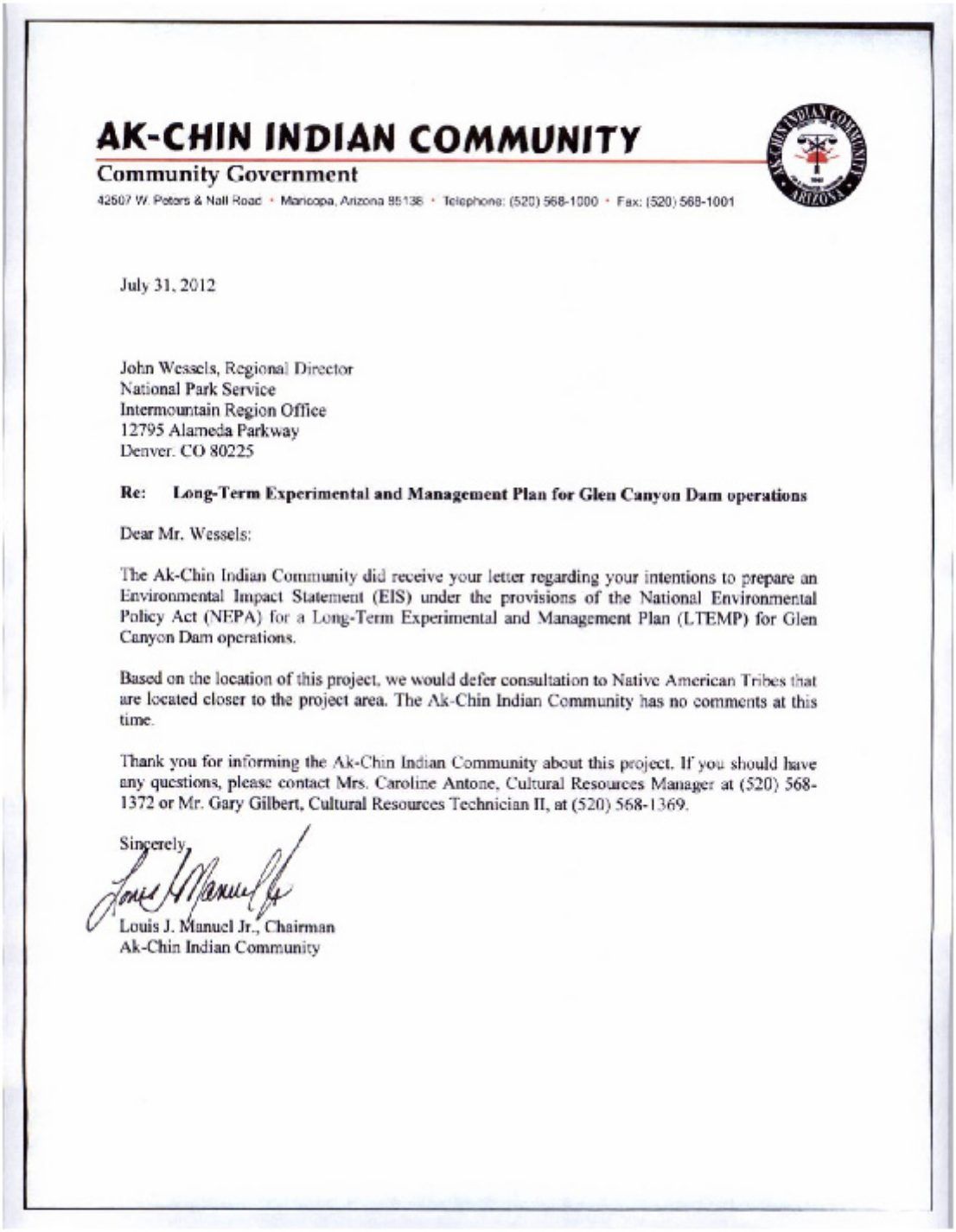
Fax: _____

Email: _____

Please return the form by January 6, 2012 to:

Glen Canyon Dam LTEMP EIS Cooperators
Argonne National Laboratory
9700 S. Cass Ave. – EVS/240
Argonne IL 60439

(b) Ak-Chin Indian Community



AK-CHIN INDIAN COMMUNITY

Community Government

42507 W. Peters & Nall Road • Maricopa, Arizona 85138 • Telephone: (520) 568-1000 • Fax: (520) 568-1001

July 31, 2012

John Wessels, Regional Director
National Park Service
Intermountain Region Office
12795 Alameda Parkway
Denver. CO 80225

Re: Long-Term Experimental and Management Plan for Glen Canyon Dam operations

Dear Mr. Wessels:

The Ak-Chin Indian Community did receive your letter regarding your intentions to prepare an Environmental Impact Statement (EIS) under the provisions of the National Environmental Policy Act (NEPA) for a Long-Term Experimental and Management Plan (LTEMP) for Glen Canyon Dam operations.

Based on the location of this project, we would defer consultation to Native American Tribes that are located closer to the project area. The Ak-Chin Indian Community has no comments at this time.

Thank you for informing the Ak-Chin Indian Community about this project. If you should have any questions, please contact Mrs. Caroline Antone, Cultural Resources Manager at (520) 568-1372 or Mr. Gary Gilbert, Cultural Resources Technician II, at (520) 568-1369.

Sincerely,

Louis J. Manuel Jr., Chairman
Ak-Chin Indian Community

(c) Gila River Indian Community

GILA RIVER INDIAN COMMUNITY
POST OFFICE BOX 2140, SACATON, AZ 85147

TRIBAL HISTORIC PRESERVATION OFFICE
(520) 562-7162
Fax: (520) 562-5083

January 3, 2012

John Wessels, Regional Director
National Park Service
Intermountain Region Office
12795 Alameda Parkway
Denver, Colorado 80225

RE: Department of the Interior, Bureau of Reclamation and National Park Service Co-Lead Agencies, Environmental Impact Statement (EIS) Preparation Long Term Experimental and Management Plan (LTEMP) Glen Canyon Dam Operations

Dear Mr. Wessels,

The Gila River Indian Community Tribal Historic Preservation Office (GRIC-THPO) has received your letter initiating government-to-government consultation regarding the preparation of an EIS for operations at the Glen Canyon Dam. The GRIC-THPO would be an interested consulting entity and we can be reached at the address listed on the letterhead. The proposed project area is within the ancestral lands of the Four Southern Tribes (Gila River Indian Community; Salt River Pima-Maricopa Indian Community; Ak-Chin Indian Community and the Tohono O'Odham Nation).

Thank you for consulting with the GRIC-THPO on this project. If you have any questions please do not hesitate to contact me or Archaeological Compliance Specialist Larry Benallie, Jr. at 520-562-7162.

Respectfully,

Barnaby V. Lewis
Tribal Historic Preservation Officer
Gila River Indian Community

(d) Havasupai Tribe

Glen Canyon Dam
Long Term Experimental and Management Plan (LTEMP)
Cooperating Agency Interest

Please return this form by January 6, 2012, to indicate your interest in participating as a cooperating agency in the development of a Long-Term Experimental and Management Plan and Environmental Impact Statement for the Glen Canyon Dam.

A cooperating agency agreement will be developed to identify the specific roles and responsibilities of each agency. In general, cooperating agencies provide information in their areas of special expertise, which will assist the Bureau of Reclamation and the National Park Service in making a more informed decision.

✓ Yes, we are interested in participating as a cooperating agency.

_____ No, we are not interested in participating as a cooperating agency.

Agency: Havasupai Tribe
Contact: Don Watahomigie
Title: Chairman
Office: Havasupai Tribal Council
Address: Box 10
Supai, AZ 86435

Direct Phone: 928-660-0023
Office Phone: 928-448-2731 → main Tribal office # Tribal Secretary is Joycee Manakaja
Mobile Phone:
Fax: 928-448-2551
Email: htchair@havasupai-nsn.gov

Please return the form by January 6, 2012 to:

Glen Canyon Dam LTEMP EIS Cooperators
Argonne National Laboratory
9700 S. Cass Ave. – EVS/240
Argonne IL 60439

HAVASUPAI TRIBAL COUNCIL
P.O. BOX 10 • SUPAI, ARIZONA 86435
(928) 448-2731 • FAX (928) 448-2551

June 21, 2012

Kirk E. LaGory, Ph.D.
Environmental Science Division
Argonne National Laboratory
9700 s. Cass Ave., Building 240
Argonnc, Ill. 60439

Sent via email to lagory@anl.gov and via mail

Re: Comments on Preliminary Draft LTEMP Alternatives

Dr. LaGory,

We thank the NPS and BoR for the opportunity to work on the LTEMP EIS process as a cooperating agency. We have reviewed the Preliminary Draft Alternatives distributed for Cooperating Agency Review on June 7, 2012 and have the following comments.

The Havasupai Tribe supports operation of Glen Canyon Dam in a way that is closest to natural conditions prior to construction of the dam. The Havasupai have resided in the study area since time immemorial. Significant religious, cultural and historical sites are located in that part of the river corridor that is within their aboriginal territory.

As a matter of form and in recognition of the Secretary's trust responsibility to the Tribe, the Havasupai request that in the lists of considerations "Indian Tribal interests" be listed before ESA. (see page 2)

The Havasupai Tribe requests that the following actions be added to the Elements Potentially Common to All Alternatives:

1. Protection of burial sites and artifacts from erosion and exposure from high flows. In previous flood events burial sites and artifacts of the Havasupai located along the river have been exposed.

2. Timely notice to the Havasupai of changes in flow regimes. Numerous people access the river corridor through the Havasupai Reservation and their safety depends on adequate notice from the Tribe of potential hazards within the River Corridor.
3. River flow regimes should not disrupt the flow of springs close to the river.

Draft Alternative #1, Condition-Dependent Adaptive Strategy is not developed sufficiently to provide comments. The decision tree process cannot be evaluated without knowing the conditions and triggers that will prompt different decisions to be made.

Draft Alternative #3, No Action, includes modifications in the current Adaptive Management Plan as required by other decisions. In order to provide a baseline for comparison of Alternatives and comparison of the decisions under this EIS to the current Adaptive Management Plan, the No Action alternative should describe in detail current conditions. If the current conditions will change prior to implementation of the LTEMP this should be explained in detail so that comparisons may be made and cumulative impacts determined.

Thank you for the opportunity to participate in this process. We look forward to working with you.

Sincerely,

Don Watahomigie, Chairman

From: Carr, Adrianne E.
Sent: Thursday, August 09, 2012 3:38 PM
To: 'Don E. Watahomigie (htchair@havasupai-nsn.gov)'; 'Jaycee Manakaja (htsec1@havasupai-nsn.gov)'
Cc: 'Margaret Vick'; Heffernan, Beverley; Knowles, Glen; Billerbeck, Rob P.; LaGory, Kirk E.
Subject: Response to Havasupai Tribe's comments on June 7 LTEMP Alternatives document

Please find the responses to the Havasupai Tribe's comments on the preliminary draft LTEMP Alternatives document for cooperating agencies.

Very best regards,
Adrianne

`~^
Adrianne Carr, Ph.D.
Hydrologist
Environmental Science Division
Argonne National Laboratory
9700 S. Cass Avenue, EVS-240
Argonne, IL 60439

630-252-1572 (office)
650-799-2625 (mobile)
adrianne@anl.gov

Response to Havasupai Tribal Council Comments Received on Preliminary Draft Alternatives

Thank you for your comments, your input is appreciated and helpful for the development of this EIS. Regarding your comment about the order of the tribal trust responsibilities in relation to ESA in the "Need" statement, we did not intend to imply any priority in the listing of items. Both responsibilities are important for this EIS.

Regarding the elements that you mentioned in your letter:

1. Impacts to burial sites and artifacts will be considered in the LTEMP EIS. As a part of compliance with both the NHPA and the GCPA, a goal of alternatives developed for the EIS will be to protect and where possible improve sites. In the context of your comment, we know that if additional sediment in certain areas would help reduce the likelihood of unwanted exposure of burials or other sites, this would be a desirable outcome.

2. The recently signed MOA for the High Flow Experiment Protocol EA provides that there will be at a minimum a 30-day notice for any high flow experiment. We expect to propose similar steps for any new actions under the LTEMP EIS.

3. The EIS team plans to examine impacts to all resources. We would like further explanation as to what the Havasupai mean by "disrupt the flow of springs close to the river." There has been research on these groundwater-fed springs, but we want to make sure that we understand your concerns before responding to this comment.

Draft Alternative #1. Thank you for your comment. We agree that the draft alternatives documented dated June 7, 2012, did not contain sufficient information for full evaluation, but we did want to circulate it for cooperating agency anyway in order to maximize cooperators' opportunities for input on the development of alternatives.

Draft Alternative #3. We agree that the EIS should fully describe current conditions and this will be appropriately captured in the 'affected environment' section of the EIS. The no action alternative is by definition how the Glen Canyon Dam will be operated in the future should none of the LTEMP EIS action alternatives be selected for implementation. This means that 'no action' would be continued operation under the 1996 ROD plus implementation of the HFEP and nonnative fish control in accordance with the two recently issued Findings of No Significant Impact.

From: Margaret Vick [mailto:mjvick@gmail.com]
Sent: Wednesday, August 29, 2012 9:18 PM
To: LaGory, Kirk E.
Cc: Tribal Chair; htvchair@havasupai-nsn.gov; Uberuaga, David V.; Balsom, Janet R.; Heffernan, Beverley; Amy Heuslein; Carr, Adrianne E.
Subject: Havasupai Comments on Tribal Perspectives and Process

Dr. LaGory,

Please find attached two documents: the comments and revised text from the Havasupai Tribe for the section titled Tribal Perspectives and my comments as attorney for the Havasupai Tribe on the EIS process for incorporating tribal input.

The Havasupai Tribal Council discussed the draft section on Tribal Perspectives at several different tribal council meetings. They want to point out to the consultants drafting these documents that the Havasupai do not share a common origin story with other Pai tribes. It should also be noted that the exclusive aboriginal territory of the Havasupai as determined by the Indian Claims Commission was from the Colorado River on the north to the Little Colorado River on the east to the San Francisco Peaks, south to Bill Williams Mountain and on the west to the Aubry Cliffs. Other tribes now claim areas within the Havasupai aboriginal territory but the Havasupai do not support this and the ICC found otherwise.

The attached statement of the Havasupai relationship to the affected area is the only statement that has been approved for inclusion.

Thank you for your cooperation.

Best regards,

Margaret Vick

Margaret J. Vick, JSD
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mjvick@gmail.com

Margaret J. Vick, PLC

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Tempe, AZ 85281

602 814 7666
mjvick@gmail.com

August 27, 2012

Kirk E. LaGory PhD
Argonne National Laboratory
9700 s. Cass ave., Building 240
Argonne, Il 60439

Sent via email: lagory@anl.gov

Re: Tribal consultation and incorporation of information in the LTEMP EIS

Dear Dr. LaGory,

I represent the Havasupai Tribe and provide these comments on the process for inclusion of data and information from Tribes in the LTEMP EIS. This letter incorporates my comments made at the LTEMP Tribal Consultation meeting in Tempe on August 10, 2012.

1. Draft "American Indian Perspectives and Values Related to the Glen Canyon Dam Long-Term Experimental and Management Plan Environmental Impact Statement," prepared by Jennifer Abplanalp and Burce Verhaaren, Argonne National Laboratory.

The EIS for operations of Glen Canyon Dam is not the appropriate document to discuss tribal religious practices, religious origins for Native Americans, regional religious connections or other matters not related to the federal action at issue, the operations of Glen Canyon Dam. Information written by a consultant based on third party publications is suspect to many tribal members and should not be re-published in this document.

The Grand Canyon National Park and the Bureau of Reclamation, the co-lead agencies are both within the Department of Interior and have long standing relationships with the Tribes and Native Americans within the affected region. Those Tribes for whom the operations of Glen Canyon Dam may be of concern have been identified as potential cooperating agencies and the process includes them in tribal consultations. Each Tribe's religious, cultural and historical connection to the Grand Canyon and surrounding area does not need to be, and cannot be, written into a Tribal Perspectives section of this EIS and remain consistent with those beliefs.

Tribal governments have limited resources to participate in federal EIS processes. Those resources are better used for the substantive issues of concern to the EIS, not refuting third party information published in books and reports.

The descriptions of individual Tribal histories in the Tribal Perspectives section as circulated for comment, do not include tribal perspectives on the operations of Glen Canyon Dam and should be deleted from the EIS.

2. Use of Tribal Comments.

The authorized representatives of Tribes will present data, information and comments on many different aspects of the EIS. The Tribal input must be given the same consideration, weight and prominence as other input on the substantive topics. An EIS that reproduces Tribal input in its own section or attaches it as an appendix relegates this input to a class of information separate from "scientific" information. The Decision Maker and the public providing comments on the EIS should have all information on a topic presented in a manner that permits a comprehensive and comparative review.

For example, at the consultation meetings representatives of the Zuni Tribe expressed concerns over the treatment of fish within the Colorado River in particular efforts to control the rainbow trout population. This information should be included in the section on fish, not in a separate Tribal or Zuni section.

The Havasupai Tribe requested notification of high-flow releases in sufficient time to warn hikers within Havasu Canyon. This is a safety concern for recreational users and should be included in the appropriate section.

Appropriate references and attribution to Tribal input may be included in the text similar to other citations. For example, references might look like this: Havasupai, 2012a, Letter from Chairman, Havasupai Tribe, August 10, 2012, on file.

3. Cultural Resources.

The Grand Canyon Protection Act requires that the Secretary operate Glen Canyon Dam "in such a manner as to protect, mitigate adverse impacts to, and improve the values for which Grand Canyon National Park and Glen Canyon National Recreation Area were established, including, but not limited to natural and cultural resources…." Tribal governments and Native Americans have worked with the NPS for decades to identify and protect religious and cultural resources within GCNP and Glen Canyon. The natural environment of the Grand Canyon is significant to Native Americans. The resources are well known to the NPS.

This EIS process should not require a new listing or cultural resources through separate identification of sites, a separate listing or Tribal specific descriptions of locations, their uses or the importance of cultural resources. Consultations with Tribal government

representatives and with Native Americans may be used for clarification and to avoid omissions and is important to the process. However, the requirements of federal law, the Grand Canyon Protection Act and the trust obligation of the Secretary require an analysis of impacts to all cultural resources already known to the Department of Interior. Tribes are not required to submit separate listings for this EIS.

If you have any questions or would like to discuss these comments, please contact me.

Best regards,

Margaret J. Vick, JSD

Cc via email: Don Watahomigie, Chairman
Matthew Putesoy, Vice Chairman
David Uberuaga, Supt. GCNP
Jan Balsom, GCNP
Beverly Heffernon, BoR
Amy Heuslein, BIA
Adrianne E. Carr, Argonne

August 29, 2012

Comments of the Havasupai Tribe on:

AMERICAN INDIAN PERSPECTIVES AND VALUES
RELATED TO THE GLEN CANYON DAM
LONG-TERM EXPERIMENTAL AND MANAGEMENT PLAN
ENVIRONMENTAL IMPACT STATEMENT

Prepared by
Jennifer Abplanalp and Bruce Verhaaren
Environmental Science Division
Argonne National Laboratory

The Havasupai Tribe requests that if the section titled American Indian Perspectives is included in a Draft EIS for LTEMP that the sections related to the Pai be revised to delete all references to the Havasupai making clear that the discussion of origins currently in the draft does not apply to Havasupai. The section on the Havasupai Tribe should be limited to the statements set forth below.

Havasupai

The Havasupai Reservation consists of 188,077 acres of canyon and plateau along the western portion of the Grand Canyon's south rim. In 1975, the Grand Canyon National Park Enlargement Act (PL 93-620) restored 185,000 acres to the Havasupai reservation and identified 95,300 acres of traditional use lands within Grand Canyon National Park that were made available for traditional Havasupai practices. The Havasupai Traditional Use Lands are north of the reservation from the plateau to the Colorado River and extend from approximately river mile 116 to river mile 165. (P.L. 93-620)

The Havasupai Tribe and tribal members have a history interwoven with that of Grand Canyon National Park since creation of the Park from within the Havasupai aboriginal territory. Members of the Havasupai Tribe have access to locations of importance within Grand Canyon National Park guaranteed by the 1919 Act to Establish Grand Canyon National Park, (40 Stat. 1175, 1919) and the 1975 Grand Canyon Enlargement Act, (88 Stat. 2089, 1975).

The Havasupai view everything in and around the Grand Canyon as sacred in all aspects of their cultural, spiritual, and traditional life (Reclamation 1995). The Havasupai were signatories to the 1994 PA, yet, chose not to participate in the GCDAMP. The Tribe works closely with the NPS for protection of cultural sites, historic locations and water resources. They are also members of the Native Voices on the Colorado River, a group that works with Grand Canyon Colorado River Outfitters to increase understanding of tribal relationships with Grand Canyon from their own perspective (NVCR 2012).

From: LaGory, Kirk E.
Sent: Thursday, August 30, 2012 10:20 AM
To: Margaret Vick
Cc: Tribal Chair; htvchair@havasupai-nsn.gov; Uberuaga, David V.; Balsom, Janet R.; Heffernan, Beverley; Amy Heuslein; Carr, Adrianne E.; Billerbeck, Rob P.
Subject: RE: Havasupai Comments on Tribal Perspectives and Process

Margaret:

I received your email, the attached Havasupai Tribe comments on the tribal perspectives section, and your letter regarding the EIS process. I will pass this information on to the joint-lead agencies for their consideration in developing the EIS.

Thank you.

Kirk LaGory

~~~~~~~~~~~~~~~~~~~~~~~~~~~~

Kirk E. LaGory, Ph.D.
Environmental Science Division
Argonne National Laboratory
9700 S. Cass Ave., Building 240
Argonne, Illinois 60439

Office: 630-252-3169
Cell: 630-564-3169
Fax: 630-252-6090
~~~~~~~~~~~~~~~~~~~~~~~~~~~~

(e) Hopi Tribe

-----Original Message-----
From: Mike [mailto:Michael.Yeatts@nau.edu]
Sent: Tuesday, August 27, 2013 5:48 PM
To: LaGory, Kirk E.
Cc: Rinkevich, Sarah; Kurt Dongoske; Bulletts, Charley; Tony Joe; Bungart, Peter; Loretta Jackson-Kelly; Leigh Kuwanwisiwma
Subject: Re: Fwd: REMINDER: Comments on LTEMP Performance Metrics and Models

Attached are some comments on the LTEMP performance metrics from the Hopi Tribe-

Mike Yeatts
HCPO

Hopi comments on Draft LTEMP
Performance Metrics (01, August, 2013)

General Comment:
An aspect that is still lacking an adequate integration of tribal values overall in the performance measures. Nine goals were developed by the tribes for consideration as additional goals to those that were developed by the agencies. Of these, five were discarded (not by the tribes) as not being useful for discriminating among the alternatives. Of the four remaining ones, only two were addressed within the final performance metrics, and only partially at that. Looking again at the overall suite of tribal goals and expanding on the performance metrics should be a first start at revising the performance metrics. The following comments will provide some specific thoughts on better addressing the tribal values.

1) Archaeological and Cultural Resources
   The performance metric currently only addresses an (unknown) subset of the archaeological sites. This measure is probably unlikely to measure the overall impacts/benefits to the full suite of archeological sites and certainly does not get at non-archeological historic properties (eg. TCPs).

   For the archeological sites, going back to the Park's monitoring data should provide some other measures with regard to site impacts, flow patterns, visitor effects, etc. Prioritization of sites for treatment was based on this information in the past – hopefully this data can also be used going forward into the future.

   For the TCP's the only mechanism I can see to adequately address them is to have specific culturally focused performance metrics under <u>each</u> of the resource categories for which there is a tribal value. In addition, the "ecosystem health" goal needs to be added as something separate from the "natural processes" goal. This is in effect getting at the overall integrity of the Grand Canyon as a TCP. It may be some type of a summation of the individual resource goal (from a tribal perspective). This could be in effect a summation that is calculated from the other data rather than being directly entered.

   Finally, from the description of the GLCA penalized flow index, this really doesn't get at historic properties in a systematic manner – it seems to primarily capture recreational issues. Instead, there needs to be a performance measure that gets at site stability throughout the system and not just in Glen Canyon. I do agree that using the aeolian deposition completely ignores the Glen Canyon stretch (and likely most of the sites in Grand Canyon.

2) Sanctity of Life
   Measurement of trout removal actions get at one portion of this concept, but do not get at the positive aspects of enhancing opportunities for life. For instance, increasing

habitat for culturally valued birds or animals. As with TCPs, it may be appropriate to add a measure that is the sum of tribal value measures in each of the other specific resource categories.

3) Natural Processes
As currently measured, this is a limited, arbitrary measure of "natural processes" and definitely does not measure system health. In order to be somewhat more rigorous, at a minimum, what is being taken as the "natural pattern" needs to be better defined. Why is only flow and water temperate being used? Why not sediment load, number of species in the riparian zone, percent of the CRE covered by vegetation, number of people present in the canyon, fish species composition, etc? All of these are part of the natural processes. As currently used, this measure is misleading and should either be expanded on or dropped. With what is currently being measured, the desired direction is wrong from the standpoint of Hopi values for the current ecosystem (with a dam in place).

4) Riparian Vegetation
To get at the Hopi values, a metric that looks at marsh habitats might be appropriate as a proxy for on aspect of the canyon as a TCP. In addition, a measure of the "value" of the vegetation as habitat for birds and other animal life would be helpful in addressing the both TCP aspects and sanctity of life. Both the type and coverage may have substantially different carrying capacities and species compositions.

5) Non-native Aquatic Species
Aquatic (or other) parasites that only effect non-native species might be considered a positive development.

6) Recreation
Use of crowding at the head of rapids because of "low" flows is really not an effective measure of wilderness, particularly at the flows that are being considered (if flows below 5,000cfs were in alternatives then there would be more of an issue, particularly with motor boats – though wilderness and motor boat has its own issue).

Also, for the Hopi, anything that increases the amount of recreation, distributes it more broadly throughout the year, or puts more people at greater numbers of places throughout the canyon would be viewed as negative, not positive.

7) Trout Fishery
Increasing the angler catch rate would seem to imply more trout, which might be viewed as not positive some tribes. Similarly with the trout abundance index.

(f) Hualapai Tribe

Jan 06 2012 9:00AM NATURAL RESOURCES 9287692309 page 2

4

Glen Canyon Dam
Long Term Experimental and Management Plan (LTEMP)
Cooperating Agency Interest

Please return this form by January 6, 2012, to indicate your interest in participating as a cooperating agency in the development of a Long-Term Experimental and Management Plan and Environmental Impact Statement for the Glen Canyon Dam.

A cooperating agency agreement will be developed to identify the specific roles and responsibilities of each agency. In general, cooperating agencies provide information in their areas of special expertise, which will assist the Bureau of Reclamation and the National Park Service in making a more informed decision.

XX Yes, we are interested in participating as a cooperating agency.

_____ No, we are not interested in participating as a cooperating agency.

Agency: Hualapai Tribe

Contact: Loretta Jackson-Kelly

Title: THPO/Director of Cultural Resources

Office: Cultural Resources Department

Address: P.O. Box 310
Peach Springs, AZ 86434

Direct Phone: 928-769-2234

Office Phone: 928-769-2223

Mobile Phone: 928-380-4429

Fax: 928-769-2736

Email: loriac@frontiernet.net

Please return the form by January 6, 2012 to:

Glen Canyon Dam LTEMP EIS Cooperators
Argonne National Laboratory
9700 S. Cass Ave. – EVS/240
Argonne IL 60439

From: Peter Bungart [mailto:pbungart@circaculture.com]
Sent: Thursday, June 28, 2012 2:11 PM
To: LaGory, Kirk E.
Cc: 'Loretta Jackson-Kelly'
Subject: RE: LTEMP Preliminary Draft Alternatives

Kirk,
Attached are two documents submitted on behalf of the Hualapai Tribe for the LTEMP EIS preliminary draft alternatives: one is a comment letter and the other a Track Changes version of the alternatives document that was sent out for review. We hope you find the comments useful.
Sincerely,
Peter

Peter Bungart
Hualapai Dept. of Cultural Resources
PO Box 310
Peach Springs AZ 86434
928.769.2223 (office)
928.606.8393 (cell)
-

Hualapai Department of Cultural Resources
P.O. Box 310
Peach Springs, Arizona 86434
Office: 928.769.2223 FAX: 928.769.2235

Kirk E. LaGory, Ph.D.
Environmental Science Division
Argonne National Laboratory
9700 S. Cass Ave., Building 240
Argonne, Illinois 60439

June 27, 2012

In reading the preliminary draft alternatives, it was striking that the various kinds of input resulting from the breakout sessions at the April 2012 LTEMP meeting in Flagstaff were apparently not integrated into this document in any tangible way. It appears the preparers narrowed the focus of the alternatives simply toward managing flows using various protocols that will affect sediment movement and native and non-native fish survival.

We understand that this document outlines preliminary draft alternatives for the LTEMP EIS, but aside from the quote in the *Purpose* section, there is absolutely no acknowledgement of the importance of tribal perspectives or values. This is disheartening, especially considering the past several years of working together, more or less successfully, on the GCDAMP. If the expectation is that tribal concerns will be brought to light later through NEPA consultation, then this approach will surely devolve into an unsatisfactory process. Consider that federal agencies have managed the area undergoing study for a few generations, yet the tribes have called the place home for countless centuries. We urge the preparers to engage the tribes more proactively and more inclusively as soon as possible.

Likewise, there is little reference to the GCPA, or explanations of how each of the preliminary draft alternatives meet its requirements or, conversely, have the potential to adversely affect river corridor resources. It would be helpful if predicted or expected

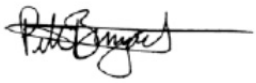
outcomes vis a vis the GCPA were provided in the discussion of alternatives, especially since it is a key component of the EIS.

The various alternatives all seem conceptually very linear, and perhaps overly simplistic in the suggested implementations of proposed actions. There seems to be three main ingredients: flows, fish, and sand. Each alternative seems to be simply variations on a theme, without regard to how their outcome may affect the values of different stakeholders. In addition, although the Colorado River ecosystem and ecological concerns are mentioned in passing, there is little to inform the reader how the various alternatives may actually affect the broader ecosystem, or even most of its components (aside from fish). This seems to be a document mainly concerned with complying with the Endangered Species Act rather than the Grand Canyon Protection Act.

Other comments and suggested language are included in the attached Track Changes version of the Preliminary Draft Alternatives.

If you have any questions, comments, or suggestions please feel free to call Loretta Jackson-Kelly or Peter Bungart at (928) 769-2223. Thank you for your consideration.

Sincerely,



Peter Bungart, Senior Archaeologist
Hualapai Department of Cultural Resources

From: Carr, Adrianne E.

Sent: Thursday, August 09, 2012 3:43 PM

To: Loretta Jackson-Kelly (lorjac@frontiernet.net); Peter Bungart

Cc: Knowles, Glen; Heffernan, Beverley; Billerbeck, Rob P.; LaGory, Kirk E.; Abplanalp, Jennifer Marie; Verhaaren, Bruce T.

Subject: Response to Hualapai Tribe's comments on June 7 LTEMP Alternatives document

Please find the responses to the Hualapai Tribe's comments on the preliminary draft LTEMP Alternatives document for cooperating agencies.

Very best regards,

Adrianne

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Adrianne Carr, Ph.D.

Hydrologist

Environmental Science Division

Argonne National Laboratory

9700 S. Cass Avenue, EVS-240

Argonne, IL 60439

Response to Hualapai Tribe Comments Received on Preliminary Draft Alternatives –

Thank you for your letter dated June 27, 2012 with comments on the LTEMP preliminary alternatives and the process. Your feedback helps us adjust our process and produce a better EIS. Below are our responses to the concerns raised in your letter.

Comment regarding alternatives structured around flows:

As the co-lead agencies worked on developing more detailed alternatives out of the concepts which came out of the April workshop, we did incorporate input received in the breakout sessions and continue to take the results of that workshop into account as we develop the alternatives.

Comment regarding incorporation of tribal perspectives and values in document:

The co-lead agencies place great importance on the input from tribes and we appreciate your feedback. If there are specific ideas on how to be better involved tribes, then we would welcome those specific suggestions. To date we have offered to meet with tribes through the tribal consultation process, and have met with the Hualapai and a number of other tribes. We have also offered additional consultation meetings with the intent of seeking input and feedback from tribes on the draft alternatives, above and beyond the opportunity provided through the cooperating agency relationship. We have also scheduled a meeting with just tribal representatives on August 10th in Phoenix, prior to the cooperating agencies meeting, as another opportunity for face to face dialogue about the LTEMP EIS process and the alternatives. We have also provided draft text for a tribal perspectives section of the EIS, and are continuing to coordinate with tribes on development of that draft, or alternate information from each tribe. As stated in that draft document, our intent is to provide to each interested tribe the opportunity to communicate their values and perspectives in the EIS.

If the Hualapai feel that there are additional steps we can take to enhance your participation in development of the EIS, we urge you to communicate that information to the joint lead project managers.

Concern about Grand Canyon Protection Act (GCPA) and potential effects of the alternatives:

We appreciate the comments regarding Hualapai concerns about the potential effects of the alternatives. At this time we are in the alternatives development phase and it would be premature at this early point in the process to attempt a description of effects or outcomes of the alternatives. The analysis of effects of alternatives to all resources will be undertaken during the process of preparing the draft EIS. At a public forum to be scheduled after the alternatives are developed, there will be presentations to articulate the scientific basis for each flow regime (and non-flow actions) included in the alternatives. As noted above, we would welcome more

discussion with tribes on what input they would like to provide for this public meeting and we hope to discuss that further at the meeting with interested tribes on August 10th.

Concern about the focus on flow, fish, sediment vs. the Grand Canyon Protection Act (GCPA).

Compliance with the GCPA is one of the main reasons that the LTEMP EIS is being prepared. The Secretary of the Interior has noted that revisiting resource conditions, and applying the knowledge we have gained since the ROD was signed in 1996, will help us to better achieve the requirements and goals of the GCPA. Accordingly, the GCPA is referenced within the purpose and need of this process which will inform the range of alternatives and the evaluation of impacts. We have also developed resource goals (based on the DFCs and other relevant documents) to inform this evaluation that consider specific resources as well as tribal values.

Response numbers here correspond to comment numbers in the June 7, 2012 draft alternatives document submitted with the June 27 letter.

1. Tribal Involvement in Alternative Development. Please see the response to the second comment in your letter, above. We have received input on the alternatives from tribes, cooperating agencies and the public at the April 4-5, 2012 meeting and via other communications. In addition to our ongoing Government to Government consultation with interested tribes, the Hualapai and other tribes who are serving as cooperating agencies have many additional opportunities to inform the EIS development process, including our monthly cooperating agency calls and the upcoming cooperating agency meeting on August 10. Prior to the meeting with all cooperators on August 10, we have scheduled a meeting with interested tribes on August 10, 2012 in Phoenix as an additional opportunity for face-to-face participation specifically to focus on tribal values and concerns.

2. Sediment Augmentation - We appreciate your concern about the engineering solution proposed to increase sediment with the goal of trying to improve downstream resources. Infrastructure additions and other alternative elements are still being considered. It is understood that sediment augmentation and other infrastructure proposals would require in-depth analysis and may require separate and additional NEPA.

3. Other Types of Knowledge - The EIS team has also recently offered additional meetings with tribes, and is planning a meeting on August 10 to discuss alternatives and seek feedback from tribes on alternatives. Recognizing the ongoing GCDAMP effort to improve consideration of tribal ecological knowledge, we would like to discuss additional approaches to incorporating tribal knowledge into the EIS process. We have also shared with Hualapai and other interested tribes the first draft of tribal perspectives write-ups for eventual inclusion in the EIS, and we do need feedback on that draft from the tribes as soon as possible.

(g) Navajo Nation

February 28, 2011

Bureau of Reclamation
Environmental Resources Division
125 South State Street, Room 7218
Salt Lake City, UT 84138

To Whom It May Concern:

The Historic Preservation Department – Traditional Culture Program (HPD-TCP) is submitting the following comments on behalf of the Navajo Nation. HPD-TCP has provided the following comments for the Glen Canyon Dam Long Term Experimental and Management Plan Preliminary Draft Outline.

The Glen Canyon Dam Adaptive Management Program (AMP) was implemented as a result of the Record of Decision on the Operation of Glen Canyon Dan Final Environmental Impact Statement to comply with consultation requirements of the Grand Canyon Protection Act (Pub. L.102-575) of 1992. The Amp includes a Federal advisory committee, the Adaptive Management Work Group (AMWG), a technical work group (TWG), a Grand Canyon Monitoring and Research Center, and independent review panels. The AMWG makes recommendations to the Secretary of the Interior concerning Glen Canyon Dam operations and other management actions to protect resources downstream of Glen Canyon Dam consistent with the Grand Canyon Protection Act. The TWG is a subcommittee of the AMWG and provides technical advice and recommendations to the AMWG.

Recommendations:

1. The Navajo Nation is in support of the removal of Non-Native fish from the Grand Canyon. The Nation recommends the removal of Non-Native fish be done about a half mile from the confluence of the Little Colorado River and the Colorado River up and down stream.
.
2. The Navajo Nation supports the lethal removal of Non-Native Fish outside the half a mile buffer from the confluence. The disposal of the Non-Native fish is something the Nation supports. The lethal extermination of the Non-Native fish outside the areas of concern and has no objections with the lethal eradication of the Non-Native fish as long as it is away from the confluence.

Concerns:

1. Operations conducted by the Bureau of Reclamation and National Park Service

negatively effect the sacredness of the Grand Canyon. Local Navajo families refuse to conduct ceremonies near the river due to the Non-Natives consideration of the river as a place of recreation.

2. Navajo communities have no access to the river because of the constant flow of river trips and scientific research. Navajo tribal members hesitate to conduct offerings and ceremonies because of fear their prayers will not be answered.

If the Bureau of Reclamation (BOR) and the National Park Service (NPS) want to consult with the Nation on any of the raised concerns, we would be more than happy to accommodate.

The Navajo Nation appreciates the opportunity to comment on such a complicated issue. If you have any questions or comments, do not hesitate to call Tony Joe at (928) 871-7750.

Sincerely,

Tony H. Joe, Jr.
Historic Preservation Department

4

Glen Canyon Dam
Long Term Experimental and Management Plan (LTEMP)
Cooperating Agency Interest

Please return this form by January 6, 2012, to indicate your interest in participating as a cooperating agency in the development of a Long-Term Experimental and Management Plan and Environmental Impact Statement for the Glen Canyon Dam.

A cooperating agency agreement will be developed to identify the specific roles and responsibilities of each agency. In general, cooperating agencies provide information in their areas of special expertise, which will assist the Bureau of Reclamation and the National Park Service in making a more informed decision.

X Yes, we are interested in participating as a cooperating agency.

_____ No, we are not interested in participating as a cooperating agency.

Agency: NAVAJO DEPARTMENT OF WATER RESOURCES

Contact: JOHN LEEPER

Title: BRANCH MANAGER

Office: WATER MANAGEMENT BRANCH

Address: PO BOX 678
FORT DEFIANCE ARIZ 86504

Direct Phone: 928 729 4501

Office Phone: 928 729 4004

Mobile Phone: 928 349 1101

Fax: 928 729 4126

Email: JOHNLEEPER@NAVAJO-NSN.GOV

Please return the form by January 6, 2012 to:

Glen Canyon Dam LTEMP EIS Cooperators
Argonne National Laboratory
9700 S. Cass Ave. – EVS/240
Argonne IL 60439

From: Carr, Adrianne E.
Sent: Tuesday, July 17, 2012 5:52 PM
To: 'Jason John'; 'Alan Downer'
Cc: Abplanalp, Jennifer Marie; Carr, Adrianne E.; Bert Frost; Heffernan, Beverley; Brian Carey; Christine Landrum; Uberuaga, David V.; Denise Shultz; Halliday, John D (John_Halliday@ios.doi.gov); Jack Schmidt; Balsom, Janet R.; Jane Lyder; Cohen, Janet; John Wessels; Karen Breslin; Turner, Kent; Knowles, Glen; LaGory, Kirk E.; Caramanian, Lori L.; Anderson, Mark; Mark_Wondzell@nps.gov; Hahn, Martha Gail; Oltrogge, Maureen; Boyles, Michael John; Michael Whiteman-Jones; Billerbeck, Rob P.; Rod Smith; Sucec, Rosemary Jean; Daron, Steve; Melis, Theodore Steven; Brindle, Todd; Dickinson, William
Subject: LTEMP: Responses to Comments on Purpose, Need, and Objectives

Dear Cooperator:

Attached to this email are the responses to your comments on the LTEMP purpose, need, and objectives from the project team.

Very best regards,
Adrianne

Adrianne Carr, Ph.D.
Hydrologist
Environmental Science Division
Argonne National Laboratory
9700 S. Cass Avenue, EVS-240
Argonne, IL 60439

Response to Comments by Navajo on Purpose, Need, and Objectives

We thank you for your comments on the purpose, need, and objectives of the Glen Canyon Dam LTEMP. The joint lead EIS team carefully reviewed these comments and concerns. Some changes were incorporated if they substantially helped to clarify purpose, need, and objectives. However, NEPA provides that the purpose and need statements should "briefly specify the underlying purpose and need," and the level of detail suggested in many comments would contravene the direction that the purpose and need statements be concise.

Purpose

- Resources of importance to Indian Tribes are not specifically listed in the GCPA; but the EIS team feels it is important to include them based on public comments, AMWG desired future conditions, and agency goals for this project. Consistent with input received, we reworded this sentence to be clearer about the intent of this statement by adding "including those" before "of importance to Indian Tribes."

Need

- No comments were received.

Objectives

- We did not make the suggested change of "Protect the interests and perspectives of the Indian Tribes" from the original "Respect the interests and perspectives of the Indian Tribes" in the fifth objective. The EIS will contain a section on tribal perspectives, which will be developed in consultation with the tribes to ensure interests and perspectives are accurately portrayed. Achieving the objective of respecting tribal interests and perspectives will depend on government-to-government consultation, which will be an important part of the LTEMP EIS process.

From: Tony Joe [mailto:tony@navajohistoricpreservation.org]
Sent: Wednesday, August 28, 2013 2:53 PM
To: LaGory, Kirk E.; Sarah Rinkevich
Subject: Metrix

Kirk.

Navajo Historic Preservation Department's comments. The official letter with signature will be sent via mail.

Tony

--
Tony H. Joe, Jr.
Supervisory Anthropologist
Traditional Culture Program
928-871-7750

THE
NAVAJO
NATION

Ben Shelly
PRESIDENT

Rex Lee Jim
VICE PRESIDENT

August 28, 2013

Kirk E. LaGory, Ph.D.
Senior Program Manager
Ecological Resources and Systems
Environmental Science Division
Argonne National Laboratory
9700 S. Cass Ave., Building 240
Argonne, Illinois 60439

Dear Mr. LaGory,

The Navajo Historic Preservation Department is in response to the Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP EIS) Performance Metrix.

The tribes were invited to Flagstaff, AZ on March 14-15, 2013 for their input. At this meeting federal officials labeled the meeting as "Tribal Values". The tribes along with representatives from the National Park Service were in attendance. It was more of a brainstorming about tribal concerns. The tribes gave suggestions and all of the tribe's issues and concerns were written on a flip chart. On March 15, 2013, the tribes developed nine goals we thought would be included in the Performance Metrix, in addition to the agencies goals. I am concerned eight of the tribal values were not considered. The following comments are in reference to concerns we have.

1. **Archaeological and Cultural Resources**
   The anticipation for windblown deposits seems to be dependent upon hope. We support the idea of wind deposits covering up cultural resources but I think more evidence needs to be shared with the interested parties. Only a few archaeological sites might benefit and overall there is no specific sites mentioned that will yield positive benefits. The Grand Canyon river corridor exhibits archaeological sites that are not mentioned or considered.

2. **Natural Processes**
   The Nation supports native habitat improvement. Native fish and plant species need some attention to recreate the natural beauty of the Grand and Glen Canyon. I suggest more studies and more emphasis on re-establishing native fish and plant species. The eradication of non-Native plants species should be a goal.

3. **Humpback Chub**

HISTORIC PRESERVATION DEPARTMENT P.O. BOX 4950 WINDOW ROCK, ARIZONA 86515 928.871.7198 (v) 928.871.7886 (fax)

Humpback Chub research is supported by the Nation. I would like to see more studies on other native fish population.

4. **Other Native Fish**
   More research needs to be conducted on other native fish. The Nation would like to be consulted on studies past and present on these species. A map showing projects that are occurring on other native fish be of recommendation so we can have a better understanding of locations for the 2014 boat trip initiated by Navajo.

5. **Recreation**
   The cultural resources will be impacted by the heavy flow of the visitor experience each year. This is an issue for the Nation.

If you have any questions, do not hesitate to contact me at 928-871-7750. Thank you for honoring our request.

Sincerely,

Tony H. Joe, Jr.
Supervisory Anthropologist
Traditional Culture Program
Historic Preservation Department

Cc TCP 13-251 Glen Canyon Long-Term Experimental and Management Plan

From: Verhaaren, Bruce T.
Sent: Tuesday, February 11, 2014 11:16 AM
To: tony@navajohistoricpreservation.org; 'Jason John (jasonjohn@navajo-nsn.gov)'
Cc: Knowles, Glen; Billerbeck, Rob P.; Balsom, Janet R.; barger, mary; Sarah_Rinkevich@fws.gov; LaGory, Kirk E.
Subject: LTEMP MOU

Tony and Jason,

Please find attached a letter from the joint leads of the LTEMP EIS concerning the pending MOU between the Navajo Nation, the Bureau of Reclamation, and the National Park Service regarding the participation of the Navajo Nation as a cooperating agency for the EIS.

I will try to contact you by telephone later in the week regarding the status of the MOU. Please feel free to contact the joint leads or me if you have questions regarding the MOU. I should be back in the office Thursday, February 13.

Best Regards,

Bruce Verhaaren, Ph.D.
Environmental Science Division
Argonne National Laboratory
9700 S. Cass Avenue
Argonne, IL 60439

Office: 630 252-3240
Fax: 630 252-4624
bverhaaren@anl.gov

United States Department of the Interior

BUREAU OF RECLAMATION
Upper Colorado Regional Office
125 South State Street
Salt Lake City, UT 84138

NATIONAL PARK SERVICE
Intermountain Region Office
12795 Alameda Parkway
Denver, CO 80225

Jason John
Navajo Department of Water Resources
P.O. Box 678
Fort Defiance, AZ 86504

Tony Joe
Historic Preservation Department
P.O. Box 4950
Window Rock, AZ 86515

Dear Mr.John and and Mr. Joe,

We are writing regarding the pending Memorandum of Understanding (MOU) between the Bureau of Reclamation (Reclamation) and the National Park Service (NPS) and the Navajo Nation for the Environmental Impact Statement (EIS) for Adoption of a Long Term Experimental and Management Plan (LTEMP) for the Operation of Glen Canyon Dam.

Reclamation and NPS first extended an invitation to the Navajo Nation to become a cooperating agency for the LTEMP EIS in a letter dated December 8, 2011. In January 2012, John Leeper of the Navajo Department of Water Resources returned the invitation form indicating an interest in the Navajo Nation becoming a cooperating agency. A draft MOU outlining the roles and responsibilities of Reclamation, NPS, and the cooperating agencies was emailed to representatives of the Navajo Nation on March 6, 2012. Suggested revisions were provided by Alan Downer of the Navajo Nation Historic Preservation Department on March 22, 2012. A revised MOU was sent to Dr. Downer and to Jason John of the Department of Water Resources on April 11, 2012 with a request that it be signed and returned.

We are aware that Navajo procedures require an MOU to be reviewed and approved by legislative committees and ultimately by the legislature as a whole before it can be signed and returned. It is our understanding that the committees involved have requested an additional work session to determine whether being a cooperating agency would impact current negotiations regarding Navajo water rights.

Sections of the EIS are currently being drafted. Signing and returning the MOU will facilitate the Navajo Nation's role as a cooperating agency in reviewing drafted sections. We request that the MOU be signed by February 21, 2012. If the Navajo Nation chooses not to act as a cooperating agency please notify the LTEMP EIS team in writing. If Navajo Nation chooses not to act as a cooperating agency, we will still conduct government to government consultation with the Navajo Nation.

To return the signed MOU you may scan it in and return via email, send by fax, or send via postal mail. The fax number is 630-252-6090, and the mailing address is as follows:

Kirk LaGory
Argonne National Laboratory
9700 S. Cass Avenue, EVS-240
Argonne, IL 60439

Please feel free to contact us if you need any additional information regarding the LTEMP EIS and MOU. We look forward to hearing from you.

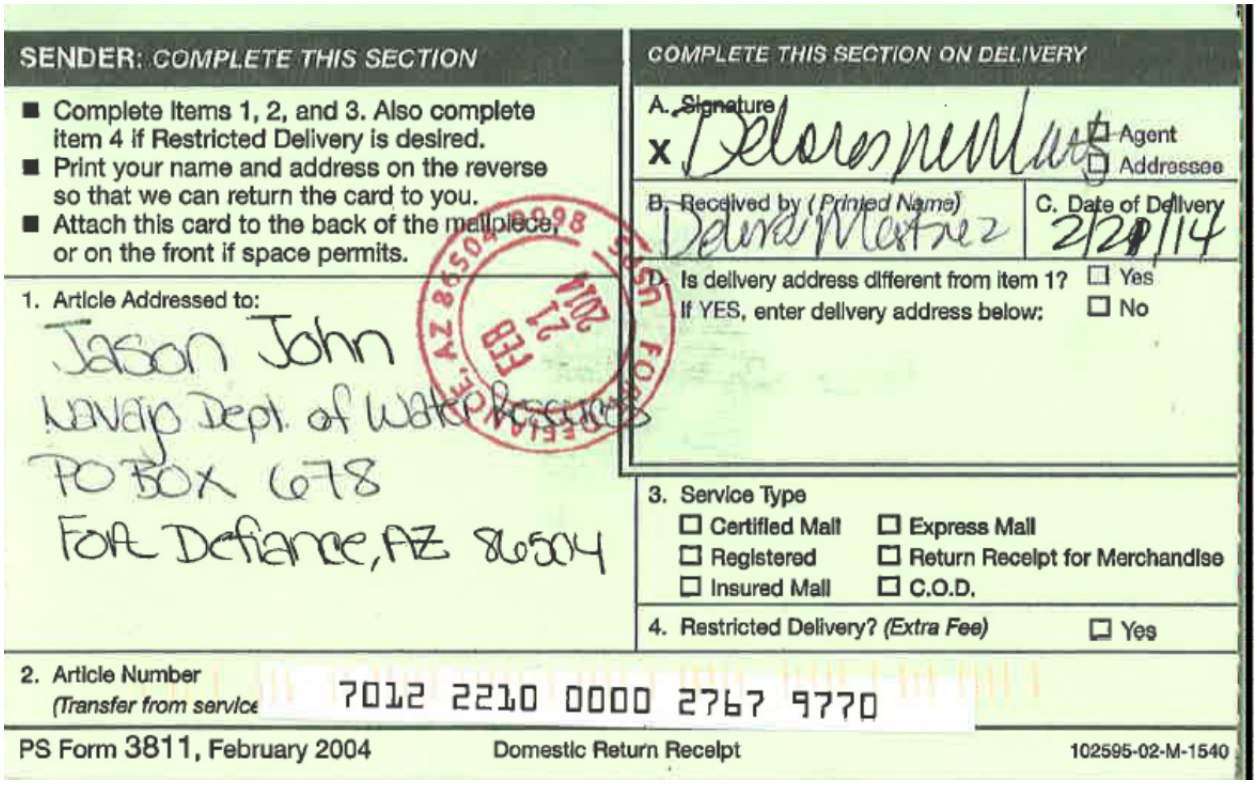
Sincerely,

2/10/14

Glen Knowles
Chief, Adaptive Management Group
Environmental Resources Division
Upper Colorado Region
Bureau of Reclamation

2/6/2014

Rob Billerbeck
Colorado River Coordinator
Resource Stewardship and Science
Intermountain Region
National Park Service



SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
Jason John
Navajo Dept. of Water Resources
PO Box 678
Fort Defiance, AZ 86504

COMPLETE THIS SECTION ON DELIVERY

A. Signature
x Delores Manuelito ☐ Agent ☐ Addressee

B. Received by (Printed Name) Delora Manuelito C. Date of Delivery 2/20/14

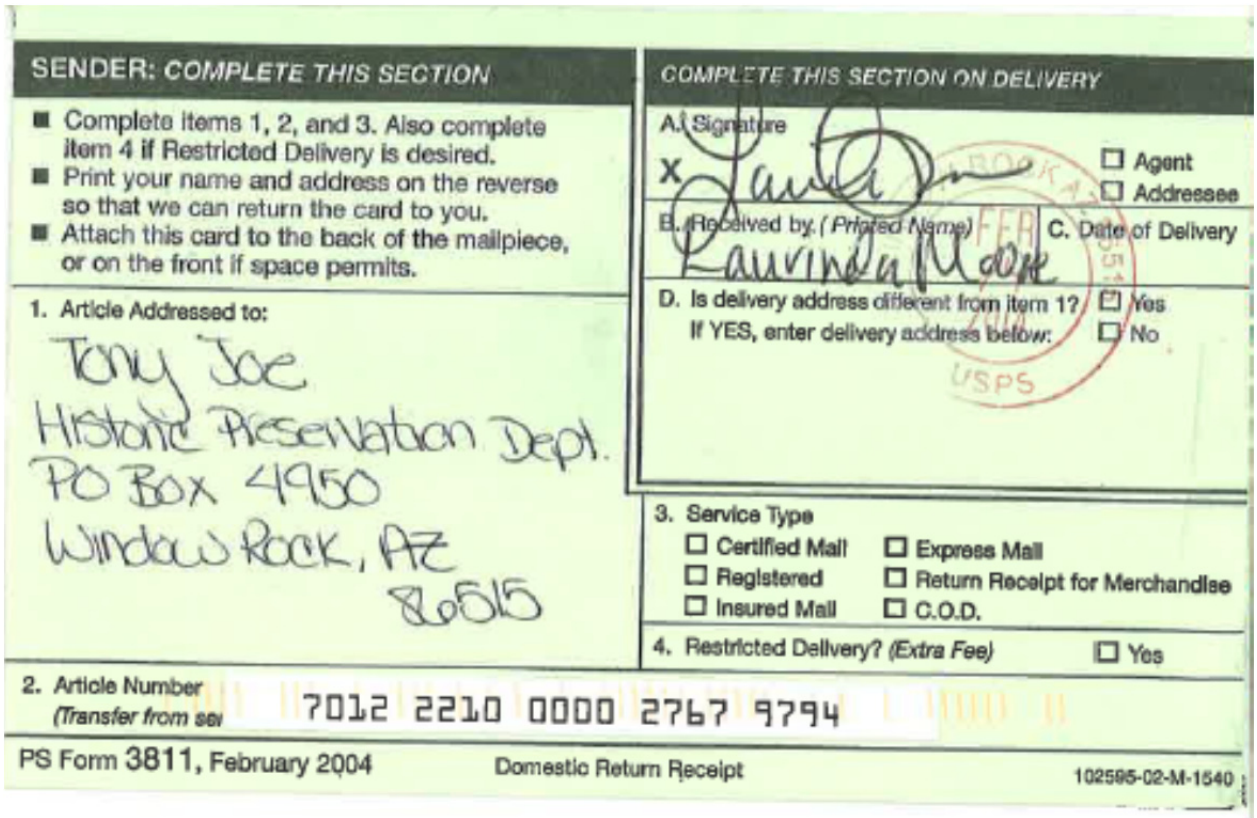
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service) 7012 2210 0000 2767 9770

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540



SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
Tony Joe
Historic Preservation Dept.
PO Box 4950
Window Rock, AZ
86515

COMPLETE THIS SECTION ON DELIVERY

A. Signature
x Lauri Mora ☐ Agent ☐ Addressee

B. Received by (Printed Name) Lauri Mora C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service) 7012 2210 0000 2767 9794

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

-----Original Message-----
From: Jason John [mailto:jasonjohn@navajo-nsn.gov]
Sent: Friday, February 21, 2014 12:51 PM
To: Verhaaren, Bruce T.; tony@navajohistoricpreservation.org
Cc: Abplanalp, Jennifer M.; Knowles, Glen; Billerbeck, Rob P.; LaGory, Kirk E.; Balsom, Janet R.; barger, mary; Sarah_Rinkevich@fws.gov
Subject: RE: LTEMP letter Date correction

Glen, Rob and Bruce,

I was at the meeting this morning with some of the Council Delegates. I can assist in the communication.

They would like a government to government meeting with NPS and BOR in Flagstaff on either March 28 at 1pm or March 4 (after 10am) or March 6 (after 10am). Their preference is in that order. The President of Navajo Nation should be signing that letter today requesting the meeting. When signed it will be emailed. I hope one of those dates work.

Jason

Jason John
Water Management Branch

THE NAVAJO NATION

BEN SHELLY PRESIDENT
REX LEE JIM VICE PRESIDENT

February 21, 2014

Glen Knowles
Chief, Adaptive Management Group
Environmental Resources Division
Upper Colorado Region
Bureau of Reclamation
125 South State Street
Salt Lake City, UT 84138

Rob Billerback
Colorado River Coordinator
Resource Stewardship and Science
Intermountain Region
National Park Service
12795 Alameda Parkway
Denver, CO 80225

The Nation is in receipt of your letter dated February 6, 2014, requesting that the Nation choose whether or not to be a cooperating agency in the development of the Environmental Impact Statement for Adoption of a Long Term Experimental and Management Plan (LTEMP) for the Operation of Glen Canyon Dam.

As you are aware, in order to be a cooperating agency, the Nation requires approval by the Naabik'iyati Committee of the Navajo Nation Council of the proposed Memorandum of Understanding with the Bureau of Reclamation and the National Park Service. When the Naabik'iyati Committee considered approving the legislation for the MOU, the legislation was tabled by Delegate Walter Phelps in order to better understand the purpose of the LTEMP for the Operation of Glen Canyon Dam and its impact to interests of the Navajo Nation.

Accordingly, we are requesting a government to government consultation meeting with the Bureau of Reclamation and the National Park Service to discuss the purpose of the LTEMP for Operation of Glen Canyon Dam and whether or not the Nation could serve in a joint lead agency role.

The Nation therefore requests a government-to-government consultation. The following are suggested dates in order of preference: February 28 at 1:00 pm, March 4, or March 6, 2014 in Flagstaff at the National Park Service agency office or other available facility.

Sincerely,

Ben Shelly, President
THE NAVAJO NATION

From: Billerbeck, Rob [mailto:rob_p_billerbeck@nps.gov]
Sent: Friday, February 28, 2014 2:45 PM
To: Knowles, Glen
Cc: Rinkevich, Sarah; Russell, Kendra L.; LaGory, Kirk E.; barger, mary; Verhaaren, Bruce T.
Subject: Re: Request for Government to Government LTEMP Consultation

I talked to Jason John on the phone today. Mostly it sounds like a misunderstanding between levels. Jason just tried to convey the need to sign the MOU to be a cooperating agency. He mentioned that we would do govt to govt down the road, but it sounds like some others were unclear on the scope of the projects and the roles. They are not requesting that Larry W and Dave U or others come to this meeting, they are just looking to have Glen and I come out and explain the process again and Jason believes that if roles and scope are explained that they will likely want to sign the cooperating agency MOU and will likely want to wait until the summer for the formal govt to govt.

I told Jason that meeting next week looked pretty difficult and he recommended an email back with dates further out. I think before we send an email back I'll try to connect with Tony Joe on the phone as well.
If we do need a meeting, we could see if that same week of the 17 works I guess.

From: Billerbeck, Rob [mailto:rob_p_billerbeck@nps.gov]

Sent: Monday, March 17, 2014 3:40 PM

To: Jason John

Cc: Verhaaren, Bruce T.; Knowles, Glen; Abplanalp, Jennifer M.; LaGory, Kirk E.; Balsom, Janet R.; barger, mary; Sarah_Rinkevich@fws.gov; Walter Phelps; Ray Benally; Assistant Attorney General Bidtah Becker; tony@navajohistoricpreservation.org; Michele Morris

Subject: Re: Request for Government to Government LTEMP Consultation

This email is in reply to the email sent on Feb 21, 2014 and attached letter from the Navajo Nation requesting to meet with the project managers of the Glen Canyon Dam Long Term Experimental and Management Plan (LTEMP) Environmental Impact Statement (EIS). We are sorry we could not meet the dates proposed for a meeting due to prior scheduling conflict, and we are happy to come out in the next few weeks to meet with representatives of the Navajo Nation and council. Based upon travel schedules and availability, we offer the following potential dates for a meeting in Window Rock:

April 2,3,10, or 14

We would have the project managers from the two lead agencies, NPS and BOR, come to discuss the LTEMP scope, issue, stakeholder roles and timelines, and answer questions regarding the LTEMP or participation from the Navajo Nation. Please let us know if any of these dates are convenient and if we are correctly understanding what you would like us to cover in the meeting. We are also available for a phone call in advance if that would help answer any specific questions.

Based on discussions with staff, here is some additional information about the LTEMP project in advance of a meeting that might be helpful:

LTEMP Scope and Issues

Federal laws and regulations require the federal government to evaluate the effects of its actions on the environment and to consider alternative courses of action. National Environmental Policy Act (NEPA) regulations require, among other things, federal agencies to include discussion of proposed actions and a range of reasonable alternatives in an EIS.

Generally, the scope of the LTEMP EIS project involves consideration of actions that could change flows from Glen Canyon Dam as well as a set of non-flow actions to address resource concerns. All alternatives will still comply with the 2007 Interim Guidelines for the annual delivery volumes. All of the action alternatives include High Flow Experiments with maximum flows of 45,000 cfs, but with some variation among how frequent or when these high flows would be employed. There is variation among the alternatives with approaches to fish management as some alternatives will have mechanical removal, some will have trout management flows and mechanical removal and one alternative utilizes neither fish management tool.

With this general scope in mind , we have heard the following might be of interest to the Navajo Nation:

- Potential impacts (positive or negative) to cultural sites
- Potential impacts (positive or negative) to natural resources such as sandbars/beaches, vegetation, wildlife habitat, fish and other aquatic resources
- Potential impacts (positive or negative) to hydropower production/effect on ratepayers
- Potential impacts (positive or negative) to the Glen Canyon fishery
- Potential impacts (positive or negative) to river recreation

There are also several issues that we have heard that are interest to the Navajo Nation that are outside the scope of this project:

- Boundary demarcation
- Water rights
- Operational concerns at Antelope Point

LTEMP Roles

- Lead Agencies - the two lead agencies for this project are the Bureau of Reclamation and the National Park Service. The responsibility for this project was delegated to these two agencies because Reclamation is responsible for the operation of Glen Canyon Dam and NPS has land management responsibility at Glen Canyon National Recreation Area and Grand Canyon National Park.. Joint lead responsibilities generally include consulting with the affected Tribes, identifying the purpose and need for the project, defining the scope of analysis, and managing the contracts for preparation of the EIS and responding to comments from cooperating agencies and the public, etc.

- Cooperating Agencies - Generally, cooperating agencies participate in the EIS by attending cooperating agency meetings, commenting on EIS materials and internal cooperating agency drafts, and assisting with the development of parts of the EIS if needed. This is a role with more interaction and opportunity to comment than a member of the public or a non-governmental entity.

- The following are the entities are cooperating agencies because they are state, local or tribal governments with appropriate expertise or jurisdiction for this project and that have signed an MOU confirming their role as a cooperating agency:

  - Arizona Game and Fish Department
  - Bureau of Indian Affairs
  - Colorado River Commission of Nevada
  - The Havasupai Tribe
  - The Hopi Tribe
  - The Hualapai Tribe
  - Kaibab Band of Paiute Indians
  - The Pueblo of Zuni
  - Salt River Project
  - U.S. Fish and Wildlife Service
  - Upper Colorado River Commission
  - Utah Associated Municipal Power Systems
  - Western Area Power Administration

- Thus far we have understood that the Navajo Nation wanted to be considered a cooperating agency so we have been inviting the Navajo Nation to meetings of cooperating agencies and providing information that is distributed to cooperating agencies.

Project Timeline

Past activities:

- July 2011 -Project started with a notice of intent in the Federal Register
- November 2012 - Public scoping meetings
- April 2012 - Public meeting presented preliminary draft alternative concepts
- June 2012 - Tribes provided comments on Tribal Consultation Plan and Tribes/cooperating agencies provided comments on preliminary alternatives

- August 2012 - in person meeting with Tribes/cooperating agencies to discuss and solicit comments on draft alternatives and goals and objectives

- February 2013 - development of models and metrics with experts, and meetings with Tribes and stakeholders regarding involvement in the process and modeling metrics

- March 2013 - meeting with Tribes regarding written contribution process to the EIS and modeling metrics.

- April-July 2013 - additional meetings with Tribes regarding modeling metrics

- August 2013 - Held meetings with Tribes and AMWG stakeholders, presented preliminary modeling and solicited structured decision making input

- November 2013 - Meeting with Tribal representatives to further develop modeling metrics useful for Tribes and discussed text that some Tribes wanted to contribute to the EIS.

- February 2014 - Revised alternatives and modeling metrics presented to Tribes and stakeholders at the AMWG meeting

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Planned activities:

- March 2014 - Meetings with stakeholders and Tribes. On March 18 there will be a web session to explain structure decision input methods and a meeting March 31-April 1 in Phoenix to present modeling results

- April 2014 - We are seeking structured decision information back from stakeholders and Tribes

- May-June 2014 - We will prepare preliminary EIS draft

- June 2014 - We plan to distribute preliminary draft EIS to cooperating agencies for comment

- July-Sept 2014- planning Government to Government meetings with most Tribes because at that point we can discuss a draft and a potentially preferred alternative

- Sept/Oct 2014 - We plan to publish a draft EIS for public comment

- 2015 - We plan to publish a final EIS

We hope this information helps with understanding the LTEMP EIS project, where we are in the process and helps the Navajo Nation understand potential participation in this project.

On Jun 2, 2014, at 2:26 PM, "Billerbeck, Rob"
<rob_p_billerbeck@nps.gov<mailto:rob_p_billerbeck@nps.gov>> wrote:

Council Delegate Phelps,
We wanted to send you a follow-up note to our meeting in Flagstaff in April regarding the Long Term Experimental and Management Plan (LTEMP) EIS for the Glen Canyon Dam. We thank you again for meeting with us and hope our information on the project was helpful. We wanted to see if there was any follow-up that you foresee in terms of the cooperating agency status of the Navajo Nation on this project. We can make ourselves available if you would like us to come out and meet with the council.

In terms of schedule, we plan to distribute a first preliminary draft EIS to cooperating agencies in July, a second cooperating agency draft in late Aug-Sept, and a public draft EIS in October.

Thank you,

Rob Billerbeck, NPS and Glen Knowles, Reclamation

--

Rob Billerbeck
Colorado River Coordinator
Resource Stewardship and Science
Intermountain Region
National Park Service
Alameda Office: 303-987-6789
Email: Rob_P_Billerbeck@nps.gov<mailto:Rob_P_Billerbeck@nps.gov>

On Tue, Jun 3, 2014 at 3:44 PM, Walter Phelps <walterphelps@navajo-nsn.gov<mailto:walterphelps@navajo-nsn.gov>> wrote:
Dear Mr Billerbeck, thank you for your follow up. The Council's Nabikiyati committee approved the resolution last month. I will send you a copy of the signed resolution upon receipt. Thank you for keeping in contact with Mrs. Becker and i on further developments.

Walter Phelps

Sent from my iPhone

(h) Paiute Indian Tribe of Utah

4

Glen Canyon Dam
Long Term Experimental and Management Plan (LTEMP)
Cooperating Agency Interest

Please return this form by January 6, 2012, to indicate your interest in participating as a cooperating agency in the development of a Long-Term Experimental and Management Plan and Environmental Impact Statement for the Glen Canyon Dam.

A cooperating agency agreement will be developed to identify the specific roles and responsibilities of each agency. In general, cooperating agencies provide information in their areas of special expertise, which will assist the Bureau of Reclamation and the National Park Service in making a more informed decision.

____ Yes, we are interested in participating as a cooperating agency.

D.M. No, we are not interested in participating as a cooperating agency. We would like to be kept updated on the project. D.M.

Agency: Paiute Indian Tribe of Utah
Contact: Doreen Martineau
Title: Cultural Resource
Office: PITU
Address: 440 North Paiute Drive
Cedar City, Utah
84721
Direct Phone: 435-586-1112
Office Phone: " 24, 107
Mobile Phone:
Fax: 435 586 7388
Email: doreen.martineau@ibs.gov

Please return the form by January 6, 2012 to:

Glen Canyon Dam LTEMP EIS Cooperators
Argonne National Laboratory
9700 S. Cass Ave. – EVS/240
Argonne IL 60439

(i) Pueblo of Zuni

ORIGINAL

Arlen Quetawki, SR.
Governor

Steve K. Boone
Lt. Governor

Vacant
Head Councilman

Vacant
Councilman

PUEBLO OF ZUNI
P. O. Box 339
Zuni, New Mexico 87327
1203-B NM State Hwy 53
Phone: (505) 782-7022
Fax: (505) 782-7202
www.ashiwi.org

505-782-7000 MAIN

Loren L. Leekela, SR
Councilman

Gerald Hooee, SR.
Councilman

Mark Martinez
Councilman

Birdena Sanchez
Councilwoman

13 December 2011

DEC 2 2 2011

CERTIFIED
Ref: ENV-6.00
Prj CC
003969101
To
700

Mr. Larry Walkoviak, Regional Director
Upper Colorado Region
Bureau of Reclamation
125 South State Street
Salt Lake City, UT 84138

Mr. John Wessels, Regional Director
Intermoutain Region Office
National Park Service
12795 Alameda Parkway
Denver, CO 80225

RE: Cooperating Agency Status for Pueblo of Zuni for the Development of an Environmental Impact Statement for a Long-Term Experimental and Management Plan (LTEMP) for Glen Canyon Dam operations. OR100

Dear Mr. Walkoviak and Mr. Wessels,

The Pueblo of Zuni has received your letter, dated 08 December 2011, inviting the Pueblo of Zuni to be a cooperating agency in the Long-Term Experimental and Management Plan (LTEMP) Environmental Impact Statement process. As you are aware the Grand Canyon, Colorado River, Little Colorado River, and all the physical, biological, and cultural resources located there are of extreme historical, cultural, and religious significance to the Zuni people. The appropriate care and management of this very sacred place and all the resources that comprise this important Zuni traditional cultural property is an on-going issue for the Zuni people; therefore, the Pueblo of Zuni accepts your invitation to become a cooperating agency in the development of this Environmental Impact Statement (EIS) for the LTEMP.

As Governor of Zuni, I designate Kurt Dongoske, RPA, Tribal Historic Preservation Officer of the Zuni Heritage and Historic Preservation Office as the primary Zuni representative as a cooperating agency in this process. Mr. Dongoske's contact information is provided in the attached form. Should you have any questions or require additional information please contact my office at 505.782.7000 or the Zuni Heritage and Historic Preservation Office at 505.782.2393. Thank you for consulting with the Pueblo of Zuni.

Sincerely,

Governor Arlen Quetawki, Sr.
Pueblo of Zuni

NOTICE IF YOU DETACH
ENCLOSURES PLEASE INSERT
CODE NO._____

4

Glen Canyon Dam
Long Term Experimental and Management Plan (LTEMP)
Cooperating Agency Interest

Please return this form by January 6, 2012, to indicate your interest in participating as a cooperating agency in the development of a Long-Term Experimental and Management Plan and Environmental Impact Statement for the Glen Canyon Dam.

A cooperating agency agreement will be developed to identify the specific roles and responsibilities of each agency. In general, cooperating agencies provide information in their areas of special expertise, which will assist the Bureau of Reclamation and the National Park Service in making a more informed decision.

__X__ Yes, we are interested in participating as a cooperating agency.

_____ No, we are not interested in participating as a cooperating agency.

Agency: Pueblo of Zuni

Contact: KURT DONGOSKE

Title: TRIBAL Historic Preservation officer

Office: Zuni Heritage and Historic Preservation Office

Address: P.O. Box 1149
Zuni, New Mexico 87327

Direct Phone:

Office Phone: 505.782.4814

Mobile Phone: 928.587.1901

Fax: 505.782.2393

Email: Kdongoske@cableone.net

Please return the form by January 6, 2012 to:

Glen Canyon Dam LTEMP EIS Cooperators
Argonne National Laboratory
9700 S. Cass Ave. – EVS/240
Argonne IL 60439

(j) White Mountain Apache Tribe

From: Cheryl Pailzote [cpailzote@wmat.us]
Sent: Tuesday, May 15, 2012 2:42 PM
To: Barger, Mary E
Cc: markaltaha@wmat.us; rlupe@wmat.us
Subject: RE: Call today about the EIS for Glen Canyon Dam flows/ tribal consultation

Hello Mary,

I had talked to our advisors about the EIS for the Glen Canyon Dam flows. From a water resources/water rights position, we do not feel that the Glen Canyon EIS alternatives will have any impact on White Mountain Apache Tribe. Mark Altaha had stated that there are impact on cultural resources. Thus, I have will recommend to Chairman Lupe that we do not need to be cooperators on this EIS. Would you need a letter from the Chairman stating such?

Thank you,

Cheryl Pailzote
Water Resources Director
WMAT

(k) Yavapai-Apache Nation

YAVAPAI-APACHE NATION
CAMP VERDE, ARIZONA

4

Glen Canyon Dam
Long Term Experimental and Management Plan (LTEMP)
Cooperating Agency Interest

Please return this form by January 6, 2012, to indicate your interest in participating as a cooperating agency in the development of a Long-Term Experimental and Management Plan and Environmental Impact Statement for the Glen Canyon Dam.

A cooperating agency agreement will be developed to identify the specific roles and responsibilities of each agency. In general, cooperating agencies provide information in their areas of special expertise, which will assist the Bureau of Reclamation and the National Park Service in making a more informed decision.

XXXXX Yes, we are interested in participating as a cooperating agency.

_____ No, we are not interested in participating as a cooperating agency.

Agency: Yavapai-Apache Nation

Contact: Christopher Coder

Title: Tribal Archaeologist YAN

Office: Cultural Preservation

Address: 2400 West Datsi
Camp Verde, AZ 86322

Direct Phone: (928) 567-7026

Office Phone: 525-3035

Mobile Phone: NA

Fax: (928) 567-3994

Email: ccoder@yan-tribe.org

Please return the form by January 6, 2012 to:

Glen Canyon Dam LTEMP EIS Cooperators
Argonne National Laboratory
9700 S. Cass Ave. – EVS/240
Argonne IL 60439

From: Verhaaren, Bruce T.
Sent: Wednesday, October 10, 2012 11:03 AM
To: ccoder@yan-tribe.org
Cc: Carr, Adrianne E.
Subject: LTEMP Cooperator?

Hello Chris,

I hope your trip went well.

Have you been able to confirm that the Yavapai-Apache Nation no longer is interested in being a cooperating agency for the LTEMP EIS?

Best Regards

Bruce

From: Chris Coder [mailto:ccoder@yan-tribe.org]
Sent: Wednesday, October 10, 2012 12:36 PM
To: Verhaaren, Bruce T.
Cc: Carr, Adrianne E.; Anthony Canty
Subject: RE: LTEMP Cooperator?

Hi Bruce/Adrianne,

Thanks for the prompt. Our internal water team meets next Monday and as I cannot make this decision unilaterally, I will get a consensus from the team and get back to you by the middle of next week with an informed opinion from the group.

Thanks Chris

(928) 567-7026

From: Verhaaren, Bruce T. [mailto:brucev@anl.gov]
Sent: Wednesday, October 10, 2012 9:03 AM
To: Chris Coder
Cc: Carr, Adrianne E.
Subject: LTEMP Cooperator?

Hello Chris,

I hope your trip went well.

Have you been able to confirm that the Yavapai-Apache Nation no longer is interested in being a cooperating agency for the LTEMP EIS?

Best Regards

Bruce

++++++++++++++++++++++++++

Bruce Verhaaren, Ph.D.
Environmental Science Division
Argonne National Laboratory
9700 S. Cass Avenue
Argonne, IL 60439

Office: 630 252-3240
Fax: 630 252-4624
bverhaaren@anl.gov

From: Verhaaren, Bruce T.

Sent: Tuesday, October 23, 2012 1:55 PM

To: ccoder@yan-tribe.org

Cc: Balsom, Janet R.; barger, mary; Carr, Adrianne E.

Subject: Cooperating status

Hello Chris,

Have you had time to verify whether Yavapai-Apache Nation no longer wish to act as a cooperating agency for the LTEMP EIS for Glen Canyon Dam? It is my understanding that they do not. Please confirm.

Thanks for checking on this.

Bruce

++++++++++++++++++++++++++++

Bruce Verhaaren, Ph.D.

Environmental Science Division

Argonne National Laboratory

9700 S. Cass Avenue

Argonne, IL 60439

Office: 630 252-3240

Fax: 630 252-4624

bverhaaren@anl.gov

From: Chris Coder [mailto:ccoder@yan-tribe.org]
Sent: Wednesday, October 24, 2012 3:22 PM
To: Verhaaren, Bruce T.
Subject: RE: Cooperating status

Hi Bruce,

I have run this by our legal counsel and they have advised we do not need to be a cooperating agency, but would like to remain in the loop to the extent we can get (electronically) the draft NEPA document.

Thanks for your patience,

Chris Coder

ATTACHMENT N.3

United States Department of the Interior

BUREAU OF RECLAMATION
Upper Colorado Regional Office
125 South State Street, Room 6107
Salt Lake City, UT 84138-1102

IN REPLY REFER TO:
UC-725
ENV-3.00

JUN 12 2014

Mr. James Garrison
Arizona State Historic Preservation Office
Arizona State Parks
1300 West Washington Street
Phoenix, AZ 85007

Subject: Initiation of the National Historic Preservation Act of 1966 (NHPA) Section 106 Compliance for Operation of Glen Canyon Dam (GCD)

Dear Mr. Garrison:

The Bureau of Reclamation, Upper Colorado Region, and National Park Service (NPS), Intermountain Region are proposing to complete an Environmental Impact Statement (EIS) for GCD operations. This EIS will address a change in dam operation for approximately the next 20 years and is called the Long Term Experimental and Management Plan (LTEMP).

We recently completed developing six alternatives for this EIS, and as a result, have a better understanding of any potential to affect historic properties. Of the six alternatives, the highest flow proposed is 45,000 cubic feet per second, the same as was identified in the Memorandum of Agreement for the GCD High Flow Experimental Protocol.

Since the LTEMP effort has started, we have briefed stakeholders and the signatories for the Operation of GCD 1994 Programmatic Agreement (PA) on our intent to complete a new PA. We also had a meeting on January 9, 2013, with both our Federal Preservation Officers (FPOs), the Advisory Council on Historic Preservation (ACHP), and Reclamation and the NPS management to discuss a potential Section 106 process. We sent a joint letter from the NPS and Reclamation to the ACHP on February 27, 2013, that discussed the results of that meeting and your office was copied, along with the PA signatories.

Currently, we have a draft Area of Potential Effects (APE) identified for the LTEMP undertaking as follows:

> Longitudinally, the Area of Potential Effect (APE) for the LTEMP undertaking associated with GCD operations includes the active channel of the Colorado River in Glen, Marble, and Grand Canyons from Glen Canyon Dam to the western boundary of Grand Canyon National Park near Pearce Ferry. Laterally, the APE extends from the Colorado River both horizontally and vertically to varying extent based on the specific

Initiation of the NHPA Section 106 Compliance for Operation of GCD

operational, topographic, and natural processes at each location. The variable upslope extent of the APE is primarily dependent on the distribution of sandbars and the potential for fine sediment redistribution by canyon winds under the prevailing flow regimes of the Colorado River as described in the LTEMP EIS. The APE includes areas affected by the flow of the Colorado River and active aeolian processes.

Pursuant to Section 106 of the NHPA, as the Federal lead agency for this undertaking, Reclamation would like to consult with you on developing the PA for this new undertaking. Please note that we are currently in the process of identifying our consulting parties per 36 CFR 800.3, and coordinating with the NPS on the first draft PA for review by consulting parties. We will be convening a meeting of these consulting parties, including your office, in the near future.

If you have any questions, please contact Mary Barger at 602-615-0809.

Sincerely,

for Anamaria Gold

Larry Walkoviak
Regional Director

cc: Ms. Jan Balsom
Grand Canyon National Park
P.O. Box 129
Grand Canyon, AZ 86023

Mr. Todd Brindle
Superintendent
Glen Canyon National Recreation Area
Rainbow Bridge National Monument
P.O. Box 1507
Page, AZ 86040

Mr. Charley Bulletts
Director
Southern Paiute Consortium
Tribal Affairs Building
HC65 Box 2
Fredonia, AZ 86022

Honorable Sherry J. Counts
Chairwoman
Hualapai Tribe
P.O. Box 179
941 Hualapai Way
Peach Springs, AZ 86434

Mr. Kurt Dongoske
Tribal Historic Preservation Office
Zuni Cultural Resource Enterprise
Pueblo of Zuni
P.O. Box 339
Zuni, NM 87327

Honorable Herman G. Honanie
Chairman
The Hopi Tribe
P.O. Box 123
Kykotsmovi, AZ 86039

Initiation of the NHPA Section 106 Compliance for Operation of GCD

Honorable Gerald Hooey
Councilman
Pueblo of Zuni
P.O. Box 339
Zuni, NM 87327

Ms. Ann Howard, Deputy
Arizona State Historic Preservation Office
Arizona State Parks
1300 West Washington
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Ms. Leslie James, Executive Director
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Distributors Association
10429 S 51st Street, Suite 230
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Colorado River Storage Project
Western Area Power Administration
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Mr. Leigh J. Kuwanwisiwma
Director
Hopi Cultural Preservation Office
The Hopi Tribe
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Mr. Charles Louis
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Phoenix, AZ 85004-3050

Mr. Tom McCullough
Advisory Council on Historic Preservation
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Western Area Power Administration
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Acting Tribal Historic Preservation Officer
Navajo Nation
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Mr. Theodore Quasula
Acting Field Manager
Bureau of Indian Affairs
Phoenix Area Office
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Phoenix, AZ 85004-3050

Honorable Arlen Quetawki, Senior
Governor
Pueblo of Zuni
P.O. Box 339
Zuni, NM 87327

Mr. Manual Savala
Kaibab Band of Paiute Indians
Tribal Administration Building
#1 Pipe Spring Road
Fredonia, AZ 86022

Initiation of the NHPA Section 106 Compliance for Operation of GCD

Honorable Ben Shelly
President
Navajo Nation
P.O. Box 7440
Window Rock, AZ 86515

Ms. Rosemary Sucec
Glen Canyon National Recreation Area
P.O. Box 1507
Page, AZ 86040

Dr. Benjamin N. Tuggle
Southwest Regional Director
U.S. Fish and Wildlife Service
P.O. Box 1306
Albuquerque, NM 87103-1306

Mr. Dave Uberuaga
Superintendent
Grand Canyon National Park
P.O. Box 129
Grand Canyon, AZ 86023

Mr. Mike Yeatts
Hopi Cultural Preservation Office
The Hopi Tribe
P.O. Box 123
Kykotsmovi, AZ 86030

Mr. Kirk Young
U.S. Fish and Wildlife Service
323 North Leroux
Flagstaff, AZ 86001

2014-0628(120202)

United States Department of the Interior

BUREAU OF RECLAMATION
Upper Colorado Regional Office
125 South State Street, Room 6107
Salt Lake City, UT 84138-1102

IN REPLY REFER TO:
UC-725
ENV-3.00

JUN 12 2014

RECEIVED
JUN 16 2014
JC
ARIZONA STATE HISTORIC PRESERVATION OFFICE

Mr. James Garrison
Arizona State Historic Preservation Office
Arizona State Parks
1300 West Washington Street
Phoenix, AZ 85007

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If you have any questions, please contact Mary Barger at 602-615-0809.

7/18/14
Thank you for this information
We look forward to working with you
on the PA.
Mary-Ellen Walsh
Archaeological Compliance Specialist

Sincerely,

for Larry Walkoviak
Regional Director

cc: Ms. Jan Balsom
Grand Canyon National Park
P.O. Box 129
Grand Canyon, AZ 86023

Mr. Todd Brindle
Superintendent
Glen Canyon National Recreation Area
Rainbow Bridge National Monument
P.O. Box 1507
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Mr. Charley Bulletts
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