Technical Appendix 15

Dams and Electrical Power Resources

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Contents

Tables

Figures

Acronyms and Abbreviations

Acronym or Abbreviation	Full Phrase
2007 Final EIS	Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead Final Environmental Impact Statement
Basin	Colorado River Basin
BCP	Boulder Canyon Project
CCS	Continued Current Strategies
cfs	cubic feet per second
CRiSPPy	Colorado River Storage Project Python-based model
CRSP	Colorado River Storage Project
CRSPA	Colorado River Storage Project Act of 1956
CRSS	Colorado River Simulation System
DMDU	Decision Making under Deep Uncertainty
DSPR	Dam Safety Priority Rating
EIS	environmental impact statement
GWh	gigawatt hour
HFE	high-flow experiment
kW	kilowatt
LB Priority	Lower Basin Priority
LB Pro Rata	Lower Basin Pro Rata
Lower Basin	Lower Colorado River Basin
LTEMP	Long-Term Experimental and Management Plan
maf	million acre-feet
MW	megawatts
MWh	megawatt hours
NERC	North American Electric Reliability Corporation
PDP	Parker-Davis Project
Reclamation	Bureau of Reclamation
ROD	Record of Decision
SLCA/IP	Salt Lake City Area Integrated Projects
Upper Basin	Upper Colorado River Basin
U.S.	United States
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council

TA 15. Dams and Electrical Power Resources

TA 15.1 Affected Environment

This section provides an overview of the four primary dams and reservoirs in the analysis area of the Colorado River corridor from the full pool elevation of Lake Powell to the Southerly International Boundary: Glen Canyon Dam/Lake Powell, Hoover Dam/Lake Mead, Davis Dam/Lake Mohave, and Parker Dam/Lake Havasu. This section provides the context for analyzing the effects of the alternatives on the electrical power capacity and spillway use of Glen Canyon Dam and Hoover Dam, and the power generation at all four dams. This section also provides the context for analyzing the effects of the alternatives on electricity rates.

Other, smaller dams and hydroelectric facilities in the analysis area include Headgate Rock, Senator Wash, Siphon Drop, and Pilot Knob. Changes to these smaller dams and their associated reservoirs are not being proposed in any of the alternatives, and due to the nature of their operations, there are no anticipated substantial effects on the electrical power capacity, generation, spillway, or safety of these dams nor are there any anticipated substantial effects relative to their electricity rates nor the economic value of the power they produce from the alternatives.

The Bureau of Reclamation (Reclamation) operates and maintains the Glen Canyon, Hoover, Davis, and Parker Dams. The Western Area Power Administration (WAPA) is responsible for marketing and transmitting the power generated at these facilities across the Colorado River Basin (Basin; Reclamation 2007a). As established in the 1922 Colorado River Compact, the Upper Colorado River Basin (Upper Basin) consists of the states of Colorado, New Mexico, Utah, and Wyoming; the Lower Colorado River Basin (Lower Basin) consists of the states of Arizona, California, and Nevada; and Lee Ferry is considered the dividing point between the two basins. Lee Ferry is located 1 mile below the mouth of the Paria River in Arizona. The Colorado River Compact established that each basin would receive 7.5 million acre-feet (maf) of water annually. In 1956, the Colorado River Storage Project Act of 1956 (CRSPA) outlined Upper Basin water storage and management processes to facilitate the apportionment of water in the Upper Basin and the delivery of water to the Lower Basin. This water storage system called for the building of four dams, with Glen Canyon Dam and Lake Powell reservoir serving as the primary water storage infrastructure for the Upper Basin.

TA 15.1.1 Hydropower Generation and Capacity Overview

Hydropower generation occurs when water stored in a reservoir passes through a turbine, which converts the energy of the falling water to mechanical energy, which is then converted to electricity as the turbine turns the rotors in the generating units. The amount of electrical power generated is directly related to the amount of water passing through the turbines and the force, or "head," of the water as it moves through the turbines. The higher the reservoir elevation, the more head the water can exert when passing through the turbines. Capacity is mainly affected by the depth of the reservoir and the number of generators.

Power generation has two main measurable components: power and energy. Power is the rate at which energy is transferred or consumed, or the amount of electricity produced at a specific time and is measured in megawatts (MW). Energy is the amount of power generated over time and is measured in megawatt hours (MWh). Capacity is the maximum power that can be produced at a specific moment. The physical capacity of a powerplant is the maximum power that results from generator and turbine capacity and reservoir levels. Firm capacity is the reliable, guaranteed amount of power output from a powerplant that accounts for operational constraints such as water releases and ramp rates[1]. Physical and firm capacity are measured in MW. This affected environment portion of this technical appendix describes the physical capacity of the Glen Canyon and Hoover Powerplants, and the environmental consequences portion analyzes the effects of the alternatives on the firm capacity of these powerplants as firm capacity takes into account all of the conditions that WAPA and Reclamation use for operational decisions.

Additional information on power generation, control, regulation, reserves, and ramping can be found in the Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead Final Environmental Impact Statement (2007 Final EIS) Section 3.11.1.1 (Reclamation 2007a); and that information is incorporated here by reference.

TA 15.1.2 Hydropower Marketing and Administration Overview

WAPA markets power and administers power contracts for electricity generated from the dams that are specific to each of the hydropower projects. WAPA sets power rates every few years for each hydropower project. The rates cover the operating costs of WAPA and those of the hydropower project (WAPA 2025a). WAPA power sales and transmission operations are organized by region with Glen Canyon Powerplant operating within the Colorado River Storage Project (CRSP) region and Hoover, Parker, and Davis Powerplants operating within the Desert Southwest Region. WAPA bundles and markets power to a variety of entities including: small and medium-sized municipalities that operate publicly owned utilities; irrigation cooperatives and water conservation districts; rural electrical associations; generation and transmission co-operatives; federal facilities; universities; state agencies; and tribes (Reclamation 2016a) across the following states: Nebraska, Wyoming, Utah, Nevada, Colorado, California, Arizona, and New Mexico.

WAPA distributes the power through four types of contracts that are classified as: long-term firm power and other long-term sales; non-firm energy and short-term sales and purchases; seasonal power sales; and purchase power (WAPA 2025a). Firm power contracts guarantee the capacity and energy that will be available 24 hours a day and non-firm contracts come without a guarantee of continuous availability (WAPA 2025a). Firm and non-firm contracts can be short- or long-term.

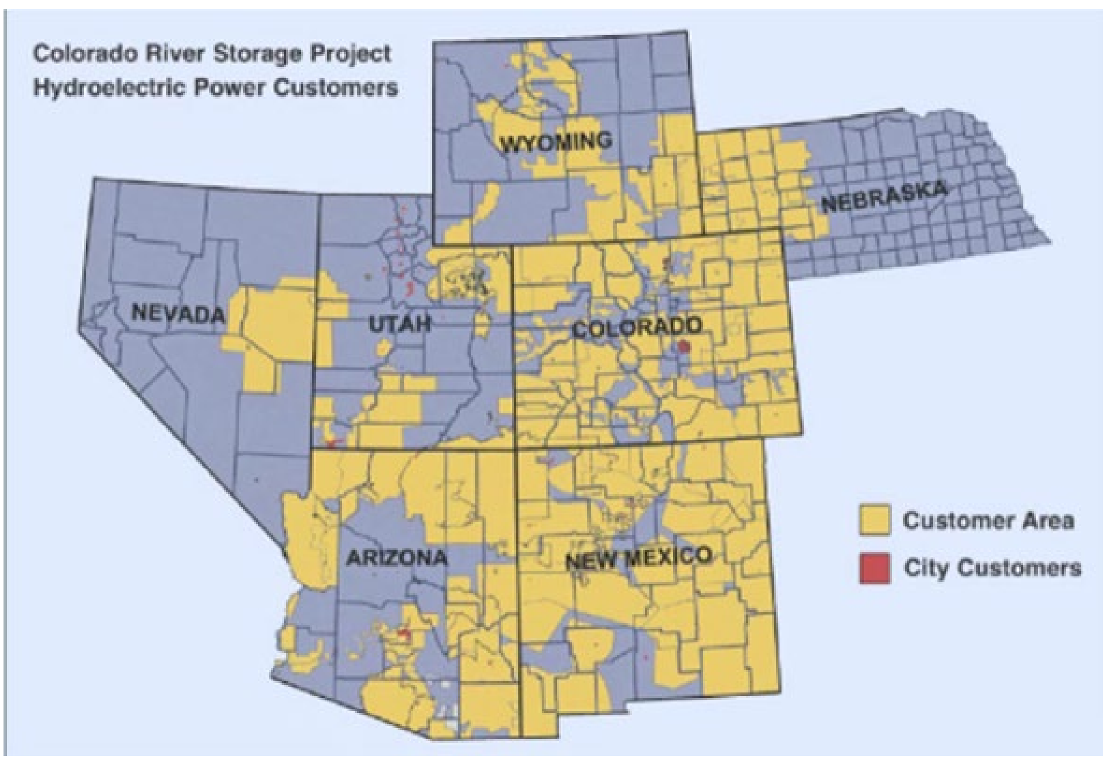
The contracts for Glen Canyon Dam power are effective 2024 through 2057 (WAPA 2023). There are more than 100 customers for Glen Canyon Dam power, and they provide electricity within the states of Wyoming, Utah, Colorado, New Mexico, Arizona, Nevada, and Nebraska. WAPA markets

[1] The ramp rate is the rate of change in instantaneous output from a powerplant. The ramp rate is established to prevent undesirable effects due to rapid changes in loading or discharge.

Hoover Dam generated power to 46 customers and Parker Dam and Davis Dam generated power to 36 customers within southern Nevada, Arizona, and southern California. Hoover Dam power is marketed as a long-term contingent capacity contract with associated energy. This means that WAPA is obligated to deliver the energy that can be generated from the available capacity. The new contracts for Hoover Dam took effect on October 1, 2017, and expire on September 30, 2067. The Parker Dam and Davis Dam power is marketed as long-term, firm contracts. Contracts for the Parker Dam and Davis Dam were signed prior to 2007 and terminate in 2028. WAPA anticipates signing new contracts that will replace the expiring contracts.

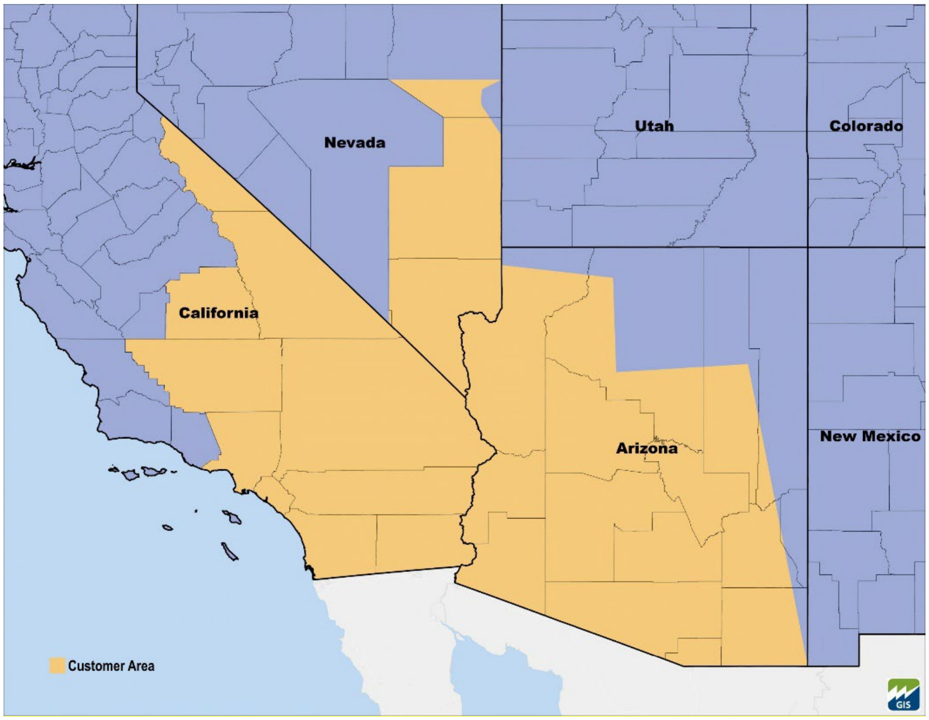
The Basin is within what is referred to as the Western Interconnection region of the Western Electricity Coordinating Council (WECC). The WECC is a regional, non-profit corporation that oversees bulk electrical system reliability planning and assessment. The Western Interconnection area includes two Canadian provinces, 14 western states, and the northern United Mexican States (WECC 2025). The Glen Canyon, Hoover, Parker, and Davis Powerplants account for approximately 2.2 percent of the total electrical capacity within the Western Interconnection region. **Figure TA 15-1** identifies the CRSP hydroelectric power customers located within the Western Interconnection, illustrating the geographic distribution of entities that receive power generated from Basin facilities. Similarly, **Figure TA 15-2** shows WAPA's Desert Southwest Region's service area map which provides electric service to customers in Arizona, southern California, and southern Nevada.

Figure TA 15-1
CRSP Hydroelectric Power Customers



Note: Glen Canyon Dam is a feature of CRSP.

Figure TA 15-2
Desert Southwest Region Hydroelectric Power Customers



Note: Hoover, Parker, and Davis Dams are features of the Desert Southwest Region.

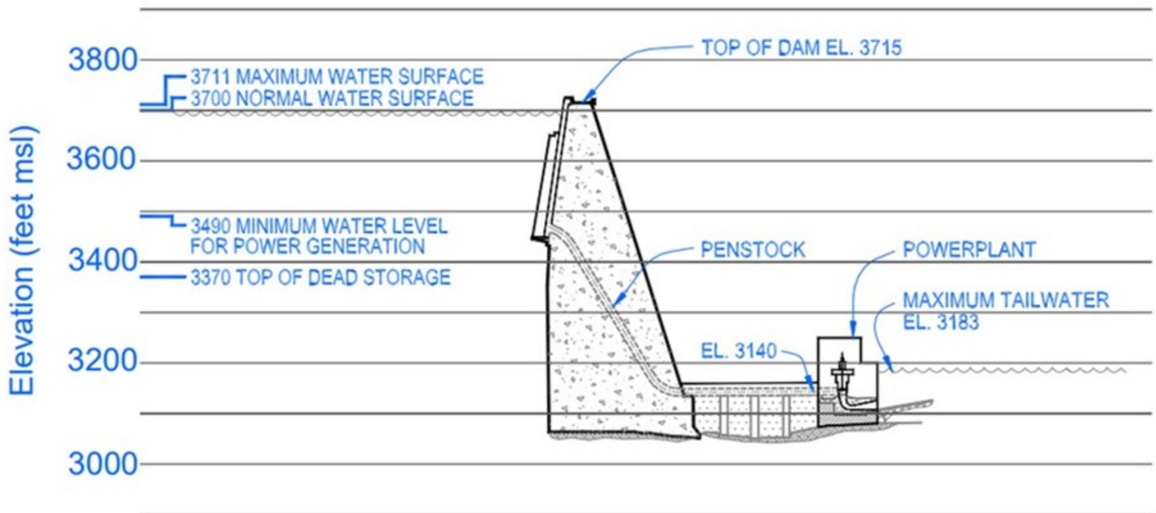
TA 15.1.3 Infrastructure Conditions and Hydroelectric Power Generation and Capacity

This section provides an overview of the infrastructure conditions of the Glen Canyon Dam/Lake Powell reservoir, the Hoover Dam/Lake Mead reservoir, Davis Dam/Lake Mohave reservoir, Parker Dam/Lake Havasu reservoir, and their hydropower capacity and generation.

Glen Canyon Dam/Lake Powell

Glen Canyon Dam is located in Page, Arizona and is a concrete arch dam rising 710 feet with a 35-foot-wide roadway connecting the dam's spillways, see **Figure TA 15-3**. The dam's reservoir, Lake Powell, has a water storage capacity of 25.16 maf and a maximum reservoir elevation of 3,711 feet. The dam and reservoir are operated and maintained by Reclamation's Glen Canyon Field Division in Page, Arizona.

Figure TA 15-3
Lake Powell and Glen Canyon Dam Important Operating Elevations



Water Releases and Operational Considerations

During normal operating conditions, water is released from Glen Canyon Dam through the Glen Canyon Powerplant through intakes on the upstream face of the dam. Eight, 15-foot steel penstocks convey water to the powerplant turbines through an elevation drop of 330 feet to a centerline elevation of 3,140 feet. Water cannot be released from the penstocks below a Lake Powell elevation of 3,490 feet (which is known as the minimum power pool and is 20 feet above the penstock intake centerline). At an elevation of 3,490 feet, it is estimated that vortex formation would begin to occur at the powerplant. As described in **Section 1.8.4.1**, there are also infrastructure concerns associated with the uncertainty of extended operations through the river outlet works as the sole means of sustained water releases from Glen Canyon Dam that could compromise the reliability and operational flexibility of Glen Canyon Dam and affect the ability to meet critical downstream water supply needs. Releases in excess of powerplant capacity are made when flood conditions are caused by high runoff in the Upper Basin or when high-flow experiments (HFEs) are triggered downstream. Historically, these releases are well above 3,490 feet. However, HFEs can be conducted down to an elevation of 3,500 feet.

Four, 96-inch steel pipes comprise the river outlet works at a centerline elevation of 3,374 feet. The outlets have a maximum combined capacity of 15,000 cubic feet per second (cfs) at elevation 3,500 feet. Below 3,500 feet the capacity decreases. Below minimum power pool, the outlet works are the sole means of releasing water. An annual release of 8.23 maf equates to a continuous flow of up to 11,368 cfs. With all four outlets operational, this release can be maintained down to approximately elevation 3,440 feet, however, operations and maintenance constraints may limit these releases or the elevation. Since the construction of Glen Canyon Dam, the river outlet works are typically reserved for flood control, HFEs, augmenting powerplant and spillway discharges, or for periods when the powerplant is not operating.

Dam operations are managed to maintain the water surface elevation near or below 3,700 feet, which is the normal operating level. Operational preference is to maintain a water surface elevation below the top of active conservation, 3,700 feet, to minimize the occurrence of flood operations and the need for additional monitoring. Glen Canyon Dam is designed to safely accommodate the probable maximum flood including operating up to the maximum water surface elevation of 3,711 feet.

Another important operational consideration is maintaining adequate vacant storage around elevation 3,684 feet on January 1, which provides necessary capacity for managing inflows from spring runoff.

In 1983, heavy late-winter mountain snow accumulation within the Basin created 150 percent of normal runoff, causing the first real use of the Glen Canyon spillway. High, extended releases through the spillways (up to 27,000 cfs from the right spillway and 32,000 cfs from the left) caused serious cavitation damage within the tunnel, particularly in the vertical bends. Cavitation is the formation of vapor cavities in a liquid. As the vapor cavities move into a zone of higher pressure, they collapse, sending out destructive high pressure shock waves (Reclamation 2019). The 1983 damage led to the installation of 4-by-4-foot air slots in the spillways to prevent future cavitation damage by introducing air into the water flow.

Current Condition

Reclamation, utilizing the Dam Safety Priority Rating (DSPR) system, evaluated Glen Canyon Dam and gave it a DSPR 5 category rating. This is Reclamation’s lowest-priority rating from a dam-safety risk standpoint, indicating the facility poses the lowest risk to the public. The total mean annualized failure probability of static, hydrologic, and seismic risks to the dam is 3 orders of magnitude below Reclamation’s Public Protection Guideline.

Maintenance tasks for the river outlet works include lining repairs and hollow-jet valve maintenance. The interior of the river outlet works was originally lined with coal tar enamel. Relining of the river outlet works with solvent borne epoxy began in the fall of 2024. The fabrication of the river outlet works hollow-jet valves dates back to the original construction of the dam, with no rehabilitation since that time. In 2023, an inspection of the outlet works found that to continue long-term operation of the outlet works, major repairs or replacement of the hollow-jet valves should be considered, as well as increasing the frequency of regular operation and maintenance tasks. River outlet works conduits were relined between 2024 and 2025. Refurbishment or replacement of the hollow jet valves is in the planning stages.

Operations

The operating criteria for Glen Canyon Dam were published in 1997. The Glen Canyon Powerplant operating regime was modified with the 2016 Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) Record of Decision (ROD), which establishes guidelines for allocating annual release volumes and defines a minimum water release rate of 8,000 cfs or more between 7:00 a.m. and 7:00 p.m., and at least 5,000 cfs between 7:00 p.m. and 7:00 a.m.; the maximum hourly increase (that is, the up-ramp rate) of 4,000 cfs per hour; a daily fluctuation limit of 8,000 cfs per 24-hour period; and a water maximum release rate of 25,000 cfs (Reclamation 2016b). The 2016

LTEMP ROD modified the daily fluctuation limit, so it is calculated as a function of the monthly volume, and it increased the down-ramp rate to no greater than 2,500 cfs per hour (Reclamation 2016b).

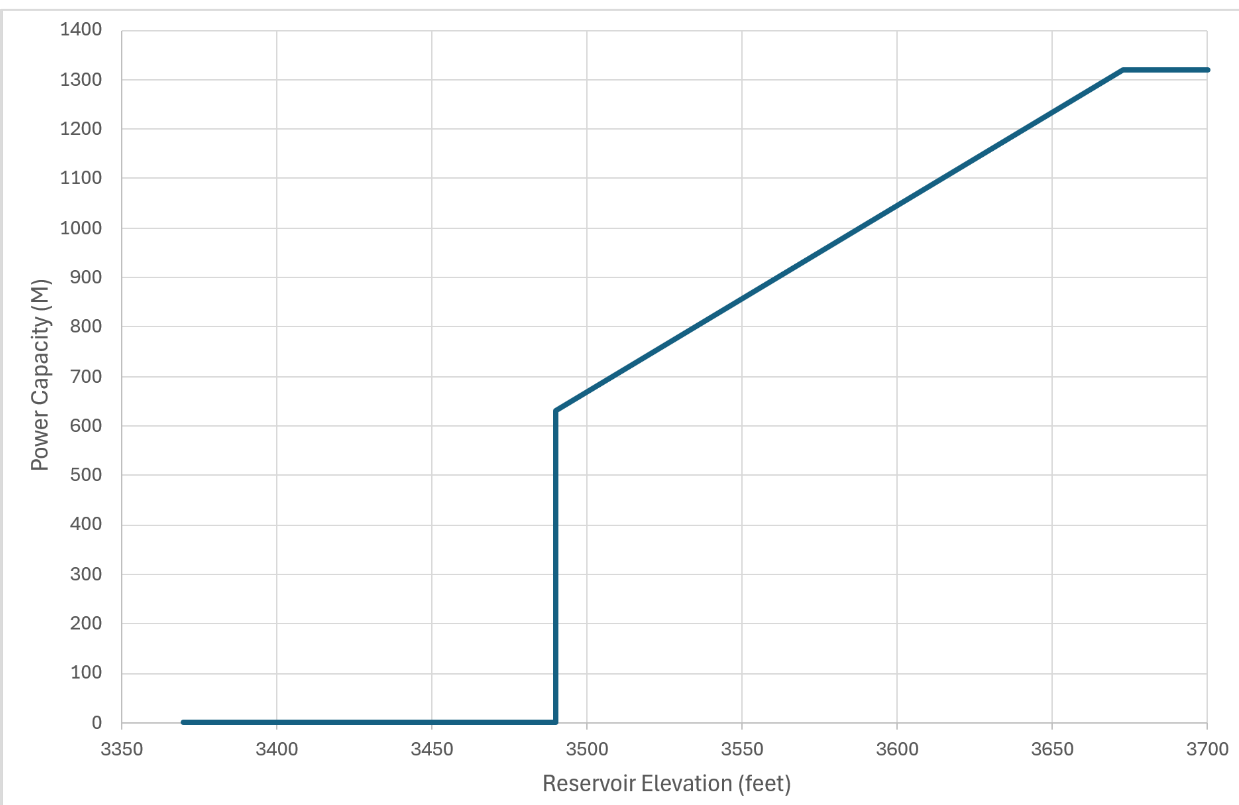
Hydropower Generation and Physical Capacity

Glen Canyon Powerplant has eight generators with a maximum combined physical capacity of 1,320 MW at a reservoir elevation of 3,700 feet (Reclamation 2016a). At minimum power pool, the powerplant has an estimated physical capacity of 630 MW.

Since 2007, the powerplant has undergone updates to improve efficiency, including: replacement of all eight turbines, four generator rewinds, replacement of all step-up transformers, optimization of software within the facility; and continued operations and maintenance (Reclamation 2024).

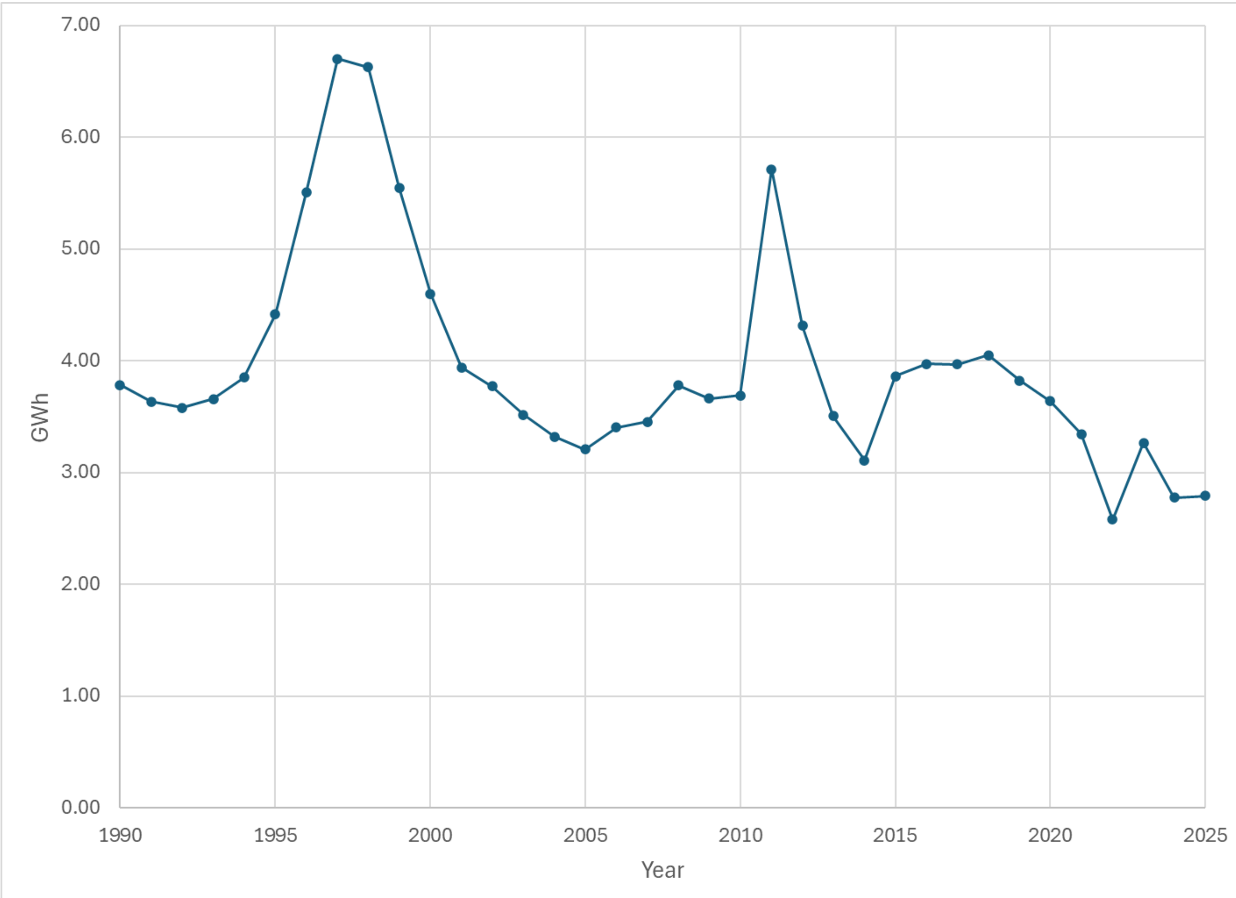
Despite the improved efficiencies, the powerplant's physical capacity to generate power has been affected by drought conditions and the resulting decreases in Lake Powell reservoir elevations. The decreases in elevation and, therefore, head, combined with reduced annual releases, have reduced power generation since 1997. **Figure TA 15-4** below shows the estimated physical capacity at a range of lake elevations. **Figure TA 15-5** displays the historical annual power generation from 1990 to present.

Figure TA 15-4
Power Capacity Estimates for Glen Canyon Powerplant at Varying Lake Powell Elevations



Source: Reclamation 2025a

Figure TA 15-5
Annual Glen Canyon Powerplant Generation from 1990 to Present

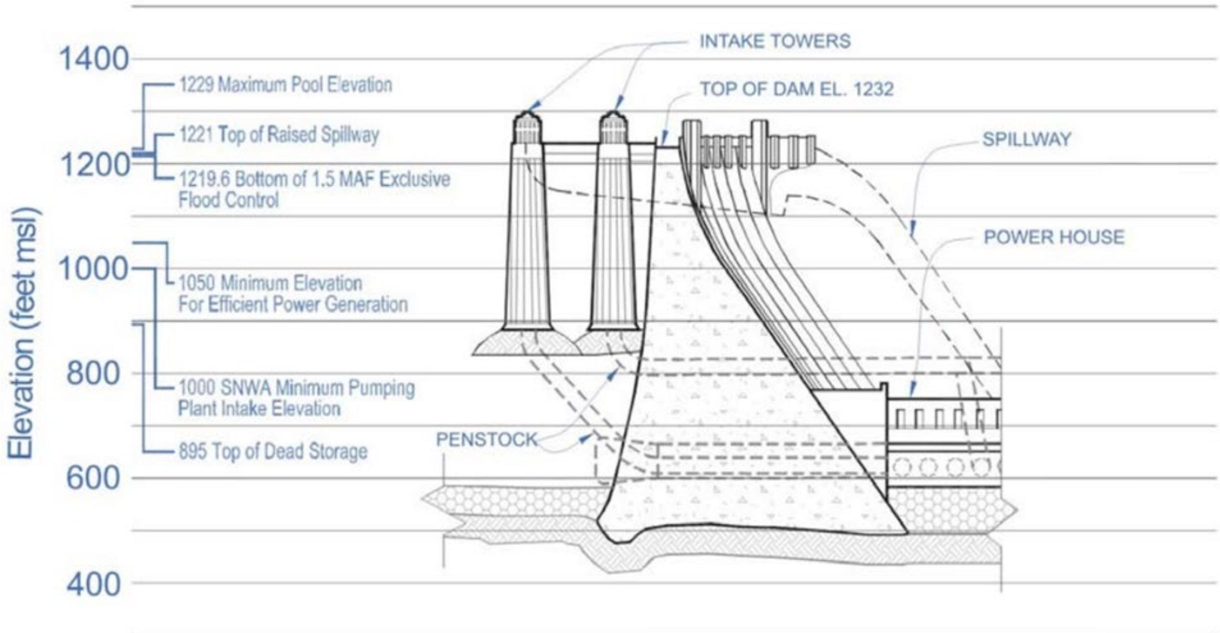


Source: Reclamation 2025a

Hoover Dam/Lake Mead

Hoover Dam is located in Black Canyon on the Arizona-Nevada state line, approximately 35 miles southeast of Las Vegas, Nevada. The dam and its reservoir, Lake Mead, are operated and maintained by Reclamation's Lower Colorado Basin Dams Office. Hoover Dam is a concrete gravity-arch structure standing 726 feet high with a crest length of 1,244 feet, see **Figure TA 15-6**. Lake Mead has a water storage capacity of 30.2 maf and a maximum reservoir elevation of 1,232 feet.

Figure TA 15-6
Lake Mead and Hoover Dam Important Operating Elevations



Water Releases and Operational Considerations

Effective power generation currently requires a minimum water elevation of 950 feet in Lake Mead (Reclamation 2024). Water levels between 895 and 950 feet constitute the inactive pool, where releases can occur but do not generate hydropower. Below 895 feet, water reaches dead pool elevation, at which point releases are no longer possible.

Water is released from Lake Mead to the river through four intake towers. These 395-foot-high towers are positioned two on each side of the canyon and each tower has two openings for water to enter the penstocks, one near mid-height at elevation 1,045 feet and one at the bottom at elevation 895 feet. These openings can be closed by two 32-foot diameter, 11-foot-tall cylindrical gates. The two upstream intake towers release water to the lower main penstocks. The two downstream intake towers release water to the upper main penstocks. Each main penstock has four 13-foot-diameter steel penstocks that connect to the main penstock and supply water to individual generator turbines. The combined discharge capacity of all generator turbines is estimated at 49,000 cfs.

In addition, to passing water through the turbines, at the end of each main penstock are outlet works. At the end of each of the main penstock the penstock pipe branches into smaller diameter penstocks controlled by outlet work valves. Each of the lower penstocks have 4 valves available to discharge water. The discharge capacities for the lower outlet works are 15,300 cfs (Nevada penstock) and 15,400 cfs (Arizona penstock) at a reservoir water surface elevation of 1,219.6 feet, which is the bottom of the exclusive flood control space. Each of the upper main penstocks have 2 valves available to discharge water, the discharge capacities for the upper outlet works are 10,800 cfs (Nevada) and 10,700 cfs (Arizona) at elevation 1,219.6 feet.

There are two spillways at Hoover Dam, each consisting of a concrete overflow crest structure and basin with four spillway drum gates each, and a concrete-lined tunnel that discharges directly into the Colorado River. The original discharge capacity of both spillways was 400,000 cfs, but the maximum safe discharge capacity for each spillway was reduced to approximately 135,000 cfs due to the formation of a hydraulic jump inside the tunnels at those flows or greater.

Under normal conditions, nearly all Colorado River flow passes through the turbines, with the spillways and outlet works used only in exceptional circumstances. The maximum safe channel capacity is estimated to be 40,000 cfs. Current operations aim to keep Lake Mead below 1,219.6 feet as much as possible. While limited operation above this level has occurred historically, it is preferred to minimize time spent in the flood control space. The bottom of the spillway drum gate is 1,205.4 feet. Operating below this elevation is desired as elevations above this point rely on mechanical gate function, where risk of failure increases. The most critical elevation threshold is 1,226.9 feet. This elevation corresponds to a spillway discharge exceeding 40,000 cfs and represents an imminent emergency.

Current Condition

The DSPR system evaluated Hoover Dam to be in the DSPR 5 (low priority, normal urgency of action) category. The total mean annualized failure probability for static, hydrologic, and seismic risks remains three orders of magnitude below Reclamation's Public Protection Guideline threshold.

Water conveyance systems at Hoover Dam are generally in good condition. The intake towers and penstocks are more than 85 years old and part of the original construction of Hoover Dam. The intake towers and penstocks cannot be replaced, and routine maintenance is required to maintain structural integrity. As part of the routine maintenance program, the penstocks are drained, inspected, and the coating is repaired as needed.

In August 1941, Lake Mead's water level was within 1 foot of the spillway crest when the spillway gates were lowered, allowing flows for the first time. Relatively modest flows, never exceeding 13,000 cfs, were passed through both spillways for 4 months. Velocities reached up to 175 feet-per-second in the Hoover Dam spillway elbow. When halted in early December 1941, an inspection of the Arizona spillway tunnel revealed a 38- by 112-foot eroded section of tunnel lining due to flow cavitation that required repairs. The 1941 damage was attributed to a slight misalignment of the tunnel invert. In response to this finding, the tunnels were patched with special heavy-duty concrete and the surface of the concrete was polished smooth. The spillways were subsequently modified in 1947 by adding flip buckets to eliminate conditions thought to have contributed to the 1941 damage.

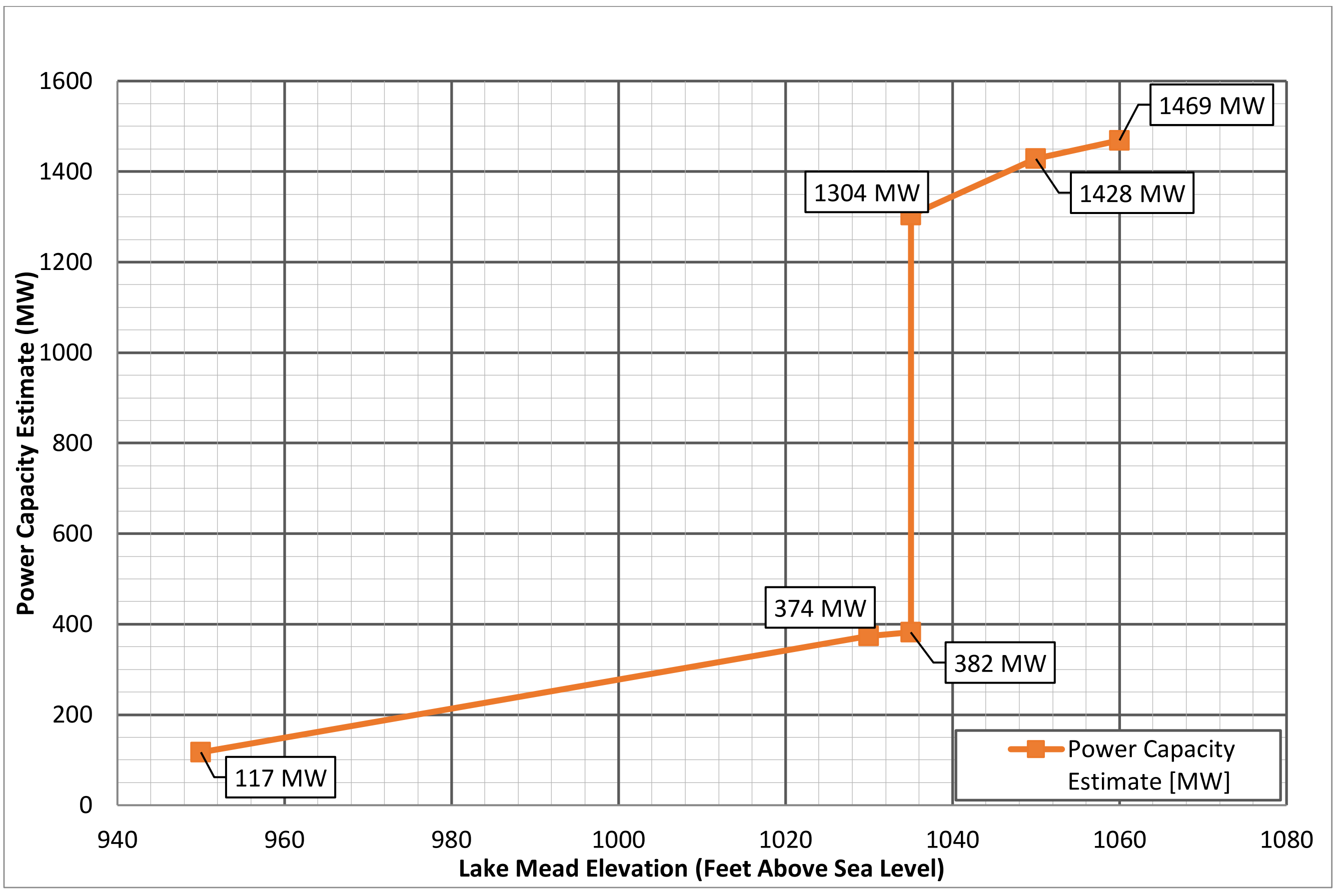
Operations

The Hoover Dam water releases are highest in the spring and summer with daily fluctuations made to meet water demands downstream as well as meet hydropower demand. The total range of flood control releases from Hoover Dam are from Step 1 - 0 cfs to Step 6 - 73,000 cfs (Reclamation 2007b). Hoover Dam releases are managed on an hourly basis to maximize the value of generated power by providing peaks during high-demand periods. Releases from Hoover Dam are also based on flood control regulations that are operated by the United States (U.S.) Army Corps of Engineers. Approximately 1.5 maf of space must be reserved at all times exclusively for flood control purposes.

Hydropower Generation and Physical Capacity

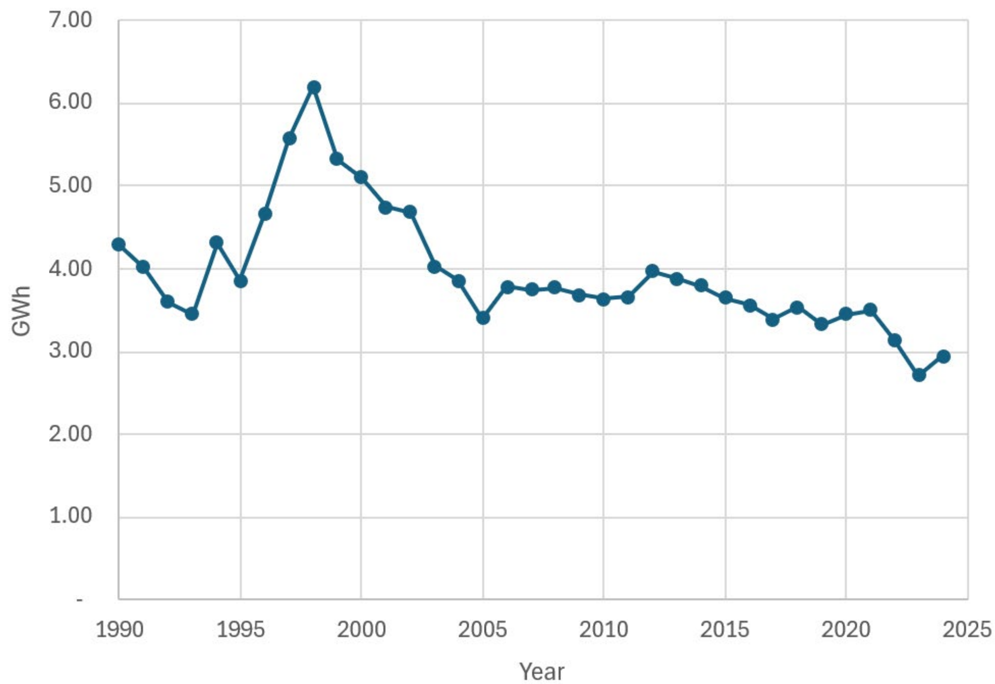
The Hoover Powerplant is the largest hydropower-generation facility in the Basin. The Hoover Powerplant has seventeen commercial generators with a maximum combined capacity of 2,074 MW. The powerplant requires a minimum Lake Mead elevation of 950 feet to produce power. At minimum power pool, the powerplant has an estimated physical capacity of 117 MW. The power-generating capacity of Hoover Dam has been affected by drought conditions. The drop in Lake Mead's elevation has reduced head, lowering electric power output. At Lake Mead elevation 1,035 feet, Hoover Dam's generating capacity is drastically reduced from 1,274 MW to 382 MW. At elevations above 1,035 feet or greater in current market conditions, hydropower can be produced at or above market value. With current turbines, if the elevation drops below 1,035 feet, it is estimated that operating costs will exceed the value of the hydropower produced. Please reference **Figure TA 15-7** and **Figure TA 15-8** below.

Figure TA 15-7
Power Capacity Estimates for Hoover Powerplant at Varying Lake Mead Elevations



Source: Reclamation 2025b

Figure TA 15-8
Annual Hoover Powerplant Net Generation from 1990 to 2024



Source: Reclamation 2025c

Since the 2007, Reclamation has replaced five existing turbines at the powerplant with "wide-head" turbines, upgraded wicket gates, modernized unit controls, and conducted typical operations and maintenance of the facility. The upgraded turbines, wicket gates and modernized unit controls have increased efficiency. However, at elevation 1,035 feet Hoover Dam would only be able to use its five wide head turbines. The 12 older turbines are expected to get excessive cavitation damage and would not be used. In May 2026, Reclamation announced $52 million from the Hoover Dam Post Retirement Benefit fund will be used for replacement of up to three older turbines with wide-head turbines designed to operate at lower lake elevations.

Despite the increased efficiencies, the power generating capacity of Hoover Dam has been affected by drought conditions. **Figure TA 15-7** shows the estimated electric power capacity at a range of Lake Mead elevations. **Figure TA 15-8** displays the historical annual power generation from 1990 to present. The decrease in the elevation of the Lake Mead reservoir has led to a decrease in head, which has resulted in a decrease in electric power output.

Davis Dam/Lake Mohave and Parker Dam/Lake Havasu

Davis Dam is a 320-foot-tall rock and earth-fill gravity dam, rising 140 feet above the Colorado River. The dam spans the border of Arizona and Nevada in Pyramid Canyon and is 67 miles downstream from Hoover Dam. Its dam crest is 1,600-feet long and 50-feet wide. Its reservoir, Lake Mohave has a water storage capacity of 1.8 maf and a maximum reservoir elevation of 647 feet. Davis Dam is operated and maintained by Reclamation's Davis Dam Field Division which is part of the Lower Colorado Basin Dams Office.

Parker Dam, commonly known as the "deepest dam in the world," is a concrete arch structure, 320 feet tall, with 73 percent of its height below the original stream bed elevation of the Colorado River. The dam is on the Arizona and California border and 88 miles downstream from Davis Dam. The dam has a crest length of 856 feet and a width of 39 feet. The dam's reservoir, Lake Havasu, has a storage capacity of 646,200 acre-feet and a maximum reservoir elevation of 450 feet. Parker Dam is operated and maintained by Reclamation's Parker Dam Field Division of the Lower Colorado Basin Dams Office.

Water Releases and Operational Considerations

Davis Dam has a rectangular concrete forebay at its eastern end. At the end of the forebay is a spillway that consists of three 50-foot x 50-foot fixed wheel gates and a spillway crest elevation of 597 feet. The river outlet works consist of 22-foot x 19-foot radial gates with a crest elevation of 542 feet. From the forebay, water enters the powerplant through five 22-foot diameter steel lined penstocks to five hydroelectric generators. The powerplant can release up to 26,000 cfs at 120 feet of head and 31,000 at 136 feet of head. Normal releases from Davis Dam are made through the powerplant turbines with the spillway and outlet works in the closed position. The safe downstream channel capacity on the river is 40,000 cfs. Normal operating elevations for the Lake Mohave reservoir are between 630 and 646 feet.

Parker Dam has a forebay on the right downstream abutment. In the center of the dam is a spillway that consists of five 50-foot-wide overflow gate bays at the dam center with a crest elevation of 400 feet. From the forebay water enters the powerplant through four 22-foot diameter steel lined penstocks that convey water to four hydroelectric generators. Their combined discharge capacity is 22,000 cfs. The safe downstream channel capacity on the river is 40,000 cfs. The normal operating elevations for the Lake Havasu reservoir are between 445 and 450 feet.

Current Condition

The DSPR system evaluated Davis and Parker Dams to be in the DSPR 4 (low urgency of action) category, as the total mean annualized failure probability of static and seismic risks to the dams is one-half order of magnitude below Reclamation's Public Protection Guideline threshold value. The dams were determined to be in good condition and performed adequately, and responses of the dams to reservoir loading are predictable, with conditions not appearing to change.

Operations

The Davis Dam fluctuates releases between 4,200 cfs and 23,000 cfs, while Parker Dam fluctuates between 1,800 cfs and 19,000 cfs. The maximum releases for the Parker and Davis Powerplants are 19,000 cfs and 23,000 cfs, respectively. The exact release depends on downstream water demands and tends to be lowest during the winter and highest in spring and summer. Parker Dam is operated under the same rule curve that determines end-of-month target elevations as prior to the Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead, maintaining Lake Havasu's water surface elevation between 445 and 450 feet. Seasonal adjustments to the reservoir's water surface elevation allow for flood control in the fall and higher water levels in the spring. The average annual elevation was 447.5 feet from 1996 to 2007, and approximately 447.7 feet from 2008 to 2022, remaining consistent for the last several decades. Current minimum releases of the Parker Dam are 1,600 cfs daily, 1,400 cfs hourly, and

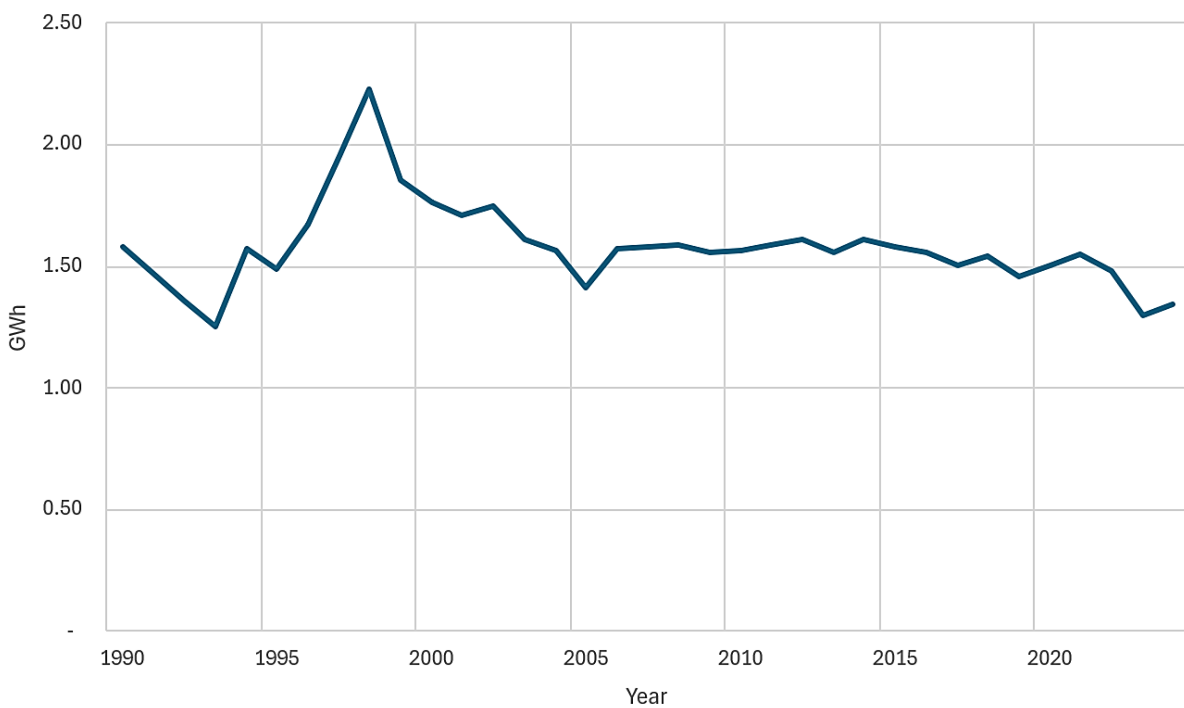
95,000 acre-feet during a 30-day month. The 2007 Final EIS stated Parker Dam releases from Lake Havasu ranged from 6.19 maf to 10.3 maf (averaged 7.4 maf) from 1996 to 2007 (Reclamation 2007a). Since 2008, annual dam releases ranged from 6.2 maf to 6.7 maf (averaged 6.4 maf) through 2022. The average annual Parker Dam releases have decreased by 1.0 maf since the issuance of the Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead.

Hydropower Generation and Physical Capacity

The Davis Powerplant has four 51.75 MW generators and one 48 MW generator for a total of 255 MW of capacity. The Parker Powerplant has four 30 MW generators, totaling 120 MW, with a discharge capacity of 22,000 cfs (Reclamation 2023).

Since 2007, both the Davis and Parker Dam facilities have undergone typical operations and maintenance. All four turbines at the Parker Powerplant were replaced between 2004 and 2010. Drought conditions have had less impact on the capacity at Davis and Parker Powerplants than the Hoover and Glen Canyon Powerplants because the elevations of Lake Mohave and Lake Havasu reservoirs have remained relatively constant. **Figure TA 15-9** shows the historical combined annual power generation at the Parker and Davis Powerplants. The slight drought induced reduction in river flow has led to a decline in electric power generation.

Figure TA 15-9
Annual Parker and Davis Powerplants Generation from 1990 to Present



Source: Reclamation 2025a

TA 15.1.4 Hydroelectrical Power Distribution

Hydroelectric power generation can be adjusted operationally through a coordinated effort between WAPA and Reclamation. This operational flexibility allows WAPA to quickly and efficiently increase or decrease generation in response to customer demand, generating unit or transmission line outages (contingency reserves), unscheduled customer deviations from internally scheduled contracted power usage (regulation and load/generation following) within a specific metered load area known as a balancing authority, integrated power system requirements, and requests for emergency assistance from interconnected utilities. Power operations are the physical operations of an electric power system, including hydropower generation and control, operational flexibility, scheduling, power generation load following, regulation, transmission, and emergency operations. These are discussed in the sections below. Additional information on power generation, control, regulation, reserves, and ramping can be found in the 2007 Final EIS Section 3.11.1.1 (Reclamation 2007a); and that information is incorporated here by reference.

Scheduling[2]

Power scheduling occurs by matching available power generation to seasonal, daily, and hourly system energy and capacity needs. Power scheduling is affected by the temporal distribution of monthly water release volumes, restrictions in water release patterns, availability of generator units (due to maintenance), availability of other regional hydropower units, power allocations, and peak and off-peak power demand period. Glen Canyon Dam scheduling by WAPA to meet power requirements typically results in higher water releases via the powerplants in the peak power demand months of December, January, July, and August. In the Lower Colorado River dams, scheduling is driven by water orders. There is high degree of flexibility in the releases within a month for Hoover Dam, but the amount of power delivered is constrained by monthly water orders. For Parker Dam and Davis Dam the scheduling occurs daily for power based on water orders.

Load Following,[3] *Ancillary Services, Generation, and Regulation*[4]

Hoover Dam and Glen Canyon Dam can change in response to changes in the load (demand) or unanticipated changes in the power generation resources within the operating region. This ability to respond to rapidly changing load conditions is called load or generation following (Reclamation 2016a). Load following creates large fluctuations in water releases, which can have impacts on some downstream environmental resources (Reclamation 2016a). The 1996 Operation of Glen Canyon Dam: CRSP ROD (Reclamation 1996) narrowed the range of operation for CRSPA purposes, thereby reducing the ability of power generation at Glen Canyon Dam to respond to customer load.

Changes in WAPA's scheduling guidelines for Glen Canyon Dam typically occur over a period of months, not only because of the operational constraints originally imposed by the 1996 Glen Canyon Dam ROD (Reclamation 1996) but also due to changing market conditions. Operational conditions for Glen Canyon Dam are further affected by the frequency, season, and time-of-day

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[2] Scheduling information is provided for context. The alternatives do not address scheduling and there are no anticipated impacts on scheduling from the alternatives.
[3] Load following are adjustments to power output as demand for electricity fluctuates throughout the day.
[4] Load following, ancillary services, generation, and regulation information is provided for context. The alternatives do not address load following, generation, or regulations and there are no anticipated impacts on them from the alternatives.

limitations that may be in effect; physical and environmental operating restrictions at other CRSP generating facilities and within the interconnected electric system; and the availability and price of replacement power (Reclamation 2016a).

National Regional Reliability Standards[5]

To ensure interconnected system reliability, WAPA follows mandatory reliability standards enforced by the North American Electric Reliability Corporation (NERC) and the WECC. In addition, WAPA follows operational criteria, guidelines, and procedures set in place by the WECC and the contingency reserve sharing group applicable to each balancing authority area. Each WECC utility is located within such a load balancing area, and one utility within the balancing authority area serves as the balancing authority operator. WAPA is the balancing authority operator for the Southwest Power Pool Regional Transmission Organization Balancing Authority Areas and is responsible for ensuring that each load-serving utility within each balancing authority serves its own internal load while meeting its power and reserve obligations. Operating as a balancing authority, WAPA is the provider of last resort should a load-serving entity not be able to fulfill its obligation to the balancing authority area, and it carries all compliance responsibility for the balancing authority function. All CRSP powerplants are within the Western Area Colorado-Missouri Region balancing authority, and the flexibility and load/generation following capability of CRSP hydroelectric powerplants, particularly Glen Canyon Powerplant, are important in meeting NERC/WECC reliability standards and criteria. Hoover, Parker and Davis Powerplants are all within the Western Area Lower Colorado balancing authority area. Hoover provides ancillary services including regulation capability through a dynamic or pseudo tie generation arrangement with four other balancing authority areas including significant capacity allocations that can provide regulation services within the California Independent System Operator.

Colorado River Storage Project Basin Fund[6]

The CRSPA; 43 U.S. Code 620d) established the Basin Fund for the collection of revenues from the operation of the CRSP and participating projects. These funds are available until expended to defray the costs of operation, maintenance and replacements for all facilities of the CRSP and participating projects. Maintaining a sufficient Basin Fund balance is critical to operating and maintaining the reliability of CRSP facilities. Reclamation and WAPA use this fund to repay the federal investment (with interest), operate and maintain facilities, purchase market power, when necessary, provide funding under a Basin States' memorandum of agreement, support environmental and salinity programs, and provide irrigation assistance. WAPA sells wholesale power to preference customers, including public utilities, municipalities, and tribes, which incorporate this power into the rest of their portfolio to fulfill their load requirements. Under WAPA's current rate structure, WAPA provides its long-term firm power customers with a set amount of power on a quarterly basis. The amount of power is based on the amount of water Reclamation forecasts to release from the CRSP units during that quarter. If the CRSP units do not generate enough power to fulfill these quarterly obligations, WAPA purchases power and necessary transmission to make up the difference. Revenues collected through WAPA's firm power rate from the sale of wholesale power are

[5] National/Regional Reliability Standard information is provided for context. The alternatives do not address these standards and there are no anticipated impacts on them from the alternatives.
[6] Basin Funds are discussed for context. The Basin Fund will not be impacted by the alternatives because it is a reimbursable fund. Any changes in generation would be offset by changes in rates.

deposited into the Basin Fund. Changes in generation identified in the alternatives will not impact the Basin Fund. The Basin Fund has historically funded environmental programs like the Glen Canyon Dam Adaptive Management Program and the San Juan River Basin Endangered Fish Recovery Programs. In recent years, appropriations have funded these base programs, while the Basin Fund continues to fund related experiments. Experimental releases that bypass the electrical generators at Glen Canyon Dam reduce hydropower generation. Accordingly, WAPA purchases replacement power to fulfill contractual delivery obligations. Under the Grand Canyon Protection Act of 1992 (Public Law 102-575), WAPA records the financial cost of environmental experiments at Glen Canyon Dam as a non-reimbursable expense. WAPA accounts for such costs as a constructive return to the U.S. Treasury rather than as an operations and maintenance expense to be recovered through WAPA's cost-based power rates.

Colorado River Dam Fund

The Boulder Canyon Project (BCP) Act of 1928 established the Colorado River Dam Fund to pay for the construction, operation and maintenance of the BCP, including Hoover Dam. All revenues generated by the project, primarily from power sales, are deposited into this fund, which is then used to repay the U.S. Treasury for the construction costs, cover operation and maintenance expenses, and fund other beneficial purposes like flood control, water delivery for Reclamation, and payments to Arizona and Nevada. In addition, surcharges are added to the charges of Nevada and California power contractors to contribute money for the salinity program. Arizona power contractors pay a surcharge for the repayment of the Central Arizona Project. BCP power contractors also contribute to the Lower Basin Multi-Species Conservation Program.

Each year WAPA and Reclamation present the proposed budget for the next ten years with a focus on the next fiscal year to the power contractors. The costs for each fiscal year budget amount is collected from the BCP power contractors and is referred to as the base charge. Each power contractor pays their contractual share of the base charge collected as an energy and capacity component. The base charge value, along with the projected energy generation which is derived from projected water deliveries for the next year creates an implied rate that is used for comparative purposes. The funds collected cover the cost of Reclamation and WAPA for operating and maintaining Hoover Dam and all associated project transmission and facilities.

Parker-Davis Project

The Rivers and Harbor Act of 1935 authorized the construction of Parker Dam. The Davis Dam Project was authorized under provisions of the Reclamation Project Act of 1939. The Consolidate Parker Dam Power Project and Davis Dam Project Act of May 28, 1954, 68 Stat. 143 authorized the Parker Dam Project and the Davis Dam Project to be consolidated into the Parker-Davis Project (PDP). As a result of original project funding, Metropolitan Water District of Southern California holds a perpetual contract for 50 percent of the power generated by the Parker Powerplant.

Reclamation Fund

WAPA has Firm Electric Service Contracts with power contractors. Under the PDP marketing plan, a set amount of monthly power is provided to the power contractors and power revenues are collected into the Reclamation Fund. If power from PDP is not generated to fulfill these contractual power obligations, WAPA purchases power to make up any difference. WAPA uses cash through their receipt authority from the Reclamation Fund to make those purchases. In 1998, Reclamation entered an Advancement of Funds Contract with the majority of the power contractors to directly fund their costs for Davis Dam and half of Parker Dam. In addition, Reclamation receives monthly transfers from WAPA for the surplus revenues collected under the 4-1/2 mills per kilowatt (kW) hour in the rates charged to power contractors in Arizona for repayment of the Central Arizona Project and 2-1/2 mills per kW hour in the rates charged to power contractors in California and Nevada for the Salinity Program pursuant to the Hoover Power Plant Act of 1984, as amended and supplemented. These funds are recorded as a pass though in PDP and are transferred to the Lower Colorado River Basin Development Fund.

Disturbances and Emergencies and Outage Assistance[7]

In the event of a widespread sudden loss of generation resource power outage, or an imbalance in the transmission system element causing a load/resource imbalance requiring an immediate response (i.e. disturbance), NERC contingency reserve standards require that available generation capacity be utilized to return the electric generation and transmission system to normal operating conditions within load/generation balance within 10 minutes following the disturbance. Generally, emergency operations contingency reserves are needed only for periods of an hour or less but can and frequently are activated several times a day.

WAPA may use available generating capacity at Glen Canyon Dam and Hoover Dam to support grid reliability and power system operations. Short-duration changes in releases may occur as part of normal power regulation activities. WAPA's ability to supply emergency assistance is limited by available transmission capacity and available generation capability, while the ability to deliver emergency assistance varies on an hourly basis, depending on firm load obligations and available generation from project resources.

Transmission System[8]

The Hoover, Glen Canyon, Parker, and Davis Powerplants are connected to a transmission system. Each facility's generation can affect transmission limitations when lines do not have enough capacity to transmit electricity from the point of generation to the point of demand. Actual transmission refers to the measured flow of power on the line. WAPA operates 17,000 circuit miles of transmission lines.

Power Marketing

WAPA markets long-term firm capacity and energy, short-term, firm capacity and energy, and non-firm energy. Firm power is capacity and energy that are guaranteed to be available to the customer. Loads are made up of firm load, non-firm sales, and interchanges out of the control area. Firm load and capacity obligations include long- and short-term firm sales, Reclamation project use loads, system losses, balancing authority control area regulation, firm load contingency reserves, and scheduled outage assistance. Capacity is reserved to provide regulation, contingency reserves,

[7] Disturbance and emergencies and outage assistance are discussed for context. The alternatives in this Final EIS do not address disturbance, emergencies, or outage assistance and there are no anticipated impacts on these from the alternatives.
[8] Transmission is discussed for context. The alternatives in this Final EIS do not address transmission and there are no anticipated impacts on transmission from the alternatives.

frequency support and response, meet contractual obligations, and participating project capacity. For Glen Canyon Dam, capacity is also reserved to serve Reclamation's irrigation and drainage pumping plant loads before being marketed as long-term firm capacity.

Colorado River Storage Project

In fiscal year 2025, WAPA marketed 4,268 gigawatt hours (GWh) of wholesale CRSP power to approximately 130 entities serving retail customers in Arizona, California, Colorado, Nevada, New Mexico, Utah, and Wyoming. Customers are small to medium-sized municipalities that operate publicly owned electrical systems; irrigation cooperatives and water conservations districts; rural electrical associations or generation and transmission co-operatives who often act as wholesales to these associations; federal facilities such as Air Force bases, universities, and other state agencies, and tribes. Capacity and energy from Glen Canyon Dam are bundled and marketed by WAPA as the Salt Lake City Area Integrated Projects (SLCA/IP). Electricity generated at SLCA/IP facilities in the Upper Colorado Region is marketed by WAPA under statutory criteria in the Reclamation Project Act of 1939, the Flood Control Act of 1944, CRSPA, and the Department of Energy Organization Act of 1977, along with associated marketing plans and contractual obligations. The majority of CRSP power is sold under long-term firm electric service contracts. If WAPA is unable to supply contract amounts of firm capacity or energy from Reclamation hydroelectric resources, it must purchase the deficit from other (primarily non-hydropower) resources for delivery. The expense for this purchase power is shared by all SLCA/IP customers. Reliance on SLCA/IP capacity and energy varies considerably among customers. In general, rural customers are more reliant on hydropower resources as a percentage of their total resource portfolio compared to urban customers.

Tribal Benefit Crediting

Tribes receive hydropower from WAPA, including hydropower from Glen Canyon Dam. Glen Canyon Dam is one component of a larger hydropower system and is included with other powerplants for marketing purposes. Capacity and energy from Glen Canyon Dam are bundled and marketed by WAPA as the SLCA/IP to consumers across Arizona, Colorado, Nebraska, New Mexico, Nevada, Utah and Wyoming. In the 2016 LTEMP Final EIS, tribal populations with the potential to be affected by project management include those who receive annual SLCA/IP allocations. The 2016 LTEMP Final EIS (Reclamation 2016a, Appendix K, Attachment 12) provides a comprehensive list of the annual SLCA/IP allocations to American Indian tribes and benefit information. When originally allocated in 2002, WAPA anticipated serving about 55.7 percent of total tribal electric use in the summer season and 58.8 percent in the winter season. There are 53 tribes or tribal entities that have signed firm electric service contracts with WAPA to receive power from SLCA/IP, which includes power from Glen Canyon Dam. Over the past 20 years, tribal load growth and reductions in hydropower due to drought have reduced that original percentage. There are currently seven tribes or tribal entities that operate electric utilities and receive power deliveries directly from WAPA. The remaining tribes operate under benefit crediting arrangements. Under a benefit crediting arrangement, the tribe's electric service supplier takes delivery of the SLCA/IP allocation and in return gives an economic benefit or payment to the tribe. In other words, the utility receives WAPA power on behalf of the tribe; subsequently, the utility receives the benefit of the power and transfers the economic benefit of the federal hydropower allocation to the tribe. Ideally, arrangements are made with public power utilities in areas that receive an allocation of power from WAPA such as a rural electric cooperative or municipality (however, exceptions apply for various reasons). Because benefit crediting arrangements are typically a function of MWh provided, a reduction in energy deliveries from WAPA translates directly into a reduced financial benefit to a tribe.

Desert Southwest Region

WAPA markets 10,600 GWh of wholesale Desert Southwest Region power to 80 entities in Arizona, southern California, and southwest Nevada. Capacity and energy from Hoover Dam are bundled and marketed by WAPA as the BCP and capacity and energy from Parker and Davis Dams are bundled and marketed by WAPA as the PDP to consumers in Nevada, Arizona, and California.

The BCP has delivered power to customers for over 80 years. The BCP Post-2017 remarketing effort was created in 2014 to determine power allocations for the Hoover Powerplant that expired in September 2017 (WAPA 2017). The new BCP contracts were signed in October 2016 and now run from 2017-2067. The existing contract delivers power to 46 direct and 74 total allocations including allocations through state agencies in Arizona, Nevada, and Southern California.

Davis Dam provides all 255,000 kW of operating capacity to the PDP and Parker Dam provides 60,000 kW of operating capacity to the PDP and 60,000 kW to the Metropolitan Water District of Southern California (WAPA 2024). The existing PDP sales contract expires in 2028 and a plan for a future remarketing is underway. At present, there are 36 contractors receiving power allocations from the PDP. The electricity produced by the PDP provides electricity to approximately 300,000 people (WAPA 2025c).

Rates

WAPA sets rates for firm electric service from Federal hydropower projects in its marketing territory based on Department of Energy regulations and applicable Federal statutes. Customers pay rates that align specifically with the project they buy power from.

WAPA has a public rate-setting process that includes collaborative planning, a public comment period, and information and comment forums. A *Federal Register* notice announces proposed rates before the comment periods and then another notice is issued with final rates at the end of the process.

Wholesale Rates

WAPA has various wholesale customers including municipal utilities, federal and state public power facilities, and rural electric cooperatives as well as tribal entities. Power rates are established in order for revenues to be sufficient to pay all costs assigned to power within required time periods. Power revenues also pay annual power operation and maintenance, purchased power, transmission service, and interest expenses on Treasury loans used to finance construction of power and transmission projects, and irrigation assistance beyond the ability of the irrigators to repay. CRSP and Lower Colorado Dam's power revenues also must contribute toward salinity control costs under the Basin Salinity Control Act. CRSP power revenue also contributes to construction costs (with interest) of CRSP-participating projects, as well as certain environmental costs as provided under the Grand Canyon Protection Act. Arizona power customers pay a surcharge for Central Arizona Project construction projects and Multispecies Conservation Program costs. Remaining annual revenues are used to pay off investment costs assigned to power, so that each investment can be paid within the time allowed (Reclamation 1995).

Retail Rates

Retail rates are those paid by end users (residential, commercial, and industrial customers of WAPA's wholesale customers). The retail rates charged by not-for-profit entities normally are set to cover system operation and capital costs. As costs of these individual components change, the retail rates are adjusted to ensure enough revenue is collected to meet the utility's financial obligations.

TA 15.2 Environmental Consequences

This environmental consequences section analyzes the effects of the alternatives on: the minimum power pool for Lake Powell and Lake Mead; the power capacity of the Glen Canyon and Hoover Powerplants; the power generation of the Glen Canyon, Hoover, Davis, and Parker Powerplants; spillway use of Glen Canyon Dam and Hoover Dam; and electricity rates and the market value of the electricity.

The spillway condition and hydropower capacity of the Davis Dam and Parker Dam are not analyzed because Lake Mohave and Lake Havasu reservoirs have historically remained relatively constant, and their elevations are expected to remain so under all alternatives. Both Lake Mohave and Lake Havasu would continue to be operated under a rule curve that provides specific target elevations at the end of each month (refer to **TA 3.1.8**, Davis Dam to Lake Havasu, in **TA-3**, Hydrologic Resources).

TA 15.2.1 Methodology

WAPA's Colorado River Storage Project Python-based model (CRiSPPy) and Reclamation's Colorado River Simulation System (CRSS) model and Decision Making under Deep Uncertainty (DMDU) analysis framework inform the basis for the effects analysis. Refer to **Chapter 3**, **Section 3.2.6**, Decision Making under Deep Uncertainty for additional details on the DMDU framework and **Appendix E**, DMDU Overview and Approach, for an overview of how to interpret the DMDU conditional box plots, robustness of futures, and vulnerability bar plots. The CRSS model models: potential water releases from the dams; reservoir elevations; and power generation for each of the alternatives and the Continued Current Strategies (CCS) Comparative Baseline. Additional information on CRSS model and model assumptions can be found in **Appendix A**, CRSS Model Documentation. The CRiSPPy model was updated to specifically address the scope of this Final EIS. The model covers 34 years of monthly operations (2027–2060) across 400 hydrology conditions with each alternative representing 163,200 model runs. The CRiSPPy model is a hydropower scheduling tool developed by Argonne National Laboratory for WAPA that combines optimization algorithms, data management, and graphical user interface. CRiSPPy model assumptions can be found in the technical report CRiSPPy: An advanced hydropower scheduling tool for the Colorado River Storage Project (Ploussard et al. 2025). The analysis of the impacts of the alternatives on electricity rates (wholesale) and the market value of the electricity for Glen Canyon Dam is based on analysis WAPA and Argonne National Laboratory prepared in the Post-

2026 Environmental Impact Statement Rate Analysis for the Colorado River Storage Project (Yu et al. 2025).

TA 15.2.2 Impact Analysis Area

The analysis area for Issues 1-4 encompasses the four primary dams in the Colorado River corridor from the full pool elevation of Lake Powell to the Southerly International Boundary: Glen Canyon Dam/Lake Powell reservoir, the Hoover Dam/Lake Mead reservoir, Davis Dam/Lake Mohave reservoir, and Parker Dam/Lake Havasu reservoir. The analysis area for Issue 5 consists of the WAPA retail power customers of Glen Canyon Dam power that are in the states of Arizona, Colorado, Nevada, New Mexico, Nebraska, Utah, and Wyoming.

Assumptions

All action alternatives, except for the Basic Coordination Alternative, incorporate mechanisms related to the storage and delivery of conserved water in Lake Powell and/or Lake Mead (refer to **Appendix S**). Unless otherwise specified, impacts reflect modeling assumptions about voluntary conservation behavior.

The Lower Basin electrical generation and firm capacity modeling results are direct outputs from the CRSS model. Refer to **Appendix A**, CRSS Model Documentation, for more details related to model assumptions and documentation. The Glen Canyon Dam electrical generation and firm capacity modeling results are direct outputs from the CRiSPPy model. The modeled firm capacity in a given month is calculated as the largest, or peak, value of the power output modeled by CRiSPPy in that month. For additional information and modeling assumptions, please refer to CRiSPPy: An advanced hydropower scheduling tool for the Colorado River Storage Project (Ploussard et al. 2025). The Glen Canyon Dam rates analysis data was developed by Argonne National Laboratory. Information and modeling assumptions for the rates analysis can be found in the Post-2026 Environmental Impact Statement Rate Analysis for the Colorado River Storage Project (Yu et al. 2025)

Impact Indicators

- Lake Powell and Lake Mead Reservoir elevations – Reservoir elevations were evaluated in relation to the minimum power pool elevations for Lake Powell and Lake Mead and in relation to Glen Canyon Dam and Hoover Dam infrastructure and safety.
- Firm capacity (MW) – Firm capacity is the reliable, guaranteed amount of power output from a powerplant that accounts for operational constraints such as water releases and ramp rates. Firm capacity is measured in MW. This analysis utilizes firm capacity as an indicator rather than physical capacity because it more accurately reflects the actual conditions WAPA and Reclamation use for operational decisions.
- Energy generation (MWh) – The amount of energy created over a certain period, measured in MWhs. Energy generation is dependent on reservoir head and water release volume.
- Spillway releases – spillway releases due to operational activities.
- Electricity rates – The minimum average rate increase amount per major rate increase measured in $/MWhs for customers of Glen Canyon Dam power.
- Market value of electricity – The future market value of electricity generated at Glen Canyon Dam measured in millions of dollars per year.

TA 15.2.3 Issue 1: How do the alternatives impact the frequency at which reservoir elevations drop below minimum power pool at Lake Powell and Lake Mead?

Minimum power pool is the lowest reservoir elevation level at which a hydropower plant can produce power. The frequency at which reservoir elevations drop below minimum power pool for Glen Canyon Dam/Lake Powell reservoir and Hoover Dam/Lake Mead reservoir were measured by calculating the percent of futures in which the elevations of the reservoirs achieve the preferred minimum performance of maintaining elevations at or above 3,490 feet and 950 feet, respectively (refer to **Figure TA 15-10** and **Figure TA 15-12**); and by using vulnerability figures that display conditions that could cause Lake Powell and Lake Mead to drop below these thresholds (3,490 feet and 950 feet respectively), representing undesirable performance when elevations fall below minimum power pool in one or more months (refer to **Figure TA 15-11** and **Figure TA 15-13**).

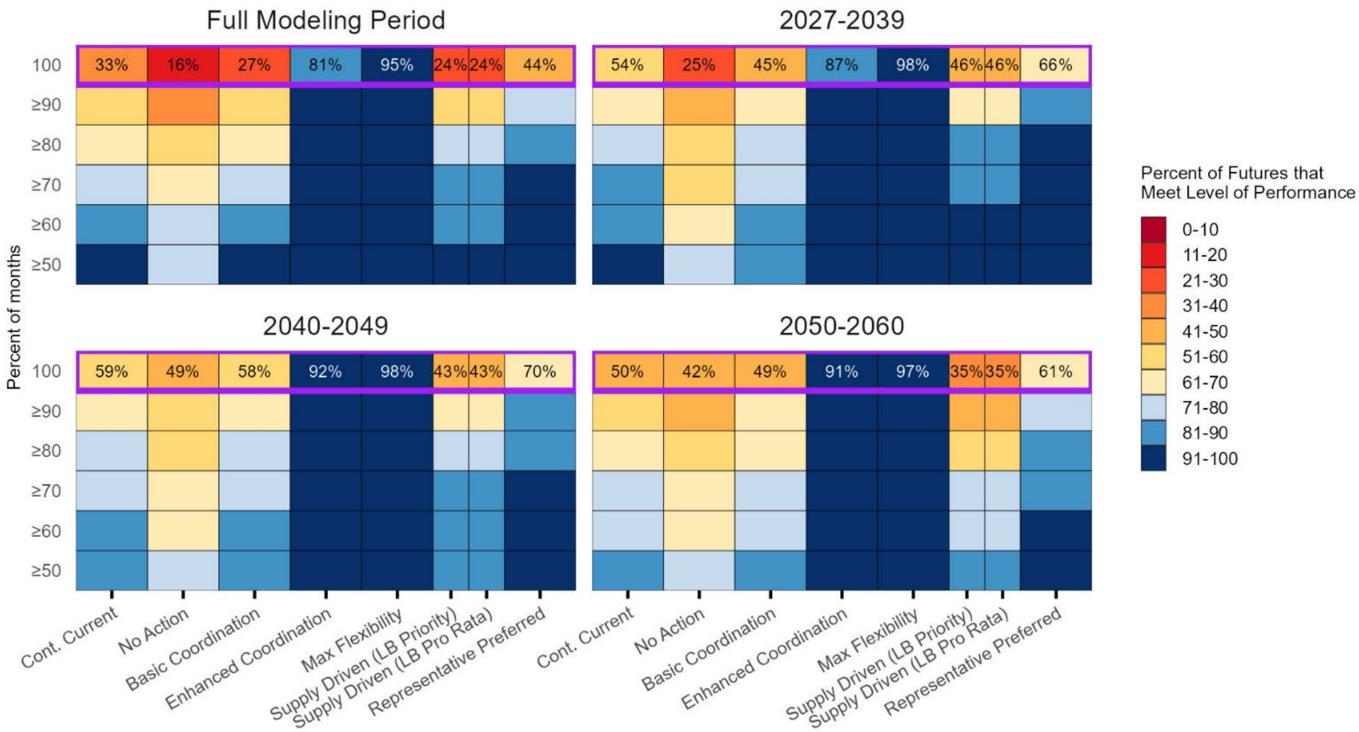
In addition to the importance of elevation 3,490 to hydropower at Lake Powell, there are also infrastructure concerns associated with the uncertainty of extended operations through the river outlet works as the sole means of sustained water releases from Glen Canyon Dam that could compromise the reliability and operational flexibility of Glen Canyon Dam and affect the ability to meet critical downstream water supply needs, as described in **Section 1.8.4.1**.

Figure TA 15-10 below shows the percentage of futures for each alternative (columns) in which Lake Powell elevation is 3,490 feet or above in the percent of months specified by each row. The highlighted row represents the preferred minimum level of performance, which is for elevations to be at least 3,490 feet in all months (i.e., 100 percent of the time). Results are shown for the Full Modeling Period and three subperiods: 2027–2039, 2040–2049, and 2050–2060.

In the Full Modeling Period, the Enhanced Coordination and Maximum Operational Flexibility Alternatives meet the preferred minimum performance in 81 percent and 95 percent of modeled futures, respectively, which is considerably more robust than the other alternatives. The Representative Preferred Alternative meets the preferred minimum performance level in 44 percent of futures, with the third highest robustness score. The No Action, Supply Driven (both Lower Basin Priority [LB Priority] and Lower Basin Pro Rata [LB Pro Rata] approaches), Basic Coordination Alternatives, and CCS Comparative Baseline are only able to meet the preferred minimum performance at or below 33 percent of futures. Across all subperiods modeled, both Enhanced Coordination and Maximum Operational Flexibility Alternatives meet the preferred minimum performance in greater percentages of futures than the others, never falling below 87 percent of futures. The next best performing is the Representative Preferred Alternative, ranging between 61 to 70 percent of futures across all subperiods.

Based on the planned length of this decision, it is important to compare robustness in the 2027-2039 modeling period. Maximum Operational Flexibility (98 percent) and Enhanced Coordination (87 percent) are the most robust alternatives, followed by the Representative Preferred Alternative (66 percent). The No Action Alternative is the least robust (25 percent), and the Basic Coordination Alternative (45 percent), Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative (46 percent), and the CCS Comparative Baseline (54 percent) perform in the middle.

Figure TA 15-10
Lake Powell Power Pool: Robustness.
Percent of futures in which Lake Powell elevation is at least 3,490 feet in the percent of months specified in each row



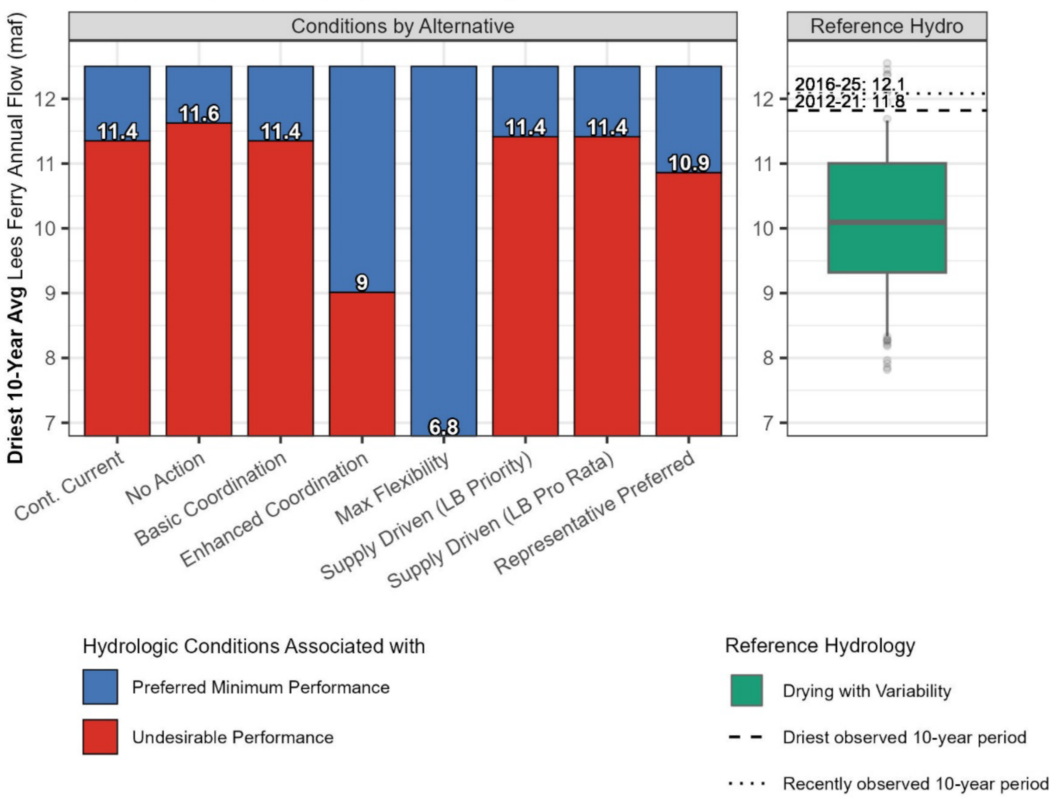
Note: Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative results differ primarily because of how the two shortage-distribution approaches interact with the modeled assumptions governing the storage and delivery of conserved water (see **Appendix B**, Modeling Assumptions: Lake Powell and Lake Mead Storage and Delivery of Conserved Water). This remains true for the following models in this technical appendix.

Figure TA 15-11 below shows what flow conditions are likely to cause Lake Powell's elevation to fall below 3,490 feet in any month. This definition of undesirable performance is based on the highlighted row in **Figure TA 15-10** above, which defined a future as successful when an alternative stayed above minimum power pool in 100 percent of months.

For this vulnerability analysis, the driest 10-year average Lees Ferry natural flow was determined to be a skillful predictor of undesirable performance. The vulnerability threshold for each alternative is described and compared to the Drying with Variability Ensemble using this streamflow summary statistic. The driest observed 10-year average flow from 2012-2021 (11.8 maf) and the average flow from 2016-2025 (12.1 maf) are also provided as dashed and dotted lines, respectively, for comparison.

The CCS Comparative Baseline, Basic Coordination and Supply Driven (both LB Priority and LB Pro Rata approaches) Alternatives would likely be vulnerable to Lake Powell elevation falling below 3,490 feet under a 10-year average Lees Ferry natural flow of 11.4 maf or drier, which is slightly less vulnerable than the No Action Alternative which is likely to be vulnerable if the 10-year average is 11.6 maf or drier. These conditions are similar to the driest observed 10-year average of 11.8 maf and occur in more than 75 percent of traces in the Drying with Variability Ensemble. The Enhanced Coordination and Maximum Operational Flexibility Alternatives are not likely to be vulnerable to undesirable performance unless the 10-year average flow is much drier than any observed conditions; fewer than 25 percent of traces in the Drying with Variability Ensemble include conditions that would be likely to cause vulnerability in the Enhanced Coordination Alternative, while the Maximum Operational Flexibility Alternative is not vulnerable to any traces in the Drying with Variability Ensemble.

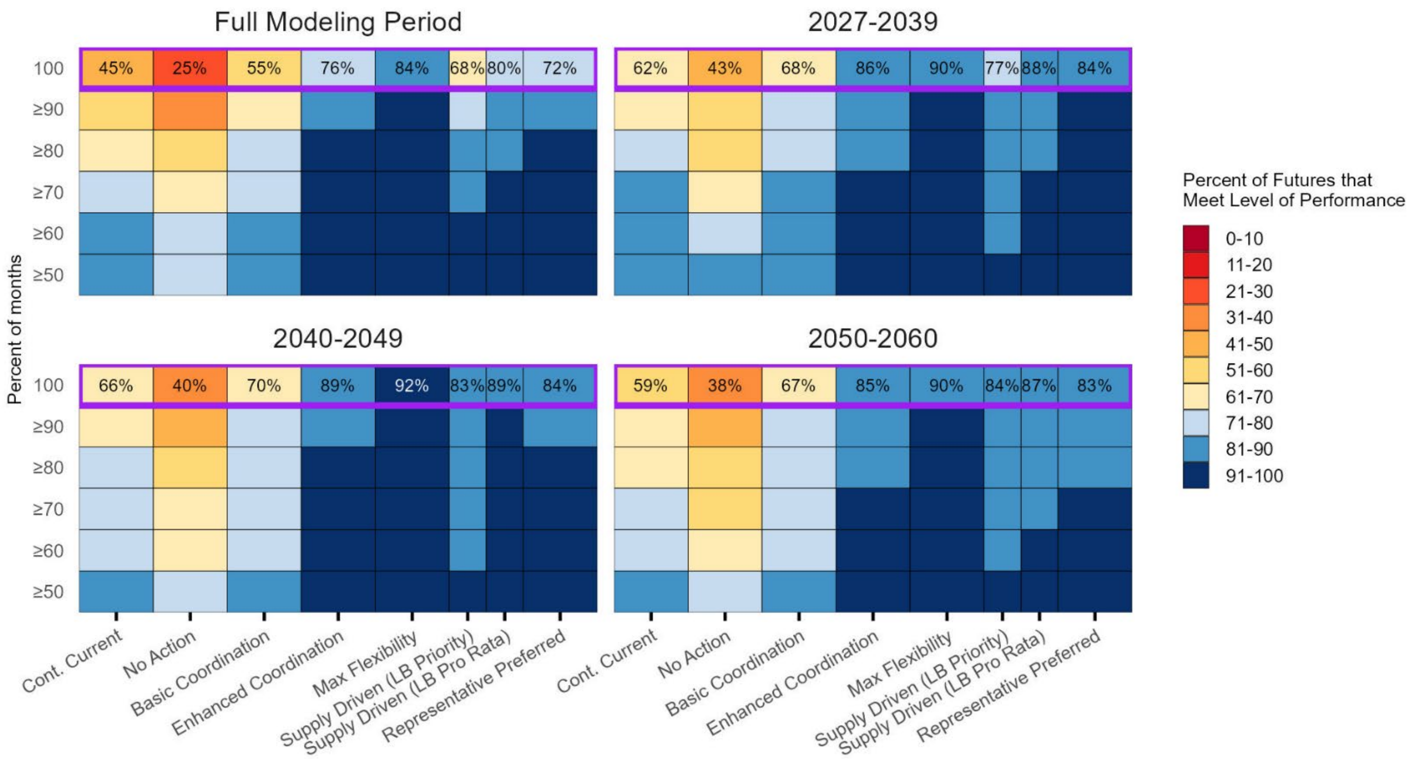
Figure TA 15-11
Lake Powell Power Pool: Vulnerability.
Conditions that Could Cause Lake Powell Elevation Below 3,490 Feet in any Month



Modeling indicates that the Representative Preferred Alternative would likely be vulnerable to at least one occurrence of Lake Powell elevation falling below 3,490 feet under a 10-year average flow of 10.9 maf. While these conditions have not yet been observed, absent additional action, this alternative is reasonably likely to be vulnerable in the next 10 years because these conditions occur in nearly 75 percent of traces in the Drying with Variability Ensemble, which represents a drier future.

Figure TA 15-12 below shows the percentage of modeled futures in which Lake Mead elevations are maintained at or above 950 feet under each alternative. Results are presented for four modeling periods: the Full Modeling Period, and 2027-2039, 2040-2049, and 2050-2060. The preferred minimum performance is shown in the purple highlighted row, which represents the percentage of futures that an alternative maintains elevations of 950 feet or above 100 percent of the time.

Figure TA 15-12
Lake Mead Power Pool: Robustness.
Percent of futures in which Lake Mead elevation is at least 950 feet in the percent of months specified in each row



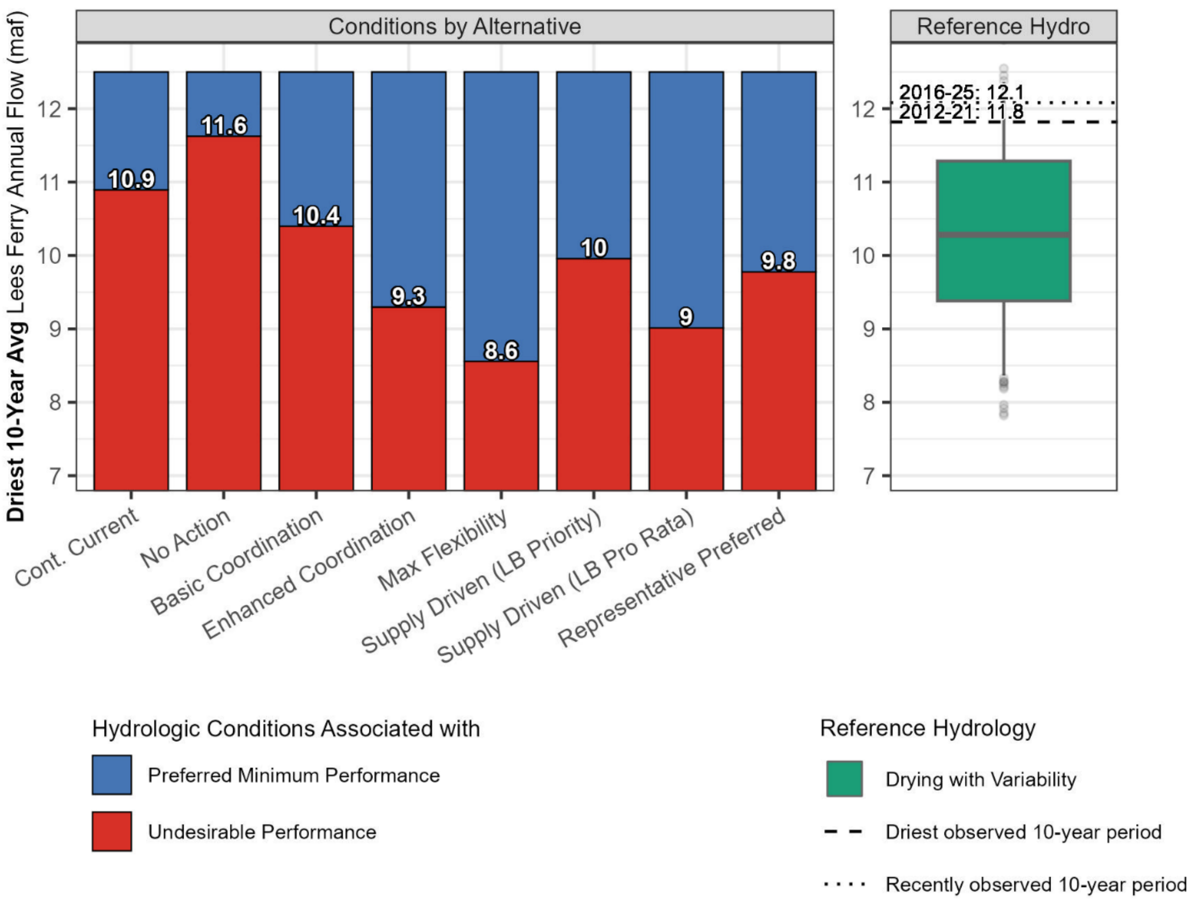
In the Full Modeling Period, the Maximum Operational Flexibility (84 percent), Supply Driven (LB Pro Rata approach) (80 percent), Enhanced Coordination (76 percent), and Representative Preferred (72 percent) Alternatives were fairly robust. The Supply Driven Alternative (LB Priority approach) performed moderately well, meeting the preferred minimum performance in 68 percent of modeled futures. The CCS Comparative Baseline (45 percent), and Basic Coordination (55 percent) and No Action (25 percent) Alternatives did not perform as well as the other alternatives.

Across the subperiods, the Maximum Operational Flexibility, Supply Driven (LB Pro Rata approach), Enhanced Coordination, and Representative Preferred Alternatives meet the preferred minimum performance in 80 to 92 percent of all futures and are considerably more robust than the other alternatives. The CCS Comparative Baseline, Basic Coordination, and No Action Alternatives met the preferred minimum performance in fewer futures.

Based on the planned length of this decision, it is important to compare robustness in the 2027-2039 modeling period. The Maximum Operational Flexibility, Supply Driven (LB Pro Rata approach), Enhanced Coordination, and Representative Preferred Alternatives meet the preferred minimum performance in 84 percent or more of futures, followed closely by the Supply Driven Alternative (LB Priority approach) (77 percent). The Basic Coordination Alternative (68 percent), CCS Comparative Baseline (62 percent), and No Action Alternative (43 percent) are less robust.

Figure TA 15-13 below shows what flow conditions are likely to cause the Lake Mead elevation to fall below 950 feet in any month, resulting in reduced or lost hydropower generation. This definition of undesirable performance is based on the highlighted row in **Figure TA 15-12** above, which defined a future as successful when an alternative maintained Lake Mead elevation above 950 feet 100 percent of the time.

Figure TA 15-13
Lake Mead Power Pool: Vulnerability.
Conditions that Could Cause Lake Mead Elevation Below 950 Feet in any Month



For this vulnerability analysis, the driest 10-year average Lees Ferry annual flow was determined to be a skillful predictor of undesirable performance. The vulnerability threshold for each alternative is described and compared to the Drying with Variability Ensemble using this streamflow summary statistic. The driest observed 10-year average flow from 2012-2021 (11.8 maf) and the average flow from 2016-2025 (12.1 maf) are also provided as dashed and dotted lines, respectively, for comparison. The Drying with Variability median value is 10.3 maf.

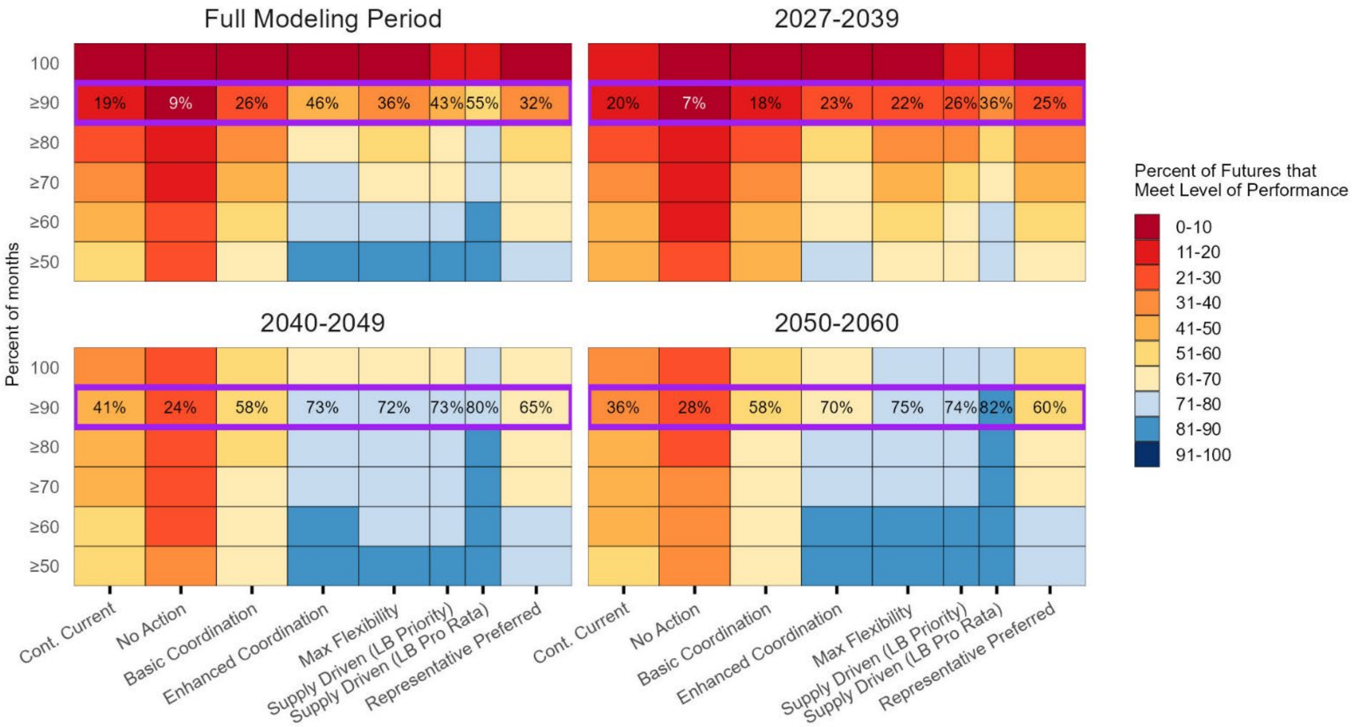
The No Action Alternative (11.6 maf) and CCS Comparative Baseline (10.9 maf) are most vulnerable to undesirable performance (nearly 75 percent or more traces in the Drying with Variability ensemble included these conditions or worse). In contrast, the Maximum Operational Flexibility (8.6 maf), Supply Driven (LB Pro Rata approach) (9 maf), and Enhanced Coordination (9.3 maf) Alternatives reach undesirable performance as hydrologic conditions become drier (around 25 percent or less of the Drying with Variability traces included these conditions or worse) indicating lower vulnerability. The Representative Preferred (9.8 maf) and Supply Driven (LB Priority approach) (10 maf) Alternatives are in the middle, being vulnerable in 25 to 50 percent of traces in the Drying with Variability Ensemble. The driest observed 10-year average Lees Ferry flow in the historical record is 11.8 maf; therefore, vulnerability thresholds for all alternatives are below what has already occurred.

Modeling indicates that the Representative Preferred Alternative would likely be vulnerable to at least one occurrence of Lake Mead elevation falling below 950 feet under a 10-year average flow of 9.8 maf. This alternative may or may not be vulnerable in the next 10 years because these conditions have not yet been observed but occur in more than 25 percent and fewer than 50 percent of traces in the Drying with Variability Ensemble, which represents a drier future.

Figure TA 15-14 below reports the percent of modeled futures in which each alternative maintains Lake Mead elevations at or above 1,035 feet in the percentage of time specified in each row. The preferred minimum performance is shown in the purple highlighted row, which represents the percentage of futures that an alternative maintains elevations at or above 1,035 feet at least 90 percent or more of the time. At an elevation of 1,035 feet, Hoover's high-head units can operate, marking the minimum elevation for viable high-head turbine operation. Total plant capacity at 1,035 feet is substantially reduced (approximately 382 MW), and additional capacity increases with higher elevations as head improves and more units become usable. Four modeling periods are shown: the Full Modeling Period, 2027-2039, 2040-2049, and 2050-2060.

In the Full Modeling Period, the percentage of futures that meets the preferred minimum performance level is highest under the Supply Driven Alternative (LB Pro Rata approach) at 55 percent, followed by the Enhanced Coordination Alternative at 46 percent. The Supply Driven (LB Priority approach) (43 percent), Maximum Operational Flexibility (36 percent), and the Representative Preferred (32 percent) Alternatives outperform the CCS Comparative Baseline (19 percent), and Basic Coordination (26 percent) and No Action (9 percent) Alternatives. The CCS Comparative Baseline, Basic Coordination and No Action Alternatives are the least robust with respect to maintaining the Lake Mead elevation required for high-head turbine performance.

Figure TA 15-14
Lake Mead High-Head Turbines: Robustness.
Percent of futures in which Lake Mead elevation is at least 1,035 feet in the percent of months specified in each row

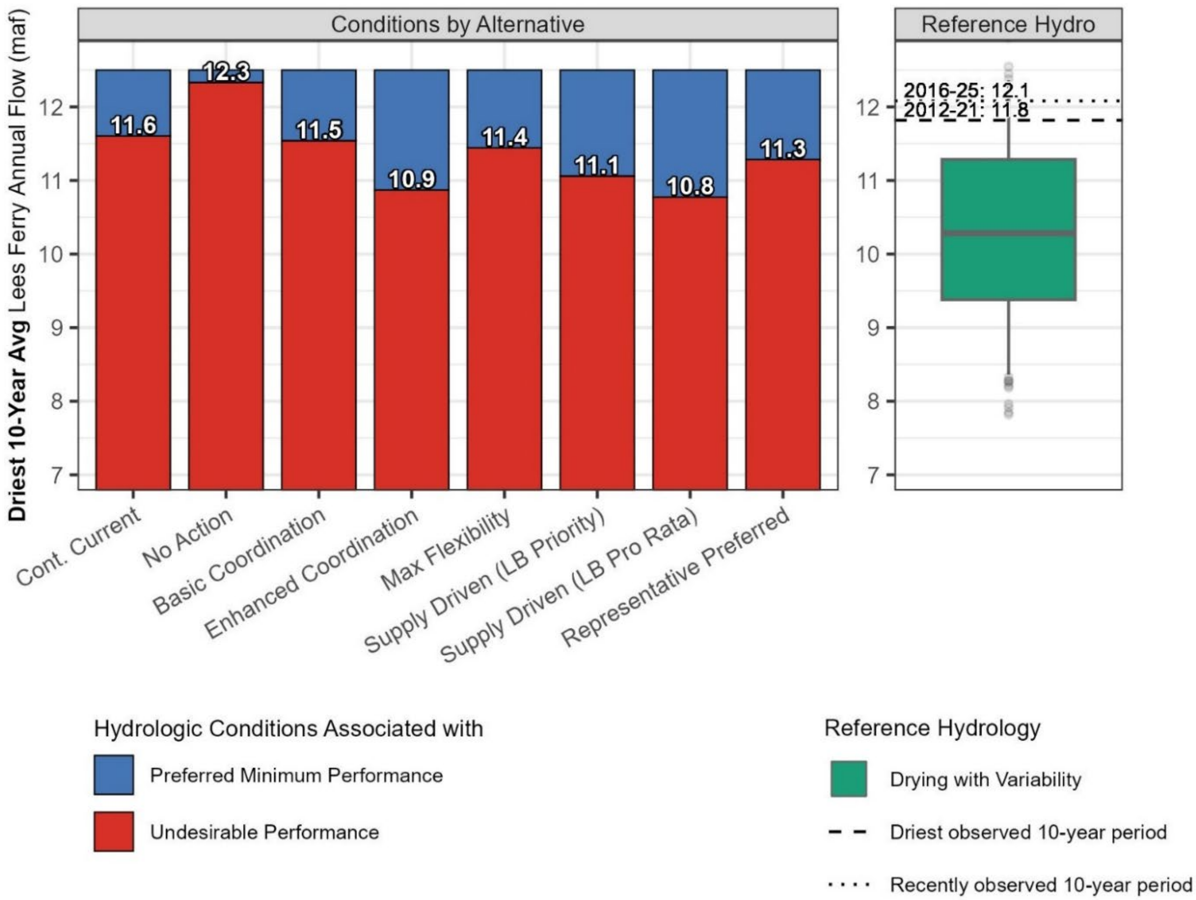


For the first sub-period (2027-2039), all alternatives achieved the preferred minimum performance in 18 to 36 percent of futures. No Action Alternative was the least robust, meeting the preferred performance in 7 percent of futures. In the second subperiod (2040-2049), the Supply Driven (LB Pro Rata approach) (80 percent), Supply Driven (LB Priority approach) (73 percent), Enhanced Coordination (73 percent), and Maximum Operational Flexibility (72 percent) Alternatives performed significantly better than the previous decade. In the final subperiod (2050-2060), the Supply Driven Alternative (LB Pro Rata approach) meets the preferred minimum performance in 82 percent of futures. The lowest performing alternative across all subperiods was the No Action Alternative, followed by the CCS Comparative Baseline.

Based on the planned length of this decision, it is important to compare robustness in the 2027-2039 modeling period. The Supply Driven Alternative (LB Pro Rata approach) is the most robust (36 percent), followed by the Supply Driven (LB Priority approach) (26 percent) and Representative Preferred (25 percent) Alternatives. The remaining action alternatives and CCS Comparative Baseline range from 18 to 23 percent. The No Action Alternative is the least robust at 7 percent.

Figure TA 15-15 below shows the flow conditions associated with Lake Mead elevation falling below 1,035 feet in one or more months. This definition of undesirable performance is based on the highlighted row in **Figure TA 15-14** above, which defined a future as successful when an alternative maintains Lake Mead elevations at or above 1,035 feet at least 90 percent of the time.

Figure TA 15-15
Lake Mead Power Pool: Vulnerability.
Conditions that could cause Lake Mead elevation to fall below 1,035 feet in more than 10 percent of months



For this vulnerability analysis, the driest 10-year average Lees Ferry annual flow was determined to be a skillful predictor of undesirable performance. The vulnerability threshold for each alternative is described and compared to the Drying with Variability Ensemble using this streamflow summary statistic. The driest observed 10-year average flow from 2012-2021 (11.8 maf) and the average flow from 2016-2025 (12.1 maf) are also provided as dashed and dotted lines, respectively, for comparison. The Drying with Variability median value is 10.3 maf.

The No Action Alternative (12.3 maf) is vulnerable to conditions wetter than the recent 10-year average of 12.1 maf, making it the most vulnerable alternative. Following are the CCS Comparative Baseline (11.6 maf), and Basic Coordination (11.5 maf), Maximum Operational Flexibility (11.4 maf), and Representative Preferred (11.3 maf) Alternatives which are vulnerable to hydrological conditions that occur in 75 percent or more of the Drying with Variability traces. Enhanced Coordination (10.9 maf), Supply Driven (LB Priority approach) (11.1 maf), and Supply Driven (LB Pro Rata approach) (10.8 maf) Alternatives were vulnerable to hydrological conditions that occur in 50 to 75 percent of the Drying with Variability traces.

The driest observed 10-year average Lees Ferry flow in the historical record is approximately 11.8 maf; except for the No Action Alternative, vulnerability thresholds are below what has already occurred.

Modeling indicates that the Representative Preferred Alternative would likely be vulnerable to Lake Mead elevation falling below 1,035 feet in more than 10 percent of months under a 10-year average flow of 11.3 maf. Absent additional action, this alternative is reasonably likely to be vulnerable in the next 10 years because these conditions are close to what has already occurred and they occur in about 75 percent of traces in the Drying with Variability Ensemble.

Summary of Issue 1 Impacts

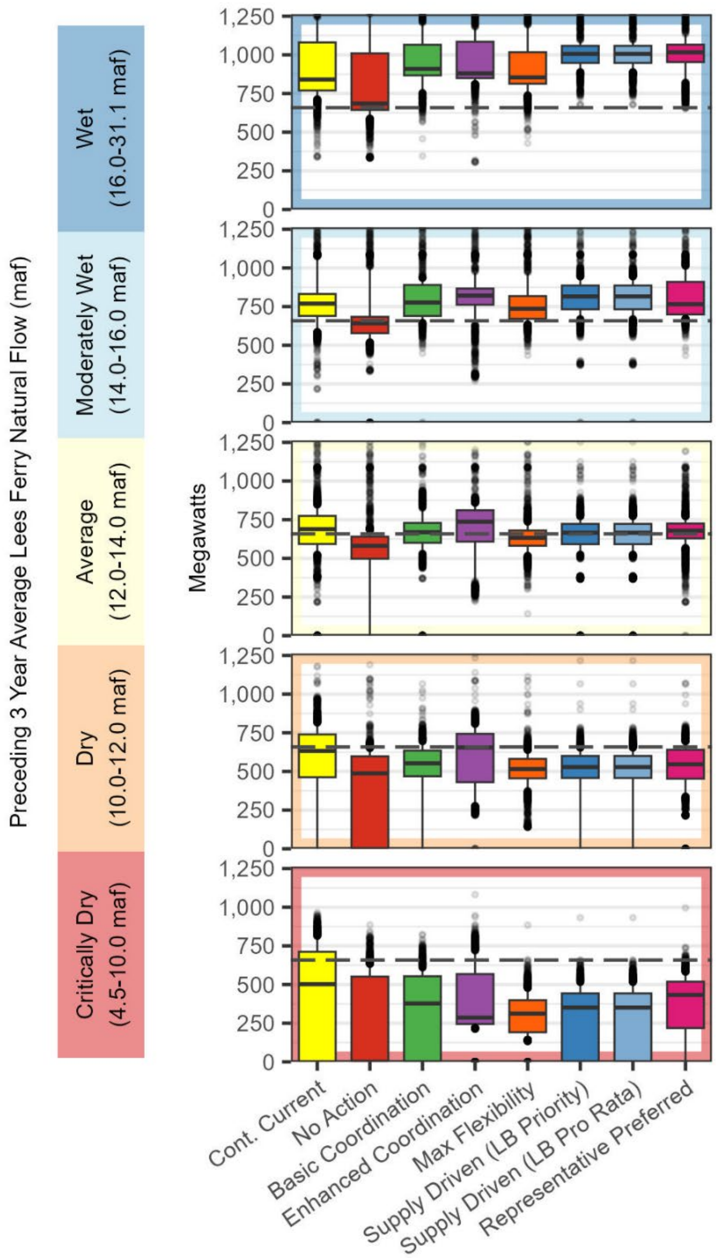
Across both Lake Powell and Lake Mead, the Maximum Operational Flexibility and Enhanced Coordination Alternatives consistently show higher robustness, maintaining elevations above minimum power pool in the greatest percentages of modeled futures, and are less vulnerable to undesirable performance under drier hydrological conditions. In contrast, the CCS Comparative Baseline, No Action, Basic Coordination, and Supply Driven (LB Priority approach) Alternatives exhibit greater vulnerability, with higher frequencies of dropping below minimum power pool and broader exposure to low-elevation conditions, especially under drier hydrology. At Lake Powell, Maximum Operational Flexibility and Enhanced Coordination Alternatives perform best, maintaining preferred conditions in 81 to 95 percent of futures over the full modeling period and showing lower vulnerability (between 6.8–9 maf), while other alternatives reach undesirable performances. The Representative Preferred Alternative is less protective of elevation 3,490 feet than the Enhanced Coordination and Maximum Operational Flexibility Alternatives, but more protective than the other alternatives and CCS Comparative Baseline. Similarly, at Lake Mead, Maximum Operational Flexibility, Enhanced Coordination, Supply Driven (LB Pro Rata approach), and Representative Preferred Alternatives demonstrate stronger performance (72 to 84 percent robustness), whereas the No Action Alternative and CCS Comparative Baseline are the least robust and most vulnerable, indicating a higher likelihood of dropping below minimum power pool under a wider range of hydrologic conditions.

TA 15.2.4 Issue 2: How would the alternatives impact the firm capacity of the Glen Canyon and Hoover Powerplants?

Firm capacity is the reliable, guaranteed amount of power output from a powerplant that accounts for operational constraints such as water releases and ramp rates. Firm capacity is measured in MW. This section will consider how the different alternatives impact the firm capacities of the hydropower plants at the Glen Canyon Dam and Hoover Dam.

Figure TA 15-16 below shows the firm capacity of Glen Canyon Dam across five different potential flow categories (Wet [16.0-31.1 maf], Moderately Wet [14.0-16.0 maf], Average [12.0-14.0 maf], Dry [10.0-12.0 maf], and Critically Dry [4.5-10.0 maf]) defined by the preceding 3-year average of Lees Ferry natural flow using August as the flow month. Reclamation used the estimated capacity for the month of August as it corresponds to peak energy demand and typically reflects the maximum available generating capacity. The dashed horizontal line represents the historical average firm capacity (658.3 MW, based on August 2016–2025 conditions). The bold center line of each box represents the median value, the box bounds represent the 25th to 75th percentile of the modeled results, the lines extend to the 10th and 90th percentiles, and the outliers are represented as dots beyond these lines.

Figure TA 15-16
Glen Canyon August Power Capacity: Box Plots



Across most alternatives, firm capacity is highest under the Wet Flow Category, with higher median values and relatively narrower interquartile ranges, indicating strong and consistent performance under wetter hydrologic conditions. The Representative Preferred Alternative performs best with a median of 1,016 MW. The Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative had a median 1,006 MW and similar variability to the Representative Preferred Alternative. The Enhanced Coordination, Maximum Operational Flexibility, and Basic Coordination Alternatives, and the CCS Comparative Baseline had median firm capacities ranging from 841 to 909

MW. The No Action Alternative had the lowest median at 685 MW, just above the historical average firm capacity from August 2016–2025 of 658.3 MW.

In the Moderately Wet Flow Category, the Enhanced Coordination, Basic Coordination, Representative Preferred, Supply Driven (both LB Priority and LB Pro Rata approaches) Alternatives, and the CCS Comparative Baseline generally exhibit higher median firm capacity and more favorable distributions than the Maximum Operational Flexibility and No Action Alternatives, which have lower medians.

Under the Average Flow Category, the Enhanced Coordination Alternative has the highest median value, followed closely by the CCS Comparative Baseline while the No Action Alternative has the lowest median indicating reduced performance. The remaining action alternatives cluster around the historical average firm capacity with similar median values and comparable interquartile ranges, suggesting similar levels of firm capacity under average hydrological conditions.

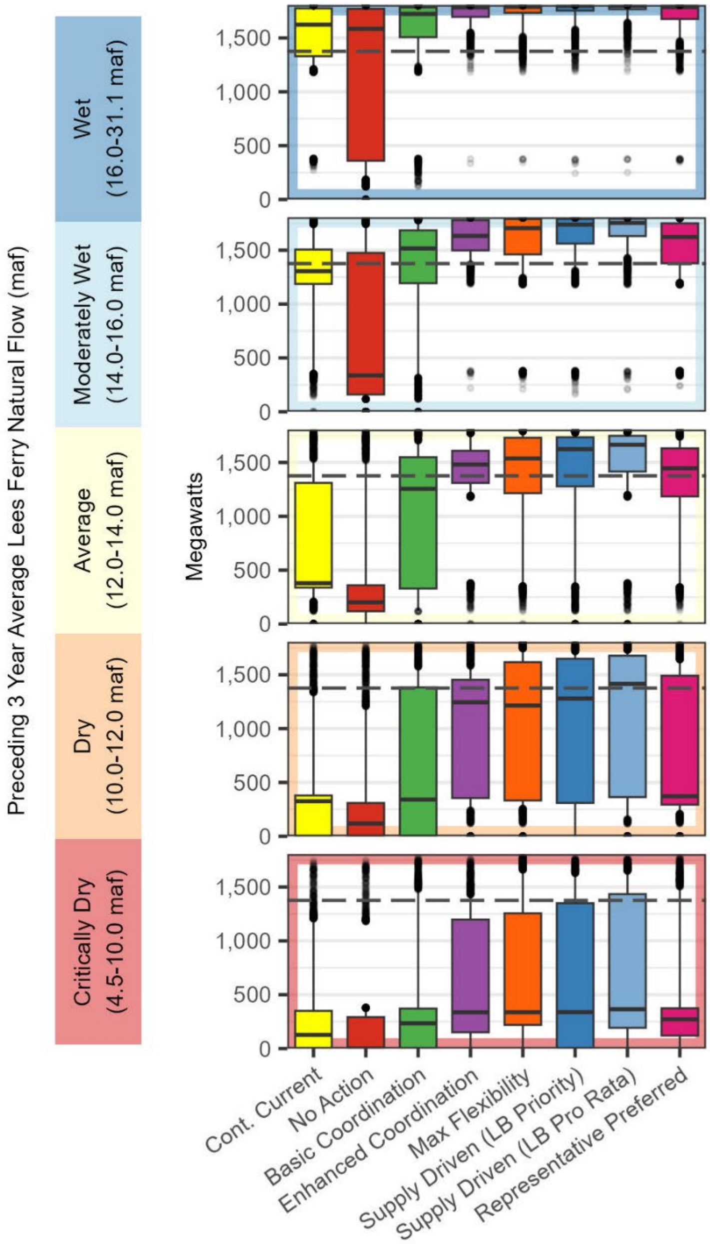
In the Dry Flow Category, median value declines across all alternatives and variability increases, reflecting heightened sensitivity to hydrologic stress. The Enhanced Coordination Alternative exhibits the highest median value in this category, followed by the CCS Comparative Baseline. While the other alternatives have lower medians, their interquartile ranges are narrower, indicating less variable firm capacities. Under dry conditions the No Action Alternative has the lowest median and a firm capacity of 0 MW in at least 25 percent of years.

Under the Critically Dry Flow Category, the CCS Comparative Baseline, and No Action, Basic Coordination, and Supply Driven (both LB Priority and LB Pro Rata approaches) Alternatives have at least 25 percents of years with 0 MW of firm capacity, indicating a high likelihood of undesirable performance under the driest conditions. These results highlight that alternatives emphasizing coordination and flexibility generally maintain higher medians and reduced variability, while less coordinated approaches are more susceptible to firm capacity loss as hydrologic conditions deteriorate.

In the Dry Flow Category, the Representative Preferred Alternative has a median August power capacity of 546 MW and an interquartile range (187 MW) that is near the middle of all alternatives. In the Critically Dry Flow Category, the Representative Preferred Alternative has a median capacity of 433 MW. With an interquartile range of 300 MW, the Representative Preferred Alternative is less variable than all alternatives, except the Maximum Operational Flexibility Alternative.

Figure TA 15-17 below shows the August firm capacity of Hoover Dam across five different potential flow categories (Wet [16.0-31.1 maf], Moderately Wet [14.0-16.0 maf], Average [12.0-14.0 maf], Dry [10.0-12.0 maf], and Critically Dry [4.5-10.0 maf]) defined by the preceding 3-year average of Lees Ferry natural flow. Reclamation used the estimated capacity for the month of August as it corresponds to peak energy demand and typically reflects the maximum available generating capacity. The dashed horizontal line represents the historical average firm capacity (1,376 MW, the average firm capacity between August 2016 to August 2025 based on historical data). The bold center line of each box represents the median value, the top and bottom of each box captures the 25th to 75th percentile of the modeled results, the lines extend to the 10th and 90th percentiles, and the outliers are represented as dots beyond these lines.

Figure TA 15-17
Hoover August Power Capacity: Box Plots



Under the Wet Flow Category, most alternatives show relatively high firm capacity with narrow interquartile ranges and similar medians, indicating stable capacity under wetter conditions. The exception in this category is the No Action Alternative which has a similar median to other alternatives (1585 MW) but much higher variability than the other alternatives with an interquartile range of 1412 MW.

In the Moderately Wet Flow Category, the Supply Driven (both LB Priority and LB Pro Rata approaches), Basic Coordination, Enhanced Coordination, Representative Preferred, and Maximum Operational Flexibility Alternatives generally have median power capacities higher than the historical average value and relatively narrow interquartile ranges. The CCS Comparative Baseline median (1,305 MW) fell slightly below the historical average firm power capacity. The No Action Alternative had the widest range of variability and the median firm capacity (337 MW) was well below the other alternatives.

Under the Average Flow Category, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative had the highest median firm capacities (1,624 and 1,664 MW respectively). The Maximum Operational Flexibility and Enhanced Coordination Alternatives had similar medians but the Enhanced Coordination Alternative was less variable than Supply Driven or Maximum Operational Flexibility. The Representative Preferred Alternative has a median firm capacity (1,446 MW) slightly above the historical average and similar variability to preceding alternatives. The Basic Coordination, and No Action Alternatives, and the CCS Comparative Baseline performed considerably worse than the other alternatives with lower median firm capacities and greater variability.

Under the Dry Flow Category, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative had the highest median firm capacities, followed by the Enhanced Coordination and Maximum Operational Flexibility Alternatives. The Representative Preferred Alternative had a much lower median firm capacity (372 MW) but similar variability to the preceding alternatives. The CCS Comparative Baseline and No Action and Basic Coordination Alternatives performed the worst with power capacity reaching zero in more than 25 percent of years.

In the Critically Dry Flow Category, the Supply Driven (both LB Priority and LB Pro Rata approaches), Maximum Operational Flexibility, and Enhanced Coordination Alternatives experienced wide variability for firm capacity but had median firm capacities around 350 MW. The CCS Comparative Baseline, and No Action, and Basic Coordination Alternatives show the lowest medians and the potential for zero capacity in more than 25 percent of years under the Critically Dry Flow Category.

In the Dry Flow Category, the Representative Preferred Alternative has a median firm capacity of 372 MW with an interquartile range of 1,197 MW. The median of the Representative Preferred Alternative is lower than the other action alternatives but the variability is similar. In the Critically Dry Flow Category, the Representative Preferred Alternative has a median firm capacity (271 MW) that is similar to the other action alternatives. With an interquartile range of 253 MW, the Representative Preferred Alternative is the least variable of all action alternatives.

Summary of Issue 2 Impacts

The firm capacity at Glen Canyon Dam under the Wet Flow Category is the highest under the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative. In the Moderately Wet Flow Category, the Supply Driven (both LB Priority and LB Pro Rata approaches) and Enhanced Coordination Alternatives performed with the highest firm capacity. Under Average and Dry Flow Category, the Enhanced Coordination Alternative had the highest median firm capacity. In the Critically Dry Flow Category, the CCS Comparative Baseline had a wide range of variability, with the highest 75th percentile exceeding the historical average firm capacity, and the 25th percentile falling to 0 MW. Enhanced Coordination, Maximum Operational Flexibility, and Representative Preferred Alternatives 25th percentiles did not fall to 0 MW like that of the other alternatives.

For the Hoover Powerplant, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative provided the highest firm capacities across all flow categories. Considered collectively, the Maximum Operational Flexibility Alternative leads to relatively high firm capacity for both the Glen Canyon Powerplant and the Hoover Powerplant. Although the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative provides high firm capacity, they have a wide interquartile variability indicating less reliable performance under drier conditions. The CCS Comparative Baseline, Basic Coordination and No Action Alternatives performed the worst across all flow categories, with lower median values and 25th percentiles falling to 0 MW in the Dry and Critically Dry Categories. The Representative Preferred Alternative outperforms the CCS Comparative Baseline, No Action Alternative, and Basic Coordination Alternative, but has a lower median capacity than the Enhanced Coordination, Maximum Operational Flexibility, and Supply Driven (both LB Priority and LB Pro Rata approaches) Alternatives, across all flow categories.

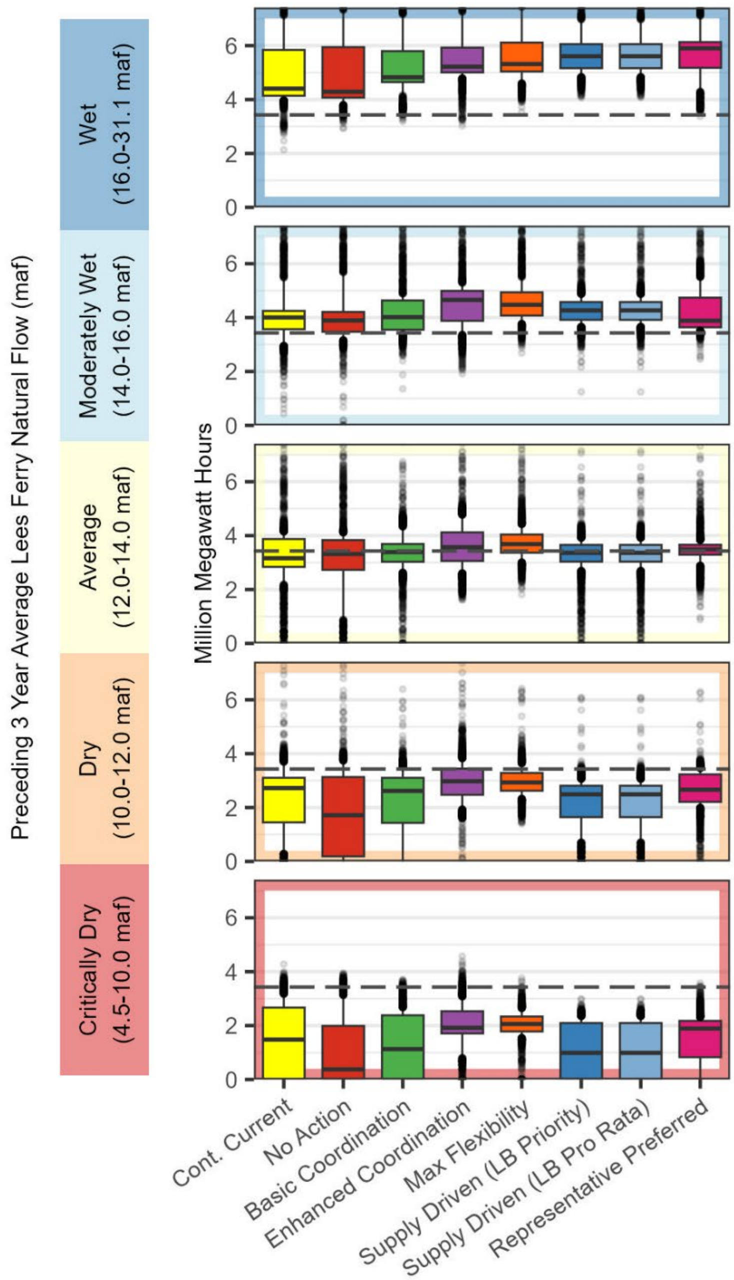
TA 15.2.5 Issue 3: How would the alternatives impact the energy generation of the Glen Canyon, Hoover, Davis, and Parker Powerplants?

Energy generation is the amount of energy created over a certain period, measured in MWhs. Energy generation is dependent on reservoir head and water release volume. The model inputs used to develop the figures in the energy generations analysis simulated releases and lake reservoir elevations to calculate estimated energy generation. **Figure TA 15-18**, **Figure TA 15-19**, **Figure TA 15-20**, and **Figure TA 15-21** illustrate the power generation response of Glen Canyon, Hoover, Davis, and Parker Powerplants, respectively. The box plots illustrate how the alternatives respond during different hydrologic conditions that are based on the preceding 3-year average of Lees Ferry natural flow. The bold center line of each box represents the median value, the top and bottom of each box captures the 25th to 75th percentile of the modeled results, the lines extend to the 10th and 90th percentiles, and the outliers are represented as dots beyond these lines.

Figure TA 15-18 below shows that under the Wet and Moderately Wet Flow Categories at Glen Canyon Dam, the Supply Driven (both LB Priority [5.6 and 4.3 million MWhs] and LB Pro Rata [5.6 and 4.3 million MWhs] approaches), Maximum Operational Flexibility (5.3 and 4.8 million MWhs), and Enhanced Coordination (5.2 and 4.7 million MWhs) Alternatives, resulted in slightly higher median energy generation values than the other alternatives. The Representative Preferred Alternative performs best under the Wet Flow Category at 5.9 million MWhs but worst under the Moderately Wet Category at 3.9 million MWhs. All alternatives performed above the historical average energy generation of 3.4 million MWhs (2016-2025) in both categories.

Under the Average Flow Category, the Maximum Operational Flexibility (3.7 million MWhs) and Enhanced Coordination (3.6 million MWhs) Alternatives performed slightly above the historical average energy generation value. The median energy generation for the other alternatives remain near the historical average energy generation of approximately 3.4 million MWhs.

Figure TA 15-18
Water Year Glen Canyon Energy Generation: Box Plots



Under the Dry Flow Category, the Maximum Operational Flexibility (2.9 million MWhs) and Enhanced Coordination (2.9 million MWhs) Alternatives have the highest median energy generation and lowest variability of all alternatives. CCS Comparative Baseline, and the No Action, and Basic Coordination Alternatives have greater variability in energy generation than the other alternatives. Under the No Action Alternative energy generation falls to 0 million MWhs in almost 25 percent of years. The No Action Alternative had the lowest median energy generation value of 1.7 million MWhs.

Under the Critically Dry Flow Category, the Maximum Operational Flexibility (2.1 million MWhs), Enhanced Coordination (1.9 million MWhs), and Representative Preferred (1.9 million MWhs) Alternatives continue to show the highest median energy generation values. Energy generation under the CCS Comparative Baseline (1.5 million MWhs), No Action (0.4 million MWhs), Basic Coordination (1.1 million MWhs), and Supply Driven (LB Priority [0.9 million MWhs] and LB Pro Rata [0.9 million MWhs] approaches) Alternatives fall to 0 million MWhs in at least 25 percent of years and have median values never exceeding 1.7 million MWhs.

The Representative Preferred Alternative in the Dry (2.7 million MWhs) and Critically Dry (1.9 million MWhs) Categories experienced higher median values.

Figure TA 15-19 below shows for the Hoover Powerplant, under the Wet and Moderately Wet Flow Categories, the Maximum Operational Flexibility Alternative (4.6 and 3.6 million MWhs), the Supply Driven (both LB Priority [4.9 and 3.6 million MWhs] and LB Pro Rata [5.0 and 3.9 million MWhs] approaches), Representative Preferred (4.6 and 3.5 million MWhs), and the Enhanced Coordination (4.5 and 3.7 million MWhs) Alternatives generally produce the highest median energy generation. The other alternatives perform similarly, except that energy generation under the No Action Alternative falls below the historical average of 3.3 million MWhs (2016-2025) in over 25 percent of years in the Wet Flow Category.

Under the Average Flow Category, the Supply Driven (both LB Priority [3.2 million MWhs] and LB Pro Rata [3.3 million MWhs] approaches) Alternative had the overall highest median energy generation, like the historical average of 3.3 million MWhs (2016-2025). All other action alternatives and the CCS Comparative Baseline had similar median values and are characterized by relatively small interquartile ranges. The No Action Alternative has the greatest interquartile variability and produces the lowest level of median energy generation at 1.9 million MWhs.

In the Dry Flow Category, median energy generation falls below the historical average energy generation for all alternatives. Variability increases markedly over the Dry Flow Category for the CCS Comparative Baseline (2.5 million MWhs), No Action (0.9 million MWhs), and Basic Coordination (2.6 million MWhs) Alternatives. Energy generation reaches 0 million MWhs in more than 25 percent of years under the No Action Alternative.

Under the Critically Dry Flow Category, median energy generation decreased considerably for the CCS Comparative Baseline (0.9 million MWhs) and No Action Alternative. Energy generation fell to 0 million MWhs in more than 50 percent of the time for the No Action Alternative. The median energy generation for the other alternatives was similar to the Dry Flow Category; however, performance was more variable (wider interquartile range) for the Enhanced Coordination, Supply Driven (LB Priority approach), and Representative Preferred Alternatives.

The Representative Preferred Alternative under Dry (2.6 million MWhs) and Critically Dry (1.0 million MWhs) Categories had relatively high median values. 25 percent of years fall to 1 million MWhs or less under the Critically Dry Flow Category.

Figure TA 15-19
Water Year Hoover Energy Generation: Box Plots

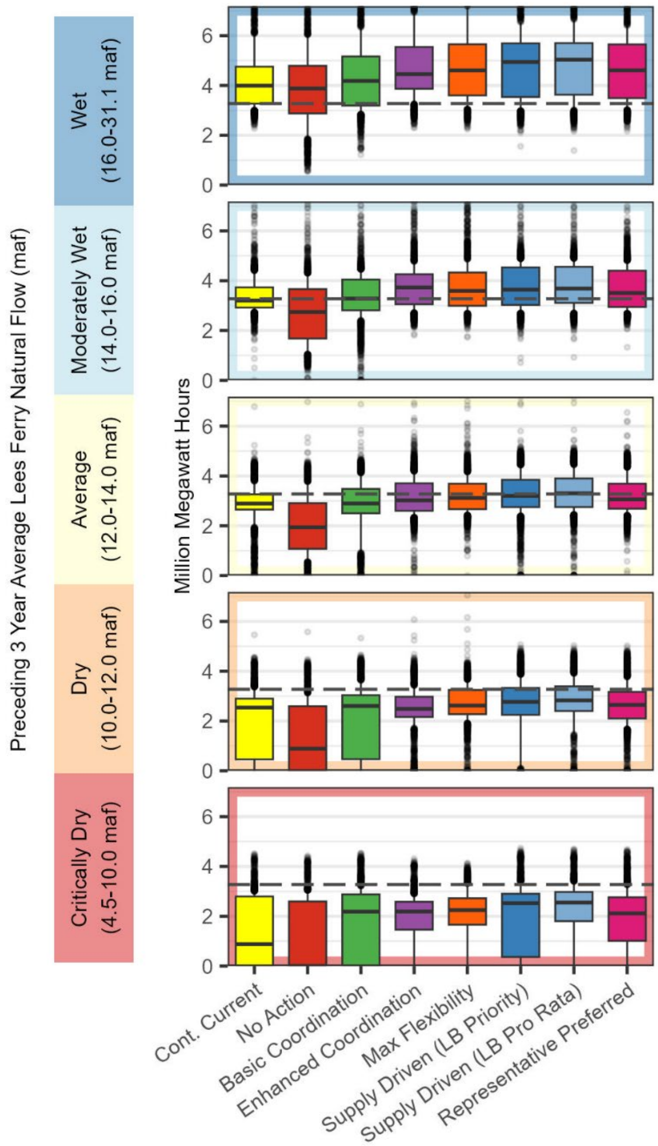
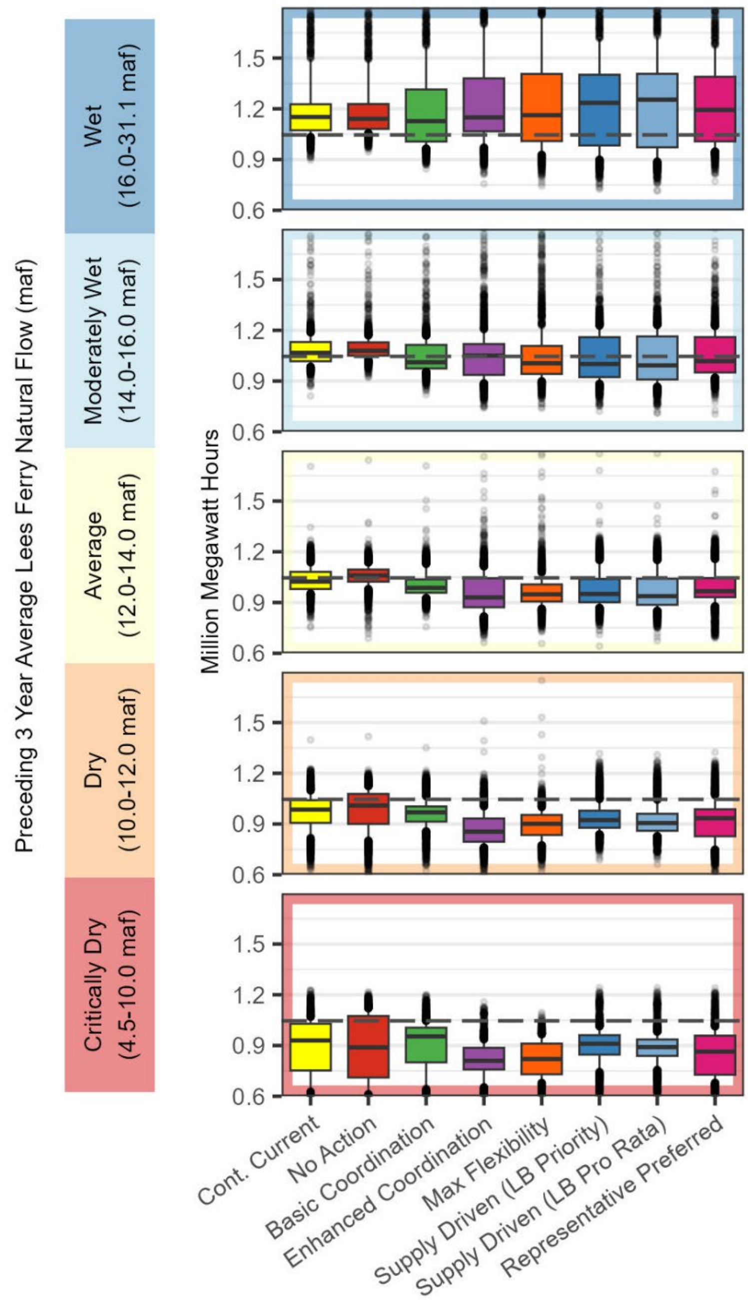


Figure TA 15-20 below shows that for the Davis Powerplant under the Wet Flow Category, the Supply Driven (both LB Priority [1.3 million MWhs] and LB Pro Rata [1.3 million MWhs] approaches) Alternative produces the highest median value, with the 25th percentile falling below the historical average value of 1.0 million MWhs and the 75th percentile at 1.4 million MWhs. All other alternatives performed similarly, with median energy generation near 1.1 million MWhs, but CCS Comparative Baseline and No Action exhibiting the narrowest interquartile ranges, indicating the lowest variability in annual generation value compared to the other alternatives.

Under the Moderately Wet and Average Flow Categories, variability decreases and all alternatives result in median energy generation values near or below the Davis Dam historical average of 1.0 million MWhs. The No Action Alternative (1.1 million MWhs) and CCS Comparative Baseline (1.0

million MWhs) median values perform best in these flow categories and, similar to the Wet Flow Category, have some of the lowest variability in annual generation values.

Figure TA 15-20
Water Year Davis Energy Generation: Box Plots



Under the Dry Flow Category, the CCS Comparative Baseline (0.9 million MWhs) and No Action Alternative (1.0 million MWhs) have slightly higher median energy generation values than the other alternatives. These alternatives begin to show greater interquartile variability in drier flow conditions. The Enhanced Coordination Alternative (0.8 million MWhs) yields the lowest median energy generation value among all alternatives. In the Critically Dry Flow Category, all alternatives perform similarly to the Dry Flow Category. Interquartile variability of energy generation increases for all alternatives, and all but the No Action Alternative falls below the historical average of 1.0 million MWhs in 75 percent or more of years.

The Representative Preferred Alternative under Dry (0.9 million MWhs) and Critically Dry (0.8 million MWhs) Categories had relatively high median values.

Figure TA 15-21 shows that for the Parker Powerplant, under the Wet Flow Category, the Supply Driven (both LB Priority [0.46 million MWhs] and LB Pro Rata [0.47 million MWhs] approaches) Alternative have the highest levels of median energy generation value and above the 2016-2025 historical average (0.42 million MWhs). The Supply Driven Alternative (LB Pro Rata approach) displays a lower 25th percentile of 0.39 million MWhs. The other alternatives have similar median energy generation values, just above the historical average with the CCS Comparative Baseline and No Action Alternative exhibiting the narrowest interquartile variability.

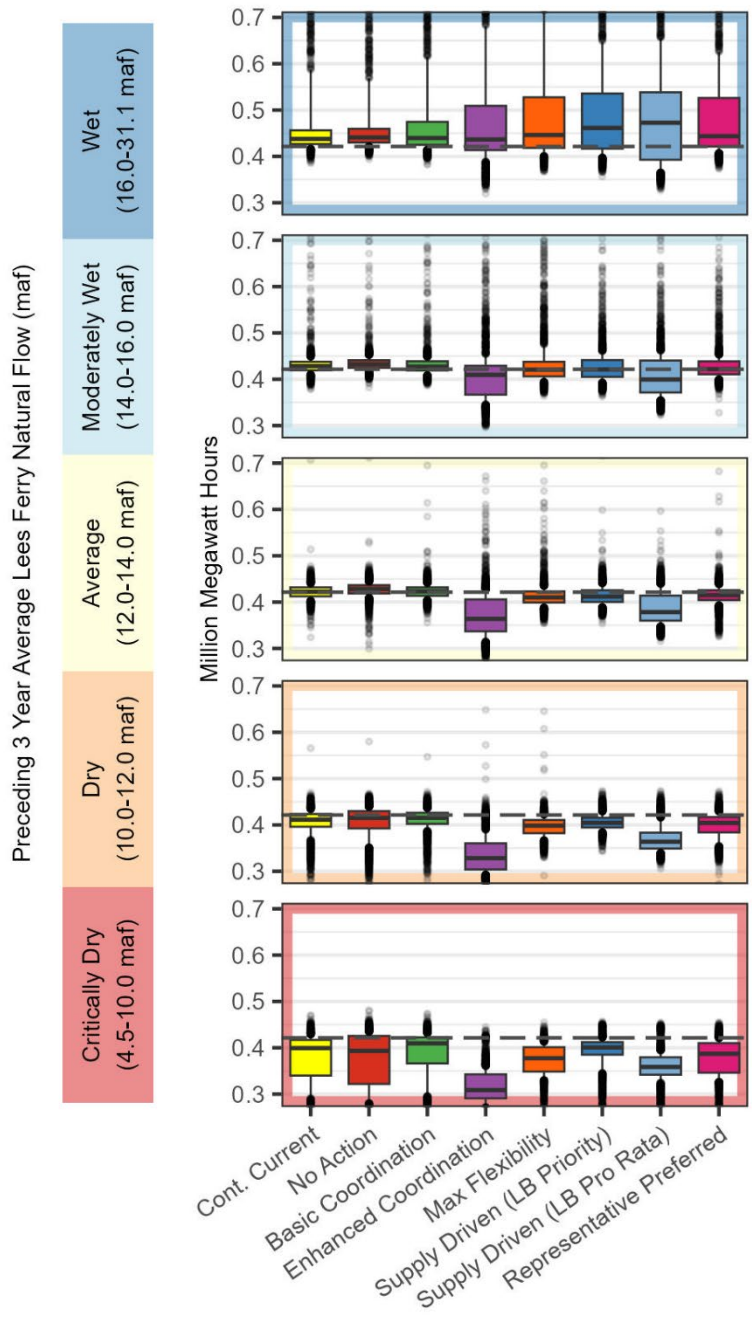
Under the Moderately Wet Flow Category, most alternatives produce energy generation at or near the historical average level. The Supply Driven (LB Pro Rata approach) and Enhanced Coordination Alternatives show relatively wider interquartile ranges indicating more variable energy generation and result in median energy generation valued at just below the historical average.

Under the Average and Dry Flow Categories, all alternatives, other than the Supply Driven (LB Pro Rata approach) and Enhanced Coordination Alternatives generally exhibit narrow interquartile variability and similar median energy generation values, ranging between 0.40 to 0.42 MWhs. The Supply Driven (LB Pro Rata approach) (0.36 million MWhs) and Enhanced Coordination (0.33 million MWhs) Alternatives resulted in a much wider interquartile ranges and a lower median value, indicating these alternatives are more sensitive to drier flow conditions than the others.

Median energy generation continues to decrease in the Critically Dry Flow Category with about 75th percent or more years for all alternatives falling below the historical average. The relative performance between Alternatives is similar to the Average and Dry Flow Categories. The most notable difference is the wider interquartile ranges for all alternatives indicating increased vulnerability to low generation outcomes under the driest conditions.

The Representative Preferred Alternative under Dry (0.4 million MWhs) and Critically Dry (0.39 million MWhs) Categories had relatively high median values.

Figure TA 15-21
Water Year Parker Energy Generation: Box Plots



Summary of Issue 3 Impacts

Energy generation at each of the powerplants responds differently under each of the alternatives. Under wetter conditions, the Glen Canyon Powerplant would have the highest energy generation under the Supply Driven (both LB Priority and LB Pro Rata approaches), Enhanced Coordination, and Maximum Operational Flexibility Alternatives. As conditions become drier, the Representative Preferred and Maximum Operational Flexibility Alternatives remain the most robust, while other alternatives exhibit greater variability and increased risk of decreased energy generation under critically dry conditions. The Hoover Powerplant would produce the highest amounts of energy under the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative in all five flow categories. The Davis Powerplant would have the highest power production under the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative under the Wet Flow Category. Under the Moderately Wet to Critically Dry Flow Categories, the No Action Alternative, followed by the CCS Comparative Baseline, generally produced the most energy generation. The Parker Powerplant would produce the most power under the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative under the Wet Flow Category. As conditions become drier, the alternatives (with the exceptions of Enhanced Coordination and Supply Driven [LB Pro Rata approach] Alternatives) have similar median values.

TA 15.2.6 Issue 4: How would the alternatives impact spillway use?

Spillway infrastructure is affected by reservoir elevation, particularly high elevations, which vary greatly between alternatives. High reservoir elevations, for extended durations, pose a risk to spillway infrastructure. Keeping the reservoir water level below the spillway crest minimizes spillway drum gate use and spillway use, preserves the water supply, maintains flood storage capacity, and reduces wear and tear on spillway infrastructure. This analysis compares the various action alternatives to the No Action Alternative and the CCS Comparative Baseline for the following metrics:

- Lake Powell pool elevations
- Lake Mead pool elevations

Lake Powell

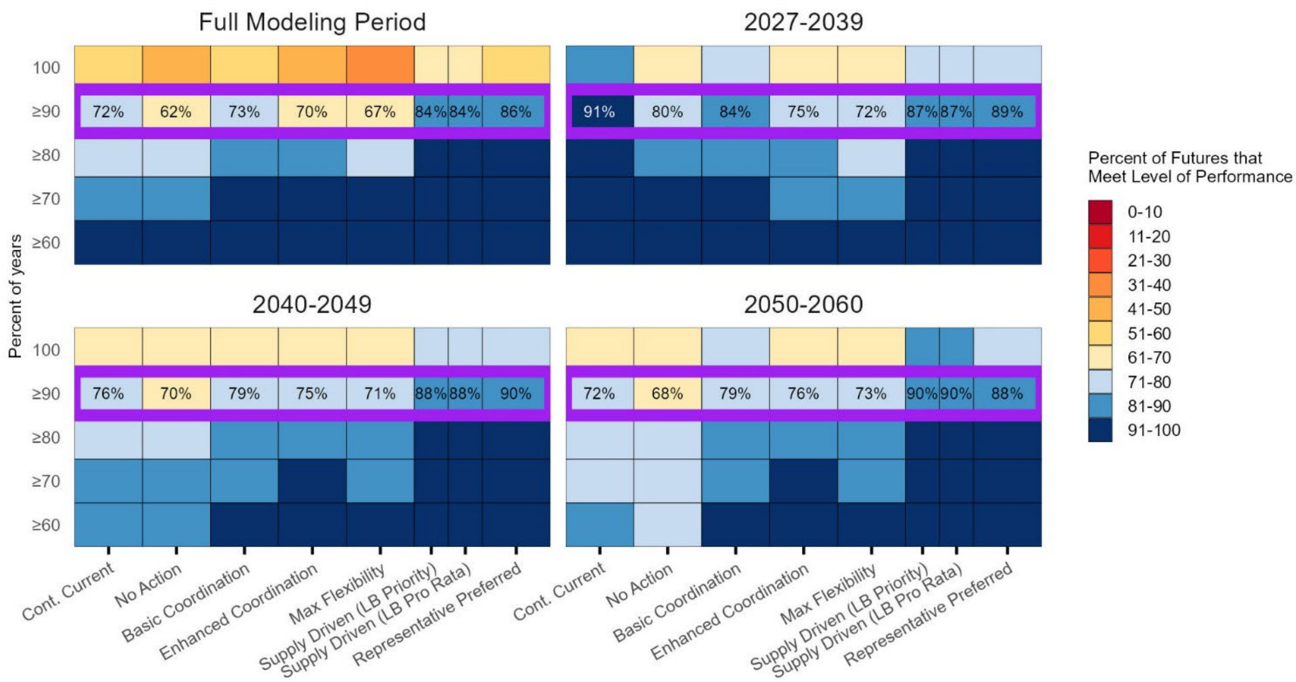
Critical high elevations at Lake Powell are listed in **Table TA 15-1** below. Reclamation minimizes controlled discharge over the spillway, as these discharges are not intended for frequent or extended operation. One way to reduce these controlled discharges is to maintain a vacant space requirement in the reservoir, which serves as a buffer of unused storage capacity to absorb large runoff inflows without causing controlled discharge.

Table TA 15-1
Critical Elevations at Lake Powell

Critical Condition	Associated Elevation	Description of Critical Elevation
Spillway	3,700 feet	Glen Canyon Dam spillway
Vacant Space Requirement	3,684 feet	Target reservoir elevation on January 1. Allows for 1.9 maf of flood control storage up to the top of the spillway

Figure TA 15-22 below reports the percentage of futures in which Lake Powell elevation does not exceed 3,684 feet on January 1 in the percent of years specified by each row. Four modeling periods are shown to capture the full modeling period, 2027-2039, 2040-2049, and 2050-2060. The preferred minimum performance is shown in the purple highlighted row, which represents the percentage of futures that an alternative maintains January 1 elevations below 3,684 feet in at least 90 percent of years. Higher rows represent stricter performance requirements that are more difficult to achieve. Keeping Lake Powell below 3,684 feet ensures that sufficient reservoir volume is reserved to accommodate spring runoff.

Figure TA 15-22
Lake Powell Elevation 3,684 Feet: Robustness.
Percent of futures in which the January 1 Lake Powell elevation does not exceed 3,684 feet in the specified percent of years



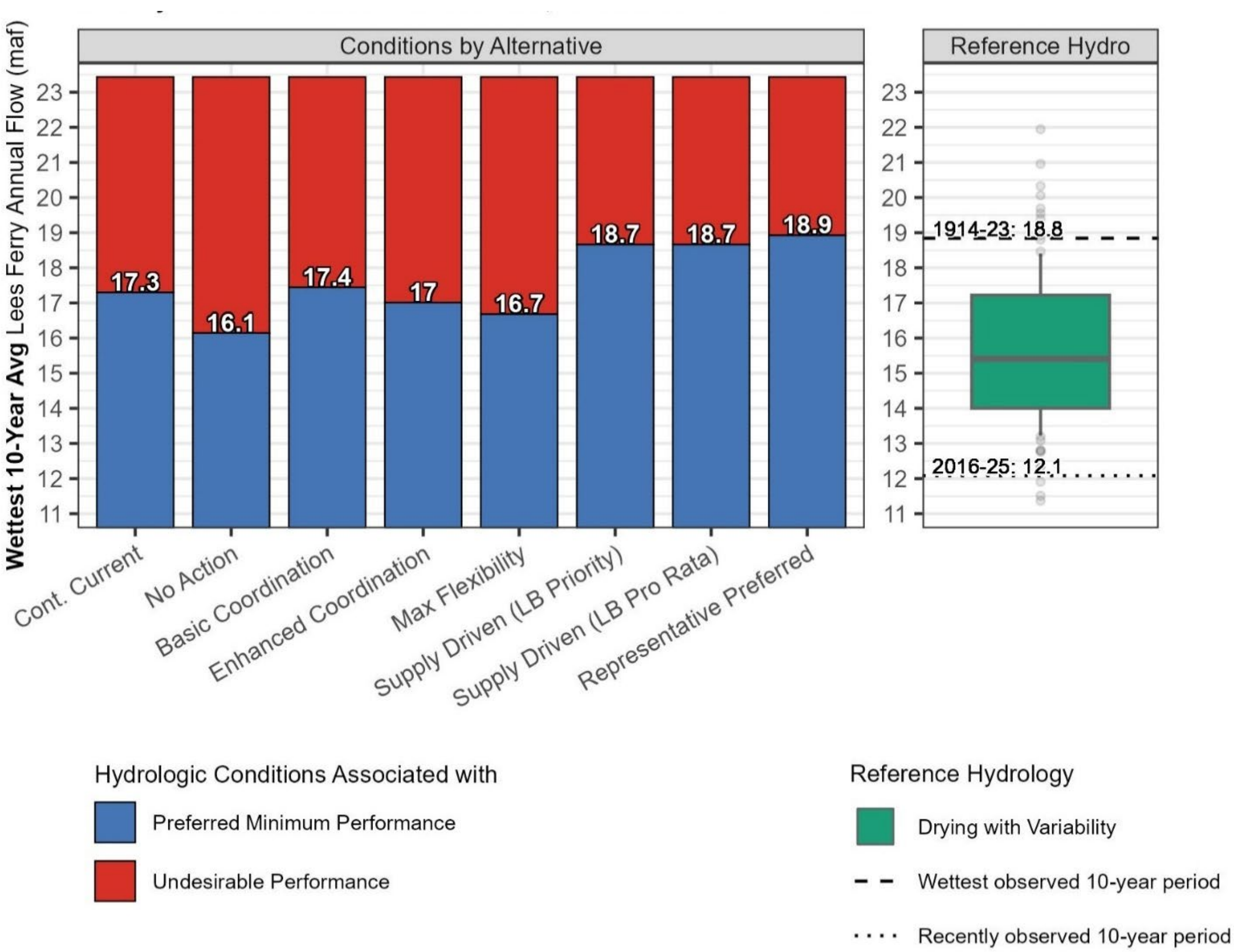
In the Full Modeling Period, the Representative Preferred Alternative is the most robust, meeting the preferred minimum level of performance in 86 percent of futures. The Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative is the second most robust, meeting the preferred minimum level of performance in 84 percent of futures. The Basic Coordination, Maximum Operational Flexibility, Enhanced Coordination Alternatives, and the CCS Comparative Baseline perform similarly, meeting the preferred minimum performance in 67-73 percent of futures. The No Action Alternative has the worst performance at 62 percent of futures.

For the subperiod 2027-2039, the CCS Comparative Baseline was the most robust with 91 percent of futures meeting the preferred minimum performance. The Supply Driven (both LB Priority and LB Pro Rata approaches) and Representative Preferred Alternatives met the preferred minimum performance in 87 and 89 percent of futures, respectively. The No Action, Basic Coordination, Enhanced Coordination, and Maximum Operational Flexibility Alternatives experienced similarly high robustness, performing between 72-84 percent of years meeting the preferred minimum performance.

In the subperiods 2040-2049 and 2050-2060, the Supply Driven (both LB Priority and LB Pro Rata approaches) and Representative Preferred Alternatives were the most robust, meeting the preferred minimum performance in 88-90 percent of futures. The No Action Alternative was the least robust meeting the preferred minimum performance in 68-70 percent of futures.

Figure TA 15-23 below looks at conditions that could cause the January 1 Lake Powell elevation to exceed 3,684 feet in 10 percent or more years. This definition of undesirable performance is based on the highlighted row in **Figure TA 15-22**, which determined a future as successful when an alternative kept Lake Powell below this buffer elevation in at least 90 percent of years.

Figure TA 15-23
Lake Powell Preservation of Spring Runoff Space: Vulnerability.
January One Conditions that Could Cause Lake Powell Elevation Above 3,684 in 10 percent or More Years



For this vulnerability analysis, the wettest 10-year average of Lees Ferry Annual Flow was identified as a skillful predictor of undesirable performance. The vulnerability threshold for each alternative is described and compared to the Drying with Variability Ensemble using this streamflow summary statistic. The wettest observed 10-year average flow from 1914-1923 (18.8 maf) and the average flow from 2016-2025 (12.1 maf) are also provided as dashed and dotted lines, respectively, for comparison. The reference Drying with Variability median value is 15.4 maf.

The Supply Driven (both LB Priority and LB Pro Rata approaches) (18.7 maf) and Representative Preferred (18.9 maf) Alternatives are the least vulnerable; less than 10 percent of traces in the Drying with Variability Ensemble include conditions this wet. The CCS Comparative Baseline (17.3 maf) and Basic Coordination Alternative (17.4 maf) are vulnerable to about 25 percent of traces in the Drying with Variability Ensemble. The No Action (16.1 maf), Maximum Operational Flexibility (16.7 maf), and Enhanced Coordination (17.0 maf) Alternatives become vulnerable under less extreme wet conditions; between 25 and 50 percent of traces in the Drying with Variability Ensemble include conditions this wet. All alternatives are expected to satisfy the preferred minimum performance under the driest 50 percent of traces in the Drying with Variability Ensemble, which includes the recent 10-year average from 2016–2025 (12.1 maf).

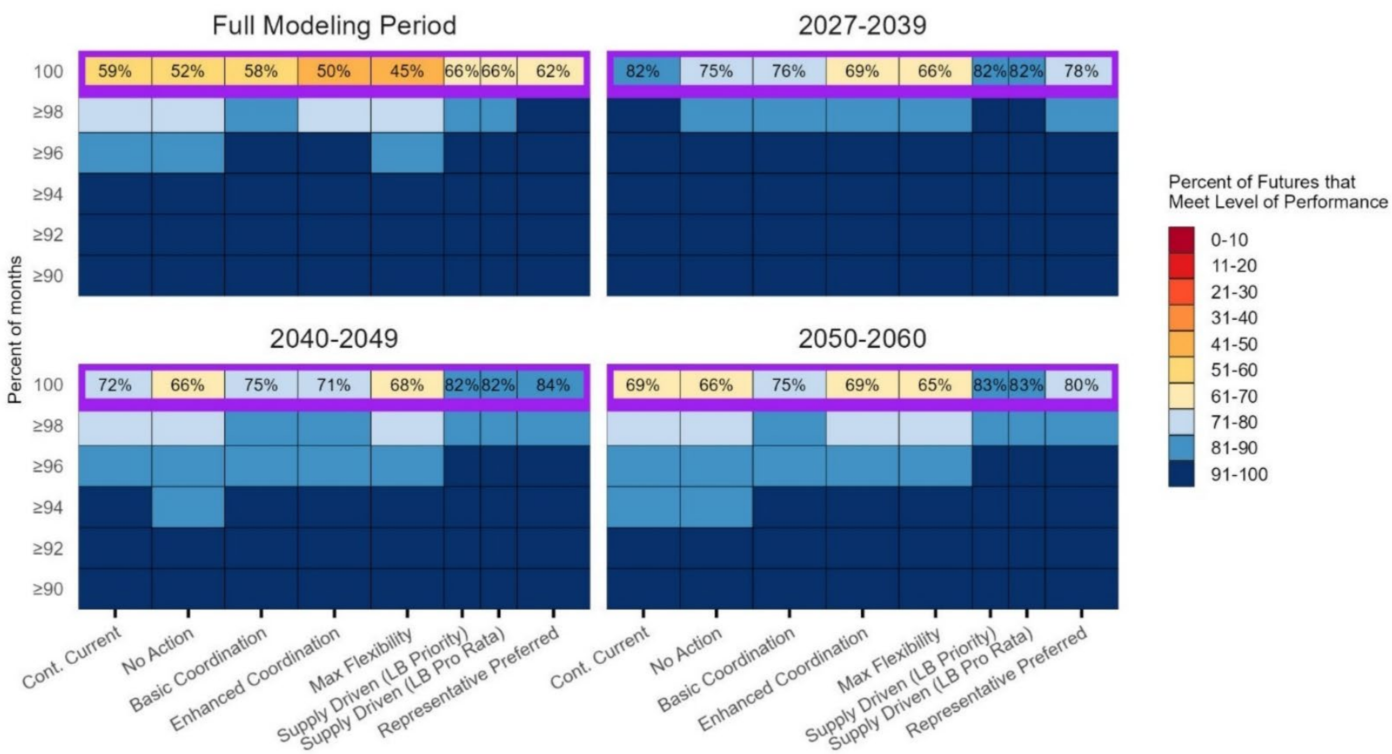
Modeling indicates that the Representative Preferred Alternative would likely be vulnerable to January 1 Lake Powell elevation above 3,684 feet in more than 10 percent of years if the wettest 10-year average Lees Ferry annual flow is greater than 18.9 maf. This alternative is reasonably unlikely to be vulnerable in the next 10 years because the recently observed 10-year period is below 18.9 maf and fewer than 10 percent of traces in the Drying with Variability Ensemble include conditions this wet.

Figure TA 15-24 below depicts the ability of each alternative to maintain a Lake Powell pool elevation below 3,700 feet in the percentage of months specified by each row. Pool elevations below this threshold reduce the likelihood of large-magnitude spillway releases and provide an important buffer to protect dam infrastructure. Four modeling periods are shown to capture the full modeling period, 2027-2039, 2040-2049, and 2050-2060. The preferred minimum performance is shown in the purple highlighted row, which represents the percentage of futures that an alternative maintains elevations below 3,700 feet in 100 percent of months.

Under the Full Modeling Period, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative is the most robust, keeping Lake Powell below 3,700 feet in 66 percent of futures. The Representative Preferred Alternative was the second most successful at 62 percent of futures. The CCS Comparative Baseline and Basic Coordination Alternative are successful in 59 and 58 percent of futures, respectively. The No Action and Enhanced Coordination Alternatives are successful in 52 and 50 percent of futures. The Maximum Operational Flexibility Alternative was the least robust with 45 percent of futures meeting the preferred minimum performance.

In the three subperiods, the Supply Driven (both LB Priority and LB Pro Rata approaches) and Representative Preferred Alternatives were the most robust, meeting the preferred minimum performance in 82 and 83 percent of futures, respectively. Basic Coordination Alternative performed consistently between 75-76 percent of futures. The CCS Comparative Baseline met the preferred minimum performance in 82 percent of futures during subperiod 2027–2039, with performance declining to 69 percent by subperiod 2050–2060. The No Action, Enhanced Coordination, and Maximum Operational Flexibility Alternatives were consistently the least robust, meeting the preferred minimum performance between 65-75 percent of futures.

Figure TA 15-24
Lake Powell Elevation 3,700 Feet: Robustness.
Percent of futures in which Lake Powell elevation is below 3,700 feet in the specified percent of months

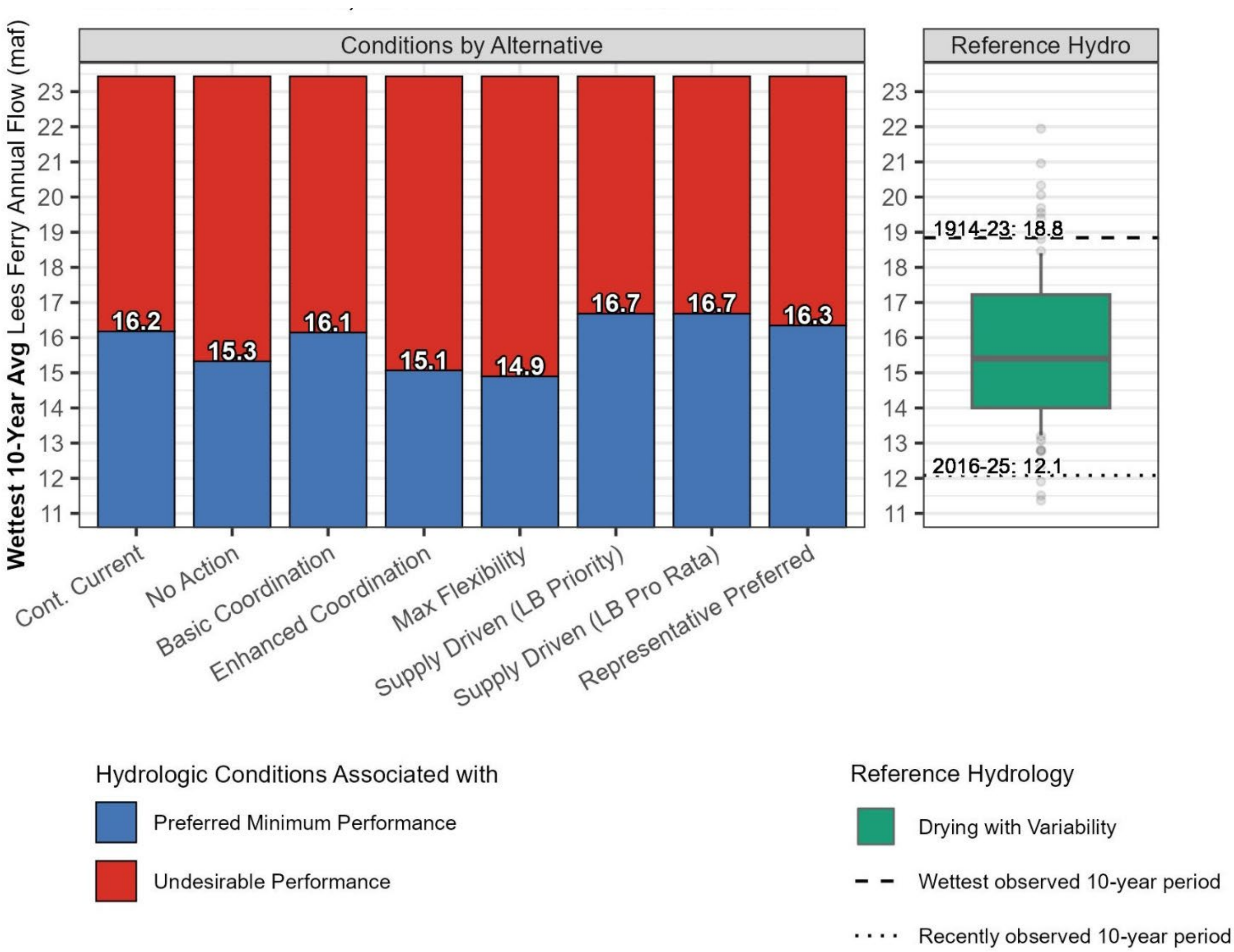


Based on the planned length of this decision, it is important to compare robustness in the 2027-2039 modeling period. The Maximum Operational Flexibility (66 percent) and Enhanced Coordination (69 percent) Alternatives are the least robust. All other alternatives and the CCS Comparative Baseline meet the preferred minimum performance level between 75 and 82 percent of futures, including the Representative Preferred Alternative (78 percent).

Figure TA 15-25 below shows what flow conditions are likely to cause the elevation of Lake Powell to exceed 3,700 feet in one or more months. This definition of undesirable performance is based on the highlighted row in **Figure TA 15-24** above, which defined a future as successful when an alternative stayed below 3,700 feet in 100 percent of months. For this vulnerability analysis, the wettest 10-year average Lees Ferry annual flow was determined to be skillful at predicting undesirable performance. The vulnerability threshold for each alternative is described and compared to the Drying with Variability Ensemble using this streamflow summary statistic. The wettest observed 10-year average flow from 1914-1923 (18.8 maf) and the average flow from 2016-2025 (12.1 maf) are also provided as dashed and dotted lines, respectively, for comparison. The reference Drying with Variability median value is 15.4 maf.

The No Action (15.3 maf), Enhanced Coordination (15.1 maf), and Maximum Operational Flexibility (14.9 maf) Alternatives show the most vulnerability being vulnerable in about 50 percent of traces in the Drying with Variability Ensemble. The CCS Comparative Baseline (16.2 maf), as well as Basic Coordination (16.1 maf) and Representative Preferred (16.3 maf) Alternatives are slightly less vulnerable. The Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative is least vulnerable, reaching undesirable performance when the wettest 10-year average flow exceeds 16.7 maf. About 25 percent of traces in the Drying with Variability Ensemble exceed this value. The wettest observed 10-year average Lees Ferry annual flow in the historical record is approximately 18.8 maf; therefore, the vulnerability thresholds for all alternatives are below what has already occurred. However, the most recent 10-year average is 12.1 maf, which is significantly drier than the conditions expected to cause vulnerability.

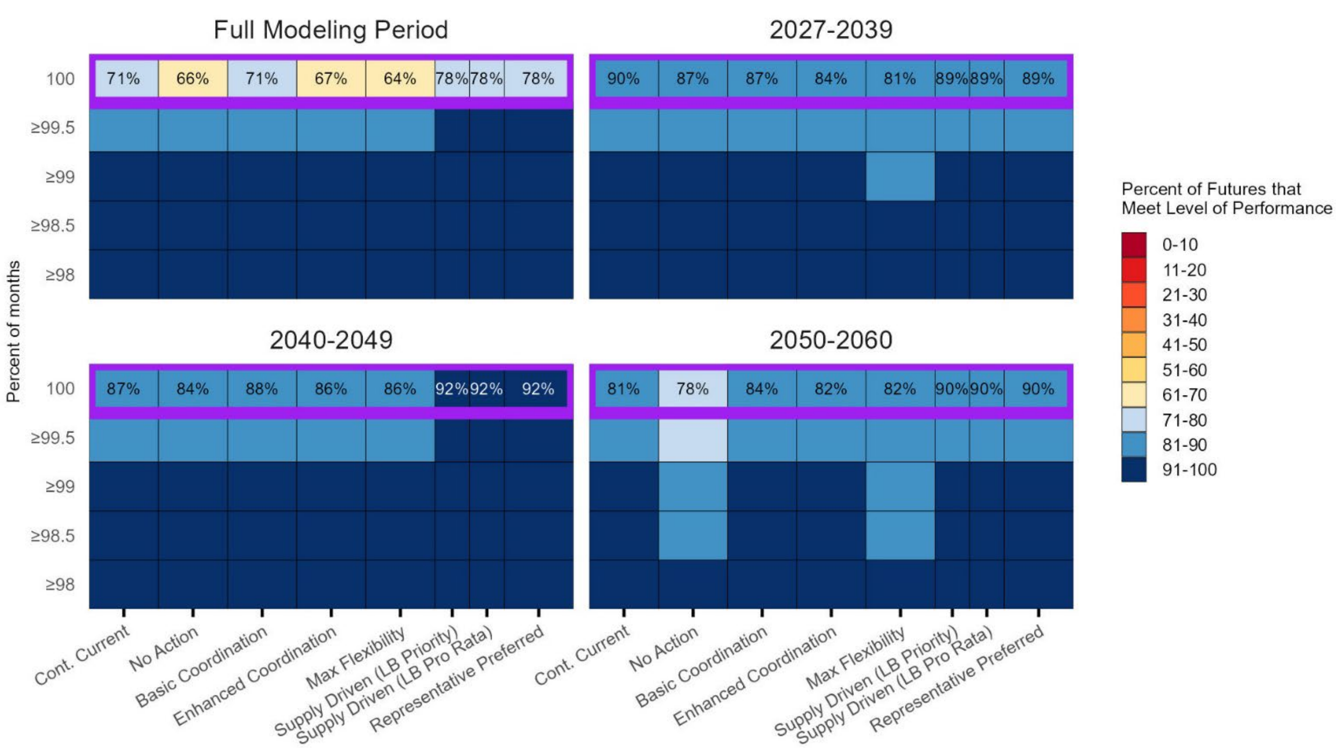
Figure TA 15-25
Lake Powell Preservation of Spring Runoff Space: Vulnerability.
Conditions that Could Cause Lake Powell Elevation Above 3,700 Feet or Greater in 10 percent or More Months



Modeling indicates that the Representative Preferred Alternative would likely be vulnerable to at least one occurrence of Lake Powell elevation above 3,700 feet if the wettest 10-year average Lees Ferry annual flow is greater than 16.3 maf. This alternative may or may not be vulnerable in the next 10 years because different aspects of the Reference Hydrology panel conflict. Considering the Drying with Variability Ensemble, between 25-50 percent of traces are greater than 16.3 maf, suggesting this alternative may or may not be vulnerable. However, the recently observed 10-year period is below 16.3 maf, suggesting that this alternative is unlikely to be vulnerable if the next 10 years are similar to or drier than the most recent 10 years.

Figure TA 15-26 below shows the ability of each alternative to avoid Glen Canyon Dam spillway releases in the specified percent of months. Four modeling periods are shown to capture the full modeling period, 2027-2039, 2040-2049, and 2050-2060. The preferred minimum performance is shown in the purple highlighted row, which represents the percentage of futures that an alternative avoids spillway releases in 100 percent of months. Minimizing spillway releases maximizes water supply and power generation while reducing wear and tear to the spillway structure.

Figure TA 15-26
Glen Canyon Dam Spillway Releases: Robustness.
Percent of futures in which spillway releases are avoided in the specified percent of months



Under the Full Modeling Period, the Supply Driven (both LB Priority and LB Pro Rata approaches) and Representative Preferred Alternatives are most robust with 78 percent of futures meeting the preferred minimum performance, followed by Basic Coordination and CCS Comparative Baseline, both at 71 percent, respectively. The No Action, Enhanced Coordination, and Maximum Operational Flexibility Alternatives were the least robust in 64-67 percent of futures.

Under the three subperiods, all alternatives maintained a high level of robustness, with no alternative falling below 81 percent of futures meeting the preferred minimum performance. The only exception to this is in subperiod 2050-2060, where the No Action Alternative is less robust with 78 percent of futures meeting the preferred minimum performance.

Based on the planned length of this decision, it is important to compare robustness in the 2027-2039 modeling period. All alternatives and the CCS Comparative Baseline perform well, meeting the preferred minimum performance between 81 and 90 percent of futures. The Representative Preferred Alternative avoids using the Glen Canyon Dam spillway in 890 percent of futures.

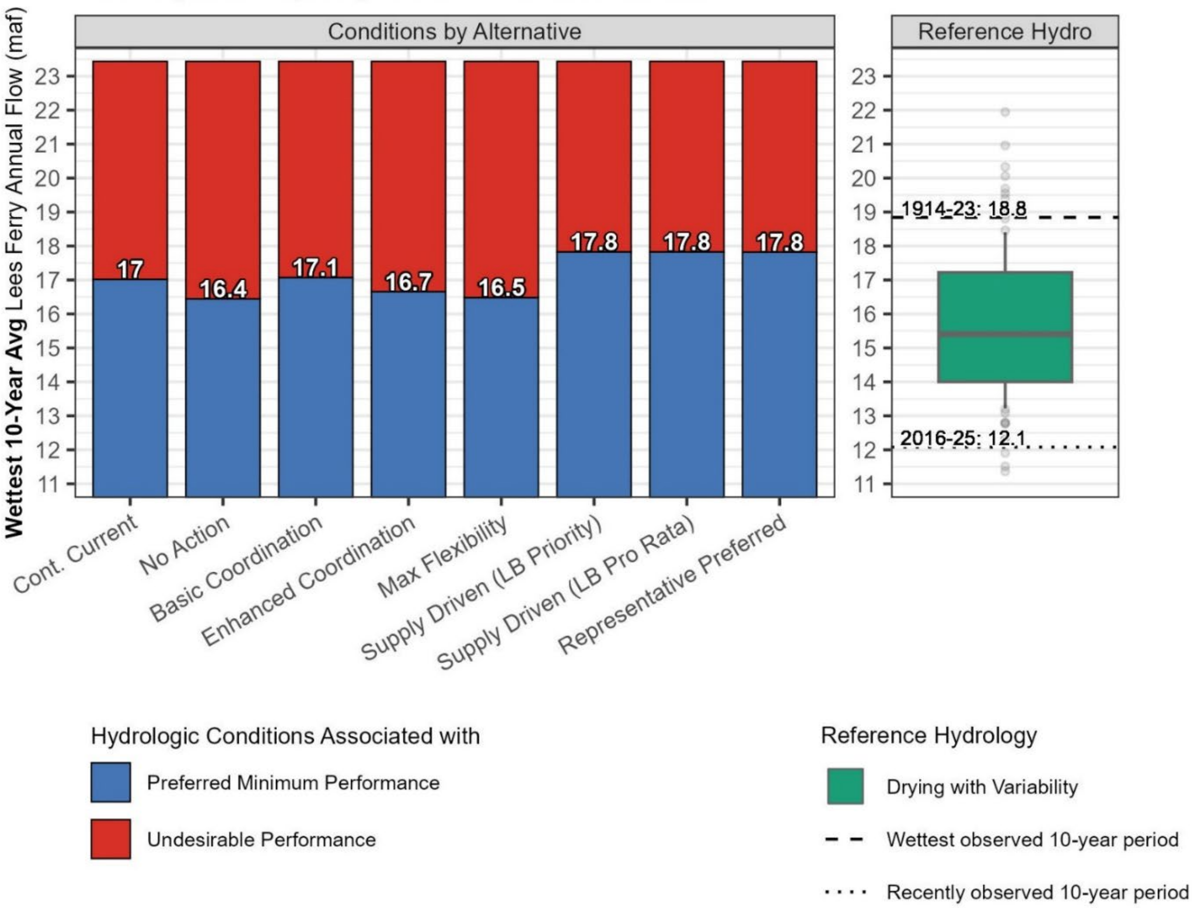
Figure TA 15-27 below shows what flow conditions are likely to cause Glen Canyon Dam spillway releases in one or more months. Spillway releases may result in reduced operational flexibility and increased flood control risk. This definition of undesirable performance is based on the highlighted row in **Figure TA 15-26** which determined a future as successful when an alternative avoided spillway releases in 100 percent of months.

For this vulnerability analysis, the wettest 10-year average Lees Ferry annual flow was determined to be skillful at predicting undesirable performance. The vulnerability threshold for each alternative is described and compared to the Drying with Variability Ensemble using this streamflow summary statistic. The wettest observed 10-year average flow from 1914-1923 (18.8 maf) and the average flow from 2016-2025 (12.1 maf) are also provided as dashed and dotted lines, respectively, for comparison. The reference Drying with Variability median value is 15.4 maf.

If the future includes a wettest 10-year average Lees Ferry annual flow of around 15.4 maf (i.e., the Drying with Variability median value), each alternative is suggested to avoid spillway releases in any month throughout the modeling period. The Supply Driven (both LB Priority and LB Pro Rata approaches at 17.8 maf) and Representative Preferred (17.8 maf) Alternatives require wetter hydrologic conditions before reaching undesirable performance and are less vulnerable compared to the other alternatives. The remaining alternatives reach undesirable performance at flows ranging from 16.4-17.1 maf, indicating greater vulnerability under comparatively lower flow conditions. All alternatives experience vulnerability to spillway releases under the wettest 10-year average in the historical record (18.8 maf).

Modeling indicates that the Representative Preferred Alternative would likely be vulnerable to one or more spillway releases if the wettest 10-year average Lees Ferry annual flow is greater than 17.8 maf. However, considering the Drying with Variability Ensemble, less than 25 percent of traces are greater than 17.8 maf, suggesting this alternative is reasonably unlikely to be vulnerable in the next 10 years. Further, the recently observed 10-year period is below 17.8 maf, suggesting that this alternative is unlikely to be vulnerable if the next 10 years are similar to or drier than the most recent 10 years.

Figure TA 15-27
Glen Canyon Dam Spillway Releases: Vulnerability.
Conditions that Could Cause Glen Canyon Dam Spillway Release in One or More Months



Lake Mead

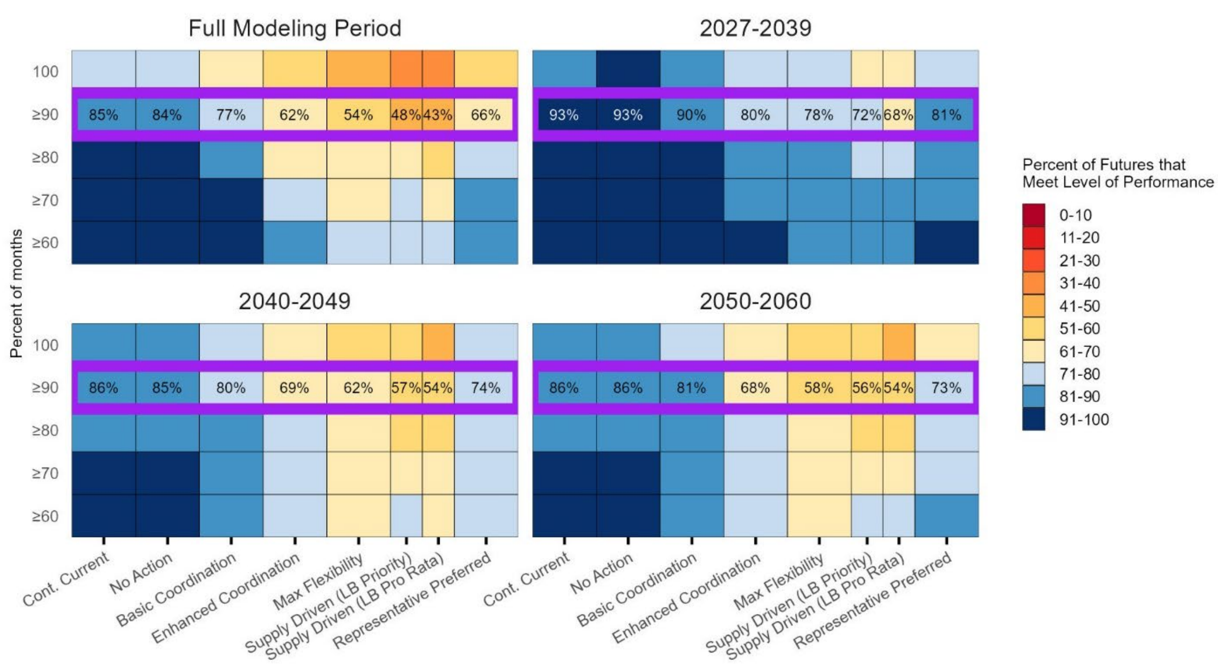
Critical high elevations at Lake Mead are listed in **Table TA 15-2** below. Reclamation minimizes uncontrolled discharge over the spillway as they are not intended for frequent or extended operation. One way to reduce these uncontrolled discharges is to maintain a vacant space requirement in the reservoir to absorb large runoff inflows without causing uncontrolled discharge.

Table TA 15-2
Critical Elevations at Lake Mead

Critical Condition	Associated Elevation	Description of Critical Elevation
Spillway	1,205.4 feet	Hoover Dam spillway crest
Maximum Operating Elevation	1,219.6 feet	Allows for 1.5 maf of flood control storage up to the top of the spillway
Maximum Spillway Discharge	1,226.9 feet	Spillway discharge at this elevation is 40,000 cfs, which triggers a "Imminent Life-Threatening Emergency" response

Figure TA 15-28 below reports the percentage of futures in which each alternative keeps Lake Mead below elevation 1,205.4 feet in the percent of months specified by each row. This elevation is the invert of the spillway drum gates for Hoover Dam, and operating above the spillway drum gates level increases the likelihood for mechanical failure. Four modeling periods are shown to capture the full modeling period, 2027-2039, 2040-2049, and 2050-2060. The preferred minimum performance is shown in the purple highlighted row, which represents the percentage of futures that an alternative maintains elevations below 1,205.4 feet in at least 90 percent of months. 90 percent of the months was chosen as the preferred minimum performance level because it provides a reasonable amount of flexibility to infrequently go above 1,205.4 feet in very wet hydrology.

Figure TA 15-28
Hoover Dam Spillway Crest Avoidance: Robustness.
Percent of futures in which Lake Mead elevation does not exceed 1,205.4 feet in the specified percent of months



In the Full Modeling Period, the CCS Comparative Baseline and the No Action Alternative are most robust at staying below elevation 1,205.4 feet in 85 and 84 percent of futures, respectively. The Basic

Coordination (77 percent), the Representative Preferred (66 percent), and Enhanced Coordination (62 percent) Alternatives futures follow. The Maximum Operational Flexibility (54 percent) and the Supply Driven (both LB Priority at 48 percent and LB Pro Rata at 43 percent) Alternatives are the least robust.

Across the three subperiods, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative is the least robust, while the CCS Comparative Baseline and No Action Alternative were the most robust with 85-93 percent of futures meeting the preferred minimum.

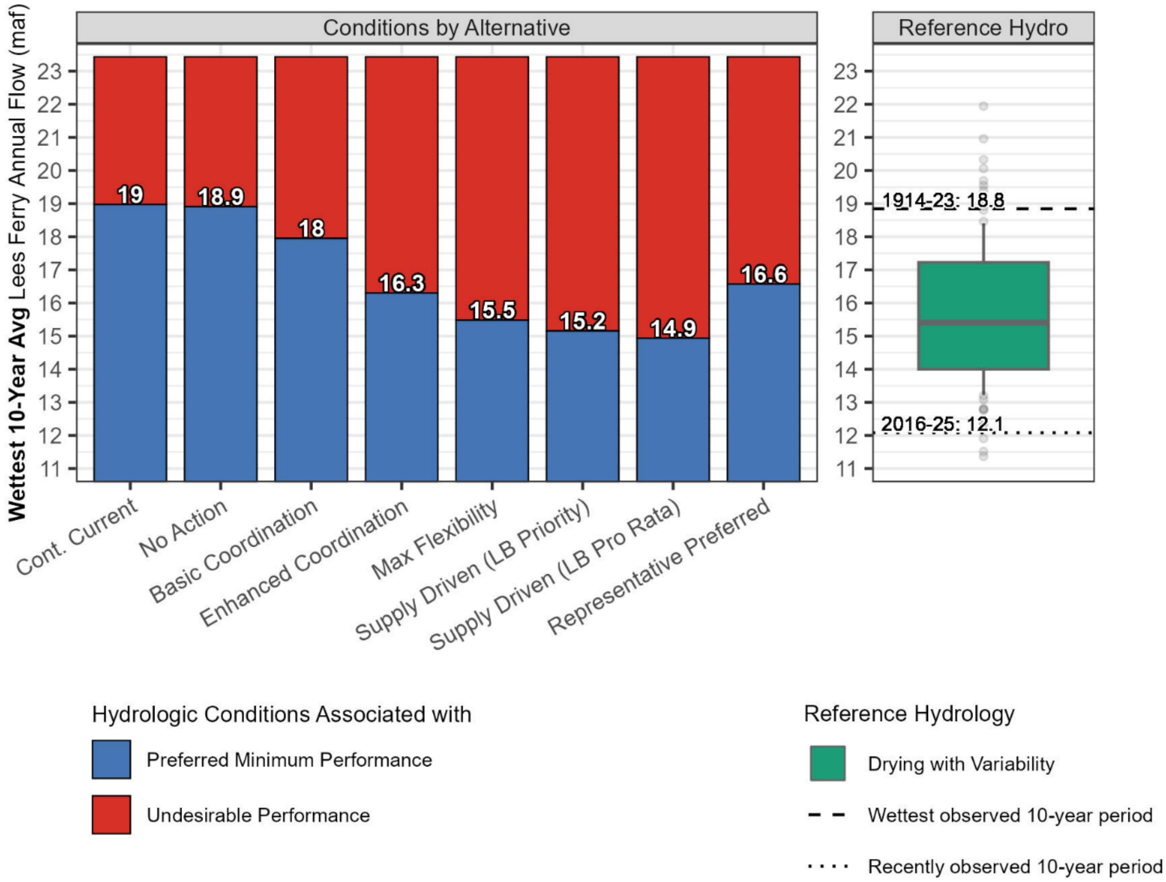
Based on the planned length of this decision, it is important to compare robustness in the 2027-2039 modeling period. The CCS Comparative Baseline and No Action Alternative are the most robust (both 93 percent), followed closely by the Basic Coordination Alternative (90 percent). The Representative Preferred (81 percent), Enhanced Coordination (80 percent), and Maximum Operational Flexibility (78 percent) Alternatives are similar. The Supply Driven (LB Priority approach) Alternative (72 percent) and Supply Driven (LB Pro Rata approach) Alternative (68 percent) are the least robust.

Figure TA 15-29 below shows what flow conditions are likely to cause the elevation of Lake Mead to exceed 1,205.4 feet in at least 10 percent of months. This definition of undesirable performance is based on the highlighted row in **Figure TA 15-28** above, which defined a future as successful when an alternative stayed below 1,205.4 feet in at least 90 percent of months.

For this vulnerability analysis, the wettest 10-year average Lees Ferry annual flow was determined to be skillful at predicting undesirable performance. The vulnerability threshold for each alternative is described and compared to the Drying with Variability Ensemble using this streamflow summary statistic. The wettest observed 10-year average flow from 1914-1923 (18.8 maf) and the average flow from 2016-2025 (12.1 maf) are also provided as dashed and dotted lines, respectively, for comparison.

If the future includes a wettest 10-year average Lees Ferry annual flow of around 15.4 maf (i.e., the Drying with Variability median value), modeling results indicate undesirable performance for the Supply Driven (both LB Priority [15.2 maf] and LB Pro Rata [14.9 maf] approaches) Alternative. This alternative, along with the Maximum Operational Flexibility (15.5 maf) Alternative, reach undesirable performance at comparatively lower flow thresholds, indicating higher vulnerability. The Representative Preferred (16.6 maf) and Enhanced Coordination (16.3 maf) display less vulnerability by performing above the median 10-year average Lees Ferry annual flow of 15.4 maf. The Basic Coordination (18 maf) and No Action (18.9 maf) Alternatives, as well as the CCS Comparative Baseline (19 maf), require wetter hydrologic conditions to reach undesirable performance and are therefore the least vulnerable alternatives. Under the No Action Alternative and CCS Comparative Baseline, Lake Mead elevations above 1,205.4 feet in more than 10 percent of months appear unlikely under most Drying with Variability traces, as the vulnerability thresholds of 18.9 maf and 19 maf, respectively, exceed the 90 percentile of the Drying with Variability Ensemble. From 1914 to 1923, the wettest 10-year average was 18.8 maf. All alternatives, with exception of the CCS Comparative Baseline and No Action Alternative, are vulnerable to conditions that have already occurred.

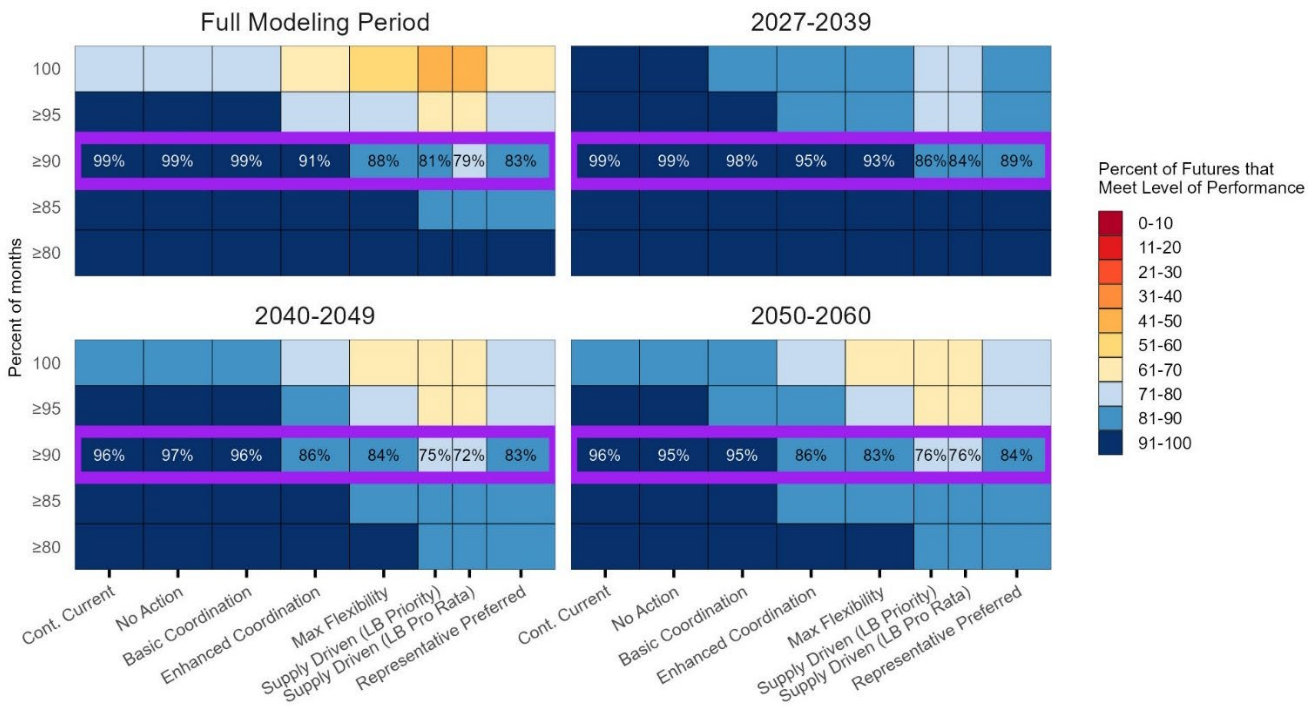
Figure TA 15-29
Hoover Dam Spillway Crest Avoidance: Vulnerability.
Conditions that could cause Lake Mead elevation above 1,205.4 feet in 10 percent or more months



Modeling indicates that the Representative Preferred Alternative would likely be vulnerable if the wettest 10-year average annual flow at Lees Ferry exceeds 16.6 maf, resulting in Lake Mead elevations above 1,205.4 feet in at least 10 percent of months. However, considering the Drying with Variability Ensemble, about 25 percent of traces are greater than 16.6 maf, suggesting this alternative is reasonably unlikely to be vulnerable in the next 10 years. Further, the recently observed 10-year period is below 16.6 maf, suggesting that this alternative is unlikely to be vulnerable if the next 10 years are similar to or drier than the most recent 10 years.

Figure TA 15-30 below depicts the ability of each alternative to maintain a Lake Mead pool elevation below 1,219.6 feet in the specified percent of months, which is an important flood buffer elevation for protecting dam infrastructure. The model evaluates multiple future simulation periods, including three subperiods: 2027–2039, 2040–2049, and 2050–2060. Results shown for the Full Modeling Period reflect performance across the complete modeled timeframe, rather than any individual subperiod. The preferred minimum performance is shown in the purple highlighted row, which represents the percentage of futures that an alternative is below 1,219.6 feet in at least 90 percent of months. The greater than or equal to 90 percent row was chosen because it provides a reasonable amount of flexibility to go above 1,219.6 feet occasionally in very wet hydrology.

Figure TA 15-30
Avoidance of Lake Mead Maximum Operating Elevation: Robustness. Percent of futures in which Lake Mead elevation does not exceed 1,219.6 feet in the percent of months specified in each row



Over the Full Modeling Period, the CCS Comparative Baseline, as well as Basic Coordination and No Action Alternatives are successful at keeping Lake Mead below 1,219.6 feet in 99 percent of futures. The Maximum Operational Flexibility and Representative Preferred Alternatives meets this threshold in 88 percent and 83 percent of futures, respectively. The Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative is least robust, with the preferred minimum performance met in 81 and 79 percent of futures, respectively.

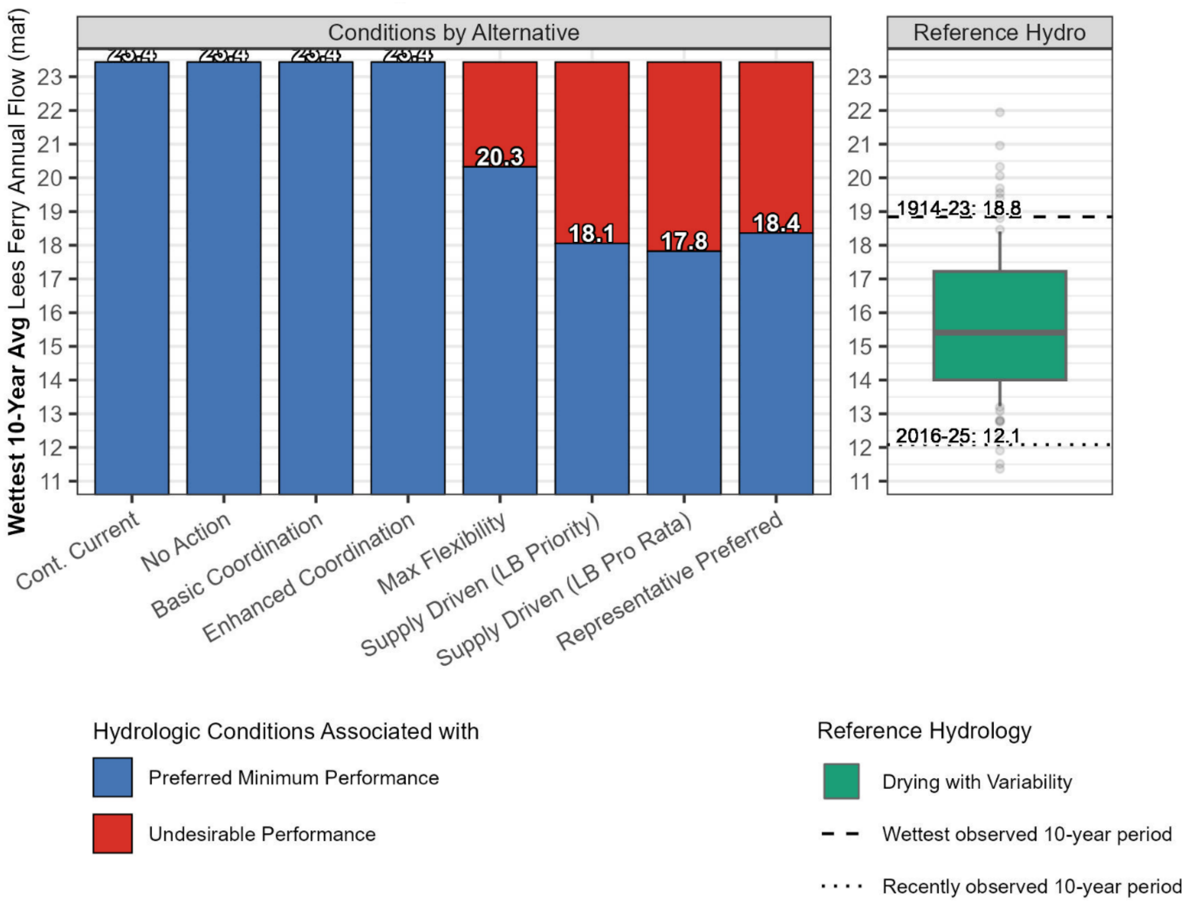
The subperiod 2027-2039 experiences high robustness across all alternatives, with the Supply Driven (both LB Priority [86 percent] and LB Pro Rata [84 percent]) Alternative being least robust. The subperiods 2040-2049 and 2050-2060 have slightly reduced robustness in respect to the subperiod 2027-2039, as the Enhanced Coordination (86 percent), Maximum Operational Flexibility (83-84 percent), Representative Preferred (83-84 percent), and Supply Driven (both LB Priority and LB Pro Rata approaches) (72-76 percent) Alternatives fall slightly.

Based on the planned length of this decision, it is important to compare robustness in the 2027-2039 modeling period. All alternatives perform well, meeting the preferred minimum performance between 84 percent (Supply Driven [LB Pro Rata approach]) and 99 percent (No Action) of futures.

The Representative Preferred Alternative meets the preferred minimum performance level in 89 percent of futures.

Figure TA 15-31 below shows what flow conditions are likely to cause the elevation of Lake Mead to exceed 1,219.6 feet in more than 10 percent of months, as elevations above this level may reduce available flood control capacity and operational flexibility. This definition of undesirable performance is based on the highlighted row in **Figure TA 15-30** above, which defined a future as successful when an alternative stayed below 1,219.6 feet in at least 90 percent of months.

Figure TA 15-31
Avoidance of Lake Mead Maximum Operating Elevation: Vulnerability. Conditions that could cause Lake Mead elevation to exceed 1,219.6 feet in 10 percent or more months



For this vulnerability analysis, the wettest 10-year average Lees Ferry annual flow was determined to be skillful at predicting undesirable performance. The vulnerability threshold for each alternative is described and compared to the Drying with Variability Ensemble using this streamflow summary statistic. The wettest observed 10-year average flow from 1914-1923 (18.8 maf) and the average flow from 2016-2025 (12.1 maf) are also provided as dashed and dotted lines, respectively, for comparison.

The CCS Comparative Baseline (23.4 maf), as well as No Action (23.4 maf), Basic Coordination (23.4 maf), and Enhanced Coordination (23.4 maf) Alternatives require wetter hydrologic conditions to reach undesirable performance and are therefore less vulnerable. These alternatives demonstrated no vulnerability for the full range of reference hydrology Drying with Variability traces, indicating a low likelihood that Lake Mead elevation would rise above 1,219.6 feet in more than 10 percent of months. The wettest 10-year average Lees Ferry annual flows for the Maximum Operational Flexibility (20.3 maf), Representative Preferred (18.4 maf), and Supply Driven (both LB Priority [18.1 maf] and LB Pro Rata [17.8 maf] approaches) Alternatives are comparatively lower; though, above the Drying with Variability median wettest 10-year average Lees Ferry annual flow of 15.4 maf.

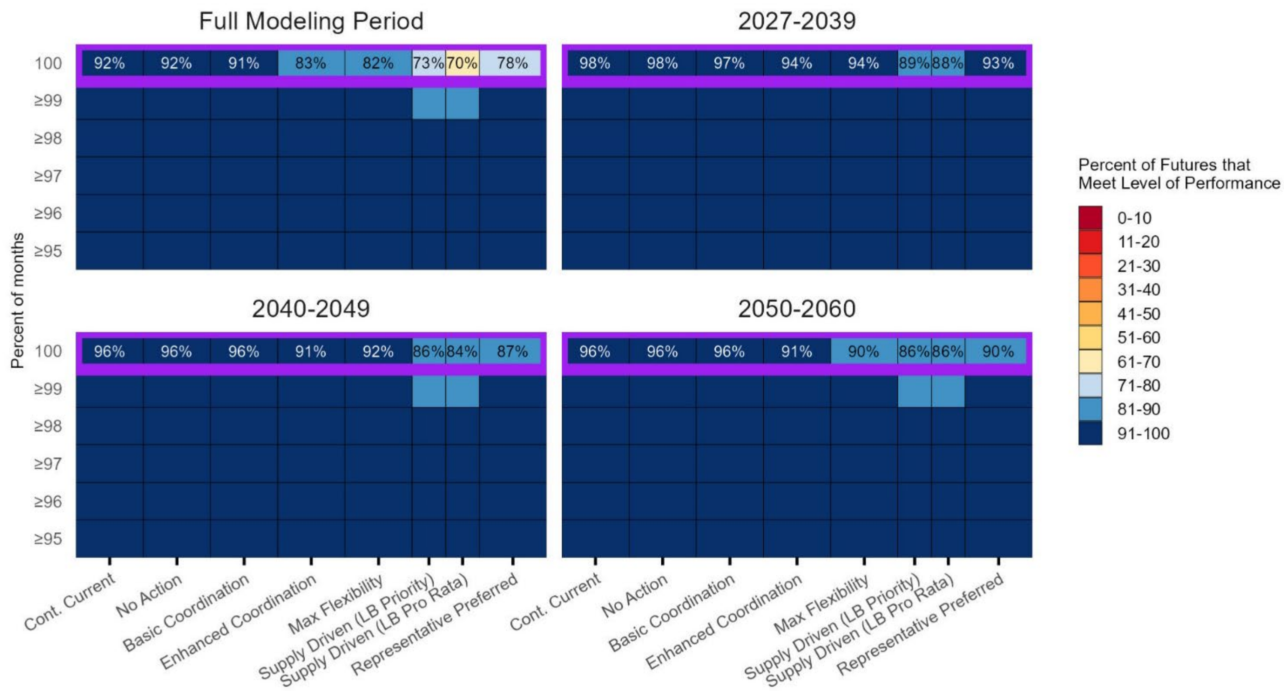
Modeling indicates that the Representative Preferred Alternative would likely be vulnerable if the wettest 10-year average annual flow at Lees Ferry exceeds 18.4 maf, resulting in Lake Mead elevations above 1,219.6 feet in at least 10 percent of months. However, considering the Drying with Variability Ensemble, only about 10 percent of traces are greater 18.4 maf, suggesting this alternative is reasonably unlikely to be vulnerable in the next 10 years. The recently observed 10-year period is well below 18.4 maf, suggesting that this alternative is unlikely to be vulnerable if the next 10 years are similar to or drier than the most recent 10 years.

Figure TA 15-32 below depicts the ability of each alternative to maintain a Lake Mead pool elevation below 1,226.9 feet in the specified percent of months. The analysis evaluates multiple future simulation periods, including three modeled subperiods: 2027–2039, 2040–2049, and 2050–2060. In addition to these subperiods, the Full Modeling Period refers to the entire future simulation horizon evaluated for each modeled future, encompassing all years in the analysis. The preferred minimum performance is shown in the purple highlighted row, which represents the percentage of futures that an alternative is below 1,226.9 feet in 100 percent of months. At this elevation, spillway releases exceed 40,000 cfs, which is considered a life-threatening emergency downstream.

Under the Full Modeling Period, the Supply Driven (both LB Priority [73 percent] and LB Pro Rata [70 percent] approaches) Alternative is the least robust. The Maximum Operational Flexibility (82 percent) performs similarly to Enhanced Coordination (83 percent) and Representative Preferred (78 percent) Alternatives. The No Action (92 percent) and Basic Coordination (91 percent) Alternatives, as well as CCS Comparative Baseline (92 percent), are the most robust with Lake Mead remaining below the critical level of 1,226.9 feet in 100 percent of futures. If the requirement relaxes to staying below 1,226.9 feet at Lake Mead in 98 percent of futures, all alternatives increase in robustness. For the subperiods, alternatives range between 84 to 98 percent of futures meeting the preferred minimum performance.

Based on the planned length of this decision, it is important to compare robustness in the 2027-2039 modeling period. All alternatives perform well, meeting the preferred minimum performance between 88 and 98 percent of futures. The Representative Preferred Alternative meets the preferred minimum performance in 93 percent of futures.

Figure TA 15-32
Avoidance of Lake Mead Maximum Spillway Discharge: Robustness.
Percent of futures in which Lake Mead elevation does not exceed 1,226.9 feet in the specified percent of months

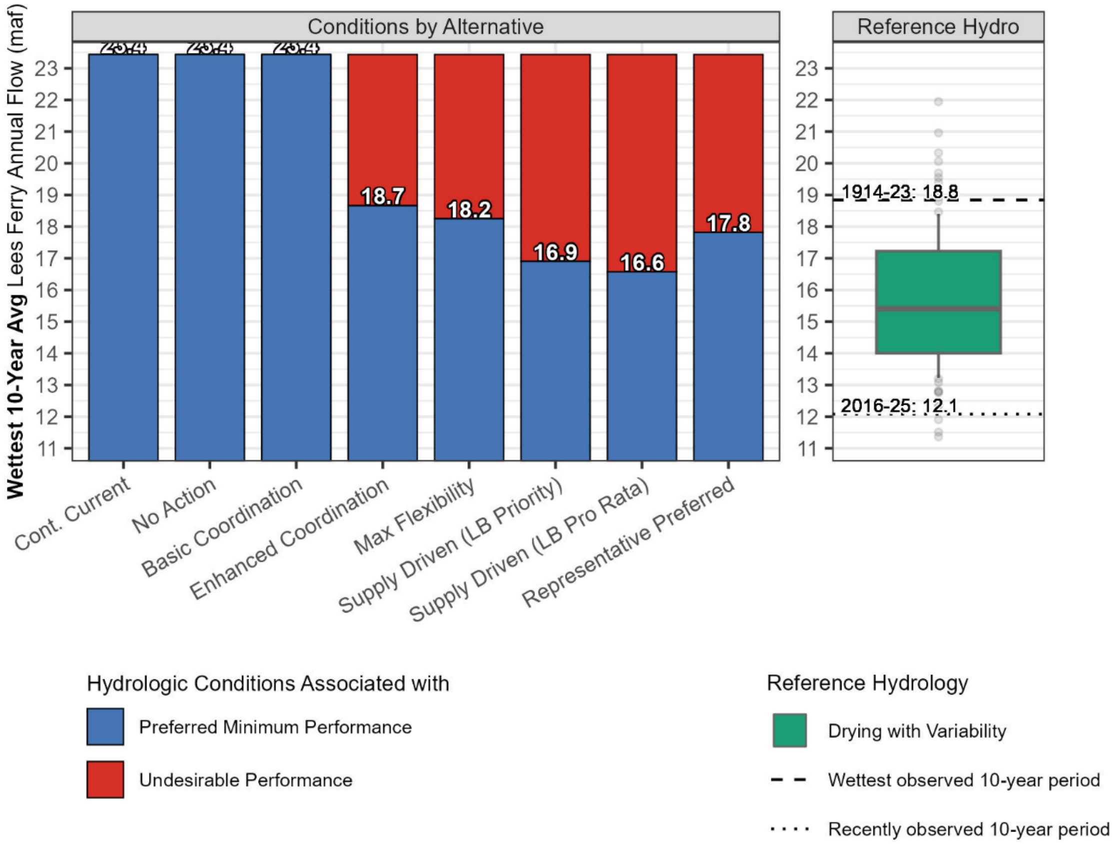


Representative Preferred **Figure TA 15-33** below shows what flow conditions are likely to cause the elevation of Lake Mead to exceed 1,226.9 feet in any month. At this elevation, release flows exceed 40,000 cfs, which is considered an emergency downstream. This definition of undesirable performance is based on the highlighted row in **Figure TA 15-32**, which specified that a future was successful if Lake Mead stayed below 1,226.9 feet in 100 percent of months.

For this vulnerability analysis, the wettest 10-year average Lees Ferry annual flow was determined to be skillful at predicting undesirable performance. The vulnerability threshold for each alternative is described and compared to the Drying with Variability Ensemble using this streamflow summary statistic. The wettest observed 10-year average flow from 1914-1923 (18.8 maf) and the average flow from 2016-2025 (12.1 maf) are also provided as dashed and dotted lines, respectively, for comparison.

The CCS Comparative Baseline (23.4 maf), as well as No Action (23.4 maf) and Basic Coordination (23.4 maf) Alternatives require wetter hydrologic conditions to reach undesirable performance and are therefore less vulnerable. Zero traces in the Drying with Variability Ensemble exhibit these conditions, indicating a low likelihood that Lake Mead elevation would rise above 1,226.9 feet in any month. The wettest 10-year average Lees Ferry annual flows for the Enhanced Coordination (18.7 maf), Representative Preferred (17.8 maf), Maximum Operational Flexibility (18.2 maf), and Supply Driven (both LB Priority [16.9 maf] and LB Pro Rata [16.6 maf] approaches) Alternatives are comparatively lower; though, above the Drying with Variability median wettest 10-year average Lees Ferry annual flow of 15.4 maf.

Figure TA 15-33
Avoidance of Lake Mead Maximum Spillway Discharge: Vulnerability. Conditions that could cause Lake Mead elevation to exceed 1,226.9 feet in 1 or more months



Modeling indicates that the Representative Preferred Alternative would likely be vulnerable to one or more occurrences of Lake Mead elevation above 1,226.9 feet if the wettest 10-year average Lees Ferry annual flow is greater than 17.8 maf. However, considering the Drying with Variability Ensemble, less than 25 percent of traces are greater than 17.8 maf, suggesting this alternative is reasonably unlikely to be vulnerable in the next 10 years. The recently observed 10-year period is well below 17.8 maf, suggesting that this alternative is unlikely to be vulnerable if the next 10 years are similar to or drier than the most recent 10 years.

Summary of Issue 4 Impacts

From a spillway use perspective, keeping the reservoir water level below the spillway crest minimizes spillway drum gate use and spillway use, preserves the water supply, maintains flood storage capacity, and reduces wear and tear on spillway infrastructure. Maintaining lower reservoir levels allows inflow to be routed through controlled outlets and respond to spring runoff. The alternatives generally perform similarly under wet hydrologic flow conditions, apart from the Supply Driven

Alternative (both LB Priority and LB Pro Rata approaches) generally performing best for Lake Powell and the No Action Alternative and the CCS Comparative Baseline performing best for Lake Mead.

High elevation reservoir infrastructure and critical flood storage buffers for Glen Canyon Dam and Lake Powell are better protected under the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative during wetter hydrological conditions. Conversely, at Hoover Dam and Lake Mead, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative has the least preferred performance in terms of keeping Lake Mead below critical high elevations. For Lake Mead, the duration spent above these high-water thresholds is minimized under the No Action and Basic Coordination Alternatives and the CCS Comparative Baseline. Under the Basic Coordination Alternative, both Glen Canyon Dam and Hoover Dam achieve preferred minimum performance and high-water thresholds are minimized. The Enhanced Coordination and Maximum Operational Flexibility Alternatives provide the second and third most preferred performance when considering Glen Canyon Dam and Hoover Dam collectively. The performance of the Representative Preferred Alternative varied, generally ranking from mid- to upper-performing at Glen Canyon Dam and roughly the middle-performing alternative at Hoover Dam.

TA 15.2.7 Issue 5: How would changes in energy generation impact electricity rates and the market value of electricity?

Glen Canyon Dam

Argonne National Laboratories and WAPA's report, "Post-2026 Environmental Impact Statement Rate Analysis for the Colorado River Storage Project" (Yu et al. 2025), assessed the relative impacts of various Glen Canyon Dam hydrological scenarios on the CRSP's Firm Electric Service rates. This analysis utilized an advanced simulation tool to estimate future generation production along with a stepwise rate adjustment framework. This framework is consistent with CRSP's obligation to remain financially self-sustaining and deliver cost-based power services (DOE 2025) and was used to evaluate the rate implications of simulated Glen Canyon Dam-only generation outcomes. It is important to note that CRSP's Firm Electric Service rates encompass hydropower generation resources beyond Glen Canyon Dam; therefore, the identified rate impacts are theoretical, representing uncertainty associated with future Glen Canyon Dam hydrological conditions. The report found that the Enhanced Coordination and Maximum Operational Flexibility Alternatives consistently yielded more favorable hydropower generation outcomes, associated with higher electricity production. These alternatives also indicated fewer rate adjustments, smaller average increases per adjustment, and substantially lower maximum rate increases when an increase was identified. Specifically, under wet or average hydrologic conditions, these alternatives led to results similar to or slightly better than other alternatives. Under dry hydrologic conditions, they resulted in substantially smaller rate increases and less frequent rate adjustments. Overall, Enhanced Coordination and Maximum Operational Flexibility are identified as entailing less adverse economic impact on U.S. electricity consumers and providing greater protection against extreme adverse outcomes compared to the other five alternatives. The modeling framework and key methodological choices supporting these findings, as documented in Yu et al. (2025), included comprehensive data on CRSP's plant characteristics, hydrological conditions, Argus forward prices, and CRSP's power purchase and sales transactions. Another important point to note is that the rate adjustment framework used in the study is a simplified version of actual rate-changing processes, as it is based solely on assumed revenue requirements and simulated electricity production. Consequently, it provides a directional analysis for comparing policy scenarios rather than forecasting actual consumer rates, requiring careful contextualization to avoid misinterpretation. Extreme hydrological conditions, potentially leading to very low or even zero simulated electricity production, can result in a non-trivial subset of degenerate results, projecting unrealistic rate increases or decreases. These extreme events, particularly zero electricity production from Glen Canyon Dam, are unprecedented and fall outside the scope of the current analysis framework, as they cannot be resolved through standard rate adjustments.

Figure TA 15-34 shows the estimated annual market value of hydropower generation by combining modeled annual energy production with an illustrative wholesale electricity price. A fixed 2028 fiscal year value per MWhs was developed using Argonne National Laboratory available data and multiplies it by the annual generation from WAPA's CRiSPPy model. Results were then applied uniformly across all alternatives and five potential flow categories (Wet Flow Category, Moderately Wet Flow Category, Average Flow Category, Dry Flow Category, and Critically Dry Flow Category). The box plots show variability in annual generation value (in millions of dollars) across futures within each flow category, highlighting how both hydrologic conditions and alternative operations influence potential energy value.

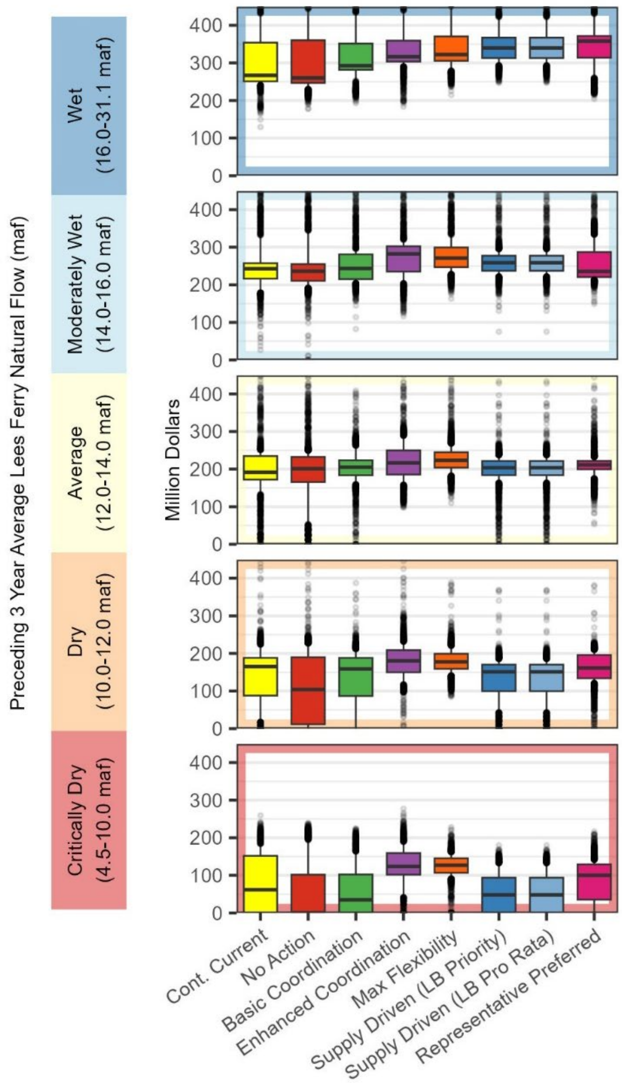
In the Wet Flow Category, the Representative Preferred Alternative resulted in the highest overall annual generation with a median value of $358 million. The Supply Driven (both LB Pro Rata and LB Priority approaches) Alternative experienced high median value of $340 million annually. The CCS Comparative Baseline ($267 million) and No Action Alternative ($260 million) had the lowest median values.

Within the Moderately Wet Flow Category, all alternatives retain similar metrics with relatively narrower interquartile ranges, indicating strong and consistent performance. However, Enhanced Coordination and Maximum Operational Flexibility experienced slightly higher median values than the others, with median values of $282 million and $271 million, respectively.

The Average Flow Category had similar performance across all alternatives and with relatively narrow interquartile ranges. The CCS Comparative Baseline had the lowest median value of $190 million, while the Maximum Operational Flexibility Alternative experienced the highest median value of $223 million.

Under the Dry Flow Category, Enhanced Coordination and Maximum Operation Flexibility had higher median values of $180 and $178 million, respectively. The No Action Alternative had the lowest value among the other alternatives, at $104 million. Both the CCS Comparative Baseline and No Action Alternative showed the widest interquartile ranges, with 25th percentiles of $12 million for the No Action Alternative and $88 million for the CCS Comparative Baseline. These larger interquartile ranges suggest greater variability in annual generation value compared to the other alternatives.

Figure TA 15-34
Annual Market Value of Glen Canyon Dam Generation: Box Plots



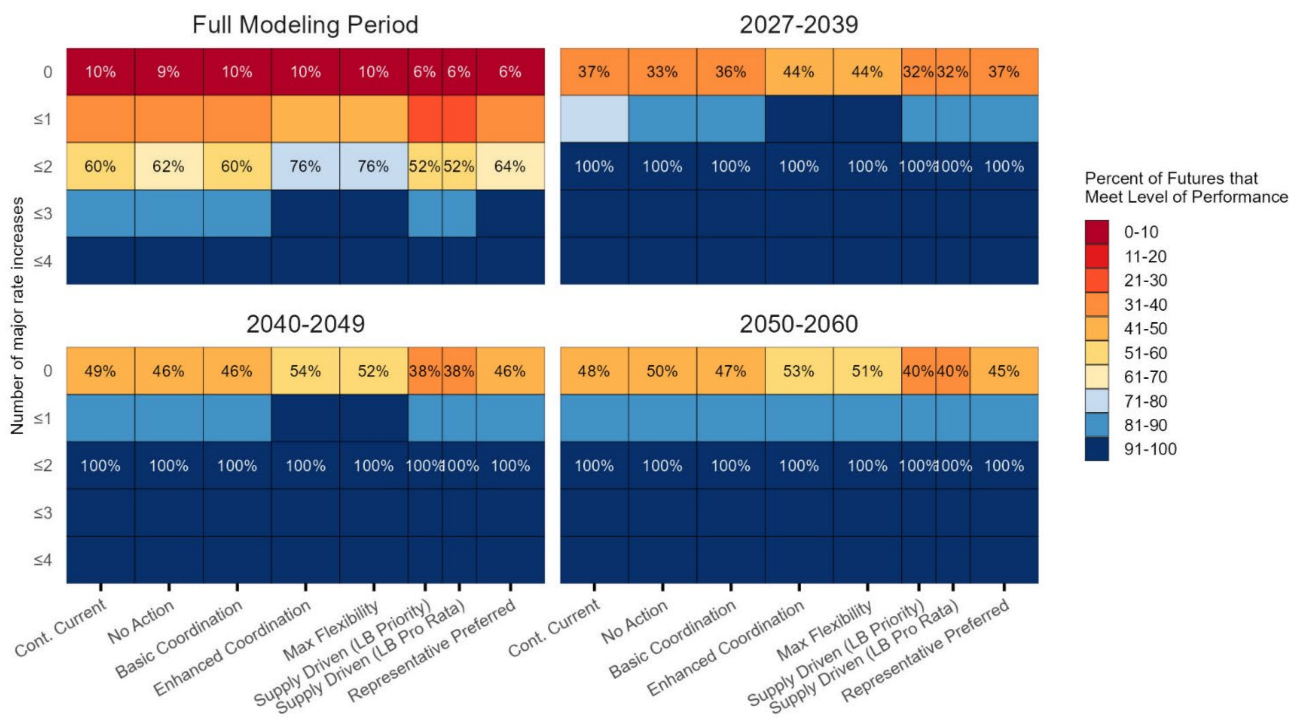
The Critically Dry Flow Category resulted in the lowest overall annual values for all alternatives. The Enhanced Coordination and Maximum Operational Flexibility Alternatives showed the narrowest interquartile ranges and highest median annual value, with median values of $124 million and $127 million. The Representative Preferred Alternative resulted in a median value of $100 million annually but with much larger interquartile ranges than the Enhanced Coordination and Maximum Operation Flexibility Alternatives. All other alternatives and CCS Comparative Baseline exhibited similarly larger interquartile ranges, but with at least 25 percent of years having values reach $0.

The Representative Preferred Alternative maintained relatively high median annual values under dry ($161 million) and critically dry ($100 million) flow conditions, outperforming the No Action, Basic Coordination, and Supply Driven (both LB Priority and LB Pro Rata approaches) Alternatives.

Figure TA 15-35 below shows the number of futures where CRSP customers could potentially see major rate increases under each alternative across the modeled futures at Glen Canyon Dam. The rows of the heat map represent the number of times in which there is major rate increases at or below a given threshold.

Figure TA 15-35 shows results for the Full Modeling Period and three subperiods: 2027-2039, 2040-2049, and 2050-2060. Consistent with WAPA's rate-setting procedures, cost-based rates are reviewed and adjusted on a five-year cycle. Therefore, the maximum number of rate changes that can occur in any of the three subperiods is 2.

Figure TA 15-35
Glen Canyon Dam CRSP Major Rate Increases: Robustness.
Percent of futures with the specified number of major rate increases



Note: Robustness modeling for the anticipated number of major rate increases was performed only for Glen Canyon Dam, based on historical rate information provided by WAPA. Each subperiod reflects the average of two rate evaluations, consistent with WAPA's rate-setting practices, which generally involve reviewing and adjusting rates on a five-year cycle but may occur more frequently in response to changing operational or hydrologic conditions.

For the Full Modeling Period, the Enhanced Coordination and Maximum Operational Flexibility Alternatives are the most robust with respect to limiting major rate increases to two or fewer times, doing so in 76 percent of futures. By comparison, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative is the least robust. Only 52 percent of futures under these alternatives remain at or below two major rate increases, and a larger share of futures exceed this threshold, indicating greater exposure to repeated or sustained rate adjustments. The CCS Comparison Baseline, as well as the No Action, Representative Preferred, and Basic Coordination Alternatives, perform intermediately, with 60 to 64 percent of futures remaining at or below two major rate increases, and declining robustness for all alternatives at more stringent performance thresholds.

Based on the planned length of this decision, it is important to compare robustness in the 2027-2039 modeling period. The Enhanced Coordination and Maximum Operational Flexibility Alternatives are the most robust at having 0 rate increases, doing so in 44 percent of modeled futures. The Representative Preferred Alternative and CCS Comparative Baseline are the next most robust, both having 0 rate increases in 37 percent of futures. All alternatives have 1 or less rate increases in 81 percent or more of futures. As noted above, WAPA's rates are reviewed and adjusted on a five-year cycle. Since the subperiods range from 9 – 12 years, it is not possible to trigger 3 or more rate increases in a subperiod, so all alternatives have a score of 100 percent in the rows for 2, 3, and 4 rate increases.

Hoover Dam

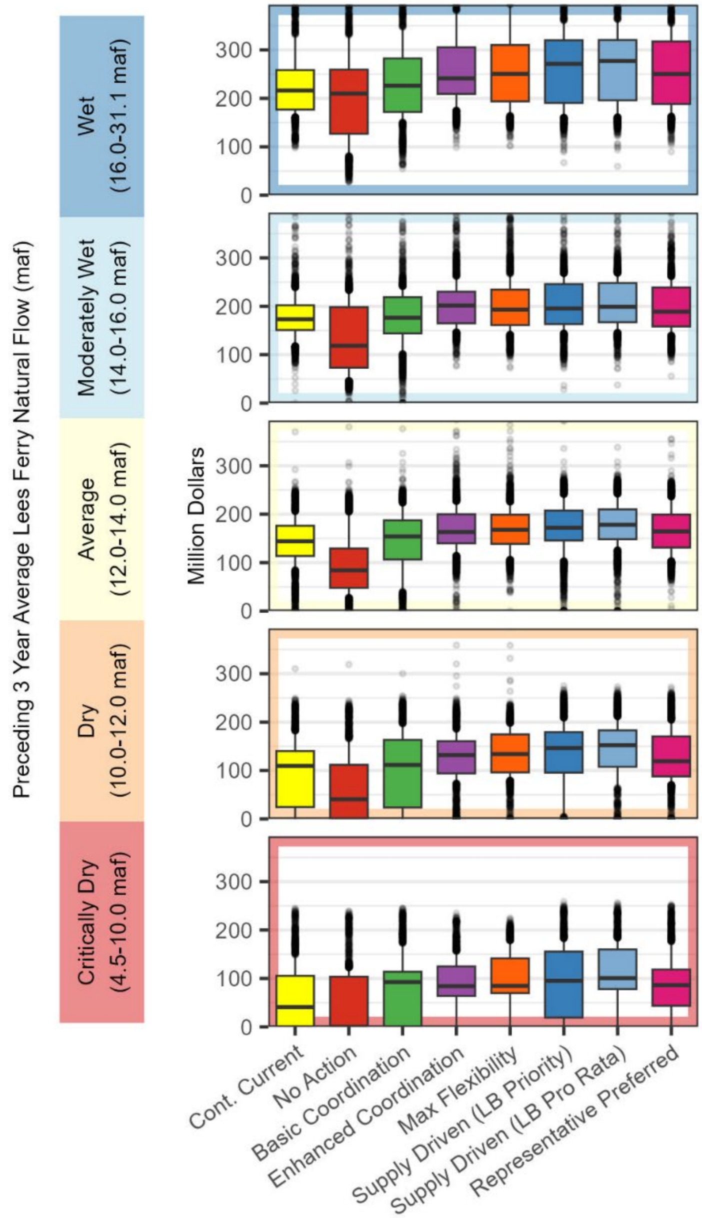
Hoover Dam provides federally marketed hydropower to Arizona, California, and Nevada through the BCP, managed by WAPA. Funding for the project's operation, maintenance, and capital costs is entirely self-supported by these hydropower sales to contracted entities, requiring no taxpayer funding. Historically, cost-based rates kept Hoover power lower than regional wholesale market alternatives. Under this framework, customers pay a fixed annual base charge to cover these costs, allocated by contract share rather than actual generation. However, as declining water levels reduce generation output, the unit cost of the remaining power rises. This creates a financial swing: when generation drops sufficiently, Hoover Dam's unit cost surpasses market rates, making power uneconomical and potentially forcing contracted entities to abandon their long-term contracts.

Figure TA 15-36 below shows the annual market value of hydropower at Hoover Powerplant. The economic analysis is based on a dollar-per-MWhs value provided by the Lower Basin Dams Office using WY 2027 data. The dollar-per-MWhs rate was then multiplied by the modeled energy generation from CRSS to compute market value. The market value depends on water surface elevation, with values being greater if elevation is above 1,035 feet and lower if below 1,035 feet. To show how market value can change due to different hydrology, results are grouped into five flow categories: (Wet Flow Category, Moderately Wet Flow Category, Average Flow Category, Dry Flow Category, and Critically Dry Flow Category).

Under the Wet Flow Category, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative result in the highest median market values of approximately $271-277 million annually. All other alternatives had a median market value that exceeded $200 million. The No Action Alternative had a value of $127 million or less in 25 percent of years, much lower than all other alternatives.

Within the Moderately Wet Category, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative experienced the highest 75th percentiles ($246-248 million) and 25th percentiles ($163-167 million). Similar to the Wet Flow Category, the No Action Alternative had the lowest median market value and the largest interquartile range, with a 25th percentile of $73 million and 75th percentile of $198 million.

Figure TA 15-36
Annual Market Value of Hoover Dam Generation: Box Plots



Under the Average Flow Category, most alternatives see a median market value decline to below $200 million. The Enhanced Coordination ($163 million), Maximum Operational Flexibility ($168 million), Supply Driven (both LB Priority and LB Pro Rata approaches) ($172 million and $178 million, respectively), and Representative Preferred ($165 million) Alternatives generally maintain higher medians and moderate interquartile ranges, while the No Action ($84 million) and Basic Coordination ($154 million) Alternatives tend to show lower medians and greater variability.

Dry and Critically Dry Flow Categories resulted in the lowest overall annual values. Maximum Operational Flexibility ($142-$175 million), Basic Coordination ($93-$112 million), Representative

Preferred ($86-119 million), and Supply Driven (LB Pro Rata approach) ($160-$183 million) Alternatives showed the highest median annual values. Basic Coordination Alternative resulted in a higher median value but with much larger interquartile ranges than the other alternatives. The CCS Comparative Baseline, No Action and Basic Coordination Alternatives all fall to $0 in 25 percent or more years.

Modeling indicates that the Representative Preferred Alternative maintained a median value of $119 million annually under the Dry Flow Category and $86 million under the Critically Dry Flow Category. In the Critically Dry Flow Category, the 25th percentile is $44 million.

Davis and Parker Dam

The PDP is a federally operated system combining the Parker and Davis Dam hydroelectric facilities and transmission infrastructure on the Colorado River. Reclamation operates and maintains the dams and powerplants, while WAPA markets and transmits the generated electricity to customers under long term contracts.

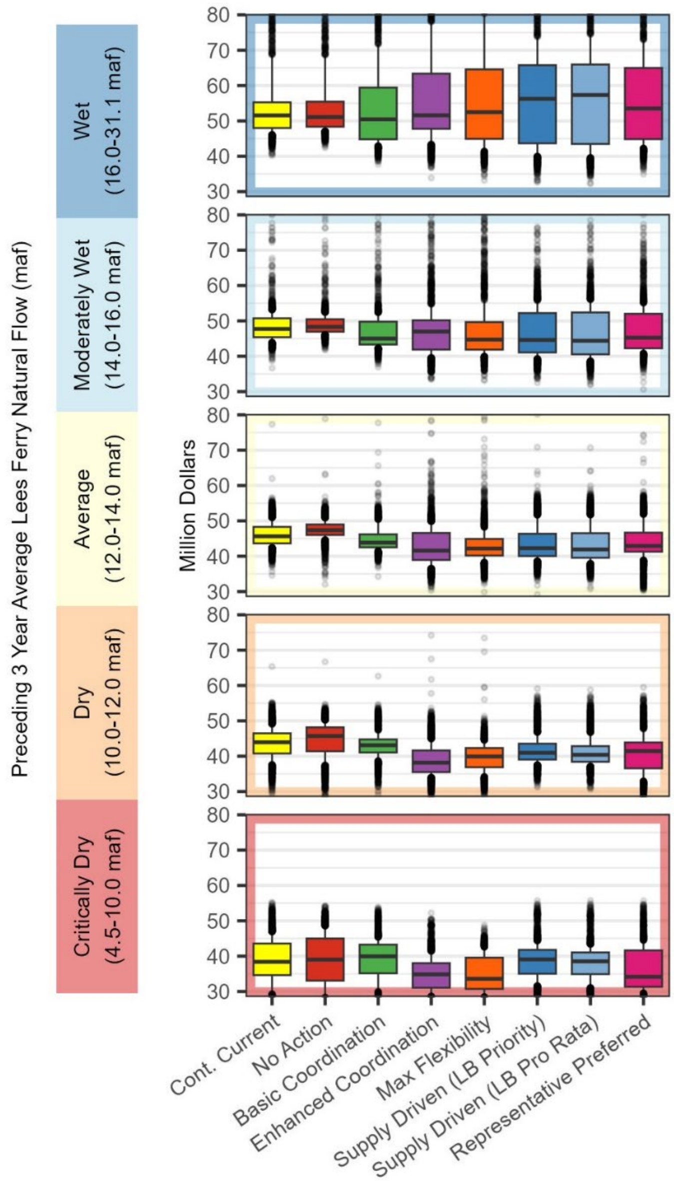
WAPA sets rates using a cost-recovery framework designed to recover annual project costs including operations, maintenance, replacements, and federal investment repayment. WAPA currently markets the project as a firm, fixed monthly delivery obligation, purchasing supplemental wholesale power to meet this commitment. Declining generation from the powerplants has increased the need for supplemental power, driving significant rate increases due to market price volatility. Starting in October 2028, a new marketing plan will align WAPA's delivery obligations with hydropower availability. This change will potentially create a financial swing. If generation drops sufficiently, PDP rates could surpass market rates, making the power uneconomical and potentially forcing contracted entities to abandon their long-term contracts.

Figure TA 15-37 below shows the annual market value of hydropower at Davis Dam based on CRSS modeling of generation and an assumed dollar-per-MWhs rate to determine the financial value (in millions of dollars). The results are grouped by preceding 3-year average Lees Ferry natural flow to show how fiscal value is influenced by hydrology for each alternative. Differences in fiscal value are driven by differences in releases across the alternatives (see **Figure TA 3-26** in **TA 3**, Hydrologic Resources for calendar year releases from Davis Dam).

Under the Wet Flow Category, all action alternatives exhibit relatively large interquartile ranges, indicating that hydropower value at Davis Dam is sensitive to operational differences during favorable hydrologic conditions. The Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative experienced the highest median value of $56-57 million annually, followed by Representative Preferred Alternative at $54 million. The Basic Coordination Alternative produced the lowest median market value, at $50 million annually.

In the Moderately Wet Flow Category, the No Action Alternative and CCS Comparative Baseline show similarly high median values of $47.7-$48 million annually. The Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative has the lowest median value at $44.3-45 million.

Figure TA 15-37
Annual Market Value of Davis Dam Generation: Box Plots



Under the Average Flow Category, the No Action Alternative and CCS Comparative Baseline show similarly high median values of $46-$47 million annually. The Supply Driven (both LB Priority and LB Pro Rata approaches) and Enhanced Coordination Alternatives have the lowest median values, both at $42 million annually.

Under the Dry and Critically Dry Flow Categories, all alternatives display substantially lower median values and vulnerability to low-generation outcomes. Under the Dry Flow Category, the No Action Alternative had the highest median values at $46 million and $44 million, respectively. The action alternatives have similar median values ranging between $38-$42 million.

Under the Critically Dry Flow Category, Maximum Operational Flexibility ($34 million), Representative Preferred ($34 million), and Enhanced Coordination ($35 million) Alternatives had the lowest median values, while the Basic Coordination Alternative had the highest median value of $40 million annually.

Modeling indicates that the Representative Preferred Alternative maintained a median value of $41 million annually in the Dry Flow Category. Under the Critically Dry Flow Category, the Representative Preferred Alternative median value dropped to $34 million annually.

Figure TA 15-38 below shows the annual market value of hydropower generation at Parker Dam, which was calculated by combining modeled annual energy production with an illustrative wholesale electricity price. Annual energy generation is simulated using CRSS, and a fixed fiscal year value per MWhs is applied to determine the dollar values anticipated for each alternative. Results are grouped into five categories by preceding three-year average Lees Ferry natural flow as shown in the figure. Differences in market value between alternatives is due primarily to differences in releases (see **Figure TA 3-27** in **TA 3,** Hydrologic Resources for calendar year releases from Parker Dam).

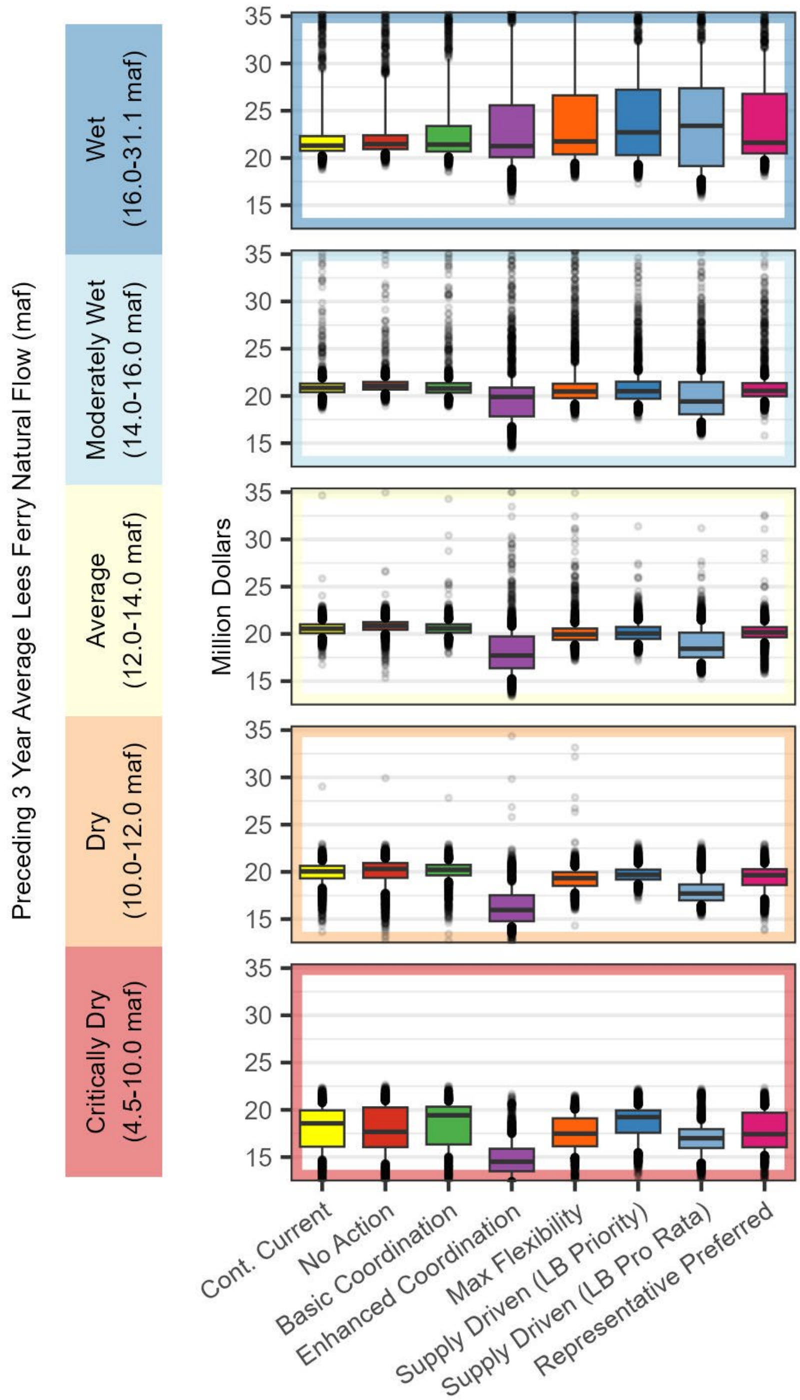
Under the Wet Flow Category, the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative exhibits the largest interquartile range, indicating larger sensitivity to operational differences when hydrologic conditions are favorable, although the median value is $22.7-$23 million annually. The median market values vary little between all alternatives with none falling less than $20 million annually.

Under the Moderately Wet and Average Flow Categories, median market values decline slightly across all alternatives and interquartile ranges narrow, reflecting less variability and sensitivity to hydrologic conditions. Median values across all alternatives range from $18-$21 million annually. Enhanced Coordination and Supply Driven (LB Pro Rata) Alternatives both experience larger interquartile ranges, with 25th percentiles dropping to $16 million and $18 million, respectively.

Under the Dry and Critically Dry Flow Categories, Enhanced Coordination and Supply Driven (LB Pro Rata) Alternatives have noticeably lower median values than the other alternatives, with values of $15 million and $16.9 million, respectively. CCS Comparative Baseline ($18.6-$20 million), as well as No Action ($17.7-$20 million), Basic Coordination ($19.4-$20 million), Supply Driven (LB Priority) ($19.2-$19.7 million), and Representative Preferred ($17.4-$19.6 million) Alternatives generally showed higher median market values across these categories.

Modeling indicates that the Representative Preferred Alternative maintained a median market value of $19.6 million annually across the Dry Flow Category. Under the Critically Dry Flow Category, the Representative Preferred Alternative had a median value of $17.4 million annually.

Figure TA 15-38
Annual Market Value of Parker Dam Generation: Box Plots



Summary of Issue 5 Impacts

Market value generally declined as hydrologic conditions became drier, reflecting lower energy generation across all facilities. The differences among alternatives was greatest at Glen Canyon Dam and Hoover Dam, while Davis Dam and Parker Dam exhibited smaller variations in market value.

For Glen Canyon Dam, the Representative Preferred Alternative achieved the highest market values under wet conditions ($358 million annually), while the Enhanced Coordination ($180-$216 million annually) and Maximum Operational Flexibility ($127-$178 million annually) Alternatives performed best under dry and critically dry conditions, maintaining the highest median values and lowest variability. The No Action Alternative and CCS Comparative Baseline generally produced lower market values and experienced greater variability.

For Hoover Dam the Supply Driven (both LB Priority and LB Pro Rata approaches) Alternative generally produced the highest market values under wet and moderately wet conditions ($195-$277 million annually). Under average, dry, and critically dry conditions, the Enhanced Coordination, Maximum Operational Flexibility, Representative Preferred, and Supply Driven (LB Pro Rata) Alternatives maintained higher median market values and narrower interquartile ranges than the CCS Comparative Baseline and No Action Alternative consistently exhibited lower values with greater variability.

For Davis Dam, under wetter flow conditions, wider interquartile ranges were present in Basic Coordination, Enhanced Coordination, Maximum Operation Flexibility, Supply Driven (both LB Priority and LB Pro Rata approaches), and the Representative Preferred Alternatives. Median values were between $50-$57 million annually. Under moderately wet and average conditions, median values generally range between $41-$489 million annually across all alternatives. Under dry and critically dry conditions, market values declined across all alternatives; however, the Enhanced Coordination Alternative had the lowest value with 25 percent of years falling to $28 million or less, annually.

For Parker Dam, market values exhibited the least variation among alternatives, with most median values ranging between approximately $15-$23 million annually, across all flow categories. Under Dry and Critically Dry Categories, the Enhanced Coordination ($15.5-$16 million) and Supply Driven (LB Pro Rata approach) ($16.9-$17.7 million) Alternatives tended to produce lower median market values than the other alternatives.

Overall, the Representative Preferred and Maximum Operational Flexibility Alternatives generally maintained higher market values and reduced variability under increasingly dry hydrologic conditions, whereas the No Action Alternative and CCS Comparative Baseline were more likely to exhibit lower market values and greater variability, particularly at Glen Canyon and Hoover Dams.

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