2024 FCRPS STRATEGIC ASSET MANAGEMENT PLAN

For the Federal Columbia River Power System

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1.0 EXECUTIVE SUMMARY

The Federal Columbia River Power System (FCRPS) consists of 31 multipurpose dam and operating projects operated by the U.S. Army Corps of Engineers (USACE) and the Bureau of Reclamation (Reclamation). As a multipurpose system, the FCRPS produces both power and non-power benefits for the Pacific Northwest. USACE and Reclamation operate and maintain the facilities with a combination of Bonneville Power Administration (BPA) direct funding and federal appropriations. BPA solely funds activities related to power generation and jointly funds activities that support the multiple purposes of the facilities. With 196 hydro generating units and a capacity of 22,050 MW, the FCRPS is the largest hydro system in the United States.

For decades, the FCRPS has been an engine of economic prosperity. It provides low-cost, carbon-free electricity, flood risk management, irrigation, navigation, municipal and industrial water supply, and recreation opportunities throughout the region. Today, the flexibility of the FCRPS supports the integration of over 2,700 MW of renewables, such as wind and solar, and is integral to BPA's participation in the energy imbalance market. As trusted stewards of these assets, BPA, USACE, and Reclamation also have an obligation to mitigate for the environmental and cultural resource impacts of the system.

Effective management of FCRPS assets requires balancing the many uses of these shared resources as efficiently as possible. The FCRPS Strategic Asset Management Plan (SAMP) strives to make coordinated operations, maintenance and investment decisions that maximize the value of FCRPS assets by reducing costs, mitigating risk, improving efficiency, and producing incremental value. This involves identifying optimal investment timing and alternatives, tailoring maintenance programs to the level of service necessary to meet obligations, and efficiently planning and operating the system. In these areas, decision making is the most mature for the capital investment program. Since 2008, BPA, USACE, and Reclamation, collectively referred to as the Three Agencies, have used decision making tools to identify the optimal level of capital investment in the FCRPS based on asset condition, criticality, and risk. Starting in 2017, the Asset Investment Excellence Initiative (AIEI) expanded the use of these tools to develop a 20-year portfolio of capital projects that is optimized on an annual basis based on project costs, benefits, and risks. During 2020 and 2021, the Three Agencies developed a new asset management structure aimed at closing gaps in the FCRPS asset management system, specifically with respect to operations and maintenance (O&M) optimization. Over the coming years, these new teams will expand our O&M decision making capabilities, bringing the level of maturity closer to that of the capital program. Since 2022, USACE and Reclamation filled the Strategic Planner positions that directly contribute to expansion of O&M information included in this 2024 SAMP.

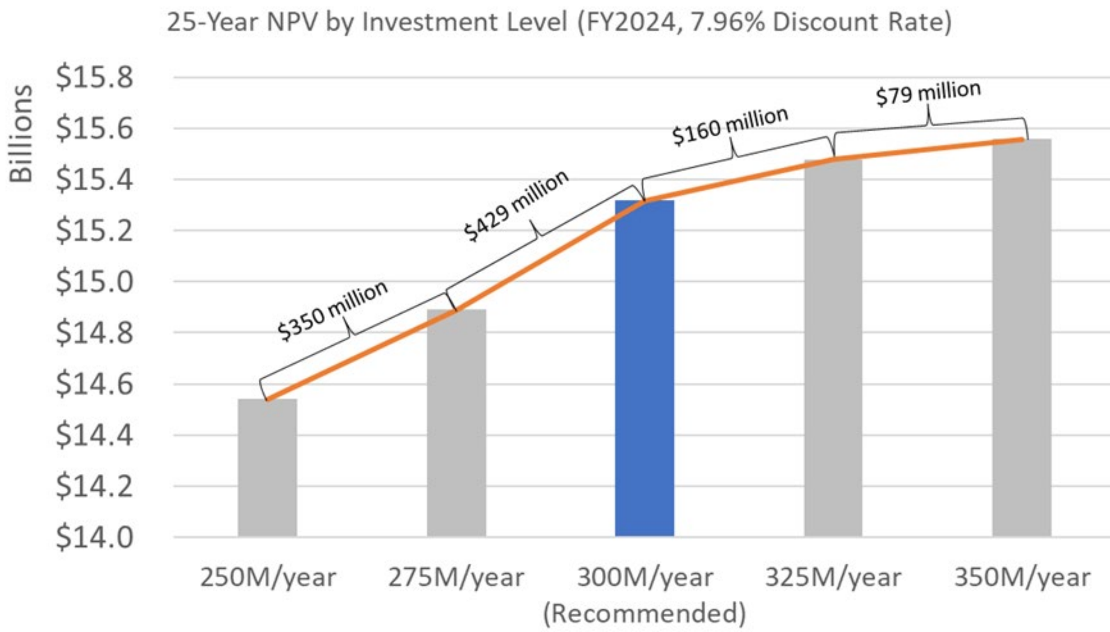
Optimal funding levels for the capital program are relatively unchanged from those presented in the 2022 SAMP. The capital investment strategy remains to ramp up to $300 million in 2024 and then escalate at the rate of inflation. Optimal numbers in Table 1.0-1 reflect the targets for USACE and Reclamation while the expected numbers are derived from a portfolio execution prediction tool that utilizes machine learning to predict future performance.

Table 1.0-1 Capital Program Forecast

	Rate Case FYs			Future Fiscal Years						
$ thousands	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Capital (Optimal)	315,678	322,623	329,785	337,172	344,725	352,481	360,553	368,846	377,366	386,008
Total Capital (Expected)	296,958	304,431	305,441	302,005	250,106	250,742	250,923	318,502	333,724	335,876

This level of investment has a $15.3 billion Net Present Value (NPV) through reductions in risk and incremental efficiency benefits. Levels of investment above the recommended strategy show diminishing returns and would be more difficult to execute. Lower levels of investment result in a significant decrease in NPV.

Table 1.0-2 Net Present Value of Investment



As part of an agency-wide effort to reduce costs, BPA held USACE and Reclamation expense programs flat and even decreased annual budgets from 2018 to 2023. At the same time, BPA, USACE, and Reclamation experienced considerable wage increases to bargaining unit employees, special salary rates to select engineering positions, and normal annual cost of living raises to the remaining support staff. Additionally, the cost for parts and contracts increased substantially, far outpacing inflation. As a result, both agencies had to either reduce FTE below historical levels or defer non-routine maintenance projects. One of the ramifications from this reduction is the loss of seasoned craftworkers to retirement and the inability to pass on their knowledge and expertise. Some corrective maintenance work that used to be a quick repair is now taking longer due to a new maintenance staff that is gaining the experience recently lost to retirements. Additionally, this reduction has necessitated prioritizing maintenance towards critical assets and deferring maintenance on other assets. USACE and Reclamation developed the optimal expense numbers in Table 1.0-3 to capture the need to fill vacant positions. To maintain recommended staffing levels, expense forecasts would have to increase at a rate higher than inflation to keep up with expected wage increases. After reviewing initial forecasts, BPA requested all generating partners to reduce expenses and find efficiencies. USACE and Reclamation reduced their expense budgets by $71.4 million over the rate period and $271.9 million over the 10-year period to meet this request. These reductions are reflected in Table 10.3-2 below.

Table 1.0-3 Expense Program Forecast

	Rate Case FYs			Future Fiscal Years						
$ thousands	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Expense (Optimal)	511,386	546,839	572,929	598,426	626,040	652,765	680,690	709,872	740,366	763,543
Total Expense (Expected)	487,586	523,039	549,129	573,503	599,919	625,436	652,094	679,949	709,052	731,238

The FCRPS Asset Management strategy results in capital and expense funding that is roughly proportional to the generation of each strategic class as shown in Table 1.0-4. While generation is often the largest driver for investment, it is important to note that investments also support the multipurpose missions of the dams and we would never expect perfect alignment.

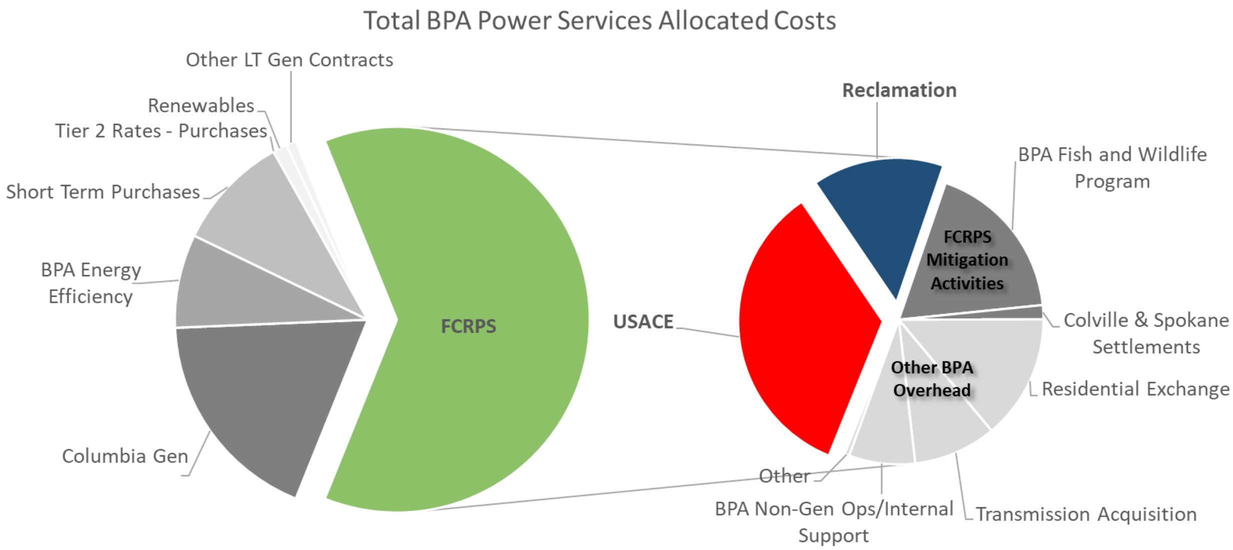
Overall, the direct funded capital and expense forecasts addressed in this SAMP are expected to result in a 50-year levelized cost of generation of $13.41/MWh. The 50-year fully loaded cost, which allocates all costs on the Power Income Statement to Power's various generating resources and Energy Efficiency, is $24.29/MWh for the 31 FCRPS plants. Both values are highly competitive when compared to alternative renewable resources and market purchases.

Table 1.0-4 Summary of Generation and Program Forecasts

Strategic Class	% of FCRPS Average Annual Generation	% of 50-Year Capital Forecast	% of 50-Year Expense Forecast	50-Year Cost of Generation ($/MWh)	50-Year Fully Loaded Cost ($/MWh)
Main Stem Columbia	79%	72%	66%	$10.92	$21.25
Lower Snake	9%	13%	13%	$21.76	$36.69
Headwater	7%	7%	8%	$14.60	$25.74
Area Support (Non-WVY)	2%	2%	4%	$23.68	$32.99
Area Support (WVY)	2%	5%	6%	$61.31	$77.56
Local Support	1%	1%	3%	$43.98	$56.40
FCRPS	100%	100%	100%	$13.41	$24.29

The power share of USACE and Reclamation costs, shown in red and blue in Figure 1.0-1 on the right below, account for about half of all costs associated with the 31 FCRPS dams. Mitigation costs and BPA overheads that are allocated to the dams make up the remainder. Costs allocated to the FCRPS dams represent about 62% of Power Services total costs, which is displayed graphically in green in Figure 1.0-1 on the left below. Columbia Generating Station, BPA's Energy Efficiency program, and short-term purchases of energy make up most of the remainder of Power Services total costs.

Figure 1.0-1 Total BPA Power Services Allocated Costs



2.0 ACKNOWLEDGEMENTS

2.1 Senior ownership

2.1.1 FCRPS Asset Management Commitment

In 2019, USACE, Reclamation, and BPA developed the FCRPS Asset Management Commitment. This commitment outlined the asset management mission, vision, and values of the FCRPS and was signed by USACE Northwestern Division Commander, Reclamation's Columbia Pacific Northwest Regional Director, and BPA's Administrator; the current executives reaffirmed their commitment in 2022.

FCRPS Asset Management Commitment

Vision

The FCRPS agencies will strive to sustain the efficiency, affordability and reliability of the System's long-term value through business processes that reflect industry best-practices in asset management. These processes include all aspects of planning, resourcing, and approving work, while informing strategies for operations, maintenance, and reinvestments of FCRPS assets.

Background

The U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, and Bonneville Power Administration act together through a strong three-agency alliance as responsible stewards of the Federal Columbia River Power System (FCRPS). The FCRPS is comprised of billions of dollars in assets and provides great economic and social benefits for the Pacific Northwest and beyond.

Mission

The FCRPS exists to deliver benefits to power, irrigation, navigation, and other customers and key stakeholders. We owe it to those customers and stakeholders to proactively implement and utilize industry leading asset management practices. This will enable us to provide those products and services with the highest regard to safety, environment, reliability, reputation, and cost.

Asset Management Values

Customers

- Embrace the FCRPS' role as a service provider to a broad range of customers and stakeholders. Cultivate a culture of commitment as federal partners to deliver demonstrated value to those customers.
- Establish ourselves as competent and transparent providers of the services expected by our customers and stakeholders while being good stewards of the public's assets.

People

- Value safety above all else – every process and action first identifies risks and preventative measures to protect our greatest asset, our employees.
- Ensure that roles and responsibilities of our organizations are clear, meaningful, valuable and rewarding.
- Enable staff to exercise leadership and appropriate levels of decision-making.
- Invest in employee training and development to effectively accomplish their function.

Process/Information

- Balance cost, performance, and risk through a consistent and credible decision-making process. Key stakeholders understand and have confidence in its integrity.
- Manage and utilize information and knowledge to enable informed decisions and effective work execution.
- Leverage innovative solutions and industry best practices to continuously improve achievement of FCRPS objectives.

Plant

- Operate, maintain, and invest in our facilities to optimize their value to customers and stakeholders over the long-term that is consistent with the financial health and stability of the FCRPS.
- Identify the business value of each facility, asset, and component and align performance expectations with that value, including all areas listed below:
  - Generation & Capacity
  - Cost
  - Risk tolerance
  - Health & safety
  - Environmental responsibilities
  - Legislative risks/requirements
  - Regulatory requirements
  - Cultural Resource responsibilities

Colonel Geoffrey Van Epps
Commander, Northwestern Division
U.S. Army Corps of Engineers

Jennifer Carrington
Regional Director
Columbia-Pacific Northwest Region
U.S. Bureau of Reclamation

John Hairston
Administrator
Bonneville Power Administration

2.1.2 BPA Senior Ownership

The Federal Columbia River Power System is a tremendous asset to the Pacific Northwest, producing low cost, reliable, carbon-free power for the region. As Trusted Stewards of the FCRPS, it is critical that BPA and its federal partners employ sound Asset Management principles to ensure the system is operated safely, efficiently and remains a competitive resource for years to come.

This SAMP represents a step forward in collaboration between USACE, Reclamation, and BPA. The additional operations and maintenance information included by our partners is the first step in expanding expense program strategies in the SAMP and integrating them with capital. Initiatives driven by our partners to mature operations and maintenance decision-making are both greatly appreciated and critical to meeting BPA's strategic goals for Asset Management. Continued collaboration and the execution of the strategies outlined in this SAMP put the FCRPS in the best position to meet each agency's strategic goals and deliver on our commitment to maximize the value of the FCRPS for the region.

Digitally signed by SUZANNE COOPER
Date: 2025.03.07 12:53:10 -08'00'

Suzanne Cooper
Senior Vice President, Power Services

2.2 Strategy Development Approach

The SAMP is developed collaboratively between BPA, USACE, and Reclamation. BPA generally leads the development of the SAMP document and capital investment strategy. USACE and Reclamation lead the development of expense strategies for their respective agencies and author those sections of the SAMP. The SAMP is reviewed internally by Generating Assets (PGA and PGAF) staff and externally by USACE (Portland District, Seattle District, Walla Walla District, and Northwestern Division) and Reclamation (Columbia Pacific Northwest Region).

2.2.1 Key Contributors

Table 2.2.1-1, Key Contributors

<table>
<tr><th>Agency</th><th>Group</th><th>Contribution</th></tr>
<tr><td rowspan="4">Bonneville Power Administration</td><td>Generating Assets (PGA and PGAF)</td><td>• Lifecycle cost minimization models (Copperleaf - Predictive Analytics)
• Equipment degradation rates
• Risk assessment
• Economic analysis</td></tr>
<tr><td>Power Forecast and Planning (PTM)</td><td>• Long Term Price Forecasts</td></tr>
<tr><td>Operations Planning (PGPO)</td><td>• Consequences of Unit Outages</td></tr>
<tr><td>Revenue Requirement, Repayment and Financial Strategy (FTR)</td><td>• Discount Rate
• Inflation Rate</td></tr>
<tr><td rowspan="3">Army Corps of Engineers</td><td>Portland, Seattle, Walla Walla Districts, Northwestern Division</td><td>• Project costs estimates and valuation
• Joint Investment Identification
• SAMP Review</td></tr>
<tr><td>Plant Staff</td><td>• Project information
• hydroAMP Condition Assessments</td></tr>
<tr><td>Hydroelectric Design Center</td><td>• Equipment Failure Curves
• Technical Expertise</td></tr>
<tr><td rowspan="3">Bureau of Reclamation</td><td>Columbia Pacific Northwest Region</td><td>• Project cost estimates and valuation
• Joint Investment Identification
• SAMP Review</td></tr>
<tr><td>Plant Staff</td><td>• Project Information
• hydroAMP Condition Assessments</td></tr>
<tr><td>Technical Services Center</td><td>• Equipment Failure Curves
• Technical Expertise</td></tr>
<tr><td rowspan="2">Three Agency Teams</td><td>Senior Oversight Group</td><td>• FCRPS Goals, Objectives, and Initiatives</td></tr>
<tr><td>Asset Strategy and Planning Team</td><td>• Development of SAMP document
• Strategies for achieving goals and objectives</td></tr>
</table>

2.2.2 Key Activities

The following table indicates key activities required to develop the SAMP on an annual basis.

Table 2.2.1-1, Key Activities

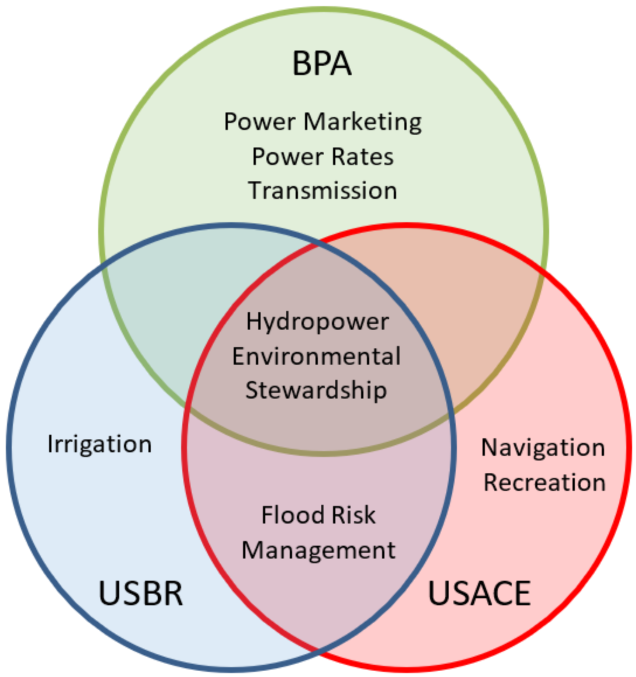
Activity	Description
Equipment Condition Assessments	• Plants perform annual condition assessment update
Update Modeling Parameters	• Price Forecast • Inflation Rate • Discount Rate • Condition Degradation Rates • Failure Curves • Equipment Outage Durations • Equipment Outage Consequences • Budget Constraints
Asset Management Maturity Assessment	• Conduct Asset Management maturity assessment by surveying FCRPS employees of various disciplines
Review and Update Goals, Objectives and Initiatives	• Goals, Objectives, and Initiatives are reviewed by FCRPS leadership, incorporating results from the maturity assessment
Run Predictive Analytics	• Analyze costs, benefits, and risk of investment at different budget levels • Identify the optimal level of achievable investment
Share preliminary results with federal partners	• Review Optimal Replacement Dates of equipment • Communicate any major changes to modeling
Develop SAMP	• Produce charts, tables and analysis describing the benefits costs and risks of pertinent investment scenarios • Create/update SAMP document
Review SAMP	• Review SAMP with Federal Partners • Present SAMP summary at Joint Operating Committees
Publish SAMP	• Incorporate changes from review and finalize document • Provide SAMP to Asset Planning team for input into Asset Plan

3.0 STRATEGIC BUSINESS CONTEXT

3.1 Alignment of SAMP with Agency Strategic Plan

USACE, Reclamation, and BPA have the unique challenge of bringing together the strategic plans of three separate agencies under three different departments of the US government. Many goals are shared across the agencies, but it is important to acknowledge that each agency has its own distinct missions that are served by FCRPS assets and resources.

Figure 3.1-1, Agency Mission Overlap



Striving to effectively balance these missions, we have collaboratively developed strategic goals for the FCRPS that incorporate elements of each agency's strategic plan. Each goal is equally important in meeting the collective missions of the Three Agencies.

Table 3.1-1, Agency Goals

Long-term Sustainability	Trusted Stewardship	Low Cost, Reliable Power
We will maintain the performance of our assets and the competency of our workforce in line with asset management principles to sustain the long-term value of the FCRPS for the benefit of future generations.	We will balance the multiple uses of our physical assets and natural resources to safely provide benefits to the region for flood risk management, water delivery, navigation, power, fish and wildlife mitigation, cultural resources, and recreation.	We will make sound operations, maintenance, and investment decisions to meet the needs of our power customers, comply with regulations, and support reliable generation and transmission service at competitive rates.

3.1.1 Alignment with BPA Strategic Plan

In 2023, BPA released its 2024-2028 Strategic Plan that sets BPA's agency-level goals and objectives for the next 5 years. This SAMP outlines FCRPS asset management goals and objectives that support BPA's agency-level goals of sustaining financial strength, maturing asset management, enhancing the value of products and services, modernizing business systems and processes, investing in people, and preserving safe, and reliable system operations. The following goals are directly supported by asset management goals, objectives, initiatives, and strategies outlined in this SAMP.

Table 3.1.1-1, BPA Strategic Plan with FCRPS Focus

2024-2028 Strategic Plan Goal	What we're doing in the FCRPS
Invest in People	We are committed to fostering a safe work environment, taking proactive measures to reduce risk and ensure employee safety. Our FCRPS Asset Management Commitment states that we value safety above all else and that is reflected in our strategies, plans, and value framework. We have asset management objectives focused on improving communication, line-of-sight, and asset management training. These objectives intend to improve staff understanding of how their work relates to FCRPS strategies and plans and how those support the missions of all three agencies.
Sustain Financial Strength	FCRPS strategies are built around minimizing lifecycle costs and plans are optimized to deliver the highest value to the region while meeting the missions of the Three Agencies. New optimization and approval processes are being implemented in asset plans and project approval to promote improved capital plan execution.
Mature Asset Management	FCRPS capital strategies have been developed using a robust understanding of criticality, health, and risk for over a decade. Data and modeling techniques continue to evolve to better understand and optimize the value of FCRPS assets across their multiple missions. USACE and Reclamation are working on initiatives to optimize their maintenance programs, leveraging asset information to develop new strategies that will incorporate more condition-based and reliability-centered maintenance principles.
Preserve Safe and Reliable System Operations	The flexibility of the FCRPS makes it well-positioned to respond to high impact events. During powerhouse modernization projects, we consider future expectations and look to preserve or enhance this flexibility where necessary.

3.1.2 Relationship to USACE Agency SAMP

In alignment with the FCRPS goal to maximize asset value, USACE is in the process of implementing the Project Maintenance Management Plans (PMMP) that will institutionalize USACE's strategy and philosophy on maintenance, while simultaneously improving our understanding of the regional operating projects through data and communication. Agency-wide application of the same standards allows USACE to compare maintenance actions and investments across the agency.

3.1.3 Relationship to Reclamation Agency SAMP and Hydropower Strategic Plan

The SAMP focuses on Reclamation's lands and constructed assets that sustain the essential functions of congressionally authorized projects. It describes Reclamation's current asset management practices in addition to strategies to meet the challenges of balancing competing demands on the Nation's water and power infrastructure.

The Reclamation strategic plan for the hydropower division of Reclamation is built around three core goals:

1. Ensure that Reclamation hydropower is a valuable part of the long-term national energy portfolio.
2. Customer satisfaction is core to the long-term success of Reclamation hydropower.
3. Invest in our people to ensure Reclamation continues to employ a skilled, dedicated, and capable workforce.

Reclamation's hydropower strategic plan provides a roadmap for organizational improvements based on data and science and will ensure that our people and mission remain a primary focus.

3.2 Scope

The SAMP presents strategies for both the FCRPS Asset Management program and FCRPS assets. Strategies for program improvements included in the SAMP typically outline areas in which all Three Agencies collaborate. In addition to FCRPS collaborative improvements, USACE and Reclamation often have internal initiatives that directly or indirectly benefit the Asset Management program but are not documented in the SAMP. Asset strategies driven by condition, criticality, and risk identify the optimal time to replace FCRPS equipment. The analysis includes over 10,000 FCRPS assets and forecasts their risk profiles over a 50-year study period. Results from this analysis and input from USACE and Reclamation staff, form the basis for the investments identified in the FCRPS System Asset Plan (SAP).

Within the 31 FCRPS plants, there are 196 main generating units and an additional 16 units that provide station service, fish attraction flows, or pumping capabilities. The SAMP primarily addresses powertrain and critical ancillary components that are either directly related to power production or are supporting equipment for day-to-day operations. About 17% of the inventoried assets are "Joint" assets. "Joint" assets serve the multiple authorized purposes of a facility, not solely hydropower, and are funded by both federal appropriations and direct funding from BPA. Even if the Three Agencies are in alignment on priority for joint assets, investments can be delayed if federal appropriations are not available. Due to these complexities, the ability to effectively plan for joint asset replacement or refurbishment is challenging. Since 2020, roughly 10% of the overall USACE capital budget is set aside for joint assets. USACE joint investments are optimized separately within this portion of the budget.

Columbia Generating Station (CGS) and other contract generating resources are not within the scope of this SAMP. Unlike FCRPS assets, BPA has less of a direct asset management role with these resources and more generally reviews the strategies and plans created by the operators of the respective assets.

3.3 Asset Description and Delivered Services

The FCRPS is comprised of 31 hydroelectric plants, 21 operated by USACE and 10 by Reclamation. It has an overall capacity of 22,050 MW. In an average water year, the FCRPS produces 73 million megawatt-hours of electricity. The 31 plants are located throughout the Columbia River Basin in Washington, Oregon, Idaho, and Montana. Each plant is grouped into one of six Strategic Classes, which describe their respective roles in the FCRPS.

Table 3.3-1, Assets

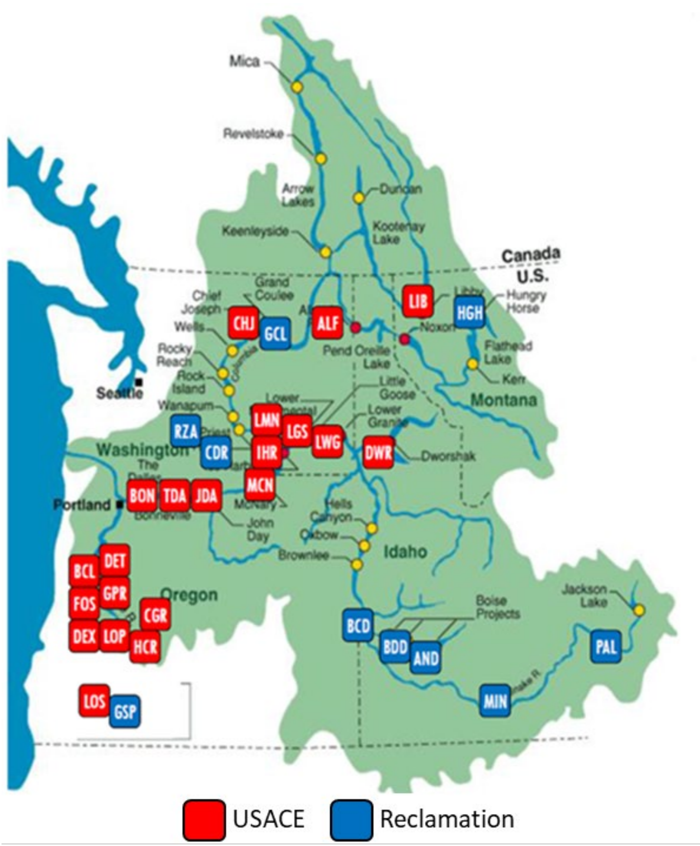
Plant	ID	Units	MW Capacity	aMW Energy[1]	Strategic Class	Operator
Grand Coulee	GCL	24	6,735	2,330	Main Stem Columbia	Reclamation
Chief Joseph	CHJ	27	2,614	1,374	Main Stem Columbia	USACE
McNary	MCN	14	1,120	556	Main Stem Columbia	USACE
John Day	JDA	16	2,480	977	Main Stem Columbia	USACE
The Dalles	TDA	22	2,052	808	Main Stem Columbia	USACE
Bonneville	BON	18	1,195	535	Main Stem Columbia	USACE
Dworshak	DWR	3	465	203	Headwater	USACE
Lower Granite	LWG	6	930	186	Lower Snake	USACE
Little Goose	LGS	6	930	188	Lower Snake	USACE
Lower Monumental	LMN	6	930	212	Lower Snake	USACE
Ice Harbor	IHR	6	693	198	Lower Snake	USACE
Libby	LIB	5	605	247	Headwater	USACE
Hungry Horse	HGH	4	428	94	Headwater	Reclamation
Albeni Falls	ALF	3	49	24	Area Support	USACE
Detroit	DET	2	115	48	Area Support	USACE
Big Cliff	BCL	1	21	13	Area Support	USACE
Green Peter	GPR	2	92	38	Area Support	USACE
Foster	FOS	2	23	12	Area Support	USACE
Lookout Point	LOP	3	138	40	Area Support	USACE
Dexter	DEX	1	17	10	Area Support	USACE
Cougar	CGR	2	28	17	Area Support	USACE
Hills Creek	HCR	2	34	17	Area Support	USACE
Lost Creek	LOS	2	56	39	Area Support	USACE
Palisades	PAL	4	176	87	Area Support	Reclamation
Minidoka	MIN	4	28	29	Local Support	Reclamation
Anderson Ranch	AND	2	40	12	Local Support	Reclamation
Boise Diversion	BDD	3	3	1	Local Support	Reclamation
Black Canyon	BCD	2	10	7	Local Support	Reclamation
Roza	ROZ	1	13	9	Local Support	Reclamation
Chandler	CDR	2	12	7	Local Support	Reclamation
Green Springs	GSP	1	18	7	Local Support	Reclamation
TOTAL		**196**	**22,050**	**8,326**		

1: aMW energy values based on operations and expected availability for FY24

Table 3.3-2, Strategic Classes

Purpose	Main Stem Columbia	Headwater/Lower Snake	Area Support	Local Support
Power	Provides 76% of energy and capacity, and 30% of storage from the FCRPS Provides nearly all the reserves and other ancillary services for supporting the 500 KV grid	Provides 20% of energy and capacity, and 50% of storage from the FCRPS Provides supplementary ancillary services for supporting the 500 KV grid	Provides 3% of energy and capacity, and 18% of storage from the FCRPS Provides voltage support to specific areas of the regional transmission grid	Provides 1% of energy and capacity, and 2% of storage from the FCRPS Provides limited voltage support to local areas of the Pacific Northwest
Flood Risk Management	Seasonal flood risk reduction and water management storage affecting significant parts of the Columbia River basin	Seasonal flood risk reduction and water management storage affecting significant parts of the Columbia River basin	Provides flood risk reduction benefits primarily in the Willamette Valley, but does not contribute significantly to the flood reduction capability of the overall Columbia River basin	Provides flood risk reduction benefits in a local area
Navigation	Provides navigation for the lower Columbia River from below Cascade Locks to the Tri-Cities	Provides navigation for the lower Snake River from the Tri-Cities to Lewiston, ID	None	None
Irrigation	Primary source of irrigation for the Columbia River Basin	Provides incidental irrigation from the reservoirs	Primary source of irrigation within a specific region (Palisades Dam only)	Primary source of irrigation within a specific region
Recreation	Significant recreation for boating and camping Includes several “destination” recreation sites and numerous local sites	Major recreation for boating and camping Includes several “destination” and local sites	Major recreation for boating and camping Includes several “destination” and local sites	Some boating and camping at local sites

Figure 3.3-1, Asset Locations



The FCRPS provides the following services to BPA’s preference customers:

- **Load Following Product:** BPA firm power service that meets the customer’s Total Retail Load less any firm energy from the customer’s Dedicated Resources on a real-time basis.
- **Block Product:** BPA firm power service sold in a specific amount each hour, offered as a flat hourly block or with Shaping Capacity.
- **Slice/Block Product:** BPA power service that combines the block product with firm power in the shape of BPA’s generation from the Tier 1 system in addition to surplus energy when available
- **Industrial Firm Power:** BPA firm power service sold to direct service industrial customers in the Pacific Northwest as defined in the Northwest Power Act.

The FCRPS also provides the following services:

- **Reactive Supply and Voltage Control from Generation Sources Service:** Required to maintain voltage levels on BPA's transmission facilities within acceptable limits.
- **Regulation and Frequency Response Service:** Necessary for the continuous balancing of resources with load and for maintaining frequency.
- **Energy Imbalance Service:** Provided when a difference occurs between the scheduled and actual delivery of energy to a load located within a Control Area.
- **Spinning Reserve Service:** Needed to serve load immediately in the event of a system contingency.
- **Supplemental Reserve Service:** Needed to serve load in the event of a system contingency, not immediately, but within a short period of time.
- **Generation Imbalance Service:** Provided when there is a difference between scheduled and actual energy delivered from generation resources.
- **Variable Energy Resource Balancing Service:** Comprised of regulating reserves, following reserves and imbalance reserves.
- **Dispatchable Energy Resource Balancing Service:** Provides reserves to compensate for differences between a thermal generator's schedule and actual generation.
- **Contingency Reserves:** Deployed to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
- **Surplus Power:** Surplus energy (capability) in excess of BPA's obligations to preference customers is sold to wholesale parties or into the Energy Imbalance Market (EIM).

- The FCRPS also provides the following services for its non-power missions:
  - **Environmental Stewardship:** Mitigation for the impacts of the FCRPS through ecosystem restoration, conservation of cultural and natural resources, and restoring fish and wildlife habitat.
  - **Irrigation and Water Delivery/Supply:** Assists with meeting the increasing water demands of agriculture through the distribution of water as well as power reserved exclusively for the use of water delivery.
  - **Flood Risk Management:** Reduce the risk to public safety and property damage caused by floods.
  - **Navigation:** Maintain safe and reliable channels, harbors, and waterways for the transportation of commerce, support to national security, and recreation.
  - **Recreation:** Provide water-based outdoor recreation opportunities to the region.

3.4 Demand Forecast for Services

While the primary purpose of powerhouse assets is to generate power, these assets also support the multipurpose missions of the dams. In addition to BPA's Loads and Resources study, the 2024 SAMP also includes demand analyses recently conducted by USACE and Reclamation for their respective powerhouses relative to their missions.

3.4.1 BPA Loads and Resources Study

The Pacific Northwest Loads and Resources Study, commonly called "The White Book", is BPA's annual publication of the Federal system and the Pacific Northwest (PNW) region's loads and resources for the upcoming ten-year period. Note that the Federal system includes generation from the 31 dams in the FCRPS, CGS, and other contract generating resources.

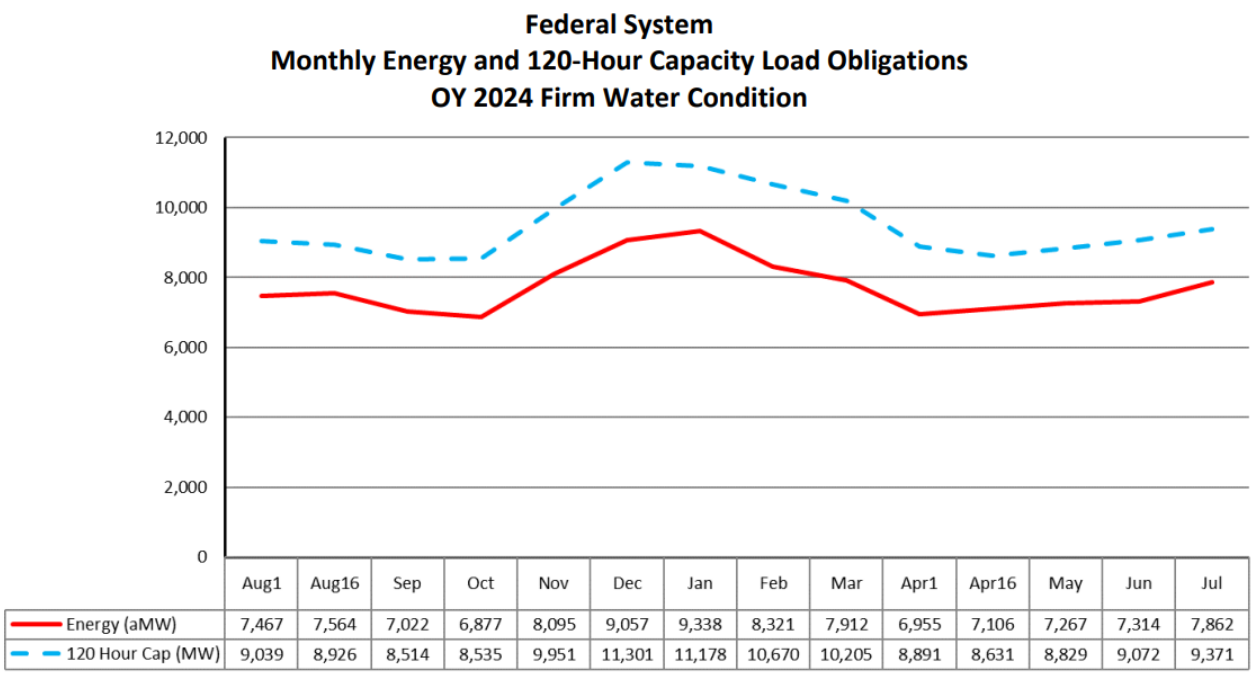
BPA uses the White Book as a planning tool, as a data source for the Columbia River Treaty studies, as an information source for customers, and as a published source of loads and resources information for other regional interests. As of the development of this SAMP, the 2023 White Book is the most recent release.

It can be found on BPA's website at the following link:
https://www.bpa.gov/-/media/Aep/power/resource-program/2023-white-book.pdf

Highlights from the 2023 White Book include:

Load Obligations – The types of Federal system load obligation forecasts include: 1) Reclamation's reserve power obligations; 2) BPA's Regional Dialogue PSC obligations to public, cooperative, and tribal utilities, and Federal agency customers; 3) BPA's contract obligations to investor-owned utilities (IOUs); 4) BPA's contract obligations to Direct Service Industry (DSI) customers; and 5) other BPA contract obligations, which include contract sales to entities within the PNW region (Intra-Regional Transfers (Out) and to those outside the PNW region (Exports)). These load obligations are all considered firm power deliveries and are assumed to be served by the Federal system regardless of weather, water, or economic conditions. The chart below shows total forecasted energy and 120-hour capacity obligations for operating year 2024.

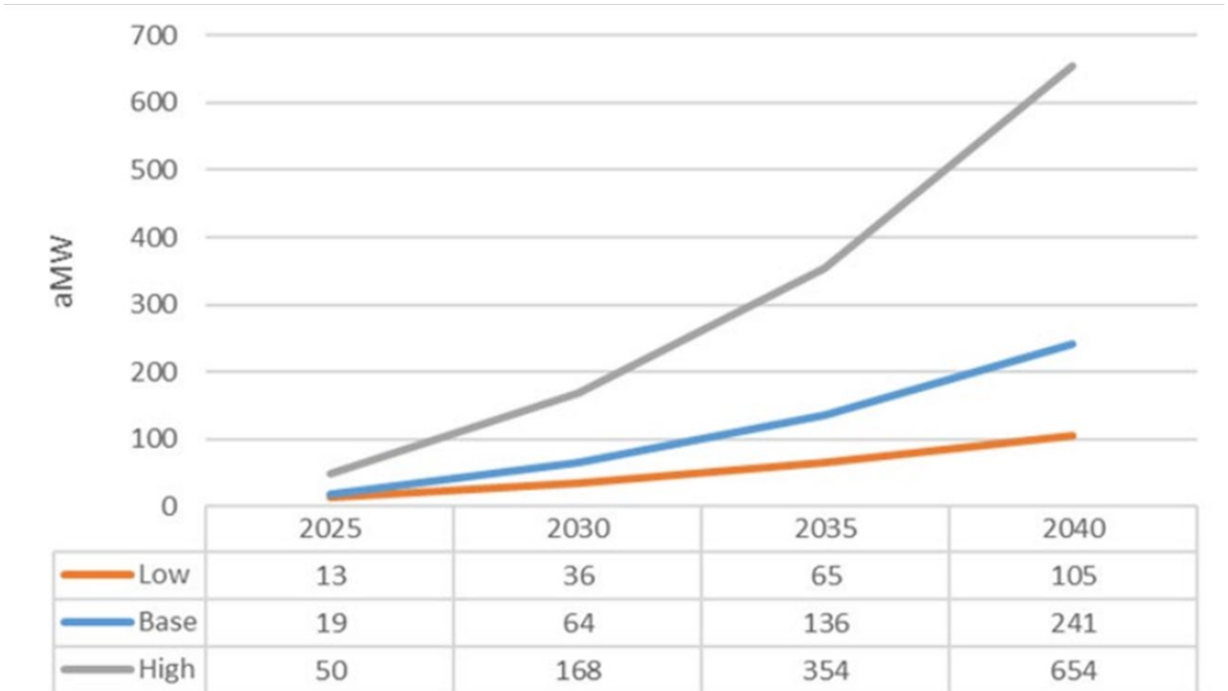
Figure 3.4-1, Forecasted Energy and 120-Hour Capacity Obligations



Winter and spring load obligations are slightly higher than those shown in the 2022 SAMP. Overall, the White Book shows a 2.5% average annual load growth from 2024 to 2033. While BPA's contractual load forecast includes a small increase in load resulting from electrification, the growing interest in electrification suggests a potential for significant load growth in the future and an area BPA will continue to monitor. The chart below presents BPA's view of the possible range of load growth resulting from electrification in customers' load. While the 2024 White Book study includes the base forecasted load increases from this chart, a range of possible customer load increase is presented. It is important to note that due to the tiered structure of BPA's Regional Dialogue PSCs, only a share of increased load may become a BPA obligation. These possible electrification increases are expected to result from electrical vehicle use and the increasing conversion to electric applications to reduce greenhouse gases.

Figure 3.4-2, Federal Load Obligation

Federal System – Annual Energy – Load Obligation Increases
(Re-print from 2022 White Book)



Federal System Analysis—forecast of Federal system firm loads and resources based on expected load obligations and different levels of generating resources that vary by water conditions. The results are summarized below:

Annual Energy Surplus/Deficits: Under firm water conditions, the Federal system is expected to have annual energy deficits throughout the study period. Compared to the previous White Book, deficits have increased throughout the study period except in the first year, with larger deficits in the end of the study period. These results reflect changes in both load obligations and Federal system generation.

Table 3.4-1, Annual Energy Surplus/Deficit Comparison

Federal System
Annual Energy Surplus/Deficit Comparison
OY 2024 through 2033
Firm Water Conditions

Energy (aMW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	-18	-289	-147	-223	-159	-303	-263	-357	-303	-424
2022 White Book 1937 Critical Water Conditions	-103	-245	-39	-118	-25	-164	-68	-204	-105	*n/a*
Difference ***(2023 WBK – 2022 WBK)***	86	-44	-107	-105	-134	-139	-195	-153	-198	*n/a*

January 120-Hour Capacity Surplus/Deficits: Under firm water conditions, the Federal system is expected to have a surplus for the 120-Hour capacity metric in all years except the last year in the study period. This is a significant difference from the 2022 White Book, but is primarily explained by the methodology change of using 10th percentile generation versus 1937 critical water conditions.

Table 3.4-2, January 120-Hour Capacity Surplus/Deficit Comparison

Federal System
January 120-Hour Capacity Surplus/Deficit Comparison
OY 2024 through 2033
Firm Water Conditions

January 120-Hour Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	414	199	467	69	98	53	66	10	15	-123
2022 White Book 1937 Critical Water Conditions	-1,215	-1,312	-1,086	-1,263	-1,254	-1,099	-1,208	-1,163	-1,267	*n/a*
Difference ***(2023 WBK – 2022 WBK)***	1629	1511	1554	1332	1351	1151	1274	1174	1282	*n/a*

As water conditions improve, the Federal system surplus/deficit forecasts can vary greatly. For example, the annual energy surpluses can increase by more than 3,000 aMW under better water conditions, while the monthly surplus or deficit position can vary by more than 5,000 aMW (March). Similarly, Federal system 120-Hour capacity surpluses and deficits for OY 2024 can vary by more than 4,500 MW in the second part of April depending on water conditions.

Federal system monthly energy deficits are generally greater than the 120-Hour capacity deficits under firm water conditions. This result indicates that the Federal system continues to be more energy constrained than capacity across the study period. BPA's Resource Program, described in Section 3.4.2, evaluates the need to address deficits and develops strategies to acquire resources when needed.

3.4.2 BPA Resource Program

BPA's Resource Program study assesses the need for power and reserves and develops acquisition strategies to meet those needs. The Resource Program study provides analysis and insight into long-term, least-cost power resource acquisition strategies. The study examines uncertainty in loads, water supply, resource availability, and electricity market prices to develop a least-cost portfolio of resources that meet Bonneville's obligations. The resource solutions produced by portfolio optimization indicate that the most economical solution for BPA to meet its energy obligations continues to be a combination of market purchases and demand-side resources. Energy efficiency and low-cost demand response were acquired in the least-cost portfolio up until it was as expensive as market purchases. Then the optimization solved for the remaining needs with market purchases. Low-cost energy efficiency remains BPA's preferred resource to meet identified energy needs.

Relative to hydropower assets, this means that BPA is not actively seeking to expand the hydro system to meet forecasted future needs. However, many capital replacement projects, specifically for turbine runners, result in efficiency improvements that will help reduce future deficits. Additionally, there are opportunities where additional units at existing FCRPS dams would help reduce financial and environmental impacts during planned and forced outages on existing units. In some cases, these units would also provide incremental generation. Hydropower expansions have not historically been included as a selectable resource in the Resource Program's portfolio optimization. However, BPA staff are discussing how forecasted efficiency improvements gained through end-of-life replacements and expansion units can be considered in future Resource Programs.

3.4.3 USACE Demand Analysis

The O&M Optimization Initiative (OMOI) is an effort to understand the demands for each of the services that the multi-purpose dams provide, particularly those provided by hydropower assets. An up-to-date understanding of each dam's relative value, and the conditions when those services are needed, will enable USACE to develop required levels of service for generating units to reliably deliver those services. As O&M budgets continue to be outpaced by cost growth, the challenge is to articulate the minimum requirements of the routine program and strategize how to efficiently and safely meet those requirements while eliminating activities which are not required. These principles should drive changes to our levels of maintenance that better reflect unit value and reduce inefficiency.

The OMOI evaluates the hydropower generation value as well as the importance of generating assets in meeting non-hydropower missions. Value is determined by the amount and value of generation from a dam's powerhouse. The importance of a hydropower asset is tied to its ability to meet and/or provide the mandatory functions concerning fish attraction, temperature control, water quality, and dissolved gas during differing river conditions.

3.4.4 Reclamation Demand Analysis

The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public. Reclamation's hydropower strategy focuses on ensuring delivery of reliable, valuable, and affordable water and power. Hydropower, as a source of low-cost power, plays a critical role in Reclamation being able to accomplish this mission. Additionally, the energy landscape is evolving quickly with the inclusion of distributed renewable energy sources, regional markets, and new alternative utility business models. Reclamation faces challenges in adapting and upgrading aging infrastructure and operational strategies to this new landscape. The intent of the demand analysis study is to evaluate the importance and value of Reclamation's Columbia-Pacific Northwest (CPN) Region's hydropower units. The results will inform and aid Reclamation leadership in making future decisions to improve Operation, Maintenance, and Replacement (OM&R) effectiveness while staying within the agency's risk tolerance for accomplishing its mission.

Within the CPN Region, Reclamation owns and operates 10 hydropower facilities. There are 50 hydropower units spread across the states of Idaho, Washington, Oregon, and Montana, ranging in size from 805 MW at Grand Coulee Dam to 1.1 MW at the Boise River Diversion Dam. This analysis focuses on the importance and value of the hydropower units and not the whole facility. Units have been grouped by similar characteristics or for having a unique operational role. Only two facilities, Grand Coulee and Minidoka, have been separated into groups while the rest of Reclamation's units are grouped by facility.

Table 3.4.4-1, Reclamation Project Generating Units and Capacity

Unit Group	Facility	No. of Units	Capacity (MW)	Unit Group	Facility	No. of Units	Capacity (MW)
AND	Anderson Ranch	2	40	GCL SS	Grand Coulee	3	30
BDD	Boise Diversion	3	3.3	GSP	Green Springs	1	17
BCD	Black Canyon	2	10.2	HGH	Hungry Horse	4	428
CDR	Chandler	2	12	MIN PP	Minidoka	2	8
GCL WPP	Grand Coulee	6	4,215	MIN IN	Minidoka	2	20
GCL LPH G1-3	Grand Coulee	3	375	PAL	Palisades	4	177
GCL LPH G4-9	Grand Coulee	6	750	ROZ	Roza	1	13
GCL RPH	Grand Coulee	9	1,125				

For purposes of this Hydropower Value Analysis (HVA) study, Reclamation's mission is separated into three main areas; Power, Water Supply, and Water Management against which the hydropower units would be ranked relative to one another in importance and value. To aid analysis, each mission area was characterized by one to six critical elements that are important to that Reclamation mission area. A summary of the analysis results for meeting the Reclamation mission and then separately for each mission area of Power, Water Supply and Water Management is provided below.

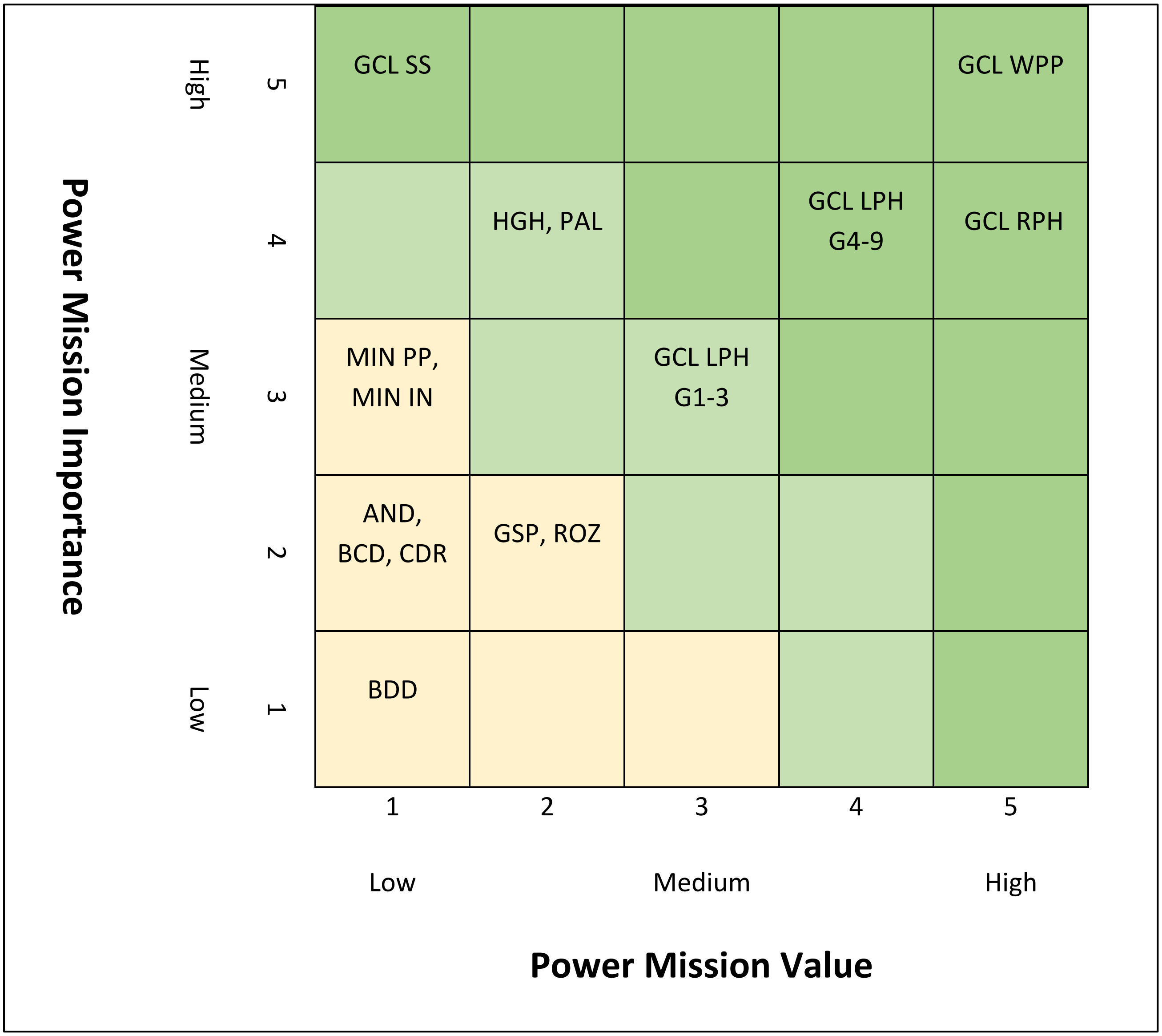
3.4.4.1 Analysis Results

Figure 3.4.4.1-1, Reclamation Project Mission Importance and Mission Value

Mission Importance		1	2	3	4	5
High	5	GCL SS	GSP	ROZ, PAL		GCL WPP, GCL LPH G1-3
	4				HGH	GCL LPH G4-9, GCL RPH
Medium	3	MIN PP, MIN IN		AND		
	2		BCD, CDR			
Low	1	BDD				
		Low		Medium		High
				Mission Value		

The following matrices provide a summary of analysis results. Results are provided for overall mission importance as well as the individual mission areas of Power, Water Supply, and Water Management. Looking at how the CPN Region's hydropower units contribute to Reclamation's mission, units ranked higher in importance have a pivotal role in power production such as Grand Coulee (GCL) or water supply to authorized Reclamation purposes such as Palisades (PAL), Roza (ROZ) and Green Springs (GSP). Those lower in importance typically are smaller capacity units with lower generation that are not necessary for water supply deliveries or managing water releases from the facility. Units higher in value tend to have larger annual generation and a low cost of generation which benefits all mission areas. Lower value units typically have lower annual generation and a high cost of generation.

Figure 3.4.4.1-2, Reclamation Project Power Mission Importance and Power Mission Value



The Power mission of Reclamation is focused on providing low cost, reliable power to the Pacific Northwest Region. Units higher in importance to the power mission tend to have larger capacity and operational flexibility or requirements for grid support to either the region or a local area such as PAL and MIN. Units with lower importance typically are smaller and limited operationally by restricted water supplies such as BDD, BCD, ROZ, and CDR. Higher value units for the Power mission tend to have high annual generation and high revenue risk for unit outages. Grand Coulee units predominately make up the higher importance, higher value grouping for Reclamation's Power mission.

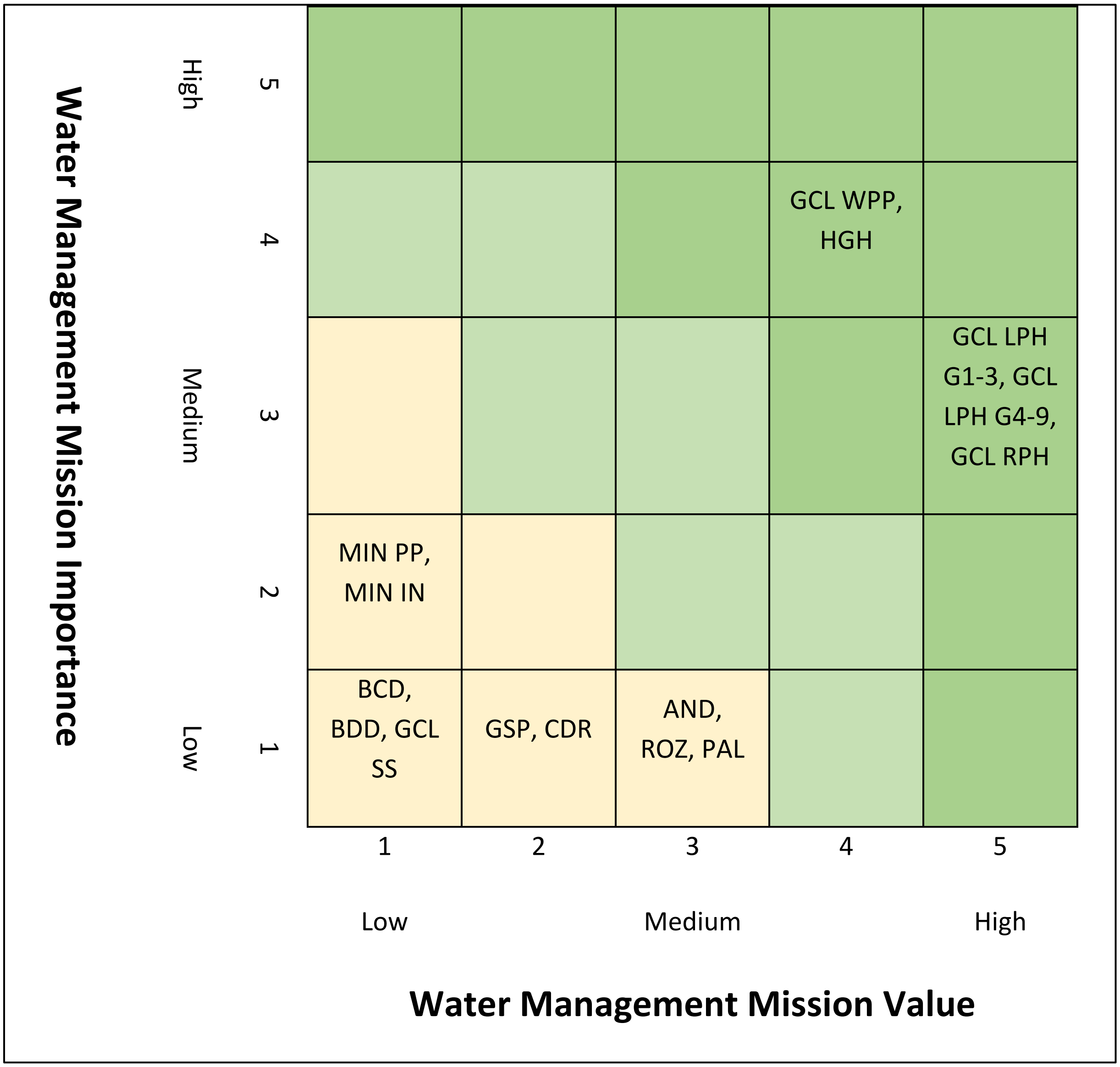
Figure 3.4.4.1-3, Reclamation Water Supply Project Mission Importance and Water Supply Mission Value

Water Supply Mission Importance		1 (Low)	2	3 (Medium)	4	5 (High)
High	5		GSP	ROZ, PAL		GCL LPH G1-3
	4					
Medium	3			AND		GCL RPH
	2	MIN IN	BCD		GCL WPP	GCL LPH G4-9
Low	1	BDD, MIN PP, GCL SS	CDR		HGH	

Water Supply Mission Value

Reclamation's Water Supply mission dates to the agency's inception and is focused on providing water to the arid west. Units higher in importance tend to be those directly required for pumping operations such as Grand Coulee LPH G1-3, water deliveries as GSP or have a large component of their annual generation contributing to a local Project Use Power (PUP) rate such as PAL and ROZ. Higher value units are those with a low cost of generation which makes the use of PUP beneficial for moving water across Reclamation Projects.

Figure 3.4.4.1-3, Reclamation Water Management Project Mission Importance and Water Management Mission Value



In general, most Reclamation units are lower in importance to the Water Management mission area as each facility has multiple methods to move water downstream. In most cases though, the hydropower units are the first and preferred way to move water at each facility and other methods (i.e. spillways, outlet works, etc.) are used secondarily. An exception being MIN where a current Biological Opinion (BiOp) dictates how much water is released from either the spillway or generators. Grand Coulee and Hungry Horse are the only facilities to rise above Medium importance. Grand Coulee attempts to avoid spill operations that can raise Total Dissolved Gas (TDG) within the river than can harm fish. Hungry Horse is High-Medium for having a selective withdraw system at the penstock inlets which can control water temperature downstream from the facility to keep in accordance with a current BiOp.

3.5 Strategy Duration

The analysis conducted in this SAMP covers a 50-year study period, primarily to capture the benefits associated with reinvestment in equipment in the hydroelectric facilities. However, the primary focus of this strategy and the associated System Asset Plan is on the first 20 years. This strategy is to be updated and reviewed every two years to align with the BPA IPR cycle.

4.0 STAKEHOLDERS

The FCRPS, with its unique three-agency partnership and multipurpose missions, has a wealth of stakeholders across the Pacific Northwest. The following sections describe the relationship of how the FCRPS is operated and funded and describes its stakeholders and expectations.

4.1 Asset Owner and Operators

USACE and Reclamation operate and maintain the dams while BPA markets and transmits the power they produce. BPA directly funds the power-related capital, operations, and maintenance costs of the two agencies through a series of Direct Funding agreements. There are four separate agreements:

- Reclamation capital costs, effective January 15, 1993
- USACE capital costs, effective December 6, 1994
- Reclamation operations and maintenance expense, effective October 1, 1996
- USACE operations and maintenance expenses, December 22, 1997

These agreements established the Joint Operating Committee (JOC), which is tasked with overseeing the implementation of the terms and conditions of the agreements, including the development of expense and capital budgets, coordination of operations, and performance metrics.

A Three Agency Executive Steering Committee (ESC) provides strategic direction to the hydropower program. Sub-committees of the JOC provide direct oversight of specific aspects of the responsibilities outlined in the agreements:

- Capital Workgroup (CWG)
- Asset Planning Team (APT)
- River Management (RMJOC)
- Cultural Resources (CRSC)
- Reliability Implementation Technical Subcommittee (RITS)
- Hydro Optimization Team (HOT)
- Technical Operations & Implementation Subcommittee (TOIS)
- Performance Committee

4.1.1 USACE and Reclamation Operated Transmission Assets

USACE and Reclamation operate a number of switchyards in the FCRPS including, Grand Coulee 500kV, 230kV, 115kV switchyards; Palisades switchyard; Minidoka switchyard; Hungry Horse switchyard; and Bonneville Powerhouse No. 1 rooftop switchyard. These switchyards provide a dual-purpose benefit to both BPA's Power Services and Transmission Services customers as they interconnect federal resources to the greater transmission network, and they support the operation of the high voltage transmission network in their respective geographic areas. This arrangement necessitates that both PS and TS account for these assets in their asset management planning, as well as pay for capital and expense costs associated with the switchyards.

As the assets are operated by USACE and Reclamation, Power Services supplies the total expense costs as they are spent, and directly funds USACE and Reclamation through the direct funding agreements indicated above. Similarly, Power Services supplies all funds to the Federal Treasury for debt service of these assets, and bonds with the treasury to secure capital funds, which PS then directly funds to USACE and Reclamation. Transmission Services' share of the capital debt service and expense costs are paid to Power Services through an inter-business allocation each year. Bonding for capital costs is coordinated between Power and Transmission Services. When investments in these assets necessitate a capital funding requirement, additional space is made available in Power Services' borrowing authority that year, which is offset by a decrease in Transmission Services' borrowing authority for that year. This process is known as the Transfer of Budget Authority.

BPA and Reclamation are proceeding on the transfer of the 500 kV, 230 kV, and 115 kV switchyards at Grand Coulee from Reclamation ownership to BPA Transmission. It is expected that this transfer will lead to an overall cost reduction for BPA through overhead savings on modernization investments, and reduction in O&M costs when BPA Transmission performs the work. Consolidating the role of transmission owner and transmission operator with BPA Transmission is also expected to improve compliance-related activities. The transfer took place in October 2024. There will be a five-year transitionary period as BPA preps the switchyards to BPA standards to take over operations and maintenance in a staged approach, switchyard by switchyard.

4.2 Stakeholders and Expectations

The FCRPS has a wide variety of stakeholders with expectations that can be both overlapping and conflicting. BPA, USACE and Reclamation must balance these varying expectations to cost effectively meet the region's needs.

Table 4.2-1, Stakeholder Expectations, Data Sources and Measures

Stakeholders	Expectations	Current Data Sources	Measures
BPA Power and Transmission	Unit Availability for generation and ancillary services	Outage Tracking System (OTS), hydroAMP, SCADA, PI, THOR, GDACS	Availability, Equipment Condition (hydroAMP), Generation Data
Canada	Columbia River Treaty Compliance	Columbia River Treaty	Assured Operating Plan, Detailed Operating Plan, Treaty Storage Regulations
Cultural Resources	Trusted Stewardship	FCRPS Cultural Resource Program, Colville Payment, Spokane Payment	Cultural Resources KPIs, Colville Payment Data, Spokane Payment Data
Fish and Wildlife	ESA-Listed Fish Populations	USACE, USFWS, and NOAA Fish Monitoring	Fish Counts, SARs (Smolt to Adult Returns, Juvenile Travel Time, Performance Standards for juvenile Dam Passage Survival)
Irrigation Customers	Unit Reliability	Sub-agreements, Annual Power Budget, hydroAMP, Reclamation PO&M database	Equipment Condition (hydroAMP or USACE Operational Condition Assessments)
Navigation Customers	Joint Funding for USACE Investments	Sub-agreements, Annual Power Budget	Equipment Condition (hydroAMP or USACE Operational Condition Assessments)
NERC/WECC	Comply with Regulations	USACE and Reclamation Systems	Reliability Metrics (Standards Compliance, Inherent Risk Assessments)
Northwest Power and Conservation Council	Pursue Actions in The Northwest Power Plan	White papers, analysis results and documentation	Report out to the Council on analysis and results.
Power Customers	Economical Rates	Integrated Program Review, Long Term Rates Forecasts	Tier 1 PF Rate forecast from Reference Case and LTRF Scenarios
	Reliability	OMBIL (USACE), PO&M (Reclamation)	Availability Metrics (Weighted Scheduled Outage Factor, Weighted Forced Outage Factor)
Public	Safety	USACE/Reclamation Dam Safety Programs	Operational Condition Assessments
	Recreation	THOR, USACE Reservoir Control Center	Rule Curves, Elevation Data
USACE and Reclamation	Direct Funding	Sub-agreements, Annual Power Budget	Capital and Expense Expenditure Rates, Equipment Condition (hydroAMP)
	Safety	USACE and Reclamation Safety Management Systems	Safety Metrics (Lost Time Accident Rates, Days Away, Restricted or Transferred, Total Case Incident Rate)
	Employee Satisfaction	Human Resources Databases	Turnover statistics, surveys
Water Quality	Water Quality – Temperature	USACE and Reclamation Monitoring Systems	State Water Quality Standards
	Water Quality – Total Dissolved Gas	USACE and Reclamation Monitor Systems, Fish Passage Center Smolt Monitoring Program	State Water Quality Standards, Gas Bubble Trauma Incidences
	Water Quality - National Pollutant Discharge Elimination System (NPDES) Permits	USACE and Reclamation Monitoring Systems	NPDES requirements, Oil Accountability Measures

5.0 EXTERNAL AND INTERNAL INFLUENCES

Table 5.0-1 details the most critical external and internal influences on FCRPS assets and the ability to meet the missions and objectives of the Three Agencies. The table describes how each influence affects the FCRPS and presents actions that have been taken or are planned in response. An emerging issue in the 2022 SAMP was the supply chain and labor shortages resulting from the pandemic. Both presented new challenges to delivering on asset management objectives that continue into 2024.

Table 5.0-1, External and Internal Influences

External Influences	Affects and Actions
Customers	Customers continue to encourage that BPA, USACE, and Reclamation to find ways to control spending and make the most efficient, economic investments. The AIEI began in 2015 to improve the selection, optimization, and execution of large capital expenditures. These processes are now established and continue to mature. USACE developed the Operations and Maintenance Optimization Initiative (OMOI) in 2019. The OMOI evaluated the value that USACE hydropower assets produce as well as their importance in supporting the multipurpose missions of the facilities. This information will drive changes in the operations and maintenance program as it is optimized. Reclamation completed a similar exercise known as the Reclamation Hydropower Value Analysis in 2023. Under the new FCRPS asset management structure described in Section 6.3.1, the Three Agencies will strive to integrate this new information into our asset management practices over the coming years.
Energy Markets	BPA's rates are impacted by the ability to market surplus generation produced by the FCRPS. Energy markets have experienced significant volatility in recent years, influenced by the pandemic, extreme weather conditions, and global crises. This contrasts with the energy market outlook in the 2010s that was characterized by historically low prices due to an abundant supply of cheap natural-gas powered resources and renewables. Looking to the future, carbon taxes could make carbon-free FCRPS hydropower an even more attractive product. BPA's entrance into the EIM provides new opportunities to take advantage of FCRPS flexibility. BPA is further exploring new market opportunities by being actively engaged in SPP's Markets+ day-ahead and real-time market initiative as well as the California Independent System Operator's Extended Day-Ahead Market (EDAM) initiative. While many of these future conditions are uncertain, the FCRPS attempts to model uncertainties to inform the design, timing, and extent to which FCRPS facilities are modernized to support future operations.
Energy Policy	In addition to electricity generation, the FCRPS provides ancillary services that help keep the power system stable and integrate sources of renewable generation. Unlike the robust ability to trade energy products, BPA has historically not had a way to effectively market these ancillary services. The Department of Energy's long-term National Hydropower Vision has called out the need to establish markets that allow hydroelectric generators to receive revenue for the value they can inherently provide to the grid such as voltage and frequency stability, reliability, and renewable energy integration. BPA's entrance into the EIM has allowed it to capture more of the flexibility value that the FCRPS provides. However, many ancillary services are still believed to be undercompensated.
Fish Operations and Mitigation	The Proposed Action consulted upon with NMFS and USFWS, as altered by the Term Sheet for Stay of Preliminary Injunction Motion and Summary Judgment Schedule (referred to as the 2022 Agreement) and the Resilient Columbia Basin Agreement (MOU signed December 14, 2024) for the *NWF et al. v. NMFS et al.* (3:01-cv-00640-SI) litigation, and the Fish Passage Plan mandate spill, flow, temperature, total dissolved gas and other operational requirements for FCRPS facilities. These requirements have impacts on the amount of water and operational flexibility available for power generation. To improve conditions for fish passage, investment in new systems, reinvestment in existing systems, and operational changes may be required. Improved fish passage turbine design has the potential to reduce impacts to power generation in the future if positive biological performance leads the region to agree upon strategic fish screen removal.
Interdepartmental Challenges	The three agencies that make up the FCRPS are part of three separate departments of government. Each is subject to their own policies, regulations, codes, and requirements driven by each department's respective headquarters. This can present challenges to project planning, procurement, and other asset management activities. From a national perspective, hydropower generation is not the core mission of USACE or Reclamation which are part of the Department of Defense and Department of the Interior, respectively. The agencies must operate within their respective regulations, policies and procedures which are not necessarily tailored to operating a commercial hydropower utility. As a result, there are inherent inefficiencies in how the FCRPS operates compared to an integrated utility whose missions are more narrowly focused on power production, transmission, and delivery.

External Influences	Affects and Actions
Intermittent Renewables Integration	Integrating renewable resources such as Wind and Solar has presented a challenge to the system, resulting in operations that were not anticipated in their original design. Increased starts and stops, frequent ramping, and operating in or passing through rough zones are potentially increasing the risk of failure and reducing the lives of generating units, spillway gates, and other assets. Across the industry, the impacts on unit reliability are not well understood. Continued participation in industry forums and further analysis as more data become available should improve the ability to quantify these impacts. As assets undergo rehabilitation and replacement, there is an opportunity to align designs with expected future operational needs.
Joint Asset Condition and Appropriations	BPA funds the power share of a portion of the non-power specific assets ("Joint Assets") at FCRPS facilities. The power shares were originally set by Congress when the plants were authorized and were intended to be proportional to the benefits received by each authorized purpose of the facility. Approval and execution of work is contingent on USACE and Reclamation receiving appropriations from Congress. The uncertainty in the federal appropriations process makes integration of Joint assets with the rest of the FCRPS System Asset Plan difficult. The FCRPS may not be able to execute the right projects at the right time if appropriations are not available. Completing the Joint asset inventory and refining how Joint assets are valued will lead to better communication between the agencies around planned joint work and may improve USACE and Reclamation's ability to receive appropriations.
Labor Shortages	USACE and Reclamation have identified some delays in projects due to shortages in skilled labor. These shortages are reflective of overall trends in the US workforce where unprecedented numbers of individuals throughout the country are changing jobs or leaving federal service. The Three Agencies have identified that the availability of more flexible remote work opportunities has contributed to departures. Together, these impacts have created gaps in areas that were already a recruiting challenge.
Load Growth/Changes in Load Characteristics	The 2023 Resource Program notes that BPA is expected have annual energy deficits in all years in the study period. Although it was determined that BPA can rely on market purchases and conservation to meet system needs, efficiency and capacity improvements on existing turbine units were not included in the baseline for Resource Program. These upgrades can help reduce pressure on the energy deficits at little to no incremental cost while the units undergo modernization. Power Services are working to include forecasts of future turbine improvements in future resource programs.
Manufacturer Support	Manufacturers ending support for equipment, especially digital equipment, is leading to extended outages and higher operations and maintenance costs. FCRPS staff are investigating how to reflect this impact in asset planning models and some changes have already been implemented to capture these risks.
NERC/WECC Regulation	Generation facilities are required by NERC, CIP, and WECC to undergo testing to ensure that they are in compliance with reliability standards. Increasing reliability requirements have resulted in increased operations and maintenance costs, primarily from the necessity to hire staff to oversee regulatory compliance programs. Additionally, physical and cyber security requirements continue to expand requiring more time and investment.
Supply Chain Issues	Global supply chain issues that emerged with the pandemic and have continued to persist are affecting project costs and schedules. Dramatic increases in the price of steel have led to significant cost increases in FCRPS investments in recent years. Various supply shortages have also resulted in project delays due to long lead times. Short-term expectations are actively being revised in the System Asset Plan and staff are evaluating how to better handle these issues in the mid-to-long term.
Water Supply/Climate Change	Changing weather conditions and the resulting changes in water supply create a degree of uncertainty unique to hydropower production. Between years, the difference in energy production from FCRPS can vary by several thousand average megawatts. This presents unique challenges to managing the entire portfolio of power supply needed to meet the demands of BPA customers. Climate change poses additional uncertainty in future energy production in the form of a changing runoff shape. This translates into greater Heavy Load Hour energy deficits in the late summer due to decreased snowpack as well as reduced deficits in the winter due to warmer temperatures and reduced winter loads.

Internal Influences	Affects and Actions
Asset Condition	About 34% of FCRPS assets are in Marginal or Poor condition as shown in Section 8.3.2. This percentage is expected to increase over the next ten years, even with significant investment in the system. This suggests that the likelihood of unit outages may continue to increase. To effectively manage risk over the next ten years, investments will primarily target the equipment in Marginal and Poor condition that present the most risk to the system and deliver the highest value.
Horizontal Alignment	In addition to the departmental differences between the Three Agencies, horizontal alignment across the Three Agencies at a local level can be a challenge given each agency's unique missions. The systems currently in place and the continued evolution of asset management across the FCRPS are intended to mitigate these horizontal differences and improve alignment over time.
New Technologies	New technologies have the capability to reduce future costs or increase revenues, improving the viability of the FCRPS. Through improvements in turbine design since original construction, turbine replacements have provided efficiency improvements in the range of 3 to 6 percent in the FCRPS. Improved fish passage turbine design has the additional benefit of potentially improving fish passage and allowing for strategic fish screen removal. This would not only relieve the need to replace deteriorating fish screens but would remove generation limitations at some plants.
Powerhouse Characteristics	Due to the inherent characteristics of the plants (number of units, unit rating, transmission system support, location within the river system, storage capability, etc.), unit reliability is more important at some plants than others. While plants are undergoing rehabilitation and replacement, it makes sense to evaluate the potential for unit uprates at plants that have low powerhouse capability relative to total plant flow to reduce the risk of future unit outages. Equipment in these plants should be prioritized ahead of equipment in plants that have a relatively low impact to unit outages due to excess powerhouse capacity.
Remote Locations	Many FCRPS facilities are located in remote locations and it is becoming increasingly difficult to attract new employees to them. Retention at remote facilities has proven a challenge in recent years with staff taking positions closer to larger cities as they gain experience. Many qualified engineers are also staying in larger cities and taking remote work positions instead of working in remote plants. A special salary rate was implemented in 2019 for engineering positions that work directly with hydropower as an aid in retention of qualified and uniquely trained employees. Challenges have persisted into 2023, however, with increased housing costs near FCRPS facilities emerging as another barrier to attracting new employees.
Retirements	With a large portion of FCRPS staff nearing retirement eligibility, considerable amounts of powerplant design, operations, and maintenance knowledge are at risk of being lost. The FCRPS is attempting to preserve this knowledge through the Hydropower Apprenticeship Program, Hydropower Intern Program, Engineer Intern Program as well as through the documentation of maintenance activities with video recordings and written instructions.
Unit Reliability	Unit reliability improvements are made to reduce the impacts of unit failure. These can be financial, safety, or environmental impacts, but can also affect public perception, employee satisfaction, and the ability of the FCRPS to comply with regulations. The FCRPS asset planning capabilities provide a common framework to evaluate and optimize these risks within constraints to deliver a portfolio that maximizes the overall value of investment (maximizing benefits and risk mitigation for all Three Agency missions for the portfolio as a whole).

5.1 SWOT Analysis

Table 5.1-1 evaluates the Strengths, Weaknesses, Opportunities, and Threats (SWOT) for the FCRPS.

Table 5.1-1: SWOT

Favorable	Unfavorable
Strengths	***Weaknesses***
• **Hydropower Generation:** The FCRPS provides an average of 76 million megawatt-hours of hydro power energy production per year, which may make FCRPS power valuable to utilities and businesses looking to diversify their energy mix. • **Flexible and Dispatchable:** The FCRPS can quickly ramp up and down as required to balance moment-to-moment changes in the load-resource balance. This capability is critical for the reliable integration of non-dispatchable forms of renewable energy, such as wind and solar, and ensuring system reliability during extreme weather events or when generators unexpectedly drop offline. • **Black Start Capability:** Unlike most generating resources, some FCRPS units can "black start" without an external power source. In the event of a powerplant or system-wide blackout, these units can quickly restore power to the plant and begin restoring the grid. • **Cost Effective and Competitive:** FCRPS facilities take advantage of economies of scale to produce an abundance of power at a low relative cost. The FCRPS is a first quartile performer among the 12 utilities benchmarked in the EUCG Hydro Productivity Committee for total cost per MWh. With a 50-year levelized cost of generation of \$13.41/MWh and all-in costs of \$24.29/MWh the FCRPS is more affordable than other utility-scale renewable alternatives. Levelized cost estimates for renewable resources range from around \$30/MWh to over \$100/MWh depending on the resource and lack the flexible and dispatchable services that the FCRPS provides. • **Three Agency Collaboration:** The Three Agency FCRPS collaboration brings a wide range of expertise that leads to more robust, positive outcomes than a "one agency" silo approach. • **Asset Management Capabilities:** The FCRPS employs sophisticated asset management tools to optimize capital investment plans and develop the best investment alternatives.	• **Environmental Impact:** The original construction of FCRPS dams impacted fish, wildlife, and cultural resources. Mitigation continues to this day to offset the impacts of the system, but public perception of hydropower still suffers relative to other renewables such as solar and wind. • **Weather Dependence:** The FCRPS has less water storage compared to other basins in North America. Annual generation is highly dependent on within year precipitation, snowpack, temperatures, and runoff. • **Compensation for Ancillary Service:** The FCRPS, like many hydropower producers, has historically been undercompensated for the grid reliability services it inherently provides. There is currently no standard way to quantify the contributions hydropower provides for grid stability and services like voltage support are not marketed in current markets. The increased reliance on the FCRPS to balance variable generating resources may also be contributing to increased wear-and-tear on equipment. • **Shared Resources and Multiple Missions:** Hydropower is just one of the many multi-purpose missions that FCRPS dams support. While the FCRPS is a very flexible resource, it operates within constraints that a typical generating resource does not face. As a result, the Three Agencies spend considerable time and effort coordinating the system to balance shared resources to meet statutory obligations and agency missions. • **Cross-Agency Challenges:** While the Three Agency collaboration provides many positives, there are inherent challenges with Asset Management and operational activities being spread across three different departments of the US government. Each department and agency have their own respective regulations, policies, and statutes within which they must operate. Many of these policies are written at the departmental level, meaning they were not specifically written with the FCRPS, or even operating dams, in mind. Each agency also has their own agency-level strategic priorities and initiatives that need to be coordinated and ultimately aligned with the SAMP. Additionally, IT restrictions across agencies present challenges in efficiently sharing data and collaborating on projects.

Favorable	*Unfavorable*
Opportunities	***Threats***
• **New Market Opportunities:** BPA has been engaged in two market initiatives underway in the West. The California Independent System Operator's Extended Day Ahead Market and Southwest Power Pool's Markets+ may provide opportunities to enhance the delivery of carbon-free FCRPS power. In the Spring of 2024, BPA staff recommended joining Markets+, citing its positive economic benefits for BPA. • **Efficiency Improvements:** Replacements to improve unit reliability provide the opportune time to increase efficiency or capacity of units at little incremental cost. • **Fish Passage Improvements:** New turbine designs have focused on improving fish survival through the units. There is potential for removal of fish screens in the future. In addition to avoiding replacement costs for fish screens that are nearing the end of their useful lives, annual installation and removal costs would also be avoided and many units would see an increase in efficiency. • **Optimizing Plant Configuration:** During powerplant modernization projects, the design, capacity, number of units, and possible future standardization of components can be evaluated given the expected future operating environment. Rightsizing and standardizing equipment at the powerplants can reduce long term capital and O&M costs while increasing efficiency. • **Three Agency Expertise**: The Three Agencies have a broad field of expertise across the nation from which data and information can be gathered to inform lifecycle cost models and asset management decisions. • **O&M Optimization:** Taking advantage of condition monitoring equipment, asset performance management systems, subject matter expertise, and other analysis tools could lead to more cost-effective O&M decisions. Pilot programs are currently underway at USACE and Reclamation facilities. • **Knowledge Transfer and Training:** Developing and maintaining competencies for FCRPS staff can reduce future outage times and costs if more work can be performed in-house. USACE and Reclamation hydropower training and apprenticeship programs aim to maintain these competencies at FCRPS facilities. • **Hybridization:** Pairing battery energy storage with hydro facilities could provide operational flexibility, reduce wear-and-tear on hydropower assets, and expand alternatives for turbine replacement. Pacific Northwest National Labs (PNNL) is currently performing studies to determine the viability if using battery energy storage solutions with hydropower.	• **Climate Change:** Changes in weather patterns, specifically with more precipitation falling as rain than snow, may present challenges to operations and flexibility in the future. • **Dam Breach:** There is continued pressure to breach the four lower Snake River dams to support recovery of four species of ESA-listed salmon and steelhead. Breaching the dams would result in significant regional reliability, peaking capacity, and ramping capability impacts unless replacement resources are acquired and installed. The costs associated with reliably replacing the services provided by the lower Snake River dams could result in significant rate increases for BPA's customers. • **Rate Pressures:** Pressure to keep rates low has constrained operations and maintenance budgets. In addition to long term impacts on reliability, collecting information needed to make asset management decisions may be impacted depending how activities are prioritized. • **Fish Infrastructure Costs:** New requirements may result in the construction of new structures to support fish passage. The cost of these complex structures could have adverse impacts on the economic viability of some FCRPS facilities, specifically in the Willamette Valley. • **Operational Changes:** Changes in operations to support fish passage could result in more spill, less hydropower production, and less flexibility. These operations cause spillways and generating units to be used in ways that were not foreseen when originally designed, potentially resulting in faster condition degradation. • **Industry Experience Loss:** Loss of experienced staff at FCRPS facilities, and in the industry in general, is leading to increased outage durations and costlier repairs. Original documentation is lacking for some plants which has required reverse engineering and even tracking down the long-retired original designers. • **Supply and Procurement:** Global supply chain challenges and market conditions are affecting procurement of hydropower equipment. This is impacting short term work, creating delays that could impact generation, safety, and environmental compliance. Outage durations due to equipment failure are expected to be longer than in the past due to longer procurement times. • **Zebra and Quagga Mussels:** Quagga mussel larvae were recently discovered in the Snake River in Idaho for the first time. While FCRPS assets are not currently affected, an established mussel colony could lead to costly increases in maintenance and changes in operations to mitigate their impacts.

6.0 ASSET MANAGEMENT CAPABILITIES AND SYSTEM

BPA, USACE, and Reclamation began developing an asset management program in the late 1990s coinciding with the signing of the direct funding agreements. The Three Agencies developed the first FCRPS asset management strategy in 1999, responding to direction from Congress to develop an integrated capital investment strategy[1]. It called for the development of a strategy that maximizes the value of the FCRPS through, "assessing the condition of the system, comparing it to industry benchmarks, identifying investments, evaluating cost effectiveness, and undertaking actions that increase reliability and enhance revenues." With many of the processes and systems called for by the 1999 asset management strategy now in place, particularly with respect to capital investment, much of the original vision has been realized. However, with advancements in asset management practices in recent years, there are still opportunities for refinement and improvement.

BPA adopted the Institute of Asset Management (IAM) model for Asset Management agency-wide. The IAM provides guidance for developing and implementing an Asset Management program compliant with ISO 55000, the international standard for Asset Management. None of the three agencies are currently considering ISO 55000 certification but are instead using the IAM model as a guideline.

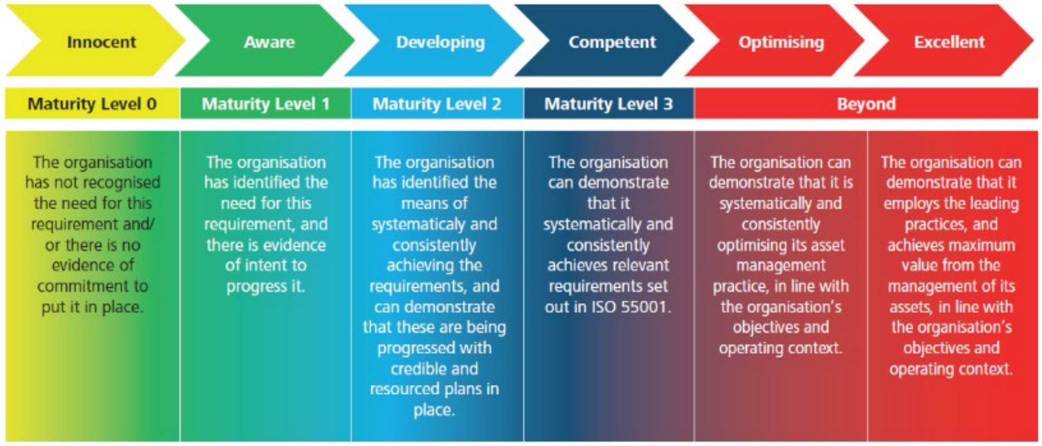
In addition to guidelines for ISO 55000 implementation, the IAM provides a maturity assessment model to assess the asset management maturity of an organization relative to ISO 55000 and IAM guidance. The IAM model focuses on six subject areas shown in Figure 6.0-1.

Figure 6.0-1, ISO 55000 Subject Areas

The IAM maturity assessment has 39 questions spanning the subject areas with each question assessed on a scale from 0 to 5. A description of the IAM maturity levels is shown in Figure 6.0-2.

[1] S. Rept. 105-206 - ENERGY AND WATER DEVELOPMENT APPROPRIATION BILL, 1999

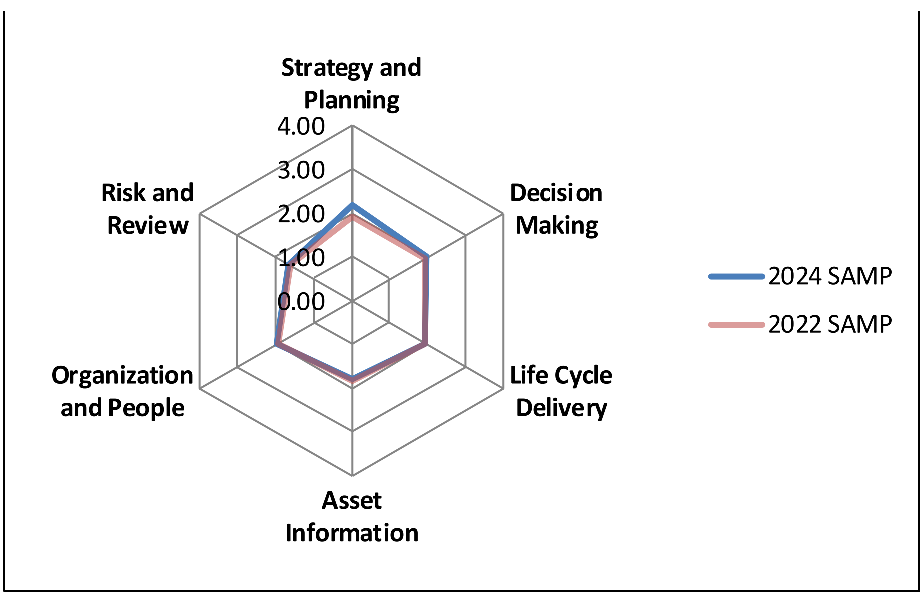
Figure 6.0-2, ISO 55000 AM Maturity Levels



A simplified survey based on the IAM Maturity Model was sent to individuals across the FCRPS in 2019. In total, there were 117 respondents across USACE, Reclamation, and BPA with a range of disciplines and years of experience.

Results from the 16 simplified questions were mapped back to the 39 IAM questions to complete Table 6.1-1 in the 2020 SAMP. For the 2024 SAMP, a smaller team of FCRPS asset management staff reviewed previous assessment results and updated scores based on progress made in recent years. With progress made on objectives described in Section 6.2, the team assessed Strategy and Planning to have improved in maturity since the 2022 SAMP. Remaining subject areas were relatively unchanged. A new FCRPS-wide survey is planned for 2024 to set the direction for the next 5 years.

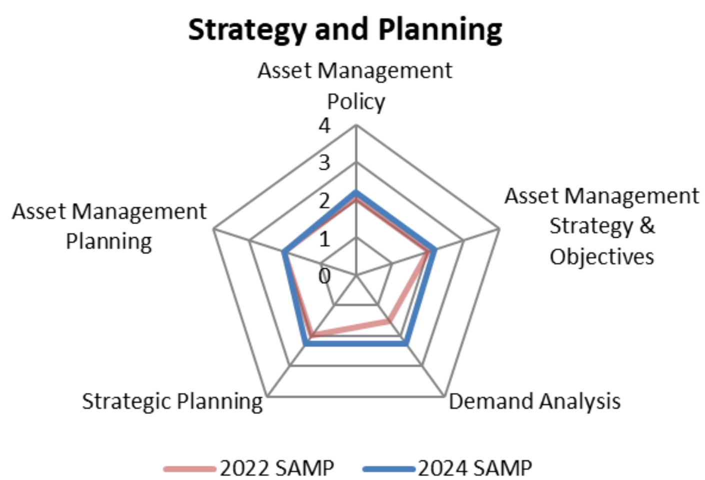
Figure 6.0-3, FCRPS AM Maturity Mapping 2022 to 2024



On average, FCRPS asset management is still in the developing phase with most subject areas having an average score near 2. Some areas of Strategy and Planning and Decision Making, specifically related to capital investment, exhibit many elements of level 3 (competent) maturity. Increased integration between capital and expense, fully incorporating the results of the USACE and Reclamation demand analyses, and continued collaboration between the Three Agencies on SAMP development will pull the FCRPS closer to level 3 maturity. Each of these elements are addressed by an objective in Section 6.2. Risk and Review is the least mature subject area as the Three Agencies are still working towards a shared understanding of risk. Table 6.1-1 describes the strengths and weakness for each subject area in more detail.

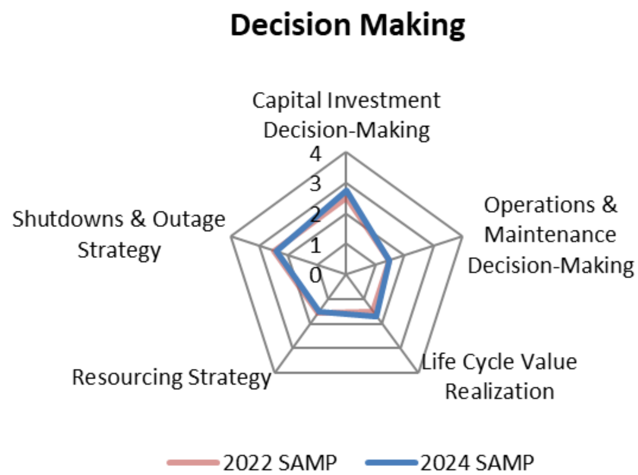
6.1 Current Maturity level

Table 6.1-1 Maturity Level

Subject Area	Maturity Level
Strategy & Planning	**Average Maturity**: 2.2 (Developing)  **Strengths:** Although the average results for most subject areas were just above Level 2 (Developing), FCRPS Asset Management processes possess many elements of Maturity Level 3 (Competent). Asset Management objectives are outlined and coordinated with Three Agency objectives. A structured approach is in place to develop Asset Plans in an iterative way that combines top-down direction with bottom-up assets needs. Investments in the asset plan are optimized using an agreed upon methodology documented in this SAMP. **Weaknesses:** Horizontal alignment, line-of-sight, and integration with human resources and procurement are the major factors holding the FCRPS back from Level 3 (Competent). The survey conducted in 2019 made it clear that an understanding of the SAMP and Asset Plans are not ubiquitous throughout the Three Agencies, especially in the field. Human resources and procurement also present a challenge as these functions at USACE and Reclamation are not specific to the FCRPS and must abide by federal policies and regulations as well as those of their respective department and headquarters. The policies and regulations of the Department of Defense and the Department of the Interior differ from each other and were not created with the strategies and plans of the FCRPS in mind. **Changes since 2022:** USACE and Reclamation completed demand analyses describing the importance of assets to their non-hydropower missions. The FCRPS is now determining how to integrate these results into strategies and plans. Coordination on the SAMP has increased with individuals across the Three Agencies tasked with collaboratively authoring the document.

<table>
<tr><th>Subject Area</th><th>Maturity Level</th></tr>
<tr><td>Decision Making</td><td>

Average Maturity: 2.0 (Developing)



Strengths: Capital Investment Decision Making and Life Cycle Value Realization contain many elements of Level 3 (Competent). For capital investment planning, a maturing process is in place to identify, plan, and execute investments such that the strategic goals are met. Capital Investment plans are developed through an understanding of asset criticality which evaluates risk throughout an asset's lifecycle. This understanding of risk, in addition to an assessment of the benefits and costs of an investment, are then used to optimize the capital investment plan and seek to maximize the value of the FCRPS. These methods are applied across all large capital investments in the FCRPS.

Weaknesses: Maintenance at FCRPS facilities is primarily performed in standard periodic cycles and not fully informed by equipment condition or risk. Maintenance data is inconsistent across the FCRPS, ease of access to documented maintenance data and sharing of this data is challenging and limited. These areas are under evaluation as part of the Operations and Maintenance Optimization Initiative. Decision Making for both capital and non-routine expense is primarily based on deterministic analysis, with some stochastic elements incorporated into major investment decisions. Mentioned in the Strategy and Planning weaknesses, the resourcing strategy is not yet well integrated with the SAMP, which is one of the reasons that the Asset Plan has been difficult to execute. Efforts are ongoing between the Three Agencies for improved and more consistent procurement practices.

Changes since 2022: Capital Investment decision-making continues to make improvements to achieve level 3 competency. New optimization processes and a project approval decision tree were implemented in FY23 which led to an increase in capital investment decision making maturity.

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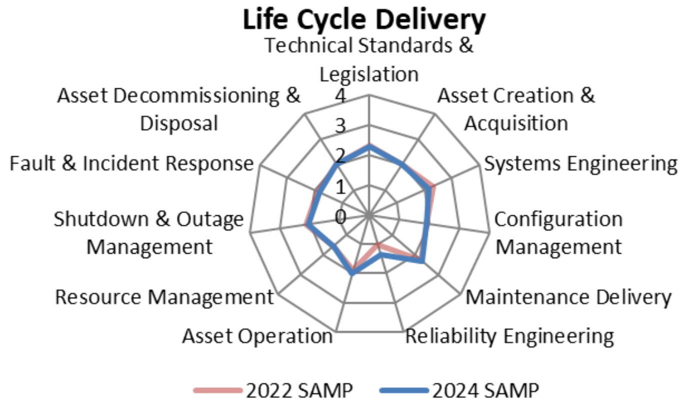
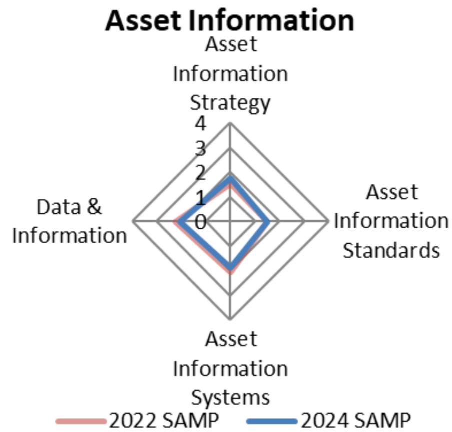
Subject Area	Maturity Level
Life Cycle Delivery	**Average Maturity**: 2.0 (Developing)  **Strengths:** Technical Standards & Legislation, Systems Engineering, and Maintenance Delivery had highest scores within the life cycle delivery. The USACE Hydroelectric Design Center (HDC) and Reclamation's Technical Services Center (TSC) are the centers of design and engineering expertise for their respective agencies. These organizations establish standards for their respective agencies. Reclamation maintains a series of manuals that are used by hydro utilities throughout the world called the Facilities Instructions, Standards and Techniques (FIST) manuals. These manuals have information on hydro plant operations, mechanical, electrical, and general maintenance, safety, and facility management. The FIST manuals also set standards for preventive maintenance intervals for most assets. Some areas of the FCRPS have elements of maturity level 3 (competent) but maturity varies from plant to plant. **Weaknesses:** Lifecycle delivery had the lowest response rate of any subject area from the broader survey conducted in 2019, suggesting that visibility throughout the Three agencies is low. While reliability engineering remains low, USACE and Reclamation developing competencies in this area. Current maintenance practices are time-based and all units within a powerplant are generally treated the same. Standardized and regularly updated operational strategies based on asset condition could extend the operating life and reduce maintenance and outage costs. Resource management, specifically procurement, was found to be one of the weakest areas in the 2019 survey. Usage, movement history, and repair cost information were identified as gaps for consumable and spare parts. The lack of a procurement and supply chain management strategy was also identified. Best practices and lessons learned are not consistently tracked or captured. **Changes since 2022:** Reliability Engineering increased from a 1.0 to 1.3 reflecting that plans are developing for more robust reliability engineering practices. The Asset Reliability Team discussed in Section 6.3.1 is intended to coordinate these activities across the FCRPS and provide condition-based and predictive maintenance recommendations. As those positions are filled, maturity is expected to progress closer to level 2 maturity.

<table>
<tr><th>Subject Area</th><th>Maturity Level</th></tr>
<tr><td>Asset Information</td><td>

Average Maturity: 1.8 (Developing)



Strengths: A common framework, hydroAMP, is used to inventory and assess asset condition. The hydroAMP condition assessment framework was originally developed by USACE, Reclamation, BPA, and Hydro Quebec and has become the de facto industry standard for hydro equipment condition assessment. Over 10,000 assets are currently inventoried. Nearly all equipment defined as Powertrain and Critical Auxiliary components are inventoried and assessed on a regular basis.

Weaknesses: Although guidelines exist for asset information through hydroAMP, formal FCRPS asset information strategies and asset information standards do not exist. Development of BPA's asset information strategy can be leveraged by the Three Agencies and adapted to the FCRPS. A hydroAMP data review process exists to improve consistency, completeness, and recency of condition assessments but the process is still maturing. Asset Information is not directly integrated with performance information or failure data. Balance of Plant assets are inconsistently inventoried across facilities and standard assessment intervals are not aligned with criticality. Personnel tasked with hydroAMP assessments are often also tasked with other duties that take a higher priority. Increased regulatory requirements have reportedly impacted time spent on hydroAMP condition assessments.

Changes since 2022: There are no material changes since 2022 and differences represent minor changes in averages across the agencies.

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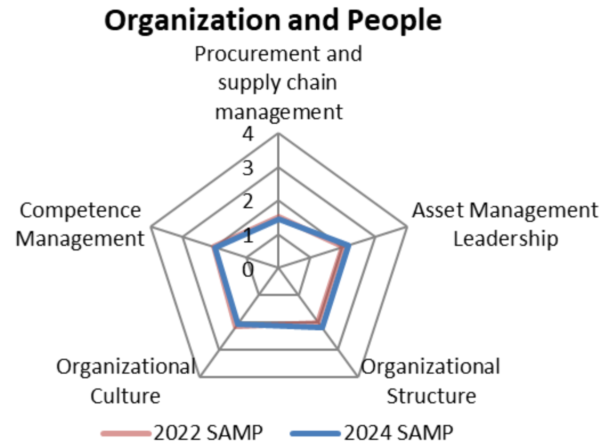
<table>
<tr><th>Subject Area</th><th>Maturity Level</th></tr>
<tr><td>Organization & People</td><td>

Average Maturity: 2.0 (Developing)



Strengths: From the 2019 assessment, about 70% of respondents were split evenly between 2 (Developing) and 3 (Competent). This suggests that most respondents recognize how they fit into their organization, are committed to achieving the goals and objectives of the Three Agencies and understand the need for collaboration. Training and Competence appears to be strong in some areas and developing in others.

Weaknesses: About 20% of the 2019 respondents selected that they were unsure how their role supports leadership's vision and goals. Although the majority responded with higher levels of maturity, this suggests that there are areas of our business where the Asset Management vision has not been effectively communicated. This reflects the Three Agency structure and the structures within the Three Agencies that makes implementation of a coordinated SAMP challenging. Obtaining the resources needed to complete tasks in a timely manner is also seen as an issue. This has contributed to the under execution of the Asset Plan.

Changes since 2022: The team assessed some improvements in Organizational Structure and Asset Management Leadership. Since 2022, progress has been made on objectives in 6.3, including making progress on building out the FCRPS Asset Management team. This included hiring the Asset Management Program Manager that coordinates FCRPS Asset Management activities and USACE/Reclamation strategic planners that contribute to SAMP development.

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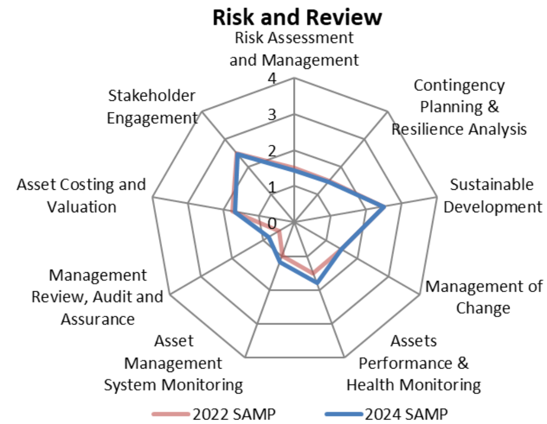
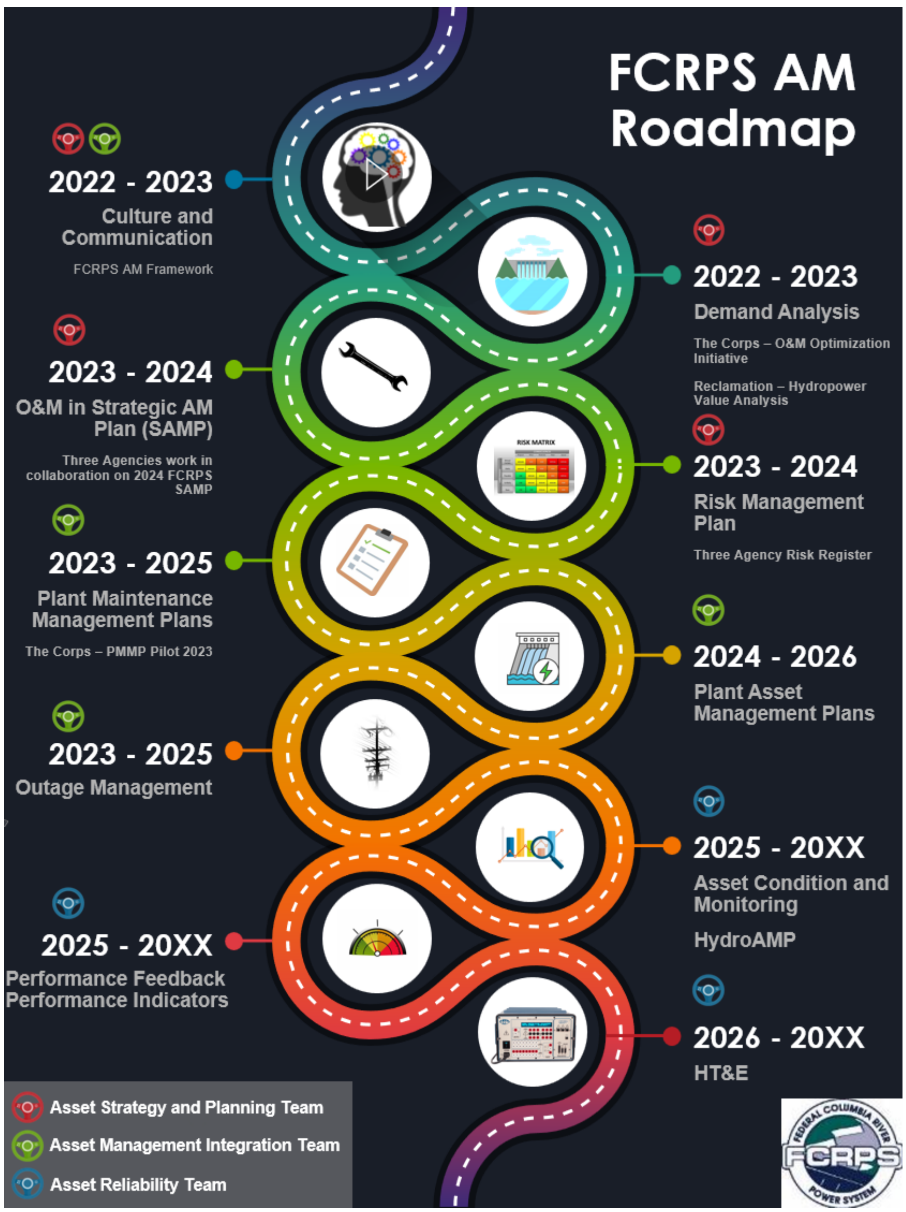
Risk & Review	**Average Maturity**: 1.7 (Developing) **Strengths:** Stakeholder engagement is a relatively mature process. FCRPS leadership has hosted roadshows at FCRPS plants, districts, and area offices to talk about BPA's Strategic Plan and how it influences FCRPS Asset Management decisions. FCRPS leadership and staff regularly inform stakeholders such as the Public Power Council about current performance and the status of FCRPS initiatives.  **Weaknesses:** Scores in risk and review were the lowest among all subject areas. Much of this stems from Asset Management activities being spread across the three agencies. Each of the agencies also have their own risk policies, appetites, and tolerances for their respective missions. While many of the activities described in the Risk and Review subject areas exist, they are not necessarily coordinated under the FCRPS Asset Management system. **Changes since 2022:** Minor changes are the result of increase in overall average from respondents.

6.2 Long Term Objectives

Based on a review of the 2019 maturity assessment, FCRPS leadership created two focus areas for improvements in Asset Management. These focus areas looked to improve our Asset Management culture and communication as well as the quality and scope of our strategies and plans. Although not the lowest scoring measures in the maturity assessment, both focus areas are foundational to Asset Management and are areas in which all three agencies collaboratively contribute to success. Asset Management staff from each of the agencies worked with FCRPS leadership to develop a series of objectives to improve maturity between FY21-FY25 within these focus areas. Sections 6.2.1 and 6.2.2 describe each objective, outcome, and current target status. As we are nearing completion of the original five-year roadmap, FCRPS Asset Management staff and leadership will discuss new focus areas and objectives in FY24 and FY25 for inclusion in the next SAMP.

Figure 6.2-1 FCRPS AM Roadmap



6.2.1 Asset Management Culture/Communication

Goal: Effectively communicate the FCRPS strategic objectives to improve line-of-sight throughout the Three Agencies.

Objective	Beginning State in 2020	Outcome	Target
1.1) Improve literacy of Asset Management principles among the workforce	Awareness of Asset Management principles, including the broader context of FCRPS strategic direction, is mostly limited to those directly involved in asset management.	Establish storage location for FCRPS documents that is accessible to all three agencies.	Completed in FY22
		Identify FCRPS positions that require IAM or similar training.	Completed in FY22
		Set training targets and coordinate Asset Management trainings.	FY24
1.2) **Update FCRPS Strategic Objectives with Three Agency collaboration and Executive engagement**	FCRPS strategic objectives have been the same for nearly 20 years. Awareness of objectives is low throughout Three Agencies.	Three Agency review of FCRPS strategic objectives. Include revisions, omissions and/or additions in 2022 SAMP.	Completed in FY22
1.3) Document and disseminate decision making processes for O&M and capital	Capital and O&M decision making processes are not understood by all stakeholders, including USACE and Reclamation employees at the plants.	Document capital project lifecycle and develop decision tree for capital project approval.	Completed FY23
		Document decision making processes in FCRPS AM Framework.	Completed FY23 but ongoing Three Agency discussion may result in changes
1.4) **Create more avenues for leadership to communicate priorities**	Line-of-sight is not always clear, especially between the Three Agencies. Some FCRPS employees can't see how day-to-day activities support mission/leadership direction.	Develop FCRPS communication plan.	Draft complete FY23 but ongoing Three Agency discussion may result in changes
1.5) Review/improve Asset Management governance processes	Review and approval of SAMP and Asset Plan documents and asset planning assumptions are ad hoc.	Document current governance structure.	Completed in FY23
		Establish a Three Agency AM governance board.	Ongoing Three Agency discussion may result in changes
		Develop an Asset Management System Manual.	FY25

6.2.2 Strategies and Plans

Goal: Expand FCRPS Strategies and Plans based on asset condition and criticality to include all missions that assets support and all programs, including capital, operations, and maintenance. Align performance expectation with the value that each asset provides for the various missions of the Three Agencies.

Table 6.2.2-1 Strategy and Plan Goals

Objective	Beginning State in 2020	Outcome	Target
2.1) Understand all sources of value at FCRPS facilities, including non-power, by performing a demand analysis	Demand and necessary level of service for FCRPS equipment with respect to non-power missions is not well defined.	Perform demand analysis for power and non-power products and services.	USACE O&M Optimization Initiative (Completed FY23) Reclamation Hydropower Value Analysis (Completed FY 23)
		Incorporate demand USACE/Reclamation demand analyses into decision making processes	FY25
2.2) Incorporate O&M Strategies into the SAMP and Increase Three Agency Collaboration in SAMP Development	The SAMP is heavily focused on capital. O&M strategies are not unified and vary from plant to plant.	Develop 2024 SAMP collaboratively with partners.	FY24
		Incorporate preliminary O&M information into FY24 SAMP.	FY24
2.3) Define risk appetite and risk tolerance for each business line and agency	Common risk tolerance and risk appetite have not been defined for the FCRPS between the Three Agencies.	Develop a Three Agency risk register.	FY25
		Define and document Three Agency risk tolerance and risk appetite.	
2.4) Develop plant-specific asset plans that integrate and implement O&M and capital strategies	Capital and O&M planning are generally performed independently. O&M is performed on a standard periodic basis and not necessarily influenced by criticality.	Compile plant asset plans that integrate the capital and O&M strategies for each facility, incorporating the demand analysis and Three Agency risk tolerance.	FY25

*Success for items 2.3 and 2.4 are dependent on resources outlined in Section 6.4

6.3 Current Strategies and Initiatives

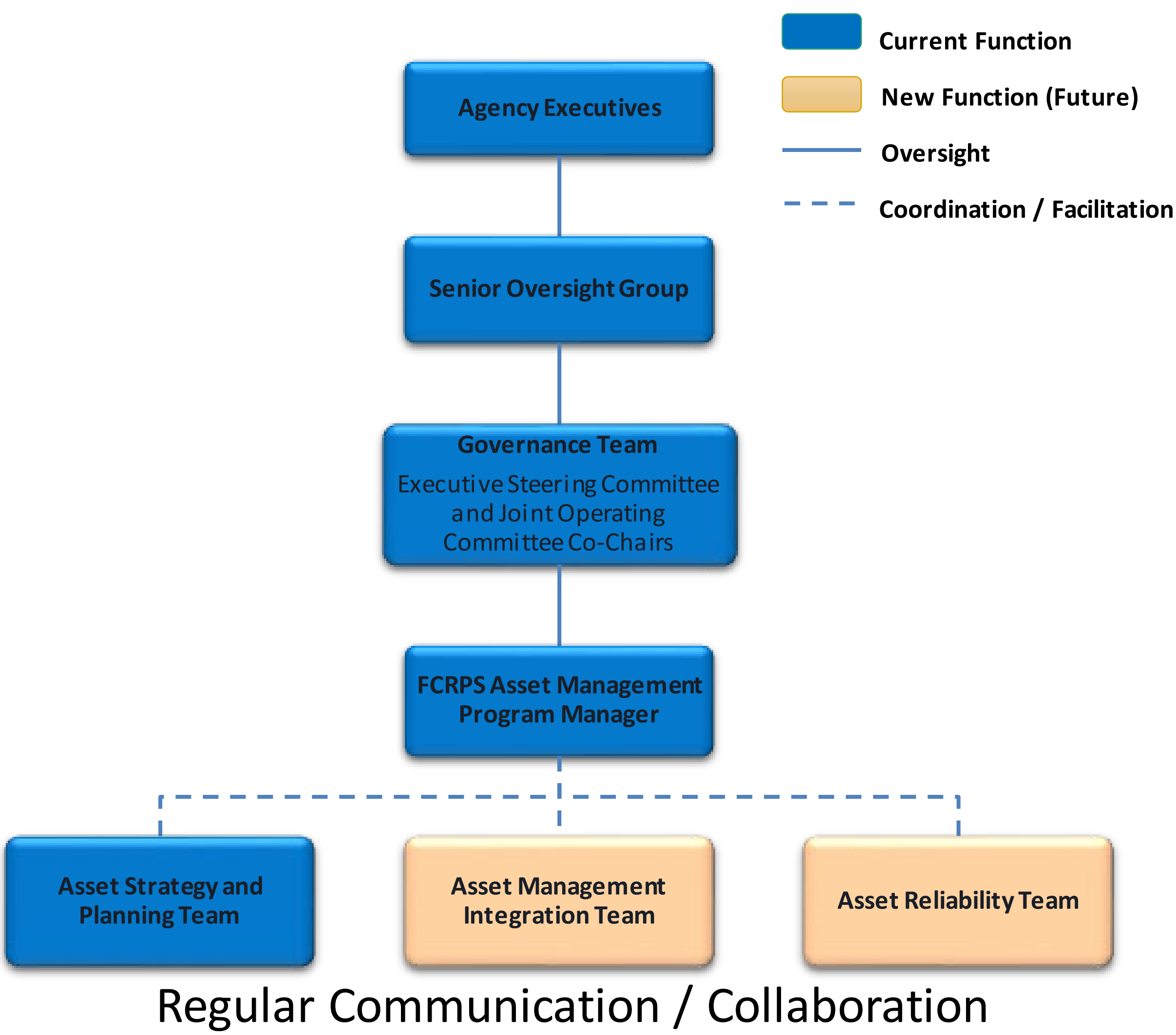
There are numerous ongoing initiatives to improve Asset Management practices across the Three Agencies. The following support the objectives described in Section 6.2 or are part of continuous improvement.

6.3.1 FCRPS Asset Management Group

In 2019, FCRPS leadership tasked a small team of Three Agency Asset Management subject matter experts to create a plan to deliver on the objectives identified in Section 6.2. The team developed a high-level roadmap, identified the resources needed to be successful, and ultimately proposed a new structure for Asset Management in the FCRPS. This new structure is based on the Asset Management structure used at Meridian Energy, a New Zealand utility regarded as a leader in Asset Management. Meridian Energy emphasizes the need for separate strategy, delivery, and reliability teams to enable the unique functions of an organization to work together in a well-defined and cohesive manner. They have designed their asset management program to understand the needs of their business, understand the current and future condition and capability of their assets, identify gaps through assessments, develop strategies and plans to bridge gaps, manage assets throughout their lifecycle, and provide continuous feedback to enhance performance. The FCRPS team drew from these concepts employed by Meridian Energy and developed a structure that aims to separate strategic and operational functions to sharpen organizational focus on asset strategy, planning, implementation, reliability, and communication processes.

The Asset Management Group (AMG) will consist of three teams that align with this focus on strategy, planning, implementation, and reliability. An Asset Management Program Manager leads the teams and reports directly to an asset management governance team composed of members of the ESC and JOC. The Program Manager develops FCRPS asset management governance processes and coordinate execution on a roadmap for continuous improvement in the FCRPS asset management program. The three teams making up the AMG are the Asset Strategy and Planning Team, the Asset Management Integration Team, and the Asset Reliability Team. Figure 6.3.1-1 illustrates the AMG structure and shows the objectives from Section 6.2 with which each team will be initially tasked. It is expected that these teams will form as the new positions are hired over the course of the next few fiscal years. The Asset Management Program Manager is currently backfilled with two consecutive 120-day details followed by a permanent backfill during summer 2024.

Figure 6.3.1-1 FCRPS AM Personnel Hierarchy



The Asset Strategy and Planning Team (ASPT) was formed in 2022, and it provides the long-term planning function. It develops and owns the FCRPS expense and capital strategies, capturing the current and evolving needs of each agency and their stakeholders. It will also develop plant-specific asset plans that integrate the capital and expense strategies while improving line-of-sight for the plants between plant operational objectives and FCRPS asset strategies. Development of the FCRPS SAMP, SAP, and associated planning models is owned by the ASPT. The team will also be tasked with developing a Risk Management Plan that helps the Three Agencies come together on an understanding of how risks are defined and how they should be treated in the FCRPS.

The Asset Management Integration Team (AMIT) will focus on the implementation of strategies and plans by bridging the gap between their development and execution. They will coordinate with plants and asset management staff to ensure that strategies and plans are logical and implementable when viewed from both perspectives. They will communicate the strategic priorities to project staff and discuss the plans to meet those objectives, helping compile feedback from field staff to inform the products of the ASPT. They will ensure that asset management training is widely available and utilized throughout FCRPS staff and ensure that operations and maintenance practices at projects reflect strategic plans, including outage plans and project maintenance management plans. These actions should result in horizontal alignment improvements.

The Asset Reliability Team (ART) will be tasked with providing feedback on asset condition and performance as it changes over time so that strategic plans can be updated on a regular basis. It will monitor existing condition information, including hydroAMP, online condition monitoring data, and other programs such as Operational Condition Assessments (OCA) and Hydro Test and Evaluations (HT&E), providing oversight over data collection and quality control. Whereas currently there is no regional group focused on aggregating such data across multiple plants and mining it for insights to improve asset performance, this team will be tasked with doing so and providing condition-based and predictive maintenance recommendations. Those recommendations will inform maintenance standards and strategies as well as the SAMP and SAP.

The new AMG structure is designed to deliver upon the goals and objectives of the FCRPS in a more focused and streamlined manner while filling the gaps that exist in the FCRPS asset management program. Section 6.4 details the positions required to achieve success under this new structure.

6.3.2 Operations and Maintenance Optimization Initiative:

Each USACE dam now has an Operations and Maintenance Optimization Initiative (OMOI) document that is used to understand and evaluate the value and importance of their hydropower assets to optimize how the assets are operated and maintained. The value and importance of the assets is determined by assessing the needs for water quality, fish passage/attraction, power generation, and ancillary services at each dam. Once the value of the assets is established, the business needs of those assets or the value of the output of those assets (power and water) will be used to develop optimized operations and maintenance activities to align the level of effort of O&M to the value of the asset. This approach ensures that the assets continue to meet the needs of the organization and that the levels of effort (O&M) are optimized to ensure that those efforts are performed in the most cost-effective manner. Many of the long-term objectives listed in Section 6.2 are addressed under the OMOI.

6.3.3 O&M Pilot Projects

Reclamation's Columbia-Pacific Northwest Region, in partnership with other offices within the agency, are in different stages of multiple pilot project efforts. There are nine (9) O&M-related pilot efforts underway within the Columbia-Pacific Northwest Region. Three (3) major efforts are listed below. Other aspects under way are efforts to improve data quality and internal controls for existing data platforms to help ensure the integrity of data that is used in various reporting, modeling, and decision-making processes.

The Hydropower Research Institute pilot project focuses on aggregating from multiple Reclamation power facilities machine condition monitoring data, SCADA data, and eventually other equipment condition monitoring data to drive the digital transformation across the Region and across the agency. It is unit data-driven (generator, excitation system, governor, turbine, etc.) and includes sharing condition/operational data sets from other hydropower utilities to provide a forum to promote collaboration as part of the digital transformation. Some of the value benefits include a prelude to reliability engineering, comparative maintenance analyses & benchmarking, inform maintenance/operational/investment strategies, reduced outages, remote equipment access and automated data transfer, aggregated de-centralized human resources, and improved root-cause analysis.

The Predictive Maintenance (PdM) business case pilot project at Grand Coulee is a business case value effort showing a financial benefit of transitioning from time-based maintenance to PdM. Benefits include framing a template method to obtain PdM cost savings, inform PdM implementation at other power facilities, inform variable unit operation, and provide insight to BPA regarding EIM implications.

Just initiated is a data processing and analysis of rotating machines pilot project for multiple Reclamation facilities. It includes exploring, testing, and developing software tools to process big data collected from rotating machines to aid in the development of condition-based maintenance and predictive maintenance tools. Some of the value benefits includes reduced maintenance costs, better defined O&M risk, improved O&M data analytics decision making, and further developed asset mitigation strategies.

6.3.4 FCRPS hydroAMP Team

In 2018, a survey consisting of eight questions was sent out to FCRPS facilities to gauge hydroAMP usage and consistency. Following the survey, an FCRPS hydroAMP team was assembled to help improve consistency, completeness, and recency of condition assessments. As part of the effort, it was determined that routine condition assessments needed additional emphasis as part of the O&M program and as an input to capital planning. In February 2021, a process document signed by all three agencies was released that focused on facility condition assessments, peer review of condition assessments, and program peer review of condition assessments (divided into holistic evaluation and technical evaluation). As part of the program peer review, various metrics are being considered and evaluated including previous versus current assessment differences, low score differences, volatility, increasing scores, differences from degradation expected scores, and recommended vs forecasted/planned replacement. Additionally, there are correlated efforts to help improve data integrity within each respective agency and to help address/improve some of the assumptions used to model asset degradation.

6.3.5 Spillway Gate Model Improvements

Spillway gates are one of the primary means of water control at a dam. They can be used to pass water when flows exceed powerhouse capacity, provide spill for fish passage and attraction, and are a critical element in flood risk mitigation. Spillway gate uses and related risks differ across the 31 dams in the FCRPS. Some spillway gates see daily operations while others are only intended to be used in the most extreme flood conditions. Understanding the various uses, characteristics, and failure consequences of these assets is critical for making sound asset management decisions and determining how they fit within the broader investment portfolio. In recent years, spillway gates have tended to compete poorly against powertrain investments in FCRPS asset planning models. This is generally because existing models are either tailored toward powertrain equipment or are too generic to capture the benefits if spillway gate replacement and maintenance.

Spillway gates are a “joint” asset, supporting the multi-purpose missions of the dams. This means that BPA pays a “Power Share” of a portion of their costs while the remainder is covered by federal appropriations. Spillway gates play a critical role in dam safety. As such, they are monitored under the USACE and Reclamation dam safety programs. This creates an overlap in asset management activities between typical FCRPS asset management processes and USACE/Reclamation dam safety processes. BPA and USACE are developing a new asset model to specifically capture the benefits of spillway gate replacement and maintenance which tend to deal with significantly higher consequences and lower probabilities of occurrence than are typically seen on powertrain equipment. Testing occurred on this new model in FY23 with a subset of USACE dams. Updated direct cost risk assumptions from this model are included in the 2024 SAMP analysis. The full model is planned for inclusion in the next SAMP.

6.3.6 Safety Value Measure Improvements

FCRPS staff are investigating improvements to the safety value measure to provide more flexibility to adequately capture safety risks and better differentiate across projects. From discussions with utilities throughout the world, there are several best practices currently under investigation within the FCRPS. This includes creating a value measure specific to dam safety that operates on its own probability and consequence scale, expanding risk matrices beyond five dimensions of probability and consequence, and including a means of capturing the number of individuals exposed to a risk. Testing best practice value measures will occur in FY24 with a goal of implementing improvements by the next SAMP.

6.4 Resource Requirements

FCRPS asset management staff evaluated the positions and skills necessary to achieve these objectives and made a recommendation to executives in 2020. In addition to existing asset management staff, the team identified 10 additional positions across the three agencies to execute on the asset management roadmap. These include:

1 Asset Management Program Manager: The Asset Management Program Manager is an FCRPS position, sitting at BPA that coordinates the activities of the 3 teams that make up the FCRPS Asset Management Team. This position was hired in FY22 but is vacant as of November 2023 as backfill options are evaluated.

2 O&M Strategic Planners: One Corps and one Reclamation position. These individuals will develop O&M strategies and incorporate them into the SAMP. These positions have been hired at both agencies as of FY23.

2 Maintenance Planning Leads: One Corps and one Reclamation position. These individuals will link strategy and execution, ensuring that strategies and plans can be implemented at the facilities.

1 Risk SME: The Risk SME is a BPA position that facilitates development of three-agency risk appetite and risk tolerance objectives for incorporation into decision making.

4 Reliability Engineers: 2 Corps and 2 Reclamation positions. These individuals analyze condition and performance data to inform condition-based and predictive maintenance strategies.

As of November 2023, the strategic planners have been hired and the next priority positions are the Risk SME and the maintenance planning leads. The Asset Management Program Manager position was vacated in August 2023 and will be backfilled with two concurrent 120-day details starting late January 2024, with the permanent backfill being filled during summer 2024. The remaining positions are expected to follow in subsequent FYs. All positions are being funded within current budgets through reallocation of FTE as determined by agency executives.

Table 6.4-1 FCRPS Asset Strategy and Planning Team

Position	Agency	Position Status
SAMP Lead	BPA	Active
Strategic Planner	USACE	Active
Strategic Planner	Reclamation	Active
Risk SME	FCRPS/BPA	New Position/Vacant
APT Member	BPA	Active
APT Member	USACE	Active
APT Member	Reclamation	Active
Demand Analysis Lead	USACE	Active
Demand Analysis Lead	Reclamation	Active

Table 6.4-2 FCRPS Asset Management Integration Team

Position	Agency	Position Status
Maintenance Planning Lead	USACE	New Position/Vacant
Maintenance Planning Lead	Reclamation	New Position/Vacant
CCAO Rep	Reclamation	Not Yet Identified
SRAO Rep	Reclamation	Not Yet Identified
GCPO Rep	Reclamation	Not Yet Identified
NWP Rep	USACE	Not Yet Identified
NWS Rep	USACE	Not Yet Identified
NWW Rep	USACE	Not Yet Identified
Project Rep for Reclamation	BPA	Identified
Project Rep for NWP	BPA	Identified
Project Rep for NWS	BPA	Identified
Project Rep for NWW	BPA	Identified

Table 6.4-3 FCRPS Asset Reliability Team

Position	Agency	Status on Team
Mechanical Engineer	USACE	New Position/Vacant
Electrical Engineer	USACE	New Position/Vacant
Mechanical Engineer	Reclamation	New Position/Vacant
Electrical Engineer	Reclamation	New Position/Vacant
Program Analyst	TBD	Not Yet Identified

7.0 ASSET CRITICALITY

The capital and expense programs use different methods of criticality assessment to inform their respective decision-making processes. For capital, criticality levels were collaboratively established during the AIEI and the FCRPS Asset Strategy and Planning team uses them to develop long-term strategies and plans. For expense, USACE and Reclamation use criticality assessments to inform day-to-day operational decisions. While criticality assessments between the capital and expense programs may become more closely tied under the work outlined in Section 6.3.1, the future state could still include separate assessments. This is due to the differing timescales over which criticality is important for each program.

7.1 Criteria

Section 7.1.1 describes how asset criticality was established for the capital program, discusses its applicability at different stages of the asset lifecycle, and details criticality criteria across the various sources of asset value and risk. Section 7.1.2 describes the USACE and Reclamation methodologies for asset criticality used for operations and maintenance decision making.

7.1.1 Capital Program Criteria

In the capital program, FCRPS assets undergo two levels of criticality assessment depending on where they are in the project lifecycle. A screening level assessment based on an asset's type, location, and condition produces an initial estimate of safety, environmental, compliance, public perception, and financial risk. This assessment is performed on all inventoried assets and forecast over a fifty-year period. As business cases develop, additional analyses capture information unique to each asset that may not have been revealed by the screening level analysis. These additional analyses target near-term investments identified in the System Asset Plan.

At the screening level, safety, environmental, compliance, and public perception consequences of failure are determined for each asset type on a five-level consequence scale. Portions of the financial consequences (lost generation and direct costs resulting from asset failure) are determined at both the asset type *and* individual asset level. Outage durations are estimated for each asset type, but the resulting lost generation and direct costs are specific to each plant and generating unit. Combined with asset condition, which informs a likelihood of failure, this information provides a high-level assessment of the asset failure risk for each asset in the FCRPS asset registry.

Upon investment planning, design, and alternatives formulation, additional or unique information about the related assets is captured. USACE, Reclamation, and BPA staff assess the likelihood and consequence of failure with respect to safety, environmental, compliance, and public perception on the same five-level consequence scale as the screening analysis. However, the assessment is tailored to the unique conditions in which the specific assets operate. This could either raise or lower failure consequences and potentially modify the likelihood of occurrence. Lost generation and direct cost risks from failure are automatically calculated per asset using the same asset models described in the screening analysis.

The likelihood of non-financial consequences is assigned using a five-level probability ordinal scale, shown below. Financial consequence likelihoods are calculated based on equipment condition but are mapped into the five levels for illustrative purposes.

Table 7.1.1-1 Non-Financial Value Measure Ordinal Scale

Rare	Unlikely	Possible	Likely	Almost Certain
1% Annual Probability	2% Annual Probability	8% Annual Probability	19% Annual Probability	80% Annual Probability

7.1.1.1 Safety

Safety Risk captures the impact of injury, disability or death of an employee or member of the public as a consequence of asset failure. The FCRPS does not purposefully expose employees or the public to safety hazards but understanding safety risk is essential to the safe operation of FCRPS assets. Typically, when a hazard is identified the risk is assessed and either eliminated or mitigated. Mitigation can be through physical barriers or operational procedures. The safety risk evaluated per asset type is based on the most likely safety threat due to failure that has not already been mitigated.

Table 7.1.1.1-1 Safety Value Measure Consequence Scale

Insignificant	Minor	Moderate	Major	Extreme
No or minor injury, first aid	Treatment by medical professional	Lost time accident - temporary disability	Permanent disability	Fatality

7.1.1.2 Environmental

Environmental risk is based on the cost of remediation efforts to mitigate harm done to the environment due to asset failure. Harm so severe as not to be reversible is assigned the most severe consequence ranking classification. Fines associated with environmental consequences are captured by compliance risk.

Table 7.1.1.2-1 Environmental Value Measure Consequence Scale

Insignificant	Minor	Moderate	Major	Extreme
No impact	Impact to on-site environment (simple remediation) or where the remediation costs < $100k	Limited impact off-site (localized remediation required) or where the remediation costs < $1M	Detrimental impact on- or off-site (long-term remediation required) or where the remediation costs < $10M	Detrimental or catastrophic impact off-site (mitigation impossible) or where the remediation costs > $10M

7.1.1.3 Compliance

Compliance risk captures the impact of an event or a failure which would cause the FCRPS to be unable to implement the actions consulted upon in Biological Opinions (BiOps) and the required actions in the Incidental Take Statements. It also captures the risk that the FCRPS is unable to comply with state laws, federal laws, and regulations such as those under the Endangered Species Act.

Table 7.1.1.3-1 Compliance Value Measure Consequence Scale

Insignificant	Minor	Moderate	Major	Extreme
No or insignificant effect on operations or administrative flexibility, or annual mandated costs <$10k	Change in operations or administrative flexibility or annual mandated costs <$100k	Effect on legal principles or precedents, project operations noticeably affected for compliance, inability to maintain system frequency or voltage, or annual mandated costs < $1M	Effect on legal principles or precedents, substantial changes needed in project operations or administration, or annual mandated costs < $10M	Extremely difficult to meet fundamental statutory obligations, extremely unreliable system, extreme changes needed in project operations or administration, or annual mandated costs > $10M

7.1.1.4 Public Perception

Public Perception risk represents the risk that a failure or event will cause the organization's customers or other external stakeholders to lose confidence in the organization.

Table 7.1.1.4-1 Public Perception Value Measure Consequence Scale

Insignificant	Minor	Moderate	Major	Extreme
No or isolated internal complaints	Local media attention, widespread internal complaints, some public embarrassment	Transitory local media / federal / customer attention and criticism, some damage control; congressional inquiry, short duration loss of power to islanded community	Ongoing media / federal / customer attention, major damage control, significant impact on staff morale, congressional inquiry, extended duration loss of power to islanded community	Adverse and ongoing media / federal / customer attention, criticism and agency intervention, extreme damage control, secretary called to congress, permanent duration loss of power to islanded community

7.1.1.5 Reliability and Financial

Unlike other value measures, financial value is directly monetized where practicable. When it is not practicable to monetize financial impacts, the categories below are used for a high-level qualitative evaluation of financial risk. This occurs for a limited number of investments where the required information to directly quantify risk is not available. Financial consequences are split into two categories: lost generation and direct cost. Lost generation is the foregone revenue or forced replacement purchases associated with unplanned equipment outages. Direct costs are the incremental costs associated with equipment failure such as emergency repair costs, contract inefficiencies, or damage to nearby equipment.

For illustrative purposes, the monetized values are mapped into the following five-level consequence scale in this SAMP for the purposes of comparison to the other value measures.

Table 7.1.1.5-1 Reliability and Financial Value Measure Consequence Scale

Insignificant	Minor	Moderate	Major	Extreme
<$10k	$10k - $100k	$100k - $1M	$1M - $10M	>$10M

7.1.1.5.1 Financial – Lost Generation

Lost generation consequences are determined by calculating the expected marginal outage cost at each facility. The marginal outage cost can be thought of as the annual value that would be lost from the next unit to go out of service, given a base level of availability. In other words, the cost is the value of the last-on-first-off unit after accounting for a base level of outages.

Marginal outage costs are calculated for each plant, by month, over a historical water record. This analysis determines a base availability for each plant, derived from each plant's 5-year outage plan and incorporating recent unit performance. At plants that carry reserves, additional units are held out of service to represent the amount of reserves typically carried at those facilities. To determine marginal outage cost, generation is first simulated under the base availability assumptions described above. Next, a second simulation is run that removes one additional unit from service. The difference in simulated generation between these two scenarios establishes the marginal outage cost at each plant. Marginal outage costs are summarized as average annual values for use in FCRPS long-term planning models.

FCRPS planning models also consider annual changes in marginal outage consequence resulting from changes in forecasted plant availability. This allows for a more accurate depiction of the risk profile over time as the models can recognize that investment strategies will impact future plant availability and, therefore, future outage consequences. There is an inverse relationship between availability and marginal outage cost. As availability declines, each successive unit outage is typically more costly than the previous. As availability improves, outages become less costly. FCRPS long-term planning models are now capable of capturing some of these dynamics rather than relying on an average assumption throughout the entire study period. This level of analysis is sufficient for the long-term planning purposes of this SAMP but more sophisticated modeling is typically employed for business cases to further hone alternatives selection.

Figure 7.1-1 illustrates the relationship between marginal outage cost and total plant generation value. It classifies plants and families of units based on their marginal outage cost and total value sto illustrate the breadth of criticality and identify the level of analysis typically required. The following descriptions provide context about the financial criticality of a generating unit outage and the level of analysis typically employed for business cases.

> **Red:** High marginal outage cost and total generation value. Unit availability is critically low or generating units are consistently relied on to meet BPA power supply obligations. The financial impact of an unplanned outage is severe in the near-term and potentially detrimental in the long-term if not mitigated. Marginal outage cost methodology is not sufficient for business cases and more sophisticated analysis is required.
>
> **Orange:** High marginal outage cost, high total generation value or combination of moderate marginal outage cost and total generation value. Financial impact of outage is high in the near-term and

potentially detrimental in the long-term if availability declines. Marginal outage cost methodology is not sufficient for business cases and more sophisticated analysis is required.

Yellow: Moderate marginal outage cost or moderate average plant generation value. Financial impacts are manageable in the near-term and lower availabilities may be acceptable in the long term. Marginal outage cost methodology may be sufficient for business cases but more sophisticated analysis is considered.

Blue: Low marginal outage cost or low total generation value. Financial impacts of outages are not detrimental to the FCRPS. Marginal outage cost methodology may be sufficient for business cases but more sophisticated analysis is considered.

At some plants, families of units with significantly different capacities are broken out to show the difference in marginal outage cost. However, each point plots the annual value for the *entire* plant as operations are interrelated between the families of units within the plant. Plant groupings are bound by blue-dashed boxes. Both axes are shown using a logarithmic scale but note the differences in magnitude.

Figure 7.1.1.5.1-1 Plant Annual Generation Value Vs. Unit Marginal Outage Cost

This chart provides a current snapshot of marginal outage consequence and total plant value. Values shown are based on 2023 White Book average generation values shown in Table 3.3-1 and levelized Mid-Columbia market price forecasts from 2026-2035. This represents a lower bound on the value of each plant as it is unlikely, especially for the larger plants, that total plant power production could be reliably replaced with spot market purchases. It also includes no value for the ancillary services and flexibility that the hydropower plants provide. As previously mentioned, marginal outage costs vary over time as plant availability changes.

7.1.1.5.2 Financial – Direct Cost

Direct costs are calculated to capture the non-generation impacts of equipment failure. The intent is to capture the inefficiencies that results from equipment experiencing failures prior to planned replacements. Those inefficiencies could be the typical repair costs to return equipment to service temporarily while plans are made for replacement or incremental costs associated with expediting replacement if repair is not possible. These costs are highly uncertain and depend on failure mode, asset type, and many other factors, but a high-level assumption is made to recognize some level of incremental risk associated with allowing equipment condition to degrade. A "direct cost ratio" is estimated for each asset type that estimates expected incremental failure costs as a percentage of its replacement cost. The following examples demonstrate how the direct cost ratio is estimated under different failure conditions.

Table 7.1.1.5.2-1 Direct Cost Risk Calculation Examples

Failure Scenario	Direct Cost Ratio Implication	Example
Failure resulting in repair and return to service	The full cost of the repair should be recognized because the repair cost is an entirely incremental cost in the lifecycle of the asset.	A generator winding fault results in a \$1,000,000 repair to return the unit to service at a derated capacity. Planned winding replacement occurs two years later at \$10,000,000. The Direct Cost Ratio in this example is: $\frac{1{,}000{,}000}{10{,}000{,}000} = 10\%$ In terms of the lifecycle cost, only the \$1,000,000 is an incremental cost.
Failure resulting in substantial replacement	Only the costs that exceed a typical replacement are recognized. This could include contracting inefficiencies, repair costs for other damaged equipment, cleanup costs, or other costs that are realized when having to replace equipment that has failed that otherwise would be avoided in a planned replacement scenario.	A transformer failure results in the need for total replacement of the transformer, repair to damaged iso-phase bus, and cleanup costs for spilled oil. In a planned scenario, this transformer would cost \$5,000,000 to replace. Due to the criticality of the related units, the contract has been expedited resulting in a total replacement cost of \$6,000,000. Iso-phase bus repairs cost \$1,000,000 and oil cleanup costs amount to \$750,000. The Direct Cost Ratio in this example is: $\frac{[(6{,}000{,}000 - 5{,}000{,}000) + 1{,}000{,}000 + 750{,}000]}{5{,}000{,}000} = 55\%$ The incremental costs are just the costs associated with oil spill cleanup, repair to damaged iso-phase bus and the contract costs in excess of planned replacement costs resulting from expediting the contract. The \$5,000,000 planned replacement cost is netted out to determine just the additional costs of the failure over a planned replacement.

The process described in Table 7.1.1.5.2-1 above was first used for a subset of asset types in the 2022 SAMP and has since been expanded to all turbine, generator, transformer, and spillway gate equipment. Subject Matter Experts are asked to outline failure modes for a specific asset type, assess the probability that each of those failure modes is realized in the event of failure, and estimate the cost to remedy the consequences associated with each failure mode. The direct cost ratio is calculated by taking the expected value of the consequences, weighted by the probability that they occur.

7.1.1.6 Expense Program Criteria

USACE is working on an enterprise-wide categorization of asset criticality in the MAXIMO asset management application. This will enable consistent communication about work needs, priorities, and urgency of assets. Assets are given a rating of a 1 to 10 score index which is then used to establish the assets overall criticality.

Figure 7.1.1.6-1 USACE Asset Criticality Categories

1	Failure won't result impact/inconvenience in providing service/availability of authorized functions.
2	Failure will result in an inconvenience in providing an authorized function.
3	Failure will result in an inconvenience in providing an authorized function that affects the public.
4	Failure will result in a significant impact to providing an authorized function.
5	Failure will result in significant impact to providing authorized function that affects the public.
6	Failure will result in unavailability of an authorized function.
7	Failure results in unavailability of authorized function affecting public. No violation of law/regs.
8	Failure results in unscheduled loss of function resulting in a violation of federal/state/local law.
9	Failure results in unscheduled function loss with impact to public health laws/safety regulations.
10	Failure expected to result in the loss of life under normal conditions.

Reclamation also establishes criticality by assigning priorities within their Maximo asset management software. These priorities are split into three categories:

Work Order Priorities

Work order priorities along with the employees allowed to set those priorities, are identified in the facility's workflow process. These priorities are scored from 1 to 4 based on the following scale:

- **Priority 4 – Critical**
  Actions required immediately to prevent or correct situations that could endanger the health or safety of employees or the public, cause an environmental release, or cause immediate and severe damage to plant equipment.

- **Priority 3 - Urgent**
  An action required to mitigate or correct an equipment or component problem that restricts plant operation or causes a loss of generation or water release.

- **Priority 2 - Normal**
  Actions assigned and coordinated on a routine basis to perform corrective work that supports plant operation (e.g., planned outage work).

- **Priority 1- Low Priority**
  Activities that do not impact plant operation and availability (e.g., painting, lighting, inspections, etc.) or activities that can be placed on hold (e.g., activities on hold due to budgetary reasons).

Equipment Priorities

Establishment of equipment priorities will assist schedulers in the development of the work schedule. These priorities are scored from 1 to 4 based on the following scale:

- **Priority 4 - Critical**
  Equipment directly related to safety, environmental protection, generation, or water delivery.

- **Priority 3 - Essential**
  Equipment (auxiliary equipment) that supports generation or water delivery; its failure would cause the loss of generation or the ability to deliver water.

- **Priority 2 - Basic**
  Equipment (auxiliary equipment) that supports generation or the delivery of water but a failure of which will not cause the loss of that capability. Any auxiliary equipment that has an installed backup capable of delivering 100
  percent of its requirements (e.g., sump pumps, governor oil pumps, etc.).

- **Priority 1 - Ancillary**
  Equipment that is not associated with the delivery of water and power. Equipment that is strictly in a support role for the facility or structure; the failure of that equipment would not cause the failure of an essential piece of equipment (e.g., ventilation fans).

PM Priorities

PM priorities are identified when establishing the PM program. These priorities are scored from 1 to 4 based on the following scale:

- **Priority 4 – Critical**
  Tasks required to meet regulatory or personnel / equipment safety requirements (e.g., relay or breaker maintenance, testing personal protective equipment, crane, or elevator inspections).

- **Priority 3 – High Priority**
  Tasks that directly affect power or water delivery (e.g., unit annual inspections, governor alignments, or voltage regulator testing).

- **Priority 2 – Normal**
  Tasks that indirectly affect power or water delivery (e.g., cooling water pump or auto greasing system inspections).

- **Priority 1 – Low Priority**
  Activities that do not affect plant operation and availability (e.g., sump pump, air compressor, or roof inspections).

7.2 Usage of Criticality Model

Capital and expense program criticality assessments have different uses influenced by the timeframes and risks under which they respectively operate. The capital program tends to focus on longer-term impacts while the expense program focuses on criticality to day-to-day operations of the multipurpose missions of the dams.

7.2.1 Usage in the Capital Program

Referenced earlier, there are two different levels of assessment for asset criticality. The first level of assessment uses Copperleaf's Predictive Analytics to identify the optimal time to replace assets based on a lifecycle cost minimization function. This analysis provides information to determine optimal long-term investment levels and analyze the impacts of differing levels of investment. The second level of assessment comes at the Investment Portfolio Optimization level where the specific costs and benefits of planned investments are assessed in the 20-year plan.

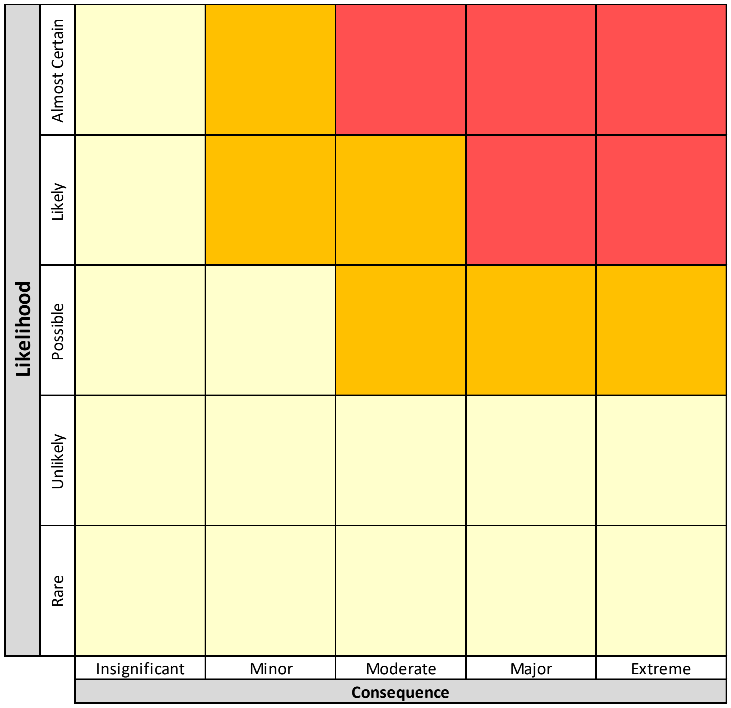
At both levels, financial risks and benefits are directly monetized, so the five-level consequence and likelihood scales are simply used to categorize and communicate risk information. For non-monetized benefits or benefits that are difficult to quantify, the five-level scales are the primary method of evaluation. Benefits and risks are calculated based on the selected likelihood and consequence on the five-level scales. The table below shows the value measures used at both levels of analysis. Since the 2020 SAMP, compliance and public perception risks have been added into the Predictive Analytics analysis.

Table 7.2.1-1 Value Measure Usage in Planning Scenarios

Value Measure	Predictive Analytics	Investment Portfolio Optimization
Safety	✓	✓
Environmental	✓	✓
Compliance	✓	✓
Public Perception	✓	✓
Financial	✓	✓

Predictive Analytics: Predictive Analytics is the first, high-level assessment run on all assets to determine their respective recommended intervention dates and collectively determines the long-term funding levels needed for the system. Economics are the first driver in the optimal intervention date calculation. The Predictive Analytics model calculates the optimal intervention date by minimizing quantified financial costs (see the detailed description in Section 10). Safety, environmental, compliance or public perception risk can override this calculation. Predictive Analytics triggers an intervention in the year in which an asset crosses into the high-risk category of the risk map based on the asset's condition and likelihood of failure. A defined amount of budget can be set aside for these risks. High-risk regions are shaded red on the risk map shown in Figure 7.2.1-1 below.

Figure 7.2.1-1 FCRPS Generic Risk Matrix



Investment Portfolio Optimization: For most investments, financial risks and benefits are quantified directly using the same models that drive Predictive Analytics. More sophisticated analyses are performed as major powertrain investments progress through the scoping and design phases. Benefits calculated in these analyses replace the benefits that Predictive Analytics produces which can impact the optimal time to execute the investment. Non-financial benefits and risks are treated differently at the Investment Portfolio Optimization stage. An assessment of the safety, environmental, compliance and public perception risks is made specific to each identified investment. This refines the high-level analysis that is performed for each asset based on its asset type. These measures are assigned a value based on the consequence and likelihood levels selected from the five-level consequence and likelihood scales. The value is then equated to the equivalent five-level financial consequence scale and any value measure weightings are applied. Currently, safety and environmental consequences receive a weight of 2 and 1.5, respectively, to more adequately reflect the collective missions of the Three Agencies in the portfolio optimization process. For example, this means a major safety consequence receives twice the value of a major financial consequence when the portfolio is optimized.

7.2.2 Usage in Expense Program

USACE is in the process of implementing Project Maintenance Management Plans (PMMPs) that will institutionalize strategy and philosophy on maintenance, while simultaneously improving understanding of the regional operating projects through data and communication. Agency-wide application of the same standards allows USACE to compare maintenance actions and investments across the agency. USACE will also be looking at the PMMP effort for determining asset hierarchies within MAXIMO which will then align with the enterprise-wide categorization their criticalities. In addition to this the OMOI demand analysis described in Section 3.4.3 is incorporated to determine generating unit priorities.

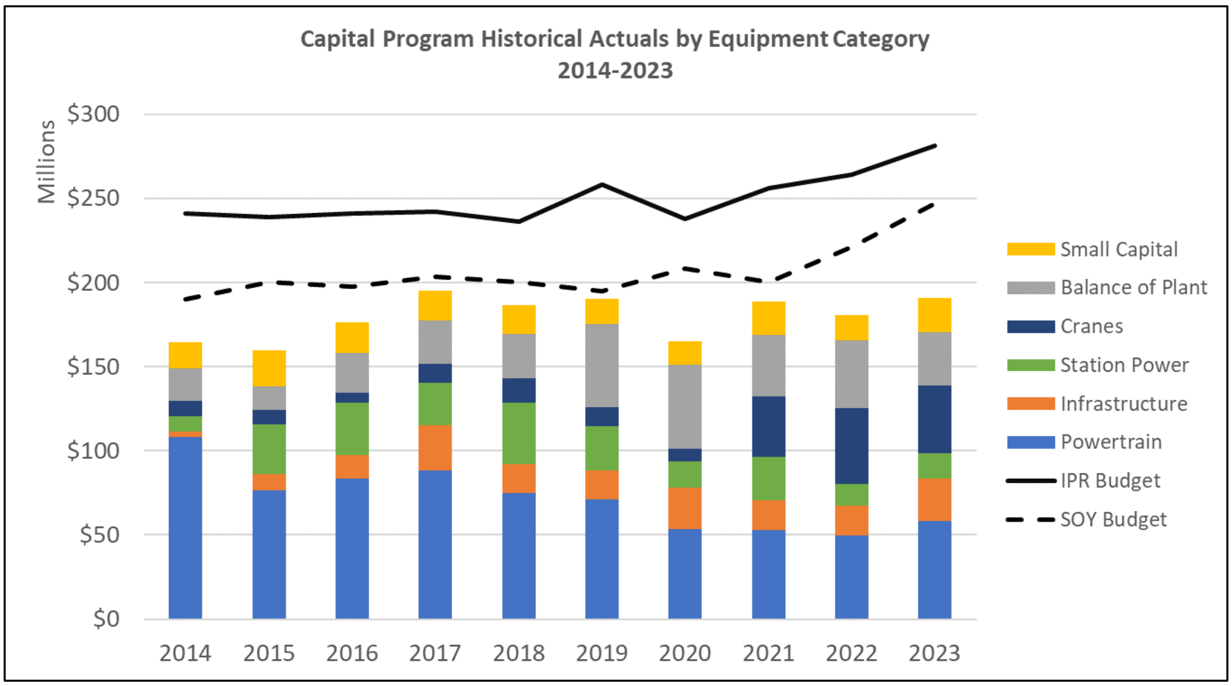
Within Reclamation's expense program, the work order priority or the PM priority mentioned in section 7.1.2 is added to the equipment priority which produces the calculated priority. This numerical value is an effective tool for prioritizing maintenance work to be undertaken at the facility level.

8.0 CURRENT STATE

8.1 Historical Costs

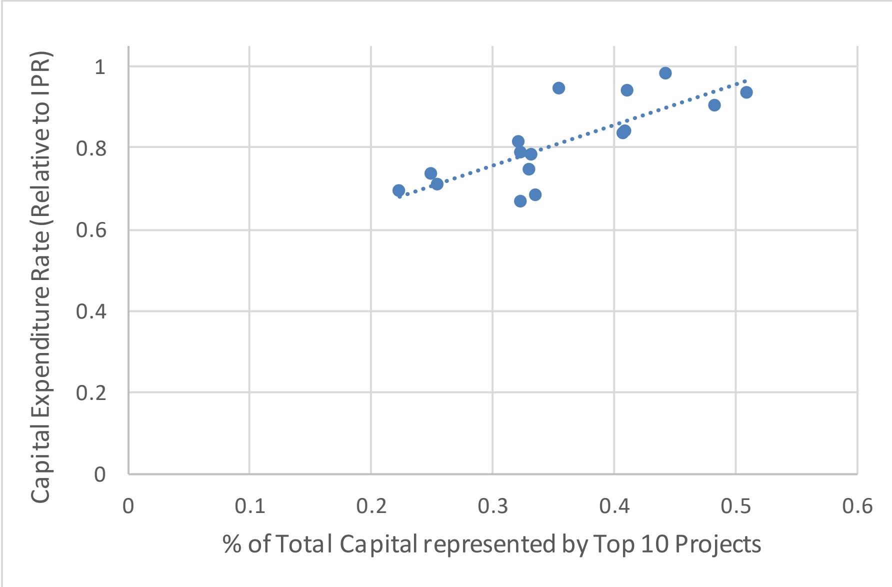
Capital investments have varied between $150 and $200 million over the last 10 years. Although analyses have supported higher levels of capital investment for many years, the FCRPS has not yet ramped up to the levels identified in previous IPRs.

Figure 8.1-1 Historical Expenditures - Capital



The ability to ramp up the program relies on several large powertrain investments, specifically at Grand Coulee, McNary, and Chief Joseph dams. These investments have taken longer to plan, design and execute than expected but are core to the business case for a higher level of investment. FY24 represents the first year of large construction expenditures on turbine runner replacements at McNary and generator winding replacements at Chief Joseph. Over 12% of the FY24 IPR budget is represented by these two projects alone and expenditures will remain at those levels into the 2030s.

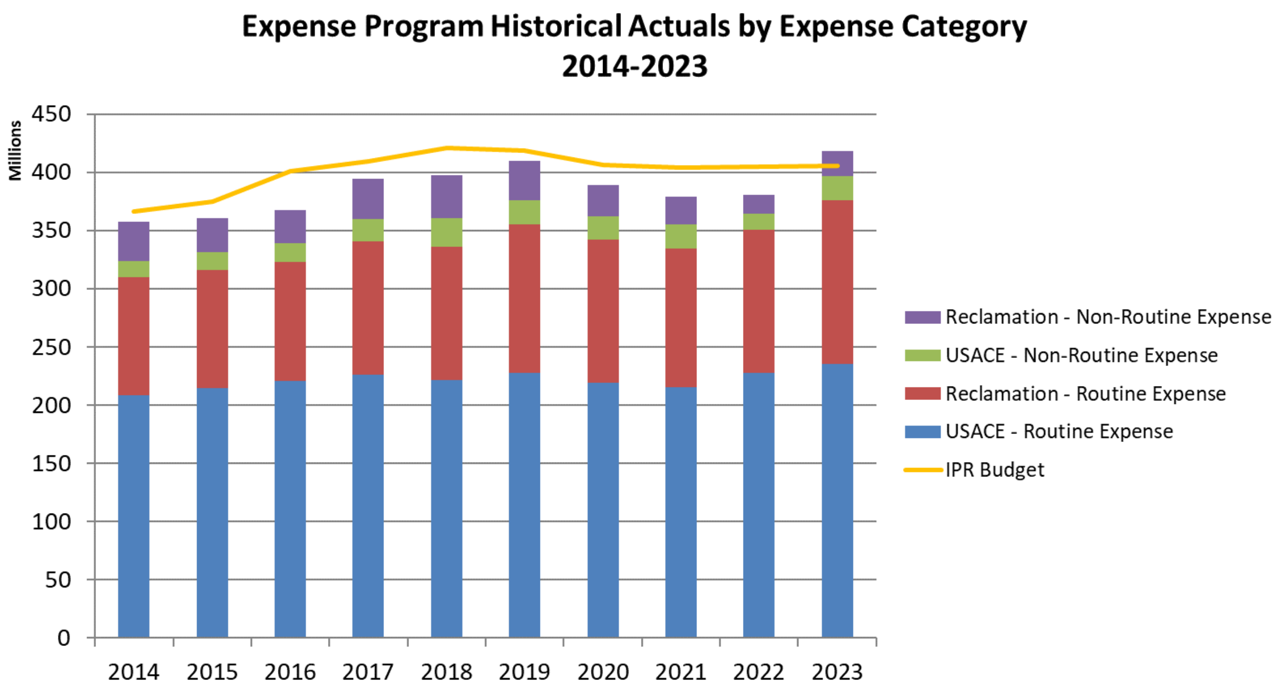
Figure 8.1-2 Capital Budget Execution Relative to Percentage of Total Budget Earmarked for Top 10 Capital Projects



Regression analysis on historical FCRPS capital program performance shows a positive correlation between budget execution and the number of large projects in the portfolio. Figure 8.1-1 above shows that powertrain investment has been relatively low in recent years. While major powertrain investments have been in scoping and design, many smaller projects have been undertaken in preparation. This can be seen with the relative increases in investment in cranes, station power, and balance of plant assets. With major projects such as those at McNary and Chief Joseph starting to reach large construction spending in FY24, the expectation is that capital budget execution will increase.

To further support improved execution, the FCRPS implemented changes in asset management processes in FY23. Starting with the FY23 System Asset Plan, investment forecasts are now adjusted based on execution expectations prior to optimizing the portfolio within the budget. An analysis of historical investment forecasts over their lifecycles informed assumptions for how investment schedules evolve over their project lifecycle. This ensures that the portfolio optimization is based on more realistic investment-level execution expectations grounded in historical performance. In previous years, the FCRPS dealt with expected schedule slips by "overprogramming" the budget and optimizing the portfolio to a higher number. The overprogramming amount was set at the portfolio level and not informed by the individual investments. By contrast, the new process adjusts the forecasts first and then optimizes directly to the budget. Implicitly, this produces an overprogramming amount that is based on investment-level analysis. It is now less likely that portfolio optimizations will unnecessarily delay investments due to optimistic expenditure schedules. Said differently, System Asset Plans going forward are more likely to have the right amount of work, scheduled at the right time to improve capital budget execution.

Figure 8.1-3 Historical Expenditures - Expense



The expense program averaged a 4.2% increase per year from 2014 through 2018. This outpaced inflation over the period and led the FCRPS to seek efficiencies in support of BPA's goal of bending the cost curve by holding program costs at or below the rate of inflation. From 2019 to 2022, total expense budgets for the FCRPS declined. This was accomplished through reorganization of positions, consolidation of duties, and attrition. At the same time, wages increased at a rate greater than inflation. Start of Year budgets were revised in 2023 above the original IPR budget to offset significant inflationary pressures that were not anticipated in the 2020 IPR. The FCRPS continues to seek efficiencies through the exploration of new maintenance strategies to offset continued inflationary pressures, but it is expected that future budgets will need to increase.

As a result of program cost being held at or below the rate of inflation USACE has seen a consistent reduction in full-time equivalent employee (FTE) hours. Figure 8.1-4 shows the total estimated initial employee count compared to the latest count for the fiscal year ending in 2023. It illustrates the trend in employee counts by General Schedule (GS), Trades and Crafts (TC), and Wage Grade (WG) employees. This was in part due to the wage increases for both the trade crafts and general schedule employees. Some of the ramifications from this reduction is the loss of seasoned craftworkers to retirement and the inability to pass on their knowledge and expertise. Some corrective maintenance work that used to be a quick repair is taking longer due to a new maintenance staff that is gaining the experience lost due to retirements. Additionally, this reduction has also led to prioritized maintenance for critical assets as well as preventative maintenance activities.

Figure 8.1-4 Historical FTE - Expense

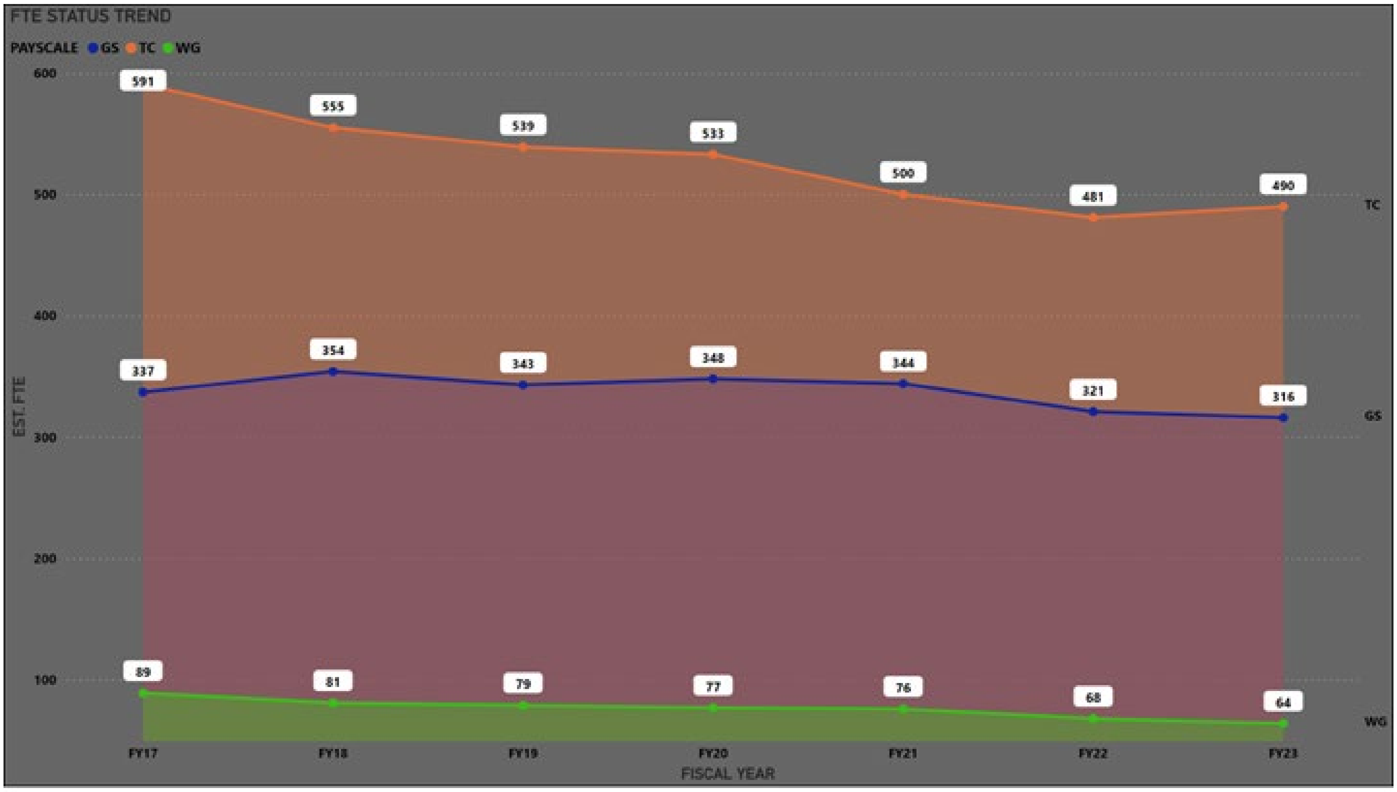
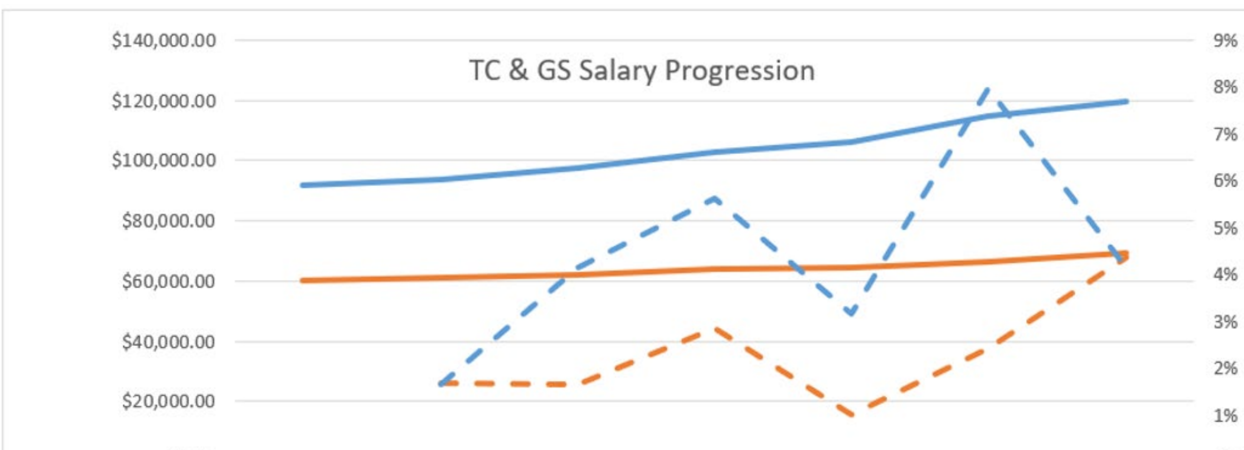


Figure 8.1-5 Historical Flat Budgets and Significant Inflation – Expense



	FY17	FY18	FY19	FY20	FY21	FY22	FY23
GS-11 Step 1	$60,210.00	$61,218.00	$62,236.00	$64,009.00	$64,649.00	$66,214.00	$69,107.00
TC-I Annual	$92,040.00	$93,558.40	$97,448.00	$102,918.40	$106,163.20	$114,608.00	$119,350.40
GS % Increase		1.67%	1.66%	2.85%	1.00%	2.42%	4.37%
TC % Increase		1.65%	4.16%	5.61%	3.15%	7.95%	4.14%

TC salary increase from FY17-22 was 30%; GS was 15%
TC labor hours reduced from 59% of total to 55%

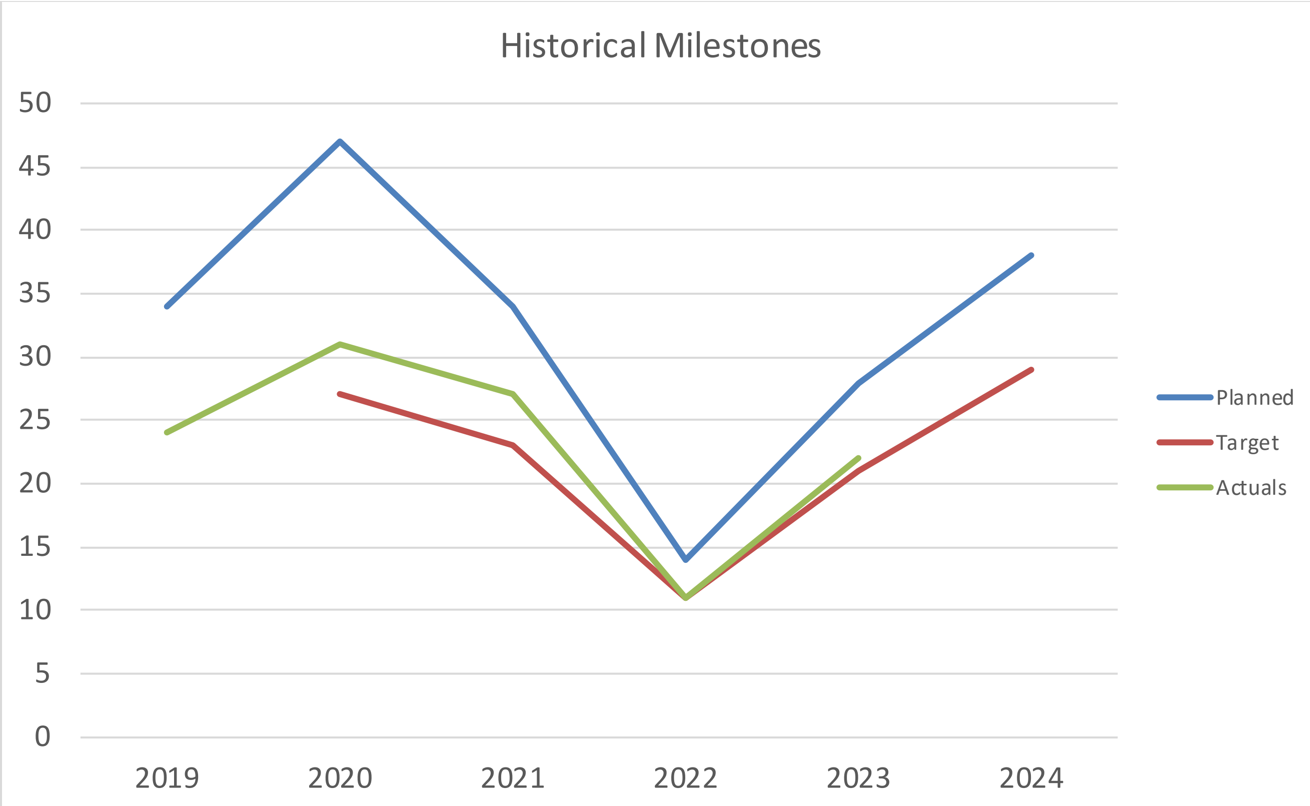
Table 8.1-1 Historical Direct Funded Capital and Expense Spending

	Historical Spend (in thousands) with Current Rate Case						
						Current Forecast or Rate Case	
Capital Expand (CapEx)	2019	2020	2021	2022	2023	2024	2025
Corps of Engineers	675	12	45	148	119	3,140	11,356
Bureau of Reclamation	0	0	0	0	0	0	0
Total Capital Expand	675	12	45	148	119	3,140	11,356
Capital Sustain (CapEx)	2019	2020	2021	2022	2023	2024	2025
Corps of Engineers	150,409	135,656	159,899	156,611	154,318	180,860	224,302
Bureau of Reclamation	35,421	29,446	31,689	23,615	36,475	30,000	40,017
Total Capital Sustain	185,830	165,102	191,588	180,226	190,793	210,860	264,319
Expense (OpEx)	2019	2020	2021	2022	2023	2024	2025
Corps of Engineers	249,965	239,078	236,071	241,194	256,562	273,437	286,802
Bureau of Reclamation	160,394	150,074	143,166	139,526	161,935	171,200	179,760
Total Expense	410,359	389,152	379,237	380,720	418,497	444,637	466,562

8.2 Historical Asset Sustain Trends vs Forecast

The FCRPS tracks various project milestones and started setting official targets in FY20. From FY19 through FY23, the metric tracked only construction milestones and physical completion. In FY24, the metric will also consider design completion and contract award milestones. Targets are typically set at the start of each year. As described in Section 8.1, the capital budget is "overprogrammed" to recognize that investment expenditure schedules tend to be optimistic. As a result, the planned milestones will often exceed the target because meeting all "planned" milestones could exceed the budget. To date, the FCRPS has met or exceeded the start of year target in each year since targets were established. This shows that we generally do a good job of forecasting what we think we will complete in the upcoming year. It also highlights that underexecution of the IPR budget results from difficulties forecasting execution two-to-three years out.

Figure 8.2-1, Historical Project Milestone Trends



Delays prior to the construction phase of an investment are a major contributor to capital underexecution relative to IPR budgets. Adding design completion and contract award milestones to our metrics will enable us to better understand problem areas in the future. Preliminary analysis indicates that these milestones are more frequently missed than construction milestones which are typically updated prior to contract award. Currently, this appears to be a more influential factor than asset type on overall performance versus expectations.

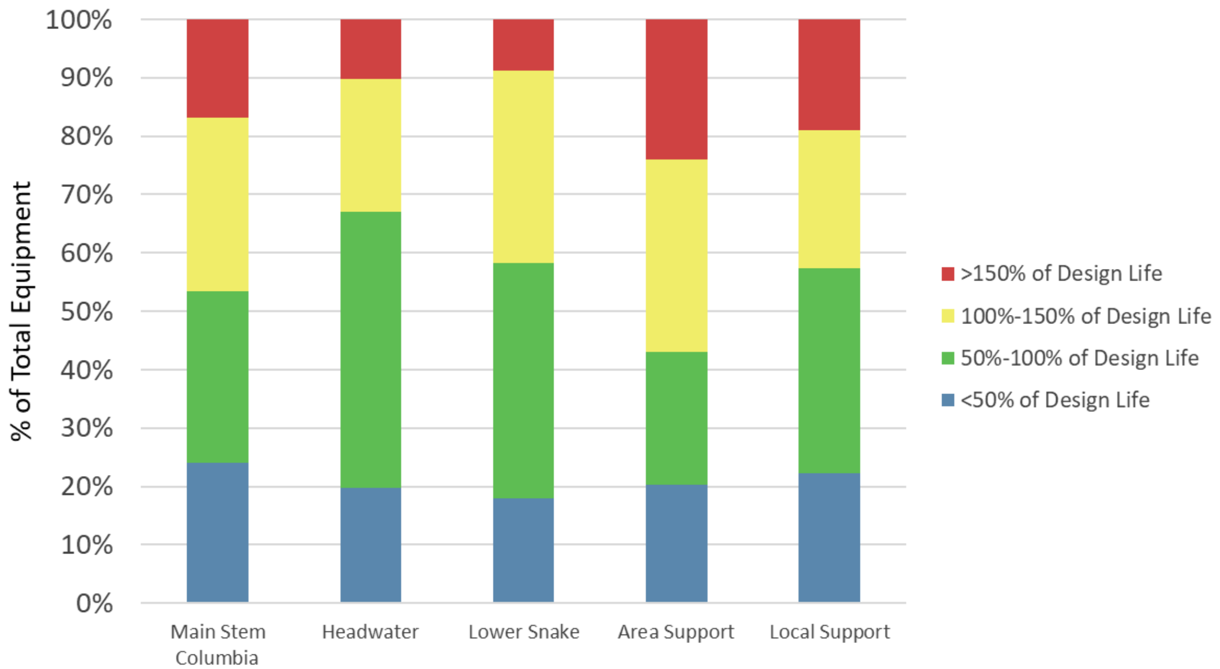
8.3 Asset Condition and Trends

Asset age and condition provide useful information about the overall health of the system. Historical trends and future forecasts help identify potential problem areas and upcoming needs. However, age and condition alone do not drive investment decisions. Some assets operate well past their design lives if their condition is still adequate, or the consequences of in-service failure are low. Conversely, other high-risk assets may be replaced earlier in their lifecycles and at higher conditions if the probability and consequence of failure is unacceptable. Section 10.2 describes how condition, probability of failure, and consequences of failure ultimately drive investment decisions.

8.3.1 Asset Age

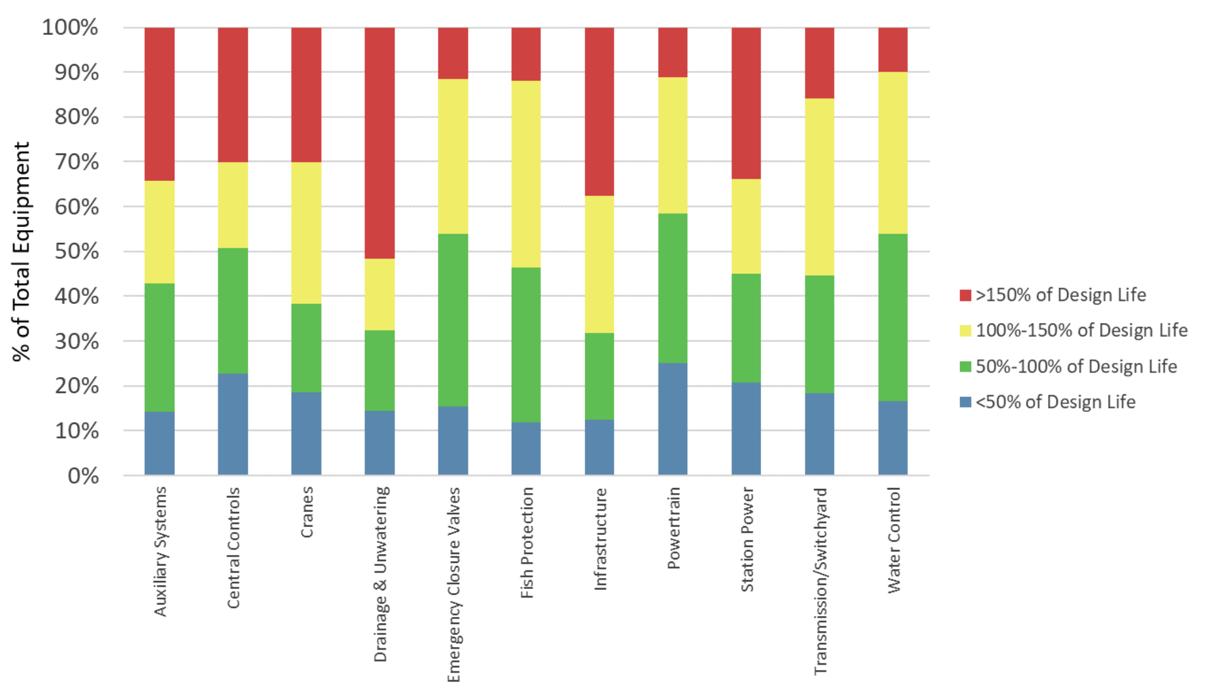
Nearly half of the FCRPS asset inventory has exceeded design life and that number will quickly rise as more plants surpass the 50-year mark in the coming decade. Without investment, for example, over 60% of FCRPS assets will have exceeded their design lives by 2030. Figure 8.3-1 illustrates asset age by strategic class.

Figure 8.3-1, Current Asset Age by Classification



Assets in the Auxiliary System, Drainage and Unwatering, Infrastructure and Transmission/Switchyard categories tend to be pushed beyond their design lives more than other equipment categories. Generally, these systems are built with a fair amount of redundancy or have more rigorous tests and inspections enabling them to stay in service for longer periods of time.

Figure 8.2-2, Current Asset Age by Equipment Category



8.3.2 Asset Condition

FCRPS equipment condition is assessed using the hydroAMP condition assessment framework, a methodology used throughout the world for hydro asset condition assessment. In total, the condition of over 10,000 pieces of FCRPS equipment and equipment systems are tracked using the hydroAMP application. The hydroAMP Condition Assessment Guide contains specific instructions for the objective condition assessment of powertrain and critical ancillary equipment. Other asset types are assessed using a more subjective but consistent “balance of plant” guide.

Condition Assessment guides have been written collaboratively by subject matter expert teams with members from BPA, USACE, Reclamation, Chelan PUD, Seattle City Light, and Hydro Quebec. Guides are periodically reviewed and revisited by the hydroAMP Steering Committee of which the above utilities are members. Development of the hydroAMP framework is supported by the 60+ member utilities of CEATI’s Hydraulic Plant Life Interest Group (HPLIG).

Of the approximately 10,000 pieces of FCRPS equipment in hydroAMP, powertrain assets (Turbines, Generator Rotors and Stators, Governors, Excitation Systems, Transformers, and Circuit Breakers) represent about a third. These assets are inventoried for each of the 31 plants in a consistent manner.

Remaining components are categorized as critical ancillary and balance of plant equipment, some of which have direct impacts on generation. The inventory of equipment in these categories is less consistent across the plants. Improvements in the consistency of asset identification throughout the FCRPS as well as improvements in how the condition assessments are collected and quality-controlled are ongoing.

Condition ratings for each asset type are based on a set of objective condition indicators related to operational performance, maintenance history, physical inspection, and age. Condition indicators are weighted and summed to derive a condition rating, ranging from 0 to 10. Numeric scores are further categorized qualitatively as follows:

Table 8.3.2-1 hydroAMP Condition Descriptions

Condition Score	Condition Description
8.0 – 10.0	**Good**
6.0 – 7.9	**Fair**
3.0 – 5.9	**Marginal**
0.0 – 2.9	**Poor**

Across the FCRPS, about 66% of the assets are in Good and Fair condition, 25% are in Marginal condition, and 9% are in poor condition. Figure 8.3.2-1 below illustrates condition for each Strategic Class. Figure 8.3.2-1 summarizes condition by each strategic class.

Figure 8.3.2-1, Current Asset Condition by Classification

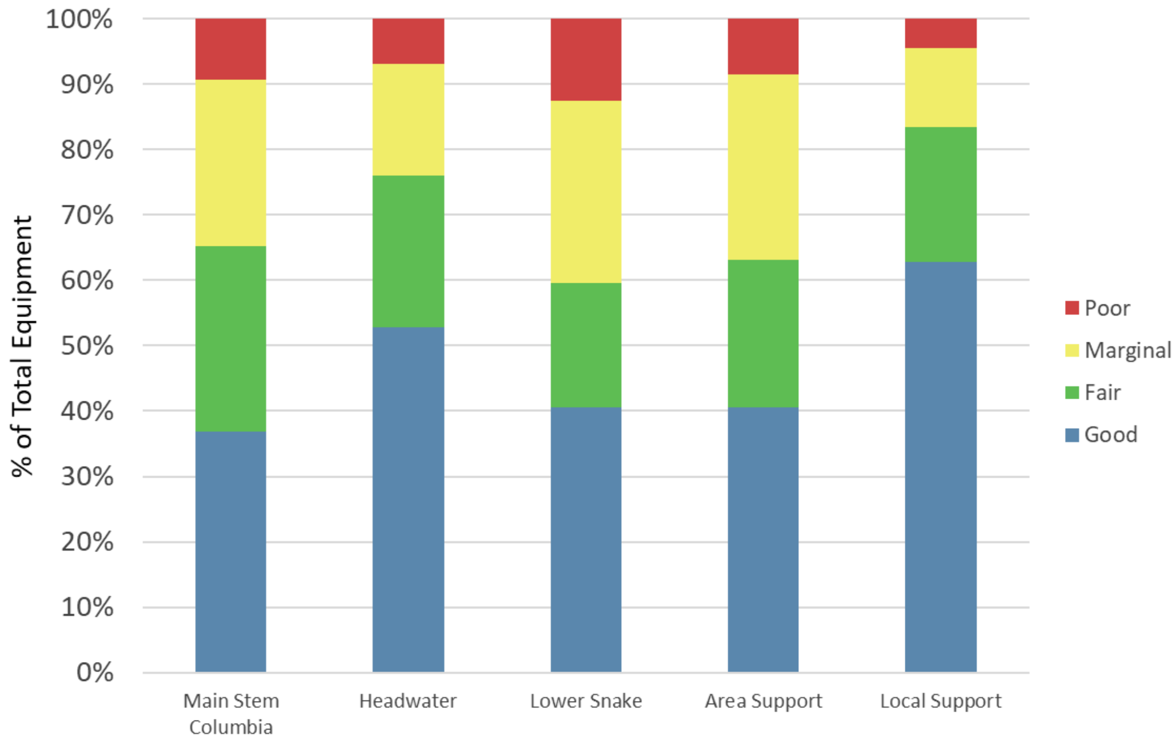
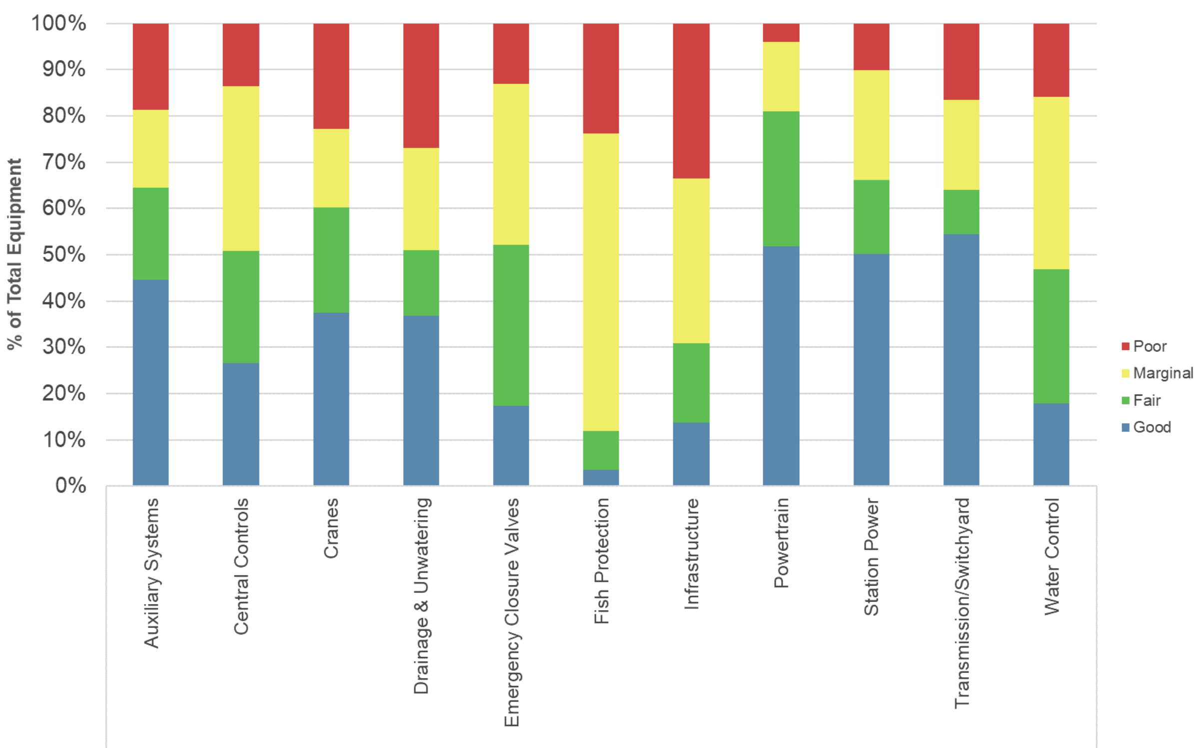


Figure 8.2-4 illustrates asset condition by equipment category. Equipment Categories summarize groups of equipment into higher-level categories for illustrative purposes.

Figure 8.3.2-2, Current Asset Condition by Equipment Category



The 2022 SAMP noted that many assets were on the cusp of the “marginal” category and that the numbers would see significant increases in the next decade without investment. Indeed, the percentage of assets in marginal and poor condition have increases in each equipment category since the 2022 SAMP.

Auxiliary Systems: 35% are in marginal or poor condition, up from 22% in the 2022 SAMP. Fire Detection Systems and Compressed Air Systems are the primary drivers.

Central Controls: 49% are in marginal or poor condition, up from 39% in the 2022 SAMP. SCADA/GDACS, Station Control Boards, Main Consoles and Annunciation Systems are the primary drivers. Over 80% would be in marginal or poor condition in 10 years without investment.

Cranes: 40% are in marginal or poor condition, up from 24% in the 2022 SAMP.

Drainage and Unwatering: 49% are in marginal or poor condition, up from 41% in the 2022 SAMP. Pumps are the primary driver.

Fish Protection: 88% are in marginal or poor condition, up from 81% in the 2022 SAMP. Fish screens are the primary driver and represent most of the inventoried assets in this category. Over 90% would be in marginal or poor condition in the next 10 years without investment.

Infrastructure: 69% are in marginal or poor condition, up from 59% in the 2022 SAMP. Communications Hardware, Elevators and HVAC are the primary drivers.

Powertrain: 19% are in marginal or poor condition, up from 15% in the 2022 SAMP. Generator windings, Turbine Runners and Transformers are the primary drivers.

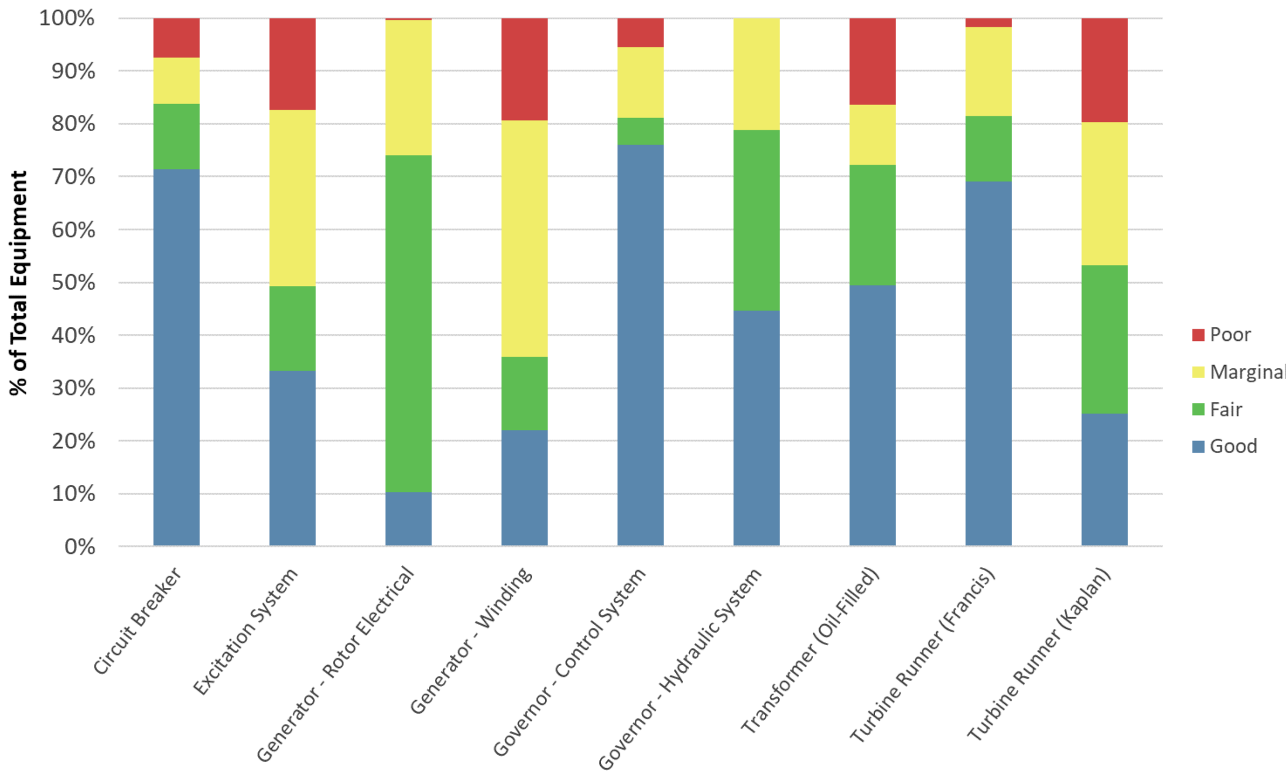
Station Power: 34% are in marginal or poor condition, up from 26% in the 2022 SAMP. Iso-Phase buses and switchgear are the primary drivers. This number rises to over 60% in the next 10 years without investment.

Transmission/Switchyard: 36% are in marginal or poor condition, up from 30% in the 2022 SAMP. Disconnects and Bus Work are the primary drivers.

Water Control: 53% are in marginal or poor condition, up from 49% in the 2022 SAMP. Emergency and Non-Emergency Closure gates are the primary drivers.

Although a smaller percentage of powertrain equipment are in marginal or poor condition, these assets still represent more than half of the risk in the system due to their long outage durations and high costs of repair. Figure 8.3.2-3 below displays condition for critical powertrain components.

Figure 8.3.2-3, Current Asset Condition by Critical Powertrain Asset Type



Nearly half of all Kaplan Turbine Runners and 65% of Generator Windings in the FCRPS are in marginal or poor condition. These two asset types have some of the longest expected outage durations in the event of failure and are among the costliest components to replace or repair. Together, runners and windings represent close to half of the cost of a generating unit. As such, investments are often driven by generator winding or turbine runner replacements. Although not as costly as windings or runners, excitation systems can also have significant impacts on unit availability. About 50% of the excitation systems across the FCRPS are in marginal or poor condition. Circuit breakers and governor control systems have higher percentages in good and fair condition from system-wide replacement projects affecting most FCRPS plants in the late 2000s and early 2010s.

8.4 Asset Performance

Maintaining performance metrics is a requirement of USACE and Reclamation's respective Direct Funding Agreements with BPA. The Performance Committee, a Three Agency subcommittee of the JOC, develops, revises, tracks, and reports on performance metrics in accordance with the Direct Funding Agreements. Performance metrics, including their addition or removal, are reviewed, and approved by the JOC and Executive Steering Committee on an annual basis. While metrics for safety, compliance, and environmental stewardship are tracked across the FCRPS, these metrics are not asset-specific and are not included in the SAMP.

8.4.1 Financial

The FCRPS tracks expenditure rates on its capital and expense programs relative to Start of Year budgets. Performance for the last 10 years is shown below.

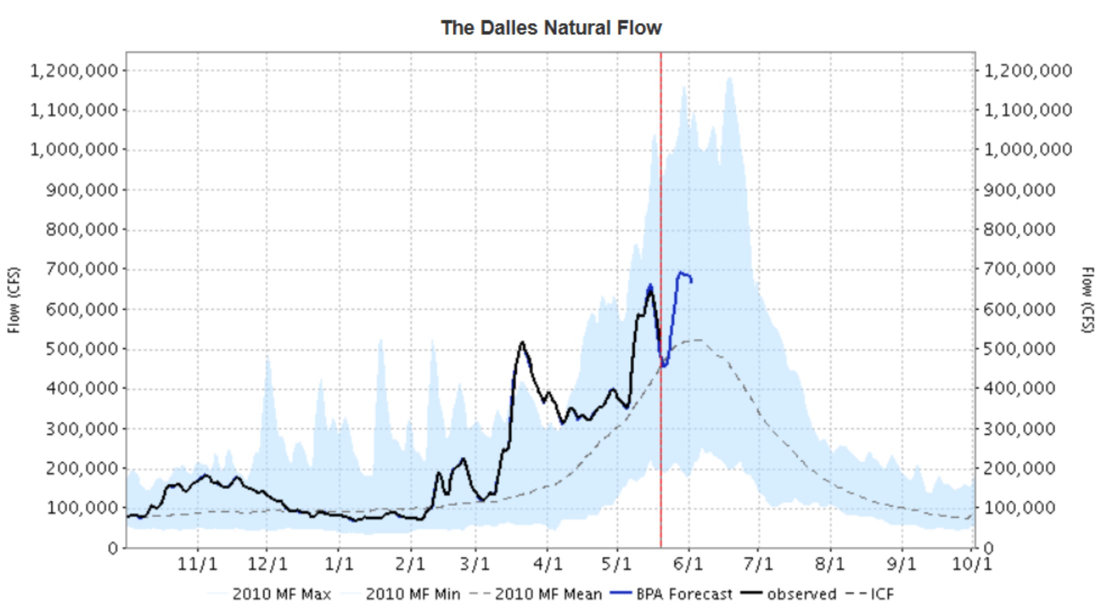
Table 8.4.3-1 FCRPS Direct Funded Capital, Expense, and NREX Budget Execution 2014-2023

Historical Performance										
Metric	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Power Expense Expenditure Rate	96%	94%	92%	97%	95%	98%	98%	97%	98%	99%
NREX Expenditure Rate	82%	79%	72%	89%	86%	99%	84%	80%	80%	110%
Large Capital Budget Expenditure Rate	90%	79%	93%	97%	103%	100%	77%	95%	70%	94%

8.4.2 Availability

Availability metrics are the primary performance indicators used to measure the performance of electric generating equipment. Generally, higher availability equates to more generation and revenue. However, hydropower resources differ from other generation resources due to the variability in their fuel source. Unlike more conventional dispatchable resources that can choose to produce when it is economical, hydro facilities are bound by the amount of water available for generation, which makes availability metrics a moving target. This is accentuated in the Columbia River Basin by the highly variable of within-year and year-to-year flows. Between fall and summer, natural flows can change by up to a factor of 10 in wet years or by as little as a factor of two in dry years.

Figure 8.4.5-1 Annual Flow Uncertainty at The Dalles



This highly variable water supply makes setting availability targets and comparing FCRPS availability to industry metrics challenging. Due to the unique configuration of each facility as well as the conditions in which they operate, the optimal level of availability will differ by plant, by month, and by year. Currently, availability targets are informed by each plant's 5-year outage plan and are updated on an annual basis. Baseline forced outage targets are developed by blending industry average forced outage factors with a 5-year average of each plant's forced outage factor.

For BPA, the level of availability is often less important than how closely plants follow their outage plans. Given enough time, BPA can adjust operations or rely on energy markets to mitigate for the impacts of outages. Unexpected changes in outages, either units going out of service or unexpectedly returning to service, tend to result in the costliest impacts. As a result, the FCRPS has recently focused on schedule outage factors. Performance targets are set to incentivize alignment with outage schedules set at the start of each fiscal year. FY23 performance and performance targets are shown below.

***Figure 8.4.5-2** FY23 Scheduled Outage Factor Performance*

FY23 - YTD Weighted Scheduled Outage Factor and Targets through September

	YTD Weighted Scheduled Outage Factor	YTD Target Projection	Min Lower Target (-5%)	Mid Lower Target (-3%)	Stretch Target (+/-2%)	Mid Upper Target (+3%)	Min Upper Target (+5%)
FCRPS	**18.3%**	**14.0%**	**9.0% - 11.0%**	**11.0% - 12.0%**	**12.0% - 16.0%**	**16.0% - 17.0%**	**17.0% - 19.0%**
Corps	**14.2%**	**12.8%**	**7.8% - 9.8%**	**9.8% - 10.8%**	**10.8% - 14.8%**	**14.8% - 15.8%**	**15.8% - 17.8%**
Chief Joseph	5.2%	9.9%	4.9% - 6.9%	6.9% - 7.9%	7.9% - 11.9%	11.9% - 12.9%	12.9% - 14.9%
Libby	18.8%	12.4%	7.4% - 9.4%	9.4% - 10.4%	10.4% - 14.4%	14.4% - 15.4%	15.4% - 17.4%
Albeni Falls	5.0%	4.5%	0.0% - 1.5%	1.5% - 2.5%	2.5% - 6.5%	6.5% - 7.5%	7.5% - 9.5%
Seattle District	**7.7%**	**10.1%**	**5.1% - 7.1%**	**7.1% - 8.1%**	**8.1% - 12.1%**	**12.1% - 13.1%**	**13.1% - 15.1%**
John Day	18.5%	5.9%	0.9% - 2.9%	2.9% - 3.9%	3.9% - 7.9%	7.9% - 8.9%	8.9% - 10.9%
The Dalles	11.6%	14.6%	9.6% - 11.6%	11.6% - 12.6%	12.6% - 16.6%	16.6% - 17.6%	17.6% - 19.6%
Bonneville	12.5%	13.7%	8.7% - 10.7%	10.7% - 11.7%	11.7% - 15.7%	15.7% - 16.7%	16.7% - 18.7%
Detroit	1.7%	1.9%	0.0% - 0.0%	0.0% - 0.0%	0.0% - 3.9%	3.9% - 4.9%	4.9% - 6.9%
Big Cliff	3.3%	3.2%	0.0% - 0.2%	0.2% - 1.2%	1.2% - 5.2%	5.2% - 6.2%	6.2% - 8.2%
Green Peter	1.1%	0.2%	0.0% - 0.0%	0.0% - 0.0%	0.0% - 2.2%	2.2% - 3.2%	3.2% - 5.2%
Foster	3.0%	16.7%	11.7% - 13.7%	13.7% - 14.7%	14.7% - 18.7%	18.7% - 19.7%	19.7% - 21.7%
Lookout Point	5.8%	5.7%	0.7% - 2.7%	2.7% - 3.7%	3.7% - 7.7%	7.7% - 8.7%	8.7% - 10.7%
Dexter	5.5%	8.3%	3.3% - 5.3%	5.3% - 6.3%	6.3% - 10.3%	10.3% - 11.3%	11.3% - 13.3%
Cougar	29.5%	1.7%	0.0% - 0.0%	0.0% - 0.0%	0.0% - 3.7%	3.7% - 4.7%	4.7% - 6.7%
Hills Creek	19.9%	9.5%	4.5% - 6.5%	6.5% - 7.5%	7.5% - 11.5%	11.5% - 12.5%	12.5% - 14.5%
Lost Creek	7.8%	6.9%	1.9% - 3.9%	3.9% - 4.9%	4.9% - 8.9%	8.9% - 9.9%	9.9% - 11.9%
Portland District	**14.1%**	**10.1%**	**5.1% - 7.1%**	**7.1% - 8.1%**	**8.1% - 12.1%**	**12.1% - 13.1%**	**13.1% - 15.1%**
Dworshak	4.1%	4.7%	0.0% - 1.7%	1.7% - 2.7%	2.7% - 6.7%	6.7% - 7.7%	7.7% - 9.7%
Lower Granite	12.8%	14.7%	9.7% - 11.7%	11.7% - 12.7%	12.7% - 16.7%	16.7% - 17.7%	17.7% - 19.7%
Little Goose	29.3%	13.5%	8.5% - 10.5%	10.5% - 11.5%	11.5% - 15.5%	15.5% - 16.5%	16.5% - 18.5%
Lower Monumental	21.1%	19.8%	14.8% - 16.8%	16.8% - 17.8%	17.8% - 21.8%	21.8% - 22.8%	22.8% - 24.8%
Ice Harbor	18.8%	25.2%	20.2% - 22.2%	22.2% - 23.2%	23.2% - 27.2%	27.2% - 28.2%	28.2% - 30.2%
McNary	19.3%	22.5%	17.5% - 19.5%	19.5% - 20.5%	20.5% - 24.5%	24.5% - 25.5%	25.5% - 27.5%
Walla Walla District	**18.5%**	**17.7%**	**12.7% - 14.7%**	**14.7% - 15.7%**	**15.7% - 19.7%**	**19.7% - 20.7%**	**20.7% - 22.7%**
Reclamation	**26.3%**	**16.5%**	**11.5% - 13.5%**	**13.5% - 14.5%**	**14.5% - 18.5%**	**18.5% - 19.5%**	**19.5% - 21.5%**
Grand Coulee	26.9%	16.0%	11.0% - 13.0%	13.0% - 14.0%	14.0% - 18.0%	18.0% - 19.0%	19.0% - 21.0%
Hungry Horse	25.0%	26.4%	21.4% - 23.4%	23.4% - 24.4%	24.4% - 28.4%	28.4% - 29.4%	29.4% - 31.4%
Grand Coulee Power Office	**26.8%**	**16.6%**	**11.6% - 13.6%**	**13.6% - 14.6%**	**14.6% - 18.6%**	**18.6% - 19.6%**	**19.6% - 21.6%**
Palisades	7.2%	9.9%	4.9% - 6.9%	6.9% - 7.9%	7.9% - 11.9%	11.9% - 12.9%	12.9% - 14.9%
Minidoka	48.1%	13.8%	8.8% - 10.8%	10.8% - 11.8%	11.8% - 15.8%	15.8% - 16.8%	16.8% - 18.8%
Upper Snake Field Office	**13.0%**	**10.4%**	**5.4% - 7.4%**	**7.4% - 8.4%**	**8.4% - 12.4%**	**12.4% - 13.4%**	**13.4% - 15.4%**
Anderson Ranch	4.6%	7.6%	2.6% - 4.6%	4.6% - 5.6%	5.6% - 9.6%	9.6% - 10.6%	10.6% - 12.6%
Boise Diversion	7.7%	6.6%	1.6% - 3.6%	3.6% - 4.6%	4.6% - 8.6%	8.6% - 9.6%	9.6% - 11.6%
Black Canyon	14.3%	5.2%	0.2% - 2.2%	2.2% - 3.2%	3.2% - 7.2%	7.2% - 8.2%	8.2% - 10.2%
Middle Snake Field Office	**6.6%**	**7.1%**	**2.1% - 4.1%**	**4.1% - 5.1%**	**5.1% - 9.1%**	**9.1% - 10.1%**	**10.1% - 12.1%**
Chandler	20.5%	36.8%	31.8% - 33.8%	33.8% - 34.8%	34.8% - 38.8%	38.8% - 39.8%	39.8% - 41.8%
Roza	12.1%	19.8%	14.8% - 16.8%	16.8% - 17.8%	17.8% - 21.8%	21.8% - 22.8%	22.8% - 24.8%
Green Springs	45.8%	48.1%	43.1% - 45.1%	45.1% - 46.1%	46.1% - 50.1%	50.1% - 51.1%	51.1% - 53.1%
Columbia-Cascades Area Office	**28.1%**	**36.1%**	**31.1% - 33.1%**	**33.1% - 34.1%**	**34.1% - 38.1%**	**38.1% - 39.1%**	**39.1% - 41.1%**

Internally, BPA tracks the FCRPS Forced Outage Factor on its performance scorecard. Forced outage factor measures the percentage of hours within a period that a generating unit is not available to run due to an unplanned event. This metric is megawatt-weighted, so larger units have a bigger influence on the Forced Outage Factor than smaller units. The target was met in 2 of the last 5 years.

Table 8.4.5-1 Historical FCRPS Forced Outage Factor Summary

Strategic Goal	Objective	Measure	Units	2019	2020	2021	2022	2023
Modernize assets	Power Reliability	Fed Hydro Forced Outage Factor	%	4.1	6.76	4.6	4.3	5.0
Modernize assets	Power Reliability	Target - Fed Hydro Forced Outage Factor	%	4.4	4.49	4.5	4.6	4.7

8.4.3 Cost of Power

For the 2020 SAMP, BPA Power and Finance developed an agreed upon methodology to calculate the cost of generation and fully loaded cost of FCRPS plants. Minor changes have since been made to allocation methodologies, but the approach remains largely unchanged. Currently, the FCRPS has not set specific targets for cost of power metrics, but targets may be considered in the future. Two metrics are tracked:

Cost of Generation: The direct cost and administrative overheads of producing power at a plant. Includes operations, maintenance, administrative, and capital related costs (interest expense). Costs such as the Lower Snake River Compensation plan that are directly attributable to plants are included in this measure.

Fully Loaded Cost: All costs of doing business associated with the hydro plant operations, power marketing, and delivery. Includes all costs from the costs of generation plus all other allocable costs to the hydro system such as BPA's Fish and Wildlife program, Residential Exchange, transmission acquisition, and other obligations.

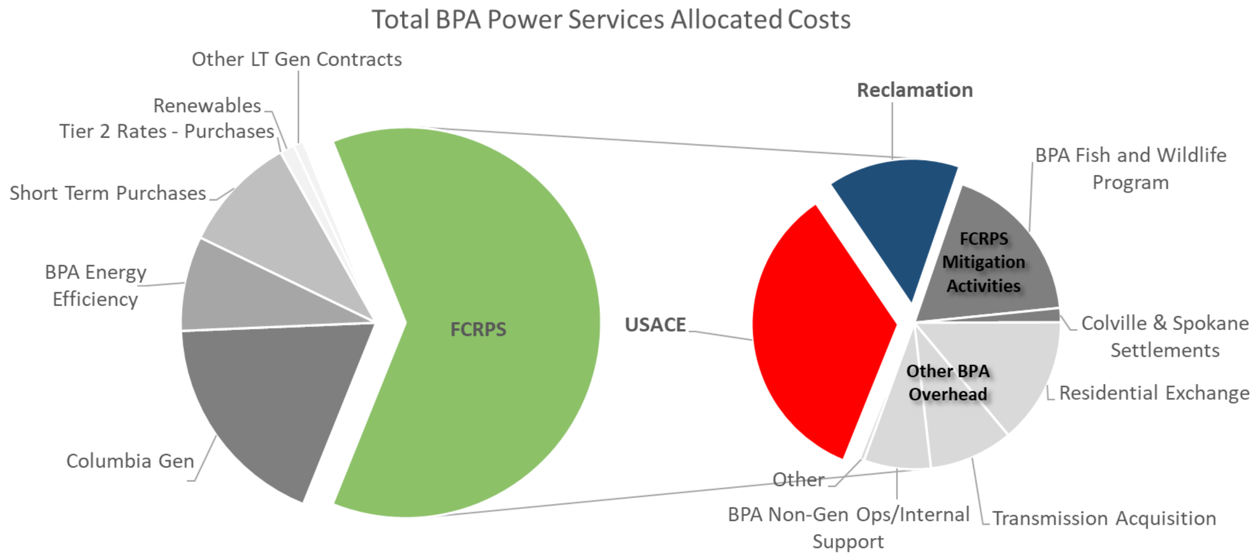
Table 8.4.6-1 Five-Year Average Cost of Power Metrics (FY18-FY22)

Strategic Class	Cost of Generation ($/MWh)	Fully Loaded Cost ($/MWh)
Main Stem Columbia	8.13	18.71
Lower Snake	18.30	30.18
Headwater	14.26	25.11
Area Support	23.52	33.91
Local Support	35.55	47.53
FCRPS Hydro	**10.49**	**21.24**

The 3-year average cost of power metrics for FY18-FY22 are shown in Table 8.4.6-1. Average costs are shown as per unit of output costs by incorporating average annual generation in the metric. The FCRPS hydro cost of generation of $10.49/MWh shows that the system is a very cost-effective resource when looking at the direct costs of power production. This measure is the most comparable to spot market prices, which are more closely tied to the marginal cost of power production. The fully loaded cost of the system was $21.24/MWh, which is also highly competitive compared to recent Mid-Columbia spot market prices and new resource costs.

The power share of USACE and Reclamation costs, shown in red and blue in Figure 1.0-1 on the right below, account for about half of all costs associated with the 31 FCRPS dams. Mitigation costs and BPA overheads that are allocated to the dams make up the remainder. Costs allocated to the FCRPS dams represent about 62% of Power Services total costs, which is displayed graphically in green in Figure 1.0-1 on the left below. Columbia Generating Station, BPA's Energy Efficiency program, and short-term purchases of energy make up most of the remainder of Power Services total costs.

Figure 8.4.6-1 Total BPA Power Services Allocated Costs



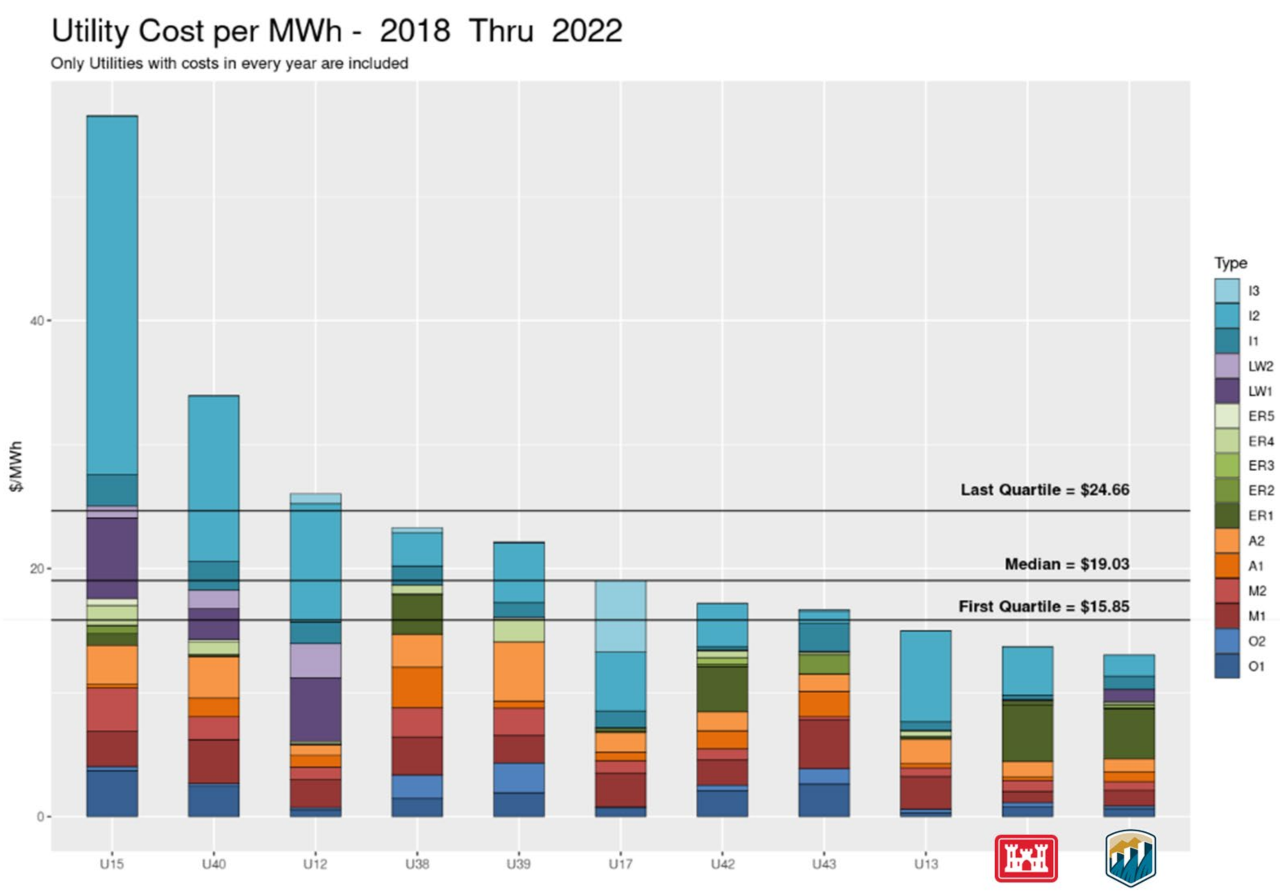
8.5 Performance and Practices Benchmarking

The FCRPS benchmarks its plants in the Hydro Productivity Committee (HPC) of the Electric Utility Cost Group (EUCG). As of 2023, there were 17 utilities in the HPC that benchmarked 349 plants. The HPC maintains a data guide that provides instructions on what costs should be included, excluded and recommendations for cost allocations. The following cost categories are used to compare costs between utilities within EUCG:

- Operations (O – blues) includes facility operations and all operations planning
- Maintenance (M – reds) includes all facility maintenance
- Administration (A – oranges) includes IT, Finance, HR, Telecom, Asset Management, and more
- Environmental/Regulatory (ER – greens) includes Fish & Wildlife, Recreation, and Cultural Resources
- Land and Water Fees (LW – purples) includes rentals or fees for use of land or water
- Investment (I – cyan) includes non-routine expense

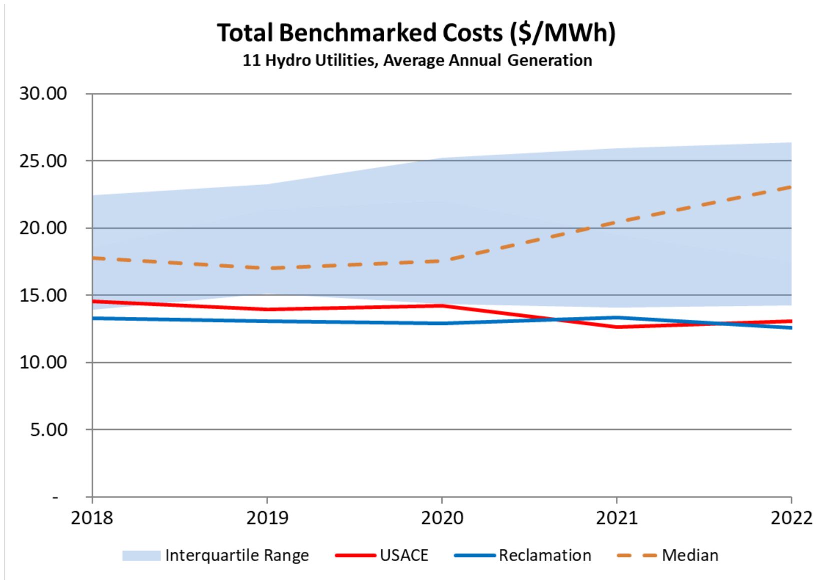
Note that the benchmarked costs and resulting $/MWh will differ from BPA's cost of generation and fully allocated cost numbers. There is an agreed upon data guide for costs to assure that numbers are comparable across utilities. Some costs included in the Cost of Generation and Fully Loaded Cost metrics are not considered in benchmarking or are considered differently.

Figure 8.5 1-EUCG Cost-per-MWh Benchmarking



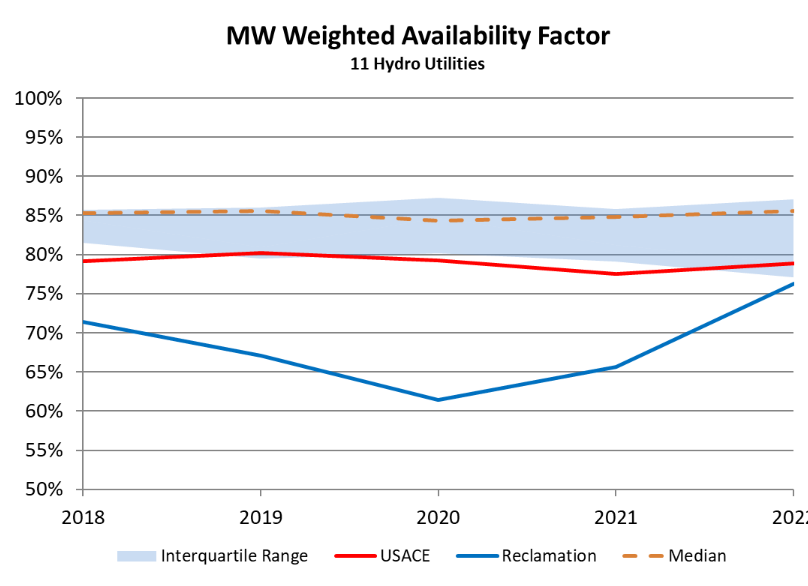
Over the 2018 to 2022 period, USACE and Reclamation were first quartile performers in total cost per MWh of production. Compared to other hydro utilities in the benchmark, USACE and Reclamation have much larger facilities that benefit from economies of scale. Figure 8.5-2 shows that USACE and Reclamation expense costs remained stable and even decreased slightly over the period while the median costs across all utilities increased.

Figure 8.5-2 EUCG Historic Benchmarked Costs Relative to USACE and Reclamation



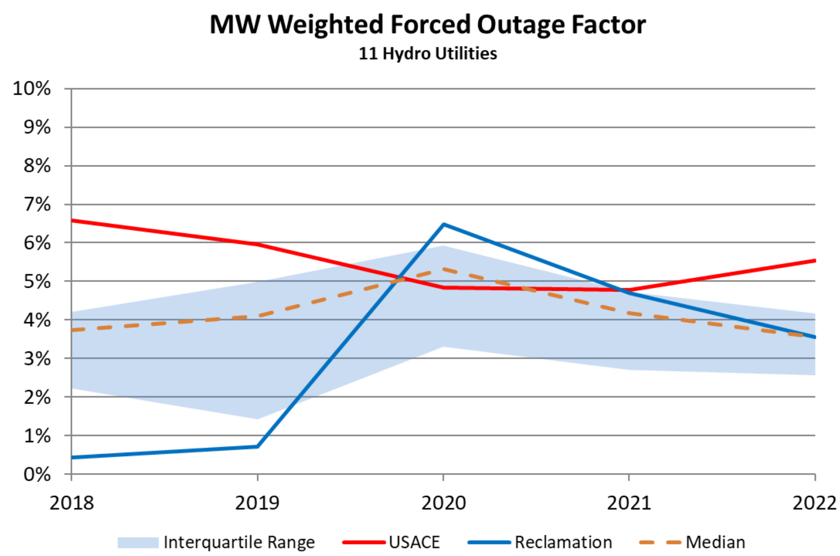
Availability has consistently been below the industry median. USACE has tended to be at the lowest quartile of availability while Reclamation has been far below the interquartile range.

Figure 8.5-3 EUCG Historic MW Weighted Availability Factor Relative to USACE and Reclamation



For Reclamation, the primary driver has been scheduled outages in the Third Powerplant at Grand Coulee. For USACE, forced outages have been a major contributor to reduced availability since 2018 and have been higher than the rest of the industry in most years. Due to the unplanned nature of forced outages, they often prove to be costlier than scheduled outages as they can occur during times when unit availability is critical and mitigation efforts are difficult to implement on short notice. John Day, The Dalles, McNary, Ice Harbor, and Grand Coulee have been major contributors to the high forced outage factor in recent years. At The Dalles and Ice Harbor, capital investments are currently underway on equipment responsible for prior forced outages. Investments in the 2020s and 2030s at McNary, John Day, and Grand Coulee will also address reliability concerns.

Figure 8.5-4 EUCG Historic MW Weighted Forced Outage Factor Relative to USACE and Reclamation

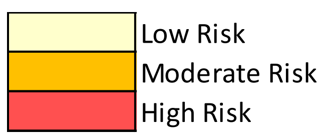


While USACE and Reclamation costs per MWh are the lowest among the 11 utilities in the 2018-2022 benchmarking period, they also have among the highest forced outage factor and lowest availability factor. This data may suggest that we are underinvesting in the system relative to our utility peers. Analysis in Section 10.2 further evaluates these cost, risk, and performance tradeoffs.

9.0 RISK ASSESSMENT

The following risk matrices show where each inventoried asset falls based on current asset condition and the resulting likelihood and consequence of failure. Risk maps are divided into three regions, described as follows:

Figure 9.0-1 Risk Matrix Legend



Risk matrices reflect a snapshot in time. As condition degrades and likelihood of failure increases, assets move up the risk matrix into the moderate and high-risk categories. Replacements and refurbishments reduce the likelihood of failure, causing assets to return to the low-risk category. Prior to replacement or refurbishment, unacceptable risks are typically mitigated through operational measures until investment occurs.

Safety Risk

Figure 9.0-2 FCRPS Asset Safety Risk Matrix with Count of Assets in High-Risk Category by Equipment Category

Likelihood \ Consequence	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	305	7	54	58	11
Likely	278	23	119	52	8
Possible	726	96	228	145	20
Unlikely	841	93	176	142	24
Rare	4514	328	423	349	100

Assets in High-Risk Category

Equipment Category	# of Assets
Auxiliary Systems	23
Central Controls	10
Cranes	2
Drainage & Unwatering	0
Emergency Closure Valves	0
Fish Protection	0
Infrastructure	13
Powertrain (incl.Main, SS, & Fish)	72
Reservoir	0
Station Power	39
Transmission/Switchyard	19
Water Control	5
Total	**183**

A total of 183 assets are in the high-risk category and shown by equipment category in the table to the right of the risk map. Since the 2022 SAMP, Reclamation inventoried a significant number of Station Power assets in preparation for a series of arc flash mitigation projects at Grand Coulee. A number of these fall in the high-risk category and are a Reclamation priority for replacement.

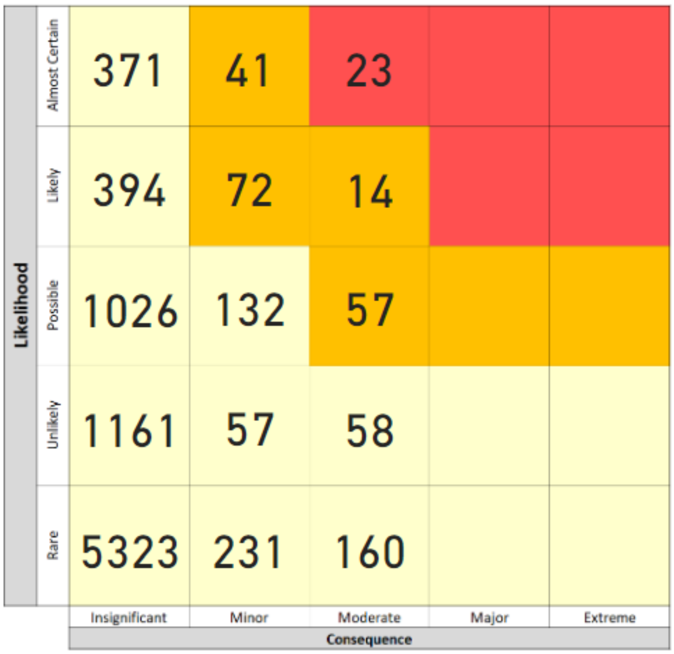
102 of the 183 assets have investments identified to mitigate their safety risk. Risk is mitigated with operational procedures for assets that do not have an investment identified. Typically, investments are planned when operational procedures are excessively costly or do not effectively mitigate the risk.

USACE is currently programmatically evaluating and prioritizing life safety improvements across their powerhouses and control rooms. This prioritization will likely result in more assets with identified investments to mitigate their risks.

Compliance Risk

In its current state, the risk map for Compliance Risk primarily measures the risk associated with failing to meet WECC/NERC standards. As mentioned in 7.1.1.3, compliance risk is also intended to capture the need to implement the actions consulted upon in the BiOps and the required actions in the Incidental Take Statements and comply with other state laws, federal laws, and regulations. Capturing these risks at the asset level was initially planned for the 2024 SAMP but work is still on-going. As before, these risks are captured when investments are created as described in Section 7.1. Relative to WECC/NERC compliance, it is not believed that many FCRPS assets pose a significantly high risk, individually. There is sufficient redundancy to ensure that consequences for any individual failures remain manageable. The highest consequence identified for an individual asset is "moderate." There are currently 23 assets in the high-risk category, 10 of which have an active investment identified.

Figure 9.0-3 FCRPS Asset Compliance Risk Matrix with Count of Assets in High-Risk Category by Equipment Category



Assets in High-Risk Category

Equipment Category	# of Assets
Auxiliary Systems	0
Central Controls	10
Cranes	0
Drainage & Unwatering	2
Emergency Closure Valves	0
Fish Protection	0
Infrastructure	0
Powertrain (incl.Main, SS, & Fish)	0
Reservoir	0
Station Power	0
Transmission/Switchyard	11
Water Control	0
Total	**23**

Reliability and Financial Risk

Reliability and financial risks are assessed through lost generation risk and direct cost risk. Lost generation risk measures the lost revenue associated with equipment not being able to generate. Direct cost risk measures the non-generation impacts of failures such as repair costs, damage to adjacent equipment, or other incremental costs incurred to restore equipment to service.

There are currently 357 assets in the high-risk category for lost generation risk. 250 of these assets have active investments planned to reduce their risk. Recent spot market prices have been significantly higher than at any point in the last 10 years, averaging $93/MWh in FY23. As a result, the consequence of unit outages is elevated and more assets have moved up into the high-risk category. The long-term price forecast suggest that prices will likely reduce from current levels and the number of high-risk assets will also drop as the outage costs reduce. For direct cost risk, there are 489 assets in the high-risk category. 306 of these assets currently have investments planned to mitigate their risks.

Figure 9.0-4 FCRPS Asset Lost Generation Risk Matrix with Count of Assets in High-Risk Category by Equipment Category

Likelihood	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	2	5	25	111	22
Likely	2	1	67	171	28
Possible	25	21	148	465	60
Unlikely	21	34	300	597	68
Rare	69	224	1204	3067	415

Consequence

Assets in High-Risk Category

Equipment Category	# of Assets
Auxiliary Systems	0
Central Controls	18
Cranes	3
Drainage & Unwatering	1
Emergency Closure Valves	0
Fish Protection	0
Infrastructure	0
Powertrain (incl.Main, SS, & Fish)	251
Station Power	41
Transmission/Switchyard	18
Water Control	25
Total	**357**

Figure 9.0-5 FCRPS Asset Direct Cost Risk Matrix with Count of Assets in High-Risk Category by Equipment Category

Likelihood	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	2	61	345	53	
Likely		40	349	89	2
Possible		142	815	242	15
Unlikely		109	958	211	1
Rare		1715	3543	463	1

Consequence

Assets in High-Risk Category

Equipment Category	# of Assets
Auxiliary Systems	83
Central Controls	15
Cranes	8
Drainage & Unwatering	36
Emergency Closure Valves	0
Fish Protection	0
Infrastructure	52
Powertrain (incl.Main, SS, & Fish)	186
Reservoir	0
Station Power	50
Transmission/Switchyard	14
Water Control	45
Total	**489**

As lost generation and direct cost risks are directly quantified, the following charts display their current levels at each of the 31 plants. High energy prices have resulted in a significant increase in lost generation risk across the FCRPS. At Grand Coulee, low condition scores on G19-21 and Washington Power Plant station service equipment contribute to both high lost generation risk and direct cost risk. Transformer issues at The Dalles, which impact multiple units at a time, similarly are resulting in higher risks than in the 2022 SAMP.

Figure 9.0-6 FCRPS Lost Generation Risk by Plant

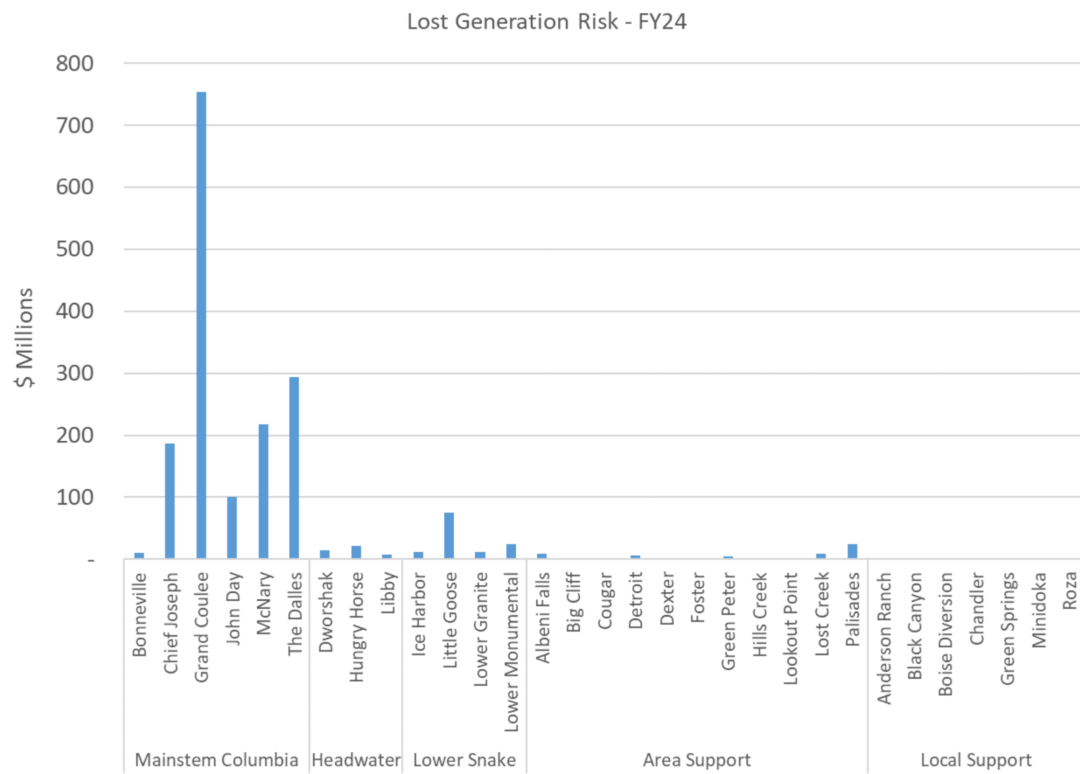
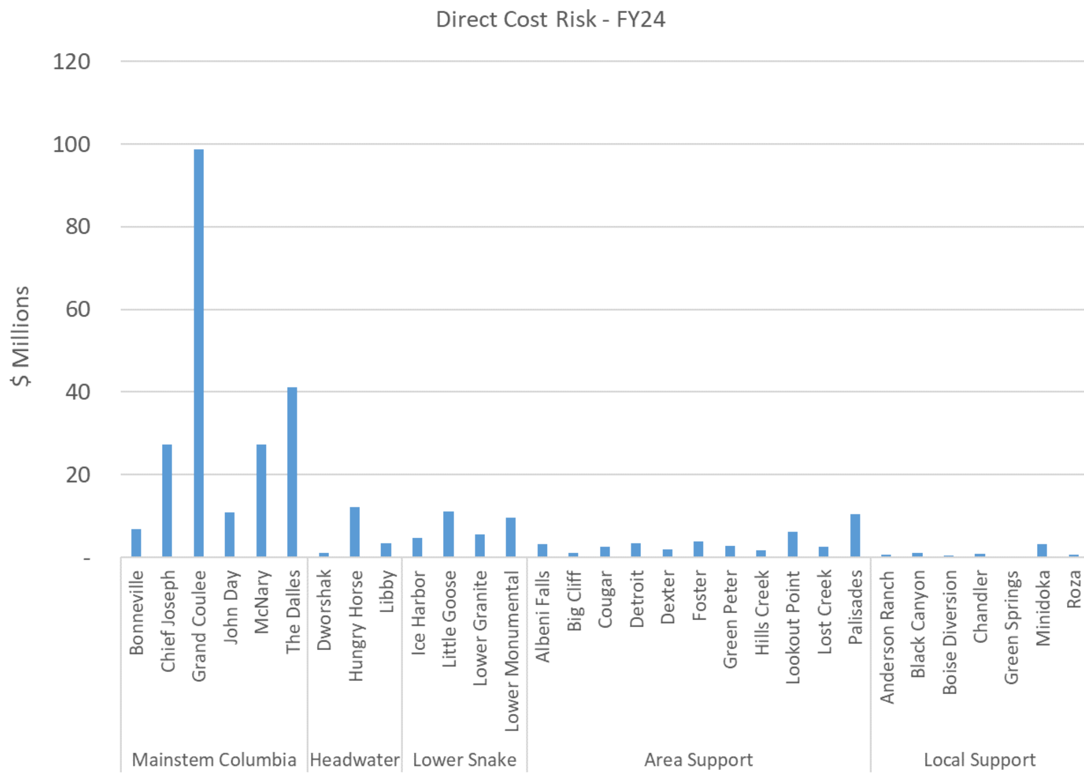


Figure 9.0-7 FCRPS Direct Cost Risk by Plant Service Category



Environmental Risk

Figure 9.0-8 FCRPS Asset Environmental Risk Matrix with Count of Assets in High-Risk Category by Equipment Category

Likelihood	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	337	23	6	69	
Likely	315	46	23	96	
Possible	701	157	198	159	
Unlikely	834	160	140	142	
Rare	4362	695	360	297	

Consequence

Assets in High-Risk Category

Equipment Category	# of Assets
Auxiliary Systems	2
Central Controls	14
Cranes	0
Drainage & Unwatering	5
Emergency Closure Valves	0
Fish Protection	0
Infrastructure	0
Powertrain (incl.Main, SS, & Fish)	66
Reservoir	0
Station Power	6
Transmission/Switchyard	0
Water Control	78
Total	**171**

There are currently 171 assets in the high environmental risk category. All of these assets have investments planned to mitigate their risks. The risk associated with the remaining assets is typically mitigated through operational measures or through the installation of new assets such as oil water separators. Once installed, those assets would likely reduce the consequence of failure below the high-risk category.

Public Perception Risk

In the 2022 SAMP, no assets were in the high-risk category. It was noted that there were a few assets that could cross into the high-risk category as condition degrades and probability of failure increases. 3 assets in the Drainage & Unwatering equipment category recently moved up into high-risk. 2 of the assets already have investments identified to mitigate their risks.

Figure 9.0-8 FCRPS Asset Environmental Risk Matrix with Count of Assets in High-Risk Category by Equipment Category

Likelihood \ Consequence	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	383	51		1	
Likely	429	49		2	
Possible	1052	76	85	2	
Unlikely	1172	64	38	2	
Rare	5431	180	87	16	

Assets in High-Risk Category

Equipment Category	# of Assets
Auxiliary Systems	0
Central Controls	0
Cranes	0
Drainage & Unwatering	3
Emergency Closure Valves	0
Fish Protection	0
Infrastructure	0
Powertrain (incl.Main, SS, & Fish)	0
Reservoir	0
Station Power	0
Transmission/Switchyard	0
Water Control	0
Total	**3**

10.0 STRATEGY AND FUTURE STATE

10.1 Future State Asset Performance

FCRPS investment strategies are driven by minimizing lifecycle cost rather than meeting specific asset performance objectives. This is because BPA's obligations to its power customers can typically be fulfilled for short periods of time, if necessary, through market purchases if FCRPS assets are unavailable. Although this preserves the load-resource balance and ensures the lights stay on, the replacement power may come at a higher cost and potentially from a carbon-emitting resource. As a result, asset-related decisions are largely based on economics rather than meeting specific availability goals. FCRPS strategies focus on optimizing asset-level tradeoffs between equipment reliability, failure costs, and other benefits associated with equipment replacement rather than targeting specific performance levels. This methodology is described in detail in Section 10.2. For the FCRPS, optimal plant availability is a result of the strategy rather than a driver.

With that in mind, BPA, USACE, and Reclamation develop a 5-year availability forecast that includes a flat long-term outlook for out-year availability. Plants develop and submit these forecasts on an annual basis based on known maintenance, capital, and forced outage expectations. Current year forecasts are used to set plant-level scheduled outage targets. Future year forecasts fluctuate from year-to-year as investment timing changes with the annual optimization of the asset plan.

Table 10.1-1 Future Asset Performance Objectives

Objective	Plant	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Weighted Availability Factor	Albeni Falls	90%	91%	90%	90%	91%	91%	91%	91%	91%	91%	91%
Weighted Availability Factor	Anderson Ranch	88%	89%	90%	89%	91%	91%	91%	91%	91%	91%	91%
Weighted Availability Factor	Big Cliff	95%	95%	95%	95%	94%	94%	94%	94%	94%	94%	94%
Weighted Availability Factor	Black Canyon	91%	93%	93%	93%	92%	92%	92%	92%	92%	92%	92%
Weighted Availability Factor	Boise Diversion	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%
Weighted Availability Factor	Bonneville	89%	91%	88%	91%	90%	90%	90%	90%	90%	90%	90%
Weighted Availability Factor	Chandler	35%	52%	56%	56%	54%	54%	54%	54%	54%	54%	54%
Weighted Availability Factor	Chief Joseph	96%	95%	96%	96%	94%	94%	94%	94%	94%	94%	94%
Weighted Availability Factor	Cougar	94%	94%	94%	94%	95%	95%	95%	95%	95%	95%	95%
Weighted Availability Factor	Detroit	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Weighted Availability Factor	Dexter	88%	89%	88%	88%	89%	89%	89%	89%	89%	89%	89%
Weighted Availability Factor	Dworshak	90%	92%	94%	92%	92%	92%	92%	92%	92%	92%	92%
Weighted Availability Factor	Foster	95%	96%	96%	96%	94%	94%	94%	94%	94%	94%	94%
Weighted Availability Factor	Grand Coulee	85%	82%	69%	68%	71%	71%	71%	71%	71%	71%	71%
Weighted Availability Factor	Green Peter	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%
Weighted Availability Factor	Green Springs	93%	93%	93%	93%	90%	90%	90%	90%	90%	90%	90%
Weighted Availability Factor	Hills Creek	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Weighted Availability Factor	Hungry Horse	78%	80%	85%	83%	80%	80%	80%	80%	80%	80%	80%
Weighted Availability Factor	Ice Harbor	72%	77%	84%	88%	76%	76%	76%	76%	76%	76%	76%
Weighted Availability Factor	John Day	84%	85%	84%	84%	93%	93%	93%	93%	93%	93%	93%
Weighted Availability Factor	Libby	89%	84%	89%	88%	87%	87%	87%	87%	87%	87%	87%
Weighted Availability Factor	Little Goose	89%	90%	89%	89%	89%	89%	89%	89%	89%	89%	89%
Weighted Availability Factor	Lookout Point	63%	63%	63%	74%	64%	64%	64%	64%	64%	64%	64%
Weighted Availability Factor	Lost Creek	94%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%
Weighted Availability Factor	Lower Granite	87%	84%	84%	88%	84%	84%	84%	84%	84%	84%	84%
Weighted Availability Factor	Lower Monumental	83%	86%	86%	88%	86%	86%	86%	86%	86%	86%	86%
Weighted Availability Factor	McNary	73%	76%	77%	77%	76%	76%	76%	76%	76%	76%	76%
Weighted Availability Factor	Minidoka	90%	89%	89%	89%	88%	88%	88%	88%	88%	88%	88%
Weighted Availability Factor	Palisades	92%	91%	91%	89%	90%	90%	90%	90%	90%	90%	90%
Weighted Availability Factor	Roza	83%	83%	83%	83%	79%	79%	79%	79%	79%	79%	79%
Weighted Availability Factor	The Dalles	81%	84%	89%	95%	90%	90%	90%	90%	90%	90%	90%

In terms of driving strategic direction, a financial performance measure such as the cost of generation ($/MWh) may be more valuable to focus on than availability. These measures are tracked and forecasted into the future, but more work is required between the Three Agencies to determine if developing targets would add value in the current asset management process. This remains to be prioritized in the Asset Management roadmap.

10.2 Strategy

The FCRPS long-term strategy is to make coordinated operations, maintenance, and investment decisions that maximize the value of FCRPS assets by reducing costs, mitigating risk, improving efficiency, and producing incremental value. A cornerstone of the strategy is decision making that is risk-informed and considers asset condition, probability of failure, and the impacts to each of the Three Agencies' missions. These factors already drive the capital investment program and progress is being made to consider similar factors for the expense program.

A key component in building the FCRPS strategy and identifying recommended funding levels is determining the optimal time to reinvest in FCRPS assets. FCRPS staff use Copperleaf, an Asset Investment Planning and Management tool, to develop the capital investment strategy and asset plan. Copperleaf tracks the benefits, costs, and assets associated with investments. It provides tools for future investment identification as well as investment decision optimization. Using asset condition, failure characteristics, and investment information, Copperleaf can calculate the optimal time to invest in an asset, optimize the timing of investments in an investment portfolio, and illustrate the costs and benefits of different investment strategies or funding levels. There are two primary capabilities leveraged by FCRPS staff to develop investment strategies and plans:

Predictive Analytics: Identifies the optimal replacement date for each asset in the FCRPS asset registry by minimizing lifecycle cost and mitigating high safety, environmental, compliance, and public perception risks within budget constraints. The optimal replacement dates produced by Predictive Analytics are intended to be directional and form the basis for long-term funding levels, investment identification, and the asset plan.

Value Framework and Investment Decision Optimization: This process optimizes the timing and alternatives of investments in a portfolio to maximize value within constraints. USACE and Reclamation utilize information from plant staff as well as Predictive Analytics recommendations to develop projects in Copperleaf. Benefits and costs of each project are assessed using the value framework and the projects are added to the FCRPS investment portfolio. The FCRPS Asset Planning Team uses the portfolio optimization functionality in Copperleaf to develop the Asset Plan.

Predictive Analytics

Copperleaf Predictive Analytics calculates optimal replacement dates by:

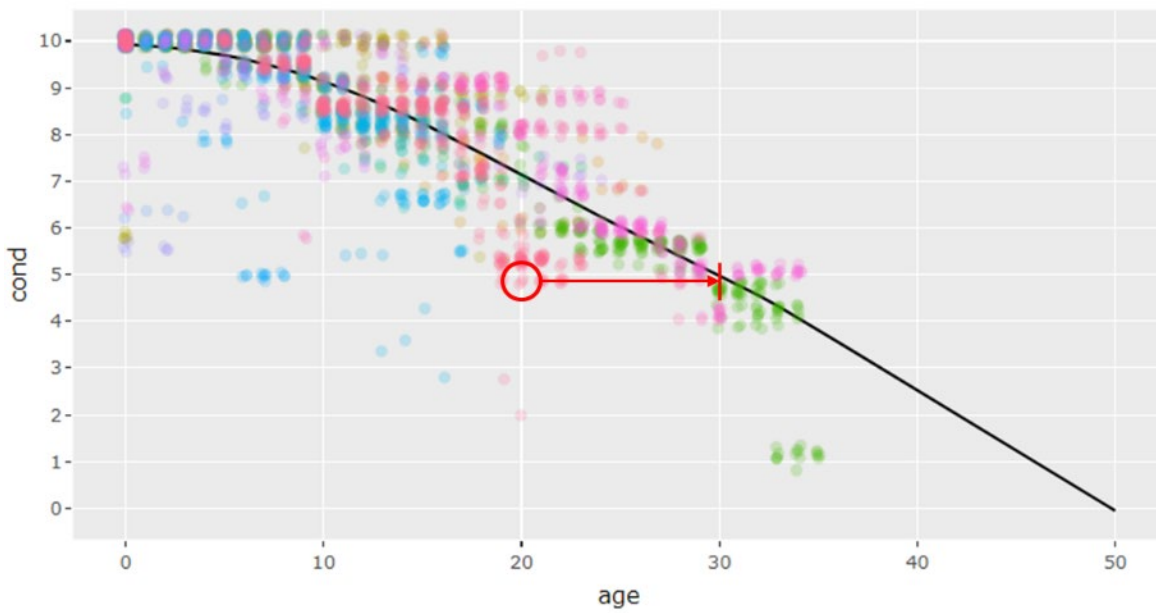
- Assessing current condition and forecasting how it changes over time;
- Relating asset condition to an effective age and probability of failure for each asset type;
- Multiplying the consequence of failure by the probability of failure for each respective asset to determine the risk it poses in a given year; and
- Minimizing the sum of the present value risk costs and replacement cost.

Condition

Historically, USACE and Reclamation assessed equipment condition for powertrain and critical auxiliary components annually and balance of plant equipment semiannually. With the ongoing expansion of the asset registry, the FCRPS has moved to requiring assessments at intervals tied to common maintenance and inspection practices. This is intended to maximize the value of time spent on condition assessment. Equipment Condition is assessed using the hydroAMP Condition Assessment framework, described in detail in Section 8.2.2.

Future condition is forecast using expected degradation rates developed using regression analyses on hydroAMP condition data that relates equipment condition to equipment age. The analysis groups condition scores into eleven buckets, rounding condition scores to ratings of 0 through 10. Logistic regressions then give the probability that a piece of equipment falls into each of the 11 buckets at a given age. The expected condition decay curve is built up from these regressions, which are the expected values at each age.

Figure 10.2-1 Example Equipment Condition Degradation Curve



The chart above illustrates an expected degradation curve with each individual point representing a condition assessment at a specific equipment age. Each individual assessment is shown on the graph with a semitransparent colored circle so that overlapping assessments produce darker regions where the data is most concentrated. This reveals the emerging expected relationships between age and condition as well as the level of variability around those patterns. The colors represent assessments from different plants in the FCRPS. Effective age is determined by comparing current asset condition to the expected degradation curve. In the example above, the circled assessment with a condition score of 5 at an actual age of 20 is more representative of an effective age of 30 based on expected degradation across the population.

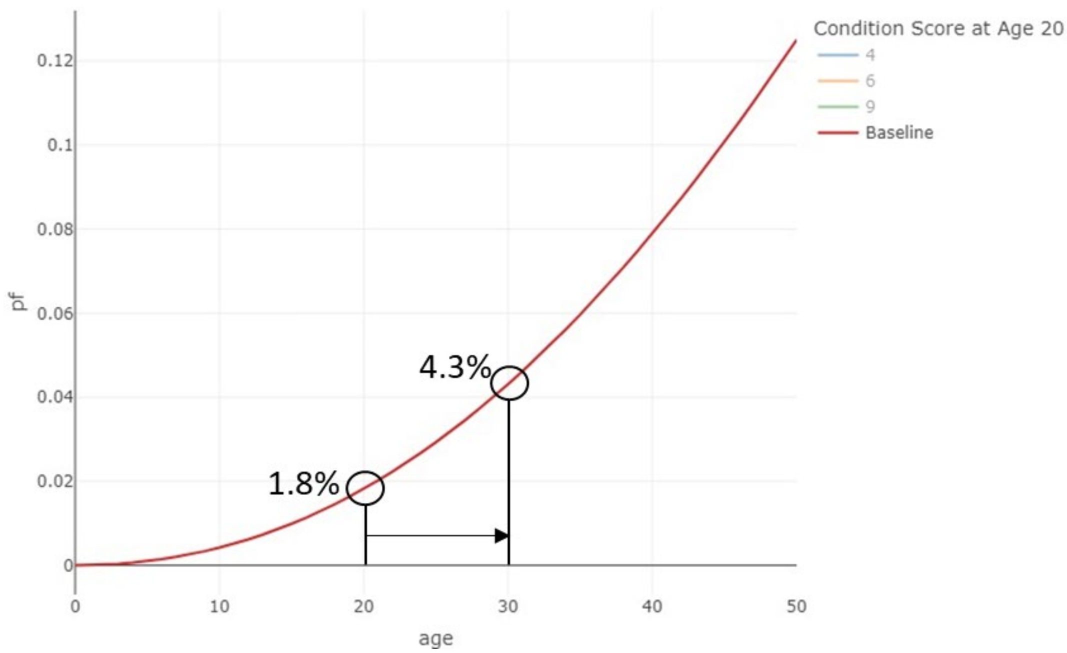
Probability of Failure

An asset's effective age is used in combination with Weibull curves associated with an asset's respective asset type to determine probability of failure. Baseline failure curves for powertrain and critical auxiliary equipment were developed in 2016 using an Expert Opinion Elicitation process facilitated by the USACE Risk Management

Center. The curves were developed for twenty-eight major hydropower assets using the opinion of Subject Matter Experts from USACE, including the Hydroelectric Design Center, BPA, Reclamation, Tennessee Valley Authority, Chelan County Public Utility District, and Western Area Power Administration. Since 2016, the FCRPS has evaluated and updated the curves as needed.

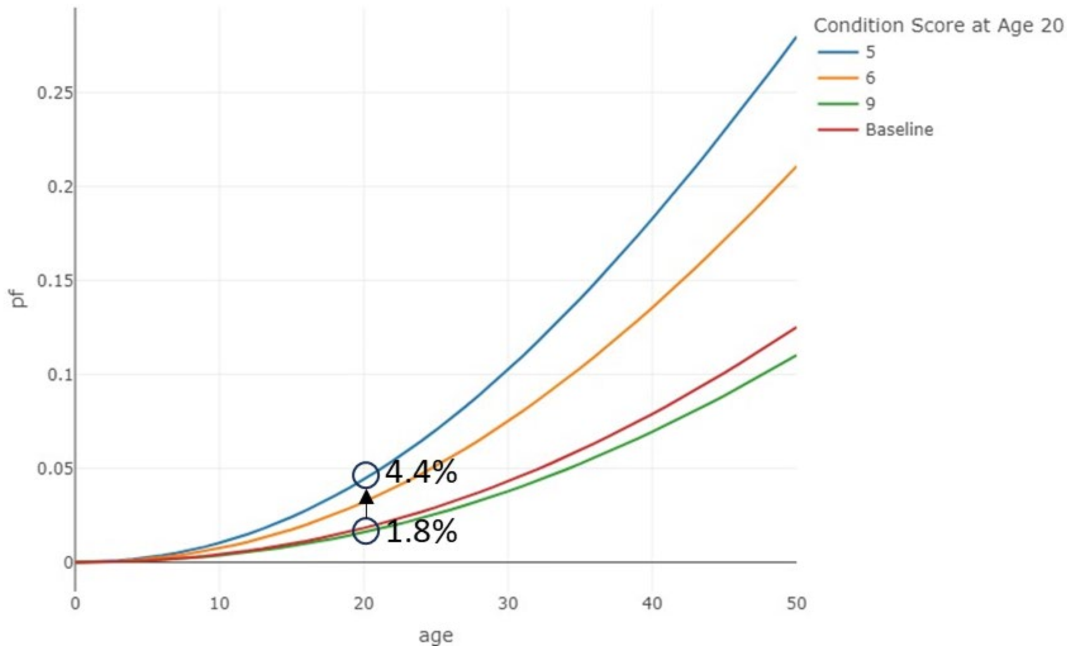
Starting in the 2024 SAMP, a new process is used to map equipment condition to probability of failure. This new process adjusts each asset's Weibull parameters based on observed conditions relative to expectations. In the old methodology, condition was used to move up or down the baseline curve as shown in the figure below. The example shows that an asset has an actual age of 20 and a 1.8% probability of failure between the age of 20 and 21. Using the asset's effective age of 30 results in a movement along the curve and a probability of failure of 4.3%. Subsequent years would then continue to follow along the baseline curve.

Figure 10.2-2 Example Weibull Curve with Old Correction for Condition



The new methodology modifies the baseline Weibull parameters to recognize that an asset degrading slower or faster than expected is likely to continue that trend rather than reverting to the baseline. Said another way, if we consider a 20-year-old asset and a 30-year-old asset that both have an effective age of 30, we expect the 20-year-old asset to continue to degrade more quickly into the future. Figure 102-2 shows how different condition scores shift the curve. Continuing with the prior example, the failure curve would shift from the red to the blue line for a condition score of 5 at Age 20.

Figure 10.2-2 Example Weibull Curve with New Correction for Condition



The resulting probability of failure is quite similar, 4.4% in the new methodology versus 4.3% in the old methodology. However, the differences grow as probability is forecast into the future. For assets that largely follow the expected condition degradation curve, there is little difference between the two approaches. The benefit is realized for assets with degradation that significantly differs from expectations. Tailoring failure curves to individual assets allows these differences to be more accurately quantified and considered in the modeling.

Risks and Costs

The following risks and costs are quantified in the modeling:

Lost Generation Risk (LGR): Captures the generation-related risk associated with equipment failure. This risk is calculated by multiplying the asset's probability of failure by its outage consequences. Outage consequences are the product of a plant's Marginal Outage Consequence in megawatt-hours, the asset's expected forced outage duration, and the market price forecast. Marginal Outage Consequences estimate the lost generation associated with an incremental forced outage at a plant relative to its planned availability. They are modeled at each plant under current operations, by month, over the historical water record. Forced outage durations are estimated for each asset type and periodically updated by FCRPS subject matter experts. BPA's long-term Mid-Columbia market price forecast is used to estimated LGR into the future. It is assumed that a forced outage results in either a forced purchase or lost sale opportunity.

Lost Generation Risk (LGR) = p(f) * Marginal Outage Cost (MWh/week) * Outage Duration (weeks) * Market Price Forecast

Direct Cost Risk (DCR): Captures the non-generation-related risk associated with equipment failure. This risk estimates the incremental lifecycle costs incurred that would otherwise be avoided had the asset been replaced prior to failure. This includes costs incurred due to collateral damage as well as planning, procurement, and scheduling inefficiencies (overtime, emergency hiring, contract premiums, etc.). These inefficiencies are estimated for each asset type as a percentage of planned replacement cost and are periodically updated by FCRPS subject matter experts. This percentage is referred to as the "Direct Cost Ratio."

Direct Cost Risk (DCR) = p(f) * Direct Cost Ratio * Replacement Cost

Lost Efficiency Opportunity (LEO): Turbine runners lose efficiency over time. Additionally, improved designs for new turbine runners will result in higher efficiency than at original construction. Deferring replacement results in a lost opportunity to capture increased generation from higher efficiency equipment. This foregone benefit is treated as a cost for purposes of lifecycle cost minimization.

Lost Efficiency Opportunity (LEO) = Unrealized Efficiency Benefit (MWh) * Market Price Forecast

Project Cost: The cost of the replacement or refurbishment activity.

Starting in 2024, the benefits of bundling assets together in the same outage are considered and the tradeoffs of advancing or delaying an asset to be a part of a bundled outage are evaluated in the modeling. The following costs are considered:

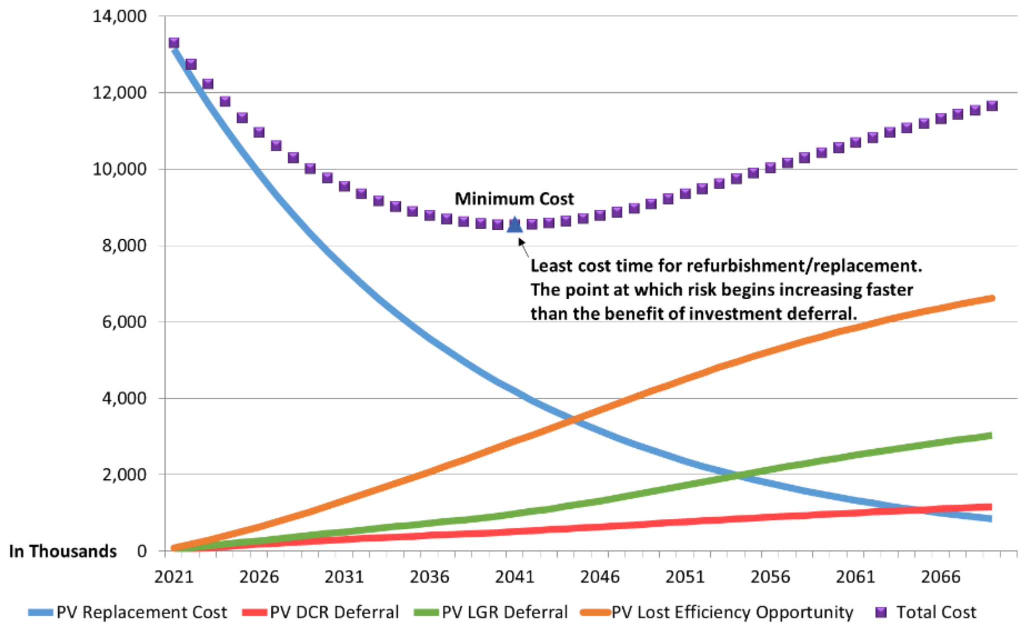
Outage Cost: The planned outage cost for a group of specified assets if they were replaced in individual outages compared to if any or all the specified assets were combined into one or more grouped outages.

Shareable Cost: Cost savings that can be achieved through combining specified assets into one or more grouped work packages and avoiding multiple contracting actions, contractor mobilizations, unit disassembly costs, etc.

Lifecycle Cost Minimization

To determine the optimal timing for replacement, each asset is evaluated in yearly time steps. In each year, the present value of accumulated financial risk cost is added to the present value cost of replacing the equipment in that year. The sum of these present value costs is the Total Cost related to a decision to delay equipment replacement until that year. This algorithm is described graphically in Figure 10.2-3.

Figure 10.2-3 FCRPS Equipment Lifecycle Cost Minimization Methodology

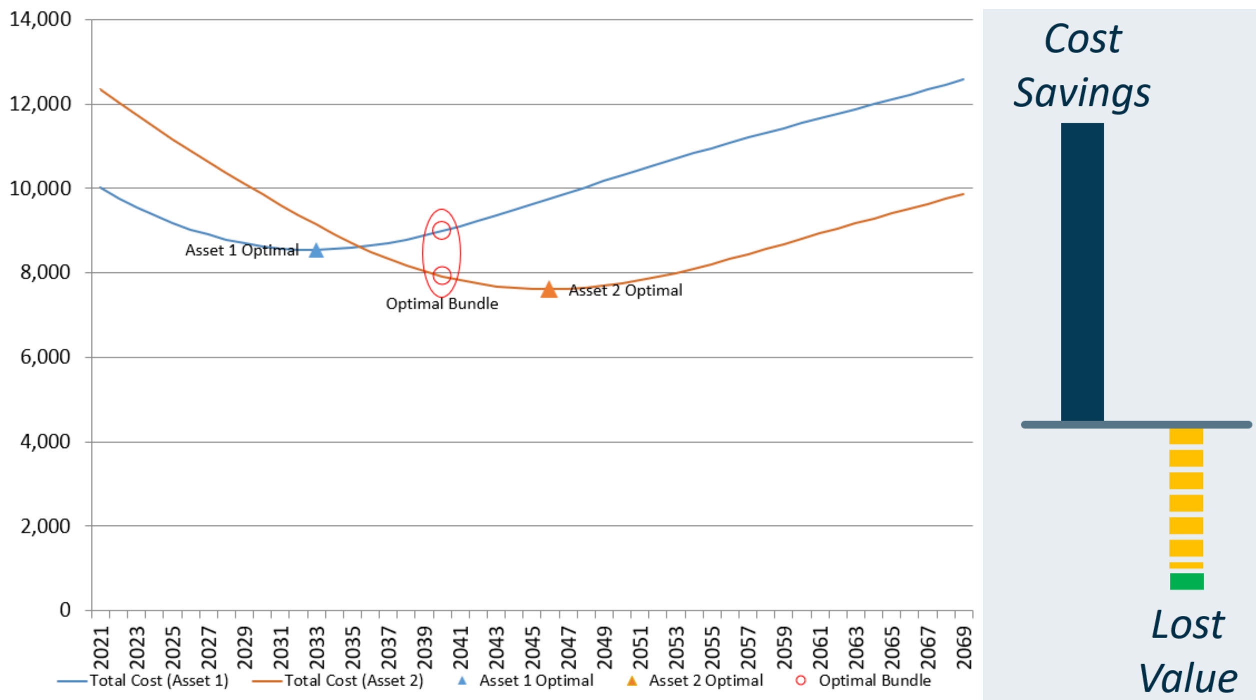


The optimal time for replacement is at minimum point on the Total Cost curve. This minimum point is the time at which the sum of financial risk costs and potential lost efficiency opportunity begin growing faster than the benefit of deferring the investment. Up until that time the value of investment deferral is greater than the expected increase in financial risk and lost efficiency opportunity costs, so it makes financial sense to continue deferring equipment replacement.

When a constraint is introduced, Predictive Analytics prioritizes all assets at or past their respective optimal replacement dates based on their cost of deferral. Assets are chosen for replacement ranked by their respective deferral cost until there is no longer room within the budget. The analytics will then seek to replace the next highest deferral cost asset that remains within the budget constraint until either the constraint is reached in full or no further assets can be selected while remaining within constraints.

If an asset is specified as part of a potential bundle group, the modeling will still consider the individual asset cost minimization but also determine if there is a net benefit in combining the assets into a single outage. If the cost savings of bundling work exceed the lost value in replacing an asset before or after it’s optimal date, the model will choose to bundle the assets if other constraints allow. In the example below, Asset 1 has an optimal replacement of 2033 and Asset 2 has an optimal replacement of 2046. If bundled together in 2040, the cost savings outweigh the lost value of a late replacement for Asset 1 and an early replacement for Asset 2.

Figure 10.2-4 Optimal Timing Example for Bundled Asset Replacement



In practice, these bundling opportunities have always been considered by USACE and Reclamation when developing investments in the Asset Plan. However, it has been in a more ad hoc manner. Introducing this capability into the Predictive Analytics produces a more realistic long-term forecast for asset replacements and can highlight which bundling opportunities should be investigated more thoroughly for the Asset Plan.

Value Framework

After optimal replacement dates are established, the Asset Planning Team, in coordination with other USACE and Reclamation planning functions, develops projects to address the risks identified by Predictive Analytics and those identified by USACE and Reclamation staff. These projects are entered into the Portfolio Management module of Copperleaf with a forecast for their annual spend and a preliminary assessment of their risks and benefits.

Benefits and risks associated with investment activities are evaluated using the Value Framework component of Copperleaf. Table 10.2-1 summarizes the value measures in the FCRPS value framework.

***Table 10.2-1** FCRPS Value Framework*

Value Measure Categories	Value Measures	Organizational Goals
Financial	Financial Benefits	Maximize cost savings and increase efficiency to ensure low cost power Maintain ability to reliably supply energy to the grid
	Generation Efficiency Benefits	
	Direct Cost Risk	
	Lost Generation Risk	
Trusted Stewardship	Compliance Risk	Reduce Safety, Environmental and Compliance risks to as low as reasonably practicable. Ensure employee and public safety Maintain mandate to operate
	Environmental Risk	
	Productive Workplace Benefit	
Safety	Safety Risk	
Community	Public Perception Risk	

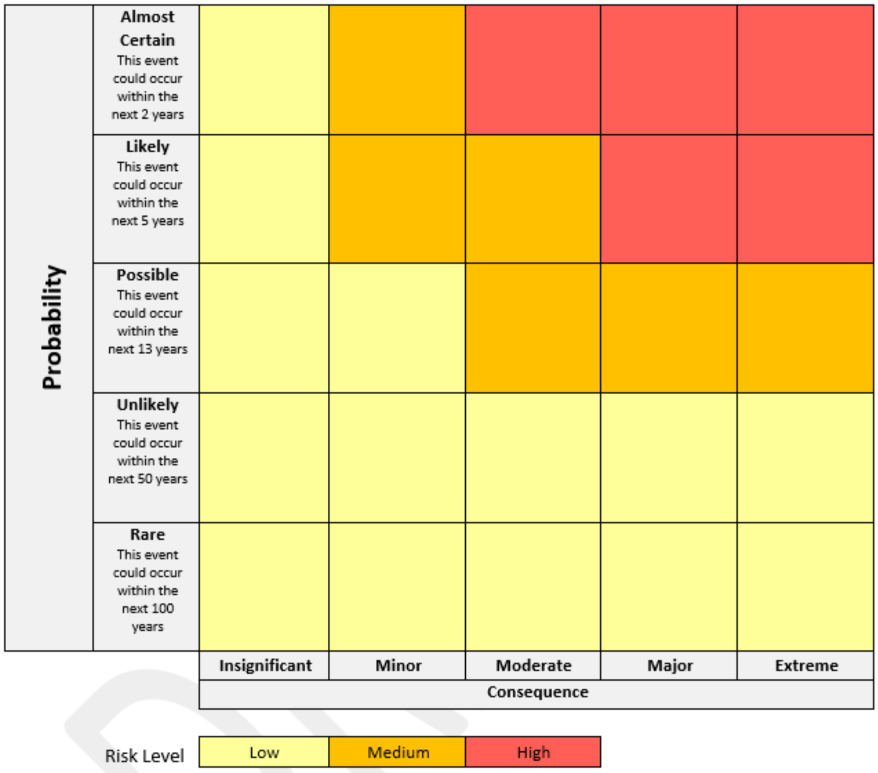
As described in Section 7.1, financial risks are assessed in dollars while trusted stewardship, safety, and community value measures are assessed qualitatively. These qualitative measures are assessed using a 5 by 5 risk matrix that aligns the consequence scales of the qualitative measures to the quantified financial risks and benefits. This creates a method of assigning value to qualitative benefits and risks. For optimization purposes, safety and environmental risk receive weightings of 2.0 and 1.5, respectively. This means that Safety risks are weighted twice as heavily as an equivalent lost generation risk and environmental risks are weighted 1.5 times as heavily as an equivalent lost generation risk.

***Table 10.2-2** FCRPS Risk Matrix Consequence Descriptions*

Consequence	Insignifcant	Minor	Moderate	Major	Extreme
Financial Risk	<$10k	$10k - $100k	$100k - $1M	$1M - $10M	>$10M
Lost Generation Risk	<280 MWh	20 MWh - 2,800 MWh	2,800 MWh - 28,000 MWh	28,000 - MWh - 280,000	>280,000 MWh
Compliance Risk	No or insignificant effect on operations or administrative flexibility, or annual mandated costs <$10k	Change in operations or administrative flexibility or annual mandated costs < $100k	Effect on legal principles or precedents, project operations noticeably affected for compliance, inability to maintain system frequency or voltage, or annual mandated costs <$1M	Effect on legal principles or precedents, substantial changes needed in project operations or administration, or annual mandated costs <$10M	Extremely difficult to meet fundamental statutory obligations, extremely unreliable system, extreme changes needed in project operations or administration, or annual mandated costs >$10M
Environmental Risk	No impact	Impact to on-site environment (simple remediation) or where the remediation costs <$100k	Limited impact off-site (localized remediation required) orwhere the remediation costs <$1M	Detrimental impact on- or off-site (long-term remediation required) or where the remediation costs <$10M	Detrimental or catastrophic impact off-site (mitigation impossible) orwhere the remediation costs >$10M
Safety Risk	No or minor injury, first aid	Treatment by medical professional	Lost time accident - temporary disability	Permanent disability	Fatality
Public Perception Risk	No or isolated internal complaints	Local media attention, widespread internal complaints, some public embarrassment	Transitory local media / federal / customer attention and criticism, some damage control; congressional inquiry, short duration loss of power to islanded community	Ongoing media / federal / customer attention, major damage control, significant impact on staff morale, congressional inquiry, extended duration loss of power to islanded community	Adverse and ongoing media / federal / customer attention, criticism and agency intervention, extreme damage control, secretary called to congress, permanent duration loss of power to islanded community

Lost Generation Risk and Direct Cost Risk (captured by “Financial Risk” above) are automatically calculated for assets that are attached to investments using the same analysis performed in Predictive Analytics described earlier. Investment impact dates and resulting condition scores from replacements or refurbishments are forecast and the mitigated Lost Generation and Direct Cost risks are calculated between the baseline and investment scenarios. For the remaining Value Measures, risk is calculated by multiplying the consequences selected from the matrix above by the assessed probability of occurrence. Mitigated risk is the difference between the assessed probabilities of occurrence with and without an investment as well as any change in future consequence that may result from an investment alternative. The risk matrix in Figure 10-2-5 displays the interaction of probability and consequence scales.

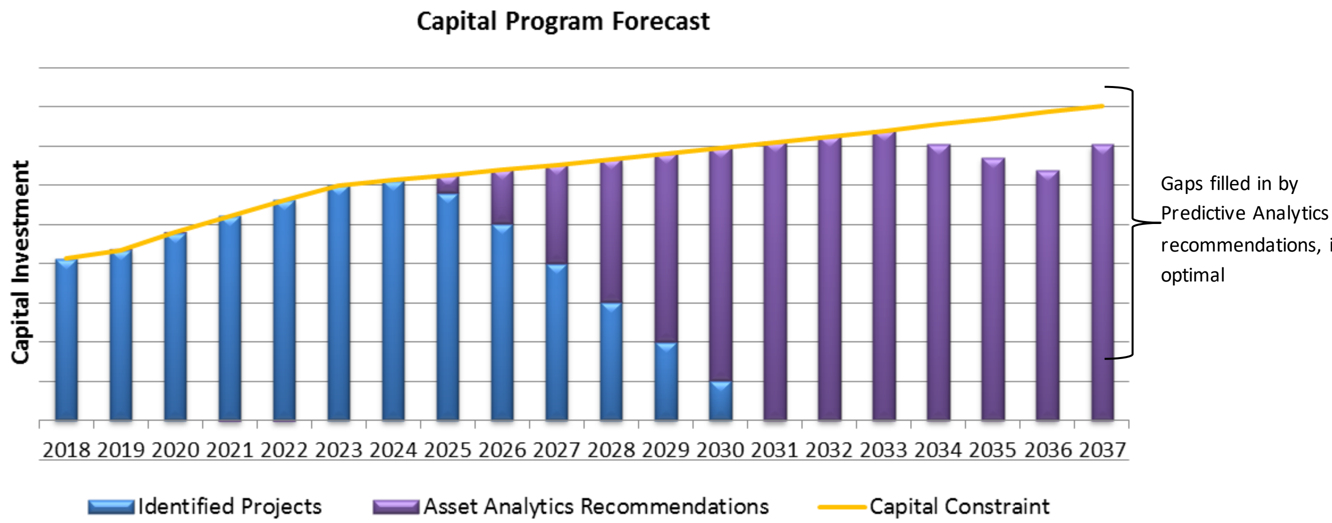
Figure 10.2-5 ***Example*** *FCRPS Risk Matrix*



The Asset Plan is constructed through iterative optimizations of the FCRPS capital investment portfolio. For development of the SAMP, planned investments from the Asset Plan are optimized under the planning levels identified in each respective Strategy Alternative. If identified projects exceed the planning levels identified in the strategy alternatives, the optimization will defer investments to maximize the value of available capital funding. In future years in which the Asset Plan is not fully programmed up to the budget constraint, Predictive Analytics will identify assets for which it is optimal to plan a replacement, but a project has yet to be identified. However, if there are no assets at or past their optimal replacement dates, Predictive Analytics is not required to spend all available funds. The strategy presented in Section 10.2 is a result of these iterative analytics. The example illustrated in Figures 10.2-6 and 10.2-7 show how optimization defers projects to stay within constraints.

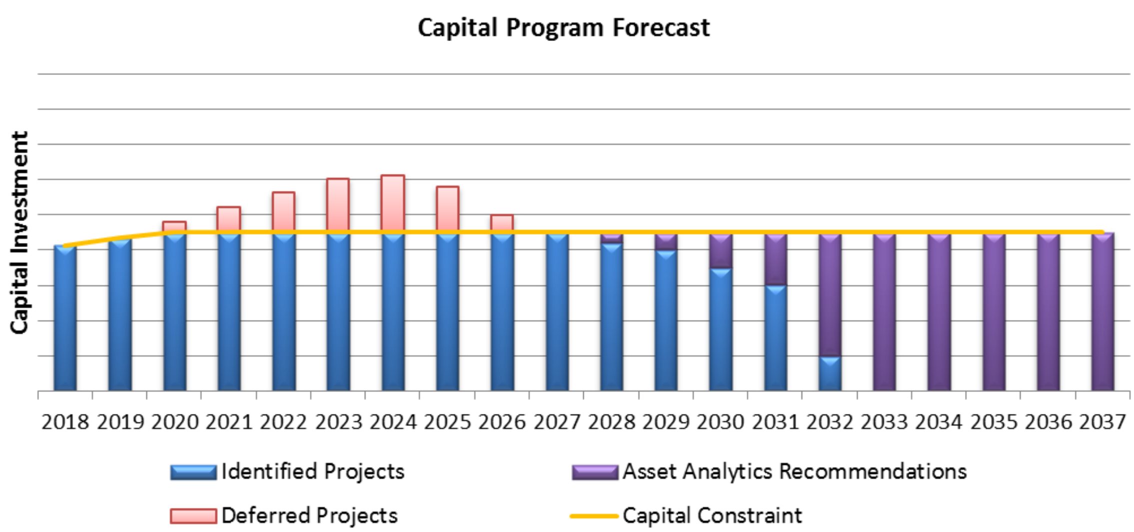
Figure 10.2-6 shows hypothetical capital investment for planned projects in blue, which represent mature investments tracked in Copperleaf. As the capital forecast associated with planned projects declines, Predictive Analytics fills in gaps by selecting assets to replace, if optimal. In some cases, it may not be optimal to spend the entire budget.

Figure 10.2-6 Capital Program Forecast with Predictive Analytics



With a more constrained budget, the existing portfolio of identified investments is optimized resulting in several projects moving to a later date. The forecast associated with deferred investment is highlighted in red in the example below. A lower budget constraint results in planned projects lasting further into the future before Predictive Analytics is required to fill in gaps in the long-term plan.

Figure 10.2-7 Capital Program Forecast with a Constrained Budget



These processes develop the sustainment and expansion strategies which lead to the development of the Asset Plan.

10.2.1 Sustainment Strategy

The Three Agencies aspire to develop sustainment strategies that combine maintenance, reinvestment, and operational strategies to maximize the value of FCRPS assets. Integration of these strategies is currently ad hoc, and maturity varies from plant-to-plant. As asset management practices continues to mature over the next decade, integration and tradeoffs between capital and expense will be better understood. At present, the sustainment strategies for the capital and expense programs can be described as follows:

10.2.1.1 Capital Investment Strategy:

- Identify the level of investment associated with minimizing asset lifecycle costs at each plant while meeting the respective missions of the Three Agencies;
- Develop projects that incorporate the results from this analysis while considering logistical requirements and potential efficiencies such as combining work into a single outage window;
- During the scoping of major plant-wide powertrain replacements, evaluate unit efficiency and capacity improvements as well as the optimal number of units to fully replace;
- Optimize the investment portfolio on an annual basis to maximize the value of the portfolio within constraints; and
- Reserve a portion of the capital budget for joint assets that will be optimized separately from power assets.

10.2.1.2 Expense Strategy:

- FCRPS - Incorporate asset criticality described in Section 7.2.2 into decision making to optimize use of operations and maintenance budgets;
- USACE – Leverage PMMP and OMOI information to help identify the appropriate level of expense costs necessary to maintain operating projects at their optimal level;
- Reclamation – Perform an annual regional quantification of individual project risk by examining impact to the facility and probability of execution;
- Reclamation – Use quantified risks to establish budget requests and project targets; and
- Reclamation - Update mid-year to manage the expense portfolio priorities within the established budget constraints given changing costs and schedules.

10.2.1.3 Willamette Valley Strategy

The federal government was sued by environmental groups in 2018 for failing to meet all of the requirements in a 2008 Biological Opinion to ensure operation and maintenance of the 13 dams in this System for all their authorized purposes was in compliance with the Endangered Species Act. A U.S. District Court Judge in Oregon ruled in favor of the plaintiffs and issued an injunction in 2021, requiring USACE to further modify operations, in the continued absence of planned structural solutions, to focus on improved fish passage at the dams and downstream water temperature management through alternative reservoir management (e.g., delayed refills, deep drawdowns, increased spill, etc.). These additional injunction measures have reduced average power generation in the Valley by over 40%. Additionally, in April of 2018, USACE re-initiated consultation in accordance with Section 7 of the Endangered Species Act (ESA), submitting a Biological Assessment on March 17, 2023 to the National Marine Fisheries Service and U.S. Fish and Wildlife Service. While the Corps is the lead federal agency for the consultation, as with the 2008 BiOp, Bonneville and the Bureau of Reclamation are also federal action agencies in this consultation given their role and missions related to the dams' operations. Concurrently, USACE has been developing the WVS Programmatic Environmental Impact Statement in accordance with the National Environmental Policy Act, that will culminate in a Record of Decision (ROD) when the agency will provide a rationale for selecting a plan that would allow the continued operations and maintenance of the WVS in accordance with all authorized project purposes, while meeting ESA obligations. A Draft PEIS was published and released for public review in November 2022. BPA believes the identified preferred alternative, proposing structural and operational measures, would likely result in significant increases in the costs of generation and impact the economic viability of power production. For purposes of this SAMP, operational assumptions are reflective of the "Near-Term Operations" scenario. Structural measure costs are funded differently than typical investments and therefor are not part of the capital forecasts shown later in this section. However, structural measure costs are included in the long-term cost of generation estimates presented in Section 10.6 based on the median cost estimate from the Draft EIS.

At the direction of Congress in the 2022 Water Resources Development Act, USACE, with input from BPA, is also working on a Congressional report and potential hydropower disposition study to evaluate the continued operation of power assets at Willamette Valley dams. This evaluation is currently ongoing at the time of writing for this SAMP. The draft EIS Preferred Alternative results in significant increases to the cost of generation in the Willamette Valley. BPA expects that these costs will continue to increase into the future. Until there is more clarity on the future economic viability of hydropower at the Willamette dams, BPA has notified USACE Portland District that it intends to pause direct funding of capital investments for the electric power generation components at the power-producing Willamette Valley federal dams. BPA is currently continuing to direct fund the power share of investments for "joint" facilities of those dams, meaning the features that are essential for the multiple purpose functions of the dams. This decision is not intended to include pausing direct funding of investments that are critical for personnel or dam safety, or implementation of the measures included in the current District Court of Oregon injunction for Willamette Valley System operations.

10.2.2 Growth (Expand) Strategy

At present, BPA is not actively seeking to expand FCRPS capacity to fulfill BPA's obligations. However, there are incremental benefits and risk reductions that can be achieved from unit upgrades or additions. The primary source of incremental generation capability is derivative of the sustainment program. Unit uprates and efficiency improvements are evaluated in conjunction with unit reliability improvements and can typically be achieved at minimal incremental cost. Both improvements are factored into business case alternatives analyses and are selected if they deliver the best value.

Dworshak and Libby Dams have long been identified as powerhouses that are undersized relative to water availability. Both plants were originally designed to have more units than were ultimately completed. As a result, unplanned outages pose high financial and environmental risks, especially if they occur while other units are already out of service. To reduce these risks during planned replacements in the next decade, BPA and USACE evaluated completing an additional unit at each plant by leveraging existing infrastructure and available components. A summary of the two projects are provided below:

10.2.2.1 Libby Unit 6

BPA's Finance Committee approved construction of Libby Unit 6 in FY23. USACE expects to be award a contract in FY24 and the unit is expected be online in early FY27.

A total of eight units were originally authorized by Congress at Libby Dam but only five were fully constructed. Original plans called for a reregulation dam downstream of Libby; however, these plans were abandoned following a legal injunction in the 1980s. Absent the reregulation dam, units 6 through 8 were seen as unnecessary and construction was halted after the turbine components were installed. Remaining components for those units were put into a long-term storage condition, where they now remain.

Upcoming outages on Units 1-5 for capital investments raised the need for financial, operational, and environmental review. BPA undertook a study in 2017 to determine the cost of completing one of the unfinished units and evaluate whether it would be a cost-effective risk mitigation measure during the long-term capital outages.

An economic analysis was performed on 12 different scenarios that assessed replacement timings on Units 1-5 with and without completing Unit 6. All scenarios that included Unit 6 had higher Net Present Values and Benefit Cost Ratios than scenarios in which Unit 6 was not completed. The scenario with the highest Net Present Value included building Unit 6 and completing capital improvements on all five existing units while the scenario with the highest Benefit Cost Ratio included building Unit 6 and completing capital improvements on four units. These results suggest building Unit 6 provides a cost-effective mitigation measure and leaves the option open to reduce the scope of future capital improvements.

10.2.2.2 Dworshak Unit 4

Dworshak Dam was originally planned to have six units but only three were constructed. Unlike at Libby, only skeleton bays and intake structures exist for the remaining three units. No equipment was installed in those bays and the powerhouse structure only encloses the first three bays. Dworshak has one of the highest marginal outage costs in the FCRPS, as demonstrated in Figure 7.1-1. This is a result of Dworshak's unique configuration of two 103 MW units and one 259 MW unit. When the larger unit is out of service, the smaller units are not adequate to pass flows during much of the year, which results in large generation losses as well as environmental impacts from spill. Unit 3, the larger unit, is critical for water quality and water management. Units 1 and 2 also have a high marginal outage cost as there are times of the year where outflows exceed powerplant capacity even when all units are available. Unlike other plants in the system, these high marginal outage costs are not a result of reduced unit reliability but powerplant design. Units 1 and 2 are expected to be out of service for capital improvements in the next 10 years and Unit 3's extended outage from winding failure is estimated to have cost more than $20 million per year.

USACE and BPA studied the economics of installing a fourth unit to determine if it could be a cost-effective risk mitigation measure for future unit outages in addition to providing some incremental generation. Unit sizes ranging from 150 to 300 MW were studied to determine what would be the most cost effective. A 300 MW unit produced the highest Net Present Value and Benefit Cost Ratio of $80 million and 1.52 (2019 Study). An expansion project of this magnitude would have large implications on the capital investment program during the construction phase. In addition to representing a large portion of the capital budget while being constructed, it is also thought to carry more execution risk than other projects in the capital investment portfolio. If the project continued forward in FY24, USACE's current schedule forecasts the unit to be in service in FY30. The costs, benefits, and current schedule for this project are included in the FCRPS System Asset Plan portfolio optimization. As of the most recent optimizations for 2024, the optimization suggests proceeding with the current schedule, suggesting that there is significant value in the project. Design is expected to move forward in FY24 to update costs estimates and benefits calculations. The value of this project in context of the FCRPS portfolio will continue to be evaluated throughout the design process.

10.2.2.3 Other Expansion Projects

The addition of a third unit was also considered at Reclamation's Black Canyon dam in the past but has been on hold as there is not a need or financial justification for proceeding with the project.

10.2.3 Strategy for Managing Technological Change and Resiliency

BPA, USACE, and Reclamation coordinate on the collective FCRPS strategies for resiliency and technological change. Many aspects of resiliency are covered under compliance with existing NERC/WECC/CIP standards as well as in continuity planning. USACE and Reclamation also have their own emergency action plans that describe how operating projects respond to emergencies. For technological change, the Three Agencies engage in several industry forums focused on technological changes in hydropower. These best practices and research opportunities are incorporated into asset management strategies, plans, and equipment designs. The following sections describe FCRPS strategies for resiliency and technological change in more detail.

10.2.3.1 Resiliency

BPA's agency definition of resiliency is, "The ability to plan, prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions." Resilience is about planning and preparing for events, which includes the ability to both withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.

FCRPS assets play a critical role in the power system resilience of the Pacific Northwest. In coordination with BPA Transmission, the FCRPS complies with NERC reliability standards by carrying out regular tests of Blackstart resources and Remedial Action Schemes. NERC requires Transmission Operators to set requirements for Blackstart resource testing and defines the minimum requirements that must be addressed during a test. Test musts be performed at least once every three years. The tests involve starting units and energizing a dead powerhouse line or bus to ensure that the operations can be performed if called upon during a power system event. NERC has a series of compliance measures to assure power system resilience. Compliance measures are listed for both Transmission Operators and Generator Operators in EOP-005-3[2]. These measures are tracked by the FCRPS Reliability Implementation & Technical Subcommittee (RITS). The FCRPS strives to meet the following metrics:

> (1) No WECC-identified alleged violations with a "high risk factor" violation and a "high" or "severe" violation severity level (level 3 or more), where "WECC-identified means either discovered by WECC during an audit or formal WECC concurrence to a self-reported alleged violation;
>
> (2) 100 percent of submitted WECC approved mitigation plan and 80% of related milestones are completed as scheduled, including self-reported violations.

Various strategies are employed to assure and enhance resiliency prior to an event, during an event, and after an event. Station service equipment serves an important function in keeping equipment running during normal operations and allowing it to operate during a grid-level event. USACE's Hydroelectric Design Center developed a station service equipment design philosophy that addresses the recommended level of redundancy for station service equipment to reduce the risk of being unable to serve critical loads due to equipment failure at the plant or during a grid-level emergency. As station service systems reach end-of-life and are modernized, this design philosophy is applied. At plants where it has already been applied over the last ten years, there has generally been an increase in redundancy, improving our preparation prior to an event.

USACE and Reclamation also have various Emergency Action Plans that describe how project operations would continue in emergencies such as floods, earthquakes, geomagnetic disturbances, or terrorism. These plans

[2] https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-005-3.pdf

provide courses of action to ensure project missions are restored as quickly as possible. BPA's Continuity of Operations Plan (COOP) integrates with USACE and Reclamation to describe how partnership operations continue during and after an event.

Finally, for equipment-level events, USACE and Reclamation have contracting mechanisms in place to allow more rapid response to equipment failures for critical equipment. When possible, spares are often kept on hand for critical equipment to decrease equipment downtime. Transformers are a focus in FY24 for a renewed sparing strategy due to the exceptionally long lead-times experienced in recent years and the number of units that can be impacted from a single transformer failure.

10.2.3.2 Managing Technological Change

Power Services engages in many areas that serve to promote and integrate technological changes. Collaboration and knowledge sharing is an important strategy to adapt to these changes. Key collaborations enable BPA to keep abreast of the latest technological changes affecting the industry. They provide forums for addressing upcoming challenges and opportunities associated with new technologies. Power Services collaborates with CEATI interest groups, Reclamation Research and Development Group, USACE Hydroelectric Design Center, DOE Water Power Technologies office, and EPRI. BPA's Technology Innovation office has aided Power Services to develop roadmaps for technology innovation. These roadmaps steer our efforts toward the most beneficial innovations. They include three main categories pertinent to hydro assets:

1) **<u>Hydropower Reliability and Life Extension</u>**
   - **Machine condition monitoring**: Aimed at improving asset condition information to avoid damaging operations and to extend equipment life.
   - **Oil analysis advancements**: Aimed at improving oil testing technologies to provide better information about the condition of oil filled equipment.
   - **Predictive Analytics**: Systems that integrate machine condition monitoring and other operational information to predict when failures might occur, when maintenance or repair interventions will be necessary, and the optimal type of intervention. This information could be used to extend equipment life, reduce routine maintenance outages, and reduce routine maintenance costs. It would enable an informed transition to condition-based maintenance.
   - **Repair and life extension technology improvements**: One example is the development of cold-spray technology to allow longer lasting repairs of water passageway surfaces that have been damaged by cavitation.

2) **<u>Hydropower Equipment Environmental Risk Reduction</u>**
   - **Oil-free Kaplan turbine technology**: Aimed at reducing oil leaks into the river that result from leaking Kaplan turbines while assuring good asset life. BPA TI supported a project (TIP 213) to design a test stand for oil-less Kaplan bushing materials in collaboration with HDC and PNNL. BPA-PGA direct funded HDC to build the test stand with PNNL and for PNNL conducted the tests. This provided valuable information for the John Day Turbine Runner replacement and other future runner replacements.
   - **Environmentally acceptable lubricants (EALs)**: Aimed at developing EALs that are more specifically tailored to various hydropower applications.
     - BPA is participating in a CEATI HPLIG Project #03/110 - Environmentally Acceptable Oil Test Program, which aims to identify, collect, and test EALs for performance characteristics that relate to hydroelectric and dam equipment.

  - Building on the CEATI work, the HDC is planning further study to include specific considerations and recommendations for selecting and deploying EALs to Corps FCRPS dams.
- **Oil accountability projects:** Power Services is direct funding HDC to develop equipment and methodologies to both measure and track oil within the facilities. The work includes modern sensors to measure oil levels and oil leaks as well as dovetailing with oil tracking and accounting systems, all with the aim of early detection and action to minimize oil leaks.
- **Improved fish passage turbine and associated testing technology:** Aimed at reducing fish mortality through turbines and more effectively testing improvements.

3) <u>Hydropower Facility Optimization</u>

- **Hydropower facility optimization**: Aimed at maximizing plant generation efficiency within operational constraints and providing actionable information to operators to assure non-damaging turbine operations in support of the Grid Modernization Federal Data Modernization project.

A long developing issue within the hydro industry is the adoption of digital control systems to replace analog control systems. This technological change has resulted in new equipment that offers advantages over the old equipment but is expected to have a shorter life. Asset management tools are being adapted to properly reflect expected replacement cycles and build them into the plans. Since condition scores are integral to the asset management process, Power Services and CEATI collaborate to improve the hydroAMP condition assessment methodology to differentiate between analog and digital equipment. Examples include:

1. Development of the hydroAMP Generic Equipment List that defines design lives for different assets, with attention paid to digital vs. analog asset types.
2. Modifications to the guides for Governors and Miscellaneous Electrical equipment to improve condition assessment of digital equipment.
3. Improvements to the hydroAMP condition assessment tools will continue into the foreseeable future, to assure they reflect current technologies as shown in the example above.

Data acquisition and control systems, known as SCADA or DACS, have been prone to short life expectancies. USACE has developed a Generic Data Acquisition and Control System (GDACS) that is intended to extend the life expectancy of this asset type by incorporating components that use industry standard protocols and design (i.e. generic) and therefore could be replaced in the future without full system replacement. GDACS systems have been utilized in the FCRPS for over a decade with success, and their deployment will continue at facilities with aging SCADA systems. Deployment is expanding to Reclamation facilities as well.

Turbine replacements with improved fish passage turbines have been identified as important improvements to the lower Columbia and Snake River dams because of their fish passage and efficiency benefits. These projects have been studied at the system level in the Turbine Replacement Strategy, with the recommendation to prioritize these projects and to perform refined studies for each facility to determine optimal investment design. Refined studies have been performed for McNary and John Day and others are on the horizon. These studies result in better identification of costs and benefits and facilitate planning and programming of turbine replacements.

CO2 generator fire-suppression systems are being re-assessed within the hydro industry for several reasons, including life safety concerns of CO2 and newer technologies that reduce fire risk, such as modern fast-acting generator protective relays, and modern low-flammability winding systems. BPA Power Services is direct funding a comprehensive study, coordinated by HDC, and executed by a consultant (HDR Engineering) with the goal of thoroughly analyzing the economics and life safety implications of various options, to determine if generator fire suppression is necessary and economical at specific facilities, and if so, which type of system is recommended. These options include replacement with modern CO2 systems, replacement with safer suppression media, and removal of the systems.

10.2.3.3 Sustainability and Climate Resilience

Increasing temperatures are decreasing winter loads and increasing summer loads. At the same time, climate change is causing flows to be higher in the winter and lower in the summer. As powerplant modernization projects are studied, turbine designs and economic analyses now incorporate climate change datasets for hydrologic information to assure that future designs are informed by the expected future operating environment.

10.3 Planned Future Investments/Spend Levels

Using the modeling process described in Section 10.2, the costs, risks, and benefits of various capital investment levels are assessed. The recommended level of investment attempts to balance costs, risks, and benefits, while considering the affordability and executability of the strategy. Table 10.3-1 shows the optimal level of investment that is believed to be realistically executable. The recommended capital strategy remains to achieve a combined expand and sustain investment level of $300 million in 2024 and then increase at the rate of inflation. Forecasts for Libby Unit 6 and Dworshak Unit 4 are shown in the Capital Expand line items for Corps of Engineers. Note Dworshak Unit 4 has yet to enter design and is optimized in the same portfolio as sustain investments. Project timing may change as the design progresses. Any changes in timing or forecasts would result in shifts between the sustain and expand forecasts, but the total capital amounts will remain unchanged.

USACE and Reclamation developed the expense numbers in Table 10.3-1 to capture the need to increase staff closer to recommended levels. To maintain increased staffing levels, expense forecasts must increase at a rate higher than inflation to keep up with expected wage increases. Additional detail is provided in Section 10.3.2.

Table 10.3-1 Optimal Future Expenditures (in thousands)

	Rate Case FY's			Future Fiscal Years						
Capital Sustain (CapEx)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Corps of Engineers	265,794	260,824	254,368	280,389	233,945	258,633	218,748	251,261	254,867	254,193
Bureau of Reclamation	41,368	57,257	70,945	53,988	53,476	36,466	75,841	107,970	122,235	131,815
Total Capital Sustain	**307,162**	**318,081**	**325,313**	**334,376**	**287,421**	**295,099**	**294,589**	**359,231**	**377,101**	**386,008**
Capital Expand (CapEx)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Corps of Engineers	8,516	4,542	4,472	2,796	57,304	57,382	65,964	9,615	265	0
Bureau of Reclamation	0	0	0	0	0	0	0	0	0	0
Total Capital Expand	**8,516**	**4,542**	**4,472**	**2,796**	**57,304**	**57,382**	**65,964**	**9,615**	**265**	**0**
Expense (OpEx)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Corps of Engineers	311,651	335,576	360,340	378,357	397,275	417,138	437,995	459,895	482,890	498,342
Bureau of Reclamation	199,735	211,263	212,589	220,069	228,765	235,627	242,695	249,977	257,476	265,201
Total Expense	**511,386**	**546,839**	**572,929**	**598,426**	**626,040**	**652,765**	**680,690**	**709,872**	**740,366**	**763,543**

Table 10.3-2 shows the expected level of execution. For this SAMP, Copperleaf's Performance Prediction tool was used to forecast execution of the capital budget. Performance Prediction is a machine learning model trained on past FCRPS investments. It forecasts how portfolio execution may vary into the future based on the characteristics of the investments in the investment portfolio. Running the tool produces an expected level of execution of the capital program and a range of uncertainty over a specified 10-year period. The expected value, or 50th percentile, from the tool is used to set the expected level of execution in Table 10.3-2. Section 8.1 discusses upcoming factors and several improvements made in the planning process that are expected to result in increased execution. The Performance Prediction tool seems to indicate that these planning process changes should result in an execution level considerably closer to the recommended level of investment.

For the expense program, BPA requested all generating partners to reduce expenses and find efficiencies relative to their initial optimal forecasts. USACE and Reclamation reduced their expense budgets by $71.4 million over the rate period and $271.9 million over the 10-year period to meet this request. These reductions are reflected in Table 10.3-2 below.

Table 10.3-2 Expected Future Expenditures (in thousands)

	Rate Case FY's			Future Fiscal Years						
Capital Sustain (CapEx)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Corps of Engineers	256,928	249,597	238,771	253,201	202,418	218,865	184,267	222,454	225,540	221,181
Bureau of Reclamation	40,031	54,834	66,670	48,805	47,687	31,877	66,656	96,048	108,184	114,696
Total Capital Sustain	**296,958**	**304,431**	**305,441**	**302,005**	**250,106**	**250,742**	**250,923**	**318,502**	**333,724**	**335,876**
Capital Expand (CapEx)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Corps of Engineers	8,516	4,542	4,472	2,796	57,304	57,382	65,964	9,615	265	0
Bureau of Reclamation	0	0	0	0	0	0	0	0	0	0
Total Capital Expand	**8,516**	**4,542**	**4,472**	**2,796**	**57,304**	**57,382**	**65,964**	**9,615**	**265**	**0**
Expense (OpEx)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Corps of Engineers	292,351	316,276	341,040	358,092	375,997	394,796	414,536	435,263	457,026	471,651
Bureau of Reclamation	195,235	206,763	208,089	215,411	223,923	230,639	237,558	244,686	252,026	259,587
Total Expense	**487,586**	**523,039**	**549,129**	**573,503**	**599,919**	**625,436**	**652,094**	**679,949**	**709,052**	**731,238**

10.3.1 10-Year Capital Program Forecast

Optimal replacement modeling suggests powertrain equipment should represent between 56% and 85% of the annual capital budget from 2026 to 2035. This is a considerable change from recent years where powertrain investment has represented about 30%. McNary turbine runner replacements, Chief Joseph generator rewinds, John Day turbine runner replacements and generator rewinds, and Grand Coulee G19-21 modernization drive the increase in powertrain investment. In practice, the Asset Plan may shift some of the budget towards balance of plant investment as multipurpose mission benefits are evaluated in more detail.

Figure 10.3.1-1 Recommended Capital Program Forecast by Equipment Category

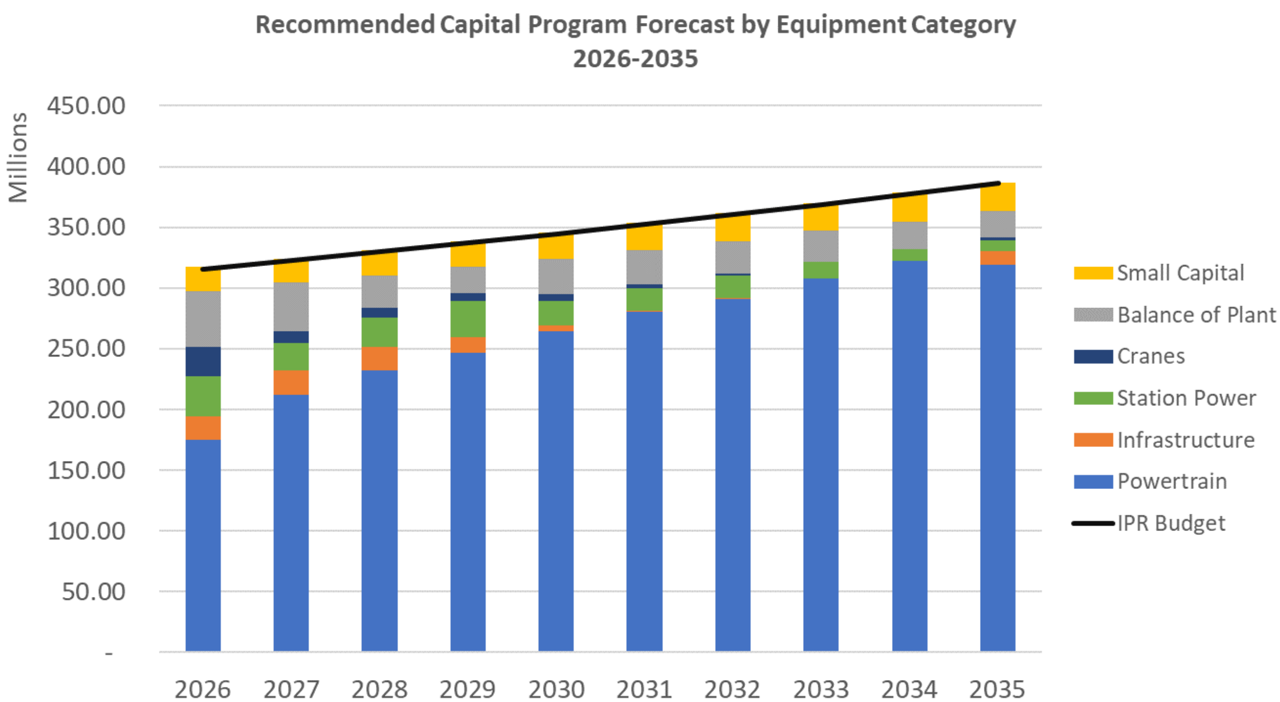
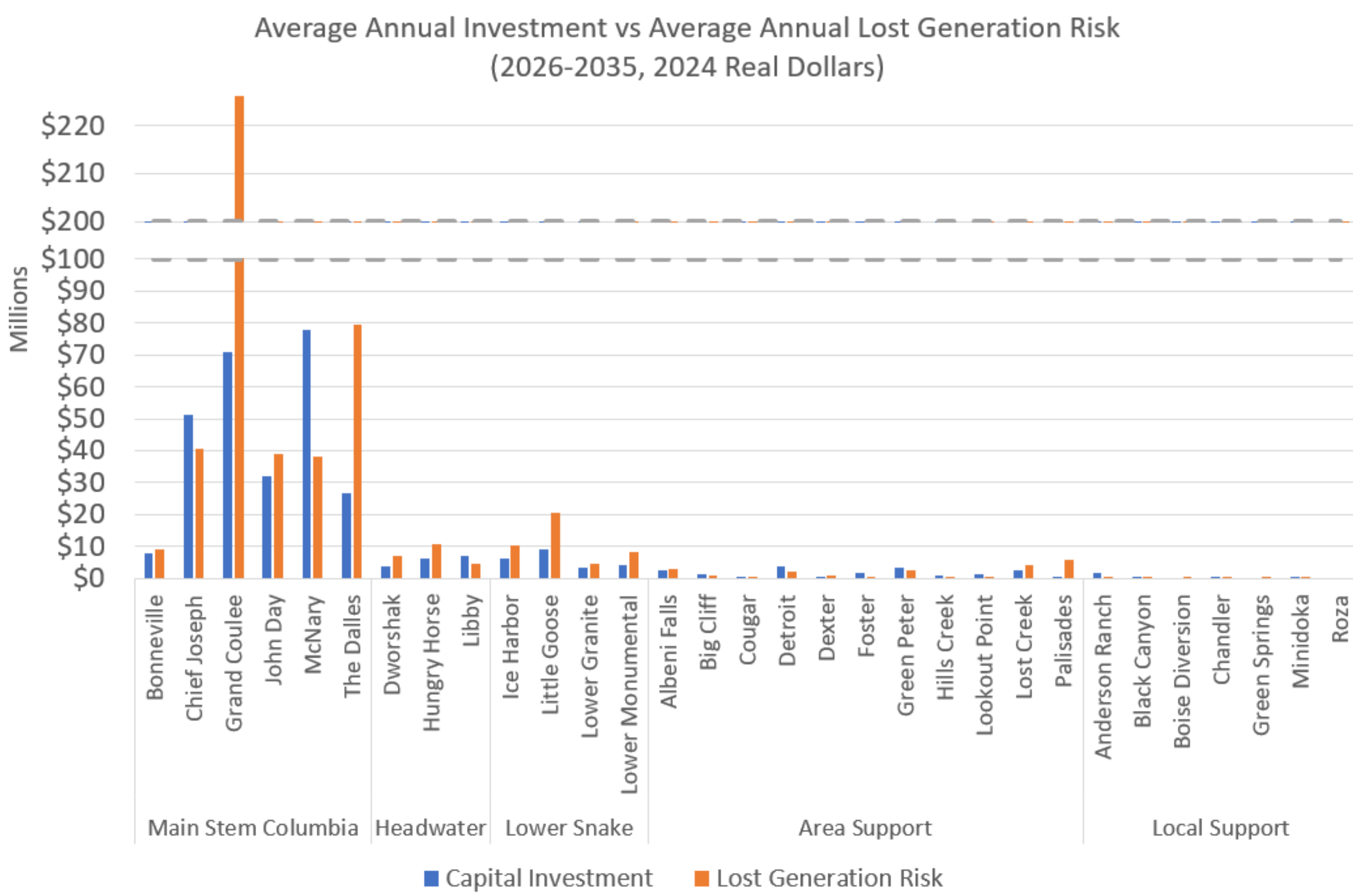


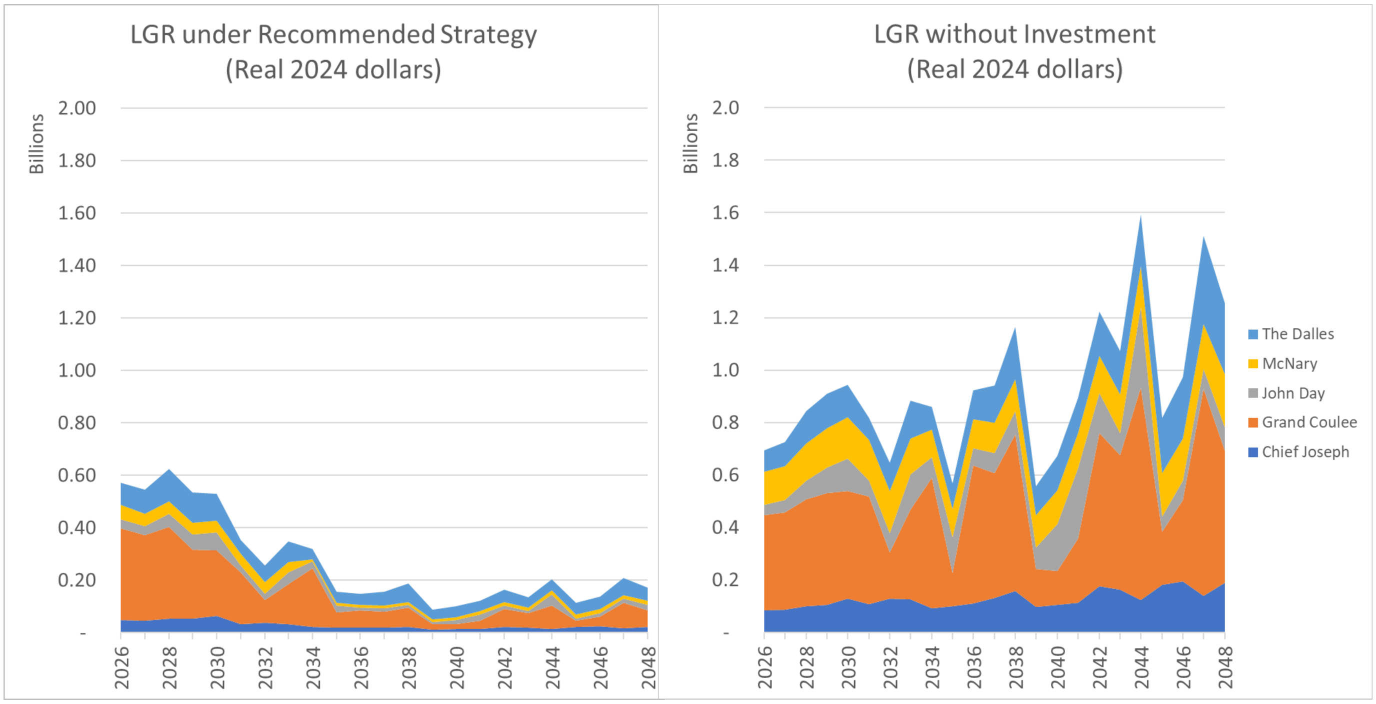
Figure 10.3.1-2 below shows the average annual capital investment forecast at each plant from 2024-2035 versus average lost generation risk. Blue bars represent planned projects that are either in scoping, design, or construction. Orange bars show the current level of Lost Generation Risk based on asset condition, probability of failure, and failure consequences. As Lost Generation Risk is the primary driver for replacement in most powertrain assets, the FCRPS strategic approach tends to drive investments to be roughly proportional to the lost generation at most plants.

Figure 10.3.1-2 Average Annual Investment Vs. Average Annual Lost Generation Risk



Compared to previous SAMPs, lost generation risk at The Dalles is currently much higher than typical due to poor transformer conditions that impacts multiple units. New transformers installed in recent years are exhibiting signs of early degradation causing the asset models to forecast a higher risk than would be expected for most new equipment. Old transformers that have yet to be replaced are also experiencing issues, including long-term forced outages. Studies for interim repair and eventual replacement are underway that will greatly reduce this risk. Previously mentioned modernization projects at Grand Coulee, John Day, McNary, and Chief Joseph will lower risks in the next ten years and prevent significant increases absent investment. Figure 10.3.1-3 shows the lost generation risk forecast at these plants with and without investment through 2048. This illustrates how investments will not only reduce the amount of current lost generation risk but prevent significant increases over time.

Figure 10.3.1-3 Lost Generation Risk Value With and Without Recommended Capital Budget Strategy



10.3.2 10-year Expense Program Forecast

USACE's Annual Power Budget (APB) is comprised of routine and Non-Routine Extraordinary Expense (NREX) programs. The routine budget funding provides for routine labor, contracts, materials, and supplies. Approximately 80% of USACE's routine program funds labor, the remaining percentage funds routine materials, supplies, and routine contracts. NREX funding provides for non-routine labor for repairs, and contracts for maintenance repairs of assets. Year-to-year NREX funding changes based on identified needs.

From FY17 through FY23 USACE basically held the APB flat. Although labor and material prices over that timeframe consistently rose, the budget was able to remain flat by deferring work and by attrition. (In many cases, as employees retired or moved on their positions were not refilled.) In FY22 USACE used a 2.7% inflation rate for the FY24 rate case. The FY24 inflation rate was nearly 18% higher than the FY23 APB. Overall labor prices and material increases have outpaced historical averages, and the assumptions made in FY22.

Across the USACE operating projects within the FCRPS, 150 full time employees have not been replaced since FY17 at the onset of flat budgets. Though the workforce is leaner the cost for labor has remained roughly the same. The increased cost for labor can be attributed to inflation and mandatory salary increases.

- The FY25 forecast was submitted in FY23 during FY24/25 rate case and FY25 was forecasted as a 4.9% increase over the FY24 forecast.
- Each District within NWD has taken a different approach to providing forecasts based on their individual needs:
- FY26: NWS is projecting an 8.7% increase, NWP is projecting a 10.0% increase, and NWW is projecting a 5.0% increase. All of these increases are attributed to increased labor, materials, and supply costs.

- FY27: NWS is projecting an 5.0% increase, NWP is projecting a 11.0% increase, and NWW is projecting a 5.0% increase. All of these increases are attributed to increased labor, materials, and supply costs.
- FY28: NWS is projecting an 5.0% increase, NWP is projecting a 10.5% increase, and NWW is projecting a 5.0% increase. All of these increases are attributed to increased labor, materials, and supply costs.
- FY29 – FY34: Inflation of 5% is applied to labor, materials and supplies, and base contracts for all Districts. NREX is also forecasted at a 5% inflation rate.

Reclamation's O&M budget comprises both the Base O&M (base) and non-routine (NREX) programs. Base budget funding provides for routine labor, materials and supplies, and routine contracts. Approximately 70% of Reclamation's base program funds labor, the remaining percentage funds routine materials, supplies, and routine contracts. NREX funding provides for non-routine labor for repairs, and contracts for maintenance repairs of assets. Year to year NREX funding changes based on identified needs.

In FY22 Reclamation used a 2% inflation rate for the BP24 rate case. The actual inflation rate has been significantly higher. Labor rate increases have outpaced historical averages, and the assumptions made for the BP24 rate case. In FY22 labor rates increased 6.06% and 8.55% at Grand Coulee and Snake River facilities respectively. In FY23 labor rates increased 5.31% and 5.25% at Grand Coulee and Snake River. In FY23 GS employees received a 4.6% increase and FY24 will be similar.

The Grand Coulee Project, which includes Hungry Horse, is authorized 550 employees. At the end of FY23 staffing levels dropped to 440. Over the period FY24-26 significant effort will be focused on restoring Grand Coulee to the historical average staffing levels required to meet mission requirements.

For the period FY25 through FY35 the following factors have been included in the O&M forecasts. The values provided are referenced to FY24.

- FY25: Inflation of 5% is applied to labor, materials, supplies, and base contracts. NREX is based on forecast NREX program needs. Reclamation is estimating that Coulee will add 17 FTE's over FY24 levels. Reclamation is preparing to cover the labor costs within the updated budget request for FY25. If labor costs exceed our planning numbers a budget adjustment may be requested.

- FY26: Inflation of 5% is applied to labor, materials, supplies, and base contracts (above FY25 levels). NREX is based on forecast NREX program needs. Reclamation is forecasting adding another 17 FTE's at Grand Coulee, for a total of 45 backfilled positions in the period FY24-FY26. Labor costs in FY26 are forecast to increase $8M to cover these 45 backfilled positions.

- FY27 – FY30: Inflation of 5% is applied to labor, materials and supplies, and base contracts. NREX is based on forecast NREX project activity needs. Some additional positions may continue to be backfilled; costs will be managed with the inflationary rates.

- FY31-35: Inflation of 3% is applied to labor, materials and supplies, and base contracts. NREX is based on forecast NREX project activity needs. Some additional positions may continue to be backfilled; costs will be managed with the inflationary rates.

Figure 10.3.2-1 10-Year FCRPS Expense Budget Forecast

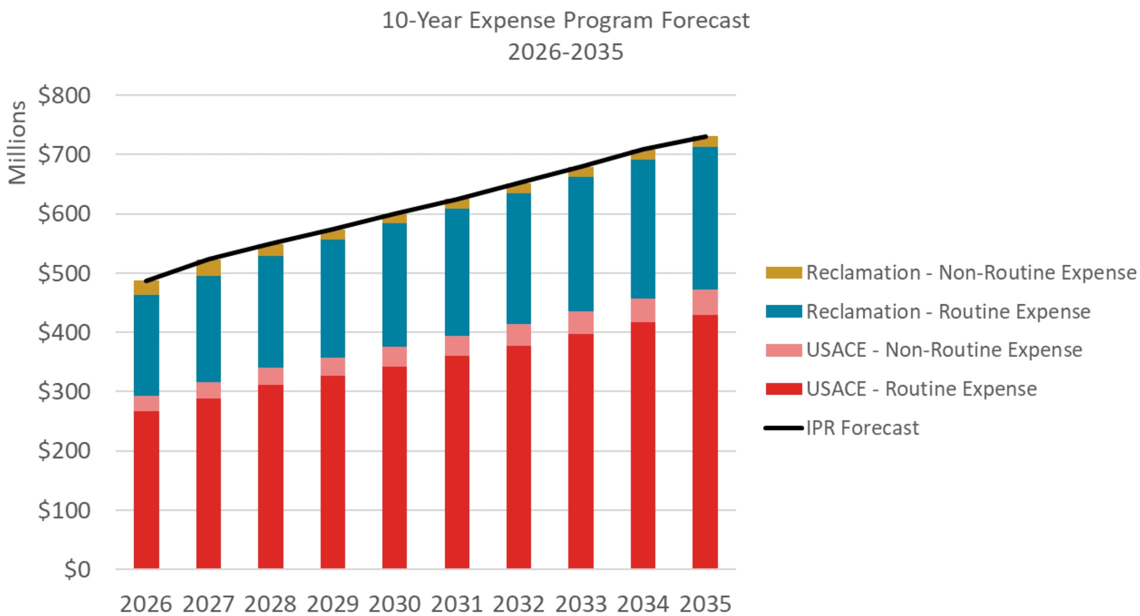
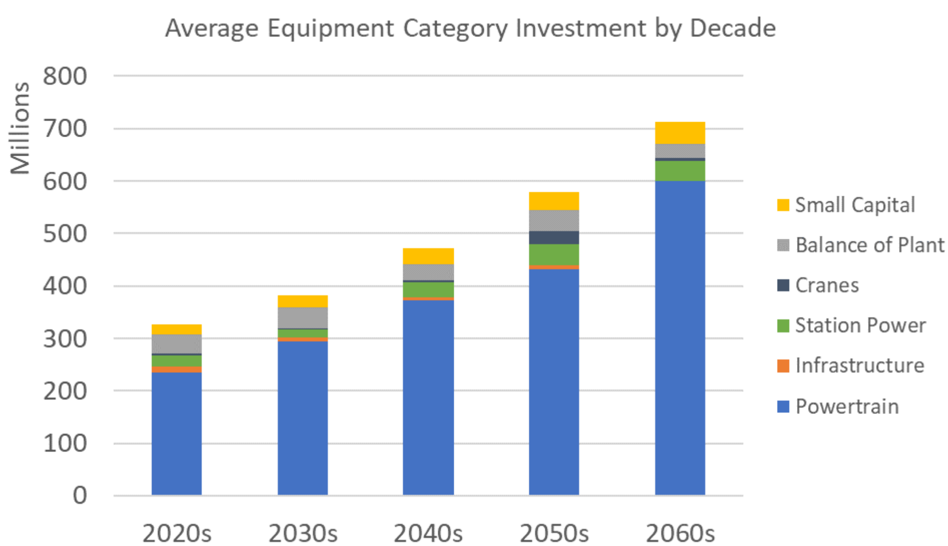


Figure 10.3.2-1 shows the expense forecast by Routine and Non-Routine expense for USACE and Reclamation after BPA's requested reductions. Final allocations of the reductions between Non-Routine and Routine expense are still under consideration.

10.3.3 Long-term Capital Outlook

Long-term forecasts from optimal replacement modeling suggests a similar trend of increased powertrain investment as shown in Section 10.3.1 through the 2060s. This reflects the many long-duration projects needed to modernize FCRPS powerhouses. Studies are underway at USACE and Reclamation to evaluate joint-funded assets, such as spillway gates, which may result in a shift toward increased infrastructure investment in future long-term studies.

Figure 10.3.3-1 Average Equipment Category by Decade



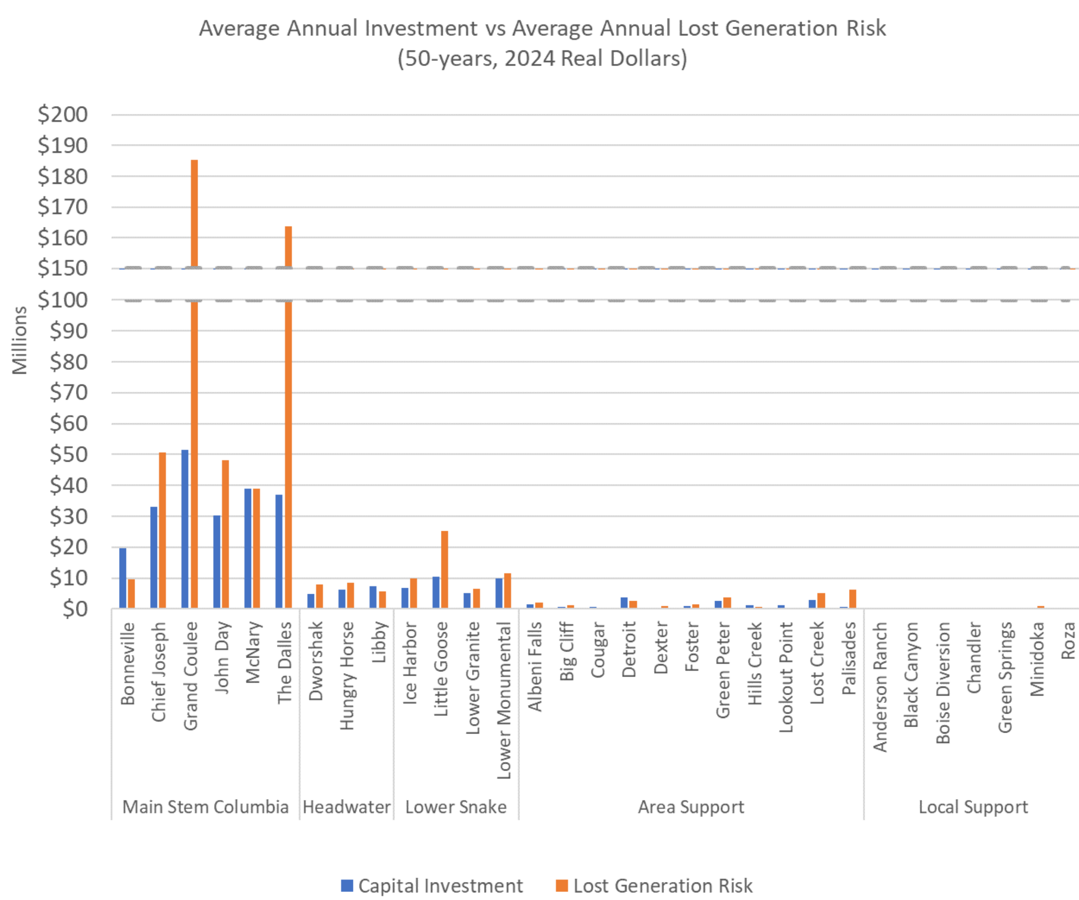
The level of investment by strategic class over the 50-year study period is highly correlated with the amount of generation provided by each strategic class. Main Stem Columbia plants are planned to receive most of the investment, consistent with the relative risk of lost generation and direct costs of failure posed by those plants. With changes in operations at Willamette Valley dams, outage impacts have been reduced. As a result, the modeling has shifted investment away from the Area Support strategic class, falling from 12% to 5% of the 50-year investment forecast since the previous SAMP.

Table 10.3.3-1, Plant Strategic Class Annual Average Generation with 50-Year Forecast of Capital Budget Share

Strategic Class	% of Average Annual Generation	% of 50-Year Capital Forecast
Main Stem Columbia	77%	75%
Lower Snake	12%	12%
Headwater	6%	6%
Area Support (Non-Willamette Valley)	2%	2%
Area Support (Willamette Valley)	2%	5%
Local Support	1%	1%

The 50-year outlook below gives a sense of the average annual long-term investment priorities. In general, this long-term outlook looks very similar to the 2026-2035 snapshot presented in Section 10.3.1.

Figure 10.3.3-2 Average Annual Investment Vs. Average Annual LGR



10.4 Implementation Risks

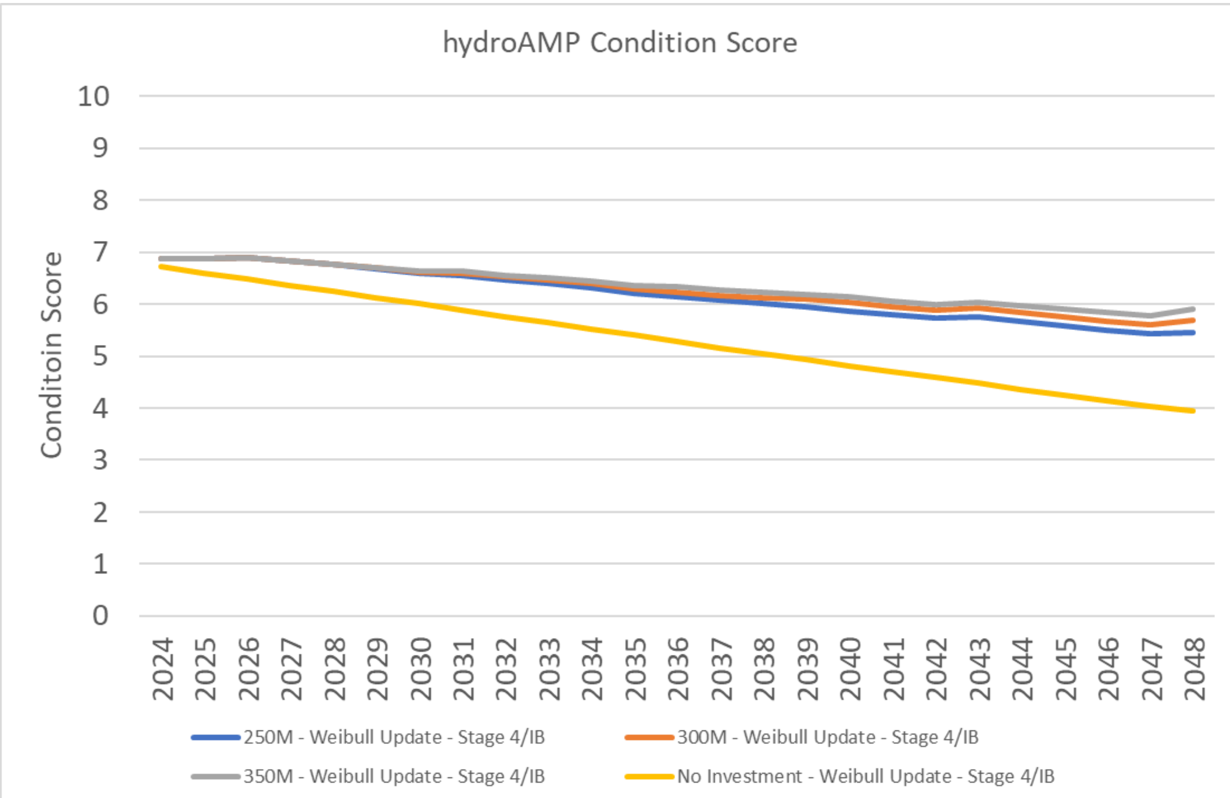
Table 10.4-1 Implementation Risks

Risk	Impact	Mitigation Plan
Global supply chain constraints, labor shortages, and material cost increases lead to project delays and project cost increases	The on-going impacts of supply chain issues, labor shortages, and material costs result in an extended period of project cost increases and delays in project execution.	At present, project cost increases are being absorbed within existing program levels and budgets are re-optimized. FCRPS leadership continues to monitor this emerging risk as it develops.
Bids received are higher than government estimates causing reevaluation of priorities	Higher than expected bids can result in the need to reevaluate the timing and merits of a project. Some changes may result in deferring projects if the business case is severely impacted. The additional time to review can affect budget execution. Delays are compounded if bids received for joint assets require requesting additional federal appropriations.	Walla Walla District is the center of expertise for cost estimation at USACE. For major projects, a cost and schedule risk analysis are employed to produce a risk-informed estimate for the cost and schedule of a project. The Capital Workgroup Decision tree provides a process for evaluating these changes and how capital investment decision making is affected.
Decision on Dworshak Unit 4 is not made in a timely manner causing delays to other investments	The construction of Dworshak Unit 4 represents a significant portion of the Walla Walla district investment program. The optimal timing of investments in existing units at Dworshak is impacted by this decision.	Proceeding with Phase 1 design will provide increased certainty around the costs and benefits of the project so that it can be adequately evaluated within the investment portfolio.
Annual re-optimization of Asset Plan results in shifting resource requirements for USACE districts and Reclamation from year-to-year	Any perceived or real uncertainty in work ramping up or down at a given district or plant makes it difficult for the districts to adjust and plan resources. This is especially true at more remote facilities.	Process improvements in the annual optimization process have resulted in less shifting in the asset plan from year-to-year. Earlier collaboration between the agencies on business cases will result in improved alignment and streamlined approval of projects. This will lend more certainty to future investments and less shifting in each revision of the plan.
Optimistic project schedules result in under-execution of capital budget	Projects could take longer to execute than expected due to as-found conditions, contractor performance, outage scheduling or other factors. Without "shelf-ready" projects that resources can be shifted to, budget execution will be impacted.	Project schedules are now modified prior to portfolio optimization based on assumptions from past performance relative to forecasts at each stage of investment. This change mitigates the risk that projects are unnecessarily deferred due to overly optimistic expenditure schedules.
Project complexity results in longer scoping and study than anticipated	Project schedules can be impacted when more studies or scoping are required than anticipated. Project justification for complex projects has taken more time than expected as our analyses and requirements evolve. This can also arise from disagreements in priorities or recommended project alternatives between BPA, USACE, and Reclamation.	The Business Process Improvement Taskforce developed a project lifecycle map that outlines the process from project identification to approval and the requirements to pass each stage gate. Early collaboration via more interagency involvement in project delivery teams during the scoping of a project between the agencies reduces disagreements and ensures requirements for approval are agreed upon early in the process.
Inconsistent regional approaches across USACE districts and between USACE/Reclamation	Regional strategies and design philosophies for non-powertrain equipment are under development. These strategies are meant to improve alignment between the agencies on investments where benefits have been difficult to quantify and FCRPS-wide priorities have not been clear. If there is not Three Agency alignment on the completed strategies, timing and scope of related investments identified by the plants and districts will remain uncertain.	Regional strategy teams have representation from each agency to ensure that coordination happens during development.

10.5 Asset Condition and Trends

Under the recommended strategy, average condition will decline from the current average score of 7 and eventually level out just below a 6. Without investment, average condition would be below a 4 by the end of the study period. There are minor differences in average condition scores across all FCRPS assets at the different levels of investment. From an aggregate condition perspective, under execution does not present a huge impact on overall condition. While the differences in condition are not large, risk trends shown in Section 10.6.7 display the significance of different levels of investment.

Figure 10.5-1 FCRPS Average Asset hydroAMP Condition Score



The following charts compare the hydroAMP condition of the recommended strategy versus no investment. This breakdown gives a bit more detail of the condition of assets across the system, using the scale presented in Section 8.3. The recommended strategy keeps 50% of the equipment in good and fair condition through the end of the study period. Without investment less than 30% of the equipment would be in good and fair condition.

Figure 10.5-1 FCRPS hydroAMP Condition Trend with Recommended Capital Budget Levels

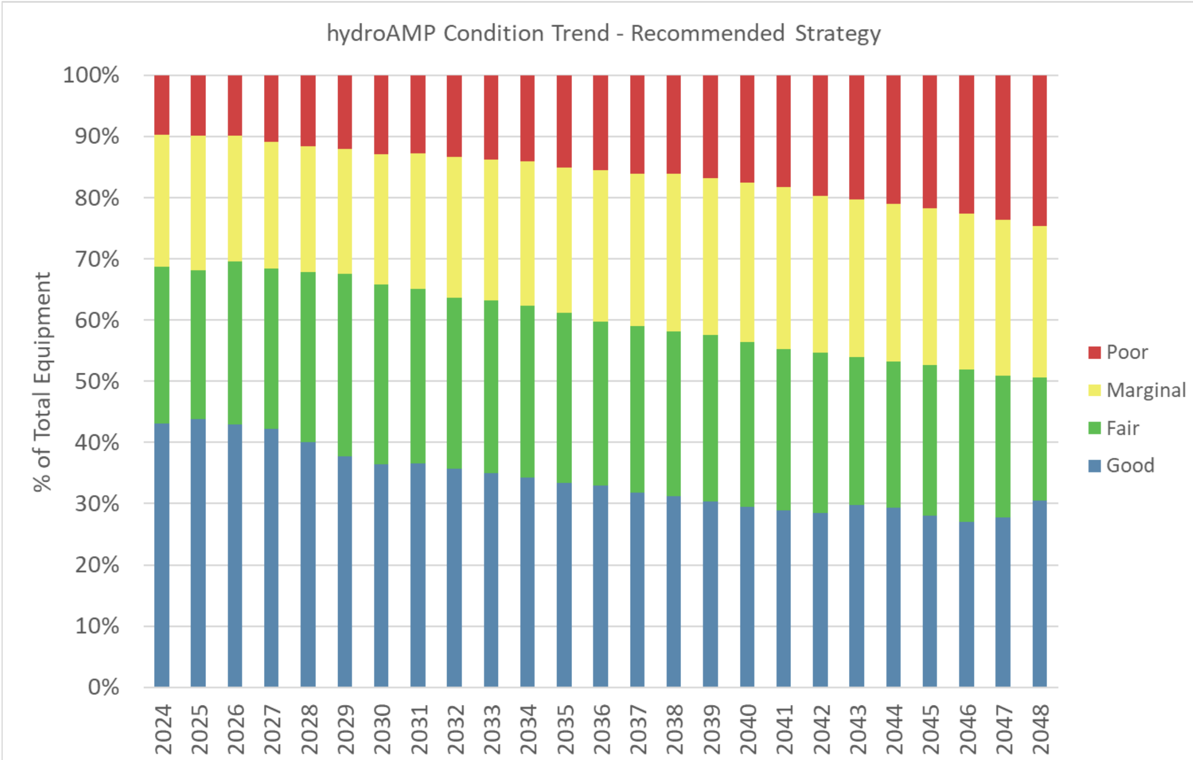
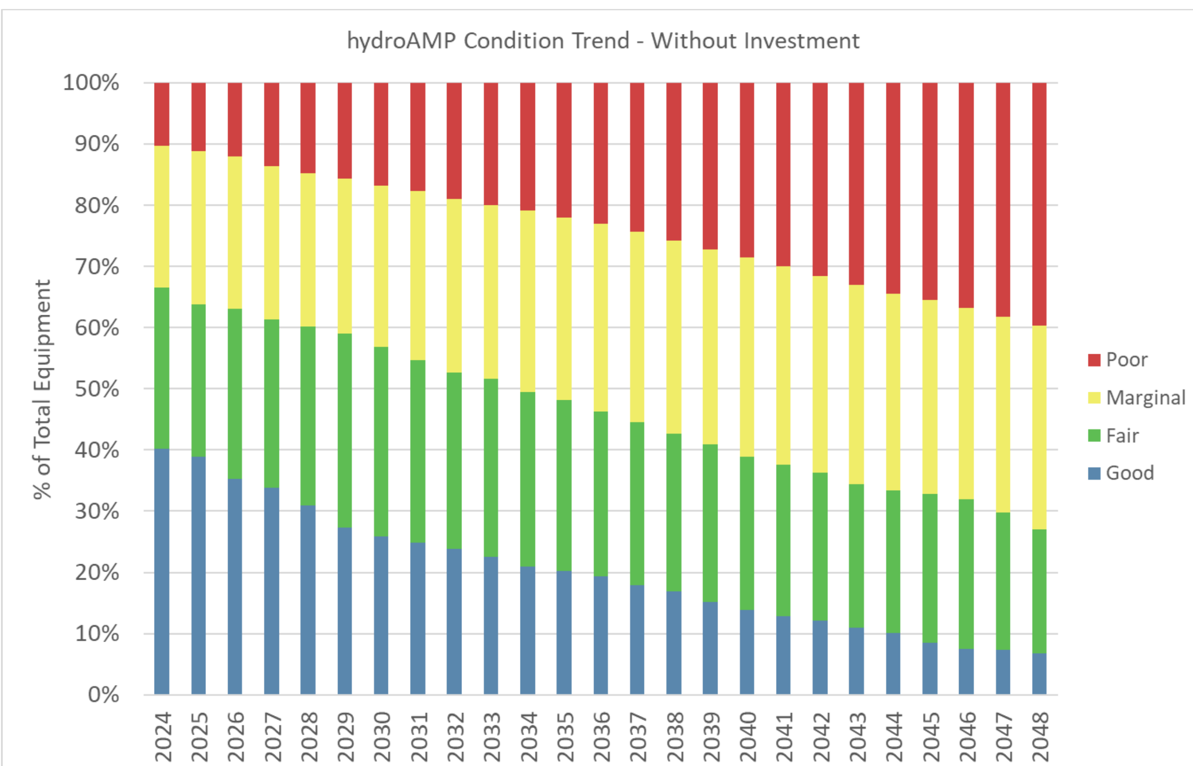


Figure 10.5-1 FCRPS hydroAMP Condition Trend without Recommended Capital Budget Levels



10.6 Performance and Risk Impact

Over time, the recommended strategy of $300 million per year (2024 dollars) will reduce the number of high-risk assets or limit increases to a manageable level. It is not expected that high-risk assets will be reduced to zero, nor is it the strategy. In some cases, the optimal intervention timing results in an asset remaining in the high-risk category for several years.

The following risk maps compare risks at the end of the 25-year study period under the recommended plan versus a no investment scenario.

10.6.1 Safety Risk

The Recommended Strategy reduces the number of assets in the high-risk category over the next 25 years. Investments reduce the number from today's level of 183 to 155 by the 2050s. Without these investments, the number would rise to 424. In practice, operational procedures reduce these risks until the equipment is replaced.

Figure 10.6.1-1 FCRPS Safety Risk Matrix with and without Recommended Capital Budget Levels

Recommended Strategy

Likelihood \ Consequence	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	429	20	52	45	23
Likely	346	55	100	31	4
Possible	1128	80	248	200	27
Unlikely	1719	235	363	223	45
Rare	3036	157	237	233	64

No Investment

Likelihood \ Consequence	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	720	33	167	137	50
Likely	473	58	191	59	11
Possible	1302	157	309	229	22
Unlikely	2312	238	258	215	42
Rare	1857	61	75	106	38

10.6.2 Lost Generation Risk

The Recommended Strategy prevents an increase in the number of assets in the high-risk category over the next 25 years. Investments are expected to reduce the number of assets in the high-risk category from today's level of 357 to 244 by the 2050s. Without investment, the number of assets in the high-risk category would rise from 357 to 898.

Figure 10.6.2-1 FCRPS Lost Generation Risk Matrix with and without Recommended Capital Budget Levels

Recommended Strategy

Likelihood \ Consequence	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	1	12	58	53	1
Likely		15	83	120	12
Possible	4	34	388	752	52
Unlikely	2	114	486	1398	105
Rare		66	487	2348	546

No Investment

Likelihood \ Consequence	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	1	11	108	383	60
Likely		14	99	283	64
Possible	4	33	445	991	71
Unlikely	2	108	445	1926	151
Rare		64	296	1268	325

10.6.3 Direct Cost Risk

The Recommended Strategy is expected to maintain the number of assets in the high-risk category near today's levels over the next 25 years. While the number of assets in the high-risk category is expected to increase from 489 to 541 by the 2050s, investments in the Recommended Strategy prevent this number from increasing to 1,164 assets. All "extreme" risks are expected to be eliminated and "major" risks are expected to be reduced by 27% relative to today.

Figure 10.6.3-1 FCRPS Direct Cost Risk Matrix with and without Recommended Capital Budget Levels

Recommended Strategy

Likelihood \ Consequence	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	1	97	438	36	
Likely		57	412	67	
Possible	1	132	1292	264	13
Unlikely		444	1854	291	2
Rare		1337	2008	386	4

No Investment

Likelihood \ Consequence	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	2	114	849	173	3
Likely		77	576	138	1
Possible		186	1487	332	15
Unlikely		698	2109	254	
Rare		992	989	161	

10.6.4 Environmental Risk

The Recommended Strategy is expected to maintain the current number of assets in the high-risk category over the next 25 years. While the number of assets in the high-risk category is expected to increase from 171 to 172 by the 2050s, there would be 355 assets in the high-risk category without investment. Additionally, the Recommended Strategy will reduce the number of assets with a "major" consequence in the high-risk category by 15% relative to today. In practice, operational mitigation measures are typically in place until investments can be completed.

Figure 10.6.4-1 FCRPS Safety Risk Matrix with and without Recommended Capital Budget Levels

Recommended Strategy

Likelihood	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	421	52	31	65	
Likely	354	68	38	76	
Possible	1174	200	169	140	
Unlikely	1830	433	202	120	
Rare	2766	328	285	348	
	Consequence				

No Investment

Likelihood	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	773	101	49	184	
Likely	487	98	85	122	
Possible	1311	263	248	197	
Unlikely	2252	461	235	117	
Rare	1726	158	110	143	
	Consequence				

10.6.5 Compliance Risk

The Recommended Strategy is expected to keep the number of assets in the high-risk category near today's level. While the number is expected to increase from 23 to 38 by the 2050s, investments prevent the number from increasing to 72 without investment. There are no assets assessed in the "major" or "extreme" consequence categories. In practice, operational mitigation measures are typically in place until investments can be completed.

Figure 10.6.5-1 FCRPS Compliance Risk Matrix with and without Recommended Capital Budget Levels

Recommended Strategy

Likelihood	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	496	35	38		
Likely	423	72	41		
Possible	1482	131	70		
Unlikely	2274	236	75		
Rare	3580	59	88		

Consequence

No Investment

Likelihood	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	938	97	72		
Likely	619	123	50		
Possible	1806	149	64		
Unlikely	2848	146	71		
Rare	2064	18	55		

Consequence

10.6.6 Public Perception Risk

The Recommended Strategy is expected to maintain the number of assets in the high-risk category near today's levels. While the number is expected to increase from 3 to 6 by the 2050s, investments prevent the number from rising to 16 without investment. In practice, operational mitigation measures are typically in place until investments can be completed.

Figure 10.6.6-1 FCRPS Public Perception Risk Matrix with and without Recommended Capital Budget Levels

Recommended Strategy

Likelihood	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	528	35	3	3	
Likely	489	24	23		
Possible	1509	90	82	2	
Unlikely	2424	89	71	1	
Rare	3511	168	31	17	

Consequence

No Investment

Likelihood	Insignificant	Minor	Moderate	Major	Extreme
Almost Certain	969	122	12	4	
Likely	722	39	31		
Possible	1827	111	79	2	
Unlikely	2918	83	63	1	
Rare	2031	65	25	16	

Consequence

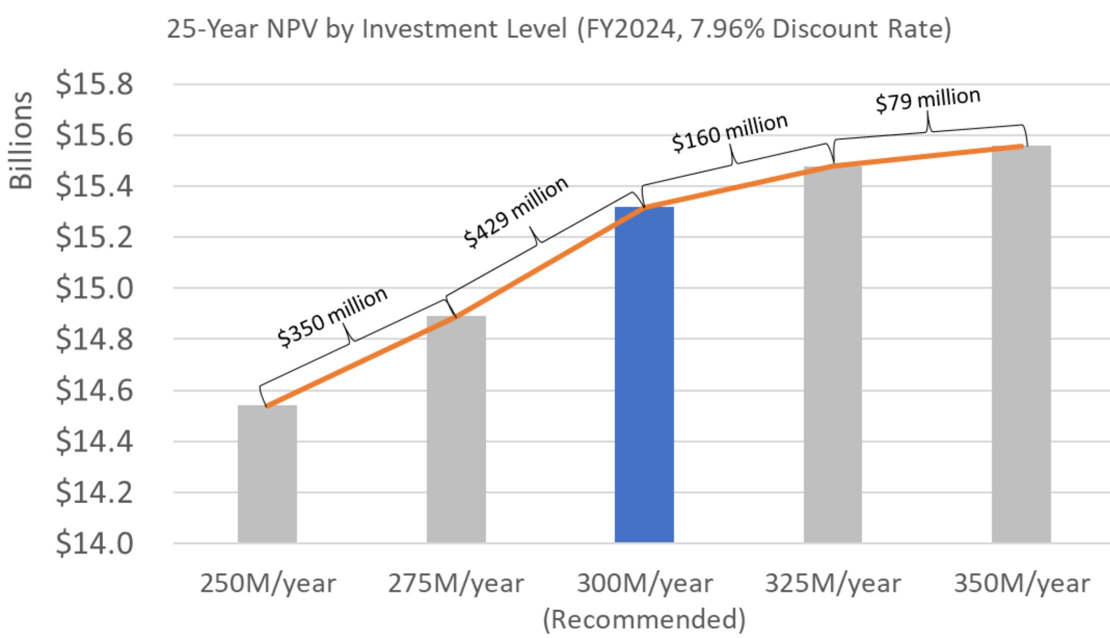
10.6.7 Economics of the Strategy

Arriving at a recommended investment level involves performing sensitivity analysis to understand the cost and risk tradeoffs of different levels of capital investment. Five levels of investment were studied ranging from $250 million per year to $350 million per year, escalating at the rate of inflation. The model will identify investments up to these budget constraints if it is optimal to do so. If there are no remaining assets at or past their optimal replacement date, the model is not required to spend the allocated budget for that year. In this year's analysis of investment level over multiple years, the budget was fully consumed in most years for each investment level.

10.6.7.1 Net Present Value of Investment

Compared to a no investment alternative, all budget levels analyzed produce a Net Present Value between $14.5 and $15.6 billion through risk mitigation and efficiency benefits. The net benefits of increased levels of investment are significant between a $250 million and $300 million investment level. Beyond $300 million per year, the incremental benefits are significantly reduced. The recommended strategy has a $15.3 billion NPV.

Figure 10.6.7.1-1 25-Year NPV by Investment Level



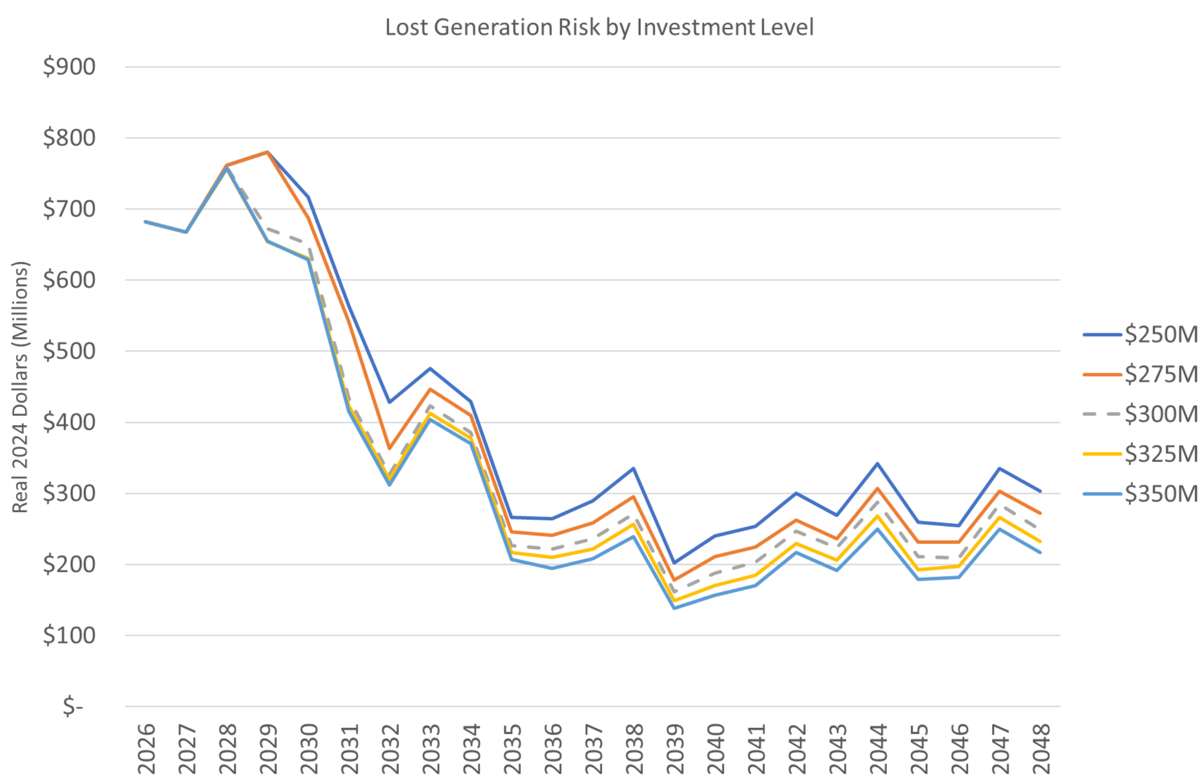
10.6.7.2 Long-term Risk Profiles

The following figures illustrate the risk profiles and lost efficiency opportunities associated with each capital investment level. As the changes in funding begin to affect the timing of investment completion, the differences in the risk profiles become apparent. Refer to Section 10.2 for how Lost Generation Risk, Direct Cost Risk, and Lost Efficiency Opportunity are defined and calculated. The modeling includes investments that currently have an awarded contract, have received approval to proceed to contract award, or are in design. Remaining budget is then filled in by the analytics that determine the optimal time to replace assets. While constraints are imposed on outage time at large plants to provide a more realistic look at how many assets could reasonably be replace in a year, the modeling still likely replaces the highest risk assets more quickly than could be achieved in reality.

10.6.7.2.1 Lost Generation Risk

In all scenarios, lost generation risk is reduced significantly by the 2030s. Existing investments primarily account for the reduction in risk between 2026 and 2030. The large reduction between 2030 and 2031 is mostly from the modeling addressing the highest risk assets. As mentioned in the previous section, it is more likely these reductions would be spread out over a few more years as the assets are packaged into an investment in the asset plan. For purposes of this analysis, the incremental differences between the scenarios is more important than the values themselves. Under investment levels less than $300 million, a more significant portion of the capital budget is devoted to non-power generation assets that improve safety, maintain day-to-day operations, or support the multipurpose missions of the dams. While there are reductions in lost generation risk beyond the $300 million investment level, the incremental benefits decrease. On average, a $300 million investment level provides an incremental reduction in lost generation risk of $52 million per year compared to a $250 million investment level. A $350 million investment level provides an additional $23 million per year reduction in lost generation risk relative to a $300 million investment level.

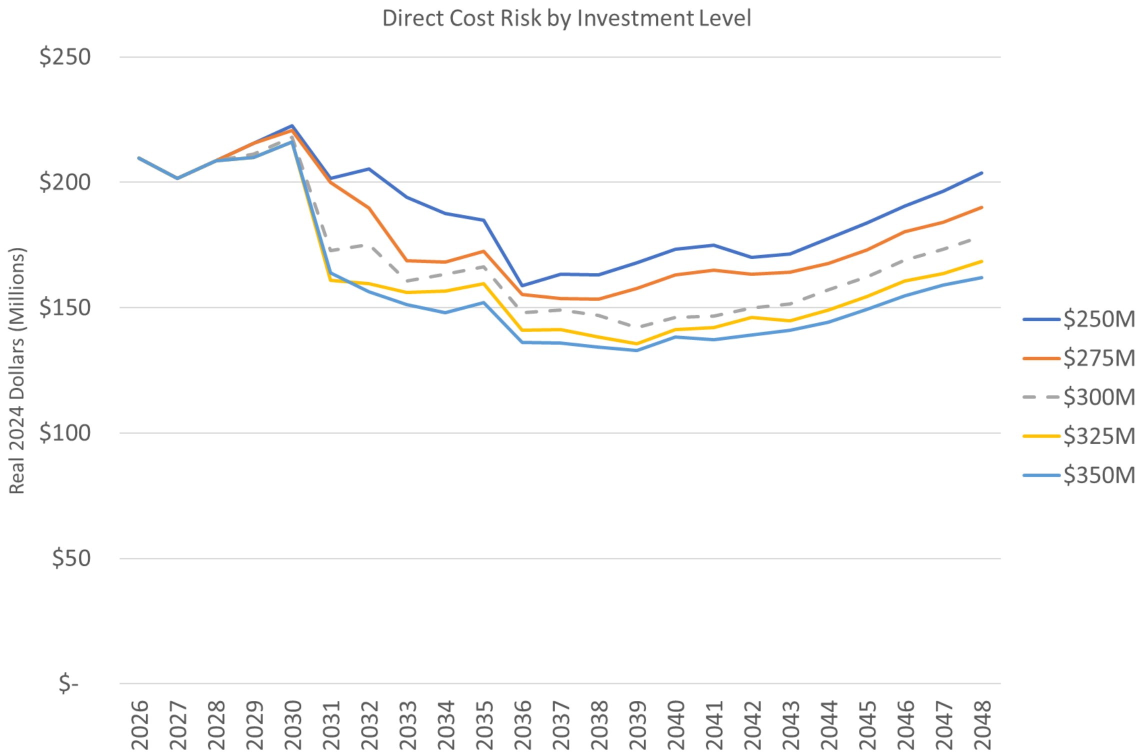
Figure 10.6.7.2.1-1 FCRPS Lost Generation Risk by Investment Level



10.6.7.2.2 Direct Cost Risk

Like lost generation risk, the aggressive replacement of high-risk assets by the modeling in 2031 is apparent. On average, a $300 million investment level provides a reduction in direct cost risk of $18.2 million per year compared to a $250 million investment level. A $350 million investment level only provides an additional $9.8 million per year in risk reduction relative to a $300 million investment level.

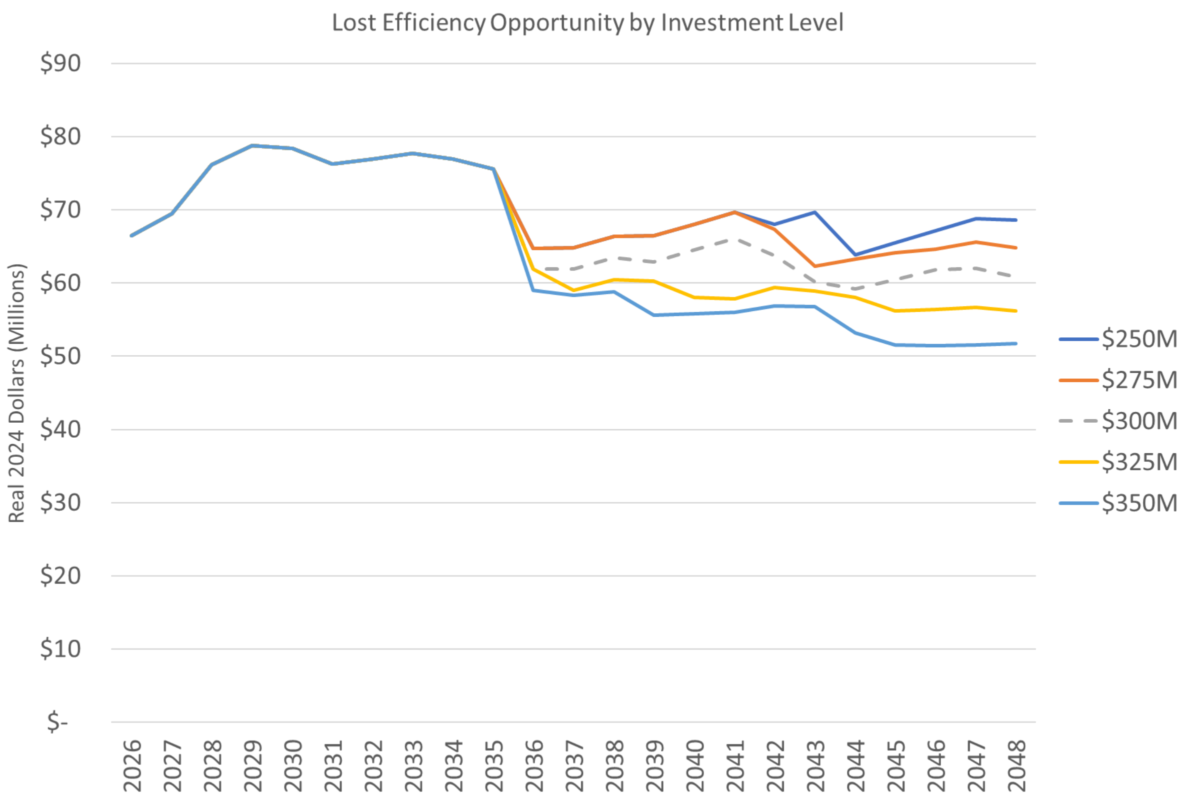
Figure 10.6.7.2.2-1 FCRPS Direct Cost Risk by Investment Level



10.6.7.2.3 Lost Efficiency Opportunity

Turbine runner replacements are complicated, costly projects. Higher levels of investment allow more turbine runner projects to proceed concurrently. A $300 million investment level reduces the lost efficiency opportunity by $4.8 million per year relative to $250 million investment level once the incremental investments complete. Lost efficiency opportunity costs can be reduced by an additional $7.1 million per year going from a $300 million investment level to a $350 million investment level.

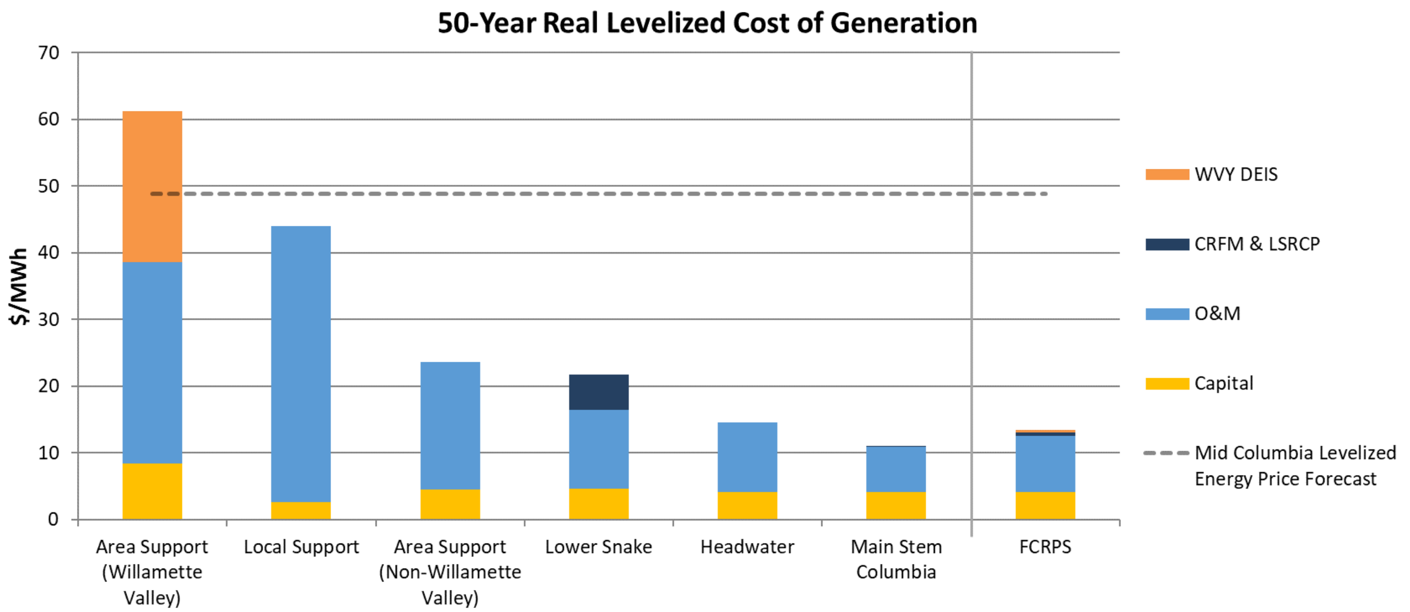
Figure 10.6.7.2.3-1 FCRPS Lost Efficiency Opportunity by Investment Level



10.6.7.3 Real Levelized Cost of Generation

The Levelized Cost of Generation is a forward look at the Cost of Generation metric described in Section 8.3.6. It takes the capital and expense programs outlined in the recommended strategy and levelizes them over a 50-year period to give a representative annual capital and expense value. Plant generation is also modified based on the changes in the lost generation risk profiles to recognize difference from current conditions. For purposes of this analysis, financing is not considered for capital expenditures, and capital dollars are recognized in the years in which they are expended. The Willamette Valley is shown separately and costs from the Willamette Valley Draft EIS (DEIS) Preferred Alternative are included. These costs represent the median estimate presented in Section M of the DEIS.

Figure 10.6.7.3-1 FCRPS 50-Year Real Levelized Cost of Generation

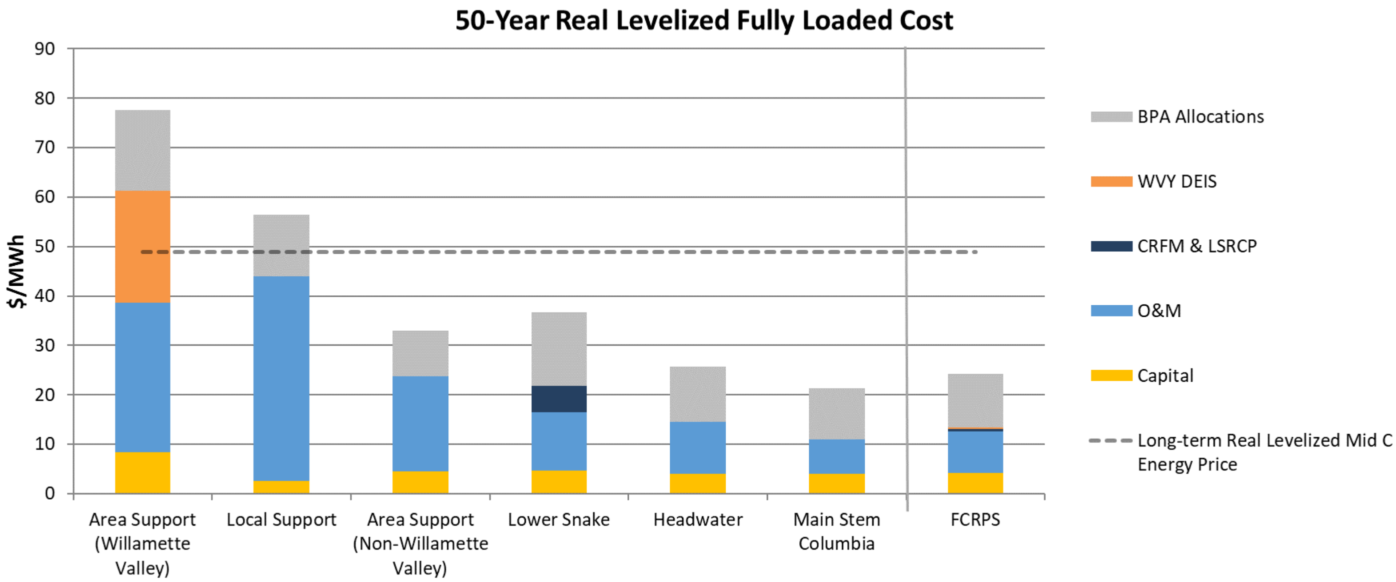


The FCRPS has a 50-Year Real Levelized Cost of Generation of $13.41/MWh compared to a real levelized energy price forecast of $48.86/MWh for the Mid-Columbia. All plants in the Main Stem Columbia, Headwater, Lower Snake, and Non-Willamette Valley Area Support strategic classes are expected to produce power at or below the real levelized energy price. This means that 95% of the capital investment program and 94% of the expense program over the next 50 years are targeted at plants producing power at a cost below the expected spot market energy price. Note that, like the Cost of Generation metric, this is not an “all-in” cost and only considers the incremental costs of generation.

10.6.7.4 Real Levelized Fully Loaded Cost

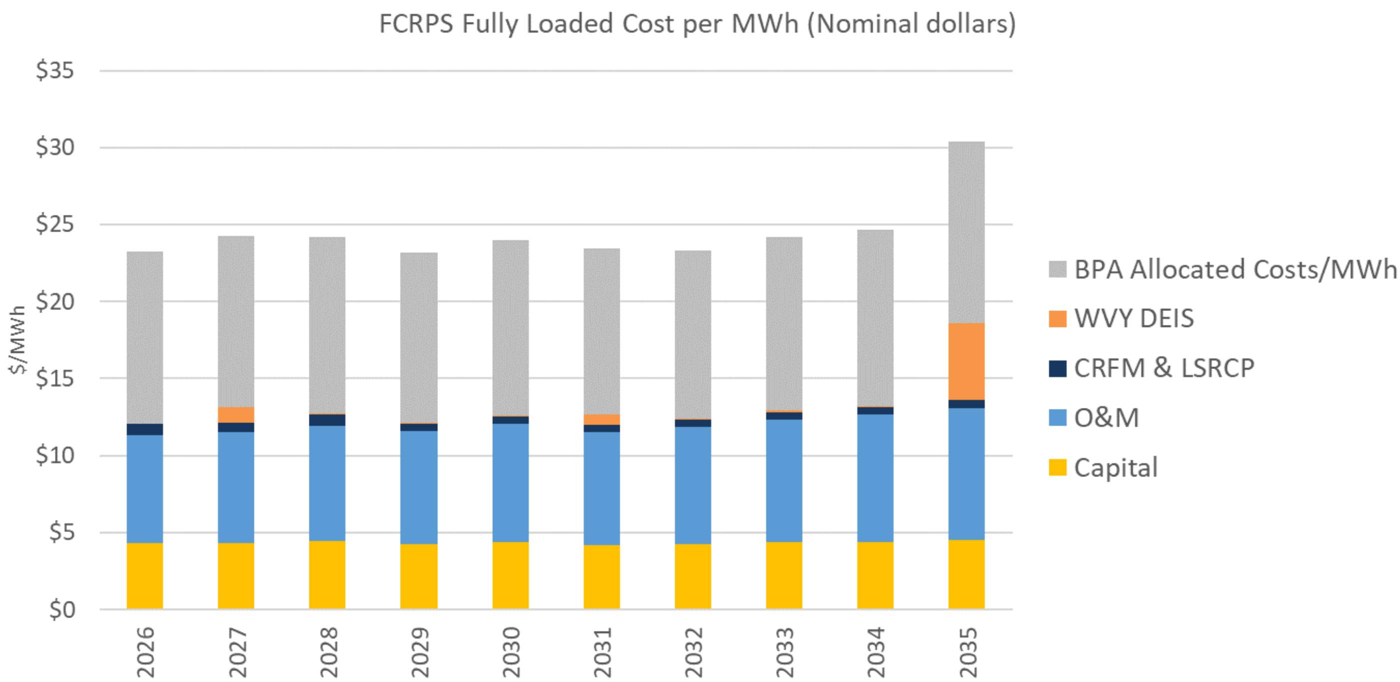
The Real Levelized Fully Loaded Cost includes allocations for all costs that can be attributed to the FCRPS. This includes BPA's Fish and Wildlife Program, Residential Exchange and other BPA overheads. Future BPA allocable costs are assumed to increase at the rate of inflation for the purpose of this analysis. The strategy outlined in this SAMP is expected to result in a Real Levelized Fully Loaded Cost of $24.29/MWh for the 50-year study period. Thus, planned investments and expense costs over the next 50 years are forecasted to result in an increase over the system's current Fully Loaded Cost of $21.24/MWh shown in Table 8.3.6-1 over FY19-FY21.

Figure 10.6.7.4-1 FCRPS 50-Year Real Levelized Fully Loaded Cost



Focusing on the next ten years, the Fully Loaded Cost per MWh is expected to slightly increase between 2026 and 2034. This is primarily driven by expense forecasts due to the expectation that wage increases in the routine expense program will outpace inflation. Reductions in lost generation risk offset some of these increases, due to improved availability and an increased average generation forecast. Implementation costs of structural measures outline in the draft EIS drive up costs in 2035. For this analysis, the full costs of the BPA share of the structure are included in the year in which it is expected to be complete.

Figure 10.6.7.4-2 FCRPS Fully Loaded Cost per MWh



10.6.7.5 Summary of Results

This SAMP targets 72% of the long-term capital program and 66% of the long-term expense program at the Main Stem Columbia, which has a 50-year incremental cost of generation of $10.92/MWh and a fully loaded cost of $21.25/MWh. Forecasts for other strategic classes are roughly proportional to their respective contributions to total FCRPS average generation. While maintaining generating equipment reliability is a major driver for the capital and expense programs, maintaining assets that support the multipurpose missions of FCRPS facilities is also a priority for USACE and Reclamation. As a system, the 50-year levelized Cost of Generation for the FCRPS is forecast to be $13.41/MWh and the 50-year levelized Fully Loaded Cost is $24.29/MWh. Both metrics are highly competitive with recent market prices and BPA's expectations for market prices in the future.

Table 10.6.7.5-1 Summary of Generation and Program Forecasts

Strategic Class	% of FCRPS Average Annual Generation	% of 50-Year Capital Forecast	% of 50-Year Expense Forecast	50-Year Cost of Generation ($/MWh)	50-Year Fully Loaded Cost ($/MWh)
Main Stem Columbia	79%	72%	66%	$10.92	$21.25
Lower Snake[3]	9%	13%	13%	$21.76	$36.69
Headwater	7%	7%	8%	$14.60	$25.74
Area Support (Non-WVY)	2%	2%	4%	$23.68	$32.99
Area Support (WVY)	2%	5%	6%	$61.31	$77.56
Local Support	1%	1%	3%	$43.98	$56.40
FCRPS	100%	100%	100%	$13.41	$24.29

[3] Lower Snake River Compensation Plan costs are now included in the 50-Year Cost of Generation metric. Previous SAMPs only included these costs in the 50-Year Fully Loaded Cost metric.

11.0 Addressing Barriers to Achieving Optimal Performance

Asset Management activities for FCRPS assets are spread across three separate government agencies each within their own separate department of the federal government. The Department of Energy, Department of Interior, and Department of Defense all have their own policies, procedures, requirements, and reporting structures under which BPA, Reclamation, and USACE respectively operate. As multipurpose dams represent a small portion of the broader focus of these federal departments, there are some barriers and inefficiencies introduced that likely would not be faced by typical non-federal utilities. It is important to acknowledge that the Three Agencies have varying levels of influence over these nationwide policies and procedures established at the departmental level. In some cases, this means that there are aspects of the asset management process over which the Three Agencies have less direct control than our utility peers. The following will outline some of the most critical barriers faced by the FCRPS and the actions that the Three Agencies are taking to mitigate them.

11.1 Hydropower Acquisition

Contracting and acquisition processes present ongoing challenges in the FCRPS that the Three Agencies are addressing. The FCRPS continues to prioritize improvement and growth in this area. With hydro equipment having so many unique and complex aspects, it is a regional priority to build more effective, efficient, and optimal acquisition strategies and processes.

11.2 Differing Agency Missions and Joint Assets

Hydropower is just one of the missions that USACE and Reclamation must balance for the dams on behalf of the region. Reclamation has a significant irrigation and water management mission and some USACE dams provide extensive navigation, flood risk mitigation, and water supply benefits. Differences in the understanding and definition of risk across the Three Agencies, especially for non-power generation assets, can occasionally be source of inefficiency in the asset management process.

One way that the Agencies are seeking to remedy this inefficiency is by improving the modeling of these assets in existing asset management processes. Modeling the benefits and risks of investment in joint assets is currently not as sophisticated as the modeling for powertrain assets. As a result, the value of joint assets often does not compare well with powertrain assets, resulting in joint investments being deferred in favor of powertrain investments. Recognizing that joint assets still must be replaced and that their risk and benefits are not fully captured, the Asset Planning Team currently reserves a percentage of the annual capital budget for joint assets. Joint investments are then optimized within this sub-portfolio and locked in place. This interim methodology ensures that a reasonable level of investment continues in joint assets. Although joint assets are not optimized with all other assets, the same optimization techniques used on the broader portfolio are used within the joint sub-portfolio to determine priorities.

In FY22, FCRPS staff developed the framework for a new spillway gate model that can more accurately capture financial risks such as the lost generation, direct cost, and downstream damage impacts of spillway gate failure. It can also capture the asset-specific non-financial risks to safety, the environment, compliance, and public perception. In FY23, the model was tested and built into the Copperleaf asset models. The direct cost risk portion of the model was used in this SAMP while the remainder of the model data is populated and intended for use in the next SAMP.

In FY21, FCRPS staff identified the need to better reflect how generating unit reliability impacts Reclamation's irrigation and water delivery missions. Reclamation recently developed a model that quantifies how unit outages affect irrigation rates and it has been used to inform two new Copperleaf value measures for irrigation and water delivery. Those new value measures are under evaluation in FY24.

11.3 Alignment of Equipment Capabilities with Operational Needs

Historically, BPA Power products and services have been developed based on the capabilities and limitations of the existing assets. With major powerplant modernization projects on the horizon, there is an opportunity to shape the design of the assets around future needs. Increased collaboration between BPA operations, the trading floor and FCRPS asset management is critical to ensure these opportunities are realized. For the John Day Turbine and Generator replacement project, for example, there has been close coordination between the USACE design team, district and plant staff, BPA Power, BPA Fish and Wildlife, and BPA Transmission to ensure that the modernized units meet the needs of each party. BPA is also coordinating internally to include expected efficiency and capacity improvements that are ancillary benefits of capital sustain program replacement projects in BPA resource planning.

11.4 Capital Program Execution

Executing the optimal level of investment in the FCRPS has historically been a challenge. FCRPS Asset Management staff are implementing several process improvements in 2024 that are expected to mitigate some of the risk of under execution. On the planning side, the Asset Planning Team changed the portfolio optimization process to ensure that the Asset Plan is not being overly constrained by optimistic expenditure schedules. Using adjustments based on historical program performance reduces the chance that projects are unnecessarily delayed in the Asset Plan. In the project approval process, a decision tree has been implemented that establishes a value-based method for determining how projects should move forward after major changes in costs or expected benefits. Prior to using the decision tree process, it was difficult to determine if a major change in project costs and benefits justified shuffling projects around to refocus resources on potentially higher value projects. This could lead to delays in eventual project approval after discussion and analysis. The decision tree process provides a structured way to determine the portfolio value impact of deferring an investment and provides guidelines on determining if deferral is valuable. This analysis is performed prior to regularly scheduled project reviews and reduces the potential for delay.

12.0 DEFINITIONS

Asset Investment Excellence Initiative (AIEI): A Federal Columbia River Power System initiative to improve long term capital investment planning capabilities and processes.

Asset Planning Team (APT): Federal Columbia River Power System long term planning team tasked with development of the System Asset Plan.

Bonneville Power Administration (BPA): Power Marketing Authority in the Pacific Northwest under the Department of Energy.

Copperleaf: Asset Investment Planning and Management Tool used by Federal Columbia River Power System long term planning staff.

Capital Workgroup (CWG): Federal Columbia River Power System technical and economic Capital Investment review team tasked with review and approval of all Large Capital investments.

CEATI: User-driven organization that facilitates electric utility information sharing and technical projects for its participants.

Columbia River Fish Mitigation (CRFM): A program to mitigate the impacts to fish posed by the dams primarily on the lower Columbia and lower Snake Rivers.

Days Away Restricted or Transferred (DART): The number of recordable non-fatal injuries and work-related illnesses resulting in lost time or days on restricted or transferred duty per 100 full-time workers.

Direct Cost Risk (DCR): A risk calculated in Predictive Analytics reflecting the incremental cost of equipment failure compared to planned replacement (not including lost generation).

Direct Funding Agreements: Memoranda of Agreement that establish the ability for BPA to directly fund the Capital and Operations & Maintenance programs of USACE and Reclamation.

Executive Steering Committee (ESC): A Three Agency leadership team that develops long term goals and strategies for the FCRPS and provides guidance to the Joint Operating Committees.

Expenditure: Term used by the Capital Investment program to describe an investment activity.

EUCG: Member-based trade association comprised of professionals from utility companies that meets semi-annually to provide a forum and tools to exchange information, share lessons learned, and find solutions to industry issues.

Federal Columbia River Power System (FCRPS): The Three Agency partnership comprised of the United States Army Corps of Engineers, United States Bureau of Reclamation and Bonneville Power Administration tasked with delivering on the multipurpose missions of the 31 federal hydroelectric facilities in the Pacific Northwest.

Hydraulic Plant Life Interest Group (HPLIG): A CEATI interest group focused on hydropower technology, asset management, operations & maintenance and best practices sharing.

hydroAMP: Hydro industry equipment condition assessment framework.

Integrated Program Review (IPR): A BPA financial public process in which capital and expense programs are reviewed with customers, stakeholders and other interested parties.

ISO 55000: A series of three international standards for Asset Management.

Joint Operating Committee (JOC): A committee tasked with overseeing the implementation of the direct funding agreements.

Lost Efficiency Opportunity (LEO): An opportunity cost calculated in Predictive Analytics that is associated with deferral of investment in more efficient equipment.

Lost Generation Risk (LGR): A risk calculated in Predictive Analytics reflecting the incremental loss of generation resulting from forced outages due to equipment failure.

Lost Time Accident Rate (LTAR): The number of recordable non-fatal injuries and work-related illnesses resulting in lost time per 100 full-time workers. Restricted to hydro-related incidents and only counts hydropower labor hours. Calculated on a 365-day rolling window to provide an annual rate, using 100 FTE = 200,000 man-hours.

North American Electric Reliability Corporation (NERC): Nonprofit corporation that develops standards for power system operation, monitors and enforces compliance, assesses resource adequacy and provides power system operation education and training resources.

North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP): A set of Cyber and Physical Security requirements designed to secure the assets required for operating North America's bulk electric system.

Non-Routine Expense (NREX): Investment projects or large, maintenance activities that are not regularly re-occurring and are not classified as a capital expenditure.

Operations and Maintenance (O&M): The routine activities performed by USACE and Reclamation as operators of the 31 hydroelectric facilities.

Operations and Maintenance Optimization Initiative (OMOI): USACE initiative to improve O&M decision making through a better understanding of value and risk to all missions at the facilities.

PAS 55: The predecessor to ISO 55000 and the first publicly available specification for optimized management of physical assets.

Predictive Analytics (PA): Copperleaf asset lifecycle cost minimization module.

United States Army Corps of Engineers (USACE): Operator of 21 Federal Columbia River Power System plants under the Department of the Army.

United States Bureau of Reclamation (Reclamation): Operator of 10 Federal Columbia River Power System plants under the Department of the Interior.

Reliability Implementation & Technical Subcommittee (RITS): Subcommittee of the Joint Operating Committee that is tasked with providing direction to the FCRPS regarding matters dealing with reliability and compliance issues, managing changes in Bulk Electric System Reliability Standards and requirements and managing interagency power generation/transmission technical issues.

Strategic Asset Management Plan (SAMP): A document specifying a long-term optimized approach to asset management, derived from, and consistent with, the organizational strategic plan and asset management policy.

Strengths, Weaknesses, Opportunities, and Threats (SWOT): A strategic planning and strategic management technique used to help an organization identify strengths, weaknesses, opportunities, and threats related to business competition or project planning.

System Asset Plan (SAP): A document specifying the projects, resources and timescales associated with achieving the goals described in the Strategic Asset Management Plan. Sometimes referred to as the “Asset Plan.”

Three Agency/Three Agencies: Refers to the partnership between Bonneville Power Administration, the United States Army Corps of Engineers and the United States Bureau of Reclamation.

Total Case Incident Rate (TCIR): The sum of all recordable non-fatal injuries and work-related illnesses per year per 200,000 labor hours.

Total Dissolved Gas (TDG): A measure of the concentration of dissolved gasses in water downstream of spillways resulting from spilled water at dams.

Value Framework: A module in Copperleaf that allows for the comparison and optimization of an investment portfolio.

Western Electricity Coordinating Council (WECC): The Regional Entity responsible for compliance monitoring and enforcement applicable to the Pacific Northwest.

Willamette Valley Draft EIS (Draft EIS): Draft Programmatic Environmental Impact Statement to address the continued operations and maintenance of the Willamette Valley System in accordance with authorized project purposes while meeting Endangered Species Act (ESA) requirements.