2014 Hydro Asset Strategy

March 2012

Executive Summary

The approach to creating this 2014 Hydro Asset Strategy is consistent with the 2012 strategy developed for the 2010 IPR.

The preferred plan for large capital in this strategy is unchanged from the 2012 Recommended Plan presented in the 2010 IPR process.

- A large capital program level of about $250 million per year provides a stable program that can be efficiently resourced for at least 15 years without accumulating a high level of risk.
- This program level is less costly in the long run than scenarios that reduce funding further.
- The preferred plan does not include costs for modernization of John W. Keys Pump Generating Plant or other uncommitted economic opportunity investments (e.g., additional units at Dworshak, Libby, or John Day).

The plan maintains an average hydroAMP condition rating for unit reliability equipment above a score of 7 (scale of 10) and reduces lost generation risk to less than 300 aMW within a decade.

Under this plan, the 20-year levelized fully allocated cost of the hydro system is forecasted to be $10 per MWh (2012 dollars).

1. Asset Category Overview

Introduction

The Federal Columbia River Power System (FCRPS) is a partnership between the US Army Corps of Engineers (Corps), the US Bureau of Reclamation (Reclamation), and Bonneville Power Administration (Bonneville).

FCRPS power related assets are financed through Direct Funding agreements between Bonneville and the Corps, and Bonneville and Reclamation. Through Direct Funding, over $400 million is spent annually by the FCRPS on Investment and O&M programs.

The FCRPS has a mandate to provide low cost, reliable power and effective resource stewardship to the Pacific Northwest region. It delivers power worth nearly $4 billion annually to the people of the Pacific Northwest in addition to providing protection, mitigation, and enhancement of fish and wildlife.

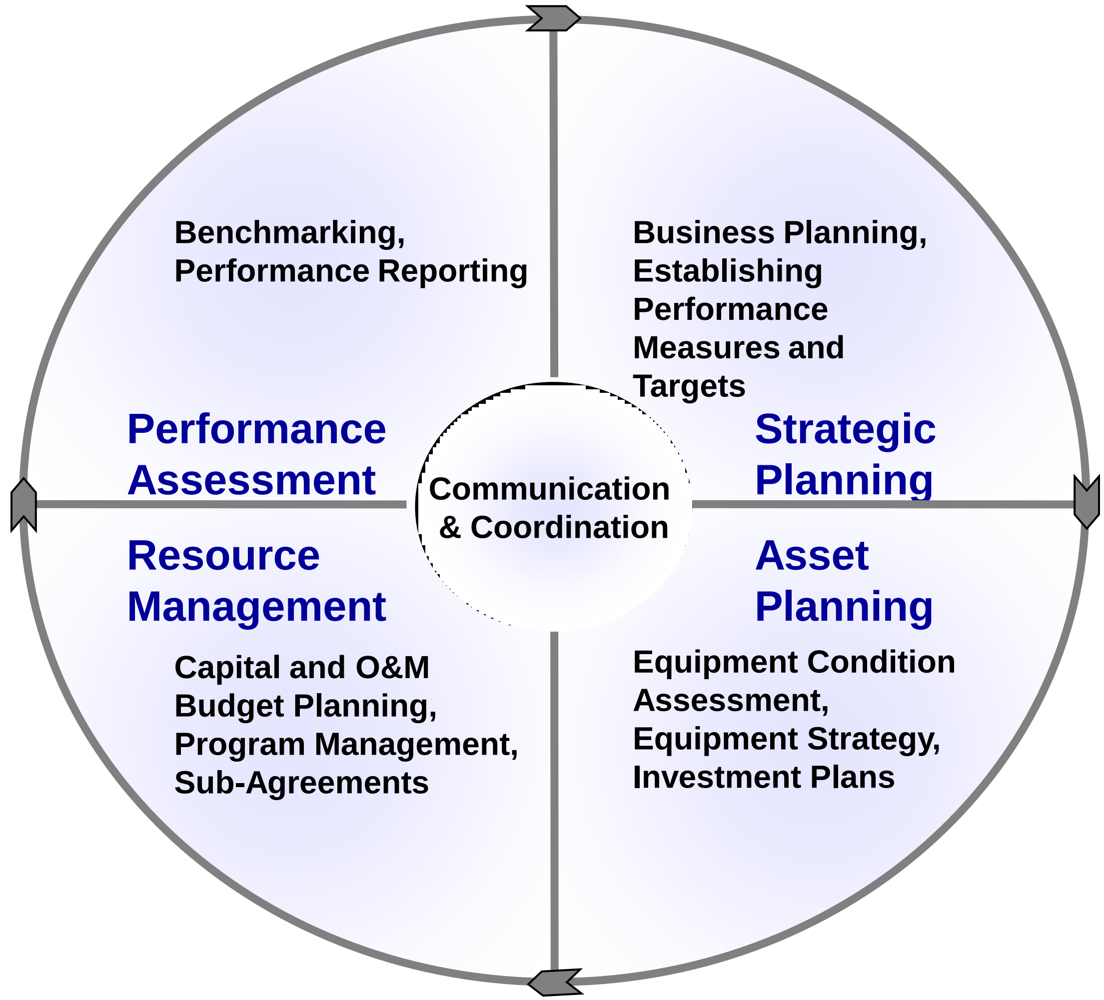
FCRPS Integrated Business Management Model

The FCRPS partnership uses an Integrated Business Management Model (IBMM) to provide a framework for ongoing asset-based planning and management. The IBMM consists of 12 business processes contained within four major areas - Strategic Planning, Asset Planning, Resource Management, and Performance Assessment.

A 3-Agency Steering Committee provides strategic direction to the hydropower program. Joint Operating Committee sub-committees provide direct oversight of specific aspects of the IBMM:

- Capital Investment Program
- O&M Program
- Performance Indicators
- River Management
- Hydro Optimization
- Technical Coordination
- Cultural Resources
- Fish and Wildlife

Direction from OMB and the three agencies of the FCRPS is to increase the level of efficiency, visibility and accountability for key business processes. The sub-committees are the primary management means for implementing this direction.



FCRPS Hydro System

The FCRPS is comprised of 31 hydroelectric plants – 21 operated by the Corps and 10 by Reclamation. The FCRPS has an overall capacity of 22,060 MW and, in an average water year, produces 76 million megawatt-hours of electricity.

Within the hydro asset category, the plants are grouped into four strategic classes depending on the role they play in the system. These categories are as follows:

- **Main Stem Columbia**: plants that provide the majority of power, ancillary services, and non-power benefits to the Pacific Northwest.
- **Headwater/Lower Snake**: plants that support services provided by Main Stem Columbia plants.
- **Area Support**: plants that do not support the region as a whole, but provide key power and non-power benefits to an area of the Pacific Northwest.
- **Local Support**: plants that primarily provide services to a local area only.

FCRPS Hydro System

Plant	ID	Units	MW Capacity	aMW Energy	Strategic Class	Operator
Grand Coulee	GCL	24	6,735	2,497	Main Stem Columbia	Reclamation
Chief Joseph	CHJ	27	2,614	1,387	Main Stem Columbia	Corps
McNary	MCN	14	1,120	575	Main Stem Columbia	Corps
John Day	JDA	16	2,480	991	Main Stem Columbia	Corps
The Dalles	TDA	22	2,052	773	Main Stem Columbia	Corps
Bonneville	BON	18	1,195	513	Main Stem Columbia	Corps
Dworshak	DWR	3	465	214	Headwater/Lower Snake	Corps
Lower Granite	LWG	6	930	272	Headwater/Lower Snake	Corps
Little Goose	LGS	6	930	263	Headwater/Lower Snake	Corps
Lower Monumental	LMN	6	930	278	Headwater/Lower Snake	Corps
Ice Harbor	IHR	6	693	211	Headwater/Lower Snake	Corps
Libby	LIB	5	605	238	Headwater/Lower Snake	Corps
Hungry Horse	HGH	4	428	113	Headwater/Lower Snake	Reclamation
Albeni Falls	ALF	3	49	24	Area Support	Corps
Detroit	DET	2	115	46	Area Support	Corps
Big Cliff	BCL	1	21	13	Area Support	Corps
Green Peter	GPR	2	92	30	Area Support	Corps
Foster	FOS	2	23	12	Area Support	Corps
Lookout Point	LOP	3	138	37	Area Support	Corps
Dexter	DEX	1	17	10	Area Support	Corps
Cougar	CGR	2	28	17	Area Support	Corps
Hills Creek	HCR	2	34	18	Area Support	Corps
Lost Creek	LOS	2	56	36	Area Support	Corps
Palisades	PAL	4	177	74	Area Support	Reclamation
Minidoka	MIN	4	28	22	Local Support	Reclamation
Anderson Ranch	AND	2	40	18	Local Support	Reclamation
Boise Diversion	BDD	3	3	2	Local Support	Reclamation
Black Canyon	BCD	2	10	9	Local Support	Reclamation
Roza	ROZ	1	13	10	Local Support	Reclamation
Chandler	CDR	2	12	9	Local Support	Reclamation
Green Springs	GSP	1	17	6	Local Support	Reclamation
Total		**196**	**22,060**	**8,716**		

Products and Services

Power Generation and Delivery

- Electricity Production (MWh)
- Peak Electricity Capacity (MW)
- Spinning and Non-spinning Reserves
- Load Following
- Voltage Support
- System Restoration (e.g., Black Start)

Non-Power Purposes

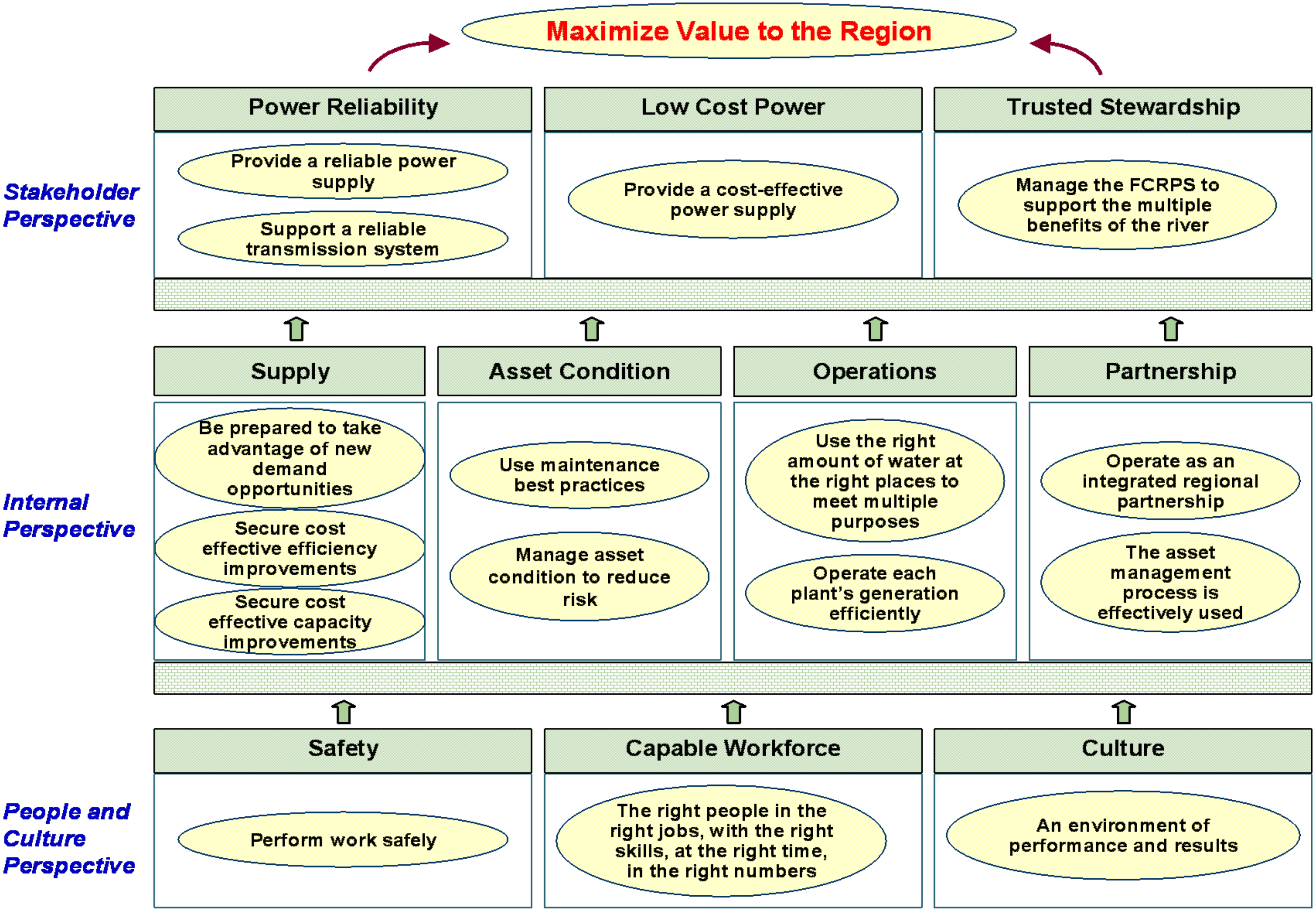
- Flood Damage Reduction – Use reservoir storage to shape natural water flows to reduce impacts to communities, farmland, and industry located along rivers.
- Navigation – Enable an inland waterway through a series of locks on the Columbia and Snake rivers.
- Irrigation – Increase the acreage of arable land in the Pacific Northwest through the storage and diversion of water.
- Recreation – Provide economic and social benefits by facilitating access to reservoirs and by making available parks and recreation areas.
- Municipal and Industrial Water Supply
- Water Quality
- Fish and Wildlife – Protect, mitigate and enhance fish and wildlife, including related spawning grounds and habitat, of the Columbia River and its tributaries.

Value of Strategic Classes by Purpose

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 Damage Reduction	Seasonal flood reduction and water management storage affecting significant parts of the Columbia River basin.	Seasonal flood reduction and water management storage affecting significant parts of the Columbia River basin.	Provides flood 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 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	None	None	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.

2. Asset Strategy Scope, Direction, and Objectives

FCRPS Hydro Strategy Map



FCRPS Hydro Strategy Logic and Scope

The FCRPS Hydro Strategy focuses on three goals:

- Low Cost Power;
- Power Reliability; and
- Trusted Stewardship

The strategy is implemented through a set of Direct Funding Agreements to:

- Ensure that life safety and environmental requirements are met;
- Meet FCRPS commitments for fish and wildlife and cultural resource programs;
- Meet Bonneville's business continuity needs for a reliable supply of low-cost generation by ensuring power generating assets are properly operated, inspected, and maintained;
- Mitigate the risk of power generation component failures by replacing or refurbishing equipment and purchasing spares when warranted;
- Increase the efficiency and/or capability of power facilities where economically feasible; and
- Fund a portion of high priority multi-purpose projects, in accordance with Bonneville's direct funding agreements with the Corps of Engineers and Bureau of Reclamation.

With this in mind, the 2014 strategy includes:

- Direct Funded O&M Program,
- Direct Funded Investment Program, and
- Appropriations reimbursed by Bonneville.

FCRPS Hydro Strategy Logic and Scope

Program funding needs are established through the IBMM model, as described in section 1.

- In general, the **O&M Program** reflects core funding for maintenance, operations, and minor equipment replacements, and is largely driven by the staffing needs of each facility.
- In contrast, the **Investment Program** is comprised primarily of large, discrete investment needs for equipment replacement or refurbishment, largely driven by condition and risk.

The Investment Program funding proposals presented within this strategy focus on the 10-year period, FY2012 – FY2021. Investments target electrical and mechanical systems, not civil features for dam safety, which are typically funded through appropriations, a share of which is reimbursed by Bonneville.

- Reinvestment costs for dam safety has been relatively low for the history of the FCRPS. Civil features are long-lived and rebuilding and/or replacement needs are negligible for the first 50 or more years of plant life. However, at some point significant reinvestment in civil works for dam safety is needed to extend useful asset life.
- For the focus period of this strategy, the exclusion of costs for dam safety civil features is not expected to materially affect the funding need forecast. However, as the hydro system continues to age, anticipating funding needs for dam safety will require more explicit attention in future strategies.

Targeted Plan Results

Target investments that address hydro strategic goals and achieve the following results by 2022:

Strategic Goal	FCRPS Hydro Partnership Objective	Bonneville Agency Long-term Outcome	Targeted Plan Result (Draft)
Low Cost Power	Provide a cost effective power supply	Meet environmental and reliability goals at the least lifecycle cost	Maintain a fully allocated cost of production of less than $10 per MWh in 2012 dollars.
			Reduce Lost Generation Risk to 300 aMW or less.
Power Reliability	Provide a reliable power supply	Meet availability requirements	Maintain an average condition rating of 7.0 or higher for unit reliability equipment (Main Stem Columbia and Headwater/Lower Snake classes).
			Implement maintenance best practices to achieve a 3-year rolling average forced outage factor of 2 percent or less (Main Stem Columbia and Headwater/Lower Snake classes).
	Support a reliable transmission system	Meet reliability standards	Full compliance with WECC/NERC reliability standards applicable to generators.
Trusted Stewardship	Optimize the multiple benefits of the river for the region	Meet hydro system environmental requirements	Mitigate the environmental consequences of high risk equipment items to an acceptable level.
	Maintain a safe work environment	Meet safety and security standards	Maintain a 3-year rolling average Lost Time Accident Rate of less than 2.0 per 200,000 employee-hours.

Criticality of Assets

Relative Cost of Unavailability. The criticality of a hydro asset is based largely on the quantity of energy produced, particularly at peak periods, and the financial impact of a loss of generation. Assets in the Main Stem Columbia and Headwater/Lower Snake strategic classes provide more than 96 percent of energy and capacity for the system.

Five plants – Grand Coulee, McNary, Chief Joseph, John Day and Dworshak – are considered particularly critical to the power system based on the significant financial impact of a generating unit outage at these facilities.

The figure on the following page groups FCRPS hydro plants by their strategic class and relative cost of unavailability (RCU) to the power system. The relative cost of unavailability is the annual cost of replacing lost generation from the least-used generating unit, or first 20 percent of lost plant availability, whichever is larger. No costs are included for replacing lost capacity, ancillary services, or non-power benefits.

Major RCU is up to $10 million per year, and is based on Bonneville’s long-term forward price forecast and average water conditions. Extreme RCU ranges from $10 to $40 million annually, while Severe RCU exceeds $40 million per year. No value is included for avoided CO_2 emissions.

The figure shows that Grand Coulee, McNary, Chief Joseph, John Day and Dworshak are the plants with the highest RCU.

Criticality of Assets

FCRPS Hydro Plant Classification

Relative Cost of Unavailability (RCU)	Local Support	Area Support	Headwater/ Lower Snake	Main Stem Columbia
Severe >$40m/yr				CHJ GCL MCN
Extreme $10 - $40m/yr			DWR	JDA
Major <$10m/yr	AND, BCD BDD, MIN, ROZ, CDR, GSP	BCL, DEX, LOS, DET, GPR, LOP, HCR, CGR, FOS, ALF, PAL	LIB, HGH, IHR, LGS, LWG, LMN	BON TDA

Strengths of the FCRPS Hydro System

Low, Stable Costs: The FCRPS hydro system provides a low and relatively stable cost of power, with a fully allocated cost of $6.89 per megawatt-hour in FY2010. Capital charges and O&M expenses each total approximately $250 million per year. Average annual generation is 76 million megawatt-hours. Costs are increasing somewhat over time for growth in the O&M Program and investments to repair and replace aging equipment.

Storage and Peaking: The FCRPS hydro system has a maximum useable storage of 10.5 ksfd, providing flood damage reduction, irrigation, fish and wildlife benefits, recreation opportunities, and increased value from the power system by storing water to be used when it is more valuable for generation.

Ancillary Services and Resource Integration: The hydro system provides all voltage support, load following, spinning and non-spinning reserves, and other ancillary services for Bonneville's transmission system. Hydropower also serves as the primary mechanism for integrating wind resources into the power system.

Climatic Risk: FCRPS hydro generation produces zero carbon dioxide emissions, which now are recognized as a primary contributor affecting climate change. Hydro generation both lessens climate change effects by reducing emissions that otherwise would be produced by alternative generation sources and remains cost effective within resulting weather variations that may influence water supply.

Energy Payback: Energy payback ratio is a comparison of the energy produced by a system divided by the energy consumed to build and operate the system over its useful life. Hydropower, with an energy payback ratio of 205, has the highest ratio of all generation sources. By comparison, the ratio for wind is 23 (without backup), nuclear fission (16), coal (11), and natural gas (4).

Skilled Workforce: The FCRPS has a dedicated and skilled workforce with a keen understanding of the operations and maintenance needs of the hydro system.

Weaknesses of the FCRPS Hydro System

Weather and Water Supply: Changing weather conditions and the resulting changes in water supply create a degree of uncertainty in hydropower production different than that from thermal generation alternatives. Between years, the difference in energy production from FCRPS hydro can be several thousand average megawatts. This presents unique challenges to managing the entire portfolio of power supply needed to meet the demands of Bonneville customers.

Environmental Costs: The FCRPS faces high environmental costs for mitigating the impact of developing the Columbia River Basin. The direct funded program costs considered in this strategy include $34 million per year for maintaining fish passage equipment and hatcheries. In addition to costs included in this strategy, environmental costs total more than $250 million per year for Bonneville's direct fish and wildlife program and the Corps' appropriated program to construct additional fish rearing and passage facilities. Indirect costs for changes in system operations now total several hundred million dollars per year.

Aging Workforce: The power industry as a whole is now facing a retirement eligibility bubble that poses significant risk to maintaining the workforce needed to operate and maintain facilities effectively. A large percentage of personnel working on-site at FCRPS hydro plants are eligible for retirement within five years.

Aging Infrastructure: The hydro system is also an aging infrastructure, approaching an average age of 50 years. The oldest plant in the system is Minidoka, with an in-service date of 1911. Bonneville Dam is the oldest Main Stem Columbia plant, with an in-service date of 1938. While many more years of valuable production can be expected from the hydro system, it faces significant challenges associated with maintenance and replacements demands to preserve this value.

Politically Unpopular: In Canada, Europe, and Australia / New Zealand, hydropower is generally seen as a clean and reliable source of renewable energy. However, in the United States, and particularly in the Northwest, hydropower is often perceived more negatively, which introduces added uncertainty into the future cost and supply of FCRPS hydro generation.

3. Current Performance, Condition, and Risk

Performance, Low Cost Power: O&M Program

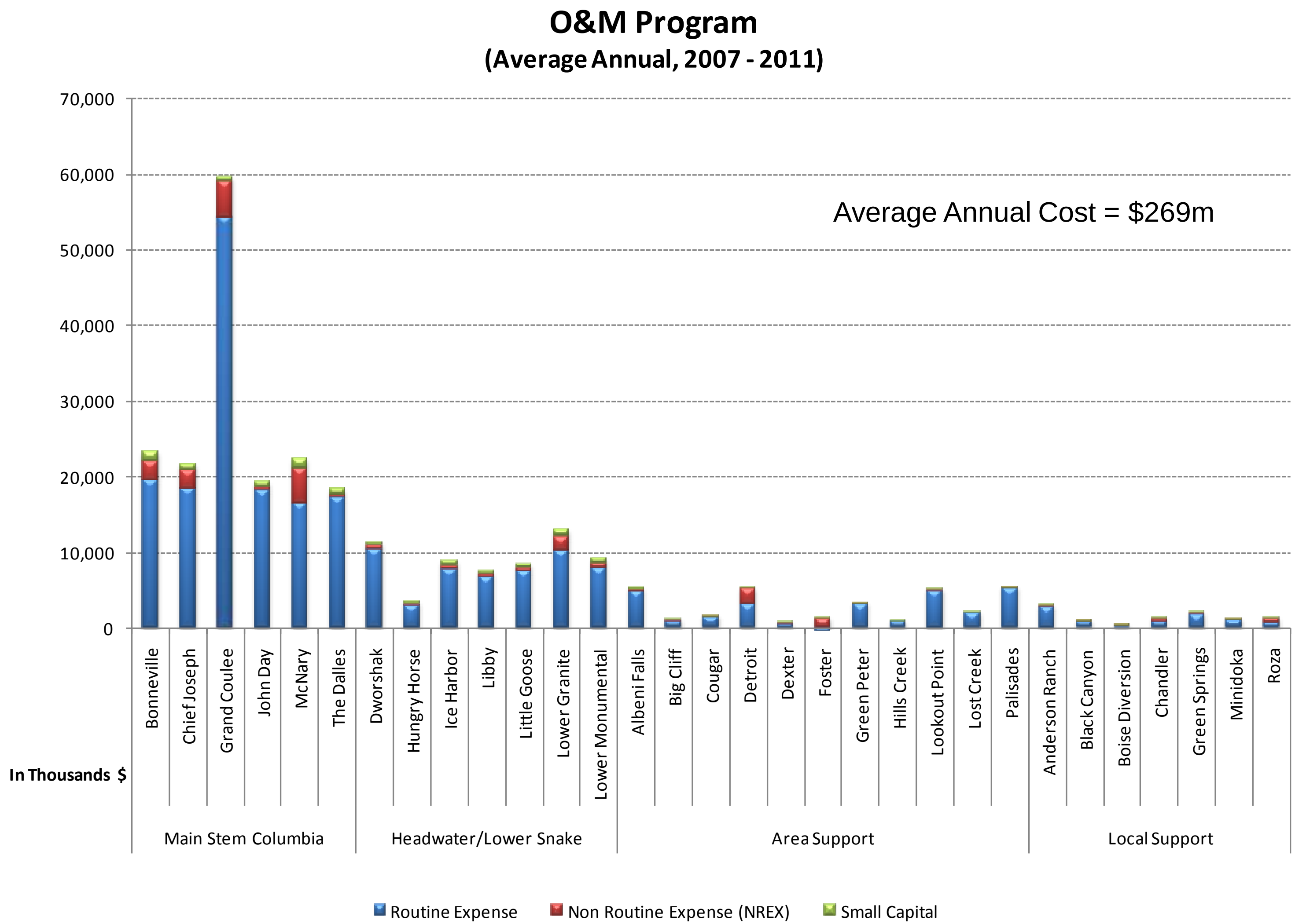
The O&M program is comprised of three general cost categories,

- Routine Expense: reflects core funding for maintenance, operations, and minor equipment replacements, and is largely driven by the staffing needs of each facility.
- Non-Routine Expense: large, infrequent maintenance activities that are categorized as expense following accounting standards.
- Small Capital: allowances for maintenance-related replacement of small components but by virtue of accounting treatment is capitalized.

About 70 percent of O&M program costs are for labor.

O&M program costs average annual cost for the FY2007 to FY2011 period was $269 million, or $12.25 per kW-yr.

Performance, Low Cost Power: O&M Program



Performance, Low Cost Power: Large Capital Program

The large capital program includes:

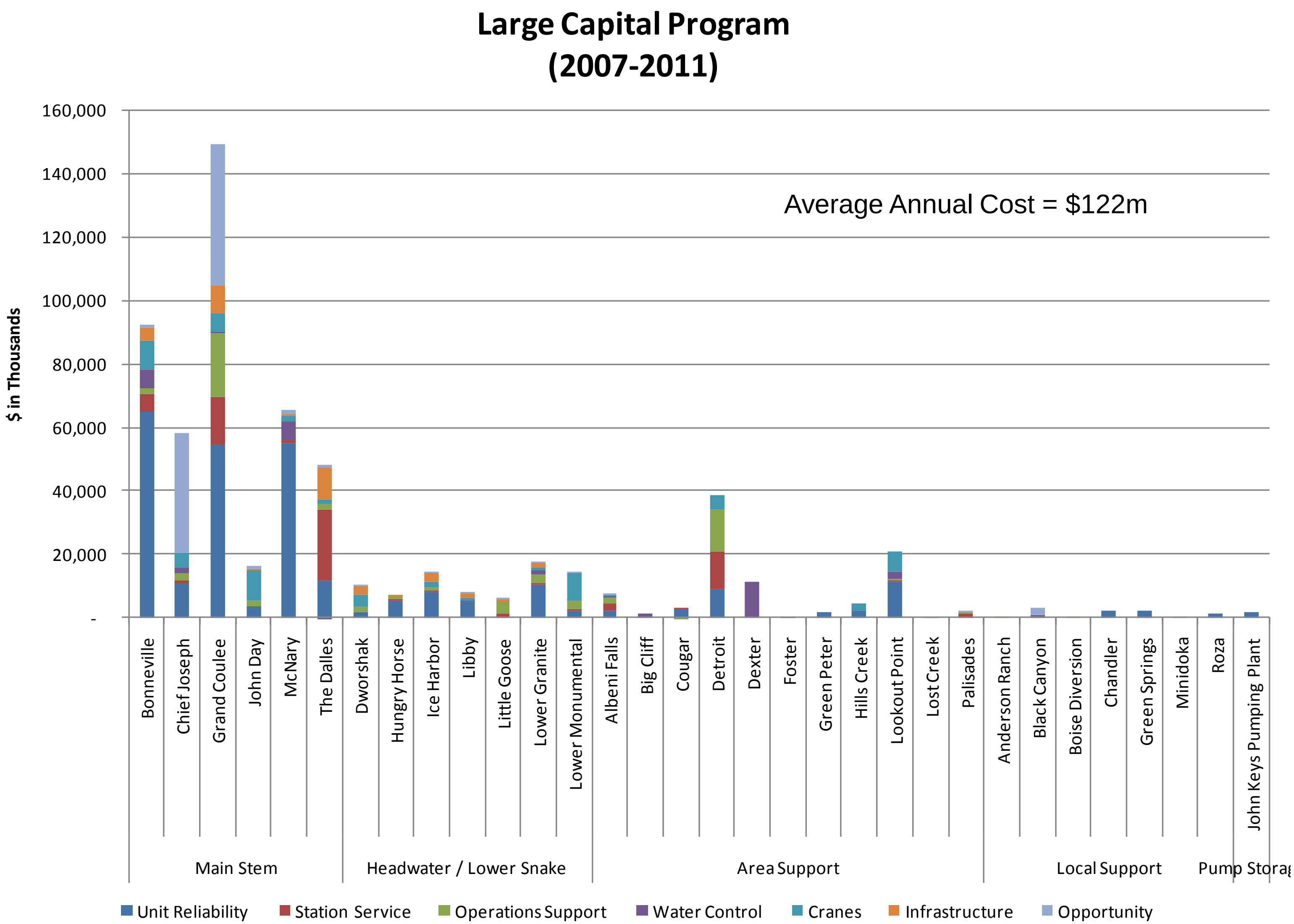
- Reliability driven replacements of capital components with the exception of smaller, "maintenance capital" replacements that are funded within the O&M program;
- Economic opportunity investments to existing assets that are undertaken to improve system performance (e.g., turbine runner replacements to improve efficiency); and,
- Investments in new assets at existing facilities (e.g., adding a new generating unit), also based on economic opportunity.

In the 5-year period, FY2007 to FY2011, the hydro program invested $608 million in repairs, replacements, and improvements to electrical and mechanical features of the system. The annual average cost was $122 million, or $5.50 per kW-year.

The FY2007 – FY2011 hydro large capital program breaks down as follows:

- Unit reliability: $270 million
- Station service: $63 million
- Operations support: $60 million
- Water control: $31 million
- Cranes: $63 million
- Infrastructure: $32 million
- Economic opportunity: $90 million (primarily runner replacements)

Performance, Low Cost Power: Large Capital Program



Performance, Low Cost Power: Fully Allocated Cost

Name of Asset	Completed Plant	Net Utility Plant	CWIP	Accumulated Depreciation	FY 2010 Depreciation	FY 2010 O&M Expense	FY 2010 Interest	Outstanding Fed. Approp.	Capital Investment	Net Generation (GWH)	Production Cost ($/MWh)	Fully Allocated Cost ($/MWh)
	"Cumulative Capital cost" /a	"Useable value of plant" /b	"included in Net Utility Plant but not in Completed Plant"	"included in Net Utility Plant but not in Completed Plant" /c	"FY 2010 Accumulated Depreciation less FY 2009 Accumulated Depreciation"	"Annual expense" /d	"Interest for this year" /e	"Sum of remaining principle" /f	"Total Capital invested during the year"	"Average generation based on 50-year hydro regulation studies"	"FY 2010 O&M Expense divided by Net Generation"	"(FY 2010 O&M Expense + Interest - Depreciation) divided by Net Generation"
Main Stem Columbia												
Bonneville	$1,056,355	$730,727	$60,964	($386,592)	($12,819)	$27,862	$34,066	$505,867	$11,232	4,490	6.21	16.65
Chief Joseph	$617,276	$355,589	$38,064	($299,750)	($11,408)	$19,270	$16,242	$238,215	$12,391	12,154	1.59	3.86
John Day	$523,889	$308,614	$14,781	($230,056)	($7,301)	$19,478	$2,070	$32,793	$8,155	8,685	2.24	3.32
McNary	$359,040	$200,355	$41,567	($200,253)	($3,659)	$20,424	$692	$13,142	$18,823	5,033	4.06	4.92
The Dalles	$416,142	$234,581	$28,985	($210,546)	($8,108)	$18,516	$4,505	$75,078	$9,477	6,771	2.73	4.60
Grand Coulee	$1,394,037	$990,952	$55,315	($458,400)	($21,472)	$64,080	$37,988	$548,798	$37,017	21,872	2.93	5.65
Total Main Stem Columbia	**$4,366,738**	**$2,820,818**	**$239,676**	**($1,785,595)**	**($64,767)**	**$169,631**	**$95,562**	**$1,413,892**	**$97,095**	**59,003**	**2.87 $/MWh**	**5.59 $/MWh**
Headwater/Lower Snake												
Dworshak	$305,423	$195,351	$6,934	($117,006)	($1,902)	$13,103	$9,053	$127,604	$5,711	1,873	7.00	12.85
Ice Harbor	$173,874	$98,472	$7,608	($83,009)	($3,335)	$8,090	$2,254	$35,286	$4,340	1,845	4.39	7.41
Libby	$441,018	$281,295	$3,180	($162,903)	($5,594)	$7,617	$16,738	$235,541	$1,364	2,086	3.65	14.36
Little Goose	$225,028	$121,190	$1,703	($105,541)	($3,202)	$7,782	$4,408	$63,790	$1,175	2,304	3.38	6.68
Lower Granite	$373,565	$235,183	$4,505	($142,888)	($5,085)	$12,066	$12,441	$177,491	$3,937	2,386	5.06	12.40
Lower Monumental	$255,185	$141,585	$3,104	($116,704)	($4,560)	$8,118	$3,604	$53,014	$2,376	2,435	3.33	6.69
Hungry Horse	$133,441	$82,327	$1,634	($52,748)	($1,733)	$4,278	$814	$12,766	$2,430	986	4.34	6.92
Total Headwater/Lower Snake	**$1,907,533**	**$1,155,404**	**$28,669**	**($780,799)**	**($25,411)**	**$61,055**	**$49,312**	**$705,491**	**$21,333**	**13,915**	**4.39 $/MWh**	**9.76 $/MWh**
Area Support												
Albeni Falls	$48,959	$31,864	$6,803	($23,897)	($1,135)	$5,074	$208	$3,090	$1,222	208	24.34	30.78
Cougar	$85,246	$77,123	$5,707	($13,830)	($1,647)	$2,467	$2,722	$52,463	$791	146	16.86	46.73
Detroit-Big Cliff	$64,399	$56,150	$20,073	($28,322)	($1,392)	$5,518	$85	$1,592	$6,022	519	10.64	13.49
Green Peter-Foster	$56,804	$33,679	$1,444	($24,569)	($799)	$4,523	$14	$227	$891	368	12.29	14.50
Hill Creek	$21,249	$11,947	$3,048	($12,350)	($450)	$898	$543	$7,976	$1,848	161	5.57	11.73
Lookout Point-Dexter	$62,066	$38,872	$18,603	($41,796)	($511)	$6,914	$730	$13,232	$5,895	410	16.86	19.89
Lost Creek	$28,620	$16,548	$126	($12,197)	($428)	$2,025	$1,006	$14,096	$73	317	6.38	10.90
Minidoka-Palisades	$113,824	$86,306	$3,073	($30,592)	($1,468)	$7,170	$3,643	$11,145	$893	841	8.53	14.60
Total Area Support	**$481,166**	**$352,490**	**$58,877**	**($187,553)**	**($7,830)**	**$34,587**	**$8,950**	**$103,823**	**$17,635**	**2,971**	**11.64 $/MWh**	**17.29 $/MWh**
Local Support												
Boise Diversion-Anderson Ranch-Black Canyon	$29,089	$21,888	$2,224	($9,425)	($439)	$3,736	$295	$4,425	$2,150	253	14.76	17.65
Chandler-Roza	$13,184	$9,921	$337	($3,600)	($180)	$2,388	$44	$862	$769	161	14.81	16.20
Green Springs	$10,821	$4,693	$2,259	($8,387)	($49)	$837	$655	$50,953	$1,582	51	16.47	30.32
Total Local Support	**$53,093**	**$36,502**	**$4,820**	**($21,412)**	**($668)**	**$6,960**	**$993**	**$56,240**	**$4,500**	**465**	**14.96 $/MWh**	**18.53 $/MWh**
Total Power Assets	**$6,808,530**	**$4,365,214**	**$332,042**	**($2,775,359)**	**($98,677)**	**$272,233**	**$154,817**	**$2,279,447**	**$140,563**	**76,354**	**3.57 $/MWh**	**6.89 $/MWh**

/a -- Sum of the initial capital and replacement costs; capital cost of retired equipment is deducted. [FY10 Interim (Year-end) ASPRJ SUMMARY Report_Excel Version.xls]
/b -- Construction Work in Progress [FY10 Interim (Year-end) ASPRJ SUMMARY Report_Excel Version.xls]
/c -- Accumulated Depreciation [FY10 Interim (Year-end) ASPRJ SUMMARY Report_Excel Version.xls]
/d -- Annual expense cost by dam. [FY10 Interim (Year-end) ASPRJ SUMMARY Report_Excel Version.xls]
/e -- For the life of a debt, BPA pays interest annually, the principle is paid as a lump sum at the end of its payment period.
BPA refinanced its debt in FY1998, resulting in slightly higher interest rates. [Approriated Interest FY10.xls: line 128]
/f -- Remaining unpaid principle [Appropriated Interest FY10.xls: line 66]

Performance, Low Cost Power: Cost Benchmarks

The FCRPS benchmarks its hydro program annually in order to identify areas of best practice and the potential for performance improvement.

Costs benchmarked include Corps and Reclamation costs for hydropower, recreation, and joint-use purposes, and Bonneville costs for program coordination, planning, scheduling, generation dispatch, and fish and wildlife mitigation.

Because Direct Funding program costs are only a subset of all costs benchmarked, one-to-one comparisons cannot be made between the Direct Funding program and the benchmarks.

But the benchmarking results do provide useful information on the allocation of costs within the program and how FCRPS costs compare with those of its peers.

Performance, Low Cost Power: Cost Benchmarks

(Distribution of O&M Costs for the FCRPS)

Public Affairs and Regulatory (54%): Recreation, fish and wildlife mitigation (including Bonneville's direct fish program), cultural stewardship, and fees for the use of land and water.

Support (17%): Human resources, fleet services, information services, security, purchasing, training, budgeting and accounting, and legal.

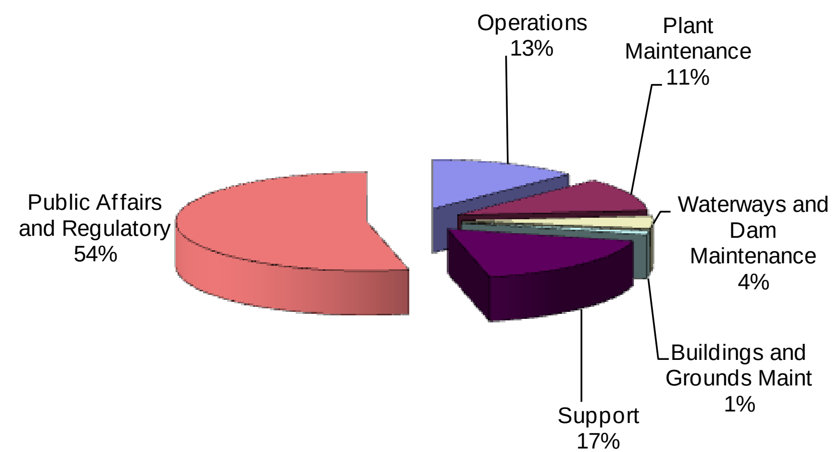
Operations (13%): On-site plant operations, off-site water management, and Bonneville's generation scheduling and dispatch.

Plant Maintenance (11%): Maintenance of generation facilities.

Waterways and Dam Maintenance (4%): Dam, spillways, and reservoir maintenance.

Buildings and Grounds Maintenance (1%).

Distribution of FCRPS O&M Costs



Performance, Low Cost Power: Cost Benchmarks

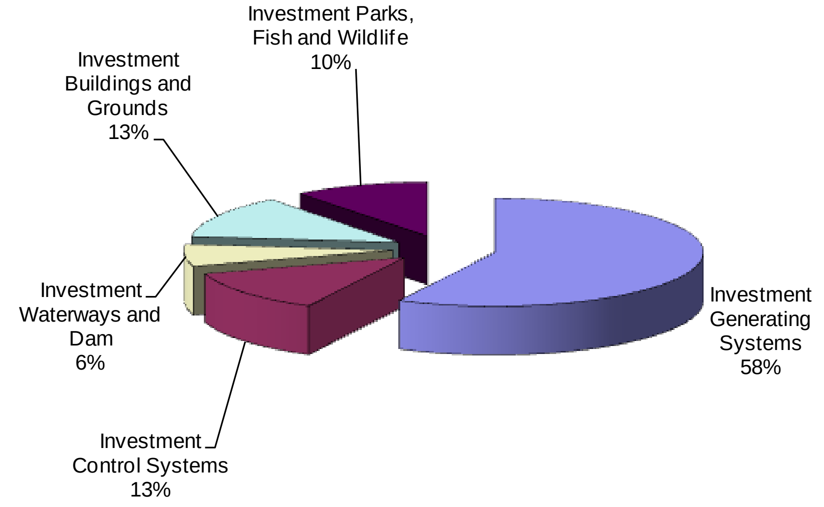
(Distribution of Investment Costs for the FCRPS)

Large Capital and Extraordinary Maintenance projects to repair, replace, and enhance hydropower and joint-use equipment.

Investment is comprised of both Direct Funding and appropriated dollars.

More than half of benchmarked Investment costs are in Generating Systems, with the remainder of costs in Control Systems and other multi-purpose equipment.

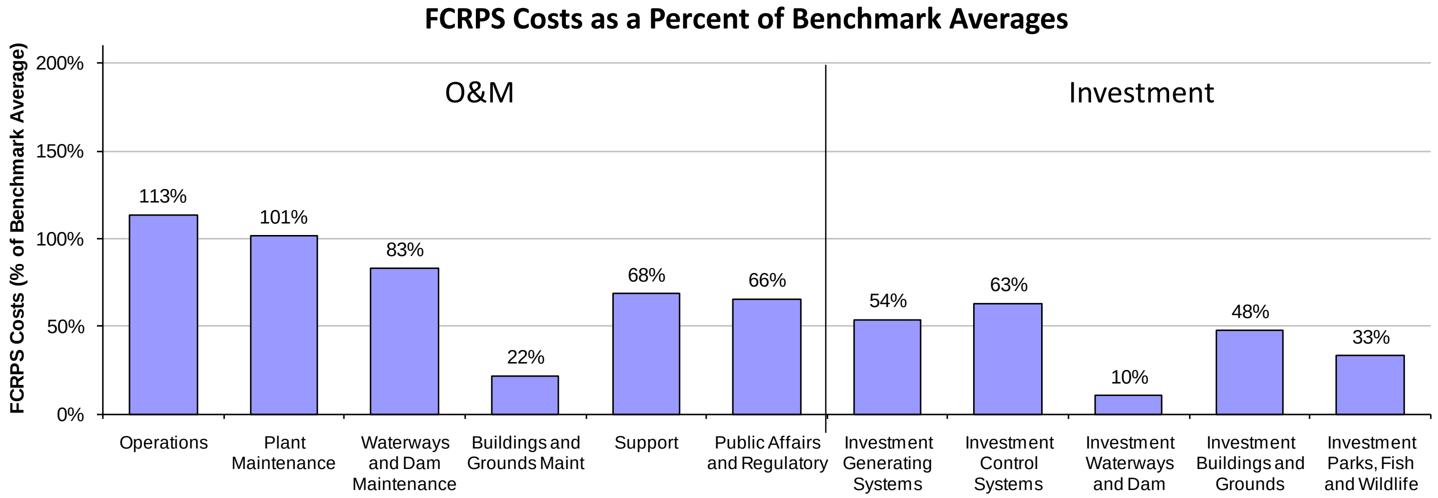
Distribution of FCRPS Investment Costs



Performance, Low Cost Power: Cost Benchmarks

Most O&M Program function costs are lower than benchmark averages.

- Operations costs are 13 percent higher than benchmark averages, in part due to water management functions that reside in three FCRPS federal agencies, but also to the number of Corps plants with staffed control rooms. Much of the industry now has automated stations, which lowers Operations staffing costs significantly.
- Powerhouse maintenance costs are 1 percent above average.
- Public Affairs and Regulatory costs for the FCRPS are high, but relatively low when compared to plants that pay falling water charges (FERC fees) or generation taxes (Canadian plants).
- Total O&M costs are 72 percent of the benchmark average.



Current Performance, Power Reliability

Availability: FCRPS hydro availability statistics have declined in recent years, primarily driven by outages at Grand Coulee. The availability factor averages 84 percent, ranging from 83 percent in 2010 to 86 percent in 2006.

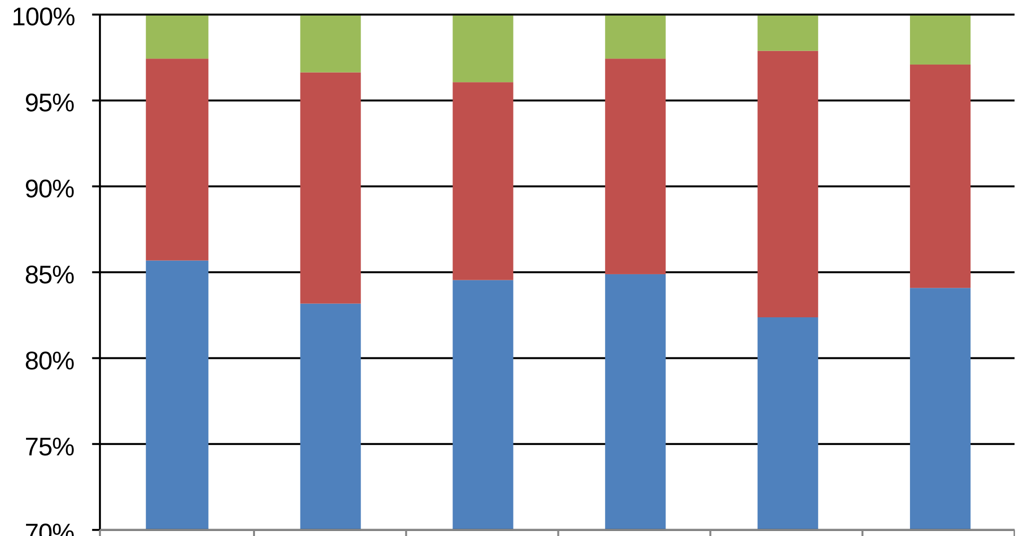
Scheduled Outage Factor: The scheduled outage factor averages 12.9 percent, slightly higher than the industry average of 12.1 percent, largely driven by outages for routine maintenance, but also for capital projects.

Forced Outage Factor: The forced outage factor averages 2.9 percent, also above the industry average of 2.3 percent. The 2010 rate was 2.1 percent, the lowest rate in several years.

Number of Instances: Other measures important to power reliability include the number of startup failures and number of forced outages. For the system, forced outages average about 2.2 per unit per year. Nearly 25 percent of forced outages are Fish and Transmission related.

Current Performance, Power Reliability

FCRPS Hydro Availability Statistics



	2006	2007	2008	2009	2010	5-yr Avg
Forced Outages	2.5%	3.3%	3.9%	2.5%	2.1%	2.9%
Scheduled Outages	11.8%	13.4%	11.5%	12.5%	15.4%	12.9%
Availability	85.7%	83.3%	84.6%	85.0%	82.5%	84.2%

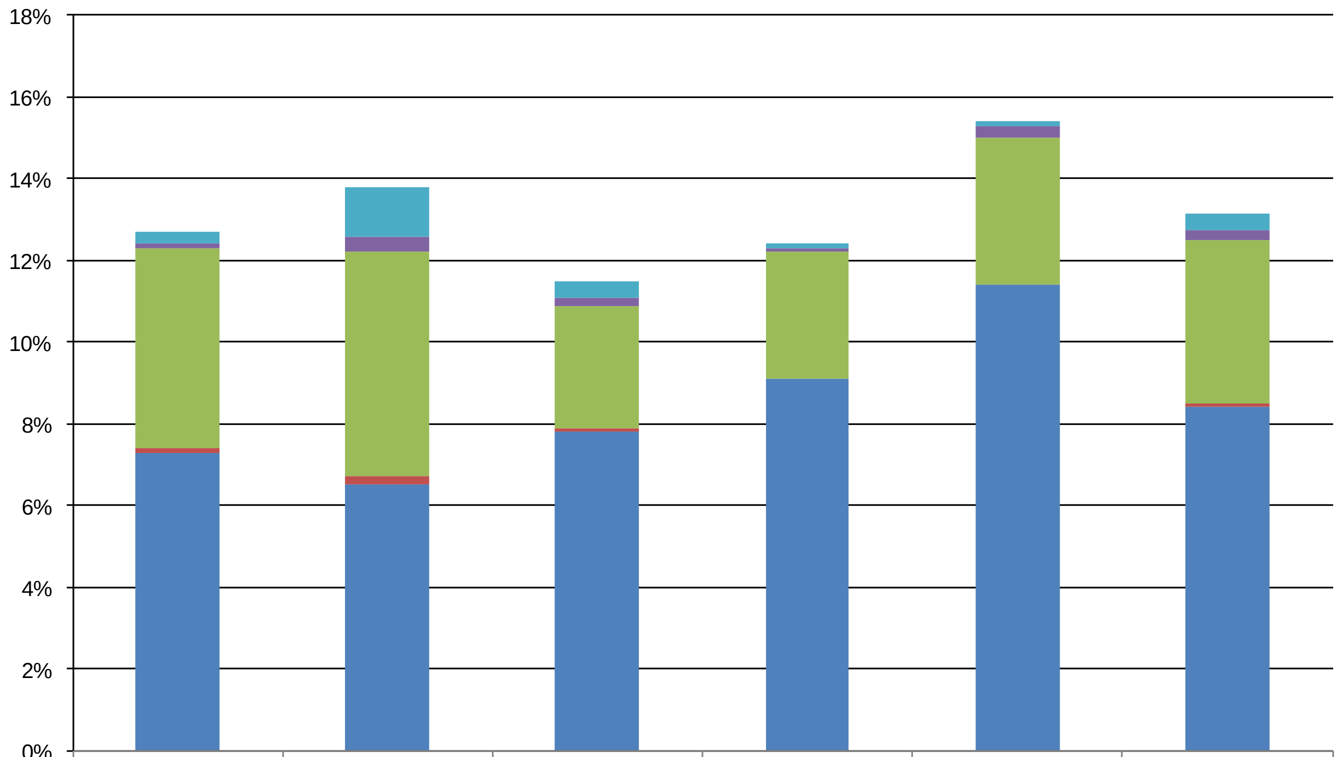
Number of Instances

Measure	2006	2007	2008	2009	2010	5-yr Avg.
Startup Failures	18	10	18	11	15	14
Forced Outages	521	479	487	375	398	452

Current Performance, Power Reliability

Scheduled Outage Factor by Source

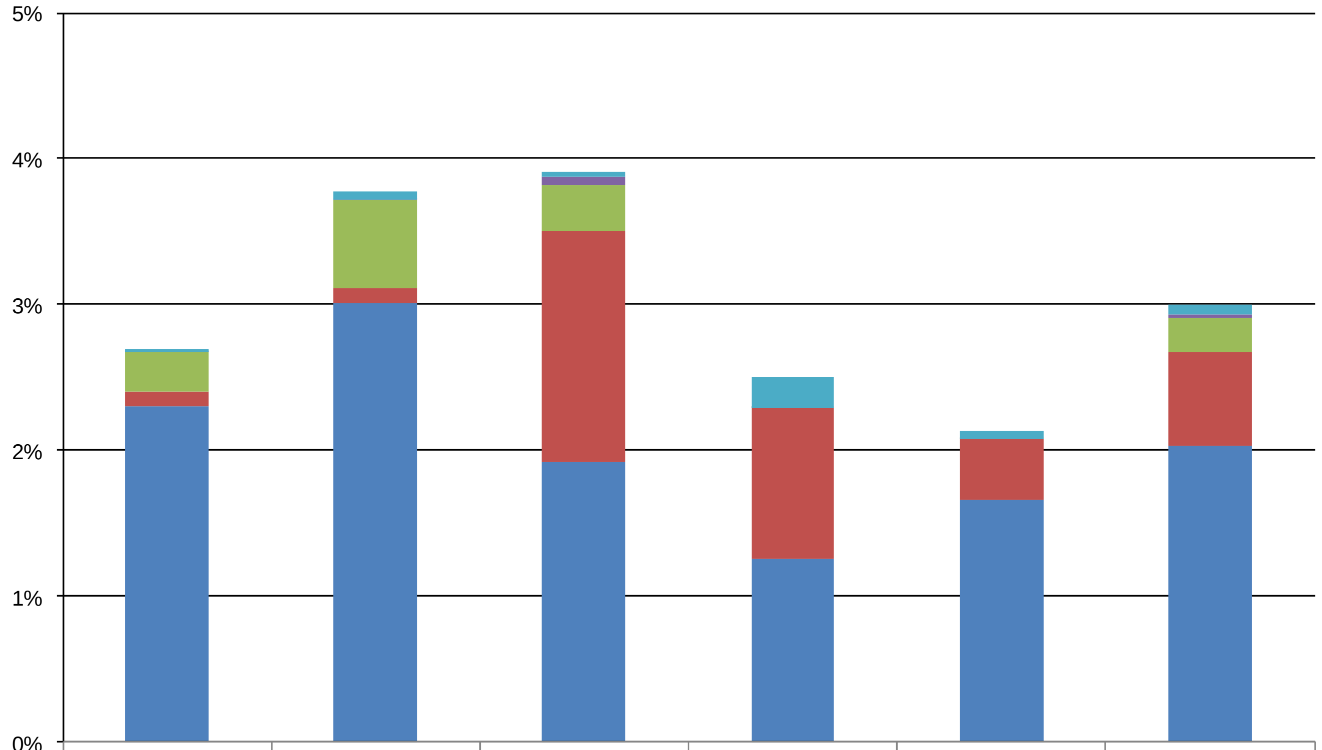
(2006-2010)



	2006	2007	2008	2009	2010	5-yr Avg
Fish	0.3%	1.2%	0.4%	0.1%	0.1%	0.4%
Transmission	0.1%	0.4%	0.2%	0.1%	0.3%	0.2%
Capital	4.9%	5.5%	3.0%	3.1%	3.6%	4.0%
Non-routine Maint.	0.1%	0.2%	0.1%	0.0%	0.0%	0.1%
Routine Maint.	7.3%	6.5%	7.8%	9.1%	11.4%	8.4%

Current Performance, Power Reliability

Forced Outage Factor by Source
(2006-2010)



	2006	2007	2008	2009	2010	5-yr Avg
Fish	0.0%	0.1%	0.0%	0.2%	0.1%	0.1%
Transmission	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
Capital	0.3%	0.6%	0.3%	0.0%	0.0%	0.2%
Non-routine Maint.	0.1%	0.1%	1.6%	1.0%	0.4%	0.6%
Routine Maint.	2.3%	3.0%	1.9%	1.3%	1.7%	2.0%

Current Performance, Trusted Stewardship

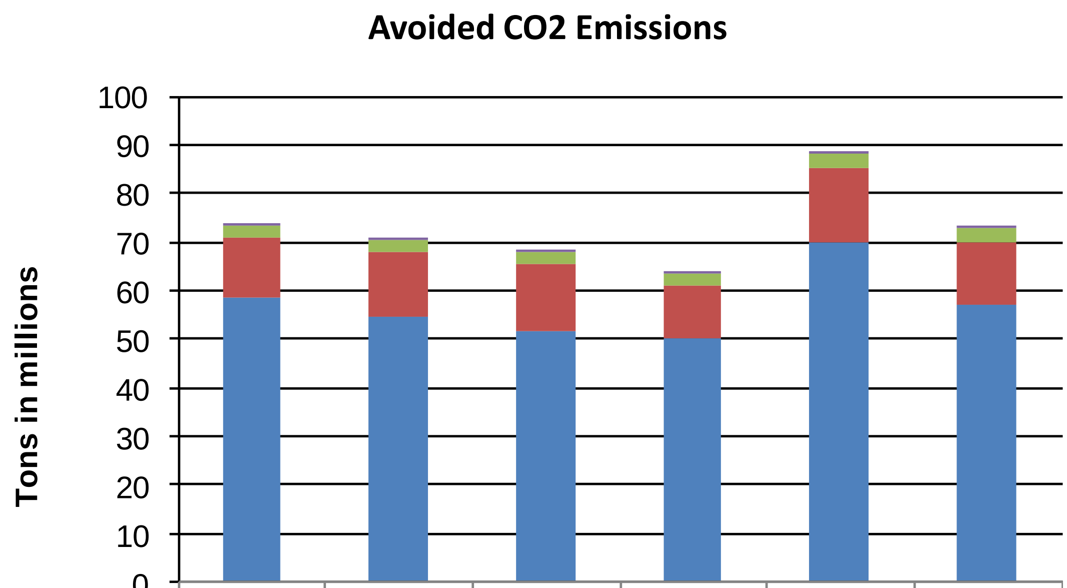
Avoided CO2 Emissions: In 2011, the FCRPS produced nearly 90 million MWh of hydro generation, causing the displacement of a like amount of energy produced by a fossil-fired resource alternative. Were that alternative a coal plant, it would have produced 90 million tons of CO2.

- FCRPS hydro delivers positive climate change benefits by reducing the amount of emissions for electricity that would be generated by other sources were the hydro system not available.
- The U.S. economy produces six billion tons of CO2 emissions each year, one third of which is produced by the electric power sector. The majority of electricity derived CO2 is produced by coal-fired power plants, with considerably less produced by natural gas and petroleum generation.
- In an average water year, the FCRPS hydro system reduces the CO2 footprint of a coal-fired alternative by 78 million tons – over one percent of total U.S. emissions.

Safety: The number of lost time accidents per 200,000 person-hours averaged 1.6 over the past five years.

- The results show that management of the safety program remains effective even during this period of growth in the large capital and extraordinary maintenance expense programs.
- This work involves activities that are non-routine and higher risk, presenting increased challenges to the workforce safety environment. The safety program also faces additional challenges related to an aging workforce.

Current Performance, Trusted Stewardship



	2007	2008	2009	2010	2011	5-yr Avg
Local Support	0	0	0	0	0	0
Area Support	2	3	3	2	3	3
Headwater/Lower Snake	12	13	13	11	15	13
Main Stem Columbia	59	55	52	50	70	57

Lost Time Accidents per 200,000 person-hours

Measure	2006	2007	2008	2009	2010	5-yr Avg.
Lost Time Accident Rate	1.3	1.9	3.3	1.2	0.5	1.6

Condition Overview

The FCRPS manages 196 generating units in 31 hydro plants, plus 16 additional station service, fish, and pump turbine units. It considers thousands of equipment components in maintenance and investment planning.

Component condition is a key driver of maintenance and investment needs.

- Routine maintenance activities identify and address deficiencies prior to their posing threats to equipment reliability.
- Even with effective maintenance programs, condition will eventually deteriorate to the point where inadequate reliability will warrant re-investment.
- There are few redundant or spare components in hydroelectric generating facilities and, as such, it is important that the condition of major components be understood and managed.

The FCRPS hydro program uses hydroAMP to assess the condition of seven power train components: unit transformers, generator windings, generator rotors, exciters, governors, unit breakers, and turbine runners. Condition of other equipment is assessed using a simplified framework based on hydroAMP.

- Condition ratings for non-hydroAMP equipment in the 2012 strategy were initially set at 10, then downgraded by exception if plant personnel knew of condition deficiencies. This process was done to reduce time demands on plant staff, resulting in an average condition rating of “Good” for non-hydroAMP equipment, which we believe was unrealistically high.
- For this 2014 strategy, each non-hydroAMP equipment item was rated, resulting in a lower average condition score.

Condition Ratings

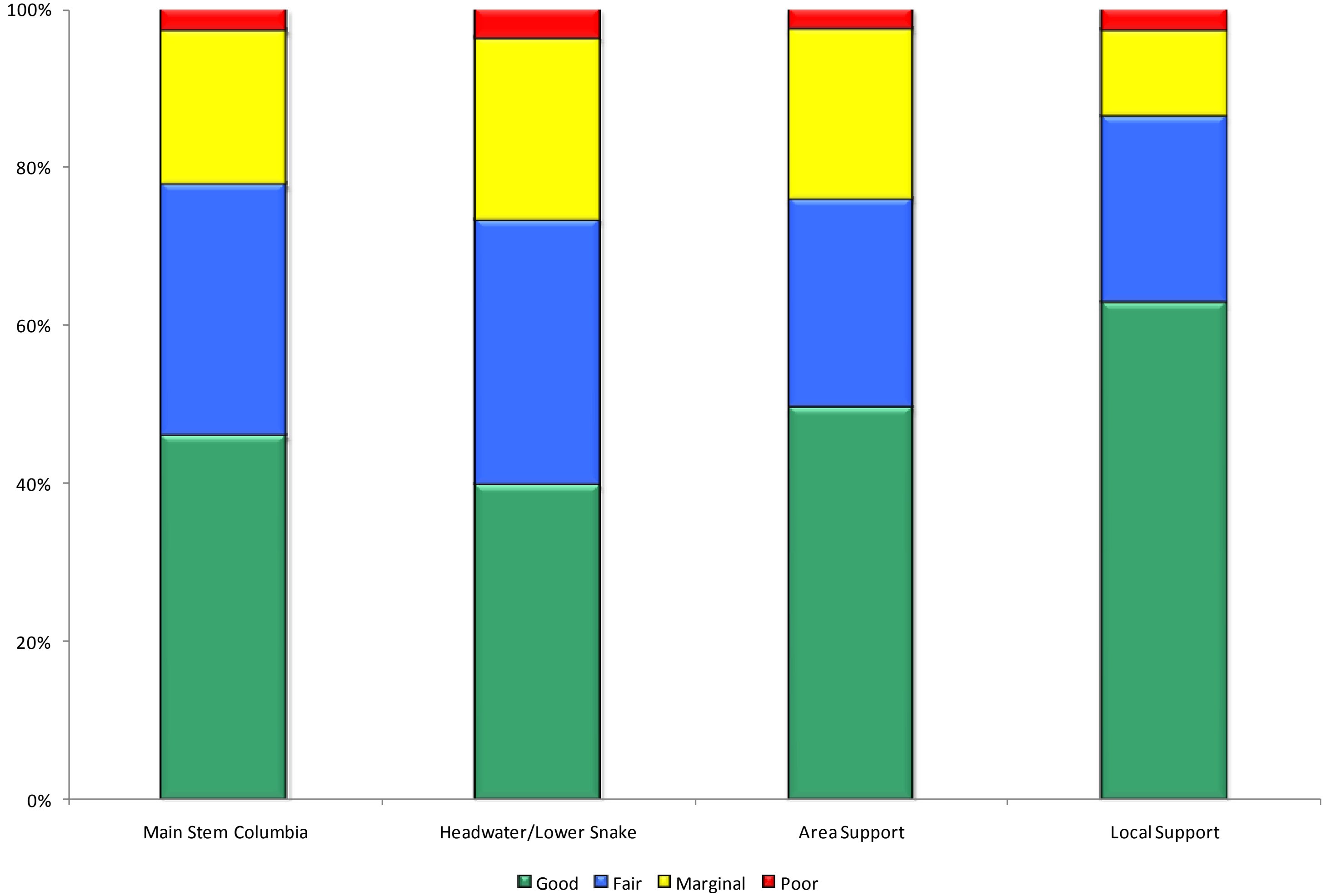
Condition ratings for each equipment type are based on a set of objective condition indicators related to operational performance, maintenance history, physical inspection, and age. Condition indicators are weighted and summed to derive a condition rating, ranging from 10 to 0. Numeric scores are further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

- 8.0 – 10.0: Good
- 6.0 – 7.9: Fair
- 3.0 – 5.9: Marginal
- 0.0 – 2.9: Poor

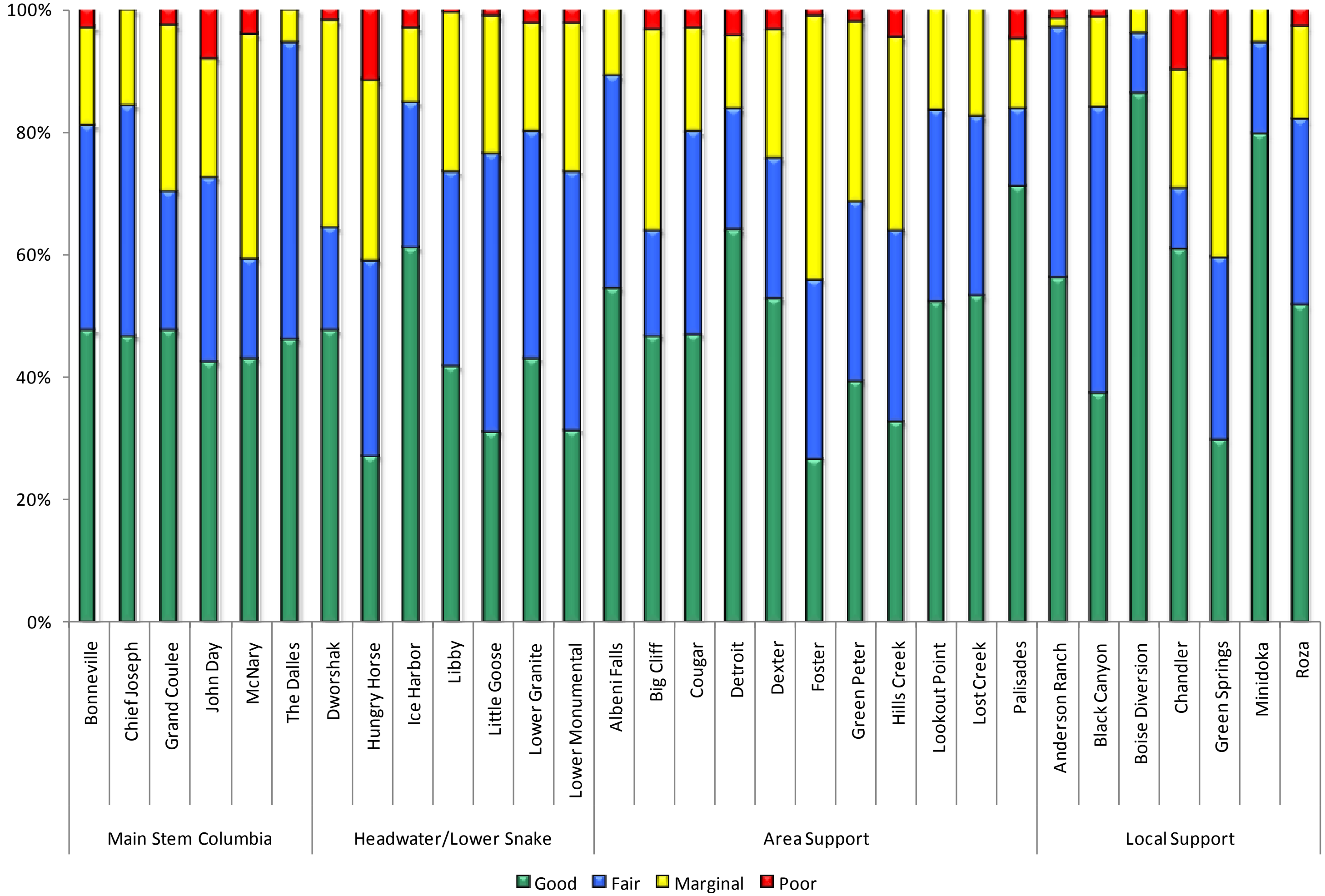
Condition by Strategic Class: About 75 percent of all equipment at Main Stem Columbia and Headwater/Lower Snake plants is currently in Good or Fair condition. Area Support and Local Support plants as a group have somewhat higher condition ratings.

Condition by Plant: Average condition rating by plant varies, with two critical plants – Grand Coulee and McNary – having below average ratings.

Current Condition by Strategic Class: All Equipment



Current Condition by Plant: All Equipment



Component Condition

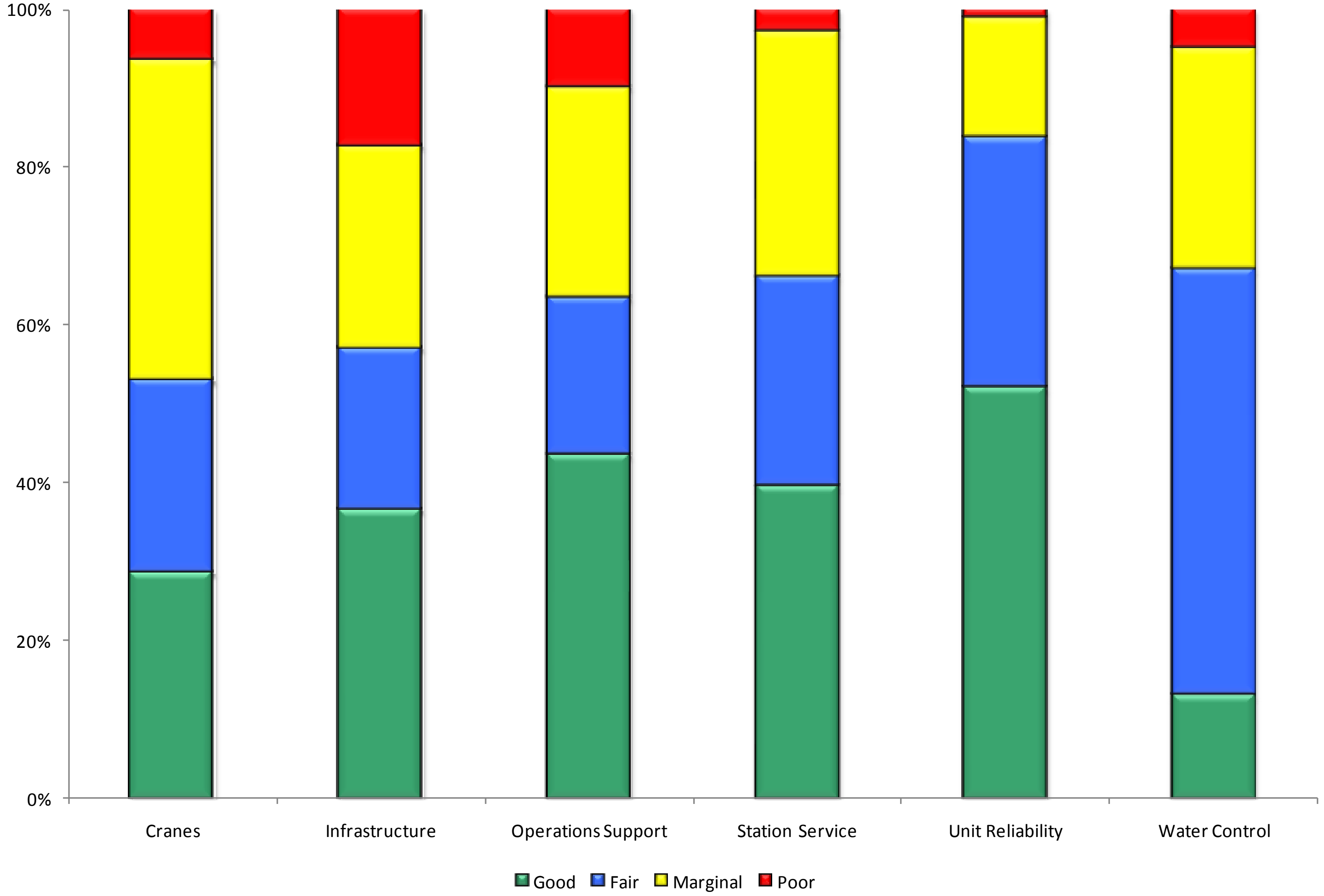
Condition by Component Type: Cranes have the lowest overall condition rating among equipment types, followed by infrastructure and operations support. Because cranes are needed to lift heavy equipment (including generation affecting equipment) and present considerable safety risk, satisfactory condition is a priority.

Station service, unit reliability and water passage systems have relatively higher condition ratings.

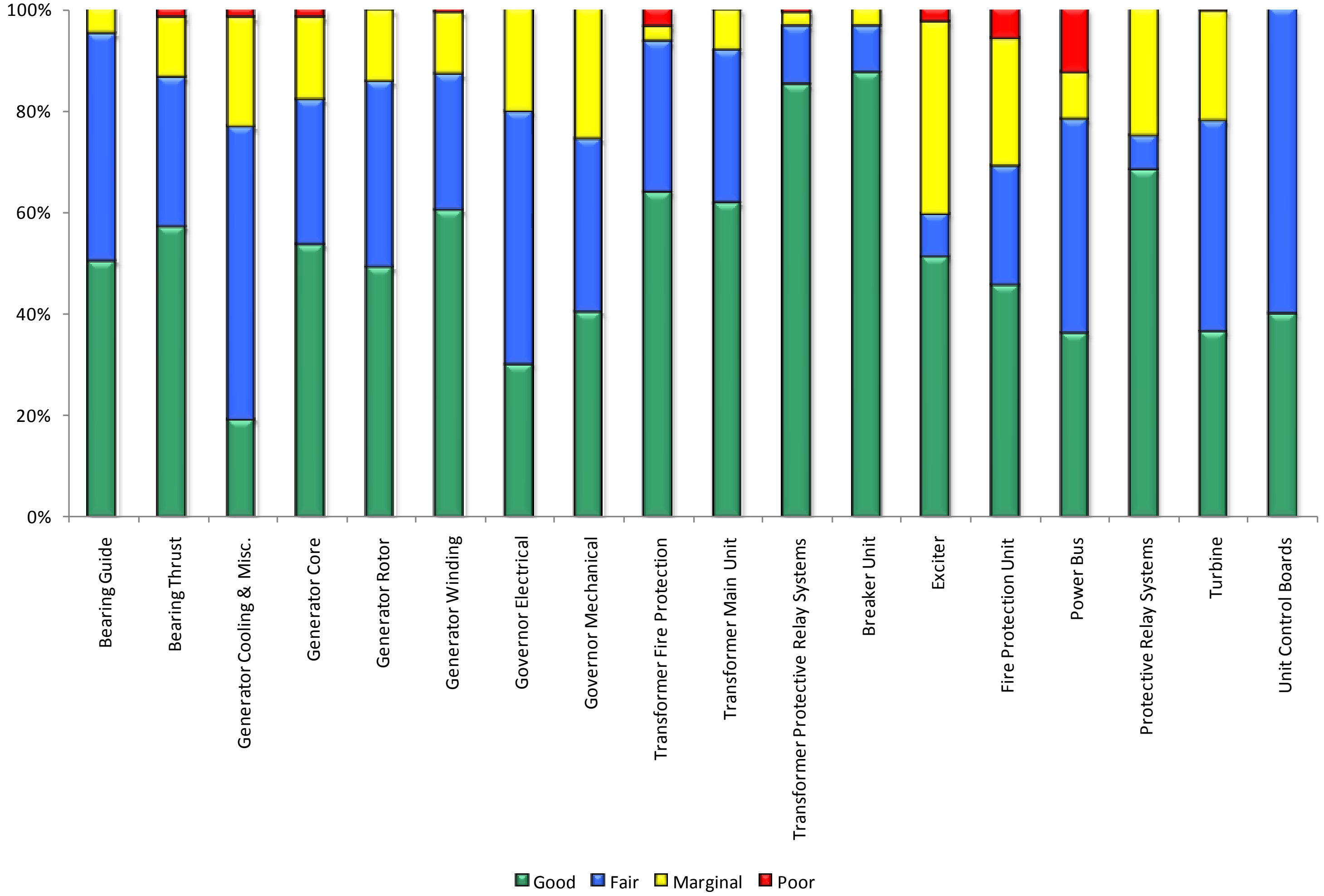
Unit Reliability: This strategy identifies 18 equipment types related to unit reliability.

- The average condition of transformers, generator rotors, and stators has declined slightly since the 2012 plan.
- The average condition of exciters and turbines has improved.
- The average condition of governors and unit breakers is essentially unchanged.
- Most other unit reliability equipment averages in Good or Fair condition.

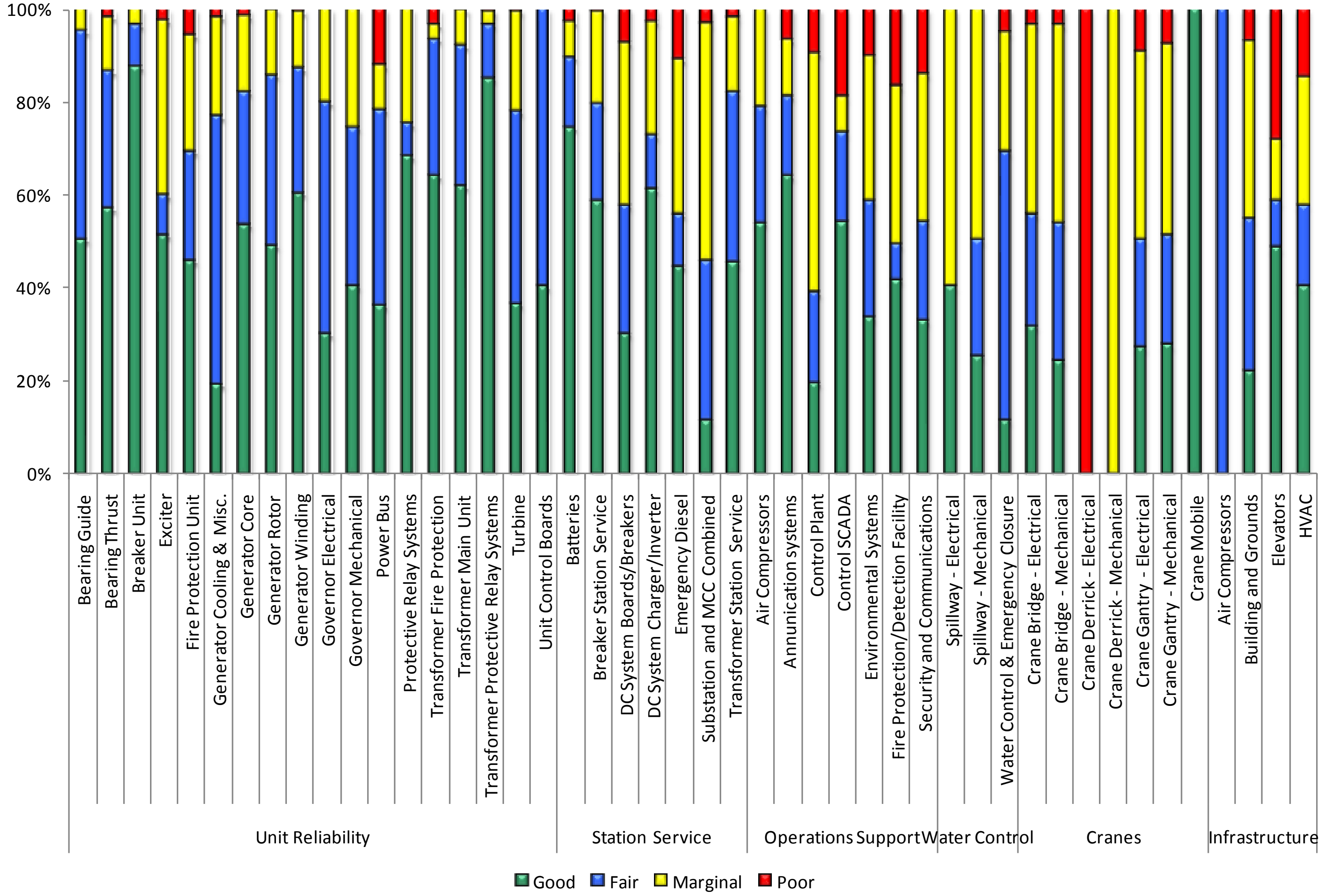
Current Condition by Equipment Type



Current Condition: Unit Reliability Equipment



Current Condition: All Equipment



Age of Equipment

Background: Near term investment needs are driven primarily by component condition and risk.

However, understanding component age helps to establish if equipment is nearing the end of its useful life and may soon present a risk to asset performance.

Furthermore, when age is profiled for the entire equipment portfolio it can become a tool to identify if near-term investment strategies could result in future investment needs that create unacceptable financial pressures or resource constraints.

The FCRPS has created age profiles of its facilities using “percent of design life” as a primary measure. For example, a 30 year old component with a design life of 40 years is represented as being at 75 percent of design life.

This allows comparison across component types, recognizing that design life can vary considerably across component types or designs.

Age of Equipment

For presentation purposes, component ages have been grouped into four categories to create asset profiles. These categories are as follows:

- Less than 50 percent of design life;
- 50 to 100 percent of design life;
- 100 to 150 percent of design life, and
- Greater than 150 percent of design life.

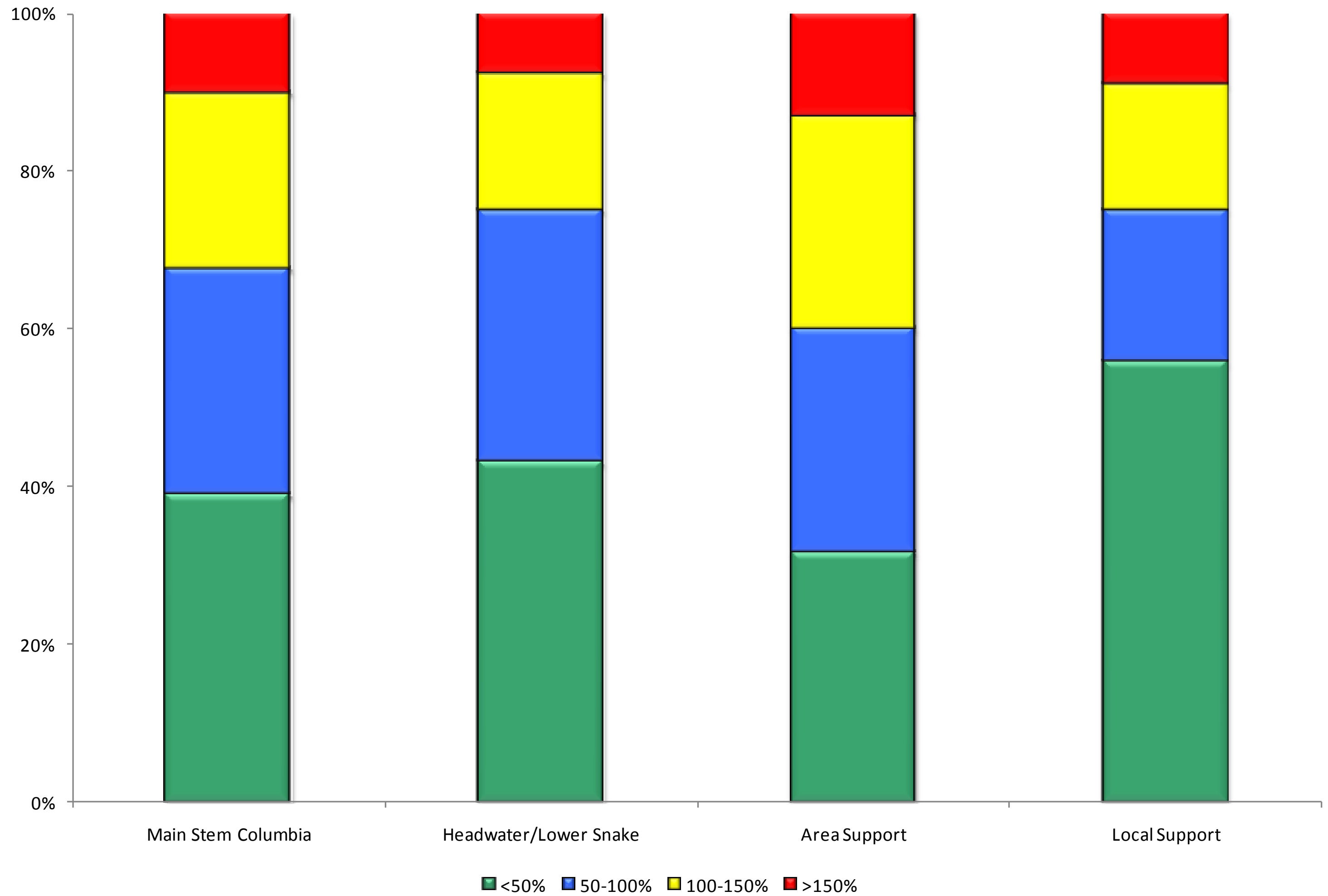
Current Age by Strategic Class:

- About 25 percent of equipment has exceeded its design life in the Main Stem, Headwater/Lower Snake and Local Support classes.
- For the Area Support class, nearly 40 percent of equipment has exceeded design life.

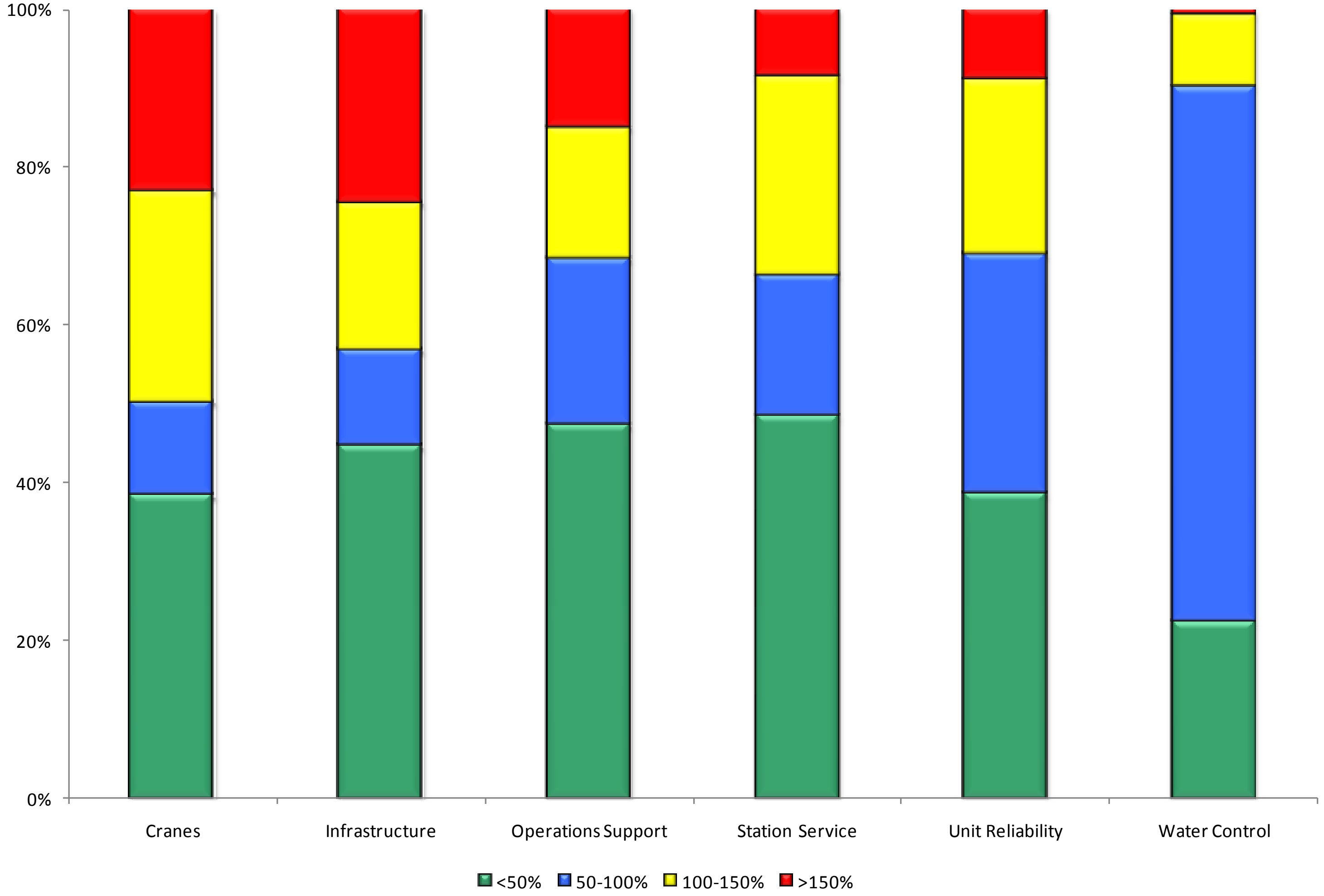
Current Age by Equipment Type:

- Nearly 50 percent of cranes and infrastructure equipment has exceeded design life. The combination of condition and age make cranes a likely candidate for re-investment.
- Water control equipment (spillway electrical/mechanical and emergency closure) has the fewest percentage of components exceeding design life.

Current Age by Strategic Class: All Equipment
(Percent of Design Life)



Current Age by Equipment Type
(Percent of Design Life)



Risk Assessment

FCRPS hydro asset management related risks are managed collaboratively by Bonneville's Federal Hydro Projects organization, the Bureau of Reclamation and Corps of Engineers. Asset management is the collective and collaborative efforts of these organizations.

Key requirements related to Bonneville's long-term outcomes are that the FCRPS:

- Meets equipment availability requirements (machine availability);
- Meets generation reliability standards, including compliance with WECC/NERC standards;
- Meets environmental requirements, particularly as related to management of water resources and equipment for fisheries purposes; and,
- Meets safety and security requirements.

Risk areas that could affect the long-term outcomes include the following:

- Failure of power train components;
- Failure of other generating station components not directly tied to the power system;
- Failure of Transmission assets;
- Effectiveness of security systems;
- Acts of nature; and
- Legal, regulatory and policy decisions that affect hydro operations or investment needs.

Failure of Hydro Plant Equipment

Loss of hydro plant equipment can lead to a number of negative consequences, including:

- Economic losses as a result of the need to replace components;
- Economic losses as a result of the need to purchase replacement power to meet contractual obligations, or lost opportunities to sell power to the market;
- Safety issues, should the catastrophic failure of a component cause injury or death;
- Environmental impacts such as the off-site release of oil;
- Regulatory violations through an inability to meet preferred unit operation, temperature controls, or Total Dissolved Gas (TDG) limits;
- Operational and Transmission support impacts such as unplanned spill or inability to provide reserves, voltage support, or capacity at peak periods, and
- Other stakeholder impacts such as lost pumping ability for Reclamation's irrigation customers.

The risk of equipment failure is assessed using two tools:

- Risk maps for safety, environmental and financial risk, and
- By quantifying lost generation risk.

Risk: Condition Index vs. Likelihood of Failure

The hydro program correlates a condition rating with the likelihood of equipment failing to perform as expected. An equipment component with a low condition rating has a higher likelihood of failure than one with a higher rating. The correlation is shown below.

Likelihood	Condition Index	Description
Almost Certain	0 to 0.9	Poor
	1 to 1.9	
	2 to 2.9	
	3 to 3.9	Marginal
	4 to 4.9	
	5 to 5.9	
	6 to 6.9	Fair
	7 to 7.9	
Rare	8 to 8.9	Good
	9 to 10	

Safety and Environmental Risk Maps

Risk is the product of likelihood and consequence. Two items with the same potential consequence will have different levels of risk if the likelihood of occurrence differs.

On the following maps, both safety and environmental risks are identified as being high, medium, or low.

- Safety consequences range from a low of “first aid required” to a high of “multiple fatalities”.
- Environmental consequences range from “no impact” to “detrimental or catastrophic off-site impact”.

Safety: There are several high risk items in this area:

- 63 Water control items (vs. 1 in the 2012 Plan)
- 53 Operations support (vs. 4)
- 15 Unit Reliability (vs. 0)

Environmental: Similarly, there are currently only six items at high risk:

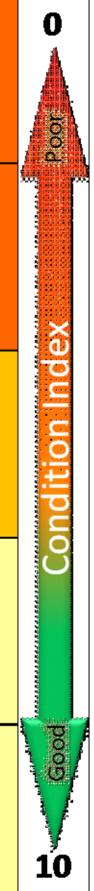
- 68 Water control (vs. 1)
- 62 Operations support (vs. 5)
- 7 Unit Reliability (vs. 0)

The increase in the number of high risk items is driven by the lower condition ratings of non-hydroAMP equipment.

Current Safety Risk Map

Likelihood	No or minor injury, first aid	Treatment by medical professional	Lost time Accident - temporary disability	Lost Time Accident - permanent disability/fatality	Multiple fatalities
Almost Certain	29 Unit Reliability 16 Station Service 1 Operations Support 1 Water Control 9 Infrastructure	16 Unit Reliability 5 Station Service 16 Operations Support 4 Water Control 17 Infrastructure	26 Operations Support	12 Operations Support	7 Unit Reliability 17 Water Control
Likely	269 Unit Reliability 137 Station Service 16 Operations Support 2 Water Control 10 Infrastructure	58 Unit Reliability 40 Station Service 22 Operations Support 4 Water Control 8 Cranes 8 Infrastructure	3 Unit Reliability 5 Station Service 38 Operations Support 12 Cranes	15 Operations Support	8 Unit Reliability 46 Water Control
Possible	420 Unit Reliability 77 Station Service 18 Operations Support 18 Infrastructure	145 Unit Reliability 29 Station Service 16 Operations Support 43 Cranes 5 Infrastructure	18 Unit Reliability 12 Station Service 13 Operations Support 39 Cranes	2 Operations Support	36 Unit Reliability 68 Water Control
Unlikely	323 Unit Reliability 26 Station Service 6 Operations Support 13 Infrastructure	13 Unit Reliability 10 Station Service 11 Operations Support 4 Water Control 4 Cranes 1 Infrastructure	26 Unit Reliability 8 Station Service 14 Operations Support 7 Cranes	2 Operations Support	25 Unit Reliability 49 Water Control
Rare	1666 Unit Reliability 121 Station Service 52 Operations Support 2 Water Control 46 Infrastructure	285 Unit Reliability 91 Station Service 67 Operations Support 4 Water Control 59 Cranes 29 Infrastructure	208 Unit Reliability 68 Station Service 38 Operations Support 45 Cranes	22 Operations Support	199 Unit Reliability 23 Water Control

Consequence

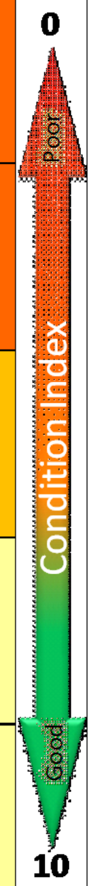


Risk Level	Low	Medium	High

Current Environmental Risk Map

Likelihood	No impact	Impact to on-site environment (simple remediation)	Limited impact off-site (localized remediation required)	Detrimental impact on- or off-site (long-term remediation required)	Detrimental or catastrophic impact off-site (mitigation
Almost Certain	29 Unit Reliability 16 Station Service 1 Operations Support 26 Infrastructure	16 Unit Reliability 5 Station Service 6 Operations Support	7 Unit Reliability 42 Operations Support 5 Water Control	6 Operations Support	17 Water Control
Likely	267 Unit Reliability 137 Station Service 16 Operations Support 8 Cranes 18 Infrastructure	60 Unit Reliability 40 Station Service 1 Operations Support	11 Unit Reliability 5 Station Service 60 Operations Support 6 Water Control 12 Cranes	14 Operations Support	46 Water Control
Possible	384 Unit Reliability 77 Station Service 18 Operations Support 43 Cranes 23 Infrastructure	181 Unit Reliability 29 Station Service 4 Operations Support	54 Unit Reliability 12 Station Service 18 Operations Support 39 Cranes	9 Operations Support	68 Water Control
Unlikely	287 Unit Reliability 26 Station Service 6 Operations Support 4 Cranes 14 Infrastructure	49 Unit Reliability 10 Station Service 1 Operations Support	51 Unit Reliability 8 Station Service 23 Operations Support 4 Water Control 7 Cranes	3 Operations Support	49 Water Control
Rare	1332 Unit Reliability 121 Station Service 52 Operations Support 59 Cranes 75 Infrastructure	619 Unit Reliability 91 Station Service 14 Operations Support	407 Unit Reliability 68 Station Service 97 Operations Support 6 Water Control 45 Cranes	16 Operations Support	23 Water Control

Consequence



Risk Level	Low	Medium	High

Current Financial Risk Map

The financial risk map is also segmented into high, medium, and low risk areas.

Financial consequences are a result of two factors in the event of a failure:

- The cost of replacement power for any lost generation, and
- Incremental direct costs for collateral damage, procurement, and scheduling/workforce inefficiencies.

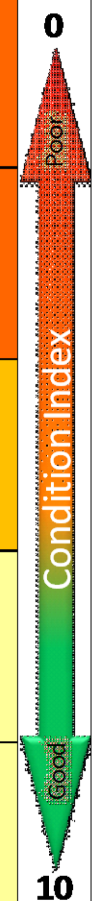
There are currently 761 equipment items in the high risk area of the map:

- 244 Unit Reliability
- 137 Station Service
- 47 Operations Support
- 45 Water Control

Current Financial Risk Map

Likelihood	Insignificant < $ 10K	Minor $ 10K to $ 100K	Moderate $ 100K to $ 1 M	Major $ 1 M to $ 10 M	Extreme > $ 10 M
Almost Certain	1 Operations Support	1 Unit Reliability 2 Station Service 8 Operations Support 1 Water Control	21 Unit Reliability 9 Station Service 40 Operations Support 13 Water Control 25 Infrastructure	26 Unit Reliability 10 Station Service 4 Operations Support 5 Water Control 1 Infrastructure	4 Unit Reliability 2 Operations Support 3 Water Control
Likely	16 Operations Support	53 Unit Reliability 26 Station Service 19 Operations Support 2 Water Control 1 Infrastructure	92 Unit Reliability 38 Station Service 55 Operations Support 26 Water Control 9 Cranes 17 Infrastructure	182 Unit Reliability 118 Station Service 22 Water Control 11 Cranes	11 Unit Reliability 1 Operations Support 2 Water Control
Possible	18 Operations Support	44 Unit Reliability 22 Station Service 8 Operations Support 6 Infrastructure	213 Unit Reliability 33 Station Service 19 Operations Support 46 Water Control 48 Cranes 13 Infrastructure	330 Unit Reliability 63 Station Service 4 Operations Support 20 Water Control 34 Cranes 4 Infrastructure	32 Unit Reliability 2 Water Control
Unlikely	6 Operations Support	4 Unit Reliability 6 Station Service 10 Operations Support 2 Water Control 6 Infrastructure	114 Unit Reliability 21 Station Service 16 Operations Support 37 Water Control 4 Cranes 6 Infrastructure	240 Unit Reliability 17 Station Service 1 Operations Support 14 Water Control 7 Cranes 2 Infrastructure	29 Unit Reliability
Rare	52 Operations Support 1 Infrastructure	299 Unit Reliability 73 Station Service 43 Operations Support 2 Water Control 3 Cranes 12 Infrastructure	582 Unit Reliability 145 Station Service 69 Operations Support 5 Water Control 66 Cranes 57 Infrastructure	1254 Unit Reliability 62 Station Service 14 Operations Support 21 Water Control 35 Cranes 5 Infrastructure	223 Unit Reliability 1 Operations Support 1 Water Control

Consequence



Risk Level	Low	Medium	High

Current Lost Generation Risk

Failure likelihood and consequence information is further evaluated to quantify the expected value of lost generation as Lost Generation Risk.

- Equipment condition correlates to a probability of failure for each component.
- These probabilities are multiplied by the lost generation consequence for each component to calculate the Lost Generation Risk (LGR), i.e., the replacement power cost risk associated with a run-to-failure strategy.

The current LGR for the system is about 587 aMW, about 15 percent higher than in the 2012 plan (508 aMW), primarily a result of lower condition ratings for non-hydroAMP equipment.

Current Lost Generation Risk by Class and Plant

55 percent of current LGR is in the Main Stem Columbia class (321 aMW).

McNary has 116 aMW of LGR, driven by several factors:

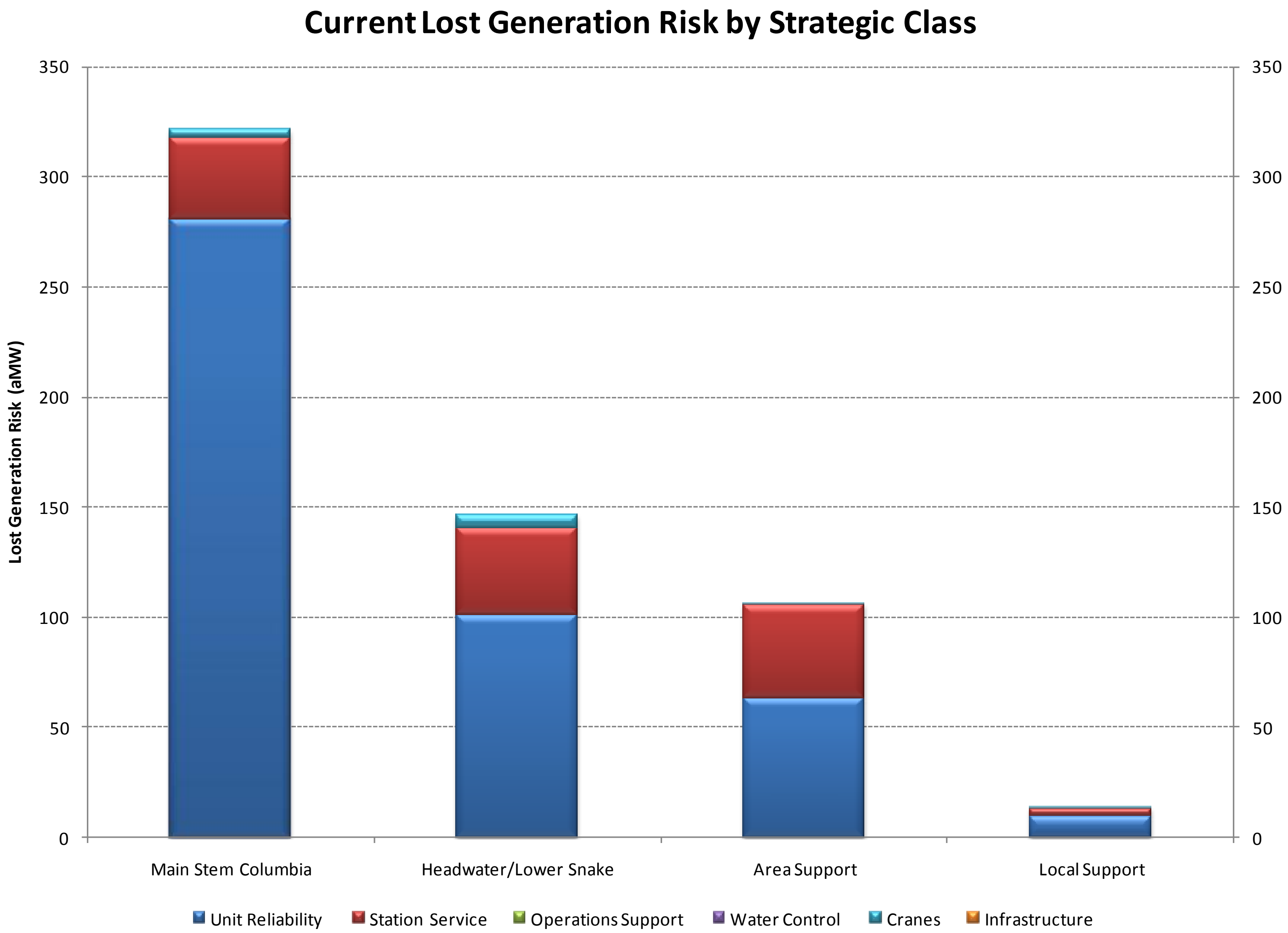
- Generally poor condition of generator stators, turbines, governors, and exciters;
- Many pieces of equipment at risk; and,
- It is a hydraulic bottleneck on the lower river, which results in high lost generation in the event of an outage.

Grand Coulee has 96 aMW of LGR, attributable mostly to the condition of generator windings, transformers, exciters, and in the Third Powerplant, turbines.

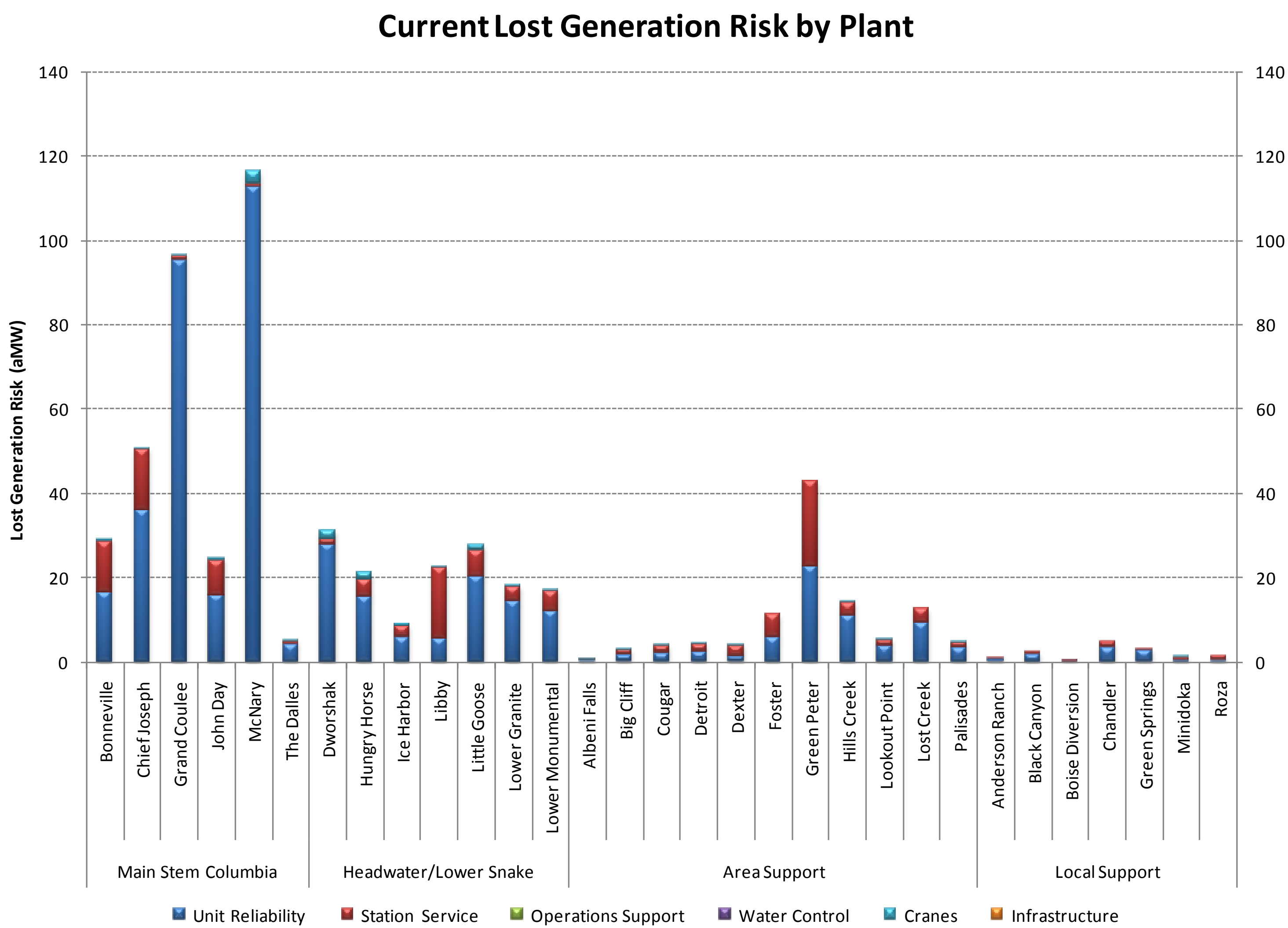
Chief Joseph has 50 aMW of LGR driven mostly by the condition of turbines, governors, and exciters.

Most other plants have LGR of less than 30 aMW.

Current Lost Generation Risk by Strategic Class

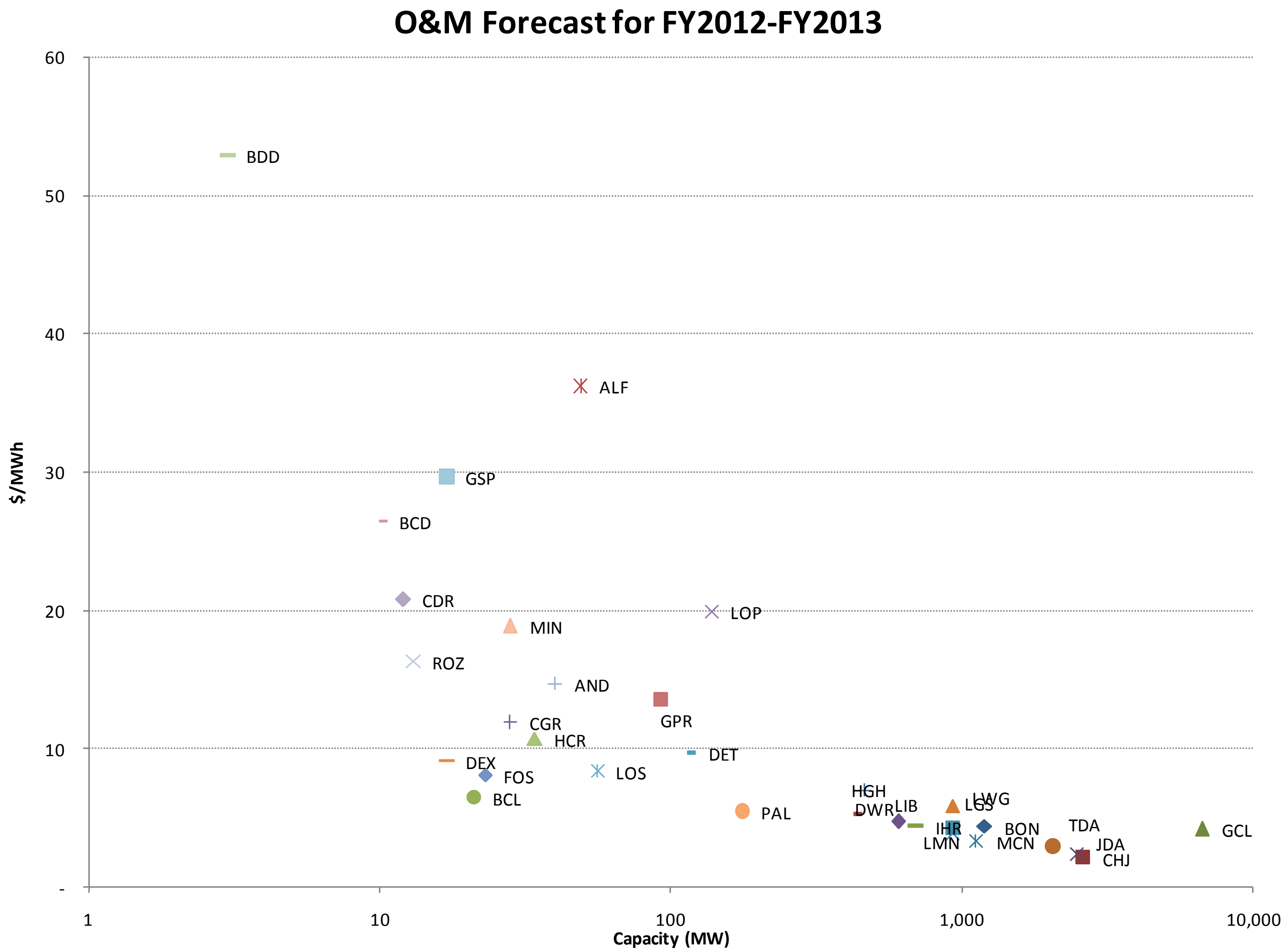


Current Lost Generation Risk by Plant

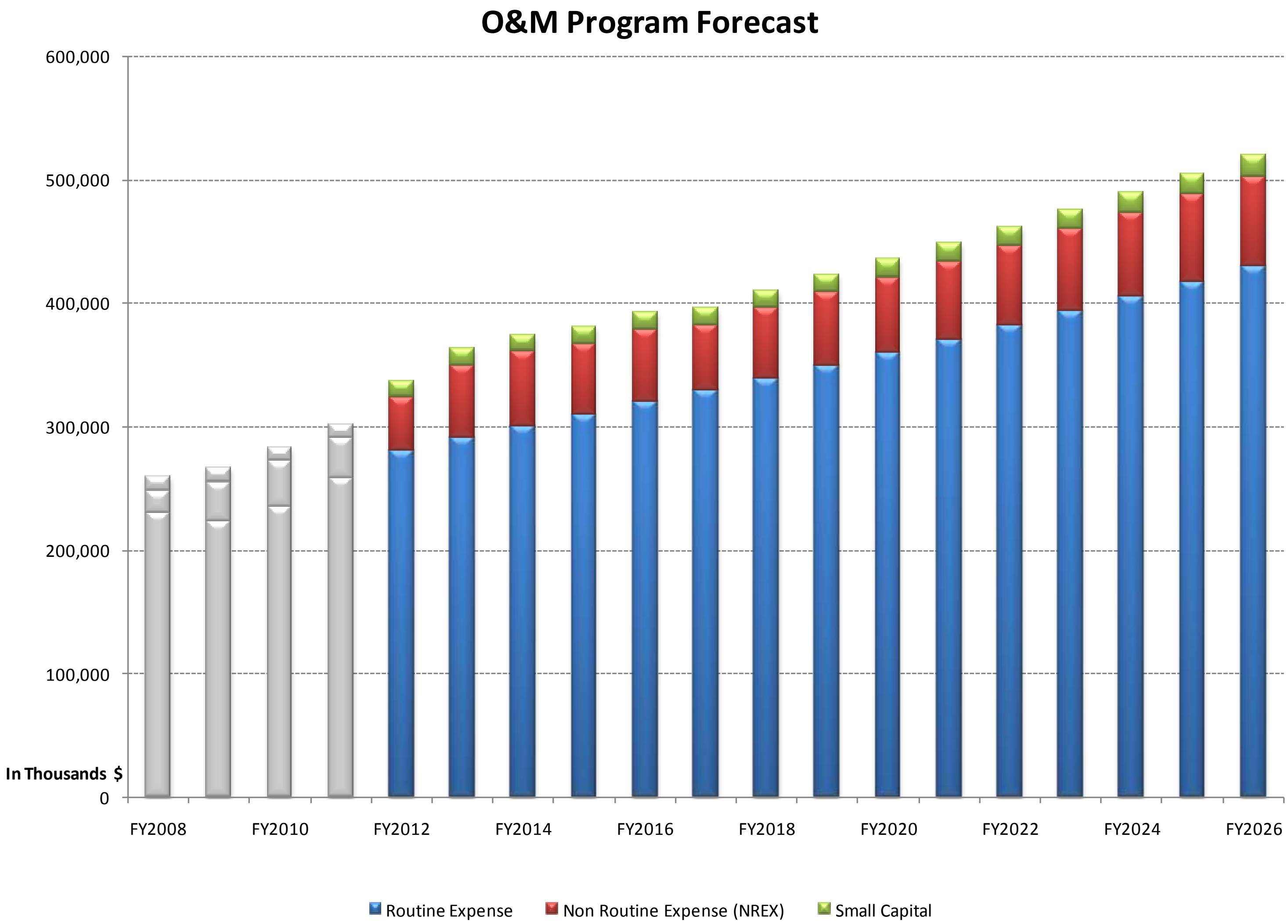


4. O&M Program

O&M Forecast for FY2012 – FY2013



O&M Program



O&M Program Forecast
600,000
500,000
400,000
300,000
200,000
100,000
0
In Thousands $
FY2008
FY2010
FY2012
FY2014
FY2016
FY2018
FY2020
FY2022
FY2024
FY2026
Routine Expense
Non Routine Expense (NREX)
Small Capital

5. Currently Committed Large Capital Program

Committed Large Capital

The Large Capital Program includes:

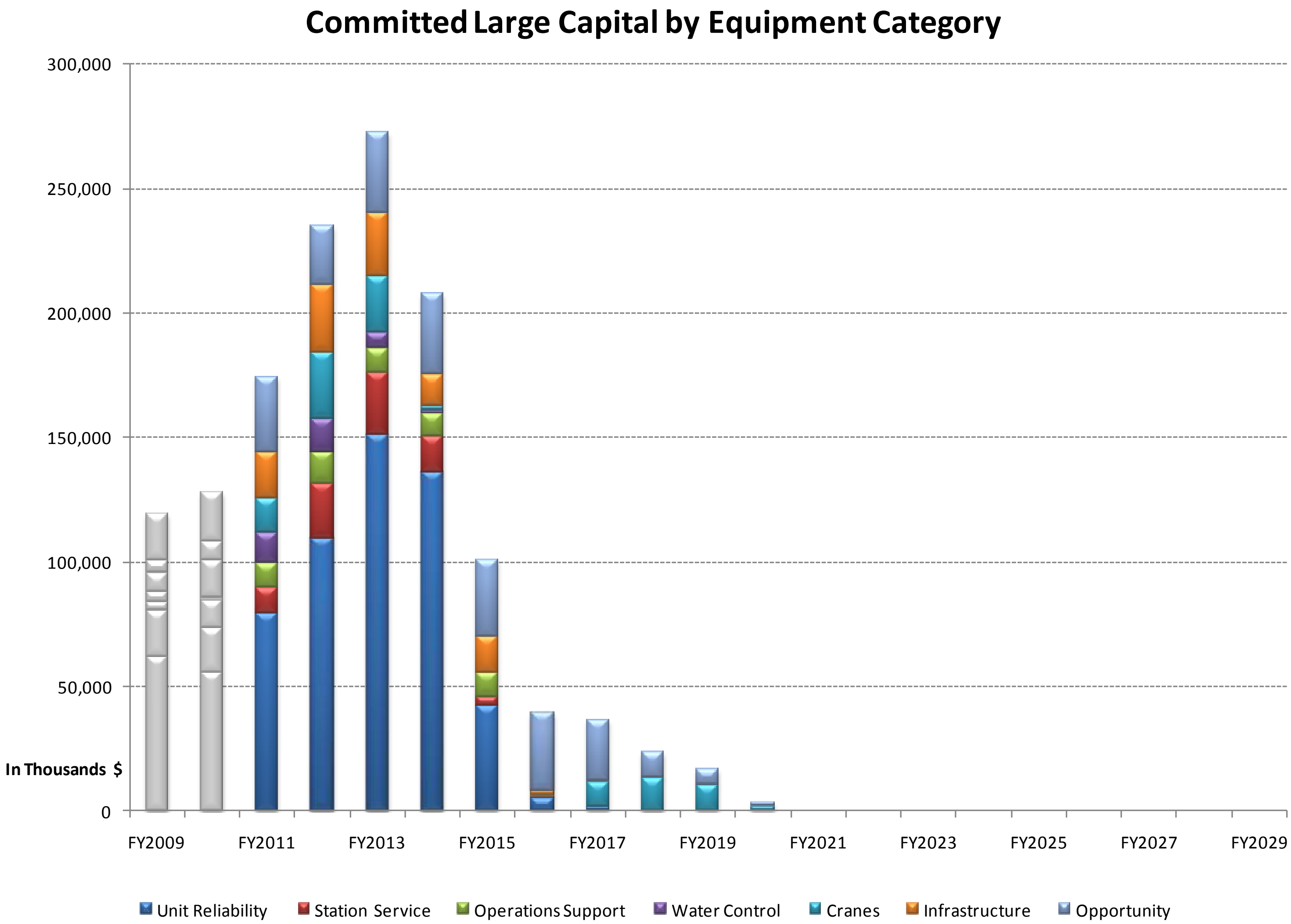
- Reliability driven replacement of electrical and mechanical components, with the exception of smaller, "maintenance capital" replacements that are funded within the O&M Program;
- Economic opportunity investments to existing assets that are undertaken to improve system performance (e.g., turbine runner replacements to improve efficiency), and
- Investment in new assets at existing facilities, also based on economic opportunities.

Committed Large Capital Program: The currently committed capital program is work managed by the 3-Agency Capital Workgroup (CWG), consistent with the 2012 Hydro Asset Strategy. An explanation of the CWG business process and detail of its 2012 – 2015 program is included in Appendix A.

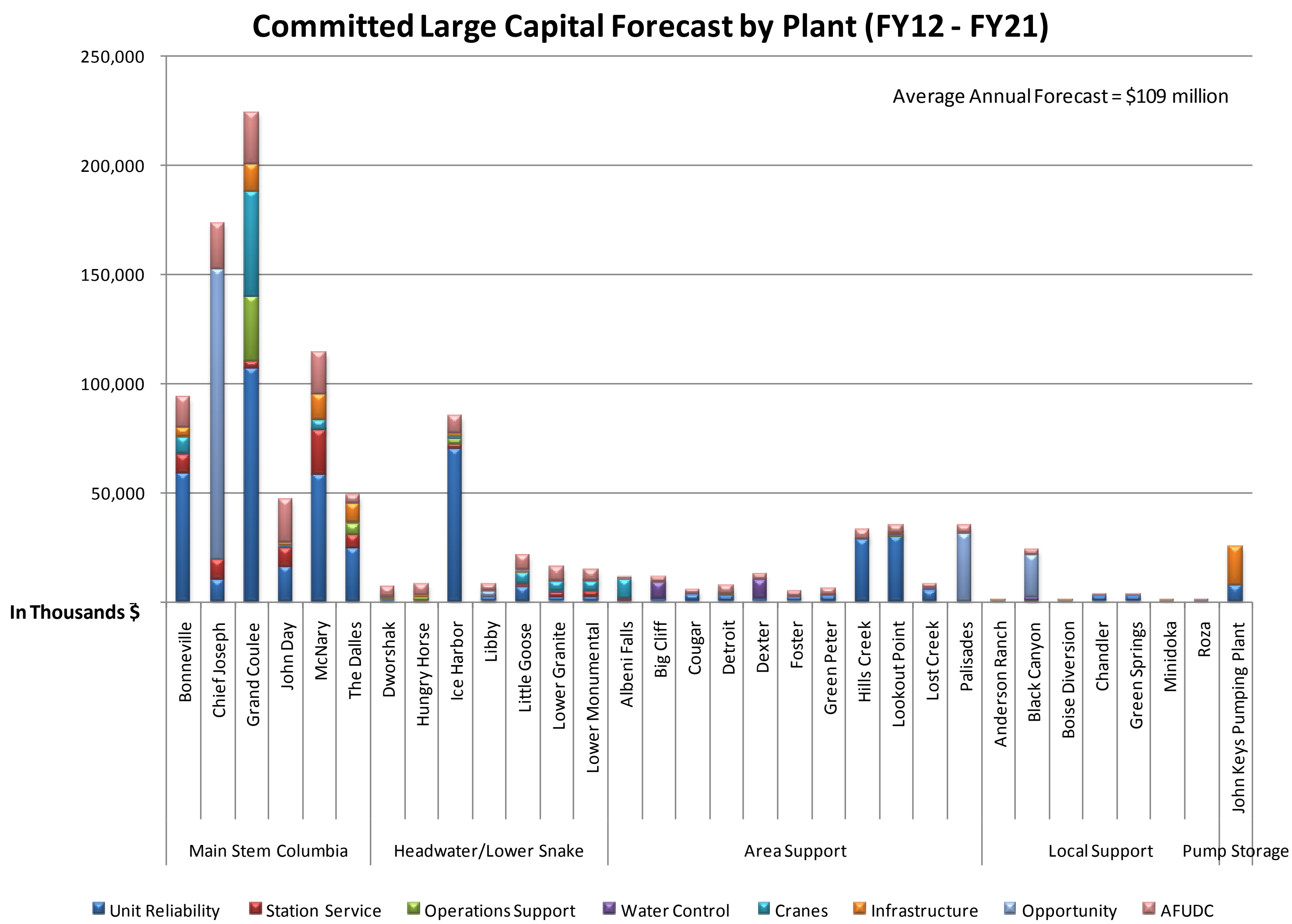
Committed Large Capital by Equipment Category: The currently committed Large Capital Program is $935 million for FY2012 – FY2021. The breakdown of commitments by equipment category is as follows:

• Unit reliability	$445 million
• Station service	$66
• Operations support	$41
• Water control	$21
• Cranes	$87
• Infrastructure	$83
• Opportunity	$192

Committed Large Capital by Equipment Category



Committed Large Capital by Plant
(FY2012 – FY2021)



6. Hydro Investment Plan

Hydro Investment Plan

This 2014 strategy takes a risk-based approach to identifying the optimum time for making new investments, consistent with the approach used for the 2012 strategy. A detailed explanation of the prioritization logic is included in Appendix D.

The strategy is consistent with Bonneville's asset management policy, which states:

- *BPA will invest in, maintain, and operate assets to:*
  - *Meet reliability standards, availability requirements, regional adequacy guidelines, efficiency needs, environmental requirements, safety and security standards, and other requirements; and*
  - *Minimize the life cycle costs of assets when practical.*

Costs Considered in the Strategy

The Hydro Investment Plan covers forecasted O&M, the committed investment program, and new investments to maintain and improve the reliability of electrical and mechanical plant equipment.

Because O&M costs are primarily labor related, and the currently committed investment program is already vetted and underway, the focus of the Hydro Investment Plan is on new investments not yet decided upon.

The O&M program forecast and risk based approach to identifying new capital investments reasonably cover costs necessary for addressing business continuity requirements, including sparing strategies for critical equipment.

This strategy improves the coverage of water control features over that identified in the 2012 strategy.

Costs Not Considered in the Strategy

John W. Keys III Pump Generating Plant

- Keys is a pump storage facility, part of the Grand Coulee Project. Pump-Generating Units 7-8 and 9-12 were commissioned in 1973 and 1983-4, respectively.
- The plant is near end-of-life, much of the unit and balance-of-plant equipment is worn or becoming obsolete.
- Capital costs for modernization are estimated at $200 – $300 million. Studies to support Keys modernization are underway. A decision on whether to proceed is expected by summer 2012.
- Additional information on Keys is included in Appendix B.

No costs are included for additional generating units at Libby, John Day, or Dworshak.

Fish facilities funded under Columbia River Fish Mitigation are aging. Initial costs of these facilities are funded under appropriations and reimbursed by Bonneville. Costs for repairs and replacements of these facilities are not covered in this strategy.

Cost also excluded are those for rebuilding or replacing dam safety civil features which are typically funded through appropriations, a share of which is reimbursed by Bonneville. For the focus period of this strategy, the exclusion of costs for dam safety is not expected to materially affect the funding need forecast. However, as the hydro system continues to age, anticipating funding needs for dam safety will require more explicit attention in future strategies.

Elements of Lifecycle Cost

Equipment Replacement Cost: Unique for each equipment type.

Incremental Equipment Failure Cost: Incremental replacement cost due to collateral damage and to planning, procurement and scheduling inefficiencies. Used to calculate Direct Cost Risk.

Replacement Power Cost: The annual generation at risk for the marginal ("least used") unit at each plant multiplied by the expected additional outage in years for each equipment type to determine the amount of lost generation if that equipment fails.

CO2 Cost: CO2 emissions produced by a natural gas-fired combustion turbine to replace generation not produced by a failed hydro unit.

Replacement Power Cost and CO2 Cost are used to calculate Lost Generation Risk.

Economics of Risk Intervention at Different Points in Time

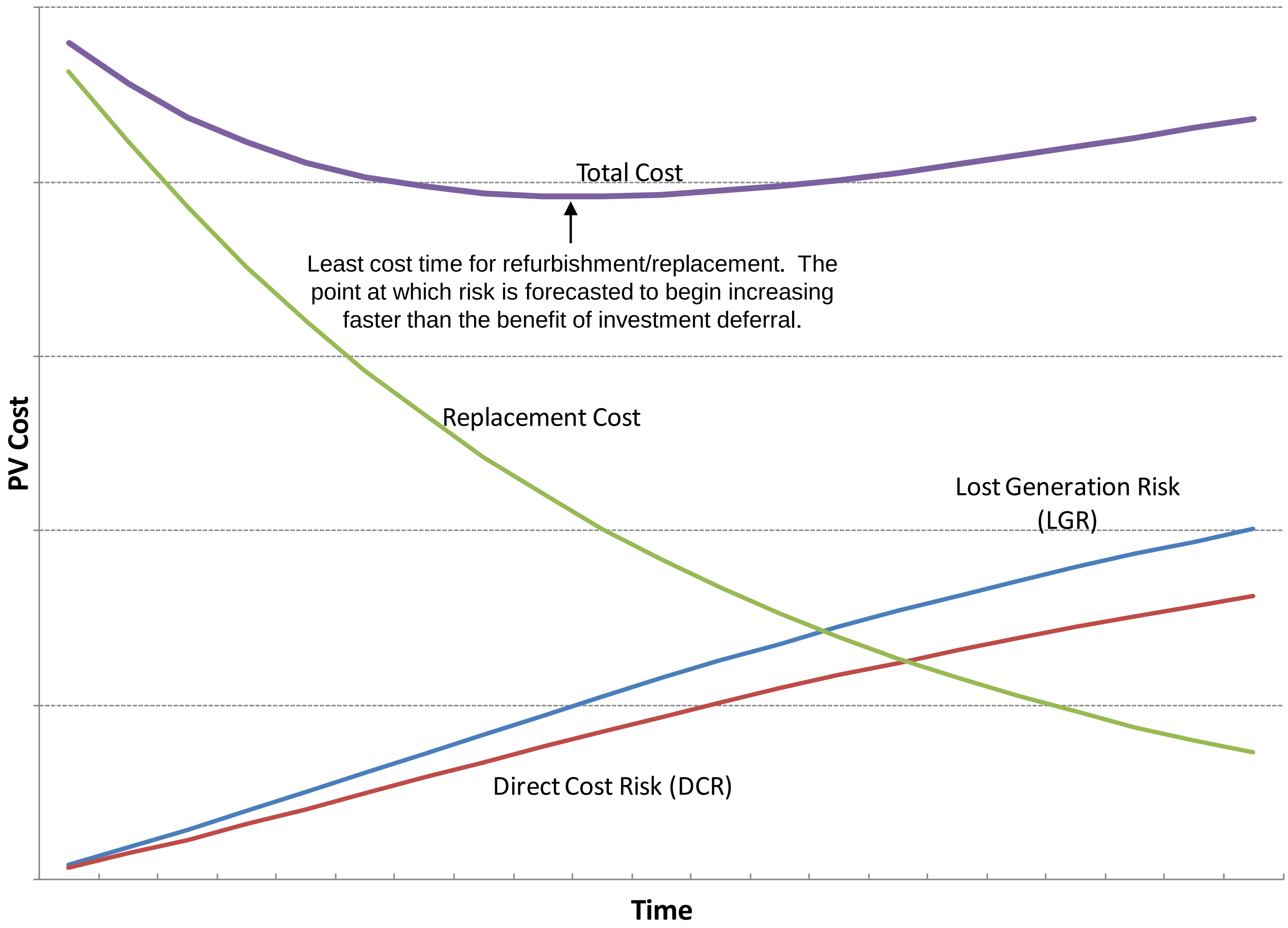
Without corrective action (intervention), equipment condition degrades over time. As equipment condition degrades, the likelihood (and risk) of equipment failing to perform as expected increases.

Three factors influencing the economics of risk intervention are outlined in the diagram on the next page. All curves show the present value of costs over time.

- **Replacement Cost** – Typically, the longer the replacement can be deferred, the lower the present value of its cost.
- **Direct Cost Risk (DCR)** – If equipment fails during the deferral period, intervention costs may be incrementally higher for collateral damage and planning, procurement, and scheduling inefficiencies (overtime, emergency hiring, contract premiums, etc.). This cost risk increases as equipment condition degrades over time.
- **Lost Generation Risk (LGR)** – Equipment failure may also result in longer outages and, thus, more lost generation than if replaced on a planned basis. LGR also increases as equipment condition degrades over time.

The **Total Cost** is the present value sum of replacement and risk costs. The cost minimum on this curve is the point at which financial risk is forecasted to begin growing faster than the benefit of investment deferral and represents the optimum time to forecast replacement to minimize lifecycle cost.

Cost of Intervention at Different Points in Time



Assumptions Used in Modeling

Assumption	Value	Source	Comment
Discount rate	12.0 percent (sensitivity at 6.0 percent)	BPA Finance	Approximately twice BPA's cost of capital
Inflation rate	1.7 percent	BPA Finance	Average annual rate based on 20-yr forecast
Forward energy price curve	20-yr, by month, HLH, LLH, flat	BPA Power Services Resource Program	Includes spot prices and a component for long-term firm capacity consistent with rate case demand rate.
Equipment cost	Varies by equipment type	FCRPS hydro program	Based on industry cost data
Real cost escalation	0 percent	BPA Finance	Global Insight
Failure curves	Varies by equipment type	BPA Federal Hydro	Based on industry data for certain equipment
Outage duration for LGR	Varies by equipment type	FCRPS hydro program	Based on industry experience
Environment and safety	Risk	BPA Federal Hydro	Treats all high risk items as "must do"
Value of avoided CO2	$41/ton	BPA Corporate Strategy	Based on Council's 6th power plan
Alternative resource for hydro lost generation	Natural gas-fired Combined-Cycle Combustion Turbine	BPA Power Services Resource Program	0.37 tons of CO2 per MWh of generation

Least Cost Case

The "least cost case" is the Total Cost for all equipment modeled if replaced at their cost minima.

To determine the least cost case, each equipment component is evaluated in yearly time steps and forecasted for refurbishment/replacement if it meets either of the following criteria:

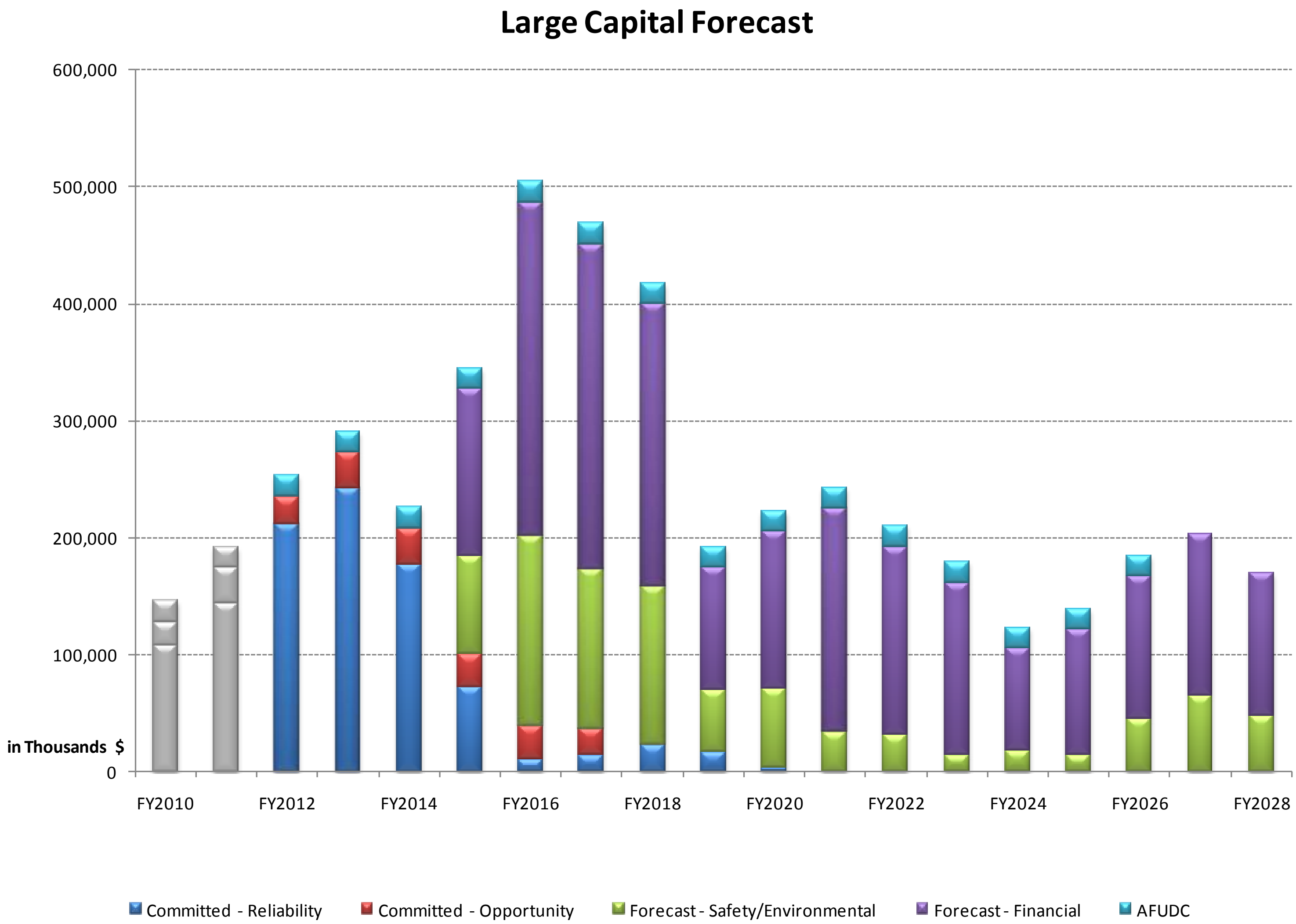
- First, if its condition places it into a high risk category for safety or environment.
- Second, if financial risk costs are increasing faster than investment deferral benefits, i.e., the equipment component is at the cost minimum.

Once the equipment component is selected for investment, its condition resets to 10 at the end of the investment period. Its condition then begins to degrade at the identified degradation rate.

The least cost case does not reflect limitations of resource and scheduling constraints and is therefore a theoretical but unrealistic plan. But it is useful for determining the costs associated with various constraints and informing discussions about whether or not it makes sense to mitigate them.

The following graph shows the resulting funding level for the least cost case.

Least Cost Case



Modeling Funding Constraints

To model funding constraints, an additional step is introduced into the modeling approach.

An annual funding limitation is defined, then the prioritization proceeds as follows:

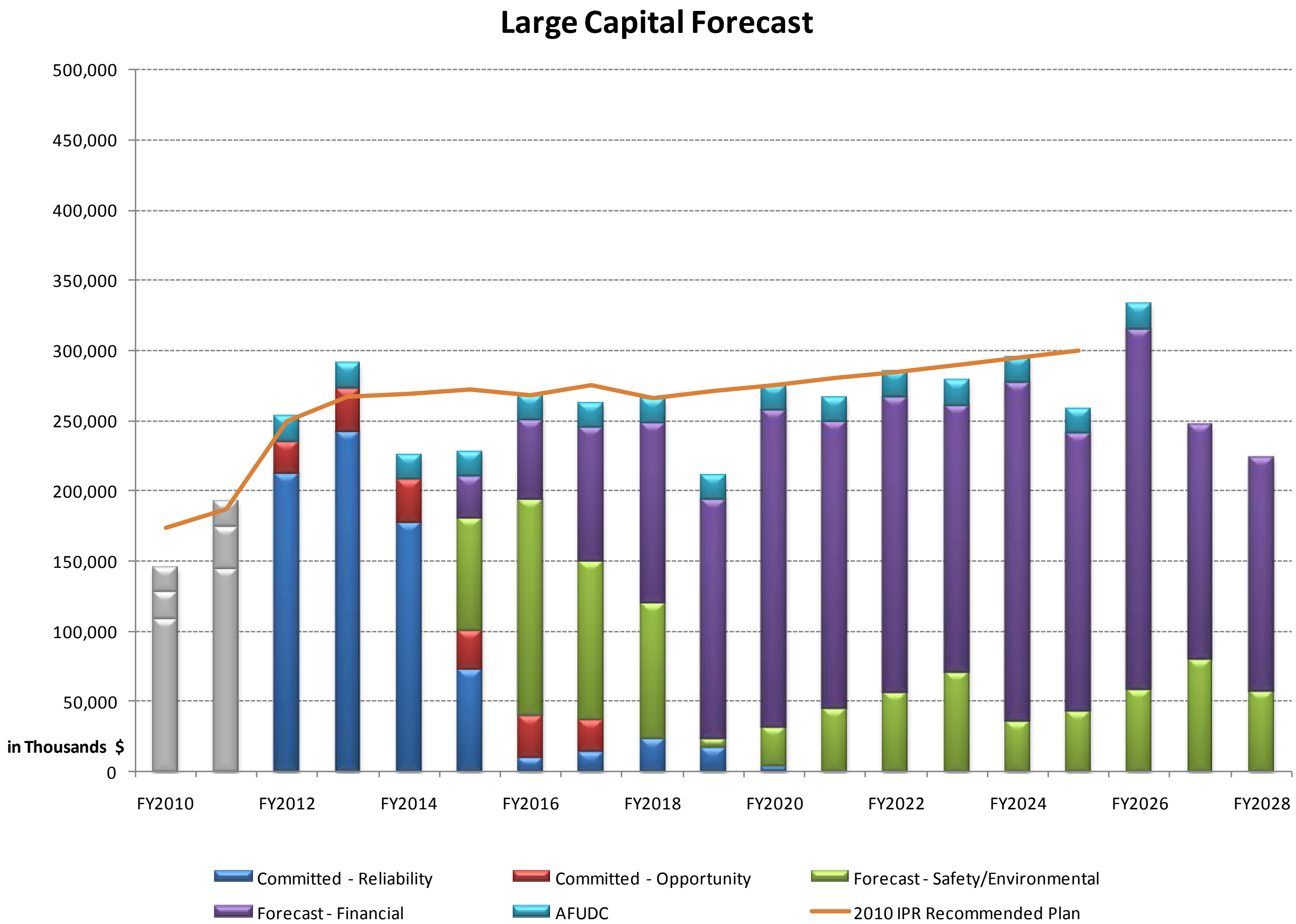
- Committed projects proceed as scheduled;
- High risk safety and environmental projects are selected as previously described;
- Financial risk driven projects are selected as described until an annual funding limitation is reached, after which investment in equipment in which financial risk is increasing the least is deferred until the following year, where it is re-evaluated using the same prioritization logic.

When funding constraints are applied, Total Cost for the system (system cost) increases because new investments are deferred past their cost minima.

Modeling funding constraints in this strategy has little effect on the 2012 – 2015 program. Nearly all available funding is committed during this period, so there is limited ability to turn these projects off without significant negative financial consequences. Funding constraints modeled in this strategy affect the number of projects that can be undertaken 5 to 15 years into the future to mitigate forecasted growth in risk.

The following graph shows modeling results when constrained to the 2010 IPR Recommended Plan budget level.

2010 IPR Recommended Plan



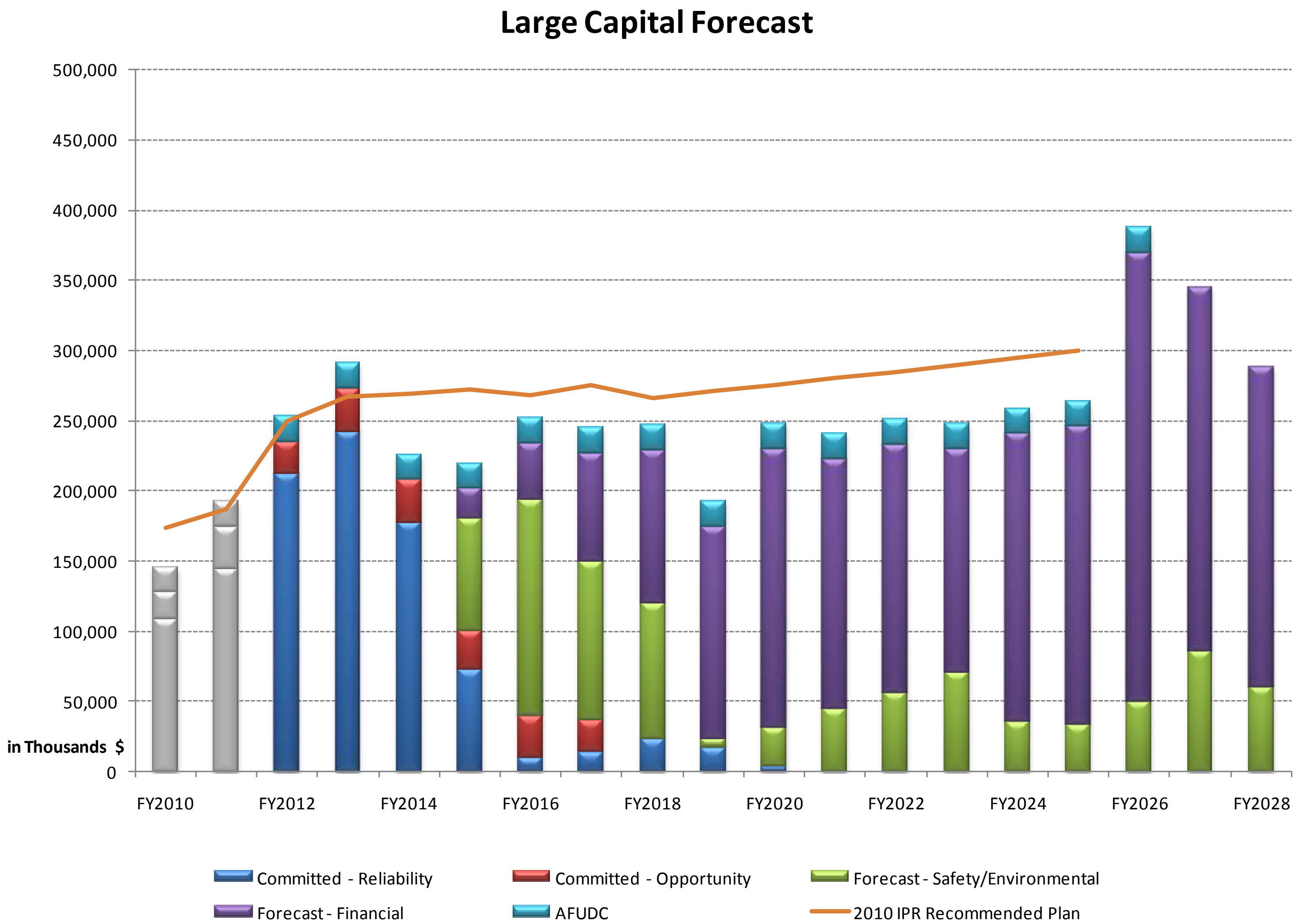
Other Funding Constraints

Consistent with work done for BPA's "Access to Capital" effort, we look at the effects of addition funding constraints in this strategy.

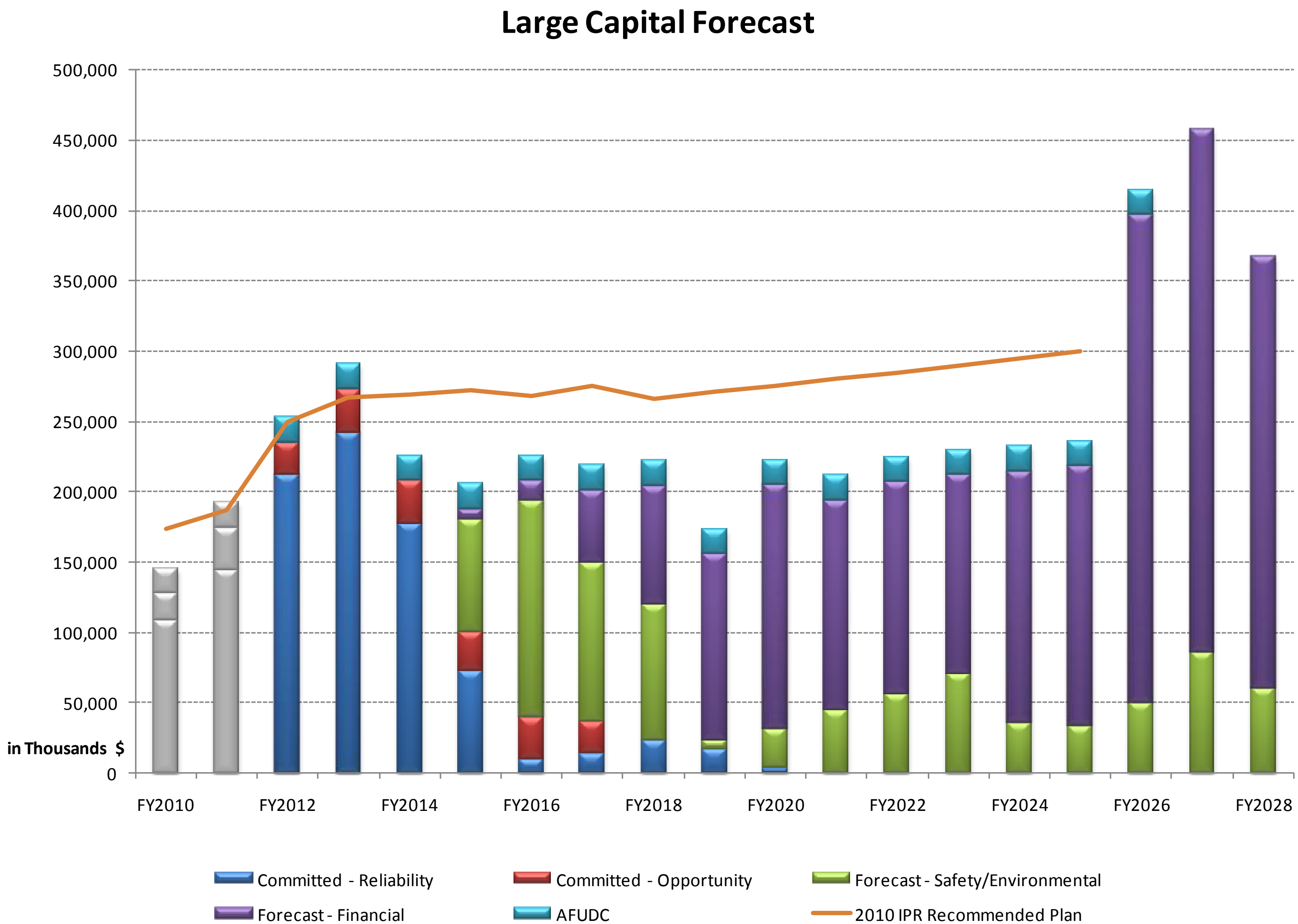
The following charts show the impact of 10 and 20 percent capital funding reductions relative to the 2010 IPR Recommended Plan.

While the John W. Keys III Pump Generating Plant is not evaluated in this strategy, the effect of funding Keys within budget limits is relatively close to the effect of incremental 10 percent capital reductions, i.e., funding Keys within the 2010 IPR Recommended Plan forecast has roughly the same effect on other investments as a 10 percent reduction in funding availability.

10 Percent Reduction Relative to 2010 IPR Recommended Plan



20 Percent Reduction Relative to 2010 IPR Recommended Plan



Effects of Funding Constraints

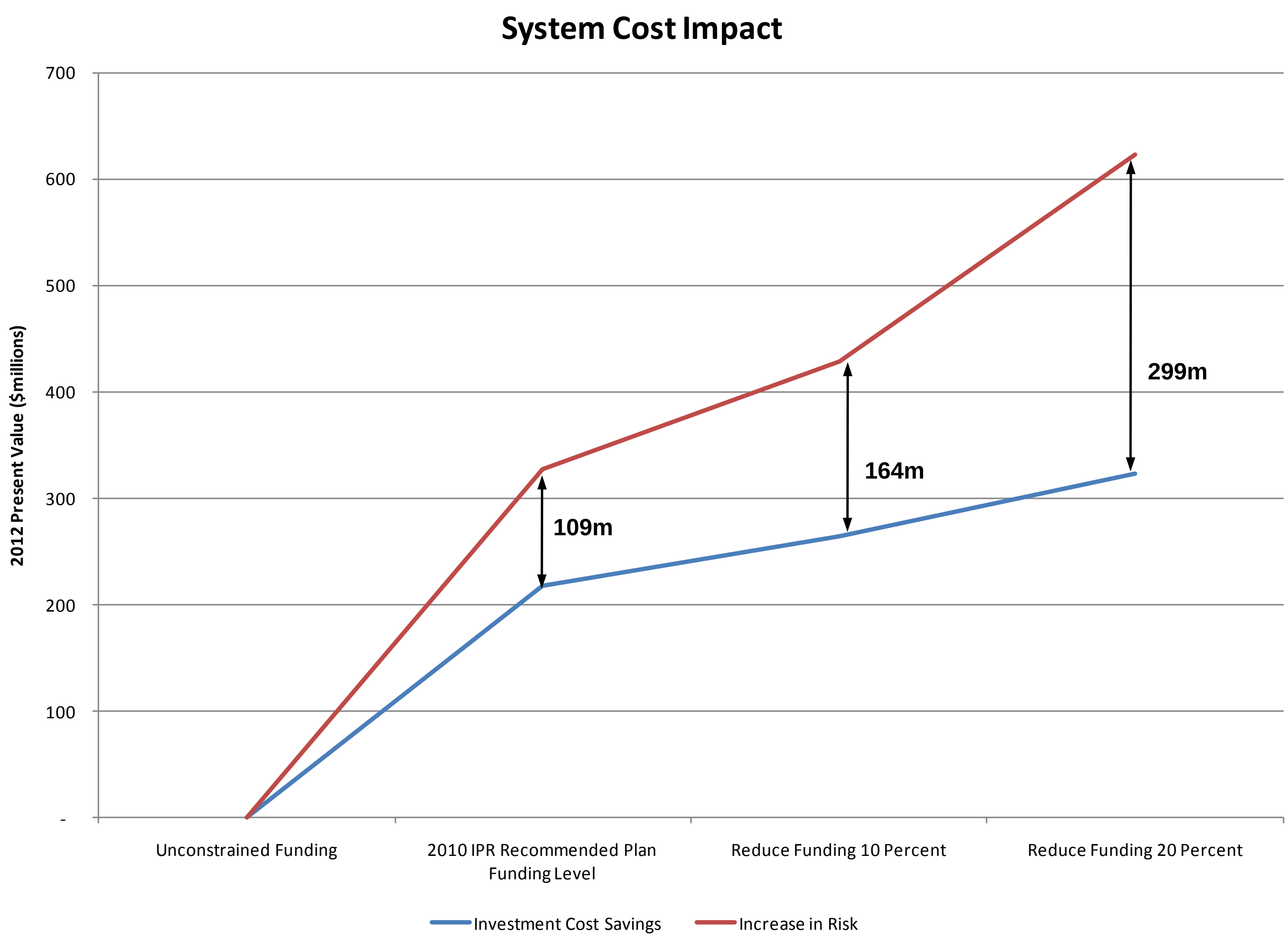
The 2010 IPR Recommended Plan yields a relatively stable program level both during and after the constrained funding period and identifies a scheduling and resource staffing capability that can be sustained for a decade or more.

The net present value of additional capital reduction scenarios are increasingly negative (higher system cost) because funding constraints cause more investments to be deferred beyond their cost minima, i.e., investment deferral benefits are less than the increase in financial risk costs.

Higher capital reduction scenarios also result in higher program need beyond the constrained funding period which would require a significant increase in resources to accomplish. The strategy does not estimate a cost for inefficiencies associated with ramping up these resources.

The following chart show the system cost impact of various capital budget reduction scenarios relative to the least cost case (no funding constraints).

System Cost Impacts of Funding Scenarios



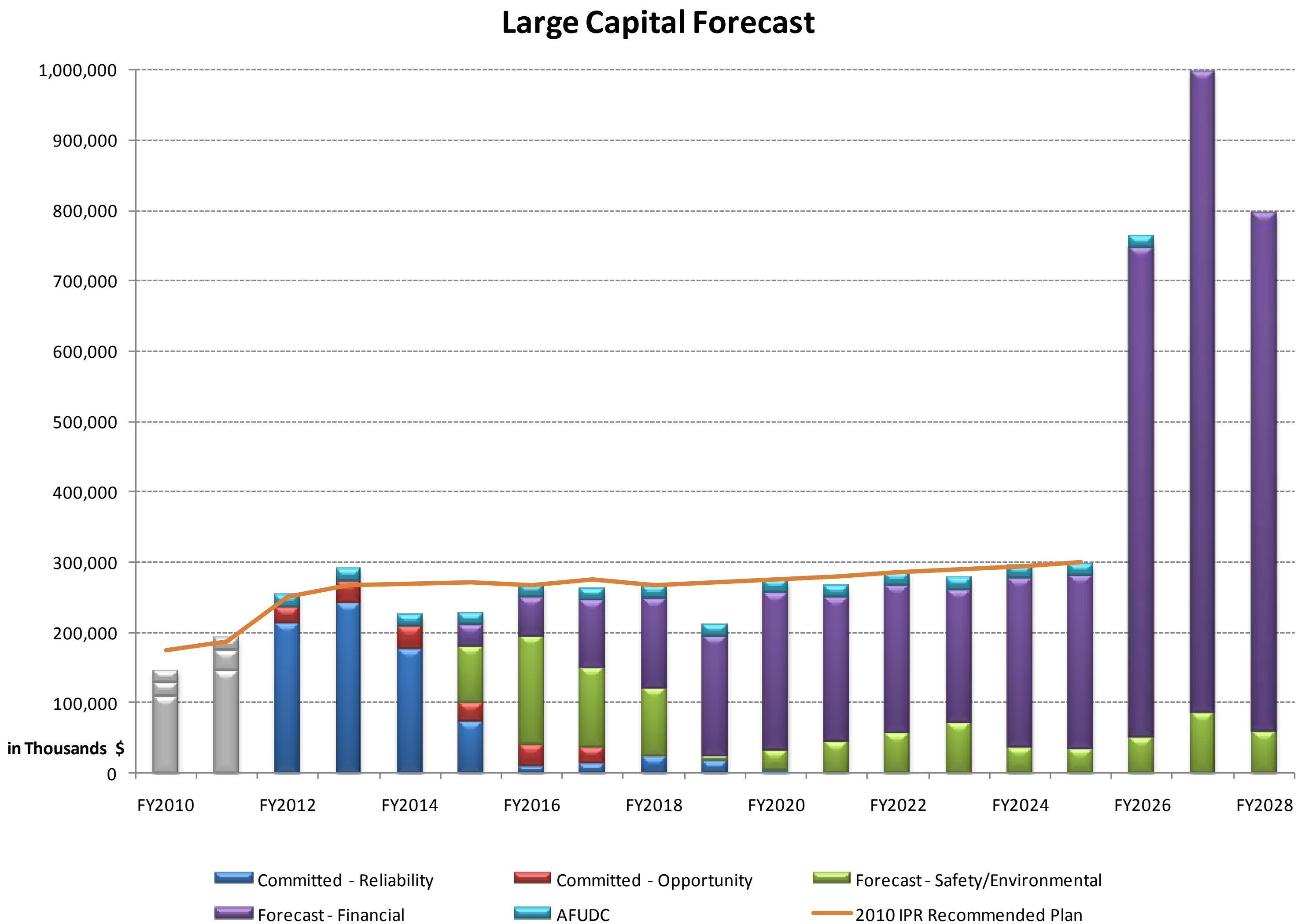
Discount Rates

In the strategy, we use a 12 percent discount rate when evaluating investment alternatives, a rate about twice that of Bonneville's cost of borrowing. A 12 percent discount rate is similar to the weighted cost of capital for a private utility financing investments with both taxable debt and equity.

We also looked at the effects of lower discount rates used often in the public sector, which more closely approximate a tax exempt cost of capital. The following graphs show the effect of a 6 percent discount rate on the large capital forecast for the 2010 IPR Recommended Plan funding level and for a program that ramps up to a stable level through 2025 and beyond, followed by a graph showing the system cost impact of various funding constraints relative to the least cost case.

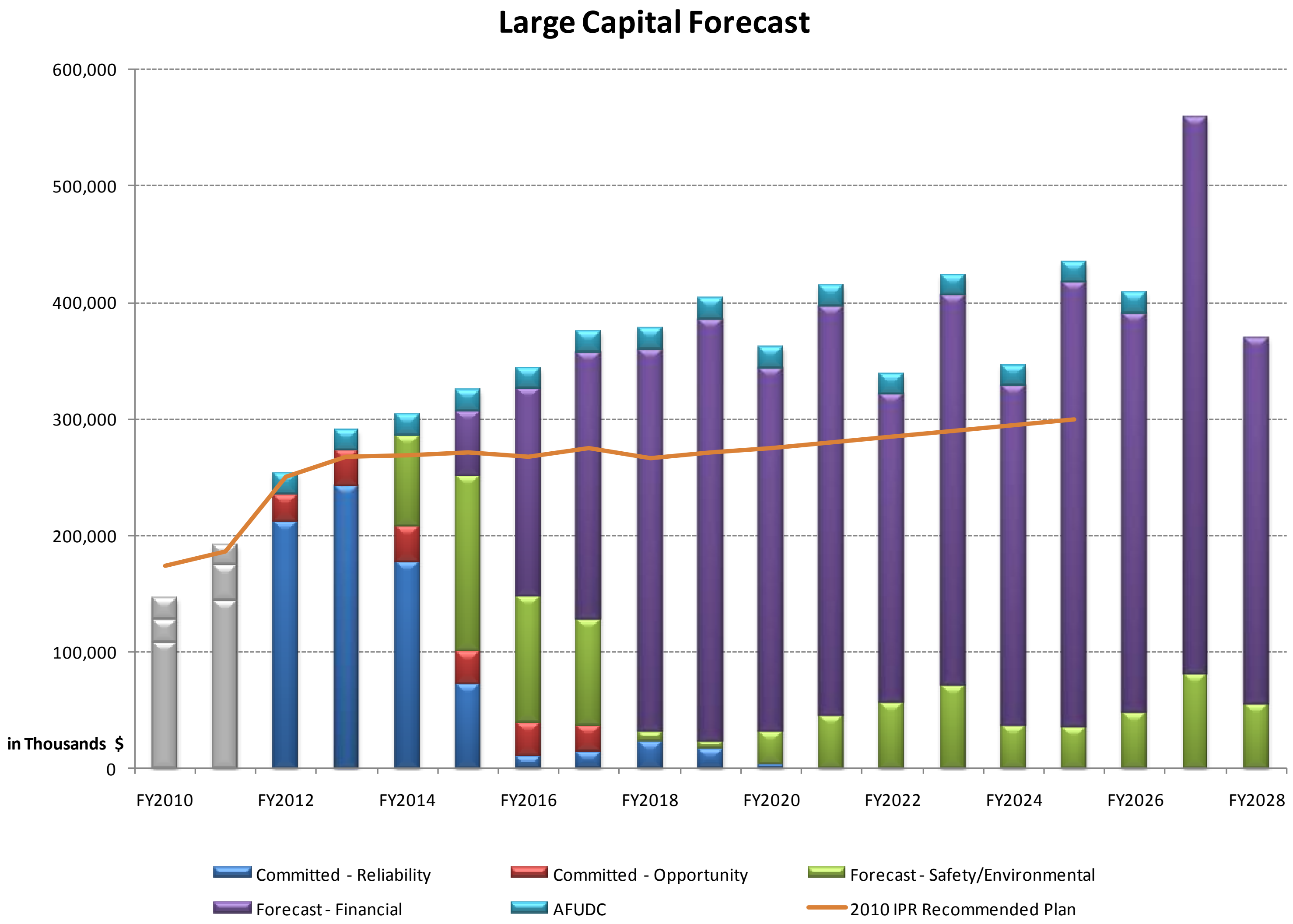
2010 IPR Recommended Plan

6 Percent Discount Rate



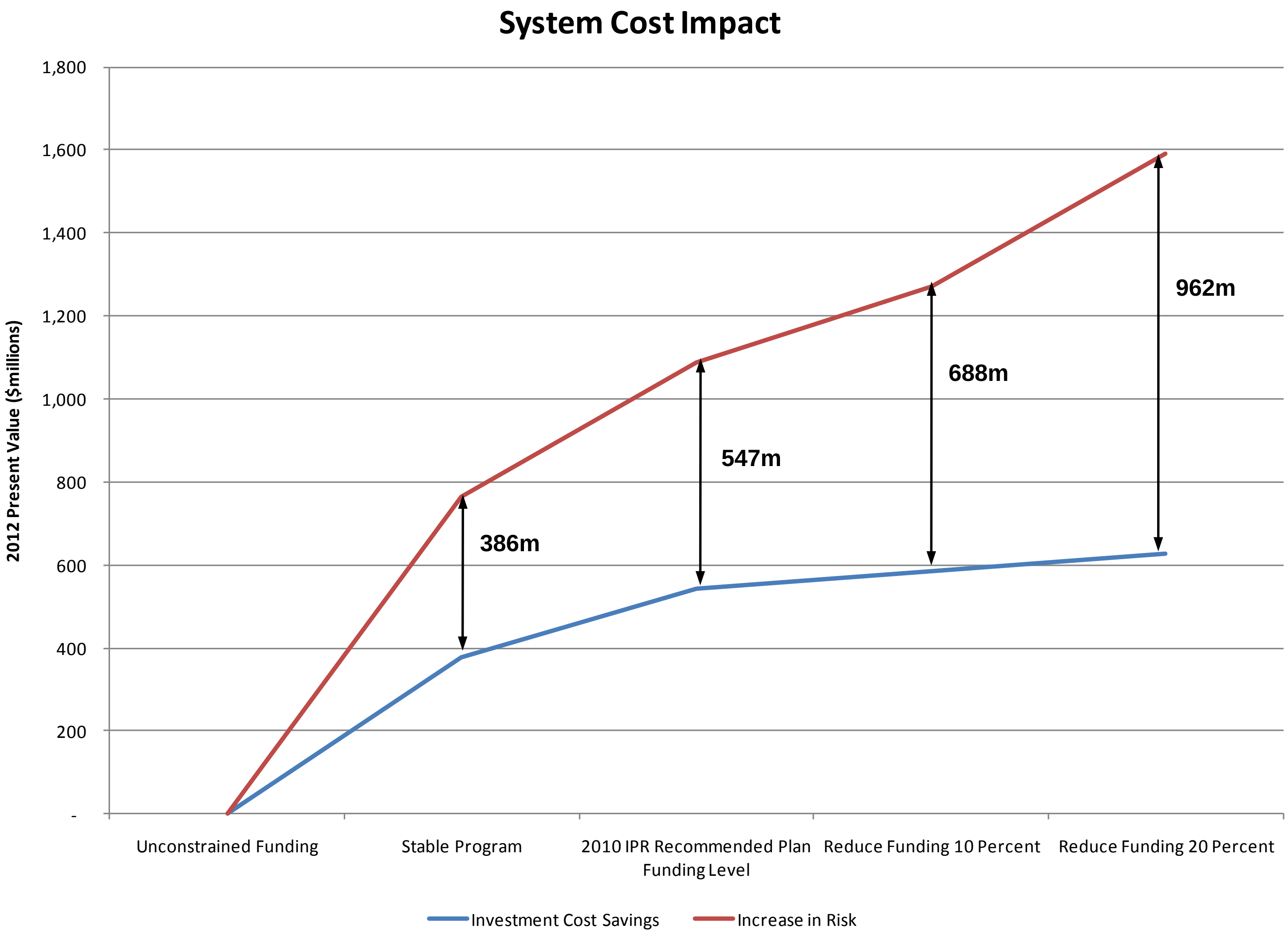
Ramp Up to a Stable Program

6 Percent Discount Rate



System Cost Impacts of Funding Scenarios

6 Percent Discount Rate



Preferred Investment Plan

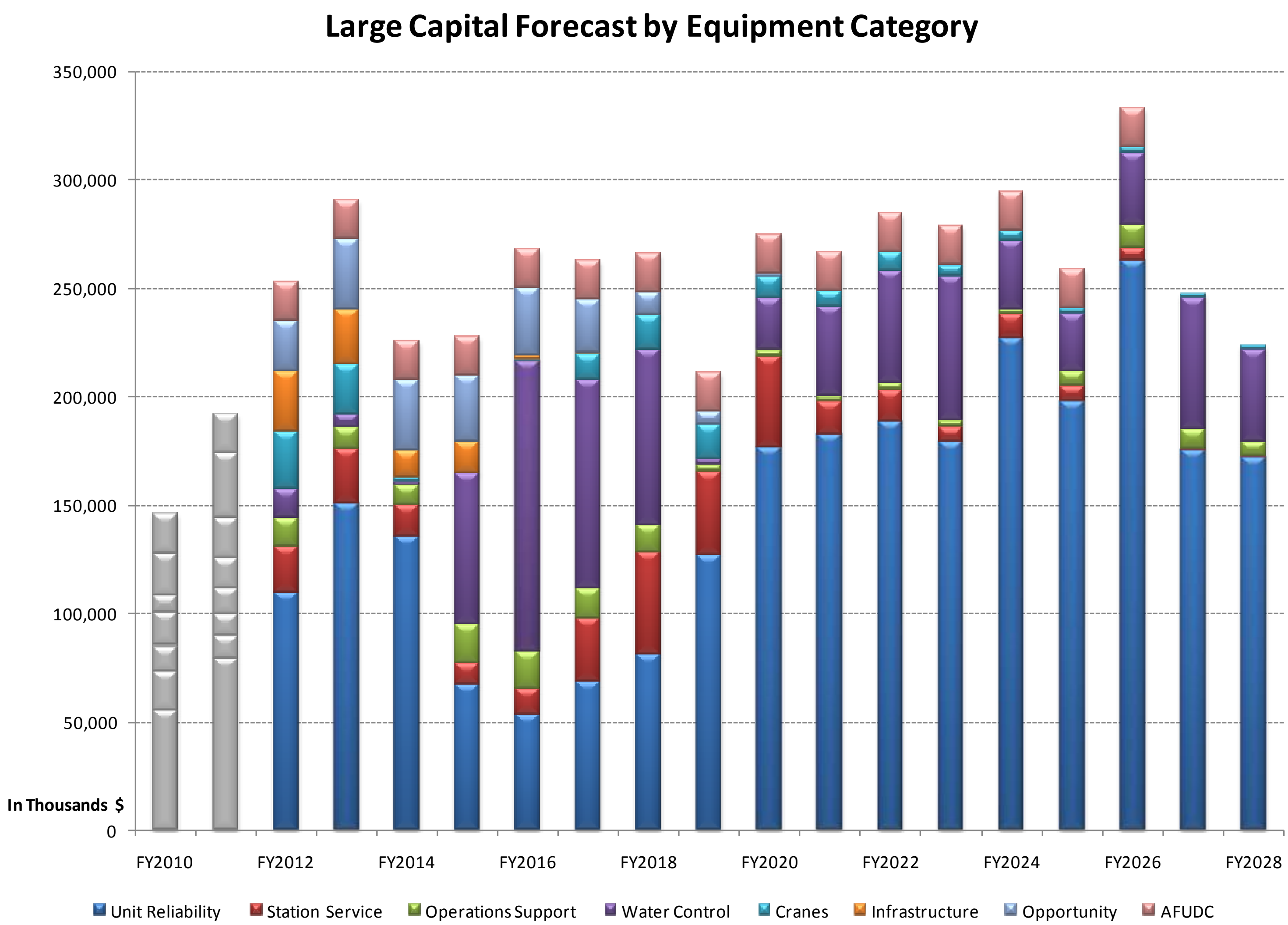
At a 12 percent discount rate, the 2010 IPR Recommended Plan identified a relatively stable capital program level of about $250 million per year both during and after the constrained funding period and a scheduling and staffing resource capability that could be sustained for a decade or more. The plan excluded costs for modernizing the John W. Keys III Pump-Generating Plant or other uncommitted economic opportunity investments.

At a 6 percent discount rate, a stable capital program level is closer to $400 million per year.

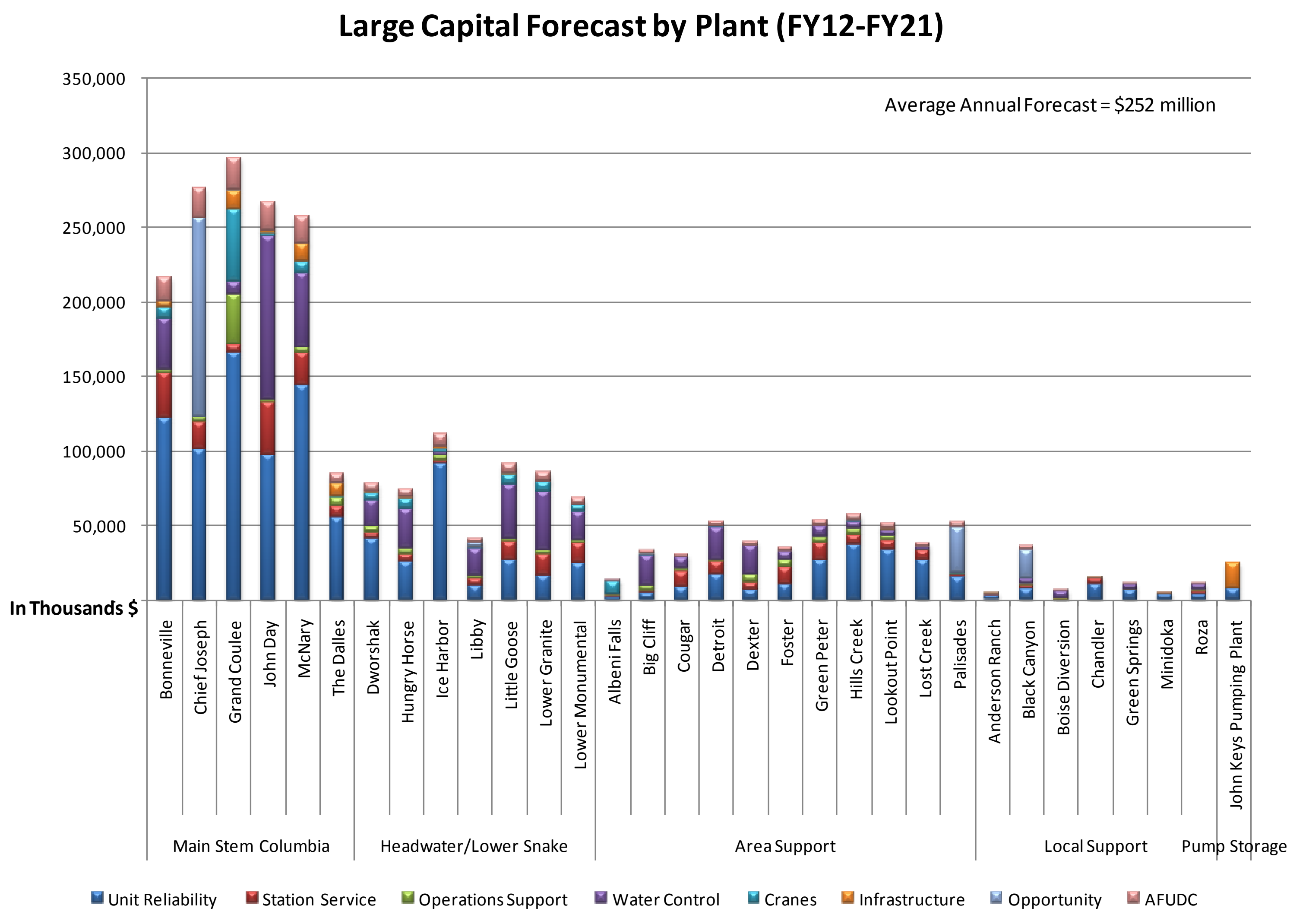
The rationale for the 2010 Recommended Plan large capital program level is still valid today, given Bonneville's 12 percent discount rate.

- The plan provides a stable program level for at least 15 years; and
- Is less costly in the long run than are scenarios that reduce funding further.

Large Capital Forecast by Equipment Category
(Preferred Plan)



Large Capital Forecast by Plant
(Preferred Plan)



The Preferred Plan has the Following Effects:

Condition

- The average condition of equipment in 2022 is forecasted to be similar to average condition today except in the Local Support class, where average condition declines.

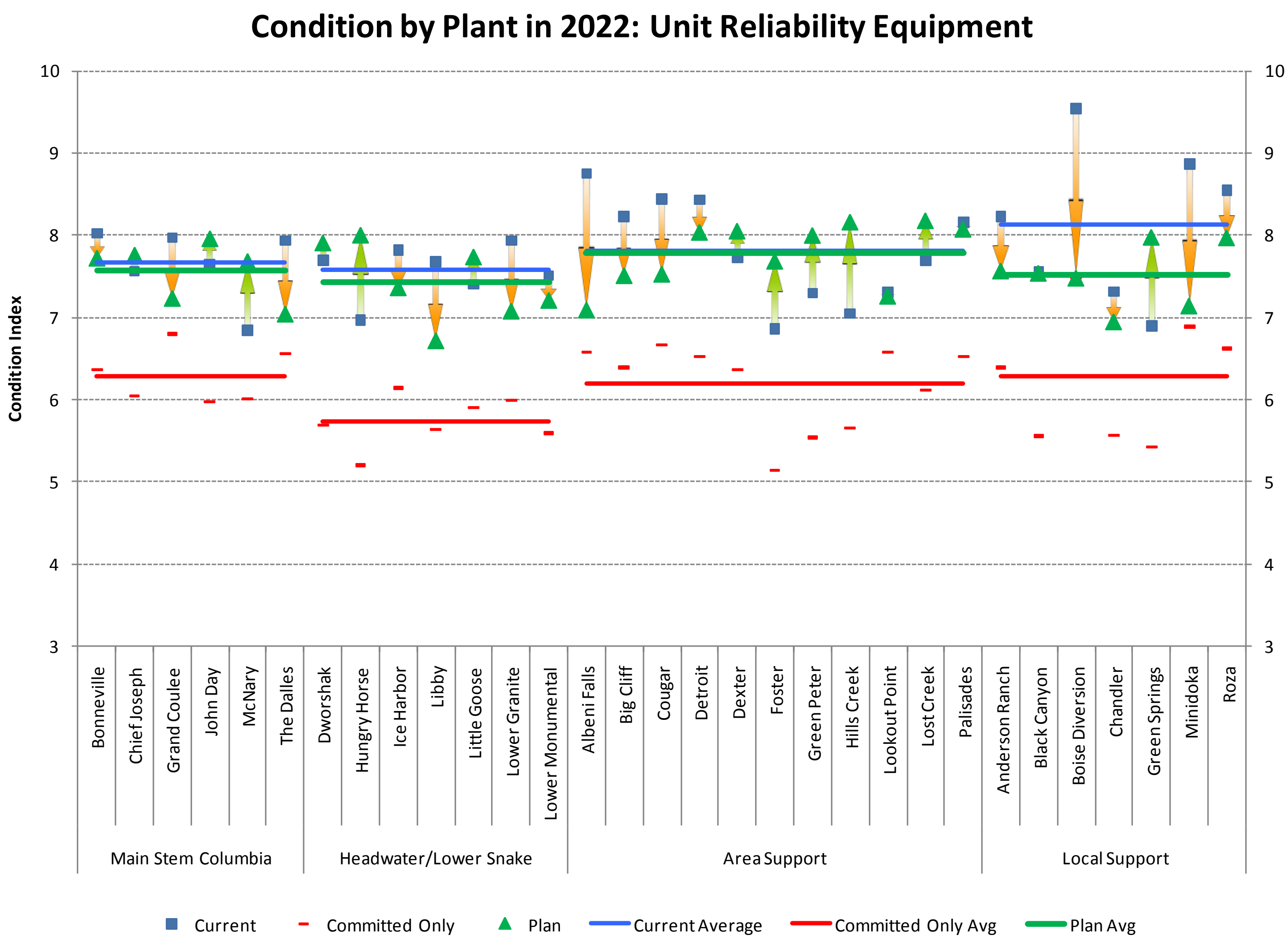
Age

- In 2022, the average age as a percent of design life decreases for unit reliability, station service and water control equipment categories. It remains the same for cranes.
- Average condition increases for operations support and infrastructure categories, in large part because the asset planning modeling algorithm does not have a good mechanism for identifying investment need in these categories.

Lost Generation Risk

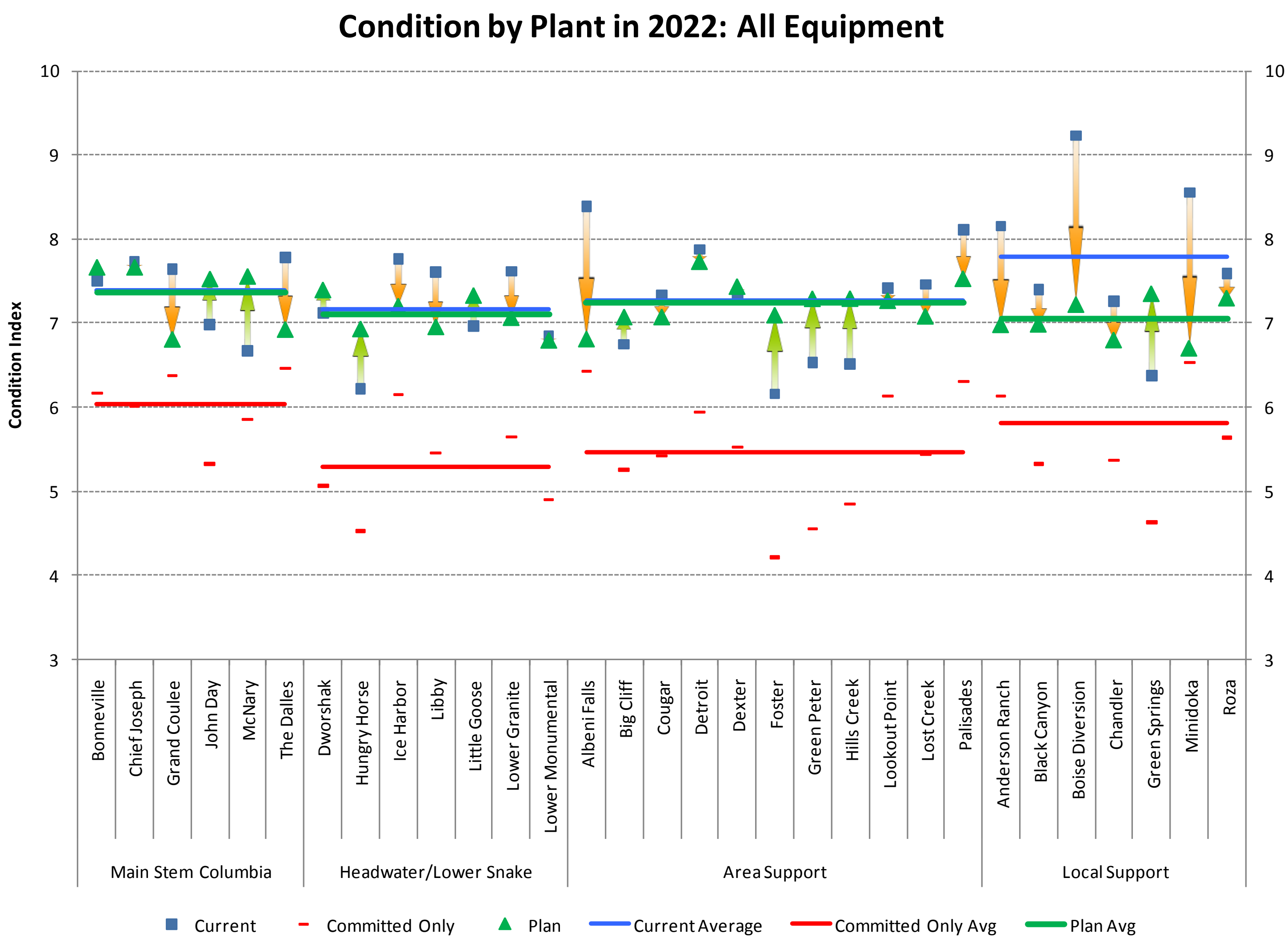
- LGR is forecasted to decline from 587 aMW today to 247 aMW in 2022.
- In 2022, McNary will still have 80 aMW of risk because the turbine runner replacement program will just be getting underway. LGR in future years should decline.
- Grand Coulee and Chief Joseph have forecasted LGR of about 20 aMW.
- Most other plants are forecasted to have LGR of less than 10 aMW.

Condition by Plant in 2022: Unit Reliability Equipment
(Preferred Plan)

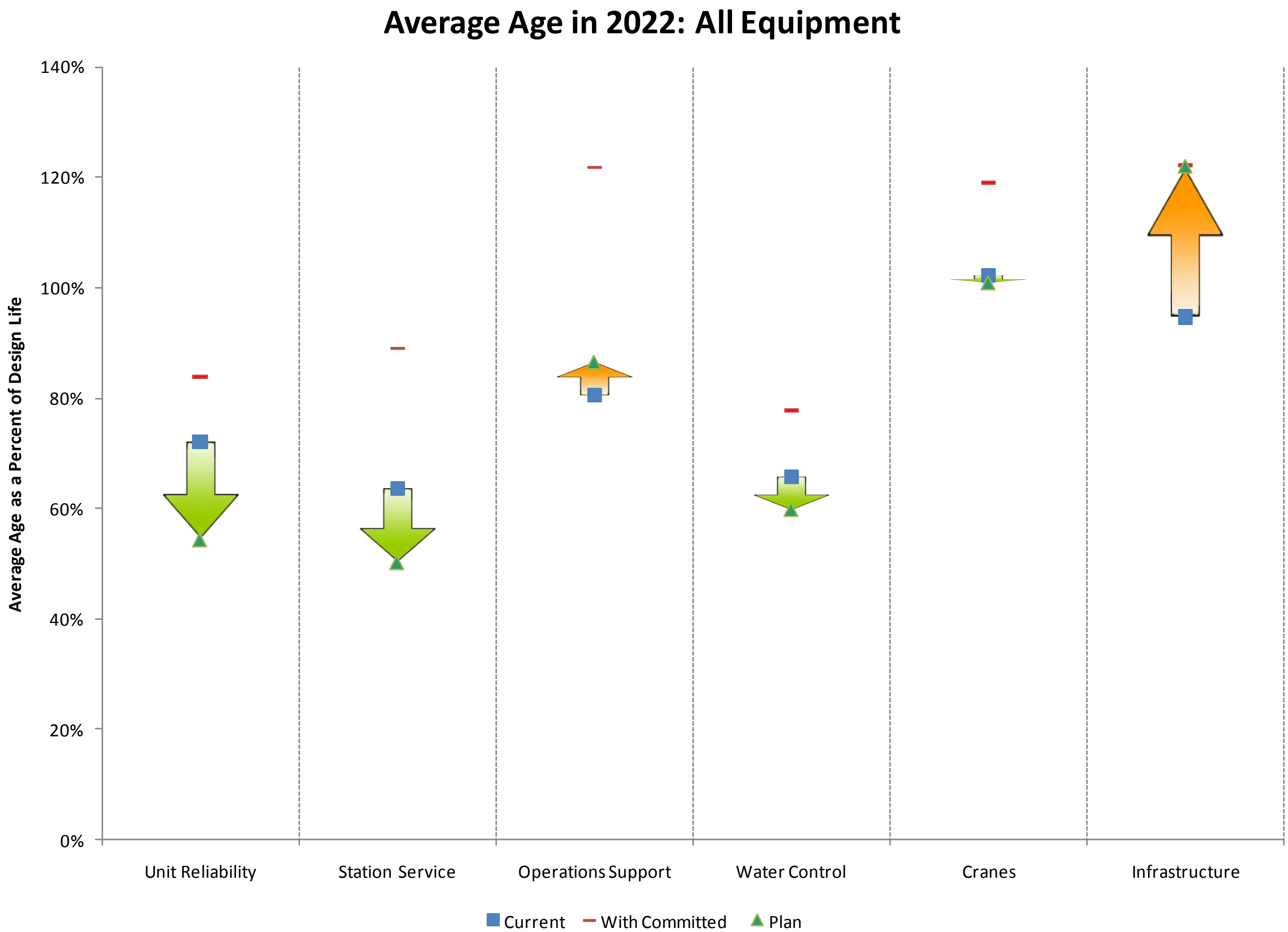


Condition by Plant in 2022: All Equipment

(Preferred Plan)

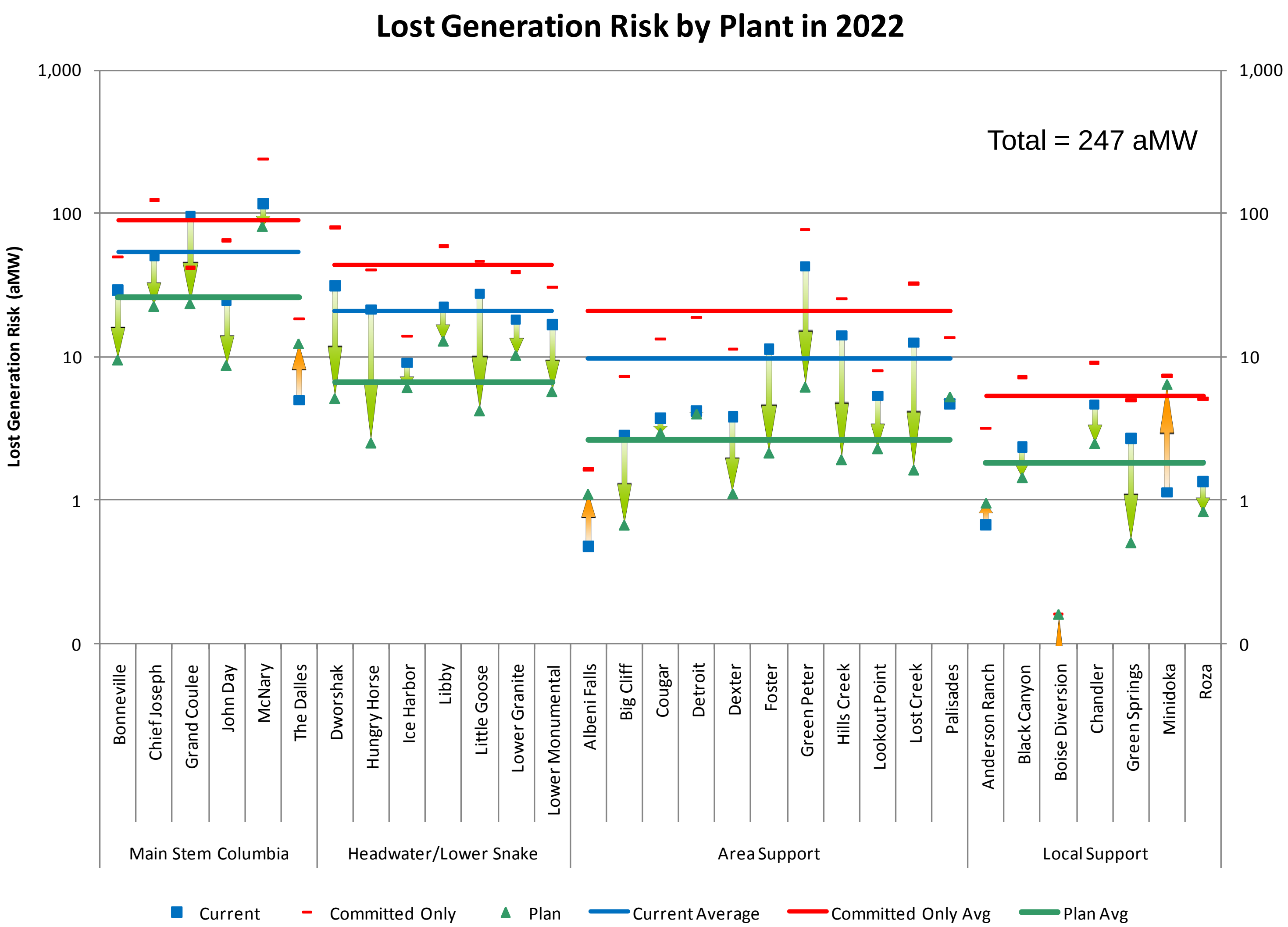


Average Age in 2022: All Equipment
(Preferred Plan)



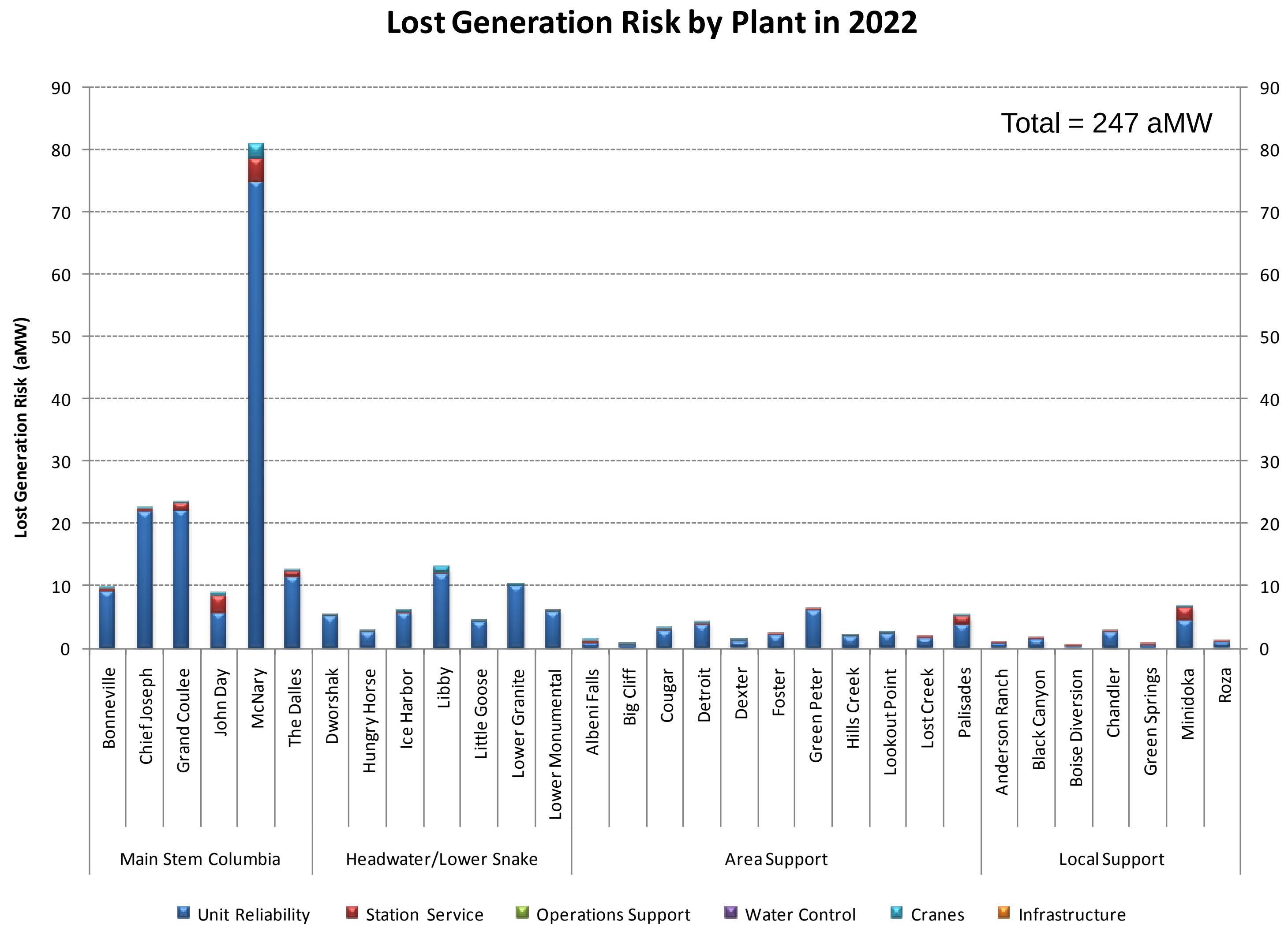
Lost Generation Risk by Plant in 2022

(Preferred Plan)



Lost Generation Risk by Plant in 2022

(Preferred Plan)



Economics of the Preferred Plan

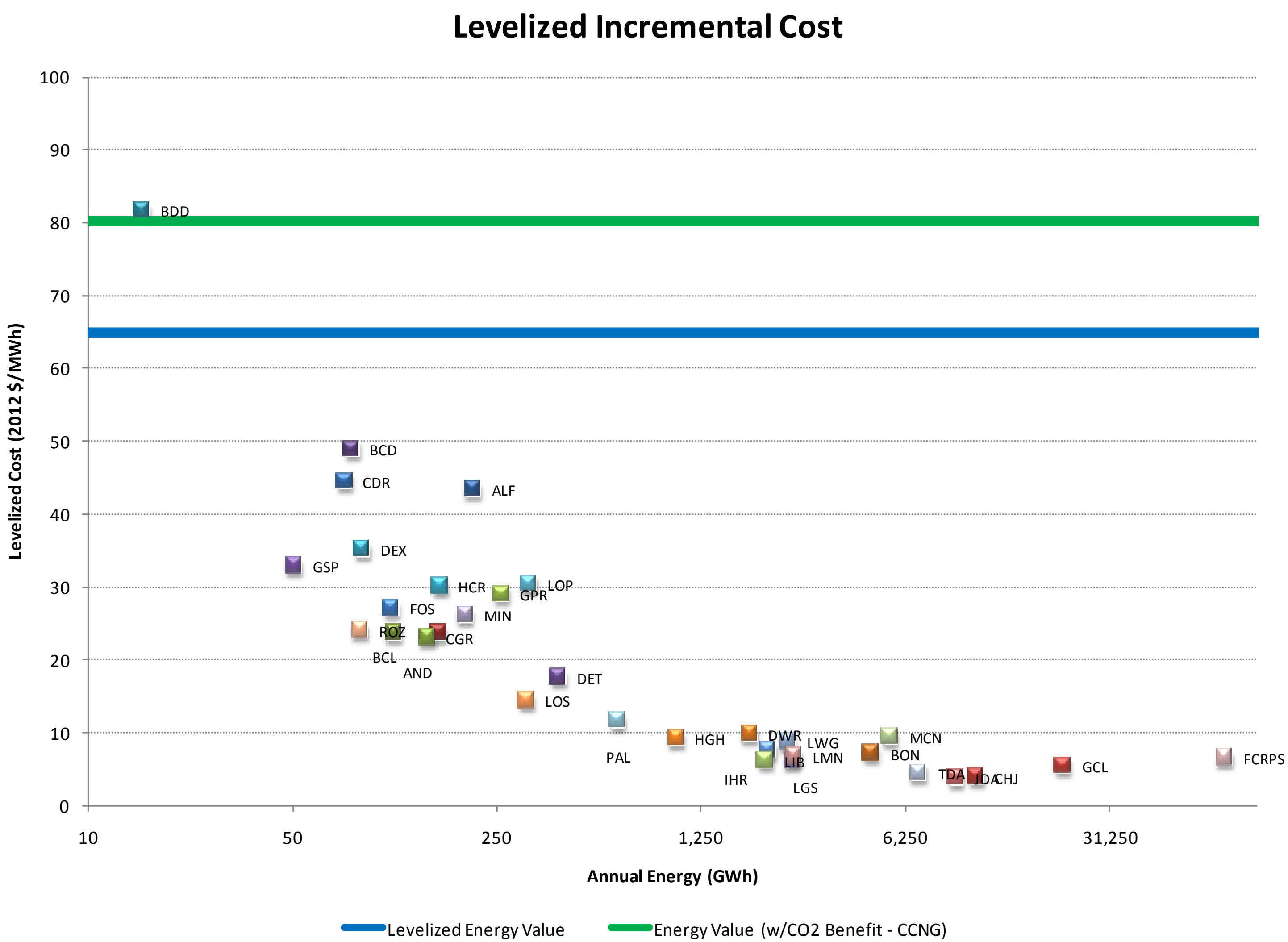
Levelized Incremental Cost (excludes sunk costs)

- Costs for all plants except Boise Diversion are below the value of power generated by the facility.

Levelized Fully Allocated Cost (includes sunk costs)

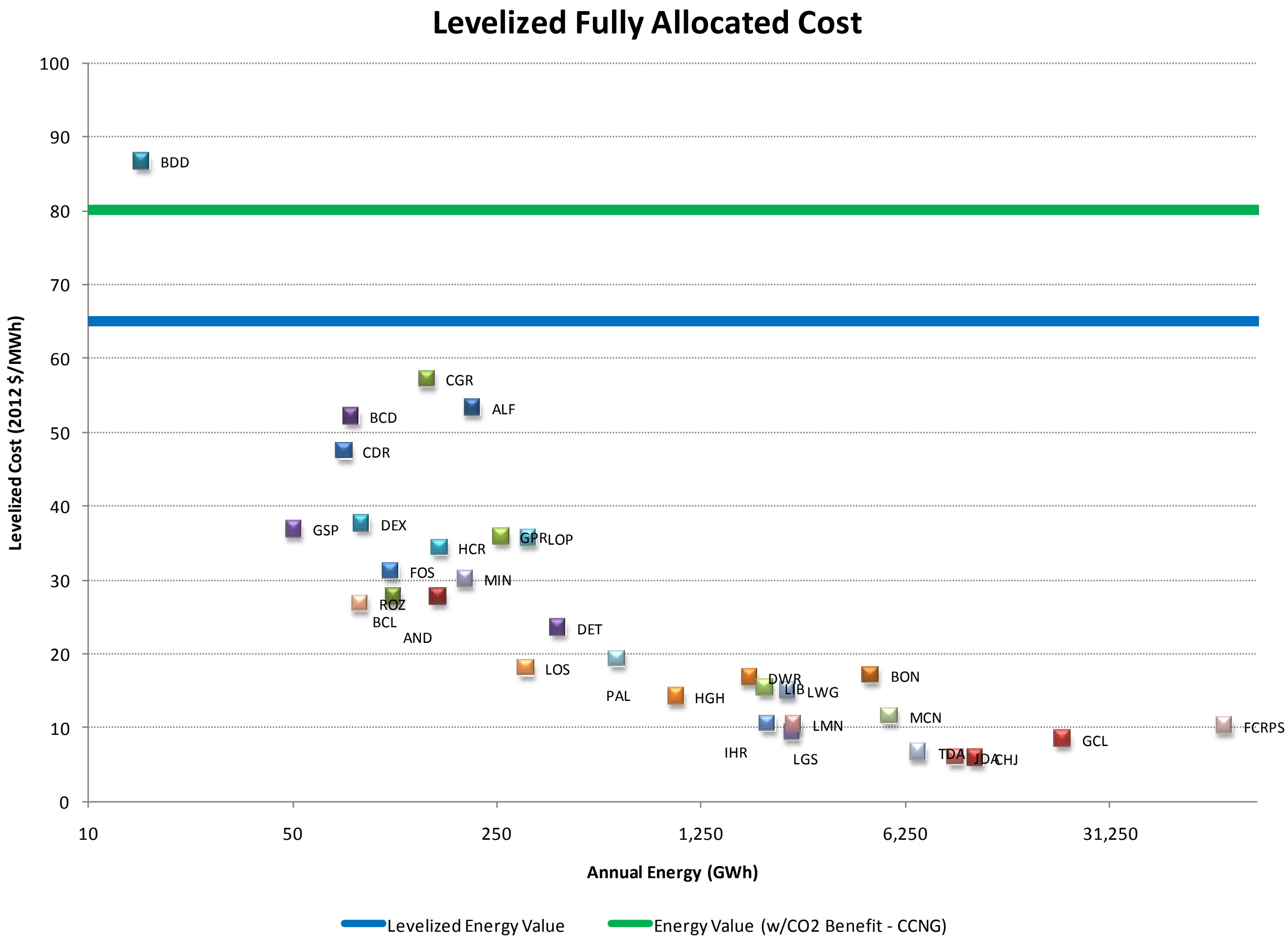
- When adding the sunk investment in the hydro system to incremental O&M and investment costs, the 20-year levelized fully allocated cost of the hydro system is $10 per MWh (2012 dollars).
- All plants other than Boise Diversion have fully allocated costs that are less than the value of power generated by the facility.

Levelized Incremental Cost
(FY2012 – FY2031 O&M and Investment Programs)



Levelized Fully Allocated Cost

(Net Utility Plant plus FY2012 – FY2031 O&M and Investment Programs)



7. Summary

Summary
(Approach and Scope)

The approach to creating this 2014 Hydro Asset Strategy is consistent with the 2012 strategy developed for the 2010 IPR.

The strategy identifies condition and risk implications of the currently committed hydro investment program and new investments prioritized around minimizing lifecycle cost. It represents a reasonable level and timing of future investment to ensure adequate business continuity and maintain the production capability of the FCRPS hydro system at a cost effective level of reliability.

The strategy includes electrical and mechanical equipment on hydropower specific and joint-use features, but excludes costs for large dam safety civil features and repairs and replacements of aging hatchery and fish passage facilities constructed for Columbia River Fish Mitigation and the Lower Snake Compensation Plan.

The strategy also excludes an evaluation of specific issues that may result in new strategic initiatives, e.g., capacity expansion opportunities, pumped storage and automation. Studies required for these issues are detailed and unique. If and when those studies develop, they will be summarized and reflected in future strategies.

Summary
(Preferred Plan)

The preferred plan for large capital in this strategy is unchanged from the 2012 Recommended Plan presented in the 2010 IPR process.

- A large capital program level of about $250 million per year provides a stable program that can be efficiently resourced for at least 15 years without accumulating a high level of risk.
- This program level is less costly in the long run than scenarios that reduce funding further.
- The recommended plan does not include costs for modernization of John W. Keys Pump Generating Plant or other uncommitted economic opportunity investments (e.g., additional units at Dworshak, Libby, or John Day),

The plan maintains an average hydroAMP condition rating for unit reliability equipment above a score of 7 (scale of 10) and reduces lost generation risk to less than 300 aMW within a decade.

Under this plan, the 20-year levelized fully allocated cost of the hydro system is forecasted to be $10 per MWh (2012 dollars).

The Capital Workgroup defines and implements a capital program consistent with this strategy.

Appendix A

Capital Program Detail

Background

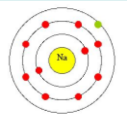
Capital Program

- The capital program is managed by a 3-Agency Capital Workgroup
- The CWG meets six times per year to review and approve new investments
- Capital program managers also meet six times per year to:
    - review investments identified in the asset strategy and, from that, develop a high level plan for out years; and,
    - to do real-time management of active subagreement contracts in order to prioritize and schedule projects within the program budget.

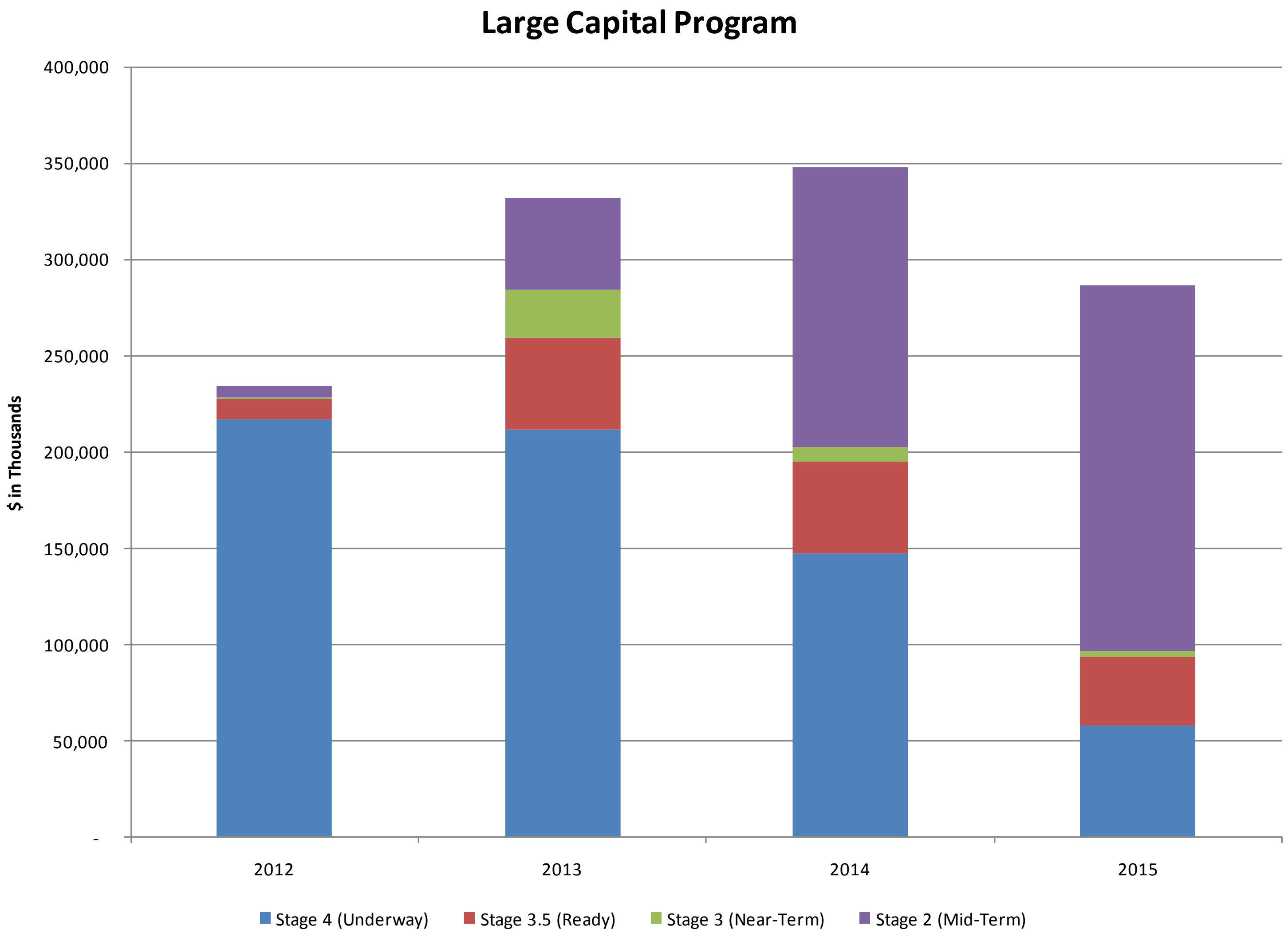
The CWG uses staging to order projects within the program based on each project's level of maturity.

- Stage 4: mature projects that are in flight. Projects are ranked to support real-time management.
- Stage 3: mature projects that are not yet in flight, but are next in line.
- Stage 2: equipment identified in the asset strategy aggregated into first order projects. Schedules are high level and fluid.
- Stage 1: equipment identified in the asset strategy not covered in other stages.

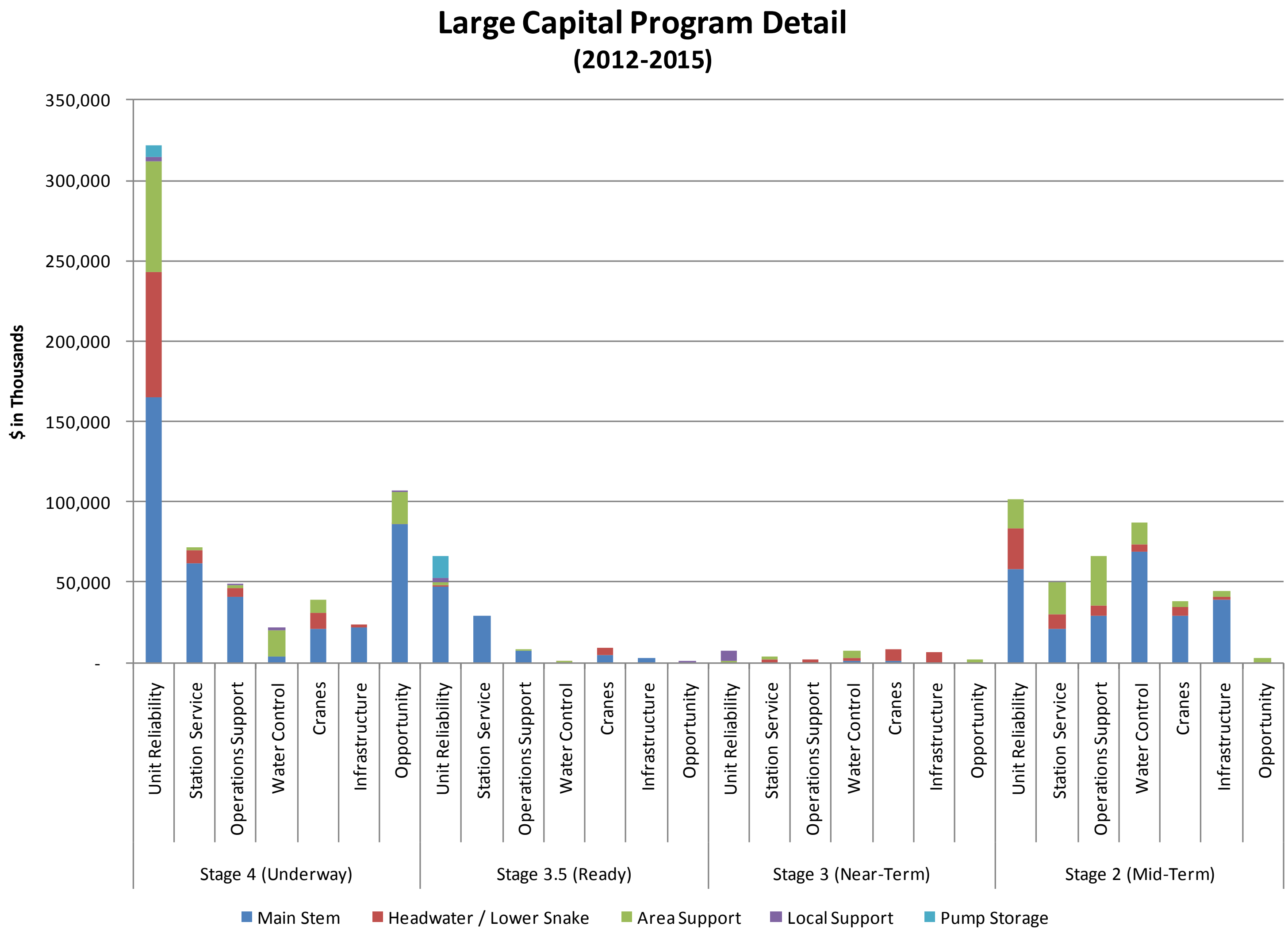
Capital Program Planning and Implementation Criteria

Planning Criteria	Stage 	Implementation Criteria					
Approved projects in flight	4	Under contract (non-deferrable)	Priority, Critical, Essential (life safety, environmental or regulatory compliance, etc) (non-deferrable)	Phase 2 approved, contract advertized but not awarded (non-deferrable)	Phase 2 approved, contract not advertized (deferrable)	Phase 1 underway (exploratory studies to refine project Phase 2 scope, cost and schedule) (deferrable)	Phase 1 approved but not yet underway (exploratory studies to refine project Phase 2 scope, cost and schedule) (deferrable)
Mature projects not yet approved	3	Refined cost and schedule estimates awaiting funding approval. Consistent with asset strategy	Developing refined cost and schedule estimates				
Equipment identified in the asset strategy aggregated into first order projects	2	Cost and schedule estimates are high level and fluid					
Equipment identified in the asset strategy not covered in other stages	1						

Capital Program by Stage by Year

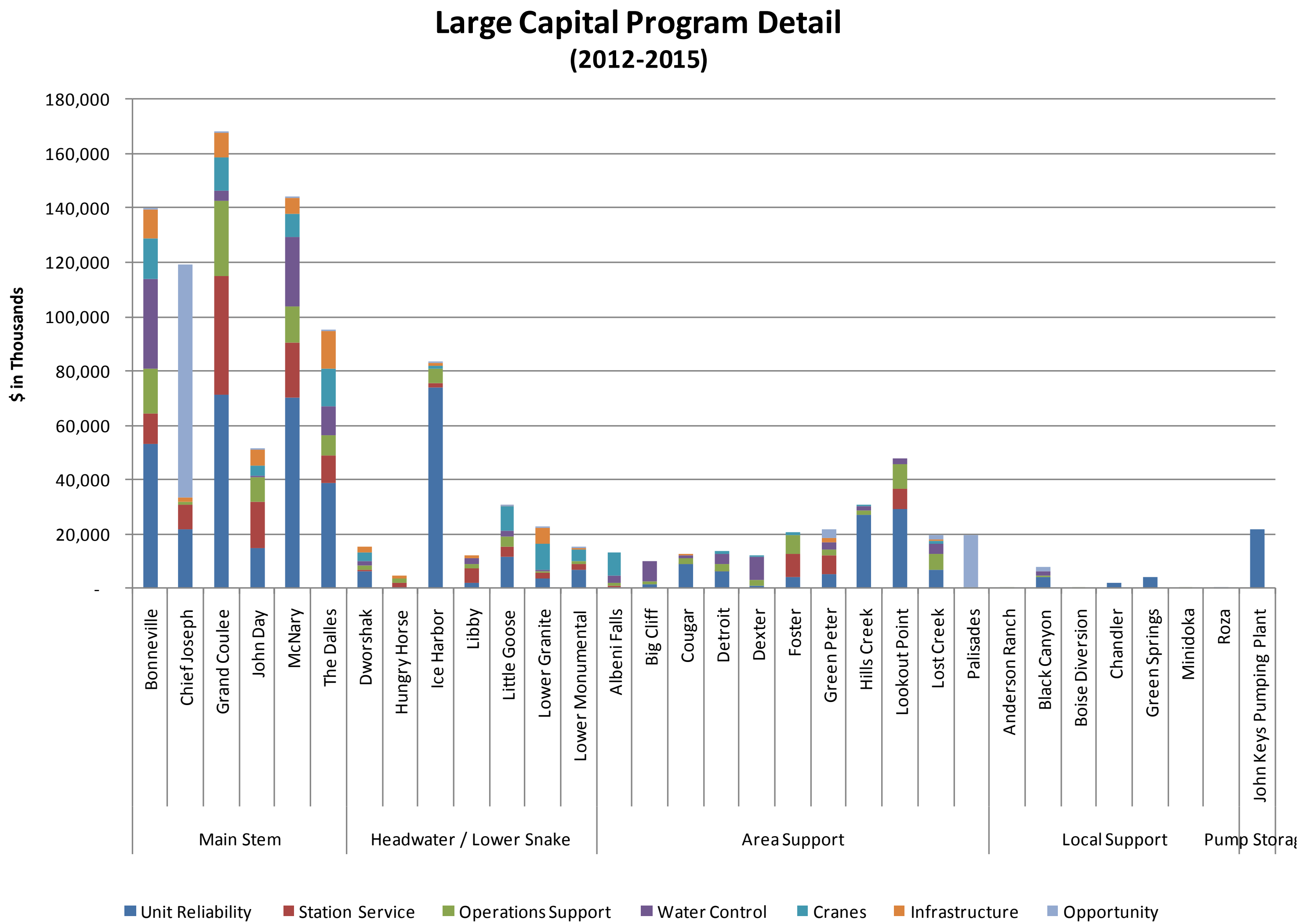


Capital Program by Stage by Equipment Type
(2012 – 2015)



Capital Program by Plant by Equipment Type

(2012 – 2015)

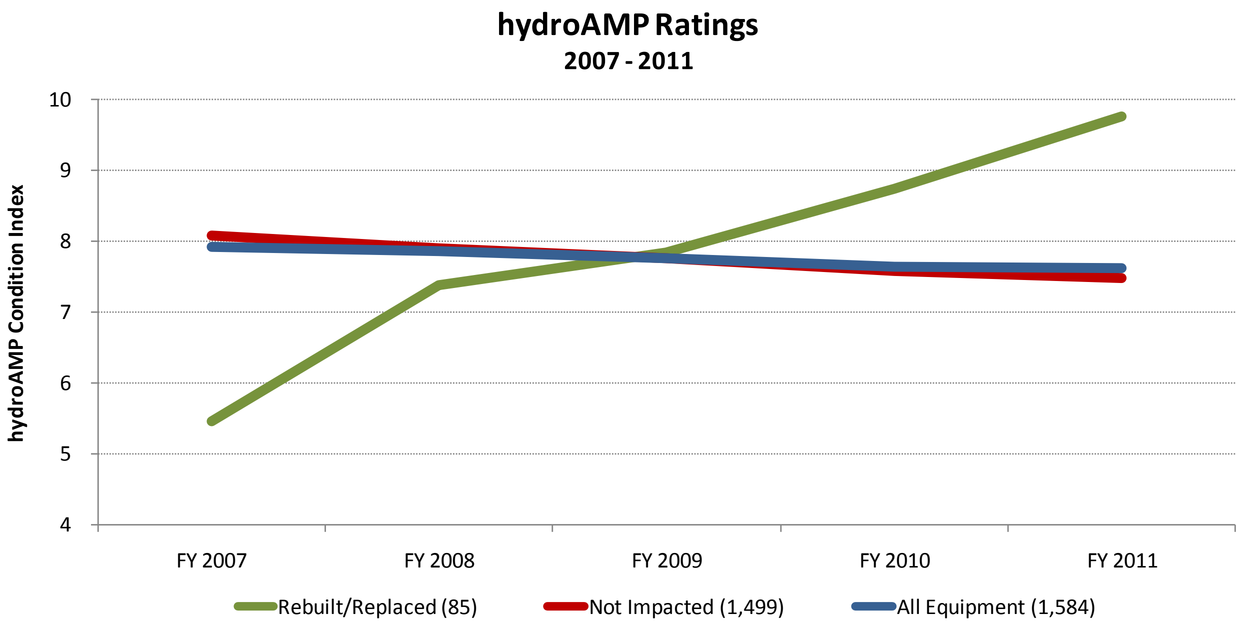


Condition Impacts of the Hydro Capital Reinvestment Program

In the past 4 years, 85 of 1,584 equipment items with hydroAMP ratings have been rebuilt or replaced, equating to an average replacement cycle of 75 years. The hydroAMP rating for replaced items has improved from an average of about 5.5 in 2007 to nearly 10 today.

Condition of equipment not impacted has declined from an average rating of about 8.1 to 7.5.

The average hydroAMP rating for all equipment has been declining at the 5-year average level of investment of $122 million per year, a supporting argument for the higher investment level identified in the Recommended Plan.



Appendix B

John W. Keys III Pump-Generating Plant

John W. Keys III Pump-Generating Plant

Original installation in 1951
- Six 50 MW pumping units

Upgrade in 1973
- Two 50 MW pump/generators installed

Upgrade in 1983-84
- Four 53.5 MW pump/generators installed

Current Capacity
- Pumping – 12 Units 614 MW
- Generating – 6 Units 314 MW

Need for Keys Modernization

PG Units 7-8 and 9-12 were commissioned in 1973 and 1983-4, respectively.

The plant is near end-of-life, much of the unit and balance-of-plant equipment is worn or becoming obsolete. Availability of the units in FY11 was 46%.

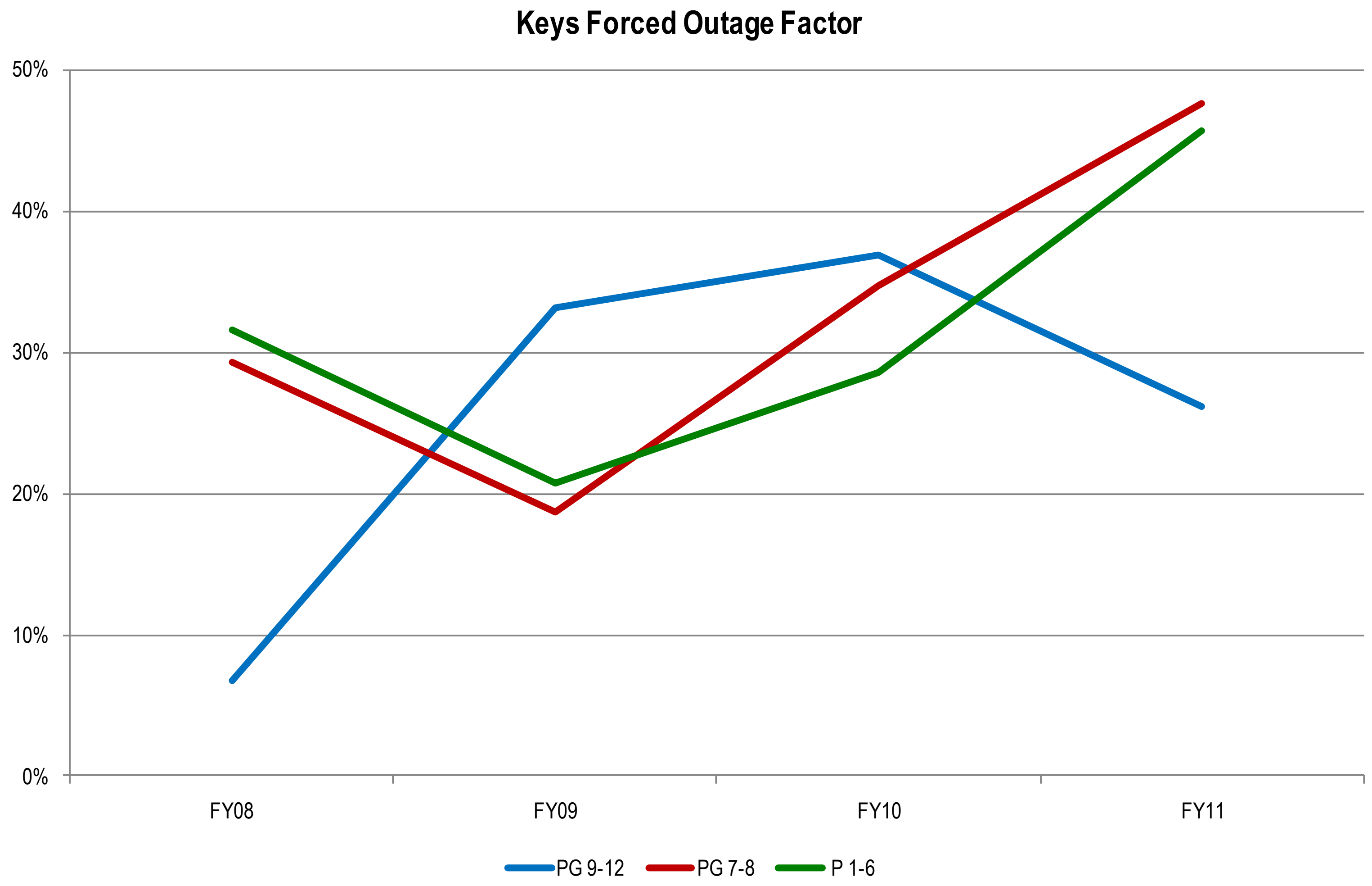
Over the years several of the pumps have been refurbished by in-kind replacement of the pump impellers, some of the motor stators have been rewound, and minor enhancements have been made to the controls and protection systems.

The pump-generators have not yet undergone similar refurbishment and still have the original pump-turbines and generator-motors, governors, and static exciters.

A modernized Keys plant could provide a reliable, low cost supply of balancing reserve capacity.

Estimated capital costs to modernize are estimated at $200 – $300 million.

Keys Forced Outage Factor



Keys Pump-Generating Plant Assessment

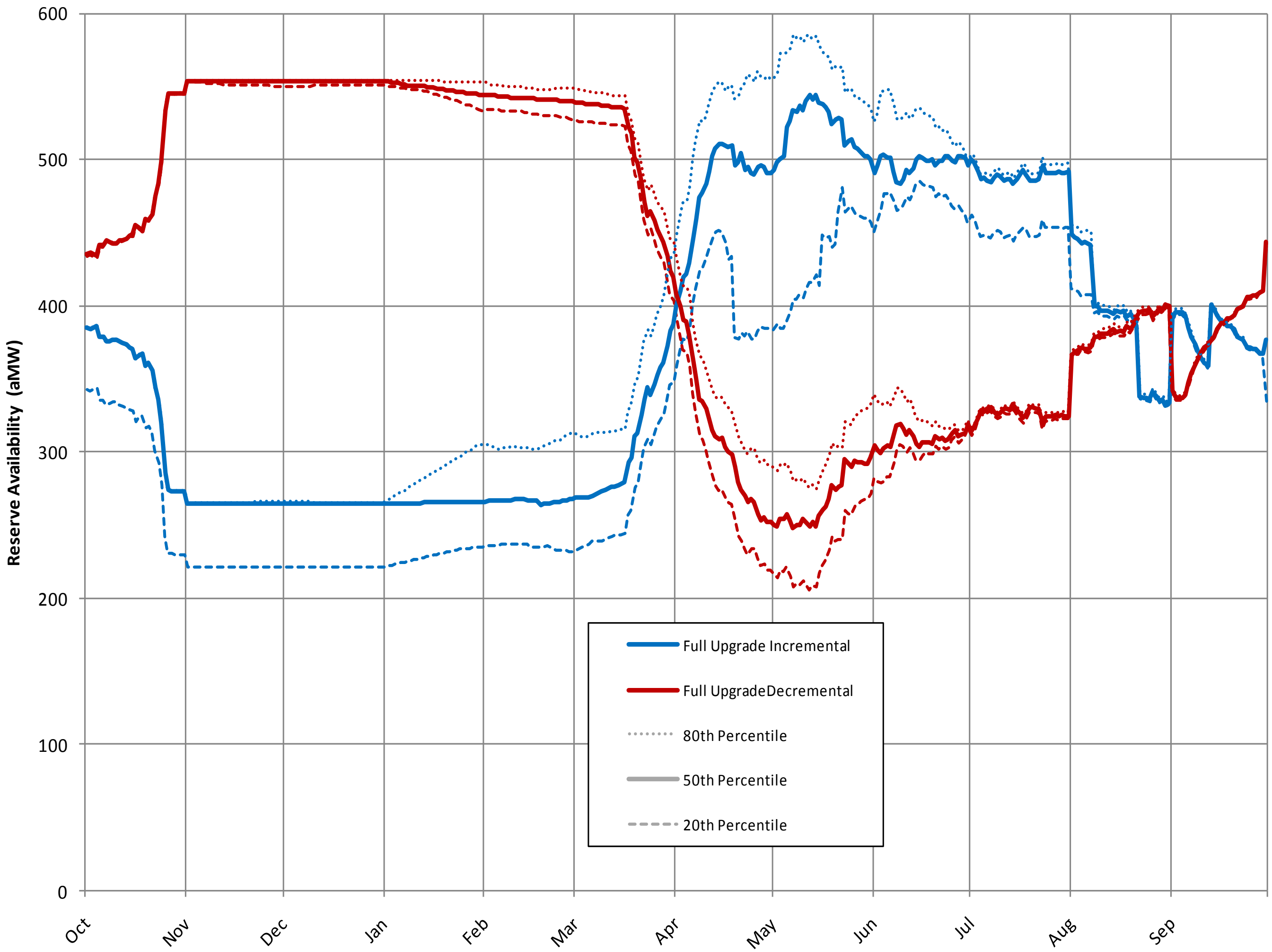
Recommendations from Reclamation's Technical Services Center and HDR Engineering under evaluation are:

- Modernization
  - Excitation
  - Governors
  - Unit Controls and Protection
  - PG Phase Reversal Switches
  - PG Unit Circuit Breakers
  - PG7 & PG8 Wicket Gate Operating Mechanism Improvements
  - Main Step-up Transformer & Transformer Disconnect Switches
  - Station Service Upgrades
  - Miscellaneous Balance-of-Plant refurbishment

Design work on this is about 60% complete

- Upgrade of Pump-Generator Units 7-12
  - Preference is to increase the operating head range of the PG units
  - Secondary goal is to increase Capacity (a 20% increase would result in pumping capacity – 660MW, generating capacity – 360MW)
  - PG7-12 Rewinds
- Decoupling Pumps from Grand Coulee Left Powerhouse

Modernized Keys Inc and Dec Balancing Reserve Capability



Schedule

Spring 2012: NEPA/NHPA Studies Complete

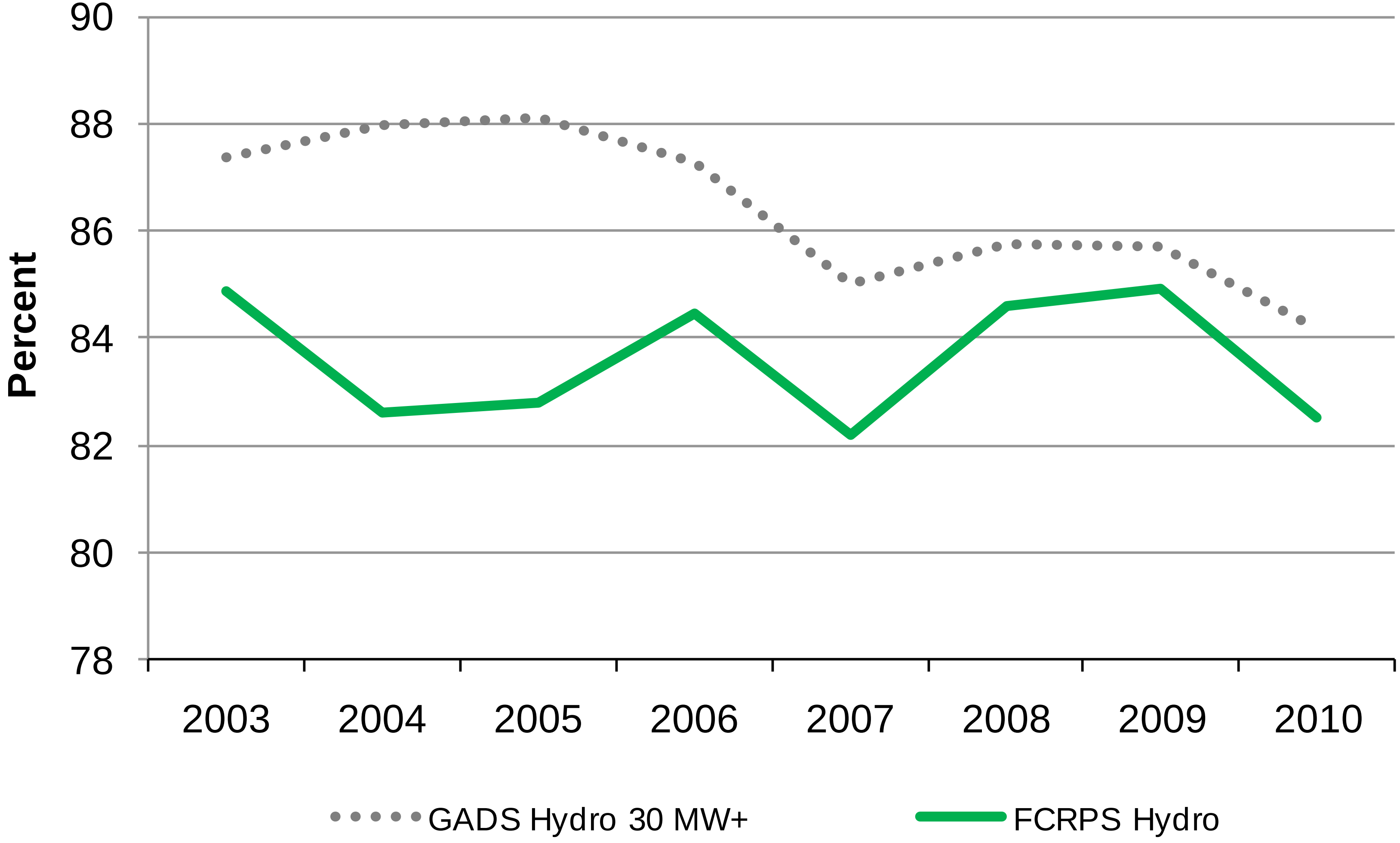
Summer 2012: BPA decision on whether to proceed

Later versions of this strategy will reflect the outcome of these decisions.

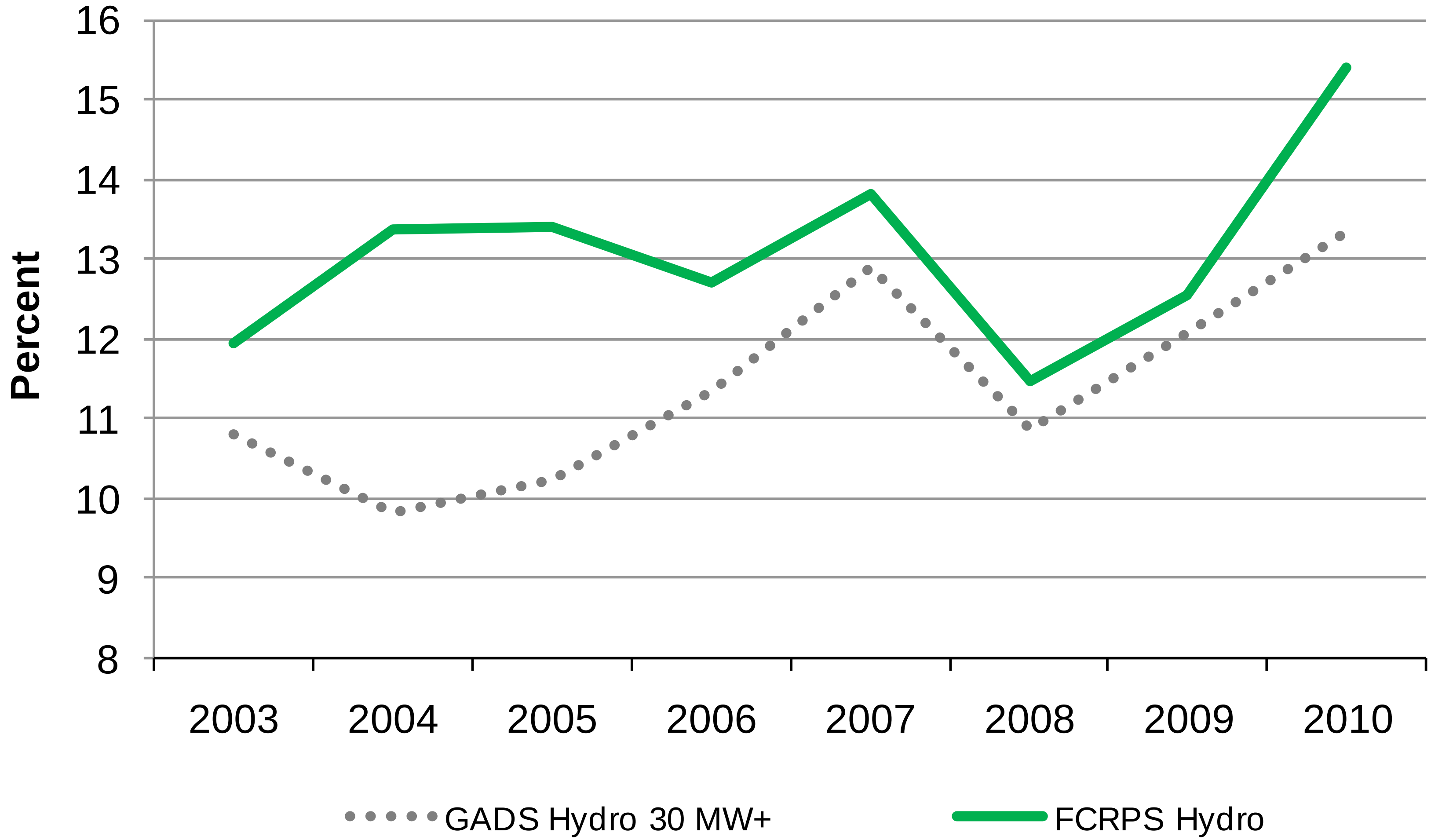
Appendix C

Availability Statistics

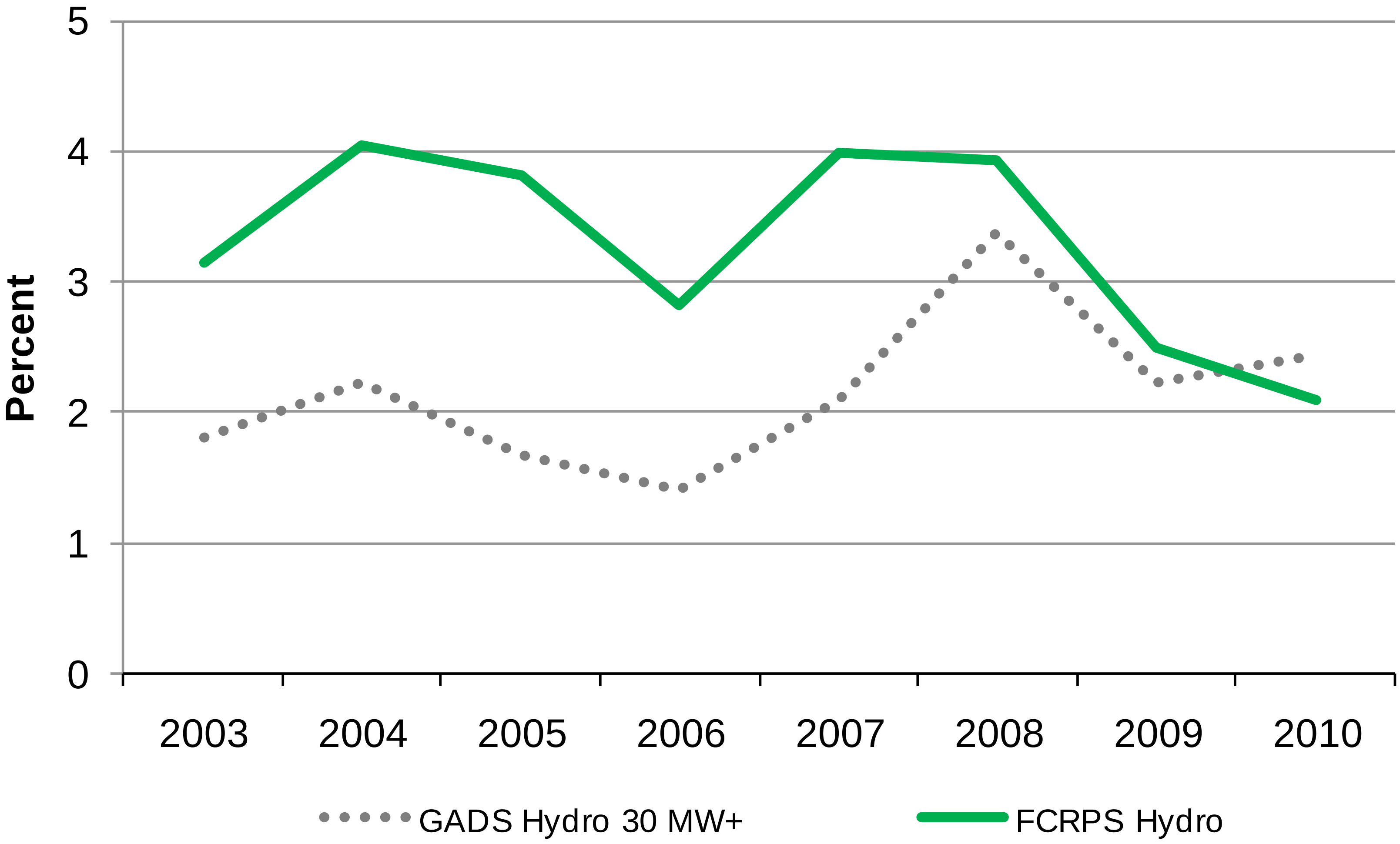
FCRPS Hydro Availability vs. Industry Average



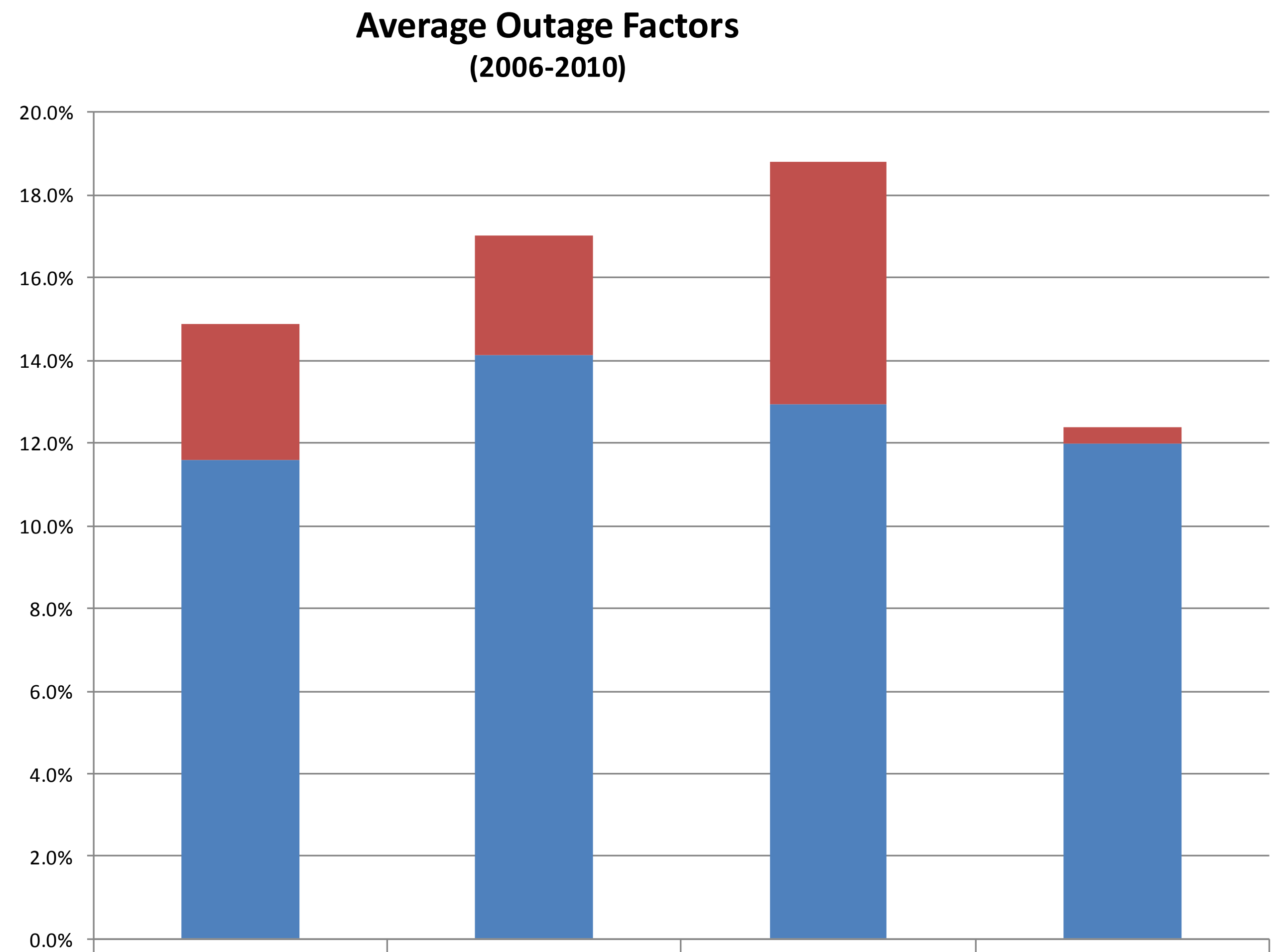
FCRPS Hydro Scheduled Outage Factor vs. Industry Average



FCRPS Hydro Forced Outage Factor vs. Industry Average

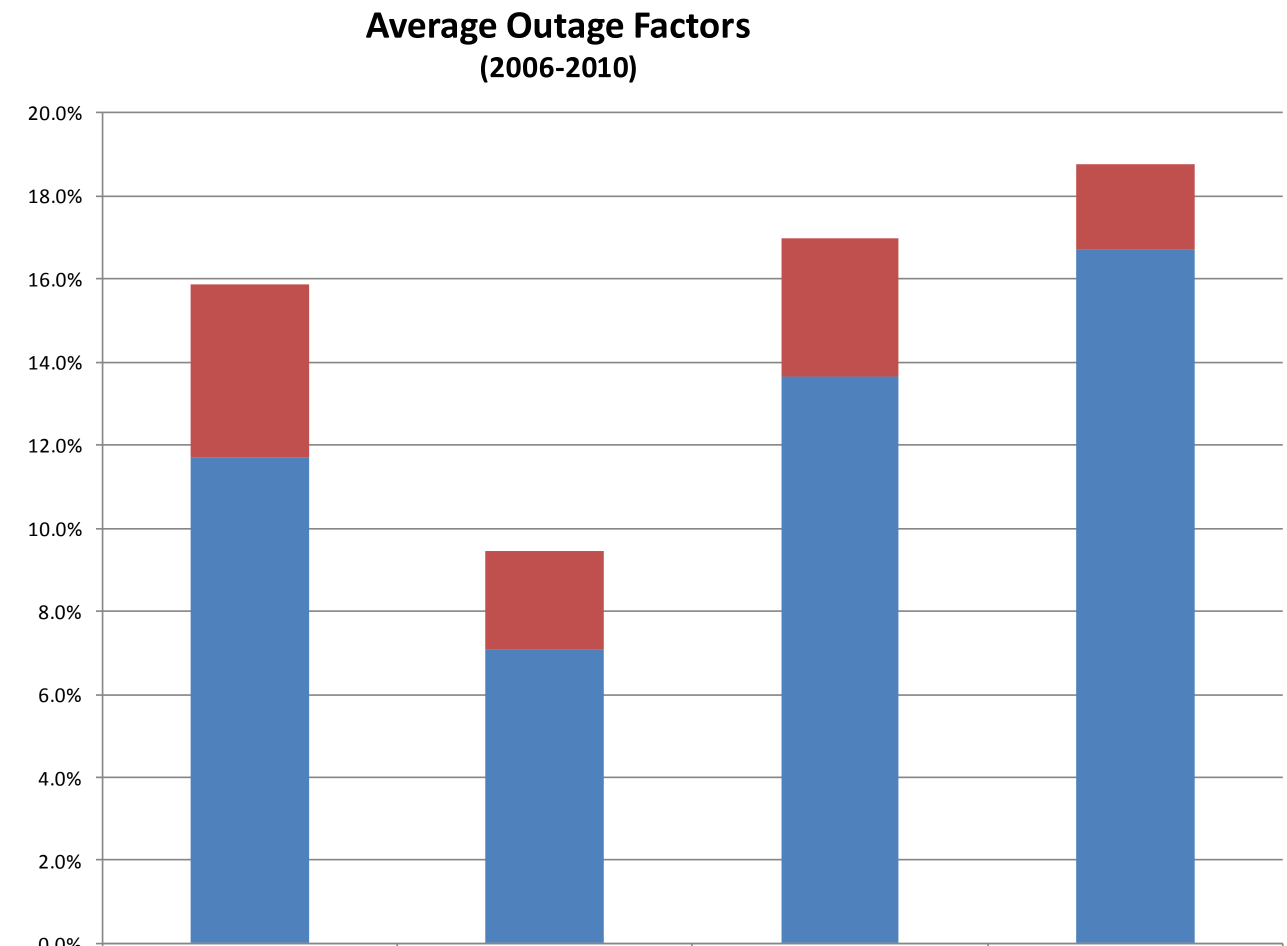


Outage Factors by Strategic Class



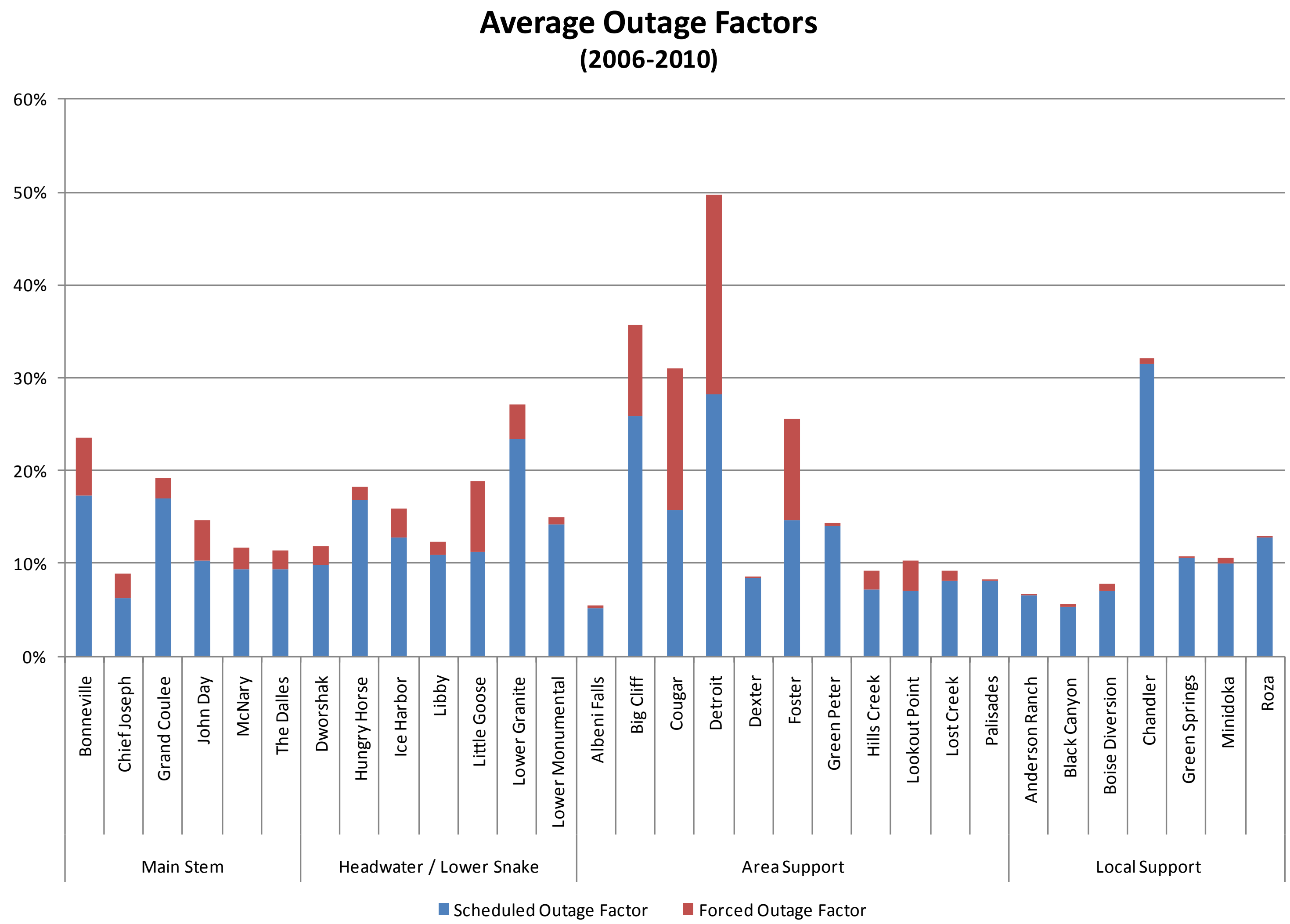
	Main Stem	Headwater / Lower Snake	Area Support	Local Support
Forced Outage Factor	3.3%	2.9%	5.9%	0.4%
Scheduled Outage Factor	11.6%	14.1%	12.9%	12.0%

Outage Factors by District/Region

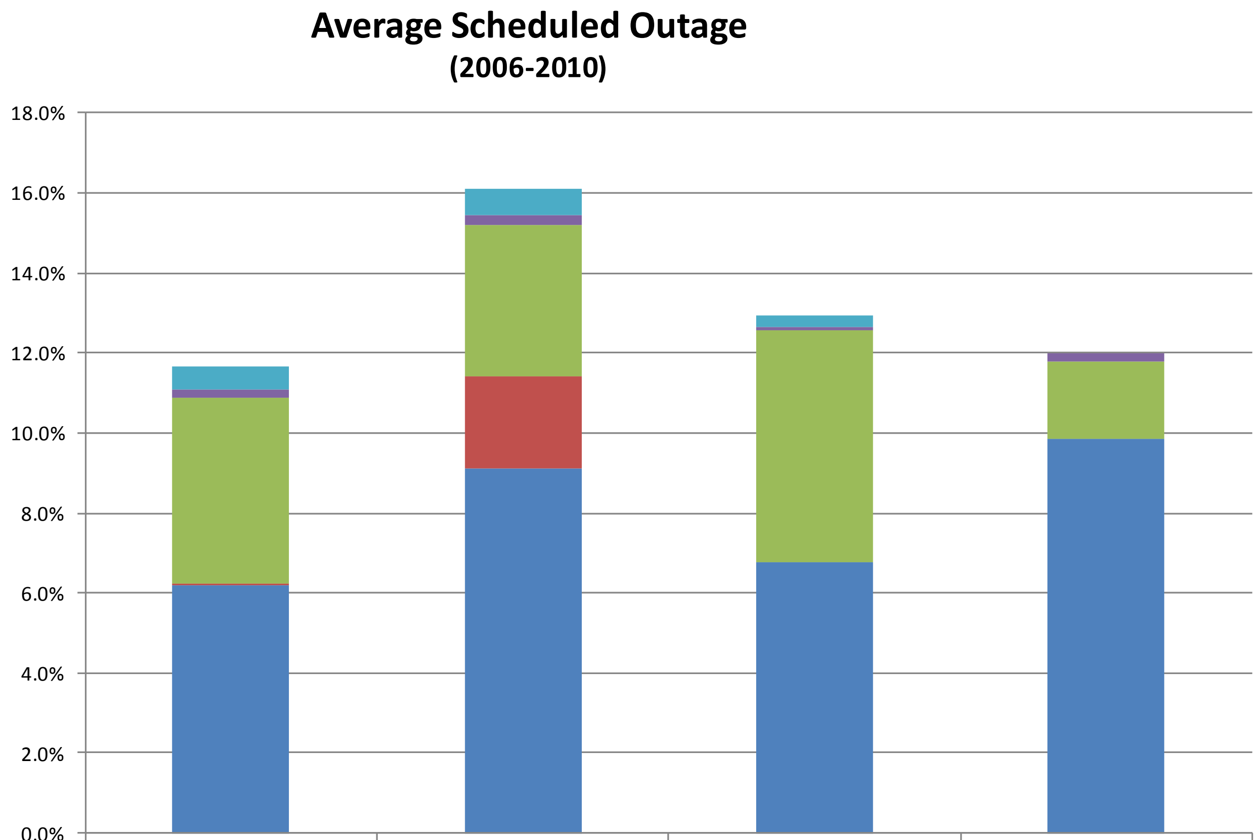


	Portland	Seattle	Walla Walla	Reclamation
Forced Outage Factor	4.2%	2.4%	3.4%	2.1%
Scheduled Outage Factor	11.7%	7.1%	13.6%	16.7%

Outage Factors by Plant



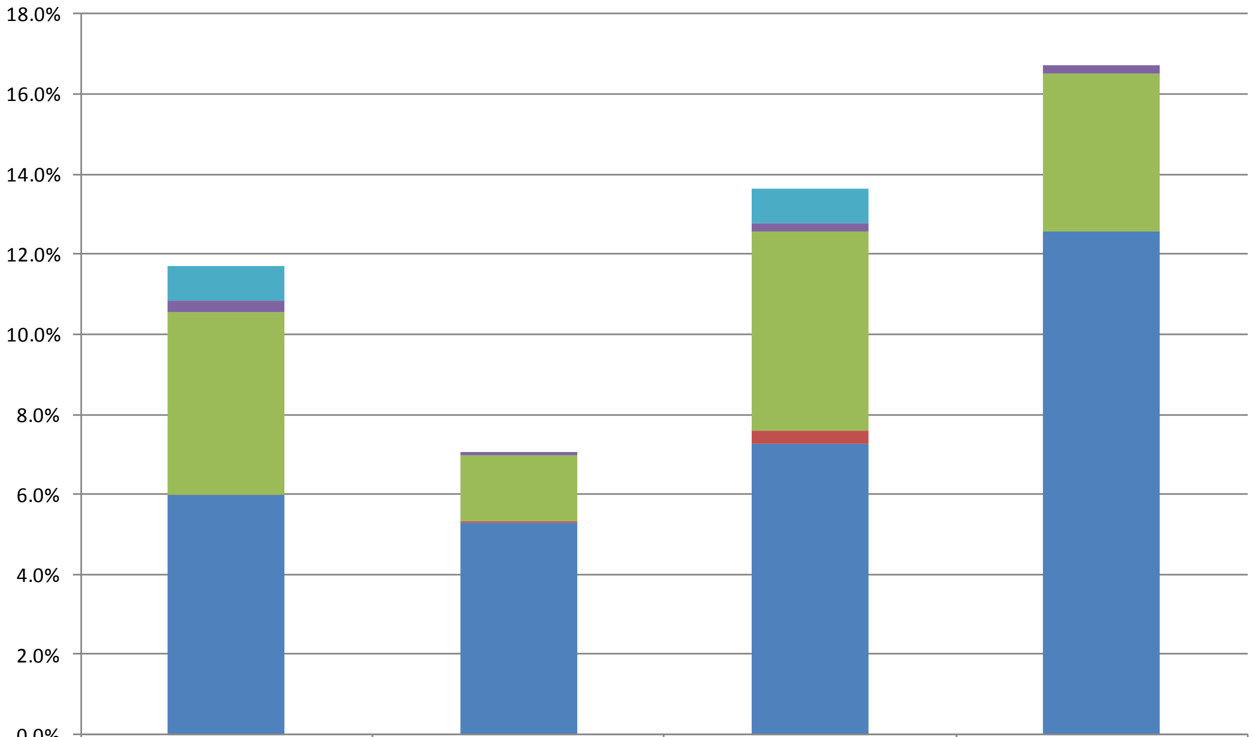
Scheduled Outage Factor by Strategic Class



	Main Stem	Headwater / Lower Snake	Area Support	Local Support
Fish	0.6%	0.6%	0.3%	0.0%
Transmission	0.2%	0.3%	0.1%	0.2%
Capital	4.6%	3.8%	5.8%	1.9%
Non-Routine Maintenance	0.1%	2.3%	0.0%	0.0%
Routine Maintenance	6.2%	9.1%	6.8%	9.9%

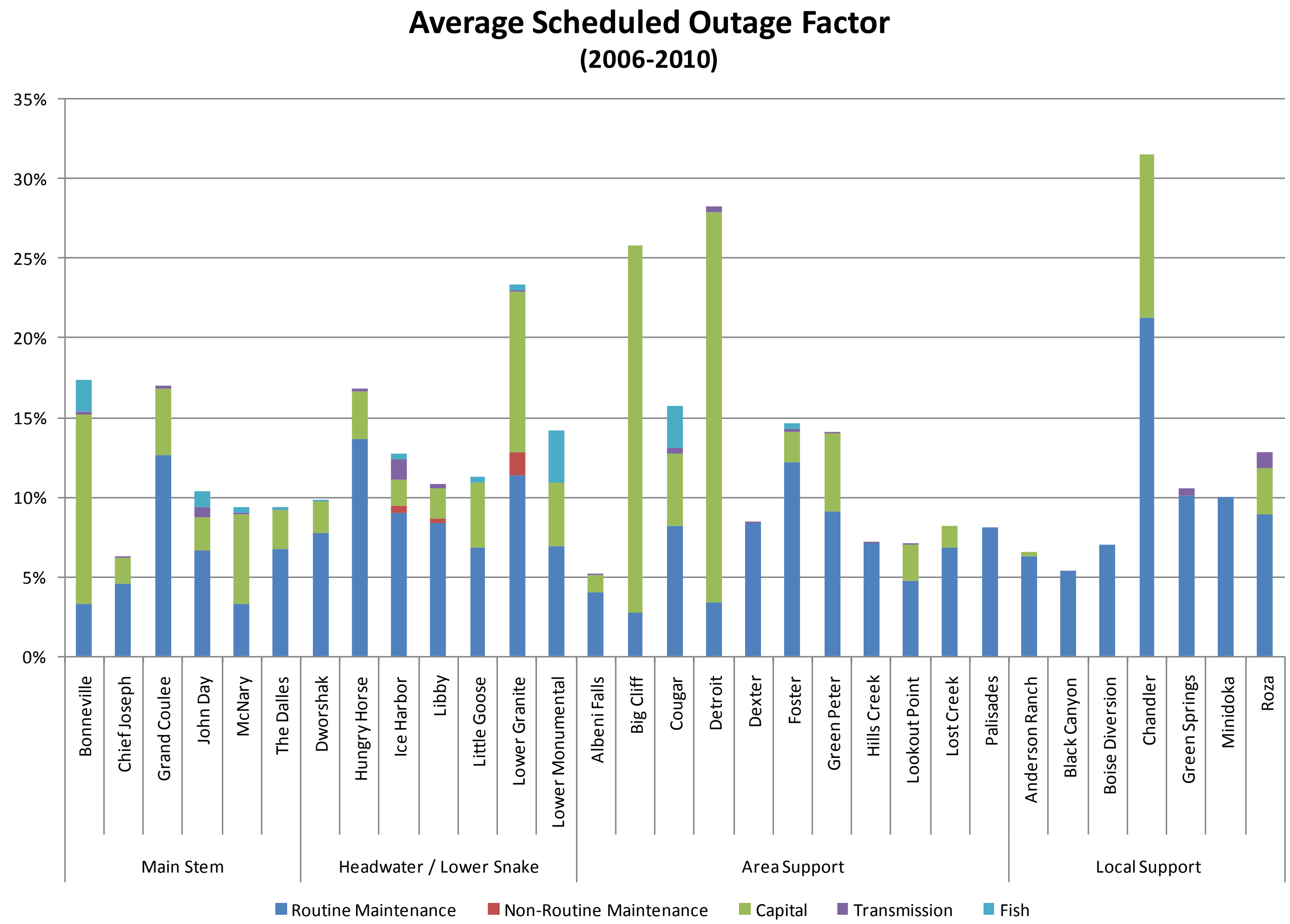
Scheduled Outage Factor by District/Region

Average Scheduled Outage Factor
(2006-2010)



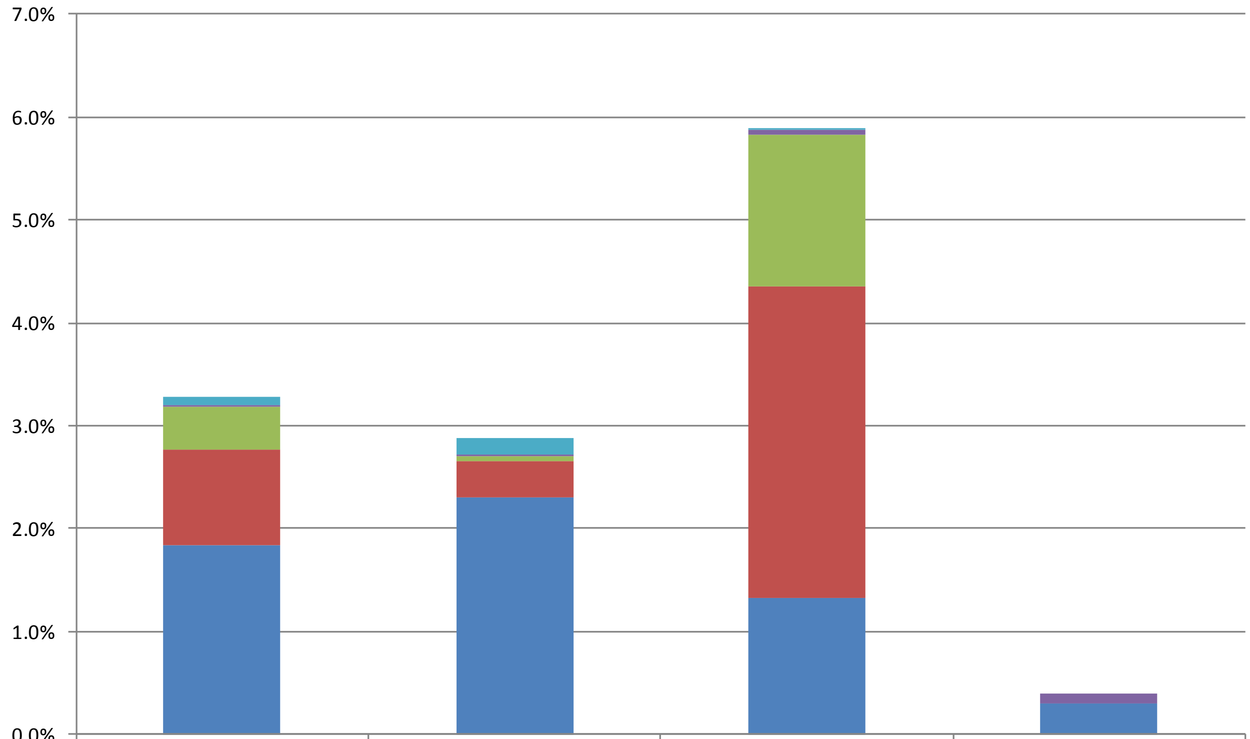
	Portland	Seattle	Walla Walla	Reclamation
Fish	0.9%	0.0%	0.8%	0.0%
Transmission	0.3%	0.1%	0.2%	0.2%
Capital	4.6%	1.7%	5.0%	3.9%
Non-Routine Maintenance	0.0%	0.0%	0.3%	0.0%
Routine Maintenance	6.0%	5.3%	7.3%	12.6%

Scheduled Outage Factor by Plant



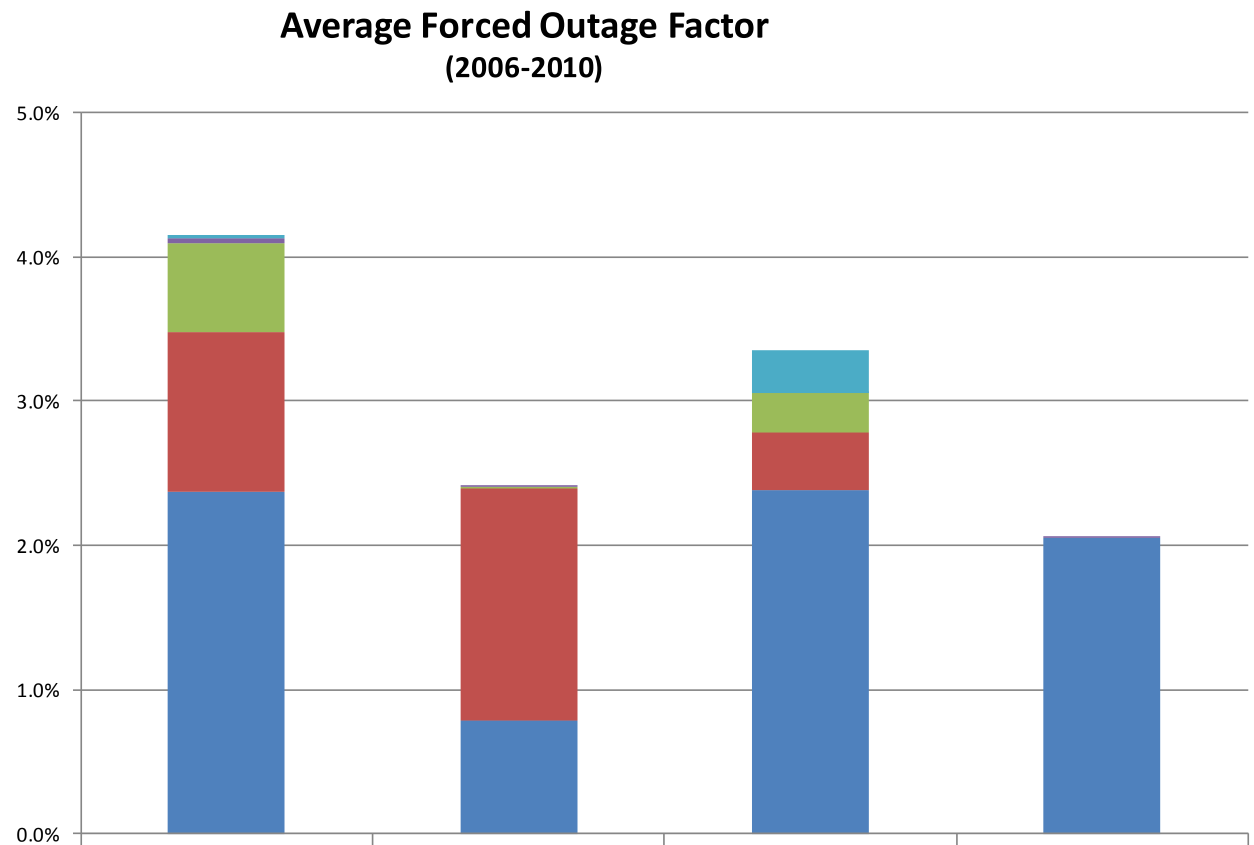
Forced Outage Factor by Strategic Class

Average Forced Outage Factor
(2006-2010)



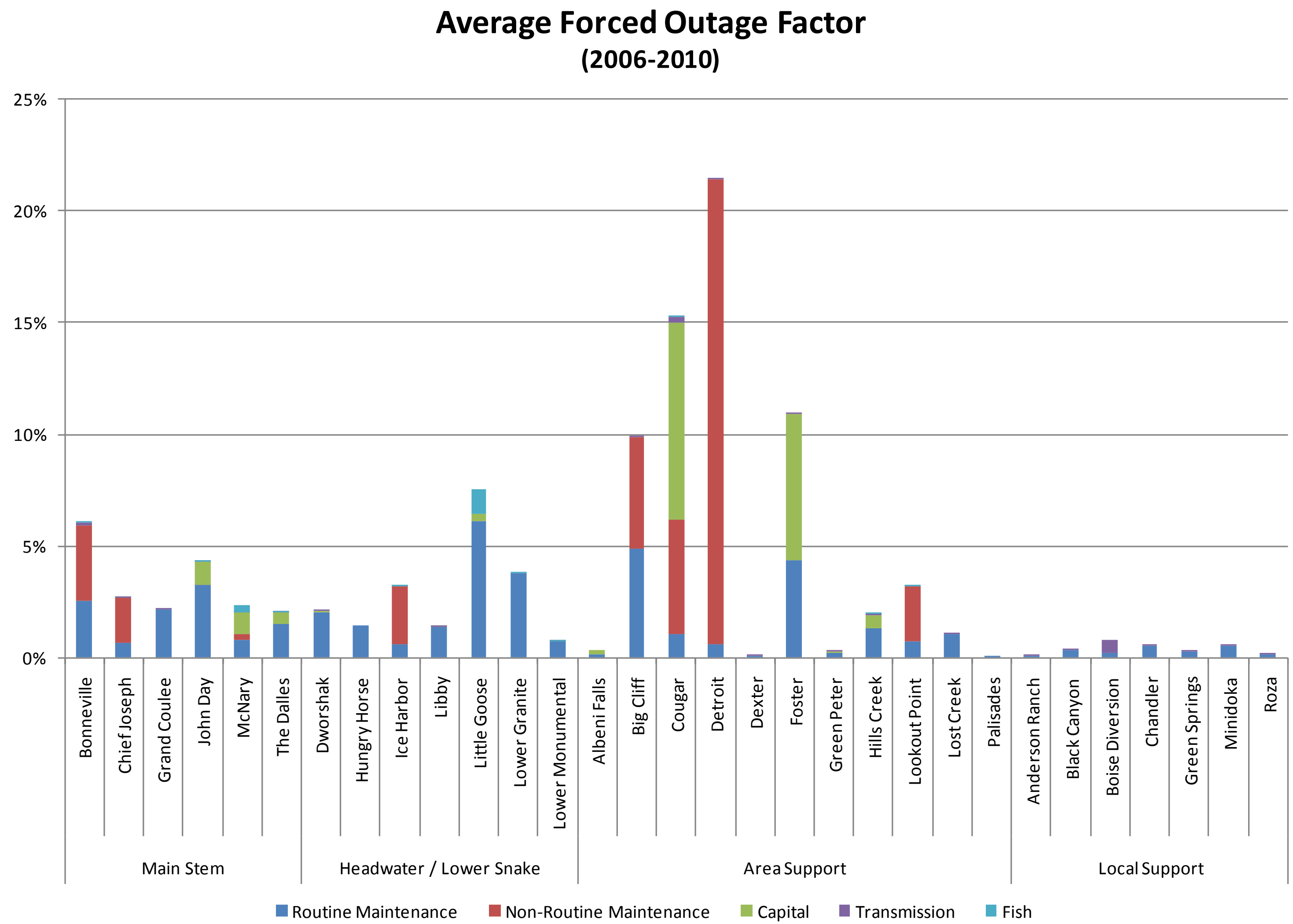
	Main Stem	Headwater / Lower Snake	Area Support	Local Support
Fish	0.1%	0.2%	0.0%	0.0%
Transmission	0.0%	0.0%	0.1%	0.1%
Capital	0.4%	0.0%	1.5%	0.0%
Non-Routine Maintenance	0.9%	0.4%	3.0%	0.0%
Routine Maintenance	1.8%	2.3%	1.3%	0.3%

Forced Outage Factor by District/Region



	Portland	Seattle	Walla Walla	Reclamation
Fish	0.0%	0.0%	0.3%	0.0%
Transmission	0.0%	0.0%	0.0%	0.0%
Capital	0.6%	0.0%	0.3%	0.0%
Non-Routine Maintenance	1.1%	1.6%	0.4%	0.0%
Routine Maintenance	2.4%	0.8%	2.4%	2.0%

Forced Outage Factor by Plant



Appendix D

Optimum Timing for Equipment Replacement

Least Cost Planning

The strategy takes a least-cost approach to determining the timing of future equipment replacement decisions. The approach is consistent with the Regional Power Act, BPA's asset management policy, and BPA's Climate Change Action Plan.

Costs Evaluated in the Strategy

Equipment Replacement Cost – Forecasted replacement costs were developed for 50 equipment types (turbine runner, transformer, etc.) by the Corps' Hydroelectric Design Center, the organization responsible for developing government estimates for procurement of Corps hydroelectric equipment. For each equipment type, cost estimates include a fixed cost component, which is the same for all equipment of that type, and a variable cost component, which is dependent on parameters related to the size and complexity of the equipment, i.e., shaft diameter, MVa rating, etc.

Incremental Equipment Failure Cost – When equipment fails, costs to repair or replace it are typically incrementally higher due to collateral damage and to planning, procurement and scheduling inefficiencies. Incremental failure costs are specific to each equipment type, expressed as a percentage of replacement cost when done on a planned basis.

Replacement Power Cost – For the asset strategy, Federal Hydro Projects used hydro regulation studies to determine the amount of generation produced by each plant on the system assuming each generating unit is available 90 percent of the time (somewhat high for the FCRPS based on recent history, but in line with industry averages and a reasonable steady-state level for a reliable plant). Generation amounts were calculated for HLH and LLH periods by month for 50 water years. Next, hydro regulation studies were run at lower levels of unit availability to determine the amount of generation that would be produced if the plants were less reliable. The difference between modeling runs produces the incremental generation from an increment of plant availability. For the strategy, the incremental generation produced by the "least used" unit (marginal unit) was calculated for each plant on the system. This is the amount of generation that is deemed to be at risk in the event of equipment failure. Although a distinct possibility, particularly for plants with many generating units or low reliability, no consideration was given to multiple and simultaneous equipment failures that would take more than one unit out of service and have increasingly higher lost generation consequences.

When equipment fails and takes a generating unit out of service, repairing and replacing the equipment typically takes longer than if work is done on a proactive, planned basis. For instance, a transformer can take three or more years to procure and, absent having a spare available, a failure would take a generating unit (or multiple units) out of service for

Costs Evaluated in the Strategy

three years or longer. Replacing a transformer on a planned basis typically requires an outage of three months or less. So, the incremental outage duration for a failed transformer can be 2.75 years if no spare is available (we assumed 1.5 years in the strategy). Other equipment types have much shorter incremental outage durations.

The annual generation at risk for the marginal unit at each plant is then multiplied by the expected additional outage in years for each equipment type to determine the amount of lost generation if that equipment fails. The lost generation is valued at BPA's rate case long-term forward price forecast to determine a replacement power cost (or lost secondary market opportunity) for the equipment failure.

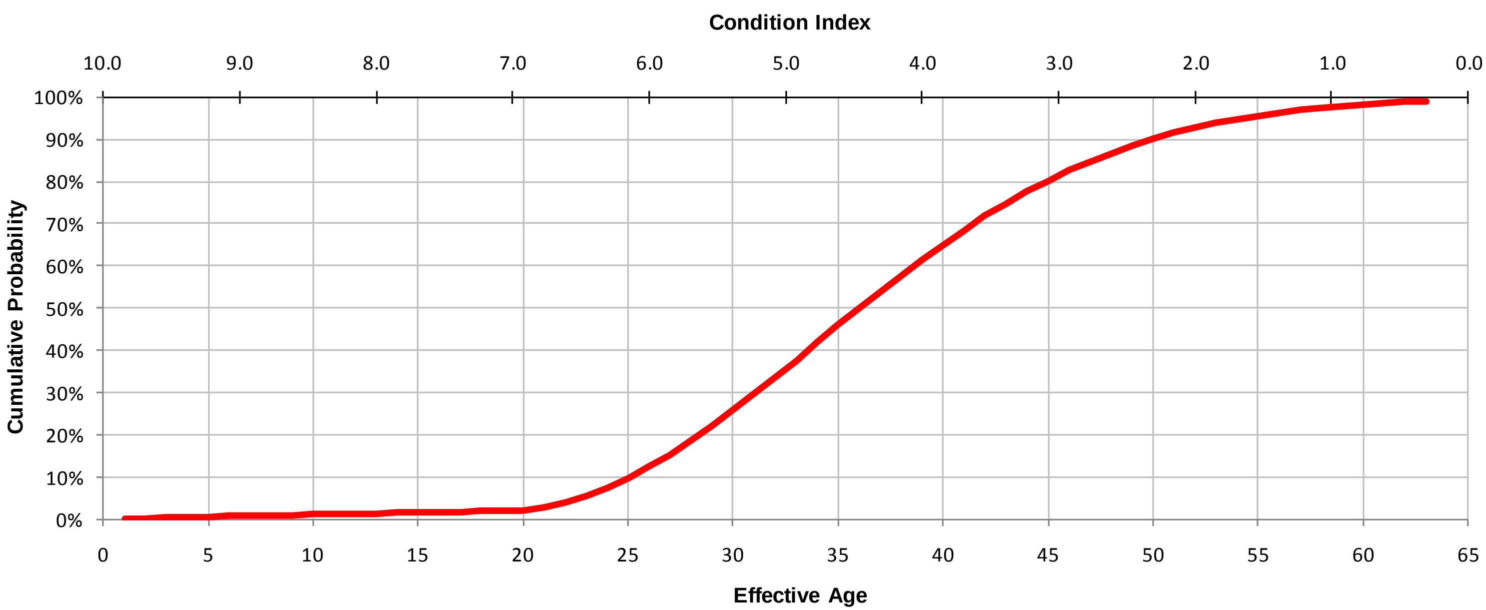
CO2 Cost – BPA's Climate Change Action Plan requires hydro investment decisions to include greenhouse gas avoidance benefits in asset planning analyses and business cases for proposed capital and major expense sub-agreements. Guidance from BPA Corporate Strategy is to use CO2 costs from the Power Council's 6th Power Plan for determining that value. The plan's 20-year levelized cost of CO2 emissions is $41 per ton (2012 dollars). This cost is multiplied by the CO2 emissions generated by a combined cycle natural gas plant (0.37 tons per MWh) – the resource that would be used to offset losses in hydro generation – to determined the avoided CO2 cost for maintaining hydro plant reliability.

For the strategy analysis, only equipment replacement costs are deterministic. Other costs are probability-based, derived from information about equipment condition that is correlated to a likelihood of failure.

Equipment Condition and its Relationship to Risk

The strategy analysis uses hydroAMP to assess condition of power train and some other hydro equipment. Developed by the Corps, Reclamation, BPA and Hydro Quebec, hydroAMP uses a set of condition indicators describing operational performance, maintenance history, physical inspection, age, and specialized testing results to derive a condition index for equipment. The condition index scale ranges from zero (Poor condition) to 10 (Good condition). For equipment not covered by hydroAMP, a simplified condition assessment tool was built based on the hydroAMP methodology.

A regression analysis was performed on the hydroAMP database to establish a correlation between a condition index and equipment "effective age". The results were then used to map the hydroAMP condition index and effective age to a survivor curve for that equipment. Survivor curves are derived from industry data and show the relationship between equipment age and the percentage of the equipment population that has failed or been retired. Mapping the hydroAMP results to the survivor curve yields a failure probability for equipment with a certain condition index and effective age.



Equipment Condition and its Relationship to Risk

Risk is a function of the probability of failure as condition degrades over time. For the strategy, four types of risk were calculated in incremental time steps:

Safety Risk, where equipment failure has a relatively high probability of causing permanent disabilities or multiple fatalities;

Environmental Risk, where equipment failure has a relatively high probability of causing detrimental or catastrophic environmental impacts;

Direct Cost Risk, which is the Incremental Equipment Failure Cost identified above multiplied by the incremental probability of failure over time; and,

Lost Generation Risk, which is the sum of Replacement Power Cost and CO_2 Cost multiplied by the incremental probability of failure.

The sum of Direct Cost Risk and Lost Generation Risk are hereafter described as financial risk.

Optimum Timing for Equipment Replacement

To determine the optimum timing for replacement, each equipment component is evaluated in yearly time steps over 20 years. 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 on the next page.

Total Cost of Replacement at Different Points in Time

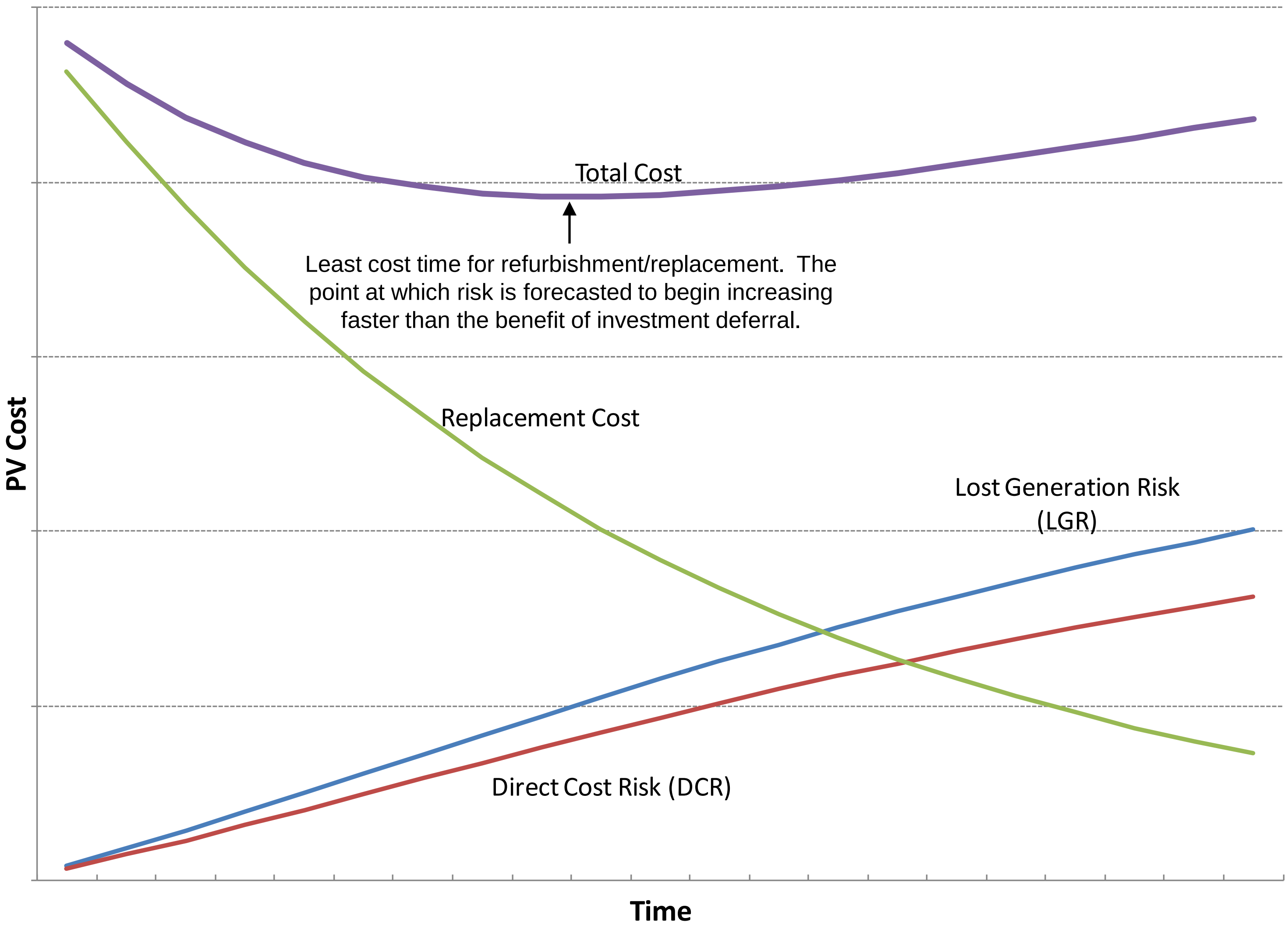
The optimum time to plan on equipment replacement is at the low point (cost minimum) of the Total Cost curve. The cost minimum is the point in time at which financial risk costs begin growing faster than the benefit of deferring the investment. Up until that time the value of investment deferral is greater than the expected increase in financial risk costs, so it makes financial sense to continue deferring equipment replacement. This objective function is applied to each of the 5,500 equipment components included in the strategy to derive an investment plan.

Running the model without funding constraints generates the "least-cost case". Under this scenario, equipment replacements for projects that are already underway are funded as planned. Potential new investments are then selected for refurbishment/replacement if they meet either of the following criteria:

- First, if condition places the equipment into a safety or environmental high risk category; or,
- Secondly, if financial risk costs are increasing faster than the investment deferral benefit, i.e., the equipment has reached the cost minimum.

The model can also be run to limit annual funding availability to any level desired. For these cases, once an annual funding limitation is reached, investment in equipment in which financial risk is increasing the least is deferred until the following year, where it is then re-evaluated using the same prioritization logic. As funding levels are increasingly constrained, more new investments are deferred past their cost minimum which causes the Total Cost to increase accordingly.

Optimum Timing for Equipment Replacement

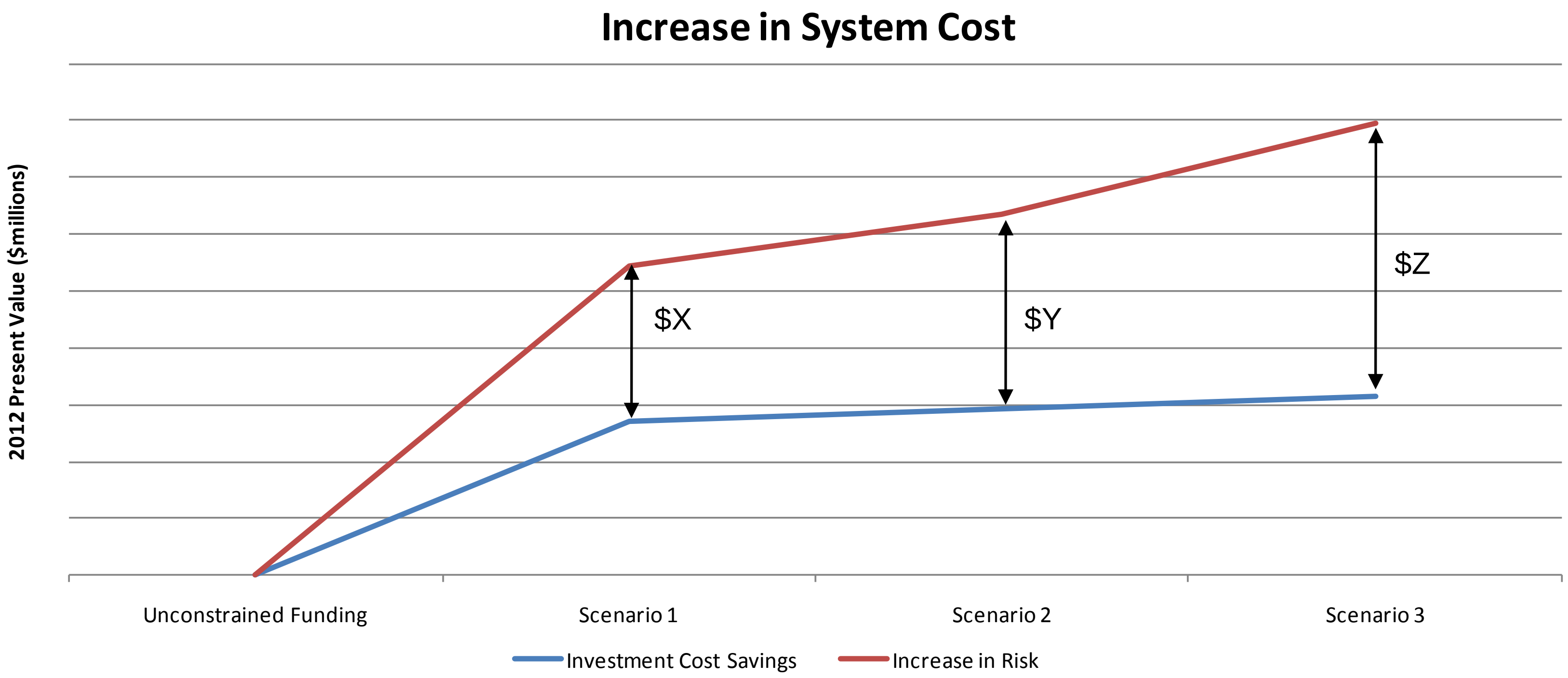


Net Present Value

Calculation of Net Present Value

The Total Cost for the system increases when a funding constraint causes new investments to be pushed out past the cost minima. The present value of investment costs is reduced, but risk increases by a larger amount. The Total Cost difference between various funding availability scenarios and an unconstrained funding alternative yields the increase in system cost.

The net present value of each scenario is the negative of the increase in system cost, i.e., the Total Cost of unconstrained funding minus the Total Cost of a constrained funding scenario.



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