Energy Northwest Briefing
Integrated Program Review

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July 18, 2012

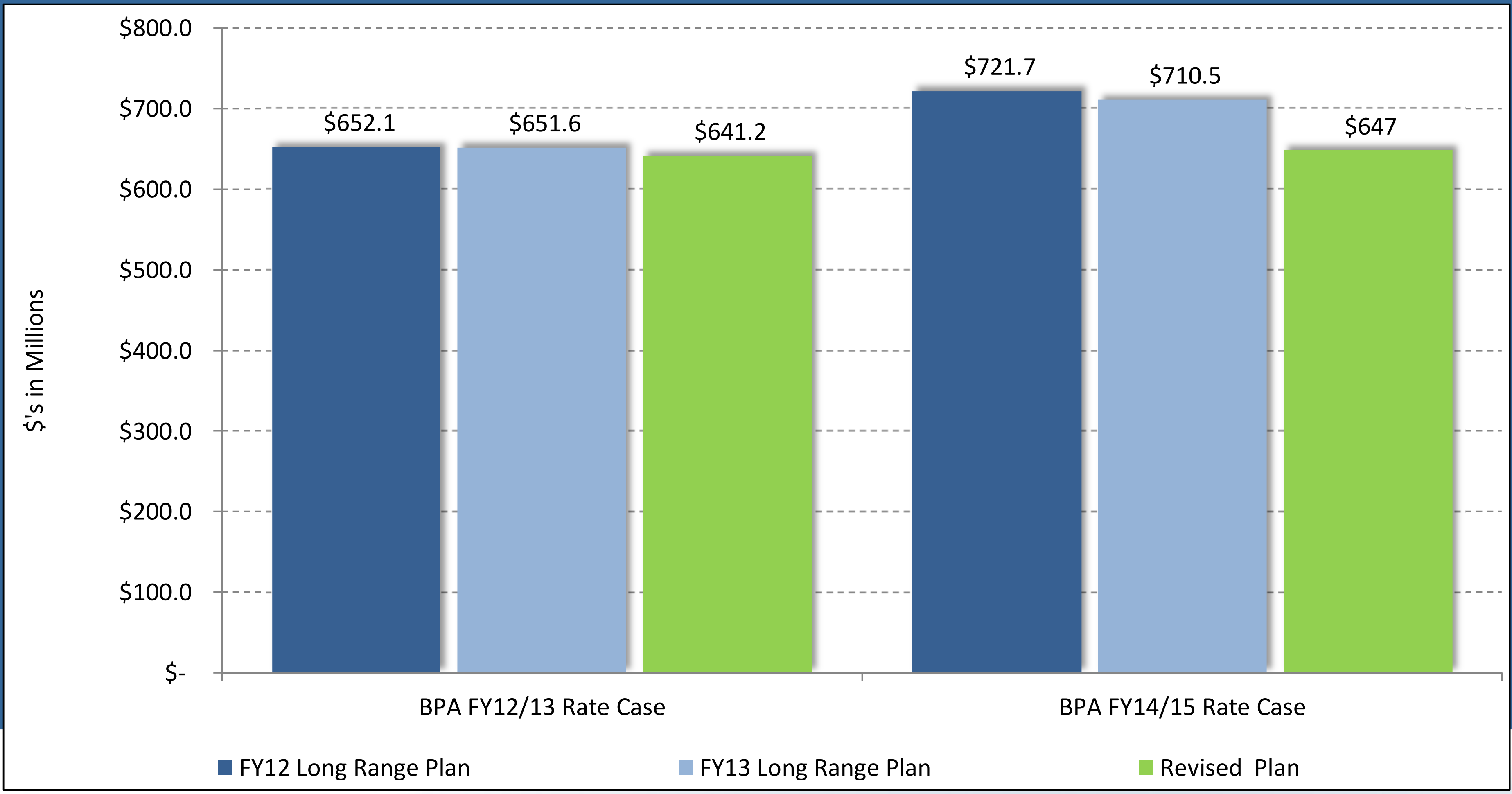
Agenda

1. Introduction
2. Project Planning Process
3. Long Range Plan (LRP)
4. Rate Case Overview

Introduction

- IPR Budget Overview
- Columbia License Extension
- Fuel Tails Purchase
- Maintenance Outage
- Early Refueling Outage 21 Station Focus

Columbia Changes to IPR



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How do we get there?

- FY12/13 – reduce decommissioning fund contribution by $10.4 million (license extension)
- FY14/15
  - Fuel reduced by $40.9m (tails purchase)
  - Decommissioning fund contribution reduced by $22.5 million (license extension)

Other Opportunities & Issues

- Debt restructuring could significantly reduce Columbia's debt in FY14/15.
- Recall that last year's restructuring reduced Columbia's debt by ~ $200m.
- Additional capital financing required for the condenser settlement.

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Project Planning Process

Jim Gaston, Business Planning Manager

Purpose of the Project Proposal & Funding Authorization Process

Note: Process is industry Standard

Establish discipline, control, and accountability surrounding the development, review, prioritization, and authorization of project proposals.

The Project Budget

- Projects are a very important part of the CGS budget
- To create an accurate Fiscal year budget and Long Range Plan, many hours must go into evaluating and determining the projects to focus on
- The approval process is a systematic approach WE use to make sure it is complete and accurate

Columbia's Budget & Long Range Plan

- Each year a Fiscal Year (FY) budget and LRP are submitted for approval to the Executive Board and the non-disapproval of BPA
  - The LRP approval is for budget not scope
  - The LRP is a dynamic document that provides a snapshot of what projects we believe today we will be working over the next 10 years and the budgets required (incorporated in a detailed Long Range Planning database)

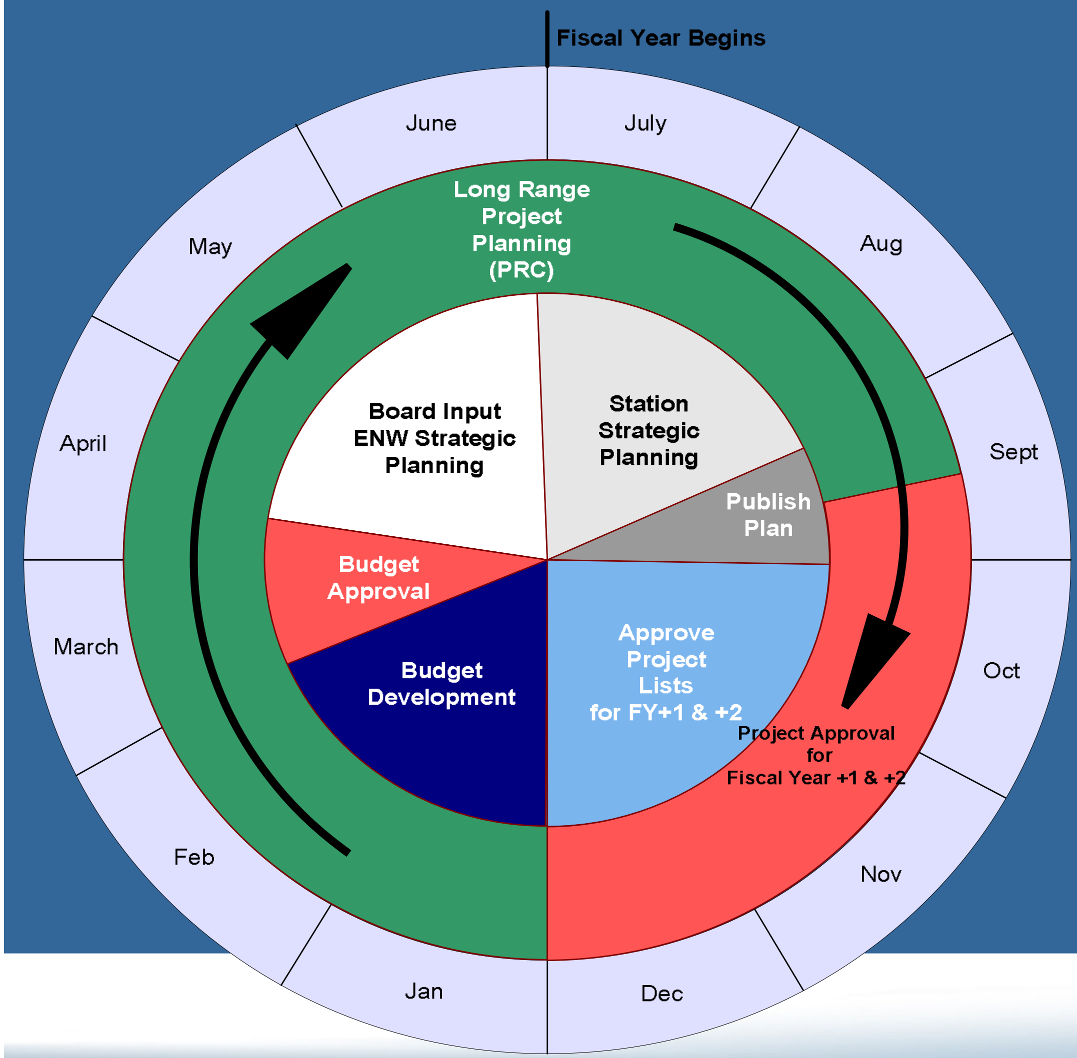
Dealing with Constraints

Budget Constraints:

- Fiscal Year (no rolling over budget to next year)
- Operation and Maintenance Costs
- Capital Costs
- Outage Costs
- Other Resources

As we deal with all of our constraints, you can see why it is very important that we are as accurate as possible to be efficient with the resources we have.

Budget/Planning Cycle



- Projects are approved and placed on the project list for the next fiscal year by September of the prior year. (9 months in advance)
- Projects are identified and taken through this process up to 3 years in advance of work performed
- Mitigation strategies are important to develop so there is ample time to PLAN for success.

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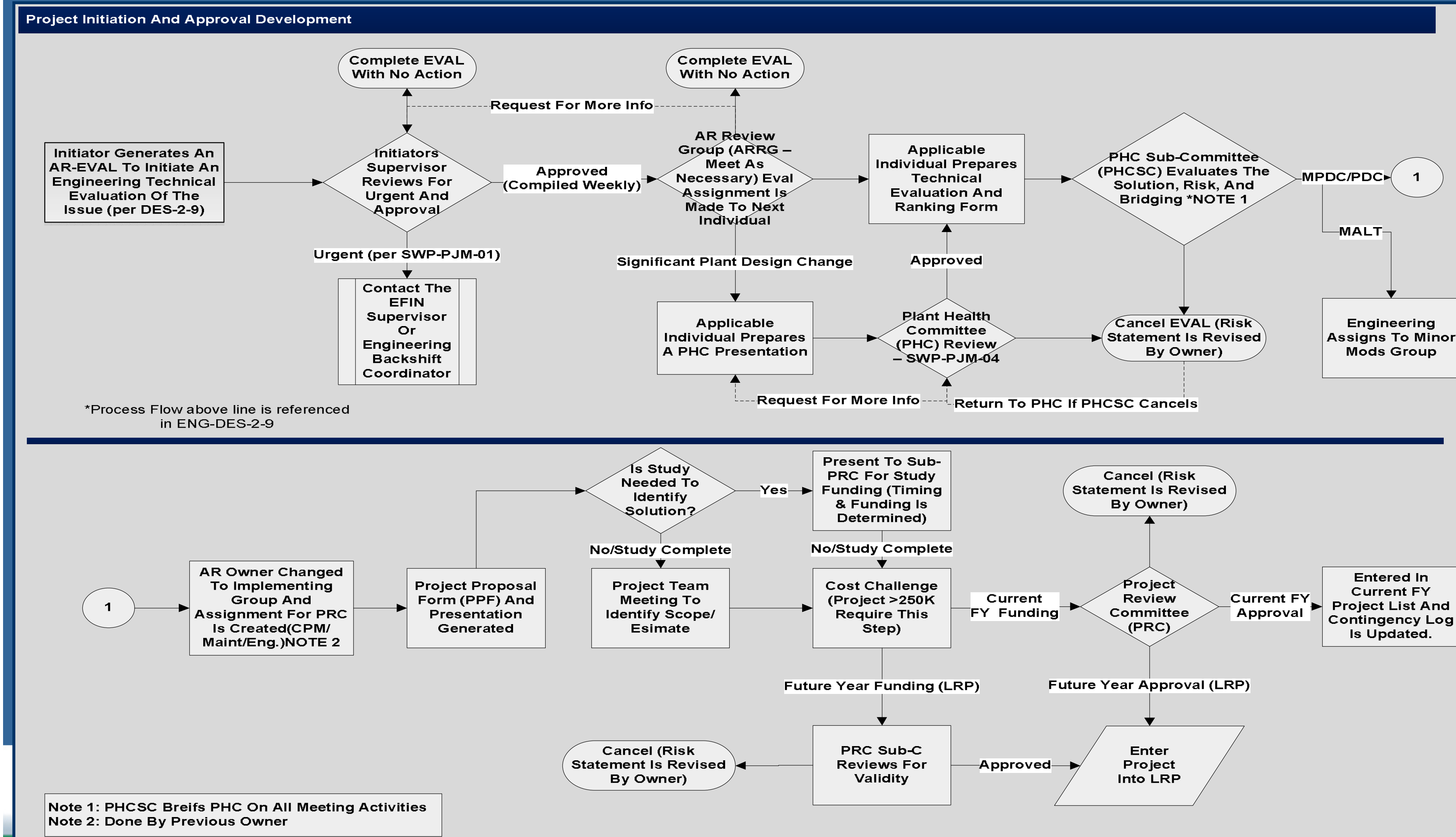
Project Selection

Projects are selected based on criteria of the plant:

- Ranking
- Budget Constraints
- Regulatory Mandates
- Cost Benefit/Analysis
- Other resources (time, engineering, contractors)
  - Plant management operates under many constraints that have to be considered in the approval process

How projects get on the LRP



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Project Approval Process

- Issue can be identified by any EN employee
- Issue needs approval by Supervisor/Initial Review Group/PHC/PRC/EAC.
- There are technical evaluations, cost challenge and fiscal year challenges before any project is placed on LRP.

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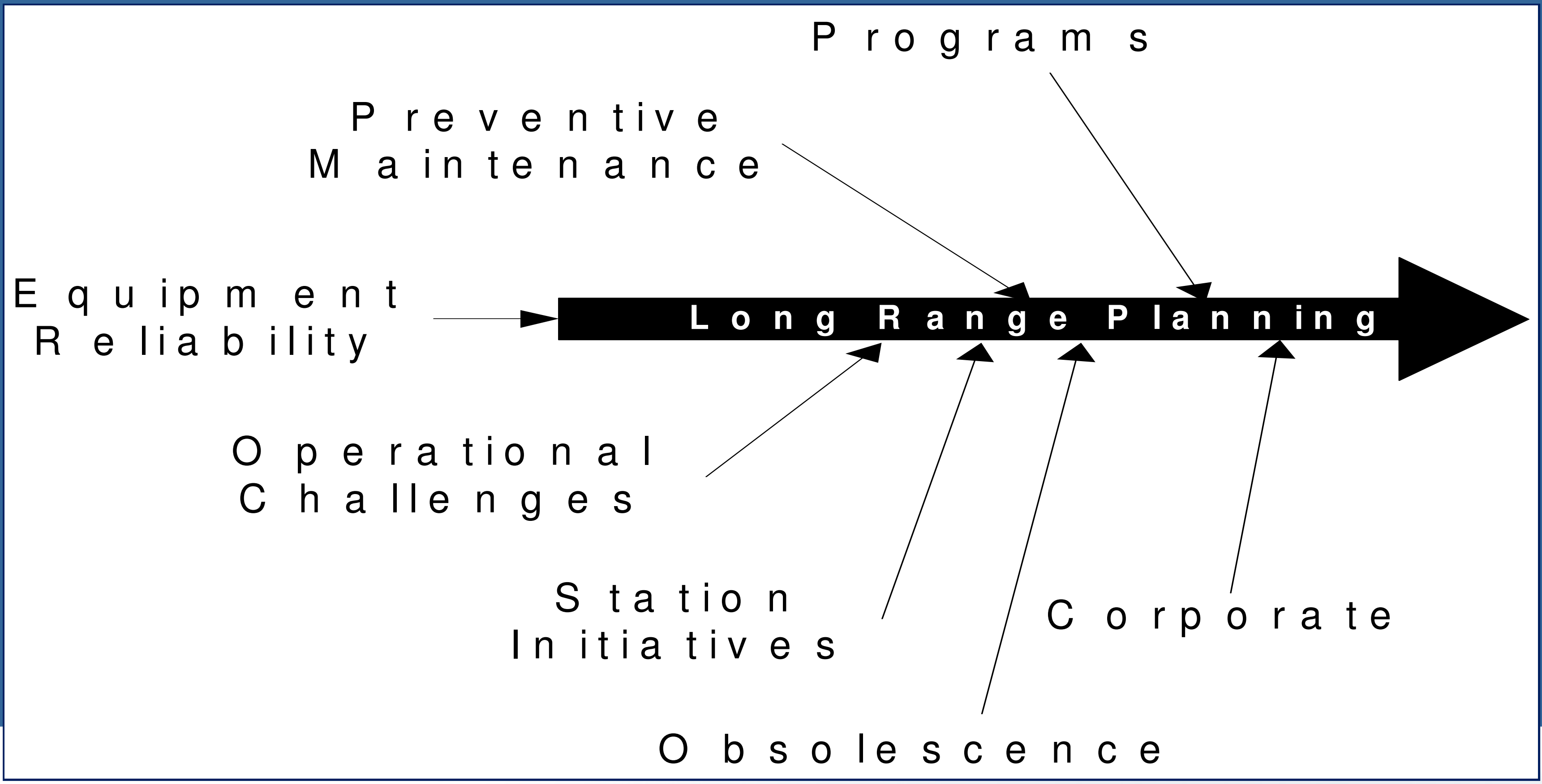
Executive Authorization Committee (EAC)

- Approves all projects > $250k
- Approves all projects that exceed PRC approval authorization
- Final approval of initial FY project list
- Approves all project deferrals
- Approves all use of contingency dollars

BPA Review of Projects

- All projects over $500k – BPA review is required.

Long Range Plan projects are based on input from all organizations



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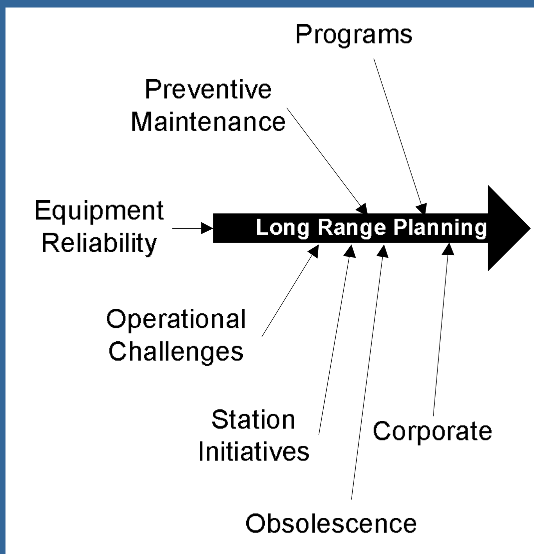
The 3 Phases of a Project

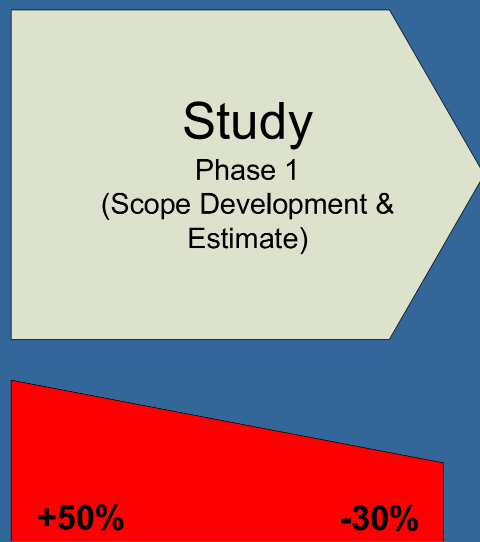
PHASE 1: STUDY

PHASE 2: DESIGN

PHASE 3: IMPLEMENTATION

Phase 1: Planning





Cost Estimate Confidence Level

Project rough estimates for long range planning purposes should be made for the **TOTAL project cost**

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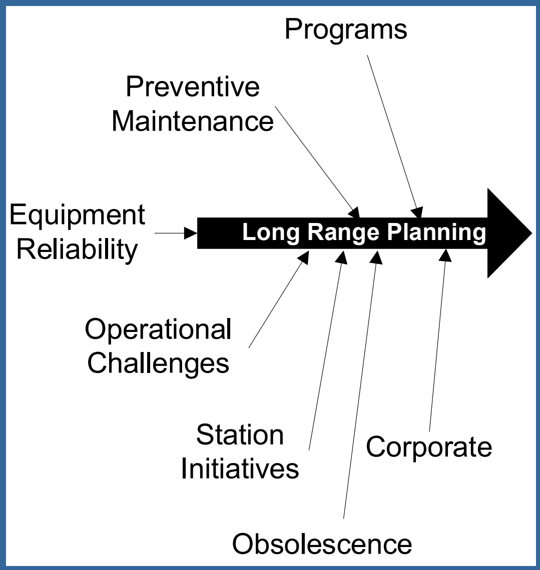
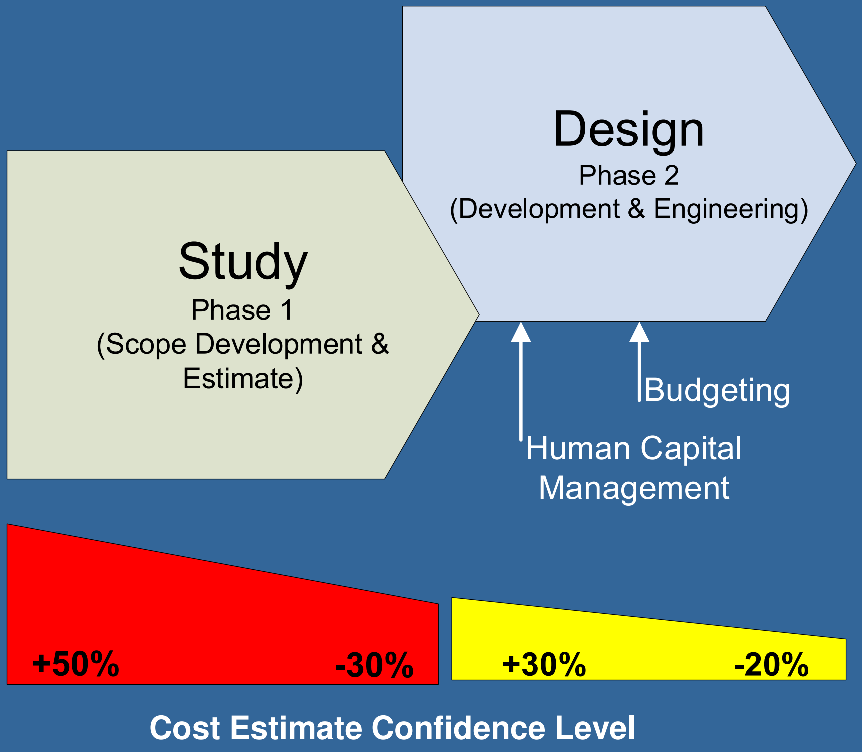
Phase 2, Design





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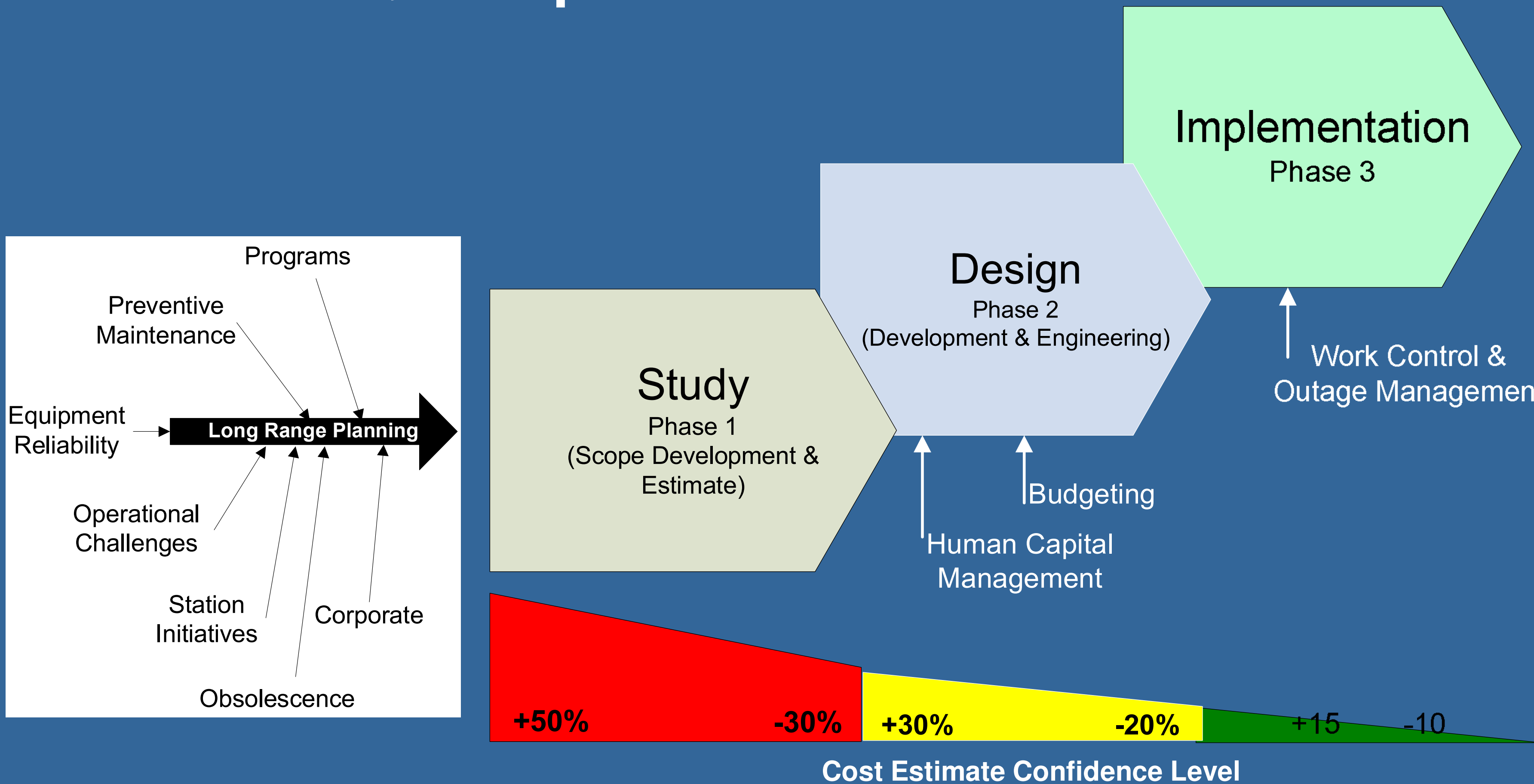
Phase 3, Implementation



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Long Range Plan

Jim Gaston, Business Planning Manager

Long Range Plan - Objective

The CGS Long Range Plan (LRP) will identify and levelize resource requirements to maintain Columbia safety and reliability over a ten year planning horizon.

Long Range Plan - Methodology

- Updated Annually - Rolling 10-Year Forecast
- Potential Needs are Evaluated:
  - AR-EVAL, Technical Evaluation, Priority Ranking Matrix
  - Design Sub-Committee (DSC) screens for need, technical justification, rank, and timing. Approves, Cancels, or RFI
  - DSC assigns to Project Owner; Project Owner develops Project Proposal Form (PPF); Rough Order of Magnitude (ROM) estimate developed
  - Project Review Committee (PRC), reviews PPF presentations; approves for entry to LRP; defines timing; may cancel
- PRC Approved Projects are entered into the LRP
- Projects are “levelized" to available budgets by rank and or Management Discretion
- LRP process is proceduralized (SWP-PJM-01, 02)

Long Range Plan - Assumptions

- Reduction of 106 positions between now and FY17
- Baseline non-labor based on FY13 costs
- Approved long range plans from the PRC, Information Technology Project Review Committee, and Facilities Project Review Committee
- Includes rough order of magnitude estimated Fukushima impacts
- Excludes extraordinary facility projects
- 3.95% average escalation

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Long Range Plan - Escalation

- Operations and Maintenance / Capital average escalation is 3.95% (up from 3.5%)
  - Regulatory fees – 5.5%
  - Flex benefits in corporate allocations – 9.0%
  - Software maintenance fees – 7.0%
  - Utilities – 5.5%
  - All other categories – 3.5%

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Columbia Long Range Plan

Item Description	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23
	BPA Rate Period	BPA Rate Period		BPA Rate Period		BPA Rate Period		BPA Rate Period		BPA Rate Period	
Direct and Indirect O&M Costs											
Baseline Costs	$ 126,308	$ 124,333	$ 120,138	$ 122,926	$ 119,588	$ 121,786	$ 119,988	$ 123,186	$ 119,988	$ 122,786	$ 119,988
Outage Costs (Incremental)	25,028	150	29,750	150	25,200	150	25,200	150	25,200	150	25,200
Admin / General (A&G)	73,479	69,903	70,349	69,444	69,560	68,700	69,634	69,070	69,819	68,752	69,317
O&M Projects	44,024	10,965	46,889	13,052	42,993	11,148	44,054	13,514	42,788	11,082	46,273
Facilities O&M Projects	589	780	890	890	890	890	890	890	890	890	890
O&M Risk Reserve	1,000	1,532	3,336	1,532	3,186	1,294	2,694	1,242	2,694	1,123	2,694
Subtotal Direct & Indirect O&M Costs	**$ 270,428**	**$ 207,663**	**$ 271,352**	**$ 207,994**	**$ 261,417**	**$ 203,968**	**$ 262,460**	**$ 208,052**	**$ 261,379**	**$ 204,783**	**$ 264,362**
Escalation on Direct & Indirect	**-**	**8,447**	**21,785**	**26,491**	**43,952**	**45,476**	**69,213**	**67,908**	**96,337**	**89,041**	**127,465**
Subtotal Direct & Indirect O&M Costs	**$ 270,428**	**$ 216,110**	**$ 293,137**	**$ 234,485**	**$ 305,369**	**$ 249,444**	**$ 331,673**	**$ 275,960**	**$ 357,716**	**$ 293,824**	**$ 391,827**
Capital Costs											
PRC Capital Projects	$ 29,818	$ 22,222	$ 29,347	$ 25,142	$ 34,690	$ 25,980	$ 40,769	$ 25,746	$ 28,271	$ 21,037	$ 42,526
Moveable Capital & Downtown Capital Projects	1,644	1,507	1,507	1,507	1,507	1,507	1,507	1,507	1,507	1,507	1,507
Facilities Capital Projects	537	500	530	535	565	565	565	565	565	565	565
Information Technology Capital Projects	3,001	7,772	6,230	5,789	5,706	9,141	6,115	6,168	5,808	7,555	6,465
Admin / General (A&G)	5,507	3,954	3,846	3,514	4,805	3,214	4,147	3,005	3,724	3,757	3,916
Capital Risk Reserve	4,414	2,412	3,508	2,052	3,641	1,989	4,002	2,142	3,848	2,142	3,848
Fukushima Impacts	5,520	11,600	9,300	6,300	6,100	-	-	-	-	-	-
Subtotal Capital Costs	**$ 50,441**	**$ 49,967**	**$ 54,268**	**$ 44,839**	**$ 57,014**	**$ 42,396**	**$ 57,105**	**$ 39,133**	**$ 43,723**	**$ 36,563**	**$ 58,827**
Escalation on Capital Costs	**-**	**1,775**	**3,917**	**4,945**	**8,567**	**8,069**	**13,311**	**10,821**	**14,145**	**13,649**	**24,627**
Subtotal Capital Costs	**$ 50,441**	**$ 51,742**	**$ 58,185**	**$ 49,784**	**$ 65,582**	**$ 50,465**	**$ 70,416**	**$ 49,954**	**$ 57,868**	**$ 50,212**	**$ 83,454**
Fuel Related Costs											
Nuclear Fuel Amortization	$ 39,532	50,732	46,252	64,739	57,477	63,684	56,560	69,672	61,856	74,419	67,090
Spent Fuel Fee	7,923	8,847	8,047	8,956	7,901	8,932	7,899	8,918	7,867	8,894	7,989
Subtotal Fuel Related Costs	**$ 47,455**	**$ 59,579**	**$ 54,299**	**$ 73,695**	**$ 65,378**	**$ 72,616**	**$ 64,459**	**$ 78,590**	**$ 69,723**	**$ 83,313**	**$ 75,079**
Total Unescalated Budget	**$ 368,324**	**$ 317,209**	**$ 379,919**	**$ 326,528**	**$ 383,809**	**$ 318,980**	**$ 384,024**	**$ 325,775**	**$ 374,825**	**$ 324,659**	**$ 398,268**
Total Escalation	**-**	**10,222**	**25,702**	**31,436**	**52,519**	**53,545**	**82,524**	**78,729**	**110,482**	**102,690**	**152,092**
Total Costs - Industry basis	**$ 368,324**	**$ 327,431**	**$ 405,621**	**$ 357,964**	**$ 436,329**	**$ 372,525**	**$ 466,548**	**$ 404,504**	**$ 485,307**	**$ 427,349**	**$ 550,360**
Total Net Generation (Gwh)	8,473	9,517	8,291	9,517	8,473	9,517	8,473	9,517	8,473	9,517	8,473
Outage Days	40	-	47	-	40	-	40	-	40	-	40
Cost of Power (Cents per kWh, constant FY13$)	4.347	3.333	4.582	3.431	4.530	3.352	4.532	3.423	4.424	3.411	4.700
Cost of Power (Cents per kWh, escalated)	4.347	3.440	4.892	3.761	5.150	3.914	5.506	4.250	5.728	4.490	6.495

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Long Range Plan Challenges

- Fukushima
- Turbine Replacement
- Plant Aging / Obsolescence
- Increased investment in equipment reliability projects
- License Extension Implementation
- Regulatory Oversight of Columbia
- Benefits expected to escalate at a higher rate
- A managed attrition plan will be required to meet commitments
- Fuel Costs

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Rate Case Overview

Mark Reed, Asset Manger/Controller

Columbia IPR Cost Elements

- Operations & Maintenance
- Fuel Disposal Fees
- Spares/Inventory Adjustments
- Generation Taxes
- Fuel Procurement
- Independent Spent Fuel Storage Decommissioning Fund
- Decommissioning Fund
- NEIL Insurance

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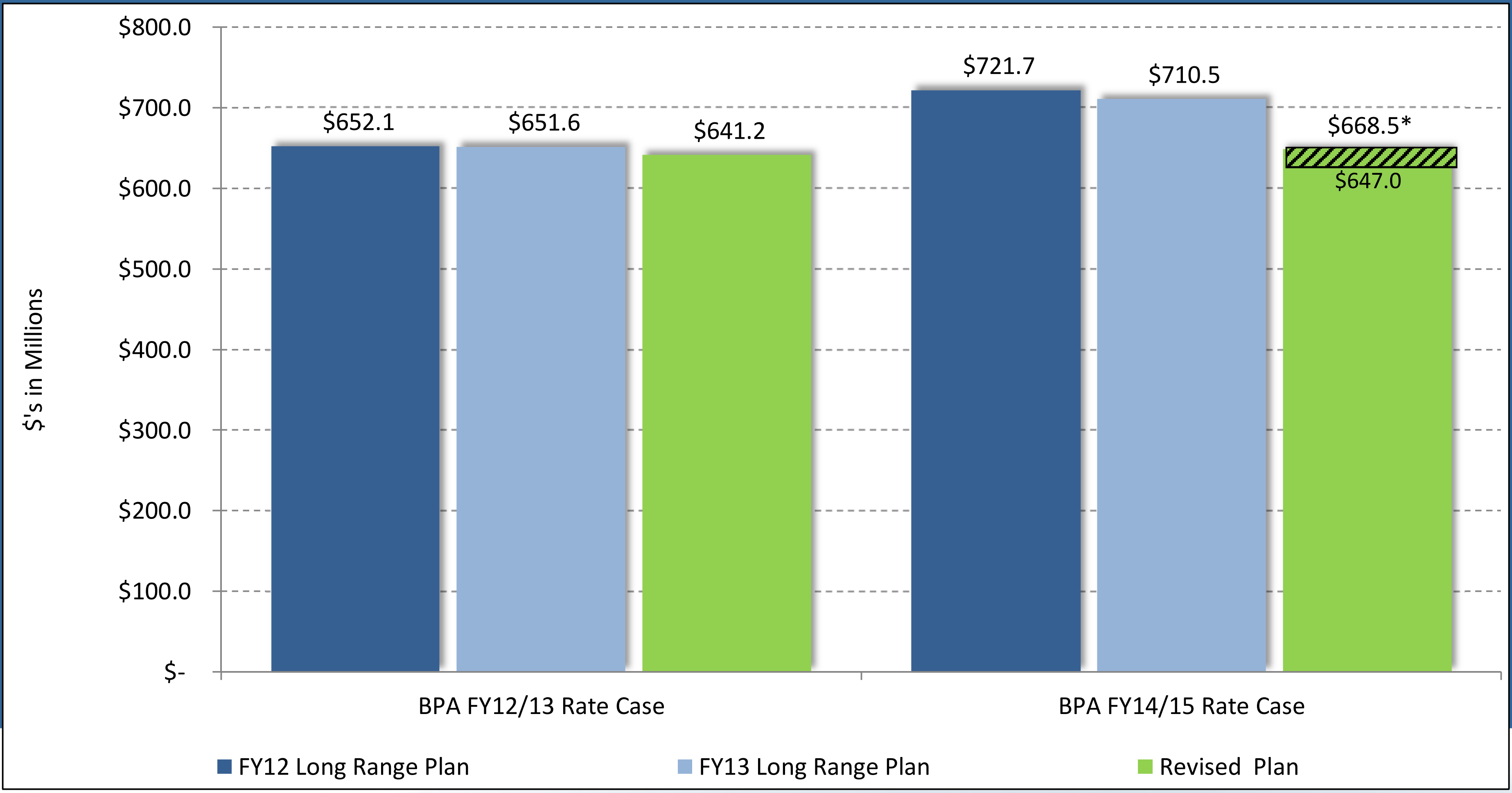
Columbia Changes to IPR



*This number does not include rate case savings from revenues net of additional debt service from fuel program (see slide 34)

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Net Fuel Savings

BPA FY 14/15	FY13 LRP	Revised Plan	Total Delta
Items Included in IPR			
Fuel Plan (CGS Budget)	$120,356	$100,935	$19,421
Items excluded from IPR			
Projected Revenues	$0	$76,235	$76,235
Additional Debt Service	$0	($54,750)	($54,750)
	$0	$21,485	$21,485
Total Rate Case Savings			**$40,906**

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Fiscal Year 12/13

BPA FY 12/13	FY12 LRP	FY13 LRP	Revised Plan	Total Delta
CGS O&M	$480,333	$480,333	$480,333	$0
Fuel Disposal	$16,352	$16,511	$16,511	$159
Spares/Inventory Adj	$6,358	$9,063	$9,063	$2,705
Generation Tax	$8,521	$8,415	$8,415	($106)
Subtotal O&M	$511,564	$514,322	$514,322	$2,758
Fuel	$111,325	$108,322	$108,322	($3,003)
Total CGS Controllable	$622,889	$622,644	$622,644	($245)
ISFSI Decomm Fund	$224	$218	$218	($6)
Total CGS	$623,113	$622,862	$622,862	($251)
Decommissioning	$25,011	$23,213	$12,813	($12,198)
NEIL Insurance	$4,005	$5,505	$5,505	$1,500
Total IPR	**$652,129**	**$651,580**	**$641,180**	**($10,949)**

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Fiscal Year 14/15

BPA FY 14/15	FY12 LRP	FY13 LRP	Revised Plan	Total Delta
CGS O&M	$507,312	$513,841	$513,841	$6,529
Fuel Disposal	$16,712	$16,703	$16,703	($9)
Spares/Inventory Adj	$9,636	$11,751	$11,751	$2,115
Generation Tax	$9,805	$9,839	$9,839	$34
Subtotal O&M	$543,465	$552,134	$552,134	$8,669
Fuel	$136,496	$120,356	$100,935 *	($35,561)
Total CGS Controllable	$679,961	$672,490	$653,069	($26,892)
ISFSI Decomm Fund	$236	$236	$236	$0
Total CGS	$680,197	$672,726	$653,305	($26,892)
Decommissioning	$37,474	$30,732	$8,232	($29,242)
NEIL Insurance	$4,000	$7,000	$7,000	$3,000
Total IPR	**$721,671**	**$710,458**	**$668,537**	**($53,134)**

*This number does not include rate case savings from revenues net of additional debt service from fuel program (see slide 34)

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Fiscal Year 14/15 Deltas

FY14/15 Deltas	Delta	Explanation
CGS O&M	$6,529	7 day longer outage
Fuel Disposal	($9)	
Spares/Inventory Adj	$2,115	revised plan based on experience
Generation Tax	$34	
Subtotal O&M	$8,669	
Fuel	($35,561) *	result of new fuel deal
Total CGS Controllable	($26,892)	
ISFSI Decomm Fund	$0	
Total CGS	($26,892)	
Decommissioning	($29,242)	result of license extension
NEIL Insurance	$3,000	latest forecast
Total IPR	**($53,134)**	

*This number does not include rate case savings from revenues net of additional debt service from fuel program (see slide 34)

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FY12/13 vs. FY14/15 Deltas

FY 12/13 vs FY14/15 Deltas	FY12 LRP	FY13 LRP	Revised Plan
CGS O&M	$26,979	$33,508	$33,508
Fuel Disposal	$360	$191	$191
Spares/Inventory Adj	$3,278	$2,688	$2,688
Generation Tax	$1,284	$1,424	$1,425
Subtotal O&M	$31,901	$37,811	$37,812
Fuel	$25,171	$12,034	($7,387)
Total CGS Controllable	$57,072	$49,845	$30,425
ISFSI Decomm Fund	$12	$18	$18
Total CGS	$57,084	$49,863	$30,443
Decommissioning	$12,463	$7,519	($4,581)
NEIL Insurance	($5)	$1,495	$1,495
Total IPR	**$69,542**	**$58,877**	**$27,357**

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Revised FY12/13 vs. FY14/15

CGS O&M	$480,333	$513,841		$33,508
Fuel Disposal	$16,512	$16,703		$191
Spares/Inventory Adj	$9,063	$11,751		$2,688
Generation Tax	$8,415	$9,839		$1,425
Subtotal O&M	$514,322	$552,134		$37,812
Fuel	$108,322	$100,935	*	($7,387)
Total CGS Controllable	$622,644	$632,490		$30,425
ISFSI Decomm Fund	$218	$236		$18
Total CGS	$622,862	$632,726		$30,443
Decommissioning	$12,813	$8,232		($4,581)
NEIL Insurance	$5,505	$7,000		$1,495
Total IPR	**$641,180**	**$647,958**		**$27,357**

*This number does not include rate case savings from revenues net of additional debt service from fuel program (see slide 34)

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Revised Plan Delta Explanations

FY 12/13 vs FY14/15 Deltas	Delta	Explanation
CGS O&M	$33,508	escalation offset by headcount reductions
Fuel Disposal	$191	FY13 revised fuel plan
Spares/Inventory Adj	$2,688	revised plan based on experience
Generation Tax	$1,425	FY13 revised fuel plan
Subtotal O&M	$37,812	
Fuel	($7,387)	result of new fuel deal
Total CGS Controllable	$30,425	
ISFSI Decomm Fund	$18	latest forecast
Total CGS	$30,443	
Decommissioning	($4,581)	result of license extension
NEIL Insurance	$1,495	latest forecast
Total IPR	**$27,357** *	

*This number does not include rate case savings from revenues net of additional debt service from fuel program (see slide 34)

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Key Issues

- The O&M forecast is based on escalation of 3.5% on most items, however, for medical benefits the escalation is 9%, and other specific costs such as regulatory fees and utilities it is 5.5%. Software maintenance fees is 7%. The average escalation is 3.95%.
- At risk compensation is funded at 100% payout.
- Headcount – reduction of 106 by FY17.

Key Issues (continued)

- License Extension has had a significant and positive impact on Columbia's cost in FY14/15.
- Future equipment reliability issues will be evaluated based on 2044 not 2024.
- Decommissioning fund contributions also benefit from license extension.

Risks Associated with Annual CGS Outage

There are risks associated with conducting a refueling outage every year at Columbia Generating Station. These negative impacts have not yet been economically quantified. However, if CGS were on a one year refueling cycle;

- Radiation exposure would increase due to the increased number of outage days and work being done in the plant over a two year period. CGS already is in the fourth quartile relative to the industry for radiation exposure. Both the Nuclear Regulatory Commission and the Institute of Nuclear Power Operations have identified the need for, and have been driving CGS to lower it's radiation exposure average. This was one of the reasons CGS transitioned from a one year refueling cycle to a two year refueling cycle.
- Refueling outages also place plants in higher nuclear safety risk situations due to shutdown and startup evolutions and non-ordinary system alignments
- Shifting CGS to an annual refueling cycle would create a significant challenge to plan and prepare for the next refueling outage. As is the industry norm, preparations for a refueling outage typically must start more than a year before the actual outage start date. This was another reason CGS transitioned from a one year cycle to a two year cycle.
- INPO places significant emphasis on plant operators to be ready to efficiently, and in an error free manner, execute their refueling outages. This objective might be impacted by the inability to properly prepare. Since outage planning horizons are longer than 12 months, executing a refueling outage while simultaneously planning and preparing for the next outage would increase organizational pressure and pressure for increased staffing.
- It is anticipated that a shift to a one year cycle would require procedural reviews and changes. In particular the preventative maintenance program would have to be re-sequenced to fit to a different overall schedule; this also applies to technical specification surveillances. These changes could potentially be costly.

When CGS is on a two year refueling cycle;

- Two year outage cycles allow more preparation time for large complex projects.
- Two year cycles allow more time for fuel, material and equipment procurement, some of which have long lead times.
- There are no plants in the US to our knowledge that currently operate on an annual cycle. All have shifted to 18 or 24 month cycles which is the industry norm.

Economic Analysis of Annual CGS Refueling Outage

A rough economic analysis was performed based on the difference between a one year refueling budget and a two year refueling budget as reflected in Operating and Maintenance costs.

- The O&M costs are expected to increase around $75 million per year.

There would be fuel savings associated with refueling each year due to less fuel loaded and more efficient use of the fuel.

- Estimated $6 million less fuel and $2 million fuel efficiency per two year period for a savings of $8 million ($4 million per year).

A range of forgone revenues were developed to reflect the effect of 30 to 40 fewer days of generation in non-refueling years. The range was based on different market conditions.

- The cost ranges result in $0 to $20 million per year increase.

The total estimated cost increase of the factors listed above results in a range of incremental cost from around $70 million to $90 million.

Analysis of Annual CGS Non-Refueling Outage

Many of the same risks would be present if CGS was simply shut down each year but not refueled. Specific risk include:

- Increased radiation exposure.
- Exposure to higher nuclear safety risk situations due to shutdown and startup evolutions and non-ordinary system alignments.

An economic analysis was not performed for an annual non-refueling CGS outage. However, it is anticipated that there would still be an increase in O&M cost relative to the two year refueling cycle.

- Energy Northwest would most likely perform repairs and maintenance during the time period when CGS was shut down.
- Also, at a variable cost of around $5/MWh, it is still economic for CGS to operate during most heavy load hours.

❖ **Given the risks and impacts associated with an annual CGS refueling or annual CGS outage, BPA is not interested in changing the current planned operation of the plant.**

Integrated Program Review

Financial Disclosure

This information has been made publicly available by BPA on July 17, 2012 and contains information not reported in agency financial statements.