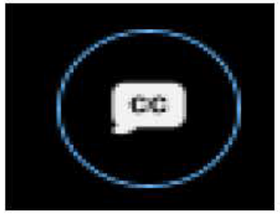
Webex Accessibility tools

To enable Closed Captions



Select the **CC icon** in the lower-left of the WebEx screen

Note: CC is set individually by each person who wants to enable them.

Change font size

Select the **ellipsis** in the lower right

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Use the slider to select the desired size

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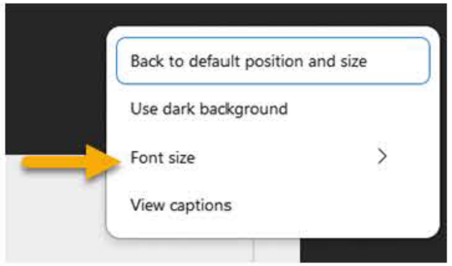

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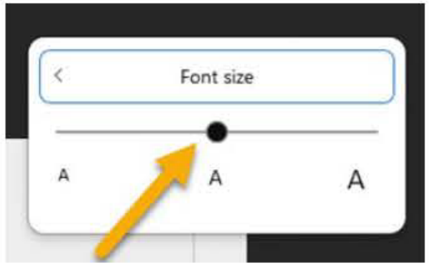

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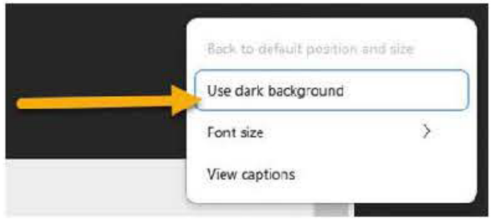
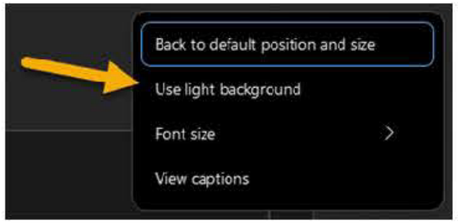




ENERGY NORTHWEST

Planning for the Future: Columbia Extended Power Uprate

BPA Workshop

April 8, 2025

KEY DEFINITIONS & ABBREVIATIONS

- ACPRT = BPA Capital Project Review Team
- BPA = Bonneville Power Administration
- CETA = Clean Energy Transformation Act
- CGS = Columbia Generating Station
- CLTP = Current Licensed Thermal Power
- EN = Energy Northwest
- EPU = Extended Power Uprate
- FC = BPA Finance Committee
- FLR = First License Renewal
- ITC =Investment Tax Credit
- LCM = Life Cycle Management
- LCOE = Levelized Cost of Electricity
- MPR = MPR Associates
- MUR = Measurement Uncertainty Recapture
- MVA = MegaVolt-Amperes
- NPV = Net Present Value
- OLTP = Original Licensed Thermal Power
- O&M = Operations & Maintenance
- PTC = Production Tax Credit
- SLR = Subsequent License Renewal
- WG = Working Group

Columbia Extended Power Uprate: Business Case Brief

Information

Present the Columbia Extended Power Uprate (EPU) Capital Project Proposal to provide insights into the business case.

Meeting Purpose and Decision Timeline

- **Today:** Walk through the final results of the Extended Power Uprate business case.
- **May:** Request to Bonneville Power Administration to approve proceeding with the EPU implementation.

Key Take Aways

- There is a growing demand for electric power in the Pacific Northwest
- An Extended Power Uprate is an industry proven method for decreasing the cost per megawatt, and increasing firm capacity
- Unique opportunity to synergize the uprate with the planned life-cycle management modifications and the resultant extended duration outages to lower incremental EPU cost, and the Tax Credits currently available.

Extended Power Uprate Financial Review Outline

- Power Uprate History
- Power Uprate at Columbia
  - Project Overview and Timeline
  - Project Governance Overview
- EPU Financial Analysis
- Closing Remarks
- Recommendation

Power Uprate History

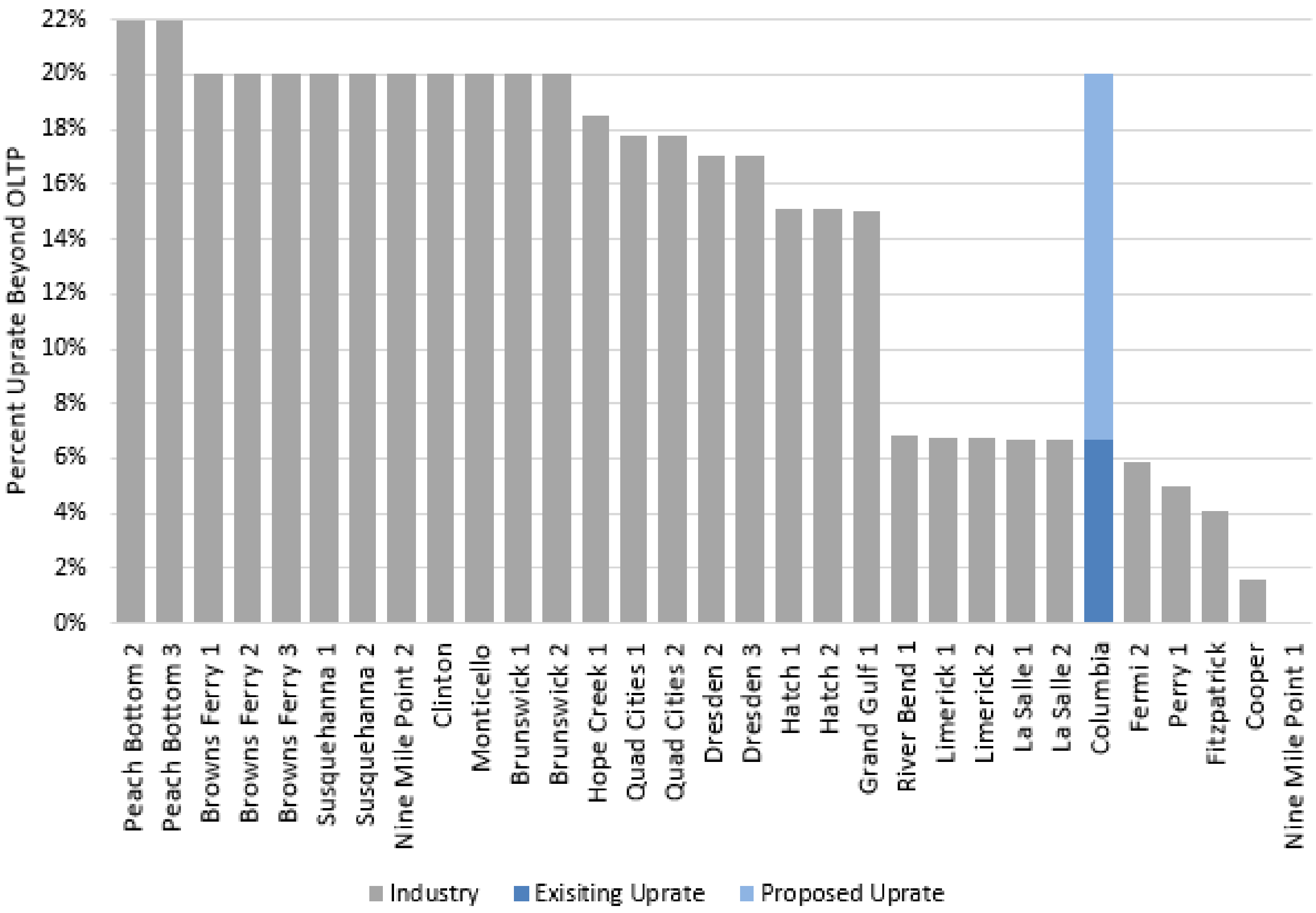
Power Uprate History

- Power Uprates have been implemented in the US since the 1970s
- To date, the NRC has approved 171 uprates, resulting in a gain of approximately 24,089 MWt (megawatts thermal) or 8,030 MWe (megawatts electric)
- Collectively, these uprates have added generating capacity equivalent to about eight new reactors
- To increase power output, typically a utility will refuel with either slightly more enriched uranium fuel or a higher percentage of new fuel
- This enables the reactor to produce more thermal energy and therefore more steam, which drives a turbine to generate electricity

Backgrounder On Power Uprates For Nuclear Plants | NRC.gov

Industry Experience – BWR EPUs Performed

- 20 of the 31 BWRs in the US have implemented an EPU
- 12 of the 20 have uprated to at least 120% of original licensed thermal power
- 8 of the 20 choose a power level less than the 120% level due to economic drivers; mainly technical barriers that would have resulted in higher costs
- 2024 NEI survey indicates 73% of units are interested in power uprate with at least 17 sites interested in EPU.



ENERGY NORTHWEST

Power Uprate at Columbia

Columbia’s Power Uprates

- Columbia’s current Gross Generating Capacity Following the *Measurement Uncertainty Recapture* in 2017 is 1,207 MWe
- With the implementation of the *Extended Power Uprate and efficiency improvements*, Columbia is anticipated to have an output of ~1,393 MWe post 2031 outage

Extended Power Uprate
120% of OLTP
(Anticipated 2031)
3,988 MWth

Measurement Uncertainty Recapture
106.7% of OLTP
(Completed 2017; Currently Columbia’s Power)
3,544 MWth

Stretch Power Uprate
104.9% of OLTP
(Completed 1994)
3,486 MWth

Original Licensed Thermal Power (OLTP)
3,323 MWth

Investment Purpose and Objectives

- **Investment Purpose:** EPU will increase electrical output of Columbia to provide additional Tier 1 power to the region.
- **Investment Objectives:**
  - Provide 162 MWe of nuclear energy to region
    - Supports Energy Northwest's desire to meet state and federal requirements and goals
    - Opportunity to capture unique uprate timing with the significant components are being replaced for life-cycle management purposes, reducing incremental EPU cost
    - Tax Credits currently available provide additional benefits if uprate occurs prior to 2032
  - Increase flexibility of BPA's resource adequacy program through addition of firm baseload power

Note: Additional increase in generation (~24MWe) are anticipated through efficiencies gains associated with the completion of other LCM projects.

BP24 Extended Power Uprate Study

- Following the Feasibility study, a project was approved to more fully understand the scope, schedule and cost of an EPU* at Columbia in BP24
  - EPU project worked to refine the scope identified in the FY21 Feasibility study (FY24 & FY25).
  - Overall, there are 30 projects that will support the EPU implementation
    - 12 Specific EPU construction projects & 5 EPU paper projects
      - Paper: Safety Analysis completion, Licensing Amendment development and submittal, flow accelerated corrosion calculations, etc.
    - 9 Lifecycle Management (LCM) construction projects with incremental modifications or sequencing alignment to support EPU operating conditions
    - 4 LCM projects that will support EPU conditions with no additional costs

*Target Uprate of 120% of original licensed thermal power (OLTP) from current licensed thermal power of 106.7% OLTP (~12.5% increase [120%/106.7%])

EPU Project Developing Cost and Risk Inputs

EPU projects were estimated Association for the Advancement of Cost Engineering (AACE) standards.

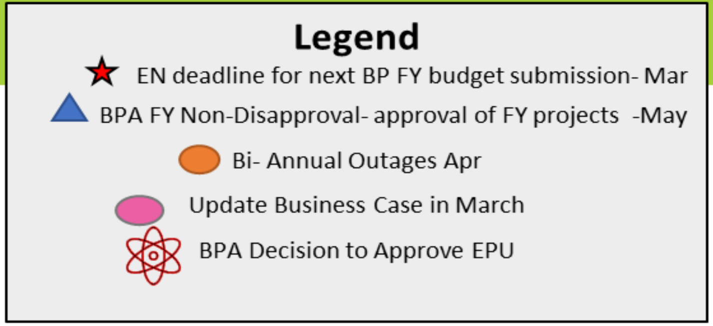
- The Cost Estimate Classification System provides guidelines for applying the general principles of estimate classification to project cost estimates
- The Cost Estimate Classification System maps the phases and stages of project cost estimating together with a generic maturity and quality matrix, which can be applied across a wide variety of industries.

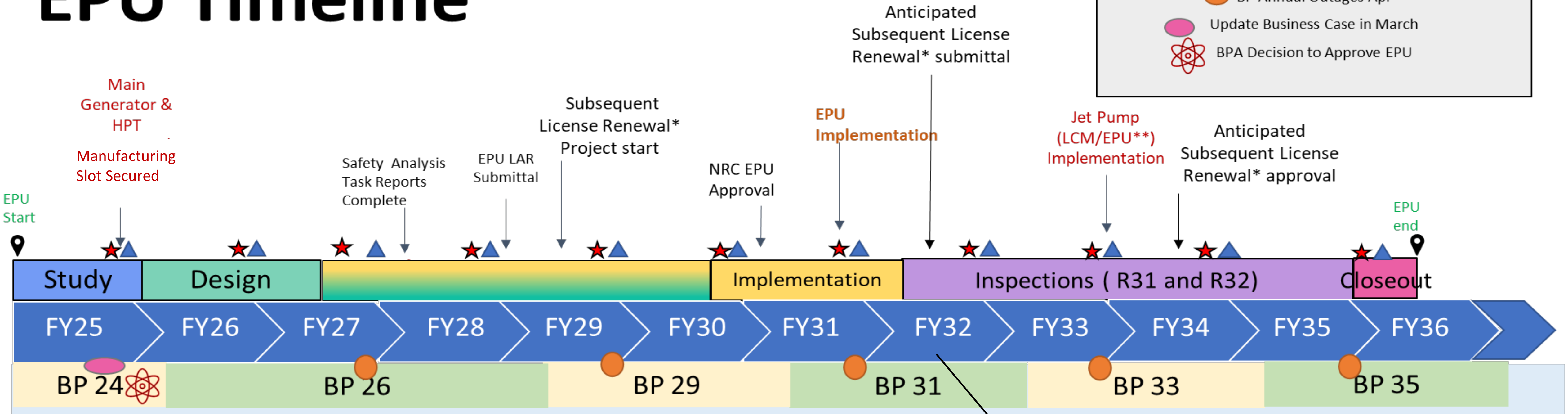
ESTIMATE CLASSIFICATION CRITERIA				
Estimate Classification	**Preliminary (class 5) +100%/-50%**	**ROM (class 4) +50%/-30%**	**Budgetary (class 3) +30%/-20%**	**Definitive (class 1) +15%/-10%**
Typical Estimating Methodology	Capacity factored, Parametric Judgement, analogy.	Parametric, judgement, analogy, Bottoms up, Vendor Quotes (ROM).	Semi to Detailed unit pricing with semi-detailed take-off.	Detailed unit pricing with forced detailed take-off.
Degree of Project Deliverables	0% to 2%	1% to 15%	10% to 70%	70% to 100%

*Note Classification 2 is not used within the EN site procedure CE-01.

- Key inputs include study recommendations, system drawings, physical walkdowns, vendor cost projections, and risk considerations.

EPU Timeline





Major Extended Power Uprate Projects will occur during the Refueling and Maintenance Outages in calendar years 2027, 2029 and 2031.

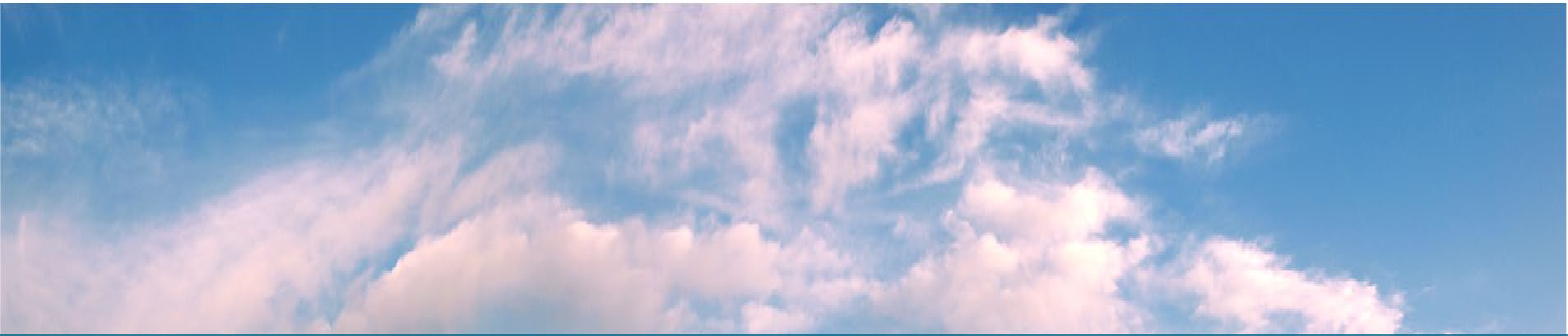
These efforts are scheduled to be executed within the existing Refueling Outage schedule and are not expected to extend the durations.

Submittal to the IRS for Tax Credits

*Represents anticipated timeframe for Subsequent License Renewal extension request and approval. EPU is not dependent upon this decision.
**EPU operating condition affect on Jet Pumps is under evaluation.

Project Governance Overview

- The project would be subject to Energy Northwest processes and procedures
- There would be regular project check-ins to coincide with BPA's annual budget approval related to EPU expenditures
- As a Capital Addition, engagement with BPA oversight is also included:
  - Additional check-in's if established thresholds for cost, schedule, scope are exceeded:
    - Estimated total project direct cost increase of ≥ $50 million
    - Estimated total project schedule delay of ≥ 6 months
    - Significant change in scope or plan of service or other major project issue. Examples include: outage window delay, major vendor dispute or performance issues, supply chain issues, major risk realized, etc.



EPU Financial Analysis

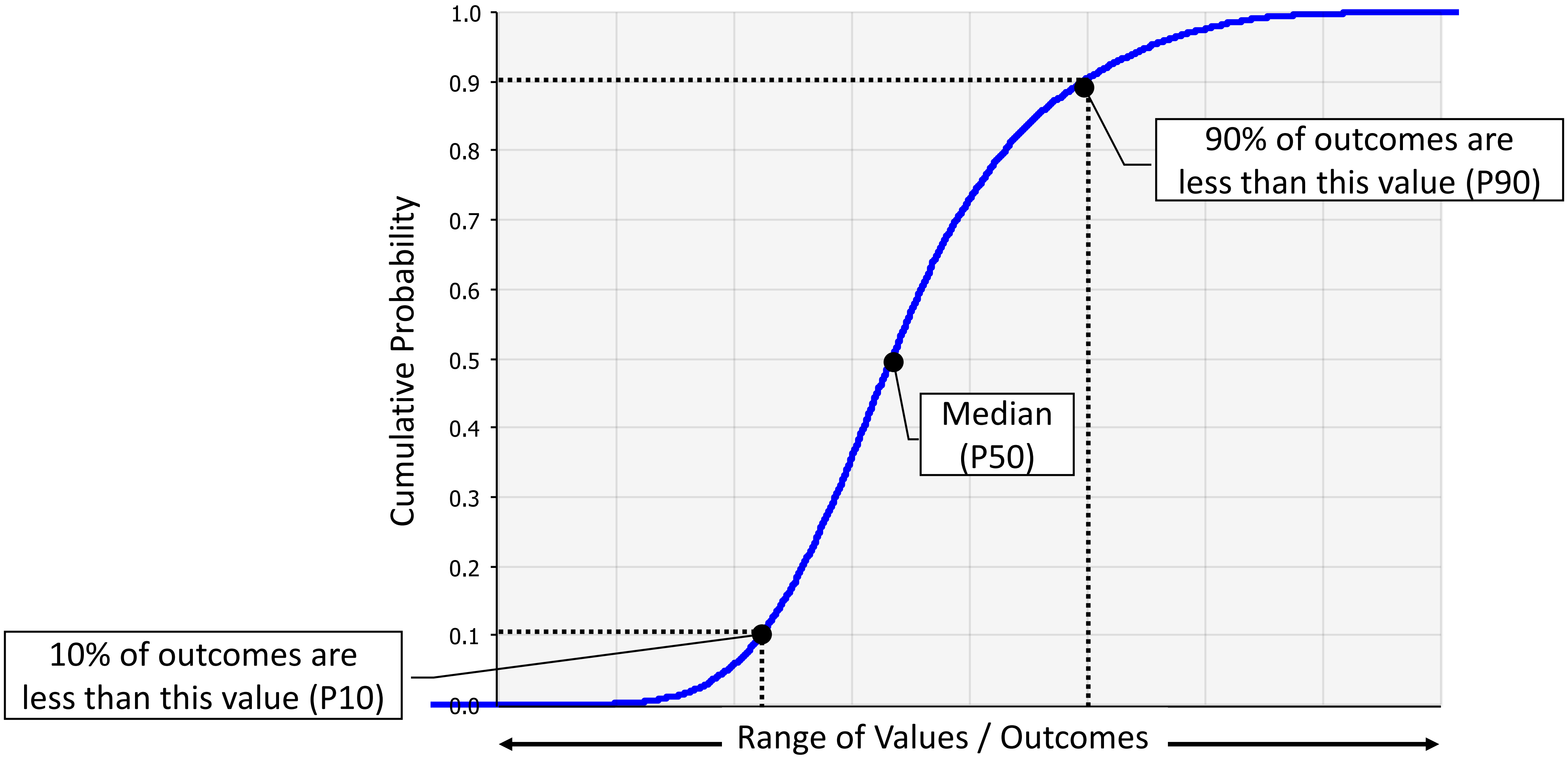
What Does a Probabilistic Analysis Entail?

The financial model developed for the business case will produce a distribution of outputs based off probabilistic inputs.

Results are commonly classified as the following:

- **PXX** – The XX% Confidence Level, meaning XX% of results are below this value. For example, the **P10** represents the **10%** Confidence Level, meaning 10% of results are below this value.
- **Frequency Distribution** – A representation of all the possible outcomes of a statistical analysis, including the value and number of occurrences.
- **Median** – The middle value of a frequency distribution (also known as the **P50**).
- **Mean** – The average value of a frequency distribution.
- **Mode** – The most frequent value of a frequency distribution.

Cumulative Distribution Example



EPU Business Case Financial Model

- The business case for EPU at Columbia evaluates the **incremental** costs and benefits associated with EPU (i.e., independent of LCM efforts).
- Four primary cashflows are considered:
  - Capital Investment
  - Fuel Investment
  - Power Revenues
  - Tax Credits
- Due to uncertainties in these inputs, a **probabilistic** discounted cashflow analysis was performed
- **Two analyses** are performed: Net Present Value and BPA Rate Impact

Power Uprate Financial Model Outputs

Analysis	Output Metric	Description	Favorable Outcome
NPV Analysis	**NPV, Cash Costs and Benefits**	Summation of present value benefits and costs. Positive indicates benefits outweigh cost.	> 0
	BPA Net Cash Ratio	Measure of profit per capital dollar invested where zero indicates breakeven and positive indicates a return.	> 0
	Discounted Payback Period (DPP)	Number of years after generation begins to break even in terms of cumulative, present value cash flow.	Earlier
	Incremental LCOE (LCOE)	The present value cost to produce a MWh averaged over the life of the asset. LCOE represents the average price needed to break even over the asset life.	Lower
Rate Impact Analysis	**Power Net Cost Impact**	Net change in the cash flow BPA requires to service debt portfolio of all assets. Negative value represents a decrease (favorable impact) to this cash flow.	< 0
	Rate Impact (Expected Life)	Average impact to BPA customer rates over the asset life. Negative value indicates rates decrease as a result of the investment over the asset life.	< 0%

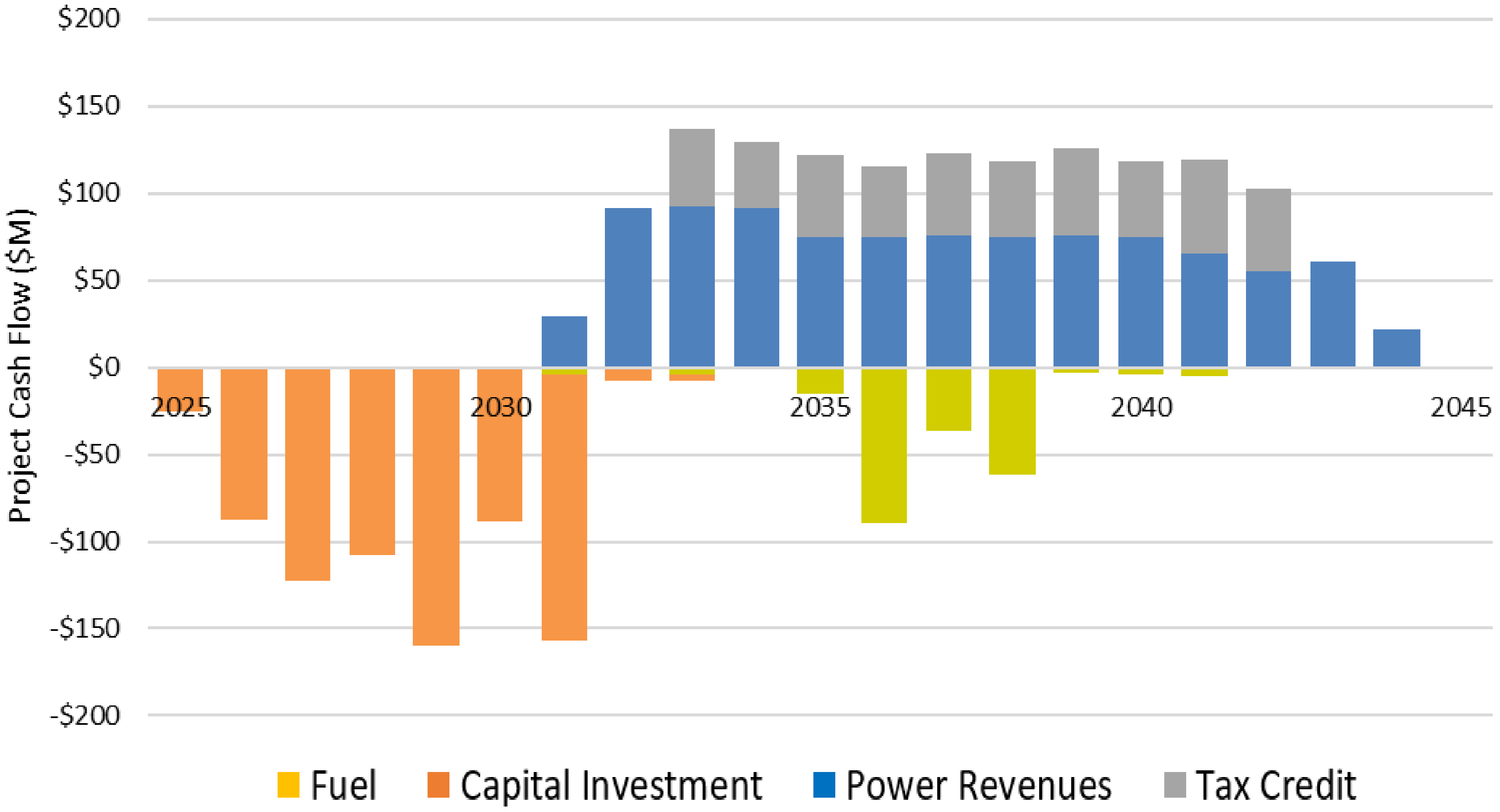
Modeling Scenarios

- **Four scenarios** are analyzed in the business case driven by two key decisions:
- **How Long Does Columbia Operate?**
  - Columbia is currently licensed through 2043 (FLR)
  - Columbia could pursue Subsequent Licensed Renewal (SLR) and operate through 2063
- **Which Tax Credit is Chosen?**
  - Production Tax Credit (PTC) = yearly credit based on incremental generation
  - Investment Tax Credit (ITC) = one-time lump sum payment for portion of capital investment

Scenario #	Columbia Operating Life	Tax Credit
1	FLR (Operation Through 2043)	PTC
2	FLR (Operation Through 2043)	ITC
3	SLR (Operation Through 2063)	PTC
4	SLR (Operation Through 2063)	ITC

Note: Seeking approval of a Subsequent License Renewal is a **separate** decision from the pursuit of an Extended Power Uprate.

Power Uprate Cash Flows – Scenario 1: FLR with PTC



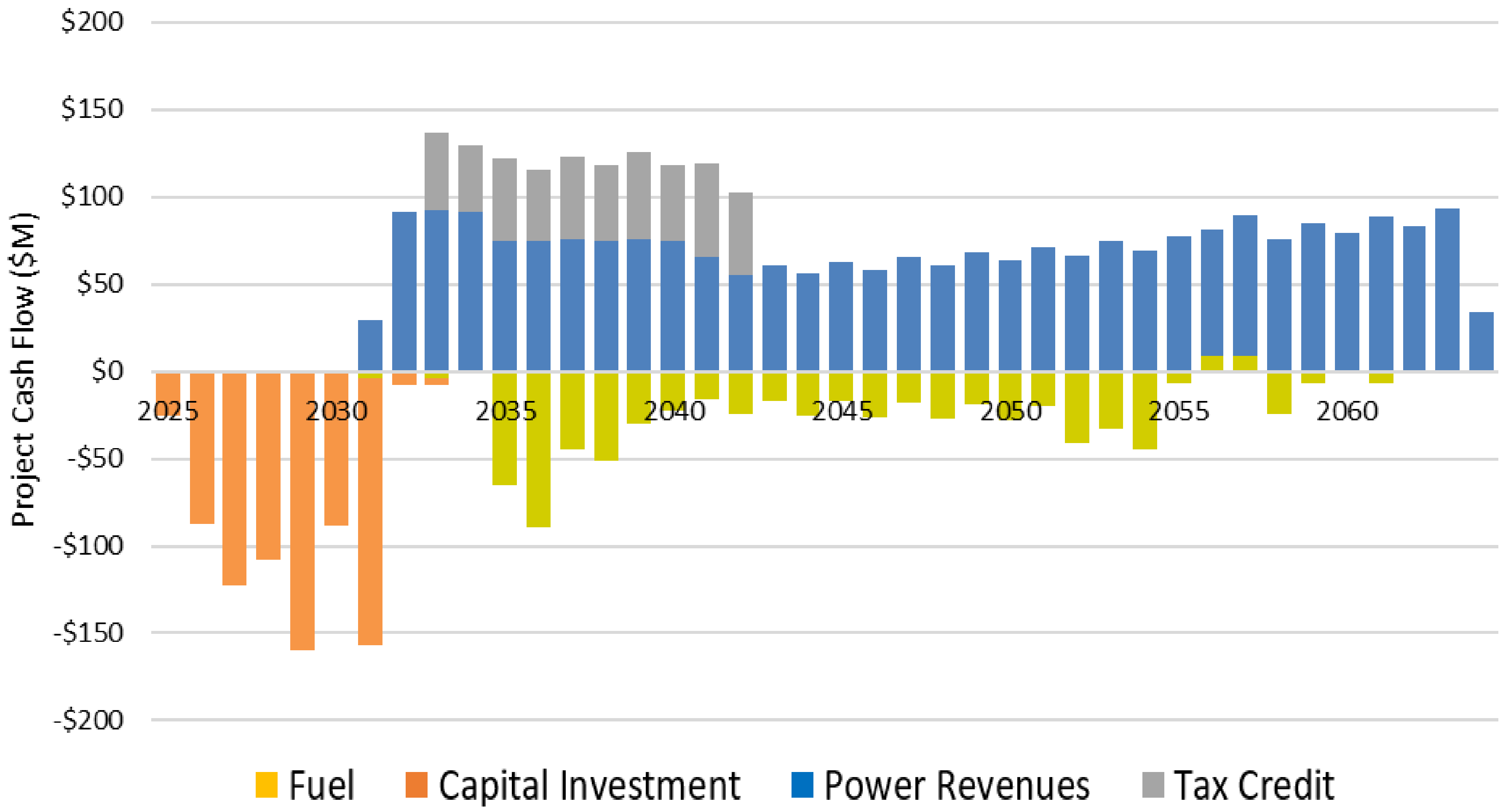
Notes:

1) Values are P50 (median) values

2) Production Tax Credit shown for this scenario.

3) FLR values shown in this scenario.

Power Uprate Cash Flows – Scenario 3: SLR with PTC



Notes:

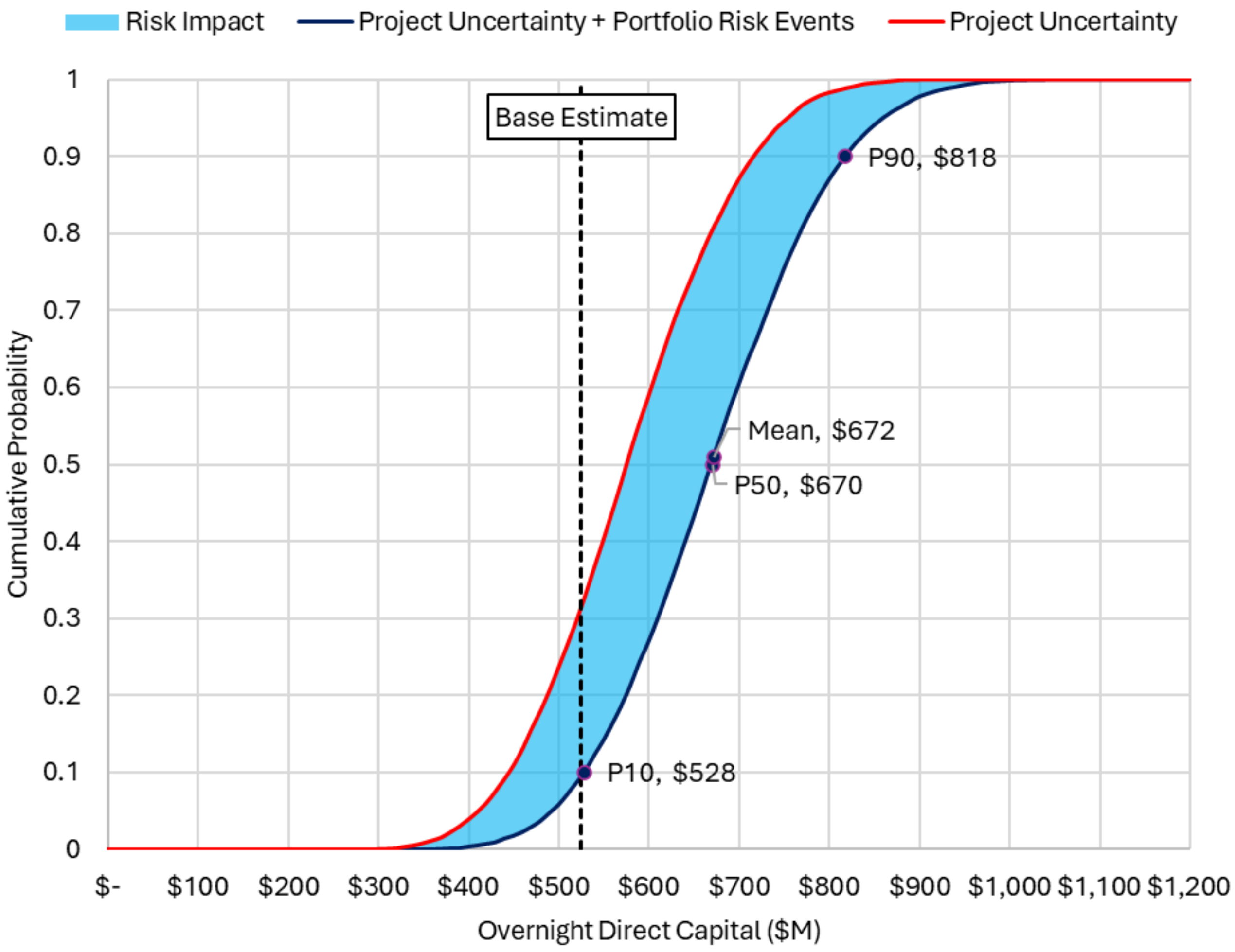
1) Values are P50 (median) values

2) Production Tax Credit shown for this scenario.

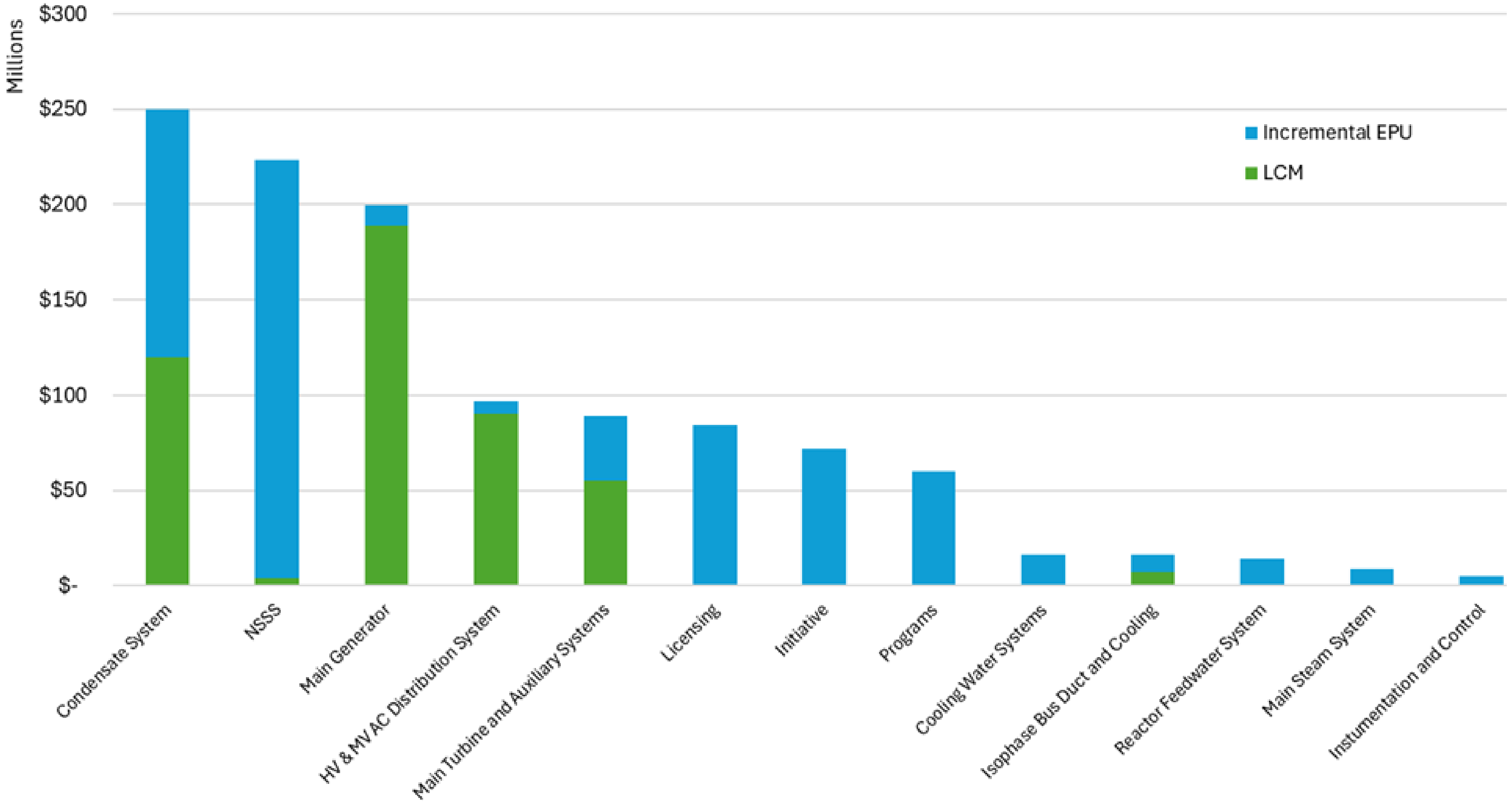
3) SLR values shown in this scenario.

Cashflow Development – Capital Costs

- Median aggregate overnight, cost of all EPU projects is ~$525M.
- Inclusion of project uncertainty and portfolio risk events increases the P50 direct overnight capital cost to ~$670M.
- Thus, to fund at P50 level, ~$145M in contingency is needed.
- Indirect costs
  - EPU incremental indirect costs estimated as ~$30M (not shown in figure);
  - Direct costs include ~$57M median value for EPU Initiative (i.e., applicable to all projects)



Why is Synergizing EPU with LCM Important?



Median Overnight Direct Costs	Value ($2025M)
LCM	~$465
Incremental Direct EPU (w/ P50 Contingency)	~$670
LCM+EPU Total	~$1,135

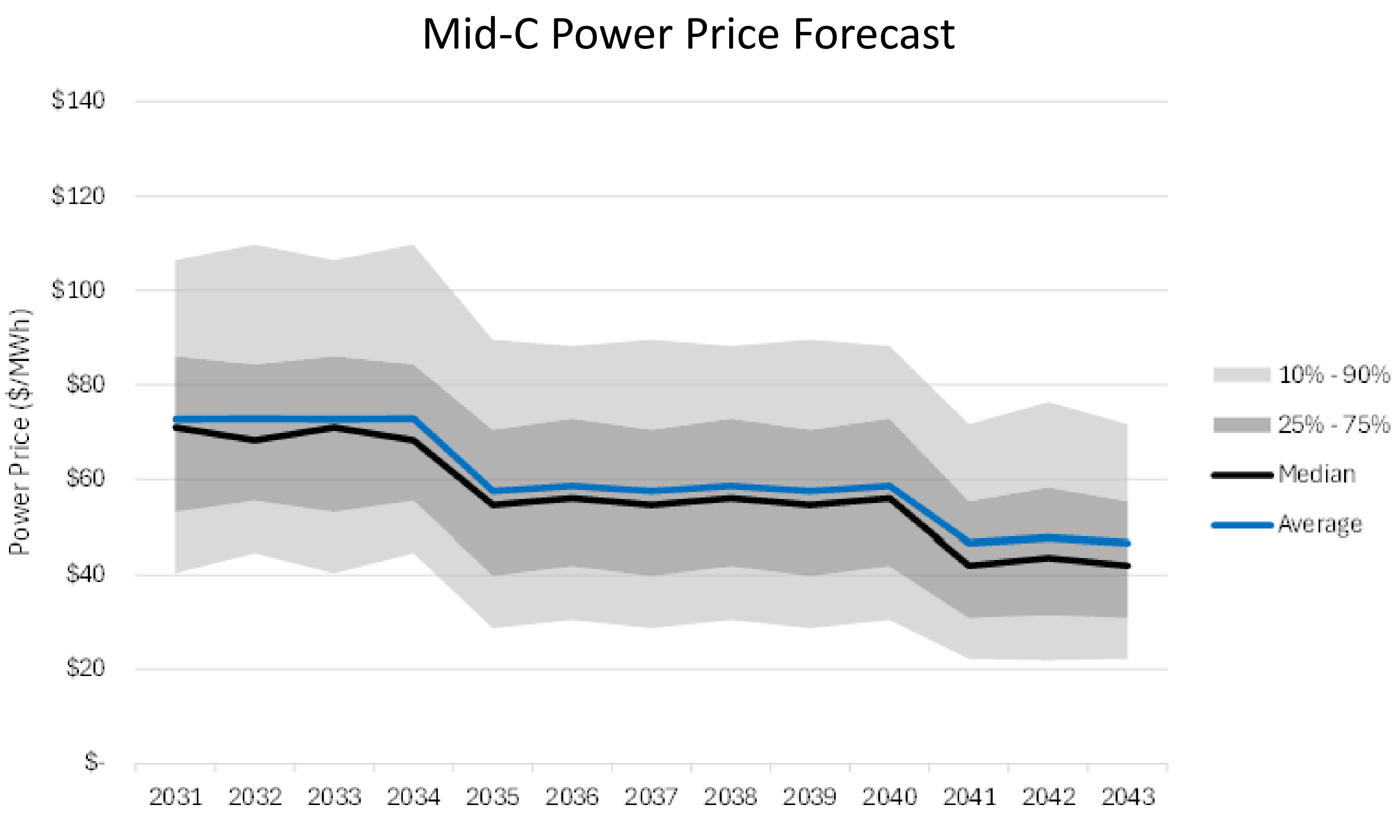
Note: This does not include indirect capital costs (~$30M)

Cashflow Development – Fuel Investment

- EN Fuels Group conducted detailed assessment to determine **incremental** fuel cost necessary for EPU
- Study utilizes current industry forecast (Energy Resources International Inc.)
  - Low Forecast = 20%
  - Mid Forecast = 65%
  - High Forecast = 15%
- Resultant P50 overnight fuel cost is ~$170M for FLR and ~$470M for SLR
- Forecasts considered conservative due to volatile market
- EN is well-positioned to enter fuel market selectively based on existing contracts

Cashflow Development – Incremental Power Valuation

- Power valuation is dependent on:
  (1) incremental generation and
  (2) projected power pricing
- EN conducted detailed analyses to project EPU Incremental generation (~162 MWe)
- Analysis utilizes **BPA resource adequacy group projections through 2044** for **Mid-C Wholesale power prices**
- For the SLR cases (2044 through 2063) prices escalated consistent with **BPA inflation forecast** (~2.14%)



Cashflow Development – Tax Benefit

- **Two Credits Applicable for Power Uprate (select one in 2031)**
  - Section 45Y – Clean Electricity PTC: Value of ~$30/MWh ($2025) if wage requirements met for 10 years indexed to inflation
  - Section 48E – Clean Electricity ITC: Value of 30% of construction expenses if wage requirements met
- **Considerations**
  - Opportunity to increase 10% for energy communities and 10% for domestic content requirements
  - Tax-exempt financing results in 15% reduction in credit value
  - Domestic content is connected to direct payment and critical for ensuring benefit is realized
  - ITC/PTC would be selected after energization occurs; credit subject to phaseout if energization does not occur prior to 2032
- **Results**
  - Columbia assumed to **meet prevailing wage** and **energy community requirements**; conservatively does not include domestic content bonus.
  - PTC is expected to be more beneficial than ITC in majority of scenarios

Financing and Other Key Inputs

- Financing
  - Assume tax-exempt bonds will be used for financing capital
    - Consistent with current Columbia debt issuance
    - Recovery through future tier 1 rate design
  - Integration into financial models
    - Discount rate = debt rate based on **BPA agency forecasts** (3.4%)
    - To assess rate impact, debt service modeled as interest only through construction then levelized through end of plant operating life
    - Resultant incremental net cost impact compared to **BPA agency net cost forecasts**
- Other Inputs
  - No material change to O&M expected (likely some decrease)
  - Inflation rates from BPA agency forecasts

Financial Analysis Median Results

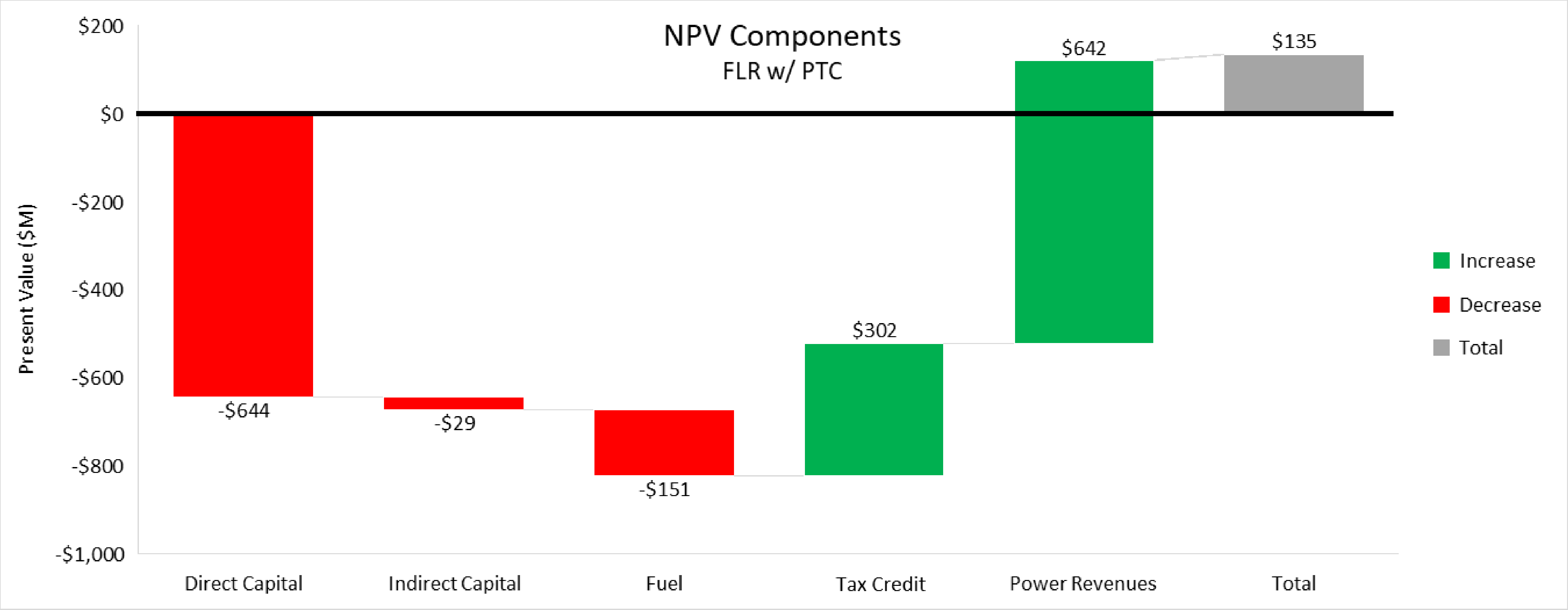
- All scenarios have median positive NPV
- All scenarios have median negative (favorable) power net cost
- Downward pressure on power rates due to avoided energy purchases from the market.
- Median discounted payback period for FLR scenarios is within the current license period

Output[1]	Units	FLR w/ PTC	FLR w/ ITC	SLR w/ PTC	SLR w/ ITC
NPV, BPA Cash Costs and Benefits	$M	$135	$31	$456	$354
BPA Net Cash Ratio	-	0.21	0.05	0.70	0.54
Power Net Cost Impact Negative is Favorable	$M	-$113	-$8	-$433	-$331
Rate Impact Negative is Favorable	%	-0.20%	0.01%	-0.41%	-0.31%
Discounted Payback Period After Generation Begins	Years	10	12	11[2]	16[2]
Nominal Incremental LCOE Lower is Favorable	$/MWh	$49	$58	$36	$41

Notes:

1. Outputs are defined in Power Uprate Financial Model Outputs Slide.
2. The discounted payback period for the SLR scenarios differs from the FLR scenarios due to additional fuel investment occurring during FLR to support operation during SLR.
3. All results are present values ($2025).

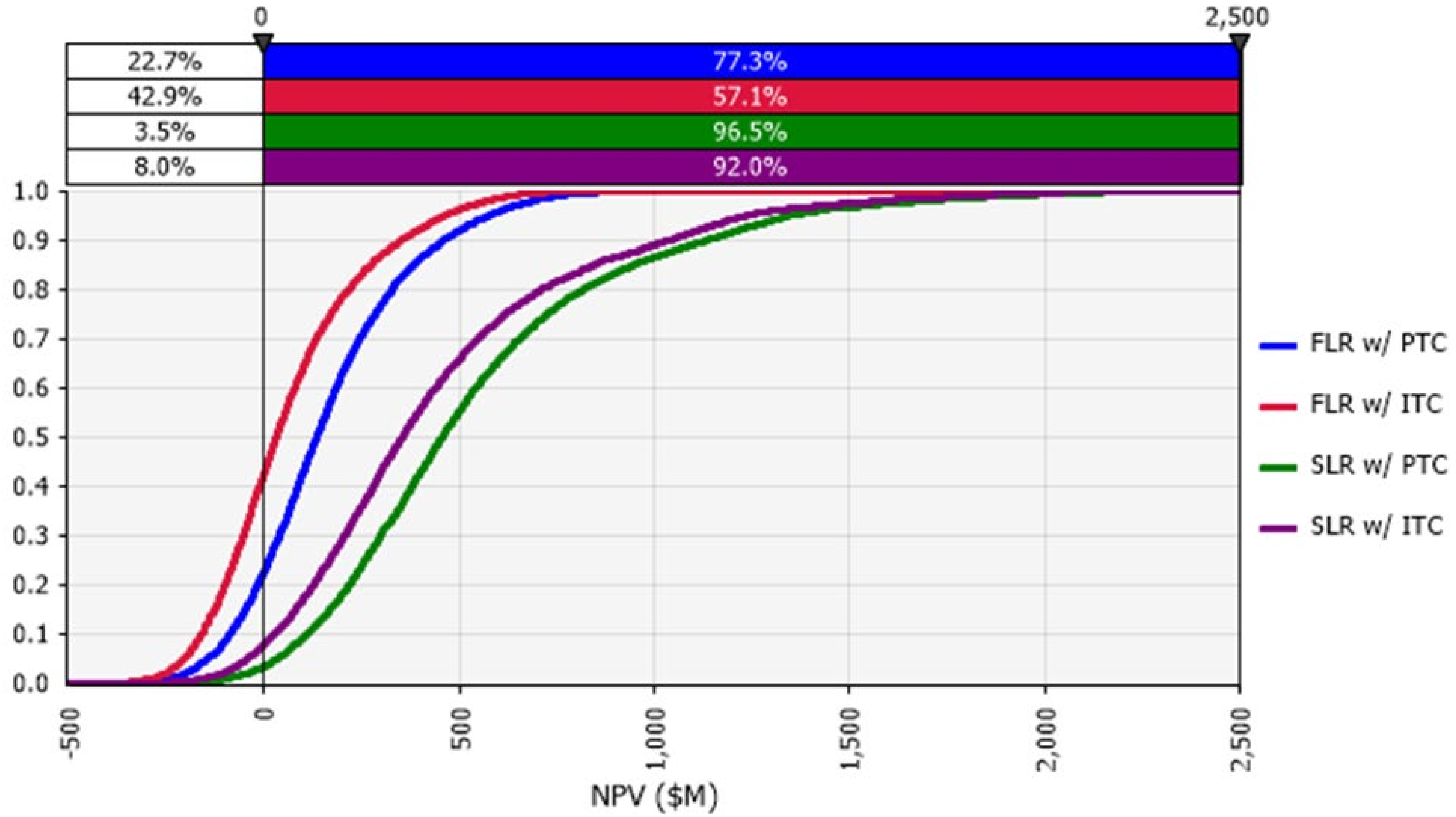
Median NPV Components – Scenario 1: FLR with PTC



Note: Individual median NPV component values do not sum to the median NPV due to the asymmetry of the distributions.

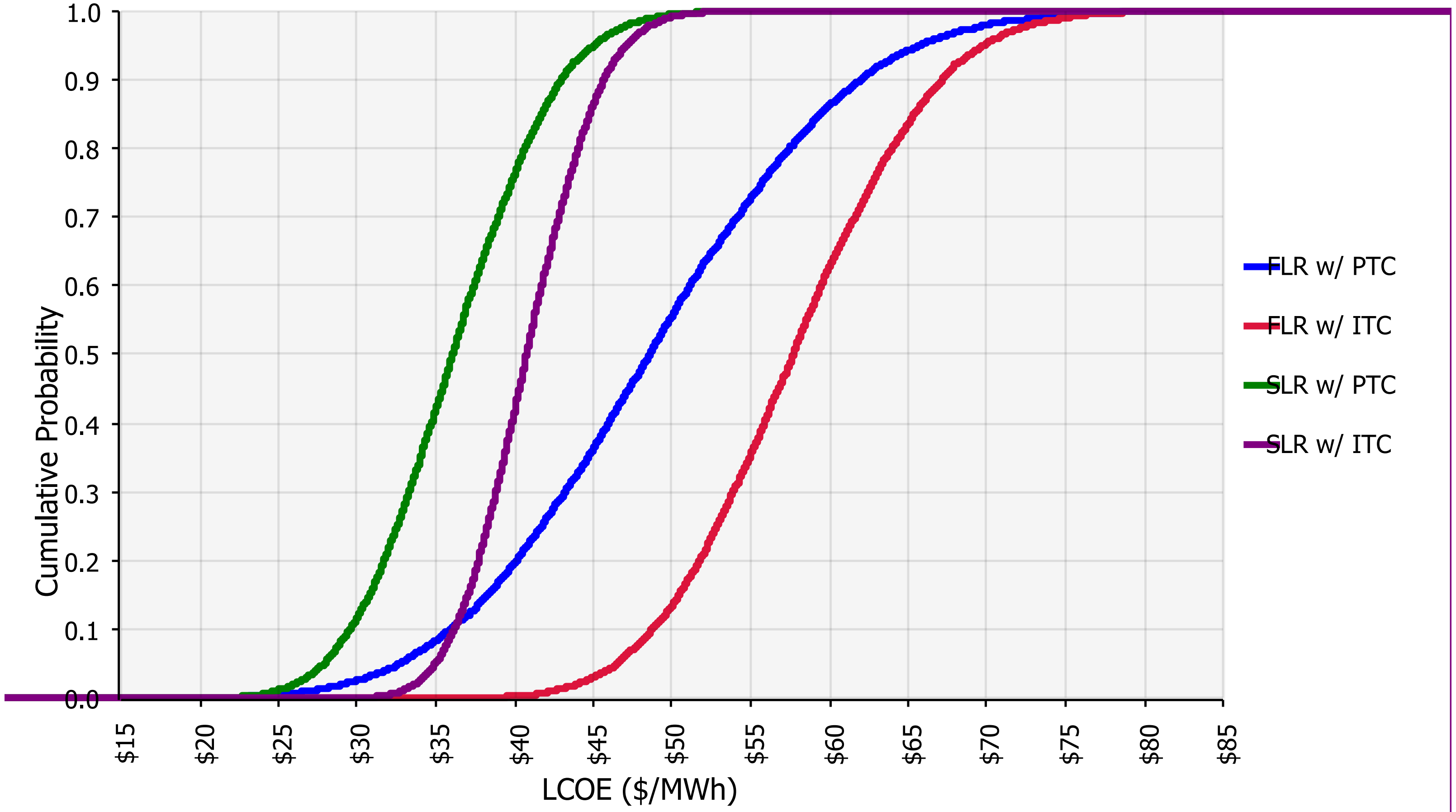
Probabilistic Outputs: Net Present Value

- Probability of positive NPV is greater than 50% in all scenarios
- SLR with PTC has the greatest probability of positive NPV at ~96%
- PTC scenarios are more favorable than ITC scenarios
- SLR scenarios are more likely to result in favorable outcomes than FLR



Probabilistic Results: Incremental LCOE

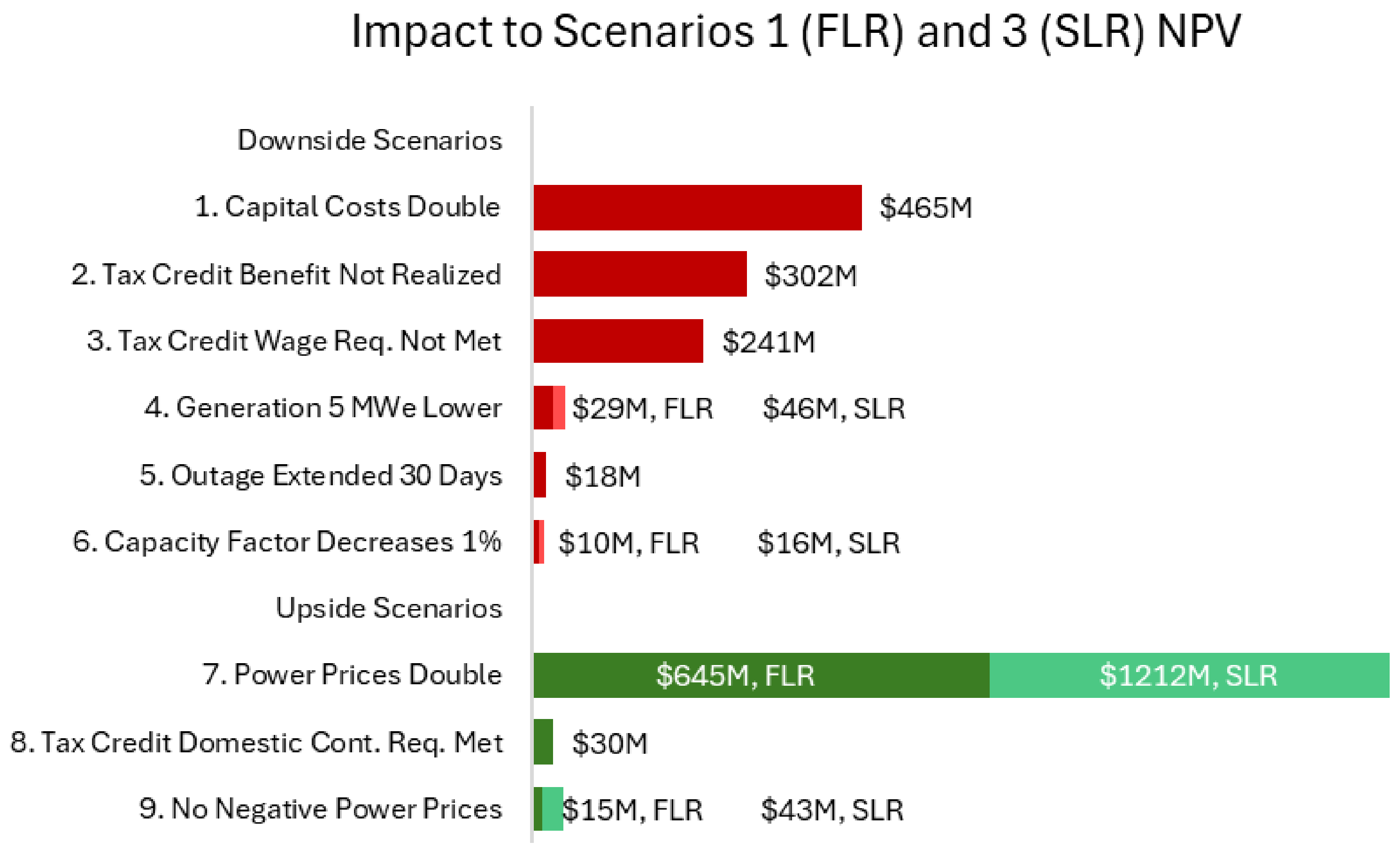
- LCOE = Levelized Cost of Energy; represents average present value cost of uprate MWh over lifetime
- Same trends as prior metrics (SLR with PTC is most favorable)
- Across all scenarios, LCOE ranges from approximately $20/MWh to $80/MWh



*These values represent the range of LCOE for the Columbia EPU incremental to existing LCM costs and benefits.

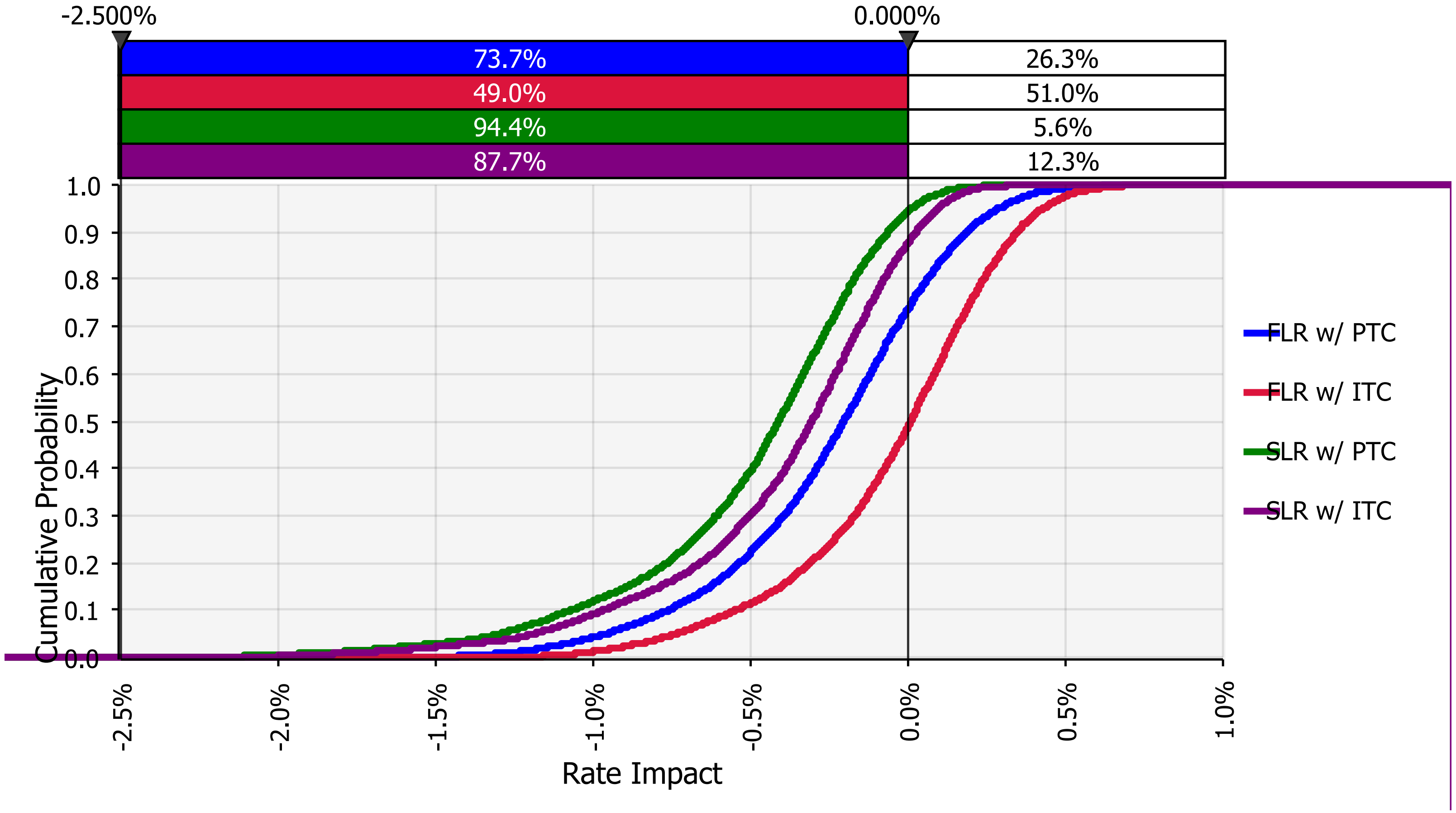
Sensitivity Studies

- **Sensitivities run on Scenarios 1 and 3: FLR/SLR with PTC to examine change in NPV due to altering inputs**
- **Median NPVs**
  - Scenario 1: ~$135M
  - Scenario 3: ~$456M
- **Key Takeaways**
  - Extreme swings in capital costs or power pricing would significantly impact the business case
  - Critical tax credit requirements are met to realize assumed value
  - Other sensitivities have an order of magnitude less of an impact



Probabilistic Results: Rate Impact

- Negative values represent an overall reduction in power rates (negative = favorable)
- Probability of negative power rates align closely with positive NPV
- SLR with PTC has the highest probability of negative rate impact (i.e., ~94%)
- Frequency distributions are skewed to the left, indicating lower (i.e., favorable) rate impact distribution.



BPA Rate Impacts

- While the expected lifecycle cost and benefits of the EPU reduces rates, there is increasing rate pressure during construction until energization of the project and energy is being generated.
- The EPU and LCM associated investments will have impacts to borrowing authority and may make it more challenging for Power to achieve the 60% leverage target.
- The tax-exempt debt issued to finance construction of the EPU and additional fuel purchases will need to be optimized within BPA's debt portfolio and repayment obligations.

NOTE: Revenue in the financial analysis is represented by avoided purchased power costs and/or additional secondary sales

2024 Resource Program Addendum Study: CGS Extended Power Uprate

Agenda

- Describe T1 System Augmentation Sensitivity Needs
- Review candidate resource options and characteristics
- Explain results of CGS Extended Power Uprate (EPU) Sensitivity study

BPA Generating Resource Portfolio

- 31 Federal Hydro Projects
  - US Army Corps of Engineers (operator)
  - US Bureau of Reclamation (operator)
  - ~ 22,000 MW nameplate capacity

- Columbia Generating Station
  - Nuclear power plant near Richland, WA
  - Energy Northwest (operator)
  - ~1,169 MW capacity

Nuclear Energy: Columbia Generating Station

- Other
  - Small amounts of wind and non-federal hydro

T1 System Size Needs - Overview

- Methods:
  - T1 System Firm Critical Output (T1SFCO) is calculated at the hourly level as the sum of existing hydro and non-hydro resource capabilities net of transmission losses, USBR sales, CER exports, and Slice product returns
  - Target T1SFCO is 7250 annual aMW shaped to reflect hourly shape of T1 obligations
  - Metric is the month-average delta between the hourly forecast and target T1SFCO under P10 hydro conditions
- Main findings:
  - Near term annualized needs range from 250 – 400 aMW, which imply much larger monthly needs during late winter and before spring runoff begins
  - Magnitude of needs in outyears significantly influenced by streamflow assumptions under RMJOC-II, ranging from 72 to 272 aMW

T1 System Size Needs - Results

- Annualized view of output (top) masks variation at monthly level (bottom)
- Fluctuations in resource capability due to CGS refueling, system operations, and streamflow sets over 20-yr study horizon

Key Differences, Business Case vs RP

- The business case evaluates potential for energy revenues to outweigh project costs over a range of potential costs and conditions.

- RP analysis is deterministic and selects resources / projects based on meeting BPA needs at the lowest total portfolio costs.
  - Sensitivities are limited.
  - Solutions can and do include resources with costs higher than revenues.

- For this study of increasing Tier 1 system size, the CGS EPU is only competing against other supply side resources (discussed on the following slide). We assume that market purchases / energy efficiency / demand response cannot contribute to these needs.
  - Generation in excess of the needs is valued at forecast Mid-C prices and reduces total portfolio costs.

- The Resource Program does not consider explicit carbon reduction benefits beyond what's included in the market price study.

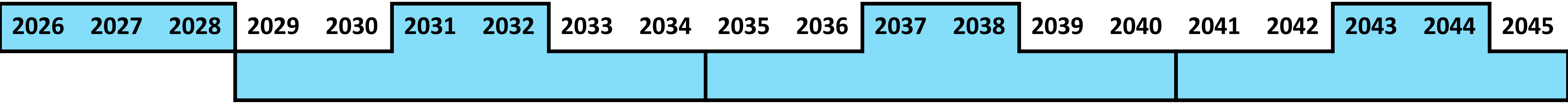
Candidate Resources

- Only supply-side resources located in the Mid-C region are allowed to contribute to meeting T1 System Size needs:
  - CGS EPU
  - Other candidate resources:
    - Solar, wind, 6- and 12-hour storage, hybrid (solar + 4-hour storage), geothermal, SMR
    - Available to come online in 2026*, 2031*, 2037, and 2043
    - Interconnection cost is set 8x higher for additions beyond 300 MW (wind, storage), 450 MW (hybrid, SMR), or 900 MW (solar) per period**
    - Geothermal limited to 100 MW per period
    - We do not include options for contracting with existing resources or for acquiring output from resources for less than their expected plant life

*Geothermal is not available in 2026. SMR is not available in 2026 or 2031.
**Interconnection costs were estimated in collaboration with Transmission SMEs. They can vary substantially across projects and are difficult to estimate.

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

RP2024 Sample years



20XX Indicates sample years that are explicitly modeled.

- Sampling is used to facilitate and simplify extending the Resource Program horizon from 10 to 20 years.

- Resources that come online in 2031 are intended to more broadly represent resources that could come online any time from 2029-2034. Online years of 2037 and 2043 are also representative for their respective sample windows.
  - The model has not been altered to account for the potential need to rely on market purchases for 2029-2030 needs in case the CGS uprate is selected, or if other resources have actual online dates later then FY2029.

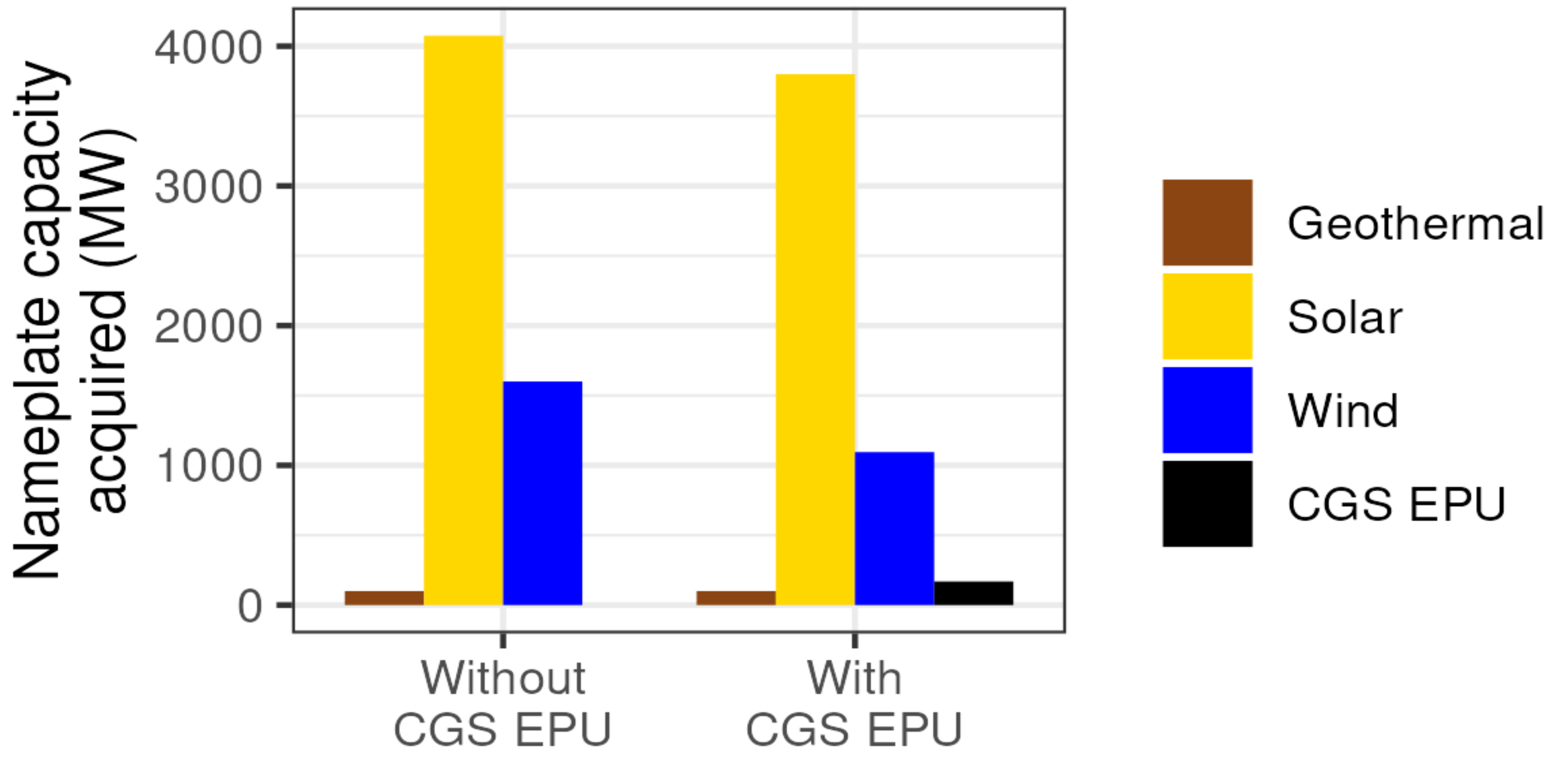
Sensitivities and Results

Sensitivity	Plant life (years)	Fixed costs	CGS EPU selected in least-cost portfolio?	Reduction in total portfolio cost* (billions of $, NPV, 2024)
13-year	13	Current best estimate**	Yes	0.9
33-year	33	Current best estimate**	Yes	1.3
13-year, cost over-run	13	2 x current best estimate**	Yes	0.1
33-year, cost over-run	33	2 x current best estimate**	Yes	0.9

*Reduction in total portfolio cost = Portfolio cost without CGS EPU – Portfolio cost with CGS EPU

**Current best estimate P50 overnight capital cost in $2025 (~$700M). This is inclusive of project estimate, uncertainty with project estimates, and discrete initiative portfolio risks.

Least-cost portfolios with and without CGS EPU



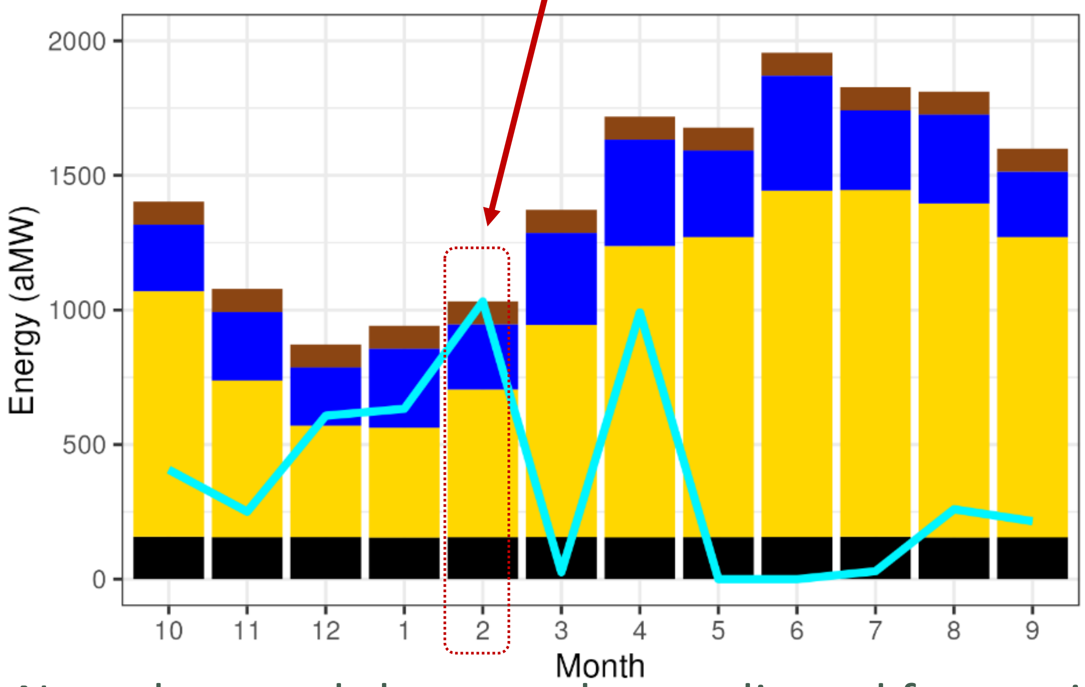
B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

aMW generation compared to P10 monthly needs

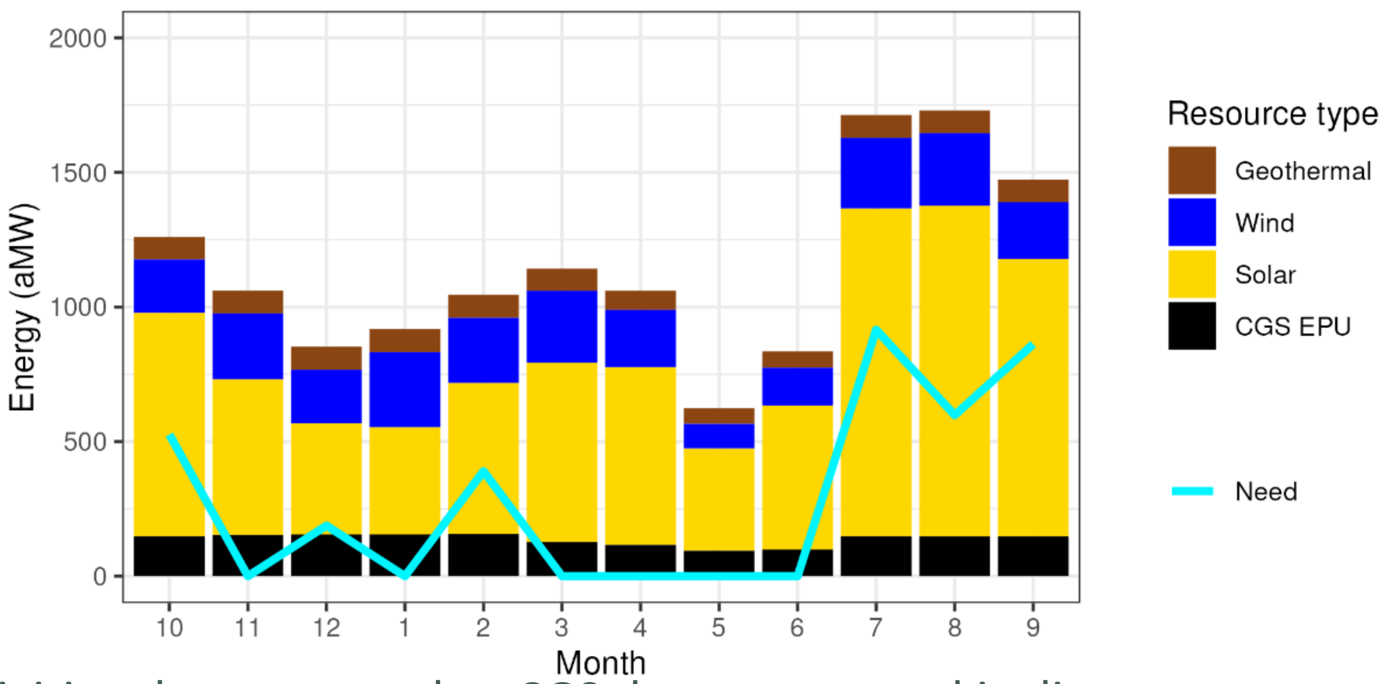
Model is building to meet February needs in 2031-2

Acquired generation greatly exceeds needs in almost all months even under P10 conditions

All hours, FY2032:



All hours, FY2044:



Note that needs have not been adjusted for sensitivities that assume that CGS does not extend its license (i.e., 13 year / FLR cases). Total portfolio costs and resource acquisitions for these cases are likely substantially understated.

Key Takeaways

- BPA and its customers have agreed to increase the Tier 1 System Size for the post 2028 contract period to an annual output of 7,250 aMW.

- Near term annualized needs for more power range from 250 – 400 aMW, with much larger monthly needs during late winter and before spring runoff begins.

- In the resource program, the CGS EPU is included in the least-cost portfolio for meeting these needs, reducing the amount of new solar and wind capacity the agency would need to acquire if the EPU were not available.

Questions and reactions?

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Closing Remarks

EPU Approval Timeline and Project Initiation

Timely project approval supports the issuance of major contracts to various vendors that will allow for the project to start and avoid costly delays.

Date	Action
March 2025	Executive Board Business Case Presentation Mar 27
April 2025	Executive Board Approval of Business Case Apr 16 or 17
May 2025	BPA Finance Committee Approval TBD
May 2025	Contract requisitions and purchase orders to support FY26 EPU scope and long – lead parts Request Executive Board approval & BPA approval to proceed
June 2025	Execute / Confirm Contracts

- Delays will challenge the overall project completion and increase risk of our ability to incorporate EPU work into existing work windows.
  - Initiation and execution of designs and material / component specifications
  - Procurement orders for long-lead parts, initiate planning and execution activities
- Implementation after 2032 could eliminate and/or reduce the Tax Credit values.

Recognition and Appreciation

- Appreciation for the collaboration between the BPA and EN staff in getting us this point
  - Working to integrate the EPU business case into the BPA framework
  - Aligning on key inputs and analysis
  - Coaching on BPA goals and drivers
  - Reviewing and providing insights into the communication products

ENERGY NORTHWEST

Key Take Aways

- There is a growing demand for electric power in the Pacific Northwest
- An Extended Power Uprate is an industry proven method for decreasing the cost per megawatt, and increasing firm capacity
- Unique opportunity to synergize the uprate with the planned life-cycle management modifications and the resultant extended duration outages to lower incremental EPU cost, and the Tax Credits currently available

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EXTENDED POWER UPRATE

Questions?

- Questions
- Commitment Recap
- Presentation Feedback

THANK YOU

Didn’t get your question answered or have feedback?

Email Communications@bpa.gov.

Projects Scope

What Does Columbia's Uprate Consist of?

EPU Construction Projects:

- Set Point Changes: Changes in operating conditions will require calibration changes to multiple systems
- Balance of Plant (BOP) Piping: Additional supports, piping replacements and or installation of vibration monitoring equipment
- Condensate 2nd string heat exchanger: Resizing of several attached nozzles and values to support increased flows
- Condensate Filter Demin: Addition of 2 filter demineralizers to support increased flow and improved margin
- Update to the Power Range Neutron Monitoring system (PRNM): Support changes in core dynamics with uprate
- Motor Operated Valve Actuator replacements
- Reactor feedwater impeller replacement
- Condensate pump and motor modification
- Condensate Booster pump and motor modification
- Steam Dryer replacement
- Condensate Acid cleaning
- Service Water valve replacement

Alignment with the Long-Range Capital Plan

Life Cycle Projects with corresponding EPU scope:

- Condensate 3rd string heat exchangers replacements
  - EPU scope: nozzles, dump and drain valves
- Condensate 4th string heat exchangers
  - EPU scope: nozzles, dump and drain valves
- Condensate 5th string heat exchangers
  - EPU scope: nozzles, dump and drain valves
- Low Pressure Turbine; 2 internal inspections
  - L2 stationary blade replacements; 3 turbines
- Isophase bus duct
  - Proration of rate for increasing size of the cooling fan
- MSR tube replacement
  - Installation support resizing of two relief valves
- Main Generator & Auxiliaries
  - Larger generator output for EPU / Design input
- 115 Kv substation
  - Implementation alignment
- AC Distribution center
  - Implementation alignment
- Jet Pump anti-vibration unit install
  - Under evaluation
- High Pressure Turbine
  - Design input

Life Cycle Management LRP Overview / EPU Integration

Moisture Separator Reheater
E-TR-N1/N2
E-SM-1, 2, & 3
Fuel Change Begins
FWHLC
Digital FW Lvl Control
Reactor Feed Pump

RFW-HX-5A/5B
COND-HX-3C
E-TR-S & E-TR-B
115Kv BPA Substation
CGS Distribution Center
DEH Control system
Condensate P&M
LPT Inspection
Isophase Bus Duct Cooler

Main Generator & Auxiliaries
MG Voltage Regulator
MG exciter HXs
HP Turbine
CCH-CR-1A/1B
Condensate Booster P&M
RMCS

COND-HX-4A/4B/4C
COND-HX-3A/3B
Jet Pump AVS
BPV Configuration

EN: FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34

Rate Case: BP 26 | R28 | BP 29 | R29 | BP 31 | R30 | R31 | BP 33

Extended Power Uprate

MSR Relief Valves

COND-HX-2A,B,C
(Replace LCV, upsize nozzles, resize HD, replace end plate)

BOP Piping

Condensate Filter Demin
RFW-HX-5A,B,C Upsize FWH & nozzles, replace LCV, dump valves & end plates.
COND-HX-3A,B, C upsize nozzles, replace LCV, dump valves & end plates.
PRNM & DSS-CD (data gathering)
Vibration Equip Install
LPT L2 Segmental / X's 3
Glad Steam Piping
MOV Actuator Replacements
Service Water Valve Replacement
Reactor Feedwater Impeller
Condensate Pump & Motors

Steam Dryer Replacement
PRNM & DSS-CD
Various Set Point Changes
BOP Vibration Monitoring
Jet Pump AVS
Condense Acid Cleaning
EPU Ascension Testing
MOV Actuator Replacements
Cond. Booster Pumps & Motors

Steam Dryer Inspections
BOP Vibration Equipment Removal

EN Fiscal Year July 1 – June 30 (1 YR)
BPA Fiscal Year Oct 1 – Sept 30 (1 YR)

Color Key
*Alignment with EPU Project

Implementation Schedule

Leveraging existing Refueling and Maintenance schedule for Columbia

- EPU Project Schedules have been compared to LCM outage schedules and currently **EPU is not expected to extend any of the outages**
- Based on current schedules, **the EPU projects are estimated to be at least ~60% or 19 days shorter in duration** than the critical path LCM project in each outage period
- Each refueling and maintenance outage window is developed by evaluating the work scope to be executed during the planned event

Additional Risk Information

EPU Project Developing Cost and Risk Inputs

- Conceptual Studies were completed to support scope development
- Risk registers were developed for each of the projects as well as the EPU portfolio
- Risk statements, along with likelihood, consequences, and mitigation methods were provided
- The risk registers were leveraged to inform project cost estimates
  - Following estimate development, high-likely project risk allocations were included in the registers and individual project estimates
- Uncertainty in project costs and discrete initiative portfolio risks were quantitatively included in the financial analysis

External Risk for Timely Integration – FY29

- **Transmission & Grid Infrastructure**
  - Interconnection Agreement: Generator MVA rating change
    - Requires updated interconnection agreement (No more than 270MVA)
    - Initial submittal August of 2023, Resubmitted in 2024 at BPA request
    - Grid Analysis is required for NRC licensing amendment submission CY28
  - 115Kv Substation build: Supports current Columbia margin issues and integration of updated pumps and motors for EPU
    - Substation will tie into an Energy Northwest distribution center,
    - Tie in for EPU components scheduled R29 / CY29
    - Previously identified predecessors:
      - Midway – Ashe Rebuild
      - South Tri-Cities Reinforcement
      - Sacajawea to Franklin – Ice Harbor #1

EPU Agency Enterprise Risk - Inherent

- ERM reviewed the initiative project risk register, assessed risks against each of the agency's enterprise risks
- ERM considered both the agency's current risk appetite as well as lessons learned from previous outages and large-scale projects to determine and assess inherent and residual risk
- This is an aggregate view of the EPU initiative risk register, considering risks which are either affected by or contribute to agency enterprise risk within the EPU initiative
- The focus was on the identified risk priority values, which is a combination of probability and impact. This is both data driven, coupled with some subjective input
- Risk Definitions:

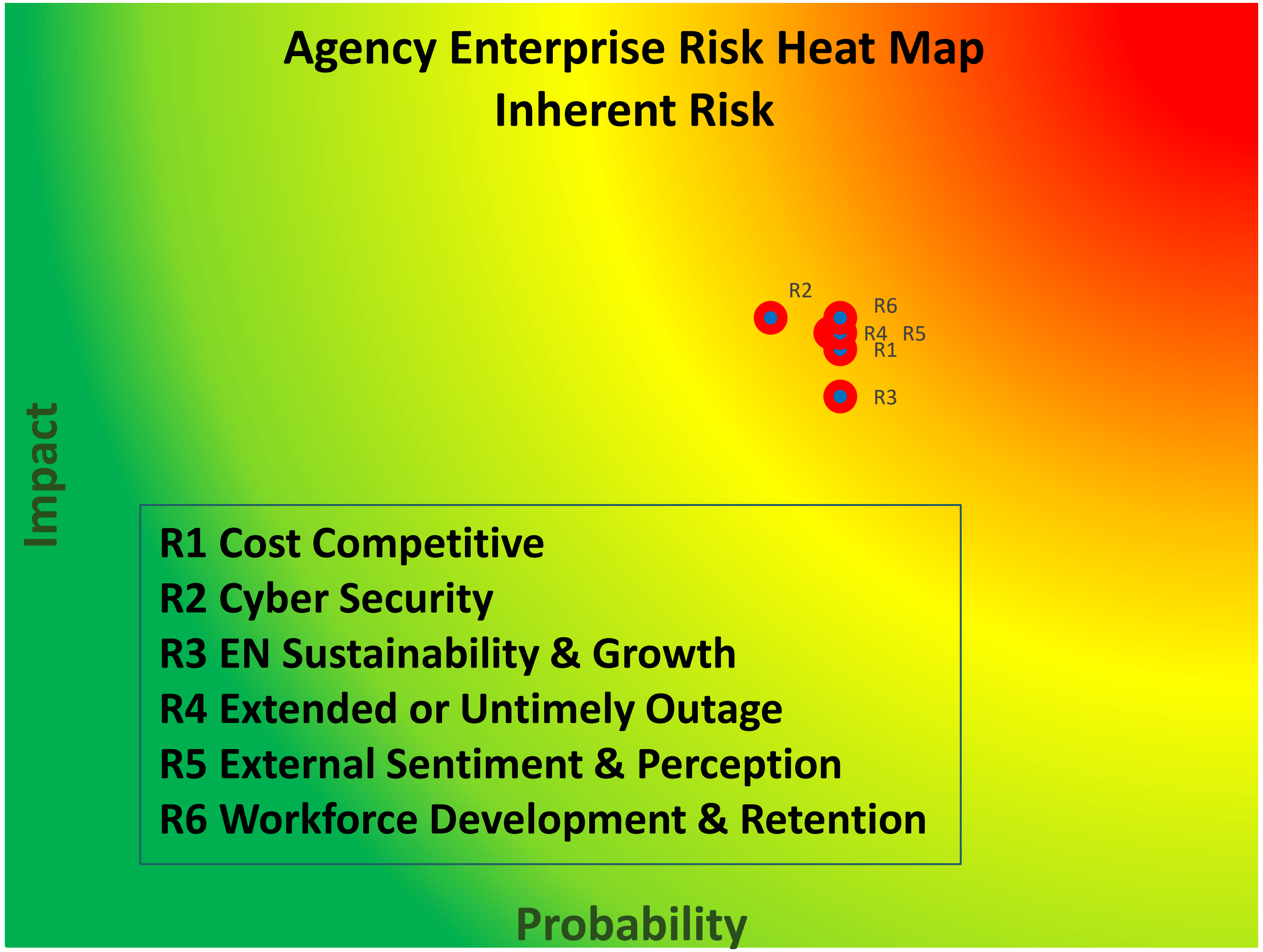
  Inherent risk: The risk in the absence of any mitigation or control

  Residual risk: The risk remaining after the mitigation or control is implemented.

EPU Agency Enterprise Risk - Inherent

Risk categories considered include:

- *Outage Duration*
- *Project Execution*
- *Inflation / Costs*
- *Technical / Design*
- *Environmental*
- *Governance*
- *Reputation*

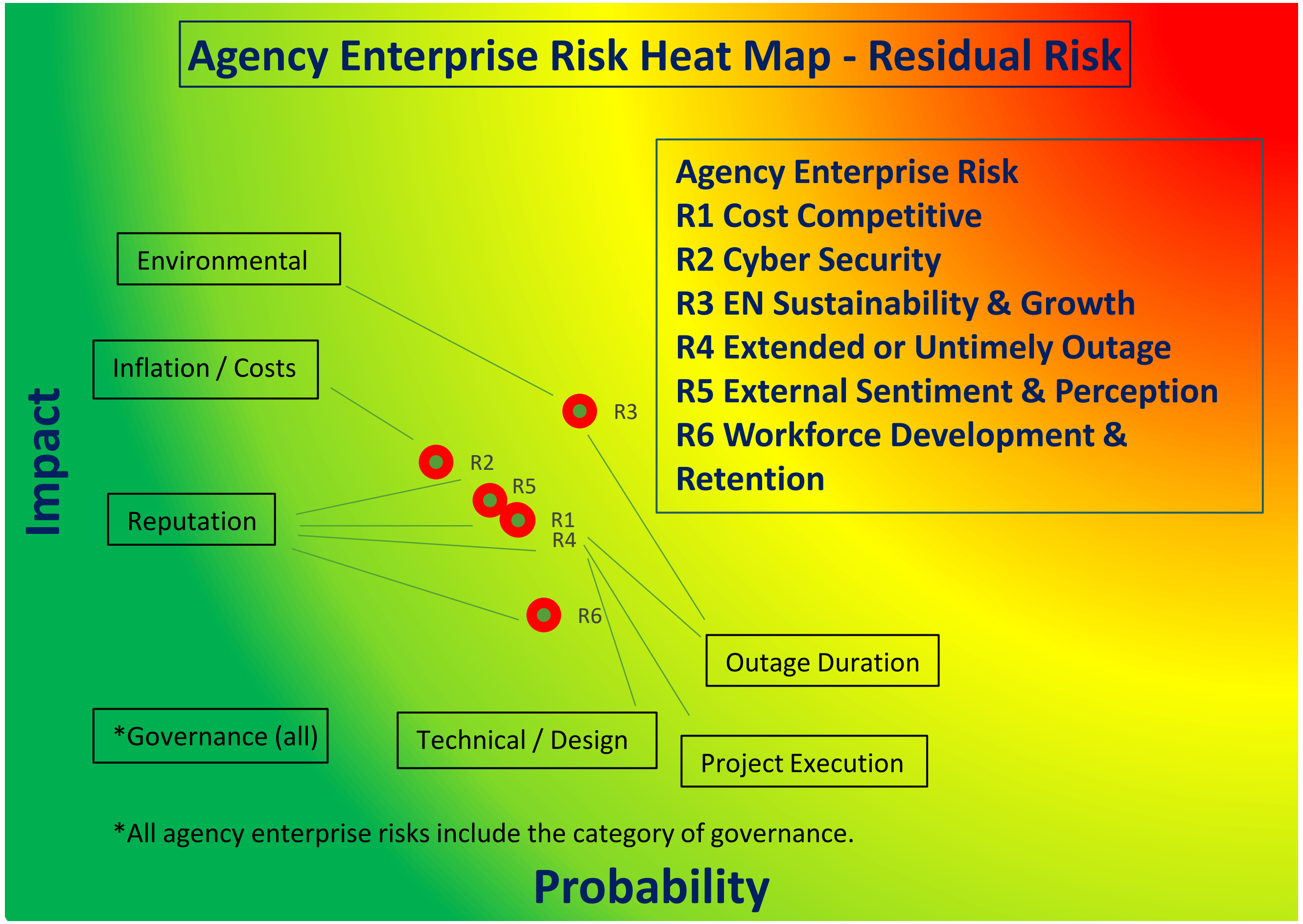


R1 Cost Competitive
R2 Cyber Security
R3 EN Sustainability & Growth
R4 Extended or Untimely Outage
R5 External Sentiment & Perception
R6 Workforce Development & Retention

EPU Agency Enterprise Risk - Residual

Mitigation Strategies Include:

- *Oversight & governance includes Executive Board and BPA oversight, Management Risk Oversight Committee, Steering Committees, etc.*
- *Industry benchmarking, including incorporating lessons learned from other plants with EPU projects, participating in industry working groups*
- *Cross-departmental collaboration including EPU Team, Enterprise Risk Management, Corporate Finance, Construction & Project Management, Design Engineering, Outage Planning, etc.*
- *Knowledge retention and succession planning incorporated into project plans*
- *Continual monitoring of external events and policy changes to incorporate into planning mitigates unpredictable external forces*

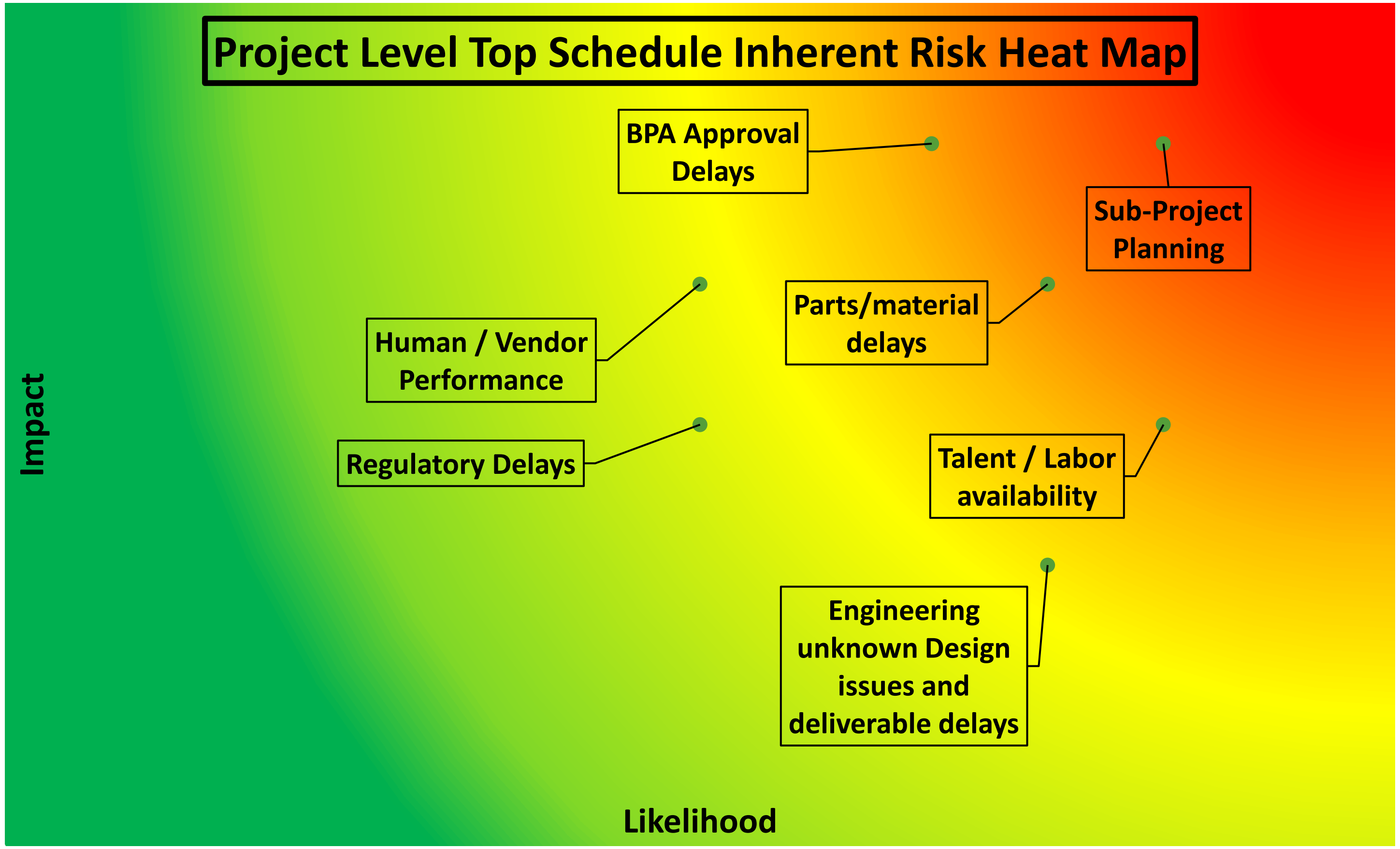


EPU Project Level Risk Management (PLRM) methodology

- PLRM reviewed the EPU initiative project and sub-project risk registers, assessed risks to successful project implementation.
- PLRM used inherent (prior to mitigation) to provide a starting point as displayed on the inherent risk slides for schedule and budget. Then the same risks were reviewed following mitigation to show the residual risks to successful project implementation.
- The focus was on the identified risk priority values, which is a combination of probability and impact. This is both data driven, coupled with some subjective input.
- The residual risk values were also determined in the same manner following implementation of the mitigation actions.
- Evaluation of mitigation actions is an on-going process to improve their effectiveness during project implementation.

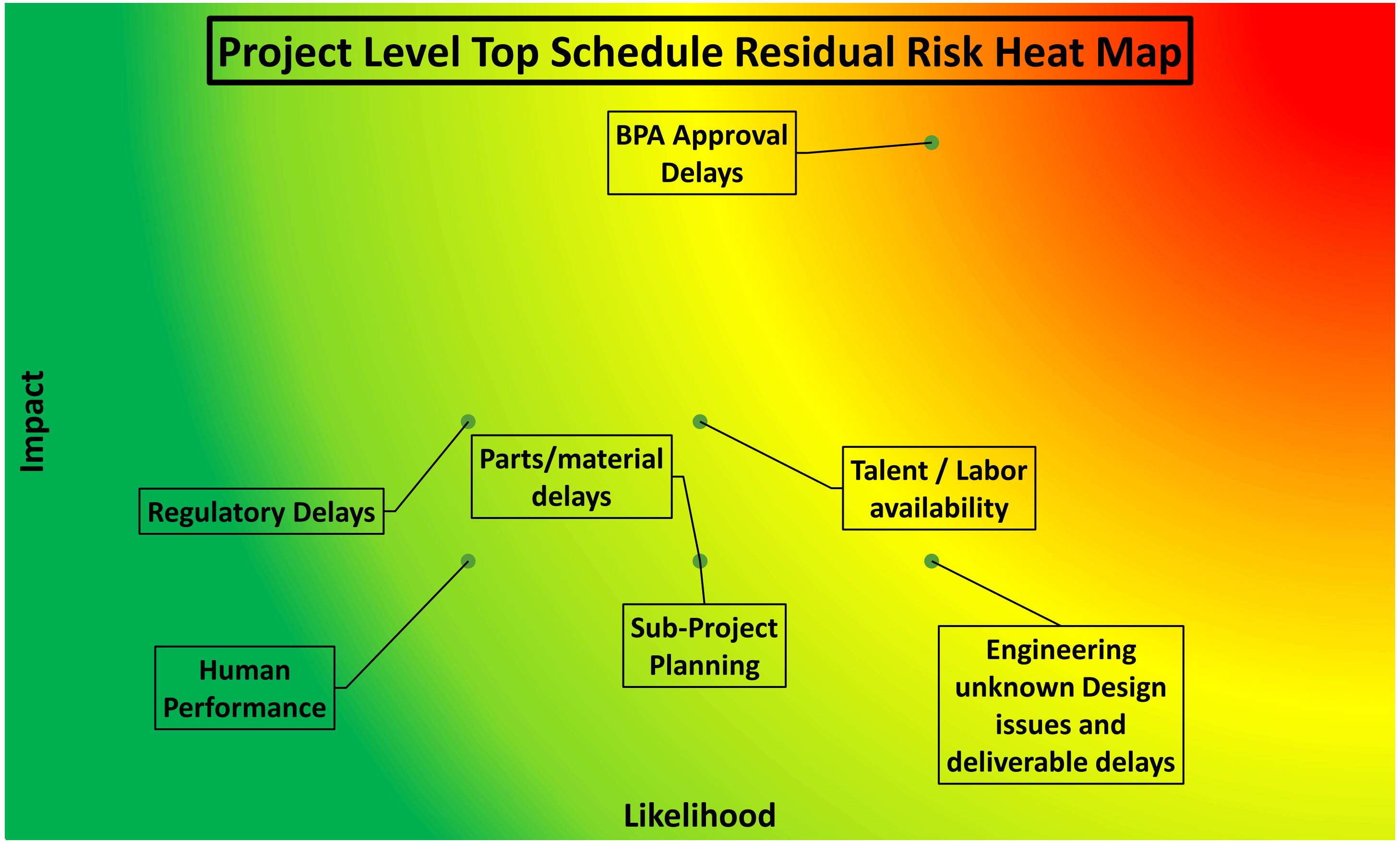
Project Level Top Risks impacting Schedule - Inherent

- *Identify Top risks to project implementation schedule.*
- *Sub-Project scope and schedule challenges until refinement of scope occurs to inform both schedule and budget.*
- *BPA Approval delays if realized impact as soon as July 1, 2025 Talent/Labor availability due to timing in relation to outages and other projects at the same time.*
- *Engineering delays is a broad category with multiple mitigation strategies.*



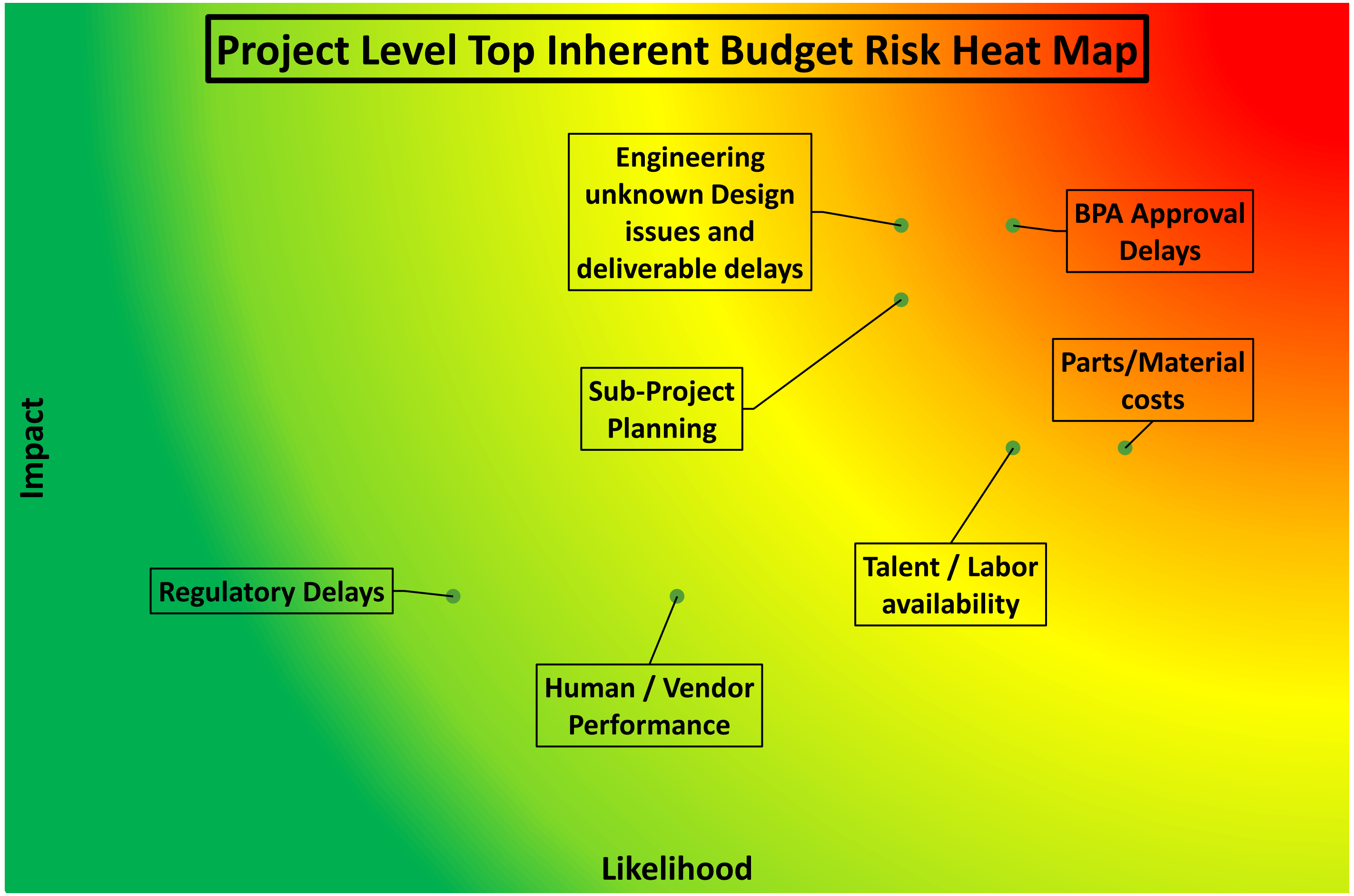
Project Level Top Risks impacting Schedule - Residual

- *BPA Approval delays mitigated through focused/constant interaction to finalize approval ASAP. Continuing this is imperative as the project implementation progresses.*
- *Sub-Project Planning risks mitigated through feasibility studies that provided refinement in the scope and planning of these projects (appx. 30 projects).*
- *Talent/Labor availability mitigated through EPU project succession planning and talent retention incentive plan.*



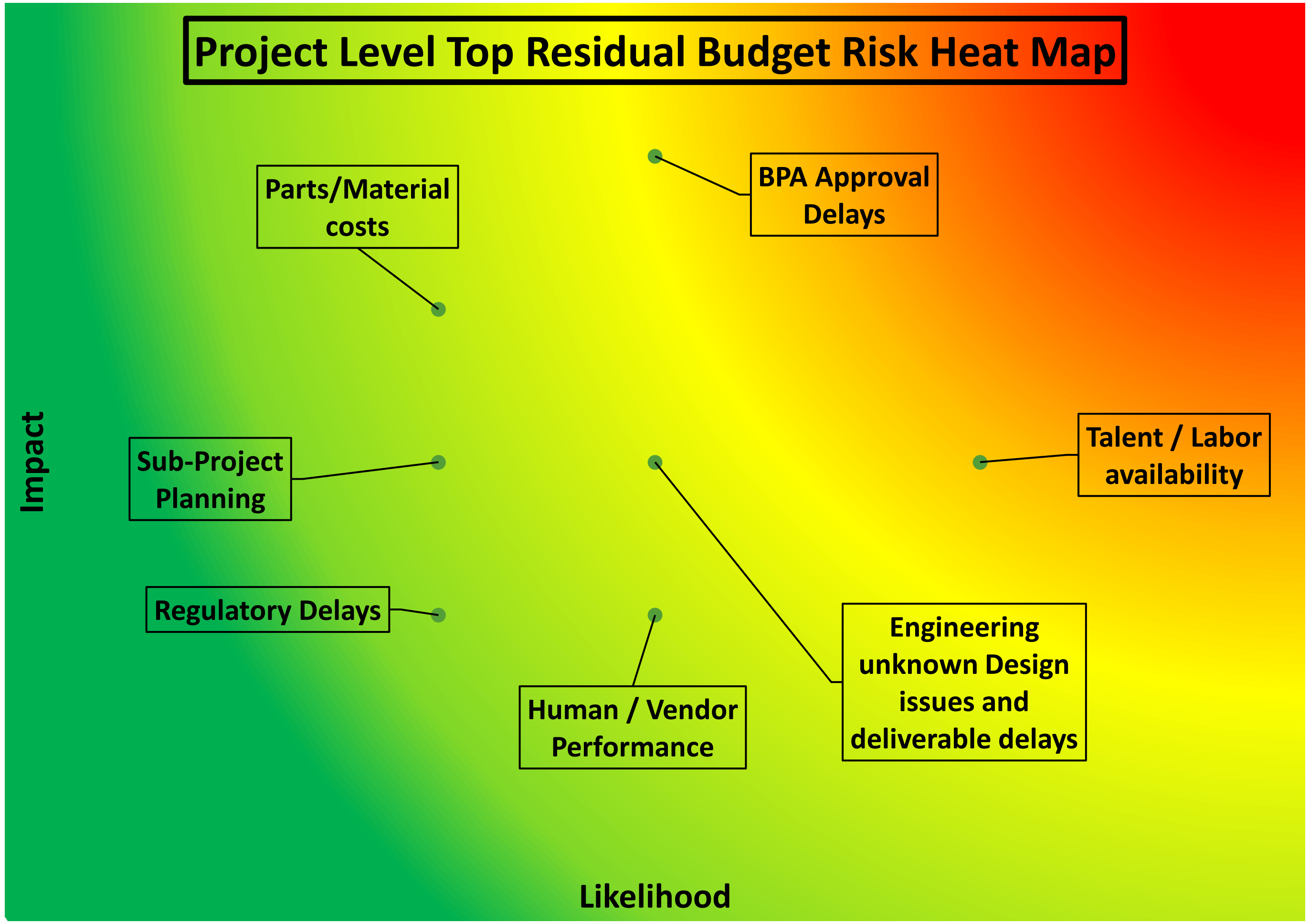
Project Level Top Risks Impacting Budget - Inherent

- *BPA Approval Delays – funding to commence implementation plan.*
- *Sub-Project Planning – identification of additional resources to recover any unknowns.*
- *Parts/Materials costs – tied to current supply cost uncertainties*
- *Engineering delays – additional costs due to current unknowns that will be identified as designs mature. This also includes any additional resources that may be needed for recovery activity.*
- *Talent/Labor availability – incentives may be necessary to retain talent.*



Project Level Top Risks Impacting Budget - Residual

- *BPA Approval Delays – mitigated through business case inclusion of worst-case scenario. Also, constant interaction with BPA counterparts.*
- *Sub-Project Planning – mitigated through feasibility studies and actions coupled with focusing risks appropriately at the sub-project level with escalation process.*
- *Parts/Materials costs – tied to current supply cost uncertainties. Mitigated through "locking in" as early as possible for larger components and monitoring supply environment*



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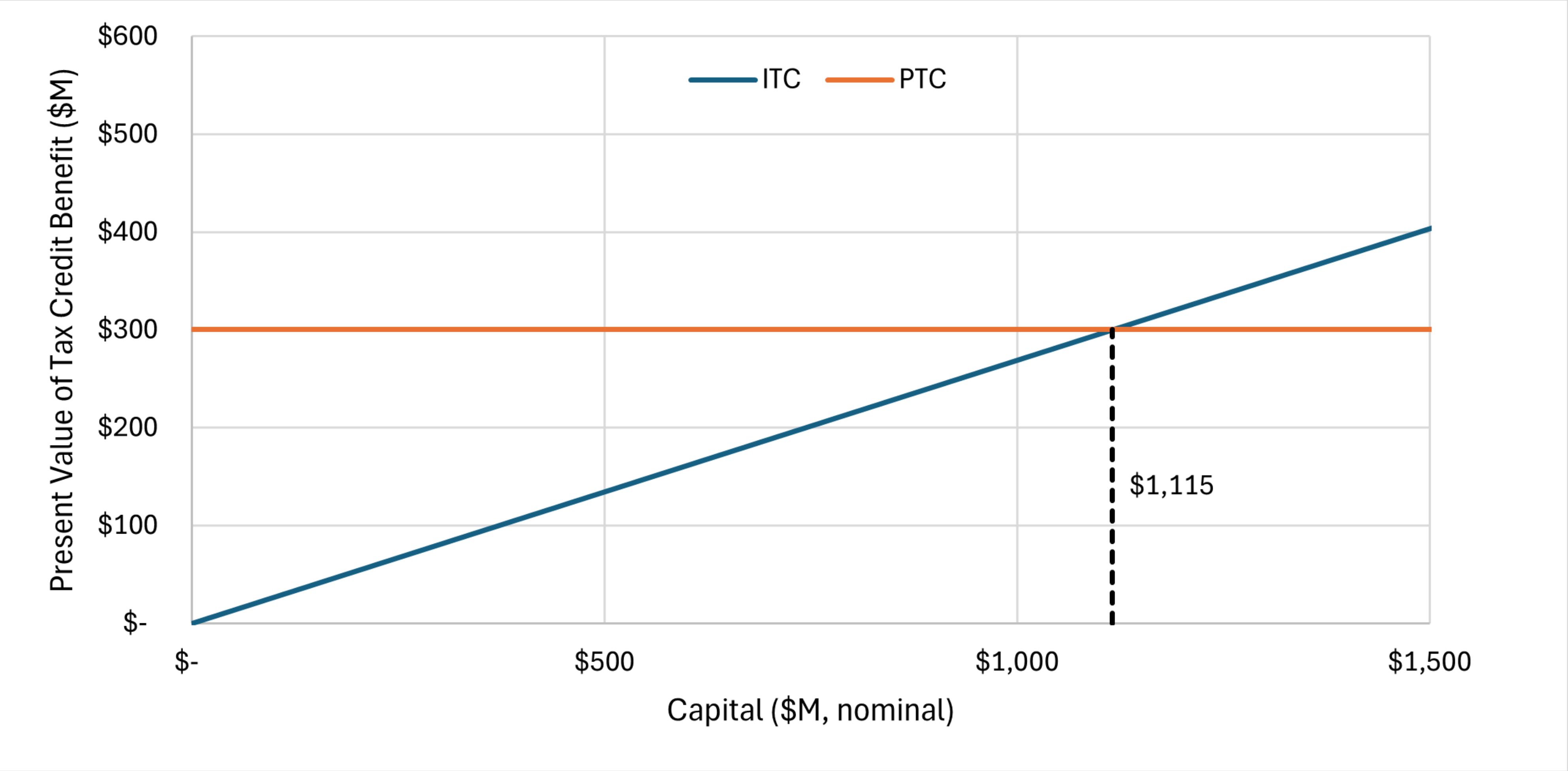
Analytic Information

Understanding Results - Economics

Result terminology includes several key variables as defined below.

- **Overnight Costs –** The cost of construction if no interest was accrued. This is the cost of something independent of the time value of money.
- **Present Value –** The current value of a future sum of money or cashflow.
- **Real Dollars –** Also known as constant dollars, this is the value of money expressed in dollars adjusted for inflation.
- **Nominal Dollars –** The actual amount of money spent or earned over a period of time – measured in terms of purchasing power (i.e., real dollars plus inflation).

Cashflow Development – Tax Credit Benefit



Financial Model Key Insights

- The median results of the business case indicate the EPU would payback within the existing license period and have a favorable rate impact for BPA customers
- EPU provides the opportunity to produce more energy should license be renewed to operate through 2063 (SLR case)
- All four scenarios analyzed had a probability of positive NPV greater than 50%, while the SLR scenarios have probabilities greater than 90%
- Sensitivity studies confirm the impact of extreme swings in projected power pricing and capital cost inputs as well as emphasize the importance of the tax credits

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2024 Resource Program Addendum Study: CGS Extended Power Uprate

CGS EPU cost assumptions

Tax Credit treatment	PTC
PTC (2025 $/MWh)	$28.72
Tax liability	WA generation (Privilege) tax
FOM (2025 $/kW-year)	$0
VOM (2025 $/MWh)	$0
Overnight capital costs (2025 $/kW)	$4,324
Weighted average capital cost (nominal)	3.40%
Plant life (years)	13 or 33 years
Construction time (years)	7 years**

*WA generation tax = 1.07 x annual generation (MWh) x wholesale preference rate ($/MWh, nominal) x 1.5%. Wholesale preference rate is assumed to have a constant real value of $34.33/MWh (2025 $)

**Some construction costs (2.1% of total) extend into years 8 and 9, after uprate comes online

Capacities available of resources other than CGS EPU

Resource type	Nameplate capacity available per start year* and type	Special restrictions in 2026 or 2031
Solar	300 MW + 1000 MW at higher interconnection cost** at each of 3 locations	Only 600 MW available per location in 2026
Wind and 6- and 12-hour storage	300 MW + 1000 MW at higher interconnection cost	Only 600 MW available in 2026
Hybrid (solar + storage)	450 MW + 1500 MW at higher interconnection cost	Only 900 MW available in 2026
Geothermal	100 MW	Not available in 2026
SMR	450 MW + 1000 MW at higher interconnection cost	Not available in 2026 or 2031***

*Start years: 2026, 2031, 2037, 2043

**Higher interconnection cost is 8x higher than the interconnection cost used for the initial 300-450 MW

***We have also run a sensitivity in which SMR is available in 2031

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Other Information

Power Plant License Renewal

- Almost all of the existing plants have had their first license renewal approved, or are in the process of obtaining approval.
- To-date, approximately 10 plants have received approval for a subsequent license renewal, with approximately 12 being reviewed.
- The remainder of the plants have identified in an Nuclear Energy Institute (NEI) survey an interest in obtaining a subsequent license renewal.