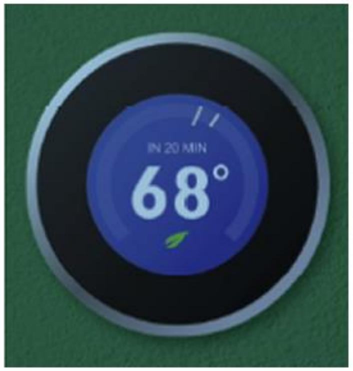
Integrated Resource Plan
2019 IRP Public Input Meeting
June 28-29, 2018



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Agenda

June 28, 2018 – Confidential Discussion

- Introductions
- Model Overview (System Optimizer / Planning and Risk)
- Lunch Break (1 hour) 11:30 PT/12:30 MT
- Unit-by-Unit Coal Study Results

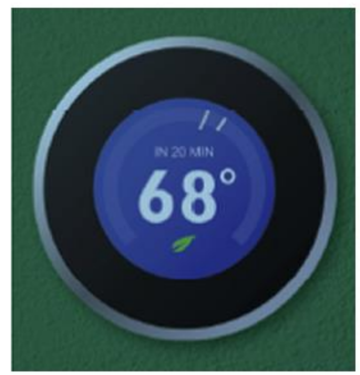
June 29, 2018 – Public Discussion

- 2017 IRP Update Highlights / 2019 IRP Topics and Timeline
- Lunch Break (1 hour) 11:30 PT/12:30 MT
- Demand-Side Management Workshop

Modeling Overview

Confidential Workshop

2019 IRP Public Input Meeting - June 28, 2018



Overview

- Discussion of optimization modeling and overview of PacifiCorp's specific IRP optimization models
- This discussion is not intended to:
  - Provide user training or replicate operator-level training provided by model vendor ABB
  - Convey instruction in optimization math
- Presentation of model functionality is from the perspective of PacifiCorp's use
- Detailed technical questions on the model logic require ABB input and may be subject to license and/or non-disclosure agreement with ABB

Optimization Modeling

Optimization Modeling Overview

- Optimization Modeling (OM) is also referred to as:
  - Linear Programming (LP) or Linear Optimization

- OM can be meaningfully compared to the alternative of "stepwise" problem solving

- Key Features:
  - OM is a mathematical model
  - OM math achieves the best (optimal) outcome (such as the lowest Present Value Revenue Requirement (PVRR))
  - OM solutions recognize and obey constraints, requirements, parameters and relationships (e.g., reserves requirements, unit capabilities, transmission constraints, market prices, etc.)
  - OM math avoids the need to examine every possible combination of inputs and options to determine the correct optimal solution

Stepwise Approach

- Solves a problem by executing a series of intuitive steps
- Example: If you know that you must hold reserves on your energy system, some of your steps might be:
  - Rank your generators by reserve carrying cost, low to high
  - Hold reserves on each unit, in order, until reserve requirements are met
  - Determine how much generating capacity is left after reserves
  - Rank order your units by energy production cost, low to high
  - Generate from each unit, in order, until all loads are met
  - Calculate remaining generating capability ("excess energy")
  - Sell excess energy at market:
    - …when economic; compare production cost to market prices
    - …when deliverable; keep a running total of transmission usage
- Repeat your steps for every hour (or other period) of every year, accounting for what you did in the prior hour (e.g., unit commitment)

OM Approach

- OM mathematically determines the best (optimal) solution:
  - By eliminating solutions that cannot meet requirements (infeasible)
  - By eliminating feasible solutions that cannot be the optimal solution
  - By assessing linear relationships to get as close to the optimal solution as possible and;
  - Provides available output about the best solution. Possible output includes:
    - Discrete decisions (e.g., add capacity at a particular site, acquire a particular DSM package)
    - Energy production of modeled resources, usage of transmission, purchases of capacity or energy from markets

- Not all information is needed to provide a solution
  - Example:
    - No need for a reserve stack
    - No need to assign reserves to specific units

A Very Simple OM Example

How much gas energy and how much coal energy should we generate?

Objective: Minimize system costs assuming two generating units (one gas, one coal), one transmission line, and one load area, operating for a period of one hour.

Relationships: A transmission line conveys energy to the load area.

Parameters and Constraints (in this one hour):

- Generate up to 120 MW from our gas unit
- Generate up to 150 MW from our coal unit
- Transmission capacity and load requirement are both 200 MW

Run cost:

- 1 MWh of gas-power costs $2 to generate
- 1 MWh of coal-power costs $3 to generate

OM Simple Example, continued

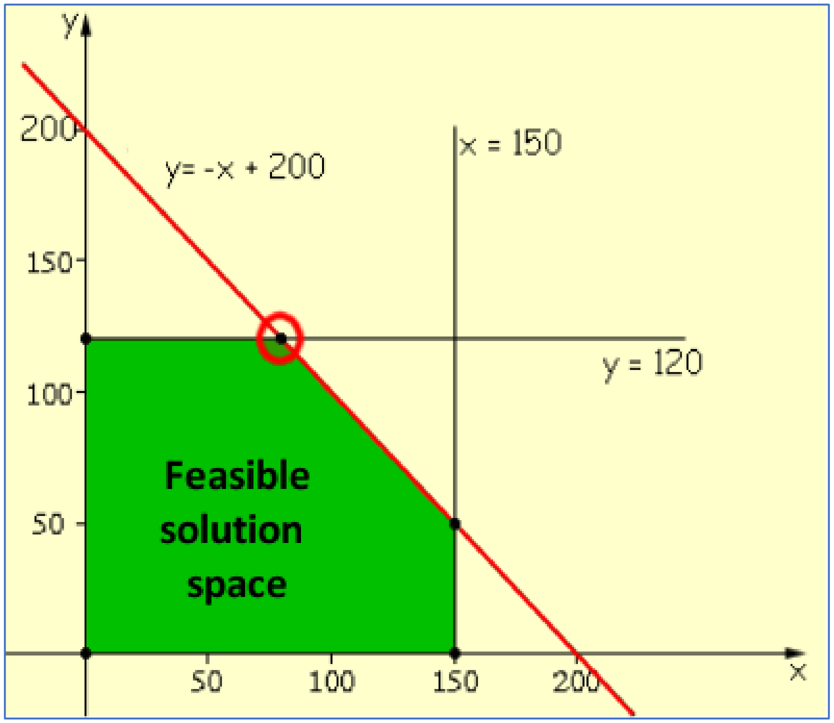
- Modeled constraints and objectives become mathematical constraints and objectives, expressed as inequalities:

Inequality	Purpose
$x \leq 150$	Coal can generate up to 150
$y \leq 120$	Gas can generate up to 120
$x + y \leq 200$	Total MW cannot exceed transmission
$x + y \geq 200$	Generation must meet load requirement
$x \geq 0$	Coal generation cannot be negative
$y \geq 0$	Gas generation cannot be negative

- The model uses these inequalities to define a "feasible solution space" – a range of possible solutions that *might* be the right answer

OM Simple Example, continued

- The graph at right illustrates how the math defines the “feasible solution space”
- The load requirement dictates that only solutions along the red line could be the right answer. (At each point on the red line, the generation total is 200 MW.)
- The model “searches” for the edge of the feasible solution space, then examines other solutions along that edge to see if moving in one direction or the other improves the solution (lower PVRR).
- The model quickly arrives at the optimal solution, found at one end (vertex) of the 200 MW load requirement.
- This vertex meets all requirements and constraints, and produces the lowest PVRR. No other solution does this.



OM Advantages and Complexities

- You get the best (i.e., optimal) answer
  - Complexity: The best answer may not be immediately intuitive

- Multi-dimensional problem solving; detailed precision and accuracy that non-optimization approaches cannot match
  - Complexity: Determining an acceptable amount of complexity
  - Complexity: Tremendous amounts of data are required
  - Complexity: Time required to produce and analyze results

- OM math is incredibly fast; does not require all solutions to be examined or known
  - Complexity: All desired outputs may not be readily available

PacifiCorp IRP Models

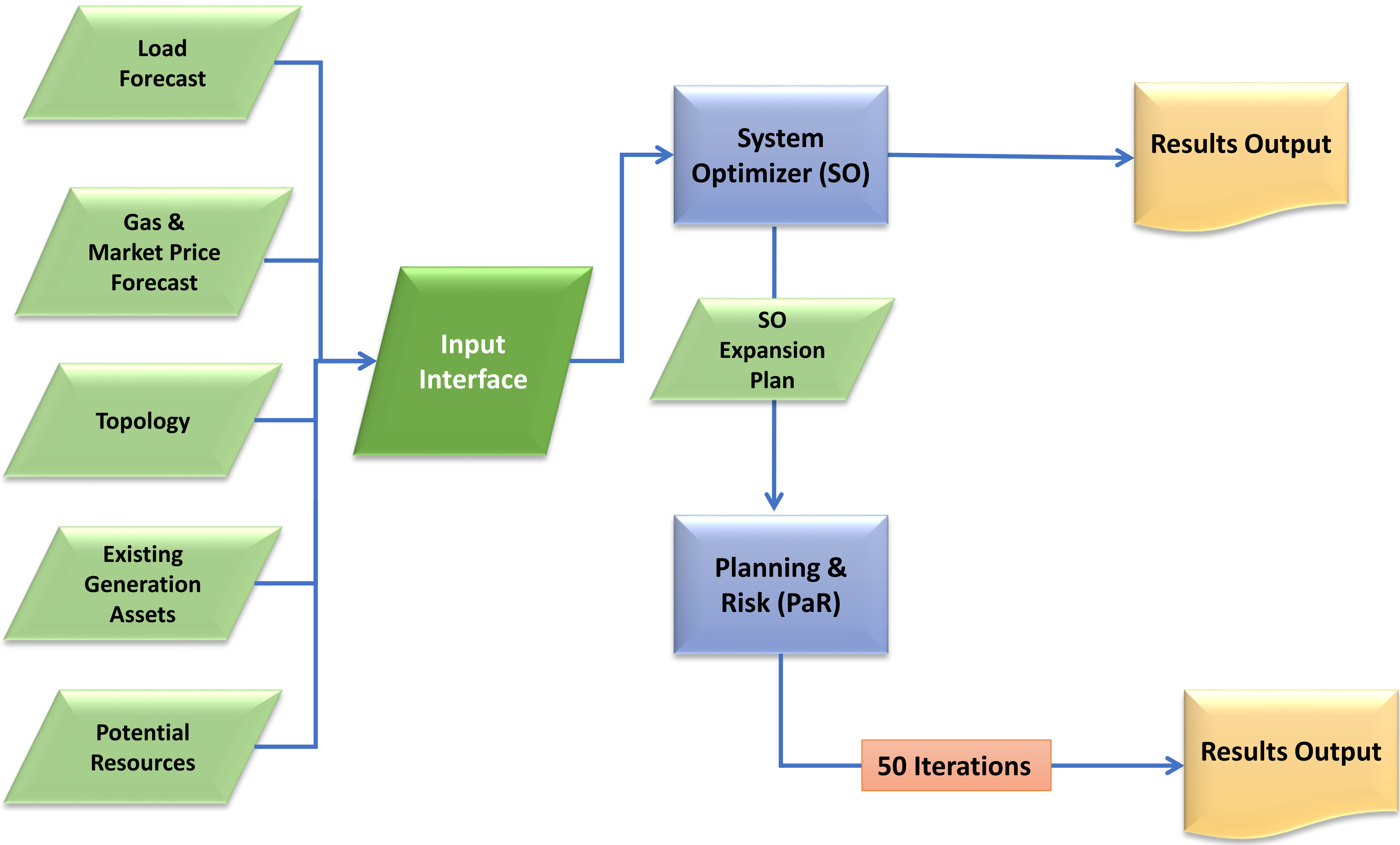
- Licensed with the ABB Group
- Two models:
  - System Optimizer (SO)
    - Capacity Expansion Planning OM
  - Planning and Risk (PaR)
    - Stochastics and Risk Chronological OM
- Common Interface
  - A standardized Windows®-based application platform
  - Integrated MS-SQL® database for input and output data
  - Multi-user access, data management and data scenario control
  - Limited automated execution of many program functions

SO and PaR Attributes

System Optimizer	Shared Attributes	Planning and Risk

• Mixed integer linear program (MILP)
• Deterministic
• Sampled hours of data
• Minimize NPV portfolio costs
• Minimize thermal and hydro dispatch costs
• Determine an optimal system-wide resource build plan
	• Same database
	• Transmission topology
	• Same inputs include:
	  • Load forecast
	  • Forward prices
	  • Hydro forecast
	  • Thermal resources
	  • Contracts
	  • DSM
	  • Expansion resources selected in SO
		• Chronological optimization model
		• Monte Carlo simulation modeling
		• Stochastic
		• Hourly data for planning horizon
		• Iterative process (50 Iterations)
		• Correlation of variables – Indices
		• Production cost valuation
		• Unit commitment logic

SO and PaR Model Workflow

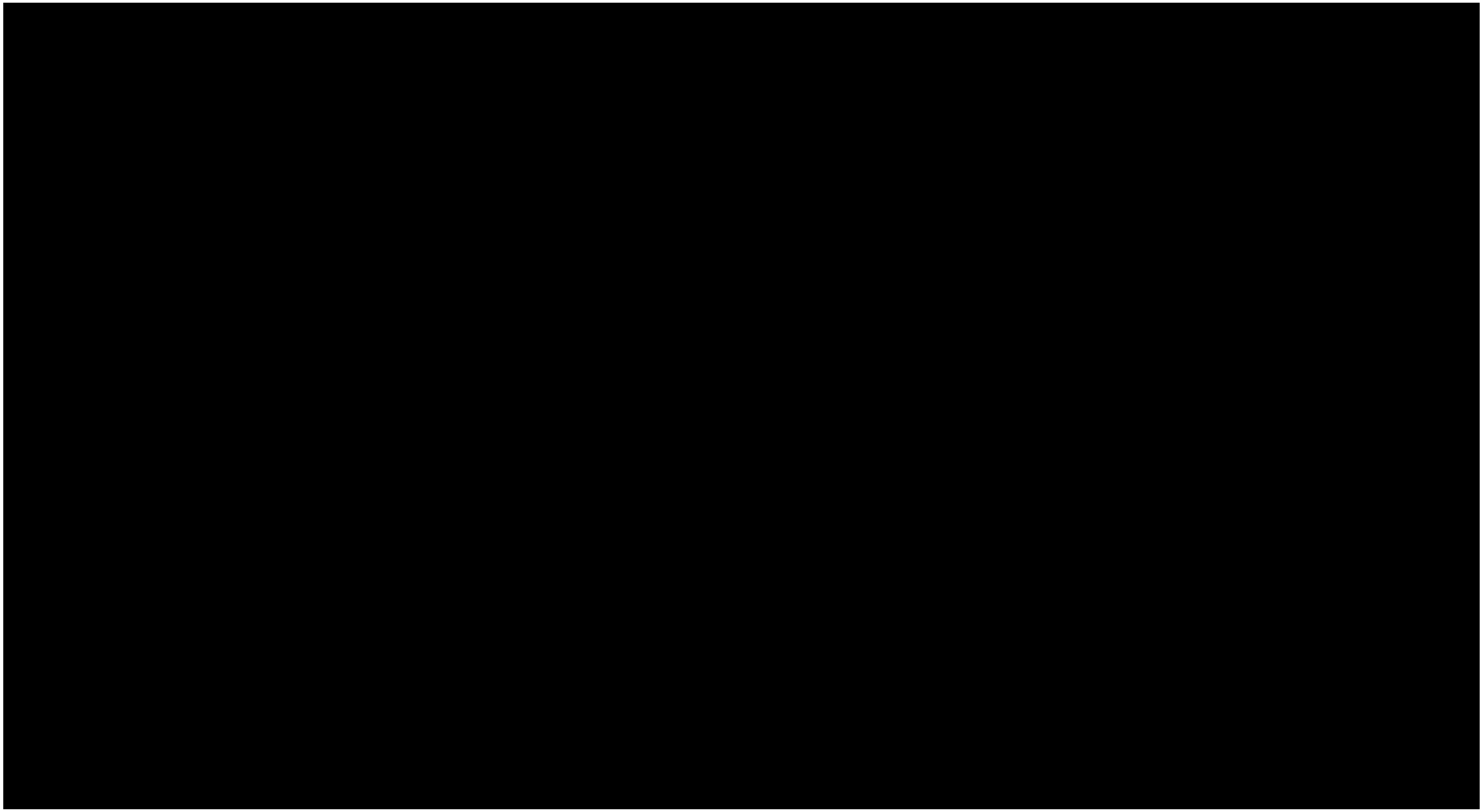


System Optimizer (SO)

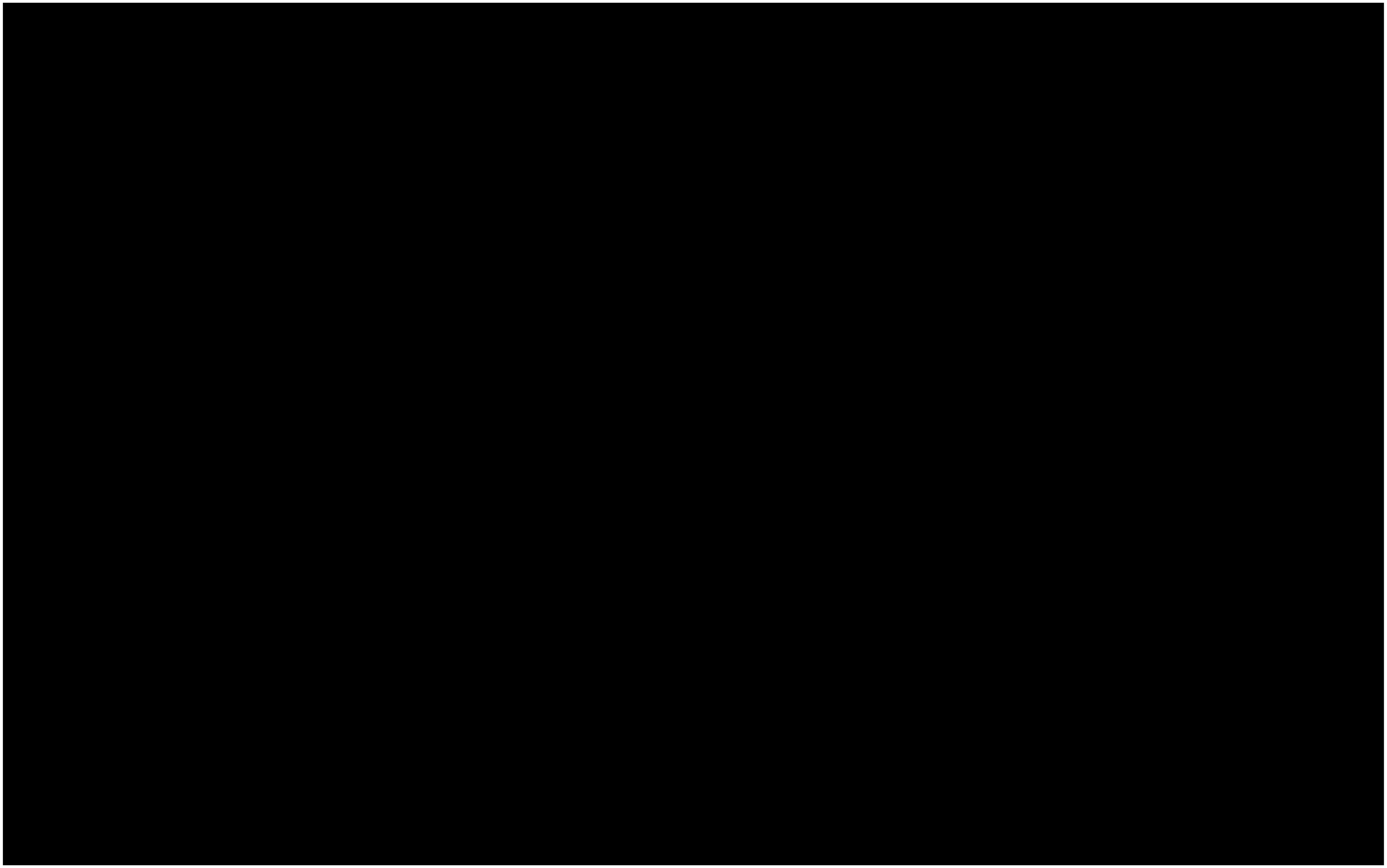
SO Overview

- SO is a capacity expansion model that produces optimized resource portfolios for subsequent stochastic modeling.
- SO addresses key resource questions:
  - What, when, where and how much to build or retire?
- Model Setup:
  - Day type aggregation - 3 Day (Ave Day, Sat, Sun)
  - Peak and Super Peak defined
- Model Run Times:
  - 1 to 4 hours depending on solution requirement for a 20-Year study
  - Resource options to evaluate increases substantially for more study years added
- Key SO Reporting Includes:
  - Resource portfolio, PVRR results, DSM selections, generation by resource, and emissions

System Optimizer Run Set-up



System Optimizer Run



Planning and Risk (PaR)

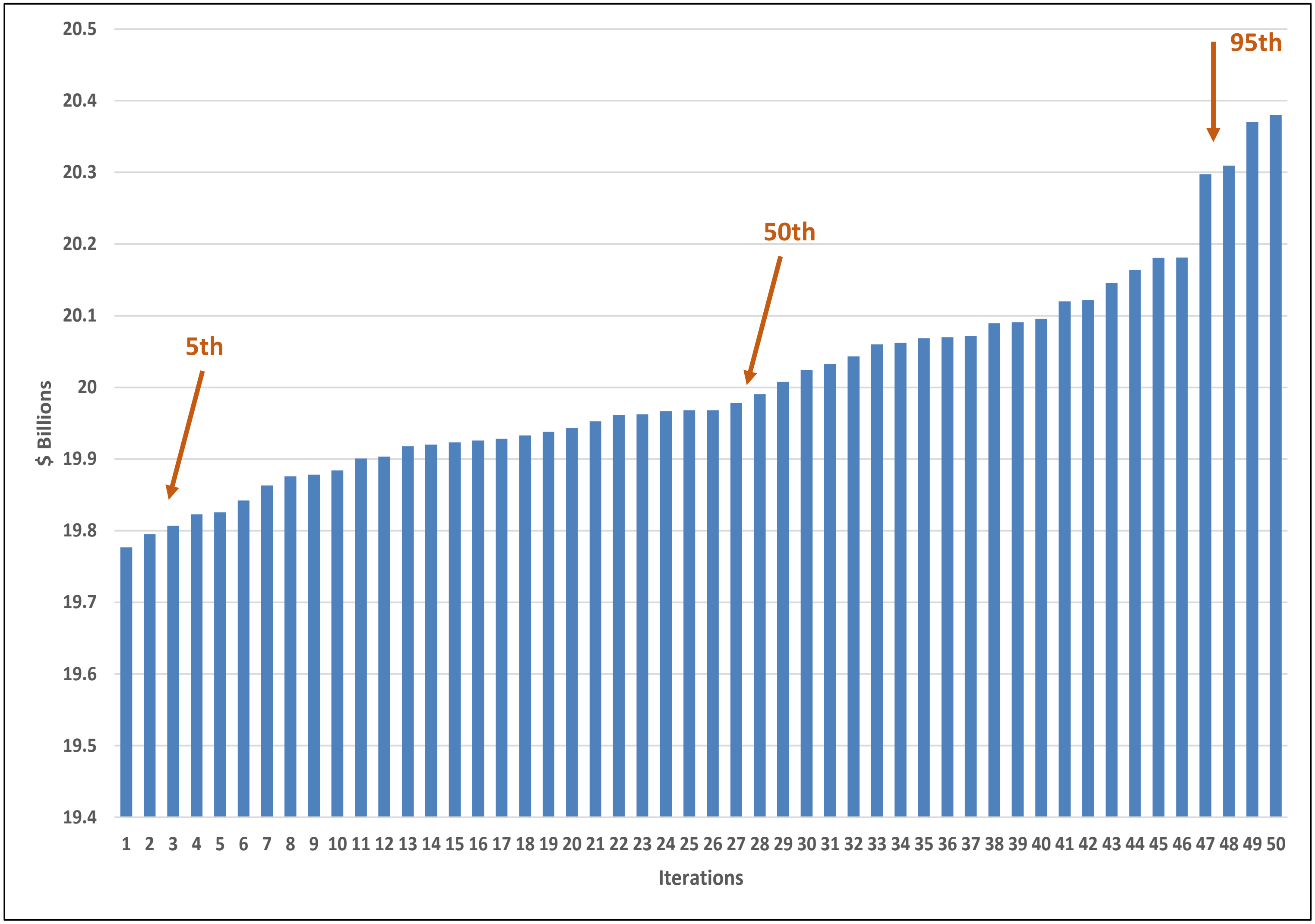
PaR Overview

- PaR is a chronological optimization model that performs stochastic risk analysis of the resource portfolios produced by SO.
- Model Setup:
  - 4 hour blocks with twelve sample weeks, one per month, for year
  - 50 Iteration Stochastic
- Model Run Times:
  - 22 to 24 hours for a 20-Year stochastic study
  - Higher stochastic iterations, more weeks in year, smaller blocks of hours, all increase stochastic model run times
- Key PaR Reporting Includes:
  - PaR Stochastic summary includes PVRR by iteration, cost summary which includes energy, emissions, PaR resource data
  - Fixed costs are from SO model reporting

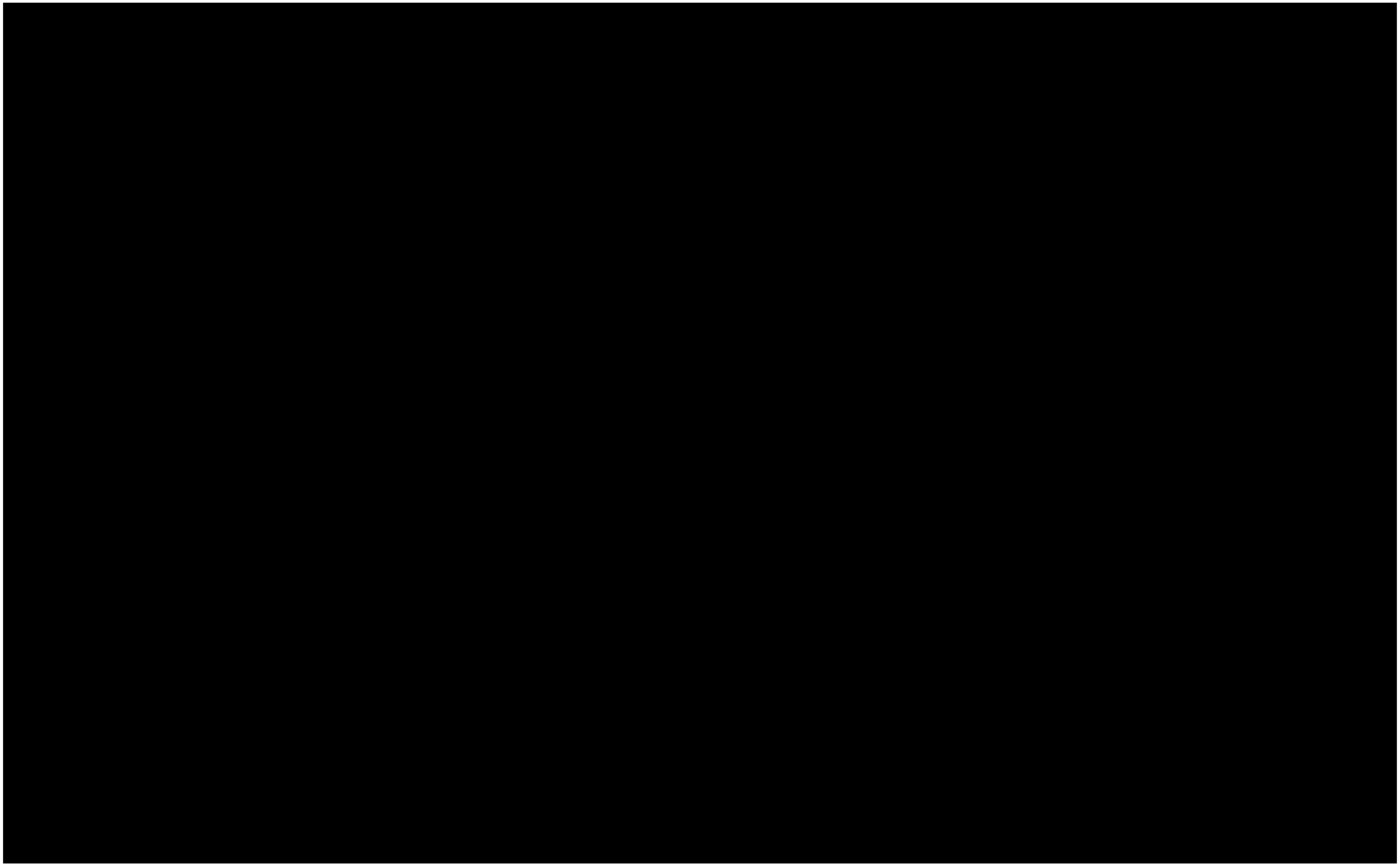
PaR Stochastic Characteristics

- Optimizes to lowest PVRR in each stochastic iteration:
  - Adheres to load and reserve requirements and transmission constraints
  - Optimizes market transactions
  - Accounts for chronological commitment and dispatch constraints
- Incorporates stochastic risk by performing Monte Carlo random sampling of:
  - Loads
  - Natural gas prices and wholesale electric prices
  - Hydroelectric generation and
  - Unplanned thermal outages
- For stochastics, the model is defined as a two-factor, short and long run, mean reverting model

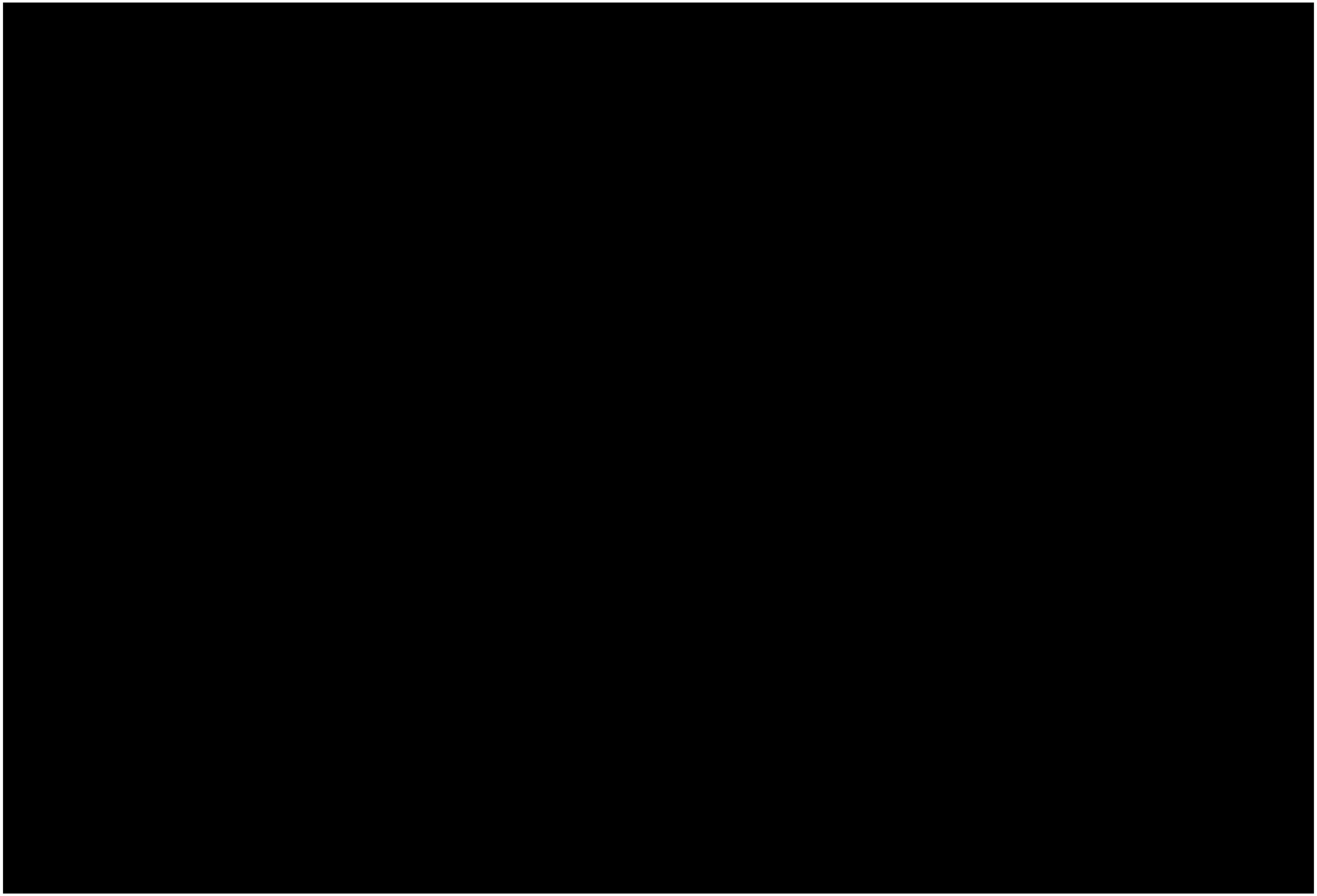
Range of Stochastic PVRR Results by Iteration and Percentiles



PaR Model Setup



PaR Run

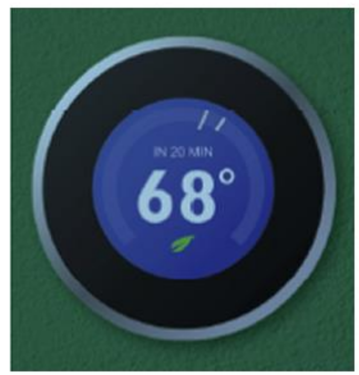


Unit-by-Unit Coal Studies

Confidential Workshop

2019 IRP Public Input Meeting - June 28, 2018



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OPUC Coal Study Requirement

- In its 2017 IRP acknowledgement order (Order No. 18-138), the Public Utility Commission of Oregon (OPUC) established requirements for additional coal-unit analysis, to be provided by June 30, 2018, as set forth below.
  - PacifiCorp agrees to perform 25 System Optimizer (SO) model runs, one for each coal unit and a base case.
  - PacifiCorp agrees to summarize results and provide:
    - a table of the difference in present-value revenue requirement (PVRR) resulting from the early retirement of each unit;
    - an itemized list of coal unit retirement cost assumptions used in each SO model run; and
    - a list of coal units that would free up transmission along the path from the proposed Wyoming wind projects if retired.
- These requirements are consistent with OPUC staff data request 65, which was submitted to PacifiCorp during the 2017 IRP acknowledgement proceeding.
  - This data request specified that PacifiCorp should assume a December 2022 retirement date for each early-retirement run.
  - The data request also specified that PacifiCorp should assume Reference Case Regional Haze assumptions (from the 2017 IRP) that are modified to exclude incremental selective catalytic reduction costs for Jim Bridger, Hunter, and Huntington in the base case.
  - In agreeing to perform this analysis, PacifiCorp explained that:
    - the studies will not provide a complete, portfolio-level view of the economics of the company's coal portfolio;
    - the structure of the analysis requested by staff would not capture the system-cost impact that would result from retiring more than one facility; and
    - results from these studies would therefore provide limited insight into a least-cost, least-risk resource portfolio.
- Recognizing PacifiCorp's concerns outlined above, the Utah Public Service Commission in its 2017 IRP acknowledgment order in Docket No. 17-035-16 states "we find that additional analysis will be helpful only if it supplements, rather than replaces, the type of coal plant modeling PacifiCorp utilized for its 2017 IRP."

System Optimizer

- The System Optimizer (SO) model develops resource portfolios with sufficient capacity to achieve a target planning-reserve margin (currently set at 13-percent).
- The SO model is configured to select from a broad range of resource alternatives (*i.e.*, front-office transactions or "FOTs", demand-side management, direct-load control, gas-fired generation, renewable generation, storage, etc.) that minimize present-value revenue requirement (PVRR).
- The SO model performs time-of-day, least-cost dispatch of existing and prospective resource alternatives for a defined set of system conditions (*i.e.*, resource attributes, transmission, load, market prices, environmental policies, etc.).
- The SO model does not consider in its dispatch:
    - unit-commitment logic, which captures unit-specific operational limitations;
    - operating reserve obligations (spin, non-spin, regulating);
    - granular representation of intra-day system conditions; and
    - volatility and uncertainty in key system parameters (*i.e.*, load, market prices, hydro generation, thermal-unit outages)
- The items identified above can be better assessed using the Planning and Risk model (PaR).
- PaR, configured with resource portfolios established by the SO model, is traditionally used in the IRP to evaluate the relative cost and risk among different resource portfolios under different system conditions.

Methodology

Step	Measure	Description

A	2017-2036 System PVRR (x1)	Base Case (One SO Model Run)
		• 2017 IRP Update with following modifications
		  • Removal of 161 MW Uinta Wind Project (2021-2036)
		  • 2017 IRP Reference Case Regional Haze assumptions
		  • March 2018 official forward price curve with medium CO_2 price inputs
		  • Results are calculated with and without incremental selective catalytic reduction costs for Jim Bridger 1 and 2

B	2017-2036 System PVRR (x22)	Retirement Cases (22 SO Model Runs)
		• 2017 IRP Update with following modifications
		  • Removal of 161 MW Uinta Wind Project (2021-2036)
		  • 2017 IRP Reference Case Regional Haze assumptions
		  • March 2018 official forward price curve with medium CO_2 price inputs
		  • No incremental selective catalytic reduction costs
		  • Each run assumes the retirement of a single coal unit at the end of 2022

C	2017-2036 System PVRR(d) (x22)	Present-Value Revenue Requirement Differential (PVRR(d)) • Change in system PVRR between the Base Case (A) and each of 22 Retirement Cases (B)

- High-level estimates of transmission reinforcement costs are applied as an adder to the results from step C.
- Each SO model run reflects unique coal-unit operating cost assumptions consistent with assumed retirement dates (*i.e.*, fuel cost, run-rate operating costs, decommissioning costs).
- PacifiCorp did not perform SO model runs in step B for Naughton Unit 3 and Cholla Unit 4, which are already assumed to retire before 2022.

PVRR(d) Results

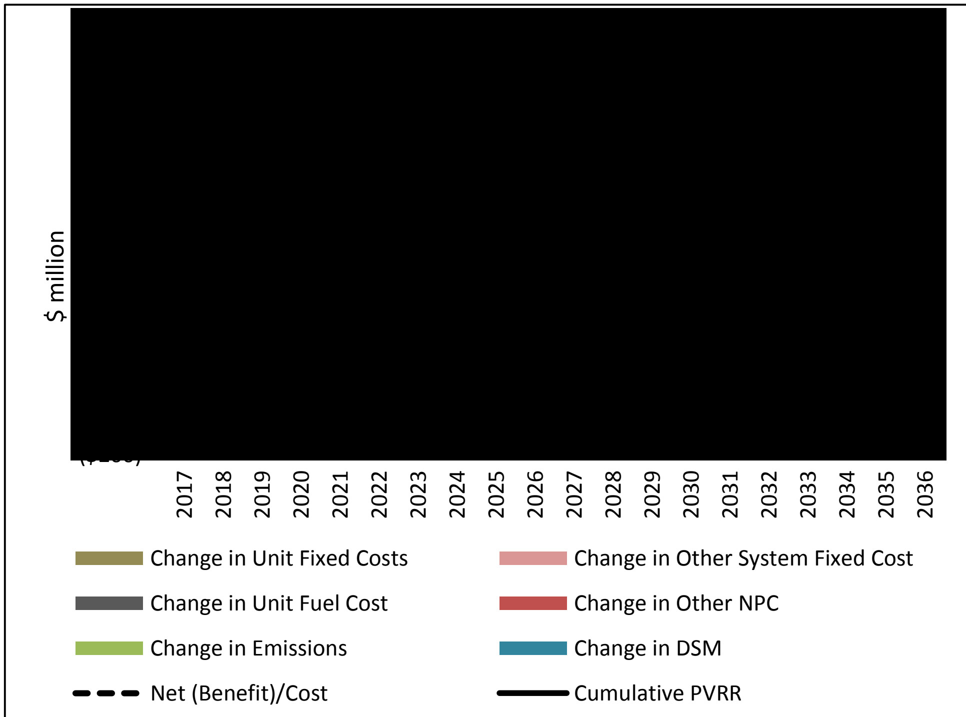
Coal Unit	PacifiCorp Share (MW)	PacifiCorp Percentage Share	State	Reg. Haze Ref. Case Retirement Year	PVRR(d) (Benefit)/Cost of 2022 Retirement ($ million)
Colstrip 3	74	10%	MT	2046	[redacted]
Colstrip 4	74	10%	MT	2046	
Craig 1	82	19%	CO	2025	
Craig 2	83	19%	CO	2034	
Dave Johnston 1	106	100%	WY	2027	
Dave Johnston 2	106	100%	WY	2027	
Dave Johnston 3	220	100%	WY	2027	
Dave Johnston 4	330	100%	WY	2027	
Hayden 1	44	24%	CO	2030	
Hayden 2	33	13%	CO	2030	
Hunter 1	418	94%	UT	2042	
Hunter 2	269	60%	UT	2042	
Hunter 3	471	100%	UT	2042	
Huntington 1	459	100%	UT	2036	
Huntington 2	450	100%	UT	2036	
Jim Bridger 1	354	67%	WY	2037	
Jim Bridger 2	359	67%	WY	2037	
Jim Bridger 3	349	67%	WY	2037	
Jim Bridger 4	353	67%	WY	2037	
Naughton 1	156	100%	WY	2029	
Naughton 2	201	100%	WY	2029	
Wyodak	268	80%	WY	2039	

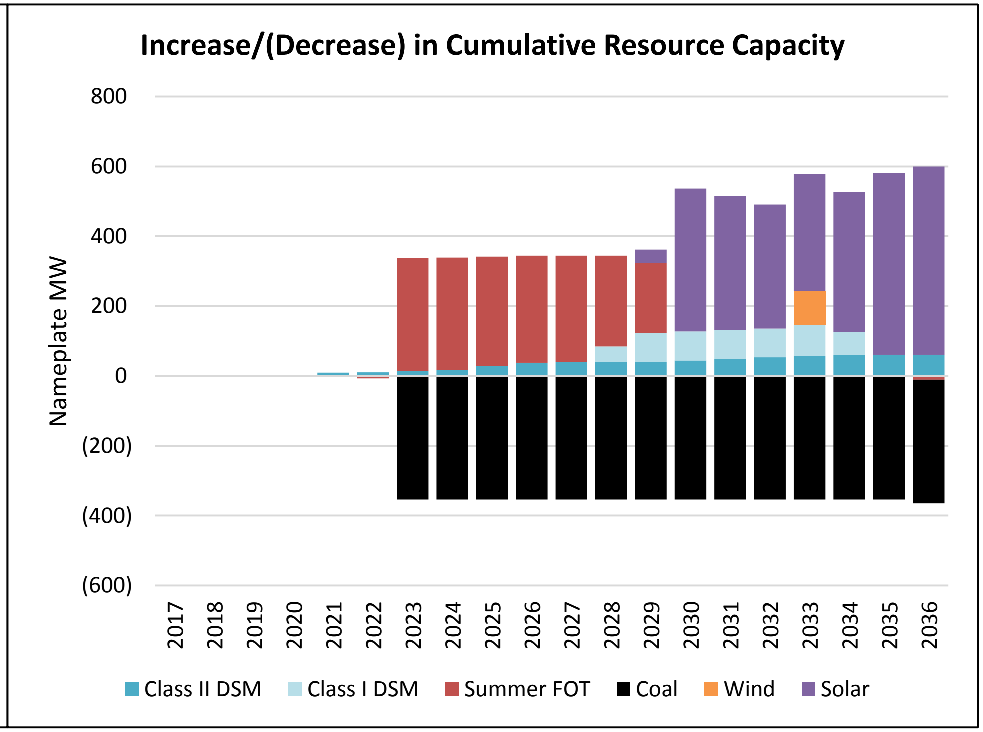
The results for Jim Bridger 1 and 2 reflect SCR costs in the base case. Excluding these costs as specified in OPUC staff data request 65 would show a [redacted] for an assumed 2022 retirement of Jim Bridger 1 and a [redacted] for an assumed 2022 retirement of Jim Bridger 2. Results for Colstrip do not reflect unquantified equipment removal costs that would be applicable to the assumed 2022 retirement date.

Coal Unit Retirement Assumptions

- Coal unit retirement cost assumptions are included with the confidential work papers supporting the modeling results summarized on the previous slide.
  - Run-rate cost-and-performance assumptions for each coal unit specific to each SO model run.
  - SO model results summarizing changes in the resource portfolio and annual system costs by year.
- Confidential work papers can be provided to interested stakeholders who either sign a non-disclosure agreement or under applicable confidentiality rules in jurisdictions where a docket has been opened.

Example of Data in Confidential Work Papers (Jim Bridger 1)





- Replacement resources (positive values in chart at top right) is initially comprised of incremental FOTs and DSM. In the 2029-2030 time frame, additional solar resources are added. Wind capacity is accelerated by one year (from 2034 to 2033) and Class 1 DSM direct-load control capacity is accelerated by seven years (from 2035 to 2028).
- System costs are presented without SCR costs in the base case.
  - Reduced system costs (negative values in the chart at top left) reflect reduced run-rate operating costs and fuel costs from Jim Bridger 1 beginning 2023 and reduced emissions costs beginning 2030 (when CO_2 prices are first assumed).
  - Increased system costs (positive values in the chart at top left) reflect increased net-power costs, increased system-fixed costs (fixed costs for new replacement resources and decommissioning costs), and increased DSM costs consistent with increased DSM in the resource portfolio.
  - The dashed black line is the net of the annual increase and decrease in costs (net of the bars in the chart), and the solid black line represents the cumulative PVRR(d) (the ending value in 2036 aligns with the results summarized in the PVRR(d) results table presented earlier).

Coal Units in Constrained Area of Wyoming

Coal Unit	PacifiCorp Share (MW)
Wyodak	268
Dave Johnston 1	106
Dave Johnston 2	106
Dave Johnston 3	220
Dave Johnston 4	330
Total	1,030

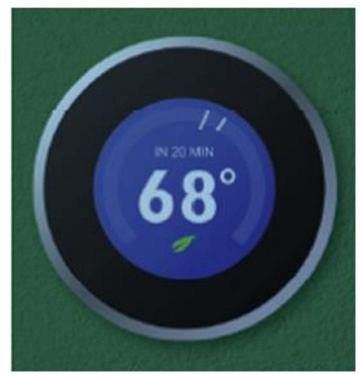
- Resource capacity in the constrained area of PacifiCorp's transmission system in eastern Wyoming exceeds transfer capability without the proposed new wind and transmission without incremental coal unit retirements.
- The proposed new wind capacity in eastern Wyoming totals 1,150 MW and the Aeolus-to-Bridger/Anticline transmission line is expected to add approximately 950 MW of incremental transfer capability—resource capacity will continue to exceed transfer capability without any incremental early retirements.
- With the retirement of any single unit listed above, resource capacity would continue to exceed transfer capability.
- Generally the retirement of one unit anywhere in the PacifiCorp system does not result in a major impact to system reliability.
- As additional units are retired, the risk of impacts to system reliability increases and more in-depth studies will be necessary to determine possible transmission mitigation, which would be completed in the transmission service request and generator interconnection request queues at the time a definitive retirement decision is made.
- These studies may show a need for additional system support with new generation that can provide rotational inertia, or other devices to provide required system support.
- It is important to note that coal units provide rotational inertia that enables frequency control and power system stability, which can influence the amount of transfer capability that can be freed up upon retirement of a generating unit.

Conclusions and Next Steps

- Relative to the Reference Case from the 2017 IRP, the SO model reports lower system costs with an assumed 2022 early retirement date for [redacted].
- Caution! The studies do not capture the impact on system costs if coal unit retirements are stacked—PVRR(d) results for each unit are not additive and system impacts are not linear.
    - Before accounting for operational impacts that are not captured by the SO model, an assumed retirement of Jim Bridger 1 *and* Jim Bridger 2 in 2022 [redacted] (driven by costs shifts to Jim Bridger 3 and Jim Bridger 4 and accelerated need for new generating capacity).
- The studies do not capture the operational and other system-reliability impacts associated with:
    - meeting balancing area reserve requirements;
    - meeting balancing area frequency response requirements;
    - reduced flexibility between balancing areas (*i.e.*, Jim Bridger provides energy and other reliability services in both the east and west balancing areas); and
    - reduced ability to participate in the energy-imbalance market due to a reduction in flexible generation and inability to pass the flex ramp sufficiency test.
- The studies do not capture system planning assumptions being updated for the 2019 IRP (*i.e.*, load forecasts, recent resource additions, planning-reserve margins, capacity-contribution values, conservation-potential assessment, supply-side resources, *etc.*)
- The studies do not analyze scenario-risk and stochastic-risk analysis.
- PacifiCorp will use these results to prioritize additional early retirement analysis for the 2019 IRP—no specific resource decisions are being made at this time.
    - PacifiCorp will incorporate 2019 IRP assumption updates as available and expand the analyses for evaluation using PaR.
    - PacifiCorp will develop "stacked" early retirement scenarios using the SO model and PaR and supplement these results with operational and system-reliability assessments.
    - Updates will be provided to stakeholders during the 2019 IRP public-input process as results become available.

2017 IRP Update Highlights / 2019 IRP Topics and Timeline June 29, 2018



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Agenda

- 2019 IRP:
  - IRP Process Overview
  - Supplemental Studies
  - Modeling Assumptions
  - Public Input Meetings
- 2017 IRP Order Requirements and Action Plan Updates
- 2017 IRP Update Highlights
- Energy Vision 2020 Update
- 2017S Request for Proposal Update
- Additional Information and Next Steps

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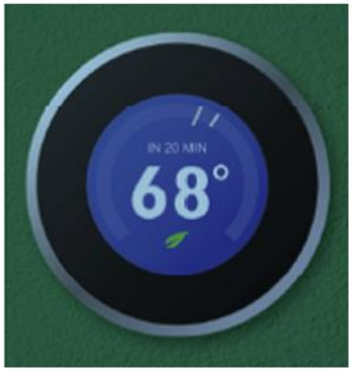
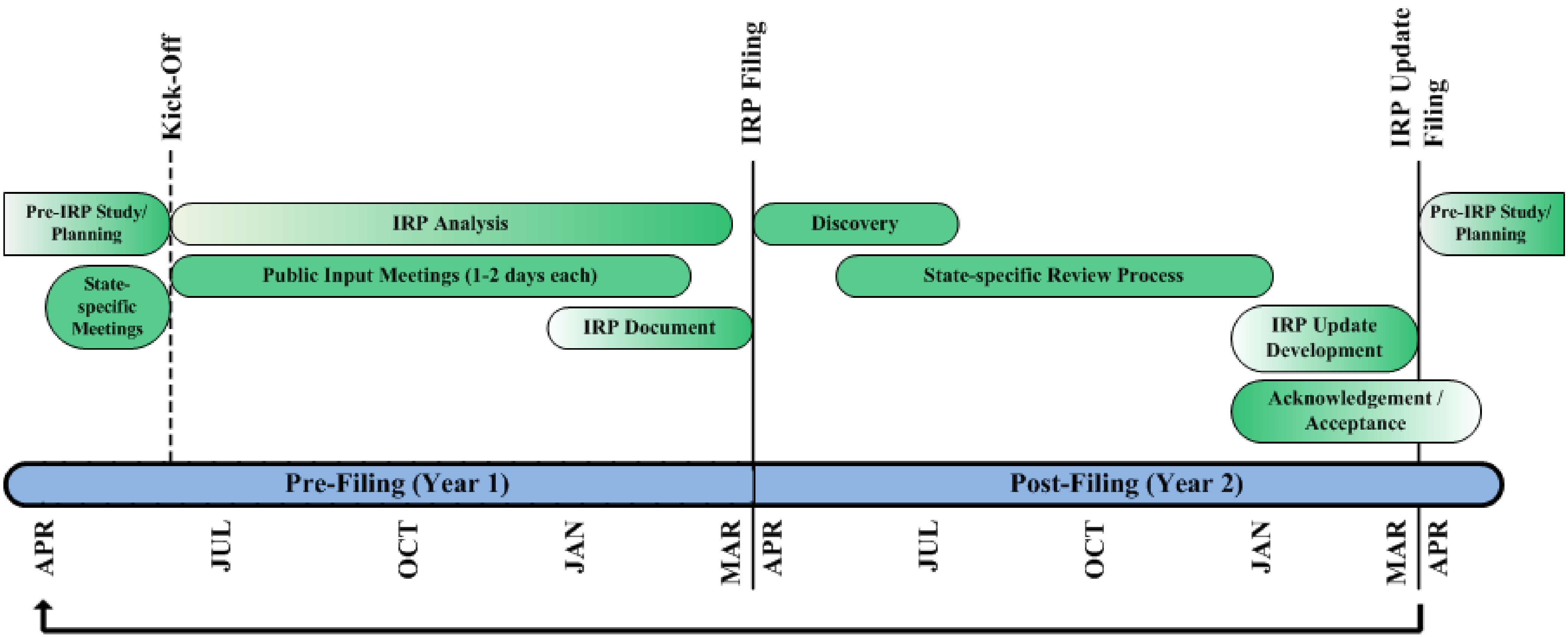
2019 Integrated Resource Plan

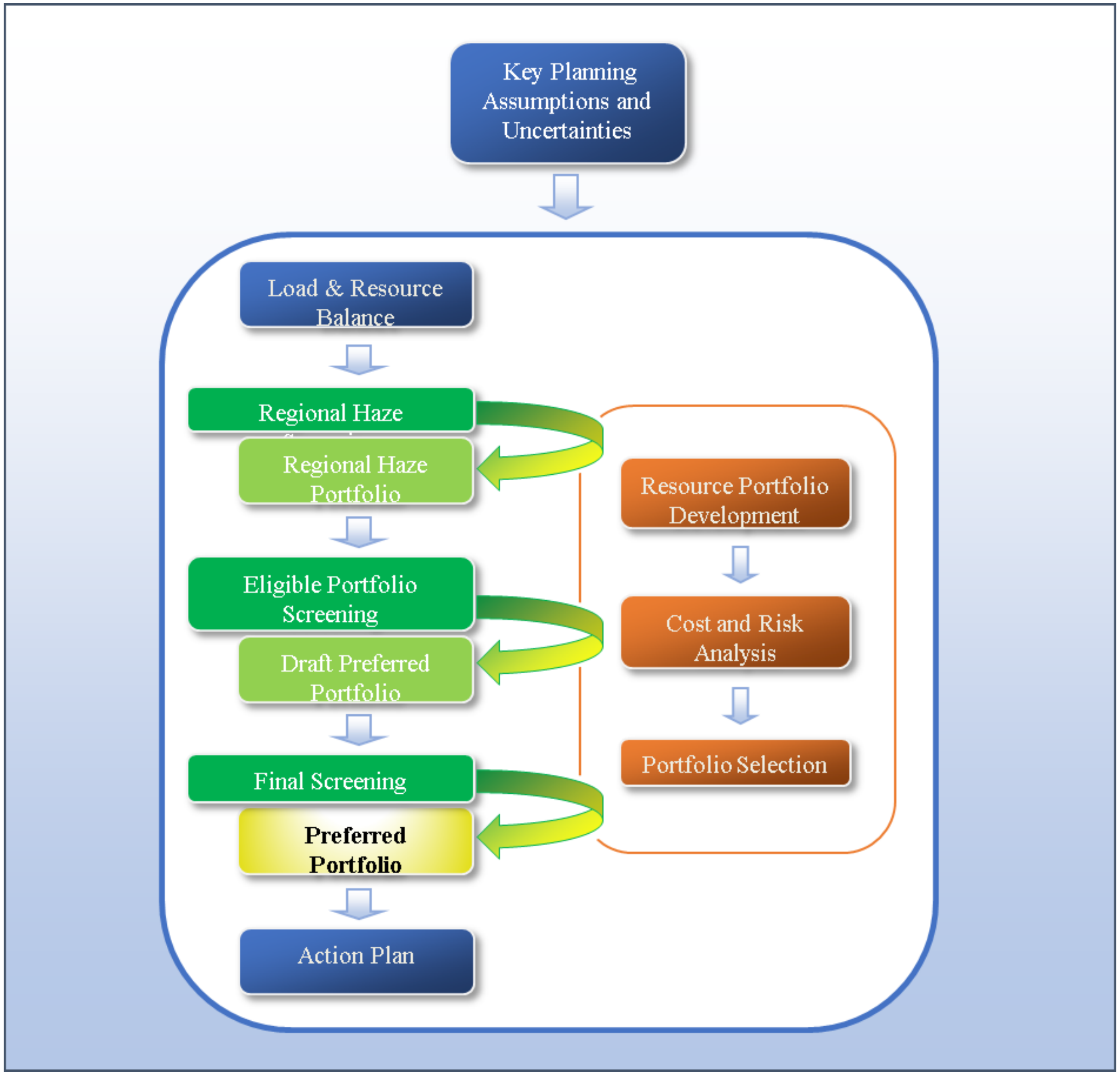


IRP Process Overview*



** Stakeholder participation milestones, timing and activities shown above are illustrative and subject to change.*

IRP Portfolio Development



2019 IRP Supplemental Studies

- Loss of Load Probability Study (LOLP) / Planning Reserve Margin (PRM)
- Wind and solar capacity contribution study
- Flexible capacity reserve study (wind / solar integration costs and to consider natural gas / storage)
- Conservation potential assessment (DSM potential study)
- Private generation market penetration study
- Stochastic parameter updates
- Resource adequacy / market reliance study

2019 IRP Modeling Assumptions

Key Modeling Assumptions:

- Corporate Tax Rate (Tax Reform Act)
- Treatment of Production Tax Credits (nominal vs. levelized)
- Intra-Hour Dispatch Credit
- Energy Storage
- Stochastic Parameters
- Flexible Reserve Study (*new* natural gas and storage)

Other Items:

- Distribution System Planning
- Multi-State Protocol Discussions

2019 IRP Public Input Meetings

Tentative Public Input Meeting Schedule and Topics *(topics are tentative and subject to change)*

- June 28-29, 2018
  - Model Tutorial (confidential)
  - Unit-by-Unit Coal Study Results (confidential)
  - 2019 IRP Process and Requirements, Energy Vision 2020 Update, Solar RFP Update, Highlights of 2017 IRP Update
- July 26-27, 2018
  - Load Forecast
  - Environmental Policy
  - Portfolio Development
- August 30-31, 2018
  - Energy Storage
  - Supplemental Study Results (as available)

2019 IRP Public Input Meetings

Tentative Public Input Meeting Schedule and Topics *(topics are tentative and subject to change)*

- September 27-28, 2018
  - Supplemental Study Results (as available)
- November 1-2, 2018
  - Portfolio Results
- December 3-4, 2018
  - Portfolio Results
- January 24-25, 2019
  - Portfolio Results
  - Draft Preferred Portfolio and Action Plan

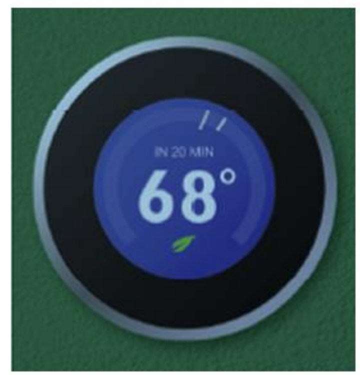
2019 IRP Public Input Meetings

Tentative Public Input Meeting Schedule and Topics *(topics are tentative and subject to change)*

- February 21-22, 2019
    - Final Preferred Portfolio and Action Plan
- March 2019 – *TBD / As Needed*
- April 1, 2019 – 2019 IRP File Date

2017 IRP Order Requirements and Action Plan Updates



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2017 IRP Acknowledgement Process

- 2017 IRP was acknowledged / accepted:
  - Oregon – April 27, 2018; Docket No. LC 67
  - Washington – May 7, 2018; Docket No. UE-160353
  - Idaho – April 3, 2018; Docket No. PAC-E-17-03
  - Utah – March 2, 2018; Docket No. 17-035-16
  - Wyoming – November 20, 2018; public meeting verbal acceptance
  - California – filing requirements tied to RPS compliance reporting

- Requirements from OR for incorporation in the 2017 IRP Update have been addressed with exception of Flexible Reserve Study requirement due to timing

2017 IRP Order Requirements

State	Order / Letter Reference	Description
ID	P.14	Expect the Company to consider public input meeting process concerns raised in the 2017 IRP as related to the Energy Vision 2020 projects and continue to evaluate all resource options and the best interest of customers when developing the 2019 IRP.
ID	P.14	The Company should let its modeling fully assess when a coal plant should be retired, and provide resource portfolios that are least-cost based on modeling, and not assumed coal plan retirement.
ID	P.14	Expect the Company to continue improving its forecasting methodologies by analyzing a broad and diverse range of measures to avoid disadvantageous or unfair forecasting treatment of certain resources over others, including coal and wind.
OR	Appendix A, P.19	Provide quarterly updates to the Commission and Staff as development of the projects chosen in the 2017R RFP and the transmission projects proceed (through the date the projects go into service).
OR	Appendix A, P.20	PacifiCorp should repeat its study of trading hub liquidity and also the market reliance risk analysis of front office transactions prior to the next IRP.
OR	Appendix A, P.20	For the 2019 IRP, if a generating resource is included in the preferred portfolio with an associated action item, then PacifiCorp will report on the cost and risk tradeoffs between the preferred portfolio and alternatives that do not include a generating resource.
OR	Appendix A, P.21	PacifiCorp is to hire an independent consultant, in coordination with Staff and the Energy Trust of Oregon, to conduct an analysis by the next IRP that identifies and compares the ongoing differences between ETO's and PacifiCorp's near to long term energy efficiency forecast with ETO's actual achieved savings. The consultant's report should include recommendations to both organizations regarding forecasting improvements that should be considered for the 2019 IRP.
OR	Appendix A, P.21	Early in the public input process for the 2019 IRP, prior to finalizing energy efficiency supply curves, PacifiCorp will hold a DSM technical workshop to review and receive input regarding how the company models energy efficiency potential in the IRP and supporting studies such as the Conservation Potential Assessment.

2017 IRP Order Requirements

State	Order / Letter Reference	Description
OR	P. 13; Appendix A, P.21	PacifiCorp will perform 25 system optimizer (SO) runs, one for each coal unit and a base case. PacifiCorp will summarize the results providing a table of the difference in the PVRR resulting from the early retirement of each unit, an itemized list of coal unit retirement cost assumptions used in each SO run, and a list of coal units that would free up transmission along the path from the proposed Wyoming wind projects if retired. PacifiCorp is to provide this information to parties in LC 67 by June 30, 2018. If there is a dispute about modeling in the meantime, PacifiCorp, Staff and parties should first attempt to resolve it informally, but if that fails, Staff may report back to the Commission at a public meeting before the 2019 IRP is filed. A Commissioner workshop will likely be scheduled to review this analysis once it is complete.
OR	Appendix A, P.21	PacifiCorp will continue to model the assumption that EPA regional haze litigation agents the company is successful and that PacifiCorp will be required to comply with the current requirements of the State Implementation Plan (SIP) and Federal Implementation Plan (FIP).
OR	Appendix A, P.22	In the IRP Update PacifiCorp will model natural gas and storage for meeting flexible reserve study needs.
OR	Appendix A, P.22	PacifiCorp will work with Staff and parties to advance distributed energy resource forecasting and representation in the IRP, and define a proposal for opening a distribution system planning investigation.
OR	Appendix A, P.22	PacifiCorp will work with Staff and parties to explore the use of AMI data in future IRPs.
UT	P.22	Encourage PacifiCorp and stakeholders to review recommendations of the DPU on process at the start of the 2019 IRP process.
UT	P.31	Encourage all parties to communicate in advance of the 2019 IRP about whether a training session on IRP capacity expansion and stochastic models would be appropriate and helpful. There is a distinction between requiring PacifiCorp to create opportunity for public involvement as required by the Guidelines, and requiring PacifiCorp to conduct analyses on behalf of parties.
UT	P.35	To satisfy Guideline 3, any changes to DSM modeling assumptions must be circulated during the IRP development process.
UT	P.37	PacifiCorp commits to conduct a workshop specific to energy storage as part of the 2019 IRP public input process prior to finalizing the supply-side resource table inputs for battery and energy storage.

2017 IRP Order Requirements

State	Order / Letter Reference	Description
UT	P.43	Expect PacifiCorp and stakeholders to review the DPU's recommendations on transmission modeling at the start of the 2019 IRP process.
WA	Attachment, P.4-6	Expects examination of Jim Bridger and Colstrip Units 3 & 4 pursuant to specific questions to be addressed in the 2019 IRP.
WA	Attachment, P.6-7	Balancing Area analysis in all future IRPs that includes a west control area and an east control area analysis with a robust description of the modeling interaction between the two discrete systems.
WA	Attachment, P.8	Expect the company to incorporate principles in the commission's policy statement on energy storage in the 2019 IRP.
WA	Attachment, P.8-9	Expect the company to provide a market reliance risk assessment in the 2019 IRP and expect the analysis will result in a quantified representation of risk that can be folded into the IRP analytical framework.
WA	Attachment, P.9-10	In future IRPs, the company should more prominently display the Quick Reference Guides included in Appendix M of its 2017 IRP.
WA	Attachment, P.10-11	In future IRPs, the company should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its preferred portfolio. The cost estimate should come from a comprehensive, peer-reviewed estimate of the monetary cost of climate change damages, produced by a reputable organization. We suggest using the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a three percent discount rate. The company should also continue to model other higher and lower cost estimates to understand how the resource portfolio changes based on these costs.
WA	Attachment, P.11	The company should develop a supply curve of emissions abatement and include this cost curve in the 2019 IRP. The analysis should identify all programs and technologies reasonably available in the company's service area, then use best available information to estimate the amount of emissions reductions each option might achieve, and at what cost.

2017 IRP Action Item Updates

- Action Item 1a – Wind Repowering
  - On track to issue EPC construction notices to proceed for specific projects beginning July 2018
  - Additional updates included in this presentation
- Action Item 1b – Wind Request for Proposals
  - Contract negotiations with parties have commenced and anticipated to be complete July 2018
  - Additional updates included in this presentation
- Action Item 1c – Renewable Portfolio Standard Compliance
  - To date, no additional RFPs have been issued for RECs in CA or OR.
  - PacifiCorp will continue to evaluate the need for unbundled RECs.

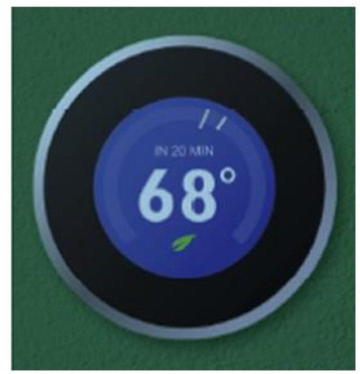
2017 IRP Action Item Updates

- Action Item 1d – Renewable Energy Credit Optimization
  - Issued two reverse RFPs to sell RECs in 2017 (June and September)
  - Will continue to issue reverse RFPs and maximize the sale of RECs not required to meet state RPS compliance obligations.
- Action Item 2a – Aeolus to Bridger/Anticline
  - On going activities to meet the 2020 in-service date
  - Additional updates included in this presentation
- Action Item 2b – Energy Gateway Permitting
  - Continued permitting and outreach for Energy Gateway segments and support of Boardman to Hemingway project consistent with the Joint Permit Funding Agreement
- Action Item 2c – Wallula to McNary Transmission Line
  - On track for 2018 completion date

2017 IRP Action Item Updates

- Action Item 2d – Planning Studies
  - Completed planning studies as required in 2017 IRP Update
- Action Item 3a – Front Office Transaction
  - Continued procurement through multiple means
- Action Item 4a – Class 2 DSM
  - Achieved the 646 GWh target for 2017
  - On track to achieve the 559 GWh target for 2018
- Action Items 5a – 5h – Coal Resources
  - Continued monitoring of regional haze compliance efforts
  - Completed additional study of Cholla Unit 4, Dave Johnston Unit 3, Jim Bridger Units 1 and 2, and Naughton Unit 3 in the 2017 IRP Update.
  - Additional study and updates in 2019 IRP as applicable.

2017 IRP Update Highlights

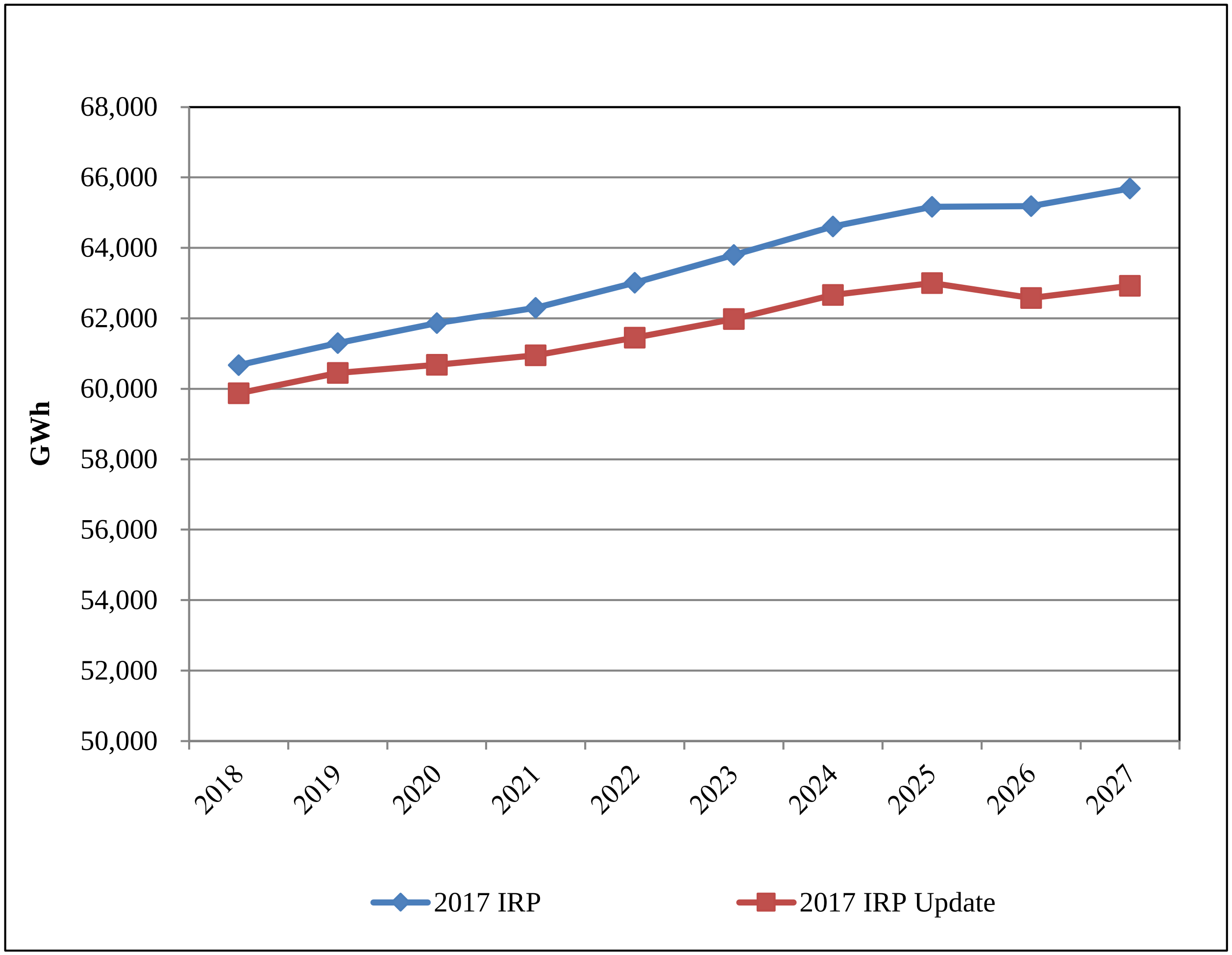


2017 IRP Update Highlights

- Energy Vision 2020 projects updated with the latest cost-and-performance information.
- With reduced loads and lower renewable resource costs, the updated preferred portfolio contains no new natural gas resources through the 20-year planning horizon.
- Through the end of 2036, the updated preferred portfolio includes over 2,700 MW of new wind resources, 1,860 MW of new solar resources, 1,877 MW of incremental energy efficiency resources, and approximately 268 MW of direct-load control resources.
- The updated preferred portfolio continues to assume existing owned coal capacity will be reduced by 3,650 MW through the end of 2036 with no incremental selective catalytic reduction (SCR) systems needed to satisfy regional haze compliance obligations.
- Coincident system peak load is down an average of 424 MW in the first ten years of the planning period.

Load Forecast Comparison (GWh)

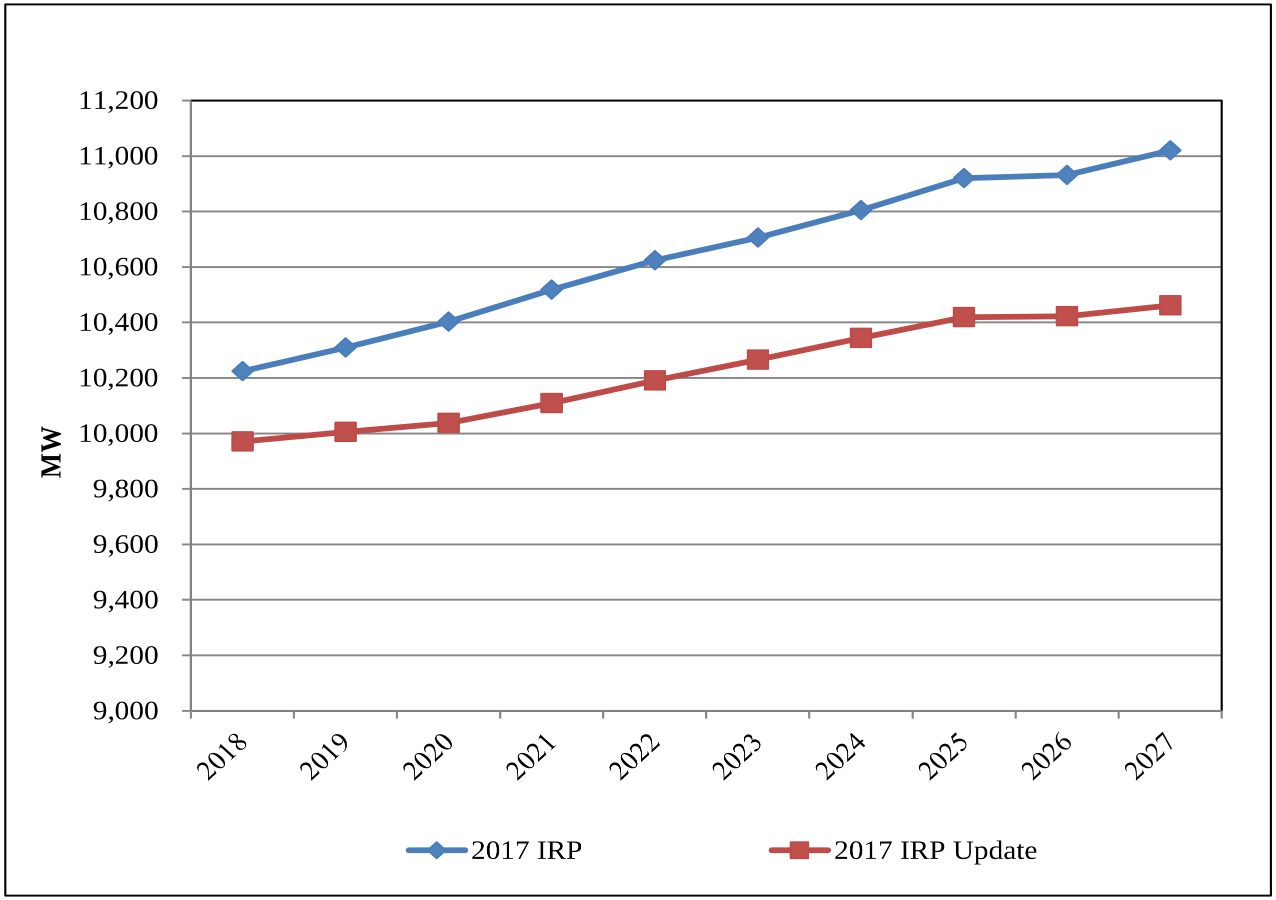
- Relative to the load forecast prepared for the 2017 IRP, PacifiCorp's 2027 forecasted energy requirement decreased in all jurisdictions other than Oregon and Idaho.
- Overall, the PacifiCorp system energy requirement decreased approximately 4.2 percent.
- These data exclude projected load reductions from new energy efficiency measures (Class 2 DSM).



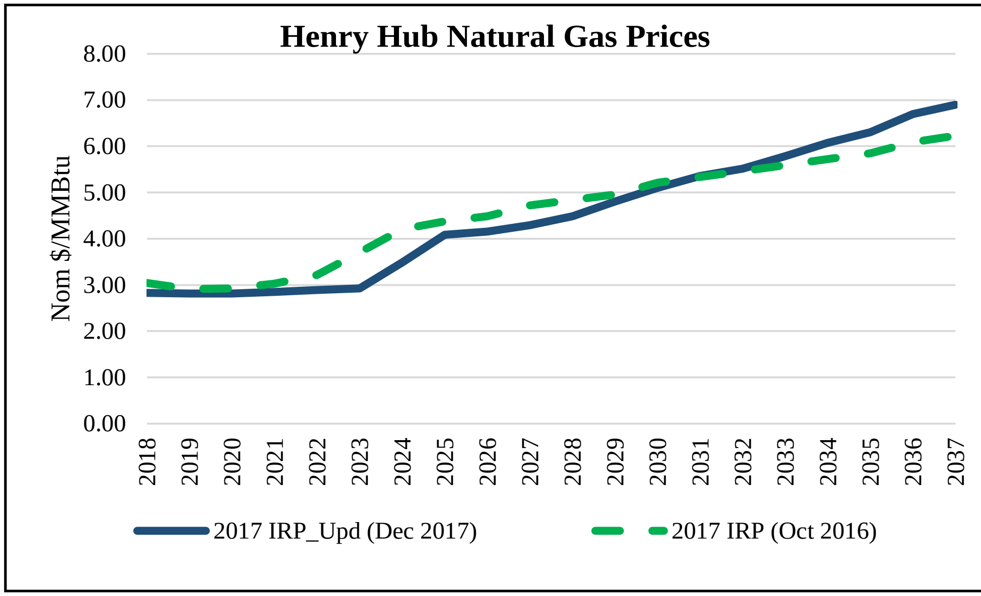
Coincident System Peak Load

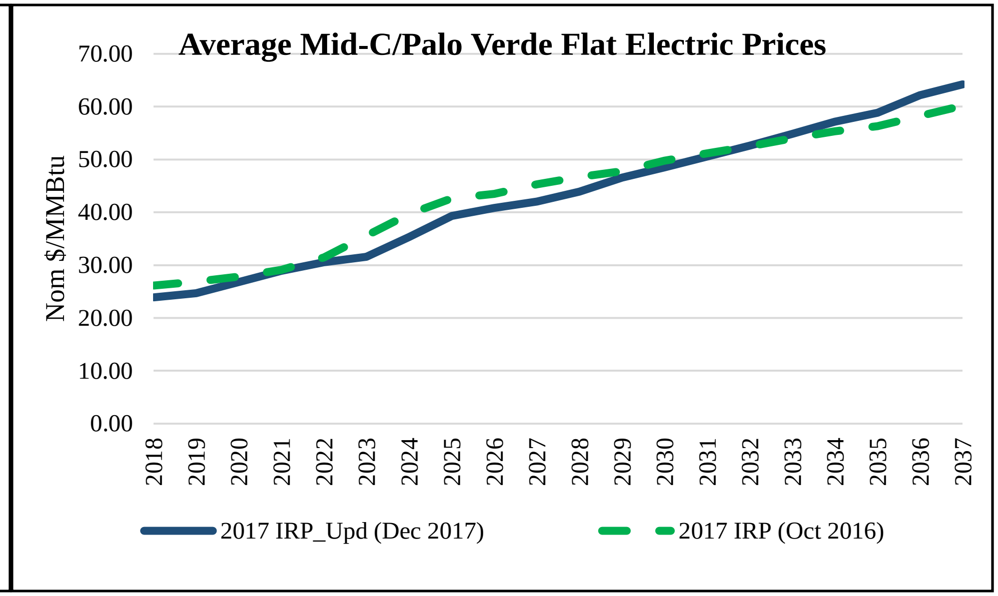
- Coincident system peak is decreased by roughly 424 MW on average across the first ten years of the planning period relative to the 2017 IRP. Contributing factors include:
  - ➢ Less favorable outlook for the industrial segment
  - ➢ Adoption of more efficient appliances by residential customers

- These data exclude projected load reductions from new energy efficiency measures (Class 2 DSM).



Power and Natural Gas Price Comparison





- Forecasted natural gas and energy prices have declined in the 2017 IRP Update from the 2017 IRP through roughly the 2030-2031 time frame.
- Domestic gas price forecasts continue to be driven down by growth in unconventional shale-gas plays. This in turn (combined with lower forecasted regional loads) impacts forward market power prices.

Emissions Policy and Pricing

Clean Power Plan (CPP)

- On March 28, 2017, President Trump issued an Executive Order directing the U.S. Environmental Protection Agency (EPA) to review the Clean Power Plan (CPP) and, if appropriate, suspend, revise, or rescind the CPP, as well as related rules and agency actions.
- On October 10, 2017, the EPA issued a proposal to repeal the CPP and the EPA took comments on the proposed repeal until April 26, 2018.
- In addition, the EPA published in the Federal Register an Advance Notice of Proposed Rulemaking December 28, 2017, seeking public input on, without committing to, a potential replacement rule. The public comment period for the Advance Notice of Proposed Rulemaking concluded February 26, 2018.

Modeling Assumptions

- PacifiCorp will continue to follow activities related to the CPP; however, the company has not included the CPP in its assumptions for the 2017 IRP Update. Rather, the 2017 IRP Update includes a medium CO_2 price assumption starting in 2030 to reflect possible regulatory changes in the future.

Preferred Portfolio Highlights

Renewables

- PacifiCorp's 2017 IRP Update preferred portfolio includes updated cost-and-performance information for the Energy Vision 2020 projects
  - 1,311 MW of new wind
  - Repowering just over 999 MW of existing wind capacity
  - New 140-mile, 500 kilovolt (kV) Aeolus-to-Bridger/Anticline transmission line in Wyoming.

Demand-Side Management

- 1,877 MW of incremental energy efficiency resources, and approximately 268 MW of direct-load control resources.

Thermal

- With reduced loads and lower renewable resource costs, the updated preferred portfolio contains no new natural gas resources through the 20-year planning horizon. This is the first time an IRP has not included new fossil-fueled generation as a least-cost, least-risk resource for PacifiCorp.

Preferred Portfolio Comparison - 2017 IRP Update to 2017 IRP

2017 IRP Update

	Capacity (MW)																				10- year Total
Resource	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2017-2036**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	150	119	126	122	105	99	96	95	100	96	90	90	84	88	87	75	70	63	61	61	**1,877**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	68	-	-	-	50	48	90	12	**268**
Renewable - Wind	-	-	-	911	400	-	-	-	-	-	-	-	-	121	-	-	800	-	333	149	**2,713**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	651	95	132	976	-	6	-	**1,860**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**1**
Front Office Transactions - Summer *	402	319	624	463	395	445	419	428	538	499	500	1,247	1,575	1,575	1,575	1,575	1,575	1,564	1,575	1,544	**942**
Front Office Transactions - Winter *	253	308	303	296	303	305	310	304	317	330	343	357	758	794	809	776	868	924	1,031	1,486	**559**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC with CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	-	(354)	-	-	-	(359)	-	-	-	**(1,463)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	(762)	-	(357)	(77)	-	(358)	-	(82)	-	**(1,635)**
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**805**	**746**	**774**	**1,792**	**815**	**848**	**825**	**827**	**954**	**843**	**934**	**933**	**2,132**	**2,871**	**2,489**	**2,559**	**3,623**	**2,599**	**3,014**	**3,252**	

*** FOT in resource total are 20-year averages**

2017 IRP Update less 2017 IRP Preferred Portfolio

	Capacity (MW)																				10- year Total
Resource	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2017-2036**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	(436)	-	-	(477)	-	-	-	**(913)**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	(200)	-	-	-	(200)	-	-	-	**(400)**
DSM - Energy Efficiency	(4)	(9)	(5)	0	(18)	(15)	(22)	(23)	(12)	(15)	(19)	(11)	(12)	(7)	(10)	(8)	(4)	(3)	(2)	(2)	**(200)**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	(193)	(71)	(5)	(3)	(3)	47	44	87	-	**(98)**
Renewable - Wind	-	-	-	911	(701)	-	-	-	-	-	-	-	-	121	(85)	-	800	-	333	(625)	**754**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	-	-	-	-	-	**(30)**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	(11)	(97)	651	(23)	(104)	751	(48)	(285)	(13)	**820**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**1**
Front Office Transactions - Summer *	(98)	(202)	(254)	(345)	(404)	(471)	(425)	(457)	(504)	(479)	(540)	(328)	-	9	-	-	-	(11)	-	6	**(225)**
Front Office Transactions - Winter *	(28)	(24)	30	(11)	(16)	(3)	4	17	(31)	(21)	47	(55)	207	278	319	326	431	447	552	720	**159**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC with CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(130)**	**(235)**	**(228)**	**556**	**(1,139)**	**(489)**	**(443)**	**(462)**	**(547)**	**(515)**	**(512)**	**(599)**	**(203)**	**610**	**199**	**210**	**1,348**	**430**	**684**	**86**	

*** FOT in resource total are 20-year averages**

Regional Haze Cases

- In accordance with action items in the 2017 IRP action plan, PacifiCorp completed four regional haze cases in the 2017 IRP Update that included studies for Naughton Unit 3, Cholla Unit 4, Dave Johnston Unit 3, and Jim Bridger Units 1 and 2.

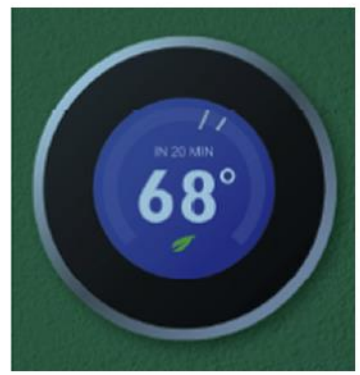
  - Consistent with the findings from these studies, the 2017 IRP Update continues to assume no incremental selective catalytic reduction (SCR) emission-reduction systems will be needed to satisfy regional haze compliance obligations.

  - PacifiCorp continues to assume Cholla Unit 4 retires at the end of 2020, Dave Johnston Unit 3 retires at the end of 2027, and Jim Bridger Units 1 and 2 retire at the end of 2028 and 2032, respectively.

  - The 2017 IRP Update assumes Naughton Unit 3 retires end of January 2019, shifted one month from the 2017 IRP that assumed retirement at the end of 2018.

Energy Vision 2020 Update



Energy Vision 2020 Introduction

- The 2017 IRP included 1,100 MW of new Wyoming wind enabled by accelerating the Aeolus-to-Bridger/Anticline transmission line, and repowering 905 MW of existing wind by the end of 2020.
- These three components of the 2017 IRP preferred portfolio are collectively referred to as Energy Vision 2020.
- Upon filing the 2017 IRP, PacifiCorp began implementing Energy Vision 2020 action items.
  - Action item 1a addresses wind repowering
  - Action item 1b addresses procurement of new wind
  - Action item 2a addresses the new transmission

Repowering Regulatory Status

- PacifiCorp filed pre-approval applications in Idaho, Utah, and Wyoming in late June to early July 2017.
- The applications sought approval to repower approximately 999 MW of existing wind capacity (up from the 2017 IRP with the inclusion of Goodnoe Hills)—594 MW in Wyoming, 304.6 MW in Washington, and 100.5 MW in Oregon.
- Idaho (Case No. PAC-E-17-06)
  - Stipulation approved December 28, 2017 (Order No. 33954), finding that the wind-repowering project to be prudent and in the public interest.
- Utah (Docket No. 17-035-39)
  - Report and order issued May 25, 2018 finding that 11 of 12 repowering projects are in the public interest (excluding Leaning Juniper).
  - PacifiCorp can still repower Leaning Juniper subject to prudence review in future general rate cases.
- Wyoming (Docket No. 20000-519-EA-17)
  - Amended stipulation approved via a bench order on June 12, 2018—written order is pending.
  - Leaning Juniper is removed from the stipulation; however PacifiCorp can still repower Leaning Juniper subject to prudence review in a future proceeding.

Repowering Economic Analysis

Price Policy Scenario 999 MW (Including Leaning Juniper)	PaR Stochastic Mean Present Value Net (Benefit)/Cost through 2036 ($ million)	PaR Stochastic Mean Annual Revenue Requirement Present Value Net (Benefit)/Cost through 2050 ($ million)
Low Gas, Zero CO_2	($141)	($127)
Low Gas, Medium CO_2	($139)	($121)
Low Gas, High CO_2	($165)	($223)
Medium Gas, Zero CO_2	($171)	($224)
Medium Gas, Medium CO_2	($180)	($273)
Medium Gas, High CO_2	($193)	($321)
High Gas, Zero CO_2	($234)	($389)
High Gas, Medium CO_2	($248)	($386)
High Gas, High CO_2	($240)	($466)

Price Policy Scenario 100.5 MW (Leaning Juniper)	PaR Stochastic Mean Present Value Net (Benefit)/Cost through 2036 ($ million)	PaR Stochastic Mean Annual Revenue Requirement Present Value Net (Benefit)/Cost through 2050 ($ million)
Low Gas, Zero CO_2	$3	$0
Medium Gas, Medium CO_2	$0	($8)

- PacifiCorp continues to work with vendors to improve the economic benefits of Leaning Juniper.
- Should PacifiCorp choose to proceed with Leaning Juniper, updated economic analysis will be shared with stakeholders in a future public input meeting.

Wind & Transmission Regulatory Status

- PacifiCorp filed pre-approval applications in Idaho, Utah, and Wyoming in late June to early July 2017.
- In these proceedings, PacifiCorp sought approval for the Aeolus-to-Bridger/Anticline transmission line, 1,311 MW of new Wyoming wind selected through the 2017R RFP, and associated interconnection network upgrades.
- Idaho (Case No. PAC-E-17-07)
  - Partial settlement with hearing held May 9, 2018 through May 11, 2018.
  - Partial settlement with staff excludes the 161 MW Uinta project, reducing the total new wind capacity to 1,150 MW.
  - Order pending.
- Utah (Docket No. 17-035-40)
  - Hearing was held May 29, 2018 through June 1, 2018.
  - PacifiCorp withdrew its request for approval of the 161 MW Uinta project, reducing the total new wind capacity to 1,150 MW.
  - Order issued June 22, 2018 approving the new wind and transmission projects.
- Wyoming (Docket No. 20000-520-EA-17)
  - Stipulation approved, granting the necessary certificates of public convenience and necessity, via a bench order on April 11, 2018—written order is pending.
  - Excludes the 161 MW Uinta project, reducing the total new wind capacity to 1,150 MW.

2017R RFP Overview

- Nine bidders (WY), five bidders (non-WY)
- 49 bid alternatives (WY), 15 bid alternatives (non-WY)
- 13 wind projects (WY), six wind projects (non-WY)
- 4,624 MW total capacity (WY), 595 MW total capacity (non-WY)
- Offers for development rights, storage, and wind projects totaling just under 600 MW were non-conforming
- Initial shortlist included 12 projects totaling over 3,700 MW
- Final shortlist included four projects totaling 1,311 MW
- Implementation is proceeding for three projects totaling 1,150 MW

Milestone	Date
Issued to the market	09/27/2017
Bidder conference	10/02/2017
Receipt of initial benchmark bids	10/10/2017
Receipt of initial WY wind bids	10/17/2017
Receipt of initial non-WY wind bids	10/24/2017
Initial shortlist for WY wind bids submitted to IE	11/06/2017
Initial shortlist for non-WY wind bids submitted to IE	11/09/2017
IE review of initial shortlist completed	11/17/2017
Best and final pricing reflecting Tax Act	12/21/2017
Final shortlist evaluation completed	02/13/2018

2017R RFP Acknowledgement

- As required by competitive bidding guidelines, PacifiCorp filed a request for acknowledgment of the 2017R RFP final shortlist in Oregon on February 16, 2018 (Docket UM 1845).
- In Order No. 18-178, the Oregon Commission did not acknowledge PacifiCorp's 2017R RFP final shortlist on a two to one vote.
- In Oregon, acknowledgement of a shortlist carries the same weight as acknowledgement of an IRP.
- Shortlist acknowledgement is not a prudence determination nor does it constitute future ratemaking.
- The order clarifies that:
  - it does not diminish the Oregon Commission's earlier acknowledgement of PacifiCorp's 2017 IRP proposal to acquire renewable resources;
  - PacifiCorp is free to move forward with procurement from the 2017R RFP final shortlist; and
  - a rate case is the forum for prudence review.
- The order also included a dissenting opinion from Chair Hardie, who concluded that:
  - the final shortlist is aligned with an acknowledged IRP, except for inclusion of the Uinta project;
  - the Oregon independent evaluator report indicates that the competitive bidding guidelines were followed; and
  - becacuse of transmission constraints, the acknowledged IRP action item to proceed with an RFP, by its nature, limited who could reasonably compete for the final shortlist.

2017R RFP Bid Data

Initial Shortlist Evaluation (Before Tax Reform)	# Bid Alternatives	# Projects	Bid Alternative MW	Project MW	Capacity-Wtd Avg. Nom. Lev. Bid Cost ($/MWh)
East WY Owned	12	12	3,842	3,842	$22.54
East WY Owned/PPA	5	2	2,760	990	$20.57
East WY 20-Year PPAs	12	8	3,981	2,506	$21.31
East WY 24-30 Year PPAs	21	11	6,076	3,237	$19.08
Other Owned	3	3	405	405	$32.83
Other 20-Year PPAs	5	4	564	484	$38.72
Other 30-Year PPAs	1	1	100	100	Confidential
Final Shortlist Evaluation (After Tax Reform)	**# Bid Alternatives**	**# Projects**	**Bid Alternative MW**	**Project MW**	**Capacity-Wtd Avg. Nom. Lev. Bid Cost ($/MWh)**
East WY Owned	10	10	3,152	3,152	$26.44
East WY Owned/PPA	5	2	2,760	990	$22.08
East WY 20-Year PPAs	7	3	2,760	1,285	$18.09
East WY 24-27 Year PPAs	18	9	5,663	2,832	$23.37
Other Owned	1	1	161	161	Confidential
Other 20-Year PPAs	1	1	161	161	Confidential
Other 30-Year PPAs	1	1	100	100	Confidential

*Many participants offered more than one bid alternative for a single project (*i.e.*, alternative pricing, term, structure, etc.). Alternatively sized projects offered at the same site or projects offered by more than one bidder are counted as a unique project.

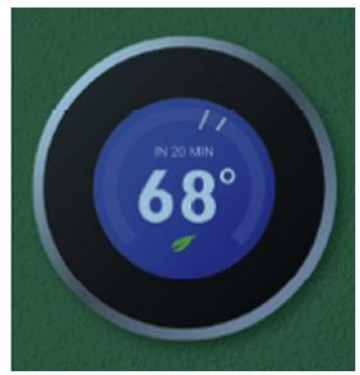
* The cost for owned projects includes capital revenue requirement, run-rate operating costs, applicable taxes and are net of PTCs. All owned wind project costs are assessed over 30 years. The cost for PPAs is reflects the offered PPA price over the term in the bid.

Wind & Transmission Economic Analysis

Price Policy Scenario 1,150 MW (Excluding Uinta)	PaR Stochastic Mean Present Value Net (Benefit)/Cost through 2036 ($ million)	PaR Stochastic Mean Annual Revenue Requirement Present Value Net (Benefit)/Cost through 2050 ($ million)
Low Gas, Zero CO_2	($143)	$154
Low Gas, Medium CO_2	($172)	$97
Low Gas, High CO_2	($312)	($145)
Medium Gas, Zero CO_2	($296)	($97)
Medium Gas, Medium CO_2	($338)	($174)
Medium Gas, High CO_2	($410)	($283)
High Gas, Zero CO_2	($517)	($411)
High Gas, Medium CO_2	($548)	($456)
High Gas, High CO_2	($629)	($576)

- The low natural gas, zero CO_2 and medium natural gas, medium CO_2 price-policy scenario results are based on the most current modeled results assuming removal of Uinta.
- All other price-policy scenarios results reflect the estimated impact of removing the 161 MW Uinta project from the 1,311 MW of new wind selected during the 2017R RFP.
- A comparison of the modeled and estimated results for the low natural gas, zero CO_2 and medium natural gas, medium CO_2 price-policy scenarios demonstrates that the estimated results for other price-policy scenarios are a reasonable representation of removing the Uinta project.
- The results summarized above are conservative (*i.e.*, no value for renewable energy credits, no transmission cost included in the case without the new wind, no accounting for expected lower wind operations & maintenance costs, CO_2 prices are low, conservative extrapolation of system benefits beyond 2036 in the results reported through 2050).

2017S Request for Proposals (RFP)



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2017S RFP Introduction

- In its order approving the 2017R RFP, the Utah Public Service Commission (Utah Commission) suggested, but did not require, a modification to expand the 2017R RFP to solicit solar bids.
- To maintain the 2017R RFP schedule while maintaining the Utah Commission's suggestion, PacifiCorp issued the 2017S RFP on November 15, 2017.
- The 2017S RFP sought bids for solar power-purchase agreements (PPAs) up to 300 MW per individual project.
- PacifiCorp retained an independent evaluator to monitor the 2017S RFP.
- The schedule for the 2017S RFP allowed PacifiCorp to:
  1) evaluate how solar resource bids might impact the economic analysis of bids selected in the 2017R RFP; and
  2) explore whether new solar resource opportunities might provide incremental economic benefits for customers.

2017S RFP Overview

- 31 bidders
- 109 bid alternatives
- 46 solar projects
- 6,496 MW total capacity
- 32 bid alternatives were non-conforming (3,039 MW)
- Initial shortlist included 10 projects from seven bidders totaling 1,629 MW (1,414 MW located in Utah)

Milestone	Date
Issued to the market	11/15/2017
Bidder conference	11/21/2017
Receipt of initial bids	12/11/2017
Initial shortlist submitted to IE	01/08/2018
IE review of initial shortlist completed	01/29/2018
Best and final pricing	02/01/2018
Final shortlist evaluation completed	03/12/2018
IE closing report issued	03/29/2018

2017S RFP Bid Data

Initial Shortlist Evaluation	# Bid Alternatives	# Projects	Bid Alternative MW	Project MW	Capacity-Wtd Avg. Nom. Lev. PPA Bid Price ($/MWh)
UT 15-Year PPAs	2	1	320	160	Confidential
UT 20-Year PPAs	23	14	2,714	2,125	$33.45
UT 25-Year PPAs	28	21	4,061	2,970	$31.50
Other 15-Year PPAs	1	1	100	100	Confidential
Other 20-Year PPAs	15	11	1,421	1,163	$39.23
Other 25-Year PPAs	5	5	490	490	$37.29

Final Shortlist Evaluation	# Bid Alternatives	# Projects	Bid Alternative MW	Project MW	Capacity-Wtd Avg. Nom. Lev. PPA Bid Price ($/MWh)
UT 15-Year PPAs	0	0	0	0	n/a
UT 20-Year PPAs	5	5	699	699	$28.47
UT 25-Year PPAs	15	13	2,475	1,799	$28.99
Other 15-Year PPAs	1	1	100	100	Confidential
Other 20-Year PPAs	3	2	330	215	$37.24
Other 25-Year PPAs	1	1	100	100	Confidential

*Many participants offered more than one bid alternative for a single project (*i.e.*, alternative pricing, term, etc.).

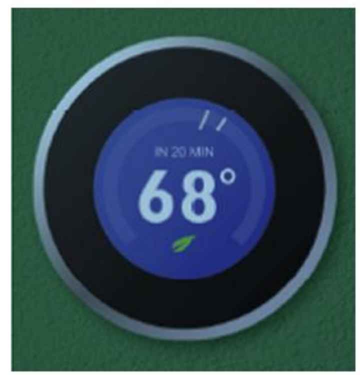
*Alternatively sized projects offered at the same site are counted as a unique project.

2017S RFP Conclusion

- Solar PPAs can provide customer benefits.
- Sensitivity analysis showed that valuation risks (hourly price profiles and capacity contribution) can reduce energy and capacity benefits.
- Bid prices may have reflected a risk premium due to tariff and tax-reform uncertainties.
- Given the later phase out of the 30-percent investment-tax credit relative to the phase out for the production-tax credit, valuation risks, and expected price reductions, PacifiCorp did not select any bids to the 2017S RFP final shortlist.
- Even through the 2017S RFP has been closed, PacifiCorp has remained actively engaged with solar developers and recently executed solar PPAs that provide customer benefits after accounting for the factors discussed above.
- Communications agreements with counterparties have not yet been finalized.
- Once these communications agreements are executed, PacifiCorp will provide additional information on these PPAs in a future public-input meeting.
- On-going assessment of solar-resource opportunities will continue in the 2019 IRP.

Additional Information / Next Steps



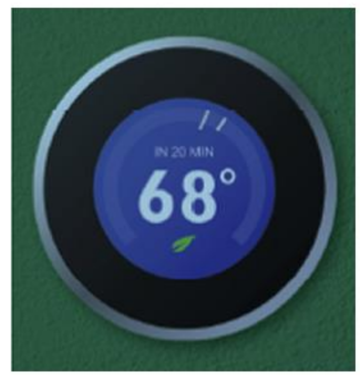
Additional Information / Next Steps

- Public Input Meeting Presentation and Materials:
  - pacificorp.com/es/irp.html
- 2019 IRP Stakeholder Feedback Forms:
  - pacificorp.com/es/irp/irpcomments.html
- IRP Email / Distribution List Contact Information:
  - IRP@PacifiCorp.com
- Upcoming Public Input Meeting Dates:
  - July 26-27, 2018
  - August 30-31, 2018
  - September 27-28, 2018
  - November 1-2, 2018
  - December 3-4, 2018
  - January 24-25, 2019
  - February 21-22, 2019
  - March 2019 – *TBD /as needed*
  - *April 1, 2019 – 2019 IRP File Date*

2019 IRP DSM Technical Workshop

June 29, 2018



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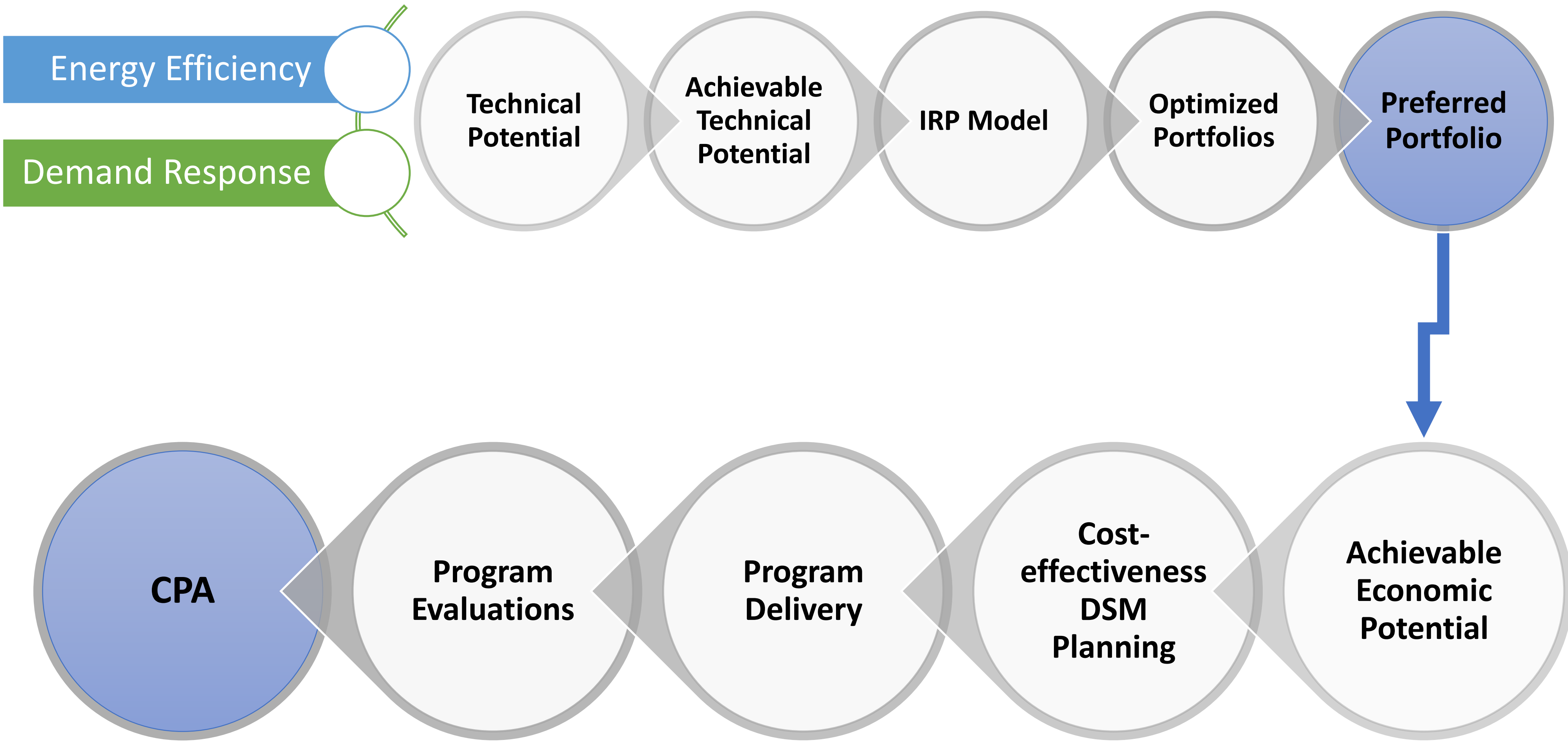
2017 IRP DSM Requirements

- In its 2017 IRP acknowledgement order (Order No 18-138), the Public Utility Commission of Oregon (OPUC) established the following requirement for demand-side management (DSM) in the 2019 IRP set forth below.
  - Early in the public input process for the 2019 IRP, prior to finalizing energy efficiency supply curves, PacifiCorp will hold a DSM technical workshop to review and receive input regarding how the company models energy efficiency potential in the IRP and supporting studies such as the Conservation Potential Assessment (CPA).
- In addition, in its 2017 IRP acknowledgement order in Docket No. 17-035-16, the Utah Public Service Commission (UPSC) states "To Satisfy Guideline 3, any changes to the DSM modeling assumptions must be circulated during the IRP development process."
- This workshop responds to the OPUC requirement and ongoing requirement of the UPSC.

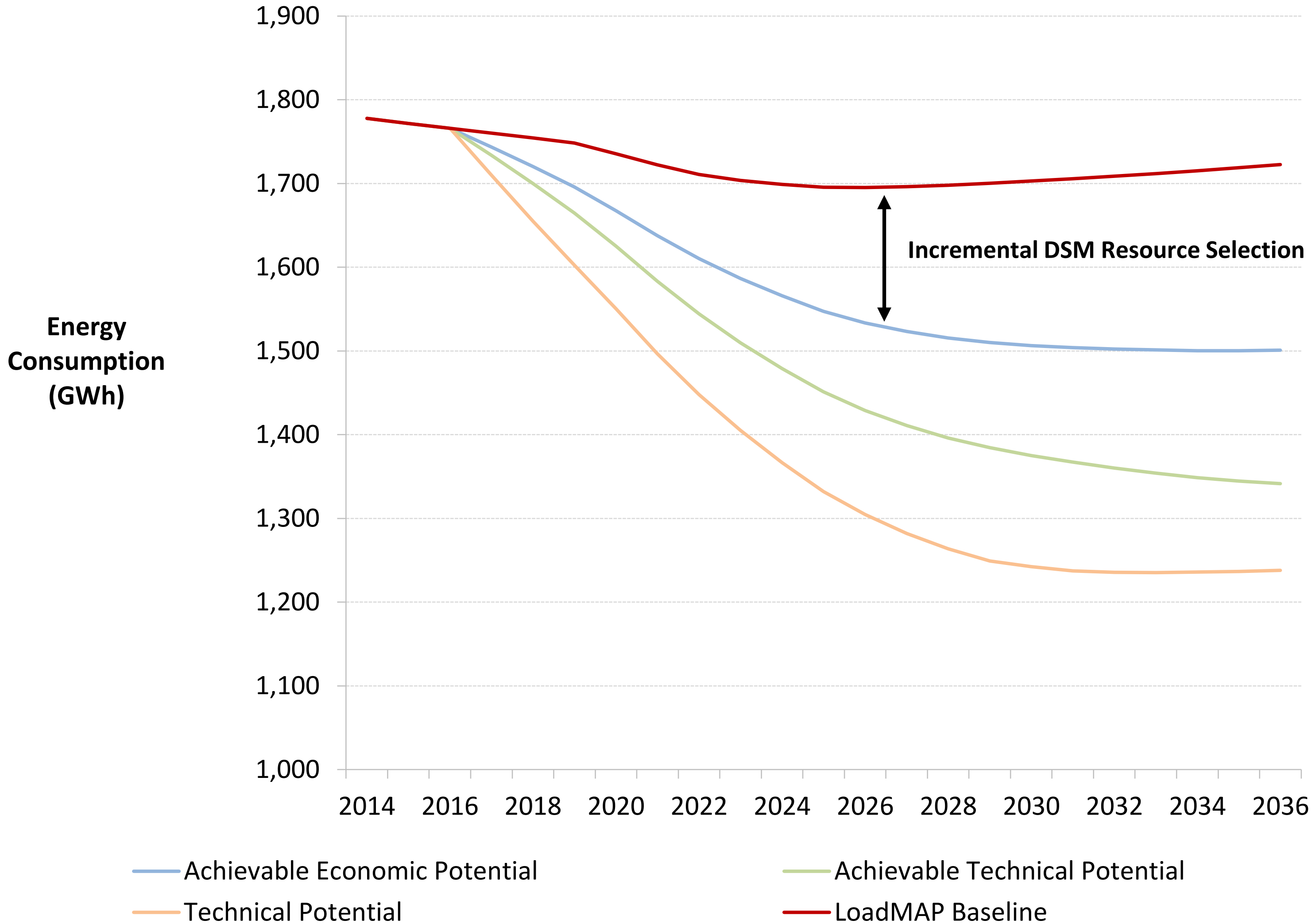
Workshop Overview

- CPA development process in all states (except Oregon)
- Oregon's potential development process
- IRP DSM modeling assumptions and approach

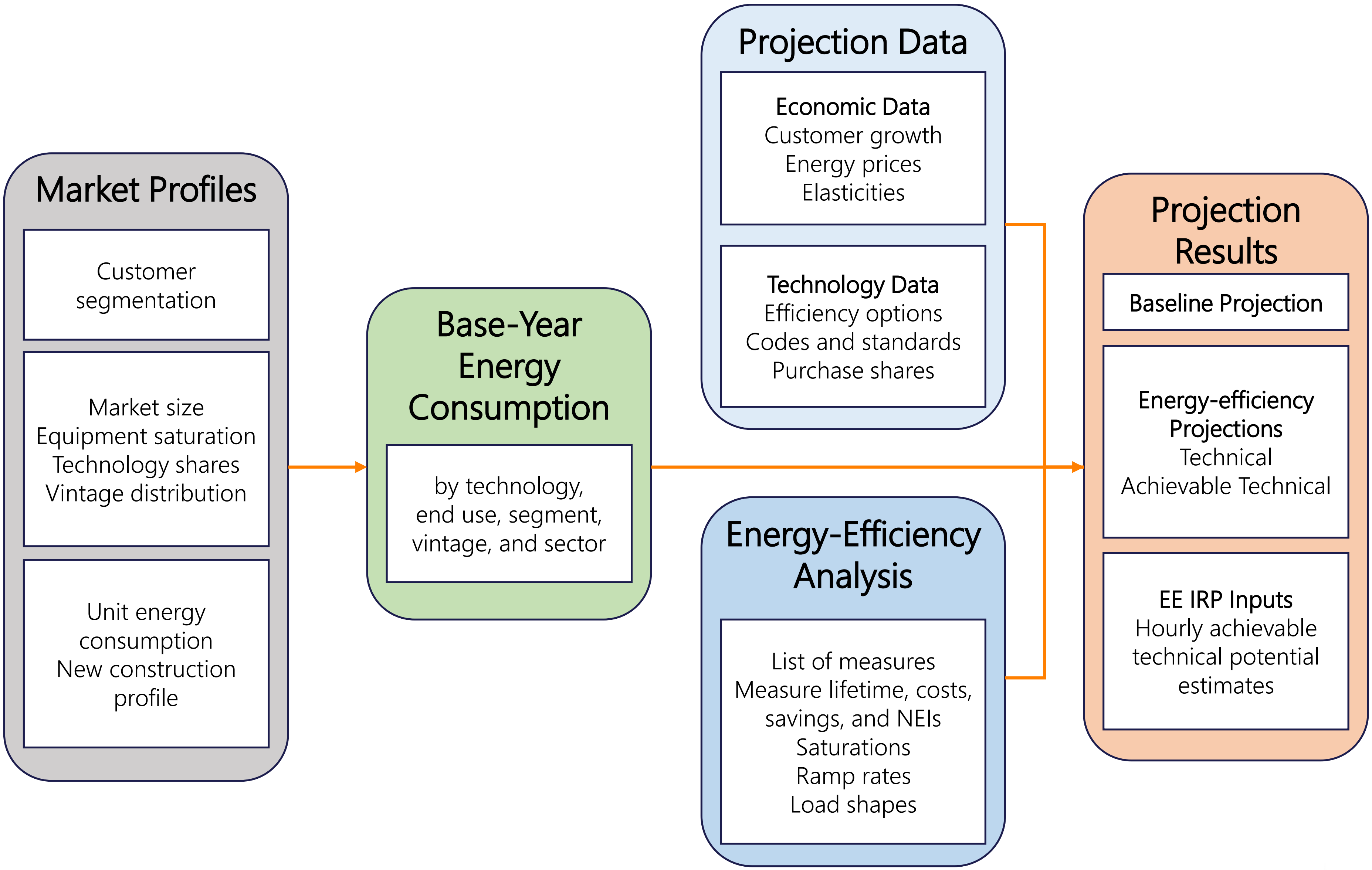
CPA Development Process



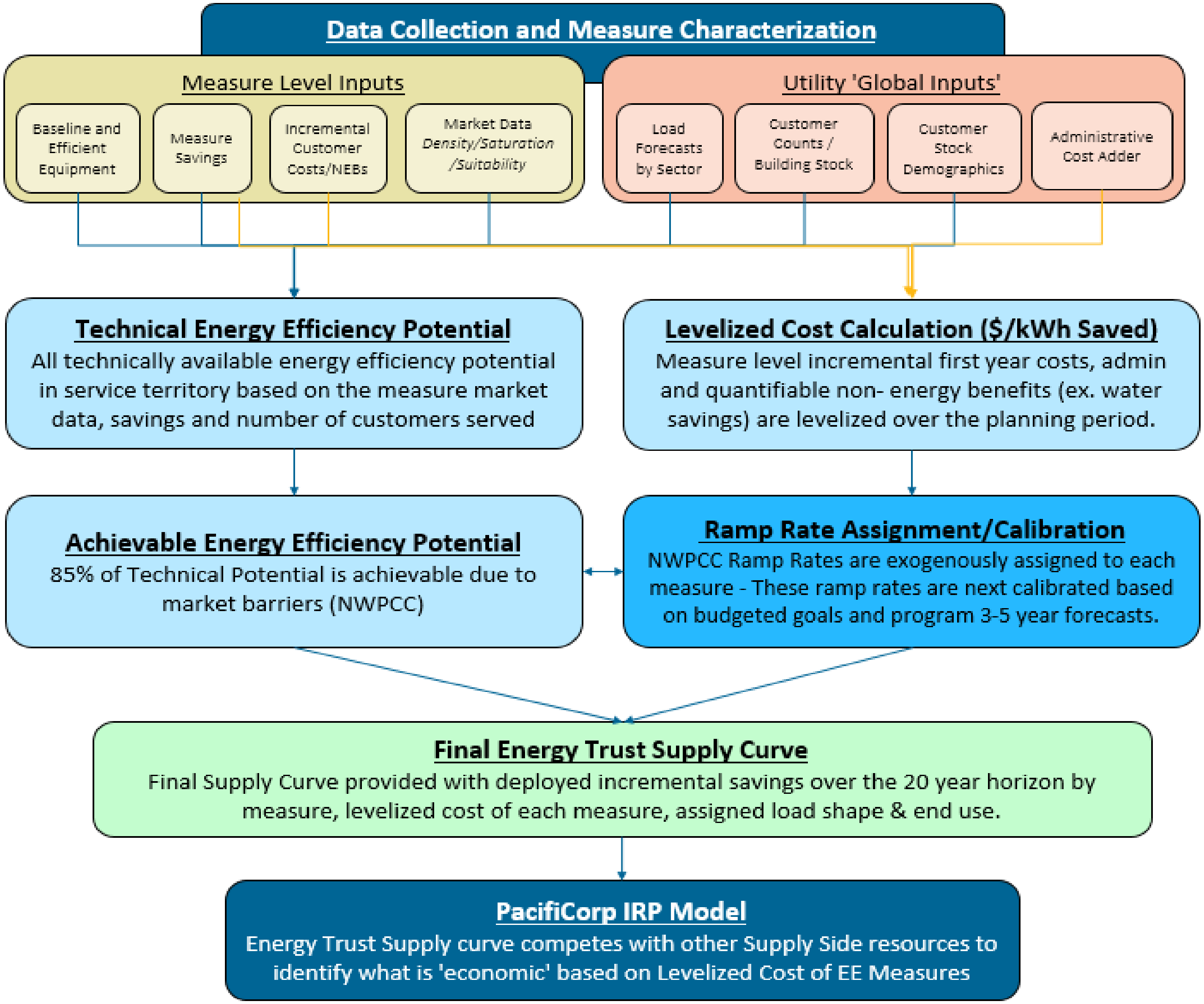
Example Energy Consumption Projections



CPA Methodology (Except OR)



Oregon CPA Methodology



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2019 IRP CPA Key Focus Areas

- Review all 2017 IRP CPA study assumptions and inputs and update with best available information regarding:
  - Stakeholder feedback
  - Emerging technologies
  - Administrative cost assumptions
- Align with existing and updated state-specific requirements
- Incorporate waste-heat-to-power analysis
- Ensure transparency into resource planning assumptions and key drivers of changes relative to the 2017 IRP CPA

Emerging Technologies

- AEG conducted a thorough review of emerging technologies for this CPA, using data from E3T, NEEA, BPA, NREL, U.S. DOE, and pilot/R&D programs throughout the nation
- All potential measures were passed through a qualitative screen based on:
  - Technical maturity (e.g. R&D, pilot, or regional implementation)
  - Applicability (e.g. small niche, one segment, one sector)
  - Data availability (e.g. manufacturer claims, independent publications, pilot data)
- Measures that were sufficiently mature and applicable for PacifiCorp's service territory were included within the CPA.
- Measures not incorporated into this CPA will be kept on a "watch" list to re-evaluate for the next CPA.

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Waste-Heat-to-Power

- Analysis was previously conducted outside the 2017 IRP CPA
- For this analysis the waste-heat-to-power was combined with the 2019 IRP CPA.
- Updates include the following:
    - Resources (Micro hydro removed, assessed in other studies)
    - Applicable facilities (e.g. added new and removed offline)
    - Assumptions (e.g. lifetime, cost, savings, etc.)
    - Measures were modeled to account for interactive effects

Administration Costs

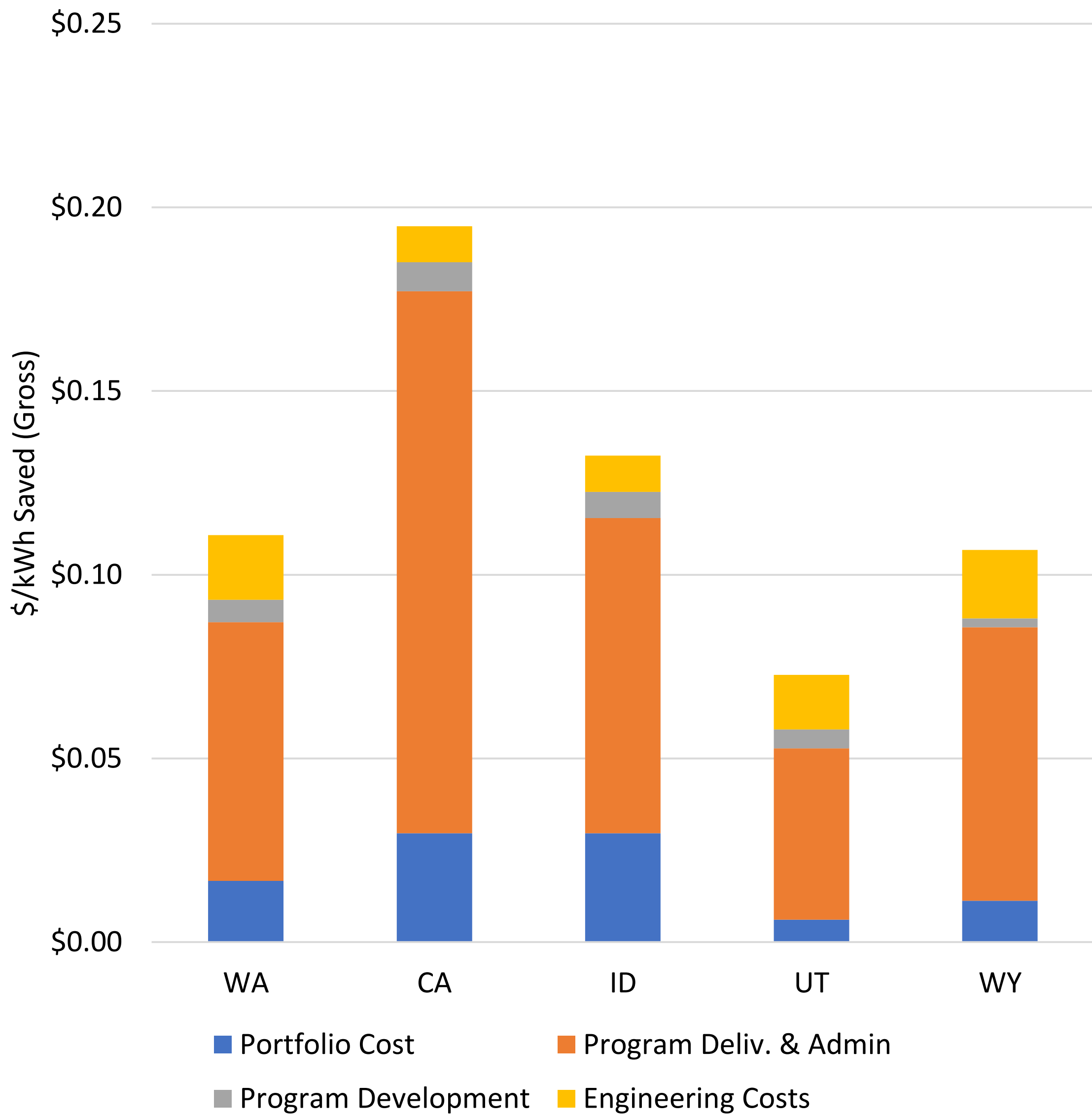
- While estimating potential, AEG assessed the actual utility costs required to administer energy efficiency programs within PacifiCorp's territory
- Administration costs included:
  - Portfolio Costs (e.g. evaluations, CPA)
  - Engineering Costs (e.g. custom project analysis and inspections)
  - Utility Admin Costs (e.g. internal labor)
  - Program Development Costs (e.g. program planning)
  - Program Delivery Costs (e.g. program implementation)
- AEG analyzed E Source's database of utility programs of available data in the western United States

Administration Costs, Con’t

- Identified that costs in Utah averaged 18 percent of incremental while the other states averaged 34 percent
  - In the prior CPA, it was assumed that NPCCC’s administrative costs equaled 20 percent of measure incremental cost
  - Using a savings-weighted average, administrative costs for all five states was 21 percent of measure incremental cost

Admin % Customer	Utah	Washington	California	Idaho	Wyoming
Average	**18%**	**35%**	**44%**	**36%**	**27%**

Administration Costs - State & Type



CPA Modeling

CPA Data Sources

- Baseline Data
  - PacifiCorp residential saturation surveys
  - Regional building stock assessments
  - Regional and national end-use consumption data
  - Future Known Federal Standards
  - PacifiCorp actual and forecasted customers and sales
- Measure Data
  - PacifiCorp program evaluations
  - Regional and national measure databases (e.g., Regional Technical Forum, California Database for Energy Efficient Resources, etc.)
- Acquisition assumptions and rates
  - Northwest Power and Conservation Council's (NWPCC's) 7th Power Plan achievability and ramp rates
  - State-specific considerations

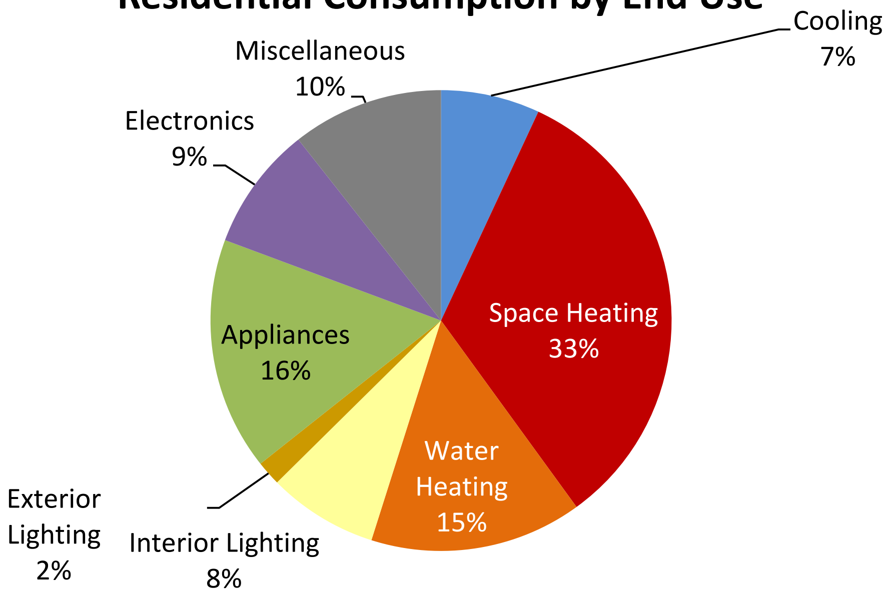
Energy-Efficiency Analysis

- Data required for each measure:
  - Technical applicability
  - Current saturation
  - Unit energy savings: annual energy and peak demand
  - Costs: installation, O&M, and non-energy impacts
  - Lifetime
  - Baseline condition (incorporated into baseline projection)
  - Appliance standards
  - Measure adoption rates

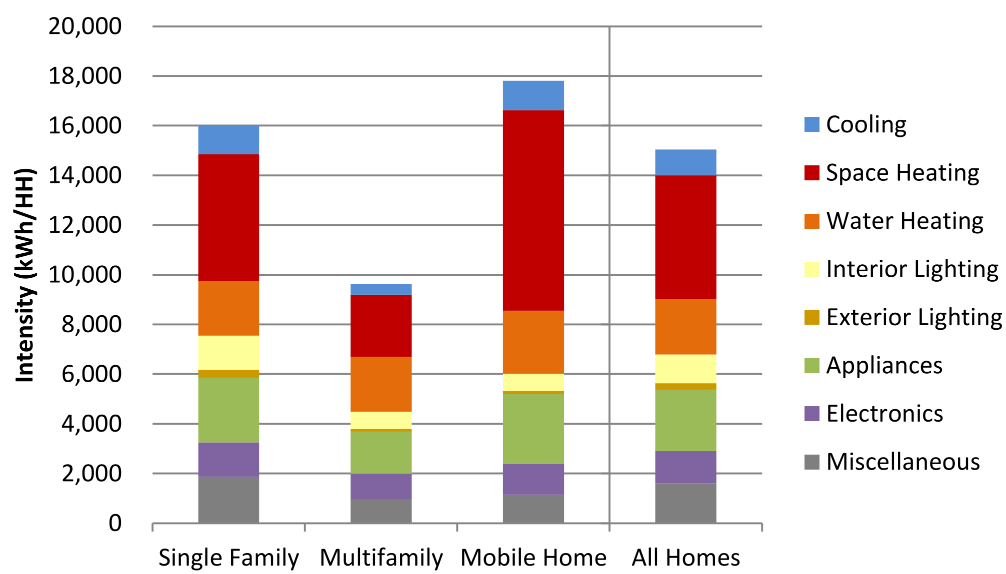
Energy Market Profiles
Washington Example

Residential Consumption Data by State	2014 Usage (MWh)	Households	Usage per Household (kWh/hh)
Single Family	1,194,961	74,524	16,035
Multifamily	194,305	20,210	9,614
Manufactured	231,705	13,016	17,802
Total	1,620,972	107,750	15,044

Residential Consumption by End Use

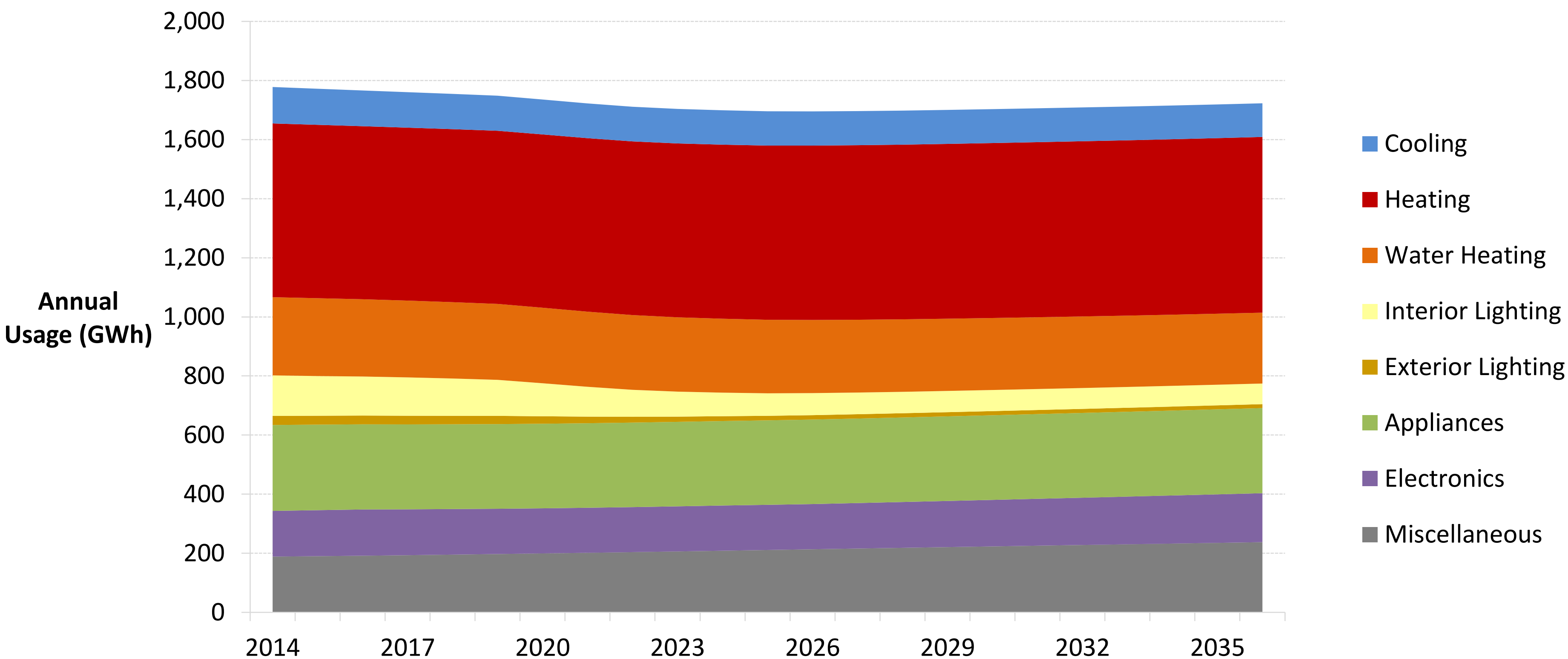


End-Use Intensity by Housing Type



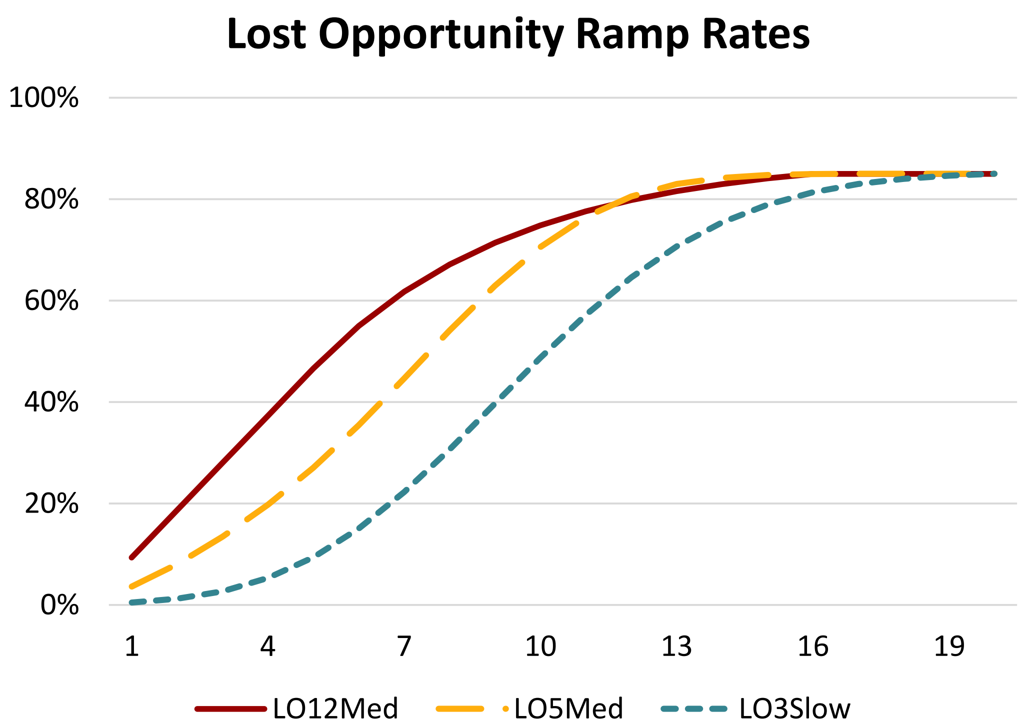
Baseline Energy Projection – Washington Residential

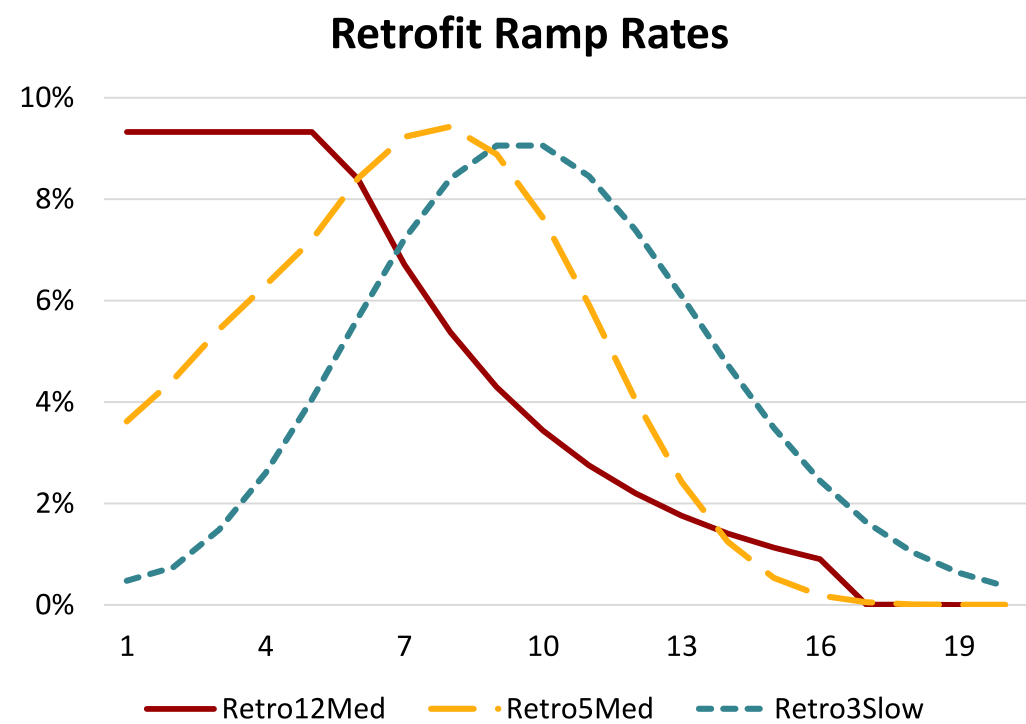
- This alignment is an important step since it finalizes the baseline upon which potential is assessed



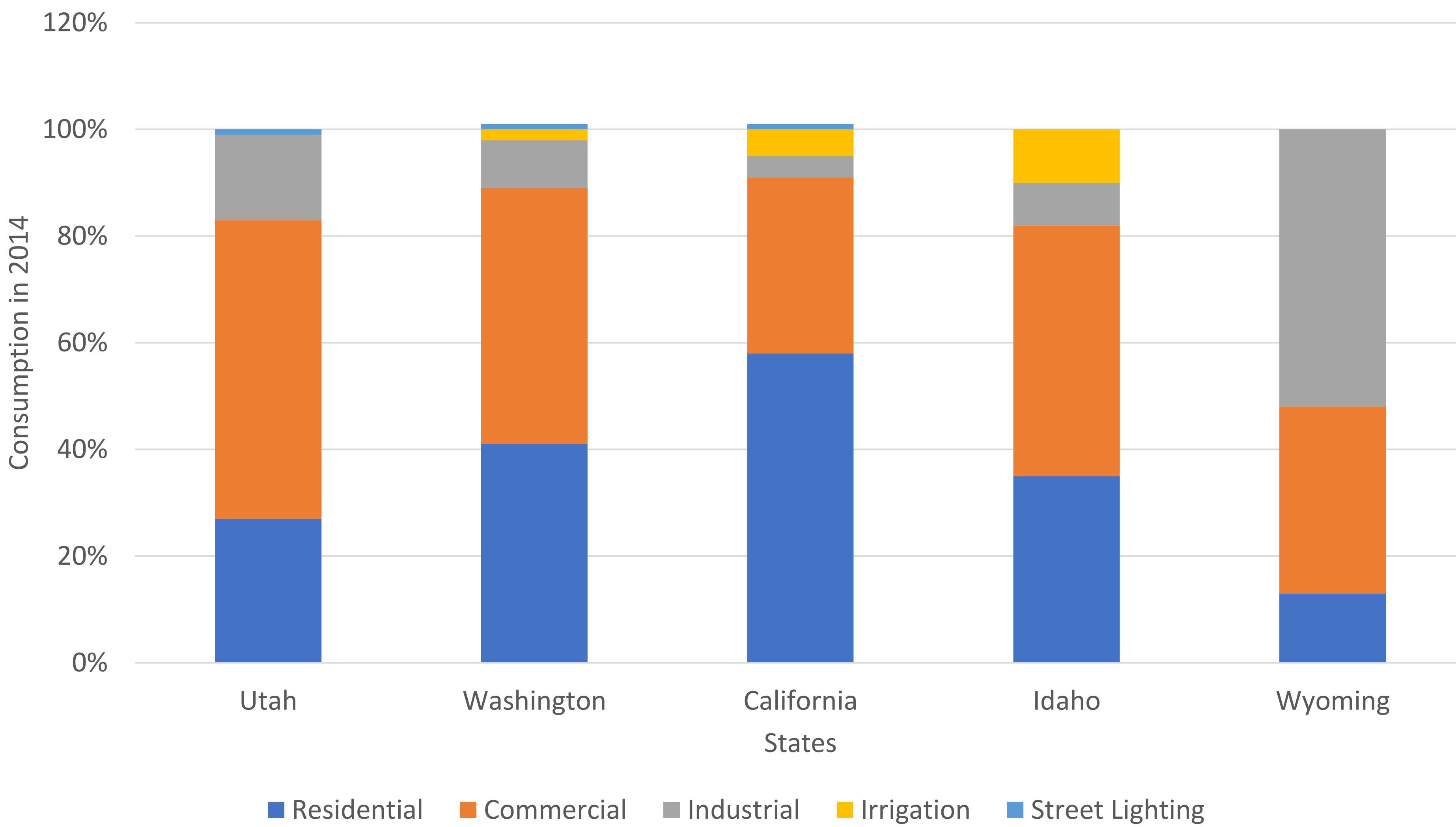
Energy-Efficiency Analysis Measure Ramp Rates

- NWPCC's Seventh Plan ramp rates are a starting point:
  - For turnover, "Lost Opportunity" measures, year-4 is used as the starting point to align with the fourth year of the Seventh Plan





Customer Segmentation



Comparing Results Across States & Studies

- Since state-specific characteristics are captured within the CPA, results tend to vary. Previous sources of change have included:
  - Customer segmentation
  - High-potential end uses
  - Changes in baselines
  - State energy codes
  - Market maturity
  - Administrative costs
  - Levelized cost methodology

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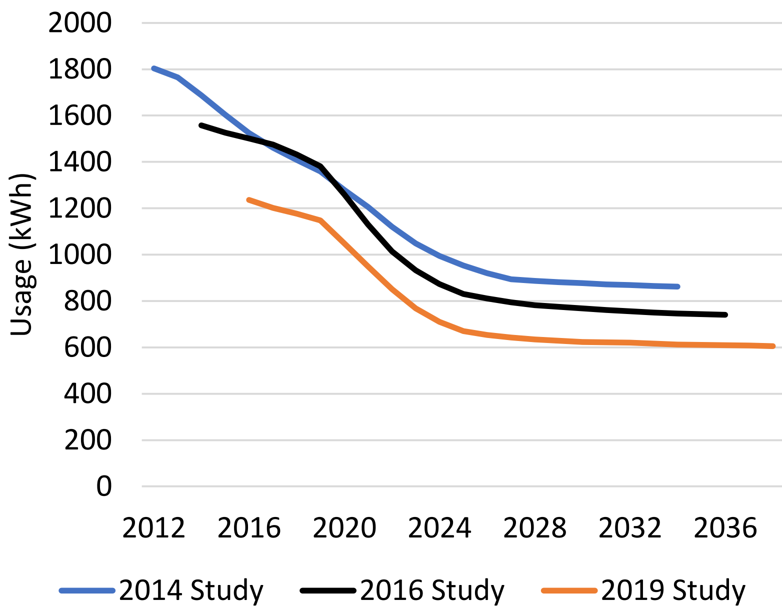
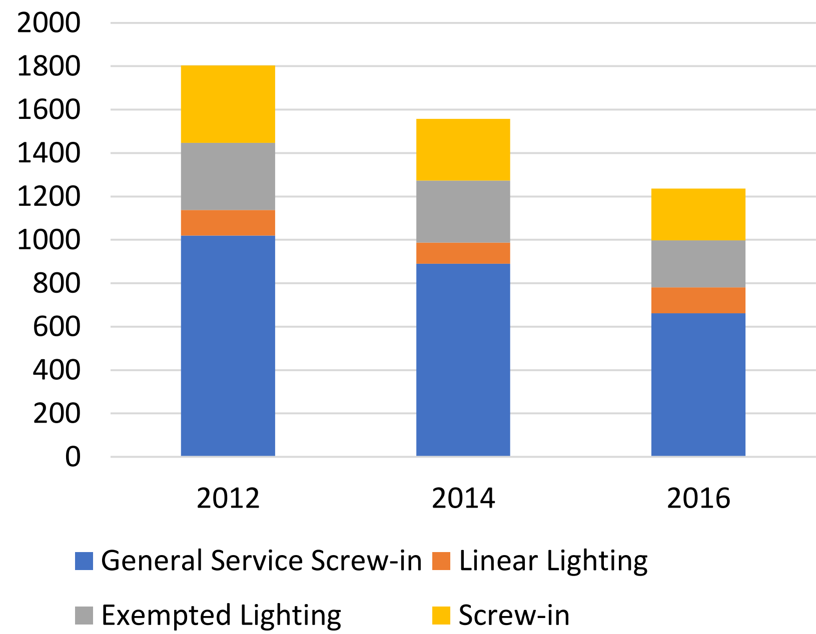
Change in Baseline Lighting Example

- Due in part to previous, and upcoming federal standards (EISA 2007), household lighting consumption has been steadily declining over time
  - Potential for high efficiency lighting doesn't disappear, it moves into the baseline

Household Lighting Consumption Change Over Time

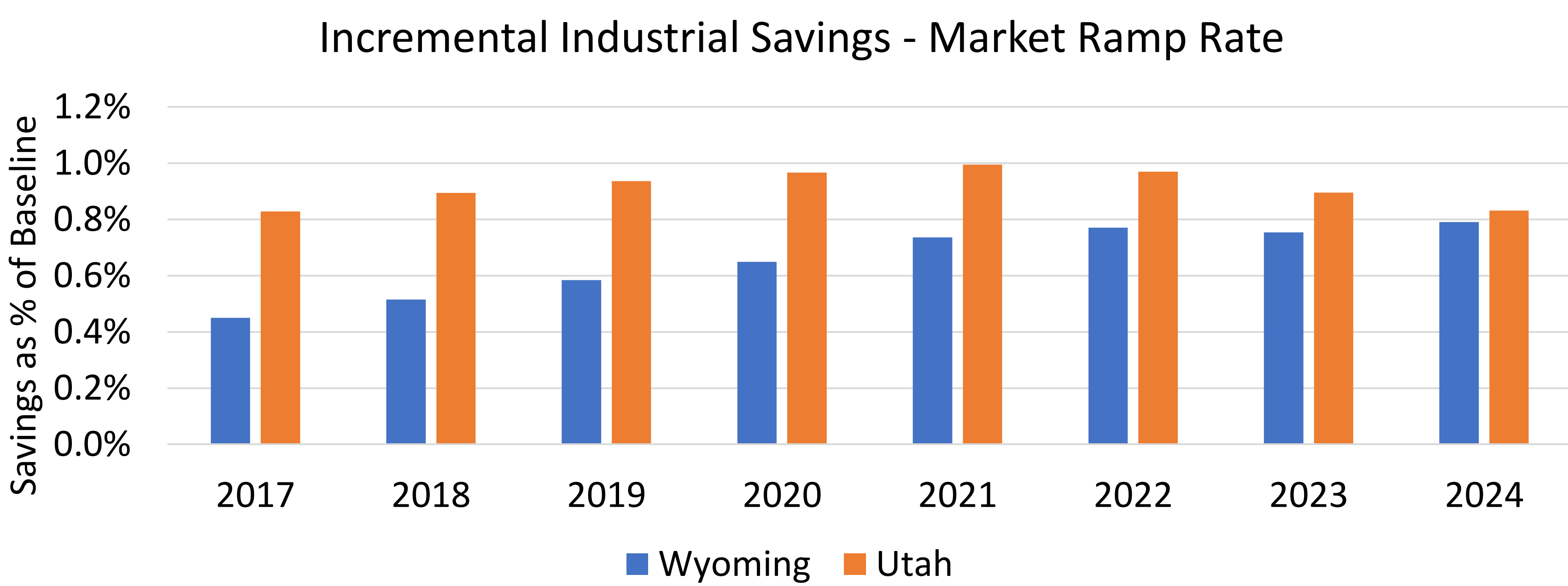


Base Year Lighting Usage by Study Year



Market Maturity

- Certain markets contain more "hard-to-reach" customers than others
- This is true in Wyoming, where the industrial mining and extraction segment has not participated at anticipated levels
  - In past studies, this was true for all of Wyoming and Idaho as well
  - Early-year WY potential is lower than other states



Levelized Cost

- Levelized cost calculation align with state specific program delivery cost-effectiveness criteria

Perspective	Total Resource				Utility		Included In:
State	OR	WA	CA	WY	UT	ID	
State and Sector-Specific Line Losses	✓	✓	✓	✓	✓	✓	Potential Study
Customer Cost	✓	✓	✓	✓			Potential Study
Utility Investment	✓	✓	✓	✓	✓	✓	Potential Study
Annual Incremental O&M	✓	✓					Potential Study
Secondary Fuel Impacts	✓	✓					Potential Study
Non-Energy Impacts	✓	✓					Potential Study
10% Conservation Credit	✓	✓					IRP
T&D Deferral Benefits	✓	✓	✓	✓	✓	✓	IRP
Risk Mitigation Benefits	✓	✓	✓	✓	✓	✓	IRP

Oregon CPA Modeling

- Energy Trust of Oregon uses a model in Analytica that was developed by Navigant Consulting in 2014
  - The Analytica RA Model calculates Technical, Achievable and Cost-Effective Achievable Energy Efficiency Potential.
  - Final IRP supply curve is the deployed Achievable Potential output from the model and the levelized cost output.
- Data inputs and assumptions in the model are updated in conjunction with IRP about every two years.
- Energy Trust of Oregon is required to go after all cost-effective achievable technical potential under our grant agreement with the OPUC
- The levelized cost is an output of Energy Trust's RA Model, but is not the final levelized cost input into the IRP Model
  - Levelized Cost Output: Customer Incremental Cost, Non-Energy Benefits

Oregon Model Inputs

Measure Level Inputs
Measure Definition and Application: • Baseline/Efficient equip. definition • Applicable customer segments • Installation type (RET/ROB/NEW)* • Measure Life
Measure Savings
Measure Cost • Incremental cost for ROB/NEW measures • Full cost for retrofit measures
Market Data (for scaling) • Density • Baseline/efficient equipment saturations • Suitability

** RET = Retrofit; ROB = Replace on Burnout; NEW = New Construction*

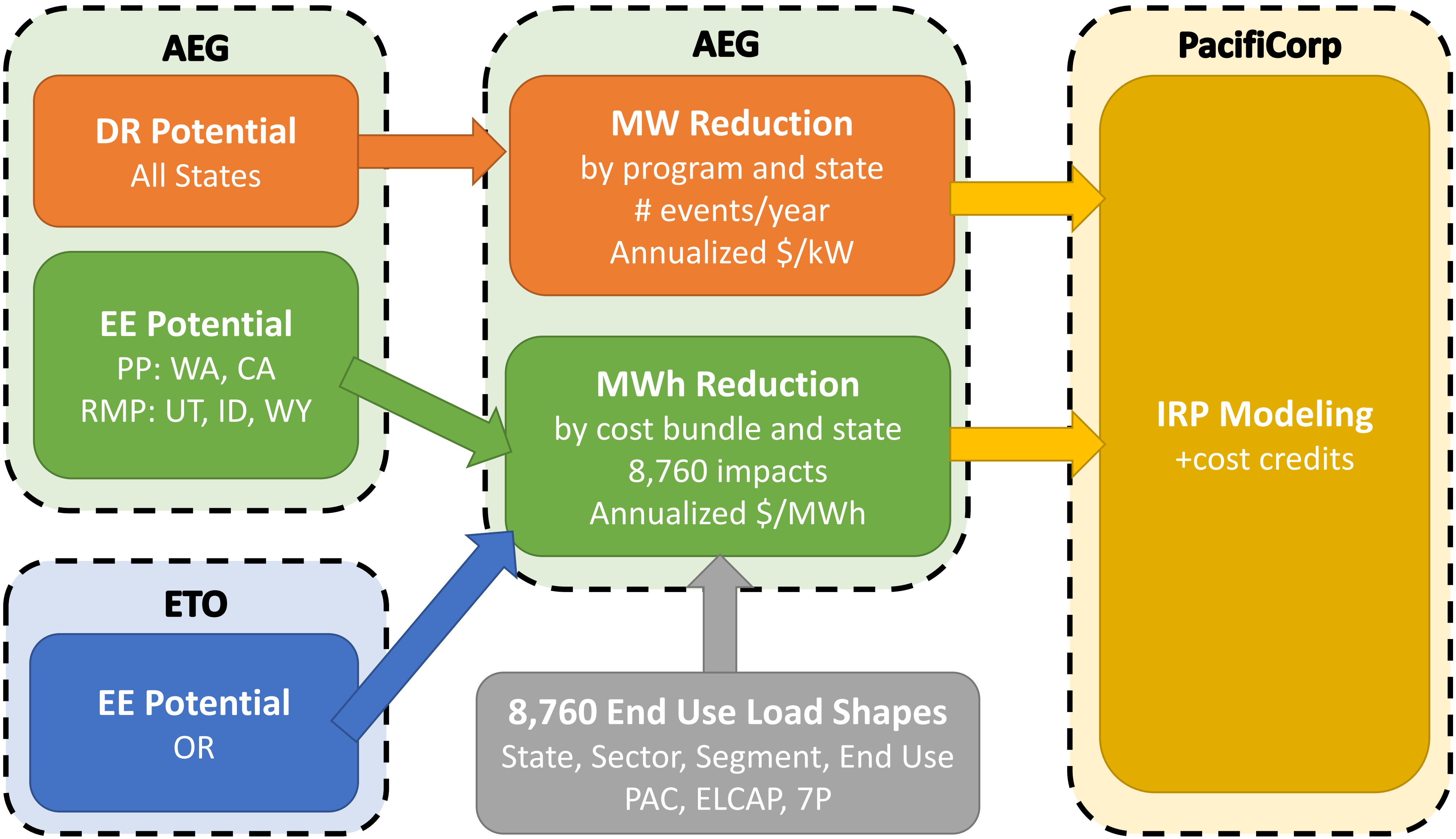
Utility 'Global' Inputs

Customer and Load Forecasts
• Used to scale measure level savings to a service territory
  • Residential Stocks: # of homes
  • Commercial Stocks: 1000s of Sq.Ft.
  • Industrial Stocks: Customer load

Admin Cost Adder (20%)
Customer Stock Demographics: • Heating fuel splits • Water heat fuel splits

Most are the same or at least similar to data inputs required for AEG model

Supply Curve Development



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IRP Modeling

Energy Efficiency Background

- Energy efficiency (EE) projects represent energy efficiency programs in six states – Oregon, Washington, California, Idaho, Utah, and Wyoming.
- Energy efficiency reduces the load demand in each state at various energy output and cost levels.
- Energy efficiency is modeled as a supply-side resource in order to compete against all other resource options in IRP modeling.

Model Inputs

IRP modeling requires the following inputs:

- Capacity Planning Factor – the EE resource's contribution toward system peak
  - Summer CPF calculated based on the provided hourly shape using an average of the July super-peak hours
  - Winter CPF calculated based on the provided hourly shape using an average of the December super-peak hours
- Contract Price ($/MWh) – based on the CPA cost provided adjusted for any cost credits (described later)
- Potential incremental capacity (MW) by year by bundle
- Hourly shape (8760 capacity factor) for each EE bundle

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Model Inputs

The Customer Solutions Planning team provides the IRP team with seven files as part of the CPA

- The "Bundle Descriptions" file provides the following data used to develop model setups:
    - Potential Capacity (Incremental MW) broken out by cost bundle.
    - Weighted Average Levelized Cost by Bundle (consistent with other supply-side resources)
        - All states except Utah & Idaho use the Total Resource Cost. Both Utah and Idaho are required to be based on Utility Cost).
- Six additional files (one for each state) containing one-year capacity factor shapes

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Load Points

Energy efficiency resources tie to one or two specific load points for each state:

- CA – South Oregon California (SOregonCal)
- WA – Walla Walla, Yakima
- OR - South Oregon California (SOregonCal)
- ID – Goshen
- UT – Utah North
- WY – Wyoming Northeast (WyomingNE)

Cost Bundles

Bundle	2017 IRP - Levelized Bundle Price after Adjustments ($/Mwh)					
	California	Idaho	Oregon	Utah	Washington	Wyoming
<= $10	-	-	-	-	-	-
$10 - $20	4.73	8.11	3.61	7.39	1.94	9.66
$20 - $30	18.76	17.48	14.93	17.77	14.49	18.51
$30 – $40	28.75	27.07	23.11	26.23	23.48	30.24
$40 – $50	39.03	39.61	33.42	36.32	32.21	37.83
$50 - $60	48.25	47.20	42.72	47.06	43.34	46.82
$60 – $70	57.66	56.77	53.05	57.07	52.19	56.83
$70 – $80	69.84	65.85	65.32	66.34	63.15	66.85
$80 – $90	77.93	78.85	74.56	77.46	74.35	77.24
$90 – $100	87.04	88.49	86.13	85.71	83.20	88.17
$100 – $110	97.09	99.11	94.61	96.85	92.91	96.31
$110 – $120	109.67	106.88	111.56	109.91	101.03	106.41
$120 – $130	119.50	119.25	111.33	115.86	111.99	117.85
$130 – $140	125.93	125.48	124.14	125.36	124.95	126.70
$140 – $150	134.74	135.05	130.27	137.75	136.82	134.29
$150 - $160	150.30	150.77	140.73	144.38	139.15	148.62
$160 – $170	160.96	156.49	151.24	156.15	153.28	160.90
$170 – $180	166.81	164.09	163.31	166.43	164.07	166.69
$180 – $190	179.73	179.38	171.88	179.01	175.68	179.84
$190 – $200	186.97	185.47	-	187.53	183.26	185.49
$200 – $250	213.11	213.81	209.52	214.30	207.69	216.08
$250 – $300	260.01	251.35	269.00	262.61	267.20	264.80
$300 – $400	346.33	337.96	337.63	325.16	333.29	341.31
$400 – $500	434.35	427.19	449.99	445.02	462.31	426.49
$500 – $750	664.40	667.87	677.08	603.25	665.74	646.11
$750 – $1,000	884.19	880.97	946.92	872.55	844.46	852.05
> $1,000	31,156.03	22,651.32	1,314.40	43,792.75	43,424.78	24,329.18

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Other Assumptions

- Energy efficiency bundles are setup to allow the model to select any amount up to the full potential of the bundle (i.e., for a bundle with 50 MW available potential, the model can select anywhere from 0 up to a maximum of 50 MW)
  - Any portion of the potential that isn’t selected in a given years is no longer available for selection in a subsequent year
- For IRP modeling purposes, the energy efficiency bundles are assumed to be effective during the full modeling period (20-year life)

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Energy Efficiency Cost Credits

The weighted levelized energy cost of the bundles is adjusted by the following factors in order to determine the final modeled bundle cost.

- Transmission and Distribution cost credit
  - Energy efficiency programs help avoid the company occurring power transfer and distribution costs due to the load reduction attribute of the programs. A nominal flat $13.56/KW-year avoided cost was assessed in 2017 IRP study, and will be updated for the 2019 IRP. This cost adjustment is converted to a $/MWh value, then weighted by the Capacity Planning Factor, and applied for all states across all cost bundles according to each bundles' energy output
- Risk Adjustment credit
  - A cost adjustment is implemented to monetize avoided market risk exposure to the company from electing EE programs. The avoided market risk assessment will be evaluated in a post 2017 IRP Update study and then carried over into 2019 IRP modeling. The credit is subtracted from the original energy cost ($/MWh). This cost adjustment is applied to all states class 2 programs in every cost bundle for System Optimizer Runs only.
- Northwest Power Act 10-percent credit (Washington and Oregon resources only)
  - By state rules, the company is required to mark 10% of electricity market value off of the energy cost from the state wide class 2 programs.

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Next Steps

- July 13, 2018: Request stakeholder feedback to inform CPA
- July 2018 – September 2018:
  - Incorporate stakeholder feedback as possible
  - Present final supply curves and/or updated DSM credits (July and/or August 2019 IRP Public Input Meeting)
- January 2019: Target publication of final CPA report
- April 1, 2019: 2019 IRP file date