2017 Integrated Resource Plan

Public Input Meeting 4

September 22-23, 2016

PACIFICORP

A BERKSHIRE HATHAWAY ENERGY COMPANY

Agenda

September 22 - Day One

- Introductions
- Portfolio Development
- Stochastic Modeling
- Lunch Break (1 hour) 11:30 PT/12:30 MT
- Resource Adequacy / Front Office Transactions
- Loss of Load Probability / Planning Reserve Margin
- Capacity Contribution Study

September 23 - Day Two

- Load & Resource Balance
- Flexible Capacity Reserve Study
- Smart Grid Update
- Next Steps





2017 Integrated Resource Plan

Portfolio Development

2017 Portfolio Development Process

Vol. III Analysis → Core Portfolios (Targeted Resource Classes) → Cost and Risk (Broader Range of Assumptions) → Sensitivity Analysis ("Benchmark" informed by Results) → Preferred Portfolio Selection

- Volume III modeling will inform Regional Haze compliance assumptions used to produce core resource portfolios for existing coal units.
  - PacifiCorp will study six Regional Haze cases, including an endogenous retirement case, among a range of market price and future greenhouse gas policy assumptions.
- Core resource portfolios will include an optimized portfolio and supplemental portfolios targeting specific types of resources.
  - Promotes portfolio diversity and eliminates the need for deterministic risk analysis.
  - Allows resources having operating characteristics not valued in System Optimizer to be analyzed in Planning and Risk during the cost and risk analysis phase of the portfolio development process.
- Cost and risk analysis performed using the Planning and Risk model will include market price and future greenhouse gas policy assumptions.
- Sensitivity analysis will be informed by modeling results from core cases.
  - PacifiCorp has preliminarily identified a number of sensitivities, but will consider additional sensitivities and identify the sensitivity "benchmark" case once core case modeling is completed.
  - As appropriate, sensitivity cases can be used to select a preferred portfolio, inform the action plan, and inform acquisition path analysis.

Vol. III: Regional Haze Cases 1 through 5

Plant	2015 IRP Update (Pref. Port.)	2017 IRP (Ref. Case)	2017 IRP (Alt. Case RH-1)	2017 IRP (Alt. Case RH-2)	2017 IRP (Alt. Case RH-3)	2017 IRP (Alt. Case RH-4)	2017 IRP (Alt. Case RH-5)
Hunter 1	SCR 2021 Ret. 2042	SCR 2021 Ret. 2042	No SCR;NO_x+ 2021 Ret. 2042	No SCR Ret. 2031	No SCR;NO_x+ 2026 Ret. 2042	SCR 2021(1) Ret. 2042	RH-1
Hunter 2	No SCR Ret. 2032	SCR 2021 Ret. 2042	No SCR;NO_x+ 2021 Ret. 2042	No SCR Ret. 2031	No SCR;NO_x+ 2027 Ret. 2042	No SCR;NO_x+ 2027(1) Ret. 2042	RH-1
Huntington 1	SCR 2022 Ret. 2036	SCR 2021 Ret. 2036	No SCR Ret. 2036	No SCR Ret. 2036	No SCR;NO_x+ 2026 Ret. 2036	SCR 2021(2) Ret. 2036	RH-1
Huntington 2	No SCR Ret. 2029	SCR 2021 Ret. 2036	No SCR Ret. 2036	No SCR Ret. 2036	No SCR;NO_x+ 2027 Ret. 2036	No SCR;NO_x+ 2027(2) Ret. 2036	RH-1
Jim Bridger 1	SCR 2022 Ret. 2037	SCR 2022 Ret. 2037	No SCR Ret. 2032	No SCR Ret. 2024	No SCR Ret. 2028	No SCR;NO_x+ 2022(1) Ret. 2032	RH-3
Jim Bridger 2	SCR 2021 Ret. 2037	SCR 2021 Ret. 2037	No SCR Ret. 2035	No SCR Ret. 2028	No SCR Ret. 2032	SCR 2021(1) Ret. 2037	RH-3
Naughton 3	No Gas Conv. Ret. 2017	Gas Conv. 2019(3) Ret. 2029	No Gas Conv. Ret. 2017	Gas Conv. 2019(3) Ret. 2029	No Gas Conv. Ret. 2017	Gas Conv. 2019(3) Ret. 2029	RH-2
Cholla 4	Gas Conv. 2025 Ret. 2042	Gas Conv. 2025 Ret. 2042	No Gas Conv. Ret. Apr-2025	No Gas Conv. Ret. 2020	No Gas Conv. Ret. Apr-2025	No Gas Conv. Ret. Apr-2025	RH-2
Craig 1	SCR 2021 Ret. 2034	SCR 2021 Ret. 2034	No SCR Ret. 2025	Gas Conv. 2023(4) Ret. 2034	No SCR Ret. 2025	No SCR Ret. 2025	RH-1

1) The Alternative Regional Haze Cases for Hunter Units 1 and 2 and Jim Bridger Units 1 and 2 have been developed for analysis purposes only with consideration given to the fact that the emissions profiles for the units are effectively identical in the Regional Haze context. The compliance actions for the units in this scenario could effectively be swapped and provide the same Regional Haze compliance outcome. The matrix presentation of different compliance actions between the units is necessary for analysis data preparation, but does not dictate or represent pre-determined individual partner plant owner strategies or preferences or individual unit strategies or preferences.
2) The Alternative Regional Haze Cases for Huntington Units 1 and 2 have been developed for analysis purposes only with consideration given to the fact that the emissions profiles for the units are effectively identical in the Regional Haze context. The compliance actions for the units in this scenario could effectively be swapped and provide the same Regional Haze compliance outcome. The matrix presentation of different compliance actions between the units is necessary for analysis data preparation, but does not dictate or represent pre-determined individual unit strategies or preferences.
3) Naughton 3 will cease coal fueled operation by year-end 2017, under this scenario.
4) Craig 1 will cease coal fueled operation by end of August 2021, under this scenario.

Vol III: Regional Haze Case 6

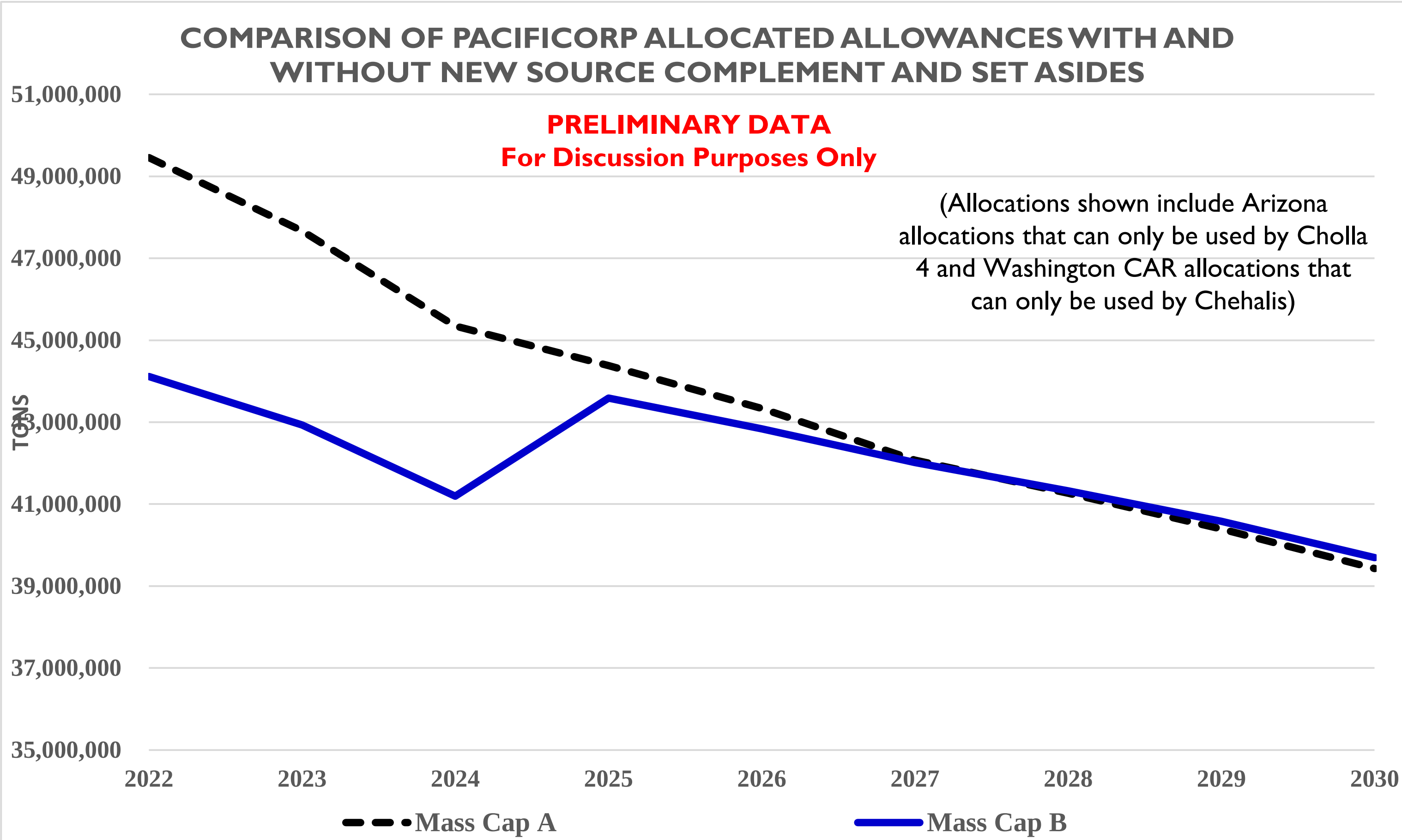
- In response to stakeholder feedback from the August public input meeting and subsequent September 8, 2016 presentation, PacifiCorp plans to include an additional Regional Haze case that allows endogenous retirements.
- In contrast to Regional Haze Cases 1 – 5, where a range of emission control installation costs and early retirement assumptions are applied as inputs to the System Optimizer model, an endogenous retirement case allows System Optimizer to choose early retirement as a compliance outcome.
- PacifiCorp will approximate operating cost impacts (i.e., run-rate fuel and non-fuel operating costs and run-rate capital costs, including costs associated with environmental projects) of early retirement alternatives for the following coal units: Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1, and Jim Bridger 2.
- Approximated cost impacts will assume early retirement, if chosen by System Optimizer, occurs at the end of the month preceding the month in which SCR equipment would otherwise need to be installed.
- The RH-6 portfolio will be considered and ranked along with the reference case and core resource portfolios RH-1 through RH-5 outlined on the previous slide.

Vol. III: Market Price and GHG Policy Scenarios

Natural Gas Prices	GHG Policy
Low	CPP Mass Cap A
Sep 2016 OFPC	CPP Mass Cap A
High	CPP Mass Cap A
Low	CPP Mass Cap B
Sep 2016 OFPC	CPP Mass Cap B
High	CPP Mass Cap B

- Each Regional Haze case will be analyzed among six different market price and GHG policy scenarios.
  - Three natural gas price scenarios with corresponding wholesale electricity price forecasts.
    - Corresponding wholesale power price assumptions will be developed using the combination of natural gas prices and GHG policy assumptions for each scenario (i.e., six different wholesale power price curves).
    - Price curve assumptions will be developed after the Company finalizes its September 2016 official forward price curve.
  - Two GHG policy scenarios:
    - CPP Mass Cap A = Mass-based compliance approach with pro-rata allowance allocation to PacifiCorp based on historical generation with no set-asides and no new source complement (cap is mathematically equivalent to a mass-based compliance approach incorporating Clean Energy Incentive Program (CEIP), renewable and output-based set-asides where PacifiCorp receives a pro-rata allocation of the set-asides).
    - CPP Mass Cap B = Mass-based compliance approach with pro-rata allowance allocation to PacifiCorp based on historical generation with new source complement allowances allocated on a pro-rata basis less the CEIP, renewable and output-based set-asides. PacifiCorp does not receive any of these set-asides.
- Resource portfolios will be optimized among each Regional Haze case and each market price/GHG policy scenario.

Volume III: Coal & Mass Cap Assumptions



Note, emissions from existing resources will need to meet the mass cap under CPP Cap A. Emissions from both new and existing resources will need to meet the mass cap under CPP Cap B.

Core Cases: Overview

- Volume III studies will be used to establish Regional Haze assumptions for existing coal units.
  - Addresses stakeholder feedback (ODOE) from the 2015 IRP recommending that core cases be compared among common Regional Haze assumptions.
  - Emission control equipment installations and costs, early retirement assumptions, and associated run-rate operating costs.
  - Once Volume III studies and initial core case studies are completed, additional Regional Haze sensitivities may be studied.
- Limited number of core case portfolios (6) that achieve resource diversity by targeting specific types of resources among different cases.
  - Allows resources having operating characteristics not valued in System Optimizer to be analyzed in Planning and Risk during the cost and risk analysis phase of the portfolio development process.
  - Simplified set of planning assumptions for portfolio development purposes.
  - Broader set of planning assumptions for cost and risk analysis.
  - Eliminates the need for deterministic risk analysis.

Core Cases: Summary

Resource Class	Case 1 (OP-1)	Case 2 (FR-1)	Case 3 (FR-2)	Case 4 (RE-1)	Case 5 (RE-2)	Case 6 (DLC-1)
Flexible Resources	Optimized	10% of Incremental L&R Balance	20% of Incremental L&R Balance	10% -20% of Incremental L&R Balance	10%-20% of Incremental L&R Balance	Optimized
Renewable Resources	Optimized	Optimized	Optimized	Just-in-Time Physical RPS Compliance	Early Physical RPS Compliance	Just-in-Time Physical RPS Compliance
Class 1 DSM Resources	Optimized	Optimized	Optimized	Optimized	Optimized	5% of Incremental L&R Balance
All Other Resources	Optimized	Optimized	Optimized	Optimized	Optimized	Optimized

- Base planning assumptions for each case:
  - September 2016 official forward price curve.
  - CPP Mass Cap B as summarized for use in the Volume III studies.
- Additional market price and GHG policy assumptions will be analyzed in the cost and risk analysis phase of the process.
- Additional Clean Power Plan assumptions will be analyzed as sensitivities.

Core Cases: Descriptions

- Case 1: Optimized Portfolio (OP-1)
  - All resources optimized (selected endogenously by System Optimizer)
  - Same approach used in prior IRPs
- Case 2: Flexible Resources (FR-1)
  - Beginning the first year a new thermal resource is added from Case 1 (OP-1), at least 10% of the system L&R need will be met with fast ramp resource capacity.
  - Fast-ramp resources available for selection include: SCCT Aero (i.e., LM6000); Intercooled SCCT Aero (i.e., LMS100); IC Reciprocating Engines; pumped storage, compressed air energy storage, and battery storage.
- Case 3: Flexible Resources (FR-2)
  - Beginning the first year a new thermal resource is added from Case 1 (OP-1), at least 20% of the system L&R need will be met with fast ramp resource capacity.
  - Fast-ramp resources available for selection include: SCCT Aero (i.e., LM6000); Intercooled SCCT Aero (i.e., LMS100); IC Reciprocating Engines; pumped storage, compressed air energy storage, and battery storage.

Core Cases: Descriptions (Cont'd)

- Case 4: Renewable Energy (RE-1)
  - Renewable resources added to physically comply with projected Oregon and Washington RPS requirements, after accounting for endogenous selection of any new renewable resources, beginning the first year in which there is a projected compliance shortfall.
  - Renewable resources available for selection include wind and solar resource options.
  - Flexible resource targets as in Case 2 (FR-1).
- Case 5: Renewable Energy (RE-2)
  - Renewable resources added beginning 2020 to comply with projected Oregon and Washington RPS requirements through the planning period, after accounting for any endogenous selection of new renewable resources.
  - Renewable resources available for selection include wind and solar resource options.
  - Flexible resource targets as in Case 2 (FR-1).
- Case 6: Direct Load Control (DR-1)
  - Beginning the first year a new thermal resource is added from Case 1 (OP-1), at least 5% of the system L&R need, but no more than market potential, will be met with Class 1 DSM resources.
  - Renewable resource assumptions as in Case 4 (RE-1).

Cost & Risk: Market Price and GHG Policy Scenarios

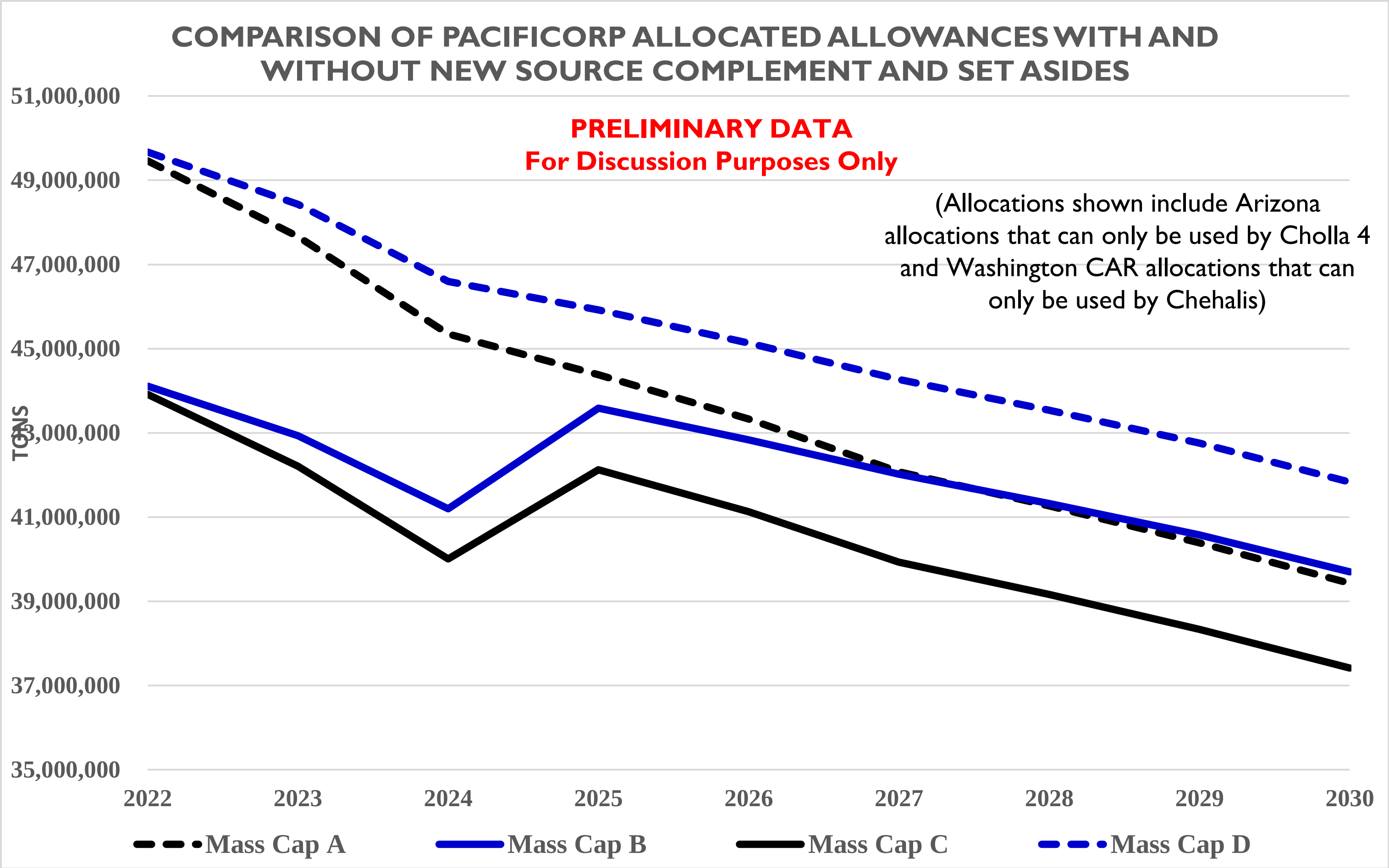
Natural Gas Prices	GHG Policy
Low	CPP Mass Cap A
Sep 2016 OFPC	CPP Mass Cap A
High	CPP Mass Cap A
Low	CPP Mass Cap B
Sep 2016 OFPC	CPP Mass Cap B
High	CPP Mass Cap B

- Each core case portfolio will be analyzed among six different market price and GHG policy scenarios in Planning & Risk (PaR).
  - Three natural gas price scenarios with corresponding wholesale electricity price forecasts
    - Corresponding wholesale power price assumptions will be developed using the combination of natural gas prices and GHG policy assumptions for each scenario (i.e., six different wholesale power price curves).
    - Price curve assumptions will be developed after the Company finalizes its September 2016 official forward price curve.
  - Two GHG policy scenarios
    - CPP Mass Cap A = Mass-based compliance approach with pro-rata allowance allocation to PacifiCorp based on historical generation with no set-asides and no new source complement (cap is mathematically equivalent to a mass-based compliance approach incorporating Clean Energy Incentive Program (CEIP), renewable and output-based set-asides where PacifiCorp receives a pro-rata allocation of the set-asides).
    - CPP Mass Cap B = Mass-based compliance approach with pro-rata allowance allocation to PacifiCorp based on historical generation with new source complement allowances allocated on a pro-rata basis less the CEIP, renewable and output-based set-asides. PacifiCorp does not receive any of these set-asides.
  - Results will be assessed with initial portfolio rankings before initiating sensitivity case runs.

Sensitivity Analysis: Preliminary List of Cases

- PacifiCorp has preliminarily identified a number of sensitivities, but will consider additional sensitivities and identify the sensitivity "benchmark" case once core case modeling is completed.
- As appropriate, sensitivity cases can be used to select a preferred portfolio, inform the action plan, and inform acquisition path analysis.
- The preliminary list of sensitivity cases is outlined below:
  - Delayed Clean Power Plan (CPP)
  - CPP with set-asides but no allocation to PacifiCorp (Mass Cap C)
  - CPP with no set-aside program and with new source complement (Mass Cap D)
  - Energy Storage (if not selected in core case portfolios)
  - Constrained Market (limits on FOTs)
  - Energy Gateway Transmission
  - East/West Split
  - Washington PM2.5 Externality (Applies to Chehalis)
  - Load Growth (Low / High / 1 in 20)
  - Private Generation (Low / High)
  - Business Plan (as approved 9/15/16; UT Commission Order Docket No. 15-035-04)

Sensitivity Analysis: Coal & Mass Cap Assumptions



Note, emissions from existing resources will need to meet the mass cap under CPP Cap A and CPP Cap C. Emissions from both new and existing resources will need to meet the mass cap under CCP Cap B and CCP Cap D.

Next Steps

- PacifiCorp plans to discuss results of the Volume III studies and preliminary portfolio results at its next public input meeting.

2017 Integrated Resource Plan

Stochastic Modeling

Cost and Risk Analysis

- PacifiCorp uses its Planning and Risk (PaR) model to perform stochastic analysis, producing cost and risk metrics to compare portfolio alternatives and inform selection of a preferred portfolio.
  - The PaR model optimizes dispatch to minimize costs while meeting load and wholesale sale obligations subject to operating and physical constraints.
  - Portfolios are “fixed”, and each portfolio is analyzed among a range different planning assumptions (i.e., greenhouse gas policy and market prices).
  - A Monte Carlo random sampling of stochastic variables is conducted on 50 iterations for the 20-year study period of each portfolio, creating a distribution of production cost outcomes.
  - Stochastic input variables include load, market prices (gas and wholesale electricity prices, including front office transactions), hydro availability, and unplanned thermal outages.
  - PacifiCorp plans to run sensitivity case portfolios in PaR.

Stochastic Portfolio Performance Measures

- Stochastic Mean PVRR
  - Average of system net variable operating costs among 50 iterations combined with real levelized capital costs and fixed costs specific to each portfolio.
  - Expressed as the present value revenue requirement (PVRR), representing costs to customers (i.e., return on, return of, taxes, run-rate fixed and variable operating costs, system balancing sales & purchases, and energy not served).
- Upper-Tail Mean PVRR
  - Measure of high-end portfolio cost risk.
  - Average of the three highest production cost simulations, on a PVRR basis, with the addition of fixed costs specific to each portfolio.
  - Used with the stochastic mean PVRR to produce "scatter plots" used to screen portfolios during the preferred portfolio selection process.
- Risk-Adjusted Mean PVRR
  - Consolidated cost and risk indicator used to rank portfolios, representing the expected PVRR of low probability, high cost outcomes.
  - Stochastic mean PVRR of system variable costs plus 5% of the 95th percentile system variable costs, with the addition of fixed costs specific to each portfolio.

Stochastic Portfolio Performance Measures (Cont'd)

- 5th and 95th Percentile
  - Reported from the 50 Monte Carlo iterations.
  - Capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes.
  - The 95th percentile PVRR is used to calculate the risk adjusted mean PVRR.
- Production Cost Standard Deviation
  - Captures production cost volatility risk.
  - Meets Oregon IRP guidelines requiring the IRP to report stochastic measures that address variability of costs in addition to a measure addressing the severity of bad outcomes.
- Average and Upper-Tail Mean Energy Not Served (ENS)
  - Certain Monte Carlo iterations will have ENS, a condition where there are insufficient resources, inclusive of system balancing purchases, available to meet load or operating reserve requirements.
  - Average and upper-tail mean ENS are measures of reliability that are compared among portfolios.

Stochastic Portfolio Performance Measures (Cont'd)

- 5th and 95th Percentile
  - Reported from the 50 Monte Carlo iterations.
  - Capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes.
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- Average and Upper-Tail Mean Energy Not Served (ENS)
  - Certain Monte Carlo iterations will have ENS, a condition where there are insufficient resources, inclusive of system balancing purchases, available to meet load or operating reserve requirements.
  - Average and upper-tail mean ENS are measures of reliability that are compared among portfolios.
- Other (CO_2 Emissions, loss of load probability, rate impacts)

Overview of Stochastic Parameters

- Stochastic parameters are used to generate stochastic inputs for risk analysis of resource portfolios
- Parameters updated using historical PacifiCorp data
  - Load: 1/1/2012 thru 12/31/2015 (4 years)
  - Hydro: 1/1/2011 thru 12/31/2015 (5 years)
  - Gas Prices: 1/1/2012 thru 12/31/2015 (4 years)
  - Power Prices: 1/1/2012 thru 12/31/2015 (4 years)
- Stochastic parameters include:
  - Short-term Volatility
  - Mean reversion
  - Correlation among variables

Short-Term Volatility Comparison 2015 IRP vs. 2017 IRP

- Volatility is a measure of variation in time-series that is observed over time.

2015 IRP S.T. Volatility Variables in Daily %

Load

	Utah	Oregon-California
Winter	2.01%	4.45%
Summer	4.52%	3.65%

Electricity Market Prices

	PV	Mid C
Winter	6.20%	17.77%
Summer	9.10%	47.69%

Gas Prices

	East Gas	West Gas
Winter	4.84%	6.31%
Summer	2.89%	2.92%

Hydro

Winter	17.00%
Summer	13.90%

2017 IRP S.T. Volatility Variables in Daily %

Load

	Utah	Oregon-California
Winter	2.20%	4.41%
Summer	4.50%	3.79%

Electricity Market Prices

	PV	Mid C
Winter	10.60%	16.20%
Summer	8.80%	38.30%

Gas Prices

	East Gas	West Gas
Winter	13.20%	14.00%
Summer	2.70%	4.20%

Hydro

Winter	20.80%
Summer	14.90%

Short-Term Mean Reversion Comparison 2015 IRP vs. 2017 IRP

- Mean reversion represents the speed at which the distributed variable will return to its seasonal expectation.

2015 IRP S.T. Mean Reversion Variables in Daily

Load

	Utah	Oregon-California
Winter	0.33	0.23
Summer	0.26	0.24

Electricity Market Prices

	PV	Mid C
Winter	0.09	0.28
Summer	0.29	0.94

Gas Prices

	East Gas	West Gas
Winter	0.06	0.09
Summer	0.06	0.07

Hydro

Winter	0.84
Summer	1.09

2017 IRP S.T. Mean Reversion Variables in Daily

Load

	Utah	Oregon-California
Winter	0.40	0.21
Summer	0.21	0.20

Electricity Market Prices

	PV	Mid C
Winter	0.16	0.14
Summer	0.25	0.91

Gas Prices

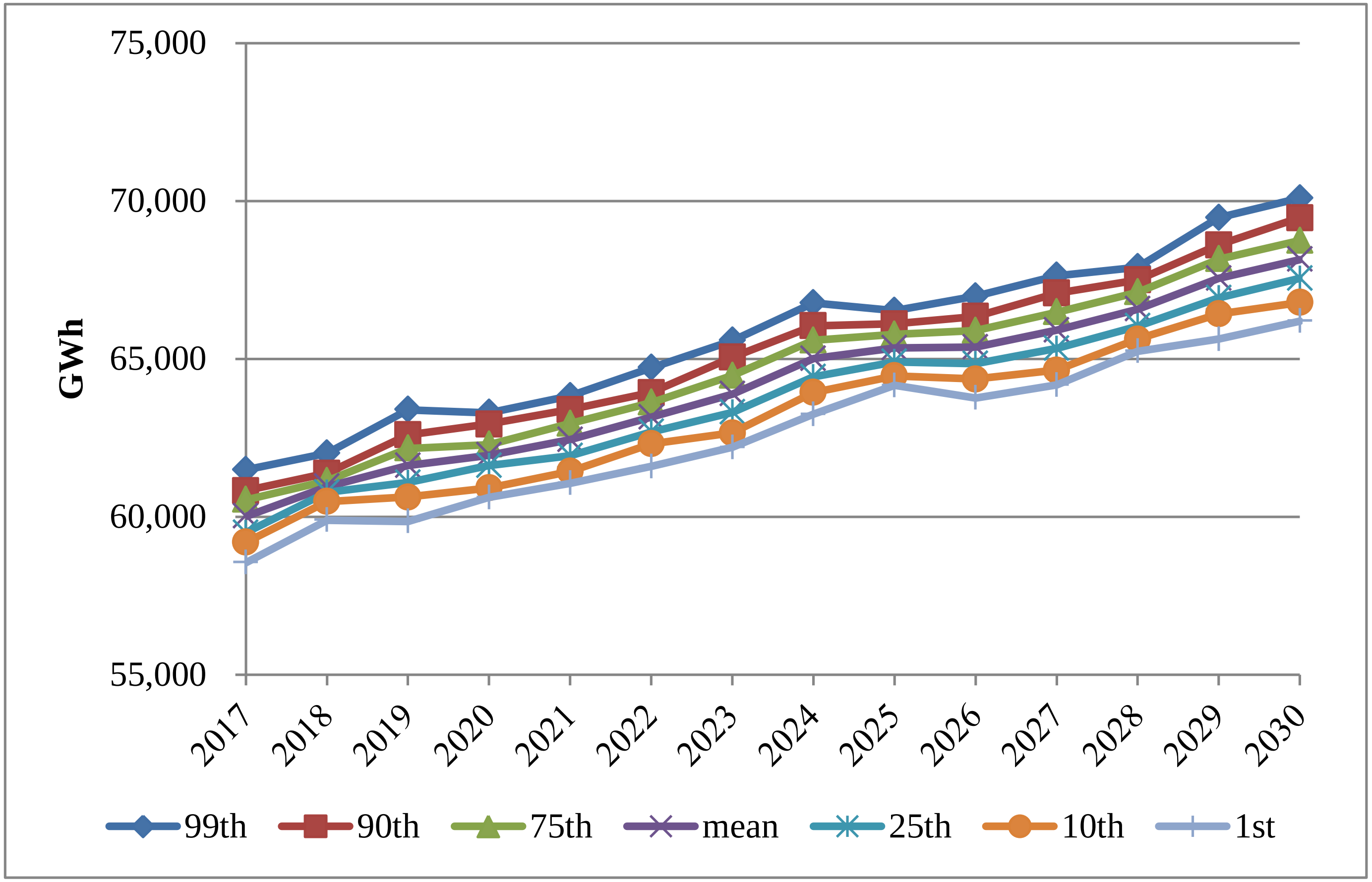
	East Gas	West Gas
Winter	0.22	0.20
Summer	0.07	0.13

Hydro

Winter	0.81
Summer	1.44

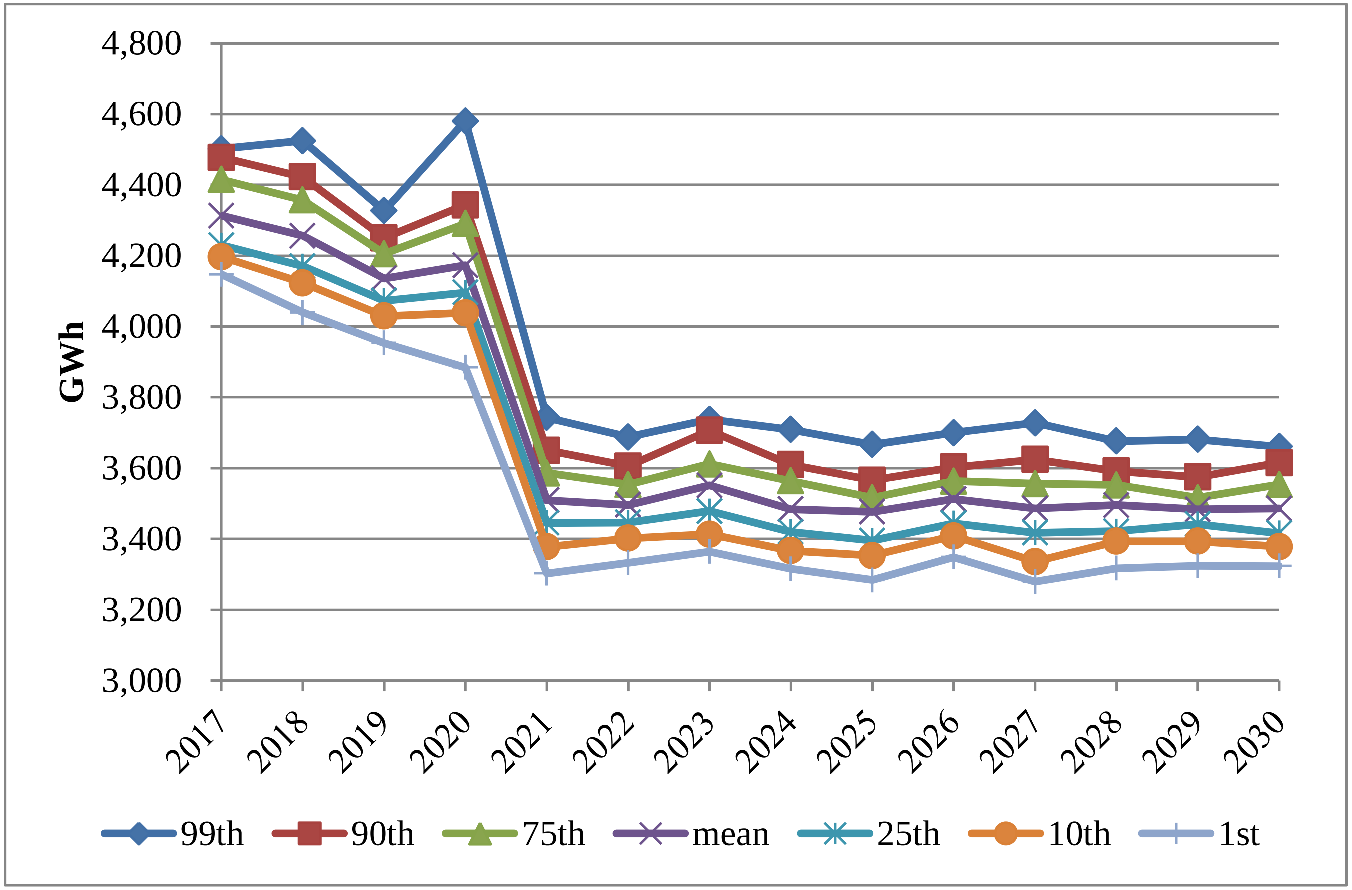
Simulated Annual System Load

- System annual loads reported at selected percentiles are based on Monte Carlo simulations using short-term volatility and mean reversion



Simulated Annual System Hydro

- System annual hydro generation reported at selected percentiles are based on Monte Carlo simulations. The sharp drop in 2021is due to the assumed decommission of the Klamath River Projects.



Short Term Correlations - Winter

- 2017 IRP short term correlations – winter

	Opal (Gas)	SUMAS (Gas)	4C	COB	Mid-C	PV	CA (Load)	ID (Load)	Portland (Load)	OR-Other (Load)	UT (Load)	WA (Load)	WY (Load)	Hydro
Opal (Gas)	100.00%	91.89%	53.06%	27.13%	26.76%	52.10%	-3.81%	6.79%	14.27%	5.89%	1.65%	12.62%	5.72%	0.77%
SUMAS (Gas)	91.89%	100.00%	46.00%	28.00%	27.55%	45.06%	-2.06%	8.97%	17.35%	10.18%	2.51%	15.50%	9.21%	-1.48%
4C	53.06%	46.00%	100.00%	53.82%	52.82%	78.45%	10.55%	21.05%	34.73%	27.12%	25.24%	33.64%	22.32%	5.97%
COB	27.13%	28.00%	53.82%	100.00%	96.49%	71.39%	13.90%	17.38%	35.05%	36.86%	17.57%	45.00%	21.95%	6.89%
Mid-C	26.76%	27.55%	52.82%	96.49%	100.00%	68.41%	13.67%	17.87%	36.37%	36.69%	18.24%	46.28%	22.77%	4.60%
PV	52.10%	45.06%	78.45%	71.39%	68.41%	100.00%	10.46%	15.73%	30.48%	25.30%	21.79%	31.34%	16.35%	8.88%
CA (Load)	-3.81%	-2.06%	10.55%	13.90%	13.67%	10.46%	100.00%	27.40%	39.76%	72.92%	32.12%	37.05%	18.34%	5.74%
ID (Load)	6.79%	8.97%	21.05%	17.38%	17.87%	15.73%	27.40%	100.00%	31.29%	33.18%	34.36%	37.07%	30.84%	-6.37%
Portland (Load)	14.27%	17.35%	34.73%	35.05%	36.37%	30.48%	39.76%	31.29%	100.00%	69.63%	51.40%	65.83%	35.18%	5.97%
OR-Other (Load)	5.89%	10.18%	27.12%	36.86%	36.69%	25.30%	72.92%	33.18%	69.63%	100.00%	42.60%	64.66%	33.29%	7.69%
UT (Load)	1.65%	2.51%	25.24%	17.57%	18.24%	21.79%	32.12%	34.36%	51.40%	42.60%	100.00%	44.37%	47.94%	0.25%
WA (Load)	12.62%	15.50%	33.64%	45.00%	46.28%	31.34%	37.05%	37.07%	65.83%	64.66%	44.37%	100.00%	32.99%	14.88%
WY (Load)	5.72%	9.21%	22.32%	21.95%	22.77%	16.35%	18.34%	30.84%	35.18%	33.29%	47.94%	32.99%	100.00%	4.55%
Hydro	0.77%	-1.48%	5.97%	6.89%	4.60%	8.88%	5.74%	-6.37%	5.97%	7.69%	0.25%	14.88%	4.55%	100.00%

Short Term Correlations - Spring

- 2017 IRP short term correlations – spring

	Opal (Gas)	SUMAS (Gas)	4C	COB	Mid-C	PV	CA (Load)	ID (Load)	Portland (Load)	OR-Other (Load)	UT (Load)	WA (Load)	WY (Load)	Hydro
Opal (Gas)	100.00%	91.89%	53.06%	27.13%	26.76%	52.10%	-3.81%	6.79%	14.27%	5.89%	1.65%	12.62%	5.72%	0.77%
SUMAS (Gas)	91.89%	100.00%	46.00%	28.00%	27.55%	45.06%	-2.06%	8.97%	17.35%	10.18%	2.51%	15.50%	9.21%	-1.48%
4C	53.06%	46.00%	100.00%	53.82%	52.82%	78.45%	10.55%	21.05%	34.73%	27.12%	25.24%	33.64%	22.32%	5.97%
COB	27.13%	28.00%	53.82%	100.00%	96.49%	71.39%	13.90%	17.38%	35.05%	36.86%	17.57%	45.00%	21.95%	6.89%
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ID (Load)	6.79%	8.97%	21.05%	17.38%	17.87%	15.73%	27.40%	100.00%	31.29%	33.18%	34.36%	37.07%	30.84%	-6.37%
Portland (Load)	14.27%	17.35%	34.73%	35.05%	36.37%	30.48%	39.76%	31.29%	100.00%	69.63%	51.40%	65.83%	35.18%	5.97%
OR-Other (Load)	5.89%	10.18%	27.12%	36.86%	36.69%	25.30%	72.92%	33.18%	69.63%	100.00%	42.60%	64.66%	33.29%	7.69%
UT (Load)	1.65%	2.51%	25.24%	17.57%	18.24%	21.79%	32.12%	34.36%	51.40%	42.60%	100.00%	44.37%	47.94%	0.25%
WA (Load)	12.62%	15.50%	33.64%	45.00%	46.28%	31.34%	37.05%	37.07%	65.83%	64.66%	44.37%	100.00%	32.99%	14.88%
WY (Load)	5.72%	9.21%	22.32%	21.95%	22.77%	16.35%	18.34%	30.84%	35.18%	33.29%	47.94%	32.99%	100.00%	4.55%
Hydro	0.77%	-1.48%	5.97%	6.89%	4.60%	8.88%	5.74%	-6.37%	5.97%	7.69%	0.25%	14.88%	4.55%	100.00%

Short Term Correlations - Summer

- 2017 IRP short term correlations – summer

	Opal (Gas)	SUMAS (Gas)	4C	COB	Mid-C	PV	CA (Load)	ID (Load)	Portland (Load)	OR-Other (Load)	UT (Load)	WA (Load)	WY (Load)	Hydro
Opal (Gas)	100.00%	56.33%	7.43%	10.44%	5.48%	10.90%	-4.00%	7.74%	12.07%	11.53%	3.98%	11.21%	-0.77%	-0.01%
SUMAS (Gas)	56.33%	100.00%	9.74%	13.08%	5.37%	13.21%	-1.25%	2.92%	15.52%	12.07%	-7.58%	11.18%	-6.23%	2.59%
4C	7.43%	9.74%	100.00%	44.94%	34.46%	84.14%	21.38%	7.55%	19.24%	19.93%	24.70%	12.37%	10.27%	5.50%
COB	10.44%	13.08%	44.94%	100.00%	66.06%	52.53%	15.85%	15.09%	34.63%	34.13%	11.52%	27.48%	-0.74%	23.63%
Mid-C	5.48%	5.37%	34.46%	66.06%	100.00%	36.89%	18.68%	9.06%	35.37%	33.58%	16.36%	29.82%	1.87%	8.40%
PV	10.90%	13.21%	84.14%	52.53%	36.89%	100.00%	16.39%	6.12%	19.38%	20.59%	20.30%	9.57%	10.91%	11.66%
CA (Load)	-4.00%	-1.25%	21.38%	15.85%	18.68%	16.39%	100.00%	30.11%	25.54%	48.90%	23.91%	37.32%	8.80%	4.11%
ID (Load)	7.74%	2.92%	7.55%	15.09%	9.06%	6.12%	30.11%	100.00%	13.86%	18.80%	38.06%	20.78%	20.03%	9.17%
Portland (Load)	12.07%	15.52%	19.24%	34.63%	35.37%	19.38%	25.54%	13.86%	100.00%	77.52%	17.87%	63.38%	-3.98%	22.10%
OR-Other (Load)	11.53%	12.07%	19.93%	34.13%	33.58%	20.59%	48.90%	18.80%	77.52%	100.00%	26.71%	74.66%	-1.99%	18.78%
UT (Load)	3.98%	-7.58%	24.70%	11.52%	16.36%	20.30%	23.91%	38.06%	17.87%	26.71%	100.00%	26.17%	42.90%	2.44%
WA (Load)	11.21%	11.18%	12.37%	27.48%	29.82%	9.57%	37.32%	20.78%	63.38%	74.66%	26.17%	100.00%	-0.75%	15.50%
WY (Load)	-0.77%	-6.23%	10.27%	-0.74%	1.87%	10.91%	8.80%	20.03%	-3.98%	-1.99%	42.90%	-0.75%	100.00%	-3.43%
Hydro	-0.01%	2.59%	5.50%	23.63%	8.40%	11.66%	4.11%	9.17%	22.10%	18.78%	2.44%	15.50%	-3.43%	100.00%

Short Term Correlations - Fall

- 2017 IRP short term correlations - fall

	Opal (Gas)	SUMAS (Gas)	4C	COB	Mid-C	PV	CA (Load)	ID (Load)	Portland (Load)	OR-Other (Load)	UT (Load)	WA (Load)	WY (Load)	Hydro
Opal (Gas)	100.00%	34.67%	13.66%	7.16%	4.14%	16.60%	8.57%	11.15%	8.50%	13.73%	7.59%	10.31%	8.26%	11.75%
SUMAS (Gas)	34.67%	100.00%	6.32%	2.75%	4.29%	0.57%	6.53%	6.80%	9.44%	15.56%	6.12%	11.11%	17.36%	6.65%
4C	13.66%	6.32%	100.00%	45.16%	37.60%	73.36%	16.11%	12.85%	22.28%	24.17%	27.73%	23.27%	10.17%	-18.30%
COB	7.16%	2.75%	45.16%	100.00%	85.33%	50.07%	6.85%	6.17%	21.24%	22.24%	20.36%	23.76%	1.36%	-11.87%
Mid-C	4.14%	4.29%	37.60%	85.33%	100.00%	36.78%	9.39%	8.61%	23.53%	25.24%	13.39%	26.33%	-0.47%	-10.01%
PV	16.60%	0.57%	73.36%	50.07%	36.78%	100.00%	12.35%	13.87%	19.74%	19.90%	26.10%	18.83%	7.79%	-15.67%
CA (Load)	8.57%	6.53%	16.11%	6.85%	9.39%	12.35%	100.00%	25.74%	43.10%	66.46%	27.28%	54.19%	19.17%	5.21%
ID (Load)	11.15%	6.80%	12.85%	6.17%	8.61%	13.87%	25.74%	100.00%	21.84%	26.77%	34.98%	24.33%	6.51%	-10.81%
Portland (Load)	8.50%	9.44%	22.28%	21.24%	23.53%	19.74%	43.10%	21.84%	100.00%	77.08%	40.27%	70.92%	31.97%	8.81%
OR-Other (Load)	13.73%	15.56%	24.17%	22.24%	25.24%	19.90%	66.46%	26.77%	77.08%	100.00%	36.91%	81.66%	30.69%	7.62%
UT (Load)	7.59%	6.12%	27.73%	20.36%	13.39%	26.10%	27.28%	34.98%	40.27%	36.91%	100.00%	36.39%	36.78%	-1.58%
WA (Load)	10.31%	11.11%	23.27%	23.76%	26.33%	18.83%	54.19%	24.33%	70.92%	81.66%	36.39%	100.00%	30.69%	8.73%
WY (Load)	8.26%	17.36%	10.17%	1.36%	-0.47%	7.79%	19.17%	6.51%	31.97%	30.69%	36.78%	30.69%	100.00%	13.46%
Hydro	11.75%	6.65%	-18.30%	-11.87%	-10.01%	-15.67%	5.21%	-10.81%	8.81%	7.62%	-1.58%	8.73%	13.46%	100.00%

2017
Integrated Resource Plan

Resource Adequacy / Front Office Transactions

2017 IRP Front Office Transaction Limits

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and July, Heavy Load Hour ("6x16") or December, Heavy Load Hour ("6x16")	400 MW, 2017 - 2036
July, Heavy Load Hour ("6x16"), December, Heavy Load Hour ("6x16")	375 MW, 2017 - 2036
California Oregon Border (COB) Flat Annual ("7x24") and July, Heavy Load Hour ("6x16") or December, Heavy Load Hour ("6x16")	400 MW, 2017- 2036
Southern Oregon / Northern California (NOB) July, Heavy Load Hour ("6x16"), December, Heavy Load Hour ("6x16")	100 MW, 2017- 2036
Mona July, Heavy Load Hour (6x16) December, Heavy Load Hour ("6x16")	300 MW, 2017-2036

- Maximum available front office transaction quantity by market hub.
- Three FOT types: annual flat product, HLH summer and winter products – limits remain unchanged from the 2015 IRP and 2015 IRP Update.
- PacifiCorp develops its FOT limits based on active participation in wholesale power markets, its view of physical delivery constraints, market liquidity/depth, and with consideration of regional resource supply.

Western Resource Adequacy

- Concerns regarding western resource adequacy in the Pacific Northwest (in particular the region's ability to meet winter peak loads) have been driven by long-term load and resource studies developed by the Northwest Power and Conservation Council (NPCC), Pacific Northwest Utilities Conference Committee (PNUCC), and Bonneville Power Administration (BPA).

- To evaluate regional resource adequacy, wholesale market risk and reliance, PacifiCorp has examined the following regional load and resource studies:
  - WECC: "2015 Power Supply Assessment" (published Nov 2015)
  - NPCC: "Pacific Northwest Power Supply Adequacy Assessment for 2020 and 2021" (published May 2015)
  - PNUCC: "2015 Northwest Regional Forecast" (published April 2015) & "2016 Northwest Regional Forecast" (published April 2016)
  - BPA: "2014 Pacific Northwest Loads and Resources Study" (published Jan 2015)

- The studies differ in some details, but in general forecast that Pacific Northwest energy and capacity surplus will become deficit around 2021.

- PacifiCorp has also assessed actual historical market purchases to provide context to front office transaction (FOT) assumptions used in the IRP.

- Based on this information, PacifiCorp does not plan to change its FOT assumptions for the 2017 IRP and will evaluate a sensitivity case that assumes reduced FOT access to inform acquisition path analysis.

WECC 2015 Power Supply Assessment

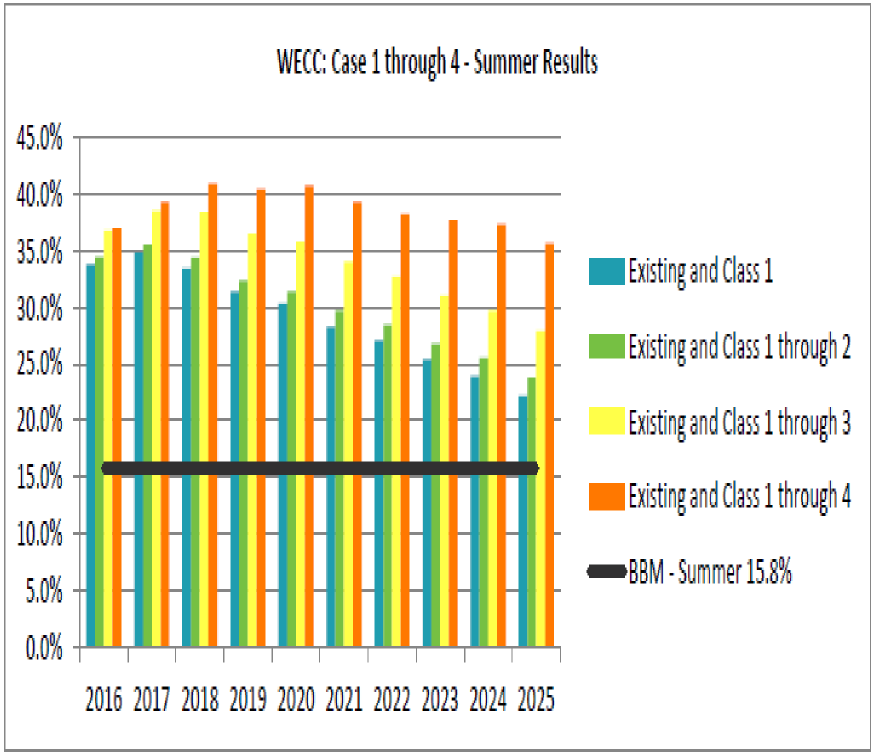
- The most recent WECC 2015 Power Supply Assessment (PSA) evaluated planning reserve margins for the WECC region and NWPP sub-region (summer and winter peak) for the forecast period 2016 – 2025.

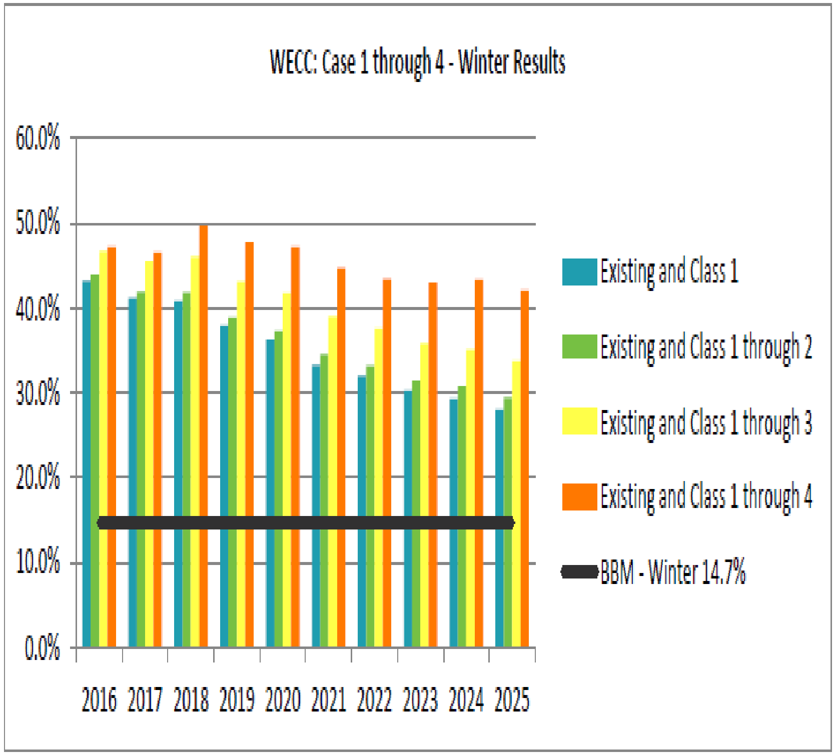
- Planning reserve margins (PRMs) are based upon varying assumptions around new resources (accounting for firm retirements).
  - Existing & Class 1 Resources = only includes resources in-service or under active construction as of 12/31/2014
  - Existing & Class 2 Resources = incremental to the above, expands new resources to include those expected to be in service as early as Class 1 resources, but that did not start construction as of 12/31/2014
  - Existing & Class 3 Resources = incremental to the above, expands new resources to include resources meeting NERC Tier 2 requirements (requested but not approved for planning)
  - Existing & Class 4 Resources = incremental to the above, expands new resources to include resources meeting NERC Tier 3 requirements (early planning stages)

- Planning reserve margin (PRM) is compared to sub-regional building block reserve margins (BBM), which WECC developed to consider four uncertainties (contingency reserves, regulating reserves, reserves for generation forced outages, and reserves for 1-in-10 weather events).

- The results indicate PRMs are sufficient (greater than or equal to the BBM) even among the most stringent assumptions around new resources (i.e., Existing & Class 1 Resources).

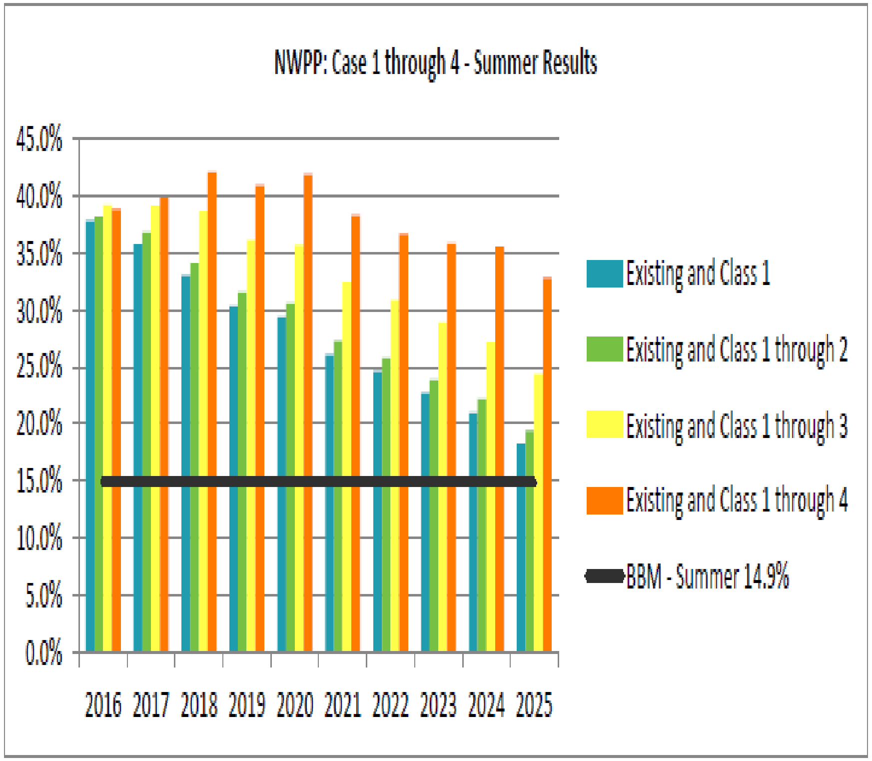
WECC 2015 PSA – WECC Region

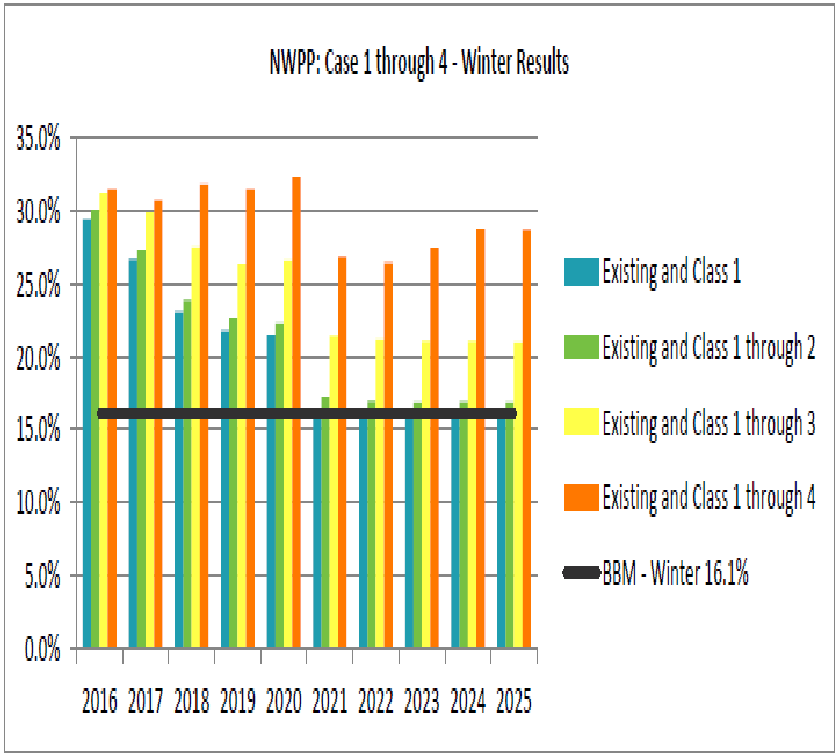




- In general, (like the 2014 PSA) the 2015 PSA shows no deficit for the 2016 – 2025 study period.
- All of the WECC's sub regions are forecasted to maintain sufficient power supply margin through 2025.

WECC 2015 PSA – NWPP Region





- In general, (like the 2014 PSA) the 2015 PSA shows no deficit for the 2016 – 2025 study period.
- All of the WECC's sub regions are forecasted to maintain sufficient power supply margin through 2025 – including the NWPP sub region, for both summer and winter.

Pacific Northwest Resource Adequacy Studies (Summary)

	NPCC (May 2015)	PNUCC (April 2015)	BPA (Jan 2015)
First Year Deficit	2021	2020	2020
Estimated Deficit	1,150 MW of gas-fired generation	1,390 MW (by 2021)	1,793 MW (by 2021)
Planned Resource Assumptions	None of the studies considered PNUCC 2016 NRF planned resources (2,185 MW nameplate, 1,562 MW winter peak)		

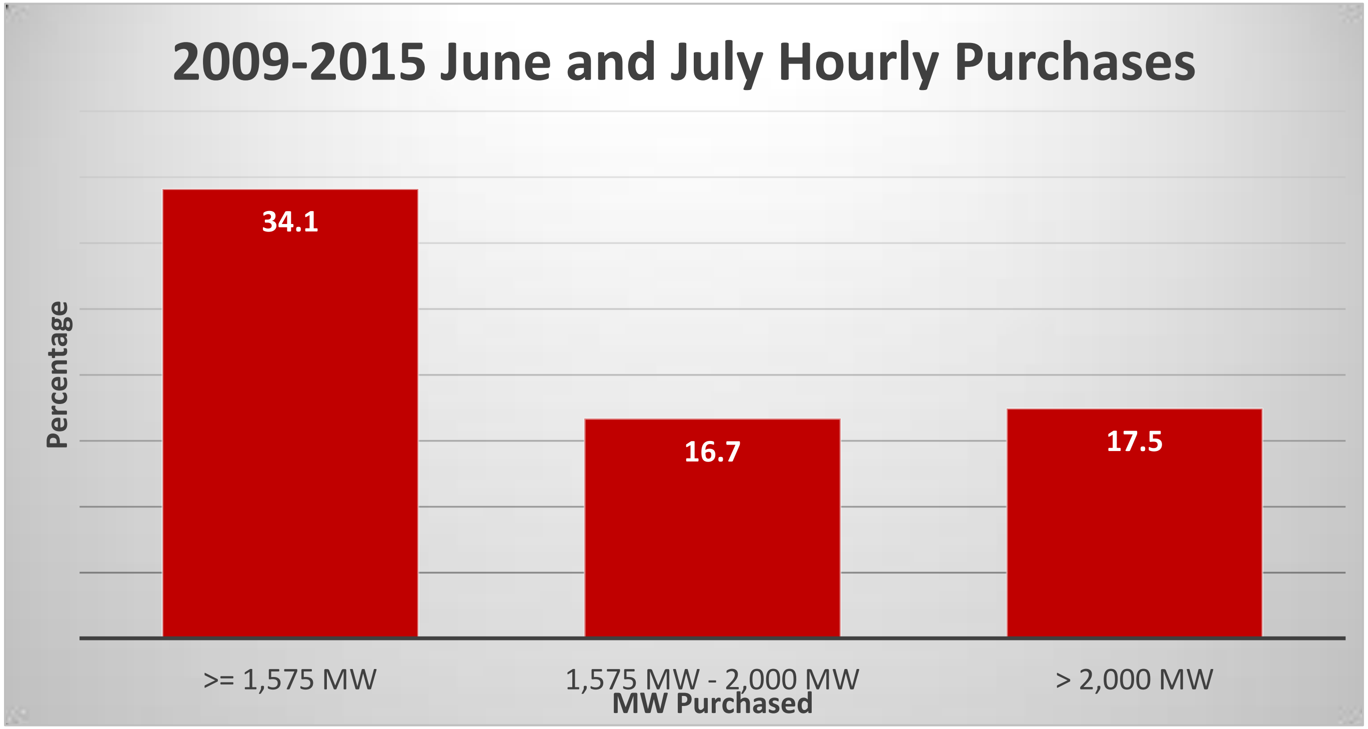
Pacific Northwest Resource Adequacy Studies

- The studies developed by NPCC, PNUCC and BPA differ in some details, but in general, each forecasts that the Pacific Northwest surplus will become deficit around 2021 (focus on winter season).
- The Council's "Pacific Northwest Power Supply Adequacy Assessment for 2020 and 2021" (published May 2015) states that the Pacific Northwest power supply (winter peaking) is expected to be adequate through 2020. The council estimates that the likelihood of a power supply shortage in that year is just under its 5-percent standard.
- By 2021, after the planned retirements of the Boardman and Centralia-1 coal plants (1,330 MW nameplate), the NPCC finds the likelihood of a shortfall (LOLP) rises to a little over 8 percent and would lead to an inadequate supply without intermediate actions.
- The NPCC states that actions to bring the 2021 power supply into compliance with the Council's standard will vary depending on the types of new generating resources or demand reduction programs that are considered. E.g. "adding 1,150 MW of gas-fired generation would bring the LOLP back to 5 percent."
- They state that "the region will likely have to plan for additional resources before 2021 when the two coal plants are retired. In all likelihood, some combination of new generation and load reduction programs will be used to bridge the gap."

Pacific Northwest Resource Adequacy Studies (Cont'd)

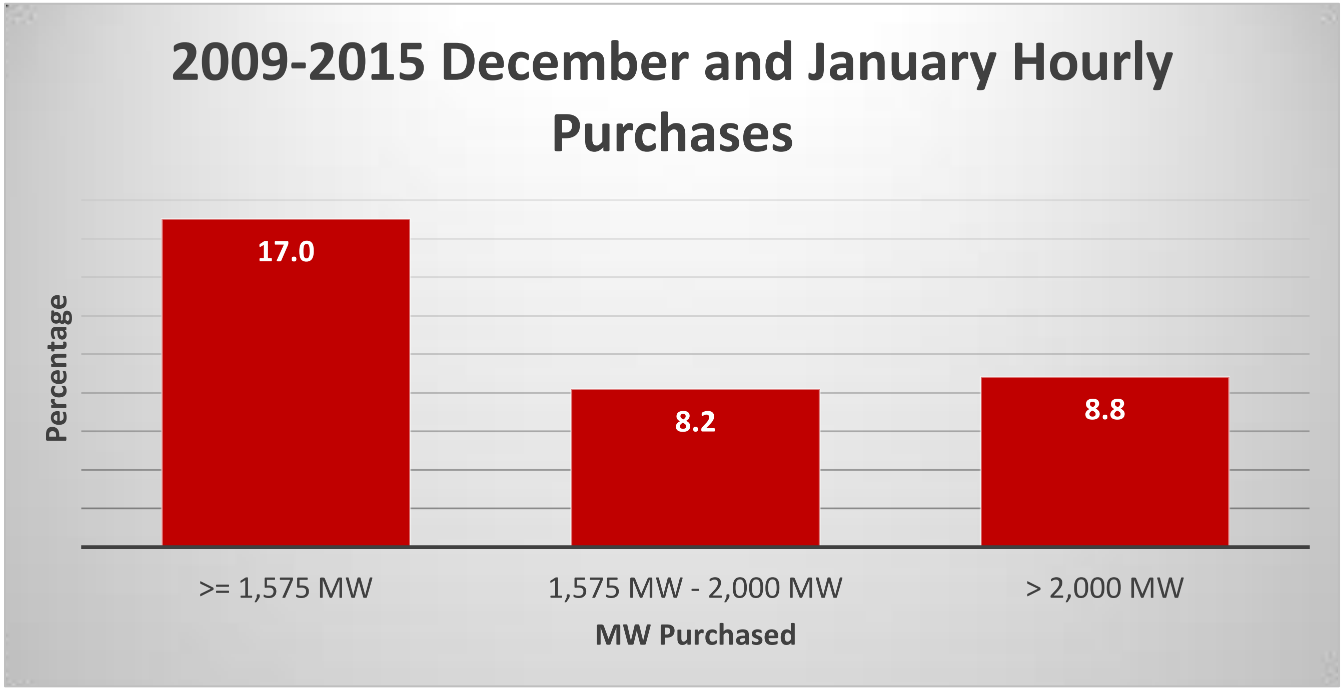
- However, there is no consideration for utility plans for planned new generation in their analysis, unless that resource is sited or licensed (study published May, 2015).
- Nor is there consideration for potential Boardman and Centralia replacement strategies.
  - PGE recently stated that upon acknowledgement of its 2016 IRP, it would go forward with a request for proposals addressing its expected capacity deficit in 2020.
- Northwest utilities, as reported in PNUCC's 2016 Northwest Regional Forecast show a combined 2,185 MW nameplate (1,562 MW winter peak) of planned generating capacity over the next 11 years (2016 – 2026) which the NPCC 2015 Adequacy Assessment study didn't include as they were not yet sited or licensed.
- The Council specifically states their analysis does not mean that there is insufficient supply.

PacifiCorp Summer Peak Market Purchases



- For resource planning purposes, PacifiCorp limits summer FOTs to 1,575 MW.
- PacifiCorp reviewed its hourly purchases June and July from 2009 through 2015.
- June and July time period reflects peak load times when market purchases may be constrained.
- In 34% of summer hours PacifiCorp purchased more than 1,575 MW.
- PacifiCorp purchased more than 3,000 MW in more than 2% of the intervals

PacifiCorp Winter Peak Market Purchases



- For resource planning purposes, PacifiCorp limits winter FOTs to 1,575 MW.
- PacifiCorp reviewed its hourly purchases December and January from 2009 through 2015.
- December and January time period reflects peak load times when market purchases may be constrained.
- In 17% of winter hours PacifiCorp purchased more than 1,575 MW and less than 1 % of purchases were above 3,000 MW
- PacifiCorp's lower purchases in winter reflect lower load requirements relative to the summer peak time period.





2017 Integrated Resource Plan

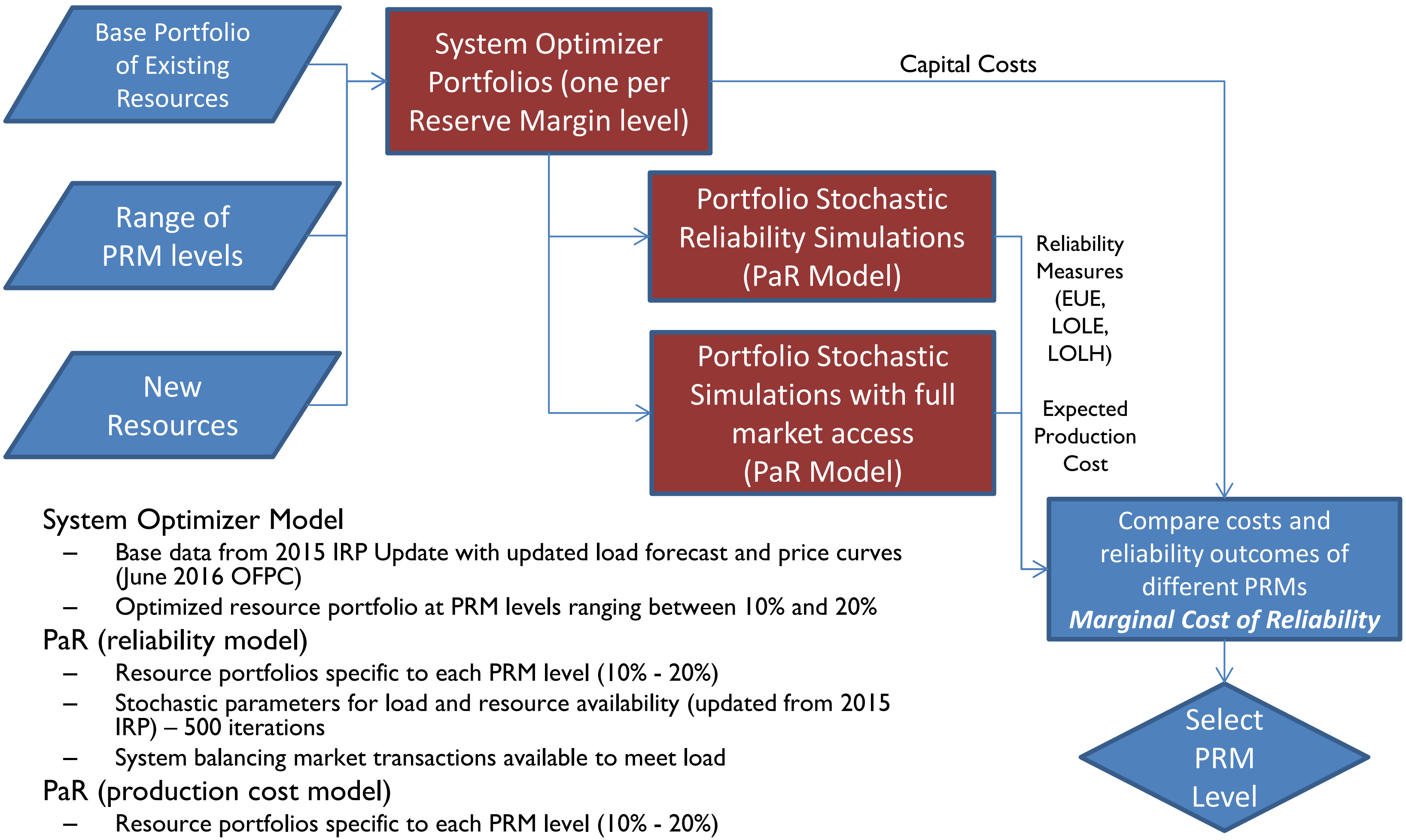
Loss of Load Probability

Planning Reserve Margin

Overview of Planning Reserve Margin

- Planning reserve margin (PRM) is the additional amount of capacity that the Company needs to acquire beyond coincident system peak load to maintain system reliability.
- Planning to a reserve margin ensures sufficient capacity is available to meet both near-term and longer-term uncertainties:
  - Contingency reserves (near-term)
  - Regulating margin reserves (near-term)
  - Changes & availability of resources (near-term and long-term)
  - Changes in customer load (near-term and long-term)
- Planning reserve margins of 10% to 20% are studied using the System Optimizer model (SO) and Planning and Risk model (PaR)
  - Eleven SO runs, 22 PaR runs
  - SO runs determine the resource portfolio given an input planning reserve margin level
  - One set of PaR runs simulates the reliability of the resource portfolio, reliability-based outputs used to measure loss of load probability (LOLP)
  - Another set of PaR runs determines the production costs of the portfolio
- Improvements implemented since the 2015 IRP
  - Application of the PRM to both winter and summer peaks (summer-only in the 2015 IRP PRM Study)
  - Resource options available for different PRM levels expanded to include resource types available when developing portfolios for the IRP (FOTs and Class 1 DSM excluded from resource portfolios in the 2015 IRP PRM Study)
  - Consideration of relative changes (between PRM levels) to reliability and cost over time (2020 through 2030) as opposed to focus on a single reference year (2017 in the 2015 IRP PRM Study) to report marginal cost of reliability

Planning Reserve Margin Study Components and Workflow



- System Optimizer Model
  - Base data from 2015 IRP Update with updated load forecast and price curves (June 2016 OFPC)
  - Optimized resource portfolio at PRM levels ranging between 10% and 20%
- PaR (reliability model)
  - Resource portfolios specific to each PRM level (10% - 20%)
  - Stochastic parameters for load and resource availability (updated from 2015 IRP) – 500 iterations
  - System balancing market transactions available to meet load
- PaR (production cost model)
  - Resource portfolios specific to each PRM level (10% - 20%)
  - Stochastic parameters for load, resource availability, electricity prices, and natural gas prices (updated from 2015 IRP) – 50 iterations
  - System balancing market transactions available to meet load and minimize cost

Planning Reserve Margin Study – Reliability Measures

- Expected Unserved Energy (EUE)
  - Gross (prior to accounting for Northwest Power Pool (NWPP) reserve sharing)
  - Net (after accounting for NWPP reserve sharing)
  - NWPP reserve sharing method assumes PacifiCorp receives energy from other participants for the first hour after a loss of load event

- Expected Loss of Load Events (LOLE)
  - One event in 10 years translates into 0.1 LOLE per year
  - Does not measure duration or magnitude

- Expected Loss of Load Hours (LOLH)
  - One day in 10 years translates into 2.4 LOLH per year
  - Does not measure the number or magnitude of occurrences

- Marginal cost of reliability informs selection of the planning reserve margin

Summer & Winter Resource Additions to Studies (2020)

	Capacity at Summer Peak (MW)						
PRM (%)	DSM Class 2	DSM Class 1	FOT HLH	FOT Flat	SCCT	CCCT	Total
10	380	0	550	176	0	0	1,107
11	374	0	651	176	0	0	1,201
12	380	0	738	176	0	0	1,294
13	384	0	828	176	0	0	1,388
14	394	0	912	175	0	0	1,481
15	400	0	1,000	175	0	0	1,575
16	382	0	1,112	176	0	0	1,670
17	425	25	1,134	174	0	0	1,759
18	431	113	1,136	172	0	0	1,852
19	396	0	982	175	0	421	1,974
20	380	0	1,093	176	0	421	2,070

	Capacity at Winter Peak (MW)						
PRM (%)	DSM Class 2	DSM Class 1	FOT HLH	FOT Flat	SCCT	CCCT	Total
10	240	0	26	176	0	0	442
11	237	0	34	176	0	0	447
12	240	0	41	176	0	0	456
13	243	0	48	176	0	0	467
14	250	0	55	175	0	0	480
15	253	0	70	175	0	0	497
16	241	0	86	176	0	0	502
17	259	25	101	174	0	0	559
18	266	113	93	172	0	0	643
19	248	0	133	175	0	487	1,042
20	239	0	149	176	0	487	1,050

Reliability Measures (2020) - Simulated

- Reliability measures, based on simulated output from the PaR reliability model, are shown both before and after accounting for PacifiCorp's participation in the NWPP reserve sharing agreement.
- The NWPP reserve sharing agreement allows a participant to receive energy from other participants within the first hour of a contingency event.
- PacifiCorp accounts for the NWPP reserve sharing agreement by assuming the first hour of any event is covered and removed in the tabulation of EUE, LOLH and LOLE measures.

	Before NWPP Adjustment			After NWPP Adjustment		
PRM (%)	Simulated EUE (GWh/Yr)	Simulated LOLH (Hours/Yr)	Simulated LOLE (Events/Yr)	Simulated EUE (GWh/Yr)	Simulated LOLH (Hours/Yr)	Simulated LOLE (Events/Yr)
10	79	0.94	0.69	21	0.25	0.15
11	80	0.93	0.68	21	0.25	0.15
12	79	0.94	0.69	21	0.25	0.15
13	78	0.92	0.68	20	0.24	0.15
14	76	0.90	0.66	20	0.24	0.15
15	75	0.90	0.66	20	0.24	0.15
16	78	0.94	0.69	21	0.25	0.15
17	72	0.92	0.68	19	0.24	0.15
18	71	0.91	0.68	18	0.23	0.14
19	33	0.78	0.60	8	0.18	0.10
20	34	0.76	0.58	8	0.19	0.10

Reliability Measures (2020) - Fitted

- Generally, reliability measures improve as the PRM level increases.
- Reliability measures do not improve monotonically among discrete PRM levels.
  - This can be caused by variability in resource location among portfolios and ability to serve load among all load pockets given static transmission assumptions when Monte Carlo sampling is applied to load, hydro generation, and thermal unit outages.
  - As in the 2013 and 2015 IRP PRM Studies, PacifiCorp has fit the simulated reliability metrics to a logarithmic function to report the overall trend in reliability improvements as the PRM level increases.

	Before NWPP Adjustment			After NWPP Adjustment		
PRM (%)	Fitted EUE (GWh/Yr)	Fitted LOLH (Hours/Yr)	Fitted LOLE (Events/Yr)	Fitted EUE (GWh/Yr)	Fitted LOLH (Hours/Yr)	Fitted LOLE (Events/Yr)
10	91	0.97	0.71	24	0.26	0.16
11	81	0.94	0.69	22	0.25	0.15
12	76	0.92	0.68	20	0.24	0.15
13	72	0.90	0.67	19	0.23	0.14
14	68	0.89	0.66	18	0.23	0.14
15	66	0.88	0.66	17	0.23	0.14
16	64	0.87	0.65	16	0.22	0.14
17	62	0.87	0.65	16	0.22	0.13
18	60	0.86	0.65	15	0.22	0.13
19	58	0.86	0.64	15	0.22	0.13
20	57	0.85	0.64	14	0.21	0.13

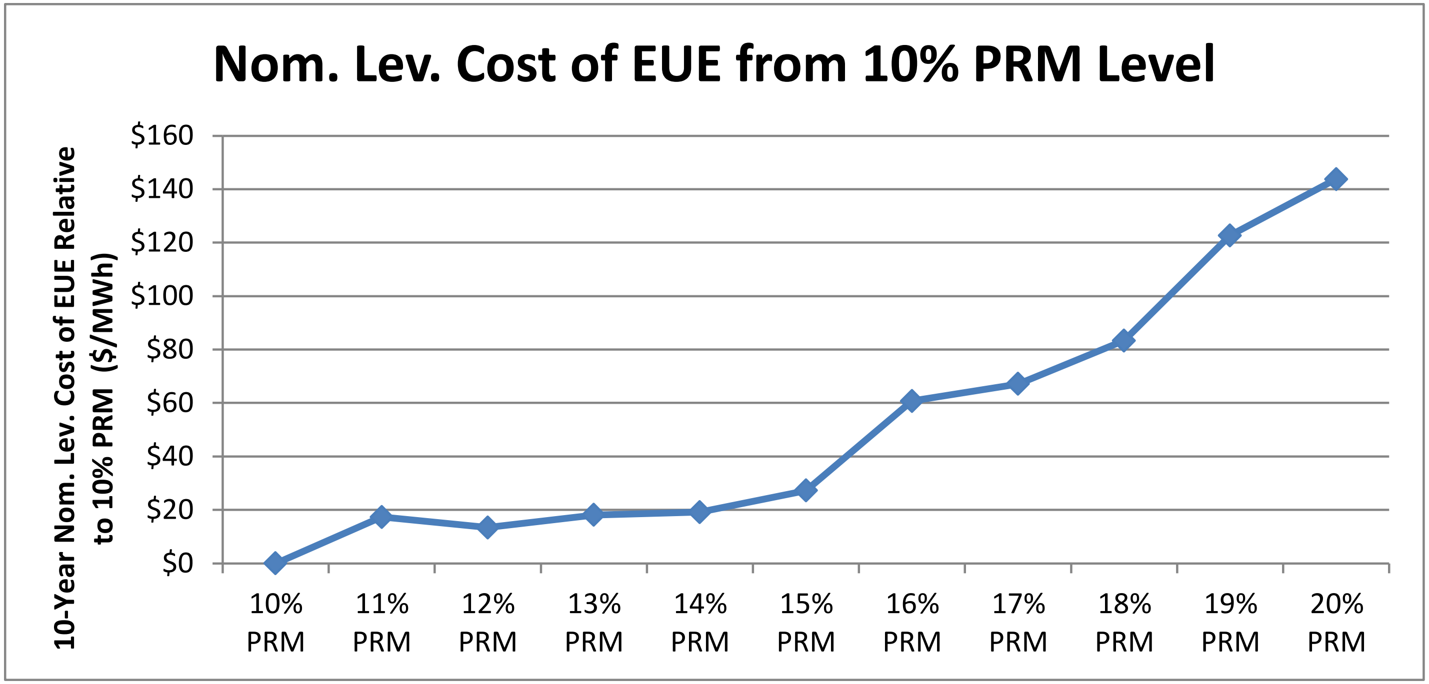
10-Year PVRR Costs by Planning Reserve Margin Level

- Costs for portfolios represent the present value revenue requirement (PVRR) over the 2020-2030 timeframe (rather than a single reference year as applied in the 2015 IRP PRM Study)
  - System Production Costs reflect the expected value for all system variable costs including fuel, variable O&M, and market purchases/sales.
  - DSM costs reflect costs to implement both Class 2 and Class 1 DSM resources in the portfolios.
  - Existing resource fixed costs reflect run-rate operating costs for existing resources, which is the same among all PRM portfolios.
  - New resource fixed costs reflect capital revenue requirement (levelized return on, return of, and taxes) and run-rate operating costs for new resources.

PRM (%)	System Production Costs ($m)	Class 2 DSM ($m)	Class 1 DSM ($m)	Existing Resource Fixed Costs ($m)	New Resource Fixed Cost ($m)	Total Costs ($m)
10	$10,969	$437	$0	$6,093	$183	$17,681
11	$11,003	$404	$0	$6,093	$197	$17,698
12	$10,966	$437	$2	$6,093	$203	$17,701
13	$10,958	$463	$9	$6,093	$193	$17,715
14	$10,906	$514	$12	$6,093	$198	$17,723
15	$10,892	$553	$28	$6,093	$181	$17,747
16	$10,923	$440	$2	$6,093	$382	$17,840
17	$10,882	$522	$18	$6,093	$354	$17,869
18	$10,865	$535	$63	$6,093	$371	$17,927
19	$10,835	$527	$26	$6,093	$581	$18,061
20	$10,870	$429	$7	$6,093	$745	$18,144

Selection of the PRM for the 2017 IRP

- The incremental cost of reliability accounts for the increase in system costs associated with an incremental reduction in EUE.
- Short-term operating reserve requirements, just one element of uncertainty and variability the PRM is intended to cover, requires approximately 11-12% of capacity be held in reserve—the PRM selected for planning purposes should exceed this level to account for other mid- to long-term uncertainties (i.e., load and resource availability).
- The incremental cost of reserves rises modestly at the 14% PRM level, more so at the 15% PRM level and more significantly with PRMs above 15%.
- With these considerations, PacifiCorp will maintain a 13% PRM level for the 2017 IRP.







2017
Integrated Resource Plan

Capacity Contribution Study

Wind and Solar Capacity Contribution

- PacifiCorp has updated its wind and solar capacity contribution study for the 2017 IRP.

- The methodology is based on a National Renewable Energy Laboratory ("NREL") report on Effective Load Carrying Capability (ELCC) approximation methods.

- The methodology (the "CF Approximation Method") relies upon weighted hourly loss of load probability (LOLP) statistics based on the reliability model used in PacifiCorp's planning reserve margin study at the 13% planning reserve margin level.

- PacifiCorp has used the updated figures to develop its load and resource balance for the 2017 IRP and will adopt these assumptions when developing resource portfolios for the 2017 IRP.

- Additional sensitivity analysis will explore how solar capacity contribution levels change with increasing penetration levels—these studies are being prepared and will be summarized at the next public input meeting.

CF Approximation Method

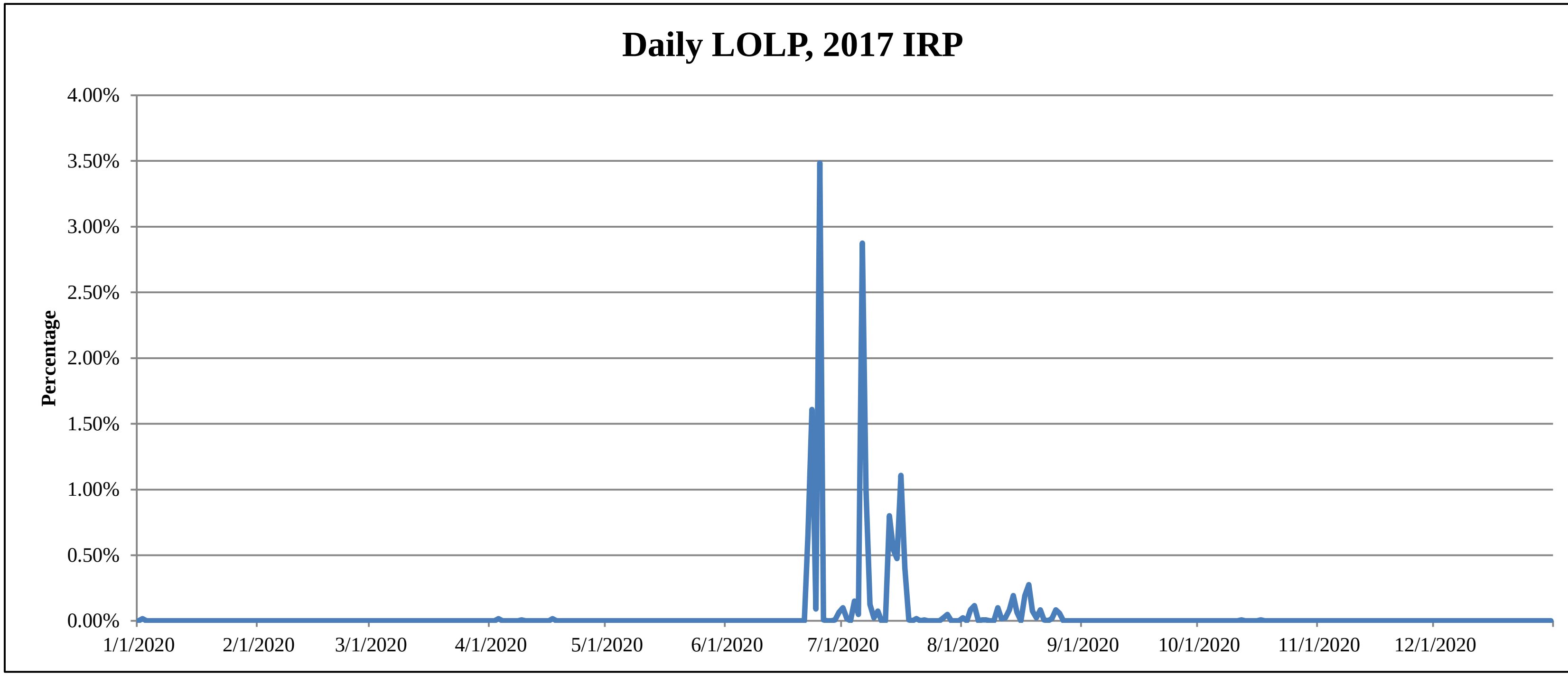
- 500-iteration hourly PaR run (based on the same reliability model used in the planning reserve margin study) is used as the basis for this analysis.
- Each hour's LOLP is calculated, with weighting factors calculated by dividing each hour's LOLP by the total LOLP in a 2020 study year.
- The capacity contribution is calculated as the sum of hourly weighted capacity factors for each resource type:
  - East and West Wind (expected generation profiles)
  - Proxy solar (fixed & tracking) in Milford, UT and Lakeview, OR (proxy profiles developed for the 2017 IRP)

Capacity Contribution Results

	Wind			Solar PV					
	West	East	Weighted Average	Lakeview, OR Fixed Tilt	Milford, UT Fixed Tilt	Average Fixed Tilt	Lakeview, OR Single Axis Tracking	Milford, UT Single Axis Tracking	Average Single Axis Tracking
2017 IRP (CF Approximation)	12.9%	15.8%	14.6%	55.1%	51.0%	53.0%	70.5%	67.9%	69.2%
2015 IRP (CF Approximation)	25.4%	14.5%	18.1%	32.2%	34.1%	33.1%	36.7%	39.1%	37.9%

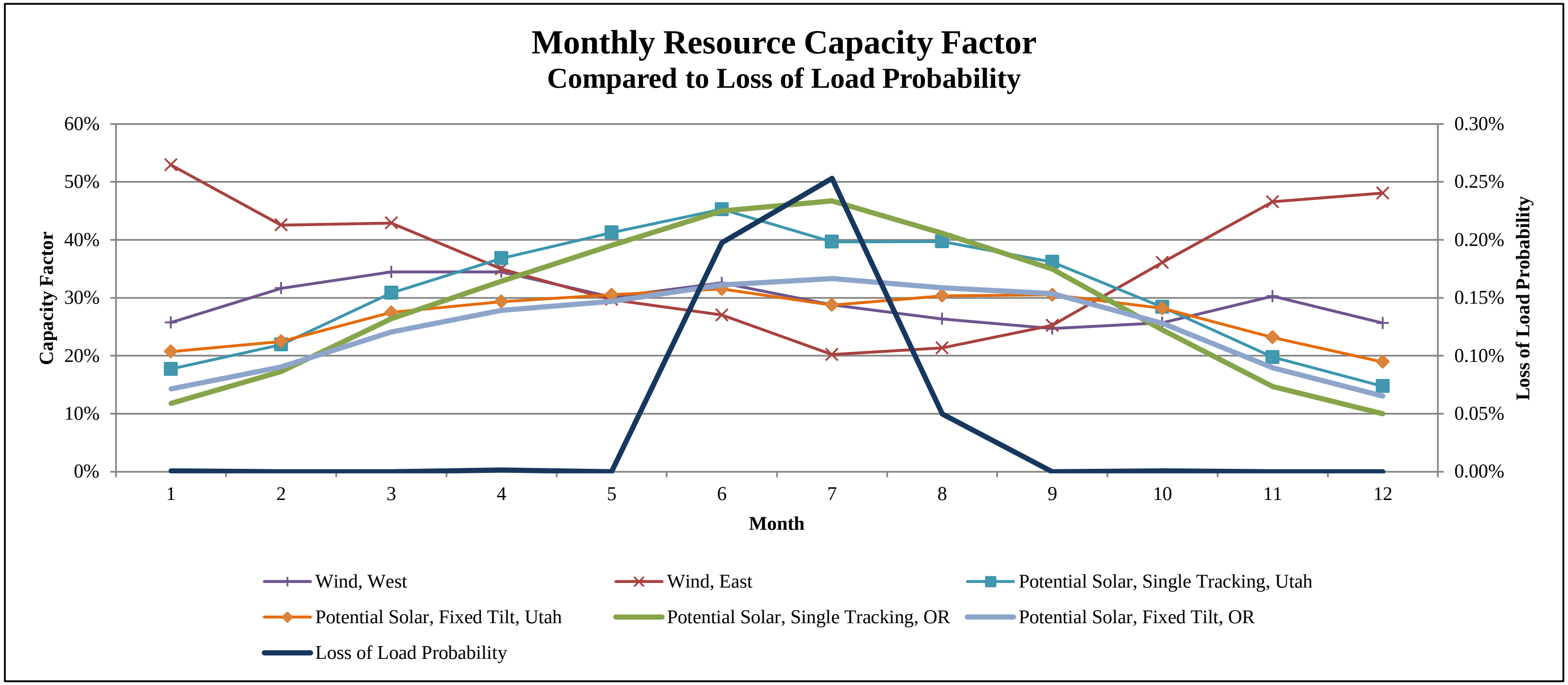
- The results of the capacity contribution study are driven by the coincidence of LOLP and resource shapes/capacity factors.
- The updated hourly LOLP distribution is more focused in the summer period than in the 2015 IRP study, which is the primary driver to changes in wind and solar capacity contribution values.
  - Solar capacity contribution values increase.
  - West wind capacity contribution values decrease.

2017 IRP LOLP



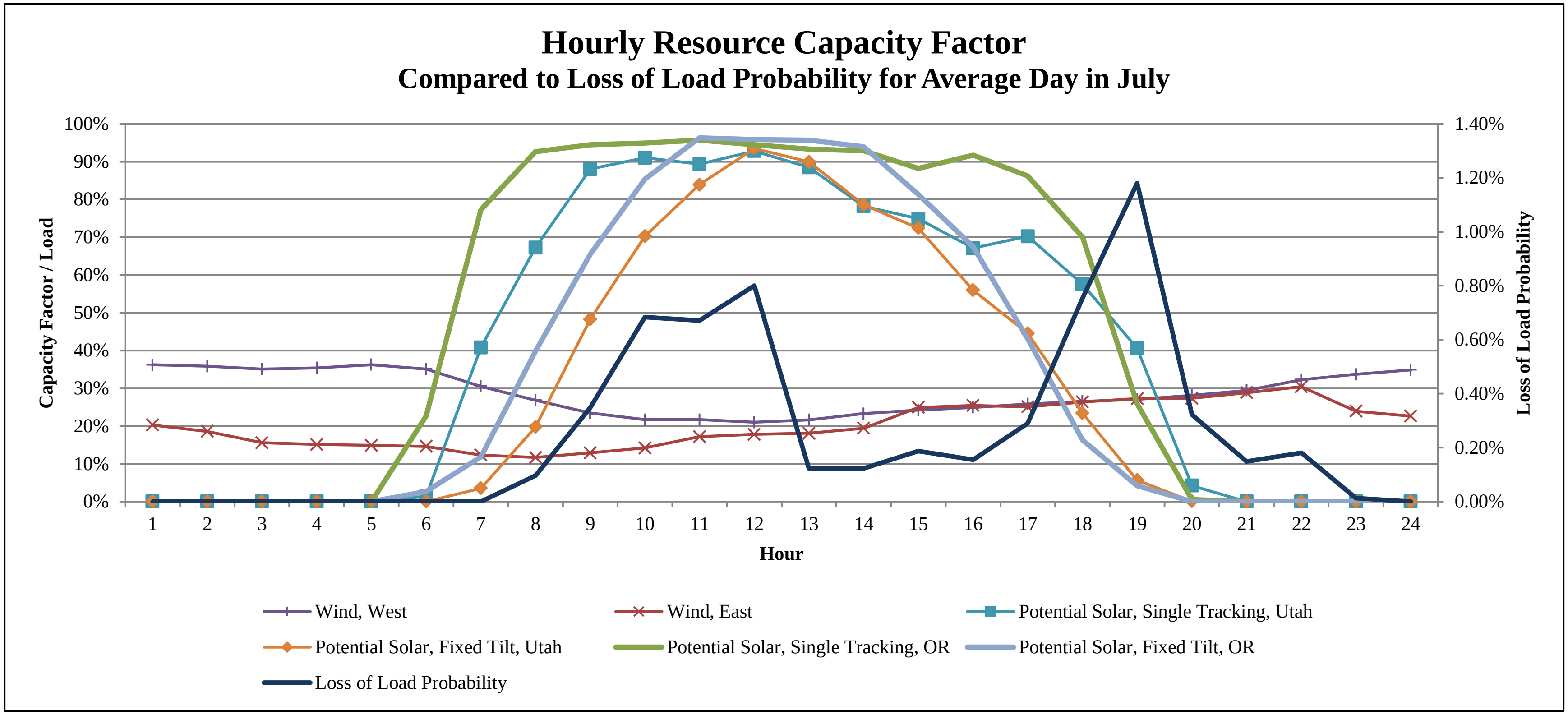
- The seasonal distribution of the 2017 IRP LOLP shows the highest loss of load probability in summer when load peaks in July.
- The difference in LOLP distribution is the main driver of the capacity contribution results.
- Resource shapes have remained relatively consistent across the studies between 2015 IRP and 2017 IRP.

2017 IRP LOLP & Capacity Factors



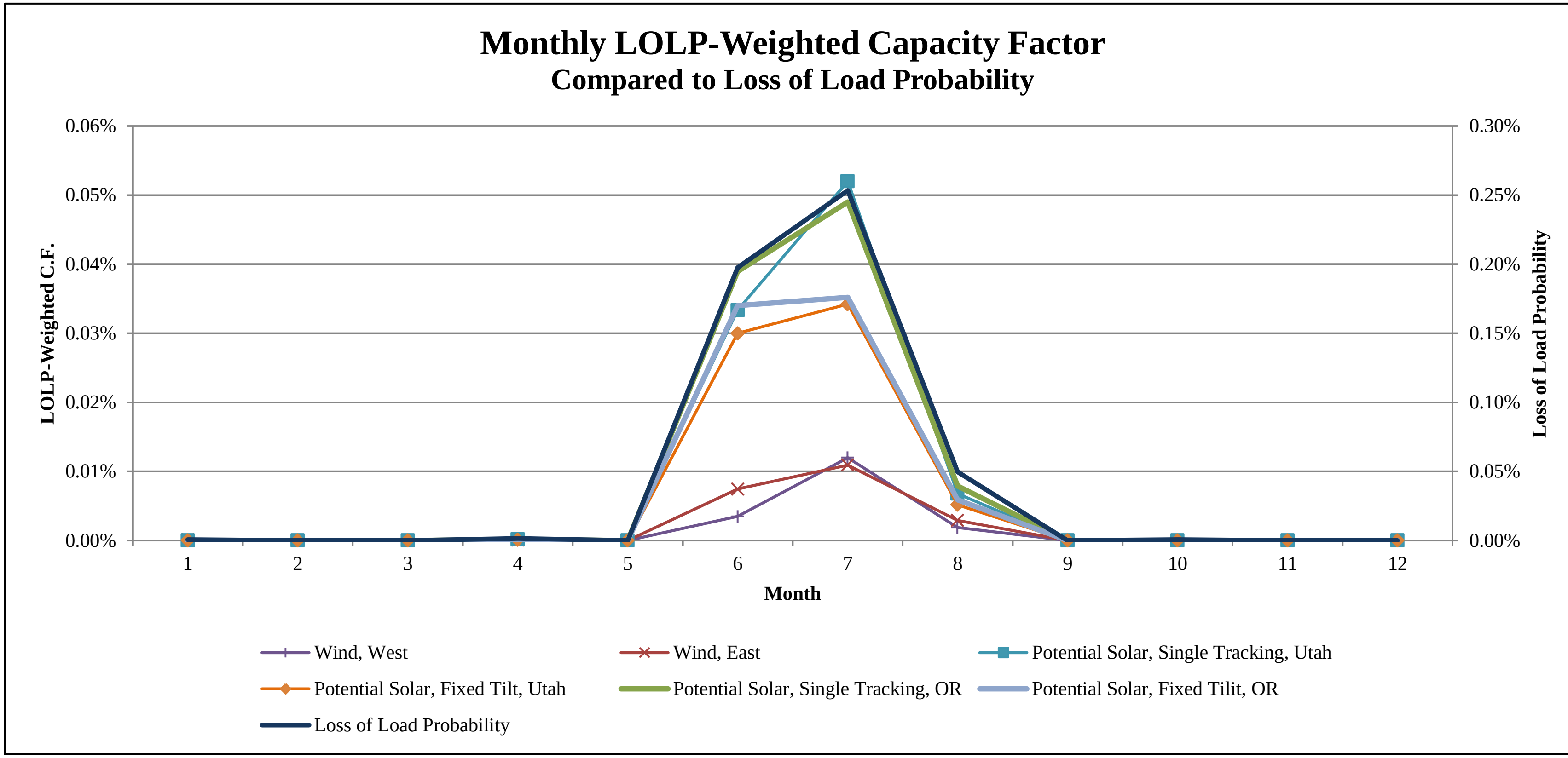
- The coincidence of the seasonal distribution of LOLP (highest in summer) and solar capacity factors increasing in summer drives the increase in solar capacity contribution.
- The coincidence of the seasonal distribution of LOLP (highest in summer) and wind capacity factors decreasing in summer drives the decrease in wind capacity contribution.
- The seasonal distribution of LOLP concentrated in summer months, when wind capacity factors are lower, pushes west wind downward.

2017 IRP LOLP & Capacity Factors



- The hourly distribution of LOLP displays a high coincidence with solar capacity factors and low coincidence with wind capacity factors, contributing to higher solar capacity contribution and lower wind capacity contribution.
- Among July hours in the 2020 study year, LOLP events peak during morning and evening ramp periods.

2017 IRP LOLP & Capacity Factors



- Key metric – weighted capacity factors. The weighted capacity factors display the dominance of single tracking solar over fixed tilt solar, and of east wind over west wind.





2017
Integrated Resource Plan

Load & Resource Balance

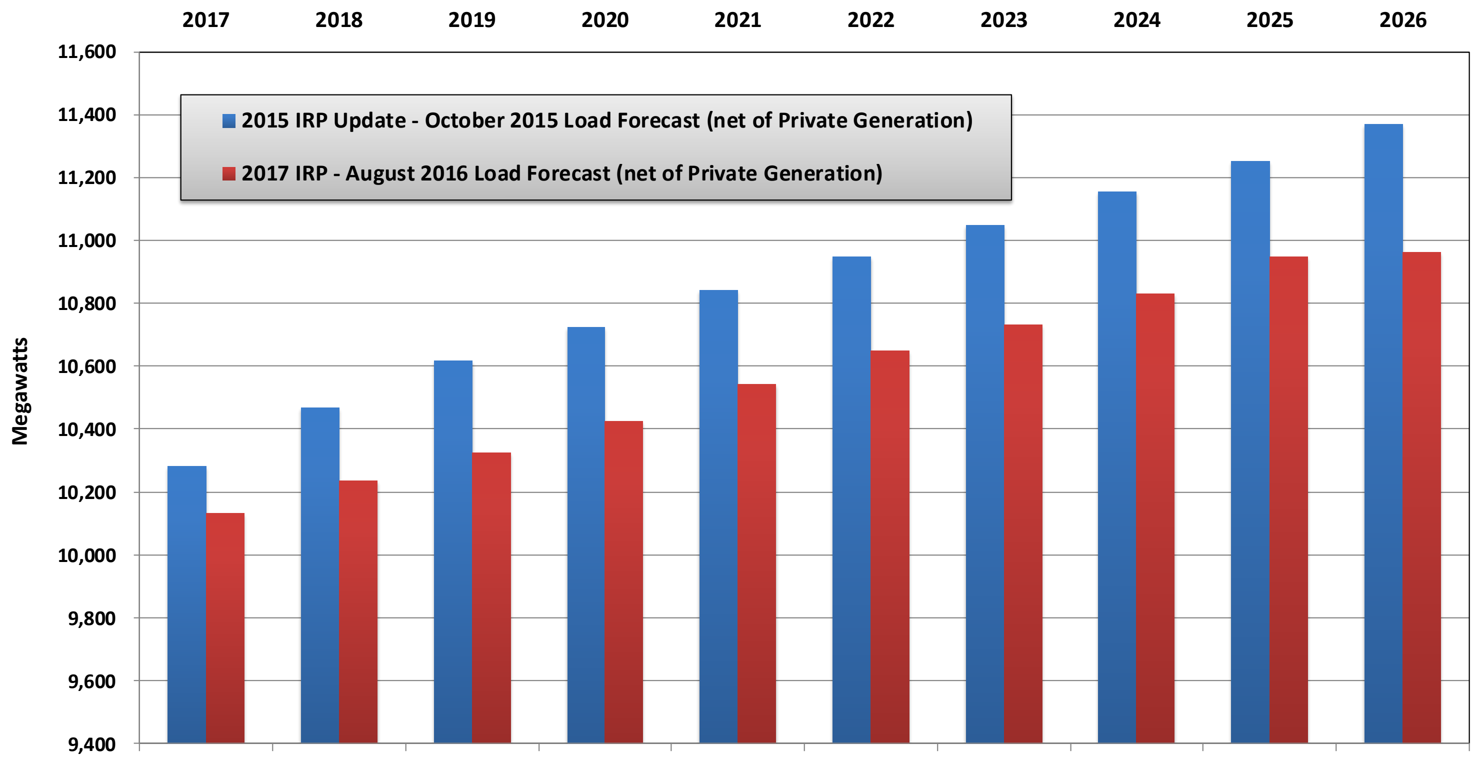
2017 IRP Initial Load & Resource (L&R) Balance

- The initial L&R addresses capacity balances, with a focus on the front ten years of the planning horizon, assuming no incremental resources are added to PacifiCorp's system.

- Improvements in the 2017 IRP L&R:
  - Developed for both winter and summer peak aligning with 2017 IRP improvement to enforce both winter and summer planning reserve margins.
  - Resource contributions specific to summer and winter ratings (i.e., thermal resources, hydro, and Class 2 DSM).
  - Private generation, an element of the load forecast, is broken out as its own line item (responsive to stakeholder feedback).

- The initial L&R reflects coal unit retirements as reported in the 2015 IRP Update.
  - Any changes to the L&R based on PacifiCorp's Volume III studies will be captured in the L&R developed inclusive of preferred portfolio resources.

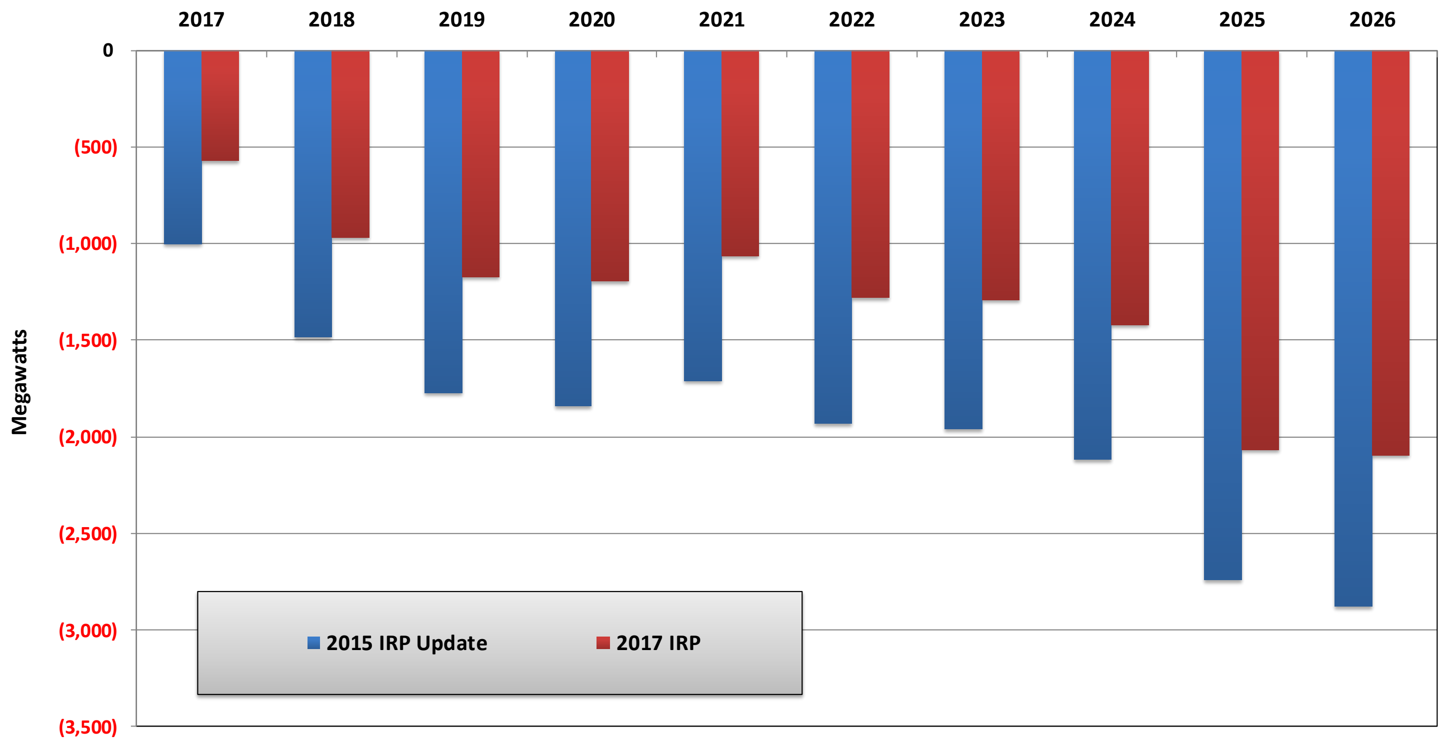
Peak Load Comparison (Summer)
2017 IRP vs 2015 IRP Update



Load Changes

- In the near term, peak load is lower - down by an average of 243 MW between 2017 and 2020
- Beyond 2021, peak load is also lower – down an average of 325 MW between 2021 and 2026

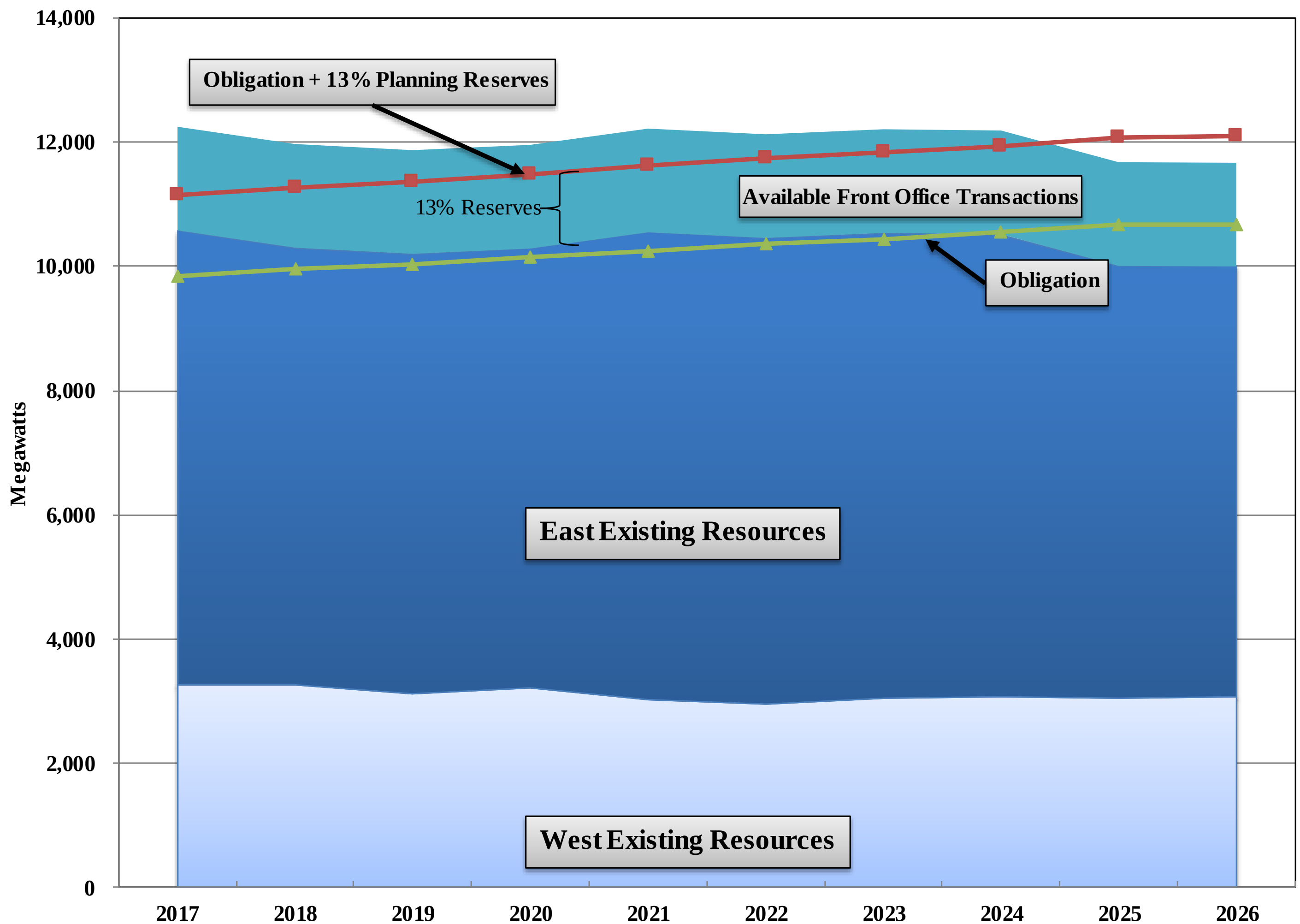
System Capacity Position Comparison – 2017 IRP vs 2015 IRP Update (Summer)



Resource Changes

- Total resources increased 334 MW by 2026.
- Notable changes driven by:
  - Wind and Solar peak contribution factor updates increased resources by 239 MW.
  - Net QF contract updates contribute an additional 67 MW.

System Position Chart - Summer



- In 2025, with a 13% planning reserve margin, peak obligations begin to exceed existing resources (including FOTs but before adding incremental DSM).

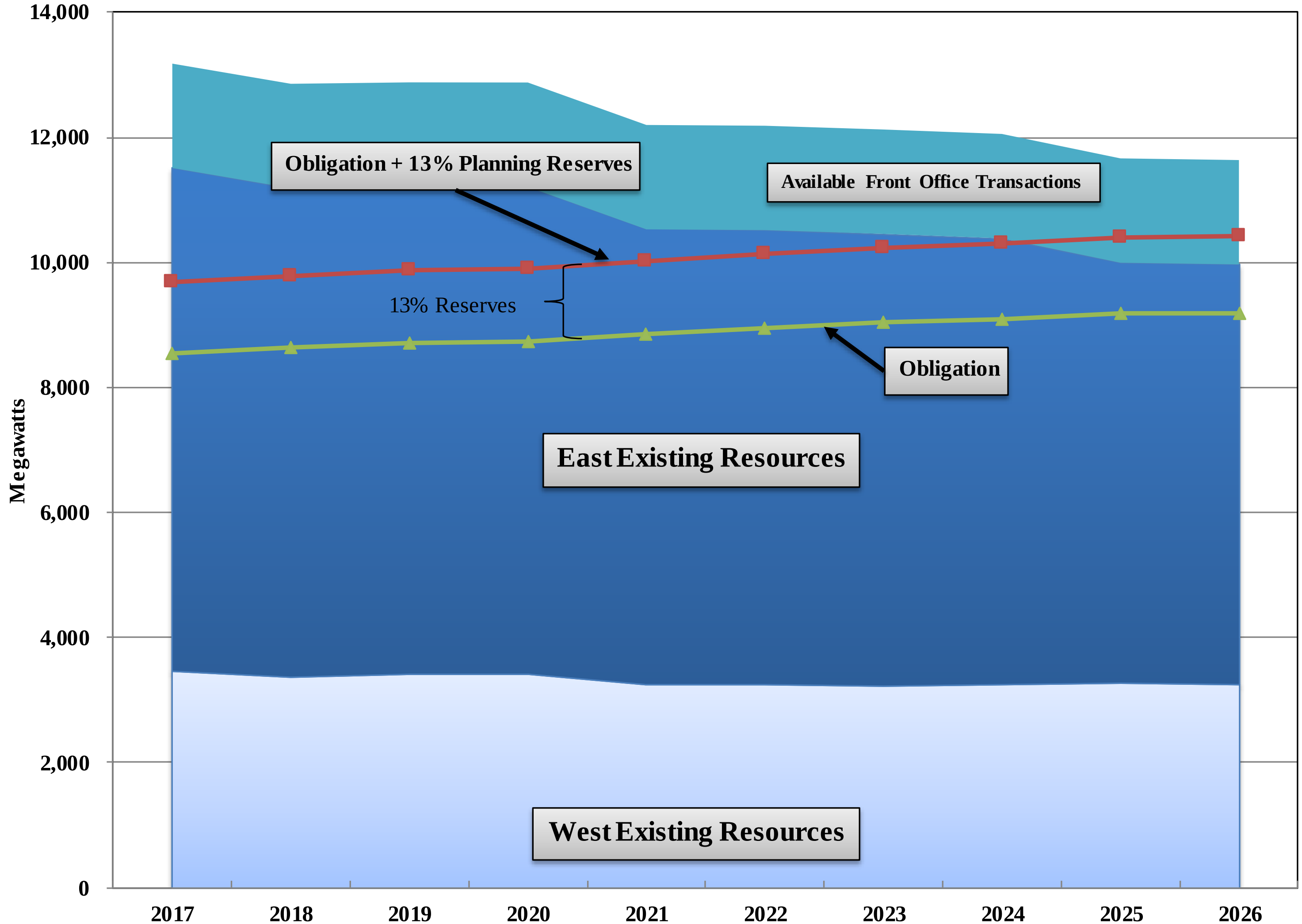
Capacity Load and Resource Balance – Summer (13% Planning Reserve Margin)

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East										
Thermal	6,406	6,126	6,126	6,126	6,126	6,126	6,126	6,126	5,735	5,645
Hydroelectric	103	106	113	113	113	113	113	92	92	92
Renewable	202	202	202	202	199	191	191	191	191	181
Purchase	249	249	249	249	221	221	221	221	121	121
Qualifying Facilities	727	716	766	757	748	736	731	677	671	666
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(652)	(652)	(652)	(652)	(172)	(172)	(172)	(146)	(146)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
East Existing Resources	**7,320**	**7,032**	**7,088**	**7,080**	**7,520**	**7,500**	**7,496**	**7,448**	**6,951**	**6,929**
Load	7,011	7,100	7,191	7,248	7,350	7,439	7,505	7,584	7,684	7,687
Private Generation	(33)	(51)	(72)	(80)	(86)	(91)	(94)	(98)	(104)	(112)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class2 DSM	(62)	(62)	(62)	(62)	(62)	(62)	(62)	(62)	(62)	(62)
East obligation	**6,721**	**6,792**	**6,861**	**6,910**	**7,006**	**7,091**	**7,154**	**7,229**	**7,323**	**7,318**
Planning Reserves (13%)	899	908	917	924	936	947	955	965	977	977
East Obligation + Reserves	**7,620**	**7,701**	**7,779**	**7,834**	**7,942**	**8,038**	**8,109**	**8,194**	**8,300**	**8,294**
East Position	**(300)**	**(669)**	**(690)**	**(754)**	**(422)**	**(538)**	**(614)**	**(747)**	**(1,349)**	**(1,365)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247
Hydroelectric	855	859	717	806	635	549	644	648	634	651
Renewable	100	100	100	100	100	67	67	62	62	61
Purchase	18	18	1	1	1	1	1	1	1	1
Qualifying Facilities	205	211	214	219	210	207	198	197	196	194
Class 1 DSM	3	3	3	3	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)	(80)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
West Existing Resources	**3,261**	**3,271**	**3,116**	**3,210**	**3,031**	**2,960**	**3,045**	**3,073**	**3,059**	**3,072**
Load	3,156	3,186	3,210	3,259	3,280	3,303	3,325	3,350	3,374	3,395
Private Generation	(1)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(5)	(6)
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)
West obligation	**3,129**	**3,159**	**3,183**	**3,231**	**3,252**	**3,274**	**3,295**	**3,320**	**3,344**	**3,364**
Planning Reserves (13%)	407	411	414	420	423	426	428	432	435	437
West Obligation + Reserves	**3,536**	**3,570**	**3,596**	**3,651**	**3,674**	**3,700**	**3,724**	**3,751**	**3,778**	**3,801**
West Position	**(275)**	**(298)**	**(480)**	**(440)**	**(644)**	**(740)**	**(679)**	**(678)**	**(720)**	**(729)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System										
Total Resources	10,581	10,303	10,204	10,290	10,551	10,460	10,541	10,521	10,010	10,002
Obligation	9,850	9,952	10,044	10,141	10,258	10,365	10,449	10,549	10,666	10,681
Reserves	1,306	1,319	1,331	1,344	1,359	1,373	1,384	1,397	1,412	1,414
Obligation + Reserves	11,156	11,271	11,375	11,485	11,617	11,738	11,833	11,945	12,078	12,095
System Position	(575)	(967)	(1,171)	(1,194)	(1,066)	(1,278)	(1,292)	(1,425)	(2,068)	(2,094)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
Net Surplus (Deficit)	1,095	702	499	475	604	391	377	245	(399)	(424)

Line Item Differences - Summer 2017 IRP less 2015 IRP Update

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East										
Thermal	9	10	10	10	13	15	18	21	18	(71)
Hydroelectric	(6)	(6)	1	1	1	1	1	1	1	1
Renewable	14	14	14	14	14	6	14	14	23	13
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	258	254	306	304	301	299	297	295	293	291
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	0	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	81
Non-Owned Reserves	1	1	1	1	1	1	1	1	1	1
East Existing Resources	**276**	**271**	**331**	**328**	**328**	**321**	**328**	**329**	**334**	**315**
Load	(106)	(185)	(241)	(279)	(284)	(288)	(306)	(322)	(300)	(403)
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
East obligation	**(107)**	**(187)**	**(242)**	**(281)**	**(286)**	**(290)**	**(308)**	**(324)**	**(301)**	**(404)**
Planning Reserves (13%)	(14)	(24)	(31)	(36)	(37)	(38)	(40)	(42)	(39)	(53)
East Obligation + Reserves	**(121)**	**(211)**	**(274)**	**(317)**	**(323)**	**(327)**	**(348)**	**(366)**	**(340)**	**(457)**
East Position	**398**	**482**	**604**	**645**	**651**	**648**	**676**	**695**	**674**	**772**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
West										
Thermal	(0)	(0)	(0)	(0)	2	6	8	8	8	8
Hydroelectric	29	22	(19)	14	13	1	(11)	5	2	8
Renewable	(72)	(72)	(72)	(72)	(72)	(50)	(50)	(45)	(45)	(46)
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	28	36	41	44	44	44	43	42	42	49
Class 1 DSM	3	3	3	3	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	1	1	1	1	1	1	1	1	1	1
West Existing Resources	**(11)**	**(11)**	**(47)**	**(11)**	**(12)**	**2**	**(9)**	**11**	**8**	**20**
Load	(44)	(50)	(48)	(20)	(17)	(13)	(11)	(1)	(4)	(2)
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	10	10	10	10	10	10	10	10	10	10
West obligation	**(34)**	**(40)**	**(38)**	**(10)**	**(7)**	**(4)**	**(1)**	**9**	**6**	**8**
Planning Reserves (13%)	(4)	(5)	(5)	(1)	(1)	(0)	(0)	1	1	1
West Obligation + Reserves	**(39)**	**(45)**	**(43)**	**(11)**	**(8)**	**(4)**	**(1)**	**10**	**7**	**9**
West Position	**28**	**34**	**(3)**	**(0)**	**(5)**	**6**	**(8)**	**1**	**1**	**11**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
System										
Total Resources	265	261	284	317	316	322	319	340	342	334
Obligation	(142)	(227)	(281)	(290)	(292)	(293)	(309)	(315)	(295)	(397)
Reserves	(18)	(29)	(36)	(38)	(38)	(38)	(40)	(41)	(38)	(52)
Obligation + Reserves	(160)	(256)	(317)	(328)	(330)	(331)	(349)	(355)	(333)	(448)
System Position	425	517	601	645	646	654	669	695	675	783
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Surplus (Deficit)	425	517	601	645	646	654	669	695	675	783

System Position Chart - Winter



Capacity Load and Resource Balance – Winter (13% Planning Reserve Margin)

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East										
Thermal	6,514	6,234	6,234	6,234	6,234	6,234	6,234	6,234	5,843	5,753
Hydroelectric	71	72	72	72	72	72	72	72	72	72
Renewable	202	202	202	199	191	191	191	191	191	181
Purchase	734	734	734	734	235	235	235	121	121	121
Qualifying Facilities	717	765	756	752	743	733	678	674	668	664
Class 1 DSM	21	21	21	21	21	21	21	21	21	21
Sale	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(146)	(146)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
East Existing Resources	**8,052**	**7,820**	**7,811**	**7,805**	**7,289**	**7,278**	**7,224**	**7,130**	**6,734**	**6,712**
Load	5,548	5,616	5,687	5,600	5,771	5,848	5,924	5,956	5,922	5,927
Distributed Generation	(11)	(17)	(24)	(28)	(31)	(32)	(33)	(35)	(37)	(40)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class2 DSM	(23)	(23)	(23)	(23)	(23)	(23)	(23)	(23)	(23)	(23)
East obligation	**5,319**	**5,381**	**5,445**	**5,354**	**5,523**	**5,598**	**5,673**	**5,704**	**5,667**	**5,669**
Planning Reserves (13%)	717	725	733	721	743	753	763	767	762	762
East Obligation + Reserves	**6,036**	**6,106**	**6,178**	**6,075**	**6,266**	**6,352**	**6,436**	**6,471**	**6,429**	**6,431**
East Position	**2,016**	**1,714**	**1,633**	**1,729**	**1,023**	**926**	**788**	**660**	**305**	**281**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308
Hydroelectric	993	915	943	937	784	782	783	779	786	786
Renewable	100	100	100	100	100	67	67	62	61	60
Purchase	6	1	1	1	1	1	1	1	1	1
Qualifying Facilities	212	203	207	209	202	195	189	188	187	183
Class 1 DSM	3	3	3	3	0	0	0	0	0	0
Sale	(162)	(162)	(162)	(154)	(154)	(113)	(113)	(81)	(81)	(81)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
West Existing Resources	**3,458**	**3,367**	**3,399**	**3,403**	**3,240**	**3,238**	**3,233**	**3,255**	**3,260**	**3,255**
Load	3,264	3,291	3,306	3,416	3,360	3,379	3,400	3,417	3,542	3,559
Distributed Generation	(1)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(5)	(6)
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
West obligation	**3,234**	**3,260**	**3,275**	**3,385**	**3,328**	**3,347**	**3,367**	**3,384**	**3,508**	**3,524**
Planning Reserves (13%)	420	424	426	440	433	435	438	440	456	458
West Obligation + Reserves	**3,654**	**3,684**	**3,700**	**3,825**	**3,761**	**3,782**	**3,805**	**3,824**	**3,964**	**3,983**
West Position	**(196)**	**(317)**	**(301)**	**(421)**	**(521)**	**(543)**	**(572)**	**(569)**	**(704)**	**(727)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System										
Total Resources	11,510	11,187	11,210	11,208	10,529	10,516	10,456	10,385	9,994	9,967
Obligation	8,553	8,641	8,719	8,739	8,851	8,945	9,040	9,088	9,175	9,193
Reserves	1,137	1,149	1,159	1,161	1,176	1,188	1,201	1,207	1,218	1,221
Obligation + Reserves	9,690	9,790	9,878	9,900	10,027	10,133	10,240	10,295	10,393	10,414
System Position	1,820	1,397	1,332	1,308	502	383	216	90	(398)	(447)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
Net Surplus (Deficit)	3,489	3,067	3,001	2,977	2,172	2,053	1,885	1,760	1,271	1,223





2017 Integrated Resource Plan

Flexible Capacity Reserve Study

Flexible Capacity Requirements

- Loads and resources must balance over each and every interval.
- Requirements are forecasted in advance but uncertain until delivery occurs.
- Variable generating resources (wind and solar) contribute to uncertainty.
- Resource flexibility is increasingly constrained as delivery approaches.
- Maintaining flexibility may require out of merit order resource dispatch, resulting in higher costs.

Regulation Reserve

- Compliance with reliability standard BAL-001-2
  - Draft study online at https://www.oasis.oati.com/ppw/index.html
  - Navigate [Documents > PacifiCorp OASIS Tariff/Company Information > OATT Pricing > Ancillary Services]

System Balancing

- Day-ahead gas plant commitment cost, same method employed in 2014 Wind Integration Study, but expanded to include solar generation.

Definitions & Acronyms

- **Operating reserve:** capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection.
- **Contingency reserve:** capacity that PacifiCorp holds available to ensure compliance with the NERC regional reliability standard BAL-002-WECC-2.
- **Regulation reserve:** capacity that PacifiCorp holds available to ensure compliance with the NERC regional reliability standard BAL-001-2.
- **L_{10}:** bandwidth of acceptable deviation between net scheduled interchange and net actual interchange under BAL-001-1
- **BAAL:** Balancing Authority Area Control Error Limit: the dynamic bandwidth of acceptable deviation under BAL-001-2
- **VER:** Variable Energy Resources
- **Non-VER:** Non-Variable Energy Resources
- **EIM:** Energy Imbalance Market

Regulation Reserve – Outline

- Enhancements since the 2014 Wind Integration Study
- Compliance Requirement: BAL-001-2
- Operational Data: Five-minute granularity
- Regulation Reserve Need: Compliance time frame and deviations
- BAAL: Allowed Deviations
- Planning Reliability: Probability of Failure
- Regulation Reserve Forecast: Amount Held
  - VER
  - Non-VER
  - Load
  - PacifiCorp System-Wide Portfolio: Diversity Benefits
- EIM Flexibility Reserve Diversity
- PacifiCorp System-Wide Portfolio with EIM Benefit
- Incremental Wind Regulation Reserve
- Solar Regulation Reserve

Enhancements since the 2014 Study

Methodology

- New Reliability Standard: BAL-001-2, effective July 1, 2016.
- EIM operational experience: base schedules, deviations, and reserve benefits
- Expanded regulation reserve requirements: now calculated for solar, and non-variable energy resources, in addition to load and wind.
- Portfolio diversity benefit quantified and allocated among all components, rather than exclusively to wind.

Application of the Results

- Base scenario reflects reserve requirements associated with existing portfolio as of 1/1/2017.
- Wind scenario reflects incremental reserve requirements and reserve costs associated with additional wind resources.
- Solar scenario reflects incremental reserve requirements and reserve costs associated with additional solar resources.

Compliance Requirement: BAL-001-2

- ***BAL-001-2: Requirement 2***

  Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…

  www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf

- **Effective Date:** BAL-001-2 (also referred to as Reliability Based Control ("RBC")) took effect July 1, 2016, but PacifiCorp has been following it since March 2010 as part of a field trial.

- **Changes from BAL-001-1:**

	Interval (minutes)	Compliance %	Allowed Variance
BAL-001-1	10	90%	Fixed: L_{10}
BAL-001-2	30	100%	Dynamic: BAAL
Impact on Requirement	Down	Up	Varies

Operational Data: Five-minute granularity

- As part of EIM operations, base schedules must be submitted for all resources at 55 minutes prior to the delivery hour (T-55). Base schedules must balance forecasted loads.
- The imbalance between resource base schedules and actual meter data for each five minute interval is supplied by PacifiCorp resources or EIM transfers.
- The regulation reserve analysis was conducted on a five minute granularity to take advantage of the data available through EIM.
- The study term is January 2015 through December 2015

Load data: load imbalance is settled on an hourly basis in EIM, so actual load data was used to develop five-minute deviations

  - Five-minute interval actual load
  - Proxy hourly base schedules developed from actual prior hour and prior week data

VER data: resources that (1) are renewable; (2) cannot be stored by the facility; and (3) have variability that is beyond the control of the facility. 2015 study period only includes wind.

  - Five-minute EIM deviations
  - Hourly base schedules

Non-VER data: all resources which are not VERs (primarily thermal and hydroelectric), and which are not dispatchable by PacifiCorp or within the EIM

  - Five-minute EIM deviations
  - Hourly base schedules

Dispatchable resources: compensate for deviations by other transmission users

Values are preliminary and subject to change

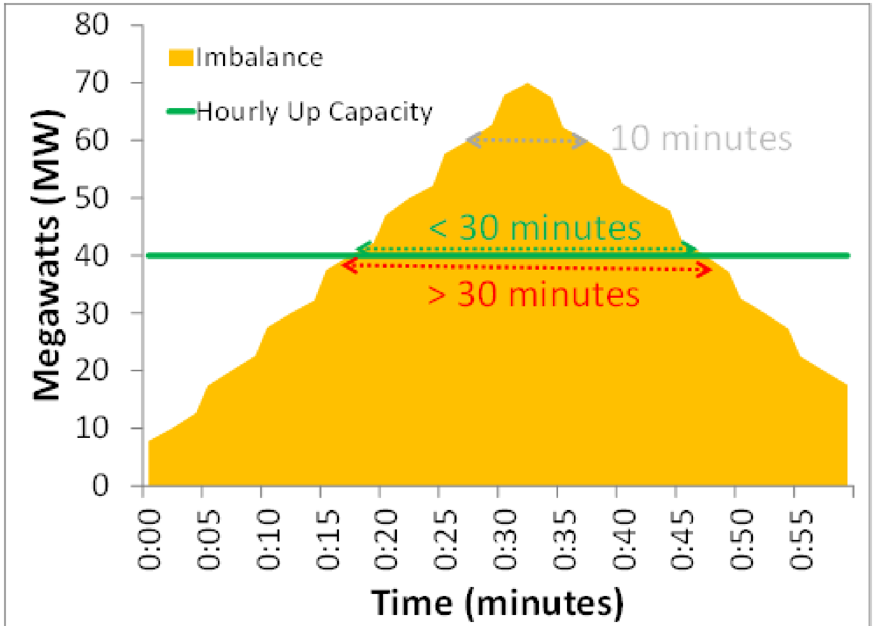
Regulation Reserve Need

For each hour:

a. Find the <u>minimum</u> five-minute imbalance for each thirty-minute rolling period.

b. Find the <u>maximum</u> five-minute imbalance among the values identified in step a.

Interval	Base Schedule	Actual	Imbalance	(a) 30-Min Up Requirement	(b) Hourly Up Capacity
0:00	2500	2510	10	10	40
0:05		2520	20	10	40
0:10		2530	30	10	40
0:15		2540	40	10	40
0:20		2550	50	10	40
0:25		2560	60	10	40
0:30		2570	70	20	40
0:35		2560	60	30	40
0:40		2550	50	40	40
0:45		2540	40	40	40
0:50		2530	30	30	40
0:55		2520	20	20	40



a. The minimum five-minute imbalance in the thirty minutes beginning at 0:15 is 40 MW.

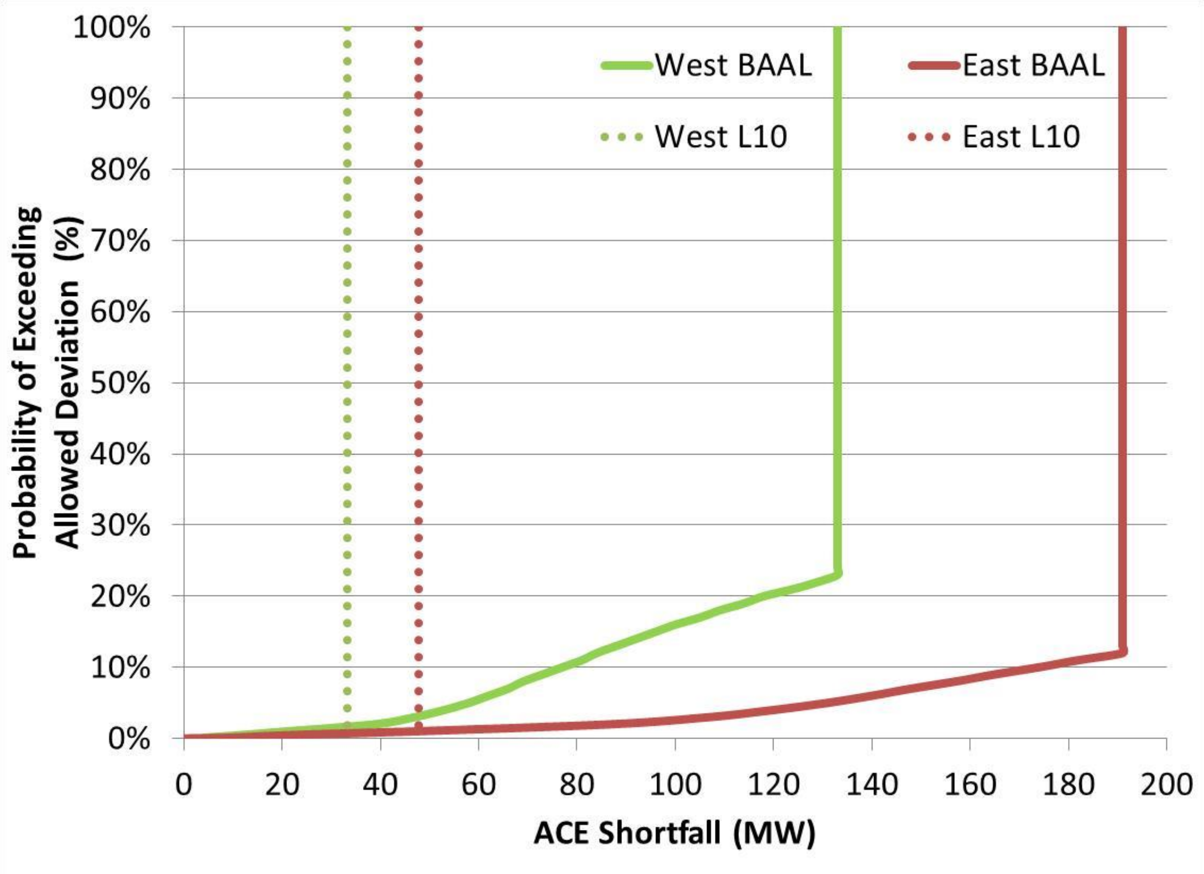
b. 40MW is the maximum five-minute imbalance in any thirty-minute period in this hour.

- The imbalance exceeds the reserves available for five 5-minute intervals, which is compliant with the BAL-001-2 requirement of not exceeding 30 minutes.
- With 40MW of regulation capability, loss of load probability is 0%.
- The same calculation applies to Load, Non-VER, VER, and Combined Imbalances.

Values are preliminary and subject to change

BAAL: Allowed Deviations

- The BAAL is specific to each BAA and varies dynamically as a function of WECC frequency.
- As WECC frequency drops below 60 Hz, ACE is increasingly restricted for BAAs with higher loads than resources.
- In addition to the BAAL, PacifiCorp policy caps ACE at 4 x L_{10}.
- As the ACE shortfall increases, the BAAL is more likely to be exceeded.



Results

- A 47MW ACE shortfall has a 1% chance of exceeding the PACE BAAL
- 47MW also happens to be approximately the PACE L_{10}.
- In 99% of five-minute intervals the allowed ACE shortfalls are now greater than L_{10}, but compliance is 100% of 30-minute intervals, vs 90% of ten-minute intervals previously.

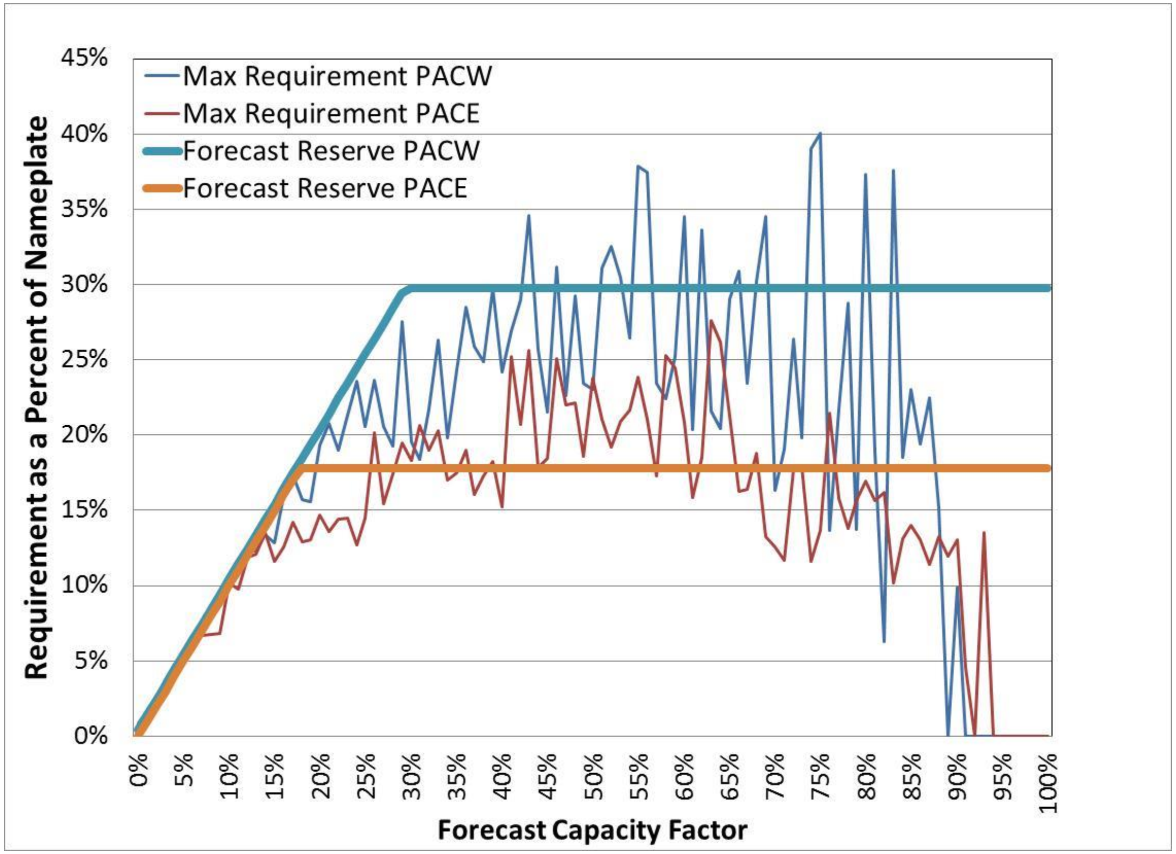
Values are preliminary and subject to change

Planning Reliability: Probability of Failure

- Resource planning commonly uses a reliability target such as loss of load probability (LOLP), i.e. a plan to curtail firm load in rare circumstances, rather than acquiring resources for extremely unlikely events.
- If available reserve is insufficient, and the ACE shortfall exceeds the BAAL, 100% compliance with the BAL-001-2 standard can be maintained by curtailing firm load.
- Curtailing firm load balances the cost of holding additional regulation reserve against the likelihood of regulation reserve shortage events.
- PacifiCorp's 2015 Integrated Resource Plan (IRP) utilized a planning reserve margin of 13 percent, which was intended to achieve 0.88 loss of load hours per year.
- This study assumes 0.88 loss of load hours per year due to regulation reserve shortages is appropriate for planning and ratemaking purposes.
- If the regulation reserve available is greater than the regulation reserve need for an hour, the LOLP is zero for that hour.
- If the regulation reserve held is less than the amount needed, the LOLP is derived from the BAAL probability distribution. As the magnitude of the shortfall increases, the probability of exceeding the BAAL increases.
- For instance, a 47 MW ACE shortfall in PACE has a one percent chance of exceeding the BAAL. A one percent probability of failing to meet the BAAL in one hour is 0.01 loss of load hours per year. Eighty-eight such hours would correspond to the targeted level of reliability.

Values are preliminary and subject to change

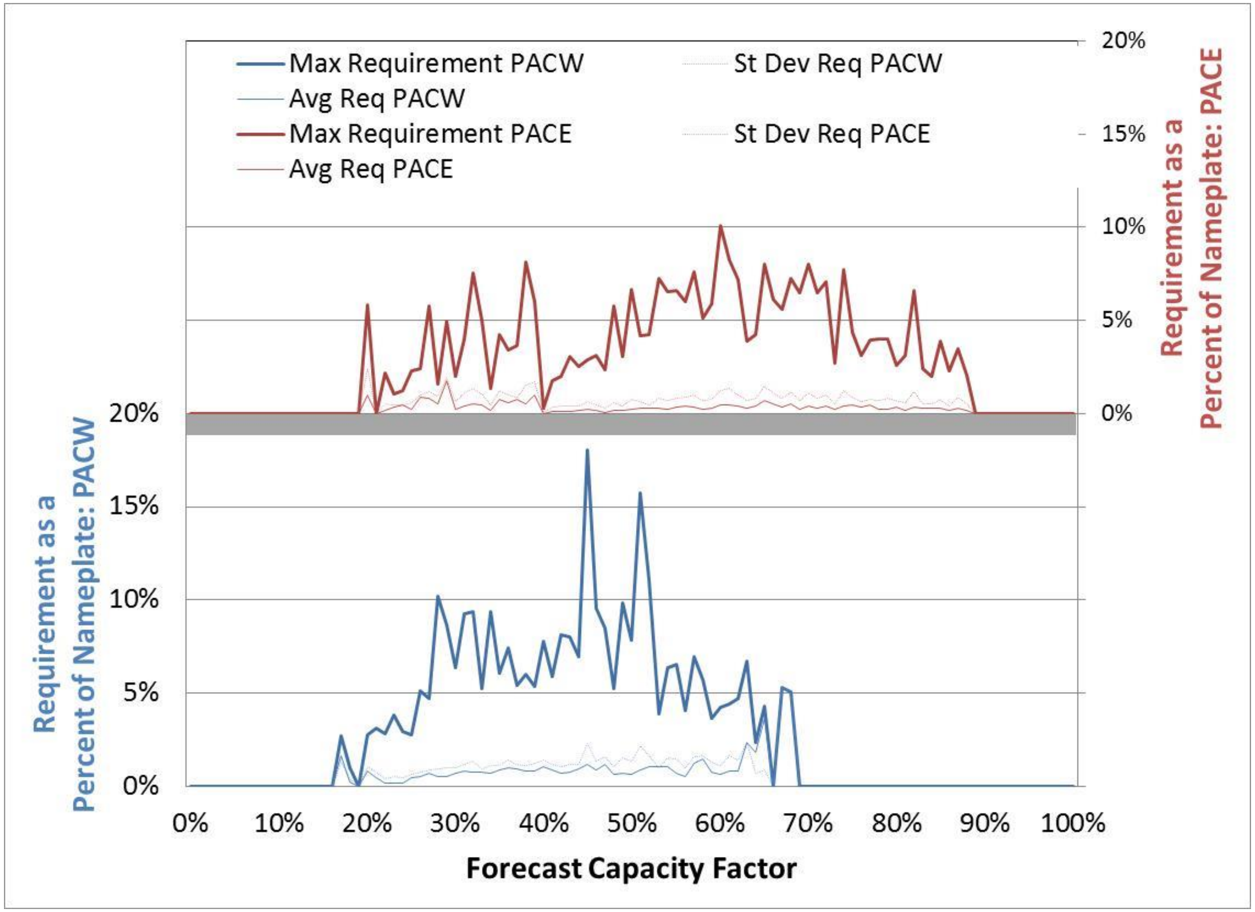
VER Regulation Reserve Forecast



- Forecast: fixed percentage of nameplate in all hours that hits reliability target, but not more than base schedule (forecasted output).
- Stand-alone VER requirement is 382 aMW, or 14.8% of nameplate capacity.

Values are preliminary and subject to change

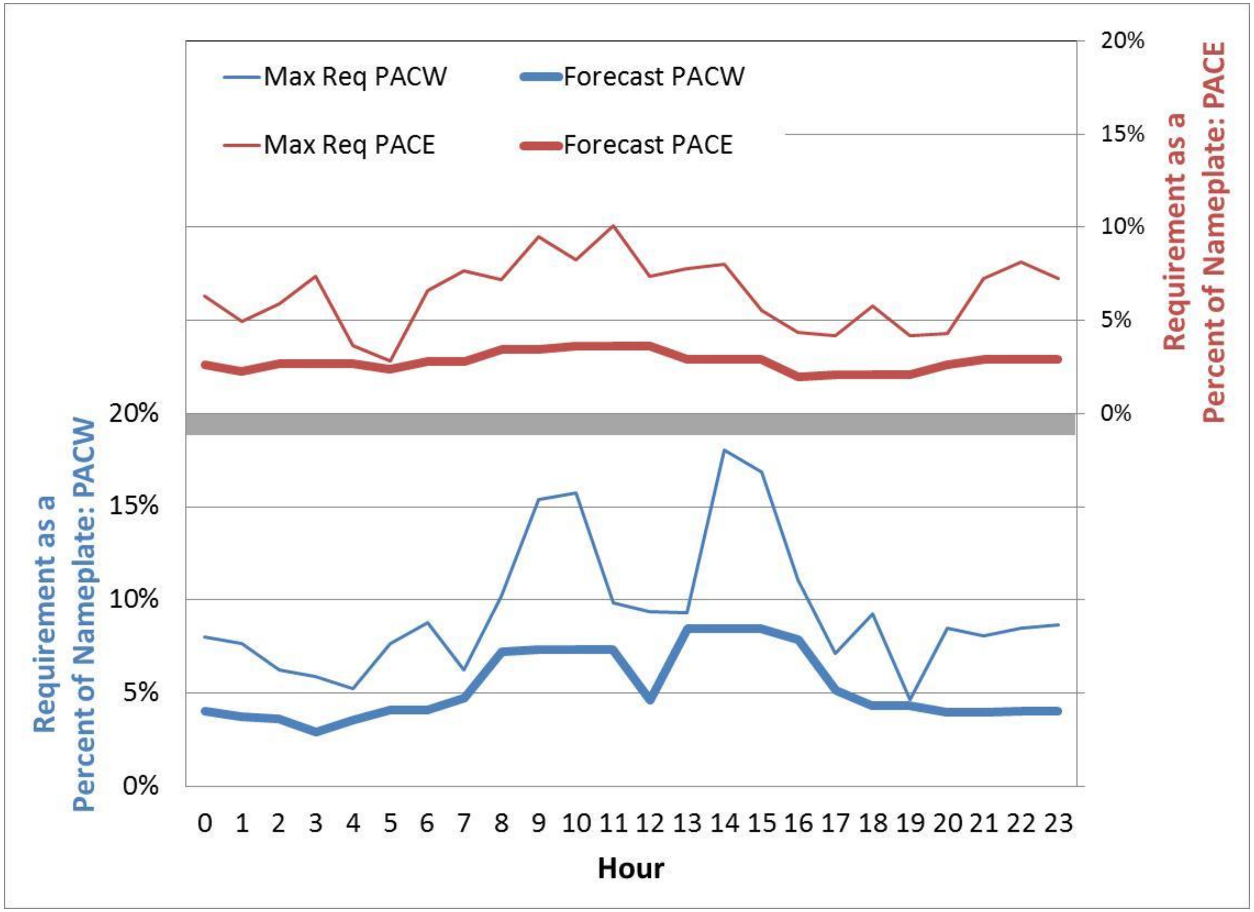
Non-VER Regulation Reserve (by output)



- Distribution of errors appears to be essentially random – not a good driver for forecasting.
- Forecast: fixed percentage of nameplate in all hours that hits reliability target
- Stand-alone non-VER requirement is 89 aMW, or 4.0% of nameplate capacity.

Values are preliminary and subject to change

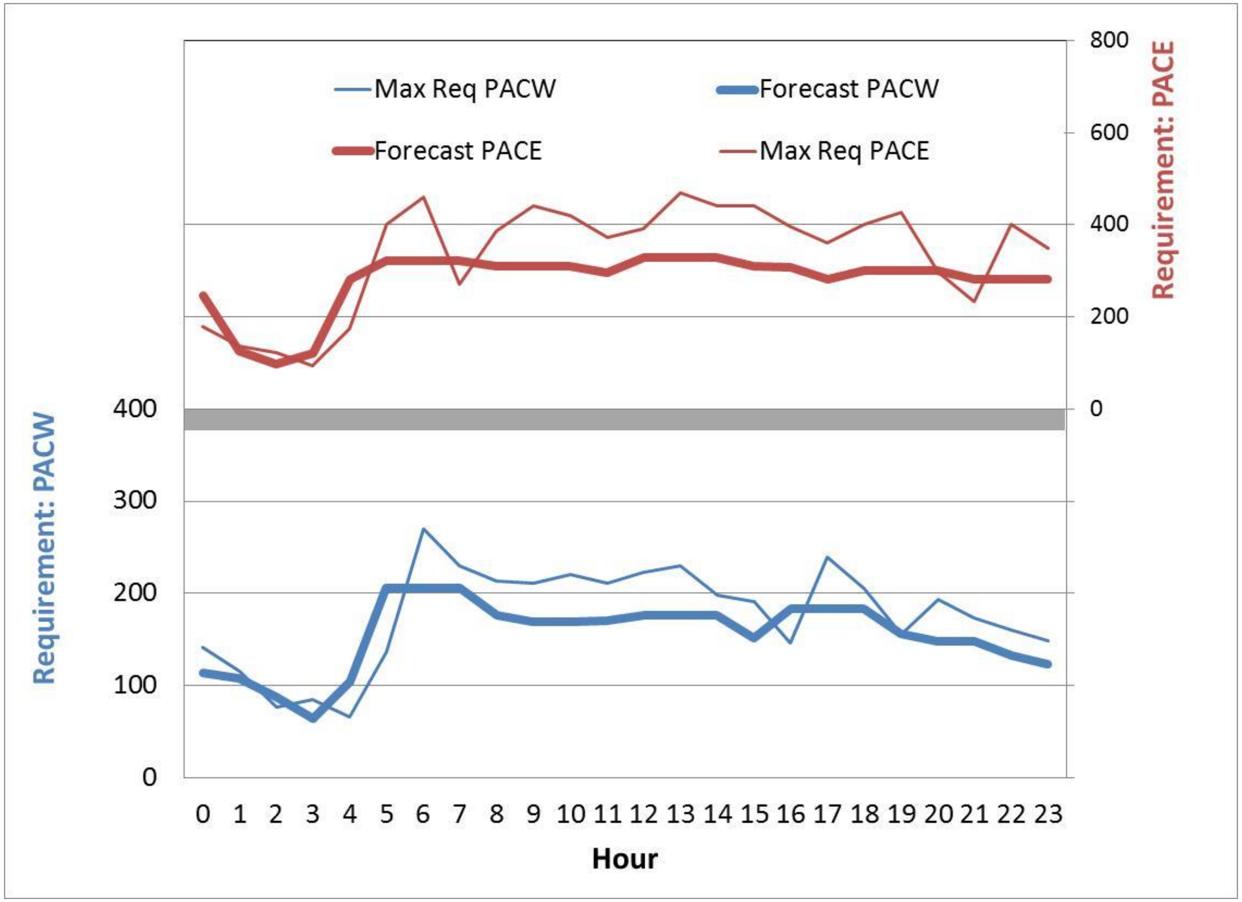
Non-VER Regulation Reserve (by hour)



- Forecast: three-hour rolling maximum, less fixed percentage to hit reliability target.
- Stand-alone non-VER requirement is 83 aMW, or 3.7% of nameplate capacity.
- This more accurate forecast by hour will be used.

Values are preliminary and subject to change

Load Regulation Reserve (by hour)



- Forecast: three-hour rolling maximum, less fixed percentage to hit reliability target.
- Stand-alone non-VER requirement is 433 aMW, or 4.4% of 12CP.

PacifiCorp System-Wide Portfolio Regulation Reserve

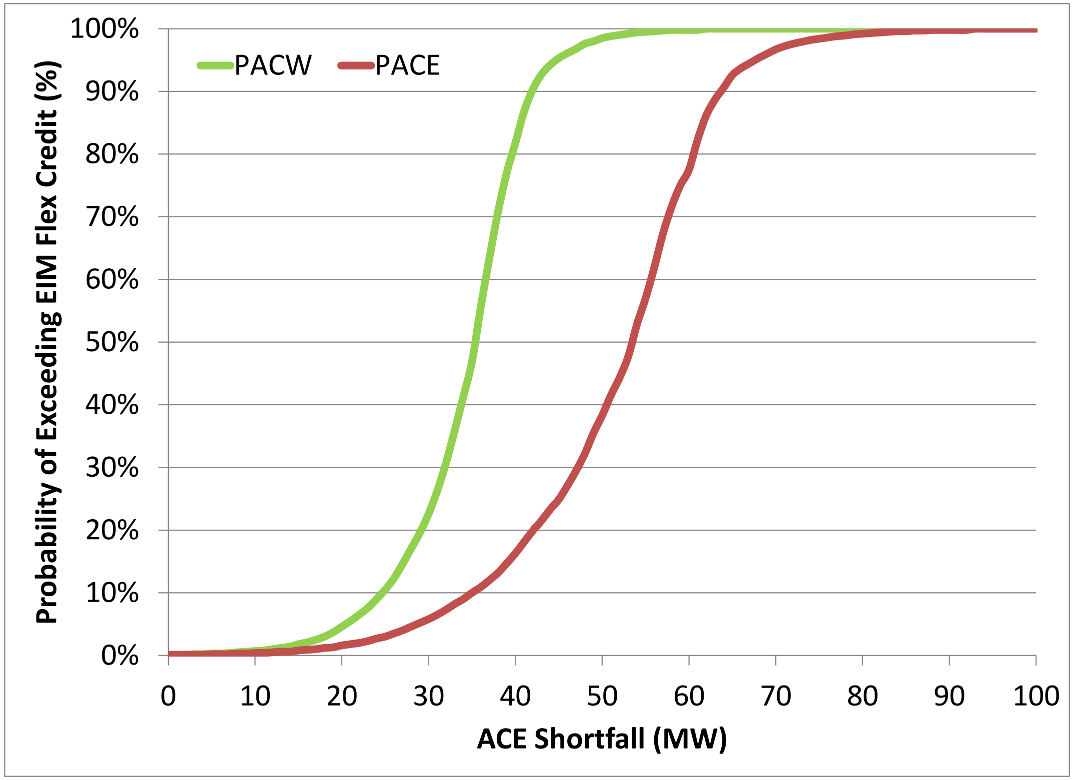
Scenario	Stand-alone Regulation Forecast (aMW)	Diversity Benefit (aMW)	Portfolio Regulation Forecast (aMW)
Non-VER	83	23	60
Load	433	118	315
VER - Wind	384	105	279
Total	900	246	654
Portfolio LOLP (hours/year)	0.03		0.88

- When considered as a combined portfolio, the stand-alone forecast results in an LOLP of 0.03 hours per year, significantly better than the target of 0.88 hours per year.
- This is a result of the diversity between the different classes, as the largest deviations in each class are infrequent and tend not to occur simultaneously.
- Regulation Reserve Forecast: the sum of the stand-alone requirements for Non-VER, Load, and VER, less a fixed percentage calculated to just achieve the reliability target.
- A total portfolio requirement of 654 MW is sufficient to achieve the reliability target of 0.88 hours per year, reflecting a 27% reduction in the regulation reserve requirement from the stand-alone forecast.

Values are preliminary and subject to change

EIM Flexibility Reserve Diversity

- Each participating BAA must pass certain CAISO tests to ensure they are not "leaning" on other participants.
- CAISO's flexible capacity test includes a flexible reserve diversity credit which allocates the diversity of the combined EIM footprint to each BAA.
- CAISO's flexible capacity definition is not the same as the BAL-001-2 requirement.
  - 15-minute duration
  - < 100% compliance



- The flex credit is not known when base schedules are submitted.
- Despite those limitations, PacifiCorp proposes including the distribution of flexibility reserve diversity credits in the reserve requirement – comparable to the BAAL.
- Participation of NV Energy in EIM increases diversity. Credits are calculated based on data from Jan. 1, 2016-Jun. 1, 2016 to capture that extra diversity.

Values are preliminary and subject to change

PacifiCorp System-Wide Results with EIM

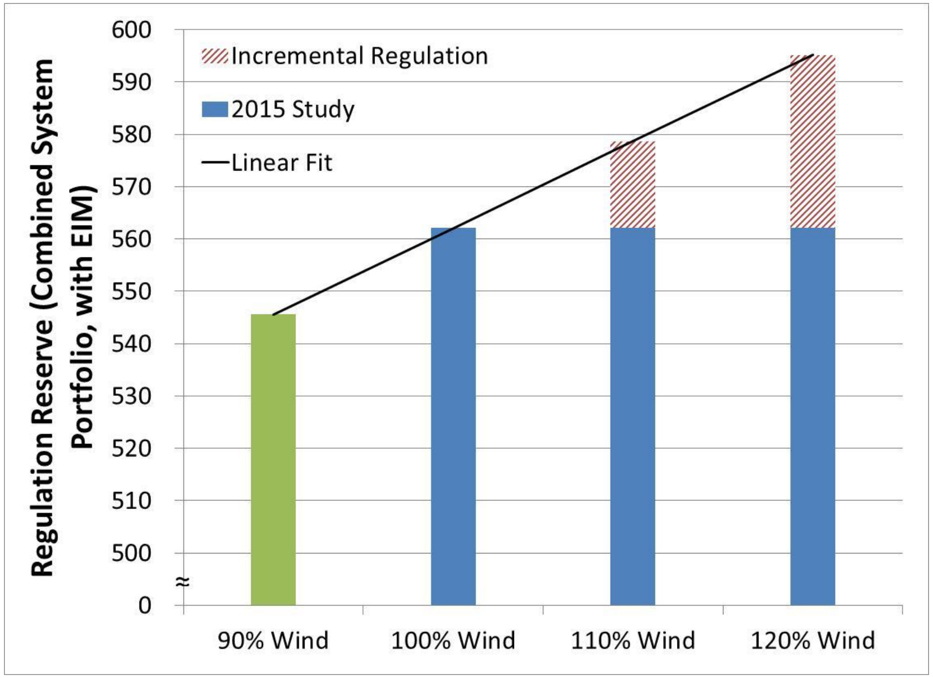
Scenario	Stand-alone Regulation Forecast (aMW)	Stand-alone Rate (%)	Portfolio Regulation Forecast with EIM (aMW)	Portfolio Rate with EIM (%)	2015 Capacity (MW)	Rate Determinant
Non-VER	83	3.7%	52	2.3%	2,228	Nameplate
Load	433	4.5%	271	2.8%	9,696	12 CP
VER - Wind	384	14.8%	240	9.2%	2,588	Nameplate
Total	900		562			
Portfolio LOLP (hours/year)	0.03		0.88			
Diversity Savings (%)			38%			

- When the EIM diversity credited is included, a total portfolio requirement of 562 MW is sufficient to achieve the reliability target of 0.88 hours per year, reflecting a 38% reduction in the regulation reserve requirement from the stand-alone forecast.
- EIM diversity reduces the regulation requirement by 92 aMW versus the total portfolio requirement without EIM.
- The stand-alone rate for each class is reduced by 38%.

Values are preliminary and subject to change

Incremental Wind Regulation Reserve

- PacifiCorp system-wide results were recalculated using only 90% of the available wind resources, removing approximately 10% of capacity from each geographic location.
- Regulation reserve requirements dropped by 6.1% of the wind capacity removed.
- This is lower than the average requirement of 9.2% in the base results due to increasing diversity from the larger pool of requirements.



- Incremental reserve requirements are assumed to increase by 6.1MW for each 100MW of wind capacity over that included in the base study.
- Incremental reserve costs are higher than average costs as they call on increasingly more expensive resources.

Values are preliminary and subject to change

Solar Regulation Reserve

- Solar resources create incremental regulation reserve requirements during periods of solar generation (i.e. daytime).
- The larger pool of requirements during the daytime creates additional opportunities for diversity benefits.
- The PacifiCorp system had extremely limited utility-scale solar generation in 2015.
- During 2016, utility-scale solar generation is expected to exceed 1,000 MW.
- Five-minute solar data is available from Jan. 1, 2016 through Jun. 30th, 2016 for two large solar resources totaling 130 MW.
- The distribution of the deviations by these two solar projects, and the correlation between them, will be used to develop solar deviations for 1,000 MW and 1,250 MW of solar capacity, representing PacifiCorp's expected solar in 2017 and incremental capacity under consideration in the IRP, respectively.
- The correlation of the solar deviations to load, wind, and non-VER deviations will also be assessed to help ensure the extrapolated results reflect realistic levels of diversity.
- The 2015 results will be adjusted to incorporate the assumed solar deviations at the two capacity levels.
- The incremental reserve requirement from the 1,000 MW solar case to the 1,250 MW solar case will be applicable to solar resource additions.
- The cost of solar regulation reserve for resource additions in the 2017 IRP will be calculated based on the incremental reserve requirement as described above and the incremental cost of that requirements.

Values are preliminary and subject to change

Regulation Reserve Cost

Regulation Reserve PaR Scenarios

#	Scenario	Resources	Regulation Requirement
B.1	Base No Reserve	Jan. 1, 2017 levels of wind and solar	None
B.2	Base With Reserve	Jan. 1, 2017 levels of wind and solar	Requirements for 1/1/17 wind and solar
W.1	Incremental Wind, Base Reserve	Study B.2 + 250MW of wind capacity	Requirements for 1/1/17 wind and solar
W.2	Incremental Wind+Reserve	Study B.2 + 250MW of wind capacity	Study B.2 + Reserve for additional 250MW wind capacity
S.1	Incremental Solar, Base Reserve	Study B.2 + 250MW of solar capacity	Requirements for 1/1/17 wind and solar
S.2	Incremental Solar+Reserve	Study B.2 + 250MW of solar capacity	Study B.2 + Reserve for additional 250MW solar capacity

Cost calculations [shown for wind, others are analogous]

#	Value	Calculation	Units
a	Base regulation reserve cost	[Study B.2] - [Study B.1]	$
b	Wind reserve requirement	[Stand-alone forecast] * [Diversity]	MWh
c	Wind generation	[Study B.1]	MWh
d	**Base wind reserve rate**	[a] x [b] / [c]	$/MWh
a'	Incremental regulation reserve cost	[Study W.2] - [Study W.1]	$
b'	Incremental wind reserve requirement	[Study W.2] - [Study W.1]	MWh
c'	Incremental wind generation	[Study W.1] - [Study B.1]	MWh
d'	**Incremental wind reserve rate**	[a'] x [b'] / [c']	$/MWh

- Because diversity is a result of the combined portfolio, the average cost per megawatt-hour of reserve in a given hour is identical for each class, though reserve volume varies.
- Reserve volumes and costs vary based on time of day, season, and other system conditions, resulting in different overall costs for each class.
- The cost of wind and solar resource additions in the 2017 IRP will be calculated based on the incremental reserve requirement and the associated incremental cost.

System Balancing Cost

System Balancing Cost Runs

Study	Forward Term	Load	Wind Profile	Solar Profile	Incremental Reserve	Commitment	Day-ahead Forecast Error
1	2017	Day-ahead Forecast	Day-ahead Forecast	Day-ahead Forecast	Yes	Study 1	n/a
2	2017	Actual	Actual	Actual	Yes	Study 2	None
3	2017	Actual	Actual	Actual	Yes	***Study 1***	For Load/Wind/Solar
4	2017	Day-ahead Forecast	Actual	Actual	Yes	Study 4	n/a
5	2017	Actual	Day-ahead Forecast	Actual	Yes	Study 5	n/a
6	2017	Actual	Actual	Day-ahead Forecast	Yes	Study 6	n/a
7	2017	Actual	Actual	Actual	Yes	***Study 4***	For Load
8	2017	Actual	Actual	Actual	Yes	***Study 5***	For Wind
9	2017	Actual	Actual	Actual	Yes	***Study 6***	For Solar

	Cost Calculations	Cost ($)	Cost ($/MWh)
a	Total Day-ahead Forecast Cost	[Study 3] - [Study 2]	
b	Load Only Day-ahead Forecast Cost	[Study 7] - [Study 2]	[b] * ([a] / [e]) / [Actual Load Volume]
c	Wind Only Day-ahead Forecast Cost	[Study 8] - [Study 2]	[c] * ([a] / [e]) / [Actual Wind Volume]
d	Solar Only Day-ahead Forecast Cost	[Study 9] - [Study 2]	[d] * ([a] / [e]) / [Actual Solar Volume]
e	Total One-off Day-ahead Forecast Cost	[b] + [c] + [d]	

- The System Balancing Cost methodology is essentially the same as in the 2014 Wind Integration Study, measuring the additional costs from gas plant commitment based on day-ahead forecasts rather than actual requirements.
- The impact of day-ahead forecast error for solar has been added.
- To simplify the results, the total system balancing cost is calculated and allocated between load, wind, and solar based on one-off studies for each.

Values are preliminary and subject to change

Comparison to Prior Results

Regulation Reserve as a % of Capacity

Study	Period	Load %	Wind %	Non-VER %	Method
2012 WIS	2011	3.9%	8.7%	-	Load+Incremental Wind
2014 WIS	2012	4.0%	8.1%	-	Load+Incremental Wind
2014 WIS	2013	4.4%	7.3%	-	Load+Incremental Wind
2016 Flex	2015	2.8%	9.3%	2.3%	2015 Portfolio Diversity
2016 Flex	2015	-	6.1%	-	2015 Portfolio+Future Wind

Background

- Requirements generally decrease as more components are added, because of diversity.
- Diversity benefits are handled differently from previous studies
- The 2012 and 2014 Wind Integration Studies calculated the regulation reserve requirement for load only, then the incremental requirement for the entire wind fleet, allocating all diversity to wind.
- The 2016 Flexible Capacity Requirement Study calculates the regulation reserve requirement for the 2015 portfolio, allocating the diversity to all components. Incremental requirements were also calculated for future wind additions.

Results

- Load was not credited with any diversity in the prior studies: its requirements decrease.
- Wind received the whole diversity credit in the prior studies: its requirements increase.
- Incremental wind requirements are lower than the 2015 portfolio average, and lower than the prior studies, reflecting the greater diversity in the larger portfolio.

Values are preliminary and subject to change

Next Steps

- Finalize solar data
- Calculate wind and solar integration costs
- Present results at the next public input meeting
- Working with the Technical Review Committee on review of study and results:
  - October 3, 2016 – Conference call with TRC
  - TRC Members:
    - Andrea Coon, Director, Western Renewable Energy Generation Information System for the Western Electricity Coordinating Council
    - Michael Milligan – Lead researcher for the Transmission and Grid Integration Team at the National Renewable Energy Laboratory
    - J. Charles Smith – Executive Director, Utility Variable Generation Integration Group
    - Robert Zavadil – Executive Vice President of Power Systems Consulting, EnerNex





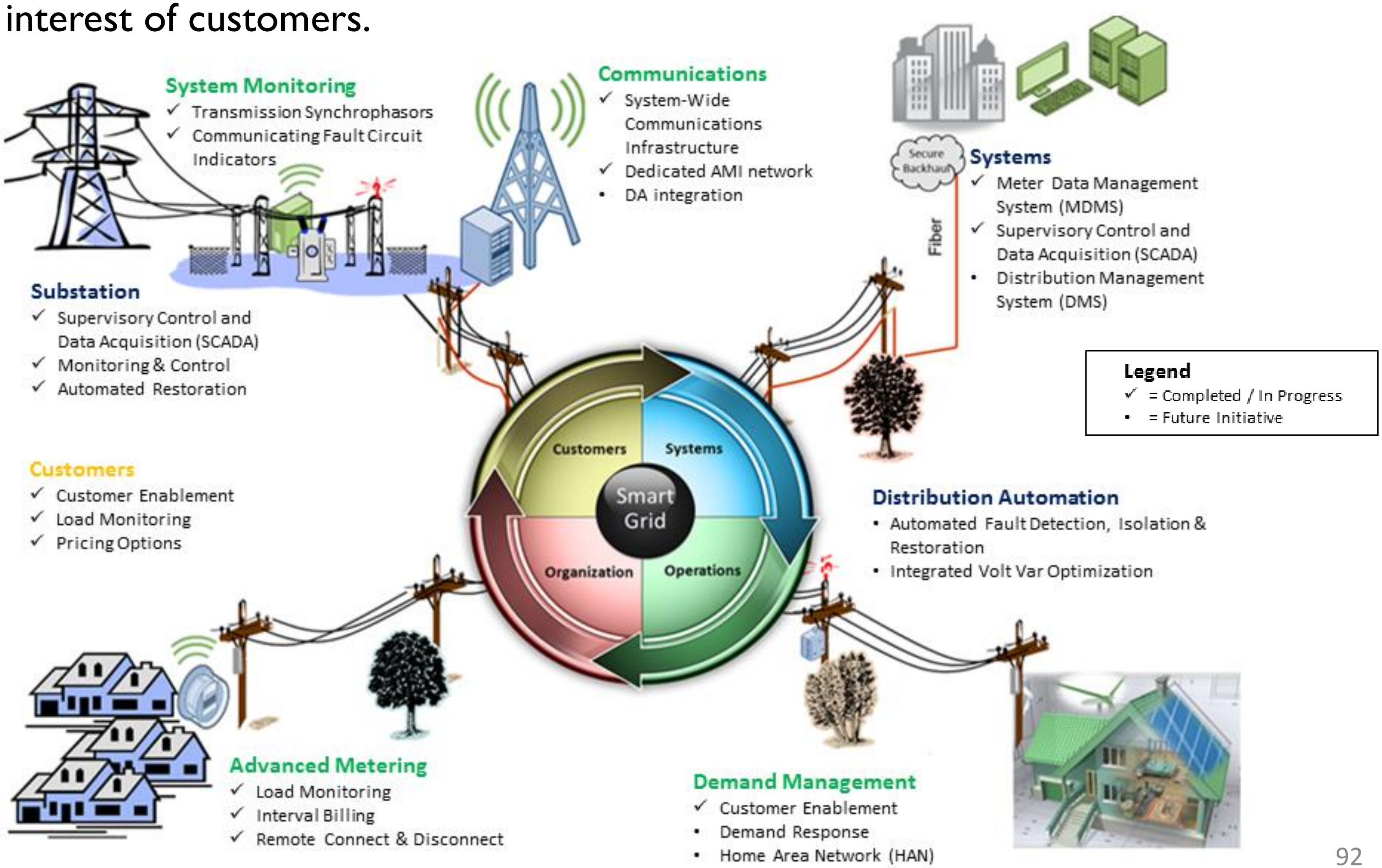
2017

Integrated Resource Plan

Smart Grid Update

PacifiCorp Smart Grid Objective

PacifiCorp seeks to leverage smart grid technologies that optimize the electrical grid when and where it is economically feasible, operationally beneficial, and in the best interest of customers.



PacifiCorp Smart Grid Strategy

PacifiCorp considers the following strategies necessary to realizing a smart grid:

- Ensure that smart grid investments provide service at reasonable and fair prices by comparing products and solutions in a financial model that highlights the most beneficial solution configurations.
- Institute cost-effective standards and equipment specifications that enable implementation of smart grid-compatible devices, either through retrofitting where appropriate or through replacement due to equipment obsolescence or failure.
- Provide customers with tools and understanding to change usage for their benefit.
- Leverage broad resources at our disposal including Berkshire Hathaway Energy, comprised of four investor-owned utilities, to benefit from existing analysis and work currently underway.
- Research industry projects and work with organizations in order to enhance PacifiCorp's understanding of smart grid technologies.

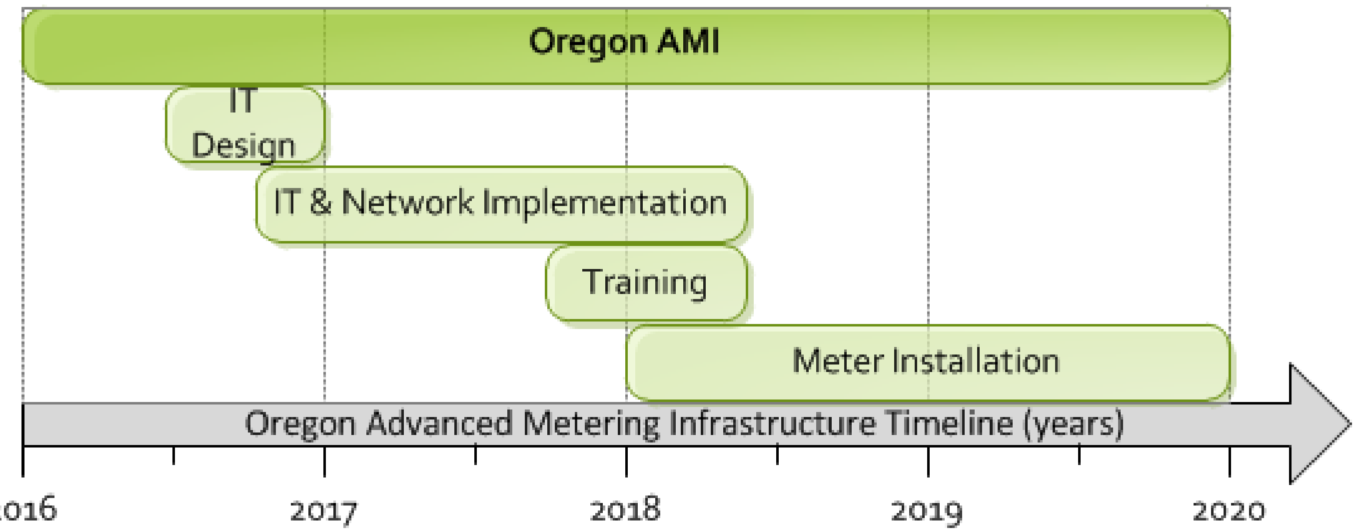
PacifiCorp Smart Grid Goals

- Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution systems
- Enhance customer service and lowering costs
- Enhance the ability to save energy and reduce peak demand
- Enhance the ability to develop renewable resources and distributed generation

Enhancing Customer Service and Lowering Costs

Oregon Advanced Metering Infrastructure (AMI)

- Pacific Power announced plans in April 2016 to install an AMI system in Oregon
- Benefits of AMI:
  - Improved customer service
    - Customer energy consumption information via web portal
    - Improved bill accuracy, fewer estimated bills
    - Improved response time for connection of service
  - Improved system operations efficiency
  - Provides the platform for future Smart Grid applications



Enhancing Customer Service and Lowering Costs

Dynamic line rating (DLR)

- Ongoing assessment of West-of-Populus line project
  - Inconclusive due to low line-loading
- Evaluation of thermal replicating relays
  - Grace-Soda 138 kV and Soda-Threemile Knoll 138 kV lines
  - Remedial Action Scheme deemed more cost-effective

Reliability, Safety, Security, Quality, and Efficiency

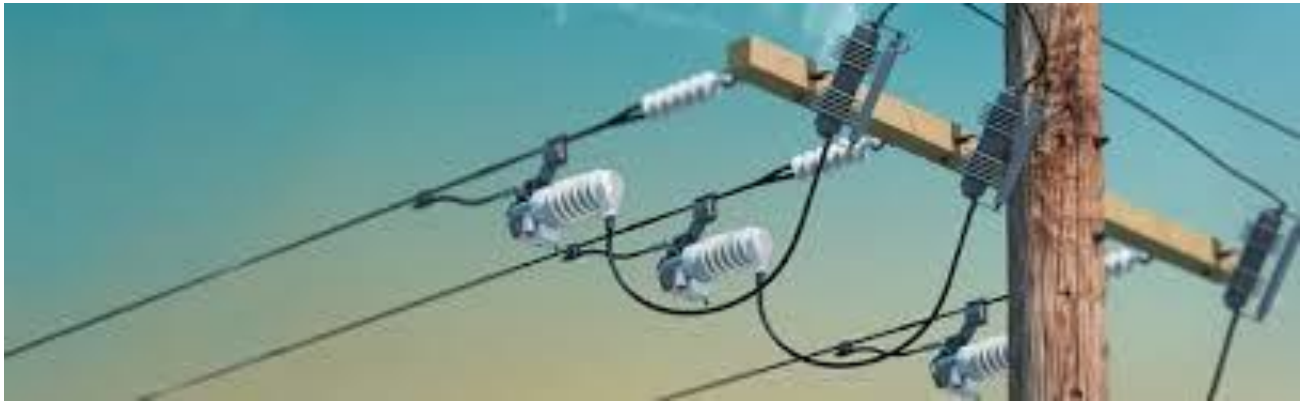
Transmission Synchrophasors

- Synchrophasor deployment to meet NERC MOD-33
  - Locations determined based on NERC PRC-002 criteria
- Evaluation of model validation
  - System data compared to planning dynamic model

Reliability, Safety, Security, Quality, and Efficiency

Deployment of equipment with progressive capability

- Installed 40+ Fuse Saving devices in Oregon and Washington
- Evaluation of recloser communications capability with AMI
- Stock items numbers for regulators with reverse flow controls
- Pilot program for distribution substation metering



FuseSaver Device – w3.Siemens.com

Reliability, Safety, Security, Quality, and Efficiency

Distribution automation and reliability

- Study of distribution automation potential in Oregon
  - Defined steps for preferred outcome
  - Determined criteria and requirements for location selection
  - Identified preliminary list of potential candidate sites
- Initiated pilot project in Walla Walla, WA
- Investigating feasibility of distribution automation with the Salt Lake City, UT airport reconstruction

Reliability, Safety, Security, Quality, and Efficiency

Centralized Energy Storage

- Potential use of Distributed Energy Resources (DER) to defer traditional solution
  - Transformer replacement project in Moab, Utah
  - Resulted in creation of DER alternatives template
- DER Alternatives Template
  - Created through cross-platform effort with Berkshire Hathaway Energy
  - Provides planning departments a screening tool to quickly identify system reinforcement projects with potential for DER solutions

Develop renewable resources and distributed generation

Distributed and renewable resource enhancements

- DER template for system reinforcement alternative solution
- Centralized Energy Storage
  - Oregon House Bill 2193 – 5 MWh storage requirement
  - Utah Senate Bill 115 – Sustainable Transportation and Energy Plan (STEP)
- Electric Vehicles
  - Oregon Senate Bill 1547 – Clean Electricity and Coal Transition Act
  - Utah Senate Bill 115 - STEP
- Smart inverters – IEEE 1547 and internal PacifiCorp policies
- CYME – Distribution Analysis Software

Develop renewable resources and distributed generation

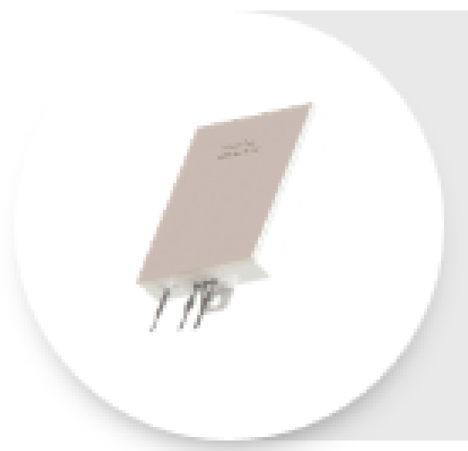
Distributed and renewable resource enhancements

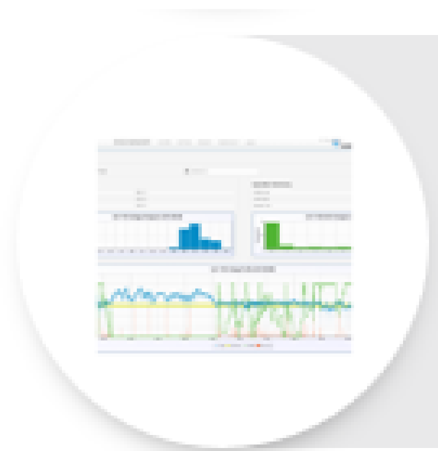
- Regulator controls with bi-directional functionality included in standards

Saving energy and reducing peak demand

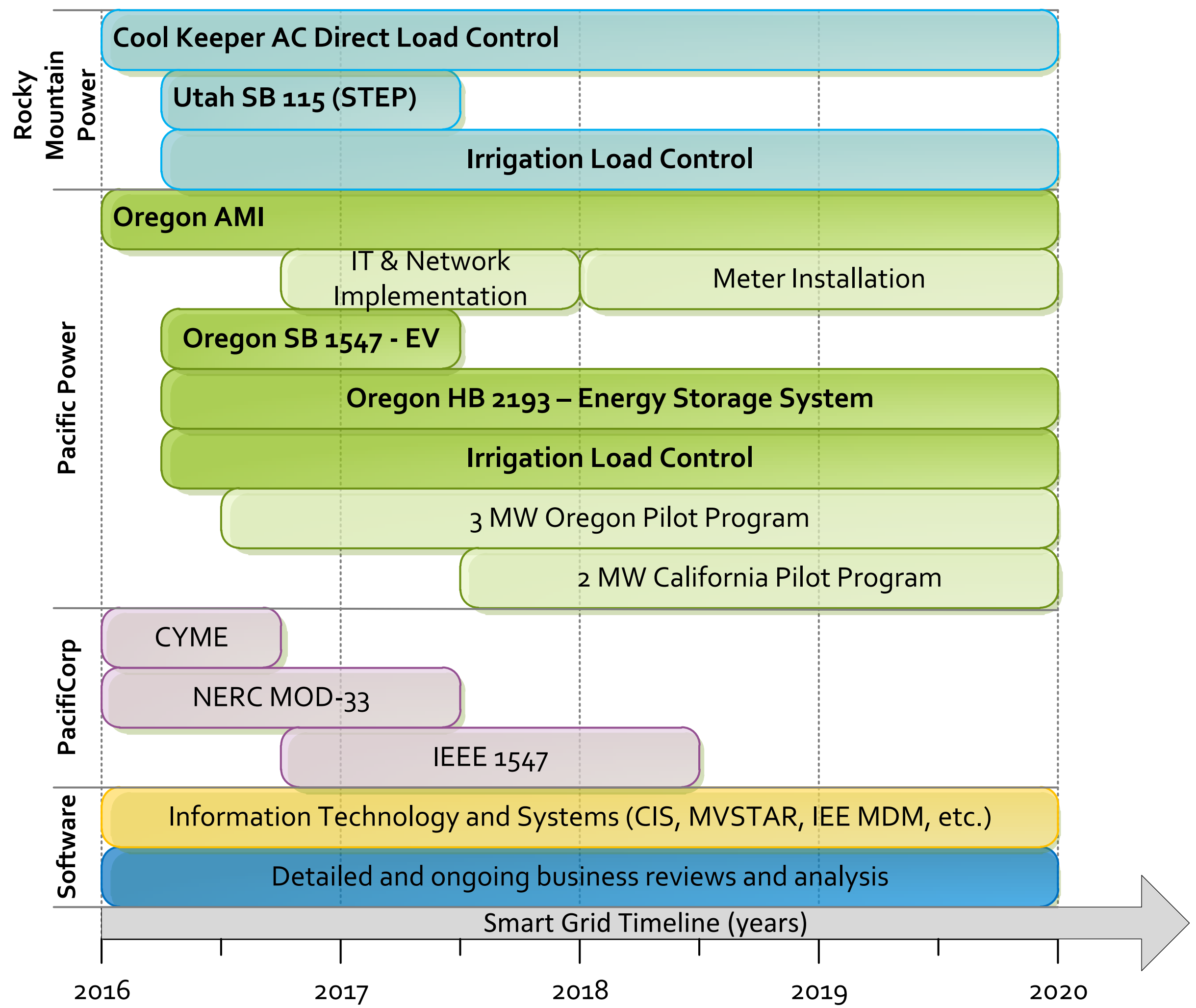
Demand Response

- Irrigation time-of-use (TOU) pilots in Oregon and California
- Irrigation direct load control pilot in Oregon and California
- Cool Keeper AC Direct Load Control in Utah





Smart Grid Road Map







2017 Integrated Resource Plan

Next Steps

Next Steps

- Next 2017 IRP Public Input Meeting
  - RESCHEDULED: October 20-21, 2016
  - NEW DATE: December 15-16, 2016
  - Topics:
    - Preliminary Volume III Studies and Portfolio Results
    - Capacity Contribution Results at Varying Solar Penetration Levels
    - Wind and Solar Integration Cost Results

Additional Information

- Meeting presentation and materials:
  http://www.pacificorp.com/es/irp.html
- 2017 IRP Stakeholder Feedback Form:
  http://www.pacificorp.com/es/irp/irpcomments.html
- Email / distribution list contact information:
  – IRP@PacifiCorp.com

- Upcoming Public Input Meeting Dates:
  – December 15-16, 2016
  – January 26-27, 2017
  – February 23-24, 2017