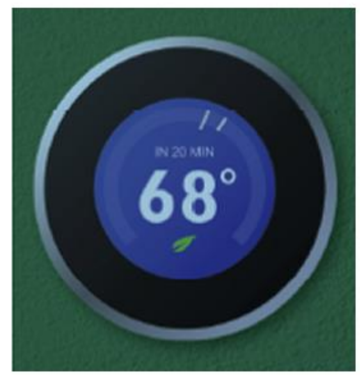
2019 Integrated Resource Plan (IRP) Public Input Meeting September 27-28, 2018



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Agenda

September 27 – Day One

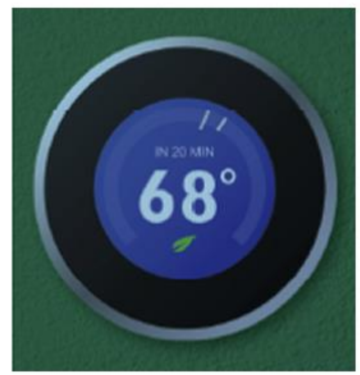
- 9:00am-10:30am pacific – Draft Supply-Side Resource Table
- 10:30am-11:30am pacific – Intra-Hour Flexible Resource Credit
- 11:30am-12:15pm pacific – Lunch Break
- 12:15pm-1:45pm pacific – Environmental Policy / Price-Policy Scenarios
- 1:45pm-2:00pm pacific – Break (if schedule allows)
- 2:00pm-3:30pm pacific – Transmission Overview and Updates
- 3:30pm-4:00pm pacific – Stakeholder Feedback Form Recap

September 28 – Day Two

- 8:30am-9:30am pacific – Flexible Reserve Study Cost Results
- 9:30am-11:15am pacific – Planning Reserve Margin / Capacity Contribution Results
- 11:15am-12:00pm pacific – Lunch Break
- 12:00pm–1:30pm pacific – Portfolios Discussion / Coal Studies Next Steps
- 1:30pm–2:30pm pacific – Demand-Side Management T&D Credit / Conservation Potential Assessment
- 3:00pm-3:30pm pacific – Wrap-Up / Next Steps

Supply-Side Resources



Background

- Data sources
  - Third-party engineering studies (performance and cost estimates)
  - Recent projects & Request for Proposals
  - Engineer-Procure-Construct contractors
  - Original Equipment Manufacturers (OEMs)
  - Developers
- General assumptions
  - Mid-2018 dollars
  - Capacities and costs adjusted to “proxy site” elevations and general locations
  - Capital costs based on “greenfield” sites for gas-fueled resources
  - Capital costs include:
    - Direct: costs: Engineering-Procure-Construct (EPC) costs to in-service year; include applicable sales taxes, insurance and contractor’s contingency
    - Owner’s costs: Development, permitting, project management/engineering, water, “outside the fence” linears, land, legal costs, interconnection, capital spares and owner’s contingency
    - Owner’s financial costs: Allowance for Funds Used During Construction (AFUDC), capital surcharge and capitalized property taxes

Renewable Resources

SSR Table Improvements

- Supply-Side Resources (SSR) table changes since 2017 IRP cycle
    - Combined studies for renewable resources into a single study
    - Added combined solar + storage and wind + storage projects
    - Added rows in the table for a wide variety of energy storage options
- Trends
    - Forecasts indicate costs for solar, wind and energy storage will continue to decline
    - New legislation may add value to energy storage systems
        - Federal Energy Regulatory Commission (FERC) Orders 841 and 842
        - Internal Revenue Service (IRS) Investment Tax Credit (ITC) guidance

Renewables Combined Study

- Burns & McDonnell is providing a single study of following renewable resources:
  - Solar
  - Wind
  - Energy Storage
  - Solar + Energy Storage
  - Wind + Energy Storage
- The report includes
  - Current capital and O&M costs
  - (10) year forecast trend of expected capital costs
  - Performance data

Renewable Resources

Performance and Cost Summary (2018$)

Description		Resource Characteristics			Costs		
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)
Solar	Idaho Falls, ID, 50 MW, CF: 28.1%	4,700	50	25	1,366	0.00	21.72
Solar	Idaho Falls, ID, 200 MW, CF: 28.1%	4,700	200	25	1,271	0.00	21.72
Solar	Lakeview, OR, 50 MW, CF: 29.7%	4,800	50	25	1,424	0.00	22.35
Solar	Lakeview, OR, 200 MW, CF: 29.7%	4,800	200	25	1,329	0.00	22.35
Solar	Milford, UT, 50 MW, CF: 32.5%	5,000	50	25	1,363	0.00	22.32
Solar	Milford, UT, 200 MW, CF: 32.5%	5,000	200	25	1,268	0.00	22.32
Solar	Rock Springs, WY, 50 MW, CF: 30.1%	6,400	50	25	1,360	0.00	21.13
Solar	Rock Springs, WY, 200 MW, CF: 30.1%	6,400	200	25	1,266	0.00	21.13
Solar	Yakima, WA, 50 MW, CF: 26.0%	1,000	50	25	1,422	0.00	22.35
Solar	Yakima, WA, 200 MW, CF: 26.0%	1,000	200	25	1,327	0.00	22.35
Solar + Storage	Idaho Falls, ID, 50 MW + 10 MW X 20 MWh, CF: 28.1%	4,700	50	25	1,628	0.00	25.60
Solar + Storage	Idaho Falls, ID, 200 MW + 50 MW X 100 MWh, CF: 28.1%	4,700	200	25	1,470	0.00	25.56
Solar + Storage	Idaho Falls, ID, 50 MW + 10 MW X 40 MWh, CF: 28.1%	4,700	50	25	1,706	0.00	29.26
Solar + Storage	Idaho Falls, ID, 200 MW + 50 MW X 200 MWh, CF: 28.1%	4,700	200	25	1,543	0.00	29.52
Solar + Storage	Idaho Falls, ID, 50 MW + 10 MW X 80 MWh, CF: 28.1%	4,700	50	25	1,626	0.00	34.91
Solar + Storage	Idaho Falls, ID, 200 MW + 50 MW X 400 MWh, CF: 28.1%	4,700	200	25	1,467	0.00	35.92
Solar + Storage	Lakeview, OR, 50 MW + 10 MW X 20 MWh, CF: 29.7%	4,800	50	25	1,623	0.00	25.60
Solar + Storage	Lakeview, OR, 200 MW + 50 MW X 100 MWh, CF: 29.7%	4,800	200	25	1,464	0.00	25.56
Solar + Storage	Lakeview, OR, 50 MW + 10 MW X 40 MWh, CF: 29.7%	4,800	50	25	1,704	0.00	29.26
Solar + Storage	Lakeview, OR, 200 MW + 50 MW X 200 MWh, CF: 29.7%	4,800	200	25	1,541	0.00	29.52
Solar + Storage	Lakeview, OR, 50 MW + 10 MW X 80 MWh, CF: 29.7%	4,800	50	25	1,756	0.00	34.91
Solar + Storage	Lakeview, OR, 200 MW + 50 MW X 400 MWh, CF: 29.7%	4,800	200	25	1,614	0.00	35.92

Performance and Cost Summary (2018$)

(Solar + Storage continued)

Description		Resource Characteristics			Costs		
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)
Solar + Storage	Milford, UT, 50 MW + 10 MW X 20 MWh, CF: 32.5%	5,000	50	25	1,844	0.00	25.60
Solar + Storage	Milford, UT, 200 MW + 50 MW X 100 MWh, CF: 32.5%	5,000	200	25	1,699	0.00	25.56
Solar + Storage	Milford, UT 50 MW + 10 MW X 40 MWh, CF: 32.5%	5,000	50	25	1,754	0.00	29.26
Solar + Storage	Milford, UT, 200 MW + 50 MW X 200 MWh, CF: 32.5%	5,000	200	25	1,612	0.00	29.52
Solar + Storage	Milford, UT, 50 MW + 10 MW X 80 MWh, CF: 32.5%	5,000	50	25	1,751	0.00	34.91
Solar + Storage	Milford, UT, 200 MW + 50 MW X 400 MWh, CF: 32.5%	5,000	200	25	1,609	0.00	35.92
Solar + Storage	Rock Springs, WY, 50 MW + 10 MW X 20 MWh, CF: 30.1%	6,400	50	25	1,842	0.00	25.60
Solar + Storage	Rock Springs, WY, 200 MW + 50 MW X 100 MWh, CF: 30.1%	6,400	200	25	1,697	0.00	25.56
Solar + Storage	Rock Springs, WY, 50 MW + 10 MW X 40 MWh, CF: 30.1%	6,400	50	25	1,992	0.00	29.26
Solar + Storage	Rock Springs, WY, 200 MW + 50 MW X 200 MWh, CF: 30.1%	6,400	200	25	1,897	0.00	29.52
Solar + Storage	Rock Springs, WY, 50 MW + 10 MW X 80 MWh, CF: 30.1%	6,400	50	25	2,098	0.00	34.91
Solar + Storage	Rock Springs, WY, 200 MW + 50 MW X 400 MWh, CF: 30.1%	6,400	200	25	2,004	0.00	35.92
Solar + Storage	Yakima, WA, 50 MW + 10 MW X 20 MWh, CF: 26.0%	1,000	50	25	1,990	0.00	25.60
Solar + Storage	Yakima, WA, 200 MW + 50 MW X 100 MWh, CF: 26.0%	1,000	200	25	1,895	0.00	25.56
Solar + Storage	Yakima, WA, 50 MW + 10 MW X 40 MWh, CF: 26.0%	1,000	50	25	1,987	0.00	29.26
Solar + Storage	Yakima, WA, 200 MW + 50 MW X 200 MWh, CF: 26.0%	1,000	200	25	1,892	0.00	29.52
Solar + Storage	Yakima, WA, 50 MW + 10 MW X 80 MWh, CF: 26.0%	1,000	50	25	2,097	0.00	34.91
Solar + Storage	Yakima, WA, 200 MW + 50 MW X 400 MWh, CF: 26.0%	1,000	200	25	2,002	0.00	35.92

Performance and Cost Summary (2018$)

Description		Resource Characteristics			Costs		
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)
Wind	3.6 MW turbine 37.1% CF WA	4,500	200	30	1,354	0.00	27.99
Wind	3.6 MW turbine 37.1% CF OR	1,500	200	30	1,334	0.00	27.99
Wind	3.6 MW turbine 37.1% CF ID	4,500	200	30	1,358	0.00	27.99
Wind	3.6 MW turbine 29.5% CF UT	6,500	200	30	1,301	0.00	27.99
Wind	3.6 MW turbine 43.6% CF WY	1,500	200	30	1,301	0.65	27.99
Wind + Storage	Pocatello, ID, Storage: 50 MW | 100 MWh, CF: 37.1%	4,500	200	30	1,738	0.00	31.83
Wind + Storage	Arlington, OR, Storage: 50 MW | 100 MWh, CF: 37.1%	1,500	200	30	1,765	0.00	31.83
Wind + Storage	Monticello, UT, Storage: 50 MW | 100 MWh, CF: 29.5%	4,500	200	30	1,735	0.00	31.83
Wind + Storage	Medicine Bow, WY, Storage: 50 MW | 100 MWh, CF: 43.6%	6,500	200	30	1,730	0.00	31.83
Wind + Storage	Goldendale, WA, Storage: 50 MW | 100 MWh, CF: 37.1%	1,500	200	30	1,772	0.00	31.83
Wind + Storage	Pocatello, ID, Storage: 50 MW | 200 MWh, CF: 37.1%	4,500	200	30	1,880	0.00	35.16
Wind + Storage	Arlington, OR, Storage: 50 MW | 200 MWh, CF: 37.1%	1,500	200	30	1,917	0.00	35.16
Wind + Storage	Monticello, UT, Storage: 50 MW | 200 MWh, CF: 29.5%	4,500	200	30	1,877	0.00	35.16
Wind + Storage	Medicine Bow, WY, Storage: 50 MW | 200 MWh, CF: 43.6%	6,500	200	30	1,872	0.00	35.16
Wind + Storage	Goldendale, WA, Storage: 50 MW | 200 MWh, CF: 37.1%	1,500	200	30	1,924	0.00	35.16
Wind + Storage	Pocatello, ID, Storage: 50 MW | 400 MWh, CF: 37.1%	4,500	200	30	2,158	0.00	41.59
Wind + Storage	Arlington, OR, Storage: 50 MW | 400 MWh, CF: 37.1%	1,500	200	30	2,214	0.00	41.59
Wind + Storage	Monticello, UT, Storage: 50 MW | 400 MWh, CF: 29.5%	4,500	200	30	2,155	0.00	41.59
Wind + Storage	Medicine Bow, WY, Storage: 50 MW | 400 MWh, CF: 43.6%	6,500	200	30	2,150	0.00	41.59
Wind + Storage	Goldendale, WA, Storage: 50 MW | 400 MWh, CF: 37.1%	1,500	200	30	2,221	0.00	41.59

Performance and Cost Summary (2018$)

Description		Resource Characteristics			Costs		
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)
Storage	Swan Lake, 400 MW X 3,800 MWh	4,457	400.0	60	1,612	0.00	52.00
Storage	Goldendale, 1,200 MW X 16,800 MWh	500	1,200	60	1,751	0.00	12.50
Storage	Seminoe, 700 MW X 7,000 MWh	580	700	60	1,609	0.00	17.00
Storage	Flat Canyon, 300 MW X 1,800 MWh	6,359	300	60	1,842	0.00	17.00
Storage	Idaho PS1, 360 MW X 2,880 MWh	5,000	360	60	1,697	0.00	17.00
Storage	CAES, 320 MW X 15,360 MWh	4,600	320	30	1,992	0.00	7.01
Storage	Li-Ion 1 MW X 250 kWh		1	15	1,897	0.00	9.29
Storage	Li-Ion 1 MW X 2 MWh		1	15	2,098	0.00	34.56
Storage	Li-Ion 1 MW X 4 MWh		1	15	2,004	0.00	56.23
Storage	Li-Ion 1 MW X 8 MWh		1	15	1,990	0.00	94.09
Storage	Li-Ion 15 MW X 60 MWh		15	15	1,895	0.00	32.63
Storage	Flow 1 MW X 6 MWh		1	15	1,987	0.00	32.00

Photovoltaic Update

- Cost per kW versus cost of energy
- Costs are frequently reported on a $/kWp basis (i.e. the STC module rating)
- Cost per kW delivered on **AC basis** is a more accurate measure of cost; commonly quoted costs are typically per kWp (panel capacity, DC)
- The overall design impacts:
  - Capacity Factor
  - Levelized Cost of Energy (LCOE)
- Owner's costs need to be included in total cost

Solar PV Cost Breakdown

Cost Breakdown of a Single Axis Tracking 50 MW AC Photovoltaic Project in Utah			
Item	**Cost**	**Unit**	**Responsibility**
Modules	407	$/kW DC	EPC
Inverter & Transformer	49	$/kW DC	EPC
Racking	133	$/kW DC	EPC
Labor, Materials & BOP	191	$/kW DC	EPC
Project Indirect Costs	100	$/kW DC	EPC
Owner Costs and AFUDC	153	$/kW DC	Owner
Cost Subtotal	**1,033**	**$/kW DC**	
Conversion from DC to AC	1.32%		
Cost Total (AC basis)	**1,363**	**$/kW AC**	

Input Assumptions

- Capital cost estimates are based on 2018 Burns & McDonnell assumptions
- 3.6 MW wind turbines are used in the SSR for all states
- Proxy sites assume flat ground allowing for evenly spaced turbines
- Wind capacity factors vary by region
- Impact of any state sales taxes are included in the capital cost estimates

Energy Storage

Input Assumptions

- Capital cost estimates are based on 2018 Burns & McDonnell assumptions
- Solar + Storage and Wind + Storage assumed to be collocated using lithium ion batteries.
- Pumped Hydro and Compressed Air Energy Storage (CAES) use cost estimates from projects under development within PacifiCorp's territory.
- Battery systems are assumed to cycle once per day.

Input Assumptions

- Proxy elevations to reflect generic locations
  - 5,050’ is the base case (“reference case”) elevation
- Capital cost estimates for natural gas resources based on engineer-procure-construct (EPC) cost and performance study prepared by Black & Veatch (2018 study)
- O&M cost updates for natural gas resources based on information provided by original equipment manufacturers, internal budgets and costs (i.e. for labor and chemicals)

Design Basis & Owner's Cost Updates

- Design basis for gas-fueled resources is dry cooling
    - Wet cooling is an option for gas repowering at existing coal generating facilities
- Costs for gas resources are based on a "proxy" green-field basis to include project development activities, external linears (transmission interconnections), land and water. Note:
    - Actual development costs will be site specific
    - Costs for new gas resources at retired coal plant locations would not incur same level of costs as a green-field resource
    - Costs for additional gas resources at new green-field locations would not incur same level of costs as the initial green-field resource

Gas Resources

Market Changes

- Further development and deployment of flexible resources (both combined cycle and peaking facilities):
    - Fast startup times and ramp rates; greater flexibility
    - Decreased startup emissions
    - Lower minimum load capability while maintaining emissions compliance
    - Highly flexible resources such as those comprised of reciprocating engines or aero-derivative combustion turbines typically consist of multiple units.

Wartsila 18V50SG engines, 18 MW

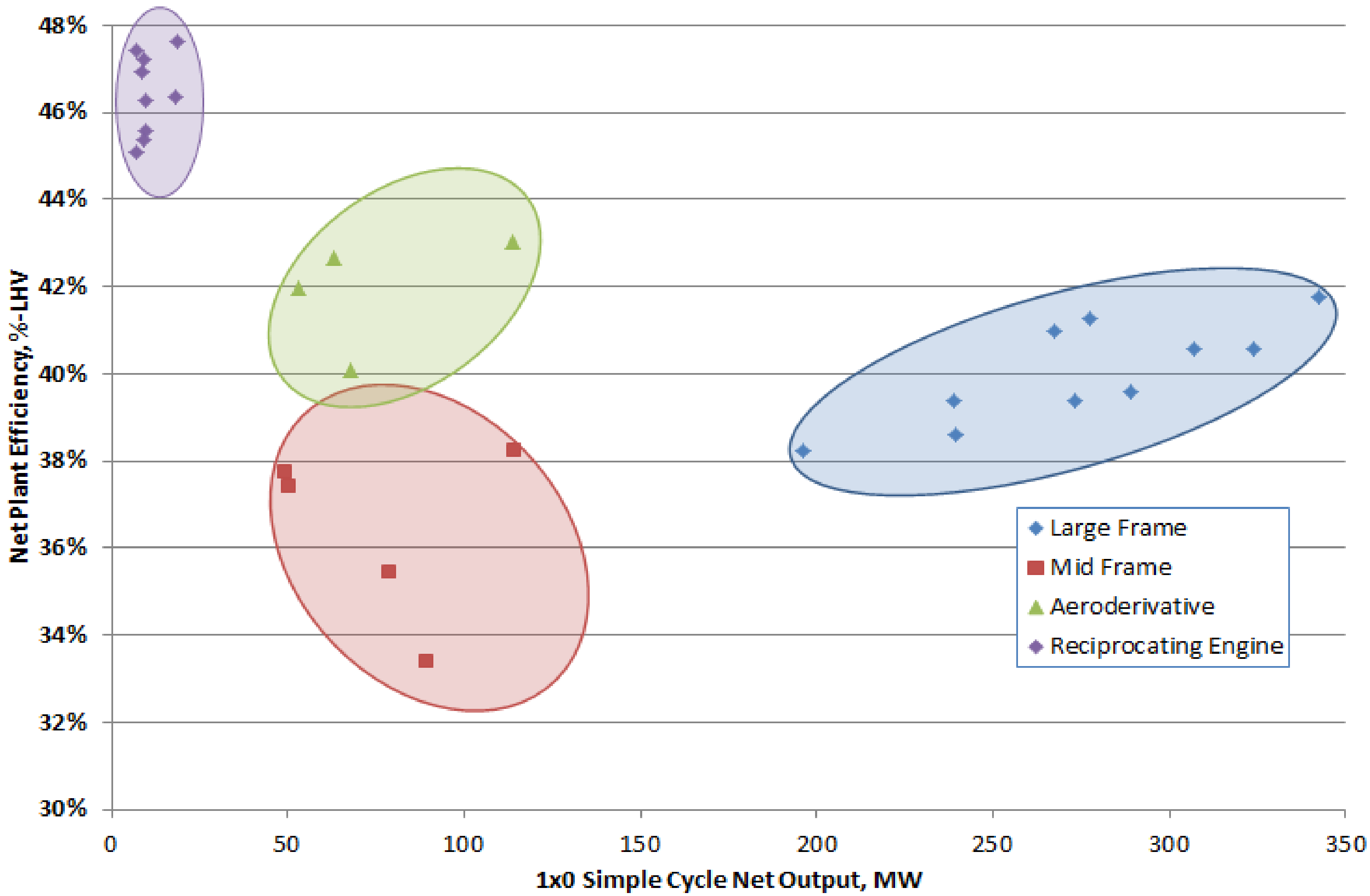
Gas Resources

Market Changes

- Multiple options on types of prime movers
  - Frame
  - Aero-derivative (may involve multiple units)
  - Reciprocating engines (involves multiple units)
- OEMs continue to improve their technologies resulting in improved efficiency, environmental performance, operating flexibility and scale

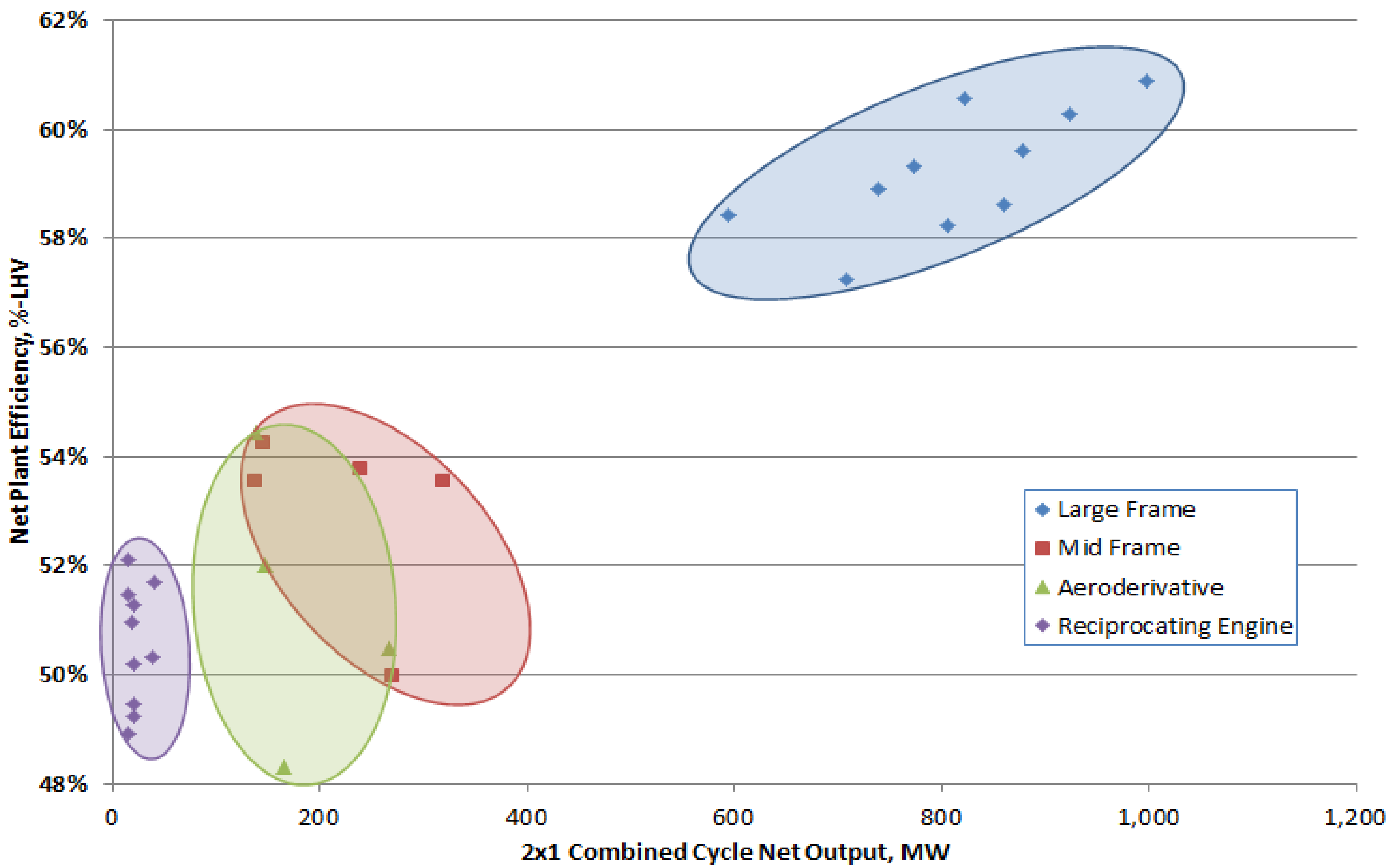
Gas Resources

Simple Cycle Market



"Technology Trends: Simple & Combined Cycle Units," Black & Veatch, January 2016

Combined Cycle Market



"Technology Trends: Simple & Combined Cycle Units," Black & Veatch, January 2016

Market Update

- Domestic gas-fueled power generation equipment sales over 2012-2018 period have been soft due a flat to declining electric loads, construction of renewables and uncertainty around EPA regulations

Brunswick County
Power Station
Dominion

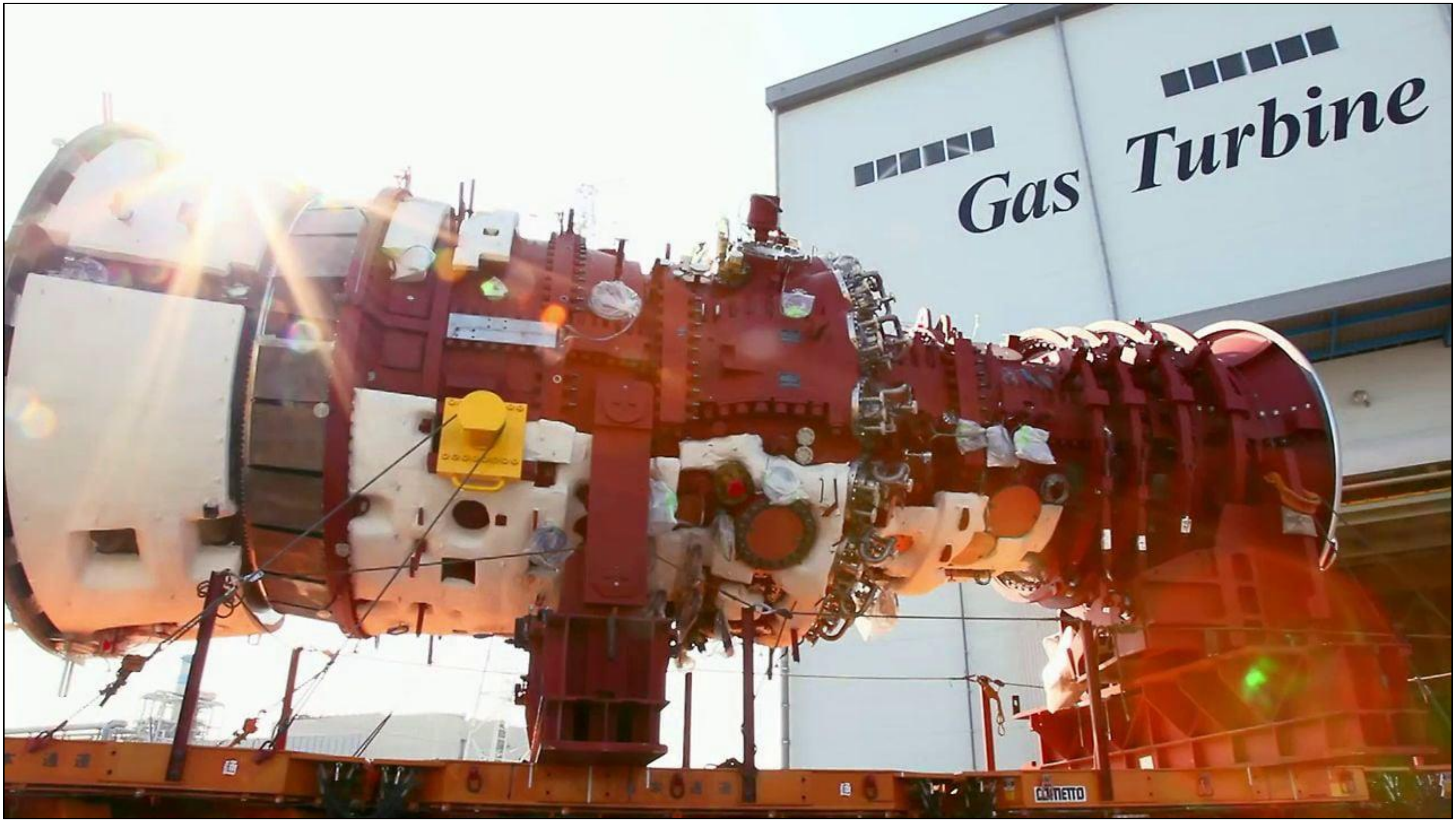
Engine "Classes" and Manufacturers

Class Designation	Manufacturer	Model	Simple Cycle, 1 Comb. Turbine, 0 Steam Turbines: Capacity (MW)	Simple Cycle: Efficiency	Combined Cycle, 1 Comb. Turbine, 1 Steam Turbine: Capacity (MW)	Combined Cycle: Efficiency
"J/HA.02" Class Engines						
"J/HA.02"	**General Electric**	**7HA.02**	337	41.4%	**501**	**61.7%**
	MHPS	M501J	327	41.0%	470	61.5%
"G and H" Class Engines						
"G/H"	**General Electric**	**7HA.01**	275	41.4%	**406**	**61.3%**
	Siemens	SGT6-8000H	296	40.0%	440	>60.0%
	MHPS	M501GAC	276	39.8%	412	59.5%
"F" Class Engines						
"F"	**General Electric**	**7F.05**	**231**	**39.5%**		
	Siemens	SGT6-5000F	242	39.0%		

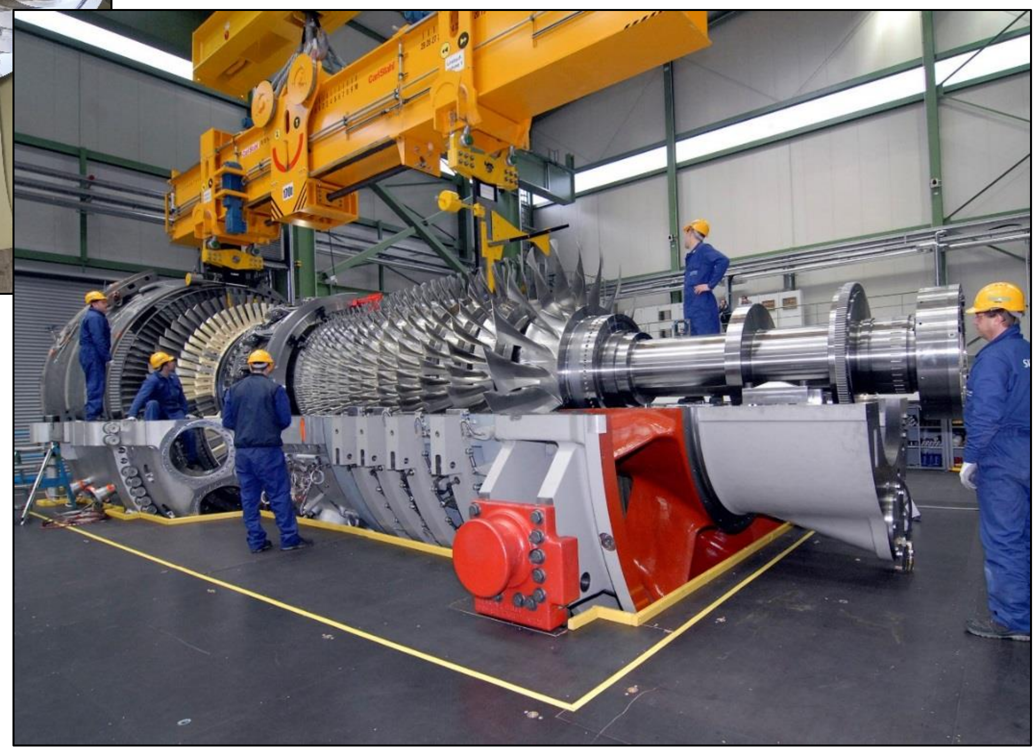
MHPS - Mitsubishi Hitachi Power Systems

Capacity and efficiency from Gas Turbine World 2015 Performance Specs 31st Edition

MHPS M501J – 327 MW



Siemens SGT5-8000H – 297 MW

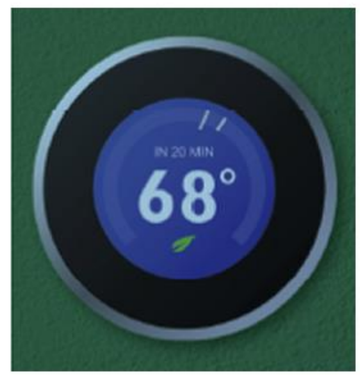


Gas Resources

Performance and Cost (2018$)

Resource	Elevation (AFSL)	Net Capacity (MW)	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency
SCCT Aero x3	5,050	122	30	1,619	8.85	31.86	9,229
Intercooled SCCT Aero x2	5,050	194	30	1,155	6.14	22.82	8,680
SCCT Frame "F" x1	5,050	194	35	747	6.61	15.97	9,805
IC Recips x 6	5,050	111	35	1,430	7.45	29.82	8,280
CCCT Dry "G/H", 1x1	5,050	344	40	1,582	2.12	24.74	6,510
CCCT Dry "G/H", DF, 1x1	5,050	51	40	423	0.15	5.39	6,510
CCCT Dry "G/H", 2x1	5,050	687	40	1,122	2.01	16.63	6,520
CCCT Dry "G/H", DF, 2x1	5,050	102	40	315	0.16	4.44	6,520
CCCT Dry "J/HA.02", 1x1	5,050	442	40	1,314	2.05	21.26	6,464
CCCT Dry "J/HA.02", DF, 1x1	5,050	63	40	361	0.16	4.86	6,464
CCCT Dry, "J/HA.02" 2X1	5,050	884	40	934	1.95	14.45	6,469
CCCT Dry "J/HA.02", DF, 2X1	5,050	126	40	273	0.16	4.05	6,469

Intra-Hour
Flexible Resource Credit



Intra-Hour Flexible Resource Credit

- To operate the system reliably, PacifiCorp must have the capability to move its resources within the hour to manage variations in load, solar and wind resources.
- The intra-hour flexible resource credit accounts for the value dispatchable resources provide through their participation in EIM.
- PacifiCorp has calculated intra-hour flexible resource credits applicable to resources that participate in EIM, based on historical data from the twelve months ending June 2018.
- Credits are expressed in $/kw-year, based on nameplate capacity.
  - **Baseload Steam**, **Peak Steam**, and **CCCT resources** reflect the historical results for those types.
  - **Proxy gas peaking resources** in the supply-side table have a range of operational parameters – specific values have been developed for each.
  - **Wind and solar resources** that can be curtailed can create value when prices drop below their marginal cost – either $0/MWh or the cost of a lost production tax credit.
  - **Energy storage resources** have significant flexibility, both up and down, and have the highest values
  - **Wind or solar with energy storage resources** have additional interactions between their generation and storage components

Intra-Hour Flexible Resource Credit

- Determination of Intra-Hour Flexible Resource Credit Components:
  - $Base = PacifiCorp's\ Hourly\ Base\ Schedule$
  - $D_{15} = EIM's\ Fifteen\ Minute\ Advisory\ Schedule$
  - $D_5 = EIM's\ Five\ Minute\ Dispatch\ Schedule$
  - $P_{15} = EIM's\ Fifteen\ Minute\ Market\ Price$
  - $P_5 = EIM's\ Five\ Minute\ Market\ Price$
  - $Bid = PacifiCorp's\ Cost\ of\ Generation$

$$Intra - Hour\ Flexible\ Resource\ Credit = (D_{15} - Base) * P_{15} + (D_5 - D_{15}) * P_5 - (D_5 - Base) * Bid$$

- Results for existing participating resources:

$/kw-year	Credit
BASELOAD STEAM	**5.54**
CCCT	**3.77**
PEAK STEAM	**4.89**

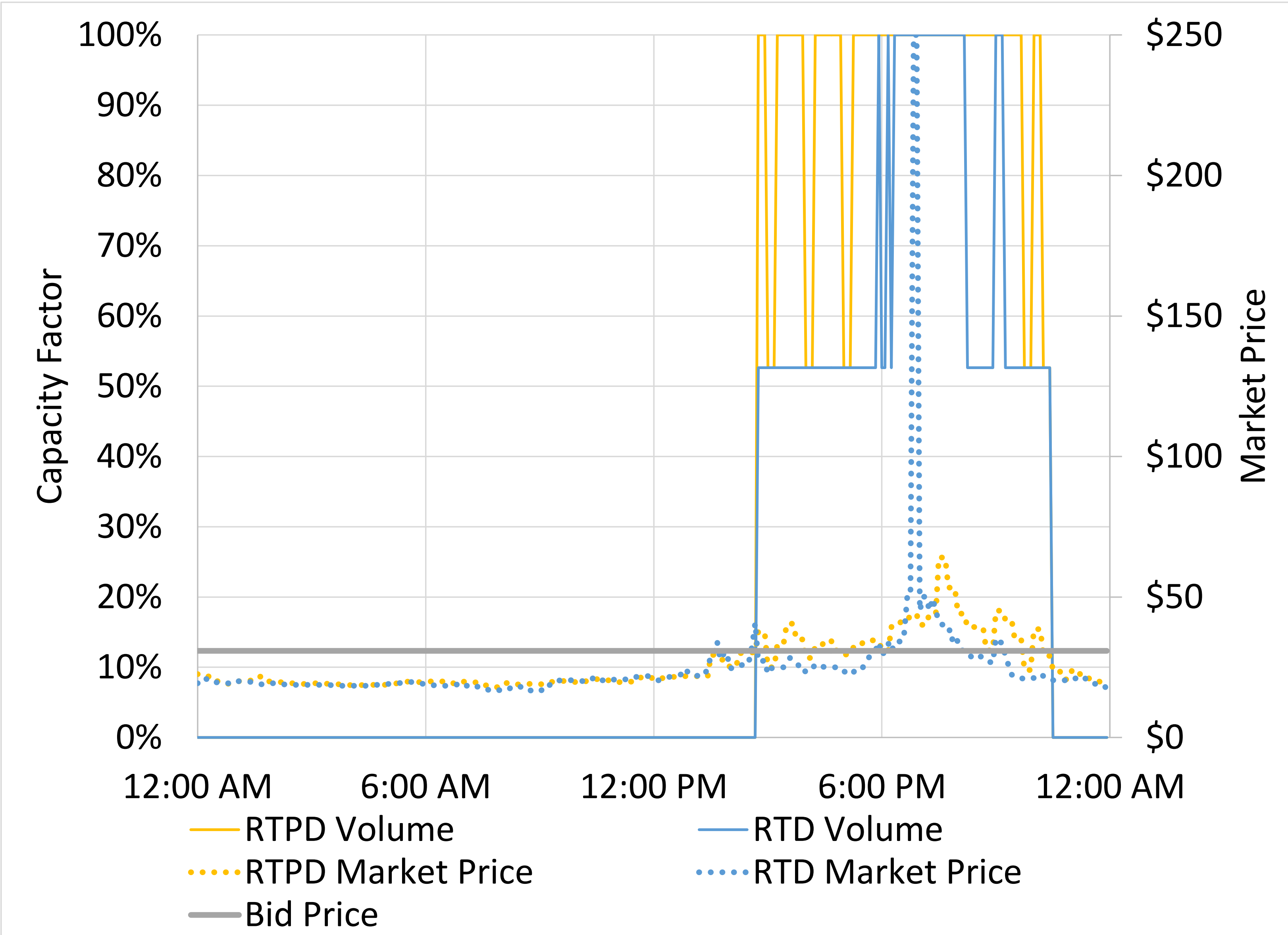
Proxy Peaking Resources

- There are three types of simple-cycle combustion turbine ("SCCT") natural gas resources in the supply-side table:
  - Aero: 3 x 40MW
  - Inter-cooled Aero: 2 x 100MW
  - Frame F: 1 x 200MW

- All three can be started in 15 minutes, so they can be committed up and down by the EIM.
- Results are based on historical market prices and the dispatch of existing SCCT resources, and account for the following operating parameters:
  - **Size and number of units** – smaller units can better align with EIM requirements – one Aero unit will be called upon more often than all three.
  - **Minimum and maximum output** – a lower minimum provides more flexibility
  - **Heat rate** – lower heat rate provides a greater margin at a given market price.
  - **Startup costs and minimum up time** – lower costs and restrictions provide more flexibility

$/kw-year	Credit
Aero (3x40MW)	**16.11**
Inter-cooled Aero (2x100MW)	**11.37**
Frame F (1x200MW)	**5.75**

Proxy Peaking Example

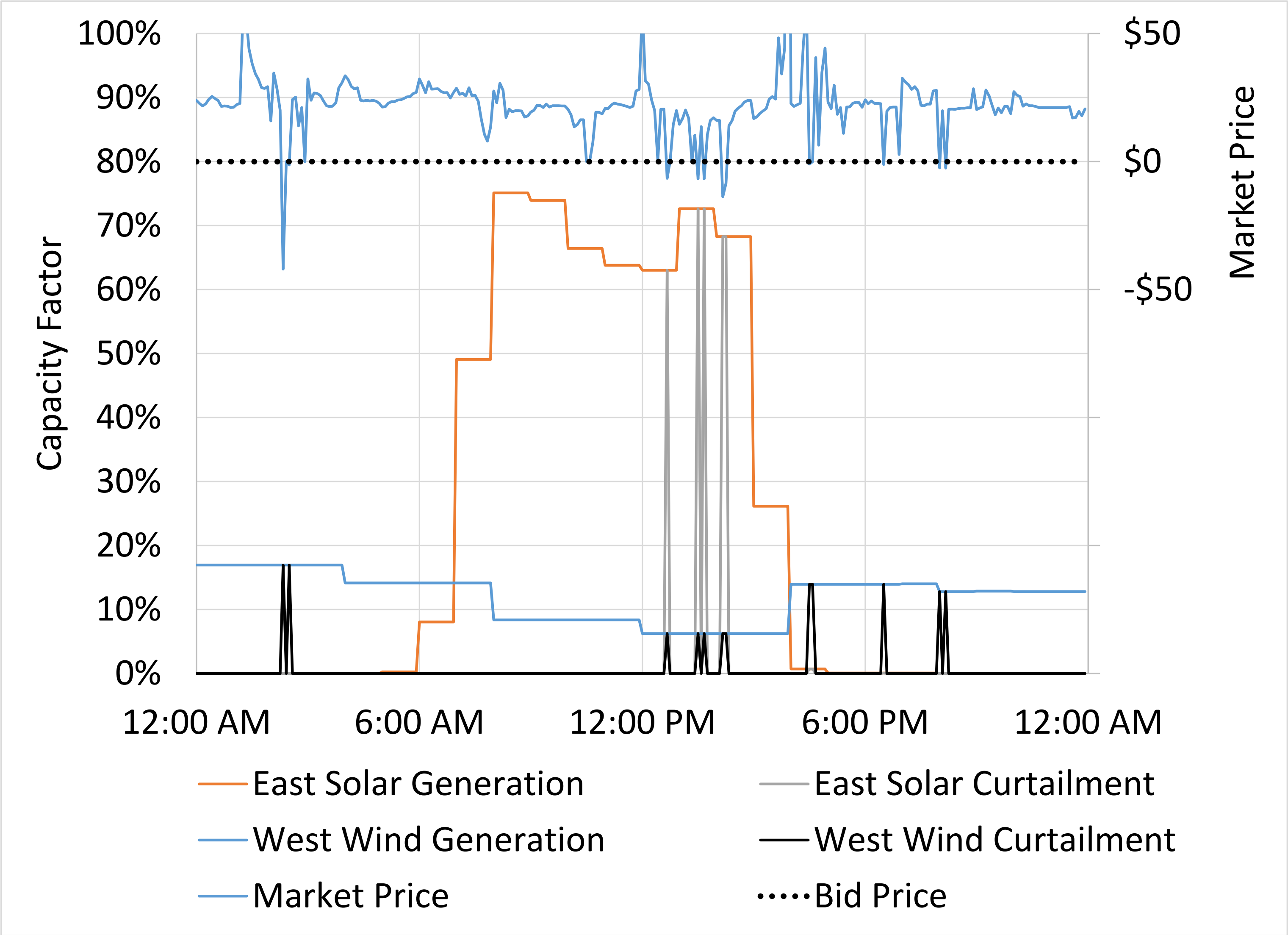


Curtailment

- When EIM prices drop below zero, it can be more economic to curtail resources, rather than generate.
- Wind with PTCs provides less value, as prices must drop below the cost of the PTC before curtailment is economic.
- The cost of lost renewable energy credits would also reduce the value of economic curtailment
- The values shown for east and west resources reflect differences in generation profiles.
- A resource available in all hours (100% c.f.) would have more opportunities to curtail, hence the higher value per kW of nameplate capacity.

		$/kw-year		**% of annual output**	
Resource	**Bid Price**	**East**	**West**	**East**	**West**
Solar	$0	**0.91**	**0.85**	**4.9%**	**4.9%**
Wind	$0	**0.89**	**0.56**	**2.8%**	**2.4%**
Wind	PTC	**0.03**	**0.02**	**0.1%**	**0.1%**
Baseload	$0	**1.90**		**2.5%**	

Curtailment Example



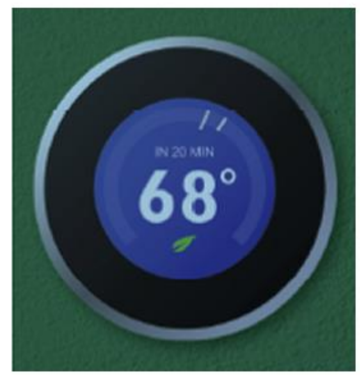
Energy Storage

- Intra-hour flexible resource credits for energy storage resources are dependent on the following characteristics, with typical values for a Lithium-Ion battery shown in parentheses:
  - Charging capacity (1MW)
  - Discharging capacity (1MW)
  - Hours of storage (4 hours)
  - Efficiency (88%)
  - Forced Outage Rate (1%)
  - Planned Outage Rate (3%)
  - Variable Cost (including degradation) ($10/MWh) – the cost of degradation is calculated as the cost of replacement energy storage equipment per MWh of discharge over the assumed cycle life.
- Intra-hour Flexible Resource Credits are being calculated for each type and configuration of energy storage resource, including:
  - Li-Ion Batteries (with various hours of storage) – High efficiency, high degradation cost
  - Flow Batteries – Lower efficiency, low degradation cost
  - Pumped hydro – moderate efficiency, low variable cost
  - Compressed Air Energy Storage – lower efficiency, also includes characteristics of natural gas resources.
- Energy storage characteristics and credits are still being finalized.

Wind or Solar with Energy Storage

- Energy storage combined with wind or solar is very similar to stand-alone energy storage, but also needs to account for the following:
  - Where storage systems allow for direct charging, inverter losses and capacity limits can be avoided, providing incremental benefits.
  - Wind or solar output will prevent storage from dispatching in some periods, reducing the value relative to stand-alone storage.
  - Where solar and storage qualifies for the ITC, tax implications require that charging be limited to the available solar output for the first five years, except under extreme circumstances.
- As a result, intra-hour flexible resource credits for wind or solar with energy storage will vary based on the following:
  - Storage characteristics
  - Generation resource profiles
  - Maximum combined output
  - Tax-related operating restrictions, which will vary over the life of the asset
- Energy storage characteristics and credits are still being finalized.

Environmental Policy & Price-Policy Scenarios



California Renewable Portfolio Standard Update

- On September 10, 2018, Governor Brown signed Senate Bill 100 (SB 100), the 100 percent Clean Energy Act of 2018, which:

  - Expands and accelerates the RPS targets

	By Dec. 2016	By Dec. 2020	By Dec. 2024	By Dec. 2027	By Dec. 2030
SB 350	25%	33%	40%	45%	50%
SB 100	25%	33%	44%	52%	60%

  - Directs the state agencies to plan for longer-term goal of100 percent of total retail sales of electricity in California coming from eligible renewable resources and zero-carbon resources by December 31, 2045.

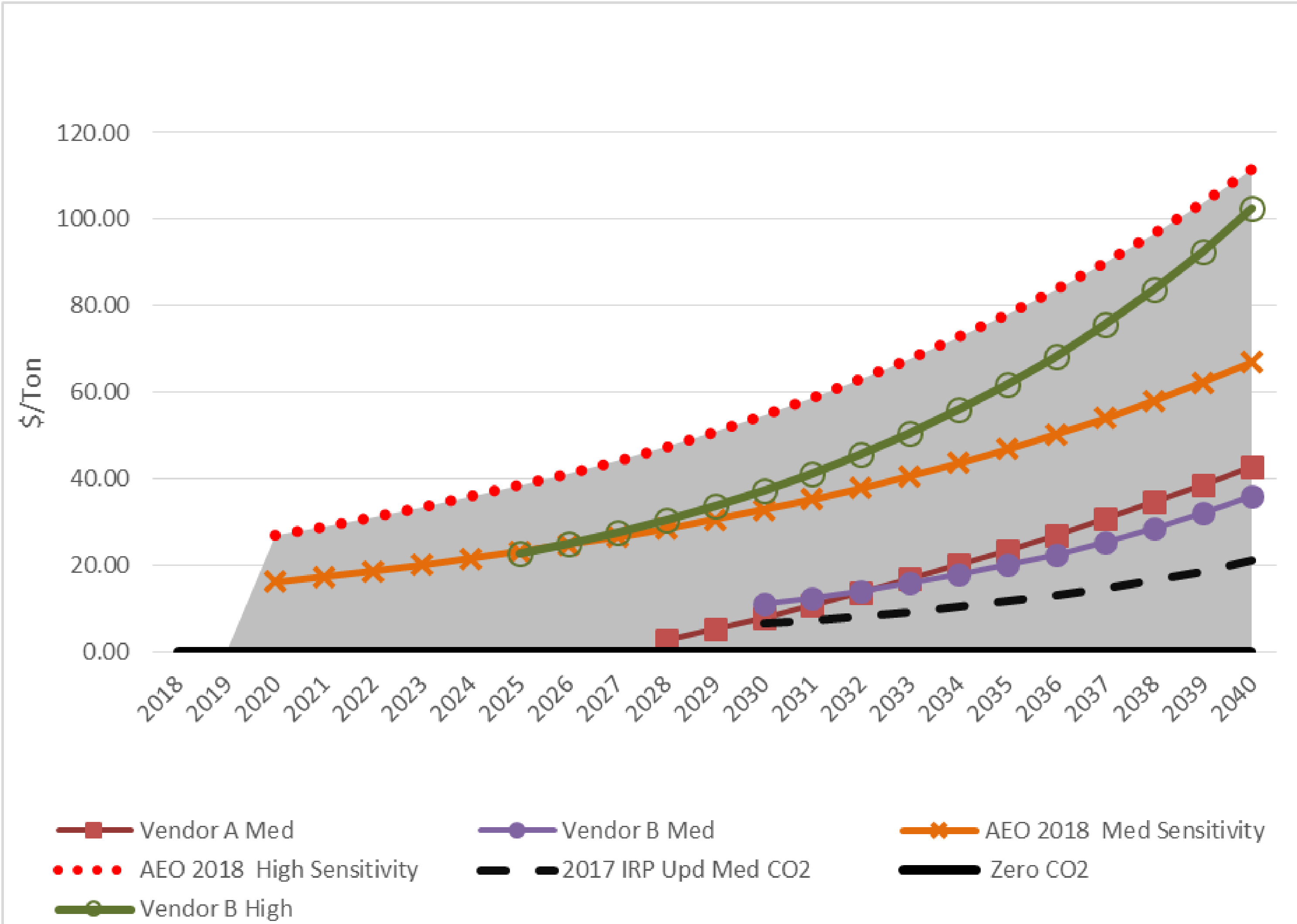
Affordable Clean Energy (ACE) Rule

- Proposed ACE Rule published in the Federal Register on August 31, 2018
- Public hearing scheduled for October 1, 2018; comment period closes October 30, 2018
- ACE Rule proposes a change to the definition of “Best System of Emission Reduction” or “BSER” for CO_2 emissions
  - BSER limited to specific Heat Rate Improvement (“HRI”) projects for coal-fired electric generating units, identified as “candidate technologies”:
    - Neural Network/Intelligent Sootblowers
    - Boiler Feed Pumps
    - Air Heater & Duct Leakage Control
    - Variable Frequency Drives
    - Blade Path Upgrade (Steam Turbine)
    - Redesign/Replace Economizer
    - Improved O&M Practices

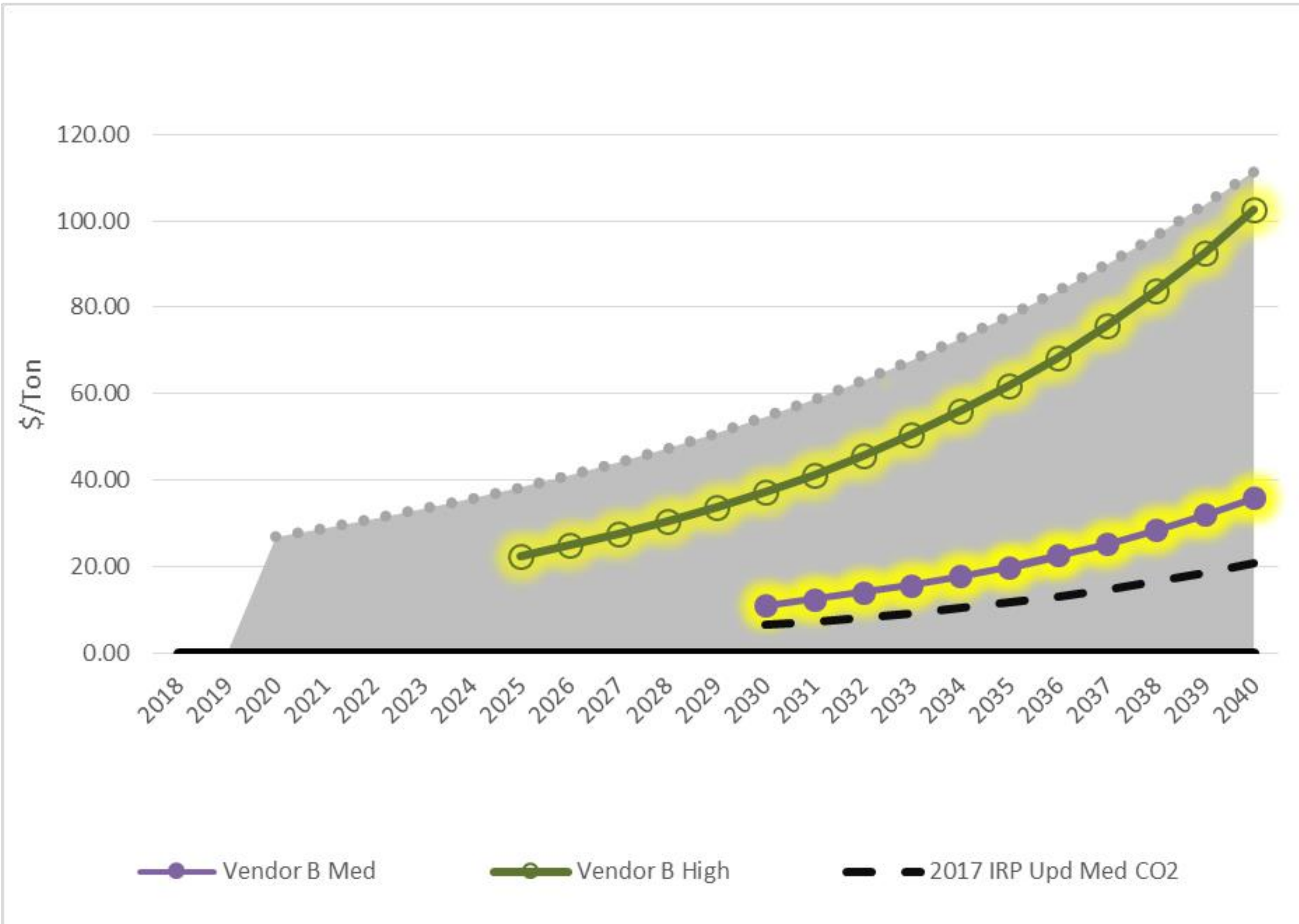
ACE Rule, continued

- EPA assessed economic effects of HRI project costs at $50 per kW and $100 per kW, providing 2.5% HRI and 4.5% HRI
- PacifiCorp has historically implemented HRI projects to enhance efficiency and reduce fuel consumption; thus HRI projects are routinely evaluated and implemented with appropriate permitting where economically justified
- HRI projects are typically accounted for through run rate capital and individual unit performance inputs that are imbedded in PacifiCorp's System Optimizer (SO) modeling
- PacifiCorp is developing comments on the ACE Rule in conjunction with Berkshire Hathaway Energy and its individual businesses

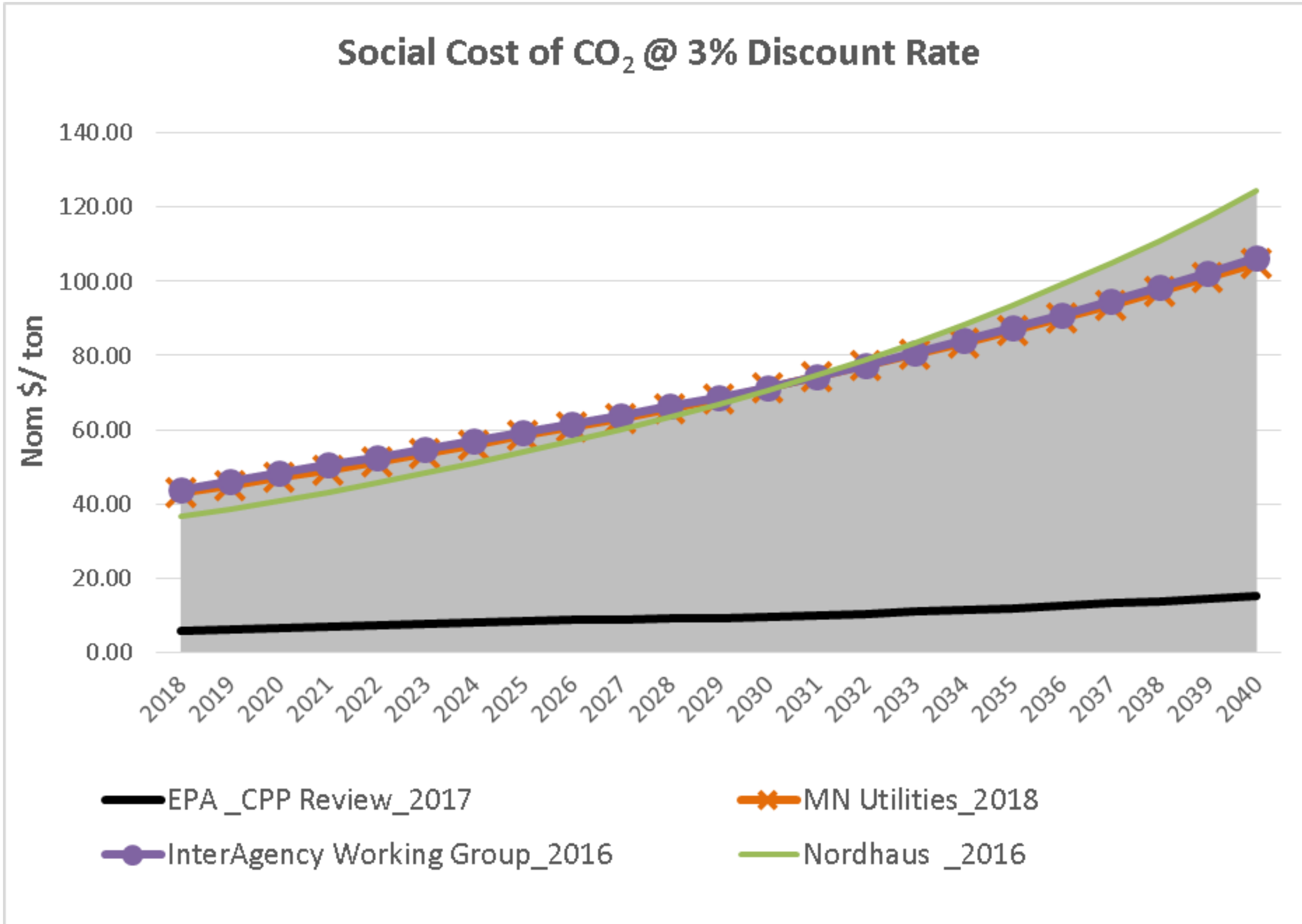
Survey of CO_2 Price Forecasts



Base and High CO_2 Price Forecasts Proposed for the 2019 IRP

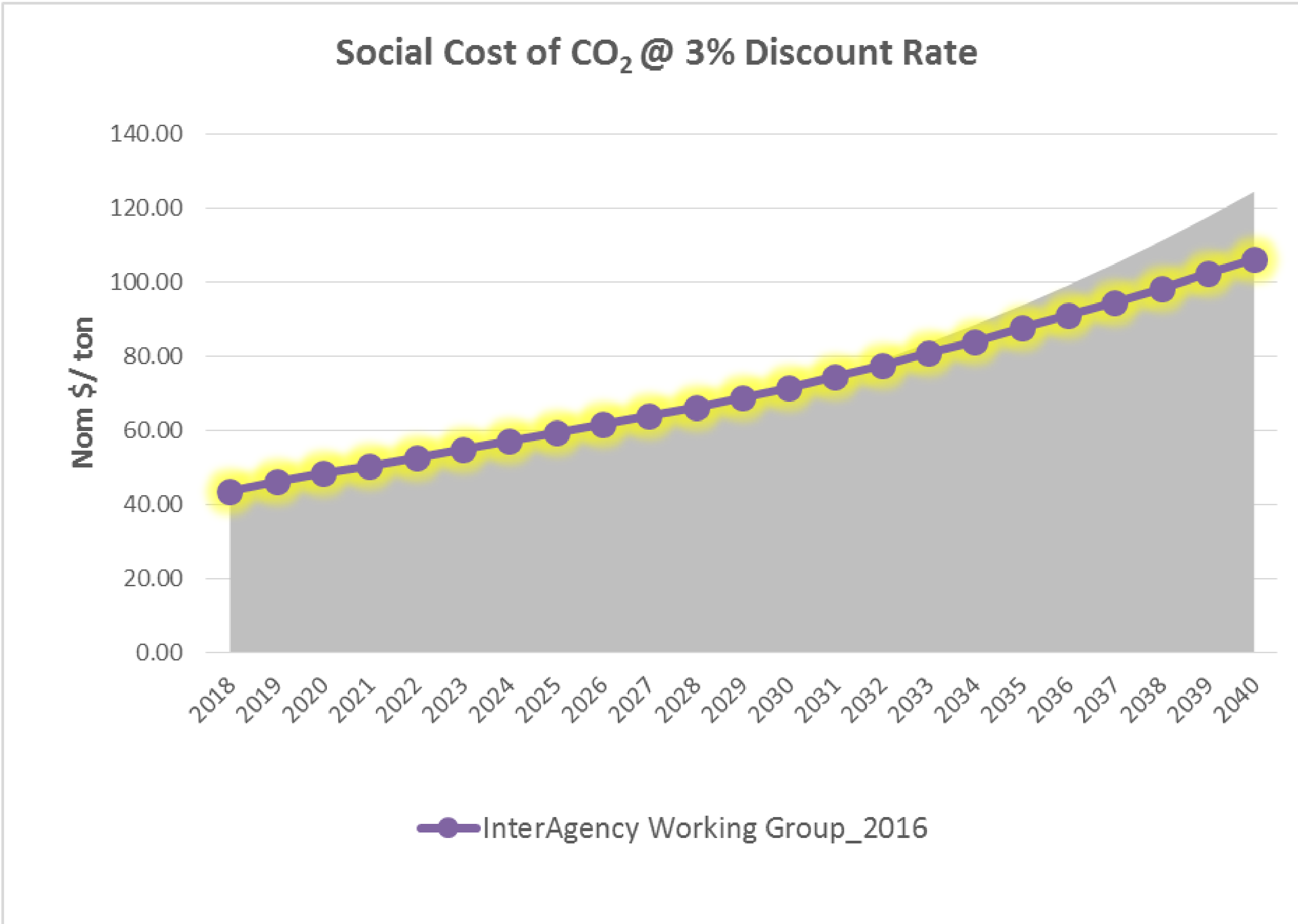


Survey of Social Costs of CO_2



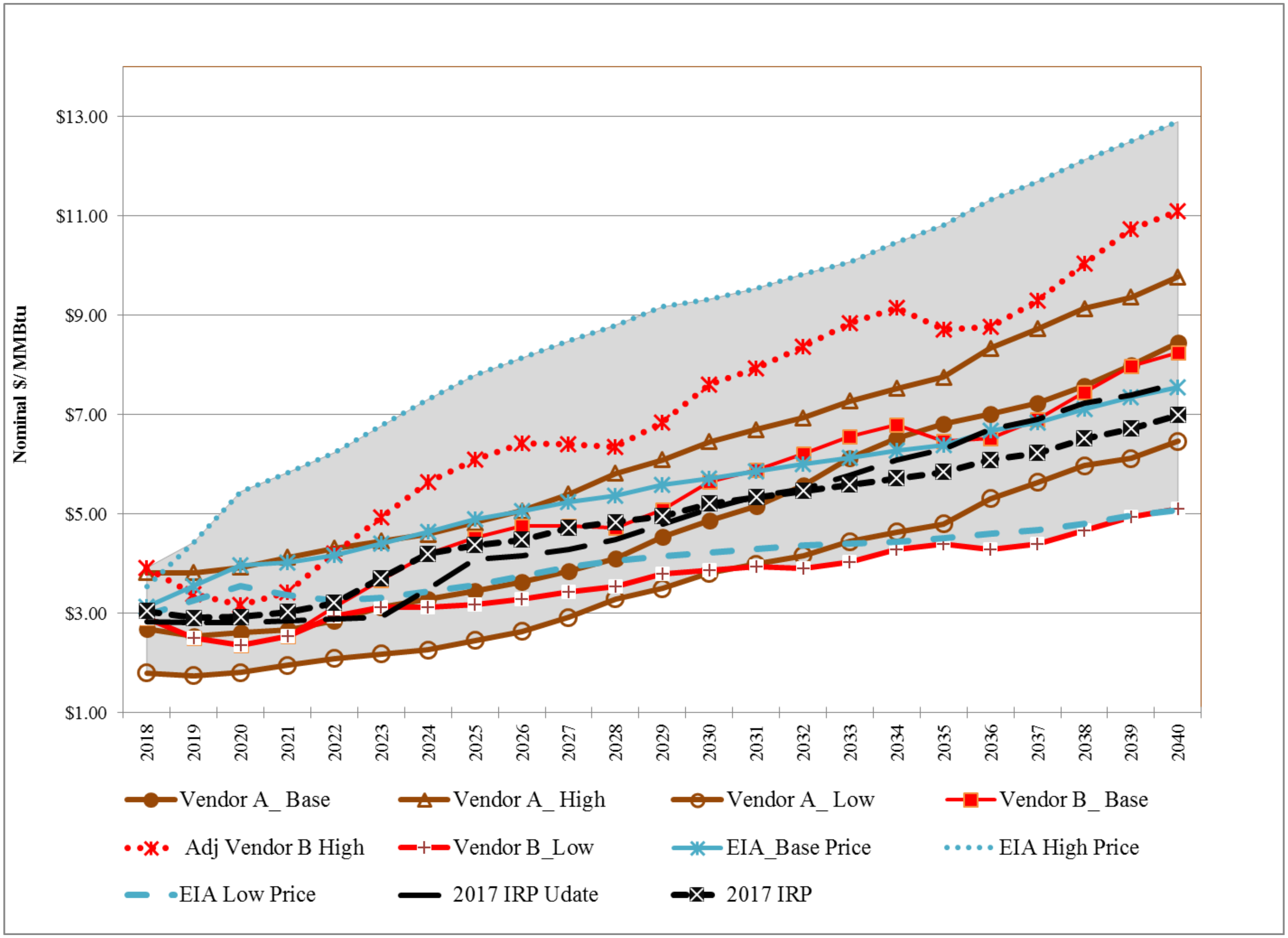
- Colorado PUC has implemented similar values to those of MN for utilities.
- InterAgency Working Group disbanded by Trump Executive Order 13783, March 2017.
- EPA revised carbon costs Oct 2017 as part of its revision of the CPP.

Social Cost of CO_2 Proposed for the 2019 IRP

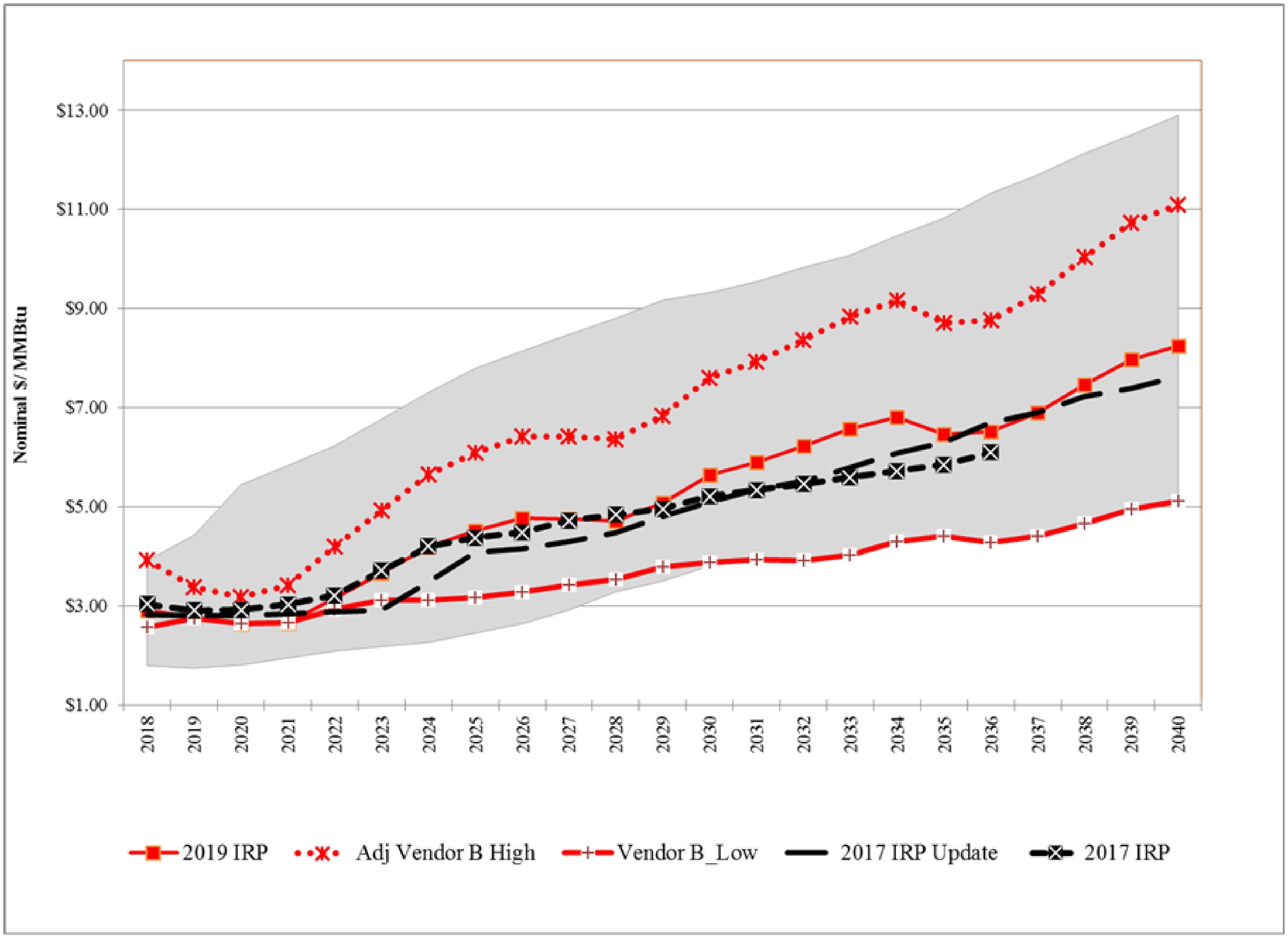


- InterAgency Working Group disbanded by Trump Executive Order 13783, March 2017.

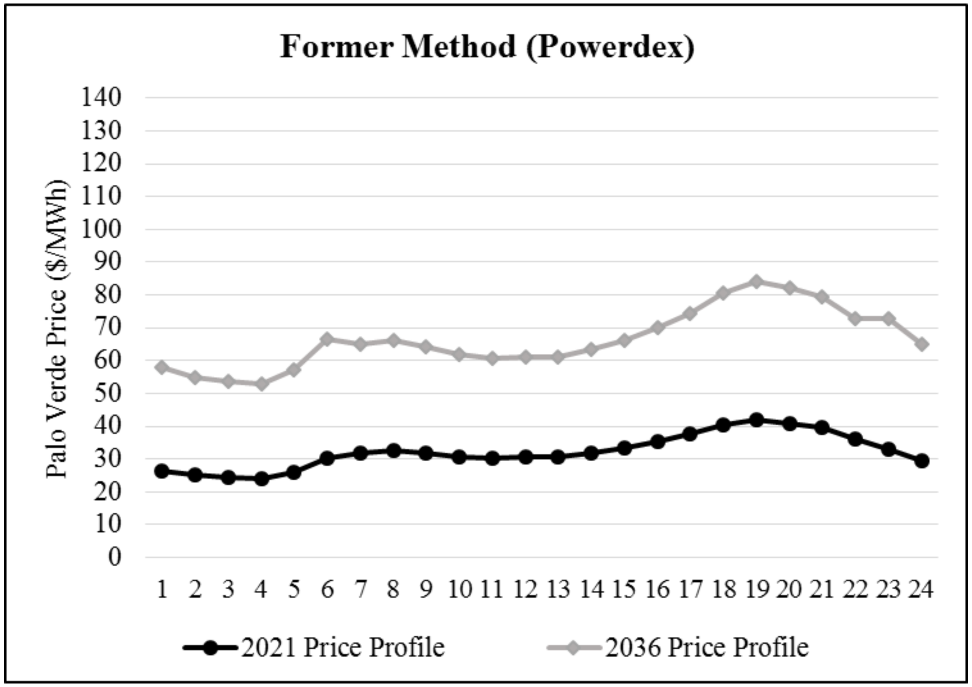
Survey of Natural Gas Price Forecasts

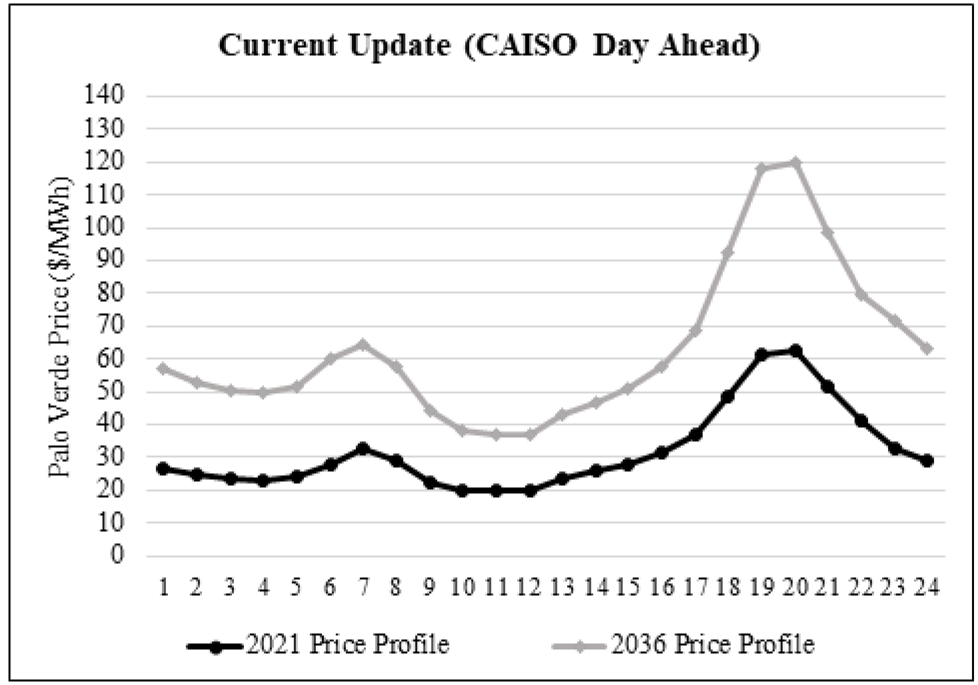


Proposed Natural Gas Price Forecasts for the 2019 IRP



Scalar Update



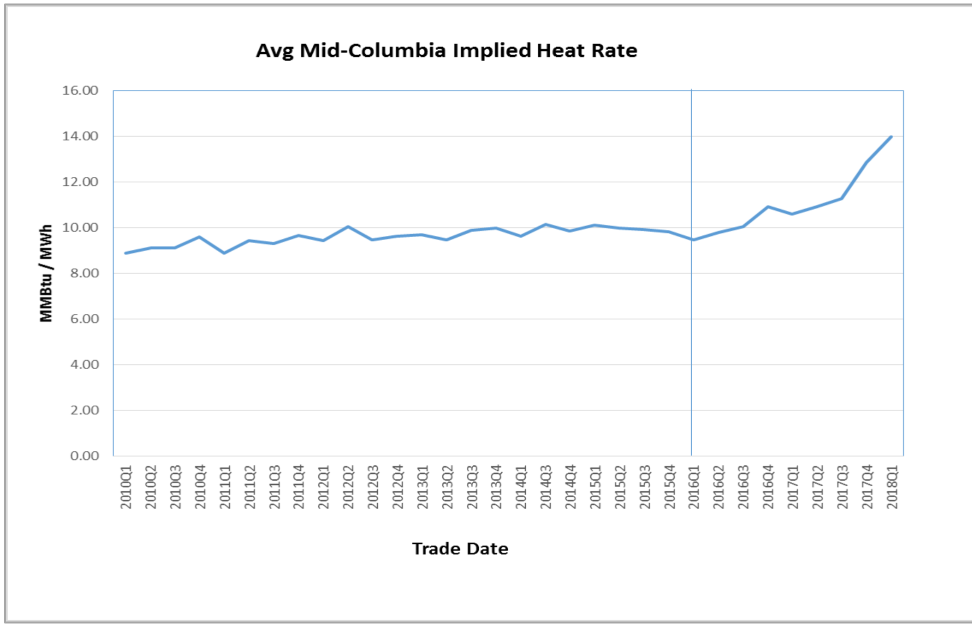


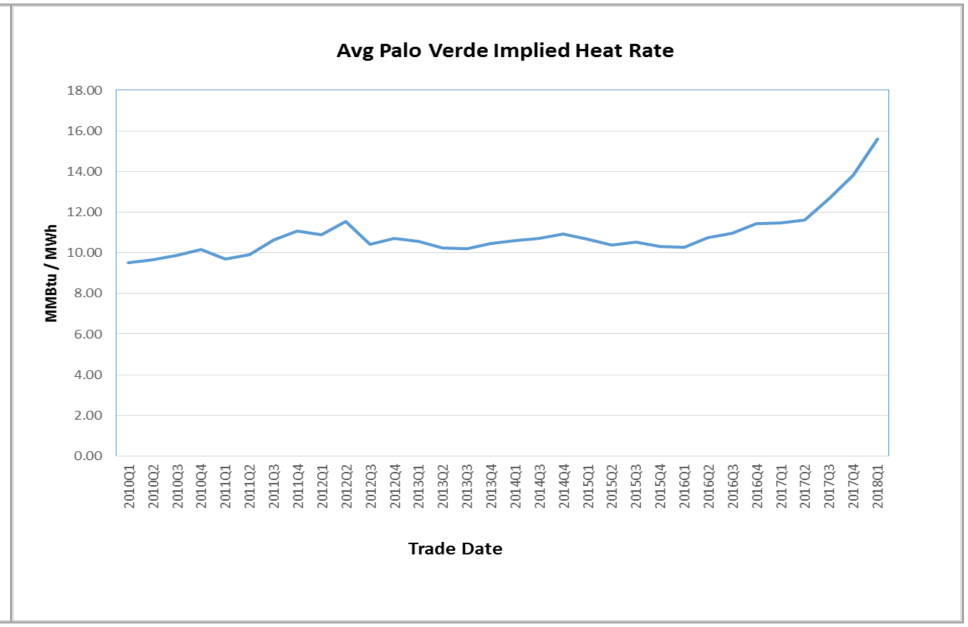
- PacifiCorp uses hourly price scalars, which get applied to monthly on-peak and off-peak prices in the forward price curve, to derive hourly market price profiles that vary by month and day type (*i.e.*, weekdays, Saturdays, and Sundays/holidays).
- In the past, PacifiCorp used five years of hourly Powerdex price data to develop price scalars; the figure at top left shows representative average hourly price profiles as derived from historical Powerdex data.
- Review of the Powerdex data shows that this price history is not supported by a significant volume of reported transactions (many hours have no market pricing inputs) and that the resulting hourly price shapes do not align with price observed in operations that are being increasingly influenced by growth in solar resources across the region.
- Consequently, PacifiCorp developed an improved price-scalar methodology, which was applied in the 2017 IRP Update, that uses one year of day-ahead hourly prices available from the California Independent System Operator (CAISO); the figure at top right shows representative average hourly price profiles derived from historical CAISO data.

Blending Update

- The Base price forecast consists of three years of forward prices followed by one year of blended prices beginning in month 37 and ending in month 48. Pure fundamentals price begins in month 49.
- During the blending period, prices are calculated as an average of the preceding year month-on-month forward prices and the following year month-on-month fundamentals price.
- Previous blending methodology utilized 72 months of market forwards, followed by one year of blended prices, before transitioning to pure fundamentals in month 84.
- The shorter blending period more closely aligns with other utilities and mitigates the implications of steeply rising implied market heat rates through the front six years of the forward market period where market liquidity begins to drop.

Blending Update, continued

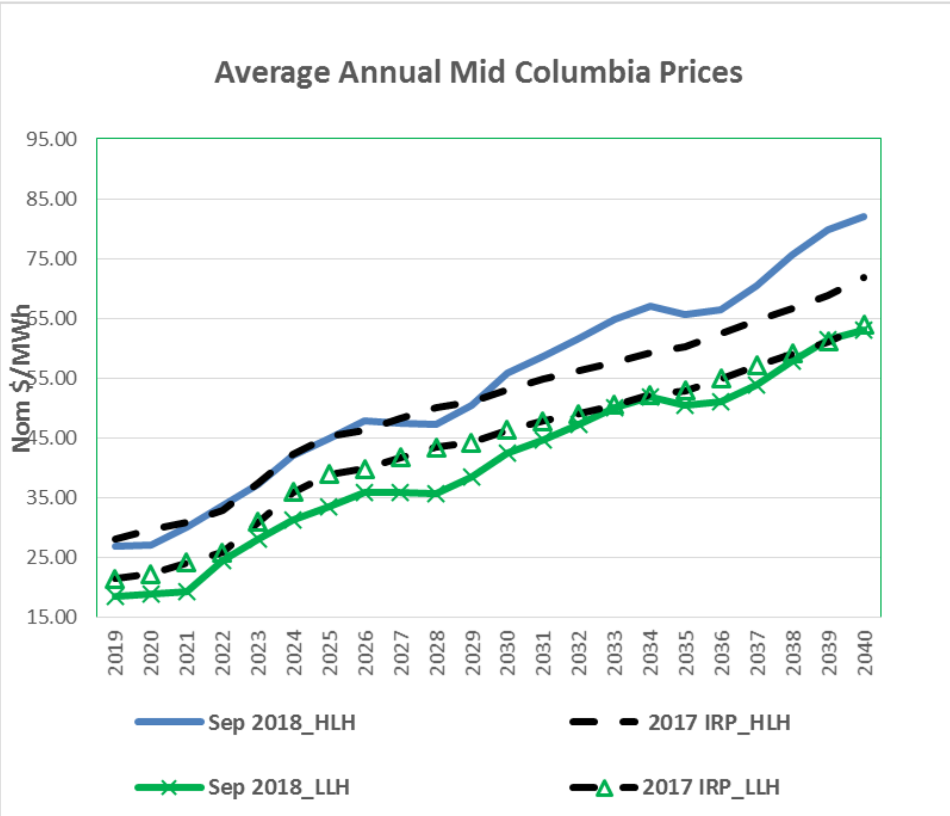


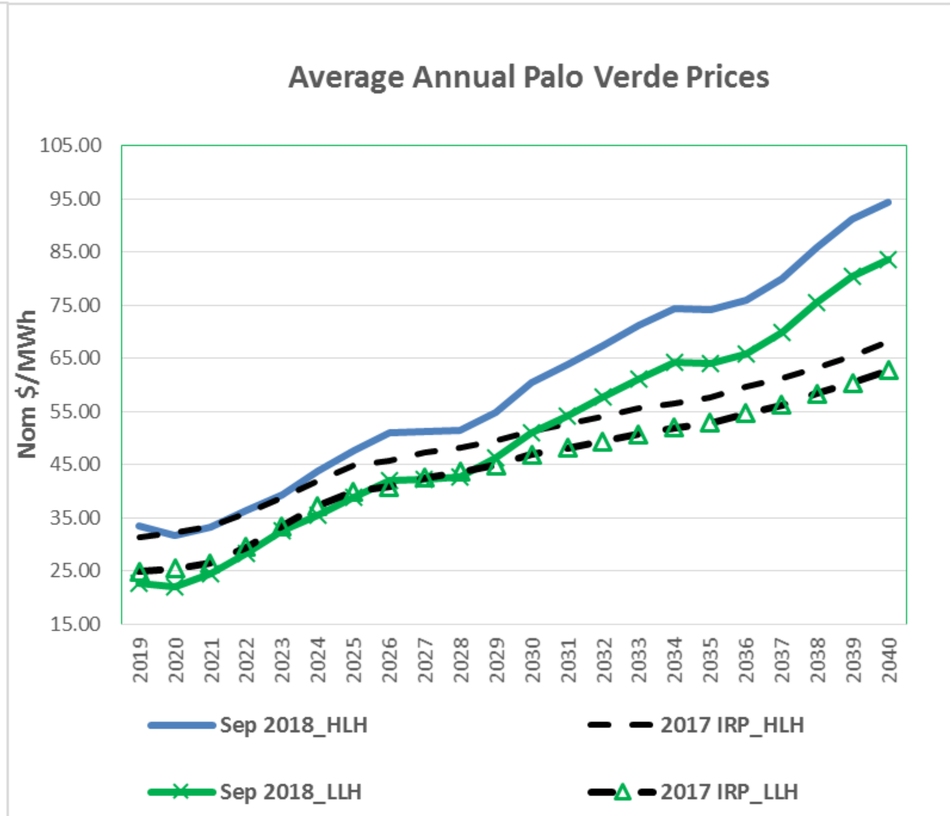


- A six-year market period with these high implied heat rates distorts the expected prices, which are more accurately represented by a fundamentals-based price forecast after the short-term.
- In addition a review of blending methodology (including NV Energy, Portland General Electric, Puget Sound Energy and Avista) suggests a six-year period of market forwards exceeds the norm.
- Typical period of market forwards reviewed was 2 to 4 years, with a blending period of 1 to 3 years.

Price Update

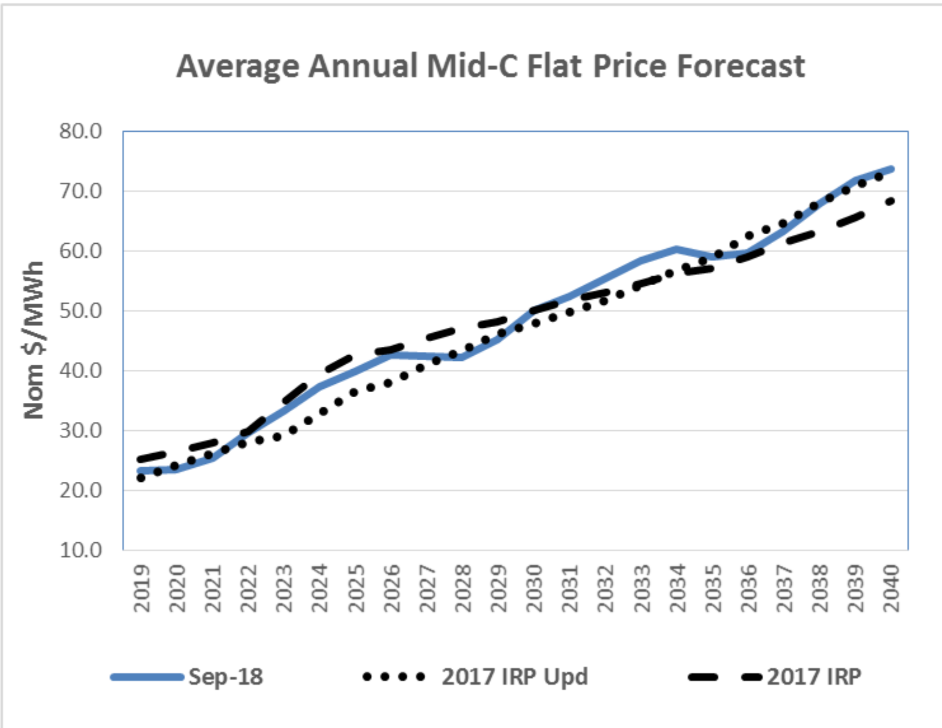
3 Years + 1 Year Blend by Peak Type

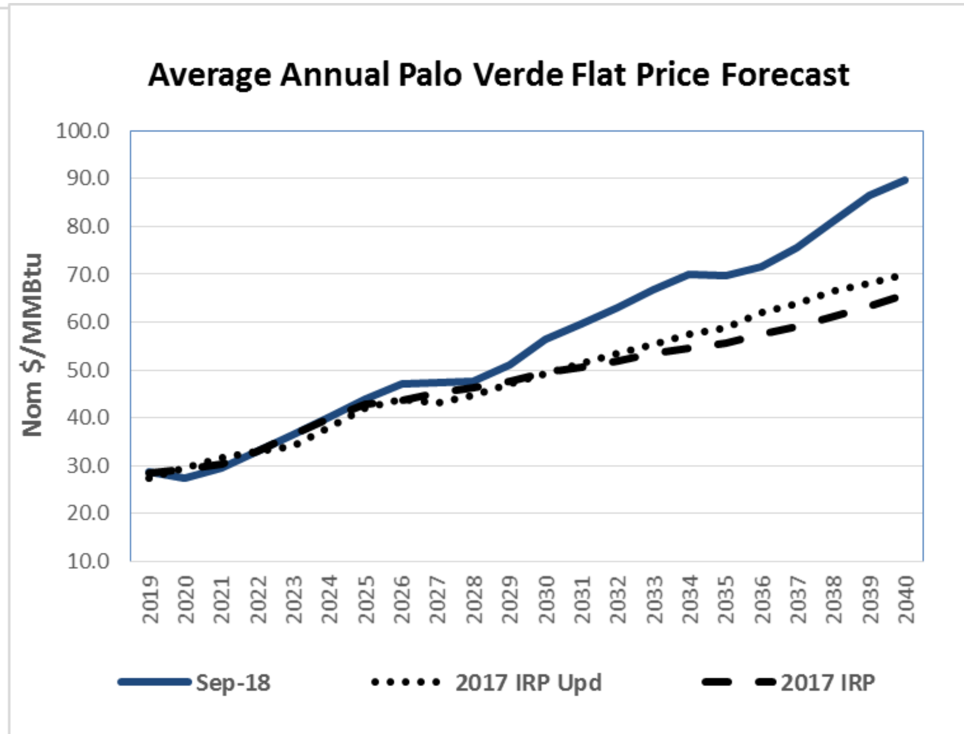




Price Update

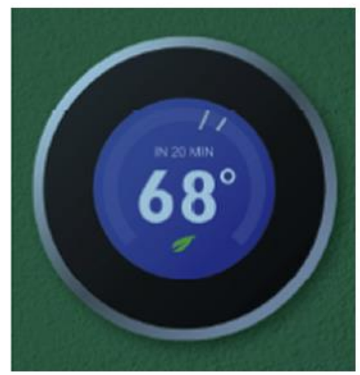
3 Years + 1 Year Blend, Flat





Transmission Overview and Updates



Transmission Overview Agenda

- Regional Planning Update
- Energy Gateway
    - Segment A – Wallula to McNary
    - Segment C – Oquirrh to Terminal
    - Segment D2 – Aeolus to Bridger/Anticline
    - Segments D1, D3, E – Gateway West
    - Segment F – Gateway South
    - Segment H – Boardman to Hemingway
- 2019 IRP Transmission Modeling Enhancements

FERC Order 1000 Regional Planning

- FERC Order No. 1000 is a Final Rule that reforms the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers.
- The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods.
- To meet the requirements of FERC Order 1000, PacifiCorp participates in the Northern Tier Transmission Group (NTTG), a regional planning organization made up of PacifiCorp, Idaho Power, NorthWestern Energy, Portland General Electric, Deseret Power and UAMPS.

FERC Order 1000, continued

- The NTTG regional planning organization was formed to provide a forum where all interested parties are encouraged to participate in the planning and coordination of a robust transmission system that is capable of supporting an efficient west-wide electricity market while meeting WECC and NERC reliability standards.
- The wide participation envisioned in this process (including transmission owners, customers and state regulators) is intended to result in transmission expansion plans that meet a variety of needs and have a broad basis of support.
- Through PacifiCorp's participation on NTTG, the Energy Gateway Project has been fully vetted through the regional planning process.

FERC Order 1000, continued

Energy Gateway Program Status

Wallula to McNary (A)
- County permits December 2015
- Federal ROW grants Q2 2017
- Construction start Q2 2018
- Target in-service: November 2018

West of Hemingway (H)
Boardman-Hemingway:
- Joint Development Agreement with BPA/Idaho Power
- BLM ROD: November 2017
- USFS ROD expected Q4 2018
- In-service: sponsor driven

Gateway West (D&E)
- ROD D/E (partial): Q4 2013
- ROD E (Full) Target: April 2018
- D1,D3, E Target In-service: 2024

Gateway West (D2)
- Full ROD NTP: March 2019
- D2 Target In-service: 2020

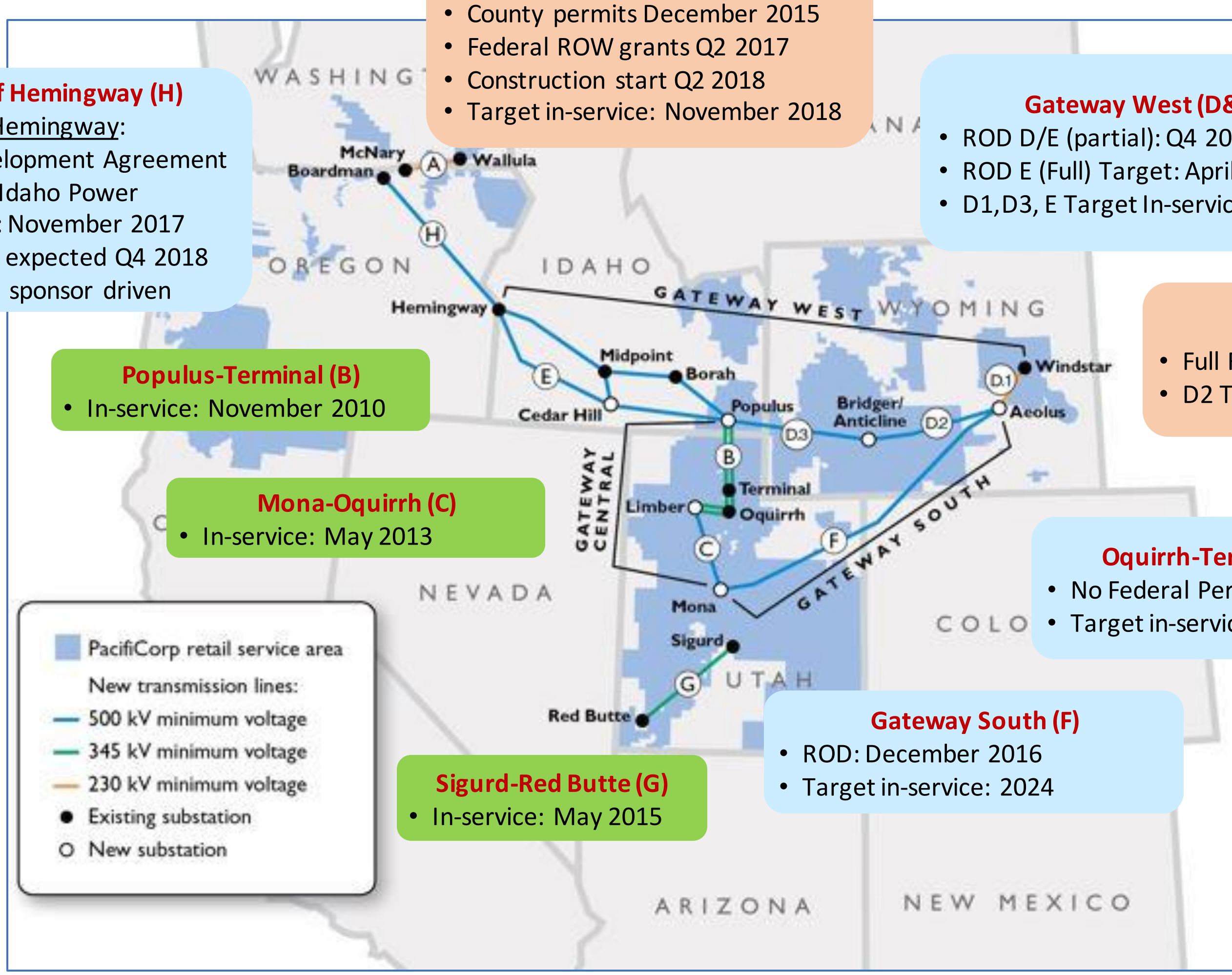
Populus-Terminal (B)
- In-service: November 2010

Mona-Oquirrh (C)
- In-service: May 2013

Oquirrh-Terminal (B)
- No Federal Permitting
- Target in-service: May 2022

Gateway South (F)
- ROD: December 2016
- Target in-service: 2024

Sigurd-Red Butte (G)
- In-service: May 2015

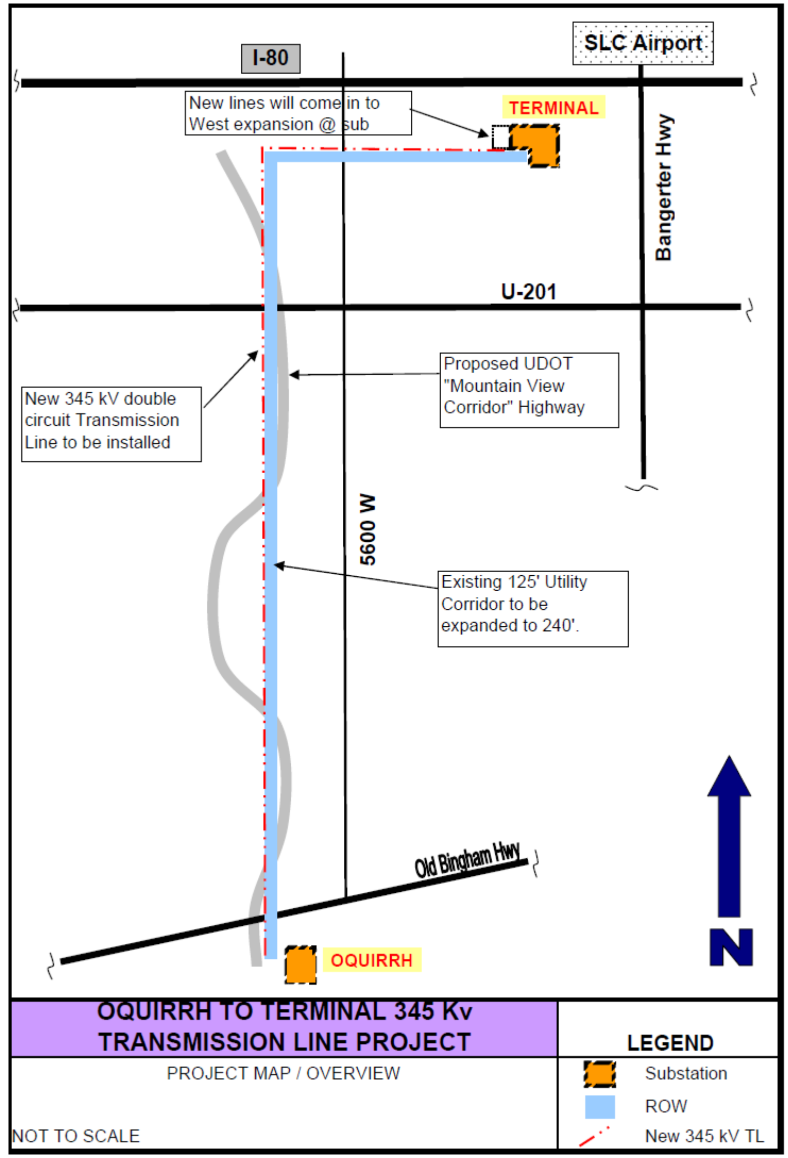


Wallula-to-McNary (Segment A)

- Approximately 30 miles between Wallula-McNary, single circuit 230-kilovolt line
- Satisfies transmission customer service request, increases reliability and load service opportunities
- Oregon Certificate of Public Convenience and Necessity received in 2011
- Local permits obtained 2015, federal ROW grants obtained in 2017
- Majority of ROW acquired 2018
- Construction started Q2 2018
- Target in-service date: November 15, 2018

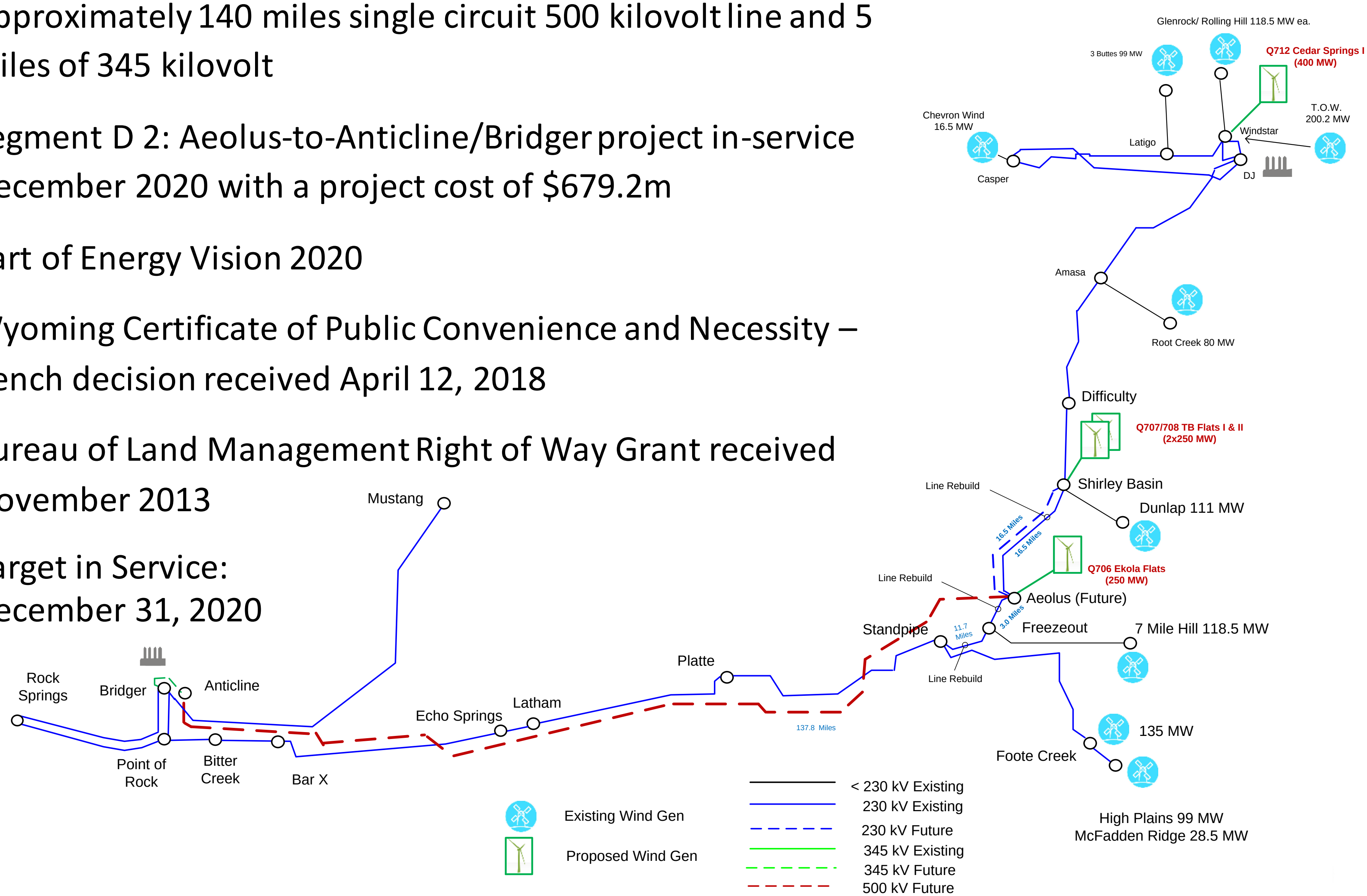
Oquirrh-to-Terminal (Segment C)

- Approximately 14 miles, double-circuit 345-kilovolt line
- Improves reliability and load service
- Line route is within existing right of way that includes realignments to accommodate construction of the Utah Department of Transportation Mountain View Corridor project
- Line connects Populus-Terminal and Mona-Oquirrh lines
- No federal permitting required
- Target in-service date due to lower expected load growth: May 2022



Gateway West (Segment D2)

- Approximately 140 miles single circuit 500 kilovolt line and 5 miles of 345 kilovolt
- Segment D 2: Aeolus-to-Anticline/Bridger project in-service December 2020 with a project cost of $679.2m
- Part of Energy Vision 2020
- Wyoming Certificate of Public Convenience and Necessity – bench decision received April 12, 2018
- Bureau of Land Management Right of Way Grant received November 2013
- Target in Service: December 31, 2020

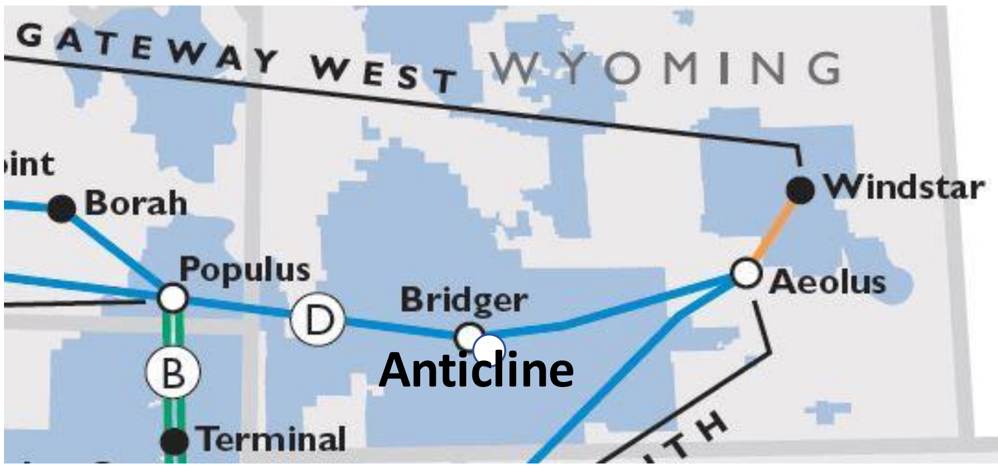


POWERING YOUR GREATNESS

Gateway West (Segment D1 and D3)

- Segment D1: Windstar to Shirley Basin
- 60 miles of single-circuit 230 kilovolt transmission
- Bureau of Land Management Record of Decision received November 2013
- Target in Service: 2024

- Segment D3: Bridger/Anticline to Populus
- 200 miles of single-circuit 500 kilovolt
- Bureau of Land Management Right of Way Grant received November 13, 2013
- Target in Service: 2024

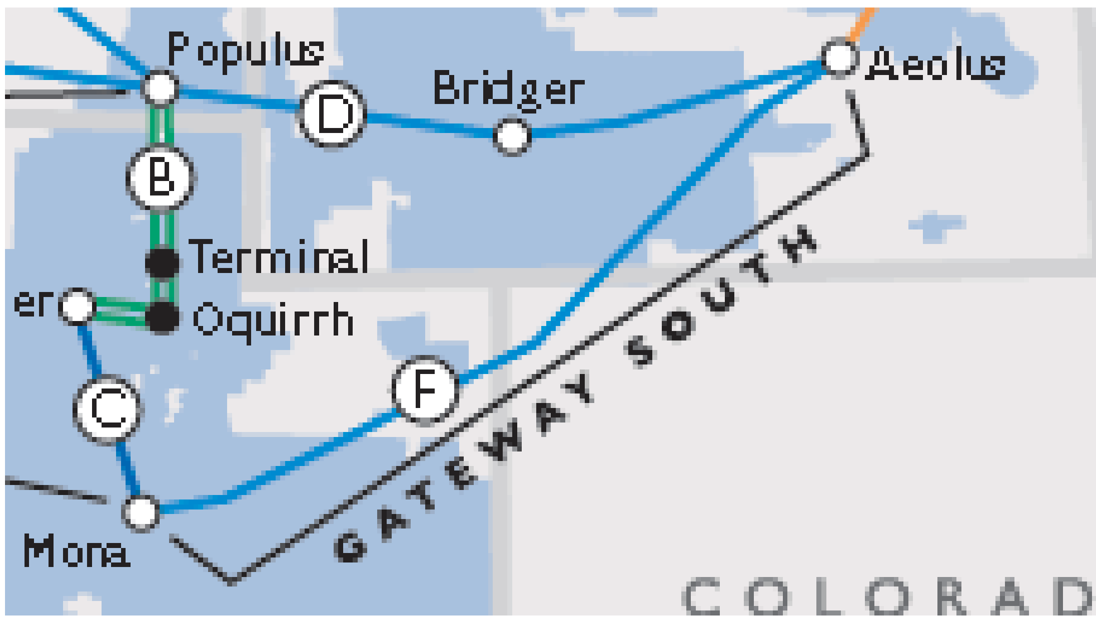


Gateway West (Segment E)

- Bureau of Land Management record of decision and right of way grant issued November 2013 for sub-segments 1-7 and 10
- Sub-segments 8 and 9 were reanalyzed in a Supplemental Environmental Impact Statement (SEIS)
- Bureau of Land Management Record of Decision and Right of Way Grant issued on May 2018 for sub-segments 8 and 9
- Two, 500KV Transmission Lines
- Target in service: 2024

Gateway South (Segment F)

- Final Environmental Impact Statement issued May 2016
- Record of Decision issued December 13, 2016
- Target in-service date: 2024



Boardman-to-Hemmingway (Segment H)

- Project participants: Idaho Power, Bonneville Power Administration, PacifiCorp
- Final environmental impact statement published November 25, 2016
- BLM Record of Decision received November 2017
- USFS ROD expected Q4 2018
- Oregon Energy Facility Siting Council order expected to be deemed complete 2018; Site Certificate expected 2020/2021
- Target in-service date, sponsor-driven, targeted for 2025 or later

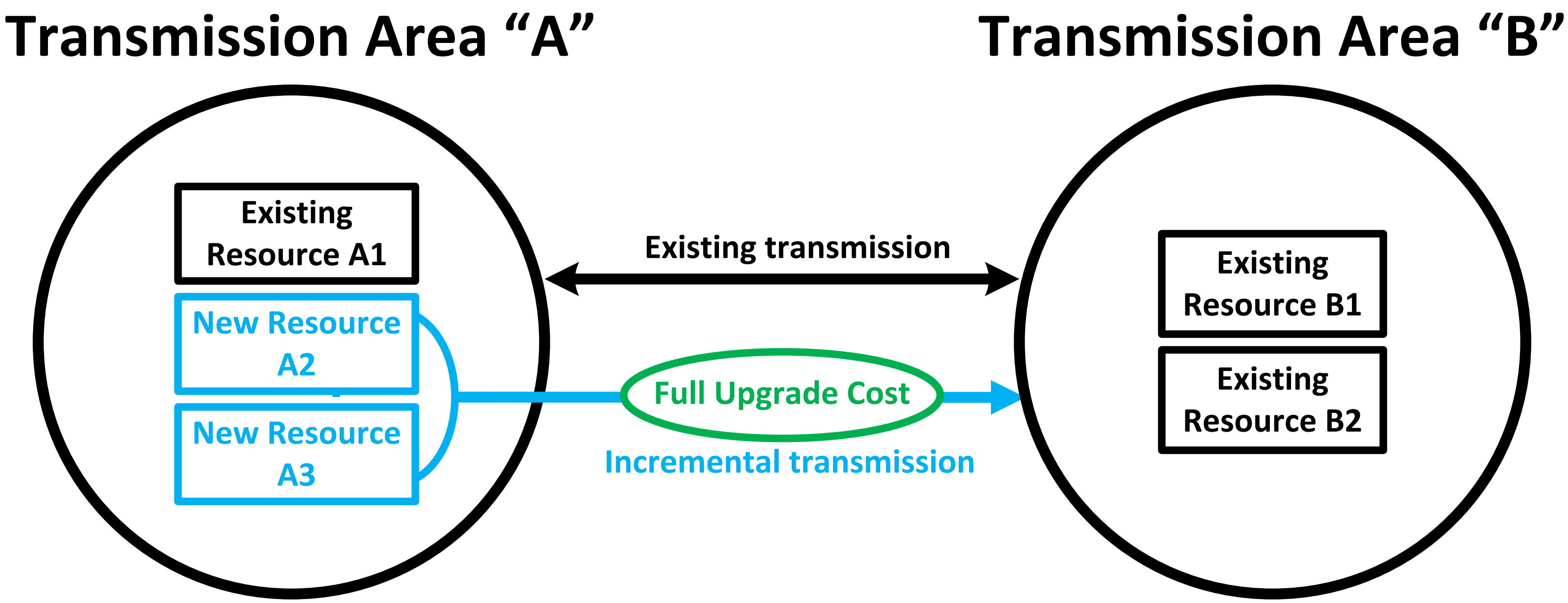
2019 IRP Transmission Modeling Enhancements

- Efforts continue to more precisely represent transmission costs and opportunities associated with plant retirements.

- Endogenous transmission modeling enhancements focus on the following areas:
  - Incremental transmission upgrades
  - Transmission upgrade costs
  - Retirement implications on transmission

- Endogenous incremental transmission upgrades and upgrade costs are now achievable (discussed further on next slide).

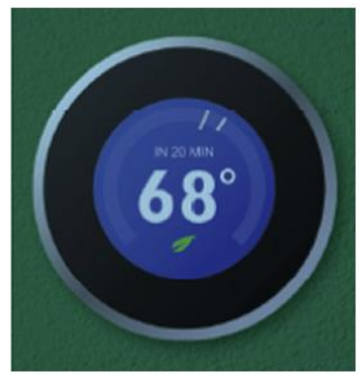
Endogenous Transmission Modeling Enhancements



- Incremental transmission can be selected endogenously by the model.
- Transmission upgrade costs are tied to total new resource capacity in a transmission area.
- Out-of-model cost reconciliation is no longer required and System Optimizer is able to identify potential benefits of added transmission capacity.
- Model run-time is negatively impacted by the enhancement – currently 3x.

Stakeholder Feedback Form Recap



Stakeholder Feedback Form

- 35 stakeholder feedback forms submitted to date
- All stakeholder feedback forms posted on PacifiCorp's 2019 Integrated Resource Plan webpage at: www.pacificorp.com/es/irp/irpcomments.html
- A matrix to summarize feedback and the company's response will be posted by October 31, 2018.
- Response to feedback will be captured in the matrix and may be provided in different ways depending on the type and complexity of the feedback including but not limited to a written response in the matrix, a standalone response document, separate email, follow-up conversation, or incorporated in subsequent public input meeting material.
- Feedback received following the most recent public input meeting (August) is summarized on following slides for reference.

Stakeholder Feedback Form

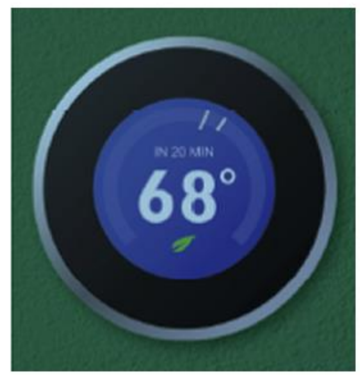
Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response
WRA, RN, PRBRC, Sierra Club, HEAL UT, NEC	Aug 24	Coal Analysis	Requests analysis that retires at least 1,100 MW of coal by 2030 beyond retirements in 2017 IRP and additional scenario to the extent the analysis requested does not result in that level/timing of retirements. Additionally, intra-hour credit impact should be isolated.	Will present scenarios addressing this feedback at the Sept 27-28 PIM coal study / portfolio discussion.
UCE	Aug 29	DSM	Requests additional data and comparison of costs and energy savings associated with DSM modeled in IRP.	Worked with UCE/SWEEP. See summary matrix.
OPUC	Aug 30	Load Forecasting	Requests additional data behind the single point estimates and modifications to presentation of data.	To be provided on filed data disc and captured in High/Low load sensitivities.
OPUC	Aug 30	IRP Filing	Requests explanation behind April 1, 2019 file date and expresses concern of short notice on topics/materials.	Date driven by other state IRP guidelines.
UCE	Sept 4	Intra-Hour Credit	Requests additional information for better understanding and a technical conference to discuss.	To be discussed at Sept 27-28 PIM.
SWEEP	Sept 6	DSM	Requests levelized cost curve presented August 30 (slide 10) and break-out of UT achievable potential by sector.	Data provided. See summary matrix.
WUTC	Sept 7	Various	Slide-by-slide clarifications and feedback submitted.	Response to be provided by Oct. 19.

Stakeholder Feedback Form

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response
NWEC	Sept 11	Portfolios	Requests clarification of how PacifiCorp will consider the social cost of carbon as required by the WUTC.	To be discussed at Sept 27-28 PIM.
Sierra Club	Sept 21	Coal Analysis	Requests details regarding approach and assumptions for next phase of coal studies to be presented.	To be discussed at Sept 27-28 PIM.
OPUC	Sept 21	Intra-Hour Credit	Requests better understanding of calculation at future public input meeting.	To be discussed at Sept 27-28 PIM.
OPUC	Sept 21	Flexible Reserves	Requests clarification, comparison of portfolios with EIM benefits and discussion of TRC by TRC member.	Response to be provided by Oct. 19.
OPUC	Sept 21	Market Reliance	Requests comparison of PRM to historic actuals and higher FOT purchase level sensitivity.	Response to be provided by Oct. 19.
OPUC	Sept 21	FOT and Gas Prices	Requests more detail regarding change in FOT modeling assumption and use of Henry Hub for gas prices.	Response to be provided by Oct. 19.
OPUC	Sept 21	Portfolios	Requests more detail on carbon price assumptions, book ends for sensitivities, use of lower-tail risk and business plan assumptions assumed in cases.	Response to be provided by Oct. 19.
OPUC	Sept 21	Private Generation	Requests sensitivities for future IRP PG studies around potential policies and further explanation of technical potential for private solar generation in 2019 IRP study.	Response to be provided by Oct. 19.
OPUC	Sept 21	Process	Post response to all comments by September public input meeting, or commit to providing a response.	Matrix with responses posted by Oct. 31.

Flexible Reserve Study Cost Results



Flexible Reserve Requirements

- The flexible reserve requirement methodology was discussed at the August 30-31 public input meetings. This provides some additional comparisons of the current study and the prior study, in response to stakeholder feedback.

	2017 Study	2019 Study
Historical Period	2015 (2016 solar)	2017
Total Requirement (aMW)	617	531
EIM Diversity (aMW)	92	104

- Enhancements since the 2017 Study:

Data	Methodology
Actual solar forecasts and results	Reserve calculated via quantile regression
Actual hour-ahead load forecasts	Co-optimized portfolio requirement
EIM diversity corrected by CAISO	Extrapolation using cumulative stacking

- The use of actual hour-ahead load forecasts, rather than proxy load forecasts based on the prior week, helped reduce stand-alone requirements for load from 433 aMW to 305 aMW. This also reduces the potential for diversity savings, so the reduction in the total requirement is smaller.

Flexible Reserve Costs

- The flexible reserve requirement methodology was discussed at the August 30-31 public input meetings.

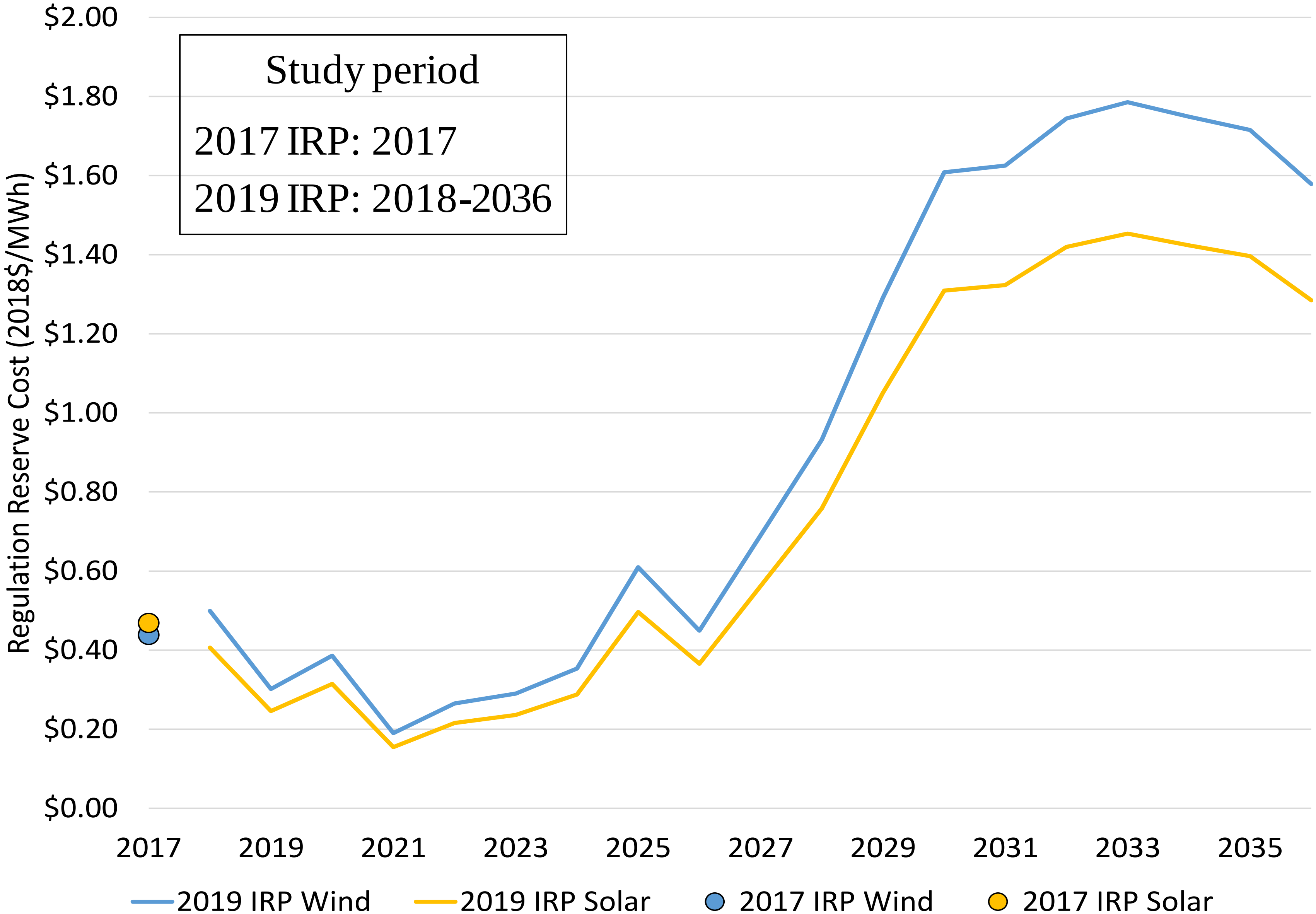
- Flexible reserve cost study design
  - Study term – 19 years, 8760 granularity
  - 1) Base Case
    - final PRM target study – no new renewables, balancing allowed to up to FOT limits

  - 2) Wind Reserve Case – reserves associated with 500MW wind resource additions:
    - 100MW x 5 locations: Dave Johnston, Goshen, Utah South, Walla Walla, Yakima
    - Incremental Reserves: 50 aMW, shaped hourly
    - Wind integration costs = (study 2 minus study 1), divided by incremental wind generation.

  - 3) Solar Reserve Case – reserves associated with 500MW solar resource additions:
    - 250MW Utah South, 125 MW Southern Oregon, 125 MW Yakima.
    - Incremental Reserves: 24 aMW, shaped hourly
    - Solar integration costs = (study 3 minus study 1), divided by incremental solar generation.

- Study improvements
  - The 19 year study term provides a more accurate escalation rate. The 2017 IRP study used a 2017 test period for reserve costs, and escalated at inflation for the balance of the term.

Flexible Reserve Costs



Flexible Reserve Study

Reserve Costs ($/MWh)	2017 IRP 2021 start (2016 $)	2019 IRP – 2021 start (2018 $)	2019 IRP – 2030 start (2018 $)
Escalation	**Inflation**	**Dynamic**	**Dynamic**
Wind (30-yr levelized)	$0.60	$1.11	$1.84
Solar (25-yr levelized)	$0.63	$0.85	$1.46

The 2019 reserve costs are higher compared to the 2017 IRP:

- Costs: Reserve costs increase as the system becomes capacity deficient, the 2017 IRP only evaluated costs in calendar year 2017.
- Volume: increased reserve per MW of renewable generation
  - Incremental wind: average reserves are 10% of nameplate additions, vs 6% in 2017 IRP.
  - Incremental solar: average reserves are 5% of nameplate additions, vs 4% in 2017 IRP.
  - More accurate load forecasts reduced overall reserve requirements, but also reduced diversity benefits, leading to higher requirements for incremental wind and solar.
- Applicability: Integration costs are used for portfolio selection in SO. Reserve requirements consistent with each portfolio are used in PaR.

Natural Gas & Storage

- OR 2017 IRP Acknowledgement Order 18-138 April 27, 2018
  - Flexible Reserve Study: In the IRP Update PacifiCorp will model natural gas and storage for meeting flexible reserve study needs.

- Proposed study design:
  - Natural Gas Sensitivity – Single Cycle Combustion Turbine
    - 200 MW East
  - Energy Storage Sensitivity – 4 hour Battery Lithium Ion
    - 100 MW East & 100 MW West

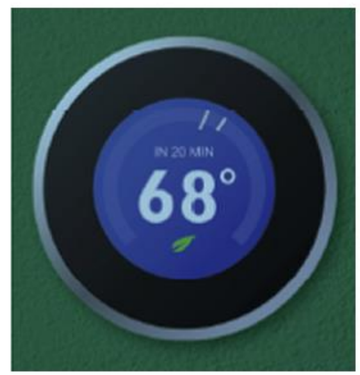
- These sensitivities will incorporate the latest supply-side table assumptions, including intra-hour flexible resource credits.

Flex Reserve Study

- System Balancing Integration Cost
  - 2017 IRP
    - The cost of sub-optimal gas plant commitment based on day-ahead load, wind, and solar forecasts, rather than actuals.
      - Example: Wind generation is expected to be low, so a gas plant is committed up to avoid market purchases. Actual wind generation comes in higher than expected, and the gas plant ends up displacing lower cost generation, instead of market.
    - The measured impact is minimal: $0.09/MWh for load, and $0.14/MWh for wind and solar.
  - 2019 IRP
    - Gas plants are dispatched in EIM to meet regional demand, not just the PacifiCorp demand reflected in the PaR model.
    - Quick-start gas plants can be committed within EIM.
    - Given the minimal impact of this cost and possible interaction with EIM, the Company is not including this cost as part of wind and solar integration for the 2019 IRP.

Planning Reserve Margin & Capacity Contribution Results



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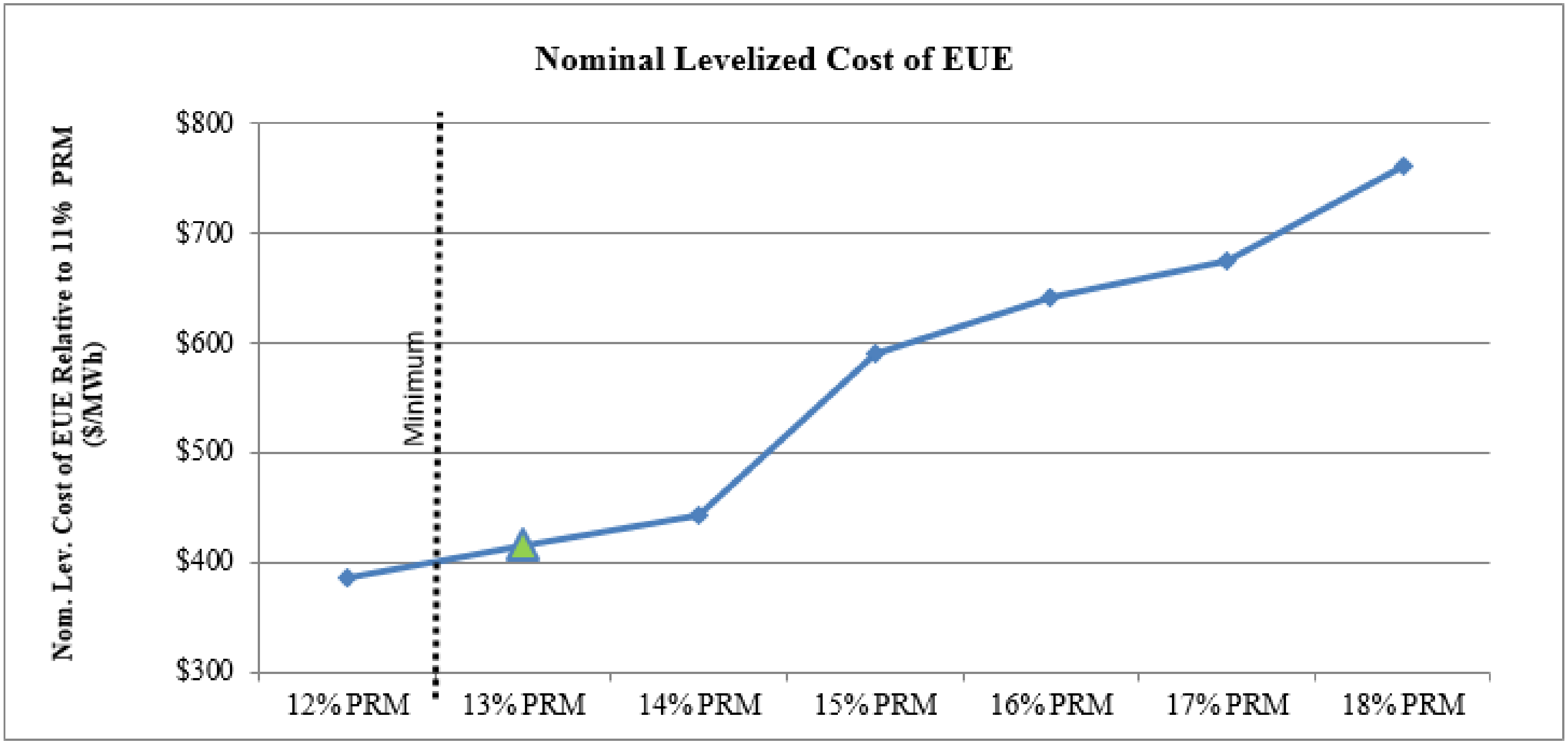
2019 IRP Planning Reserve Margin (PRM)

PacifiCorp will continue to assume a 13% PRM with these key considerations:

- The 13% PRM achieves a 1-in-10 loss of load hour (LOLH) target.
- The marginal cost of reliability accounts for the increase in system costs associated with an incremental reduction in expected unserved energy (EUE).
- The incremental cost of reserves rises with thermal and DSM resource additions; summer FOT selections do not vary significantly between the PRM levels.
- The PRM selected for planning purposes must exceed 11-12% to reliably meet contingency and regulating requirements:
  - 6% short-term contingency reserves
  - 4.5 to 5.5% regulating margin at peak load
  - This minimum is before consideration of long-term uncertainties such as extended outages (transmission or generation) or unanticipated load growth

Incremental Cost of Reliability

- The change in EUE cost is gradual from 12% to 14% PRM
- The 15% PRM reports an increase in EUE cost due to the addition of a large gas resource after 2030.
- The 18% PRM reports an increase in EUE cost due to the addition of a second large gas resource.



PVRR Costs by Planning Reserve Margin Level (2030 to 2036)

PRM (%)	System Production Costs ($m)	Class 2 DSM ($m)	Class 1 DSM ($m)	Existing Resource Fixed Costs ($m)	New Resource Fixed Cost ($m)	Total ($m)
11	11,368	818	120	2,823	3,398	18,527
12	11,383	802	131	2,823	3,472	18,611
13	11,352	833	122	2,823	3,540	18,670
14	11,302	855	130	2,823	3,609	18,719
15	11,313	886	120	2,823	3,684	18,825
16	11,134	936	132	2,823	3,862	18,887
17	11,289	863	134	2,823	3,830	18,939
18	11,149	983	137	2,823	3,931	19,023

PRM Summer & Winter Resource Additions (2030)

PRM (%)	Capacity at Summer Peak (MW)					
	DSM					
	Energy Efficiency	Demand Response	FOT	Nat. Gas	Geo-Thermal/ Other	Total
11	824	240	1,313	1,264	31	3,672
12	821	219	1,416	1,287	31	3,775
13	830	244	1,313	1,459	31	3,877
14	844	218	1,416	1,468	31	3,977
15	854	241	1,313	1,639	31	4,078
16	870	271	1,312	1,694	31	4,177
17	853	273	1,315	1,810	31	4,282
18	891	323	1,313	1,865	31	4,423

PRM (%)	Capacity at Summer Peak (MW)					
	DSM					
	Energy Efficiency	Demand Response	FOT	Nat. Gas	Geo-Thermal/ Other	Total
11	729	0	306	1,458	31	2,524
12	727	0	314	1,484	31	2,556
13	736	0	321	1,682	31	2,769
14	749	0	328	1,692	31	2,801
15	759	0	336	1,889	31	3,015
16	775	0	0	1,915	31	2,721
17	759	0	350	2,087	31	3,227
18	796	0	0	2,113	31	2,940

Reliability Measures (2030) - Simulated

- Reliability measures are determined by PaR simulation results, reported with and without 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. NWPP participation reduces each of these measures by roughly half.

Year	PRM (%)	**Before NWPP Adjustment**			**After NWPP Adjustment**		
		Simulated Energy Not Served (GWh)	LOLH (<2.4 target year) (Hour)	Loss of Load Episodes	EUE (GWh)	LOLH (Hour)	Modeled Loss of Load Episodes
2019 IRP							
2030	11	602	2.46	1.12	327	1.34	0.54
	12	1,038	3.75	1.45	637	2.30	0.78
	13	514	1.97	0.90	279	1.07	0.45
	14	377	1.64	0.79	196	0.85	0.37
	15	193	0.98	0.44	106	0.54	0.23
	16	157	0.87	0.38	88	0.49	0.18
	17	71	0.54	0.27	35	0.27	0.09
	18	107	0.41	0.19	56	0.21	0.08

Capacity Contribution

- Discussed 2019 IRP methodology at the July and August public input meetings.

- Key refinements include:
  - Study year 2030
  - Reflect PRM 13%
  - Hourly study with 500 iterations (3 days run time for 1 year)
  - Planned wind and solar included
  - Isolated the impact of existing wind and solar
  - Isolated the impact of incremental wind and solar additions, an improvement
  - Solar inputs now reflect historical data, not available in 2017 IRP. Historical wind data also updated.
  - Capacity factor of individual wind and solar resources impacts their capacity contribution.
  - Present the trended of capacity contribution for future wind and solar

Capacity Contribution Results

	System					
	East Wind	West Wind	Average Wind	East Solar PV	West Solar PV	Average Solar PV
2019 IRP Existing Resource Results	21.0%	23.6%	**21.6%**	54.4%	41.2%	**44.7%**
2019 IRP Incremental Resource + 1st 500			**19.0%**			**19.7%**
2019 IRP Incremental Resource + 2nd 500			**16.1%**			**7.1%**

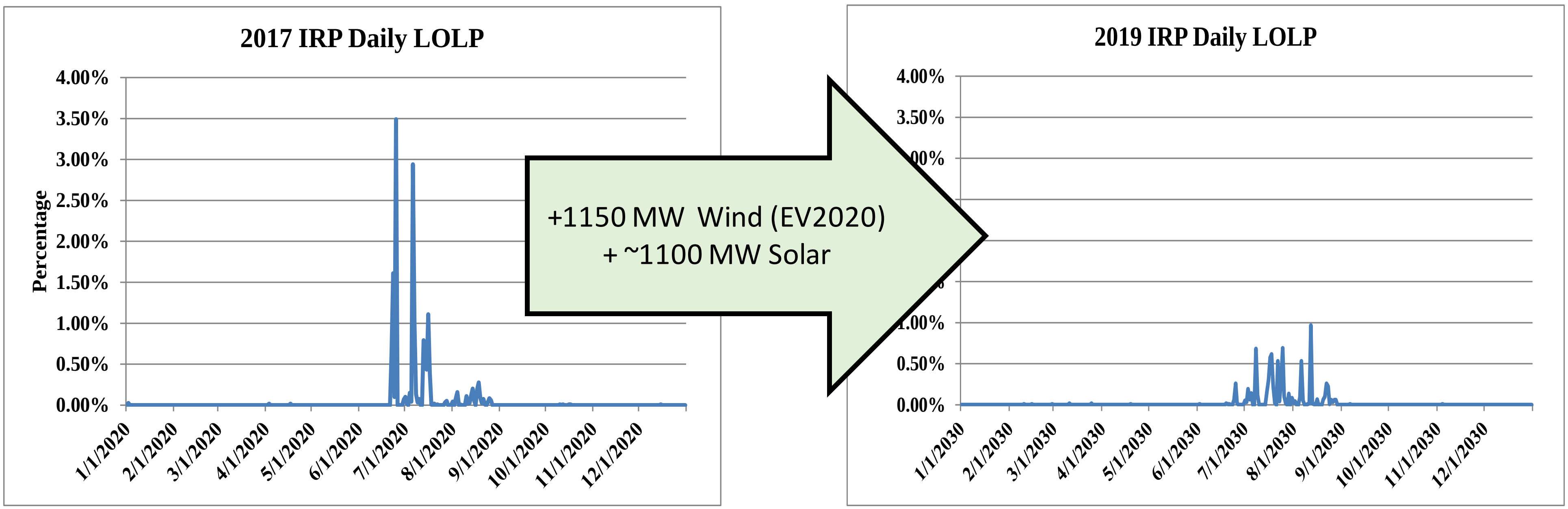
- The results of the capacity contribution study are driven by the coincidence of LOLP and resource shapes/capacity factors and location.
- The updated hourly LOLP distribution is focused on the summer period – the primary driver to changes in wind and solar capacity contribution values.
- Transmission availability will be affected by resource additions and removals, potentially impacting capacity contribution.

Capacity Contribution
CF Approximation Method

	Wind			Solar PV					
	West	East	Average Wind	West, OR Fixed Tilt	East, UT Fixed Tilt	Average Fixed Tilt	West, OR Single Axis Tracking	East, UT Single Axis Tracking	Average Single Axis Tracking
2019 IRP Results	23.9%	26.1%	**25.5%**	19.4%	14.1%	**15.5%**	30.4%	12.2%	**13.8%**
2017 IRP Results	12.9%	15.8%	**14.6%**	52.3%	36.6%	**46.2%**	63.6%	57.2%	**58.5%**

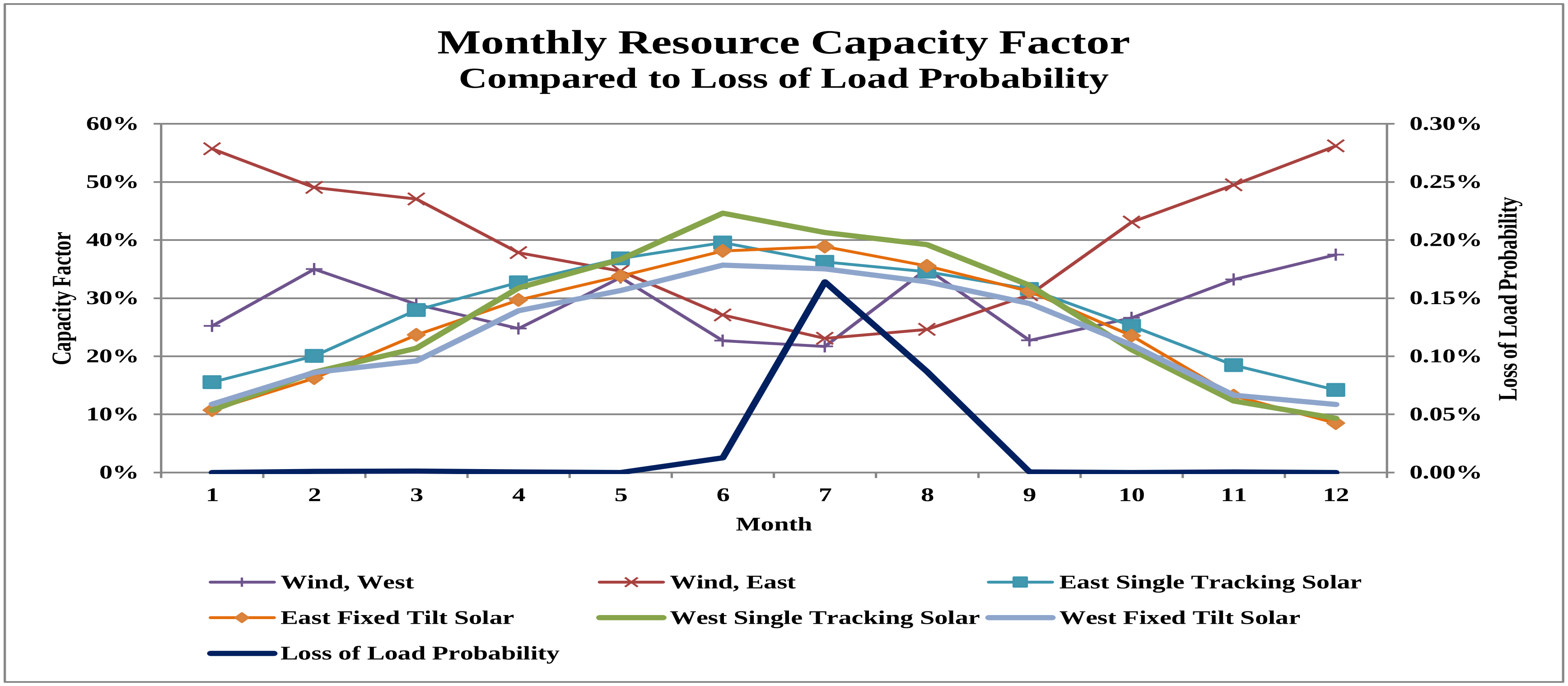
- The updated hourly LOLP distribution during the summer is driving differences from the 2017 IRP.
- 2019 IRP trends in capacity contribution impacted by LOLP distribution:
    - Wind capacity contribution increased against the new LOLP shape
    - Solar capacity contribution decreased against the new shape, driven by increasing solar saturation

2019 IRP LOLP



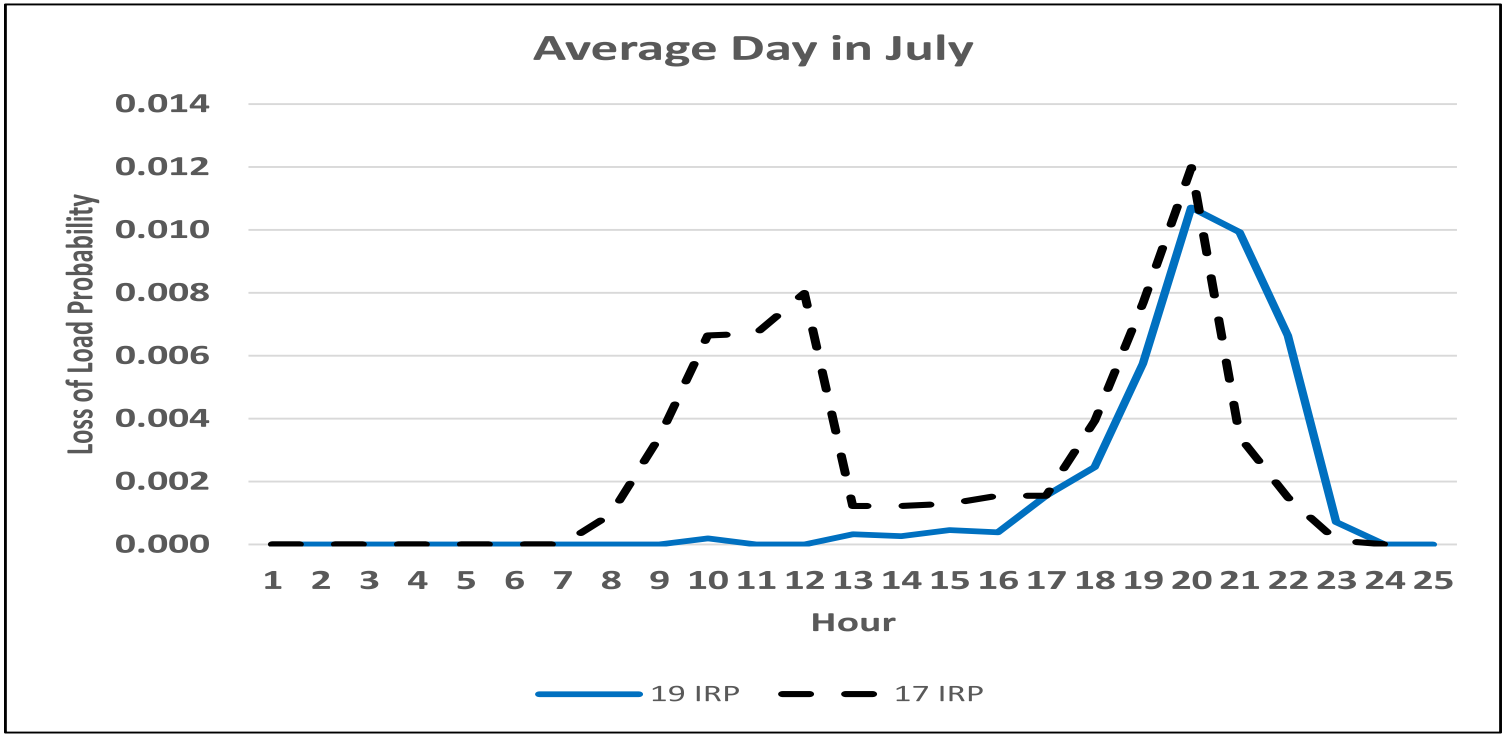
- 2019 IRP Daily LOLP is lower than reported in the 2017 IRP capacity contribution studies.
- The LOLP percentage has dropped, lower in June, but with more events in August.
- The seasonal distribution of the 2019 IRP LOLP shows the highest loss of load probability in summer, aligning with peak loads in July and August.
- LOLP distribution is the main driver of capacity contribution results; planned resources leading up to target year 2030 are the main driver of the change in LOLP distribution.
- Resource shapes remain relatively consistent between the 2017 IRP and 2019 IRP.

2019 IRP LOLP & Capacity Factors



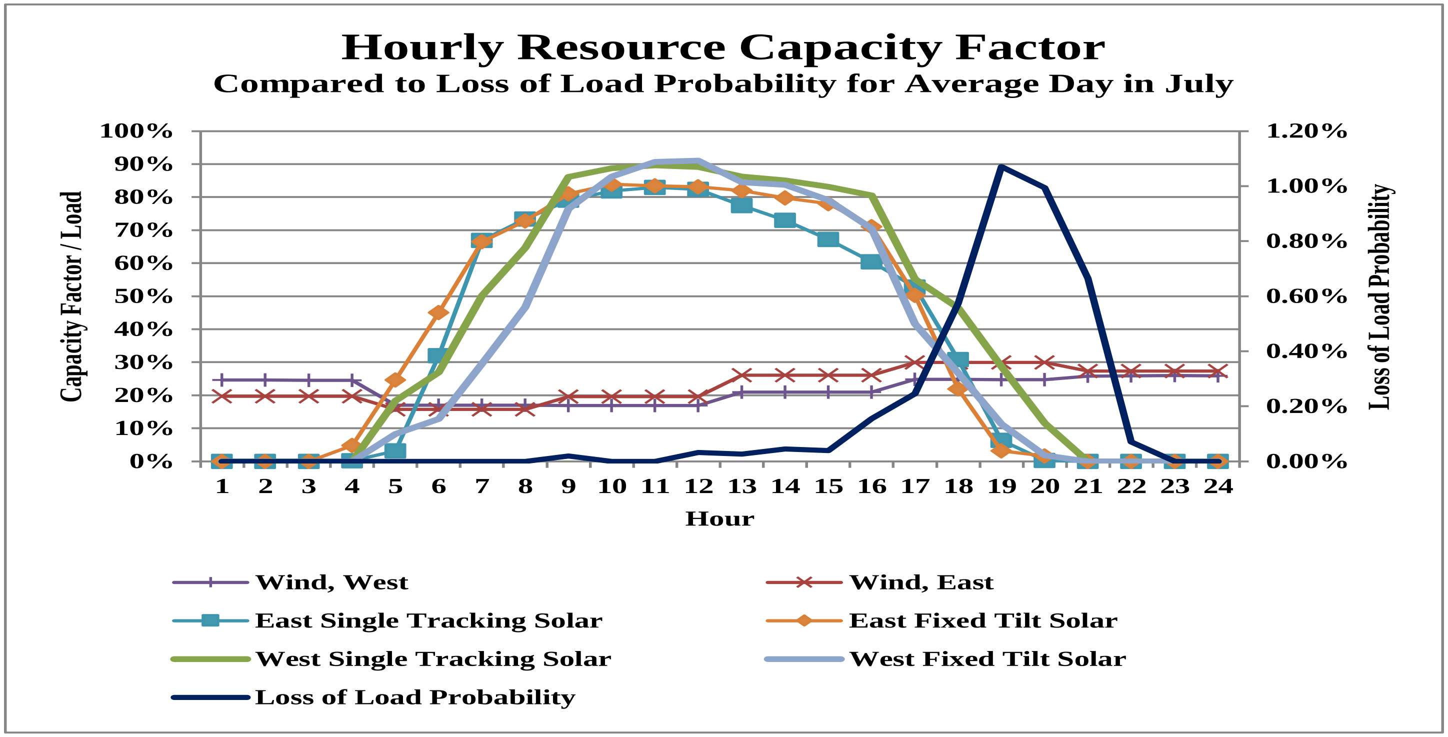
- Monthly impacts should be considered along with the hourly impacts reflecting time of day.
- Both the coincidence of the seasonal distribution of LOLP (highest in summer) and solar capacity factors increase in summer.
- The coincidence of the seasonal distribution of LOLP (highest in summer) while wind capacity factors are lowest in summer.

2019 IRP LOLP



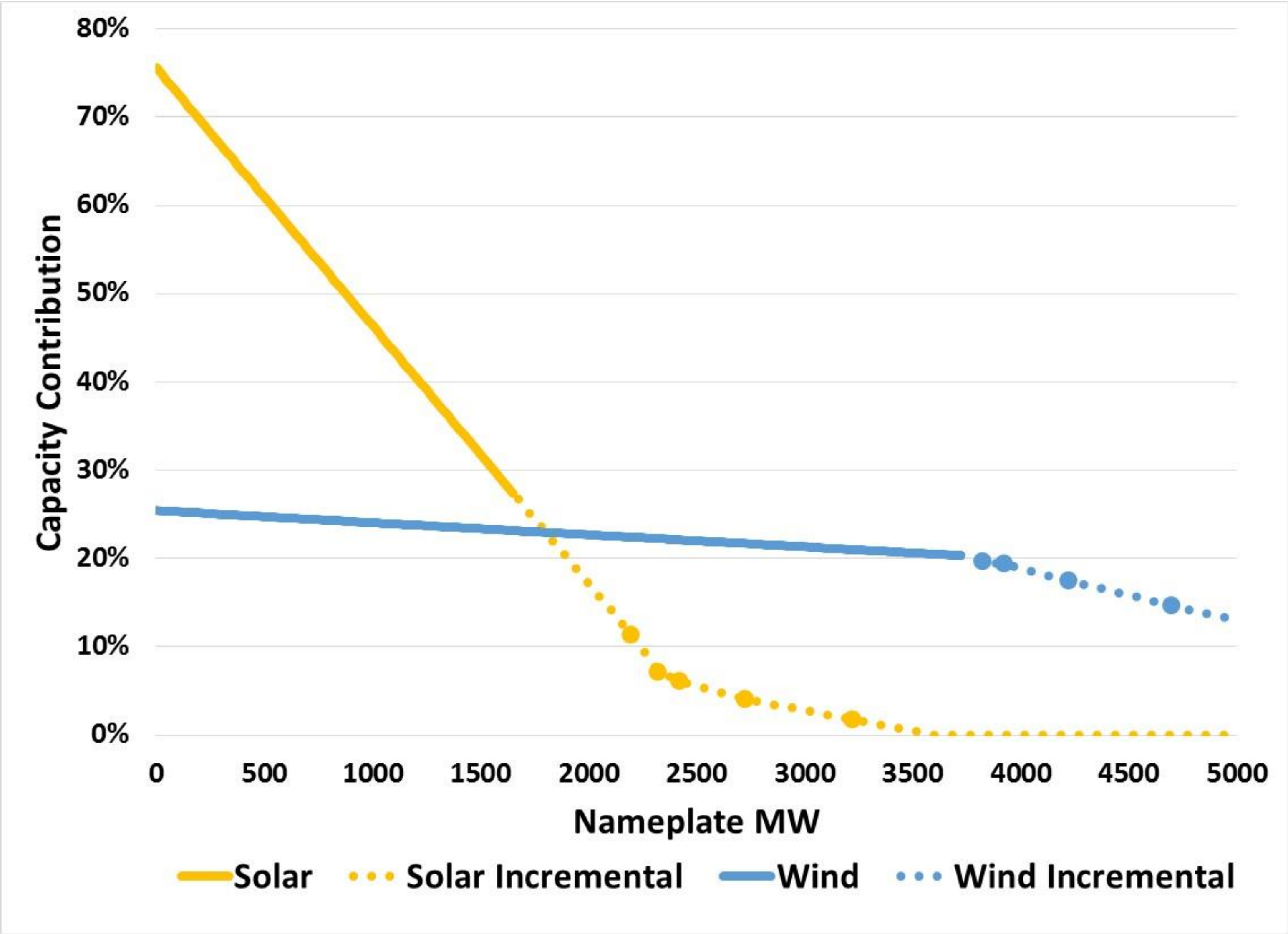
- The trend in the 2019 IRP loss of load probability shifted only to the evening ramp, losing the mid-day bump in the 2017 IRP.
- Driven by planned wind and solar resources.

2019 IRP LOLP & Capacity Factors

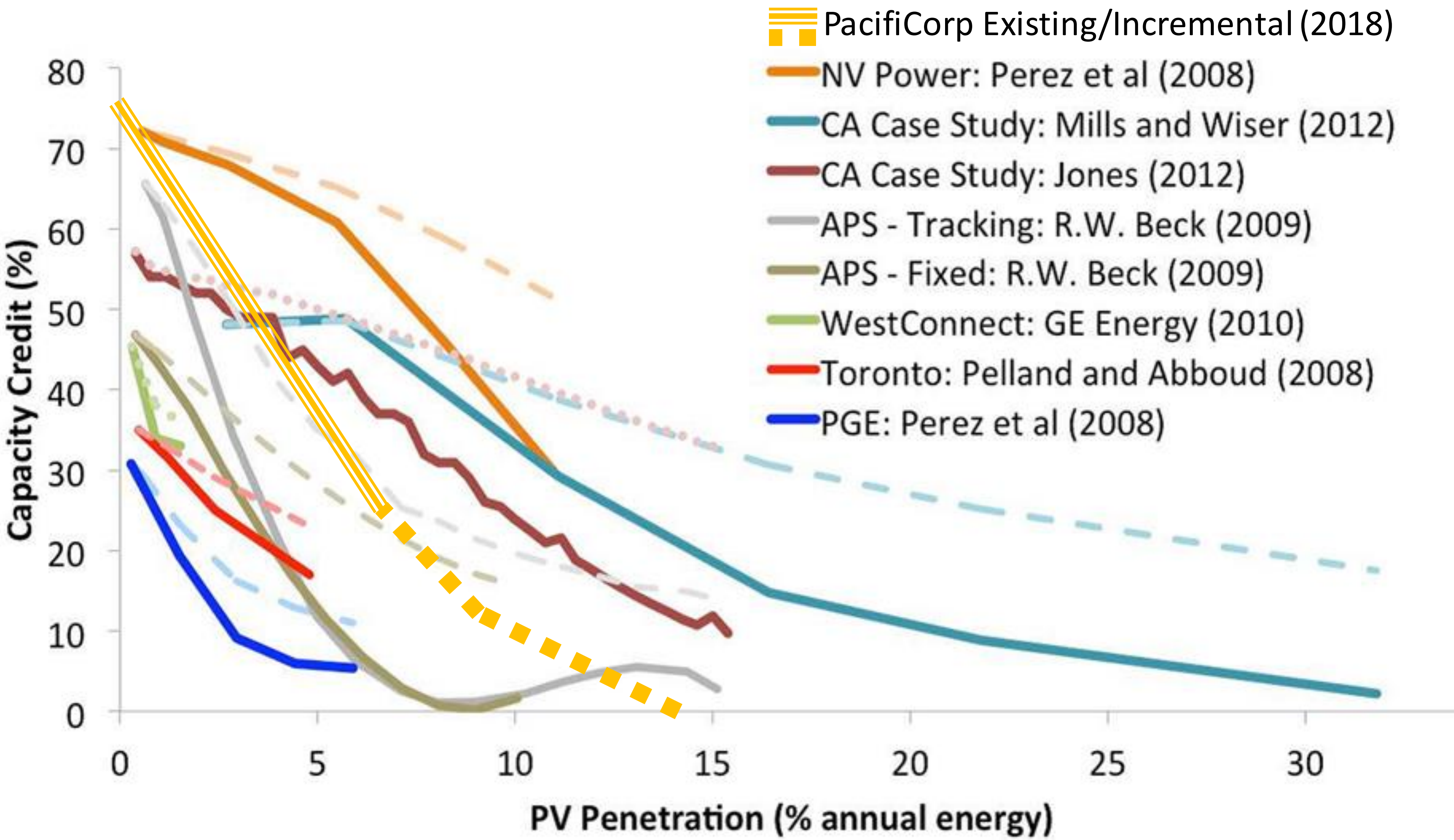


- The hourly distribution of LOLP displays a low coincidence with solar capacity factors, occurring as the sun sets.
- The hourly distribution of LOLP displays a high coincidence with wind capacity factors as wind is generating during these hours.
- For July hours, LOLP events peak during evening ramp periods. This is different from the 2017 IRP where LOLP events peaked in both morning and evening where planned resources EV 2020 and solar additions were not included.

Capacity Contribution vs System Capacity by Technology



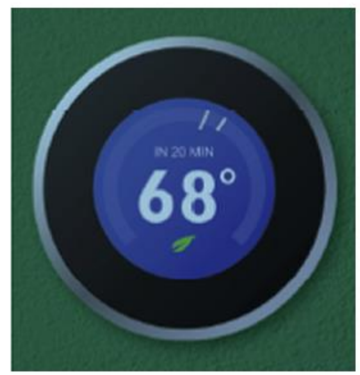
Comparison of Solar Capacity Contribution Studies



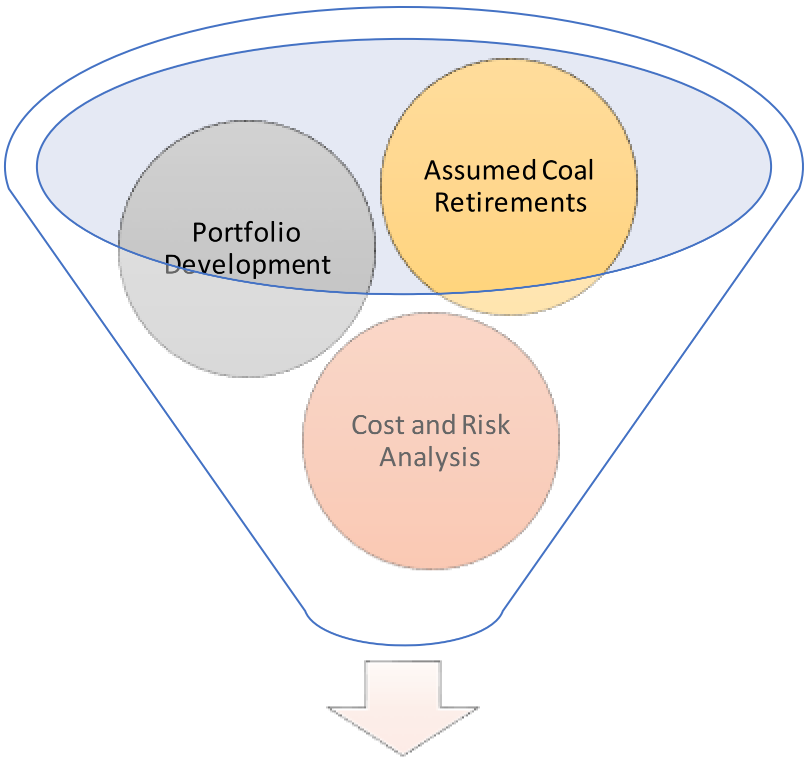
Non-PacifiCorp source: Mills, Andrew, and Ryan Wiser. 2012. "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes." LBNL-5933E, Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory.

Portfolios Discussion & Coal Studies Next Steps



Portfolio Development from 30,000 Feet



Least-Cost, Least-Risk Preferred Portfolio

- Assumed Coal Retirements
  - Economic retirements
  - Regional haze compliance
  - Near-term decisions
  - Commission-ordered studies
- Portfolio Development
  - CO_2 policy
  - Market pricing
  - FOT availability
  - Energy Gateway
  - DSM bundling
  - Other (i.e., state RPS)
- Cost and Risk Analysis
  - Stochastic mean
  - Upper tail risk
  - Reliability
  - Emissions
  - Resource diversity
  - Other
- ≥ 62 System Optimizer runs and ≥ 186 PaR runs

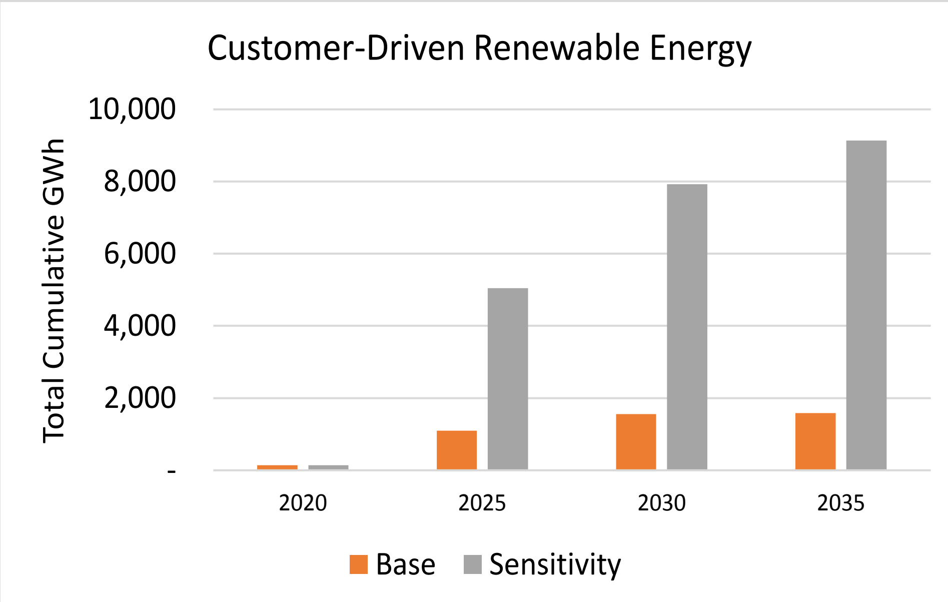
Use of Key Planning Assumptions

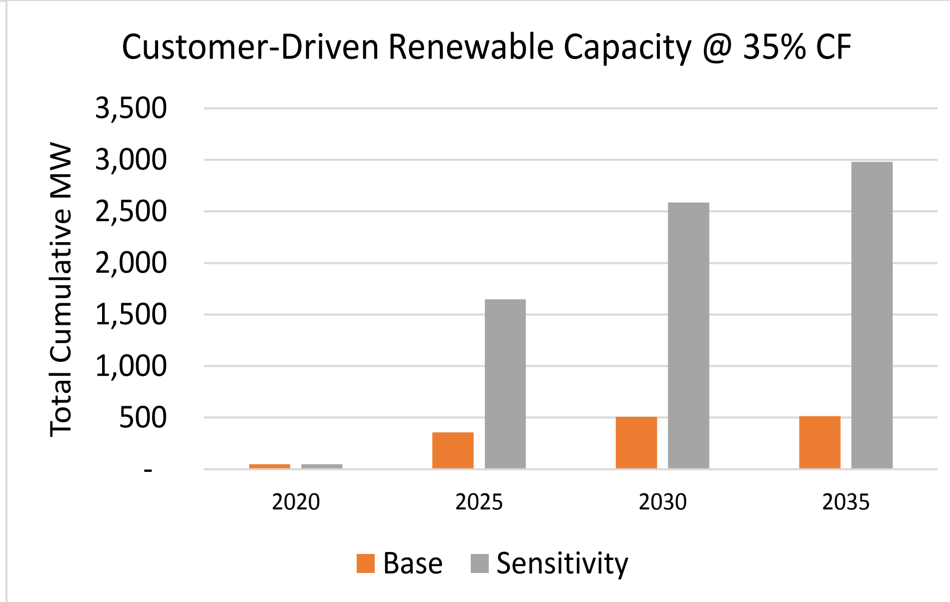
	Base Assumption	Impact Evaluated in Portfolio-Development Process	Impact Evaluated in Scenario and Stochastic Risk Analysis	Impact Evaluated in Sensitivity Analysis
Planning-Reserve Margin	✓	✗	✗	✗
Capacity-Contribution Values	✓	✗	✗	✗
Flex-Reserve Requirements	✓	✗	✗	✗
Stochastic Variables	✓	✗	✗	✗
Hourly Market-Price Profile	✓	✗	✗	✗
Supply-Side Resources	✓	✗	✗	✗
Conservation Potential Ass.	✓	✗	✗	✗
DSM Bundling	✓	✓	✗	✗
Coal-Unit Retirements	✓	✓	✗	✗
Transmission Topology	✓	✓	✗	✗
FOT Availability	✓	✓	✗	✗
Market Prices	✓	✓	✓	✓
CO_2 Prices	✓	✓	✓	✓
Load Forecast	✓	✗	✓	✓
Hydro Generation	✓	✗	✓	✗
Private Generation	✓	✗	✗	✓
Business Plan Resources	✓	✗	✗	✓
West Control Area	✓	✗	✗	✓
Customer-Drive Renewables	✓	✗	✗	✓

Planning for Customer-Driven Renewable Resources

- Customers are increasingly interested in supporting incremental renewable resources that generate sufficient electricity to match their annual energy needs.
- PacifiCorp is actively working with a number of municipalities, counties and corporations to identify renewable projects that can meet their renewable resource targets.
- It is important that PacifiCorp's resource plan account for these incremental renewable resources and the 2019 IRP will include proxy renewables needed to meet the renewable resource goals for these customers.
- Any customer-driven renewable resources included in the preferred portfolio will be explicitly identified as such.
- The 2019 IRP will also evaluate alternative customer-driven renewable resource assumptions in two different sensitivity studies:
    - Additional growth in customer-driven renewable resources over time.
    - No incremental customer-driven renewable resources.
- Changes in the resource portfolio and associated system cost from these two sensitives can be compared to a portfolio and associated system cost reflecting base case customer-driven renewable assumptions.
- The change in system cost can be used to estimate, in aggregate, the incremental costs that renewable customers would need to cover to ensure that other customers are indifferent to customer-driven renewable resource choices.

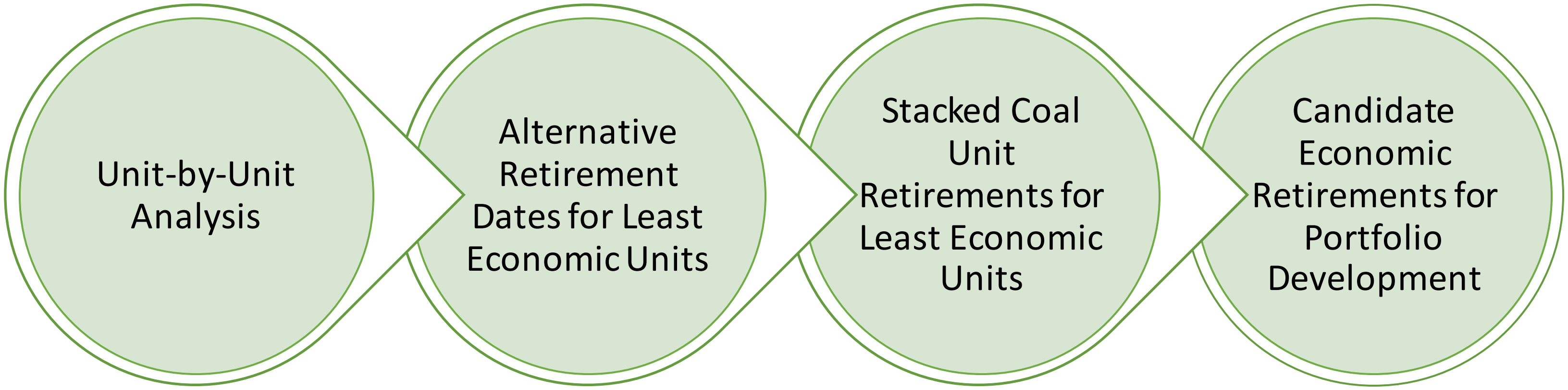
Customer-Driven Renewable Resource Assumptions





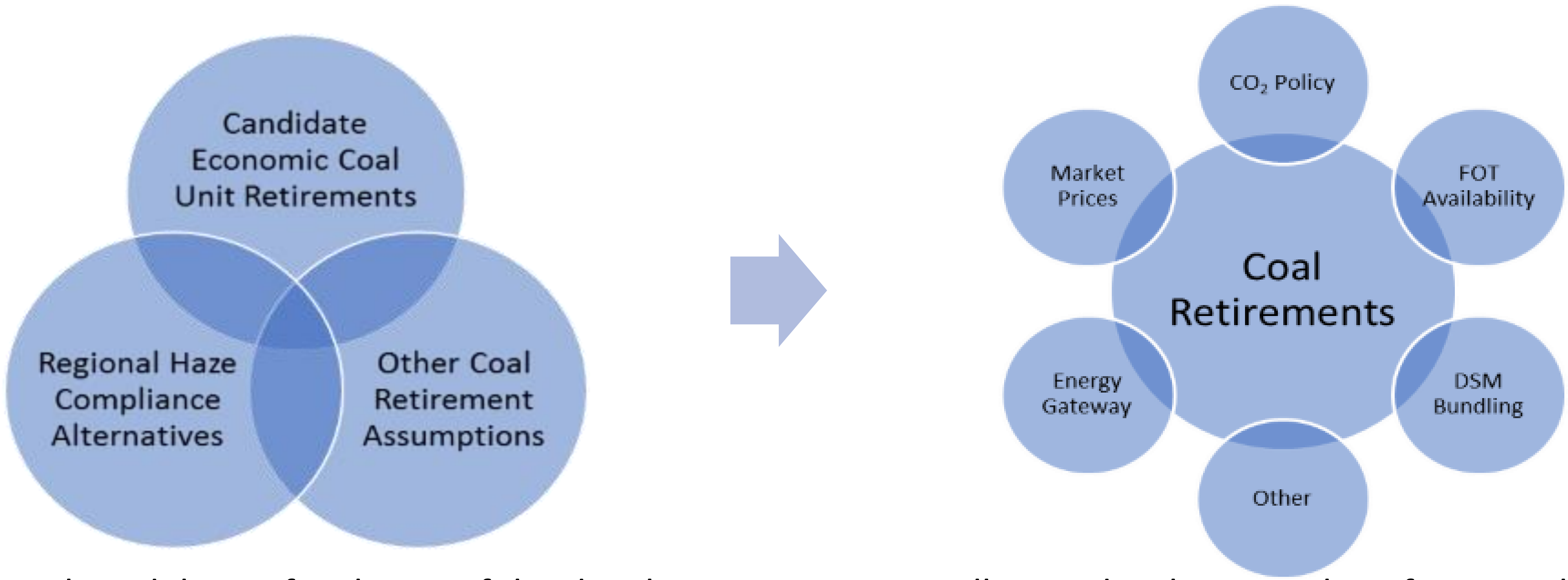
- PacifiCorp will configure the System Optimizer model to endogenously choose renewable resources that generate sufficient annual energy to meet customer-driven renewable targets.
- Renewable capacity (nameplate) shown at top right is illustrative and calculated using a 35% capacity factor—the actual capacity will vary depending upon the capacity factor of the specific renewable resources added to the portfolio.
- The energy and capacity shown for the sensitivity includes the energy and capacity shown for the base case.
- As noted on the previous slide, PacifiCorp will also produce a sensitivity that does not include any customer-driven renewable resources.

Economic Coal Unit Retirement Analysis Process



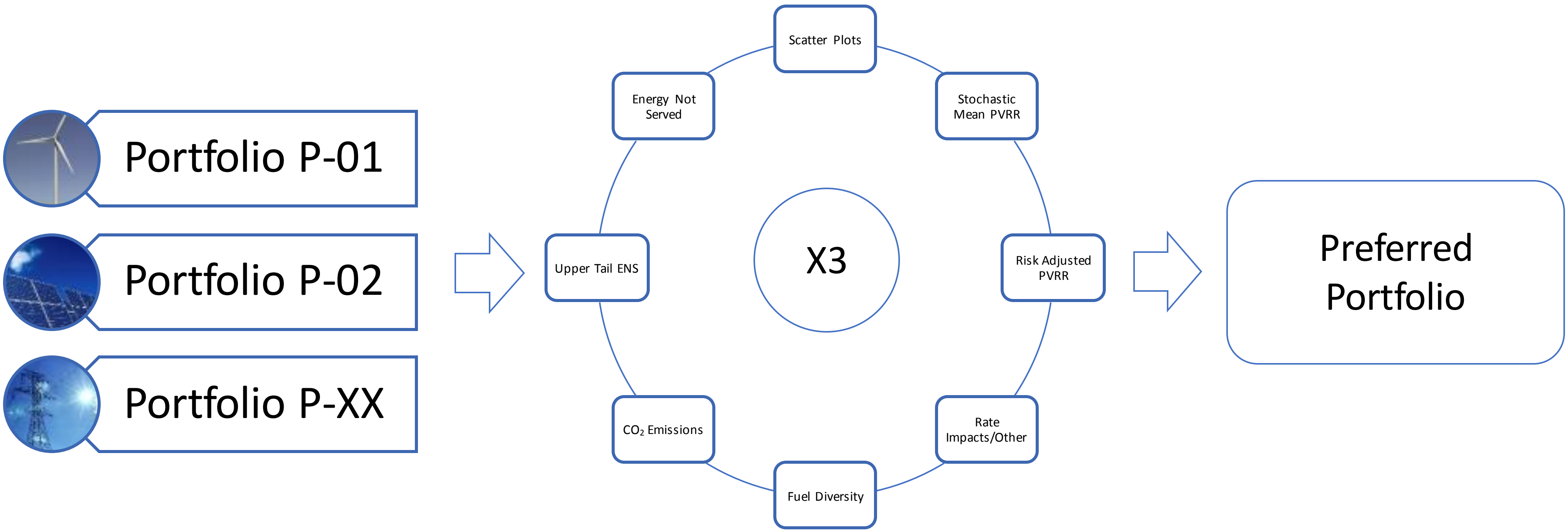
- Updated unit-by-unit analysis will reflect 2019 IRP planning assumptions, consider impacts on system reliability, and be evaluated using the Planning and Risk model (PaR).
- PacifiCorp will assess alternative retirement dates for the least economic units (2022, 2025, 2028, and 2031).
- Stacked analysis will be performed on the least economic units, assuming retirement dates that are consistent those identified from the alternative retirement date studies.
- Potential economic retirements, informed by the analysis described above, will be further evaluated in the 2019 IRP portfolio development process.
- Portfolios will be developed using the System Optimizer model with base case price-policy assumptions, and cost-and-risk analysis will be performed using PaR under three different price-policy scenarios.
- ≥ 30 System Optimizer runs and ≥ 90 PaR runs

Portfolio-Development Process



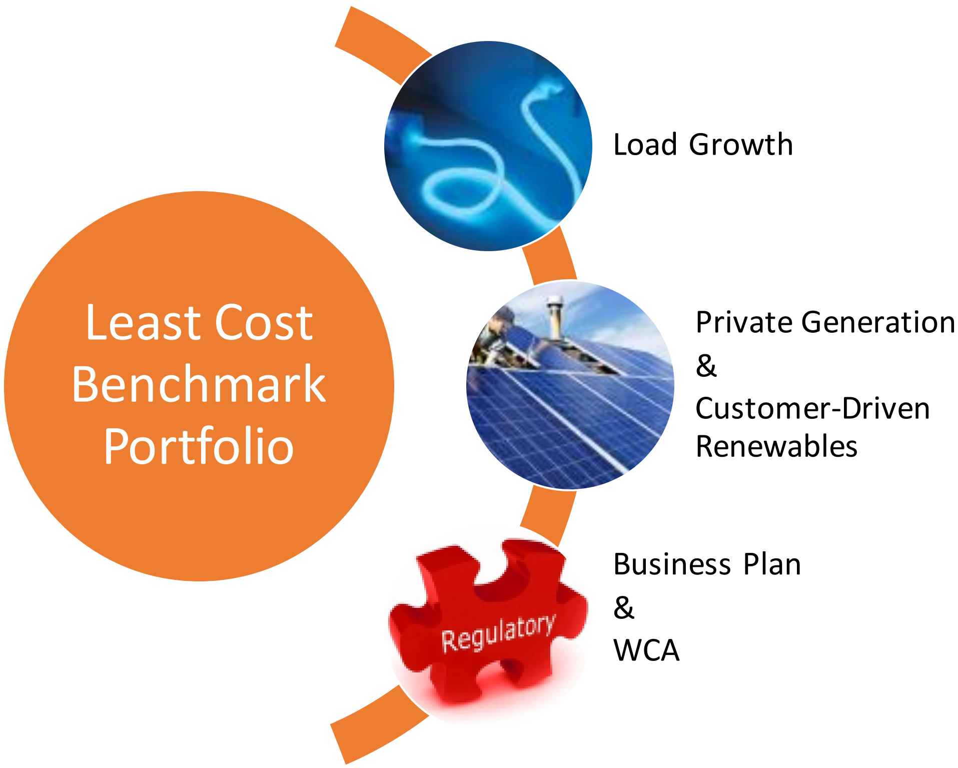
- Initial model runs for the portfolio-development process will consider the interplay of Regional Haze compliance alternatives with potential economic coal unit retirements while evaluating near-term coal unit decisions (*i.e.*, Naughton 3, Jim Bridger 1 and 2), updating analysis from the 2017 IRP (*i.e.*, Cholla 4), and incorporating commission-ordered analysis (*i.e.*, Colstrip 3 and 4).
- Additional portfolio will be developed, using coal retirement assumptions that can meet compliance obligations and that minimize system costs, using alternative assumptions for other system variables (*i.e.*, CO_2 policies, market prices, FOT availability, Energy Gateway, and DSM).
- Once initial model results are available, additional portfolios may be developed.
- Cost-and-risk analysis will be performed using PaR under three different price-policy scenarios.
- ≥ 23 System Optimizer runs and ≥ 69 PaR runs

Preferred Portfolio Selection Process



- Multiple cost and risk metrics are used to rank resource portfolios across three different price-policy scenarios.
- The Washington Utilities and Transportation Commission (WUTC) 2017 IRP acknowledgement letter requires PacifiCorp to consider the monetary cost of climate change in the preferred portfolio and suggests using the Interagency Working Group on Social Cost of Greenhouse Gases with a three percent discount rate.
- PacifiCorp will meet this requirement by evaluating cost and risk metrics, reflecting the social cost of carbon price assumption, as applied to top-performing portfolios, including the portfolio developed assuming application of the social cost of carbon price.
- The resulting portfolio rankings for the various cost and risk metrics will inform PacifiCorp's selection of the preferred portfolio in the 2019 IRP.

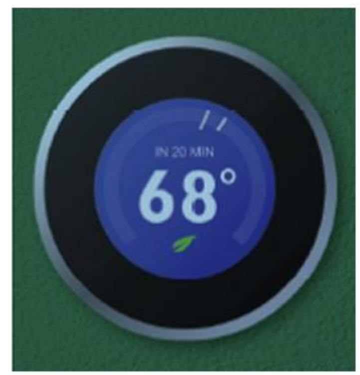
Sensitivities

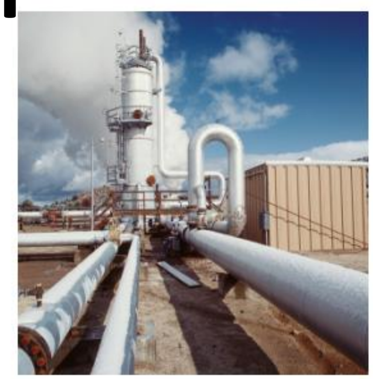


- Sensitivity studies are used to understand how specific planning assumptions might alter the resource portfolio over time.
- These studies, along with analysis performed in the portfolio development process, are useful when developing the acquisition-path analysis in the IRP.
- PacifiCorp plans to evaluate variations in load growth assumptions, private generation assumptions, customer-driven renewables, and other regulation-driven studies (*i.e.*, business plan, west-control area).
- Once initial model results are available, additional sensitivities may be developed.
- ≥ 9 System Optimizer runs and ≥ 27 PaR runs

Demand-Side Management T&D Credit & Conservation Potential Assessment Follow-Up





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T&D Deferral Key Inputs

- Transmission and Distribution Capacity Capital Investment
  - 5 year forward looking
  - Estimated costs
- Capacity Installed
  - Net
- Power Factor
  - Standard Power factor
- Real Levelized Carrying Charge
  - Transmission and Distribution (by state)
- Locational Proxy
  - Distribution Substation Transformer Utilization (by state)

T&D Deferral Calculation

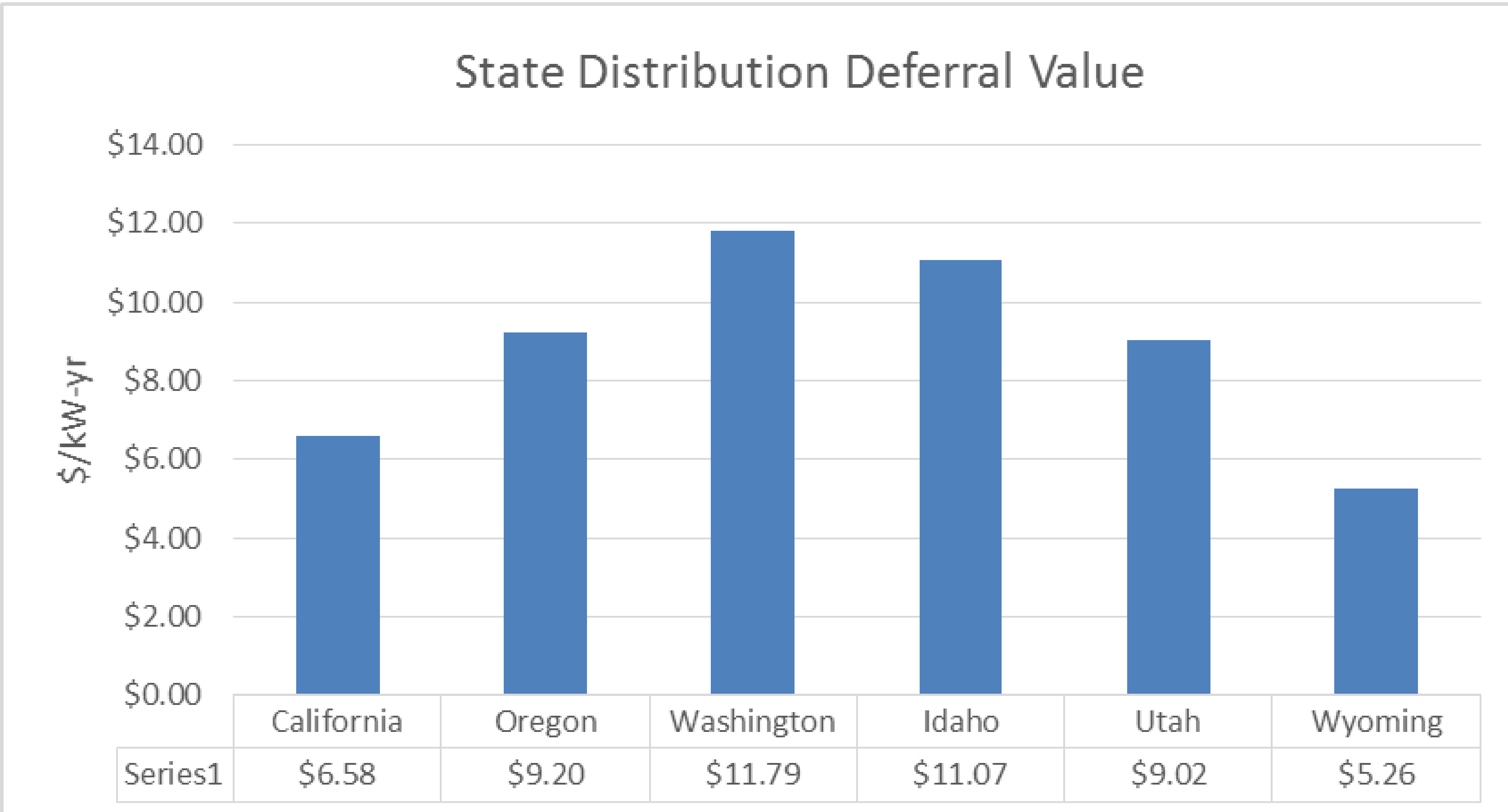
- Transmission

$$\left(\left(\frac{Transmission\ Capacity\ Investment}{Capacity\ Installed}\right) \div Power\ Factor\right) \times Real\ Levelized\ Transmission\ Carrying\ Charge$$

- Distribution

$$\left(\left(\frac{Distribution\ Capacity\ Investment}{Capacity\ Installed}\right) \div Power\ Factor\right) \times State\ Real\ Levelized\ Distribution\ Carrying\ Charge \times State\ Dsitribution\ Substation\ Transformer\ Utilization$$

Energy Efficiency T&D Deferral Value



2019 IRP Class 2 DSM MWh Potential by Bundle

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming	Total
<= 10	37,982	95,994	549,917	1,374,149	202,336	385,803	2,646,181
10 - 20	5,441	34,885	109,045	554,083	73,645	108,425	885,524
20 - 30	4,471	66,699	344,713	682,479	67,854	68,278	1,234,494
30 – 40	32,775	47,348	611,481	582,203	165,377	250,951	1,690,134
40 – 50	13,351	24,002	527,253	345,752	52,067	233,885	1,196,310
50 - 60	6,380	36,192	260,480	235,827	46,071	167,710	752,660
60 – 70	3,710	19,892	200,163	130,816	47,889	74,661	477,131
70 – 80	7,787	8,866	168,229	188,637	29,395	30,744	433,658
80 – 90	2,951	12,395	70,325	134,635	24,964	14,246	259,516
90 – 100	4,346	14,015	11,637	144,485	23,268	41,217	238,968
100 – 110	4,334	7,662	56,015	183,102	18,871	86,120	356,104
110 – 120	2,214	15,316	39,623	136,360	14,274	20,511	228,298
120 – 130	2,179	13,959	15,688	86,526	25,384	13,763	157,500
130 – 140	10,389	7,141	115,146	94,022	35,672	6,258	268,629
140 – 150	7,598	4,989	62,573	172,631	18,036	19,701	285,529
150 - 160	1,862	5,160	137,281	44,539	13,692	9,562	212,096
160 – 170	1,947	9,325	33,284	46,556	10,030	6,764	107,906
170 – 180	2,458	2,375	72,957	44,348	7,055	17,161	146,353
180 – 190	1,723	1,855	15,798	37,928	11,793	9,643	78,740
190 – 200	792	1,375	2,294	34,678	20,893	4,788	64,819
200 – 250	14,110	32,105	2,924	115,685	56,325	44,743	265,891
250 – 300	9,988	8,302	4,795	101,965	17,686	19,268	162,003
300 – 400	11,696	13,838	4,220	171,167	31,321	23,597	255,839
400 – 500	1,864	4,084	17,134	55,848	11,575	10,118	100,625
500 – 750	6,037	10,541	46,965	131,313	24,533	12,734	232,124
750 – 1,000	5,581	4,590	42,758	26,605	22,829	16,075	118,439
> 1000	7,528	14,243	21,631	184,592	37,792	42,275	308,062
Total	**211,495**	**517,148**	**3,544,327**	**6,040,931**	**1,110,628**	**1,739,002**	**13,163,531**

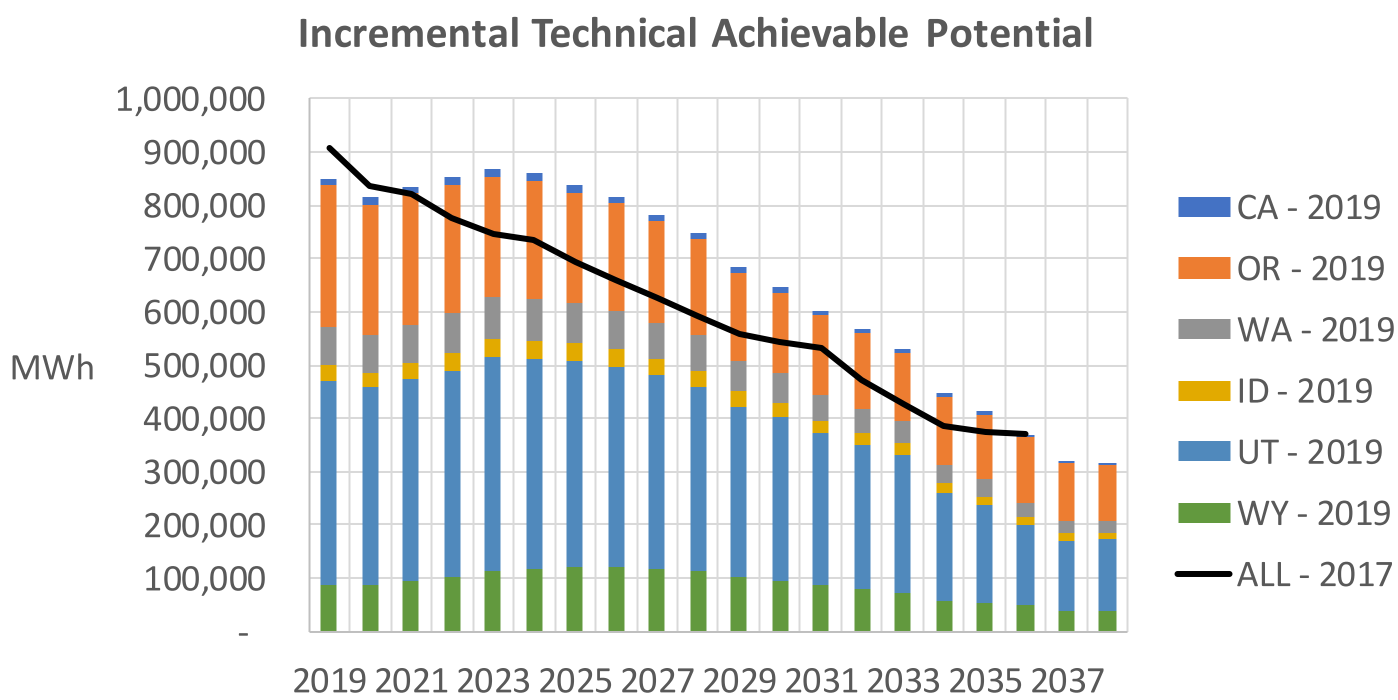
2017 IRP Class 2 DSM MWh Potential by Bundle

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming	Total
<= 10	27,146	91,695	610,445	972,850	118,725	211,694	2,032,555
10 - 20	8,772	37,868	186,280	869,625	43,968	91,745	1,238,259
20 - 30	10,126	45,728	688,346	588,821	79,553	131,056	1,543,631
30 – 40	14,956	38,417	334,064	411,008	52,584	342,310	1,193,338
40 – 50	9,775	52,426	229,316	483,287	65,569	193,275	1,033,648
50 - 60	4,341	36,941	77,508	530,396	87,588	151,994	888,767
60 – 70	17,388	15,456	5,469	455,608	61,885	64,025	619,832
70 – 80	9,417	25,123	134,301	220,392	42,658	107,615	539,508
80 – 90	5,154	10,915	100,947	108,222	26,837	49,829	301,905
90 – 100	10,254	16,337	326,823	73,579	34,445	23,983	485,421
100 – 110	11,845	15,402	123,499	73,895	40,142	83,812	348,595
110 – 120	5,672	5,813	84,733	81,351	25,457	20,135	223,161
120 – 130	2,185	1,895	31,830	135,611	13,624	8,299	193,444
130 – 140	1,180	2,936	243	96,048	12,904	7,132	120,443
140 – 150	3,650	9,583	8,074	102,483	20,565	19,236	163,591
150 - 160	5,327	13,075	5,370	171,330	1,751	12,537	209,389
160 – 170	2,948	2,079	11,767	79,327	11,433	31,246	138,800
170 – 180	1,553	21,250	123,068	20,376	27,385	13,435	207,068
180 – 190	2,420	4,429	21,219	72,989	24,746	2,655	128,458
190 – 200	1,461	1,412	0	8,995	28,040	7,011	46,919
200 – 250	20,293	20,386	13,612	51,139	28,980	33,316	167,726
250 – 300	1,173	4,187	24,169	30,894	11,539	7,536	79,498
300 – 400	3,750	6,470	30,240	174,195	16,937	12,491	244,083
400 – 500	1,627	3,338	57,170	154,893	13,614	10,608	241,249
500 – 750	7,154	9,940	4,520	87,716	16,628	20,803	146,761
750 – 1,000	1,954	4,118	4,553	36,122	7,967	4,789	59,502
> 1000	2,418	7,107	124,020	55,743	11,637	19,268	220,193
Total	**193,941**	**504,325**	**3,361,587**	**6,146,893**	**927,162**	**1,681,837**	**12,815,746**

DSM Class 2 Potential Update

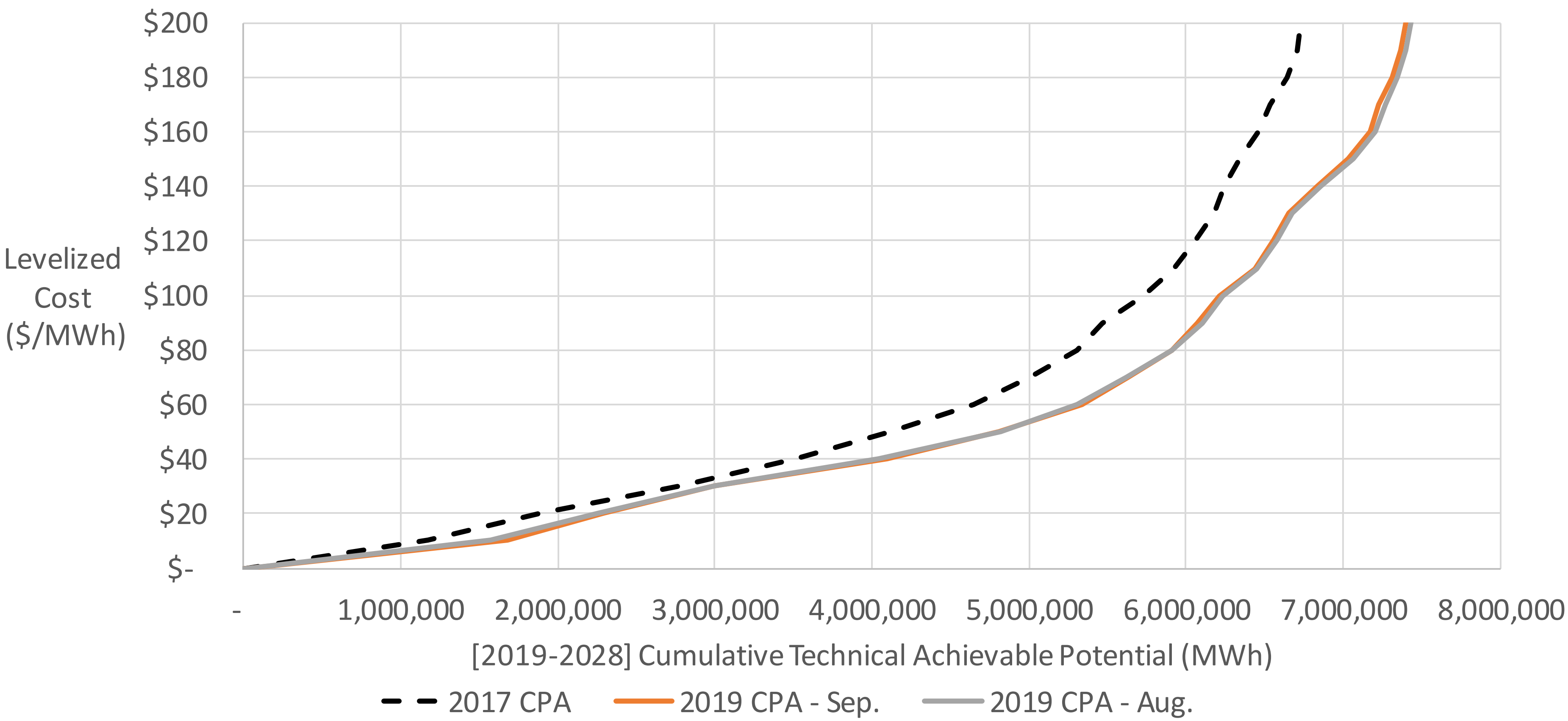
- Updated costs for lighting
  - Aligned commercial lighting incentives with actual spend
  - Updated residential baseline lighting costs with current RTF assumptions
  - Assumed greater mix of linear LEDs in California's nonresidential baseline per DEER assumptions/Title 24 compliance
- Updated ENERY STAR commercial reach-in refrigerator savings to reflect the 2017 federal standard
- Considering a project adder in all states

Technical Achievable Potential Comparison



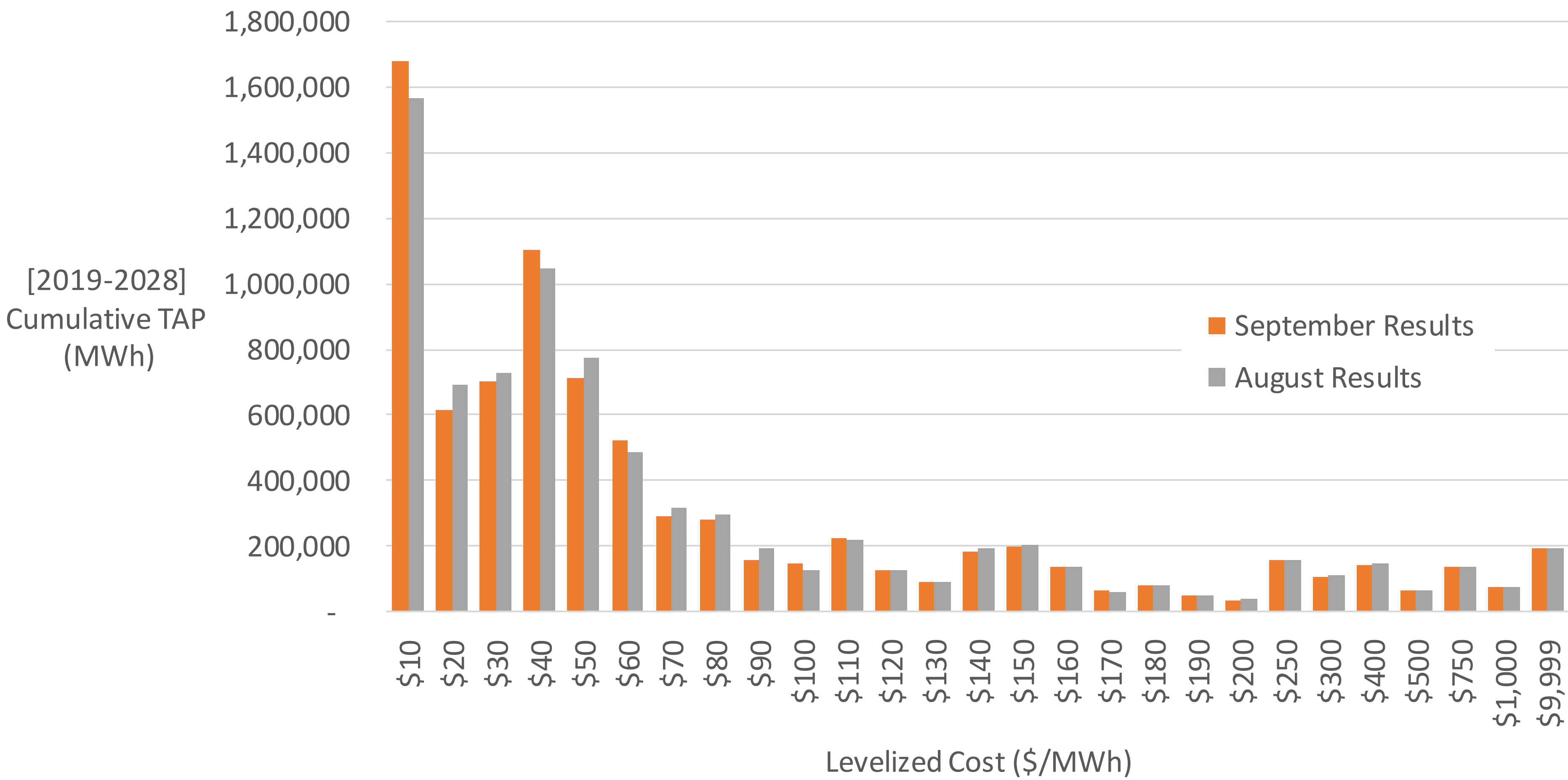
- Potential has not significantly changed since the August IRP workshop.
- Lower-cost bundles have slightly higher potential as seen on the following slide.

Technical Achievable Potential Supply Curve Comparison (All States)



- Grey line summarizes TAP August meeting estimates, orange line summarizes current estimates
- Cost bundles represent the Technical Achievable Potential, the not Economical Achievable Potential. Each cost bundle represents a different shape based on the measures within it.
- Cost bundles are selected based on their ability to meet the Company's system peak.

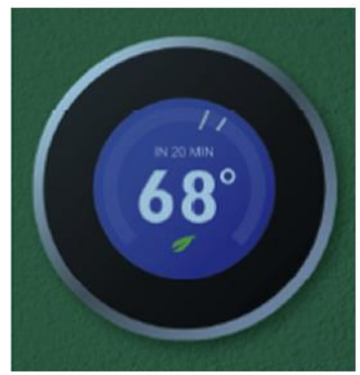
Technical Achievable Potential by Cost Bundle (All States)



- Graphic summarizes cumulative Technical Achievable Potential in 2028 by cost bundle
- Potential migrated into lower cost bundles due to lighting cost changes previously noted

Additional Information and Next Steps



PACIFICORP
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Draft Topics for Upcoming PIMs*

October 11, 2018 PIM Conference Call (1:00pm-3:00pm pacific):

- Supply-Side Resource Table
- Intra-Hour Flexible Resource Credit (storage)

November 1-2, 2018 PIM*:

- Coal Studies
- Stakeholder Feedback Form Recap

December 3-4, 2018 PIM*:

- Load & Resource Balance
- Regional Haze Portfolios
- Portfolios / Sensitivity Cases
- Stakeholder Feedback Form Recap

** Topics and timing are tentative and subject to change*

Additional Information and Next Steps

- Public Input Meeting Presentation and Materials:
  - pacificorp.com/es/irp.html
- 2019 IRP Stakeholder Feedback Forms and Summary Matrix:
  - pacificorp.com/es/irp/irpcomments.html
- IRP Email / Distribution List Contact Information:
  - IRP@PacifiCorp.com
- Upcoming Public Input Meeting Dates:
  - October 11, 2018 – Conference Call
  - November 1-2, 2018
  - December 3-4, 2018
  - January 24-25, 2019
  - February 21-22, 2019
  - March 2019 – *TBD /as needed*
  - *April 1, 2019 – 2019 IRP File Date*