2023 Integrated Resource Plan
IRP Public-Input Meeting
July 14, 2022




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Agenda

(times shown in Pacific time zone)

- 9:00 – 9:15 a.m. – Introductions
- 9:15 – 10:15 a.m. – Draft Load Forecast Update
- 10:15 – 11:45 p.m. – Draft Private Generation Study
- 11:45 – 12:30 p.m. – Lunch Break
- 12:30 – 2:00 p.m. – Draft Distribution System Planning
- 2:00 – 2:45 p.m. – Renewable Portfolio Standards
- 2:45 – 3:00 p.m. – Stakeholder Feedback
- 3:00 – 3:30 p.m. – Ozone Transport Rule Update
- 3:30 – 3:45 p.m. – Wrap-Up / Next Steps

Draft 2023 IRP Load Forecast




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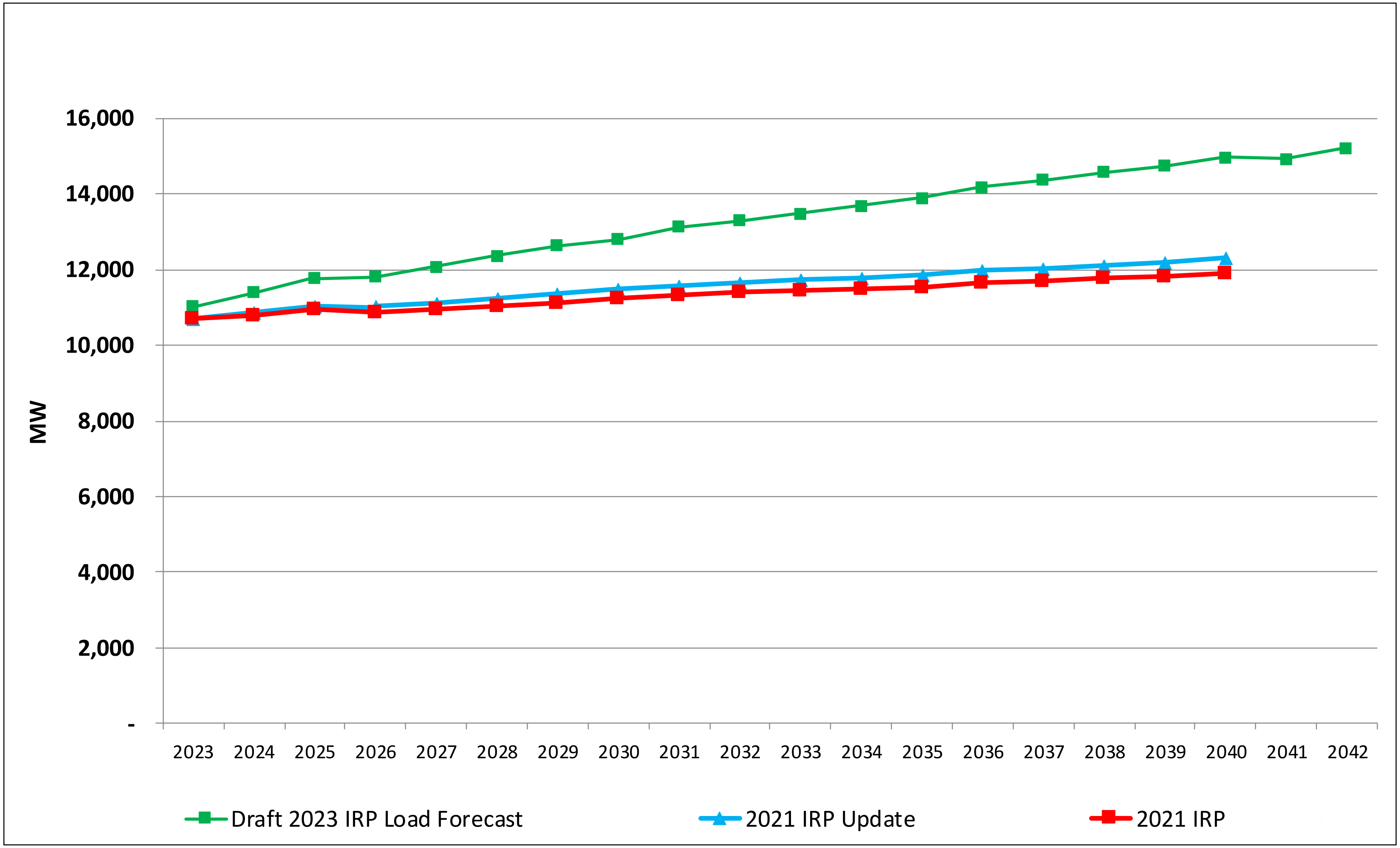
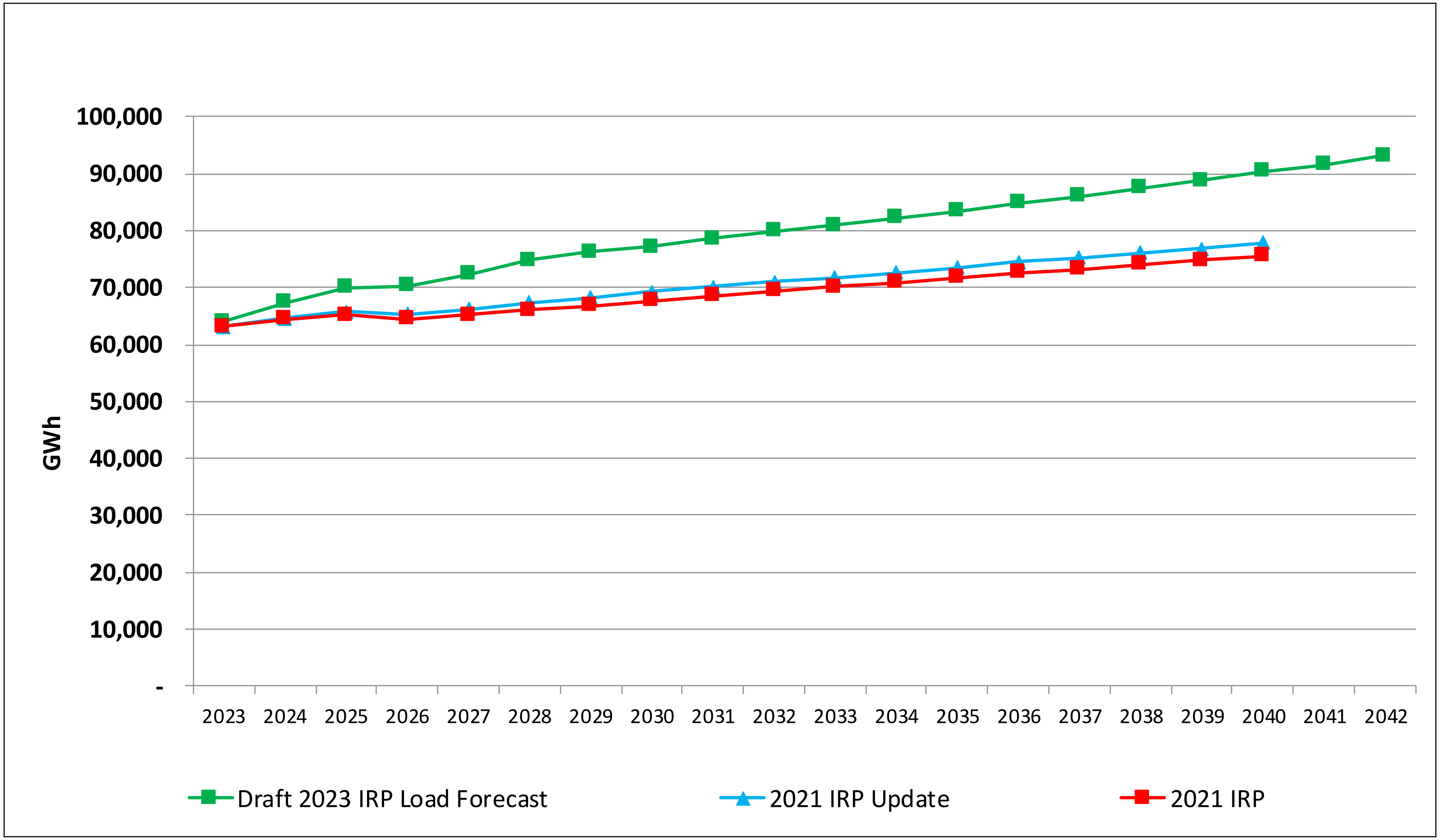
System Peak Load Forecast Change



System Energy Load Forecast Change



Draft 2023 IRP Load Forecast Key Drivers

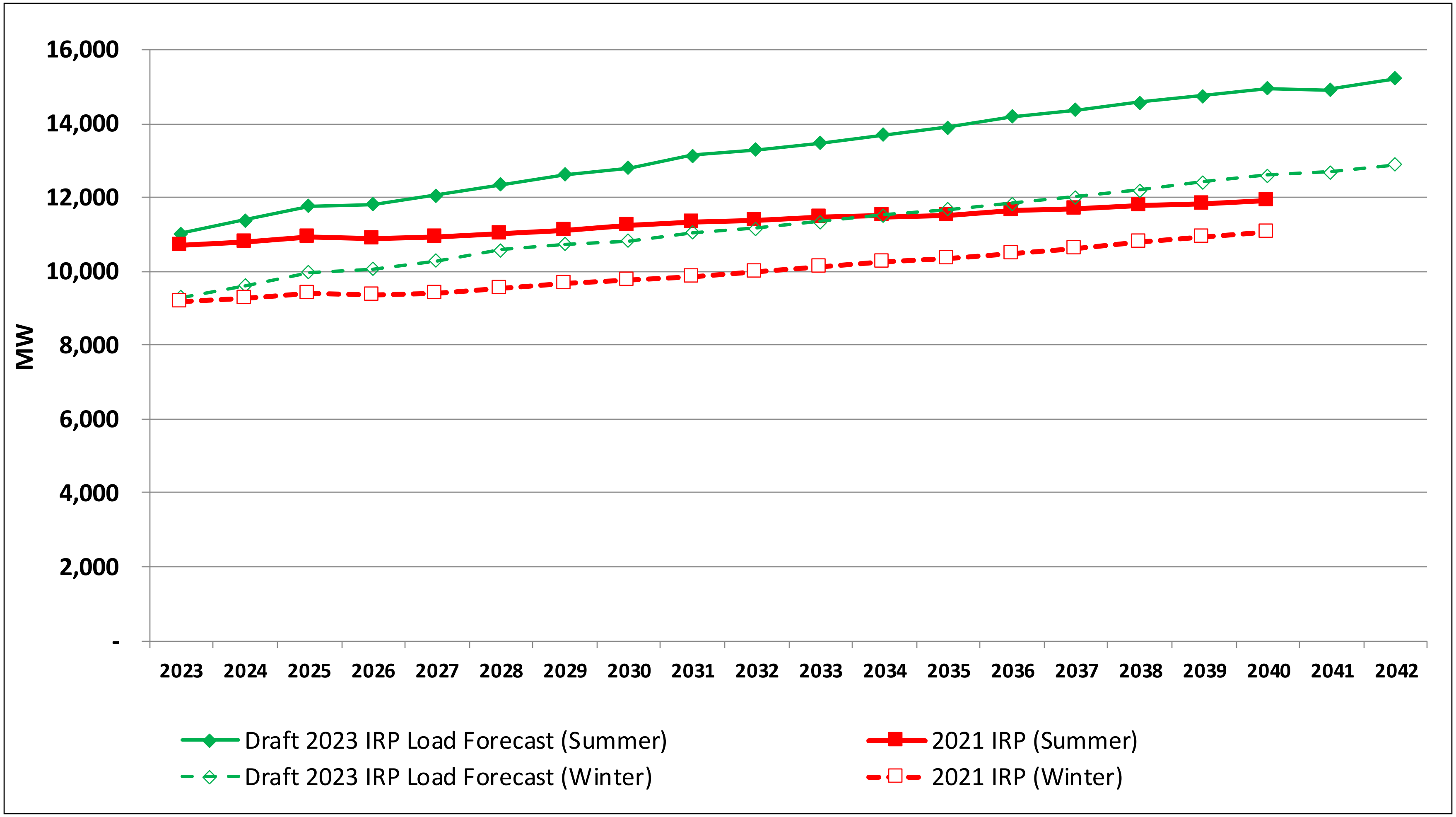
- New customer projects are a major contributor to the increase projected in load by 2032, accounting for roughly 65% of the change in the 2023 IRP relative to the 2021 IRP.
- Energy consumption affiliated with increased central air conditioning saturation and estimates for energy consumption for miscellaneous devices in all states is higher by roughly 7 percent in the 2023 IRP relative to the 2021 IRP.
- Company-wide the electric vehicle forecast is relatively unchanged over the 2022 to 2029 timeframe however, higher adoption expectations in Utah and Oregon begin driving an increase in 2029.
- Incorporated median climate change projections from Bureau of Reclamation March 2021 Study. Results in roughly 2% increase to system peaks and 0.1% decrease to energy in 2032.

Projected Temperature Change

Reclamation Study (March 2016) - 2021 IRP		2020		2050	
		Low	High	Low	High
Klamath River near Klamath	California	1.4	2.4	2.6	4.4
Snake River near Heise	Idaho	1.6	3.1	3.1	5.6
Klamath River near Seiad Valley	Oregon	1.4	2.5	2.7	4.5
Green River near Greendale	Utah	1.7	3.1	3.1	5.7
Yakima River at Parker	Washington	1.5	2.6	2.7	5.0
Green River near Greendale	Wyoming	1.7	3.1	3.1	5.7
		2020		**2050**	
Reclamation Study (March 2021)		**Low**	**High**	**Low**	**High**
Klamath River near Klamath	California	1.7	2.6	3.6	5.2
Snake River near Heise	Idaho	1.6	3.0	4.1	5.9
Klamath River near Seiad Valley	Oregon	1.8	2.7	3.7	5.3
Green River near Greendale	Utah	1.8	3.3	4.2	6.3
Yakima River at Parker	Washington	1.8	2.8	3.6	5.6
Green River near Greendale	Wyoming	1.8	3.3	4.2	6.3
		2020		**2050**	
Temperature Change		**Low**	**High**	**Low**	**High**
Klamath River near Klamath	California	0.3	0.2	1.0	0.8
Snake River near Heise	Idaho	0.0	-0.1	1.0	0.3
Klamath River near Seiad Valley	Oregon	0.4	0.2	1.0	0.8
Green River near Greendale	Utah	0.1	0.2	1.1	0.6
Yakima River at Parker	Washington	0.3	0.2	0.9	0.6
Green River near Greendale	Wyoming	0.1	0.2	1.1	0.6

Bureau of Reclamation Study projects future decade temperature changes over the average 1990 temperatures for multiple locations. This is used to estimate average daily temperature and the associated HDDs/CDDs under a climate change future for PacifiCorp's service territory

Winter and Summer System Peak Load Forecast



2023 IRP Load Forecast Next Steps

- Finalize 2023 IRP load forecast
  - Updated private generation forecast
  - Updated electric vehicle forecast (Oregon)

- Other load forecast activities:
  - Sensitivities:
    - 1-in-20 year (5 percent probability) historical extreme peak producing weather sensitivity
    - High and low load sensitivities
      - High and low economic growth
      - 95% confidence intervals
      - High and low climate change weather
    - High and low private generation
  - Climate change scenario (Washington)

Draft Private Generation




DNV

WHEN TRUST MATTERS

PacifiCorp
Private Generation Resource Assessment

Long-Term Planning

11 July 2022

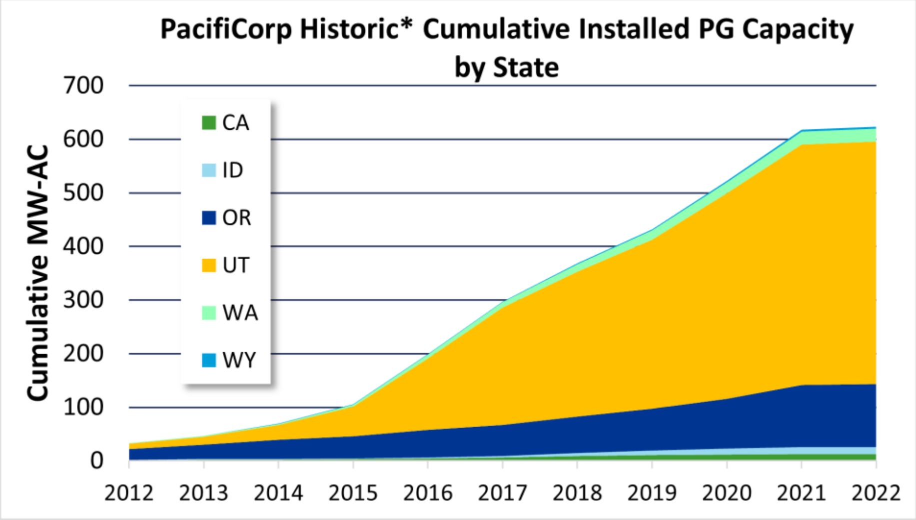
Agenda

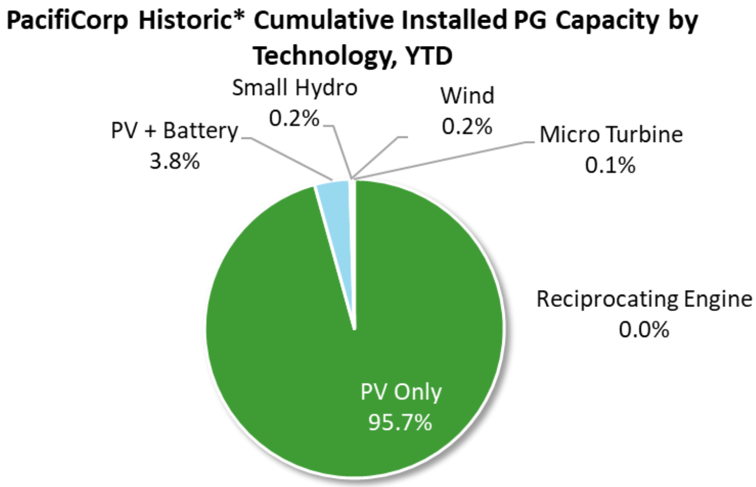
- Introduction and Background
- Study Methodologies and Approaches
- Draft Results
- Appendix: Incentives

Methodologies and Approaches

Introduction and Background

- DNV prepared the Long-Term Private Generation Resource Assessment for PacifiCorp covering the service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington.
- This study evaluated the expected adoption of behind-the-meter technologies including photovoltaic solar, photovoltaic solar coupled with battery storage, small scale wind, small scale hydro, reciprocating engines, and microturbines for a 20-year forecast horizon.
- DNV has provided projections for 3 cases: base, high, and low adoption.
- The private generation projections will be used in support of PacifiCorp's 2023 Integrated Resource Plan.
- DNV developed its assumptions, inputs, methodologies, and forecasts independently from prior Private Generation Assessments that have been previously performed for PacifiCorp.





*PacifiCorp interconnection data as of February 2022

Study Methodologies and Approaches

- DNV developed a behind-the-meter economic perspective including
  - Costs to acquire and install each technology net of available incentives
  - Benefits of ownership including energy cost savings
- Calculated payback by year for each technology, state, and sector
- Estimated technical feasible applications by technology, state, and sector
- Utilized Bass diffusion curves to model annual adoption
  - Adoption trend over time is characterized by three parameters: innovation coefficient, imitation coefficient, and ultimate market potential
  - We tied ultimate market potential to payback; market interventions shift the diffusion curve
  - Innovation and imitation are calibrated to current penetration for each technology, sector, and state

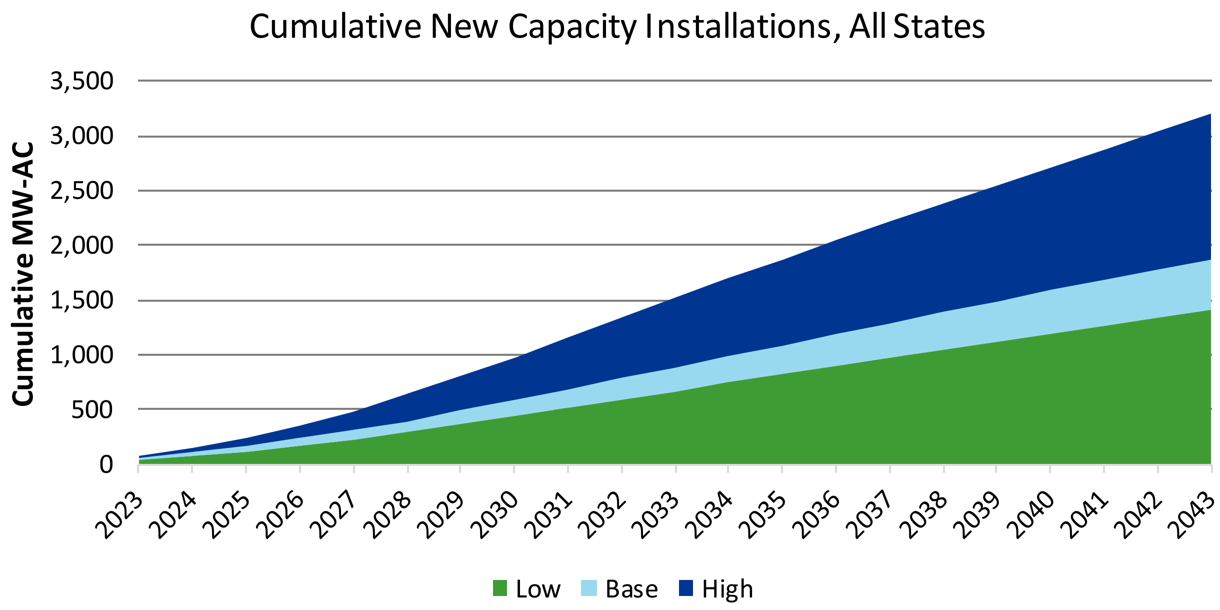
Private Generation Technologies

Cost & Performance Metric	Solar PV	Solar PV + Battery	Wind	Hydro	Microturbine	Recip. Engine
Installed Cost – Residential ($/kW, 2022)	$2,858-3,025/kW-DC (depending on state)	$3,613-4,034/kW-DC (depending on state)	$5,675/kW-AC	N/A	N/A	N/A
Installed Cost – Non-Residential ($/kW, 2022)	$1,756-2,799/kW-DC (depending on state)	$2,070-3,505/kW-DC (depending on state)	$4,300-5,675/kW-AC (depending on state)	$3,936-5,248/kW-AC (depending on state)	$3,300-3,350/kW-AC (depending on state)	$2,850-3,750/kW-AC (depending on state)
Annual Installed Cost Change (%, 2022-2043)	Scaled from base year installed costs using NREL Annual Technology Baseline (ATB) annual scaling factors specific to technology & size					
Fixed O&M – Residential ($/kW-yr, Base Year)*	$25.8	$30.7	$24.3	N/A	N/A	N/A
Fixed O&M – Non-Residential ($/kW-yr, Base Year)*	$17.2	$27.2	$35.0	$157.5-209.9	N/A	N/A
Variable O&M ($/kWh, Base Year)	N/A	N/A	N/A	N/A	$0.008-0.016	$0.019-0.024
Annual O&M Cost Change (%, 2022-2064)	Scaled from base year O&M cost using NREL Annual Technology Baseline (ATB) annual scaling factors specific to technology & size					
Capacity Factor (%)	14.6-18.5%	14.6-18.5%	7.7-10.8% - Residential 17.9-42.6% - Non-Res.	45%	43% - Commercial 51% - Industrial	48% - Commercial 58% - Industrial
Fuel Cost & Annual Cost Change ($/MMBtu, %)	N/A	N/A	N/A	N/A	$10.5/MMBtu – Com., $6.3/MMBtu – Ind. Scaled from AEO 2022 Pacific Region Forecast	
Electric Heat Rate (Btu/kWh, HHV)	N/A	N/A	N/A	N/A	11,566-13,648	9,721-11,765
DC/AC Derate Factor (%)	76.9-89.5% (based on customer type & size)	76.9-89.5% (based on customer type & size)	N/A	N/A	N/A	N/A

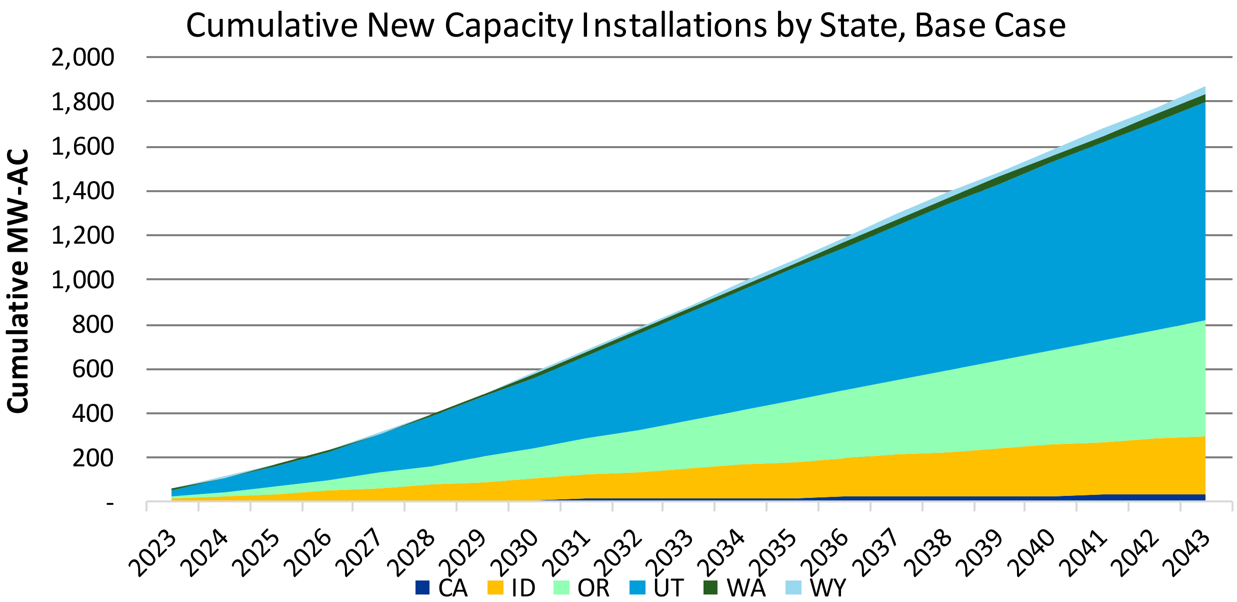
*Fixed O&M costs for solar PV and solar PV + Battery are in $/kW-DC-yr; all other technologies are in $/kW-AC-yr

Draft Results

Draft – Private Generation Forecast



Draft – Base Case Cumulative Installations by State



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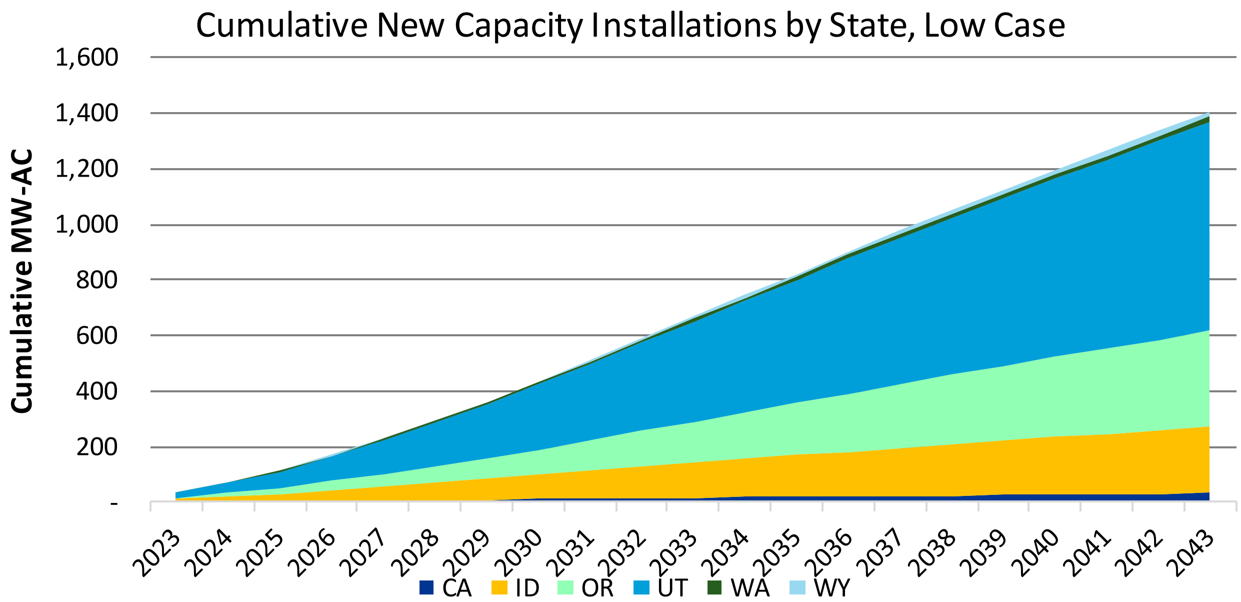
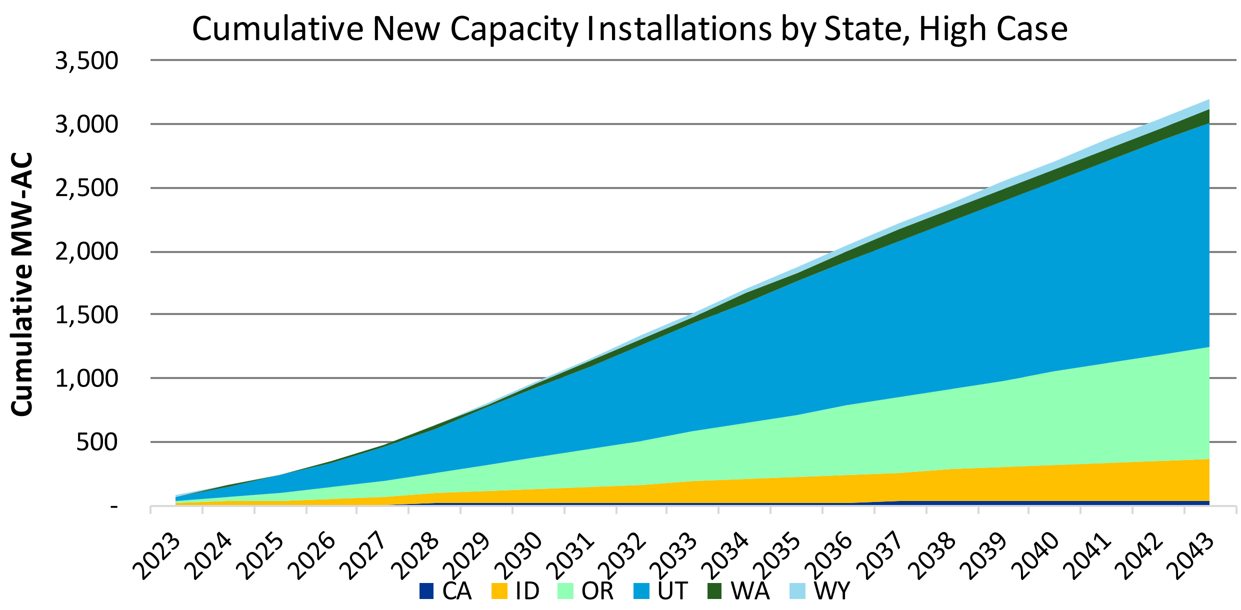
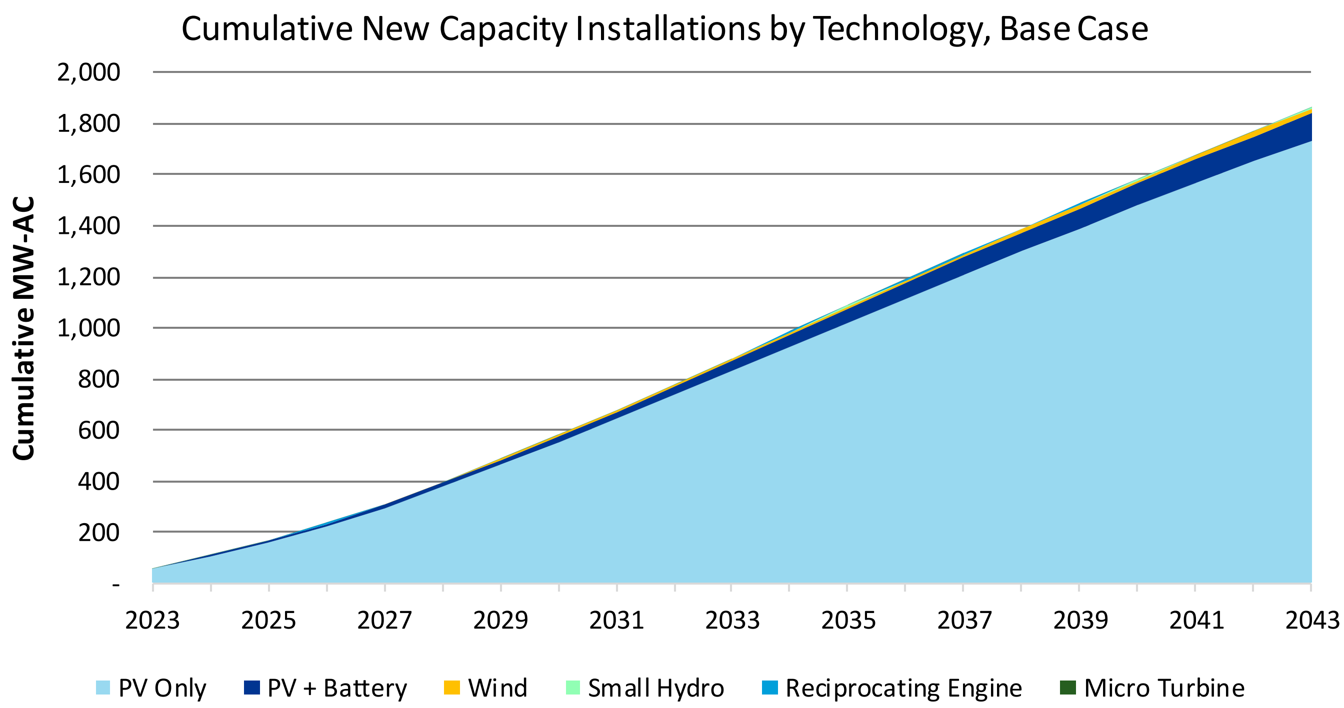
Draft – Low Case Cumulative Installations by State



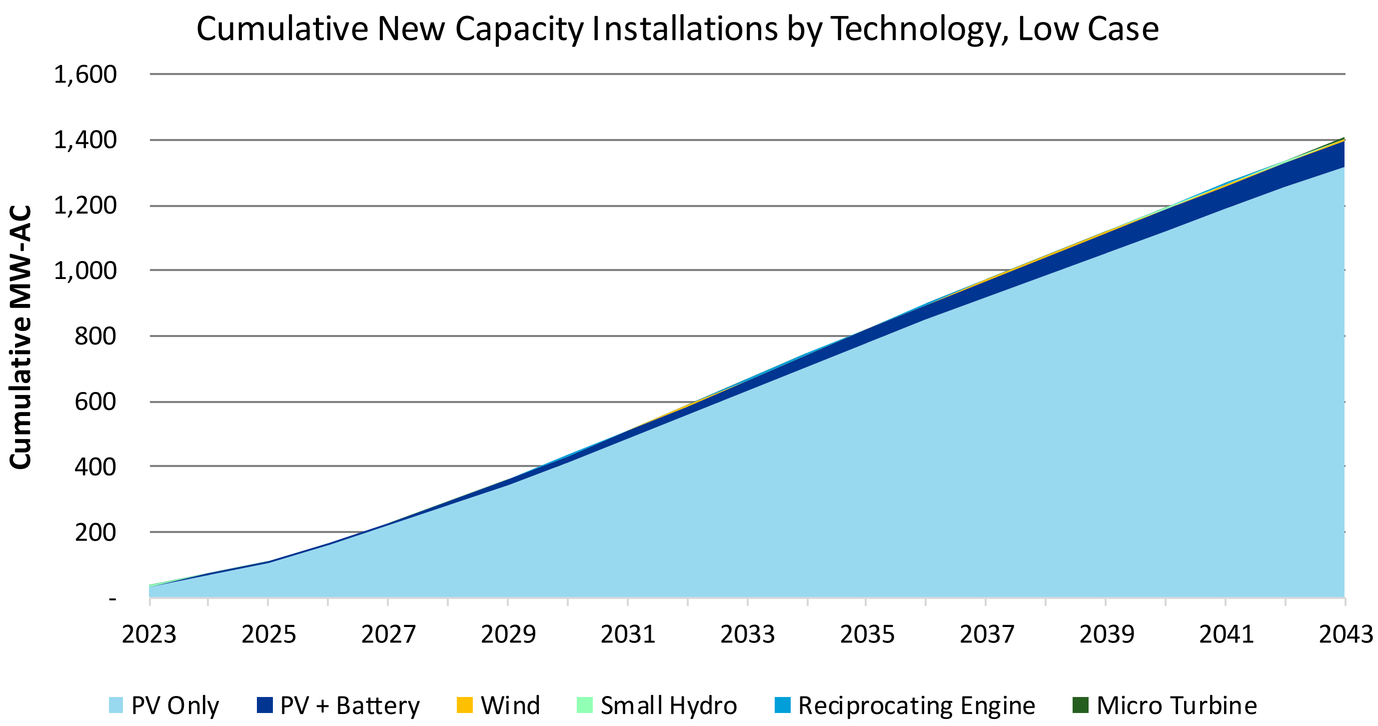
Draft – High Case Cumulative Installations by State



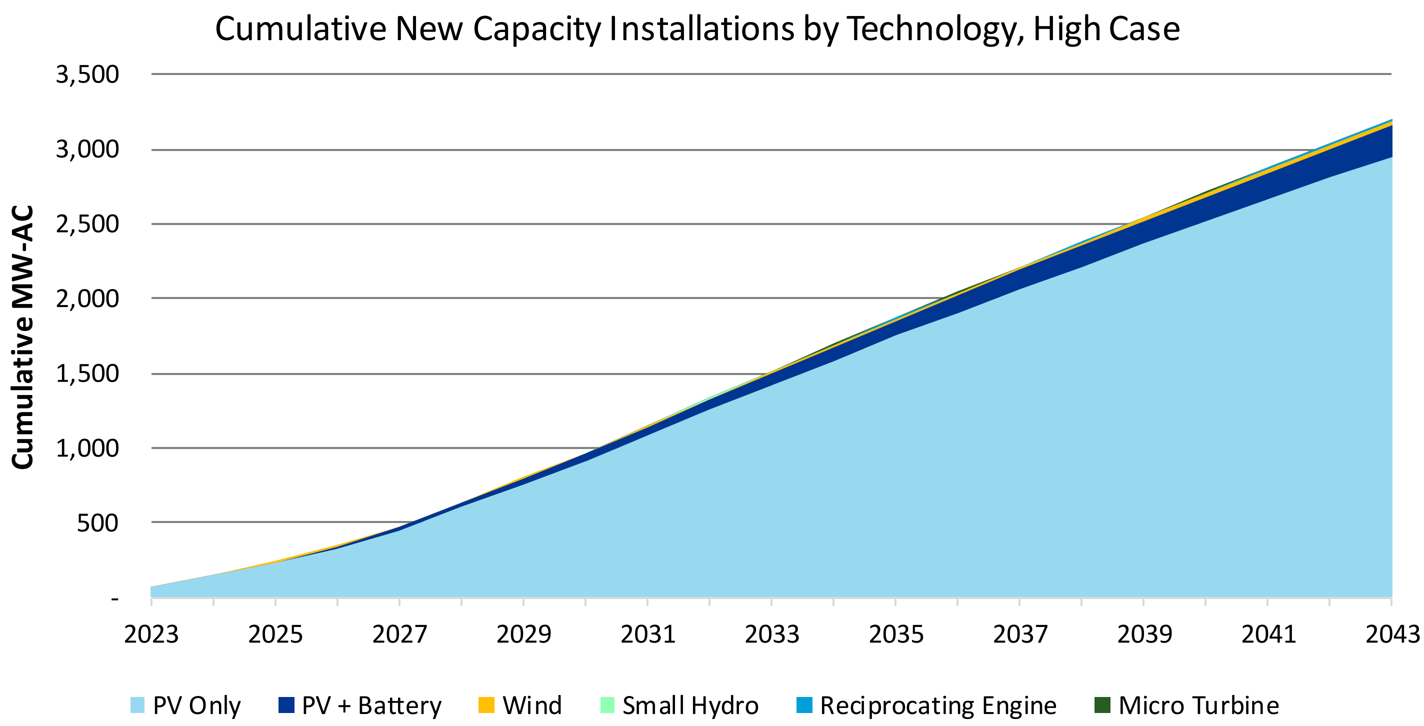
Draft – Base Case Cumulative Installations by Tech



Draft – Low Case Cumulative Installations by Tech

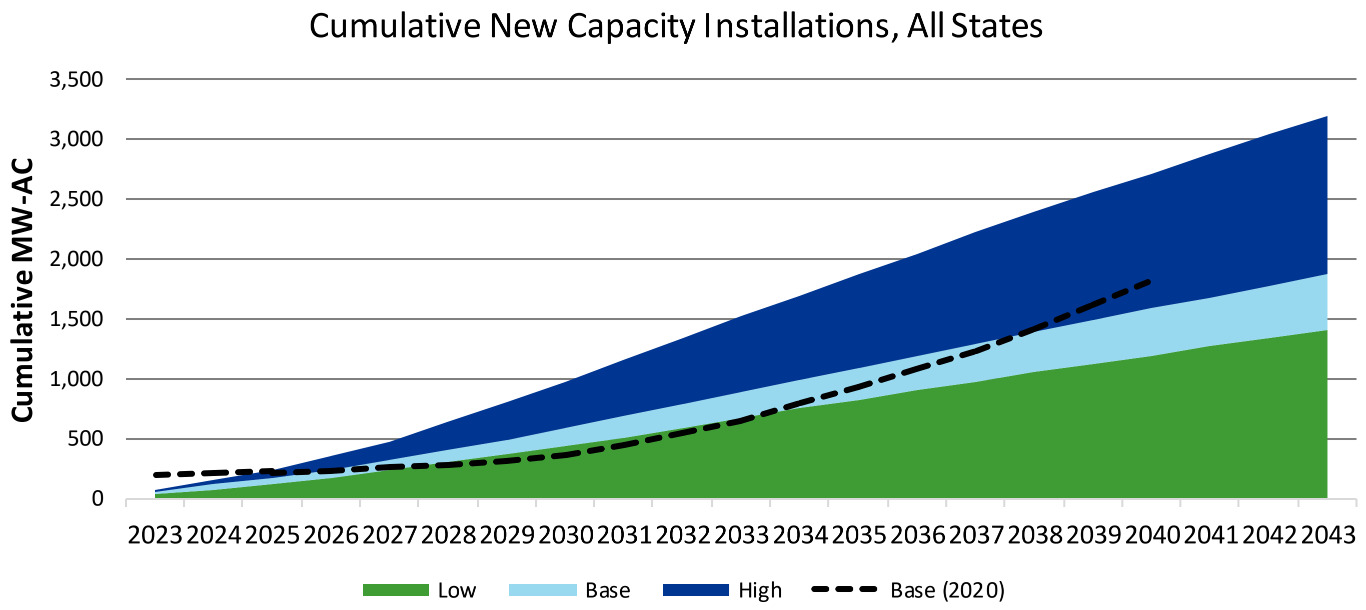


Draft – High Case Cumulative Installations by Tech



Cumulative Base Case Comparison

Since the 2020 study, projected PV capacity is expected to grow at a faster rate in the early years and at a slower rate towards the end of the forecast period, reaching similar overall adoption. The key drivers of these differences include larger average PV system sizes, decreases in PV + Battery costs, and the maturity of rooftop PV technology. Technology adoption follows an S-curve with adoption initially increasing at an increasing rate but eventually passing an inflection point where adoption continues to increase but at a decreasing rate.



Incentives Assumptions

Federal Incentives Overview

Incentive	Technology	End of 2020	End of 2021	End of 2022	End of 2023	End of 2024	End of 2025	Future Years
Residential Tax Credit	Solar Photovoltaics (PV)	26%	26%	26%	22%			
Business ITC	PV	26%	26%	26%	22%	22%	22%	10%
Business ITC	Small Wind	26%	26%	26%	22%			
Business ITC	Micro turbines	10%	10%	10%	10%			
Business ITC	Large Wind	18%	18%					

Other Incentives

Modified Accelerated Cost-Recovery System (MACRS)

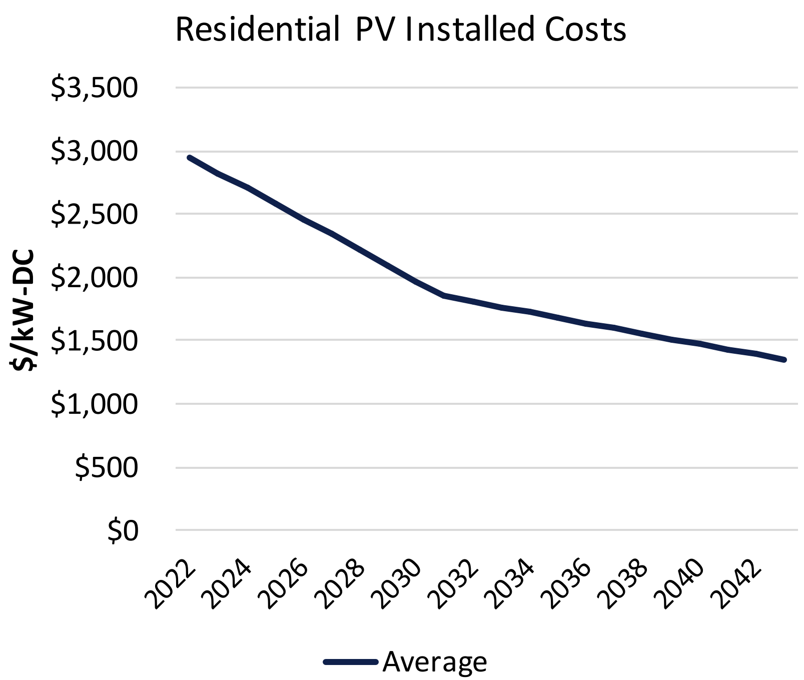
- Eligible technologies: Solar Photovoltaics, Wind (All), Wind (Small), Micro turbines

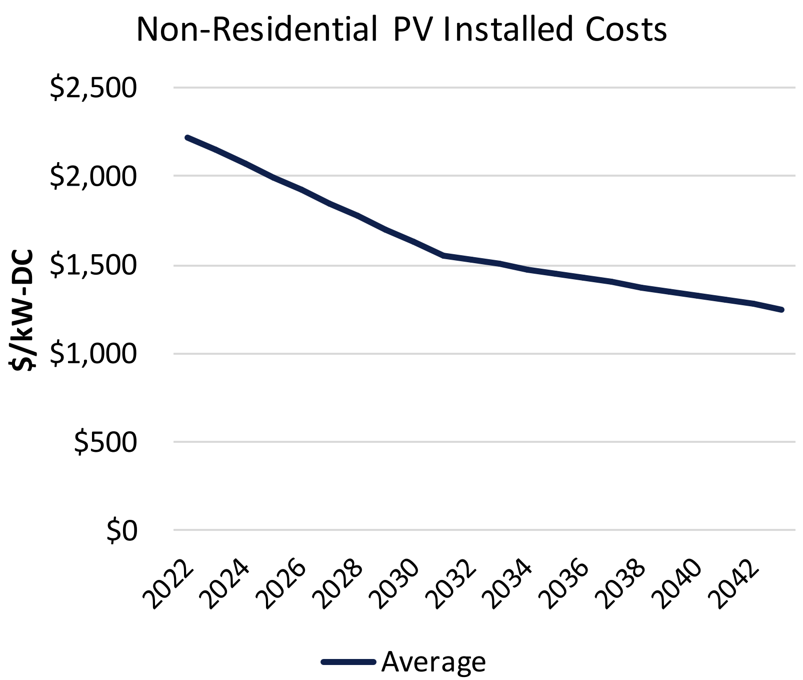
State Incentives

State	Residential		Non-Residential
Oregon	**Solar:** Up to $5,000	**Energy Storage:** Up to $2,500	$0.20/watt up to $20,000
Utah	**Solar:** 2022—$800 2023—$400	**Non-Solar:** Up to $2,000	Up to 10 percent of the eligible system cost or up to $50,000*
Idaho	Annual maximum of $5,000, and $20,000 over four years**		None
California	None		None
Washington	None		None
Wyoming	None		None

* Solar PV, wind, geothermal, hydro, biomass or certain renewable thermal technologies
** Mechanism or series of mechanisms using solar radiation, wind or geothermal resource

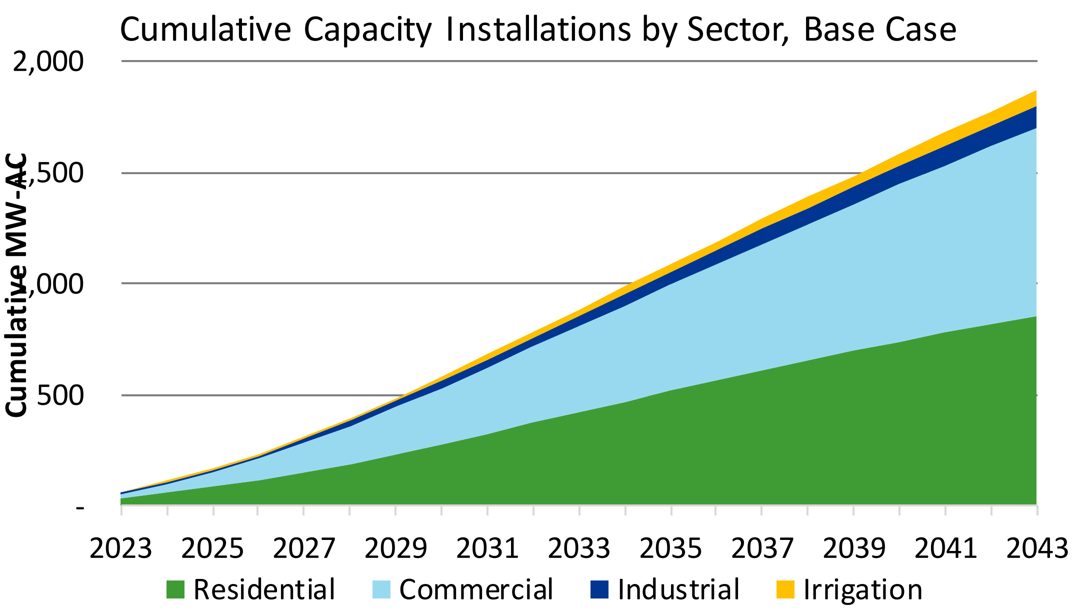
Residential and Non-Residential Solar System Costs, 2022-2043, Average of All States

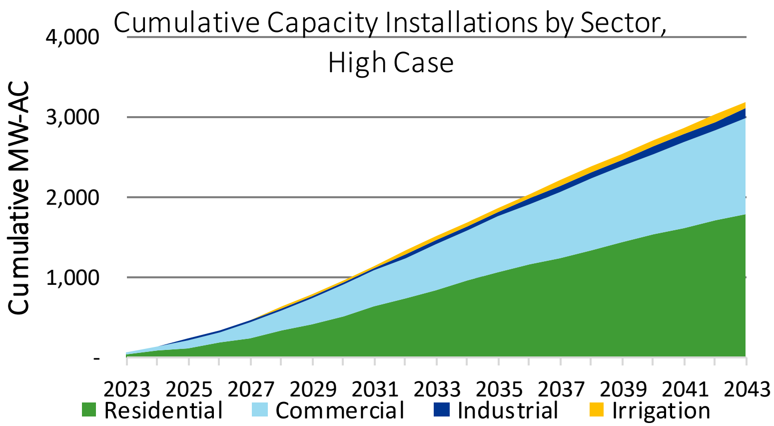


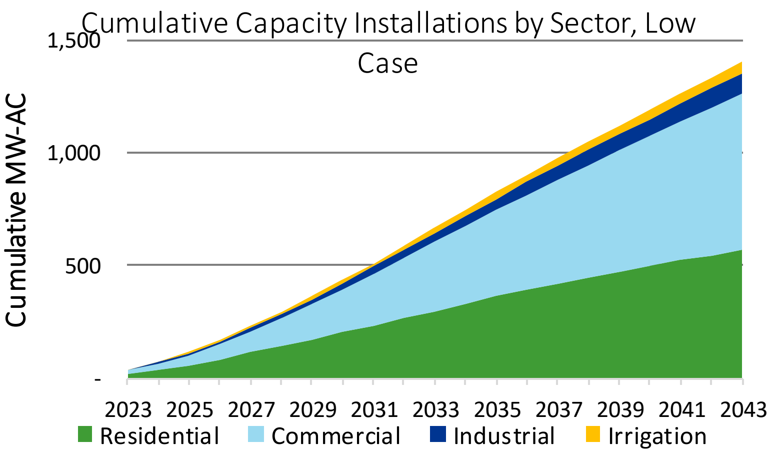


Supplemental Information & Response to Questions

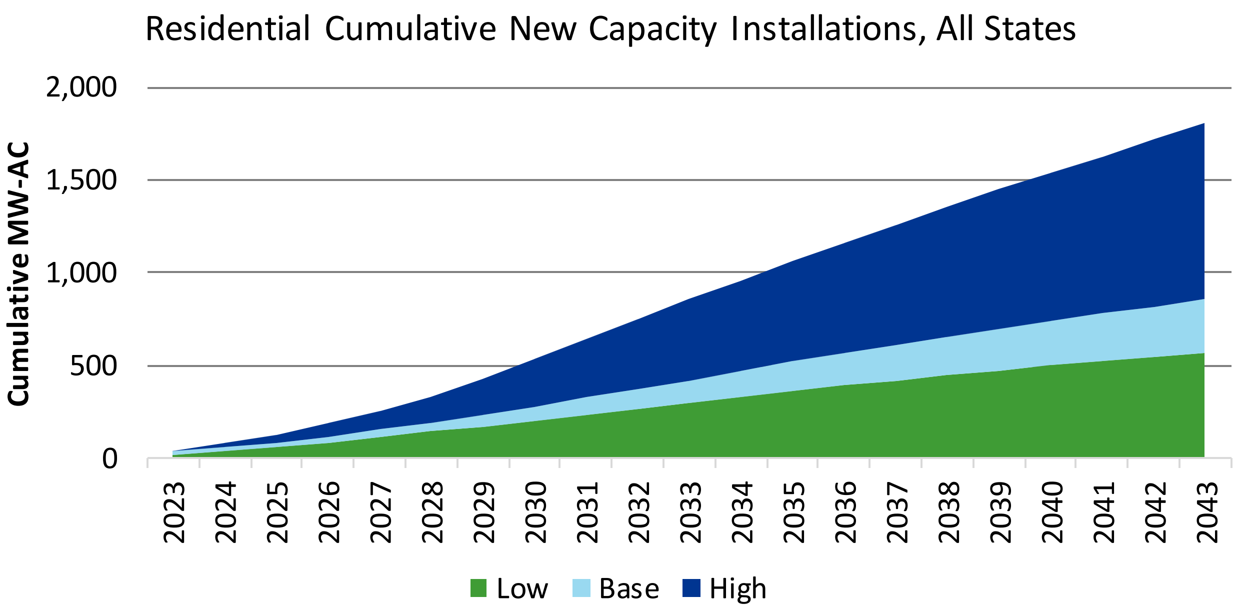
Draft – Cumulative Installations by Sector



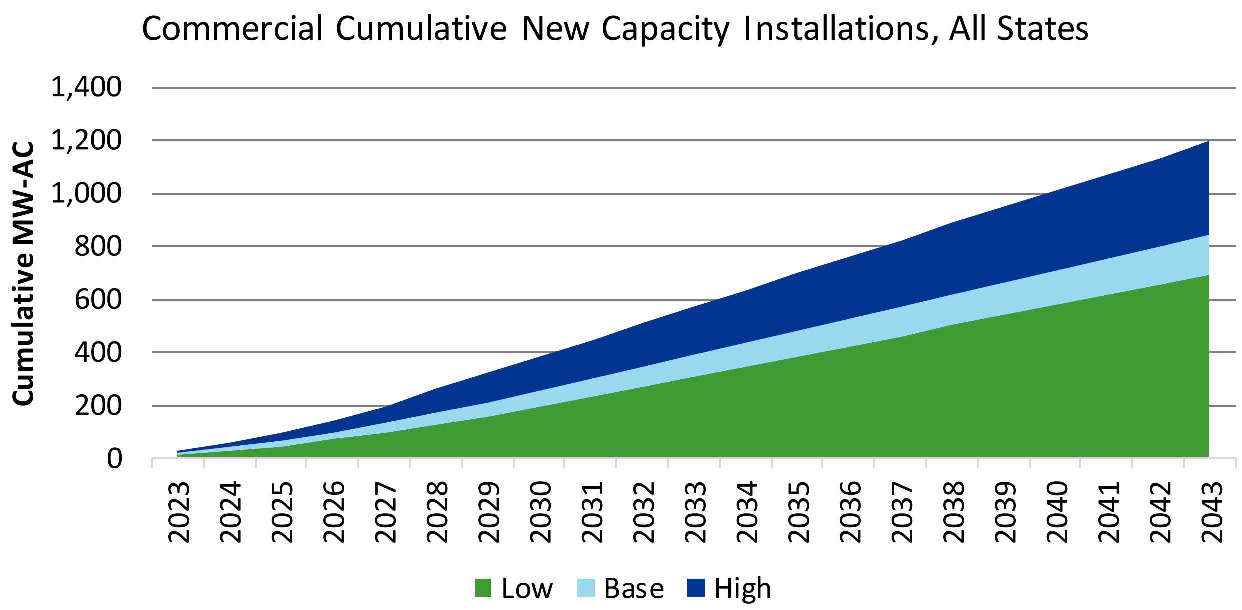




Draft – Residential Private Generation Forecast



Draft – Commercial Private Generation Forecast



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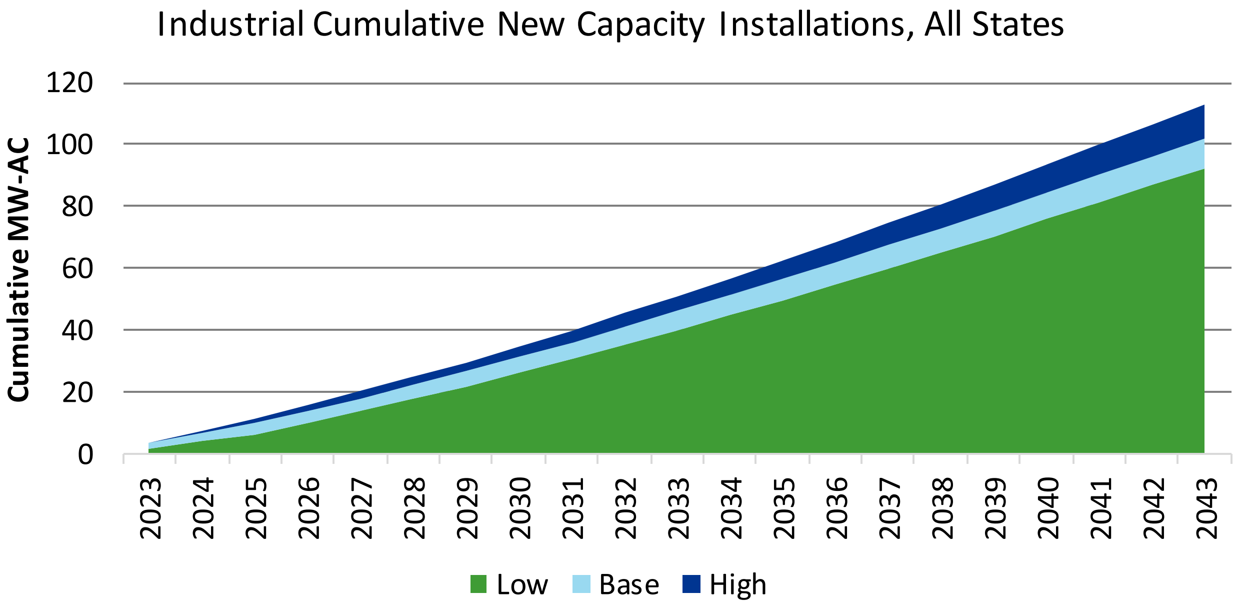
Draft – Industrial Private Generation Forecast



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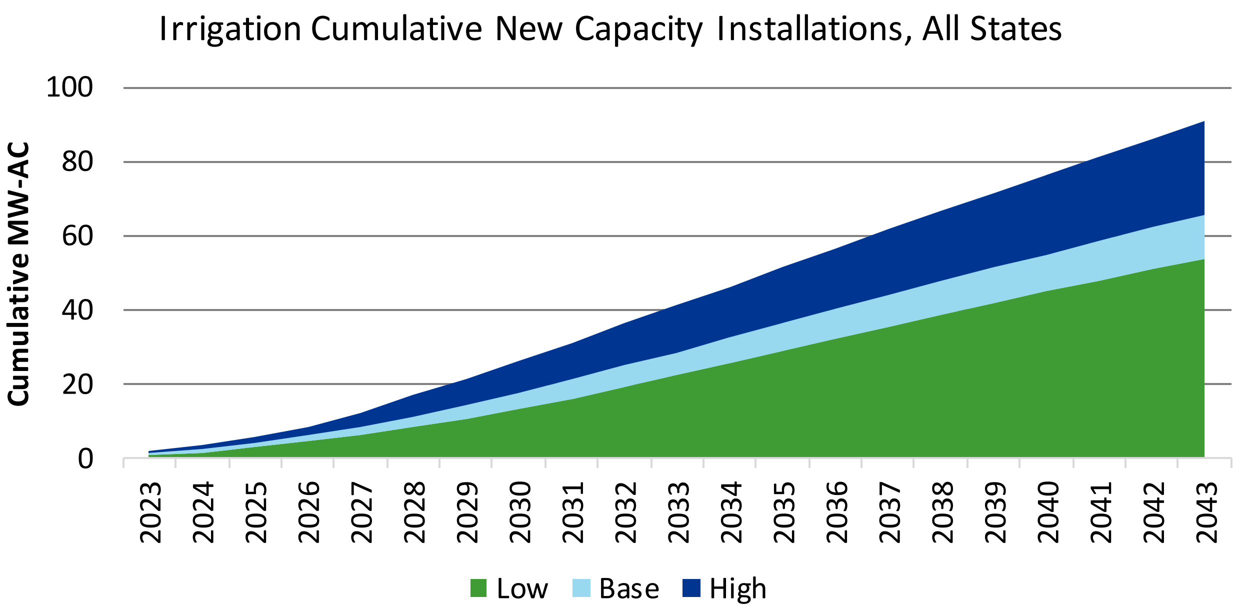
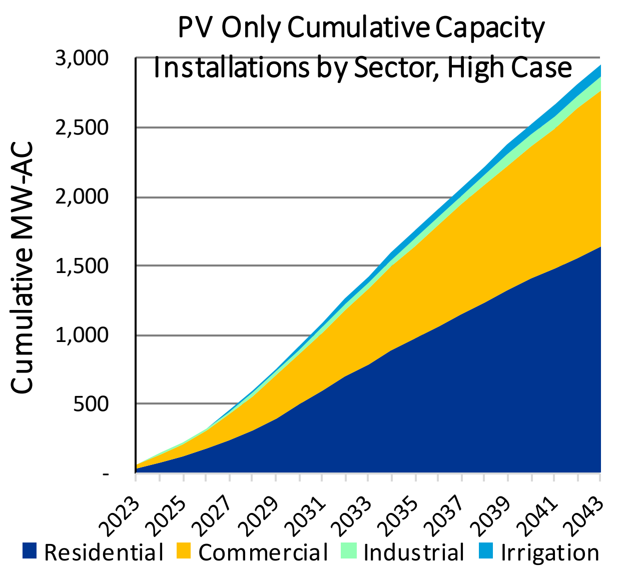
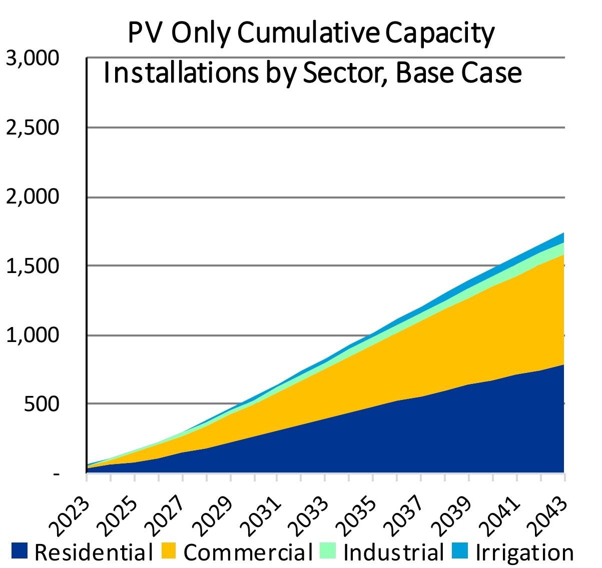
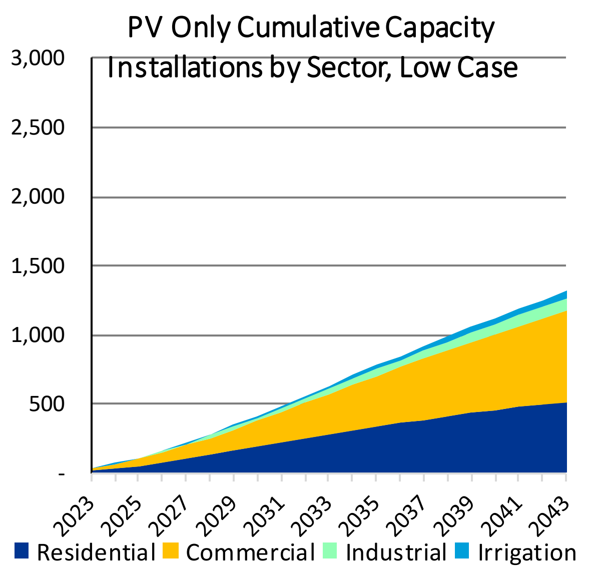
Draft – Irrigation Private Generation Forecast



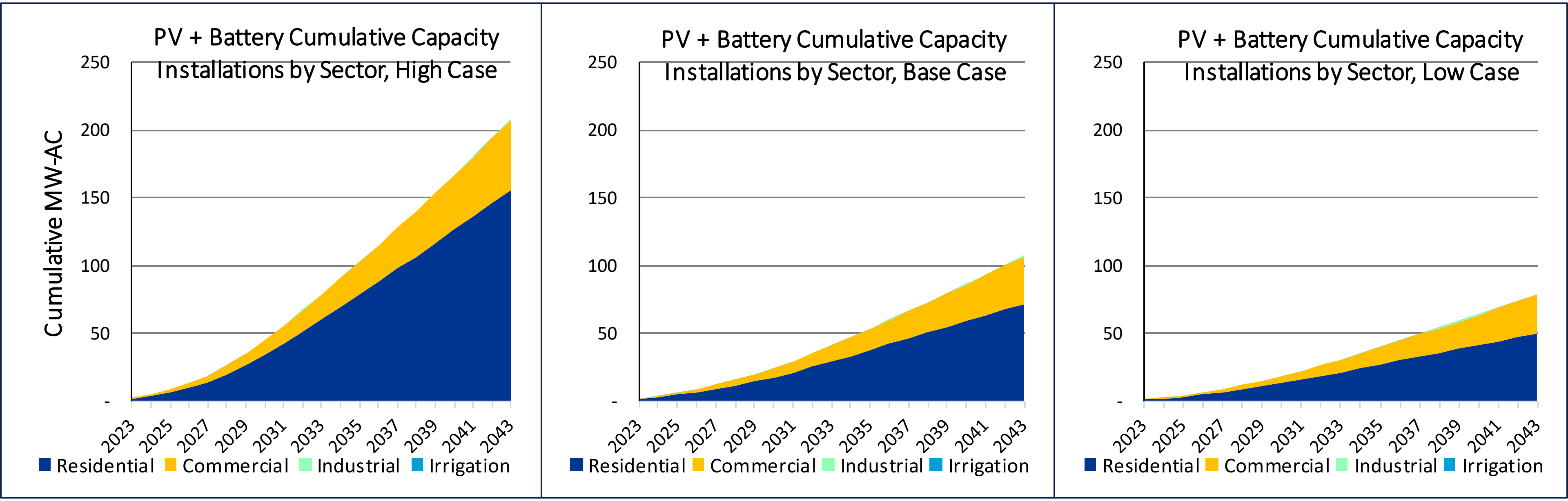
Draft – Solar PV Forecast by Sector and Scenario







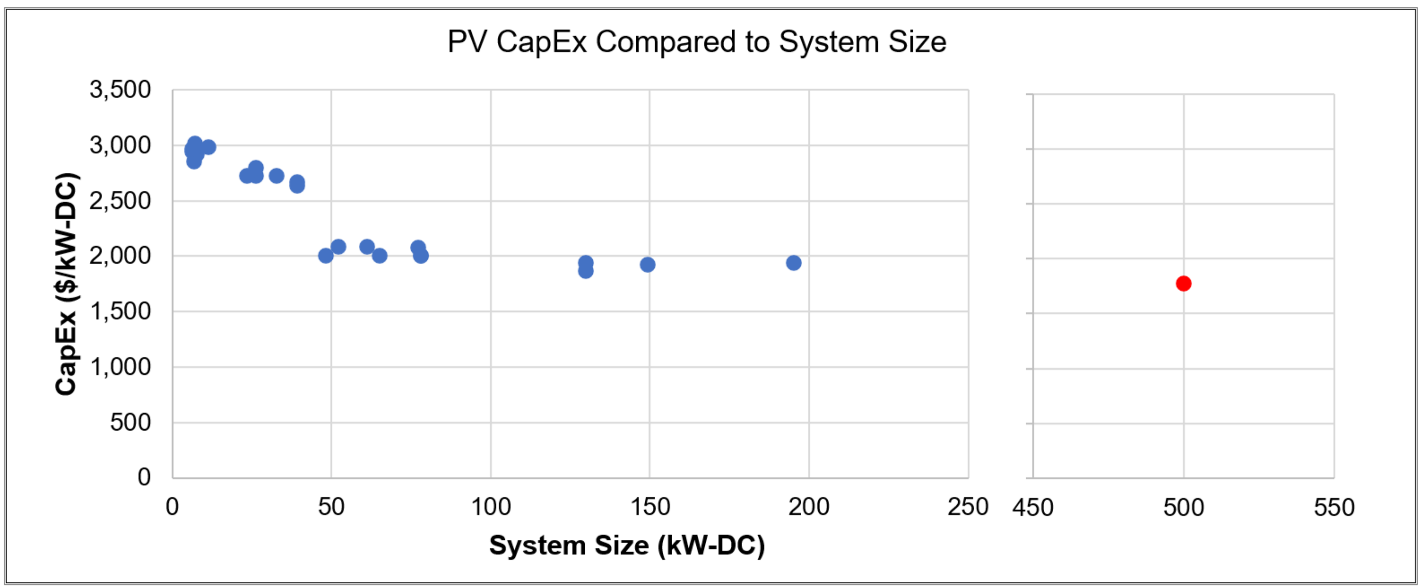
Draft – PV + Battery Forecast by Sector and Scenario



Response to Questions #1: SOLAR PV INSTALLED COSTS

Non-Residential PV CapEx

The average commercial solar PV system size modeled in the private generation forecast is much smaller than the average commercial system size modeled in the NREL ATB (200 kW-DC) or the Wood Mackenzie US PV All-In Construction Costs (500 kW-DC). Larger systems benefit from economies of scale in costs for hardware, labor and related markups. So as system sizes increase, the per-watt cost to build systems decreases. The figure below shows the CapEx for residential and non-residential solar PV systems modeled in the PacifiCorp private generation forecast as a function of system size, including the Wood Mackenzie US PV All-In Construction Costs for a 500 kW-DC commercial PV system.



Response to Questions #1: SOLAR PV INSTALLED COSTS

Residential PV CapEx

The following representative residential solar PV only systems were modeled in the private generation forecast. DNV's renewables experts determined the following attributes best represented the residential solar PV only market in PacifiCorp's territory. Microinverters are modeled rather than string inverters, which have a higher cost, but more control and higher electricity yield.

Representative System	Units	CA	ID	OR	UT	WA	WY
Nameplate Capacity	kW-DC	6.5	6.0	6.8	5.5	10.0	5.5
Module Type	n/a	c-Si	c-Si	c-Si	c-Si	c-Si	c-Si
Installation Requirements	n/a	Fixed-tilt Roof Mounted	Fixed-tilt Roof Mounted	Fixed-tilt Roof Mounted	Fixed-tilt Roof Mounted	Fixed-tilt Roof Mounted	Fixed-tilt Roof Mounted
CapEx Categories	**Units**	**CA**	**ID**	**OR**	**UT**	**WA**	**WY**
PV module	2022$/kW-DC	$468	$468	$468	$468	$468	$468
PV inverter	2022$/kW-DC	$334	$334	$334	$334	$334	$334
Balance of plant	2022$/kW-DC	$1,545	$1,426	$1,480	$1,481	$1,514	$1,496
EPC overhead and margin	2022$/kW-DC	$679	$631	$641	$664	$672	$668
Total installed cost	**2022$/kW-DC**	**$3,025**	**$2,858**	**$2,922**	**$2,946**	**$2,988**	**$2,966**
Energy Sage Avg Installed Cost by State	*2022$/kW-DC*	*$2,363-$3,197*	*$2,414-$3,266*	*$2,202-$2,978*	*$2,338-$3,162*	*$2,270-$3,070*	*$3,414-$3,971**

*No Wyoming data available from Energy Sage, source is https://homeguide.com/costs/solar-panel-cost#state

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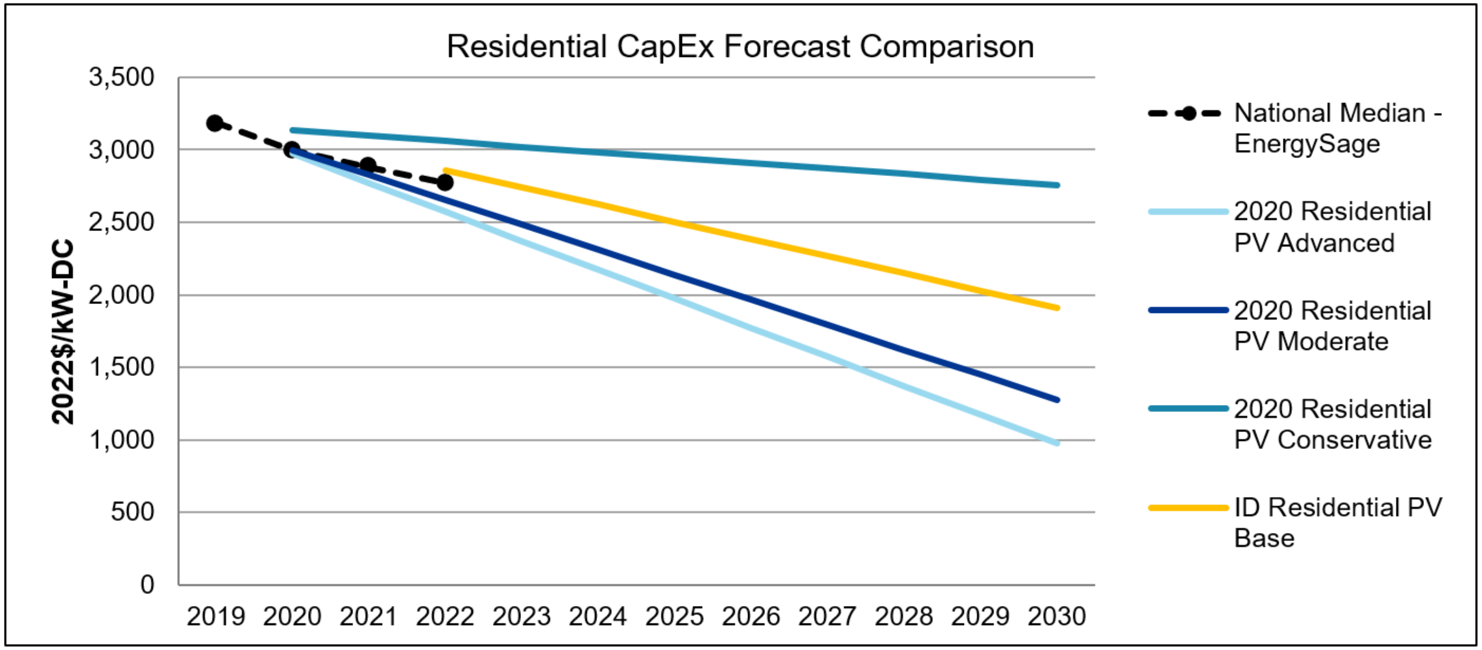
Response to Questions #1: SOLAR PV INSTALLED COSTS

- **Definitions:**

- PV Module: PERC P-type Mono c-Si. There is uncertainty around PV module prices given the recent anti-circumvention investigation initiated by Department of Commerce. Module prices remain fluid.
- PV Inverter: Microinverter. Microinverters allow designs with different roof configurations (e.g., orientations and tilts), constantly track the maximum power point for each module, and provide rapid shutdown at the module level (required in CA, ID, OR, UT, WA, WY). Microinverters have a higher cost than single-phase string inverters.
- Balance of Plant: Includes electrical and structural balance of system costs, labor, design and engineering, permitting and inspection, supply chain, logistics and miscellaneous costs, taxes, customer acquisition costs (blended cost from various EPC sizes).
- EPC Overhead and Margin: Assumes a single EPC company completes the project. There is no additional margin beyond that of the EPC.
- Total Installed Cost: Capital expenditures (CAPEX) are expenditures required to achieve commercial operation in a given year. Cost does not include ITC or local rebates/incentives.

Response to Questions #2: SOLAR PV TECHNOLOGY COST FORECASTS

The following figure shows the comparison of the 2020 NREL ATB Residential PV CapEx forecasts compared to the national median prices reported by EnergySage and the Idaho Residential PV CapEx forecast used in the base case of the draft PacifiCorp Private Generation Forecast. DNV's renewable energy experts reviewed the PV technology costs presented in the NREL ATB and recommended using a more gradual cost decline in the base case of the PacifiCorp private generation forecast, to reflect the market conditions of PV CapEx more accurately.



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Response to Questions #3: FEDERAL INCENTIVES

The federal tax credits in the following table were included in the base case economic analysis.

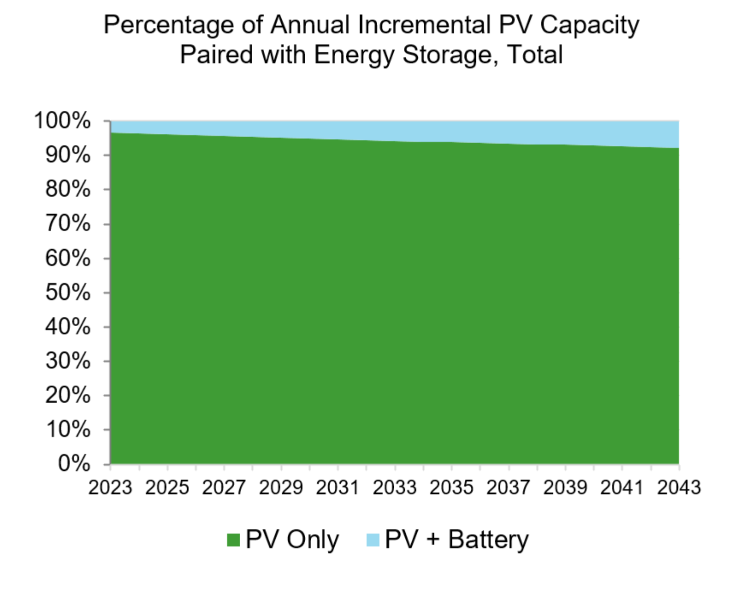
Incentive	Technology	End of 2020	End of 2021	End of 2022	End of 2023	End of 2024	End of 2025	Future Years
Residential ITC	Solar Photovoltaics (PV)	26%	26%	26%	22%			
Business ITC	PV	26%	26%	26%	22%	22%	22%	10%
Business ITC	Small Wind	26%	26%	26%	22%			
Business ITC	Micro turbines	10%	10%	10%	10%			
Business ITC	Large Wind	18%	18%					

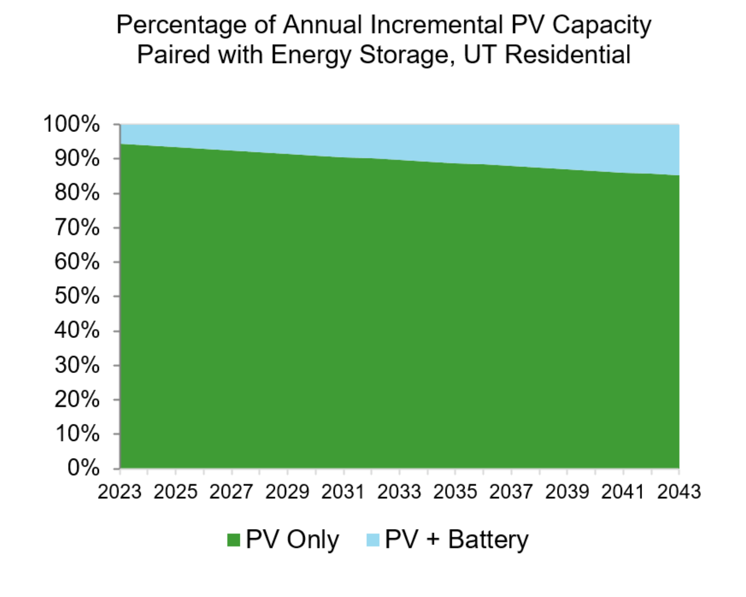
“The Investment Tax Credit (ITC) is currently a 26 percent federal tax credit claimed against the tax liability of residential (under Section 25D) and commercial and utility (under Section 48) investors in solar energy property… Both the residential and commercial ITC are equal to 26 percent of the basis that is invested in eligible solar property. The ITC then steps down according to the following schedule:

- 26 percent for projects that begin construction in 2021 and 2022
- 22 percent for projects that begin construction in 2023
- After 2023, the residential credit drops to zero while the commercial credit drops to a permanent 10 percent” (Source: https://www.seia.org/initiatives/solar-investment-tax-credit-itc).

Response to Questions #4: SOLAR + BATTERY CO-ADOPTION

The figures presented in the draft results slides show cumulative adoption of solar systems paired with energy storage, whereas the figure from the Wood Mackenzie market insight report show incremental adoption. The Wood Mackenzie report is estimating national adoption of PV + Battery systems, which may not be representative of PacifiCorp's customers. The figures below show the percentage of annual incremental PV capacity paired with energy storage for all states and sectors in PacifiCorp's service territory and for Utah residential customers.





Response to Questions #5: INFLATION ASSUMPTIONS

All values are given in 2022 USD, using the CPI for All Urban Consumers for dollar year conversions where the source year dollars do not match 2022. Financial calculations for projections use an inflation assumption of 2.5% per year.

Response to Questions #6: RECs

The economic analysis of this study assumes all private generation technologies are bought by customers with cash. Therefore, selling renewable energy credits (RECS) was not considered as a potential value stream for customers installing private generation systems.

Draft Distribution System Planning

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Introduction to DSP

What is the Oregon Distribution System Planning (DSP)?

- Order No. 20-485, effective December 16, 2020 - Consideration of adoption of Public Utility Commission of Oregon staff proposed guidelines to DSP

Background:

The Commission issued Order No. 19-104 March 22, 2019, opening UM 2005 investigation to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investment."

Staff white paper for distribution system planning in 2019 identified the following two proactive drivers:

- Insight – The need for increased and holistic engagement in utilities and distribution investment
- Optimization – The need for a long term plan to ensure the operation of changing distribution system is maximizing operational efficiency and customer value

Staff manages stakeholder process to develop DSP guidelines which results in:

- Utilities develop and file distribution system plans in two parts, the first part in Fall 2021 and second part in Summer 2022
- During plan development, prior to filing each part, utilities must hold two workshops with stakeholders

High-Level DSP Part 1 and Part 2 Scope and Requirements

Oregon DSP Key Requirements:

DSP Part 1: Filed October 15, 2021

- ✓ Baseline Data & System Assessment (Info about PAC OR distribution system, planning and maintenance processes and current distribution planning process).
- ✓ Hosting Capacity Analysis (Assess and report ability to host DERs on circuits across PAC OR territory – implemented GIS toolset to provide greater access and visibility)
- ✓ Community Engagement Plan (Outlined plan to establish and leverage Community Input Group and engage with stakeholders)
- ✓ Long-term DSP Plan (High-level plan explaining how distribution planning is expected to evolve over the coming 5-10 years, including 3 Options to support HCA)
- ✓ Plan for Development of Part 2

DSP Part 2: Due August 15, 2022 (more details on next slides)

- ❑ Forecasting for Base Load Growth in addition to customer-side options (DERs and Transportation Electrification, etc.)
- ❑ Grid Needs Identification
- ❑ Solution Identification, Including Evaluation of Two Non-wires Alternatives in Traditionally Under-represented Areas
- ❑ Near-Term Action Plan

DSP Part 2 Requirements Summary

Due: August 15, 2022

Forecasting of Load Growth, DER/EV Adoption (REQ 5.1)

- Describe **current state for Load Forecasting** – process, tools, data
- For DERs and Electric Vehicles, explain:
  - Forecast methodology and geographic allocation
  - Include High/Med/Low Adoption scenarios (**to Substation Level**)
- Initial forecast results including DER/EV scenarios + document constraints

Grid Needs Analysis (REQ 5.2)

- Document process to assess grid adequacy and identify grid needs (Distribution Level)
- Discuss criteria used to assess reliability and risk – methods, tools used
- Develop **and Publicly Present** a summary of prioritized grid constraints, including prioritization criteria and timeline to resolve constraints

Solution Identification (Req 5.3)

- Document process for identifying the range of solutions to address grid needs
- **For each need, describe the data used to support investment decisions**
- For large projects, describe process for engaging communities and getting input
- **Propose and evaluate two pilot Non-wires Solutions** (alternatives to traditional wires solutions). Develop and evaluate pilot NWS with robust Community Engagement. *Pilot NWS does not need to be cost effective, nor is it required to be implemented.*

Near-Term Plan (Req 5.4)

- Provide 2-4 year plan to address grid needs
- **Disclose planned spending, timeline and recovery mechanism**
- Discuss relationships between planned investments
- Discuss pilots being conducted to enhance the grid

Pacific Power Service Territory

Overview of Pacific Power – Oregon

- 502 distribution circuits
- 191 distribution substations

Office	NORTH REGION			CENTRAL REGION			SOUTH REGION	
	Portland	Walla Walla	Yakima	Bend	Albany	Roseburg	Klamath Falls	Medford
Responsible Operating Areas	Clatsop (Astoria) Portland Hood River	Walla Walla Hermiston Pendleton Enterprise	Sunnyside Yakima	Madras Hood River Bend/Redmond Prineville	Albany Corvallis Dallas/Independence Cottage Grove Stayton Lebanon Lincoln City Junction City	Coos Bay Roseburg	Alturas Lakeview Mt Shasta Klamath Falls Yreka	Crescent City Medford Grants Pass
Distribution Profile	95 Circuits 1,200 Line Miles 107,000 Customers	42 Circuits 2,500 Line Miles 54,000 Customers	106 Circuits 3,300 Line Miles 108,000 Customers	65 Circuits 2,800 Line Miles 77,000 customers	86 Circuits 3,700 Line Miles 137,000 Customers	66 Circuits 2,300 Line Miles 70,000 Customers	110 Circuits 5,000 Line Miles 75,000 Customers	138 Circuits 5,700 Line Miles 156,000 Customers
District Specific Attributes	Portland UG Networks DA Pilot Project FHCA		FHCA	High Growth Rate/New Connections FHCA	DA Pilot Project	FHCA	Multiple Code Requirements FHCA & HFTD Footprint Energy Storage Pilot	Large FHCA Footprint DA Pilot Project

Pacific Power Service Territory

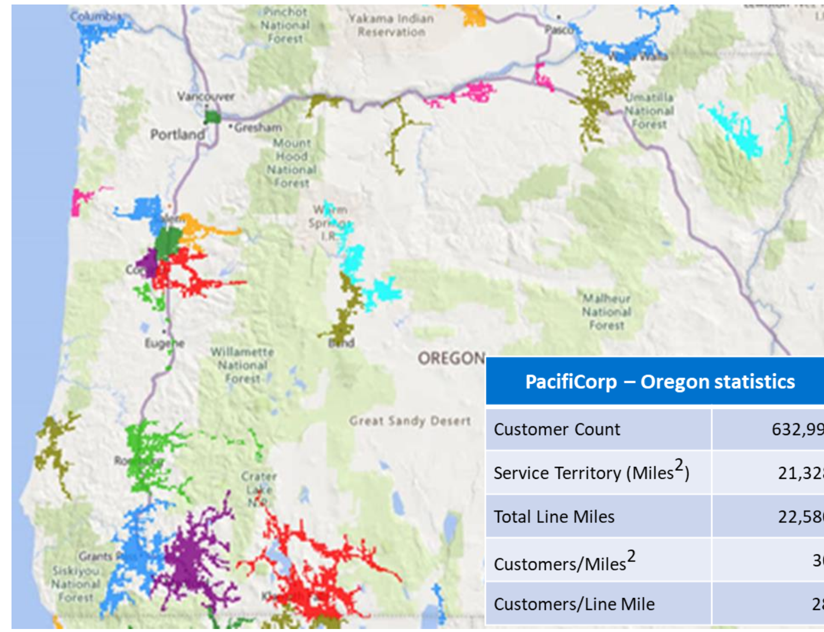
Dispersed and Varied Geography: Territory spans from Washington to California and the coast to Idaho, broken into eight distinct planning districts

Diverse Circuit Loading/Composition:

- Densest circuit in Portland with 638 customers per line mile
- Least dense in Hermiston with one customer per line mile
- Oregon average is 28 customers per line mile

Diverse Environmental Conditions: Distribution in eight of nine Oregon climate zones

Various Touchpoints: Interconnections with 16 other electrical power companies, including CAISO and Bonneville Power

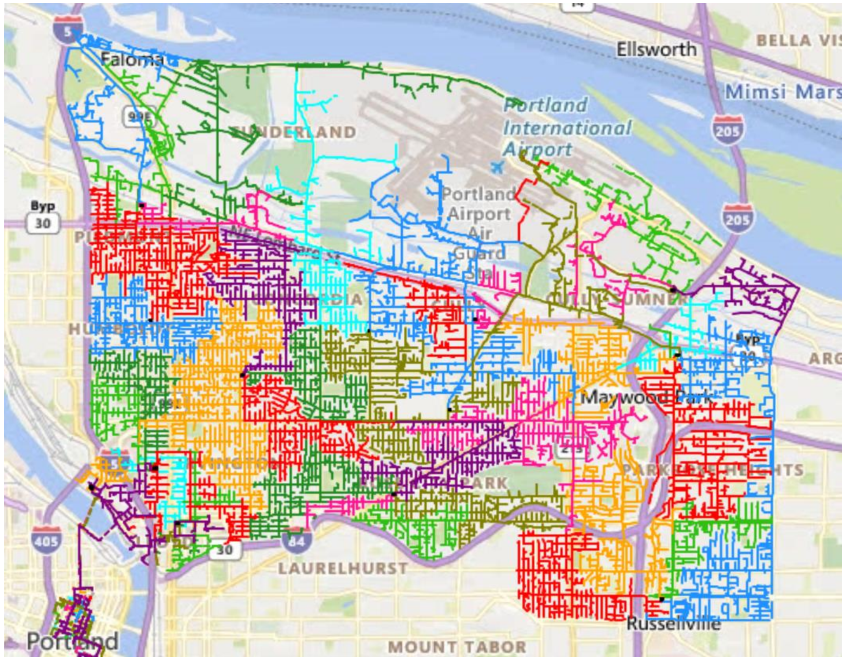


PacifiCorp – Oregon statistics	
Customer Count	632,997
Service Territory (Miles^2)	21,328
Total Line Miles	22,580
Customers/Miles^2	30
Customers/Line Mile	28

As-Is DSP/5-Year Planning Cycles

Distribution Planning Studies

- All distribution system planning studies are scheduled to be completed on a 5-year cycle
- Study schedules are evaluated each year and studies may be shifted to occur sooner or later depending on a number of factors (high load growth activity, large load additions, etc.)
- Currently 99 planning studies on 5-year cycle in Pacific Power service territory



Ad-hoc Studies (Generation Interconnect or System Impact Study)

- Typically driven by load, generation interconnection service or transmission service requests
- Study is generally focused on a limited area, and the immediate effects of the request on reliability and load service

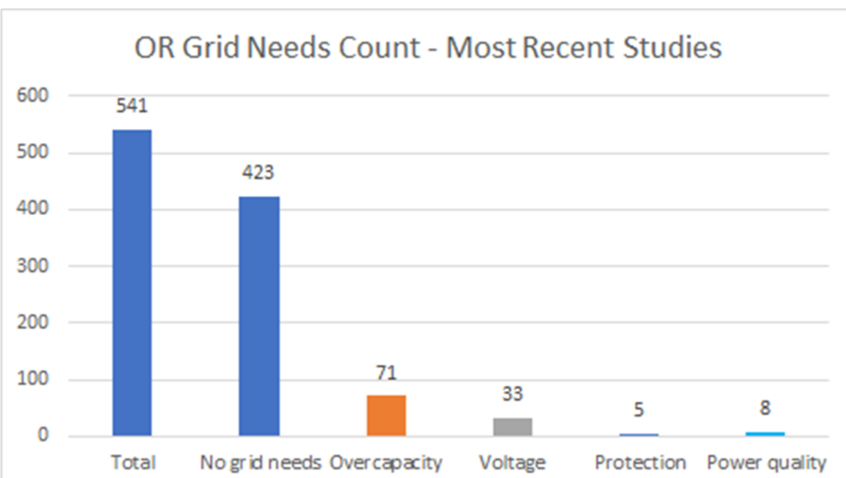
Distribution System Planning (DSP) Grid Needs Context

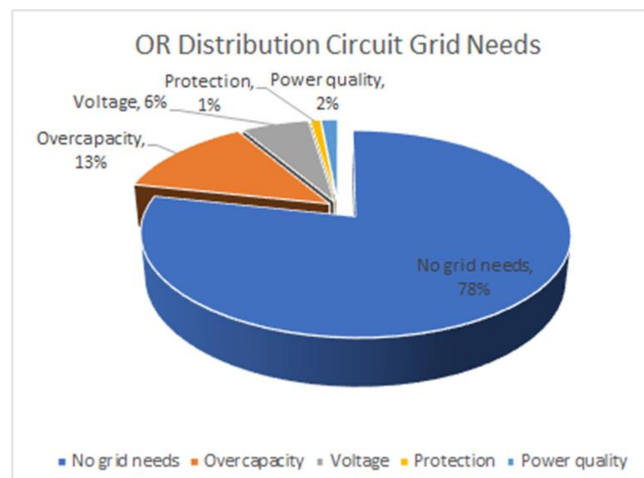
Reviewed the latest DSP Studies for all study areas in Oregon (excludes customer-driven or ad-hoc studies):

- Categorized the grid needs that were identified in the studies (see results below)
- Captured rough cost estimates for wires solutions and added that breakdown – 117 total Grid Needs Identified:
  - 32% between $0 and $5K,
  - 54% between $5K and $200K,
  - 14% more than $200K

Findings:

- Grid needs found in 22% of circuits
- Overcapacity is the most common grid need (61% of found needs)
- 86% of found grid needs cost less than $200K
- Of those needs, not all will be suitable for NWS





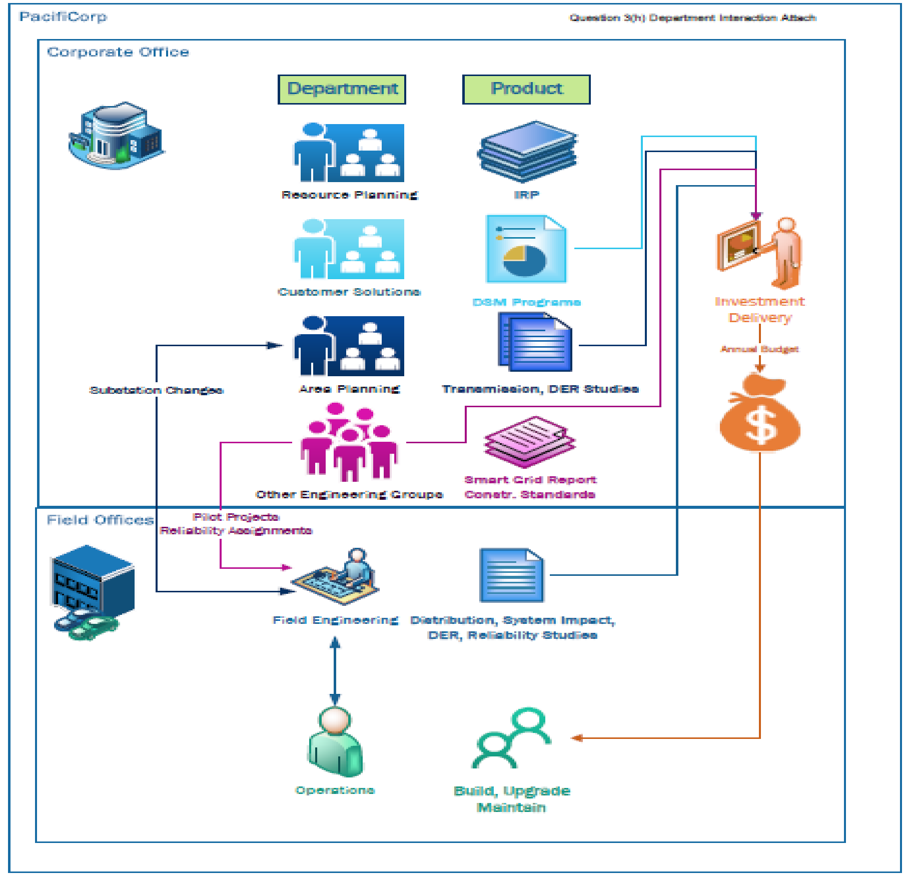
As-Is DSP/5-Year Planning Budget Process

Distribution Planning Studies

- Develop list of distribution projects to resolve potential system deficiencies/conditions
- Generally provided to investment delivery department prior to the end of Q2 to be incorporated in capital plan annual update
- After Q2, review existing plan to verify scope and timing aligns with results of current studies

Ad-hoc Studies (Generation Interconnect or System Impact Study)

- Develops a distribution project to resolve identified system deficiencies/condition to serve new load/generation addition
- Timeline established by customer need
- Incorporated into capital plan during annual update



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As-Is DSP/Area Planning Process

Study Needed

Drivers:
- Study cycle
- New Load/Resource Proposed
- Area Need (e.g., high load growth activity)
- Anticipated large load additions (short and long term)
- Transmission Impact

Load Forecasting

Tasks Required:
- ✓ Review Historical summer/winter peak load SCADA data at circuit breaker level
- ✓ Adjust for large load additions and planned system changes consistent with capital plan
- ✓ Adjust for large DER additions
- ✓ Option: Normalize for weather if base data not representative

Load Flow Model Updates/Verification

Tasks Required:
- ✓ Review equipment and line data in CYME Model
- ✓ Perform field Verification of model data
- ✓ Update CYME Model per field verification

Identify Grid Needs

Tasks Required:
- ✓ Run CYME Model based on load forecast
- ✓ Identify and analyze grid need and timeline due to issue (For Example)
- ✓ Undervoltage
- ✓ Overvoltage
- ✓ Thermal overload

Apply initial solution to model and Re-analyze Iterate until solutions have addressed issues

Identify and Determine Potential Solutions

Tasks Required:
- ✓ Identify and determine solution to resolve issue For example:
- ✓ Load transfer
- ✓ Phase balancing,
- ✓ Capacitor bank
- ✓ Etc.

Finalize proposed solution(s) to develop a project list (includes high-level scope of work, budget, and timeline)

Develop Proposal for Investment Delivery

Tasks Required:
Develop proposal for each project listed which includes:
- ✓ Description of work to be performed
- ✓ Purpose and Necessity
- ✓ Risk Assessment
- ✓ Alternatives Considered
- ✓ Preliminary Cost Estimate
- ✓ Investment Reason

Proposals go to Investment Delivery to get incorporated into capital plan

Transitional/Pilot Planning Process

New Activities For Transitional/Pilot Planning Areas

Study Needed

Drivers:
- Study cycle
- New Load/Resource Proposed
- Area Need (e.g., high load growth activity)
- Anticipated large load additions (short and long term)
- Transmission Impact

Load Forecasting

Tasks Required:
- ✓ Review Historical summer/winter peak load SCADA data at circuit breaker level
- ✓ Adjust for large load additions and planned system changes consistent with capital plan
- ✓ Adjust for large DER additions
- ✓ Option: Normalize for weather if base data not representative
- ❑ **Incorporate EV and DER Forecasts with H/M/L Adoption Estimates at Circuit Level**
- ❑ **Develop 24 hour load profile based on load/DER type and usage class (Residential, Commercial, etc.)**
- ❑ **Refine IRP/DSM forecasts to circuit level**

Load Flow Model Updates/Verification

Tasks Required:
- ✓ Review equipment and line data in CYME Model
- ✓ Perform field Verification of model data
- ✓ Update CYME Model per field verification

Identify Grid Needs

Tasks Required:
- ✓ Run CYME Model based on load forecast
- ✓ Identify and analyze grid need and timeline due to issue (For Example)
- ✓ Undervoltage
- ✓ Overvoltage
- ✓ Thermal overload
- ✓ Apply initial solution to model and Re-analyze
- ✓ Iterate until solutions

Identify and Determine Potential Solutions

Tasks Required:
- ✓ Identify and determine solution to resolve issue For example:
- ✓ Load transfer
- ✓ Phase balancing,
- ✓ Capacitor bank
- ✓ Etc.

Finalize proposed solution(s) to develop a project list (includes high-level scope of work, budget, and

- ❑ **Develop prioritization process for NWS**
- ❑ **Identify Grid Need and Potential NWS**
- ❑ **Evaluate wires solution and at least two NWS pilots/proposals**
- ❑ **Publicly share prioritized Grid Needs**
- ❑ **Engage Community to review Grid Needs, develop , evaluate and review NWS pilots**
- ❑ **Identify process improvements**
- ❑ **Refine and update process**

Develop Proposal for Investment Delivery

Tasks Required:

Develop proposal for each project listed which includes:
- ✓ Description of work to be performed
- ✓ Purpose and Necessity
- ✓ Risk Assessment
- ✓ Alternatives Considered
- ✓ Preliminary Cost Estimate
- ✓ Investment Reason

Proposals go to Investment Delivery to get incorporated into capital plan

- ❑ **Update Proposals (as needed)**

Transitional Study Areas

From DSP Part 1, PacifiCorp targeted two regional areas:

- Klamath Falls
- Pendleton

Areas selected for transitional planning:

- ✓DG Capacity and Readiness (SCADA availability, DG Protection Measures, Daytime Minimum Load)
- ✓Study cycle timing
- ✓Historical DER project activity
- ✓Area demographics and characteristics (Suburban/Rural)

PacifiCorp is seeking input on these areas:

- Requesting feedback via workshop, webpage, community engagement
- Asking DSP workshop participants if they have any suggestions, feedback, etc.

2022 Distribution System Planning Pilot Circuits								
Revised Load Bubble	BPA NITS		Central Oregon	West Main				
Revised Sub Load Bubble	Pendleton	Santiam	Bend	Clatsop Astoria	Southern Oregon/California			
DSP Planning Area	Pendleton	Stayton	Bend	Astoria	Klamath Urban	Merlin	Roseburg Urban	Upper Rogue
Circuits	5W202 5W203 5W401 5W402 5W403 7W451 7W452 7W453 7W454	4M120 4M70	5D10 5D12 5D155 5D196 5D238 5D241 5D243 5D411 5D413 5D418	5A204 5A211	5L112 5L113 5L45 5L46 5L48 5L49 5L54	5R232 5R234 5R248 5R251	4U10 4U22 4U30 4U31 4U38 4U39 4U5 4U81 5U15 5U17 5U19	4R13 4R17 4R9

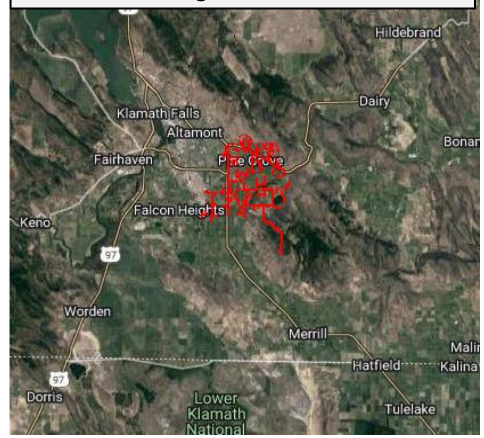
Preliminary Grid Needs – Transitional Planning Areas

Circuit/Area Characteristics:

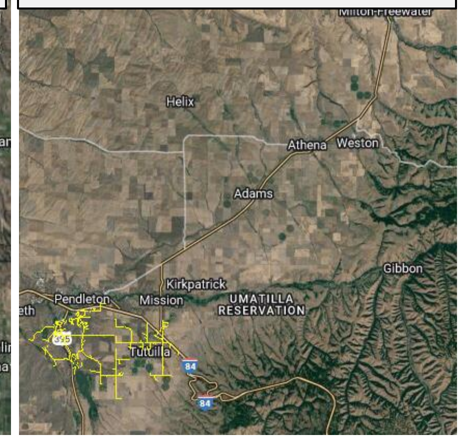
- Suburban/rural feeders (low load density with high circuit miles)
- Small conductor on the mainline which allows for less load capacity and higher voltage drop (Does not necessarily = less DG readiness)
- Historically higher DER adoption than other areas in Pacific Power service territory (I.E. Portland, Astoria, etc.)
- Ranked higher in DG capacity and readiness than other areas

Preliminary findings/Grid Needs:

Klamath Falls – Crystal Springs – 5L45
- Projected peak summer load drives overload on conductor
- Phase imbalance
- Low voltages on circuit



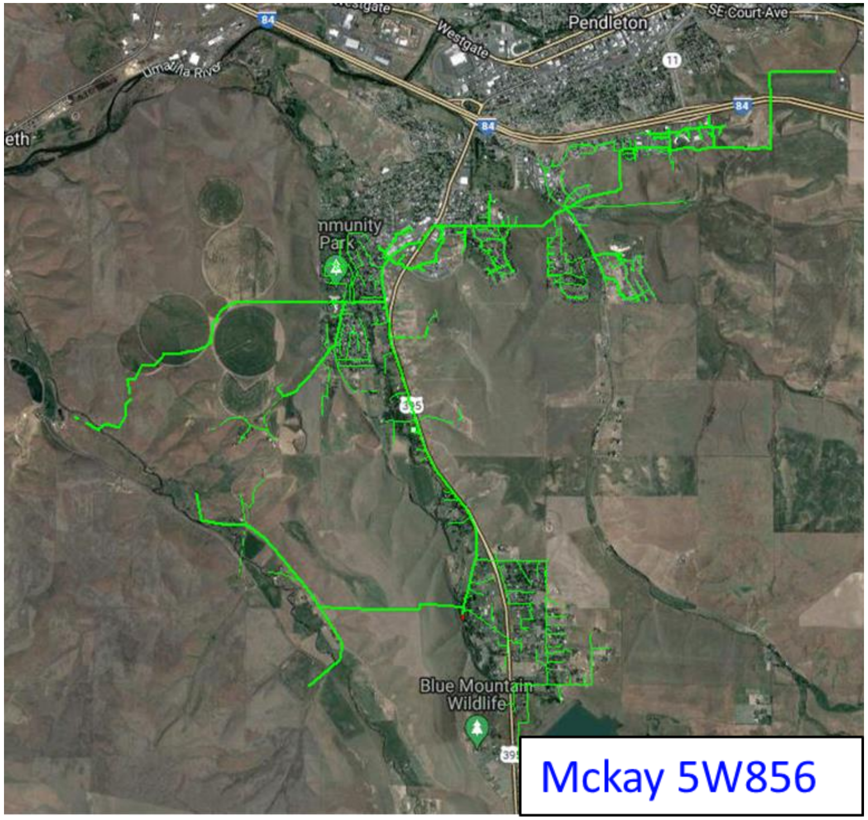
Pendleton – Hotel District – 5W856
- Limited grid needs due to recent investment upgrades
- Low voltages in outlying areas



Grid Needs – Pendleton

Circuit Details:

- Circuit 5W856 served from McKay substation
- Circuit operates at 12.47 kV
- Peak loading occurs during summer
- Daytime minimum loading occurs during the spring
- Overall Customer makeup:
    - 1,802 Total number of customers
        - 1,641 Residential
        - 28 Irrigation
        - 131 Commercial
        - 1 Industrial
        - 1 Hospital



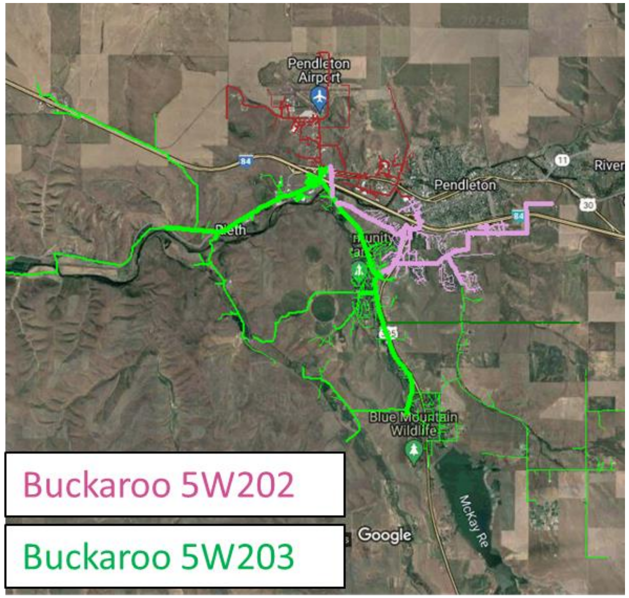
No Grid Needs Found:

- Ad-hoc study performed during planning study cycle resolved any Grid Needs for area.

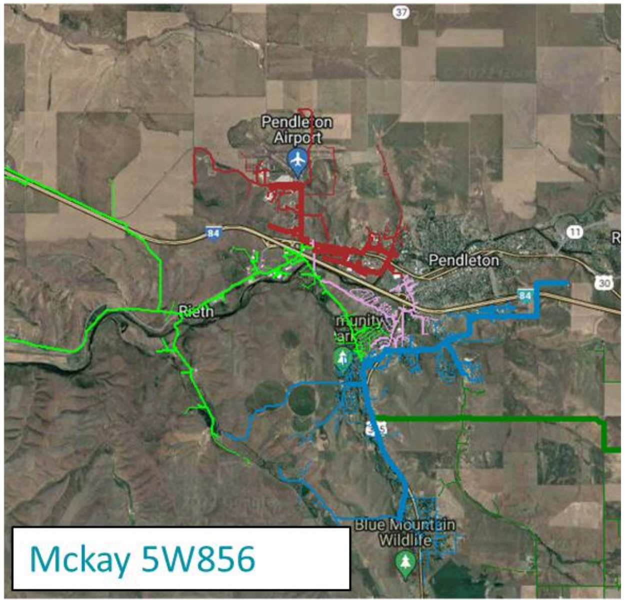
- **What Grid Needs could we have found if the Ad-hoc study did not occur?**

Grid Needs – Pendleton

Before:



After:



<u>Model Scenario</u> – Analyze the previous circuits as if the new substation and Ad-hoc study did not exist
McKay 5W856 is made up of sections of Buckaroo 5W202 and 5W203 served from Buckaroo Substation.

Scenario analyzes the two circuits without the new substation and applies the PV and EV forecast for Buckaroo 5W202 and 5W203

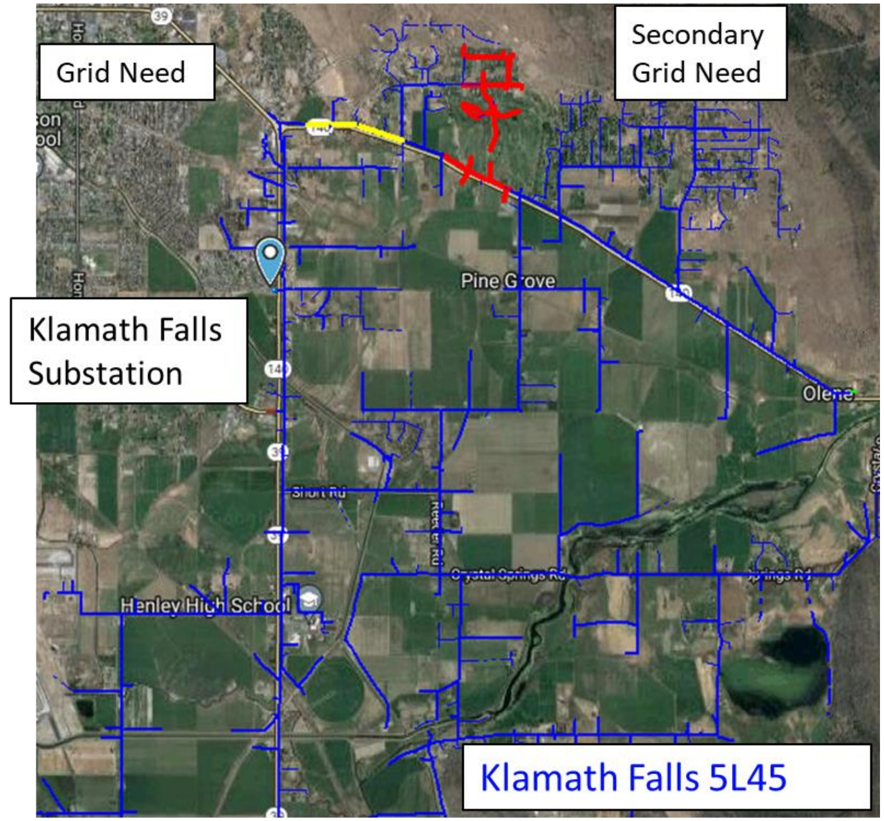
After removing the impact of the Ad-hoc study … No Grid Needs Found

Grid Needs – Klamath Falls

Circuit Details:

- Circuit 5L45 served from Klamath Falls substation
- Circuit operates at 12.47 kV
- Peak loading occurs during summer
- Daytime minimum loading occurs during the spring

- Overall Customer makeup:
  - 1,499 Total number of customers
    - 1,196 Residential
    - 155 Irrigation
    - 145 Commercial
    - 3 Industrial



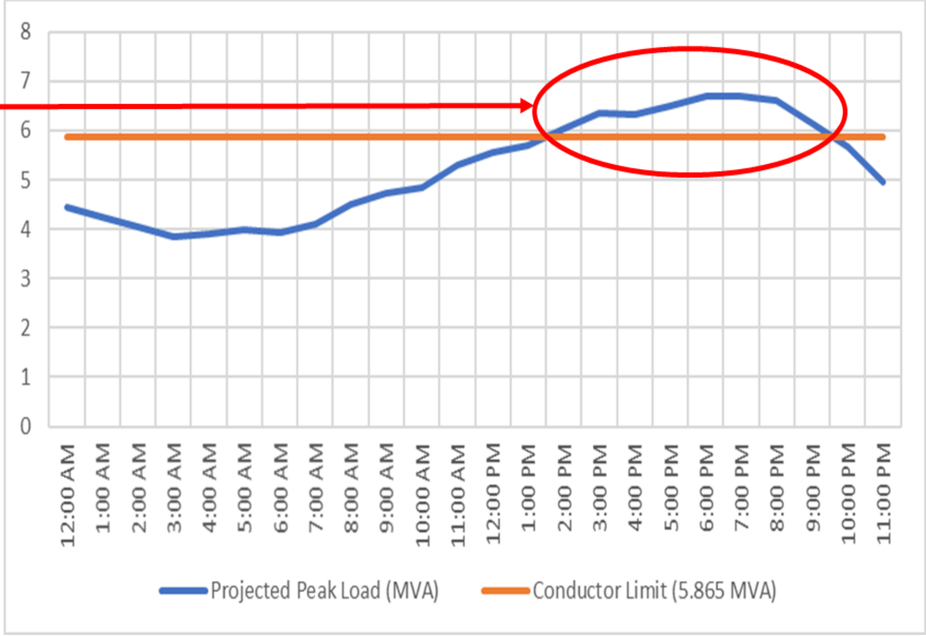
Grid Needs:

- Study identified an overcapacity issue causing conductor overload
- Also causes low voltage downstream

Grid Needs – Klamath Falls

Grid Need:

- Approximately 850 kW over existing conductor limit
- Occurs ~20 – 50 hours total per year in Summer ~ June through August



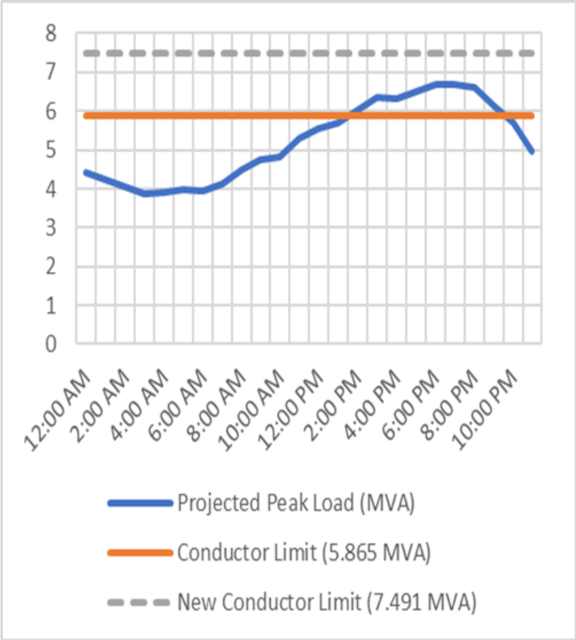
- Number of customers downstream of issue:
  - 511 Total customers (37% Summer kWh)
    - 461 Residential (24%)
    - 33 Irrigation (13%)
    - 17 Commercial (1%)
    - 0 Industrial (0%)

Based on the Grid Need and characteristics of circuit, there are several solutions available. All have different effects in terms of complexity, performance, and reliability.

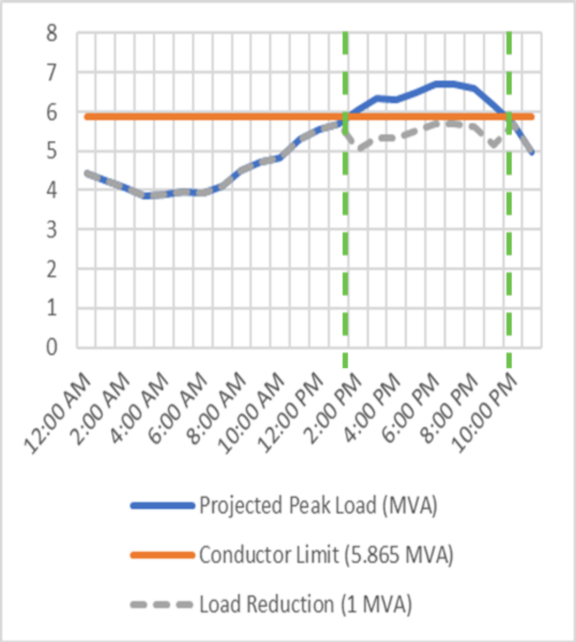
Grid Needs – Klamath Falls

List of hypothetical solutions:

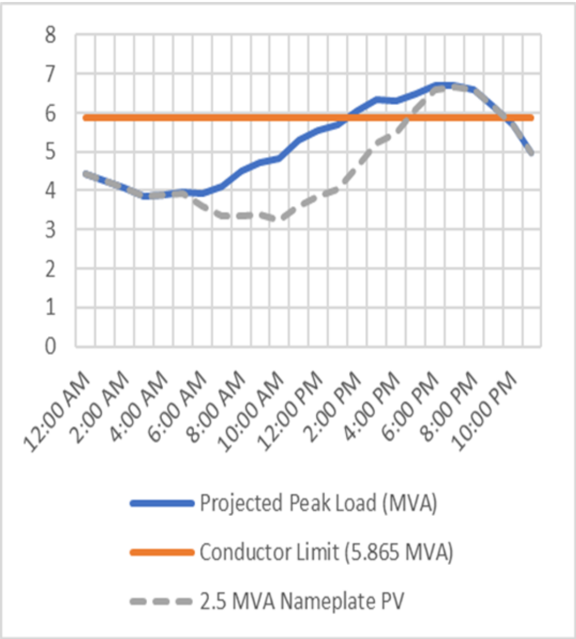
Traditional Wires Solution – Reconductor overloaded conductor



Demand Side Management (DSM) Solution - Load reduction



Non-Wires Solution - Solar Only



Klamath Falls Grid Need and Potential Non-Wires Solutions

Klamath Falls – Crystal Springs – 5L45

- Projected peak summer load drives overload on conductor
- Phase imbalance
- Low voltages on circuit

Non-Wires Solutions PAC is Considering for evaluation

•Solar

•***Solar + Battery Storage***

•Load Control, Curtailment, Demand Response

•Targeted DSM

•Other DER

Non-Wires Solutions Proposed by Stakeholders:

Farmer's Conservation Alliance:

•***Solar + Battery Storage***

OSSIA:

•Pilot use of ***Smart Inverters***

•Pilot "Solarize Campaign"

Opportunity to Evaluate *Solar + Battery Storage, w/Smart Inverter*

- Work with local KFalls stakeholders + FCA + OSSIA
- Develop skillset to model and evaluate solar + storage and ID system impacts

2nd NWS – TBD Seek input from KFalls Stakeholders

Initial Lessons Learned

DSP requires significantly more than historical approach…

- Much more Data Intensive
  - Requires new data sources and increased granularity for existing data
  - Analysis requires development of 24-hour representative curves instead of single peak point
  - Requires feeder SCADA telemetry instead of manually recorded data
  - Scaling up for DSP requires new toolsets/systems and analytical capabilities

- Broader and More Frequent Outreach
  - Significantly higher degree of community involvement
  - Discussions require deeper education to cover increasingly complex subjects
  - Expanding outreach processes to increase transparency

- Significant Changes to Internal Processes
  - Improve cross-functional/cross-department collaboration
  - Increased reporting requirements (not just DSP)
  - New groups, new responsibilities, and new procedures
  - New regulatory requirements

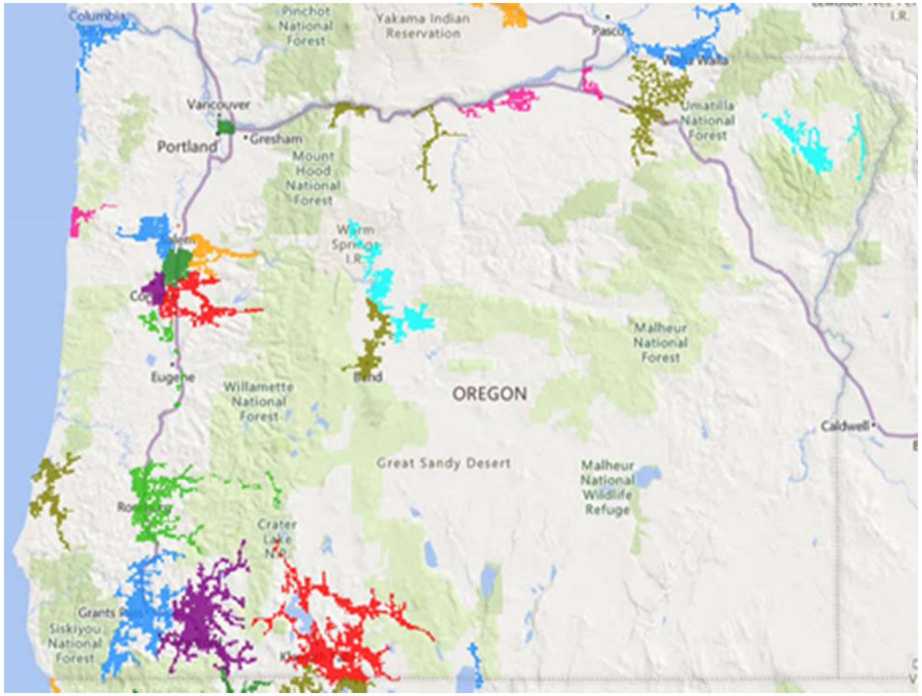
Differences between DSP and IRP Forecast

- DSP load forecasting and analysis completed at feeder level vs IRP load forecasting at jurisdiction/state level

- DSP utilizes SCADA data and peak load information at feeder level to develop forecast vs IRP jurisdictional forecast allocated based on peak load per transformer information

- DSP analysis requires a 24-hour peak load curve specific to the feeder (for non-wires solution) vs IRP uses hourly jurisdiction load

- DSP forecast based on historical actual temperatures vs IRP forecast based on forecasted normalized temperatures



Renewable Portfolio Standards

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Renewable Portfolio Standard - Oregon

- Enacted by Senate Bill 838 (SB 838) in 2007, requiring Oregon utilities to deliver at least 25 percent of electricity from eligible renewable resources by 2025
- Expanded by the Clean Electricity and Coal Transition Plan (Senate Bill 1547) which passed March 8, 2016. Key provisions include:
  - Elimination of coal from Oregon rates by 2030
  - Increased RPS targets

2015 - 2019	2020 - 2024	2025 - 2029	2030 - 2034	2035 - 2039	2040 Onward
15%	20%	27%	35%	45%	50%

  - Elimination of solar capacity standard (previously mandated by House Bill 3039)
    - Required that by January 1, 2020, the total solar photovoltaic generating nameplate capacity of all Oregon utilities be at least 20 MW_{AC}. PacifiCorp's share of that was 8.7 MW_{AC}, of which 7 MW_{AC} have been developed.

Renewable Portfolio Standard - Oregon

- **Community Solar Program**
  - For residential and commercial customer to own off-site solar
  - At least 10% of program capacity set aside for low-income customers
  - The program opened to Project Managers in the Spring of 2020.
  - Two community solar projects in Pacific Power territory are now operational. The Company anticipates 1-3 more projects going live by 2023, for an estimated 3-5MW of total capacity.
- **Small-scale Renewables**
  - Requirement rather than goal
  - By 2030, at least 10% of state's aggregate electrical capacity to come from renewables 20 MW or less.
- **Transportation Electrification**
  - Investor-owned utilities required to propose programs to accelerate transportation electrification
  - In 2021, the Oregon Clean Fuels e-mobility grants received more than 30 applications from around the state, with more than $3m in funds requested. A total of $800k was awarded to customers, resulting in 11 new projects funded during the 2021 cycle. The 2022 grant cycle is now open for applications
  - Over the next three years, Pacific Power estimates investing at least $20 million to develop electric transportation programs throughout rural and urban communities.
  - The company has developed programs in all three west coast states with a focus on: EV fast chargers along underserved key corridors; developing interest and engagement with electric vehicles across all service areas; providing technical assistance; and creating partnership opportunities with community grants and larger-scale transit funding

Renewable Portfolio Standard - Oregon

- **Eligible Resources**
  - Operational after January 1, 1995
    - Pre-1995 Hydro – eligible if certified by the Low Impact Hydro Institute, and only up to 50 average megawatts of utility-owned and 40 average megawatts not owned by the utility annually (total 90 aMW per year)
    - Pre-1995 Biomass and Solid Waste – eligible for use immediately, with the passing of SB 1547; previously not recognized as eligible until 2026
  - RPS-certified by Oregon Department of Energy
  - Located within the Western Electricity Coordinating Council (WECC)
  - Technologies – Wind, Solar, Solar Thermal, Geothermal, Wave, Tidal, Ocean Thermal, Hydro located outside protected water areas, Incremental Hydro (efficiency upgrades), Biomass, Municipal Solid Waste, Thermal RECs from Biomass (SB 1547 addition)

Renewable Portfolio Standard - Oregon

- **Renewable Energy Certificates (RECs)**
  - Must be issued in Western Renewable Energy Generation Information System (WREGIS)
  - Can be a combination of Bundled and Unbundled RECs (unbundled limited to 20% of annual RPS target
    - Qualifying Facilities (QFs) located in Oregon do not contribute to unbundled REC limit)
  - Retirement of RECs no longer required to follow first-in-first-out rule (SB 1547)

- **Banking Provisions (SB 1547)**
  - REC life limited to five years (previously unlimited)
  - Exceptions (Unlimited REC life):
    - Long-term resources coming online between bill passage and the end of 2022 generate RECs with unlimited REC life for the first five years of the resource's life
    - Existing REC bank (anything generated prior to bill passage)

Renewable Portfolio Standard - Oregon

- **Cost Controls**
  - Alternative compliance payments can be used in lieu of meeting the RPS requirement with renewables
  - The commission establishes an alternative compliance rate every two years.
  - Cost Cap – a utility is not required to comply with the RPS if the incremental cost of the RPS exceeds 4 percent of annual revenue requirement in a compliance year

- **Penalties**
  - Oregon Public Utilities Commission (OPUC) can impose penalties for failing to comply with the RPS in an amount determined by the OPUC

Renewable Portfolio Standard - California

- Established in 2002; expanded in 2011 under Senate Bill 2 (SB2-1X) requiring at least 33% renewable resources by 2020
- Senate Bill 350, the Clean Energy and Pollution Reduction Act was signed into law on October 7, 2015, which requires the state to procure 50% of electricity from renewable resources by 2030
  - Starting 2021, at least 65% of procurement must be from long-term resources (10 or more years)
  - Increased flexibility in banking bundled RECs
- Senate Bill 100, passed in 2018, requires that renewable energy and zero-carbon resources supply 100 percent of electric retail sales to end-use customers by 2045 and increased the renewable target to 60% by 2030

Renewable Portfolio Standard - California

- **Eligible Resources**
  - RPS-certified by California Energy Commission
  - Located within the Western Electricity Coordinating Council (WECC)
  - Technologies – Wind, Solar, Solar Thermal, Geothermal, Wave, Tidal, Ocean Thermal, Biomass, Landfill Gas, Municipal Solid Waste, Digester Gas, Fuel Cells, Hydro*

    * Hydro – eligible if capacity of 30 megawatts or less and procured or owned as of effective date of act

- **Renewable Energy Certificates (RECs)**
  - Must be issued in Western Renewable Energy Generation Information System (WREGIS).
  - California procurement is defined by Portfolio Content Categories (buckets) which increasingly limit the use of unbundled RECs over time. The policy is intended to encourage the procurement of in-state renewables.
  - As a multijurisdictional utility serving California load, PacifiCorp is exempt from the bucket limitations.

Renewable Portfolio Standard - California

- **Cost Controls**
  - No cost controls in place however, the California Public Utilities Commission (CPUC) is tasked with developing a Procurement Expenditure Limitation as part of SB 350

- **Penalties**
  - CPUC has the authority to impose penalties for not meeting RPS targets
  - SB 350 tasked CPUC with developing those penalties

Renewable Portfolio Standard - Washington

- Enacted by Initiative 937 (I-937) in 2006, requiring the use of at least 15% eligible renewables by 2020
- **RPS Targets**

2012-2015	2016-2019	2020 Onward
3%	**9%**	**15%**

- **Eligible Resources**
  - Operational after March 31, 1999
  - Located within the Pacific Northwest as defined by Bonneville Power Administration; for multijurisdictional utilities, resource can be located in any state served by the utility
  - Technologies – Wind, Solar, Solar Thermal, Geothermal, Wave, Tidal, Ocean Thermal, Incremental Hydro (only upgrades after March 1999), Biomass, Anaerobic Digestion

Renewable Portfolio Standard - Washington

- **Renewable Energy Certificates (RECs)**
  - Must be issued in Western Renewable Energy Generation Information System (WREGIS)
  - Can be a combination of Bundled and Unbundled RECs
    - No limit on unbundled RECs
  - Resources outside of 'Pacific Northwest' must be utility-owned or long-term contract (more than 12 months)
- **Banking Provisions**
  - RECs can be produced during the compliance year, the preceding year or the subsequent year
- **Cost Controls**
  - Utility is not required to comply with the RPS if the incremental cost of the RPS exceeds 4 percent of annual revenue requirement in a given year
- **Penalties**
  - $50 per megawatt-hour of shortfall

Stakeholder Feedback




Stakeholder Feedback Form Update

- 12 stakeholder feedback forms submitted to date
- Stakeholder feedback forms and responses can be located at:
  pacificorp.com/energy/integrated-resource-plan/comments
- Depending on the type and complexity of the stakeholder feedback, responses may be provided in a variety of ways including, but not limited to, a written response, a follow-up conversation, or incorporation into subsequent public-input meeting material
  - Generally, written responses are provided with the form and posted online at the link mentioned above
- Stakeholder feedback following the previous public input meetings is summarized on the following slides for reference

Summary – Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary*	Response*
Utah Division of Public Utilities	June 7, 2022	Formatting/stakeholder feedback suggestions	PacifiCorp must date its responses to stakeholder feedback forms or questions.	PacifiCorp will include its response date to Stakeholder Feedback Forms.
Utah Division of Public Utilities	June 7, 2022	Proxy Resources/Plexos Modeling	Requests Company updates its Supply Side table with current operating and costs characteristics of natural-gas fueled generation resources and allow the model to endogenously select natural gas generating resources as proxy resources, as it has done in the past.	In the 2021 IRP, PacifiCorp ran an analysis which included options for new gas. For the 2023 IRP the company is also currently assessing viable options for the inclusion of new gas in its base modeling.

*Full comments and PacifiCorp's responses can be found online at https://www.pacificorp.com/energy/integrated-resource-plan/comments.html

Summary – Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary*	Response*
Utah Clean Energy; Western Resources Advocates; Sierra Club; Interwest Energy Alliance; Powder River Basin Resource Council; NW Energy Coalition; Salt Lake City	June 14, 2022	Infrastructure Investment & Jobs Act	Request that PacifiCorp include time and materials in an upcoming 2023 IRP stakeholder presentation to discuss the benefits and opportunities that may be available through the Infrastructure Investment and Jobs Act, and how they may affect resource and transmission planning.	PacifiCorp is in the early phases of actively collaborating with our state jurisdictions, as a majority of IIJA funds for grid projects will be allocated to each state. We are closely monitoring the release of any new information on the IIJA programs to make sure we fully understand expectations and program details before finalizing our plans to seek IIJA funds.
Salt Lake City Corporation	June 16, 2022	Feasibility assessment- battery storage vs. natural gas	Studying whether a battery with a grid-forming inverter would provide a lower-cost alternative to natural gas spinning reserves.	PacifiCorp considers a wide range of technologies for supply-side resources. Battery energy storage systems (BESS) are among those technologies.

*Full comments and PacifiCorp's responses can be found online at https://www.pacificorp.com/energy/integrated-resource-plan/comments.html

Summary – Pending Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary*	Response*
Western Resource Advocates	June 23, 2022	Load, Weather & Climate Forecasting	Parties recommend modeling two emissions reduction trajectories, in lieu of the “medium” and “high” carbon price scenarios, in addition to the social cost and no-cost GHG price assumptions.	**Pending Review**
Holland & Hart	June 27, 2022	Transparency in GHG price policy scenarios	How did PacifiCorp develop the GHG cost methodology and what third-party resources were used to develop these costs?	**Pending Review**
Sierra Club	July 1, 2022	Natrium Project, Emissions Profiles and State Policy Updates	IRP, GHG, RPS, CETA, Load Forecast Updates	**Pending Review**
Western Resource Advocates	July 11, 2022	Jim Bridger modeling, energy mix disclosure, GHG reporting, natural gas resources, hydrogen updates.	Reiteration of recommendations from WRA’s comments on the 2021 IRP/ requests for additional resource information.	**Pending Review**

*Full comments and PacifiCorp’s responses can be found online at https://www.pacificorp.com/energy/integrated-resource-plan/comments.html

Ozone Transport Rule Update

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EPA Ozone Transport Rule - Update

- At the April public-input meeting, PacifiCorp provided a high-level overview of the March 11, 2022, pre-publication version of the “Ozone Transport Rule” (OTR) issued by the Environmental Protection Agency (EPA). EPA formally proposed the rule April 6, 2022.
- OTR is focused on reduction of nitrogen oxides, precursors to ozone formation, and now covers 26 states including, for the first time, Wyoming, Utah, Nevada and California.
- OTR construct:
  - Beginning in 2023, trading allowances and emissions budgets are expected to be set to achieve reductions through immediately available measures.
  - Starting in May of 2026, emissions budgets are expected to be set for coal-fired units at levels achievable through the installation of selective catalytic reduction (SCR) controls.
  - Daily emission limits for units with SCR will become effective in 2027.
- Public comments were filed June 21, 2022. Berkshire Hathaway Energy submitted comments on behalf of affected companies, including PacifiCorp. The comments draw attention to several concerns with the proposed rule.

Summary of Concerns Raised in Comments

- Western states should be removed from the proposed rule.
  - The Proposed Rule is based on a pre-existing framework that was not designed for, and is not workable for, western states.
  - EPA incorporated the four new western states (California, Nevada, Utah and Wyoming) into the proposed rule based on flawed modeling and questionable administrative procedures.
  - The proposed rule is likely to force early coal-unit retirements on a timeline expected to disrupt the reliable delivery of electricity and could directly result in electricity shortages throughout the West and have significant cost implications for customers.
- If EPA does not remove the western states from the proposed rule, several elements must be corrected.
  - EPA should undertake meaningful outreach with the Western Electricity Coordinating Council and the North American Energy Reliability Corporation to ensure that any final interstate transport rule is appropriately modeled to address reliability impacts.
  - EPA’s over-control analysis for Utah and Wyoming is flawed and must be revisited.
  - The proposed “enhancements” to the existing trading program eliminate the benefits of a market-based trading program and should be modified.
  - Additional flexibility and a safety valve are necessary to the success of the trading program.

OTR – Next Steps

- EPA received more than 100,000 comments on the proposed rule. EPA has indicated it expects to finalize the rule by late 2022 or early 2023 so the rule will be in effect for the 2023 ozone season (May – September).

- PacifiCorp is considering OTR implications in potential modeling scenarios and endogenous optionality for Plexos as part of its 2023 IRP modeling approach and plans to present and discuss these recommendations with stakeholders for consideration and feedback at an upcoming public-input meeting.

Wrap-Up/Additional Information

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Additional Information

- 2023 IRP Upcoming Public Input Meetings:
  - September 1-2, 2022 (Thursday-Friday)*
  - October 13-14, 2022 (Thursday-Friday)
- Public Input Meeting and Workshop Presentation and Materials:
  - pacificorp.com/energy/integrated-resource-plan/public-input-process
- 2023 IRP Stakeholder Feedback Forms:
  - pacificorp.com/energy/integrated-resource-plan/comments
- IRP Email / Distribution List Contact Information:
  - IRP@PacifiCorp.com
- IRP Support and Studies:
  - pacificorp.com/energy/integrated-resource-plan/support

* Changed from August 25-26 to avoid MSP meeting conflict