PGE CEP & IRP Roundtable 26-1

Feb 24th 2026

Meeting Details

1

Electronic version of presentation

https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-public-meetings

2

Zoom meeting details

Join Zoom Meeting
https://us06web.zoom.us/j/84372774388?pwd=WGdNfwfAFGcWgHxYjX0Mk2QbhDDaa7.1

- Meeting ID: 843 7277 4388
- Passcode: 108126

3

Participation

- Use the raise the hand feature to let us know you have a question
- Unmute with microphone icon or *6

Meeting Logistics

Focus on Learning & Understanding

- There will be no chat feature during the meeting to streamline taking feedback
- Team members will take clarifying questions during the presentation, substantive questions will be saved for the end (time permitting)
- Attendees are encouraged to 'raise' their hand to ask questions

Follow Up

If we don't have time to cover all questions, we will rely on the CEP/IRP feedback form

February 24, 2026 – Agenda

9:00 | Welcome

9:05 | Clean Energy Plan & Integrated Resource Plan Community Engagement Updates

9:20 | Flexibility Study Draft Results

9:50 | CBRE Update

10:10 | IRP Emissions Forecasting

10:25 | Diverse Market Transmission Framework

10:45 | Portfolio Scoring

11:05 | ELCCs

11:25 | RFP Update and Proxy

11:55 | Closing Remarks - Next Steps

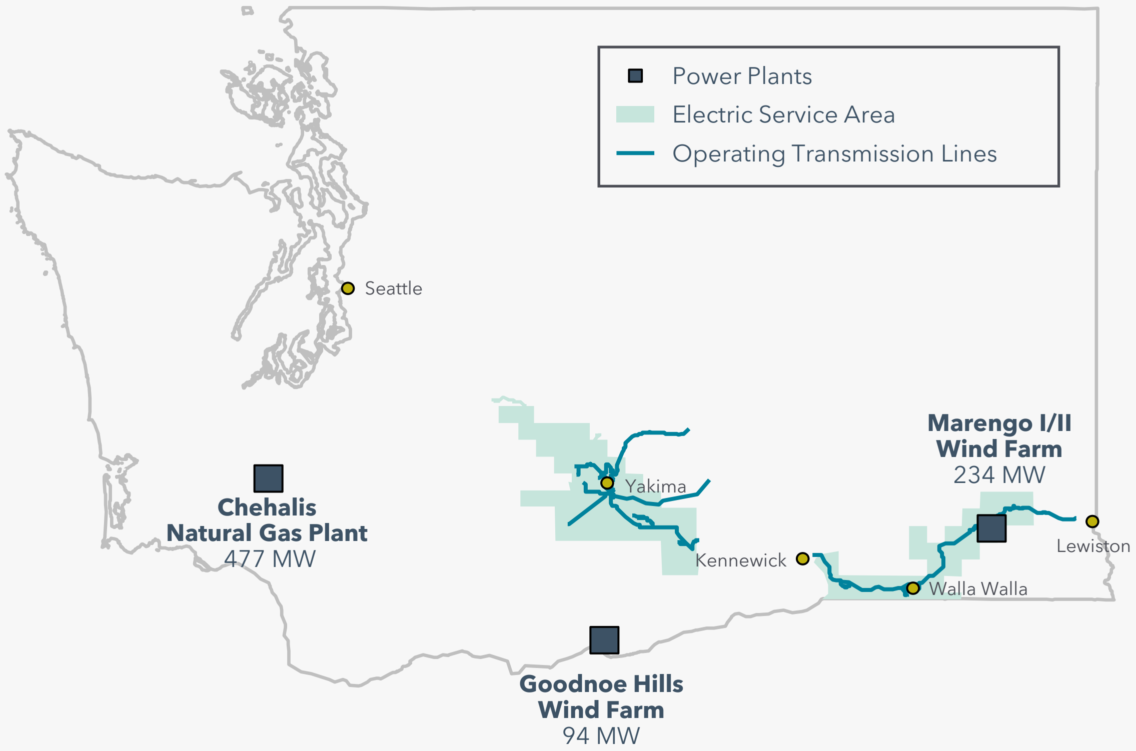
Upcoming Roundtable Schedule for the 2026 CEP/IRP

Wednesdays from 9 to 12 pm, Online Via Zoom

6	**February 24, 2026**	Portfolio scoring, flexibility study results, ELCCs
7	**April 08, 2026**	
8	**May 20, 2026**	
9	**July 01, 2026**	

PGE announcement to acquire WA utility

Service Area



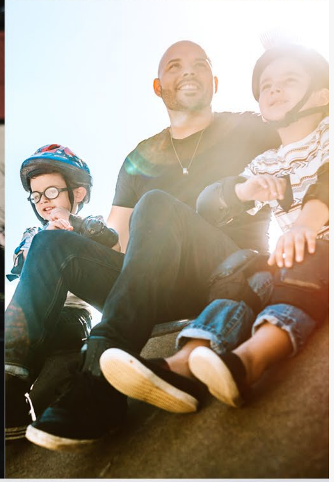
Summary Metrics

Customers	~140,000
Service Area	~2,700 square miles
Transmission Miles	~500 miles
Distribution Miles	~4,000 miles
Generation Capacity	~800 MW

Acquisition is subject to customary regulatory approvals; close expected **12 months** after regulatory filing submission

If approved, the WA utility will be a **separate entity** from PGE, continuing to serve WA customers and be regulated by WA

No impact to the 2026 Integrated Resource Plan and Clean Energy Plan.



Clean Energy Plan & Integrated Resource Plan Community Engagement Updates

Presenter: Samantha Thompson, Senior Community Engagement Specialist

February 24, 2026

Our Community Engagement Outcomes and Approach for Integrated Resource Plan (IRP) & Clean Energy Plan (CEP)

Outcomes

- Build shared understanding of how long-term resource planning affects customers and communities.
- Create accessible entry points for participation and learning.
- Learn from community voices to help inform assumptions and balance priorities in resource planning.

Our approach

- Provide a space for transparent and inclusive conversations where customers/interested parties can participate and shape ongoing engagement efforts.
- Multiple touchpoints across audiences via established venues.
- Integrate resource planning and related topics into cohesive, accessible learning that strengthens ongoing engagement, awareness, and energy knowledge for customers/interested parties.

Community Engagement Updates

Community Benefits & Impact Advisory Group (CBIAG)

What we did

- Presented PGE's CEP/IRP engagement approach and delivered an IRP 101 overview.
- Explained the purpose, timeline and regulatory context of long-term resource planning.
- Invited questions to support understanding of technical planning concepts.

What we heard

- Appreciation for early, plain-language CEP/IRP information.
- Questions about assumptions, uncertainty, affordability and community and customer impacts.
- Interest in transparency around how feedback influences planning.

What we learned

- Continued learning opportunities are important as planning progresses.
- Clarity on constraints and tradeoffs helped members understand the complexity of long-term resource planning.

Feedback Comment Categorization

(Ask / Concern / Advice / Education)

Category	Count	Percent	Description
Ask	18	75%	Request for clarity or action.
Concern	4	17%	Potential impacts, risks, or challenges flagged.
Advice	1	4%	Suggestions or solution-oriented recommendations.
Education	1	4%	Knowledge-sharing feedback.
Total	**24**	**100%**	

Total CEP/IRP related comments/questions – **24**
- **21** from CBIAG members
- **3** from the third-party facilitator

Community Engagement Updates Continued

CBIAG Post Meeting Survey Results

All eight survey respondents rated the IRP presentation positively.

- **100%** (8 of 8 respondents) either **agreed** or **strongly agreed** the content was relevant and useful.
- **100%** (8 of 8) **Agreed** or **strongly agreed** the presentation increased their knowledge of the subject.
- **100%** (8 of 8) **Agreed** or **strongly agreed** the presentation was well organized and easy to follow.

Members prioritization (select up to three options) in long-term planning, they most frequently selected:

- **Increasing community benefits** (selected by 7 of 8 respondents)
- **Prioritizing affordable power bills** (6 of 8 respondents)
- **Increasing clean energy resources** (6 of 8 respondents)
- Improving resiliency of grid infrastructure (3 of 8 respondents)
- Considering reliability and frequency of outages (3 of 8 respondents)

Community Engagement Updates Continued

CBIAG members ranked their top energy concerns:

- Cost of energy / monthly bills was ranked as the top concern by the majority of respondents (**5 of 8 ranked it #1**).
- Extreme weather impacts and outages / reliability were most frequently ranked second or third.
- Wildfire impacts / public safety power shutoffs generally ranked in the middle.
- Clean energy transition ranked lower overall compared to affordability and reliability concerns.

Community Engagement Activity Timeline

Nov. 19, 2025

CBIAG meeting: Grid 101 & DSP

Jan. 28, 2026

CBIAG meeting: CEP & IRP Overview

Feb. 21, 2026

Community-based Event:

East County Resiliency Fair

Feb. 25, 2026

CBIAG meeting: All-Source RFP 101 & Labor Standards

Q1 2026

External Meeting: Equitable Policy Council meeting

Q1 2026

Public Learning Space:

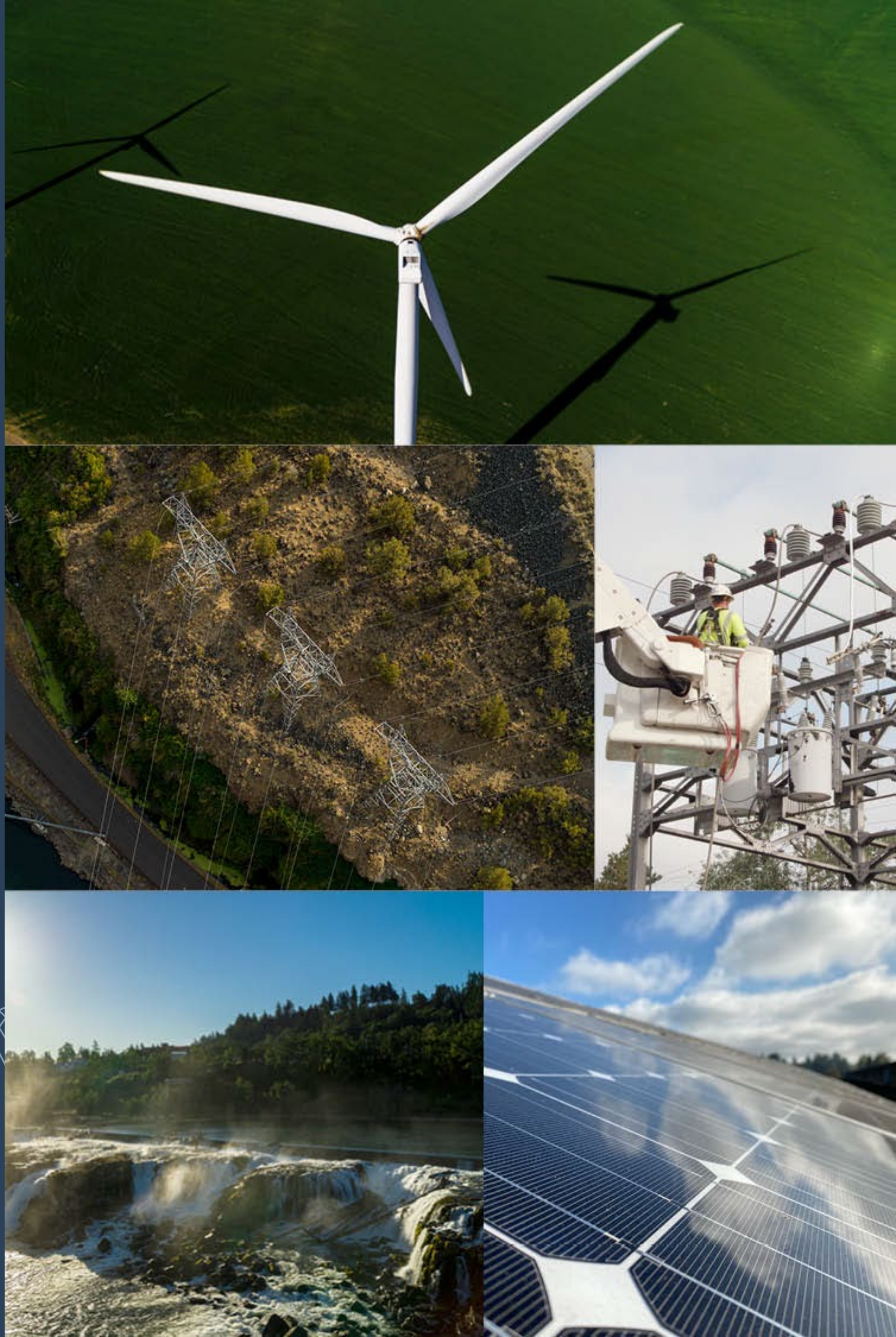
Watt's Up

2026 & Beyond

Ongoing engagement beyond the 2026 IRP/CEP cycle, which includes other utility plans and topics.

Flexibility Study Draft Results

Ana Mileva (Sylvan Energy) /
Lauren Slawsky and Devin Mounts (PGE) (30 minutes)



PGE An Oregon kind of energy.[SM]

Outline

- Background
- Methodology and Challenges
- Flexibility Study Draft Results

Sylvan Energy Analytics

provides consulting services and innovative grid analytics software to guide clean energy planning and policy

SYLVAN ENERGY ANALYTICS

PGE

- Extensive experience in integrated resource planning, working across the utility industry, with specific expertise in the Pacific Northwest
- Expertise across a range of topics:
  - Integrated resource planning, portfolio optimization, and asset valuation
  - Clean energy policy
  - Grid modeling and software development
- Sylvan develops and maintains GridPath, an open-source, versatile grid-analytics platform for capacity expansion, production cost, and resource adequacy analysis

- **PGE has engaged Sylvan to refresh the 2023 IRP flexibility analysis**
- **Experience with PGE IRPs**
  - 2016 IRP: led capacity-adequacy and reliability study (E3)
  - 2019 IRP: led flexibility adequacy analysis (Blue Marble Analytics)
  - 2023 IRP: led flexibility adequacy analysis (Blue Marble Analytics)

GridPath is an open-source, versatile modeling ecosystem for power system planning

- Open-source codebase available at https://github.com/blue-marble/gridpath
- Has been benchmarked against PLEXOS and RESOLVE

Flexibility Analysis Methodology

Flexibility Study Purpose and Uses for PGE

- Cost results from the study inform components of net costs:
  - ROSE-E capacity expansion resource valuation
  - Avoided cost dockets
  - RFP valuation

- Leverage learnings to inform broader system planning, such as:
  - Resource adequacy
  - Flexibility adequacy
  - Renewables integration
  - Battery capabilities
  - Operational considerations, such as commitment and forecast error

Figure 91. Deriving the blended cost of 1 kW of capacity contribution

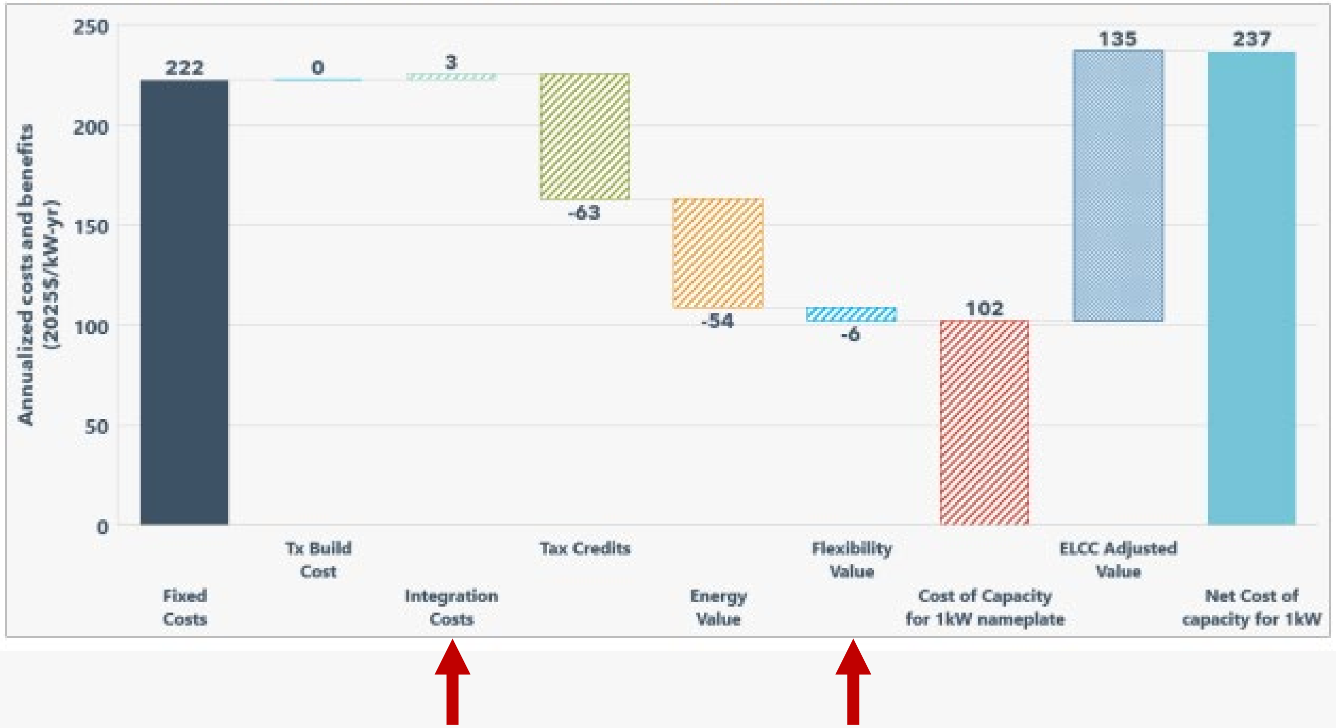


Figure from PGE's 2023 CEP/IRP Update:
https://downloads.ctfassets.net/416ywc1laqmd/UlLUBLOdenMjnrFJHv2mV/c382e175edae0e6ccffb806cd02bb6db/2023_CEP_IRP_Update_Errata.pdf

Flexibility Analysis Scope Overview

Flexibility Adequacy	Flexibility Value	Variable Energy Resource Integration Costs
evaluates unserved energy events that can be attributed to insufficient short-term flexibility.	evaluates the marginal value of flexibility provided by resources such as energy storage.	estimates the costs associated with the variability and uncertainty of resources added to the PGE system.

- ‘Flexibility’ here refers to the ability of a given resource portfolio to respond to **short-term** variability and uncertainty in electricity supply/demand
- Detailed simulation of the PGE system with a high degree of operational fidelity under median conditions
- Flexibility analysis reports the difference in system **operational** cost between two very similar systems, a base system and one with a small increment of the resource being evaluated
- These values are used as “adders” in overall resource economics and portfolio design

GridPath: Production-Cost Simulation

Multi-stage unit-commitment and dispatch with flexible temporal span and resolution

Day-Ahead (DA) Commitment

- Generator commitment schedules based on DA load and renewable forecasts (hourly)

Hour-Ahead (HA) Commitment

- Residual generator commitment schedules based on HA load and renewable forecasts (15-minute)

Real-Time (RT) Dispatch

- Actual load and renewable output (15-minute)

Generators modeled with a high level of operational fidelity:

Heat rate curves	**Minimum up and down times**	**Ramp rates**

Can also incorporate:

- Market availability limits
- Reserve requirements
- Fuel constraints

Base Case Assumptions

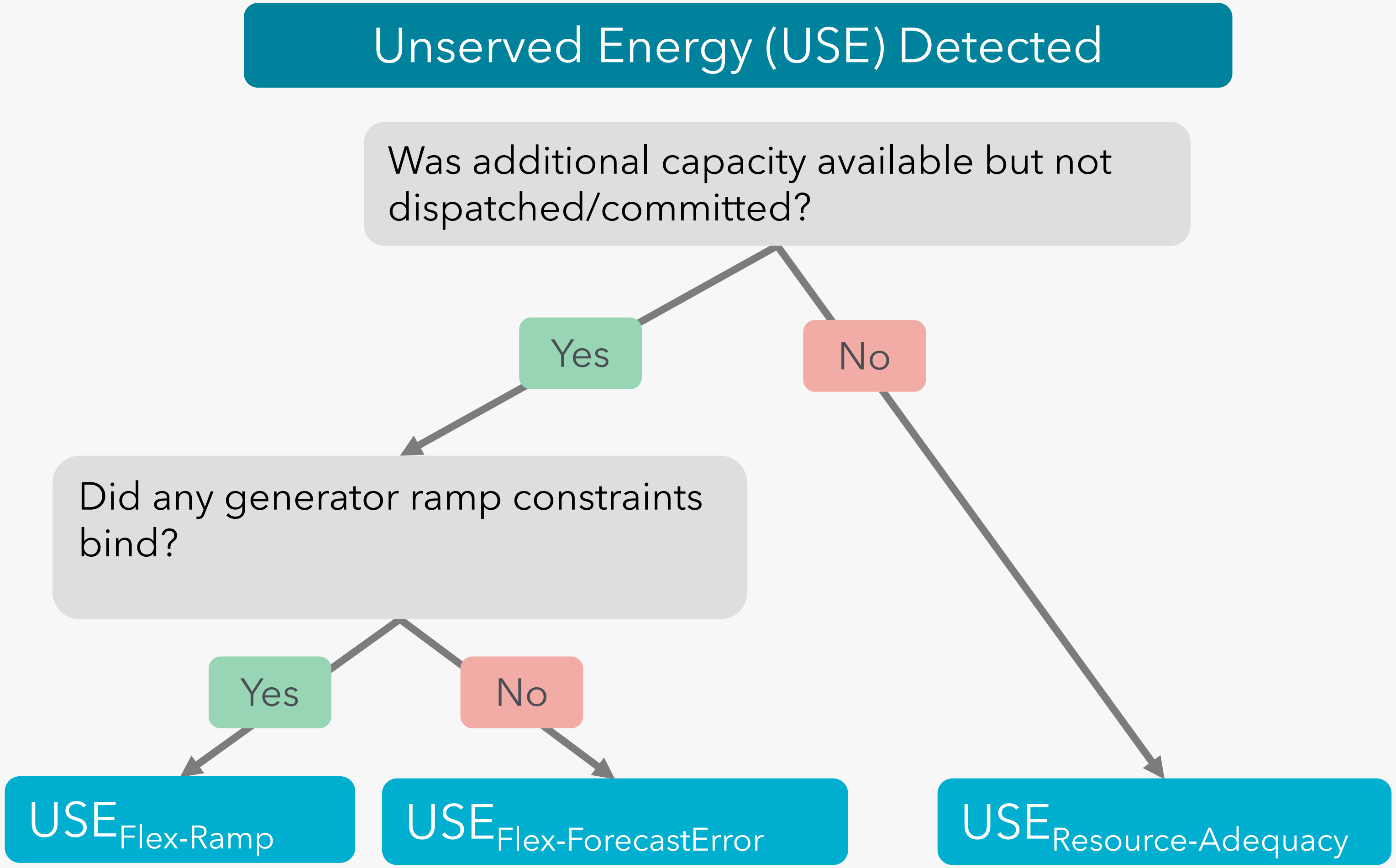
Data Input	Flexibility Adequacy	Flexibility Values and Integration Costs
Test Years	2030, 2035	←
Gas Prices	Reference	←
Carbon Prices	Reference	←
Electricity Prices	Reference	←
Load Forecast	PGE Sep 2025 for P50 year	←
VER generation	Updated profiles	←
Existing Contracts	Up to date	←
Market Availability	Aligned with p50 RA Assumptions (Dec. 2025 Roundtable).	←
Reserves	Regulation, contingency, and load-following reserves	←
Capacity Availability	Day-ahead, high load hour (HLH) block capacity that is more expensive than existing system generation & markets, and provides no flexibility	Proxy resource additions: Representative resources informed by '25 RFP (2030) and ROSE-E portfolio additions (2035)

Flexibility Adequacy

2030 Results

Measuring Unserved Energy Due to Flexibility (USE_{Flex})

- The flexibility adequacy study evaluates unserved energy events that can be attributed to insufficient short-term flexibility
- Important to distinguish between unserved energy attributable to flexibility shortages and those due to resource adequacy shortages
- The approach also distinguishes between uncertainty- and variability-related events



Flexibility Adequacy: 2030 Results

RA gap filled with block high load hour (HLH) product committed in the DA in 100 MW increments

- Provides no flexibility, so that magnitude of flexibility shortage can be identified

Very few flexibility adequacy events observed:

Real Time Unserved Energy (USE_{Flex})	
# 15-min Timepoints	14
% Timepoints	0.0%
Total MWh	17
Max MW	24

- Portfolio has more batteries, hybrids, and additional gas relative to 2023 IRP
- Supports 2023 IRP conclusion: "The flexibility adequacy issues encountered could be addressed by planning for a diverse portfolio containing wind and solar, and operationally flexible hybrid resources and batteries instead of highly inflexible DA capacity blocks."
- Including additional proxy resources eliminates flex adequacy events

Flexibility Value and Integration Costs

2030 Results

Portfolio Effects

Value and costs of resources are not static, but depend on the rest of the portfolio

With more wind in the system, additional wind will be harder to integrate

With more batteries in the system, additional solar may be easier to integrate, but additional batteries may see reduced value

Uncertainty is higher with a larger resource gap

Flexibility Value: 2030 Draft Results

- Objective: estimate the operational flexibility value of incremental storage resources when added to the PGE system

- A case is run with and without 100 MW of each potential new resource, and system operational costs are compared

- Starting system has considerably more batteries and hybrid resources as well as additional gas relative to 2023 IRP portfolio

- Increased storage duration provides additional flexibility benefit, with diminishing marginal returns

Proxy Resource	Round-trip Efficiency	Flexibility Value – 2030 (2026$/kW-year)	'23 IRP Flexibility Value – 2026 (2026$/kW-year)	'23 IRP Flexibility Value – 2030 (2026$/kW-year)
4-hour Battery	85%	10.7	10.4	20.0
6-hour Battery		12.7	11.4	22.0
10-hour PHS	81%	17.5	12.2	22.2
100-hour MDS	35%	6.8	N/A	N/A

Integration Costs: 2030 Draft Results

- Objective: estimate costs associated with the variability and uncertainty of new resources when added to the PGE system

- 100 aMW of each new resource is added to the system in separate runs

- The integration cost of a proxy resource is estimated as the difference in system cost relative to a separate model run that instead adds a resource block matching the test resource's weekly capacity factor

- The goal is to isolate operational costs associated with the variability and uncertainty of the test resource over short timeframes

Proxy Resources	Integration Cost - 2030 (2026$/MWh)	'23 IRP Integration Cost - 2026 (2026$/MWh)	'23 IRP Integration Cost - 2030 (2026$/MWh)
Solar (East)	6.3	3.3	3.5
Solar (West)	4.3	-	-
Wind (Montana)	1.6	1.0	1.6
Wind (Washington)	4.8	2.7	4.1

Next Steps

Draft results for 2035

Leverage results in this IRP

Guided Feedback – Flexibility Study Draft Results

Do you have any comments or questions regarding the purpose and approach of the flexibility study, or the draft results?

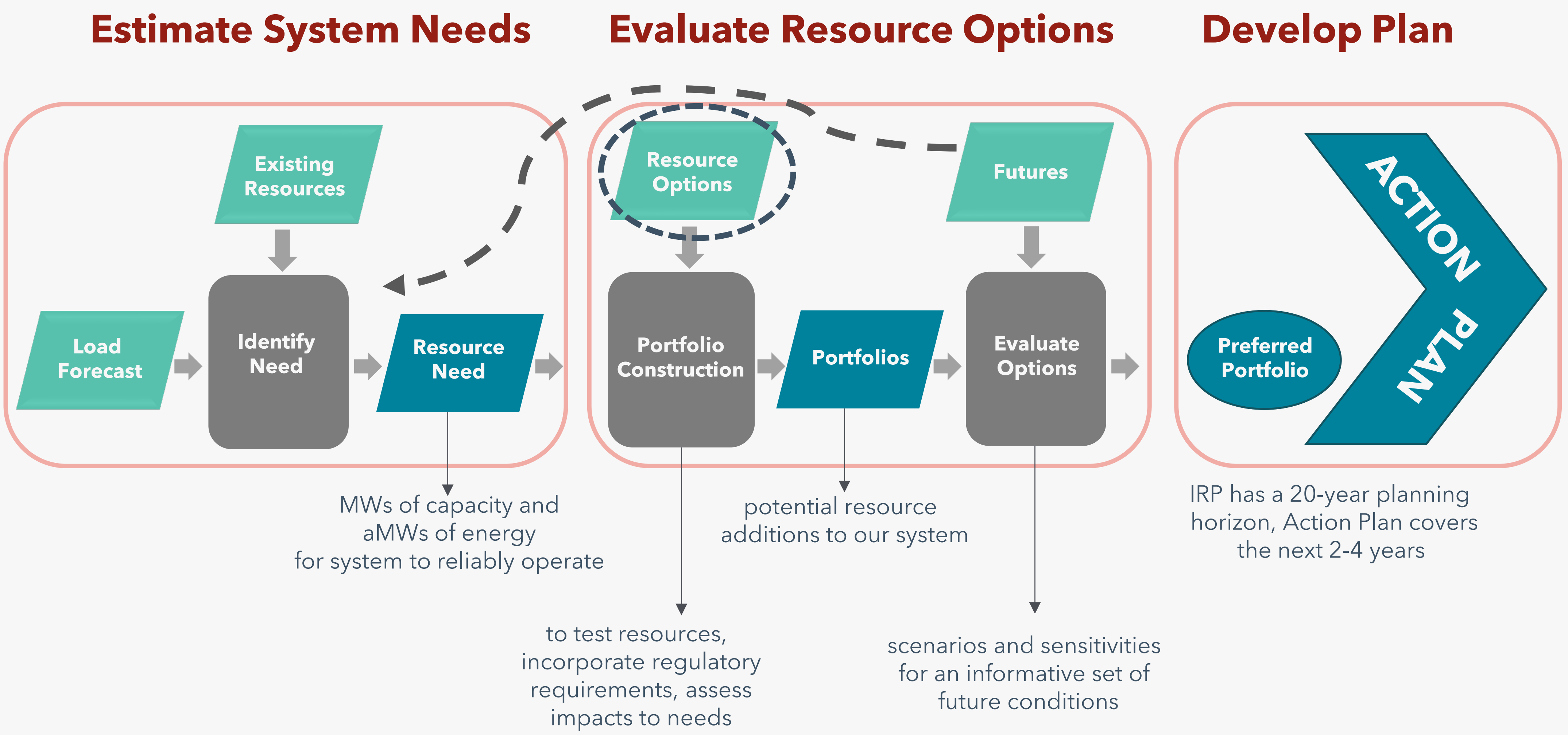
Community-based Renewable Energy (CBRE) Update

Stasia Brownell, PGE

Kyle Billeci, PGE (20 minutes)

PGE An Oregon kind of energy.℠

High-Level IRP Analysis Process



Outline

- Overview of CBRE Treatment in IRP
- CBRE RFO Update
- IRP CBRE Modeling

Community-Based Renewable Energy (CBRE)

HB 2021 Definition of CBRE:

One or more renewable energy systems that interconnect to utility distribution or transmission assets and may be combined with microgrids, storage systems or demand response measures, or energy-related infrastructure that promotes climate resiliency or other such measures, and that:

Provide direct benefit to a particular community through community-benefits agreements or direct ownership by a local government, nonprofit community organization or federally recognized Indian tribe

OR

Result in increased resiliency or community stability, local jobs, or economic development

CBRE Treatment in IRP

- Community-Based Renewable Energy is defined in HB 2021 as renewable resources designed to deliver **local**, **equitable**, and **resilience-oriented** benefits, not solely least-cost energy.
- CBREs expand traditional IRP evaluation beyond cost, risk, and emissions to include **community benefits indicators (CBIs).**
- CBREs are not a replacement for utility-scale renewables; they are a complementary resource class.
- The 2023 CEP/IRP represented PGE's first systematic integration of CBREs into long-term resource planning.

CBRE Implementation Process

1 2023 IRP/CEP

PGE conducted a **Community Lens Potential Study** to estimate feasible CBRE capacity aligned with HB 2021 definitions

Results were translated into **proxy CBRE resources** suitable for IRP

Methodology emphasized screening technical potential, not **project-specific** siting or cost certainty

2 2023 IRP Update

CBREs remain analytically consistent but shift towards implementation with active **CBRE RFO** activity and ongoing engagement with Staff and CBIAG to inform procurement design

Continue to be modeled as incremental to embedded DERs and reaffirms CBRE additions in the Preferred Portfolio rather than revising quantities or methodology

3 2026 IRP/CEP

CBRE RFO targeted solicitation for community-based renewable resources to meet HB 2021 equity, resilience, and community benefit objectives, distinct from utility-scale RFPs

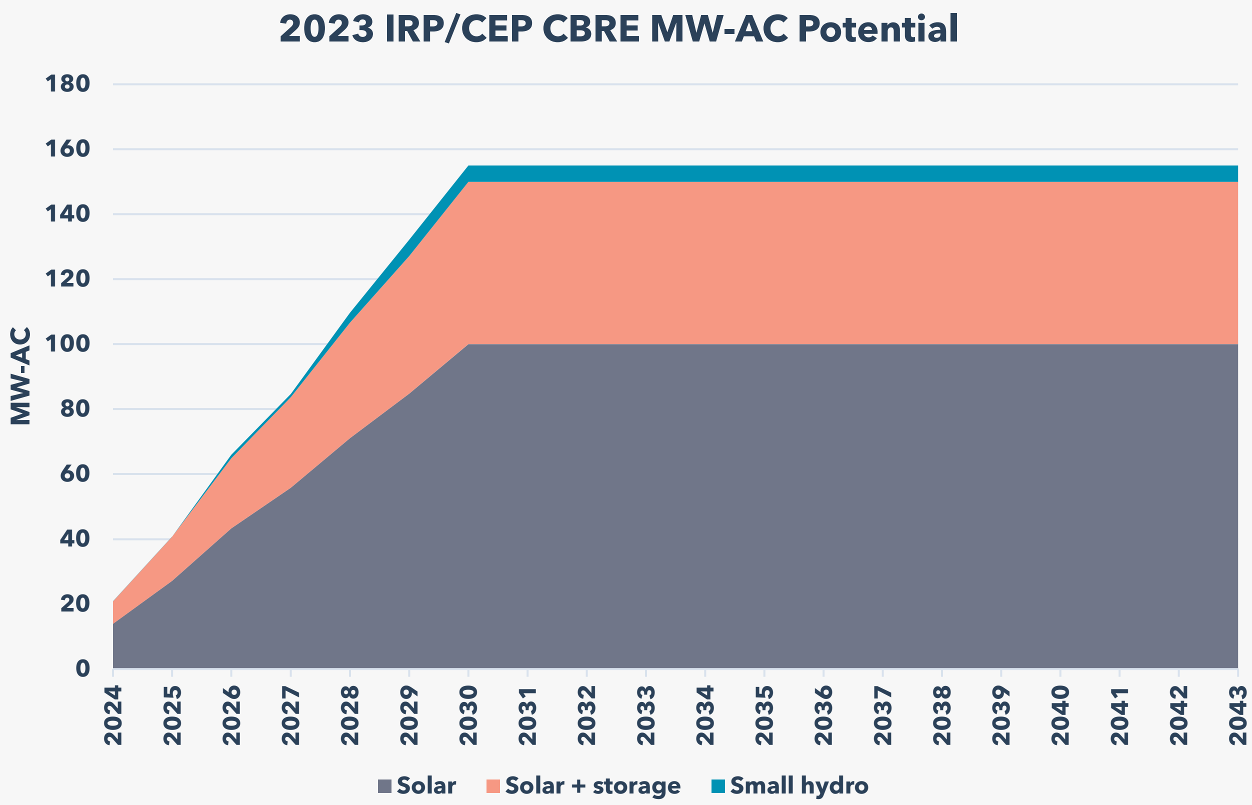
RFO results will update **CBRE potential, technology, and cost assumptions**, replacing proxy estimates with **market-informed inputs**.

Reminder – 2023 IRP/CEP CBRE Potential Study Results

- **155 MW-AC** of total resource potential by 2030
- **66 MW-AC** by 2026
- Deployment phased over time to reflect market immaturity and limited municipal capacity
- Excluded land-use constraints, including local availability and real estate costs

Caveats:

- CBRE potential was modeled incremental to DERs already embedded in the load forecast and DSP, including rooftop solar, behind-the-meter storage, demand response, and customer microgrids.
- Most customer-sited DERs are **net-metered or otherwise ineligible** for small-scale renewable compliance, requiring **separate CBRE proxy resources and targets.**



CBRE RFO Process

Negotiate Contracts

1 **2023 IRP**

Identified an opportunity for 66 MW by 2026 and 155 MW by 2030

2 **CBRE RFO**

Launched Nov 24' and finalized Dec 25':

- Round 1: 25 MW
- Round 2: 88 MW
- Round 3: 7 MW

3 **BIDDERS**

PGE supported bidders with interconnection/ community benefits to improve projects for customers

4 **EVALUATION**

PGE evaluated bids for price and maturity; CBIAG evaluated Community Benefit

5 **SHORTLIST**

Qualified BESS + Solar projects advancing to contract evaluation

HB 2021 defined CBRE

CBRE RFO Takeaways

The RFO successfully lowered barriers for non-traditional bidders and generated strong market intelligence through robust engagement, iterative feedback, and improved pricing and community benefit guidance.

Flexibility and iteration increased complexity, with interconnection study results, queue movement, and pricing updates causing bid attrition and a shifting bid landscape over time.

Interconnection costs and timelines proved to be binding constraints, particularly for larger projects that faced high upgrade costs or multi-year delays that limited contractability.

Keeping the RFO open for a full year is **not recommended**; future solicitations should preserve feedback loops while tightening timelines to reduce bidder uncertainty and internal burden.

Translating RFO learnings into clearer expectations and success criteria would improve bidder confidence and proposal quality in future iterations.

Collaboration with CBIAG was valuable, and future work will focus on clearer definition, measurement, information requirements, and evaluation of community benefits.

CBRE RFO Next Steps

Use the current RFO for planning validation, not volume expansion:
Leverage the strong engagement and market response from the CBRE RFO to **inform IRP assumptions and updates**, recognizing that it validated feasibility and pricing but was not designed to maximize near-term MWh or MW scale.

Targeted design for future MW upside:
Explore more prescriptive future solicitations (e.g., defined size, price signals, or configurations) to unlock additional CBRE capacity—acknowledging that gains may be **less scalable and more bespoke**, especially under current interconnection and cost headwinds.

2026 IRP Enhancements of CBRE Assumptions

Overall, CBRE assumptions for modeling are informed by market-based responses from the RFO:

- ~**60-75 MW of CBRE available by 2030**
    - Based on market responses in CBRE RFO and expanded to reflect additional plausible projects not captured in submitted RFO bids
- CBREs for IRP modeling to be represented as **CBRE-Microgrid** as each CBRE bid was solar paired with storage
    - Projects typically sited as small commercial
- CBRE average costs were approximately **40% to 60% higher** than a comparable utility-scale 1:1 resource on a $/kW-yr basis via draft results from LUCAS

Guided Feedback - CBREs

Process: Do you have any questions on how the CBRE RFO results informs proxy CBRE representation in this IRP?

Content: Is there interest in proxy CBRE categories for the IRP other than that informed by the RFO (i.e. only microgrids = solar+storage); such as standalone solar?

IRP Emissions Forecasting

Lauren Slawsky (15 minutes)

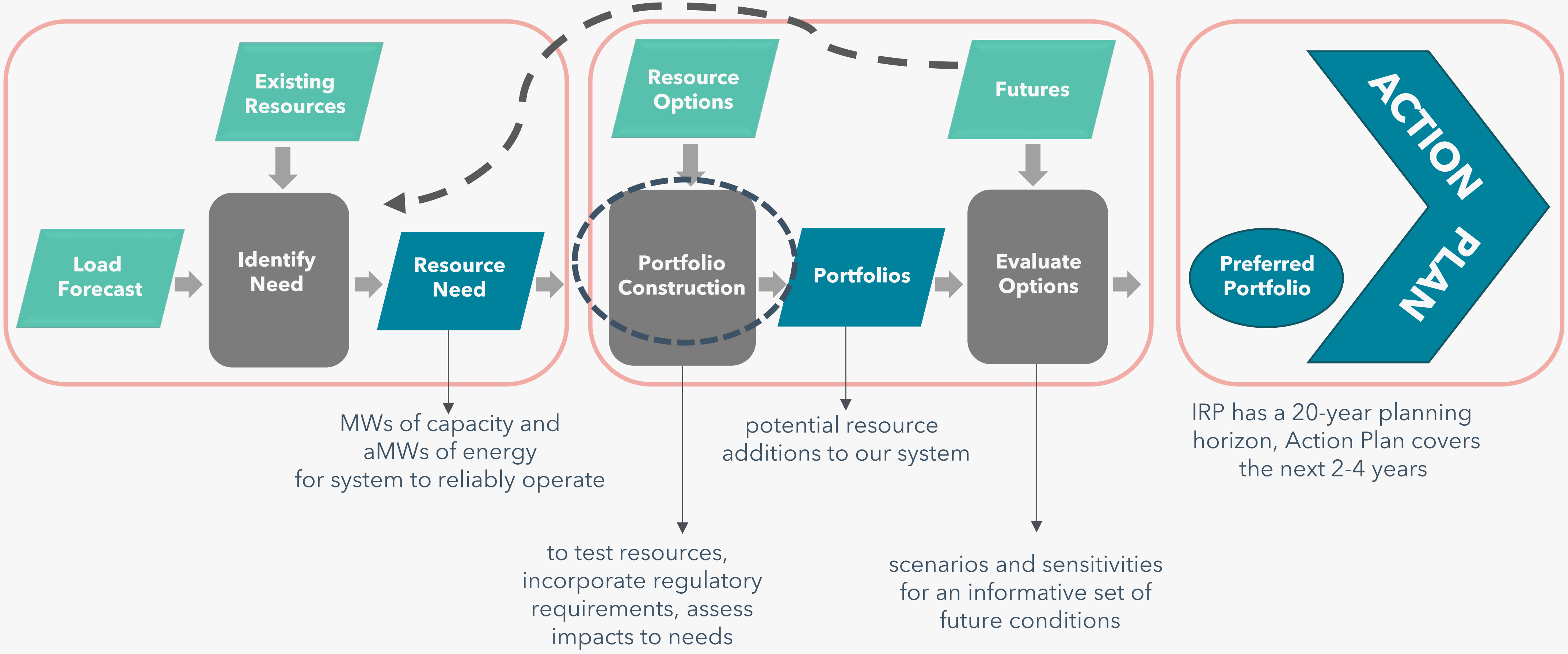
PGE An Oregon kind of energy.℠

High-Level IRP Analysis Process

Estimate System Needs

Evaluate Resource Options

Develop Plan



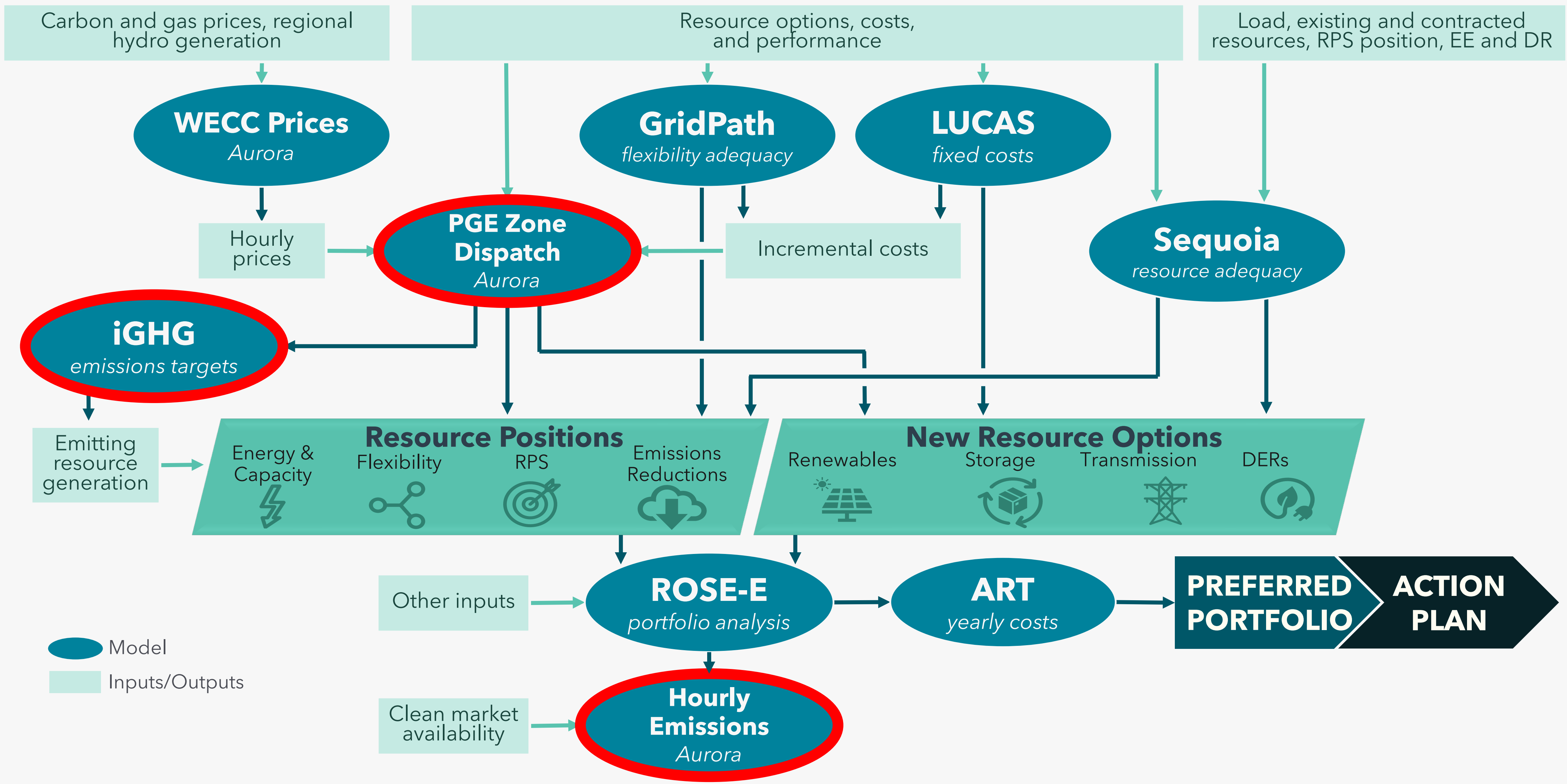
Outline

- Revisiting PZM Enhancements
- Emissions and Market Assumptions
- Application in Portfolio Analysis

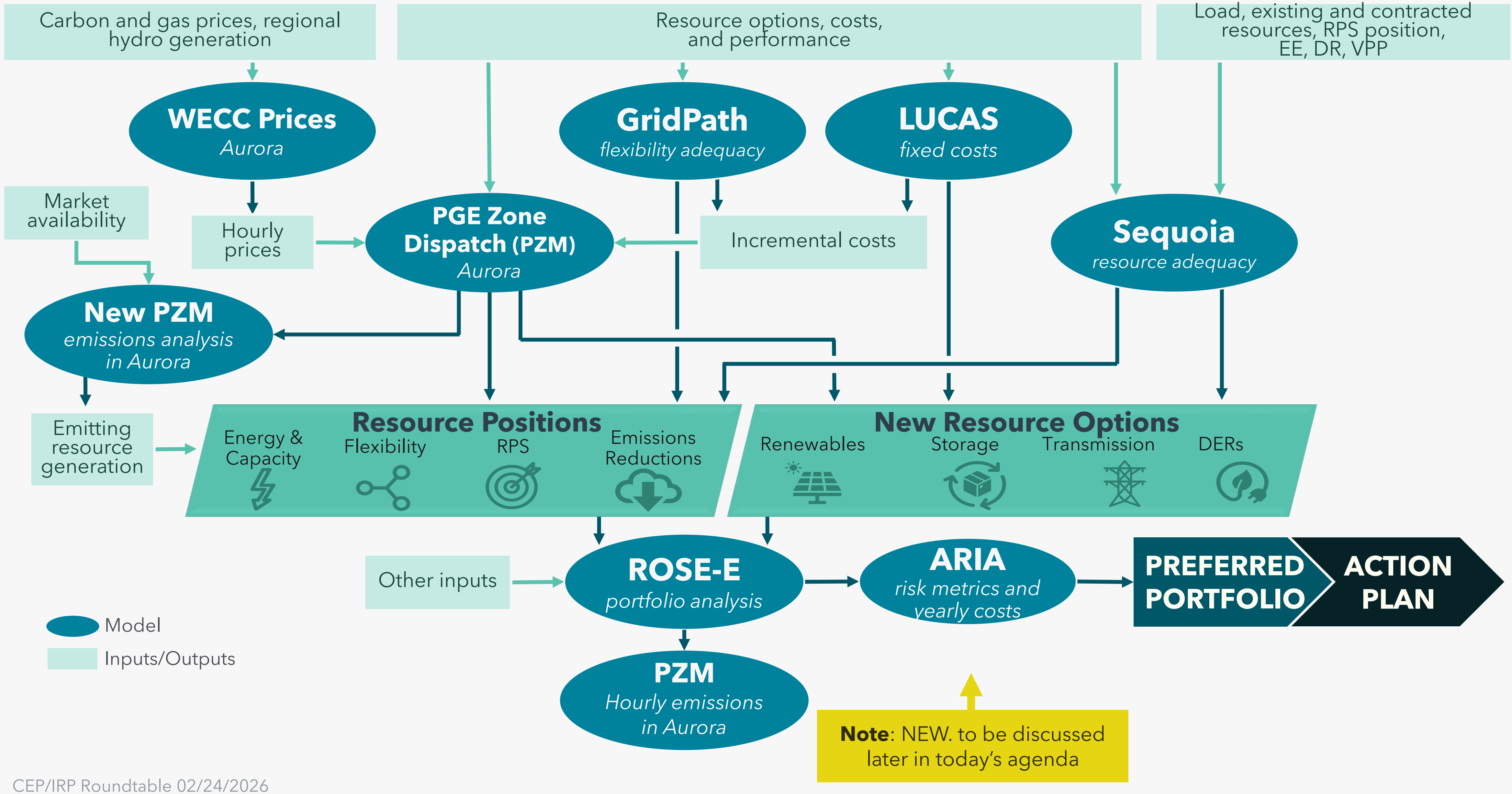
Revisiting the PGE Zone Model (PZM)

- The Aurora model facilitates this production cost modeling aspect of the IRP through economic dispatch of PGE's system
    - Zones contain resources (e.g., Beaver, PW1, hydro, storage, etc.) and/or loads (e.g., PGE net load)
    - Links represent the ability for energy to move between zones
- **Topology Enhancements**: described at the October 2025 Roundtable
    - Refinements for this IRP cycle enhance the model to:
        - Consider GHG emissions constraints in economic dispatch (replaces previous use of iGHG model)
        - Simulate resource interactions with PGE's load and with model's representative market
- **Assumptions**: today's focus
    - CEP GHG emissions targets
    - Market representation
- PZM outputs of existing resources' economic dispatch are inputs to ROSE-E for portfolio analysis
    - For all price futures across all years

2023 IRP Update Modeling Flow

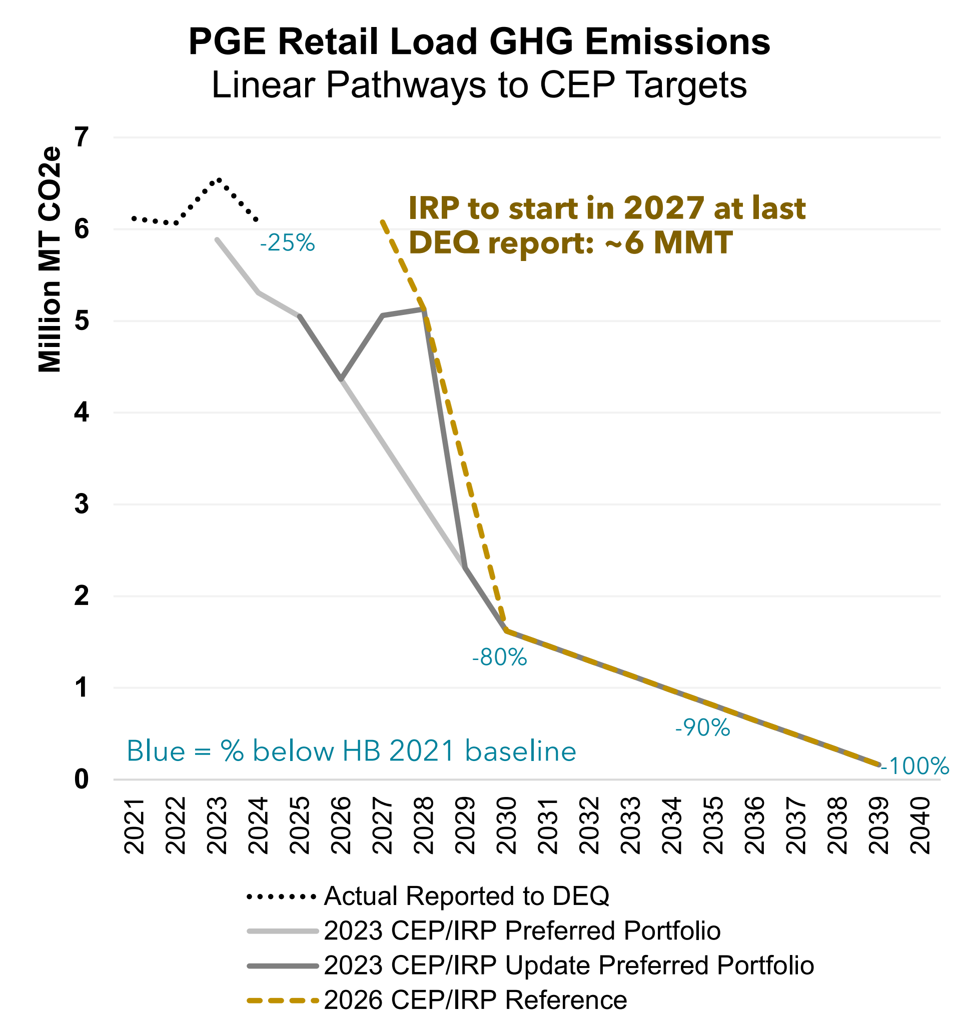


2026 IRP Modeling Flow



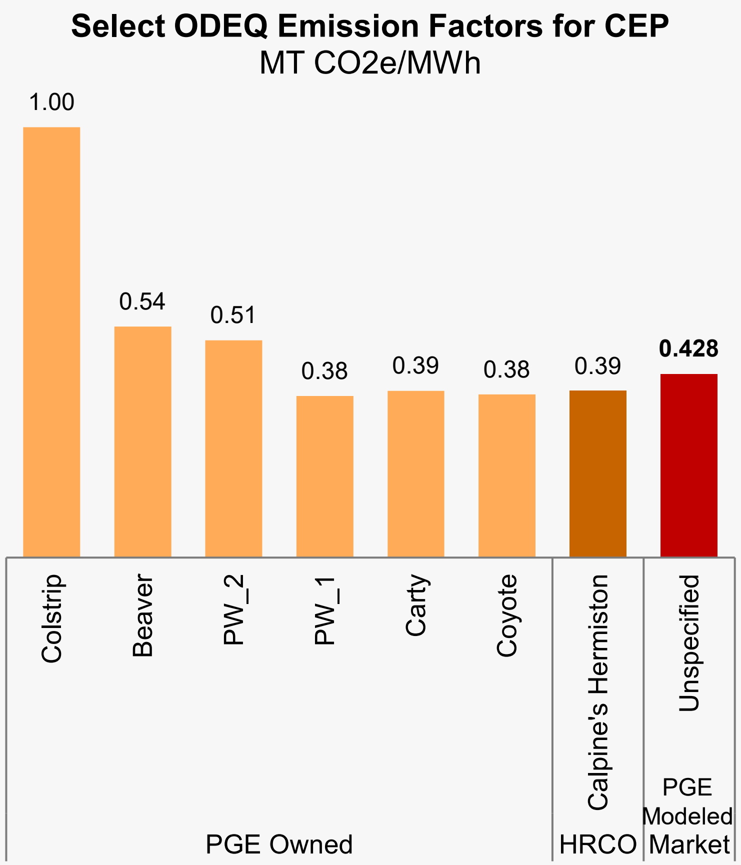
PZM and CEP Emissions Targets

- The CEP must analyze pathways to the clean energy targets in ORS 469A.410 (established in HB 2021), which are **GHG emissions targets** for retail load, below a baseline level
- Progress on HB 2021 was discussed at the January 2026 Roundtable and will be further described in the IRP
- Forward-looking PZM projects economic dispatch at an hourly-level
  - The **gold** annual GHG limits in the chart will be applied as **reference in HB 2021 scenarios**
    - Immediate-term roughly informed by realities of load growth and procurement abilities
  - GHG limits will inform operations throughout the year, along with other model constraints
    - i.e., costs, resource-specific emission factors, market limits, etc.



PZM and Market Interactions

- The 2023 IRP and Update relied on an external Brattle Group study regarding forecast of surplus clean energy on the market
  - Informed clean (non-emitting) market assumptions assumed in the Update
- The forthcoming IRP will not assume PGE has access to purchase from a clean (non-emitting) market
- Similar to 2023 IRP Update, this IRP will still investigate **alternative market scenarios**
  - Such as a *market emission factor*, representing potential changes to the western grid in the future, relevant for purchases (see next slide)



- HRCO = heat rate call option
- ODEQ = Oregon Department of Environmental Quality
- More from ODEQ on CEP and GHG emissions here: https://www.oregon.gov/deq/ghgp/pages/clean-energy-targets.aspx

PZM and Market Interactions

- **Alternative market scenarios** in the IRP may be informed by real-world policy proposed by CAISO
  - Hourly load balancing informs an annual *market emission factor*
  - Better representation of diversity of emitting and non-emitting resources available for purchase on the market
  - Would rely on forecast data for the West, i.e., *estimate* of west-wide policy realization
- Use in scenarios to analyze the impacts of a different emission factor representing market purchases on overall thermal dispatch and portfolio analysis

CAISO approach to residual resources (and emissions) on the market:

Approach: On an hourly basis, calculate:

	Owned and contracted resources
-	Attributed resources
+/-	GHG pricing region adjustment
	Total
If Total > Load	
-	Allocate excess to residual rate data set
If Total < Load	
+	Add in using residual rate data set
	FINAL TOTAL

CAISO GHG Accounting Proposal: https://stakeholdercenter.caiso.com/InitiativeDocuments/Accounting-and-Reporting-Final-Proposal-Greenhouse-Gas-Coordination-Working-Group-Oct-15-2025.pdf

Existing Resource Dispatch to Portfolio Analysis

- PZM outputs of existing resources' economic dispatch are inputs to ROSE-E for portfolio analysis
  - Resulting output and GHG emissions levels will vary across scenarios to be analyzed
- Portfolio analysis explores different scenarios to vary conditions, assess uncertainties, balance priorities, and ultimately inform least-cost/least-risk planning and a preferred portfolio
  - Some likely scenarios for this IRP, previously discussed at the January 2026 Roundtable:

Scenario	Description
HB 2021: Meets Emissions Targets	• Thermal resources retained to serve retail load with emissions decline along linear glidepath. • No additional natural gas resources added.
Reliability Only	• Not subject to HB 2021 emissions constraints.
No Large Load Growth	• Resources are added to meet organic load growth only. • Exclude growth associated with Schedule 96 (data centers).
New Contracts / Extensions	• Test the impact of acquiring energy and capacity through the extension of existing expiring contracts, or execution of new contracts.
HB 2021: Cost Cap	• New - estimates the cost, resource need, and emissions impacts of triggering HB 2021's cost cap provision, as represented within the model.

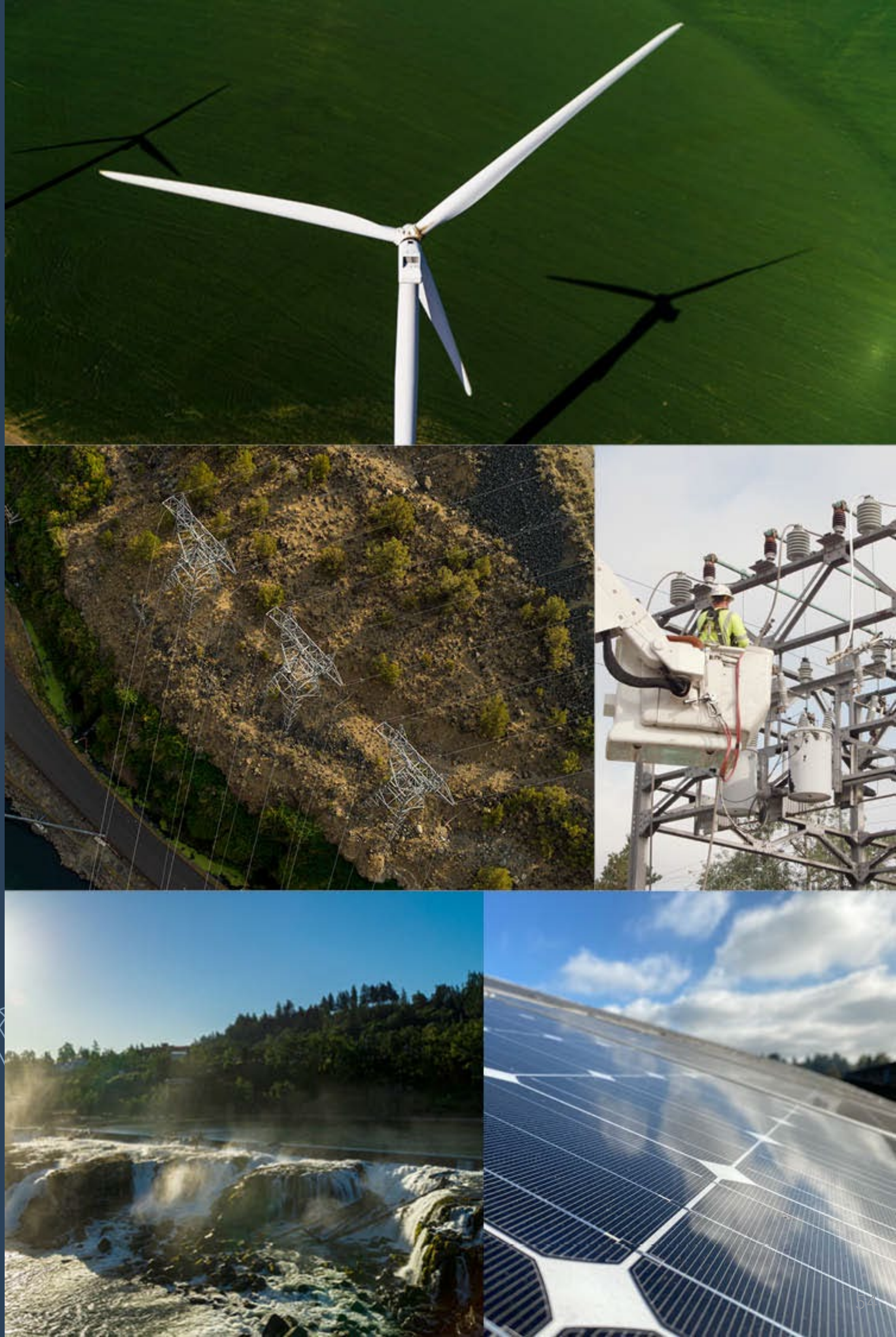
Guided Feedback – IRP Emissions Forecasting

Process: Do you have any comments or questions regarding how GHG emissions assumptions will be incorporated in a different model in this IRP cycle?

Content: Do you have any comments or questions for emissions and/or market related assumptions within the new PZM, that ultimately inform parts of scenarios within IRP portfolio analysis?

Diverse Market Transmission Framework

Devin Mounts (20 minutes)



PGE An Oregon kind of energy.℠

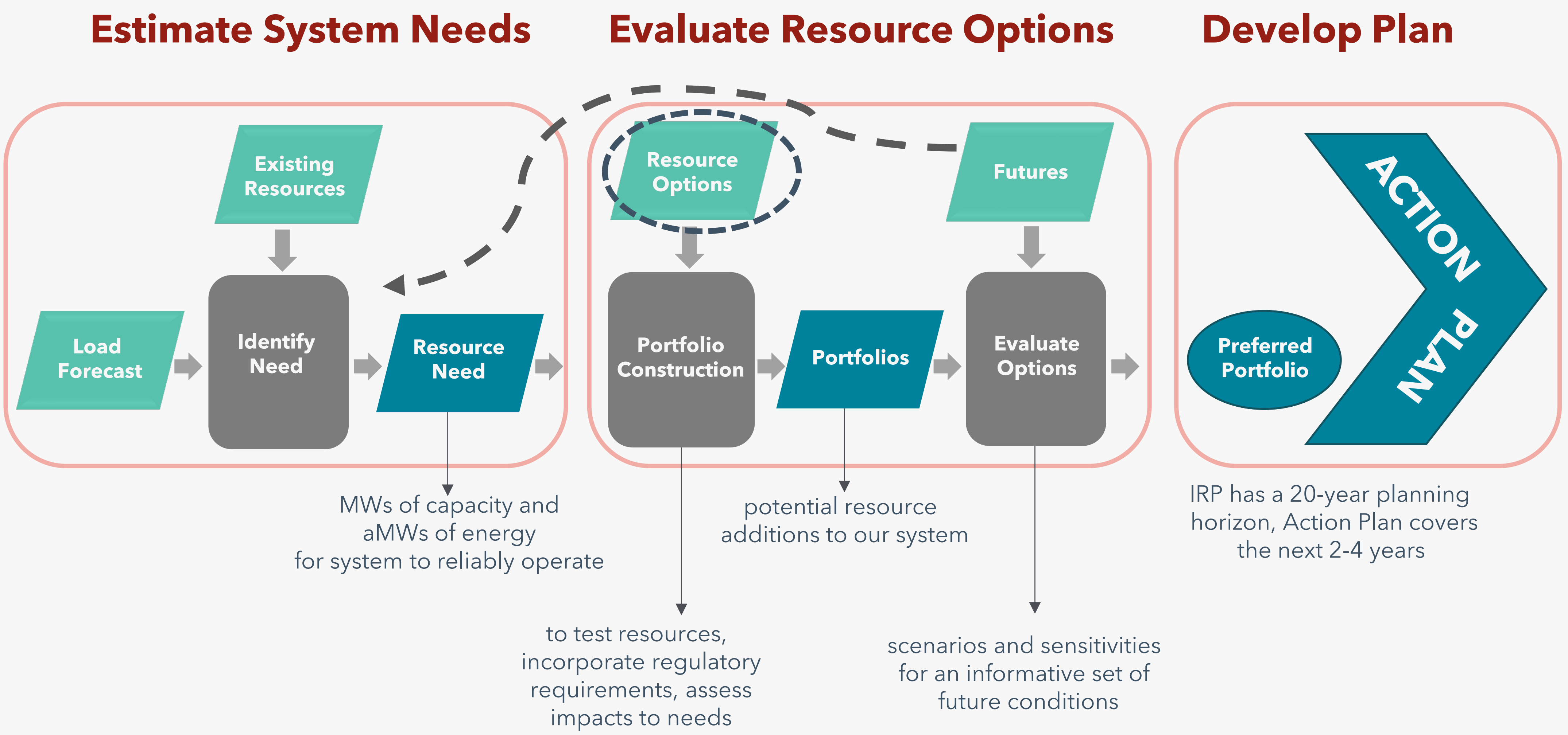
Outline

Review Transmission Options

Extra-regional Transmission Connectivity Benefits
– Correlations in Load & Generation

Diverse Market Value Assumptions

High-Level IRP Analysis Process



2026 CEP/IRP Transmission Modeling

PGE’s geography necessitates an analysis with three components:

1. A characterization of the regional transmission system – **December Roundtable**

What regional projects are assumed available in the Northwest?

2. A characterization of extra-regional transmission system - **December Roundtable**

What future projects can expand PGE’s connectivity to resources across the greater WECC?

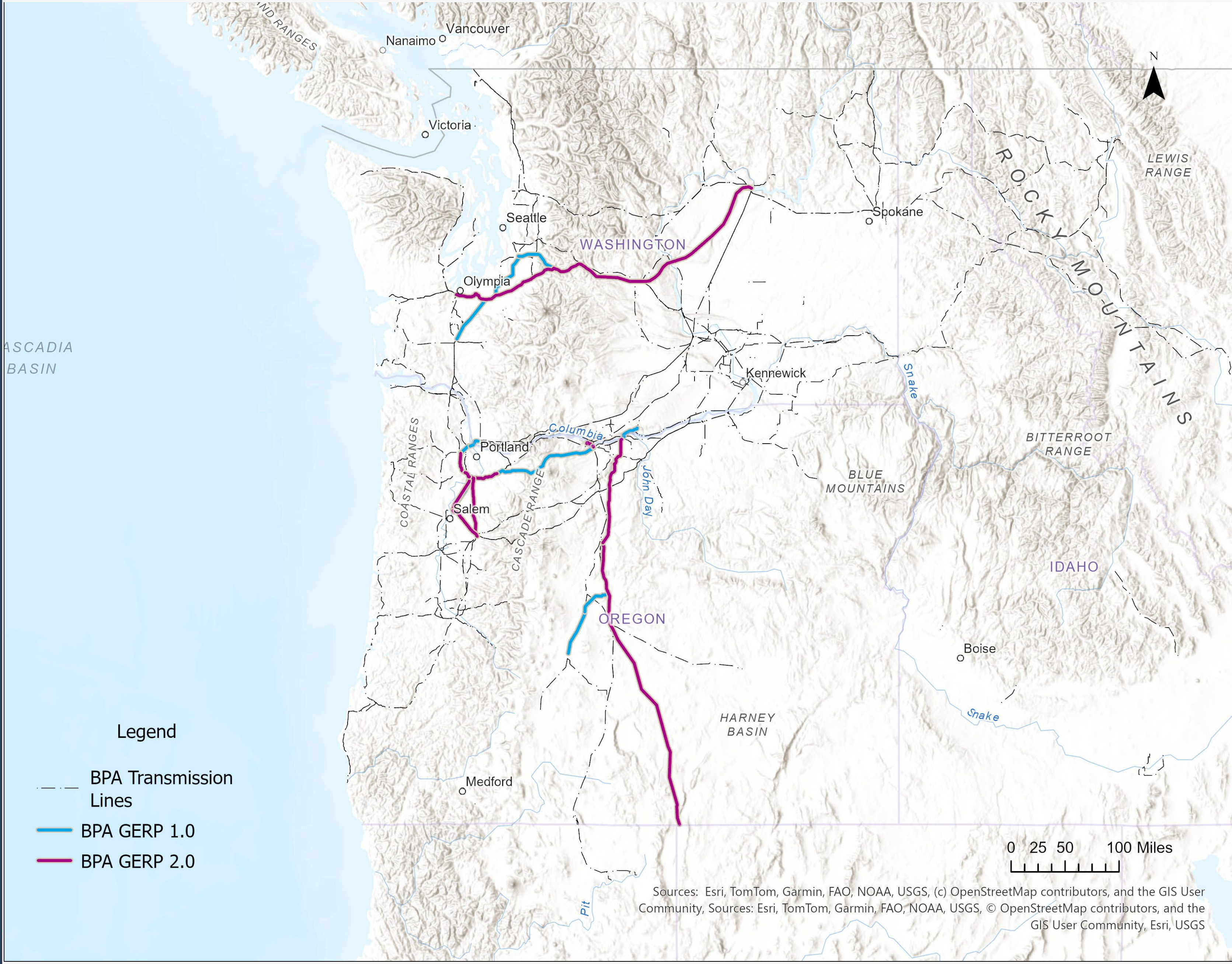
3. Capacity Benefits of extra-regional transmission

Transmission may increase connectivity to other markets

BPA Grid Expansion and Reinforcement Projects

PGE's 2026 IRP is to assume that BPA GERP 1.0 and 2.0 projects are energized to facilitate:

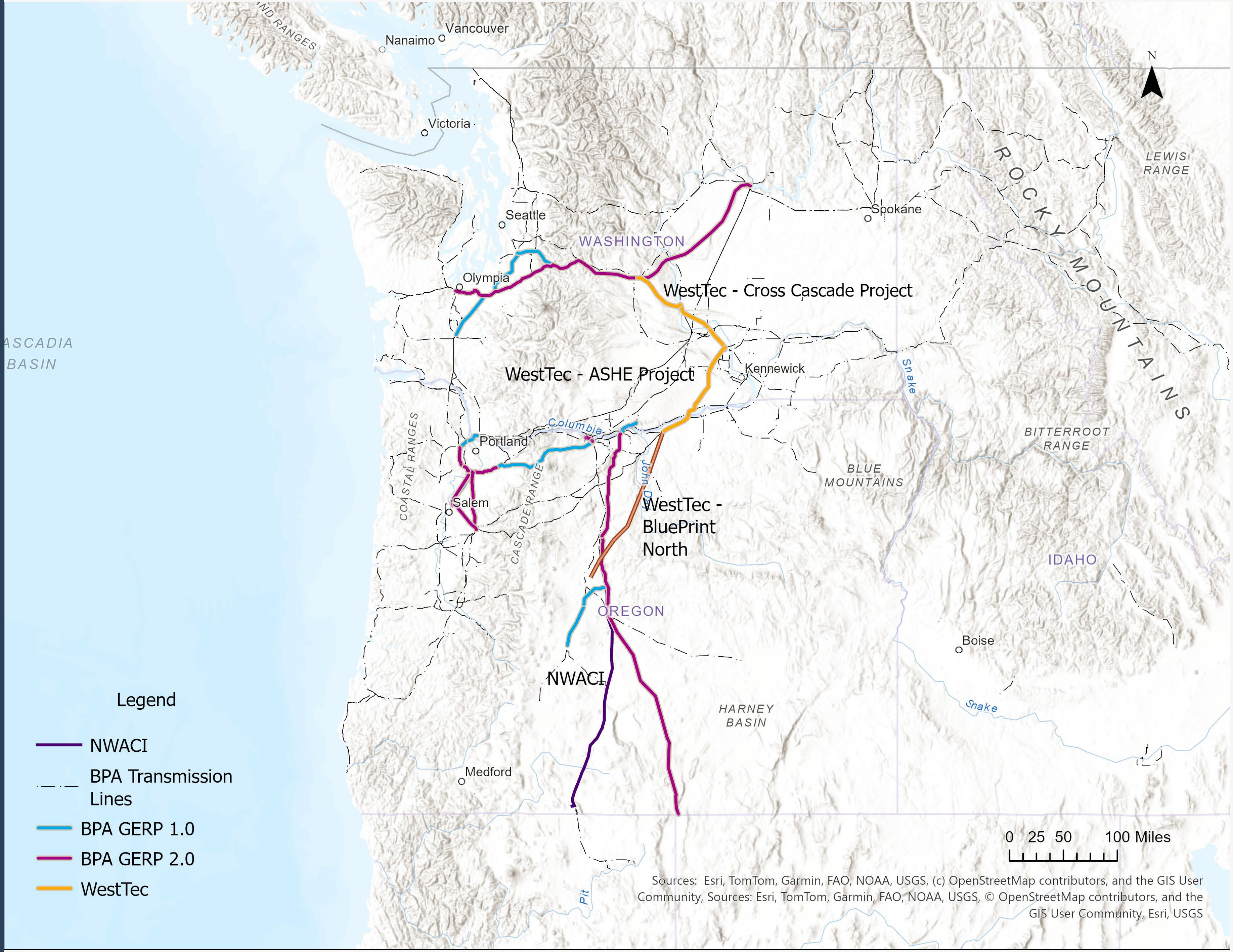
- Service of PGE retail load
- Plan of service for 2506 MW of existing service requests delivering to PGE
- Provide necessary connectivity for intraregional and Circle 3 transmission projects studied by PGE



WestTEC Expansion Projects

PGE's 2026 IRP is to assume that Corral-Grasslands (BluePrint North) and PSE Cross Cascades facilities recommended by WestTEC energized by 2035 to:

- Provide necessary connectivity for intraregional and Circle 3 transmission projects studied by PGE



PGE Proposed Transmission Options for 2026 IRP Study

All transmission options as proposed by Energy Strategies in 2023 IRP Update.

Additionally:

- North Plains Connector 2032 COD distinct from Colstrip Transmission Upgrade 2038 COD
- Blueprint South

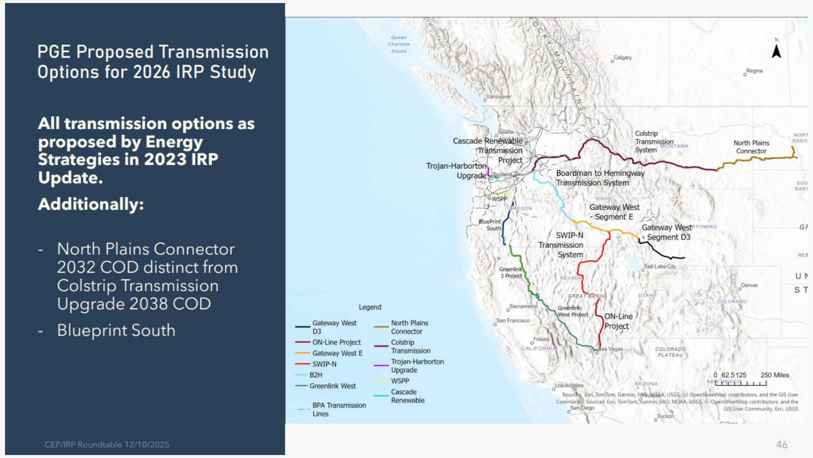
Reminder : 2023 IRP Update

November 2024 Roundtable

Energy GPS presented 'Market Liquidity Analysis for PGE'

Slide 35 *– November 2024 Roundtable*

Slide 46 *– December 2025 Roundtable*



Conclusions

- **Conclusion #1:** Transmission to SPP or MISO, will likely have access to energy and capacity during **both summer and winter.**
- **Conclusion #2:** Transmission to DSW or CAISO, will likely have access to energy and capacity **in the winter.**

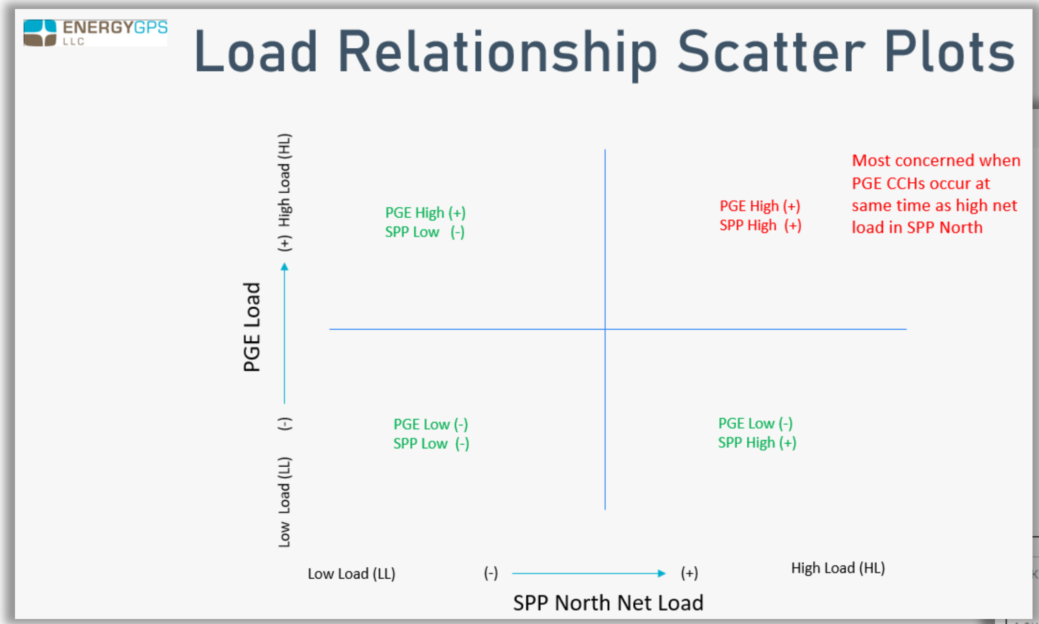
Each transmission option carries costs and benefits

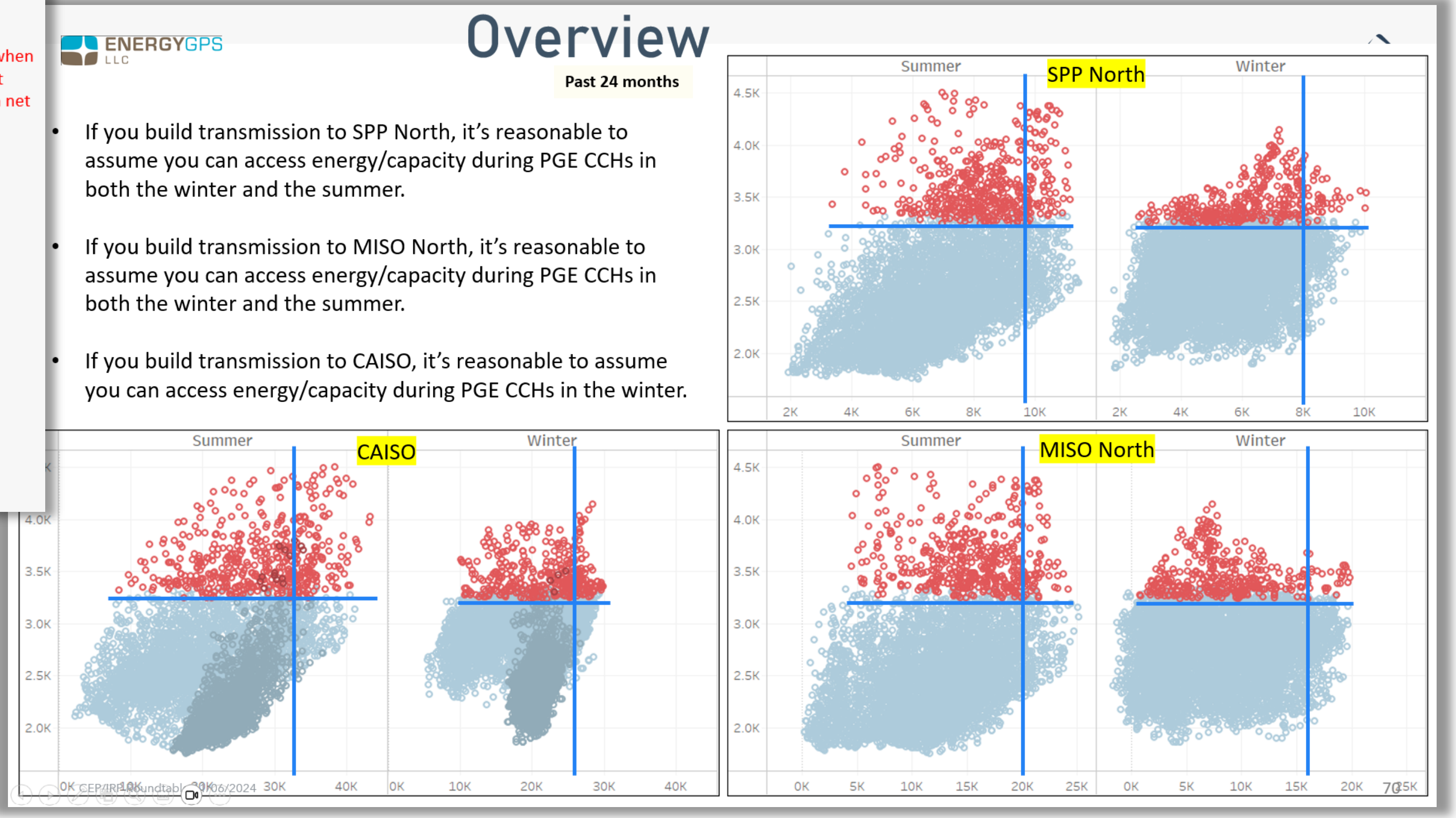
Benefits	Example
Resource energy	Assumed MWh generation of Wyoming wind
Resource capacity contribution	Estimated Wyoming wind ELCC
Market access adequacy contribution	**Resource adequacy benefit of transmission capacity when Wyoming wind generation isn't available (e.g. Capacity backed contract)**
Costs	**Example**
Transmission build	Cost per mile per MW
Resource build	Wyoming wind resource cost
Market access	**Cost of market transactions that support reliability under constrained conditions**

PGE engaged EGPS to estimate these two components

Review of Energy GPS Market Access Study – November 2024

Correlation between PGE Capacity Critical Hours (CCH) and market CCH used to estimate whether or not capacity is available in external markets. ***"Could PGE to secure a capacity backed contract with a market counterparty?"***





Review of Energy GPS Market Access Study – November 2024

Energy GPS Findings - Summary and Takeaways

- Interconnecting to SPP, MISO, or both would have reliability benefits for PGE.
  - Very little correlation of tight conditions in SPP North and MISO North with those in the PNW, or in PGE specifically.
  - Very little correlation of wind production in SPP North and MISO North with that in the PNW.
  - PGE is a small system relative to SPP or MISO. Adding a few hundred MW of supply to PGE's system could potentially help relieve scarcity in PGE, while not making a substantial difference in SPP or MISO's demand.
- Large additions of solar and storage are required in CA and the DSW to meet current policy goals and maintain reliability.
  - Forecast shows by 2035 CA and the DSW will be tight (slightly below planning reserve margins) during the summer peak load month, though continue to be long during the winter binding season.
  - Forecast shows up to 22.5 GW and 20 GW of available firm export capacity in CA and the DSW, respectively, in the winter binding season of 2035.

ENERGYGPS LLC

Resulting Market Capacity Assumptions – 2026 CEP/IRP

Cost of accessing extra-regional market benefits is assumed equal to the **real-levelized cost of 6hr battery**

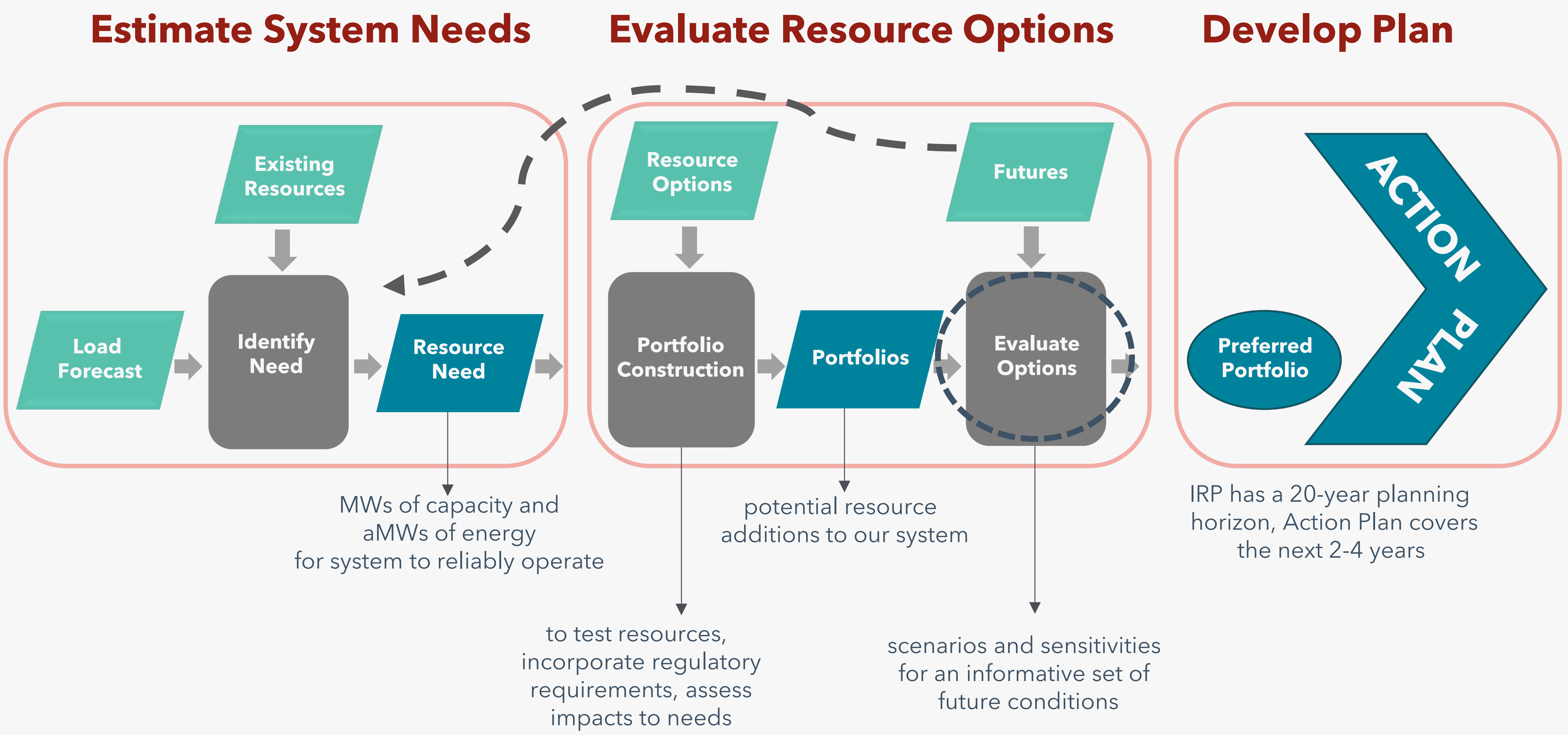
Project	Capacity (MW)	MW Available to PGE	COD	Extra-regional Market	Market Capacity Limit (MW)	Summer Capacity Benefit	Winter Capacity Benefit
Warm Springs Power Pathway	3,000	3000	2032	CAISO	327[1]	0%	100%
Cascade Renewable	1,100	1,100	2032	None	0	-	-
Trojan-Harborton	800	800	2035	None	0	-	-
Blueprint South	725	725	2035	CAISO	725	0%	100%
Gateway	5,000	400	2035	None	0	0%	0%
SWIPN	4,073	400	2035	CAISO/DSW	400	0%	100%
Colstrip Transmission Upgrade	1,500	330	2038	MISO/SPP	330	100%	100%
North Plains Connector	3,000	270	2032	MISO/SPP	270	100%	100%
Greenlink	800	221	2035	CAISO/DSW	221	0%	100%
Clearwater Transmission	0	0	2032	MISO/SPP	180	44%[2]	36%[2]

1. Represents 627 MW of PGE rights of NWACI minus 300 MW of reliability related intertie transfers. See December 2025 Roundtable
2. Percentage represents headroom above estimated Clearwater capacity value of 100 MW and 115 MW for Summer and Winter, respectively.

Portfolio Scoring

Rob Campbell (20 minutes)

High-Level IRP Analysis Process



Outline

- Purpose of portfolio scoring
- Portfolio scoring metrics
- Conceptual scoring matrix

Purpose of Portfolio Scoring

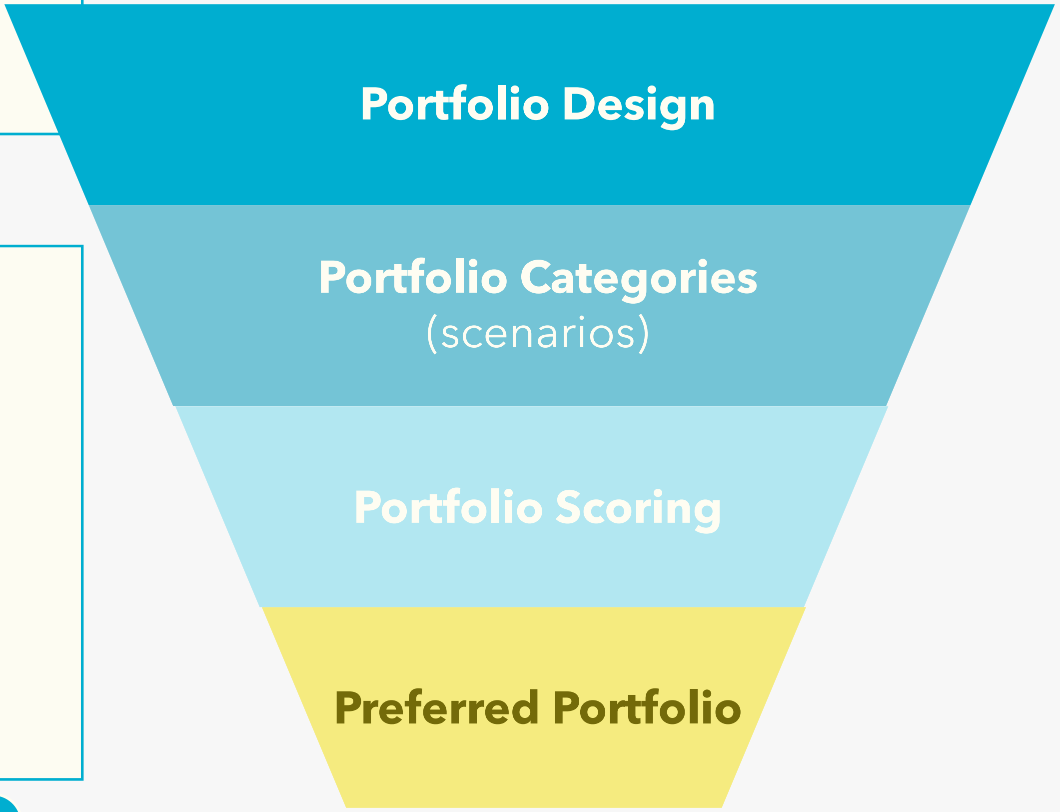
Traditional IRP Guidelines require a Preferred Portfolio to be identified that meets load and policy requirements, while balancing cost and risk for customers

Requires making tradeoffs that are valued by PGE, stakeholders, and customers

Portfolio scoring is designed to generate and display metrics that show tradeoffs across various attributes of scenarios

- Comparing across consistent metrics allows PGE to quantify the impact of changes in key assumptions on portfolio outcomes
- All scoring metrics are designed to capture **quantifiable costs, benefits, and considerations** for the variety of different ways that potential meanings of least-cost, least-risk planning may be conceptualized
- This scoring is **not comprehensive to all costs and risks** but like all aspects of IRP, is designed to directionally inform planning, next steps, and future action items

IRP has displayed a combination of traditional and non-traditional scoring metrics in the past. This IRP will also introduce new risk metrics that aim to address new proposed planning rules.



Traditional Portfolio Scoring Metrics

Metric	Description	Units
Cost	Net present value of revenue requirement (NPVRR), calculated for each of the future scenarios for the analysis timeline. IRP costs consist of only those associated with existing and incremental generating resources (including associated transmission costs) and do not include other PGE costs (e.g. administrative costs, wildfire costs, etc.).	Million 2026$
Variability	Semi-deviation of NPVRR across all futures, relative to the Reference Case. This metric captures the potential variation in cost outcomes across futures, considering only futures in which NPVRR exceeds the Reference Case. Portfolios with low variability scores tend to provide more cost certainty and lessen the customer's impacts of higher-than-expected cost conditions.	Million 2026$
Severity	The tail value at risk (TailVAR) at the 90th percentile of the NPVRR across futures. This metric measures the potential magnitude of very high-cost outcomes across all futures. Portfolios with low severity scores tend to have less costly worst-case scenarios for customer cost impacts.	Million 2026$

Used in multiple previous IRPs

Allow comparison of portfolio cost and certain types of risk

Typically focused on the resource buildout of the Reference Case

Traditional: Variability and Severity metrics capture the risk of cost outcomes compared to the Reference Case, while allowing resource portfolio buildout to vary

New: risk analysis in ARIA provides additional insight by considering how a given resource portfolio buildout performs across the full range of potential economic futures allowing consideration of whether a non-reference case buildout may result in a better balance of cost and risk

Non-Traditional Portfolio Scoring Metrics: pCBIs

Metric	Description
pCBI 1: **Economic Impacts**	Economic development, increased access to jobs, economic well-being, increased productivity
pCBI 2: **Energy Equity**	Improved awareness and access to clean energy programs by environmental justice and tribal communities; increased affordability; increased efficiency of housing stock; reduced arrearages and disconnections
pCBI 3: **Health and Community Wellbeing**	Increased comfort; improved public health outcomes, particularly for environmental justice communities; reduced local emissions; improved home health and safety (including indoor air quality)
pCBI 4: **Resilience / Reliability**	Improved grid resiliency; increased resilience/reliability in environmental justice communities, including reduced recovery time and frequency of outages
pCBI 5: **Environmental Impacts**	Reduced air emissions, including CO_2 and criteria pollutants

pCBIs are a unitless measure of community benefits

pCBIs accrue on a per MW basis of eligible resources added to a portfolio

pCBIs do not influence resource selection in ROSE-E

pCBIs allow the relative level of different types of community benefits provided to be compared across portfolios

Note – rCBIs which are accounted for as reduced fixed costs of eligible resources and can influence resource selection are applied on in select scenarios and are not included as a portfolio scoring metric.

Other Non-Traditional Portfolio Scoring Metrics

Previous IRPs have included report-out of a range of other metrics for comparing across scenarios

PGE is considering including these and possible other metrics for comparisons:

- **Emissions** – How much progress is being made toward emissions reduction targets of HB 2021
- **Clean Energy Additions** – The quantity of clean energy builds in each scenario
- **Annual Costs** – Annual costs have been reported for select portfolios in the past and can provide insight on temporal distribution of costs, including near-term impacts

New Model & New Risk Metrics

PGE has developed a new quantitative method for informing portfolio comparisons, using a new model called **ARIA** (**A**nalysis of **R**isk in **I**nvestments and **A**ssets) which will replace the prior annual cost model ART (Annual Revenue-requirement Tool).

ARIA can perform all the same analyses as ART with additional capabilities. The primary new use that ARIA provides are quantitative analyses allowing for comparisons of risk vs average cost, and a deeper ability to identify risks, cost drivers, and differences between how different technologies interact with various possible futures.

PGE is introducing this new model in the 2026 IRP with the intention to use it to provide incremental insights on top of what the existing PGE IRP modeling suite is capable of. PGE intends to continue to explore how these new model results could be used in other areas, such as portfolio scoring; but is not proposing at this time to replace the existing scoring methods.

ARIA Model is further described on following slides, along with some **illustrative example results** to demonstrate model capabilities. These numbers and figures are *not* 2026 IRP draft results

Note: Cost-based assessment is informed by what's available in IRP, therefore does not capture all costs nor risks the company may consider in real-world decision-making

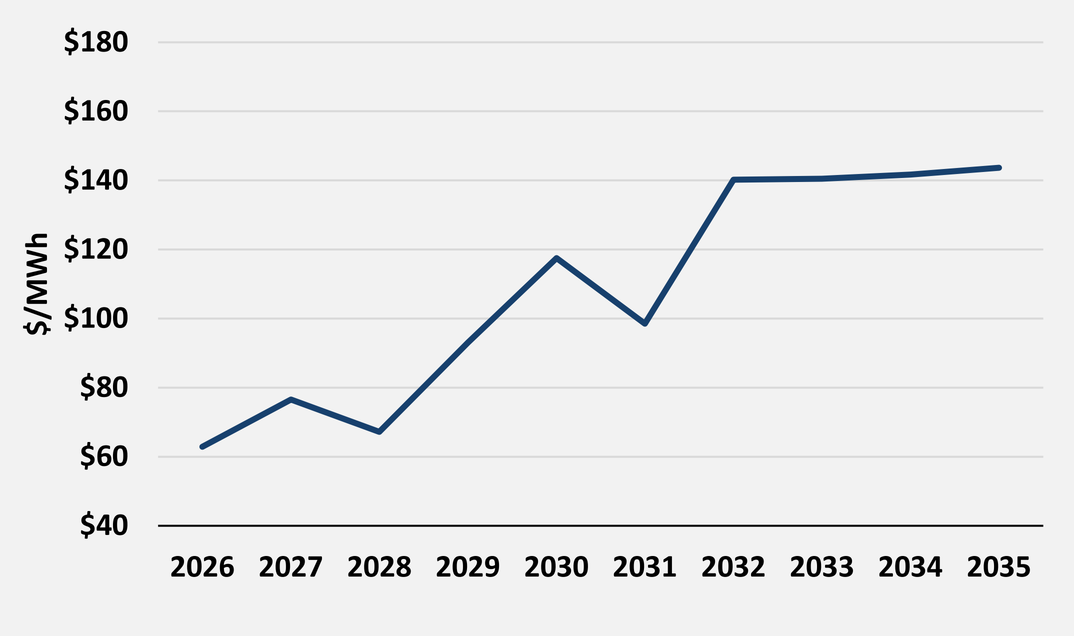
ARIA Model Introduction

The ARIA Model provides the same core functionality as ART

- Breaking the 20-year net present value revenue requirement (NPVRR) from ROSE-E into annual costs
- Allowing for the testing of different ownership structures (ratio of owned vs contracted new resources)
- Illustrating the uneven impact of resources, e.g.,
  ✓EE costs happen in first year with benefits accruing over the life of the resource
- Showing costs in $/MWh units

ROSE-E output
NPVRR = $42 Billion
over 20 years

ART →



ARIA Model Introduction

NEW with the ARIA model is the ability to create a much richer comparison of portfolios and scenarios and consider how they each perform over the many different futures

- Using the 2023 IRP Update as an example, for the HB 2021 compliant **scenario**, ROSE-E generated 351 **portfolios** for each of the **futures** analyzed in that IRP
- ARIA can run *each* of those 351 portfolios through *each* of the 351 futures, generating 123,201 outcomes, allowing PGE to:

✓Consider the 351 range of possible outcomes for any given portfolio buildout

✓Assess the biggest drivers of risk (through a cost-based assessment)

✓Potentially identify portfolios (resource buildouts) that better balance risk and cost*

For portfolio scoring and preferred portfolio selection, any buildout must be assessed for reliably meeting load expectations, therefore load comparisons will only be for reference

However, within the ARIA model, load is allowed to vary from high to low for more robust risk assessment

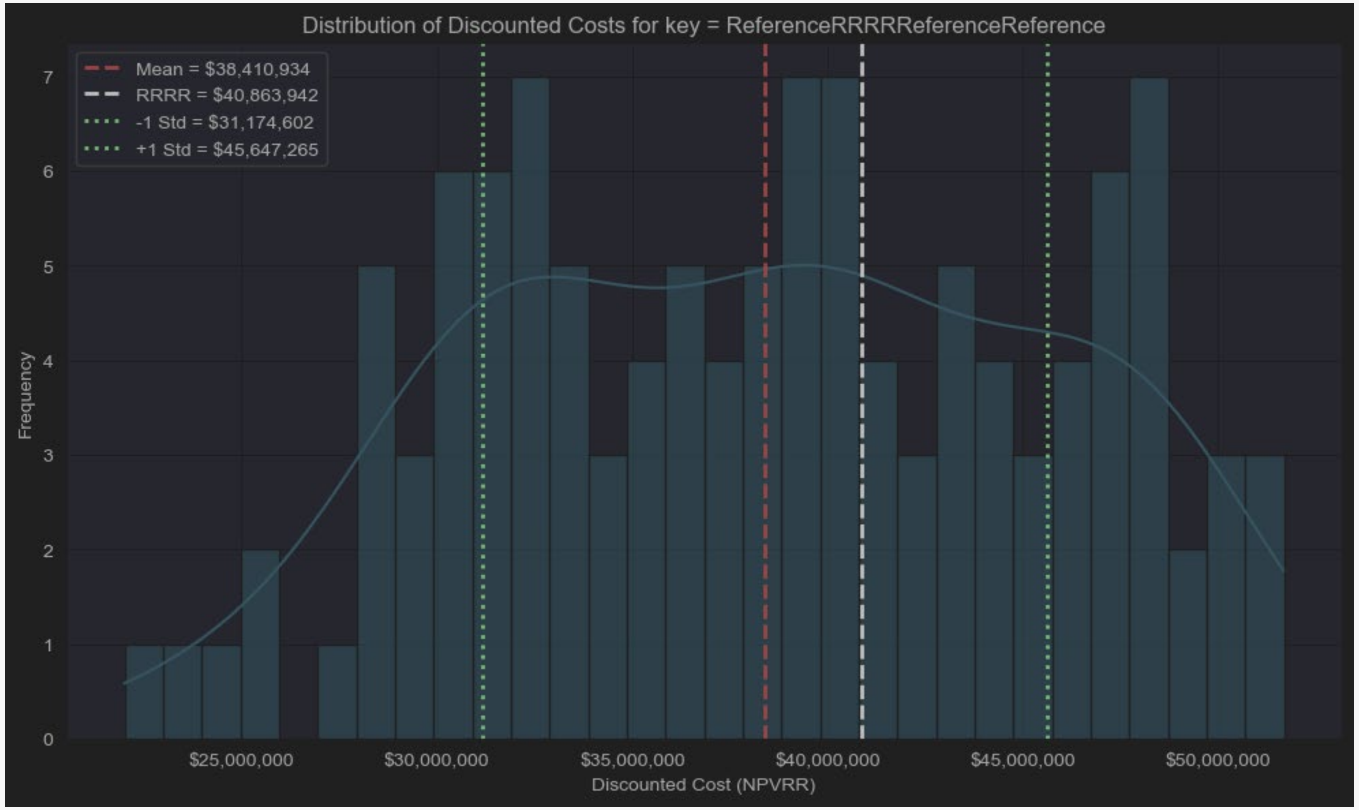
***Note:** this is a cost-based assessment informed by what's available in IRP, therefore does not capture all costs nor risks the company may consider in real-world decision-making

ARIA Model
Example Results – Portfolio Spread of Outcomes

For each portfolio, ROSE-E provides a single cost data point to score each buildout. Now we can generate a **histogram showing the outcomes for every future for a given single buildout**

- **white line** "RRRR" represents the NPVRR of the preferred portfolio reference case from 2023 CEP/IRP Update
- **bars** are histogram bins, showing how many (frequency or count) of the futures ended up in the cost range
- **red line** is the mean cost
- **green dotted lines** show one standard deviation up and down from the mean

This distribution is created for all the different portfolios to show the trade-off of risk and cost between buildouts (see next slide)



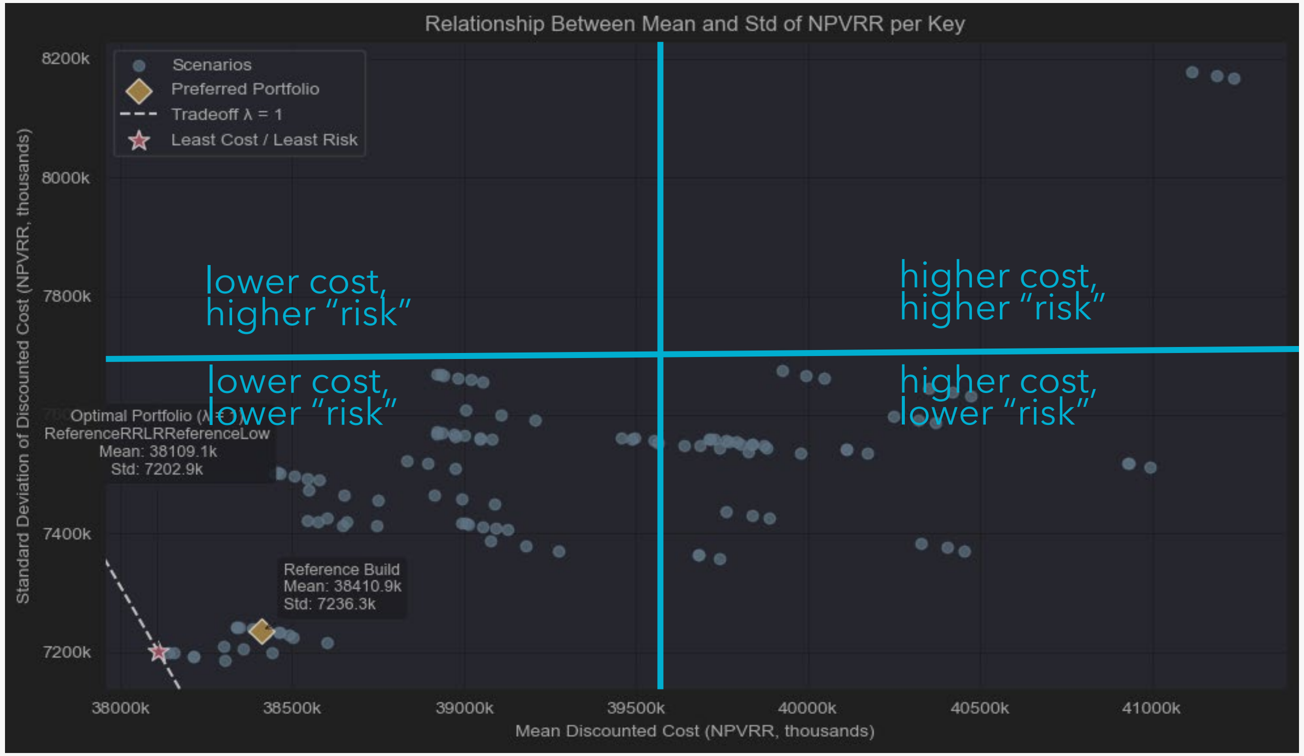
Data from 2023 CEP/IRP Update

ARIA Model
Example Results – all portfolios

This graph demonstrates how results could inform portfolio scoring and comparisons

- The **x-axis** is the mean cost (red line on prior graph)
- The **y-axis** is the standard deviation across all futures (green line on prior graph)
- The **dots** represent the average cost and standard deviation of cost for each portfolio across all possible futures it is run through
- The **dashed white line** represents a frontier of least-cost least-risk, given a particular risk vs. cost tradeoff (here it's 1:1)

Analytically, the portfolio with a **star** which crosses the dashed line is the buildout which performed the best across all futures, given the defined risk-cost tradeoff

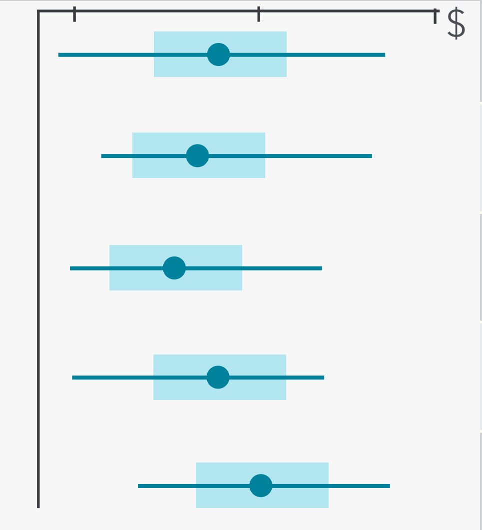


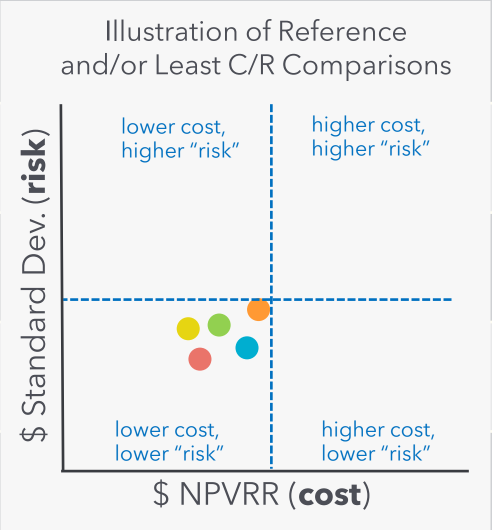
Data from 2023 CEP/IRP Update

Illustrative Portfolio Scoring Results

Mock-up of potential report out metrics for comparisons across scenarios

	Traditional Metrics	-NEW- Risk Metrics	Non-Traditional Metrics*			
Scenario	**NPVRR ($2025): Cost (dot), Variability (box), Severity (line)**	**Cost / Risk of Futures Analyzed (Metrics TBD)**	**5 columns for pCBIs**	**2030 GHG Emissions below base**	**Clean** Additions by 2030**	**Etc….**
HB 2021: Meets Emissions Limits			# # # # #	80%	MWa	
Reliability Only (HB 2021 Counterfactual)			# # # # #	%	MWa	
New Contracts / Extensions			# # # # #	%	MWa	
HB 2021: Cost Cap			# # # # #	%	MWa	
Etc…			# # # # #	%	MWa	





Notes:
- The above is illustrative and does not represent actual data, results, nor findings.
- *Non-traditional metrics to be reported in summary for one representative future TBD, such as RRRR.
- **Clean additions of new utility-scale supply-side resources built in portfolio analysis: wind, solar, etc.; storage could be reported separate.

Next Steps

- Capacity expansion modeling
- Presentation of draft results
- Selection of draft Preferred Portfolio

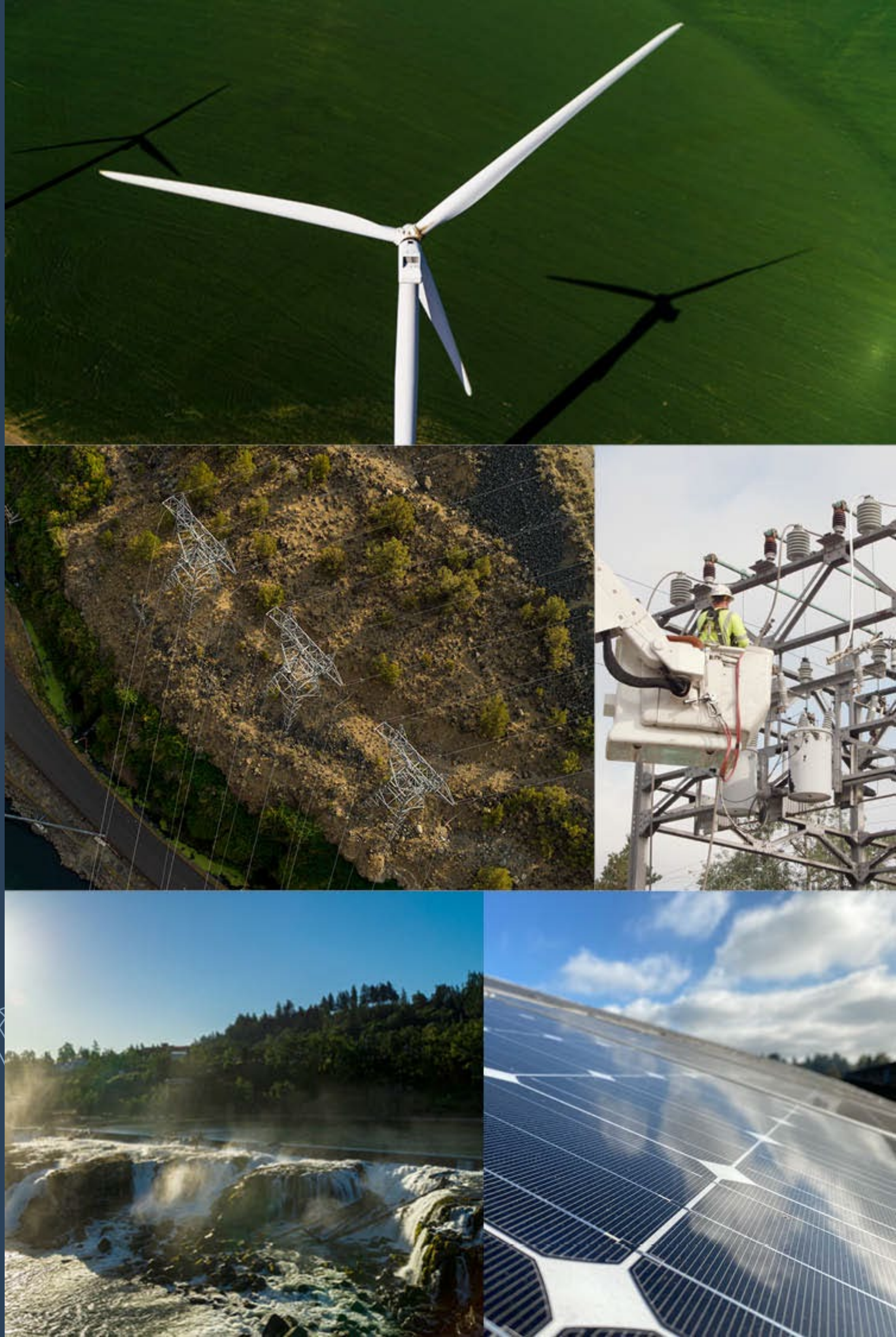
Guided Feedback – Portfolio Scoring

Content: Is it clear how the traditional scoring, non-traditional metrics, and new risk metrics may each provide different insight regarding portfolio performance across the range of futures and scenarios analyzed?

Effective Load Carrying Capabilities (ELCC)

Devin Mounts

(20 minutes)



PGE An Oregon kind of energy.℠

Outline

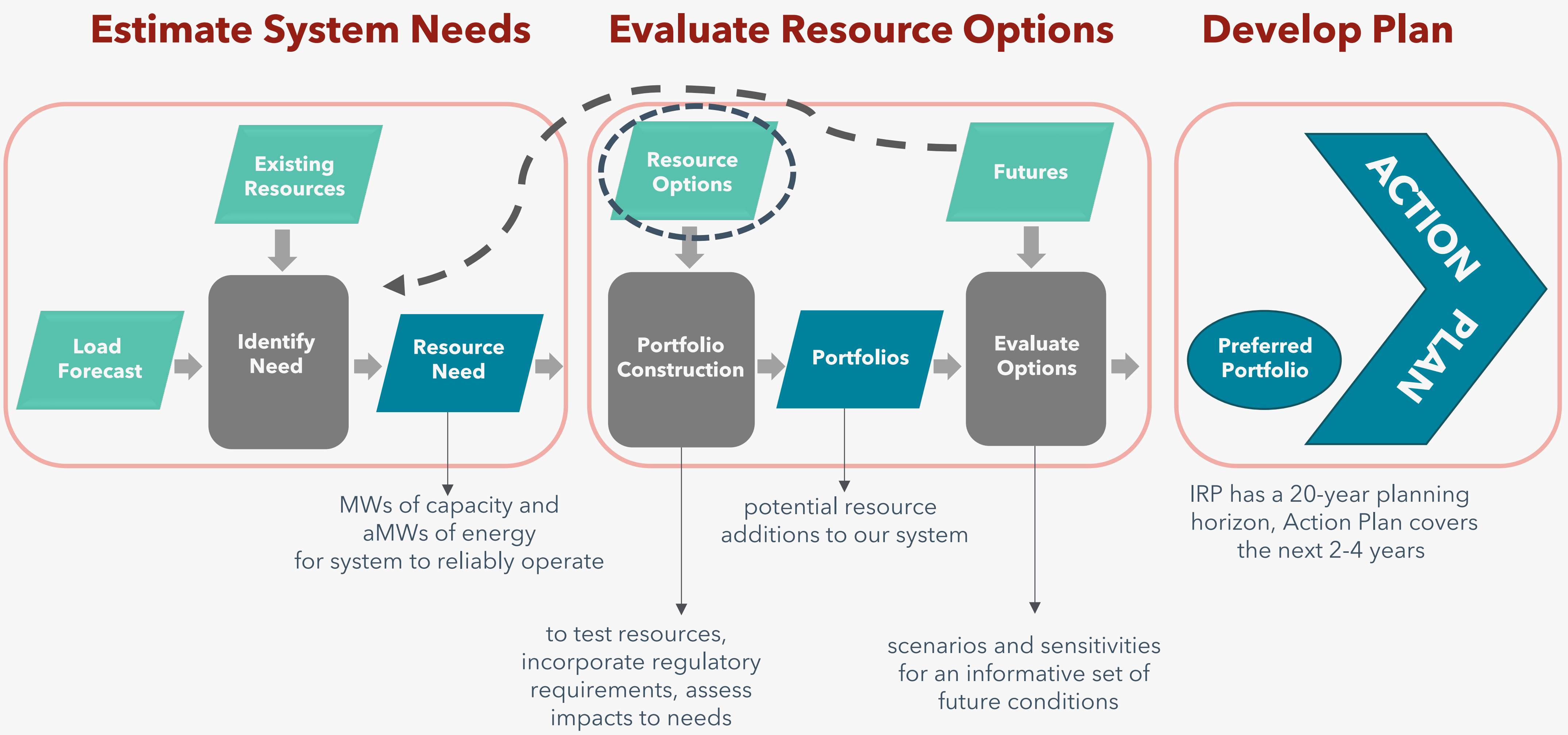
Review of Resource Adequacy

Effective Load Carrying Capacity (ELCC)

Resource ELCCs Summary

Diesel Stand-by Generation ELCC

High-Level IRP Analysis Process



Resource Adequacy
Sequoia Review

Sequoia is a stochastic resource adequacy (RA) model. It simulates load and resource combinations to answer two primary questions for long-term planning:

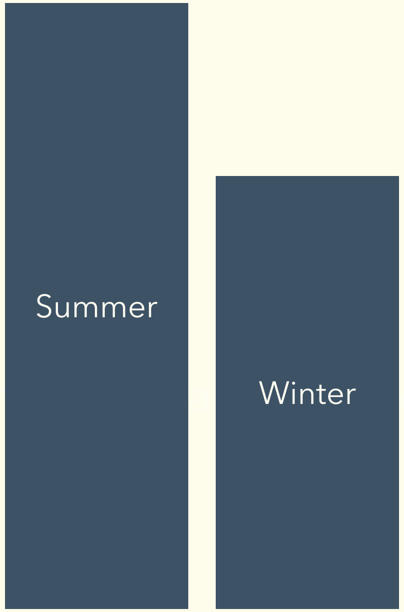
1. How much capacity is needed to keep the system adequate on a planning basis?
2. How much capacity could generation resources provide to the system?

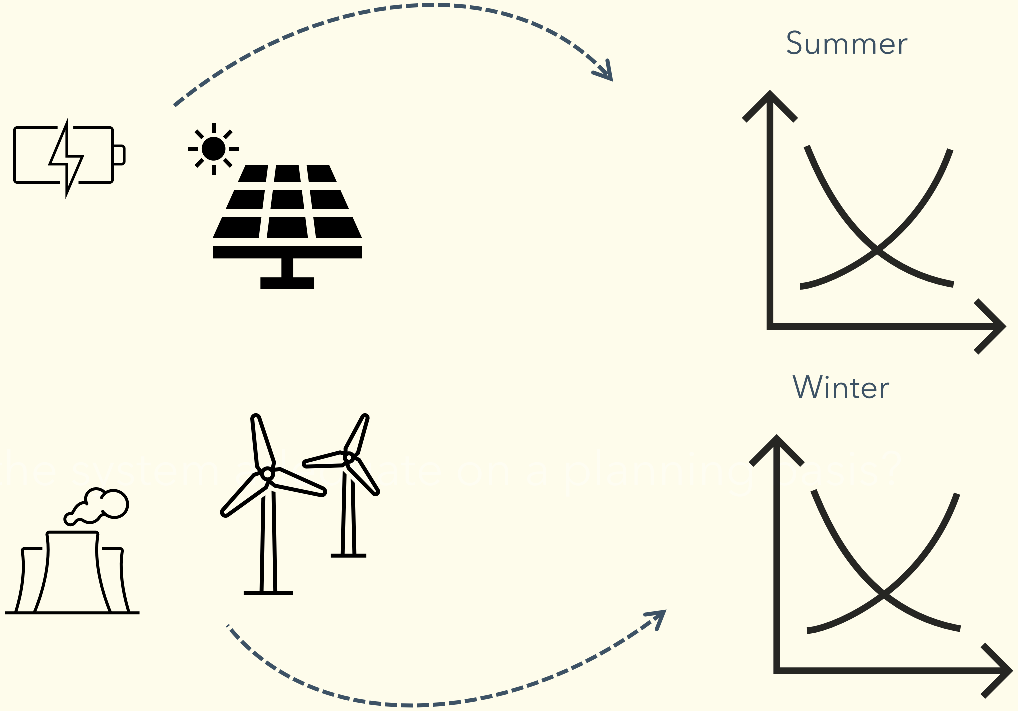
Sequoia was developed following the 2019 IRP to advance modeling of energy-limited resources, such as hydro with storage, battery storage and flexible load[1]

Sequoia's loss-of-load (LOL) study targets a seasonal (winter/summer) adequacy level of 1 event day in ten years.

1. For more information on Sequoia see: 2019 IRP Update, Appx. K., 2023 CEP/IRP Aug. '24 Roundtable, & 2023 CEP/IRP Jan. '25 Roundtable

How Do ELCCs Get Used?





1 Capacity Need

(Demand)

Load and resource portfolio drive reliability need

2 ELCC

(Supply)

Generation's ability to reduce need

3 Portfolio Expansion

(Equilibrium)

Generation that meets need at lowest cost

Resources Evaluated - Summary

Seasonal ELCC's were evaluated for 41 resources across 7 categories.

Resource Categories

1) Storage

2) Variable Energy Resources (VER) – Bonneville Power Administration Transmission System (BPA)

3) VER – Extra-regional Transmission System (Tx Expansion)

4) Other Renewable
   - Existing Wind Optimization (Solar+Storage)
   - Existing Wind Repower (Replacement of Turbines 1:1)

5) Emitting

6) Non-Cost Effective (NCE) Energy Efficiency (EE)

7) Virtual Power Plant (VPP)

Resources Evaluated - Summary

Resource assumptions, additions, and removals informed by PGE 2025 Request for Proposal (RFP)

Resource Assumptions

1. Transmission:
   - Off-system resources assumed to have 75% firm transmission
     - Discussed in: Jan. 2025 Roundtable
   - ELCCs no longer consider conditional firm products
     - Majority of RFP projects with conditional firm products were conditional firm bridge, transitioning to firm within a few years

2. Resource Additions
   - Wind site optimization (Solar + Storage)
   - Wind Hybrid (Wind + Solar + Storage)
   - VPP resources – Elected in Portfolio Expansion
     - Previously assumed as fixed given AdopDER estimates

3. Resource Removals
   - 2:1 Solar Hybrids
   - Uncommon Short-Duration Storage
     - 2,8,16, and 24-hour lithium-ion batteries

Resources Evaluated – Page 1 of 2

ID	Resource Category	Resource Group	Resource Name	Description
1	**Storage**	Storage	Bat_4hr	4-hour lithium-ion
		Storage	Bat_6hr	6-hour lithium-ion
		Storage	**Bat_100hr**	**100-hour iron-air**
		Storage	PSH_10hr	10-hour Pumped Storage - Hydro
2	**VER - BPA**	Solar	Solar_CV	Christmas Valley Solar
		Solar	Solar_Mcm	McMinnville Solar
		Solar	Solar_Wasc	Wasco Solar
		SolarHybrid	CV_Hyb_1	Christmas Valley Hybrid - Solar:Storage (1:1)
		SolarHybrid	MCMN_Hyb_1	McMinnville Hybrid - Solar:Storage (1:1)
		Wind	Wind_Gorge	Gorge Wind
		Wind	Wind_MT	Montana Wind
		Wind	Wind_Off	Off-shore Wind
		Wind	Wind_SEWA	Southeast (SE) Washington Wind
		WindHybrid	**Gorge_Hyb**	**Gorge Hybrid - Wind:Solar:Storage (1:0.67:0.67)**
		WindHybrid	**MT_Hyb**	**Montana Hybrid - Wind:Solar:Storage (1:0.67:0.67)**
		WindHybrid	**SEWA_Hyb**	**SE Washington Hybrid - Wind:Solar:Storage (1:0.67:0.67)**
3	**VER - Tx Expansion**	Solar	Solar_NV	Nevada Solar
		Wind	Wind_ND	North Dakota Wind
		Wind	Wind_WY	Wyoming Wind
		WindHybrid	**ND_Hyb**	**North Dakota Hybrid - Wind:Solar:Storage (1:0.67:0.67)**

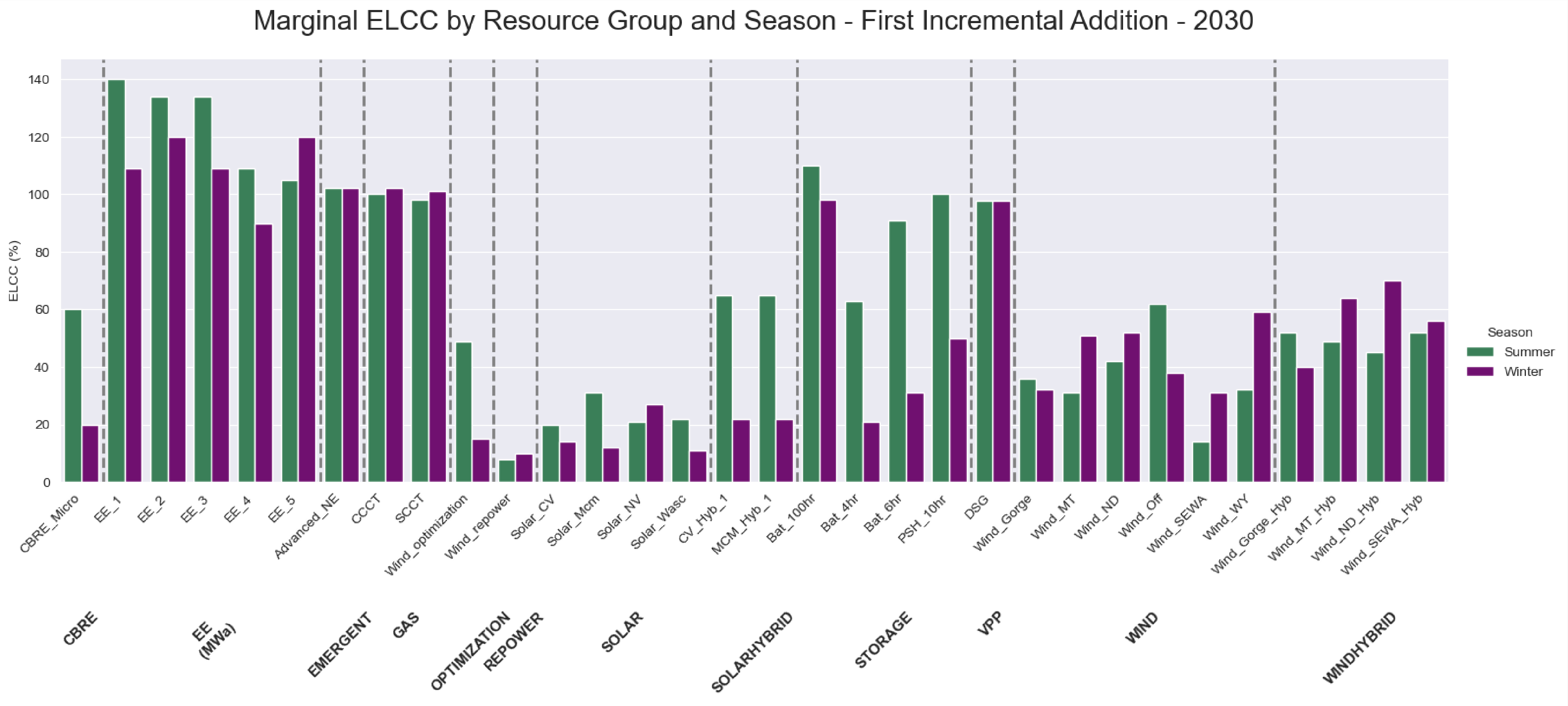
Bold denotes new resources evaluated as part of the 2026 CEP/IRP

Resources Evaluated – Page 2 of 2

ID	Resource Category	Resource Group	Resource Name	Description
4	Other Renewable	OtherRenewable	CBRE	Community Based Renewable Energy Hybrid Solar:Storage (2:1)
		OtherRenewable	**Wind_Opt**	**Optimization of existing wind sites with Solar:Storage (1:1)**
		OtherRenewable	**Wind_Repower**	**Repowering existing wind sites with additional wind generation**
5	Emitting	Emitting	CCCT	Combined Cycle Combustion Turbine
		Emitting	SCCT	Single Cycle Combustion Turbine
6	NCE EE	EE	EE_1	Energy Efficiency Bin 1
		EE	EE_2	Energy Efficiency Bin 2
		EE	EE_3	Energy Efficiency Bin 3
		EE	EE_4	Energy Efficiency Bin 4
		EE	EE_5	Energy Efficiency Bin 5
7	VPP	**VPP**	**DR_1_sum**	**Demand Response Bin 1 - Summer**
		VPP	**DR_1_win**	**Demand Response Bin 1 - Winter**
		VPP	**DR_2_sum**	**Demand Response Bin 2 - Summer**
		VPP	**DR_2_win**	**Demand Response Bin 2 - Winter**
		VPP	**DR_3_sum**	**Demand Response Bin 3 - Summer**
		VPP	**DR_3_win**	**Demand Response Bin 3 - Winter**
		VPP	**DR_4_sum**	**Demand Response Bin 4 - Summer**
		VPP	**DR_4_win**	**Demand Response Bin 4 - Winter**
		VPP	**DR_5_sum**	**Demand Response Bin 5 – Summer**
		VPP	**DR_5_win**	**Demand Response Bin 5 – Winter**
		VPP	**DSG**	**Dispatchable Standby Generation**

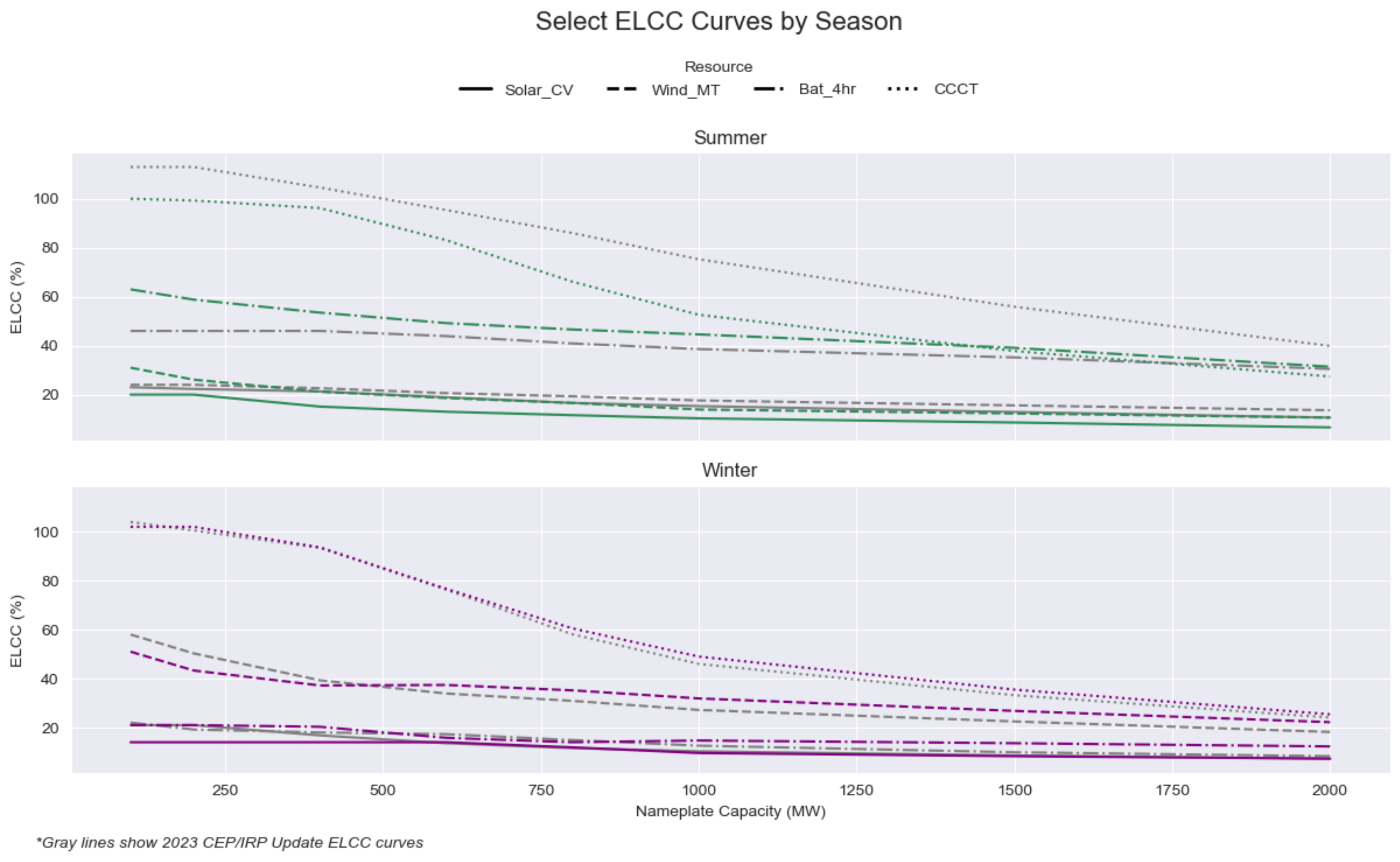
Bold denotes new resources evaluated as part of the 2026 CEP/IRP

Resources Evaluated – Draft ELCCs



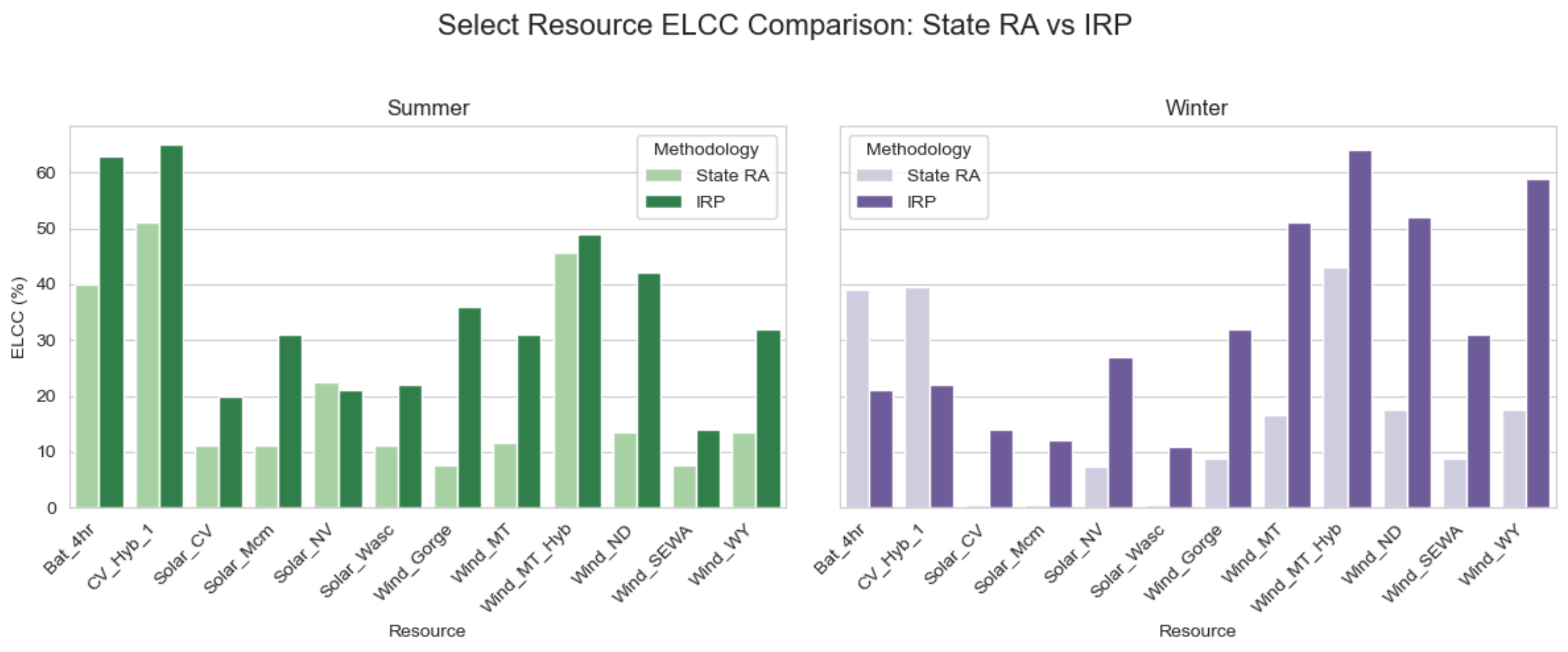
Draft ELCC Curves – Comparison w/ 2023 CEP/IRP Update

As in past IRP's, ELCCs are not only a point estimate. An ELCC curve is used to estimate the value of additional MW of any resource, capturing its diminishing marginal returns.



IRP – WRAP Draft ELCC Method Comparison

As in the 2023 CEP/IRP Update, the 2026 CEP/IRP will include a State RA Requirements portfolio sensitivity based on Western Resource Adequacy Program (WRAP) methods, including ELCCs.[1]



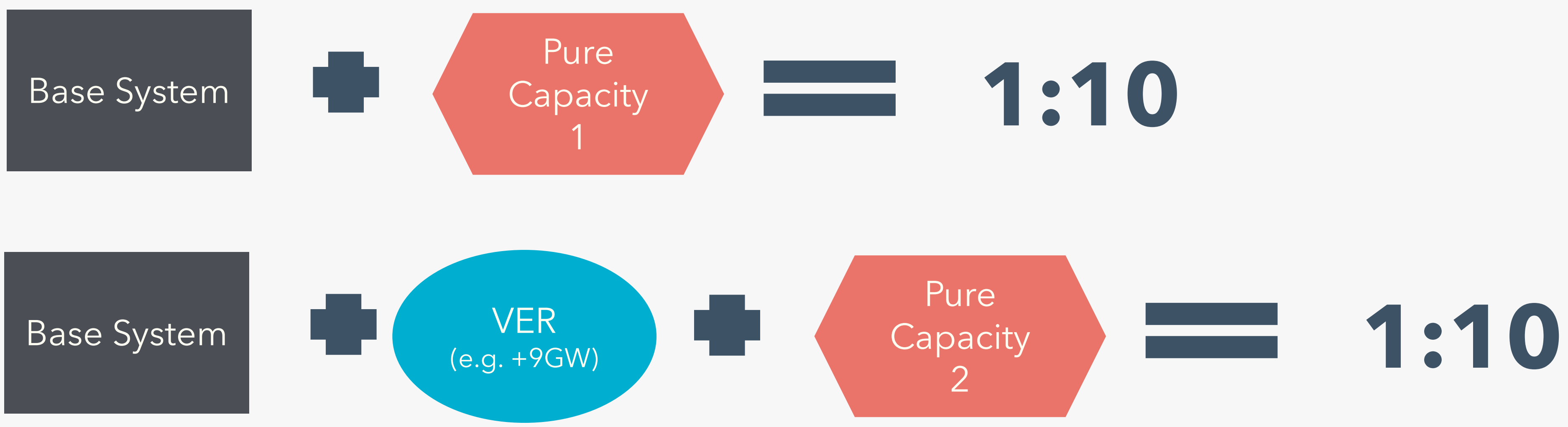
State RA (WRAP) ELCCs based on Summer '27 and Winter '26-'27 metrics. Published ELCCs of incremental GW installations used to derive marginal ELCC estimates used in the IRP.

1. For more detail see February 2025 Roundtable: Inputs for WRAP Standards Portfolio, 2023 CEP/IRP Update Section 6.3.2 – State RA requirements and 2023 CEP/IRP Update Appendix I – Inputs for state RA requirements portfolio.

WRAP ELCC Overview – Average ELCC

WRAP provides Average ELCC estimates for variable energy resources (VERs) at incremental GW installations. These average ELCCs are estimated for different quantities of resource penetration. ELCCs are estimated for WRAP using a similar iterative approach of the regional system as the IRP uses for the PGE system.

The ELCC of a resource is the reduction in perfect capacity required to achieve a 1 event-day in 10-year adequacy benchmark in the base system once the VER is included.



$$Average\ ELCC = Pure\ Capacity\ 1\ - Pure\ Capacity\ 2$$

WRAP groups all VER resources by type and region and does not estimate incremental GW installations ELCCs for hybrids.

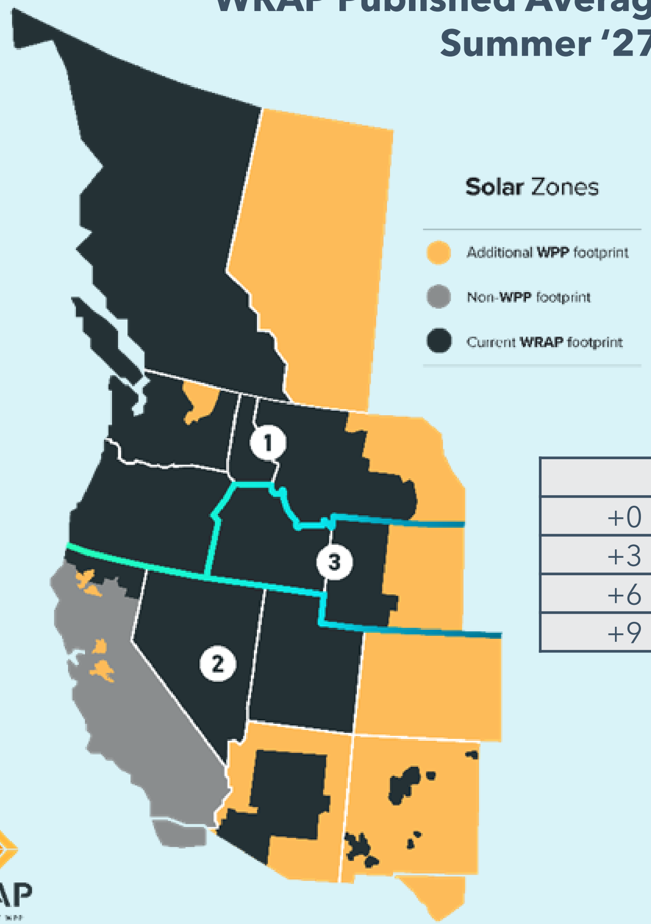
1. WRAP ELCC Study Process: BPM 105 Sec. 4.3.3

WRAP ELCC Overview – Deriving Marginal ELCC

PGE derives a marginal ELCC from WRAP's published average ELCC using the change from the +6GW to +9GW buildout scenario average ELCCs.

Example:

WRAP Published Average ELCC Estimates – Summer '27 Solar



Solar Zone	Nameplate Capacity (MW)
Solar VER 1	2,054
Solar VER 2	14,974
Solar VER 3	1,469

	Solar VER 1	Solar VER 2	Solar VER 3
+0 GW	70.3%	31.4%	29.4%
+3 GW	54.2%	31.3%	29.3%
+6 GW	39.9%	29.0%	27.2%
+9 GW	30.3%	26.8%	25.0%

PGE Derived Marginal ELCC Estimates – Summer '27 Solar

Marginal ELCCs are derived by calculating the change in cumulative effective capacity from the +6GW to + 9GW buildout scenarios for each VER zone.

- ΔC = total added solar capacity (MW)
- E(ΔC) = average ELCC at penetration level (%)
- F(ΔC) = cumulative effective capacity from added solar (MW)

$$F(\Delta C) = \Delta C * E(\Delta C)$$

$$\begin{aligned} F(9{,}000) &= 9{,}000 \times 0.303 \\ &= 2727 \text{ MW} \end{aligned}$$

$$\text{Marginal ELCC}_{6GW-9GW} = \frac{F(9{,}000) - F(6{,}000)}{\Delta C_{9GW} - \Delta C_{6GW}}$$

$$= \frac{2727\ MW - 2394\ MW}{3{,}000\ MW}$$

$$\boxed{= 11\%}$$

WRAP-IRP ELCC Gaps

WRAP does not estimate ELCCs for Hybrids and for some Proxy Resources there is not overlap with a WRAP ELCC region. In such cases, the IRP uses the below ELCC estimation methods

Proxy Resources	Proposed ELCC estimation method
North Dakota Wind	Assign WRAP region 4 ELCC estimates (Colorado and Wyoming)
Batteries of varying durations	Assign WRAP 4hr battery estimates
Hybrids	Weighted Sum of WRAP Wind, Solar, Battery ELCCs Solar Hybrids (1:1) Wind Hybrids (1:0.67:0.67)
Other resources (ie. EE, DERs, CBREs, etc.)	Maintain IRP based ELCC estimates

DSG ELCC - Methodology

Dispatchable Stand-by Generation resources are **call-limited resources**, operating no more than 50 hours of per year. This call limited aspect presents challenges in RA modeling in Sequoia where thousands of years are simulated non-linearly.

Methodology

Proportion call limits based on loss of load hours (LOLH)

~80% Winter, ~20% Summer

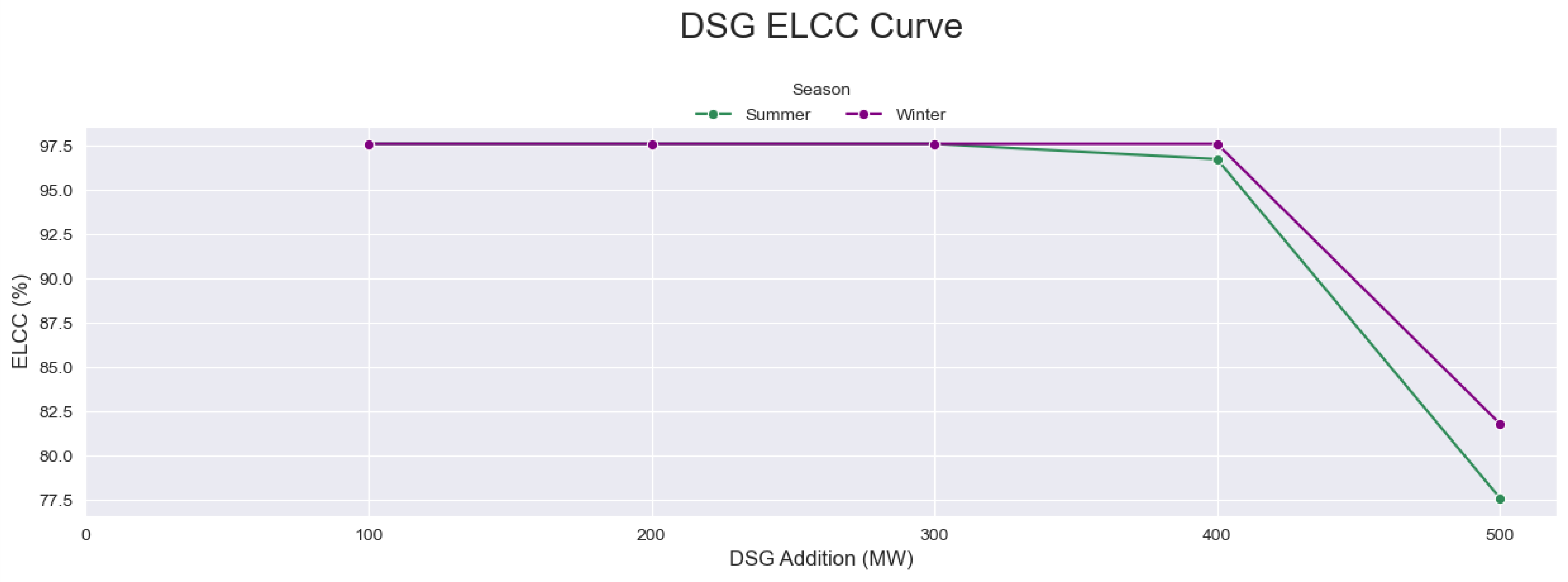
Reduce greatest capacity shortfall hours up to call limit by DSG MW

Assumes

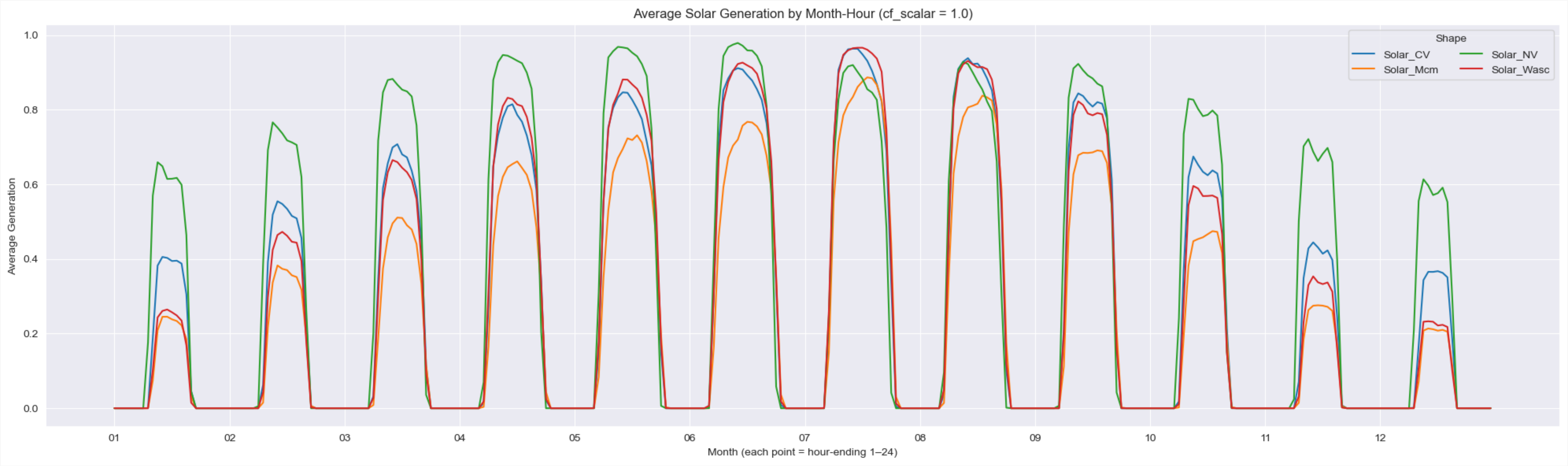
- Perfect foresight
- Forced Outage Rate of SCCT (2.38%)

DSG ELCC - Results

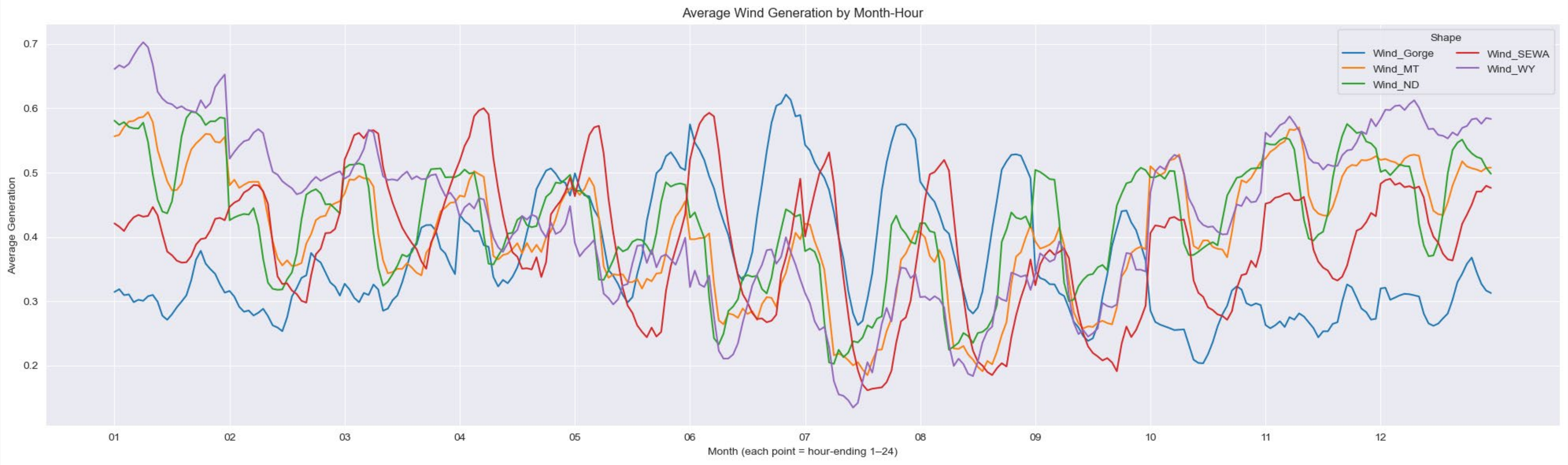
ELCCs for DSG



Supplemental Information – Solar Shapes

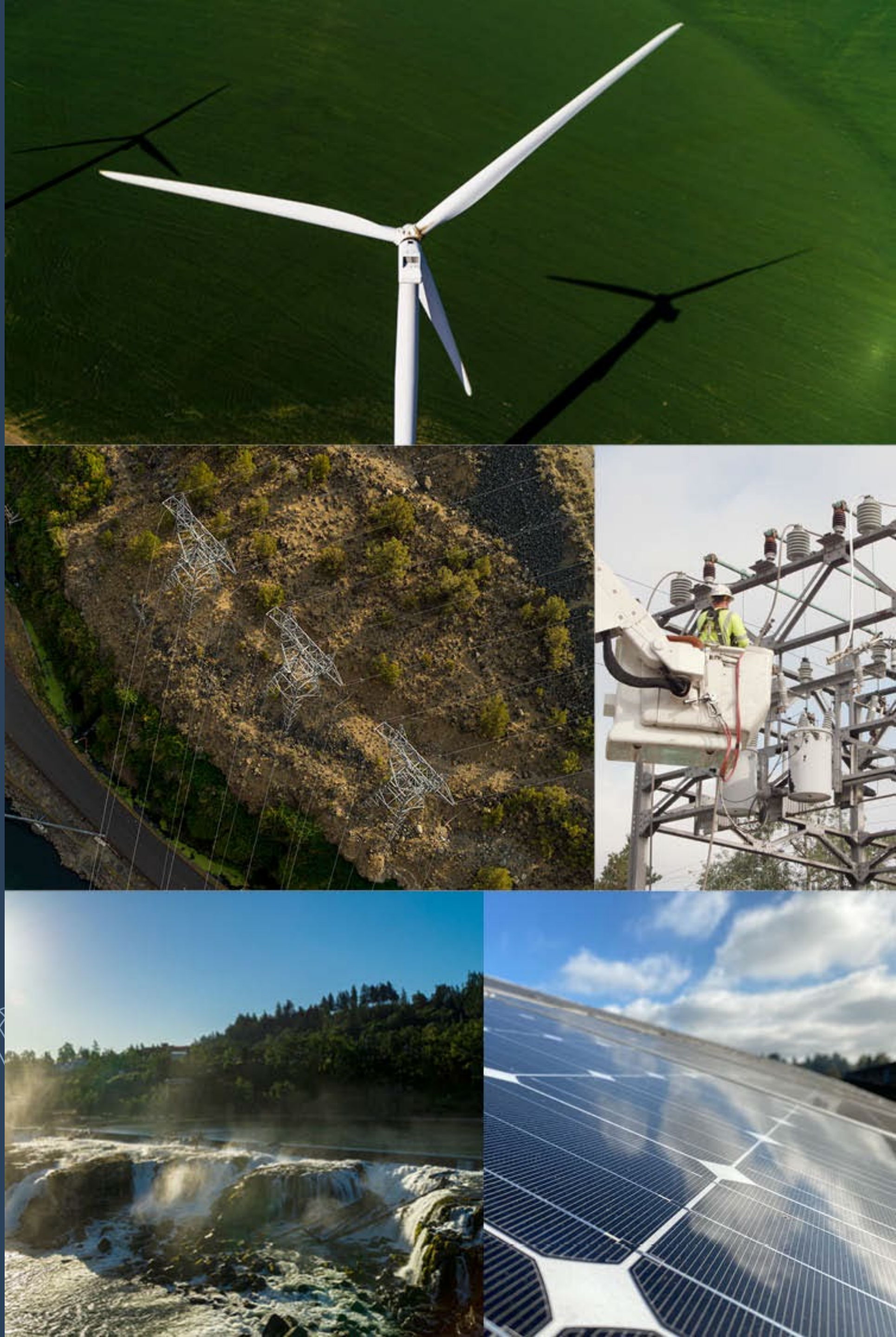


Supplemental Information – Wind Shapes



RFP Update and Proxy

Sam Newman & Jimmy Lindsay (20 minutes)



PGE An Oregon kind of energy.℠

RFP Updates and Resource Proxy Resource Assumptions

2023 All-Source RFP and Related Actions

Final commercial agreements executed by Q1 2026 with:

- Biglow 125 MW solar + 125 MW BESS
- Wheatridge 240 MW solar + 125 MW BESS

400 MW of additional BESS agreements currently seeking OPUC approval via waivers

Modeled as additions to base portfolio in all 2026 IRP analysis going forward

2025 All-Source RFP

Final Shortlist filed with OPUC Feb. 2026:

- 8 renewable and hybrid projects, 2028-2030 COD
- 4 storage projects, 2028-2029 COD

4,798 MW total nameplate capacity

Modeled as individual proxy resources available for selection in 2026 IRP portfolio analysis

(non-RFP proxy resources will not be available before 2030 in IRP models)

Detail on 2025 RFP Final Shortlist (filed in OPUC Docket UM 2371)

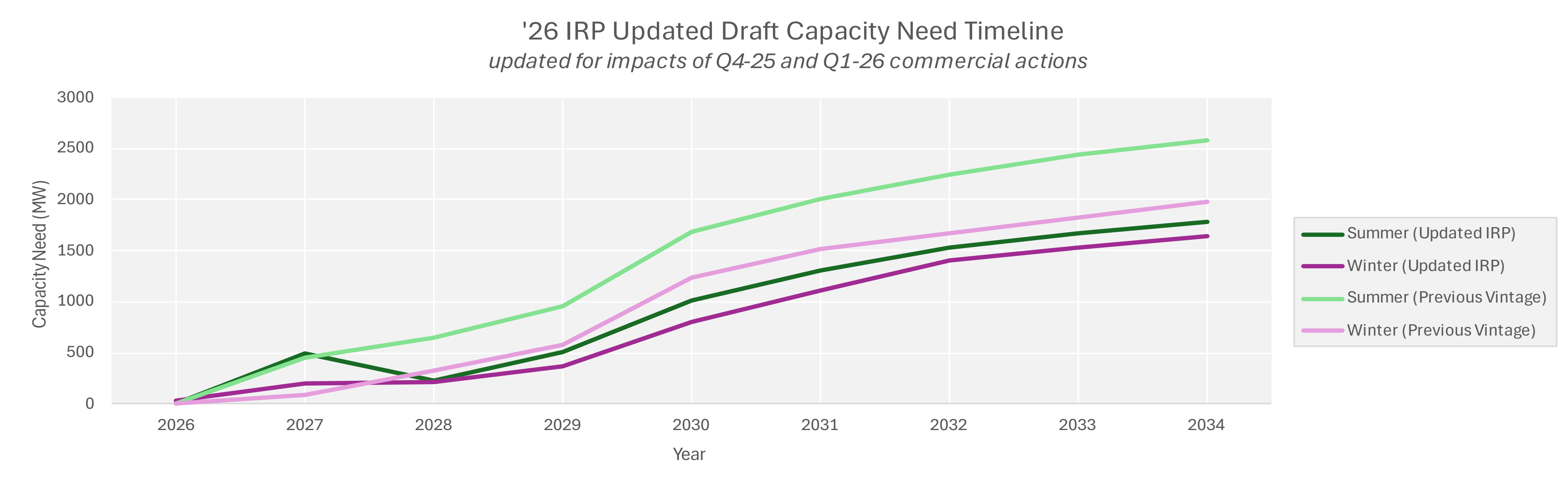
Technology	Commercial Structure	COD	Location	MW Wind	MW Solar	MW Storage	Energy (MWa)	Capacity (ELCC MW)
Li-Ion Storage	SCA	2029	NW Oregon	0	0	185	(5)	83
Li-Ion Storage	SCA	2028	NW Oregon	0	0	200	(5)	92
Wind	PPA	2029	E Washington	560	0	0	139	61
Solar	PPA	2028	E Washington	0	100	0	23	19
Wind	PPA	2028	E Oregon	103	0	0	29	32
Solar+Storage	Hybrid	2029	E Oregon	0	400	400	98	224
Wind, Solar, Storage	Hybrid	2029	E Washington	340	260	200	140	130
Solar+Storage	BTA	2028	E Oregon	0	200	250	43	112
Solar+Storage	BTA	2029	E Oregon	0	200	200	40	103
Li-Ion Storage	BTA	2029	NW Oregon	0	0	100	(2)	42
Li-Ion Storage	BTA	2029	NW Oregon	0	0	200	(5)	78
Solar+Storage	PPA	2030	E Oregon	0	450	450	87	165
				1,003	**1,610**	**2,185**	**581**	**1,139**

Upcoming regulatory and commercial schedule:

- **Mar-May 2026:** regulatory and stakeholder review, Commission acknowledgment consideration
- **Q2-Q3 2026**: proceeding to negotiations prioritizing renewables, expecting to successfully procure ~2,500 MW

Impacts on PGE Capacity Needs

PGE's Dec. 2025 roundtable identified IRP capacity needs for 2030 of 1690 MW summer, 1290 MW winter. Revised analysis shows reductions to **1018 MW summer, 800 MW winter**



Season	Method	2026	2027	2028	2029	2030	2031	2032	2033	2034
Summer	IRP	1	498	230	508	1,018	1,308	1,531	1,668	1,787
Winter	IRP	27	200	217	362	800	1,108	1,404	1,527	1,644

RFP Market Insights for IRP Analysis

RFPs provide a valuable source of market intelligence to inform IRP analysis. Observations from the 2025 RFP include:

Regional transmission is scarce but present

- ~40% of renewables projects offered new transmission
- Total of 1,750 MW incremental long-term transmission to PGE (220 from Montana, 600 MW from SE Wash. and 750 MW from eastern Columbia Gorge)

Development efforts of >2,000 MW of lithium-ion battery storage projects on PGE's system are underway. More broadly, RFP offers are predominantly from Oregon and Washington solar, wind and lithium-ion storage resources, with some additional Montana projects

New resource pricing has not materially changed versus the 2023 RFP, with projects still forecasting ability to capture tax credits

Project viability presents challenges to successful commercial negotiation (ie transmission plans dependent on redirects, interconnection agreements not signed and complex plans of service, dependence on future surplus interconnection or material modification, uncertain permitting timelines, exposure to equipment supplier or tax credit availability risks)

NEXT STEPS

A recording from today's webinar will be available on our website in one week

Upcoming Roundtable: April 8, 2026

Thank you

Contact us at
IRP.CEP@PGN.COM

An

Oregon

kind of energy

ACRONYMS

ARIMA: autoregressive integrated moving average
ART: annual revenue-requirement tool
ATC available transfer capability
BPA: Bonneville Power Administration
C&I: commercial and industrial
CBI: community benefit indicators
CBIAG: community benefits and impacts advisory group
CBRE: community based renewable energy
CDD: colling degree day
CEC: California energy commission
CEP: clean energy plan
CF   conditional firm
DC: direct current
DER: distributed energy resource
DR: demand response
DSP: distribution system plan
EE: energy efficiency
ELCC: effective load carrying capacity
EJ: environmental justice
ETO: energy trust of Oregon
EUI: energy use intensity
GHG: greenhouse gas
HB2021: House Bill 2021
HDD: heating degree day
HVDC: high-voltage direct current
IE: independent evaluator
IOU: investor-owned utilities
ITE: information technology equipment
ITC: investment tax credit
kW: kilowatt
LOLH: loss of load hours
LT/ST: long term/ short term
LTF long-term firm
MW: megawatt
MWa: mega watt average
NAICS: North American industry classification system
NCE: non-cost effective
NG: natural gas
NPVRR: net present value revenue requirement
OASIS Open Access Same Time Information System
ODOE: Oregon department of energy
PPA: power purchase agreement
PSH: pumped storage hydro
PUC: public utility commission
PURPA: Public Utility Regulatory Policies Act
PV: photovoltaic
REC: renewable energy credit
RLRR: low carbon price future
ROSE-E: resource option strategy engine
RPS: renewable portfolio standard
RRRR: reference case price future
RTO: regional transmission organization
SoA: South of Allston
T&D: transmission and distribution
TSR: transmission service request
TSEP: TSR study and expansion process
Tx: transmission
UPC: usage per customer
UPS: uninterruptible power supply
VER: variable energy resources
VPP: virtual power plant
WECC: western electricity coordinating council