PGE CEP & IRP Roundtable 25-8

December 10th 2025

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/9291862450?pwd=xVXQI4jIjt7FdetDzWD0G35FFvayF8.1&omn=84372774388
- Meeting ID: 929 186 2459
- Passcode: 108198

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

December 10, 2025 – Agenda

9:00 | Welcome

9:05 | Supply-Side Resource Options

9:35 | Capacity Need & Its Drivers

10:30 | Transmission Options

10:50 | Role of VPP in the IRP

11:10 | EE Integration into IRP

11:55 | Closing Remarks - Next Steps

Upcoming Roundtable Schedule for the 2026 CEP/IRP

Wednesdays from 9 to 12 pm, Online Via Zoom

4	**December 10, 2025**	Supply-side resource options, Transmission capacity needs, Transmission options, Role of VPP, EE/DR integrations, ETO EE forecast
5	**January 14, 2026**	Resource options & related economics, CBIs, RFP proxies, CEP emissions reductions, flexibility study
6	**February 26, 2026**	Portfolio/scenarios designs, flexibility study
7	**April 08, 2026**	Draft portfolio analysis results
8	**May 20, 2026**	Updates prior to filing
9	**July 01, 2026**	Office Hours after filing

8 Workshops

Topics noted here are subject to change

Supply-Side Resource Options

Robert Brown
Senior Principal Integrated Resource Planning Analyst, Integrated Resource Planning

Bachir Salpagarov
Principal Strategy & Planning Analyst, Integrated Resource Planning

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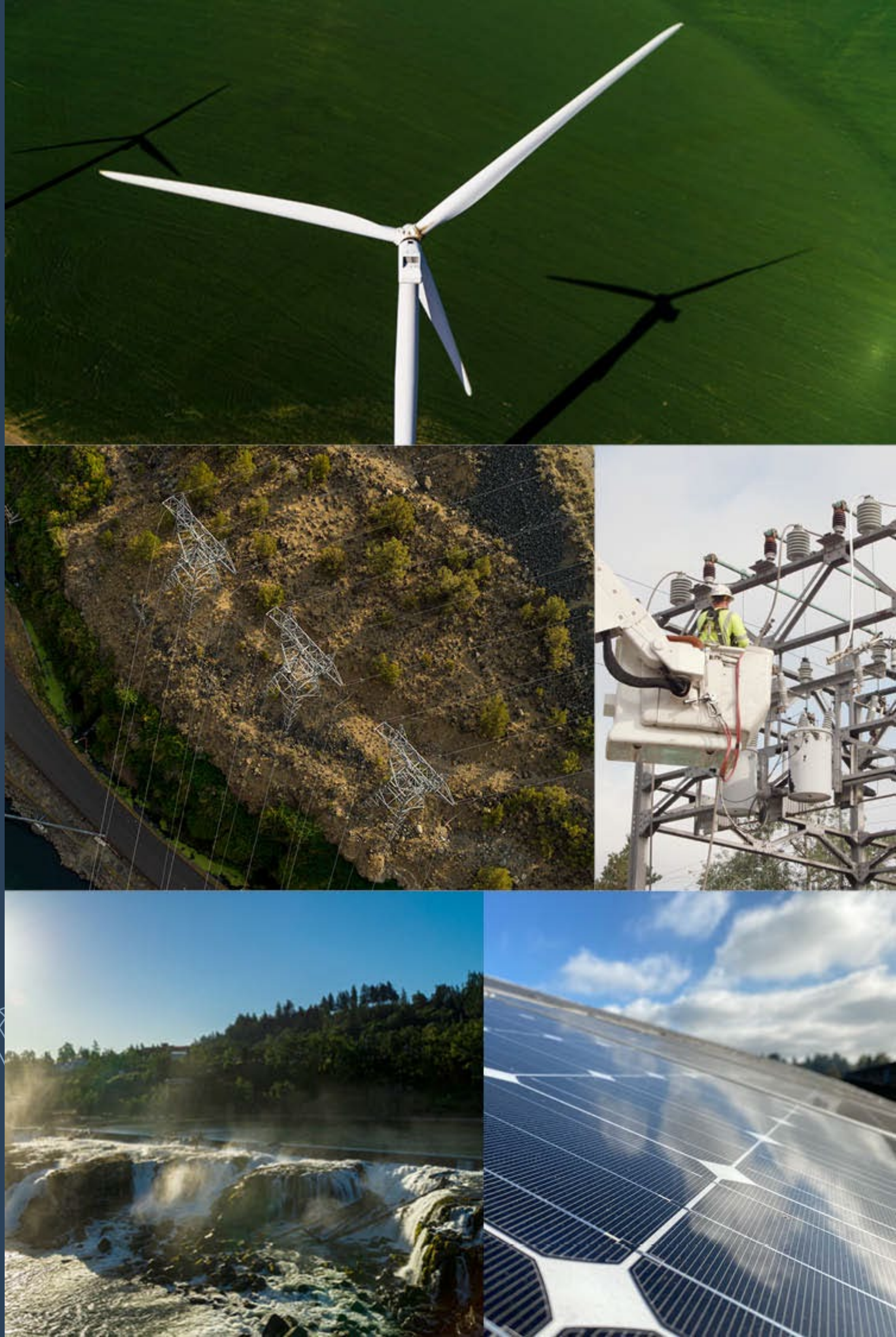
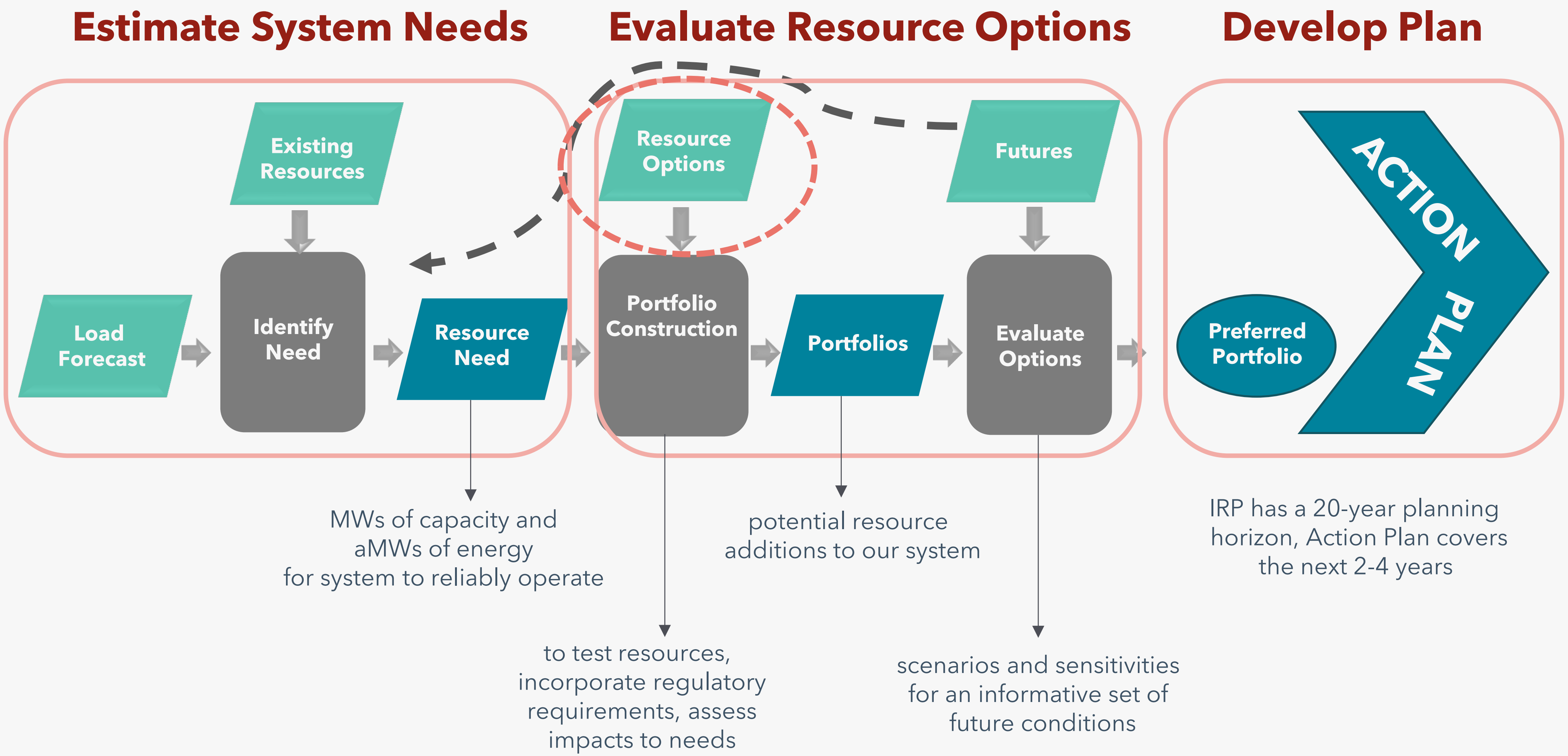


Supply-Side Resource Overview

- Sources, tools, and analyses
- Current utility-scale resource options
- Planned updates

High-Level IRP Analysis Process



Sources of Supply-Side Resource Information

Recent past and current status

2023 CEP/IRP[1] and 2023 Update[2] relied on publicly-available information, primarily	National Laboratory of the Rockies (NLR) Annual Technology Baseline (ATB)	2024 ATB
	Energy Information Administration (EIA) Annual Energy Outlook (AEO)	AEO 2025 (research published Q1 2024)
2026 IRP Goal	Update cost information and resource attributes to latest NLR ATB in Q3-Q4 2025	
Current reality	NLR ATB has been delayed	
	Evaluating options for resource assumptions to inform 2026 IRP by year end	

[1] See PGE's 2023 CEP/IRP, Appendix M for a detailed discussion of resources considered: https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf#page=601
[2] filed June 18, 2025
National Laboratory of the Rockies was previously the National Renewable Energy Laboratory (NREL)

Supply-Side Resource Information Flow

Inputs to outputs

Resource Costs

- Fixed Costs
  - Revenue requirements model
- Variable Costs
  - Aurora

Resource Attributes

- Dispatchable Resources
  - Aurora
  - Sequoia
- Variable Energy Resources (Wind & Solar)
  - NLR SAM
  - Aurora
  - Sequoia

ROSE-E

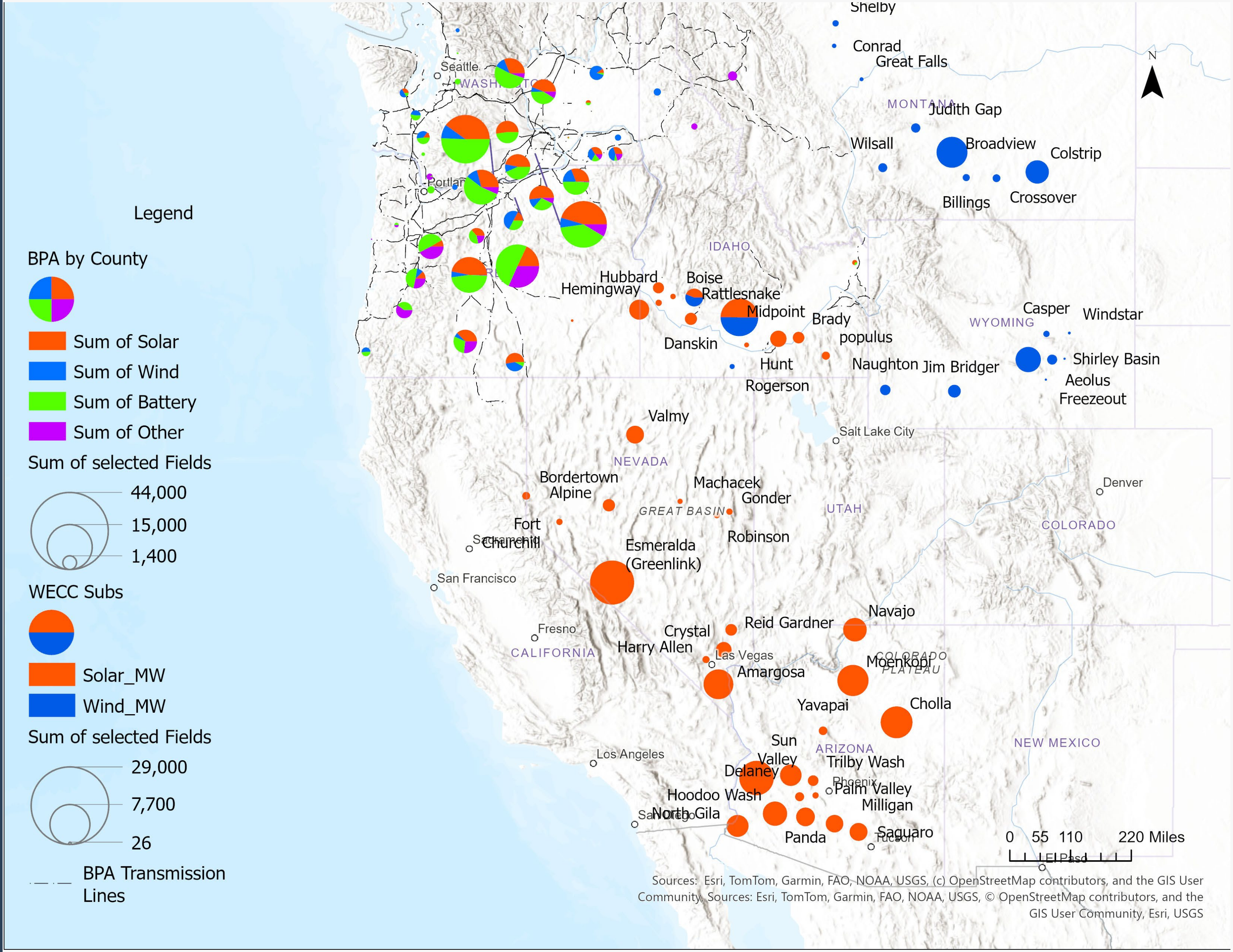
Proxy New Supply-Side Resources

Consideration in 2026 IRP

Resource	Description	Location	First Year
Wind	Onshore	Oregon Gorge, SE Washington, Montana	2029
		Wyoming	2035
		North Dakota	2038
Wind	Offshore	Southern Oregon	2036
Solar PV	Single-axis tracking	Central Oregon, Oregon Gorge, Willamette Valley,	2029
		Nevada	2035
Energy Storage	Lithium-Ion (LI) Battery (multiple durations)	On system	2029
	Iron-Air Battery (100 hour)	On system	2030
	Pumped Storage (PS) Hydro (10 hour)	PNW	2032
Hybrid	Wind + Solar + LI Battery	Same as new wind (above)	2029
	Solar + LI Battery	Same as new solar PV (above)	2029
Existing Site Optimization	Solar + LI Battery	Co-locate incremental solar + LI battery storage with existing wind	2029

Interconnection Queue Visual

Public interconnection queue studies from transmission providers including BPA, Idaho Power, Northwestern Energy, PacifCorp, NV Energy, and Arizona Public Service indicate generation resources are available in PGE's 2023 IRP Update transmission zones .

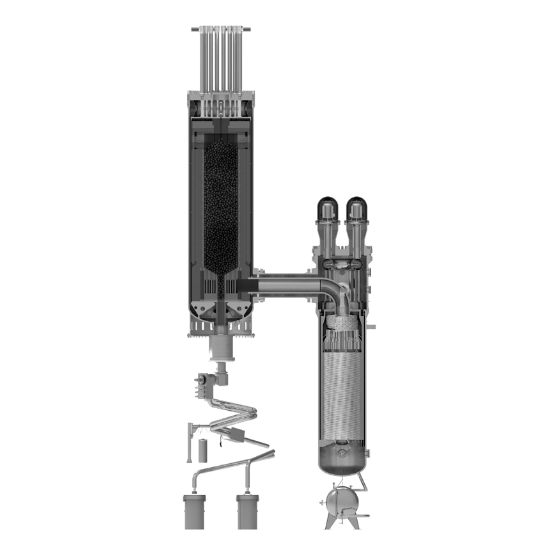


Proxy New Supply-Side Resources

Consideration in 2026 IRP

Resource	Description	Location	First Year
Advanced Non-Emitting Generation		**PNW / Western US**	**2035**
Geothermal	Enhanced Flash		
Nuclear	Small Modular Reactor		

Cost estimates for these resources will form the basis for an advanced, non-CO_2 emitting, generator eligible for selection in ROSE-E



Images: x-energy.com, energy-northwest.com

Proxy New Supply-Side Resources
Consideration in 2026 IRP

Resource	Description	Location	First Year
Representative Emitting Generation		**PNW / Western US**	**2030**
Thermal	Combined-Cycle Combustion Turbine (CCCT)	Western US	
	Simple-Cycle CT (SCCT)	Western US	

Cost estimates will represent the cost of participating in the output of an existing resource potentially eligible for selection in certain portfolios for a defined period of time

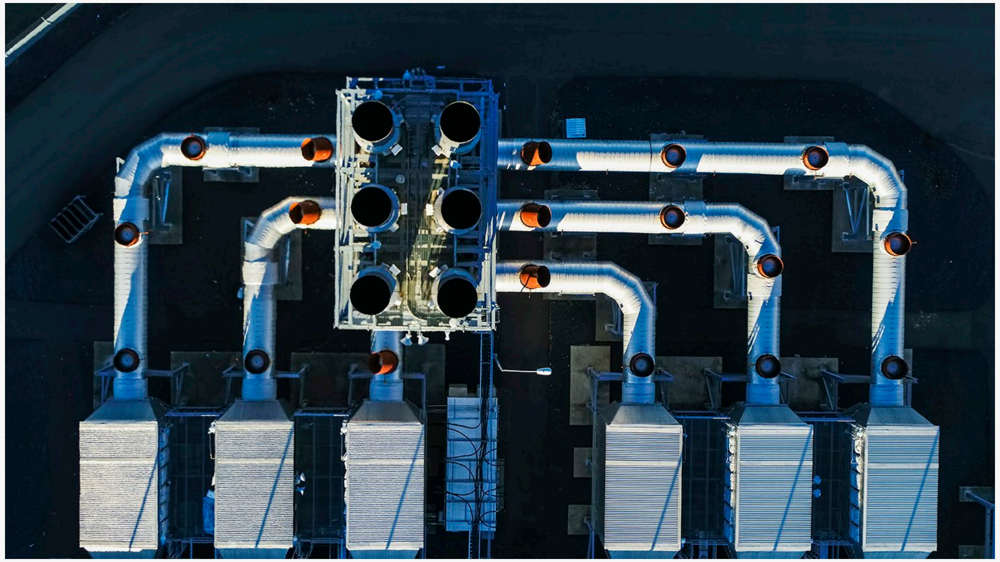


Image: Guidehouse

Additional Planned Updates

Tax Credits - Reference case will reflect current Federal policy (OBBBA)

Resource Costs & Attributes – Pending NREL ATB release

VER shapes - wind & solar

Guided Feedback - Supply-Side Resource Options

Process: If NREL's 2025 ATB is delayed, should we pause analysis or proceed with 2024 data?

Content: Should we add or remove any technologies from the proposal? Do you recommend any public data sources?

Questions/Comments

Capacity Need & Its Drivers

Devin Mounts
Senior Integrated Resource Planning Analyst, Integrated Resource Planning

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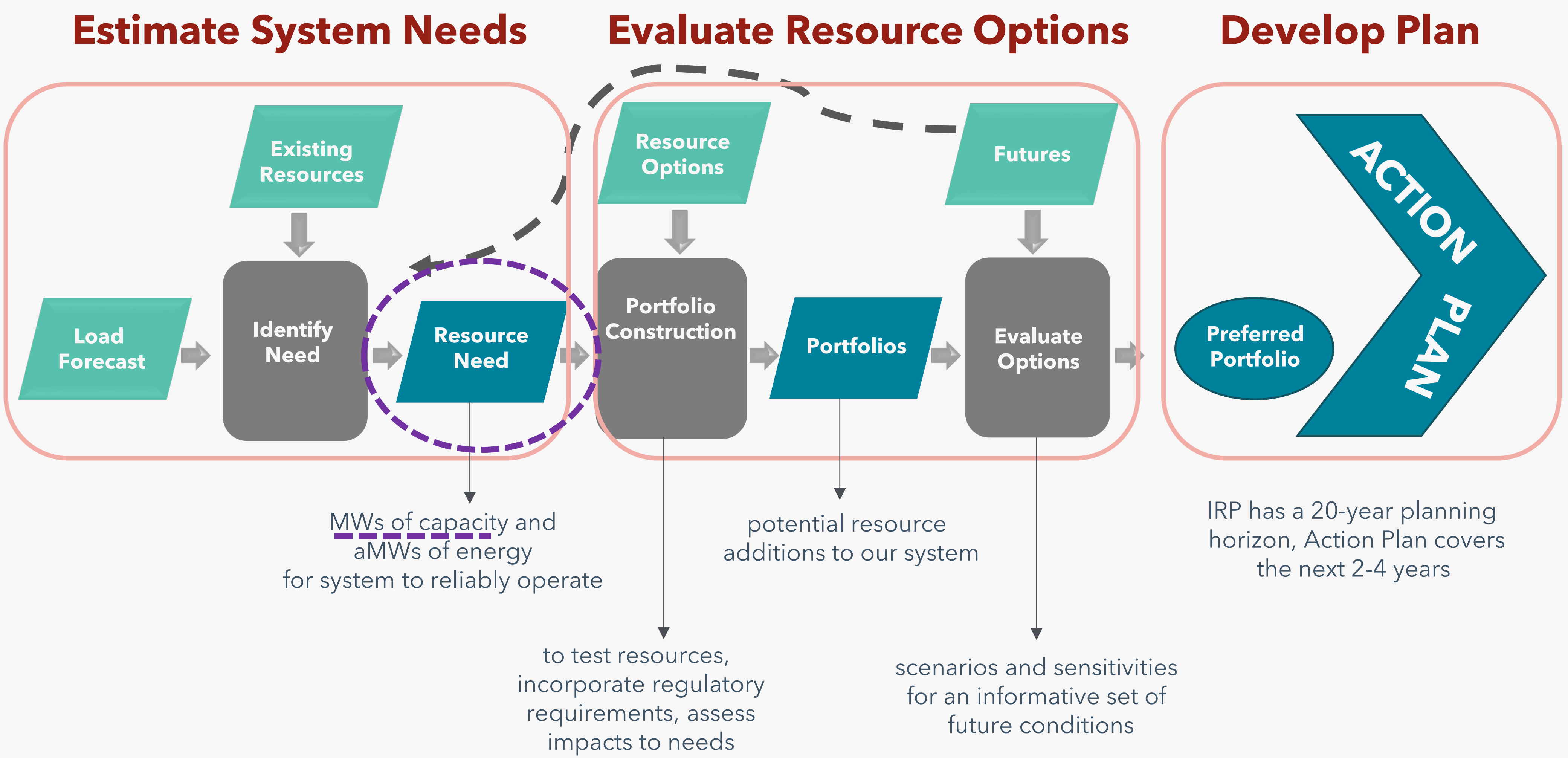
Outline

- Inputs to Capacity Need
- Capacity Need Results
- System Risk Profile

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 historically targets a seasonal (winter/summer) adequacy level of 24 hours in ten years (2.4 LOLH)

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

Updates to Sequoia: 2026 CEP/IRP

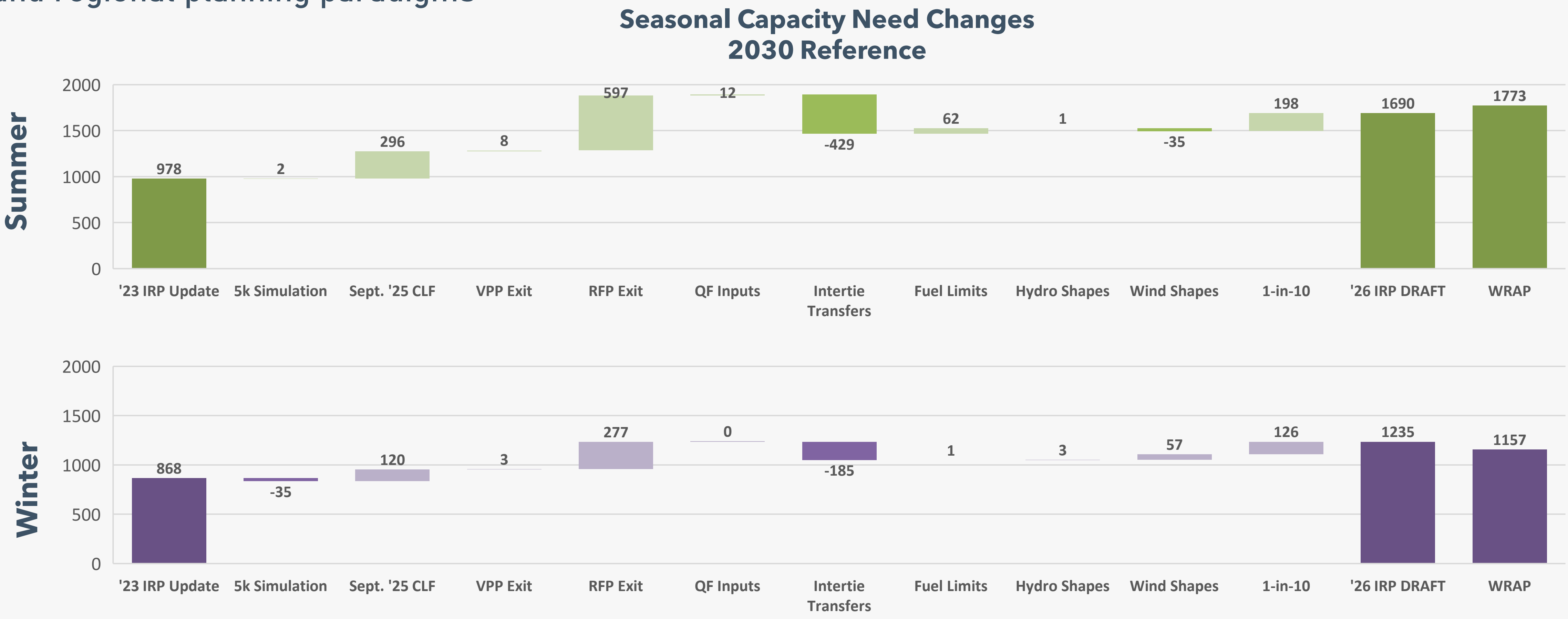
Supply, demand and methodology assumptions updated to align with PGE's current portfolio, load forecast and regional planning paradigms

Category	Update	Description & Source
Supply	AdopDER (VPP) Exit	Removed from base portfolio, quantity and timing will be elected in portfolio expansion. Resource contributions of PGE's AdopDER model (Fall '25) included for comparison (VPP)
	Hydro Shapes	Refreshed weekly energy limits for major projects and contracts based on 2024 BPA Load & Resources Study (Whitebook)
	Intertie Transfers	Revised emergency intertie capacity based on PGE's historical reliability related operations
	Qualified Facilities (QF) Inputs	Refreshed to fall 2025 PGE QF projects, methodology discussed in Aug. 2025 Roundtable
	'23 Request for Proposal (RFP) Proxy Resources	Removed yet uncontracted RFP projects previously included in 2023 CEP/IRP Update. This is a change of convention consistent with proposed IRP rules to only include contracted resources in utility need assessment
	Fuel Limits	Revised natural gas fuel capacity from PGE MONET model
	Wind Shapes	Appended actual generation for Biglow, Tucannon & Wheatridge[1]
Demand	Sept. '25 Corporate Load Forecast (CLF)	Discussed in Oct. 2025 Roundtable. Includes refreshed binning of load for stochastic matching, as discussed in Aug. 2024 Roundtable[2]
Methodological	1-day-in-10 reliability metric (1-in-10)	Updated PGE reliability metric interpretation to align with WRAP Business Practice Manual (BPM) 102
	Five thousand Monte-Carlo simulations	Covered in this Roundtable

1. Biglow actual generation updated through 2020, as contracted service and maintenance work at facilities anticipated to restore generation to historical levels.
2. 5 load bins defined using same methodology as described in the Aug. 2024 Roundtable. However, for the '26 IRP the IRP binned values of PGE's 30-year weather dependent CLF for year 2030, rather than detrended historical load as used for the 2019 IRP and 2023 CEP/IRP. PGE's 30-year weather dependent CLF was derived specifically for RA modeling.

Effects of Updates to Sequoia: 2026 CEP/IRP

Supply, demand and methodology assumptions updated to align with PGE's current portfolio, load forecast and regional planning paradigms



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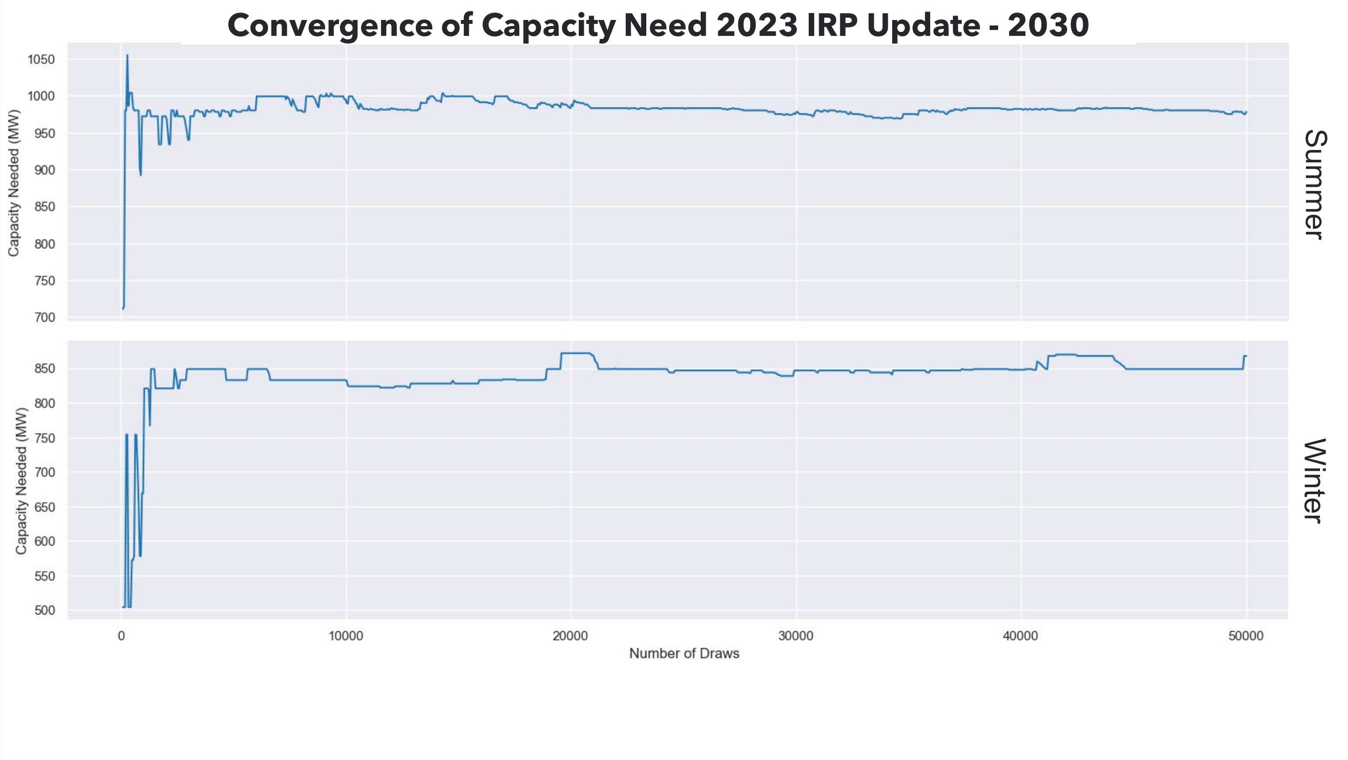
2. Marginal changes in waterfall should be interpreted as representative changes given the modeled sequence. Re-ordering sequence would result in changes in values due to interactive effects in Sequoia. However, reordering sequence does not affect terminal '26 IRP DRAFT estimates. Marginal changes ran at five thousand simulated weeks, '26 IRP DRAFT values at ten thousand simulated weeks

Convergence in Sequoia: 2026 CEP/IRP

Current IRP practice simulates 50,000 weeks per season. Review of capacity need convergence suggest capacity need stabilizes at approximately 5,000 weekly simulations.

At 5,000 simulated weeks estimated 2030 capacity need from the '23 IRP Update is ± .5 MW in Summer and ± 1.33 MW in Winter from the theoretical mean, with a 99% confidence interval[1]

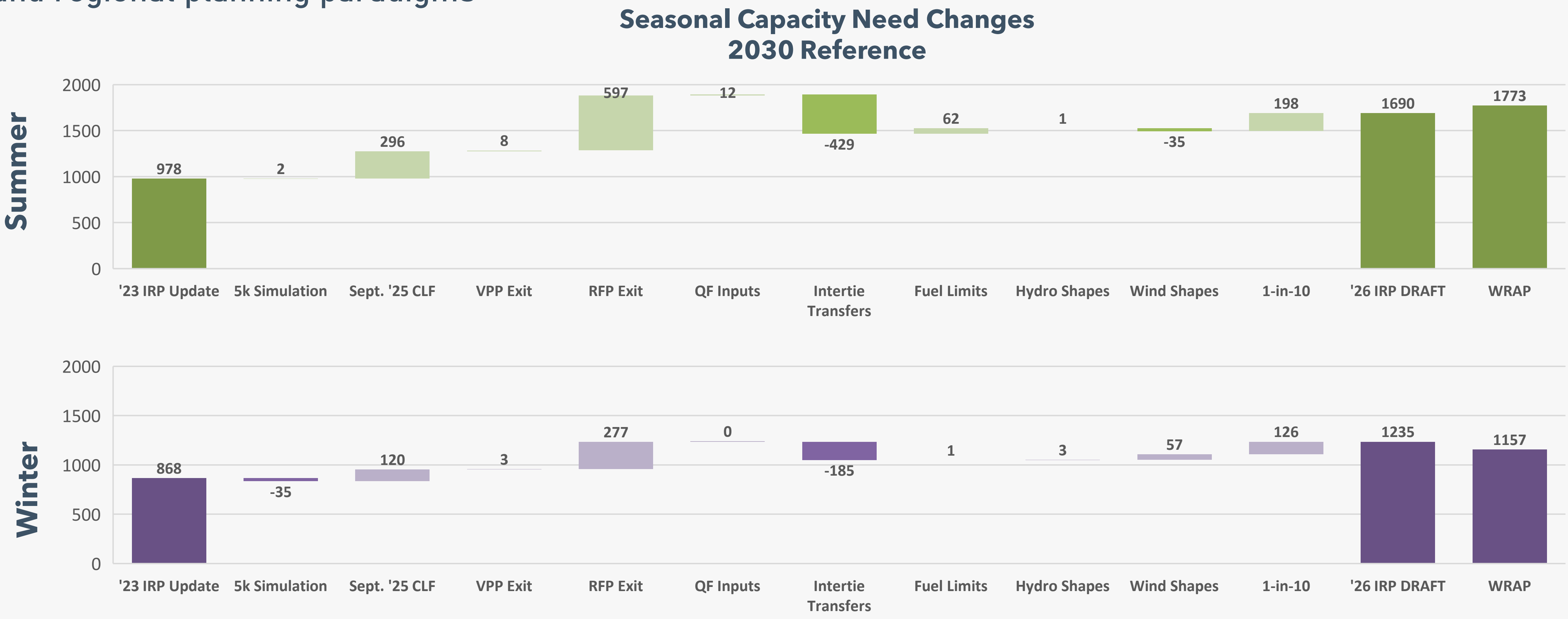


*Moving forward the **IRP proposes using 10,000 simulated weeks per season**, reducing model run time by ~60%. This change allows a more agile RA analysis, while maintaining high confidence in estimates.*

1. The required Monte Carlo sample size (N) follows from the classical normal-approximation confidence interval (1 − α) for the sample mean and standard deviation (σ²), leading to the standard expression for the required number of Monte-Carlo samples: $N = (z_{1-\alpha/2} * \sigma / \varepsilon)^2$. See, for example, Christian P. Robert and George Casella, *Monte Carlo Statistical Methods*, 2nd edition, Springer, 2004.

Effects of Updates to Sequoia: 2026 CEP/IRP

Supply, demand and methodology assumptions updated to align with PGE's current portfolio, load forecast and regional planning paradigms



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Intertie Transfers: Review of '23 IRP Assumptions

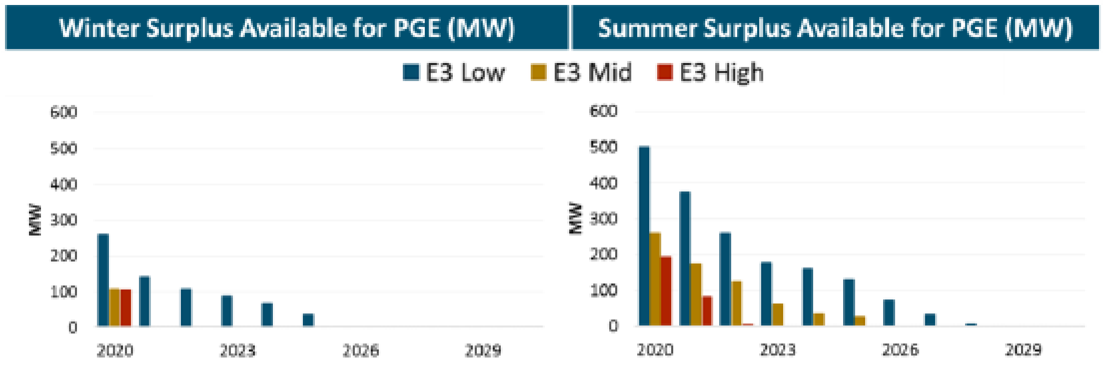
Previous 2023 CEP/IRP reliability driven intertie transfer assumptions represented increasing constraints in summer and winter.

2023 CEP/IRP relied on 2018 E3 RA Study which suggested tightening surpluses in the region[1]

- Pronounced Q3 shortfalls and constraints in 2022, 2023 were attenuated in '24 and '25 due to supply.
- Entry of battery energy storage systems (BESS) have altered regional surplus dynamics, especially in summer.
- Forthcoming RA studies in the region emphasize winter reliability constraints

Depiction of 2018 E3 Study Findings:

Figure 14. Net annual surplus market capacity available for PGE by scenario.



2023 IRP intertie transfer assumptions contributed to higher capacity needs, as compared against Western Resource Adequacy Program (WRAP) estimates[2]

'23 IRP Import Capacity Limits in heavy-load hours (HLH)

Season	HLH - MW
Winter	100
Spring	200
Summer	0
Fall	200

1. See 2023 CEP/IRP Appx. G. Market capacity study
2. See Feb. 2024 CEP/IRP Roundtable for IRP v. WRAP needs comparison

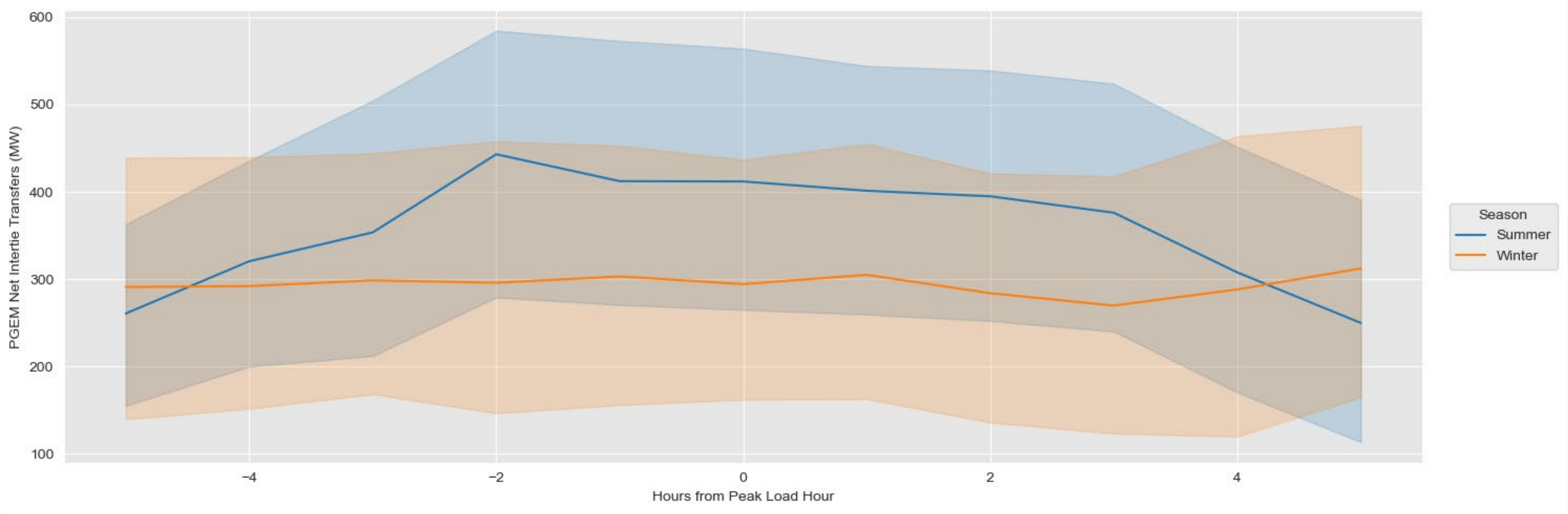
Intertie Transfer Analysis: 2026 IRP Proposal

The 2026 CEP/IRP proposes the definition of intertie transfers for use in RA modeling based on PGE's historical reliability driven operations, informed by forthcoming Extended Day-Ahead Market (EDAM) participation.

PGE IRP and Operations teams examined peak-hour physical intertie transfers from 24 historical days of PGE heavy-load[1]

- Excludes imports from PGE pseudo-tied assets
- Excludes imports from PGE contracts
- Excludes 12 entities committed to Markets+, as of Oct. 2025

PGE Retail (PGEM) peak-hour intertie transfers:



PGE retail (PGEM) peak-hour intertie transfers averaged **400 MW in Summer** and **300 MW in Winter**

1. Twelve summer and winter days, respectively, from 2021 to 2024 where PGE retail load was above the 97th percentile by season
2. Shaded area reflects 95% confidence interval around mean.
3. Average peak hours-beginning (Pacific Standard Time, UTC-8): 16:30 summer, 15:00 winter

Top-Down Validation: January 2021 Cold Event and Regional RA Assessment

Public reports from Energy GPS, hourly data from EIA-930, and E3's forthcoming RA in the PNW report validate similar quantities of winter intertie transfers by PGE during peak hours

	Energy GPS[1]	EIA-930[2]	E3 RA-PNW '25[3]
PNW Peak (MW)	35,991	36,381	-
PGE BA Peak (MW)	3,991	3,991	-
Share Peak (%)	11.08	11.00	-
PNW Intertie Transfers (MWa)	4,900	4,660	3,750
PGE BA Share PNW Intertie Transfers (MWa)	543	513	412

1. Energy GPS values derived from Analysis of Jan '24 Cold Snap in Pacific Northwest, slide 4 (PNW Peak, PGE BA Peak), slide 9 (PNW Imports).
2. EIA-930 BAs queried: Avista, Avangrid, BPA, Chelan PUD, Duglas PUD, Grant PUD, Idaho Power, Northwest Montana, Pacific Power-West, PGE, Puget Sound Energy, Seattle City Light, Tacoma Power and Water. Dates: 2024-01-12 to 2024-01-16
3. Forthcoming report as discussed in fall 2025 at Northwest and Intermountain Power Producers Coalition, Committee on Regional Power Cooperation, and PNW Regional Energy Symposium. Intertie transfers scaled by an estimated 11% PGE load share.

RA Intertie Transfer Assumptions: 2026 IRP Proposal

2026 CEP/IRP intertie transfer assumptions reflect historical reliability events, reducing 2030 capacity need by 414 MW and 165 MW in Summer and Winter, respectively.

Derived Import Capacity Assumptions:[1,2]

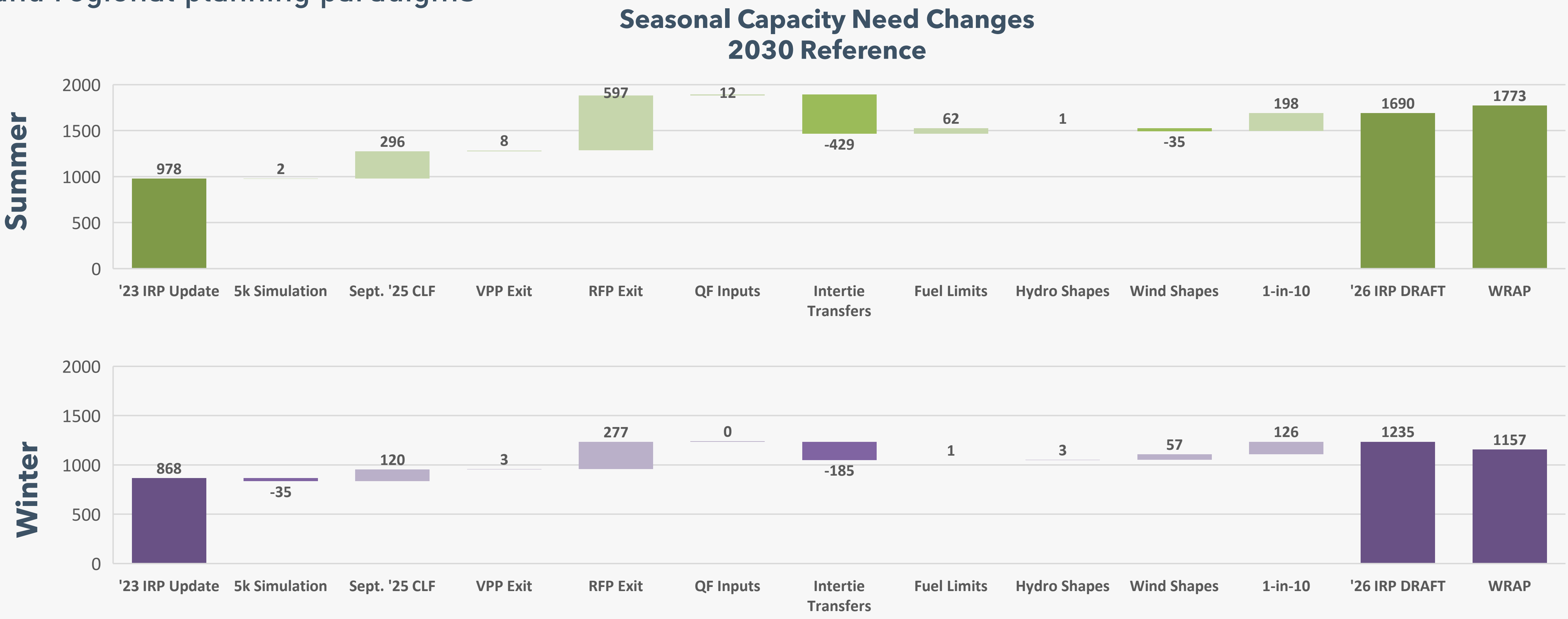
Load Percentile	Load Bin	Summer		Winter		Spring		Fall	
		LLH	HLH	LLH	HLH	LLH	HLH	LLH	HLH
0-20th	1	942	942	942	942	942	942	942	942
20th-40th	2	942	942	942	942	942	942	942	942
40th - 60th	3	942	942	942	942	942	942	942	942
60th - 80th	4	942	400	942	300	942	500	942	500
80th - 100th	5	400	400	300	300	942	500	942	500

1. Analysis of recent heavy-load days defines imports for heavy-load hours (HLH) where daily average load by month is in above 60th percentile and light-load hours (LLH) above 80th percentile.
2. PGEM long-term firm import rights from Pacific Power West and California-Oregon Border used to estimate all other hours.[3]

1. Summer: Jun.-Aug., Winter: Dec.-Feb., Spring: Mar.-May, Fall: Sept.-Nov.
2. HLH: Mon-Sun.: HE 07:00-22:00
3. PGE currently holds 627 MW of long-term firm from California-Oregon Border to John Day. The company has submitted a BPA TSEP request for the equivalent quantity to land power in PGE's territory.

Effects of Updates to Sequoia: 2026 CEP/IRP

Supply, demand and methodology assumptions updated to align with PGE's current portfolio, load forecast and regional planning paradigms



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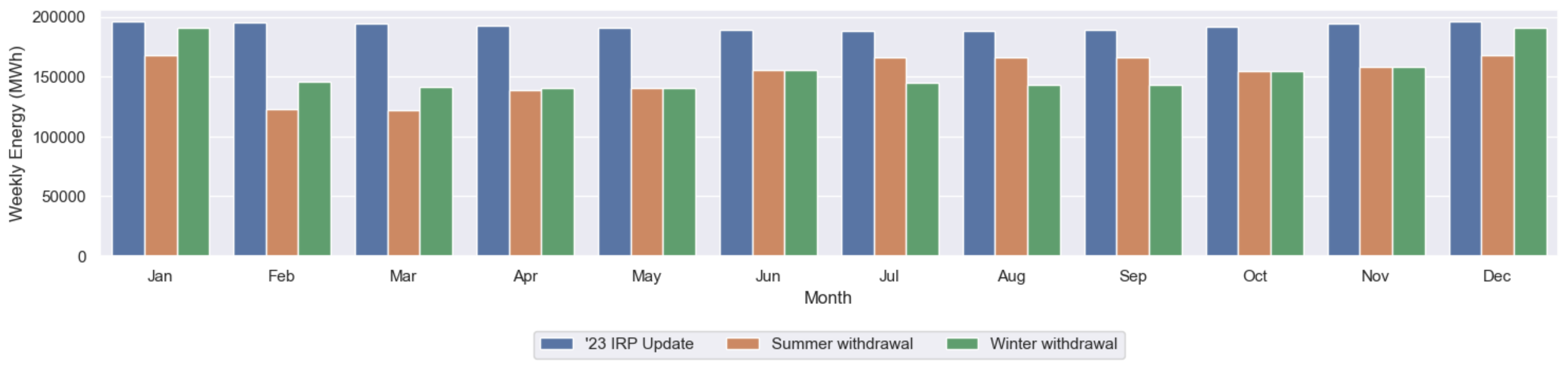
Fuel Limits: 2026 IRP Proposal

Shifting thermal fuel withdrawals from Summer to Winter months reduces Winter capacity need with nominal effect on Summer need. This change alleviates constraints which make Winter reliability events harder to address with available technology.

Weekly Fuel Budget - West of Cascades:



Weekly fuel budgets updated to reflect PGE's current firm fuel limits and storage capacity, then adjusted with respect to winter reliability challenges

- PGE currently withdraws fuel from storage in summer months
- Shifting fuel withdrawals to from July, August and September to December, January and February **reduces Winter capacity by 41 MW** relative to summer withdrawal assumption, increasing summer capacity need by 62 MW.

Reliability Metric: Updated interpretation of 1-day-in-10-years

PGE's 24-hours-in-10-years interpretation of system reliability differs from regional RA planning

1) PGE began stochastic RA modeling as part of the 2016 IRP, with the use of E3's RECAP model

"The reliability target selected was a loss of load expectation (LOLE) of 1-day-in-10-years, or 2.4 hours per year"[1]

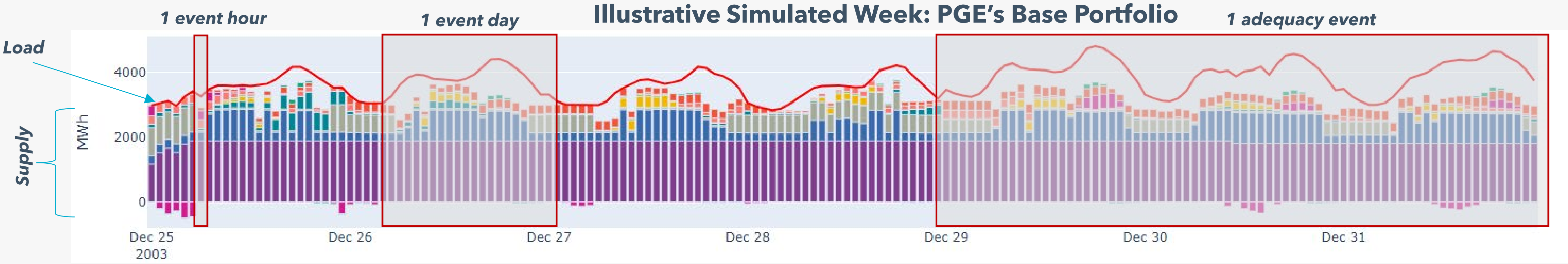
2) The 24-hours-in-10-years interpretation of reliability was transitioned to Sequoia as part of the 2019 IRP Update[2]

3) Reliability planning experts emphasize that a 24-hours-in-10-years interpretation leads to a less reliable system[3]

"A common adaptation of the historical "1 day in 10 years" criterion to hourly assessments has been to interpret it as "24 hours in 10 years", based on the incorrect but understandable premise … that the original criteria referred to a full day's duration of shortfall."

4) Regional planning standards (WRAP) interpret reliability metric as 1-day-in-10-years of loss-of-load[4]

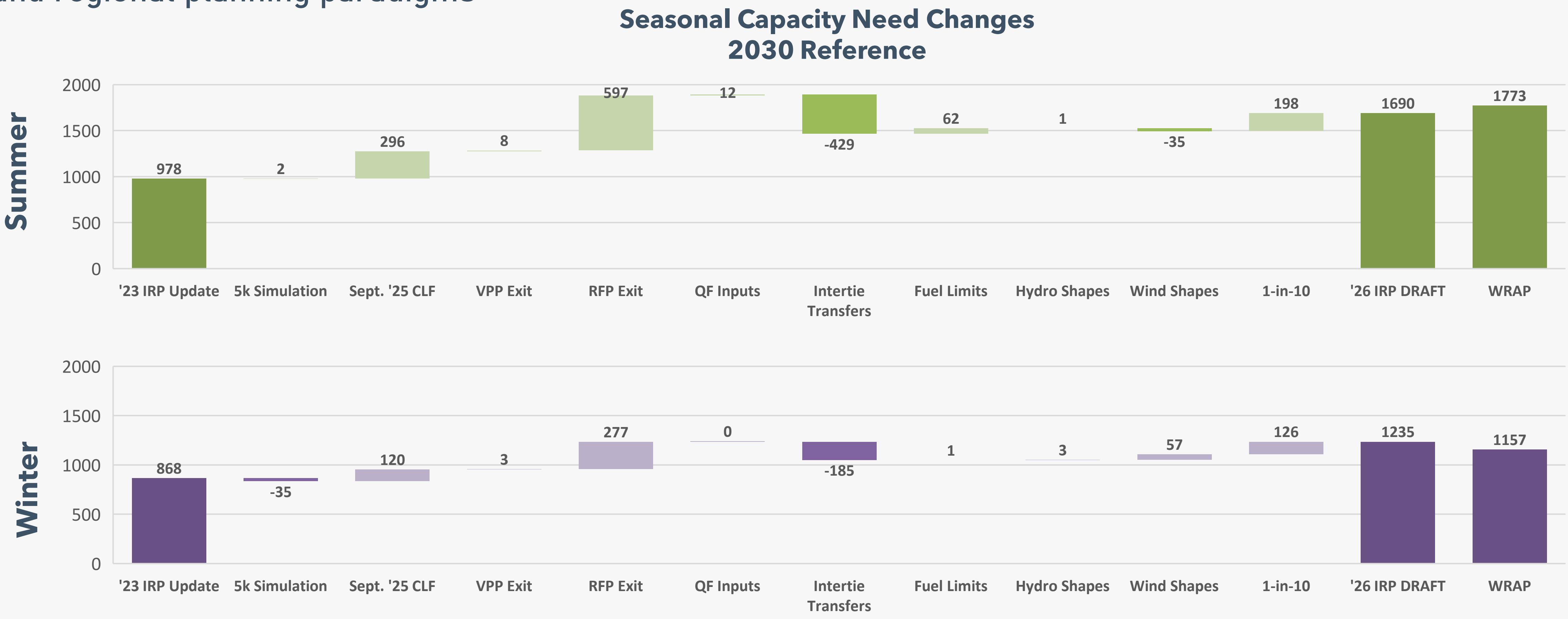
Updating PGE's reliability metric to 1-day-in-10-years will aide alignment with regional planning standards.



1. See PGE 2016 IRP, p 116
2. See PGE 2019 IRP Update, Appendix K. p 81
3. See Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric. Gord Stephen, et. al. 2024
4. See WRAP Business Practice Manual 102 – Forward Reliability Metrics

Effects of Updates to Sequoia: 2026 CEP/IRP

Supply, demand and methodology assumptions updated to align with PGE's current portfolio, load forecast and regional planning paradigms



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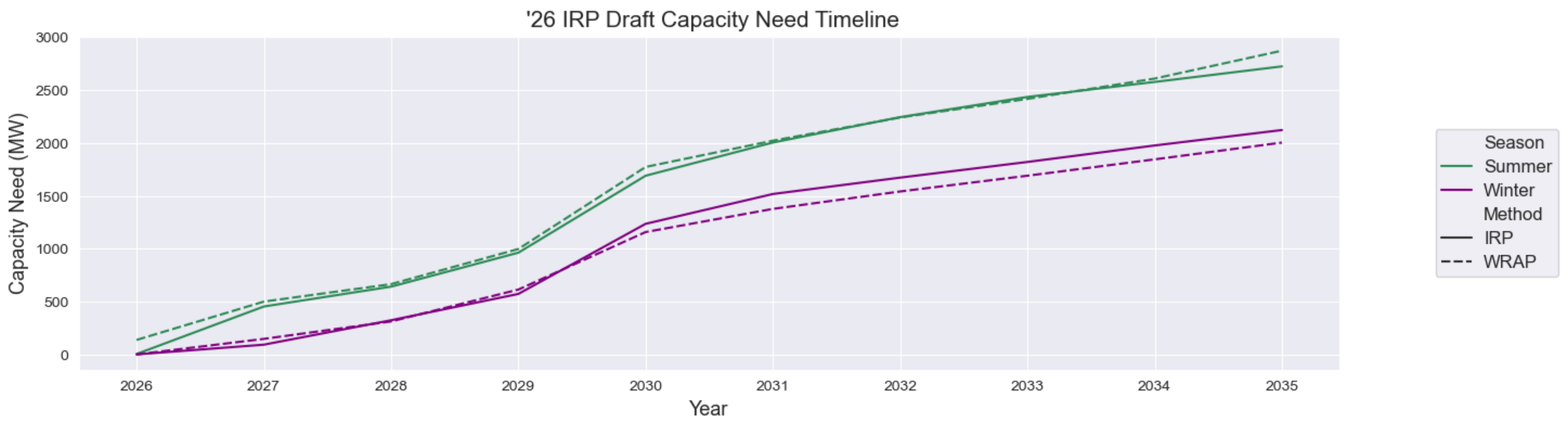
2026 CEP/IRP – Draft Capacity Values

'26 IRP draft capacity needs follow similar trends to WRAP estimates. IRP estimates between 2026-2035 differ from WRAP on average by 50 MW less in Summer and 64 MW greater in Winter.



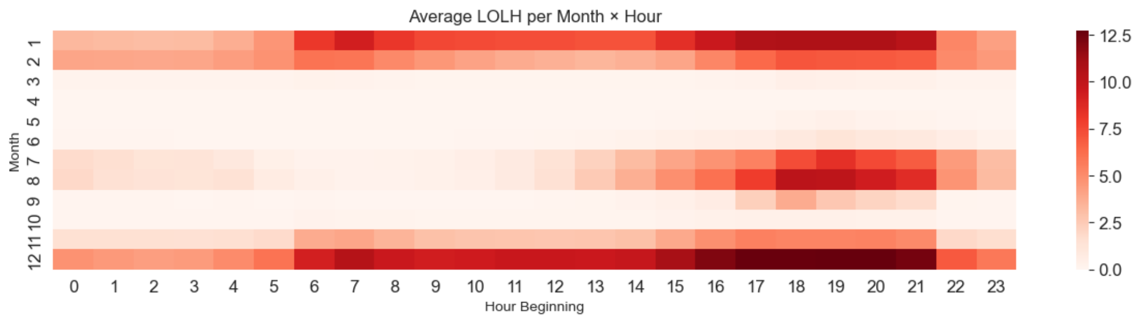
Season	Method	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer	IRP	4	453	641	962	1,690	2,004	2,244	2,435	2,577	2,724
	WRAP	137	499	665	997	1,773	2,021	2,241	2,417	2,609	2,873
Δ		**-133**	**-46**	**-24**	**-35**	**-83**	**-17**	**3**	**18**	**-32**	**-149**
Winter	IRP	0	92	323	572	1,235	1,517	1,672	1,820	1,976	2,122
	WRAP	0	147	312	613	1,157	1,376	1,541	1,690	1,845	2,003
Δ		**0**	**-55**	**11**	**-41**	**78**	**141**	**131**	**130**	**131**	**119**

1. Annual growth rate of 3% assumed for WRAP based load forecast, estimated using PGE's Sept. '25 CLF. This growth rate deviates from the WRAP assumed annual average growth rate of 1.1% as defined in WRAP BPM 103 (LOLE Study Load Forecast and Load Growth Rate).

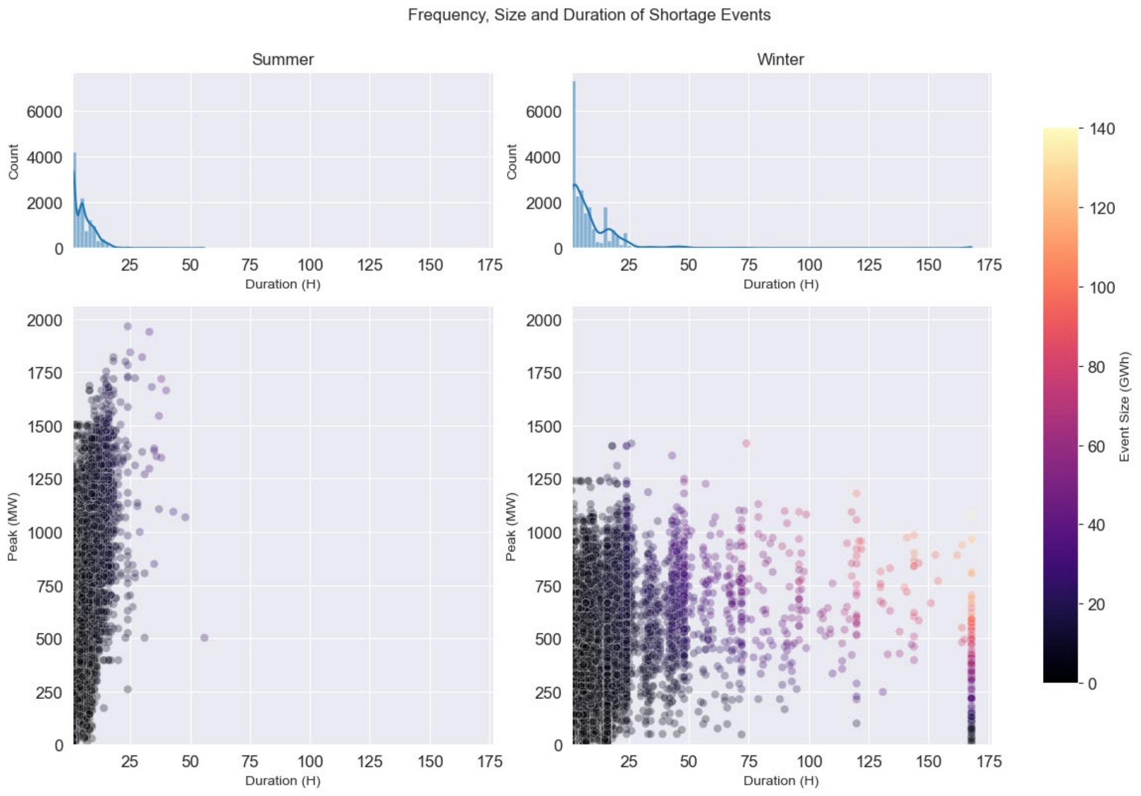
2030 System Risk – 2026 CEP/IRP

PGE's system risk is focused in Winter months. Winter's broad multi-hour events are contrasted against short-duration and high-peak Summer events. This system risk is prior to resource additions, including RFP's, bilateral contracts and VPP.

- 76% of hourly loss of load hours observations are in Nov.-Feb.



- Winter adequacy events are less frequent than summer events [1]
  - Winter events have 2/3 the peak capacity shortfall and double the duration, resulting in **greater unserved energy** than Summer events.



Metric	Summer	Winter
Adequacy Event Count (N)	12,204	10,105
Avg. Peak (MW)	546	354
Avg. Duration (hrs)	5.5	10.3
Avg. Unserved Energy (GWh)	2.8	3.9

1. Adequacy events are considered as contiguous loss of load hours.

Summary

'26 CEP/IRP draft capacity needs have increase since the '23 CEP/IRP Update

2030 Summer Capacity Need: 1,690 MW	**2030 Winter Capacity Need: 1,235 MW**
+ 712 MW from '23 CEP/IRP Update	+ 367 MW from '23 CEP/IRP Update

Resulting needs are roughly equivalent to WRAP estimates

Summer 2030: 83 MW less than WRAP	Winter 2030: 78 MW more than WRAP

Winter reliability events emphasize the importance of energy in achieving capacity adequacy

Guided Feedback – Capacity Need & It's Drivers

Process: Do you need more discussion or detail on any waterfall components?

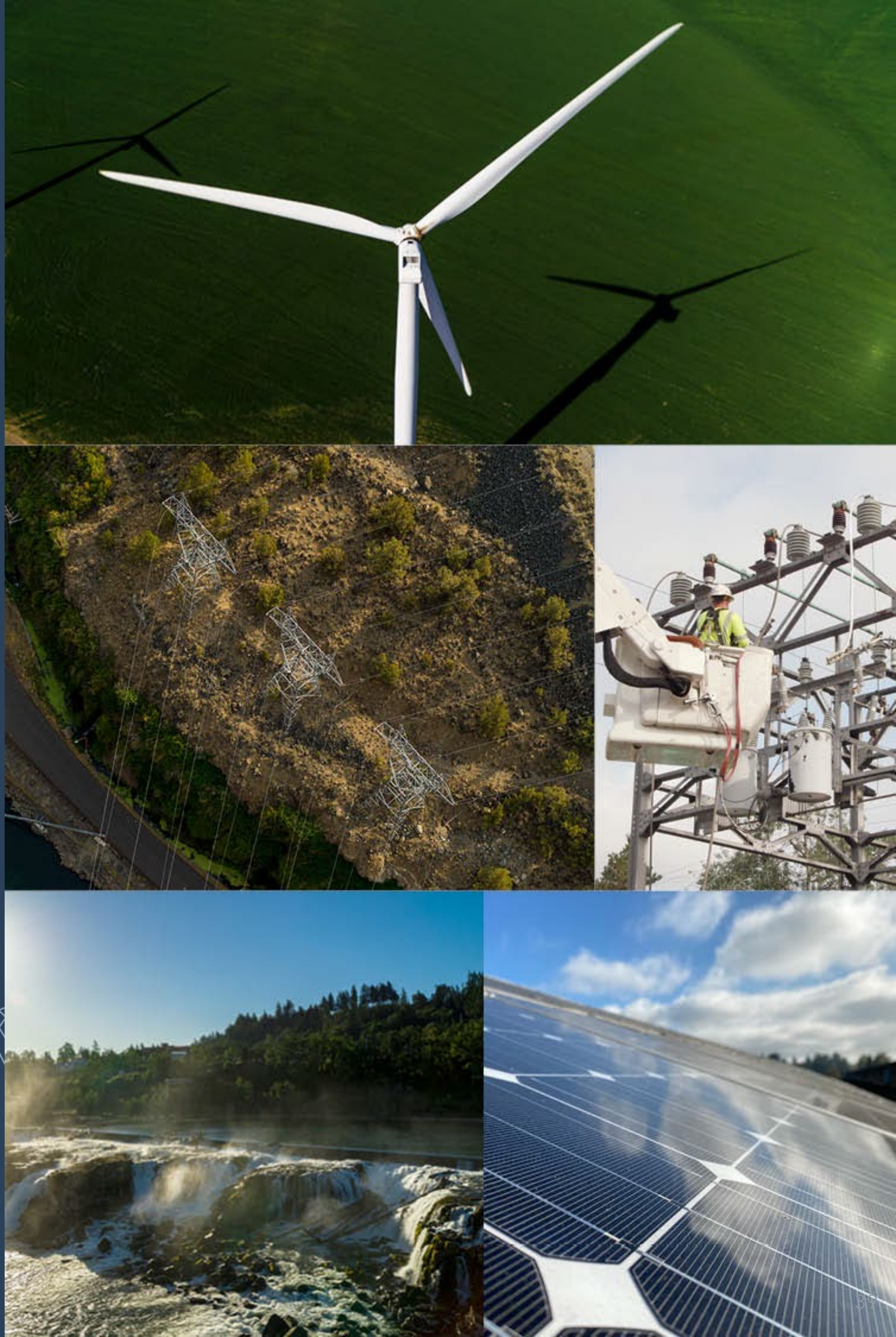
Content: Do you support reducing simulation iterations (Slide 25) to speed up capacity-related analysis across IRP, RFP, QF, and DSP?

Questions/Comments

Transmission Options

Jarek Oliver
Principal Integrated Resource Planning Analyst, Integrated Resource Planning

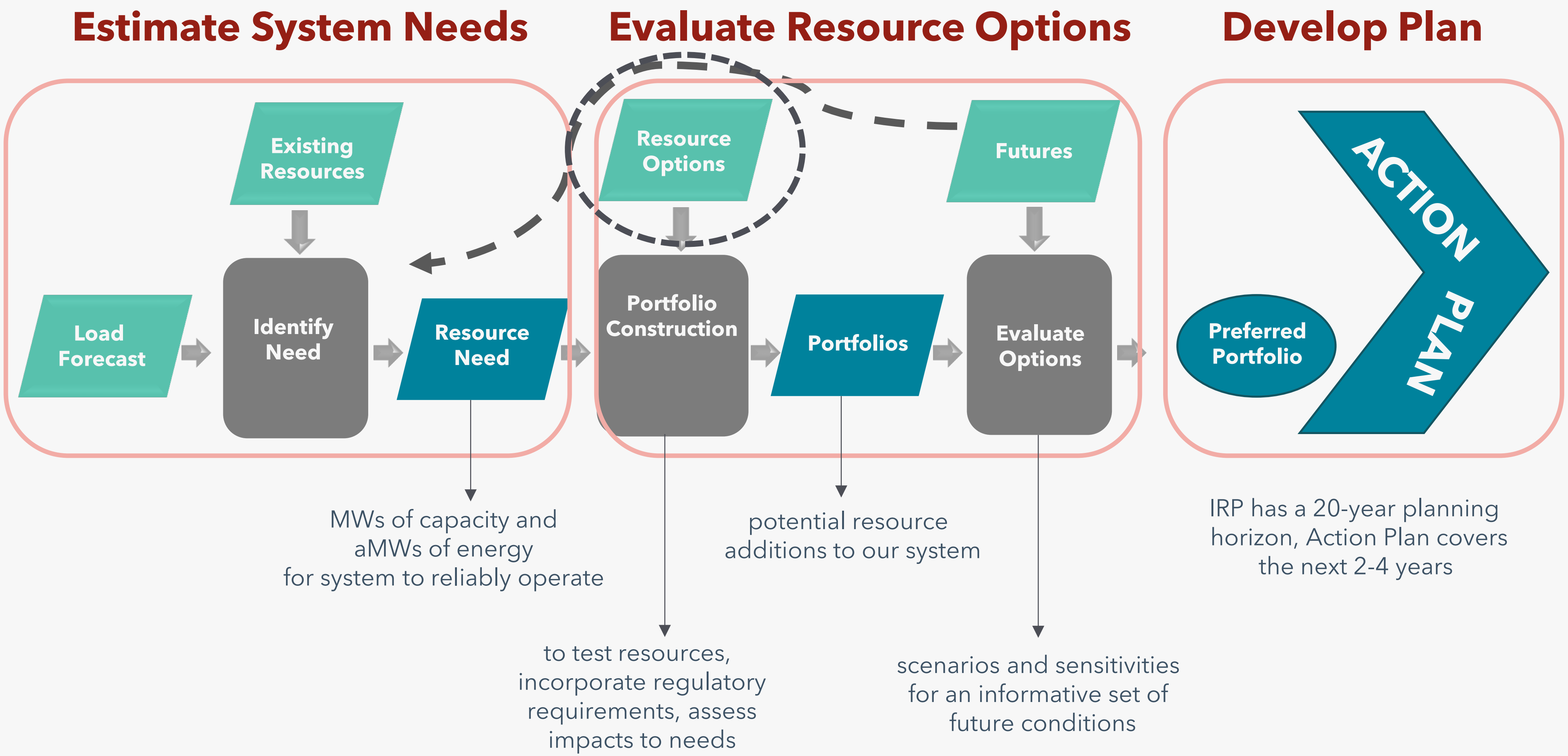
PGE An Oregon kind of energy.[SM]



Outline

- Overview of Transmission Options
- Updates from 2023 IRP Update
- Summary of results

High-Level IRP Analysis Process



Reminder : 2023 IRP Update

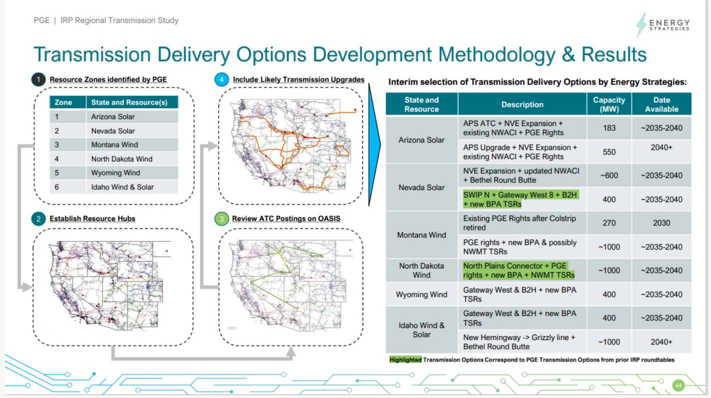
January 2025 Roundtable

Energy Strategies presented 'Transmission Options'

Compliance with 2023 IRP/CEP Order 24-096 required PGE to perform a risk informed, cost-benefit transmission study.

PGE worked with Energy Strategies to develop risk informed transmission options evaluated in PGE's portfolio analysis

Slide 44 - January 2025 Roundtable



PGE | IRP Regional Transmission Study

ENERGY STRATEGIES

Transmission Delivery Options Development Methodology & Results

1 Resource Zones identified by PGE

Zone	State and Resource(s)
1	Arizona Solar
2	Nevada Solar
3	Montana Wind
4	North Dakota Wind
5	Wyoming Wind
6	Idaho Wind & Solar

2 Establish Resource Hubs

3 Review ATC Postings on OASIS

4 Include Likely Transmission Upgrades

Interim selection of Transmission Delivery Options by Energy Strategies:

State and Resource	Description	Capacity (MW)	Date Available
Arizona Solar	APS ATC + NVE Expansion + existing NWACI + PGE Rights	183	~2035-2040
	APS Upgrade + NVE Expansion + existing NWACI + PGE Rights	550	2040+
Nevada Solar	NVE Expansion + updated NWACI + Bethel Round Butte	~600	~2035-2040
	SWIP N + Gateway West 8 + B2H + new BPA TSRs	400	~2035-2040
Montana Wind	Existing PGE Rights after Colstrip retired	270	2030
	PGE rights + new BPA & possibly NWMT TSRs	~1000	~2035-2040
North Dakota Wind	North Plains Connector + PGE rights + new BPA + NWMT TSRs	~1000	~2035-2040
Wyoming Wind	Gateway West & B2H + new BPA TSRs	400	~2035-2040
Idaho Wind & Solar	Gateway West & B2H + new BPA TSRs	400	~2035-2040
	New Hemingway -> Grizzly line + Bethel Round Butte	~1000	2040+

Highlighted Transmission Options Correspond to PGE Transmission Options from prior IRP roundtables

44

Figure 43 – 2023 IRP Update

Ongoing Regional Transmission Planning and Service Initiatives

GERP

BPA's Grid Expansion and Reinforcement Projects

Formally known as 'Evolving Gird', BPA has communicated its intention to construct two phases (1.0 and 2.0) of intraregional transmission with implications for PGE.

WestTEC

Western Transmission Expansion Coalition

A West-wide study to be published February, suggesting necessary regional transmission expansion for inter-regional reliability and congestion. Coordinated by WPP with Energy Strategies technical consulting.

GAT

Grid Access Transformation

BPA's proposed reform of its transmission service request process. To be evaluated through BPA tariff change in 2027 with additional 'future state' reforms.

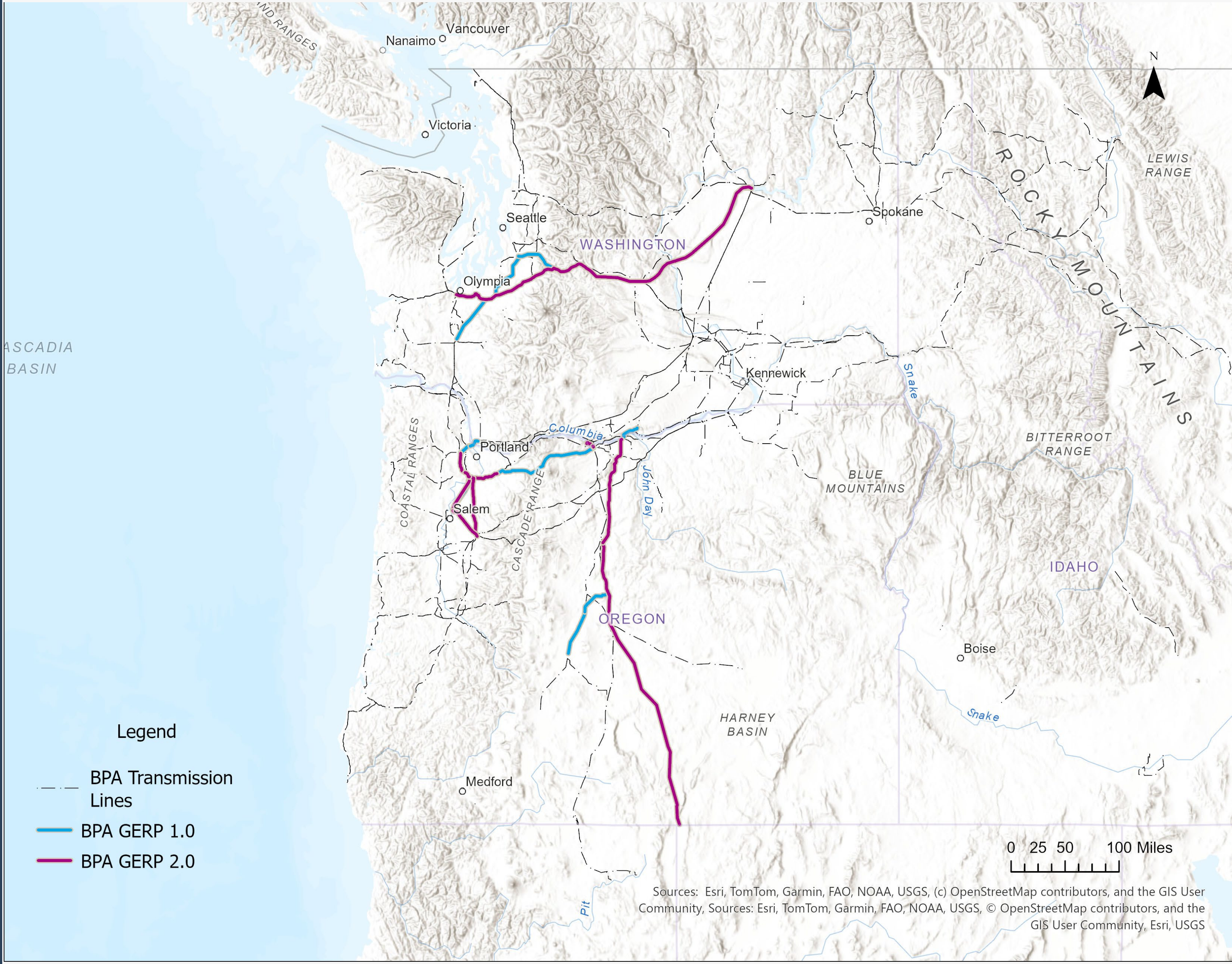
All proposed transmission activities include uncertainty in development timelines and project viability. The 2026 IRP will rely on the most recently available information at the input finalization.

GERP – Link
WestTEC – Link
GAT - Link

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:

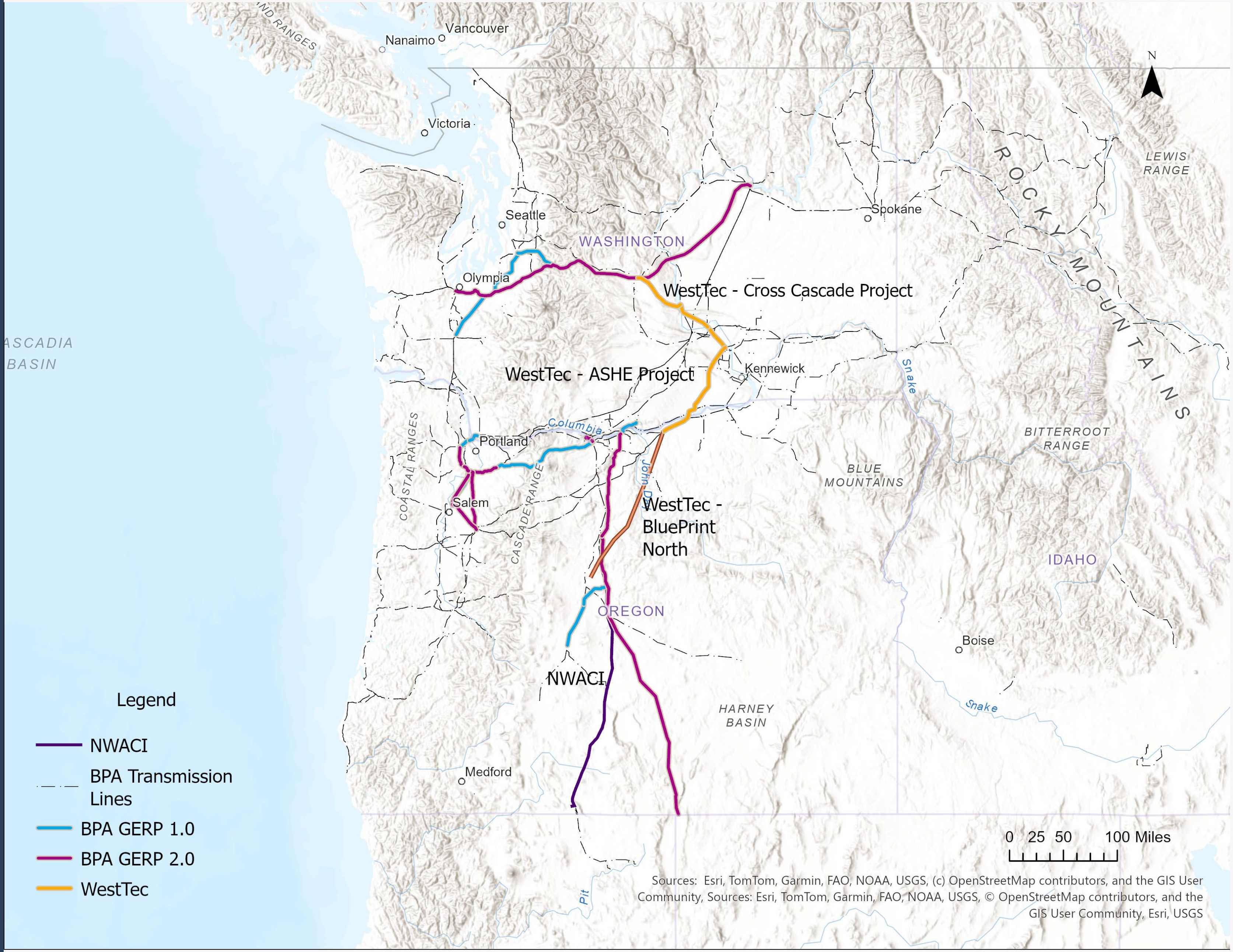
- Service of PGE retail load
- Plan of service for 2506 MW of existing service requests delivering to PGE
- Provide necessary connectivity for intraregional and Circle 3 transmission projects studied by PGE



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

Updates to 2026 Cost Assumptions

BPA Transmission Rates updated to the BP-26 Final GRSP

Modeled cost year updated to 2026 for transmission O&M and capital cost forecasts

Line cost per mile still referencing the NREL 2024 study, but adjusted for inflation

Transmission Options Data Sources

Information used to estimate cost, COD, and ATC are from publicly available sources.

General information about paths, length of line, MW available all come from public reports from the respective utilities or government websites.

Costs per mile are estimated using NREL data from their 2024 report, adjusted to 2026 dollars.

-The base cost per mile is multiplied by a DOE terrain multiplier, which adjusts the cost to reflect the type of land the line will traverse.

Table D-3. Land Cover and Terrain Classification Categories With Multiplier

Terrain Type	Terrain Type Identifier	Multiplier
Forested	1	2.25
Scrubbed/Flat	2	1
Wetland	3	1.2
Farmland	4	1
Desert/Barren Land	5	1.05
Urban	6	1.59
Rolling Hills (2%–8% slope)	7	1.4
Mountain (>8% slope)	8	1.75

Table D-4. Cost per Mile by Voltage Class

Voltage Class	Cost per Mile
230-kV Single Circuit	$1,024,335
230-kV Double Circuit	$1,639,820
345-kV Single Circuit	$1,434,290
345-kV Double Circuit	$2,295,085
500-kV Single Circuit	$2,048,670
500-kV Double Circuit	$3,278,535

Resulting Costs for 2026 IRP

Project	Capacity (MW)	MW Available to PGE	Expected COD	Length (mi)	Real Levelized Cost $/kW-mo ($2026)	
					2023 IRP Update	2026 IRP
Warm Springs Power Pathway	3,000	3,000	2032	98	$5.76	$5.89
Cascade Renewable	1,100	1,100	2038	100	$12.66	$13.26
Gateway	5,000	400	2035	971	$8.52	$8.81
North Plains Connector	3,000	600	2032	412	$10.26	$10.80
Colstrip Transmission Upgrade	1,500	600	2038	500	NA	$14.58
SWIPN	4,073	400	2035	674	$9.97	$10.44
Trojan-Harborton	800	800	2035	34	$5.85	$5.94
Greenlink	800	221	2035	300	$10.19	$10.85
Blueprint South	725	600	2035	310	NA	$11.43

** Note these costs are draft and expected to be changed and updated in January before input to ROSE-E

Next Steps

PGE will continue to monitor these identified transmission options as the 2026 IRP is modeled for any updates to cost, timeline, or capacity. As well as continuing to look for additional transmission options.

These transmission expansion options will be inputs into ROSE-E's portfolio expansion modeling to identify the areas of highest value to PGE.

Guided Feedback – Transmission Options

Process: What additional transmission methodology topics should we cover in the 2026 roundtables? Are there changes from the 2023 IRP Update you'd recommend?

Content: Are there other transmission expansion options PGE should consider?

Questions/Comments

Role of VPP in the IRP

Seemita Pal

Senior Principal Strategy & Planning Analyst, Integrated Resource Planning

Kyle Billeci

Principal Strategy & Planning Analyst, Integrated Resource Planning





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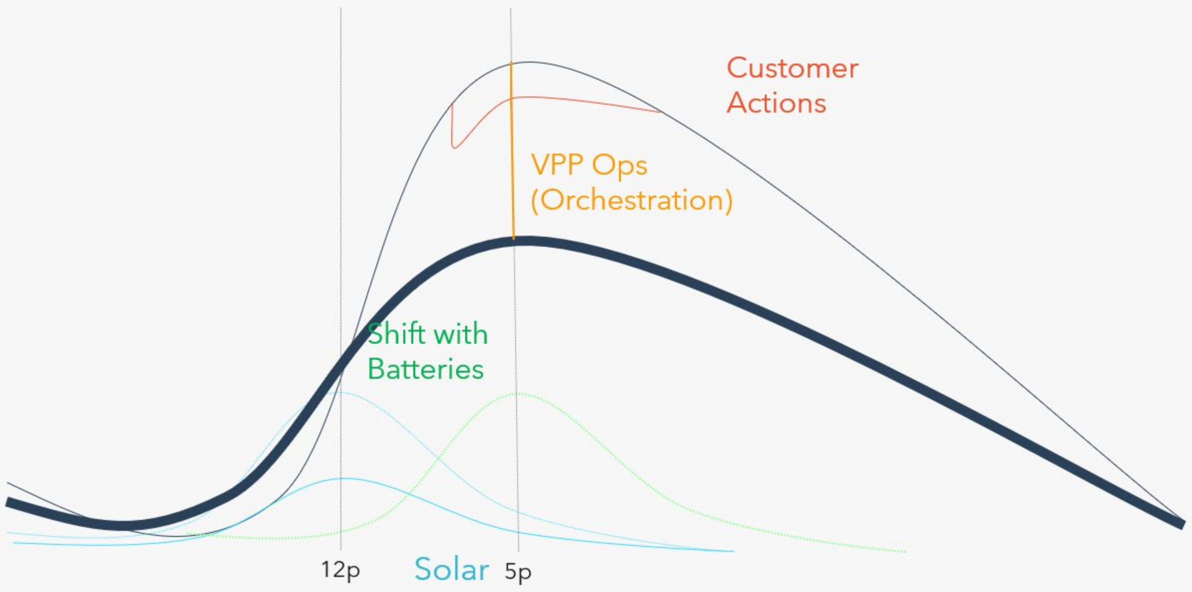
Outline

Role of VPP in relation to the IRP

What is currently done to model those resources

Proposed modifications in IRP modeling

Virtual Power Plant (VPP)



VPP is the orchestration of Distributed Energy Resources (DERs), and distribution system connected energy storage through technology platforms, to provide grid services

Future goal is to eventually optimize their dispatch (based on resource type) to maximize benefits to customers and system

VPP: Illustrative Example of Resource Mix

VIRTUAL POWER PLANT

DEFINITION: The orchestration of Distributed Energy Resources and Flexible Load, through technology platforms, to provide grid and power operations services.

OUTCOME: 25% peak usage offset while supporting 100% of customer energy needs by targeting over 2,000 VPP-enabled megawatts by 2030.

Resource	Flexible Load	Distributed Solar + Storage	Distributed Thermal[2]	Utility Storage
2024	105 MW	0 MW[1] + 27 MW	114 MW	275 MW
2030	250 MW	350 MW + 150 MW	300 MW	600 MW+
Examples	Example: • Customer Programs in Multi-Year and TE Plans	Example: • Community Based Renewable Energy	Example: • Customer Dispatchable Standby Generation	Example • Sundial Battery Storage
Technology	**Technology Platforms** Examples: • Advanced Distributed Management System, Distributed Energy Resource Management System			Example • Energy Management Sys.

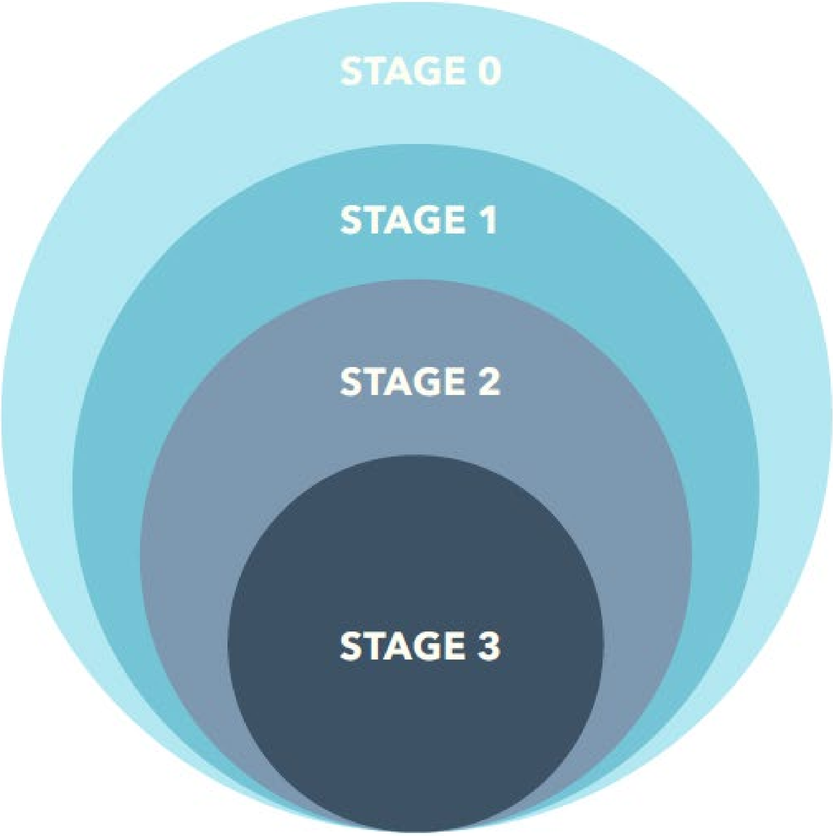
Utility Storage is complementary to VPP

(1) Distributed Solar interconnected capacity from the Net Energy Metering Program is approximately 286 MW in Sep 2024; excluded from VPP because it is not integrated with PGE's VPP technology platforms.

(2) Distributed Thermal represents the customer back-up engines in the Dispatchable Standby Generation (DSG) program.

2024 DSP. Figure 19. Available at https://edocs.puc.state.or.us/efdocs/HAA/haa333816025.pdf#page=67

Capability Stages of VPP Resources



STAGE 0

Physically connected within PGE service territory and has potential to provide a Grid Service.

STAGE 1

Capable of delivering a Grid Service for any 60-minute window in a 24-hour period.

STAGE 2

Dispatched via telemetry integrated with PGE to deliver a Grid Service for a specified duration within the required response time to improve reliability.

STAGE 3

Dispatched to lower cost based on a market signal when a Grid Service is most valuable.

Goal for VPP Modeling within IRP

Model VPP resources within IRP analysis to directionally inform VPP targets based on the Preferred Portfolio and include short-term Action Plan in conclusion

1. Catalog VPP resources
2. Determine resource characteristics
3. Model resources and scenarios for evaluation
4. Inform resource capacity targets over years

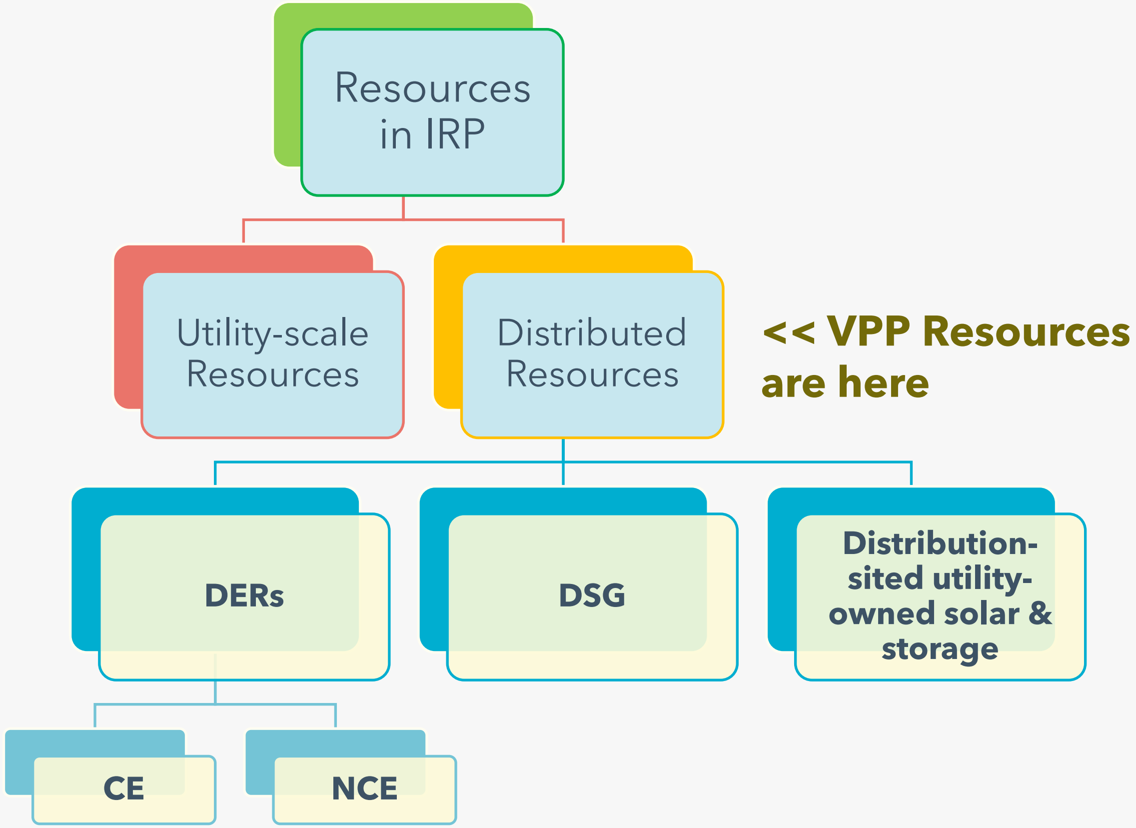
Historical Treatment of VPP Resources in IRP

Optimal capacity expansion model (ROSE-E) identifies resource additions over time and across potential futures that minimizes the expected value. Historical treatment of some of the resources on ROSE-E are as follows:

CE Flex Load	Modeled as load modifiers using AdopDER forecasts embedded in capacity and energy needs
Distributed solar	Modeled as load modifier using AdopDER and Program forecasts
NCE DER bundles	Modeled as selectable resource options. ROSE-E chooses them when they reduce cost or meet reliability/policy requirements
Resources are evaluated independently	Without considering VPP platform-enabled dispatch.

IRP Resource Selection Hierarchy

	Utility-scale Resources	Distributed Resources
Capacity	Incremental additions are outputs of ROSE-E	Constrained by forecasted capacities which are inputs
Costs	Fixed costs from LUCAS; variable costs from Aurora	Fixed costs from AdopDER; variable costs from Aurora
Characteristics	Proxy resource characteristics from various data sources	Resource shapes from AdopDER



DSG: Dispatchable standby generation
CE: Cost-Effective DER Capacities
NCE: Non-Cost-Effective DER Capacities

Current Forecast Sources

Distributed Resources

From AdopDER

- Distributed Solar & Storage
- *CBRE
- DERs
  - CE DR/Flex Load
  - NCE DR/Flex Load

***CBRE:** Community-Based Renewable Energy includes solar, solar + storage, and low-impact hydro from 2023 IRP study. *To be updated in 2026 IRP.*

Outside AdopDER

- DSG
- Distribution-sited utility-owned solar and/or storage

Includes PGE Programs:
- *Energy Partner Sch 26*
- *Energy Partner Thermostats*
- *MFWH*
- *Res Smart Thermostat*
- *Peak Time Rebate*
- *Time of Use/Day*
- *Res EV Smart Charging*

CE DR/Flex Load (including PGE programs) are bundled by resource type and included as load modifiers for resource adequacy modeling (SEQUOIA):
- Curtailment
- Direct Load Control (Thermostats)
- Direct Load Control (Water Heaters)
- Peak-Time Rebates
- Time-of-Use

All NCE DR/Flex Load is selectable for capacity expansion modeling (ROSE-E)

Current Treatment and Opportunities in Modeling

There is opportunity to modify modeling of some of the VPP resources in ROSE-E instead of assuming them to be embedded in the capacity

This would allow the resources to be selectable options based on capacity need

Resources	Current Treatment in 2023 IRP Update	Opportunities
Utility Storage	Modeled as discrete resource type	-
Distributed solar	Modeled as part of net load	-
Flex load	CE DERs are load modifiers; NCE DERs selected by model	Model CE Flex Load as discrete resource types
Distributed Storage	CE portion are load modifiers; NCE portion modeled as discrete resource type	Model CE distributed storage as discrete resource types
Distributed Thermal	Not incorporated	Model as discrete resource type

Proposed Updates to CE Flex Load, CE Distributed Storage and DSG

Create multiple scenarios in Sequoia

- With all CE DERs and DSG embedded in capacity as currently done

- With portion of CE DERs and DSG backed out to compute updated ELCC and capacity needs

Flexibility study

Obtain proxy flexibility values for the VPP resources

ROSE-E

- Utilize fixed costs from AdopDER (for DERs), updated ELCC from Sequoia, and proxy flexibility values from the Flexibility study as inputs
- Evaluate CE and NCE categories of specific resources. Measures within CE and NCE will be binned appropriately for efficiency

Summary / Discussions

IRP is a forecasting modeling exercise based on best available assumptions. Goal is to inform the VPP resource targets based on updated modeling of VPP resources

As a first step the VPP resources will be modeled as discrete selectable resources but capacity-only

Proposed updates will require modifications to multiple steps within the IRP pipeline

It is important to remember that the proposed updates are new and have not been attempted before. It would take some time and iteration to execute, analyze and calibrate the changes

Guided Feedback – Role of the VPP in the IRP

Process: Does the proposed methodology address OPUC Staff's direction in the 2024 DSP Acceptance decision?

Content: Past IRPs have not modeled DSG. What should PGE consider when modeling DSG for the 2026 IRP?

Questions/Comments

Energy Efficiency (EE) Integration into IRP

Kyle Morrill
Energy Trust of Oregon

Lauren Slawsky
Principal Integrated Resource Planning Analyst, Integrated Resource Planning

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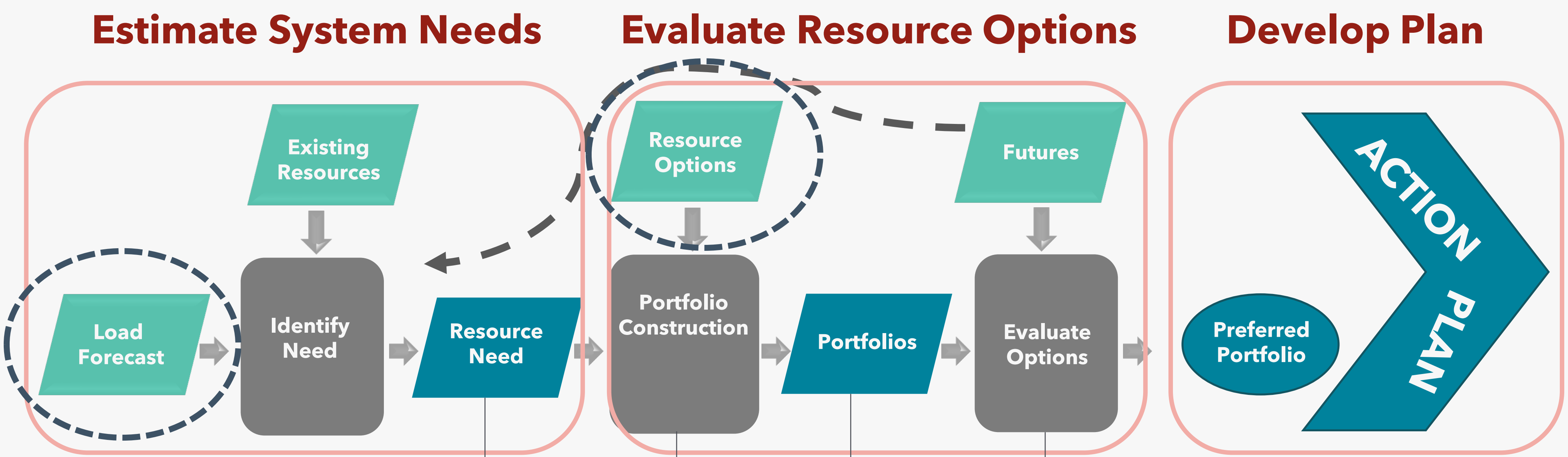
Outline

- Energy Trust EE results for 2026 IRP
- EE in IRP Comparisons
- Non-Cost-Effective EE

High-Level IRP Analysis Process



MWs of capacity and aMWs of energy for system to reliably operate

potential resource additions to our system

IRP has a 20-year planning horizon, Action Plan covers the next 2-4 years

to test resources, incorporate regulatory requirements, assess impacts to needs

scenarios and sensitivities for an informative set of future conditions

Energy Efficiency Resource Assessment

PGE 2026 IRP

December 10, 2025

Energy Trust of Oregon

Agenda

Resource Assessment Model Overview

PGE 2026 Resource Assessment Results and Deployment Forecast

About us

Independent nonprofit

Serving 2.4 million customers of Portland General Electric, Pacific Power, NW Natural, Cascade Natural Gas and Avista

Providing access to affordable energy

Generating homegrown, renewable power

Building a stronger Oregon and SW Washington

Clean and affordable energy since 2002

From Energy Trust's investment of $3.1 billion in utility customer funds:

842,000 sites transformed into energy efficient, healthy, comfortable and productive homes and businesses

34,000 clean energy systems generating renewable power from the sun, wind, water, geothermal heat and biopower

$15.8 billion in savings over time on participant utility bills from their energy-efficiency and solar investments

46.1 million metric tons of carbon dioxide equivalent emissions kept out of our air, equal to removing 12.5 million cars from our road for a year

Energy Trust Resource Assessment Model Overview

RA Model Background

Estimate of 20-year energy efficiency potential

“Bottom-up” modeling approach

- Measure level inputs are scaled to utility level
- Stock and measure basis, savings are at the meter

Measure inputs

- Baseline and efficient equipment
- Measure savings
- Incremental cost
- Market data

Utility inputs

- Load and customer count/building stock forecast
- Customer stock demographics
- Avoided costs

Modeling Updates

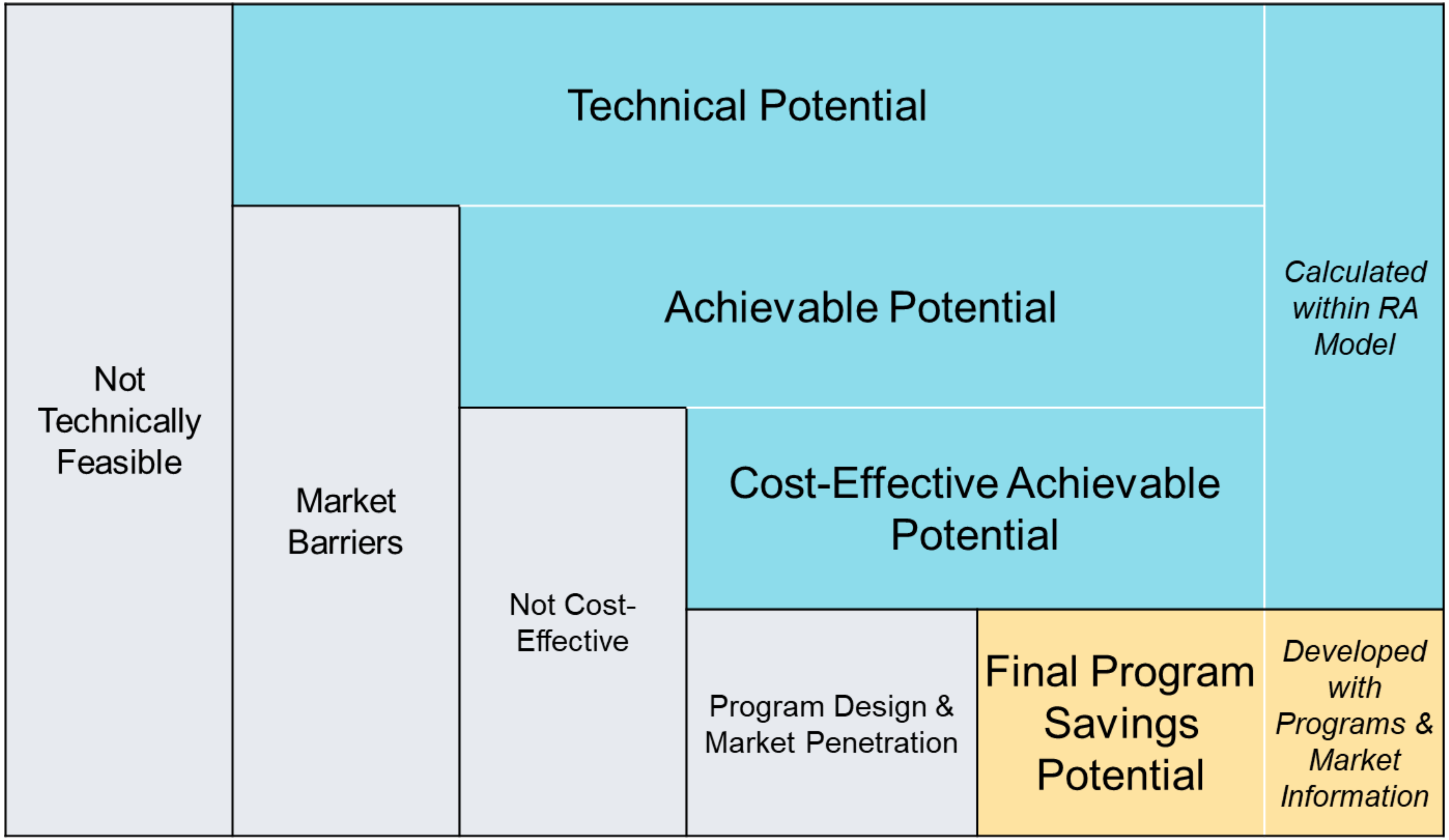
Measure Updates

- Measure savings, incremental cost
- New measures
- Emerging technologies

2022 Residential Building Stock Assessment (NEEA)

- Total measure density, technical suitability and baseline initial saturation
- Heating fuel, water heating fuel splits

Forecasted Potential Types



Cost-Effectiveness Screen

RA model utilizes the Total Resource Cost (TRC) test to screen measures for cost-effectiveness

$$\text{TRC} = \frac{\textit{Measure Benefits}}{\textit{Total Measure Cost}}$$

Measure benefits

- NPV avoided costs per first-year kWh
- Quantifiable non-energy benefits

Measure costs

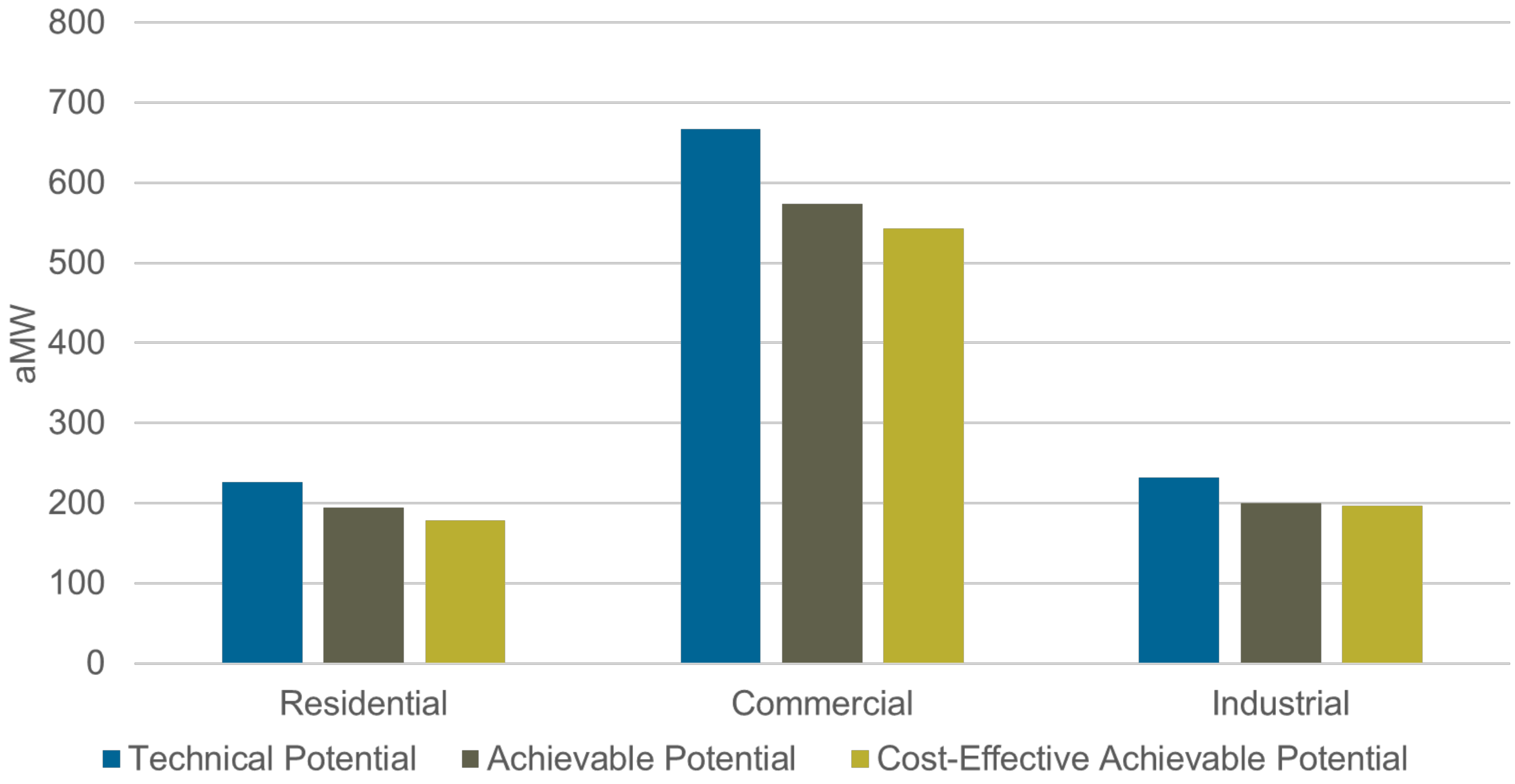
- The customer cost of installing an efficiency measure (full cost for retrofits, incremental over baseline cost for replacement)

Cost-Effectiveness Override

- Measures under an OPUC exception

Resource Assessment Results
PGE 2026 IRP

Cumulative Potential by Sector and Type



Cumulative Potential by End Use

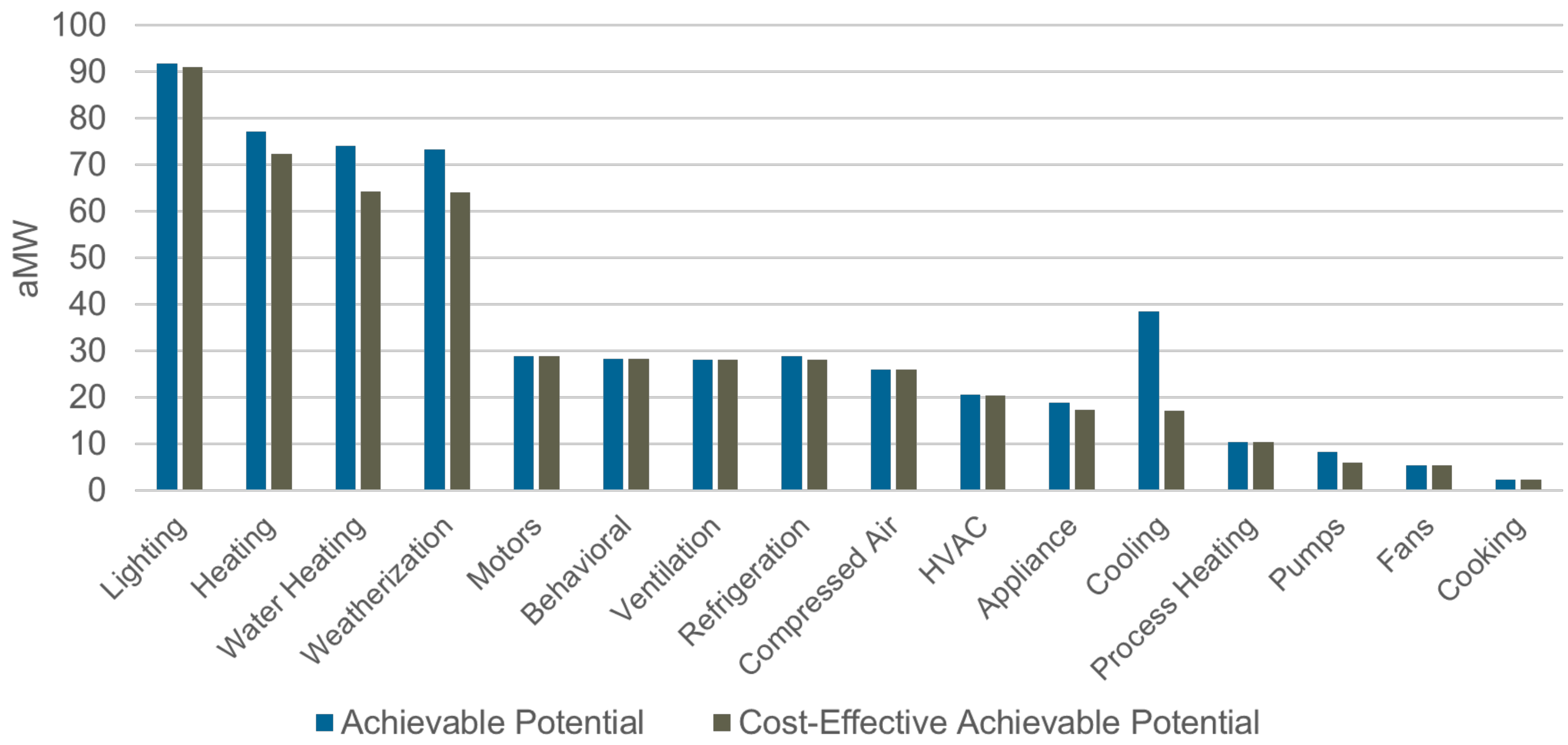


Chart includes major end uses only and does not add up to total potential.

Results and Deployment

20-Year Energy Efficiency Potential (aMW) - PGE

Sector	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Deployed Savings Projection*
Residential	226	195	178	156
Commercial	668	574	543	252
Industrial	232	200	197	196
Total	**1125**	**969**	**918**	**605**

2025 Total	*969*	*839*	*777*	*622*
% change	*16%*	*15%*	*18%*	*-3%*

**Savings projection of modeled potential. Final savings deployment includes additional exogenous savings.*

Exogenous Savings

Some projected savings are estimated outside of the RA model if they do not fit into the modeling framework.

Includes prior codes, home energy reports and residential electrification from PGE's AdopDER model.

Savings are added in the deployment step and represent a best estimate of load reductions from efficiency.

Program	Category	20-Year Deployed Savings Projection (aMW)
New Buildings	Prior Codes	5.3
New Homes	Prior Codes	2.9
Existing Homes	Home Energy Reports	33.6
Existing Homes	Electrification	39.1
Total		**81.0**

PGE Deployment, Cost-Effective and Exogenous Potential

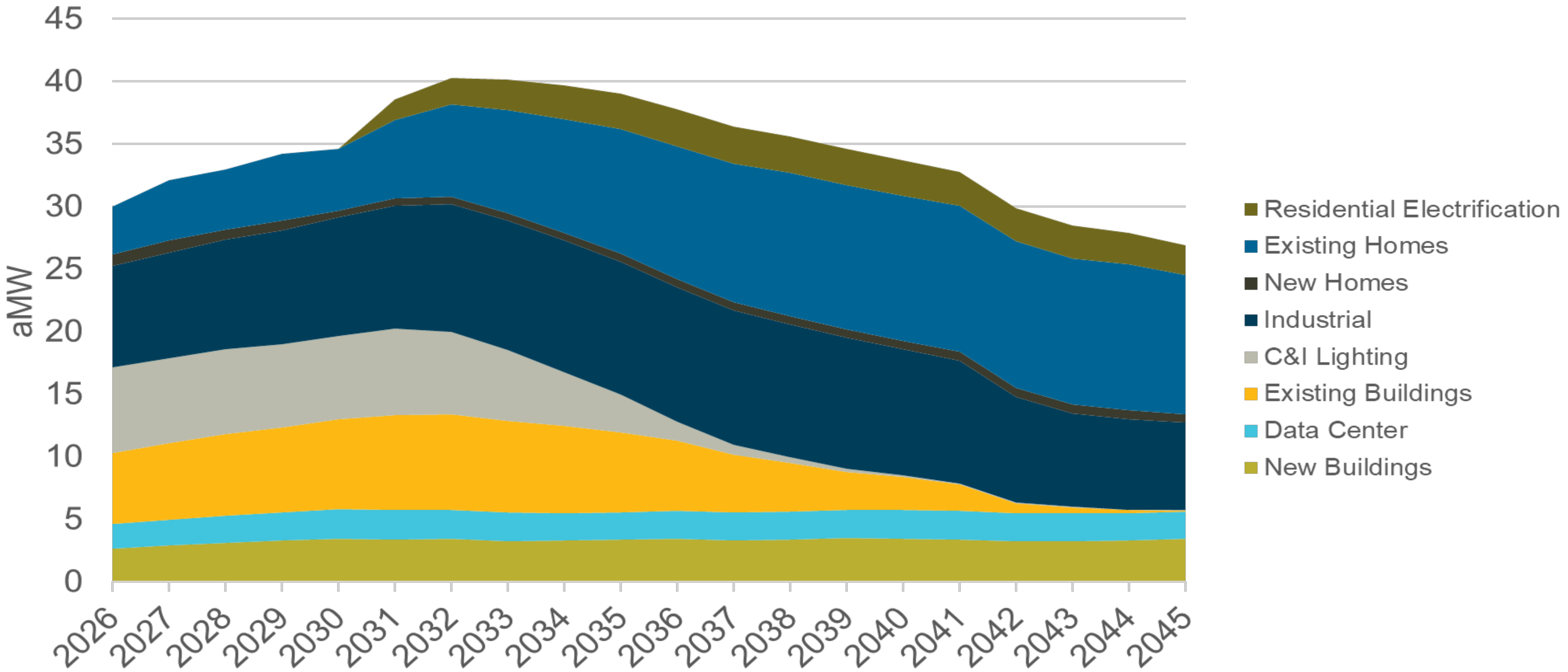
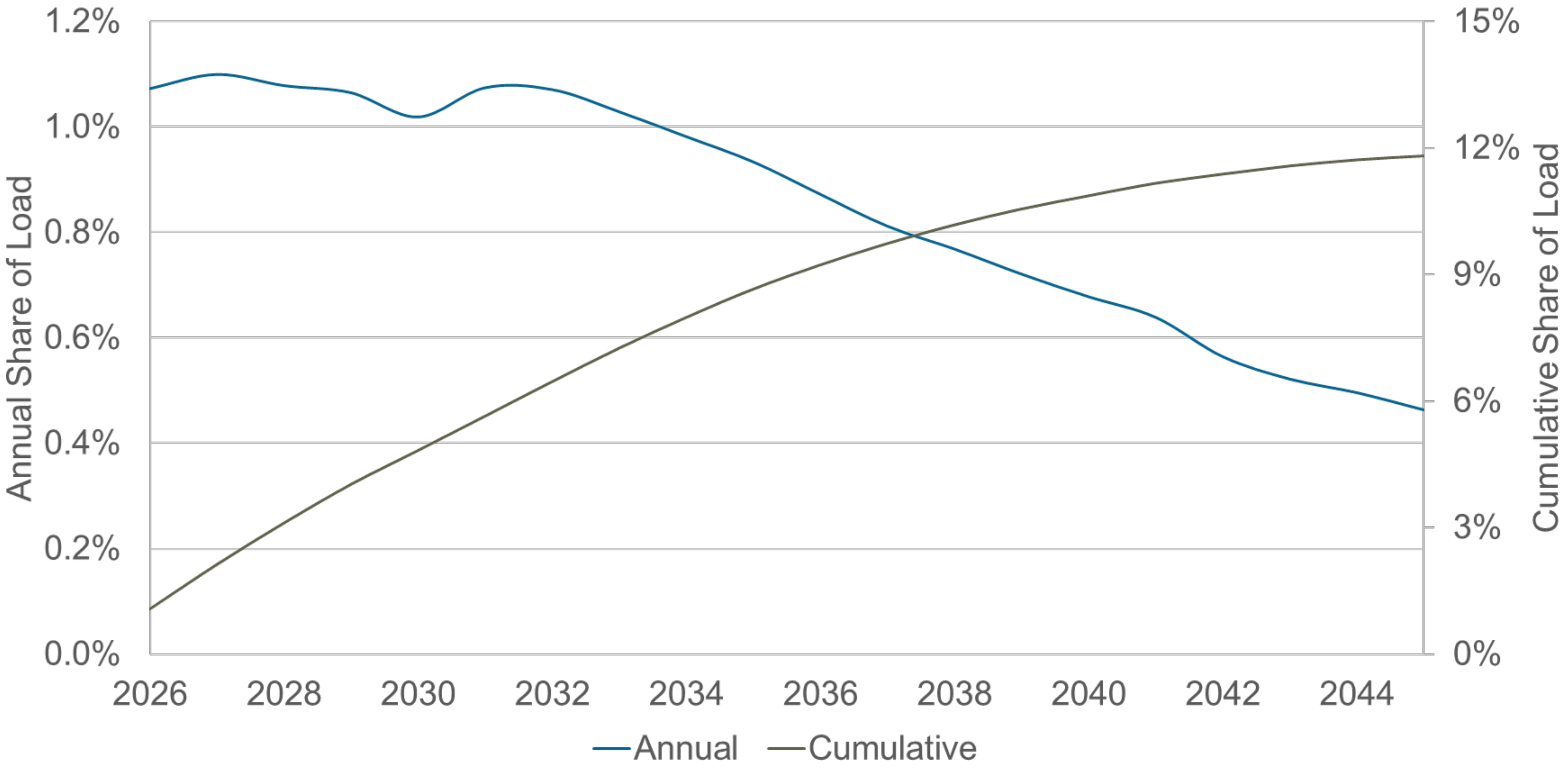


Chart shows total expected efficiency and includes savings from codes and standards. Energy Trust may not claim the entirety of savings depicted above.

Deployed Savings Compared to Load Forecast



Thank you

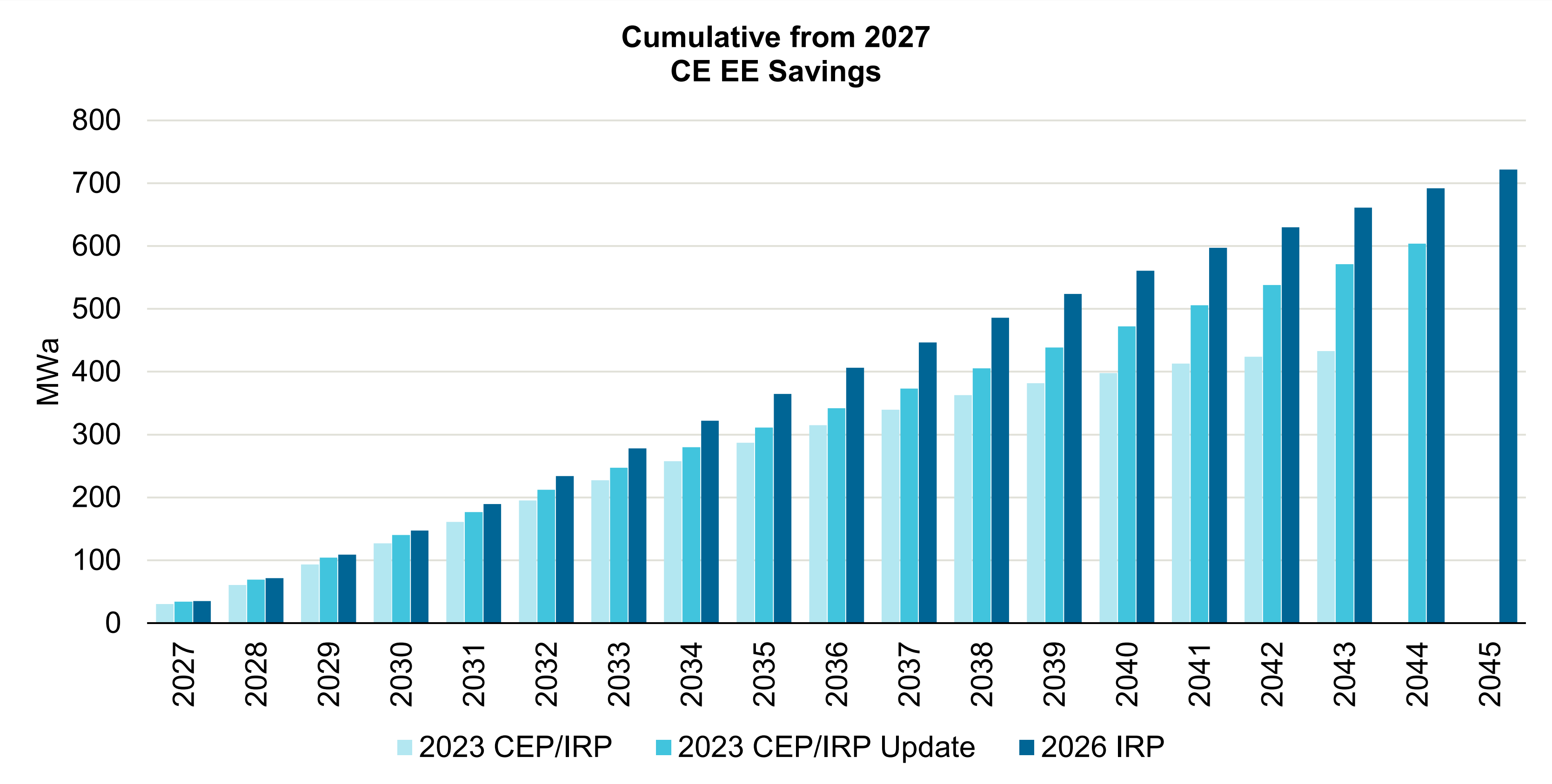
Kyle Morrill, Senior Planning Analyst
kyle.morrill@EnergyTrust.org

Energy Trust of Oregon

Forecast Comparisons
Cost-Effective (CE) Energy Efficiency (EE)

Embedded in IRP load forecast

Cumulative total savings from 2027-2030 are nearly 5% higher in most recent forecast (for 2026 IRP) compared to previous (for 2023 Update)

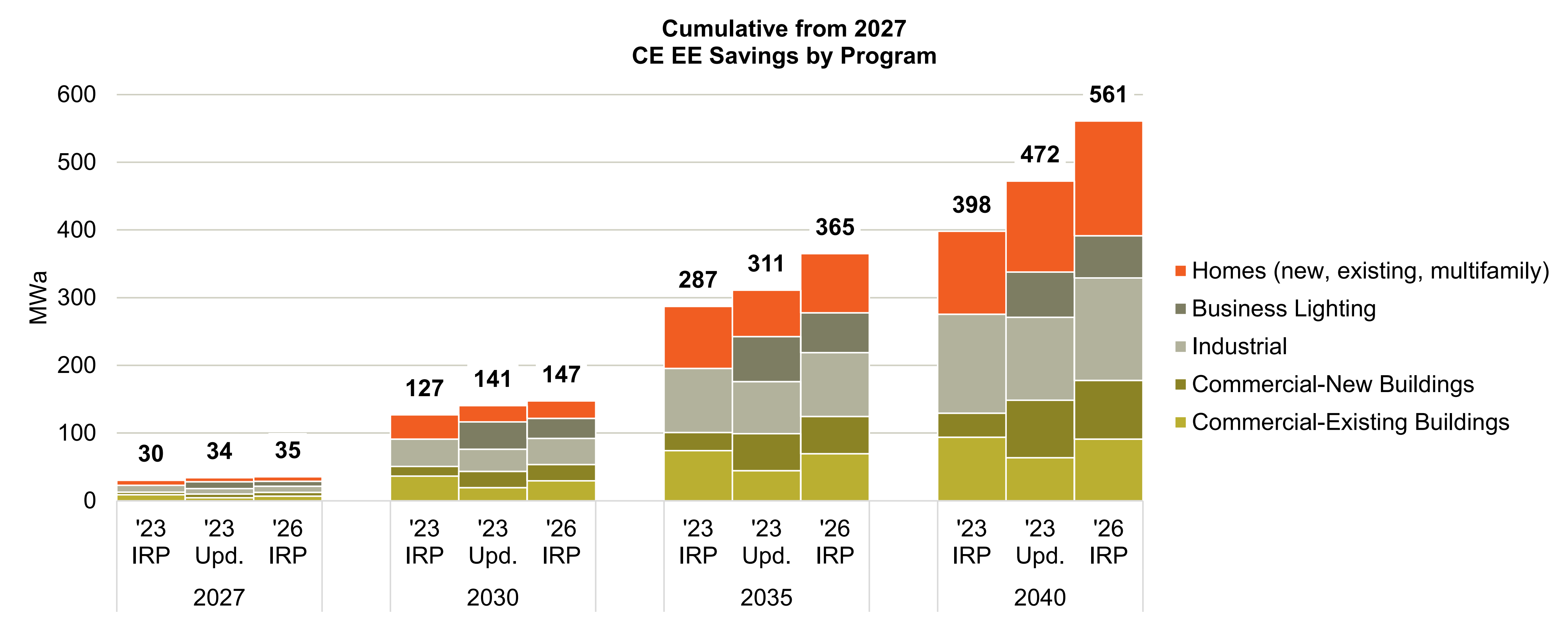


Forecast Comparisons

Cost-Effective (CE) Energy Efficiency (EE)

Embedded in IRP load forecast

Accumulating savings for most programs are greater than last forecast (2023 Update), except for slower growth now forecasted for business lighting

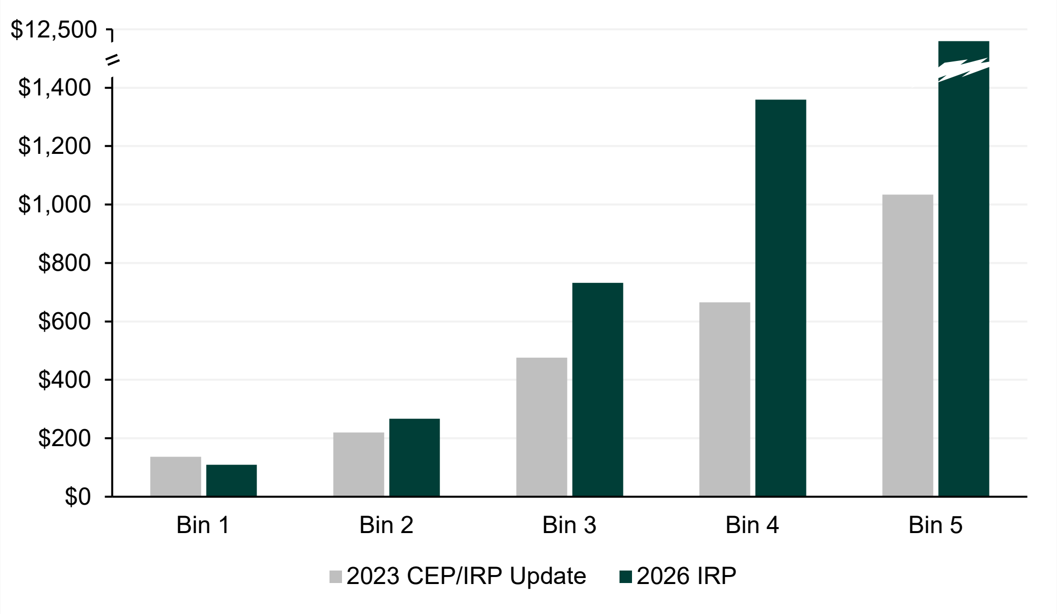


DRAFT for IRP Portfolio Analysis

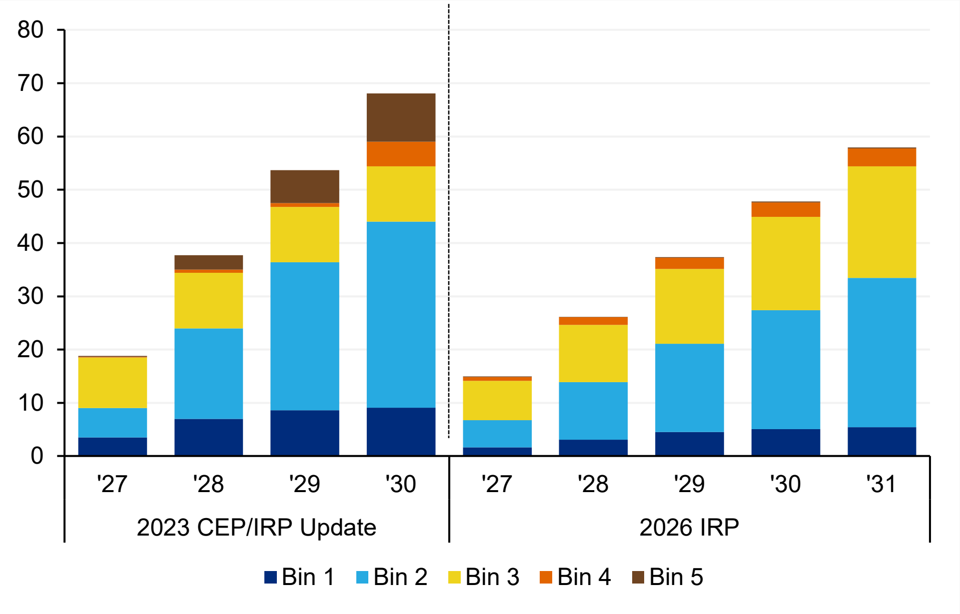
Non-cost-effective (NCE) Energy Efficiency (EE) Potential

- ETO provides PGE data for measures that do not pass the cost-effectiveness screening in the ETO model
- PGE then adopts a similar process to the Northwest Power and Conservation Council to aggregate NCE EE measures into bins based on levelized costs, for simplified representation in IRP analysis
  - Draft here slightly different than in past to focus on binning measures by similar costs rather than by creating roughly similar bin sizes (of potential MWa)
  - ELCCs, capacity factors, energy values for each Bin will be calculated (in Sequoia, Aurora, etc.) to characterize the NCE EE as resource options available for selection in portfolio analysis (ROSE-E)

IRP Comparison of
Average NCE EE Fixed Cost by Bin ($2025/MWh)



IRP Comparison of
Cumulative NCE EE potential by Bin (MWa)



Bin 5 now has <1 MWa

Guided Feedback - Energy Efficiency (EE) Integration into IRP

Process: Are there areas where you'd like ETO to expand or provide more analysis?

Content: Do you have recommendations for improving PGE's NCE EE binning approach for portfolio availability?

Questions/Comments

NEXT STEPS

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

Upcoming Roundtable: January 14th, 2026

Thank you

Contact us at
IRP.CEP@PGN.COM

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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: cooling 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