PGE CEP & IRP Roundtable 25-4

June 4th 2025

June 4th, 2025 – Agenda

9:00 – 9:05	Welcome | Meeting Logistics
9:05 – 9:35	Examining Winter Reliability Constraints
9:35 – 9:45	2023 CEP/IRP Update | Energy Value
9:45 – 10:30	2023 IRP Update | Final Portfolio
10:30 – 11:10	Additional Tax Policy and Reliability Planning Scenarios
11:10 – 11:25	2023 CEP/IRP Update | Report Structure
11:25 – 11:30	Closing Remarks | Next Steps

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

Examining Winter Reliability Constraints

Energy and Capacity Interactions in Storage

Devin Mounts

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Presentation Outline

Definition of Non-Emitting Contracts in Preferred Portfolio

Review of Preferred Portfolio Reliability Results – April Roundtable

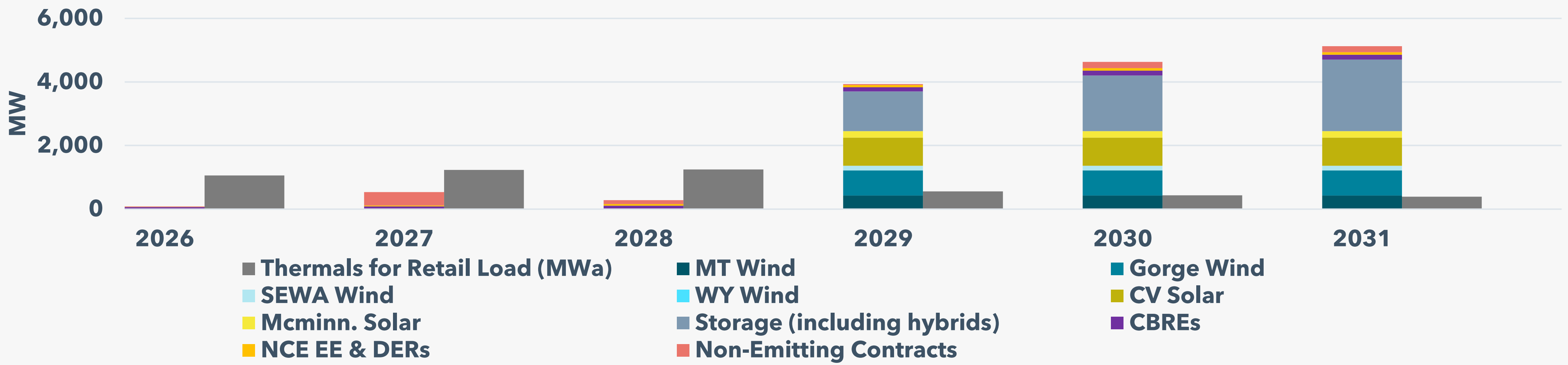
Testing Reliability Effects of Preferred Portfolio Energy and Storage

Can Market Access Improve Winter Storage Inefficiencies?

A Blended Energy and Capacity Marginal Resource

Preferred Portfolio – Non-Emitting Contracts

As discussed in the **April Roundtable**, Non-Emitting Contracts are a component of the Preferred Portfolio in 2026-2031. These contracts represent remaining energy or capacity need after all available resource additions were selected.



	2026	2027	2028	2029	2030	2031	Definition
Capacity Need	16	422	120	0	15	187	Remaining Capacity Need
Energy Need	0	56	52	22	123	114	Remaining Energy Need
Energy Need as Capacity	0	86	80	34	189	175	Remaining Energy Need valued as capacity based on recent hydro agreements
Non-Emitting Contract	**16**	**422**	**120**	**34**	**189**	**187**	Maximum annual value of Capacity Need and Energy Need as Capacity

Review - Preferred Portfolio Resource Adequacy

As discussed in the **April Roundtable**, The resource adequacy (RA) contribution of the Preferred Portfolio, including Non-Emitting Contracts, is tested to ensure it provides sufficient capacity to meet the Company's 24 hours in 10 years adequacy metric.

- The Preferred Portfolio results in an adequate system for years with significant resource additions.
  - Proxy resources are assumed unavailable prior to 2029.
- Winter 2030 presents resource adequacy challenges that appear to drive resource buildout.
  - Loss of load hours (LOLH) estimate in winter 2030 appears to represent a binding constraint.

System Capacity Need with Preferred Portfolio

Year	Summer Need (MW)	Winter Need (MW)
2026	0	0
2027	0	0
2028	0	68
2029	0	0
2030	0	0

System LOLH Estimate with Preferred Portfolio

Year	Summer LOLH	Winter LOLH
2026	2.27	0.03
2027	1.45	0.20
2028	0.41	4.41
2029	0.00	0.00
2030	0.06	2.25

Short-term adequacy challenges may require structured/bi-lateral capacity agreements or regional sharing mechanisms (e.g., WRAP)

Preferred Portfolio RA Binding Constraint - Winter

LOLH metrics in 2030 suggest resource buildout is driven by winter reliability challenges. While the Preferred Portfolio results in an adequate system in both summer and winter 2030, the degree of adequacy is less in winter.

System Capacity Need with Preferred Portfolio

Year	Summer Need (MW)	Winter Need (MW)
2026	0	0
2027	0	0
2028	0	68
2029	0	0
2030	0	0

System LOLH Estimate with Preferred Portfolio

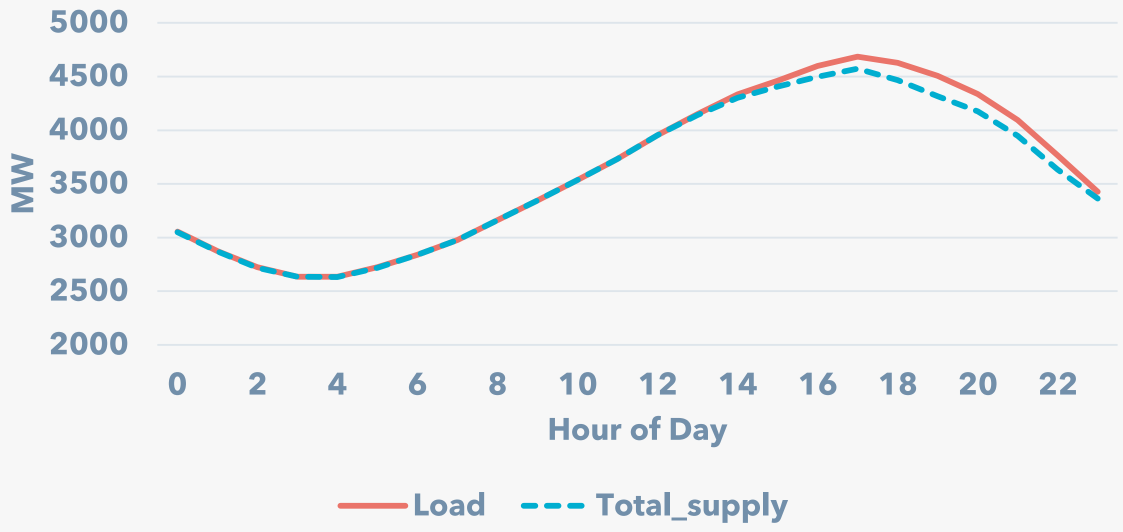
Year	Summer LOLH	Winter LOLH
2026	2.27	0.03
2027	1.45	0.20
2028	0.41	4.41
2029	0.00	0.00
2030	0.06	2.25

A LOLH measure of 2.4 indicates a system that is perfectly adequate at the 24 hours in 10 years measure, suggesting the Preferred Portfolio is adequate on the margin of the standard in Winter 2030.

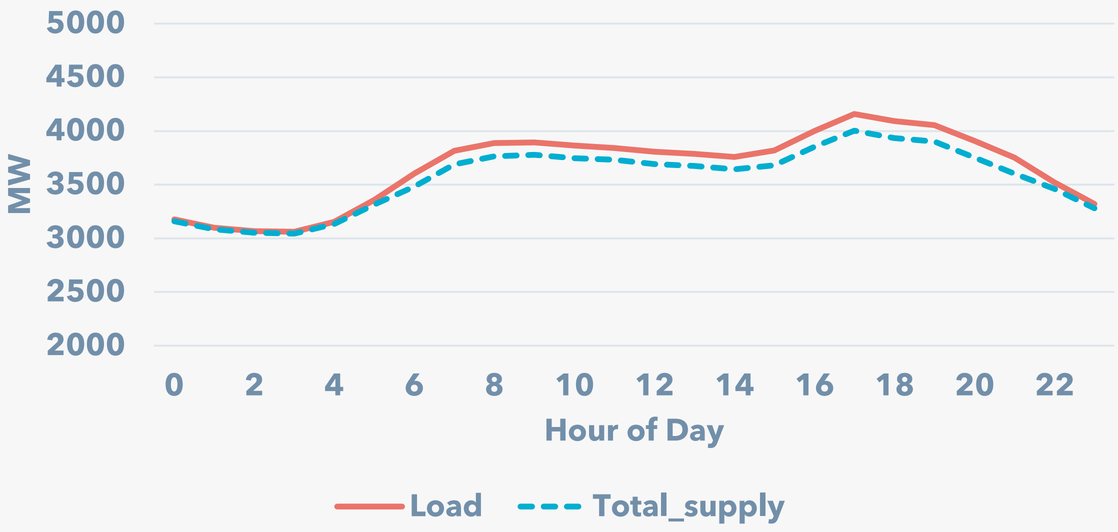
Review - Profile of Reliability Events by Season

Summer reliability events are short and deep. Winter events are long and shallow, reflecting energy scarcity. This difference creates inefficiencies in winter for short-duration storage, PGE's assumed marginal resource.

Illustrative Summer Reliability Event-Day



Illustrative Winter Reliability Event-Day



Illustrative event days are representative of the loss-of-load heat map discussed in the ***January 2025 Roundtable*** *on resource effective load carrying capability (ELCC).*

Testing the Reliability Role of Energy vs. Storage

PGE conducted an energy sensitivity analysis of the Preferred Portfolio to further the understanding of energy and capacity interactions highlighted in winter reliability challenges.

Approach:

1. Split Preferred Portfolio resources into energy and storage
   - 4,679 MW resources (4629 MW of resources plus 50 MW of storage from CBRE Micro hybrid)
   - 2,879 MW of energy resources (Energy Only Portfolio)
   - 1,800 MW of 4-hour battery storage

2. Test system adequacy with Energy Only Portfolio

3. Incrementally add storage resources

Validation of Approach - 2030 LOLH Metrics:

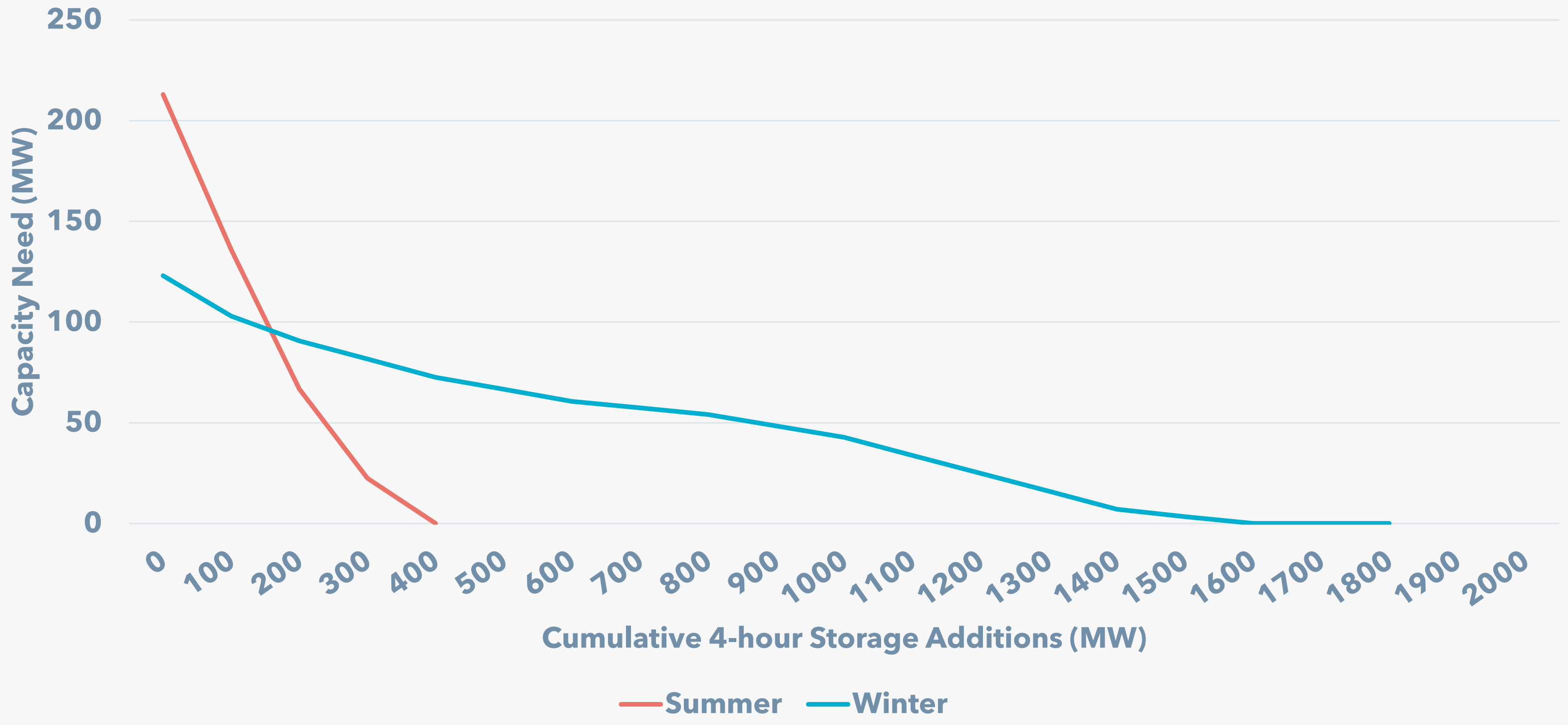
	Summer LOLH	Winter LOLH
Preferred Portfolio	0.06	2.25
Energy Only Portfolio + 1,800 MW 4hr Batteries	0.01	2.21

The difference in adequacy estimates results from portfolio modeling simplifications, including interconnection size and charging behavior between hybrid and standalone storage resources.

Energy Sensitivity Analysis - Findings

The Energy Sensitivity Analysis confirms that winter adequacy events are driving resource additions and suggests short-duration storage resources are an inefficient marginal capacity resource.

Capacity Need of Energy Only Portfolio and 4-hour Storage Additions – 2030 Reference



Summer:

- 400 MW of 4hr batteries required to resolve 213 MW of capacity need
  - 53% ELCC

Winter:

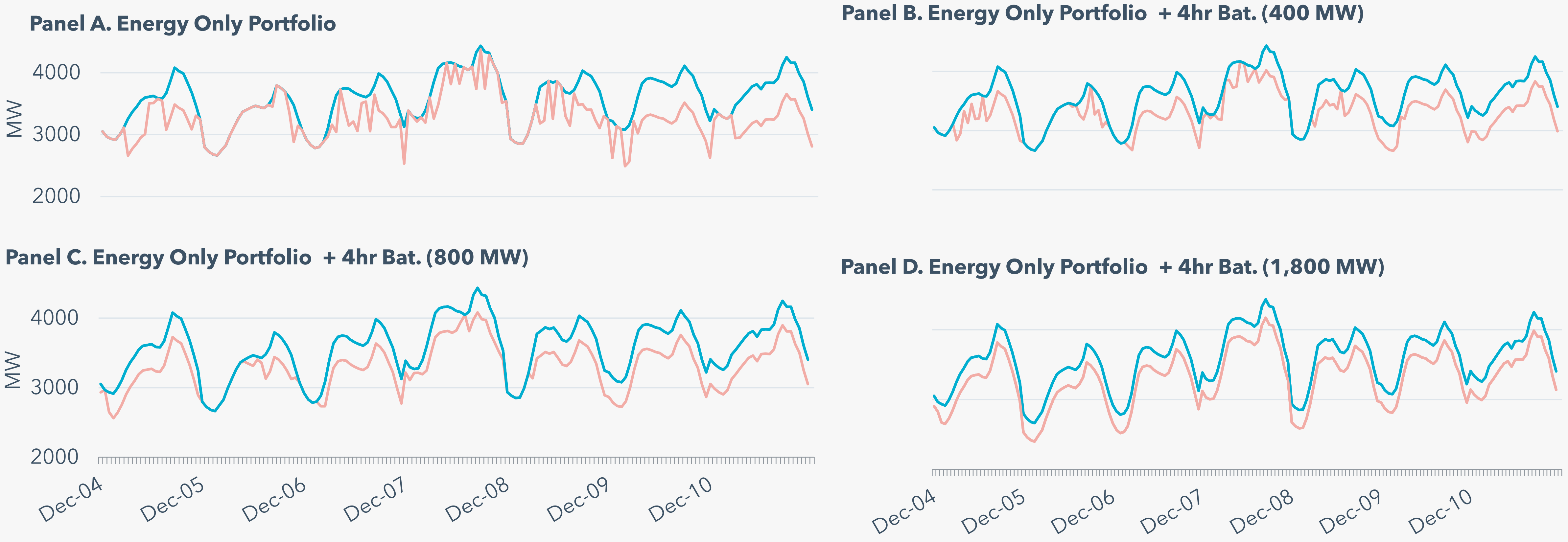
- 1,800 MW of 4hr batteries required to resolve 123 MW of capacity need
  - 6.8% ELCC

Storage additions were made in 100, 200, 400, 600, 800, 1000, 1400, 1800, and 2000 MW tranches then smoothed and interpolated using the same methodology as in the 2033 CEP/IRP and 2023 CEP/IRP Update.

Winter Weekly Adequacy Simulation - Detail

Sample RA simulations from Sequoia show how short duration storage resources attempt to resolve reliability events. Insufficient energy results in the shifting of energy as additional capacity is added.

December Weekly Adequacy Simulation – 2030 Reference Tail Event



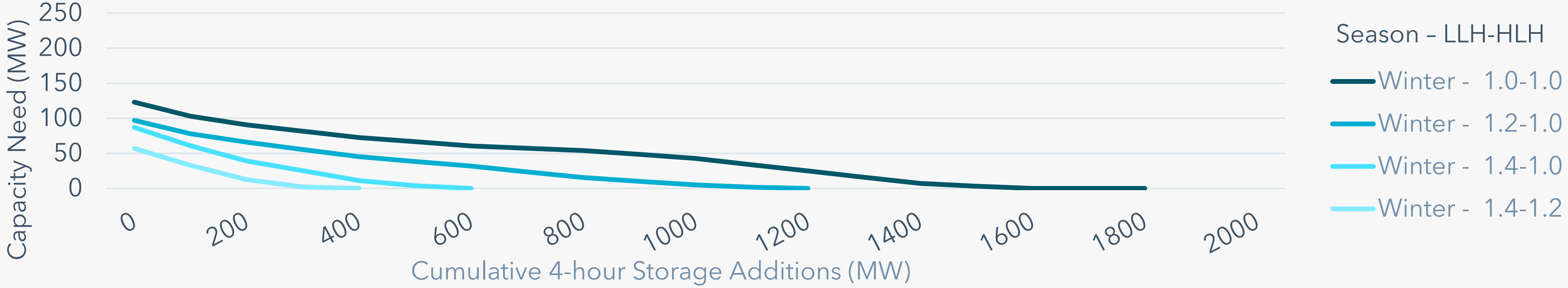
Sequoia's objective is to minimize the sum of the greatest capacity shortfall and the average energy shortfall across the week.

Market Access & Storage's Reliability Contribution

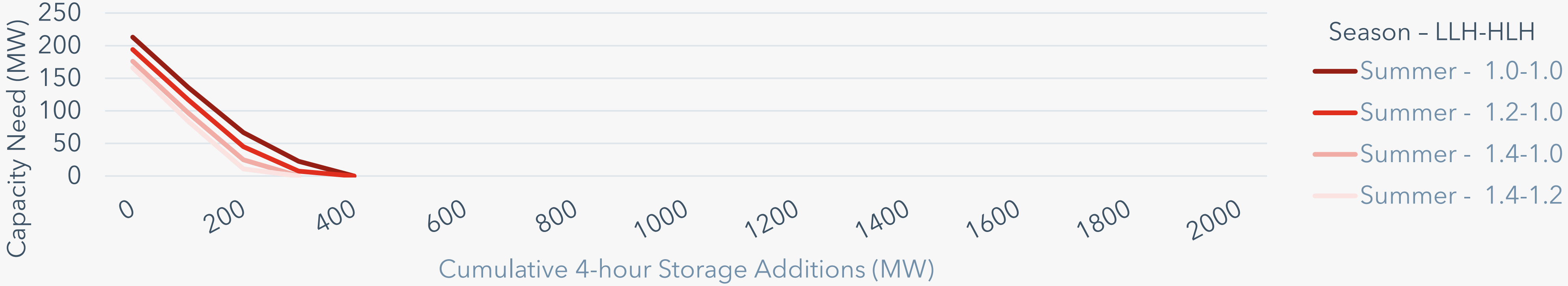
Sequoia's market access assumptions were varied to test the effect of additional energy on short-duration storage resources' ability resolve reliability events. Additional energy does not appear to significantly improve the capacity value of short-duration storage resources in these tail events.

Capacity Need of Energy Only Portfolio with Incremental 4-hour Storage Additions and Variable Market Availability Assumptions

Panel A. Winter



Panel B. Summer



Market access assumptions were scaled in Low-Load Hours (LLH) and Heavy-Load Hours (HLH).*

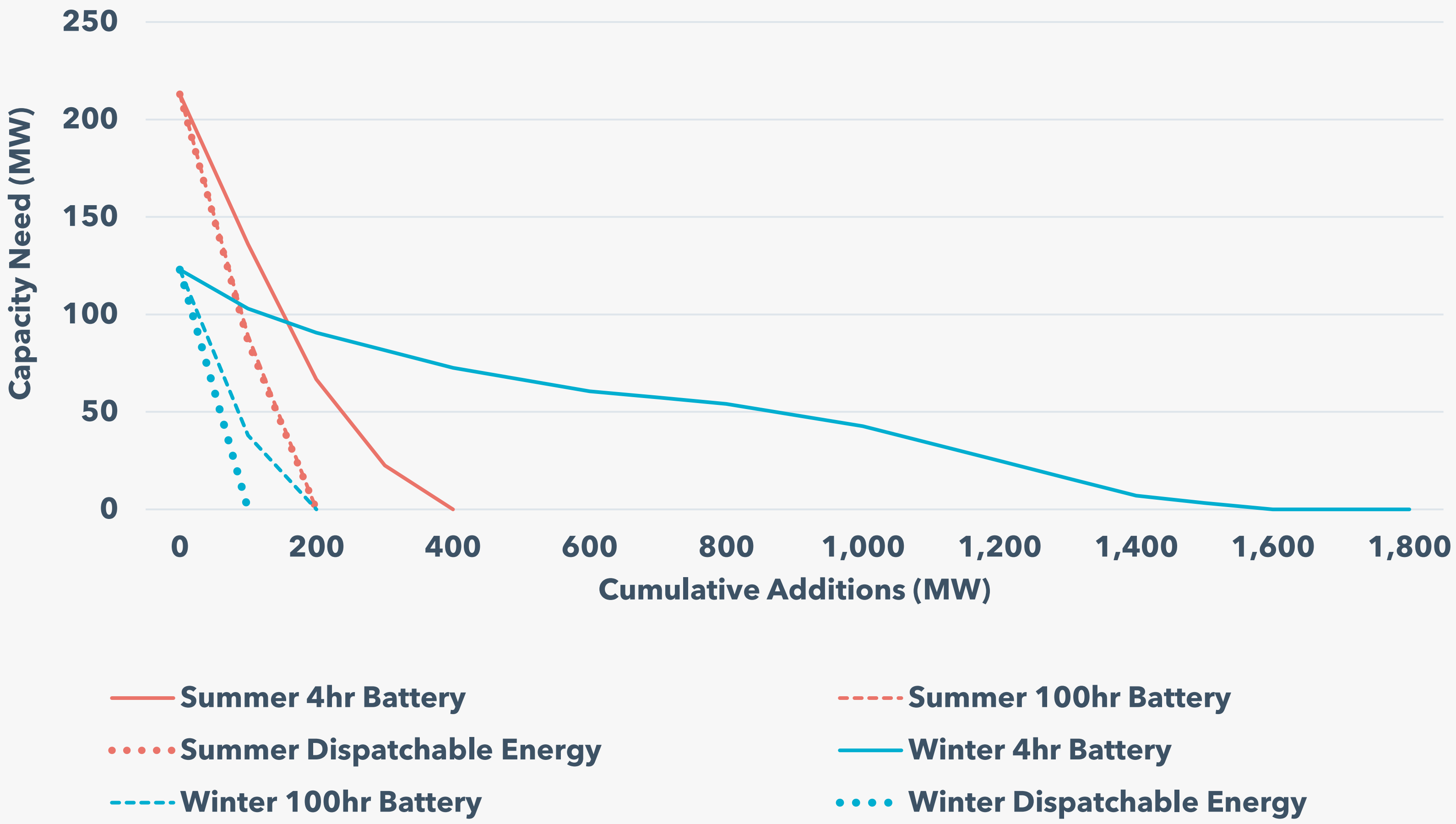
Additional energy does reduce the capacity need and amount of storage needed to achieve adequacy. However, the ELCCs of incremental storage additions remain relatively constant.

*HLH: weekday hours ending 07:00-22:00. Market access values vary by month, hour and are negatively correlated with load. Maximum imports assumed to be 1 GW in LLH and 150 MW in HLH for December and 1 GW in LLH and 0 MW in HLH for August.

Preliminary Test of Emergent Technologies

Initial tests to estimate the effect of 100-hour storage and dispatchable energy resources highlight that emergent technologies present opportunities for more efficient marginal resource additions.

Capacity Need of Energy Only Portfolio and Emergent Technology Additions – 2030 Reference

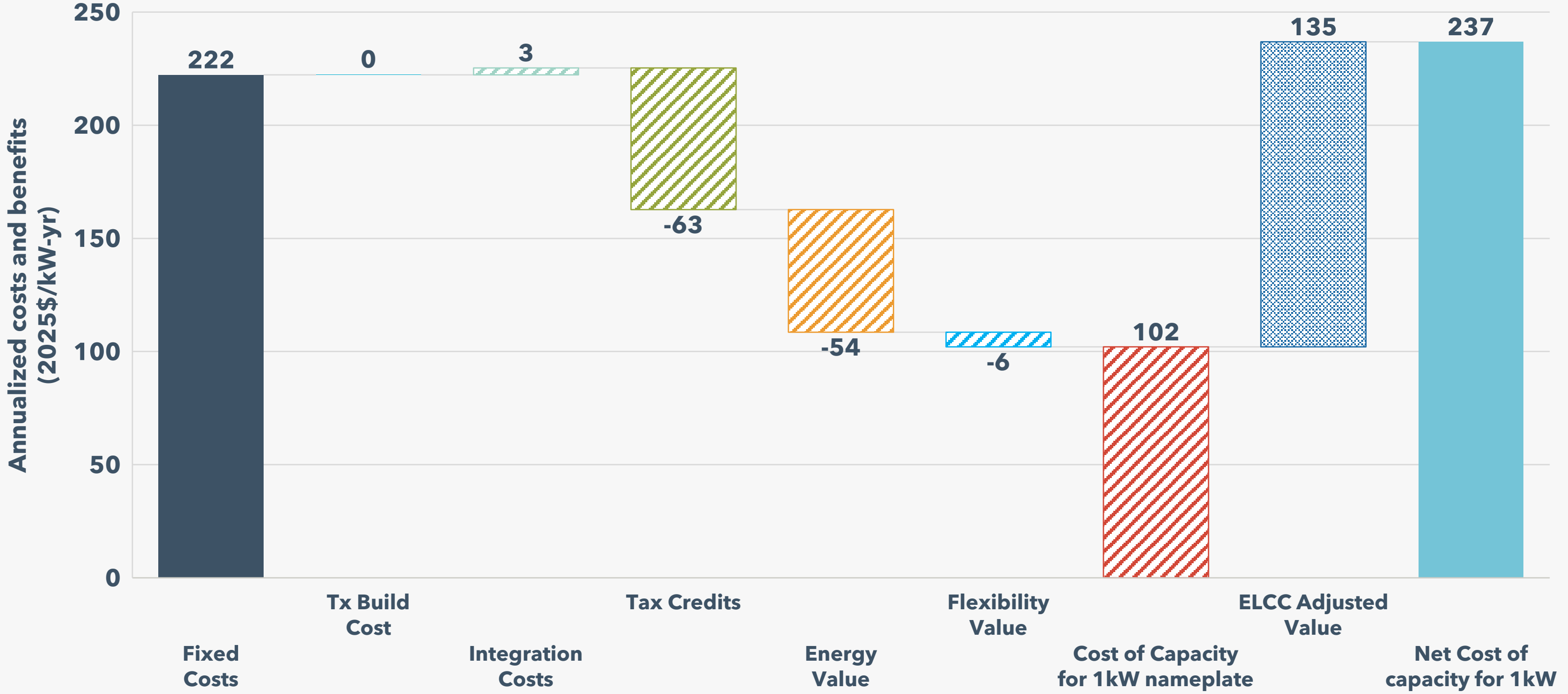


- 200 MW of 100hr batteries modeled at 35% round-trip efficiency provide energy roughly equivalent to 1800 MW of 4-hour batteries at 93% efficiency.
- 100hr storage resources contribute a roughly equivalent capacity value in Summer as a dispatchable energy resource, highlighting influence of energy availability.

A Blended Net Cost of Capacity

The above analysis suggest that 4-hour batteries alone are not representative of a marginal capacity resource, as such a resource requires both capacity and energy to ensure adequacy. To represent the marginal resource, PGE presents a blended Net Cost of Capacity value. Further work should estimate emergent technologies' appropriateness as the marginal resource.

Deriving the blended cost of 1 kW of capacity contribution



The blended Net Cost of Capacity is calculated using a weighted average of resource additions' costs, values, and ELCCs in the Preferred Portfolio for 2030.

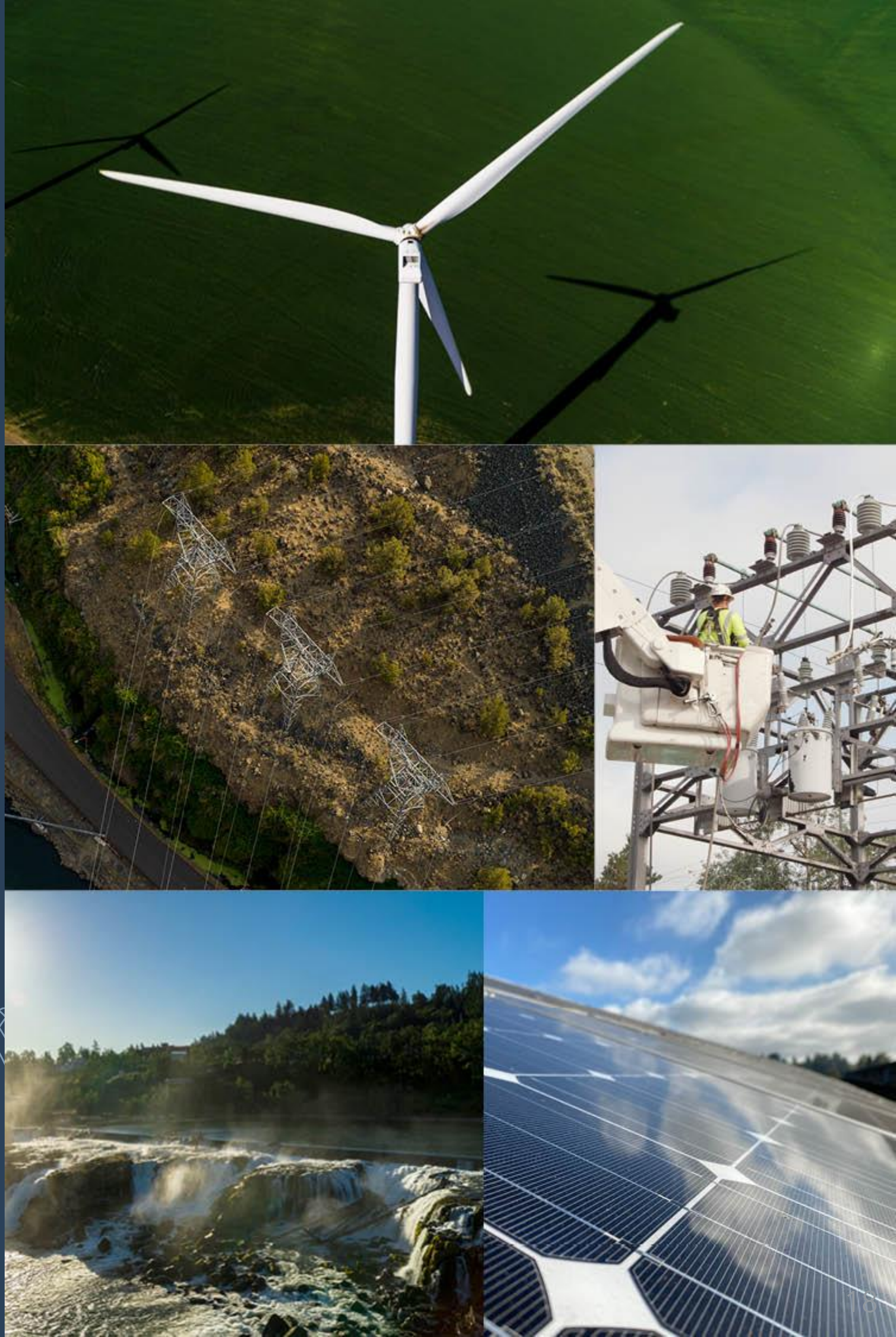
This blended value represents the cost of energy and capacity required to achieve adequacy within the Preferred Portfolio.

Conclusions

1	Winter reliability events are driving portfolio expansion in 2030	Four times as many storage resources are needed in winter than summer
2	4-hour storage resources are an inefficient marginal capacity resource due to the extended duration of winter reliability events	1,800 MW of storage required to resolve 123 MW of need in winter 2030
3	A blended net cost of capacity value better quantifies the capacity and energy costs required to ensure adequacy	4-hour battery costs alone do not account for energy costs necessary for reliability
4	Emergent technologies should be further analyzed for appropriateness as a marginal capacity resource in future IRPs	Initial tests suggest emergent technologies may be more efficient at addressing the capacity and energy interactions needed for resource adequacy

2023 CEP/IRP Update
Energy Value

Chris White



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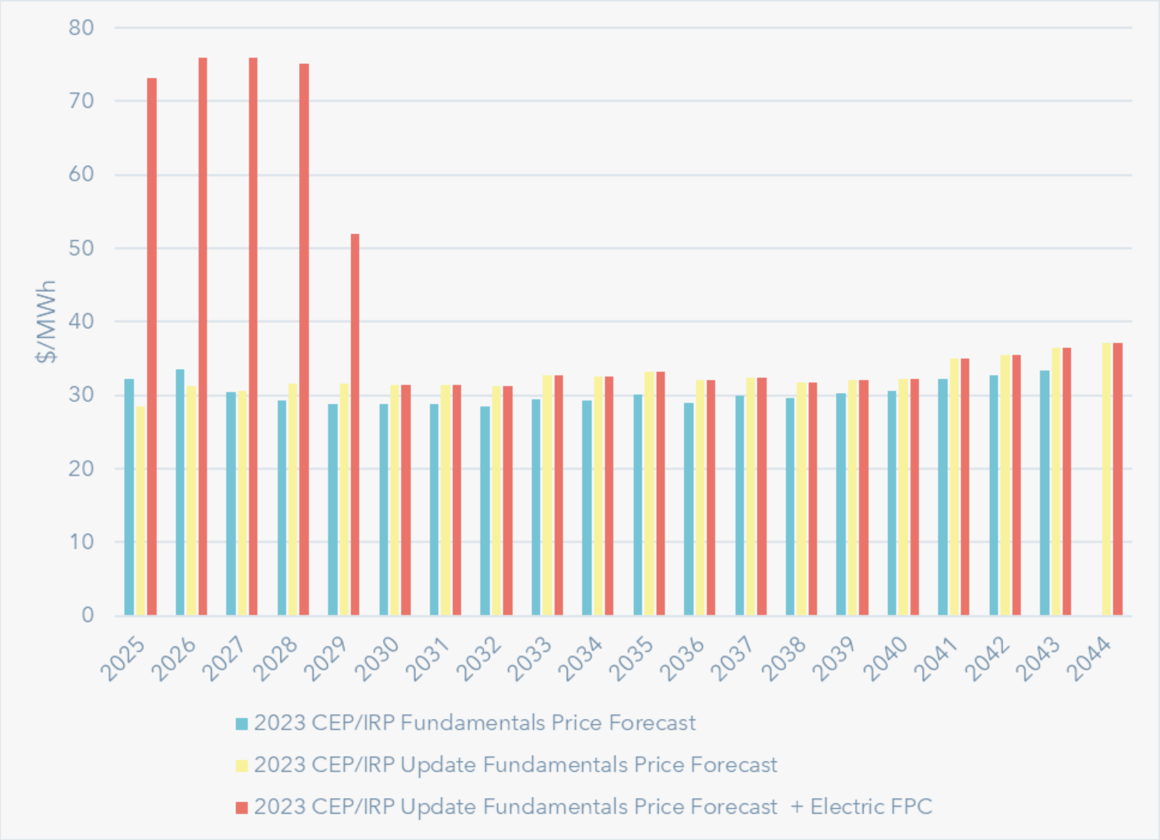
2023 CEP/IRP Update Price Forecast



For the years 2025 through 2028, the PGE electricity FPC replaces the long-term fundamentals price forecast.

After 2029, the IRP electricity price forecast is based on the fundamentals forecast.

In 2029, the price forecast is calculated as the hourly average blend of the two forecasts for each of the 39 price futures.

See Roundtable presentation from October 2024 for a description of the updated price forecast methodology.

2023 CEP/IRP Update Energy Values

Resource	Levelized energy value (2025$/MWh)	
	Reference case	Range
Solar CV	$23.51	$15.36 - $34.54
Solar MCMN	$22.52	$14.77 - $33.12
Solar Wasco	$22.03	$14.45 - $32.41
Wind Gorge	$27.70	$17.91 - $41.19
Wind MT	$32.53	$20.81 - $47.98
Wind SE WA	$30.03	$19.28 - $44.41
Wind ND	$31.05	$19.98 - $45.86
CV hybrid 1	$28.72	$18.96 - $40.70
CV hybrid 2	$26.00	$18.02 - $37.87
MCMN hybrid 1	$29.33	$19.47 - $41.34
MCMN hybrid 2	$25.81	$17.97 - $37.47

PGE uses Aurora to estimate the energy value of dispatching existing generating resources, contracts, and candidate new resources using electricity prices and associated risk variable inputs from each price future.

These values are levelized across each resource's economic life, for resources with 2028 commercial operation dates.

Energy values presented here for a 2028 COD are higher on average than those in the 2023 CEP/IRP by roughly *10%* to *35%*, depending on the resource.

This is driven in part by the upward change in the electricity price forecast for early model years

IRP Update Final Portfolio

Rob Campbell

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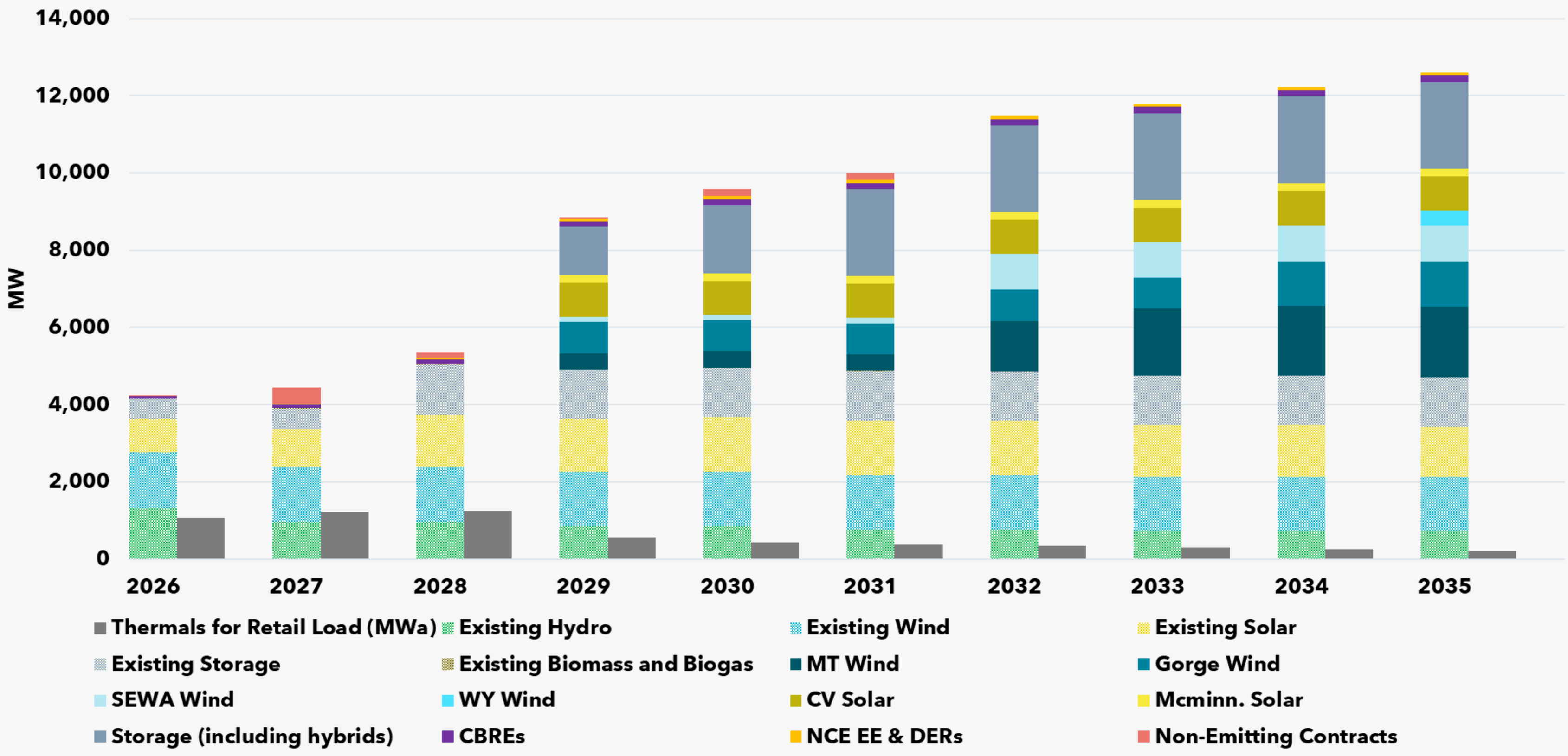
Preferred Portfolio Resources



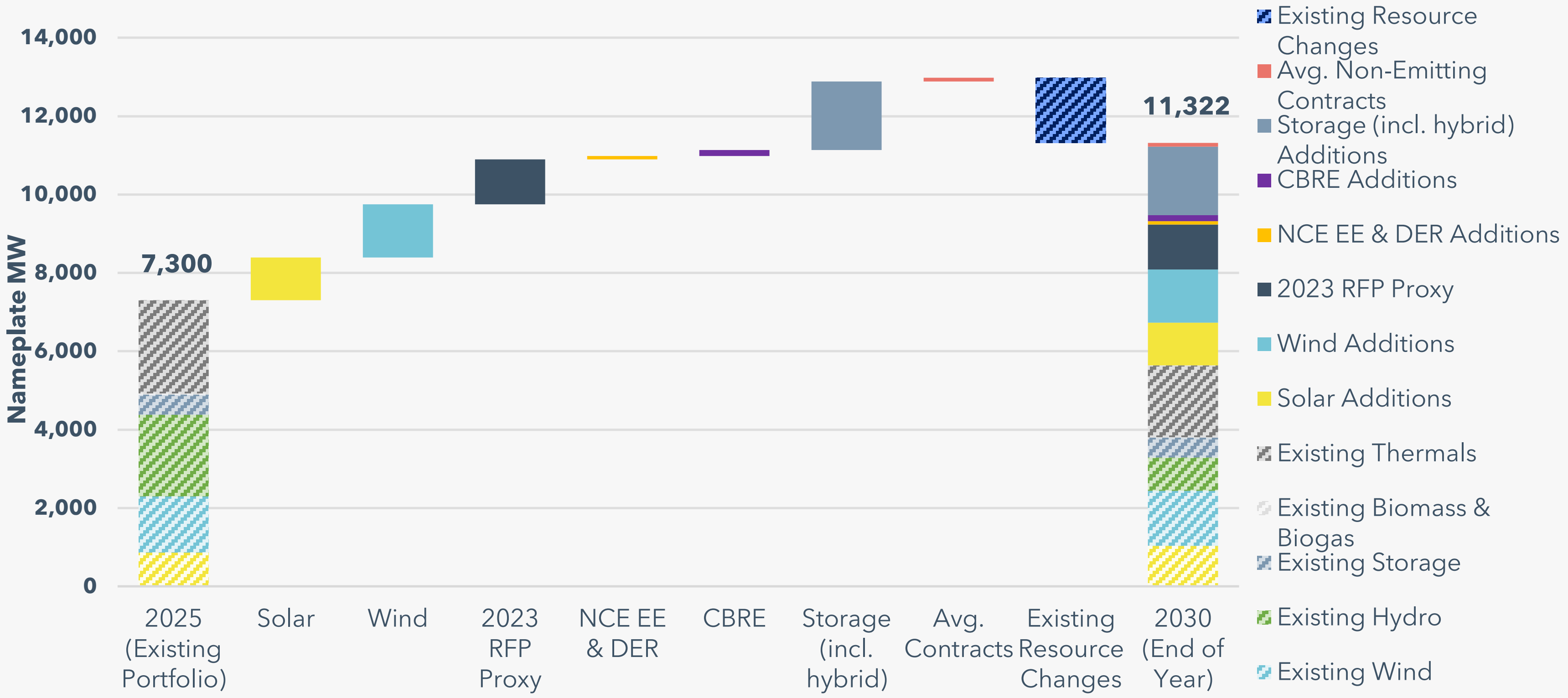
The Preferred Portfolio makes substantial additions to PGE's existing portfolio of non-emitting resources.*

A large amount of resources are added in 2029 in alignment with RFP procurement timelines.

Off-system renewables access is limited until 2032 when transmission options become available.

* Existing resources in this figure includes the 2023 RFP Proxy, which contains 375 MW of solar and 775 MW of storage from Group A shortlist bids.

Preferred Portfolio and Existing Portfolio Incremental Changes through 2030



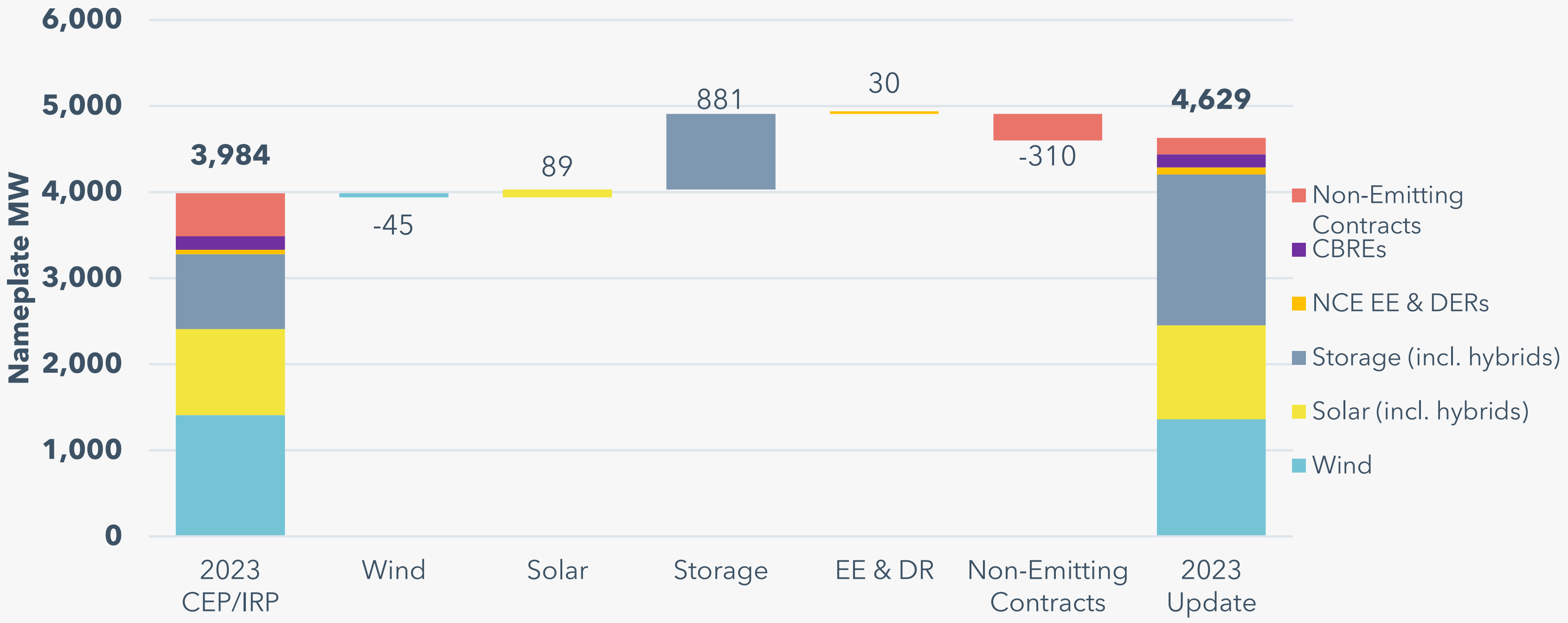
Total capacity in PGE's portfolio grows by roughly 1.5x between 2025 and 2030 to add sufficient capacity to maintain resource adequacy in light of growing load, with a focus on clean energy to also meet HB 2021 2030 GHG target.

Preferred Portfolio Cumulative Resource Additions (MW)

Resource	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Wind	0	0	0	1,362	1,362	1,362	2,989	3,420	3,844	4,274	4,761	5,352	5,947
Solar (including hybrids)	0	0	0	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089
Storage (including hybrids)	0	0	0	1,250	1,750	2,250	2,250	2,250	2,250	2,732	3,232	3,732	4,232
CBREs	66	85	110	133	155	155	155	155	155	155	155	155	155
NCE EE (MWa)	0	21	38	58	68	68	68	68	68	68	68	68	68
NCE DERs	3	8	12	13	15	16	16	16	16	16	16	16	16
Transmission	0	0	0	0	0	0	3,000	3,000	3,000	5,227	5,227	5,227	6,927
Non-Emitting Contracts	16	422	120	33	190	187	0	0	0	0	0	0	0
Cost-effective EE (MWa)	104	138	173	208	245	281	317	352	384	415	446	478	510
Cost-effective DR	142	172	199	225	248	266	284	299	312	325	336	348	356
2023 RFP Proxy Solar (incl. hybrids)*	0	0	375	375	375	375	375	375	375	375	375	375	375
2023 RFP Proxy Storage (incl. hybrids)*	0	0	775	775	775	775	775	775	775	775	775	775	775

* Includes resources from final shortlist Group A only.

Change in 2030 Resources Since 2023 CEP/IRP

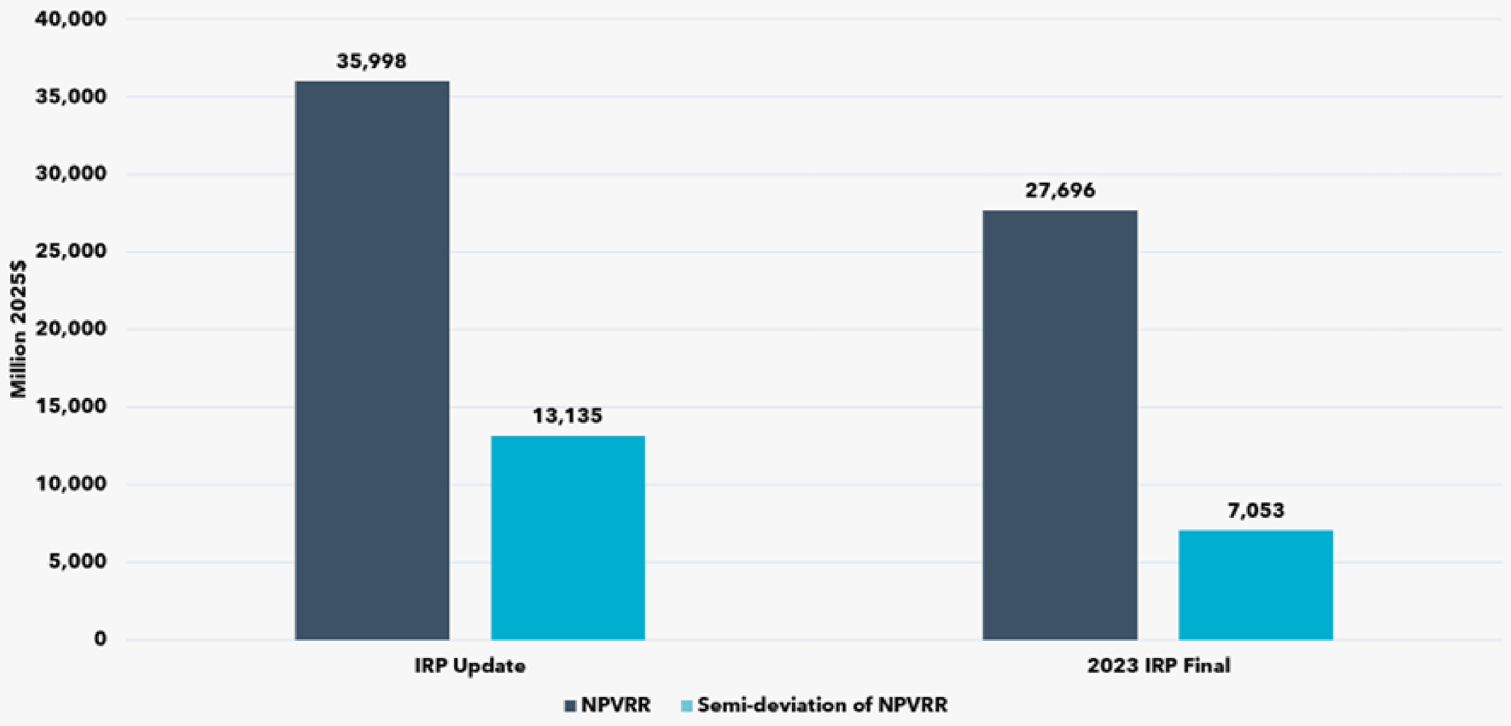


645 MW (16%) increase in 2030 resources compared to final 2023 CEP/IRP.

Increase in resources is driven predominantly by storage additions.

The increase in storage is driven by lower ELCCs (especially in winter).

Change in Portfolio Costs Since 2023 CEP/IRP

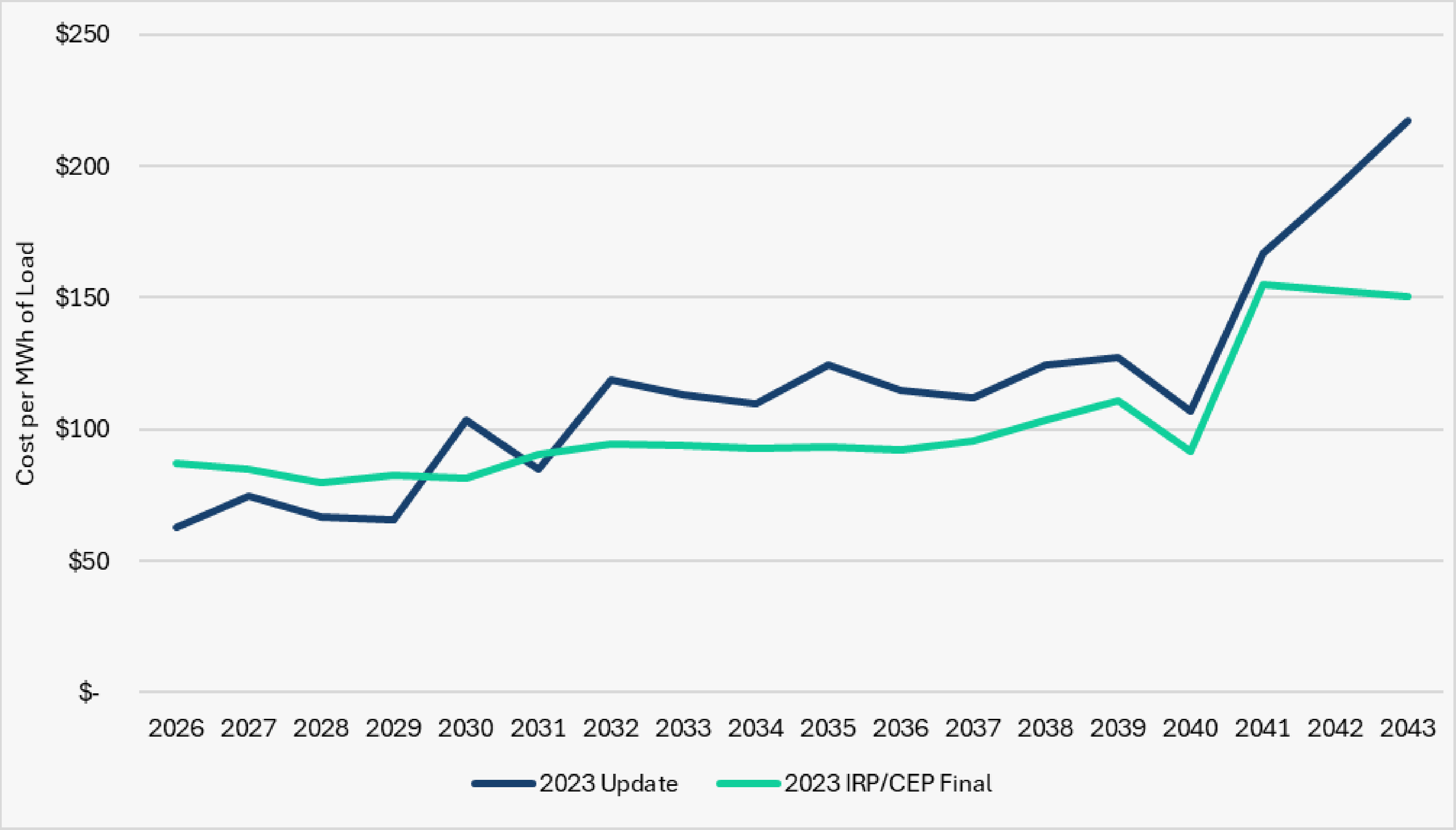


$8,302 million increase in NPVRR from the final 2023 CEP/IRP Preferred Portfolio.

Increase in portfolio cost is driven by a combination of increased quantity of resource additions and increased $/kW-yr resource costs projections for some types of supply-side resources.

Note: Portfolio costs in the 2023 CEP/IRP were reported in 2023 $'s and have been adjusted to 2025 $'s for this comparison.

Preferred Portfolio Annual Costs: Update vs Final '23 IRP



Annual costs are lower in the update in the first few years due to a higher market price assumption combined with a larger volume of emitting sales.

Costs in the final years increase due to resource need that cannot be met with existing resource availability, causing the model to choose a large amount of generic capacity resource

Additional Tax Policy and Reliability Planning Scenarios

Jarek Oliver & Rob Campbell

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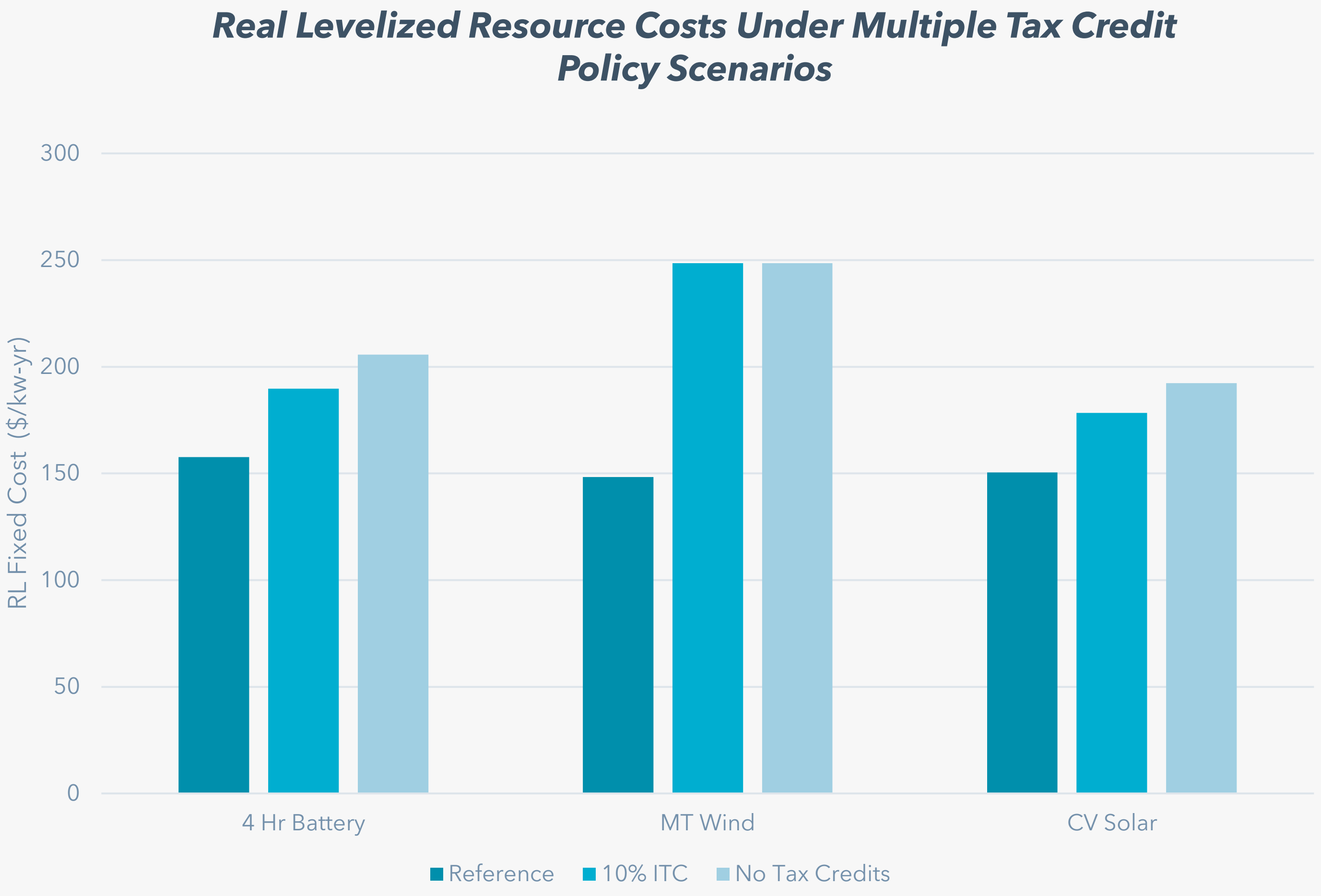
Resource Costs Under Different Tax Credit Scenarios

Congress is actively discussing changes to the tax credits made available through the Inflation Reduction Act. At the time of IRP analysis, the timing and magnitude of the proposed changes is uncertain. To study how PGE's portfolio costs could be impacted by changes to tax credits for new generation and storage resources, the IRP Update includes portfolio sensitives on tax policy. In addition to reference case assumptions consistent with current law, PGE studies:

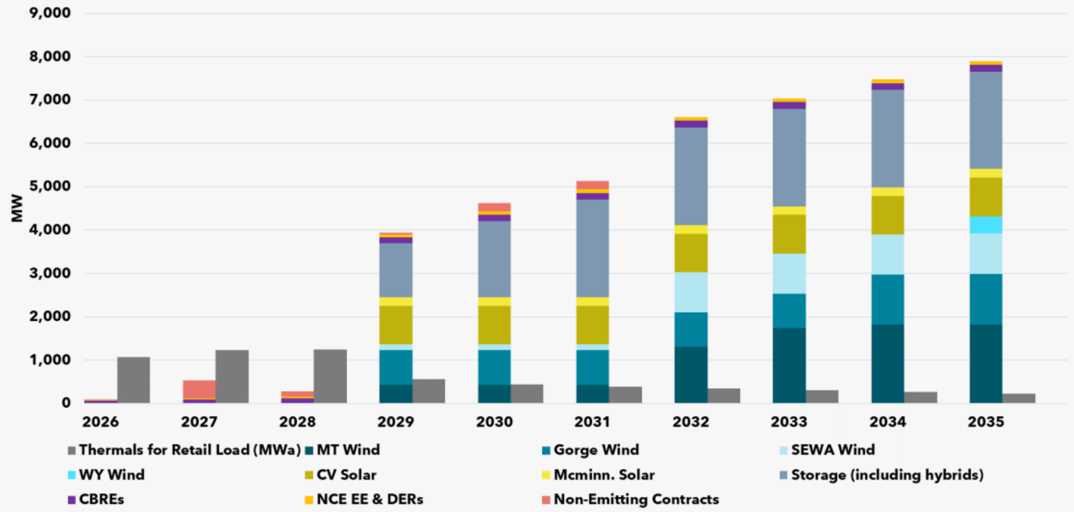
- Repeal of PTC & ITCs
- PTC & ITC drawdown schedules consistent with pre-IRA law.



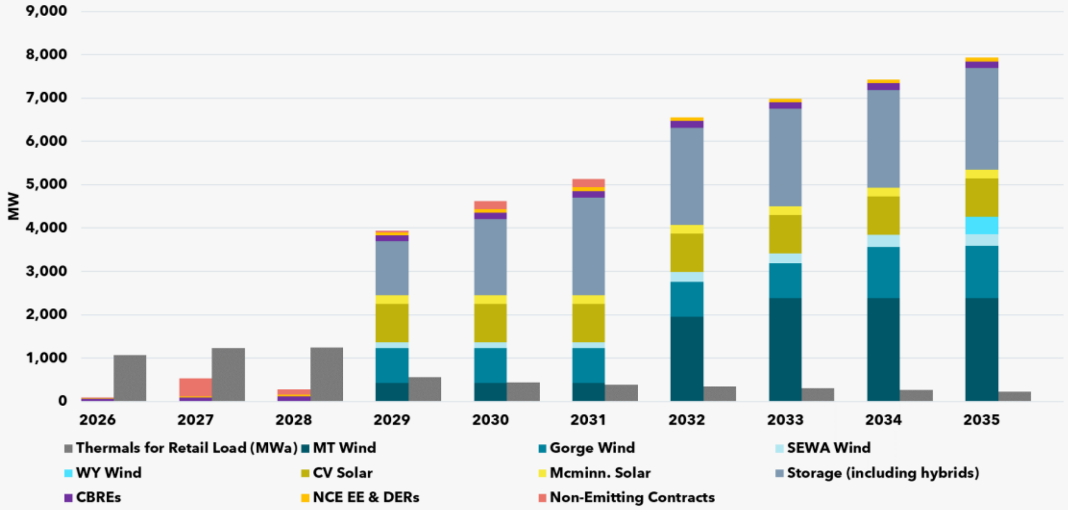
Tax Policy Portfolio Scenario Results

Tax policy portfolio sensitivities do not result in significant changes to capacity expansion results. Portfolio resource needs and resource benefits are not altered in the sensitivities. While new resource costs are increased in the tax credit sensitives, wind, solar and storage remain least cost resources especially when considering the lack of alternative resource technologies available for selection.

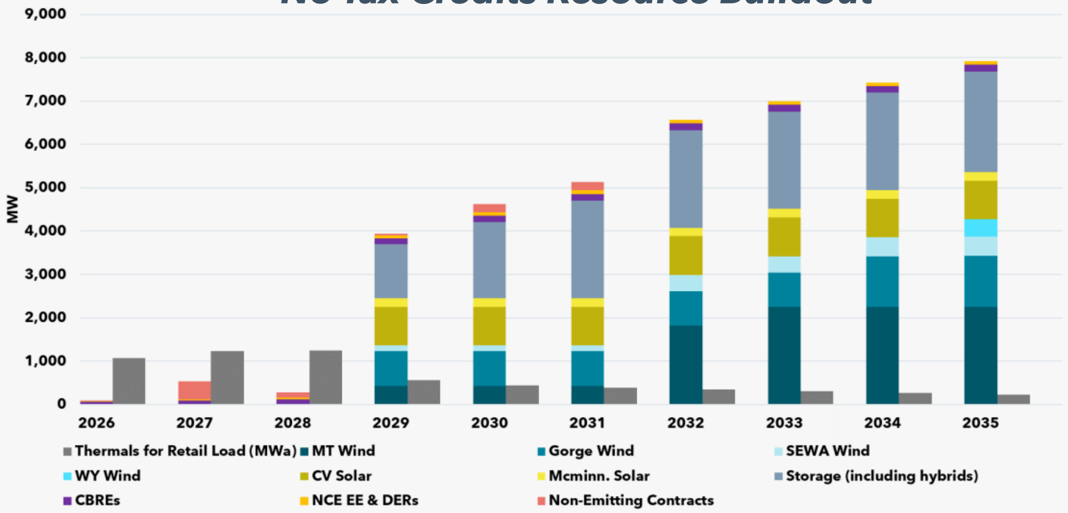
Preferred Portfolio Resource Buildout



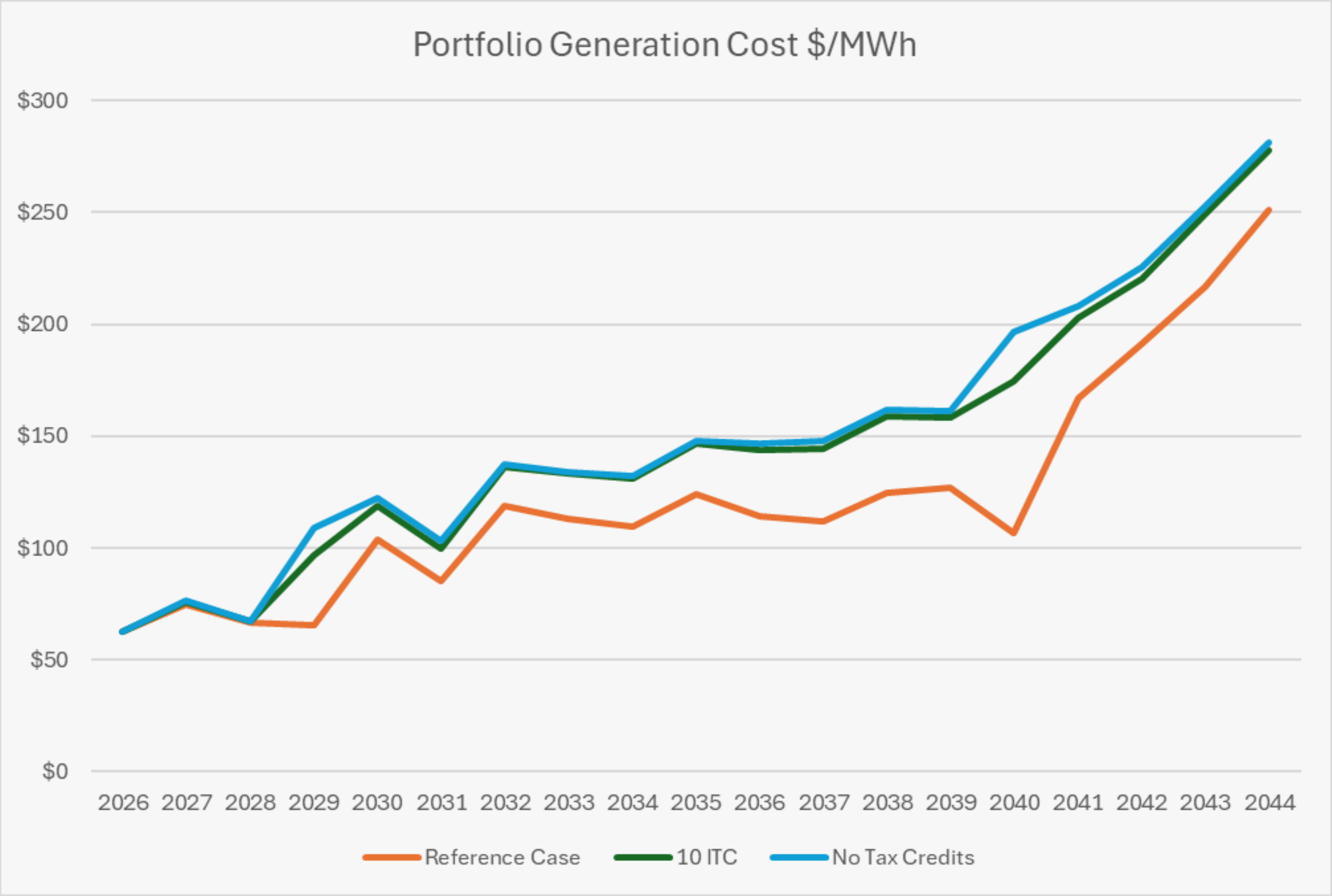
10% ITC Resource Buildout



No Tax Credits Resource Buildout



Preferred Portfolio Annual Costs Under Different Tax Credit Scenarios



Loss of PTCs & ITCs would significantly impact the costs of PGE's portfolio

PGE anticipates that tax policy uncertainty will resolve before the 2025 RFP bidding deadlines

Cost implications of tax policy change to be reviewed in PGE's 2025 RFP shortlist filings in addition to the long-term implications reviewed in the 2026 IRP

Additional Reliability Sensitivities

Additional Reliability Sensitivities expand upon the 'Reliability Needs Only' scenario by considering how needs are reduced by assuming:

1. PGE extends a 250 MW contract for dispatchable emitting energy – **"Dispatchable Emitting Contract"** scenario
2. PGE extends a 250 MW contract for dispatchable emitting energy in addition to a 250 MW non-emitting hydro contract – **"Dispatchable Emitting and Hydro Contracts"** scenario

Both contract extensions are assumed to provide energy and capacity from 2030 through 2034. Aside from the contract extension assumptions, these scenarios rely on identical assumptions to the **"Reliability Needs Only"** scenario.

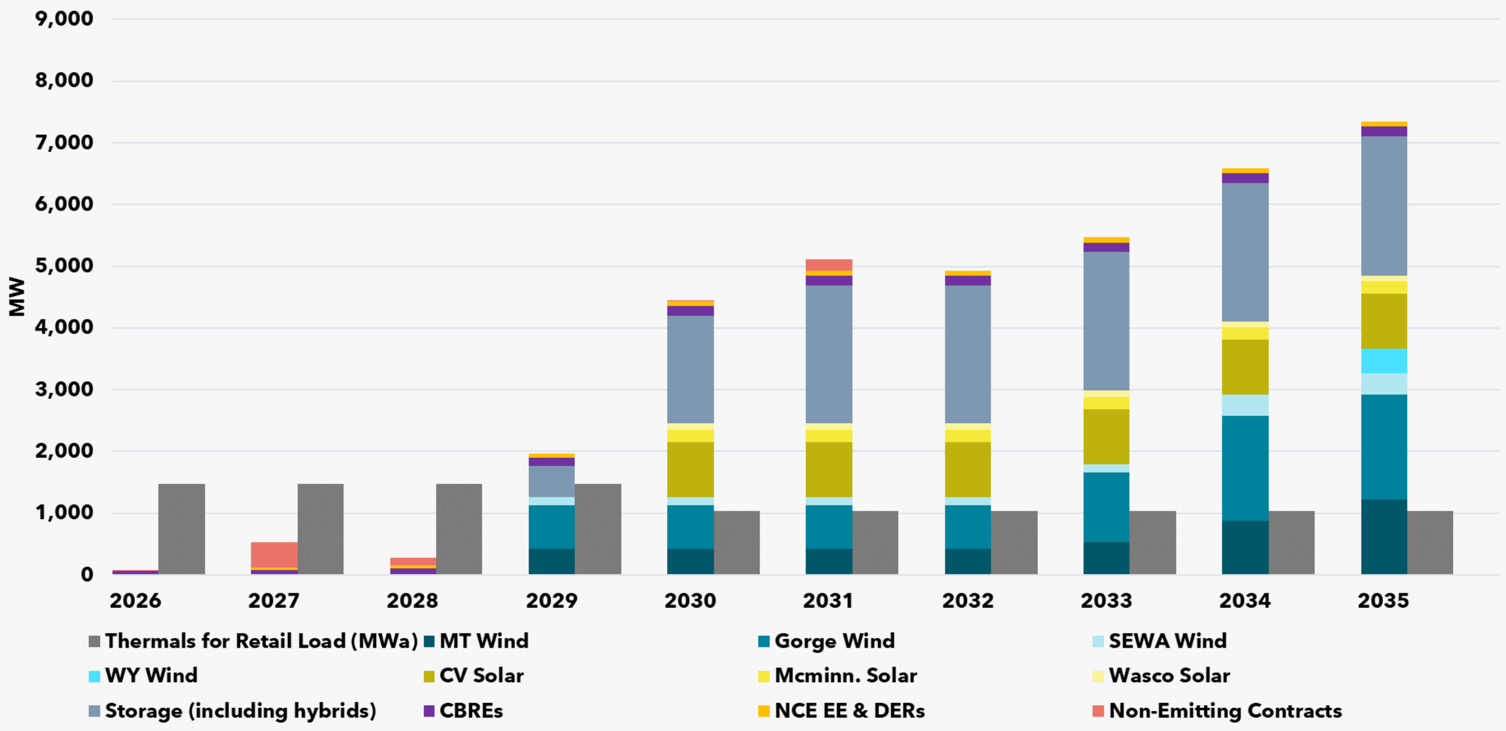
Reminder: Reliability Needs Only Scenario

The ‘Reliability Needs Only’ scenario demonstrates how capacity and energy needs driven by load growth and portfolio composition changes.

GHG policy is relaxed to examine how PGE’s resource needs are driven by capacity and energy requirements distinct from GHG compliance.

The ‘Reliability Needs Only’ scenario is RPS compliant and no new natural gas additions can be made.

Reminder: Reliability Needs Only Resource Buildout



2030 resource additions

1,262 MW wind

1,189 MW solar (including hybrid)

1,745 MW storage (including hybrid)

155 MW CBREs

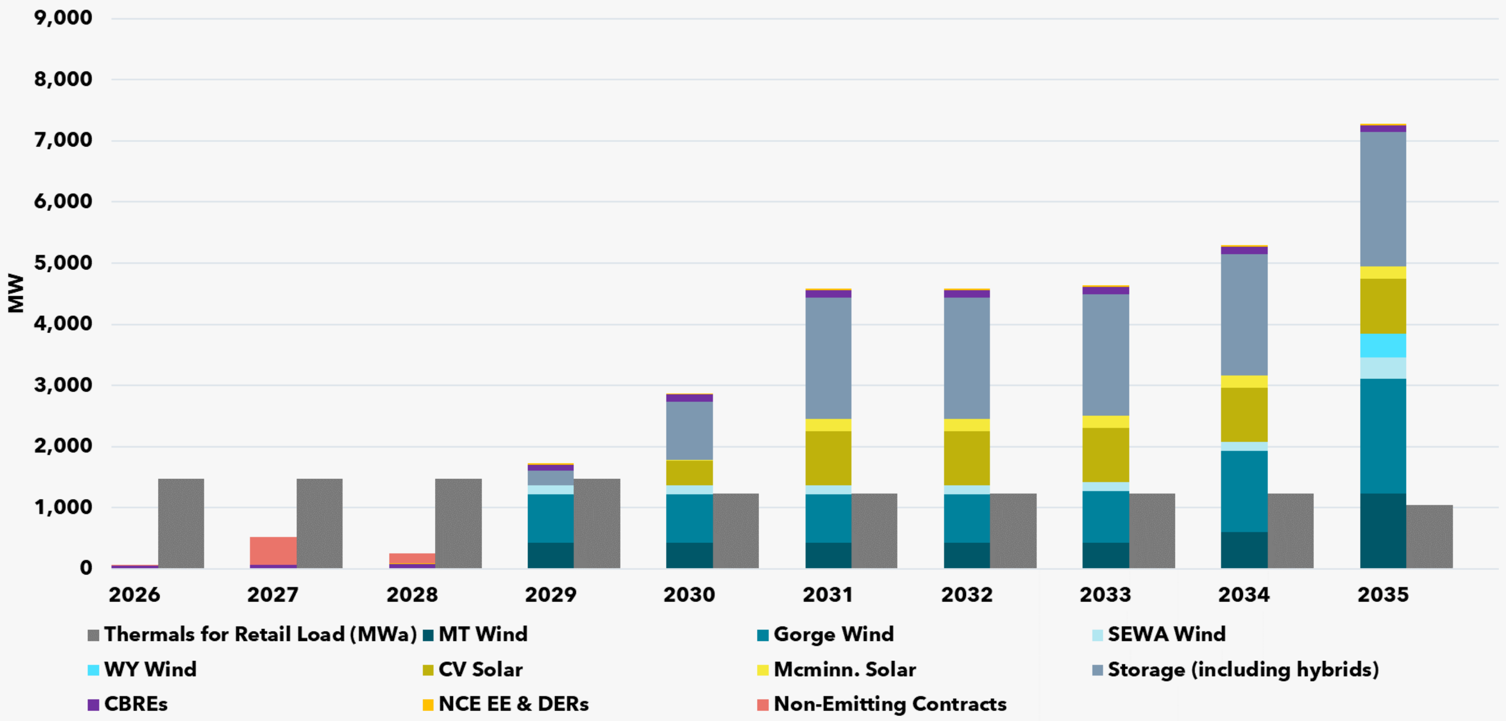
83 MW EE and DERs

9 MW non-emitting contracts

Key Takeaways

4,443 MW 2030 resource additions without reducing thermals suggests resource adequacy is a main driver of resource need.

Dispatchable Emitting Contract Scenario



2030 resource additions

1,362 MW wind

415 MW solar (including hybrid)

952 MW storage (including hybrid)

119 MW CBREs

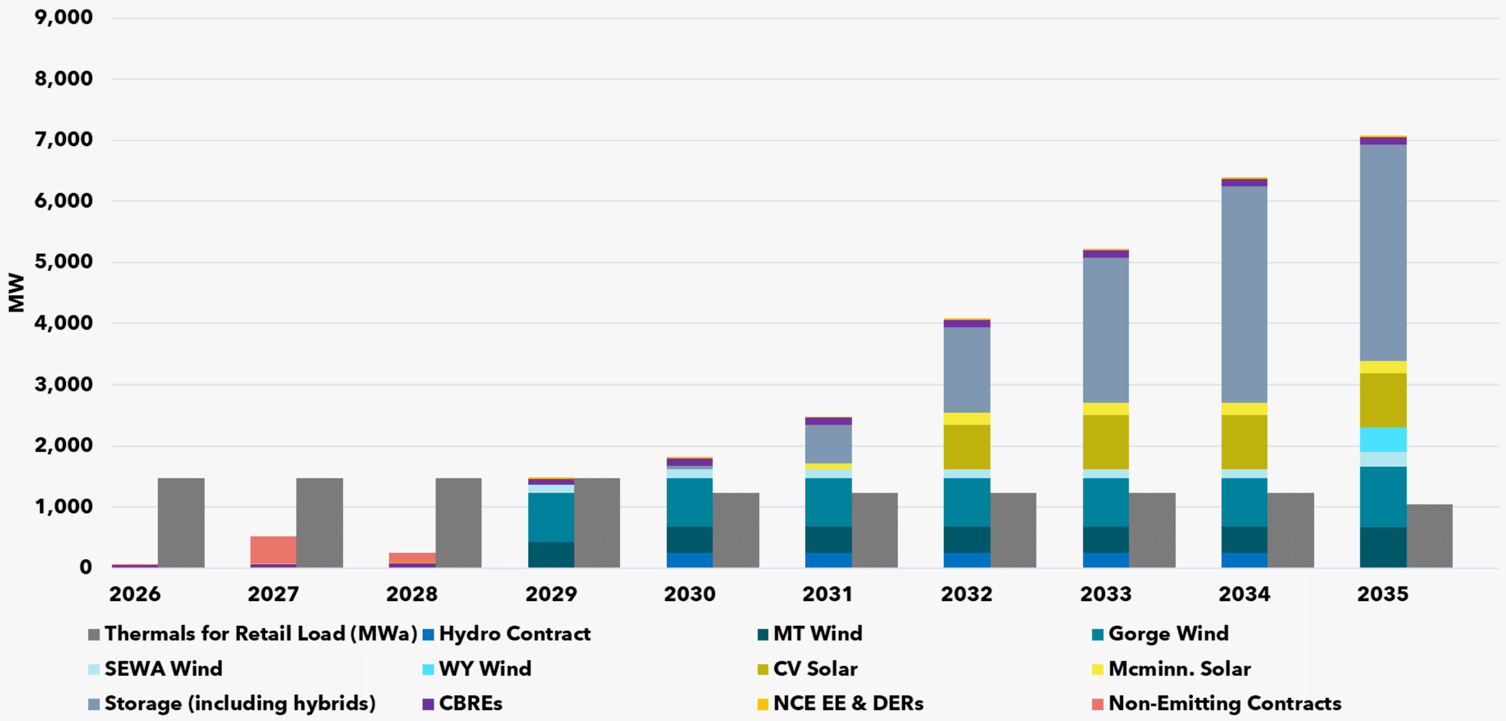
24 MW EE and DERs

Key Takeaways

2,872 MW 2030 resource additions is 1,571 MW lower than "Reliability Needs Only" scenario.

Addition of capacity and energy from 250 MW contract extension substantially reduces 2030 resource needs.

Dispatchable Emitting and Hydro Contracts Scenario



2030 resource additions

1,362 MW wind

64 MW storage

119 MW CBREs

24 MW EE and DERs

Key Takeaways

1,569 MW 2030 resource additions is 2,874 MW lower than “Reliability Needs Only” scenario.

500 MW of contract extensions substantially reduces 2030 resource needs.

Conclusions

1 PGE's portfolio costs are significantly impacted by federal tax policy

Any change of law to be reviewed and reported on within 2025 RFP and 2026 IRP

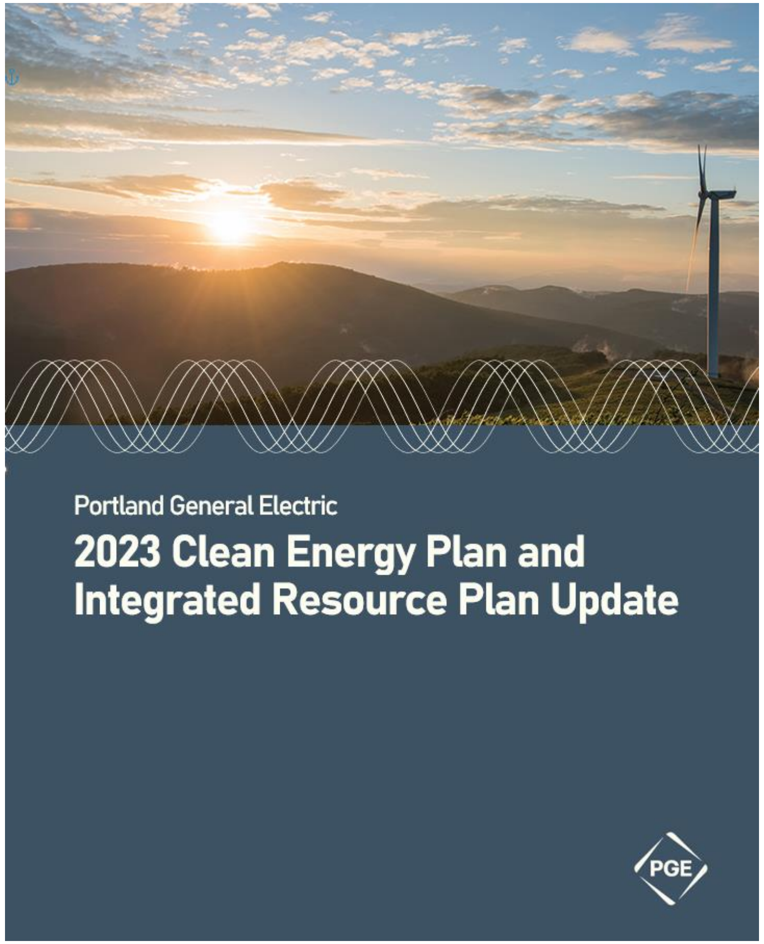
2 PGE's reliability needs are significant but can be partially addressed through various resource action pathways

- PGE's reliability needs can be reduced though extension of dispatchable energy resources and non-emitting hydro contracts
- Regional exchange of resource adequacy accretive products, as is proposed in the State's RA program, can also significantly reduce resource needs associated with reliability
- PGE will continue to review emergent generation and storage resources which meet PGE's winter reliability needs more effectively than short-term storage

Questions

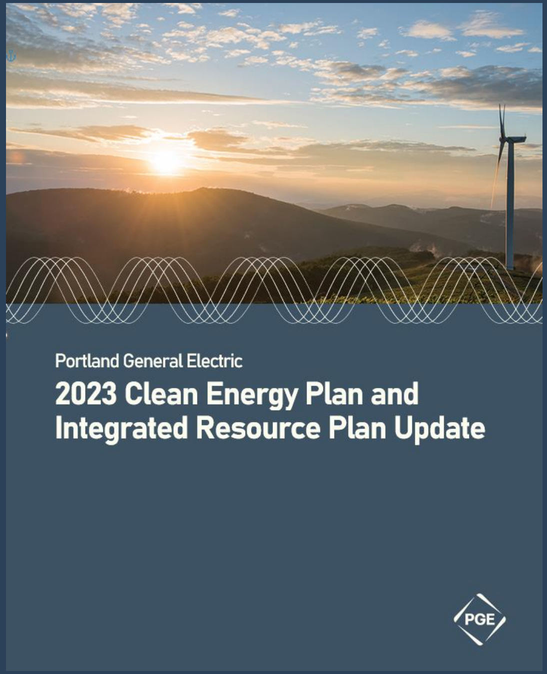
2023 CEP/ IRP Update Report Structure

Jimmy Lindsay, Director Resource Planning



Clean Energy Plan & Integrated Resource Plan

Filing the Integrated Resource Plan and Clean Energy Plan Update jointly June, 2024.



Report structure

7 Chapters

- Introduction
- Chapter 1. CEP Update
- Chapter 2. Planning environment
- Chapter 3. System needs
- Chapter 4. Transmission landscape
- Chapter 5. Resource options
- Chapter 6. Resource plan
- Chapter 7. Action Plan

10 Appendices

- Appendix A Federal Grant Funding
- Appendix B Sequoia methodological update
- Appendix C QF capacity update
- Appendix D Hourly emissions methodology
- Appendix E Energy Trust of Oregon (ETO)
- Appendix F Market for non-emitting energy
- Appendix G Stakeholder engagement
- Appendix H Regional planning processes
- Appendix I Inputs for state RA requirements portfolio
- Appendix J Transmission Options Study

Ch 1: Clean energy plan Update

- Chapter 1. CEP Update
  - 1.1 Overview
  - 1.2 Historical emissions trends and resource mix
  - 1.3 Pathways to emissions targets
  - 1.4 Progress in the CEP Update
    - 1.4.1 Annual goals
    - 1.4.2 GHG emissions
    - 1.4.3 GHG emissions intensity
    - 1.4.4 Average electric rates for Oregon customers
    - 1.4.5 Community impacts and benefits
  - 1.5 High-level opportunities, potential barriers, critical dependencies
  - 1.6 Acknowledged Actions, Order requirements and other updates

Chapter Highlights & Updates Following 2023 CEP/IRP

- PGE is reducing emissions and maintaining reliable service by replacing emitting generation and market purchases with non-emitting energy and capacity resources.
- Uncertainties regarding the most cost-effective path to accelerate emissions reductions have increased due to external factors such as likely changes to federal tax credits, trade policy, and more.
- Transmission solutions are integral to maintaining reliability and providing long-term pathways for decarbonized power supply.
- Updated analysis finds 2030 emissions targets can be met by technologies and resources that are currently known and commercially available, though assumed resource costs have increased and the timing of additions may be constrained.

Ch 2: Planning environment

- Chapter 2. Planning environment
  - 2.1 EPA powerplant rules
  - 2.2 Market development
    - 2.2.1 CAISO's Extended Day Ahead Market
    - 2.2.2 Western Resource Adequacy Program (WRAP)
  - 2.3 Transmission coordination
    - 2.3.1 Western Transmission Expansion Coalition (WestTEC)
  - 2.4 Semiconductor and data center growth
    - 2.4.1 General trends in electricity demand across the Western Interconnection
    - 2.4.2 Data center growth in the Pacific Northwest
    - 2.4.3 Regulatory and policy responses to large customer demand growth
  - 2.5 Federal administration changes
    - 2.5.1 Tax credit policy
    - 2.5.2 Grant Funding
    - 2.5.3 BPA

Chapter Highlights & Updates Following 2023 CEP/IRP

- On June 28th, 2024, PGE has signed an implementation agreement to join CAISO's Extended Day-Ahead Market (EDAM) with go-live scheduled for October 2026.
- PGE is currently developing regional alignment on Resource Adequacy planning standards as a precursor for a regional reliability program.
- The Western Transmission Expansion Coalition's (WestTEC) West-Wide Transmission Study Project represents a new regional effort to address transmission constraints.
- Significant expansion in expected future load growth for large industrial customers compared to the 2023 CEP/IRP assumptions.
- At the federal level, the EPA is reconsidering the powerplant emission limit final rules under Section 111 of the Clean Air Act that were established on April 25, 2024, under the previous administration.
- Congress is also actively evaluating proposals that would remove federal tax incentives for new non-emitting generation and storage resources.

Ch 3: Systems needs

- Chapter 3. System needs
  - 3.1 Econometric load forecast
    - 3.1.1 Energy forecast
      - 3.1.1.1 Energy Forecast Methodological Changes
      - 3.1.1.2 Large customer forecast
      - 3.1.1.3 Resulting Energy Forecast
      - 3.1.1.4 Energy High and Low Forecasts
      - 3.1.1.5 IRP Update Comparison to 2023 CEP/IRP
    - 3.1.2 Seasonal peak demand forecast
      - 3.1.2.1 Peak Forecast Methodological Changes
      - 3.1.2.2 Resulting Peak Forecast
      - 3.1.2.3 Peak High and Low Forecasts
      - 3.1.2.4 IRP Update Comparison to Previous Filings
    - 3.1.3 Load forecasts – excluding large customer load
      - 3.1.3.1 Methodology: Excluding load from large customers
      - 3.1.3.2 Resulting forecast – excluding large customer load
  - 3.2 2023 RFP results
    - 3.2.1 Target and need
    - 3.2.2 2023 RFP proxy
  - 3.3 Energy need
  - 3.4 Capacity need
    - 3.4.1 Seasonal need – reference case
    - 3.4.2 Changes to modeling capacity need
      - 3.4.2.1 Updated analysis period
      - 3.4.2.2 Load forecast updates
      - 3.4.2.3 Supply-side updates
    - 3.4.3 Capacity need under different futures
  - 3.5 State policy requirements
    - 3.5.1 HB 2021
    - 3.5.2 RPS obligation
    - 3.5.3 Small scale renewables standard

Chapter Highlights & Updates Following 2023 CEP/IRP

- Twenty-year average annual growth rates are estimated at 2.8 percent annually, a 1.2 percentage point increase from the 2023 CEP/IRP Addendum forecast. Growth is driven primarily by unprecedented industrial sector expansion, especially in semiconductor manufacturing and data centers.
- Resources assumed to be added following the conclusion of the 2023 RFP reduce long term capacity needs and make important contributions to addressing near-term capacity deficits.
- PGE continues to procure resources as part of the 2025 RFP. Such resource additions are likely to enter the system approximately 2029, limiting near-term emissions reductions.
- Monthly assessment of PGE's long-term energy need increases resource need relative to annual energy accounting.

Ch 4: Transmission landscape

- Chapter 4. Transmission landscape
  - 4.1 Transmission and regulatory environment
    - 4.1.1 Regulatory environment
    - 4.1.2 PGE's transmission system
    - 4.1.3 Transmission system topology
      - 4.1.3.1 BPA and Pacific Northwest transmission system
      - 4.1.3.2 PGE and BPA
      - 4.1.3.3 Paths and flowgates
      - 4.1.3.4 North of Pearl
  - 4.2 PGE transmission projects
  - 4.3 Transmission strategy/outlook
    - 4.3.1 Concentric circles of transmission
      - 4.3.1.1 PGE's system
      - 4.3.1.2 Connecting PNW to PGE's transmission system
      - 4.3.1.3 Connecting the PNW to other regions
    - 4.3.2 Existing PGE projects/local transmission plan
    - 4.3.3 BPA projects important to PGE
  - 4.4 Assessment of available BPA point-to-point transmission
  - 4.5 Third-party assessment of PGE regional transmission options
  - 4.6 Transmission options for portfolio analysis
    - 4.6.1 Bethel-Round Butte upgrade
    - 4.6.2 Harborton-Trojan upgrade
    - 4.6.3 Gateway + B2H + Longhorn (Gateway)
    - 4.6.4 NVE + SWIP-N + Gateway + B2H + Longhorn (SWIP-N)
    - 4.6.5 North Plains Connector
    - 4.6.6 NVE + Greenlink 3 + Cpt. Jack to Grizzly + BRB upgrade (Greenlink)
    - 4.6.7 Cascade Renewable Transmission project
    - 4.6.8 Transmission options summary
    - 4.6.9 Transmission cost assumptions

Chapter Highlights & Updates Following 2023 CEP/IRP

- PGE's transmission system is highly constrained, with limited capacity for new resources—especially on BPA's system—until upgrades occur.
- Since August 2023, the North of Pearl (NOPE) flowgate has posed major operational challenges, requiring multiple reliability projects to address rising south-to-north power flows.
- Transmission is essential for accessing diverse generation outside PGE's territory; several projects are underway to connect to new renewable resources.

Ch 5: Resource options

- Chapter 5. Resource options
  - 5.1 Resource economics
    - 5.1.1 PGE financial parameters
    - 5.1.2 Supply-side resource costs
    - 5.1.3 Tax credit sensitivities
    - 5.1.4 Electricity price forecast
    - 5.1.5 Supply-side resource energy value
    - 5.1.6 Resource capacity contribution
    - 5.1.7 Comparison of resource capacity contribution to 2023 IRP/CEP
    - 5.1.8 Resource capacity value
    - 5.1.9 Resource net cost
  - 5.2 Distributed energy resources (DERs)
    - 5.2.1 Passive DERs
    - 5.2.2 Cost-effective demand response
    - 5.2.3 Non-cost-effective demand response
  - 5.3 Energy efficiency
    - 5.3.1 Cost-effective energy efficiency
    - 5.3.2 Non-cost-effective energy efficiency
    - 5.3.3 Bundling of NCE energy efficiency measures
    - 5.3.4 Comparing NCE energy efficiency in 2023 CEP/IRP to the 2023 CEP/IRP Update
    - 5.3.5 Energy efficiency program and policy
  - 5.4 SSR resource
  - 5.5 Community benefits indicators (CBIs)
    - 5.5.1 Background and regulatory framework
    - 5.5.2 Advancing CBI methodologies and integrating to the IRP
    - 5.5.3 Challenges and next steps
    - 5.5.4 Conclusion
  - 5.6 Long lead-time resources
    - 5.6.1 Post-2030 resource options
    - 5.6.2 Hydrogen and ammonia
    - 5.6.3 Nuclear
    - 5.6.4 Geothermal
    - 5.6.5 Post-2030 wind/solar generation
    - 5.6.6 Long-term hybrid resources
    - 5.6.7 Long-duration storage

Chapter Highlights & Updates Following 2023 CEP/IRP

- Resource costs have risen, mainly due to fixed costs, with varying benefits across energy, capacity, and storage; potential tax credit reductions are also analyzed.
- Including non-cost-effective DERs helps assess their future role in a decarbonized grid.
- Community Benefit Indicators (CBI) assumptions were refined to reflect stakeholder input and now include measurable metrics for resilience, health, environment, equity, and economic impact.

Ch 6: Resource plan

- Chapter 6. Resource plan
  - 6.1 Portfolio analysis design and scoring
    - 6.1.1 GHG emissions
    - 6.1.2 Energy need
    - 6.1.3 Capacity need
    - 6.1.4 Resource availability
    - 6.1.5 Transmission constraints and options
    - 6.1.6 Portfolio scoring
  - 6.2 Preferred Portfolio
    - 6.2.1 Yearly cost estimates
    - 6.2.2 Hourly energy and emissions accounting results
    - 6.2.3 Preferred Portfolio resource adequacy testing
  - 6.3 Portfolio sensitivities
    - 6.3.1 Reliability needs only
    - 6.3.2 Further Reliability need sensitivities
    - 6.3.3 Large industrial customer growth
    - 6.3.4 Market scenarios
    - 6.3.5 State RA requirements
    - 6.3.6 Resource Community Benefits Indicator (rCBI)
    - 6.3.7 Absence of non-emitting market
  - 6.4 Small scale renewables plan
    - 6.4.1 SSR needs assessment
      - 6.4.2 Contributions from baseline resource acquisition
      - 6.4.3 Remaining SSR need
    - 6.4.4 SSR compliance cost assessment
    - 6.4.5 SSR acquisition strategy
  - 6.5 Portfolio CBIs
  - 6.6 Federal tax credit availability scenarios
  - 6.7 Net cost of capacity resources

Chapter Highlights & Updates Following 2023 CEP/IRP

- The updated Preferred Portfolio meets HB 2021 targets through the 20-yr planning horizon with a least-cost, least-risk mix: 1,362 MW wind, 1,089 MW solar, 1,750 MW storage, and 155 MW CBRE by 2030.
- Hourly emissions analysis shows compliance with the 2030 emission target, with thermal use concentrated in winter.
- Winter adequacy challenges highlight the need for substantial storage and better long-term capacity resources suited for cold-season demand.

Ch 7: Action Plan

- Chapter 7. Action Plan
  - 7.1 Action Plan
    - 7.1.1 Customer resource action
    - 7.1.2 CBRE action
    - 7.1.3 Energy action
    - 7.1.4 Capacity action
    - 7.1.5 Transmission expansion action
  - 7.2 Conclusion

Chapter Highlights & Updates Following 2023 CEP/IRP

- PGE is not requesting Oregon Public Utility Commission acknowledgement of this IRP Update and is therefore maintaining its Action Plan that was acknowledged as part of the 2023 CEP/IRP.
- The acknowledged Action Plan continues to represent the best combination of cost, risk, community benefit, and emission reductions to guide near-term energy and capacity actions.
- PGE continues to identify the need for more RFPs to procure additional resources for resource adequacy, reliability, and compliance with HB 2021 emissions reduction targets.
- Updated analysis described in this Update suggests resource need has increased.

Questions

NEXT STEPS

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

Upcoming Roundtable: July 9th, 2025

Thank you

Contact us at
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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