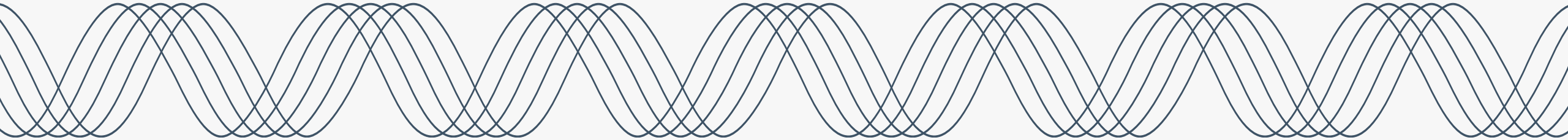
PGE CEP & IRP Roundtable 24-2

June 5, 2024



June 5th, 2024 – Agenda

9:00 – 9:05	Welcome | Meeting Logistics
9:05 – 9:20	North Plains Connector
9:20 – 11:10	Hourly Energy and Emissions Accounting | Parts I & II
11:10– 11:25	Qualifying Facility Forecast
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/84391255924?pwd=RDQ2VFpUZERVSEcraU5CZWw3VDhQZz09
- Meeting ID: 843 9125 5924
  Passcode: 108198

3

Participation

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

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

North Plains Connector

Jacob Goodspeed, PGE

Building on 2023 CEP/IRP Discussions

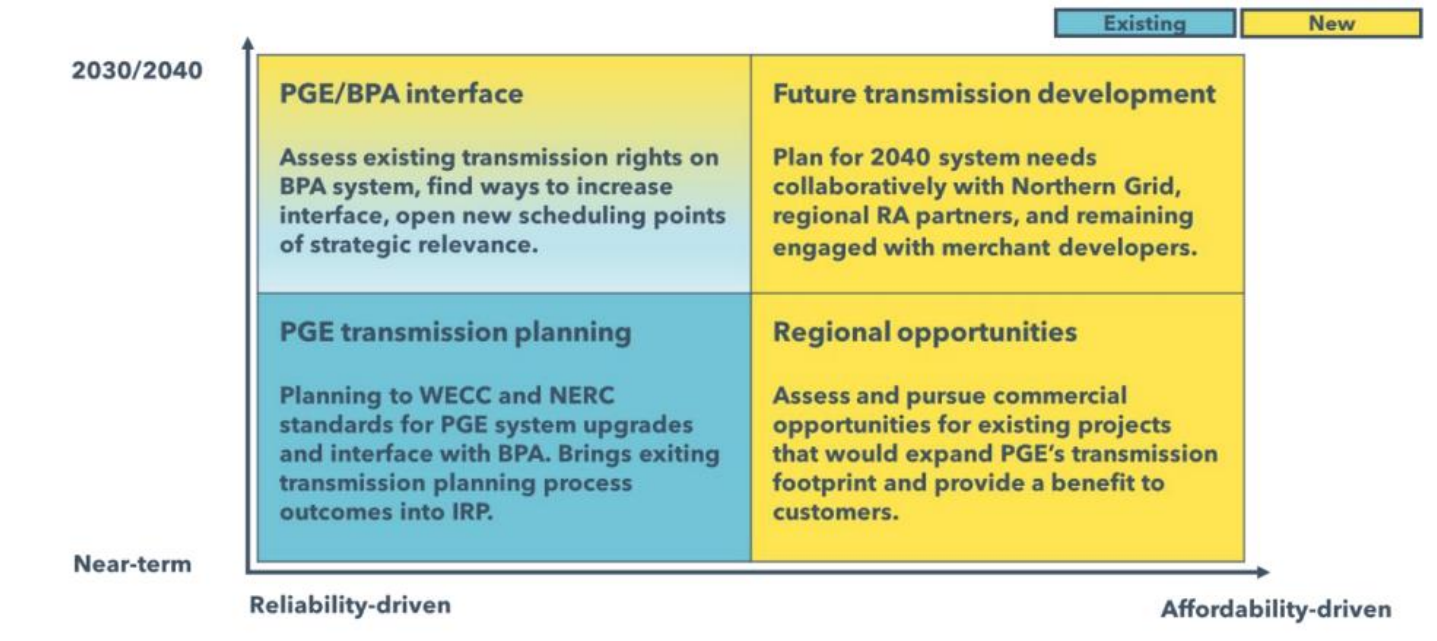


Figure 63 from 2023 CEP/IRP

In the 2023 CEP/IRP, PGE and stakeholders discussed the need to consider transmission to maximize best outcomes for customers as we decarbonize.

This included two action plan items:

- Pursue options to alleviate congestion on the South of Allston Flowgate
- Explore options to upgrade the Bethel-Round Butte line

Additionally, PGE would continue to assess opportunities on a longer timeframe to diversify our portfolio and bring resources that complement our current generation.

MOU to Explore Customer Benefit

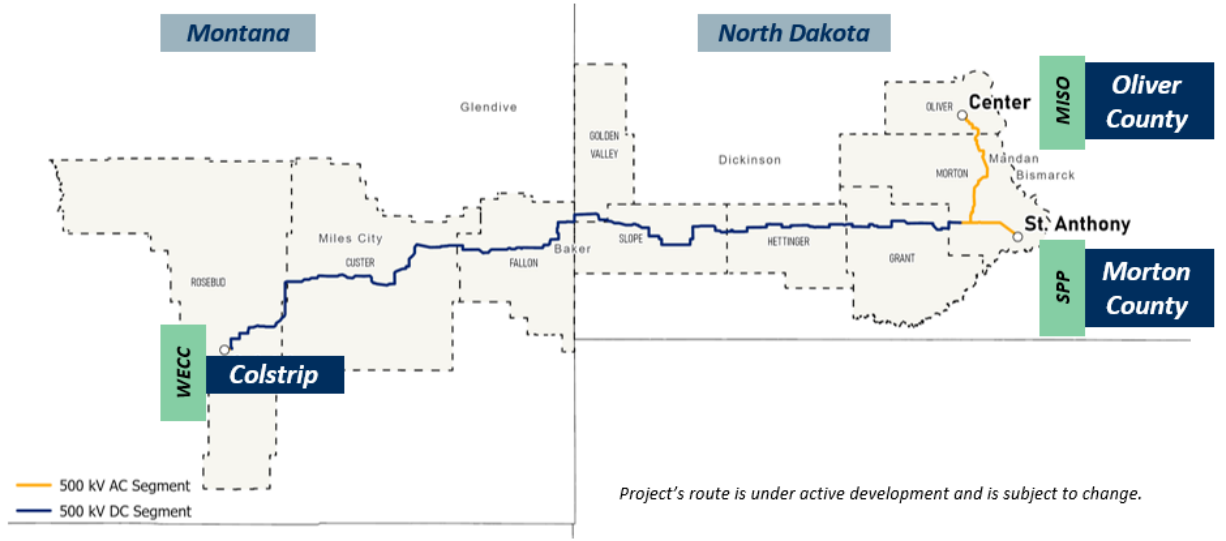
On May 28, PGE announced a memorandum of understanding (MOU) with Grid United for potential participation in the North Plains Connector transmission project.

NPC is an approximately 412-mile high-voltage direct-current (HVDC) transmission line to be constructed with endpoints near Bismarck, North Dakota and Colstrip, Montana.

The North Plains Connector will be the nation's first HVDC transmission connection among three regional U.S. electric energy markets - the Midcontinent Independent System Operator, the Western Interconnection and the Southwest Power Pool - providing additional flexibility and the sharing of resources across multiple time zones.

PGE plans to demonstrate the costs and benefits of participation in NPC throughout CEP/IRP processes.

Preliminary Route



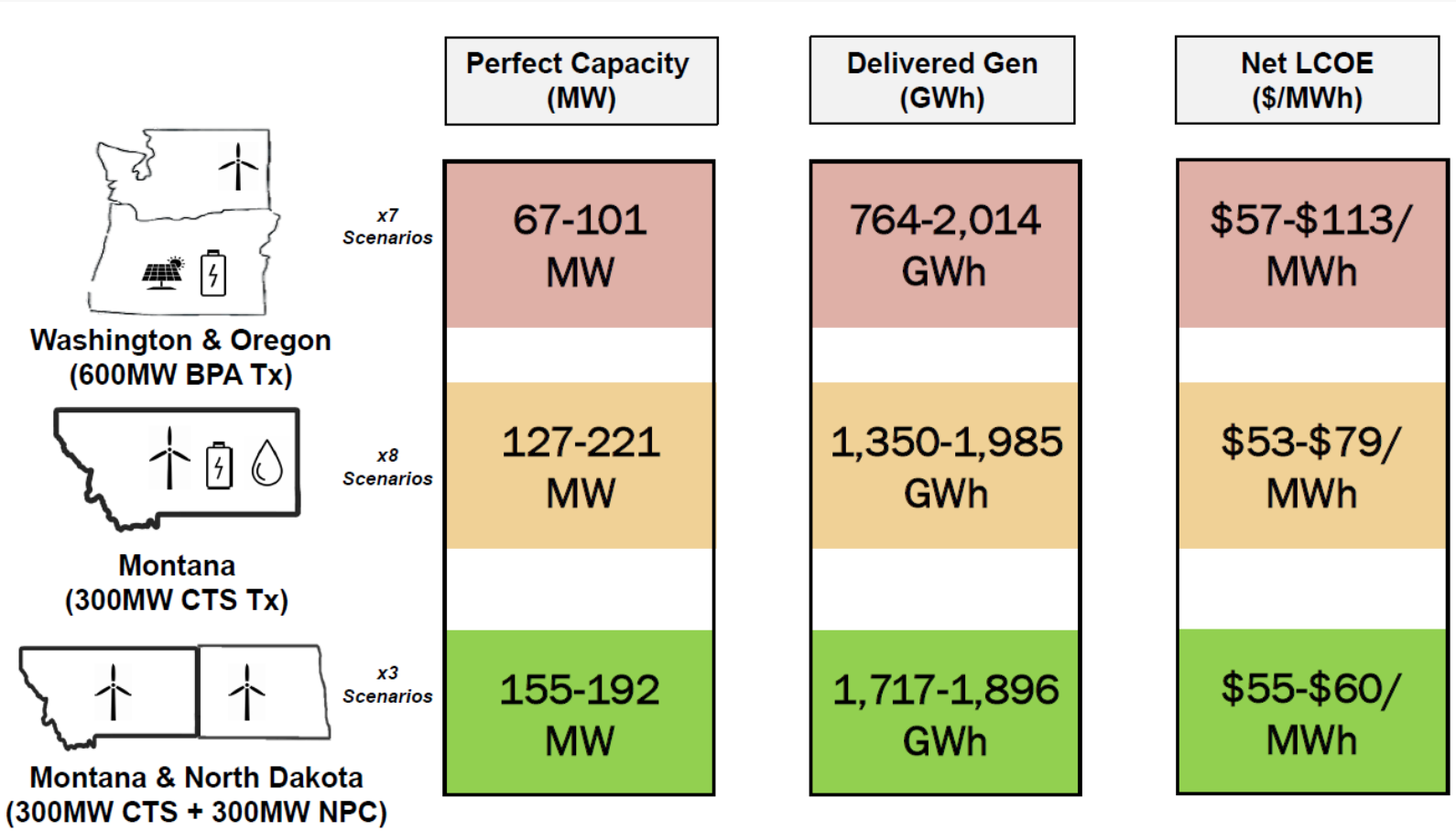
Project Configuration

Development	Grid United and ALLETE
Length	~412 mi. | ~85% private ROW acquired
Configuration	HVDC (VSC) | 525 kV | 3,000 MW | bi-directional
Interconnections	• WECC – 3,000 MW into Colstrip, MT 500kV system • MISO – 1,500 MW (AC) to new substation in Oliver County, ND; connects to MN Power (an ALLETE company) upgrades at MISO endpoint • SPP – 1,500 MW (AC) to new substation in Morton County, ND
Timeline	Construction start: 2028 – 2029 (expected) COD: 2031 – 2032 (expected)

Resources in Dakotas, Montana, and in alternative markets could bring low-cost energy

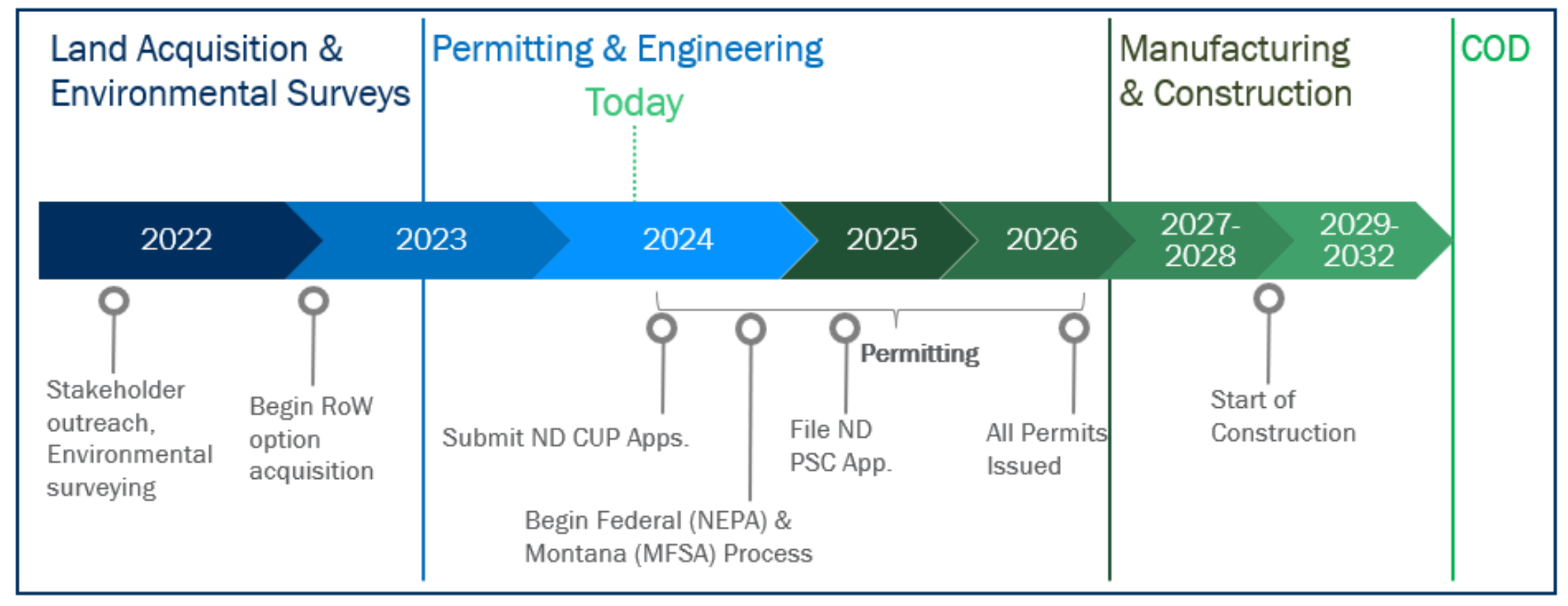
Resources that could be delivered via this line have the potential to complement the resource additions in Oregon.

PGE will continue working with regional partners and stakeholders to demonstrate value to customers.



Analysis as of August 2023

Anticipated Timeline



Hourly Energy & Emissions Accounting – Part I

Chris White, PGE

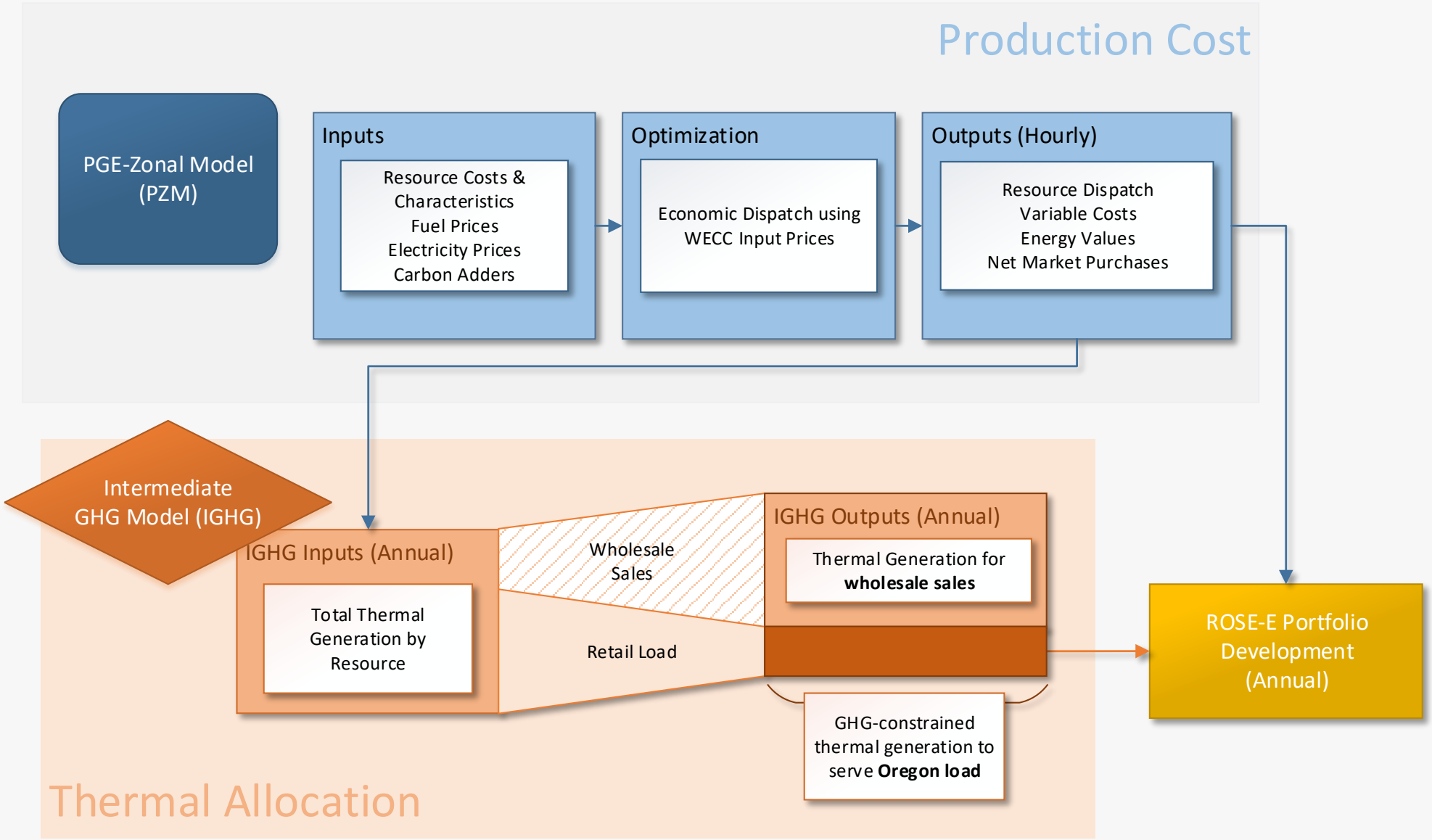
Part I Discussion Framework

Describe 2023 IRP modeling processes and identify previous feedback from stakeholders

Hourly analysis of 2023 IRP preferred portfolio

Identify actions to improve hourly modeling of PGE's energy position

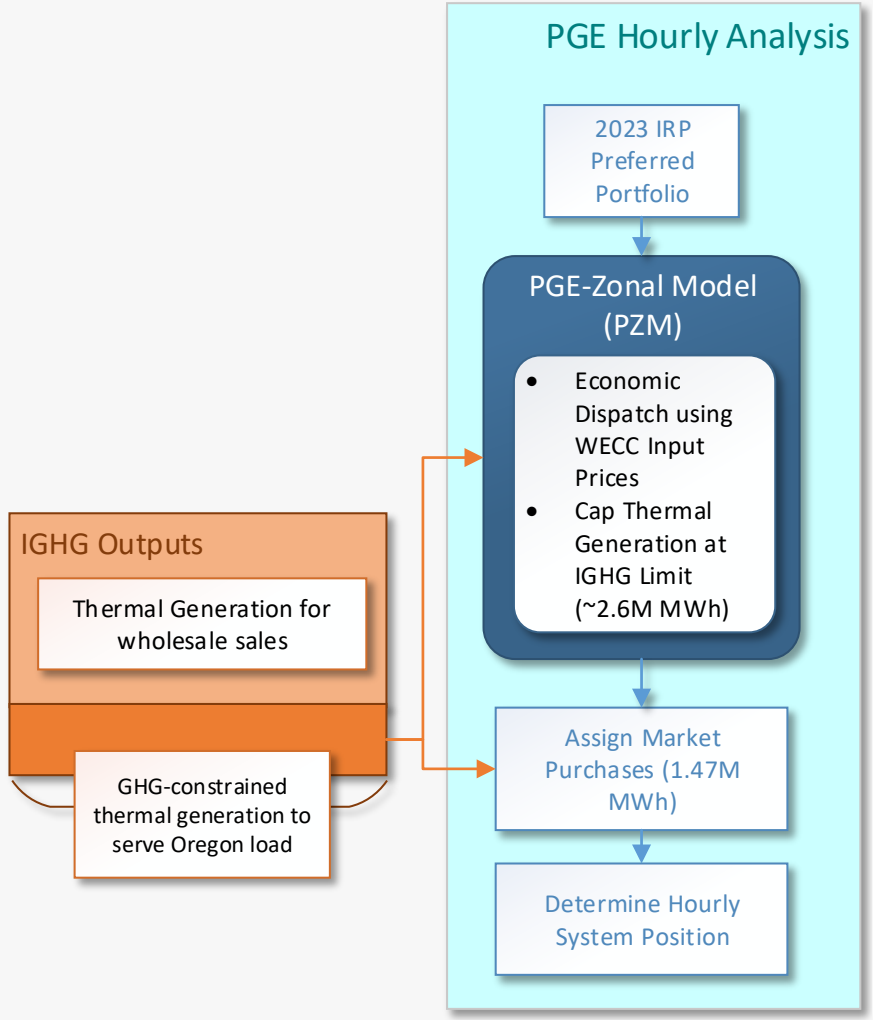
2023 CEP/IRP Methodology



Round 1 Comments: PGE Response

On September 6, 2023, PGE filed LC80 – Reply to Round 1 Comments. In Section 4.7.1, PGE included an hourly analysis of the preferred portfolio.

- Hourly Position (+/-) =
  - Generation + Market Purchases - Load
- The annual position was adequate on average (9MWa long).
- But how will PGE resolve hours in which PGE is short on generation and market purchases to meet load?



Round 1 Comments: PGE Response

Modeling Questions in PGE's Hourly Analysis

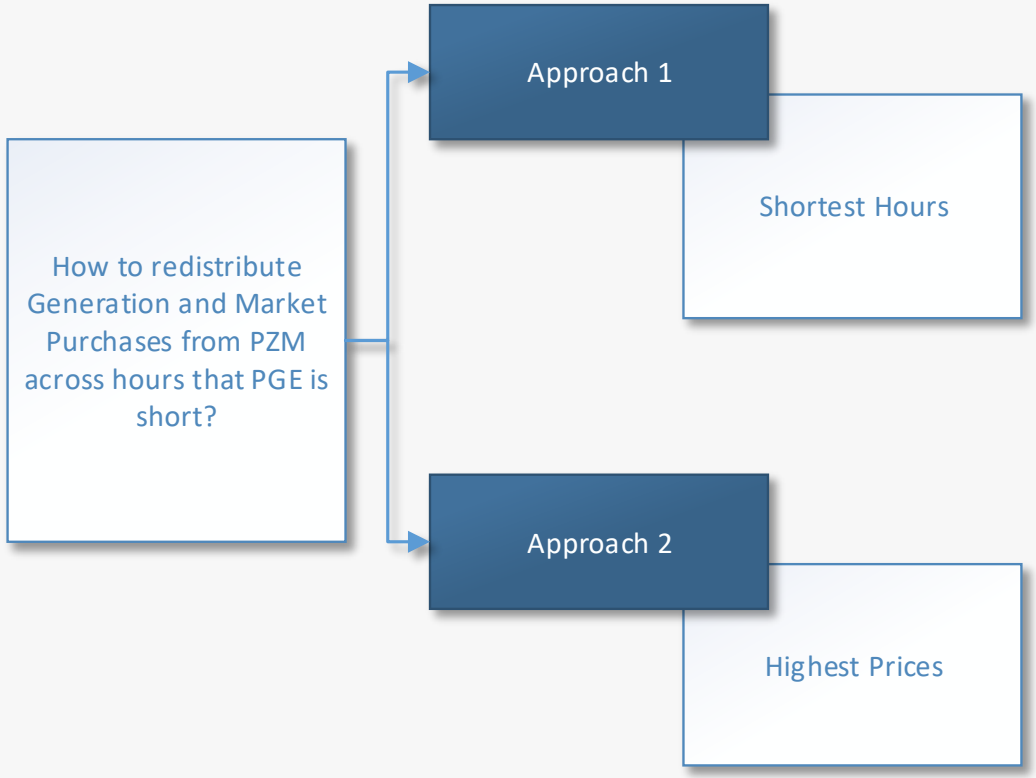
Why schedule thermal generation to serve retail load in hours in which PGE is long?

- Economic dispatch in PZM allocated thermal dispatch to hours when PGE is already long.
- Reallocated this thermal generation of 148 GWh to hours when PGE is estimated to be short.

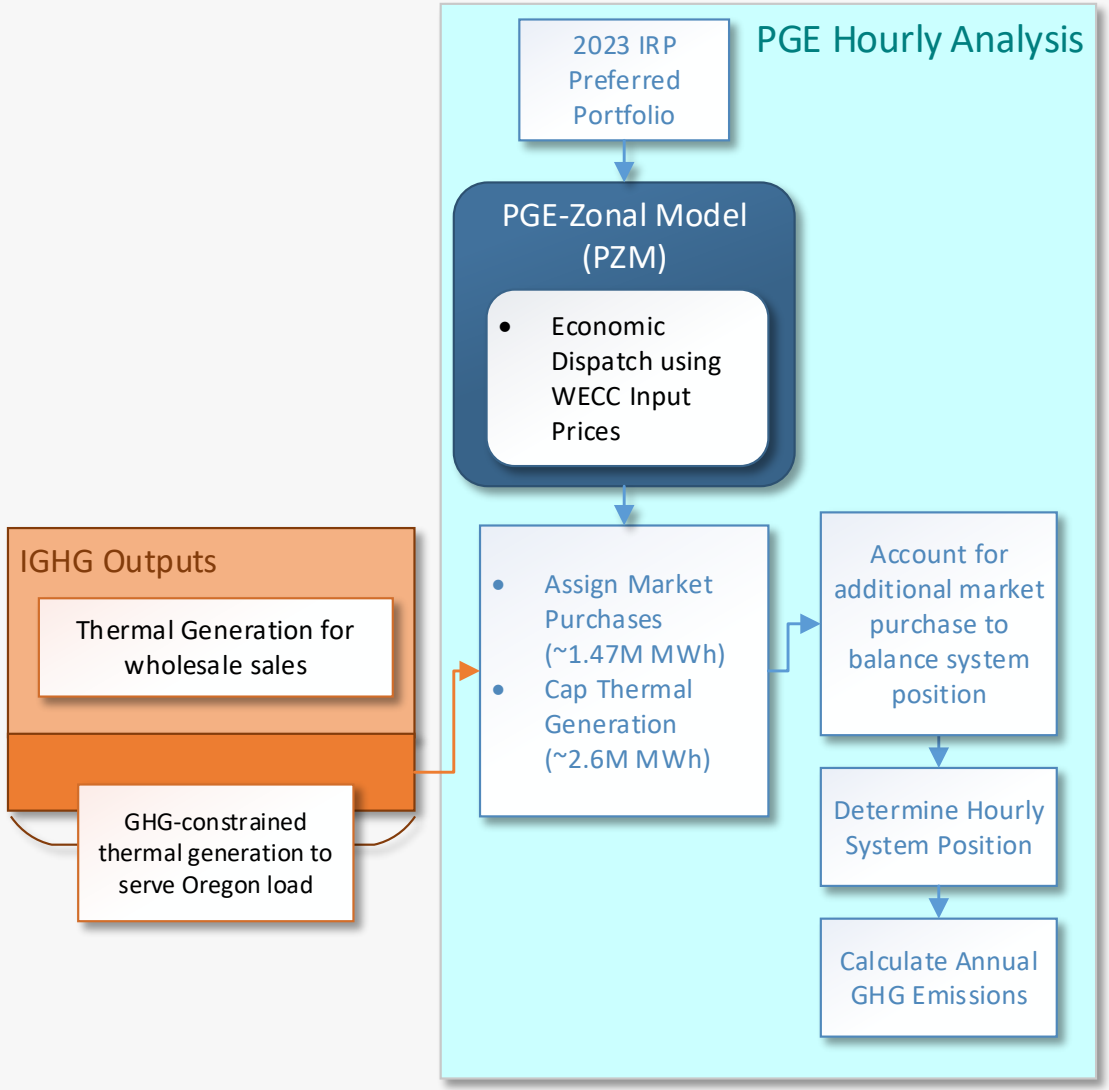
How should emitting market purchases be distributed across the year?

- Assumed that PGE would not make market purchases with associated emissions in hours in which the company was long.

Both approaches reduced the number and total MWh's that PGE is short across the year.



Round 2 Comments: PGE Response



On November 21, 2023, PGE filed LC 80 - Reply to Staff Round 2 Comments and Recommendations that includes an analysis of total 2030 emissions under the 2023 preferred portfolio.

- PGE expanded upon its Round 1 Comments by presenting the GHG hourly emissions from the resources included in the preferred portfolio.
- PGE's hourly analysis demonstrated that emissions would exceed the 1.62mmtCO2e target as modeled.

Modeling Concerns for GHG Hourly Analysis

Each of these analyses suggested an energy position with some hours of deficit

- Assuming no market to buy non-emitting energy in those hours, the analysis forecasted the need to purchase energy with associated emissions
- In this case PGE would be forecasting HB 2021 non-compliance

PGE agreed with the parties who articulated these positions

To return to forecasted HB 2021 compliance, PGE would need to add generation resources to the Action Plan

PGE disagreed with the parties who articulated these positions

- To identify the type and size of the resource as well as the timing of incremental resource additions, PGE undertakes a well-developed process (portfolio analysis) to ensure the investments present the best combination of cost and risk
- PGE raised several concerns about its ability to accurately select specific need and resources within LC 80 – these concerns are articulated in the following two slides

Modeling Concerns for GHG Hourly Analysis

Modeling Concerns	Description
Allocating Thermal Generation	The two approaches that were used for allocating thermal generation to serve retail load or sell thermal generation into the wholesale market were simplistic. The results of these allocations had a large effect on the shape of PGE's resulting energy position.
Allocating Market Purchases	The two approaches that were used for allocating market purchases to serve retail load were simplistic. The results of these allocations had a large effect on the shape of PGE's resulting energy position.
Battery and Hybrid Storage Dispatch	In the 2023 IRP/CEP production cost modeling, storage resources were dispatched to price. This dispatch logic omitted important information about PGE's system position and emissions impact.

Modeling Concerns for GHG Hourly Analysis

Modeling Concerns	Description
Model Overfitting	PGE did not capture any volatility in influential input data, such as the shapes of variable energy resources, which led to deterministic results that fit too closely to historical data.
Resource Adequacy Modeling C-50 Scenarios	PGE applied C-50 conditions to expected weather, plant operations and hydro conditions. There was no representation of the alternative resource adequacy modeling scenarios.
Hourly Load Profile	PGE applied an hourly shape to the monthly load forecast to create an hourly load profile. PGE did not explore alternative hourly shapes to capture variation in demand.
Non-Emitting Market Generation	PGE was unable to address the energy and emissions impact of relying on the WECC-wide emitting and non-emitting market without estimates of availability of WECC-wide emitting and non-emitting generation. This topic is further discussed in the next 3 slides.

Market Non-Emitting Generation

The yearly iGHG model in the filed CEP/IRP utilized an assumption that PGE was able to buy and sell non-emitting generation at times in which it was short and long.

- If this assumption was false, then both PGE and Staff's draft analyses were in alignment. Both pointed to a need for an increased quantity of non-emitting generation to be acquired between now and 2030 to ensure compliance with HB 2021 under expected average conditions.

- If this assumption was true, then this analysis indicated that meeting emission reduction targets with the preferred portfolio's set of incremental resource additions is possible under expected conditions.

Market Non-Emitting Generation

"… if PGE is not able to access adequate non-emitting generation from the market when it is needed, the emissions resulting from the Company's preferred portfolio could fall outside of the Company's 1.62 mmtCO2e target." (December 14, 2023, Staff Report)

- Variation in non-emitting energy resources may be more highly correlated across PGE's footprint than non-emitting energy generation profiles across WECC.
- No assessment of the availability of non-emitting energy resources during periods when PGE's non-emitting generation is scarce.

Market Non-Emitting Generation

"PGE's plan relies on the ability to access non-emitting generation, at no price premium." (December 14, 2023, Staff Report)

- In the analysis provided by PGE in the response to LC80 Round 2 Comments, PGE assumed no market availability for non-emitting energy.
  - All market purchases above those allocated by the IGHG model were treated as unspecified and assigned the default emission factor.
  - Assigning the default emissions factor is consistent with current Oregon DEQ GHG reporting requirements.
- However, it is unclear as to what extent the regional diversity of non-emitting generation will provide Oregon retail customers with clean energy.

Staff Recommendation 3

In the December 14, 2023 Staff Report, Staff identified the following impacts associated with PGE's current annual aggregation of emissions accounting:

- PGE's annual approximations neglect important aspects of system operations that may impact the company's annual GHG emissions.
- PGE's plan relies on the ability to access non-emitting energy from the market during hours when PGE's load exceeds its available non-emitting generation, at no price premium.
- Staff is concerned that this assumption results in an overly optimistic assessment of the resource actions.

Commission Directive

On April 18th, the Public Utility Commission of Oregon issued Order No. 24-096 directing PGE to make the following revisions and resubmit the revised plan **with** its CEP/IRP Update in 2025 according to Staff Recommendation 3:

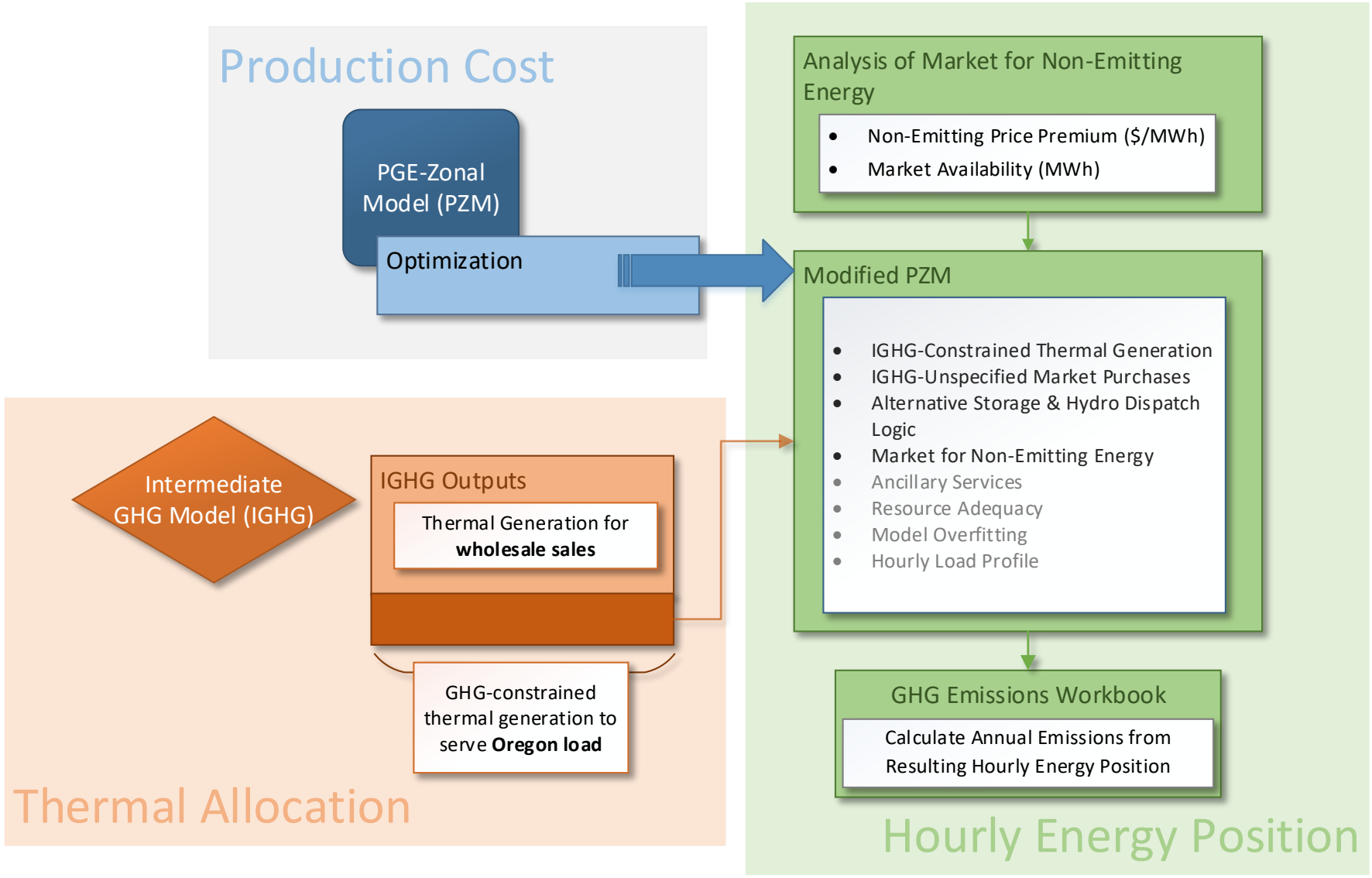
- PGE shall conduct hourly production cost simulation of its preferred portfolio under the reference case in a manner that separately tracks hourly purchases and hourly sales. PGE will use this analysis to revise its GHG emissions forecast and to revise its submission to DEQ.

- PGE shall update the preferred portfolio accordingly and provide a brief narrative explanation of the key planning insights derived from this exercise.

PGE Actions for Hourly Emissions Accounting

Modeling Concerns	Potential Actions	
Non-Emitting Market Generation	PGE has hired an external consultant to provide estimates of market availability for non-emitting generation and corresponding non-emitting price premiums.	In Progress
Battery and Hybrid Storage Dispatch Logic	Replace the current economic dispatch logic with an alternative that better incorporates the need to reduce GHG emissions.	In Progress
Thermal Generation Allocation	Explore alternatives to price-sorting or deficit-sorting logic to incorporate thermal operating constraints and prevent thermal dispatch when PGE is already long.	Proposed
Market Purchase Allocation	Explore alternatives to price-sorting or deficit-sorting logic to prevent market purchases when PGE is already long and incorporate a better understanding of the non-emitting market conditions.	Proposed
Hydro Dispatch Logic	Consider alternative hydro dispatch logic that is co-optimized with other dispatchable resources.	Proposed
Resource Adequacy Modeling	Create alternative C-level choices for low and high scenarios to expand the analysis beyond the C-50 average system conditions.	Unlikely for Update
Model Overfitting	Add stochastic representation of variable energy resources profiles to capture uncertainty surrounding VER volatility.	Unlikely for Update
Ancillary Services	Expand PZM modeling to include hourly AS requirements.	Unlikely for Update
Hourly Load Profile	Add variation in load forecasts and load shapes.	Unlikely for Update

CEP/IRP Update



Hourly Energy & Emissions Accounting Part II – Capacity Expansion

Rob Campbell, PGE

Need to Link Hourly Analysis to Capacity Expansion Modeling

PGE's capacity expansion model, **ROSE-E**, makes resource addition decisions for energy need at an annual granularity, ensuring energy sufficiency on average across the year

Conducting modeling at annual granularity likely understates the quantity of resources needed to meet HB 2021 GHG targets

Alignment between resource generation and load at an hourly level is not guaranteed using annual capacity expansion leaving PGE in a short position in some hours

Addressing short hours requires adding more resources – in past analysis* additional resources were added without being informed by capacity expansion modeling

* Hourly analysis done is response to comments in the LC 80 Docket

Goals of New Method

Produce a portfolio that provides sufficient energy and meets HB 2021 GHG emission reduction targets at an hourly level

Incorporate principles of portfolio optimization so that resource additions are targeted at meeting this objective

Create an energy adequate and compliant portfolio in a more informed manner than guess-and-check approach

Enhanced Capacity Expansion Modeling Approach

Use a process that connects ROSE-E and PGE's Hourly Analysis to account for the coincidence of proxy resource generation profiles with forecast hours of energy need

Encourage the addition of resources in ROSE-E that are most effective at addressing hours of need identified in the hourly analysis

1. New metric that captures coincidence of generation with hours of need
2. New constraint to influence resource additions in ROSE-E

New Metric: Weighted Annual Capacity Factors

ROSE-E currently relies on annual capacity factors (CF) which represent the percent of generation produced compared to plant maximum output across a full year

To capture the impact of intra-annual generation shapes of proxy resources, a different metric is needed to drive resource additions toward those that help meet identified hours of energy need

A new metric, weighted annual capacity factor (CF_w), provides a measure of the likelihood of generating during hours of need for each proxy renewable resource in ROSE-E

Calculation of Weighted Capacity Factors

1. Compare hourly generation profiles of proxy renewable resources from **Aurora** against PGE's hourly energy position
2. In hours when PGE is energy sufficient or long, replace CF with zero
3. Take annual average of modified hourly CFs to produce CF_w

Example

		CF		**CFw**	
Hour	Short Position?	CV Solar	Gorge Wind	CV Solar	Gorge Wind
1	No	75%	50%	0%	0%
2	No	87%	11%	0%	0%
3	No	94%	2%	0%	0%
4	No	93%	50%	0%	0%
5	Yes	91%	0%	91%	0%
6	Yes	90%	10%	90%	10%
7	Yes	0%	75%	0%	75%
8	Yes	0%	78%	0%	78%
9	Yes	0%	65%	0%	65%
10	Yes	0%	87%	0%	87%
…					
8760	No	50%	71%	0%	0%
Annual Avg		**27%**	**44%**	**14%**	**24%**

- Higher coincidence of generation with hours of need translates to higher CFw
- CFw is lower than CF for all resources
- Fewer short hours mean less CFw credit for all resources

Note: All numbers are for illustrative purposes only

New Constraint: Problematic Hours

Total contribution of each proxy renewable to meeting the constraint in each year is its weighted CF times MW of the resource added: CF_w * MW = $Contribution_{ph}$

Constraint in ROSE-E ($Constraint_{ph}$) says that the sum of $Contribution_{ph}$ across all resource additions must be greater than a target metric

Target metric is a unitless value that encourages addition of resources that contribute to hourly sufficiency

Like any other constraint in ROSE-E, optimization will meet the constraint using the lowest-cost combination of available resources

Note: While storage additions also help address hours of energy need, they are not included in the problematic hours constraint. Storage added to meet capacity needs in ROSE-E is added independently to the hourly analysis and dispatched to minimize hourly deficits.

Example of ROSE-E Problem Hours Constraint

Constraint		
Gorge Wind CF_w x MW + CV Solar CF_w x MW	>=	Target Metric

Potential Solution if Target Metric is 100:

300 MW of Gorge Wind and 240 MW of CV Solar

0.24 x 300 + 0.14 x 240 = 100

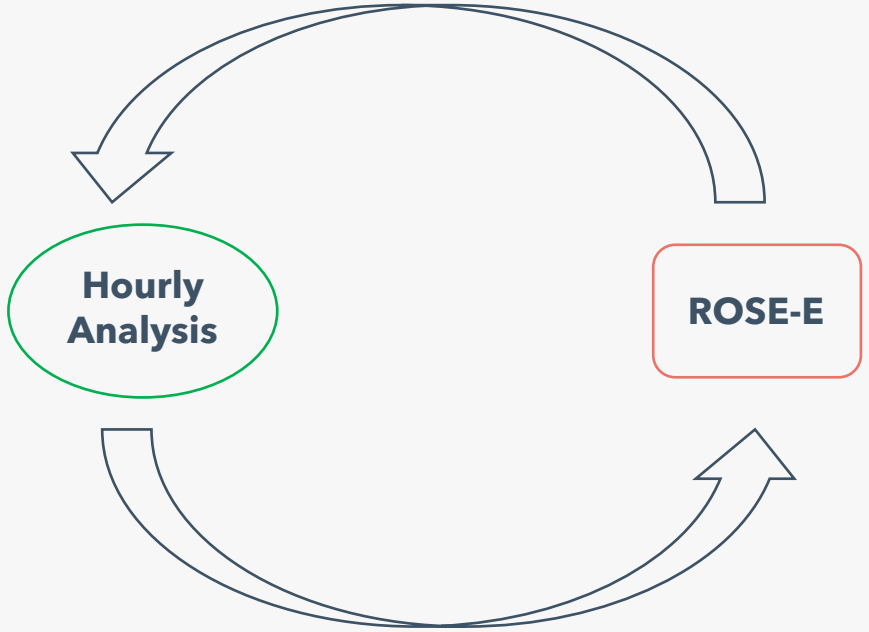
Note: All numbers are for illustrative purposes only

Checking for a Compliant Portfolio

2030 resource buildout from ROSE-E using new constraint is passed back to Hourly Analysis to assess impact on PGE's hourly position and annual emissions

The new constraint will result in a larger resource buildout than when meeting annual constraints only, but may not prove to be sufficient at an hourly level

If the first portfolio is not sufficient, iterate between ROSE-E and Hourly Analysis to target remaining problematic hours until none remain



Iterative Process

New resources from each iteration are added to the portfolio in PGE's Hourly Analysis

Energy from the new resources contributes to PGE's hourly energy position based on hourly generation shapes, reducing the number of hours of need

With each iteration in ROSE-E, resource buildout increases because of declining CFw contributions

Each time new resources are added, the hourly energy position and annual GHG emissions are checked

Iterations occur until GHG targets and hourly energy sufficiency are achieved

The final version of portfolio is passed to Aurora for testing

Example of Iterative Weighted Capacity Factors

Iteration 1

Short hours = 3000

Renewable Resource	CFw
Gorge Wind	0.24
Christmas Valley Solar	0.14

Iteration 2

Short hours = 1500

Renewable Resource	CFw
Gorge Wind	0.18
Christmas Valley Solar	0.12

Iteration 3

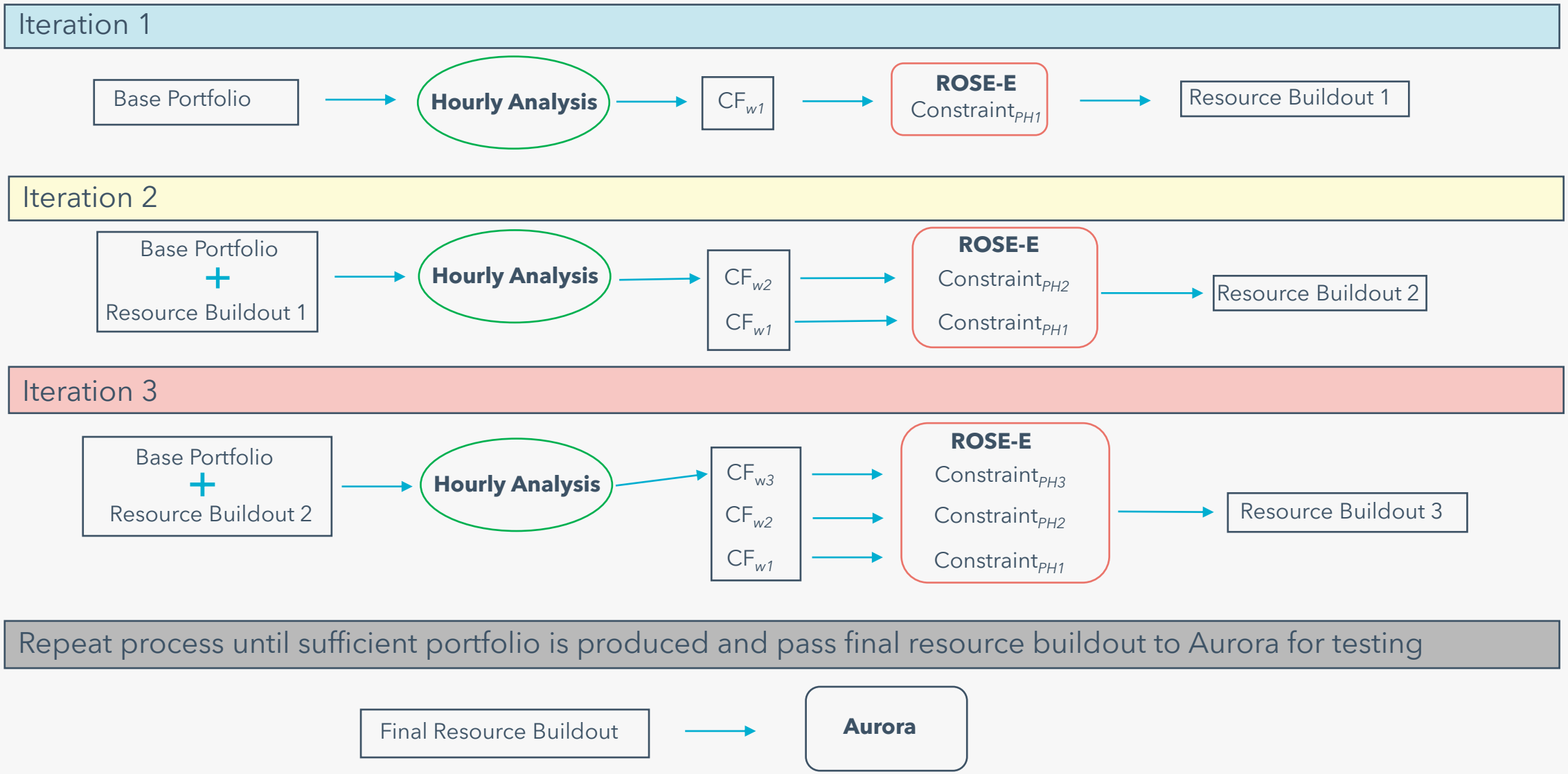
Short hours = 500

Renewable Resource	CFw
Gorge Wind	0.12
Christmas Valley Solar	0.06

The number of short hours decreases with each iteration, reducing the likelihood of renewable resource generation coinciding with hours of need, lowering CF_w

Note: All numbers are for illustrative purposes only

Illustration of Iterative Process



Qualifying Facility Forecast

Kori Mead, PGE

Qualifying Facility (QF) Assumptions

The 2023 IRP/CEP used the following QF assumption in the portfolio:

- "All QFs that are currently online plus 50 percent of executed Schedule 201 projects and 100 percent of executed Schedule 202 projects are included."

Order No. 24-096 directed PGE to do the following:

- "We adopt Staff's recommendation to decline to acknowledge PGE's avoided cost pricing inputs and direct PGE to recalculate its IRP inputs using an assumption of 75 percent for QF renewals and the QF success rate for Schedule 202 projects."

QF Assumption Summary

Assumption		2023 IRP	Current
Online	Schedule 201*	100%	100%
	Schedule 202**	100%	100%
Contracted, Not Online	Schedule 201*	50%	50%
	Schedule 202**	100%	75%
Renewal Rate	Schedule 201*	0%	75%
	Schedule 202**	0%	75%

*Schedule 201 – QFs <10MW ("standard" contracts);
**Schedule 202 – QFs >10MW ("negotiated" contracts)

Updated QF Forecast

Forecast based on 2023 IRP

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
QFs																		
MW	377	440	440	435	435	429	429	429	429	418	340	330	297	204	147	58	5	5
MWh	790,735	977,157	994,686	962,537	950,660	917,052	914,918	914,856	899,939	770,542	697,981	659,143	512,520	382,700	193,064	82,722	7,831	7,845
MWa	90	111	114	110	109	104	104	104	103	88	80	75	59	44	22	9	1	1

Current Forecast[1]

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
QFs																		
MW	358	406	406	404	404	403	403	403	403	400	381	378	370	347	332	314	304	304
MWh	764,397	904,418	916,475	888,717	876,840	878,528	876,671	876,796	861,900	754,244	822,578	800,637	698,679	705,311	622,954	565,448	509,280	510,675
MWa	87	103	105	101	100	100	100	100	98	86	94	91	80	80	71	65	58	58

Difference

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
QFs																		
MW	(18)	(34)	(34)	(30)	(30)	(26)	(26)	(26)	(26)	(17)	40	48	73	143	186	256	299	299
MWh	(26,338)	(72,739)	(78,212)	(73,820)	(73,820)	(38,524)	(38,247)	(38,060)	(38,039)	(16,299)	124,597	141,494	186,159	322,611	429,890	482,726	501,448	502,830
MWa	(3)	(8)	(9)	(8)	(8)	(4)	(4)	(4)	(4)	(2)	14	16	21	37	49	55	57	57

[1] *Current Forecast includes updates to QF assumptions, and an updated snapshot as of May 8, 2024*

Questions

NEXT STEPS

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

Upcoming Roundtable: July 11th

Thank you

Contact us at
IRP.CEP@PGN.COM

An

kind of energy

ACRONYMS

ART: annual revenue-requirement tool
ATC: available transfer capacity
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
CEC: California energy commission
CEP: clean energy plan
CF: conditional firm
CF: capacity factors
CFw: weighted capacity factors
CV: Christmas Valley
DC: direct current
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
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
MOU: memorandum of understanding
MW: megawatt
MWa: mega watt average
NAICS: North American industry classification system
NCE: non-cost effective
NG: natural gas
NPC: North Plains Connector
NPVRR: net present value revenue requirement
ODOE: Oregon department of energy
PPA: power purchase agreement
PSH: pumped storage hydro
PUC: public utility commission
PV: photovoltaic
QF: qualifying facility
REC: renewable energy credit
RLRR: low carbon price future
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
UPS: uninterruptible power supply
VER: variable energy resources
VPP: virtual power plant
WECC: western electricity coordinating council