BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 390

In the Matter of	)	
	)	
PACIFICORP, dba PACIFIC POWER,	)	OREGON CITIZENS' UTILITY BOARD'S EXHIBITS
2022 Transition Adjustment Mechanism.	)	
	)	
	)	

The Oregon Citizens' Utility Board ("CUB") CUB submits the following Exhibits for inclusion in the administrative record in this proceeding:

- CUB 300 –Redacted *Final Shortlist for the 2020 All Source Request for Proposals and Sensitivity Analysis Presentaion* in the docket number UM 2059, filed July 30th, 2021.
- CUB 301 – *PacifiCorp's Opening Comments* in the docket number UM 2024, filed March 16th, 2020.
- CUB 302 – *Opening Comments of Portland General Electric Company* in the docket number UM 2024, filed March 16th, 2016.

Dated this 23rd day of August, 2021.

Respectfully submitted,

Michael P. Goetz, OSB #141465
General Counsel
Oregon Citizens' Utility Board
610 SW Broadway, Ste. 400
Portland, OR 97205
(503) 227-1984 phone
mike@oregoncub.org

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 30, 2021

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

RE: UM 2059 – Final Shortlist for the 2020 All Source Request for Proposals and Sensitivity Analysis

PacifiCorp, d/b/a Pacific Power (PacifiCorp) submits the attached highly confidential and redacted presentation covering the Final Shortlist (FSL) for the 2020 All-source RFP and sensitivity analyses as revised and provided to the Independent Evaluator on July 20, 2021. The presentation is an update to the original FSL presentation provided June 8, 2021. Highly confidential information is provided subject to modified protective order 21-202.

Please direct informal inquiries regarding this filing to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's **Final Shortlist for the 2020 All Source Request for Proposals and Sensitivity Analysis Presentation** on the parties listed below via electronic mail and/or or overnight delivery in compliance with OAR 860-001-0180.

Service List
UM 2059

MATTHEW MULDOON **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308-1088 matt.muldoon@puc.oregon.gov	JACK STODDARD MORGAN LEWIS & BOCKIUS ONE MARKET SPEAR STREET TOWER SAN FRANCISCO CA 94105 fjackson.stoddard@morganlewis.com
ALLIANCE OF WESTERN ENERGY CONSUMERS	
BRENT COLEMAN **(C)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY, SUITE 450 PORTLAND OR 97201 blc@dvclaw.com	BRADLEY MULLINS **(C)** MOUNTAIN WEST ANALYTICS 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 brmullins@mwanalytics.com
TYLER C PEPPLE **(C)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com	
AVANGRID RENEWABLES	
JIMMY HULETT 1125 NW COUCH ST STE 700 PORTLAND OR 97209 jimmy.hulett@avangrid.com	ERIN KESTER AVANGRID RENEWABLES, LLC 1125 NW COUCH STE 700 PORTLAND OR 97209 erin.kester@avangrid.com
INNERGEX	
SEAN YOVAN INNERGEX syovan@innergex.com	
INTERMOUNTAIN WIND	
DAVID D'ALESSANDRO STINSON LLP 1775 PENNSYLVANIA AVE. NW WASHINGTON DC 20006 david.dalessandro@stinson.com	PAUL MARTIN INTERMOUNTAIN WIND PO BOX 353 BOULDER CO 80306 paul@intermountainwindllc.com

HARVEY REITER STINSON LLP 1775 PENNSYLVANIA AVE. NW WASHINGTON DC 20006 harvey.reiter@stinson.com	
NIPPC	
JONI L SLIGER **(C)** SANGER LAW PC 1041 SE 58TH PLACE PORTLAND OR 97215 joni@sanger-law.com	SPENCER GRAY NIPPC sgray@nippc.org
IRION A SANGER **(C)** SANGER LAW PC 1041 SE 58TH PLACE PORTLAND OR 97215 irion@sanger-law.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
SUDESHNA PAL **(C)** OREGON CITIZENS UTILITY BOARD sudeshna@oregoncub.org	
PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com	CARLA SCARSELLA **(C)** PACIFIC POWER 825 MULTNOMAH STREET STE 2000 PORTLAND OR 97232 carla.scarsella@pacificorp.com
RENEWABLE NORTHWEST	
RENEWABLE NORTHWEST 421 SW 6TH AVE., STE. 975 PORTLAND OR 97204 dockets@renewablenw.org	MAX GREENE **(C)** RENEWABLE NORTHWEST 421 SW 6TH AVE STE 975 PORTLAND OR 97204 max@renewablenw.org

STAFF	
ROSE ANDERSON **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308 rose.anderson@puc.oregon.gov	JOHANNA RIEMENSCHNEIDER **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4796 johanna.riemenschneider@doj.state.or.us
SWAN LAKE NORTH HYDRO LLC	
NATHAN SANDVIG SWAN LAKE NORTH HYDRO LLC 404 WYMAN STREET WALTHAM MA 02451 nathan.sandvig@nationalgrid.com	ERIK STEIMLE SWAN LAKE NORTH HYDRO LLC 220 NW 8TH AVE PORTLAND OR 97209 erik@ryedevelopment.com
CHRIS ZENTZ VAN NESS FELDMAN LLP cdz@vnf.com	

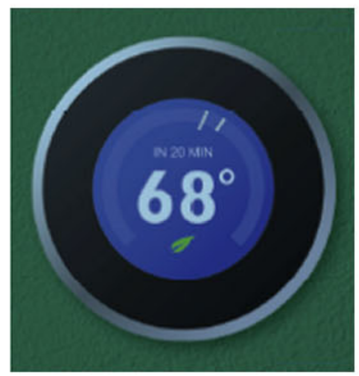
Dated this 30th day of July, 2021.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

2020 All Source RFP
Final Short List
Revised July 20, 2021



PUBLIC VERSION

PACIFICORP
POWERING YOUR GREATNESS

RFP Modeling Revisions

Issues with the previously filed final shortlist (FSL) analysis were identified as a result of a verification process initiated after developing responses to questions ask by the independent evaluators:

- Net delivery costs and indicative generation values were revised to reflect corrections in annual generation and net capacity factors:
  - Embedded text (rather than values) in provided generation profiles resulted in the omission of hours with no generation in some bidders' 8760 profiles.
  - Solar bids that provided net solar and storage 8760 profiles, instead of the requested solar output.
- Failed uploads to the model resulted in use of proxy resource profiles, rather than bid profiles in some instances.
- The modeled location of one bid was corrected from Utah North to Wyoming East.
- PacifiCorp repeated and expanded its final shortlist analysis after incorporating and verifying these changes.

Key Findings

- FSL bid selections remain unchanged.
- Modeling changes reduce the value of resources in eastern Wyoming; however, the eastern Wyoming bids continue to provide customer benefits.
- Bid selections by price-policy show minimal changes.
  - The low gas, no CO_2 bid-portfolio no longer includes Steel Solar
- After revisions, the LN Bid portfolio appears to be low cost under the base price-policy scenario, but the cost trend is notably unfavorable at end of study horizon.
- SNS bids with proxy resources selected under an LN price-policy scenario (the SNS Bid-LN portfolio) results in lower costs than the LN Bid portfolio when analyzed under the base price-policy scenario (MM).

PACIFICORP
POWERING YOUR GREATNESS

Introduction

- PacifiCorp issued the 2020AS RFP to the market on July 7, 2020; bidder responses were returned to PacifiCorp for evaluation on August 10, 2020
  - The market responded with over 28,000 MW of conforming bids
  - An additional 12,500 MW of bids were submitted that did not conform with minimum requirements set forth in the 2020 AS RFP
- In October 2020, the initial shortlist was identified, which included 5,453 MW of renewable resource capacity—2,974 MW of solar or solar with storage (1,130 MW of battery storage), 2,479 MW of wind, and 200 MW of standalone battery capacity
- The transition interconnection cluster study process was subsequently initiated, and in April 2021, PacifiCorp began to evaluate best-and-final pricing updates from bidders
- Consistent with the bid evaluation and selection methodology set forth in the 2020AS RFP, PacifiCorp has evaluated a range of potential bid portfolios, reflecting results from the transitional interconnection cluster study process, to select the final shortlist, which includes:
  - 1,792 MW of new wind resources (590 MW as build-transfer agreements and 1,202 MW as power-purchase agreements)
  - 1,306 MW of solar capacity (all power-purchase agreements)
    - After modeling was well underway, Steel Solar I & II withdrew its combined 147 MW Utah solar and storage bids. These bids remained in the modeling effort and were removed from the Final Shortlist total after modeling was complete and not replaced.
  - 697 MW of battery energy storage system capacity—497 MW paired with solar bids (after Steel Solar I & II were removed) and 200 MW as standalone battery storage (power-purchase agreement)
- When using base case market price and CO_2 price assumptions, present-value net benefits of the final shortlist portfolio are $571 million over the best performing portfolio without bids

PACIFICORP
POWERING YOUR GREATNESS

Resource Need

Calendar Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
System										
Total Resources	10,671	10,646	10,685	10,391	10,334	9,997	9,943	9,043	8,538	8,313
Obligation	9,899	9,985	10,064	10,103	10,162	10,012	10,011	10,044	10,069	10,112
Reserves	1,310	1,321	1,331	1,336	1,344	1,325	1,324	1,329	1,332	1,338
Obligation + Reserves	11,209	11,306	11,395	11,439	11,506	11,336	11,335	11,372	11,401	11,449
System Position	(538)	(660)	(711)	(1,048)	(1,172)	(1,339)	(1,392)	(2,329)	(2,863)	(3,136)

- Final shortlist bids will help PacifiCorp fill a resource need.
- After accounting for a higher load forecast and recently signed contracts, the company's unmet capacity position is 1,172 MW in 2025—the first summer in which all resources from the 2020AS RFP will be online.
- The final shortlist has an estimated capacity contribution value of 998 MW.
- While the company's 2019 IRP assumed that over 1,400 MW of market purchases could be used to meet its requirements, the capacity position of the western interconnect is much tighter than in past years, with resource adequacy an ongoing concern in California and a growing concern elsewhere.
- The 2021 IRP assumes 500 MW market purchases available in summer and 1,000 MW in winter.

PACIFICORP
POWERING YOUR GREATNESS

Summary of Bids Evaluated

- 27 projects from 16 bidders can achieve a commercial operation date before the end of 2024 based on signed interconnection agreement or study results and were considered for selection to the final shortlist.

Project Count	East					East Total	West			West Total	Grand Total
Type	East WY	SW WY	Goshen ID	UT North	UT South		Central OR	South OR	Yakima WA		
BESS				1		1					1
Solar				1	1	2	1	1	2	4	6
Solar + BESS				2	6	8		2	1	3	11
Wind	7	1	1			9					9
Grand Total	**7**	**1**	**1**	**4**	**7**	**20**	**1**	**3**	**3**	**7**	**27**

Capacity (MW)	East					East Total	West			West Total	Grand Total
Type	East WY	SW WY	Goshen ID	UT North	UT South		Central OR	South OR	Yakima WA		
BESS				200		200					200
Solar				42	95	137	103	40	340	483	620
Solar + BESS				192	956	1,148		210	94	304	1,452
Wind	1,744	122	151			2,017					2,017
Grand Total	**1,744**	**122**	**151**	**434**	**1,051**	**3,501**	**103**	**250**	**434**	**787**	**4,288**

PACIFICORP
POWERING YOUR GREATNESS

REDACTED

2020AS RFP Final Shortlist

Project Name	Bidder	Type	Location	COD	Term/Life (Years)	Resource Capacity (MW)	Battery Capacity (MW)	Battery Duration (Hours)	Net Capacity Factor (%)	Bid PPA Price ($/MWh)	Bid PPA Price (Fixed / Esc)	Battery Price Applied to Battery Capacity ($/kW-mo)
Anticline	NextEra	Wind	WY	12/31/2024	30	100.5	n/a	n/a	[redacted]	[redacted]	[redacted]	[redacted]
Cedar Springs IV	NextEra	Wind	WY	12/31/2024	30	350.4	n/a	n/a	[redacted]	[redacted]	[redacted]	[redacted]
Rock Creek I*	Invenergy	Wind	WY	12/31/2024	30	190	n/a	n/a	[redacted]	[redacted]	[redacted]	[redacted]
Rock Creek II*	Invenergy	Wind	WY	12/31/2024	30	400	n/a	n/a	[redacted]	[redacted]	[redacted]	[redacted]
Boswell Springs	Innergex	Wind	WY	10/1/2024	30	320	n/a	n/a	[redacted]	[redacted]	[redacted]	[redacted]
Two Rivers	Blue Earth Renewables LLC & Clearway Renew LLC	Wind	WY	12/31/2024	25	280	n/a	n/a	[redacted]	[redacted]	[redacted]	[redacted]
Cedar Creek	rPlus Energies	Wind	ID	12/31/2022	25	151	n/a	n/a	[redacted]	[redacted]	[redacted]	[redacted]
~~Steel Solar I & II~~	~~DESRI~~	~~PVS~~	~~UT~~	~~12/31/2023~~	~~25~~	~~147~~	~~37.5~~	~~2~~	[redacted]	[redacted]	[redacted]	[redacted]
Rocket Solar II	DESRI	PVS	UT	12/31/2023	25	45	12.5	4	[redacted]	[redacted]	[redacted]	[redacted]
Fremont	Longroad Energy	PVS	UT	11/30/2023	20	99	49.5	4	[redacted]	[redacted]	[redacted]	[redacted]
Rush Lake	Longroad Energy	PVS	UT	11/30/2023	20	99	49.5	4	[redacted]	[redacted]	[redacted]	[redacted]
Parowan	First Solar	PVS	UT	12/31/2024	25	58	58	4	[redacted]	[redacted]	[redacted]	[redacted]
Hornshadow I	enyo energy	PVS	UT	12/31/2023	30	100	25	2	[redacted]	[redacted]	[redacted]	[redacted]
Hornshadow II	enyo energy	PVS	UT	12/31/2023	30	200	50	2	[redacted]	[redacted]	[redacted]	[redacted]
Green River I & II	rPlus Energies	PVS	UT	12/31/2024	20	400	200	2	[redacted]	[redacted]	[redacted]	[redacted]
Hamaker	ecoplexus	PVS	OR	12/31/2023	30	50	12.5	4	[redacted]	[redacted]	[redacted]	[redacted]
Hayden 2	ecoplexus	PVS	OR	12/31/2023	30	160	40	4	[redacted]	[redacted]	[redacted]	[redacted]
Dominguez I	Able Grid	BESS	UT	7/1/2024	15	n/a	200	4	[redacted]	[redacted]	[redacted]	[redacted]
Glen Canyon	sPower	Solar	UT	12/31/2023	30	95	n/a	n/a	[redacted]	[redacted]	[redacted]	[redacted]

*BTA bids (additional price information in the next slide). All other bids are PPAs.

- Total wind and solar capacity = 3,098 MW
  - Wind = 1,792 MW
  - Solar = 1,306 MW (Note: this is without Steel Solar, which is in the revised analysis but has since been withdrawn by the developer.)
- Total battery energy storage system capacity (BESS) = 697 MW
  - Paired with photovoltaic (PVS) = 497 MW (excluding Steel Solar I & II, which withdrew from the RFP after being notified it was selected to the final shortlist)
  - Standalone BESS = 200 MW

PACIFICORP
POWERING YOUR GREATNESS

REDACTED

Final Shortlist BTA Pricing

Nominal $

Project Name	Bidder	Wind Bid with Direct-Assigned Interconnection Capital Cost	Wind Owner's Capital Cost & AFUDC	In-Service Interconnection Network Upgrade Capital Cost	Total In-Service Capital Cost
Rock Creek I	Invenergy	[redacted]			
Rock Creek II	Invenergy				

- In-service capital costs total $[redacted]m ($[redacted]m for bid capital, $[redacted]m for capitalized owner's costs, AFUDC, and property tax during construction, and [redacted]m for capital associated with interconnection network upgrades).

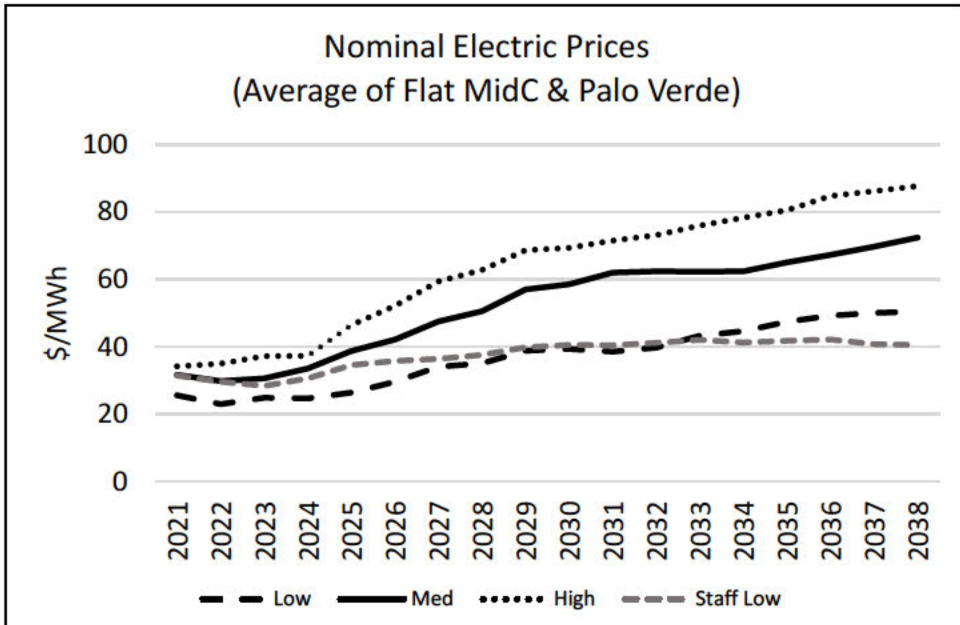
PACIFICORP
POWERING YOUR GREATNESS

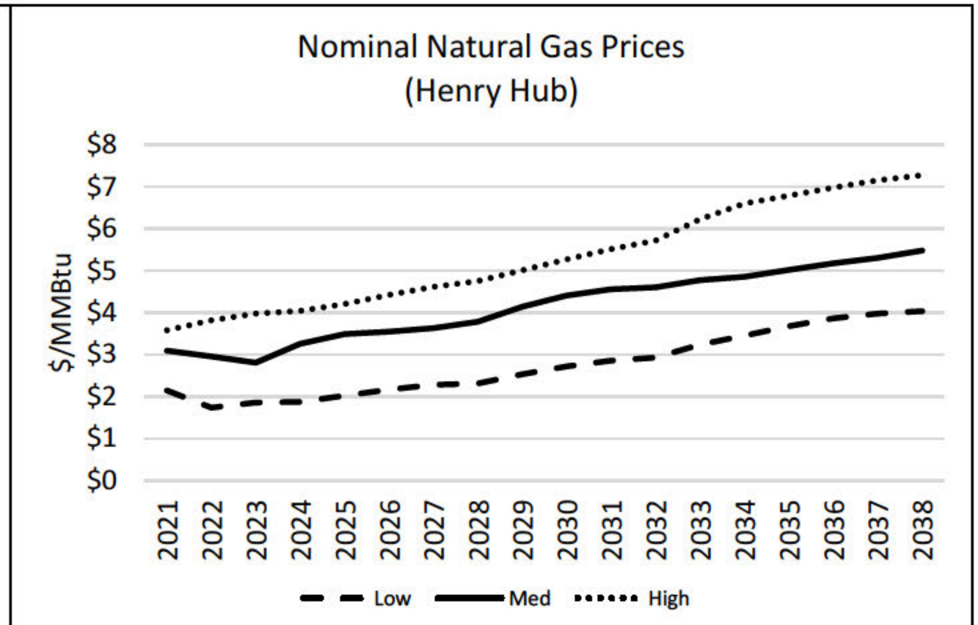
Portfolio-Selection Scenarios

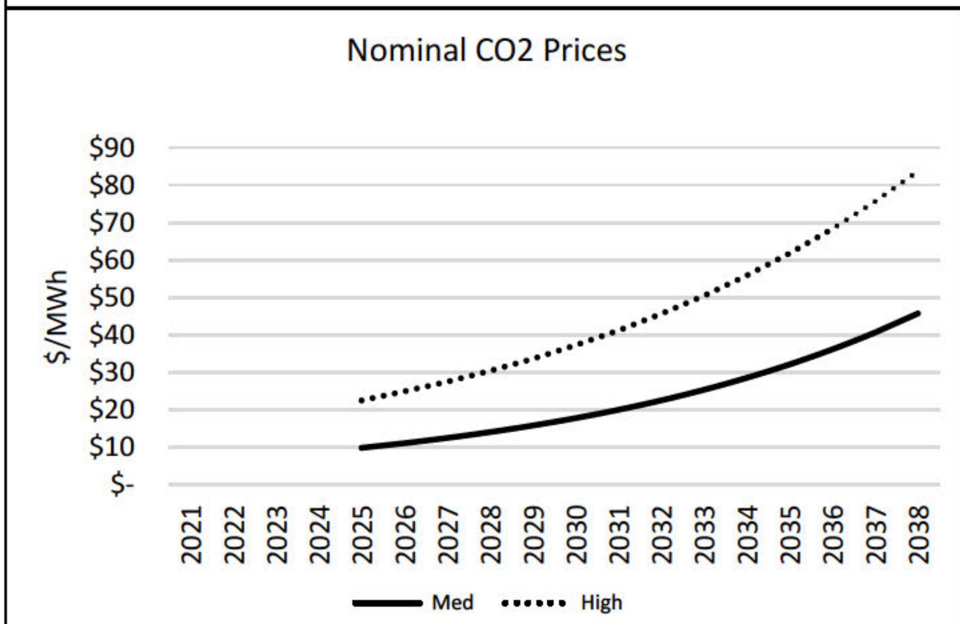
- Portfolios were selected under a range of price-policy scenarios, plus others recommended by staff of the Public Utility Commission of Oregon:
  - LN: low gas/market price, no carbon price
  - MM: medium gas/market price, medium carbon price
  - HH: high gas/market price, high carbon price
  - SL: Staff's low market price sensitivity that assumes high renewable penetration in the WECC, medium gas price, and medium carbon price
  - SNS (MM): medium gas/market price, medium carbon price, but no wholesale market sales allowed
  - SNST (MM): the same as SNS (MM), plus PTC/ITC assumed extended through 2030
  - SNS Bid (LN): bid selections from the SNS (MM) case with proxy resources selected under LN price-policy assumptions (note, this case was not in the initial FSL evaluation, but added in this update to further analyze drivers to system cost differences between the SNS and LN bid portfolios)
- Portfolios with no RFP bids were also prepared—these scenarios are compared to the final shortlist bid portfolio to calculate net customer benefits.

PACIFICORP
POWERING YOUR GREATNESS

Price-Policy Assumptions







- The assumptions for electricity prices, gas prices, and CO_2 prices summarized here were applied to the portfolio-selection scenarios summarized on the previous slide.

PACIFICORP
POWERING YOUR GREATNESS

REDACTED

Bid Selections by Scenario

Location	Company	Project / Facility Name	Resource type	Contract Type	Generating Asset (MW)	BESS Capacity (MW)	BESS Duration (Hours)	LN	MM	HH	SL	FSL SNS (MM)	SNST (MM)	Type
East WY	NextEra	Cedar Springs IV	Wind	PPA	350.4	0	0	0	350.4	350.4	350.4	350.4	350.4	Wind
East WY	Innergex Renewable	Boswell Springs	Wind	PPA	320	0	0	0	320	320	320	320	320	
East WY	BluEarth/Clearway Renew	Two Rivers Wind Project	Wind	PPA	280	0	0	0	280	280	280	280	280	
East WY	NextEra	Anticline	Wind	PPA	100.5	0	0	0	100.5	100.5	100.5	100.5	100.5	
East WY	Invenergy	Rock Creek I BTA	Wind	BTA	190	0	0	0	190	190	190	190	190	
East WY	Invenergy	Rock Creek II 400	Wind	BTA	400	0	0	0	400	400	400	400	400	
[redacted]														
Goshen ID	rPlus	Cedar Creek	Wind	PPA	151	0	0	0	151	151	151	151	151	
[redacted]														
UT South	Enyo Renewable Energy	Hornshadow II	Solar + BESS	PPA	200	50	2	200	200	200	200	200	200	Solar and/or Battery
UT North	Able Grid Energy Solutions	Dominguez I	BESS	BSA	0	200	4	200	200	200	200	200	200	
UT South	rPlus	Green River Solar I & II	Solar + BESS	PPA	400	200	2	400	400	400	400	400	400	
~~UT North~~	~~DESRI~~	~~Steel I 80 + Steel II~~	~~Solar + BESS~~	~~PPA~~	~~147~~	~~37.5~~	~~2~~	~~0~~	~~147~~	~~147~~	~~147~~	~~147~~	~~147~~	
UT South	Long Road Energy	Rush Lake	Solar + BESS	PPA	99	49.5	4	99	99	99	99	99	99	
UT South	Long Road Energy	Fremont	Solar + BESS	PPA	99	49.5	4	99	99	99	99	99	99	
UT North	DESRI	Rocket II	Solar + BESS	PPA	45	12.5	4	0	45	45	45	45	45	
UT South	Enyo Renewable Energy	Hornshadow I	Solar + BESS	PPA	100	25	2	100	100	100	100	100	100	
UT South	AES Clean Power (sPower	Glen Canyon A	Solar	PPA	95	0	0	0	95	95	95	95	95	
UT South	First Solar (now Leeward	Parowan	Solar + BESS	PPA	58	58	4	58	58	58	58	58	58	
[redacted]														
South OR	ecoplexus	Hayden Mountain 2	Solar + BESS	PPA	160	40	4	0	160	160	0	160	160	
South OR	ecoplexus	Hamaker	Solar + BESS	PPA	50	12.5	4	0	50	50	0	50	50	
[redacted]														
							Total Maximum Capacity (MW)	1,156	3,722	4,247	3,235	3,445	3,445	
							Total Capacity Contribution (MW)	575	1,081	1,148	924	998	998	

* Change from June 8, 2021 RFP Presentation – selection made by model, not due to withdrawn bid
* FSL = final shortlist
* Note, the Energy Gateway South transmission line was selected in all but the LN portfolio

PACIFICORP
POWERING YOUR GREATNESS

Demand Response Selections

- Each 2020AS RFP bid portfolio includes bids submitted into the 2021DR RFP as a resource alternative (as selected by the System Optimizer model).
- Demand response selections are incremental to existing programs.
- Demand response selections vary by portfolio-selection scenario.
- Selected programs begin in 2022 and grow over the first ten years.
- The ability to ramp quickly into the full capacity identified starting in 2022 in any scenario below may be limited by program selection, design, and delivery requirements.
- Commitments to specific programs will be made as part of ongoing or new procurement processes, and in some instances regulatory approvals.

DR Bid Selections (MW)	2022				2030			
	MM	SNS	LN	SNS Bid-LN	MM	SNS	LN	SNS Bid-LN
Rocky Mountain Power	59	75	75	43	229	245	245	198
Pacific Power	12	46	46	45	91	316	316	260
Total	71	121	121	88	320	561	561	458

PACIFICORP
POWERING YOUR GREATNESS

Portfolio Costs – MM Scenario

Revised Analysis

PaR Stochastic Mean PVRR and Change From LN Bids Portfolio ($ millions)

	Portfolio							SNS
Price-Policy	**LN Bids**	**MM Bids**	**HH Bids**	**No Bid LN**	**No Bid MM**	**No Bid HH**	**SNS Bids**	**Bids-LN**
MM	23,828	23,968	24,408	24,306	24,345	24,959	23,893	23,735
Delta	0	139	580	477	517	1,131	65	(94)

- Of the scenarios considered previously, the LN Bid portfolio has the lowest cost under MM price-policy conditions.
- However, taking the SNS bids and selecting future proxy resources under LN conditions has an even lower cost—additional details are provided on the following slides.
- Portfolios with bids provide several hundred million dollars in benefits relative to portfolios without bids.

June 8, 2021 Analysis

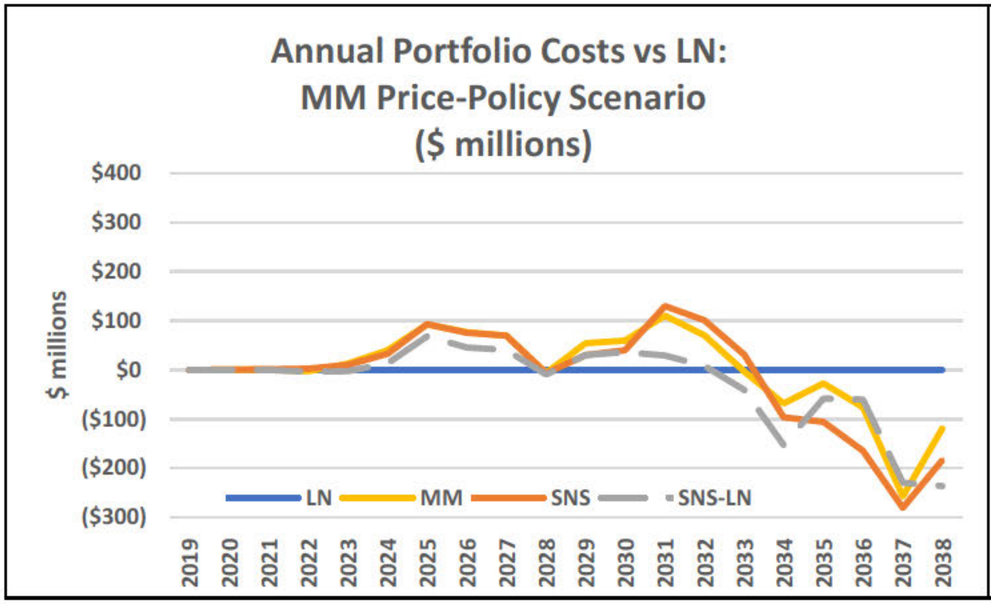
PaR Stochastic Mean PVRR ($ millions)

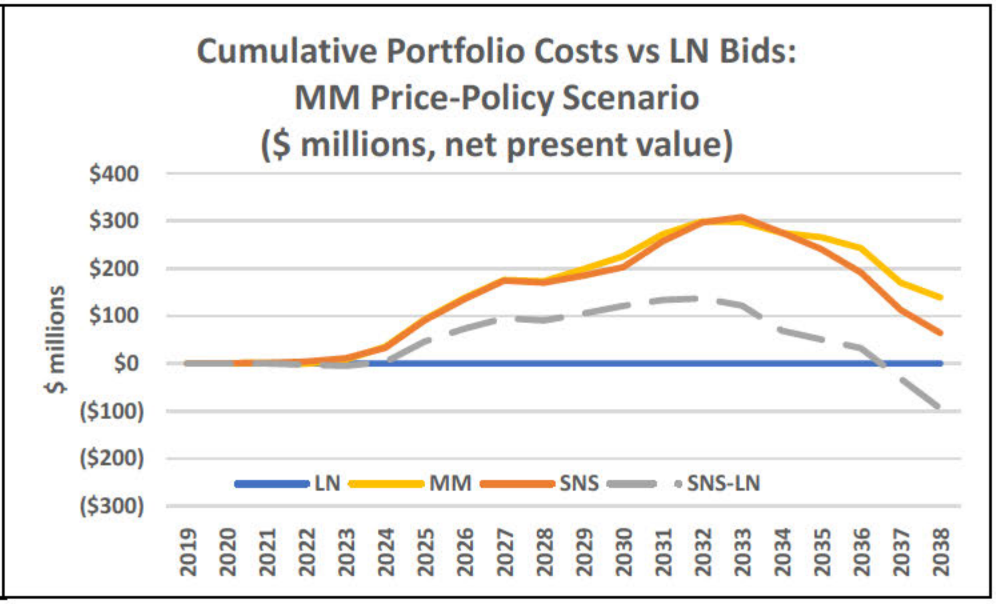
	Portfolio						
Price-Policy	**LN Bids**	**MM Bids**	**HH Bids**	**No Bid LN**	**No Bid MM**	**No Bid HH**	**SNS Bids**
MM	23,903	23,898	24,594	24,306	24,345	24,959	24,022
Change from MM Portfolio	5	0	696	408	447	1,061	124

PACIFICORP
POWERING YOUR GREATNESS

Annual Portfolio Costs

- The LN bid portfolio has the lowest annual costs through 2032 in the MM price-policy scenario, but costs climb quickly thereafter.
- Reported present value results are for 2019-2038, consistent with the 2019 IRP study horizon.
- The LN bid portfolio costs in 2039 and beyond are expected to continue to be higher than other portfolios, suggesting the results would worsen over a longer study horizon.

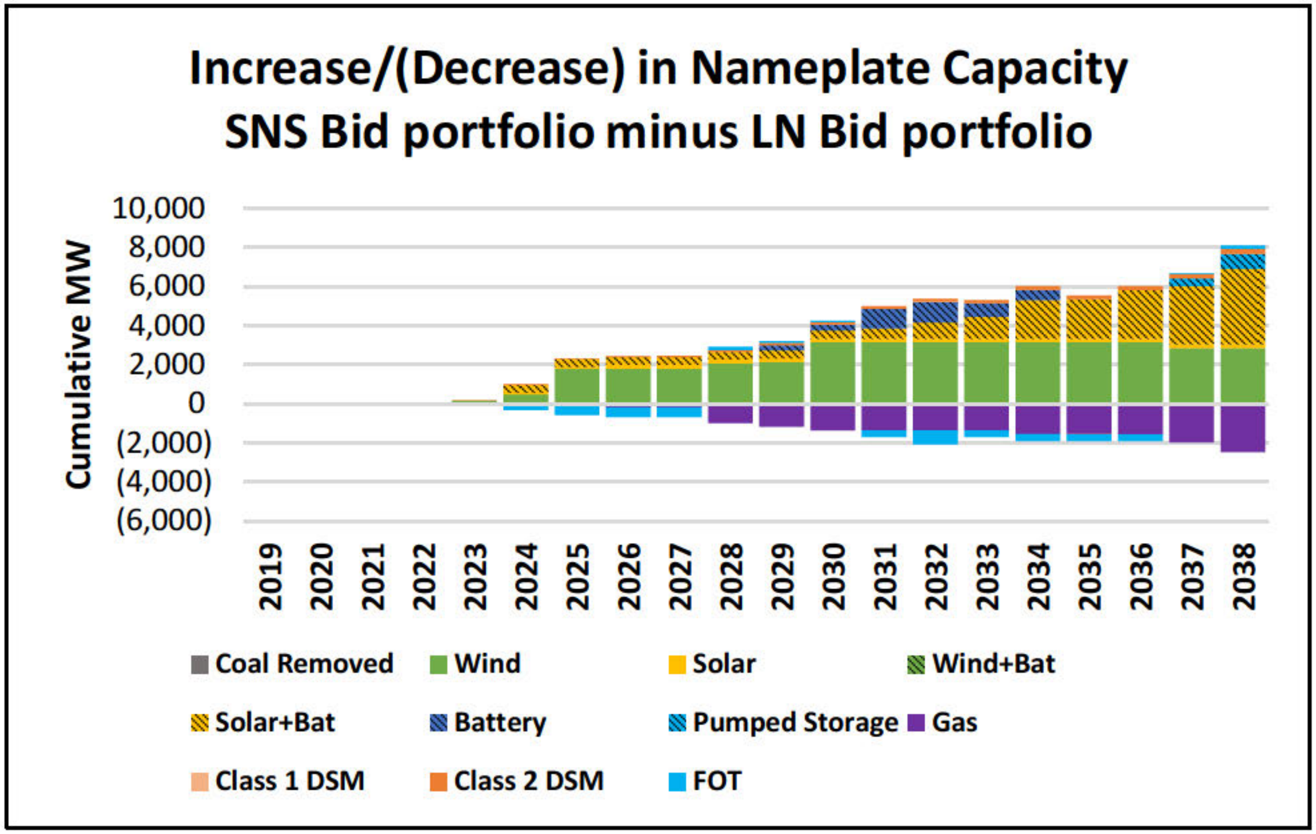




PACIFICORP
POWERING YOUR GREATNESS

Portfolio Compare SNS Bid vs LN Bid

- The SNS bid portfolio has less gas and a lower open position (depicted with FOTs) relative to the LN bid portfolio.
- In addition, to these changes, the SNS bid portfolio adds more wind in 2030, battery capacity in 2031, and solar and storage thereafter.
- Annual cost results indicate some of the LN bid portfolio selections for proxy units in the intermediate timeframe are more cost-effective than proxy resource selections in the SNS bid portfolio.



PACIFICORP
POWERING YOUR GREATNESS

SNS Bid-LN Portfolio

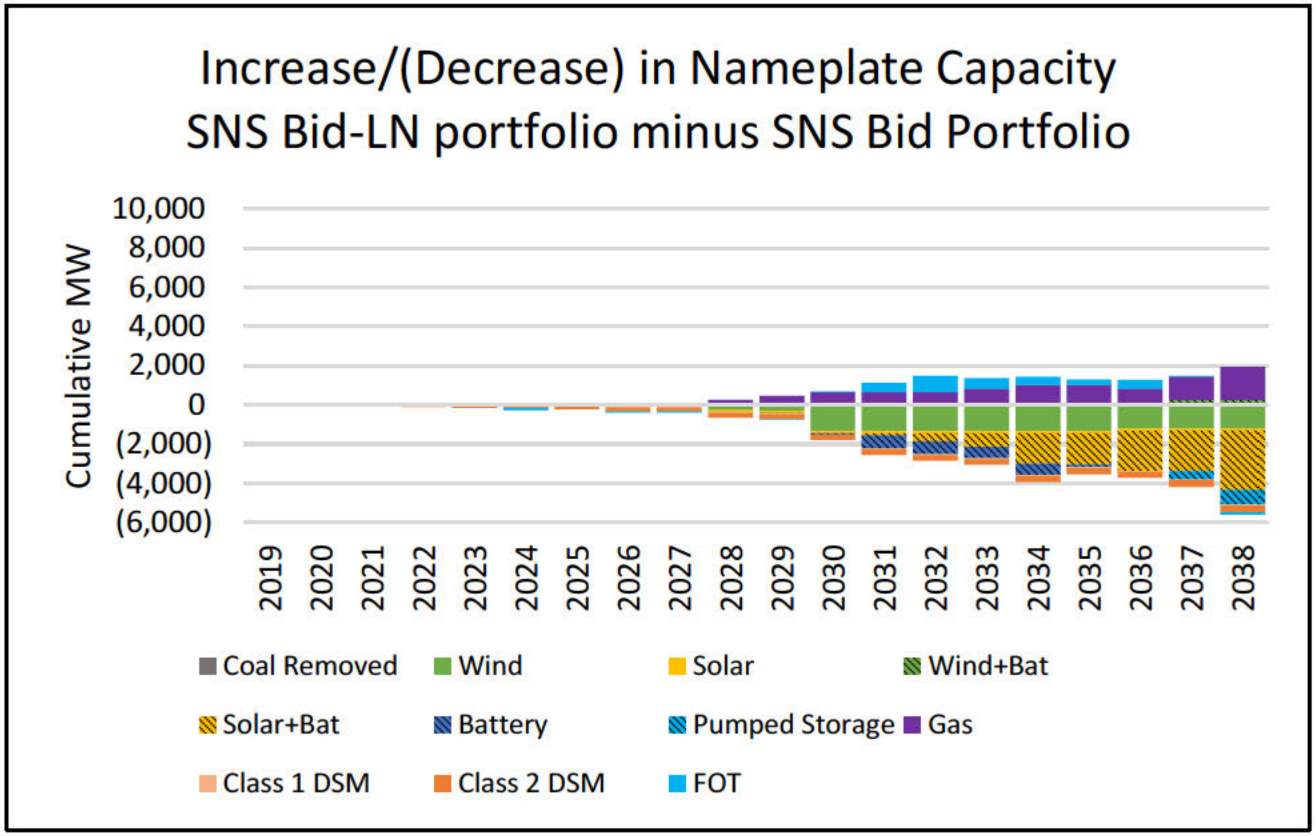
- Considering these portfolio cost trends, the company looked for a way to combine the best aspects of the SNS and LN portfolio selections to better isolate value drivers associated with bids from value drivers associated with future proxy resources.
- The SNS portfolio was developed using the MM price curve, but with no market sales allowed.
- An alternate portfolio (SNS Bid-LN) was developed with:
  - The bids selected in the SNS portfolio
  - SO model selections of additional proxy resources for the remainder of the study period under LN price-policy conditions.
  - As in the LN bid portfolio, market sales were allowed.
- This portfolio's performance was evaluated under the same price-policy conditions as the other portfolios.

PACIFICORP
POWERING YOUR GREATNESS

Portfolio Compare SNS Bid-LN vs SNS Bid

Relative to the SNS Bid portfolio, the SNS Bid-LN portfolio has:

- Wind: 1,297 MW lower in 2028-2030
- Solar w/ storage: 3,000 MW lower in 2031-2038
- Stand-alone battery: 675 MW delayed 3-5 years
- Gas peakers: 589 MW higher in 2028-2030, plus 379 MW in 2033-2034, and more thereafter.



Portfolio Costs – LN Scenario

Revised Analysis

PaR Stochastic Mean PVRR and Change From LN Bids Portfolio ($ millions)

	Portfolio							
Price-Policy	**LN Bids**	**MM Bids**	**HH Bids**	**No Bid LN**	**No Bid MM**	**No Bid HH**	**SNS Bids**	**SNS Bids-LN**
LN	18,578	20,106	21,124	18,744	20,064	21,099	20,096	19,299
Delta	-	1,528	2,546	166	1,486	2,521	1,518	721

- Under LN price-policy conditions, the LN Bid portfolio, SNS Bid portfolio, SNS Bids-LN portfolio, and the LN and MM portfolios without bids, outperform the MM portfolio.
- The MM Bid and SNS Bid portfolios produce similar results.
- The SNS Bid-LN portfolio results are midway between the LN Bid and MM Bid portfolio results.

June 8, 2021 Analysis

PaR Stochastic Mean PVRR ($ millions)

	Portfolio						
Price-Policy	**LN Bids**	**MM Bids**	**HH Bids**	**No Bid LN**	**No Bid MM**	**No Bid HH**	**SNS Bids**
LN	18,713	20,179	21,287	18,744	20,064	21,099	20,192
Change from MM Portfolio	(1,465)	-	1,109	(1,435)	(114)	920	14

PACIFICORP
POWERING YOUR GREATNESS

Portfolio Costs – HH Scenario

Revised Analysis

PaR Stochastic Mean PVRR and Change From MM Bids Portfolio ($ millions)

	Portfolio							
Price-Policy	**LN Bids**	**MM Bids**	**HH Bids**	**No Bid LN**	**No Bid MM**	**No Bid HH**	**SNS Bids**	**SNS Bids-LN**
HH	28,653	27,351	27,455	29,419	28,307	28,559	27,367	27,799
Delta	1,302	-	104	2,068	956	1,208	16	448

- The MM Bid portfolio is top-performing in the HH price-policy scenario, followed closely by the SNS Bid portfolio
- The SNS Bid-LN portfolio results are slightly closer to the MM Bid portfolio than the LN Bid portfolio.
- Note, the difference between the SNS Bid portfolio and the SNS Bid-LN portfolio is entirely driven by differences in proxy resources (and not bids).

June 8, 2021 Analysis

PaR Stochastic Mean PVRR ($ millions)

	Portfolio						
Price-Policy	**LN Bids**	**MM Bids**	**HH Bids**	**No Bid LN**	**No Bid MM**	**No Bid HH**	**SNS Bids**
HH	28,675	27,315	27,673	29,419	28,307	28,559	27,493
Change from MM Portfolio	1,361	-	358	2,104	992	1,244	178

PACIFICORP
POWERING YOUR GREATNESS

Marginal Bids

- Appendix A includes an indicative assessment of the net benefit or cost for each bid.
- This information helped identify which bids in the SNS portfolio might be marginal in terms of customer benefit.
- PacifiCorp further evaluated these bids to ensure their potential inclusion in the final shortlist would provide value for customers. Based on the nature of the revised inputs, the revised analysis focused on the lowest value eastern Wyoming bids: Rock Creek 1 and Rock Creek 2.
- Removing Rock Creek 1 or 2 results in higher costs, so these bids remain in the final shortlist.

Revised Analysis

PaR Stochastic Mean PVRR vs SNS Bids-LN Portfolio

($ millions)	Portfolio		
	SNS Bids-LN	Remove Rock	Remove Rock
Price-Policy		Creek 1	Creek 2
MM	23,735	23,760	23,893
Delta	0	26	159

June 8, 2021 Analysis

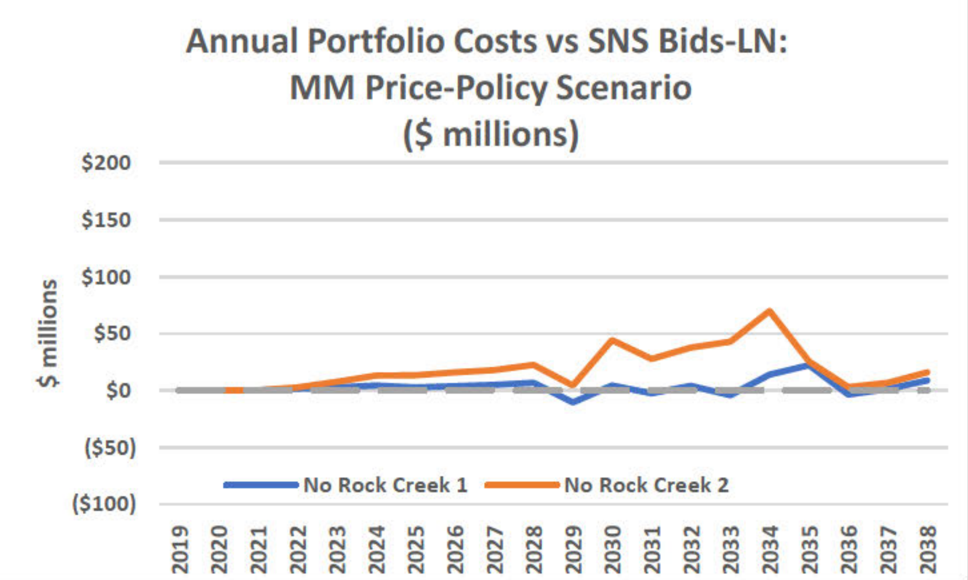
PaR Stochastic Mean PVRR ($ millions)

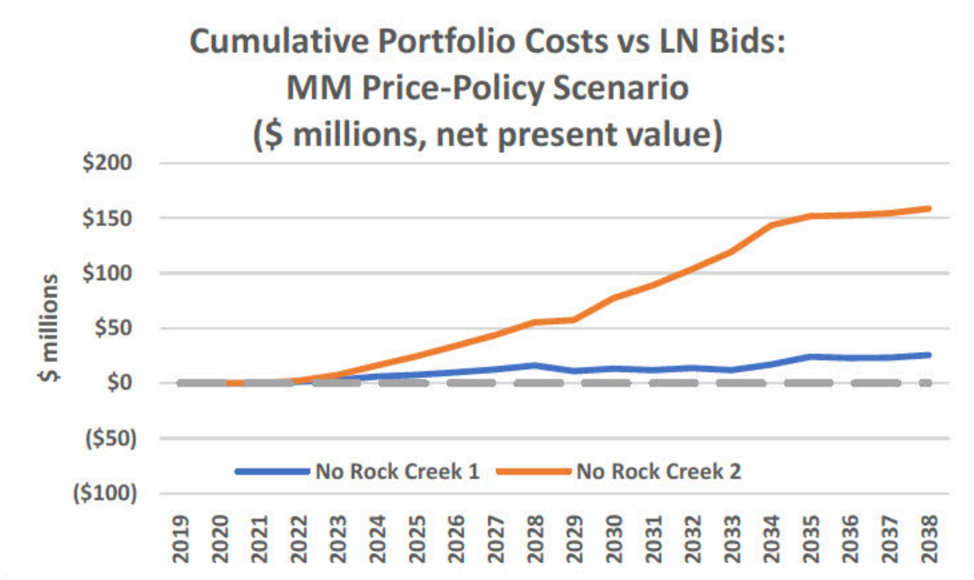
	Portfolio				
		Remove Glen	Remove	Remove	Remove
Price-Policy	SNS	Canyon	Hamaker	Rock Creek 1	Rock Creek 2
SNS	25,857	25,943	25,896	25,986	26,067
Change from SNS Portfolio	0	86	38	129	210

PACIFICORP
POWERING YOUR GREATNESS

Marginal Bids – Annual Costs

- Each additional resource in a congested location produces lower benefits.
- The sensitivities evaluate the last-in benefits of each Rock Creek resource in eastern Wyoming.
- Because of its larger size (400 MW vs 190 MW for Rock Creek 1) Rock Creek 2 provides proportionately higher benefits, despite having a slightly lower indicative net benefit.
- Rock Creek 1, the smaller of the two Rock Creek bids, provides benefits in most years of the study period.
- Note a positive value indicates a net benefit, a negative value indicates a net cost.

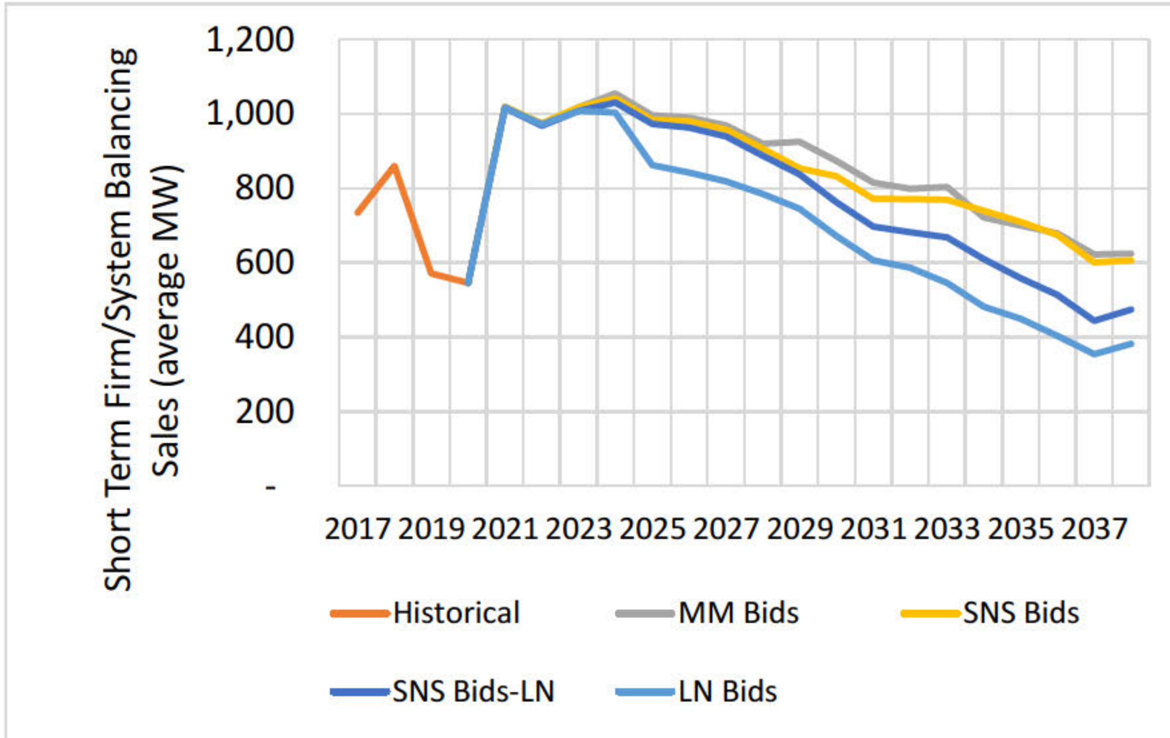




PACIFICORP
POWERING YOUR GREATNESS

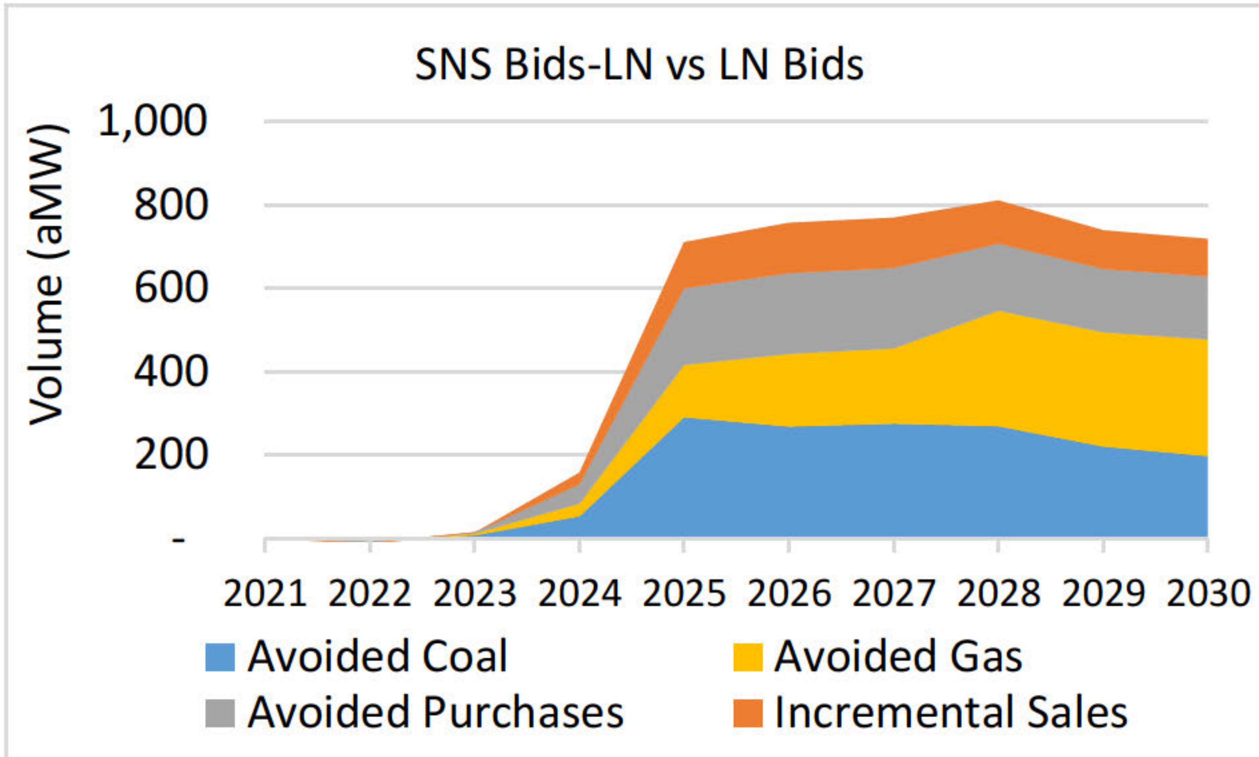
Market Sales by Portfolio

- While there is a slight uptick in forecasted market sales in 2024, market sales are forecasted to decline in the MM price-policy results for the LN, MM, SNS, and SNS Bids-LN resource portfolios.
- Market prices and volumes were low in 2019 due to weather and in 2020 due to COVID-19.
- Modeled markets can be more liquid (more purchases and sales) than current market structures, which primarily trade multiple hour blocks (e.g., the heavy load hour product from 6 a.m. to 10 p.m.)
- EIM has made intra-hour trading more liquid and an extended day-ahead market may further increase the liquidity of short-term firm transactions.



Incremental Bid Volumes (1)

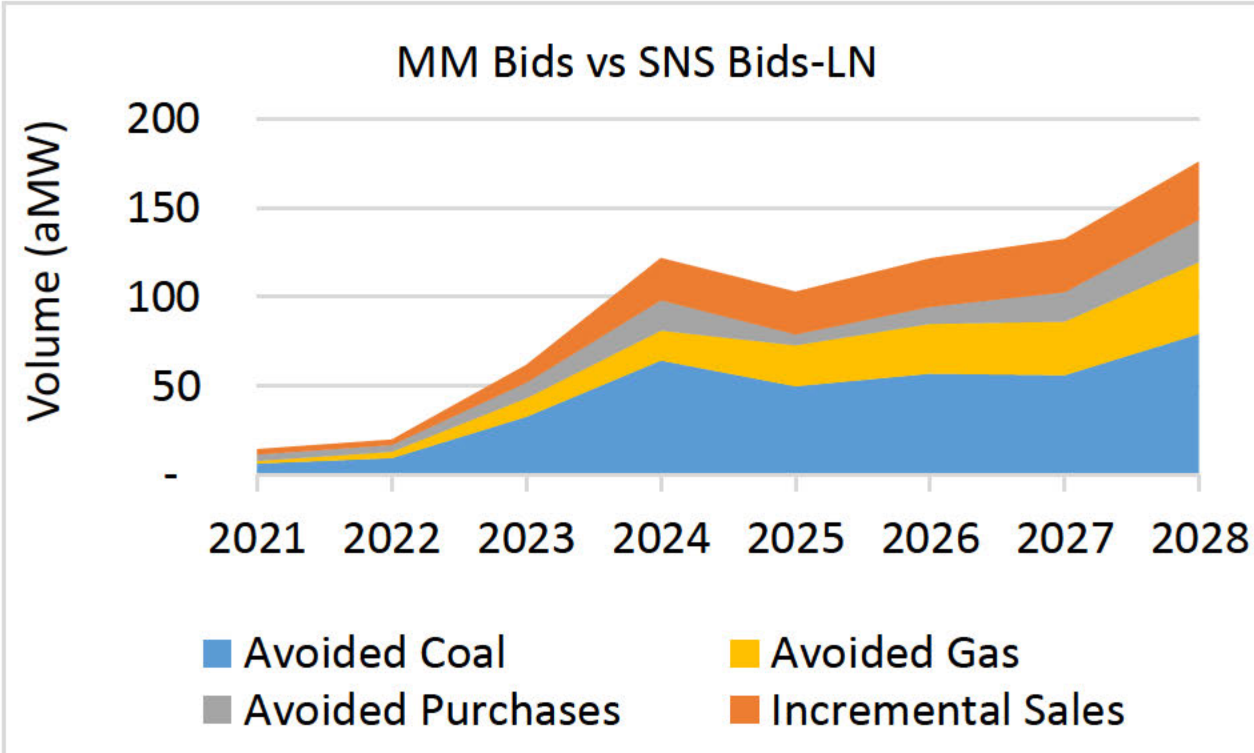
- All bids have scheduled CODs by the end of 2024 based on signed interconnection agreement or study results.
- Relative to the LN Bid portfolio, the SNS Bid-LN portfolio includes Gateway South and eastern Wyoming wind, plus solar in OR and UT.
- Under MM price-policy assumptions, the additional bids in the SNS Bids-LN portfolio mainly avoid coal, gas, and market purchases.
- Incremental sales in the SNS Bids-LN portfolio amount to roughly 16% of the total change in system energy in 2025-2027 and decline thereafter.



PACIFICORP
POWERING YOUR GREATNESS

Incremental Bid Volumes (2)

- Relative to the SNS Bid-LN portfolio, the MM Bid portfolio includes off-system wind in eastern Wyoming, plus solar in Washington.
- Under MM price-policy assumptions, the additional bids in the MM Bid portfolio lean more heavily on incremental market sales, which represent 23% of the total change in system energy in 2025-2027.
- As a result, the value of these bids is more dependent on market prices.
- These bids are expensive relative to other resource options—future alternatives may provide greater value.



PACIFICORP
POWERING YOUR GREATNESS

Additional MM Considerations

- Emissions and Reliability

Revised	CO2 (ktons)	ENS (GWh)
MM Bids	557,013	361
LN Bids	647,710	242
SNS Bids	562,984	183
SNS Bids-LN	599,584	183

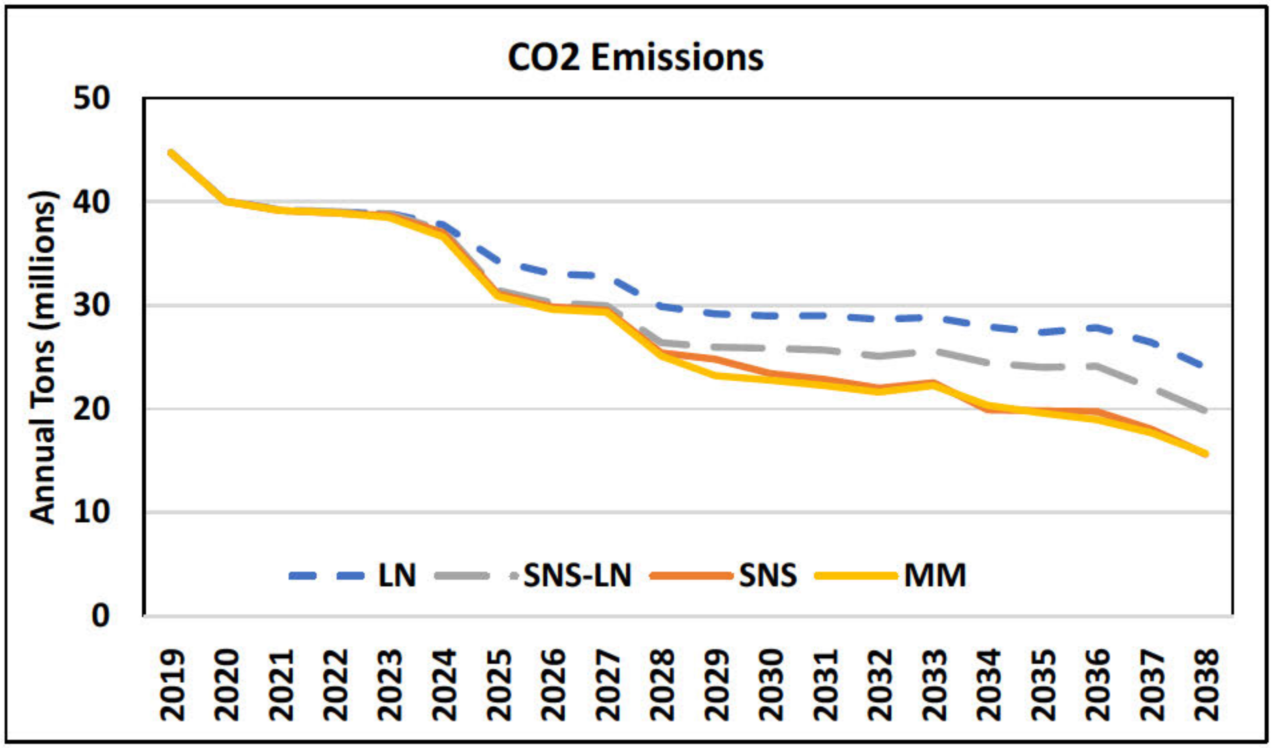
6/8/2021	CO2 (ktons)	ENS (GWh)
MM Bids	561,244	170
LN Bids	644,970	274
SNS Bids	565,943	349

  - CO_2 emissions in the MM Bid and SNS Bid portfolios are comparable, while the LN Bid portfolio emissions are 16% higher. The SNS Bid-LN portfolio is midway between MM and LN.
  - Most ENS is in the last ten years in all studies.
  - The company will be further refining its reliability calculations in its 2021 IRP and will be able to identify the best resource additions to address any shortfalls.
- Gateway South is included in the MM, SNS, and the SNS Bids-LN portfolios, but not in the LN portfolio:
  - Gateway South strengthens transmission at Mona/Clover allowing additional renewable generation in southern Utah with new transmission development.
  - Gateway South acts as a relief valve during low load and outage conditions increasing the reliability of the transmission system especially with the addition of renewable resources in southern Utah.
  - Modeled results do not fully capture these effects.

PACIFICORP
POWERING YOUR GREATNESS

CO_2 Emissions

- CO_2 emissions are highest for the LN Bid portfolio due to higher dispatch of existing coal and gas, and more natural gas proxy resource additions.
  - 16% higher than MM Bids
  - 8% higher than SNS Bid-LN
- SNS Bid-LN portfolio emissions are comparable to MM and SNS until 2028 – the resource decisions that drive this difference will not be made for several more years.



PACIFICORP
POWERING YOUR GREATNESS

Portfolio Costs – Sensitivities

Revised Analysis

PaR Stochastic Mean PVRR ($ millions)

Price-Policy	Portfolio MM Bids	Sensitivity	Change from MM Portfolio
SL	24,003	23,981	(22)
SNS	25,987	25,834	(153)
SNST	25,665	25,183	(482)

June 8, 2021 Analysis

PaR Stochastic Mean PVRR ($ millions)

Price-Policy	Portfolio MM Bids	Sensitivity	Change from MM Portfolio
SL	24,143	24,058	(85)
SNS	25,922	25,857	(65)
SNST	25,812	25,283	(529)

- "Sensitivity" portfolios were developed and evaluated for each of Staff's price-policy assumptions.
- The MM Bid portfolio was also evaluated under each of these assumptions for comparison.
- Each Sensitivity outperforms the MM Bid portfolio under its respective price-policy assumptions, though the impact in the SL and SNS scenarios is relatively small.
- The SNST portfolio has the same wind selections as the SNS portfolio identified in the final shortlist, so benefits are from future wind selections that supplement rather than replace the RFP bids.

PACIFICORP
POWERING YOUR GREATNESS

FOT Sensitivity

- Additional sensitivities were prepared using the FOT limits from the 2021 IRP.
  - 500 MW in summer and 1,000 MW winter, starting 2022
- Reducing FOT limits results in substantially higher costs in the LN Bids case, but only a modest cost increase in the MM Bids and SNS Bids cases.

PaR Stochastic Mean PVRR and Impact of Reduced FOT Limit ($ millions)				
Price Policy	RFP Bids (MW)	2019 IRP FOT Limits	2021 IRP FOT Limits	Delta
LN Bids	1,156	23,828	25,078	1,249
MM Bids	3,722	23,968	24,076	109
SNS Bids	3,445	23,893	24,079	186

PACIFICORP
POWERING YOUR GREATNESS

REDACTED

MM Bids vs. SNS Bids

- There are three fewer bids selected in the SNS Bid-LN portfolio, relative to bids selected in the MM Bid portfolio
  - [redacted] (off-system in Eastern Wyoming)
    - This resource is the most expensive remaining bid in eastern Wyoming
    - Because it is located within the Tri-State Generation and Transmission (TSGT) BAA, it requires transmission service to the PacifiCorp system
    - While the developer covers transmission service costs, it is unclear how it will be treated for intra-hour dispatch, or future day-ahead market or resource adequacy showings
    - Parts of TSGT are in the intra-hour market run by SPP, and not the Western EIM run by CAISO in which PacifiCorp participates (www.spp.org/weis/)
  - [redacted] and [redacted] (Yakima)
    - Relative to other solar with storage and solar bids, these projects are higher cost
- For these reasons and considering the increased reliance on market sales for the MM Bid portfolio relative to the SNS Bid-LN portfolio (described earlier), PacifiCorp is not considering these three bids for selection to its final shortlist.

PACIFICORP
POWERING YOUR GREATNESS

Value of Final Shortlist Bids

Revised Analysis

PaR Stochastic Mean PVRR ($ millions)

Portfolio

Price-Policy	SNS Bids	Best No Bid	Change with no bids
LN	20,096	18,744	(1,352)
MM	23,893	24,306	413
HH	27,367	28,559	1,192

Price-Policy	SNS Bids-LN	Best No Bid	Change with no bids
LN	19,299	18,744	(555)
MM	23,735	24,306	571
HH	27,799	28,559	760

June 8, 2021 Analysis

PaR Stochastic Mean PVRR ($ millions)

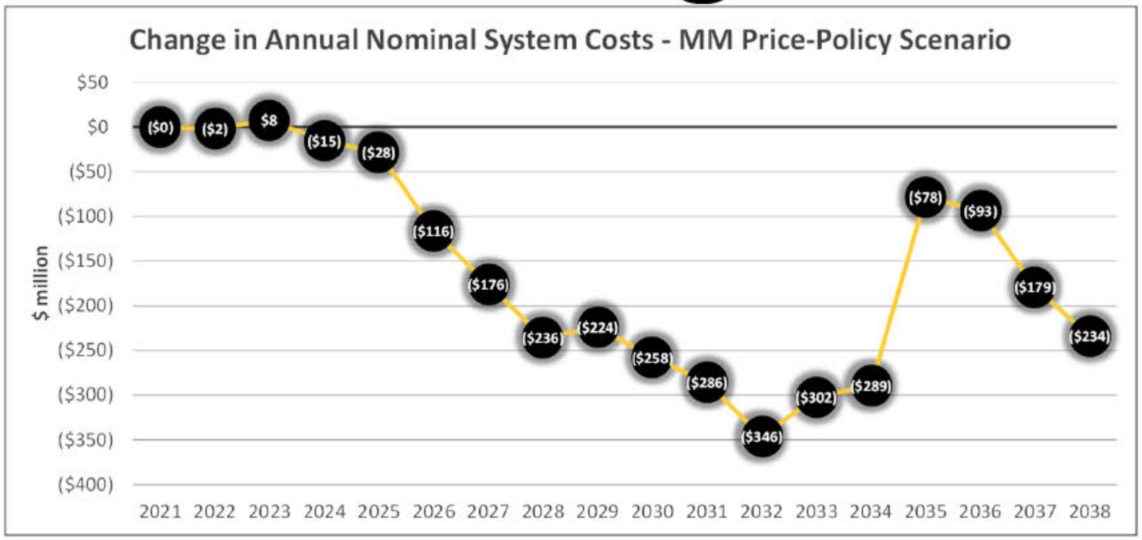
Portfolio

Price-Policy	SNS Bids	No Bid	Change from SNS Portfolio
LN	20,192	18,744	(1,449)
MM	24,022	24,345	323
HH	27,493	28,559	1,066

- Under MM and HH price-policy conditions, the SNS Bid portfolio outperforms the best no bid portfolio.
- The SNS Bid-LN portfolio has even lower costs under LN and MM conditions.
- After adding the SNS bids to the company's portfolio, many opportunities will remain to reoptimize future resource decisions.

PACIFICORP
POWERING YOUR GREATNESS

Nominal Change in Annual Cost



Best portfolio w/ bids in MM:
SNS Bid-LN

minus

Best portfolio w/o bids in MM:
No Bid LN

- The figure above summarizes annual nominal revenue requirement impacts associated with the RFP final shortlist bids and all associated transmission costs relative to the no-bid scenario assuming MM price-policy assumptions—negative values represent a reduction in revenue requirement with final shortlist bids and associated transmission projects.
- In 2025, the first full year all shortlisted bids and transmission projects are in service, the system nominal revenue requirement decreases by $28m.
- Year-to-year variability in annual nominal costs over time are largely influenced by changes in the timing of future resources between the two scenarios (with and without shortlisted bids).
  - Without shortlisted bids, gas resources are needed in 2026-2028 timeframe, battery resources are accelerated in 2031-2032, and wind and solar are added in 2036-2037, all of which reduce revenue requirement relative to the case with shortlisted bids (the SNS Bid-LN portfolio).
  - PTCs for the two build-transfer agreement wind bids expire beginning 2034, resulting in an uptick in system costs.
  - The increase in annual savings in the 2037 timeframe coincides with the retirement of Huntington, which is replaced by a combination of gas peakers and solar with storage in both studies, with a larger amount of solar with storage added in the portfolio without bids.

PACIFICORP
POWERING YOUR GREATNESS

Appendix A

Indicative Assessment of the Net Benefit/Cost for Each Bid

Overview of Appendix A

- To determine which resources might be marginal, the company used the system benefit curve values developed for the ISL and the final bid costs to identify a net benefit (or cost) for each bid.
- This data is provided for informational purposes only to give a sense of how the potential value of bids with the same or similar technology in a region compare to one another.
- System benefit curve values were developed using the company's June 2020 market prices and resource additions from the 2019 IRP preferred portfolio.
- When preparing values for a location, resources in that location were cut by half so that the result represents an average value for that location, rather than a last-in or marginal value.
- As a result of market price changes, declining marginal benefits within each location, and interactions across the system, the actual value of generation is expected to vary from that identified here, but is expected to impact resources in the same location and of the same type in a comparable manner, making the results useful for assessing the relative value or cost of specific bids.
- Updated Net Delivery Costs and Indicative Generation Values reflect corrections in annual generation and net capacity factors related to embedded text and omission of hours with no generation in some bidders' 8760 profiles.

PACIFICORP
POWERING YOUR GREATNESS

REDACTED

Wind Bids

- Seven (7) wind resource bids are in eastern Wyoming, including five PPAs and two BTAs
- One bid is in Goshen, Idaho and one is in southwest Wyoming
- The Indicative Generation Value is based on hourly locational prices from June 2020 used in price scoring for the initial shortlist, which is mainly useful for comparing resources of the same type and location
- Net Benefit/(Cost) reflects the final bids and network upgrade costs

Location	Company	Project / Facility Name	Contract Type	Generating Asset (MW)	BESS Capacity (MW)	BESS Duration (Hours)	FSL Proposed COD	Net Delivery Cost ($/MWh)	Indicative Generation Value ($/MWh)	Net Benefit / (Cost)
East WY	NextEra	Cedar Springs IV	PPA	350.4	0	0	1/1/2025	[redacted]	[redacted]	[redacted]
East WY	Innergex Renewable	Boswell Springs	PPA	320	0	0	10/1/2024	[redacted]	[redacted]	[redacted]
East WY	BluEarth Renewables US/Clearway Renew	Two Rivers Wind	PPA	280	0	0	1/1/2025	[redacted]	[redacted]	[redacted]
East WY	NextEra	Anticline	PPA	100.5	0	0	1/1/2025	[redacted]	[redacted]	[redacted]
East WY	Invenergy	Rock Creek II 400	BTA	400	0	0	12/31/2024	[redacted]	[redacted]	[redacted]
East WY	Invenergy	Rock Creek I BTA	BTA	190	0	0	12/31/2024	[redacted]	[redacted]	[redacted]
[redacted]										
Goshen ID	rPlus	Cedar Creek	PPA	151	0	0	12/31/2022	[redacted]	[redacted]	[redacted]
SW WY	Invenergy	Uinta	BTA	121.8	0	0	12/31/2024	[redacted]	[redacted]	[redacted]

PACIFICORP
POWERING YOUR GREATNESS

REDACTED

Utah Bids

- All Utah bids are for solar and/or battery storage
- Bids for solar with storage have battery capacity ranging from 25% to 100% of solar capacity, and duration ranging from two to four hours
- The Indicative Generation Value is based on hourly locational prices from June 2020 used in price scoring for the initial shortlist, which is mainly useful for comparing resources of the same type and location
- Net Benefit/(Cost) reflects the final bids and network upgrade costs

Location	Company	Project / Facility Name	Contract Type	Generating Asset (MW)	BESS Capacity (MW)	BESS Duration (Hours)	FSL Proposed COD	Net Delivery Cost* ($/MWh)	Indicative Generation Value ($/MWh)	Net Benefit / (Cost)
UT South	Enyo Renewable Energy	Hornshadow II	PPA	200	50	2	12/31/2023	[redacted]	[redacted]	[redacted]
UT North	Able Grid Energy Solutions, Inc.	Dominguez I	BSA	0	200	4	7/1/2024	[redacted]	[redacted]	[redacted]
UT South	rPlus	Green River Solar I	PPA	400	200	2	1/1/2025	[redacted]	[redacted]	[redacted]
UT South	Long Road Energy	Rush Lake	PPA	99	49.5	4	11/30/2023	[redacted]	[redacted]	[redacted]
UT South	Long Road Energy	Fremont	PPA	99	49.5	4	11/30/2023	[redacted]	[redacted]	[redacted]
UT South	Enyo Renewable Energy	Hornshadow I	PPA	100	25	2	12/31/2023	[redacted]	[redacted]	[redacted]
~~UT North~~	~~DESRI~~	~~Steel I 80 + Steel II~~	~~PPA~~	~~147~~	~~37.5~~	~~2~~	~~12/31/2023~~	[redacted]	[redacted]	[redacted]
UT South	First Solar (now Leeward Energy)	Parowan	PPA	58	58	4	12/31/2024	[redacted]	[redacted]	[redacted]
UT South	AES Clean Power (sPower LLC)	Glen Canyon A	PPA	95	0	0	12/31/2023	[redacted]	[redacted]	[redacted]
UT North	DESRI	Rocket II	PPA	45	12.5	4	12/31/2023	[redacted]	[redacted]	[redacted]
[redacted]										

* Net Delivery Cost is net of value of storage, if applicable

PACIFICORP
POWERING YOUR GREATNESS

REDACTED

West Bids and Ranking

- All west-side bids are for solar or solar with battery storage
- Bids are in Central Oregon, Southern Oregon, and Yakima, Washington
- The Indicative Generation Value is based on hourly locational prices from June 2020 used in price scoring for the initial shortlist, which is mainly useful for comparing resources of the same type and location
- Net Benefit/(Cost) reflects the final bids and network upgrade costs

Location	Company	Project / Facility Name	Contract Type	Generating Asset (MW)	BESS Capacity (MW)	BESS Duration (Hours)	FSL Proposed COD	Net Delivery Cost* ($/MWh)	Indicative Generation Value ($/MWh)	Net Benefit / (Cost)
[redacted]										
South OR	ecoplexus	Hayden Mountain 2	PPA	160	40	4	12/31/2023	[redacted]		
South OR	ecoplexus	Hamaker	PPA	50	12.5	4	12/31/2023			
[redacted]										

* Net Delivery Cost is net of value of storage, if applicable

PACIFICORP
POWERING YOUR GREATNESS

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 16, 2020

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

RE: UM 2024—PacifiCorp's Opening Comments

PacifiCorp d/b/a Pacific Power encloses for filing its opening comments in the above-referenced proceeding.

If you have questions about this filing, please contact Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM 2024

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS Petition for Investigation into Long-Term Direct Access Programs.	PACIFICORP'S OPENING COMMENTS

PacifiCorp appreciates the opportunity to file these comments in response to the Phase I Stipulated Issues List issued in this docket on February 21, 2020. In this phase of the docket, the parties have been asked to comment on several direct-access issues that are important to the implementation of direct access policies. These include the potential benefits and potential costs to customers of long-term direct access, the manner in which other states are handling direct access issues, and, importantly, resource adequacy issues. PacifiCorp looks forward to engaging on these and other issues in this docket.[1]

I. Background of Oregon's Direct Access Law — SB 1149

The Oregon Legislature enacted Senate Bill (SB) 1149 in 1999. In the late 1990s, Oregon, along with other states, showed interest in the potential benefits of retail electric market competition. Retail electric prices were high in the 1990s, due in part to cost overruns and failed investment in nuclear plants in the prior decade.[2] The falling cost of gas plants, along with the Federal Energy Regulatory Commission's (FERC) deregulation of the wholesale electric market, led many customers, particularly industrial customers, to believe that retail competition would bring benefits in the form of lower costs.[3]

SB 1149 was designed to deregulate the retail electric energy service in Oregon and to allow the development of some elements of a competitive retail electricity market. As the Oregon Legislature stated in the preamble to SB 1149:

[1] The first phase of this docket is a comment phase, with reply comments to be filed on April 6, 2020. The second phase is currently envisioned to be a legal-briefing phase, followed by a contested-case phase.
[2] *See, e.g.,* Richard J. Pierce, Jr., *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity,* 132 U. Pa. L. Rev. 497 (1984) (describing national and state energy policies that led to canceled nuclear plants).
[3] David B. Spence, *Realizing the Promise of Elec. Deregulation: Article: The Politics of Elec. Restructuring: Theory vs. Practice*, 40 Wake Forest L. Rev. 417, 446-47 (2005) ("In most restructuring states, restructuring was driven by industrial customers who believed that they subsidized other customer classes under regulated rate tariffs and that they could get better rates on a competitive market.").

> Whereas the divestiture or functional separation of electrical power generation from the distribution functions is the most effective means of stimulating competition, providing depth and liquidity to the wholesale market and facilitating the transition to a fully competitive market by alleviating horizontal and vertical monopoly market power and providing a more accurate estimation and mitigation of stranded costs; and
>
> Whereas price and service unbundling is the best way to identify the costs associated with generation, transmission and distribution of electricity services and is essential to the development of a competitive market; and [. . .]
>
> Whereas all Oregon retail electricity consumers should be provided fair, non-discriminatory access to competitive electricity options [. . . .][4]

The law gave the Public Utility Commission of Oregon (Commission) authority to require utilities to make implementation filings,[5] subject to the mandate that the "provision of direct access to some retail electricity customers must not cause the unwarranted shifting of costs to other retail electricity consumers of the electric company."[6] The Commission implemented this statute through rules requiring electric utility consumers to receive a credit or pay transition charges "equal to 100 percent of the net value of the Oregon share of all [investments] as determined pursuant to an auction, an administrative valuation, or an ongoing valuation."[7]

Notably, the law in Oregon, unlike the laws in some states, did not purport to move all customers to "competitive" retail options. Residential and small retail customers would instead be permitted to choose from a "portfolio" of options that remained subject to the full regulatory authority of the Commission.[8] The result of SB 1149 was to provide smaller customers with a suite of regulated options, and a limited subset of larger customers with a direct-access option—as long as that direct access created "no unwarranted cost shifting" and met other statutory requirements.

The Western Energy Crisis of 2000-2001 halted the movement toward fully competitive retail electricity markets in much of the nation.[9] Two years after SB 1149 was adopted, the Oregon

---

[4] SB 1149, 70th Or. Leg. Assemb., Reg. Sess. (1999) (preamble).
[5] SB 1149, Sec. 20; ORS 757.661.
[6] SB 1149, Sec. 8; ORS 757.607(1). The cost-shifting statute is written broadly and does not limit its protection to Oregon customers. For a multi-state utility like PacifiCorp, this means the impact on customers from other states is a relevant consideration.
[7] OAR 860-038-0160(1).
[8] SB 1149, Sec. 4; ORS 757.603(2); OAR 860-038-0220. The portfolio option was supported by the Oregon Citizens' Utility Board (CUB), and by a broad stakeholder group called the Fair and Clean Energy Coalition. CUB disputed the idea that retail deregulation would bring benefits for smaller customers and opposed proposed legislation that would "do away entirely with regulated rates and throw everyone into a retail market with almost no rules or protection." CUB, "You'll Have the Power," *The Bear Facts*, Fall 1998, at 5, available at https://oregoncub.org/images/uploads-legacy/pdfs/1998-3-FallOCR.pdf. For smaller customers, CUB argued, "[w]e want to keep the existing protections, yet still give consumers options and the information necessary to make informed choices." *Id*.
[9] "The Energy Crisis brought California blackouts and economic hardship. In 1999, the first full year of deregulation, Californians paid $7.4 billion for wholesale electricity. A year later, those costs rose 277 percent—

Legislature amended SB 1149 by enacting House Bill (HB) 3633, which (1) delayed SB 1149's effective date and (2) required the state's two largest investor-owned utilities to continue to offer all customers a cost-of-service rate.[10] Additional legislation was passed that same year, intended to ensure there were adequate regulatory incentives to build new generation in light of existing scarcity.[11] That legislation, enacted only two years after SB 1149, contained introductory clauses reflecting a far different energy landscape:

> Whereas the western United States is experiencing a shortage of electrical generating capacity, and as a result consumers in Oregon are faced with the prospect of significant increases in the cost of electricity; and
>
> Whereas wholesale power markets in the western United States are reflecting extreme price volatility, and there is substantial uncertainty with respect to the level of wholesale electricity prices in the future; and
>
> Whereas there is considerable uncertainty about the extent to which electric companies will be called upon to supply electricity to Oregon consumers at cost-based rates; and
>
> Whereas the current regulation of electric companies and electric services may not sufficiently promote the development of new electric generating resources; and
>
> Whereas in the current economic and regulatory environment, electric companies face substantial risk in respect to the construction or acquisition of new electric generating resources; and
>
> Whereas the Public Utility Commission has the unique expertise to understand and lead changes in the regulation of electric companies that are necessary to further the purpose of this 2001 Act for the benefit of Oregon consumers [. . . .][12]

Since then, the Oregon Legislature has neither moved to extend direct access to additional customer classes, nor repealed the existing direct access provisions of SB 1149. Instead, the Legislature has continued to ask the Commission to exercise its "unique expertise" to implement the existing direct access statutes in a manner that protects customers' access to safe, reliable, affordable electricity, and to do so in harmony with other Commission obligations—including its implementation of other laws intended to move the state toward its energy policy goals.[13]

Oregon thus continues as a state with a partially deregulated retail electric market. It remains a piecemeal system with no market monitoring function other than the Commission's oversight. Oregon's version of direct access therefore requires continuous, vigorous Commission review

---

$27.1 billion. In 2001, wholesale power costs held fast at the exorbitantly high level of $26.7 billion." Cal. Att'y Gen., *Attorney General's Energy White Paper* at 6 (Apr. 2004), available at https://oag.ca.gov/sites/all/files/agweb/pdfs/publications/energywhitepaper.pdf.

[10] HB 3633, 71st Or. Leg. Assemb., Reg. Sess., Secs. 1 and 2 (2001); *see also In the Matter of a Rulemaking to Modify OAR 860-038-004(23)*, Docket AR 394, Order No. 02-053 at 3 (Jan. 28, 2002).

[11] HB 3696, 71st Or. Leg. Assemb., Reg. Sess. (2001).

[12] HB 3696 (preamble).

[13] *Id.*

and enforcement to ensure that the departure of large commercial and industrial customers from the system does not harm the state's remaining retail customers.

II. What Are the Potential Benefits and Potential Costs to Customers from Long-Term Direct Access[14] Participation?

Direct energy purchasing by large customers can increase costs for other ratepayers, as these large customers "defect" from existing utility-procured resources, leaving a smaller pool of ratepayers to cover embedded costs.[15] Ongoing capital investments or operational costs needed to provide reliable service within a Balancing Authority Area (BAA) can also be unfairly shifted to utility customers if third-party providers are not required to carry those reliability obligations in equal measure.[16] In addition, various state public policy and legislative mandates must be implemented by utilities, even when those mandates cause utilities to incur above-market costs. By increasing utility system costs, these mandates create additional financial incentives for mobile customers to exit the system, which can leave a smaller and smaller pool of remaining customers responsible for financing statewide energy policy goals.[17]

If significant customer load departs the system under direct access, and remaining customers are not financially protected from the departure of that customer load, the following are illustrative of the types of costs that can be shifted to remaining utility customers:

- Stranded costs associated with system assets that were acquired by the utility to serve customers but are no longer needed to serve departing customer loads.
- Stranded costs associated with higher-cost but prudently incurred legacy contracts, such as long-term contracts needed to serve load or meet Renewable Portfolio Standards (RPS) requirements, executed when natural gas prices were higher and/or before the steep decline in renewable energy prices.
- Stranded costs associated with contributions towards eventual power plant decommissioning and environmental remediation costs.
- Ongoing costs associated with the continued need to plan for the potential return of departing customers.
- Ongoing costs associated with short- and long-term grid reliability, if reliability obligations are housed with utilities rather than fairly allocated between utilities and third-party providers.[18]

---

[14] Also called "retail access," "customer choice," "retail competition," and "retail wheeling."
[15] Advanced Energy Economy (AEE) Report on Policies to Expand Corporate Access to Advanced Energy at 16-17 (2018), available at: https://info.aee.net/hubfs/AEE_July2018/PDF/AEE-Policies-to-Expand-Corporate-Access-to-Advanced-Energy.pdf. AEE is a national association of businesses, including many major energy customers such as Microsoft, Apple, Oracle, Amazon, Google, and Lockheed Martin.
[16] *In the Matter of Portland Gen. Elec. Co. Advice No. 19-02 New Load Direct Access Program*, Docket UE 358, Order 20-002 at 9 (Jan. 7, 2020) ("We expect development of [a resource adequacy] solution or requirement for direct access to be a top priority in the UM 2024 investigation.").
[17] *Id.* at 16 (recognizing that the allocation of costs associated with RPS compliance "is equally applicable . . . for all customers on direct access").
[18] *Id.* at 9 (suggesting that resource adequacy obligations may be placed "in the hands of customers").

- Ongoing costs associated with complying with legislative and Commission public policy mandates that require utility investments or other commitments in above-market resources.
- Ongoing cost of environmental compliance requirements for cost-of-service customers (unless direct access customers are required to comply with these requirements).
- Lost opportunity costs associated with diminished hosting capacity on the delivery system that could be utilized by potential new cost-of-service customers who make a contribution to fixed embedded costs.
- Cost shifts due to market depth issues if Energy Service Suppliers (ESS) are using up market depth or market liquidity rather than contributing to the construction of new capacity resources.

The potential benefits of a well-designed direct access program include the following:

- Increased customer choice.
- Potential deferral of planned resource acquisitions due to customer defection, assuming other specific conditions are also present.[19]
- Potential benefits of competition, which can increase utility incentives to keep costs low. As noted previously, however, if departing customers do not carry their fair share of historical or ongoing costs, this "competition" becomes cost-shifting.

A. What Are the Potential Cost Shifts?

Stranded Costs. When customers leave a utility's system to buy power from other sources, utilities may be left with unrecoverable long-term sunk costs incurred to meet the utility's obligation to serve all customers, including the departing customers.[20] As part of their obligation to serve, these utilities have already invested in existing generating plants, committed to long-term power and fuel contracts, and planned system expansions.[21] When customers leave the system, any unrecoverable long-term costs incurred to serve the departing customers will shift either to the utility, or to the utility's remaining customers. To prevent this cost shift, departing customers must be required to pay appropriate transition charges.

A transition charge is intended to account for these stranded costs, offset by the value of the energy freed up by the departing direct access customer.[22] For PacifiCorp, these costs are calculated annually in the Transition Adjustment Mechanism.

POLR Obligations. If utilities are required to serve as providers of last resort (POLR) for departing customers, a customer's election to return to the utility can create significant cost shifts to the electric customers who chose to remain. ESSs have argued that utilities can meet their

[19] *In the Matter of PacifiCorp dba Pacific Power Transition Adjustment, Five-Year Cost of Service Opt-out*, Docket UE 267, Order No. 15-060 at 5 (Feb. 24, 2015) (explaining PacifiCorp's position that there were no resource acquisitions to defer within the next 10 years, based on the Company's Integrated Resource Plan (IRP)).
[20] Wayne C. Turner and Steve Doty, *Energy Management Handbook*, 639 (The Fairmont Press, Inc. 2007).
[21] Turner & Doty at 639.
[22] Order No. 15-060 at 7.

POLR obligations to returning direct access customers through market-based purchases if necessary.[23] Given the tightening of capacity in the Northwest, however, the availability of market purchases at reasonable costs remains a risk factor in assessments of resource adequacy region-wide.[24]

Reliability Costs. Costs associated with short- and long-term grid reliability, including costs of investing in new generation and other reliability needs, may be shifted to utility customers if reliability obligations are housed with utility customers rather than fairly allocated between utility customers and direct access customers.[25]

Public Policy Costs / Costs of Other Mandates. Utilities are tasked with implementing legislative and Commission public policy mandates that may not be cost-effective, and thus have the potential to drive up costs and accelerate customer defection. These mandates may include legislative or Commission requirements for utilities to invest in technologies that are not yet cost-effective (e.g., early mandates to invest in batteries), to stand up programs that require extensive cost-subsidization (e.g., community solar), to enter into contracts that the utility may otherwise find non-competitive or carry the risk of disallowance (e.g., the Public Utility Regulatory Policies Act), to provide low-income assistance and other public policy funds to customers (e.g., SB 1149's public purpose charge), or to enhance the electric system in other ways that may not be cost-effective but may reflect changes in technology and public policy (e.g., distribution system planning). These public policy mandates, and others like them, increase the cost of utility service beyond the cost of competitive energy procurement and increase the risk of customer defection (and stranded costs) when third-party providers fail to carry these obligations in equal measure.

Other Costs. While costs of new generation continue to decline, costs of power delivery continue to increase. The addition of new competitive suppliers may require the addition of new transmission, additional costs to balance the system, and other BAA costs.

Market Failures / Reliability Failures. Unless the Commission's implementation of direct access includes robust mechanisms to assure the Commission has effective control over the issues noted above, regulatory gaps could create issues with availability or deliverability of resources. These issues can result in cost-shifts, as noted previously, but can also lead to market effects that amplify the risk of market shortages or, in extreme cases, load curtailment (brownouts or blackouts).

---

[23] *See, e.g., In re Pub. Util. Comm'n of Or. Investigation into the Treatment of New Facility Direct Access Load,* Docket UM 1837, Initial Brief of Northwest and Intermountain Power Producers Coalition at 9-11 (Sept. 8, 2013).
[24] *See Wah Chang v. PacifiCorp,* Docket UM 1002, Order No. 09-343 (Sept. 2, 2009) (PacifiCorp customer signed special contract in 1997 giving it access to wholesale market prices during time of favorable wholesale energy prices, then unsuccessfully petitioned for a return to cost-of-service rates when, in the midst of the Western Energy Crisis, in a single month, customer paid nearly $5.9 million for energy that would have cost less than $500,000 under the standard tariff).
[25] *See* UCLA Luskin School of Public Affairs "The Promises and Challenges of Community Choice Aggregation in California," 33 (2019) (discussing the allocation of responsibility for grid reliability), available at: https://innovation.luskin.ucla.edu/wp-content/uploads/2019/03/The_Promises_and_Challenges_of_Community_Choice_Aggregation_in_CA.pdf.

Direct access without sufficient regulatory or market protections can disrupt markets.[26] The inelasticity of electric demand, combined with the need for the electric system to instantaneously balance supply and demand, can lead to volatility unless the system is protected by either (1) a competitive market with appropriate market monitoring rules (e.g., Texas), or by (2) robust ongoing regulatory mechanisms (e.g., Oregon, Nevada).

Since the Oregon Legislature retreated from movement to full retail deregulation, this Commission has followed a careful, incremental approach to direct access, one that has moved the state further toward its energy policy goals without threatening cost or reliability. Increased interest in direct access, the potential for capacity shortages in the near-term, and heightened policy-driven directives are risk factors for both cost and reliability.

B. What Are the Potential Benefits?

Increasing Customer Choice. A well-designed direct access program neither benefits nor harms utilities while providing customers with additional choices.

Deferring Planned Resource Acquisitions. In theory, it could be possible to defer some planned resource acquisitions due to customer departures, assuming other specific conditions are also present. The Commission has previously noted, however, that any such deferral must be demonstrated and cannot simply be assumed.[27] Given its obligation to serve, a utility must plan for customer needs significantly in advance of actual service.

Incentivizing Efficient Performance. In theory, competition could increase utility incentives to keep costs low. As noted previously, however, unless departing customers are required to carry their fair share of historical costs or ongoing costs for supporting state energy policy goals, this defection simply creates cost-shifting. Moreover, without a well-designed competitive market to establish market costs on an apples-to-apples basis for similarly situated market participants (such as Texas' market or certain FERC-jurisdictional Independent Systems Operator (ISO) /Regional Transmission Organization (RTO) markets), customers in vertically integrated states rely on state commissions to make and enforce policies that ensure that utility customers are held harmless from direct access implementation.

III. How Are Other States Handling Customer Choice and Access to Wholesale Markets for Different Customer Classes?[28]

The California Public Utilities Commission (CPUC) has identified a series of gaps associated with direct retail access to energy markets:

---

[26] As noted previously, California's flawed implementation of customer-choice legislation led to disruption of electric markets across the West, exacerbating market scarcity and causing regional wholesale spot market prices to spike up to nearly $400/megawatt-hour (MWh) in December 2000, with average daily prices reaching nearly $1200/MWh. Spence, *supra,* at 427.

[27] Order No. 15-060 at 5-7.

[28] This section focuses primarily on other WECC states, per Commissioner Tawney's request. A matrix of which states affirmatively offer retail and wholesale market access is included in AEE's 2018 Report on Policies to Expand Corporate Access to Advanced Energy, beginning on page 25. The differences in programs and nomenclature for

- Provider of last resort obligations;
- Price disclosure;
- Data disclosure;
- General enforcement authority;
- Pricing of departing load;
- Market design and alignment with customer choice;
- Oversight, compliance and reliability responsibilities;
- Capacity and reliability.[29]

The Commission has asked for an assessment of how other states have responded to these issues.

Below is a brief summary of customer choice options in various Western Electricity Coordinating Council (WECC) states.[30] It appears that Oregon is one of the few Western states to have maintained direct access for a subset of retail customers in the wake of Western Energy Crisis. Oregon, California, and Nevada[31] are among the few states that have robustly engaged with many of the direct access issues listed above. However, other state commissions have touched on some of these concerns in the context of reviewing specific special contracts or tariffs for large utility customers, which can also impact other ratepayers.[32]

While it does not appear that any other state's approach to direct access provides a clear roadmap for Oregon, it is possible that certain specific elements of other state policies may be worth additional scrutiny as the focus in this docket becomes more granular.

A. Most Other WECC States Have Only Limited Direct Access to Wholesale Markets

1. *Idaho*

Idaho does not have a direct access program akin to Oregon's. While the Idaho Public Utilities Commission (IPUC) previously approved special contracts for large customers,[33] Idaho has since

describing the various opportunities available to customers leads to come inconsistencies in reporting, with states like Oregon with partial deregulation described by various sources as states with retail access, no retail access, or partial retail access (or "choice").

[29] Cal. Pub. Utils. Comm'n, *California Customer Choice Project: Choice Action Plan and Gap Analysis* at 8-18 (Dec. 2018) available at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Final%20Gap%20Analysis_Choice%20Action%20Plan%2012-31-18%20Final.pdf.

[30] PacifiCorp does not focus on California in this discussion, as the Commission is familiar with the CPUC's recent customer choice reports and has referenced them in public meetings. That said, further examination of California's policy decisions may be helpful as the issues in this docket become more granular.

[31] Arizona has considered elements of retail competition for years and continues to investigate issues such as community choice aggregation. *See* Quilici, Lisa M., et al., *Retail Competition in Electricity* at 13-14 (July 23, 2019) available at https://ceadvisors.com/wp-content/uploads/2019/07/AEPG-FINAL-report.pdf.

[32] *See, e.g.,* Quilici, *supra*, at 72-73, noting proliferation of "innovative products" currently being provided through utility green tariffs and other programs, even in states without retail competition.

[33] *In the Matter of the App. of PacifiCorp dba Utah Power & Light Co. for Approval of an Elec. Serv. Contract with Monsanto Co.*, Case No. UPL-E-95-4, Order No. 26282 (Dec. 1, 1995) (approving a new power supply agreement for the large customer based on the understanding that Monsanto could acquire alternative energy from a nearby municipal utility).

passed legislation precluding utilities from serving other entities' customers without the incumbent utility's permission.[34] The IPUC does not appear to have addressed the direct access or retail competition issues identified in this docket.

2. Montana

Montana does not have an existing direct access program. The Montana Legislature deregulated the retail electric market in 1997.[35] In light of market failures, the legislature re-regulated the industry and reestablished vertically integrated utilities in 2007. The legislature explained that the new legislation was due to (a) a lack of competitive markets for small customers and increasing exposure to higher market prices; (b) the distribution provider's lack of bargaining power when contracting for energy, due to its inability to self-supply generation; (c) the difficulty of planning for load given that the law provided for customer choice but no real competitive market existed; and (d) a need for more power to serve Montana customers.[36] Montana faces the same types of near-term capacity deficits that have been identified in the Pacific Northwest.[37]

3. Washington

Washington does not currently have formal "direct access," as Oregon defines it, but has previously allowed some degree of "retail wheeling" subject to the Washington Utilities and Transportation Commission's (WUTC) ongoing oversight. Because of this ongoing oversight, the WUTC does not have precisely the same issues Oregon does with respect to departing customers.

Retail wheeling developed in Washington in the mid-1990s, and allows a utility customer to contract with a third party to provide power, which is then wheeled to the customer over the utility's transmission and distribution facilities.[38] In 1999, as the country moved toward retail competition, Puget Sound Energy (PSE) developed Schedule 48 to provide large customers with access to "competitively priced electricity."[39] As energy prices spiked during the Western Energy Crisis, however, large customers who had signed onto the market-based tariffs appealed to the WUTC for relief. The WUTC approved a comprehensive settlement of complaints

---

[34] Idaho Code § 61-332 *et seq.* (Electric Supplier Stabilization Act).
[35] *In the Matter of the App. of PacifiCorp for Approval of its Elec. Util. Restructuring Transition Plan Filed Pursuant to Sen. Bill 390*, Docket No. D97.7.91, Order No. 5987b ¶ 13 (Sept. 22, 1997).
[36] Montana Dept. of Enviro. Quality, *Understanding Energy in Montana 2018* at 44 (2018) (summarizing committee minutes of House Bill 25 during the 2007 legislative session), available at: https://leg.mt.gov/content/Committees/Interim/2017-2018/Energy-and-Telecommunications/Understanding%20Energy%202018.pdf.
[37] *See* Northwestern Energy's 2019 Electricity Supply Resource Procurement Plan at 1-3 - 1-10, available at https://www.northwesternenergy.com/docs/default-source/documents/defaultsupply/plan19/ch-2019-vol-1-final.pdf.
[38] While the Washington legislature has a stated policy to encourage public utilities and cooperatives to enter into agreements to avoid unnecessary duplication of service facilities, this encouragement is non-binding. RCW 54.48.020; *see also Wash. Utils. and Transp. Comm'n v. Puget Sound Energy*, Docket UE-161123, Order 06 ¶ 22 (July 13, 2017) (describing Washington's retail wheeling).
[39] *Air Liquide America Corporation, et al. v. PSE*, Docket UE-981410, Fifth Supp. Order at 3 (Aug. 3, 1999).

between PSE and 12 large customers and terminated Schedule 48 on October 31, 2001.[40] Another retail wheeling tariff continues to apply to a handful of customers, but appears closed to new customers.[41] Outside of a single recent exception (described below), it does not appear that PSE has offered retail wheeling to new customers since shortly after the Western Energy Crisis.[42]

More recently, the WUTC approved a special retail wheeling arrangement in 2017, allowing Microsoft to purchase energy directly from alternative suppliers.[43] The WUTC approved the special contract with significant customer protection provisions to ensure that Microsoft's access did not result in "unreasonable or unaffordable rates for remaining customers, especially those least able to pay, or threaten the integrity, safety, reliability, and quality of the electric system and retail electric service."[44] Microsoft was required to pay transition fees, to comply with state RPS laws and public policy goals, and to assume the "risks and benefits of direct access to the wholesale market[.]"[45]

Washington's recent Clean Energy Transformation Act of 2019 (CETA) sets targets for reducing the carbon impact of energy resources serving Washington customers—requirements that apply to market customers as well.[46] The WUTC has been directed to promulgate rules by June 30, 2022, for "specification, verification, and reporting" requirements associated with retail electric load that is met with market purchases and to prevent double-counting of non-power attributes.[47] Rather than increasing customer retail choice, the legislature appears to recognize the need to ensure that the statute's mandates are not avoided by customers going to market to procure wholesale power that may not comply with the state's renewable energy goals.

---

[40] *Air Liquide America Corporation, et al. v. PSE*, Dockets UE-001952 and UE-001959, Eleventh Supp. Order ¶ 31 (April 5, 2001) ("The essential thrust of Schedules 448 and 449 is to broaden significantly the power supply options available to PSE's industrial customers. In addition to self-generation options, a customer who takes service under Schedule 448 may arrange for one or more power suppliers other than PSE to make available to PSE power sufficient to meet the customer's load. Under Schedule 448, PSE will purchase power from the power supplier(s) on terms and at rates negotiated by the customer and the power supplier. PSE then will resell the power to the customer under a so-called Buy/Sell Contract without any mark-up or additional charges for the commodity, except for applicable state and local utility taxes."). *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-161123, Order 06 ¶ 25 (July 13, 2017) ("The Commission terminated Schedule 48 on October 31, 2001.").
[41] Docket UE-161123, Order 06 ¶ 25.
[42] *Id.* at ¶ 50 ("PSE has not offered retail wheeling to new customers in over 15 years[.]").
[43] *Id.* at 12.
[44] *Id.* at ¶ 91.
[45] *Id.* at ¶ 93.
[46] ESSB 5116, 66th Wash. Leg., Reg. Sess. (2019) (CETA), Secs. 4-5 (requiring market customers to comply with the requirement for electricity sales to be greenhouse gas neutral by 2030 and to be supplied by 100 percent non-emitting and renewable resources by 2045).
[47] CETA Sec. 13.

4. Utah

Utah does not have a direct access program, but instead provides opportunities for customers to select renewable energy options through utility-specific renewable energy tariffs.[48] For example, Rocky Mountain Power's Schedule 34 allows customers the option of contracting to have renewable energy purchased on their behalf. Such renewable energy tariffs were specifically authorized in Utah through 2016 legislation, which established Utah Code Ann. Ch. 17 Part 8 ("Renewable Energy Contracts"). The legislation requires renewable tariff customers to "bear all reasonably identifiable costs" that the utility incurs to deliver the power, including procurement, billing, and administrative costs.[49] This appears to be more akin to a utility "green tariff" than direct access to alternative suppliers.

5. Wyoming

Wyoming does not have a direct access program for retail energy customers. However, The Wyoming Public Service Commission has approved a Large Power Contract Service (LPCS) tariff for Cheyenne Light, Fuel and Power Company (Cheyenne) in anticipation of new large load from a single commercial customer—Microsoft.[50] The precise details of the contract between the parties remain confidential.[51] Cheyenne's LPCS tariff allows the utility to access Microsoft's own self-generated power supplies to meet the utility's peak demand needs, while allowing Cheyenne to purchase power from the market on Microsoft's behalf at a firm price to meet Microsoft's energy needs.[52] This appears to be more akin to a special tariff than direct access to alternative suppliers.

6. Nevada

Nevada has a form of direct access, known as "distribution only service" (DOS) for large utility customers.[53] Nevada initially pursued full deregulation in the 1990s, before returning to an integrated system following the Western Energy Crisis. However, Nevada has continued to allow large utility customers to apply to leave the regulated utility's system. This mechanism has only recently seen much interest, and the legislature responded in 2019 by tightening the

---

[48] *In the Matter of Rocky Mountain Power's Proposed Elec. Serv. Sched. No. 34, Renewable Energy Tariff*, Docket No. 16-035-T09, Order Memorializing Bench Ruling Approving Settlement Stipulation (Aug. 18, 2016) (approving Rocky Mountain Power's Schedule 34).
[49] Utah Code Ann. § 54-17-805.
[50] *In the Matter of the App. of Cheyenne Light, Fuel and Power Co. for Authority to Establish a Large Power Contract Serv. Tariff*, Docket No. 0003-146-ET-15 (Record No. 14242), Memorandum Opinion, Findings and Order Approving Application (July 28, 2016).
[51] Docket No. 0003-146-ET-15 (Record No. 14242), Memorandum Opinion ¶ 46e.
[52] UtilityDive, "How Microsoft and a Wyoming utility designed a data center tariff that works for everyone," (Dec. 20, 2016) available at: https://www.utilitydive.com/news/how-microsoft-and-a-wyoming-utility-designed-a-data-center-tariff-that-work/430807/.
[53] *Application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto*, Docket No. 19-06002, Order (Dec. 23, 2019) *reconsideration granted* Order on Rehearing (Feb. 14, 2020) (setting the case for rehearing to address the appropriate methodology for weather-normalization only).

requirements for departing customers. Other recent efforts to deregulate the state's power markets were defeated by the Nevada electorate in 2018.

In the mid-1990s, Nevada had moved towards full deregulation and a competitive energy market.[54] In 2001, Nevada returned to a vertically integrated system, with an exception for certain large customers.[55] At first, the program went largely unused, with only a few applications made before 2014.[56] Beginning in 2018, however, an additional 13 large customers applied to leave and become DOS customers.[57] In response, the 2019 Nevada legislature passed a bill restricting customers' ability to leave the utility's system. The bill also required the Public Utilities Commission of Nevada (PUCN) to implement additional customer protections.[58]

These changes were implemented to mitigate the impacts associated with too many organizations leaving the utility's system, including: (a) increased prices; (b) stressors on the grid as companies move between suppliers; (c) unpredictable demand; (d) evasion of public policy costs; (e) reduced renewable energy; and (f) shifting costs to residential customers.[59]

A recent effort to comprehensively overhaul and expand access to the competitive energy market was defeated in the 2018 election cycle.[60] The Natural Resources Defense Council, the Sierra Club, and other clean energy groups opposed the initiative, arguing that market restructuring would undermine existing decarbonization efforts.[61]

B. What Has Worked Well and What Has Not?

As demonstrated by the establishment and later repeal of retail competition in Montana and other states, increasing customers' access to the wholesale energy marketplace can be problematic

[54] Pub. Utils. Commission of Nevada Presentation to the Governor's Committee on Energy Choice, "Historic Overview: Nevada Deregulation 1990's" at 4 (Nov. 7, 2017) available at: http://energy.nv.gov/uploadedFiles/energynvgov/content/Programs/TaskForces/2017/11-07-2017_EnergyChoice_Agenda6_PUCN%20Presentation.pdf.
[55] The new exception for large customers, known as NRS 704B, allows existing utility customers with 1 megawatt or more in average annual load to apply to depart the incumbent utility's system and obtain energy from an alternate provider. NRS 704B.080.
[56] *App. of Placer Turquoise Ridge Inc. as Operator of Turquoise Ridge Joint Venture to purchase energy, capacity and/or ancillary services from a provider of new elec. resources,* Docket No. 06-07026, Order (Dec. 05, 2006); *App. of Nevada Power Co. for approval of the Distribution Only Service Agreement with the Las Vegas Valley Water Dist. and the Colorado River Comm'n*, Docket No 06-03017, Order (Apr. 26, 2006); *App. of Barrick Gold U.S. Inc., operator of Cortez Joint Venture dba Cortez Gold Mines, to purchase energy, capacity, and/or ancillary services from a provider of new elec. resources*, Docket No. 08-03025, Order (July 11, 2008)
[57] The Nevada Independent, "Last-minute bill would severely curtail ability of businesses to leave NV Energy" (May 16, 2019), available at: https://thenevadaindependent.com/article/last-minute-bill-would-severely-curtail-ability-of-businesses-to-leave-nv-energy.
[58] SB 547, 80th Nev. Leg. (2019).
[59] Nev. Sen. Committee on Growth and Infrastructure, Presentation by Senator Chris Brooks, Dist. No. 3, "SB 547: A History of NRS 704B and Energy Deregulation in Nevada" at C14 (May 23, 2019), available at: https://www.leg.state.nv.us/Session/80th2019/Exhibits/Senate/GRI/SGRI1295C.pdf.
[60] The Nevada Independent, "Voters reject energy choice ballot question, as other initiatives advance on comfortable margins" (Nov. 7, 2018) available at: https://thenevadaindependent.com/article/voters-reject-energy-choice-ballot-question-as-other-initiatives-advance-on-comfortable-margins.
[61] UtilityDive, "Green groups come out against Nevada retail choice ballot measure," (July 27, 2018) available at: https://www.utilitydive.com/news/green-groups-come-out-against-nevada-retail-choice-ballot-measure/528729/.

unless carefully implemented. Some WECC states have retreated from retail access (like Montana); others appear to rely more heavily on specific supply offerings such as utility green tariffs rather than customer departures to implement customer choice; and still others, like Nevada and California, continue to struggle with the implementation of their retail access programs, which, like Oregon's, are partially deregulated and create a fragmented regulatory scheme.

In states that completely deregulated their retail electric markets, like Texas, vertically integrated utilities were often required to spin off their generating assets, and their stranded costs were determined through the market sale of generating assets, other specific valuation methods, or through quasi-judicial administrative hearings. Those stranded costs, and other costs associated with above-market and public policy goals, were generally made non-bypassable and recoverable over time through charges on the distribution utility's system.[62]

In states like Oregon, however, with partially deregulated retail markets, assessments of stranded costs (and other ongoing costs needed to prevent cost-shifting) must be made accurately and repeatedly year-after-year, in the face of continued advocacy for the removal of such charges.

In short, the complex, multi-level regulatory schemes of partially deregulated markets can create vexing issues in partially deregulated states like Oregon, California, and Nevada, where, instead of tackling the issues of cost shifting in a holistic and dispositive manner, state commissions are tasked with continually addressing the transitional issues related to the partial and potentially temporary migration of customers, while still maintaining a fair and functional regulated market.

C. How Can These Findings Be Applied to Oregon, Including Consideration of the Fact That Oregon's Direct Access Market Is Limited to Non-Residential Customers?

As the previous discussion indicates, there are few WECC states with records of successful, widespread direct access implementation.

Because direct access options in Oregon are limited to non-residential customers, this Commission is relieved of the burden of developing the complex customer protection requirements that would be necessary if direct access were extended to residential customers (as in California). Because direct access customers in Oregon are sophisticated business entities, they can and should be expected to bear the risks associated with their economic decisions to leave and/or come back to the utility.

Despite limiting direct access to non-residential customers, the costs and risks of direct access remain substantial. Mitigating these risks and allocating these costs will require careful assessment of transition charges, clear allocation of responsibility for the state's POLR, reliability, and resource adequacy needs, as well as ongoing cost allocation flexibility as technologies and state policies require continued system, resource, and remediation investments.

---

[62] *See, e.g. Tex. Indus. Energy Consumers v. CenterPoint Energy Houston Elec., LLC*, 324 S.W.3d 95, 104 (Tex. 2010) (describing key elements of deregulatory scheme).

PacifiCorp looks forward to addressing these issues in more detail during the course of this investigation.

IV. Resource Adequacy

A. What Is Resource Adequacy?

Resource adequacy means that a Balancing Authority (BA) or other entity with responsibility for maintaining resource balance in a particular region has enough resources to serve load across a wide range of conditions and with a sufficient degree of reliability.[63] The North American Electric Reliability Corporation (NERC)—the FERC-certified Electric Reliability Organization that, among other things, enforces reliability standards and oversees WECC—defines resource adequacy as "[t]he ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[64]

Typically, the time span over which resource adequacy is measured is 1-4 years. "Resource sufficiency," by contrast, requires a utility to have sufficient operating reserves to ensure reliable operation of the grid on day-to-day basis.[65] IRPs look at yet another time horizon: the utility's ability to meet its future loads over a time period of 20 years or more.

NERC has explained that the bulk-power system achieves an adequate level of reliability when it possesses the following characteristics:

1. The system is controlled to stay within acceptable limits during normal conditions;
2. The system performs acceptably after credible contingencies;
3. The system limits the impact and scope of instability and cascading outages when they occur;
4. The system's facilities are protected from unacceptable damage by operating them within facility ratings;
5. The system's integrity can be restored promptly if it is lost; and

---

[63] NERC, *Glossary of Terms Used in NERC Reliability Standards* at 4 (updated Feb. 24, 2020) (defining "Balancing Authority"), available at: https://www.nerc.com/files/glossary_of_terms.pdf. A BA is responsible for maintaining resource balance within a particular region, known as a BAA. *Id.*
[64] NERC, *Glossary of Terms Used in NERC Reliability Standards* at 1
[65] Northwest Power Pool (NWPP), *Exploring a Resource Adequacy Program for the Pacific Northwest* at 44-45 (Oct. 2019) (distinguishing resource adequacy from resource sufficiency), available at: https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf.

6. The system has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.[66]

B. How Is It Provided?

BAs are required not only to maintain sufficient resources to serve anticipated customer load, but also to procure additional "planning reserves" *not* intended to serve customer load on a regular basis, but to be held back to ensure there are sufficient resources available to serve load even in unexpected conditions. The amount of planning reserves needed may be determined in a number of ways, but an important element often includes setting a planning reserve margin PRM or determining an acceptable loss of load probability associated with a certain set of loads/resources and contingencies.[67]

Importantly, resource adequacy is an issue that needs to be addressed in advance, not after it becomes a problem. Electricity is unlike other consumer products in a number of ways, but critically in this context; in order for the grid to function, grid operators must instantaneously balance supply and demand. They must do so while being constrained by the physical limitations of the system to deliver power to any particular point on the grid. A failure to achieve this instantaneous balancing in one location can threaten the stability of the entire grid.[68] Grid management challenges are further exacerbated by the increasing diversity and intermittency of renewable resources and the pressures to move away from fossil fueled generation resources.

Despite the need for this balance, both consumer demand for electricity and the availability of electric generation supply (once output nears capacity) are relatively inelastic.[69] Load shedding means blackouts, a result that is anathema to public policy, and yet new generation resources that can provide power at precisely the time customers need them do not appear on demand. Such resources take time to plan and build.

Consequently, BAs must plan to have adequate, firm resources available for system needs to ensure system failure does not occur when something goes wrong.

C. What Regulatory Requirements or Market Structures Are Used in Other States with Direct Access to Ensure Resource Adequacy?

Resource adequacy can be a concern for a region even in the absence of direct access. Direct access simply complicates and adds additional strain to a region's existing resource adequacy

---

[66] NERC, *Definition of "Adequate Level of Reliability"* at 6 (Dec. 2007) (emphasis added) (stating the definition of "Adequacy" in the May 2007 NERC Glossary of Terms), available at: https://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.
[67] NWPP, *Exploring a Resource Adequacy Program for the Pacific Northwest* at 13.
[68] Severin Borenstein, *The Trouble With Electricity Markets: Understanding California's Restructuring Disaster*, 16 J. of Econ. Perspectives 1, 195-96 (2002), available at: http://faculty.haas.berkeley.edu/borenste/download/JEP02ElecTrbl.pdf; Spence, *supra*, at 439-440.
[69] *Id.*

concerns because, in the absence of compelled resource adequacy obligations for third parties, third-party providers are financially incentivized to procure only enough energy and capacity to serve their customers; they have no incentive to procure the additional planning reserves needed to meet appropriate resource adequacy standards.

In the absence of strong regulatory controls, then, these providers may "lean" on regulated utilities or other load-serving entities as a (potentially expensive) backstop, or they may simply rely on electricity markets to provide "extra" resources when contingencies occur. Both of these scenarios have the potential to increase utilities' costs of serving customers and may even threaten reliability if the resources needed to meet contingencies simply do not materialize.

There are a number of ways that resource adequacy is regulated:

- <u>The Pacific Northwest.</u> In the Pacific Northwest, investor-owned utility resource adequacy needs are generally addressed by individual utilities through state commission resource-planning processes (typically, IRPs), followed by utility resource procurements.

  While utility-by-utility planning has been reasonably effective, recent developments in the electric sector have led to projections of near-term regional capacity deficits. The downside of siloed, individual assessments of resource adequacy is that utilities are unable to take advantage of wider resource pooling, diversity benefits, and greater visibility into regionwide market depth and/or resource availability that might be possible with increased coordination. Without access to wider information, individual utility assessments of market depth may be incorrect, or multiple areas may be relying on the availability of the same market purchases or the same resources (double-counting) for resource adequacy purposes. This risk is exacerbated if third-party providers like ESSs intend to rely on market purchases, or expect utilities to do so, to cover any type of resource shortfalls for either direct access customers or for customers returning to the utilities' systems.

  More recently, the NWPP, a reserve sharing group comprised of multiple utilities across the Western Interconnect, has been studying a voluntary program that would allow electric utilities to forecast and manage resource adequacy in a coordinated manner. By planning as a group, participating utilities would have a clearer understanding of the resource adequacy of the region, thereby better informing resource acquisition decisions.[70]

- <u>ISO/ RTO Capacity Markets.</u> Some ISOs/RTOs, such as PJM and ISO New England, operate centralized capacity markets for procurement of resource adequacy needs. These markets are highly FERC-regulated and have recently been the subject of significant

[70] *See, e.g.*, NWPP, *Status of Resource Adequacy Program for NWPP Members and Stakeholder Engagement Opportunities* (Jan. 3, 2020), available at: https://www.nwpp.org/private-media/documents/2020.01.03_NWPP_RA_Stakeholder_Engagement_Public_Document.pdf.

litigation between the states and FERC, due to friction between state-specific resource procurement policies and FERC's interest in federally regulated price competition.[71]

- Other ISO/RTO Resource Adequacy Programs. Other ISOs/RTOs, like the Southwest Power Pool (SPP), have resource adequacy programs that are also FERC-regulated, but are largely bilateral in nature and provide more flexibility for state resource procurement policies. SPP, for example, provides consistent metrics across its footprint to assess regional and sub-regional resource adequacy, allocates responsibility for procurement to member utilities, and qualifies resources that wish to be considered for the program. Utilities meet the resource adequacy obligations assigned to them by SPP by procuring new resources or through bilateral contracts. The public utility commissions of the member states have a significant influence on SPP's resource adequacy program and member utilities have flexibility in procuring various types of resources to meet their resource adequacy needs.[72]

- California's Resource Adequacy Program. California has a resource adequacy program that, like SPP's, is largely based on bilateral contracts or individual utility procurements. The CPUC, California Energy Commission (CEC), and the California ISO (CAISO) jointly implement the program. The CPUC calculates resource adequacy needs, allocates those needs among the state's load-serving entities, establishes common capacity counting, and enforces compliance. CAISO has the authority to procure backstop capacity, while the CEC oversees resource adequacy for publicly owned utilities.[73] The California resource adequacy program is currently being evaluated by both the CPUC as well as through CAISO's implementation of the resource adequacy program.[74] Both of these efforts to revamp the resource adequacy program reflect the changes in California's grid relative to solar and wind penetration as well as recent retirements in gas generation.

Like many issues in the electric industry, resource adequacy is not a major subject of discussion when resources are plentiful, deliverability is straightforward, and compliance is affordable and manageable from a regulatory perspective. When resource adequacy becomes threatened, however, the issues become more complicated, and regulatory solutions have proven to be challenging in many regions.

PacifiCorp looks forward to a meaningful exploration in this docket of options to ensure that all providers are subject to robust and enforceable requirements to carry their fair share of resource adequacy obligations.

---

[71] *See, e.g., Calpine Corp. et al. v. PJM Interconnection, LLC*, 163 FERC ¶ 61,236 (2018) (rejecting PJM's capacity market proposal).
[72] NWPP, *Exploring a Resource Adequacy Program for the Pacific Northwest* at 37.
[73] NWPP, *Exploring a Resource Adequacy Program for the Pacific Northwest* at 69.
[74] *See, e.g., Order Instituting Rulemaking to Oversee the Resource Adequacy Program*, R-17-09-020, Application for Rehearing of Decision 19-10-021 of the CAISO (Nov. 18, 2019) (seeking reconsideration of the CPUC's decision addressing resource adequacy import rules).

D. Why Is It Important or Not Important?

Resource adequacy is critical to the continued reliable operation of the grid. If resources are insufficient to cover a range of contingencies, any number of events can create price volatility or even customer load curtailments. A system that plans appropriately for resource adequacy can successfully operate in the event of generation outages, storm damage, unexpected weather, or any number of occurrences. A system that does not plan appropriately for resource adequacy may need to rely on exorbitantly expensive purchases to continue operation when these events occur, or it may simply need to shut down.

The Northwest Electric Power and Conservation Council explained it succinctly:

> The Western Electricity Crisis of 2001-2002 <u>is widely believed to have had its roots in resource inadequacy</u>. For a number of reasons, resource development in the 1990s failed to keep pace with growth in the region and, in fact, the entire West. When poor hydro conditions manifested themselves in the summer of 2000 and on into 2001, the underlying tight supply was made apparent and wholesale prices went out of control. The lights never went out in the Northwest during 2000 and 2001 but the region experienced extremely high wholesale prices. This occurred even though large amounts of load, mostly from the Direct Service Industries, were taken off the system.[75]

The Western Energy Crisis centered on California markets and resulted in blackouts across the state. Although its ripple effects did not lead to blackouts in the Pacific Northwest, it had a significant impact on Oregon's economy and permanently decimated the Northwest's aluminum industry.[76]

The state's economy and the health of its citizens depend on a reliable, affordable electric supply that allows businesses to operate, schools to remain open; lights, refrigerators, and elevators to continue running; and medical equipment to continue functioning. Resource adequacy plays an important role in ensuring the reliability of this supply.

E. What Direct Access Issues May/Should Be Considered in the Contested Case Phase?

PacifiCorp believes this question may be more constructively answered after the parties complete comments and briefing. Comments and briefing may allow the parties to better identify areas of agreement (or disagreement) on this issue, and whether there are consensus areas that limit the scope of issues in need of evidentiary support. In addition, the ongoing efforts to stand up a regional plan for resource adequacy may be further along by the time comments and briefing are completed, which may also inform the parties' discussions.

---

[75] Northwest Power and Conservation Council, *The Fifth Northwest Electric Power and Conservation Plan*, Vol. 2, Ch. 8 at 8-1 (May 2005) (emphasis added), available at: https://www.nwcouncil.org/sites/default/files/_08__Resource_Adequacy_1.pdf.
[76] *See* Northwest Power and Conservation Council, *Aluminum* (2020) available at https://www.nwcouncil.org/reports/columbia-river-history/aluminum.

As mentioned above, there are multiple current efforts within the Western region to review resource adequacy given the changing landscape of resource portfolios and announced resource retirements. It will be crucial for Oregon parties to stay engaged in the regional efforts and to recognize that an Oregon resource adequacy framework for direct access customers may need to be revisited to ensure consistency between a potential regional program and the state program. PacifiCorp supports the efforts of the Commission to provide guidance and clarification on the resource adequacy obligations of direct access customers, as it believes this will ultimately provide a more fair and equitable allocation of the costs associated with reliable grid operations.

V. Conclusion

PacifiCorp appreciates the opportunity to file these comments and looks forward to engaging on these and other issues in this docket.[77]

Respectfully submitted this 16th day of March, 2020.

By: ______________________
Matthew McVee
Chief Regulatory Counsel
PacifiCorp d/b/a Pacific Power

[77] The first phase of this docket is a comment phase, with reply comments to be filed on April 6, 2020. The second phase is currently envisioned to be a legal-briefing phase, followed by a contested-case phase.

Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

March 16, 2016

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: UM 2024 PGE's Opening Comments on Phase I

Dear Filing Center:

Portland General Electric respectfully submits these Opening Comments in Phase I (informal phase) of UM 2024 AWEC's Petition for Investigation into Long-Term Direct Access and looks forward to reviewing the comments of Staff and stakeholders and responding with Closing Comments on April 6, 2020.

If you have any questions, please contact Michael O'Brien at (503) 464-7799.

Sincerely,

/s/ Karla Wenzel
Karla Wenzel
Manager, Regulatory Policy and Strategy

KW/np
Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2024

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS Petition for Investigation into Long-Term Direct Access Programs.	**OPENING COMMENTS OF PORTLAND GENERAL ELECTRIC COMPANY**

Contents

PGE appreciates the opportunity to submit these comments to the Public Utility Commission of Oregon (Commission or PUC) in response to the Stipulated Issues list for Phase I (non-contested case phase) of PUC Docket No. UM 2024, posted on February 21, 2020.[1] PGE has included Appendix I – Long-Term Direct Access History, which provides valuable context for this docket, along with Appendix II - PGE Implementation of Direct Access, which documents PGE's implementation of this program over the last two decades for those less familiar with direct access.[2].

I. Context for PGE Comments

Over 100 years ago, Portland General Electric Company (PGE or Company) began providing electricity service to Portland area customers with its innovative, first-in-the-country, long distance transmission of alternating current (AC) power from Willamette Falls to Portland in 1889 and generation from the Sullivan Plant Station B in 1895. In the early years, the electricity generated powered the Lewis and Clark Centennial Exposition, electric streetcar-based floats for Rose Festival, and the first Portland building to feature permanent exterior lighting. Electrification changed lives, enabling home heating and cooling, preserving foods, providing safety through lighting, electrifying devices from early appliances to current day electronic devices and electric vehicles. Throughout the 20th century, PGE constructed generating facilities to meet increasing loads, ran energy efficiency campaigns, offered renewable energy power supply choices for customers, while keeping customers safe and warm through powerful storms. Customers used electricity to make their lives better in their homes and workplaces. Electricity became viewed as an essential service, "affected by the public interest," and it was desired that the service be extended broadly and offered on a nondiscriminatory basis to customers.

Electric utility regulation evolved over time, with initial recognition that multiple companies attempting to compete to deliver electricity service could mean inefficient and confusing deployment of distribution poles and wires by different companies down opposite sides of the street in the same neighborhood. This effort required substantial capital to build electricity generating plants and delivery infrastructure; state regulation then was premised on the efficiency of leveraging a company's access to private capital to develop generation and an electricity delivery system. A regulatory compact developed, between the state and the electric company, in which the electric company was granted a monopoly franchise in a geographically bounded service territory, and was required to provide safe, reliable, nondiscriminatory and affordable service with cost-based rates. In exchange the company would be allowed a reasonable return on capital. The goal was economic efficiency, serving customers well at fair prices. The electric company tapped capital markets for the public good, fueling rapid economic growth,

---

[1] Public Utility Commission of Oregon. "Ruling." UM 2024. Public Utility Commission of Oregon. 21 Feb 2020. https://edocs.puc.state.or.us/efdocs/HDA/um2024hda12440.pdf

[2] While PGE offers a short-term direct access program, these comments are intended to apply to only long term direct access programs which include the long term direct access five year opt out program and new load direct access.

industrialization, and customer well-being. The compact proved an effective model to allocate and share risks associated with major resource decisions.

At the close of the 20th century, Oregon passed Senate Bill (SB) 1149, a partial electricity deregulation law, experimenting as other states were doing, with the option for nonresidential customers to purchase electricity from the market instead of the company. The thinking at the time was that for purchasing electricity, more sophisticated customers would be offered a competitive choice, and the commodity aspect could be carved off for the market while the utility would retain delivery responsibility and provide reliability.

Oregon's approach was cautious, even slowing down its initial approach. After observing the Western United States Energy Crisis (Energy Crisis) in the fall of 2000 and the spring of 2001. In the end, the vertically integrated utility provided options for customers: residential customers could choose among a portfolio of renewable and market based rate options; and nonresidential customers had the option of direct access to the market through electricity service suppliers (ESSs), the company's own standard offer service, and cost of service rate options. The company also provided the backstop for direct access customers with default service. While the law was focused on choice and competition, customer advocates fought for the inclusion of public purpose funding to create a steady stream of investments in energy efficiency, low-income weatherization, renewables, low-income bill assistance and other social goods to be funded by all customers in a non-bypassable manner. The design seemed clear: recognize and protect the public interest no matter the choices of customers; have all customers contribute to those important public interests; and ensure that customer choices do not result in cost shifts to non-participating customers, namely direct access customers shifting costs to PGE's other customers.

Since SB 1149 became law and over the last two decades, policy makers, experts and others have come together on the compelling public interest in slowing climate change, particularly the need to reduce greenhouse gas emissions from power production, by moving to more renewable energy generation, demand response and energy efficiency. In 2007, the legislature passed SB 838 establishing Oregon's first renewable portfolio standard (RPS), and in 2016, through SB 1547, the RPS was significantly accelerated. The intent of the RPS was to increase the amount of clean energy generation over time. In response to renewable energy needs, PGE forecasted customer loads, planned resources, issued competitive bid requests, and used its access to capital to build renewables in the most efficient manner for customers.

As supported by the actions of our customers, the cities we serve, and the Governor's Office, our strategic imperative is to accelerate decarbonization of the energy transportation sectors through electrification. Independent of our decarbonization effort, we must also ensure that we plan for and provide for the reliability of the electric system through resource adequacy (RA) as fossil-fuel resources continue to retire. The acquisition and integration of replacement capacity for retiring plants has significant implications for planning to serve customers, and for maintaining the reliability of an increasingly complex, integrated electricity system. PGE's positioning as

Oregon's largest energy provider and a fully regulated electric company, enables us to be a full partner in the state's policy direction. We are serving our customers through our integrated system with affordable, and increasingly clean energy, recognizing that "[r]eliable electric service requires expert management of a complex, interconnected grid."[3]

Planning and procuring for RA is a key issue in this docket as a result of the Company raising the subject in the Commission's investigation into PGE's New Load Direct Access, Docket No. UE 358. Given concerns that neither ESSs nor new load direct access customers contribute to RA, PGE proposed to charge for RA. Rather than approve the charge, the Commission included RA in the scope of this broader long-term direct access investigation. Resolution should address ESS and/or customer responsibility to provide RA through a robustly regulated, transparent planning and procurement process, or if not directly provided, then through meaningful contributions to RA costs. Short of that outcome, ESSs and their direct access customers will continue to lean on cost-of-service (COS) [4] customers who pay for RA. The RA issue has increased in visibility lately as challenges occur from increasing number of coal plant retirements, transmission pathway constraints, and increasing customer loads.

In closing this introduction, PGE welcomes the Commission's investigation into long-term direct access, particularly the exploration of the cost and risk shifts that occur when customers choose direct access. PGE recommends that the Commission update the structure of direct access to ensure that all customers contribute to resource adequacy and the costs associated with electric company programs to meet Oregon public policy objectives. New regulatory mechanisms to address these issues become even more important with the addition of new load direct access (NLDA) programs, increasing the amount of long-term direct access load that is not planned for and does not meaningfully contribute to RA by 119 MWa, for a total of 419 MWa. At the center of PGE's requests is the Commission's interest in a reliable, resource adequate, and customer-serving system while ensuring that long term direct access programs (including new load) adhere to the statutory prohibition against "[…] unwarranted cost shifting of costs" to other retail customers.[5]

II. Executive Summary

PGE's comments for this Phase 1 of the UM 2024 direct access investigation are organized to respond to the stipulated issues list, focusing on resource adequacy, the costs and benefits of direct access, and then lessons learned from other states. The following is a brief summary of key points:

---

[3] Public Utility Commission of Oregon. "Actively Adapting to the Changing Electricity Sector – SB 978 Final Report." Senate Bill 978. Oregon State Legislature. 24 Sep 2018, page 17. Retrieved from https://olis.leg.state.or.us/liz/2017I1/Downloads/CommitteeMeetingDocument/150413

[4] For the purposes of these comments, "cost-of-service" means customers not participating in long-term or new-load direct access.

[5] 2017 ORS 757.607 Direct Access Conditions – Cost Recovery. Accessed February 2020.

- PGE is fully invested in furthering Oregon's decarbonization goals. We are uniquely suited for this work as the state's largest investor owned utility whose customers are supportive of Oregon's direction. Our strategic direction, decarbonize, electrify and perform, is aligned with the Oregon direction.

- In light of the changes over the last twenty years since direct access was first instituted, the long-term direct access regulatory framework requires updating, and the time is now:

  - The framework must be reformed to ensure that all system participants, including long term and new load direct access customers, and Electricity Service Suppliers (ESSs) meaningfully contribute to supply adequacy and reliability.

  - The Commission should reform direct access to include an RA process that provides robust regulatory oversight, planning and analysis, procurement when necessary, and transparency that results in load serving entities making a showing of resource adequacy with secured resources that meet the need. The outcome should be a fair and equitable allocation of RA costs and responsibilities across all customers and their suppliers.

  - The Commission should reform direct access so that customers who choose direct access, and ESSs, that offer direct access, must not bypass important state policies and contribute to the costs and compliance responsibilities related to implementing the public policies.

  - The Commission should look to other states to inform direct access policy reforms, including intentional resource adequacy planning (Texas, Michigan, California), the importance of updating the policy framework (California), contributing to public policy costs (California and Nevada), and benefits of using program caps to guard against cost-shifting to COS customers (Oregon, California, Arizona, Nevada, and Michigan).

III. Introduction to PGE's Response to Stipulated Issues List

In accordance with the stipulated list, these comments will explore: RA; the potential benefits and potential costs to customers from long-term direct access (LTDA) participation; and, how other states are handling customer choice and access to wholesale markets for different customer classes.

A. Costs and Benefits of Long-Term Direct Access

Following a procedural history of this docket (Section II), we describe how the Company is the provider of last resort for all our customers, including direct access, even though we are not permitted to plan for them (Section III). This is followed by a study of the existing frameworks for LTDA and NLDA, which explores the extent to which costs are recovered through transition adjustments and supplemental adjustment schedules, identifying the potential for the current direct access framework to allow customers to bypass both system costs and the costs of public policies (Section IV). This is followed by a discussion of the potential harms to COS customers caused by direct access service as currently structured, including insufficiently contributing to physical generating assets; contributing to the fragmentation of the system and undermining the value of an integrated grid; increased COS customers' rates; taking advantage of low-marginal cost power without fully contributing to the costs of the underlying assets; bypassing the costs associated with Public Utility Regulatory Policies Act (PURPA) that are unavoidable for COS customers; avoiding contributing to the costs of public policy mandates such as net metering, the solar payment option/volumetric incentive rate, and Oregon's Community Solar Program (CSP); and contributing insufficiently to state and regional RA (Section VI). Sections V, VII, and VIII highlight the ability of direct access customers to bypass costs and shift them to remaining customers. PGE recommends that any costs associated with effectuating public policies through the electric utility should not be by-passable by customers choosing an alternative energy supplier.

B. Customer Choice in Other States

Section IX surveys how other states are handling customer choice and access to wholesale markets for different customer classes. PGE has mostly focused on the Western Electricity Coordinating Council (WECC) but included examples from other partially regulated states where the lessons learned seemed relevant to this docket. This survey of customer choice demonstrates the need for change in Oregon's direct access program so that we might learn from other states and avoid mistakes. Repeatedly, utilities in partially regulated states must serve their COS customers while trying to manage the inherent tensions between regulation and energy markets, typically leading to increased burden for COS customers as direct access customers bypass policy costs and take advantage of the wholesale market. Examples from Texas show that without intentional programs that are required to support RA in customer choice environments, markets will fail to deliver on RA targets (Section IX.A), while California's RA program (established in 2004), performed well until 2018 saw the rapid expansion of Community Choice Aggregators (CCAs) that were unable to meet their targets. Michigan requires alternative electricity suppliers to file capacity demonstration plans for the subsequent four years, allowing the state to secure adequate capacity resources through 2023. The states of California and Nevada provide examples of mechanisms aimed at reducing the costs that customers leaving COS are able to bypass (Section IX.B). Following an assessment of the importance of direct access caps in Oregon, California, Arizona, Nevada, and Michigan as a tool to help limit unwarranted cost shifting to COS customers (Section IX.C), PGE concludes by describing the importance of a strong regulatory framework when trying to protect consumers, keep rates affordable, and reduce greenhouse gases in a partially deregulated market.

C. Resource Adequacy

PGE welcomed the Commission's statements that "[…] all system participants contribute tangibly to BA [Balancing Area] RA, and that one way or another, NLDA and LTDA customers will be required to support RA – just as all cost-of-service customers are required to support RA."[6] Section VI defines RA as PGE's ability to plan to have, and obtain, sufficient resources in the longer term – including generation, efficiency measures, and demand-side resources – to serve our loads across a wide range of conditions with an acceptable degree of reliability. Following an assessment of RA metrics, the case is made that transparent, intentional planning and procurement process – such as PGE's integrated resource plan (IRP) – are necessary to meet these metrics and provide for RA (Section VI.B.1-2). These planning and procurement elements serve to provide signals for the development of necessary resources to achieve and maintain RA. Due to the nature of the wholesale energy market, these signals for direct access customers and providers to contribute to RA are absent from the current DA framework. PGE therefore recommends that direct access policy should be reformed in this docket to enable the Company to satisfy its RA obligations in a manner fair and equitable to all customers. After parsing the differences between RA (longer-term) and resource sufficiency (RS, shorter term) (Section.VI.B.3), PGE highlights the regional resource shortages that are anticipated (Section VI.C). Following a discussion of how the current direct access framework takes advantage of the wholesale markets to access standardized traded energy products which are not supported by a specified physical resource (Section VI.D), PGE discusses the interplay between direct access and wholesale markets. After an exploration of state and regional RA efforts (Section VI.E), PGE concludes with a list of key RA elements to be further explored (Section VI.F).

IV. UM 2024 Procedural History

Oregon Senate Bill (SB) 979 was introduced in March 2017, with the aim of establishing a form of renewable direct access in which transition charges and transition credits would not be applied to "new commercial load".[7] The legislation did not pass, but PUC Staff (Staff) reviewed an April 3, 2017, legislative hearing and "[…] found substantial public interest in SB 979, including interest in the treatment of new direct access loads."[8] The Commission subsequently opened an Investigation into the Treatment of New Facility Direct Access Load (PUC Docket No. UM 1837) in May 2017.[9]

Order No. 18-031, filed in UM 1837, concluded that the Commission has the authority to develop a direct access program focused on new load.[10] A rulemaking into NLDA was subsequently

[6] Public Utility Commission of Oregon. "Order 20-002." UE 358. Public Utility Commission of Oregon. 7 Jan 2020. Retrieved from https://apps.puc.state.or.us/orders/2020ords/20-002.pdf
[7] 79th Oregon Legislative Assembly. "Senate Bill 979." Oregon State Legislature. 2017. Retrieved from https://olis.leg.state.or.us/liz/2017R1/Downloads/MeasureDocument/SB979/Introduced
[8] Public Utility Commission of Oregon. "Staff Report Item No. 4." Public Utility Commission of Oregon. 16 May 2017. Retrieved from https://edocs.puc.state.or.us/efdocs/HAA/haa15428.pdf
[9] UM 1837. "Staff Investigation into The Treatment of New Facility Direct Access Loads." Public Utility Commission of Oregon. 2020. Retrieved from https://apps.puc.state.or.us/edockets/docket.asp?DocketID=20777
[10] Public Utility Commission of Oregon. "Order 18-031." UM 1837. Public Utility Commission of Oregon. 30 Jan 2018. Retrieved from https://apps.puc.state.or.us/orders/2018ords/18-031.pdf

opened (PUC Docket No. AR 614), entering rules through Order No. 18-341 in September 2018.[11] On February 5th, 2019, PGE filed tariff sheets in Advice No. 19-02 to be effective for service on or after April 1, 2019, to establish PGE's NLDA program.[12] The Commission suspended PGE Advice No. 19-02 for a period of nine months on March 22, 2019, to investigate the propriety and reasonableness of the tariff sheets.[13] PUC Docket No. UE 358 was opened on March 21, 2019, to further explore PGE's NLDA program proposal.[14]

During the pendency of the UE 358 investigation, the Commission opened UM 2024 on August 2, 2019, upon a petition from the Alliance of Western Energy Consumers (AWEC).[15] On January 7, 2020, the Commission entered Order No. 20-002, requiring PGE to file new tariffs consistent with the order, and "[…] invit[ed] PGE to propose changes to its curtailment schedules applicable to NLDA customers as we consider reliability and resource adequacy contributions from all direct access customers in the docket UM 2024 investigation".[16] A Stipulated Issues List and Phasing Proposal for UM 2024 was approved by the Administrative Law Judge on February 21, 2020.[17]

V. PGE Remains the Provider of Last Resort for All Customers

PGE remains the provider of last resource (POLR) for all loads on our system, including direct access, even though we are not permitted to plan for the load associated with LTDA or NLDA. In response to Oregon House Bill (HB) 3633, from the 2001 regular session, PGE designed Schedule 82[18] to "[…] provide back-up service for any direct-access customer that loses its ESS and has not provided PGE with the notice required to receive service under the applicable standard offer service rate."[19] PGE proposed to provide this back-up service on an "as available" basis to "prevent a returning direct access customer from causing PGE to curtail service to other customers who did not go to direct access […] other customers should not be required to suffer rolling outages to provide emergency default service or pay for standby resources for direct access customers." Staff noted that "[b]ecause PGE remains the provider of last resort within its service territory […] the company is obligated to provide safe and adequate service to all customers

[11] Public Utility Commission of Oregon. "Order 18-341." AR 614. Public Utility Commission of Oregon. 14 Sep 2018. Retrieved from https://apps.puc.state.or.us/orders/2018ords/18-341.pdf

[12] Portland General Electric Company. "PGE Advice No. 19-02." ADV 919. Public Utility Commission of Oregon. 5 Feb 2019. Retrieved from https://edocs.puc.state.or.us/efdocs/UAA/uaa165643.pdf

[13] ADV 919. "PGE – New Load Direct Access Program." Public Utility Commission of Oregon. 2019. Retrieved from https://apps.puc.state.or.us/edockets/docket.asp?DocketID=21787

[14] UE 358. "Portland General Electric Company Advice No. 19-04 New Load Direct Access." Public Utility Commission of Oregon. 2020. Retrieved from https://apps.puc.state.or.us/edockets/docket.asp?DocketID=21861

[15] Public Utility Commission of Oregon. "Order 19-271." UM 2024. Public Utility Commission of Oregon. 12 Aug 2019. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-271.pdf

[16] Public Utility Commission of Oregon. "Order 20-002." UE 358. Public Utility Commission of Oregon. 7 Jan 2020. Retrieved from https://apps.puc.state.or.us/orders/2020ords/20-002.pdf

[17] Public Utility Commission of Oregon. "Ruling." UM 2024. Public Utility Commission of Oregon. 21 Feb 2020. Retrieved from https://edocs.puc.state.or.us/efdocs/HDA/um2024hda12440.pdf

[18] Nonresidential Emergency Default Service is now provided through Schedule 81.

[19] Public Utility Commission of Oregon. "Order 01-777." UM 115. Public Utility Commission of Oregon. 31 Aug 2001, page 38. https://apps.puc.state.or.us/orders/2001ords/01-777.pdf

within its service area". The Commission resolved that "[…] customers who choose direct access should not be limited to default service on an "as available" basis."[20]

One year later in 2002, the Commission began an investigation into IRP requirements.[21] Five years later, the Commission adopted IRP Guideline 9 relating to direct access loads where they reinforced that PGE is not allowed to plan for LTDA load, even though we are obligated to be the POLR: "[a]n electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier."[22] The Commission believed that LTDA customers are "[…] 'effectively committed to service' under direct access and should be excluded from the IRP load-resource balance over the planning horizon".[23] This means that even though PGE has to be there non-discriminately for all customers in an emergency, we are not permitted to plan for LTDA loads in our IRP.

PGE is committed to continued reliability for all customers while ensuring that benefits, costs, and risks are borne equitably. As the reliability provider and the POLR, PGE has the ultimate responsibility for all customers in our service territory regardless of whether the customer receives energy from PGE or an ESS. PGE meets its POLR responsibility (which is exclusively designed to provide an energy "backstop" in the event a direct access customer loses its ESS or energy supply) by accepting the responsibility of procuring the necessary energy and services on a short-term basis to supply the customer.[24] While PGE is not allowed to conduct planning for these loads, ultimately PGE still serves as the reliability provider due to its BA responsibilities and the integrated nature of the system. PGE is meeting its reliability provider obligations by acquiring sufficient resources, the costs of which are included in the generation revenue requirement, to provide sufficient resource capability to serve COS loads under a wide array of possible conditions. PGE believes it is only fair that all customers contribute towards the costs of providing this service and that it is unfair for direct access customers to continue to lean on COS customers, many of whom are families, low-income and underserved individuals, and small businesses to bear the full burden of paying for this service, a position that the Commission, Staff, and some parties support.[25,26] Meaningful planning and contribution to reliability is only increasing in importance as we work toward Oregon's clean energy future and greenhouse gas reduction goals outlined in Oregon Revised Statute (ORS) 468.405A.

---

[20] Ibid.

[21] UM 1056. "Request to Open an Investigation into Integrated Resource Planning Requirements." Public Utility Commission of Oregon. 2007. https://apps.puc.state.or.us/edockets/docket.asp?DocketID=10081

[22] Public Utility Commission of Oregon. "Order 07-002." UM 1056. Public Utility Commission of Oregon. 8 Jan 2007, page 19. https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

[23] Ibid.

[24] Per Schedule 81 – Nonresidential Emergency Default Service, the Energy Charge Daily Rate is 125% of ICE-Mid-C Firm Index plus 0.306 cents per kWh for wheeling, plus losses.

[25] Public Utility Commission of Oregon. "Order 20-002." UE 358. Public Utility Commission of Oregon. 7 Jan 2020. https://apps.puc.state.or.us/orders/2020ords/20-002.pdf

[26] PGE estimates that at least 17% of our total residential customer base are low income. Source: PGE presentation to low-income working group at PUC, 'PGE Low Income Customers', September 18, 2018.

A. Resource Adequacy and PGE's Provider of Last Resort Responsibility are Distinct

As described above, the Company acknowledges that it has an existing obligation to serve as the POLR for all loads within its service territory. However, providing RA through its role as the reliability provider is not the same as the POLR obligation. As described below in Section VI, RA is implemented and achieved on a longer-term basis than POLR and serves to ensure that the resources available can meet the various needs of the system. POLR is a construct resulting from the implementation of SB 1149. As discussed further in Section VI, the regional circumstances and direct access paradigm are materially different now more than ever. The POLR construct is rooted in PGE supplying energy to a customer who unexpectedly returns to COS in the event their ESS fails, something that would necessitate action on PGE's behalf to ensure that it meets the obligation to provide safe and adequate service to all customers.[27] Providing RA is not the result of an unexpected action. Instead it is a forward-looking mechanism to ensure that adequate resources are available to meet the system's needs under various scenarios and ensure that all providers contribute to such system needs on an equal basis. The current overlap between POLR and RA is simply that PGE is responsible for providing both to all customers, regardless of their supply choices.

An RA framework is not needed to establish a mechanism by which PGE "backstops" the energy needs of customers under ESS failure; however, an RA framework is essential to ensure that PGE, or any other provider, has secured enough resources such that PGE is not backstopping direct access customers whose supply has not been planned for appropriately.

VI. Given the current and projected future of regional supply, Oregon's direct access policies and practices are insufficient to support resource adequacy

PGE welcomed the Commission's notice of its intention that "[…] all system participants contribute tangibly to BA RA, and that one way or another, NLDA and LTDA customers will be required to support RA – just as all cost-of-service customers are required to support RA."[28] This section introduces RA as PGE's ability to plan to have, and obtain, sufficient resources in the longer term – including generation, efficiency measures, and demand-side resources – to serve our customers' energy needs across a wide range of conditions with an acceptable degree of reliability. Meeting RA metrics requires transparent planning and robust regulatory oversight, both of which are absent from Oregon's current direct access framework. In addition, the current framework allows direct access customers to access standardized traded energy products on the wholesale market that are not backed by a specified physical resource. PGE therefore

[27] Public Utility Commission of Oregon. "Order 01-777." UM 115. Public Utility Commission of Oregon. 31 Aug 2001, page 38. Retrieved from https://apps.puc.state.or.us/orders/2001ords/01-777.pdf

[28] Public Utility Commission of Oregon. "Order 20-002." UE 358. Public Utility Commission of Oregon. 7 Jan 2020. Retrieved from https://apps.puc.state.or.us/orders/2020ords/20-002.pdf

recommends that the Commission reform direct access policy in this docket to ensure system reliability is maintained in a manner that is fair and equitable to all customers.

A. PGE's Role as Balancing Authority Reliability Provider

PGE, like most IOUs in the WECC, also serves as the BA for its service territory and is the sole entity responsible for complying with the operational standards and requirements of entities such as the North American Electric Reliability Corporation (NERC), WECC, and Federal Energy Regulatory Commission (FERC).[29] At the highest level, a BA is defined as the entity that "integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area (BAA), and supports interconnection frequency in real time."[30] This is achieved through constant monitoring and action as well as compliance with industry adopted NERC reliability standards.[31]

NERC was initially formed to address reliability issues that surfaced from a 1965 blackout, and evolved overtime to become the Electric Reliability Organization (ERO) responsible for mandatory, enforceable reliability standards developed by industry and adopted and enforced by NERC with oversight by its independent board, FERC, and Canadian provincial regulators with the monitoring and compliance delegated to Regional Reliability Organizations, such as WECC.[32] These requirements range from contingency reserves, which ensure enough capacity is available to support the grid in the event of an unexpected loss of generation, to voltage support and cyber security, all of which PGE, as the BA, is charged with compliance. In an organized market, there is commonly one market operator that serves as the BA over the entire market footprint with participating entities either being LSEs, generator owners, or pure marketers.[33] However, there are approximately 40 BAs across the WECC footprint, each with LSEs, generator owners, or active marketers of their own.[34] Each BA is charged with monitoring reliability and complying with NERC standards. Individual BA responsibility ensures the overall reliability of the WECC

[29] The geographic footprint of PGE's service territory and its Balancing Authority Area do not overlap in all areas. PGE has small pockets of retail load that are within the PacifiCorp and BPA BAAs and vice versa. These are commonly referred to as "borderline" loads. PGE still maintains reliability responsibility for the borderline loads within its BAA and supply responsibility for its borderline loads in other BAAs.

[30] Glossary of Terms used in NERC Reliability Standards. February 4, 2020. https://www.nerc.com/files/glossary_of_terms.pdf

[31] *Id.* NERC defines reliability standards as "A requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk-Power System. The term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk-Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity."

[32] The History of the North American Electric Reliability Corporation, https://www.nerc.com/AboutNERC/Resource%20Documents/NERCHistoryBook.pdf

[33] There are other participating entities, such as Transmission Owners, but for the purposes of these comments The Company is referring to entities relating to supply/demand of electricity.

[34] https://www.wecc.org/Administrative/Balancing_Authorities_JAN17.pdf

footprint. Ultimately, it is PGE as the BA that bears responsibility for reliability and compliance for the entire PGE area, not the electricity service supplier or the end-use customer.

Through PGE's Open Access Transmission Tariff (OATT) and current requirements of the DA program, ESSs are obligated to purchase some of these reliability services commonly referred to as "ancillary services", such as contingency reserves, regulation, reactive supply and voltage control, from PGE as the transmission provider. PGE does not debate that this framework is well established and non-bypassable in nature. We provide this information to present a complete picture in the interests of transparency and level-setting. The OATT framework ensures that ESSs are equally contributing either through self-provision or purchase of services so that the responsible entity, PGE as the BA, can meet specified reliability requirements. However, these services are a subset of what is required to ensure safe and reliable services for all of our customers. Settlements associated with the real-time operational rates and tariffs do not substitute for the long-term planning and procurement activities necessary to ensure resources are available to meet forecasted needs. Ensuring an adequate power system requires a regulatory framework that recognizes, requires, and integrates a continuum of actions ranging from long-term planning to real-time operations.

Figure 1- Reliability across different time horizons.

As discussed below and displayed in Figure 1, the reliability standards and compliance related actions commonly occur within the operations timeframe (current hour, next hour and next day) as they are focused on maintaining grid reliability and stability. Deliberate planning and resource actions are needed in advance (one year or more) to not only ensure adequate supply for meeting real-time demand, but also adequate supply characteristics to provide the capabilities necessary to meet the requirements outlined in the various reliability standards. While RA can be broadly defined to include all these types of supply, PGE's comments in this docket will focus on RA as it relates to providing reliable supply for load service (one to four years).

B. Resource Adequacy Under Oregon's Current Framework

RA refers to having enough resources – generation, efficiency measures, and demand-side resources – to serve loads across a wide range of conditions with a sufficient degree of reliability.[35] NERC defines RA as "the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components."[36] At the most fundamental level, RA is a planning and procurement framework aimed at identifying system needs and resource contributions to such needs under a wide array of circumstances. While there is no industry-wide set of standardized RA rules or principles, there are common practices and metrics. For example, RA is generally viewed on a longer-term basis (e.g., next year or multiple years ahead) and measured using target metrics such a Planning Reserve Margin (PRM), Loss of Load Probability (LOLP), or Loss of Load Expectation (LOLE). RA programs also focus largely on capacity, using concepts such as Effective Load Carrying Capability (ELCC)[37], Unforced Capacity (UCAP)[38], and Installed Capacity (ICAP)[39] to determine how various resources, including renewable resources, contribute to RA requirements. At a high-level, one of the main results of an RA program is LSEs making a "showing" of adequacy consisting of the resources they have secured compared to their RA related need, as determined by their load and the appropriate metric(s). In a well-functioning program, it then becomes the LSE's responsibility to plan and procure accordingly to make a showing of being resource adequate. Table *1*, below, gives examples of RA practices in other regions.

---

[35] "Exploring a Resource Adequacy Program for the Pacific Northwest - An Energy System in Transition." Northwest Power Pool. Oct 2019, page 12. Retrieved from https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf

[36] "2018 Long-Term Reliability Assessment." North American Electric Reliability Corporation. Dec 2018, page 5. Retrieved from https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

[37] Expressed as a percentage, ELCC refers to a resource's capacity contribution (MW) divided by the resource's installed capacity. Capacity contribution is commonly determined as the MW reduction to the amount of conventional capacity (e.g. Simple Cycle CT) needed to achieve the stated reliability target.

[38] UCAP generally refers to available generator capacity after accounting for generator forced outages and de-rates.

[39] ICAP generally refers to available generator capacity before accounting for generator forced outages and de-rates.

Table 1 - Examples of RA practices in other jurisdictions.[40]

Jurisdiction	Reliability Metric(s)	Standard Value	Notes
CAISO	PRM	15%	Stipulated, not based on an explicit reliability standard[7]
ERCOT	N/A	N/A	Tracks PRM for information purposes; "Purely information" PRM of 13.75% achieves 0.1 events/yr; Economically optimal = 8-10.5%; Market equilibrium = 10.25%
MISO	LOLE	0.1 days/year	8.4% UCAP PRM; 17.1% ICAP PRM[8]
SPP	LOLE	0.1 days/year	PRM assigned to all LSE's to achieve LOLE target: 12% Non-coincident PRM & 16% Coincident PRM

[7] While the CAISO's PRM requirement is not updated regularly based on a reliability study, the California Public Utilities Commission has established a 0.1 days/year LOLE target to assess long-term reliability in its IRP proceeding.

1. Transparency allows for Commission input into PGE's RA plans

Currently in Oregon, RA for IOUs is predominantly achieved through the IRP process and subsequent procurement actions. While the IRP is not solely an RA exercise, it has several elements which should be considered central tenets of RA: specifically, a robust planning and modeling framework, transparency, and Commission oversight. Although the IRP is longer-term in nature, these tenets still hold true for RA (1-4 years) which overlaps with the time window of the IRP action plan (2-4 years). PGE's IRP uses a modeling approach that considers historical load data, forced outages, reserve requirements, hourly generation patterns for some resources to arrive at an assessment of PGE's capacity position. The Company's IRP targets a 1-in-10 LOLE as its reliability metric for RA planning purposes. The details of this modeling exercise, its inputs, metrics, and findings are all shared with the Commission, Staff, and stakeholders through the public process of the IRP. This process ensures transparency and oversight by clearly establishing the targets and the corresponding methodologies used to conduct the supporting analysis. Additionally, it provides opportunity for the Commission, Staff, and stakeholders to provide

[40] "Exploring a Resource Adequacy Program for the Pacific Northwest - An Energy System in Transition." Northwest Power Pool. Oct 2019, page 15. Retrieved from https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf

input, ask questions, scrutinize assumptions and raise concerns regarding the Company's capacity position and plans for achieving RA for our customers.

2. Intentionally Planning and Procurement Allows PGE to Provide RA

Ultimately, if the IRP process results in an identified capacity need that is incorporated into PGE's action plan, as acknowledged by the Commission, PGE will begin the necessary procurement processes (e.g., a Request for Proposals or RFP) to secure the identified amount of capacity to maintain a resource-adequate system. PGE's approach to RFPs is to use the above-described modeling framework to quantify the capacity contribution of the submitted bids when evaluating benefits of the bid individually as well as portfolios consisting of multiple bids in combination with PGE's existing resources. The goal of the RFP is to procure the necessary least-cost, least-risk resources sufficiently in advance of need with long enough resource duration to maintain RA. Additionally, PGE has the option of pursuing existing resources on a medium-term (e.g., 3-5 years) basis outside of an RFP process should the Company and its customers be in a position that more immediate action is needed to address RA concerns.[41]

While the bilateral procurement process and the RFP process are different, they share key common elements: rigorous planning and procurement. Because PGE is charged with maintaining reliability and RA, mid-term actions can and do occur outside the IRP and RFP processes. However, these actions are based on planning and analysis. These elements do not exist within the current direct access framework. There is no requirement for direct access customers or suppliers to procure or provide RA. There is no planning requirement or transparent process, which is further exacerbated by an expanding direct access program and a prohibition on planning for such a program. There are no standards or procurement requirements. Instead, direct access customers and suppliers are economically incented to purchase energy in short term markets at marginal cost, thereby avoiding the fixed costs necessary for providing RA (see Section VIII.C).

As detailed below, the wholesale energy market is a short-term market designed to facilitate sales and purchases of surplus energy. It does not provide capacity and is not a substitute for RA. It is the short-term duration and energy-only nature of the wholesale market that makes it inherently inefficient. The wholesale market is only able to provide signals through short duration events with high energy prices. These price events do not provide efficient economic signals to spur the resource development necessary to support RA as they are short-term in nature and infrequent. This structure fails to provide market participants with the necessary lead time to take long-term action.

The Company understands and appreciates the economic sensitivities of its large customers; however, the current direct access framework is allowing for these customers to shift the costs and risks of RA to the remainder of the system and to other customers. Ultimately, PGE is the BA and will effectuate its responsibilities to comply with all associated obligations and to provide

[41] The Competitive Bidding Rules apply to "a resource or contract for more than an aggregate 80 megawatts and five years in length." Source: OAR 860-089-0100(1)(a).

safe and reliable electric service. Direct access policy must be reformed to enable PGE to satisfy its reliability obligations in a manner that is fair and equitable to all customers.

3. Meeting Requirements in the Operations Timeframe is not Resource Adequacy

As detailed above, RA is a construct that focuses on the medium to long-term aspects of supply (1 to 4 years) with an eventual impact to the operations timeframe (e.g. next day, next hour, or current hour). Achieving specific operational needs (e.g. contingency reserves, ramping capability, sufficient committed resources) are an outcome of RA, but are not the absolute measure. Adequacy assessments include some of these operating requirements such as contingency reserves to ensure that the RA focus is not only on meeting forecasted peak loads under various scenarios, but also provides consideration to the ability to meet established reliability requirements or standards as there are limited actions available within the operations timeframe. These operational needs and requirements are in place to ensure the reliability and stability of the electric system and are essential to fulfilling the Company's BA obligations. However, meeting these standards and requirements is predominately measured and achieved in the real-time window, and is best characterized as resource sufficiency (RS) rather than RA.

RS is a concept to ensure that entities can meet specific near-term obligations such as the next hour's load and ramping requirements. These specific obligations are aimed at creating a framework within a market construct whereby one participant cannot "lean" on the other participants. RA, on the other hand, ensures enough resource capability on a planning basis to serve peak demand under a wide array of conditions. In the Pacific Northwest, RS is an operational requirement most associated with the Western Energy Imbalance Market (EIM) which applies various tests that each Balancing Authority (or EIM Entity) must pass in real-time to fully participate in the EIM. These tests ensure that EIM Entities have sufficient resources to serve load for discrete market intervals, including ramping capability to meet forecasted uncertainties and variability in load and resource performance. Regional conversations around expanding the EIM to include a day-ahead resource optimization (Extended Day-Ahead Market or EDAM) also contemplate RS tests of a similar nature that would be performed in the day-ahead timeframe. However, neither EIM nor EDAM include any RA requirements or obligations as they are focused on the next hour or next day.

RS is exclusively focused on the short-term obligations of a market participant rather than the long-term needs of the overall system. As this docket further explores RA and the appropriate structure that should be implemented in Oregon, PGE, the Commission, and parties must clearly delineate between RS and RA. While RA and RS have similarities in concept, they are fundamentally different, and the purpose of this docket is not to explore RS. Instead, the Commission has correctly determined that one of the appropriate areas of focus in this docket is

RA and developing solutions that ensures a fair and equitable outcome whereby all customers contribute tangibly to RA.[42]

C. Anticipated changes in regional supplies point to the deficiencies of Oregon's direct access framework

The Pacific Northwest and the broader WECC is moving out of a historical period of abundant regional capacity to a period of resource shortages that are forecast to manifest in the near future and persist. This change is largely driven by announced retirements of significant amounts of firm capacity, primarily from coal, nuclear, and natural gas generation.[43] Several recent regional studies and long-standing assessments of the regional capacity position have flagged this paradigm shift.[44] The Commission acknowledged this reality in UE 358: "[r]ecent regional studies have highlighted that capacity additions and RA must be a focus of regional, state and utility efforts over the next several years."[45]

The direct access framework in Oregon could not have envisioned this regional paradigm shift. Combined with steady increases in direct access participation over time and a lack of supply planning framework for direct access loads, Oregon's retail electric system faces imminent challenges.[46] While an Oregon RA framework has the potential to address these challenges, it must be approached with an eye on both the near-term as well as long-term needs of the system and customers. The regional supply will continue to shift as growing amounts of low-to-zero marginal cost resources, such as wind and solar, put downward pressure on wholesale energy markets and energy-limited storage resources are deployed at an increasing rate to attempt to address capacity needs of various entities and customers. New policies and requirements are needed to adapt the existing direct access programs to today's realities and prepare them for tomorrow's challenges.

D. Interplay of Direct Access with Wholesale Energy Markets

The wholesale energy markets that exists within the West, except for the CAISO, are bilateral markets relying on arms-length transactions or market intermediaries to match buyers with sellers. There is no central market design providing for expanded products such as capacity and ancillary

[42] Public Utility Commission of Oregon. "Order No. 20-002." UE 358. Public Utility Commission of Oregon. 7 Jan 2020, page 9. Retrieved from https://apps.puc.state.or.us/orders/2020ords/20-002.pdf

[43] US Energy Information Administration. "Electric Power Monthly with Data for December 2019." US Department of Energy. EIA. Feb 2020, page 177. Retrieved from https://www.eia.gov/electricity/monthly/current_month/epm.pdf

[44] "Capacity Needs of the Pacific Northwest – 2019 to 2030." Energy + Environmental Economics. Dec 2019. Retrieved from https://www.ethree.com/wp-content/uploads/2019/12/E3-PNW-Capacity-Need-FINAL-Dec-2019.pdf

[45] Public Utility Commission of Oregon. "Order No. 20-002." UE 358. Public Utility Commission of Oregon. 7 Jan 2020, page 9. Retrieved from https://apps.puc.state.or.us/orders/2020ords/20-002.pdf

[46] In 2005, approximately 11.3% of eligible loads took service from ESSs. As of 2018, roughly 32% of eligible load has opted out of PGE's cost of service supply. Source: Public Utility Commission of Oregon. "Order 07-002." UM 1056. Public Utility Commission of Oregon. 8 Jan 2007, page 19. Retrieved from https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

services, nor is there coordinated operations and dispatch across the entire WECC footprint.[47] Instead, each electric utility operates independently to plan, procure, and operate its resources to ensure electric system reliability. While most industry stakeholders agree that this framework is inefficient from an economic and operations perspective, the West has several unique attributes including a robust mix of entities (e.g., mix of IOUs, COUs, and federal entities like BPA) that have historically presented an organizational challenge to forming a fully organized market. While there have been recent grid integration developments such as the EIM and the Regional Planning Organization for transmission planning, the West is still largely driven by bilateral energy trading and these expanded frameworks, such as EIM or EDAM, do not provide for RA.

Against this backdrop, the rules and requirements of the current Oregon's direct access programs do not accurately reflect the state of the western wholesale energy markets. Instead, Oregon's direct access programs have allowed certain classes of customers to bypass costs and responsibilities due to market and regional dynamics that have evolved beyond the original intent of the enabling direct access policies. As described above, there is no capacity market in the region and the current wholesale energy market framework functions only to allow buyers and sellers to economically optimize by matching incremental demand to the lowest cost supply made available to the market. PGE actively participates in the wholesale market and supports a liquid and well-functioning bilateral market so that the Company can optimize resources and provide value to our customers through reduced power costs by optimizing our portfolio. However, RA is not an explicit component of the existing and evolving western wholesale energy market landscapes and relying on short-term energy purchases should not be considered a substitute to capacity planning.

Exchanged forward energy purchases often do not convey rights to generation from capacity resources. It is common practice that standard traded energy products are not explicitly linked to a physical resource. Instead, short-term transactions in the wholesale energy market are primarily "hub delivered" power with no specified source and only liquidated financial damages as remedy for failure to perform.[48] This allows a seller to commit to providing physical delivery of energy without identifying any source of supply at the time the transaction is executed. Instead, the seller can elect to take a speculative position, transfer their obligation to another party by purchasing the same product, or wait until the day-ahead or real-time bilateral market windows to attempt to procure physical supply. Because of this, Oregon's current direct access framework allows ESSs to rely on the wholesale energy market for meeting direct access customer energy needs in the short-term, but provides no requirement for the same suppliers or direct access customers to take

[47] The EIM serves to extend the existing CAISO real-time market, both the fifteen- and five-minute markets, to entities outside the CAISO who have joined the EIM. While this does provide a more coordinated dispatch it is limited to entities that have joined and is excludes longer-term unit commitment that commonly occurs in the day-ahead stage or prior.

[48] Example transaction confirmation for Mid-C Physical Peak Energy commodity available on the Intercontinental Exchange (ICE) https://www.theice.com/products/1073/Mid-C-Physical-Peak-bilateral/sample-confirms

the necessary actions to meaningfully contribute to RA through the advanced procurement of physical resources.

The Company supports the development of more organized frameworks in the West, provided that those frameworks can demonstrate a benefit to the region and our customers. Additionally, PGE actively supports a liquid and well-functioning bilateral market so that the Company can optimize resources and provide value and reduced costs to customers through its wholesale activities. PGE supports this market development by playing active leadership roles in these various efforts; however, they are complex efforts, involve a multitude of stakeholders across the West, involve complex FERC jurisdictional matters, and take many years to come to fruition.

It is important for the Commission, Staff, and stakeholders to be informed on the current and possible future states of the wholesale market, but not do so in such a way that hampers Commission action of policy development that supports the Oregon electric system and its users. The Commission has correctly identified that Oregon's current direct access programs have flaws which need to be addressed to ensure that COS customers are not unfairly burdened with supporting a reliable system for all customers and the Commission should act accordingly without creating dependencies on other regional processes with long-lead times and significant complexities.

E. Regional Efforts towards a Resource Adequacy Standard

The western electricity resource mix is changing, with significant amounts of traditional thermal generation retiring – primarily coal, nuclear, and natural gas generation[49] - and being replaced by variable renewable energy resources. Utilities across the west have approached resource planning and RA through methods or processes that are specific to their individual system or regulatory framework and do not yield a common set of metrics or requirements across the region. In doing so, individual utilities may be viewed as "resource adequate" while the region as a whole does not have a comprehensive and consistent view of RA. Historically, this individualized approach has been sufficient, but as we enter a period of changing regional dynamics, deficiencies such as market availability assumptions are becoming increasing concerning. Gradually, the region has come to the conclusion that it is essential we work together to assess our overall supply situation so we can each better understand our individual needs and necessary actions, to ensure that each entity is supporting RA for their customers as well as RA for the broader interconnected region.

As part of this regional effort, the Northwest Power Pool (NWPP) held a large symposium event in October 2019 that brought together industry leaders and experts, regional policymakers and regulators, and a great diversity of stakeholders to discuss the need to explore a regional RA program. Since that time, NWPP members have been working to develop a

[49] US Energy Information Administration. "Electric Power Monthly with Data for December 2019." US Department of Energy. EIA. Feb 2020, page 177. Retrieved from https://www.eia.gov/electricity/monthly/current_month/epm.pdf

conceptual program framework, including potential RA program design elements. The group is looking at how participants would demonstrate their RA plans, how the program would identify criteria to inform which generating assets would be eligible to provide RA, and how much capacity they could contribute. The effort will also look at the need for compliance rules and penalties for non-compliance and an operational component that could determine when, why and how a participant in the program could access pooled capacity resources. The NWPP effort has articulated 2022 as an aspirational launch date for the RA program. The members have begun outreach to stakeholders, but there is much more work to do to develop and implement the program envisioned by NWPP's membership.

While the relatively recent success of the EIM is encouraging evidence that the region can come together to bring greater efficiencies to the grid, such regional efforts involve a multitude of diverse stakeholders and many complex technical, operational and regulatory components. Like many other utility members of the NWPP, PGE is supportive and playing a leadership role in many aspects of the regional RA effort. To date, PGE is encouraged by progress with respect to the regional program. While there is great optimism and momentum, there is also significant complexity; waiting for the regional effort to come to full fruition is not the best course for Oregon's customers given the importance of reliable operations of the grid and the near-term risks that we face. While the NWPP effort is focused on developing a regional RA program, there is still a need for the Commission to clarify RA obligations of direct access customers to ensure reliability as well as fair and equitable allocation of RA obligations. PGE believes it is important for the Commission and stakeholders to be aware and mindful of the direction of regional RA efforts, recognizing that any framework or program the Commission implements for Oregon may need to be revisited to create cohesiveness with a regional program, should one come to fruition.

It is also important for the Commission to recognize a need for cohesiveness and flexibility due to the fact that the NWPP RA effort is a regional effort that will look to establish a multi-state RA program across the region, involving multiple utilities, state commissions, and regional stakeholders. This regional effort is likely to provide a high level of expertise and information from across the region, which may inform a more efficient and effective program, but also, due to the regional nature of the program, and the fact that it would include several FERC-jurisdictional entities, it is likely that FERC would have jurisdiction over aspects of the multi-state RA program. While there may be FERC oversight on elements of a multi-state RA program, states will continue to regulate electric generation resource planning, procurement decisions and adequacy requirements. This essential and necessary role of the Commission will remain and requires attention in this proceeding.

F. Key Elements of Resource Adequacy to be Explored in Phase III

In the stipulated issues list,[50] the parties identified that it would be beneficial for the comments in the non-contested case phase of this docket to discuss potential RA related issues that should be further explored in the contested case phase. The list below is an initial survey of potential issues the Company views as being integral to the contested case phase:

- Key elements and principles of a state RA requirement;
- A fair and equitable approach for allocating the requirement and/or costs associated with meeting an RA standard;
- Identification and allocation of responsibilities that follows prudent principles, such as cost causation and risk alignment;
- Determination of the "what" and the "how" regarding resources, products, or services and their ability to meaningfully contribute to RA; and
- Recognition that the utility and BA has responsibilities and obligations that cannot be shifted to third parties.

PGE looks forward to reviewing other stakeholders' lists of RA related issues for the contested case phase and discussing the compiled list with the Commission at the workshop contemplated after all-party closing comments in Phase I are filed on April 6th, 2020.

VII. Existing Long-Term Direct Access and New Load Direct Access Framework

The existing transition adjustment framework and applicable schedules do not necessarily capture all the costs and risks that LTDA and NLDA customers are able to bypass, thereby burdening COS customers. The current framework allows LTDA and NLDA customers to bypass costs and unfairly shift costs to remaining COS customers. The Commission has used tools like participation caps , transition adjustments, and supplemental adjustment schedules to try and fulfil its statutory requirement not to cause "[…] unwarranted cost shifting of costs" from direct access customers to other retail electricity customers.[51] These cost-shift mitigation tools are important, and contribute to a reduction in cost shifting, but are insufficient to prevent unwarranted cost shifting.

LTDA customers are subject to transition adjustments and some supplemental rate schedules to prevent cost shifting to COS customers, but transition adjustments (a charge or a credit depending on the market) only cover costs for five years.[52] In addition to the five years of transition adjustments, LTDA customers are also subject to certain supplemental rate schedules related to

---

[50] Public Utility Commission of Oregon. "Ruling." UM 2024. Public Utility Commission of Oregon. 21 Feb 2020. Retrieved from https://edocs.puc.state.or.us/efdocs/HDA/um2024hda12440.pdf
[51] 2017 ORS 757.607 Direct Access Conditions – Cost Recovery. Accessed February 2020.
[52] Portland General Electric Company. "Transition Adjustments." Transition Adjustments. Portland General Electric. Retrieved from https://www.portlandgeneral.com/business/power-choices-pricing/market-based-pricing/transition-adjustments

cost recovery for certain services and activities not captured in the transition adjustment or in base rates from the previous general rate case, but not all policies and services that LDTA customers could benefit from are captured by supplementary schedules. This section describes the transition adjustments that LTDA and NLDA customers are subject to, and the supplemental rate schedules applicable to LTDA and NLDA.

A. Direct Access Caps Are an Essential Tool for Limiting Cost Shifts

PGE's LTDA program has a cap of 300 MWa, and our NLDA program has a 119 MWa cap. PGE believes that these direct access caps are an essential tool to help mitigate the potential for cost shifting as they place a limit on the amount of load that can bypass costs. PGE notes that the Commission has observed that it "[…] routinely use[s] caps and limits to place bounds on potential negative outcomes, particularly where future system impacts for a course of action are unknown or unknowable."[53] As the state and the region works to resolve impending RA while decarbonizing the electric system in line with state policy goals, and as PGE works to address the climate emergency by intentional work and planning to decarbonize our electric system utilizing our integrated grid and planning processes, which undergo a rigorous and transparent public vetting process at the Commission, it is imperative that the direct access caps remain in place as they are. The importance of caps is recognized in other states as a tool to mitigate cost shifting, as discussed in Section IX.C.

B. Direct Access Transition Adjustments

The existing framework for LTDA and NLDA transition costs (as recovered through PGE Rate Schedules 129 and 139 respectively) collects five years' worth of costs over five years, and ends after five years of direct access service, leaving the remaining COS customers to absorb any remaining unrecovered costs, including those that support meeting Oregon's policy goals. During the transition period the LTDA customer contributes to RA and some policy costs but not after. For example, after five years, an LTDA customer would no longer contribute to costs associated with the legislatively mandated Solar Payment Option/Volumetric Incentive Rate.[54] NLDA customers contribute nothing at all towards either of these schedules. For another example, both LTDA and NLDA customers cease contributing to any fixed generation costs after five years – resources that, in part, provide the foundation for system reliability and RA – leaving the bulk of the cost of resources acquired before the customer opted out to be paid for by remaining COS customers.[55] After five years of direct access service, the cost and risks associated with the services and programs behind these schedules are borne solely by COS customers.

[53] Public Utility Commission of Oregon. "Order 19-128." UE 335. Public Utility Commission of Oregon. 26 Oct 2018. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-128.pdf

[54] 75th Oregon Legislative Assembly. "Enrolled House Bill 3039." Oregonians for Renewable Energy Progress. Retrieved from http://www.oregonrenewables.com/Publications/Oregon_HB_3039_Enrolled_Draft.pdf

[55] NLDA customers only pay 20% of fixed generation costs for the five-year transition term.

1. Long-term direct access transition adjustments only cover five years of costs

Transition adjustments "[…] compare COS prices with expected market prices related to generation […]" and "[…] include both fixed generation and net variable power costs [NVPC]."[56] Together, fixed generation costs and NVPC are the total production costs.[57] PGE defines NVPC to include "…wholesale (physical and financial) power purchases and sales (purchased power and sales for resale), fuel costs, and other costs that generally change as power output changes."[58] The transition adjustment for LTDA customers is charged or credited through Schedule 129 – Long-term Transition Cost Adjustment.[59]

Long-Term Transition Cost Adjustments in Schedule 129 are calculated for a LTDA schedule at a certain delivery voltage, for an enrollment period, for a particular year, for five years. The calculation takes the NVPC from the previous rate case and adjusts for the following PGE supplemental schedules:

- Schedule 122 – Renewable Resources Automatic Adjustment Clause (any deferrals associated with renewable energy resource and energy storage projects not otherwise included in rates);
- Schedule 125 – Annual Power Cost Update (estimated adjustments due to changes in PGE's NVPC, corrected as required by Schedule 126);
- Schedule 137 – Customer-owned Solar Payment Option Cost Recovery Mechanism (costs associated with the Solar Payment Option/Volumetric Incentive Rate pilot not otherwise included in rates);
- Schedule 145 – Boardman Power Plant Decommissioning Adjustment.[60]

This results in the Total Part A COS price. The anticipated market value of the power for that year is then deducted from this total, resulting in the Schedule 129 Part A Transition Adjustment for that year. For a LTDA schedule and enrollment window, the five-year Levelized Schedule 129 Part A payment is then calculated. Schedule 129 Current Part B is the fixed generation costs from the previous general rate case for a particular year. The sum of the Levelized Schedule 129 Part A and Schedule 129 Current Part B results in the Schedule 129 Transition Adjustment for a particular year, which has the potential to be either a cost or a credit.

After five years, the LTDA customer no longer pays Schedule 129 transition adjustments, so any ongoing costs associated with these schedules (in particular Schedule 137 and Schedule 145) are borne solely by COS customers, while the LDTA customer continues to reap ongoing system

[56] Portland General Electric Company. "PGE Direct Testimony." UE 335. Public Utility Commission of Oregon. 15 Apr 2018, page 711. Retrieved from https://edocs.puc.state.or.us/efdocs/HTB/ue335htb172131.pdf
[57] Id, page 841.
[58] Id, page 90.
[59] PGE Rate Schedule 129 – Long-Term Transition Cost Adjustment covers both three year and five year opt-outs.
[60] PGE Rate Schedule 146 – Colstrip Power Strip Power Plant Operating Life Adjustment is set at zero as the accelerated depreciation is included in base rates, thus it is bypassable for direct access customers

benefits associated with fixed generation investments. PGE believes that fixed generation costs will grow over the next few years, with renewable resource requests for proposal potentially coming soon, as well as increases in the renewable portfolio standard (RPS). PGE's 2019 IRP anticipates a Request for Proposals in 2020, seeking approximately 150 MWa of RPS-eligible resources to enter our portfolio by the end of 2023.[61] In 2025, Oregon's RPS increases from 20% to 27% of energy, with further increases of 35% in 2030, 45% in 2035, and 50% in 2040.[62]

To better protect remaining COS customer from unwarranted cost-shifting potentially caused by only five years of transition adjustments, PGE has previously proposed modifying Schedule 129 to recover ten years of fixed generation costs in five years of transition adjustments, as the Commission has allowed PacifiCorp to do.[63]

In 2003, PacifiCorp proposed a "customer opt-out charge" as part of its transition adjustment for its five-year COS opt-out program.[64] PacifiCorp explained that the charge was "[…] a valuation of the fixed generation costs incurred by the Company to serve customers, offset by the value of the freed-up power made available by the departing customers for years six through 20" adding that it was "[…] necessary to minimize cost shifting to nonparticipating customers when customers in this [five-year cost of service opt-out] program cease paying Base Supply Service […] after five years."[65] The stipulating parties in UE 267 asserted that the "[…] record contains no comprehensive analysis of projected stranded costs beyond the five-year transition adjustment period."[66] The Commission found that the:

> The Stipulating Parties failed to rebut PacifiCorp's evidence of transition costs, up to approximately $60 million, in years six to ten of the program, and rely too heavily on mere assertions about how transition costs beyond year five can be reduced or erased. Moreover, we reject the Stipulating Parties' arguments that PacifiCorp's system load growth will completely mitigate any transition costs.[67]

It is noteworthy that the Commission found evidence in this case that transition costs extended beyond the five-year transition adjustment period, and that it rejected arguments from the

---

[61] Portland General Electric Company. "PGE's 2019 IRP." Portland General Electric. 2019, pages 33-34.
[62] 78th Oregon Legislative Assembly. "Enrolled Senate Bill 1547." Oregon State Legislature. 2016. Retrieved from https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547
[63] Portland General Electric Company. "PGE Direct Testimony." UE 335. Public Utility Commission of Oregon. 15 Apr 2018, page 712. Retrieved from https://edocs.puc.state.or.us/efdocs/HTB/ue335htb172131.pdf
[64] PacifiCorp. "Five-Year Cost of Service Opt-Out Program Opening Testimony of PacifiCorp." UE 267. Public Utility Commission of Oregon. 14 Jun 2013, page 6. Retrieved from https://edocs.puc.state.or.us/efdocs/HTB/ue267htb144643.pdf
[65] Ibid.
[66] Riemenschneider, Johanna. "Joint Post-Hearing Reply Brief of Stipulating Parties." UE 267. Public Utility Commission of Oregon. 28 Jul 2014, page 10. Retrieved from https://edocs.puc.state.or.us/efdocs/HBC/ue267hbc165746.pdf
[67] Public Utility Commission of Oregon. "Order 15-060." UE 267. Public Utility Commission of Oregon. 24 Feb 2015, page 7.

Stipulating Parties in that docket that "load growth will completely mitigate any transition costs."[68]

2. <u>New load direct access transition adjustments cover only a portion of fixed costs for five years</u>

NLDA transition costs are recovered through Schedule 139.[69] The Commission rulemaking related to the NLDA program resulted in "[…] an initial charge at the 20 percent level" of the fixed generation charge, recognizing that the charge "[…] represents real costs and risk to the system but that these costs and risks have not been quantified".[70] The New Large Load Transition Cost Adjustment calculates costs or credits for NLDA customers at a particular voltage, for a particular year, for a period of five years and also recovers "[a]ll reasonable costs of administering" the program.[71] Unlike the Schedule 129 LTDA transition adjustment, Schedule 139 does not account for NVPC (as the NLDA customer was never on COS), and only considers the fixed generation costs from the previous general rate case for a particular year. After five years, the NLDA customer no longer pays Schedule 139 transition adjustments. In short, NLDA customers reap any ongoing system or public benefits associated with fixed generation costs even more so than LTDA customers without contributing to or recognizing what the Commission has referred to as "real costs and risk".[72]

C. Supplemental Adjustment Schedules Do Not Capture the Costs of All System and Public Benefits

In addition to the five years of transition adjustments contained in Schedule 129 and Schedule 139, LTDA and NLDA customers are ostensibly permanently subject to certain supplemental adjustment schedules that cover "[…] any service performed by [PGE] within the state" that is not captured within a general rate case.[73] However, neither NLDA customers nor LTDA customers are subject to costs associated with PGE's demand response pilots (Schedule 135), which the legislature has stated has public health, safety and environmental benefits, or costs incurred during the design and implementation of Oregon's CSP, a public policy program to support providing access to solar for customers who cannot install solar on their roofs and are primarily interested in the environmental benefits of going solar. By opting-out of COS, these direct access customers are bypassing the costs associated with implementing these policies, meaning they are not contributing to the public good these programs bring, and COS customers are paying more than their fair share for these programs. The adjustment schedules to LTDA and

---

[68] Ibid.
[69] PGE Rate Schedule 139 – New Large Load Transition Cost Adjustment.
[70] Public Utility Commission of Oregon. "Order 18-341." AR 614. Public Utility Commission of Oregon. 14 Sep 2018, page 2. Retrieved from https://apps.puc.state.or.us/orders/2018ords/18-341.pdf
[71] Oregon Administrative Rule 860-038-0740 New Large Load Program Enrollment and Rates. Accessed February 2020.
[72] Public Utility Commission of Oregon. "Order 18-341." AR 614. Public Utility Commission of Oregon. 14 Sep 2018, page 2. Retrieved from https://apps.puc.state.or.us/orders/2018ords/18-341.pdf
[73] 2017 ORS 757.205 Filing Schedules with Commission – Data Filed with Schedules.

NLDA do not cover costs associated with demand response or Oregon's community solar program. The applicable permanent supplemental adjustments for LTDA customer include[74]:

- Schedule 105 – Regulatory Adjustments (miscellaneous nonrecurring items such as gains from property transactions);
- Schedule 106 – Multnomah County Business Income Tax Recovery;
- Schedule 108 – Public Purpose Charge (each ESS that provides direct access service in PGE's service territory will collect a Public Purpose Charge from its customers);
- Schedule 110 – Energy Efficiency Customer Service (to fund energy efficiency programs administered by the ETO);
- Schedule 112 – Customer Engagement Transformation Adjustment (to recover costs associated with PGE's updates of its Customer Information System and Meter Data Management System);
- Schedule 115 – Low-Income Assistance ($20 million annual bill payment assistance to the Oregon Housing and Community Services Department, legislatively limited to no more than $500 per month per site);
- Schedule 126 – Annual Power Cost Variance Mechanism (to account for differences in a given year between Actual NVPC and the estimated NVPC in Schedule 125).
- Schedule 131 – Oregon Corporate Activity Tax Recovery;
- Schedule 132 – Federal Tax Reform Credit;
- Schedule 134 – Gresham Retroactive Privilege Tax Payment Adjustment (for customers in the City of Gresham);
- Schedule 142 – Underground Conversion Cost Recovery Adjustment (to recover costs associated with undergrounding electric facilities for customers in municipalities requiring such conversion).
- Schedule 143 – Spent Fuel Adjustment (costs associated with the decommissioning of the Trojan nuclear plant decommissioning); and
- Schedule 149 - Environmental Remediation Cost Recovery Adjustment Automatic Adjustment Clause (recovery of costs and revenues associated with the Portland Harbor Superfund site and others).

It should be noted that NLDA customers are subject to the same supplemental adjustment schedules as LTDA customers, listed above, with the exception of:

- Schedule 126 – Annual Power Cost Variance Mechanism (this is not applicable to NLDA customers as it accounts for differences in a given year between

[74] These adjustment schedules are not exclusive to LTDA (PGE Rate Schedules 485, 489, and 490), see PGE Rate Schedule 100 – Summary of Applicable Adjustments.

Actual NVPC and the estimated NVPC in Schedule 125, as it relates to the Schedule 128 LTDA transition adjustment); and

- Schedule 132 – Federal Tax Reform Credit (as NLDA customers were never COS, they are not eligible for any benefits associated with this schedule).

There are two PGE supplemental adjustment schedules that are not currently applicable to LTDA or NLDA customers:

- Schedule 135 – Demand Response Recovery Mechanism (expenses associated with demand response pilots).
- Schedule 136 – Oregon Community Solar Program Start-up Cost Recovery Mechanism (cost incurred during the development of the CSP, including prudently incurred cost associated with implementation).

To the extent that demand response or the Oregon CSP elicits any system benefits that accrue to LTDA and NLDA customers, those direct access customers are bypassing the associated costs. And, as these programs are legislatively mandated for the broader public good, all customers should support them. For example, the Oregon Legislative Assembly has found that "[d]emand response resources […] protect[] the public health and safety and improve[] environmental benefits."[75] Similarly, the start-up costs associated with the Oregon CSP contribute to the ability of low-income residential customers to participate.[76] Benefits associated with these programs are not supported by LTDA and NLDA customers as they are able to bypass the costs by opting-out of COS.

VIII. Direct Access Harms Cost-of-Service Customers by Bypassing Costs and Risks

Direct Access causes harm to COS customers through the ability of direct access customers to bypass costs and risks, that are then unfairly borne by COS customers. The program also fragments the system, undermining the value of an integrated grid and impeding coordinated, transparent system planning. Section IV dealt with costs and activities that PGE could potentially recover through the transition adjustment mechanisms and any relevant supplemental schedules to reduce cost-shifting in certain areas from direct access customers to COS customers. This section explores the extent to which LTDA and NLDA customers might not sufficiently contribute to the physical generating assets on the grid, especially renewable resources, and the value they provide to the entire system and all customers in meeting the state's greenhouse gas reduction goals. In addition to fragmenting the system, opt-out customers increase the revenue requirement burden on remaining COS customers. LTDA and NLDA customers also bypass the

[75] 2017 ORS 757.054 Cost-effective energy efficiency resources and demand response resources – legislative findings and planning and pursuit by electric company required. Accessed February 2020.
[76] 78th Oregon Legislative Assembly. "Enrolled Senate Bill 1547." Oregon State Legislature. 2016, page 22. Retrieved from https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547

cost associated with PURPA that are unavoidable for COS customers, along with the costs associated with implementing public policies such as net metering and Oregon CSP. PGE emphasizes that mandated costs associated with effectuating public policies should not be bypassed by choosing an alternative energy supplier. Other states' approaches to ensuring public policies are not bypassed are discussed in Section IX.B.

A. The Value of Physical Renewable Assets

Given the urgency of the climate emergency, the intent of Oregon's Clean Electricity and Coal Transition Plan[77], and Oregon's own greenhouse gas reduction goals defined in ORS 468A.405, as well as preferences expressed by many of our customers,[78] PGE believes that it is appropriate to continue our practice of bringing new clean resources onto the grid that support RPS compliance while also displacing thermal generation. ESSs have not been part of this transformation of our energy system. ESSs have had the option of relying solely on unbundled renewable energy credits (RECs) since 2007, while PGE is limited to meeting no more that 20 percent of its annual RPS requirements with unbundled RECs.[79] This RPS compliance limitation does not apply to an ESS during compliance years before 2021,[80] which has led, on a whole, to ESSs having a price advantage in complying with the RPS. Furthermore, direct access customers should not be able to bypass the costs of tangibly contributing to Oregon's greenhouse gas reduction goals defined in ORS 468A.405. The essential role of physical renewable assets in other states' greenhouse gas plans is discussed in Section IX.D.

B. The Value of an Integrated Grid

The Commission has recognized that "[r]eliable electric service requires expert management of a complex, interconnected grid."[81] PGE believes this expert management includes a highly trained workforce, focused on optimizing flexible generation and flexible load through a complex grid, with thoughtful, data-based planning, rigorous safety and reliability standards, and objective, independent oversight over planning, prices and decision-making, all of which helps ensure Oregon is moving to a clean energy future while maintaining accountability, fairness, reliability, and affordability. ESSs management, planning and RPS compliance approaches are not subject

---

[77] 78th Oregon Legislative Assembly. "Enrolled Senate Bill 1547." Oregon State Legislature. 2016. Retrieved from https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547

[78] PGE customers have made our Renewable Energy Program the largest in the United States. Source: Portland General Electric Company. "Ten years of PGE customers leading the nation in renewable power adoption." Portland General Electric. 23 Sep 2019. Retrieved from https://www.portlandgeneral.com/our-company/news-room/news-releases/2019/09-23-2019-ten-years-of-pge-customers-leading-the-nation-in-renewable-power

[79] 2017 ORS 469A.145 Limitations on use of unbundled certificates to meet renewable portfolio standard. Accessed February 2020.

[80] 78th Oregon Legislative Assembly. "Enrolled Senate Bill 1547." Oregon State Legislature. 2016, page 9. Retrieved from https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547

[81] Public Utility Commission of Oregon. "SB 978 – Actively Adapting to the Changing Electricity Sector." Public Utility Commission of Oregon. 2018 Sep, page 17. Retrieved from https://www.oregon.gov/puc/utilities/Documents/SB978LegislativeReport-ExecSummary.pdf

to the same standards of transparency, third-party oversight, and public vetting as PGE and other fully regulated electric companies leading to a fragmented grid and reduced regulatory oversight over a system that is critical to our state.

The Commission requires fully regulated electric companies like PGE to file an IRP with the Commission within two years of its previous IRP acknowledgement[82], comply with Commission Order Nos. 07-002[83], 07-047[84], and 08-339[85] and "[…] present the results of its filed IRP to the Commission at a public meeting prior to the deadline for written public comment."[86] The plan sets forth the near-term actions required to meet those needs in a way that best balances cost and risk. To understand our needs, we examine supply and demand under various conditions. We consider factors like economic growth, customer behavior, transmission, transportation electrification, weather, energy efficiency, distributed energy resources, and generation resource availability. We also consider local, state and federal policies, technology, and market trends to help determine what types of resources can help meet demand. Our IRPs are informed by stakeholder and public feedback on our methodologies, assumptions, and proposed actions through a public and transparent process. This is followed by a formal process which allows for further refinement based on feedback from the Commission, customer groups, and stakeholders with a final Commission decision regarding acknowledgment.

There is not a comparable level of transparency into how ESSs plan to serve LTDA or NLDA customers, or public vetting and oversight to ensure this planning meets important standards. Other states' perspectives on the importance of an integrated grid when planning for reliability and RA is discussed further in Sections IX.A and VI.B.1, and emphasized in Section IX.D's exploration of regulatory oversight outside of Oregon.

C. Direct Access and Energy Markets

Direct access customers can increase the rates of COS customers while taking advantage of low-marginal cost power without fully contributing to the costs of the underlying assets. When LTDA and NLDA customers opt-out of COS, they choose to expose themselves to the risks and opportunities of power pricing on the open market – while still leaning on PGE as the POLR – but in doing so they can increase the rates of remaining customers. As a regulated utility, PGE collects its Commission-approved revenue requirement from its customers according to rate class. If a customer elects to go direct access, the number of COS customers goes down, creating upward

[82] Oregon Administrative Rule 860-027-0400(3) Integrated Resource Plan Filing, Review, and Update. Accessed February 2020.
[83] Public Utility Commission of Oregon. "Order 07-002." UM 1056. Public Utility Commission of Oregon. 8 Jan 2007. Retrieved from https://apps.puc.state.or.us/orders/2007ords/07-002.pdf
[84] Public Utility Commission of Oregon. "Order 07-047." UM 1056. Public Utility Commission of Oregon. 9 Feb 2007. Retrieved from https://apps.puc.state.or.us/orders/2007ords/07-047.pdf
[85] Public Utility Commission of Oregon. "Order 08-339." UM 1302. Public Utility Commission of Oregon. 30 Jun 2008. Retrieved from https://apps.puc.state.or.us/orders/2008ords/08-339.pdf
[86] OAR 860-027-0400(4) Integrated Resource Plan Filing, Review, and Update. Accessed February 2020.

pressure on rates as fixed costs are spread across less load. Furthermore, as CUB has argued, the power that ESSs purchase on the open market for their LTDA and NLDA customers is generated by physical assets with fixed costs that the ESS does not contribute to, allowing the ESS to buy power at "[…] the utilities marginal cost of energy (variable power costs), whereas when the utility serves customers, the utility is selling power at its embedded cost (variable power costs plus the fixed costs of financing underlying assets)."[87] Importantly, the low marginal cost energy that direct access customers can take advantage of requires physical generation resources, which – as discussed in Section VIII.A – EESs do not necessarily contribute to.

D. Direct Access Customers can bypass costs associated with compensating solar programs

LTDA and NLDA customers can bypass the costs of net-metering and Oregon CSP – legislatively mandated public policies – so these costs are solely borne by COS customers. Net metered customers and Oregon CSP subscribers are compensated at the retail rate, which is above the resource value of solar (RVOS), the market rate for renewable power, and the rate customers would pay for a utility scale renewable energy facility like Wheatridge.[88] For a solar net metered customer, PGE "[…] measure[s] the net electricity produced or consumed during the billing period".[89] This means that one kWh of a net-metered customer's electricity supplied by PGE is offset by the generation of one kWh of the customer's own generation. In effect, this values the customer's own generation at retail rate. The first 40 MW of Oregon CSP will also be compensated for its generation at the retail rate.[90] PGE's retail rate for residential customers is 11.24 cents per kwh (for the first 1,000 kWh per month).[91] PGE's latest calculation of the RVOS is 5.62 cents per kWh.[92] This difference in value represents the value of the public policy that is absorbed by COS customers.

E. Direct Access Customers and PURPA

LTDA and NLDA customers can bypass the costs of PGE's obligations under PURPA. PGE is required under federal and state law to enter into contracts with PURPA Qualifying Facilities (QFs) and pay them for their power at a calculated avoided cost rates.[93] The avoided cost is calculated at a certain time, and then locked in for the term of the power purchase agreement

[87] Citizen's Utility Board of Oregon. "Testimony." UE 335. Public Utility Commission of Oregon. 4 Sep 2018, pages 3-5. Retrieved from https://edocs.puc.state.or.us/efdocs/HTB/ue335htb16197.pdf
[88] PGE, Resource Planning – Wheatridge Renewable Energy Facility. Accessed March 2020. https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/wheatridge-renewable-energy-facility
[89] 2017 ORS 757.300(3)(a) Net metering facility allowed to connect to the public utility. Accessed February 2020.
[90] Public Utility Commission of Oregon. "Order 18-177." UM 1930. Public Utility Commission of Oregon. 23 May 23, 2018. Retrieved from https://apps.puc.state.or.us/orders/2018ords/18-177.pdf
[91] PGE Rate Schedule 7 – Residential Service.
[92] Portland General Electric Company. "Compliance Filing to Update RVOS." UM 1912. Public Utility Commission of Oregon. 18 Jul 2019. Retrieved from https://edocs.puc.state.or.us/efdocs/HAD/um1912had16416.pdf
[93] For a detailed explanation of PGE's PURPA avoided cost methodology, see: Portland General Electric Company. "PGE's Response to Stakeholder Questions." UM 2000. Public Utility Commission of Oregon. 29 Mar 2019. Retrieved from https://edocs.puc.state.or.us/efdocs/HAC/um2000hac16523.pdf

(PPA). When the five-year LTDA transition charges are calculated (Schedule 129) executed QF contracts are considered in the NVPC. However, transition adjustment are not updated for QF contracts executed after the initial calculation of transition adjustments. NLDA transition charges (Schedule 139) do not account for NVPCs, thus NLDA customers do not contribute to QF costs. During the term of the QF PPA, COS customers fund QF's avoided costs for the amount above what PGE would have otherwise procured on the market. After the five-year transition period, LTDA customers can bypass the risks associated with PURPA policies implemented while they were on COS, while NLDA customers are completely insulated from PURPA's costs and risks.

F. Direct Access Customers are not Contributing Sufficiently towards RA

RA is a foundational requirement for all customers and communities within PGE's service territory, and its importance is only magnified by a changing energy landscape where existing fossil resources are retiring, transmission is increasingly limited[94], and new renewable resources are being built to help address the climate emergency and meet greenhouse gas reduction goals. Until the Commission has completed its examination of systemwide RA, and in the absence of a mechanism like PGE's proposed Resource Adequacy Capacity (RAD) Charge, PGE is concerned that LTDA and NLDA customers are not contributing sufficiently towards RA. PGE has set forth proposals aimed at identifying and securing RA in Section VI.

During the NLDA program design process, PGE proposed a RAD charge to protect COS customers from compromised reliability associated with NLDA's customers reduced contribution to fixed generation costs (Section VII.B.2) and lack of contribution to RA. PGE's aim was to ensure that it can "[…] secure capacity to adequately serve all load, protecting electric reliability for our system" and to that end suggested the "[…] RAD be the mechanism in place until system wide capacity resource planning/resource adequacy is examined by the Commission."[95] The Commission denied PGE's request to impose a RAD charge on NLDA customers, and instead invited PGE to "[…] propose changes to its curtailment schedules applicable to NLDA customers" as the Commission "[…] considers reliability and resource adequacy contributions from all direct access customers in the docket UM 2024 investigation."[96]

PGE does not believe that modified curtailment protocols for direct access customers, whether mandatory or voluntary, are an adequate or sustainable solution to RA and system reliability. Curtailment of direct access loads in an emergency is an interim solution that would merely serve to protect COS customers from the immediate effects of LTDA and NLDA customers' lack of sufficient contribution to RA but does not support furtherance of a robust and reliable electric system that is essential to our state's economic and public well-being. A non-interim solution is

[94] Limited transmission paths to allow ESSs to deliver market energy purchases to PGE mean that our remaining cost of service customers are inherently taking risks that were likely not contemplated in the development of direct access programs.

[95] Portland General Electric Company. "Advice No. 19-02." ADV 919. Public Utility Commission of Oregon. 5 Feb 2019, page 6. Retrieved from https://edocs.puc.state.or.us/efdocs/UAA/uaa165643.pdf

[96] Public Utility Commission of Oregon. "Order No. 20-002." UE 358. Public Utility Commission of Oregon. 7 Jan 2020. Retrieved from https://apps.puc.state.or.us/orders/2020ords/20-002.pdf

required in the near-term, and PGE believes that a RAD-like charge is still necessary until a statewide or regional RA mechanism is in place and applied to all electricity providers.

IX. Other State Examples of Customer Choice Demonstrate the Need for a Change in Oregon's Direct Access Program

A review of other states and their application of customer choice is instructive for Oregon's current market. Over the last 25 years, several states across the United States have created or expanded customer choice with the general aim of lowering retail electric prices for consumers while ensuring sufficient reliability. Many of these states have found it challenging to ensure affordable and reliable power for residents and businesses in the state during a rapidly evolving electricity market with dozens of service providers. Challenges are exacerbated by diminished and disjointed regulatory authority over non-regulated suppliers' prices, choices, planning, decision-making and behavior._As the prior President of the California Public Utilities Commission (CPUC), Michael Picker, stated in 2018: "[i]n the last deregulation, we had a plan, however flawed. Now, we are deregulating electric markets through dozens of different decisions and legislative actions, but we do not have a plan. If we are not careful, we can drift into another crisis."[97] Expanded customer choice is unlikely to be in the public interest if it hinders meeting larger state policy goals around greenhouse gas reductions, raises customer prices, and/or increases reliability risks. Examples of customer choice programs in other states provide valuable examples for the Commission to consider within this proceeding.

Through electric restructuring following the passage and implementation of SB 1149 (Appendix I – Long-Term Direct Access History, Oregon implemented partial retail competition (Appendix II - PGE Implementation of Direct Access). Seven other states in the United States have similarly implemented partial electric deregulation. In addition to Oregon, partially deregulated states include, but are not limited to, California, Nevada, Arizona, and Michigan.[98] Unlike fully deregulated states with retail choice where all customers are served by competitive suppliers with common obligations and requirements, partially deregulated states like Oregon retain vertically integrated and regulated electric service for residential and commercial customers, while providing electric service retail choice to certain customer classes with large loads (generally large business). Utilities in partially deregulated states must serve their COS customers while grappling with differing regulatory oversight and policy expectations between themselves and electric service suppliers. Without intentional and careful program design, partially deregulated states are susceptible to inequitable cost and risk shifts between COS and direct access customers,

---

[97] Colvin, Michael, Fellman, and Rodriguez. "California Customer Choice – An Evaluation of Regulatory Framework Options for an Evolving Electricity Market. Public Utility Commission of California. Aug 2018, page iii. Retrieved from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf

[98] Quilici, Lisa M., Powers, Therrien, Davis, and Preito. "Retail Competition in Electricity – What Have We Learned in 20 Years?" Concentric Energy Advisors. 23 Jul 2019, page 2. Retrieved from https://ceadvisors.com/wp-content/uploads/2019/07/AEPG-FINAL-report.pdf

typically with unfair burden borne by COS customers, a majority of whom are residential and commercial customers. While other state retail electric markets are not completely analogous to Oregon, the experience of other partially deregulated states provides some lessons and instruction on how Oregon's direct access policy needs to change to protect reliability, avoid cost shifts to COS customers, and ensure critical consumer protections.

A. In A Fragmented Electric Market, Reliability Is Achieved by A Regulatory Framework That Ensures Resource Adequacy

Currently, Oregon direct access policy does not require ESSs to provide or contract for resource types that support reliable electric service. In contrast, vertically integrated utilities are required to demonstrate to the Commission through IRP planning that on a forward basis they plan to procure the necessary resources required to support Commission acknowledged reliability standards and meet other legislative mandates. Oregon's ESSs are not required to, and do not engage in, any such reliability planning that is vetted and acknowledged by the Commission and are not required to secure or reserve capacity to meet their customers' peak load conditions.

Purchase of wholesale energy at exchanged prices does not substitute the need for RA programs that ensure there are enough resources – generation, efficiency measures, and demand-side resources – to serve loads across a wide range of conditions, with a sufficient degree of reliability. Across the United States, pricing for electricity in wholesale markets is based on the variable cost of generation in addition to any short-run premiums extracted due to changing forces of supply and demand. Wholesale energy prices across most hours do not reflect the fixed costs associated with constructing and maintaining generation. The gap between fully allocated costs necessary to support the maintenance of generation and the variable costs informing wholesale prices is generally paid for by retail electric customers through regulated tariffs or through capacity markets in applicable market frameworks.[99] The operators of capacity resources are then compensated for maintenance, and potential expansion, as necessary, either through awards from the capacity market or recovery of bilateral agreements through COS regulation. This is another illustration of how, because they are not required to provide RA, ESSs can take advantage of market prices allowing them and their customers to avoid costs for the capacity resources that provide RA.

Programs that are intentionally designed to provide RA are necessary in customer choice environments. Texas provides a clear example of how a lack of regulation or an intentional market design will frustrate a region's ability to assure reliability. In the Texas energy market (Electric Reliability Council of Texas or ERCOT), a conscious choice was made to pursue an energy only market design, without any RA requirement or compensation, despite the presence of some of the

[99] Organized markets like Midcontinent ISO, New York ISO, PJM Interconnection LLC (PJM) and ISO New England all operate mandatory capacity markets of various designs that require electricity suppliers to purchase capacity ahead of need to meet peak load obligations.

most expensive[100] and volatile power prices in the United States today. ERCOT wholesale energy prices alone struggle to support the costs associated with adding generation capacity and supporting RA. The limitations of this market design are evidenced in the failure of ERCOT to meet its established target capacity reserve margin of 13.75% of peak electricity demand.[101] In five of the last 10 years, ERCOT's summer planning reserve margins (PRMs) have fallen below a 13.75% target.[102] ERCOT went into the 2019 summer with a reserve margin of 8.1%, meaning retail electricity customers are at a higher risk of a major service disruption.[103]

In contrast to Oregon, the state of California is an example of a partially deregulated market that has established intentional RA programs to ensure all load serving entities (LSEs)[104] contribute to capacity costs and prevent alternative electricity suppliers from evading the costs necessary to support reliability. Historically, California has promoted a robust retail electricity market for both residential and non-residential customers, including commercial and industrial customers. The state was the first to consider a full retail choice market, an effort which was quickly abandoned when reliability and consumers were found to be at risk.[105] Today, electricity needs for residential customers may be met through the traditional investor-owned utility (IOU), CCA, or distributed energy resource, such as rooftop solar, energy storage or demand response. Non-residential customers have the added option of direct access. Over the last few years, California has experienced a rapid transition from a handful of LSEs serving residential and non-residential

[100] ERCOT has authorized elevated energy price bid caps in ERCOT to allow for wholesale market prices up to $9,000/MWh which are the highest price caps in the Northern Hemisphere. Source: Mickey, Joel. "Milestones in Restructuring: The ERCOT Experience so far…." Ercot. 6 Dec 2016. Retrieved from https://www.ncsl.org/Portals/1/Documents/energy/Energy_Mickey_Joel_present.pdf

[101] "2019 Long Term Reliability Assessment." North American Electric Reliability Corporation. 2019, page 13. Retrieved from http://www.ercot.com/news/releases/show/348#_Toc277772169

[102] Magness, Bill. "Ercot." Ercot. 13 Feb 2019. Retrieved from http://www.ercot.com/content/wcm/lists/172486/ERCOT_Briefing.pdf

[103] Ibid.

[104]CAISO defines an LSE as any "[…] Any entity (or the duly designated agent of such an entity, including, e.g., a Scheduling Coordinator), including a load aggregator or power marketer, that (a) (i) serves End Users within the CAISO Balancing Authority Area and (ii) has been granted authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to End Users located within the CAISO Balancing Authority Area; (b) (i) is an End User, (ii) has been granted authority pursuant to state or local law or regulation to serve its own Load through the purchase of electric energy from an entity that does not qualify as a Load Serving Entity, and (iii) serves its own Load through purchases of electric energy, or (c) is a federal power marketing authority that serves End Users. Notwithstanding the above, an entity is not a Load Serving Entity under this definition solely because it provides electric energy at no cost to its tenants or because it purchases or sells electric energy from a generating resource pursuant to a state or local law or regulation that permits the generating resource to make direct sales of electric energy to an End User, the rates, terms, and conditions of which sale are not subject to regulation by a Local Regulatory Authority." Source: California ISO. "Business Practice Manual for Definitions & Acronyms - Version 18." Business Practice Manual Change Management. California ISO. 4 Dec 2019. Retrieved from https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Definitions%20and%20Acronyms

[105] Colvin, Michael, Fellman, and Rodriguez. "California Customer Choice – An Evaluation of Regulatory Framework Options for an Evolving Electricity Market. Public Utility Commission of California. Aug 2018, page iv. Retrieved from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf

customers to over 40 LSEs, excluding publicly owned utilities, operating in the state. This sudden market expansion has consequently resulted in abrupt and significant load shifts for the IOUs.[106] It is estimated that almost 85% of load from California's three largest IOUs will have shifted to an alternative retail provider by 2030.[107] While the increase in providers has offered customers more choice, the lack of regulatory oversight and authority over this new, fragmented retail electric system has resulted in splintered decision-making and defacto deregulation.

California's RA program was established in 2004 to ensure reliability of electric service in the state.[108] California Public Utilities Code Section 380 required that the CPUC establish RA requirements for LSEs in consultation with the California Independent System Operator (CAISO). Under the program, LSEs must contract with generators to ensure system reliability,[109] as well as meeting the minimum reliability requirements of the WECC. The RA program operated without notable issues until large amounts of departing load from the IOUs increased the fragmentation of the system. The rapidly expanding number of LSEs in the California, driven by a large increase in CCAs, led to reliability challenges as many LSEs could not meet their RA requirements.

Furthermore, until 2018, CCAs were not required to comply with the same planning and reporting timeline for forward-looking RA requirements, leaving utilities to take account of CCA customers as part of their own load forecasts.[110] Significant structural changes caused by both CCAs and direct access providers, or Energy Service Providers (ESPs), challenged the program's ability to meet adequate reserve margins under the current market program design for RA. In 2018, eleven LSEs sought waivers from the CPUC for failure to meet RA obligations and were granted these waivers.[111] Similarly, in 2019, another eleven LSEs, the majority of which were again ESPs and CCAs, filed for waivers from the year-ahead local, system, and flexible RA requirements.[112] The repeated failure of LSEs to meet their RA requirements in California, the integration of additional variable resources, imminent retirement of gas plants, and other factors drove the CPUC to adopt a minimum three-year forward multi-year RA requirement beginning in the 2020 RA compliance

---

106 "Electric Load-Serving Entities (LSEs) in California." Electricity Data. Public Utility Commission of California. Accessed March 2020. Retrieved from https://ww2.energy.ca.gov/almanac/electricity_data/utilities.html

107 O'Shaughnessy et al, *NREL*, 'Community Choice Aggregation: Challenges, Opportunities, and Impacts on Renewable Energy Markets, p 39. Retrieved from: https://innovation.luskin.ucla.edu/wp-content/uploads/2019/03/Community_Choice_Aggregation.pdf

108 "Resource Adequacy." Public Utility Commission of California. Retrieved from https://www.cpuc.ca.gov/RA/

109 California Code, Public Utilities Code - PUC § 380. Retrieved from https://codes.findlaw.com/ca/public-utilities-code/puc-sect-380.html

110 California Public Utilities Commission. "CPUC Proposal Would Require CCAs to Coordinate with Resource Adequacy." CPUC News Blog. California Public Utilities Commission. Retrieved from https://www.cpuc.ca.gov/cpucblog.aspx?id=6442455641&blogid=1551

111 "Waivers and Penalties." California Public Utilities Commission. Retrieved from https://www.cpuc.ca.gov/General.aspx?id=6442460914

112 Ibid.

year.[113] In addition to these regulatory programs, policymakers have also sought legislative solutions to system fragmentation that try and address long-term RA and renewable procurement issues that put California at risk of not meetings its goals.[114] In 2018, Assembly Bill (AB) 56 was introduced in the California Assembly, which gave the CPUC the ability to task the state to serve as a backstop for procurement of electricity to meet the state's climate, clean energy and reliability goals.[115]

Finally, the Michigan Public Service Commission (MSPC) has also recognized the need to deploy a regulatory framework that establishes RA and capacity requirements for all LSEs including vertically integrated utilities and competitive energy suppliers (alternative electric suppliers). Over twenty-years ago, the MSPC established requirements for jurisdictional vertically integrated utilities to prepare forward plans for meeting their peak electrical demands.[116] Several years later, the MSPC expanded these adequacy and reliability reporting expectations on a voluntary basis to all LSEs including alternative electricity suppliers. In 2013, LSE's forward capacity reporting requirements were extended from one to three years and again extended to a five-year showing starting in 2014.[117] In 2016, the Michigan legislature passed Public Act 341 that mandates alternative electric suppliers to file capacity demonstration plans for the subsequent four years.[118] In addition, the Act requires that should an alternative electric supplier's demonstration be deficient, the supplier is subject to a State Reliability Mechanism (SRM) to recover costs associated with back-stop actions to support RA. The SRM provides cost recovery for vertically integrated utilities to conduct necessary backstop functions on a four-year forward basis.[119] Michigan's strong regulatory framework for RA enabled the state to meet its reliability needs and overcome a critical period of coal retirements in 2015.[120] Michigan's required filings form a

---

113 "2020 Guides and Resources." Resource Adequacy Compliance Materials. California Public Utilities Commission. Retrieved from https://www.cpuc.ca.gov/General.aspx?id=6311

114 Trabish, Herman K. "Renewable procurement gaps pose risk for California's climate goals, but what solution is best?" Deep Dive. Utility Dive. 15 Apr 2019. Retrieved from https://www.utilitydive.com/news/renewable-procurement-gaps-pose-risk-for-californias-climate-goals-but-wh/552184/

115 California Legislature. "AB 56." California Legislative Information. 3 Dec 2018. Retrieved from https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB56

116 Michigan Public Service Commission. "Order for Case No. U-17751." Michigan Public Service Commission. 14 Dec 2014. Retrieved from https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UMQZAA4

117 Ibid.

118 98th Legislature. "Enrolled Senate Bill No. 437." State of Michigan. 21 Dec 2016. Retrieved from https://www.legislature.mi.gov/documents/2015-2016/publicact/htm/2016-PA-0341.htm

119 "State Reliability Mechanism." Michigan.gov. State of Michigan. 2020. Retrieved from https://www.michigan.gov/mpsc/0,9535,7-395-93309_93439_93463_93723_93730-411741--,00.html

120 Public Sector Consultants. "A Roadmap for Michigan's Energy Markets and Planning Program - Baseline Research." Public Sector Consultants. National Association of State Energy Office. 21 Dec 2017, page 42. Retrieved from https://www.naseo.org/Data/Sites/1/emap/meo-doe-baseline-research-report-updated.pdf

combined reliability assessment that demonstrates that suppliers have secured adequate capacity resources through 2022 and 2023.[121]

B. All Customers of the Retail Electric Market Should Pay Their Fair Share of Costs to Maintain the System Irrespective of Their Service Provider

In addition to ensuring that RA needs are met, all customers of the retail electric market should pay their fair share of costs to maintain the system irrespective of their service provider. California and Nevada provide instructive examples of ways to ensure all customers of the system pay non-bypassable charges.

California Public Utility Code Sections 366.1 and 366.2 require the CPUC to ensure that departing customers do not burden remaining utility customers with costs that were incurred to serve them. To maintain "customer indifference," CCA and direct access customers are required to pay a power charge indifference adjustment (PCIA) in perpetuity. The PCIA is calculated by taking the difference between the "actual portfolio cost" and the "market value" of a portfolio. Additionally, pursuant to statutory mandates, all customers pay towards nuclear decommissioning and public purpose charges, as well numerous non-bypassable departing load charges, including the: Energy Cost Recovery Amount (PG&E only); Department of Water Resources bond charge; the Competition Transition Charge; and the Cost Allocation Mechanism Charge (to pay for new resources needed for ongoing system reliability).[122]

In 2019, Nevada legislators passed SB 547 which included significant policy changes to the state's direct access program (Nevada Revised Statutes 704B) to ensure all customers, regardless of service provider, pay the necessary costs to support the public interest. The influx of applications from large electricity users to exit utility COS via the 704B program prompted policymakers and consumer advocates to examine the shortcomings of the existing policy framework. As described by Nevada Senator Chris Brooks in a legislative presentation, 704B was initially designed as a release valve in response to the volatile energy markets of the 1990s.[123] The program's intent was to allow large organizations with intensive energy needs to independently create new electric resources in order for utilities to avoid market purchases at unprecedented levels of expense.

---

[121] Michigan Public Service Commission Staff. "Capacity Demonstration Results – Planning Year 2022/23 – Case No. U-20154." Licensing and Regulatory Affairs. Michigan Public Service Commission. 28 Mar 2019, page iii. Retrieved from https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000004PmgNAAS

[122] California Public Utilities Commission. "Power Charge Indifference Adjustment." California Public Utilities Commission. Jan 2017. Retrieved from https://www.cpuc.ca.gov/uploadedfiles/cpuc_public_website/content/news_room/fact_sheets/english/pciafactsheet010917.pdf

[123] Brooks, Chris. "SB547: A History of NRS 704B and Energy Deregulation in Nevada." Nevada Legislature. Retrieved from https://www.leg.state.nv.us/App/NELIS/REL/80th2019/ExhibitDocument/OpenExhibitDocument?exhibitId=43882&fileDownloadName=SB547_Presentation_Senator%20Brooks.pdf

In recent years, large corporations looked to leverage the 704B program to bypass fully allocated costs of reliable electric service, with projected lifetime savings driving decision-making, as articulated by industry experts.[124] According to the Nevada Consumer Advocate, this has resulted in the program becoming "a mechanism that legally permits large, sophisticated industrial ratepayers to exit and thus avoid costs and responsibilities embedded into current rates that captive ratepayers must still pay and will never be able to avoid."[125]

SB 547 directed Nevada's PUC to exert its authority over departed customers in order to collect costs of various public policy programs, which could apply to expenses such as energy efficiency, low income assistance, net metering, and natural disaster preparation. Specifically, SB 547 introduced a mechanism to ensure 704B participants continue to contribute fairly to high cost legacy contracts and resources associated with RPS compliance by the utility.[126] Additionally, SB 547 directs the PUCN to consider additional criteria before approving 704B exit applications, for example, applicants must demonstrate that their exiting utility COS furthers the public interest. Nevada's Consumer Advocate wrote of the need to revise program rules:

> In a span of 18 years, the current system has become a legal loophole much to the detriment of the residential and small business ratepayers […] The current system is antiquated, broken, and is failing residential and small business ratepayers. This is because the current system fails to take into account the cumulative effect of all these users leaving the system. Because the models are only predicted for a 6 year time span, over time, the result will leave the residential and small business ratepayers stuck with the tab for stranded costs that extend beyond 6 years.[127]

As was recognized in Nevada, precautions must be taken via program design and limitations to ensure costs necessary to support the public interest are fairly recovered from all customers, including those opting out of COS.

---

[124] "Casinos are incredibly energy intensive and run 24/7, so they're an ideal customer," says Frank Felder, director of the Center for Energy, Economic & Environmental Policy at Rutgers University. "Power has to be a large part of their operating expenses, so even a small savings on electricity makes a big difference. That's what is underlying the trend." https://www.citylab.com/life/2016/10/why-las-vegas-casinos-are-gambling-on-solar/502649/

[125] Figuero, Ernest. "Testimony." SB 547. Nevada State Legislature. 23 May 2019. Retrieved from https://www.leg.state.nv.us/App/NELIS/REL/80th2019/ExhibitDocument/OpenExhibitDocument?exhibitId=44495&fileDownloadName=SB547_Supporting%20Testimony_Ernest%20Figueroa.pdf

[126] 80th Nevada Legislature Session. "SB 547." Nevada State Legislature. 2019. Retrieved from https://www.leg.state.nv.us/App/NELIS/REL//80th2019/Bill/7057/Text

[127] Figuero, Ernest. "Testimony." SB 547. Nevada State Legislature. 23 May 2019. Retrieved from https://www.leg.state.nv.us/App/NELIS/REL/80th2019/ExhibitDocument/OpenExhibitDocument?exhibitId=44495&fileDownloadName=SB547_Supporting%20Testimony_Ernest%20Figueroa.pdf

C. Other states that support customer choice have capped the direct access market to protect consumers and maintain a reliable system while providing customers options

As has been recognized previously by the Commission, limitations or caps on participation in customer choice programs "place[s] bounds on potential negative outcomes, particularly where future system impacts for a course of action are unknown or unknowable."[128] This practice is also employed in other jurisdictions with partial deregulation. As PGE has argued above, participation in direct access programs without well-designed regulatory frameworks that account for new policies to serve the public interest, leads to potentially substantial and lasting cost shifts onto remaining COS customers. Evading costs relating to reliability, legacy resource decisions, and existing public program costs means those customers choosing to depart regulated service for competitive supply benefit at the expense of COS customers. Without limitations on the number of customers able to avoid mandated obligations meant to serve the public interest, all those motivated by lower electric prices would choose to opt out of COS. This general tendency can be observed in other partially deregulated states including California, Michigan, Nevada, and Arizona, examples which are discussed below, where competitive supply options are capped and fully subscribed. All western, partially deregulated states have established caps or limits on competitive electric supplier choice.

The direct access market in California is restricted to non-residential customers and has been capped since the Energy Crisis to protect consumers. California's effort to deregulate initially allowed customers to directly purchase electricity from an ESP with the idea that direct access providers would increase competition and lower costs.[129] However, in 2001 after the Energy Crisis, the legislature capped the Direct Access program at 25,000 GWh/annually (about 12% of the market) for existing customers and any new service was suspended.[130] While California has incrementally expanded direct access since the Energy Crisis, the state has never returned to an open-ended retail market for service from ESSs as previously envisioned under deregulation. In 2010, the Direct Access program was reinstituted, but with a cap at pre-Energy Crisis levels and was phased in over three years.[131] Since the California direct access market was revived, there have been numerous unsuccessful attempts to increase the cap for direct access in the state. Many of these efforts have been strongly opposed by the state consumer advocate, The Utility Reform

---

[128] Public Utility Commission of Oregon. "Order 19-128." UE 335. Public Utility Commission of Oregon. 26 Oct 2018. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-128.pdf

[129] "AB 1890." California State Legislature. 24 Feb 1995. Retrieved from http://www.leginfo.ca.gov/pub/95-96/bill/asm/ab_1851-1900/ab_1890_bill_960924_chaptered.html

[130] "Bill Analysis." AB 117. California State Legislature. 25 Jun 2002. Retrieved from http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0101-0150/ab_117_cfa_20020625_115107_sen_comm.html

[131] SB 695 Section 2.365.1.(b). California State Legislature. 11 Oct 2009 Retrieved from http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=200920100SB695

Network. It was not until recently that in 2018 the California legislature voted to increase the cap by 2.3% of the market, a modest amount, only 4,000 GWh/annually.[132]

Arizona provides another example of a partially deregulated state that has relied continuously on program caps to manage the inherent tensions between the regulated utility model and open energy markets. Arizona's jurisdictional customers can elect for competitive supply on a very limited basis. In 2012, Arizona Public Service (APS) introduced an "Experimental Rate Service Rider Schedule," referred to as AG-X, which enabled customers with Aggregated Peak Load of 10 MW to receive designated power from third party providers. The original program design, introduced as part of a settlement agreement, was later determined to be problematic for the system and non-participating customers, therefore adjustments were made to introduce capacity reserve charges, increased administrative management fees, and an energy imbalance protocol.[133] Despite these robust enhancements, the Arizona regulator determined that maintaining the program cap at its current level (200 MW) was necessary to protect non-participating customers from unintended and unforeseen consequences.

Arizona regulators have resisted increasing the original AG-X program cap of 200 MW, despite the program being fully subscribed. However, in 2019 APS proposed in its general rate case an additional market access program for commercial customers capped at 200 MW, referred to as AG-Y, which includes design elements intended to ensure participating customers did not create, "[…]issues of resource adequacy, preferential transmission access or increased ancillary service costs borne by non-AG-Y [participating] customers… Essentially, for AG-Y customers, APS will continue to provide resource adequacy."[134] Despite these provisions, a program cap was an essential design element to protect non-participating customers.

Nevada has recently imposed strong limitations on further expansion of competitive supply which would have otherwise run counter to the public interest. Following changes to Nevada Law under SB 547, the Public Utilities Commission of Nevada (PUCN) now requires utility IRPs to identify appropriate limits on the volume of competitive supply choices available to customers. Customer elections to receive competitive supply must be approved by the PUCN and those customers must demonstrate that their election furthers the public interest.[135]

---

[132] "SB 237 Chapter 600." California State Legislature. 20 Sep 2018. Retrieved from https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB237
[133] "Settlement Agreement." E-01345A and E-01345A-16-0123. SEC. 27 Mar 2017. Retrieved from https://sec.report/Document/7286/000076462217000030/pnw3311710qdoc.htm
[134] Arizona Public Service Company. "Direct Testimony of Leland R. Snook." E-01345A-19-0236. Arizona Corporation Commission. 31 Oct 2019. Retrieved from http://s22.q4cdn.com/464697698/files/doc_downloads/regulatory_info/2019/Leland-Snook.pdf
[135] Brooks, Chris. "SB547: A History of NRS 704B and Energy Deregulation in Nevada." Nevada Legislature. Retrieved from https://www.leg.state.nv.us/App/NELIS/REL/80th2019/ExhibitDocument/OpenExhibitDocument?exhibitId=43882&fileDownloadName=SB547_Presentation_Senator%20Brooks.pdf

Finally, while not a western state, Michigan provides another useful example of limitations placed on competitive supply within a partially deregulated state. Michigan law caps participation in competitive supplier programs. Public Act 286 in 2008 limited eligibility to 10% of a utility's average load. When revisiting the requirements for competitive electricity suppliers in 2016 as part of Public Act 342, Michigan chose to maintain the cap at 10% while requiring competitive energy suppliers to demonstrate or otherwise pay for adequate capacity.[136] Michigan's competitive supplier programs remain at capacity with long queues of customers who have requested competitive supply but are unable to participate.[137] As in Oregon, this Michigan example shows that program caps can be used as a tool to "place bounds on potential negative outcomes" even when there is demand for more customer choice.[138]

D. A Strong Regulatory Framework is Critical in Partially Deregulated Electricity Markets to Protect Consumers, Keep Rates Low, and Advance Progress on Decarbonization

Partially deregulated states have experienced challenges in advancing their mandates to ensure safe, reliable, and affordable electricity while decarbonizing due to a fragmented regulatory framework and incomplete authority by state public utility commissions. Generally, in states with customer choice, some service providers, such as CCAs, and are overseen by their local governments and not the PUC. Similarly, ESSs are not fully regulated by state PUCs.

1. General limitations on regulatory oversight

The general enforcement authority of state commissions on competitive suppliers is limited. In Oregon, the Commission has asserted an authority to grant or revoke ESS licenses to operate.[139] In similar fashion, both Nevada and Michigan use licensing authority to impose requirements on competitive energy suppliers. In response to challenges exerting authority over electric service suppliers, Nevada's SB 547 granted the PUCN explicit authority to "revoke a license issued to a provider of new electric resources if such action is necessary to protect the public interest or to enforce a provision of the laws of this State or a regulation adopted by the Commission that is applicable to the provider of new electric resources."[140] While Michigan also retains its power to grant or revoke a license to operate as a competitive energy supplier, recent change of law has also expanded the MPSC's authority to require all competitive suppliers to make capacity

[136] 98th Michigan Legislature. "Enrolled Senate Bill No. 438." State of Michigan. 21 Dec 2016. Retrieved from https://www.legislature.mi.gov/documents/2015-2016/publicact/htm/2016-PA-0342.htm

[137] "Electric Customer Choice." Michigan Public Service Commission. Michigan.gov. Retrieved from https://www.michigan.gov/mpsc/0,9535,7-395-93308_93325_93423_93501_93509---,00.html

[138] Public Utility Commission of Oregon. "Order 19-128." UE 335. Public Utility Commission of Oregon. 26 Oct 2018. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-128.pdf

[139] Public Utility Commission of Oregon. "Order 20-002." UE 358. Public Utility Commission of Oregon. 7 Jan 2020. Retrieved from https://apps.puc.state.or.us/orders/2020ords/20-002.pdf "ORS 757.649 provides us with the sole authority to allow an ESS to operate in Oregon" page 9.

[140] 80th Nevada Legislature Session. "SB 547." Nevada State Legislature. 2019. Retrieved from https://www.leg.state.nv.us/App/NELIS/REL//80th2019/Bill/7057/Text

demonstrations and require those suppliers to pay for residual capacity charges should the capacity demonstration be deficient.[141]

In California, the limitations of general regulatory enforcement authority over non-IOU energy suppliers has prompted concern. This lack of regulatory oversight over CCAs and direct access providers has frustrated California's public policy objectives.[142] Without a more cohesive regulatory framework, fragmented decision-making and planning will inevitably impair California's ability to ensure that electricity remains affordable, reliable and can be leveraged effectively to reduce greenhouse gas emissions.

2. Obstacles to decarbonization

The vertically integrated, fully regulated investor-owned utility serves as a vehicle in various states to advance significant decarbonization, resiliency, and social programs at scale. For example, like Oregon, the CPUC has implemented legislatively mandated decarbonization and environmental policies through IOU programs, such as utility-scale renewable energy development, procurement of distributed energy resources, electric vehicles, energy efficiency, rooftop solar, storage mandates and other mechanisms. While these investments have been possible due to the investment grade creditworthiness of the California IOUs, the current utility financing model for these investments may destabilize as there are fewer customers to socialize costs.[143] This could inevitably jeopardize future technological innovation and decarbonization at scale. As of May 2019, only two of the 19 community choice aggregators had acquired investment grade credit ratings from Moody's, which is important to financing new renewable energy projects.[144] Consequently, project development of renewable projects in California has significantly slowed during a time when the state's policy is to double down on efforts for decarbonization. The CPUC has stated:

> Over time California energy policy will require significant new investment in generation. The success of the California RPS program relied largely on the larger utilities to invest in projects by raising low-cost capital in financial markets, and

---

[141] "State Reliability Mechanism." Michigan.gov. State of Michigan. 2020. Retrieved from https://www.michigan.gov/mpsc/0,9535,7-395-93309_93439_93463_93723_93730-411741--,00.html

[142] Colvin, Michael, Fellman, and Rodriguez. "California Customer Choice – An Evaluation of Regulatory Framework Options for an Evolving Electricity Market. Public Utility Commission of California. Aug 2018, pages iii, v and 63.Retrieved from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf

[143] Colvin, Michael, Fellman, and Rodriguez. "California Customer Choice – An Evaluation of Regulatory Framework Options for an Evolving Electricity Market. Public Utility Commission of California. Aug 2018, pages 22-23. Retrieved from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf

[144] Ciampoli, Paul. "Moody's assigns investment grade credit rating to CCA." American Public Power Association. 8 May 2019. Retrieved from https://www.publicpower.org/periodical/article/moodys-assigns-investment-grade-credit-rating-cca

> then recovering costs through sales of electricity. This method of financing capital projects may be in jeopardy as more and more customers leave the IOUs. There is a question whether the necessary capital investment needed to decarbonize the electric sector to meet the state's 2030 goals and beyond can be financed and, if so, delivered on time if the state transitions away from a few larger buyers to many small buyers.[145]

California's RPS requires all publicly owned utilities, IOUs, CCAs, and ESPs to meet certain targets. The CPUC has raised concerns that CCAs and ESPs may face challenges in meeting their requirements, which will in turn put the state at risk of not meeting its clean energy goals.[146] Based on the CCAs' Renewable Net Short calculations, the CCAs will have an immediate RPS procurement need of approximately 6,900 GWh beginning in 2020. Current load forecasts indicate the overall CCA need to meet RPS requirements is approximately 16,800 GWh in 2020.[147] However, as of 2019, CalCCA (CCA proponents in California) indicated that there were only 2 GW of renewable energy projects under development or already built to serve load by 2020.[148] It could reasonably be expected that not all of these projects will be built, and the history of energy project development indicate that a portion will never make it to the finish line. The ESPs are also facing similar challenges as the CCAs, with insufficient resources in place or in development.[149] Further complicating this concern is the fact that IOUs are seeking to exit the retail service market and suspend further procurements. This leaves California relying on CCAs to meet the state's aggressive GHG reduction targets, but their lack of sufficient creditworthiness will make signing financeable contracts challenging.[150]

3. Grid Safety and Control

In California, the IOUs are also responsible for grid safety and resiliency irrespective of whether they are conducting normal operations or managing catastrophic events. As IOUs are the owner

[145] Colvin, Michael, Fellman, and Rodriguez. "California Customer Choice – An Evaluation of Regulatory Framework Options for an Evolving Electricity Market. Public Utility Commission of California. Aug 2018, page 66. Retrieved from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf

[146] Albright, Mallory, Cox, and Singh. "California Renewables Portfolio Standard: Annual Report - November 2019." California Public Utilities Commission. Nov 2019, page 20. Retrieved from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/2019%20RPS%20Annual%20Report.pdf

[147] Singh, Amanda. "California Renewables Portfolio Standard: Annual Report - November 2018." California Public Utilities Commission. Nov 2018. Retrieved from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Renewables%20Portfolio%20Standard%20Annual%20Report%202018.pdf

[148] Id.

[149] Id.

[150] Trabish, "The new kid on the block: CCAs face credit, other challenges to lead California's renewable energy growth", *Utility* Dive, 8 Jul 2019. Retrieved from: https://www.utilitydive.com/news/the-new-kid-on-the-block-ccas-face-credit-other-challenges-to-lead-califo/556975/

and operator of the transmission and distribution grid, they bear the obligation (and liability in California) for managing the system. With increased customer choice options, such as CCAs, direct access, and rooftop solar, current safety controls and protocols become more difficult to fund and to coordinate in times of crisis. The CPUC states that:

> Fair and equitable compensation to the IOUs for competitive neutrality on the grid to accommodate the growth of CCAs, distributed energy resources, self-generation and more customer-controlled purchasing is the central challenge in the regulatory adaptation necessary to accommodate that growth. Indeed, with the recent wildfires in the state, the utilities are working to "harden the grid" to provide a safer system and are expending greater capital in a climate of financial instability. The questions of what is required, how much it costs and who is responsible to pay the IOUs for grid operation are currently before the Commission.[151]

X. Conclusion

PGE has been serving our customers ever since the Company began delivering electricity with the first long distance alternating current (AC) transmission line over a hundred years ago, during the partial utility deregulation legislation at the end of the 20th Century, through to the passing of a law in 2007 that established Oregon's RPS and a law in 2016 that began the phase out of coal-fired electricity deliveries. Today, as PGE helps build Oregon's clean energy future, we are guided by considerations of affordability and equity for all our customers. We therefore welcome this opportunity to submit opening comments in Phase I of UM 2024, an Investigation into Long-Term Direct Access (LTDA) Programs. When direct access was introduced in Oregon two decades ago there were expectations of increased electric utility restructuring, deregulation, and divestiture; these have not come to pass (Appendix I – Long-Term Direct Access History). Instead we find ourselves trying to combat climate change while maintaining resource adequacy as direct access participants are able to bypass the costs of regulatory and reliability obligations and avoid public policy costs.

PGE is required to exclude all long-term direct access customers from our needs assessments, including energy, capacity, RPS, and flexibility needs (Section V).[152] Excluding these customers, while planning for resource adequacy and retaining provider of last resort responsibility (POLR) shifts reliability risks from direct access participants to cost-of-service customers. While POLR obligations require being ready to supply energy to a customer that unexpectedly returns to cost-

[151] Colvin, Michael, Fellman, and Rodriguez. "California Customer Choice – An Evaluation of Regulatory Framework Options for an Evolving Electricity Market. Public Utility Commission of California. Aug 2018, pages 22-23. Retrieved from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf

[152] Public Utility Commission of Oregon. "Order 07-002." UM 1056. Public Utility Commission of Oregon. 8 Jan 2007, page 19. https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

of-service, the provision of resource adequacy is not the result of an unexpected action. Resource adequacy is planning to have enough resources – generation, efficiency measures, and demand-side resources – to serve loads across a wide range of conditions with a sufficient degree of reliability (Section VI).[153]

While EESs are not required to plan for, or procure, resources in advance necessary to meet resource adequacy, PGE has an obligation to plan for cost-of-service supply customers (Section VIII.B). These reliability risks are being exacerbated by plant retirements, transmission constraints, and the expansion of loads in the new load direct access program, leading to increasing needs for new capacity at the same time as more load falls outside of regulated long-term planning processes (Section VI.C). This puts all customers (including direct access) at risk of a reliability event: the ESS has no obligation to plan to avoid such an adverse scenario and PGE has no ability to ensure that all the loads in our BA have associated plans for resource adequacy. This asymmetry in resource adequacy obligations between regulated energy providers like PGE and unregulated electrical service suppliers introduces risk to PGE's cost-of-service supply customers. PGE supports the Commission's direction that this is the docket to investigate and ensure that "[…] all system participants contribute tangibly to BA RA".[154]

The lack of ESS resource adequacy provision is compounded by direct access customers' ability to bypass other system and policy costs, including:

- LTDA customers paying only five years towards the fixed generation costs that support the physical generating assets that underpin the integrated grid (Section VII.1);
- NLDA customers paying only 20% of those fixed generating costs over five years (Section VII.2);
- LTDA and NLDA customers' lack of contribution to the recovery of costs associated with demand response programs, the solar payment option/volumetric incentive rate, and Oregon's CSP (Section VII.C);
- ESS's ability to comply with the RPS through unbundled RECs until 2021, while PGE responds to the urgency of the climate emergency by investing in physical renewable resources (Section VIII.A);
- LTDA and NLDA customers bypassing the costs associated with compensating net-metered and Oregon CSP at retail rate rather than RVOS (Section VIII.D);
- LTDA and NLDA customers bypassing the costs of PGE's obligation under PURPA (Section VIII.E).

[153] Exploring a Resource Adequacy Program for the Pacific Northwest, E3 for the NWPP, October 2019, p.12 https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf
[154] Public Utility Commission of Oregon. "Order 20-002." UE 358. Public Utility Commission of Oregon. 7 Jan 2020. Retrieved from https://apps.puc.state.or.us/orders/2020ords/20-002.pdf

To ensure unwarranted cost-shifting, PGE recommends that any costs associated with effectuating public polices through the electric utility, including system costs that support those policies, should not be by-passable by choosing an alternative energy supplier.

The way other states are handling customer choice is instructive for Oregon (Section IX). ERCOT's choice to pursue an energy only market design and subsequent failures to meet capacity reserve margins show the importance of intentionally designing programs to provide resource adequacy (Section IX.A). Michigan's requirement that alternative electricity suppliers file plans demonstrating capacity sufficiency for four years have allowed the state to secure adequate capacity. California requires departing customers to pay numerous non-bypassable charges, including certain power costs in perpetuity as opposed to five years for customers leaving PGE (Section IX.B). These and other examples show how Oregon should modify its direct access program to allow only warranted cost shifts and ensure resource adequacy.

PGE looks forward to submitting closing comments in this docket on April 6th, 2020.

Dated this 16th day of March, 2020.

Respectfully Submitted,

/s/ *Karla Wenzel*

Karla Wenzel
Manager, Regulatory Policy and Strategy
Portland General Electric Company
121 SW Salmon Street, 1WTC0306
Portland, OR 97204
503.464.8718

XI. Appendices

A. Appendix I – Long-Term Direct Access History

SB 1149, "[r]elating to restructuring of electric power industry", was passed by the 70th Oregon Legislative Assembly in 1999. The legislature's goals, articulated in the preamble, took into "consider[ation] national trends toward electric deregulation" at the time, anticipating divesture of generation assets (selling to a third party) as an effective way of promoting a competitive electric market in the state.[155] SB 1149 included provisions for direct access, which was defined as "[…] the ability of a retail electricity consumer to purchase electricity and certain ancillary services, as determined by the commission for an electric company or the governing body of a consumer-owned utility, directly from an entity other than the distribution utility."[156]

Much has changed since the passage of this Enron-era deregulation law, particularly Oregon's greenhouse gas reduction goals (ORS 468A.205) to combat climate change. At the time of SB 1149's passage, the Citizens' Utility Board of Oregon (CUB) described SB 1149 as legislation that "allow[ed] the 'big guys' to buy their power on the open market while allowing residential ratepayers to continue receiving a 'protected' rate from their current utility"[157] and quoted "[…] a huge victory for consumers"[158]Oregon's Fair and Clean Energy Coalition, of which CUB was a member at the time, touted benefits of SB 1149 that California's restructuring law did not include, such as that SB 1149 did not throw residential customers into the market; and provided for portfolio options for residential customers, increased conservation and renewable energy development funding, and low income energy assistance. CUB now believes that additional protections are necessary to help protect remaining COS from undue cost shifting due to LTDA.[159]

Businesses also touted the benefits of restructuring and SB 1149. Now defunct Energy Services Provider, PG&E Energy Services stated that access to the market would provide market opportunities to spark innovation and investment.[160] Other testimony submitted to the legislature asserted benefits including businesses matching electricity service options with their needs, saving money, and working with electric suppliers as partners (being viewed as customers, not

---

155 70th Oregon Legislative Assembly. "Senate Bill 1149." Energy Trust of Oregon. 1999. Retrieved from https://www.energytrust.org/wp-content/uploads/2016/10/sb1149.pdf
156 Id, page 2.
157 Jenks, Bob. "The Bear Facts – Fall 1999." Citizen's Utility Board of Oregon. 1999, page 3. Retrieved from https://oregoncub.org/images/uploads-legacy/pdfs/1999-3-FallOCR.pdf
158 Ibid.
159 Citizen's Utility Board of Oregon. "CUB's Objection to Partial Stipulation on Direct Access Issues." UE 335. Public Utility Commission of Oregon. 4 Sep 2018, page 3. Retrieved from https://edocs.puc.state.or.us/efdocs/HAE/ue335hae163833.pdf
160 Oglesby, Douglas. "Testimony to the Senate Public Affairs Committee." Senate Bill 1149 Public Hearing Tape 20A. 12 Mar 1999.

ratepayers). Testimony provided examples of how the direct access law might work, including:[161] a commercial building owner will shop for the best electricity service considering price, reliability and innovative services; a hospital might buy the use of a switch so it could use its own backup power to shave peak loads and cut costs; a restaurant might want time of day pricing to take advantage of off-peak times for certain high energy activities. The testimony also noted the PUC's authority to oversee many aspects of the law's implementation, provide oversight so that unwarranted cost shifting is prevented; determine transition charges and benefits and certify ESSs.[162]

A contemporaneous news article from Medford's Mail Tribune stated, "the Senate approved a bill [...] to let Oregon's business and industrial customers seek their own power suppliers" adding "Portland General Electric, which Enron Corp. of Houston bought in 1997, has moved toward its own form of deregulation."[163] Just four years after the launch of direct access, as part of a distribution to its creditors, the then bankrupt Enron subsequently relinquished control of PGE in 2006, making the utility a stand-alone, publicly-traded company once again.[164] Over twenty years after the passage of SB 1149, the idea of restructuring through divestiture is a thing of the past, like Enron, and PGE now either wholly or jointly owns over eighty percent of the net capacity on our system.[165]

Not long after SB 1149 passed in 1999, the Western United States experienced the Energy Crisis of 2000 and 2001.[166] The 71st Oregon Legislative Assembly passed HB 3633, "[r]elating to restructuring by electric power industry", postponing direct access from October 1, 2001, until March 1, 2002, and requiring electric companies to "[...] provide all retail electricity customers that are connected to the electric company's distribution system with a regulated, cost-of-service rate option" that could be waived if the Commission found a market exists in which "[...] retail electricity consumers subject to the waiver are able to [...] [o]btain reliable supplies of electricity".[167] In HB 3633, the Legislature also amended SB 1149 to eliminate the ability of the Commission to order the divestiture of utility generating assets after observing the negative pricing consequences that arose for California utilities during the Western Energy Crisis after all generation except hydro and nuclear facilities where sold to independent power producers.

---

[161] Conkling and Eisdorfer. "Written Testimony to the House Commerce." Senate Bill 1149. 5 May 1999.
[162] Conkling-Eisdorfer Testimony House Commerce, May 5, 1999
[163] Wong, Peter. "Here's what SB 1149 does." Mail Tribune. 21 Apr 1999. Retrieved from https://mailtribune.com/business/here-s-what-senate-bill-1149-does
[164] Taub and Reason. "Enron Sets Portland General Free." CFO. 3 Apr 2006. Retrieved from https://www.cfo.com/risk-compliance/2006/04/enron-sets-portland-general-free/
[165] As of December 2017, wholly owned and jointly owned net capacity total 3,902 MW and Purchased Power Agreements total 964 MW. Source: Portland General Electric Company. "How We Generate Electricity." Portland General Electric. Retrieved from https://www.portlandgeneral.com/our-company/energy-strategy/how-we-generate-electricity
[166] Federal Energy Regulatory Commission. "Addressing the 2000-2001 Western Energy Crisis." FERC. 21 Oct 2010. Retrieved from https://www.ferc.gov/industries/electric/indus-act/wec.asp
[167] 71th Oregon Legislative Assembly. "Enrolled House Bill 3633." Oregon State Legislature. 2001, page 1. Retrieved from https://www.oregonlegislature.gov/bills_laws/archivebills/2001_EHB3633.pdf

Fast forward 20 years, the innovations that businesses described would come from non-regulated electric suppliers have predominately only come from fully regulated electric company.companies. PGE, for its part, is the one providing innovative products, often partnering with other energy market participants and providers. In fact, PGE is: recognized among asas the top electric utility in the nation for its voluntary renewable program, offering Green-e certified renewable energy certificate purchases from designated generating facilities; offering time of day pricing options, non-demand charge pricing for low load factor nonresidential customers, public and business electric vehicle charging, offering a green tariff for nonresidential customers, and offering demand response options, including direct load control pilots, and peak time rebates. Furthermore, almost two decades after SB 11149, Oregon's consumer advocate believes that additional protections are necessary to help protect remaining COS from undue cost shifting due to direct access.[168]

[168] Citizen's Utility Board of Oregon. "CUB's Objection to Partial Stipulation on Direct Access Issues." UE 335. Public Utility Commission of Oregon. 4 Sep 2018, page 3. Retrieved from https://edocs.puc.state.or.us/efdocs/HAE/ue335hae163833.pdf

B. Appendix II - PGE Implementation of Direct Access

Following the passage of SB 1149 in 1999, the design of the various direct access offerings has largely been left to the discretion of the Commission. PGE began offering a one-year direct access/market price option effective March 1, 2002, consistent with the provisions of SB 1149 and HB 3633.[169,170] With the aim of giving the direct access program some momentum, PGE offered a Shopping Incentive Rider (Schedule 130) from March 1, 2002[171], until December 31, 2009, enabling the first 10% of eligible large nonresidential consumers' loads to go direct access[172].

In the 2003 service period, PGE added the option for eligible customers to opt out of COS energy supply for a minimum of five-years (LTDA) with a pre-specified transition adjustment. Eligibility for this option was and continues to be an enrollment of at least one MWa from each service point, with each serving point also having a facility capacity of at least 250 kW.[173] This eligibility requirement was put into place to limit the number of accounts that must be separately tracked, thereby helping to mitigate the administrative burden onto PGE. At the time this option allowed customers to opt out of COS with the option to return with a two-year notice. Following direct access related workshops, docketed as UM 1081, PGE again offered the five-year direct access option (called enrollment period B) for service year 2004. PGE has offered the option every year since.

Commencing with the 2005 service period, along with its five-year, Period C, offering, PGE added a three-year COS opt-out provision to the LTDA schedules, again with a pre-specified transition adjustment, but with an automatic return to COS pricing after the three-year period (Adv 04-14). Commencing with the 2008 service year, PGE added quarterly balance-of-year direct access windows and a new split-load schedule (Schedule 84) that allowed very large customers to receive direct access service for a percentage of their usage, with the remainder served by PGE at COS prices. As part of a 2011 investigation into 3- and 5-year COS opt-out direct access, PGE removed the split load schedule and eliminated the quarterly direct access enrollment windows.[174]

---

169 70th Oregon Legislative Assembly. "Senate Bill 1149." Energy Trust of Oregon. 1999. Retrieved from https://www.energytrust.org/wp-content/uploads/2016/10/sb1149.pdf
170 71th Oregon Legislative Assembly. "Enrolled House Bill 3633." Oregon State Legislature. 2001. Retrieved from https://www.oregonlegislature.gov/bills_laws/archivebills/2001_EHB3633.pdf
171 Portland General Electric Company. "Advice No. 02-5." Public Utility Commission of Oregon. 19 Feb 2002.
172 Portland General Electric Company. "Advice No. 07-01." UE 180. Public Utility Commission of Oregon. 16 Jan 2007.
173 Transmission Access Service Schedules: 485 – Large Nonresidential Cost of Service Opt-Out (201-4,000 kW); 489 – Large Nonresidential Cost of Service Opt-Out (>4,000 kW); 490 – Large Nonresidential Cost of Service Opt-Out (> 4,000 kW and Aggregate to >100 MWa). These all have a Minimum Five-Year Option and a Fixed Three-Year Option.
174 Public Utility Commission of Oregon. "Order 12-057." UE 236. Public Utility Commission of Oregon. 23 Feb 2012. Retrieved from https://apps.puc.state.or.us/orders/2012ords/12-057.pdf

Finally, in a stipulation with various parties in 2013, PGE made further modifications to direct access and the parties agreed not to make any new proposals for the 2015-2018 service years.[175] The pre-moratorium modifications to the LTDA included requiring customers to provide three year's notice to return to COS.[176] The stipulation also added new schedules to LTDA options for street lighting and traffic signal customers.[177] As of the end of 2019, PGE has offered LTDA on eighteen different occasions and NLDA once.

[175] Public Utility Commission of Oregon. "Order 13-459." UE 262. Public Utility Commission of Oregon. 09 Dec 2013. Retrieved from https://apps.puc.state.or.us/orders/2013ords/13-459.pdf
[176] Id, page 9.
[177] PGE Rate Schedule 491 – Street and Highway Lighting Cost of Service Opt-Out, Schedule 492 – Traffic Signals Cost of Service Opt-Out, Schedule 495 Street and Highway Lighting New Technology Cost of Service Opt-Out.