PGE CEP & IRP Roundtable 26-6

July 22, 2026

Meeting Logistics

Focus on Learning & Understanding

- Team members will take clarifying questions during the presentation, substantive questions will be saved for the end (time permitting)
- Attendees are encouraged to 'raise' their hand & chat to ask questions

Follow Up

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

Meeting Details

Wednesdays from 9 to 12 pm, Online Via Zoom

1

Electronic version of presentation

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

2

Zoom meeting details

- Join Zoom Meeting https://us06web.zoom.us/j/84372774388?pwd=WGdNfwfAFGcWgHxYjX0Mk2QbhDDaa7.1
- Meeting ID: 843 7277 4388
- Passcode: 108198

3

Participation

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

CEP/IRP Roundtables For 2026 Filing

Date	Roundtable Topics
September 3, 2025	IRP 101, 2026 CEP/IRP Analysis Refinements, 2026 CEP/IRP Timeline & Q&A
October 22, 2025	Corporate Load Forecast – Methodology & Trends, Draft AdopDER Forecast, Existing Resources & Resource Topology, Future/Markets
December 10, 2025	Supply-Side Resource Options, Capacity Need & Its Drivers, Transmission Options, Role of VPP in the IRP, EE integration into IRP
January 14, 2026	PGE Longer Term Local Transmission Plan For the 2024-2025 Planning Cycle, Resource Contract Extension - Update, Flexibility study - Overview, Clean Energy Plan – Overview, Community Benefit Indicators, PGE'S Community Engagement Approach for 2026 CEP, Portfolio/Scenarios- Designs
February 24, 2026	PGE Announcement To Acquire WA Utility, Clean Energy Plan & Integrated Resource Plan Community Engagement Updates, Flexibility Study Draft Results, CBRE Update, IRP Emissions Forecasting, Diverse Market Transmission Framework, Portfolio Scoring, ELCCs, RFP Update and Proxy
April 8, 2026	Community Engagement, Transmission Constraints: Methodology & Approach, Price Futures Update, Energy Value for Resources, Generic Resource Cost Update, Market Emission Factor Scenarios

CEP/IRP Roundtables For 2026 Filing

Date	Roundtable Topics
May 20, 2026	Stakeholder Feedback Responses, Community Benefit Indicators (CBIs), Portfolio Analysis Scenarios, Cost Cap (now Continued Progress) Scenario Update, Transmission Constraint: Results and Analysis, VPP Integration & ELCC Review
June 10, 2026	Community Impacts Metrics, Report Outline, Draft Portfolio Analysis Results, Corporate Load Forecast Update
July 22, 2026	Updated Transmission Analysis, Energy Strategies Transmission Analysis, Capacity Need & ELCCs Update, Updated Draft Portfolio Results, Draft Portfolio Resource Adequacy Assessment, & Backcast Review
August 2026	TBD
September 2026	TBD
October 2026	TBD

Jul 22, 2026 – Agenda

9:00 | Welcome

9:05 | Updated Transmission Analysis

9:25 | Energy Strategies Transmission Analysis

10:00 | Capacity Needs & ELCCs Update

10:15 | Updated Draft Portfolio Results

11:00 | Draft Portfolio Resource Adequacy Assessment

11:25 | Backcast Review

11: 55 | Next Steps and Close

Updated Transmission Analysis

Bhavana Katyal

Luke Tutino

Jennifer Galaway

PGE An Oregon kind of energy.℠

Update Explanation

UPDATE

BPA provided updated North of Pearl (NOPE) total transfer capability (TTC) values for use in the 10-year planning horizon, incorporating the incremental capacity from the planned transmission upgrades

CHANGES

The TTC values have increased and are now applied seasonally (Spring/Fall, Summer, and Winter); previously there was one year-round static TTC value

RESULT

There are now significantly less constrained and congested hours forecasted for 2035 with more realistic results for seasonal variation

Production Cost Modeling (PCM): Transmission Constraint Analysis Outline

10-Year Total Transfer Capability (TTC) Utilization and Path Constraints

- Path Flow 2035 TTC Utilization and Constraint Forecasting
- Heatmaps and Path Breakdowns
- Focus is Percent of Path Flow to Available TTC Limits

Transmission Upgrades Path Impacts

- Impact of Transmission Upgrades on Transmission Constraint
  - ➢Headroom Heatmap (NOPE)
  - ➢Seasonal Utilization

Updated analysis from the <u>May 2026 CEP/IRP Roundtable</u>

Forecasting Path Transmission Constraints via PCM

- **12 BPA Interfaces Identified**
  - West of Cascades North (Path 4)
  - West of Cascades South (Path 5)
  - West of Hatwai (Path 6)
  - South of Allston (Path 71)
  - West of John Day (Path 86)
  - West of McNary (Path 87)
  - West of Slatt (Path 88)
  - North of Pearl
  - North of Grizzly
  - North of Hanford
  - Raver Paul
  - West of Lower Monumental

- **Constrained Definition**
  - If interface flow >= 80% of TTC

- **Simulation Model**
  - 2035 data obtained using GridView Production Cost Modeling (PCM) software and the WestTEC case version 2.0

- **Heatmap Grid**
  - 12x24 representing every hour of every day for each month
  - If any of the 12 interfaces is constrained the entire hour counts as constrained
  - Percent in each cell = Total Constrained Hours / Total Hours
  - Ex: A value of 100% for month 7 and hour 14 means at least one path was constrained during that hour every day in July

2035 Combined Path Heatmap – 80% of TTC (May Results; using old static lower NOPE TTC)

		Month											
		1	2	3	4	5	6	7	8	9	10	11	12
Hour	1	26%	50%	42%	43%	6%	33%	19%	0%	0%	0%	0%	0%
	2	16%	50%	42%	47%	6%	27%	19%	0%	0%	0%	0%	0%
	3	16%	61%	45%	43%	10%	23%	19%	0%	0%	0%	0%	0%
	4	16%	57%	39%	50%	16%	17%	19%	0%	0%	0%	0%	0%
	5	23%	68%	35%	57%	16%	13%	19%	0%	0%	0%	0%	0%
	6	29%	79%	65%	60%	23%	37%	71%	23%	7%	0%	0%	0%
	7	45%	79%	71%	83%	39%	67%	94%	71%	67%	13%	20%	0%
	8	61%	89%	77%	100%	74%	80%	100%	97%	90%	35%	30%	6%
	9	52%	86%	87%	100%	77%	83%	100%	97%	87%	48%	53%	23%
	10	45%	93%	97%	100%	87%	90%	100%	100%	93%	68%	77%	52%
	11	65%	96%	100%	100%	94%	87%	100%	100%	93%	71%	93%	65%
	12	65%	96%	100%	100%	94%	93%	94%	100%	97%	74%	90%	77%
	13	74%	93%	100%	100%	100%	97%	97%	100%	97%	61%	80%	77%
	14	65%	93%	100%	100%	90%	93%	90%	100%	93%	55%	87%	61%
	15	71%	96%	100%	100%	90%	97%	84%	87%	90%	58%	63%	42%
	16	58%	89%	100%	100%	94%	83%	65%	61%	70%	32%	30%	3%
	17	61%	61%	100%	77%	42%	40%	16%	16%	17%	16%	33%	0%
	18	71%	61%	74%	33%	6%	7%	6%	6%	17%	13%	37%	0%
	19	55%	64%	77%	27%	0%	13%	6%	0%	10%	10%	27%	0%
	20	55%	79%	90%	50%	3%	17%	13%	0%	3%	6%	23%	0%
	21	39%	75%	74%	47%	0%	20%	19%	0%	0%	0%	10%	0%
	22	29%	54%	58%	50%	6%	27%	16%	0%	0%	0%	13%	0%
	23	16%	46%	52%	50%	3%	27%	13%	0%	0%	0%	7%	0%
	24	35%	57%	52%	33%	16%	30%	16%	0%	0%	0%	0%	0%

Path	Constrained Hours	Percent
WO Cascades North	0	0%
WO Cascades South	5	0%
WO Hatwai	**415**	**9%**
NO Hanford	0	0%
Raver Paul	0	0%
WO Lower Mon	**666**	**15%**
SO Allston	1	0%
WO John Day	5	0%
WO McNary	0	0%
WO Slatt	0	0%
NO Grizzly	0	0%
NO Pearl	**3300**	**75%**

2035 Combined Path Heatmap – 80% of TTC (July Results; using new NOPE TTCs)

		Month											
		1	2	3	4	5	6	7	8	9	10	11	12
Hour	1	26%	46%	42%	33%	6%	33%	19%	0%	0%	0%	0%	0%
	2	16%	43%	42%	40%	6%	27%	19%	0%	0%	0%	0%	0%
	3	16%	54%	45%	40%	10%	23%	19%	0%	0%	0%	0%	0%
	4	16%	50%	39%	43%	16%	17%	19%	0%	0%	0%	0%	0%
	5	23%	61%	35%	43%	16%	13%	16%	0%	0%	0%	0%	0%
	6	29%	71%	65%	20%	6%	27%	42%	6%	0%	0%	0%	0%
	7	45%	75%	48%	37%	3%	47%	58%	23%	0%	0%	0%	0%
	8	52%	71%	39%	37%	13%	50%	81%	52%	37%	0%	3%	0%
	9	39%	54%	45%	47%	13%	63%	90%	61%	57%	0%	17%	0%
	10	32%	50%	45%	77%	23%	70%	84%	81%	50%	0%	27%	3%
	11	32%	57%	48%	73%	45%	77%	94%	81%	57%	0%	23%	0%
	12	26%	57%	45%	90%	68%	73%	84%	71%	50%	3%	23%	0%
	13	29%	61%	42%	87%	71%	73%	77%	77%	60%	6%	27%	0%
	14	23%	46%	55%	87%	61%	67%	61%	77%	60%	10%	27%	0%
	15	29%	36%	58%	90%	58%	50%	55%	52%	47%	6%	20%	0%
	16	48%	21%	45%	87%	26%	33%	29%	32%	37%	0%	7%	0%
	17	52%	46%	45%	30%	10%	17%	10%	0%	3%	0%	0%	0%
	18	61%	39%	35%	17%	6%	7%	6%	0%	0%	0%	0%	0%
	19	48%	43%	29%	7%	0%	13%	3%	0%	0%	0%	0%	0%
	20	45%	50%	42%	20%	0%	13%	6%	0%	0%	0%	0%	0%
	21	35%	46%	19%	10%	0%	17%	3%	0%	0%	0%	0%	0%
	22	29%	18%	13%	3%	3%	23%	3%	0%	0%	0%	0%	0%
	23	16%	11%	10%	3%	3%	27%	10%	0%	0%	0%	0%	0%
	24	35%	54%	52%	27%	16%	30%	16%	0%	0%	0%	0%	0%

Path	Constrained Hours	Percent
WO Cascades North	0	0%
WO Cascades South	5	0%
WO Hatwai	**415**	**17%**
NO Hanford	0	0%
Raver Paul	0	0%
WO Lower Mon	**666**	**27%**
SO Allston	1	0%
WO John Day	5	0%
WO McNary	0	0%
WO Slatt	0	0%
NO Grizzly	0	0%
NO Pearl	**1300**	**55%**

This analysis updates prior May CEP/IRP results using the new 2035 NOPE TTC values for the 'Upgrades Scenario'. The NOPE TTC for 'No Upgrades' scenario remains unchanged.

Transmission Upgrades Path Impacts

Forecast Transmission Constraints

- Analyze the impact of planned network upgrades on the frequency of constrained hour and utilization rates to quantify future risk exposure

Study Setup

- Two scenarios compared in a 10-year future:
  - ➢ ***No Upgrades (2027 Topology):*** Assumes no transmission upgrades between 2027-2035 for NW, MT, ID, NV regions + 2027 NOPE TTC assumption.
  - ➢ ***Upgrades Scenario (2035 Topology):*** Includes planned transmission upgrades through year 2035 in NW, MT, ID, NV regions + **updated 2035 NOPE TTC values**
- Analysis assumes PACW, PGE, and CAISO participation in EDAM market.

May Results: Available Headroom
(Static lower 2035 NOPE TTC assumption for Upgrades Scenario)

Under the static lower 2035 TTC assumption, NOPE exhibited year-round constraint risk during the solar production window

Average Headroom (MW) by Month and Hour
_Pth-BPA-North of Pearl

No Upgrades

PT Hour Ending	January	February	March	April	May	June	July	August	September	October	November	December
0	1140	990	1063	697	1112	1276	1144	1217	1255	1355	1313	1038
1	1119	953	1029	635	1135	1216	1108	1096	1175	1304	1313	1083
2	1033	882	909	599	1150	1173	1092	1041	1119	1258	1261	1032
3	996	887	841	515	1152	1144	1062	1010	1064	1190	1204	1009
4	972	896	792	500	1087	1100	1022	962	1016	1147	1163	935
5	948	913	820	513	949	727	700	888	926	1063	1210	965
6	929	913	768	190	252	223	205	452	428	817	1138	1008
7	860	662	416	31	151	127	81	235	153	360	612	868
8	614	325	183	22	92	104	37	99	68	197	337	569
9	528	205	98	8	47	40	37	61	64	162	176	403
10	448	96	28	5	18	12	27	58	56	108	94	261
11	374	36	12	0	11	13	35	50	41	112	28	156
12	275	26	12	0	0	40	80	62	48	98	37	89
13	247	35	12	0	0	41	117	91	72	134	75	150
14	245	36	13	0	8	43	161	114	75	162	73	160
15	289	25	7	2	20	69	205	171	138	228	145	287
16	548	119	12	3	50	92	286	328	337	519	756	650
17	568	323	146	90	298	388	495	547	625	736	725	680
18	527	260	193	227	729	731	722	781	745	726	627	631
19	585	250	150	213	710	799	788	751	727	689	611	675
20	615	273	158	192	640	734	750	731	658	704	561	651
21	668	306	225	181	606	717	664	743	735	794	693	698
22	779	393	332	253	622	765	710	816	736	836	723	683
23	869	464	429	334	745	868	750	837	807	912	817	785

No Upgrades Scenario

Average Headroom (MW) by Month and Hour
_Pth-BPA-North of Pearl

Upgrades

PT Hour Ending	January	February	March	April	May	June	July	August	September	October	November	December
0	1479	1303	1232	926	1529	1620	1474	1537	1462	1622	1544	1289
1	1409	1262	1185	901	1531	1562	1400	1376	1378	1477	1517	1268
2	1367	1229	1074	850	1521	1537	1386	1305	1327	1466	1439	1217
3	1339	1227	1021	797	1579	1539	1362	1278	1293	1388	1381	1190
4	1327	1246	990	759	1492	1482	1315	1238	1260	1386	1379	1163
5	1346	1272	1023	755	1288	1098	925	1128	1178	1364	1406	1241
6	1327	1304	970	360	645	478	269	606	693	1044	1388	1280
7	1218	930	513	145	399	301	120	339	389	772	739	1067
8	880	393	306	93	257	229	61	179	223	549	583	789
9	719	228	188	31	155	169	39	138	193	488	402	628
10	656	127	95	19	95	124	39	115	174	416	276	482
11	546	76	59	6	71	87	32	106	140	375	229	355
12	457	72	47	3	49	96	92	137	171	395	249	275
13	432	87	55	5	48	70	151	166	194	413	273	292
14	456	90	63	4	94	114	218	186	205	437	293	356
15	457	72	61	5	103	163	321	263	254	462	332	469
16	729	203	48	10	156	250	463	452	445	637	679	850
17	772	518	177	238	582	705	807	786	773	816	667	861
18	736	463	244	508	1095	1162	1037	933	890	849	591	898
19	791	416	221	510	1091	1211	1091	976	861	871	667	946
20	802	394	222	457	1057	1073	1008	923	834	945	678	922
21	898	423	256	420	1052	1033	956	933	872	1043	768	939
22	1014	553	373	526	977	1040	946	985	925	1108	821	939
23	1115	619	433	567	1087	1148	989	1050	1011	1154	902	990

Upgrades Scenario

Note: Color scale revised for consistency between May and July results to enable direct visual comparison given the expanded range resulting from the new TTC values in the July results.

July Results: Updated 2035 NOPE TTC values improves Available Headroom

Upgrades Scenario: Available headroom increases substantially across most hours, reducing congestion exposure relative to the May analysis. Residual constraints remain concentrated during solar-driven daytime periods.

Average Headroom (MW) by Month and Hour
_Pth-BPA-North of Pearl

No Upgrades

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1127	985	1045	694	1106	1272	1149	1212	1256	1325	1308	1048
1	1115	958	1008	611	1125	1218	1102	1100	1163	1305	1314	1068
2	1026	888	887	585	1148	1161	1090	1047	1110	1237	1261	1036
3	988	894	821	511	1131	1149	1064	1006	1048	1182	1203	993
4	962	900	772	494	1083	1132	1022	959	1014	1136	1163	949
5	943	933	805	519	907	765	706	884	928	1058	1203	957
6	911	925	766	196	254	222	240	451	437	822	1140	1020
7	848	699	412	41	151	136	92	232	173	369	596	845
8	597	344	173	20	88	95	42	96	85	204	338	591
9	520	200	79	7	41	47	32	62	64	165	170	402
10	443	87	24	5	17	16	27	65	68	117	93	269
11	376	35	13	0	3	13	36	54	50	110	30	164
12	273	29	9	0	0	41	77	50	59	116	33	98
13	243	36	10	0	0	41	113	90	69	132	74	156
14	240	35	10	0	10	41	151	99	68	167	77	169
15	264	33	7	0	22	62	194	167	138	229	151	292
16	541	109	13	3	63	93	287	316	321	514	762	656
17	559	317	162	87	299	372	501	539	589	735	712	664
18	512	256	213	232	740	717	730	777	737	736	646	644
19	566	240	165	227	709	793	791	760	716	714	572	663
20	608	246	173	202	635	721	752	721	647	713	549	645
21	695	282	227	188	606	704	666	740	720	800	658	676
22	772	403	339	259	615	770	715	800	727	834	718	701
23	862	464	430	332	738	864	738	837	801	906	807	777

No Upgrades Scenario

Average Headroom (MW) by Month and Hour
_Pth-BPA-North of Pearl

Upgrades

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	2455	2294	2196	1677	2225	1984	1848	1910	1863	2299	2253	2272
1	2406	2272	2172	1651	2249	1911	1783	1757	1761	2156	2201	2266
2	2343	2245	2085	1665	2238	1914	1777	1684	1701	2113	2129	2212
3	2319	2213	2019	1637	2233	1881	1763	1662	1669	2051	2069	2196
4	2316	2239	2021	1586	2163	1830	1676	1608	1645	2048	2067	2155
5	2326	2246	2026	1603	1961	1482	1305	1500	1580	2066	2106	2226
6	2315	2276	1961	1272	1314	861	571	852	1078	1788	2066	2272
7	2193	1948	1536	901	1297	799	415	702	811	1538	1459	2033
8	1854	1428	1265	766	1124	650	285	523	639	1264	1274	1786
9	1692	1165	1018	628	981	543	241	438	560	1212	1049	1612
10	1622	914	816	477	875	381	245	395	513	1128	877	1469
11	1518	697	716	331	663	395	214	363	450	1083	812	1331
12	1427	653	698	308	534	374	289	404	482	1062	841	1260
13	1408	700	723	210	473	356	353	445	436	1099	856	1259
14	1433	758	740	297	553	454	461	480	466	1131	856	1328
15	1416	820	690	294	642	568	621	610	560	1152	909	1447
16	1707	1095	747	419	869	629	789	859	785	1332	1329	1821
17	1767	1612	1158	870	1330	1115	1147	1218	1168	1520	1375	1844
18	1729	1647	1376	1407	1862	1597	1475	1413	1407	1639	1278	1873
19	1782	1591	1294	1386	1919	1682	1649	1542	1381	1663	1350	1957
20	1799	1523	1218	1359	1923	1597	1567	1401	1302	1683	1393	1928
21	1903	1546	1235	1319	1875	1504	1431	1392	1317	1791	1478	1936
22	2003	1591	1330	1268	1737	1485	1411	1401	1340	1788	1531	1929
23	2096	1632	1429	1314	1738	1581	1401	1465	1393	1845	1603	1984

2455
1228
0

Upgrades Scenario + Updated NOPE TTCs

May Results: Constraint Frequency
(Static Lower 2035 NOPE TTC Assumption for Upgrades Scenario)

Upgrades Scenario: Under the static lower TTC assumption, NOPE experiences constraint risk during 40% of annual hours (an improvement of 9% over No Upgrades Scenario) and showed constraint risk across all seasons.

% of Hours Over Utilization Threshold (>=80%)

Season	Winter		Spring		Summer		Fall	
Name	No Upgrades	Upgrades	No Upgrades	Upgrades	No Upgrades	Upgrades	No Upgrades	Upgrades
_Pth-BPA-North of Pearl	40%	29%	66%	57%	49%	43%	42%	32%
P04 West of Cascades-North	6%	0%	12%	0%	1%	0%	0%	0%
P05 West of Cascades-South	36%	0%	33%	0%	30%	0%	9%	0%
P06 West of Hatwai	0%	6%	0%	10%	0%	5%	0%	0%
P71 South of Allston	0%	0%	0%	0%	0%	0%	0%	0%
P86 West of John Day	1%	0%	2%	1%	1%	0%	0%	0%
P87 West of McNary	0%	0%	0%	0%	0%	0%	0%	0%
P88 West of Slatt	0%	0%	0%	0%	0%	0%	0%	0%
Pth BPA North of Grizzly	10%	0%	7%	0%	7%	0%	5%	0%
Pth BPA North of Hanford	0%	0%	0%	0%	0%	0%	0%	0%
Pth BPA Raver-Paul	2%	0%	9%	0%	11%	0%	0%	0%
Pth BPA West of Lower Monumental	7%	23%	2%	9%	0%	1%	0%	0%

Key Findings:

- ✓ **Constraint Improvements:** Network upgrades reduced constrained hours across majority of paths.
- **Exceptions:** *W. of Lower Monumental* (Higher East->West flows); W. of Hatwai (Higher ID/MT -> WA flows)
- **Highest Constrained Path- *NOPE:*** High utilization & constraints risks persists year-round in both scenarios

July Results: Constraint Frequency with updated NOPE TTC values

Upgrades Scenario: Annual NOPE constraint frequency decreases from 40% to 16% under the updated TTC values. Constraint risk is primarily concentrated during Spring and Summer.

Seasonal Constraint Frequency

% of Hours Over Utilization Threshold (>=80%)

Season	Winter		Spring		Summer		Fall	
Name	No Upgrades	Upgrades	No Upgrades	Upgrades	No Upgrades	Upgrades	No Upgrades	Upgrades
_Pth-BPA-North of Pearl	40%	4%	66%	21%	49%	29%	42%	9%
P04 West of Cascades-North	7%	0%	12%	0%	1%	0%	0%	0%
P05 West of Cascades-South	36%	0%	34%	1%	30%	0%	9%	0%
P06 West of Hatwai	0%	5%	0%	10%	0%	5%	0%	0%
P71 South of Allston	0%	0%	0%	0%	0%	0%	0%	0%
P86 West of John Day	1%	0%	2%	0%	1%	0%	0%	0%
P87 West of McNary	0%	0%	0%	0%	0%	0%	0%	0%
P88 West of Slatt	0%	0%	0%	0%	0%	0%	0%	0%
Pth BPA North of Grizzly	10%	0%	7%	0%	7%	0%	5%	0%
Pth BPA North of Hanford	0%	0%	0%	0%	0%	0%	0%	0%
Pth BPA Raver-Paul	3%	0%	9%	0%	11%	0%	0%	0%
Pth BPA West of Lower Monumental	7%	23%	2%	9%	0%	1%	0%	0%

Upgrades Scenario: NOPE Constraint Frequency Update

Season	May Results	July Results	Change
Winter	29%	4%	-25%
Spring	57%	21%	-36%
Summer	43%	29%	-14%
Fall	32%	9%	-23%
Annual	**40%**	**16%**	**-24%**
Risk Profile	Year-round	Primarily Spring-Summer	

July Results: Updated NOPE TTC Results

⚠️ **North of Pearl**

- Remains the most constrained path across all scenarios evaluated. 11 other WECC and BPA paths studied experience low constraint frequency after upgrades.
- Primary Congestion Driver - Cheap California solar exporting to Northwest during solar production window
- Without network upgrades, annual constraint frequency reaches 49%.
- Network upgrades reduce annual constraint frequency to 40% under the May static lower TTC value and to 16% with updated TTC values.
- BPA's proposed Keeler–Pearl #2 500 kV line remains critical for addressing constraint risk.

Impact of Updated NOPE TTC values on the 2035 Upgrades Scenario

	May Analysis	**July Analysis**
Annual constraint frequency	40%	16%
Risk Profile	Year-round	Concentrated in Mar-Sep; with occasionally significant in other months.

Summary and Guided Feedback

Summary: The updated analysis indicates that while North of Pearl is still the most constrained path for delivering power to PGE's service territory, there are significantly less constrained hours, and more headroom, because of the updated, higher and seasonal TTC values.

Content: Do you have any suggestions regarding additional transmission analyses that should be completed to inform the CEP/IRP?

Energy Strategies Transmission Analysis

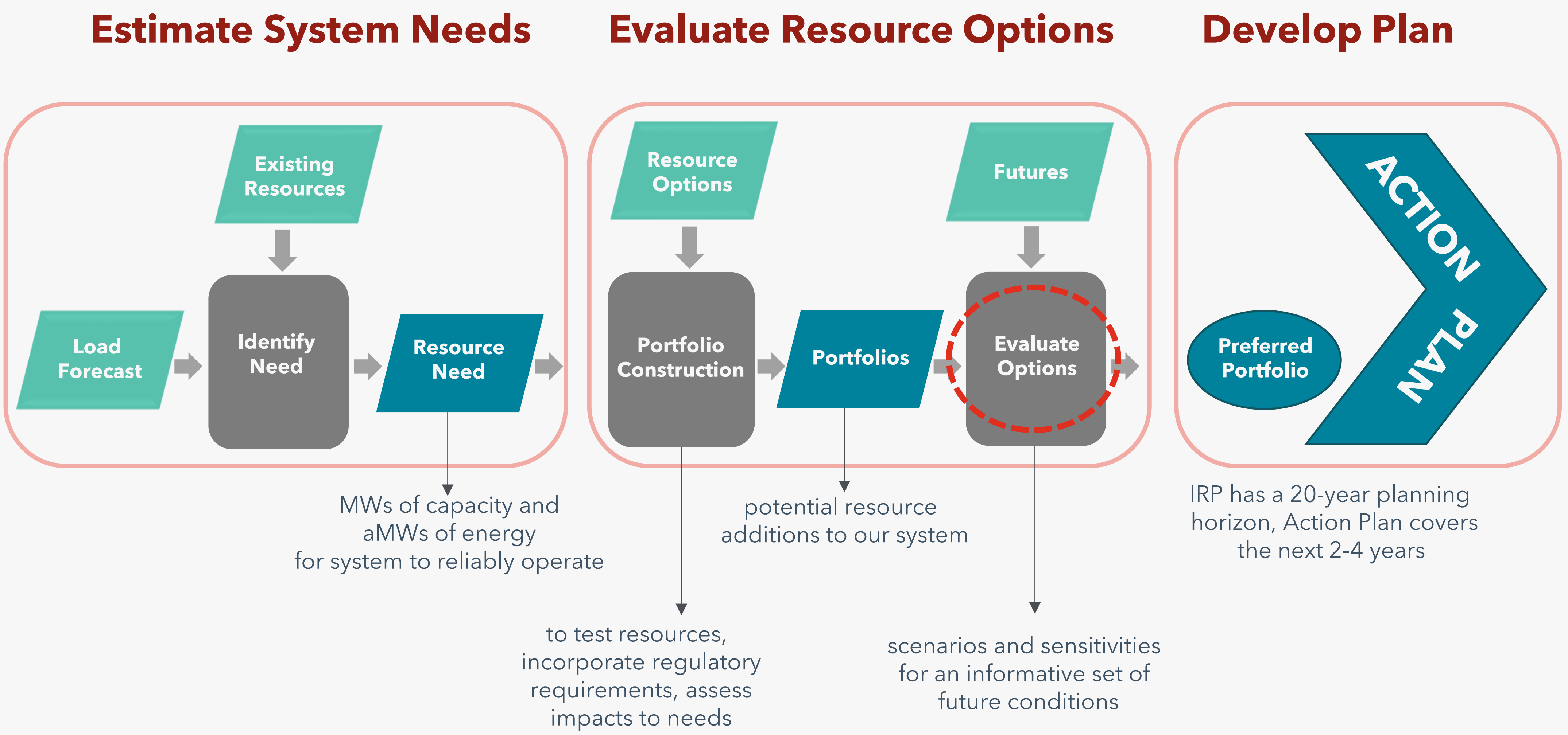
Keegan Moyer (Energy Strategies)

Jimmy Lindsay





High-Level IRP Analysis Process



North of Pearl Risk Assessment

Portland General Electric July 2026 IRP Roundtable

July 22, 2026

PGE

ENERGY STRATEGIES

ENERGY STRATEGIES

Presentation Contents

NOPE Background & High-Level Findings

NOPE Background & High-Level Findings

- PGE previous IRP modeling assumed 25% of new remote resource capacity could utilize non-firm transmission
- PGE April and May 2026 IRP Roundtables detailed role of Bonneville Power Administration (BPA) flowgates in potentially constraining non-firm transmission availability
- The BPA North of Pearl (NOPE) constraint specifically emerged as a risk to non-firm transmission with past IRP Roundtables stating that NOPE flows > 80% of Total Transfer Capability (TTC) indicate non-firm transmission availability is at risk
- PGE's approach for the coming IRP cycles is to use nodal Production Cost Modeling (PCM) to forecast physical flows on NOPE and to incorporate corresponding forecasts of non-firm availability into downstream zonal portfolio modeling

- Our findings validate and identify:

  1. **NOPE flows >80% of TTC as a data-driven threshold indicating non-firm transmission availability risk**
  2. **Use of the PCM modeling results to forecast flows and inform zonal portfolio modeling**
  3. **Possible refinements to this approach for future IRP cycles**

- *These findings are detailed in the contents of our presentation*

2024-2026 historic data average % of hours NOPE Non-Firm unavailable:

Hour Ending	Month 1	2	3	4	5	6	7	8	9	10	11	12
1	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	27%	2%
2	5%	0%	0%	0%	0%	0%	0%	0%	0%	2%	27%	2%
3	3%	0%	0%	0%	0%	0%	0%	0%	0%	2%	25%	2%
4	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	27%	2%
5	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	28%	2%
6	6%	2%	2%	0%	0%	0%	0%	0%	0%	3%	32%	2%
7	10%	9%	10%	2%	0%	0%	0%	0%	0%	3%	40%	3%
8	29%	46%	34%	5%	3%	0%	0%	0%	0%	8%	47%	13%
9	45%	57%	55%	5%	6%	2%	0%	2%	3%	21%	47%	18%
10	48%	61%	58%	7%	11%	5%	0%	2%	3%	23%	50%	16%
11	48%	57%	65%	12%	11%	5%	3%	2%	5%	26%	50%	19%
12	50%	57%	63%	8%	11%	8%	5%	5%	5%	24%	50%	21%
13	48%	57%	58%	8%	6%	7%	5%	6%	3%	24%	50%	21%
14	48%	55%	63%	8%	8%	8%	10%	8%	0%	23%	50%	18%
15	47%	57%	60%	8%	8%	10%	15%	10%	2%	21%	50%	18%
16	42%	55%	55%	7%	8%	10%	18%	11%	0%	23%	50%	15%
17	15%	27%	42%	8%	8%	10%	15%	13%	0%	18%	47%	10%
18	16%	0%	19%	5%	6%	7%	11%	10%	0%	10%	47%	13%
19	15%	2%	15%	0%	0%	7%	11%	11%	0%	6%	47%	10%
20	13%	0%	13%	0%	0%	3%	3%	3%	0%	8%	47%	10%
21	11%	7%	11%	0%	0%	3%	0%	3%	0%	10%	43%	8%
22	8%	2%	11%	0%	0%	2%	0%	0%	0%	6%	42%	6%
23	5%	2%	0%	0%	0%	0%	0%	0%	0%	2%	33%	2%
24	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	30%	2%

2035 Production Cost Modeled % of hours NOPE Non-Firm unavailable:

Hour Ending	Month 1	2	3	4	5	6	7	8	9	10	11	12
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	20%	39%	6%	0%	0%	0%	0%
8	0%	0%	3%	23%	0%	40%	55%	23%	0%	0%	0%	0%
9	0%	0%	6%	30%	10%	47%	81%	52%	37%	0%	3%	0%
10	0%	7%	23%	43%	13%	57%	90%	61%	57%	0%	17%	0%
11	0%	29%	39%	73%	23%	70%	84%	81%	50%	0%	27%	0%
12	0%	50%	45%	73%	45%	77%	94%	81%	57%	0%	23%	0%
13	0%	46%	42%	90%	68%	73%	84%	71%	50%	3%	23%	0%
14	0%	50%	42%	87%	71%	73%	77%	77%	60%	6%	27%	0%
15	0%	39%	45%	87%	61%	67%	61%	77%	60%	10%	27%	0%
16	0%	29%	52%	87%	58%	50%	55%	52%	47%	6%	20%	0%
17	0%	4%	39%	87%	26%	30%	29%	32%	37%	0%	7%	0%
18	0%	0%	13%	23%	0%	10%	10%	0%	3%	0%	0%	0%
19	0%	0%	3%	7%	0%	0%	6%	0%	0%	0%	0%	0%
20	0%	0%	0%	7%	0%	0%	3%	0%	0%	0%	0%	0%
21	0%	0%	13%	7%	0%	0%	3%	0%	0%	0%	0%	0%
22	0%	0%	0%	7%	0%	0%	3%	0%	0%	0%	0%	0%
23	0%	0%	0%	3%	0%	0%	3%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%

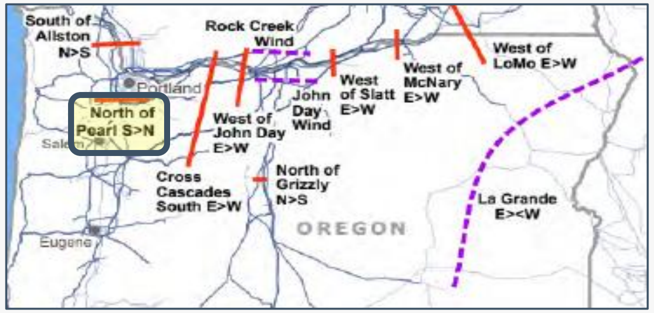
Background from PGE IRP and IRP Roundtables

Background from PGE IRP Update & IRP Roundtables

PGE's IRP update detailed the challenges that the NOPE flowgate poses[(1)]:

- *During spring of 2024 & 2025 the North of Pearl flowgate reached flow levels near its upper limits*
- *Additionally unscheduled energy flows have been observed coming from the Pacific Northwest and through PGE's service territory*
- *These unscheduled flows have caused BPA to take actions including curtailing approximately 4000 MWs of transmission schedules across the region*

Location of NOPE Flowgate:



- PGE's **April 2026 IRP Roundtable** detailed how high flows lead to risks for non-firm transmission on the NOPE flowgate:
  - *"non-firm transmission can be suspended as a congestion management tool to prevent further loadings on congested flowgates"[(2)]*
- Thus, non-firm transmission can be unavailable even when the flowgate is below its seasonal TTC
  - This leads to defining the threshold at >= 80% of TTC
  - Still may not capture all conditions where non-firm availability could be impacted

- PGE's **May 2026 IRP Roundtable** proposed threshold for a flowgate to be congested (for non-firm availability) when the flows were >= 80%[(3)]
  - Nodal Production Cost Modeling (PCM) can be used to simulate how often this occurs in future study years
  - During hours that the flows are >=80%, non-firm transmission is assumed to be unavailable
    - *Previous PGE IRP modeling assumed planned resources would only need* ***75% of capacity contracted as firm transmission service*** *and the remainder could be available as non-firm[(4)]*
  - PGE's current plan is to update IRP modeling to consider when NOPE flows are >= 80% and non-firm transmission is at risk

(1) https://assets.ctfassets.net/416ywc1laqmd/54JgOyxGa8dfAZch4vc54p/db067fc5010d0c23efcd903c56a65cf3/Chapter_4._Transmission_landscape.pdf pp.8

(2) https://assets.ctfassets.net/416ywc1laqmd/5BeH4dfyFys9hQtdBaR4li/61bbbd699da5bd06a6c2dc45b69edba4/CEP_IRP_Roundtable_Apr_8-3.pdf#page=1 pp.21

(3) https://assets.ctfassets.net/416ywc1laqmd/iOtlq68CuHUHy2e6d0Jv7/f822e4294d6c0035a1d75299a83bf491/CEP_IRP_Roundtable_May_20_-_4.pdf#page=1 pp.54

(4) https://assets.ctfassets.net/416ywc1laqmd/54JgOyxGa8dfAZch4vc54p/db067fc5010d0c23efcd903c56a65cf3/Chapter_4._Transmission_landscape.pdf pp.16

Energy Strategies Scope of Work & Sources

Study Process – Detail on Historic & PCM Analysis Methods

Compile & Analyze Historical BPA Constraint Data → Validate & Analyze PGE PCM Outputs → Develop Risk Framework → Estimate Future NOPE Risk Exposure → Develop Refinements & Recommendations for PGE Planning Models

2024-2026 Historic:

- Flows over NOPE & other regional flowgates
- PNW & CA Renewable Generation
- PNW & CA Loads

2035 PCM:

- Flows over NOPE & other regional flowgates
- PNW & CA Renewable Generation
- PNW & CA Loads

De-seasonalized Pearson Correlation

Results detailed in following slides and in appendix

Driver	Category	Feb-May (7a-5p) Actuals	Feb-May (7a-5p) PCM 2035	Feb-May (7a-5p) Δ Act-PCM	Jun-Sep (7a-5p) Actuals	Jun-Sep (7a-5p) PCM 2035	Jun-Sep (7a-5p) Δ Act-PCM	Oct-Jan (7a-5p) Actuals	Oct-Jan (7a-5p) PCM 2035	Oct-Jan (7a-5p) Δ Act-PCM
West of Cascades South (E->W)	BPA internal path	+0.64	+0.79	-0.15	+0.67	+0.77	-0.09	+0.61	+0.76	-0.15
COI (northbound)	Intertie flow	+0.34	+0.47	-0.13	+0.45	+0.55	-0.09	+0.51	+0.26	+0.25
PDCI (northbound)	Intertie flow	+0.30	+0.12	+0.18	+0.35	+0.09	+0.26	+0.38	+0.09	+0.29
COI + PDCI (northbound)	Intertie flow	+0.37	+0.47	-0.10	+0.46	+0.55	-0.09	+0.52	+0.28	+0.24
CA net-export	Intertie flow	+0.25	+0.43	-0.18	+0.42	+0.43	-0.02	+0.49	+0.27	+0.23
BPA Wind	BPA generation	+0.48	+0.36	+0.12	+0.34	+0.31	+0.04	+0.23	+0.51	-0.27
BPA / PNW Hydro	BPA generation	-0.16	-0.21	+0.05	-0.26	-0.21	-0.04	-0.19	+0.06	-0.25
PNW load (total)	BA load (north)	+0.12	+0.17	-0.05	+0.13	+0.01	+0.12	+0.34	+0.20	+0.14
BPAT load	BA load (north)	+0.05	+0.19	-0.14	+0.19	+0.04	+0.15	+0.31	+0.20	+0.11
Puget load (PSEI+SCL+TPWR)	BA load (north)	+0.24	+0.11	+0.13	+0.15	+0.09	+0.06	+0.40	+0.20	+0.20
PSEI load	BA load (north)	+0.26	+0.12	+0.13	+0.15	+0.11	+0.04	+0.41	+0.21	+0.19
SCL (Seattle) load	BA load (north)	+0.17	+0.07	+0.10	+0.13	+0.05	+0.08	+0.35	+0.16	+0.18
TPWR (Tacoma) load	BA load (north)	+0.25	+0.11	+0.14	+0.08	+0.04	+0.03	+0.40	+0.19	+0.21
PGE load	BA load (loads path)	+0.06	+0.13	-0.07	+0.19	+0.04	+0.14	+0.20	+0.13	+0.07
PACW load	BA load (south)	+0.06	+0.15	-0.08	-0.09	-0.06	-0.03	+0.29	+0.13	+0.17
South load (PGE+PACW)	BA load (south)	+0.06	+0.14	-0.08	+0.05	-0.01	+0.06	+0.25	+0.13	+0.12
CISO (California) load	BA load (south/CA)	-0.34	-0.07	-0.26	-0.34	-0.24	-0.10	-0.19	-0.11	-0.08
CISO Solar	CA generation	-0.07	+0.39	-0.46	+0.12	+0.30	-0.18	+0.06	+0.09	-0.02

Outputs:

- "De-seasonalized" correlations that control for seasonal and diurnal relationships.
- Answers the question: *"When NOPE has a peak flow day, what else tends to peak with it?"*

Source	What it provides
BPA Interties & Flowgates	Path Actual flow (MW) + TTC: NOPE, COI, PDCI, West of Cascades-South.
BPA BA Load & VER feed	5-min BA Load, Wind, Hydro, Thermal, Net Interchange (Pacific; archives to 2007).
EIA-930 – Hourly Electric Grid Monitor	Hourly demand by BA, generation by fuel, and interchange (BA-level; 2019→).
EIA-923	Monthly per-plant hydro generation, WA/OR/ID (primeMover = HY; 2019→).
BPA Hourly Firm Data Monitoring & Evaluation	TC-20 Report (actual firm/non-firm curtailments) + TLR Avoidance Summary; 2008→.
BPA OASIS (OATI)	ATC (System Data Summary report), Outages (Notices: Message Summary report), Operational message log; reliability-curtailment & congestion postings.
CAISO OASIS	NOPE flowgate shadow prices (indicative of EIM (Energy Imbalance Market) binding)

- Interpretation:
  - Estimate Future NOPE Risk Exposure
    - Corroborate PGE's current approach
  - Develop Refinements and Recommendations for future PGE Modeling
    - Provide possible future refinements to use in following IRP cycles

Findings from Review of Historic Data

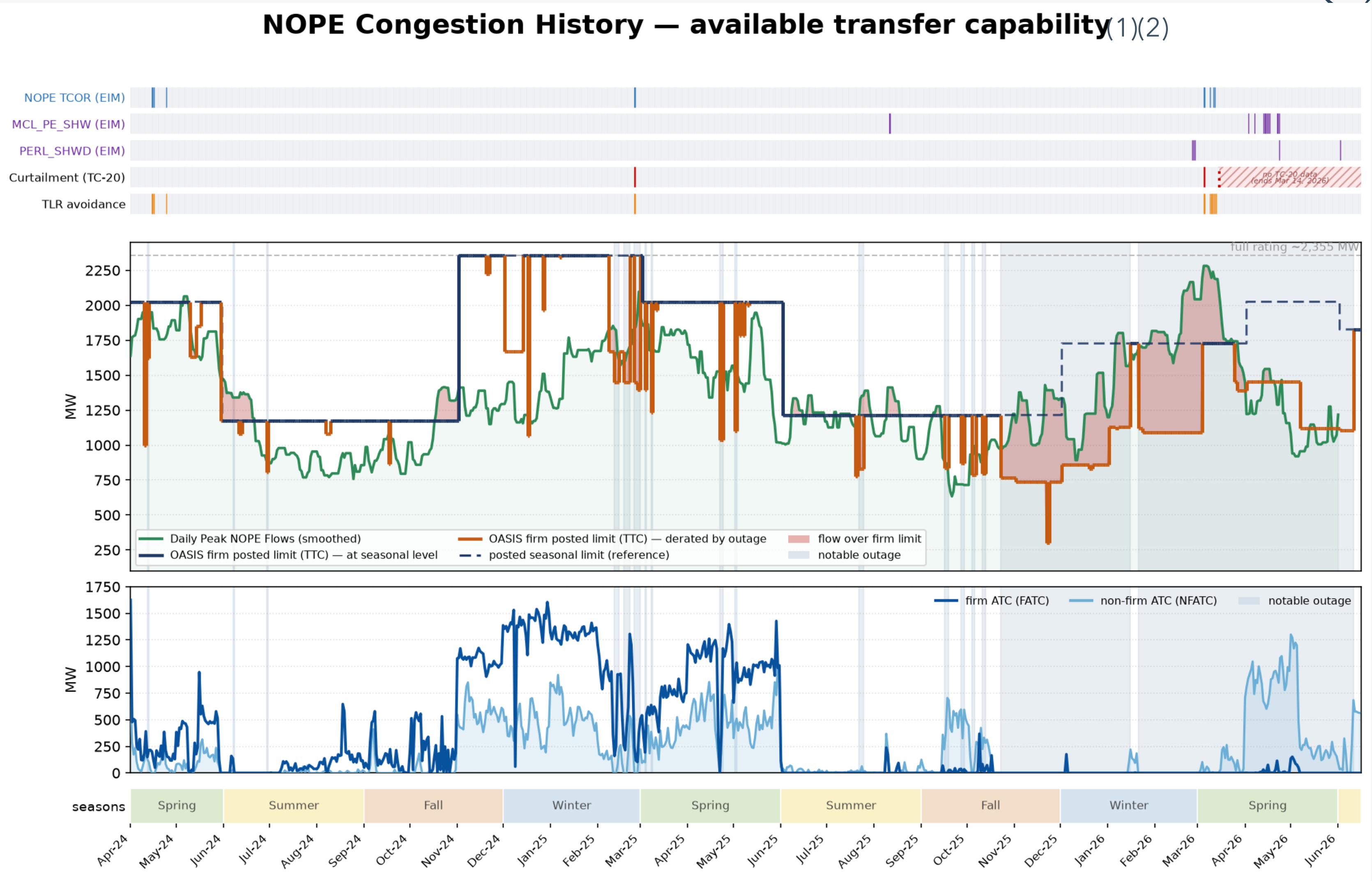
Overview of Historic NOPE Congestion

What did we look at when attempting to characterize historical congestion

- Curtailment (TC-20)
- TLR-Avoidance
- EIM Binding (NOPE & Constituent Lines)
- NOPE Flows, TTC, and Outages
- Firm/Non-Firm ATC availability

Historically, NOPE Non-firm transmission availability has been extremely limited during the summer months and periods of extensive planned outages

Non-firm ATC historically goes to 0 when flows approach TTC

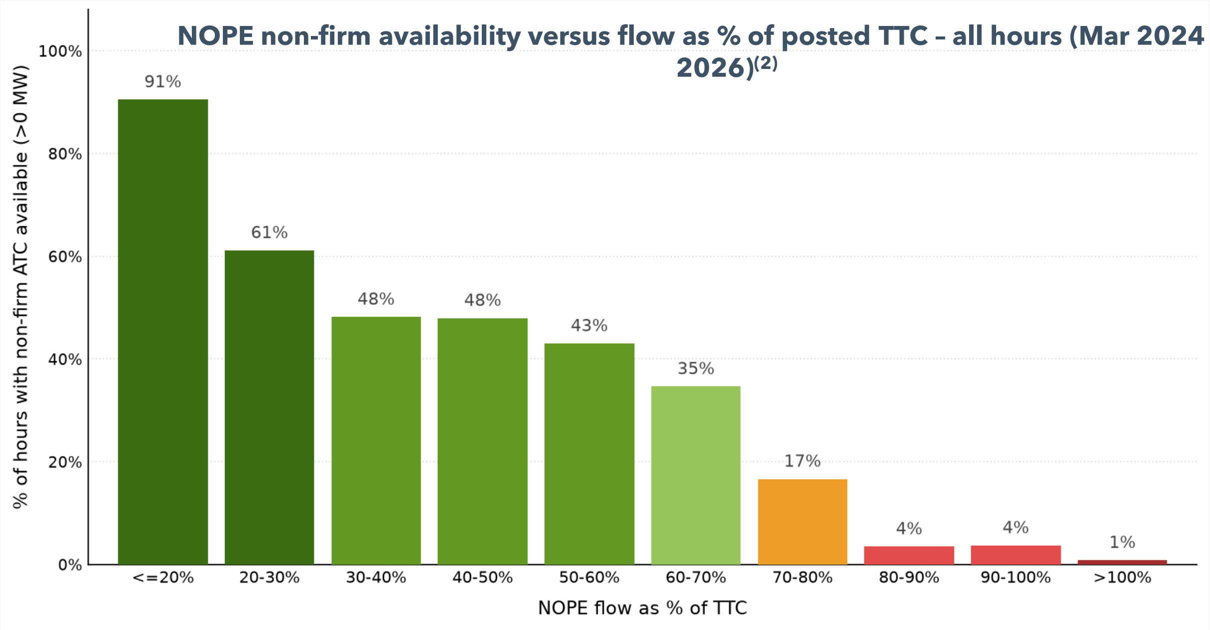


Sources: (1) BPA Flows, Curtailment & TLR Avoidance, ATC OASIS System Data Summary report for "W/BPAT/NOPE_S>N//"
(2) CAISO Intertie Constraint Shadow Prices

Acronyms: TLR – Transmission Loading Relief, EIM – Energy Imbalance Market, TTC – Total Transfer Capability, ATC – Available Transfer Capability

NOPE ATC vs Flow & 2 Years Historic Data 12x24 Heatmap

- **Non-firm transmission is the interruptible, short-term tranche of transfer capability:**
  - It can't be reserved long-term, it's the first product curtailed to relieve congestion, and it can be suspended as a congestion-management tool even when the flowgate is below its seasonal TTC[1]
- **As flows on NOPE exceed 80% of posted TTC historically, non-firm ATC increasingly unavailable**
  - The figure confirms this empirically: non-firm ATC is available in ~91% of hours when flow is ≤20% of TTC, falling to ~4% in the 80–90% band and ~1% above TTC (x-axis = NOPE hourly peak flow as % of TTC; y-axis = % of hours with non-firm ATC available)
  - The headroom between TTC and flow is the proxy for incremental non-firm availability; comparing forecasted or historical flow to an 80%-of-TTC threshold is a practical, observable way to forecast non-firm availability without reproducing the full ATC accounting (a proxy, not exact – schedules and market dispatch also drive flow)



- Using two years of 15-minute historic data[3] we can see the temporal occurrence of NOPE flows hitting >80% of TTC:
  - Hours with >80% of NOPE TTC occur primarily in spring and fall on peak hours
  - **Strong confounding factor is TTC derates that happened with planned outages in late 2025 and early 2026**

Historic 2 year % of days at each hour for each month that NOPE >80% (100% means every hour of each day that month)

Hour Ending	Month 1	2	3	4	5	6	7	8	9	10	11	12
1	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	27%	2%
2	5%	0%	0%	0%	0%	0%	0%	0%	0%	2%	27%	2%
3	3%	0%	0%	0%	0%	0%	0%	0%	0%	2%	25%	2%
4	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	27%	2%
5	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	28%	2%
6	6%	2%	2%	0%	0%	0%	0%	0%	0%	3%	32%	2%
7	10%	9%	10%	2%	0%	0%	0%	0%	0%	3%	40%	3%
8	29%	46%	34%	5%	3%	0%	0%	0%	0%	8%	47%	13%
9	45%	57%	55%	5%	6%	2%	0%	2%	3%	21%	47%	18%
10	48%	61%	58%	7%	11%	5%	0%	2%	3%	23%	50%	16%
11	48%	57%	65%	12%	11%	5%	3%	2%	5%	26%	50%	19%
12	50%	57%	63%	8%	11%	8%	5%	5%	5%	24%	50%	21%
13	48%	57%	58%	8%	6%	7%	5%	6%	3%	24%	50%	21%
14	48%	55%	63%	8%	8%	8%	10%	8%	0%	23%	50%	18%
15	47%	57%	60%	8%	8%	10%	15%	10%	2%	21%	50%	18%
16	42%	55%	55%	7%	8%	10%	18%	11%	0%	23%	50%	15%
17	15%	27%	42%	8%	8%	10%	15%	13%	0%	18%	47%	10%
18	16%	0%	19%	5%	6%	7%	11%	10%	0%	10%	47%	13%
19	15%	2%	15%	0%	0%	7%	11%	11%	0%	6%	47%	10%
20	13%	0%	13%	0%	0%	3%	3%	3%	0%	8%	47%	10%
21	11%	7%	11%	0%	0%	3%	0%	3%	0%	10%	43%	8%
22	8%	2%	11%	0%	0%	2%	0%	0%	0%	6%	42%	6%
23	5%	2%	0%	0%	0%	0%	0%	0%	0%	2%	33%	2%
24	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	30%	2%

Sources: (1) PGE April 2026 IRP Roundtable pp 21; (2) ATC OASIS System Data Summary report for "W/BPAT/NOPE_S>N//"; (3) BPA Flows

Findings from Review of PGE 2035 PCM Modeling

PCM Modeled Outputs 12x24 Heatmap & Top Correlations

- With magnitude of solar additions in 2035 model versus 06/2024-06/2026 actuals, magnitude of hours with >80% seasonal TTC from 2035 PCM outputs[(1)] increases to >24 days out of 30 and shifts from February and March to April and July
    - Stands as an indicator of increasing role of solar, though wind still correlates highly through most of the year

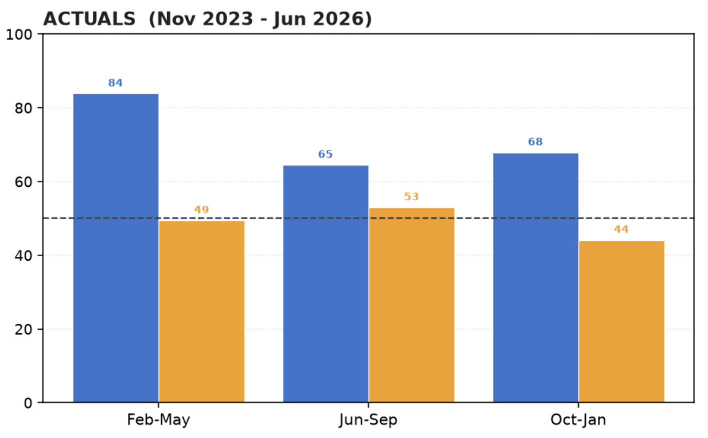
PCM modeled 2035 % of days at each hour for each month that NOPE >80% (100% means every hour of each day that month)

Hour Ending \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	20%	39%	6%	0%	0%	0%	0%
8	0%	0%	3%	23%	0%	40%	55%	23%	0%	0%	0%	0%
9	0%	0%	6%	30%	10%	47%	81%	52%	37%	0%	3%	0%
10	0%	7%	23%	43%	13%	57%	90%	61%	57%	0%	17%	0%
11	0%	29%	39%	73%	23%	70%	84%	81%	50%	0%	27%	0%
12	0%	50%	45%	73%	45%	77%	94%	81%	57%	0%	23%	0%
13	0%	46%	42%	90%	68%	73%	84%	71%	50%	3%	23%	0%
14	0%	50%	42%	87%	71%	73%	77%	77%	60%	6%	27%	0%
15	0%	39%	45%	87%	61%	67%	61%	77%	60%	10%	27%	0%
16	0%	29%	52%	87%	58%	50%	55%	52%	47%	6%	20%	0%
17	0%	4%	39%	87%	26%	30%	29%	32%	37%	0%	7%	0%
18	0%	0%	13%	23%	0%	10%	10%	0%	3%	0%	0%	0%
19	0%	0%	3%	7%	0%	0%	6%	0%	0%	0%	0%	0%
20	0%	0%	0%	7%	0%	0%	3%	0%	0%	0%	0%	0%
21	0%	0%	13%	7%	0%	0%	3%	0%	0%	0%	0%	0%
22	0%	0%	0%	7%	0%	0%	3%	0%	0%	0%	0%	0%
23	0%	0%	0%	3%	0%	0%	3%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%

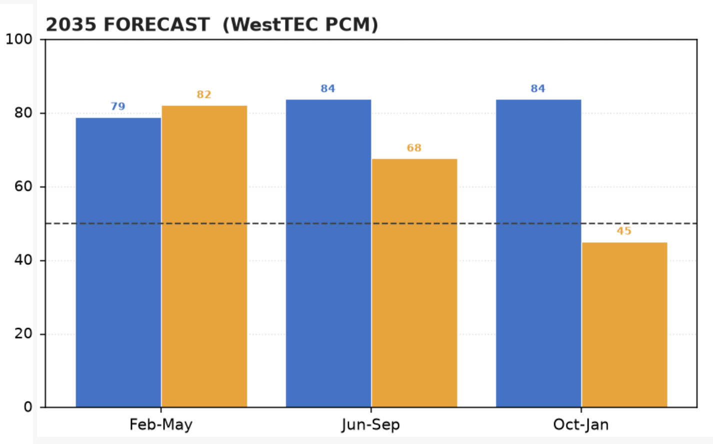
Sources: (1) PGE WestTEC adjusted PCM outputs with NOPE not binding for TTC

CA Solar and BPA Wind Percentiles on the Top 10% of NOPE Flow Days (7am-5pm) Historic vs PCM (showing correlations from 0-100% on highest NOPE days median versus each day's +/- 15 day local normal)

- In 2+ years of historic data, Pacific Northwest (PNW) wind had the highest correlation with top 10% flow periods of flow on NOPE



- In 2035 PCM modeling, solar emerges as highest correlation factor in springtime, however PNW wind continues to dominate correlations through rest of the year



Pearson Correlation Analysis – Summary Results

The correlation analysis shows renewable generation and load drivers as normalized covariant components, isolating the underlying signals that move with south to north NOPE flow after seasonality is stripped out

- Positive values show increases in the factor with S->N NOPE flows, negative values show a factor that decreases when NOPE flows increase
- This analysis considered correlations with factors against NOPE flow in general and not conditioned on congestion or on the ≥80%-of-TTC threshold (see appendix for details)
- In the historic data PNW wind (measured as wind in the BPA region) has the highest covariance, in the PCM modeled data CA net solar (California solar minus California load) also emerges as strong factor covariant with NOPE flows
- PNW load, primarily captured as PGE + Puget Sound load, also has high covariance some times of the year

- **Based on this statistical analysis, <u>PNW Wind</u>, <u>CA Net Solar</u> and <u>PNW load</u> values were chosen as exogenous predictive factors to consider when forecasting NOPE flows (and non-firm unavailability) for years and conditions independent of PCM unit dispatch results**

		Feb-May (7a-5p)			Jun-Sep (7a-5p)			Oct-Jan (7a-5p)		
Factor	**Category**	**Historic**	**PCM 2035**	**Δ Act-PCM**	**Historic**	**PCM 2035**	**Δ Act-PCM**	**Historic**	**PCM 2035**	**Δ Act-PCM**
COI + PDCI (northbound)	Intertie flow	+0.37	+0.47	-0.10	+0.46	+0.55	-0.09	+0.52	+0.28	+0.24
CA net-export	Intertie flow	+0.25	+0.43	-0.18	+0.42	+0.43	-0.02	+0.49	+0.27	+0.23
BPA Wind	**BPA generation**	**+0.48**	**+0.36**	**+0.12**	**+0.34**	**+0.31**	**+0.04**	**+0.23**	**+0.51**	**-0.27**
PNW load (total)	BA load (north)	+0.12	+0.17	-0.05	+0.13	+0.01	+0.12	+0.34	+0.20	+0.14
CISO (California) load	BA load (south/CA)	-0.34	-0.07	-0.26	-0.34	-0.24	-0.10	-0.19	-0.11	-0.08
CISO Solar	**CA generation**	**-0.07**	**+0.39**	**-0.46**	**+0.12**	**+0.30**	**-0.18**	**+0.06**	**+0.09**	**-0.02**
BPA / PNW Hydro	BPA generation	-0.16	-0.21	+0.05	-0.26	-0.21	-0.04	-0.19	+0.06	-0.25

Recommendations for PGE Future Planning Models

Future Modeling: Incorporating Findings from PCM into Aurora

Modeling flow on NOPE from exogenous zonal input variables

- Use 2035 PCM case modeled flow as a target to train a regression model
- The regression model outputs hourly flow against BPA seasonal TTC limits by using input variables as they relate to PCM modeled NOPE flows, then determines the likely congested state as hours when flows are >80% of seasonal TTC

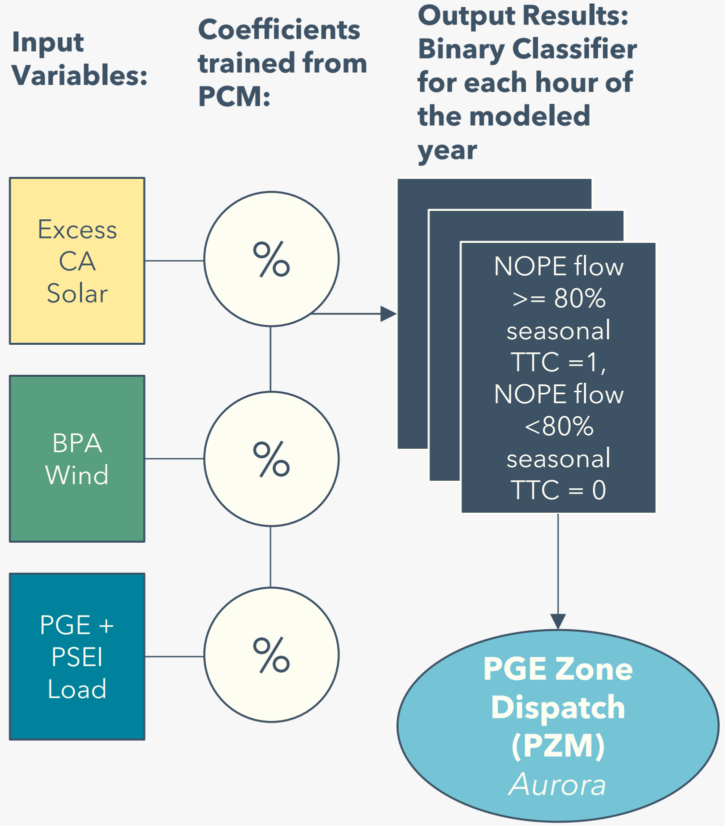
Input Variables

- Excess CA Solar
  - Determined by obtaining positive values for CISO solar output minus CISO load
- BPA Wind
  - Wind output for the BPAT region
- PNW Load (west-wide only)
  - Sum of PGE and PSEI area load

Results

- Binary Classifier 1 = NOPE flow at hour expected to be >= 80% seasonal TTC, 0 = < 80% seasonal TTC
- Can be run each year for Aurora using different annual sets of above input variables

- The results show **1,489 hours** of the year (vs. **1,333 hours in the PCM**) where NOPE flows would exceed 80% of seasonal TTC and as a result indicate risk for the ability to obtain non-firm transmission service
- The regression can be further refined by using multiple PCM results derived from different weather years before using in future IRP cycle Aurora modeling



Result Category	2035 PCM	Predicted
True Positives (TP)		941
False Positives (FP)		548
Total Positives	1,333	1,489
False Negatives (FN)		392
True Negatives (TN)		6,879
Total Negatives	7,427	7,271
Total		8,760
Balanced Accuracy		**0.816**

Predicted 2035 % of days at each hour for each month that NOPE >80% (100% means every hour of each day that month)

Hour Ending \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	23%	3%	0%	0%	0%	0%	0%
9	0%	0%	0%	47%	29%	80%	55%	48%	67%	0%	0%	0%
10	0%	18%	19%	67%	58%	90%	84%	94%	87%	16%	7%	0%
11	0%	54%	48%	83%	84%	93%	87%	97%	100%	35%	33%	0%
12	0%	61%	61%	100%	87%	97%	87%	97%	97%	48%	53%	0%
13	0%	75%	58%	100%	84%	100%	81%	87%	97%	55%	60%	0%
14	0%	75%	61%	100%	77%	93%	65%	68%	70%	52%	53%	0%
15	0%	61%	48%	93%	65%	87%	48%	45%	33%	16%	13%	0%
16	0%	39%	26%	70%	35%	60%	32%	29%	10%	0%	0%	0%
17	0%	0%	0%	7%	3%	7%	19%	13%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	3%	16%	13%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	3%	19%	13%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	3%	16%	13%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	13%	10%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	13%	10%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Conclusions & Next Steps

Findings

PGE NOPE Flows >= 80% of Seasonal TTC is a reliable risk metric for non-firm ATC availability in the historic data

Current IRP modeling approach to use PCM results for NOPE flows to estimate non-firm transmission risk is a useful update to past assumptions around 25% non-firm availability year round

Analysis of historic data and 2035 PCM modeling also can be used to identify a set of factors that are covariant with NOPE flows

High CA solar net of load, PNW wind output and PNW load have strongest correlation with high NOPE flows in the PCM

In future IRP cycles, these factors can be used to estimate NOPE flows using a regression model trained on PCM-generated flows across multiple weather years and applied within Aurora

Recommendations

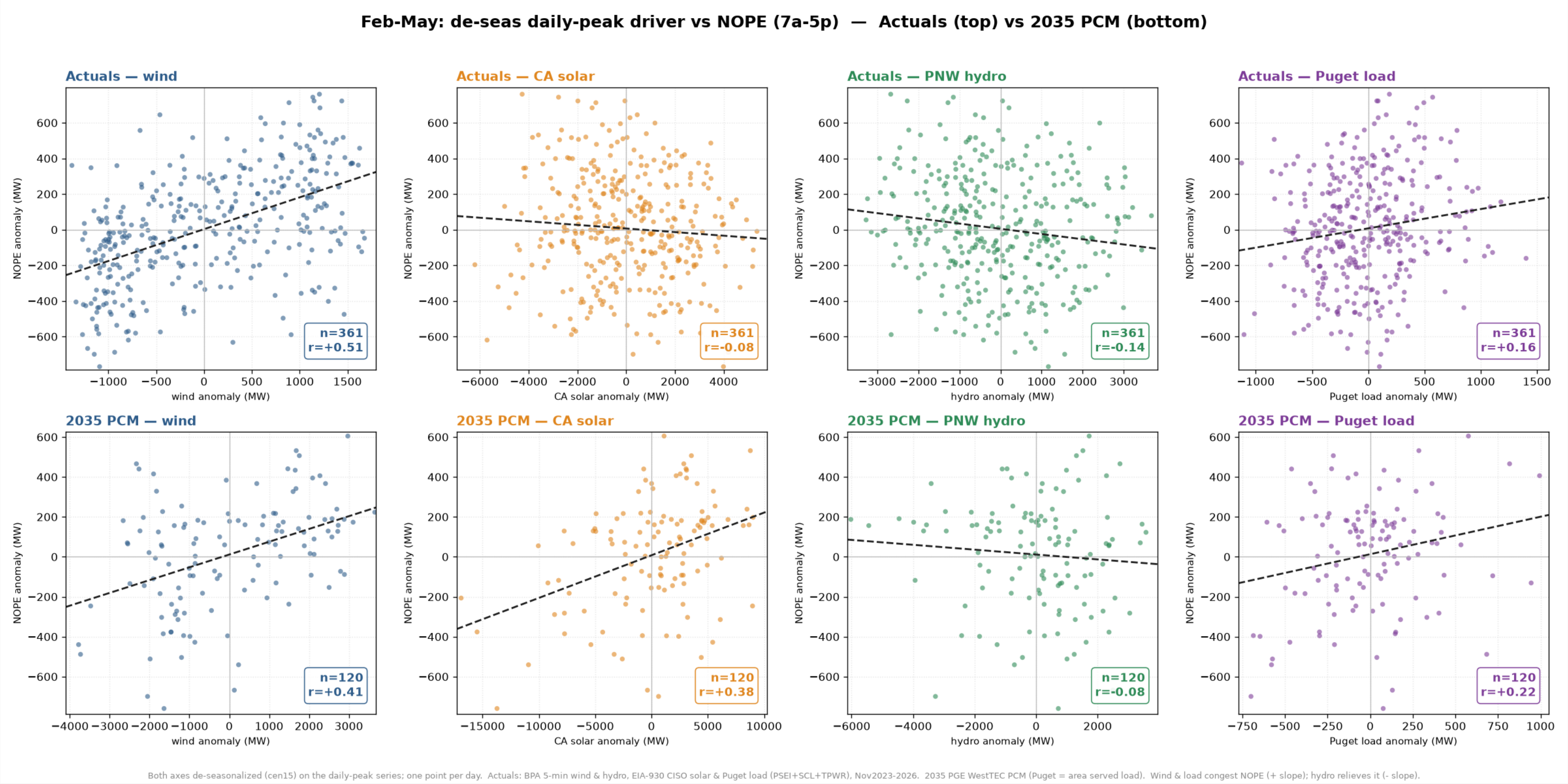
In the current IRP cycle, retain 80% of NOPE seasonal TTC in modeling as a proxy for likely congestion and unavailability of non-firm transmission

In future IRP cycles, consider implementing a weather-year generalized regression model informed by PCM-generated flows across multiple weather years within Aurora as a proxy for non-firm transmission availability on NOPE

- This will allow future study years and the capacity expansion model to consider non-firm availability on NOPE subject to changing system conditions across the West
- Doing so should help PGE's modeling tools better assess non-firm transmission availability risks and arrive at a lower-risk resource portfolio

Appendix – IRP Roundtable

Top Individual Correlated Factors Scatter Plots



Correlation Analysis – Details

The de-seasonalized Pearson Correlation (PC) analysis decomposes correlated renewable generation and load drivers into normalized covariant components, isolating the underlying signals that move NOPE after seasonality is stripped out

- This correlation analysis is computed on de-seasonalized daily-peak NOPE flow across all days in each seasonal bucket, in the S→N (northbound) direction

- **These correlations describe what moves NOPE flow in general – they are not conditioned on congestion or on the ≥80%-of-TTC threshold**
  - Identifying when flow crosses 80% of seasonal TTC is the job of the regression/binary classifier shown later, which is equally valuable for identifying hours below 80% as above it – We deliberately did not condition the correlations on only the ≥80% hours
  - Conditioning the correlations on only the ≥80% hours would restrict the fit to a small, rare subset – roughly 15% of hours in the 2035 PCM (1,333 of 8,760), and fewer still in the ~2-year historic record – drawn from a single PCM weather year.
  - With so few congested observations and no weather-year variation, the fitted relationships would tend to track noise particular to those hours rather than drivers that generalize.
  - Correlating on flow across all hours retains the full signal and lets the same drivers explain both congested and non-congested conditions, which is what the downstream classifier needs.

		Feb-May (7a-5p)			Jun-Sep (7a-5p)			Oct-Jan (7a-5p)		
Driver	**Category**	**Actuals**	**PCM 2035**	**Δ Act-PCM**	**Actuals**	**PCM 2035**	**Δ Act-PCM**	**Actuals**	**PCM 2035**	**Δ Act-PCM**
West of Cascades South (E->W)	BPA internal path	+0.64	+0.79	-0.15	+0.67	+0.77	-0.09	+0.61	+0.76	-0.15
COI (northbound)	Intertie flow	+0.34	+0.47	-0.13	+0.45	+0.55	-0.09	+0.51	+0.26	+0.25
PDCI (northbound)	Intertie flow	+0.30	+0.12	+0.18	+0.35	+0.09	+0.26	+0.38	+0.09	+0.29
COI + PDCI (northbound)	Intertie flow	+0.37	+0.47	-0.10	+0.46	+0.55	-0.09	+0.52	+0.28	+0.24
CA net-export	Intertie flow	+0.25	+0.43	-0.18	+0.42	+0.43	-0.02	+0.49	+0.27	+0.23
BPA Wind	BPA generation	+0.48	+0.36	+0.12	+0.34	+0.31	+0.04	+0.23	+0.51	-0.27
BPA / PNW Hydro	BPA generation	-0.16	-0.21	+0.05	-0.26	-0.21	-0.04	-0.19	+0.06	-0.25
PNW load (total)	BA load (north)	+0.12	+0.17	-0.05	+0.13	+0.01	+0.12	+0.34	+0.20	+0.14
BPAT load	BA load (north)	+0.05	+0.19	-0.14	+0.19	+0.04	+0.15	+0.31	+0.20	+0.11
Puget load (PSEI+SCL+TPWR)	BA load (north)	+0.24	+0.11	+0.13	+0.15	+0.09	+0.06	+0.40	+0.20	+0.20
PSEI load	BA load (north)	+0.26	+0.12	+0.13	+0.15	+0.11	+0.04	+0.41	+0.21	+0.19
SCL (Seattle) load	BA load (north)	+0.17	+0.07	+0.10	+0.13	+0.05	+0.08	+0.35	+0.16	+0.18
TPWR (Tacoma) load	BA load (north)	+0.25	+0.11	+0.14	+0.08	+0.04	+0.03	+0.40	+0.19	+0.21
PGE load	BA load (loads path)	+0.06	+0.13	-0.07	+0.19	+0.04	+0.14	+0.20	+0.13	+0.07
PACW load	BA load (south)	+0.06	+0.15	-0.08	-0.09	-0.06	-0.03	+0.29	+0.13	+0.17
South load (PGE+PACW)	BA load (south)	+0.06	+0.14	-0.08	+0.05	-0.01	+0.06	+0.25	+0.13	+0.12
CISO (California) load	BA load (south/CA)	-0.34	-0.07	-0.26	-0.34	-0.24	-0.10	-0.19	-0.11	-0.08
CISO Solar	CA generation	-0.07	+0.39	-0.46	+0.12	+0.30	-0.18	+0.06	+0.09	-0.02

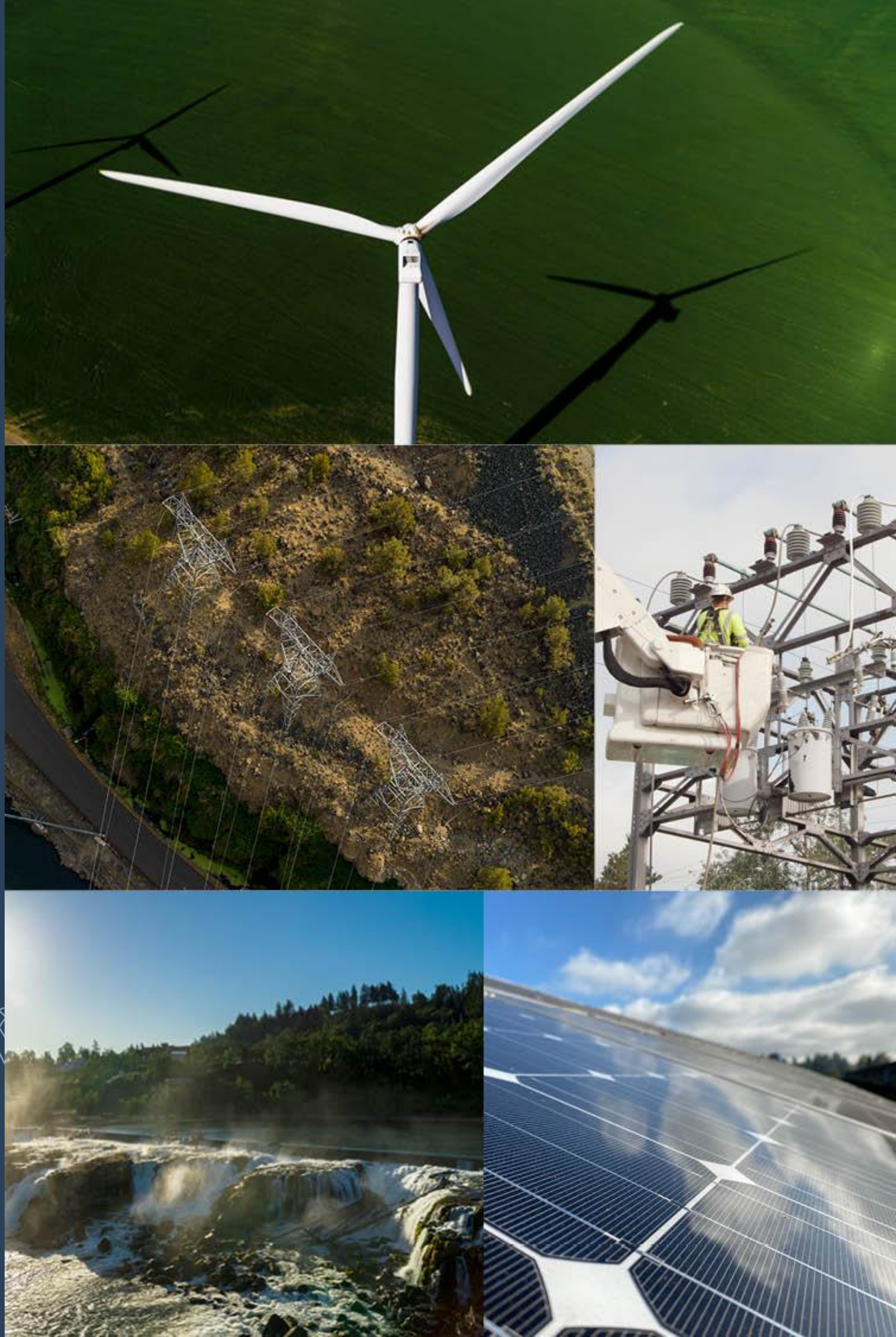
Summary and Guided Feedback

Summary: See Findings and Recommendation slide.

Content: What additional questions do you have about the findings and recommendations about the NOPE flowgate?

Capacity Need and ELCCs Update

Devin Mounts



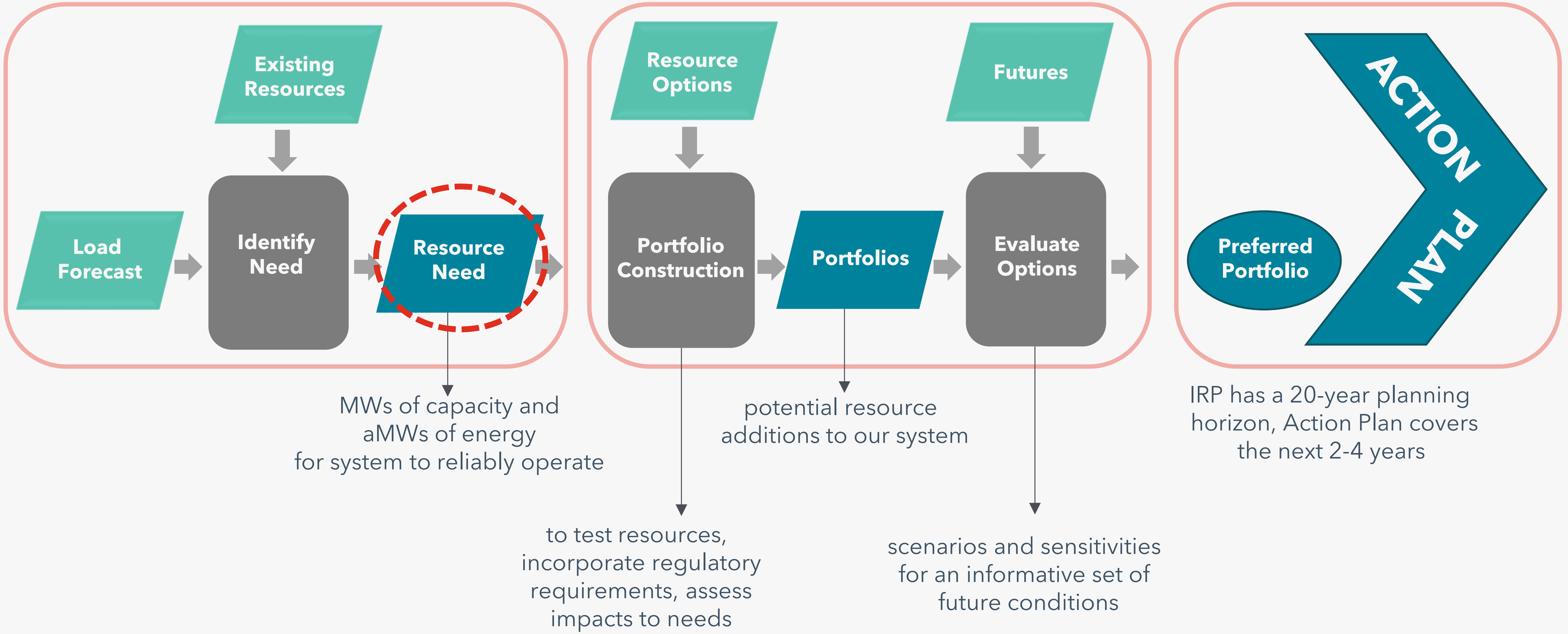
PGE An Oregon kind of energy.[SM]

High-Level IRP Analysis Process

Estimate System Needs

Evaluate Resource Options

Develop Plan



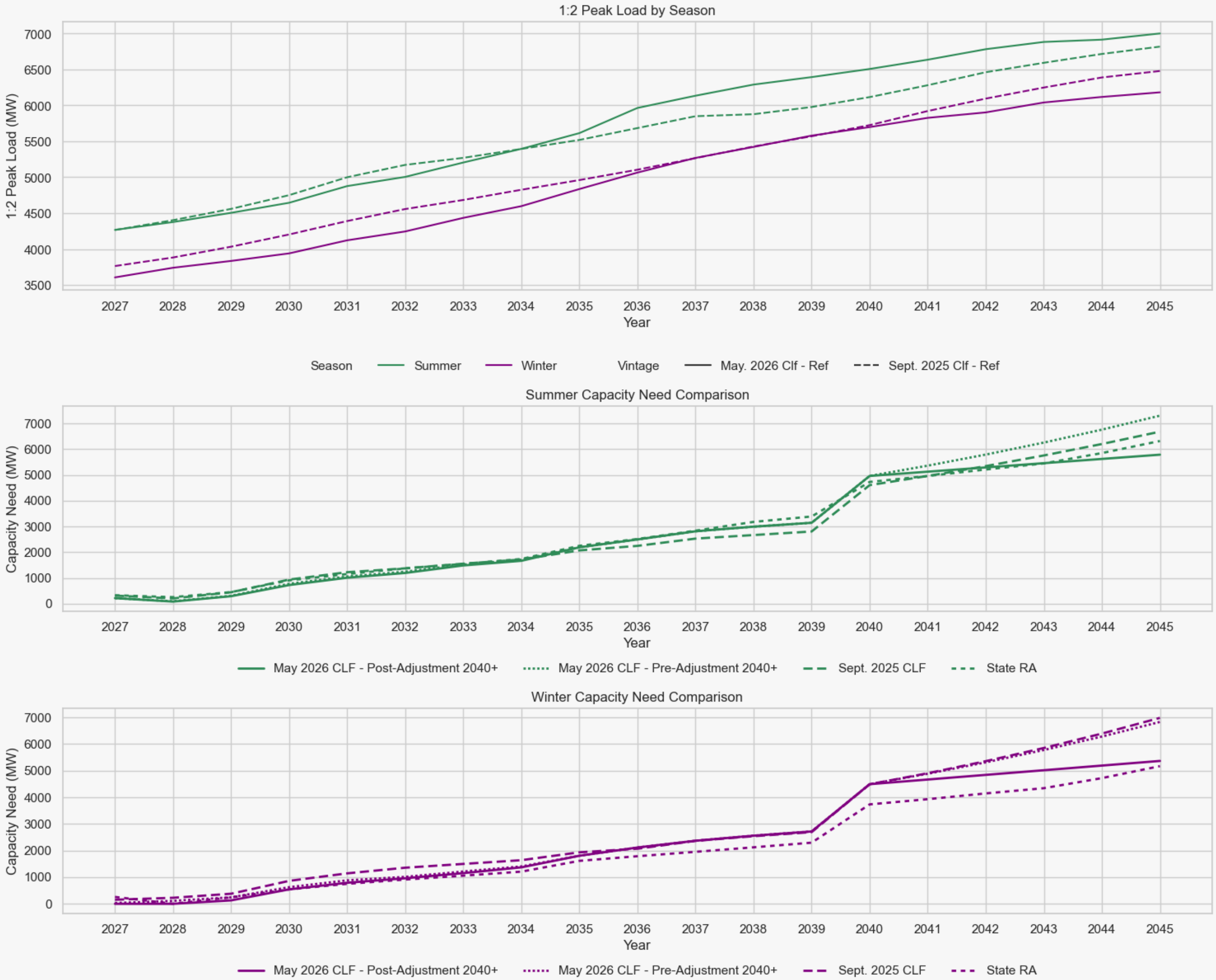
Load Forecast Update: Effects on Capacity Need

Updated Capacity Needs reflect trends in corporate load forecast presented in **June's Roundtable**. Additionally, post 2040-extrapolation method changed to align winter capacity needs with State RA estimates scenario.[1]

*Changes in the forecast result in **smaller summer and winter peak** loads **in the near-term**. Summer peaks are greater beginning in 2035.*

***Summer** need is **163 MW less in 2030**, and 120 MW more in 2035*

***Winter** need is **237 MW less in 2030**, and 129 MW less in 2035. "Post-Adjustment 2040+" need is 2GW less in 2045.*

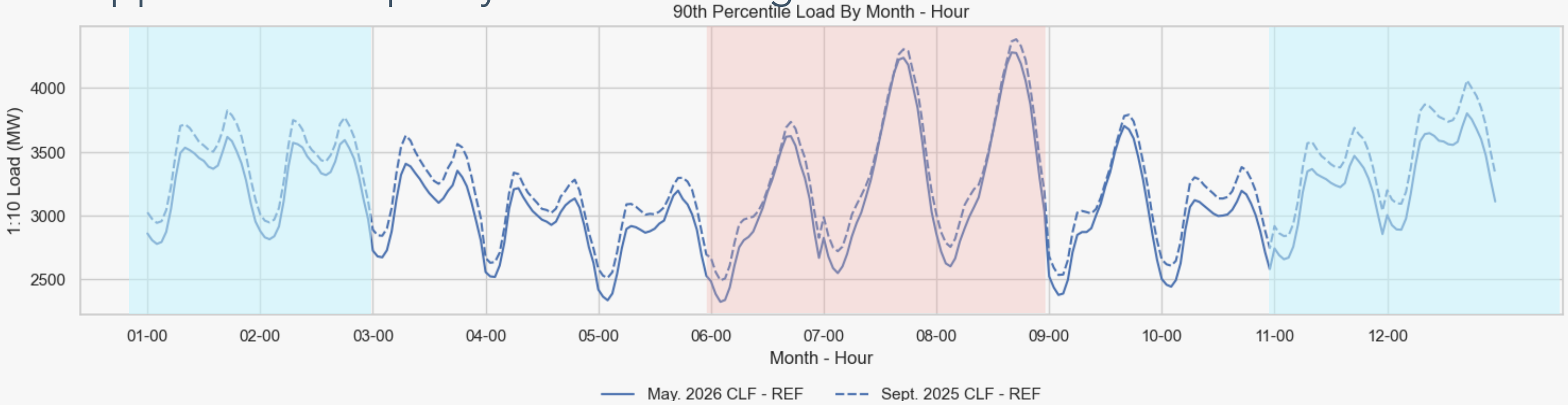


1. Extrapolating capacity needs post 2040 is required as many simulated weeks are unsolvable, reducing sample size and biasing the capacity need estimates downward. See Figure 45, 2023 CEP/IRP. Methodology changed from average percentage change from 2027-2029 to average absolute change.

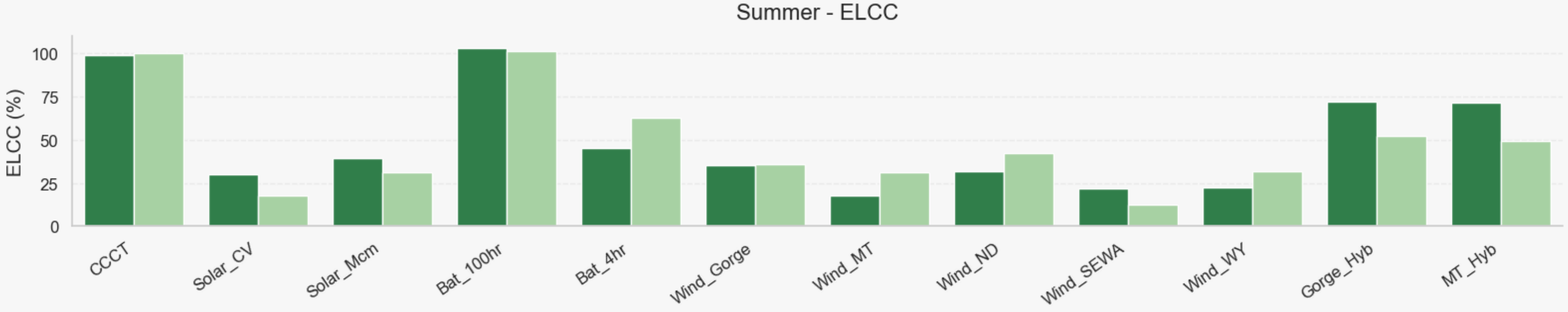
Load Forecast Update: Effects on Supply Side ELCCs

Updated ELCCs reflect earlier summer peaks and lower energy constraints during winter reliability events. Test year updated from 2030 to 2032, to maintain approximate capacity needs and align ELCCs with Action Plan time horizon.

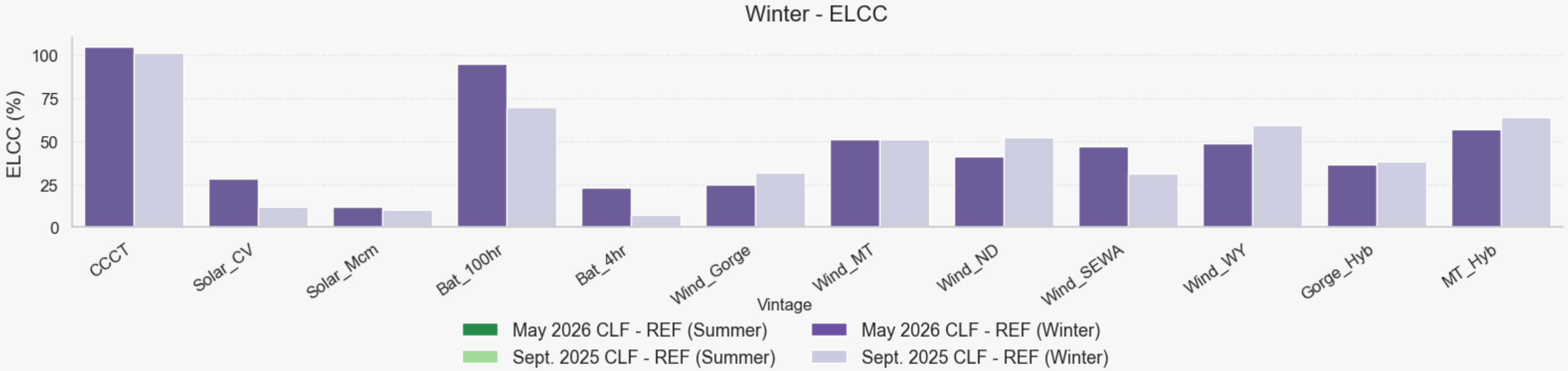
1. ***Summer peaks occur earlier*** *in the day with* ***lower loads in the evening****.*
2. ***Lower winter loads*** *across all hours*



Earlier summer peaks increase likelihood of overlap with solar generation and decrease the value of shifting energy.



Lower winter loads decrease the likelihood of multi-day events, adding value to shifting energy

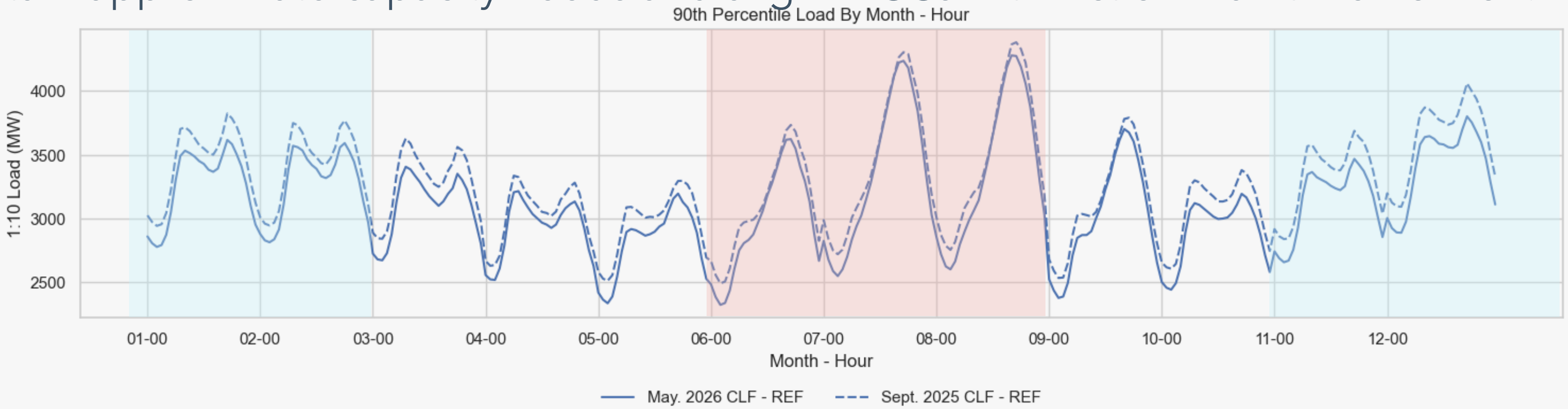


A subset of ELCCs is shown here for informative comparison. A full review of ELCCs resulting from the May 2026 Corporate Load Forecast will be included in the 2026 CEP/IRP.

Load Forecast Update: Effects on EE/VPP ELCCs

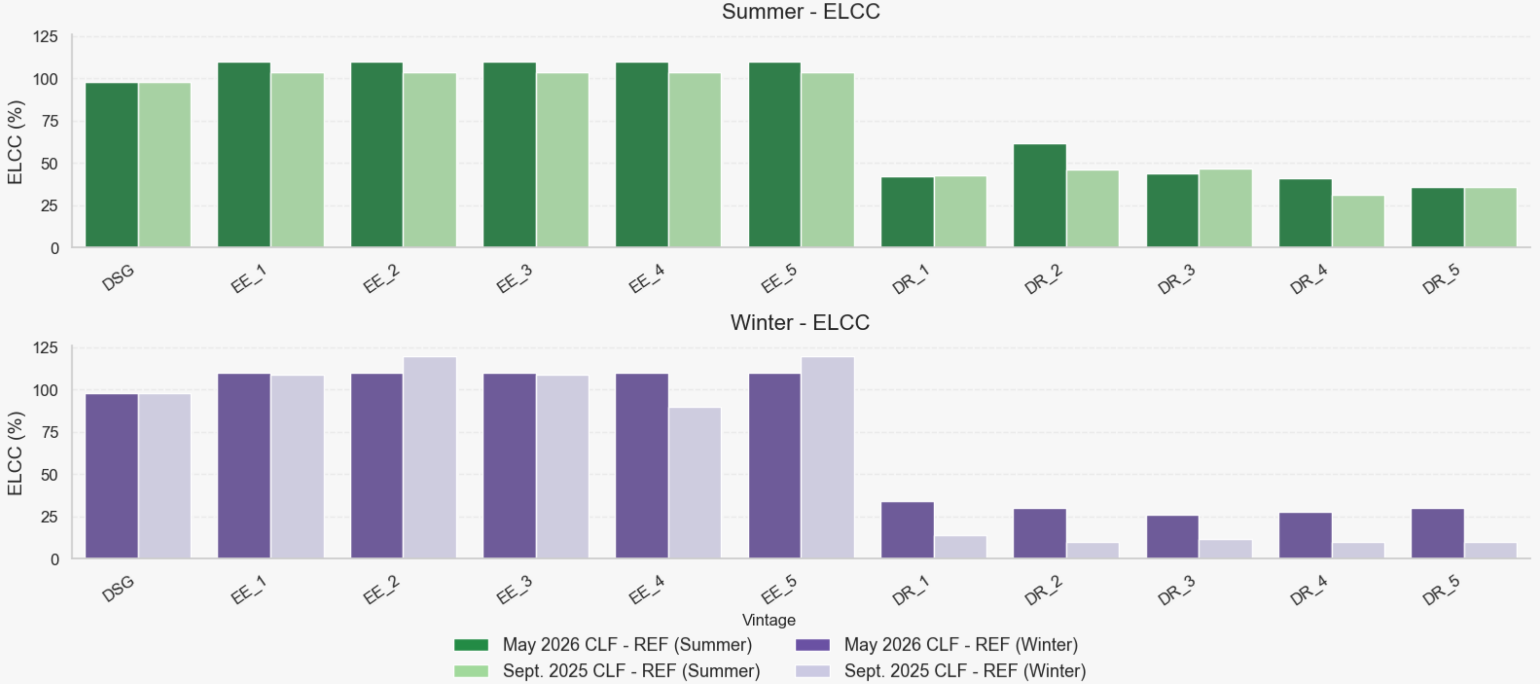
Updated ELCCs reflect earlier summer peaks and lower energy constraints during winter reliability events. Test year updated from 2030 to 2032, to maintain approximate capacity needs and align ELCCs with Action Plan time horizon.

1. **Summer peaks occur earlier** *in the day with* ***lower loads in the evening***.
2. ***Lower winter loads*** *across all hours*



Lower energy demands allow for capacity to be directed to shorter duration peak events, increasing the value of energy efficiency

Lower winter loads decrease the likelihood of multi-day events, adding value for Flex Load Programs



A subset of ELCCs is shown here for informative comparison. A full review of ELCCs resulting from the May 2026 Corporate Load Forecast will be included in the 2026 CEP/IRP.

Summary and Guided Feedback

Content: Do you have any questions about the updated Capacity Needs and ELCCs that reflect the changing energy and capacity constraints driven by the May 2026 Corporate Load Forecast?

Purpose: Capacity Needs and ELCCs are key inputs to portfolio analysis. Understanding how they've changed compared to earlier draft data helps contextualize changes in quantity and timing of resources added in portfolio expansion modeling.

Updated Draft Portfolio Results

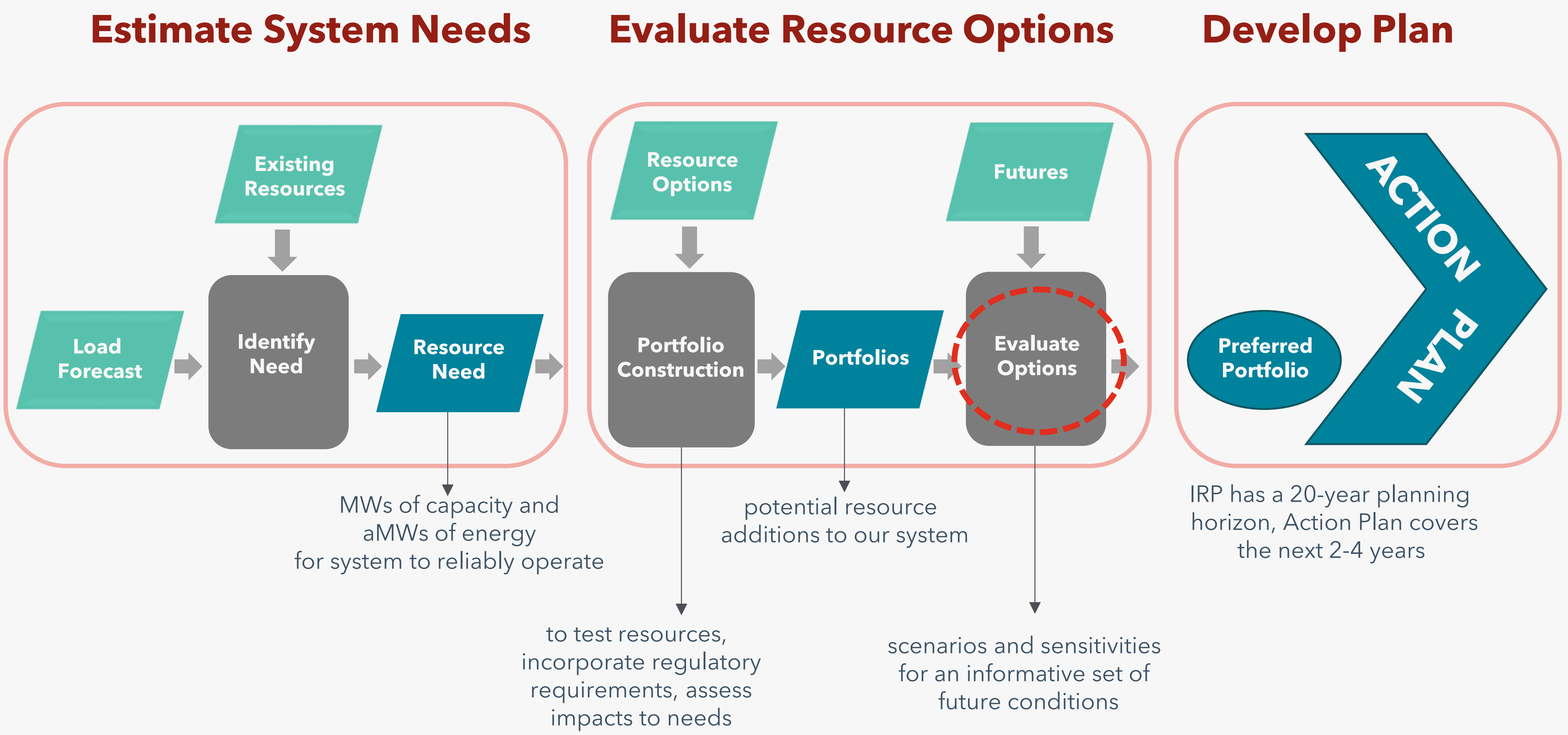
Rob Campbell

PGE An Oregon kind of energy.[SM]





High-Level IRP Analysis Process



Outline

- Key portfolio results: Sept '25 CLF vs May '26 CLF comparison
- Analysis of updated draft results for key portfolios
- Draft results for remaining scenarios
- Draft results for transmission expansion

DRAFT: Planned Scenarios for Portfolio Analysis

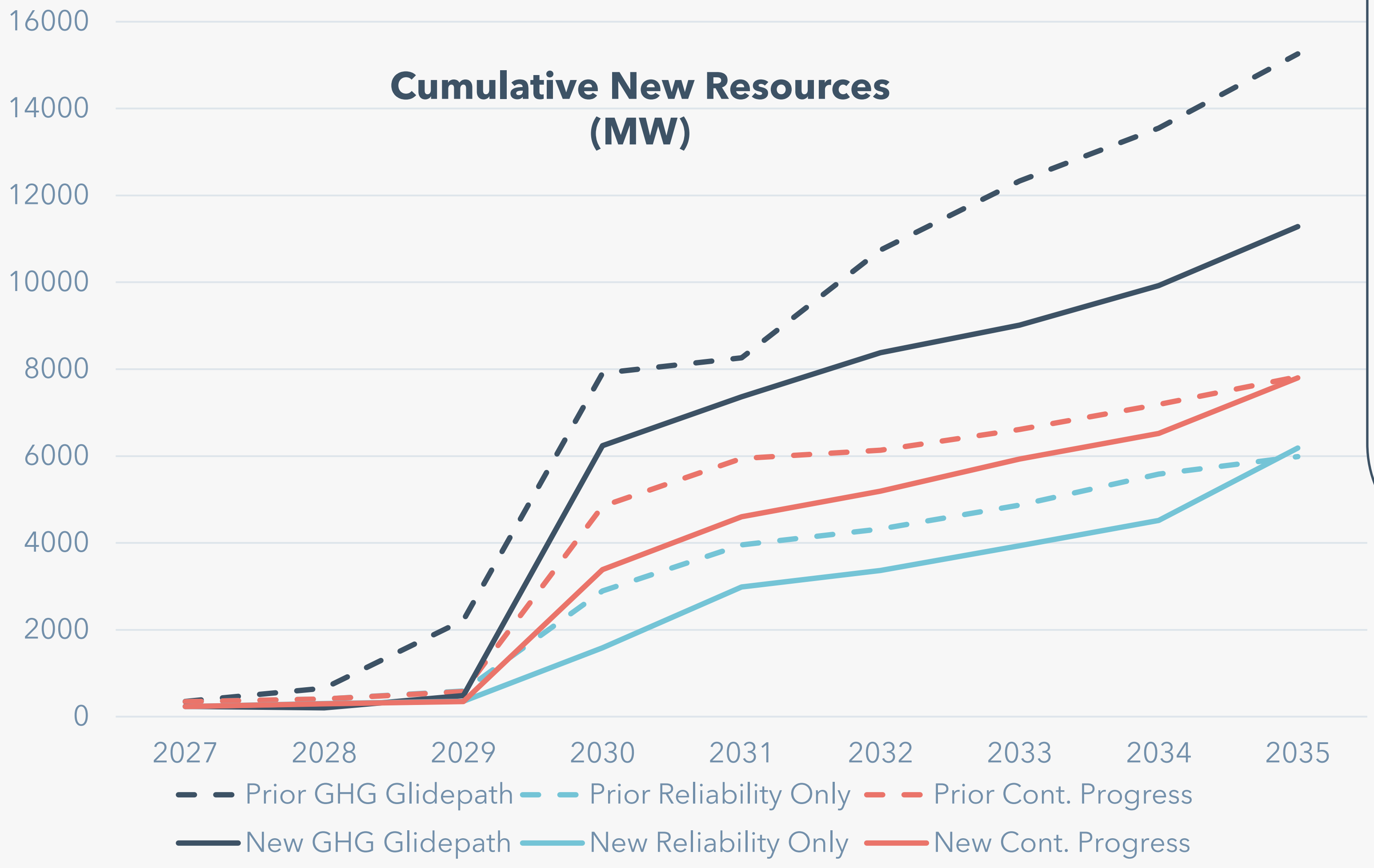
- "Standard" load forecast = for each high, reference, low
- RA= resource adequacy
- Core Growth load scenarios do not include DSG growth

22 main scenarios proposed to analyze a range of policy and utility considerations

Portfolio #	Regulatory Environment	Load Forecast	Resource Considerations: New Gas Contracts Available	Resource Considerations: Resource Availability	Capacity Methodology	Transmission Expansion
1	80% Emissions Glidepath	Standard	No		IRP Metrics	Available
2	Reliability Only	Standard	Yes		IRP Metrics	Available
3	HB 2021 – Cont. Progress	Standard	Yes		IRP Metrics	Available
4	80% Emissions Glidepath	Core Growth Only	No		IRP Metrics	Available
5	Reliability Only	Core Growth Only	Yes		IRP Metrics	Available
6	HB 2021 – Cont. Progress	Core Growth Only	Yes		IRP Metrics	Available
7	80% Emissions Glidepath	Standard	No	Hydro	IRP Metrics	Available
8	Reliability Only	Standard	Yes	Hydro	IRP Metrics	Available
9	HB 2021 – Cont. Progress	Standard	Yes	Hydro	IRP Metrics	Available
10	80% Emissions Glidepath	Core Growth Only	No	Hydro	IRP Metrics	Available
11	Reliability Only	Core Growth Only	Yes	Hydro	IRP Metrics	Available
12	HB 2021 – Cont. Progress	Core Growth Only	Yes	Hydro	IRP Metrics	Available
13	Reliability Only	Standard	Yes	Colstrip	IRP Metrics	Available
14	Reliability Only	Core Growth Only	Yes	Colstrip	IRP Metrics	Available
15	Reliability Only	Standard	Yes	Colstrip + Hydro	IRP Metrics	Available
16	Reliability Only	Core Growth Only	Yes	Colstrip + Hydro	IRP Metrics	Available
17	HB 2021 – Cont. Progress	Standard	Yes		IRP Metrics	Unavailable
18	HB 2021 – Cont. Progress	Standard	Yes		IRP Metrics	No WSPP
19	HB 2021 – Cont. Progress	Standard	Yes		IRP Metrics	No NPC
20	HB 2021 – Cont. Progress	Standard	Yes		IRP Metrics	No T-H
21	Reliability Only	Standard	Yes		State RA Metrics	Available
22	80% Emissions Glidepath	Standard	No	rCBI	IRP Metrics	Available

Key Portfolio Results: Sept ’25 CLF vs May ‘26 CLF Comparison

Decrease in near-term resource additions for new draft results

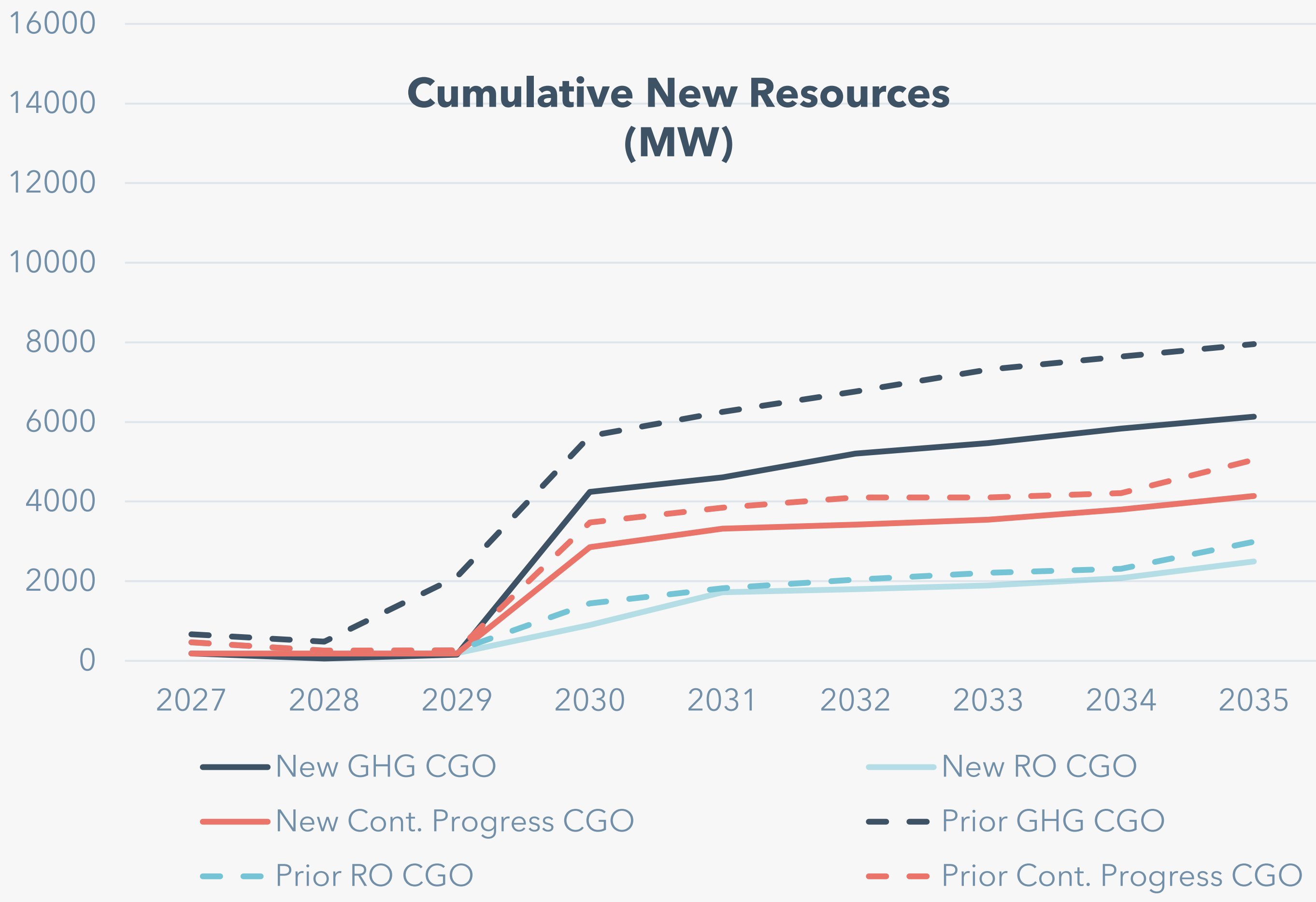


Near-term resource additions for key portfolios have **decreased** due to updates for the following items:

- **Corporate Load Forecast**: Decrease in near-term load, combined with the increase in summer peak and decrease in winter peak activity, is driving down resource additions across portfolios in 2030 and 2032
- **BPA Study**: Increased available non-firm transmission in ROSE-E from 712 MW to 1380 MW, decreasing near term transmission additions
- **2040+ Capacity Needs Extrapolation**: Large decrease in post-2040 capacity needs in summer and winter drives down resource additions even prior to 2040 in higher need scenarios due to pre-building to meet later year needs

	June Results 2030 MW	July Results 2030 MW	% Change
GHG	7910	6237	(21%)
Cont. Progress	4847	3387	(30%)
RO	2893	1585	(45%)

Decrease in near-term resource additions for new draft results: Core Load Growth Only (CGO)



Near-term resource additions for key portfolios that have no new large load growth have also **decreased** due to items discussed on the previous slide:

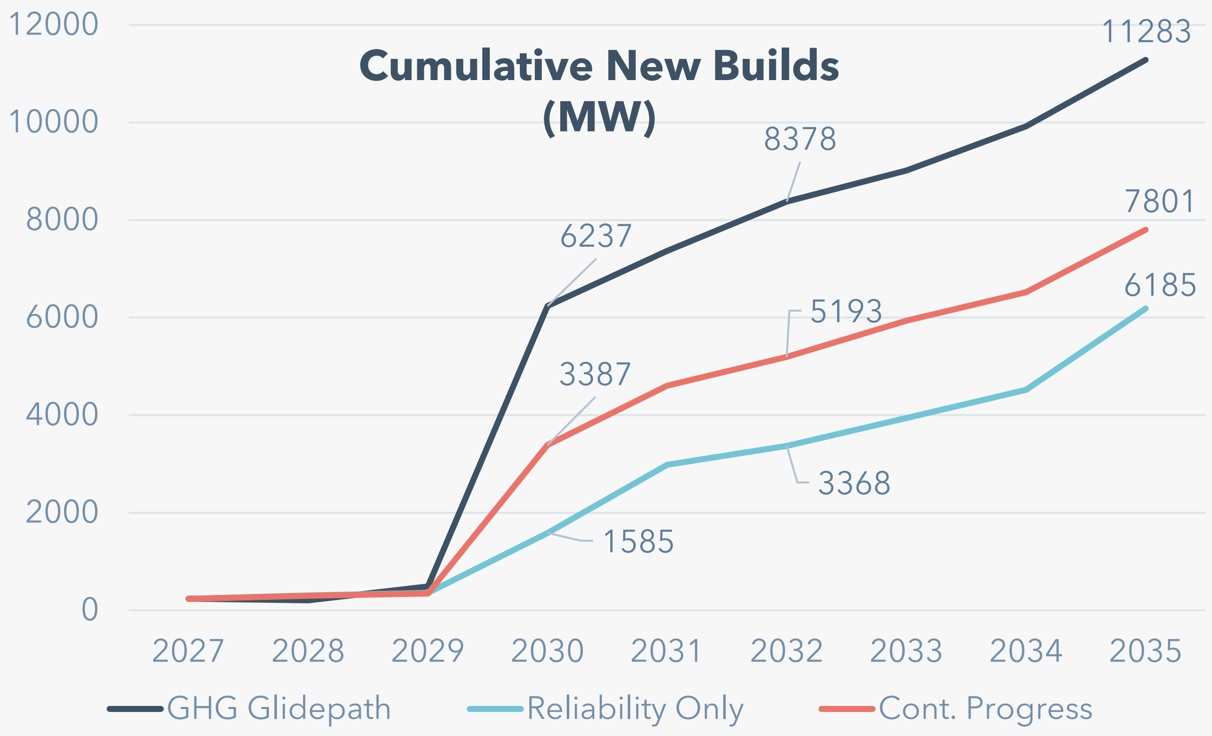
- Corporate Load Forecast
- BPA Study
- 2040+ Capacity Needs Extrapolation

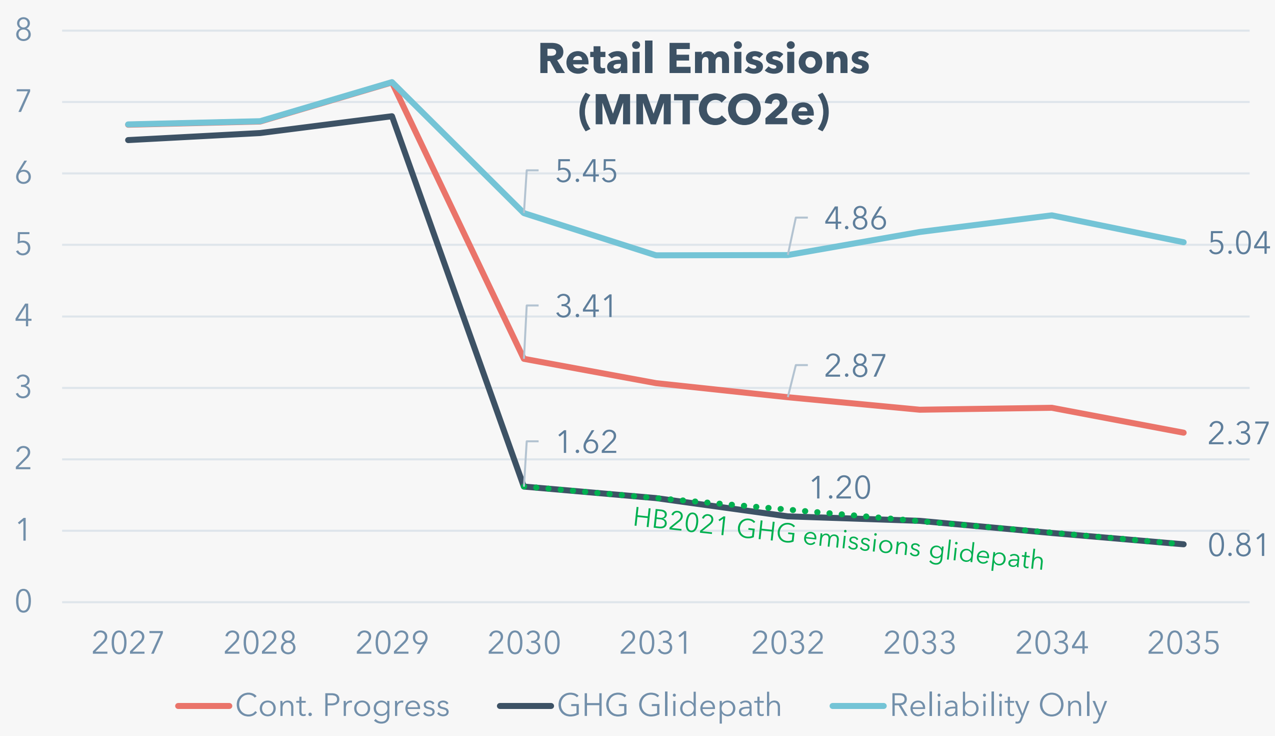
Core Growth Only	June Results 2030 MW	July Results 2030 MW	% Change
GHG	5647	4246	(25%)
Cont. Progress	3473	2854	(18%)
RO	1443	898	(38%)

Analysis of Updated Draft Results for Key Portfolios

New draft results for key portfolios

Portfolio	Description	Draft Result
GHG Glidepath	Thermal resources for retail load decline along linear glidepath	**6.2GW** needed by 2030 to meet reliability needs and add sufficient renewables to achieve **80%** emissions reduction from Baseline
Reliability Only	Minimal incremental generation needed to meet reliability and RPS, no GHG constraints	**1.6GW** needed by 2030 to meet reliability needs, achieves **33%** reduction in emissions from Baseline
Continued Progress	Limits expenditures on renewable resources to 6% above that of RO portfolio	**3.4GW** needed by 2030 for reliability needs and continued decarbonization, limited to 6% above RO portfolio spend. Achieves **58%** emissions reduction





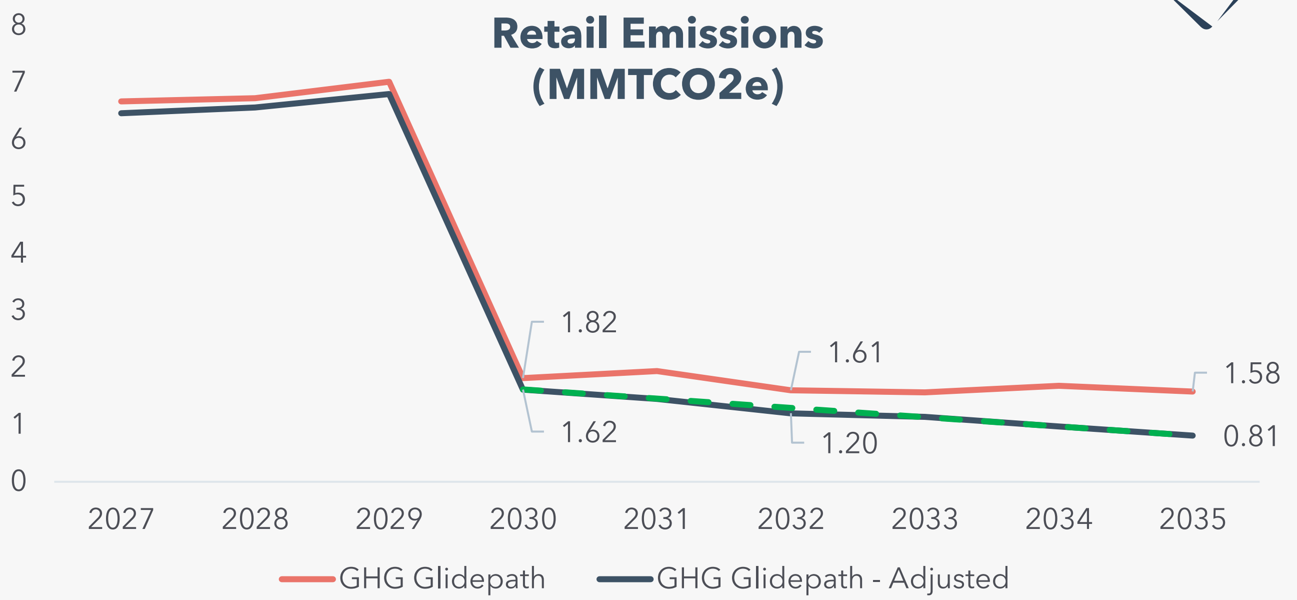
Achieving emissions reductions targets in GHG Glidepath

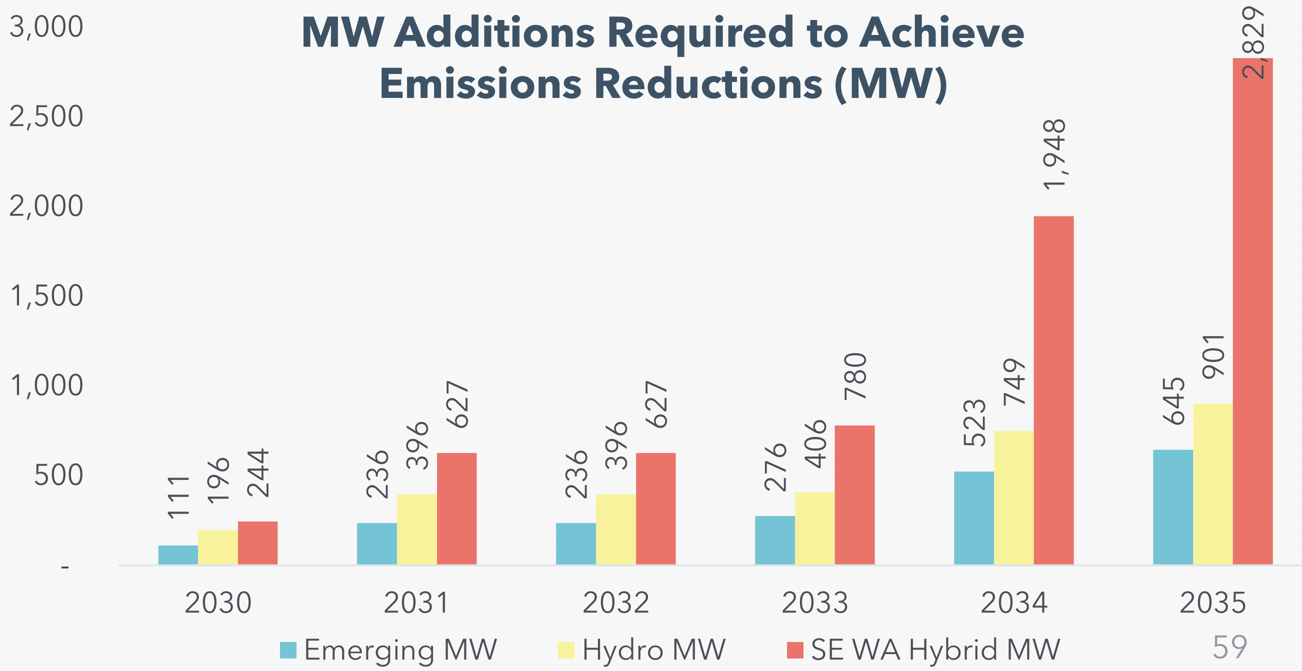
ADJUSTMENT PROCESS

- PGE's capacity expansion model, **ROSE-E**, makes resource addition decisions for energy need at a monthly granularity, which differs from the Commission's interest in hourly emissions analysis
- Alignment between resource generation and load at an hourly level is not guaranteed when using the capacity expansion model with monthly energy accounting
- If the first portfolio is not sufficient, iterate within Hourly Analysis tool (**new Aurora PZM**) to target remaining MW additions needed

RESULTS

- Initial ROSE-E results achieved majority of emissions reductions needed, but did not exactly meet the target in 2030, 2035 and 2040
- Iterative analysis concludes that an additional volume of non-emitting resources is needed in 2030 to achieve exact emissions reductions compliance with HB21
- Emissions targets were shown to be achievable using additional quantities of a variety of resource types, with emerging technology requiring the fewest additional MWs
- The volume of the emerging resource option will be added to the final GHG Glidepath portfolio

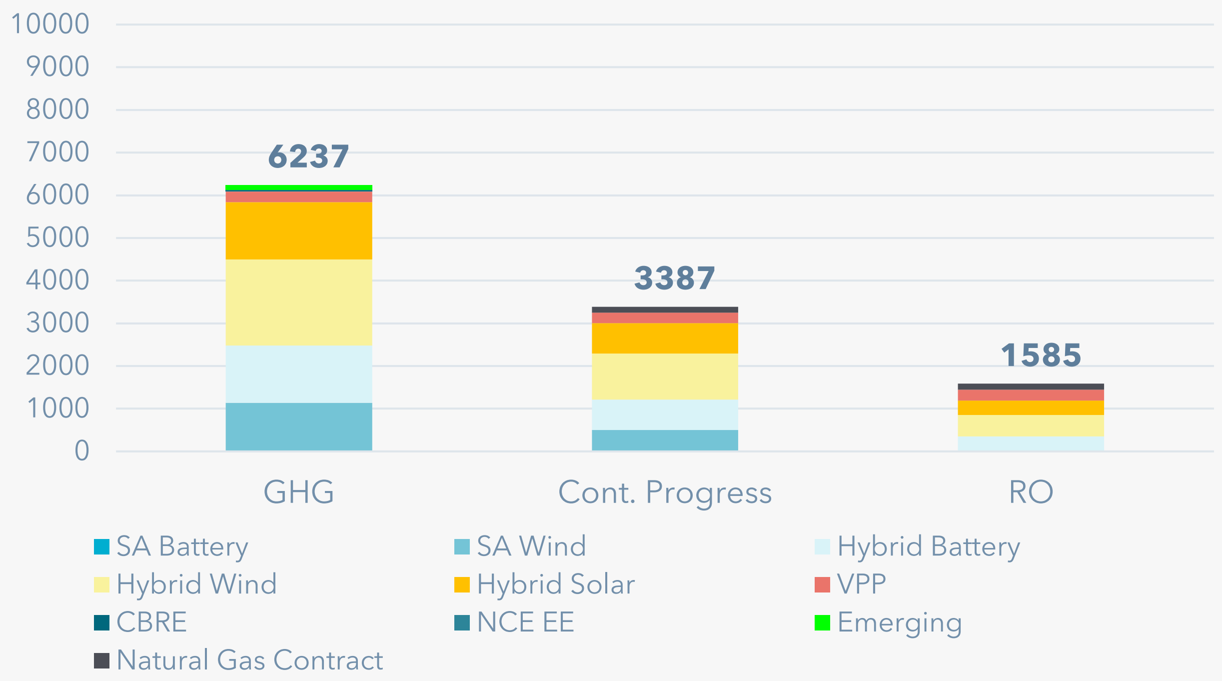




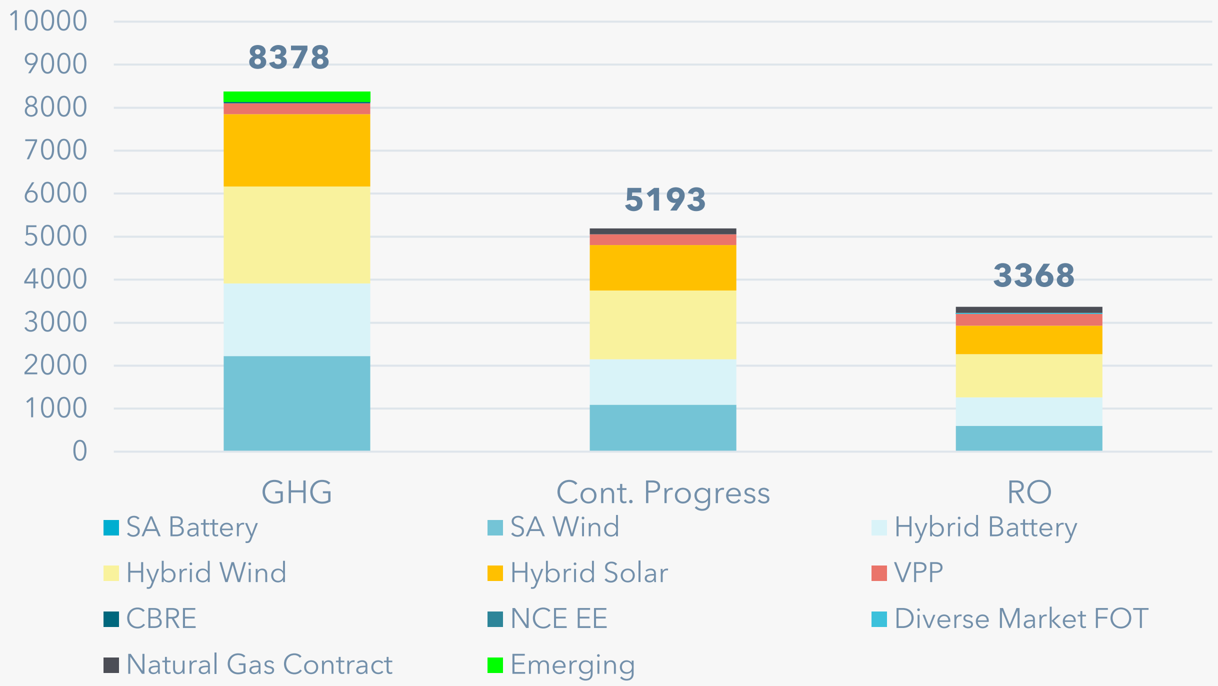
Summary of New Resource Buildout by Portfolio

- Overall structure of resource buildout remains consistent with results presented in June.
- Continue to see a significant volume of hybrid resources (wind/solar/storage) selected across all portfolios in the near-term. These resources maximize transmission utilization, which remains a critical need across the region.
- Through 2032, new results do not include stand-alone (SA) battery, higher reliance on standalone wind.
- In addition to significant renewable additions, GHG portfolios require use of emerging technology, which does not yet exist, to fully achieve HB21 emissions reduction targets.

2030 (MW)

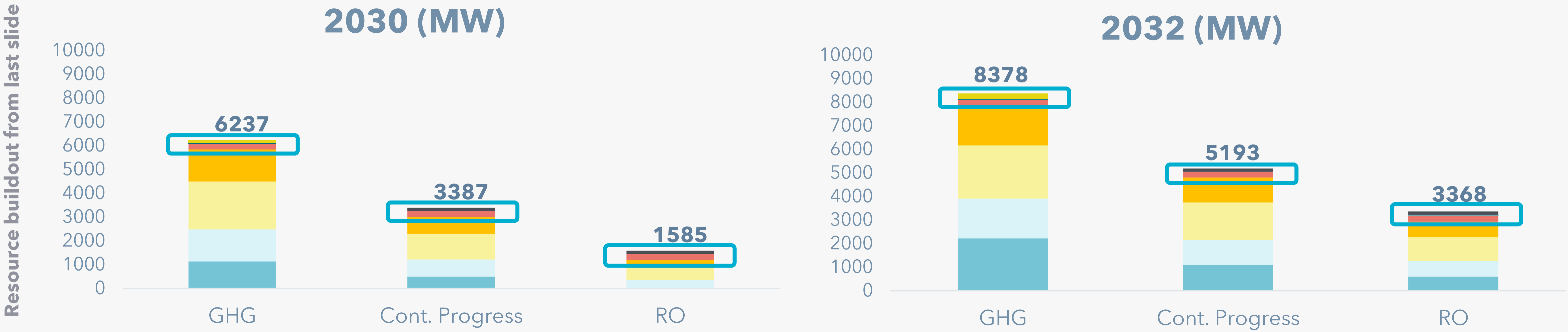


2032 (MW)

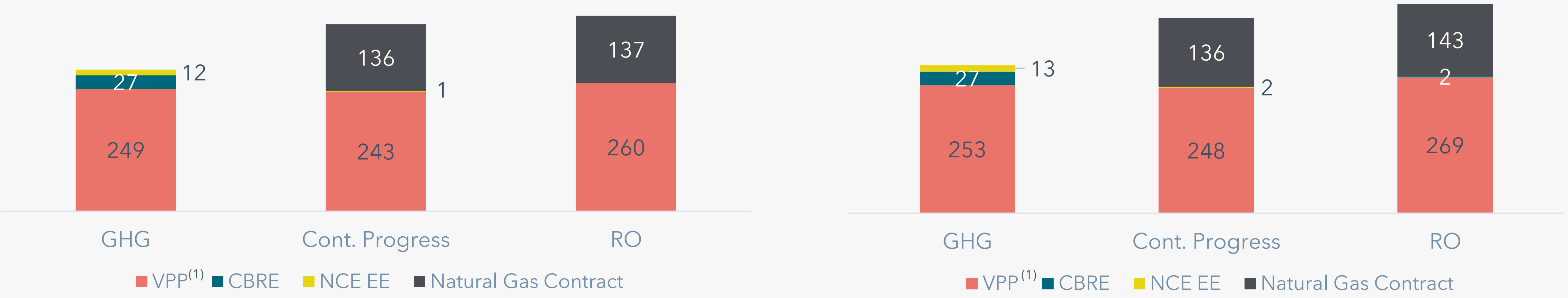


Non-emitting contract – Representative of a PPA contract for non-emitting MW
Diverse Market Front office transaction (FOT) – Representative of a bilateral contract for capacity with peer utilities

Closer look at Subset: VPP, CBRE, EE & Natural Gas



- **VPP** resources selected across all portfolios.
- **CBRE and NCE EE,** modest amounts selected in GHG compliant portfolios. Selection of CBREs reduced across portfolios given high resource costs and lower load forecasted for near-term.
- **Natural gas contract** continues to be selected when available, but not at the maximum amount (200MW).

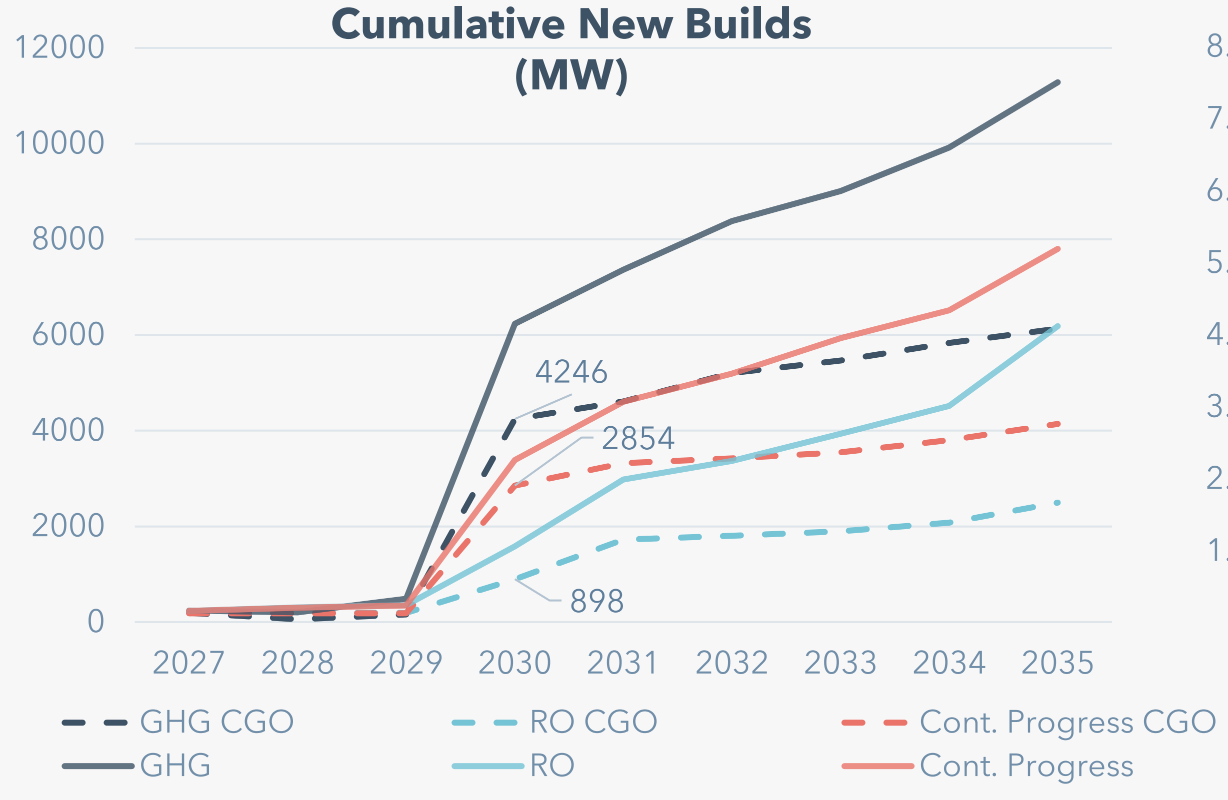


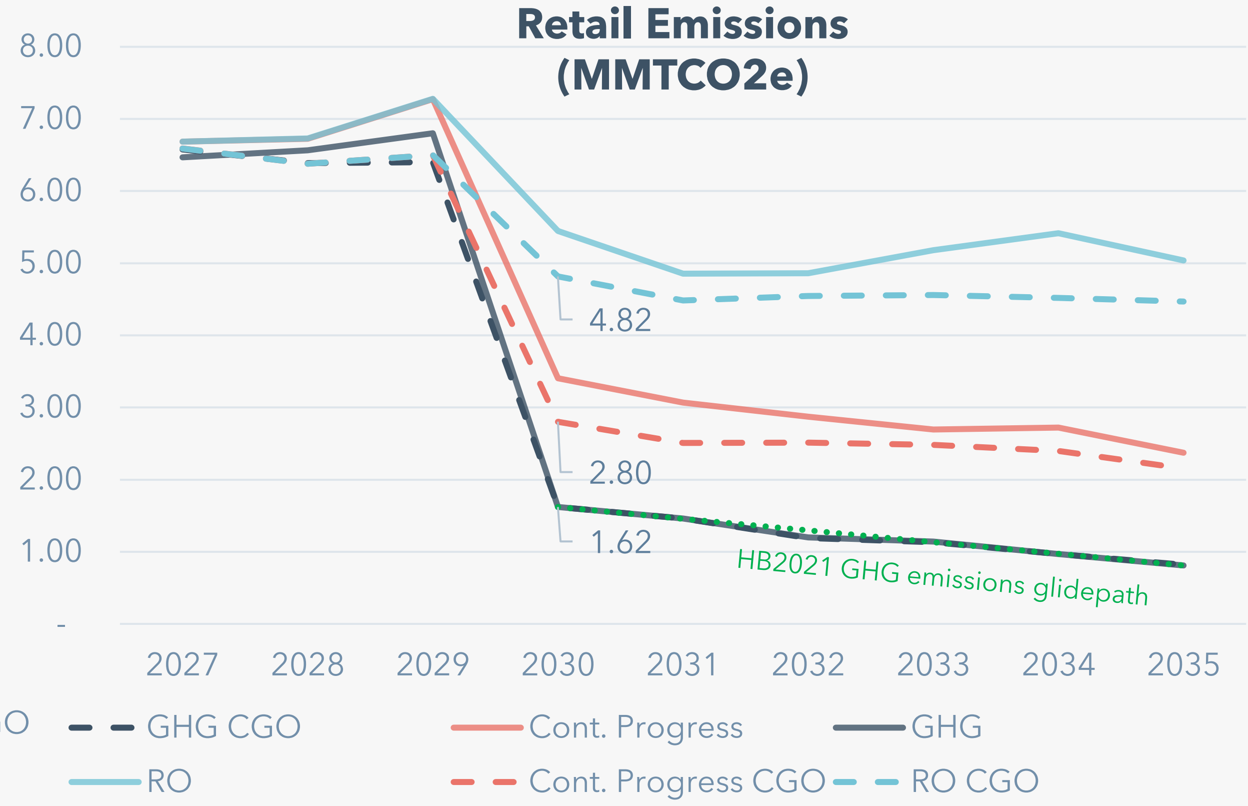
1) VPP totals include volumes associated with DSG and both summer and winter demand response program totals.

Draft results for remaining scenarios

Core Load Growth Only

- PGE has developed a **"core load growth only"** forecast. This forecast excludes growth associated with Schedule 96 customers, consistent with the definition of House Bill 3546.(1)
- Draft analysis indicates that **a substantial amount of renewable and storage resources are needed, for both core load growth only and all customer load growth**, in order to meet reliability needs and meet emission reduction targets.

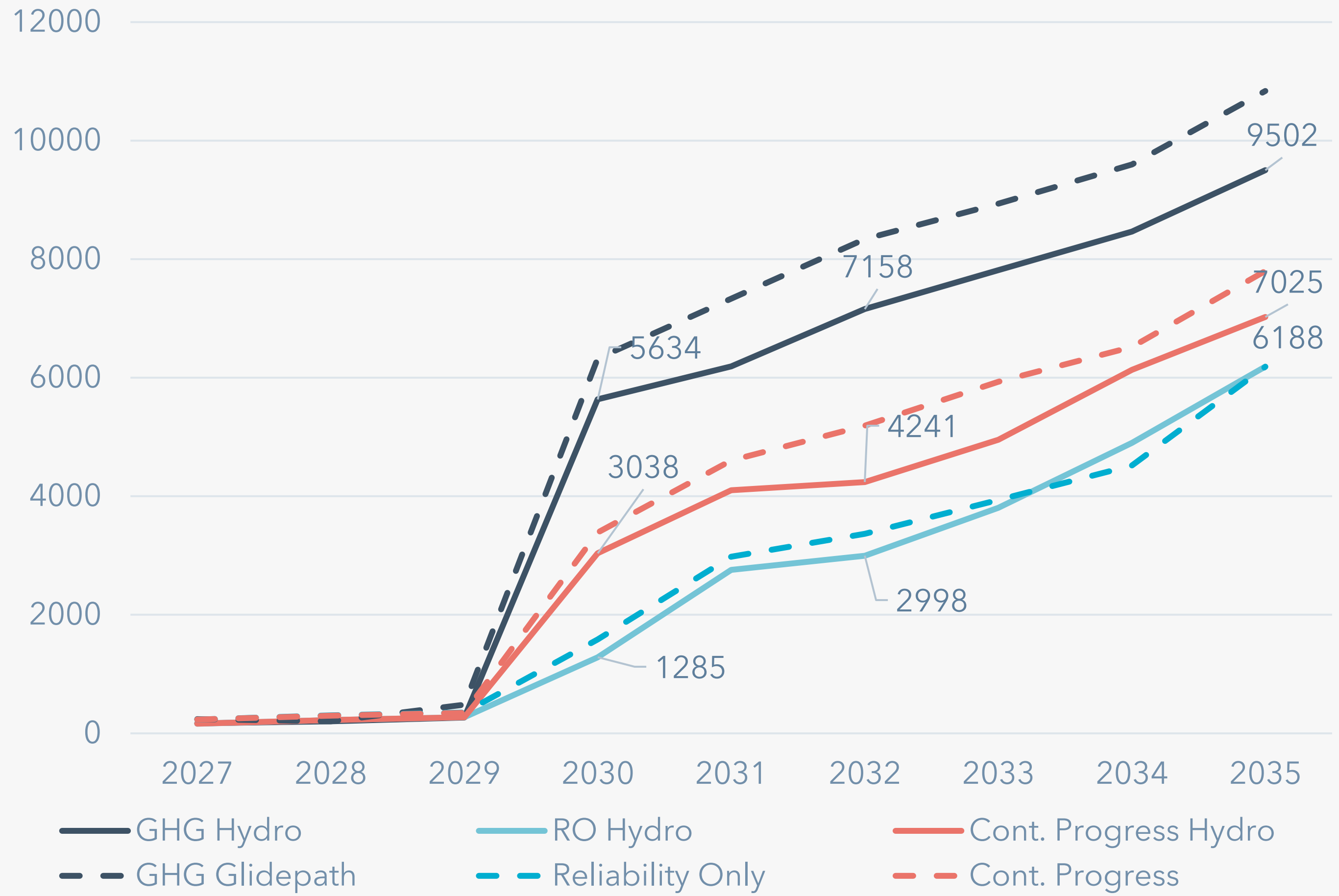




(1) Does not have access to Schedule 96 customer sited distributed standby generation (DSG) resources in VPP potential.

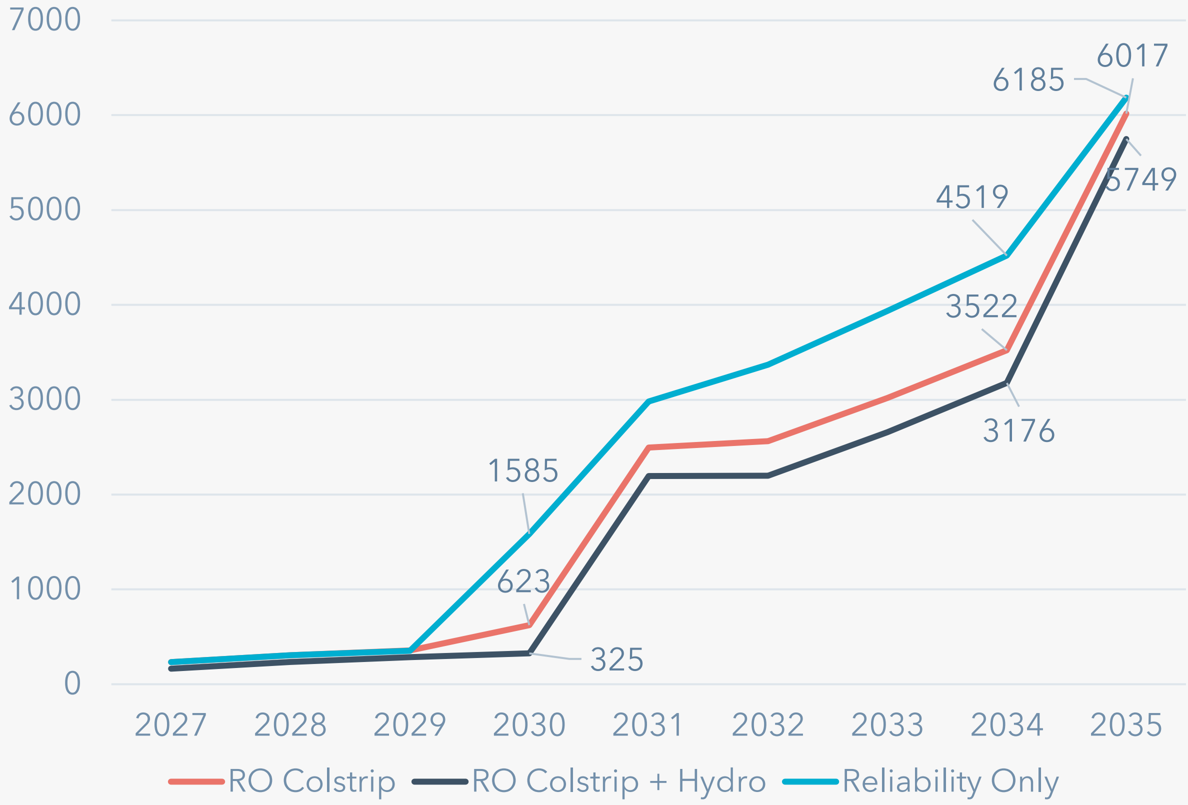
Hydro Contract

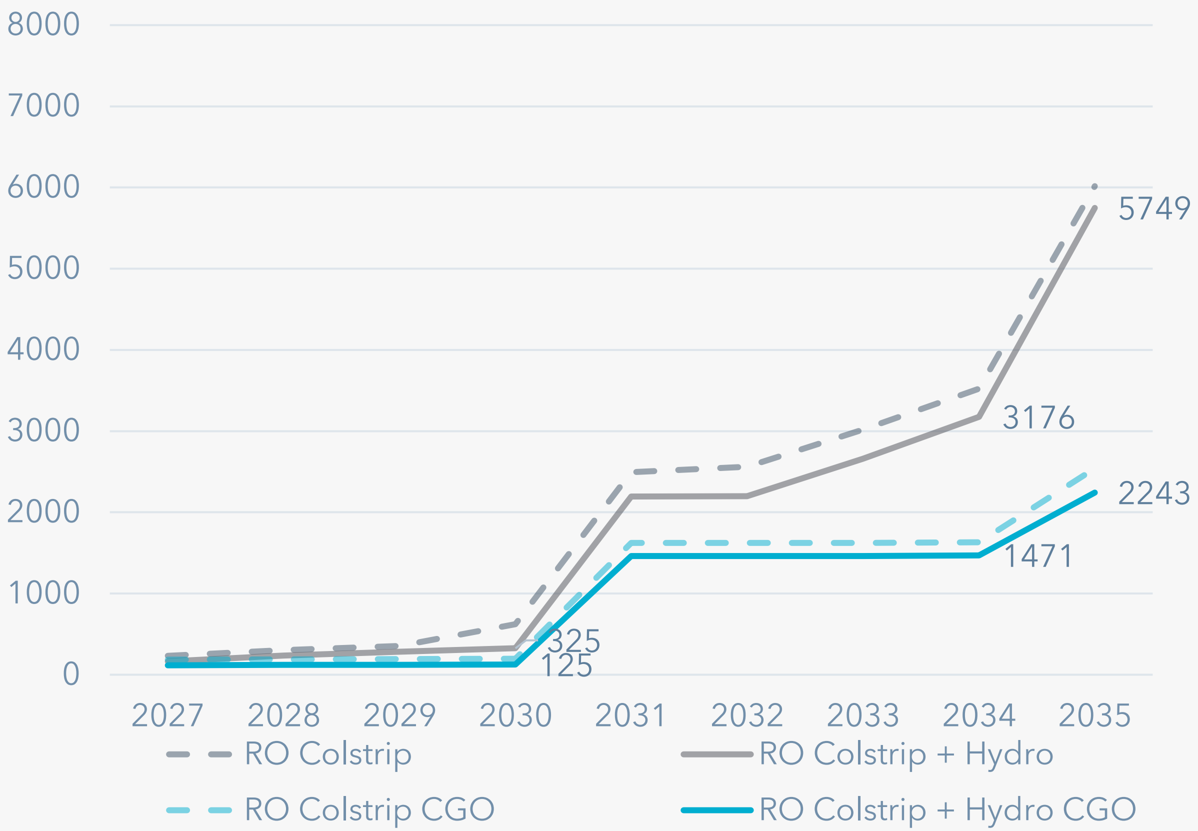
Hydro scenarios include 100 MW hydro contract in 2027 – 2029 and 200 MW contract from 2030 – 2046. Hydro inclusion reduces 2030 resource needs by **11%** under GHG scenario, **19%** under Reliability Only, and **10%** under the Continued Progress scenario.



Colstrip Scenario

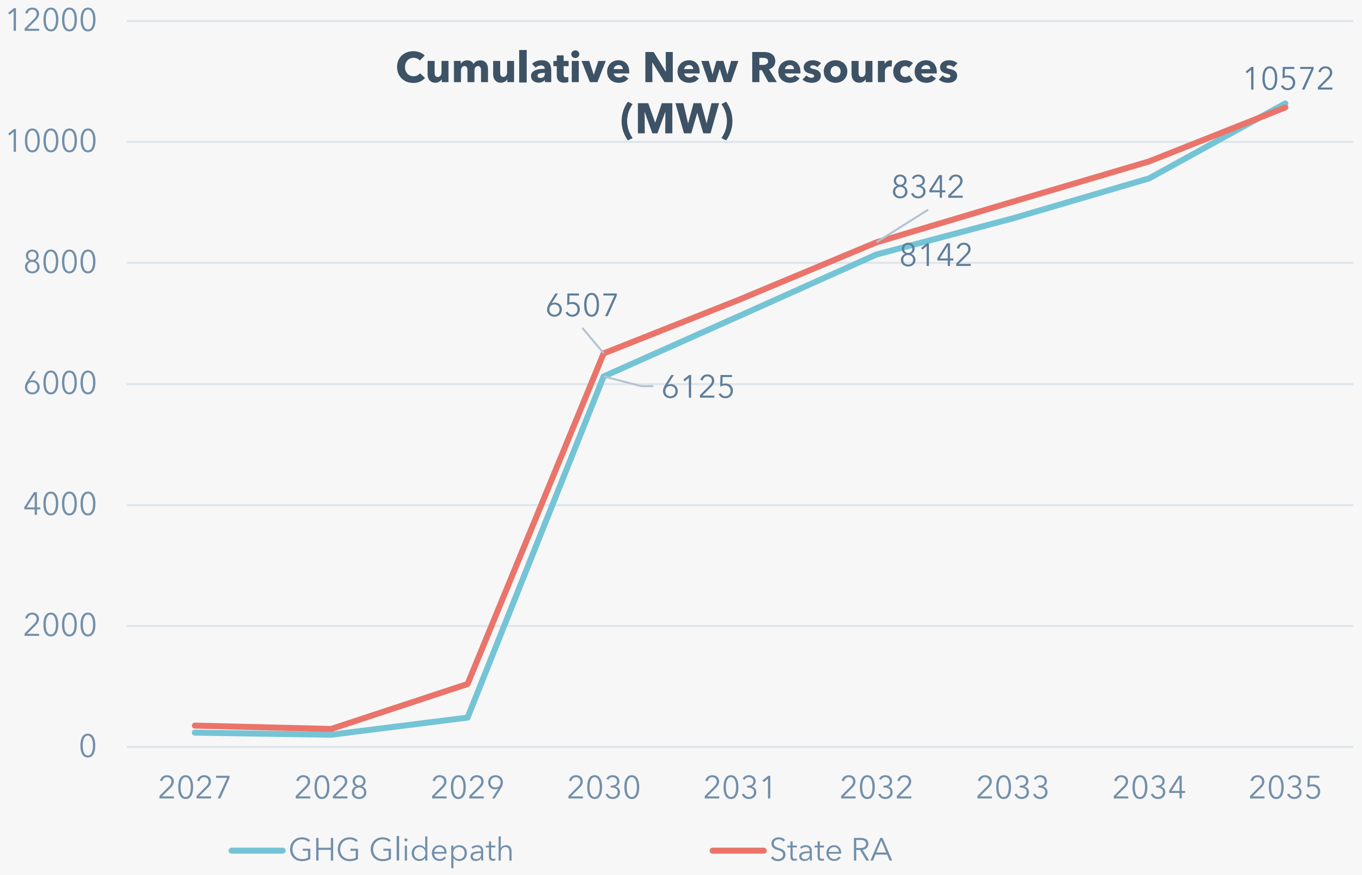
The Colstrip scenario reduces resource needs by an average of **29%** between 2030 and 2034 for Reliability Only scenario. Combined effect of Colstrip and hydro contract reduce need by an average of **41%.**





State Resource Adequacy Scenario

The State Resource Adequacy (RA) scenario uses alternative resource adequacy methods to estimate capacity needs and proxy resource ELCCs. The scenario shares all other assumptions with the GHG Glidepath scenario.



State RA portfolio resource additions are about 6% (382 MW) higher in 2030 in the than the GHG Glidepath portfolio.

Results suggest that resources needs are similar using either State RA or PGE IRP metrics.

* For a level comparison, post-ROSE-E resource additions for emissions achievement in GHG glidepath scenario are not included here.

Draft results for Transmission Expansion

Transmission Expansion Inputs: COD & MW Available

Transmission expansion and upgrades are a critical component for the creation of a reliable and HB 2021-compliant portfolio.

Transmission expansion allows for expanded access to diverse geographic locations and new resource development.

Some transmission options provide additional capacity through access to diverse markets.

COD

2032 | 2033 | 2034 | 2035 | 2036

2032

Warm Springs Power Pathway (WSPP) - Circuit 1
(1,000 MW + winter capacity)
Cascade Renewables
(1,100 MW)
North Plains Connector
*(270/600 MW + summer and winter capacity)***
Blueprint
(600 MW + winter capacity)

2034

Trojan-Harborton
(545 MW)

2035

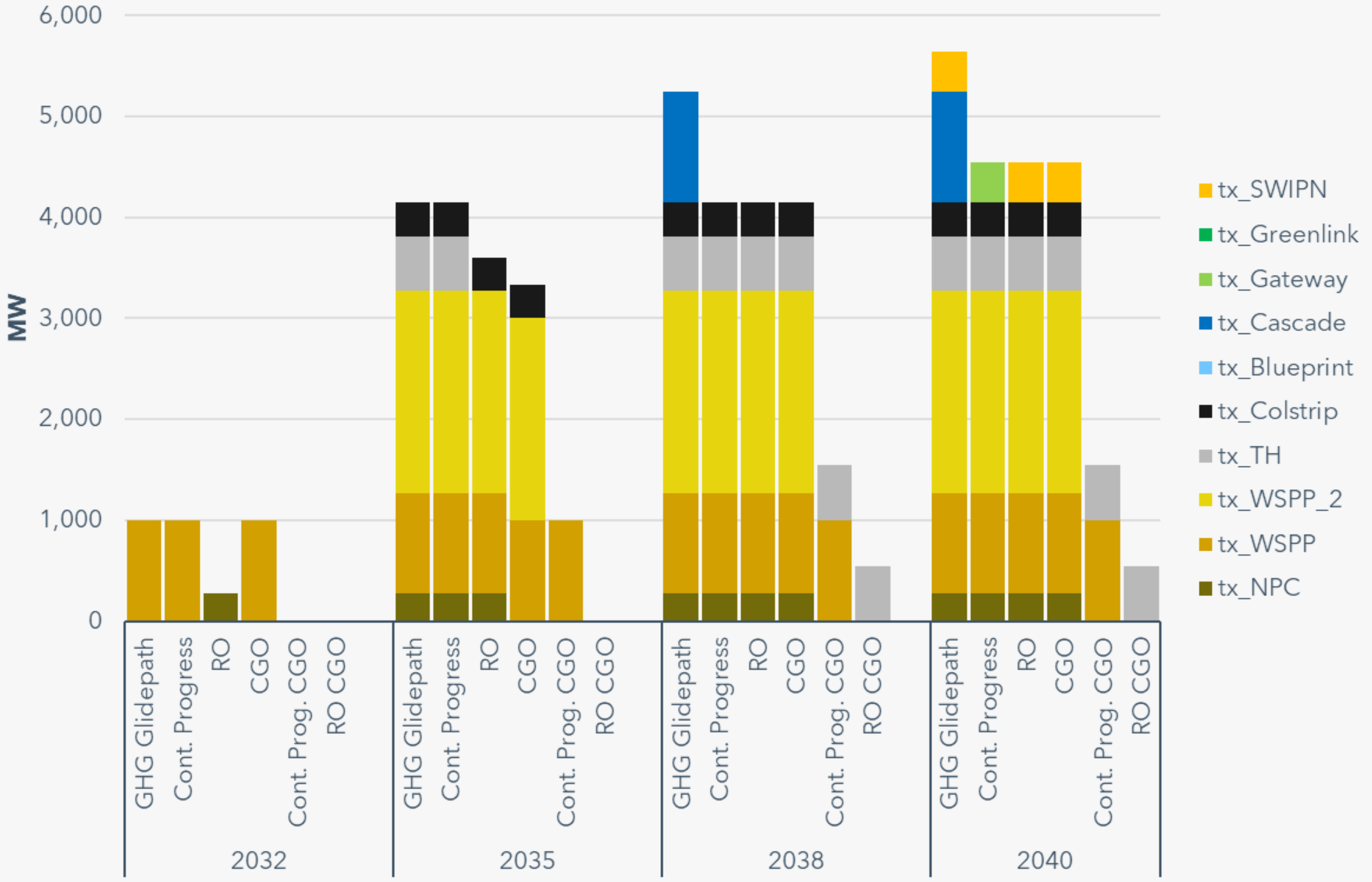
WSPP – Circuit 2
(2,000 MW + winter capacity)
Colstrip to Ashe Upgrade
*(330/600 MW + summer and winter capacity)***
Greenlink
(490 MW)

2036

SWIP North & B2H
(400 MW + winter capacity)
Gateway West & B2H
(400 MW)

**PGE will not have enough firm transmission rights to use all 600MW of North Plains Connector capacity until the Colstrip to Ashe Upgrade. We are modeling NPC as 270MW with PGE's existing rights and Colstrip to Ashe as 330MW.

Transmission Expansion Results
Select Scenario Comparisons



RO – Reliability Only
CGO – Core Growth Only

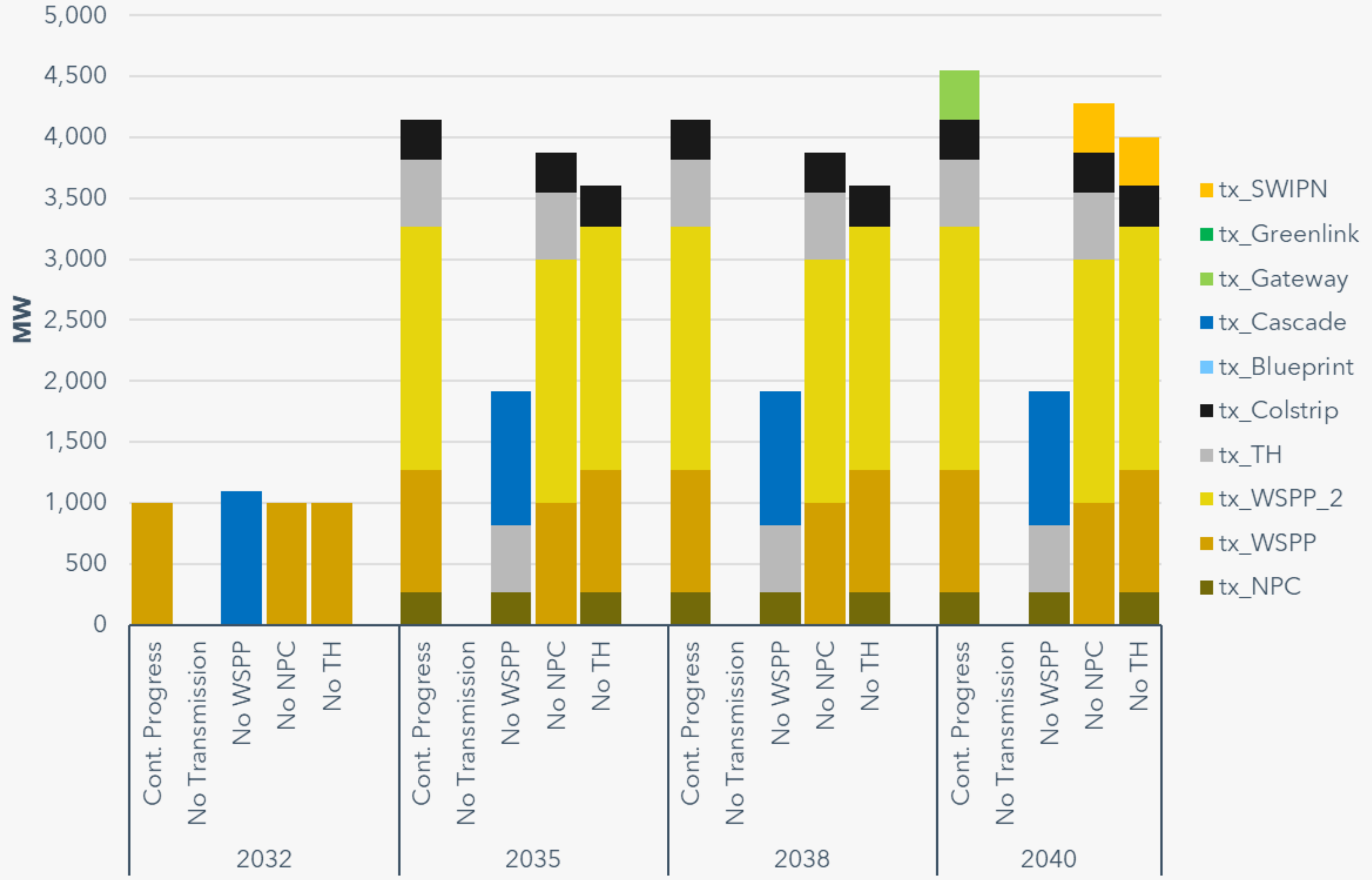
Key Takeaways

- All reference load scenarios, regardless of policy assumptions, are adding transmission to meet growing needs over time
- **NPC** selected by 2035 in critical portfolios, displayed at left
- **WSPP Circuit 1** selected in most scenarios by 2035
- **WSPP Circuit 2** selected in most scenarios by 2038
- **Trojan Harborton (TH)** selected in all scenarios by 2038. Assumes Trojan scheduling point

Note: Analysis does not include specific project cost estimates – all transmission cost relies on generic cost estimates

Transmission Sensitivities – Tx Additions

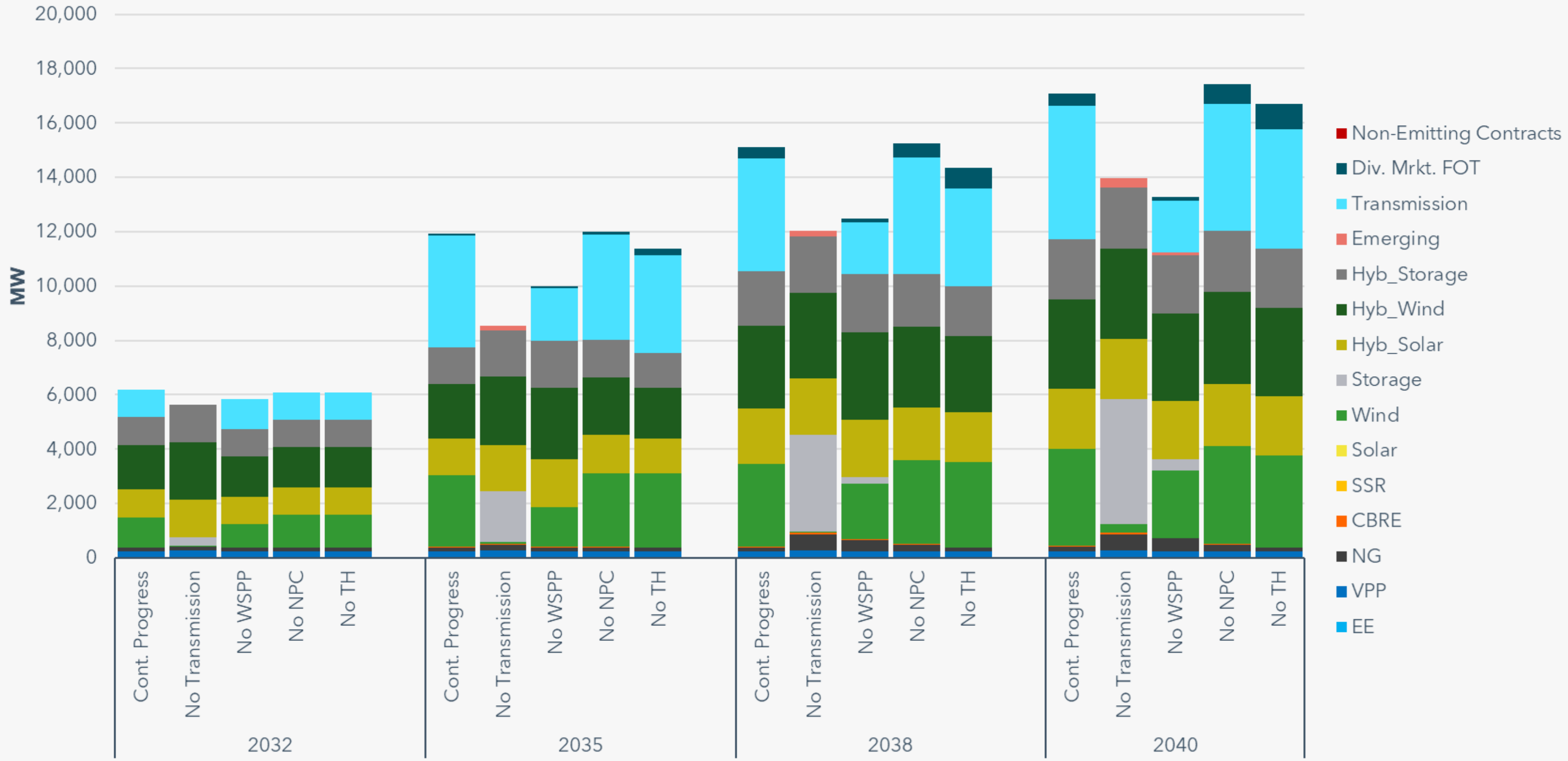
Transmission scenarios test the sensitivity of portfolio outcomes to changes in availability in select transmission options. Transmission scenarios share other assumptions with the Continued Progress scenario.



When transmission options are limited, the model substitutes other Tx options when available and non-Tx resources (standalone storage and Emerging).

Multiple Tx options are dependent on WSPP (Colstrip, Blueprint, Greenlink, SWIPN, Gateway) so 'No WSPP' scenario results in substantially less Tx availability.

Transmission Sensitivities – New Resource Additions



When Tx options are limited, non-Tx resources like standalone storage and Emerging increase.

Increased reliance on these resources results in more expensive portfolios.

Summary and Guided Feedback

Summary: Results have been updated to reflect the latest vintage of PGE's corporate load forecast, which has resulted in decreased volumes of resource additions.

Content: What questions do you have about the IRP draft results?

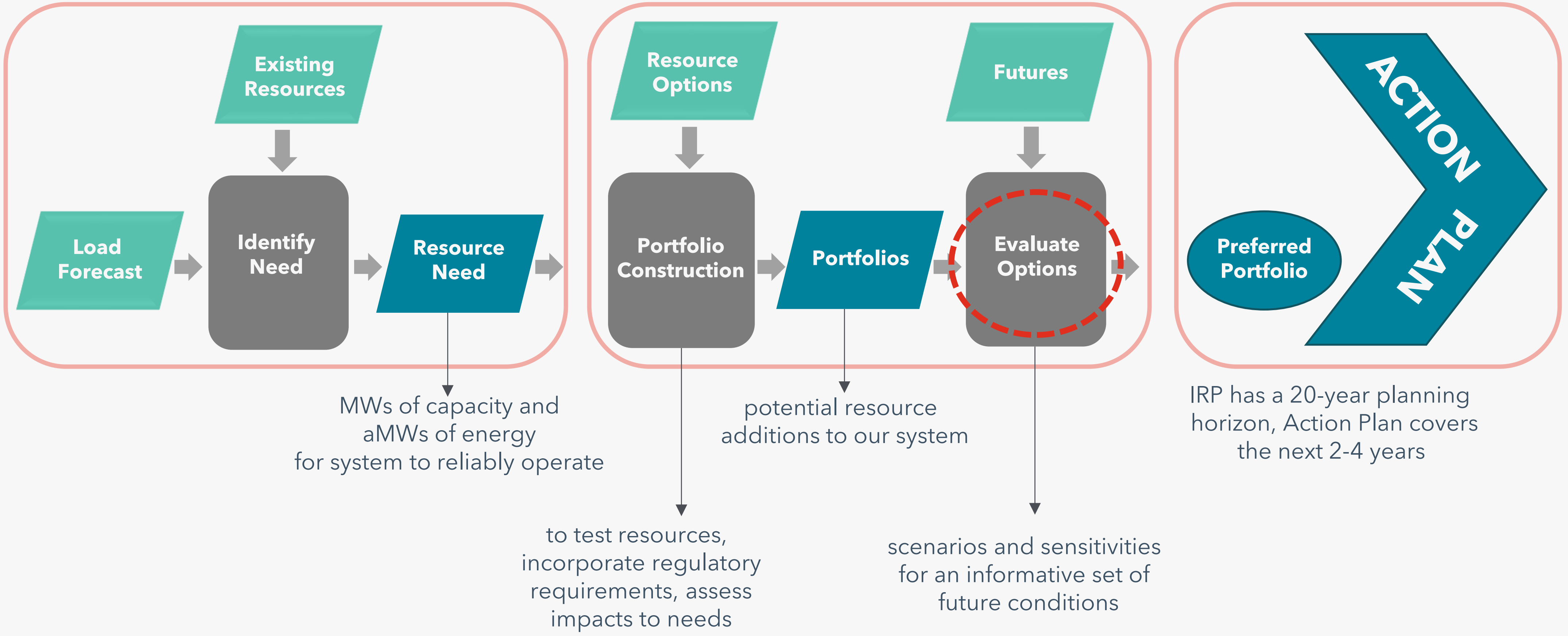
Draft Portfolio Resource Adequacy Assessment

Devin Mounts

PGE An Oregon kind of energy.SM

High-Level IRP Analysis Process

Estimate System Needs   Evaluate Resource Options   Develop Plan



Contents

1. Introducing Exogenous vs. Endogenous Resource Adequacy (RA) Modeling
    - ELCCs and resource interactive effects in ROSE-E vs. Sequoia

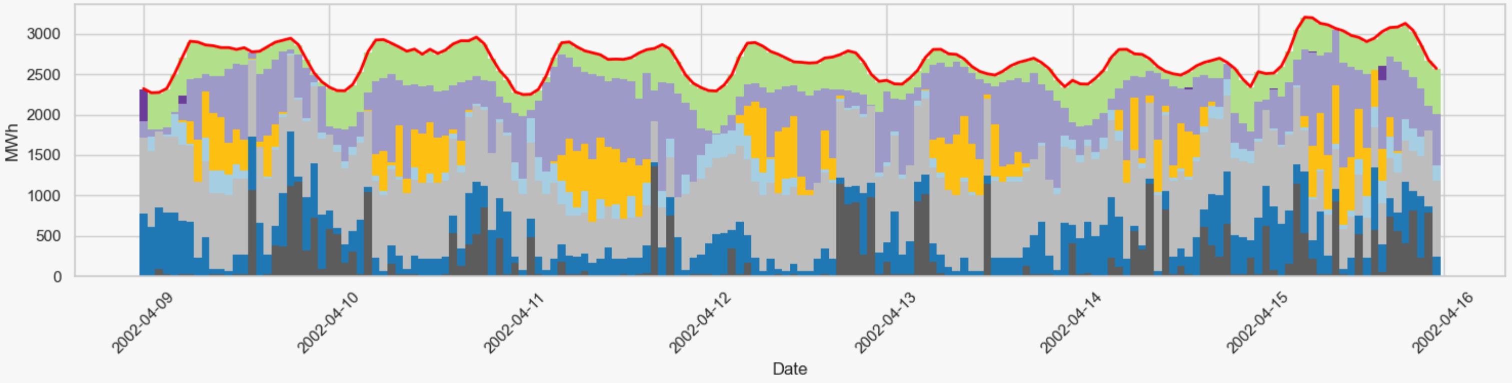
2. ROSE-E **portfolios meet capacity need** requirements

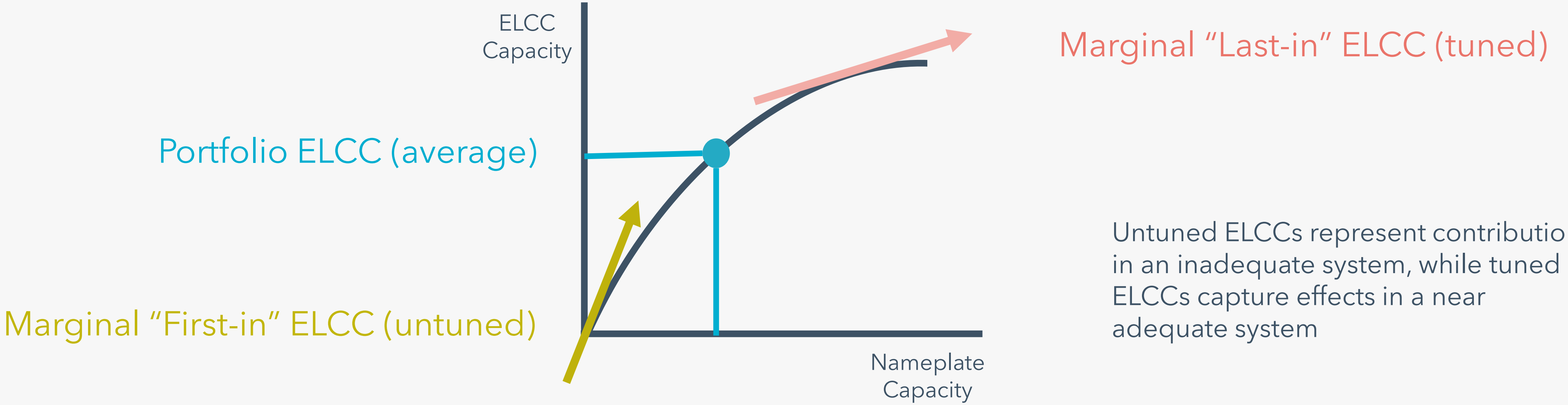
3. Sequoia RA assessment confirms **key portfolios are resource adequate through 2032**
    - Diminishing reliability benefits with increased decarbonization:
        - Continued Progress portfolio 3.5x more adequate than industry standard, while GHG 4x
    - Remaining capacity need in latter years confirms antagonistic interactive effects in resource portfolios

ELCC Primer

Loss of Load Probability modeling endogenously captures energy and capacity interactions. Effective Load Carrying Capability (ELCC) is a measure of marginal change that intrinsically varies with respect to resources in a portfolio

Illustrative Hourly Dispatch in Sequoia – Endogenous Interactions





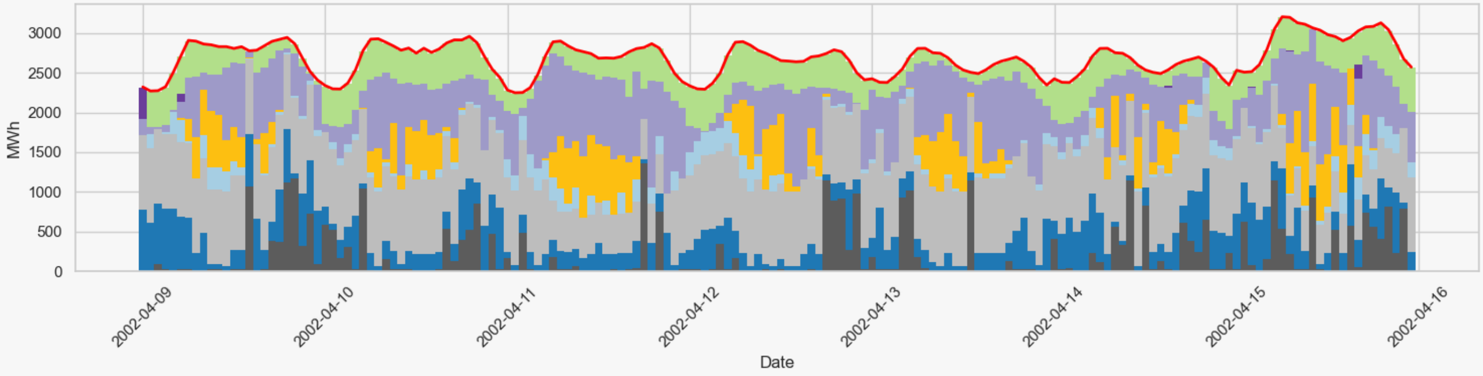
Untuned ELCCs represent contributions in an inadequate system, while tuned ELCCs capture effects in a near adequate system

Portfolio Resource Adequacy Assessment – Review

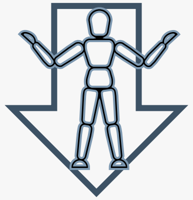
Hourly dispatch in Sequoia *results in seasonal inputs* for portfolio expansion in ROSE-E: *Capacity Need and ELCCs.* To determine adequacy of portfolios this process is inverted.

Illustrative Hourly Dispatch in Sequoia – Endogenous Interactions

1. *Hourly dispatch captures energy and capacity interactions across resources in the system*

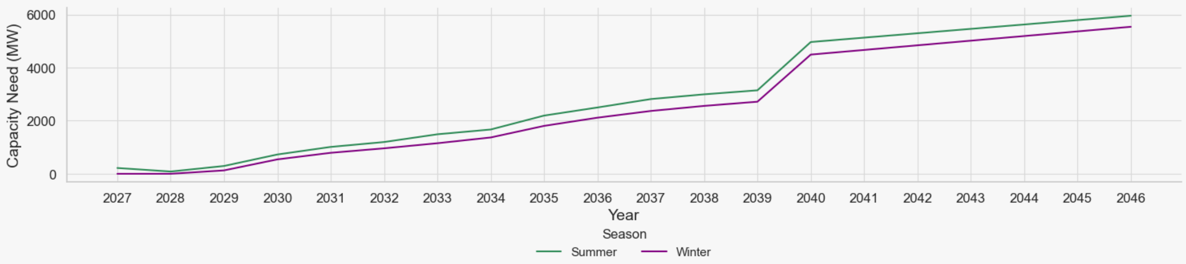


"Flattening" the modeled space from hourly to seasonal makes portfolio optimization computationally tractable

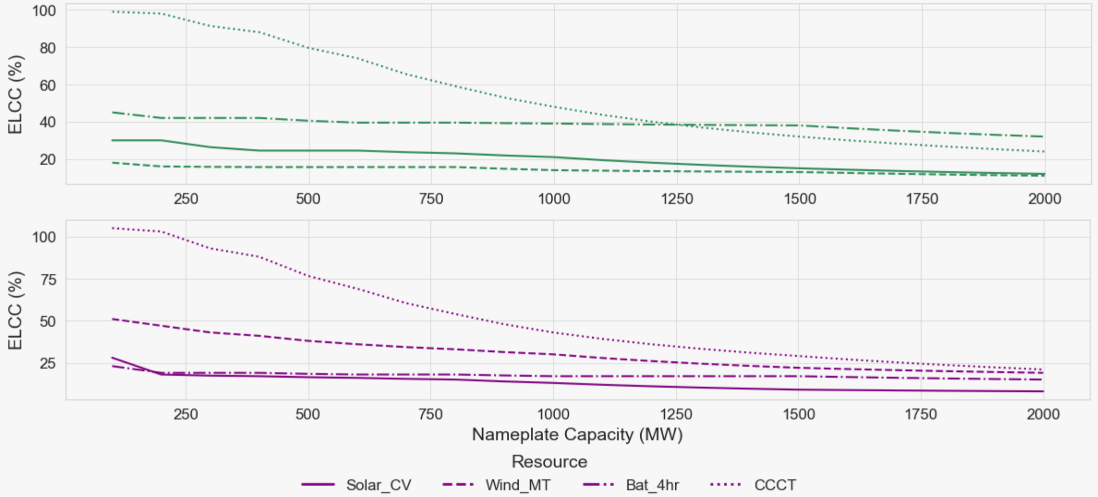


2. *ELCC curves estimate marginal effects of resource specific additions, and do not capture interactions across resources*

Seasonal Capacity Need



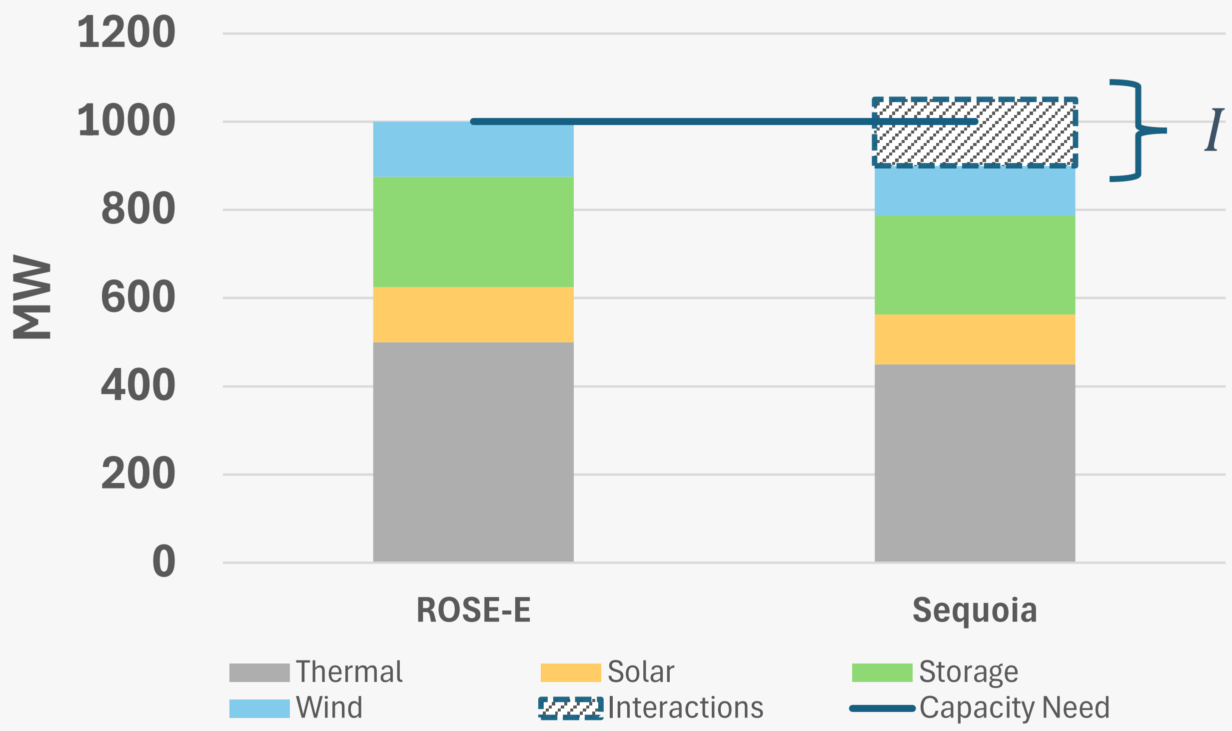
Seasonal ELCC



Portfolio Resource Adequacy Assessment – Why?

ROSE-E constructs portfolios that meet Capacity Need given marginal ELCCs. Marginal ELCCs do not capture energy and capacity interactions in the system

Illustrative Capacity Need Constraint Comparison



*There are infinite number of permutations and combinations of resource interactive effects. **ROSE-E's exogenous** ELCC estimates will always approximate a resource's capacity contribution, whereas **Sequoia** captures interactive effects **endogenously**.*

ROSE-E solves its capacity constraint with a linear equation. Capacity need (C) is met by the sum of nameplate additions multiplied by their ELCC:

$$C_{need} = \sum_{\{r \in R\}} Nameplate_r \cdot ELCC_r$$

ELCCs measure marginal effects of resource additions. However, capacity need in Sequoia captures complementary and antagonistic interactive effects (I) within a portfolio of resources:

$$C_{need} = \sum_{\{r \in R\}} Nameplate_r \cdot ELCC_r + I$$

Complementary Interaction Example:
Solar + Storage

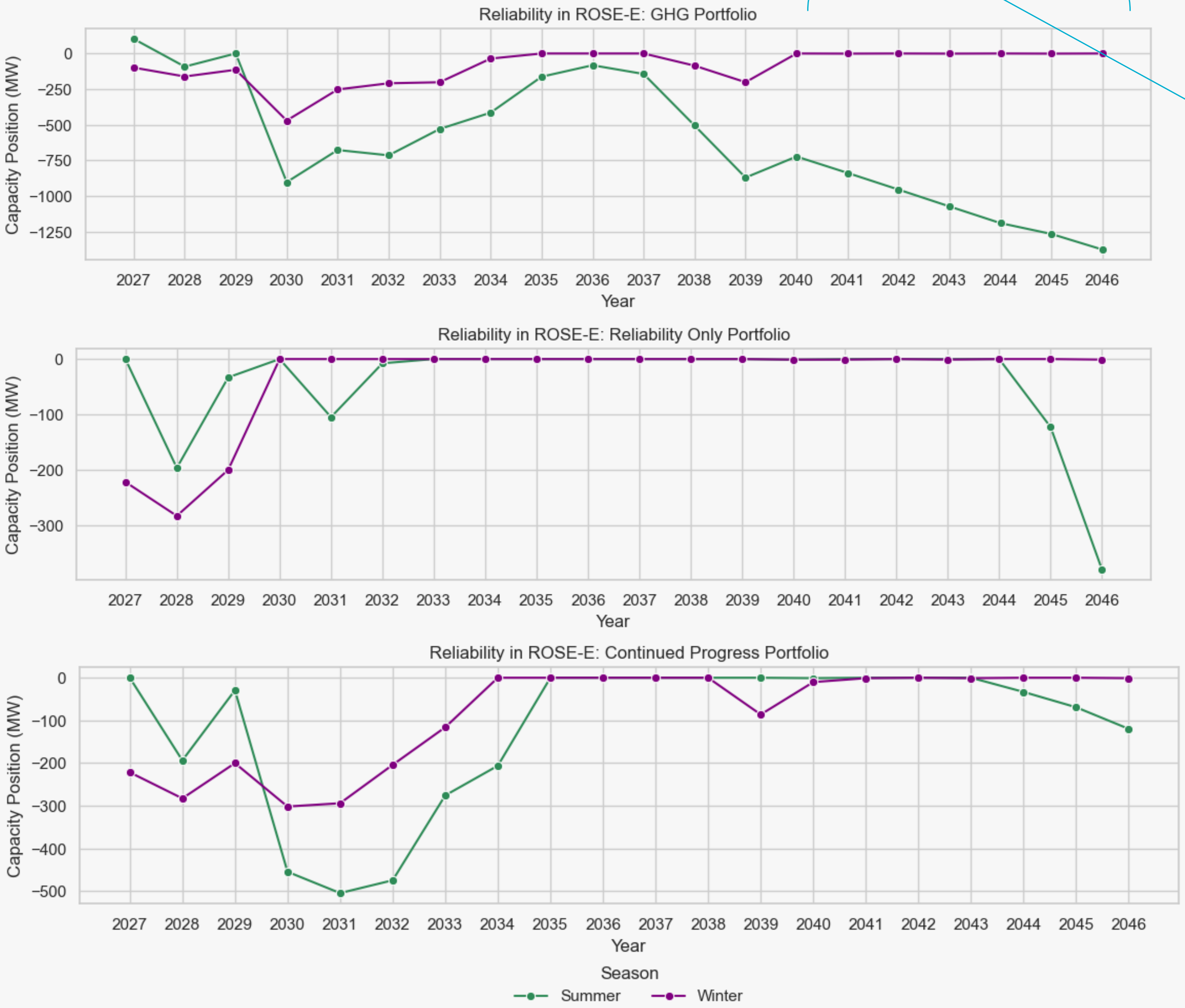
Antagonistic Interaction Example:
Solar Region 1 + Solar Region 2

Portfolio RA Assessment – Draft ROSE-E Results

Recreating ROSE-E's capacity need constraint confirms portfolios are built to be reliable.

GHG is consistently long on capacity due to emissions constraints driving increased quantities of resource buildout

Reliability Only and Continued Progress Portfolios built to meet winter constraints in most years



Position equals Capacity Need minus Portfolio ELCC

GHG Portfolio requires 4.8 GW of storage and 300 MW of non-emitting firm technology from 2040-2046 to achieve winter adequacy

**Negative values indicate capacity length*

Portfolio RA Assessment – Draft Sequoia Results

Simulating portfolio operations at an hourly granularity in Sequoia indicates that **key portfolios are resource adequate within the Action Plan window**. Results for latter years indicate antagonistic interactive effects across resources in a portfolio.

Portfolio Remaining Capacity Need – Sequoia Estimates

	GHG		Reliability Only		Continued Progress	
Year	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
2030	0	0	0	0	0	0
2032	0	0	0	0	0	0
2035	0	56	227	0	30	97
2040	246	429	284	64	202	64

2\. *Adequacy in earlier years indicates 2032 is a representative year to derive near-term ELCCs*

1\. ***ELCC curves are simulated in year 2032 given forecast load shapes and supply portfolio***

3\. *Values are approximately equal to the antagonistic interactive effect, suggesting ~12% of effective capacity is lost due to interactive effects in Summer 2035 – Reliability Only. Inadequacies in latter years indicates antagonistic resource interactive effects increase at higher penetrations.*

Portfolio RA Assessment – Draft Sequoia Results

Resource additions in decarbonized portfolios demonstrate diminishing marginal reliability benefits

Loss of Load Expectation – Estimated Event Frequency (years)

	GHG		Reliability Only		Continued Progress	
Year	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
2030	-	-	10	10	-	250
2032	-	53	11	13	-	45
2035	20	6	2	67	8	5
2040	1	0	1	6	4	6

1 event-day in 10-years reliability standard: Event Frequency = 10.

1. *Reliability Only (RO) portfolio roughly equivalent to 1 event-day in 10-years reliability metric. Complementary interactions are observed in 2032.*

2. *Continued Progress portfolio 3.5x more reliable than RO portfolio*

3. *GHG portfolio 4x more reliable than RO portfolio*

Summary and Guided Feedback

Summary: Portfolio Buildouts are constructed to meet **reliability and are resource adequate within the Action Plan** window. Latter years in the planning horizon require increasing quantities of resources to meet resource adequacy due to antagonistic ELCC interactive effects.

Purpose: Portfolio Expansion methodologies meet reliability constraint and ELCC methodologies reasonably approximate resources interactions at levels of buildout forecast for the Action Plan period.

Backcast Review

Chris White

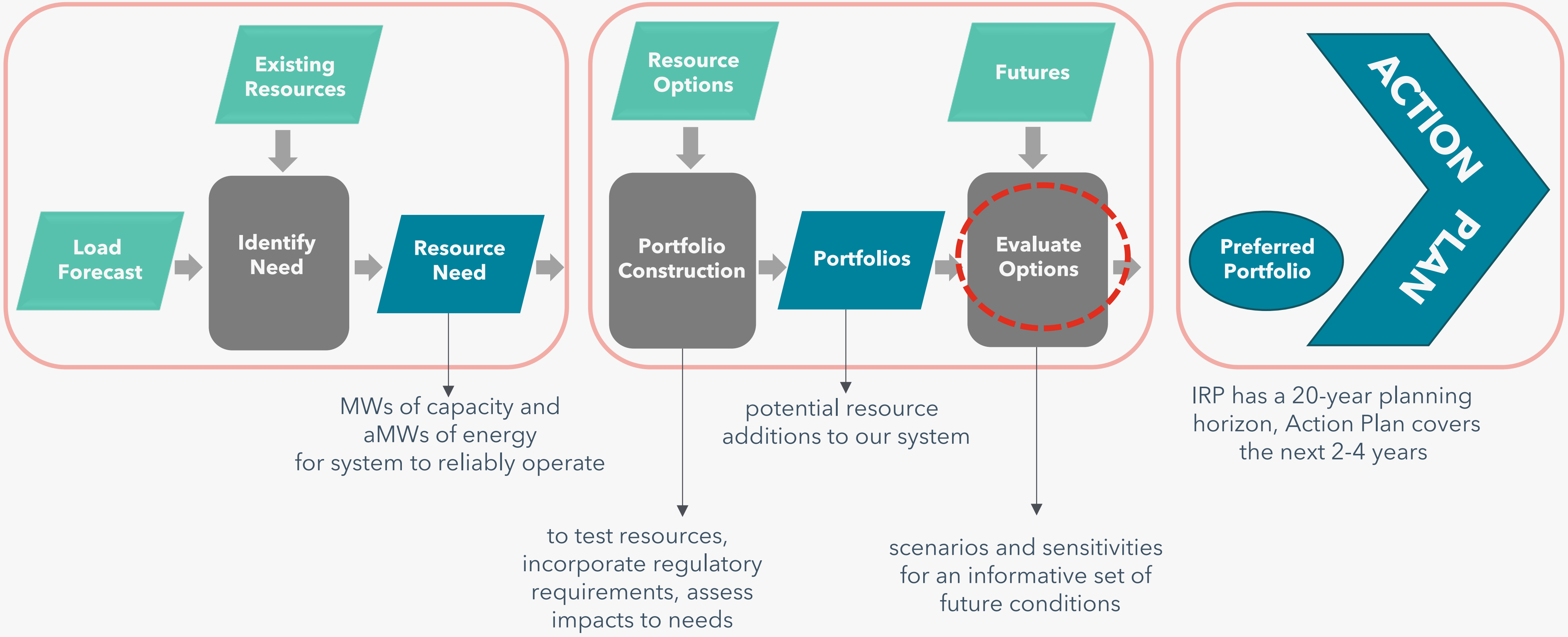
PGE An Oregon kind of energy.℠

High-Level IRP Analysis Process

Estimate System Needs

Evaluate Resource Options

Develop Plan



Outline

- Introduce IRP Backcast
- Discuss IRP Backcast Methodology
- Draft results for remaining scenarios
- Questions

IRP Backcast

Objective of IRP Backcast:

Utilizing the PZM, we replace forecasted hourly shapes with historical shapes from years 2021-2024 to test how the **2030 Reliability-Only (RO) Portfolio** can meet system load.

- Historical Shapes (*data sources)* used in the IRP Backcast analysis:
    - Wind *(2025 AUT, EIA-930)*
    - Solar *(NLR*)*
    - Hydro *(PGE historical generation data)*
    - Load *(PGE historical load data)*

Rationale for IRP Backcast:

Using historical weather-driven inputs (e.g., load, variable renewable energy, and hydro conditions) in IRP production cost modeling provides several important benefits:

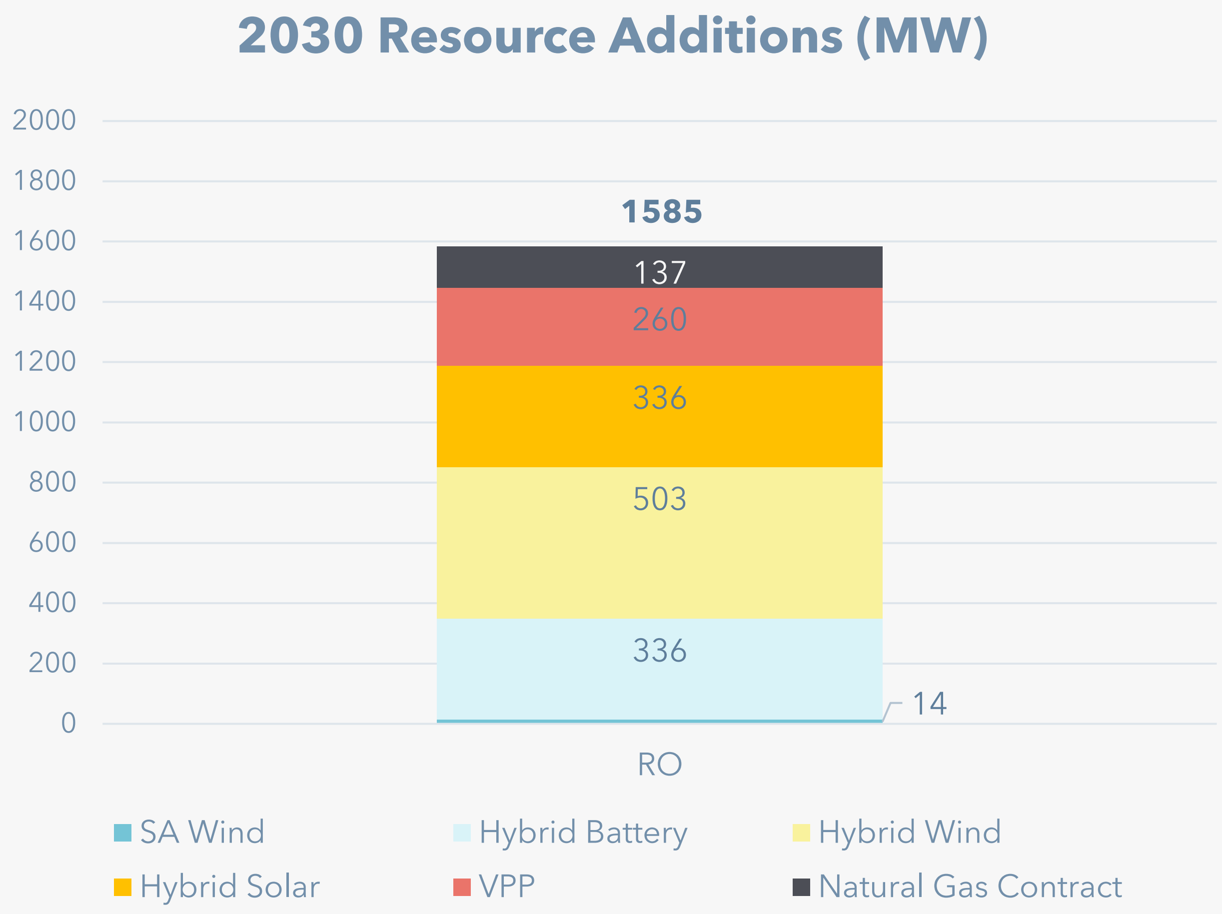
- Captures realistic weather variability by preserving the temporal relationships between electricity demand, wind generation, solar generation and hydro generation.
- Identifies portfolio robustness by revealing whether candidate resource portfolios perform consistently under different weather and hydrologic conditions.
- Supports evaluation of operational flexibility including the ability of storage and thermal resources to respond to changing system conditions.

*Formerly NREL

Reliability Only Portfolio – Draft 2030 Resource Additions

Portfolio Design: Minimal incremental generation needed to meet system reliability, regardless of GHG constraints.

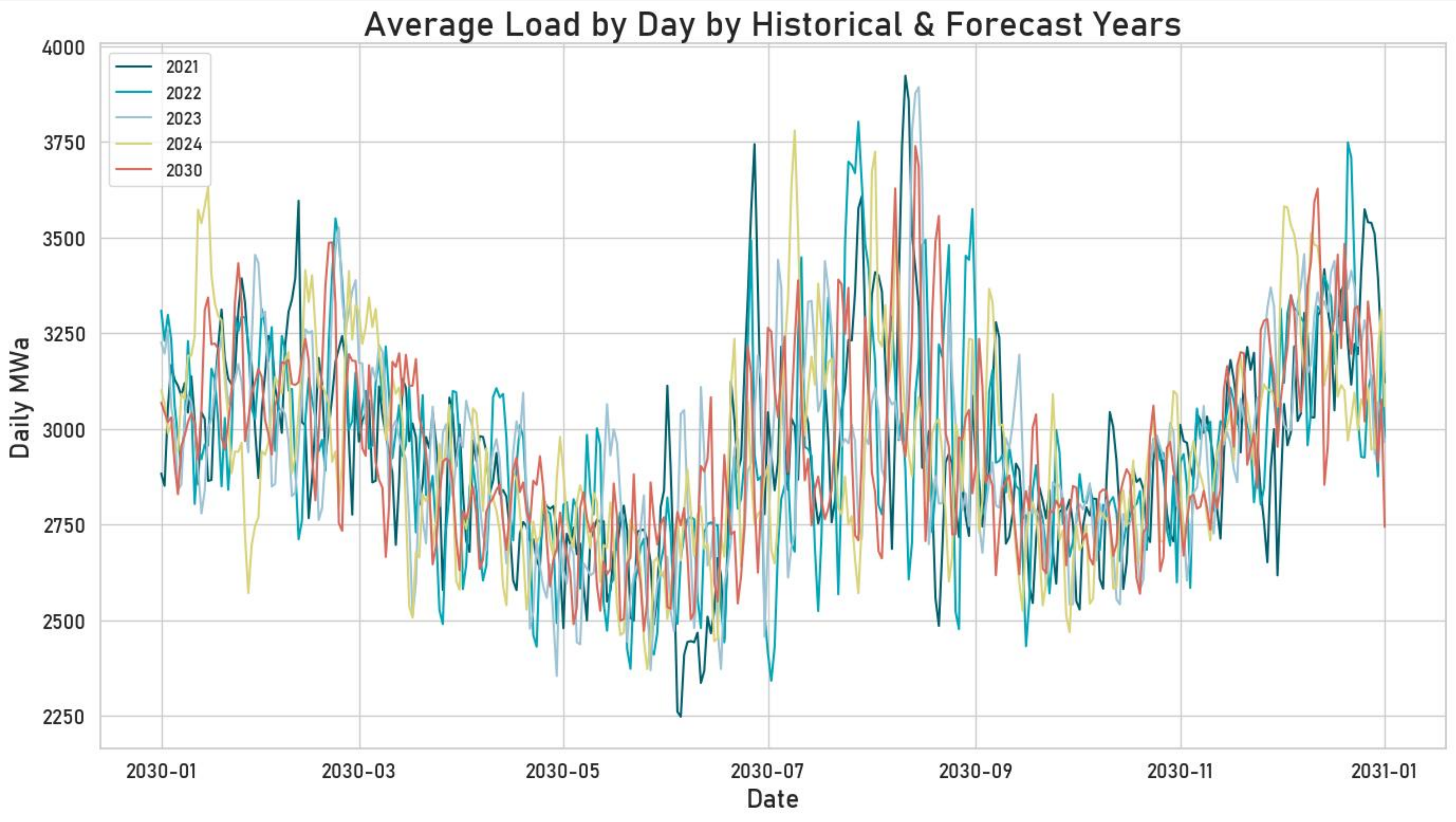
- Additional natural gas resources are available for selection, beyond the already existing natural gas resources currently owned by PGE.
- This additional natural gas represents limited potential for new contracts and does not represent new or expanded gas-fired power plants in the state, consistent with Oregon law.



IRP Backcast Methodology

Assumptions:

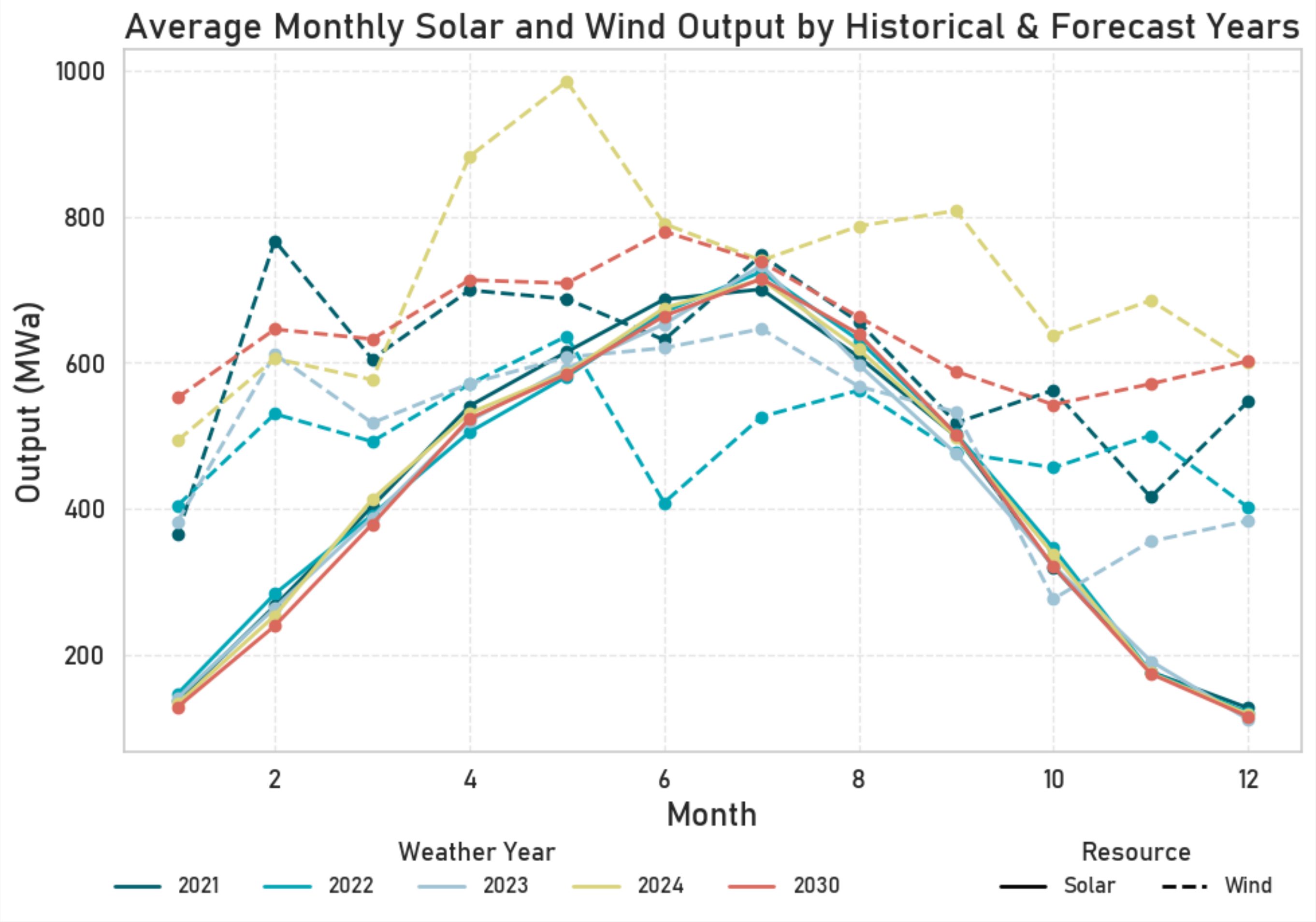
- No market access; unserved load assumed for hours with insufficient generation.
- Normalized hourly load shapes replaced with historical hourly load shapes.
- Load is updated to reflect the hourly shape, but the overall amount of load for any given month is the same across each model.
- **Finding: Forecasted 2030 shapes consistent with variation in historical values.**



IRP Backcast Methodology

Assumptions:

- Existing VER resources updated to historical normalized hourly shapes.
- Candidate VER resources updated to historical normalized hourly shapes that scale with portfolio capacity.
- Hydro resource generation replaced with aggregate hydro production according to actual observed hydro generation for each hour of that year.
- **Finding: Forecasted 2030 shapes consistent with variation in historical values.**



IRP Backcast Results

- 2023 is the most challenging year for the model to meet load due to low hydro and VER performance.
- 2024 is the least challenging year for the model to meet load to an expansion in the Columbia hydro contracts and higher wind generation.
- For forecasted year 2030, conditions appear similar to historical years suggesting model representation is not dissimilar from historical behavior.

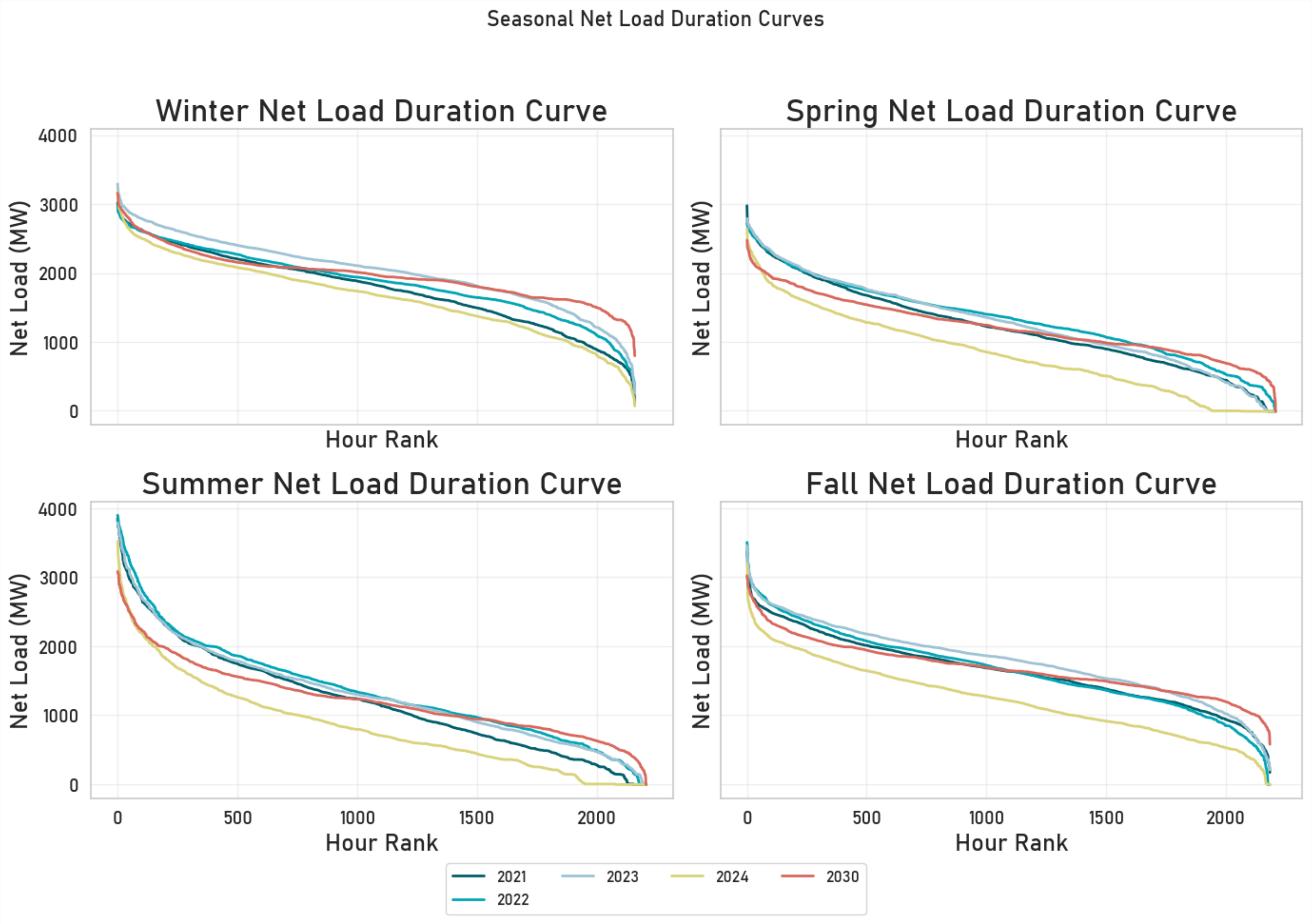
	Historical Years				Forecasted Year
Source	**2021**	**2022**	**2023**	**2024**	**2030**
Beaver	134	154	155	91	129
Generic CCCT	54	61	71	30	57
Carty	370	375	374	337	385
Coyote	202	202	202	176	219
Hermiston	167	182	183	127	181
Hydro	482	484	436	694	361
PW1	293	325	317	223	347
PW2	63	74	80	39	73
Storage	88	87	77	96	62
VER	1,010	908	913	1,118	1,062
PGE_load	2,943	2,943	2,943	2,943	2,943
Net Load	1,933	2,034	2,030	1,824	1,881
Unsecured Reliability Purchases	83	96	140	17	71

MWa by resource/load type

In PGE's market operations, PGE balances system conditions using market purchases and sales to balance PGE's net position for any given month,-day-hour.

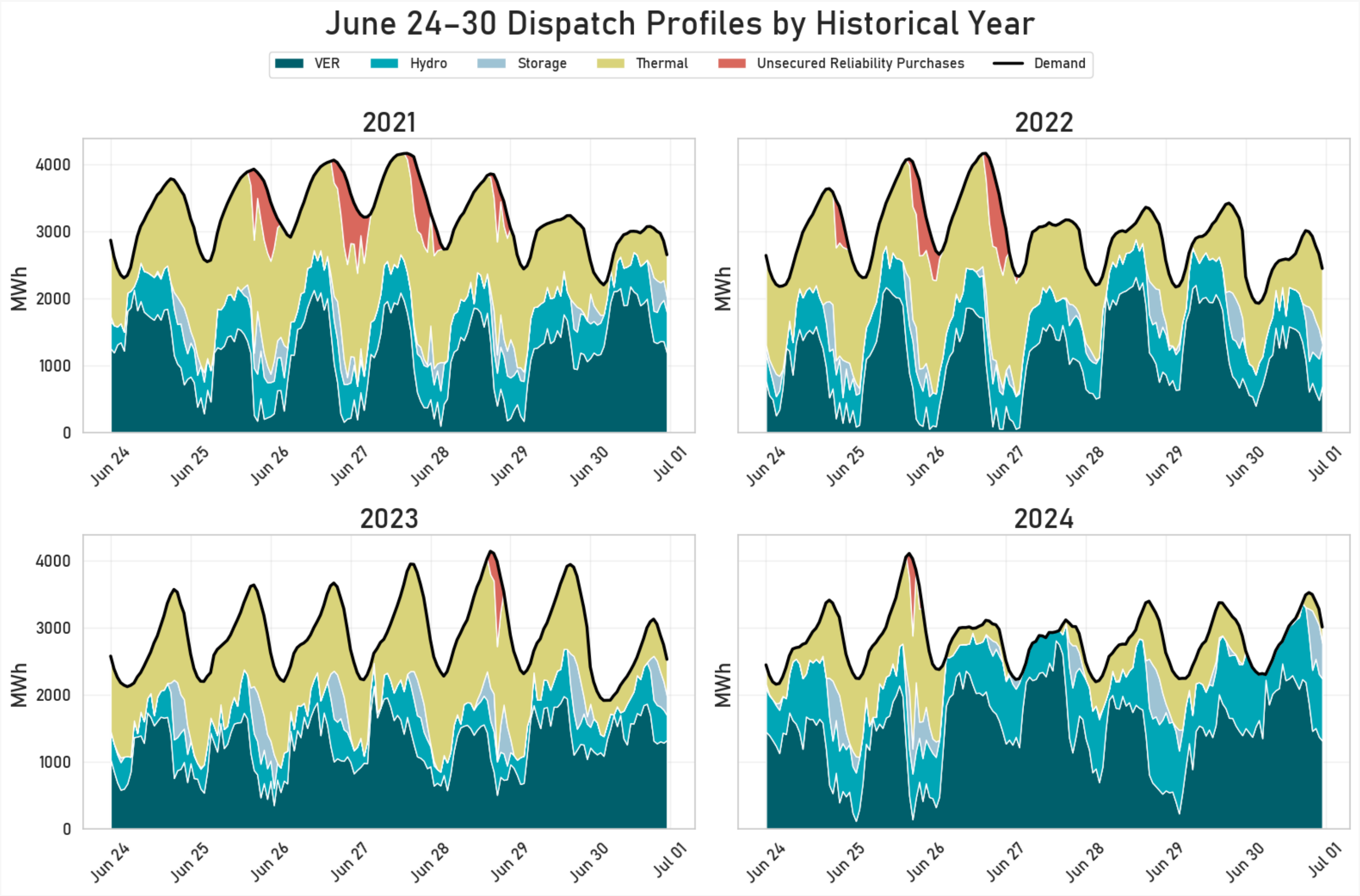
IRP Backcast Results

- Net load duration curves by season allow PGE to inspect PGE's most difficult hours for dispatchable resources to cover net load.
- The impact of the larger hydro contract in 2024 is noticeable in shifting the shape of the net load duration curve downward.



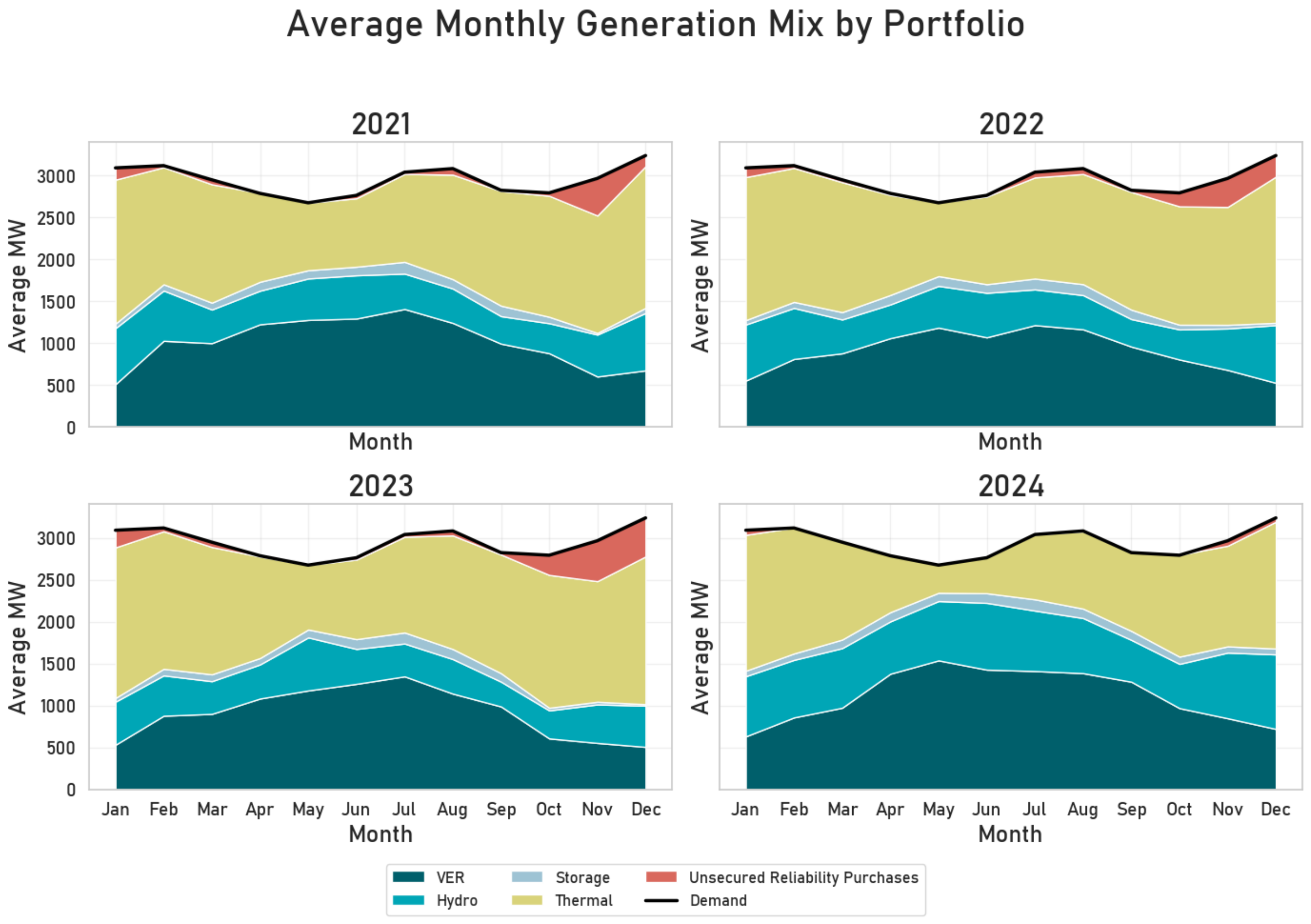
IRP Backcast Results

- The Backcast allows us to consider how well the system responds to periods of high net load.
- This graphic shows the composition of generation resources used in the backcasting model to meet load at the end of June.
- The week includes the heat dome of 2021.



IRP Backcast Results

- Using the Backcasting Model allows PGE to visual the composition of generation resources used across the year and the timing of when we will be more heavily reliant on the market for load service.
- This analysis demonstrates that with additional market purchases, the reliability portfolio is capable of meeting load across a variety of historical weather years.
- This analysis underscores the importance of flexible natural gas resources to address reliability needs.



Summary and Guided Feedback

Summary: PGE performed additional analysis to test the performance of the reliability-only portfolio across a variety of historical weather years. This analysis demonstrates that, with additional market purchases, the reliability portfolio is capable of meeting load in the historical years reviewed. This analysis provides further confidence in the results of the reliability-only portfolio.

Content: What questions do you have about the backcast review?

NEXT STEPS

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

Upcoming Roundtable: August 27, 2026

Thank you

Contact us at
IRP.CEP@PGN.COM

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kind of energy

ACRONYMS

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