NS POWER 2020 IRP
DRAFT FINDINGS RELEASE

SEPTEMBER 2, 2020

Nova Scotia
POWER
An Emera Company

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Note: In parallel with this release, NS Power has also provided a separate Modeling Results deliverable containing model output and metrics for each Scenario

PROCESS UPDATE & WORK COMPLETED

UARB NSP Pre-IRP
Deliverables

- Capacity Study
- Supply Options Study
- Demand Response Assumptions
- Stability Study

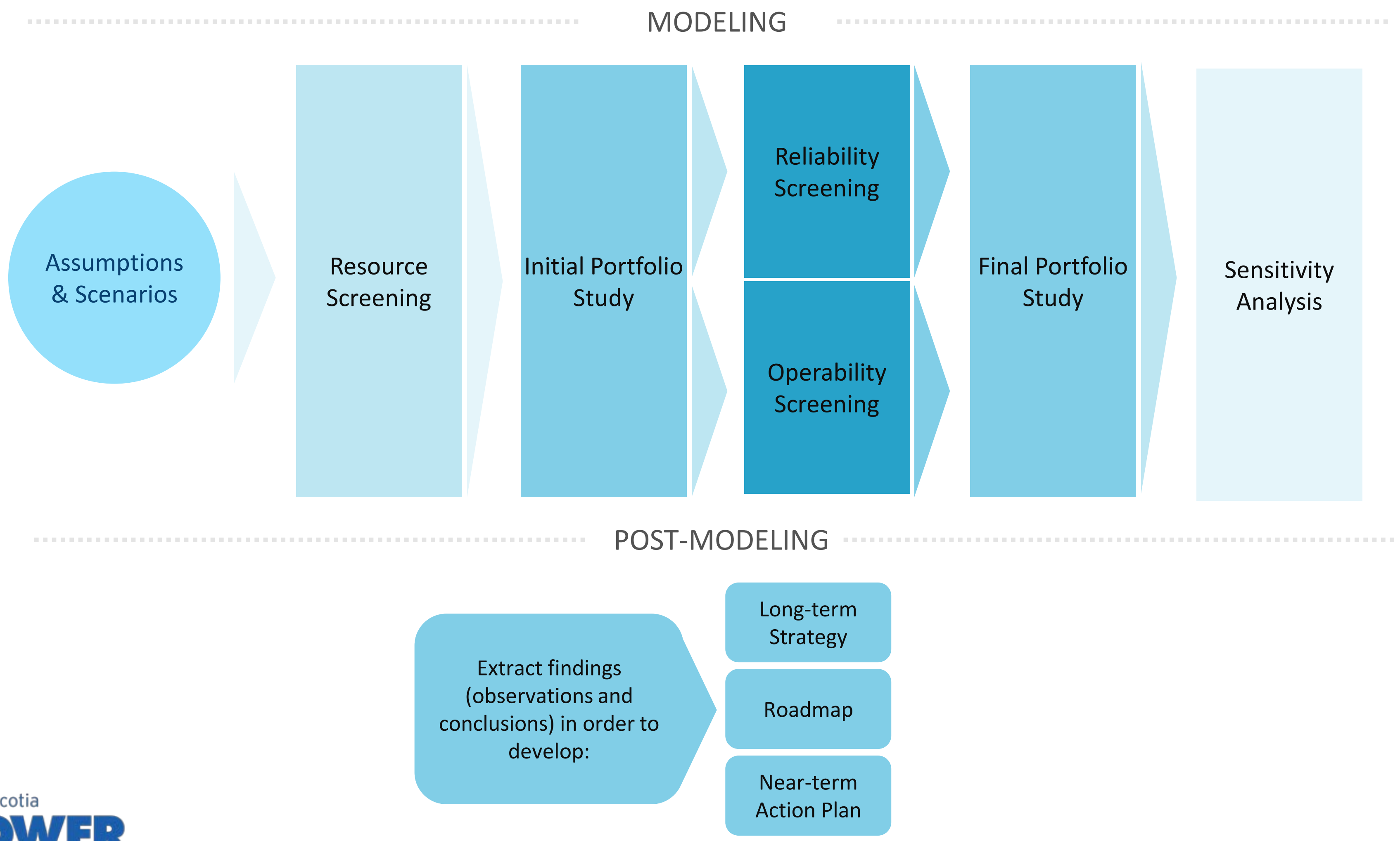
Core IRP Process
resulting in Final Report

Oct 2020

- Terms of Reference
- Scenario Development
- Modeling Plan
- Assumptions
- Modeling
- Analysis/Conclusions
- Report, Roadmap, & Action Plan

Completed – Pre-IRP
Completed
In Progress

IRP MODELING PLAN



RELIABILITY SCREENING

RELIABILITY SCREENING OVERVIEW

The Reliability Screening phase of the IRP evaluated several future resource plans against reliability criteria to confirm that resource plan changes have not lowered the reliability of the future system.

For the 2020 IRP, NS Power working with E3 completed reliability analyses on the following three resource plans from the June 26 Modeling Results release:

- 2.0C – Low Electrification / Base DSM / Net Zero 2050 / Regional Integration
- 2.1C – Mid Electrification / Base DSM / Net Zero 2050 / Regional Integration
- 3.2C – High Electrification / Max DSM / Accelerated Net Zero 2045 / Regional Integration

These three resource plans represent significant evolutions of NS Power's generation mix and include the highest levels of wind and storage penetration that were selected in the original model runs, and as a result are important test cases for reliability modeling.

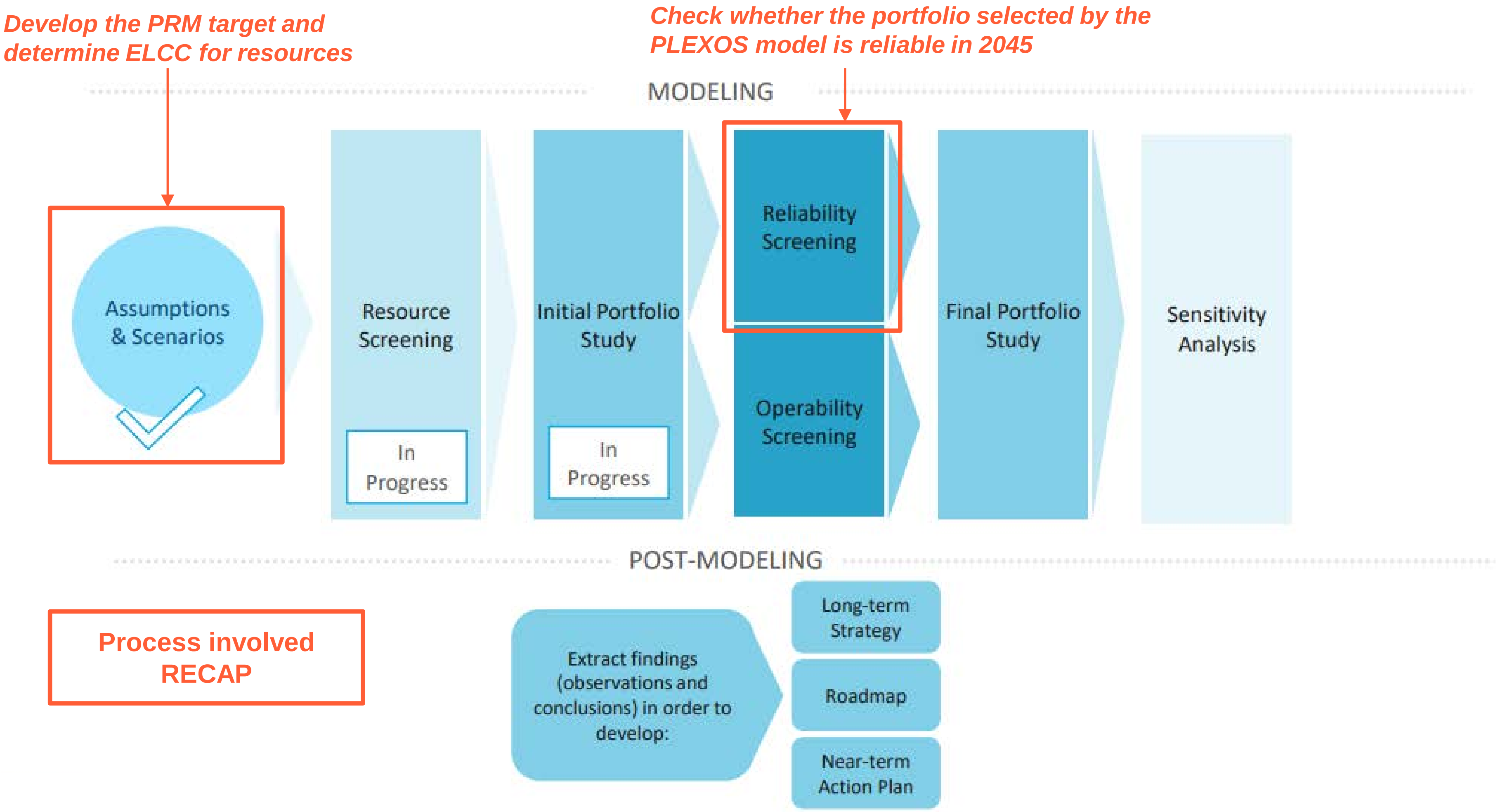
The Reliability screening work concludes that:

- All three resource plans met the stated reliability criteria (i.e. 1 day in 10 years Loss of Load Expectation)
- A Planning Reserve Margin target of 8-9% on a UCAP basis continues to be appropriate in 2045 under these 3 scenarios

Overview of RECAP Model and Inputs

Modeling Process

+ NS Power relied on E3's loss-of-load probability model (RECAP) to estimate a planning reserve margin and effective load capacity contributions in the pre-IRP phase, and to check the reliability of select PLEXOS portfolios in 2045



RECAP: E3's Renewable Energy Capacity Planning Model

+ **RECAP is a loss-of-load probability (LOLP) model used to test the resource sufficiency of electricity system portfolios**
  - This study uses a 1-day-in-10-year standard (0.1 days/yr LOLE) to determine the target PRM
+ **RECAP evaluates sufficiency through time-sequential simulations over thousands of years of plausible load, renewable, and stochastic forced outage conditions**
  - Captures thermal resource and transmission forced outages
  - Captures variable availability of renewables & correlations to load
  - Tracks hydro and storage state of charge

Inputs

Load
- *Hourly load for many weather years*

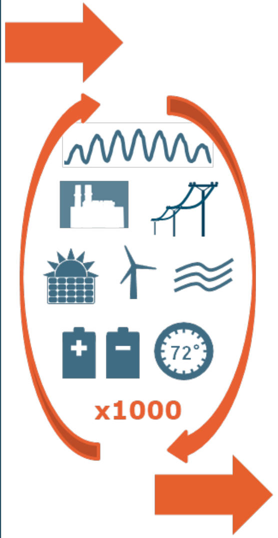
Dispatchable Generation
- *Capacity*
- *FOR*
- *Maintenance*

Renewables
- *Capacity*
- *Hourly generation profiles for many weather years*

Hydro
- *Hydro availability for many hydro years*
- *Max/min constraints*

Storage
- *Capacity*
- *Duration*
- *Roundtrip efficiency*
- *FOR*

Demand Response
- *Capacity*
- *Max # of calls*
- *Duration of each call*



Outputs

LOLE
- *Loss of load expectation*
- *Days/yr of total expected lost load per year*

LOLH
- *Loss of load hours*
- *Hours/yr of total expected lost load per year*

EUE
- *Expected unserved energy*
- *MWh/yr of energy that cannot be served*

ELCC
- *Effective load carrying capability*
- *Equivalent quantity of 'perfect capacity' for a variable or energy-limited resource*

TPRM
- *Target planning reserve margin*
- *PRM required to achieve a specified reliability threshold (i.e. LOLE, ALOLP, or EUE)*

Information about E3's RECAP model can be found here:
https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

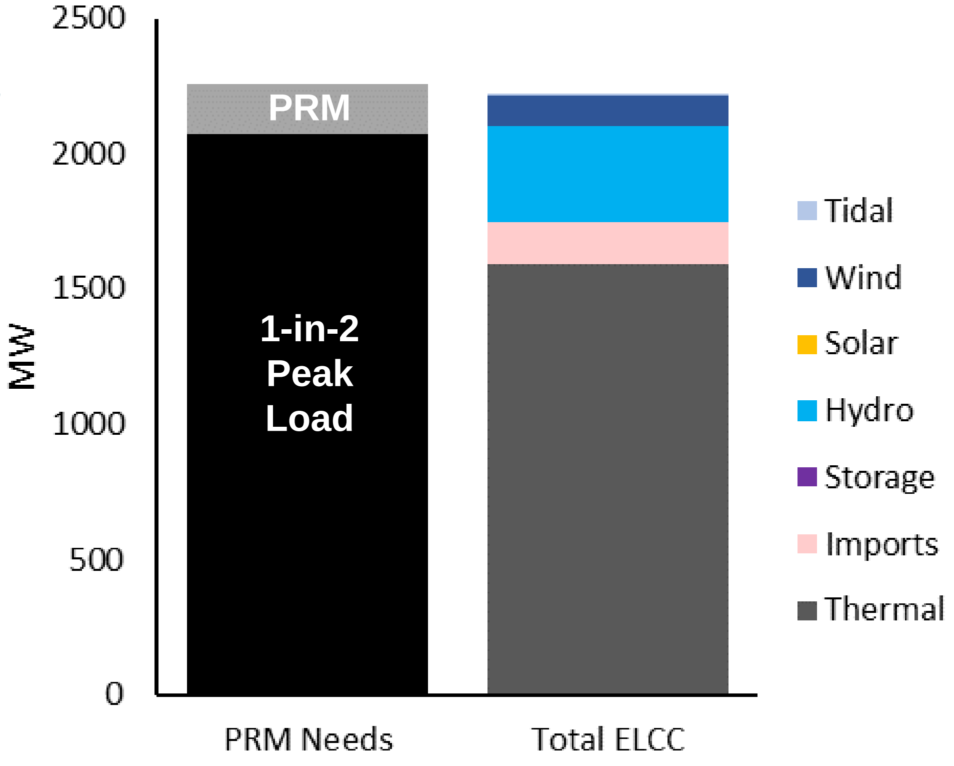
Planning Reserve Margin

+ **To satisfy NS Power's reliability target, RECAP calculates a Planning Reserve Margin required to meet a one-day-in-ten-year standard (LOLE= 0.1 days/year)**
  - PRM based on Installed Capacity (ICAP): 20%
  - PRM based on Unforced Capacity (UCAP): 9%

Used as constraint in capacity expansion modeling

A UCAP planning reserve margin of 9%, or 186 MW, is necessary to ensure reliability

The 1-in-2 net peak load was forecast by NS Power to be 2070 MW in 2020



In UCAP PRM, all resources are de-rated to account for their contribution of "perfect" or "100% firm" capacity

RECAP is used to test the reliability of the final PLEXOS portfolios

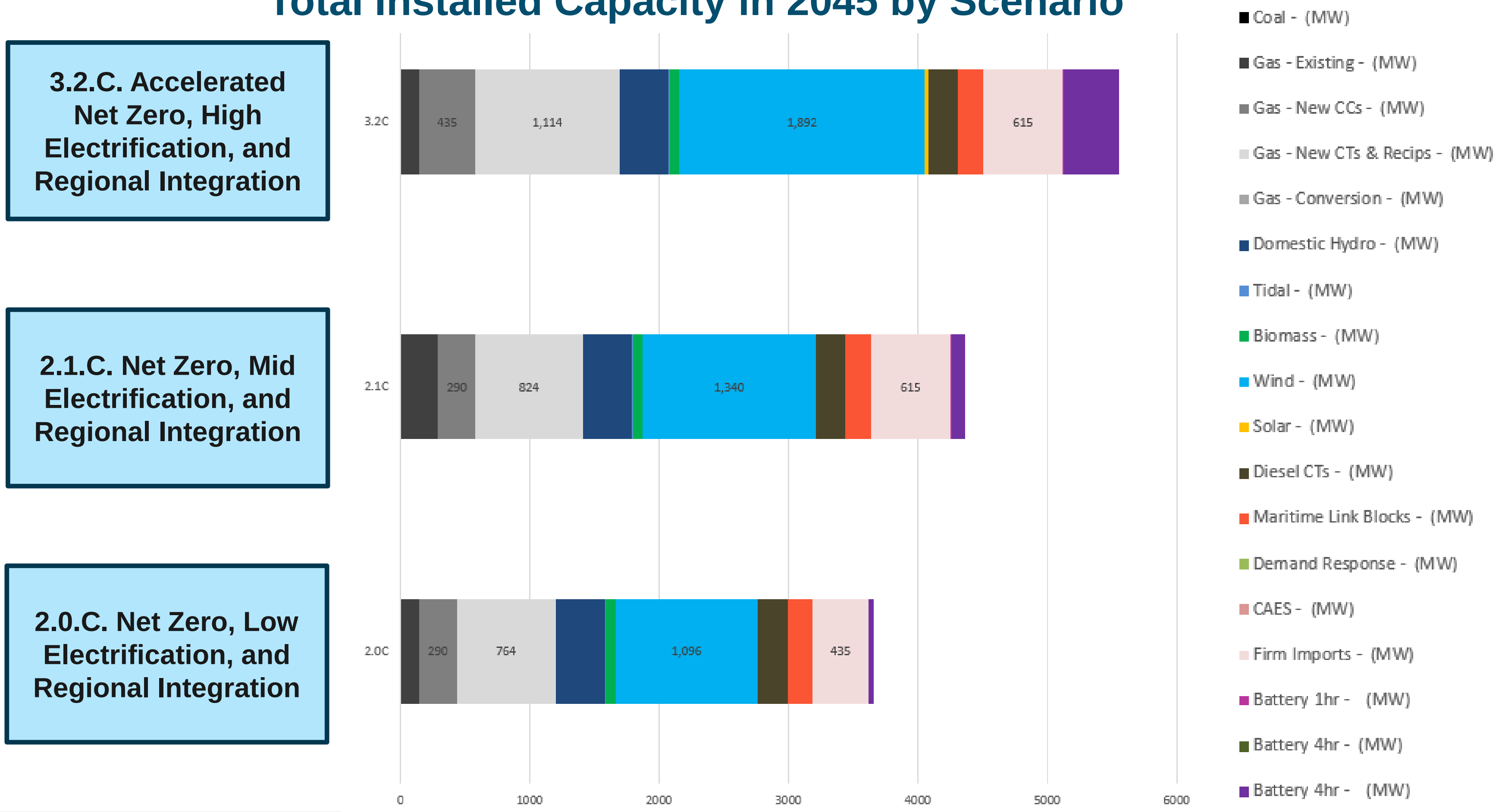
+ **RECAP calculates inputs for capacity expansion modeling**
  - Planning Reserve Margin (PRM) to help ensure PLEXOS and RESOLVE select enough capacity for an adequate system
  - Contribution of various resources toward resource adequacy using Effective Load-Carrying Capability (ELCC) values consistent with PRM calculation
+ **Use of RECAP inputs does not guarantee a reliable portfolio**
  - Because of the dynamic nature of ELCC values (ELCCs change with the portfolio), the PRM achieved by the selected portfolio may not be precisely what is needed to achieve LOLE of 0.1 days/year
+ **A final test is performed using RECAP to ensure that the portfolios selected are reliable**

Scenarios Evaluated

2045 Installed Capacity in PLEXOS Model Runs

+ **After the initial PLEXOS modeling, RECAP tested the reliability of the system in 2045 under three different PLEXOS scenarios, reflecting increasingly aggressive carbon targets, electrification loads, and resulting renewable build**

Total Installed Capacity in 2045 by Scenario



Results

Results Summary

- **The 2045 portfolios are tested against the 0.1 days/year LOLE target**
- **Target UCAP PRM varies slightly by scenario due to load shapes**
  - Loads are scaled for 2045 using PLEXOS methods (based on annual peak and energy)
  - Synchronized reserves based on estimated requirements for spinning, regulation up, and ramping reserves (modeled to scale with renewable capacity)
- **All scenarios achieve the LOLE target**

Key Reliability Statistics for NSP 2045 System

	2.0.C	2.1.C	3.2.C
LOLE Target (days/yr)	0.10	0.10	0.10
Achieved LOLE (days/yr)	0.06	0.02	0.06
Achieved LOLh (hrs/yr)	0.18	0.08	0.21
PRM Target (UCAP)*	8%	8%	9%
Achieved PRM (UCAP)	9%	11%	10%
Excess Capacity (MW)	32	77	40

All scenarios remain reliable in 2045, with small amounts of excess capacity

* RECAP estimates a PRM target endogenously given the scenario load characteristics and reserves in 2045, thus it may differ slightly from the PRM target estimated for the 2020 system.

Scenario 2.0.C.
Detailed 2045 RECAP results

- E3 modeled NSP's 2045 PLEXOS installed capacity and load in RECAP for 2.0.C, generating a UCAP target of 8%
- RECAP modeled ELCCs reflect 2045 loads and incorporate diversity impacts

Firm Demand (GWh)	10,084
Firm 1-in-2 Peak (MW)	2,260
Synchronized Reserves (MW)	87
LOLE Target	0.1 days/yr
LOLE Achieved	0.06 days/yr
PRM Target (UCAP)	8%

	Installed Capacity (MW)	ELCC (MW) / UCAP	ICAP (MW)
Dispatchable	1,505	1,418	1,505
Firm Imports	588	527	588
DR	-	-	-
Storage	33	27	27
Variable	1,132	152	152
Hydro	366	342	366
Total Portfolio ELCC	3,624	2,467	2,639
Achieved PRM (UCAP) (%)	9%		
Achieved PRM (ICAP) (%)	17%		
Capacity Surplus (MW)	32		

Includes all thermal units

Includes only firm imports

Thermal, imports and hydro are counted at nameplate in ICAP

Capacity in excess of the minimum needed to hit the target LOLE

Note: RECAP estimates a PRM target endogenously given the scenario load characteristics and reserves in 2045, thus it may differ slightly from the PRM target estimated for the 2020 system. Similarly, ELCCs are also a function of the load shape and portfolio and thus won't match estimates based on 2020 curves precisely.

Scenario 2.1.C.
Detailed 2045 RECAP results

+ **E3 modeled NSP's 2045 PLEXOS installed capacity and load in RECAP for 2.1.C, generating a UCAP target of 8%**
+ **RECAP modeled ELCCs reflect 2045 loads and incorporate diversity impacts**

Firm Demand (GWh)	11,228
Firm 1-in-2 Peak (MW)	2,636
Synchronized Reserves (MW)	103
LOLE Target	0.1 days/yr
LOLE Achieved	0.02 days/yr
PRM Target (UCAP)	8%

	Installed Capacity (MW)	ELCC (MW) / UCAP	ICAP (MW)
Dispatchable	1,713	1,633	1,713
Firm Imports	768	682	768
DR	0	0	0
Storage	109	92	92
Variable	1,376	180	180
Hydro	366	337	366
Total	4,331	2,924	3,118
Achieved PRM (UCAP) (%)	11%		
Achieved PRM (ICAP) (%)	18%		
Capacity Surplus (MW)	77		

Note: RECAP estimates a PRM target endogenously given the scenario load characteristics and reserves in 2045, thus it may differ slightly from the PRM target estimated for the 2020 system. Similarly, ELCCs are also a function of the load shape and portfolio and thus won't match estimates based on 2020 curves precisely.

Scenario 3.2.C.
Detailed 2045 RECAP results

- E3 modeled NSP's 2045 PLEXOS installed capacity and load in RECAP for 3.2.C, generating a UCAP target of 9%
- RECAP modeled ELCCs reflect 2045 loads and incorporate diversity impacts

Firm Demand (GWh)	12,200
Firm 1-in-2 Peak (MW)	3,162
Synchronized Reserves (MW)	130
LOLE Target	0.1 days/yr
LOLE Achieved	0.06 days/yr
PRM Target (UCAP)	9%

	Installed Capacity (MW)	ELCC (MW) / UCAP	ICAP (MW)
Dispatchable	2,000	1,889	2,000
Firm Imports	768	721	768
DR	0	0	0
Storage	430	305	305
Variable	1957	278	278
Hydro	366	279	366
Total	5,521	3,472	3,717
Achieved PRM (UCAP) (%)	10%		
Achieved PRM (ICAP) (%)	18%		
Capacity Surplus (MW)	40		

Note: RECAP estimates a PRM target endogenously given the scenario load characteristics and reserves in 2045, thus it may differ slightly from the PRM target estimated for the 2020 system. Similarly, ELCCs are also a function of the load shape and portfolio and thus won't match estimates based on 2020 curves precisely.

2.0.C. Average Month-Hour Load and LOLP

- Loss of load events may be triggered by any combination of high load, low renewable generation, or unit outages
- For NS Power's system, the probability of loss of load correlates well with periods of high load

Avg Month-Hr Load (MWh)

	1	2	3	4	5	6	7	8	9	10	11	12
0	1358	1374	1189	924	725	622	638	638	602	710	944	1238
1	1308	1329	1153	895	694	591	606	606	577	679	897	1182
2	1275	1301	1139	890	688	583	592	592	568	669	868	1147
3	1266	1293	1146	908	702	590	592	595	575	681	863	1137
4	1279	1311	1189	969	750	617	615	628	626	740	889	1151
5	1339	1377	1307	1108	870	723	690	702	746	880	976	1212
6	1486	1528	1442	1241	1020	879	825	824	878	1029	1131	1354
7	1621	1657	1524	1301	1097	972	945	943	961	1098	1253	1488
8	1686	1711	1545	1309	1122	1018	1026	1026	1009	1125	1301	1558
9	1704	1709	1529	1294	1124	1044	1074	1073	1035	1132	1305	1583
10	1694	1687	1508	1278	1123	1061	1104	1103	1053	1134	1298	1580
11	1681	1666	1485	1258	1110	1057	1106	1106	1049	1120	1288	1571
12	1672	1649	1444	1214	1078	1037	1093	1093	1031	1092	1271	1562
13	1629	1599	1395	1176	1049	1015	1075	1075	1016	1066	1238	1525
14	1598	1561	1373	1172	1049	1019	1073	1076	1026	1072	1226	1502
15	1618	1573	1395	1203	1080	1046	1095	1100	1058	1111	1265	1530
16	1706	1637	1428	1217	1092	1051	1095	1099	1061	1143	1371	1652
17	1837	1734	1445	1191	1057	1005	1047	1051	1033	1172	1463	1776
18	1822	1783	1505	1209	1048	979	1012	1022	1053	1193	1428	1736
19	1780	1760	1532	1267	1077	974	1001	1042	1055	1150	1383	1693
20	1722	1708	1471	1224	1075	986	1012	1015	970	1066	1321	1640
21	1630	1619	1369	1112	966	898	923	908	853	952	1224	1550
22	1505	1497	1276	1023	857	784	807	797	744	851	1109	1418
23	1422	1425	1220	967	775	686	699	694	654	771	1018	1319

Avg Month-Hr LOLP (frac hrs w/ lost load)

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
1	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
2	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
3	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
4	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
5	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
6	0.039%	0.032%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
7	0.000%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
8	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
9	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
10	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
11	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
12	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
13	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
14	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
15	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
16	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
17	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.039%
18	0.039%	0.032%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
19	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
20	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
21	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
22	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
23	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%

2.1.C. Average Month-Hour Load and LOLP

Avg Month-Hr Load (MWh)

	1	2	3	4	5	6	7	8	9	10	11	12
0	1534	1554	1328	1005	762	636	655	654	611	742	1028	1387
1	1473	1499	1284	969	723	598	616	616	581	705	971	1320
2	1434	1464	1266	963	716	587	598	599	569	693	936	1277
3	1422	1455	1276	985	733	596	599	602	578	708	930	1264
4	1438	1477	1329	1059	792	629	627	642	640	780	962	1282
5	1511	1557	1472	1229	938	759	719	734	787	951	1068	1356
6	1691	1743	1637	1391	1122	950	883	882	948	1132	1257	1529
7	1856	1900	1737	1465	1216	1063	1030	1027	1049	1217	1406	1694
8	1936	1965	1763	1474	1247	1119	1129	1129	1108	1250	1464	1778
9	1956	1963	1743	1456	1249	1150	1188	1186	1140	1259	1470	1809
10	1945	1937	1717	1437	1247	1172	1224	1223	1162	1261	1461	1806
11	1929	1911	1689	1412	1231	1167	1226	1226	1157	1244	1449	1794
12	1918	1889	1639	1359	1192	1143	1210	1210	1135	1209	1428	1784
13	1865	1828	1580	1313	1157	1116	1189	1189	1116	1178	1388	1738
14	1828	1782	1553	1307	1157	1120	1187	1190	1129	1185	1373	1710
15	1852	1798	1580	1345	1195	1154	1213	1220	1168	1232	1421	1745
16	1960	1876	1620	1363	1210	1159	1213	1218	1171	1272	1550	1894
17	2119	1994	1640	1330	1167	1103	1155	1159	1137	1308	1663	2046
18	2101	2054	1714	1352	1156	1071	1112	1124	1162	1333	1620	1996
19	2050	2026	1747	1424	1191	1066	1098	1148	1164	1280	1565	1943
20	1979	1962	1673	1371	1188	1080	1112	1116	1060	1178	1489	1878
21	1866	1853	1548	1233	1055	973	1003	985	918	1038	1371	1769
22	1715	1704	1434	1126	922	833	861	849	785	915	1230	1608
23	1613	1616	1366	1057	822	713	730	723	675	817	1119	1486

Avg Month-Hr LOLP (frac hrs w/ lost load)

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
1	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
2	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
3	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
4	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
5	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
6	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
7	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
8	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
9	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
10	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
11	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
12	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
13	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
14	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
15	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
16	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
17	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
18	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
19	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
20	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
21	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
22	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%

3.2.C. Average Month-Hour Load and LOLP

Avg Month-Hr Load (MWh)

	1	2	3	4	5	6	7	8	9	10	11	12
0	1722	1749	1454	1031	713	549	574	573	517	688	1062	1531
1	1643	1677	1396	984	663	499	524	523	477	640	987	1443
2	1591	1632	1373	976	654	486	500	501	462	624	941	1387
3	1576	1620	1385	1005	677	497	501	505	473	643	934	1370
4	1598	1648	1454	1102	753	540	538	557	555	737	975	1393
5	1693	1753	1642	1324	944	710	658	677	746	961	1113	1490
6	1927	1995	1857	1536	1184	959	872	871	956	1198	1361	1716
7	2143	2200	1988	1632	1307	1107	1064	1060	1089	1309	1555	1931
8	2247	2286	2021	1644	1347	1181	1194	1194	1166	1351	1631	2041
9	2274	2283	1996	1621	1350	1221	1270	1268	1208	1363	1639	2082
10	2259	2248	1962	1596	1348	1249	1318	1316	1236	1366	1627	2077
11	2238	2215	1925	1563	1327	1243	1320	1320	1230	1344	1611	2062
12	2225	2187	1860	1494	1276	1211	1300	1300	1201	1299	1584	2049
13	2155	2107	1782	1433	1230	1176	1272	1272	1177	1257	1532	1989
14	2107	2047	1748	1426	1230	1182	1269	1273	1194	1266	1513	1952
15	2138	2067	1783	1476	1279	1226	1303	1312	1244	1328	1575	1998
16	2278	2169	1835	1499	1299	1233	1303	1309	1248	1380	1744	2192
17	2487	2324	1862	1456	1243	1159	1227	1233	1204	1427	1890	2391
18	2463	2402	1958	1485	1229	1118	1171	1186	1237	1460	1835	2326
19	2397	2365	2000	1579	1275	1111	1153	1219	1240	1390	1763	2257
20	2304	2282	1904	1509	1271	1130	1171	1176	1104	1257	1663	2172
21	2157	2140	1741	1330	1097	989	1028	1005	917	1075	1510	2029
22	1958	1945	1592	1189	923	807	844	828	744	914	1325	1820
23	1826	1830	1503	1099	793	650	672	663	600	786	1180	1660

Avg Month-Hr LOLP (frac hrs w/ lost load)

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
1	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
2	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
3	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
4	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
5	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
6	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
7	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
8	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
9	0.000%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
10	0.010%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
11	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
12	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
13	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
14	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
15	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
16	0.029%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
17	0.029%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
18	0.068%	0.043%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
19	0.049%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
20	0.049%	0.032%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.029%
21	0.029%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
22	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
23	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%

Conclusions

Conclusions

- **All portfolios meet their LOLE reliability targets, indicating that the PLEXOS portfolios are reliable in all three cases tested in 2045 (2.0.C., 2.1.C., 3.2.C)**
- **While the data provides confidence that the system is sufficiently reliable, more detailed modeling of the electrification load shapes is recommended to develop a robust assessment of how electrification changes the PRM target in the long-term**
  - The reliability assessment is based on load shapes utilized in PLEXOS, which scale load and peak load using the 2018 load shape and projected monthly energy and peak demands
  - A rigorous assessment of how electrification changes the PRM target from the 2020 target of 9% UCAP would involve:
    - More detailed modeling of the peak impacts of electrification loads (particularly in buildings) as a function of expected extreme weather events
    - Detailed assessment of the extent to which vehicle charging load would coincide with peak events and potential means to ensure flexible charging to avoid such coincidence

OPERABILITY SCREENING

OPERABILITY SCREENING OVERVIEW

The Operability Screening phase of the Modeling Plan allowed NS Power to examine the behaviour of the optimized resource plans for certain scenarios at an hourly level of granularity. This enabled the verification that the proposed resource plan was operable with all hourly constraints considered, including:

- System Operability Constraints were met (e.g. system inertia, import limitations, emissions limits, etc.)
- Unit Operability Constraints were met (e.g. minimum thermal unit up/down times, combustion turbine operation, etc.)
- System Reserve Requirements were met (e.g. spinning, ramping, and non-spinning reserve, etc.)

Data from Operability Screening was also used in the refinement of sustaining capital assumptions (e.g. number of operating hours, number of unit starts per year)

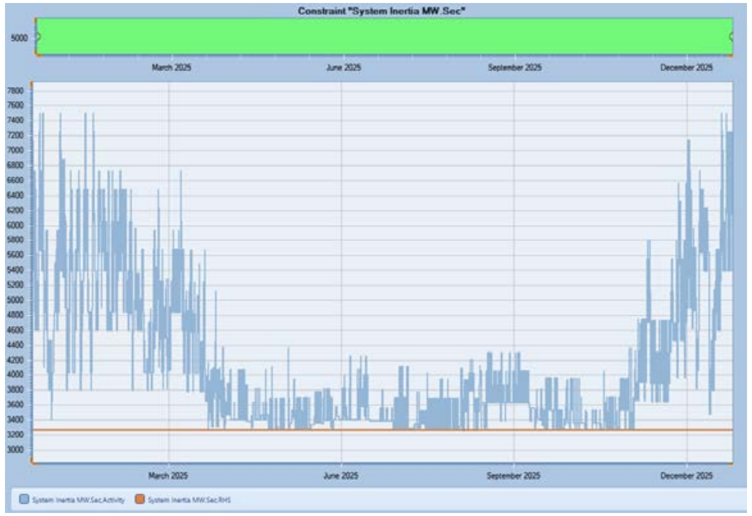
Operability Screening was conducted on the following models:

- 2.0C – Low Electrification / Base DSM / Net Zero 2050 / Regional Integration
- 2.1C – Mid Electrification / Base DSM / Net Zero 2050 / Regional Integration
- 3.1C – Mid Electrification / Base DSM / Accelerated Net Zero 2045 / Regional Integration
- 3.2C – High Electrification / Base DSM / Accelerated Net Zero 2045 / Regional Integration

The results of the Operability Screening led to additional refinements which were incorporated into the final round of modeling to ensure that all constraints were accurately represented while enabling the model to find feasible solutions

INERTIA CONSTRAINT

- The graphs below show the hourly output of the system inertia constraint as modeled, with a lower bound of 3266 MW.sec, for two years of Scenario 2.1C:
  - 2025 (pre-Reliability Tie & Regional Interconnection) *(Left, below)*
  - 2038 (post-Reliability Tie & Regional Interconnection) *(Right, below)*
- It can be seen that the simulation is respecting the constraint in all hours of both years
- The constraint appears to have more influence on unit dispatch during the summer (light load) months, while in the winter sufficient thermal units are online to serve load that the constraint is generally not binding



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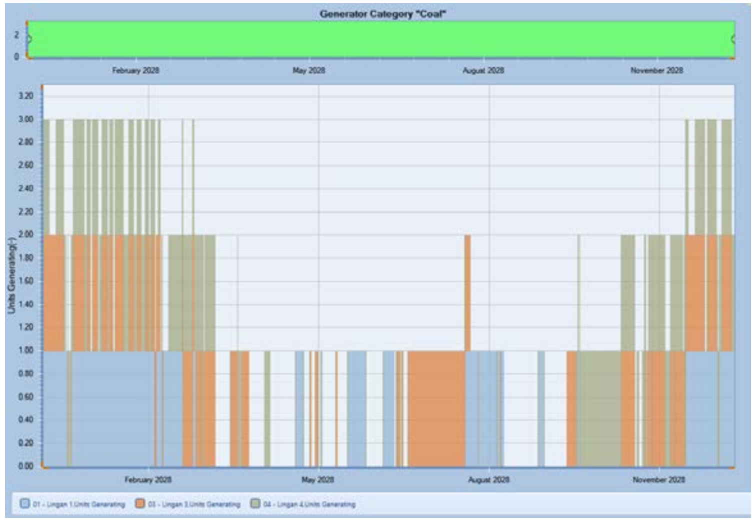
THERMAL UNIT OPERATING CONSTRAINTS

- PLEXOS models minimum up and downtime constraints on thermal units; the graphs below show when units are online at an hourly level for one sample year.
- The results show that the constraints have been respected under the new resource plans, in this case from Scenario 2.1C for two groupings of coal units:



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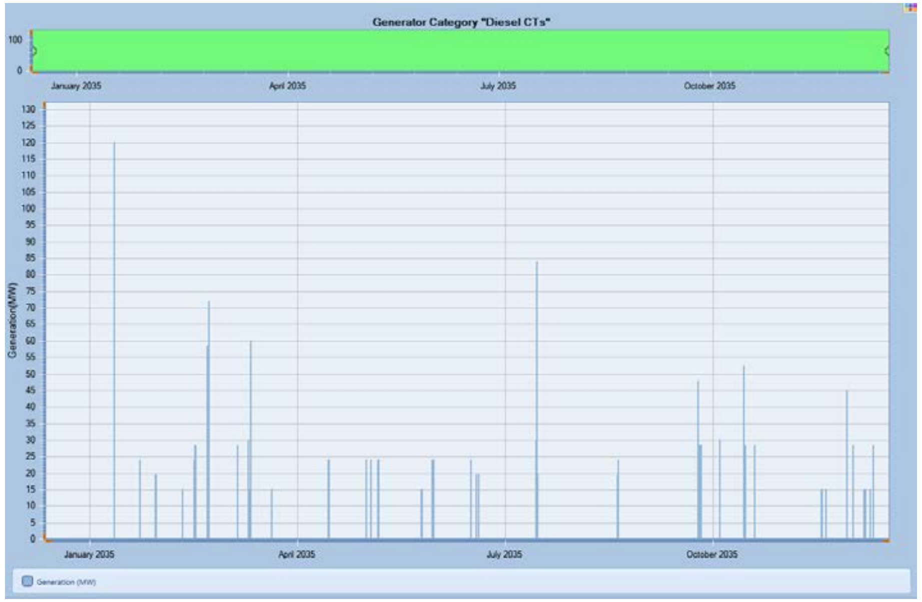
COMBUSTION TURBINE OPERATION

- Because they operate only during a limited number of hours each year, combustion turbine operation can be difficult to evaluate using PLEXOS LT results
- PLEXOS MT/ST is more likely to call on these resources to operate; if they are operating at a high capacity factor, it may indicate that the PLEXOS LT module has found a solution which is not operable when examined in the hourly model
- All of the modeling results included with this modeling release used PLEXOS MT/ST hourly dispatch simulations to produce generation data as well as production costs that were incorporated into financial analysis
- The model output below shows hourly Diesel CT operation (left) and new Natural Gas CT operation (right) for Scenario 2.1C in 2035:



ADDITIONAL MODELING UPDATES

ADDITIONAL MODELING UPDATES

Based on the stakeholder workshop held in July as well as comments received following the modeling results release, NS Power has implemented enhancements in IRP modeling in two areas to improve results and be responsive to stakeholder input:

- PLEXOS capacity expansion model enhancements
- Development of a rate impact model

KEY PLEXOS MODEL UPDATES

1. Do not allow new supply-side builds in 2021 / limited new resource availability in 2022; allow Planning Reserve Margin violation in first 2 years
2. Added ability of model to select local firm imports on 3-year terms; remove local firmed energy from non-firm availability when selected
3. Allow new wind generation to provide ramp down reserve service
4. Allow a maximum of 3 steam unit retirements per year
5. Correct DR program cost representation; offer at 3 entry points - 2021/2025/2030
6. Add additional (existing) units that can contribute to ramping reserve constraint (scales with wind additions) – Tufts Cove Units 4 & 5
7. Complete sustaining capital profile review based on observed unit utilization
8. Input two sustaining capital cost profiles for coal units – aligned with 2030 and 2040 retirement dates

RATE IMPACT MODEL

NS Power has developed a simplified calculation of rate impact that uses the cost and load outputs of the optimized IRP resource plans to provide illustrative effects of various levels of electrification and Distributed Energy Resources.

The rate model considers the following inputs:

- IRP Partial Revenue Requirement by year for each scenario modeled
- Estimate of non-IRP Revenue Requirement from most recent rate proceeding
- Estimate of marginal contribution of incremental / decremental load to non-IRP Revenue Requirement ($80/MWh)
- Load forecast by year for each scenario, net of losses (assumed at 6.7% average per 2020 Load Forecast Report)

Assumptions and limitations underlying this approach include:

- All load gained or lost between scenarios contributes to Revenue Requirement at the marginal contribution rate
- Rates should be viewed as relative to one another rather than absolute and are approximate in nature
- Actual rates will differ from forecast both with respect to items included in the analysis and factors not included (e.g. new cost pressures, other asset additions, etc.)

Comparison of the rate impact for select scenarios is presented on slide 42 and results for each scenario are included in the Modeling Results file

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FINAL PORTFOLIO STUDY RESULTS
SCENARIO COMPARISONS

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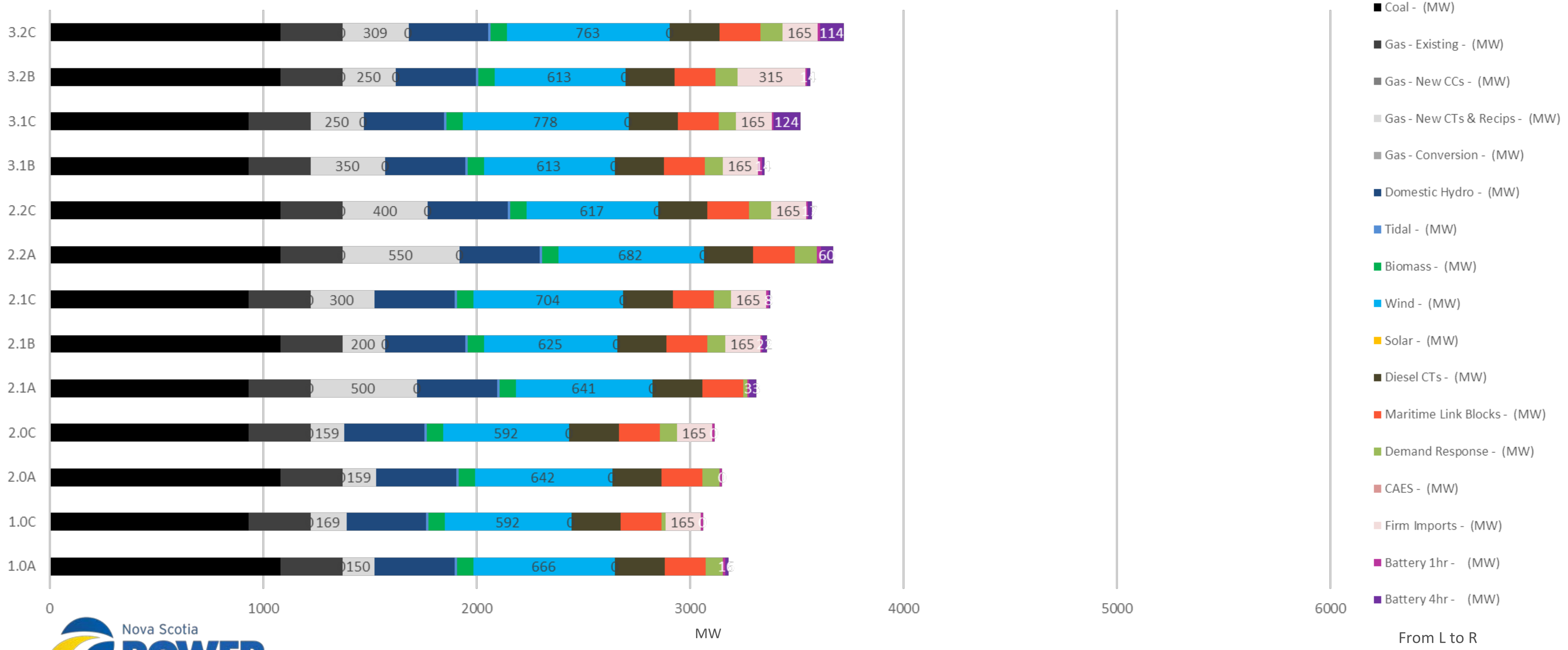
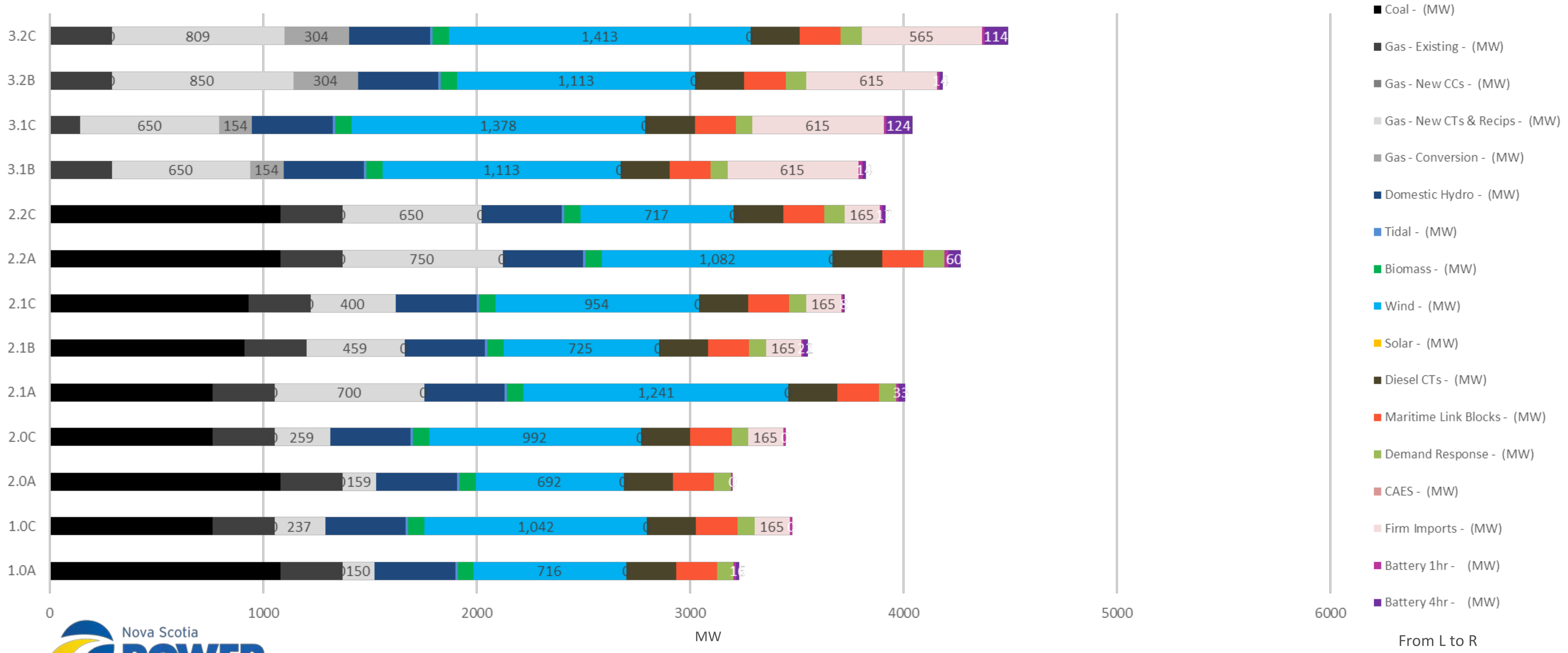
FINAL PORTFOLIO STUDY

- The following slides provide an overview comparison of the Final Portfolio Study results from PLEXOS for the key scenarios
- Outputs presented here consist of capacity expansion optimizations in PLEXOS LT, supplemented by hourly production cost simulations in PLEXOS MT/ST
- The section includes several summary comparison slides; detailed model outputs for each run are provided in a second presentation *“IRP Modeling Results 2020-09-02”* and in the accompanying data tables
- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and specific costs considered outside of the long-term model optimization (i.e. energy efficiency costs)

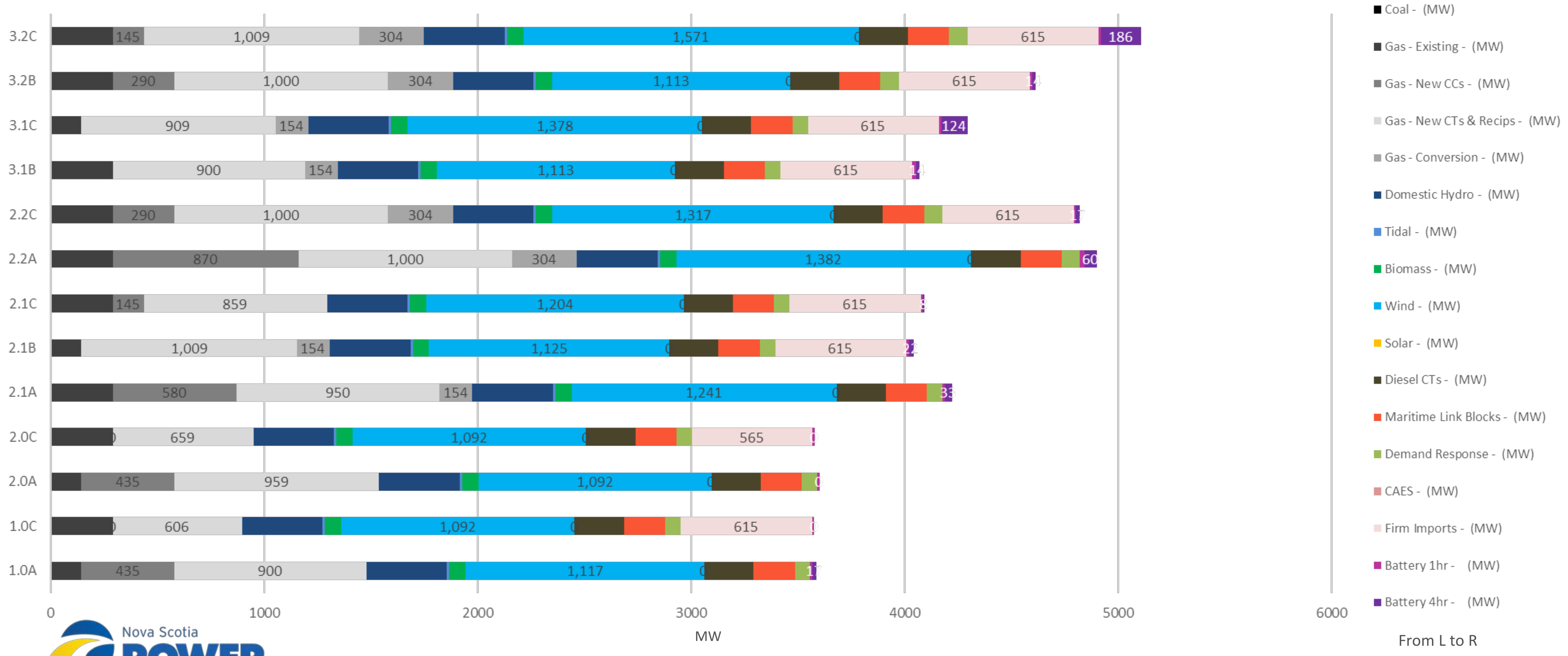
RESOURCE PORTFOLIO COMPARISON (2026)



RESOURCE PORTFOLIO COMPARISON (2030)



RESOURCE PORTFOLIO COMPARISON (2040)



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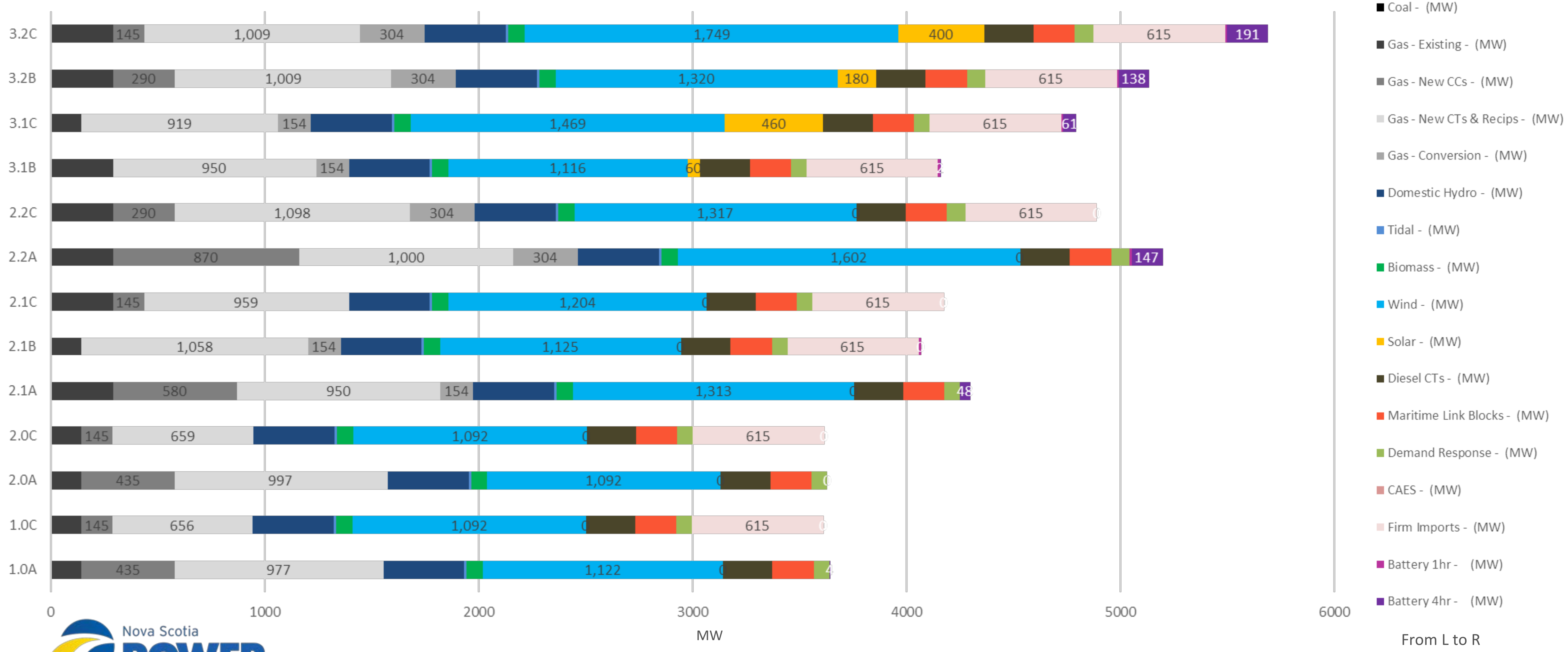
RESOURCE PORTFOLIO COMPARISON (2045)



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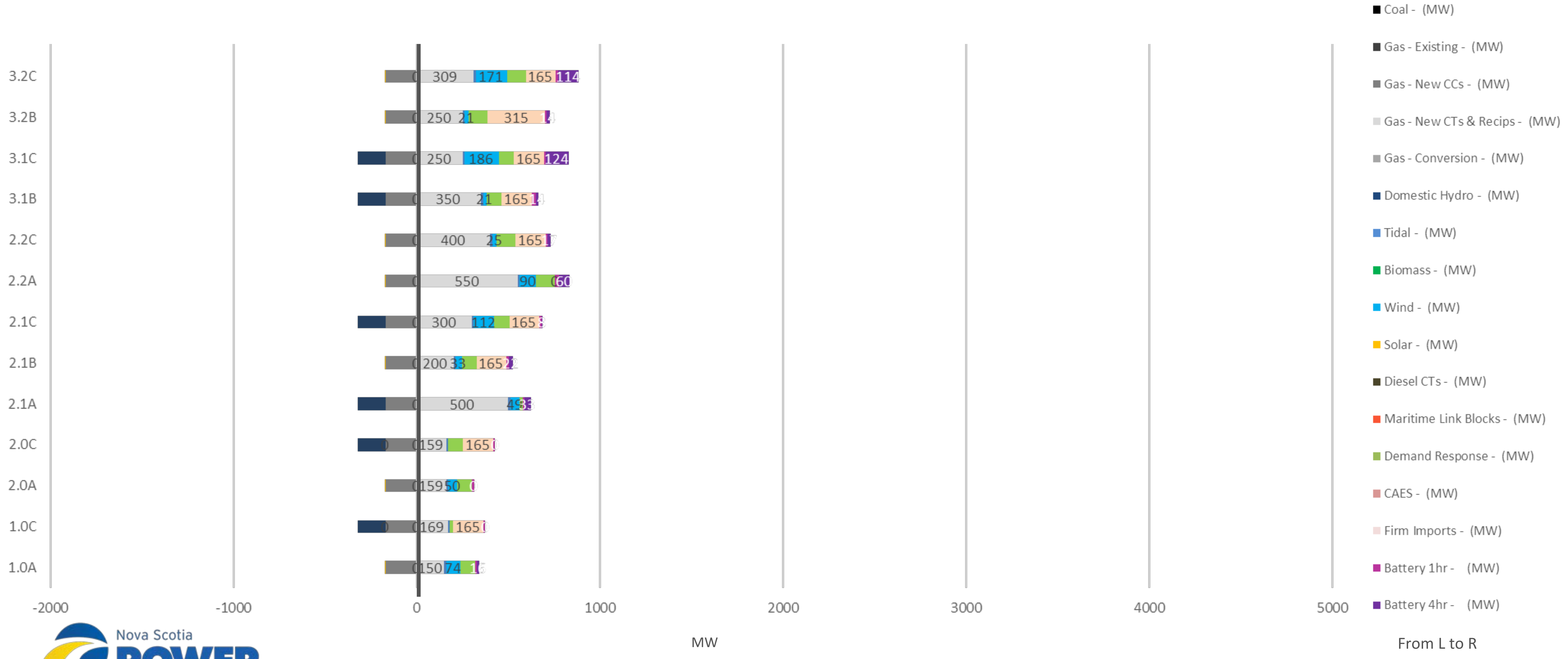
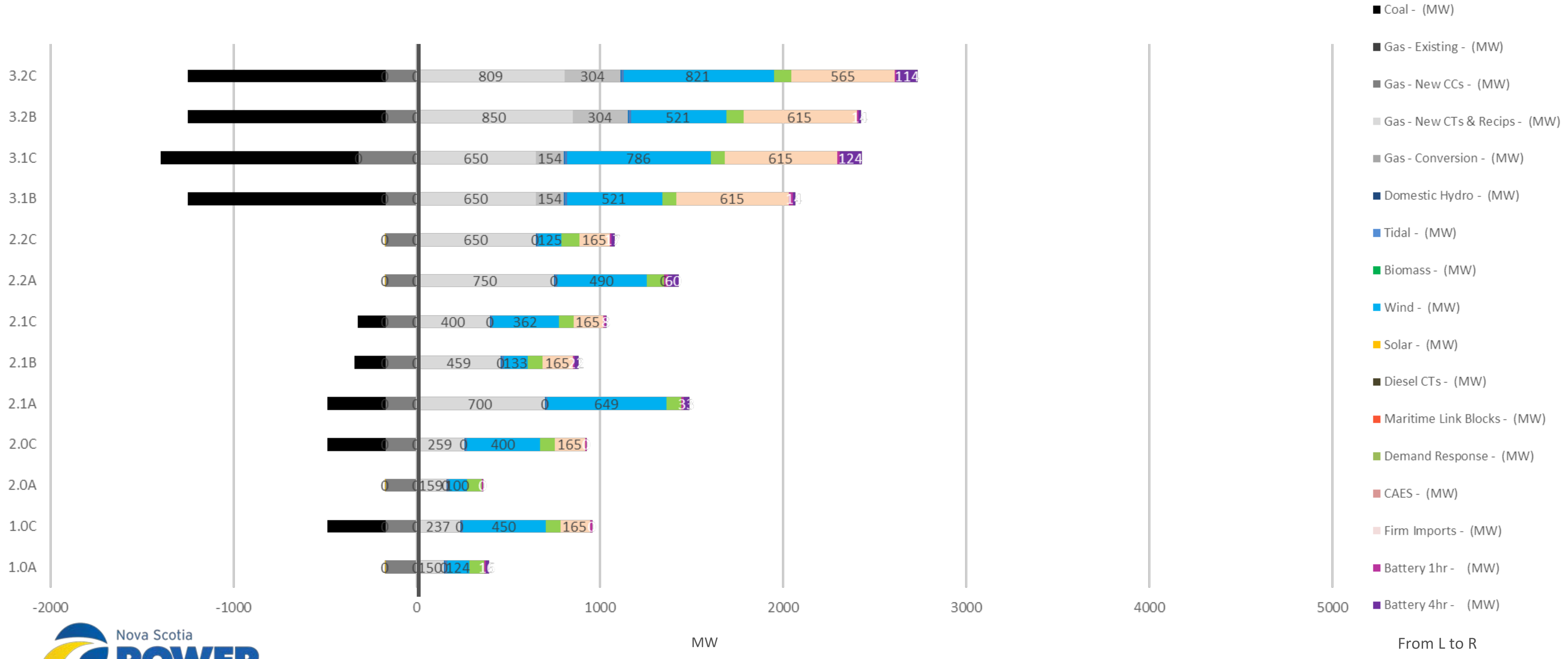
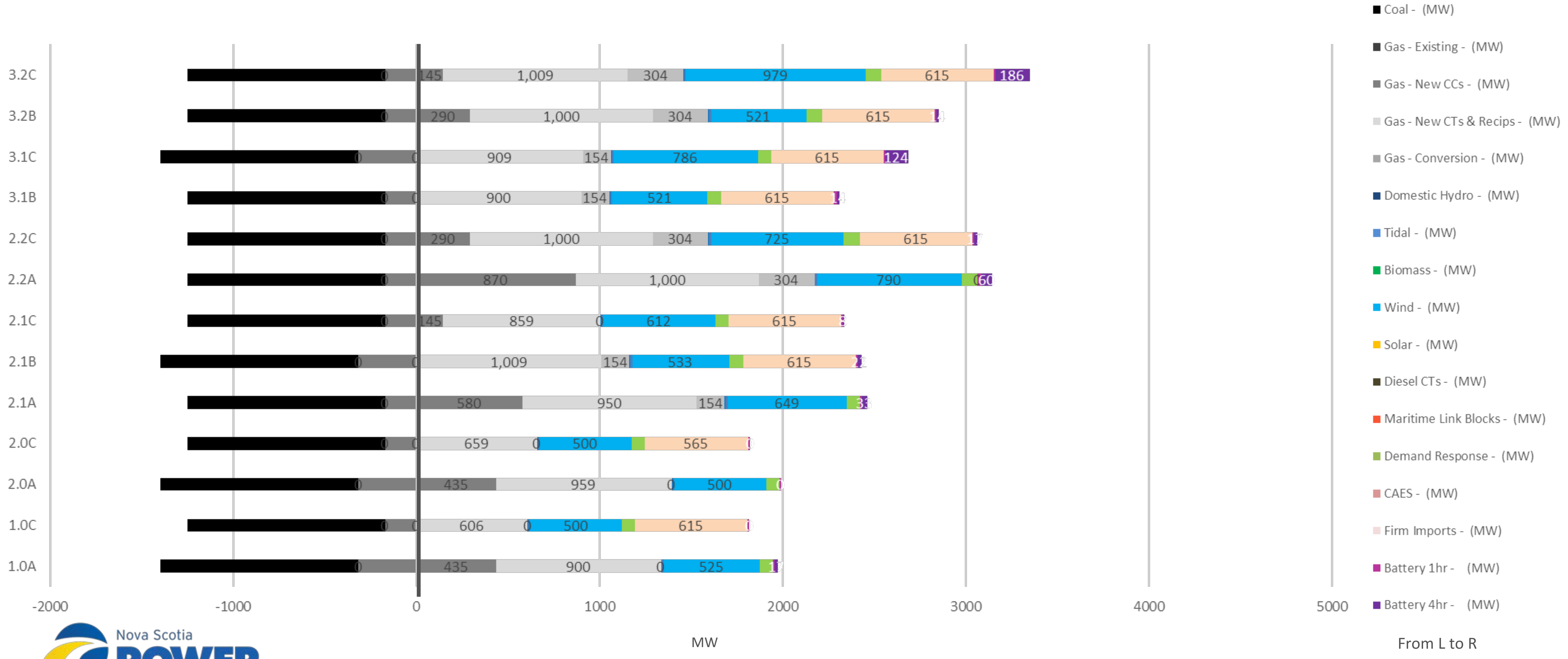
RESOURCE PORTFOLIO CHANGES (2026)



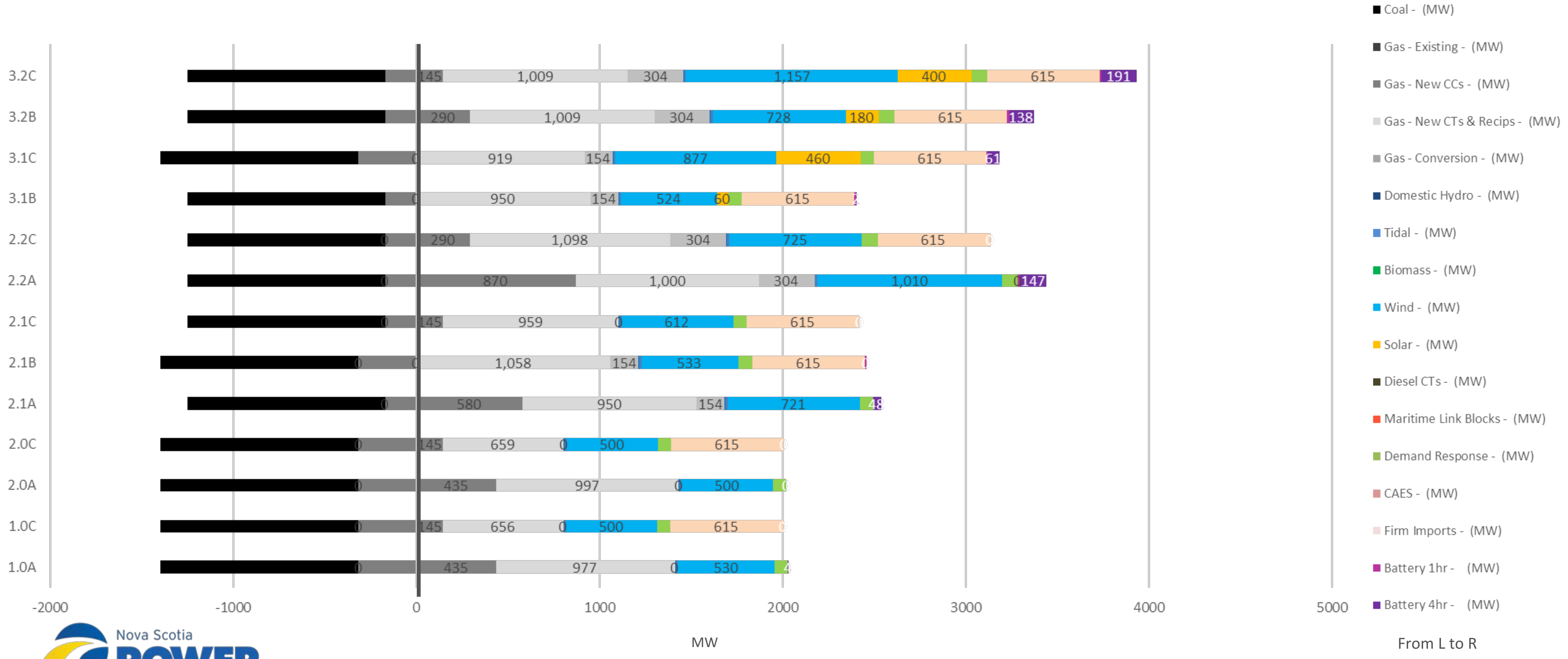
RESOURCE PORTFOLIO CHANGES (2030)



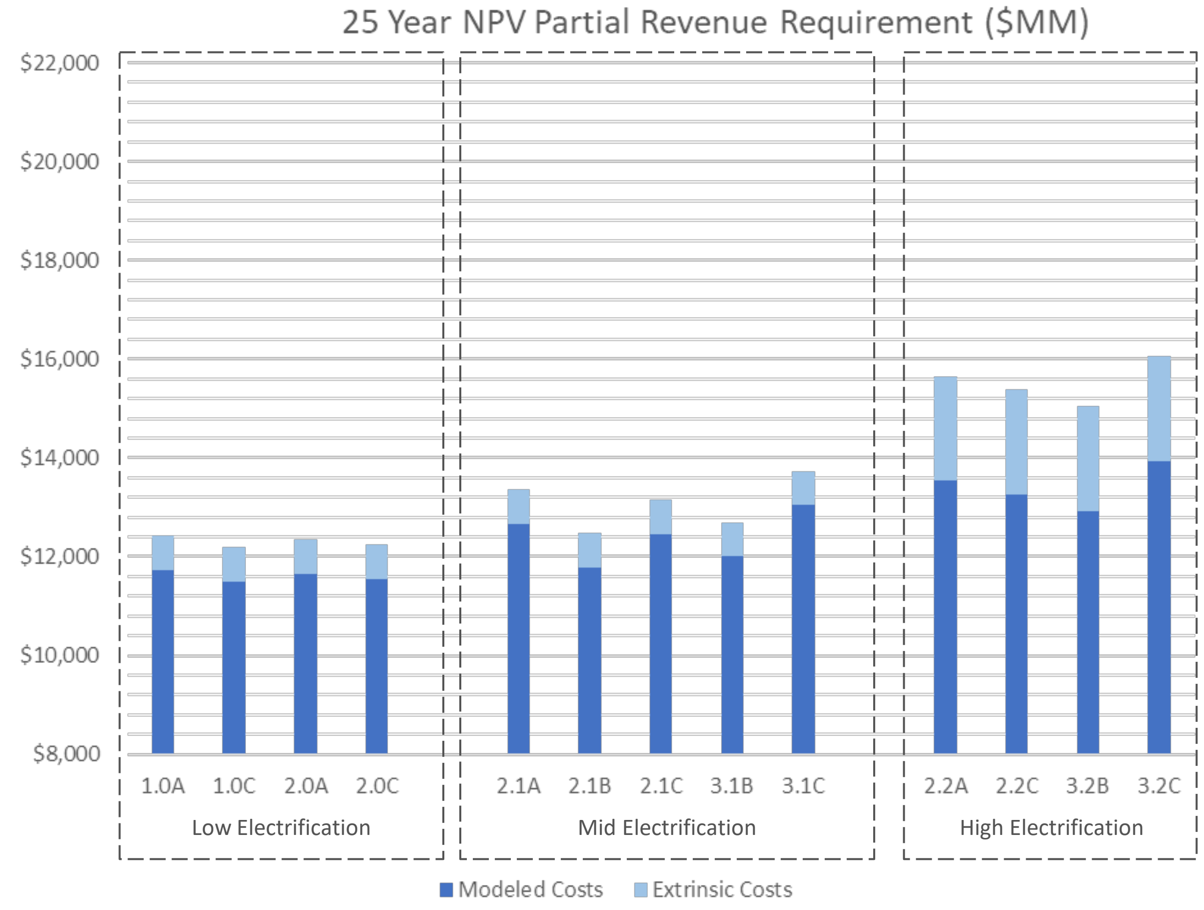
RESOURCE PORTFOLIO CHANGES (2040)

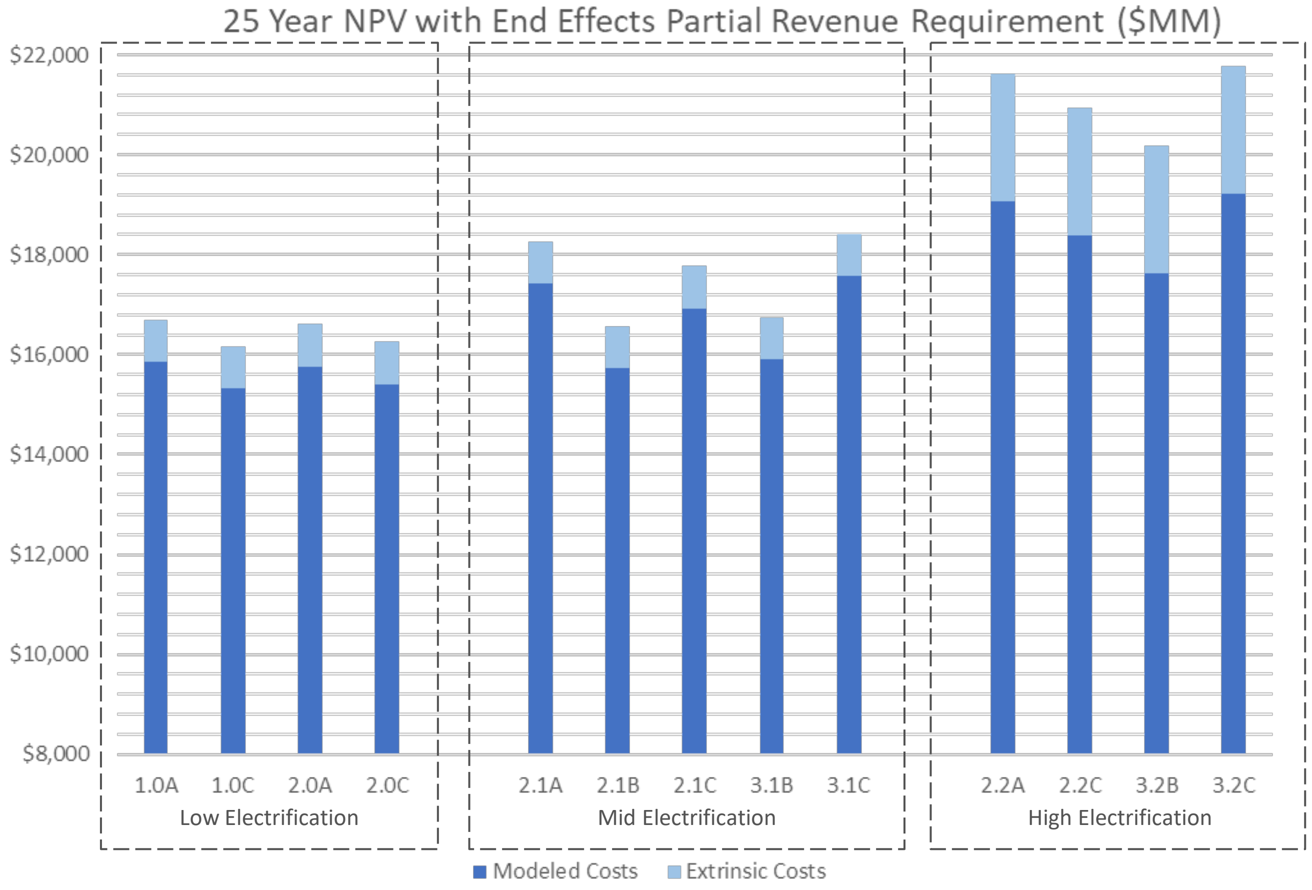


RESOURCE PORTFOLIO CHANGES (2045)



NPV PARTIAL REVENUE REQUIREMENT COMPARISON





Due to differences in forecast system load affecting production costs, resource plan partial revenue requirement results should not be compared across electrification scenarios

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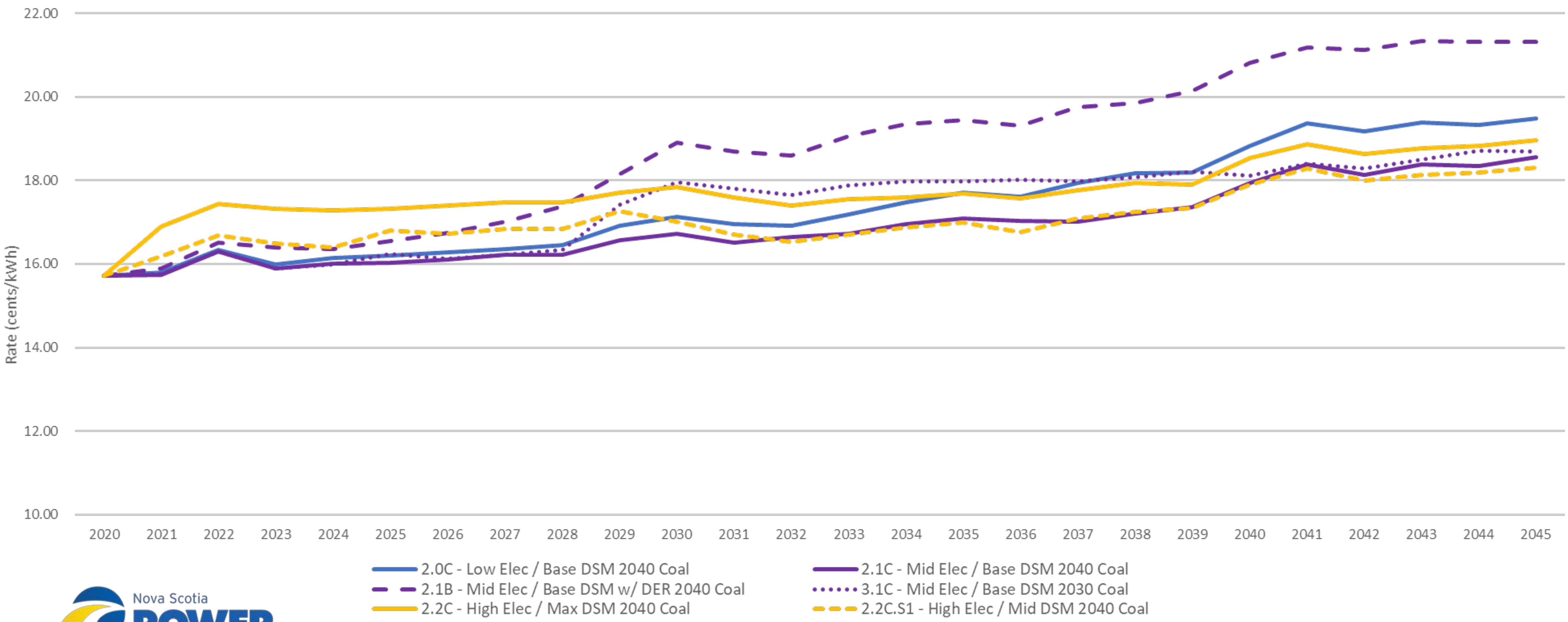
RATE IMPACT COMPARISON (SELECT SCENARIOS)



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DRAFT FINDINGS

IRP FINDINGS OVERVIEW

The summary of Findings is a key output of the 2020 IRP. As described in the 2020 IRP Terms of Reference, the results and observations of the modeling work will form a summary of findings, which will guide the development of a long-term electricity strategy.

The Draft Findings summarized in the following section include insights and ranges informed by the model outputs, as analyzed across the scenario plans. These continue to be reviewed and interpreted and should be understood in terms of their orders of magnitude or directional time frames.

NS Power looks forward to receiving stakeholder comments on these Draft Findings, which will then be refined for inclusion in the IRP Final Report.

DRAFT FINDINGS

1. Steeply **reducing carbon emissions** in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the **electricity sector playing a major role**.

a) Key pillars of **economy-wide decarbonization** include greater reliance on non-emitting electricity supplies, focused demand side management, and electrification of end uses currently reliant on fossil fuels.

b) Increased electricity sales due to electrification can help to **reduce upward pressure on electricity rates** while **facilitating carbon reductions** in other sectors.

c) Nova Scotia Power's direct carbon emissions are reduced to between 0.5 Mt and 1.4 Mt per year by 2045 in all resource plans, representing **an 87%-95% reduction from 2005 levels**. Earlier emissions reductions are possible at incremental cost relative to the lowest cost plans.

DRAFT FINDINGS

2. Decarbonizing Nova Scotia Power's electricity supply will require investment in a **diverse portfolio of non- and low-emitting resources**.

a) Regional Integration (i.e. investment in stronger interconnections to other jurisdictions) is an economic component of the least-cost plans under each load scenario. Both the **Reliability Tie**, which strengthens our connection to the North American electrical grid, and a **Regional Interconnection**, which enables access to firm capacity and energy imports, are shown to have value.

b) **Wind is the lowest cost domestic source of renewable energy** and is selected preferentially over solar in all resource plans. Incremental wind capacity of 500 - 800MW is selected by the model over the period, with major installations paired with coal retirement dates to provide replacement emissions-free energy. Further work is required to assess system stability at these significant penetrations and determine whether additional dynamic system inertia constraints can enable this level of additional wind integration on the Nova Scotia system.

DRAFT FINDINGS

2. **CONTINUED** Decarbonizing Nova Scotia Power's electricity supply will require investment in a **diverse portfolio of non- and low-emitting resources**.

c) Coal units are generally sustained economically until their model-imposed retirement date, with capacity factors falling in line with declining emissions caps. Many resource plans incorporate economic **retirement of one coal unit in the near term,** as early as 2023 if replacement capacity and energy can be procured. **New generating capacity** is required to offset retiring coal units, to **lower carbon emission intensity**, and to **meet growing electricity demand** in all scenarios.

d) NS Power's existing **domestic Hydro** resources provide economic benefit to customers and are **economically sustained** through the planning horizon with appropriate reinvestment requirements.

e) **DSM energy efficiency programs** consistent with a range of the "Low" to "Base" profiles, consistent with the E1 Potential Study, are shown to be most economic relative to other options evaluated.

DRAFT FINDINGS

3. Firm capacity resources will be a key requirement of the developing NS Power system in both the near and long term.

a) **New combustion turbines, operating at low capacity factors,** are the lowest cost domestic source of firm capacity and replace retiring thermal capacity in all resource plans. These units are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy. 50-150MW is required by 2025, while 600-1000MW of new capacity is required by 2045 to support retirement of steam units.

b) NS Power's existing Combustion Turbine resources provide economic benefit to customers and are **economically sustained** through the planning horizon with appropriate reinvestment requirements.

c) Low-cost, low-emitting generating capacity may be provided economically through **redevelopment of existing natural gas-powered steam turbines or coal unit conversions**. Fuel flexibility, including low/zero carbon alternative fuels, may also be an option for new and redeveloped resources.

DRAFT FINDINGS

3. CONTINUED Firm capacity resources will be a key requirement of the developing NS Power system in both the near and long term.

d) **Battery storage** can enable wind integration while providing firm capacity and energy storage; however, its ability to substitute for firm capacity resources is limited by its relatively short duration. Up to 120MW of storage by 2045 is selected in the portfolios with deployments of 30-60MW by 2025 in many plans.

e) The aggregated **Demand Response** (DR) programs modeled in the IRP have economic value to the Nova Scotia system, offsetting firm generation capacity requirements. A DR program with a target final nameplate capacity of approximately 70MW is shown to have value.

f) A Planning Reserve Margin (PRM) of 9% (on a UCAP basis, consistent with 20% 1 in 10 year ICAP method) is found to **maintain supply reliability** across the studied range of resource plans and electrification scenarios.

DRAFT FINDINGS

4. Similar resource plans are selected when considering both 2030 and 2040 coal unit retirement dates. The earlier retirement scenarios are less economic on an NPV basis but have similar cumulative rate implications by 2045.

DRAFT ACTION PLAN

ACTION PLAN OVERVIEW

The Action Plan is a key output of the 2020 IRP. As described in the 2020 IRP Terms of Reference, the Action Plan identifies the critical undertakings required over the near-term to implement the long-term electricity strategy.

The Draft Action Plan summarized in the following section includes insights and ranges informed by the model outputs and Draft Findings, as analyzed across the scenario plans. These continue to be reviewed and interpreted and should be understood in terms of their orders of magnitude or directional time frames.

NS Power looks forward to receiving stakeholder comments on this Draft Action Plan, which will then be refined for inclusion in the IRP Final Report.

DRAFT ACTION PLAN

1. Develop a **Regional Integration Strategy** to provide access to firm capacity and low carbon energy, increase the reliability of Nova Scotia's interconnection with North America, and enable economic coal unit retirements. This strategy will include:

a) Identifying opportunities for near term firm imports over existing transmission infrastructure

b) Conducting detailed engineering and economic studies for firm import options requiring new transmission investment and strengthened regional interconnections, including evaluations of availability and security of supply and dispatch flexibility

c) Based on the results of this detailed work, commence the development of a Reliability Tie and Regional Interconnection via an appropriate regulatory process with target in-service dates as follows:

i. Reliability Tie: 2025-2029

ii. Regional Interconnection: 2028-2035

DRAFT ACTION PLAN

2. Electrification is a key variable in this IRP and results indicate that under economic resource plans it can **support provincial decarbonization** while **reducing upward pressure on electricity rates** for customers. NS Power proposes several action plan items from this IRP related to electrification:

a) Initiate an electrification strategy to understand options for encouraging economic electrification with the goals of maintaining rate stability while decarbonizing the Nova Scotia economy in parallel with the Sustainable Development Goals Act.

b) Monitor electrification growth in Nova Scotia so that NS Power can understand at what point the provincial load profile starts to move from Low, to Mid, to High levels of electrification.

c) Initiate a program to collect detailed data, including data on the quantity, flexibility and hourly load shape of incremental electrification demand, to assist with further system planning work.

d) Address electrification impacts on the Transmission & Distribution system as additional experience and data become available.

DRAFT ACTION PLAN

3. Initiate a **Thermal Plant Retirement, Redevelopment and Replacement Plan** including:

a) Develop a plan for the retirement of Trenton 5, targeting 2023-2025 while identifying replacement capacity and energy in parallel; begin decommissioning studies for NS Power's other coal assets and develop and execute a coal retirement plan including associated regulatory approval process; this coal retirement plan will include significant engagement with affected employees and communities.

b) Develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels.

c) Initiate a wind procurement strategy, targeting 50-100MW new installed capacity by 2025 and up to 350MW by 2030.

DRAFT ACTION PLAN

4. Create a **Demand Response Strategy** with a target capacity of 75MW, for deployment by 2025. The strategy will build on learnings from NS Power's Smart Grid Project, NS Power's Time Varying Pricing application, the DR Joint Working Group between NS Power and Efficiency One, the ELIADC tariff, and the Large Industrial Interruptible Rider.

DRAFT ROADMAP

ROADMAP OVERVIEW

The Roadmap is a key output of the 2020 IRP. As described in the 2020 IRP Terms of Reference, the Roadmap identifies additional work that supports the long-term electricity strategy, beyond the items in the Action Plan.

The Draft Roadmap summarized in the following section includes insights and ranges informed by the model outputs and Draft Findings, as analyzed across the scenario plans. These continue to be reviewed and interpreted and should be understood in terms of their orders of magnitude or directional time frames.

NS Power looks forward to receiving stakeholder comments on this Draft Roadmap, which will then be refined for inclusion in the IRP Final Report.

DRAFT ROADMAP

1. Advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations.

2. Complete detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling results.

3. Pursue economic reinvestment in existing hydro and combustion turbines with individual business cases as applicable.

4. Complete a thermal plant Depreciation Study to update depreciation rates and a recovery strategy to better align depreciation with updated useful lives for generation assets.

DRAFT ROADMAP

5. Monitor the development of **low/zero carbon fuels** that could replace natural gas in powering generating units to provide firm, in-province capacity beyond 2050.

6. Continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low" pricing scenarios).

7. Continuously refine these Findings and Action Plan items via an evergreen IRP process. This process should facilitate regular updating of the IRP model as conditions change and technology or market options develop.

NEXT STEPS

NEXT STEPS

1. Stakeholder Workshop – September 10
2. Comments on Draft Findings, Action Plan, Roadmap – September 18
3. Draft Final Report
4. Final Report, Action Plan, Roadmap

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