New York ISO
Independent System Operator

Appendix F

2021-2040 System & Resource Outlook (The Outlook)

A Report from the New York Independent System Operator

September 22, 2022

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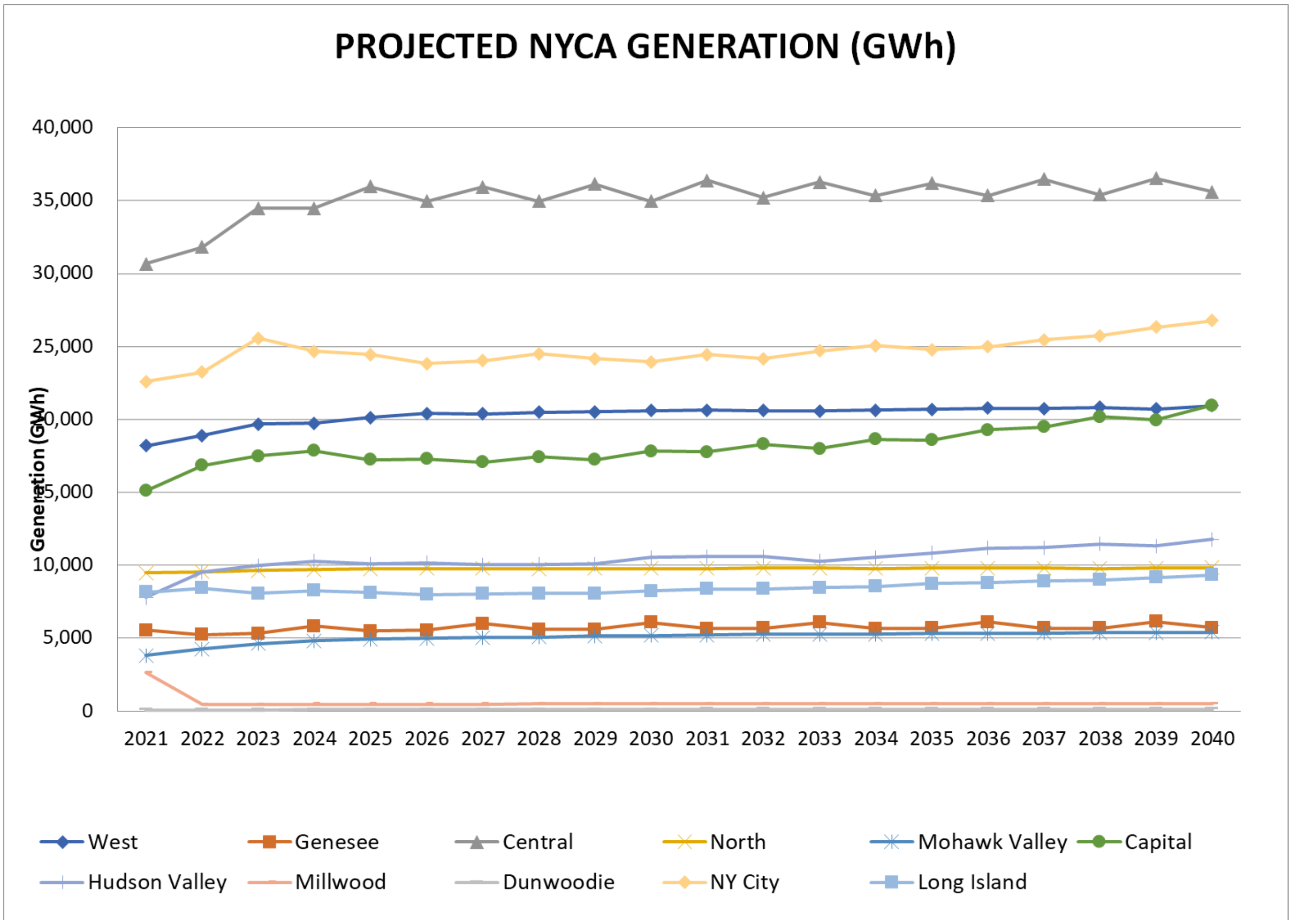
Figure 36: Projected NYCA Generation by Zone



F.1.2. Net Imports

Figure 37: Projected Net Imports by Interface

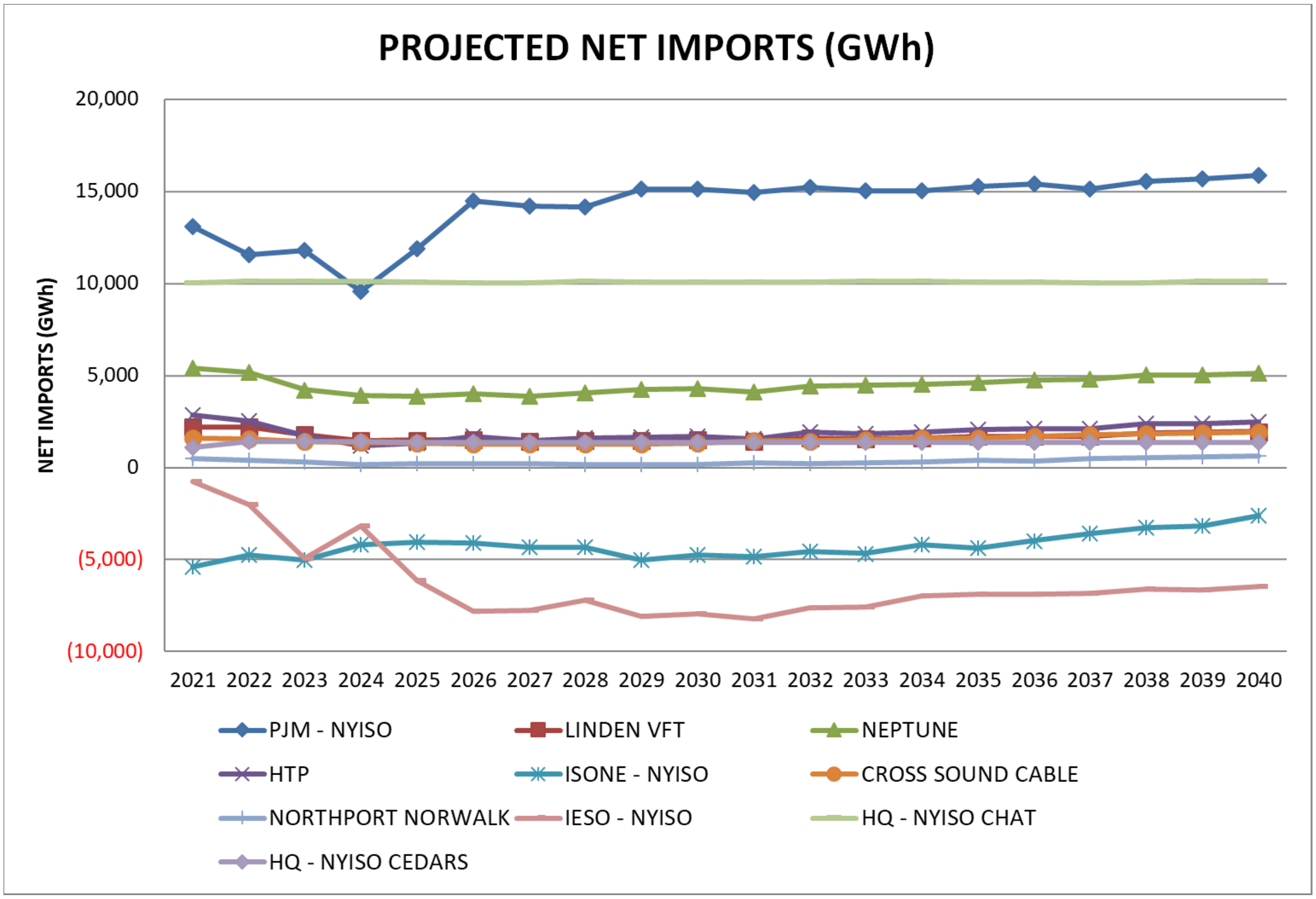


Figure 37 shows the projection of net imports on each interface for the Baseline Case. Net imports from Ontario decline with the retirement of the Pickering nuclear power plant in 2024 and 2025 and the refurbishment of the Darlington and Bruce nuclear power plants throughout the study period. Net imports from PJM increase in response to this refurbishment schedule. Across the other interfaces, net imports are largely flat through the study period.

F.1.3. Unserved Energy

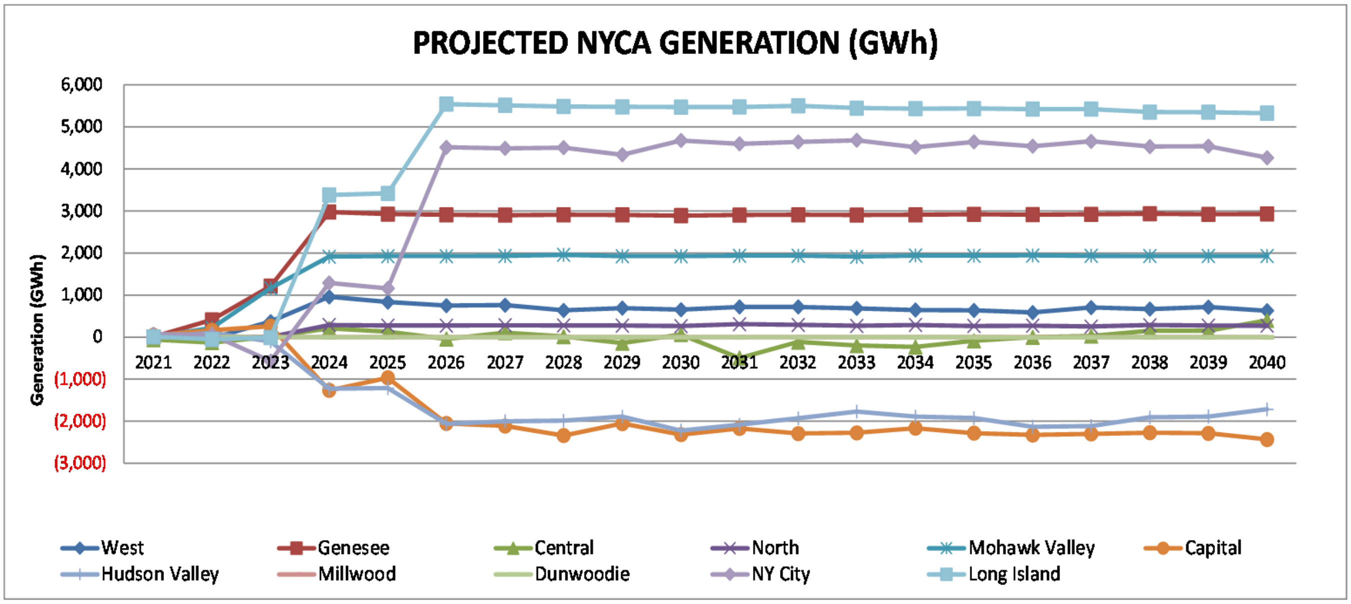
In the production cost model, unserved energy occurs when the model lacks sufficient resources to serve load in a given hour. Any unserved energy in a load zone is met by a zonal 'dummy' generator in the MAPS program. In the Baseline Case, four hours in Zone J in 2040 experience unserved load, which results in 409 MWh of operation from the dummy generator in Zone J. It is important to note that while the study period of the Baseline Case ends in 2040, no new generation is added to the case past 2023 based on the inclusion rules. A lack of new resources over a period of almost 20 years is unrealistic, and the presence of unserved load in later years should not be interpreted as projected violation of system reliability.

Appendix F.2: Contract Case Results

This section summarizes study results for The Outlook Contract Case.

F.2.1. Annual Generation

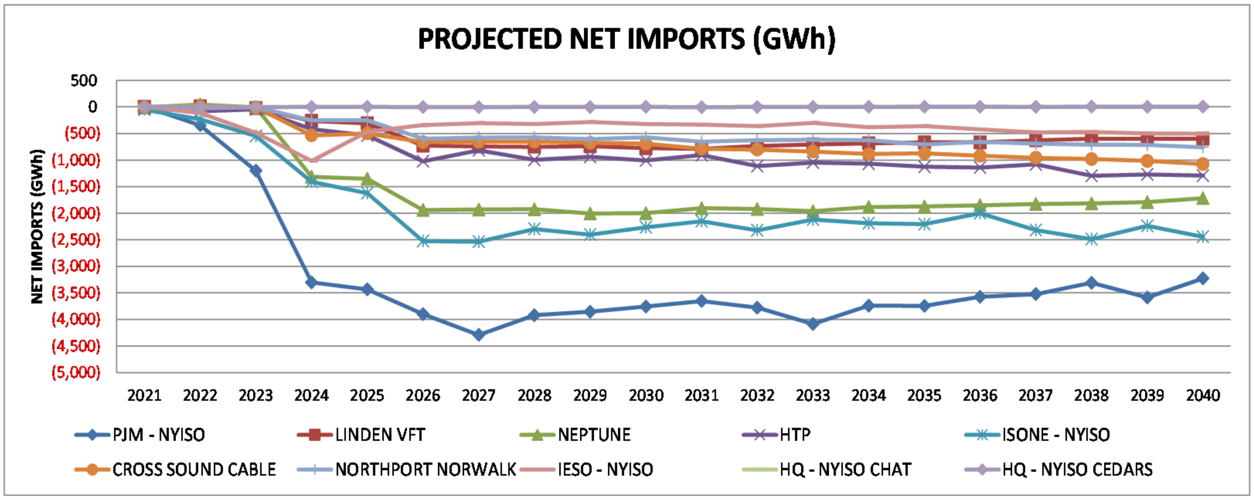
Figure 38: Projected NYCA Generation by Zone, Delta from Baseline Case



F.2.2. Net Imports

Figure 39 shows the change in net imports from the Baseline Case by interface.

Figure 39: Projected Net Imports by Interface, Delta from Baseline Case



F.2.3. Congestion

Figure 40: Projected Demand Congestion by Zone, Delta from Baseline Case

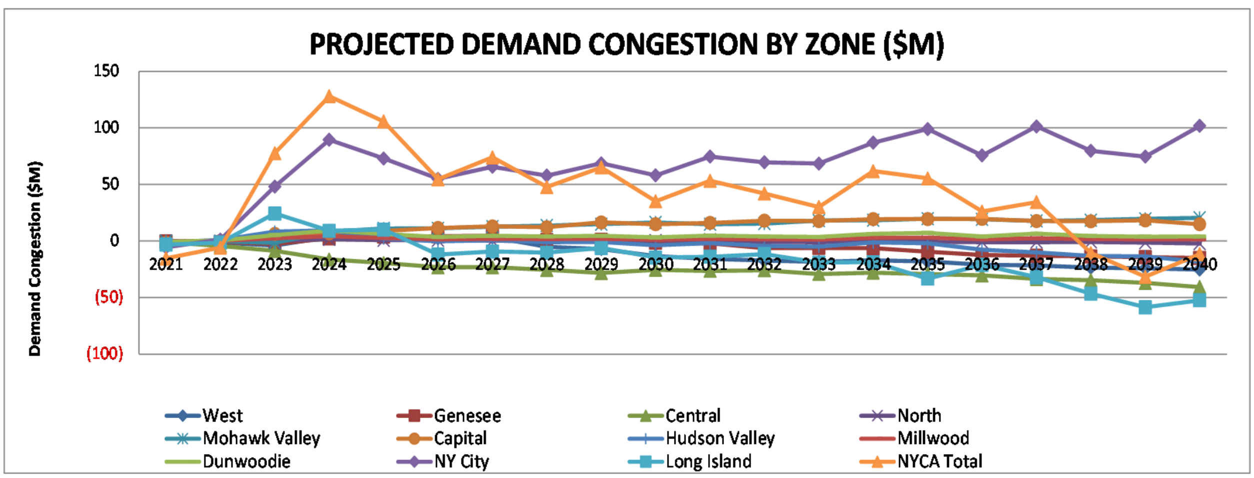


Figure 41: Demand Congestion by Constraint, Delta from Baseline Case

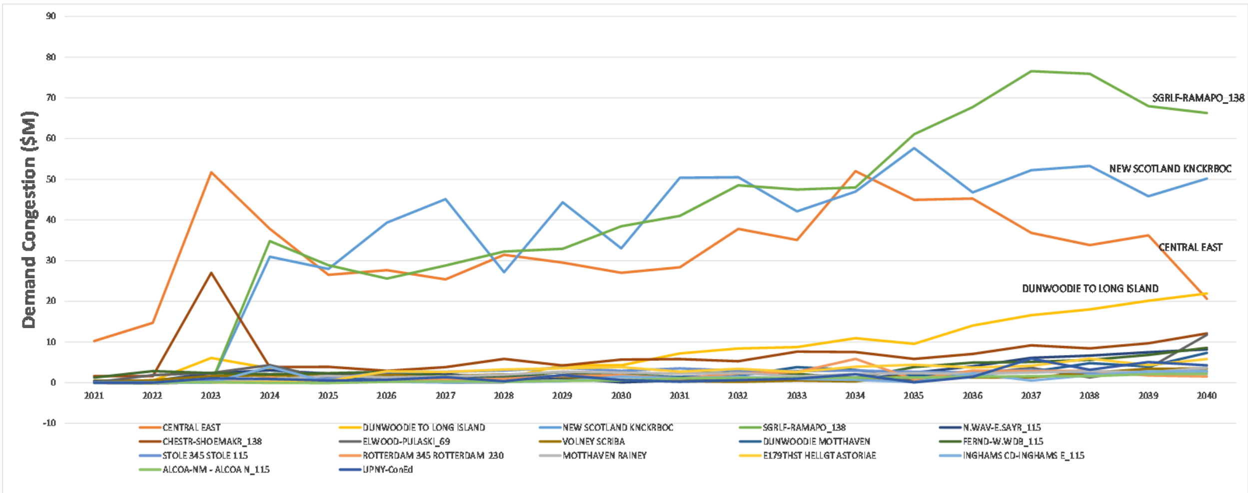


Figure 40 and Figure 41 show the changes from the Baseline Case in demand congestion both zonally and by constraint. Zone J sees the most significant increase in demand congestion while Central and Long Island see decreases in demand congestion. The constraints with the most prominent increases in demand congestion are Sugarloaf to Ramapo, New Scotland to Knickerbocker, Central East, and Dunwoodie to Long Island.

F.2.4. Renewable generation and curtailment

The Contract Case generator additions include renewable energy projects under contracts with NYSERDA that have procured REC contracts to serve energy in New York. The following chart shows renewable energy generation by type in each zone for the 20 years studied in the Contract Case.

Figure 42: Annual Generation by Unit Type and Zone

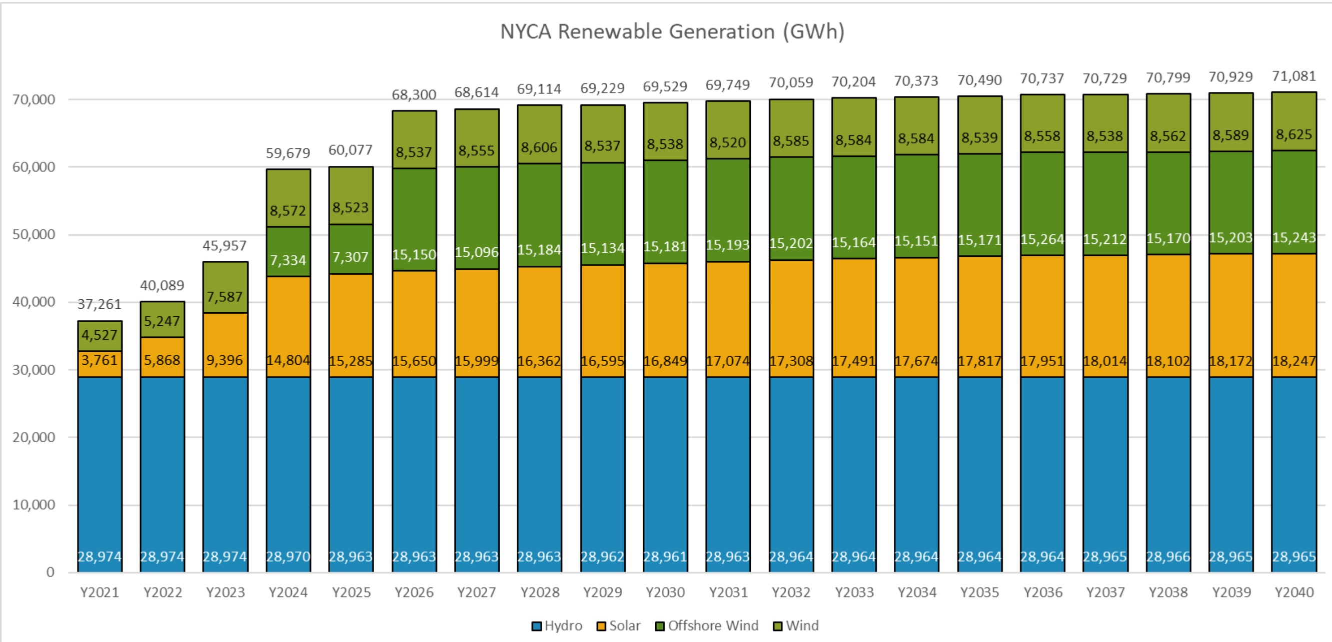
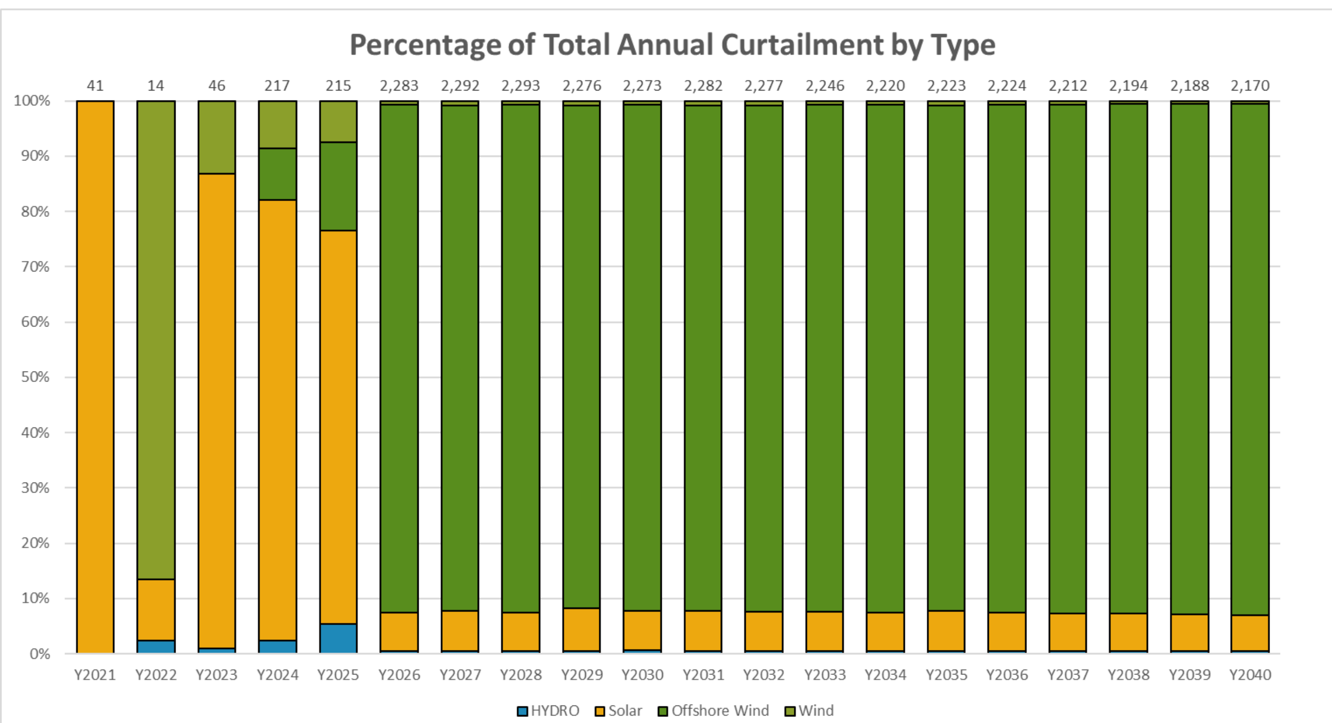


Figure 43: Annual Curtailment by Unit Type



As shown in the chart above, curtailment levels are low in the Contract Case in the early years of the study period and can be attributed mostly to solar units in upstate New York. The NYISO also observed an amount of hydro and land-based wind resource curtailment. Starting in 2026, a significant increase in offshore wind curtailment can be observed. The Contract Case includes offshore wind projects which have received Offshore Wind Renewable Energy Certificates (ORECs) from NYSERDA. The offshore wind curtailment can mostly be attributed to local constraints at the point of interconnection in Zone K. Specific substation configurations and transmission upgrades related to the interconnection of each project were not modeled as part of the production cost modeling. The numeric values displayed above the bars in Figure 43 identify the total annual renewable energy curtailment in GWh.

F.2.5. Unserved energy

Periods of unserved energy in production cost simulations occur when there are not enough dispatchable resources available to serve load in an area. This is typically caused by transmission congestion in a localized zone which does not allow load to be served within that pocket or zone. To ameliorate this condition, the NYISO's production cost database has 'DD' units (Dispatchable Demand), which are hypothetical, high operating cost thermal units designed to come online and serve load in situations where capacity is deficient or dispatchable resources in the system are unable to serve load due to congestion. The output from these units is distributed to each load bus in a zone proportional to the load factor of the bus. Activation of any zone's DD unit for any number of hours indicates that there exists a capacity deficiency in that particular hour or there are significant amounts of congestion in and around the load such that energy cannot be delivered. The Contract Case observed three hours in 2040 when DD units operate in New York City, which is similar to the unserved energy found in the Baseline Case.

Appendix F.3: Policy Case Results

This section presents summary level results for The Outlook Policy Case.

F.3.1. Capacity Expansion Simulation Results

Results of the capacity expansion model represent the optimization outcome for minimization of total operational and fixed costs including capital costs over the entire 20-year study period. The system representation model of the NYCA included splitting each year into 17 time slices and 11 zones while satisfying policy and other constraints. Given that the global optimization results would differ if performed on a full nodal system representation with hourly resolution, as will occur in production cost modeling in a single year, these results should not be viewed as buildouts that would fully achieve the CLCPA targets even as the capacity expansion model 'solved' to them. Rather, these results represent potential future scenarios that can meet policy objectives absent the detailed technical constraints that are evaluated later in the production cost model.

For purposes of this Outlook study, two capacity expansion scenarios were selected, S1 and S2, and were run through production cost simulations for further analysis in the Policy Case. The intention of these two scenarios is to show a range of potential future capacity buildouts resulting from two sets of differing input assumptions. This Outlook study does not endorse one scenario over the other, and these scenarios should be viewed as possible outcomes given the large uncertainty of the future system.

For certain types of generation, the results were similar for S1 and S2, as these outcomes were likely driven by policy constraints or build limits modeled in both scenarios. Results for other types of generation, whether in terms of installed capacity and/or generation mix, differed between the two scenarios, as these results were driven by the assumptions specific to each scenario. Overall, results for S2 showed a higher level of renewable penetration than S1, most notably in UPV capacity builds, and had different projection of the capacity expansion throughout the study period as compared to S1 for all generator types. The main factors for these differences are the assumptions for load forecasts and differences in constraints modeled between the two scenarios.

Results that are similar between the two cases are noted below, and results that are specific to each scenario are described in detail in the S1 or S2 section below respectively.

Existing Generation

For purposes of this section, existing generation in the capacity expansion model is limited to generation in the NYCA consistent with the Baseline Case as well as scheduled generation builds in service consistent with the assumptions in the Contract Case of this Outlook study. The generator types assumed as existing generation as of the 2021 start year include: fossil fuel-fired, nuclear, hydro (including qualifying imports from Hydro Quebec), LBW, UPV, storage (including pumped storage hydro and battery storage), and Other (*i.e.*, landfill gas, refuse, and biomass fired generators).

Due to the CLCPA requirement of a zero emissions grid by 2040, the NYISO modeled all fossil fuel-fired units to retire by the horizon year since these CO_2 emitting generators cannot operate in 2040. Existing zero-emitting generation, such as nuclear, hydro, LBW, and UPV generation, remains operational in the system through 2040.

Generation Expansion

In both S1 and S2, a significant amount of capacity from renewable generation and DEFRs was installed by 2040. The results show a total of approximately 111 GW of installed capacity for S1 and 124 GW of installed capacity for S2, inclusive of NYCA generators and qualifying imports from Hydro Quebec only. This level of total installed capacity would be needed in 2040 to satisfy the state policy, energy, and resource adequacy constraints for S1 and S2, respectively. Of this total amount of installed capacity, approximately 85 GW to 100 GW is attributed to generation expansion for S1 and S2, respectively, beyond what is the 9.5 GW planned through state contracts. For comparison, the Baseline and Contract Cases have approximately 42 GW and 51 GW, respectively, of installed capacity by 2040. Additionally, the total installed capacity was approximately 43 GW in the 2019 Benchmark simulation.

In both Policy Case scenarios, a significant amount of LBW capacity was built by 2040. As compared to the other renewable technologies available to the model, LBW was preferred due to its assumed capital cost, generation profile (*i.e.*, HRM shape's implied capacity factor), and UCAP ratings. In both scenarios, LBW adds to the assumed capacity build limits imposed (~16 GW).

Additionally, a significant amount of DEFR capacity was installed by 2040 in both scenarios S1 and S2, however, the types of DEFRs built in each case differed. Additional detail on the generation expansion and operations from DEFRs is discussed below.

Lastly, more than 10 GW and 11 GW of battery storage capacity was built in S1 and S2, respectively. Approximately 1 GW of additional battery storage capacity was built in S2 to help satisfy the capacity reserve margins, due to its assumed UCAP rating and relatively low capital cost, as compared to the other generator types available for expansion in S2.

Results Specific to S1

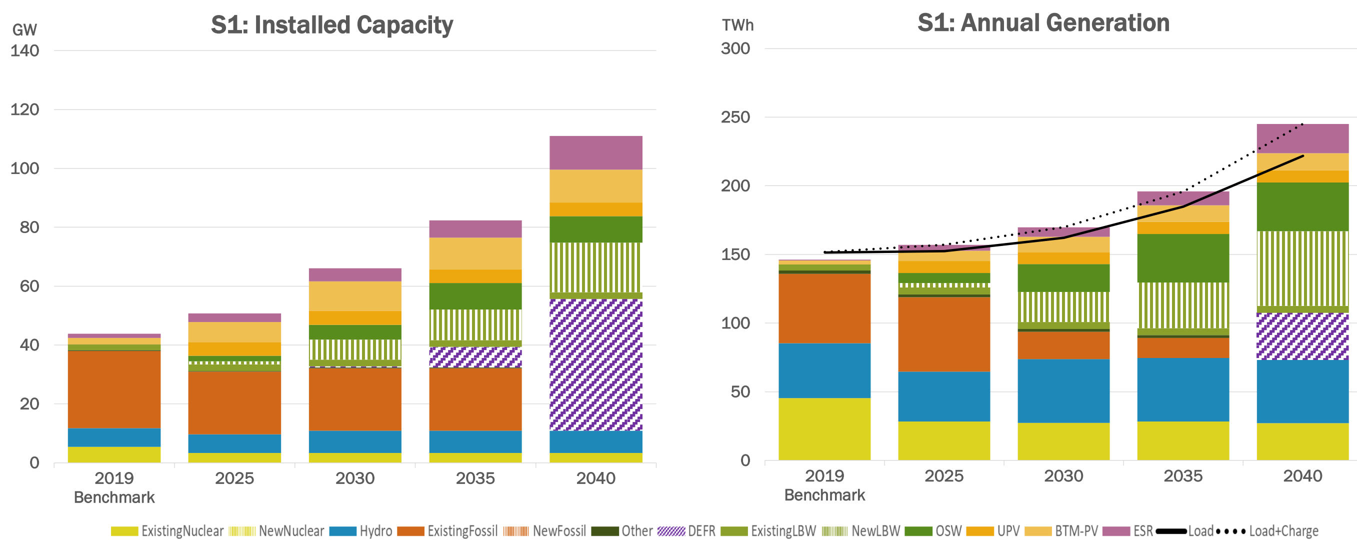
The results show that a significant amount of DEFR capacity is needed to support the higher loads and renewable penetration built by 2040. The High Capital/ Low Operating cost DEFR option generates a significant amount of energy in 2040; this DEFR option essentially operates as a baseload generator in the capacity expansion model. The Low Capital/High Operating cost DEFR option generates very little energy in the capacity expansion model in 2040 and is primarily selected to help satisfy the capacity reserve margins at the statewide and Locality levels due to its high assumed UCAP rating and low capital cost, as compared to the other generator types available. While an option, the Medium Capital/ Medium Operating cost DEFR option is not built in S1.

In the S1 case, UPV capacity does not build beyond what is planned through state contracts (included in the Contract Case). The lower energy contribution, especially in the overnight load blocks, in addition to its comparatively low UCAP rating, are the primary reasons that UPV does not build economically in S1. The transition to a winter peaking system, when solar irradiance levels are the lowest, also impacted the ability of UPV to assist in meeting capacity and energy needs.

Additionally, OSW capacity does not exceed its nine GW minimum requirement per the CLCPA. Of the candidate generator types eligible for capacity expansion, OSW is assumed to have the highest capital cost, excluding the High Capital/Low Operating cost DEFR option. The high capital cost and relatively lower UCAP rating of OSW, after nine GW are selected, are the primary reasons that OSW capacity does not exceed the capacity required by its respective CLCPA target in S1.

Results specific to S1 are included in Figure 44 below. The figure displays 2019 Benchmark capacity (GW) and generation (TWh) alongside the capacity expansion model outputs provided in five-year intervals. Results on the NYCA level are broken out by generation type in both graphical and tabular form. The generation table includes calculation of total, renewable, and zero-emissions generation relative to the load in units of energy and percentage and show that the CLCPA 70% renewable generation by 2030 and 100% zero-emissions by 2040 policy constraints were satisfied. The resultant CO_2 emissions reductions are also included in the figure.

Figure 44: S1 Capacity and Generation Results



Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,310	21,232	21,234	-
DEFR - HcLo	-	-	-	-	3,812
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	420	7,053	40,938
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	3,335	9,086	12,612	19,087
OSW	-	1,826	5,036	9,000	9,000
UPV	32	4,676	4,676	4,676	4,676
BTM-PV	2,116	6,834	10,055	10,828	11,198
Storage	1,405	2,910	4,410	5,793	11,450
Total	43,838	50,763	66,460	89,376	111,066

Emissions (million tons)					
	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	23.53	8.50	6.22	-

* Storage includes Pumped Storage Hydro and Batteries
* Utility solar (UPV) includes existing (77 MW) and new UPV
* Hydro includes hydro imports from Hydro Quebec

Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	54,174	19,987	14,516	-
DEFR - HcLo	-	-	-	-	33,482
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	523
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	8,189	26,971	38,297	59,362
OSW	-	7,331	20,186	35,460	35,647
UPV	51	8,817	8,816	8,817	8,819
BTM-PV	2,761	7,483	11,068	11,983	12,454
Storage	612	4,347	7,004	10,084	21,339
Total Generation	146,262	157,088	169,810	195,879	245,109
RE Generation	47,261	68,238	113,383	140,949	162,672
ZE Generation	93,301	100,922	147,831	179,371	245,109
Load	151,386	152,336	162,122	184,836	221,828
Load+Charge	151,773	157,089	169,811	195,879	245,109
% RE [RE/Load]	31%	45%	70%	76%	73%
% ZE [ZE/(Load+Charge)]	61%	64%	87%	92%	100%

* Land-Based Wind (LBW), Offshore Wind (OSW), Zero Emissions (ZE)
* Dispachable Emission Free Resource (DEFR), High Capital Low Operating (HcLo), Medium Capital Medium Operating (McMo), Low Capital High Operating (LcHo)

Results Specific to S2

The results of S2 show that less DEFR capacity is needed to support the lower peak load levels and high renewable penetration built by 2040 relative to S1. For comparison, the total amount of DEFR capacity built by 2040 was comparable to the total NYCA fossil fuel-fired capacity installed as of the 2019 benchmark analysis. S2 assumes that the Medium Capital/Medium Operating cost DEFR is the only capacity expansion DEFR generator option. The Medium Capital/Medium Operating cost DEFR produces a different operational profile in the capacity expansion model as compared to the High Capital/Low Operating and Low Capital/High Operating cost DEFR generators.

Of note, S2 assumed lower maximum capacity limitations for LBW generators through model year 2030, while maintaining the same maximum capacity limitations for LBW for model years 2031-2040.[1] Due to the lower build limit, less LBW was built by 2030 as compared to S1. However, like S1, LBW builds to the maximum allowable capacity in all zones by 2040, as imposed by its respective constraints.

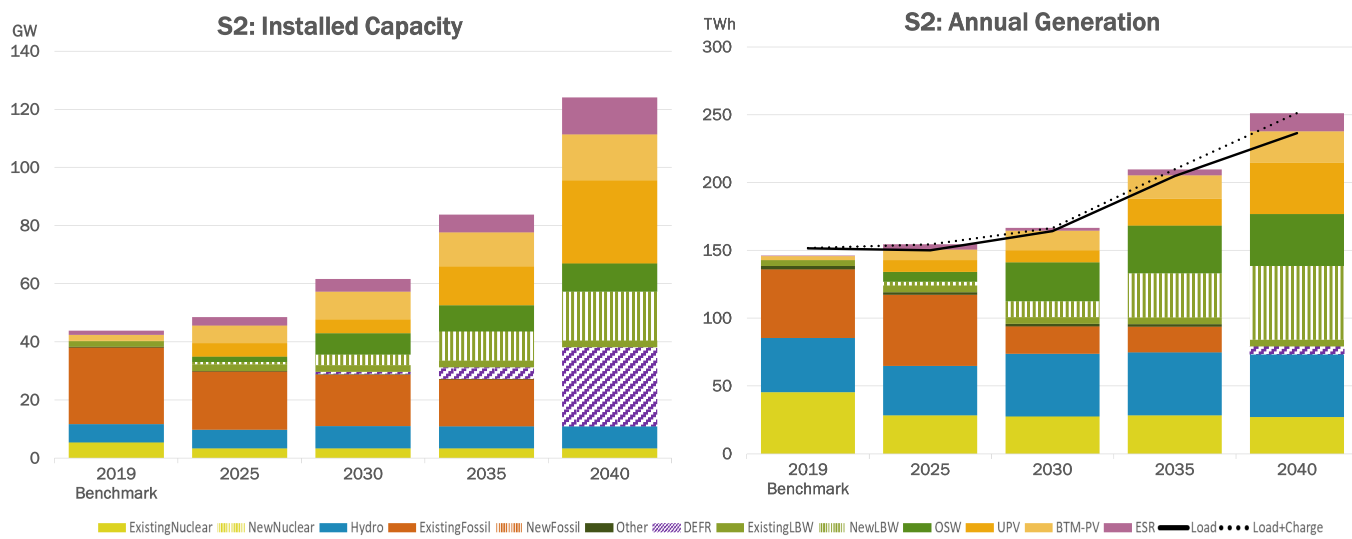
As compared to S1, which did not observe economic builds from UPV, a significant amount of UPV capacity is built in S2 later in the model horizon to help address the system's energy needs, most notably in the upstate zones. This is primarily driven by the load forecast and DEFR options allowed for generation expansion in S2. Of note, LBW and OSW are the preferential build options in the capacity expansion model as compared to UPV due to their assumed costs, generation profiles, and UCAP ratings. Whereas LBW and OSW see a significant portion of their total capacity built prior to 2030, UPV capacity is not built until after 2030; with the majority of UPV capacity built between years 2035 and 2040. UPV capacity is built in Zones A-G and K as a lower cost energy option as compared to the Medium Capital/Medium Operating cost DEFR.

In S2, the candidate generators in Zones J & K are limited to the Medium Capital/ Medium Operating DEFR option, UPV, and OSW. Due to the limited candidate generation types available for Zones J & K in S2, OSW capacity is built beyond the minimum required by the 9 GW CLCPA target to help satisfy the energy needs in these zones because it is comparably the more economic choice. Additionally, the amount of OSW capacity built by 2030 was higher in S2 as compared to S1 to help satisfy the 70% renewable generation by 2030 CLCPA target. Ultimately, more OSW was built earlier on because less LBW capacity was allowed to build by 2030 due to the assumed build constraints for LBW in S2.

Results specific to S2 are included in the figure below.

[1] Zonal capacity limitations are assumed for candidate LBW, OSW, and UPV generators and are based on the 2040 limitations for the applicable generator type, per https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-1-Input-Assumptions.ashx, excluding LBW in S2. For LBW in S2, the maximum allowable capacities for model years 2021-2030 are based on the 2030 limitations for LBW and model years 2031-2040 are based on the 2040 limitations.

Figure 45: S2 Capacity and Generation Results



Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,988	17,650	16,071	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,200
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	3,138	5,890	12,366	19,087
OSW	-	1,826	7,436	9,000	9,720
UPV	32	4,676	4,676	13,448	28,606
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	6,147	12,810
Total	43,838	48,523	62,454	87,787	124,135

Emissions (million tons)					
	2019	2025	2030	2035	2040
CO2 Emissions	22.24	22.87	8.98	8.50	-

* Storage includes Pumped Storage Hydro and Batteries
* Utility solar (UPV) includes existing (77 MW) and new UPV
* Hydro includes hydro imports from Hydro Quebec

Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	52,437	20,066	18,908	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	5,584
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	7,518	16,494	37,460	59,362
OSW	-	7,331	28,865	35,247	38,388
UPV	51	8,817	8,816	19,661	37,705
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	4,007	2,086	4,492	13,414
Total Generation	146,262	154,488	166,567	209,714	251,155
RE Generation	47,261	67,715	114,979	155,984	205,065
ZE Generation	93,301	100,059	144,509	188,814	251,155
Load	151,386	150,047	164,255	204,764	236,334
Load+Charge	151,773	154,488	166,567	209,715	251,155
% RE [RE/Load]	31%	45%	70%	76%	87%
% ZE [ZE/(Load+Charge)]	61%	65%	87%	90%	100%

* Land-Based Wind (LBW), Offshore Wind (OSW), Zero Emissions (ZE)
* Dispachable Emission Free Resource (DEFR), High Capital Low Operating (HcLo), Medium Capital Medium Operating (McMo), Low Capital High Operating (LcHo)

F.3.2. Production Cost Simulation Results

Capacity expansion results were ported to the production cost model and the hourly simulations were performed. Policy Cases were simulated in five-year intervals from 2025 to 2040. Generation capacity remains consistent between the capacity expansion and production cost simulations, but the operation of the fleet can differ due to a more detailed nodal network, higher temporal resolution, and full modelling of neighboring systems in the latter. The differing results between the models provides important insights into the challenges that may occur when procuring a significant amount of renewable generation capacity to meet policy objective(s). The more detailed results also help to identify specific needs that may arise for the future scenarios evaluated (*e.g.*, ramping characteristics, and transmission congestion leading to decreased renewable generation energy deliverability within emerging generation pockets).

Unserved Energy

Unserved energy represented by operation of Dispatchable Demand ("DD") units in MAPS represents the load energy not met by installed generators in the system or area due to transmission constraints. The retirement of existing fossil fuel generation and the addition of intermittent resources in the Policy Case scenarios resulted in periods of unserved energy that are greater in number than those compared to the Baseline and Contract Cases. In 2040, there was a total of 969 combined hours representing 319 GWh of energy in S1 and 444 combined hours representing 109 GWh of energy in S2 supplied by DD units. In both scenarios, Capital (Zone F) had the greatest number of hours of DD operation. With significant amounts of fossil fuel units retiring, high amounts of congestion directly upstream of Central East and limited build of new resources might be some of the causes for DD units turning on to serve load in the Capital Region.

The charts in Figure 46 through Figure 51 show the system and zonal capacity, energy production, and curtailment results for both scenarios simulated (S1 and S2).

Figure 46: Scenario 1 Production Cost Capacity by Type by Zone

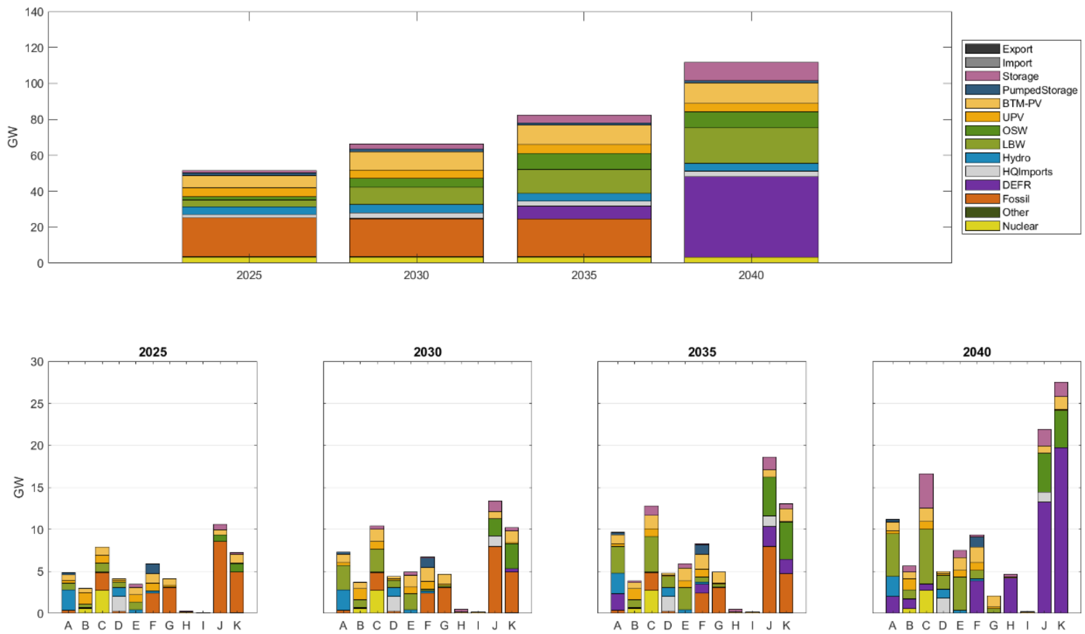


Figure 47: Scenario 2 Production Cost Capacity by Type by Zone

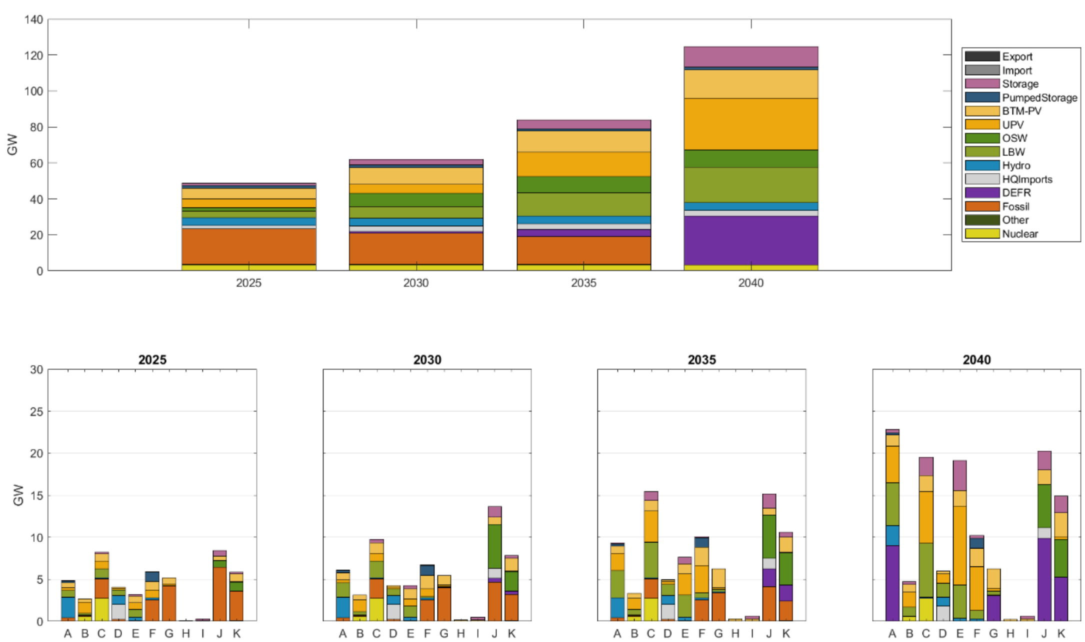


Figure 48: Scenario 1 Production Cost Energy by Type by Zone

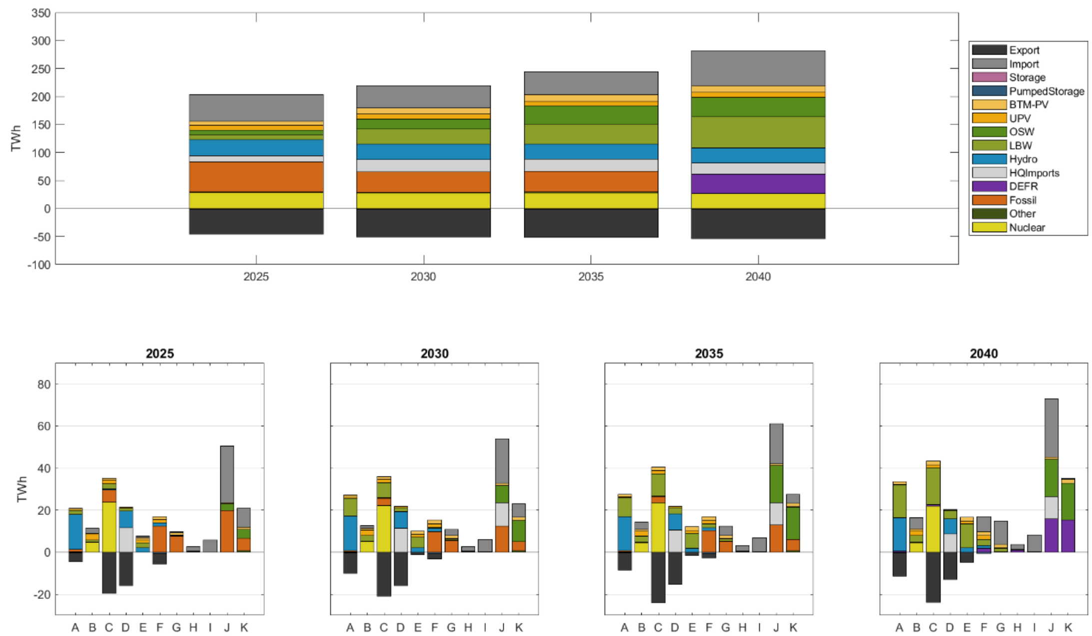


Figure 49: Scenario 2 Production Cost Energy by Type by Zone

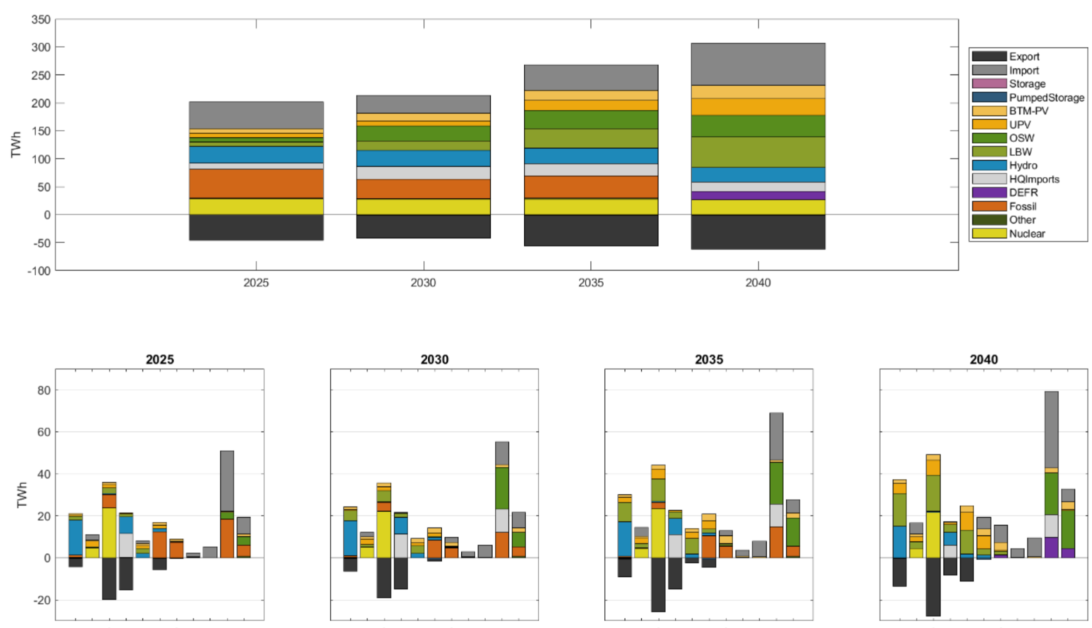


Figure 50: Scenario 1 Production Cost Curtailment by Type by Zone

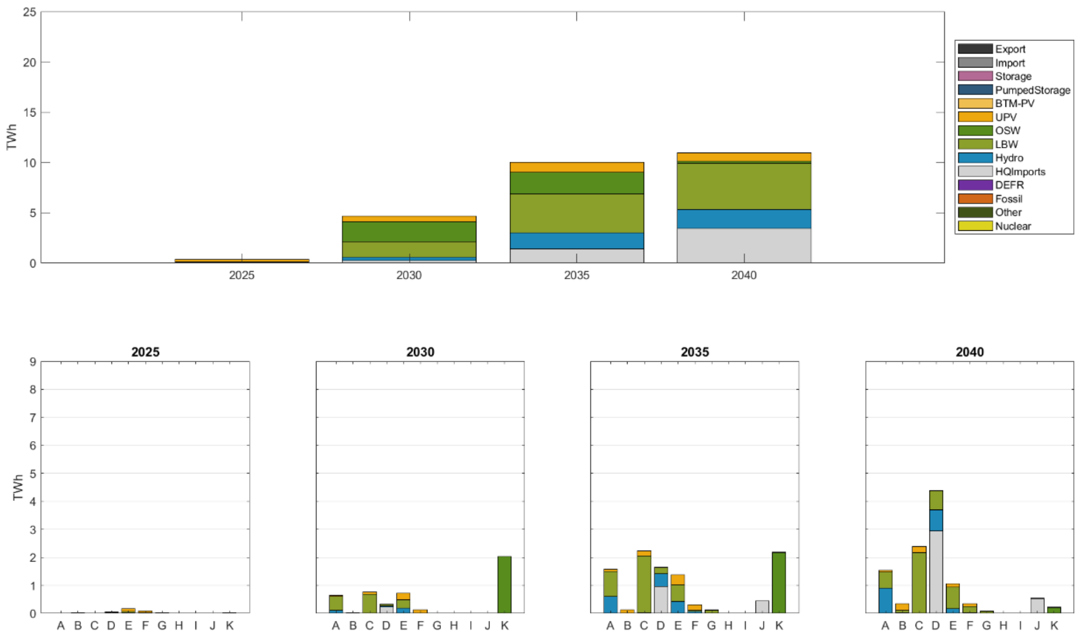
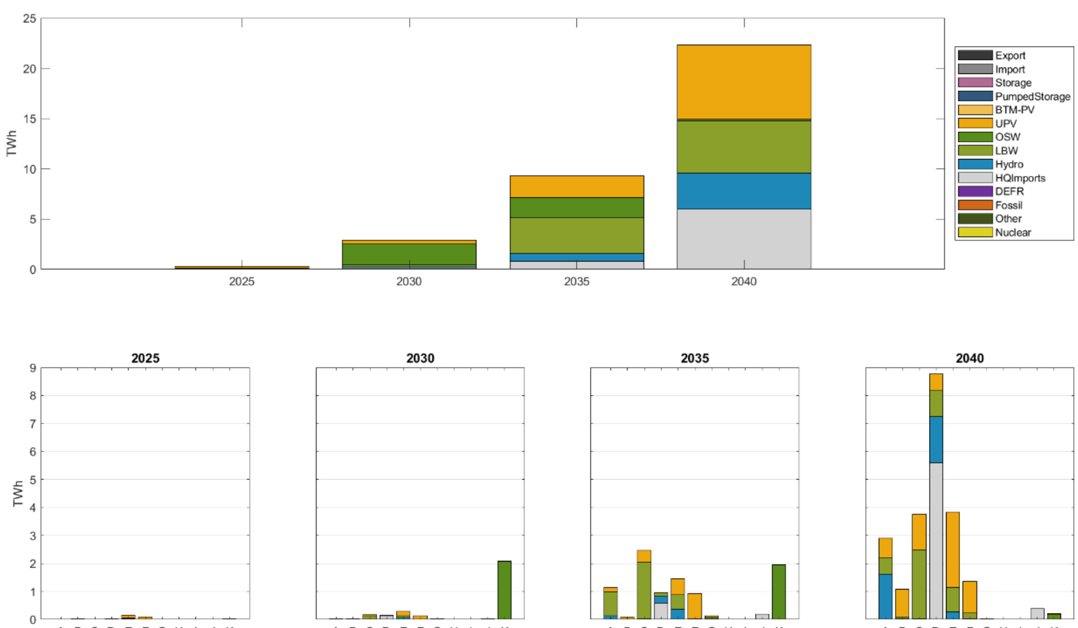


Figure 51: Scenario 2 Production Cost Curtailment by Type by Zone



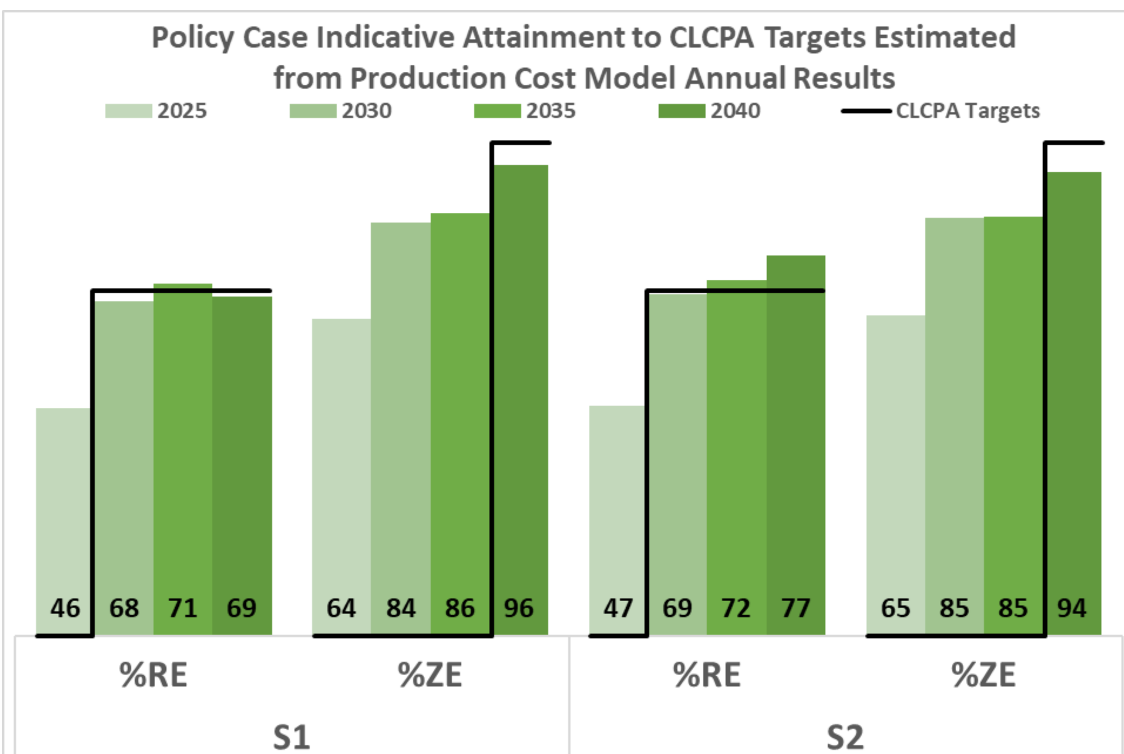
Policy Attainment Assessment

The official renewable generation accounting towards CLCPA policy attainment will be based on programs to be developed by the NYSPSC. In this analysis, a simplified representative calculation of the renewable and zero-emissions percentages are provided for informational purposes. These output metrics are distinct from the actual computations performed by NYSERDA/NYSPSC to calculate the state's fuel mix and progress towards achieving the CLCPA targets, *e.g.*, imports and exports were not considered as part of this simplified calculation, and the contributions from Tier 4 projects are included as soon as the projects are assumed to be in-service.

In the production cost model, the generation placement is based on the results of capacity expansion analysis, and no further attempt was made to achieve full attainment of CLCPA requirements as The Outlook is focused on identifying the challenges to the system along the way to, rather than the exact solutions to, achieving policy goals.

The CLCPA Targets include 70% renewable generation in 2030 and (100%) zero-emissions in 2040. Indicative CLCPA annual renewable energy (%RE) and zero-emissions (%ZE) metrics were calculated and compared against the targets as show in the figure below.

Figure 52: Policy Case CLCPA Target Attainment Estimate



The specific calculations for renewable energy and zero-emission energy were as follows:

RE = LBW + OSW + UPV + BTM-PV + Hydro + HQ Imports

ZE = RE + Nuclear + DEFR

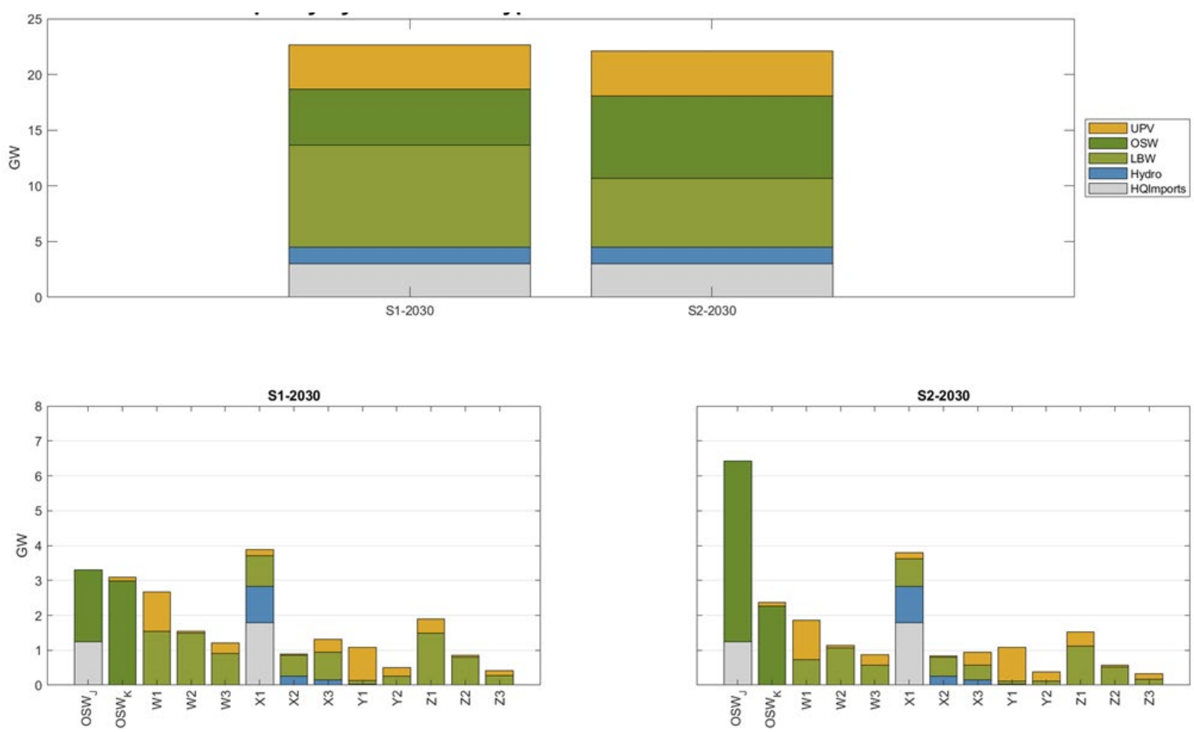
%RE = RE/Gross Load

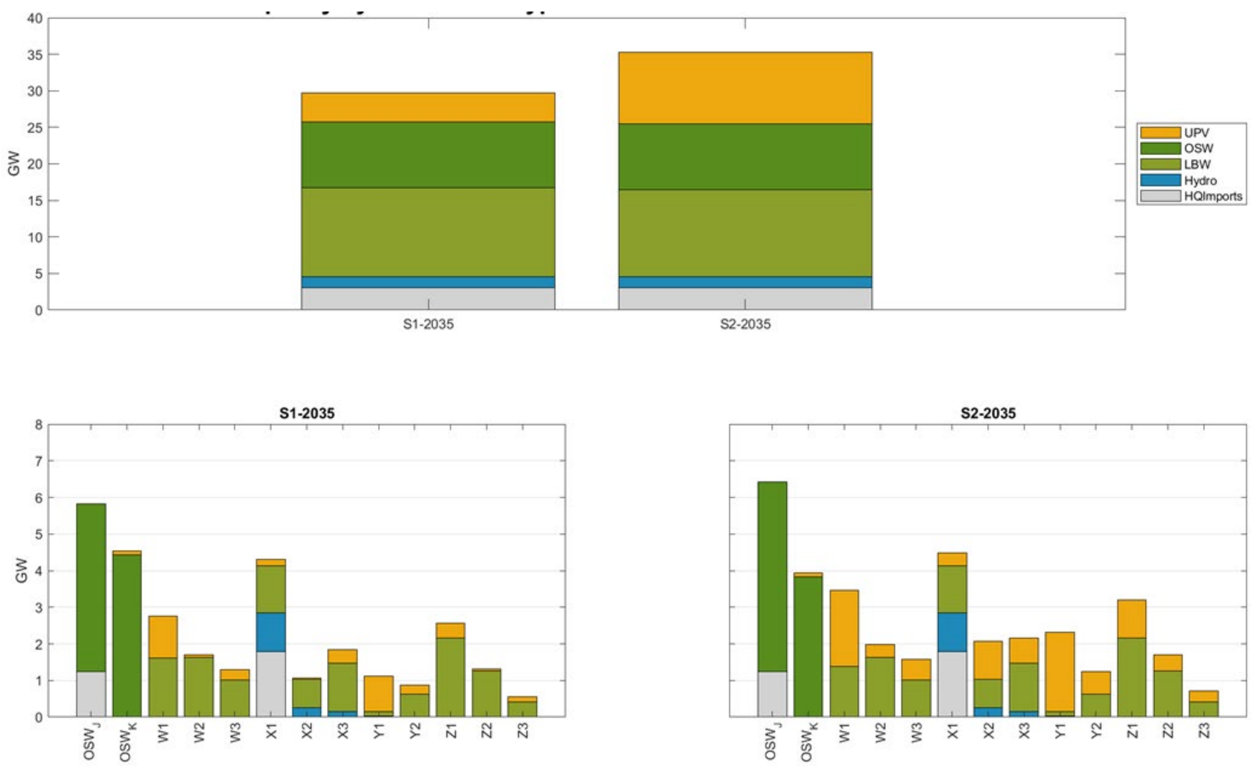
%ZE = (ZE + Storage Discharge)/ (Gross Load + Storage Charge)

Storage includes Pumped Storage and Batteries. The percentage of ZE computed in all years includes impact of Storage Discharge and Storage Charge even though not all storage charging will be from ZE: supply before 2040.

F.3.3. Policy Case Renewable Generation Pockets

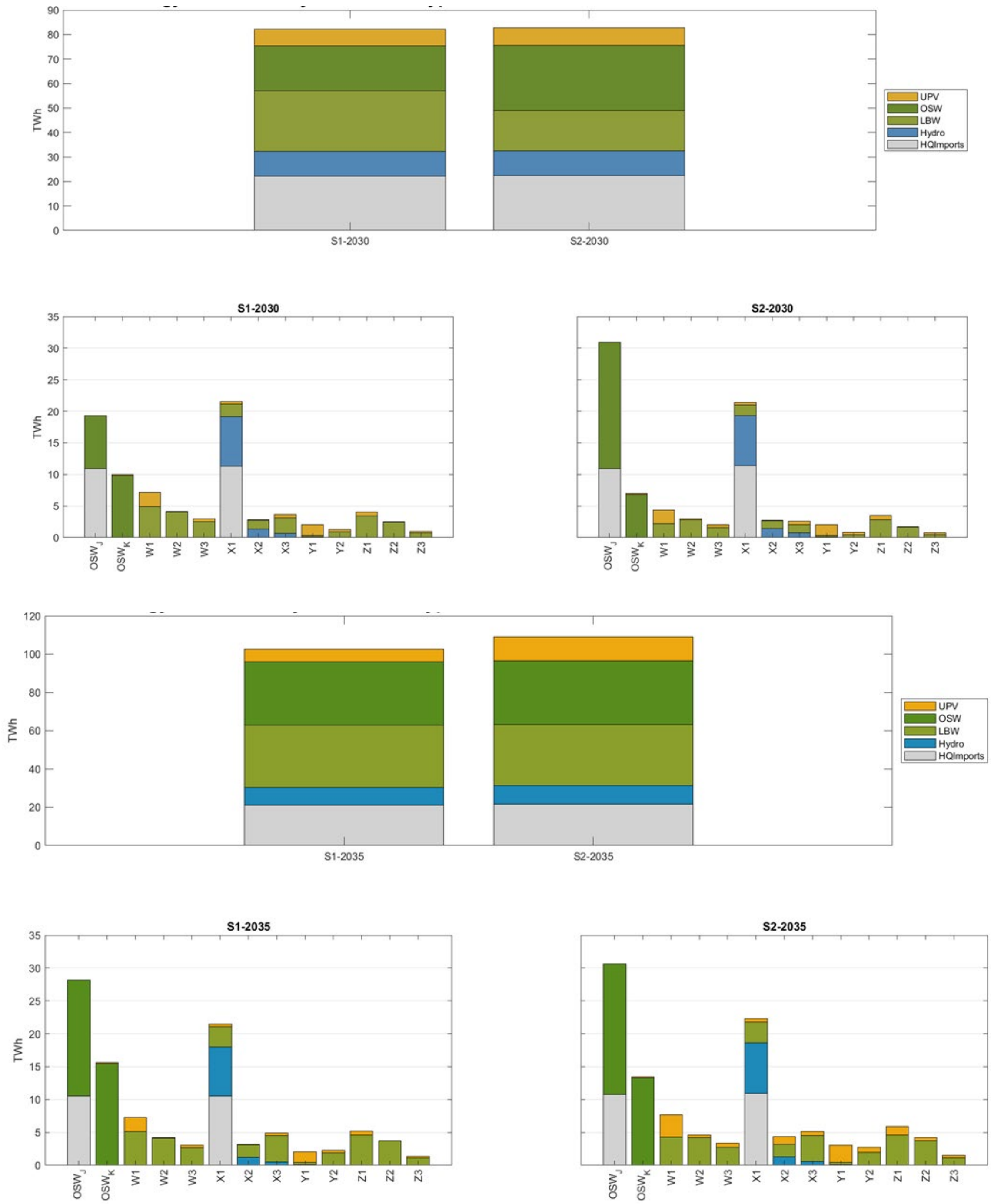
Figure 53: Summer Capacity by Generation Type Across Identified Pockets





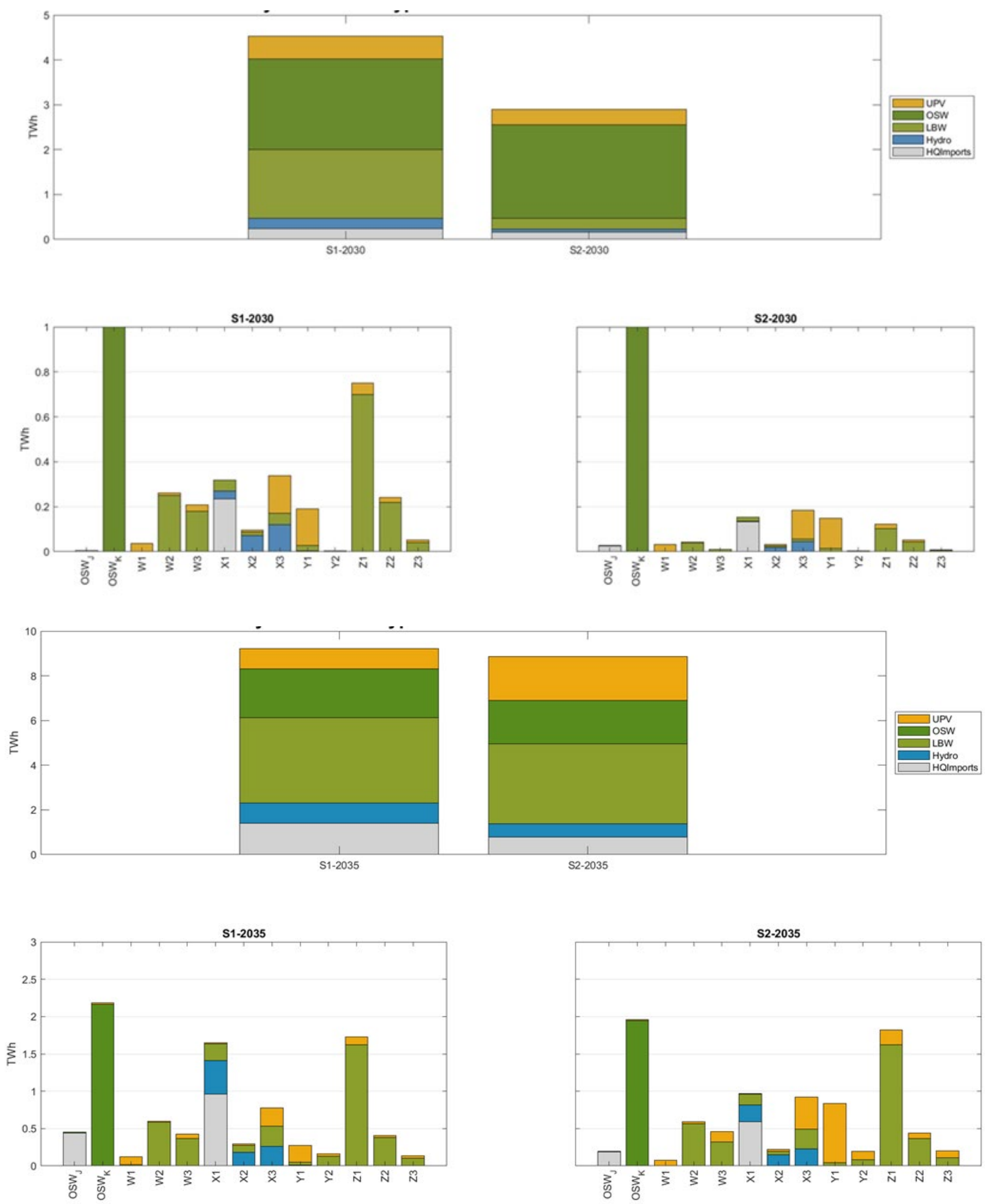
The energy production from generators within the pockets in 2030 is approximately the same on aggregate for S1 and S2. However, the distribution of energy between land-based wind and offshore wind is different, owing to the differences in installed capacity between the two scenarios. S2 has slightly higher generation due to higher solar buildout in 2035 and retirements of existing fossil resources.

Figure 54: Energy Production by Generator Type Across Identified Pockets



Due to large amounts of renewable resources added in the Policy Cases, the level of curtailment is high compared to the Baseline and Contract Cases. Offshore wind curtailment continues to stand out as the largest curtailment by generator type in 2030 for both Policy Cases. Local congestion at the point of interconnection and surrounding constraints causes high levels of curtailment for this resource, which would need to be resolved in a separate process. Curtailment of resources is also highly dependent on retirements of existing fossil fuel resources. S2 has more capacity retiring in 2030 compared to S1, driven by differing assumptions between the two scenarios. Some fossil fuel units (especially in Zones J and K) have must-run reliability rule requirements that require them to be online or generate in most hours of the year. Retiring such units allows for more flexible resources to generate or intermittent resources to dispatch when more available.

Figure 55: Curtailment by Generation Type Across the Identified Generation Pockets



F.3.4. Policy Case Bulk Transmission Congestion

Both Policy S1 and S2 cases have significant amounts of congestion on the bulk transmission system. Constraints which are already constrained in the Base and Contract cases see persistent congestion in the Policy Cases with additional resources injecting power into paths carrying power to load centers especially from upstate to downstate. Some constrained paths might have less congestion depending on where resources are added. For example, Dunwoodie to Long Island which historically flows from Zone I to K has less congestion in the Contract and Policy case compared to the Baseline Case as Offshore Wind resources are added downstream of the constraint which pushes back on some of the flow on the line. The 2040-year case highlights the congestion on the bulk system when all lower kV constraints are removed. Higher congestion can be seen on most constraints in this case as relieving lower kV constraints allows for more energy to be delivered to the bulk system. Overall, bulk level constraints which are identified in the Baseline and Contract Cases do show significant congestion in the Policy Cases as highlighted in the tables below.

Figure 56: Percentage of Hours Congested, Years 2030 and 2035[2]

% of Year Congested (2030)	S1	S2
North Tie: OH-NY	92%	91%
DUNWOODIE TO LONG ISLAND	55%	70%
BARRETT to VALLEY STREAM	56%	54%
STOLE 345 STOLE 115	14%	22%
CENTRAL EAST	28%	6%
ROTTERDAM 345 ROTTERDAM 230	15%	11%
SGRLF-RAMAPO_138	8%	9%
NEW SCOTLAND KNCKRBOC	3%	3%
DUNWOODIE MOTTHAVEN	1%	1%

% of Year Congested (2035)	S1	S2
North Tie: OH-NY	92%	91%
DUNWOODIE TO LONG ISLAND	57%	57%
BARRETT to VALLEY STREAM	57%	56%
CENTRAL EAST	26%	24%
ROTTERDAM 345 ROTTERDAM 230	24%	25%
STOLE 345 STOLE 115	14%	28%
SGRLF-RAMAPO_138	9%	16%
NEW SCOTLAND KNCKRBOC	2%	5%
DUNWOODIE MOTTHAVEN	1%	2%

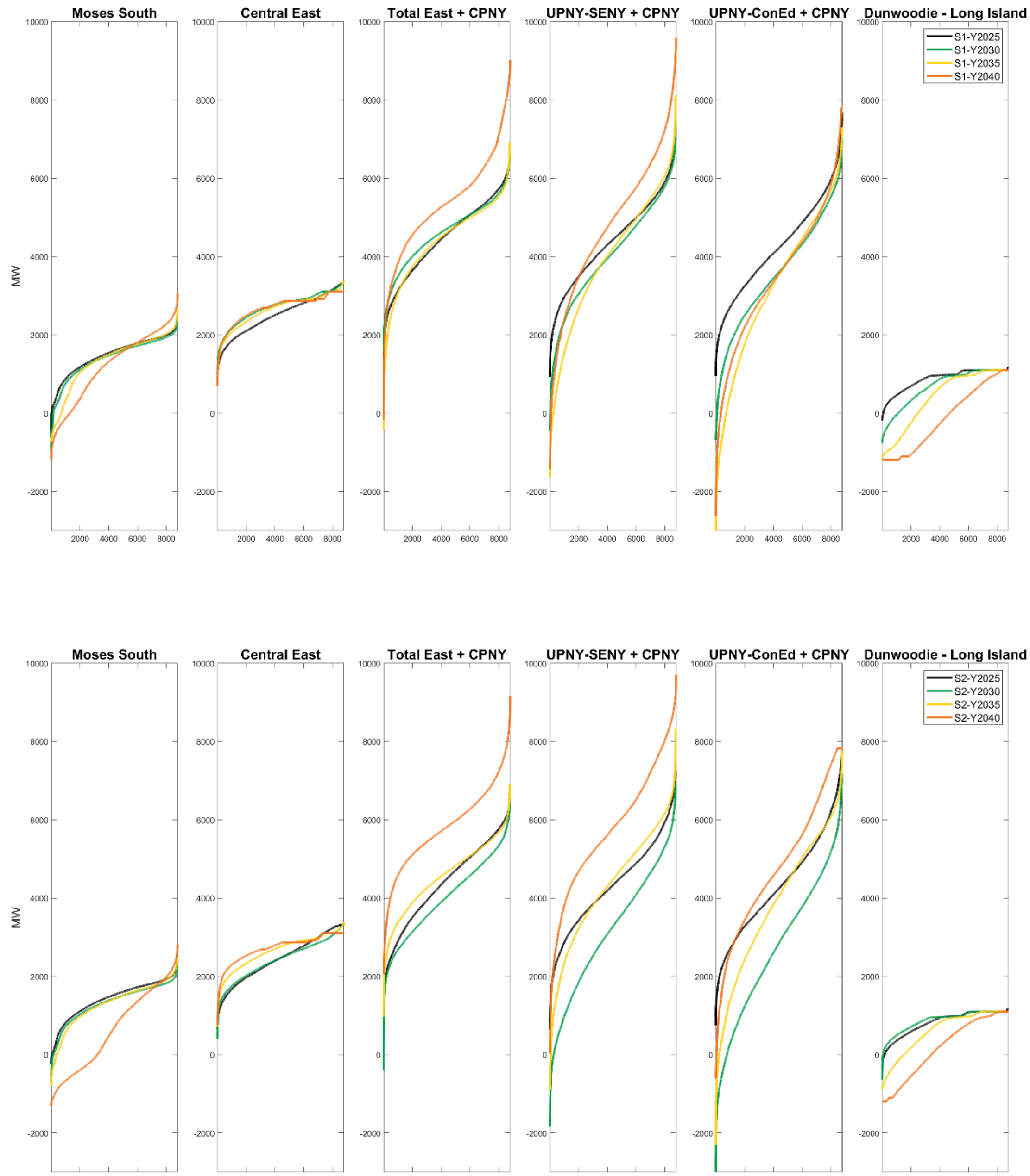
[2] Congestion reported on North Tie: OH-NY may not reflect actual operation of PAR controlled interface which operates at a fixed schedule to reduce congestion on either side of the interface. Projected congestion reported here is a result of securing the interface in production cost simulation analysis. The Stolle Road 345/115 kV transformer congestion reported is a result of an invalid contingency which does not reflect actual topology in the Stolle Road substation.

Figure 57: Percentage of Hours Congested, Year 2040

Constraint	S1	S2
North Tie: OH-NY	81%	86%
STOLE 345 STOLE 115	51%	65%
ROTTERDAM 345 ROTTERDAM 230	53%	45%
DUNWOODIE TO LONG ISLAND	48%	45%
CENTRAL EAST	45%	45%
DUNWOODIE MOTTHAVEN	5%	9%
NEW SCOTLAND KNCKRBOC	1%	9%
NIAGARA 230 NIAGARA 115	2%	0%

Figure 58 below shows the bulk level flows in both S1 and S2 Policy Cases. Flows across the system are impacted by the addition of renewable resources upstate and retirement of fossil generation downstate. Bulk level flows are also largely impacted by the addition of offshore wind projects in Zones J and K. It especially impacts flows across Dunwoodie-Long Island which shows a reversal in flow for about 40-50% of the year in later years as more offshore generation is put into service. Bulk flows in S2 is comparatively higher than S1 likely due to higher average loads being modeled and a lower level of generating capacity downstate compared to S1.

Figure 58: Policy Case Bulk Level Interface Flow Duration Curves

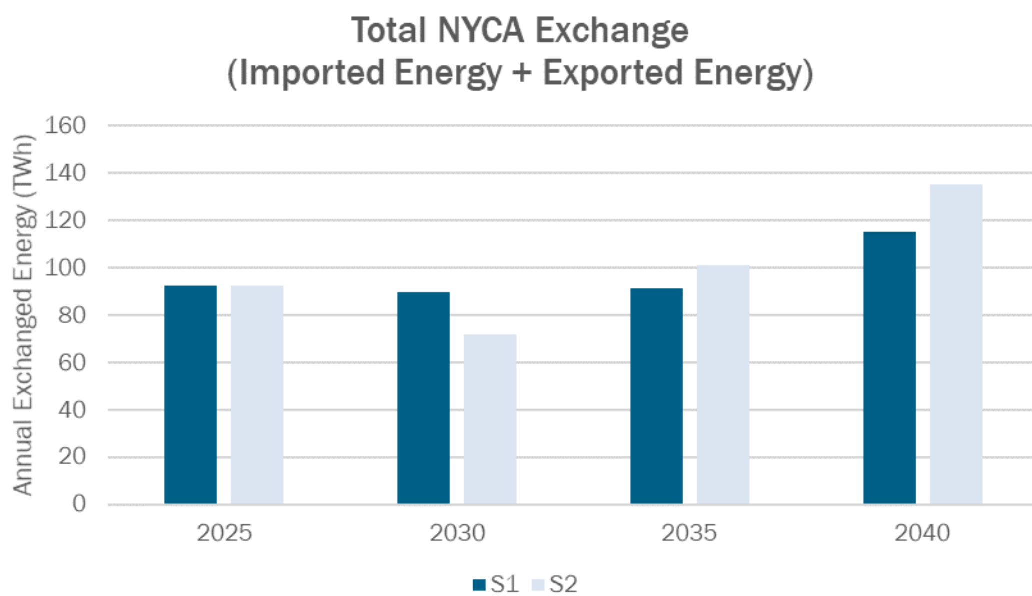


F.3.5. Policy Case Hourly Seasonal Analysis

Leveraging the hourly results from the Policy simulations a detailed seasonal dispatch analysis was performed. Some observations obtained from evaluating the seasonal and five-year trends from each scenario follow:

- In both S1 and S2, the Spring season experiences the most curtailment of wind, solar, and hydro generation. Spring in New York can be characterized as having lower energy demand (less heating and cooling required because of more moderate temperatures), higher wind generation profiles, moderately high solar irradiance, and high water flows due to snow-melt runoff. These weather characteristics result in a power system condition where significant renewable generation energy is available while electric demand is low, which ultimately leads to high levels of curtailment of resources as they are not needed.
- Fossil fleet operation is at a minimum during the Spring and a maximum during the Summer season. Fossil generation online during many Spring days has been committed for reliability purposes and represents the minimum potential fossil dispatch.
- As time progresses through the study period and increased economic or age-based retirements occur an increasing amount of renewable capacity has to be built to replace the capacity and energy provided by the retired generators. S2 includes an increased number of age-based retirements compared to S1 (approximately 12 GW scheduled fossil retirements). This results in a larger amount of renewable generation capacity built by 2035 being primarily solar in S2. Comparing the 2035 Summer period between S2 and S1, one can observe a large amount of solar induced curtailment during peak hours as a result of the increased solar capacity on the system, which is attributable to the additional age-based retirements assumed in S2.
- The production cost model includes nodal representations of three (3) of New York's neighboring systems. Like today's energy market operations, the economic exchange of energy occurs between markets through imports and exports with each neighbor. In both S1 and S2, the reliance on imported and exported energy to meet system demands changes by season. In Spring and Fall, New York exports the excess of renewable energy produced that cannot be consumed with lower load levels and minimal dispatchable generation available. Energy interchanged differs between S1 and S2 during Summer as S1 exhibits a diurnal pattern of imports during daytime net-peak load and overnight exports, which increase through time. S2 exhibits a differing pattern where energy is imported in 2025 and 2030 to assist in meeting peak load until significant amounts of solar capacity is built by 2035 when the system tends to export the excess solar during peak periods. The Winter season interchange patterns are more variable in both scenarios and tends to change day-to-day depending on the net load pattern. Low levels of solar production and higher levels of wind production has the effect of aligning interchange more closely with wind production patterns, especially as more land-based and offshore wind capacity is built through time.
- The magnitude of interchange, both imports and exports, increase through time in both scenarios as more variable renewable resources are added to the system. Figure 59 below shows the total magnitude of interchange. S1 and S2 increase energy exchange by 24% and 47% by 2040 with S2 having a higher value due to having a much larger energy demand and greater variability in net-load. Exchange increases in 2040 as high cost DEFR generators lead to additional economic imports.

Figure 59: Total Annual Interchanged Energy with ISO-NE, PJM, and IESO



- Most of the renewable downward dispatch observed is a result of "curtailment" caused by transmission congestion as opposed to "spillage" caused by net-load exceeding dispatchable generation + exports. While neighboring systems were included in the model, any new policy-based generation capacity or load changes were not included in those systems. Excess renewable energy generated within NYCA would likely flow into neighboring regions provided the flow does not encounter any congestion. Any curtailment observed for resources in NYCA is likely due to congestion of transmission paths within the four-pool model. If neighboring regions were to be modeled with policy goals like New York, limitations on exports to neighboring regions would likely result in spillage of unused energy.
- Storage is modeled using the production cost model's internal scheduling function and represented on a zonal basis in a distributed fashion in the same way BTM-PV is distributed to buses within a zone. Storage discharge shapes target cost minimization using initial unit commitments around net load to reduce overall system costs, charging when net loads are low (and prices are low) and discharging during peak net loads (and prices are higher). The price spread must be sufficient to overcome storage losses to reduce cost on the modeled system.
- In both cases, the dispatchable fleet transitions from requiring maximal operation during the summer peak to during a winter peak in the mid-2030s. This transition continues into 2040 as DEFRs operate at higher levels during winter. Ramping behavior of the dispatchable fleet increased due to larger diurnal load swings driven by electrification and the increasing level of weather dependent intermittent renewable resources added. New resources with increased ramping capabilities will be needed to balance load with supply across the system and during multiple timescales.

Hourly generation, imports/exports, curtailment, and loads are shown over three-monthly periods for each Policy Case and year studied in the following figures. January, April, and July are selected because they coincide with the systems seasonal peaks in July and January. April on the other hand represents a spring shoulder month period with lower loads and higher renewable energy resource output. The fall season is very similar to the spring season and was therefore not presented for simplicity. The figures show NYCA-wide generation and net imports relative to load. The charts are presented with a data range between -20GW and 70GW and colors corresponding to the following chart key.

Figure 60: Hourly Seasonal Analysis Chart Key

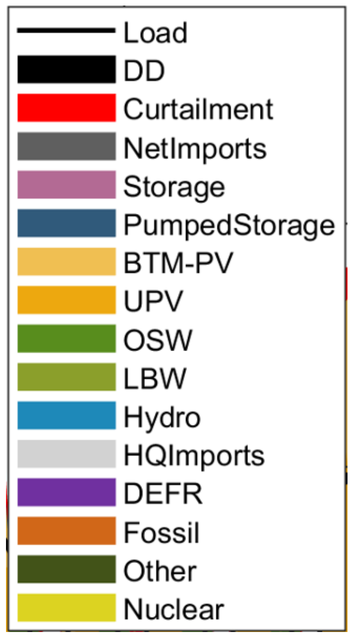


Figure 61: Scenario 1 2025 Summer Month Hourly Dispatch

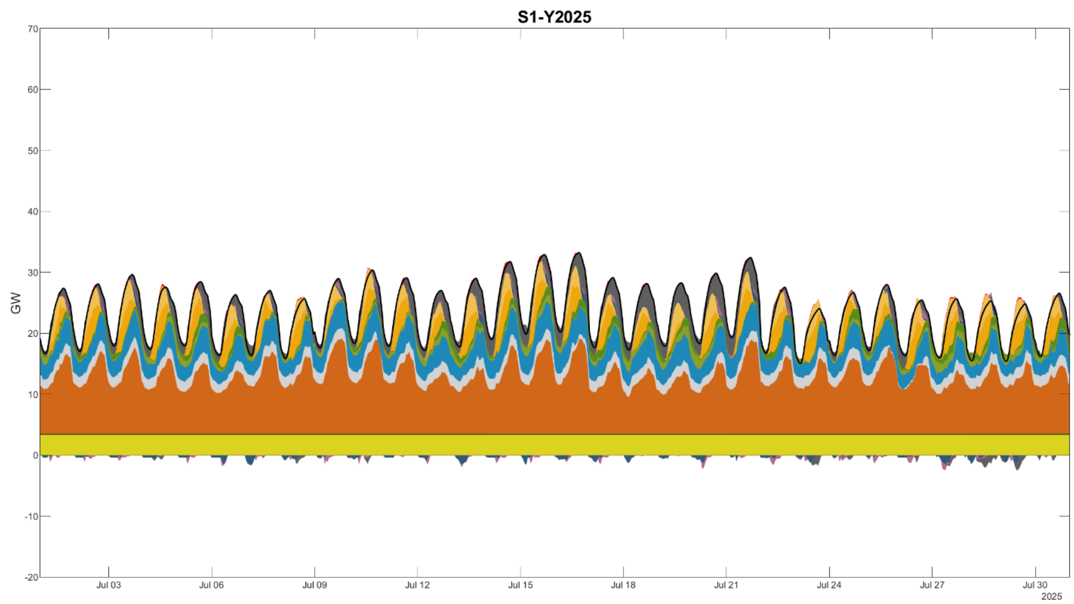


Figure 62: Scenario 1 2025 Spring Month Hourly Dispatch

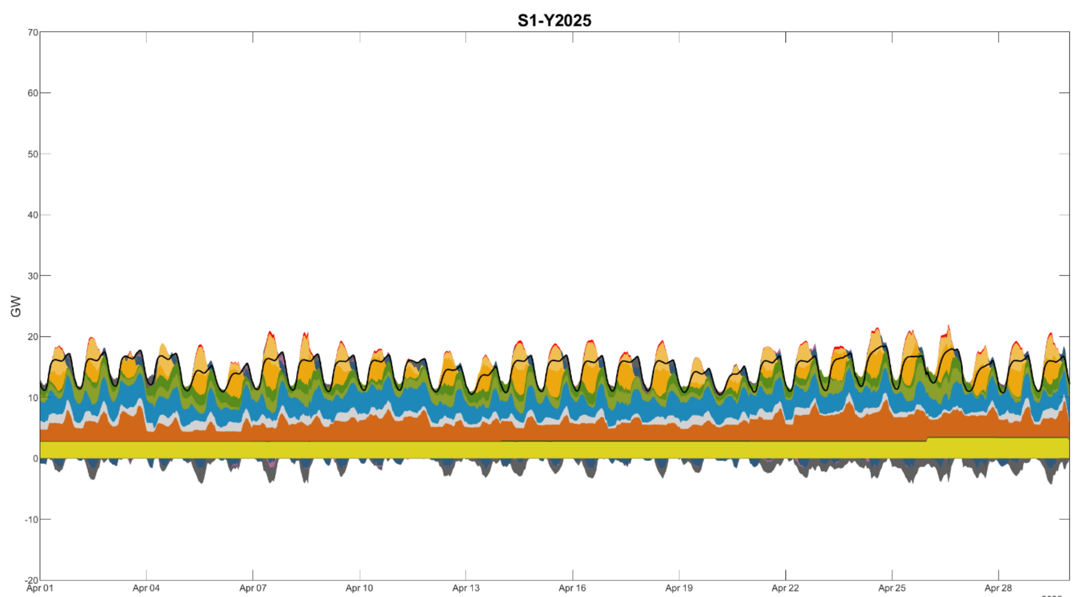


Figure 63: Scenario 1 2025 Winter Month Hourly Dispatch

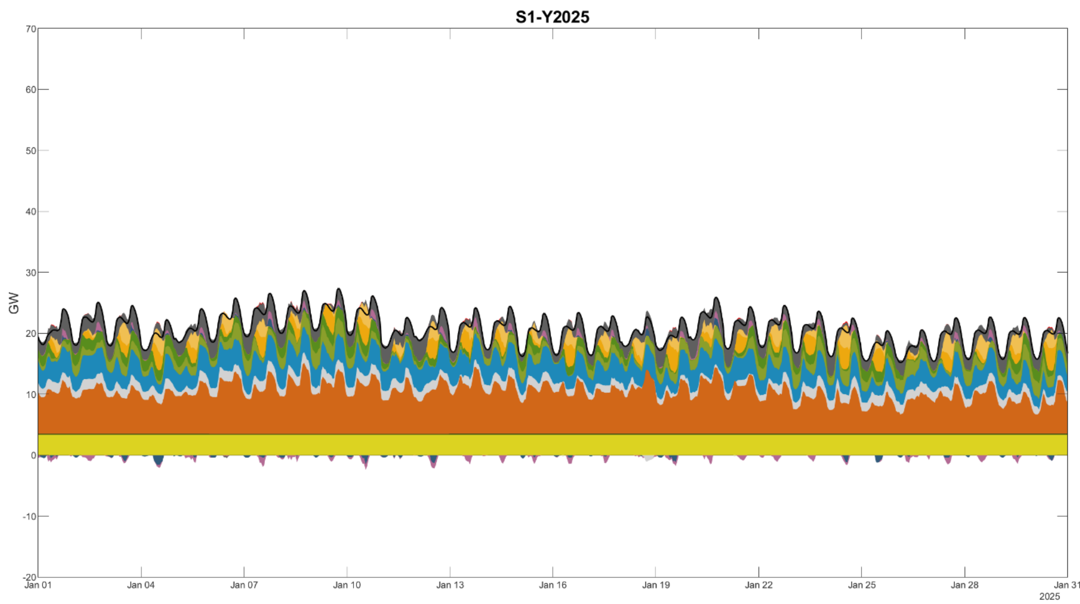


Figure 64: Scenario 1 2030 Summer Month Hourly Dispatch

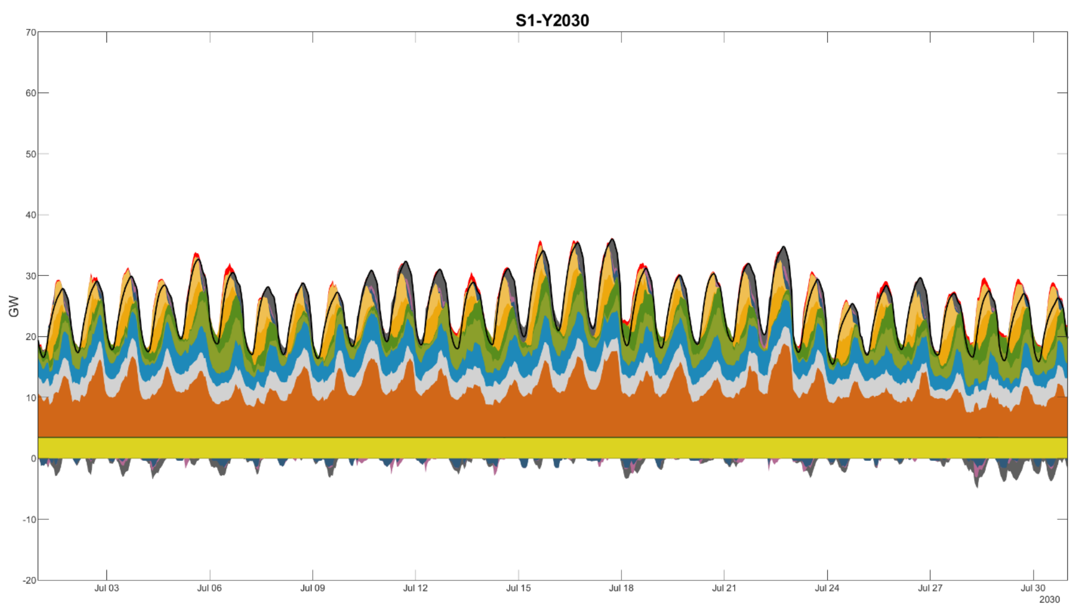


Figure 65: Scenario 1 2030 Spring Month Hourly Dispatch

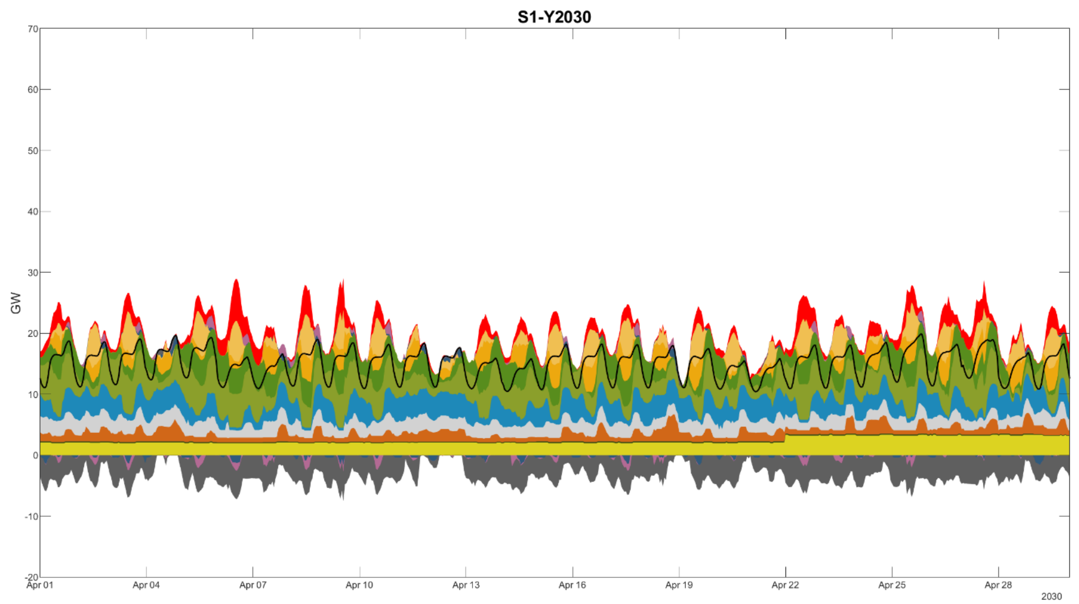


Figure 66: Scenario 1 2030 Winter Month Hourly Dispatch

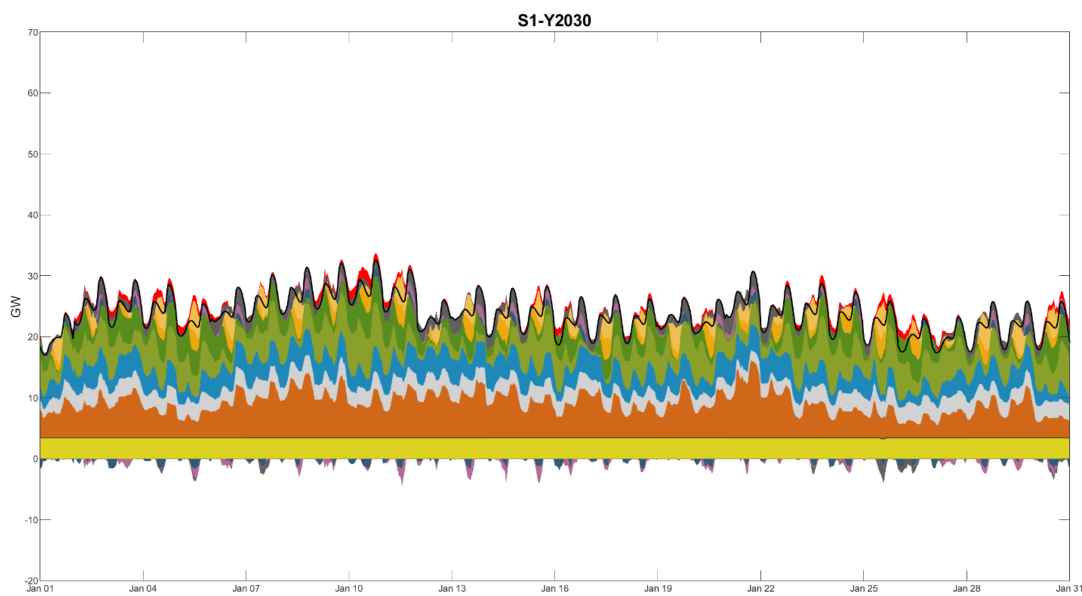


Figure 67: Scenario 1 2035 Summer Month Hourly Dispatch

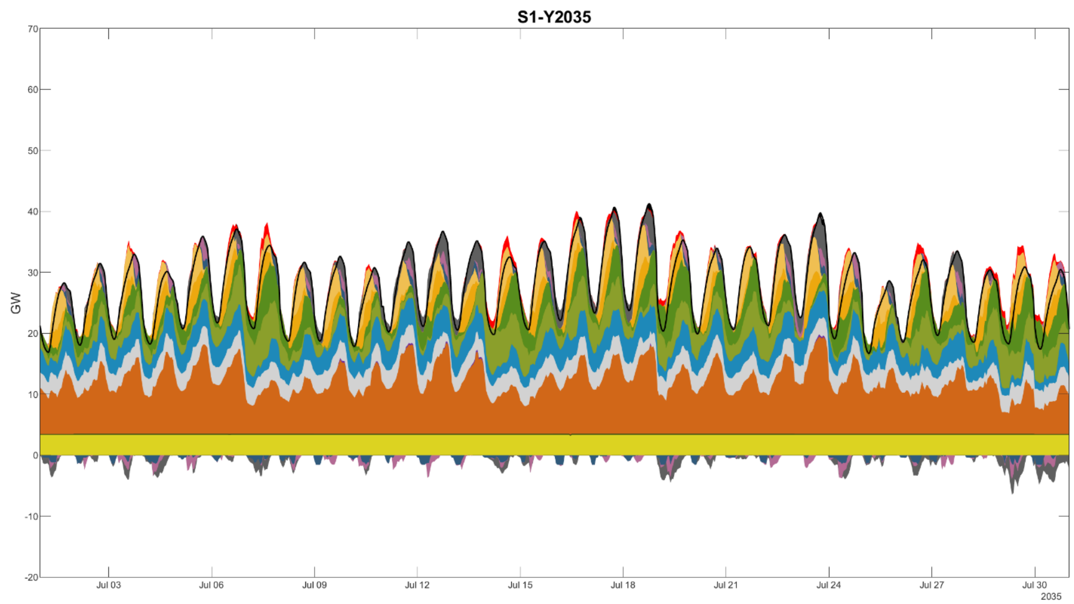


Figure 68: Scenario 1 2035 Spring Month Hourly Dispatch

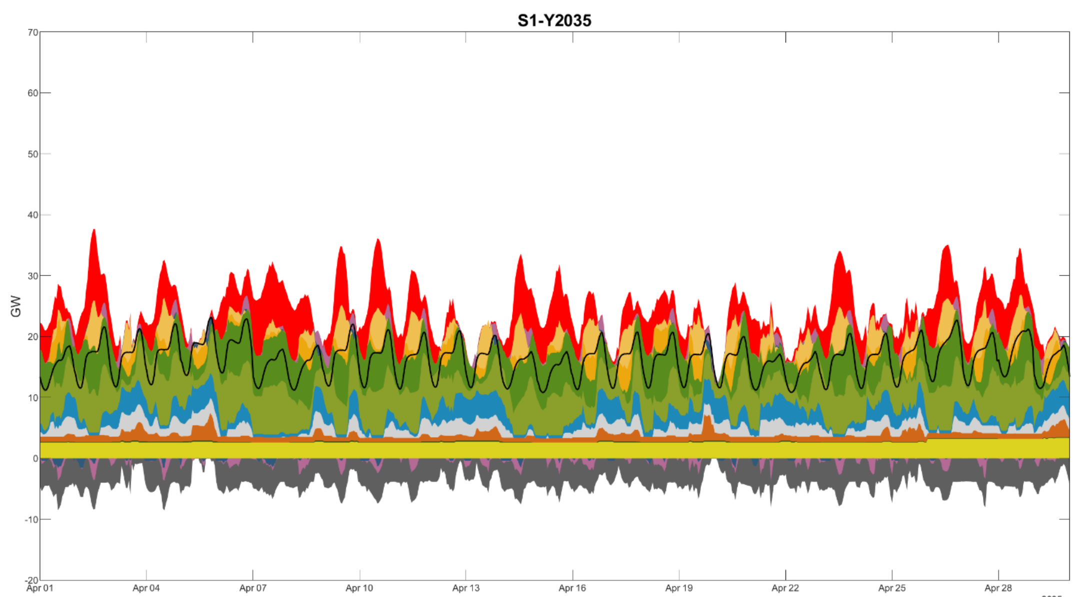


Figure 69: Scenario 1 2035 Winter Month Hourly Dispatch

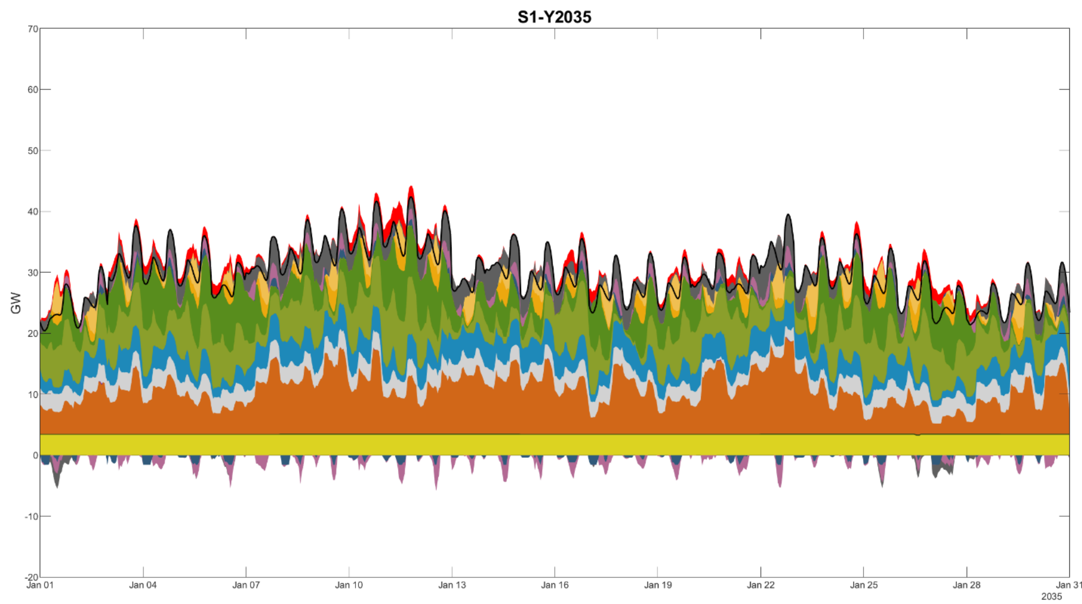


Figure 70: Scenario 1 2040 Summer Month Hourly Dispatch

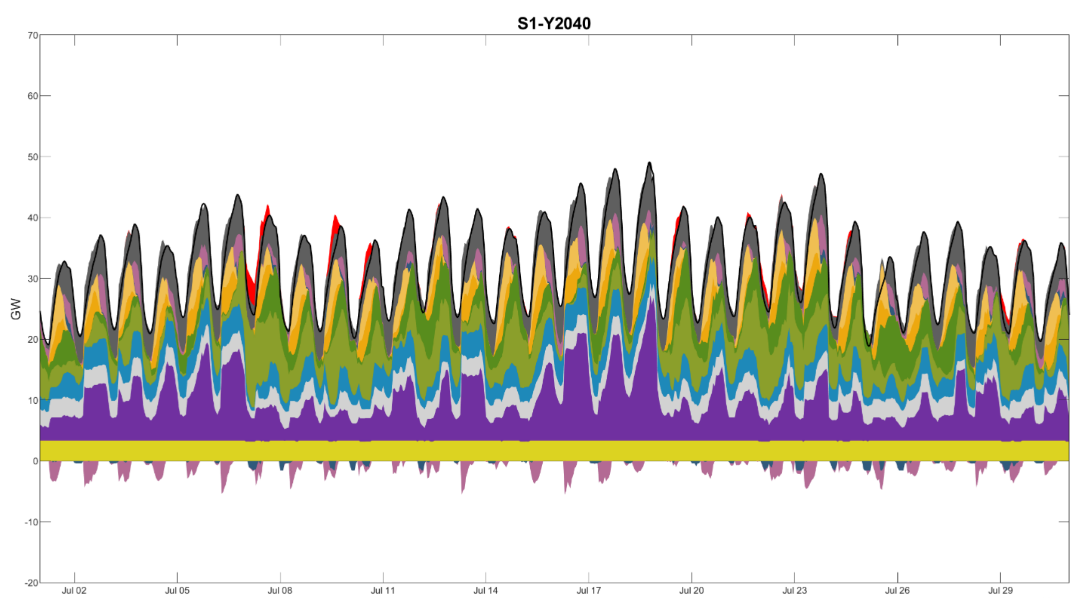


Figure 71: Scenario 1 2040 Spring Month Hourly Dispatch

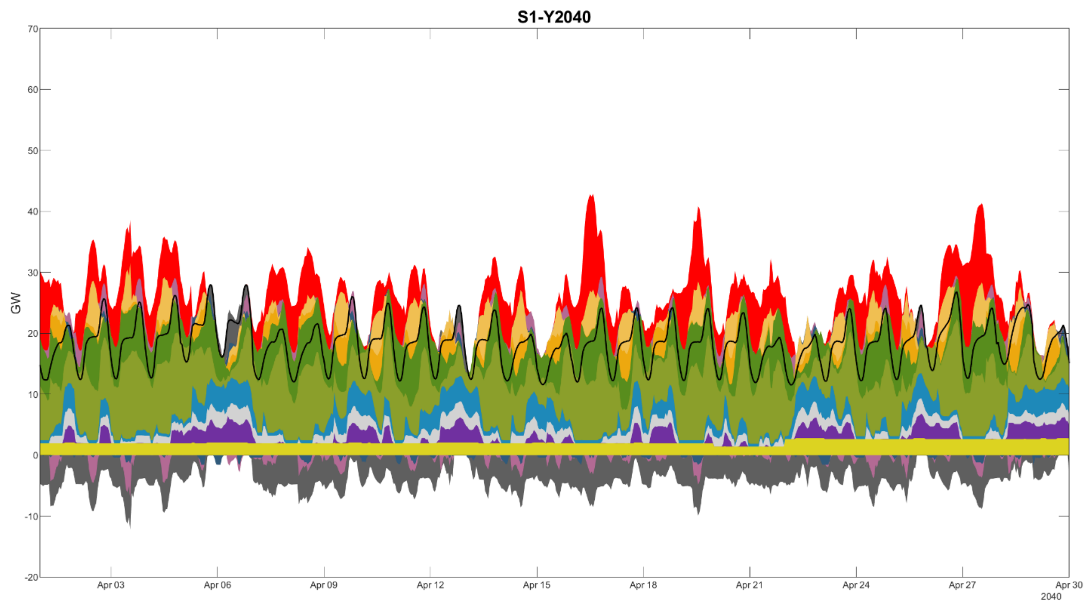


Figure 72: Scenario 1 2040 Winter Month Hourly Dispatch

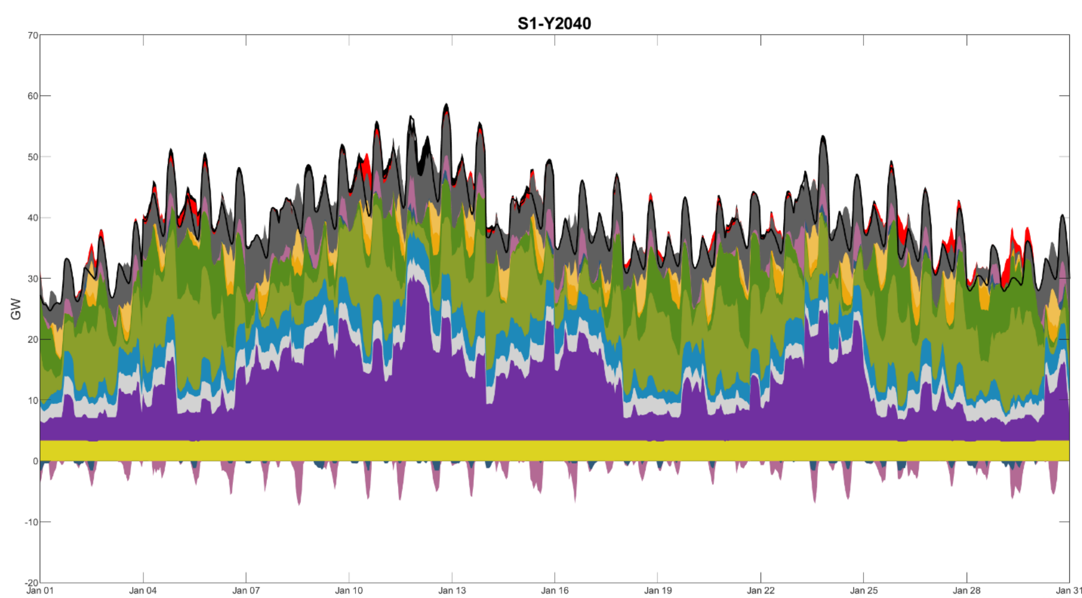


Figure 73: Scenario 2 2025 Summer Month Hourly Dispatch

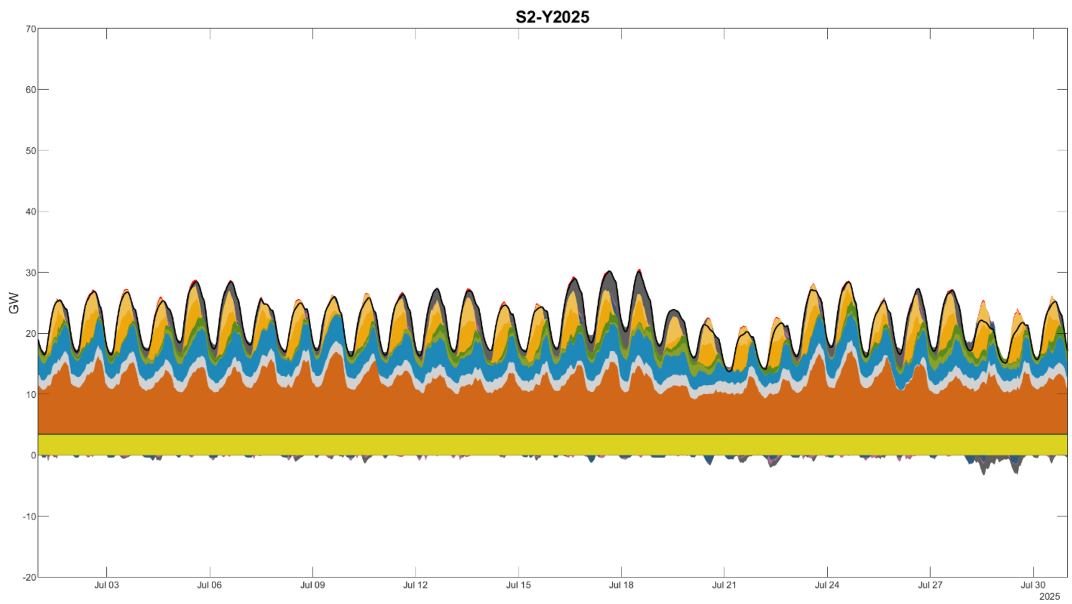


Figure 74: Scenario 2 2025 Spring Month Hourly Dispatch

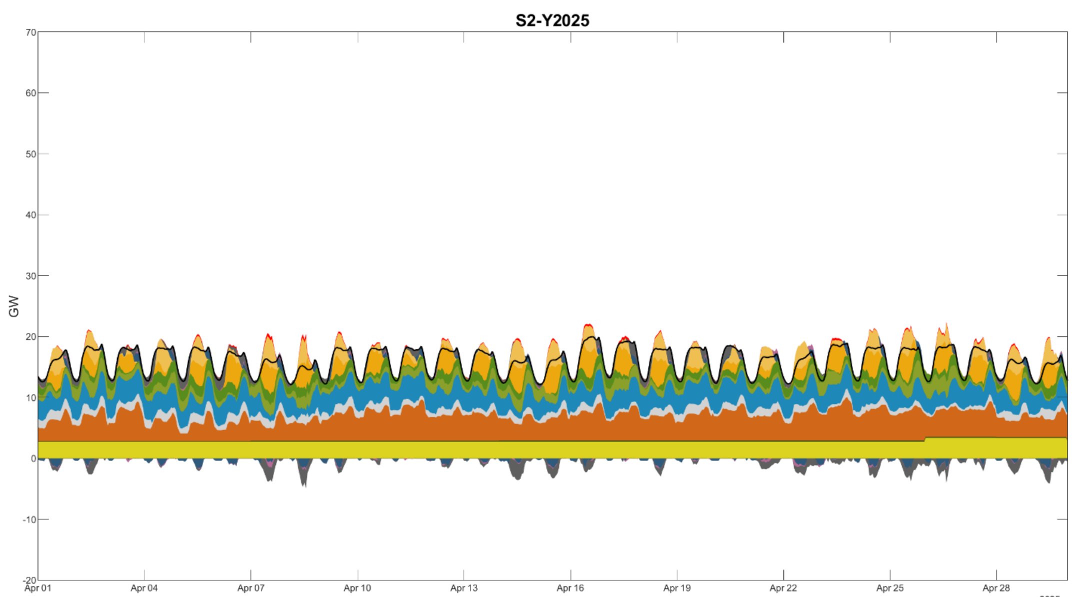


Figure 75: Scenario 2 2025 Winter Month Hourly Dispatch

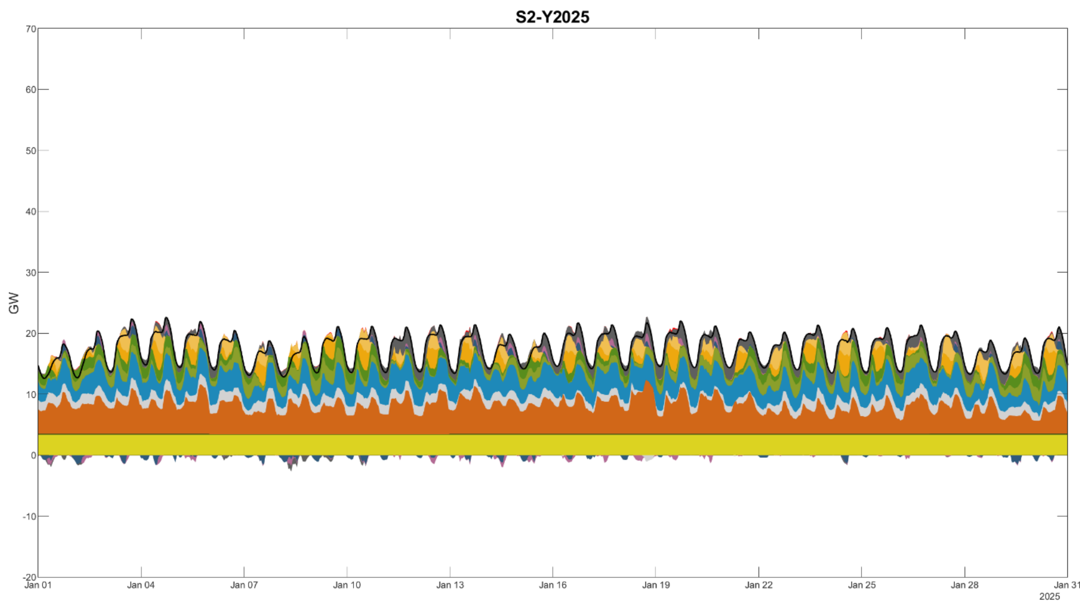


Figure 76: Scenario 2 2030 Summer Month Hourly Dispatch

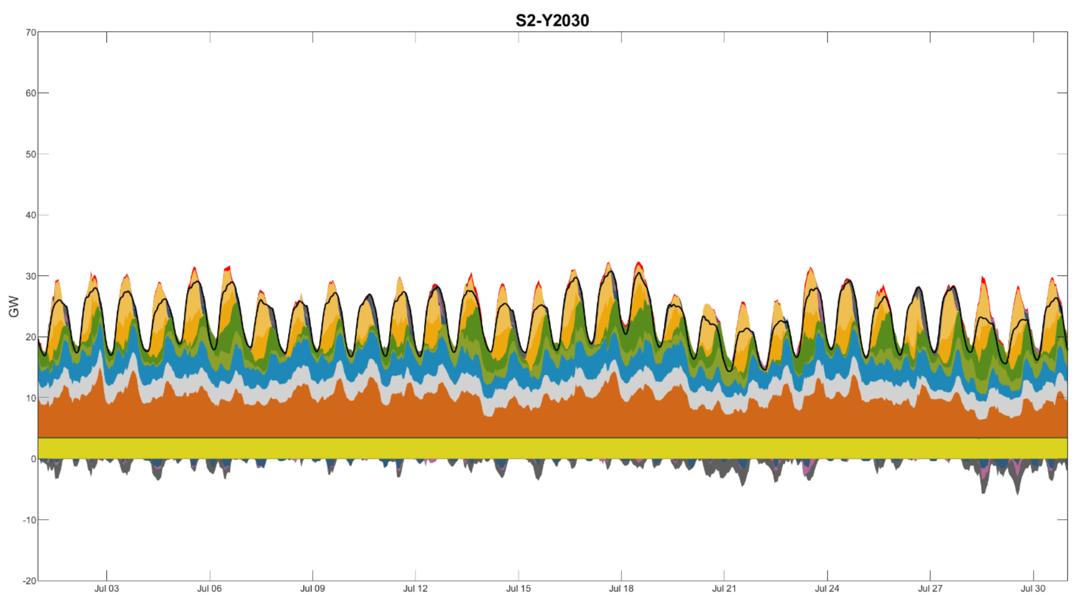


Figure 77: Scenario 2 2030 Spring Month Hourly Dispatch

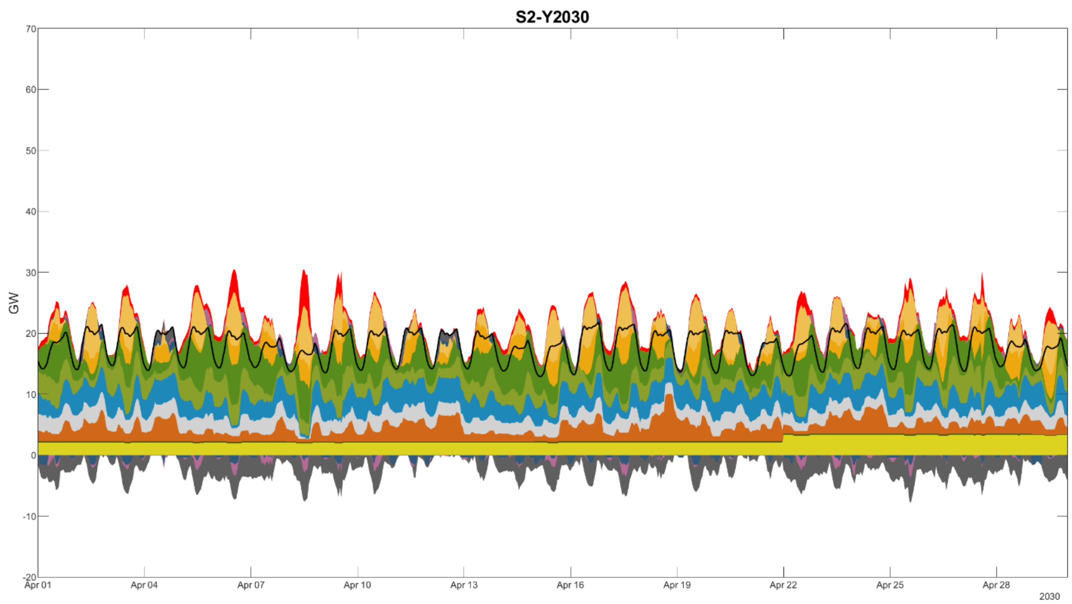


Figure 78: Scenario 2 2030 Winter Month Hourly Dispatch

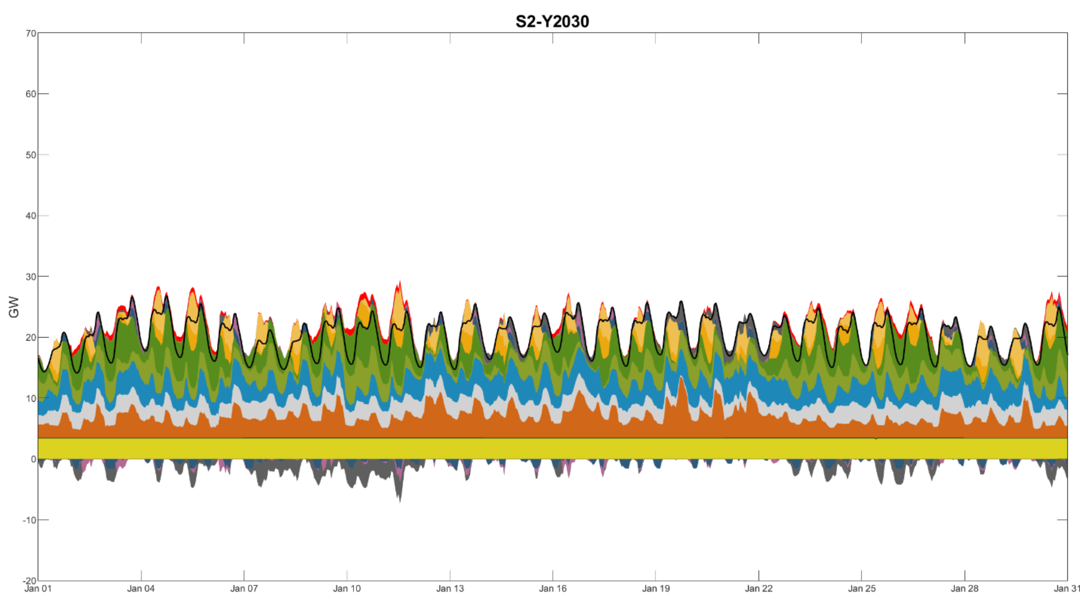


Figure 79: Scenario 2 2035 Summer Month Hourly Dispatch

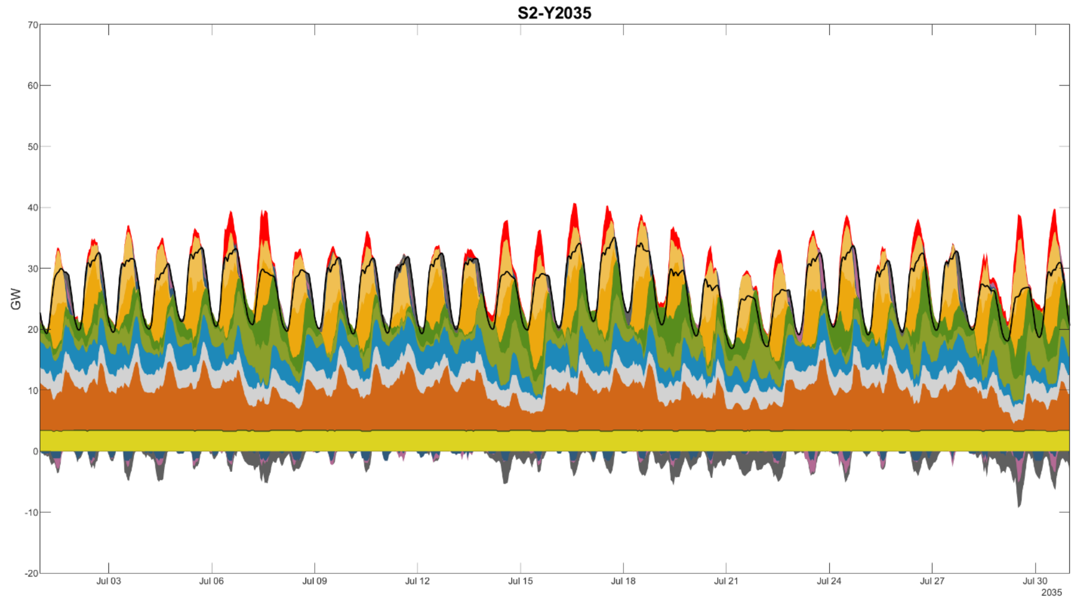


Figure 80: Scenario 2 2035 Spring Month Hourly Dispatch

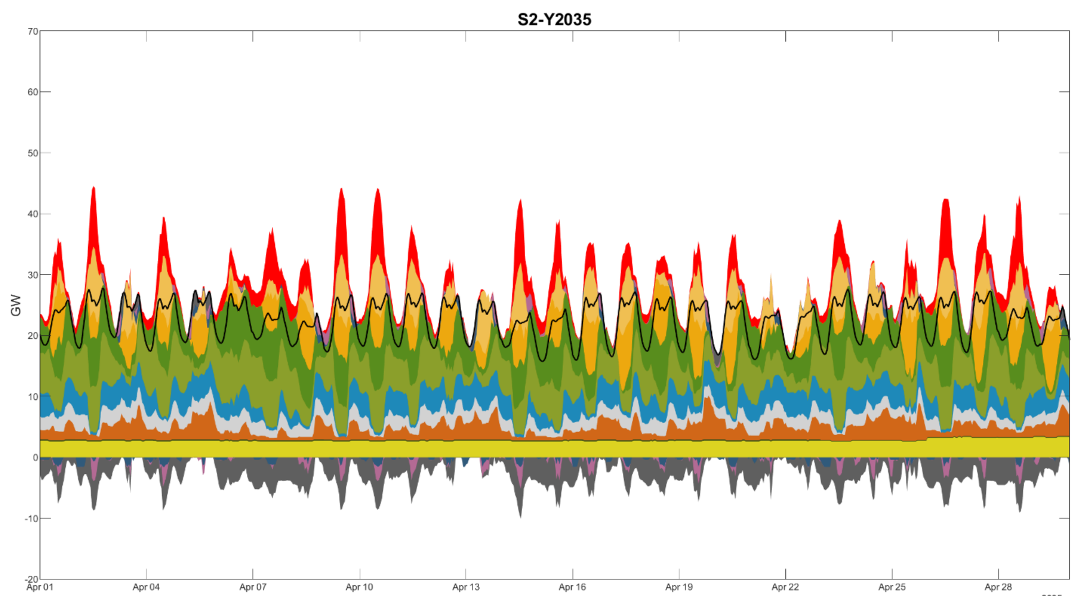


Figure 81: Scenario 2 2035 Winter Month Hourly Dispatch

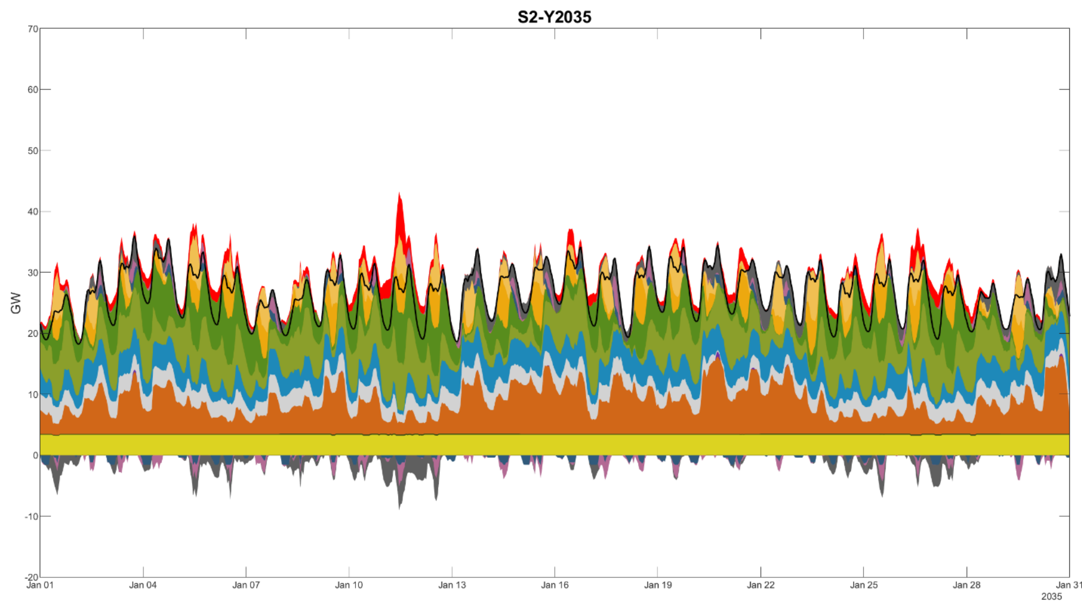


Figure 82: Scenario 2 2040 Summer Month Hourly Dispatch

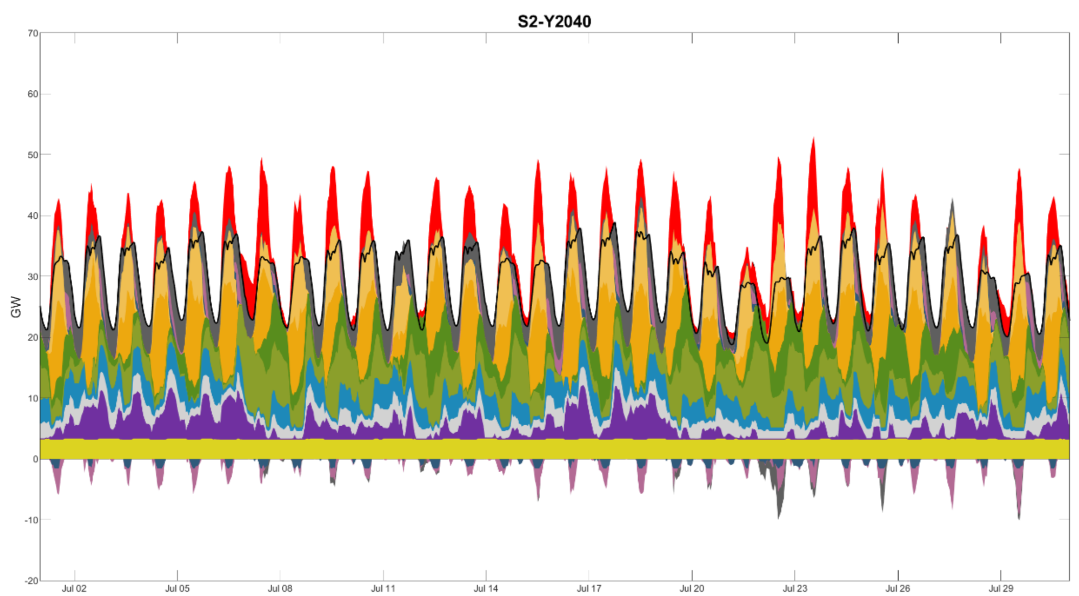


Figure 83: Scenario 2 2040 Spring Month Hourly Dispatch

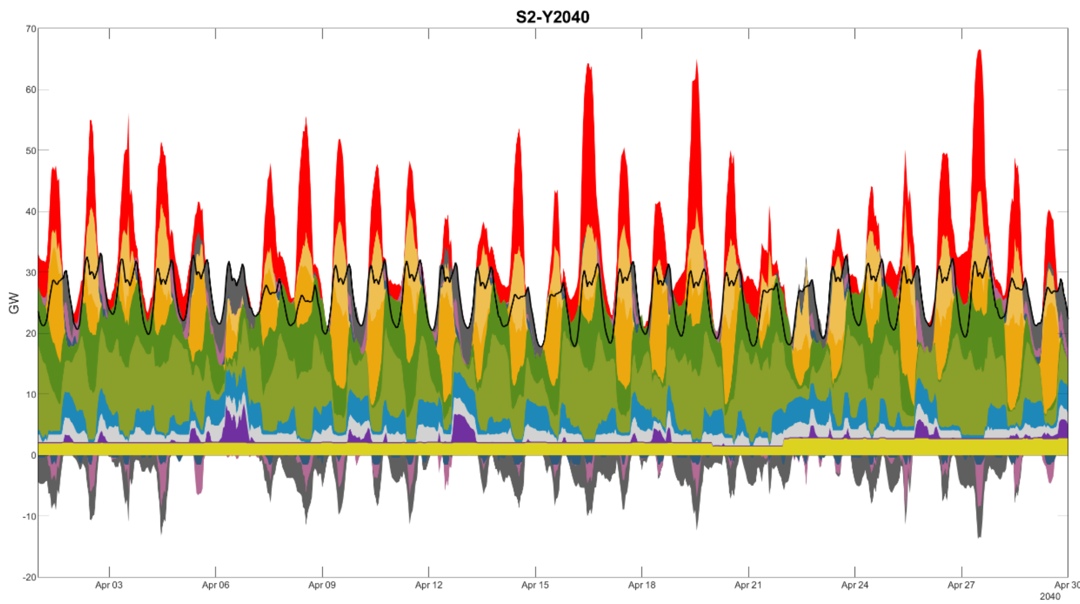
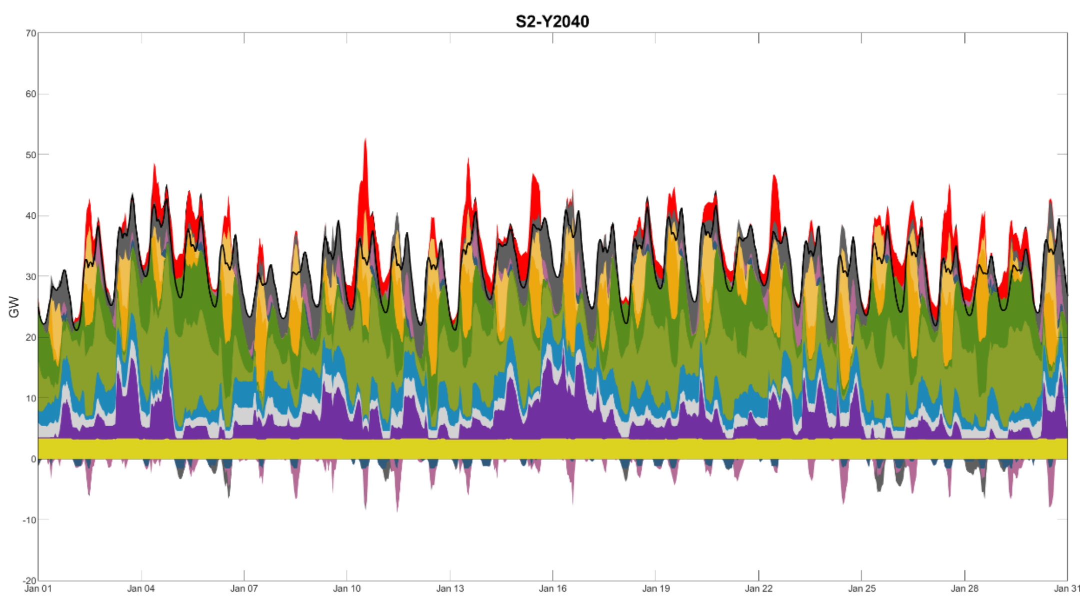


Figure 84: Scenario 2 2040 Winter Month Hourly Dispatch



F.3.6. Policy Case Operational Analysis

This section reviews the impacts of increased renewable resource output and shifting load patterns on the dispatchable fleets modeled. Average utilization, number of starts, and ramp parameters are reviewed for both fossil and DEFR generators.

Existing Thermal Fleet Impact

The existing fossil fleet currently operates to maintain the supply and demand balance in response to changes in net load, forecast uncertainty, reliability rules, and real-time events. Net load is defined here as the system load minus the output of intermittent resources such as wind and solar generators. In addition, fossil fuel-fired generators may be called on to provide reserves, regulation, and/or other products that help maintain the reliability of the grid. As increasing levels of intermittent generation are added to the system, this dispatchable fleet is expected to operate more flexibly and less frequently overall across an increasing number of starts. This occurs because many renewable generators will be selected to run in the NYISO's markets due to low operating and zero fuel costs.

Examination of the operational patterns of the dispatchable fleet in the Policy Cases reveals trends associated with the future fleet operations. The fossil fleet is called upon to start more often to compensate for the variability of the intermittent renewable energy generation. In 2035, when both fossil and DEFR generators are available, the fossil fleet provides nearly all the flexible operations. By 2040, as the DEFR generators become the only dispatchable option they tend to fill the role which was previously filled by the fossil fleet's operations. Overall, the total number of starts in 2035 are the highest of the model years at approximately 10,000 starts per year. The number of DEFR starts decrease in 2040.

The figures below show cumulative capacity curves for several operational parameters across different segments of the fossil fleets. Each point along a curve represents a single generator's operational performance over the course of the model years in the S1 and S2 cases.

Operations of the combined cycle (CC) fleet are most sensitive to increasing penetration of renewable generators as they currently operate most frequently and flexibly among the fossil fuel-fired generation fleet. Results indicate reductions in CC capacity factors and an increase in the number of starts for these generators moving from 2025 to 2030 and 2035. Meanwhile, the simple cycle combustion turbine (CT) fleet, which typically operates less frequently, sees an increase in both annual capacity factor and number of starts as these generators are used more often to fill in shorter intervals in the net load requirements. The steam turbine (ST) fleet has a more muted response, due to the less flexible nature of these generators, where both an increase and decrease in capacity factor and starts are observed across the fleet. Before 2040, while some DEFR are available, so too are fossil fuel-fired generators, which continue to operate such that the DEFR fleet is rarely, if ever, called upon. In 2040, as all fossil fuel-fired generators are retired the DEFR fleet serves the role of meeting net load. Generally, the DEFR fleet operates at capacity factors below 20% (similar to ST units) but has a larger number of starts (similar to CC units), indicating generally lower runtimes per start than either the ST or CC fleets.

Figure 85: Fossil Fleet Cumulative Capacity Curve: Unit Level Capacity Factors

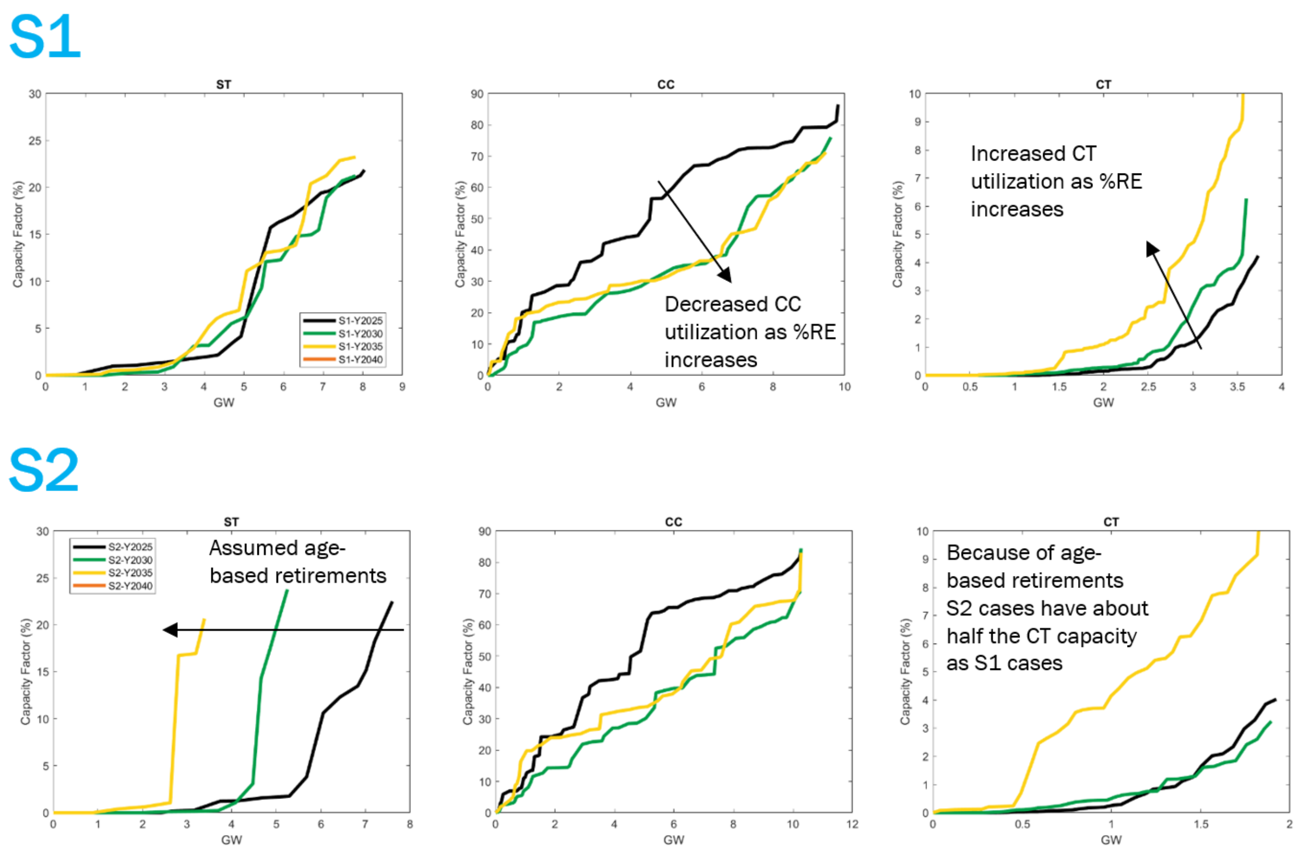


Figure 86: Fossil Fleet Cumulative Capacity Curve: Unit Level Number of Starts

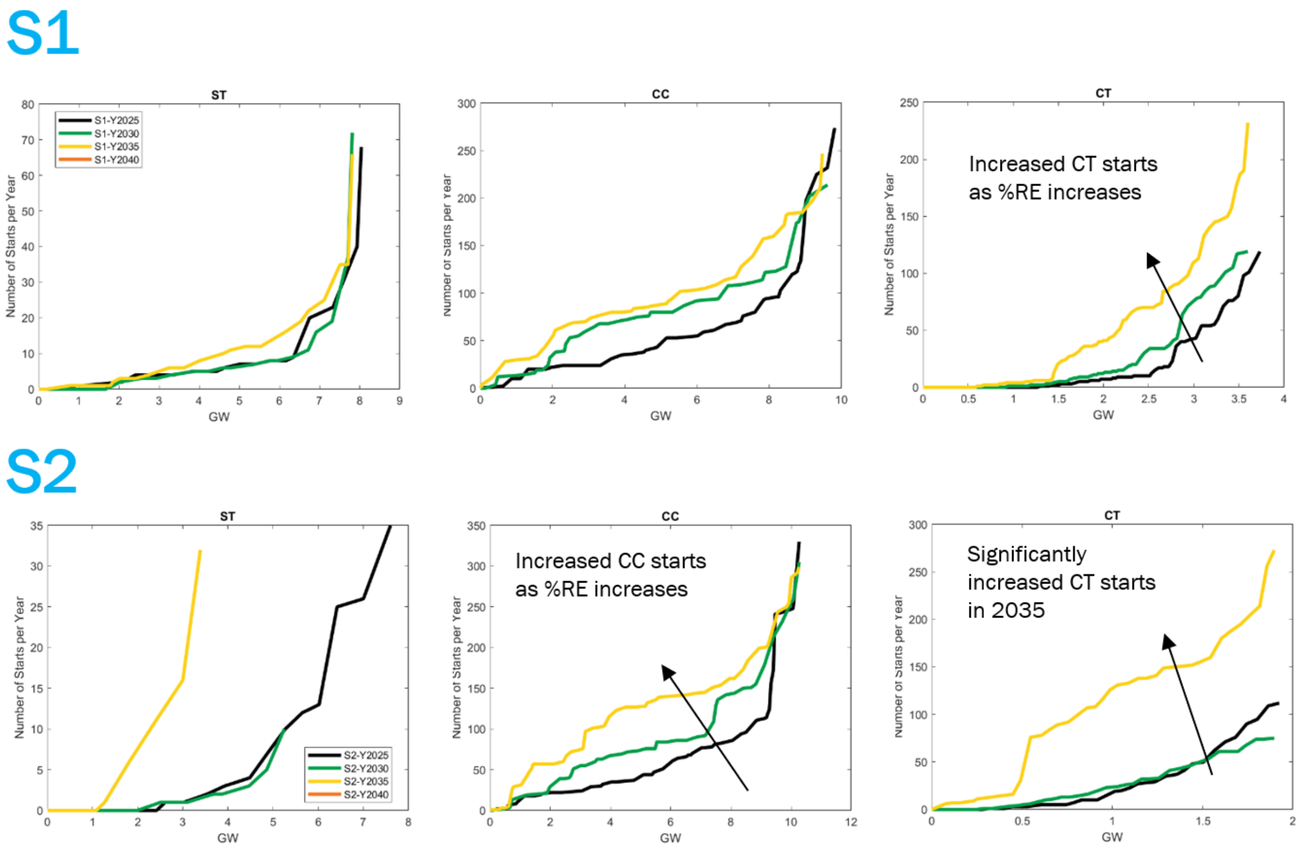
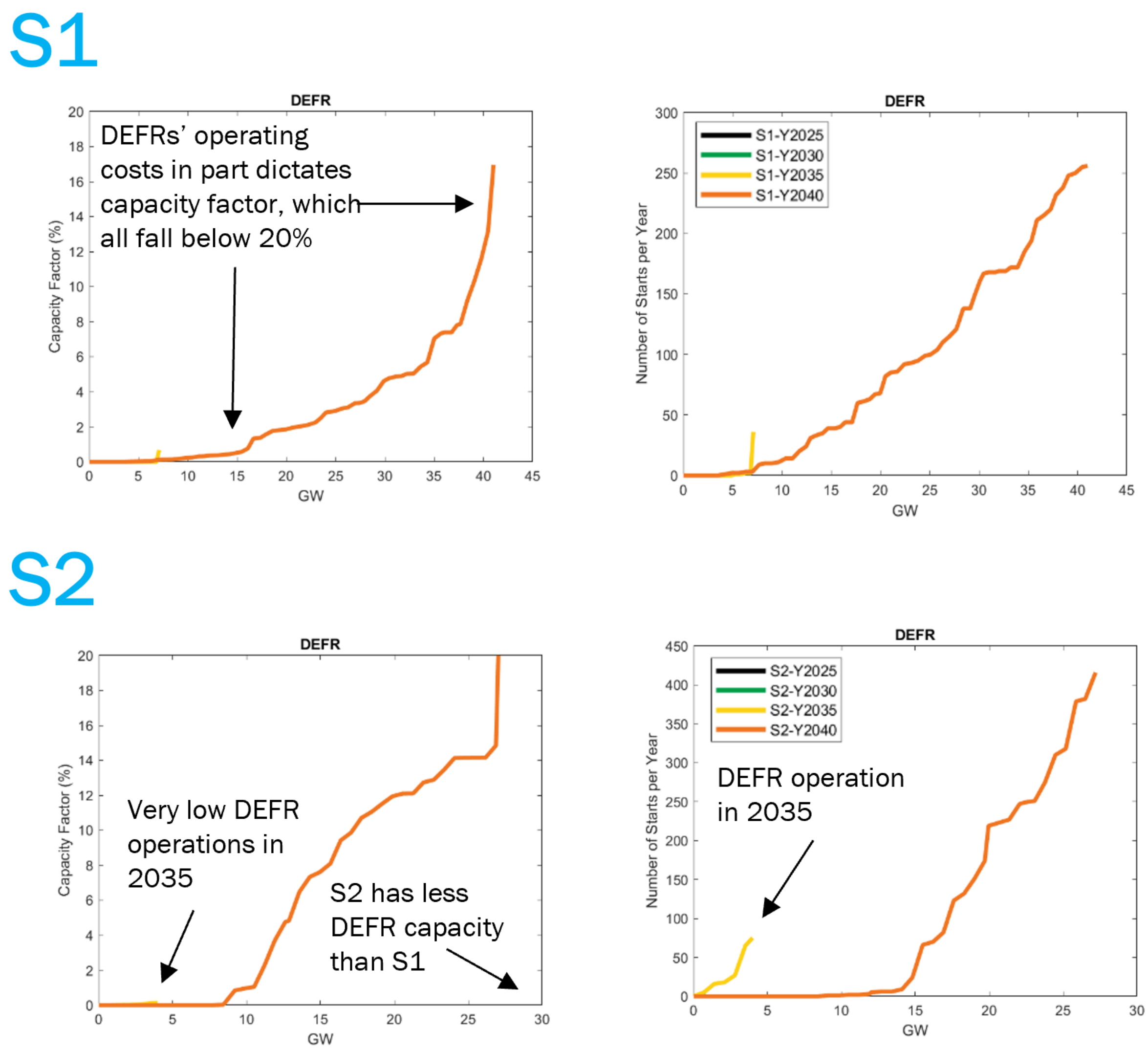


Figure 87: DEFR Cumulative Capacity Curve: Unit Level Capacity Factors and Number of Starts



Hourly ramp rates of the fossil fleet in 2030 allows the flexibility of these generators to be examined. Figures showing hourly operation by fuel type in both cases are displayed in Appendix F.3.5. The figures below display the NYCA fossil fleet maximum up (increasing output) and down (decreasing output) ramp, in MW/hour which occurred during each month and hour and signify the highest increase or decrease in fossil fleet output called upon in the model in each hour of each month. Generally maximum up-ramps increase throughout the study period and display consistent ramp-demand patterns in both S1 and S2. High up-ramp requirement periods generally align with the traditional morning load pickup as well as the late afternoon net-load increase caused by the sharp decrease in solar production as loads rise past sunset.

Fossil fleet maximum up-ramp occurred during the morning and afternoon load ramp events across the year, while down-ramp primarily occurred in the late overnight intervals. High down-ramp needs are concentrated around the midnight hour as load decreases towards its minimum value each day.

Figure 88: Maximum Fossil Fleet Up-Ramp (MW/hour) by Month and Hour

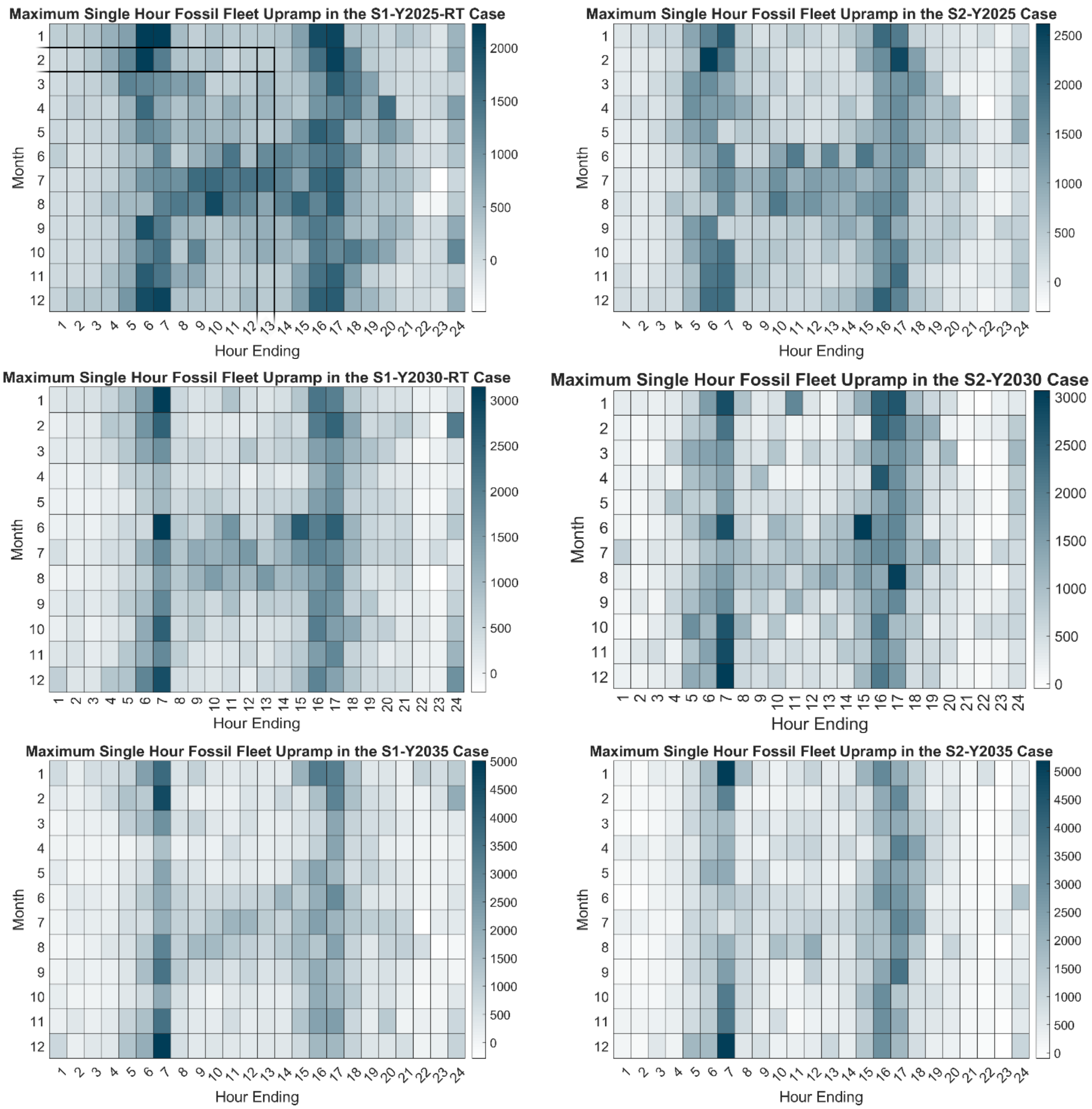
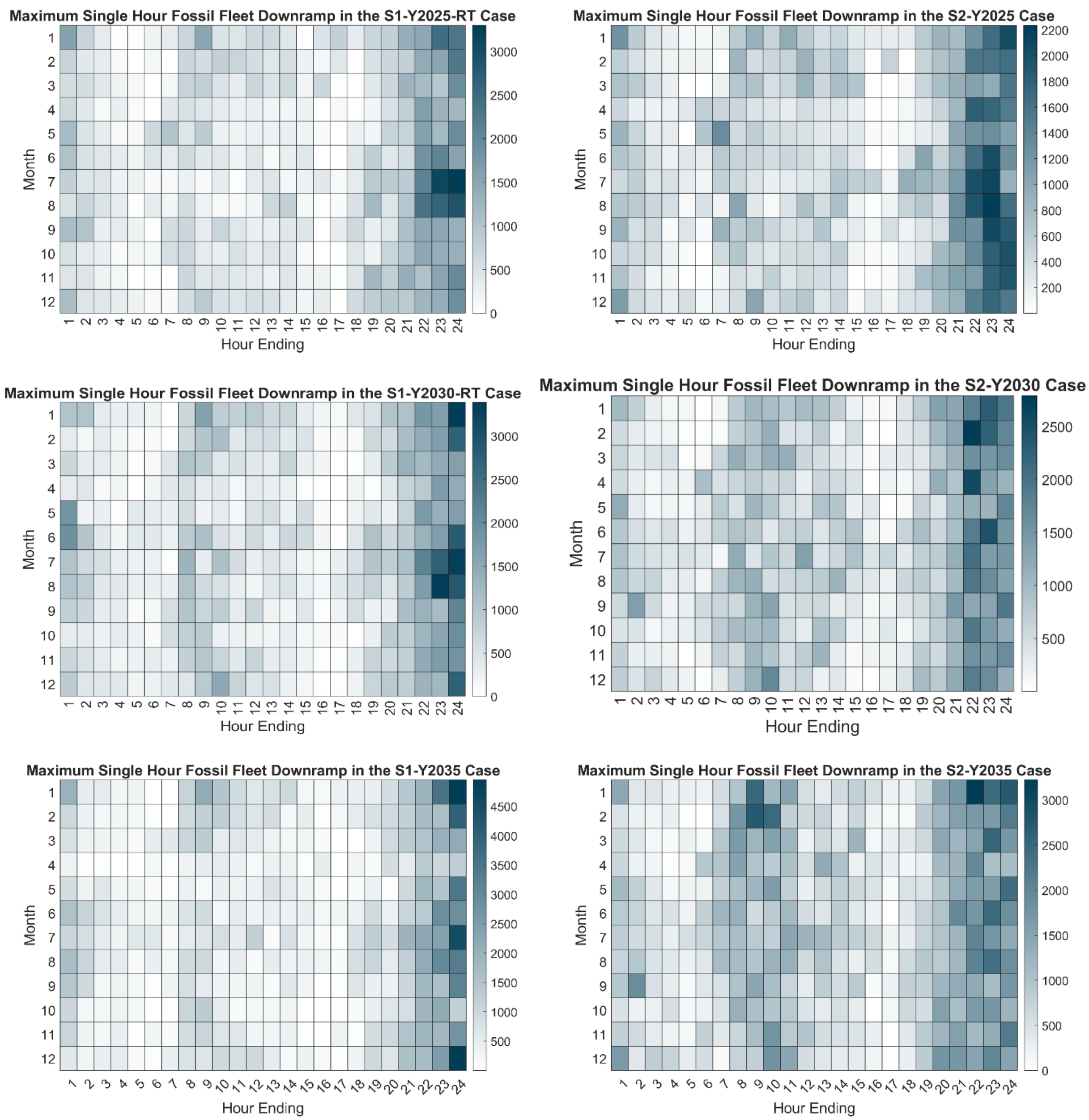


Figure 89: Maximum Fossil Fleet Down-Ramp (MW/hour) by Month and Hour



DEFR Operation & Implications

While not currently commercially available, the DEFRs will be expected to balance load and supply on a zero-emissions grid. Although DEFRs operate at some level in all years included in the simulations, they do not operate significantly until 2040, when the NYCA has no fossil generators available.

The figure displays, in monthly-hourly bins, the average and maximum capacity factors of the entire DEFR fleets in 2040 for both scenario cases, S1(top) and S2 (bottom). DEFR output increases in the summer and winter months and is reduced during the shoulder spring and fall seasons with lower loads and higher renewable generation. In both cases, capacity factors appear to increase throughout the day. Similarities in operation across S1 and S2 would be expected because the same renewable profiles were used in both cases; however, the buildout capacities of the two scenarios are different. As different load shapes were used in the two scenario cases the net load contained some similar characteristics. The monthly-hourly pattern is similar to the pattern of maximal capacity factors in S1. However, in S2 the pattern of maximal DEFR fleet utilization becomes slightly more dispersed across more hours with a different structure.

Figure 90: Average and Maximum DEFR Fleet Capacity Factors by Month and Hour: 2040 S1

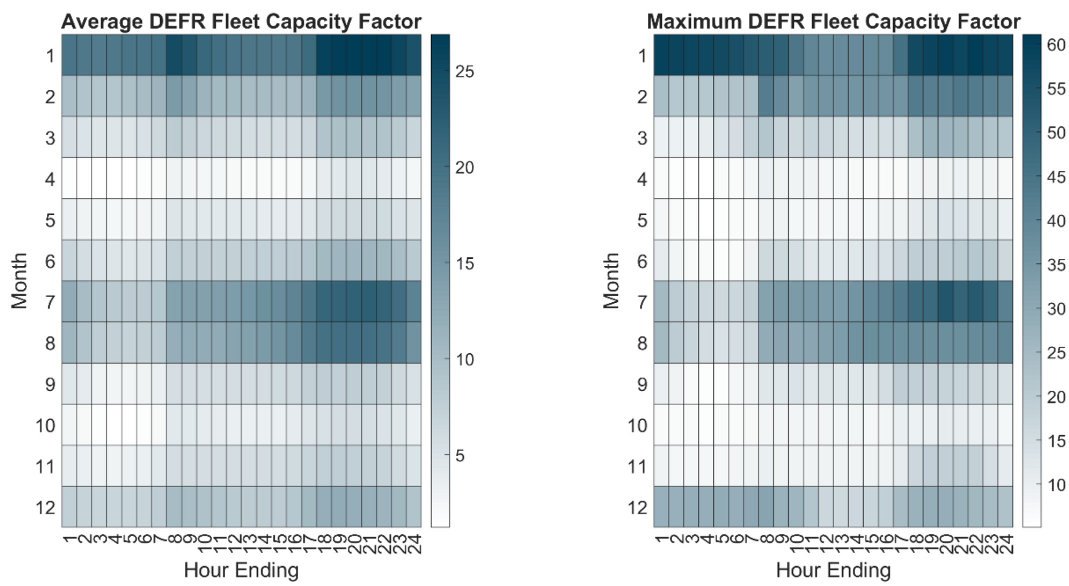
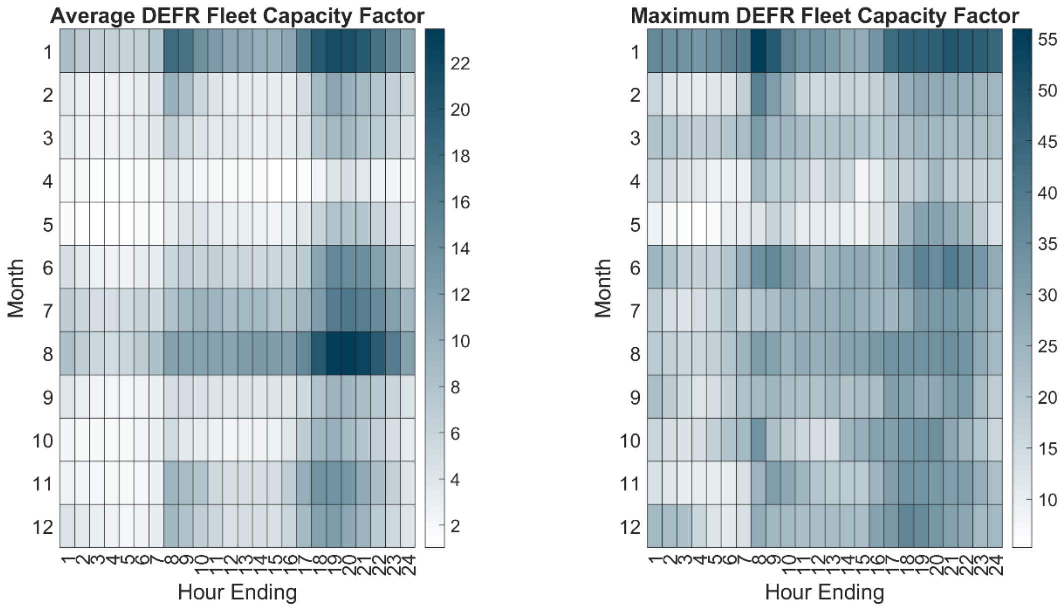
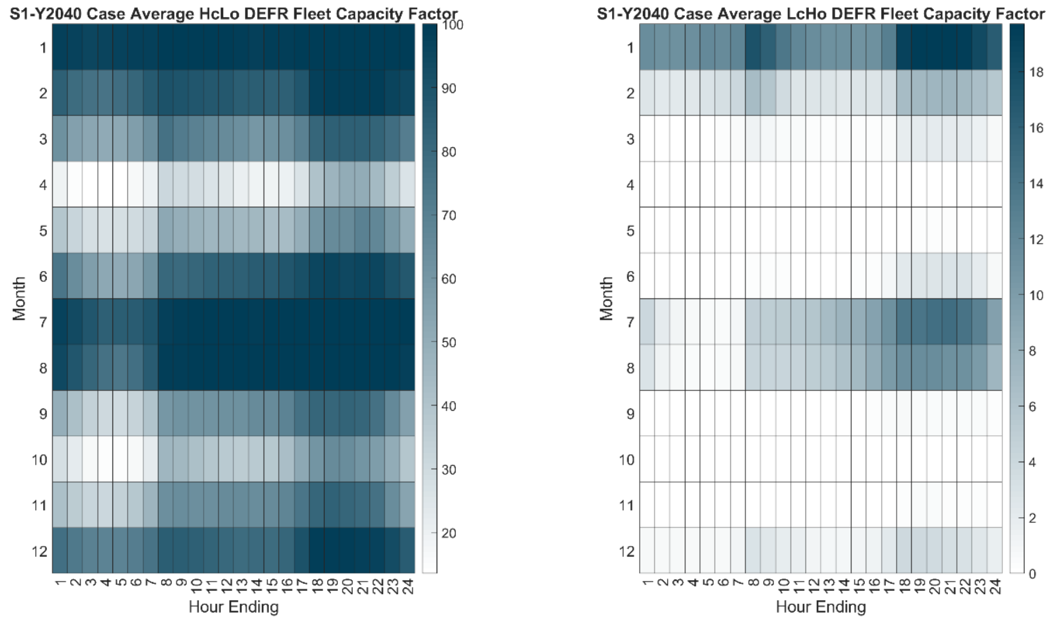


Figure 91: Average and Maximum DEFR Fleet Capacity Factors by Month and Hour: 2040 S2



In S1, two types of DEFRs were modeled in production cost while in S2 a single intermediate DEFR option was included. Figure 92 below shows the split operations of the High Capital Low Operating (HcLo) and Low Capital High Operating (LcHo) cost DEFR options in 2040 for Policy Case S1. The pattern of operations is similar, however, utilization of the low operating cost option (HcLo) was strongly preferred, as expected. The highest output of the high operating cost option (LcHo) occurs around the winter overnight peak in January 2040.

Figure 92: Average DEFR Fleet Capacity Factor by Month and Hour: 2040 S1



Overall, the DEFR fleet operations mirrored those of the fossil fleet but with higher costs leading to overall lower operations. Comparison of the DEFR up-ramp and down-ramp pattern in the following figures show them to be similar but muted compared to the similar fossil fleet figures above. Significantly, the scale of the maximal hourly ramps increases across the DEFR fleet in comparison to the fossil fleets, indicating the impacts from increased electrification and as well as new requirements on the dispatchable fleet caused by increased renewable penetration.

Figure 93: Maximum DEFR Fleet Up-Ramp (MW/hour) by Month and Hour: 2040 S1 and S2

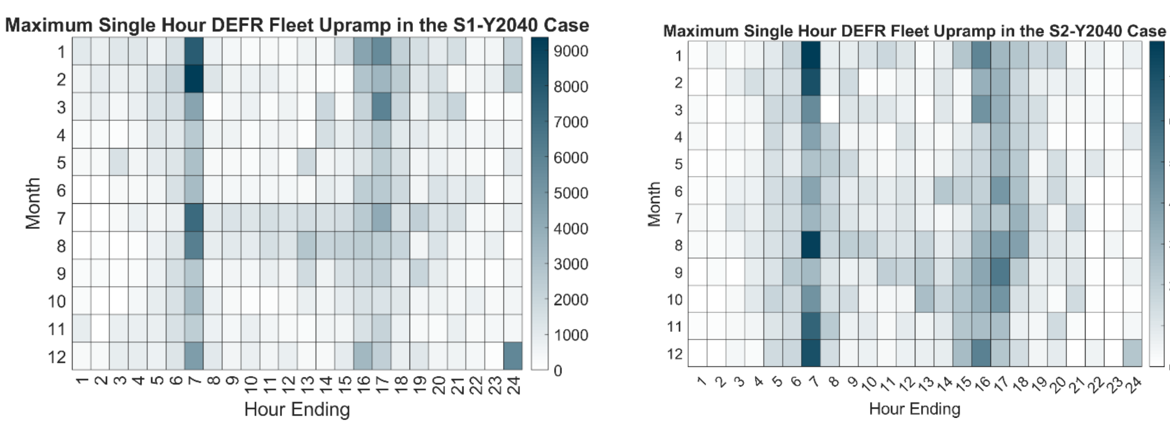
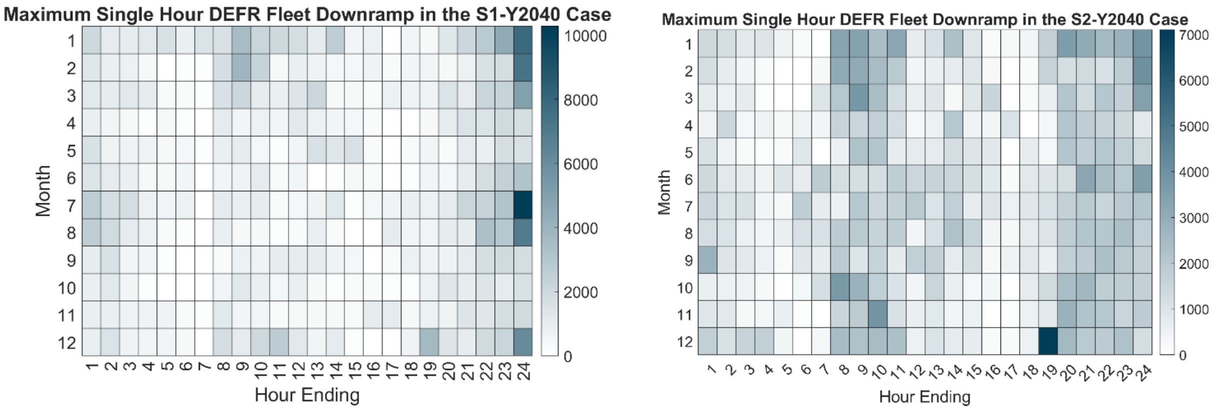


Figure 94: Maximum DEFR Fleet Down-Ramp (MW/hour) by Month and Hour: 2040 S1 and S2



The hourly model does not capture sub-hourly variations, day-ahead to real-time market arbitrage, forecast uncertainty, transmission outages and other unplanned events. These real-world considerations could tend to increase flexibility demand on the DEFR generators. As stated in the assumptions section, as fossil generators were removed, additional reliability constraints were not imposed on the replacement DEFRs. Should additional reliability rules or programs be imposed, higher capacity factors and different operations would be expected to occur. The careful progression from an operating fossil fleet to one supplying similar services by an as-yet undefined set of technologies requires further study, including how reliability constraints may need to evolve as the system advances towards decarbonization.