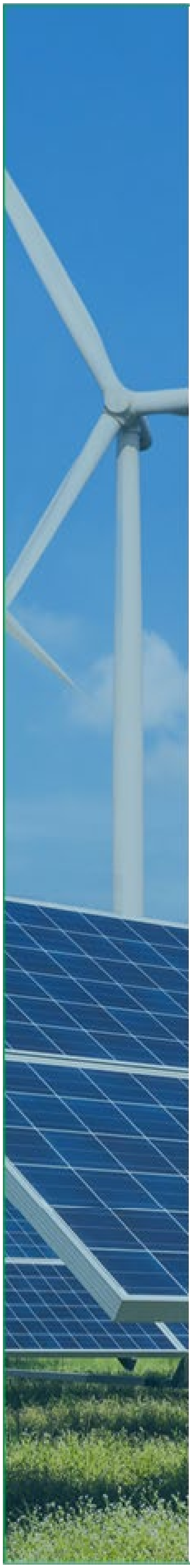


New York ISO
Independent System Operator

Appendix G: Production Cost Model Results

2023-2042 System & Resource Outlook

A Report from the New York Independent System Operator

July 22, 2024

Appendix G: Production Cost Model Results

Base Case

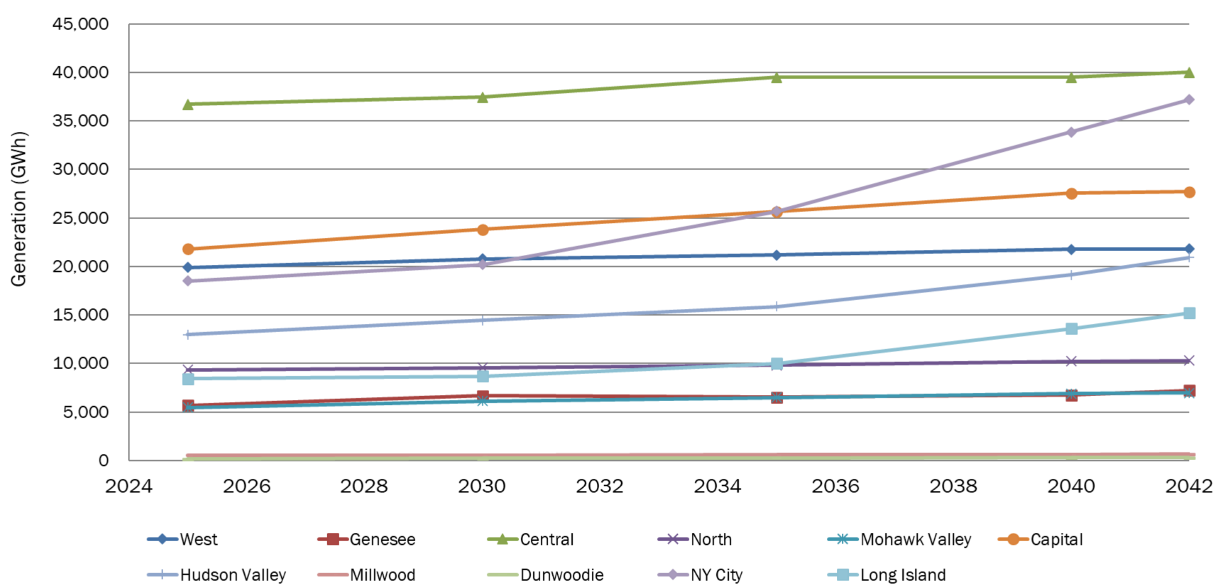
This section presents summary level results for the Outlook Base Case. Additional detailed results can be found in spreadsheet format posted with the Outlook materials.

The assumptions used to develop the Base Case can be found in Appendix B: Production Cost Assumptions Matrix. The primary drivers for trends in Base Case results include:

- Energy demand and peak forecast assumptions for the four-pool system (e.g., NYISO, PJM, ISO-NE, IESO); and
    - Compared to previous study cycles, energy demand in New York and in the neighboring systems increased significantly over the study period (2023-2042).
    - Energy demand and peak forecasts for the neighboring systems were extended for each neighboring system, as applicable, to align with the Outlook study period.[1] The NYISO used a linear growth model to extend forecasts through 2042.
- Limited changes in the generation mix through time (i.e., retirements and new resource additions) due to inclusion rules for the Base Case.

Generation

Figure G-1: Projected NYCA Generation (GWh), Base Case



[1] Energy demand forecasts for neighboring systems were extended for study years beyond 2032 for ISO-NE and 2038 for PJM.

Figure G-1 shows the projection of zonal generation in the Base Case. Zone J generation increases most significantly, primarily due to load growth in that zone.

Net Imports

Figure G-2: Projected Net Imports (GWh), Base Case

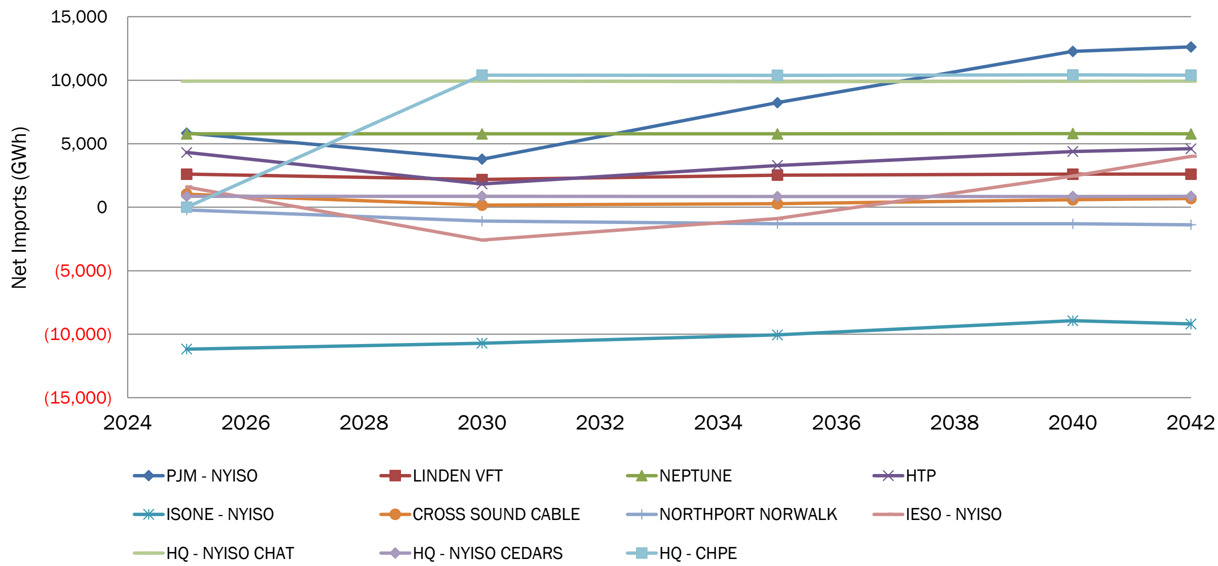


Figure G-2 shows the projection of net imports on each interface for the Base Case. Net imports from PJM to serve load increases in Zone J recover steadily through the study horizon after PJM generator retirements in the first years of the study. However, the net imports from PJM are still overall lower than the previous Outlook cycle due to load increases in PJM. Net imports from IESO are heavily dependent on IESO's load and availability of nuclear units during the refurbishment periods. Net imports are largely flat through the study period across the other interfaces with neighboring systems.

Transmission Congestion

Figure G-3: Demand Congestion by Zone, Base Case

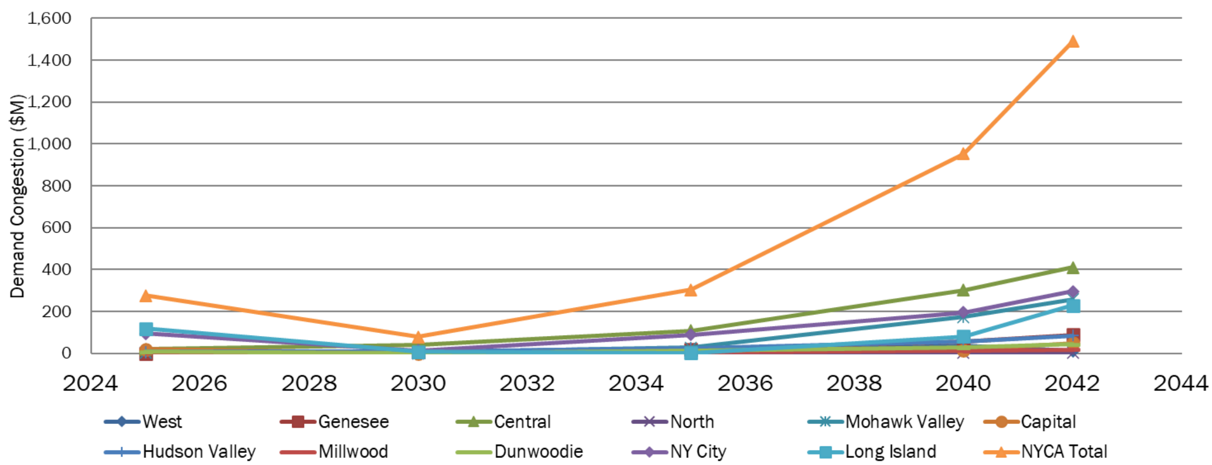
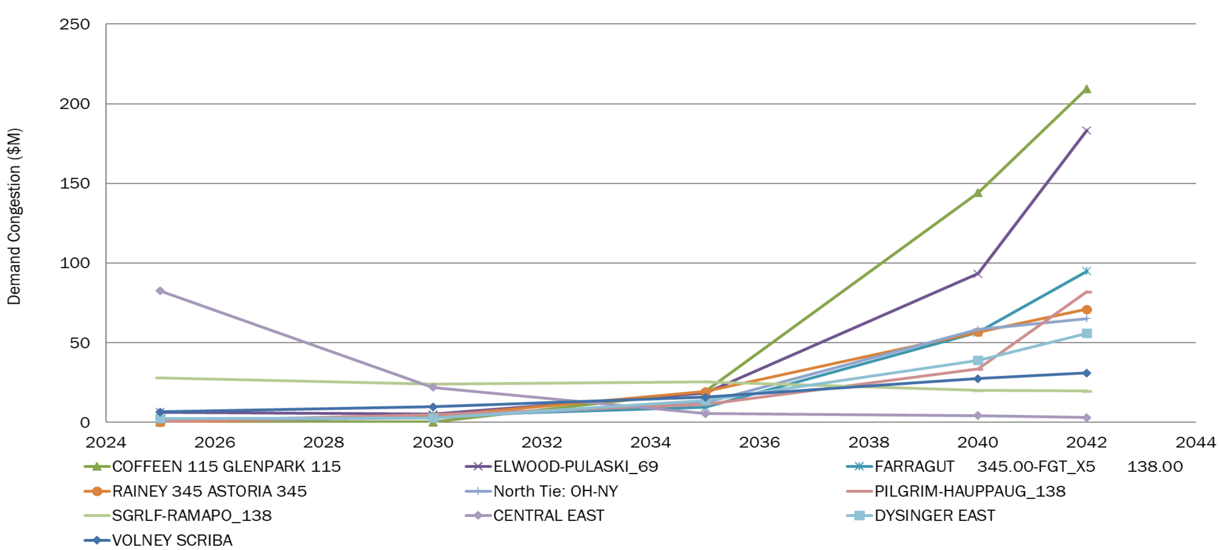


Figure G-4: Demand Congestion by Constraint, Base Case[2]



Figures G-3 and G-4 portray the resulting demand congestion by NYCA zone and by constraint for the Base Case, respectively. Zone C (Central) sees the most significant increase in demand congestion, which is primarily driven by increased energy demand (e.g., native forecast and large loads). The constraints with the most prominent increases in demand congestion are Coffeen-Glenpark 115 kV, Elwood-Pulaski 69 kV, and constraints in Zones J and K. Central East continues to show decreased demand congestion over the study horizon with the completion of the

[2] North Waverly – E. Sayre 115 kV and IESO-NY: North Tie lines not shown in this figure as operations protocols would dictate the operation of these lines.

transmission projects that addressed Segments A and B of the AC Transmission Public Policy Transmission Need.

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 measured by a zonal "dummy" generator in the production cost model. These dummy generators help solve the load-gen balance equation while running the production cost simulation. These generators help fill in the gaps in generation required by allowing a highly flexible unit to operate in these hours. This could represent generic solutions (e.g., generation, transmission, or demand response) which could be employed to cover for hours where traditional resources are constrained and unable to serve demand. In 2040, dummy generators across the state ran for a total of 57 hours, resulting in a total of 15 GWh of unserved energy. In 2042, dummy generators across the state ran for total 191 hours, resulting in a total of 63 GWh of unserved energy.

While the study period of the Base Case ends in 2042, the NYISO did not add any new generating resources to the case past 2025 to remain strictly aligned with the inclusion rules. However, a lack of new resources over a period of almost 20 years where load is growing is unrealistic, and the presence of unserved load in later years in the production cost model should not be interpreted as projected violations of system reliability.

Key Takeaways

- Higher overall load forecasts for New York and neighboring systems contribute to higher levels of internal New York generation and lower imports, as compared to the prior Outlook study.
- Lower kV overloads are more prominent compared to congestion on the bulk power system in later years of the study.

Contract Case

This section summarizes study results for the Outlook Contract Case. Additional detailed results can be found in Appendix I: Transmission Congestion Analysis and Appendix J: Renewable Generation Pockets.

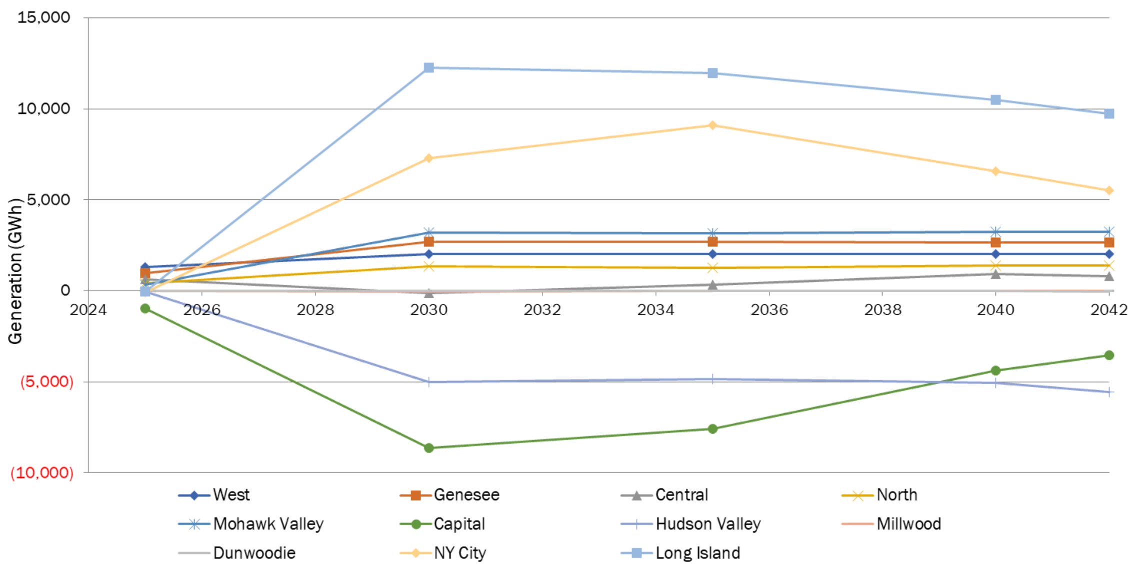
The assumptions used to develop the Contract Case can be found in Appendix B: Production Cost Assumptions Matrix. The primary driver for trends in Contract Case results, compared to the Base Case results, include:

- Approximately 7 GW of additional UPV by 2030
- Approximately 1 GW of additional LBW by 2030

Generation

The figure below shows the change in NYCA generation, by zone, compared to the Base Case.

Figure G-5: Projected NYCA Generation by Zone, Delta from Base Case

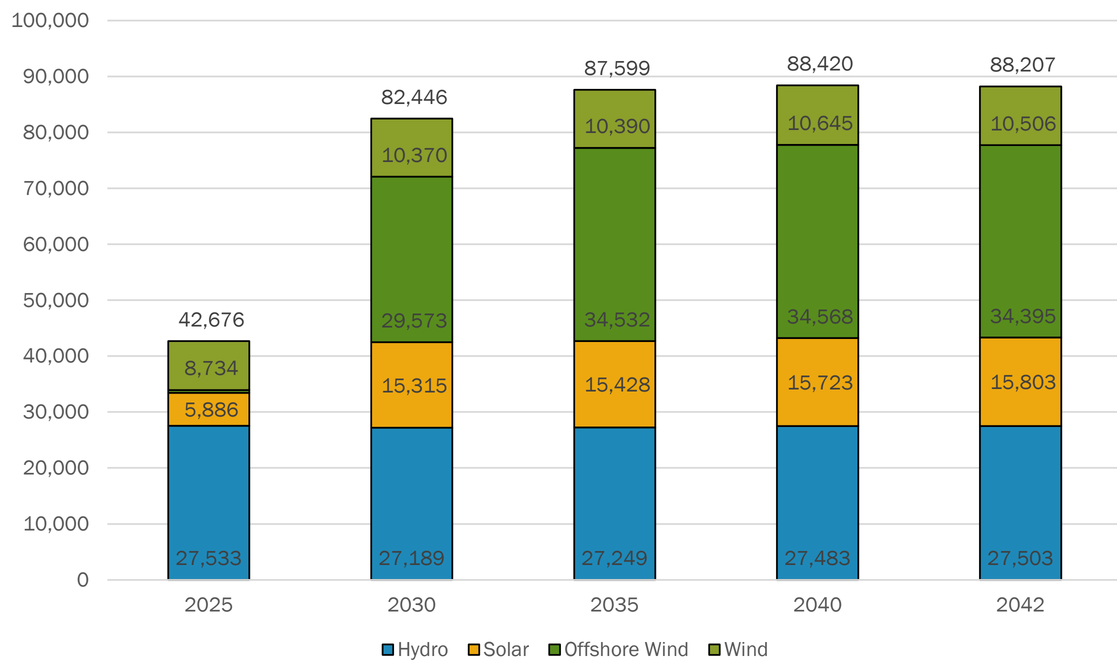


Renewable Generation & Curtailment

The Contract Case resource additions include renewable energy projects that have been awarded Renewable Energy Certificates (REC) or Offshore Renewable Energy Certificates (OREC) by NYSERDA to serve energy in New York.[3] The following figure shows renewable generation by resource type.

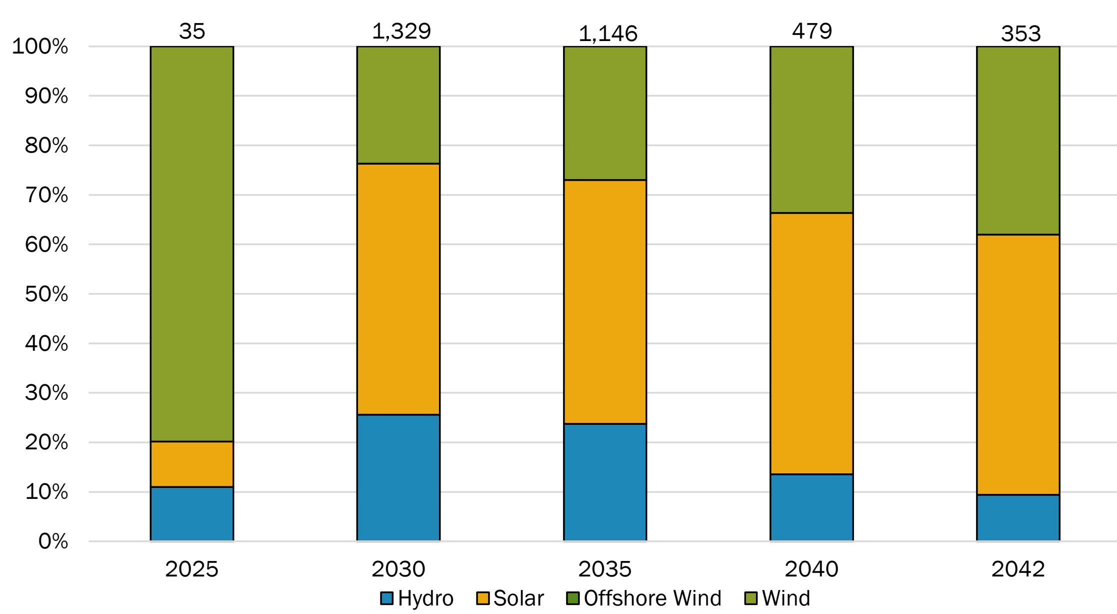
[3] Renewable energy projects assumed as firm resource additions in the Contract Case include those in the NYSERDA Renewable Energy Certification contracts database and announced awards as of the lockdown date (i.e., October 30, 2023) for the 2023-2042 System & Resource Outlook Contract Case.

Figure G-6: Annual Generation by Resource Type



Based on the assumed energy demand, behind-the-meter solar, and modeled large load projects, 66% of the load in model year 2030 is served by renewable energy.

Figure G-7: Annual Curtailment by Unit Type

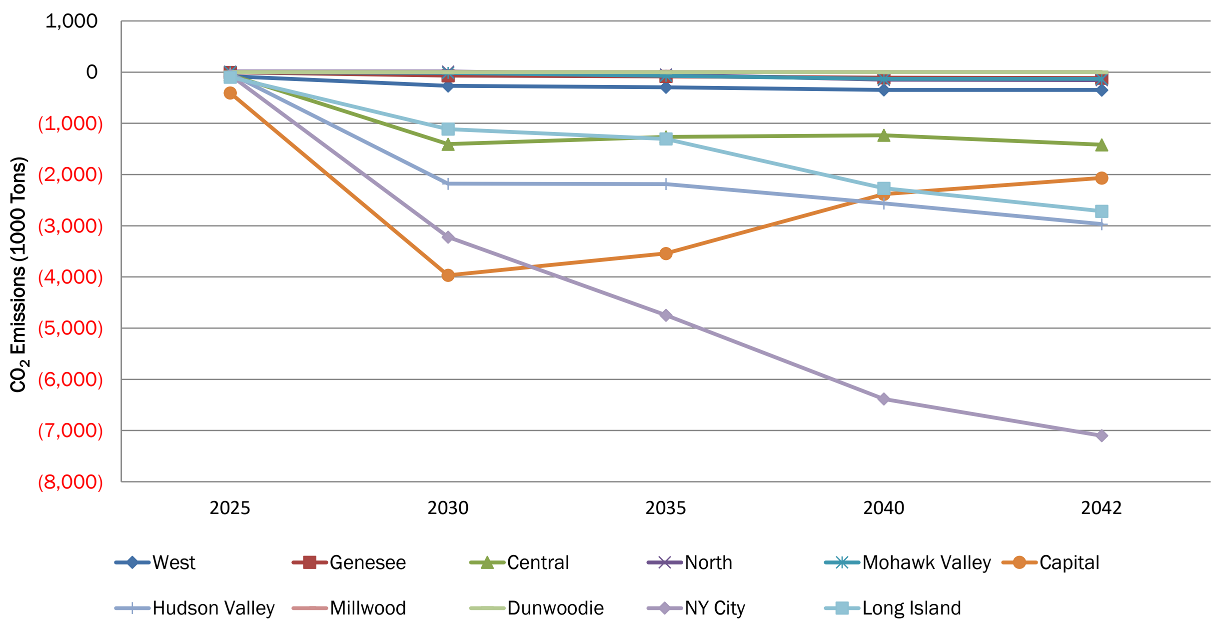


As shown in the chart above, curtailment levels are low in the Contract Case in 2025; most of which is attributed to land-based wind units in upstate New York. Starting in 2030, more offshore wind capacity comes into service and an increase in solar curtailment can be observed. The Contract Case includes offshore wind projects that have been awarded OREC by NYSERDA.[4] In the Contract Case, curtailment of offshore wind is minimal with the inclusion of the transmission project that addresses the Long Island Offshore Wind Export Public Policy Transmission Need. The numeric values displayed above the bars in Figure G-7 identify the total annual renewable energy curtailment in GWh.

[4] The offshore wind resources are included if they meet the inclusion rules as of the assumed lockdown date (October 30, 2023) for the Contract Case.

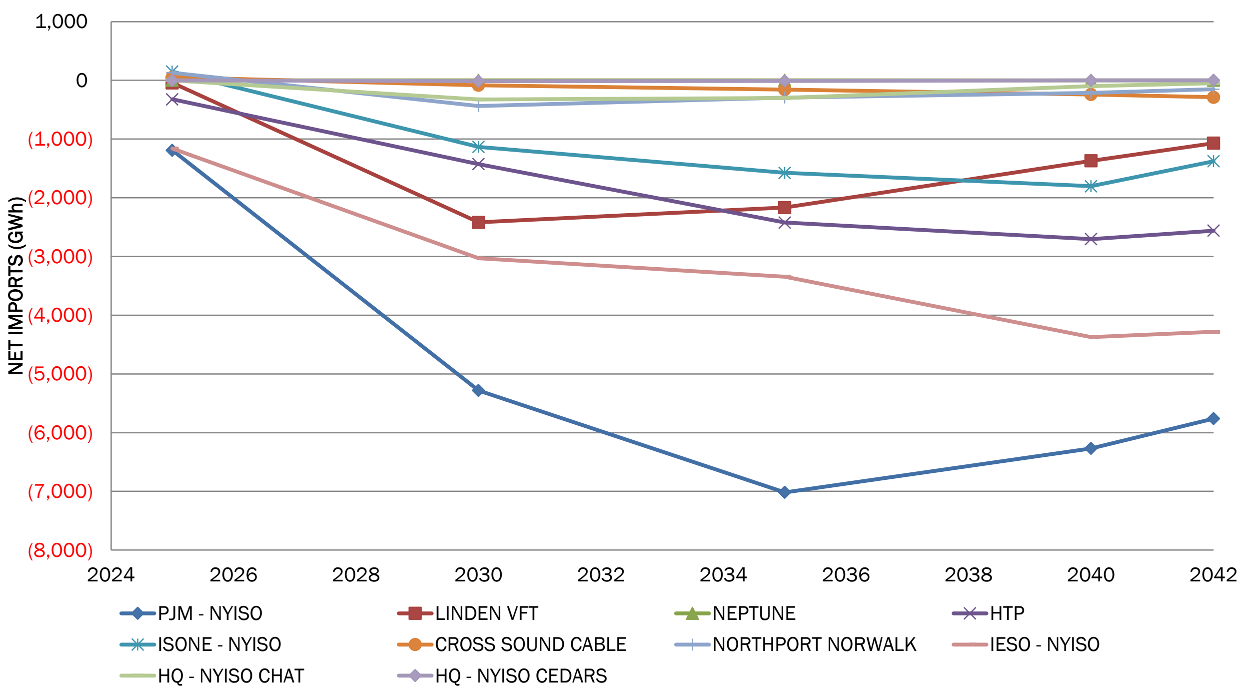
Emissions

Figure G-8: Projected CO_2 Emissions, Delta from Base Case



Net Imports

Figure G-9: Projected Net Imports by Interface, Delta from Base Case



Congestion

Figure G-10: Projected Demand Congestion by Zone, Delta from Base Case

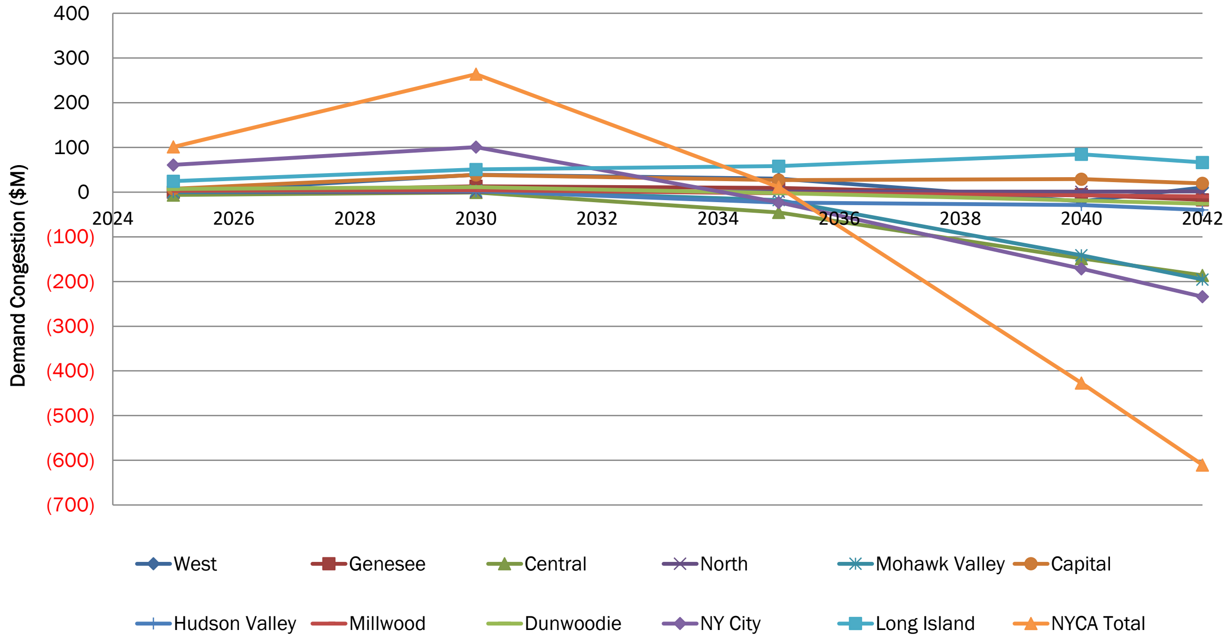
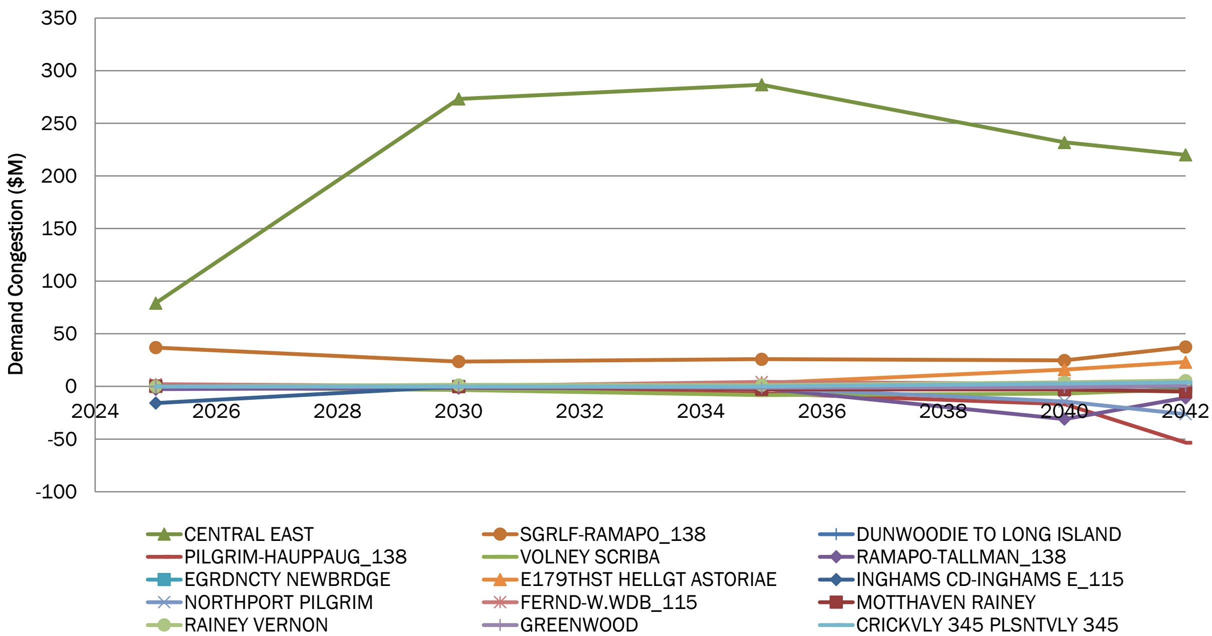


Figure G-11: Demand Congestion by Constraint, Delta from Base Case[5]

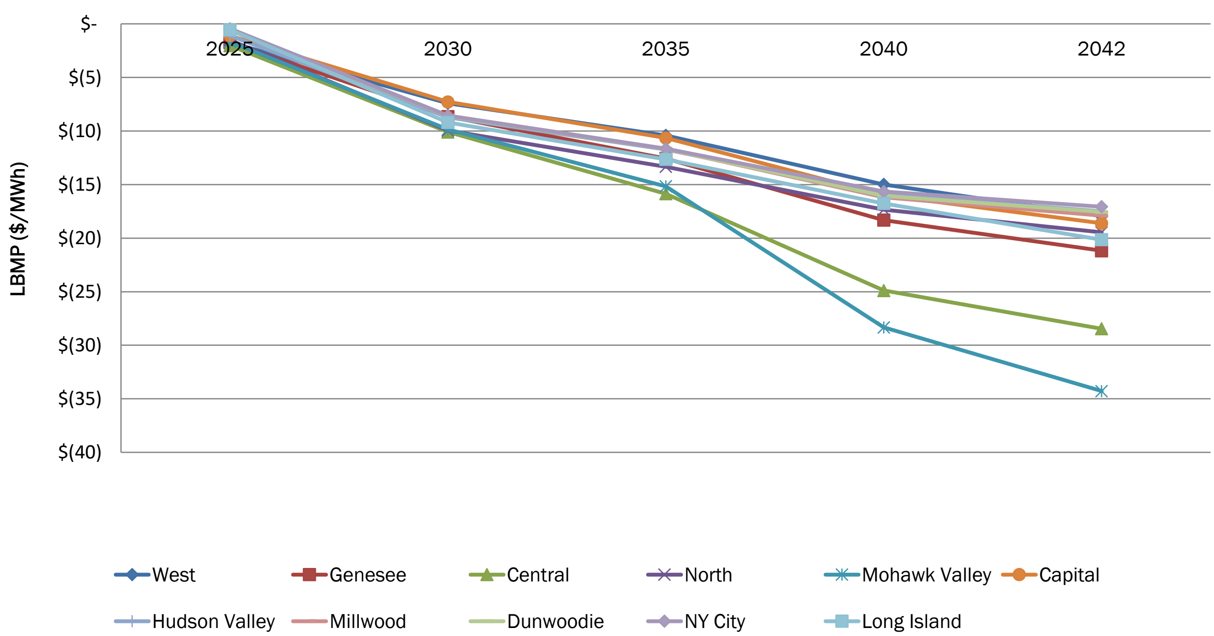


Figures G-10 and G-11 show the change in demand congestion results between the Base Case and Contract Case both zonally and by constraint. Zones A and C see most of the increase in congestion, particularly on Central East, in the early years of the study when the added renewable generation come into service. The upstate zones see a decrease in congestion in the later years of the study with the addition of offshore wind generation in downstate zones offsetting some needs to transfer energy between upstate and downstate.

[5] North Waverly – E. Sayre 115 kV and IESO-NY: North Tie lines are not shown in this figure, as operational protocols would dictate the operation of these lines.

LBMPs

Figure G-12: Projected Zonal LBMPs, Delta from Base Case



Unserved Energy

Consistent with the Base Case, any unserved energy in a load zone is measured by a zonal "dummy" generator in the production cost model. In the Contract Case, dummy generators ran for a total of 6 hours, resulting in 1.3 GWh of unserved energy in year 2040 and for a total of 36 hours, resulting in 4.9 GWh of unserved energy in year 2042.

Key Takeaways

- Approximately 16 GW of renewable generation was added to the Contract Case compared to Base Case, which displaces internal fossil fuel generation and net imports.
- Additional generation in upstate zones increases congestion on Central East compared to the Base Case.
- Additional generation in downstate zones (e.g., offshore wind) leads to a reduction in net imports and demand congestion in those zones compared to the Base Case.
- Additional renewable generation capacity in the Contract Case offsets fossil generation from the Base Case and leads to a reduction in CO_2 emissions and reduction in LBMPs.

Policy Case

This section presents summary level results for the Policy Case. Additional details on Policy Case analyses are included in Appendix I: Transmission Congestion Analysis and Appendix J: Renewable Generation Pockets.

Results from capacity expansion modeling were imported to the production cost model, and the NYISO performed the hourly simulations. Simulations for the Policy Case scenarios were performed in five-year intervals only for 2025, 2030, and 2035. In addition, the NYISO simulated 2042 to show results for the last year of the study period. The major assumption in the 2042 simulation was relaxation of the lower kV transmission. Generation capacity remains consistent between the capacity expansion and production cost simulations, but the operation of the fleet can differ between the two simulations due to a more detailed nodal network, higher temporal resolution, and full modeling of neighboring systems for production cost. The differing results between the models provide important insights into the challenges that may occur when procuring a significant amount of renewable generation capacity to meet policy objectives. 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 energy deliverability within emerging generation pockets).

Unserved Energy

In 2025 to 2035, dummy generators do not run in the Policy Case (Lower and Higher Demand) scenarios, meaning the analysis did not identify any unserved energy. However, the retirement of existing fossil fuel generation and the addition of intermittent resources in the Policy Case scenarios resulted in periods of unserved energy in 2042 that are greater in number than those compared to the Base and Contract Cases. In the Lower Demand scenario, dummy generators ran for a combined 2,234 hours and 3,589 GWh of energy. In the Higher Demand scenario, dummy generators ran for a combined 3,644 hours and 8,369 GWh of energy. In both scenarios, nearly all of the unserved energy is in Zones J and K and is driven by local constraints and load pockets downstate. This, in part, is caused by the placement of DEFRs in the nodal production cost model assumed in this Outlook.

Compared to the Base and Contract Cases' unserved energy values, the Policy Case shows higher number of hours and energy demand for unserved energy. Even though the Policy Case considers DEFR units as highly flexible units and do provide for the ramping requirements in a high renewable scenario, there does still exist gaps in generation required when a zero-emissions grid is studied in the hourly production cost models.

The charts in Figure G-13 through Figure G-42 show the system and zonal capacity, energy production, and curtailment results for the Policy Case scenarios simulated. While the generation capacity amounts match the results of the capacity expansion simulations, the energy generated differs because the production cost model produces a more granular commitment and dispatch of generation.

Figure G-13: Lower Demand Case Production Cost Capacity by Type

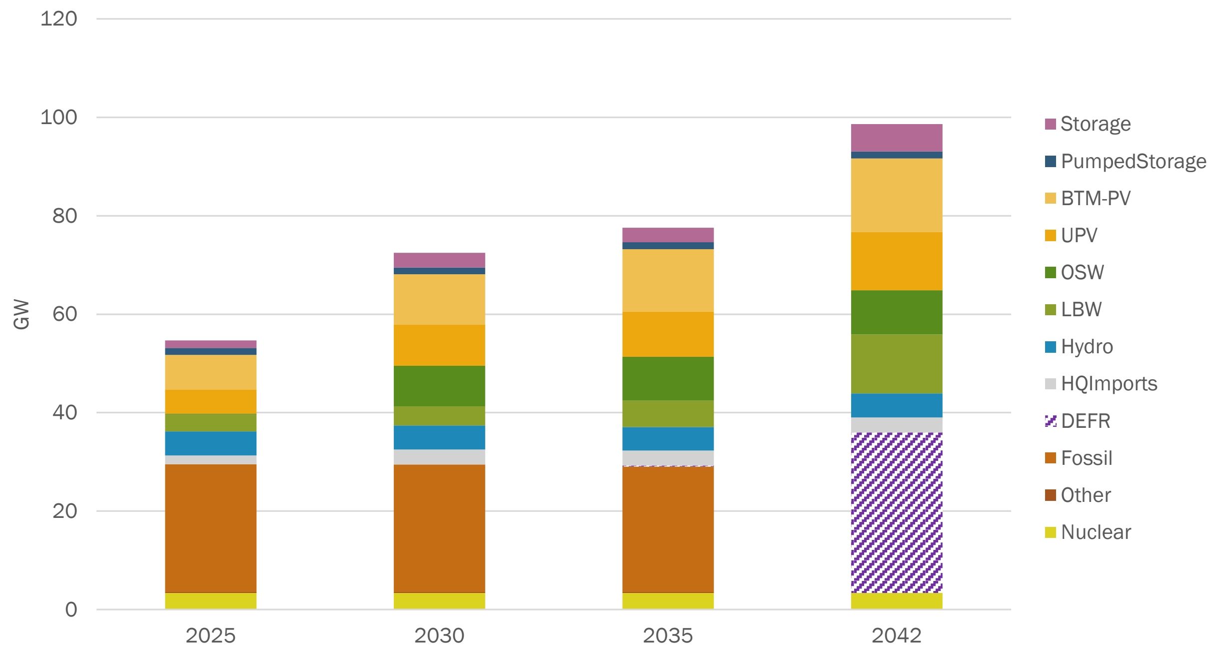


Figure G-14: Higher Demand Case Production Cost Capacity by Type

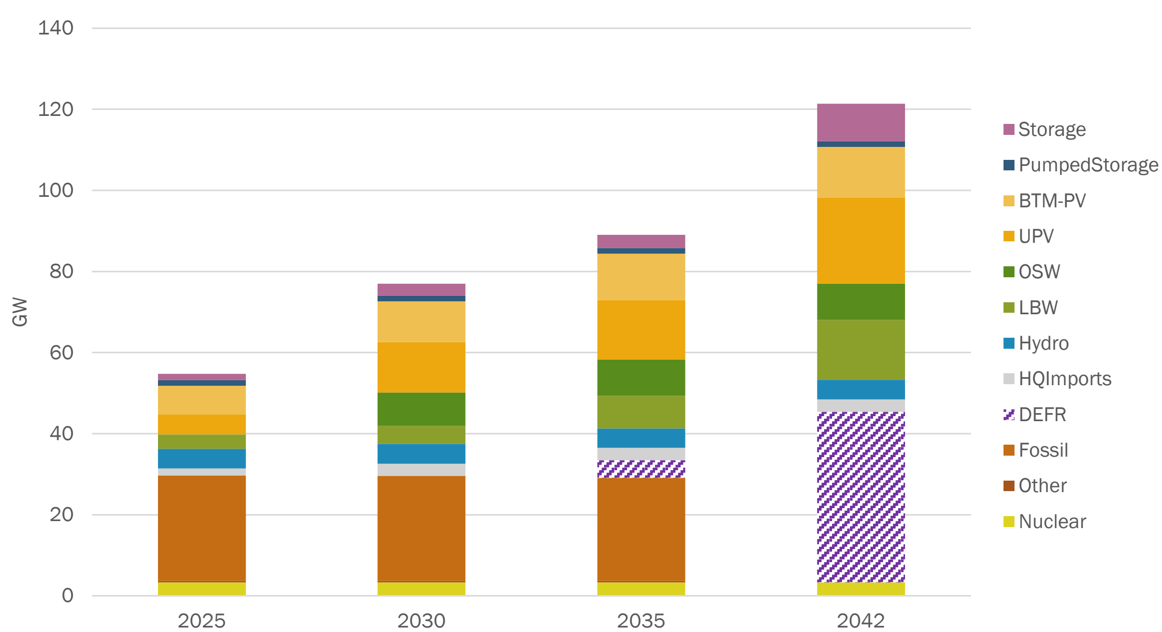


Figure G-15: Lower Demand Case Energy by Type

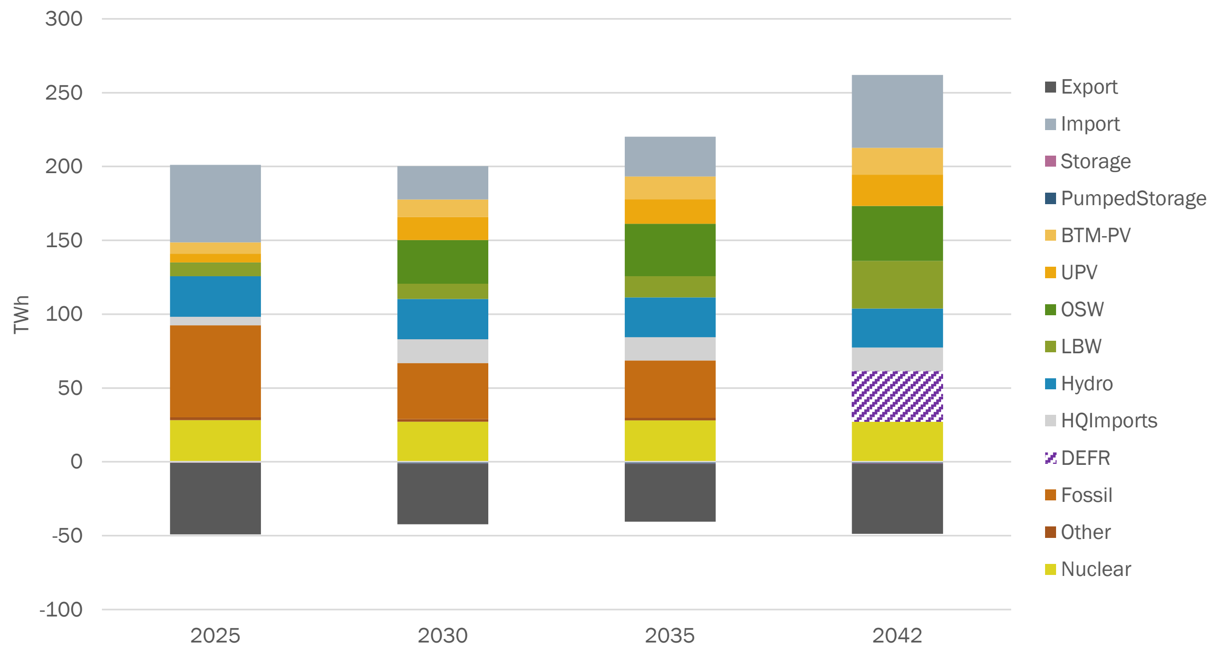


Figure G-16: Higher Demand Case Energy by Type

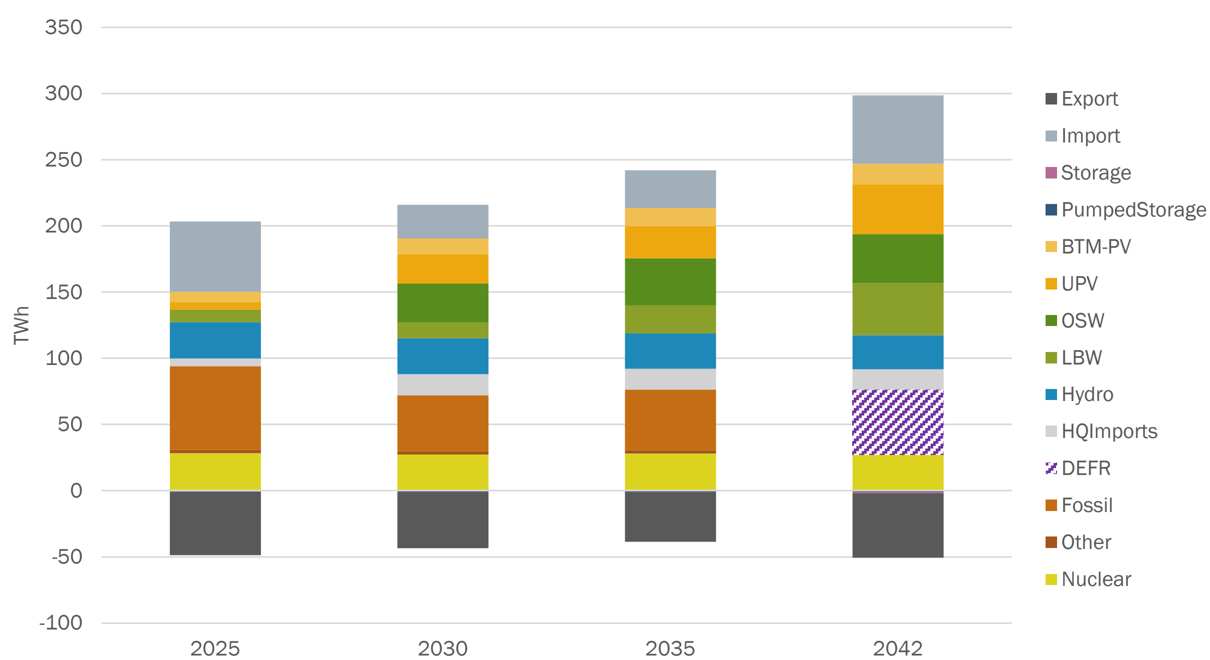


Figure G-17: Lower Demand Case Curtailment by Type

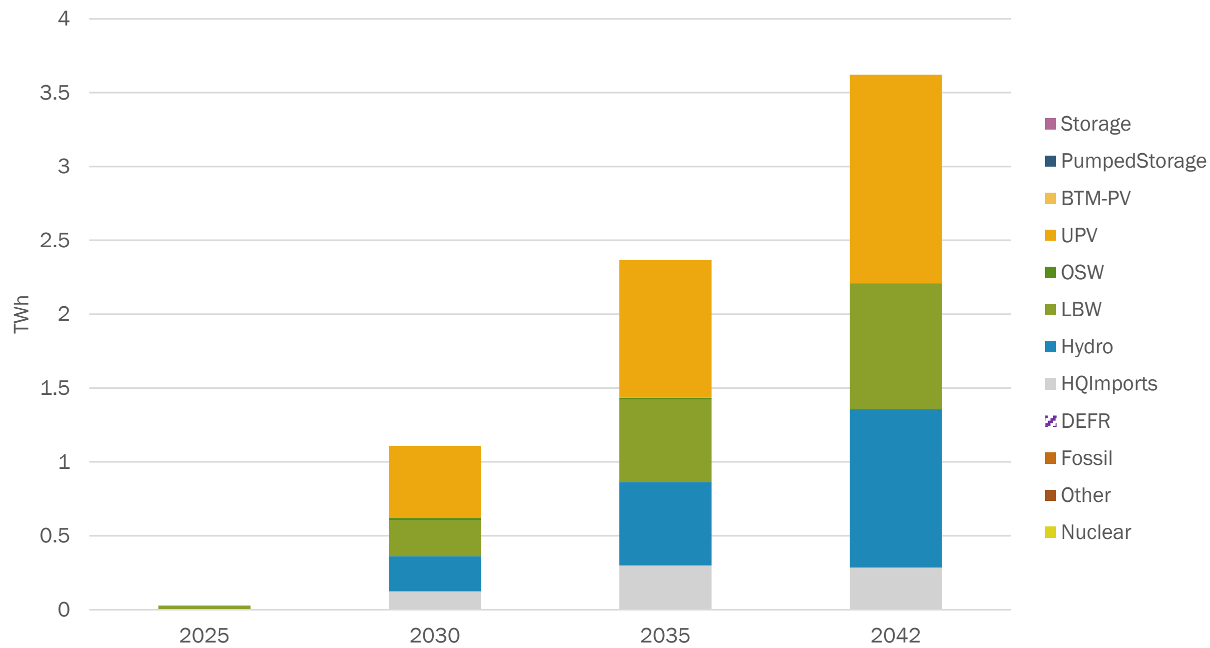


Figure G-18: Higher Demand Case Curtailment by Type

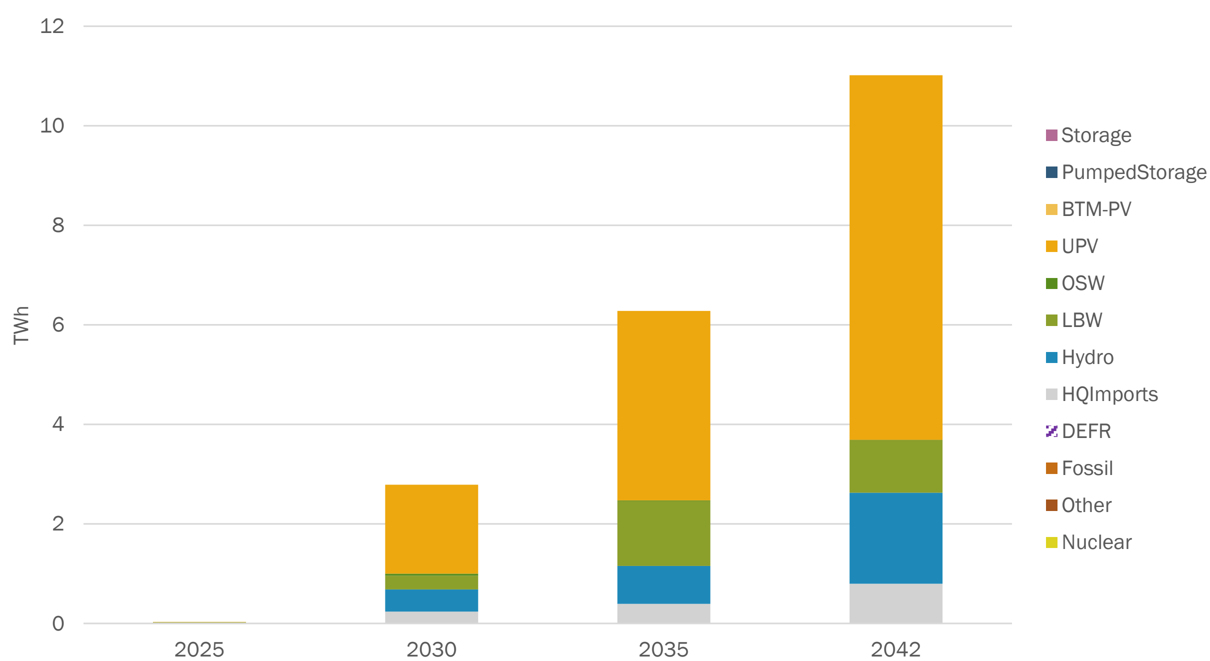


Figure G-19: Lower Demand Zonal Capacity by Type, 2025

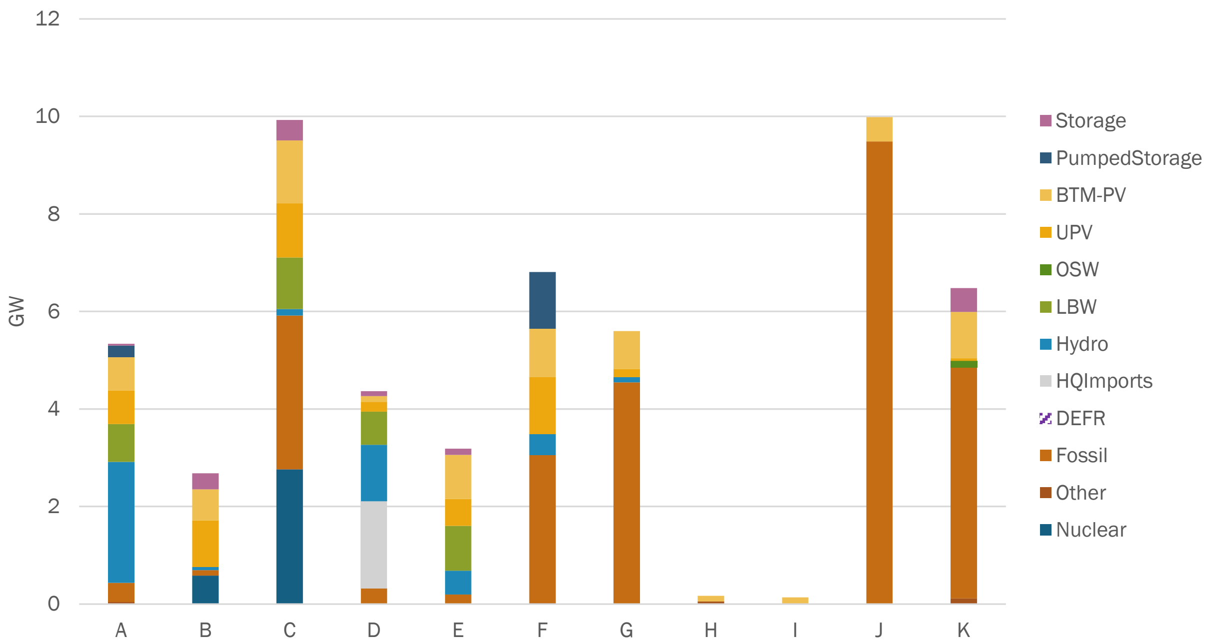


Figure G-20: Lower Demand Zonal Capacity by Type, 2030

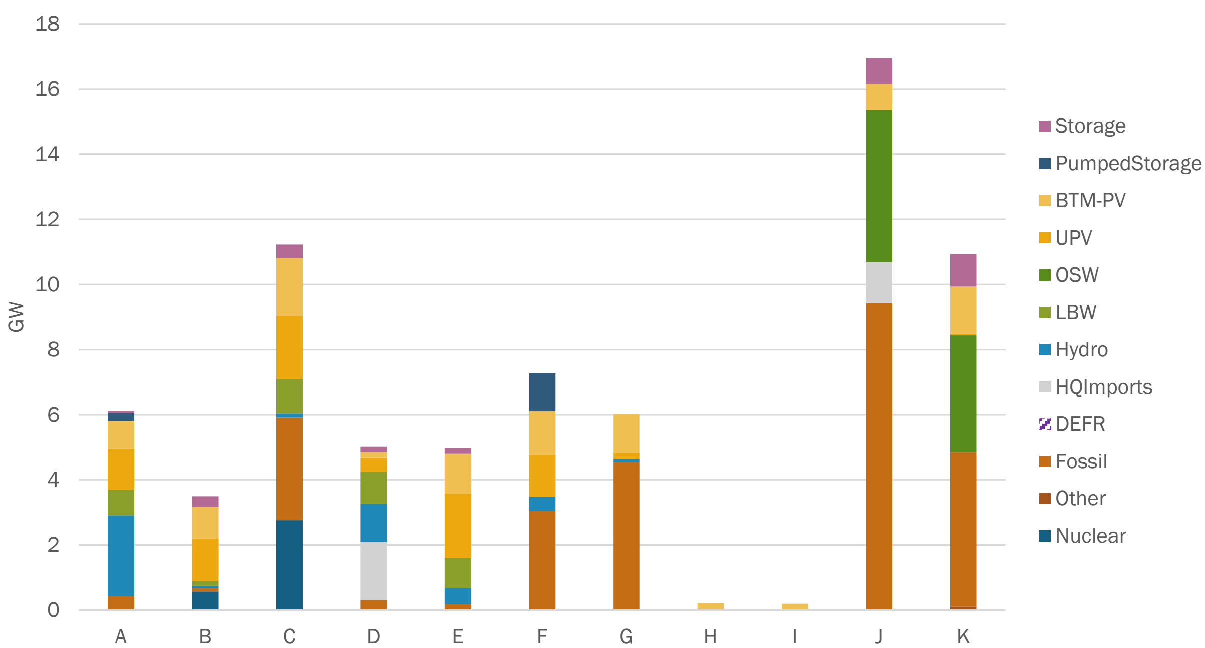


Figure G-21: Lower Demand Zonal Capacity by Type, 2035

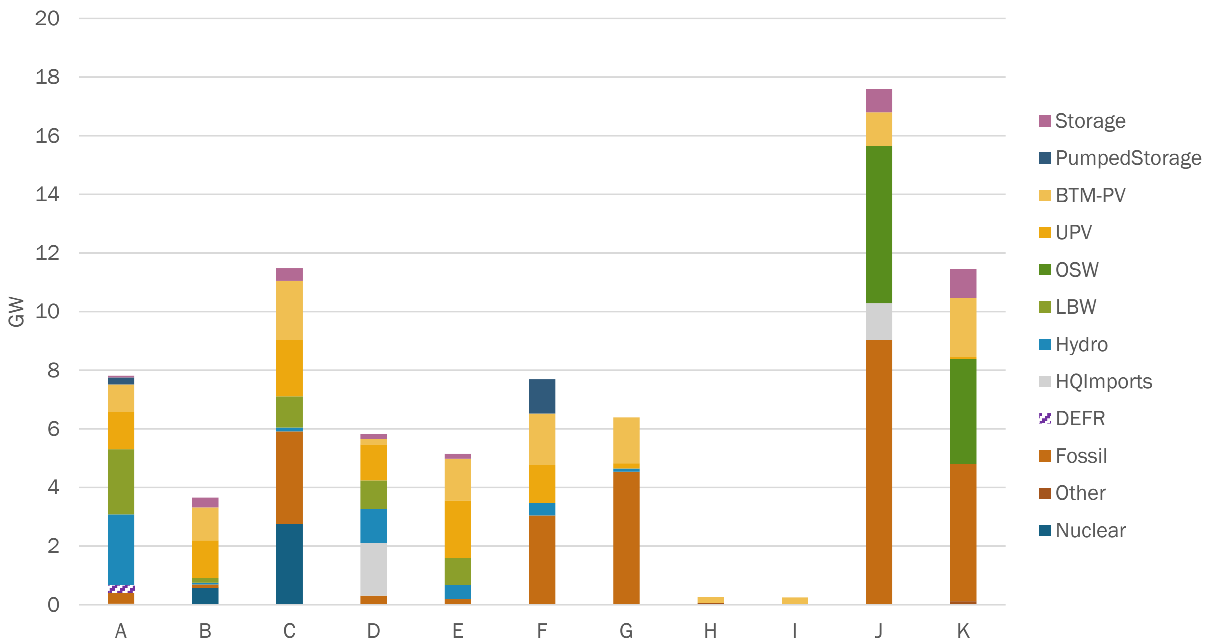


Figure G-22: Lower Demand Zonal Capacity by Type, 2042

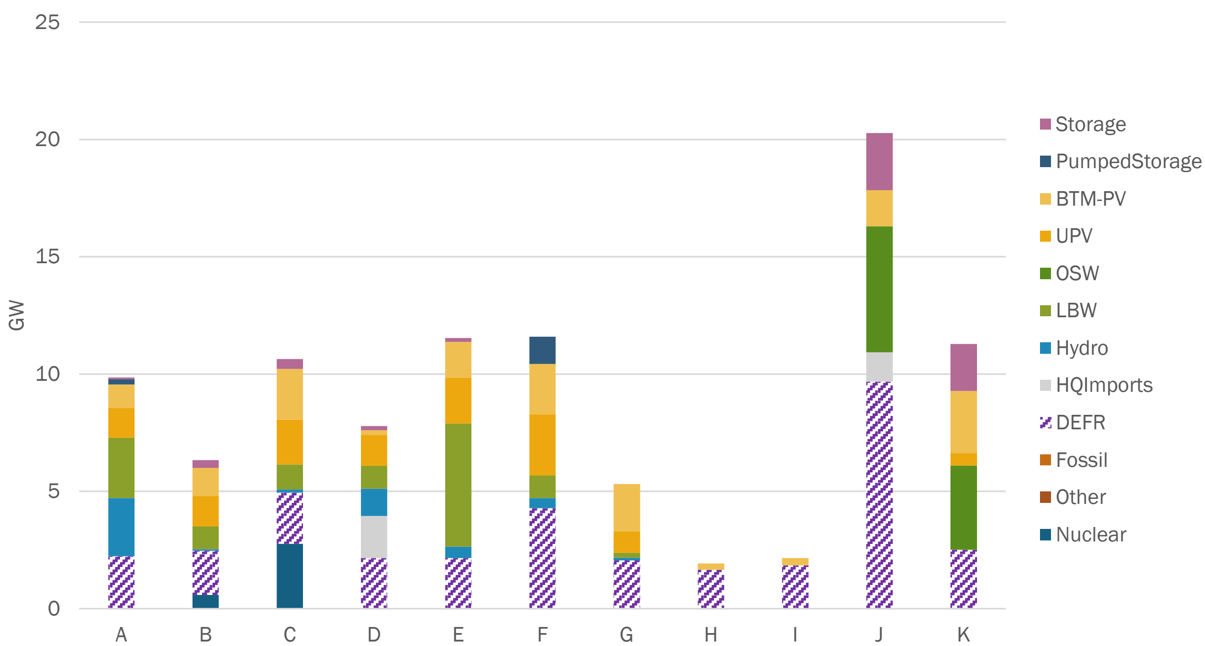


Figure G-23: Higher Demand Zonal Capacity by Type, 2025

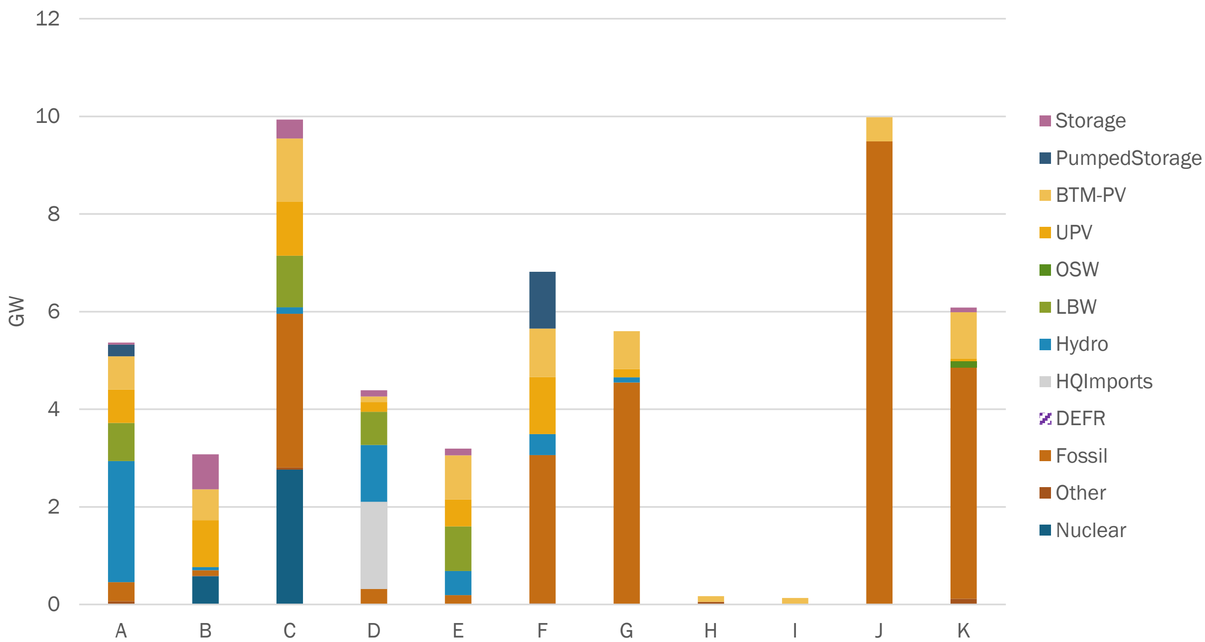


Figure G-24: Higher Demand Zonal Capacity by Type, 2030

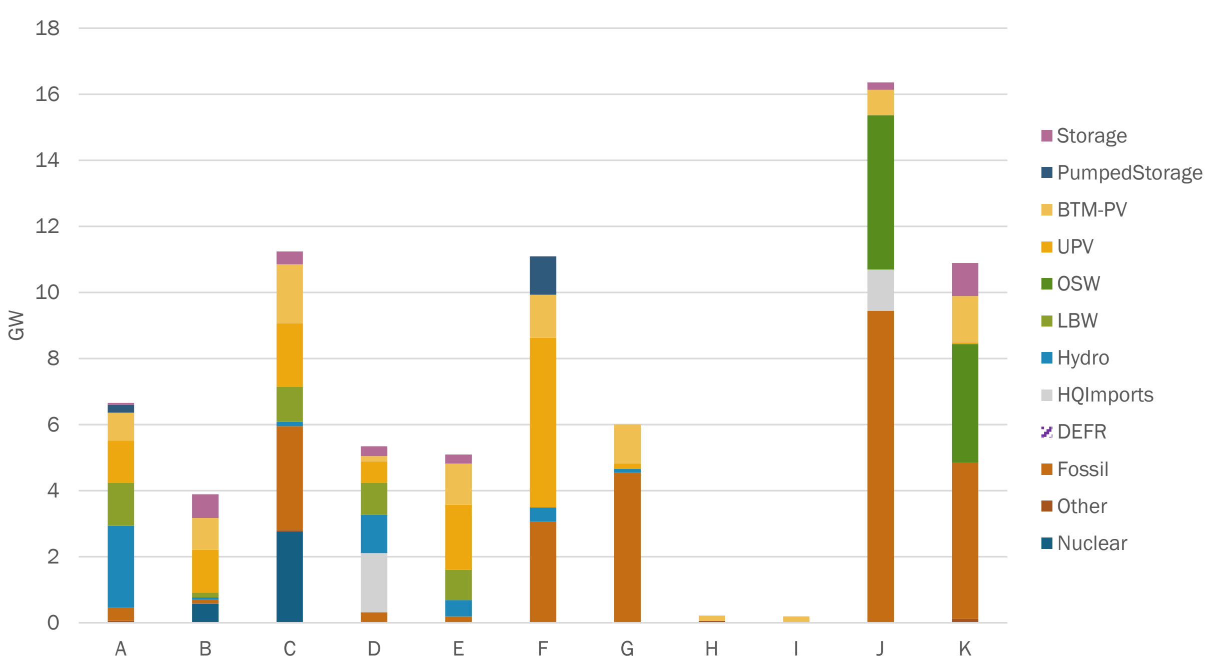


Figure G-25: Higher Demand Zonal Capacity by Type, 2035

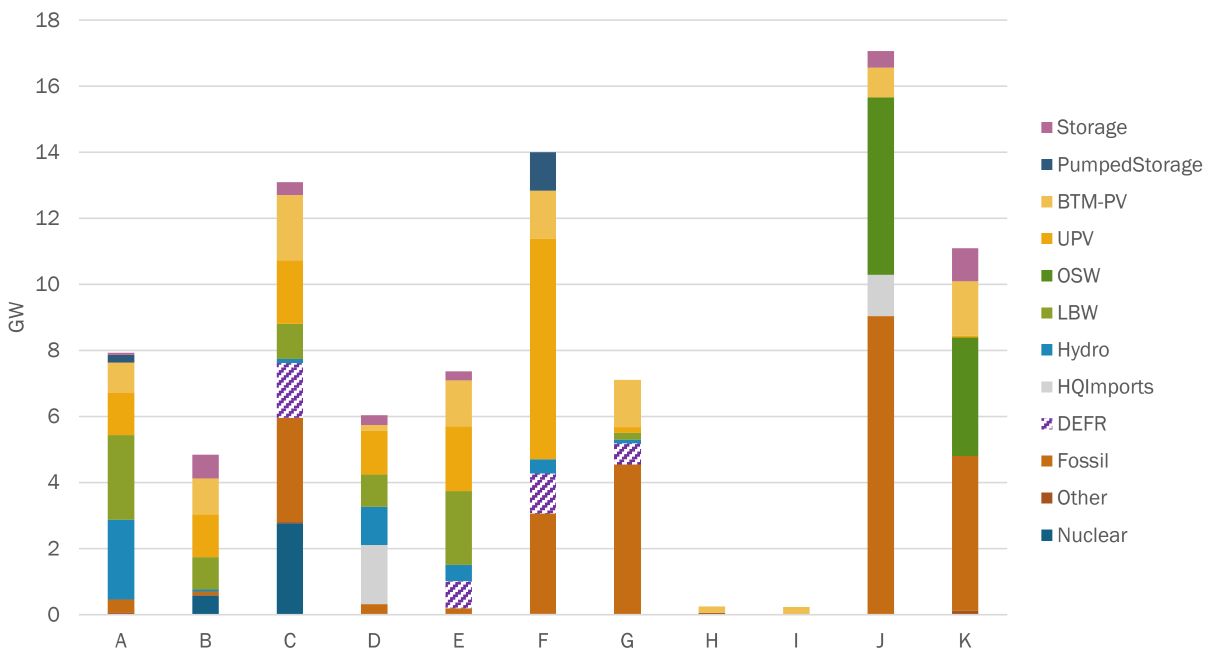


Figure G-26: Higher Demand Zonal Capacity by Type, 2042

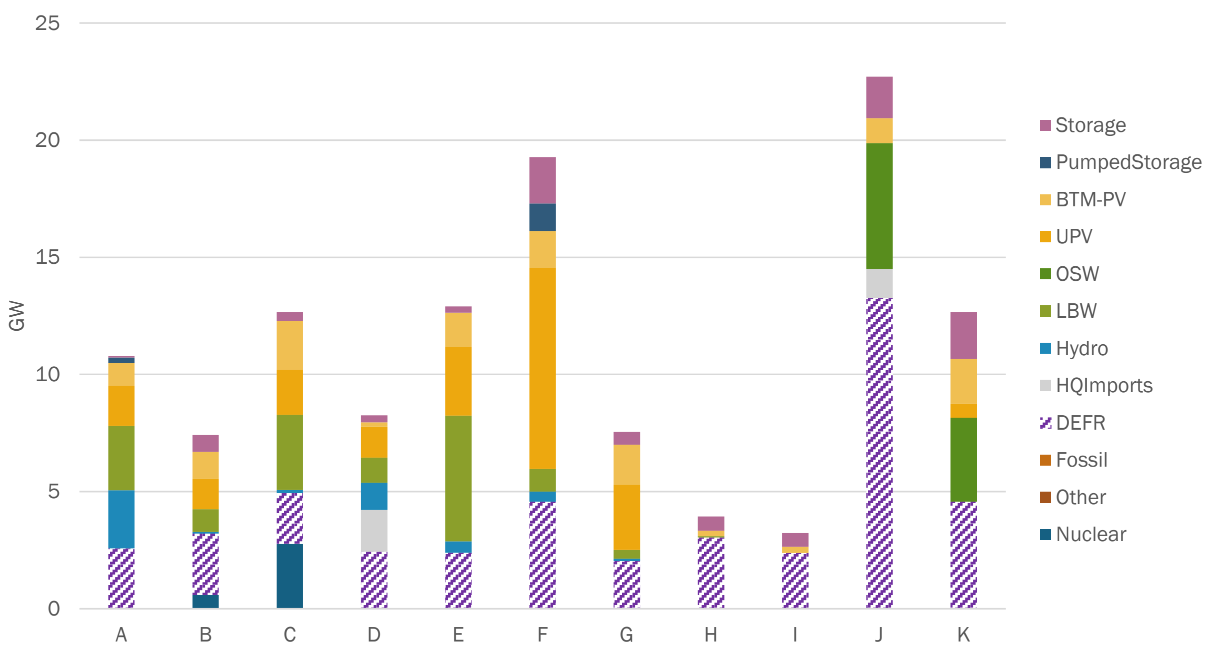


Figure G-27: Lower Demand Zonal Energy by Type, 2025

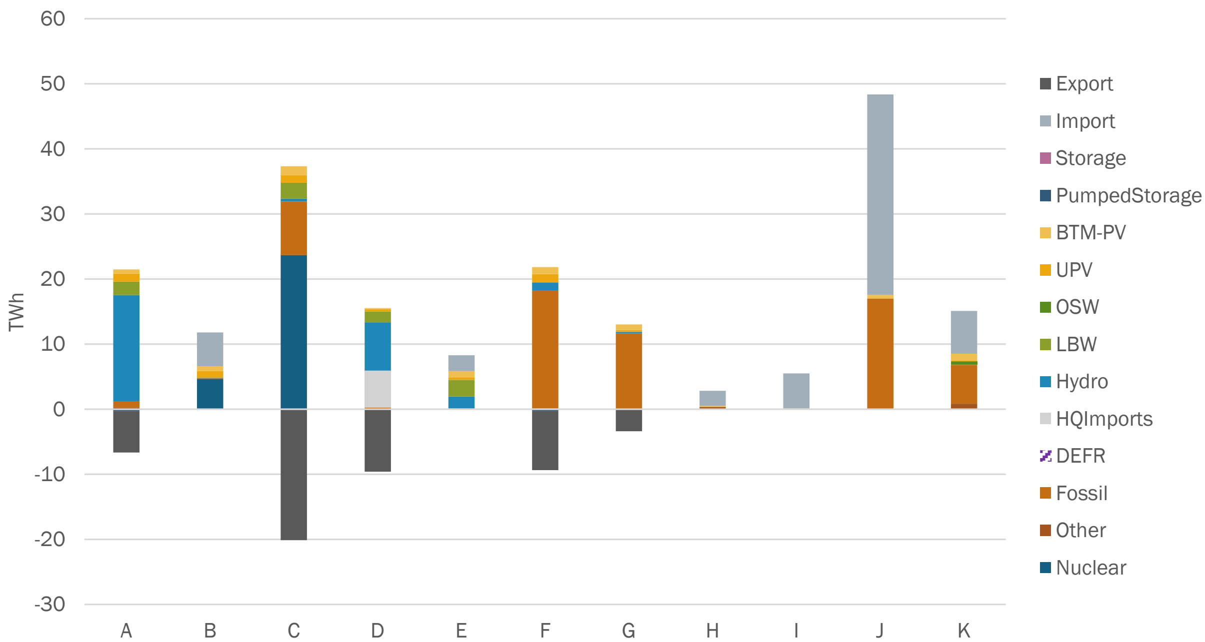


Figure G-28: Lower Demand Zonal Energy by Type, 2030

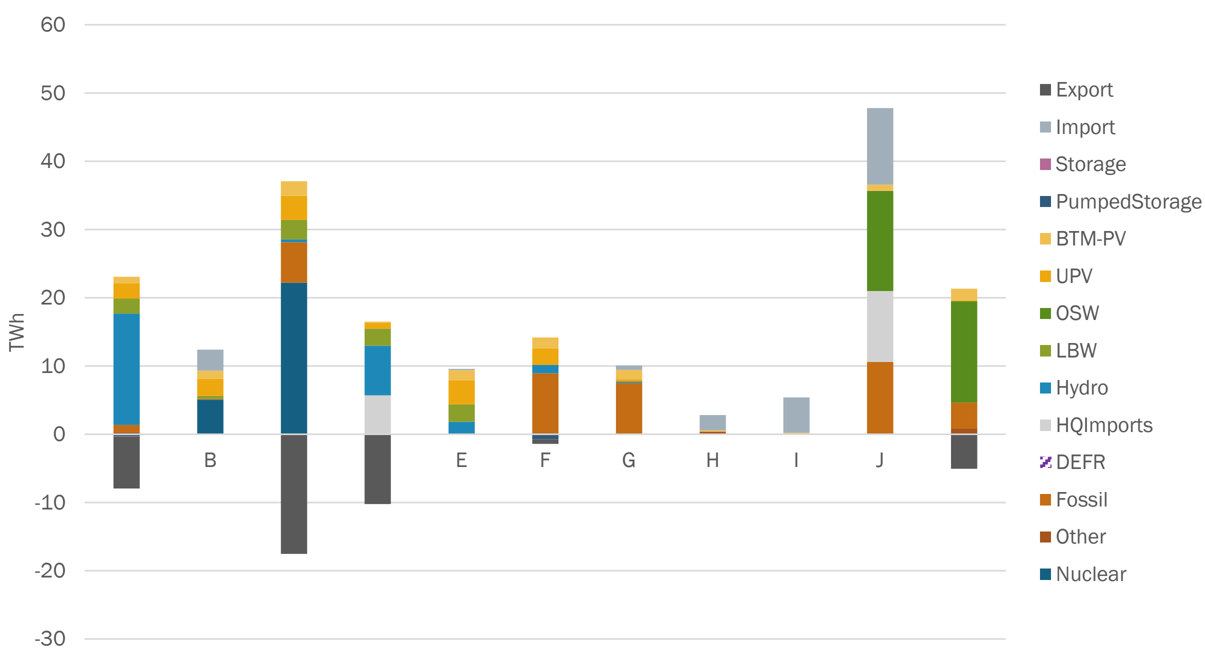


Figure G-29: Lower Demand Zonal Energy by Type, 2035

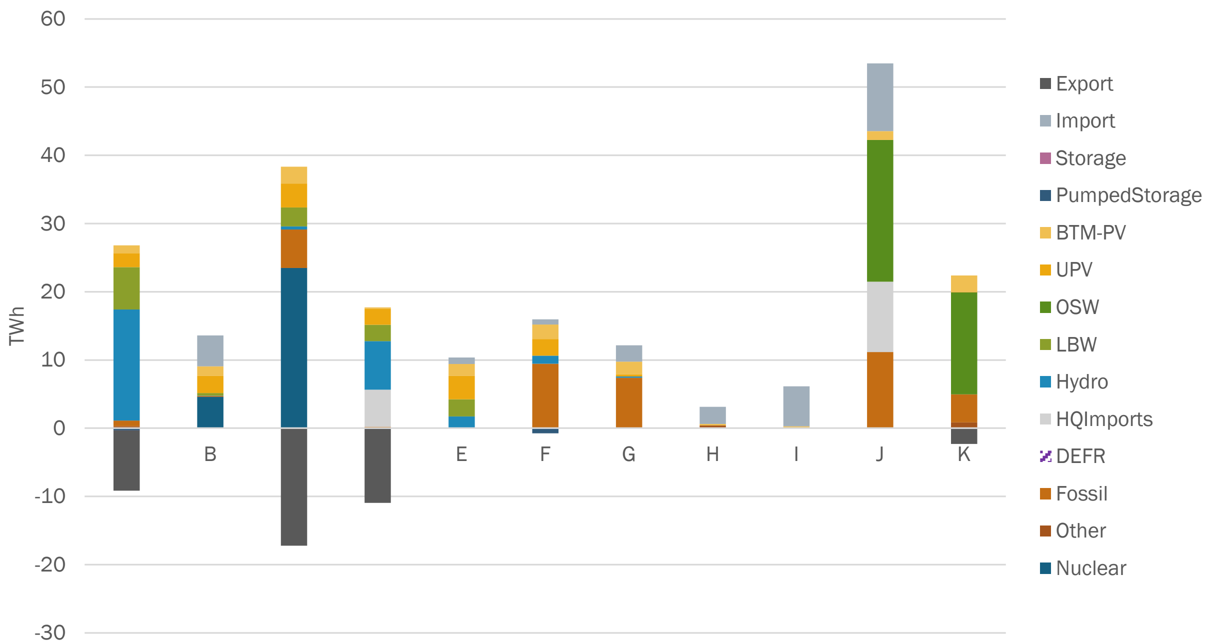


Figure G-30: Lower Demand Zonal Energy by Type, 2042

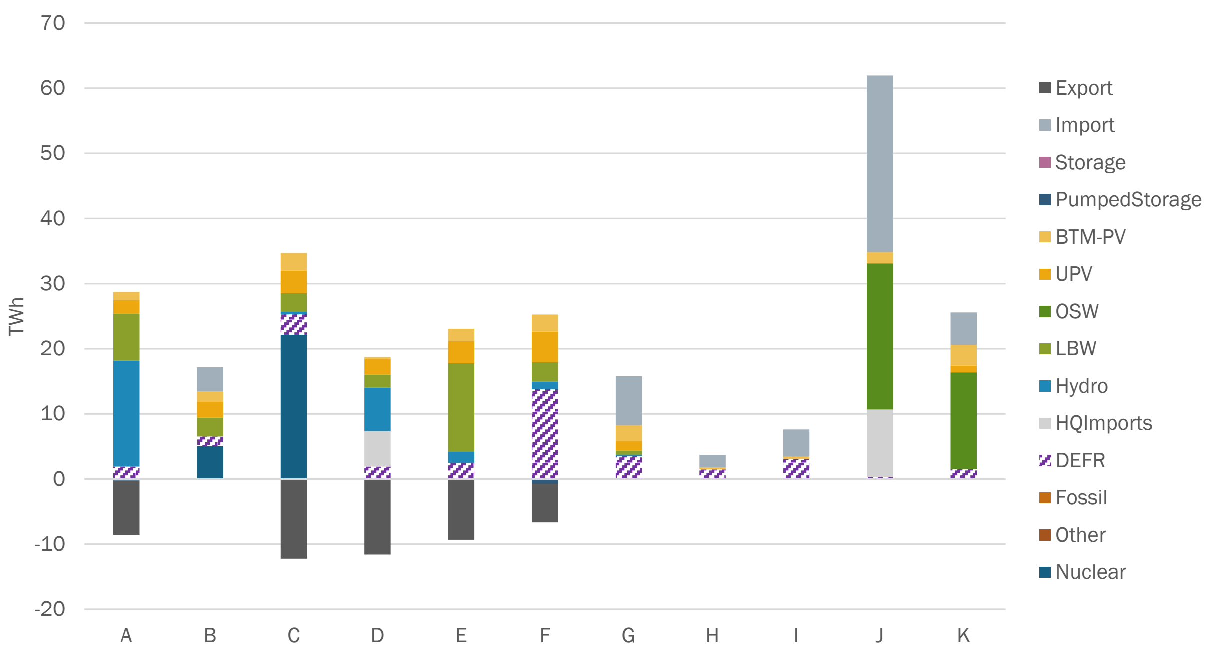


Figure G-31: Higher Demand Zonal Energy by Type, 2025

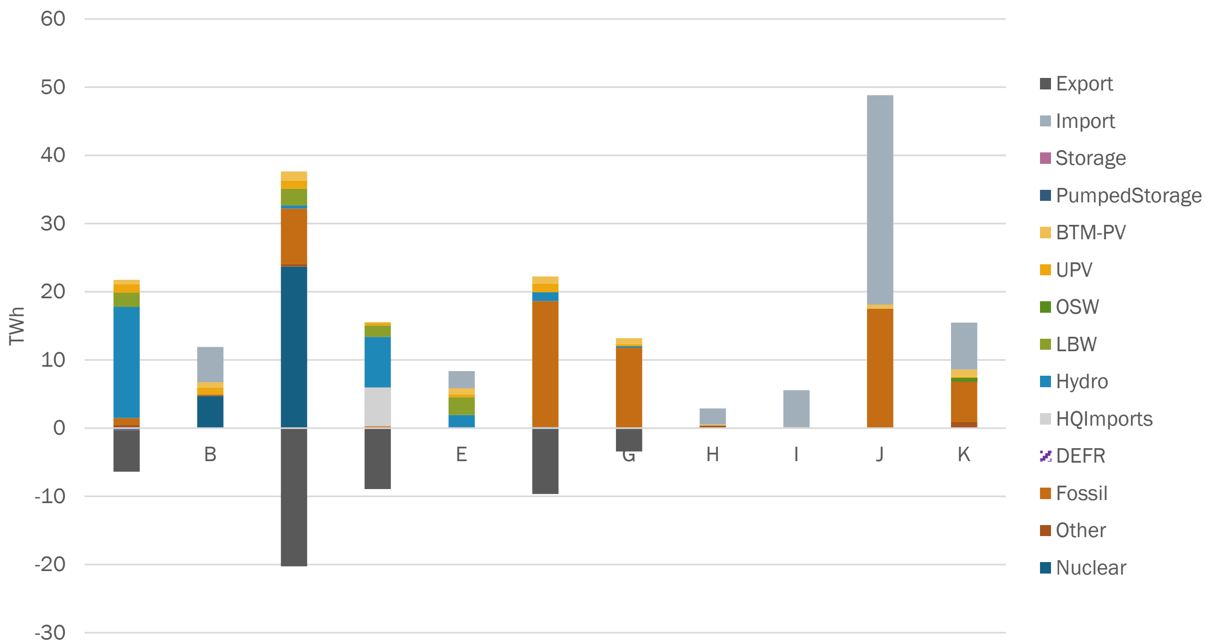


Figure G-32: Higher Demand Zonal Energy by Type, 2030

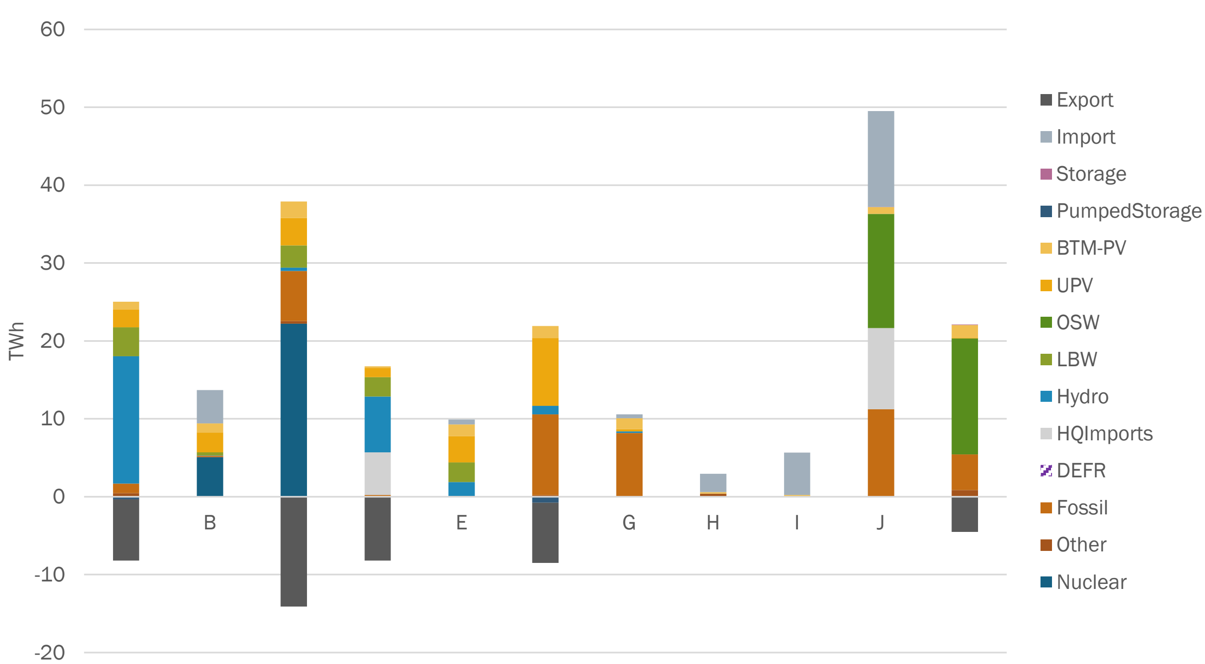


Figure G-33: Higher Demand Zonal Energy by Type, 2035

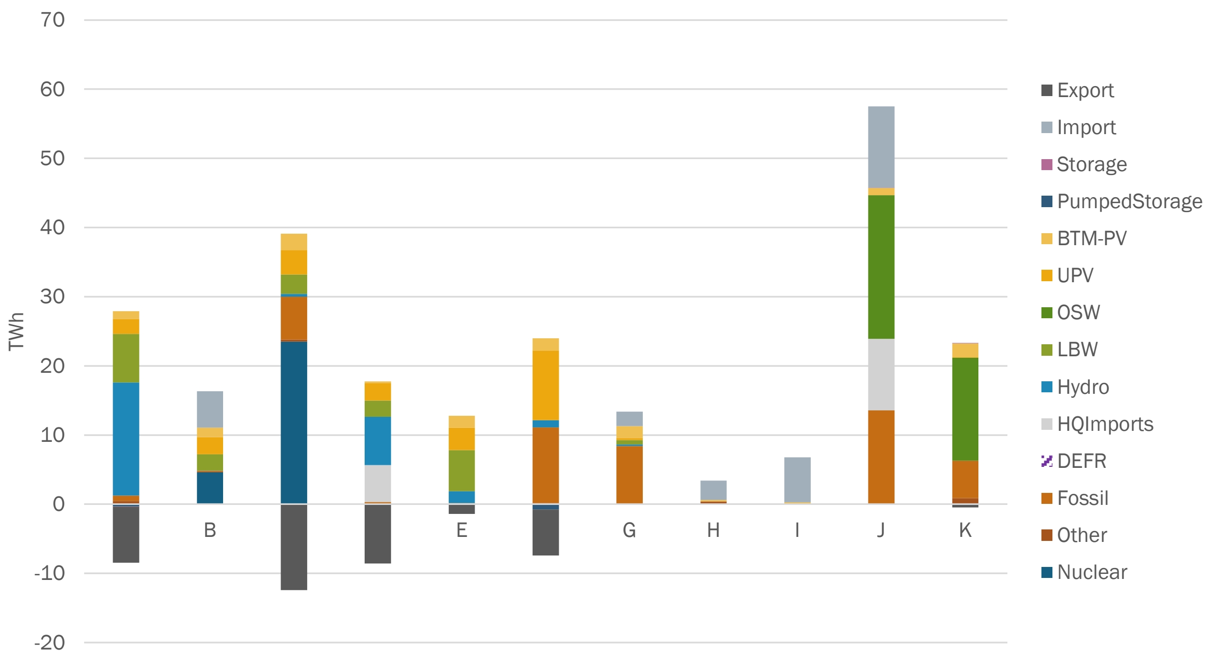


Figure G-34: Higher Demand Zonal Energy by Type, 2042

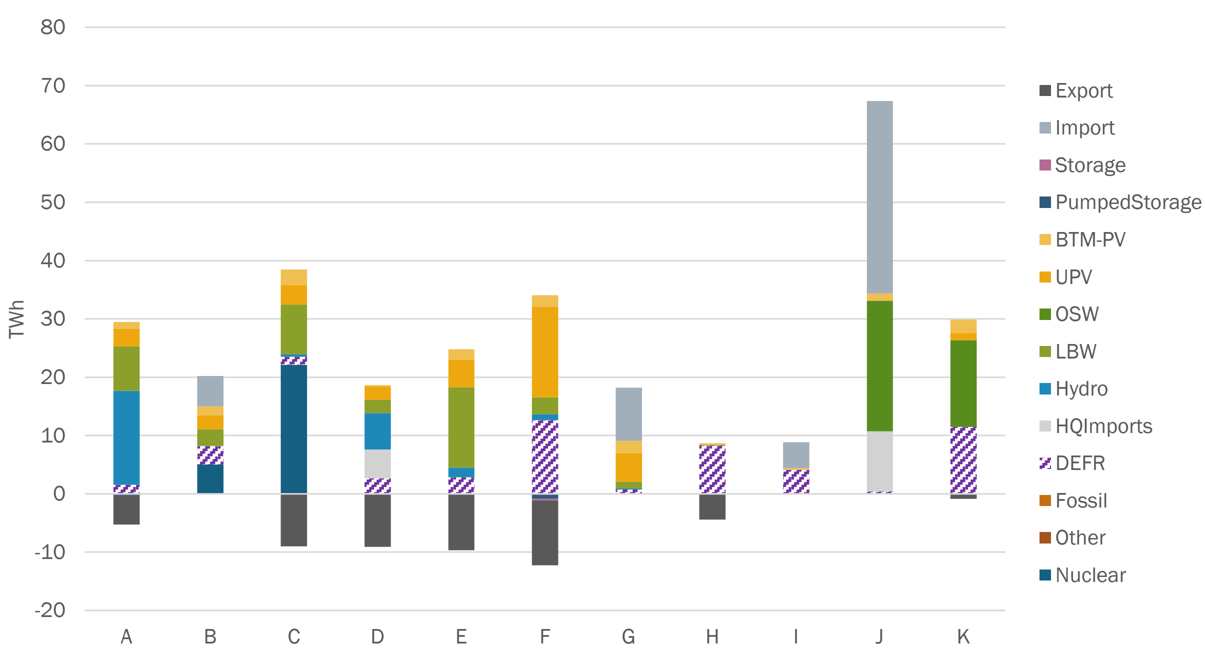


Figure G-35: Lower Demand Zonal Curtailment by Type, 2025

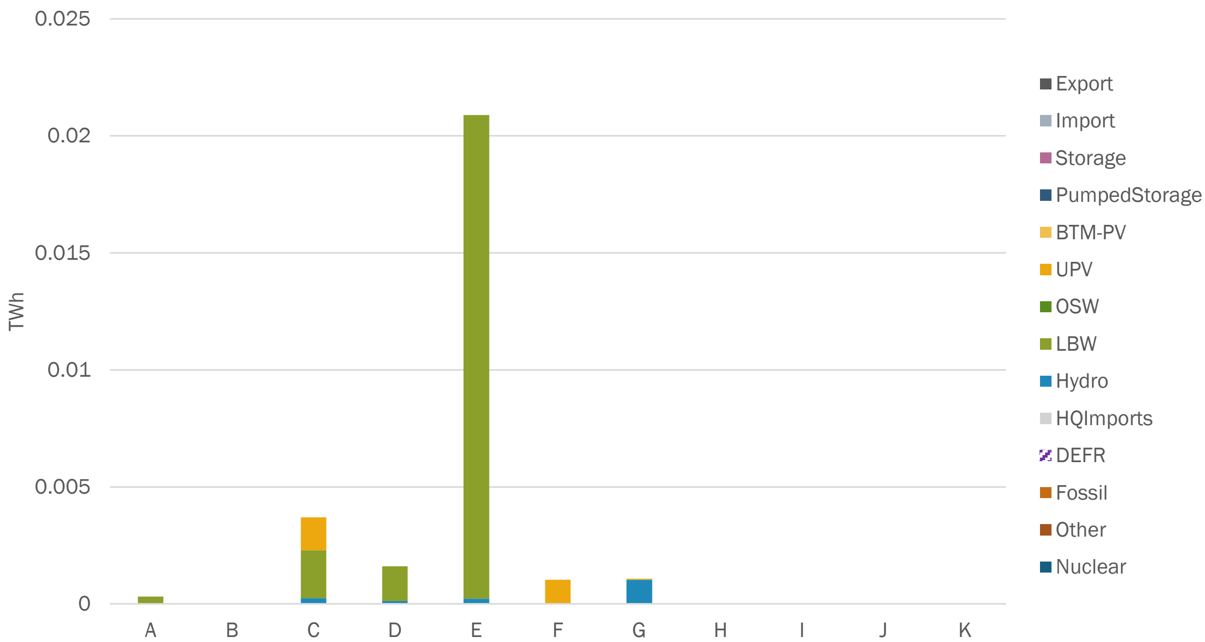


Figure G-36: Lower Demand Zonal Curtailment by Type, 2030

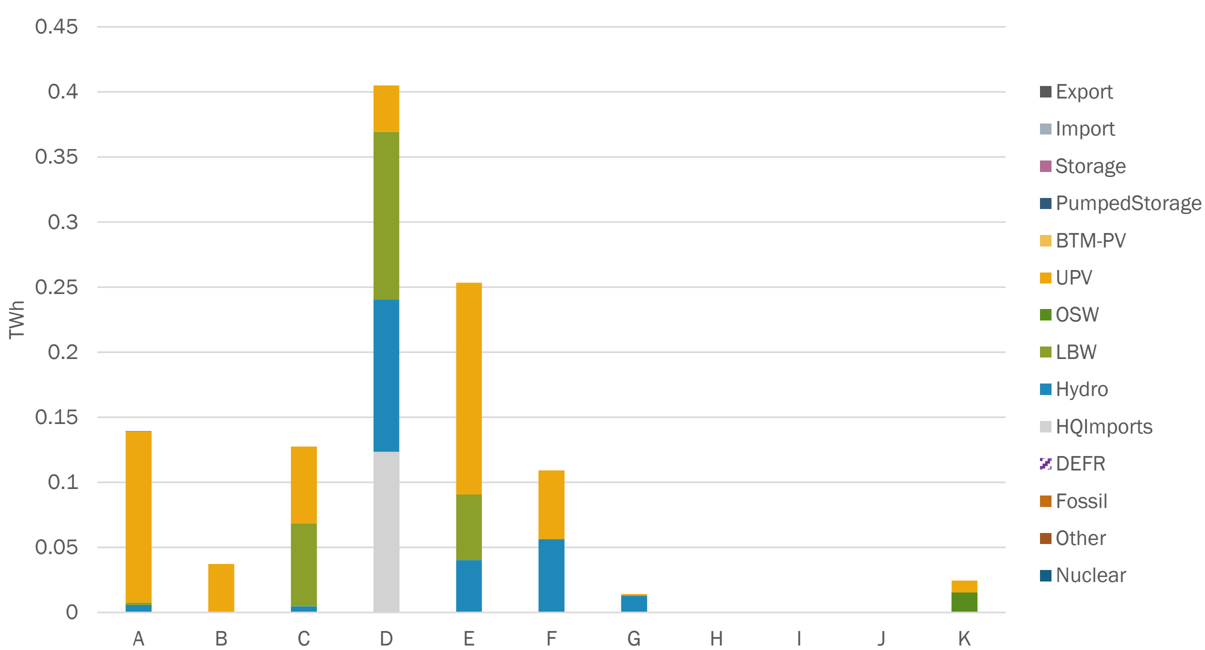


Figure G-37: Lower Demand Zonal Curtailment by Type, 2035

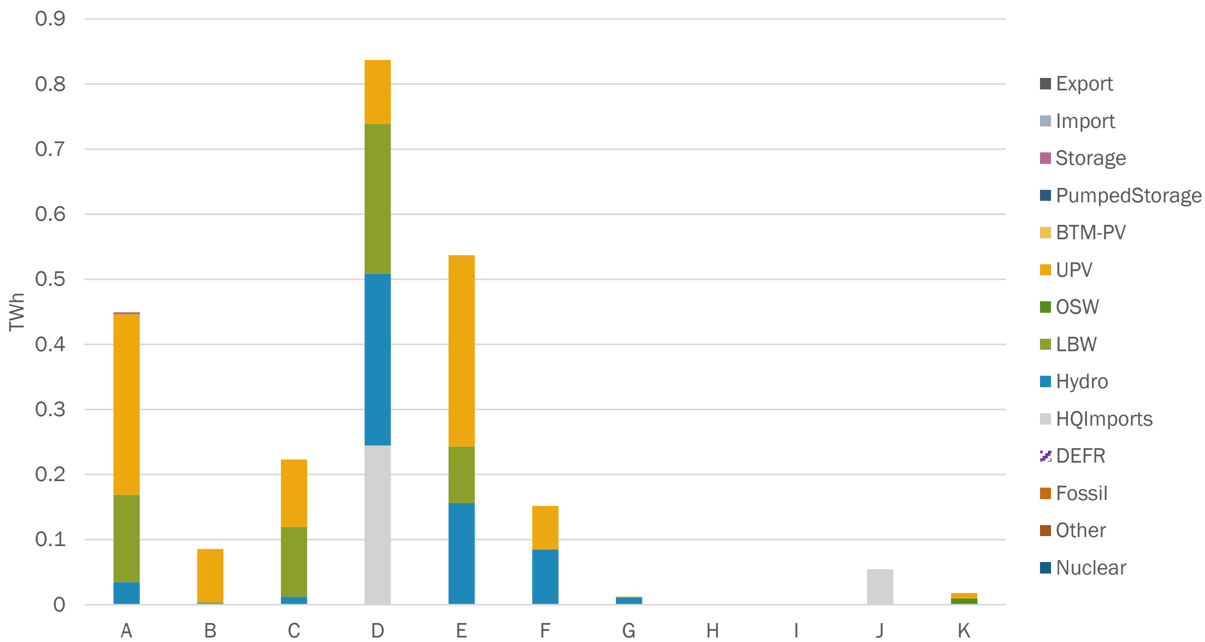


Figure G-38: Lower Demand Zonal Curtailment by Type, 2042

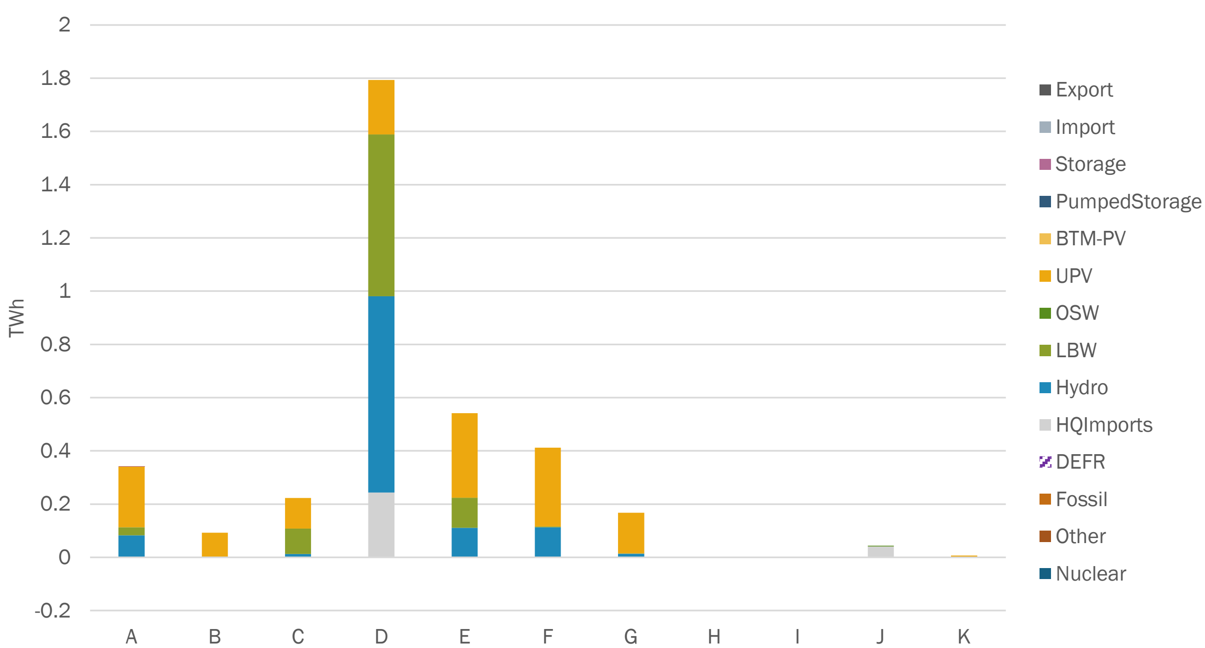


Figure G-39: Higher Demand Zonal Curtailment by Type, 2025

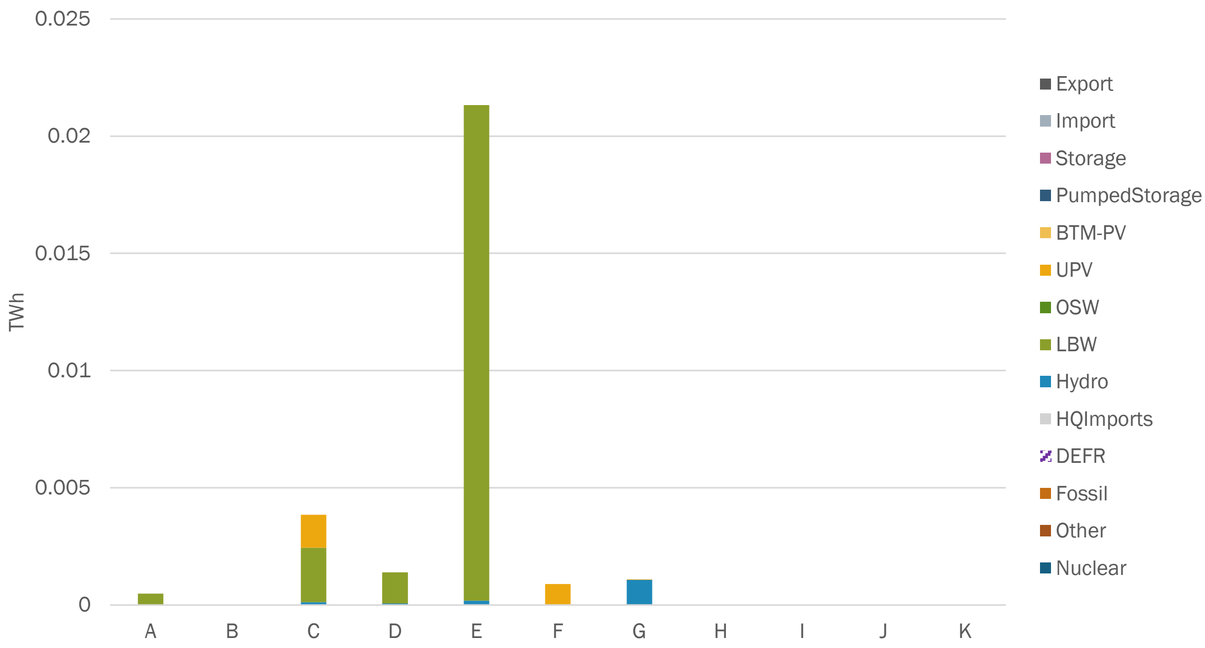


Figure G-40: Higher Demand Zonal Curtailment by Type, 2030

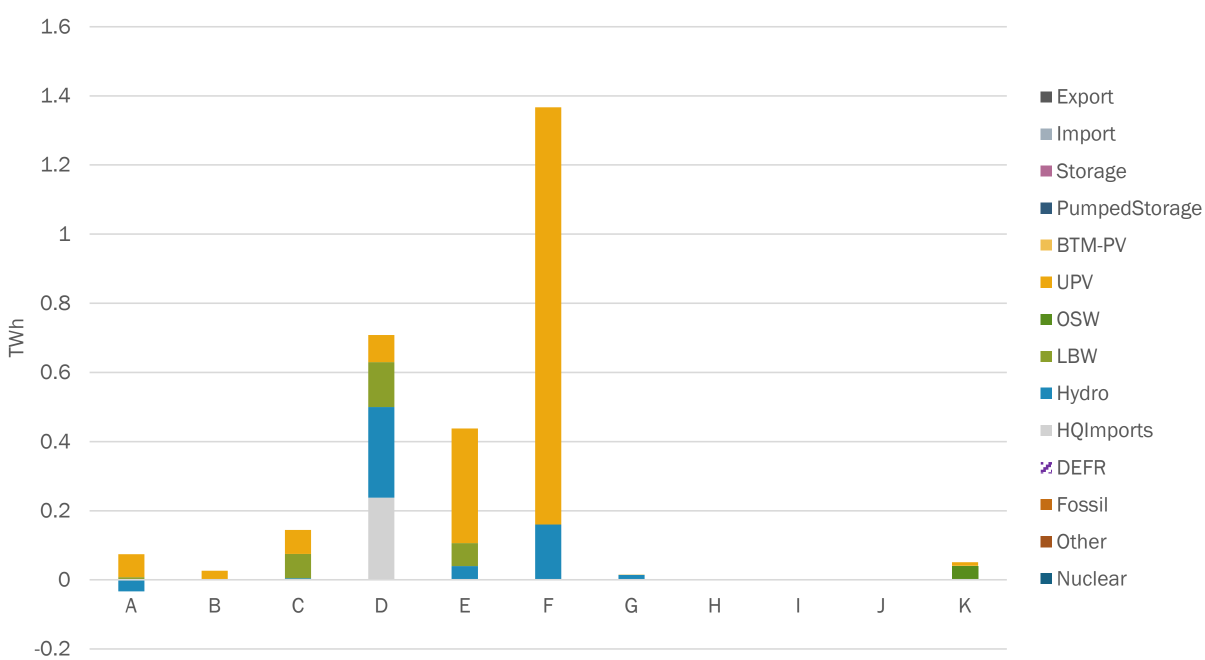


Figure G-41: Higher Demand Zonal Curtailment by Type, 2035

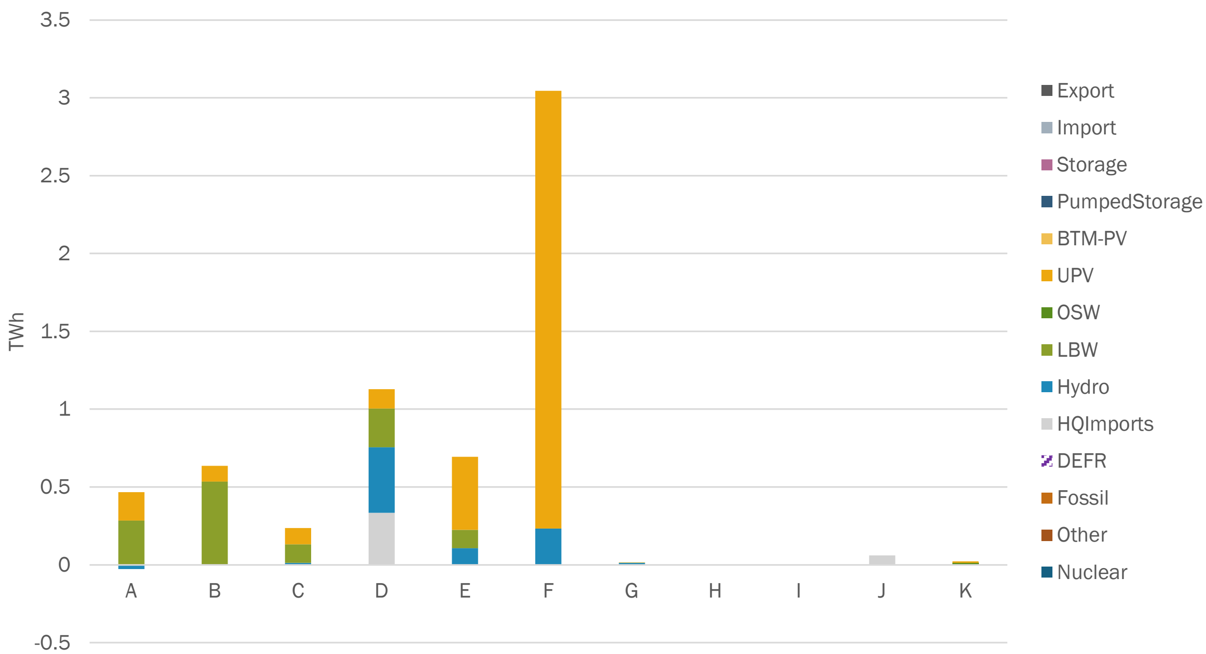
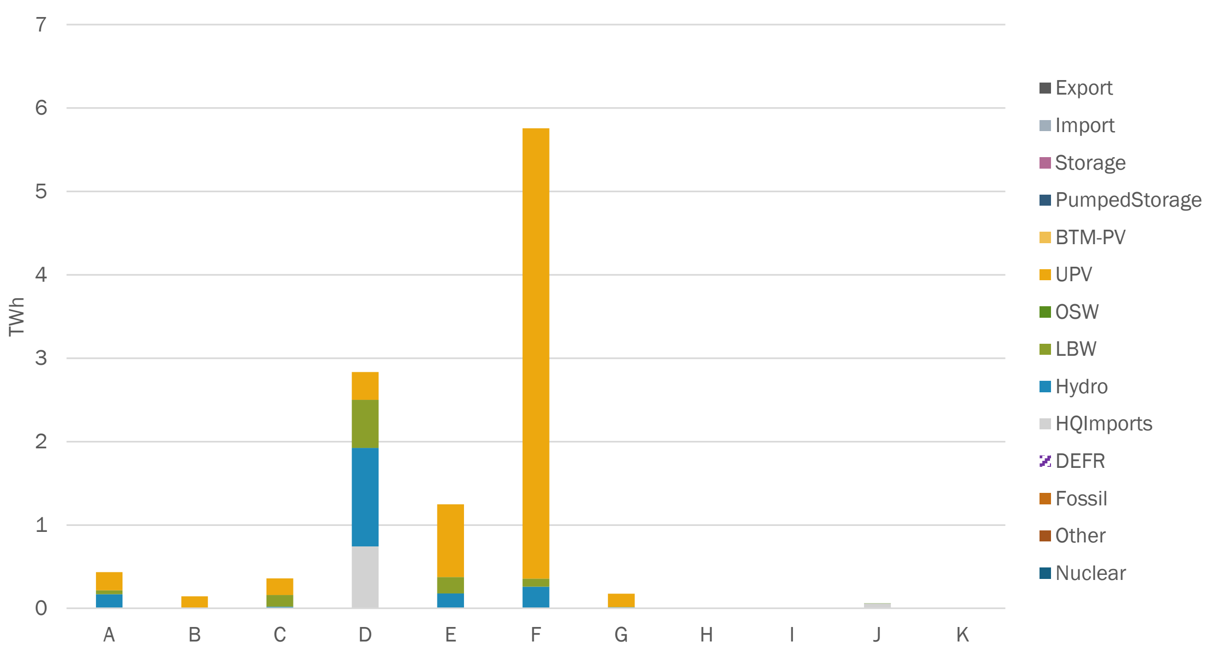


Figure G-42: Higher Demand Zonal Curtailment by Type, 2042



Policy Attainment Assessment

To provide information, this analysis performs a simplified representative calculation of the renewable energy percentages. These output metrics are distinct from the actual computations performed by NYPSC and/or NYSERDA to calculate the state's fuel mix and progress towards achieving the CLCPA mandates. For example, 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 resource placement is based on the results of capacity expansion analysis. As a result, the NYISO did not attempt to further achieve full attainment of CLCPA mandates given the purpose of the Outlook to identify the challenges to the system, rather than the exact blueprint to achieve policies.

The CLCPA mandates include, among others, 70% renewable generation in 2030. An indicative CLCPA annual renewable energy (%RE) metric for 2030 was calculated and compared against the target using the following calculation:

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

%RE = RE/Gross Load[6]

Given this calculation, the %RE in the Lower Demand Case is 69%, and 68% in the Higher Demand Case in 2030.

[6] This calculation does not explicitly include energy storage injection as Renewable Energy generation nor incremental load due to storage losses in the gross load.