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Alternative modeling scenarios and other considerations for Virginia Electric and Power Company's 2024 Integrated Resource Plan

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Table of Contents

Executive Summary	4
Background	8
Methodology	8
Model Comparison	9
Model Formulation	9
Model Validation	10
Quantitative Scenario Analysis	12
Quantitative Analysis with 2039 Horizon	14
Capacity by Technology in 2039	15
Total Present Costs in 2039 Scenarios.....	16
CO ₂ Emission Trends 2024–2039.....	20
Gas Resource Trends in 2039 Scenarios	22
Quantitative Analysis with 2045 Horizon	23
Costs in 2045 Scenarios	28
Summary of Quantitative Analysis and Comparison of 2039 with 2045 Scenarios	30
Additional Comments and Critiques of the IRP	32
Gas	32
Hydrogen	35
Environmental Justice	36
Carbon Emissions	39
Notable Resources Excluded from Dominion’s IRP Model	39
Long Duration Energy Storage (LDES), Solar Plus Storage, and Virtual Power Plants (VPPs).....	39
Grid Enhancing Technologies (GETs)	41
Data Center Demand Flexibility.....	41
Conclusions & Recommendations	42
Appendices	44
Appendix A: Relevant Policies Background	44
The Virginia Clean Economy Act (VCEA).....	44
Regional Greenhouse Gas Initiative (RGGI)	45
Virginia Environmental Justice Act (VEJA).....	45
EPA 111(b)	46
Net Energy Metering	46
Appendix B: Detailed Scenario Results	47
VCEA WITHOUT EPA.....	48
VCEA EPA RGGI	50
VCEA 2039 EPA RGGI DOUBLE CLEAN	52

VCEA EPA RGGI NEM6.....	54
VCEA EPA RGGI NEM8.....	56
VCEA 2045 EPA RGGI	58
VCEA 2045 EPA RGGI 2X CLEAN.....	60
VCEA 2045 EPA RGGI 3X CLEAN.....	62
VCEA 2045 EPA RGGI 3X CLEAN 6X BESS	64
VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR	66
Appendix C: Extension of Model Inputs to 2045	68
Expanded maximum build constraints.....	68
Expanded capacity cost assumptions	68
Expanded capacity requirement assumptions	68
Expanded RGGI carbon costs	68
Expanded market transmission capacity	69

Executive Summary

The purpose of this report is to provide a quantitative and qualitative analysis of the Virginia Electric and Power Company (Dominion or DOM) 2024 Integrated Resource Plan (IRP). The central objective of our quantitative analysis seeks to answer the following question: ***what does an IRP that complies with the Virginia Clean Economy Act (VCEA)—including the 2045 carbon retirement requirements—look like?*** The analysis is broadly divided into three categories: 1) quantitative analysis of the scenarios that share the IRP model horizon of 2039; 2) quantitative analysis of scenarios that expand the model horizon to 2045 to account for the VCEA’s zero-carbon requirement; and 3) additional critiques of the IRP.

Issue 1: Proprietary modeling process. The quantitative portion is achieved through the replication and modification of open-source modeling software called GenX, which operates similarly to the proprietary PLEXOS software used by Dominion. Like Dominion’s model, the GenX model we used solves for energy and capacity requirements across the model horizon in a least-cost manner. Recreating the DOM IRP model required several months of work by multiple energy system modeling experts on the IdeaSmiths team.

Recommendation: Direct Dominion to transition its planning software away from proprietary models like PLEXOS and instead use free, open-source software such as GenX. Accessible modeling will greatly reduce the cost and time required to analyze the IRP, allowing parties to generate alternative scenarios and provide the State Corporation Commission (SCC or Commission) with a better sense of what is possible.

Alternative Recommendation: Require Dominion to fund intervenor licenses to use PLEXOS and the necessary commercial solvers, such as CPLEX or Gurobi, and provide access to the compute resources required to operate the model.

Issue 2: The 2039 scenarios have limited value. The DOM portfolios, which model only out to 2039, do not allow Dominion to plan for compliance with key legal requirements under the VCEA. Dominion’s modeling does not “see” the 2045 zero-carbon requirement and therefore will not solve for this constraint. In contrast, we recreated the IRP model and then extended the timeline to 2045 to explore how the capacity expansion decisions change when the zero-carbon requirement is accounted for. When doing so, we found that the optimal build decisions, including build decisions for new gas between today and 2039, differ when the model can “see” the 2045 zero-carbon requirement. In other words, accounting for the 2045 requirement results in different optimal build decisions even within the 15-year planning period. Thus, not considering the 2045 zero-carbon policy results in suboptimal decision making and likely stranded assets that ratepayers will have to pay for.

Recommendation: Any scenarios that only plan through 2039 are of limited value to the Commission and should be discounted accordingly. Requiring Dominion to

model scenarios for 25 years would capture the 2045 requirement and present solutions and strategies that better reflect system needs and incorporate legally mandated policies. As an alternative, the Commission could require Dominion to run its model through a horizon that includes all relevant legal requirements at that time. This requirement could apply in any future process that seeks to justify new capital investment.

Issue 3: Dominion’s IRP modeling appears overly constrained to favor gas over

other resources. The DOM portfolios included in the IRP have similar build plans with only minor differences. This fact alone suggests that there are only a very narrow set of future possibilities. Dominion’s analysis does not include other potential paths forward or *any* pathway that complies with all legal requirements.

Moreover, while the DOM portfolios all install the maximum available new gas generation, our 2045 analysis indicates that installing new gas generators is short-sighted. When our model sees the 2045 zero-carbon requirement and can select alternative capacity resources, it does not build any gas generation because doing so is not optimal. Even in the 2039 horizon scenarios evaluated in this report, we found that no new combustion turbine (CT) gas generators should be purchased (with the exception of one scenario that excludes the EPA Rule 111(b) requirements). Furthermore, an analysis of Dominion’s portfolios shows that the new CT generators it purchased would operate only rarely. Across eight IRP scenario results, the CT generators have a mean annual capacity factor of 2.5% and a median annual capacity factor of 1.26% (minimum of 0.02% and maximum of 20%). In combination with the 2045 zero-carbon requirement, this discovery suggests the CTs Dominion proposes in the IRP are suboptimal investments, likely resulting from a short-sighted and over-constrained model rather than optimized planning.

Recommendation: Direct Dominion to consider and evaluate cleaner, lower cost, and more efficient capacity resources, as opposed to just gas projects. Future IRPs should perform sensitivity analyses by raising the capacity deployment limitations of cleaner generation and storage resources to potentially uncover lower cost and cleaner solutions. Investment in cleaner capacity resources like storage can reduce the risk of unnecessary investments in generation and other infrastructure, provide more customer benefit, and help Dominion meet the 2045 zero-carbon requirement rather than making compliance more costly.

Issue 4: There are pathways to zero-carbon compliance, with energy storage being a “no regrets” proposition.

Our 2045 analysis identified two feasible paths to meeting the zero-carbon requirement, both of which underscore the importance of near-term efforts to ensure sufficient, clean capacity can be brought online by 2045. In other words, Dominion can meet the 2045 zero-carbon requirement if it starts planning for it now by deploying higher levels of clean resources, including significantly more storage and nuclear resources than are allowed in the IRP. In contrast, when we extended the DOM IRP’s

resource deployment assumptions to 2045, we found that the model was unable to meet the 2045 zero-carbon requirement.

The results in both our 2039 and 2045 scenarios indicate that storage additions are especially important early in the planning horizon to keep costs low while meeting the zero-carbon requirement. In all scenarios, our model installs the maximum amount of storage capacity by the final year. Additionally, allowing for more storage capacity resources would reduce the solar capacity required to meet the zero-carbon requirement, which in turn would reduce the land area required to host the new resources.

Our 2045 scenarios also highlight that while new nuclear capacity will likely be needed, the majority of it is not needed until 2045. Even with long lead times for nuclear projects, the Commission has close to a decade to determine whether these investments are necessary, which would still leave multiple years for potential development and construction. In the meantime, the load forecast might change substantially due to outside market forces (e.g., advances in computing and chip efficiency, changes in the artificial intelligence race or global demand, other jurisdictions competing for data centers) or due to changes implemented by the Commission. All of these factors may dramatically alter the energy and capacity needs beyond the short term.

Recommendation: Direct Dominion to pursue significantly more energy storage projects in the near and medium term—beyond the minimum petition requirements in the VCEA. While new nuclear capacity will likely be needed, the need is not immediate, and the required capacity might change in the future.

Issue 5: Dominion’s scenarios increase emissions and public health harms. Our analysis of carbon emissions through 2039 and 2045 also revealed important shortcomings in the DOM IRP. We first examined carbon emission values for the entire generation fleet using the metrics Dominion cites in the IRP: intensity in metric tons-CO₂/MWh and annual total metric tons-CO₂. The IRP and our analysis both show that carbon intensity will decrease in most years in all of the scenarios. However, our analysis of total annual emissions in the 2039 scenarios shows that 2039 levels will be similar to 2025 or 2026 levels. And, as noted earlier, Dominion’s assumptions are unable to produce scenarios that achieve zero-carbon emissions when evaluated out to 2045. The annual emissions trends highlight the need to consider more clean generation resources to reach the zero-carbon requirement.

Our analysis also evaluates damages from CO₂ emissions and the increased mortality and morbidity burdens from increased air pollution placed on (often already marginalized) communities that are near the power plants themselves. When assessing these impacts, we find that the DOM IRP scenarios pose significant hidden costs. Depending on the IRP scenario, total damages from CO₂ emissions increase the IRP portfolio costs by between \$10.4 billion and \$12.2 billion. In addition, total damages borne by local communities (particularly environmental justice communities) from increased air pollution enlarge the IRP portfolio costs by between \$7.4 billion and \$13.9 billion.

Recommendation: Direct Dominion to present annual emissions for each scenario in future IRPs and, as above, model compliance with the 2045 zero-carbon requirement.

Recommendation: Direct Dominion to quantitatively assess, across its portfolios and future IRPs, the (i) damages from CO₂ emissions and (ii) public health harms to local communities from increased local air pollution.

Issue 6: The feasibility of hydrogen blending to reduce emissions is likely overstated.

We caution the Commission that the results of the hydrogen section in the DOM IRP do not consider many aspects—such as the carbon intensity of the hydrogen blending and the infrastructure needed to supply it—and therefore likely show better-than-real-world emissions reductions.

Recommendation: Direct Dominion that in future modeling, baseline scenarios should not rely on hydrogen for compliance with the 2045 zero-carbon requirement unless the full lifecycle emissions of the hydrogen blending are taken into consideration. To the extent Dominion wishes to present a sensitivity that incorporates hydrogen, Dominion should be directed to analyze the entire lifecycle emissions of the hydrogen fuel.

Issue 7: The IRP modeling excludes a number of clean supply-side resources. The DOM IRP excludes a number of supply-side resources that could be cost effective, including solar plus storage, virtual power plants, and long duration energy storage. Some of these technologies are further along in development than technologies such as hydrogen, which Dominion did include in its IRP modeling, and thus are good candidates to consider for alternative technology deployment scenarios. In addition, Dominion did not consider any grid enhancing technologies (GETs) in the IRP.

Recommendation: Direct Dominion to expand the resource profiles in future modeling to include additional clean capacity resources, including solar plus storage, virtual power plants, and long duration energy storage.

Recommendation: Consistent with the law, direct Dominion to comprehensively assess the potential application of GETs in future IRPs in a manner that ensures grid reliability and safeguards the cybersecurity and physical security of the electric distribution grid.

Background

This report provides additional modeling and context for the Virginia Electric and Power Company’s 2024 Integrated Resource Plan. For the purposes of this report, the Virginia Electric and Power Company will be referred to as “Dominion” or “DOM” and the Virginia Electric and Power Company’s 2024 Integrated Resource Plan will be referred to as the “IRP.”

Methodology

For the alternative and additional modeling provided in this analysis, we utilized a customized version of the GenX open-source capacity expansion model. GenX has been employed by various stakeholders, including groups intervening in integrated resource plans for utilities such as Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU).¹ GenX has also been utilized in multiple peer-reviewed scientific studies.² While GenX is similar to PLEXOS in its core functionality, it’s open-source nature makes it more accessible which, in turn, fosters greater transparency.³ This accessibility allows stakeholders to better understand how the electricity sector might evolve under various assumptions about future loads, fuel costs, technology costs, and policy constraints. By contrast, the proprietary nature of PLEXOS can make its application more cost prohibitive and less transparent.

Recreating DOM’s PLEXOS IRP model in GenX required several energy modeling experts on our team to spend months setting up the GenX model, essentially duplicating Dominion’s work. In the future, it would greatly benefit the community of concerned citizens, the Commission, researchers, and others, if Dominion transitioned to open-source modeling software or provided intervenors with PLEXOS licenses, either of which would avoid the need for this large amount of duplicative work. Requiring intervenors to purchase PLEXOS licenses, which are typically hundreds of thousands of dollars, would also present a major barrier. Reducing the cost and time required to analyze the IRP would enable more parties to generate alternative scenarios and informed analyses for the Commission’s consideration. Also, it will be easier for the Commission to identify concrete ways to improve the model if all parties are using the same model—or starting from the same baseline.⁴

Recommendation: Direct Dominion to transition its planning software away from the proprietary PLEXOS and instead use a free, open-source software such as

¹ See Mark Dyson, et al., *Power Planning to the People How Stakeholder-Driven Modeling Can Help Build a Better Grid*, Rocky Mountain Inst. (2022) 11, <https://rmi.org/insight/power-planning-to-the-people/>.

² See, e.g., Drew A. Kassel et al., *A Method to Analyze the Costs and Emissions Tradeoffs of Connecting ERCOT to WECC*, 378 *Applied Energy* (Jan. 15, 2025), <https://www.sciencedirect.com/science/article/pii/S0306261924021159?via%3Dihub>; Michael Schulthoff, et al., *Role of Hydrogen in a Low-Carbon Electric Power System: A Case Study*, 8 *Frontiers in Energy Research* (2021), <https://www.frontiersin.org/journals/energy-research/articles/10.3389/fenrg.2020.585461/full>.

³ Dyson, *supra* note 1, at 10-11, 20-22.

⁴ *Id.*

GenX. This requirement would greatly reduce the cost and time required to analyze the IRP, allowing parties to generate alternative scenarios and provide the Commission with a better sense of what is possible.

Alternative Recommendation: Require Dominion to fund intervenor licenses to use PLEXOS and the necessary commercial solvers, such as CPLEX or Gurobi, and to provide access to the compute resources required to operate the model.

The following section offers a high-level comparison of PLEXOS, the model used in the IRP, and GenX, the model used for this report.

Model Comparison

We selected GenX, an open-source electricity sector capacity expansion model, as the primary modeling tool for this analysis due to its flexibility, modularity, and ability to address long-term planning and policy analysis.⁵ Similar to PLEXOS, GenX employs an optimization-based framework to minimize system costs while meeting predefined constraints such as demand, emissions, and operational requirements. Both models can perform capacity expansion analysis, incorporating economic factors like capital and operational costs, and support a broad range of technologies including conventional thermal plants, renewable energy sources, energy storage, and demand-side resources. GenX and PLEXOS also share the ability to model systems with hourly temporal resolutions, capturing daily and seasonal variations critical to accurate resource planning.

Because PLEXOS is a closed-source model, the exact formulation of PLEXOS is unknown. However, we do know that both PLEXOS and GenX are, at their core, capacity expansion models. Because the two models have the same core objectives, as well as the same inputs and outputs, we know that GenX effectively replicates the key features of PLEXOS modeling as used in the IRP, such as the long-term (LT) formulation, hourly time resolution, and treatment of market energy and capacity prices. We ran a validation model on one of DOM's portfolios to showcase this, which we explain in more detail below. Additionally, GenX's open-source design enhances transparency and allows for rapid scenario analysis, making it a useful tool for responding to IRPs and analyzing the DOM LSE region.

Model Formulation

We used GenX to solve a deterministic multi-stage planning problem with perfect foresight, which is analogous to the PLEXOS LT model formulation Dominion used for the IRP. We recreated the IRP model of the DOM LSE region in GenX by using the same inputs that Dominion used in the PLEXOS modeling.

Dominion identified most of the required inputs in response to discovery requests, and we drew the others from the IRP itself. At a high level, these inputs include:

⁵ "Welcome to the GenX Documentation!", GEN.jl, <https://genxproject.github.io/GenX.jl/stable/> (last visited Feb. 24, 2025)

- **Loads:** We utilized “Attachment United Set 02-09(a) (JLM) SUPP.csv” for the base load profiles, which was provided in the supplemental response to Advanced Energy United Data Request 2-9.⁶
- **Behind-the-meter photovoltaic (BTM PV):** We adjusted the load profiles using installed capacities by year from “BTM_solar_NEM_Attachment APV Set 06-06(a) (JLB).xlsx.” We multiplied the installed capacity by a normalized “CE4 DER PPA_Fixed Tilt” solar profile from “Hourly Wind and Solar Shape (JLM) CONF.zip, provided in response to Sierra Club Data Request 1-02.
- **Generators:** We utilized confidential data provided in response to Sierra Club Data Request 1-02, including “Operational Data - Existing Resources (JLM) ES.xlsx” for information about power plant sizes, operational characteristics, Effective Load Carrying Capability (ELCC) values, power purchase agreement (PPA) pricing, REC pricing, etc. We also used information provided in the same response from the “Green Sheets (CJR) ES.xlsx,” as well as “New Resource Parameters (JLM) ES.xlsx” for new resource costs, characteristics, and build limits.
- **Fuel prices:** We utilized data from the IRP Appendix 5B for future fuel prices.
- **Capacity prices:** We utilized data from the IRP Appendix 5B for future capacity prices.
- **Energy prices:** We utilized “APV Set 02-06(b)(1) (KLC).csv” and “APV Set 02-06(b)(2) (KLC).csv” for future energy market prices.
- **Renewable profiles:** We utilized confidential data from “Hourly Wind & Solar Shape (JLM) CONF.zip” for future hourly wind and solar profile shapes, which was provided in response to Sierra Club Data Request 1-02.
- **Capacity value of resources:** We utilized the ELCC values given in the PLEXOS inputs to calculate the firm capacity value of existing and future resources.
- **Firm capacity requirements:** We utilized the PLEXOS results, summing up the “Firm Capacity” for each year.

Model Validation

To validate the GenX model and create a baseline to perform sensitivities for this report, we recreated the IRP PLEXOS results from the data Dominion provided in discovery. We chose the “VCEA WITHOUT EPA” IRP scenario as the starting point for sensitivities, which allows addition of components such as the EPA requirements to demonstrate their impact on the model results. Figure 1 shows a comparison of the GenX model results and the IRP PLEXOS results.

⁶ Our use of Dominion’s load forecast assumptions in this modeling exercise do not indicate an endorsement of the underlying assumptions.

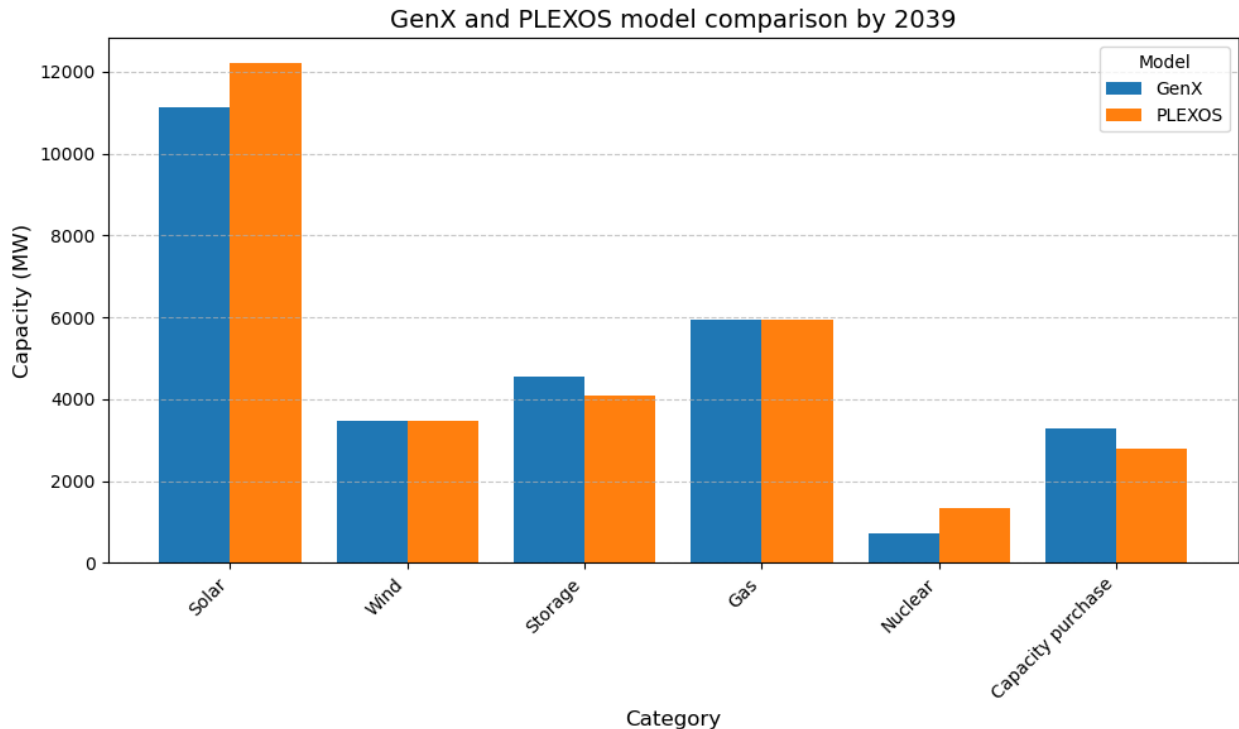


Figure 1: Comparison of GenX and IRP PLEXOS results for model validation (case: VCEA WITHOUT EPA). Total builds by technology and total capacity purchases by 2039 for both GenX and PLEXOS modeling. Capacity purchases are shown as the average annual capacity purchases from 2025–2039.

The results of the models are almost identical for wind and gas deployments. However, the GenX model built about 1,060 MW less solar and 625 MW less new small modular reactor (SMR) nuclear capacity than the PLEXOS modeling built. The GenX model also procured about 450 MW more storage and more capacity in the market (about 480 MW-yr average) than the PLEXOS model did.

These differences are reasonably explained by comparing the annual costs of building more nuclear versus purchasing more capacity in the PJM market. GenX, like PLEXOS LT, calculates an annualized annuity cost for each type of resource under consideration. This annuity cost is a function of the capital cost to build, the weighted average cost of capital, and the capital recovery period. The units of this annuity cost are MW-year, which represents how much it costs, this year, to have an additional MW of capacity for a particular technology. Thus, there is an economic tradeoff between building a power plant to have the capacity (and energy) or purchasing capacity in the capacity market and energy in the energy market or running other generators more often. This tradeoff becomes even more profound when high levels of energy-rich but capacity-limited resources, such as renewables, provide high levels of low-cost energy to the grid. That is, if capacity is a larger concern than energy, building power plants that can provide both is important. In this case, the annualized capacity investment cost for a new SMR is multiple times higher than the highest capacity market costs in IRP Appendix 5C.⁷ Thus, our model found it more

⁷ SMR costs can be found in the confidential file attachment to Sierra Club Data Request 1-02: “New Resource Parameters (JLM) ES.xlsx.”

economical to purchase more energy storage capacity (but still within the build limits in the PLEXOS inputs) and purchase more capacity from the capacity market.

Quantitative Scenario Analysis

The purpose of this report is to provide scenarios for the Commission to consider when evaluating the needs of the DOM LSE region. The approach taken in this analysis was to incorporate the current Commonwealth policy requirements, namely the Virginia Clean Economy Act (VCEA), as the base scenario. We then layered on additional policy requirements, such as compliance with EPA’s Rule 111(b), the reintroduction of Regional Greenhouse Gas Initiative (RGGI) pricing, as well as others to show their impact on the capacity expansion decisions over the model horizon. We started with scenarios that ran from 2024 to 2039 like the IRP. We then extended some of these scenarios out to 2045 to model the VCEA requirement of 100% carbon-free electricity by 2045. At a high level, the scenarios run in this report include:

- **EPA Rule 111(b) impacts on new gas generators**—specifically that new gas generators cannot operate beyond a 40% annual capacity factor (unless they install carbon capture technologies, which neither Dominion nor our team modeled for this IRP).⁸
- **Virginia’s participation in RGGI**—modeled by including the estimated RGGI allowance price in the scenarios’ total costs.⁹
- **Increasing the installed capacity limits for clean energy technologies**—defined as nuclear, battery, solar, and offshore wind.¹⁰
- **Increasing the amount of BTM solar PV adoption.**
- **Extending the model to 2045 to capture the VCEA zero-carbon requirement.**

⁸ See IRP at 54.

⁹ “Attachment APV Set 06-17 (ATS) SUPP.xlsx.”

¹⁰ Note that we only doubled the ability to build future offshore wind capacity that is not currently under construction.

Table 1 provides a summary of the scenario names used throughout the report and their descriptions.

Table 1: Report Scenario Names and Short Descriptions.

Scenario	Description
2039 Horizon	
VCEA WITHOUT EPA	IRP validation scenario. “VCEA” includes Renewable Portfolio Standard (RPS) requirements, renewable targets, and storage targets.
VCEA EPA RGGI	Limits new gas generators to 40% annual capacity factors and assumes RGGI participation.
VCEA EPA RGGI DOUBLE CLEAN (DOUBLE CLEAN)	VCEA EPA RGGI baseline + increases maximum allowed installed capacity limits for nuclear, battery, solar, and offshore wind by 2.
VCEA EPA RGGI NEM6/8	VCEA EPA RGGI baseline + replaces the BTM PV capacity from discovery with a capacity equal to 6% / 8% of the peak load in each year.
2045 Horizon	
VCEA 2045 EPA RGGI	Extends 2039 scenario to 2045, allowing the model to see the 2045 retirement requirement.
VCEA 2045 EPA RGGI 2X CLEAN (2X CLEAN)	VCEA 2045 EPA RGGI baseline + increases the clean energy build limits by 2.
VCEA 2045 EPA RGGI 3X CLEAN (3X CLEAN)	VCEA 2045 EPA RGGI baseline + increases the clean energy build limits by 3.
VCEA 2045 EPA RGGI 3X CE 6X BESS (6X BESS)	VCEA 2045 EPA RGGI baseline + increases the clean energy build limits by 3 and the battery energy storage system (BESS) build limits by 6.
VCEA 2045 EPA RGGI 3X CE 6X NUCLEAR (6X NUCLEAR)	VCEA 2045 EPA RGGI baseline + increases the clean energy build limits by 3 and the nuclear build limits by 6.

The following sections discuss, at a high level, the differences between the results of each of the scenarios considered. We begin with a quantitative analysis of the scenarios that end in 2039. The Quantitative Analysis with 2045 Horizon section focuses on the scenarios that end in 2045. More detailed results for each scenario are available in **Appendix B: Detailed Scenario Results**.

Quantitative Analysis with 2039 Horizon

As noted at the outset, we believe that the 2039 results are of limited use because the model cannot “see” the 2045 zero-carbon requirement and, thus, chooses resources that are not optimal in the 2045 time horizon. When the model can “see” the 2045 zero-carbon requirement, the resulting portfolios are very different from the 2039 portfolios. The 2045 modeling is presented and discussed in the subsequent section.

Recommendation: Scenarios with a horizon only through 2039 are of limited value to the Commission and should be discounted accordingly. Moving forward, the Commission should require Dominion to model scenarios through a horizon that captures all relevant legal requirements at that time, including the current 2045 zero-carbon requirement.

Although of limited value, the 2039 analysis reveals several trends of note:

- All scenarios install the maximum amount of energy storage capacity by 2039.
- All scenarios deploy the New Combined Cycle (CC) gas generation up to the maximum amount of 2,536 MW by 2039.
- No scenarios except VCEA WITHOUT EPA deploy the New Combustion Turbine (CT) gas generation units.
- All scenarios retire the least efficient existing CT gas generators.
- No scenarios retire coal.
- All scenarios except the DOUBLE CLEAN scenario install the maximum amount of wind generation.
- New Nuclear SMR is installed at the maximum value of 1,876 MW except when EPA Rule 111(b) is not enforced for new gas generators or when more battery storage is available in the DOUBLE CLEAN scenario.
- All available solar PV, including PPAs, is purchased (except a relatively expensive 3 MW utility system), except when there are additional storage or nuclear resources or when EPA Rule 111(b) is not enforced.
- In all scenarios, the general trend of CO₂ emissions intensities across time is downward. However, when considering total annual CO₂ emissions, all scenarios with a 2039 horizon have a downward, then upward trend. These trends in annual

emissions are caused by the retirement of the least efficient CT generators in early years, then the installation of new CC generators in later years.

- The DOUBLE CLEAN and higher NEM scenarios achieve the lowest emissions by both intensity and annual metrics. However, like the other 2039 scenarios, these two portfolios still include new gas because they do not “see” the 2045 zero-carbon requirement.

Capacity by Technology in 2039

Figure 2 shows the final installed capacities by technology and scenario in 2039. Many of the trends enumerated above can be drawn from Figure 2. For example, 4.58 GW of storage is installed in all scenarios except the DOUBLE CLEAN scenario,¹¹ which has twice the amount of storage installed at 9.13 GW (values rounded). In all scenarios, 2.54 MW of new gas is installed except for the VCEA WITHOUT EPA scenario (the IRP validation scenario utilizing Dominion’s assumptions), which installs 5.93 MW.

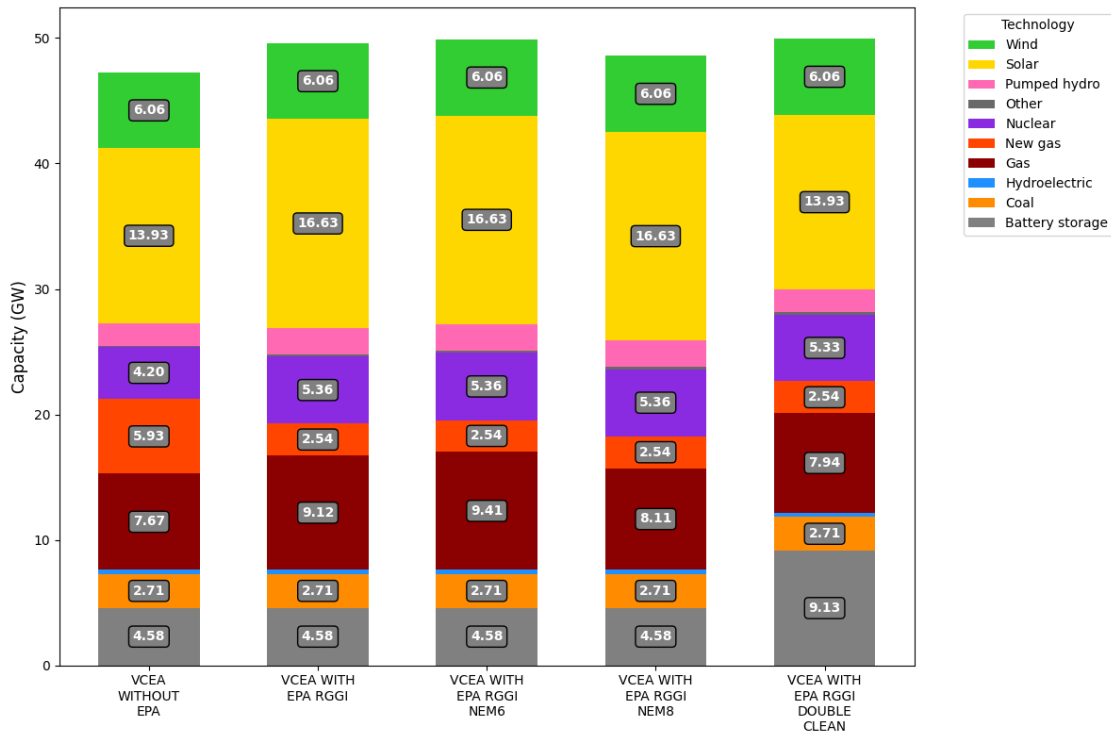


Figure 2: Capacities installed in 2039 compared across the VCEA WITHOUT EPA, VCEA WITH EPA RGGI, VCEA WITH EPA RGGI NEM6, VCEA WITH EPA RGGI NEM8, and VCEA WITH EPA RGGI DOUBLE CLEAN scenarios.

The importance of storage is evident in the DOUBLE CLEAN results when also comparing the total net present costs shown in Figure 3. The DOUBLE CLEAN scenario installs less solar PV than the other EPA RGGI scenarios while keeping costs lower.

¹¹ Note that the scenarios that allowed more clean energy allowed it as a higher maximum build limit, they did not force the model to build more.

Total Present Costs in 2039 Scenarios

The following section provides the total present costs for the 2039 scenarios. However, we again underscore the limited utility of these numbers. None of these scenarios can see the 2045 zero-carbon requirement and thus the build plans driving these costs would likely change significantly in the six years following the 2039 planning horizon. In addition, since each assumes Dominion would continue to rely on gas and coal and emit carbon, these scenarios would pose additional costs from CO₂ impacts and harm to local communities. For example, as discussed further in **Section: Environmental Justice**, the VCEA WITHOUT EPA, which has the highest CO₂ emissions of the IRP 2039 scenarios, costs an additional almost \$25 billion when considering CO₂ impacts and local harms from air pollutants.

Figure 3 shows that the lion’s share of costs in all scenarios are the fixed (including capital costs) and fuel costs, followed by CO₂. The energy and capacity market transactions are relatively small compared to the other costs. Note that the total costs in our 2039 scenarios align well with the “Total System Costs” of the Primary Portfolios presented in the DOM IRP Table 5.2.2, which range from \$72.1B to \$81.3B.¹²

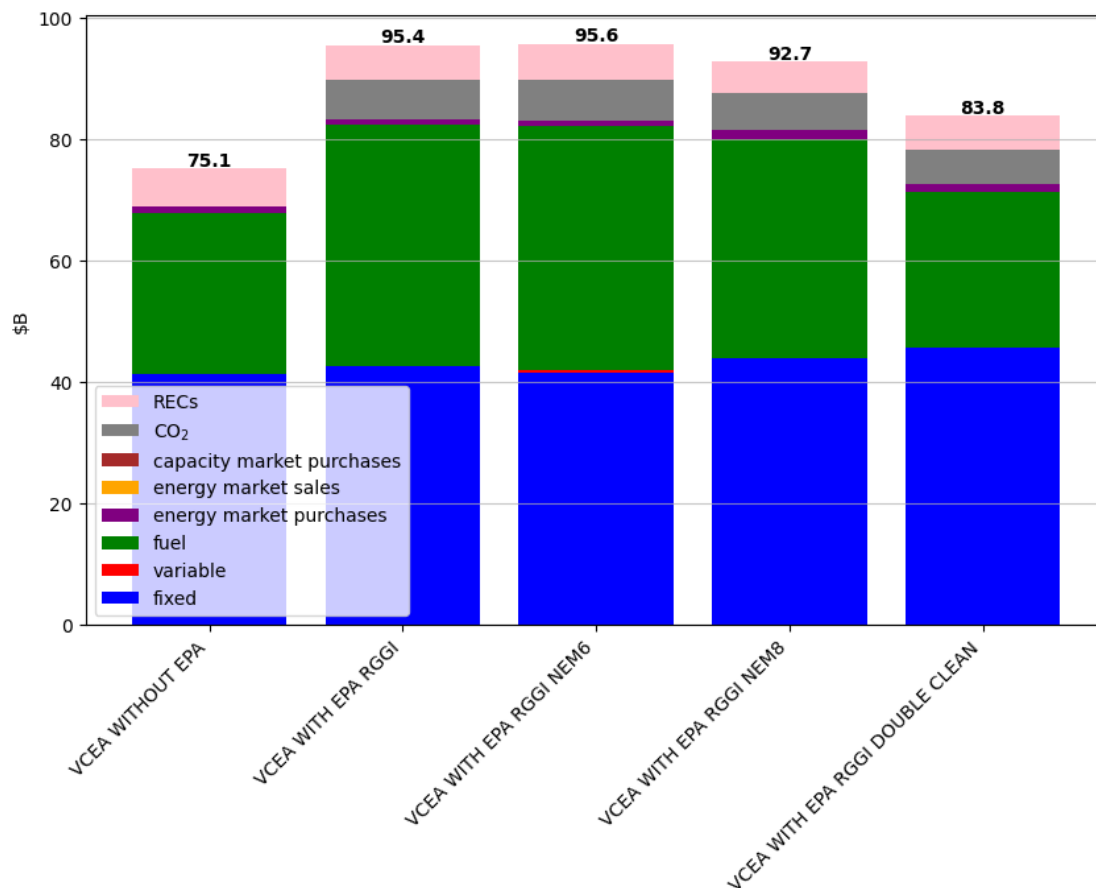


Figure 3: Total present costs of all 2039 scenarios. “RECs” is Renewable Energy Certificates.

¹² Note that the scenarios in Dominion’s IRP do not include the cost of carbon in their total cost values.

The VCEA WITHOUT EPA scenario appears to have the lowest cost by retiring more, less efficient gas generators and buying newer, more efficient gas generators at higher capacity factors, which results in the purchase of less nuclear power than other scenarios. However, the fact that the model sees it as economic to build new gas resources 10–15 years before they must retire (based on the 2045 zero-carbon requirement) provides a direct example of the limitations of this planning horizon. While this portfolio appears as the lowest cost of the 2039 portfolios, it also contains the greatest amount of counterproductive investments for efficiently meeting the 2045 zero-carbon requirement. In fact, and as discussed in **Section: Quantitative Analysis with 2045 Horizon**, using the assumptions in VCEA WITH EPA RGGI but modeling out to 2045, we found the build limits to be too restrictive to find a solution that fulfills the capacity needs or the 2045 zero-carbon requirement.

It is also worth noting that VCEA WITHOUT EPA ignores applicable law (EPA Rule 111(b) and RGGI). When accounting for these existing legal requirements, VCEA WITH EPA RGGI DOUBLE CLEAN, which increases the maximum capacity limits on zero-carbon generators (including solar, wind, storage, and nuclear) by a factor of two, is the lowest cost portfolio. The DOUBLE CLEAN portfolio also has the lowest fuel costs of all the 2039 portfolios.

Figure 4 breaks down the fuel costs shown in the total costs chart by fuel type.

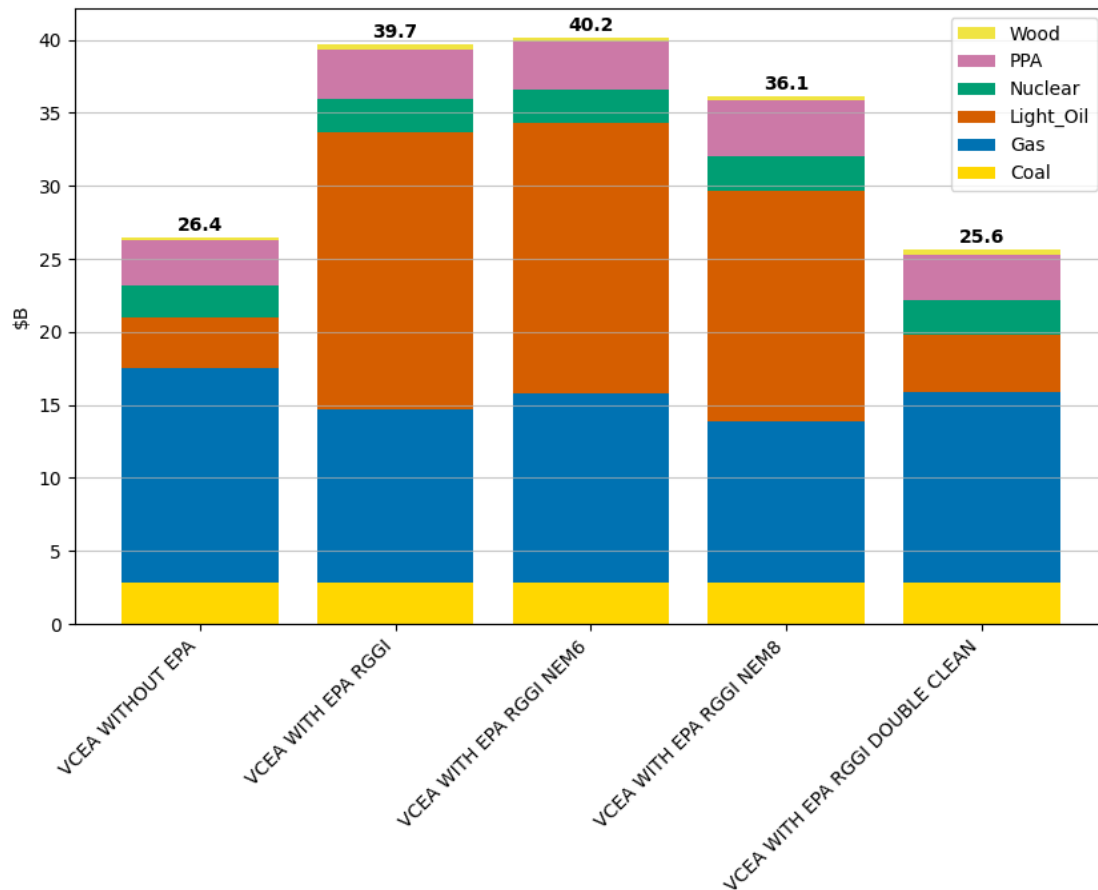


Figure 4: Total present fuel costs of all 2039 scenarios.

Figure 5 shows the annual CO₂ emissions across several scenarios including the VCEA WITHOUT EPA scenario. While it's interesting to note that the VCEA WITHOUT EPA scenario achieves relatively lower emissions in middle years from retiring gas generators, the annual emissions rise back up to 2025 levels in later years with the addition of new gas generators.

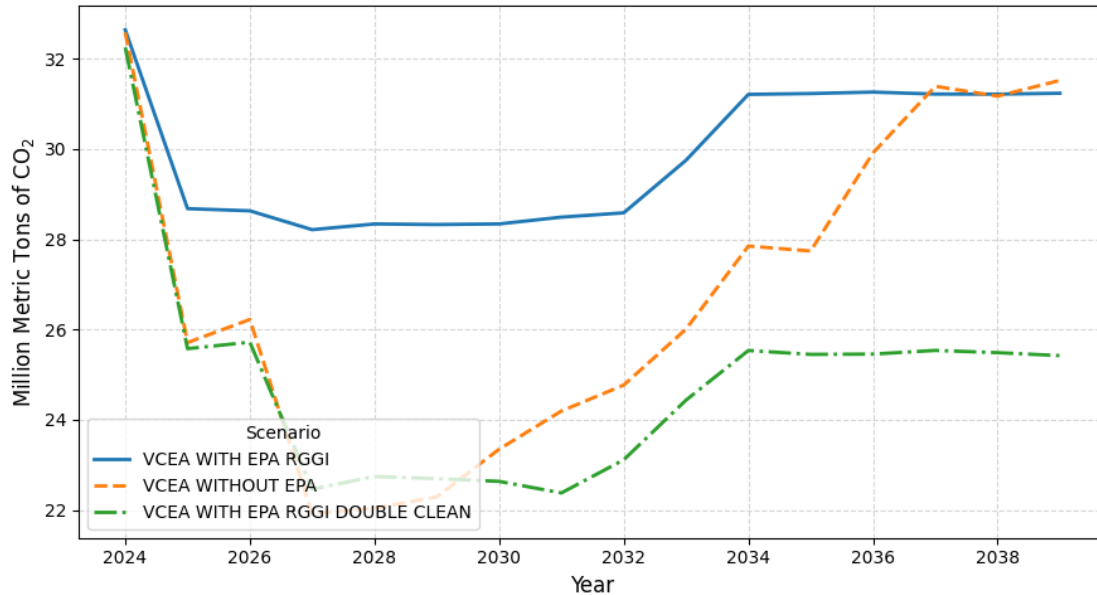


Figure 5: Annual CO₂ emissions from 2024–2039 for scenarios: VCEA WITH EPA RGGI, VCEA WITHOUT EPA, and VCEA WITH EPA RGGI DOUBLE CLEAN.

In addition to being the lowest cost 2039 portfolio that accounts for EPA Rule 111(b) and RGGI requirements, the DOUBLE CLEAN scenario reveals several key takeaways that increasing zero-carbon build limits results in a more efficient, future-proof portfolio:

- The DOUBLE CLEAN scenario has lower fuel costs relative to the other 2039 scenarios primarily by installing the maximum amount of energy storage available—without requiring the maximum amount of solar and wind resources. These trends are visible in Figure 4 and Figure 7.
- There is almost 3 GW less solar generation installed by 2039 in the DOUBLE CLEAN scenario than the VCEA WITH EPA RGGI scenario. These results highlight a benefit of allowing the model to build more storage capacity: with more storage, the DOUBLE CLEAN scenario can maximize the impact of daytime solar generation by shifting it to evening peak hours. By contrast, with less storage available, the model finds it economic to install greater solar capacity to meet more load on the shoulder hours of the day—but this strategy also requires greater solar curtailment. For example, in 2039 the DOUBLE CLEAN scenario curtails a total of 379 GWh (about 1.1%) of solar and wind generation while the VCEA WITH EPA scenario curtails

2,700 GWh (about 8.4%) of solar and wind generation. Building lower quantities of solar also reduces local land use impacts.

- The DOUBLE CLEAN scenario chooses to build more than 2 GW of new storage *before* building any new gas, as shown in Figure 6. This result suggests that investing in storage earlier could displace or put off any short-term gas needs, providing Dominion and the Commission time to develop more clarity for the current load growth uncertainty as well as more time to better understand emerging technologies, like long duration storage and nuclear, that will not become stranded assets in 2045.

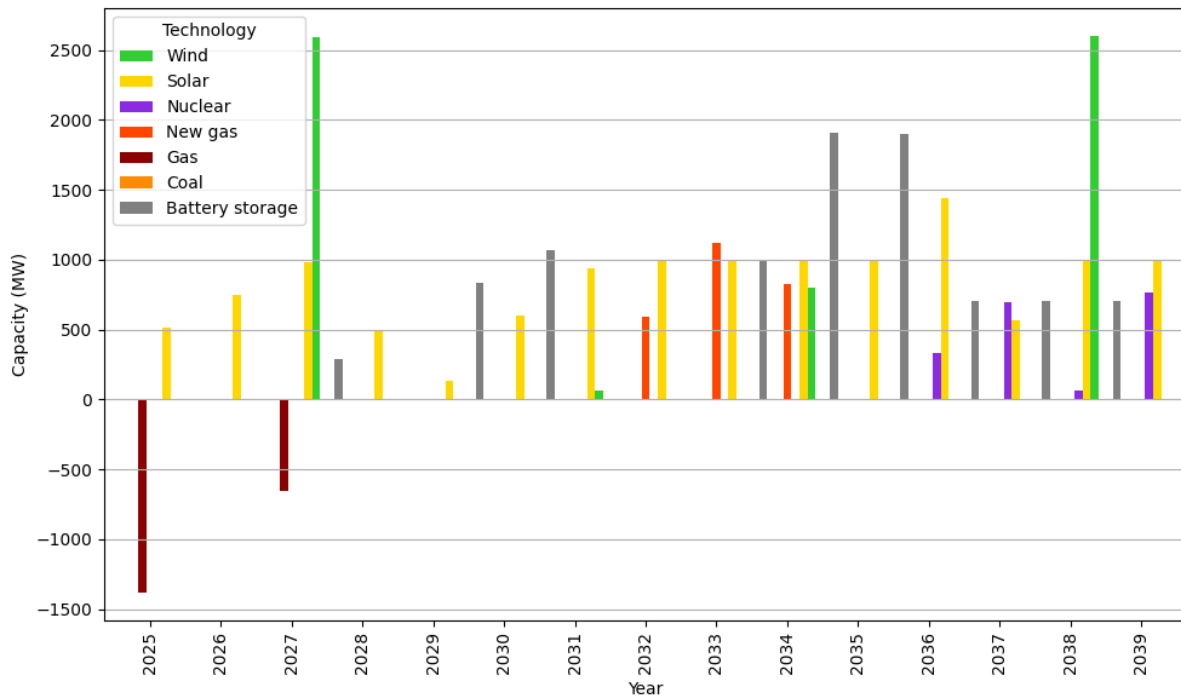


Figure 6: Capacity changes by type of power plant per year for the VCEA WITH EPA RGGI DOUBLE CLEAN scenario.

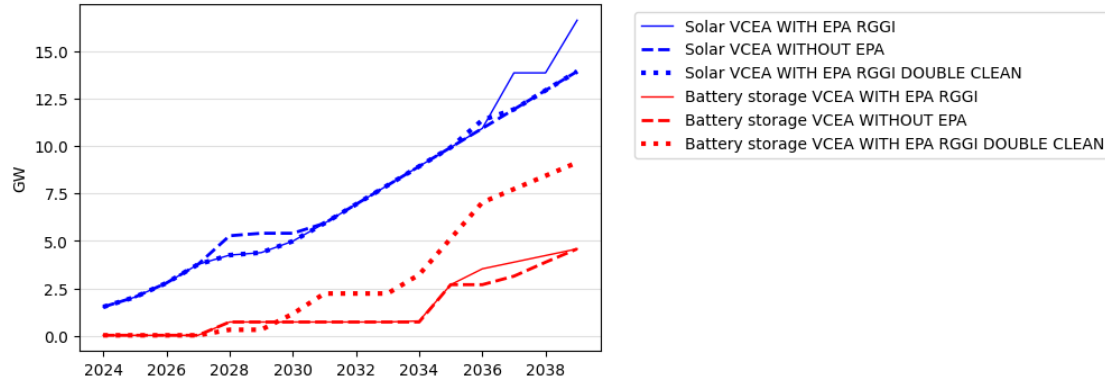


Figure 7: Solar and storage capacity trends from 2024–2039 for VCEA WITHOUT EPA and VCEA WITH EPA RGGI DOUBLE CLEAN scenarios.

Similar amounts of nuclear generation are purchased in the VCEA WITH EPA RGGI and DOUBLE CLEAN scenarios, even though the DOUBLE CLEAN scenario can install twice as much capacity, as shown in Figure 8. We can also see that less nuclear is installed without the EPA Rule 111(b) capacity factor limit on gas generators.

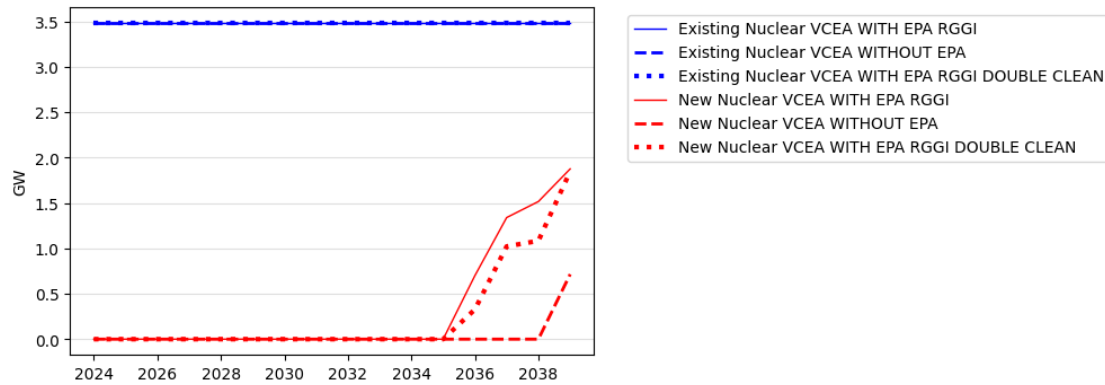


Figure 8: Existing and new nuclear capacity trends 2024–2039 for VCEA WITHOUT EPA and VCEA WITH EPA RGGI DOUBLE CLEAN scenarios.

CO₂ Emission Trends 2024–2039

Figure 9 and Figure 10 show the CO₂ emission intensity and annual emissions trends, respectively, for all the 2039 scenarios. As expected, the DOUBLE CLEAN scenario achieves some of the lowest emissions almost every year in both metrics.

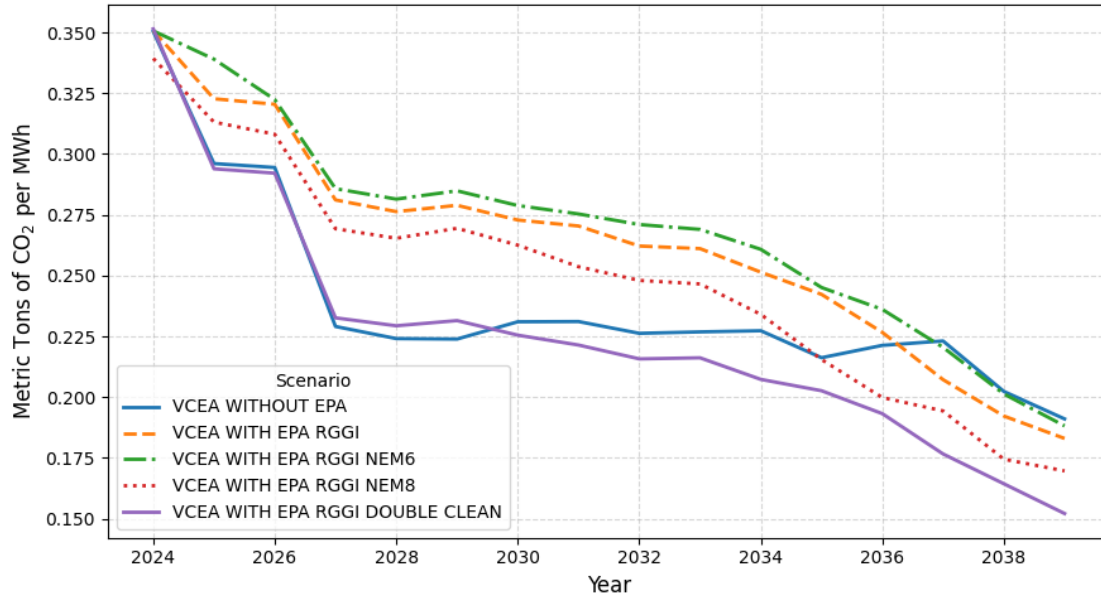


Figure 9: CO₂ intensity trends 2024–2039 for all 2039 scenarios.

The trend of dropping annual emissions in earlier years and rising annual emissions in later years in Figure 10 is explained by the gas generation capacity trends shown in **Section: Gas Resource Trends in 2039 Scenarios**, where some existing gas generation is retired in early years and new capacity is installed in later years. This finding illustrates yet another reason why the Commission should require Dominion to extend the planning horizon to 2045. Otherwise—even under the cleanest scenarios—the model will install resources that keep CO₂ emissions elevated over the long term.

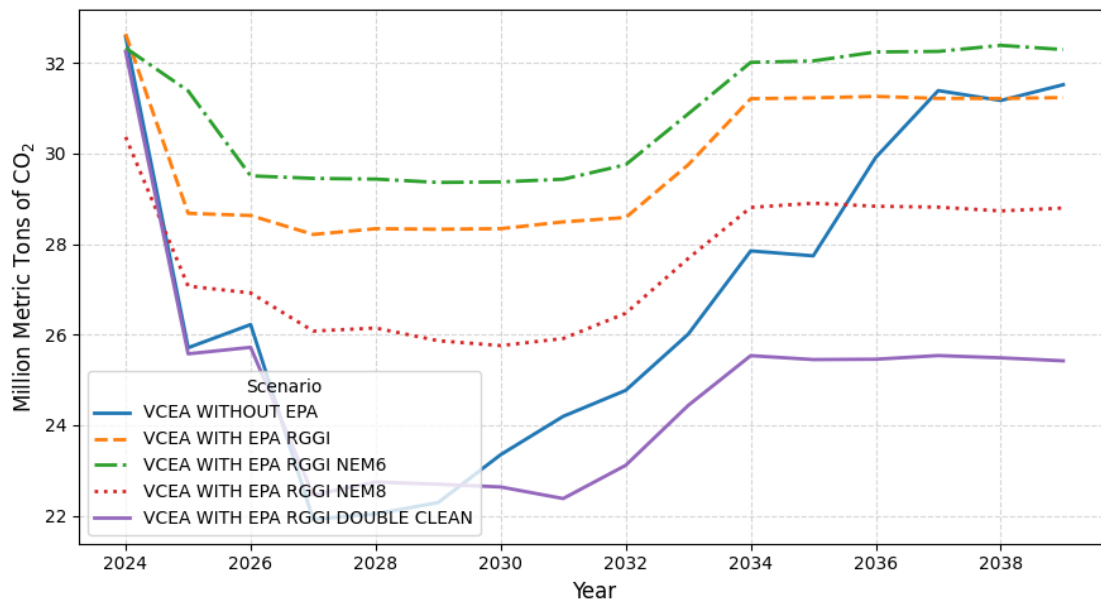


Figure 10: Annual CO₂ emissions trends 2024–2039 for all 2039 scenarios.

Gas Resource Trends in 2039 Scenarios

The trends in gas resource capacities for existing and new generators are shown in Figure 11 and Figure 12. Figure 11 highlights the additional gas generation that is installed when the 40% capacity factor limit on gas resources is removed in the VCEA WITHOUT EPA scenario. Otherwise, the three figures all show that the 2,536 MW of new CC gas generation is built by 2037 or sooner, and that roughly 1–3 GW of existing gas generation is retired in the first four years.

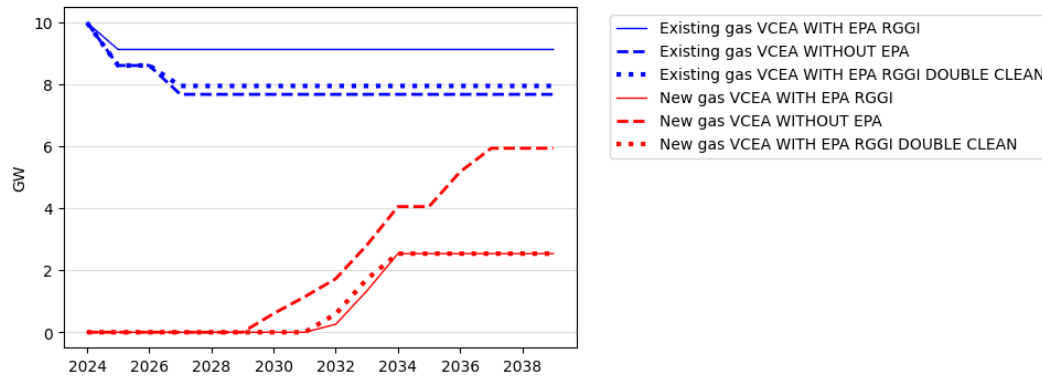


Figure 11: Gas capacity trends 2024–2039 in VCEA WITH EPA, VCEA WITHOUT EPA, and VCEA WITH EPA RGGI scenarios, broken down by existing and new installations.

When comparing the NEM scenarios in Figure 12, the NEM6 scenario keeps more existing gas generation than the NEM8 scenario. The additional gas generation in the NEM6 scenario is also visible in the emission charts in **Section CO2 Emission Trends 2024–2039**.

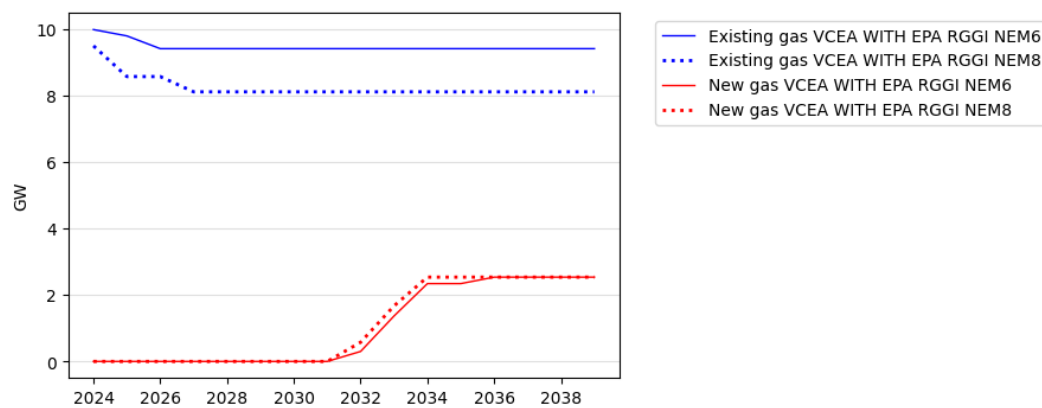


Figure 12: Gas capacity trends 2024–2039 in VCEA WITH EPA RGGI NEM6 and VCEA WITH EPA RGGI NEM8 scenarios, broken down by existing and new installations.

Quantitative Analysis with 2045 Horizon

The Virginia Clean Economy Act requires Dominion to achieve 100% zero-carbon electricity no later than 2045—which includes phasing out all carbon-emitting power plants by 2045, unless the SCC grants reliability exemptions on a case-by-case basis. Our analysis determined that compliance can be achieved to serve the full load in Dominion’s forecast through the adoption of renewable energy, energy storage, and other zero-carbon technologies such as SMRs.

To extend our model to 2045, some of the discovery data had to be extended beyond 2039. For details on the process used to extend the model inputs, see **Appendix C: Extension of Model Inputs to 2045**. In addition to extending the discovery data, we raised the IRP capacity limits so that the model could reach the zero-carbon goal.

Key points from the 2045 scenarios are:

- Storage and nuclear resources are crucial to reliably meeting the zero-carbon requirement.
- Across scenarios, the model selects near-term storage investment and installs the maximum amount of storage available by the end of the model horizon.
- It is not optimal for the model to build new gas when it is able to “see” the 2045 zero-carbon requirement and has the option to select additional storage and/or nuclear resources instead.
- When either more storage or more nuclear resources are available, just ~12 GW of new solar is sufficient to meet the zero-carbon requirement.

We modeled the zero-carbon requirement by placing a soft constraint on carbon production in 2045. The constraint places a very high cost on any carbon production in 2045 so that the model is able to produce results even when it cannot meet the zero-carbon requirement. We also modeled the capacity reserve margin requirement with a soft constraint, but with a much higher price on violating the reserve requirement than the zero-carbon requirement. With a much higher price on the capacity reserve requirement, the model prioritizes meeting the reserve requirement over the zero-carbon requirement.

As Figure 13 shows, the VCEA 2045 EPA RGGI scenario cannot meet the zero-carbon requirement. (It also has a capacity reserve shortfall in 2045). Thus, we raised the limits on clean energy resources to find solutions that could meet the zero-carbon requirement. When increasing the clean energy resources available to build by two and three times, the model continues to fall short of the zero-carbon requirement at ~17.5 and ~5 million metric tons of CO₂ emissions by 2045, respectively, and at similar costs to the 2045 baseline scenario (see Figure 20). Contrast these CO₂ numbers to the baseline scenario (using extended IRP values), which emits ~29 million metric tons of CO₂ in 2045. To identify VCEA-compliant solutions, we further increased the amount of storage and nuclear capacity available to the model by six times.

The annual emissions for the 2045 scenarios are shown in Figure 13, which shows that the zero-carbon requirement can be met only when the limits on storage (BESS) or nuclear (SMR) resources are significantly raised relative to the IRP. Figure 14 shows the carbon intensity for the 2045 EPA RGGI scenario and the two scenarios that do meet the zero-carbon requirement. Here we can see that the scenario with more nuclear achieves the lowest annual carbon intensity values starting in about 2035.

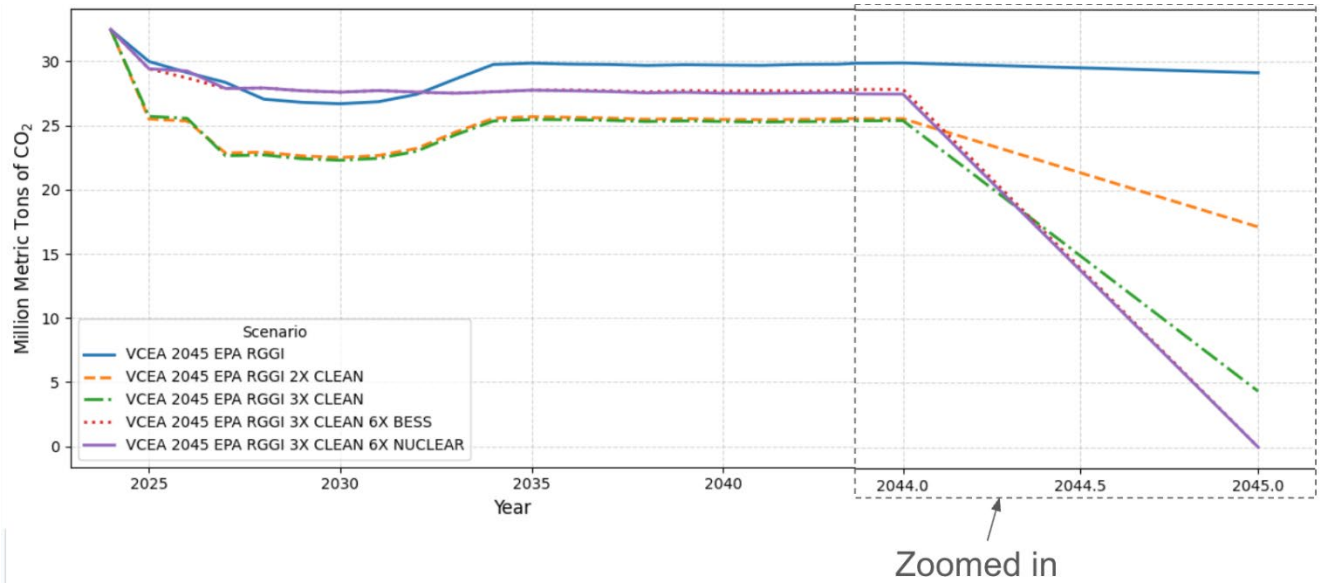


Figure 13: Annual CO₂ emissions trends 2024–2045 for all 2045 scenarios.

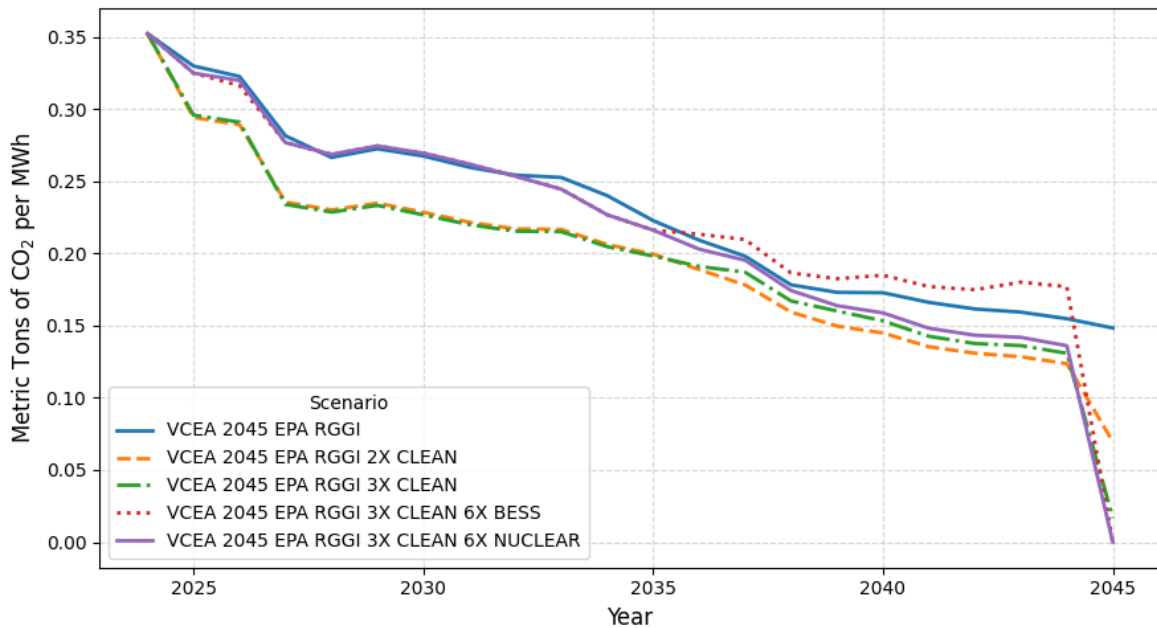
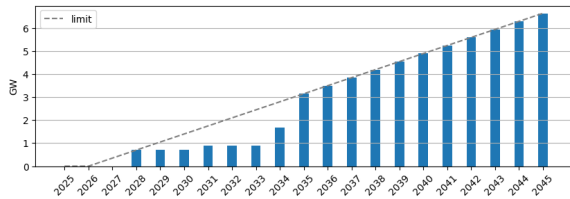


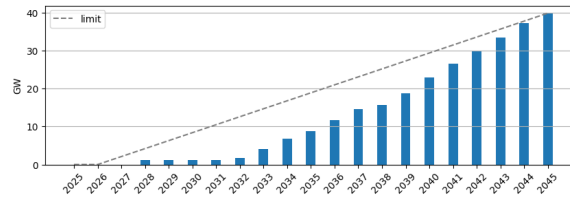
Figure 14: CO₂ intensity trends 2024–2045 for VCEA EPA RGGI, the 2X and 3X scenarios that do not meet the zero-carbon requirement, and the 6X scenarios that do meet the zero-carbon requirement.

All scenarios except the 6X NUCLEAR scenario installed the maximum allowed SMR capacity 2045. For example, in the 3X CLEAN scenario (which does not meet the zero-carbon requirement), the model can and does install 10,452 MW of new SMRs. However, the 6X NUCLEAR scenario installs only 16,138 MW of new SMR resources by 2045, even though the scenario’s upper limit is 20,904 MW.

All of the 2045 scenarios install the maximum amount of storage available by the end of the model horizon. Figure 15 shows the cumulative new storage capacity in two 2045 scenarios to highlight this point.



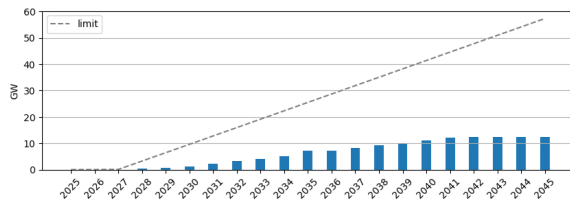
(a) Cumulative installed storage capacity vs. the build limits in the VCEA 2045 EPA RGGI scenario.



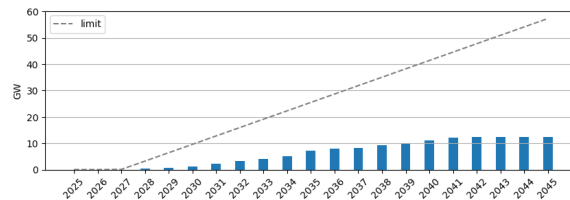
(b) Cumulative installed storage capacity vs. the build limits in the VCEA 2045 EPA RGGI 3X CE 6X BESS scenario.

Figure 15: Comparison of installed storage capacity vs. the capacity limits between two 2045 scenarios. Both scenarios install the maximum amount of energy storage. Note the different vertical scales between subfigures (a) and (b).

The 2X CLEAN and 3X CLEAN scenarios install the maximum amount of solar (~37 and ~56 GW respectively) in 2045 without meeting the zero-carbon requirement. However, when either more storage or more nuclear resources are available to meet the zero-carbon requirement, just 12 GW of new solar is sufficient to meet the zero-carbon requirement, as shown in Figure 16.



Cumulative new solar capacity vs. the build limits in the VCEA 2045 EPA RGGI 3X CLEAN 6x BESS scenario.



Cumulative new solar capacity vs. the build limits in the VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR scenario.

Figure 16: Cumulative new solar capacity over time in two 2045 scenarios that meet the zero-carbon requirement. Both scenarios build a total of ~12 GW of solar by 2045.

Figure 17 shows the gas capacity trends in the VCEA WITH EPA RGGI scenario (which ends in 2039) against the two 2045 scenarios with enough clean energy capacity to meet the zero-carbon requirement. Note that none of the VCEA-compliant 2045 scenarios install new gas, in contrast with all the 2039 scenarios that install the maximum amount of new CC gas generation.

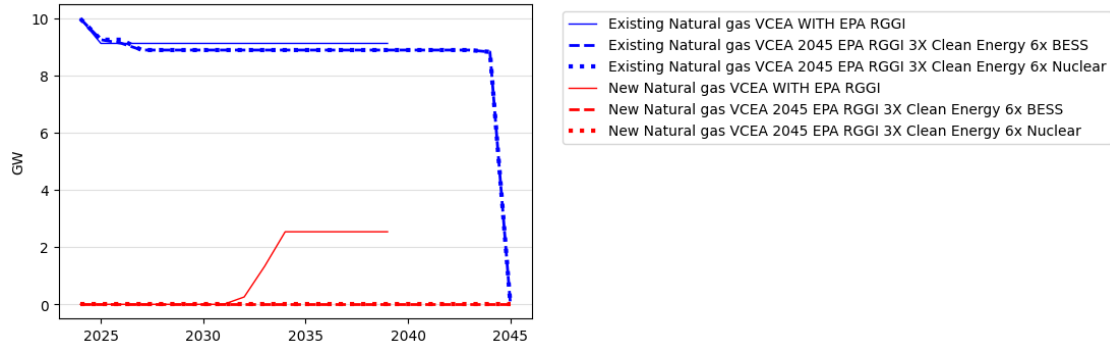


Figure 17: Gas capacity trends 2024–2045 in VCEA WITH EPA RGGI, VCEA 2045 EPA RGGI 3X CLEAN 6X BESS, and VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR scenarios, broken down by existing and new installations.

Figure 18 and Figure 19 show the capacity changes by technology in each year for the two scenarios that reach the zero-carbon requirement in 2045. These figures show that battery storage additions of a few GW before 2033 combined with additional renewable generation can preclude the need for new gas generation. Even in the 6X NUCLEAR scenario, the model installs battery storage earlier on in the planning horizon than nuclear.

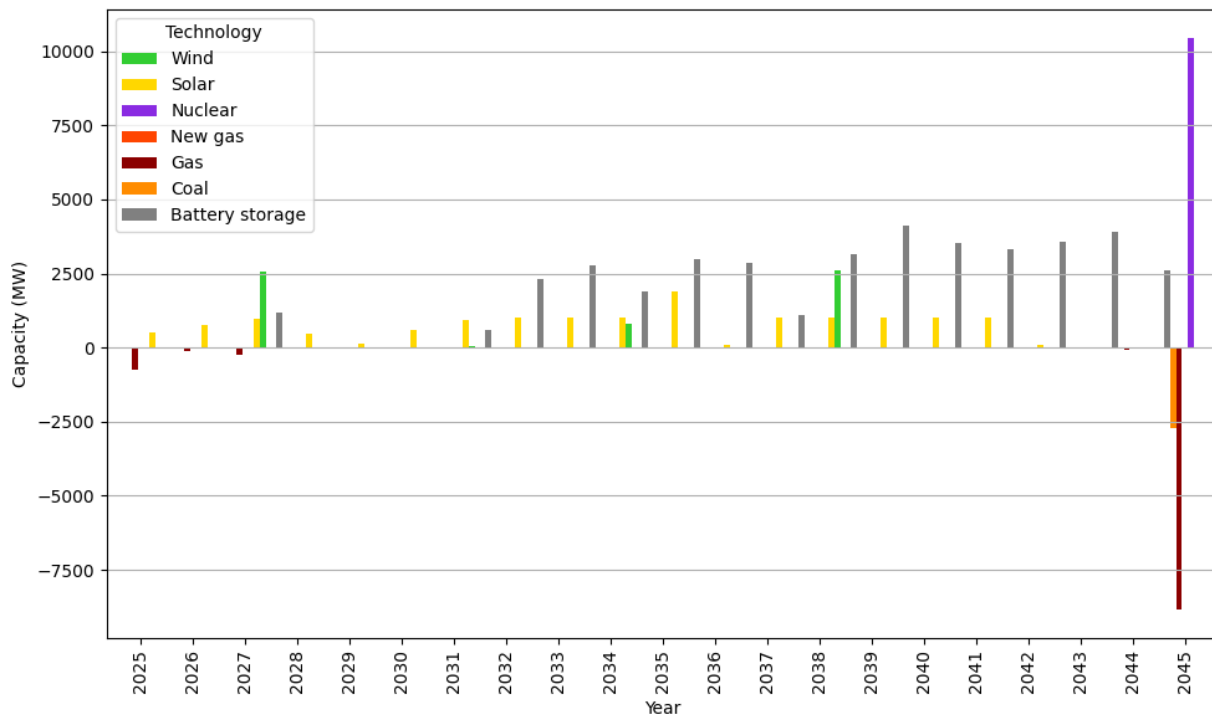


Figure 18: Capacity changes by technology and year for the VCEA 2045 EPA RGGI 3X CE 6X BESS scenario.

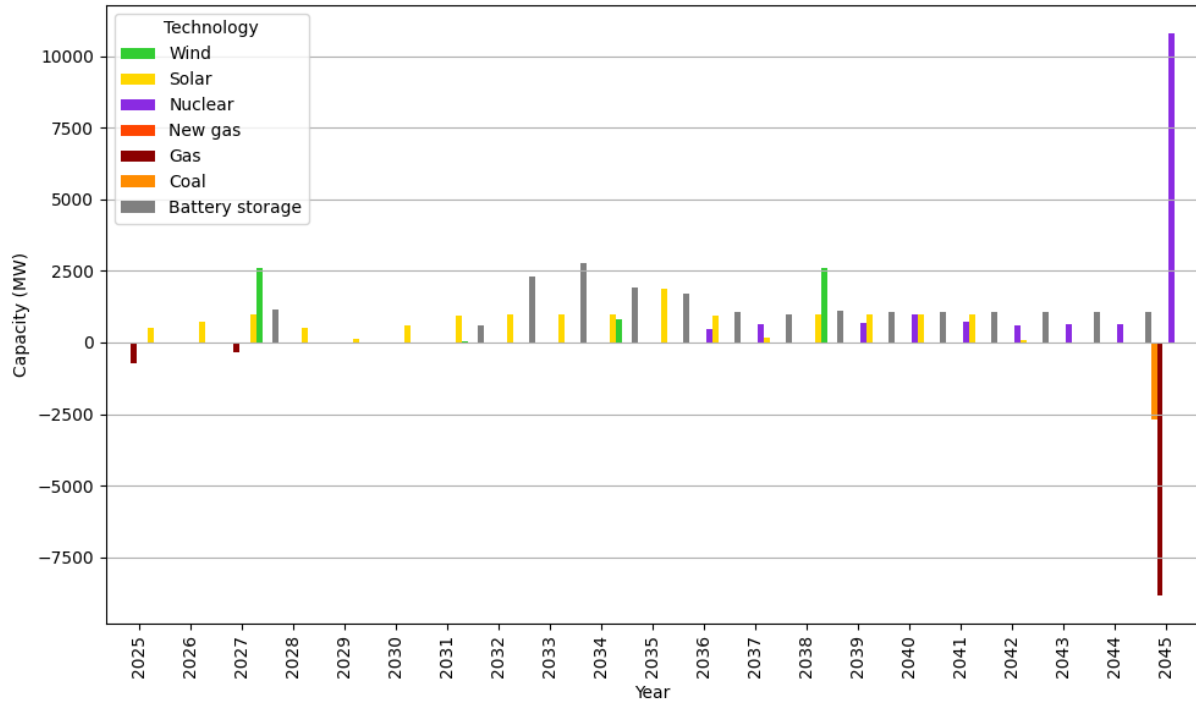


Figure 19: Capacity changes by technology and year for the VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR scenario.

For more details on capacity and energy dispatch decisions in each scenario, see **Appendix B: Detailed Scenario Results**.

Costs in 2045 Scenarios

Figure 20 and Figure 21 show the total present costs for each of the 2045 scenarios. While the 6X BESS and 6X NUCLEAR scenarios have higher total costs than the other scenarios, it is important to note that the other scenarios do not meet the 2045 zero-carbon requirement. In fact, the additional costs in the 6X scenarios are primarily from fixed capital costs.

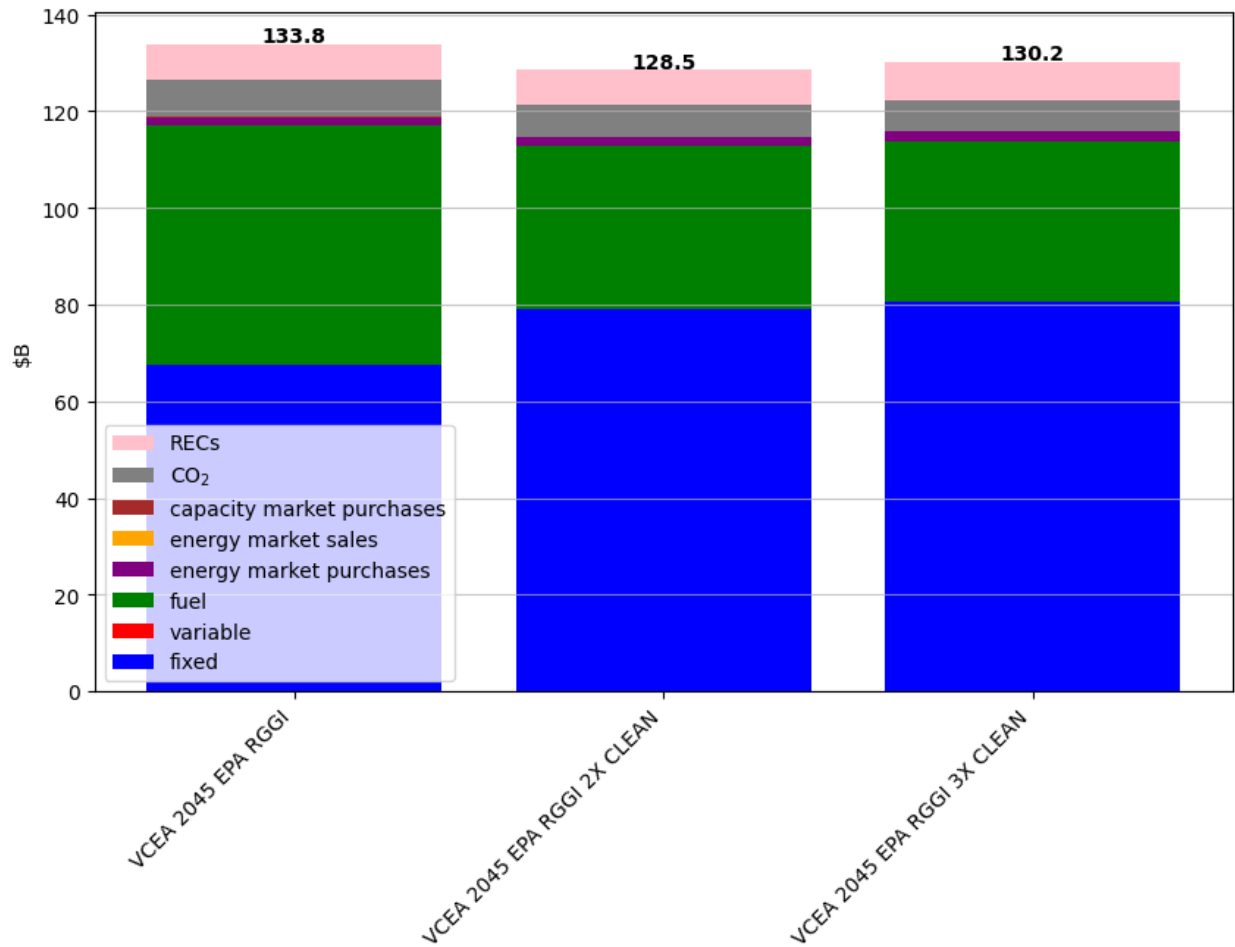


Figure 20: Total present costs (\$B) for VCEA 2045 EPA RGGI, VCEA 2045 EPA RGGI 2X CLEAN, and VCEA 2045 EPA RGGI 3X CLEAN scenarios. **NOTE THAT THESE SCENARIOS DO NOT MEET THE 2045 ZERO-CARBON REQUIREMENT.** “RECs” is Renewable Energy Certificates.

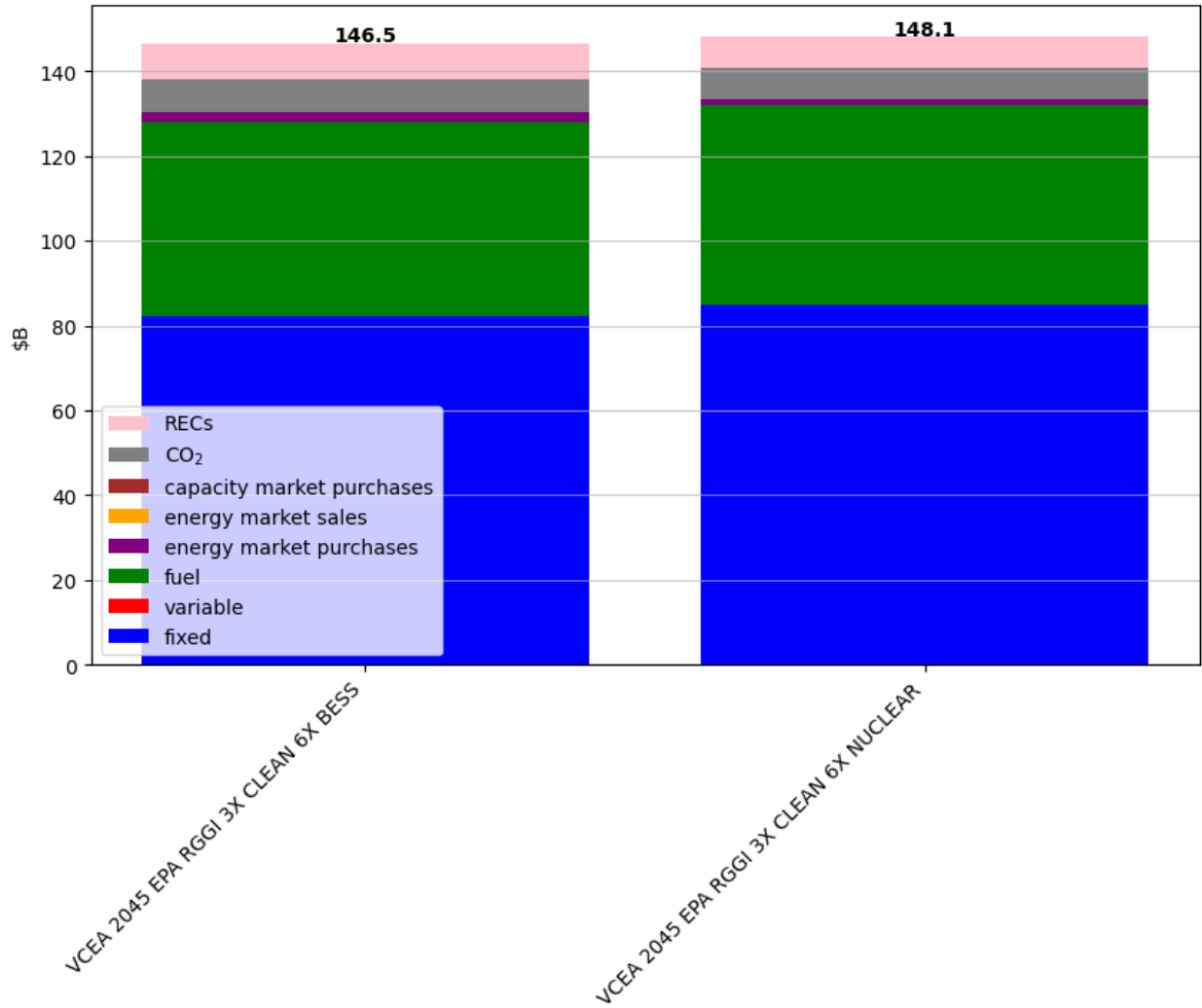


Figure 21: Total present costs for VCEA 2045 EPA RGGI 3X CLEAN 6X BESS and VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR scenarios. **Note that these scenarios are the only two that were able to meet the 2045 VCEA zero-carbon requirements.** “RECs” is Renewable Energy Certificates.

Figure 22 shows that fuel costs drop significantly in the 6X scenarios in 2045 when the zero-carbon requirement is met, while fuel costs remain higher in the non-compliant scenarios.

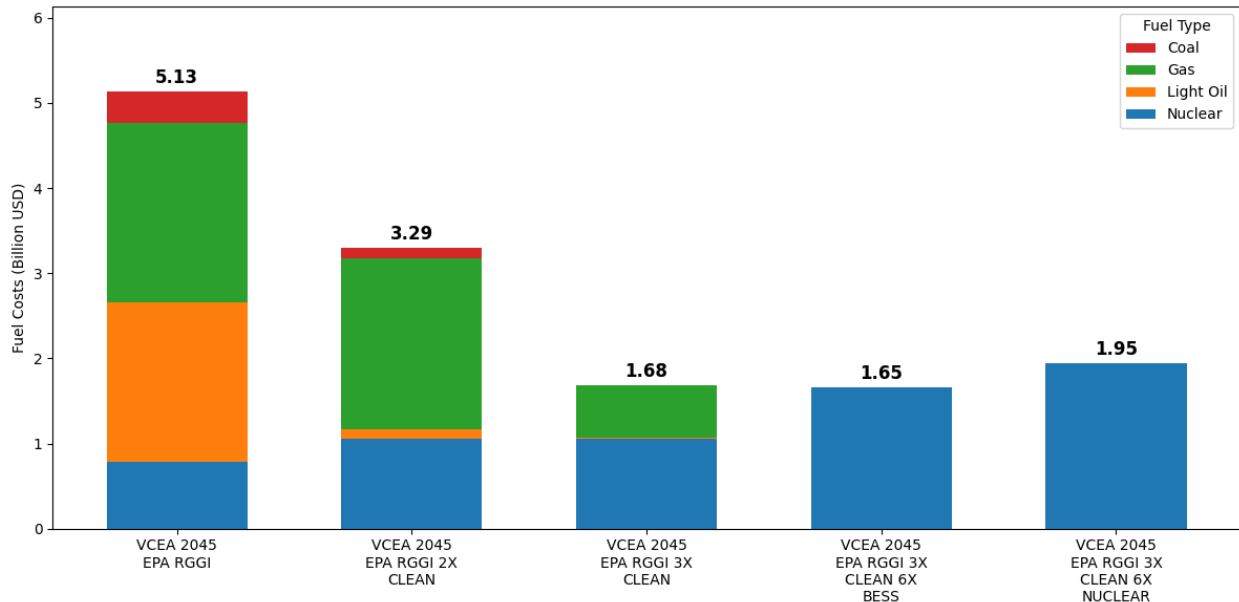


Figure 22: Figure showing fuel costs in 2045 for all 2045 scenarios.

For example, the 2024–2045 present costs for the non-compliant VCEA 2045 EPA RGGI scenario are about \$12.7B lower than the compliant VCEA 2045 EPA RGGI 3X CLEAN 6X BESS case (see Figure 20 and Figure 21). However, the fuel costs in 2045 for the non-compliant VCEA 2045 EPA RGGI scenario are about \$3.48B *higher* than the compliant 6X BESS scenario. Assuming these values carried forward, it is possible that the total costs of the 6X scenarios could be at or lower than the total costs of non-compliant cases as soon as a few years past 2045. However, one would need to model further into the future to assess this possible outcome.

Also note that the costs in Figure 20 and Figure 21 do not include the damages discussed in **Section: Environmental Justice**, which show that the damages from NO_x, SO₂, and PM_{2.5} emissions are non-trivial, but would decline to \$0 (from the power sector) when the model reaches 2045 in the 6X scenarios.

Lastly, these costs come from serving the full load in Dominion’s forecast, which could change significantly in the future if load growth follows more historical patterns.

Summary of Quantitative Analysis and Comparison of 2039 with 2045 Scenarios

Contrasting the 2039 and 2045 scenarios, we find that:

- In the 2039 scenarios comparable to the IRP, our analysis showed that annual CO₂ emissions will drop in the near term if the least efficient gas generators are retired, but then annual emissions will climb back up to roughly today’s levels due to the addition of new gas generation. Our additional 2039 scenarios showed that more

behind the meter solar or more clean energy resources can reduce both emissions and costs.

- In all scenarios—both 2039 and 2045 horizons—battery storage is shown to be a crucial “no-regrets” resource that keeps costs low while reliably meeting demand and laying the foundation for a zero-carbon future. Battery storage allows less solar and wind generation capacity to be used more efficiently by reducing curtailment and land impacts.
- In contrast with the DOM IRP, when the 2045 zero-carbon requirement is visible to the model, no new gas generation is optimal. Instead, more solar PV, energy storage, and SMR nuclear resources should be sourced. In fact, even when using the 2039 horizon, our analysis indicates that purchasing new CT gas generation is not economical when considering existing federal laws.
- Our 2045 results show two potential pathways to meet the 2045 VCEA zero-carbon requirements while also meeting capacity requirements and serving the full load in Dominion’s forecast. Both scenarios include near-term additions of batteries. The 2045 scenarios that meet the VCEA zero-carbon requirements demonstrate the limitations of modeling only through 2039. The most notable difference is that the model makes different optimal build decisions between now and 2039 when it can “see” the 2045 zero-carbon requirement. Future IRPs should model through a horizon that incorporates all relevant legal requirements at that time to inform better capacity expansion decisions and reduce the risk of tying ratepayers to stranded assets.

Recommendation: Direct Dominion to evaluate cleaner, lower cost, and more efficient capacity resources, as opposed to just gas projects. Future IRPs should perform sensitivity analyses by raising the capacity limitations of generation and storage resources to potentially uncover lower cost and cleaner solutions. Investment in cleaner capacity resources like storage will reduce the risk of unnecessary investments in generation and other infrastructure, provide more customer benefit, and help Dominion meet the 2045 zero-carbon requirement rather than making compliance more difficult.

Recommendation: Direct Dominion to pursue significantly more energy storage projects in the near and medium term—beyond the minimum petition requirements in the VCEA. While new nuclear capacity will likely be needed, the need is not immediate and can be reassessed in future IRPs.

Additional Comments and Critiques of the IRP

Gas

Dominion claims that “[i]n order to meet the energy and capacity needs associated with the load forecast and without a commercially viable carbon-free, dispatchable generation alternative, natural gas generation will be a critical component to ensuring the ability to *reliably* meet generation demand.”¹³ Historically, gas-powered energy generation technologies have been considered firm and thus available at all hours of the year, whenever they are needed. Recently, however, concerns have arisen about the assumed high reliability of both gas generators and the gas system during extreme weather events.

In November 2024, the North American Electric Reliability Corporation (NERC) updated its winter reliability assessment, which projects how national electric systems might fare during the current winter weather. Within the latest version of this report, NERC shows elevated risks for some electrical systems during extreme winter weather. Figure 23 shows the headline graphic from the report.¹⁴

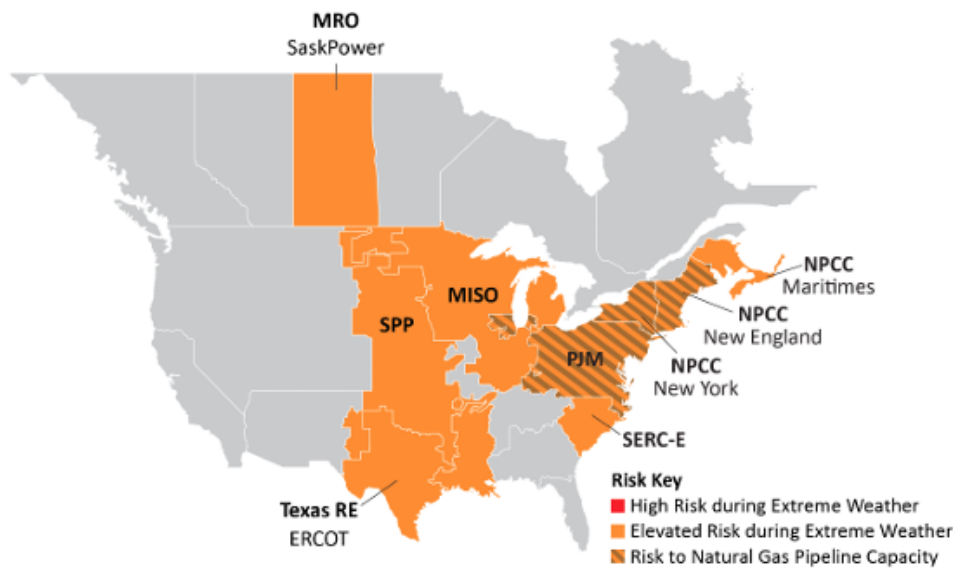


Figure 1: Winter Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Figure 23: Winter Reliability Risk Area Summary Figure from the NERC 2024–2025 Winter Reliability Assessment (November 2024).

¹³ IRP at 41 (emphasis added).

¹⁴ 2024-2025 Winter Reliability Assessment, N. Am. Elec. Reliability Corp. (Nov. 2024) 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

One reason for this elevated risk is the risk to gas pipeline capacity. NERC describes this risk as one in which the ability for gas fuel to reliably make its way to the generators is threatened by ongoing concerns with the production and delivery systems during extreme weather. These concerns stem from extreme winter weather events that have occurred and caused real shortages and failures of gas infrastructure.¹⁵

In February 2021, a regional winter storm froze over Texas and parts of the south-central United States. A joint report published by the Federal Energy Regulatory Commission (FERC) and NERC discusses this event in detail. The report explains how during this extreme weather event, the gas generation fleet experienced generation outages alongside both wind and coal. Figure 24 shows power plant outages, including gas plants, during Winter Storm Uri in ERCOT.¹⁶

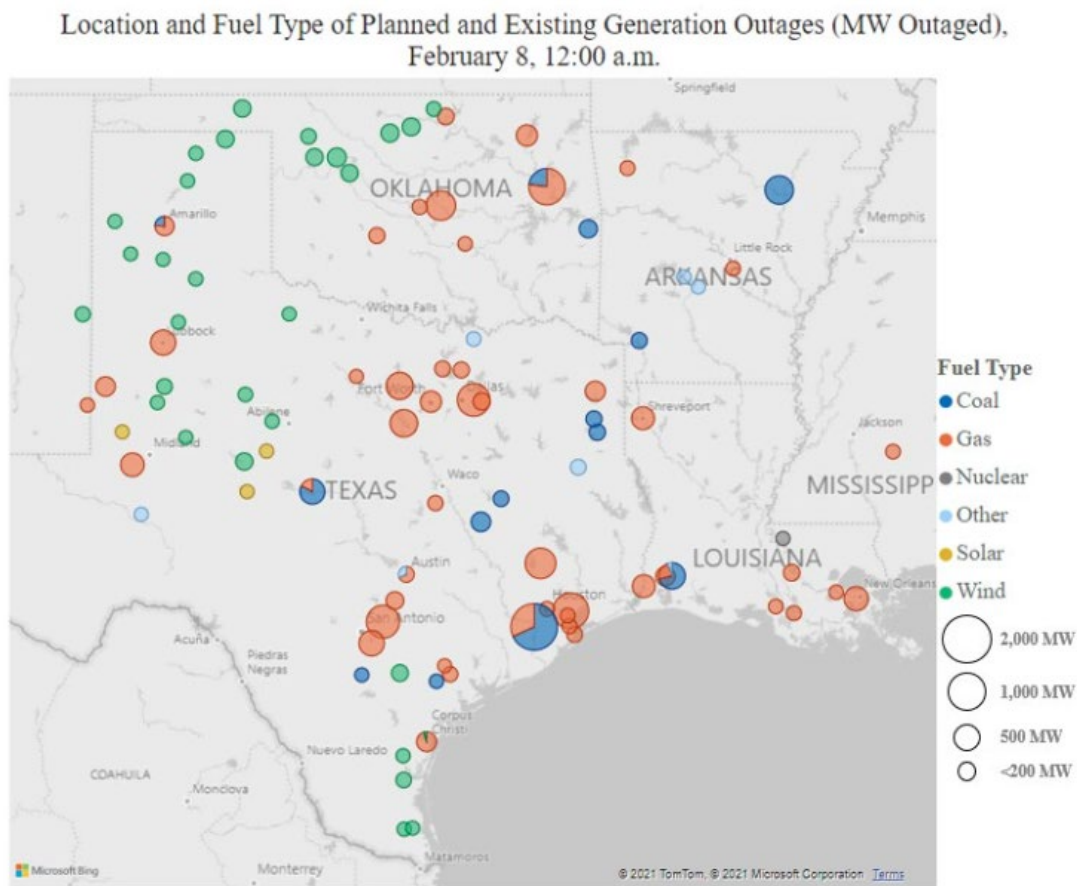


Figure 24: Location and Fuel Type of Planned and Existing Forced Generation Outages in ERCOT (MW Outage), February 8, 12:00 a.m. from FERC’s *The February 2021 Cold Weather Outages in Texas and the South-Central United States* (November 2021).

¹⁵ *Id.* at 6, 8.

¹⁶ *The February 2021 Cold Weather Outages in Texas and the South Central United States*, Fed. Energy Reg. Comm’n & N. Am. Elec. Reliability Corp. Reg’l Entities (Nov. 2021) 15–17, <https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and>.

One reason why many generation resources were unable to generate power was because of a lack of gas fuel due to fuel production and distribution issues. The high loss of gas production during these events resulted in power plant outages for lack of fuel even when there were functional pipelines and power plants that could have conveyed and utilized the fuel.

While the same type of freeze-offs at gas production wells were not as bad in the PJM region during Winter Storm Elliot, gas supply and gas power plant failures nonetheless were significant and resulted in over 30 GW of gas plant outages during the storm as illustrated in Figure 25.¹⁷

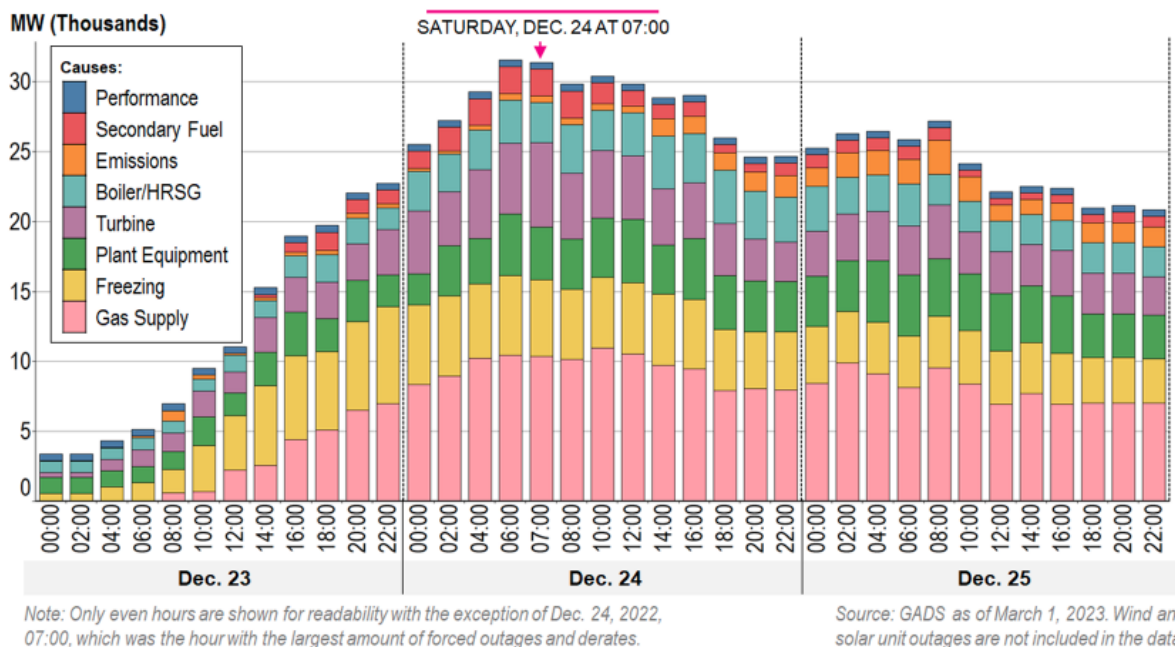


Figure 25: Gas plant forced outages during Winter Storm Elliot in PJM, by reason from PJM’s Winter Storm Elliott Event Analysis and Recommendation Report (July 17, 2023).

PJM’s analysis also found that power plant mechanical failures were responsible for most of the gas power plant outages, meaning that a large portion of the outages would have presumably occurred even if the utility experiencing the outage had fuel supply backup like an attached liquefied natural gas (LNG) facility. PJM has since expanded its ELCC methodology to include thermal generators, accounting for correlated generator outages that might occur during extreme operating conditions.

¹⁷Winter Storm Elliott: Event Analysis and Recommendation Report, PJM (July 17, 2023) at 49, 51, <https://www.pjm.com/-/media/DotCom/library/reports-notice/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf>.

This event, alongside other smaller events,¹⁸ has provided push-back against the often-assumed reliability of gas plants, particularly in extreme cold weather.

Recommendation: See additional clean capacity recommendation in following “Notable Resources Excluded from Dominion’s IRP Model” section.

Hydrogen

The IRP included a high-level analysis of the carbon intensity of electricity with hydrogen blending. It appears that only the “inside the fence” impacts of hydrogen blending were considered, *i.e.*, the carbon emissions rates were lowered based on burning up to a 30% blend of hydrogen in the gas fleet. It does not appear that these results included the carbon intensity of the hydrogen itself. Fuel grade hydrogen is not readily available, and it often needs to be created either by thermally splitting the hydrogen from methane gas (CH₄) or by splitting water (H₂O) with electricity. Both methods require significant amounts of energy which can increase the carbon intensity of the hydrogen and thus erode the savings when the hydrogen is later combusted for power.

Previous estimates indicate that the “embedded carbon emissions of the hydrogen must be below 6 kg-CO₂ per kg-H₂ for the overall power plant emissions to be lower than burning 100% natural gas.”¹⁹ Steam methane reforming, the most common hydrogen production method today, produces hydrogen with about 9 kg-CO₂/kg-H₂²⁰ and grid electricity electrolysis produces hydrogen with about 2.4 kg-CO₂/kg-H₂ in Virginia.²¹

While electrolysis produces lower carbon intensity hydrogen, it requires significant energy inputs, resulting in round trip efficiencies (electricity to hydrogen to electricity) of only 20-40%. It is unclear if this excess energy was considered in the IRP.

The IRP discusses Methane Pyrolysis, which could produce very low carbon intensity hydrogen but will still have high levels of energy inputs that must be considered. Moreover, Methane Pyrolysis currently has a Technology Readiness Level (TRL) of 6, which indicates that it is not ready for commercial deployment at this time.²²

There was also no mention in the IRP of the infrastructure that would be needed to support the delivery and potential storage of hydrogen, such as pipelines, compressors, and storage tanks. Hydrogen is a very small molecule and, as such, requires much stricter tolerances for pipeline material, seals, compressors, etc. Hydrogen is also often piped at higher pressure because its volumetric energy density is lower than that of methane gas and thus requires higher flow rates to deliver similar amounts of energy.

¹⁸ Such as Winter Storm Gerri where over half of PJM’s forced outages were gas plants. *Winter Storm Gerri Review January*, PJM (Feb. 8 2024) 14, <https://www.pjm.com/-/media/committees-groups/committees/oc/2024/20240208/20240208-item-11---cold-weather-update.ashx>

¹⁹ Joshua D. Rhodes et al., *Hydrogen Blending in Texas Natural Gas Power Plants at Scale*, Univ. of Tex. Austin (2022) (“Hydrogen Report”) at 7, <https://sites.utexas.edu/h2/files/2022/01/TX-H2-Power-Plant-Blending.pdf>.

²⁰ *Id.*

²¹ Assuming Virginia electricity to have about 69% of the carbon intensity of Texas electricity: <https://www.eia.gov/electricity/data/emissions/> and using data from the Hydrogen Report.

²² “Hydrogen TCP,” Tech. Collaboration Programme, <https://www.ieahydrogen.org/trl-assessments/> (last visited Feb. 24, 2025).

Thus, it is likely that the hydrogen intensity reductions from hydrogen blending in the IRP are very optimistic.

Recommendation: Direct Dominion that in future modeling, baseline scenarios should not rely on hydrogen for compliance with the 2045 zero-carbon requirement. To the extent Dominion wishes to present a sensitivity that incorporates hydrogen, the Commission should direct Dominion to analyze the entire lifecycle emissions of the hydrogen fuel.

Environmental Justice

This report also assessed the environmental justice impacts of the operations of Dominion’s power plant fleet, based on Dominion’s four Primary Portfolios, on the communities that bear those burdens most. Some power plant pollutants, such as CO₂ and methane, are global and their impacts will be borne by all of us through the impacts of climate change. These impacts are disproportionately severe for members of disadvantaged communities, due in large part to underlying pollution burden and underinvestment in clean energy infrastructure. Additionally, local exposure to pollutants from power plants can increase significant health impacts for those living in close proximity to a power plant, who are often members of disadvantaged communities.²³

Because these communities are also often burdened with other issues, such as other nearby polluting industries, lower socioeconomic status, and less access to high-quality health care, greater attention should be placed on evaluating the potential for disproportionate impacts, such as degraded environmental conditions created by local power plant emissions for communities in close proximity to these plants.

While it is not possible to capture the full impacts in a grid model or its results, evaluating impacts from a generation planning perspective is. We accomplish this by assessing the increased mortality and morbidity using the AP3 version of the Air Pollution Emission Experiments and Policy analysis (APEEP) model developed by Dr. Nick Muller at Carnegie Mellon University. The APEEP model is an integrated assessment model that links emissions of air pollution to exposures, physical effects, and monetary damages in the contiguous United States.²⁴ The model provides county-level damages for multiple pollutants, including NH₃, NO_x, PM_{2.5}, SO₂, and VOCs. The IRP model results only included emissions rates and totals for NO_x and SO₂. We augmented them with technology-specific emissions factors for PM_{2.5} from the scientific literature.²⁵ Accordingly, the estimated

²³ Bethel Tarekegne et al., *Analysis of Energy Justice and Equity Impacts from Replacing Peaker Plants with Energy Storage*, Pac. Nw. Nat’l Lab. (2023) 4-5, https://www.pnnl.gov/sites/default/files/media/file/Analysis_of_Energy_Justice_and_Equity_Impacts_from_Replacing_Peaker_Plants_with_Energy_Storage.pdf.

²⁴ “AP4 (AP3, AP2, APEEP) Model,” Nick Muller’s Home Page, <https://nickmuller.tepper.cmu.edu/APModel.aspx> (last visited Feb. 24, 2025).

²⁵ Conservatively assuming the best available control technology (BACT) from: Joshua D. Rhodes, et al., *A Geographically Resolved Method to Estimate Levelized Power Plant Costs with Environmental Externalities*, 102 Energy Policy 491 (Mar. 2017), <https://www.sciencedirect.com/science/article/pii/S0301421516306875#t0010>.

damages are conservatively low, as they do not incorporate damages from all the other pollutants that these plants emit.

We calculated the economic damages associated with NO_x, SO₂, and PM_{2.5} emissions by first finding the NO_x, SO₂, and PM_{2.5} emissions calculated by the PLEXOS model (or estimated based on emissions factors found in the literature) in each of Dominion's Primary Portfolios. We find the emissions for every generation unit and in every year. We then take the emissions, given in short tons, and convert to metric tons in order to match the economic data.

The economic damages data comes from the AP3 model²⁶ and provides marginal damages data (in year 2000 dollars), measured in dollars per metric ton, of NO_x, SO₂, or PM_{2.5} emissions in every county in the United States. We converted from year 2000 dollars to year 2025 dollars, adjusting for inflation, using the Consumer Price Index (CPI). We used CPI numbers from the year 2000 and the most recent numbers from December 2024.

Finally, we multiplied the metric tons of NO_x, SO₂, and PM_{2.5} emissions produced by each generation unit in the PLEXOS model results with each corresponding county's AP3 damages values for that county. For example, emissions from the Clover Power Station were multiplied by the marginal damage rate for Halifax County, Virginia because that is where the power plant exists, and that county is where the localized damages from its emissions will be felt. For new builds, we used the average damages rate across the existing fleet. We present the results in today's dollars in Table 2. While this approach does not provide an analysis on a community-by-community basis, it does provide an informative baseline for understanding impacts of Dominion's existing generation fleet on a county wide basis. From this baseline, further evaluation can be conducted to better understand potential disproportionate impacts for environmental justice communities and fenceline communities, who by virtue of their proximity to a major pollution source may experience increased health risk as compared to communities further from the pollution source.

²⁶ Nicholas Muller, *Boosting GDP Growth by Accounting for the Environment*, 345 Science 873 (Aug. 22, 2014), <https://www.science.org/doi/10.1126/science.1253506>; https://github.com/ptschofen/PNAS_SectoralMortality/blob/master/md_M_2014.csv.

Table 2: Additional cost of the IRP scenarios when local air pollutants are considered for the communities where the power plants exist.

Scenario	Total NO_x Damages (2024–2039, \$B)	Total SO₂ Damages (2024–2039, \$B)	Total PM_{2.5} Damages (2024–2039, \$B)	Total Damages (2024–2039, \$B)
VCEA w/ EPA	\$2.57	\$2.32	\$2.54	\$7.43
VCEA w/out EPA	\$3.07	\$5.30	\$4.72	\$13.08
REC RPS w/ EPA	\$2.78	\$2.34	\$2.86	\$7.97
REC RPS w/out EPA	\$3.21	\$5.64	\$5.04	\$13.88

From the analysis above, we estimate a more accurate cost of the Primary Portfolios Dominion presented in the IRP to be between at least \$7.4B and \$13.9B higher than the "Total System Costs" provided. For a more complete cost analysis, including local impacts from all air pollution emissions would be necessary. Our analysis only included the three air pollutants listed above, but it would be possible to include more.

While not undertaken in this analysis, future IRPs could include the costs of pollutant damages directly as variable costs for the power plants. Taking this approach would create a more accurate assessment of the cost of running existing generation assets on nearby communities and would likely result in different outcomes for building and siting new resources by allowing environmentally preferable alternatives to be more easily found.

Recommendation: Direct Dominion to quantitatively assess, in future IRPs, the public health harms to local communities due to air pollutants, across its portfolios.

Carbon Emissions

Similar to how we calculated the impacts of air pollutants from power plants on local communities, we also calculated the societal costs of the CO₂ emissions from the same generation fleet. As a proxy for the social cost of carbon we use the RGGI costs. It is important to note that the actual societal costs will typically be much higher.²⁷

The economic damages associated with CO₂ emissions were determined by first finding the CO₂ emissions calculated by the PLEXOS model in each of four IRP scenarios for every generation unit in every year. We then took the emissions and multiplied by the projected current and future RGGI cost of carbon provided by Dominion in discovery (see Appendix C for annual values). The total results are shown in

Table 3.

Table 3: Total CO₂ damages for various scenarios during the 2024–2039 period.

Scenario	Total CO ₂ Damages (2024–2039, \$B)
VCEA w/ EPA	\$10.40
VCEA w/out EPA	\$11.80
REC RPS Only w/ EPA	\$10.78
REC RPS Only w/out EPA	\$12.24

Thus, our analysis indicates that each of the scenarios are between \$10B and just over \$12B higher in costs than presented in the IRP when CO₂ emissions are considered.

Recommendation: Direct Dominion to include societal costs of carbon emissions for each scenario in future IRPs.

Notable Resources Excluded from Dominion’s IRP Model

This section outlines additional resources that should also be considered in IRPs for DOM.

Long Duration Energy Storage (LDES), Solar Plus Storage, and Virtual Power Plants (VPPs)

Several already viable resources were not modeled by Dominion.

For example, the IRP only considered 4-hour energy storage systems and, while noting them in the inputs documentation, did not model 6-hour, 8-hour, or 10-hour storage. It would be reasonable for Dominion to model these longer durations of storage, especially

²⁷ For example, the EPA estimates are an order of magnitude greater than the RGGI values. *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances: Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,”* Env’tl Protection Agency (Nov. 2023) 4, https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf.

considering that PJM has developed class ratings for each of the longer durations.²⁸ Similar utilities, such as the Salt River Project, are already issuing Requests for Proposal (RFPs) for 10-hour energy storage systems.²⁹

PJM’s own ELCC projections note that LDES systems have ELCC values that currently surpass steam units and are expected to maintain those levels into the future.³⁰ Considering LDES systems would likely make the capacity requirement easier to achieve given their higher ELCC values, which, in turn, would likely make it easier to achieve the 2045 requirements of the VCEA. Some LDES technologies have achieved a TRL of 7, which exceeds that of the methane pyrolysis hydrogen production method discussed in the IRP.³¹

The IRP also did not model VPPs, which are aggregations of distributed energy resources that can serve a grid in the same manner as a conventional power plant. These resources are becoming increasingly prevalent.³²

Similarly, the IRP did not include solar plus storage as an available resource. 66 out of the 80 “hybrid” power plants added in 2023 were solar plus storage.³³ Storage attached to solar can help smooth out the generation profile of solar facilities while also storing energy that might otherwise be curtailed, as discussed in **Section: Total Present Costs in 2039 Scenarios**. In addition, in ERCOT’s 2024 Long Term System Assessment, solar co-located with storage was found to be economic in a high load growth and environmental regulations scenario.³⁴ Specifically, the ERCOT model economically added 19 GW of co-located batteries and 59 GW of standalone batteries by 2039.³⁵

Recommendation: Direct Dominion to expand the resource profiles in future modeling to include additional clean capacity resources, including solar plus storage, virtual power plants, and long duration energy storage.

²⁸ “Preliminary ELCC Class Ratings for period Delivery Year 2026/27 – Delivery Year 2034/35,” PJM, <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx> (last visited Feb. 24, 2025).

²⁹ “2024 Long Duration Energy Storage (LDES) Pilot Request for Proposals (RFP),” Salt River Project (2024), <https://www.srpnet.com/assets/srpnet/pdf/doing-business/suppliers/2024-CCERC-LDES-RFP.pdf>.

³⁰ “Preliminary ELCC Class Ratings for period Delivery Year 2026/27 – Delivery Year 2034/35,” PJM, <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx> (last visited Feb. 24, 2025); see also Nestor A. Sepulveda, et al., *The design space for long-duration energy storage in decarbonized power systems*, 6 *Nature Energy* 506 (2021), <https://www.nature.com/articles/s41560-021-00796-8>.

³¹ Jeffrey Marqusee et al., *Long-Duration Energy Storage: Resiliency for Military Installations*, Nat’l Renewable Energy Lab. (Oct. 2023) v, <https://www.nrel.gov/docs/fy24osti/87646.pdf>.

³² Autumn Proudlove et al., *50 States of Virtual Power Plants & Supporting Distributed Energy Resources: 2024 State Policy Snapshot*, Smart Electric Power Alliance (Feb. 2025), https://sepapower.org/resource/50-states-of-virtual-power-plant-and-supporting-distributed-energy-resources-2024-state-policy-snapshot/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202025-02-13%20Utility%20Dive%20Renewable%20Energy%20%5Bissue:70485%5D&utm_term=Utility%20Dive:%20Renewable%20Energy; Sonali Razdan et al., *Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update*, U.S. Dep’t of Energy (Jan. 2025), https://liftoff.energy.gov/wp-content/uploads/2023/09/LIFTOFF_DOE_VirtualPowerPlants2025Update.pdf.

³³ Will Gorman et al., *Hybrid Power Plants: Status of Operating and Proposed Plants*, 2024 Edition, Lawrence Berkely Nat’l Lab. (Sept. 2024) 43, https://eta-publications.lbl.gov/sites/default/files/2024-09/hybrid_plant_tracking_2024_v3.pdf.

³⁴ *2024 Long-Term System Assessment for the ERCOT Region*, ERCOT (Dec. 2024) 48-50, https://www.ercot.com/files/docs/2024/12/20/2024_ltsa_report.zip.

³⁵ *Id.*

Grid Enhancing Technologies (GETs)

It was noted through discovery that Dominion did not consider any grid enhancing technologies (GETs) in the IRP. GETs include, but are not necessarily limited to, Dynamic Line Ratings, Dynamic Transformer Ratings, and Power Flow Control & Topology Optimization mechanisms.³⁶ These tools generally allow grid operators to maximize the use of their existing infrastructure based on actual current operating conditions rather than static limits that are often based on a worst-case scenario that might rarely, if ever, occur.

Recommendation: Consistent with the law, direct Dominion to comprehensively assess the potential application of GETs in future IRPs in a manner that ensures grid reliability and safeguards the cybersecurity and physical security of the electric distribution grid.

Data Center Demand Flexibility

Given that data centers have been flagged as driving much of the projected energy and peak demand growth in the region, it would be worth requiring Dominion to assess the ability of these new data centers to participate in demand response programs during critical system peak hours. Even in absence of actually reducing electricity usage, modern data centers are often built with over 100% backup generation. Newer backup generation or backup generation equipped with scrubbers could be called upon to reduce the energy that the data center consumes from the grid. In fact, a recent study demonstrated that if new large loads were willing to curtail for just 0.5% hours of the year, an additional 18 GW of data center load could be incorporated into PJM without the need to build new generation.³⁷

As part of this analysis, the Commission should require Dominion to run a sensitivity that incorporates meaningful demand response participation by large loads and compares the air pollution effects of a demand response program that may rely on backup generators for a few hours a year, versus a no-demand-response scenario that may increase the need for new generation. This sensitivity would help the Commission assess the overall costs and benefits of a robust demand response program.

³⁶ *Grid-Enhancing Technologies: A Case Study on Ratepayer Impacts*, U.S. Dep't of Energy (Feb. 2022) iii, <https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf>

³⁷ Tyler H. Norris, *Rethinking Load Growth Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*, Nicholas Inst. for Energy, Env't & Sustainability, Duke Univ. (2025) 2, <https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf>.

Conclusions & Recommendations

Unlike Dominion's IRP, this analysis extended the model horizon to 2045 to incorporate the VCEA zero-carbon requirement. We found that when sufficient clean power resources are available, no new gas generation is needed. Reaching the zero-carbon requirement while meeting the capacity reserve requirements in years beyond 2039 will require installing more storage, solar, wind, and nuclear resources than are allowed in the IRP.

Furthermore, the results indicate that storage is especially important to keep costs low while meeting the zero-carbon requirement. Additionally, with more storage resources, the model shows that CO₂ emissions can be reduced sooner by replacing the least efficient gas resources. Also, allowing for more nuclear and storage capacity resources reduces the total solar capacity required to meet the zero-carbon goal. Considering the 2045 zero-carbon requirement, the Commission should direct Dominion to evaluate cleaner, lower cost, and more efficient capacity resources than the gas resources evaluated in the IRP. Several clean capacity resources, including solar plus storage, VPPs, and LDES, that were left out of Dominion's modeling, should be included in future IRPs.

The DOM IRP and our analysis both show that carbon intensity will decrease in most years. However, an analysis of total annual emissions shows that levels in 2039 will be similar to today's levels under Dominion's scenarios. These annual emissions trends also emphasize the need to consider more clean generation resources to reach the zero-carbon requirement.

Finally, we also find that, depending on the IRP scenario, total damages from CO₂ emissions increase the portfolio costs by \$10.4 billion to \$12.2 billion. Further, we find that total air emissions damages borne by local communities increase the portfolio costs from \$7.4 billion and \$13.9 billion.

Accordingly, based on the above findings, we recommend that the Commission issue the following directives to be implemented by Dominion in future IRPs:

- Direct Dominion to transition its planning software away from proprietary models like PLEXOS and instead use free, open-source software such as GenX, or, in the alternative, require Dominion to fund intervenor licenses to use PLEXOS and the necessary commercial solvers, such as CPLEX or Gurobi, and provide access to the compute resources required to operate the model.
- In any future IRP or proceeding that seeks to justify new capital investment, require Dominion to model scenarios that extend through 25 years—or through a horizon that includes all relevant legal requirements at that time—to ensure the analysis identifies solutions and strategies that meet the Commonwealth's policies and legal requirements.

- Direct Dominion to present annual emissions for each scenario in future IRPs and, as above, model compliance with the 2045 zero-carbon requirement.
- Direct Dominion to consider and evaluate cleaner, lower cost, and more efficient capacity resources (including co-located solar and storage, virtual power plants, and long duration energy storage) and perform sensitivity analyses by raising the capacity deployment limitations of cleaner generation and storage resources to potentially uncover lower cost and cleaner solutions.
- Direct Dominion to comprehensively assess the potential application of GETs in future IRPs in a manner that ensures grid reliability and safeguards the cybersecurity and physical security of the electric distribution grid.
- Direct Dominion to quantitatively assess, across its portfolios in future IRPs, the (i) damages from CO₂ emissions and (ii) public health harms to local communities from increased local air pollution.
- Direct Dominion that in future modeling, baseline scenarios should not rely on hydrogen for compliance with the 2045 zero-carbon requirement unless the full lifecycle emissions of the hydrogen are taken into consideration. To the extent Dominion wishes to present a sensitivity that incorporates hydrogen, Dominion should be directed to analyze the entire lifecycle emissions of the hydrogen fuel.

In addition, we recommend that the Commission require Dominion to prioritize one, immediate action prior to the next IRP: ***Dominion should take steps to add significantly more energy storage projects to its system in the near and medium term—beyond the minimum petition requirements in the VCEA.*** For example, the Report shows that when the storage capacity limits are relaxed, and the 2045 horizon is included, more than 6 GW of new storage capacity should be installed by 2035.

Appendices

Appendix A: Relevant Policies Background

The Virginia Clean Economy Act (VCEA)

The Virginia Clean Economy Act (HB 1526 and SB 851) was signed into law by Governor Ralph Northam in 2020. The bill establishes a renewable energy portfolio standard (RPS), which mandates that Dominion Energy Virginia produce 100 percent renewable electricity by 2045. At a high level, the VCEA put into policy:

1. Renewable Portfolio Standard (RPS) Targets
 - a. The VCEA establishes mandatory RPS compliance targets for Dominion:
 - i. 26% renewable energy sales by 2025.
 - ii. 41% renewable energy sales by 2030.
 1. Includes solar, wind, and other eligible renewables (e.g., biomass, hydro, waste-to-energy, or landfill gas-fired generating resources located in the Commonwealth and in operation as of January 1, 2020, provided that such resources do not use waste heat from fossil fuel combustion).
 - iii. Beginning in 2025, 75% of all RECs for RPS compliance must come from resources located in Virginia.
2. 100% Carbon-Free Electricity by 2045
 - a. The VCEA requires Dominion to achieve 100% zero-carbon electricity no later than 2045, which includes:
 - i. Phasing out all carbon-emitting power plants by 2045, unless the State Corporation Commission (SCC) grants reliability exemptions on a case-by-case basis.
 - ii. Compliance through renewable energy adoption, energy storage, and other zero-carbon technologies like small modular reactors (SMRs).
3. Renewable Targets (but can petition for more)
 - a. Dominion must petition for 16,100 MW of solar/onshore wind by 2035:
 - i. 3,000 MW from July 1, 2020, to December 31, 2024.
 - ii. 3,000 MW from January 1, 2025, to December 31, 2027.
 - iii. 4,000 MW from January 1, 2028, to December 31, 2030.

- iv. 6,100 MW from January 1, 2031, to December 31, 2035.
 - b. Dominion must petition for 5,200 MW of offshore wind by 2035.
- 4. Energy Storage Targets in VCEA
 - a. Dominion must petition for 2,700 MW of energy storage capacity by 2035.
- 5. Energy Efficiency Targets (measured in net savings): Dominion must “implement energy efficiency programs and measures to achieve the following total annual energy savings”:
 - a. 2022: 1.25%.
 - b. 2023: 2.5%.
 - c. 2024: 3.75%.
 - d. 2025: 5.0%.
 - e. 2026: 3.0%
 - f. 2027: 4.0 %
 - g. 2028: 5.0%³⁸
- 6. Increased net metering cap from 1% to 6% of previous year’s adjusted Virginia peak-load forecast.

Regional Greenhouse Gas Initiative (RGGI)

Based on the court’s decision in *Association of Energy Conservation Professionals vs. Virginia State Air Pollution Control Board* (Floyd Cir. Ct. Nov. 18, 2024), our model assumed that Virginia will re-enter RGGI in 2026. Incorporating RGGI costs into the Company’s portfolios will impact total costs. Thus, our scenarios all include a cost of carbon based on future assumptions about RGGI allowance prices.

Virginia Environmental Justice Act (VEJA)

Under Virginia law, it is the policy of the Commonwealth to “promote environmental justice and ensure that it is carried out throughout the Commonwealth, with a focus on environmental justice and fence line communities.”³⁹ For this reason, it is crucial to evaluate the environmental justice impacts of the various scenarios.

³⁸ Final Order, *In the matter of establishing energy efficiency savings targets for Virginia Electric and Power Company pursuant to VA Code section 56-596.2 B 3, et al.*, Case No. PUR-2023-00227 (Feb. 27, 2025) at 10.

³⁹ Va. Code § 2.2-235.

EPA 111(b)

For the purposes of this analysis, we also considered the impacts of the EPA’s New Source Performance Standards released April 2024 under section 111(b) of the Clean Air Act. The standards require new gas generators that operate with a greater than 40% annual capacity factor to capture approximately 90% of CO₂ emissions (using assumptions on plant efficiency and other technical parameters). The revised compliance deadline is 2032. Since the IRP did not include carbon capture and sequestration (CCS) technologies, and because CCS is a relatively nascent technology, we chose to require new gas generators to operate at no more than a 40% annual capacity factor instead of modeling CCS.

Net Energy Metering

Virginia law provides that net metering contracts should be available to customer-generators “until the rated generating capacity owned and operated by eligible customer-generators, eligible agricultural customer-generators, and small agricultural generators in the Commonwealth reaches six percent, in the aggregate.”⁴⁰ The General Assembly also directs the Commission in Dominion’s upcoming 2025 net metering proceeding to evaluate the six percent cap and allows them to, “if appropriate, raise or remove such cap.” This analysis attempted to evaluate the benefits of raising that cap to benefit customers and help meet the 2045 VCEA requirements.

⁴⁰ Va. Code § 56-594(E).

Appendix B: Detailed Scenario Results

For each scenario evaluated, this Appendix presents figures for the following:

- Annual total installed capacity by year and technology.
- Capacity changes by year and technology.
- Annual energy generated by year and technology.
- Capacity reserve requirement by year and scenario.

VCEA WITHOUT EPA

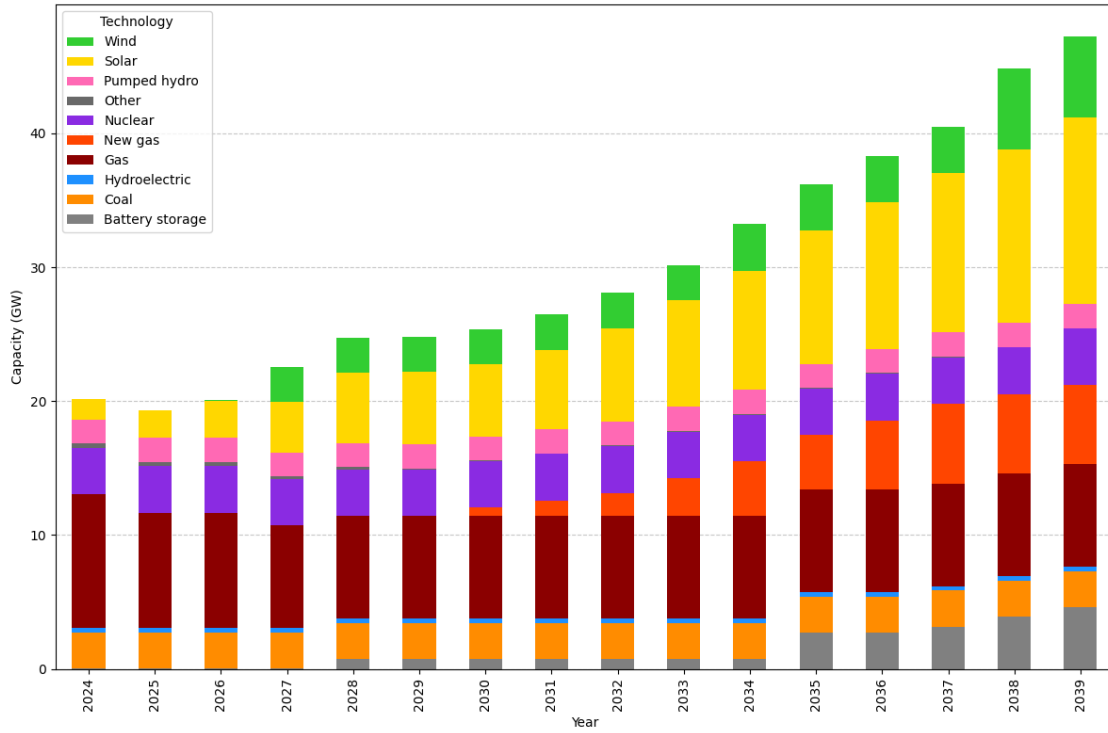


Figure 26 Total capacity by year and technology in the VCEA WITHOUT EPA scenario.

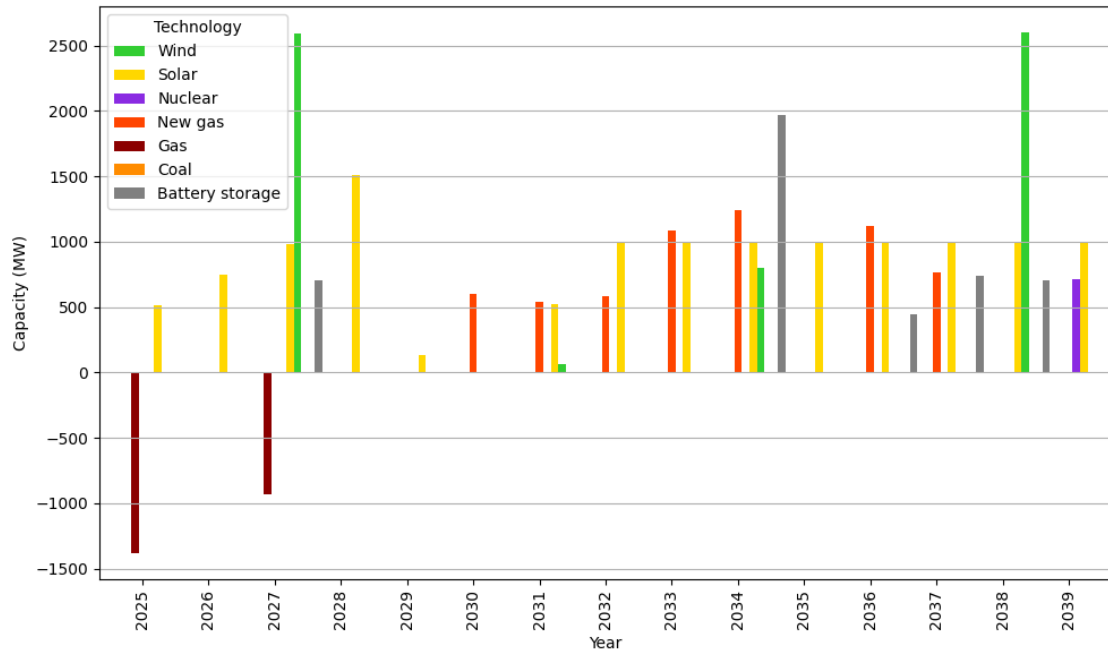


Figure 27 Capacity changes by year and technology in the VCEA WITHOUT EPA scenario.

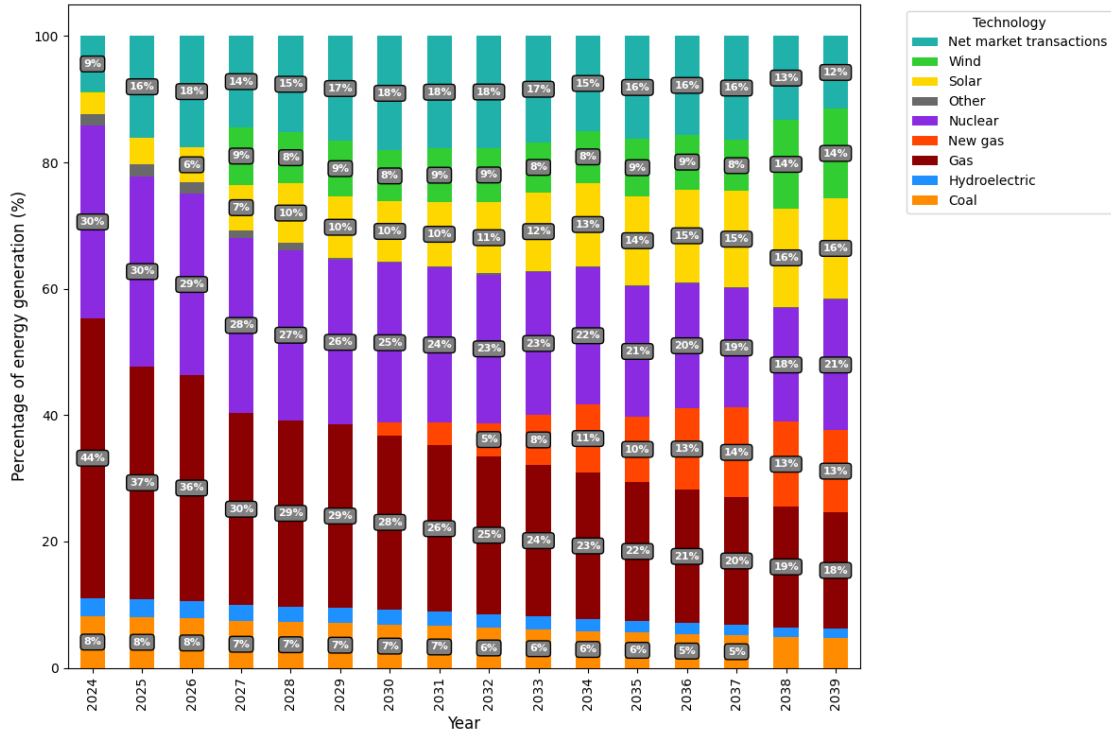


Figure 28 Energy generation by year and technology in the VCEA WITHOUT EPA scenario.

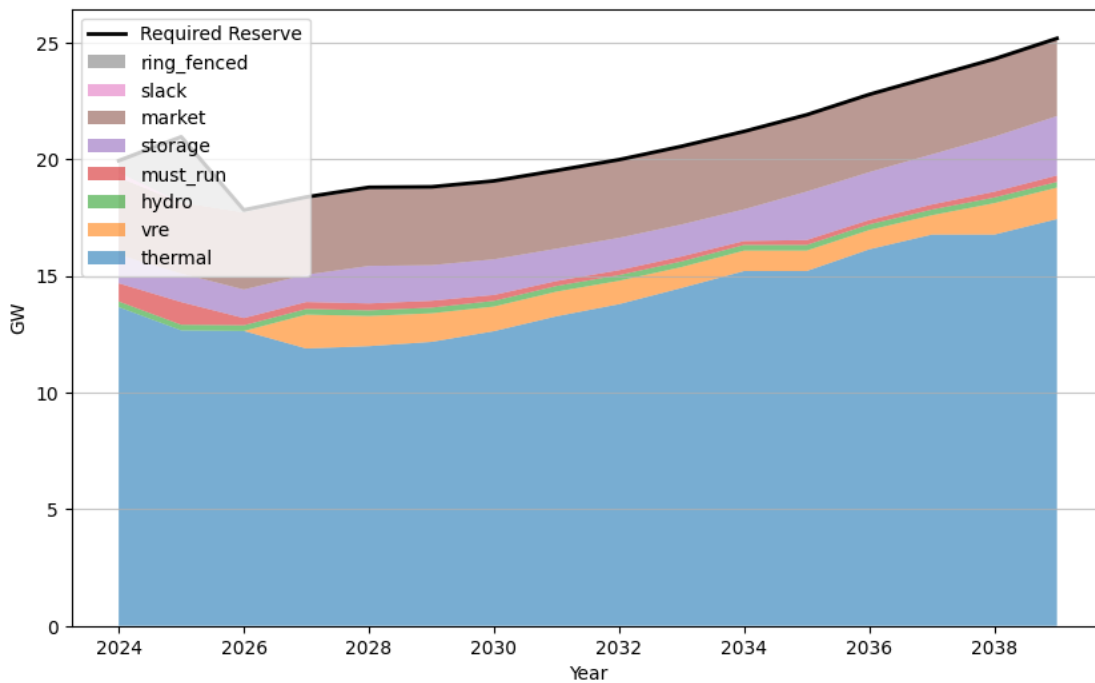


Figure 29 Capacity reserve margin and how it is met in the VCEA WITHOUT EPA scenario.

VCEA EPA RGGI

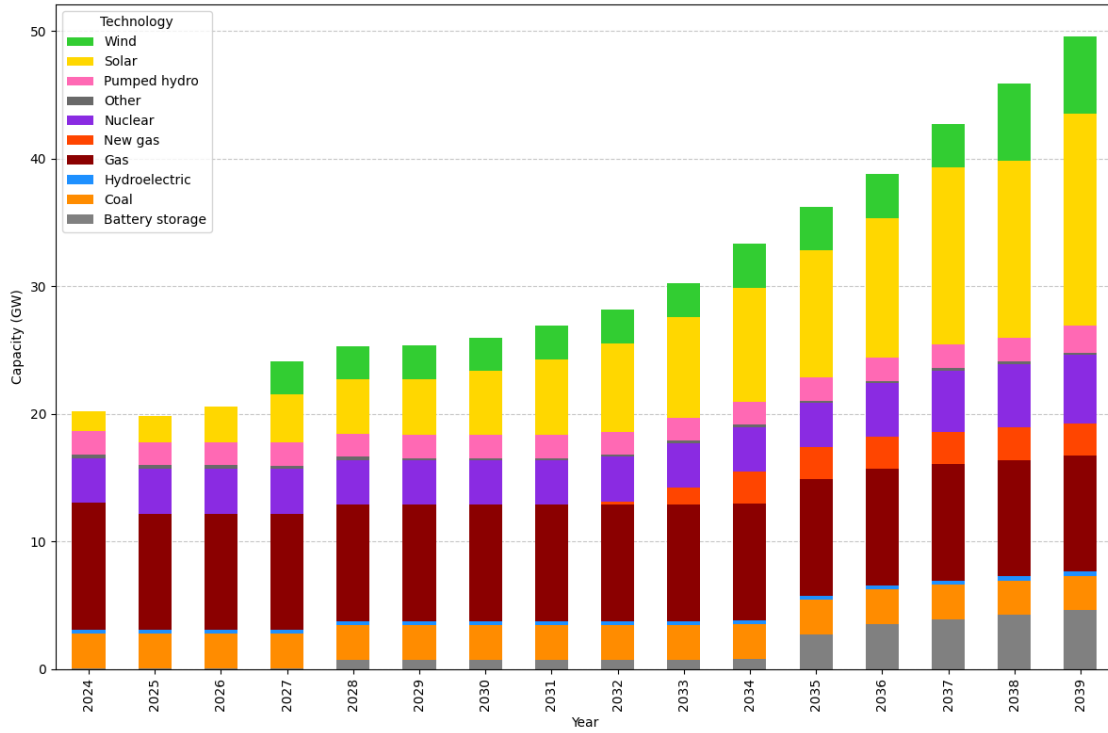


Figure 30 Total capacity by year and technology in the VCEA WITH EPA RGGI scenario.

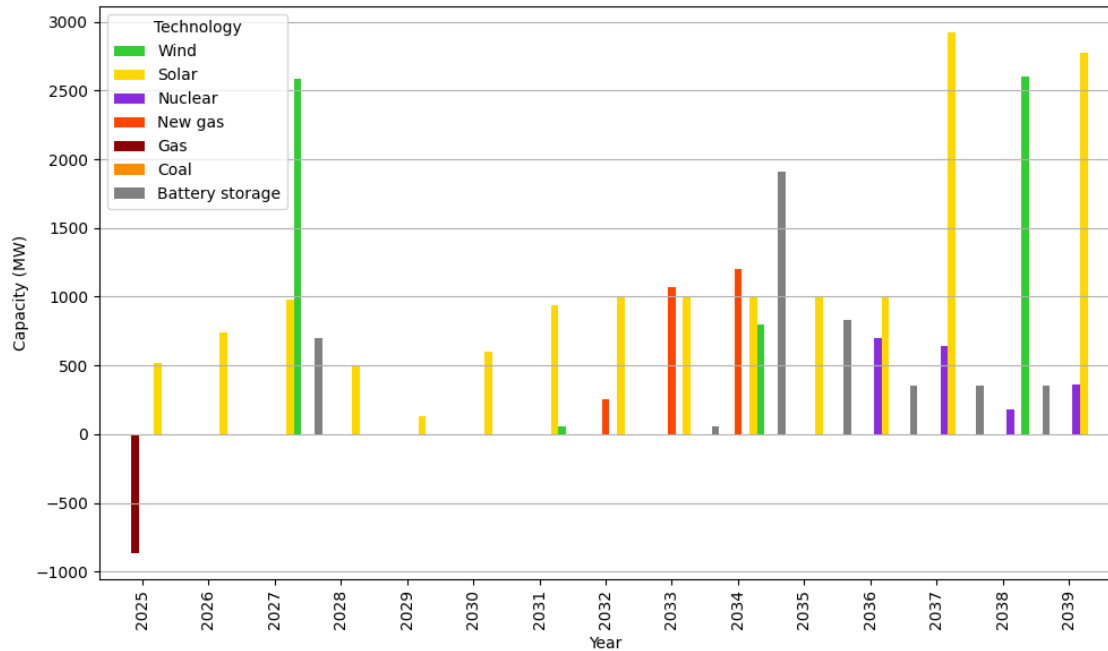


Figure 31 Capacity changes by year and technology in the VCEA WITH EPA RGGI scenario.

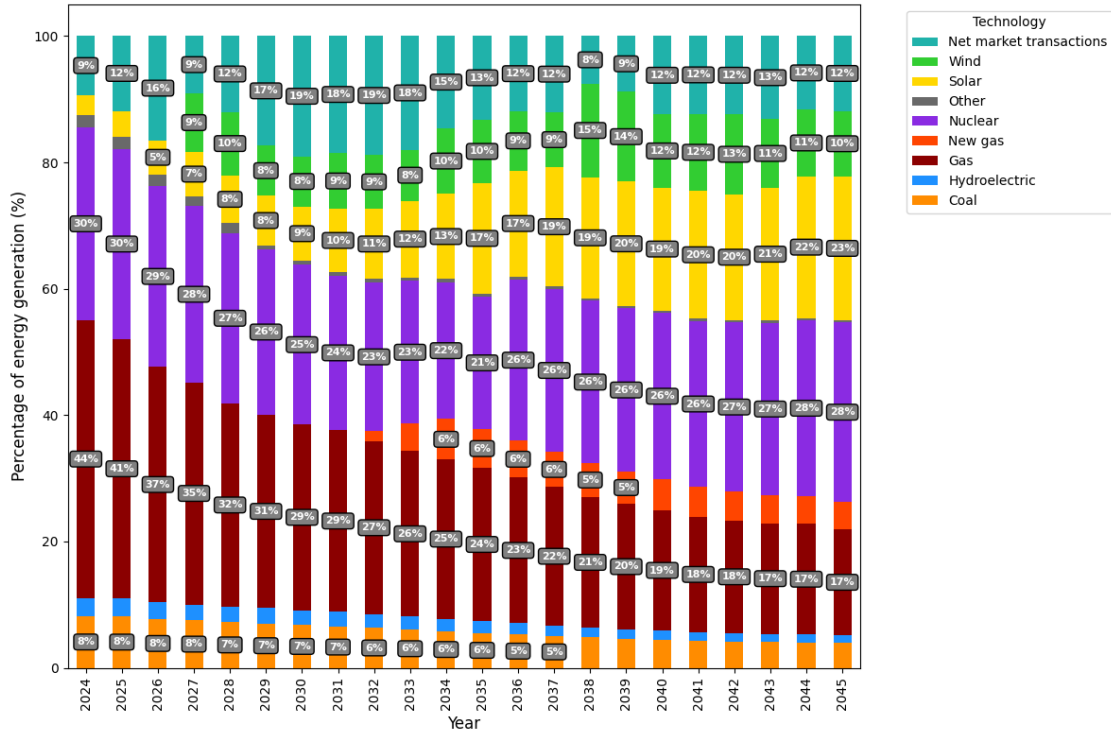


Figure 32 Energy generation by year and technology in the VCEA WITH EPA RGGI scenario.

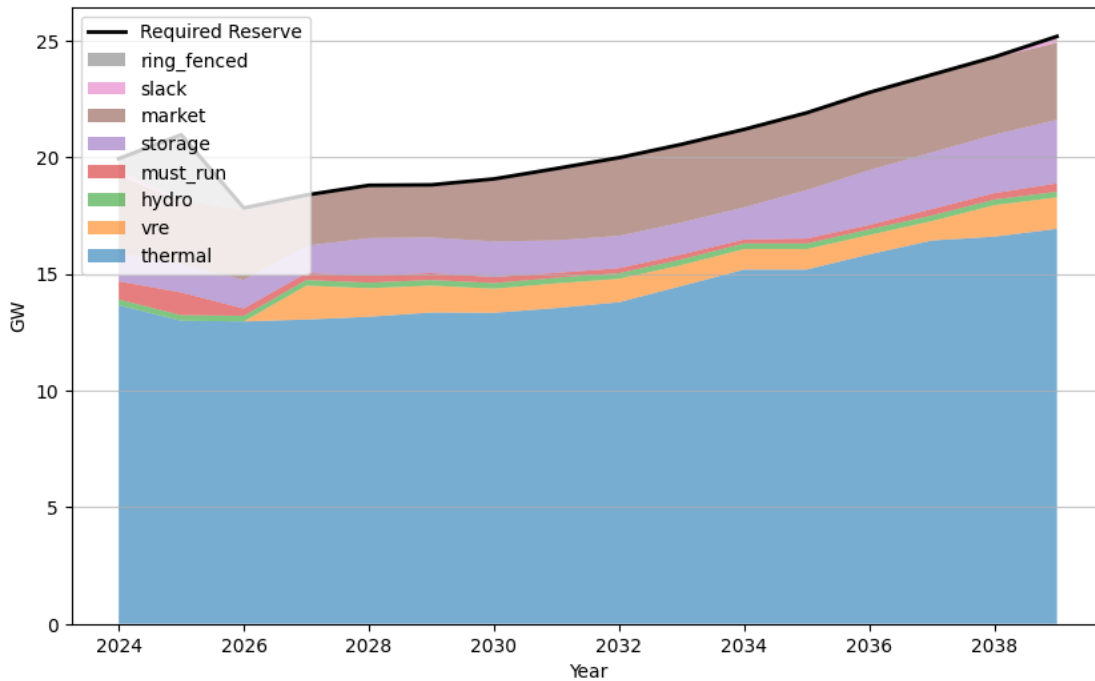


Figure 33 Capacity reserve margin and how it is met in the VCEA WITH EPA RGGI scenario.

VCEA 2039 EPA RGGI DOUBLE CLEAN

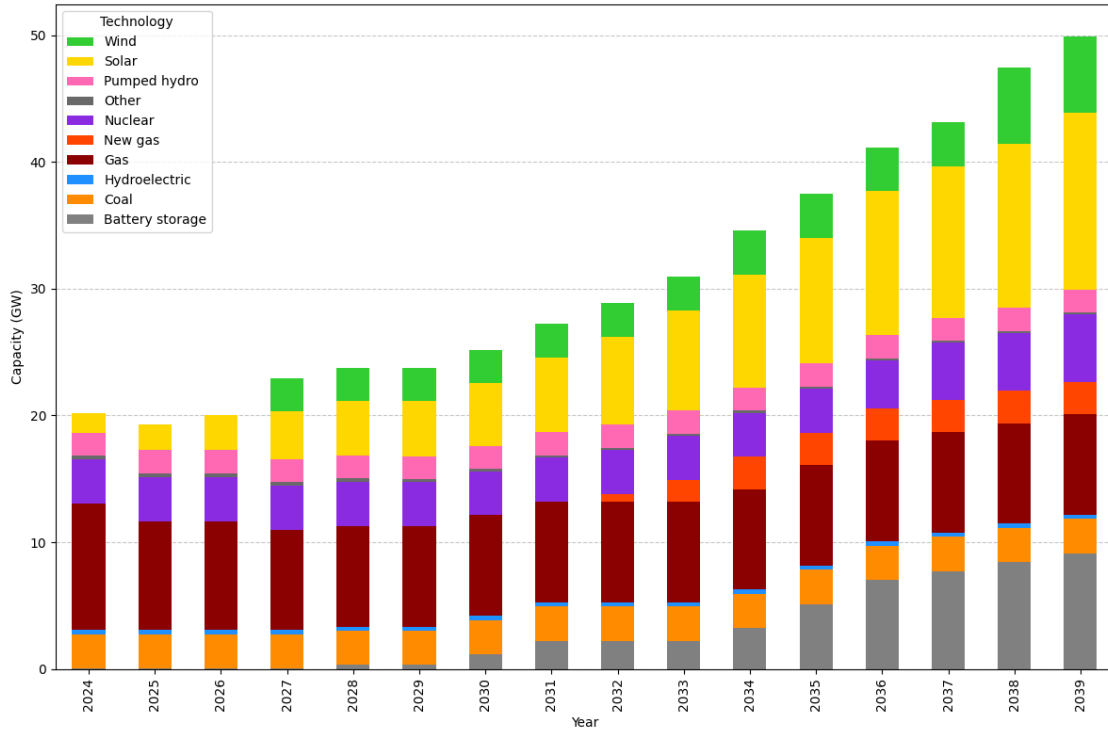


Figure 34 Total capacity by year and technology in the VCEA WITH EPA RGGI DOUBLE CLEAN scenario.

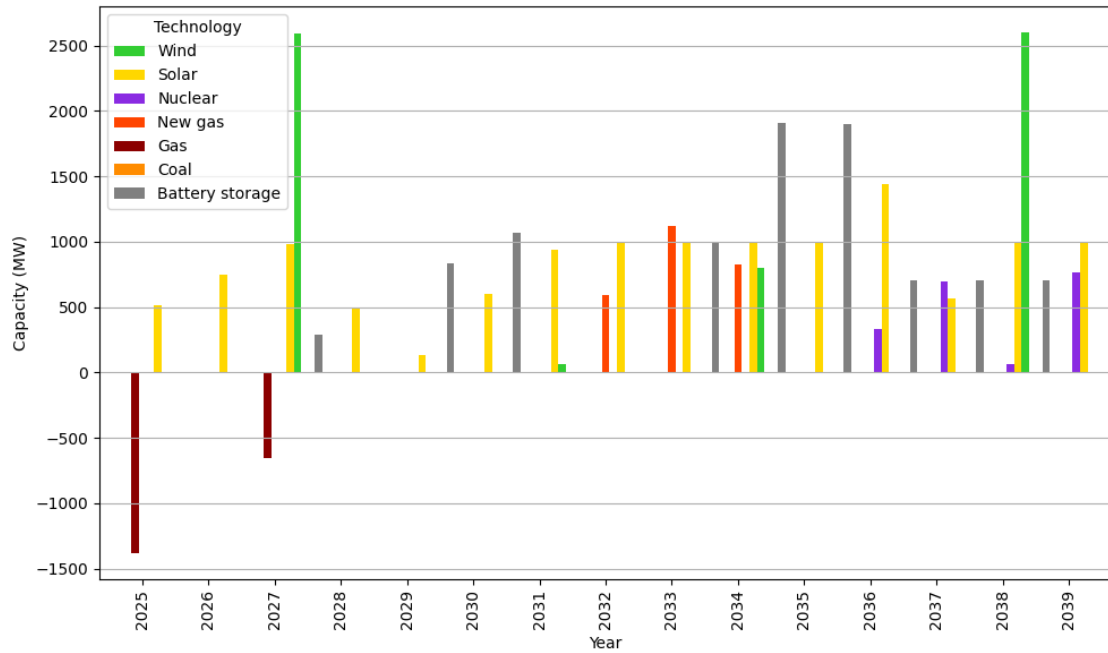


Figure 35 Capacity changes by year and technology in the VCEA WITH EPA RGGI DOUBLE CLEAN scenario.

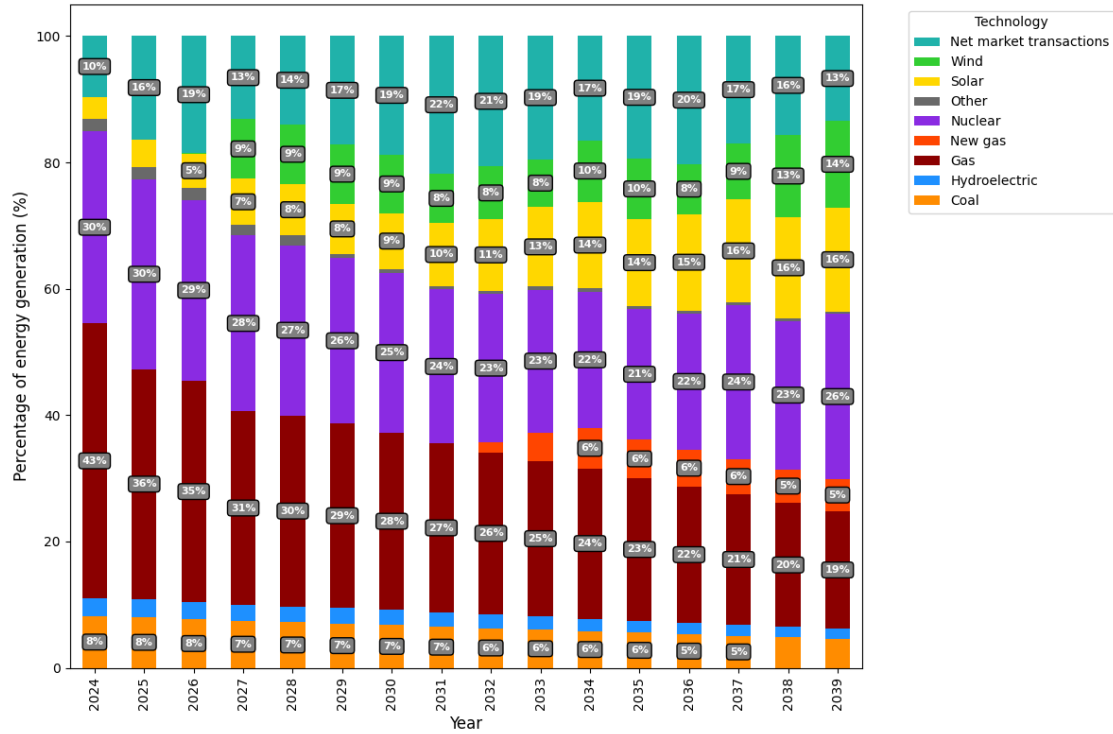


Figure 36 Energy generation by year and technology in the VCEA WITH EPA RGGI DOUBLE CLEAN scenario.

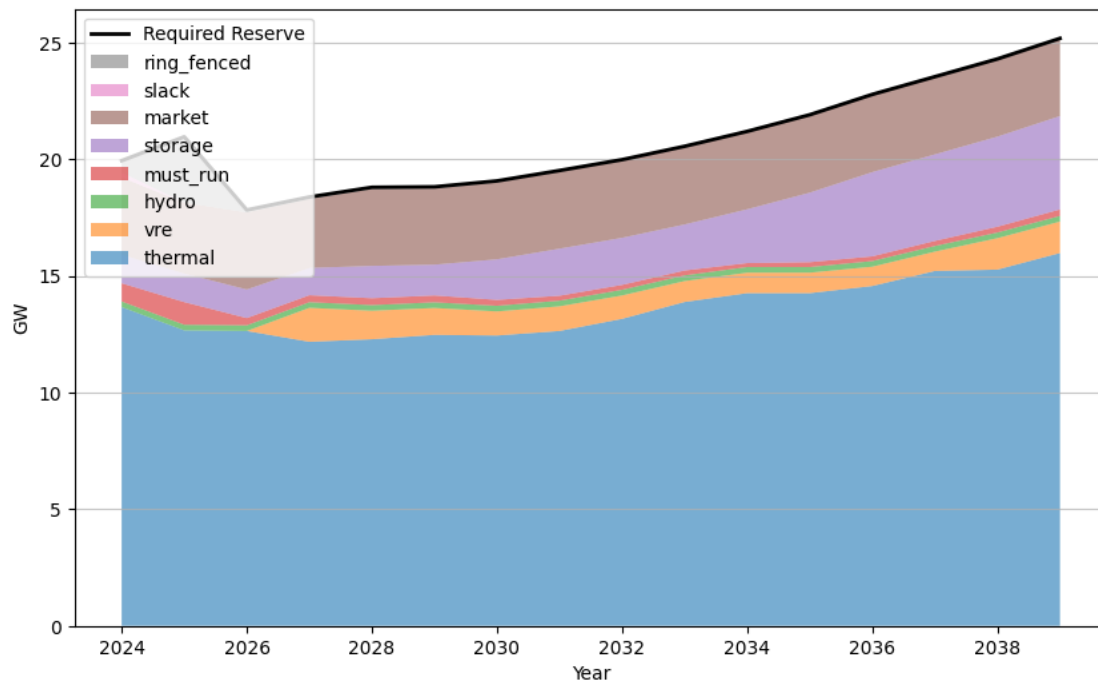


Figure 37 Capacity reserve margin and how it is met in the VCEA WITH EPA RGGI DOUBLE CLEAN scenario.

VCEA EPA RGGI NEM6

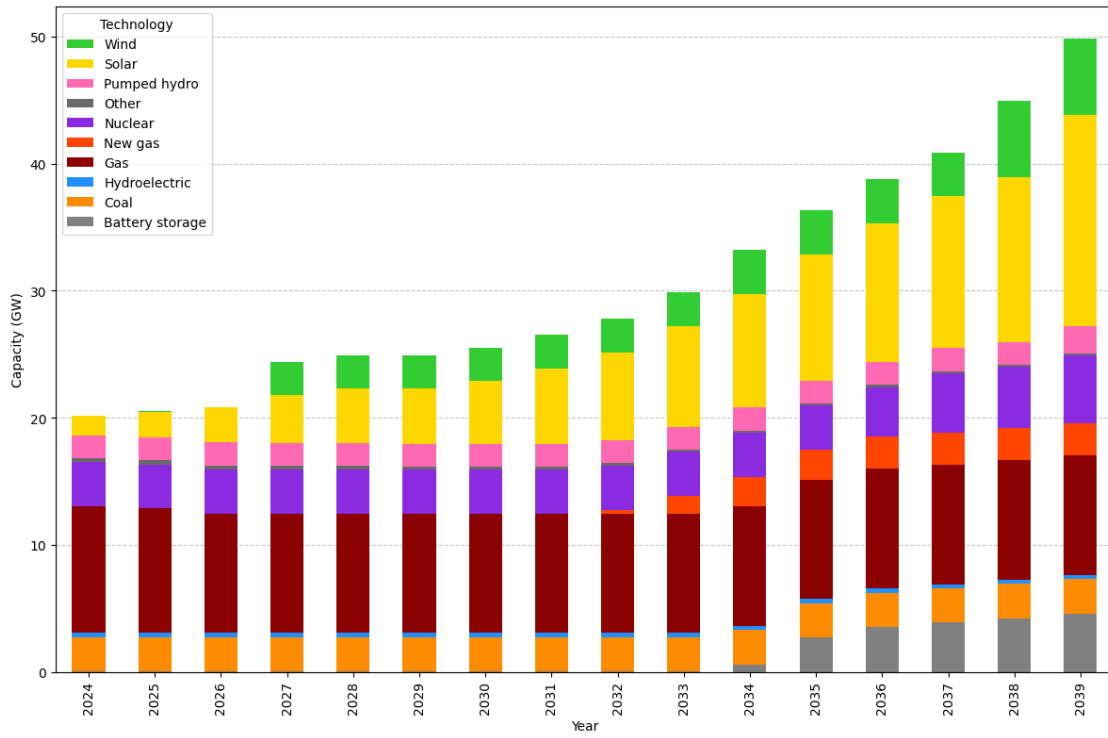


Figure 38 Total capacity by year and technology in the VCEA WITH EPA RGGI NEM6 scenario.

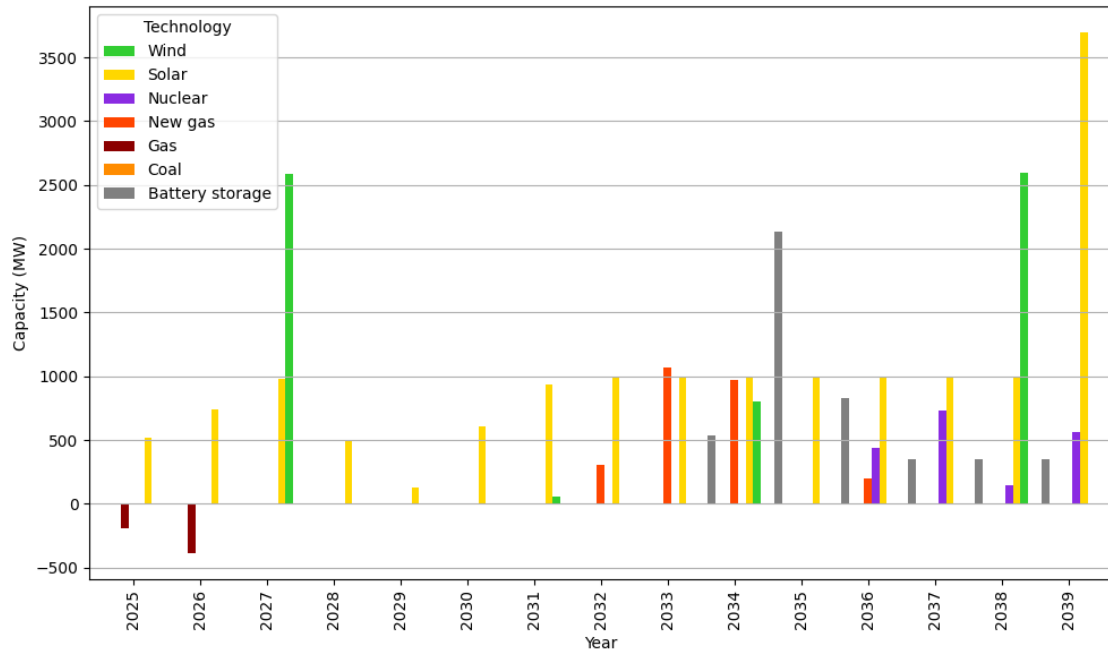


Figure 39 Capacity changes by year and technology in the VCEA WITH EPA RGGI NEM6 scenario.

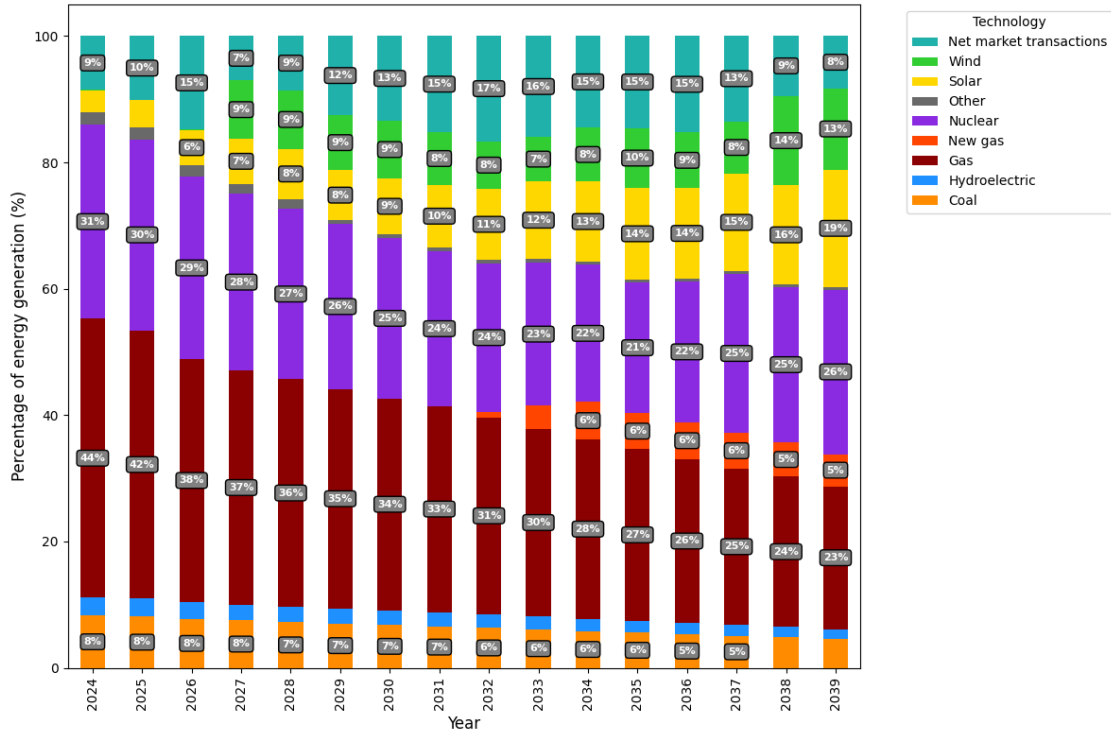


Figure 40 Energy generation by year and technology in the VCEA WITH EPA RGGI NEM6 scenario.

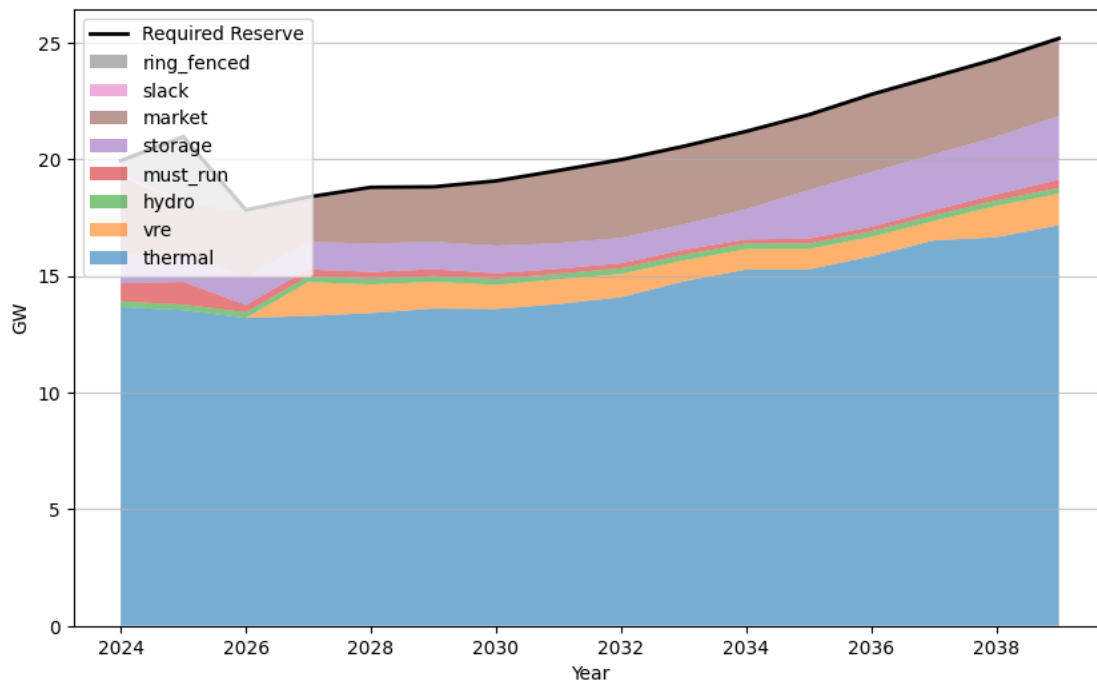


Figure 41 Capacity reserve margin and how it is met in the VCEA WITH EPA RGGI NEM6 scenario.

VCEA EPA RGGI NEM8

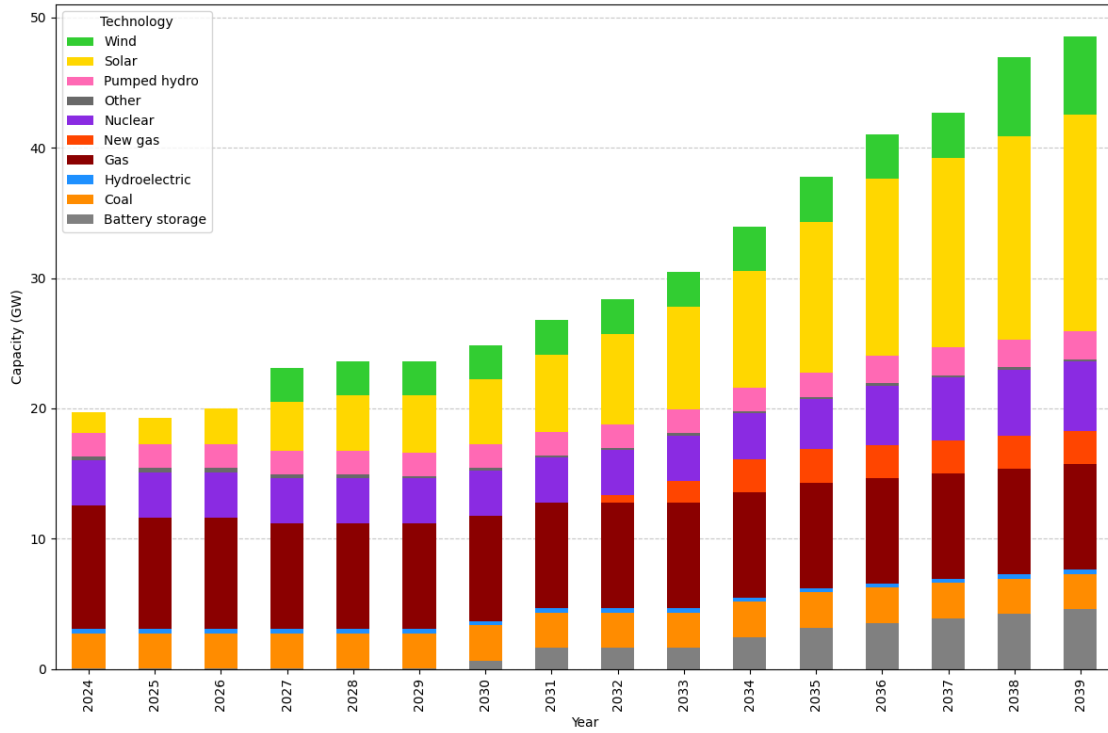


Figure 42 Total capacity by year and technology in the VCEA WITH EPA RGGI NEM8 scenario.

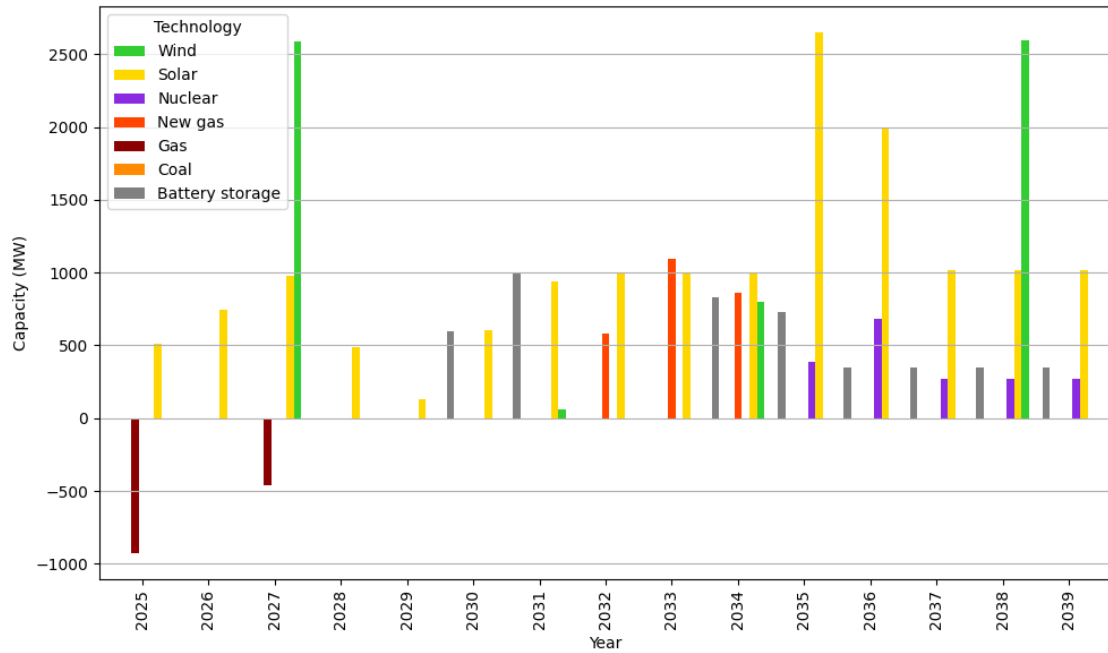


Figure 43 Capacity changes by year and technology in the VCEA WITH EPA RGGI NEM8 scenario.

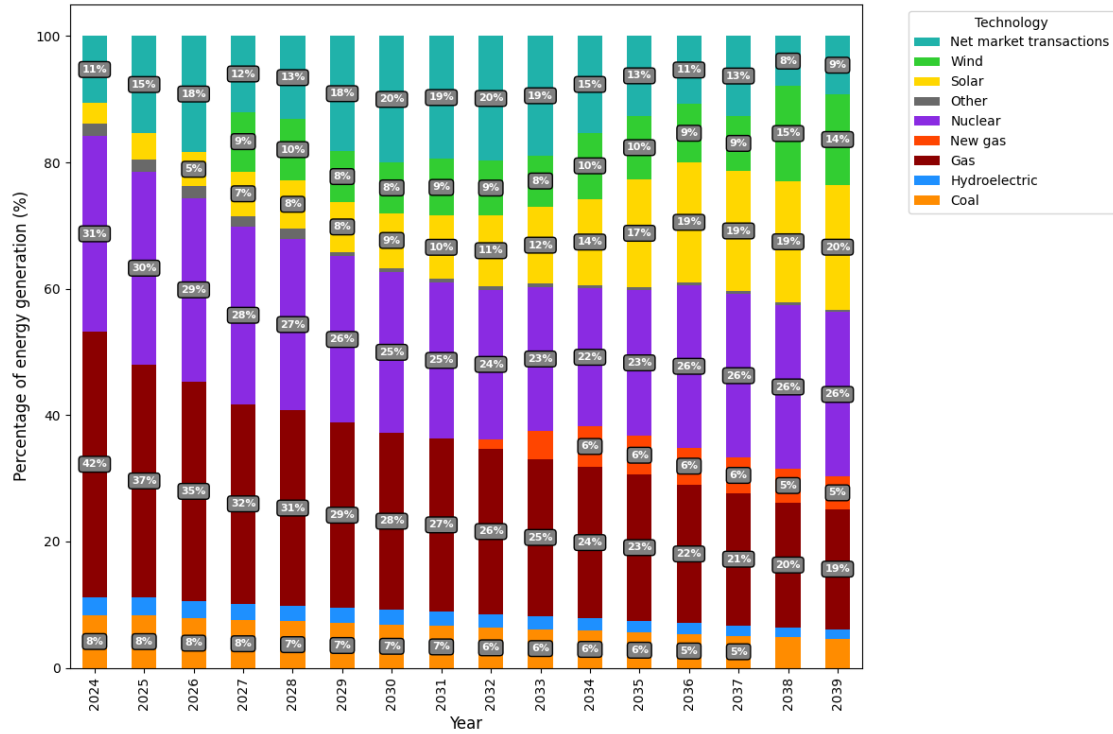


Figure 44 Energy generation by year and technology in the VCEA WITH EPA RGGI NEM8 scenario.

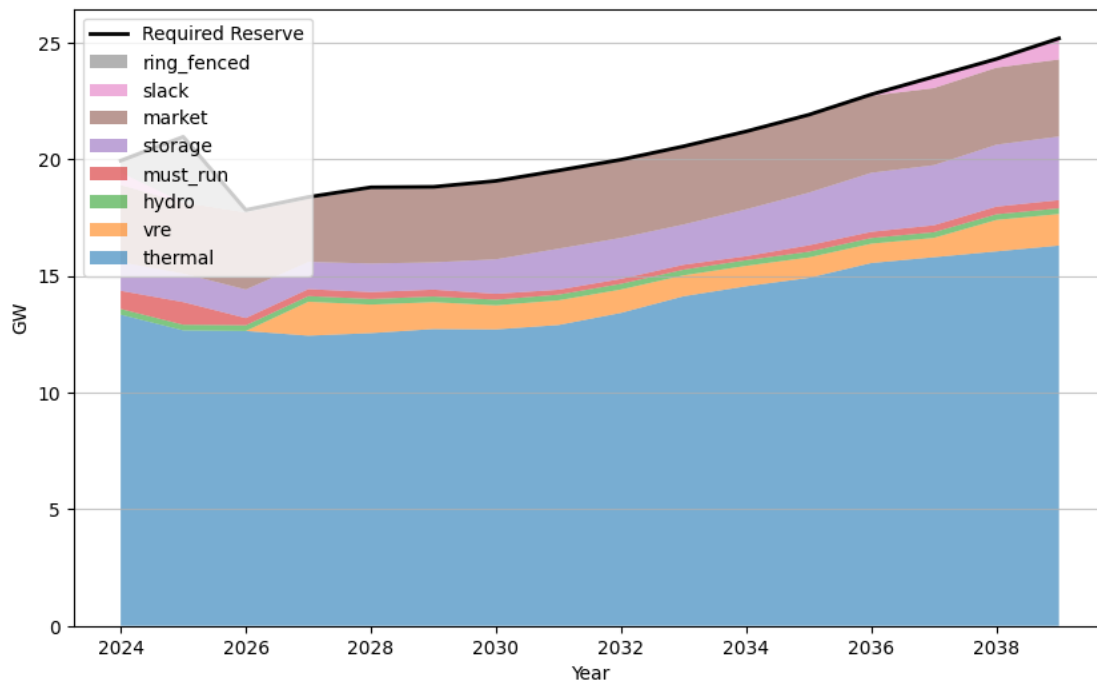


Figure 45 Capacity reserve margin and how it is met in the VCEA WITH EPA RGGI NEM8 scenario.

VCEA 2045 EPA RGGI

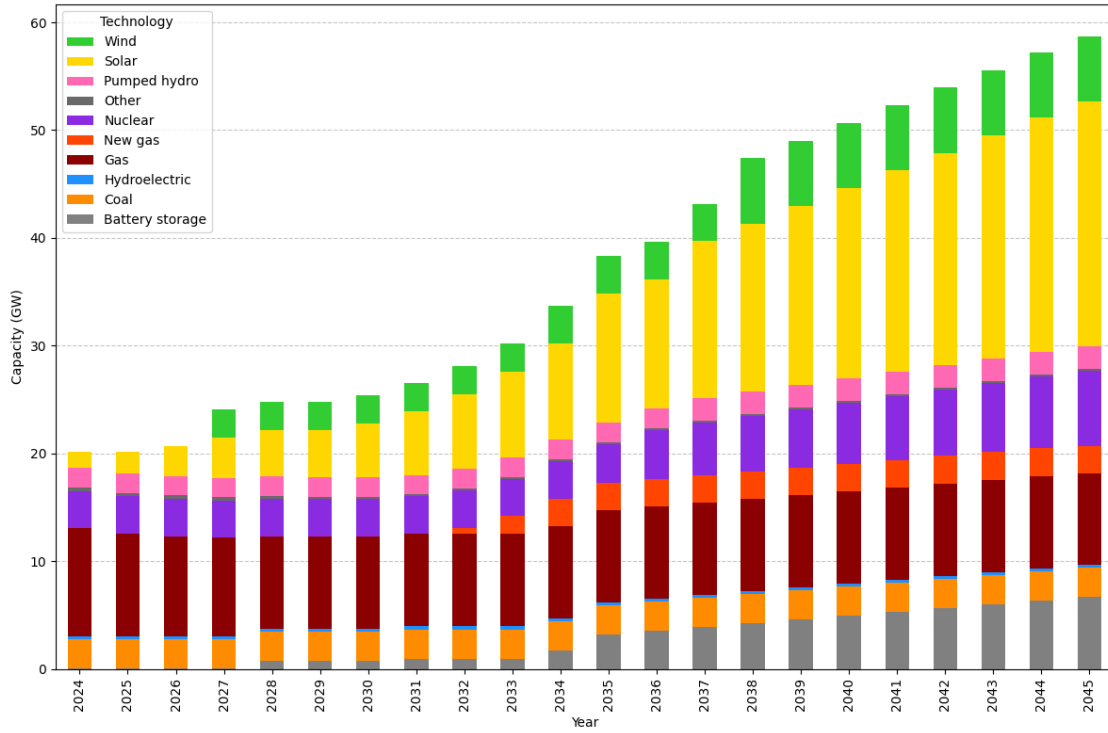


Figure 46 Total capacity by year and technology in the VCEA 2045 EPA RGGI scenario.

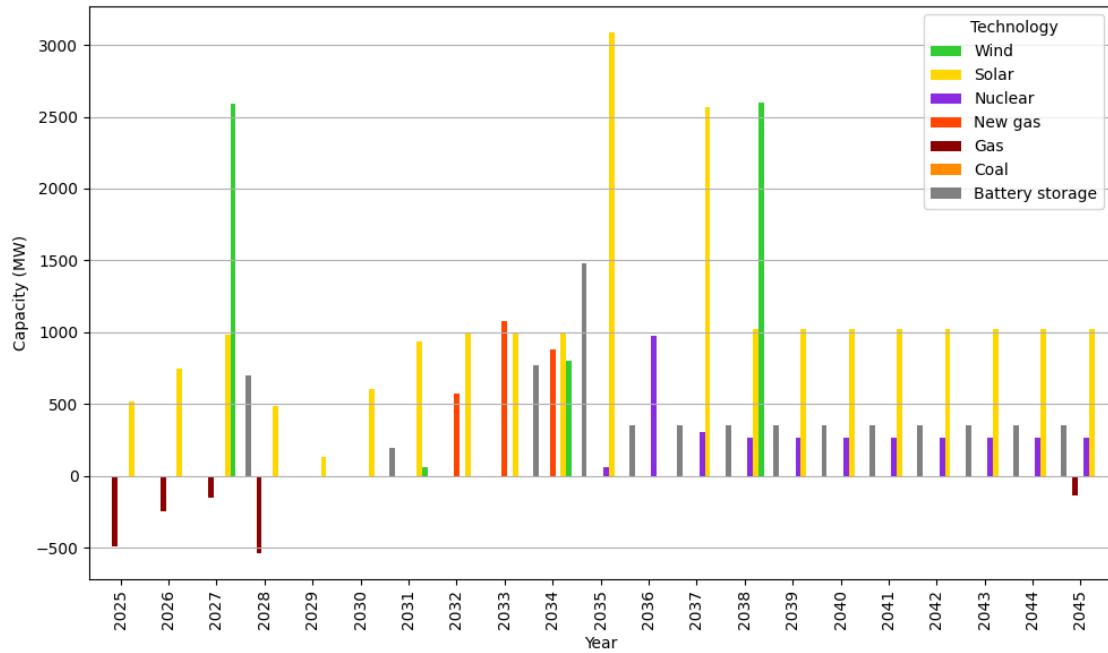


Figure 47 Capacity changes by year and technology in the VCEA 2045 EPA RGGI scenario.

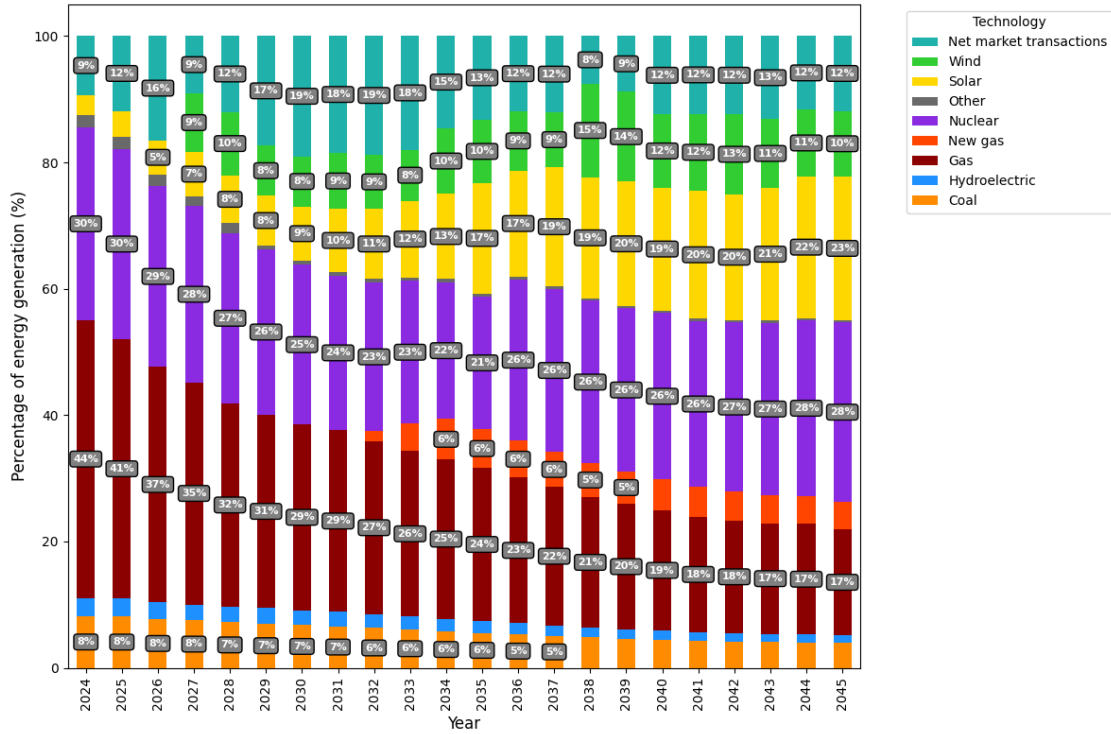


Figure 48 Energy generation by year and technology in the VCEA 2045 EPA RGGI scenario.

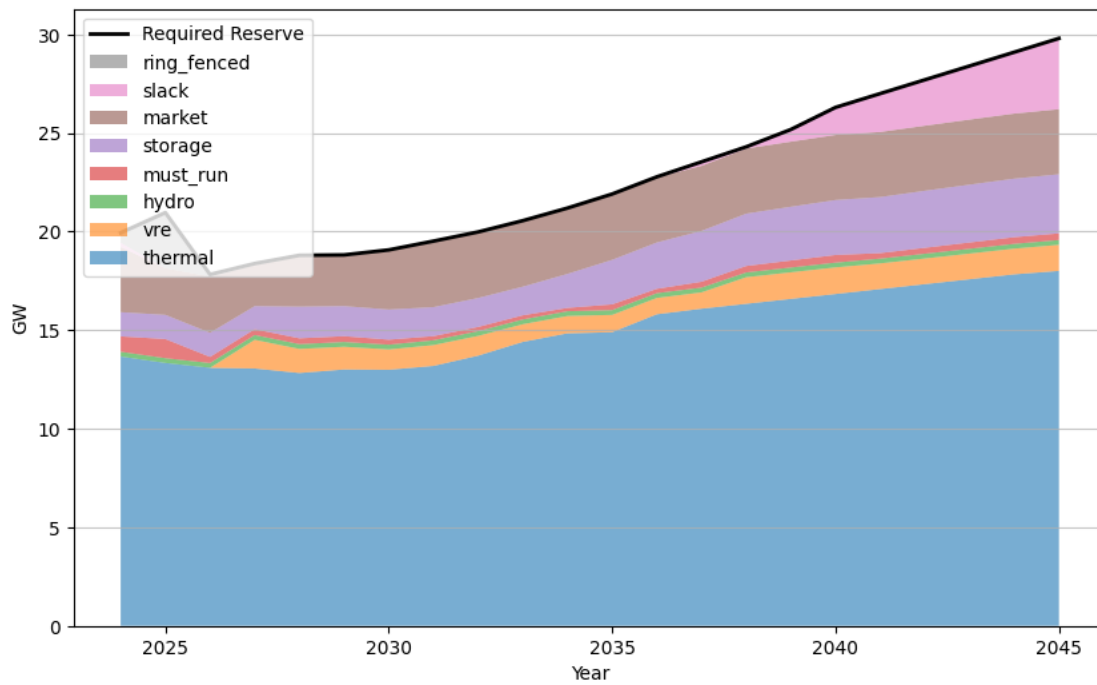


Figure 49 Capacity reserve margin and how it is met in the VCEA 2045 EPA RGGI scenario.

VCEA 2045 EPA RGGI 2X CLEAN

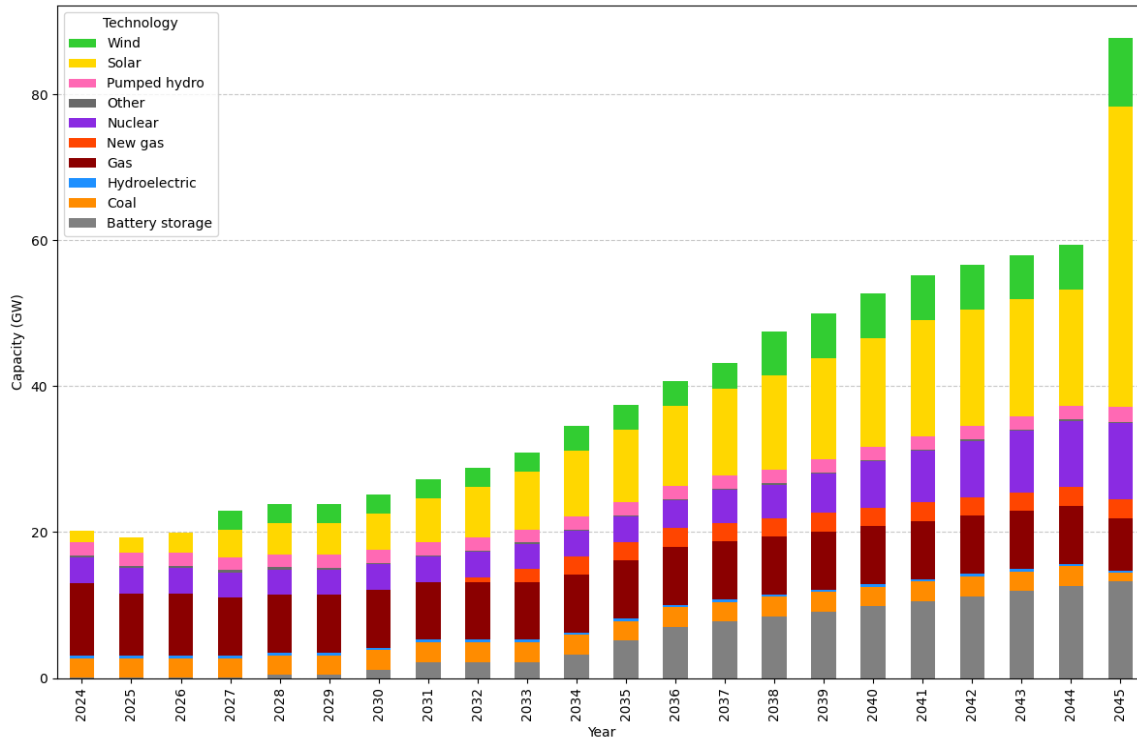


Figure 50 Total capacity by year and technology in the VCEA 2045 EPA RGGI 2X CLEAN scenario.

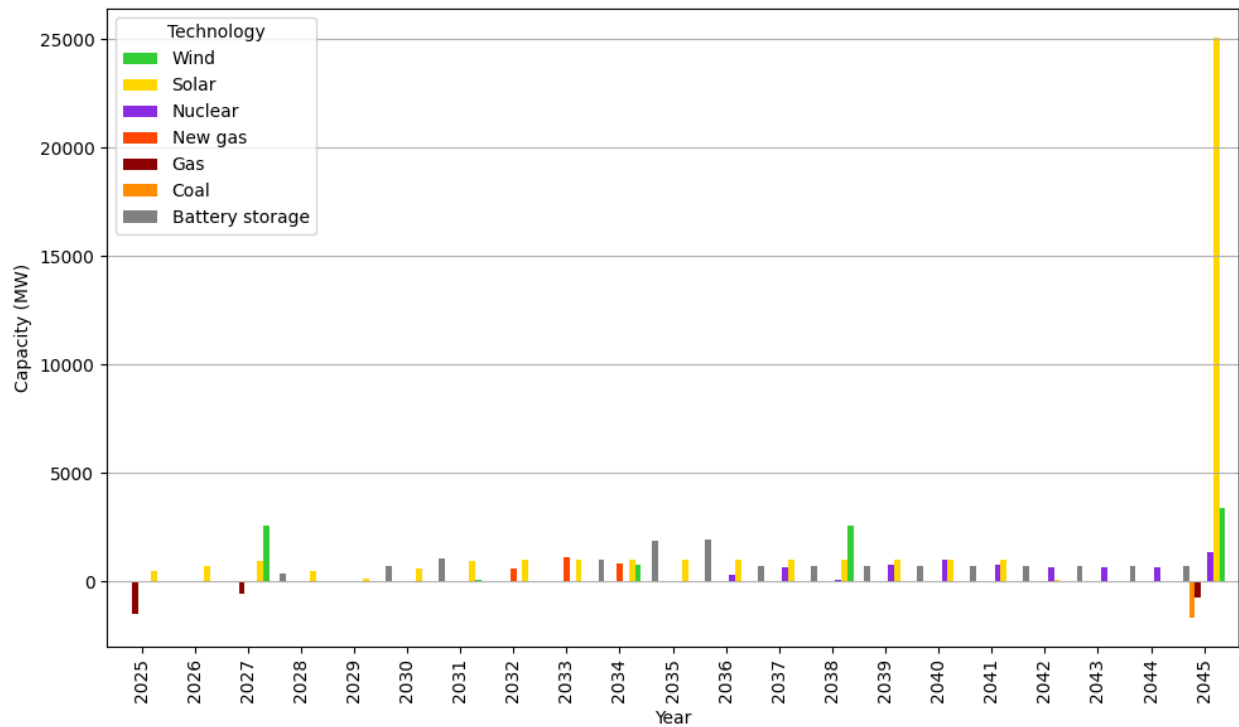


Figure 51 Capacity changes by year and technology in the VCEA 2045 EPA RGGI 2X CLEAN scenario.

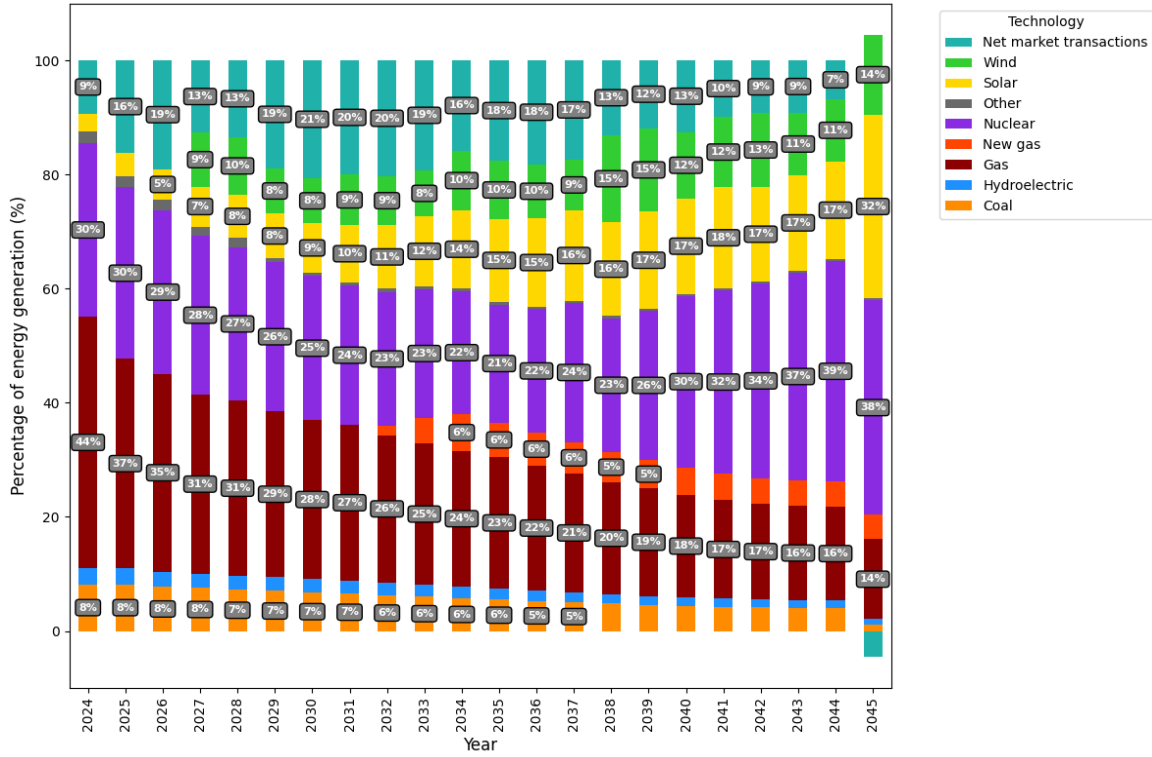


Figure 52 Energy generation by year and technology in the VCEA 2045 EPA RGGI 2X CLEAN scenario.

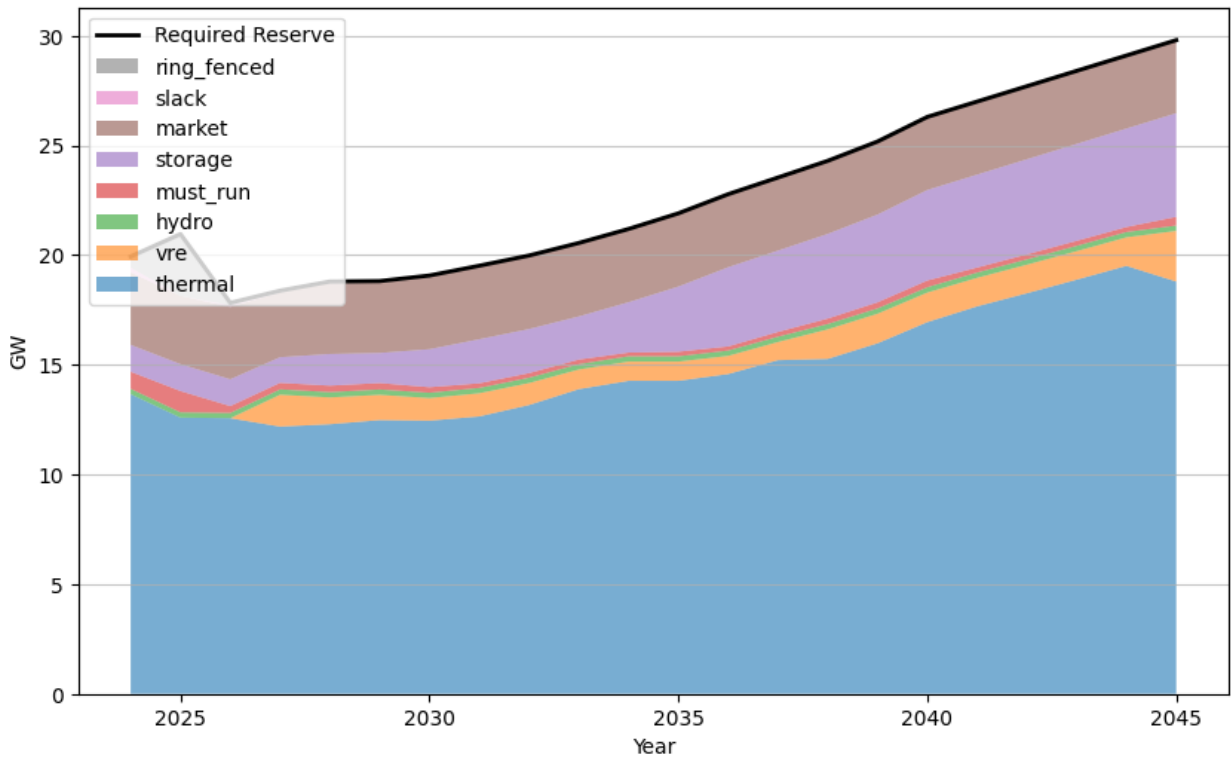


Figure 53 Capacity reserve margin and how it is met in the VCEA 2045 EPA RGGI 2X CLEAN scenario.

VCEA 2045 EPA RGGI 3X CLEAN

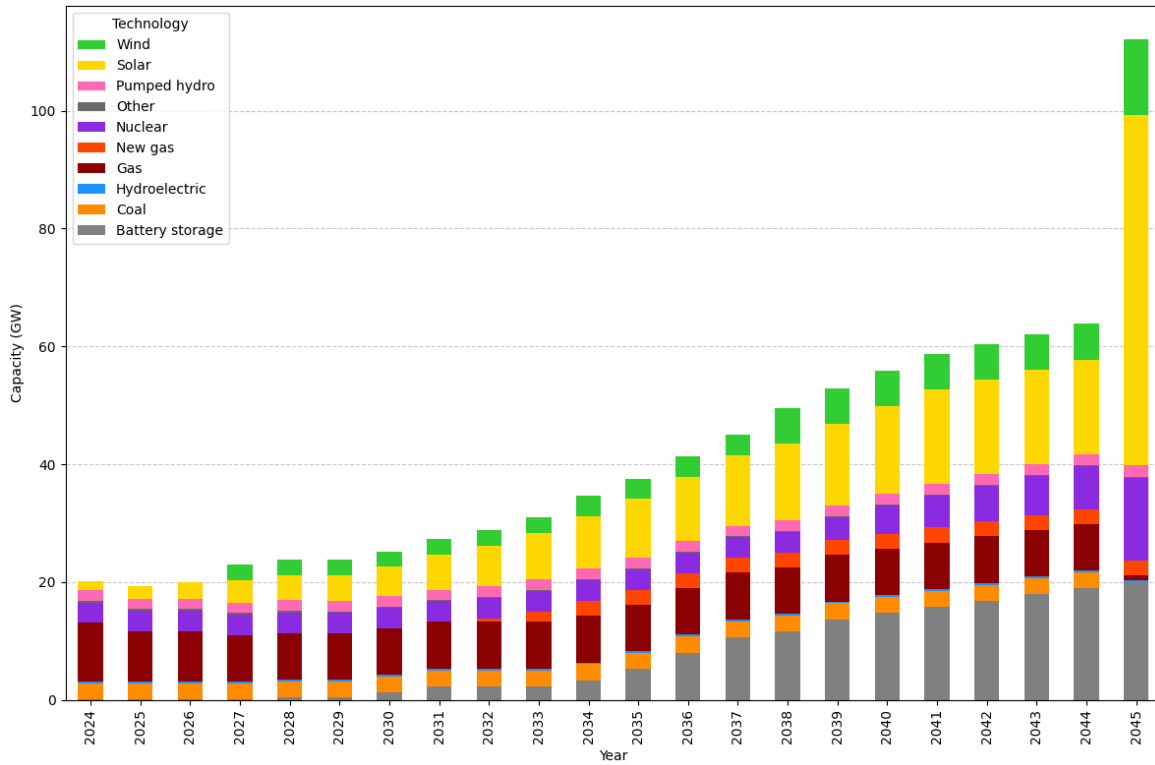


Figure 54 Total capacity by year and technology in the VCEA 2045 EPA RGGI 3X CLEAN scenario.

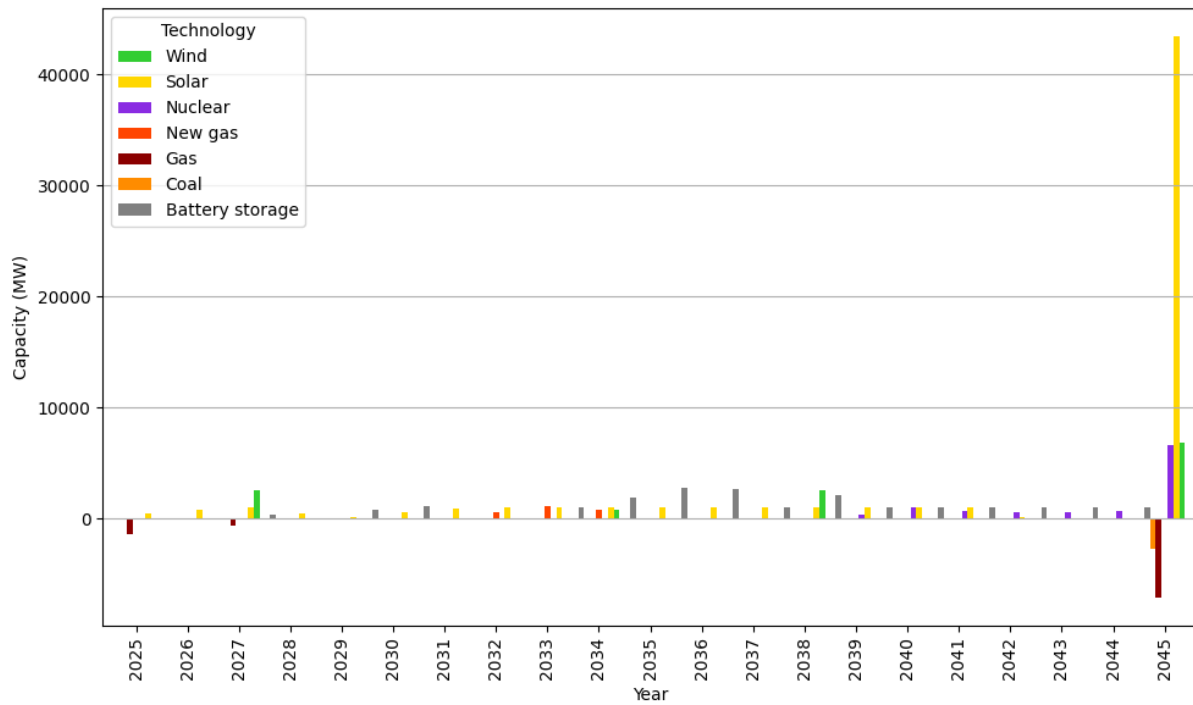


Figure 55 Capacity changes by year and technology in the VCEA 2045 EPA RGGI 3X CLEAN scenario.

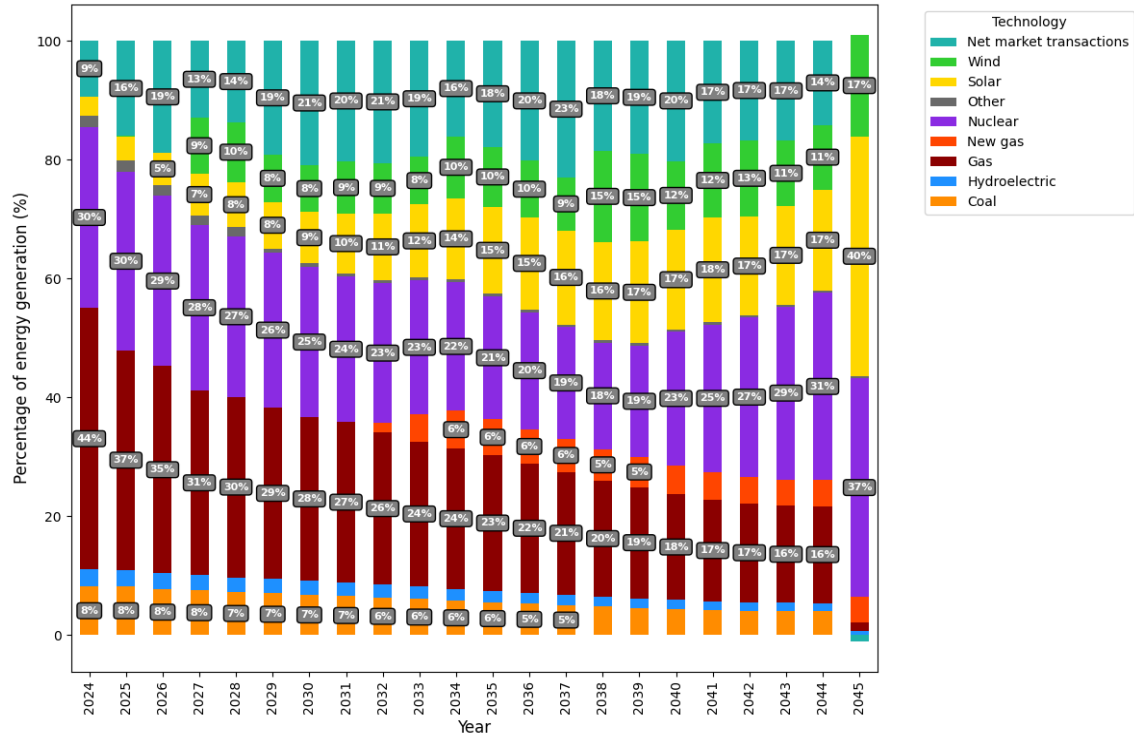


Figure 56 Energy generation by year and technology in the VCEA 2045 EPA RGGI 3X CLEAN scenario.

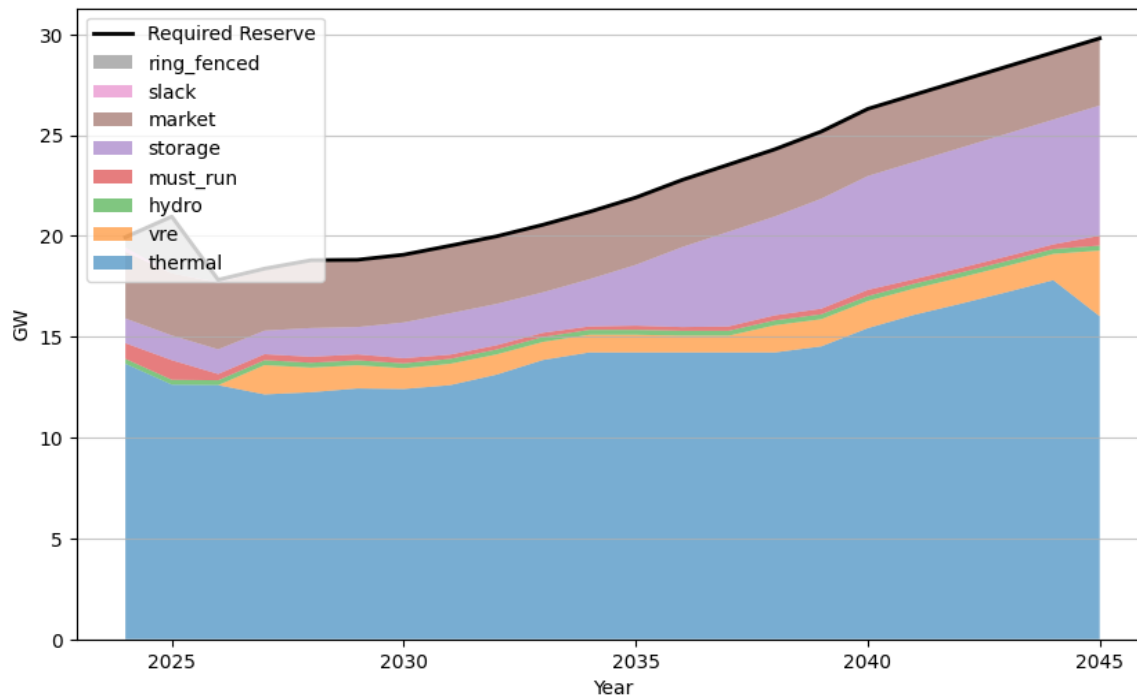


Figure 57 Capacity reserve margin and how it is met in the VCEA 2045 EPA RGGI 3X CLEAN scenario.

VCEA 2045 EPA RGGI 3X CLEAN 6X BESS

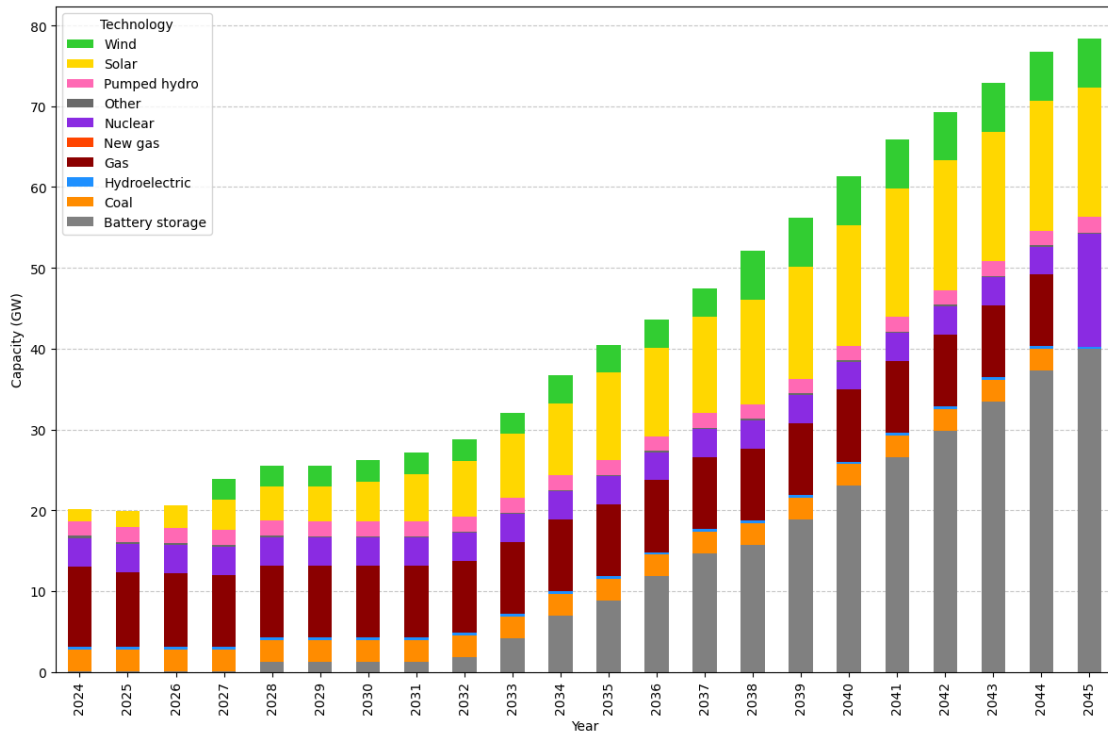


Figure 58 Total capacity by year and technology in the VCEA 2045 EPA RGGI 3X CLEAN 6X BESS scenario.

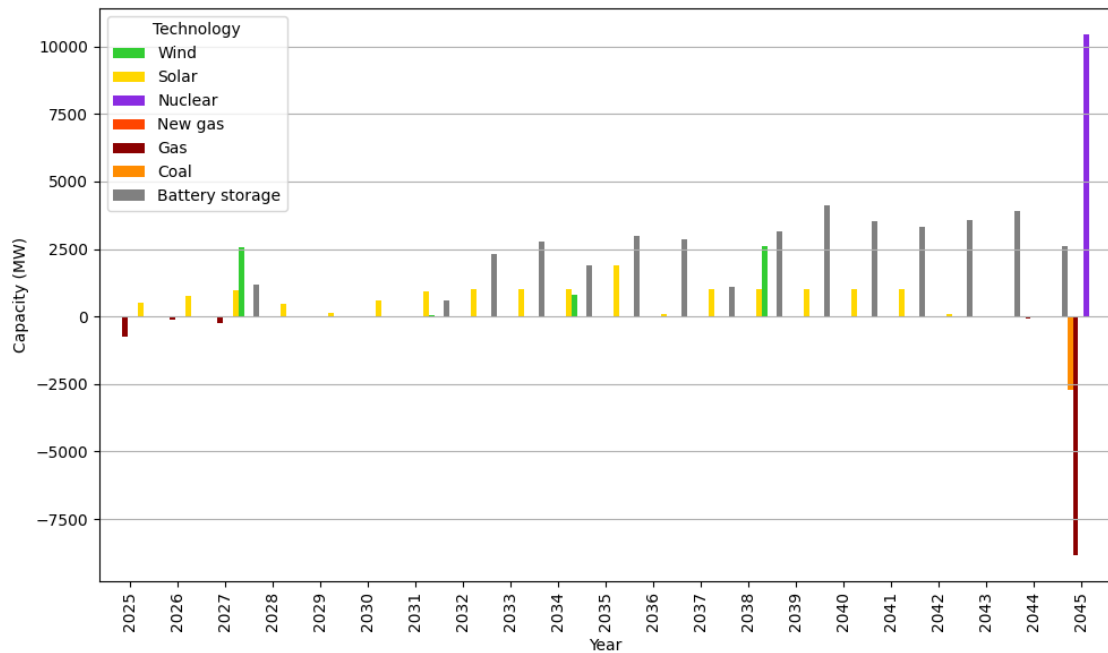


Figure 59 Capacity changes by year and technology in the VCEA 2045 EPA RGGI 3X CLEAN 6X BESS scenario.

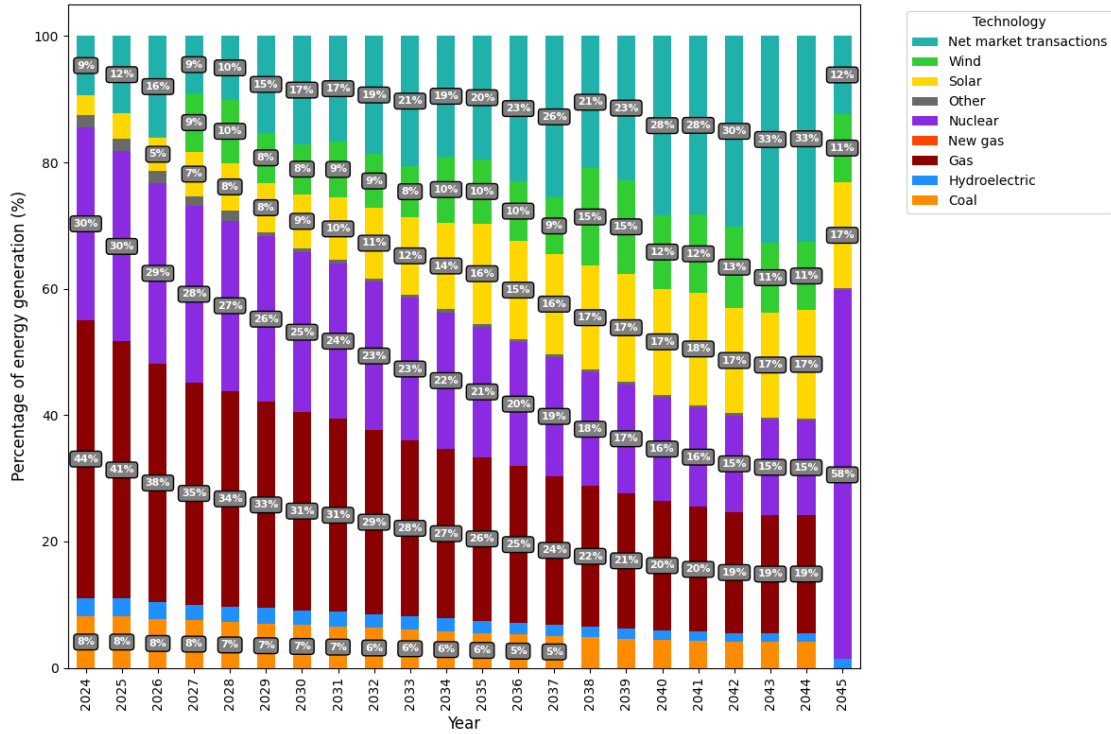


Figure 60 Energy generation by year and technology in the VCEA 2045 EPA RGGI 3X CLEAN 6X BESS scenario.

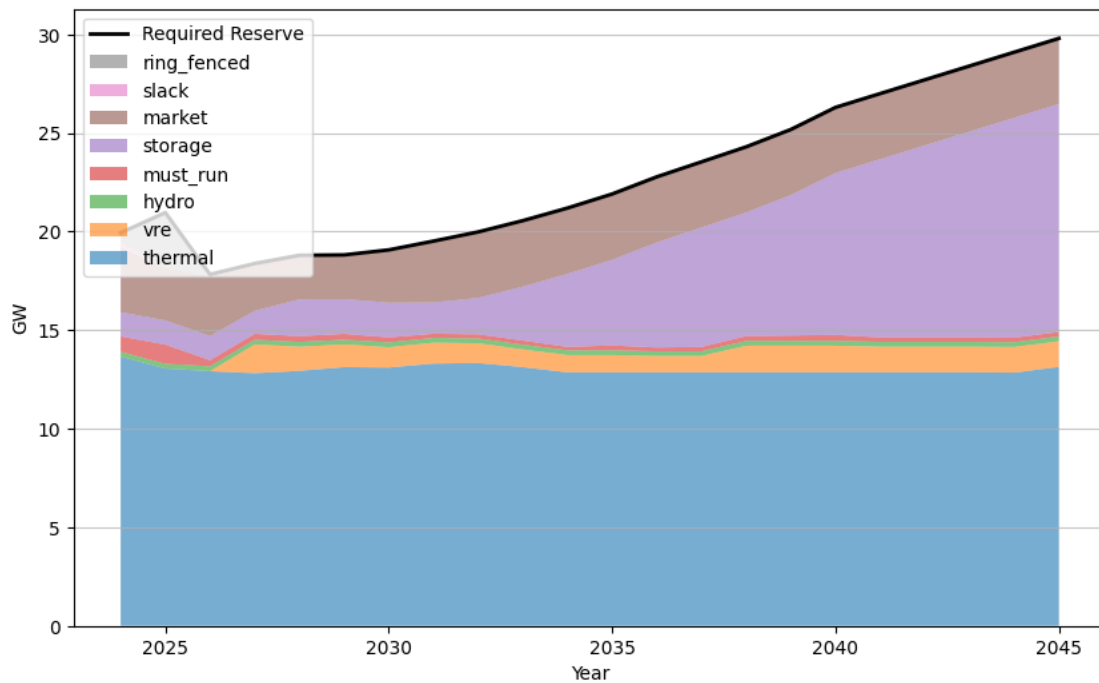


Figure 61 Capacity reserve margin and how it is met in the VCEA 2045 EPA RGGI 3X CLEAN 6X BESS scenario.

VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR

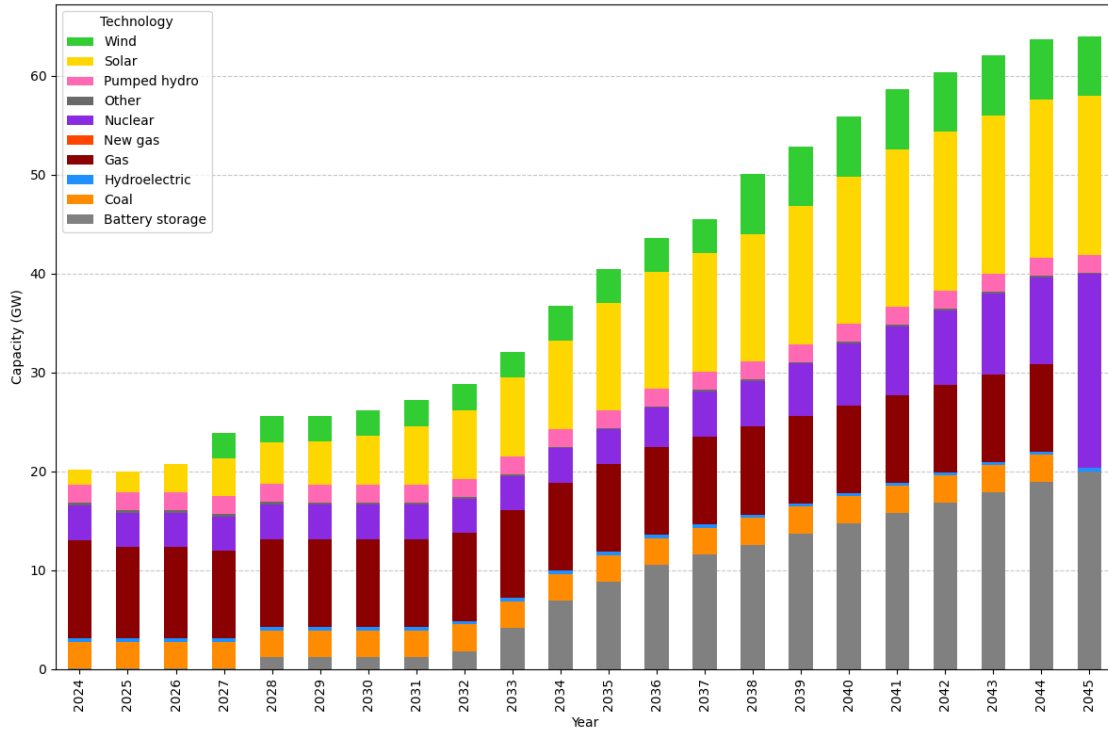


Figure 62 Total capacity by year and technology in the VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR scenario.

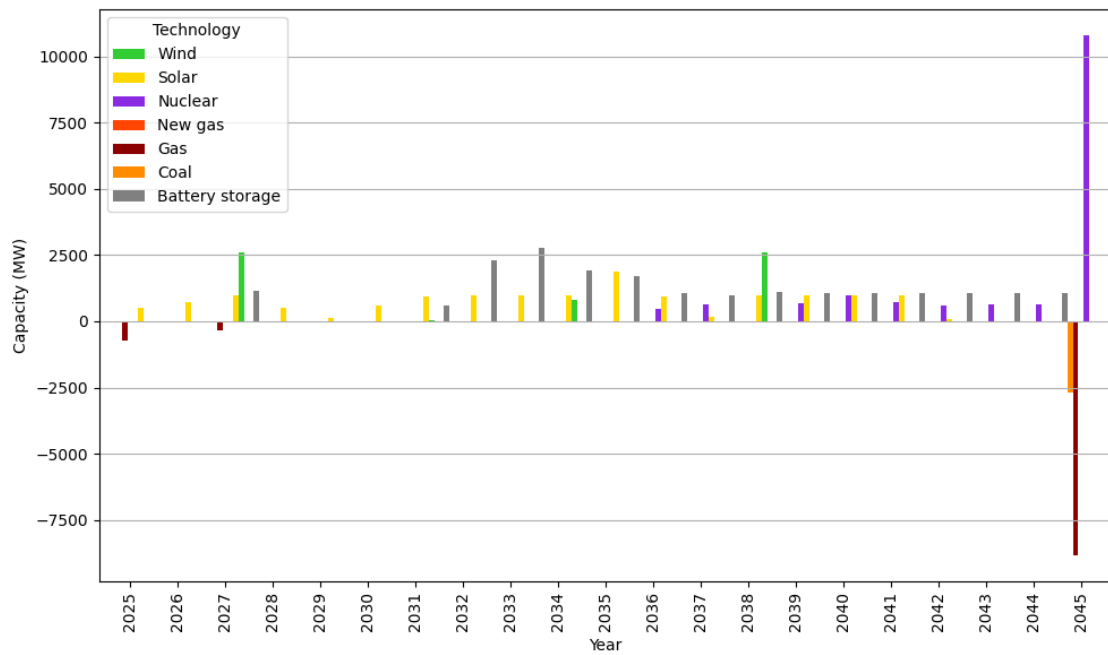


Figure 63 Capacity changes by year and technology in the VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR scenario.

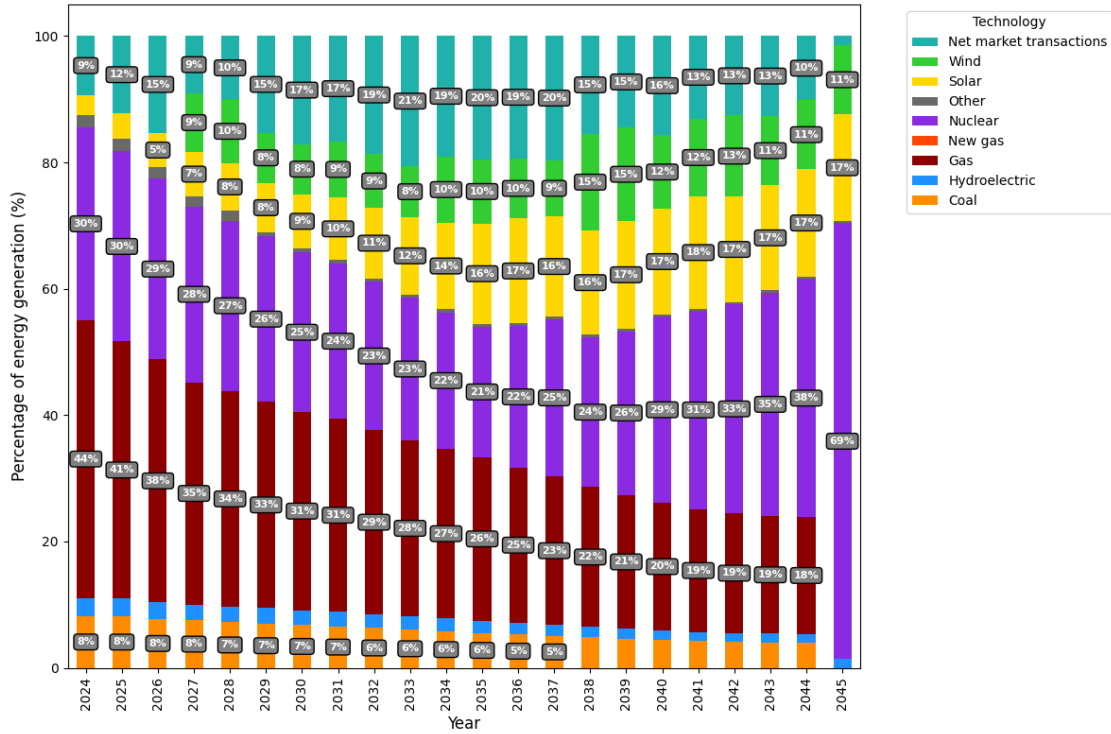


Figure 64 Energy generation by year and technology in the VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR scenario.

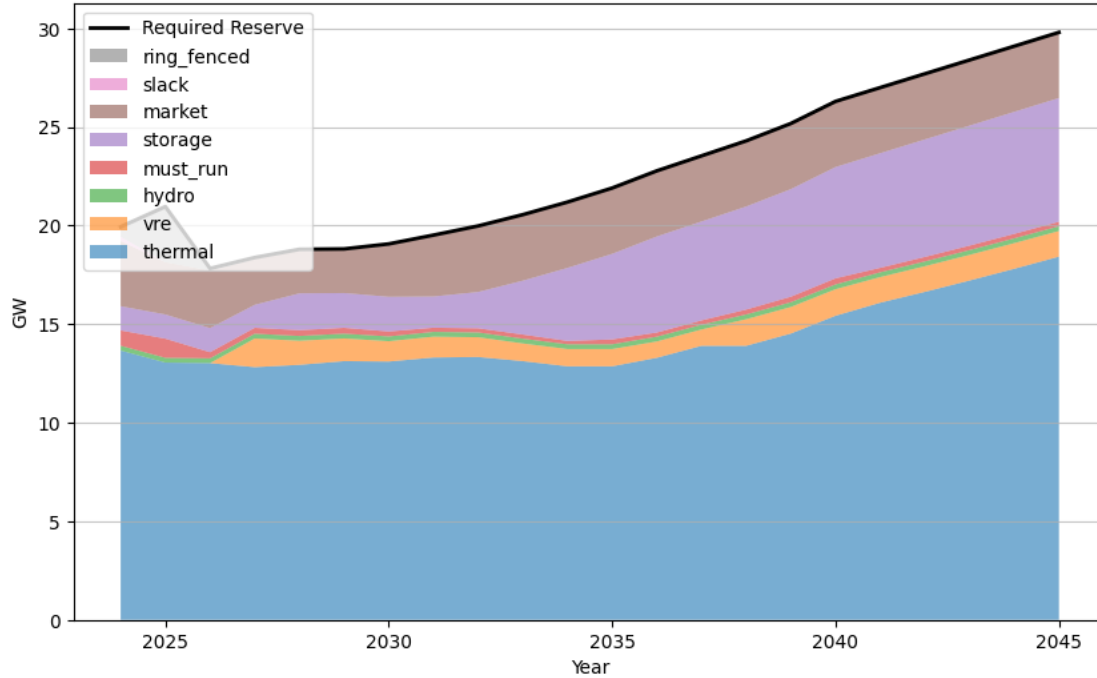


Figure 65 Capacity reserve margin and how it is met in the VCEA 2045 EPA RGGI 3X CLEAN 6X NUCLEAR scenario.

Appendix C: Extension of Model Inputs to 2045

While the IRP only considered a horizon out to 2039, critical parts of the VCEA come into force later, particularly the retirement of all carbon emitting assets by 2045. Models can only “see” into the future as far as their inputs go. Thus, we modeled the DOM system out until 2045 so that the model could see a hard stop for carbon emissions at that time, theorizing that the model might make decisions in earlier planning periods as a result. To extend the planning horizon, we needed to provide the model with six more years of inputs (2040–2045) than were included in Dominion’s IRP model. When the inputs provided through the discovery process went out to 2045 (and beyond), such as load forecasts, we utilized those inputs to build the model for the additional years. However, when the inputs provided only went through 2039, we had to extrapolate the data out to 2045. This section describes our approach to develop those extrapolated inputs.

Expanded maximum build constraints

For technologies that the model could choose to build, we extended out the maximum annual build limits for the additional six years unless noted otherwise in the scenario titles. For example, in the VCEA EPA 2045 RGGI, we kept the maximum build limit for solar the same from 2040 to 2045 as it was from 2028 to 2039.

Expanded capacity cost assumptions

For capacity market costs beyond 2039, we developed a linear fit to the 2034 to 2039 data and then used that equation to calculate the values from 2040 to 2045.

Expanded capacity requirement assumptions

Because we based our firm capacity requirement on the amount of annual firm capacity procured by the PLEXOS model, we needed to extrapolate those values out to 2045. We did so by taking the average annual increase from 2031 to 2039 (rounded up to the nearest 100 MW) and adding that value annually for the extended time period.

Expanded RGGI carbon costs

The RGGI carbon costs data provided through discovery only went out to 2039. We fit a second order polynomial to all of the data and used that equation to extend the values out to 2045.

Table 4 shows the assumptions for CO₂ prices used in this analysis.

Table 4: Projected assumed future RGGI carbon price in both short ton and metric ton. Note that values from 2040 to 2045 were extrapolated based on a second order polynomial fit of the 2024 to 2039 data as provided in discovery (APV Set 06-17 (ATS) SUPP).

Year	CO2 Price (\$/short ton)	CO2 Price (\$/metric ton)
2024	21.96	19.92
2025	22.26	20.20
2026	22.57	20.48
2027	22.87	20.75
2028	23.17	21.02
2029	23.47	21.29
2030	23.75	21.55
2031	24.39	22.13
2032	25.02	22.70
2033	25.64	23.26
2034	26.27	23.83
2035	26.91	24.41
2036	27.56	25.00
2037	28.21	25.60
2038	28.87	26.20
2039	29.54	26.81
2040	30.52	27.69
2041	31.38	28.47
2042	32.28	29.29
2043	33.22	30.15
2044	34.20	31.03
2045	35.22	31.96

Expanded market transmission capacity

We extended the monthly market transmission capacity limits past 2039 by assuming that they would grow similarly to how they are expected to grow from 2024 to 2039⁴¹. We kept the same cyclical profiles that are in the 2024–2039 data, but we assumed that in 2040 that there would be an additional increase in the transmission capacity. The original data provided included increases in capacity in 2029 and 2033. The average LSE limit (divided up by the 4 tiers) from 2024–2028 was about 5,075 MW, the average from 2029–2032 was

⁴¹ Discovery Attachment APV Set 02-06(a) (KLC).xlsx was used for the market transmission capacity limits.

about 5,933 MW, and the average from 2033–2030 was about 7,305 MW. Utilizing the same monthly variation that was present in the earlier data, we increased the average LSE limit for 2040–2045 to about 9,405 MW.