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**2025 Integrated Resource Plan**

**Resource Mix Study**

January 2025

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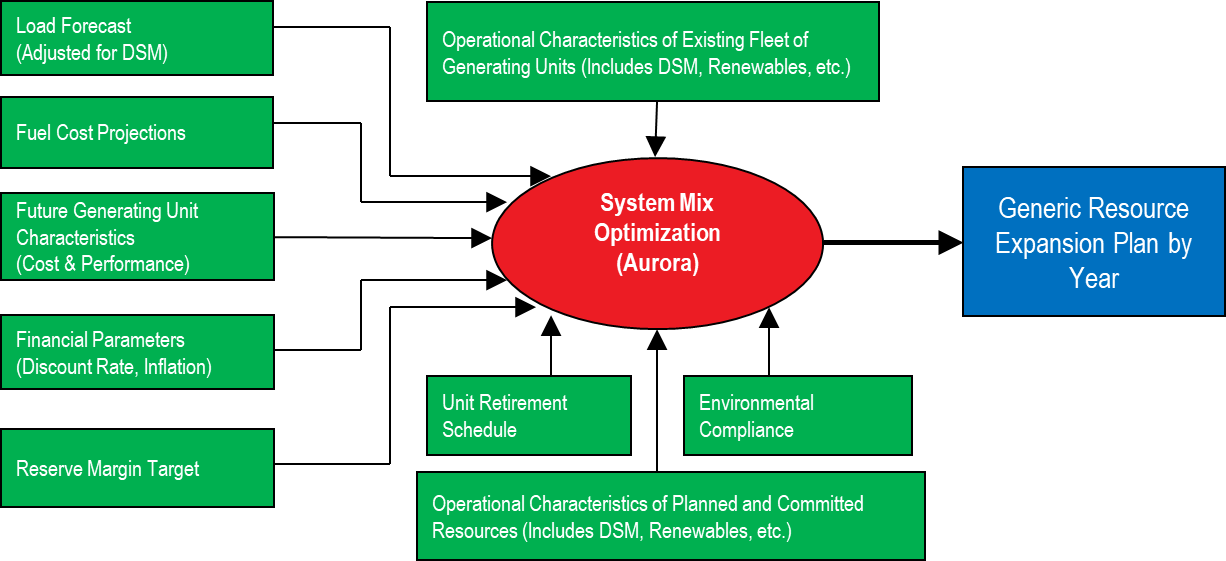
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# 1 Summary

The primary objective of the Resource Mix Study (“Mix Study”) is to provide information regarding the development of an optimal least-cost resource mix or generic expansion plan. The generic expansion plan was selected to minimize revenue requirements while complying with reliability criteria and environmental laws and regulations, considering risk and flexibility. This study provides an informative roadmap for long-term decisions. The scenarios contained in this Mix Study do not represent commitments but instead provide generic expansion plans used for planning and to support analyses. Under the framework established in the state of Georgia, when a capacity need is identified through an Integrated Resource Plan (“IRP”), Georgia Power Company (“Georgia Power” or the “Company”) will meet such identified need in accordance with the Georgia Public Service Commission (“Commission”) rules and will utilize Georgia Power specific information, as appropriate.

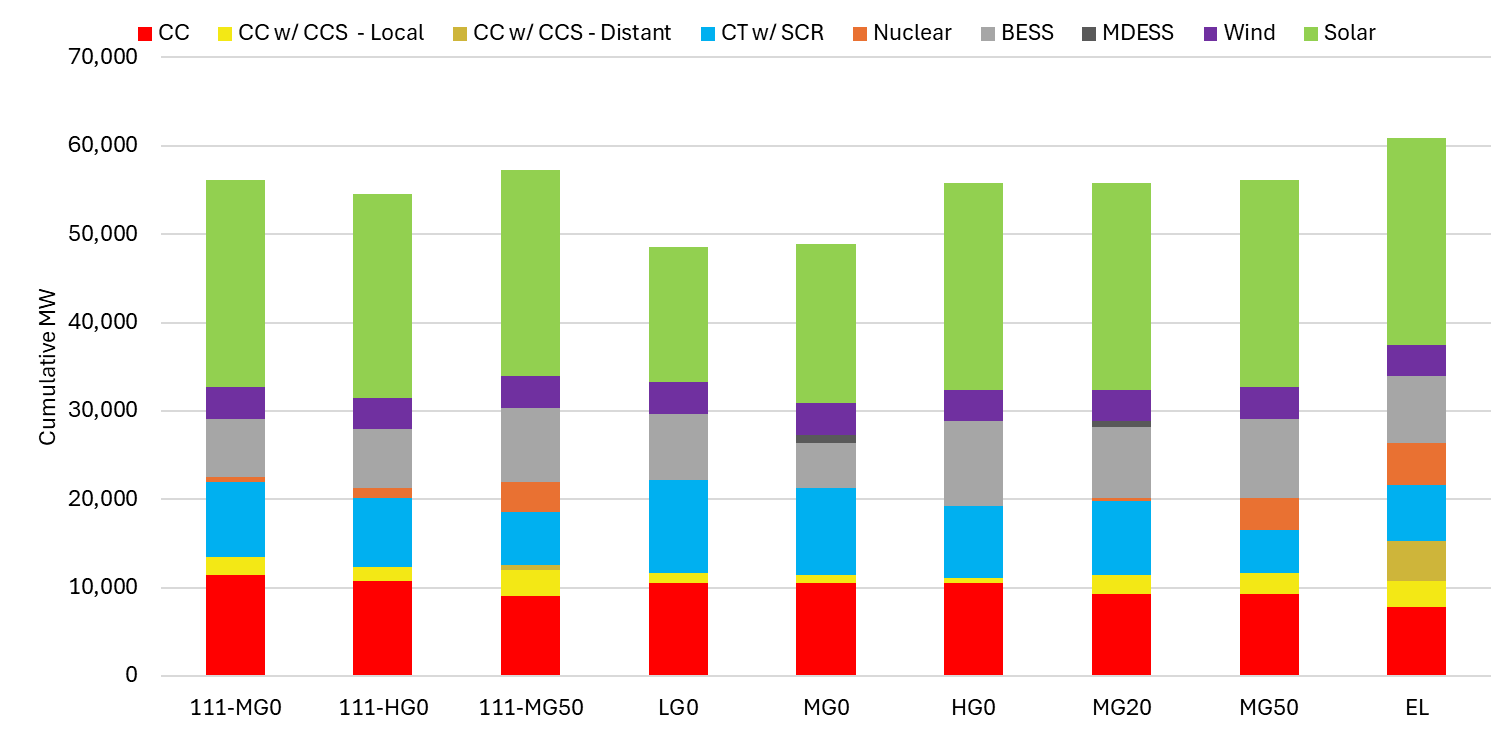
This report summarizes the results of the 2025 IRP Resource Mix Study. The recommendations of the study provide input to an optimum resource addition schedule for the retail operating companies. The resource addition schedule is based on maintaining minimum winter and summer reserve margins and minimizing the total operating and capital costs over the planning horizon. While both summer and winter seasons are reviewed, future resource addition schedules are based on the additions needed to meet the higher of the summer or winter capacity need for the retail operating companies that are part of the Southern Company System (“System”). For the Budget 2025 (“B2025”) resource plan, the System winter capacity need occurred earlier and was higher than the summer capacity needs for the entire planning horizon. Therefore, the System expansion plan includes additions to address the forecasted winter capacity needs. An overview of the expansion plan optimization process is shown in Figure 1 below.

Figure 1: Expansion Plan Optimization Process Overview



The expansion planning analysis maintains the Company’s Target Reserve Margins while considering a wide range of possible future scenarios. The results of the expansion planning analysis ensure the Company is evaluating a range of economic and policy conditions that may differ materially from current conditions. This process ensures the Company is making decisions with the best available information, while appropriately considering the risk associated with long-term resource planning decisions in the best interest of customers. The outcome of this process is a cost-effective mix of demand-side and supply-side resources that inform the Company’s long-term avoided costs.

Figure 2 shows the expansion plans over the 20-year planning period (2025-2044) in cumulative megawatts (“MW”). Combustion turbine (“CT”) and combined cycle (“CC”) resources, in addition to battery storage, are selected in all scenarios to help fulfill the capacity need. Nuclear resources are selected in all scenarios that include greenhouse gas (“GHG”) pressure, including all scenarios that include the recently finalized Environmental Protection Agency (“EPA”) rules under sections 111(b) and 111(d) of the Clean Air Act (“111 GHG Rules”). All scenarios show substantial additions of solar and wind resources to be cost-effective through the planning period.

Figure 2: B2025 Generic Expansion Plan Results – Cumulative MW (2025-2044) 

These generic expansion plans are combined with the existing fleet of resources as inputs into more detailed production cost modeling to produce hourly forecasted marginal energy costs for each scenario. Marginal energy costs are used for a range of purposes, including asset and Request for Proposal (“RFP”) evaluation.

# 2 Scenarios

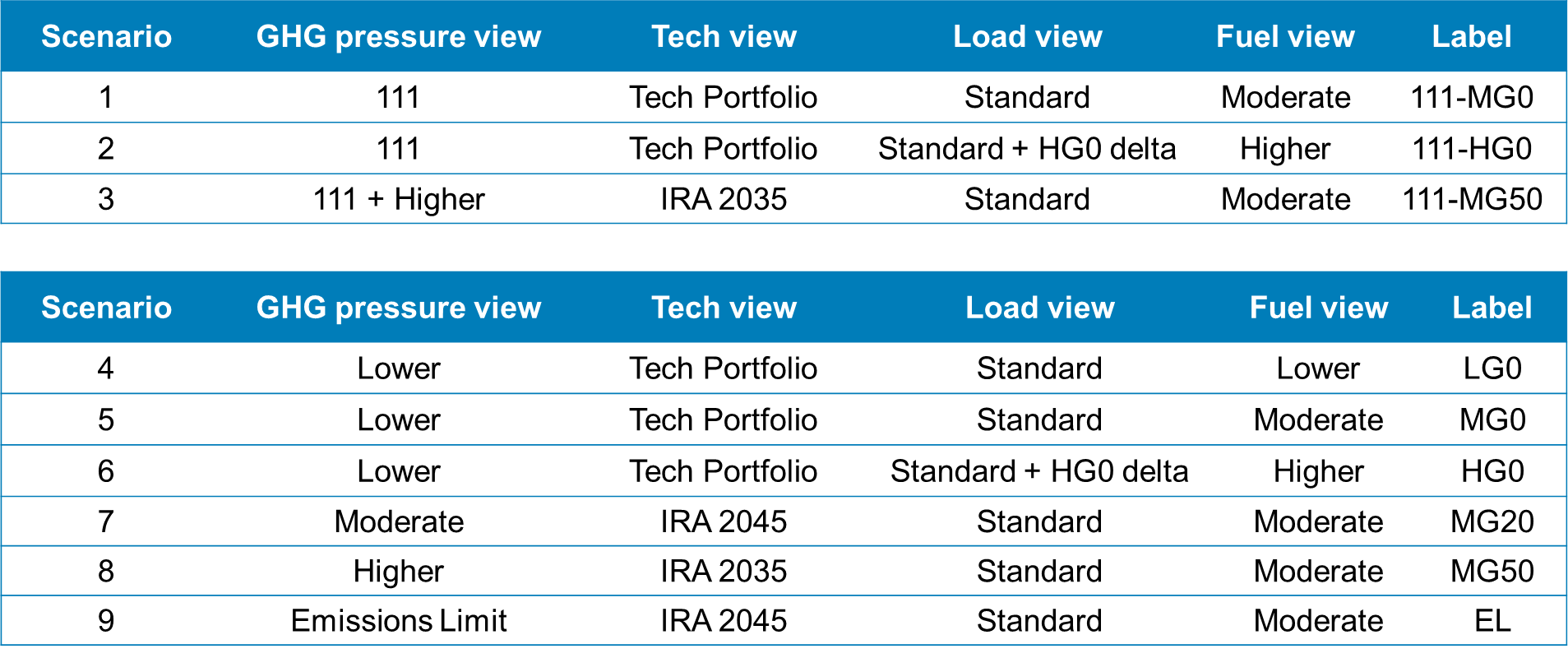
Many factors affecting resource planning involve future uncertainties. Thus, the Company creates scenarios to help understand these future uncertainties, which allows it to make appropriate planning decisions. Key uncertainties affecting planning include (1) future pressure on carbon dioxide (“CO2”) and other greenhouse gas (“GHG”) emissions, (2) cost and performance of future generating technologies, (3) future load growth, and (4) future fuel prices. To construct its planning scenarios, the Company identifies different reasonably plausible views of the future that are impactfully different from one another in each of these four areas. These views are then combined to create several scenarios. For each scenario, the Company uses its modeling system, Aurora, to identify a least-cost expansion plan that reliably meets load and satisfies many other conditions. The views and scenarios are refreshed annually.

For B2025 analyses, the Company created nine scenarios. For purposes of the Resource Mix Study, all nine scenarios were evaluated. Any specific analysis the Company performs may be based on all or a subset of those scenarios.

## 2.1 Budget 2025 Scenarios

The Company considers multiple views of the four key areas of uncertainty: the future degree of greenhouse gas pressure, the future cost and performance of generating and storage technologies, future load growth, and future price of fuels. For B2025, the Company assembled multiple views in these four areas into nine scenarios as summarized in Table 1. For example, as shown in Table 1, Scenario 1 (111-MG0) is defined by pressure on CO2 emissions consistent with the 111 GHG Rules, includes the *Tech Portfolio* view of future cost and performance of technologies, the *Standard* load forecast view, and the *Moderate* view of future fuel prices. The views of GHG pressure, technology cost and performance, load, and future fuel prices are described in more detail in Section 2.2.

Table 1: B2025 Scenario Design



The B2025 scenario design reflects an appropriately diverse set of plausible, meaningfully different views of the future evolution of the key resource planning drivers. The description of the assumptions and details of these different scenario views are provided in Section 2.2 below.

## 2.2 Scenario Views

As shown in Table 1, the Company divided its scenarios into two sets. The first set adopts the view that the recently finalized 111 GHG Rules remain in effect. There are three scenarios in this set. The other set of scenarios adopts the view that the 111 GHG Rules do not remain in effect. There are six scenarios in this set. All nine scenarios differ from one another by adopting different combinations of views in four key areas: the future degree of GHG pressure, the future cost and performance of generating and storage technologies, future load growth, and future price of fuels. The description and details of each of these four key areas are discussed in the following sections.

### 2.2.1 Greenhouse Gas Pressure Views

The degree of pressure on GHG emissions[[1]](#footnote-2) in the future is uncertain. The Company considered six different views of how future GHG pressure could evolve. The first view is that GHG pressure remains unchanged from where it is today (*111* view). The second view is that in addition to the 111 GHG Rules remaining in place, a higher degree of GHG pressure is exerted on the Company’s emissions (*111 + Higher* view). The third view is that the 111 GHG Rules requirements do not remain in place, and no additional pressure takes their place (*Lower* view). The fourth view is that the 111 GHG Rules do not remain in place, and a moderate degree of GHG pressure is exerted on the Company’s emissions (*Moderate* view). The fifth view is that the 111 GHG Rules do not remain in place, and a higher degree of GHG pressure is exerted on the Company’s emissions (*Higher* view). Finally, the sixth view is that a limit is placed on the Company’s aggregate emissions (*Emissions Limit* view). These views have been chosen to span a range of currently plausible outcomes.

Under EPA’s 111 GHG Rules, beginning January 1, 2032, new natural gas combined cycle (“NGCC”) units must either capture and sequester at least 90% of their GHG emissions or operate with an annual average capacity factor of 40% or less. Existing coal units have three options: (1) retire by January 1, 2032; (2) capture and sequester 90% of their GHG emissions beginning January 1, 2032; or (3) generate at least 40% of their energy using natural gas beginning January 1, 2030, and retire by January 1, 2039. The Company’s *111* views require compliance with the provisions of these rules.

In addition to the 111 GHG Rules requirements, the Company’s *111 + Higher* view of future GHG pressure imposes a higher degree of CO2 pressure in the form of a fee on GHG emissions from the Company’s facilities. The fee begins in 2035 at $50 (2023$) per metric ton of CO2 and rises at 7% above inflation through the modeling horizon. The fee is a proxy for various forms of GHG pressure, including regulatory or legislative policy, or pressure from customers or investors.

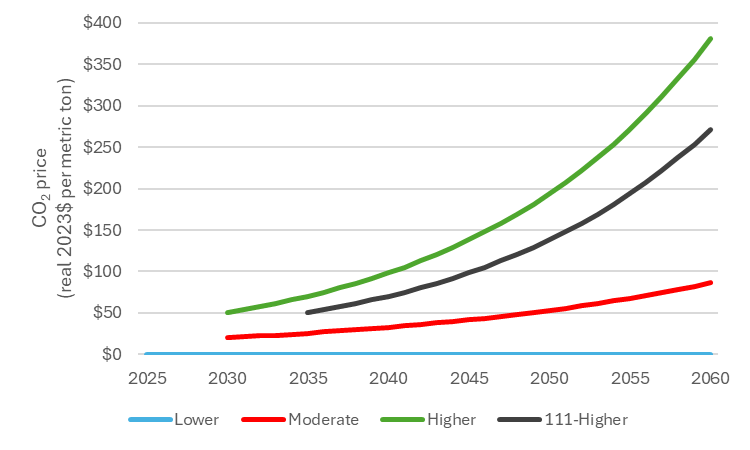
In the Company’s *Lower* view, the 111 GHG Rules do not remain in effect. The *Lower* view assumes no fee on CO2 emissions but does require carbon capture at all new NGCC units that become operational in 2040 and after. The assumed carbon capture requirement date reflects uncertainty in the legal outcome of the existing rules, as well as the pace of technology advancement, but considers that EPA is required to review and potentially update the GHG emission standards on a regular basis.

The Company’s *Moderate* view adds to the *Lower* view a fee on CO2 emissions that begins in 2030 at $20 (2023$) per metric ton of CO2 and grows at 5% above inflation through the modeling horizon. This fee is a proxy for various forms of pressure on the Company’s GHG emissions, including regulatory or legislative policy, or pressure from customers or investors. The assumed 2030 start year is consistent with a projected compliance horizon for future regulation or legislation. In this view it is also assumed that carbon capture is required at all new NGCC units beginning in 2037. These dates are uncertain but reflect potential outcomes from future policies and/or reviews required under the Clean Air Act.

The Company’s *Higher* view builds on the requirements of the *Lower* and *Moderate* views and adopts a fee on CO2 emissions that begins in 2030 at $50 (2023$) per metric ton of CO2 that grows at 7% above inflation through the modeling horizon. The assumed 2030 start year is consistent with a projected compliance horizon for future regulation or legislation and assumes carbon capture is required at all new NGCC units beginning in 2037.

These views are illustrated in Figure 3.

Figure 3: Views of future pressure on CO2 emissions



Finally, the Company’s CO2 *Emissions Limit* view imposes a requirement that the Company’s annual aggregate CO2 emissions in 2050 are reduced by about 95% relative to 2007 emissions. This view is implemented in the Company’s Aurora expansion plan modeling through an iterative process, applying a price on CO2 emissions that achieves the 2050 emissions limit target.

### 2.2.2 Technology Cost and Performance Views

Electricity generating technology is always evolving, and there are numerous resources that can contribute to meeting the demand for electricity. The pace and direction of the evolution of each of these resources is uncertain. The Company maintains a technology screening process that evaluates a wide portfolio of technologies at varying levels of development for inclusion in planning scenarios. This screening process characterizes technologies that are commercially available as well as those that are expected to be commercially available at some point during the planning horizon.

For the B2025 analyses, the technologies that passed initial screening, indicating their potential cost-effectiveness, include NGCC, dual-fuel CT with selective catalytic reduction (“SCR”) (oil-fueled in winter, natural gas otherwise), solar photovoltaic (“PV”), wind, nuclear (AP-1000), lithium-ion battery storage, and compressed air or pumped thermal energy storage. In addition, NGCC with CCS also passed initial screening based on an assumed trajectory of technology and infrastructure development towards future commercial availability. While this trajectory and ultimate costs remain highly uncertain, the inclusion of NGCC with CCS allows the Company to evaluate scenarios for this potential future resource option. Please see Section 3.6.1 and the Technology Screening and Application Standards in Technical Appendix Volume 2 for more information on the technology screening process.

The Company considers three different views of technology cost and performance uncertainty, all based on the same portfolio of technology options (i.e., “Tech Portfolio”) (see Section 3.6 for additional discussion). The cost of these technologies varies across scenarios based on the timing of the phase out of the Inflation Reduction Act (“IRA”) production tax credits (“PTCs”) and investment tax credits (“ITCs”). The IRA includes provisions for when the Clean Electricity tax incentives for carbon capture and sequestration (“CCS”) and new zero-carbon technologies (e.g., solar, wind, storage, nuclear) are set to end. Many tax credits, including the ITCs and PTCs, are set to phase out at the later of 2032 or when nation-wide electric sector carbon emissions reach 25% of 2022 levels. As the latter year is unknown and impactful, the Company considers three different views of it. For the Expansion Plan modeling, the IRA PTCs and ITCs are assumed to extend through the planning horizon for each scenario that includes the *Lower* and *111* greenhouse gas views. For the *Moderate, Higher, 111 + Higher,* and *EL* greenhouse gas views, the IRA PTCs and ITCs are assumed to phase out earlier due to the additional greenhouse gas pressure associated with those views. The phase out is assumed to begin in 2045 for the *Moderate* and *EL* views and in 2035 for the *Higher* and *111 + Higher* views.

The IRA Clean Electricity ITC (48E) allows a base tax credit of 6% of the cost of the facility, and the PTC (45Y) base credit is $5.5 per MWh (2022$). These IRA Clean Electricity incentives include a credit 5X multiplier if prevailing wage and apprenticeship requirements are met, resulting in a total ITC of 30% and a PTC of $27.5 per MWh (2022$) that rises over time with inflation. Additional IRA bonuses for meeting the domestic content and the energy community provisions were not included for generic expansion units due to uncertainty regarding the ability to meet the requirements. The IRA also increased the 45Q tax credit for CCS to $85 per metric ton of CO2 (2026$), which rises with inflation. The PTC is available to eligible facilities for 10 years of operation while the 45Q tax credit is available to eligible facilities for 12 years of operation. Table 2 shows the IRA assumptions included in the Expansion Plan scenarios.

Table 2: Inflation Reduction Act assumptions

|  |  |  |  |
| --- | --- | --- | --- |
|  | Clean Energy ITC (48E) | Clean Energy PTC (45Y) | CCS Tax Credit  (45Q) |
| Credit Amount |  |  |  |
| All Views | 30% of cost | 10 years of operation $27.5/MWh (2022$) | 12 years of operation $85/metric ton (2026$) |
| Credit Availability |  |  |  |
| Tech Portfolio | Through model horizon | Through model horizon | Begin construction by end of 2032 |
| IRA 2035 | Begin construction by end of 2035 | Begin construction by end of 2035 | Begin construction by end of 2032 |
| IRA 2045 | Begin construction by end of 2045 | Begin construction by end of 2045 | Begin construction by end of 2032 |

The IRA includes provisions for transfer or sale of tax credits. Market transactions for tax credits have been observed to trade below the full value of the tax credit due to, among other reasons, risks that are borne by the purchasers. For modeling purposes, the Company has assumed a 10 percent discount on Clean Electricity (48E and 45Y) tax credits. Because of the nascent state of CCS and associated concerns with commercial deployment of the technology, the Company assumed a 25 percent discount on 45Q tax credits.

More details around all technologies included in the Tech Portfolio and analyzed in the Resource Mix Study can be found in section 3.6.1.

### 2.2.3 Load Views

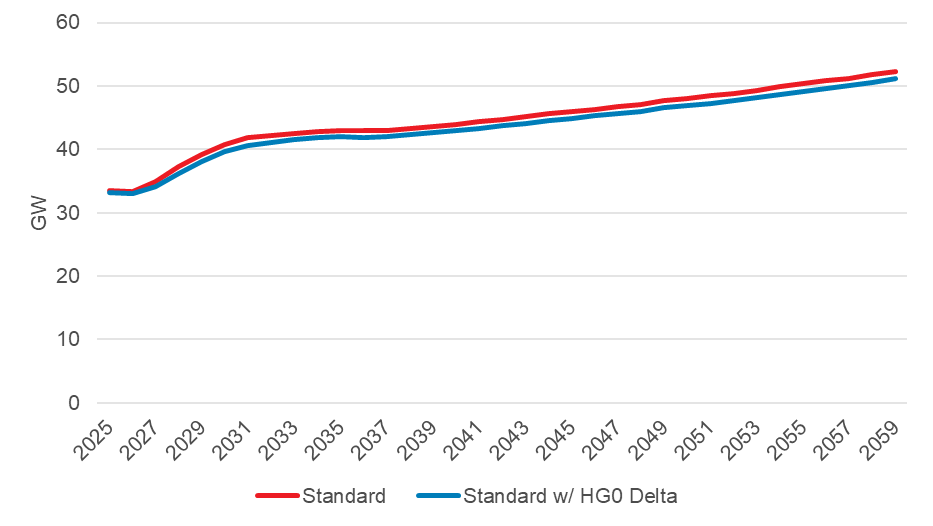
To assess uncertainties around future electricity consumption, the Company considers two different views of future load growth in the Mix Study: a *Standard* view and a view consistent with lower loads due to higher future natural gas prices (*Standard with HG0 Delta*). Additional load views are considered in the B2025 Load & Energy Forecast in Technical Appendix Volume 1 and in the Financial Review in Technical Appendix Volume 2.

* **Standard view**. The Company annually updates its forecast of electricity consumption through the planning horizon. The forecast is done separately for each of the three types of customers (i.e., residential, commercial, and industrial) for each of the three Southern Company retail operating companies and is aggregated into a System total for expansion modeling. This view of future load growth is used in most scenarios. This view includes significant growth of electricity consumption associated with commercial and industrial customers expected to initiate or expand operations as Company customers.
* **Standard with HG0 Delta view**. This view recognizes the relationship between the future consumption of electricity and the future price of natural gas. The Company has developed a load growth adjustment, derived from analyses done by the U.S. Energy Information Administration (“EIA”) for its Annual Energy Outlook (“AEO”). The AEO identifies a lower electricity consumption path associated with higher future natural gas prices, reflecting the important feedback in the relationship between future natural gas prices and future load growth.

For the B2025 planning process, the Company compared southeast U.S. electricity load growth in the AEO 2023 case with a higher future price of natural gas to southeast U.S. electricity load growth in the AEO 2023 Reference case. This difference was smoothed and then used as an adjustment to the Company’s Standard load growth view.

The System winter peak load associated with both views of future load growth in the Mix Study are illustrated in Figure 4.

Figure 4: Views of System Winter Peak Load (MW)



### 2.2.4 Fuel Price Views

The future price of fuel is unknown. For the B2025 planning process, the Company considered three different views of how the long-term price of fuels could evolve: a *Lower* price path, a *Moderate* price path, and a *Higher* price path. For B2025, the Company adopted paths produced by the U.S. EIA in its 2023 AEO as its source for long-term future prices of natural gas, coal, and oil. The AEO is a major annual product of the EIA and is publicly available on the EIA’s website ([https://www.eia.gov](https://www.eia.gov/)). EIA did not produce a 2024 AEO, so the 2023 AEO is EIA’s current view.

For B2025, the three different views of long-term future natural gas prices that the Company adopted are:

* *Lower* price view: AEO’s High Oil and Gas Supply case
* *Moderate* price view: AEO’s Reference case
* *Higher* price view: AEO’s Low Oil and Gas Supply case

Estimates of technically recoverable tight/shale oil and natural gas resources are particularly uncertain and change over time as new information is gained through drilling, production, and technology development. AEO’s “High Oil and Gas Supply” and “Low Oil and Gas Supply” views appropriately reflect this uncertainty.

In AEO’s Low Oil and Gas Supply case, the estimated ultimate recovery per well is assumed to be 50% lower than in the Reference case for tight oil, tight gas, shale gas in the U.S., for undiscovered resources in Alaska, and for production offshore of the Lower 48 states. Rates of technological improvement that reduce costs and increase productivity in the U.S. are also 50% lower than in the Reference case. These assumptions increase the per-unit cost of crude oil and natural gas development in the U.S.

In AEO’s High Oil and Gas Supply case, the estimated ultimate recovery per well is assumed to be 50% higher than in the Reference case for tight oil, tight gas, shale gas in the U.S. for undiscovered resources in Alaska, and for production offshore of the Lower 48 states. Rates of technological improvement that reduce costs and increase productivity in the U.S. are also 50% higher than in the Reference case. These assumptions decrease the per-unit cost of crude oil and natural gas development in the U.S. In addition, tight oil and shale gas resources are added to reflect new prospects or the expansion of known prospects. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% higher than in the Reference case.

Some of the key drivers of the AEO change from year to year reflect the evolution of important information about the U.S. energy economy. As an example of some of these changes, Table 3 provides some of the key assumption changes from AEO 2022 to AEO 2023.

*Table 3: Key Natural Gas Values for AEO 2023 Reference Case*

|  |  |
| --- | --- |
| **Driver** | **Key Values for AEO 2023 Reference Case** |
| **Resource Size** | * 445.3 Tcf in proved shale reserves   (20.1 Tcf decrease from AEO 2022)   * 2,973 Tcf in total technically recoverable (TTR) U.S. dry natural gas resources   (1.6% growth from AEO 2022 to AEO 2023) |
| **Technological Improvement** | * Drilling costs fall by 1%/yr * Equipment costs fall by 0.5%/yr * Well productivity increase up to 4%/ yr |

More information regarding the fuel price input assumptions can be found in Section 3.5.

# 3 Model Input Assumptions

The key inputs to the study are the cost of capital and escalation rates, a reliability criterion represented by the Target Reserve Margin, the operating data and retirement or projected unavailability dates of existing and committed generating units, projected demand-side options (“DSOs”), load forecasts, fuel forecasts, and costs, performance characteristics, and deployment of candidate generating technologies. The following provides details for each of these key inputs.

## 3.1 Financial Assumptions

Cost of capital rates are based on the S&P Global June 2024 forecast of interest rates and economic conditions. Table 3 details the capital structure and weighted costs used in the Mix Study.

Table 3: Capital Structure

| Component | Ratio | Cost | Weighted | After Tax Hurdle Rate | Revenue Requirement Rate |
| --- | --- | --- | --- | --- | --- |
| Debt | 45% | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Equity | 55% | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Weighted Cost | | | **REDACTED** | **REDACTED** | **REDACTED** |

## 3.2 Reserve Margin

The 2025 IRP reflects a 20% Summer Target Reserve Margin and 26% Winter Target Reserve Margin for long-term resource planning purposes, consistent with the 2024 Reserve Margin Study, found in Technical Appendix Volume 1.

## 3.3 Existing Capacity Mix

The Company’s current generating capacity consists of 47% gas and oil, 17% coal, 12% nuclear, 5% hydro, and 19% other (Solar, Solar + Storage, Wind, DSO, and Biomass). Over the course of the planning horizon, the capacity mix will change due to many factors, including, but not limited to, unit rating changes, resource additions, nuclear license expirations, power purchase agreement expirations, and retirements. For scenarios that include the 111 GHG Rules, the Company has chosen to reflect the co-fire pathway with retirement by 2039 for existing coal units. While discrete retirement dates of Company-owned generating units were used in in the modeling, these assumptions are only for planning purposes. Please refer to Resource Mix Study “Georgia Power Territorial Base Case Load vs. Existing Capability Table – 2025 IRP.xlsx” for more details.

### 3.3.1 Demand-Side Options

DSOs are either “dispatchable” or “non-dispatchable.” Examples of dispatchable DSO include interruptible load and other options that can be controlled and dispatched by a utility. Examples of non-dispatchable DSO include options such as insulation or end-use equipment efficiency, which are not directly controllable by a utility.

Dispatchable DSOs were included as capacity resources in this study. Each interruptible contract load was appropriately adjusted to equate it to the supply side by one or more of the following corresponding factors: availability factor, loss factor, and Effective Load Carrying Capability (“ELCC”). For all operating companies, non-dispatchable DSOs are accounted for in the load forecast. Please see Resource Mix Study “GPC and System DSO Data TRADE SECRET.xlsx” for additional information regarding DSO assumptions used in the 2025 IRP.

Figure 5 below shows the existing, planned, and committed System capacity changes for the 2025 – 2044 period.

Figure 5: Retail Operating Companies' Existing and Planned Capacity Forecast

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## 3.4 Load Forecast

As described in section 2.2.3 Load Views, the Company produces specific load forecasts for multiple scenario views to address the uncertainty of future electricity consumption. Load forecasts were provided by each retail operating company. The System peak demand is the sum of each retail operating company’s non-coincident peak demand multiplied by a load diversity factor. The diversity percentages are based on a historical ten-year average of monthly diversities from 2014 through 2023. More information on the Company’s load forecasts can be found in the 2025 IRP Main Document and the B2025 Load and Energy Forecast in Technical Appendix Volume 1.

## 3.5 Fuel Forecast

#### Short- and Long-Term Future Natural Gas Prices

The natural gas price views that the Company has used for the B2025 Mix Study combines different sources of information for short- and long-term natural gas price forecasts. For these views, the Company focuses on the price of natural gas at the Henry Hub (a reference location in south-central Louisiana). This is a common benchmark in the natural gas industry. These are the prices to which a delivery cost is added to get the price of natural gas delivered to any individual unit.

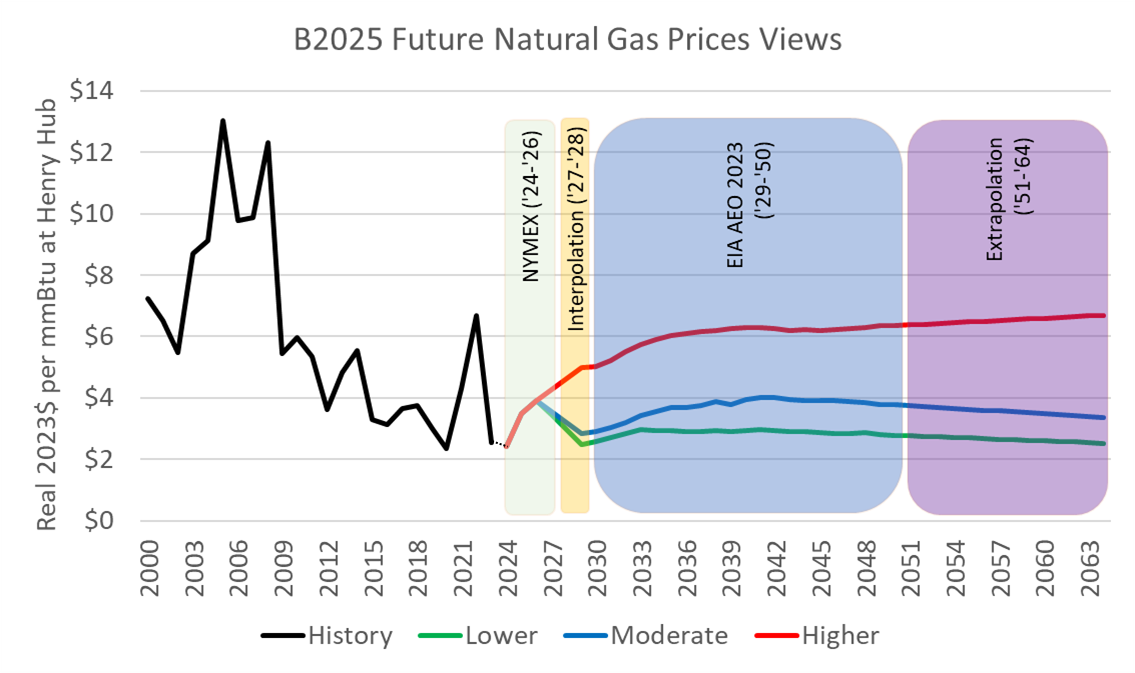
For the short-term natural gas price forecast (through 2026), the Company adopts average closing prices on the New York Mercantile Exchange (“NYMEX”) of natural gas contracts for future delivery. The Company adopts only one short-term view of future natural gas prices.

As described previously, the Company adopted three different views of long-term (2029 through 2050) future natural gas prices for B2025 that are based on AEO views:

* *Lower* price view: AEO’s High Oil and Gas Supply case
* *Moderate* price view: AEO’s Reference case
* *Higher* price view: AEO’s Low Oil and Gas Supply case

Natural gas prices for 2027 and 2028 are based on a linear interpolation between the 2026 (NYMEX) and 2029 (AEO) values. The AEO provides price paths through 2050. Beyond 2050, the Company extrapolates the price path from its slope for its last 10 years. The three natural gas views are illustrated in Figure 6.

Figure 6: Views of future price of Natural Gas at Henry Hub



The candidate expansion unit gas price is a capacity need weighted average, by retail operating company, of several potential plant locations throughout the Southern Company System. NGCC additions include the cost of contracting for firm annual natural gas delivery, while CT additions include the cost of contracting firm summer only natural gas delivery.

#### Future Coal and Oil Prices

The future price of coal and oil is also uncertain. For B2025, the Company has adopted three different views of future coal prices and three different views of future oil prices. These views are the coal and oil price paths from the AEO 2023 Reference, High Oil and Gas Supply, and Low Oil and Gas Supply cases. These price paths are illustrated in Figures 7-10.

The relationship between the future price of coal and the future supply of oil and gas is not straightforward. In general, coal and natural gas are substitutes for each other, so when the price of gas is higher, the demand for coal, and thus its equilibrium price, is higher. Because the overall growth of the U.S. economy can be sensitive to the price of oil and natural gas, however, lower future prices of natural gas can increase overall economic growth enough to increase the price of coal too. These competing effects can be seen in the coal price diagrams that follow. The AEO does not consider cases that directly involve higher or lower views of the future price of coal.

Figure 7: Views of future price of coal at mine, by scenario, Central Appalachia

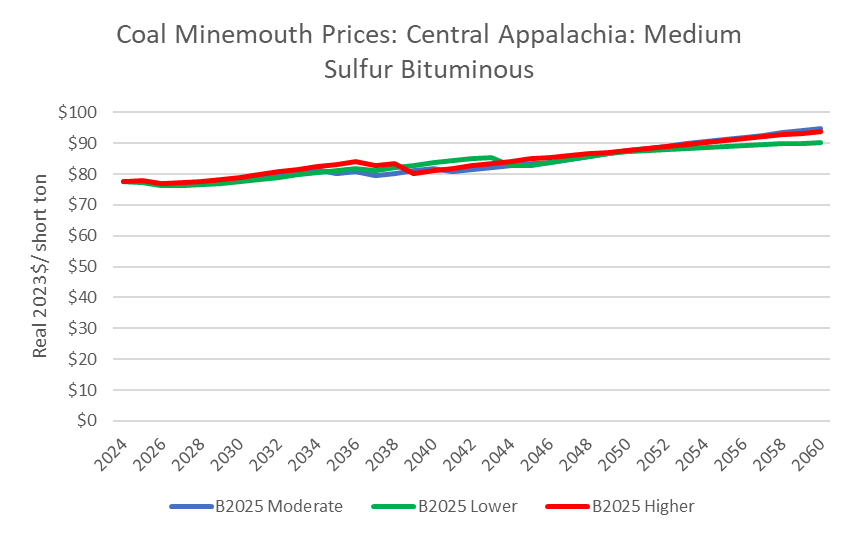


Figure 8: Views of future price of coal at mine, by scenario, Illinois Basin

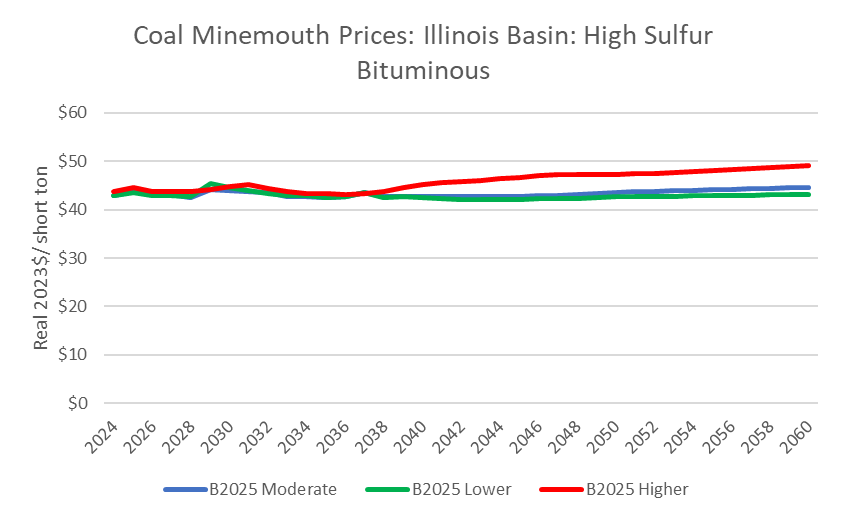


Figure 9: Views of future price of coal at mine, by scenario, Powder River Basin

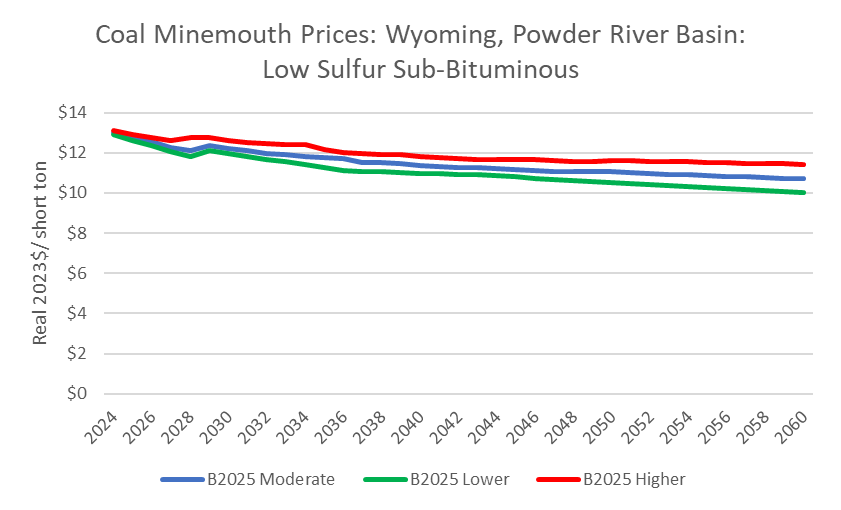
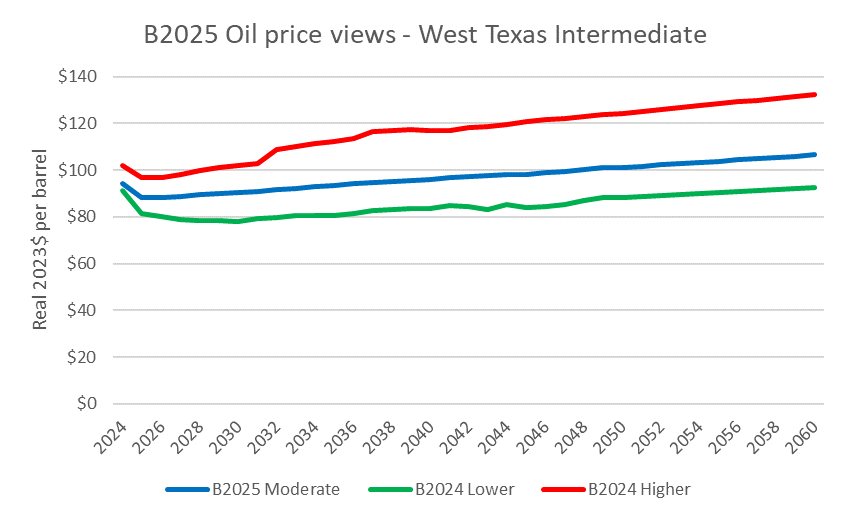


Figure 10: Views of future price of oil, West Texas Intermediate

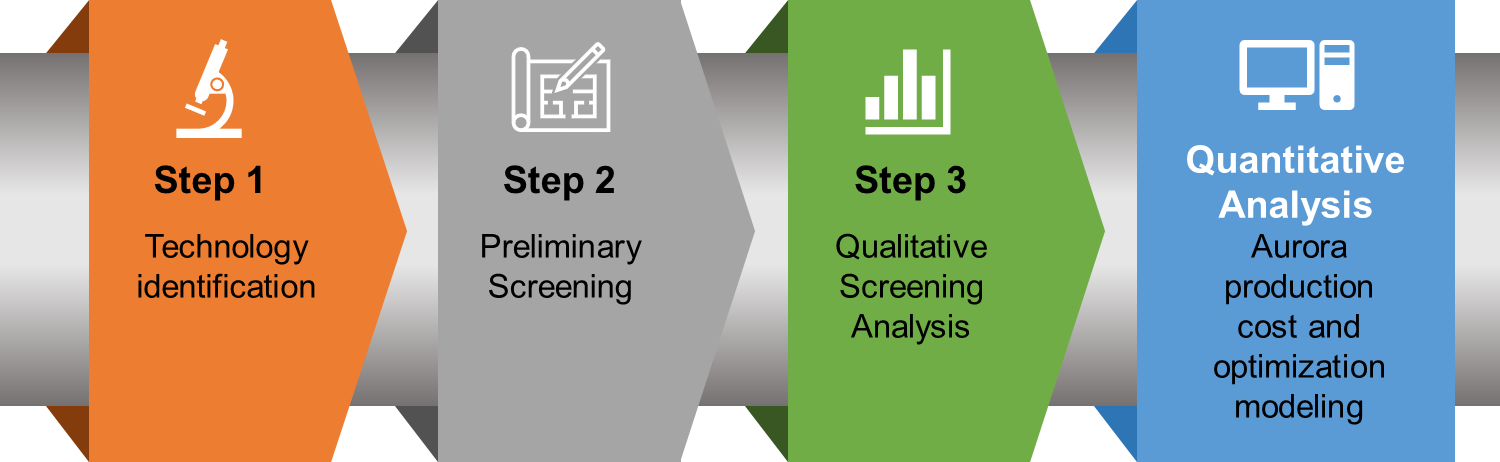


## 3.6 Technology Screening

The Company performs detailed expansion planning and production cost analysis during each IRP. This detailed analysis requires extensive and complex computational analysis. Therefore, the Company completes a technology screening assessment of new generation technologies to reduce the potential list of new supply-side options to a manageable list of technologies that are likely to be economically competitive. This technology screening assessment evaluates both established and emerging generating technologies. The objective is to assess the cost, maturity, safety, operational reliability, flexibility, economic viability, environmental acceptability, fuel availability, construction lead times, and other relevant factors of new supply-side generation options.

The technology screening process includes three main steps: (i) the Technology Identification, (ii) Preliminary Screening, and (iii) Detailed Qualitative Screening Analysis, as illustrated in Figure 11. Supply-side options retained after these steps are then considered in the more detailed expansion plan modeling.

Figure 11: Technology Screening Process



The screening process is useful for comparing costs of resource types but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process. Additional information is found in the Technology Screening and Applications Standards in Technical Appendix Volume 2.

### 3.6.1 Expansion Plan Candidate Resources

Electricity generating technology is always evolving. Therefore, as discussed previously, the Company’s screening process identifies those technologies that have the greatest possibility of playing a cost-effective role in the System during the modeling horizon. Even among the technologies that might play such a cost-effective role, there remains uncertainty about the cost of each technology relative to its expected productivity and other technology options.

For B2025 analyses, the technologies that passed initial screening, indicating their potential cost-effectiveness, include NGCC, dual-fuel CT with SCR (oil-fueled in winter), solar PV, wind, nuclear (AP-1000), lithium-ion battery storage, and compressed air or pumped thermal energy storage. In addition, NGCC with CCS also passed initial screening based on an assumed trajectory of technology and infrastructure development towards future commercial availability. While this trajectory and the ultimate costs remain highly uncertain, the inclusion of NGCC with CCS allows the Company to evaluate scenarios for this potential future resource option. Table 4 summarizes select modeling assumptions associated with the candidate expansion technologies. Note that for certain technologies, such as NGCC with CCS, there may be additional infrastructure or technology limitations that are not yet well understood at this time and are not captured in the model.

Table 4: Candidate Technology Assumptions

| Technology | First Year Available | Last Year  Available | Modeling  Limitations | IRA  Applicability |
| --- | --- | --- | --- | --- |
| NGCC | 2029 | * 111: available through planning horizon; limited to 40% capacity factor beginning 2032 * *Lower CO2* : 2039 * *Moderate, Higher, & EL CO2*: 2036 | * Market options (2029 limited to 900 MW) * Natural gas firm transportation (“FT”) availability | N/A |
| NGCC with CCS (local sequestration) | 2037 | Available through planning horizon | * FT availability * Geology (**REDACTED** total for system;  **REDACTED** in Georgia) | 45Q Tax Credit  COD before 2039 |
| NGCC with CCS (distant sequestration) | 2037 | Available through planning horizon | FT availability | 45Q Tax Credit  COD before 2039 |
| CT with SCR | 2029 | Available through planning horizon | * Oil operation in winter months (Dec-Jan-Feb) * 20% capacity factor annually | N/A |
| Solar PV | 2028 | Available through planning horizon | * 1,500 MW/year | PTC (45Y)  Tech: Planning horizon  IRA 2045: COD by 2049  IRA 2035: COD by 2039 |
| Wind | 2033 | Available through planning horizon | * 300 MW/year * 4,500 MW total | PTC (45Y)  Tech: Planning horizon  IRA 2045: COD by 2049  IRA 2035: COD by 2039 |
| BESS | 2028 | Available through planning horizon | * 3,000 MW/year | ITC (48E)  Tech: planning horizon  IRA 2045: COD by 2049  IRA 2035: COD by 2039 |
| MDESS | 2033 | Available through planning horizon | * 3,000 MW/year | ITC (48E)  Tech: Planning horizon  IRA 2045: COD by 2049  IRA 2035: COD by 2039 |
| Nuclear  (AP-1000) | 2037 | Available through planning horizon | * 600 MW/year | ITC (48E)  Tech: Planning horizon  IRA 2045: COD by 2053  IRA 2035: COD by 2043 |

#### Natural Gas Combined Cycle (NGCC or CC)

The Company’s current assumption for planning purposes is that new NGCC plants without carbon capture facilities are available for fleet expansion beginning in 2029. Based on varying greenhouse gas pressure views, new NGCC plants are required to capture at least 90% of their CO2 emissions, therefore requiring the addition of CCS by various dates. This corresponds to the *Lower* view requiring CCS in 2040, the *Moderate* and *Higher* views requiring CCS in 2037, and the *111* view requiring either CCS in 2032 or that new NGCC plants without CCS be limited to a 40% capacity factor beginning in 2032 through the planning horizon. The timing of this requirement is based on the Company’s understanding of the existing Clean Air Act and its statutory schedule for review of abatement technologies and requirements (i.e., New Source Performance Standards and Best Available Control Technology).

The Company assumes that NGCC with CCS that enters commercial operation prior to 2039 will receive the 45Q tax credit for each ton of CO2 that is captured and stored during the first 12 years of operation. The cost and performance characteristics assumed for the NGCC with CCS technology are a proxy for various forms of efficient gas-fueled technologies that separate their CO2 for disposal, including post-combustion capture and supercritical CO2 (Allam cycle). The geology for CO2 storage is not uniform across the System’s territory. For the System modeling analysis, it is assumed that **REDACTED** **REDACTED** of NGCC with CCS could be sited near “local” sequestration sites; additional NGCC with CCS would require a longer (and more expensive) pipeline to transport the captured CO2 for more distant sequestration sites. NGCC is limited by FT availability as further described in Section 3.6.3.

#### Natural Gas Combustion Turbines (NGCT or CT)

The Company’s current assumption for planning purposes is that dual-fuel CTs with SCR are available for fleet expansion beginning in 2029 and are assumed to operate on oil in the winter months and natural gas in all other months. Combustion turbines must significantly reduce their NOx emissions by being equipped with a SCR device. This assumption is consistent with recent deployments of this technology across the industry and the Company’s understanding of the existing Clean Air Act and its statutory requirements for review of abatement technologies and requirements.

#### Solar PV

Solar PV with single-axis tracking is available as an expansion resource beginning in 2028. The Company’s view is that the cost of solar will continue to decline in real terms, meaning it will become increasingly cost-effective through the study timeframe. The Company assumes that solar will receive clean electricity PTCs for 10 years as provided in the IRA. In scenarios adopting the *Lower* view of future CO2 pressure, the PTCs are assumed to be available for solar installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for solar whose construction starts by 2045 (scenarios adopting the *Moderate* or *Emissions Limit* views of future CO2 pressure) or by 2035 (scenarios adopting the *Higher* view of future CO2 pressure). Solar is limited to 1.5 GW per year (including planned and committed solar).

#### Wind

Wind is available as an expansion resource beginning in 2033. The Company assumes that wind will receive clean electricity PTCs for 10 years as provided in the IRA. In scenarios adopting the *Lower* view of future CO2 pressure, the PTCs are assumed to be available for wind installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for solar whose construction starts by 2045 (scenarios adopting the *Moderate* or *Emissions Limit* views of future CO2 pressure) or by 2035 (scenarios adopting the *Higher* view of future CO2 pressure). Wind is limited to 0.3 GW per year and 4.5 GW total during the modeling horizon.

#### Battery Energy Storage System (4-hour option)

Battery Energy Storage System (“BESS”) is available as an expansion resource beginning in 2028. The Company’s view is that BESS costs will continue to decline into the middle of the planning horizon, before leveling off in real terms, meaning that it will become increasingly cost-effective throughout the study timeframe. The Company assumes that BESS will receive the ITCs as provided in the IRA. In scenarios adopting the *Lower* view of future CO2 pressure, the ITCs are assumed to be available for BESS installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for BESS whose construction starts by 2045 (scenarios adopting the *Moderate* or *Emissions Limit* views of future CO2 pressure) or by 2035 (scenarios adopting the *Higher* view of future CO2 pressure). BESS is limited to 3 GW per year. The capacity contribution of incremental BESS installations decreases as more BESS is added to the resource mix.

#### Medium Duration Energy Storage System (12-hour option)

Medium Duration Energy Storage System (“MDESS”) is available as an expansion resource beginning in 2033. The modeled cost and performance of MDESS is a proxy for either pumped thermal energy storage or compressed air energy storage (“CAES”). The Company assumes that MDESS will receive the ITCs as provided in the IRA. In scenarios adopting the *Lower* view of future CO2 pressure, the ITCs are assumed to be available for MDESS installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for battery storage whose construction starts by 2045 (scenarios adopting the *Moderate* or *Emissions Limit* views of future CO2 pressure) or by 2035 (scenarios adopting the *Higher* view of future CO2 pressure).  Build limits have not been applied to MDESS in the modeling study.

#### Nuclear

Nuclear units (AP-1000) are available as an expansion resource beginning in 2037. The Company assumes that nuclear units will receive the ITCs as provided in the IRA. In scenarios adopting the *Lower* view of future CO2 pressure, the ITCs are assumed to be available for nuclear installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for nuclear units whose construction starts by 2045 (scenarios adopting the *Moderate* or *Emissions Limit* views of future CO2 pressure) or by 2035 (scenarios adopting the *Higher* view of future CO2 pressure). Nuclear is limited to 0.6 GW per year.

The cost estimates for each of the natural gas, storage, solar, wind, and nuclear technology options were developed based on proprietary sources of information. Current estimates for costs, spending curves, emissions, and operating characteristics for these resources are contained in the Technology Screening and Applications Standards in Technical Appendix Volume 2.

### 3.6.2 Generic Unit Costs and Performance

Table 5 shows the technology assumptions for the candidate units offered in the 2025 IRP Resource Mix Study.

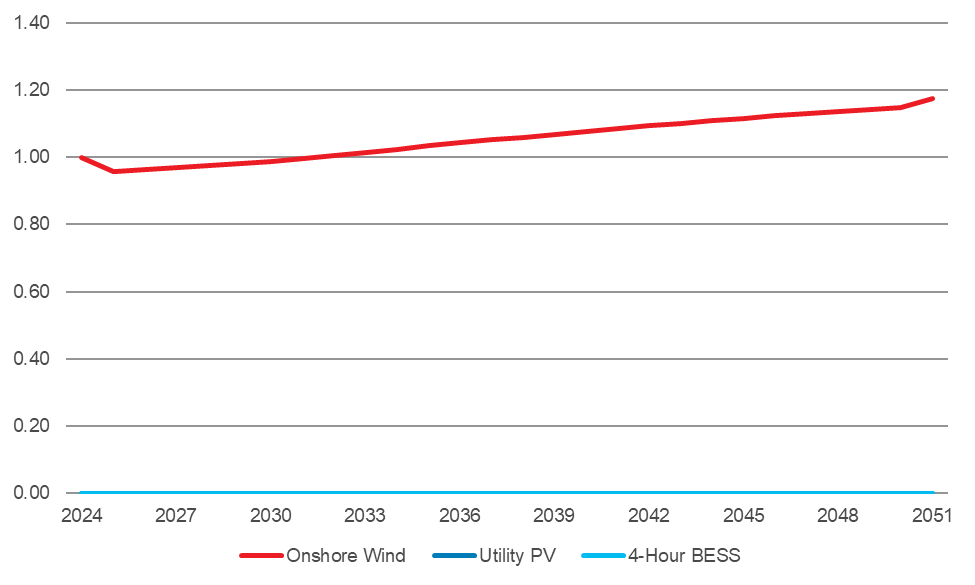
Table 5: B2025 Technology Cost and Performance Summary

| **Technology** | **Winter Capacity (MW)** | **ELCC** | **Average Heat Rate (Btu/ kWh)** | **Round Trip Efficiency** | **Fixed Capacity Factor** | **Overnight Cost (2024$/ kW)** | **Recurring Fixed Cost[[2]](#footnote-3) (2024$/ kW-yr)** | **Variable O&M ($/MWh)** | **Asset Life (Yrs)** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Natural Gas Combined Cycle (NGCC) | **REDACTED** | 100% | **REDACTED** |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| NGCC with Local CCS | **REDACTED** | 100% | **REDACTED** |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| NGCC with Distant CCS | **REDACTED** | 100% | **REDACTED** |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Combustion Turbine with SCR, Oil Winter (CT w SCR) | **REDACTED** | 100% | **REDACTED** |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Solar Photovoltaic (PV) - Single Axis Tracker (SAT) | **REDACTED** | 0% |  |  | **REDACTED** | **REDACTED** | **REDACTED** |  | **REDACTED** |
| Onshore Wind Power | **REDACTED** | 35% |  |  | **REDACTED** | **REDACTED** | **REDACTED** |  | **REDACTED** |
| Lithium-ion Battery Energy Storage System (BESS) - 4 Hr | **REDACTED** **REDACTED** | 0-3000 MW :95% 3001-6000 MW : 75% 6001-9000 MW : 50% 9001+ MW : 25% |  | **REDACTED** |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Medium Duration Energy Storage System | **REDACTED**  **REDACTED** | 100% |  | **REDACTED** |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Nuclear (AP-1000) | **REDACTED** | 100% |  |  |  | **REDACTED** | **REDACTED** |  | **REDACTED** |

Construction cost escalation rates for all technologies except solar, wind, and BESS are based on the Gross Domestic Product Implicit Price Deflator (“GDP-IPD”) from the S&P Global June 2024 Forecast, which is **REDACTED**% for the duration of the planning period.

Figure 12 shows the normalized cost projections for southeast wind, solar, and BESS, which reflect the escalation trajectory used in the Resource Mix Study.

Figure 12: Wind, Solar, and BESS Normalized Capex Forecast



Utility PV and 4-Hour BESS **REDACTED**

Aurora selects new units based on minimizing total operating and capital costs. To minimize the potential for bias resulting from the different MW sizes of available expansion resources, a unit size of 300 MW was considered for all technologies. The model adds resources in multiples of 300 MW.

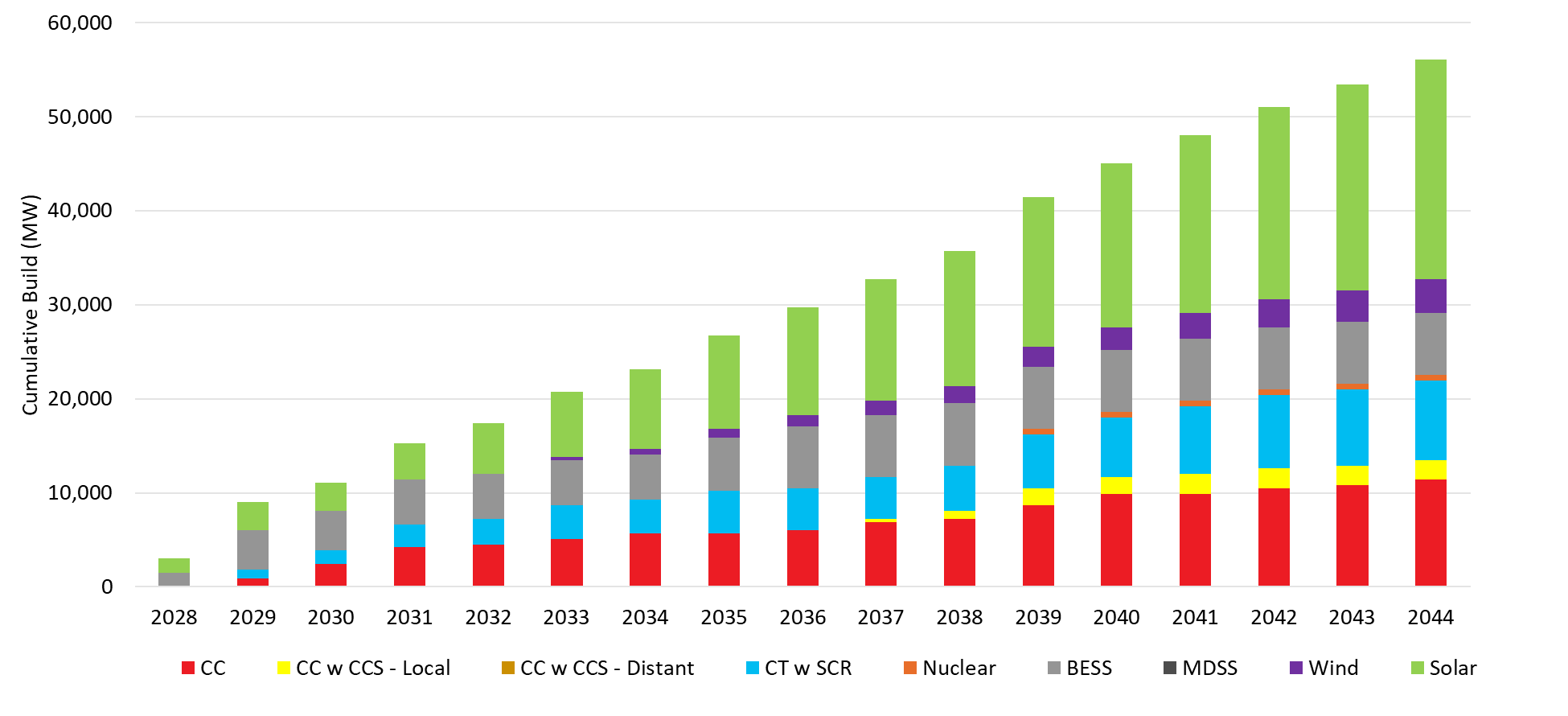
### 3.6.3 Fuel Availability

The natural gas pipelines serving the Company region have become increasingly constrained and less flexible in recent years. These constraints limit the amount of swing and daily imbalance through frequent issuance of daily Operational Flow Orders (i.e., curtailment of gas supply). In addition, the ability to expand and construct new pipeline infrastructure has been challenging. Given the current operational realities and the challenges facing the pipeline infrastructure industry, the Company applied a limit on new NGCCs in the model. In addition, the Company assumes the most reliable operational plan is for new generic expansion CTs to be dual-fueled with the ability to burn fuel oil year round, but augmented with natural gas when it is available. For generic NGCCs, the Company assumed natural gas FT used for existing units would be available to use for new generic NGCCs as either existing units retire or power purchase agreements (“PPA”) expire. Beyond this FT, based on recent industry experience and its own judgement, **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**. Applying this methodology resulted in a limit of **REDACTED REDACTED REDACTED REDACTED**. While this constraint may limit new NGCC selection in some years, overall, there is enough FT between existing FT becoming available and the new FT to add approximately **REDACTED** of new NGCCs by 2050. For generic CTs, the Company assumed oil dispatch during the winter months (December, January, and February) and assumed natural gas dispatch for the remainder of the year.

# 4 Base Case Generic Expansion Plan

The Company produced a base case capacity addition schedule to be used as an input to the integrated resource planning process for the retail operating companies. This base case reflects the scenario with the 111 GHG Rules, moderate gas, and zero-dollar carbon (“111-MG0”) views. Figure 13 shows the recommended capacity and energy addition schedule for generic expansions.

Figure 13: B2025 111-MG0 Expansion Plan



The conclusion of this study, based upon the results of the 111-MG0 case, is that additional generation capacity requirements may involve a mixture of natural gas CC (with and without CCS), dual-fuel CT with SCR, solar, wind, battery storage, and nuclear. Additionally, the study concludes that near term capacity needs may be met with a combination of battery storage, natural gas CC, and dual-fuel CT with SCR. At the appropriate time, actual resource selection will occur in accordance with Commission rules.

Please see Resource Mix Study “GPC and System IRP Summary Data TRADE SECRET.xlsx” for additional summary information regarding the Georgia Power and System capacity, peak demands and energies, actual and target reserve margins, and capacity needs.

# 5 Scenario Analysis Results

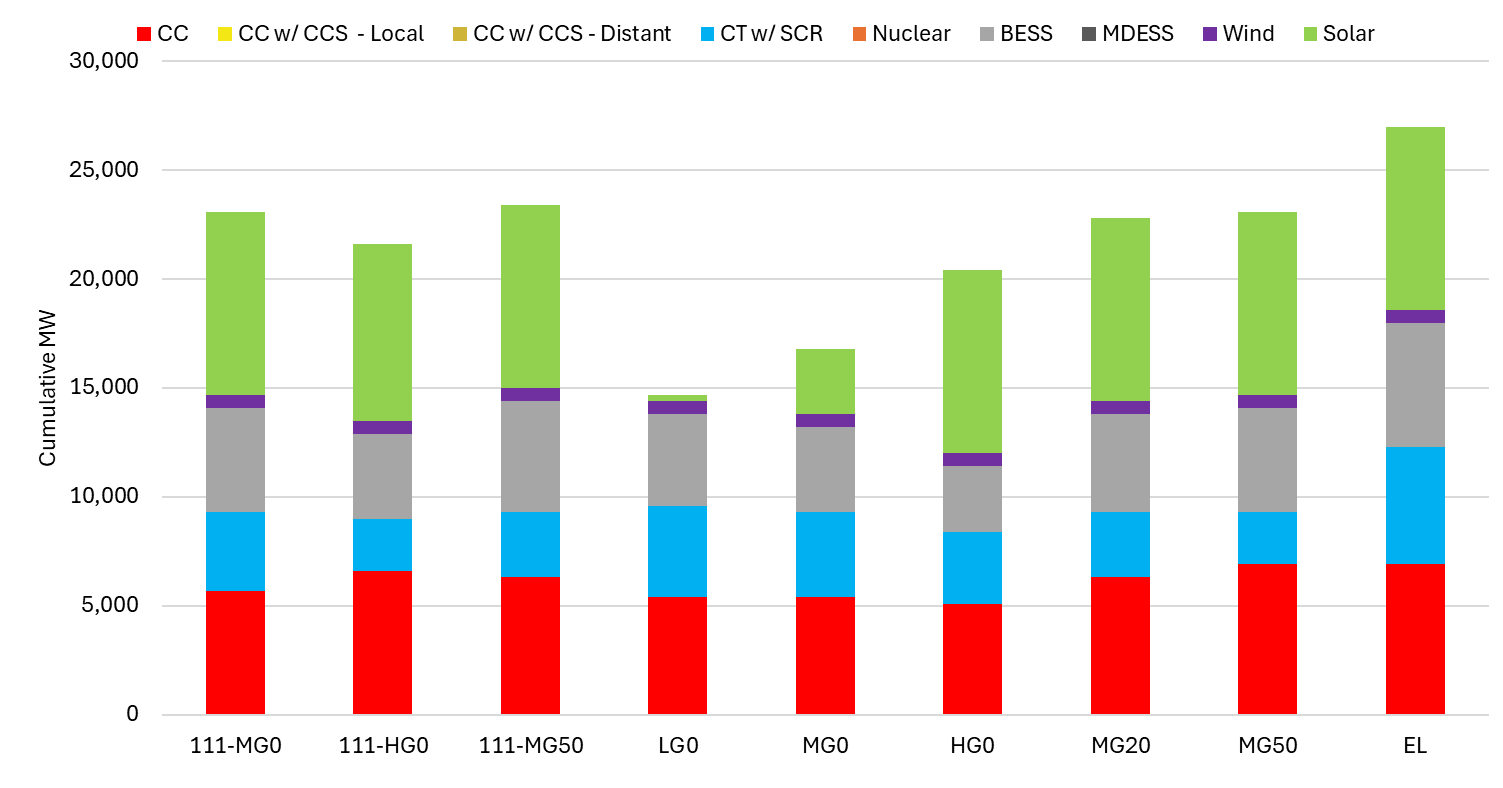
## 5.1 Planning Scenario Cases

As described in Section 2, the Company considers multiple views of the future to account for uncertainties related to long term fuel cost, carbon pressure, technology cost and performance, and future electricity consumption. These futures include variations in future natural gas prices, future pressure on the Company’s CO2 emissions, future cost and performance of generating technologies, and future electricity consumption. For the 2025 IRP, the Company assembled views in those four areas into nine planning scenario cases to explore the potential impacts. This resulted in nine outlooks of capacity and energy mixes, as reflected in Table 1.

## 5.2 Results Summary

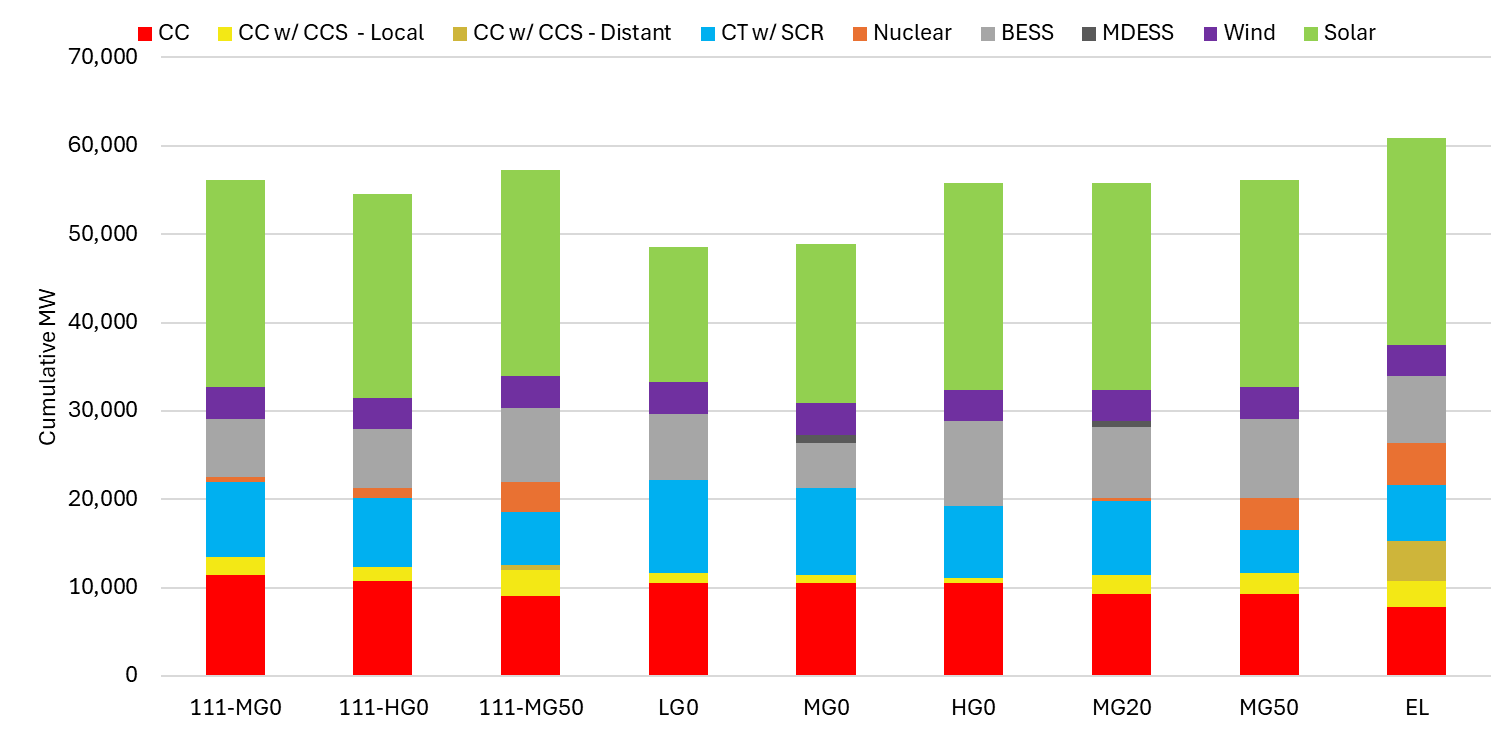
The results of the Resource Mix Study provide an economically optimum resource addition schedule for the retail operating companies, based on the various futures described in Section 2. These results provide an indicative roadmap for long-term decisions based on future uncertainties.

The results of the scenario analysis are broken into two sections, near-term and long-term optimum resource mix. Figure 14 shows the System cumulative build by 2034 and details the near-term optimal capacity and energy expansion plan for all nine scenarios. Based on the scenario results, it can be concluded that additional generation capacity requirements in the near-term may involve a mixture of natural gas CC, dual-fuel CT with SCR, solar, wind, and battery storage.

Figure 14: B2025 Generic Expansion Plan Results – Cumulative MW (2025-2034)

Based on the results of the study, immediate capacity needs are optimally met with a combination of storage, CTs, and CCs. In all nine scenarios, storage is selected as early as 2028. All nine scenarios include a mix of thermal units, renewables, and storage, regardless of variation in input assumptions.

A long-term look at the System scenario analysis offers similar conclusions. Figure 15 shows the cumulative build by 2044 for the nine scenarios. In addition to storage, CTs, and CCs, all scenarios show substantial additions of solar and wind resources to be cost-effective through the planning period. Nuclear shows up in all the scenarios that include GHG pressure, including all the 111 GHG Rules scenarios. The results also indicate that natural gas CC with CCS and medium duration storage may be cost effective to help meet generation and capacity needs based on various futures.

Figure 15: B2025 Generic Expansion Plan Results – Cumulative MW (2025-2044)

Please see Resource Mix Study “Capacity Expansion Plans TRADE SECRET.xlsx” for a summary of results for analyses around all nine scenarios.

1. As referred to herein, carbon pressure, CO2 pressure, and GHG pressure are all used to refer to measures (e.g., taxes, penalties, regulation) to induce reductions of GHG emissions from the electric sector. [↑](#footnote-ref-2)
2. Recurring fixed costs include Fixed O&M, Maintenance Capital, and Natural Gas Firm Transportation. [↑](#footnote-ref-3)