

**Modeling and Key Assumptions Questions:**

**1. What is a capacity expansion model? How does it differ from a production cost model and why are both being used for this study?**

Capacity expansion models simulate mid- to long-term evolution of the power system and are frequently used as a component of long-term power system planning efforts. Capacity expansion models are important tools to help identify and evaluate long-term power system transformation. They synthesize the many different constraints and drivers of change and investment in the power sector, including prices of technologies and fuels, policies and regulations, technology performance and constraints, fuel supply constraints, and changes in load shape and total demand, to identify investment pathways and future systems that meet the policy and/or planning criteria.

Typically, capacity expansion models are formulated as “least-cost” optimizations—they identify generation and transmission investment and operational pathways that meet all power system and environmental/policy constraints at lowest cost. These constraints require that sufficient generation and transmission capacity exists to meet load (plus an additional margin for resource adequacy) at all times and in all regions, that sufficient resources exist to meet ancillary service needs, and that all policy and environmental requirements are met. The models typically use, as inputs, projections of future electricity demand, fuel prices, technology cost and performance, and policy and regulation.

Given that these models simulate both the investment in and operation of a power system over years to decades, they necessarily use simplified representations of grid parameters and power system operations—such as aggregated transmission representations, representative load shapes, and model or aggregate generating units—to ensure that they can be computationally solved in a reasonable amount of time. Furthermore, because such models typically seek a system-wide least-cost optimization, they implicitly assume perfect market conditions. As a result, they do not capture the effects of market failures (or imperfections)—e.g., asymmetric information, market power—nor do they typically capture risk, or non-economic/social drivers of investment. In this study, we use NREL’s Regional Energy Deployment System (ReEDS) model<sup>1</sup> for the capacity expansion modeling.

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<sup>1</sup> See <https://www.nrel.gov/analysis/reeds/about-reeds.html> for ReEDS model documentation.

By comparison, production cost models utilize higher resolution data on transmission, load, and other parameters to simulate how a power system buildout would operate. Such models explore routine power system operations, covering each hour of the year using detailed load, transmission and generation fleet data, and determine the commitment and operation schedule that minimizes production costs.<sup>2</sup>

Although capacity expansion models are often used by utilities in their planning processes, given that they make necessary simplifications and do not capture all power system factors or factors that can impact investment decisions, they are used as a component or core input to developing resource plans. Utility integrated resource plans (IRPs) involve further analysis of investment options, operational (production cost) modeling of future systems, and stakeholder engagement among other aspects that ultimately inform the plans.

In this study, the future systems identified through the ReEDS analysis will be further evaluated with more detailed production cost modeling (using the PLEXOS model) in the next step of Phase 2. It is important to note that investment pathways identified in the ReEDS analysis are subject to change based on the findings of the production cost modeling analysis.

## **2. What are some of the key assumptions of the capacity expansion model?**

Assumptions for this study were reviewed and agreed upon by Duke Energy. Cost assumptions were based on the NREL [Annual Technology Baseline \(ATB\)](#) moderate generation and storage cost and performance projections and Annual Energy Outlook (AEO) 2020 reference fuel cost projections for the South Atlantic region. This ATB case assumes falling capital costs for solar, wind, and battery storage over the period modeled. The AEO projects relatively stable coal and uranium prices, and natural gas prices that increase over this decade but remain relatively steady between 2030 and 2050, slowly climbing from \$4.10 per MMBtu (2030) to \$4.40 per MMBtu (2050). The ReEDS model includes a representation of all current federal and state-level emissions regulations, tax incentives, and portfolio standards relevant to the power sector. This includes a representation of the Virginia Clean Economy Act. Coal retirement dates are based on the current book life of the asset—which is consistent with Duke Energy’s 2018 and 2019 IRPs—but with the option to retire the coal units earlier. New natural gas combined-cycle plants built in the Carolinas are assumed to incur a cost of \$1.50 per MMBtu of natural gas fuel as a proxy for the cost of additional firm pipeline capacity. Existing nuclear plants are assumed to receive approval for relicensing. Additional details on the assumptions and input data used in the ReEDS model

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<sup>2</sup> See <https://www.osti.gov/biblio/1233204> for additional discussion on the distinction between capacity expansion and production cost models.

can be found in the [ReEDS documentation](#). This study also includes an analysis of a number of sensitivities to the cost assumptions and other key parameters.

**3. Why is NREL modeling the entire Carolinas for capacity expansion and not just the Duke Energy balancing areas (BAs) as was done in Phase 1?**

The ReEDS capacity expansion model simulates the power sector evolution of the entire Eastern Interconnection in order to more accurately capture interactions between the Duke Energy system and its neighbors. For this portion of Phase 2, NREL is focusing the analysis on the Carolinas, which are spatially resolved within ReEDS into four balancing areas. The underlying boundaries of the ReEDS balancing areas do not perfectly align with the Duke Energy service territory; thus, results for only Duke Energy's assets are not feasible to produce and we report results for North Carolina and South Carolina (see question 7 for a map of the balancing areas).

**4. How did NREL determine scenario design and assumptions for the base case and the policy case? How were the emissions targets selected and designed?**

The scenario design and assumptions were determined collectively by NREL and Duke Energy subject matter experts. Design and assumptions for the base case were chosen to reflect as best as possible existing and near- to mid-term future conditions. The policy case includes all the same assumptions but layers on the emissions targets—this allows for the exploration of the impact of those targets on investment pathways and the technology mix. The base case generally represents the current state with respect to the lack of any policy or required carbon limits. The policy cases assumed mass-based carbon dioxide emissions limits to represent the North Carolina Clean Energy Plan (CEP) target of 70% reduction carbon dioxide emissions by 2030 relative to 2005 levels and net-zero carbon by 2050. Because the CEP does not include interim target pathways, the modeled scenario did not include such a trajectory. Such targets (assuming a linear ramp between 2030 and 2050) would generally be expected to spread out more of the investment across time, but would be unlikely to substantially affect the portfolio of technologies built.

**5. Why does the study assume that Duke Energy's coal plants run through their book life?**

The analysis assumes that Duke Energy's coal plants must retire by the end of their book life. This retirement date serves as an upper bound for each coal unit; the model also includes logic that allows a coal plant to be retired prior to the end of its book life if the plant's net-value is unfavorable. However, in the scenarios explored, no early retirements are observed. The core scenarios assume that fossil units are allowed to provide operating reserves and in the resulting simulations of the scenarios coal units remain online to help meet reserve requirements. However, it should be noted that even in the base case the

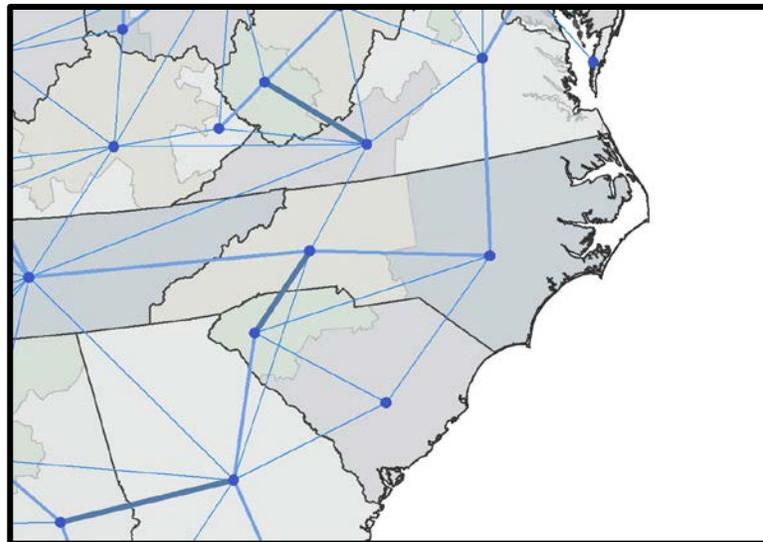
utilization of these plants is reduced substantially over time, and the policy case eliminates coal use for energy provision in North Carolina in 2050.

**6. In the simulations, are any of the other regions assumed to have net zero targets?**

The base case assumption includes the Virginia Clean Economy Act (VCEA), as well as the existing renewable portfolio standards, clean energy standards, and carbon emissions policies (e.g., Regional Greenhouse Gas Initiative, or RGGI) for other states passed as of June 2020. In addition, we examine a sensitivity that explores the potential impacts of an Eastern Interconnection-wide net-zero target in 2050.

**7. Are the Carolinas modeled as one transmission area (i.e., no transmission limits between Duke Energy Progress (DEP), Duke Energy Carolinas (DEC), and Dominion South Carolina)?**

Within ReEDS, the Carolinas are represented as four balancing areas, two each in North and South Carolina. These balancing areas have broadly similar boundaries to the DEP/DEC footprint, but because those utility territories span across states they are not analogous. ReEDS captures the aggregate transmission limits between each of the four geographic balancing areas, but it does not capture the transmission within each modeled balancing area. The figure below highlights the balancing area and transmission representation of the Carolinas in ReEDS.



*Figure 1: ReEDS representation of the Carolinas.*

**8. What are the assumptions around energy exports and imports?**

Overall, the ability to exchange energy between regions is governed by the transmission limits, specifically the assumed thermal rating of the aggregate transmission capacity

between regions. Power flow in ReEDS is represented as simple pipe-flow between regions. However, in addition to these physical limits, this analysis assumes a hurdle rate of approximately \$10/MWh for energy imported by the Carolinas from its neighbors or exported from the Carolinas to its neighbors. This assumed hurdle rate is intended to capture existing challenges in inter-regional coordination and the associated costs to secure transmission for imports and exports. As a result, imports to or exports from the Carolinas will only occur if the difference in the price across regions exceeds this assumed hurdle rate. Lastly, we assume that the Carolinas must attain all firm capacity resources needed to meet its planning reserve from within the geographic boundary of the Carolinas. Although the optimization considers costs in all regions, the costs reported for the Carolinas exclude the costs of capacity builds outside the Carolinas, but do include the costs (or revenues) associated with any imports (or exports).

#### **9. Does this study evaluate reliability or resilience?**

The capacity expansion model used in this study, ReEDS, includes resource adequacy constraints to ensure that sufficient capacity is available to meet load at all times. These constraints are used as a proxy for formal reliability analysis, which involves computationally intensive AC power flow simulations that are not feasible to include within a long-term investment model or even within a production cost model. Instead, within ReEDS a resource adequacy proxy is used. The model dynamically calculates and assigns the capacity credit (the portion of a given plant's nominal capacity that can be relied on during times of system stress, such as high load or low renewable resource quality hours) of both variable generation assets (wind and PV) and non-variable generation assets (e.g., natural gas combined cycle, nuclear) and ensures that during the hours of highest system stress, sufficient capacity (plus a margin for reserves) is available.

Furthermore, NREL will use production cost modeling to evaluate the robustness of the system and identify if the ReEDS buildout can serve load in all hours of a representative year. This type of analysis still differs from formal steady-state and transient reliability analysis. However, it is worth noting that to the extent that the historical representative weather year used for the production cost modeling captures severe weather (e.g., loss of solar output during hurricane), NREL's modeling can assess the ability of the system to operate during extreme events. The modeling will not include a full evaluation of system resilience to major disasters, transmission line outages, or other hazards. Such analysis would require more detailed modeling and can be conducted, but it is beyond the scope of the current study.

#### **10. What are the assumptions on energy efficiency and demand response?**

The AEO 2020 reference load projections account for consumer and utility adoption of energy efficiency measures over the next few decades. After including these estimates, these projections estimate an approximate 0.9% continuous annual load growth rate in the Carolinas from 2020 to 2050. After consulting with Duke Energy, NREL revised the projection to represent additional energy efficiency adoption by reducing annual load growth rates to 0.6%. Demand response resources are not considered in the analysis.

### **Case results questions**

#### **11. What are the key takeaways from this part of Phase 2?**

Overall, the results reinforce the value of diversity in renewable resources as well as flexible dispatchable resources, particularly over the longer planning horizon. The emissions targets are shown to be achieved through rapid deployment of new PV, storage, and wind resources. In the near- to mid-term, PV and storage account for the majority of the new builds with onshore wind playing a smaller role. However, over the longer term, as the capacity value of solar decreases with higher levels of deployment, the economics for wind become more favorable leading to further deployment of both onshore- and offshore-wind resources beginning in the 2030s and growing through the 2040s.

These results are driven in part by the assumed declining costs and increasing performance of solar and storage technologies, along with a gas price forecast substantially above observable market gas prices over this period. However, explored sensitivities to the assumptions about future solar, storage, and wind costs as well as natural gas prices show that although alternative future technology or fuel costs can impact the level of deployment of different technologies (e.g. reduced PV deployment under the High Cost Solar/Low Cost Gas sensitivity), the major trends observed are consistent: solar and storage play a larger role in the near term with wind assets being deployed at increasing rates later in the analysis period. This does not rule out that other sensitivities could result in substantial changes to the resource mix.

Under the net-zero 2050 policy case for North Carolina, a rapid buildout of solar, storage, and wind in the final years leading to 2050 is observed to meet winter and summer peaks and eliminate the last 5 million metric tons of CO<sub>2</sub>. We note that this study did not evaluate the feasibility of the implied rate of siting and interconnection of the resources identified in the ReEDS analysis. Limitations on the rate of siting and/or interconnection could require spreading resource deployment across more time.

#### **12. What is the significance of the base case?**

The base case is meant to be a source of comparison for evaluating the technology buildout, emissions trajectory, and system costs relative to the policy case. The base case is not intended to be a forecast of future evolution, but rather a reference projection that adopts reasonable assumptions for future variables over the long term (such as capital and fuel costs) with which to compare the policy case.

### **13. Does the large amount of solar indicate no role for wind?**

While the analysis identifies the high value of solar and storage resources, both onshore and offshore wind are deployed jointly to meet the net-zero target and future energy demand. Substantially greater deployment of wind is observed in sensitivities exploring alternative future capital costs and technology performance, and broader Eastern Interconnection-wide decarbonization. This indicates that under certain conditions, wind will play an even greater role in the Carolinas. In addition, supply chain or logistical constraints on solar and/or storage deployment or siting could lead to a near-term need for further wind deployment. The importance of wind in these instances illustrates the benefits of having a diverse mix of resources for achieving deep decarbonization.

### **14. Why do the results show a large jump in installed capacity in 2050 in the policy case?**

The large jump in resources occurs, in part, due to the myopic nature of the model used—it is a sequential model that optimizes for existing conditions, including policy constraints. Therefore, the optimization does not consider future changes in the stringency of the target that could result in alternative resource mixes. The policy case includes a net-zero CO<sub>2</sub> emissions target for 2050 for North Carolina. This constraint becomes active in 2050 without interim targets beyond the 70% CO<sub>2</sub> reduction (relative to 2005 levels) required in 2030; accordingly, the least-cost solution from the myopic model is to wait until the constraint is binding to build sufficient capacity to meet this target. As noted above, the ReEDS model does not include constraints on the rate of buildout of new capacity; potential limiting factors such as supply chain, permitting, or interconnection/grid upgrades may require that the buildout needed to achieve the 2050 target be spread out over more time, which could impact both the total costs and timing of those costs.

### **15. Why do emissions in the policy case flatline from 2030 to 2035?**

The mass-based CO<sub>2</sub> emissions limits for the policy case were set at discrete points, 2030 and 2050, with no additional interim targets. Therefore, there is no incentive represented within model to achieve additional reductions on a linear emissions trajectory between the targets. In practice, emissions policies often create flexibility in timing of investments and associated emissions reductions with mechanisms such as banking and borrowing of allowances. Such policy mechanisms, allow for a smoother trajectory of investment and

associated emissions reductions, although outcomes are not predetermined and banking and borrowing can result in reductions/investment being concentrated more in the nearer-term or long-term.

**16. Is the study evaluating a specific carbon policy tied to the CEP goals?**

For the purposes of modeling, a policy must be assumed in the model, and we assume a mass-based CO<sub>2</sub> emissions limit, without the option to trade allowances, bank and borrow allowances, or use alternative compliance methods (e.g., offsets). However, our intent is not to evaluate the merits of alternative policies that might drive deployment toward this goal. Rather, the intent of the NREL study is to explore potential technology pathways to achieving a decarbonized Duke Energy power system in the Carolinas, and to estimate the associated cost of such pathways.

**Technology-based questions:**

**17. Is the capacity credit (or the share of nominal capacity that contributes to net-peak demand reduction) of battery resources constant, or does it drop as you add more?**

ReEDS includes a detailed module for endogenously calculating the capacity credit of storage and variable renewable energy technologies. This module uses detailed hourly load, wind, and solar data for a full-year (8,760 hours) to calculate the capacity credit for new wind, solar, and storage technologies. As more storage resources are added to the system, the net load peaks become wider and flat (due to the shifting of load from peak to trough), which decreases the capacity contribution of a storage technology with a specific duration of storage (e.g., 4-hr), all else equal. However, the declining capacity credit can be mitigated by increasing the duration of new storage technologies built, e.g., from 2-hr to 4-hr, or 4-hr to 6-hr. Furthermore, increasing penetrations of solar PV assets can shift the peak to the evening (from afternoon) and also narrow the peak's duration; this effect is synergistic with storage as it allows shorter-duration storage to maintain its capacity credit. These effects are all captured endogenously within the ReEDS model—they are dynamic with the system composition and load.

**18. What are the assumptions around pumped hydro storage?**

In addition to the pumped hydro storage resources that already exist in the region, all cases assume that 1,600 MW of 12-hour pumped hydro storage capacity is added 2035. This could be thought of interchangeably with an equivalent amount of 12-hour battery energy storage.

**19. Can excess solar generation move between the four BAs?**

Yes, within the four Carolina BAs represented, energy generated from any technology can pass between regions, but the amount is limited by the available transmission capacity between these modeled BAs and informed by the assumed hurdle rate.

**20. What's the assumption for coal unit retirements in the rest of the Eastern Interconnection?**

For existing plants in the Eastern Interconnection, the ReEDS model uses a combination of information on announced plant retirements and technology-specific lifetimes to determine retirements. This retirement date represents that latest existing coal units could operate; the model can also retire plants whose costs exceed the value they provide to the system before its announced retirement date.

**Comparisons to other recent long-term planning studies of the region**

**21. How does the model used for this study and the associated modeling results compare to the models used and results for other recent studies of the region, e.g., the Duke Energy IRPs, or ongoing Nicholas Institute study being conducted for the State?**

In comparing various modeling analyses, key aspects to consider are: 1) the assumptions and input data; and, 2) the model structure and underlying methods. Assumptions and input data, such as future technology costs and performance assumptions, projected fuel prices, load, resource supply (e.g., wind or solar resource availability), and other baseline policy or market conditions can be compared, evaluated, and, with some effort, even harmonized across studies if desired. However, model structures (spatial and temporal resolution, spatial and temporal extent), and methods, including the optimization approach and the methods used to capture complex power system processes and often non-linear phenomena (e.g., generator dispatch, resource adequacy and capacity credit of variable resources and storage, and transmission/power flow) often differ substantially, and these structural and methodological differences can lead to differences in results.

Given this, it is challenging without a deeper analysis to identify the full set of drivers that can lead to different results of two seemingly analogous scenarios simulated by different models.

The ReEDS model is designed to analyze scenarios that achieve high penetrations of variable renewable energy and storage technologies. To that end the model includes very high spatial and temporal resolution of wind and solar resources to characterize to the best degree possible resource availability and quality. The model also employs hourly

chronological algorithms (re-evaluated between solve years) to dynamically assign capacity credit to variable resource and storage assets, and minimum curtailment rates to variable resources. These features allow for a robust treatment of both the values of variable renewable and storage assets as well as the challenges operating systems with high penetrations of such technologies.

For further information on ReEDS, see <https://www.nrel.gov/docs/fy20osti/74111.pdf>.

For further discussion on the representation of wind and solar technologies within long-term capacity expansion models (including ReEDS, IPM, NEMS, and REGEN), see <https://www.nrel.gov/docs/fy18osti/70528.pdf>.