Reliability and Operational Resilience Considerations

Transitioning the power system to lower-carbon sources of energy has been identified as one of the grid's highest magnitude reliability risks by the North American power industry.[1] A core objective of the Carolinas Carbon Plan ("Carbon Plan" or the "Plan") is to meet Session Law 2021-165's ("HB 951") requirement that "any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."[2] This requirement recognizes Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP" and, together with DEC, "Duke Energy" or the "Companies") public service obligation to plan and operate their generating fleets and transmission and distribution systems to provide reliable power system operations to their customers 24 hours per day, 7 days per week, 52 weeks per year in accordance with federally mandated North American Reliability Corporation ("NERC") Reliability Standards.

Each of the Carbon Plan portfolios will require major changes in generation resources and create new challenges to ensuring the adequacy and reliability of the systems. The changes required to execute the Carbon Plan will include the retirement of existing coal units, the addition of significant amounts of intermittent renewable generation, the addition of new flexible gas-fired generation and energy storage necessary to enable coal unit retirements and integration of renewable resources.

To ensure the continued reliability of the DEC and DEP systems under each of the Carbon Plan pathways and portfolios, the Companies evaluated reliability risks and mitigating solutions in the following areas:

- Resource and energy adequacy from renewables and storage
- Additional firm gas generation and transportation
- Coal generator reliability during the transition

[1] North Am. Elec. Reliability Corp., 2021 ERO Reliability Risk Priorities Report (July 2021), *available at* nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf.

[2] HB 951, Section 1(3).

- Zero Emitting Load Following Resources to reach net-zero
- Flexible generation needs for integrating renewables
- Future system resilience to withstand extreme events[3]

Drawing on the detailed technology and modeling discussions through the Plan, this Appendix documents the sources of these reliability risks and the Companies' planned mitigating solutions as Duke Energy begins executing the Carbon Plan.

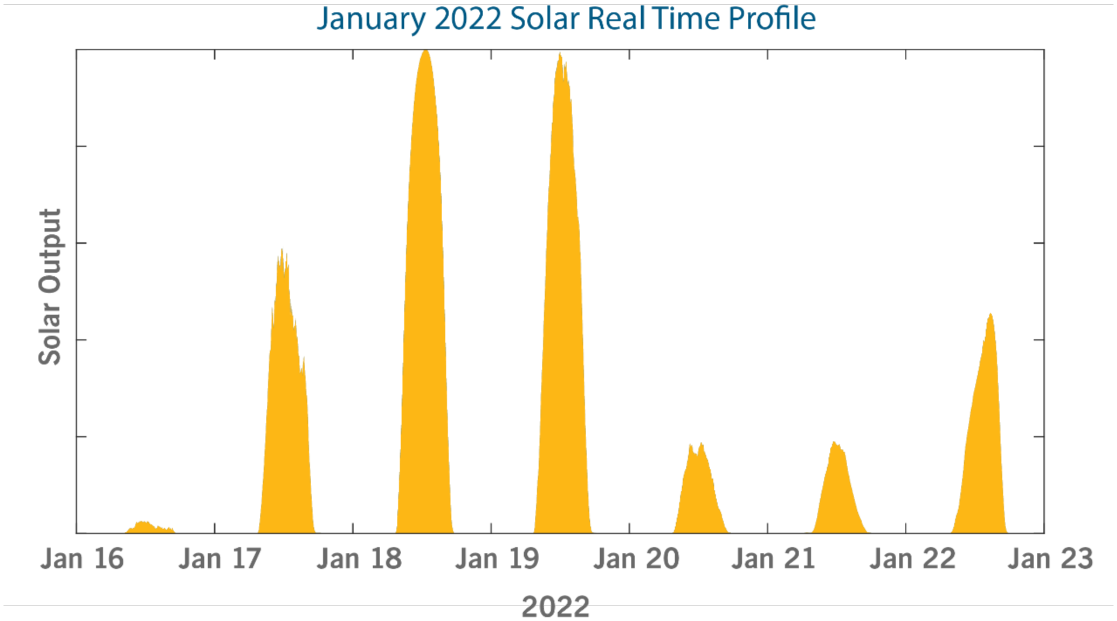
Resource and Energy Adequacy from Renewables and Storage

Today, the Companies primarily rely on a mixture of nuclear, coal, gas, pumped storage hydro and increasing amounts of solar to provide the capacity and energy necessary to meet peak electricity demands. In the traditional planning environment in which these systems have been designed, resource adequacy has entailed having sufficient *capacity* resources available to reliably serve electric demand, with consideration given to unplanned outages of generating equipment, uncertainties in load and renewable forecasts, fuel availability, high loads and weather-dependent renewable output caused by extreme weather events.

With increased levels of renewable generation, capacity adequacy remains relevant, but a new risk of *energy* adequacy is introduced. Weather patterns leading up to peak events may not allow renewables to generate (and storage to allocate) energy to meet demand in all hours. Energy adequacy is a particular concern in the winter months during which the Companies' systems experience the highest potential loads due to electric heating during cold weather events. As weather during the winter has high variability, shorter daylight hours, and the potential for consecutive days of low irradiance (low solar output), periods of extended low output from solar are possible. A recent example of this is shown in Figure Q-1 below for a week from January 2022. This week featured multiple winter storm systems that brought rain, snow and ice to the Carolinas. The combination of wintry precipitation and cloud cover suppressed solar output for much of the week, with only two days experiencing relatively high solar capacity factors. During an extreme cold weather period, similarly low solar capacity factors - even with the significant nameplate solar additions identified in the Carbon Plan - could lead to insufficient energy for serving load if not supplemented with alternative dispatchable, high capacity factor, fuel secure resources.

[3] The potential adverse impacts to the electric grid has been a topic of concern for both the North Carolina Utilities Commission and Public Service Commission of South Carolina, both of which directed utilities subject to their respective jurisdiction to provide information regarding measures that have been or will be taken to mitigate the effects of an extreme weather event to customers. *See Order Opening Investigation, Scheduling Technical Conferences, Requiring Responses, and Allowing Comments and Reply Comments*, Dkt Nos. E-100, Sub 173 & E-100, Sub 163 (January 26, 2022) (opening investigation into the reliability and integrity of North Carolina utilities during extreme weather events and in light of the outages and rolling blackouts experienced in Texas in February of 2021 due to Winter Storm Uri); *Order Establishing Docket and Guidelines by Utilities and Other Interested Stakeholders Regarding Mitigation of Impact of Threats to Safe and Reliable Utility Service*, Order No. 2021-163, at 1, Docket No. 2021-66-A (Mar. 10, 2021) .

Figure Q-1: Solar Real-Time Profile



Seasonal and daily variations in renewable output also have a strong influence on these resources' ability to contribute to meeting peak loads. In winter, solar output generally does not align with the demand peaks experienced at dawn and dusk. Pairing solar with integrated or system-level storage capabilities can help shift its output to times of greater demand, and this synergistic relationship can make both resources more valuable to the grid - contingent on favorable weather conditions. For wind, the meteorological conditions that cause high wind output tend to align with winter peak demands, with onshore and offshore wind having higher overall output in winter than summer seasons. However, weather patterns with low wind speeds are possible during summer peak season.

This variability and potential for extended periods of low output drive a need for resource diversity and complementary, dispatchable resources[4] to ensure energy adequacy. Gas generation provides this needed flexibility and dispatchability on the near-term trajectories to decarbonization. On longer-term pathways to achieving carbon neutrality by 2050, new Zero Emitting Load Following Resources ("ZELFR"), including hydrogen, will be necessary components of resource and energy adequacy.

The Companies must also plan to meet these challenges without over-reliance on neighboring systems, which are also rapidly transitioning toward a cleaner resource mix.[5] Other utilities may

[4] "Dispatchable" resources are able to have their power output increased and decreased on demand. Traditional fossil fuel, hydropower, and energy storage resources are generally considered to be dispatchable, but future technological advancements may allow for essential flexibility from low-carbon resources such as nuclear, wind, and solar.

[5] For example, even without new policy measures, the combined growth of solar PV in the SERC Southeast and Central Regions and PJM West and Dominion regions exceeds 75 GW by 2050 as modeled in the reference case by the U.S. Energy Information Administration ("EIA"). *See* EIA 2022 Annual Energy Outlook, *available at* https://www.eia.gov/outlooks/aeo/.

potentially experience concurrent periods of limited energy and capacity availability at the same time as the Companies.

Additional Gas Generation and Transportation

Gas resources (combustion turbines ("CT"), combined cycle units ("CC") and dual fuel conversions) are a necessary reliability "bridge" to achieving carbon neutrality to fill part of the resource adequacy needs created by the retirement of coal facilities. As NERC President and CEO James Robb explained to the United States Senate Committee on Energy and Natural Resources in March 2021:

> Natural gas is essential to a reliable transition. . . . [O]n a daily basis in areas with significant solar generation, the mismatch between the solar generation peak and the electric load peak necessitates a very flexible generation resource to fill the gap. Natural gas generation is best positioned to play that role. The criticality of natural gas as the "fuel that keeps the lights on" will remain unless or until very large-scale battery deployments are feasible or an alternative flexible fuel such as hydrogen can be developed.[6]

In all Plan portfolios, additional gas generation capacity is a necessary complement to renewables and storage to provide energy adequacy during winter months when solar outputs are not well correlated to the peak load shape and overall energy demands can remain high for extended periods of time. New gas generation resources are also necessary to work in tandem with storage to provide the increasing level of dispatchable operational reserves necessary to match the growing variability and uncertainty that accompany a grid more reliant on weather-dependent renewables.

Like existing coal resources, gas technology options have the key reliability advantage of controllable output over long durations. Advantageously, unlike coal units, CTs and CCs are more efficient, rely on a less complex physical fuel supply infrastructure (no railroads, conveyor belts, coal pulverizers or other ancillary systems coal units require), and are capable of intra-day commitment and cycling, with some specifically designed CTs capable of coming online within 10 minutes of being called upon, making them highly valuable as operational reserves. Utilizing gas dual-fuel capabilities at existing coal units also allows for faster ramp rates, lower turndown and more flexible commitment - albeit less flexibly than for CC units. For similar reasons, gas-fired units tend to have higher availability rates, reducing the reserve capacity required in system planning to account for unplanned generator outages.

These operational advantages of utilizing additional gas to provide resource adequacy in the Carolinas require the need to secure new, firm interstate natural gas pipeline capacity to ensure that gas is available throughout the year and specifically on cold winter days. Whereas coal facilities can rely on a month or more of on-site fuel storage (coal "on the pile"), gas-fired generation relies on the availability

[6] James R. Robb, North Am. Elec. Reliability Corp., Testimony Before United States Senate Committee on Energy and Natural Resources, Full Committee Hearing On The Reliability, Resiliency, And Affordability of Electric Service, at 9, 10 (Mar. 11, 2021), *available at* https://www.energy.senate.gov/services/files/EB1D7E02-4DFF-A6A9-002341DA34CF.

of adequate real-time pipeline deliverability or onsite diesel to ensure fuel availability. As discussed in Appendix N (Fuel Supply), the major interstate pipeline supplying the Carolinas is fully subscribed, and during the coldest winter days, the gas demand for electricity generation coincides with peak Local Distribution Company demand. Currently, obtaining delivered gas supply into the Carolinas from the marketplace during these periods of high demand is constrained. The constrained market also leads to gas supply that can be cost prohibitive, if even available at volumes required.

At present, Duke Energy manages its gas supply during winter peak by cost-effectively utilizing other generation resources like coal to provide essential capacity for resource adequacy, running diesel-capable combustion turbines when firm gas supply and transportation could be unavailable or too costly to secure, and utilizing the available gas supply for more efficient CC units or those CTs without diesel-fired capability. During some of these periods, combustion turbines running on diesel were necessary resources to maintain reliability, most notably during a multiday North American cold wave the first week of 2018.

Additional CC and CT units are necessary to replace the peak capacity provided by existing coal units, and this can only be reliably accomplished by securing incremental interstate gas firm transportation to ensure adequate supply for existing gas resources on the Companies' systems in the absence of coal generation, and incremental gas firm transportation and/or on-site fuel backup for new gas resources. Any additional planned diesel or liquified natural gas backup fuel usage would require expanded on-site supply and storage infrastructure to ensure fuel certainty during prolonged peak events. The Carbon Plan includes a fuel supply portfolio sensitivity analysis to quantify resource selection and portfolio performance changes if Appalachian gas supply does not materialize. The lack of new Appalachian supply in this sensitivity presents reliability considerations as unconstrained gas burn in 2030 and 2035 could exceed 2 billion cubic feet during the most extreme winter peaks, which is more than quadruple the current capacity of DEC and DEP's interstate firm transportation portfolio. New incremental firm transportation is needed to help make this level of utilization possible and in the alternative would require resources to increasingly operate on backup fuels and delivered market supply, thereby increasing exposure to price volatility and constrained supply during these events.

To reach the 2050 carbon neutrality target, not assuming carbon capture, emissions from natural gas ultimately must be phased out. However, the new CT and CC resources that utilized natural gas to support the 70% reduction are selected as part of the resource portfolio because their flexibility and dispatchability are a core enabler of emissions reductions. These resources (and their contribution to resource adequacy) can, and are expected to, operate even in a net-zero power system by utilizing a carbon-free fuel such as hydrogen (see Appendix O (Low-Carbon Fuels and Hydrogen)).

Coal Units Reliability During the Transition

Modeling for the Carbon Plan has shown that much of the Carolinas coal facilities must be retired by 2030 to meet HB 951 CO_2 emissions reductions targets. Additionally, the Carbon Plan retires the final coal units (or ceases coal operations in the case of Cliffside 6) by the end of 2035, consistent with Duke Energy's goal to be out of coal by 2035. However, the Companies' planned exit of coal generation does not come without risks, and while renewables, storage and gas begin to replace coal, properly managing the coal units through the transition process is essential to maintaining reliability. Due to their significant size and on-site fuel storage capability, the coal units - even as they are planned to be retired - contribute in a substantial way to resource adequacy. Iterative modeling of the pathways to carbon neutrality has shown that the timing of coal unit retirements can be challenging to match their contribution to resource adequacy with replacement generation resources. For example, when some of the Companies' supercritical coal units are retired, adequate new dispatchable resources must already be available for the system to remain reliable once those units are no longer in service.

Coal units remaining in service must also be kept reliable during the transition. Given their importance to system reliability, these units must be adequately maintained so that they are available when called upon. It is possible as the system transitions that these units are used less frequently - sometimes only seasonally for reliability purposes - and these new operating patterns may increase reliability risks if not adequately considered.

Fuel certainty at the remaining coal facilities will also be essential. Units with Dual Fuel Operations capability - able to run on gas or a blend of gas and coal - are slated to be the last of the coal units retired. However, given the gas supply constraints discussed above, these units are likely to run on coal during times of winter reliability events. While coal generation has traditionally been a reliable provider of resource adequacy in part due to its long-term, onsite fuel storage, contracting for adequate coal supply and associated transportation may become increasingly difficult as coal is retired across the country and the coal mining industry faces an uncertain future. As such, coal supply and inventory management strategies will continue to be essential challenges for the duration that coal remains in service.

These issues and the appropriate role of the Companies' coal units during decarbonization are in more detail in Appendix N (Fuel Supply).

Zero Emissions Load Following Resources ("ZELFR")

Achieving the 2050 carbon neutrality target will require new technologies to meet the reliability challenges posed when achieving carbon neutrality. Assessing technology viability and progress multiple decades into the future is uncertain, but the attributes desirable in new grid sources are knowable based on system needs. In general, it is expected that additional incremental reliability and carbon reductions provided by new variable renewables and storage will decrease at very high penetrations. What is needed are resources that do not emit carbon and have the dispatchability and flexibility characteristics that are fundamental to power system reliability (e.g., load-following capabilities). This new technology need is referenced throughout the Carbon Plan as a general need for zero emissions load following resources or "ZELFR." To the extent that known innovations meet the ZELFR criteria and were considered viable modeling options (such as standard modular nuclear reactors and use of hydrogen as a zero-carbon fuel), these have been modeled in the portfolios. However, the ultimate resource portfolio solution to reliably meet long-term, carbon neutrality targets will be influenced by many factors, and power system transformation plans will be adjusted as new information on technological development becomes available.

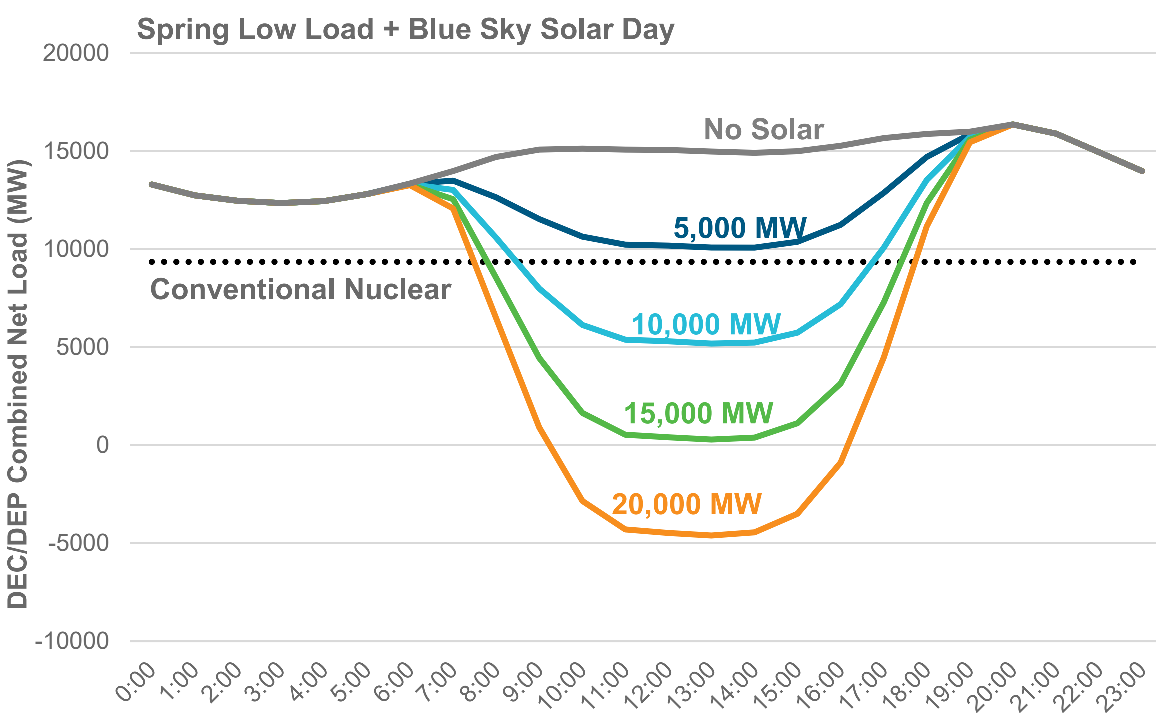
Flexible Generation Needs for a Changing Grid

As intermittent renewable energy becomes an increasingly large share of generation capacity in DEC and DEP, the remaining electricity demand that must be met by dispatchable sources - that is, the electric load net of renewable energy contributions, commonly referred to as “net load” - will change in timing, shape and magnitude in ways that will place new stresses on the power system. Given the day-night (diurnal) pattern of output, high levels of solar can become increasingly difficult to manage, with two key challenges that must be met in future portfolios: accommodating very low net loads at midday, and managing the associated increasingly rapid decreases and increases in net load as the sun rises and sets.

The Net Load Valley

High levels of solar can create a deep “valley” of net load during sunlight hours. In the summer months, this increase in solar energy output typically aligns with increases in electricity demand for cooling as the day becomes hotter into the afternoon hours. However, in winter and in the spring and fall “shoulder” seasons, load patterns are different (afternoons being milder than in the summer), and high solar output and low load combine to create a valley in the net load profile that the remaining system must accommodate. To illustrate this, Figure Q-2 below overlays the load profile from a mild, sunny spring day with potential solar output at different levels of installed capacity.

Figure Q-2: Spring Low Net Load Example Scenarios

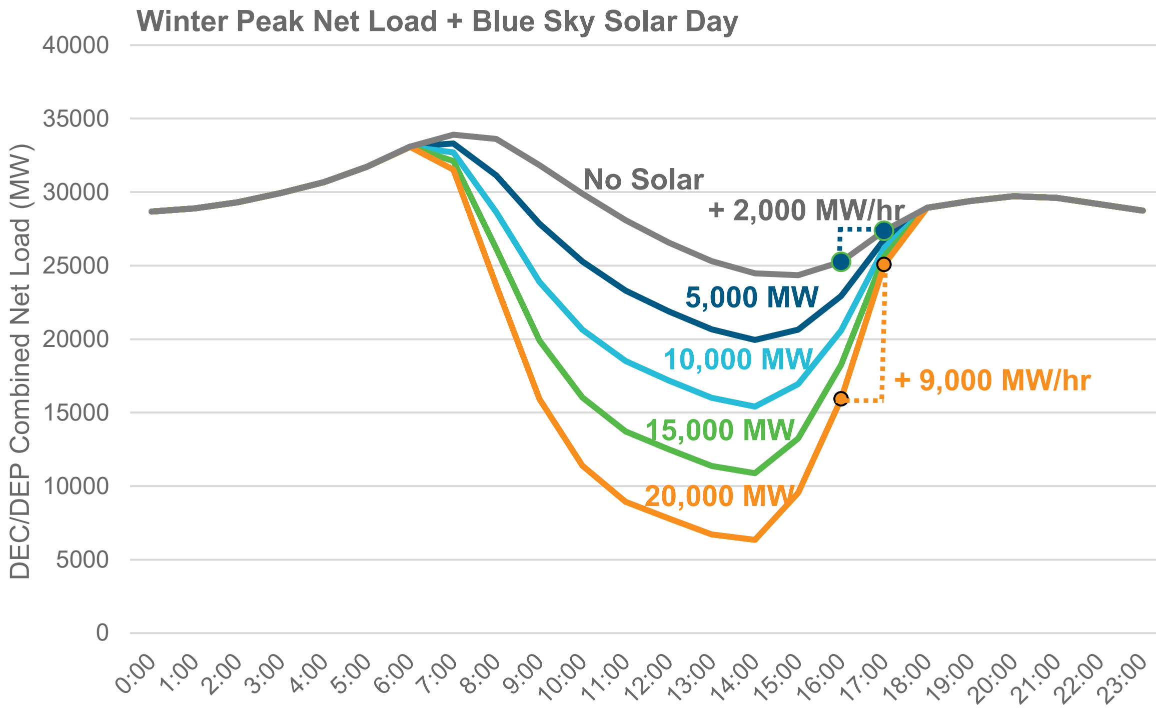


In a system without solar, this prototypical mild spring day would be most likely to experience a minimum net load in the early AM hours. The addition of solar begins to shift this minimum to lower and lower levels, bottoming out in the early afternoon as the net load profile becomes dominated by output from solar resources. At high solar penetrations, springtime minimum loads begin to drop to - and below - the potential output from Carolinas' conventional nuclear power plants. Energy usage must be instantaneously balanced with energy supply, and as the combined output from nuclear and solar exceeds demand throughout midday, dispatchable units (such as combustion turbines) must turn off, and energy storage and load shifting become necessary to increase electricity demand. In the absence of adequately high demands, low-carbon energy output would have to be curtailed to maintain system balancing and frequency metrics within required levels. At the highest potential solar penetrations seen on the path to carbon neutrality, net load can drop below zero; at this level of solar output new energy demands (such as "green hydrogen" production) could be considered to utilize renewable energy outputs more efficiently. If new demands fail to materialize, curtailment of surplus renewable energy must become a routine operational strategy to maintain system reliability during the most challenging seasons.

Load Following and Ramping

Beyond the issues created by low (or even negative) net loads in isolation, high levels of solar output create an additional challenge in the evening as sunlight wanes and solar output drops, causing net load to "ramp" upward quickly. The rate of this increase in net load is high in the spring scenario which has a relatively flat load throughout the day, but the reliability challenges become worse if load is increasing at the same time solar output is declining. This can occur during winter, and Figure Q-3 below, using historical solar and load profiles, shows the impact of solar penetration on evening ramp when the system is experiencing peak load from low temperatures.

Figure Q-3: Winter Peak Net Load Examples, with Maximum Hourly Ramp Requirement



In the absence of solar generation, net load would be expected to peak in the morning around 7 AM, decline throughout the day, and increase steadily to a secondary evening peak in the 7-9 PM time frame. In following this typical peak load pattern, the maximum hour-over-hour change in system demand is approximately 2,000 MW per hour with no solar output during a 4-5 PM ramp upward to the evening peak. Adding solar to this standard pattern creates additional stress on the system as solar and load are following opposite trajectories. At the extremes, with 20,000 MW of installed solar under sunny conditions, the combined DEC/DEP system would experience a 4 PM to 5 PM ramp exceeding 9,000 MW - equivalent in magnitude to turning on the full capacity of the Duke Energy-owned Carolinas' nuclear fleet in a single hour. The morning hours present a mirror image of this challenge, where dispatchable resources must ramp *down* quickly as load recedes and solar output increases. While Figure Q-3 above represents these challenges using historical data, changes in load and the installed solar resources may cause future ramps to be even steeper, with ramp rates in the 2035 portfolio modeling exceeding 11,000 MW/hour depending on the quantity of solar deployed.

In the modeling efforts in support of the transition to achieve carbon-neutrality, the combined flexibility of storage and gas resources is necessary to reliably navigate the net load valleys and manage the steep ramps as solar output increases and then decreases throughout the day. For example, storage resources such as battery storage and the Bad Creek Hydroelectric Station expansion project help mitigate the depth of the net load valley and ease the morning and evening ramps. However, given the need to hit morning and evening peaks with limited solar contributions, and the frequent need to satisfy energy requirements through the nighttime that exceed nuclear output and storage capability, the system relies on existing and new CC gas turbines as a flexible workhorse technology. Through the transition to carbon neutrality, the demands on the CC units shift from operating as near-baseload resources as they are today, to a resource that frequently "cycles" (turns off then on again within the day) on a regular basis to fill in the gaps left by renewable energy.

Combined Cycle Flexibility

In coordination with energy storage, operating the CC fleet in a more flexible manner to meet the ramping and cycling demands of portfolios with significantly increased amounts of intermittent resources will be necessary to maintain system reliability in all portfolios to achieve HB 951's CO_2 emissions targets. Historically, the DEP and DEC CC fleets have been designed and operated specifically for baseload operations and have faced a limited need to cycle given the flexibility of the remaining generators. DEP, with a higher solar penetration, even invokes a Lowest Reliability Operating Limit ("LROL") designed to ensure sufficient synchronous generation such as gas CCs stay on-line to ensure adequate reliability and energy for serving the evening peak demand when solar output decreases to zero. This LROL process requires curtailment of solar if off-system sales of the excess energy are not available during the mid-day net demand valley in order to avoid cycling CCs for reliability purposes. However, for certain periods of the year, some of the Carbon Plan portfolios require cycling the majority of the CC fleet on a daily basis in order to keep zero-carbon energy injecting into the system to meet carbon reduction objectives. This operational approach will be new to the Companies' fleet and is likely to require changes to operations and maintenance practices and investments and upgrades to increase unit flexibility. The process of restarting the majority (and in some seasons, entirety) of the CC fleet within a few hours has not been tested, and coordination among all units and stages will be a challenge to precisely match the rapid increases in net load into the evening hours. CC units have startup profiles, holds, and minimum operating loads that must be respected to maintain reliability and ensure a successful startup without equipment damage. Various studies and experience have shown an increase in startup failures for CC units relative to other peaking units (e.g., CT, hydro), and the relationship between cycling capability and the lowest capacity at which CCs can operate reliably is not yet fully understood.

One known risk is that increasing the cycling frequency of the CC fleet is expected to result in diminished reliability of the units as they incur wear and tear from repeated starts and stops. Various studies have shown a direct correlation between an increase in cycling and an increase in unexpected reductions in generating capability.[7] There are several strategies that may be implemented to help reduce the additional reliability risks that result from increased CC cycling such as modifications to existing units including additional infrastructure and equipment. CCs operating in cyclic environments tend to operate more reliably if they have additional equipment such as automatic valves, advanced control systems, fuel controls, trip prevention, and additional and more automated controls. Additional operator monitoring and training should also help increase unit reliability. There would also be an expected change in operation and maintenance needs to cover additional preventive maintenance to

[7] Elec. Power Research Institute, Impact of Cycling on the Operation and Maintenance Cost of Conventional and Combined-Cycle Power Plants: 2013 Technical Report (Sept. 2013), *available at* epri.com/research/products/3002000817.

mitigate the impacts of cycling, training the operations and maintenance teams, and updating operating procedures to prepare the CTCC fleet for cycling operations.

Accommodating Increasing Uncertainty

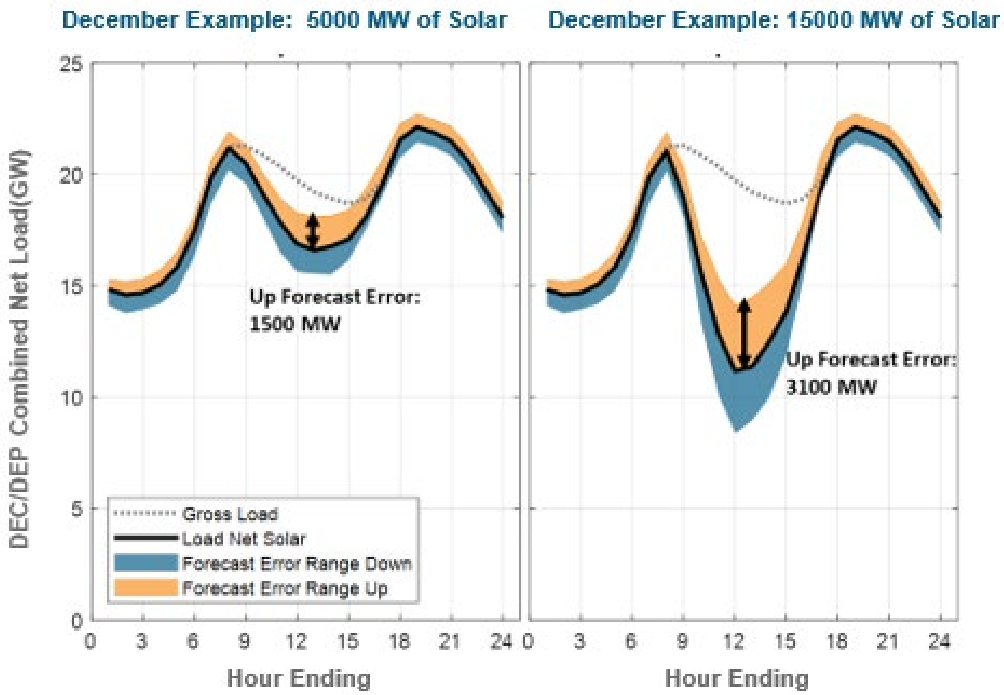
In addition to changing the shape and magnitude of net load in ways that may be challenging for the power system to manage, increasing levels of intermittent renewables also increase the uncertainty of balancing supply and demand. This uncertainty manifests in two ways: higher magnitudes of forecast errors and higher intra-hour variability in the load net of renewables. In both cases, sufficient dispatchable resources must be available to ramp fast enough to ensure reliable operation of the grid. These resources are held "in reserve" (that is, not otherwise in use) to respond to any potential variability. Other regions are already experiencing a growing need for reserves as uncertainty on the power system increases: Midcontinent Independent System Operator ("MISO") has recently added new reserve products and increased its "up" reserve requirements,[8] and power markets across the U.S. are facing new forecasting and ancillary reserve capacity challenges to integrate increasing amounts of weather-dependent renewables.[9]

Renewable resources like solar are not perfectly forecastable into the future due to being driven by the weather. Figure Q-4 below shows a typical December load shape for the combined DEC/DEP footprints with either 5,000 MW (left panel) or 15,000 MW (right panel) of solar on the system. The bands around the net load shape show the amount of operating reserve capacity that needs to be carried by dispatchable generation resources to respond to a routine forecast error due to load and solar uncertainty.

[8] MISO Energy, MISO's Response to the Reliability Imperative: Updated January 2022, *available at* https://cdn.misoenergy.org/MISO%20Response% 20to%20the%20Reliability%20Imperative504018.pdf.

[9] Fed. Energy Reg. Comm'n, Energy and Ancillary Services Market Reforms to Address Changing System Needs: A Staff Paper, Dkt. No. AD21-10-000 (Sept. 2021), *available at* https://www.ferc.gov/new-events/new/ferc-staff-issues-report-energy-and-ancillary-services-market-reforms-address.

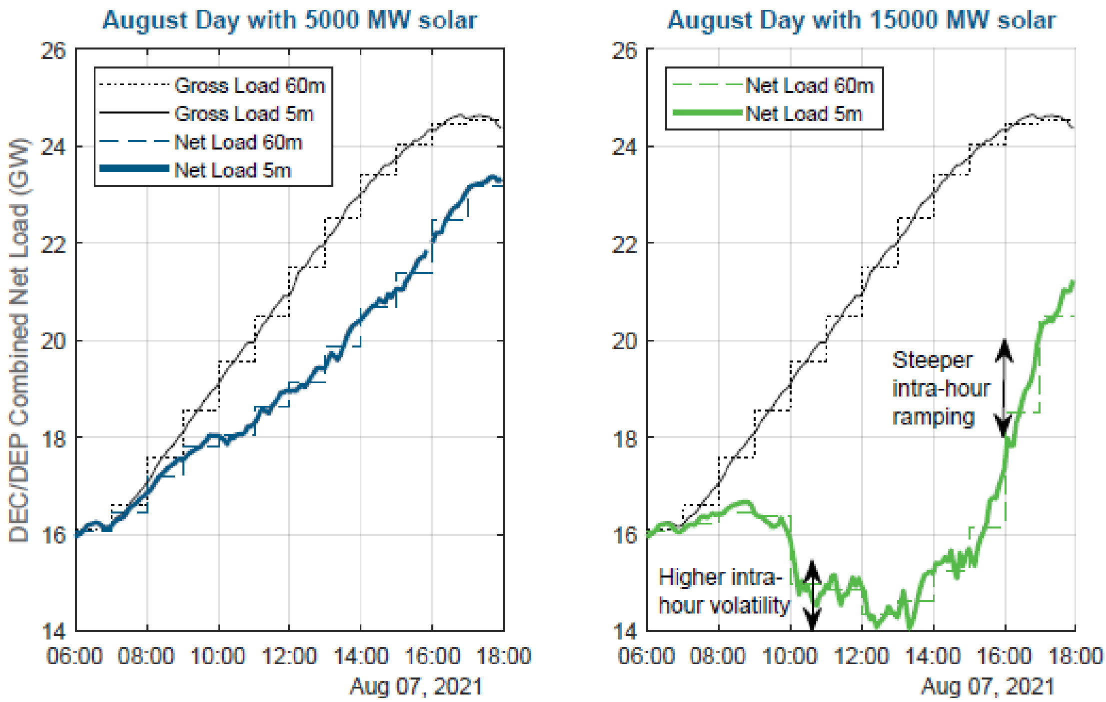
Figure Q-4: Example December Day Forecast Error Uncertainty



In this December example, Duke Energy system operators ensure the system can respond in a timely fashion to potential forecast errors by ensuring enough additional generating capacity is available during the day-ahead planning process. Enough spare capacity would need to be available from either online units (typically coal and CCs) or units that can start up fast enough to respond to the realization of forecast uncertainties (storage and CTs).

Reliable operation of the grid requires that electricity demand be balanced with supply at all times, and the collection of units committed and online must be able to ramp fast enough to mitigate minute-by-minute deviations in the net load. A larger portion of renewable resources in the generation mix creates a larger requirement of online, fast-ramping dispatchable generation. Figure Q-5 below shows the hourly and intra-hour observations of load and net load for an August day with 5,000 MW or 15,000 MW of solar on the system. The higher solar portfolio highlights the challenges of larger intra-hour deviations and steeper intra-hour ramps, both of which require additional regulating reserves to maintain reliable operation of the grid. Reserves serving the role of matching intra-hour volatility are commonly known as “regulation” reserves and can respond to updated dispatch instructions every four seconds.

Figure Q-5: Example August Day Net Load Volatility



In the case of both types of uncertainties, spreading responsibility for holding operating reserves across a larger, more diverse power system can lower the overall ancillary reserve requirements. This load and renewable resource diversity is one of the primary benefits from the proposed Combined Systems Operations approach described in Appendix R (Consolidated System Operations).

Storage as a Reserve Resource

Energy storage resources have many operational characteristics that make them ideal for providing fast response reserves. These types of units can commit and ramp quickly and tend to have wide operating ranges. This flexibility allows them to respond to grid reliability needs as they emerge, whether it is following rapid minute-to-minute net load fluctuations or dispatching in response to an unexpected generator outage. However, as discussed in the resource adequacy section, storage resources are energy limited and their capability to provide operating reserves is dependent on the amount of energy available to charge them, as well as the limited foresight the operator has about future conditions to plan for charging and discharging at optimal times. A storage resource can only provide as much “up” reserve as it has available stored energy, and only as much “down” reserve as it has headroom to maximum storage volume. Due to small efficiency losses when both charging and discharging energy, storage becomes a net consumer of energy from the grid when deploying its reserve capabilities. Storage is highly capable but deploying those capabilities to meet reserve requirements must be carefully considered in any reliability analysis.

Primary Frequency Response Issues

CO_2 emissions reductions will also change how, electrically and physically, the grid responds to disturbances such as a generator outage. Today, when a generator or transmission line unexpectedly goes offline ("trips"), the supply-demand balance on the system is disturbed and system frequency begins to drop; the remaining generators respond in two ways. First, synchronous generators (for example, physically rotating hydropower, steam or gas turbines) intrinsically "push back" against the loss of frequency the disturbance causes. These spinning generators have a physical inertial response that transfers their rotational energy to the electrical system, slowing the rate at which the system loses frequency. Secondly, unit control systems ("governors") respond to locally sensed frequency deviations and change fuel inputs (e.g., steam, gas, water) to the mechanical system to compensate for the system being out of balance. The amount of inertial mass – number and size of synchronous machines connected to the interconnection – determines rate and magnitude of the change caused by deviations in resource and demand power balance. Inertia intrinsically slows the loss of frequency while governor response then reacts to help restore balance. For both of these reasons, the more synchronous machines on the system, the less volatile changes to the system's electrical and mechanical speed.

There are many synchronous resources from generators to motors in an interconnected system as large as the Eastern Interconnection. As the Companies' combined fleet transitions to fewer synchronous and more asynchronous resources, the interconnection will become "lighter" (less spinning mass) and system frequency more susceptible to deviations in the balance between power supply and demand. Smaller, "islanded" systems without tight integration with many neighbors, such as individual Hawaiian islands or Texas' ERCOT market, must maintain very tight sets of controls to manage such frequency deviations compared to the much larger Eastern and Western Interconnections.

New resources will need to be responsive to frequency deviations by both decreasing and increasing their power output. Because each resource actually consists of a large number of smaller resources (e.g., invertors), their local control systems will need to have appropriately responsive and coordinated control system designs. Due to inherent speed and time delays, they will also need to be coordinated with other systems, much like within relay protection coordination. Fast, accurate response from these new resources will be necessary as the system loses the inherent physical buffer provided by synchronous generator inertia. Conversely, if inadequate control systems, such as those that do not allow for inverter-based resources to ride through minor frequency events, are utilized, new asynchronous resources may exacerbate frequency deviations instead of being managed to mitigate them. To ensure inverter-based resources are properly controlled for power system stability, the North American Electric Reliability Corporation ("NERC") has begun to issue new performance guidelines to support improved design,[10] although it is recognized that more research is needed to ensure stability in future systems with many more inverter-based resources.

[10] NERC, Reliability Guideline, BPS-Connected Inverter-Based Resource Performance (Sept. 2018), *available at* https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

Impact of System Decarbonization Across Neighboring Utilities

The combined DEC/DEP power systems are situated in the Eastern Interconnection, and any frequency deviation is seen by every piece of equipment within the interconnection within milliseconds. Other states, utilities and markets in the interconnection are also planning to decarbonize their systems to varying degrees, and their resource changes, along with Duke Energy's, will all combine to require tighter controls and mechanisms to maintain system frequency within normal operating bounds. As the Eastern Interconnection retires synchronous generators and adds new asynchronous renewables, the system will become more susceptible to deviations in the power balance, and thus frequency deviations will increase in magnitude. These deviations are also translated to active and reactive power flow deviations within and between the interconnected transmission regions.

Such power flow deviations will occur within a different time domain than the typical steady-state, predictable response of the system. This response will show transmission lines at, or near thermal limits one minute and not near the limits the next. Such volatility demands additional modeling and analysis capabilities to not only identify system constraints, but also that constraints are suspected to be sustained and thus need remediation, and that are transient. Such models will require tighter coordination between systems within Duke Energy and between Duke Energy and other regions within the Eastern Interconnection.

Modeling Reliability

In the context of these reliability concerns, each of the proposed portfolios has passed an initial hourly screening to ensure that the resulting portfolio performs at levels of reliability equivalent to or better than the current system configuration. As discussed in Appendix E (Quantitative Analysis), these portfolios performed better on the metric known as the Loss of Load Expectation ("LOLE"). LOLE is an industry standard metric that measures the probability of shedding firm load to maintain supply and demand balance, and for the purpose of the Carbon Plan is considered a strong starting point for comparing the reliability of future scenarios to the current system. However, there is a growing need to evaluate reliability using more sophisticated reliability metrics, and more granular analyses can help better identify reliability issues in the future as the grid evolves. Increasing levels of renewable energy and other aspects of grid transformation are changing the nature of resource adequacy and new metrics that move from characterizing the likelihood of experiencing a reliability event, to more carefully analyzing the depth, duration, and source of reliability concerns will become more relevant. The Energy Systems Integration Group[11] provides an overview on the role of new metrics, such as those that capture the amount of energy unserved, in the context of grid transformation and recent loss-of-load events in California and Texas.

In addition to improved grid metrics, additional modeling resolution can help identify potential reliability concerns caused by increased uncertainty and volatility in the power system. A more complete analysis of specific portfolios could simulate dispatch with sub-hourly forced outage and load and

[11] Energy Systems Integration Group, Redefining Resource Adequacy for Modern Power Systems (2021), *available at* https://www.esig.energy/wp-content/uploads/2021/08/ESIG-Redefining-Resource-Adequacy-2021.pdf.

renewables volatility, and more highly resolved models could identify power flow and frequency response issues in a decarbonized grid.

Future System Resilience

Separate from reliability, resilience refers to the ability of the grid to withstand or, if necessary, recover from extreme events. Considerations of resilience look beyond the standard measures of resource adequacy to identify low-probability, high-impact events that directly affect grid assets or disable critical enabling infrastructure such as transportation networks and fuel supplies.

First and foremost a resilient decarbonized grid must be designed to address potential weather extremes. As has previously been discussed, the Companies' power systems are planned to accommodate winter peaks in the course of normal operations, but beyond modeling standard weather variability, there are certain extreme winter conditions that factor into planning a resilient system.

- Extreme cold temperatures are possible in the Carolinas. In the last 10 years, the system average temperature in both the DEC and DEP regions has dipped into the upper single digits and is susceptible to even colder temperatures. Within recent history, 1985 brought a low of negative 5º to the DEC regions and negative 1º to DEP. As seen during the 2021 ERCOT cold weather event, temperatures this low can cause unexpected operational difficulties if generating units and fuel infrastructure are not properly winterized.

- Often cold weather is transitory in the Carolinas. The cold weather events in 1985, 2014 and 2015 elevated loads for one to three days. However, in 2018, the Carolinas experienced a much different cold snap lasting for an extended period. During this period the measured temperature in Raleigh remained at or below freezing for seven continuous days. Notable cold of this duration can change customer behavior in ways that are difficult to model (increasing reliance on space heaters, for example) and place stresses on diesel fuel oil supplies. These risks can be compounded by extreme events such as an ice storm, which could disrupt unit refueling.

Beyond winter risks from extreme cold and ice storms, summer and fall in the Carolinas come with the added risk from major hurricanes and related flooding. Historically, Category 3 and 4 storms have made landfall on Carolinas shores, and Category 4 and 5 storms are known to have passed within close proximity of potential offshore wind sites. Resilience includes a substantial element of recovery from extreme events, and new planning and response measures will be necessary to ensure that distributed wind and solar resources can be repaired and quickly returned to service after potential widespread damage from major hurricanes.

Weather is not the only resilience concern for the power system. Cybersecurity is an increasing concern for reliable and resilient grid operations. The power industry is a prime target for criminal organizations and nation-state actors, and a changing grid with new resource configurations (reliance on distributed resources, customer-sited generation, and load reductions) creates new areas for attack against the grid. Cyber risks to the grid can also come from impacts to critical infrastructure including fuel supply, which was made clear by the Colonial Pipeline hack in 2021.

In the event of a major outage (be it from weather, cyberattack or otherwise), quickly and safely returning power supply is a major feature of power system resilience. As the resource mix in the Carolinas changes, new challenges can emerge for re-energizing the power system after a blackout. This process of restoring system power, known as "black-start," relies on a carefully planned and coordinated strategy for re-energizing transmission pathways and bringing loads and generation back online in a balanced manner. New, variable generating resources such as solar can complicate this process by increasing the volatility of the system net load during restoration should these resources restart and re-energize automatically. New planning and processes to handle these risks will be necessary. Distributed resources also create new opportunities for resilience as microgrids powered by distributed renewables and storage could maintain islands of power during blackout events - keeping critical loads such as hospitals online and aiding in restoration.

While none of these conditions are explicitly modeled as scenarios in this initial Carbon Plan, they are important considerations that will help inform the design and operation of the grid both during and after the transition to net-zero.

Conclusion

As has been discussed in this Appendix, the power system transformation illustrated by the Carbon Plan pathways involves many new challenges for managing the grid. At the core of these challenges will be how increasing levels of renewable generation will fundamentally change patterns of net load demand and increase uncertainty. However, with appropriate management and execution, the modeling discussed in the plan suggests that reliability is achievable even as the grid evolves. Maintaining current standards of reliability will require new, flexible solutions including natural gas generation, energy storage, and long-term technology innovation. As the grid rapidly changes, on an ongoing process of operational integration, learning, and adjustment- including how bulk power system reliability itself is modeled and measured - will be needed to keep pace with the demands of the evolving system.