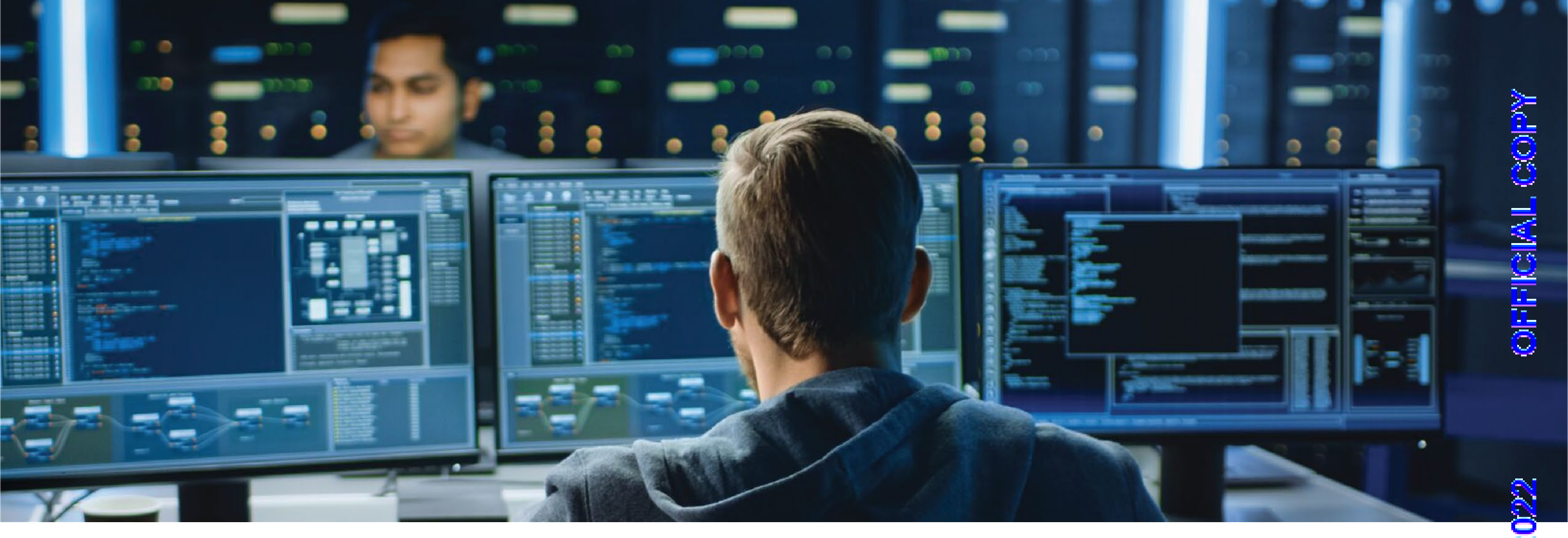
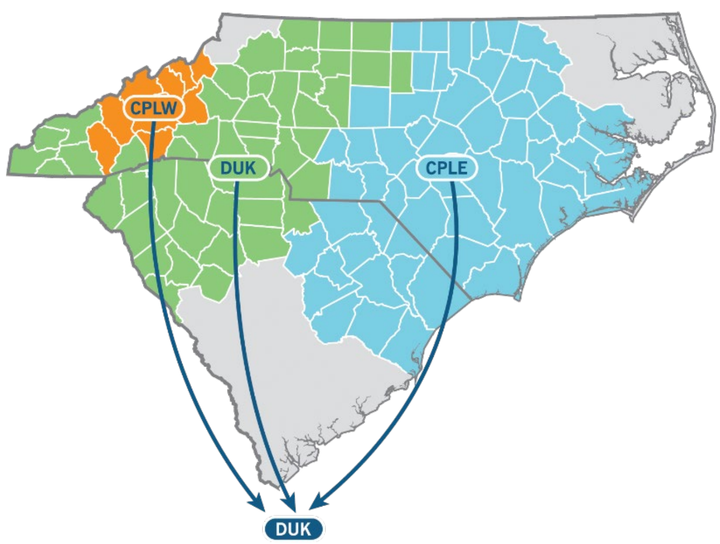


R Consolidated System Operations

Currently Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, "Duke Energy" or the "Companies") operate as separate North American Electric Reliability Corporation ("NERC") registered Balancing Authorities ("BA"), Transmission Operators ("TOP"), and Transmission Service Providers ("TSP") and plan as separate NERC registered Transmission Planners. As registered BAs, the Companies separately integrate unit commitment plans ahead of time, maintain generation-load-interchange-balance within each Balancing Authority Area and contribute to interconnection frequency in real time. DEC has one Balancing Authority Area (DUK), and DEP has two Balancing Authority Areas (CPLE and CPLW) as shown in Figure R-1 below. As registered TOPs, the Companies are responsible for the real-time operating reliability of the transmission assets in their separate TOP Areas. The Duke Energy TOPs have the authority to take certain actions to ensure that they operate reliably. As registered TSPs, Duke Energy administers the FERC-approved open access transmission tariff ("OATT") for the separate Duke Energy transmission zones and provides transmission service to transmission customers under applicable transmission service agreements. Duke Energy is proposing to consolidate System Operations, i.e., the BA, TOP, and TSP operating functions during the near-term (2022-2024).

Figure R-1: Legacy Areas Consolidated to Single Balancing Authority Area



In addition to consolidation of the aforementioned operating functions, the consolidated system operations project proposes to consolidate the Duke Energy transmission service zones in the OATT. As separate NERC-registered Transmission Planners ("TP"), the Companies develop long-term plans (generally one year and beyond) for the reliability (adequacy) of the interconnected bulk electric transmission systems within the separate Duke Energy TP areas. The consolidation of the DEC and DEP transmission zones in the joint OATT into one Carolinas transmission zone with one set of tariff rates and one set of transmission ancillary schedules will allow for consolidation of the Companies' TP functions.

Consolidated System Operations Benefits

The consolidation of NERC functions and system operations has many benefits in the areas of resource portfolio flexibility, production cost savings, simplifications with NERC compliance, and transmission service provisions.

This consolidation of Duke Energy NERC-registered functions and consolidation of the Duke Energy transmission service zones in the current OATT into one Carolinas transmission service zone will eliminate the transmission interface between the Companies. The consolidation will have immediate benefits from efficiently sharing operating reserves in a more economic manner to allow for integration of more variable renewable energy resources through optimization of a larger fleet of regulation resources. Additionally, the ability to share operating reserves will be reflected in less combustion turbine peaker starts and associated CO_2 emissions reductions. A summary of benefits from implementing the consolidated system operations project is shown in Table R-1 below.

Table R-1: Consolidated System Operations Benefits

Flexibility	Production	Simplification
• Optimization of existing resources for operating reserves and regulation • Less solar curtailment • Reduction in CO_2	• Reduced generation costs from optimized use of operating reserves and regulation • Reduced dump energy • Improved market purchases • Improved storage utilization	• NERC standard compliance • One OATT • Single wholesale view
Reserves	**Response**	**Reliability**
• Reduction in day ahead planning reserves • Reduction in planning reserve margin	• Larger balancing area better able to aggregate greater amounts of variable generation and load	• Reserve sharing • Consolidated system operations

Another benefit of the consolidated system operations project is improved reliability in conjunction CO_2 carbon reduction objectives. Consolidated system operations will enable a reduction in risk to meet a one day in 10-year loss of load probability ("LOLP"), also known in the industry as loss of load expectation ("LOLE"). Defined at the highest level, risk is simply the probability of an adverse event occurrence combined with the consequence severity of such event should it occur. The one day in 10-year standard (LOLP of 0.1 or LOLE of 0.1) is interpreted as one day with one or more hours of firm load shed (the consequence severity) every 10 years due to a shortage of generating capacity and is used across the industry to set minimum target reserve margin levels. For Duke Energy, as separate Balancing Authorities, the risk for each BA to meet the 0.1 LOLE reliability metric independently is higher as compared with planning to meet this reliability metric as one consolidated BA with consolidated functions. This reduction in risk is due to the ability of the consolidated system operations to dedicate operating reserves to serving the consolidated BA demand during seasonal extreme peak scenarios. With the reduction in risk associated with meeting the 0.1 LOLE, this effectively lowers the necessary planning reserve margin. It is important to realize that there are other factors that impact the probability and thus the risk to meeting a 0.1 LOLE. NERC's most recent Long-Term Reliability Assessment[1] addresses the concern of future retirements of traditional generation resources like coal-fired generation and the need to consider the risk to resource adequacy and energy risks by supporting the addition of variable energy resources, like wind and solar, with flexible resources that include sufficient dispatchable, fuel-assured and weatherized generation:

> "Most areas are projecting to have adequate resource capacity to meet annual peak demand associated with normal weather. Capacity shortfalls, where they are projected, are the result of future generator retirements that have yet to be replaced with new resource capacity. Capacity-based estimates, however, can give a false indication of resource adequacy. Energy risks emerge when variable energy resources (VER), like wind and solar, are not supported by flexible resources that include sufficient dispatchable, fuel-assured, and weatherized generation."[2]

NERC's Long-Term Reliability Assessment further reflects these risks as increasing during periods of extreme weather considering diminishing levels of flexible generation (i.e., fuel-assured, weatherized and dispatchable resources):

> "Wide-area and long duration extreme weather events driven by climate change threaten reliability when electricity demand is driven above forecasts and supplies are reduced. Diminished levels of flexible generation (i.e., fuel-assured, weatherized and dispatchable resources) create vulnerabilities to energy shortfalls when extremely hot or cold weather settles over a wide area for extended duration or when weather-dependent generation is impacted by abnormal atmospheric conditions, such as smoke or wind or drought."[3]

[1] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

[2] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf; page 5.

[3] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf; page 6.

Thus, as variable energy resources increase for the Carolinas and coal generation is retired, without commensurate increase in flexible resources with high-capacity factor capability when needed, the risk to meeting the resource adequacy metric of 0.1 LOLE will increase. As a result, the Companies' planning reserve margins will need to increase. Even though planning reserve margins would need to increase with increasing amounts of wind and solar, the planning reserve margin for the consolidated BA will not need to increase as significantly as continuing to operate as independent BAs. This consolidated system operations benefit of dampening the needed increase in planning reserve margin can result in the reduced need for additional capacity resources and thus keep costs lower for customers.

Modeling of Consolidated System Operations in the Plan

Transmission Service for Economic Energy/Regulation Reserves Exchange

With elimination of the transmission interface, transmission reliability margin ("TRM") will not need to be reserved between the Companies. In lieu of the TRM reservation, the Transmission Operator will utilize and monitor Real-time Contingency Analysis to ensure the transmission system remains secure with respect to responding to a balancing contingency event. This method would allow for further optimization and utilization of the transmission system for the benefit of all transmission customers.

Consolidated system operations allow for reducing the level of conservatism in the interface limits to better represent how consolidated system operations would work operationally with implementation of a consolidated BA economic dispatch. A simple way to approximate this directionally is to use the mean value of historical posted non-firm Available Transfer Capability ("ATC"), which was used to represent the post-consolidated system operations transfer capability.

Resource Dispatch

Consolidated system operations will enable a common economic dispatch of supply resources within the new consolidated BA boundary in lieu of the legacy joint dispatch of resources being facilitated by the dynamic schedule and non-firm transmission service reservations. Consolidated BA joint dispatch savings will be determined by a state commission-approved methodology. Additional regulatory approvals needed to implement the consolidated system operations project are addressed below.

Consolidated system operations would not provide for joint unit commitment because DEC and DEP would remain separate companies with separate ownership of their generation facilities. Pursuant to NERC function criteria, DEC and DEP would each retain their responsibilities as Generation Owners and Generator Operators to submit separate unit commitment plans to the consolidated BA function. However, the BA function, even once consolidated, would not perform an economic optimization of those separate unit commitment plans. The BA function would only revise these plans for reliability reasons.

Beyond Consolidated System Operations – Potential Merger of the Duke Energy Utilities

Many of the near-term regulatory approvals and operational changes required to achieve consolidated system operations would also be necessary to undertake a potential merger of the DEC and DEP utilities. The Companies could implement consolidated system operations and then sequentially transition to a full merger of the DEC and DEP utilities or, alternatively, could immediately begin planning toward a full merger of the Companies to operate as "one utility" in the Carolinas.

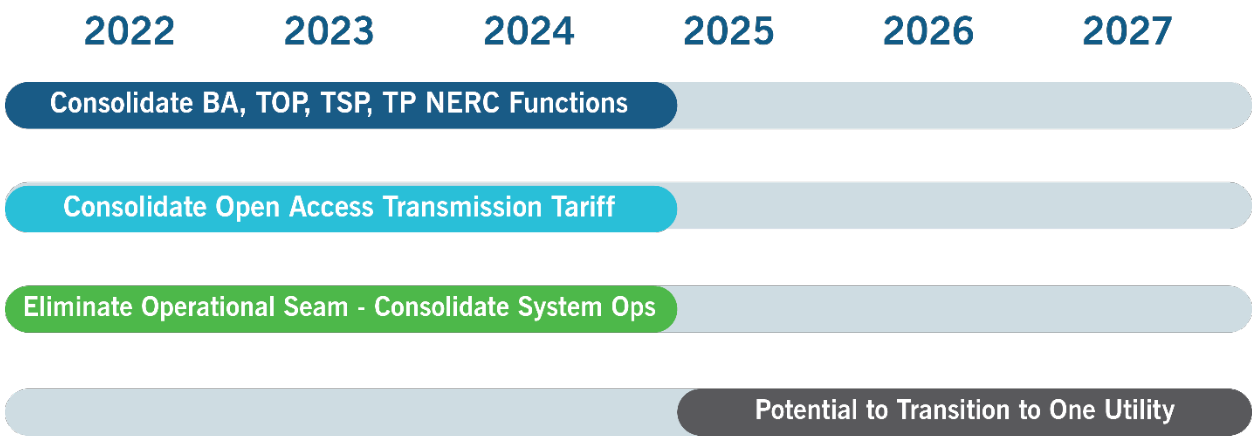
As Duke Energy undertakes consolidated system operations, the Companies will continue to evaluate the timing, costs, and benefits of a potential full merger of the DEC and DEP utilities. For example, a full merger of the Companies' legal entities would allow for a single unit commitment of the merged power supply resources and long-term planning of supply resources as one portfolio. Enabling a single unit commitment of the merged power supply resources and consolidating resource planning could allow for additional customer savings and may allow a more efficient transition to the 2050 carbon neutrality target. Pursuing merger of the DEC and DEP utilities to operate as one utility would tend to smooth the trend of future rate increases as the Plan is implemented; however, the Companies would need to address current rate disparities and cost allocation shifts.

Consolidated System Operations Regulatory Approvals

In addition to the Plan modeling of projected consolidated system operations functions, an additional detailed analysis will be needed to support the Carolinas and FERC regulatory filings. These filings are expected to occur in the first quarter of 2023 and the third quarter of 2023, respectively. Also, the Southeastern Reliability Corporation ("SERC"), the regional reliability organization reporting to NERC, will need to certify the consolidated registered NERC entity functions and supporting technical infrastructure relative to their roles in meeting mandatory reliability standards. This certification is expected to occur in late 2024, closer to the planned effective date of the consolidated system operations.

The timeline for implementation of consolidated system operations by year end 2024 is aggressive and highly dependent on achieving the necessary regulatory approvals in a timely manner. State regulatory approvals need to be achieved by third quarter of 2023 and FERC approvals need to be achieved by third quarter of 2024 to meet the timeline shown in Figure R-2 below. Any significant delay or insurmountable barrier to implementing consolidated system operations would significantly hinder the ability to manage the variability and intermittency of variable energy resources such as solar and thus hinder the ability to meet the CO_2 reduction targets laid out in the Carbon Plan.

Figure R-2: Timeline for implementation of Consolidated System Operations



Conclusion

Consolidating the NERC BA, TOP, TSP, and TP functions as well as the transmission service zones and tariff for DEC and DEP will provide needed benefits for enabling the Carbon Plan. A vital component of increasing the amount of renewable generation in the DEC and DEP service areas will be a flexible portfolio of resources and associated operating reserves to manage the variable nature of and the net demand ramping resulting from renewable output. Consolidated system operations will provide many benefits for customers as identified in the "Consolidate System Operations Benefits" section above.

Additional benefits for customers and further enablement of the pathway toward the 2050 carbon neutrality target can be achieved through merging the DEC and DEP utilities. These benefits include a single resource plan, as well as a joint unit commitment achieving further cost savings for customers. The Companies plan to continue to evaluate the timing and benefits of a potential full merger of the DEC and DEP utilities to one utility. Alternatively, if continued alignment between North Carolina and South Carolina is not achievable and separate state resource planning is necessary, a merger and separation of DEC and DEP resulting in a North Carolina utility and a South Carolina utility would ultimately be required.