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Transmission Project Summaries
Duke Energy Carolinas, LLC
2022 DEC MYRP Technical Conference
Docket No. E-7, Sub 1276

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System Intelligence
Project Summary

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Transmission –

System Intelligence

Project purpose

This System Intelligence project is critical to providing grid operators and engineers with enhanced information to respond to changing conditions that challenge reliability. Remote asset monitoring allows proactive decisions to be made when equipment health is threatened, and remote operated switches play a vital part in sectionalizing transmission lines to limit the customer impact of faults from external causes and equipment failures.

Timeline for construction

Refer to Master Project List for location-specific timelines. At the project level, construction is planned from December 2022 to December 2026.

Estimated in-service date

Refer to Master Project List for location-specific dates. At the project level, individual location in-service dates range from October 2023 to December 2026.

Project description

The Transmission System Intelligence project includes modernizing relays, remote substation and asset monitoring, and upgrades to remote control switches.

Electromechanical-to-Digital Relays

This scope of work replaces non-communicating electromechanical and solid-state relays with digital relays. Modern relay design with communications capabilities and microprocessor technology enables quicker recovery from events than the design of the existing electromechanical relays. One digital relay is capable of replacing a variety of legacy single-function electromechanical relays. The need for more device functionality has increased due to the following factors: more demanding regulatory requirements, advances in technology, higher demand for operational data, and higher demand for increased performance and reliability. Two-way communications and event recording capabilities allow digital relays to provide device performance information following a system event to support continuous system design and operational improvements. Additionally, the relays identify line fault locations, which is the ability to use device data to calculate the distance down a line to a line fault, rather than manually assessing and patrolling transmission lines. Relay replacements are prioritized based on failure rates, known deficiencies, function, and location.

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Typical electromechanical relays


Typical digital relays

Remote Substation and Asset Monitoring
This scope of work enables operators to remotely monitor and control substations. These improvements include the installation or upgrade of supervisory control and data acquisition system ("SCADA") interfaces for substation devices, called remote terminal units ("RTU"s), and upgrades to associated data communication channels. This scope is also an enabler for CD programs like Integrated Volt/Var Control and Distribution Automation. Additionally, it upgrades serial communication to IP communication for existing RTUs to collect more data and support more devices. Also included are digital fault recorder (DFR) upgrades providing improved fault locating capability, informing system operators of sectionalizing options and directing field personnel to trouble locations to speeding up restoration efforts.

The Asset Monitoring scope involves installing on-line Condition-Based Monitoring ("CBM") equipment to continuously and remotely monitor the condition of critical substation transformers to identify developing problems and allow corrective action to be taken in a planned manner before the transformer fails or otherwise causes an unplanned outage. Transformer CBM could include Electronic Temperature Monitors ("ETM"), Dissolved Gas Analyzers ("DGA"), Bushing Monitors ("BM") with partial discharge capabilities, and data collection back to the enterprise for further analysis. These online transformer monitors are used to diagnose internal transformer problems by monitoring key parameters on a continuous basis. This information is supplied to our Health and Risk Management ("HRM") program. HRM is a machine learning platform that is utilized to determine the health of assets and remaining life expectancy so that replacements can be targeted prior to failures occurring.

Remote Control Switches
This scope of work replaces, and upgrades manually operated switches with modern switches enabled with SCADA communication and remote-control capabilities. Sectionalizing, a grid operation used to section off portions of the transmission system in order to perform equipment maintenance or isolate faults to minimize impacts to customers, has historically required a technician to go to a physical location and manually operate one or more line switches. This scope of work increases the number of remote-controlled switches to support faster isolation of trouble spots on the transmission system and more rapid restoration following line faults. Common causes of failures with these switches are heating issues, insulator failures, as well as age related degradation that causes malfunctioning.

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Remote-controlled switches

Control box for switch operations

Projected costs (capital expenditure)

Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

	Aug’23-Dec ‘24	Jan ’25-Dec ‘25	Jan ’26-Dec ‘26	Total
Projected costs (DEC System)	$45.9M	$35.4M	$49.9M	**$131.2M**

Grid capabilities enabled

- Strengthened grid against outages
- Increased resiliency to recover from outages including during extreme weather and storm events
- Increased grid operator visibility to system conditions
- Improved reliability
- Optimized ability to monitor the grid for variable conditions associated with DER deployments

HB951 Policy Considerations addressed

- Encourages peak load reduction or efficient use of the system
- Encourages utility-scale renewable energy and storage
- Promotes resilience and security of the electric grid
- Maintains adequate levels of reliability and customer service

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Transmission

System Intelligence

Cost Benefit Analysis

Is the Project required by law?	
No.	
Explanation of need for proposed expenditure	
This System Intelligence project is critical to providing grid operators and engineers with enhanced information to respond to changing conditions that challenge reliability. Remote asset monitoring allows proactive decisions to be made when equipment health is threatened, and remote operated switches play a vital part in sectionalizing transmission lines to limit the customer impact of faults from external causes and equipment failures.	
Financial cost-benefit analysis	
Total Project Costs	**NPV as of Sept 2022**
Project capital	$120.5M
Total Costs	**$120.5M**
Total Project Benefits	
Reliability benefits	$2,681.4M
Total Benefits	**$2,681.4M**
Benefit to Cost Ratio (BCR)	**22.3**

Other qualitative benefits	
Benefit Category	**Description**
Improve reliability	Reduces outage duration and number of customers impacted from vegetation and line component failure events.
Increase operational efficiency	Improves grid operators' and engineers' visibility to system events and equipment health.

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Transmission Line Hardening & Resiliency

Project Summary

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Transmission –

Transmission Line Hardening & Resiliency ("H&R")

Project purpose
The Transmission Line H&R project works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events, natural or man-made.
Timeline for construction
Refer to Master Project List for location-specific timelines. At the project level, construction is planned from August 2021 to December 2026.
Estimated in-service date
Refer to Master Project List for location-specific dates. At the project level, individual location in-service dates range from December 2023 to December 2026.
Project description
The Transmission H&R project can be broken down into scopes of work that address unique challenges to harden the system to reduce impacts to customers, while enhancing their electric service experience. **Cathodic Protection** extends the life of the existing transmission towers that deliver electricity from power plants to substations for delivery across the grid. Cathodic Protection improvements install passive protective systems onto structures using highly polarized magnesium anodes that mitigate further corrosion to the structure. Towers that are identified as corroded to the point of impacting structural integrity are addressed through installation of structural braces, or through complete tower replacement when warranted. **Targeted Line Strengthening for Extreme Weather** replaces vulnerable wooden structures and lattice steel towers and rebuilds transmission line segments. 44kV lines are rebuilt to 100kV structural and electrical standards to improve reliability and enable future capacity needs including renewable generation interconnections. Degraded 100kV and 230kV lattice towers are addressed through the replacement of insulators and hardware that support the conductor or, when warranted, through replacement of the entire tower. When towers are replaced, they are redesigned to updated structural standards that harden against storm impacts. Degraded static ground wires are also replaced to ensure the transmission line segments have maximum protection against lightning and other fault-inducing events. Replacement static wire is redesigned to current standards and upgraded to fiber optic ground wire where warranted, which then allows the ground wire to also be used as a high-speed communication medium between remote substations and Energy Control Centers. Altogether, these H&R efforts not only enhance the functionality of individual assets, but substantially improve the overall functionality of the transmission grid, particularly under extreme weather conditions.

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Typical 44 kV Line Prior to Rebuild

Typical 44 kV Line Being Rebuilt

Typical 44 kV Line After Rebuild

<table>
<tr><td colspan="10">Projected costs (capital expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC</td></tr>
<tr><td colspan="2"></td><td colspan="2">Aug ’23-Dec ‘24</td><td colspan="2">Jan ’25-Dec ‘25</td><td colspan="2">Jan ’26-Dec ‘26</td><td colspan="2">Total</td></tr>
<tr><td colspan="2">Projected costs (DEC System)</td><td colspan="2">$98.8M</td><td colspan="2">$92.5M</td><td colspan="2">$117.4M</td><td colspan="2">$308.7M</td></tr>
<tr><td colspan="2">O&M costs (DEC System)</td><td colspan="2">$0.6M</td><td colspan="2">$0.6M</td><td colspan="2">$0.5M</td><td colspan="2">$1.7M</td></tr>
<tr><td colspan="5">Grid capabilities enabled</td><td colspan="5">HB951 Policy Considerations addressed</td></tr>
<tr><td colspan="5">• Strengthened grid against outages from extreme weather and storm events, as well as other threats
• Increased resiliency to recover from outages
• Improved reliability</td><td colspan="5">• Promotes resilience and security of the electric grid
• Maintains adequate levels of reliability and customer service</td></tr>
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Transmission –

Transmission Line Hardening & Resiliency ("H&R")

Cost benefit analysis

Is the Project required by law?
No.

Explanation of need for proposed expenditure
The transmission system is an essential part of Duke Energy's power delivery network, and any disruption in the flow of electricity across the system can interrupt service for thousands of customers across entire regions. Severe weather, animal interference and structural degradation are just some of the external factors that affect the performance of the transmission system. Transmission Line H&R project works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme weather, as well as other physical threats and disruptions.

Financial cost-benefit analysis	
Total Project Costs	**NPV as of Sept 2022**
Project capital	$288.4M
O&M	$1.4M
Total Costs	**$289.8M**
Total Project Benefits	
Reliability benefits	$6,879.2M
Total Benefits	**$6,879.2M**
Benefit to Cost Ratio (BCR)	**23.7**

Other qualitative benefits	
Benefit Category	**Description**
Improve reliability	Reduced outages caused by line component failures as well as reduced voltage spikes, sags, and momentary interruptions.
Increase operational efficiency	Reduced or avoided emergency repair or replacement, and reduced or avoided after-hours work.

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Substation Hardening & Resiliency Project Summary

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Transmission –

Substation Hardening & Resiliency ("H&R")

Project purpose
The Transmission Substation H&R project works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events, natural or man-made.
Timeline for construction
Refer to Master Project List for location-specific timelines. At the project level, construction is planned from June 2020 to December 2026.
Estimated in-service date
Refer to Master Project List for location-specific dates. At the project level, individual location in-service dates range from October 2023 to December 2026.
Project description
The Transmission Substation H&R project includes animal mitigation, substation reliability upgrades, and air break switch upgrades. Each of these Transmission Substation H&R scopes address unique challenges, discussed below, to harden the system and minimize impacts to customers. The **Animal Mitigation** scope involves installation of equipment specifically designed to prevent animal-induced events from impacting customers directly through an outage or indirectly through a system perturbation such as a voltage depression.  **Animal Mitigation Fencing**

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The **Substation Reliability Upgrade** scope includes the replacement of major substation assets along with ancillary equipment. Transformer and breaker upgrades are typically the key project drivers in these station upgrade projects, although in addition supporting assets such as regulators, circuit switchers, protective relaying, and ancillary equipment such as instrument transformers and switches are upgraded to modern reliability standards as the equipment health dictates. Substations that reach a certain age and level of decline in reliability warrant a more wholesale approach to reliability improvement. Cost efficiencies are gained in the planning, design, and execution of the project. Station layouts are redesigned to the latest electrical standards which sometimes dictate additional footprint in order to accommodate phase spacing and Minimum Approach Distance ("MAD") requirements of the National Electric Safety Code. In some instances, temporary portable transformers, breakers, and other equipment are installed during the construction phase of the project in order to minimize the outage impacts to customers. This requires a reliability inventory of portable equipment to support numerous concurrent projects. In other cases, rebuilding the station on a new footprint is the most efficient solution- under this scenario the customer is minimally impacted, and the service is "swapped" to the new station once construction and testing is complete.

The **Air-Break** switch project scope replaces existing motor operated air-break switches and spring charged air break switches with more reliable circuit switchers. The air-break switches do not have a rated capability to interrupt load and fault current. Furthermore, when an air-break switch is required to operate, many times the switch will fail to open, fail to fully open, or whenever it does open, it will flash phase to ground. This causes a transmission line outage and any customers being served on that line will have at least a momentary interruption if not a sustained outage. Replacement of these air-break switches with circuit switchers with fault interruption capability will reduce future customer outages, voltage sags, and minimize collateral damage during fault events that could lengthen the duration and costs of outages. In summary, the upgraded circuit switcher will provide better fault protection for adjacent power transformers along with being safer to operate from a remote location.

Air-Break Switch

Altogether, these H&R efforts not only enhance the functionality of individual assets, but improve the overall functionality of the system, particularly under extreme weather conditions.

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Projected costs (capital expenditure) *Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC*				
	Aug '23-Dec '24	**Jan '25-Dec '25**	**Jan '26-Dec '26**	**Total**
Projected costs (DEC System)	$94.1M	$32.9M	$38.9M	**$165.9M**

Grid capabilities enabled	**HB951 Policy Considerations addressed**
• Strengthened grid against outages including during extreme weather and storm events • Increased resiliency to recover from outages • Improved physical security	• Promotes resilience and security of the electric grid • Maintains adequate levels of reliability and customer service

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Transmission –

Substation Hardening & Resiliency ("H&R")

Cost benefit analysis

Is the Project required by law?
No.

Explanation of need for proposed expenditure
Substations are essential components of the transmission system and serve as the off-ramps from the high voltage transmission energy highway to the distribution system that carries power throughout a community. Substation outages and disruptions can result in large-scale outage events that can potentially last a long duration. In recent years, storms have increased in frequency and severity in the Carolinas. Outages from equipment failures and animal interference continue to be a challenge impacting customers. Finally, new technologies and smarter capabilities are driving the need to upgrade substations to meet the expanded needs of customers and the desire to transform the grid to meet clean energy goals of the future. The Transmission Substation H&R project works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events, natural or man-made, and ready for the energy opportunities that lie ahead.

Financial cost-benefit analysis	
Total Project Costs	**NPV as of Sept 2022**
Project capital	$197.9M
Total Costs	**$197.9M**
Total Project Benefits	
Customer benefits	$5,757.6M
Total Benefits	**$5,757.6M**
Benefit to Cost Ratio (BCR)	**29.1**

Other qualitative benefits	
Benefit Category	**Description**
Improve reliability	Reduce outages caused by substation component failures; reduce impacts of extreme weather and external events.
Increase operational efficiency	Reduced or avoided emergency repair or replacement and reduced or avoided after-hours work.

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Transmission Vegetation Management Project Summary

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Transmission – Hardening & Resiliency (H&R)

Vegetation Management

Project purpose

The Transmission H&R Vegetation Management project works to create a hardened transmission grid capable of withstanding extreme weather events and reducing the frequency of outages impacting customers.

Timeline for construction

Refer to Master Project List for specific timelines. At the project level, construction is planned from January 2024 to December 2026.

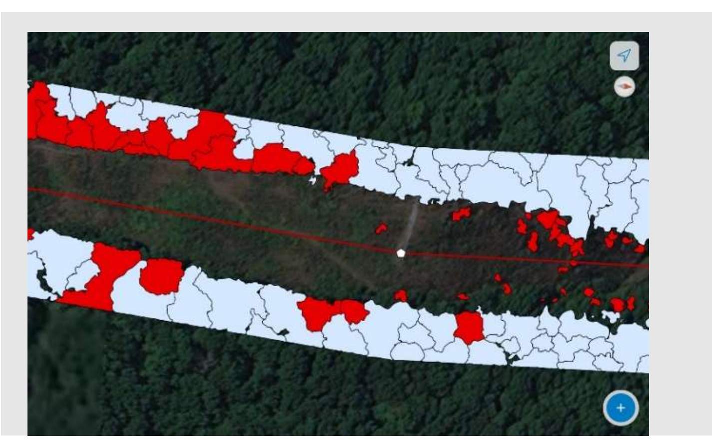
Estimated in-service date

Refer to Master Project List for specific dates. At the project level, individual location in-service dates range from January 2024 to December 2026.

Project description

Duke Energy Carolina's ("DEC") Transmission Integrated Vegetation Management ("IVM") project is focused on ensuring the safe and reliable operation of the transmission system by minimizing vegetation-related interruptions and maintaining adequate conductor-to-vegetation clearances, while maintaining compliance with regulatory, environmental, and safety requirements or standards. Project activities focus on the removal of vegetation within and along the right of way to minimize the risk of vegetation-related outages, and to ensure necessary access within all transmission line corridors.

A multi-year vegetation work plan based on the date of previous work, outage history and line criticality serve as the core work strategy. This plan is then optimized by a threat-based and condition-based approach, incorporating intelligence obtained through remote sensing, inspections, and field assessments.



Tree canopy risk model

Transmission circuit

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Projected costs (capital expenditures) *Note: Timing for costs based on in-service dates for associated projects*				
	Aug ’23-Dec ‘24	**Jan ’25-Dec ‘25**	**Jan ’26-Dec ‘26**	**Total**
Projected costs (DEC System)	$17.3M	$20.2M	$19.5M	**$57.0M**

Grid capabilities enabled	**HB951 Policy Considerations addressed**
• Strengthened grid against outages including during extreme weather and storm events • Improved reliability	• Maintains adequate levels of reliability and customer service

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Transmission – Hardening & Resiliency (H&R)

Vegetation Management

Customer Benefits

Is the Project required by law?	
Yes. Select work under this project is required to maintain compliance with NERC Standards.	
Explanation of need for proposed expenditure	
Transmission outages from vegetation can be extremely disruptive to customers and costly for the Company. Additionally, vegetation-based outages can also create regulatory compliance issues for the Company. The transmission vegetation management project works to create a hardened transmission grid capable of withstanding extreme weather events and reducing the frequency of outages impacting customers.	
Benefits created for customers *[Describe benefits in the context of the overall filing narrative, which could include the following]*	
Benefit	**Description**
Operational savings	Proactive tree removal leads to less emergency work and less collateral equipment damage.
Reduced customer interruptions	Reduces customer outages as vegetation is one of the leading causes of outages.
Storm hardening	Reduces the impact to the grid and customers during extreme weather events and storms.

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Breaker Upgrades
Project Summary

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Breaker Upgrades

Project purpose
The Breaker Upgrade project involves replacing degraded transmission circuit breakers, including oil circuit breakers ("OCBs") with new transmission circuit breakers. This project is typically completed in conjunction with upgrading the associated protection and control relays. The new communication and control capabilities of modern breakers better position the transmission and distribution systems to effectively respond to electric grid events. These reliable gas and vacuum breakers are also better suited for protecting circuits during high-frequency fault events such as winter storms and hurricanes.
Timeline for construction
Refer to Master Project List for location-specific timelines. At the project level, construction is planned from March 2022 to December 2026.
Estimated in-service date
Refer to Master Project List for location-specific dates. At the project level, individual location in-service dates range from October 2023 to December 2026.
Project description
Circuit breakers are electro-mechanical switching devices installed within substations to connect or disconnect transmission or distribution circuits remotely or locally. Similar to smaller breakers in a home or business, these utility-scale circuit breakers allow the normal line or bus current to flow through them and will open very rapidly, when called upon, to interrupt both normal operating load current and the much higher currents that flow during a system fault. Failure to operate fast enough to clear fault currents will activate backup protection systems, potentially leading to a larger outage for customers. In addition, the failure of any oil containing equipment can lead to environmental impact. Replacement of these breakers will improve the environmental impact from potential oil spill risk. Oil circuit breakers are a legacy technology that involves the immersion of energized and current-carrying portions of the circuit breaker within a tank containing insulating mineral oil. These older technologies have been replaced with gas circuit breakers for 44-kV and higher applications, and vacuum circuit breakers for 35-kV and lower needs. These breakers are at or approaching end of life, and at times fail to operate properly due to degraded sub-components. Spare parts and manufacturer support are no longer available due to obsolescence. Upgrading to newer breaker technology can help avoid maintenance challenges and supply issues for outdated assets and ensure continued operational compliance and efficiency by reducing reliance on older technologies.

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Typical Transmission Oil Circuit Breaker

Typical Transmission Gas Circuit Breaker

Typical Distribution Oil Circuit Breaker

Typical Distribution Vacuum Circuit Breaker

Projected costs (capital expenditures)
Note: Timing for costs based on in-service dates for associated projects

	Aug'23-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Projected costs (DEC System)	$97.9M	$108.3M	$121.8M	**$328.0M**

Grid capabilities enabled

- Allowed for additional capacity on the system
- Enhanced reliable fault interrupting capability
- Reduced environmental footprint
- Improved reliability
- Strengthened grid against outages
- Increased resiliency to rapidly recover from outages

HB951 Policy Considerations addressed

- Promotes resilience and security of the electric grid
- Maintains adequate levels of reliability and customer service

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Transmission -

Breakers

Cost benefit analysis

Is the Project required by law?
No.

Explanation of need for proposed expenditure
Circuit breaker technology has advanced in recent years and has moved away from oil-filled breakers to gas and vacuum-based technologies. As the electric grid is modernized and improved to support new functionalities and smarter technologies, it is important that the safety and power management systems advance and deliver the energy experience customers expect. Oil-filled breakers are an increasingly outdated technology, and not replacing this technology increases risk of maintenance delays due to supply chain issues, as well as potential failures from equipment at or near end-of-life. Additionally, the new communication and control capabilities of this modern technology better position the transmission and distribution systems to respond to electric grid outages and events more effectively. These more reliable gas and vacuum breakers are better suited for protecting circuits with higher solar and other variable distributed and energy resources.

Financial cost-benefit analysis	
Total Project Costs	**NPV as of Sept 2022**
Project capital	$282.4M
Total Costs	**$282.4M**
Total Project Benefits	
Reliability benefits	$8,645.4M
Total Benefits	**$8,645.4M**
Benefit to Cost Ratio (BCR)	**30.6**

Other qualitative benefits	
Benefit	**Description**
Improve reliability	Minimize the number of customers impacted from outage events, component failures, or slow to operate breakers.
Strengthen the grid and manage risk	Reduce risk of a more extensive grid outage resulting from breaker mis-operation or failure.
Increase operational efficiency	Reduce or avoid emergency repair or replacement of breakers, or after-hours work.

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Transformer Upgrades
Project Summary

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Transmission –

Transformer Upgrades

Project purpose
The objective of the Transmission Transformer Upgrade project is to anticipate future transformer failures and replace those transformers in a proactive manner, avoiding the cost and customer outages associated with these failures. Failures can result in significant customer outages, collateral damage, and oil release requiring environmental mitigation.
Timeline for construction
Refer to Master Project List for location-specific timelines. At the project level, construction is planned from April 2023 to November 2026.
Estimated in-service date
Refer to Master Project List for location-specific dates. At the project level, individual location in-service dates range from January 2024 to November 2026.
Project description
Predictive and proactive replacement scopes like **Transformer Bank Replacement** significantly reduce impacts and costs of replacement when compared to performing the same work following a catastrophic failure. The power transformer plays a vital role in the transfer of electric energy between generation and distribution. During its operating life, a transformer is exposed to thermal, electrical, chemical, and mechanical stresses. The combination of all these stresses contributes to the deterioration of the condition of a transformer. Critical power transformers in poor condition can fail and result in outages for customers and costly unplanned restoration costs. Additionally, legacy transformer designs utilize arc-in-oil load tap changers which are susceptible to failure from repetitive voltage adjustments associated with variable energy resources. Upgraded designs eliminate this failure mode by utilizing vacuum tap changers. For these reasons, it is important to identify at-risk transformers and upgrade them under a planned project before they fail. Power transformers are a critical component of most substations. These devices convert power from one voltage level to another, and can be classified based on the voltages to which they are connected: • Transmission-to-Transmission (T/T) – High-voltage and low-voltage windings operate at 44kV or higher (e.g., 500kV/230 kV) • Transmission-to-Distribution (T/D) – High-voltage winding operates at 44kV or higher; Low-voltage winding operates at 35 kV or lower (e.g., 100kV/13kV)

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Duke Energy uses a predictive maintenance approach to monitor the health of its substation transformers. Diagnostic tests are performed on a periodic basis, including electrical testing and dissolved gas analysis (“DGA”) of the insulating oil which indicates the presence of abnormal heating and moisture.
This information, along with other key parameters, feeds into the Health and Risk Management (“HRM”) platform, which utilizes machine learning to determine asset health and inform replacement needs. Transformers which indicate deterioration may be subjected to additional or more frequent monitoring and identified for condition-based planned replacement.

As part of a transformer upgrade, temporary mobile/portable transformers are installed where there is no ability to serve customer load from other sources. The mobile transformers are needed to energize customers to ensure they can be served during the upgrade with limited interruption. Ensuring an adequate supply of reliability mobile transformers is a critical aspect of this project scope in order to execute the work while minimizing impacts to customers.

Typical transmission transformer

Typical T/D transformer

Projected costs (capital expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

	Aug ’23-Dec ‘24	Jan ’25-Dec ‘25	Jan ’26-Dec ‘26	Total
Projected costs (DEC System)	$116.0M	$73.2M	$37.7M	**$226.9M**

Grid capabilities enabled

- Strengthened grid against outages including during extreme weather and storm events
- Increased resiliency to recover from outages
- Improved reliability when accommodating variable conditions associated with DER deployments
- Improved performance from vacuum load tap changer (LTC) technology

HB951 Policy Considerations addressed

- Encourages DERs
- Promotes resilience and security of the electric grid
- Maintains adequate levels of reliability and customer service

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Transmission – Hardening & Resiliency

Transformers

Cost Benefit Analysis

Is the Project required by law?
No.
Explanation of need for proposed expenditure
The objective of the Transformer Upgrade project is to anticipate future transformer failures and replace those transformers in a proactive manner, avoiding the cost and customer outages associated with these failures. Failures can result in significant customer outages, collateral damage, and oil release requiring environmental mitigation.

Financial cost-benefit analysis	
Total Project Costs	**NPV as of Sept 2022**
Project capital	$213.4M
Total Costs	**$213.4M**
Total Project Benefits	
Reliability benefits	$4,637.6M
Total Benefits	**$4,637.6M**
Benefit to Cost Ratio (BCR)	**21.7**

Other qualitative benefits	
Benefit Category	**Description**
Improve reliability	Reduces outages caused by transformer and regulator failures.
Strengthen the grid and manage risk	Reduces risk of unplanned events, collateral damage from failed transformers, and environmental threats from oil spills.
Increase operational efficiency	Avoids system loading contingencies due to loss of capacity from a failed transformer.

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Transmission Capacity and Customer Planning Project Summary

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Transmission -

Capacity and Customer Planning

Project purpose
As demand on the transmission system grows and changes over time, new transmission projects and upgrades are needed to serve retail customers and keep the grid reliable and in compliance with North American Electric Reliability Corporation ("NERC") standards. Transmission expansion projects also facilitate the connection of additional utility scale renewable generation sources.
Timeline for construction
Refer to Master Project List for location-specific timelines. At the project level, construction is planned from January 2022 to December 2026.
Estimated in-service date
Refer to Master Project List for location-specific dates. At the project level, individual location in-service dates range from September 2023 to December 2026.
Project description
In this 2024-2026 MYRP, transmission improvement projects include upgrading equipment such as line conductors, transformers, breakers, and switches to a higher capacity. Protective relay systems are upgraded to add redundancy to help reduce the likelihood and severity of critical equipment outages. Transmission expansion projects, also known as the Red Zone Expansion Plan ("RZEP"), are also included to prepare the grid for the lower carbon and clean energy transition, by uprating and networking key circuits that are in regions of maximum solar generation viability and currently have little margin for additional generation capacity. These projects will make ready these segments of the grid for new solar generation interconnections from both internal and external sources. After DEC Transmission Planning identifies future overloads and network upgrades, the plan is screened by the Integrated System and Operations Planning ("ISOP") process to identify projects that have the potential to be deferred or avoided by a non-traditional solution ("NTS"), such as energy storage. A collaborative effort between Transmission Planning and ISOP identifies the locations and specifications required from an NTS to meet the system needs. Even when the NTS is not selected, this ISOP-informed planning ensures the optimal solutions are being selected in the final transmission plan. Together, these transmission upgrades help DEC maintain grid reliability and compliance with NERC Standards as customer demand grows.

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230/100-kV Autotransformer

500-kV Breaker

Projected costs (capital expenditure)
Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC

	Aug '23-Dec '24	Jan '25-Dec '25	Jan '26-Dec '26	Total
Projected costs (DEC System)	$78.4M	$173.9M	$287.2M	**$539.5M**

Grid capabilities enabled	HB951 Policy Considerations addressed
• Served increased customer demand • Maintained reliability • Enabled connection of more solar generation	• Encourages utility-scale renewable energy and storage • Encourages DERs • Encourages beneficial electrification, including electric vehicles • Promotes resilience and security of the electric grid • Maintains adequate levels of reliability and customer service

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Oct 19 2022

Transmission -

Capacity and Customer Planning

Cost benefit analysis

Is the Project required by law?
Yes. Select work under this project is required to maintain compliance with NERC Standards.
Explanation of need for proposed expenditure
As customer demand grows or shifts over time, loading on transmission equipment, including transmission lines and transformers, grows, and voltages on the transmission grid decline. Generator stability margins can decline as well, and the magnitude of fault current that circuit breakers must interrupt can increase over time. NERC and local standards set requirements for transmission system power flows, voltages, stability, and breaker capability to maintain a safe and reliable transmission grid and avoid widespread grid blackouts, as occurred several times in prior decades. In addition, as customer demand on retail and wholesale distribution systems grows and spreads over time, those distribution systems require new deliveries from the transmission system.

Financial cost-benefit analysis	
Total Project Costs	**NPV as of Sept 2022**
Project capital	$496.4M
Total Costs	**$496.4M**
Total Project Benefits	
Reliability benefits	$6,495.1M
Total Benefits	**$6,495.1M**
Benefit to Cost Ratio (BCR)	**13.1**

Other qualitative benefits	
Benefit Category	**Description**
Improve reliability	Meet federal compliance mandates for grid reliability and maintain grid reliability and stability. Provide capacity upgrades and new connections to serve customer needs.
Societal Benefit	Facilitates the clean energy transition.