Multi-Value Strategic Transmission (MVST)

Cost-Benefit Analysis Whitepaper

Introduction

The MVST process is built on a foundation of collaboration and stakeholder engagement. Throughout the development of this process, input from various stakeholders, including the Transmission Advisory Group (TAG) and other industry experts, has been solicited and incorporated. This collaborative approach ensures that the MVST process is aligned with the needs and priorities of all stakeholders.

The primary objective of this whitepaper is to document a methodology for quantifying each benefit and review with TAG stakeholders prior to the Solutions Meeting. The cost-benefit analysis will inform decision-making and support the development of a robust business case for the proposed transmission projects.

Benefits

The benefits included in the scope for the 2024 MVST study are:

1. Avoided Generation Capacity Costs
2. Generation Capacity Savings from Reduced Losses
3. Congestion and Fuel Savings
4. Energy Savings from Reduced Losses
5. Avoided Customer Outages
6. Avoided Transmission Investment

During the benefits quantification process, DEC and DEP shall provide an estimated breakdown by benefit for any project likely to be recommended or selected for inclusion in the Local Transmission Plan. Additionally, any TAG stakeholder shall be able to request that DEC or DEP provide an estimated breakdown by benefit for any project to inform recommendations on the final transmission portfolio. The final report will include a comprehensive summary of all the study activities as well as the recommended strategic transmission improvements including estimates of costs, portfolio multi-value benefits, and construction schedules.

Avoided Generation Capacity Costs

The avoided generation capacity costs represent the savings achieved by delaying or avoiding investments in additional generation facilities.

Step 1: Utilizing PowerGEM's Transmission Adequacy and Reliability Assessment (TARA) software, calculate the change in transfer capability available between the Balancing Authorities DUK, CPLE, and CPLW due to the MVST transmission portfolio projects.

Step 2: Leverage Astrape Strategic Energy Risk Valuation Model (SERVM) cases used for reliability verification in IRP. Perform exploratory analysis of the impact of different transmission constraints on the Loss of Load Expectation (LOLE) in long-term cases and, if needed, estimate generation capacity to maintain a reliable LOLE.

Step 3: Calculate the value of the generation capacity avoided. In the Avoided Cost dockets, Duke Energy utilizes the "Peaker Method" to calculate the value of avoided generation capacity. This method allows for consistent application of generation capacity whether a program is 1 MW or 1000 MWs. It also references publicly available data, currently the PJM CONE 2026/2027 Report, for the costs of simple cycle combustion turbines (CTs).

Step 4: The avoided peak demand will be multiplied by the generation capacity savings in each year for the life of the transmission projects.

Generation Capacity Savings from Reduced Losses

Generation capacity savings from reduced losses occur when the transmission projects effectively minimize energy losses during peak needs. These savings can be assessed by comparing the current losses with the projected reductions after implementing the improvements. The methodology involves calculating the avoided peak demand due to reduced line losses and then determining the generation capacity value over the lifetime of the projects.

Final Rule Benefit 7: Capacity Cost Benefits from Reduced Peak Energy Losses

Paragraph 818 from Order 1920:

> "One potential way to measure capacity cost savings from reduced peak energy losses is to calculate the present value of capital cost savings associated with the reduction in installed generation requirements. To arrive at the value of capital cost savings, the estimated net cost of new entry (i.e., the cost of new peaking generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource constrained) could be multiplied by the reduction in installed generation capacity requirements. The resulting value would represent the avoided cost of procuring more generation to cover transmission system losses during peak-load conditions, savings that would be passed on to customers via lowered generation capacity costs."

Methodology:

Step 1: The line losses will be calculated and averaged across the top 10 peak hours in Encompass nodal for a reference scenario and a change scenario that has the proposed transmission solutions modeled. The difference in line losses between the two scenarios will be the avoided peak demand due to reduced line losses.

Step 2: Calculate the generation capacity value of reducing peak demand. In the Avoided Cost dockets, Duke Energy utilizes the "Peaker Method" to calculate the value of avoided generation capacity. This method allows for consistent application of generation capacity whether a program is 1 MW or 1000 MWs. It also references publicly available data, currently the PJM CONE 2026/2027 Report, for the costs of simple cycle CTs.

Step 3: The avoided peak demand will be multiplied by the generation capacity savings each year for the life of the transmission projects.

Congestion and Fuel Savings

Congestion and fuel savings are achieved by alleviating bottlenecks in the transmission system, which in turn reduces the need for more expensive dispatch of generation resources. Enhancing the transmission network leads to lower fuel consumption and reduced operational costs. The generator interconnection process studies a robust set of cases and contingencies to ensure that generators have deliverability, which minimizes congestion. However, there may be cases where large amounts of interchange between the Balancing Authorities is transmission limited. To the extent that constraints on the dispatch of resources or interchange are identified, these constraints will be modeled in a production cost model to quantify the savings that could be achieved through transmission upgrades.

Step 1: Model identified constraints in the nodal production cost model and calculate the adjusted production costs (APC) for the reference case.

Step 2: Add the MVST transmission projects and calculate the new APC for the change case.

Step 3: Compare the change case vs reference case to quantify the APC savings due to relieving congestion.

Since resources and transmission beyond the 10-year horizon are not modeled, congestion savings for the MVST transmission portfolio will be escalated at the rate of inflation.

Energy Savings from Reduced Losses

Energy savings from reduced losses occur when the transmission system is optimized to minimize energy lost during transmission. New and upgraded transmission facilities can decrease system resistance and line loading, resulting in lower energy losses and reduced energy consumption. The value of reduced energy losses can be quantified through production cost savings.

The methodology selected leverages a new feature in Encompass nodal to calculate annual energy losses.

Step 1: Using the same nodal production cost models developed for calculating "Congestion and Fuel Savings," calculate the line losses and production cost of line losses for the reference scenario.

Step 2: Add the MVST transmission projects and calculate the new line losses for the change scenario.

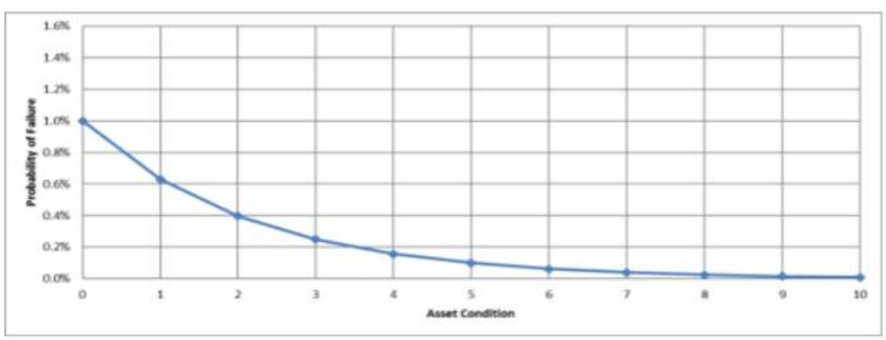
Step 3: To avoid double-counting the impacts of "Congestion and Fuel Savings", the change in losses (difference between change and reference) will be multiplied by the reference's marginal costs to calculate the production cost savings from reduced energy losses.

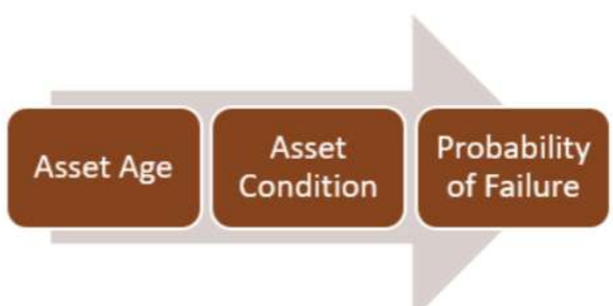
Note: If you compare the "losses costs" calculated in Encompass directly between 2 scenarios, you can see large swings due to higher or lower costs for all losses that should be attributed to "Congestion and Fuel" and not "Energy Savings from Reduced Losses."

Avoided Customer Outages

Avoided customer outages result from maintaining reliability and resilience of the transmission infrastructure. By addressing aging infrastructure, the frequency and duration of outages can be minimized. This translates into improved service continuity, customer satisfaction, and reduced economic losses associated with interruptions in power supply when compared with a transmission plan that does not address aging infrastructure.

Step 1: Quantify the asset condition of existing transmission assets that are being replaced due to the MVST transmission portfolio. In the graph below, an Asset Condition of 10 is very good condition and 1 is very poor condition.





Step 2: Leverage the Interruption Cost Estimator (ICE)[1] tool developed by Lawrence Berkeley National Laboratory and Nexant to determine estimated interruption costs and the value of reliability improvements based on asset deterioration curves and failure probabilities.

The Transmission Frequency and Duration cost tables below are based on the ICE 2.0 calculator, released in Spring 2025. The outputs from the ICE tool are inputs to the Copperleaf tool.

State	Number of Residential Customers	Number of Non-Residential Customers	Total Customers	SAIDI	SAIFI
North Carolina	3,369,858	541,270	3,911,128	13.68	0.13
South Carolina	740,664	138,290	878,954	18.51	0.17

Table 1: 2025 ICE Calculator Parameters per State

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Version: interruption.2.1.0
Required User Inputs are Highlighted in Light Green

Choose State(s):	
State 1	North Carolina
State 2	None
State 3	None
State 4	None
State 5	None
State 6	None
State 7	None
State 8	None
State 9	None
State 10	None

Number of Customers:	
Non-Residential	541,270
Residential	3,369,858

Reliability Inputs:	
SAIFI	0.13
SAIDI	13.68
CAIDI	106.1

Main Output:

Sector	Number of Customers	Cost Per Customer Event (2023$)	Cost Per Customer Average kW (2023$)	Cost Per Customer Unserved kWh (2023$)	Cost Per Customer Minute Interrupted (2023$)	Annual Cost Per Customer (2023$)	Total Cost of Power Interruptions (2023$)
Non-Residential	541,270	$3,137.48	$271.53	$153.59	$29.58	$404.76	$219,084,438.04
Residential	3,369,858	$9.77	$6.97	$3.94	$0.09	$1.26	$4,245,785.78
All Customers	3,911,128	$442.62	$157.76	$89.24	$4.17	$57.10	$223,330,223.82

Figure 1: Example ICE Calculator Results

State	Frequency Cost (Cost per Average KW)		Duration Cost (Cost per Unserved kWh)		Customer Minutes of Interruption (CMI) Cost
	Residential	Non-Residential	Residential	Non-Residential	
North Carolina	$6.97	$271.53	$3.94	$153.59	$4.17
South Carolina	$6.88	$255.47	$3.72	$138.34	$5.25

Table 2: 2025 Frequency and Duration Cost per Customer Type and State (2023 $)

[1] Icecalculator.com – "The Interruption Cost Estimate (ICE) Calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory (LBNL) and Resource Innovations. This tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States."

Step 3: Utilize the Copperleaf Product Suite, a proprietary asset replacement value model to quantify the reliability benefits from replacing aging infrastructure.

- Baseline Risk: The risk present if the Investment is not completed.
- Residual Risk: The risk present after the Investment is completed.

Value of Risk Mitigated is computed as: Mitigated Risk = Baseline Risk – Residual Risk (Post-Investment Baseline Risk)

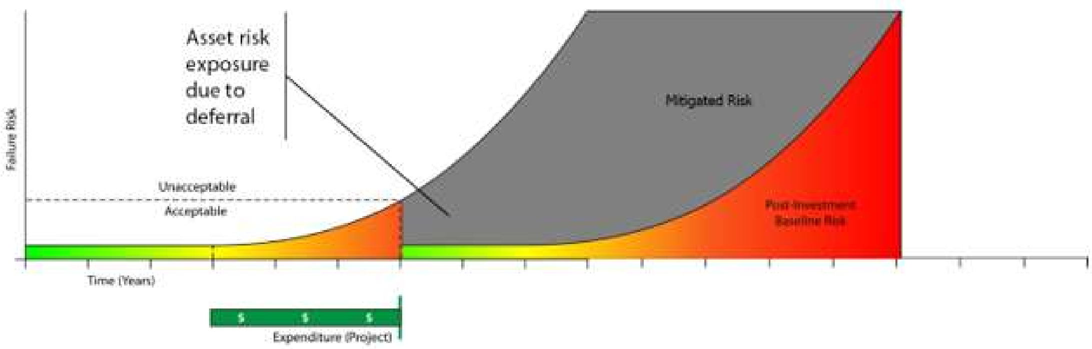

Figure : Mitigated Risk Over Time

Avoided Transmission Investment

Avoided transmission investment refers to the financial benefits of not having to undertake additional transmission infrastructure projects that would otherwise be necessary without the proposed improvements. By optimizing the existing network and implementing strategic enhancements, the need for further investments can be significantly reduced, leading to cost savings and efficient capital allocation.

Investments to Avoid: Although many Needs are identified in the MVST study, avoiding an overload of any of these Needs is not sufficient to qualify as "Avoided Transmission Investment" due to the uncertainty on if or when some overloads will occur. Therefore, only transmission investments that appear in a CTPC Base Reliability plan will be eligible as an "Avoided Transmission Investment."

$$Gross\ Benefit\ NPV = \frac{Year\ 1\ Net\ Savings}{1 + Discount\ Rate} + \frac{Year\ 2\ Net\ Savings}{(1 + Discount\ Rate)^2} + \cdots$$

where Net Savings is costs deferred minus costs accelerated due to changes in year of need.

Step 1: Model proposed MVST transmission solutions and perform contingency analysis.

Step 2: Identify any overloaded facilities addressed by Base Reliability projects that have reduced loading due to the MVST solution.

Step 3: Calculate the number of years of deferral (i.e. Year of Need with MVST Solution minus Year of Need without MVST Solution) due to reductions in loading on the identified facilities. If the Base Reliability project is completely avoided, then the entire project cost will be included as a benefit by deferring the project outside the 30-year benefit analysis timeframe

Step 4: The Net Present Value (NPV) of the transmission capital costs will be scaled by a Present Value Revenue Requirement (PVRR) factor to allow comparison of capital costs with the other benefits.

Portfolio Analysis

The Present Value Revenue Requirement (PVRR) of the transmission portfolio costs will be compared against the Net Present Value (NPV) of all benefits across a 30-year horizon.

Model Assumptions

Input	**Assumption**	**Source**
Evaluation Period	30 years	Consistent with MYRP
Transmission Book Life	50 years (may vary by technology)	Blend of structures and conductor expected life
CapEx Spend	3 years – 20/30/50	Internal generic assumption until actuals are available
Year 1	2026	The year the CTPC Collaborative Transmission Plan Report will be issued and spend could begin
Discount Rate	7%	Generic discount rate based on historical utility approved Weighted-Average Cost of Capital (WACC).
Inflation Rate	2.5%	Technology-agnostic long-term inflation rate
Tax Depreciation	15 Year Modified Accelerated Cost Recovery System (MACRS) for Transmission	General Depreciation System (GDS) for electric transmission property

Sensitivity Analysis

For the 2024 MVST Study Scope, TAG members requested the following sensitivities:

- Sensitivity on the forecasted price of natural gas
    - Benefits #3 and #4 will be calculated for Low, Medium, and High natural gas prices.
- Sensitivity that does not include alternative solutions and only considers reconductoring and rebuilding transmission lines with high-performance conductors in existing rights-of-way
    - Where upgrades are appropriate, reconductoring and rebuilding existing transmission lines will be considered for each overloaded line that advances through the MVST Selection Criteria. The cost and benefits of these upgrades will be compared to the final MVST portfolio of solutions.

Version History

Date	Revisions
3/3/2025	Draft for Internal Review
3/18/2025	Draft for CTPC Oversight Steering Committee (OSC)
12/3/2025	Draft updated based on preliminary benefits analysis
1/30/2026	Added ICE tables to the Avoided Customer Outage benefit methodology

Appendix

Benefits required in Docket No. RM21-17-000; FERC Order 1920:

Benefit 1: Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement

- "the reduced costs due to avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities." *– P 542 & n.745 (1920)*

Benefit 2(a): Reduced Loss of Load Probability or Benefit 2(b): Reduced Planning Reserve Margin

- Reduced Loss of Load Probability – "the reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages (if the planning reserve margin is not changed despite lower loss of load events), as well as improved physical reliability benefits by reducing the likelihood of load shed events. Benefit 2(a) measures reduced loss of load probability for resource adequacy planning, which typically includes the consideration of normal system conditions. One method of measuring a reduction in loss of load probability benefit is to quantify the incremental increase in system reliability by determining the reduction in expected unserved energy between the base case and the change case, determining the value of lost load, and multiplying these two values to obtain the monetary benefit of enhanced reliability associated with a Long-Term Regional Transmission Facility or a portfolio of Long-Term Regional Transmission Facilities" *– P 550 & n.756 (1920)*
- Planning Reserve Margin - "the reduction in capital costs of generation needed to meet resource adequacy requirements (i.e., planning reserve margins) while holding loss of load probability constant." *– P 552 & n.758 (1920)*

Benefit 3: Production Cost Savings

- "savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production, as well as a reduction in market prices as lower-cost suppliers set market clearing prices." *– P 560 & n.767 (1920)*

Benefit 4: Reduced Transmission Energy Losses

- "the reduced total energy necessary to meet demand stemming from reduced energy losses incurred in transmittal of power from generation to loads." *P 568 & n.781 (1920)*

Benefit 5: Reduced Congestion Due to Transmission Outages

- **"**reduced production costs resulting from avoided congestion during transmission outages." *P 571 & n.788 (1920)*

Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions

- "reduced production costs and reduced loss of load (or emergency procurements necessary to support the system), including due to increased Interregional Transfer Capability, during extreme weather events and unexpected system conditions, such as unusual weather conditions or fuel shortages that result in multiple concurrent and sustained generation and/or transmission outages." *P 583 & n.800 (1920)*

Final Rule Benefit 7: Capacity Cost Benefits from Reduced Peak Energy Losses

- "reduced generation capacity investment needed to meet peak load." *P 598 & n.817 (1920)*

Supporting Materials:

Estimating Power System Interruption Costs: A Guidebook for Electric Utilities | Energy Markets & Policy

Re-Vision-Economic-Methodology-for-the-Evaluation-of-Emerging-Renewable-Technologies-MP-11-9-11.pdf