Generator Interconnection Request

System Impact Study

For: [redacted]

Cleveland County Combined Cycle Plant

Service Location: Cleveland County, North Carolina

Total Output: Additional 937 MW

In-Service Date: 6/1/2014

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1.0 Introduction

Following are the results of the Generation System Impact Study for the installation of 937 MW of generating capacity in Cleveland County, North Carolina. This site is located near Ripp Switching Station with a new switching station as the point of interconnection and has an estimated Commercial Operation Date of June 1, 2015. This study included both Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS).

2.0 Study Assumptions and Methodology

The power flow cases used in the study were developed from the Duke internal year 2015 summer peak case. The results of Duke's annual screening were used as a baseline to identify the impact of the new generation. All cases were modified to include 937 MW of additional generation at a new switching station in Cleveland County, North Carolina. To determine the thermal impact on Duke's transmission system, the new generation was modeled with a new interconnection station on the Sampson Lines (Ripp Switching Station to Riverbend Switching Station). The economic generation dispatch was also changed by adding the new generation and forcing it on prior to the dispatch of the remaining Duke Balancing Authority Area units. The study cases were re-dispatched, solved and saved for use.

The NRIS thermal study uses the results of Duke Energy Transmission Planning's annual internal screening as a baseline to determine the impact of new generation. The annual internal screening identifies violations of the Duke Energy Power Transmission System Planning Guidelines and this information is used to develop the transmission asset expansion plan. The annual screening provides branch loading for postulated transmission line or transformer contingencies under various generation dispatches. The thermal study results following the inclusion of the new generation were obtained by the same methods, and are therefore comparable to the annual screening. The results are compared to identify significant impacts to the Duke Energy transmission system.

The ERIS thermal study utilizes a model that includes the new generation with relevant higher queued projects and associated known upgrades. The new generation economically displaces Duke Balancing Authority Area units. Transmission capacity is available as long as no transmission element is overloaded under N-1 transmission conditions. The thermal evaluation will only consider the base case under N-1 transmission contingencies to determine the availability of transmission capacity. ERIS is service using transmission capacity on an "as available" basis; adverse generation dispatches that would make the transmission capacity unavailable are not identified. The study will also identify the maximum allowable output without requiring additional Network Upgrades at the time the study is performed.

Stability studies are performed using an MMWG dynamics model that has been updated with the appropriate generator and equipment parameters for the new units. The SERC dynamically reduced 2016 summer peak case was used for this study. The case was modified to turn off some units to offset the new generation. Several transmission system improvements were identified for the addition of these units during the power flow portion of the interconnection request and were added to the dynamics case. NERC Category B, Category C, and Category D faults were evaluated.

Fault studies are performed by modeling the new generator and previously queued generation ahead of the new generator in the interconnection queue. Any significant changes in fault duty resulting from the new generator's installation are identified. Various faults are placed on the system and their impact versus equipment rating is evaluated.

Reactive Capability is evaluated by modeling a facility's generators and step-up transformers (GSUs) at various taps and system voltage conditions. The reactive capability of the facility can be affected by many factors including generator capability limits, excitation limits, and bus voltage limits. The evaluation determines whether sufficient reactive support will be available at the Connection Point.

Any costs identified in the fault duty, stability or reactive capability studies are necessary for both ERIS and NRIS service.

3.0 Thermal Study Results

3.1 NRIS Evaluation

The following network upgrades were identified as being attributable to the studied generating facility:

Facility Name/Upgrade	Existing Size/Type	Proposed Size/Type	Mileage	Estimated Cost	Lead Time (months)
1. Hook 100kV Lines	795 ACSR	B795 ACSR	7.47	$4.9MM*	24**
2. New Switchyard on Sampson Lines and Sampson Line Fold-in				$8.75MM	12
THERMAL NRIS CUSTOMER COST ESTIMATE				**$13.65MM**	**12**

Note 1: If the project with queue ID 40577-01 is built, the customer will only be charged for 5 years of acceleration costs for upgrade 1.

Note 2: The lead time for upgrade 1 is 24 months. The need for the project is currently projected to be by summer 2016, therefore the effective lead time is 12 months before COD.

3.2 ERIS Evaluation

Under the terms of ERIS service, the full output of the plant can be delivered at the time the study was performed. The only upgrade required for ERIS service is the new Switching Station on the Sampson Lines with the Sampson Line Fold-in, as shown above. **Therefore the thermal ERIS Customer Cost Estimate is $8.75MM.**

4.0 Fault Duty Study Results

The following breakers will need to be replaced:

1. At Ripp Switching Station the following thirteen 230kV breakers: PCB 1, PCB 2, PCB 3, PCB 4, PCB 5, PCB 13, PCB 14, PCB 15, PCB 21, PCB 22, PCB 23, PCB 24, PCB 25
2. At Tiger Tie the following two 230kV breakers: Flint Bl & Wh Line Breakers
3. At Wylie Hydro Station the following two 100kV breakers: Weddington Wh & Wylie Bl Line Breakers

Total estimated cost for breaker replacements: **$3.84MM**

If the project with queue ID 40577-01 is built, the following additional breakers will need to be replaced:

1. At Mill Creek Combustion Turbine Station the following four 230kV breakers: PCB 1, PCB 2, PCB 3, PCB 4
2. At Peach Valley Switching Station the Cherokee Bl 100kV breaker and the Peach Valley Bl 230kV breaker

Additional estimated cost for breaker replacements if the project with queue ID 40577-01 is built: **$1.3MM**

5.0 Stability Study Results

All fault simulations were transiently stable except for some of the NERC Category D faults. NERC does not require stability for Category D faults because of their low probability of occurrence.

NERC TPL-004 defined events involving a three-phase fault on a transmission line or on a bus with three-phase breaker failure cause generators to go unstable and trip off-line. The tested breaker failure clearing time was 18 cycles, of which 12 cycles is intentional delay to give primary protection time to operate. The critical clearing time (CCT) for all of the unstable faults at the Cleveland County 230 kV switching station ranged from 11.0 to 16.5 cycles. The CCTs for all of the unstable faults at the Ripp 230 kV switching station ranged from 11.5 to 12.0 cycles. If desired, stability could be achieved for all Category D faults with breaker failure by reducing the intentional delay time from the typical 12 cycles to 5 cycles, with total breaker failure clearing time of 11 cycles. If 5 cycles intentional delay time is not achievable, any reduction from 12 cycles would increase the likelihood of stability following a Category D fault with breaker failure. Therefore it is recommended that the breaker failure intentional delay time be reduced to the minimum practical value for all breakers at the Ripp and the new Cleveland County 230 kV Switching Stations.

NERC TPL-004 defined events involving a three-phase fault on a transmission line with pilot relay failure cause generators to go unstable and trip off-line. The tested Zone 2 regular clearing time was 29.5 cycles, of which 24 cycles is intentional delay to give primary protection time to operate. The CCTs for all the unstable faults at the Cleveland County CC 230 kV switching station ranged from 14.0 to 16.0 cycles. The CCTs for all the unstable faults at the Ripp 230 kV switching station ranged from 15.0 to 15.5 cycles. If desired, stability could be achieved for all Category D faults with pilot relay failure by reducing the intentional delay time from the typical 24 cycles to 8.5 cycles, with total Zone 2 clearing time of 14 cycles. If 8.5 cycles intentional delay time is not achievable, any reduction from 24 cycles would increase the likelihood of stability following a Category D fault with pilot relay failure. Alternately, redundant relaying could be installed to achieve stability for the pilot relay failure contingencies.

NERC does not require stability for Category D faults because of their low probability of occurrence. As such, none of the suggested Category D solutions are required.

Because instability was seen for some faults, out-of-step relaying is required for the new Cleveland County CC generators.

The Cleveland County CC generators and the nearby generators performed well for all other simulated faults.

The manufacturer proposed power system stabilizers (PSS) were not studied because there was sufficient damping without them. However, a PSS should be purchased along with each exciter. If problems arise in the future, then the facility can quickly implement a PSS solution.

The addition of the proposed 937 MW to the new switching station near Ripp Switching Station does present some stability concerns. However, with the solutions outlined in this report, the Customer's proposed 937 MW generating facility will not negatively impact the overall reliability of the generators or the interconnected transmission system.

6.0 Reactive Capability Study Results

With the proposed generating facility, the level of reactive support supplied by the units has been determined to be acceptable at this time. Evaluation of MVAR flow and voltages in the vicinity of the new switching station near Ripp Switching Station indicates adequate reactive support exists in the region.

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