System Impact Study Report

For: XXXXXXXXXXX ("Customer")

Queue #: 42544-01

Service Location: Laurens County, SC

Total Output: 72 MW (equally split between two Connection Points)

Commercial Operation Date: 12/1/2017

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1.0 Introduction

Following are the results of the Generation System Impact Study for the installation of 72 MW of generating capacity, equally split between two facilities in Laurens County, SC. The results of the study have been revised to account for the ability of each of the Customer's facilities to provide adequate reactive support at the MW value associated with the System Impact Study Agreement. These sites are located near Clinton Tie and have an estimated Commercial Operation Date of 12/1/2017. This study includes 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 Energy Carolinas (DEC) internal year 2018 summer peak case. The results of DEC's annual screening were used as a baseline to identify the impact of the new generation. To determine the thermal impact on DEC's transmission system, the new generation was modeled as two new interconnections—one on each of the Clinton 100 kV lines. All cases were modified to include 36 MW of additional generation at each of the Customer's two facilities. The economic generation dispatch was changed by adding the new generation and forcing it on prior to the dispatch of the remaining DEC Balancing Authority Area units. The study cases were re-dispatched, solved and saved for use. The impacts of changes in the Generator Interconnection Queue were not evaluated, because it was determined that no earlier queued generators would have a significant impact on the study results.

The NRIS thermal study uses the results of DEC 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 DEC transmission system.

The ERIS thermal study utilizes a model that includes the new generation with relevant earlier queued projects and associated known upgrades. The new generation economically displaces DEC 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.

Short circuit analysis is performed by modeling the new generator and earlier queued generation ahead of the new generator in the interconnection queue. Any significant changes in short circuit current resulting from the new generator's installation are identified. Various faults are placed on the system and their impact versus equipment rating is evaluated.

Stability studies are performed using a Multiregional Modeling Working Group dynamics model that has been updated with the appropriate generator and equipment parameters for the new unit(s). The SERC dynamically reduced 2018 summer peak case was used for this study. The case was modified to turn off some existing generation to offset the new generation. The power flow portion of the interconnection request did not identify any transmission system improvements associated with the addition of the new generation that needed to be added to the dynamics case. The contingencies in NERC TPL-001-4 Table 1 were simulated to evaluate the dynamic stability system impact of the new generation.

Reactive Capability is evaluated by modeling a facility's generators and step-up transformers (GSU's) 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. The DEC Facilities Connection Requirements (FCR) for generators connected to the Transmission System requires that the generator must be capable of supplying power factor in the range from .93 lagging (producing VARs) to .97 leading (absorbing VARs) measured at the Connection Point. For more information on generator reactive requirements, reference the 'Generator Power Factor Requirements' document on the DEC OASIS site[1].

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

[1] http://www.oatioasis.com/DUK/DUKdocs/Generator_Interconnection_Information.html

3.0 Thermal Study Results

3.1 NRIS Evaluation

No earlier queued projects were deemed to have a material impact on the results of the study.

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)
A. Interconnection Cost	[redacted]			$3 MM	24
B. Upgrade Clinton 100 kV Lines (Bush River-Laurens) and install OPGW[2]	477 ACSR, 2/0 Cu, 336 ACSR	954 ACSR	29.23	$44 MM	48
CUSTOMER TOTAL COST ESTIMATE				$47 MM	48

3.2 ERIS Evaluation

Under the terms of ERIS service, the full output of the plant can be delivered at the time of the study without causing thermal upgrades. For ERIS service, the estimated cost and lead time for the upgrades associated with the interconnection facilities are identified in section 3.1 If the Customer elects to pursue OPGW as the means of communication, ERIS service will also require the upgrade of the Clinton 100 kV lines for which the estimated cost and lead time is identified in section 3.1; if the Customer elects to use third party communication rather than OPGW, the upgrade of the Clinton 100 kV line is not required.

4.0 Short Circuit Analysis Results

There are no breakers that need to be replaced as a result of the new generation.

[2] The need to rebuild the Clinton 100 kV lines is driven by the installation of Optical Ground Wire (OPGW) that would be associated with the Customer's facility; the need to rebuild the Clinton 100 kV lines is not driven by thermal loading issues. DEC utilizes OPGW for providing a communication path for system protection purposes and at times to populate the Energy Management System with operating data (MW, MVAR, etc.). The 100 kV transmission line the Customer desires to interconnect to uses structures that cannot support the additional weight of OPGW. As a result, the entire 29.23 mile 100 kV transmission line would need to be rebuilt in order to install OPGW. DEC will consider alternative forms of communication proposed by the Customer. Any alternative communication schemes must be presented to and approved by DEC during the Facility Study.

5.0 Stability Study Results

There are no contingencies that caused angular or voltage stability concerns in the system. The inverters were able to ride through all faults and returned to their pre-fault power output after the fault cleared.

With the assumptions and models used in this study, the Customer's proposed 72 MW facility (equally split between two Connection Points) will not negatively impact the overall reliability of the facility or the interconnected transmission system. Any changes to assumptions or models may change these results.

6.0 Reactive Capability Study Results

The Customer proposed installing a 12.5 MVAR capacitor bank at each of its facilities; however, the maximum allowable size for a capacitor bank associated with each facility is 5.1 MVAR, which allows the Customer to compensate only for plant losses. With a 5.1 MVAR capacitor bank installed and in service at each facility, the requested output at each facility (36 MW) meets the reactive capability requirements, and the reactive power range will be between 14.2 MVAR lagging and 9 MVAR leading at each facility. If the Customer does not install the capacitor banks or the capacitor banks are not in service, the maximum output of each facility that meets the reactive capability requirements is 35.3 MW, and the reactive power range will be between 13.8 MVAR lagging and 8.7 MVAR leading. The recommended tap setting at the high side of the GSU is 101.25 kV.

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