System Impact Study Report

For: [redacted] ("Customer")

Queue #: 42696-01

Service Location: Catawba County, NC

Total Output: 69.3 MW

Commercial Operation Date: 8/1/2018

Prepared by:
Orvane Piper, Duke Energy Carolinas

Table of Contents

Date: **3/17/2017**

1.0 Introduction

Following are the results of the Generation System Impact Study for the installation of 69.3 MW of generating capacity in Catawba County, NC. This site is located near Newton Tie and has an estimated Commercial Operation Date of 8/1/2018. 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 a new interconnection on the Mull Wh 100 kV line. All cases were modified to include 69.3 MW of additional generation at the Customer's facility. 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. 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. 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. No transmission system improvements that needed to be added to the dynamics case were identified for the addition of the new generation during the power flow portion of the interconnection request. NERC TPL-001-4 Planning Events and Extreme Events were evaluated.

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 Customer's generating facility:

Facility Name/Upgrade	Existing Size/Type	Proposed Size/Type	Mileage	Estimated Cost	Lead Time (months)
A. Interconnection Cost	[redacted]			$1.5 MM	24
B. Upgrade Mull W 100 kV Line (Customer's Facility-Carolina Mills Tap) and install OPGW[2]	336 ACSR, 556 ACSR	556 ACSR	5.7	$9.5 MM	30
TOTAL ESTIMATED COST FOR THERMAL UPGRADES				$11 MM	30

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 Mull W 100 kV line 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 Mull W 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 a portion of the Mull W 100 kV line is driven by the installation of Optical Ground Wire (OPGW) that would be associated with the Customer's facility; the need to rebuild this portion of the Mull W 100 kV line 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, a 5.7 mile portion 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. With the recommended tap setting at the high side of the GSU of 106.3 kV, the inverters were able to ride through all faults and returned to their pre-fault power output after the fault cleared. If the tap setting at the high side of the GSU is lower than 106.3 kV, the inverters may not be able to ride through some normal clearing faults due to post-contingency high voltage in the system.

With the assumption and models used in this study, the Customer's proposed 69.3 MW facility 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

While operating at .93 pf lagging, the maximum output of the facility that would not thermally overload the main step up transformers is 69.3 MW. Assuming an output of 69.3 MW, the maximum allowable size for a capacitor bank associated with this facility is 23.2 MVAR, which allows the Customer to compensate only for plant losses. With a 23.2 MVAR capacitor bank installed and in service, the reactive capability requirements set forth in DEC's FCR document are satisfied. If the Customer does not install the capacitor bank or the capacitor bank is not in service, the maximum output of the facility that meets the reactive capability requirements is 62.6 MW. The recommended tap setting at the high side of the GSUs is 106.3 kV. Any optimization of the taps on the inverter step up transformers that is needed to manage potentially high voltage on the Customer's equipment is the sole responsibility of the Customer.

Study completed by: ________________________________
Orvane Piper, Duke Energy Carolinas

Reviewed by: ________________________________
Edgar Bell, Duke Energy Carolinas
Director, Transmission Planning Carolinas

Date: **3/17/2017**