Feasibility Study Report

For: [redacted] ("Customer")

Queue #: 42916-02

Service Location: Chester County, SC

Total Output Requested By Customer: 74.5 MW

Commercial Operation Date Requested By Customer: 1/7/2019

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1.0 Introduction

Following are the results of the Generation Feasibility Study for the installation of 74.5 MW of generating capacity (solar) in Chester County, SC. This site is located near Great Falls Switching Station and has a requested Commercial Operation Date of 1/7/19. 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 2019 summer peak and off-peak cases. The cases were modified to include 74.5 MW of additional generation at the Customer's facility, which was modeled assuming one of two interconnection options: 1) tap on Landsford Bl 100 kV line or 2) tap on Landsford Wh 100 kV. Evaluation of a switching station was requested by the Customer; however, the project does not meet DEC's criteria for considering a switching station as a method of interconnection, which method is available only to generating facilities (a) with a maximum net generating capacity exceeding 80 MW and (b) for which the Transmission Provider exercises discretion on a case-by-case to permit such method. 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 evaluated by creating additional models with earlier queued generation included.

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 internal 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 are obtained by the same methods, and are therefore comparable to the annual internal 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; therefore, adverse generation dispatches that would make the transmission capacity unavailable are not identified. If the full output of the Customer's facility cannot be delivered at the time of the study, the study will identify the maximum allowable output at the time of the study that does not require additional Network Upgrades.

Short circuit analysis is performed by modeling the new generation and any associated transmission upgrades. Various faults were placed on the system and their impact versus equipment rating was evaluated. Any significant changes in short circuit current resulting from the new generation's installation were identified.

Reactive Capability is evaluated by modeling a facility's generation 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 inverter capability limits and bus voltage limits. The evaluation determines whether sufficient reactive support will be available at the Connection Point based on the requirements set forth in DEC's Facilities Connection Requirements (FCR) for generation connected to the Transmission System. For more information on reactive requirements for generation, reference the 'Generator Power Factor Requirements' document on the DEC OASIS site[1].

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

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

3.0 Interconnection Overview

The following tables include a preliminary estimate for the transmission modifications associated with the interconnection station, relaying and communication at the remote ends of the transmission line, and the recommended communication solution for the Customer's generating facility. The details of the interconnection station are further defined in subsequent phases of the interconnection process.

Interconnection Option 1 (Tap on Landsford Bl 100 kV line):

Facility Name/Upgrade	Mileage	Estimated Cost	Estimated Time Prior To Back Feed for Start of Activity (months)
1. 100 kV Interconnection - Tap[2]	[redacted]	$2.5 MM	24
2. Modify Relay and Communication Equipment (Bowater Switching Station, Great Falls Switching Station, Frances Tap)		$0.5 MM	12
3. Install OPGW on Landsford 100 kV Lines (Bowater Switching Station-Great Falls Switching Station)[3]	19.47	$2.5 MM	24
TOTAL ESTIMATED COST[4]		$5.5 MM	24

[2] Includes Transmission Provider's Interconnection Facilities and Network Upgrades associated with the interconnection of the Customer's generating facility.

[3] The Landsford 100 kV lines do not currently have OPGW installed, but the line structures can support the addition of OPGW.

[4] This does not include costs that may be identified in thermal or short circuit studies.

Interconnection Option 2 (Tap on Landsford Wh 100 kV line):

Facility Name/Upgrade	Mileage	Estimated Cost	Estimated Time Prior To Back Feed for Start of Activity (months)
1. 100 kV Interconnection - Tap[5]	[redacted]	$2.5 MM	24
2. Modify Relay and Communication Equipment (Bowater Switching Station, Great Falls Switching Station)		$0.3 MM	12
3. Install OPGW on Landsford 100 kV Lines (Bowater Switching Station-Great Falls Switching Station)[6]	19.47	$2.5 MM	24
TOTAL ESTIMATED COST[7]		$5.3 MM	24

Optical Ground Wire (OPGW) is the recommended communication solution for generator installations tapping a single circuit. DEC currently allows the use of 3rd party communications, in lieu of the recommended installation of OPGW. The 3rd party communications should include a continuous path of leased fiber to ensure communications reliability. Regardless of the communications medium utilized, DEC will implement protection settings that automatically trip the delivery for loss of communications and for violating the latency requirements. Some of the sites currently utilizing 3rd party communications are experiencing significant communications interruptions, resulting in automatic trip events. If unacceptable reliability performance occurs, DEC will evaluate alternatives and require additional improvements to meet reliability requirements. This study report assumes the installation of OPGW, which is identified as a Network Upgrade. If the developer elects to utilize 3rd party communications, the cost for the installation of OPGW can be omitted from the initial estimate.

[5] Includes Transmission Provider's Interconnection Facilities and Network Upgrades associated with the interconnection of the Customer's generating facility.

[6] The Landsford 100 kV lines do not currently have OPGW installed, but the line structures can support the addition of OPGW.

[7] This does not include costs that may be identified in thermal or short circuit studies.

4.0 Thermal Study Results

4.1 NRIS Evaluation

The following thermal upgrades were identified as being attributable to the Customer's generating facility:

Required Network Upgrade	Proposed Size/Type	Mileage	Estimated Cost	Estimated Time Prior To Back Feed for Start of Activity (months)
1. Upgrade Monroe 100 kV Lines (Lancaster Main-Monroe Main)[8]	954 ACSR	22.96	$34.5 MM	36
TOTAL ESTIMATED COST			$34.5 MM	36

4.2 ERIS Evaluation

Under the terms of ERIS service, the full output of the Customer's facility can be delivered at the time of the study without causing thermal upgrades.

5.0 Short Circuit Analysis Results

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

[8] Either a portion or all of this upgrade has been identified for one or more earlier queued generation projects. Scope and cost responsibility for this upgrade will have to be reassessed in the future as Customers make decisions about their projects. Final scope and cost responsibility cannot be determined at this time due to uncertainty about earlier queued generation projects.

6.0 Reactive Capability Study Results

The maximum allowable size for a capacitor bank associated with the Customer's generating facility is 13.8 MVAR, which allows the Customer to compensate only for plant losses. With a 13.8 MVAR capacitor bank installed and in service, the maximum output of the Customer's generating facility that meets the reactive capability requirements set forth in DEC's FCR document is 69.4 MW, and the reactive power range will be between 27.3 MVAR lagging and 17.2 MVAR leading. If the Customer does not install the capacitor bank or the capacitor bank is not in service, the maximum output of the Customer's generating facility that meets the reactive capability requirements set forth in DEC's FCR document is 64 MW, and the reactive power range will be between 25.2 MVAR lagging and 16 MVAR leading.

At the requested output, the Customer's generating facility cannot meet the reactive capability requirements. The MW value included in the Interconnection Agreement shall not exceed a MW value higher than that which meets the reactive capability requirements.

The recommended tap setting at the high side of the GSU is 102.5 kV.

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