SCREENING STUDY

SPP-DPT-2018-003

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REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
12/27/2018	SPP	Original	

CONTENTS

EXECUTIVE SUMMARY

Oklahoma Gas and Electric Company (OGE) has requested a screening study to determine the impacts on Southwest Power Pool (SPP) and third party facilities due to a 2 MW request. Third party includes both first-tier neighboring facilities outside SPP and Transmission Owner facilities within SPP that are not under the SPP Open Access Transmission Tariff (OATT). The period of the service requested is from 1/1/2019 to 6/1/2035.

The principal objective of this study is to identify system problems and potential system modifications necessary to facilitate the Delivery Point Transfer (DPT) request while maintaining system reliability. SPP studied the DPT request by using two system scenarios. The service included a transfer from Golden Spread Electric Cooperative (GSEC) to OGE.

The service does not adversely impact facilities on the SPP system.

INTRODUCTION

OGE has requested a screening study to determine the impacts on SPP and third party facilities for OASIS request 87991342 for 2 MW. The principal objectives of this study are to identify the constraints on the SPP and third party transmission systems that may limit the requested service and to determine the potential least cost solutions required to alleviate the limiting facilities.

This study includes steady-state contingency analysis (Power System Simulator for Engineering (PSS/E) function ACCC). The steady-state analysis considers the impact of the request on transmission line and transformer loadings, and bus voltages for outages of single transmission lines, transformers, and generating units, and selected multiple transmission lines and transformers on the SPP and third party systems.

SPP studied the DPT request by using two system scenarios. The service included a transfer from GSEC to OGE. SPP also studied the two scenarios to capture system limitations caused by the requested service. Scenario 0 includes projected usage of transmission service included in the SPP 2017 Series Cases. Scenario 5 includes transmission service not already included in the SPP 2017 Series Cases. Scenario 5 Summer only violations were not evaluated for mitigations, consistent with the 2018 ITP study.

STUDY METHODOLOGY

DESCRIPTION

SPP conducted the facility study analysis to determine the steady-state impact of the requested service on the SPP and first-tier non-SPP control area systems. SPP performed the steady-state analysis that was consistent with current SPP Criteria and North American Electric Reliability Corporation (NERC) Reliability Standards requirements. SPP conforms to NERC Reliability Standards, which provide strict requirements related to voltage violations and thermal overloads during normal conditions and during a contingency. NERC Standards require all facilities to be within normal operating ratings for normal system conditions and within emergency ratings after a contingency.

Normal operating ratings and emergency operating ratings monitored are Rate A and B in the SPP Model Development Working Group (MDWG) models, respectively. The upper bound and lower bound of the normal voltage range monitored is 105% and 95%. The upper bound and lower bound of the emergency voltage range monitored is 105% and 90%. SPP uses Transmission Owner voltage monitoring criteria if more restrictive.

The contingency set includes all SPP control area branches and ties 69 kV and above; first-tier non-SPP control area branches and ties 115 kV and above; any defined contingencies for these control areas; and generation unit outages for the control areas with SPP reserve share program redispatch. The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first-tier non-SPP control area branches and ties 115 kV and above. SPP performs voltage monitoring for SPP control area buses 69 kV and above.

SPP applied TDF cutoffs (SPP and third party) and voltage threshold (0.02 change) to determine the impacted facilities.

MODEL DEVELOPMENT

SPP used the following SPP Transmission Expansion Plan 2017 Series (2018 ITP Near-Term) Cases to study the impact of the requested service on the transmission system:

- 2018/19 Winter Peak (18WP)
- 2022 Summer Peak (22SP)
- 2022/23 Winter Peak (22WP)
- 2027 Summer Peak (27SP)
- 2027/28 Winter Peak (27WP)

The Summer Peak models apply to June through September, and the Winter Peak models apply to December through March.

The chosen base case models were updated to reflect the current modeling information, including confirmed transactions from previous studies. From the seasonal models, two system scenarios were developed. Scenario 0 includes projected usage of transmission included in the SPP 2017 Series Cases. Scenario 5 includes transmission service not already included in the SPP 2017 Series Cases. Scenario 5 Summer only violations were not evaluated for mitigations, consistent with the 2018 ITP study.

TRANSMISSION REQUEST MODELING

SPP modeled the Network Integrated Transmission Service (NITS) request as generation-to-load transfer in addition to generation-to-generation transfer.

TRANSFER ANALYSIS

SPP compared the results (with and without the requested transfer modeled) by using the PSS/E Activity ACCC to determine the facility overloads caused by the transfer. SPP also applied TDF cutoffs (SPP and third party) and a voltage threshold (0.02 change) to determine the impacted facilities. Appendix A lists the PSS/E options chosen to conduct the analysis.

STUDY RESULTS

STUDY ANALYSIS RESULTS

TABLE 1

Table 1 lists no SPP and third party thermal transfer limitations caused by the transfer for applicable scenarios.

TABLE 2

Table 2 lists no SPP and third party voltage transfer limitations caused by the transfer for applicable scenarios.

TABLE 3

Table 3 lists no network upgrades required to mitigate the limitations caused by this request.

TABLE 4

Table 4 lists no potential redispatch relief pairs to prevent deferral of service.

CONCLUSION

The results of the screening study show that limiting constraints do not exist on the SPP system for the 2 MW request. No new Network Upgrades are required to support the requested transfer. Since SPP identified no limitations, we will accept the request. Once the customer confirms the request, SPP will update and re-issue the service agreement.

APPENDIX A

PSS/E OPTIONS IN RUNNING LOAD FLOW PROGRAM AND ACCC

BASE CASE SETTINGS:

• Solutions:	Fixed slope decoupled Newton-Raphson solution (FDNS)
• Tap adjustment:	Stepping
• Area Interchange Control:	Tie lines and loads
• VAR limits:	Apply immediately
• Solution Options:	X Phase shift adjustment _ Flat start _ Lock DC taps _ Lock switched shunts

ACCC CASE SETTINGS:

• Solutions:	AC contingency checking (ACCC)
• MW mismatch tolerance:	0.5
• System intact rating:	Rate A
• Contingency case rating:	Rate B
• Percent of rating:	100
• Output code:	Summary
• Minimum flow change in overload report:	3 MW
• Exclude cases w/ no overloads from report:	YES
• Exclude interfaces from report:	No
• Perform voltage limit check:	Yes
• Elements in available capacity table:	60,000
• Cutoff threshold for available capacity table:	99,999
• Minimum contingency case voltage change for report:	0.02
• Sorted output:	None
• Newton Solution:	
• Tap adjustment:	Stepping
• Area Interchange Control:	Tie lines and loads (Disabled for generator outages)
• VAR limits:	Apply immediately
• Solution options:	X Phase shift adjustment _ Flat start _ Lock DC taps _ Lock switched shunts

Table 1 - SPP Facility Thermal Transfer Limitations

Scenario	Season	From Area	To Area	Monitored Branch Over 100% Rate B	Base Case Loading (%)	Transfer Case Loading (%)	TDF (%)	Outaged Branch Causing Overload	Upgrade Name	Solution
				None						

Table 2 - SPP Facility Voltage Transfer Limitations

Scenario	Season	Area	Monitored Bus with Violation	Post-transfer Voltage (PU)	Outaged Branch Causing Overload	Upgrade Name	Solution
			None				

Table 3 - Upgrade Requirements and Solutions Needed

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
	None				

Construction Pending Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
	None			

Expansion Plan Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
	None			

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
	None			

Table 4 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

Limitations were not identified; therefore, redispatch was not calculated.