Screening Study SPP-DPT-2014-002

4/28/2014

SPP Engineering, Transmission Service Studies

Table of Contents

Executive Summary

Arkansas Electric Cooperatives Corporation has requested a screening study to determine the impacts on SPP and first-tier third party facilities due to a Delivery Point Transfer of 320 MW. Third party includes both first-tier neighboring facilities outside SPP and Transmission Owner facilities within SPP that are not under the SPP OATT. The service type requested for this screening study is Delivery Point Transfer (DPT). The period of the service requested is from 6/1/2014 to 6/1/2019.

The principal objective of this study is to identify system problems and potential system modifications necessary to facilitate the DPT request while maintaining system reliability. The DPT request was studied using two system scenarios. The service was modeled by a transfer from EES to CSWS. The two scenarios were studied to capture system limitations caused or impacted by the requested service. An analysis was conducted on the planning horizon.

The requested service does not significantly impact facilities on the SPP system. Tables 1 and 2 summarize the results of the screening study analysis for the new source location for the scenarios listed in the table. Table 1 lists SPP and first-tier third party thermal transfer limitations identified. Table 2 lists SPP and first-tier third party voltage transfer limitations identified. Table 3 lists the network upgrades required to mitigate the limitations impacted by this request. Table 4 lists the potential redispatch relief pairs to prevent deferral of service, if applicable.

Load Transfer Restrictions

Some of the delivery points that AECC has requested to transfer may have the capability of being connected together on the load-side of the meter to delivery points that are not being transferred, such that load could be physically shifted between the delivery points. This study has been conducted under the assumption that network service to these delivery points will remain separate from those remaining in the current network service agreement, and that there will be no long-term load shifts between delivery points in different network service agreements without a request for study. Should this service be confirmed, a clause will be added to the network service agreements to limit load shifts to short-term periods that may be required for emergency, maintenance, or construction purposes. In addition, prior notice to the SPP Reliability Coordinator of any such load shifts will be required, with as much notice as possible, except for emergency load shifts, in which notice can be provided as soon as possible thereafter. Also, if not already installed, additional metering will be required as needed to allow SPP to determine the simultaneous load designated under both network service agreements.

Introduction

Arkansas Electric Cooperatives Corporation has requested a screening study to determine the impacts on SPP and first-tier third party facilities for a Delivery Point Transfer of 320 MW. The principal objective of this study is to identify the constraints on the SPP and first-tier 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 (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 first-tier third party systems.

The DPT request was studied using two system scenarios. The service was modeled by a transfer from EES to CSWS. Two scenarios were studied to capture the system limitations caused or impacted by the requested service. Scenario 0 includes projected usage of transmission service included in the SPP 2012 Series Cases. Scenario 5 includes transmission service not already included in the SPP 2012 Series Cases.

Study Methodology

Description

The facility study analysis was conducted to determine the steady-state impact of the requested service on the SPP and first tier non-SPP control area systems. The steady-state analysis was performed to ensure current SPP Criteria and NERC Reliability Standards requirements are fulfilled. 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%. Transmission Owner voltage monitoring criteria is used if more restrictive. The SPS Tuco 230 kV bus voltage is monitored at 92.5% due to pre-determined system stability limitations. The WERE Wolf Creek 345 kV bus voltage is monitored at 103.5% and 98.5% due to transmission operating procedure.

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 monitor 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. Voltage monitoring was performed for SPP control area buses 69 kV and above.

A 3 % transfer distribution factor (TDF) cutoff was applied to all SPP control area facilities. For first tier non-SPP control area facilities, a 3 % TDF cutoff was applied to AECI, AMRN (Ameren), and ENTR (Entergy) control areas. A 2 % TDF cutoff was applied to WAPA. For voltage monitoring, a 0.02 per unit change in voltage must occur due to the transfer or modeling upgrades to be considered a valid limit to the transfer.

Model Development

SPP used six seasonal models to study the 320 MW DPT request for the requested service period. The following SPP Transmission Expansion Plan 2012 Build 1 Cases were used to study the impact of the requested service on the transmission system:

2014 Summer Peak (14SP)
2014/15 Winter Peak (14WP)
2018 Summer Peak (18SP)
2018/19 Winter Peak (18WP)
2023 Summer Peak (23SP)
2023/24 Winter Peak (23WP)

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 modified to reflect the current modeling information. From the six seasonal models, two system scenarios were developed. Scenario 0 includes projected usage of transmission included in the SPP 2012 Series Cases. Scenario 5 includes transmission not already included in the SPP 2012 Series Cases.

Transmission Request Modeling

Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation transfers. Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation because the requested Network Integration Transmission Service is a request to serve network load with the new designated network resource, and the impacts on Transmission System are determined accordingly. Generation to Generation transfers are accomplished by developing a post-transfer case for comparison by dispatching the request source and redispatching the request sink.

Transfer Analysis

Using the selected cases both with and without the requested transfer modeled, the PSS/E Activity ACCC was run on the cases and compared to determine the facility overloads caused or impacted by the transfer. Transfer distribution factor cutoffs (SPP and 1st-Tier) and voltage threshold (0.02

change) were applied to determine the impacted facilities. The PSS/E options chosen to conduct the analysis can be found in Appendix A.

Study Results

Study Analysis Results

Tables 1 and 2 contain the initial steady-state analysis results of the DPT. The tables are attached to the end of this report, if applicable. The tables identify the scenario and season in which the event occurred, the transfer amount studied, the facility control area location, applicable ratings of the thermal transfer limitations and voltage transfer limitations, and the loading percentage and voltage per unit (pu).

Table 1 lists the SPP and first-tier third party thermal transfer limitations caused or impacted by the 320 MW transfer for applicable scenarios. Solutions are identified for the limitations in this table.

Table 2 lists the SPP and first-tier third party voltage transfer limitations caused or impacted by the 320 MW transfer for applicable scenarios. Solutions are identified for the violations in this table.

Table 3 lists the network upgrades required to mitigate the limitations caused or impacted by this request. Engineering and construction costs are provided for assigned upgrades in this table.

Table 4 lists the 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 320 MW DPT. No significant impacts were identified for the requested term of this DPT. Since no additional limitations were identified, the request will be accepted. Once the request has been confirmed, SPP will issue a service agreement.

Appendix A

PSS/E CHOICES 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
• Min flow change in overload report:	3 MW
• Excld cases w/ no overloads from report:	YES
• Exclude interfaces from report:	NO
• Perform voltage limit check:	YES
• Elements in available capacity table:	60000
• Cutoff threshold for available capacity table:	99999.0
• Min. contng. Case Vltg chng 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	Case Loadir	er Case Load	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	NTC
	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)	Estimated Engineering & Construction Cost	NTC
	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			

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

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