Impact of the PJM 2016/2017 Base Residual Auction on the North Carolina Electric System

A Joint Study performed by:
Midcontinent Independent System Operator, Inc.
North Carolina Transmission Planning Collaborative
PJM Interconnection LLC

Study performed at the request of
the North Carolina Utilities Commission

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Executive Summary

The Midcontinent Independent System Operator, Inc. (MISO), North Carolina Transmission Planning Collaborative (NCTPC), and PJM Interconnection LLC (PJM), collectively referred to as the "study participants", performed this joint interregional study to address a request from the North Carolina Utilities Commission (NCUC). The NCUC noted that in May of 2013, PJM conducted a Base Residual Capacity Auction (BRA) for its 2016/2017 delivery year and that PJM subsequently stated that an unprecedented amount of the capacity that cleared in that auction is from generation resources outside of PJM, primarily within the MISO footprint. The NCUC requested the study participants to study whether or not these imports from MISO into PJM could reasonably be expected to exacerbate loop flows on the transmission grid of North Carolina. Specifically, the NCUC requested the study to determine whether the planned imports would be likely to cause Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) to alter their joint generation dispatch in a manner that increases costs for North Carolina customers and whether the planned imports would reduce the reliability of the North Carolina transmission grid. Additionally, the study participants modeled and studied all BRA related generation that cleared in the PJM 2016/2017 auction, regardless of physical location (i.e. those resources physically located in the MISO footprint and those physically located in other footprints) to understand its complete impact.

This joint interregional study is comprised of a reliability analysis to address the NCUC's grid reliability question and an economic analysis to address the NCUC's joint dispatch question.

The reliability analysis evaluated potential impacts to the transmission systems of DEC and DEP ("study area"). The potential impacts on the study area will be those that result from loop flows caused by generation resources that cleared in the PJM 2016/2017 BRA located outside of the PJM transmission system, including a significant amount located within the MISO transmission system that may be delivered to the PJM transmission system in the 2016/2017 delivery year. Some of these cleared resources have preexisting firm delivery service to PJM load, and some may have yet to procure this necessary firm transmission service. This study distinguished the 2016/2017 PJM BRA resources that have yet to procure the firm transmission service and focused the analysis on this resource list. Resources already possessing firm transmission service should be embedded in the existing planning processes of the Eastern Interconnection, subject to the time lag of building the coordinated power flow models and folding them into local planning processes. The purpose of this analysis was to identify impacts rather than to determine limits to the yet to be procured and necessary firm delivery service.

This analysis examined 7,663 MW of external generation that cleared in the PJM 2016/17 BRA and 2,774 MW[1] of that cleared generation (~36%) has yet to procure firm transmission service. Of the 2,774 MW[2] of 2016/2017 BRA resources without firm transmission service, approximately 463 MW will flow through the DEC and DEP transmission systems, or approximately 17%. A vast majority of the power that flows through DEC and DEP is on 500 kV and 230 kV transmission facilities, and approximately 50% of the flow

[1] These values were determined based on the status of the 2016/17 Auction results as of approximately June 2014. As of December 2014 approximately 1600 MW of the Auction capacity has yet to confirm their full path firm transmission service.

[2] See Table 2-2 sum of Totals for Change and Sensitivity Cases

through the DEC and DEP system is confined to the 500 kV system with all facilities in service. Flows increase on approximately 2/3 of the DEC and DEP transmission facilities and decrease on approximately 1/3 of these facilities[3].

Under contingency scenarios, flows on some DEC and DEP facilities increase above their emergency ratings. Some of these overloads have operating procedures to relieve them. These operating procedures will be reviewed by DEC and DEP to ensure their continued ability to be relied upon for relief of these facilities. The aggregate impacts of the 2,774 MW on these facilities is less than 2%[4] meaning that any overloaded facility carries less than 2% of the total 2,774 MW. Before the aggregate impact of the 2,774 MW is studied, all of the overloaded facilities identified in the study have post-contingency loadings greater than 95%[4] of their emergency rating.

A few DEC facilities with post-contingency loadings above their emergency ratings do not have operating procedures identified to relieve the overloads. This study did not determine solutions that may be appropriate to address these overloads. The actual status of PJM Load Serving Entity plans for capacity imports are not finalized until the year prior to the delivery year. Additional operational planning analysis prior to the delivery year, therefore, may be necessary. PJM will provide needed support for this analysis.

Individual Transmission Service Request (TSR) studies commonly use a distribution factor (DF) cutoff of 3% to 5% to determine if a transmission facility is significantly affected by the TSR. TSR studies however, are performed on a contract path basis and would only come into play for DEC/DEP when they are requested to provide transmission service. Loop flows are governed by business practices agreed upon in the Eastern Interconnection which generally rely on a 5% DF cutoff. PJM believes that these facts are an important perspective when judging the impacts cited in this analysis. Duke Energy does not agree and feels that this measure is not appropriate for an analysis of multiple resources spread over a large geographic region.

The DFs ranged from 0.07% to 2.0%[4] in this study for the entire BRA group on overloaded DEC and DEP transmission facilities under contingency conditions. Of the resources comprising the 2,774 MW, the highest individual 2016/2017 BRA resource DF on any of the facilities cited as overloaded in this analysis is less than 3.0%[4]. PJM believes this indicates that these generating units from the 2016/2017 BRA are not a significant cause of the DEC and DEP transmission issues cited in this study. The percentage loading on these facilities increases by 1.5% to 9.3%[4], which Duke Energy feels is a significant impact.

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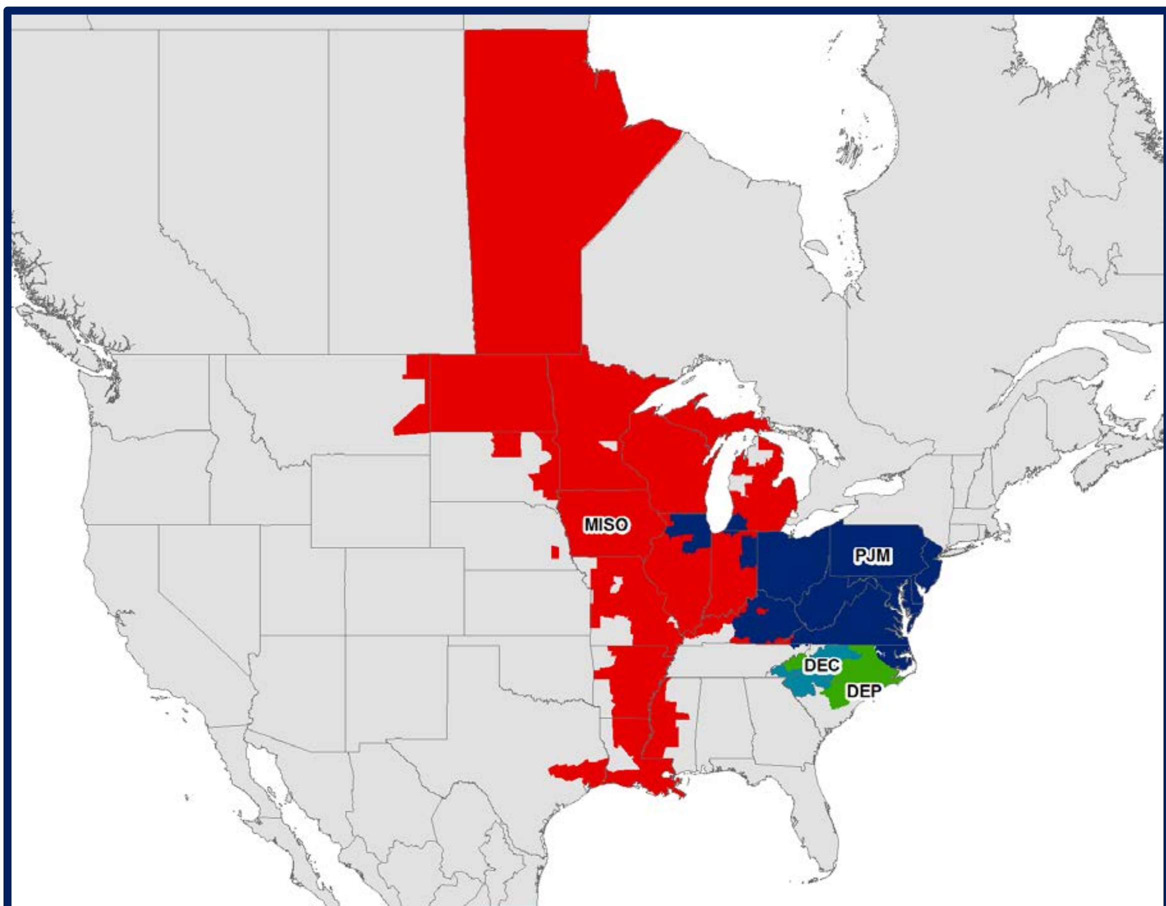
[3] See Table 3-1 and Figure 3-1. Data underlying this table and figure is used to derive some of the facts in this paragraph

[4] See Tables 4-1 through 4-4

1 Introduction

The Midcontinent Independent System Operator, Inc. (MISO), North Carolina Transmission Planning Collaborative (NCTPC), and PJM Interconnection (PJM), collectively referred to as the "study participants", performed this joint inter-regional study to address a request from the North Carolina Utilities Commission (NCUC). The NCUC requested the study participants to study whether or not the external generation resources which cleared in the PJM 2016/2017 base residual capacity auction (BRA) are expected to exacerbate loop flows on the transmission grid of North Carolina due to an unprecedented amount of those generation resources (7,663 MW[5]) being located outside the PJM transmission system. Specifically, the NCUC requested the study to determine whether the planned imports would be likely to cause Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) to alter their joint generation dispatch in a manner that increases costs and whether the planned imports would reduce the reliability of the North Carolina transmission grid.

Figure 1-1 Map of DEC, DEP, MISO, & PJM Control Areas



[5] This value was updated at the time of the study and may differ from previously announced values.

This joint interregional study is comprised of two separate and distinct analyses—a reliability analysis to address the NCUC's grid reliability question and an economic analysis to address the NCUC's joint generation dispatch question. Sections 1-5 of this report focus on the reliability analysis. Sections 6-10 focus on the economic analysis.

The reliability analysis evaluated potential impacts to the transmission systems of DEC and DEP, the "study area". The potential impacts will be those that result from loop flows caused by generation resources that were cleared in the PJM 2016/2017 base residual capacity auction (BRA) located outside of the PJM transmission system, including a significant amount located within the MISO transmission system that may be delivered into the PJM transmission system in the 2016/17 delivery year. The original reliability analysis scope intended to assess the impact of the PJM 2016/2017 BRA units physically located in the MISO transmission system only. However, through the course of the analysis, the scope was modified to assess all of the cleared PJM 2016/2017 BRA generation resources by NCUC's request, regardless of physical location (i.e. those resources physically located in the MISO transmission system and those physically located in other transmission systems). The study incorporated the request by developing an extra scenario (called "Sensitivity") as described in Section 2 of this report. Results are presented for all scenarios in Sections 3 & 4 of this report.

Some of these cleared resources may have preexisting firm delivery service to PJM load, and some may have yet to procure this necessary firm transmission service. This study distinguished the PJM 2016/2017 BRA resources that have yet to procure the firm transmission service and focused the analysis on this resource list. This analysis examined 7,663 MW of external generation that cleared in the PJM 2016/17 BRA and 2,774 MW[1] of that cleared generation (~36%) has yet to procure firm transmission service. Resources already possessing firm transmission service should be embedded in the existing planning processes of the Eastern Interconnection, subject to the time lag of building the MMWG models and folding them into local planning processes. The purpose of this analysis is to identify impacts rather than to determine limits to the yet to be procured and necessary firm delivery service.

2 Power Flow Case Development

The 2013 series Multiregional Modeling Working Group (MMWG) 2015 Summer Peak model was used for the systems external to DEC, DEP, MISO, and PJM as the starting point for the Merged Case to be used by the NCTPC, MISO, and PJM in their analyses. The Merged Case included the detailed internal models for DEC, DEP, MISO, and PJM and the current transmission additions planned to be in-service for the summer of 2016. The DEC model that is used in regional models is an equivalent representation of the sub-100 kV transmission system, whereas the detailed representation of the sub-100 kV transmission system was used for this study. The Merged Case included all current Open Access Same-time Information System (OASIS) confirmed long-term firm transmission reservations that were known when the 2013 series of MMWG cases were created, assuming rollover rights are exercised through the study year. The long-term transmission reservations were recorded in the MMWG Interchange Table accompanying the 2015 Summer Peak model. Some of the firm transmission reservations known at the time of this study for the 2016/17 BRA resources were not present in the MMWG or Merged cases. The interchange values for every region in the model were maintained throughout the case development process. The only exceptions were: 1) the addition of a new OASIS transaction of 673 MW between MISO and Manitoba to the Merged Case and 2) adjustments to the Base, Change and Sensitivity Cases to accommodate the BRA resources sending power to PJM. The transaction between MISO and Manitoba was incorporated into all study cases. Table 2.1 shows the power flow area summary for the North Carolina entities.

DEP consists of two control areas – CPLE and CPLW. In much of the analysis discussed in this report, CPLW (the western portion of DEP, centered on Asheville, NC) was ignored since its susceptibility to interregional power flows is minor. CPLW has 230 kV connections to the north and south. However, those 230 kV lines each step down to 115 kV inside CPLW without a 230 kV connection all the way through the area.

The DEC control area is called DUKE in this report.

Table 2-1 Power Flow area summary for the final Merged Case

Area Number	Area Name	Generation (MW)	Load (MW)	Interchange (MW)	Losses (MW)
340	CPLE	11,798	12,533	-956	221
341	CPLW	766	908	-151	9
342	DUKE	21,907	21,299	-37	645
NC Total:		34,471	34,740	-1,144	875

A series of three study cases ("Base Case", "Change Case", & "Sensitivity Case") were developed from the Merged Case, each building upon the other, to allow the evaluation of different aspects of the PJM 2016/2017 BRA generation resources on the study area. Interchange adjustments were made, as necessary, to reflect imports and exports related to the BRA.

The Base Case was built from the Merged Case and modeled the PJM 2016/2017 *BRA units with confirmed firm transmission service* sending power to the PJM transmission system (4,889 MW). An unspecified portion of the 4,889 MW was already included in the Merged Case, some of which may have been scheduled to areas other than PJM. At the time that the MMWG cases were created in 2013, there were generation resources that participated in the BRA that had confirmed transmission service to non-PJM areas; therefore, it was necessary to model those generation resources as now sending power to the PJM transmission system if firm transmission service to the PJM transmission system had been acquired in the time between the creation of the MMWG cases and the performing of this joint study. The 4,889 MW was not an incremental adjustment to the Merged Case.

The Change Case was developed using the Base Case as a starting point and included an additional 1,940 MW of PJM BRA generation resources, *physically located within MISO that have not yet secured firm transmission service,* dispatched to send power to PJM.

The Sensitivity Case was developed using the Change Case as a starting point and included an additional 834 MW of PJM BRA generation resources, representing the *remaining PJM 2016/2017 BRA units that have not yet secured firm transmission service* *(All PJM 2016/2017 BRA units)* sending power to PJM.

In all cases, when PJM generation was reduced to receive the imported power, the method applied was to use PSS®E's scale command to scale online generation only while observing generation limits. Nuclear units in PJM were dispatched at their maximum and were not scaled down to simulate an import.

Due to confidentiality provisions included in PJM's governing documents and code of conduct, PJM has some restrictions on its ability to share certain types of data. The specific units and capabilities that have bid into PJM Auctions are one of those exceptions to PJM data sharing.

Table 2-2 shows a summary of the amount of cleared generation resources from the PJM 2016/2017 BRA and its approximate location/region in each study case developed. The external BRA capacity shown in Table 2-2 sums to approximately 7663 MW[6]. The "South" region contains the transmission systems to the south of the PJM footprint, including the non-PJM Virginia-Carolina (VACAR) companies, TVA and LG&E-KU. The "West 1" region contains most of the transmission systems to the west of the PJM footprint including portions of the MISO footprint and its western neighbors such as Western Area Power Administration. The "West 2" region contains the remaining transmission systems to the west of the PJM footprint, including portions of the MISO footprint such as MISO South. Appendix 1 contains a table with the list of power flow areas and associated company names incorporating each of the regions shown in Table 2-2.

Table 2-2 PJM 2016/2017 BRA Cleared Resources by Scenario

Region	Base Case	Change Case	Sensitivity Case
South	580	-	834
West 1	1,620	1,076	-
West 2	2,689	864	-
Total:	4,889	1,940	834

3 Flow Impacts with All Facilities in Service

3.1 Flow Impact of all BRA Generation on NC Balancing Areas

At a high level, we can look at how much power flow from all PJM 2016/2017 BRA generators goes through the North Carolina utilities to reach the PJM market. An easy way to calculate this is to look at how the flow changes on the tie-lines connecting the North Carolina utilities with their neighbors. Table 3-1 below was created by summing all of the tie-lines flows that increased into the CPLE and DUKE control areas (inflow), and also summing all the tie-lines flows that increased out of the CPLE and DUKE control areas (outflow) as a result of adding each group of the PJM 2016/2017 BRA generators (Base, Change, & Sensitivity). If no BRA units are located in North Carolina, the inflow will be approximately equal to the outflow within the accuracy of the modeling software. Table 3-1 lists the total change in

[6] Since this study began, approximately 860 MW of this capacity has withdrawn, reducing the total to 6803 MW.

outflows for the power flow cases previously described, in both MW and as a percentage of the total PJM 2016/2017 BRA generation added in each case. This percentage can be thought of as an area-wide distribution factor ("DF" in the table). The difference between inflow and outflow does not materially affect the results.

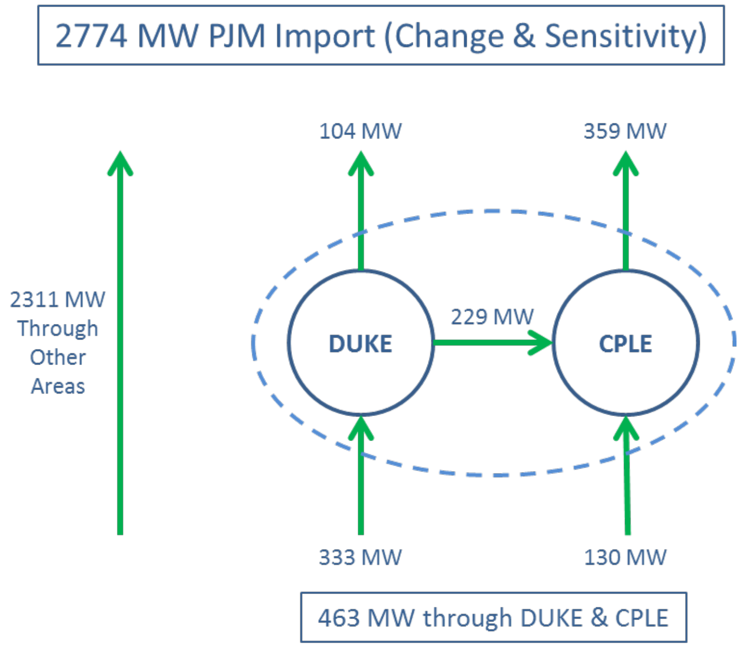
Table 3-1 is a table showing the incremental impacts of various groupings of BRA resources. The "Incremental Base Flow Impact" column is the incremental impact from the Merged Case to the Base Case of all the PJM 2016/2017 BRA units that already have firm transmission service. This is the impact of the full 4,889 MW group of BRA units. The "Incremental Change Flow Impact" column is the incremental impact between the Base Case and the Change Case due to the BRA units physically located within the MISO transmission system that do not yet have firm transmission service. The "Incremental Sensitivity Flow Impact" column is the incremental impact between the Change Case and the Sensitivity Case due to all the remaining PJM 2016/2017 BRA units, not physically located in the MISO footprint that do not yet have firm transmission service. The flow impacts were also combined into a "Change & Sensitivity" incremental flow impact, which represents all PJM 2016/2017 BRA units that do not have firm transmission service, and "Base, Change, & Sensitivity" incremental flow impact which represents all PJM 2016/2017 BRA units, both with and without firm transmission service. Note that all flow changes in Table 3-1 are for the condition with all facilities in service (i.e. N-0).

Table 3-1 Incremental Flow Impact on CPLE and DUKE Areas from PJM 2016/2017 BRA Generation

	Incremental Base Flow Impact		Incremental Change Flow Impact		Incremental Sensitivity Flow Impact		Change & Sensitivity		Base, Change, & Sensitivity	
Area	MW	DF	MW	DF	MW	DF	MW	DF	MW	DF
CPLE	530	11%	232	12%	130	16%	**359**	13%	892	12%
DUKE	393	8%	204	11%	129	15%	**333**	12%	726	9%
CPLE & DUKE	622	13%	289	15%	177	21%	**463**	17%	1088	14%
Total Transfer	4889		1940		834		**2774**		7663	

Since the BRA units in the Base Case already have firm transmission service, the "Change and Sensitivity" flows are the most relevant. The MW flows in the "Change & Sensitivity" column are shown graphically in Figure 3-1. This drawing helps show why the total flow through DUKE and CPLE combined (463 MW) is less than the sum of the individual through flows (359 and 333 MW). The sum of the flows into an area must equal the sum of flows out of an area. Figure 3-1 shows that 333 MWs flow into DUKE from the south and 333 MW flow out of DUKE (104 MW flow from DUKE to PJM plus 229 MW flow from DUKE to CPLE). Likewise, 359 MW flow into CPLE (229 MW flow from DUKE into CPLE plus 130 MW flow from the south into CPLE) and 359 MW flows out of CPLE. The same logic can be applied to the combined bubble of DUKE and CPLE. In this case 463 MW flow into the combined DUKE and CPLE bubble (333 MW from the south into DUKE plus 130 MW from the south into CPLE) and 463 MW flows out of the combined DUKE and CPLE bubble (104 MW flow from DUKE to PJM plus 359 MW from CPLE to PJM).

Figure 3-1 Flow Chart for Change and Sensitivity Flows



3.2 Branches with Increasing and Decreasing Flows

As another perspective, the number of DEC and DEP branches impacted by the PJM 2016/2017 BRA resources can be quantified. This can be used as an indicator of the impacts on the study system. This exercise does not purport to be an exact count of impacted branches but uses that metric merely as an indicator of the overall system impacts. The point is that BRA resources may increase flows on some facilities and decrease flows on other facilities.

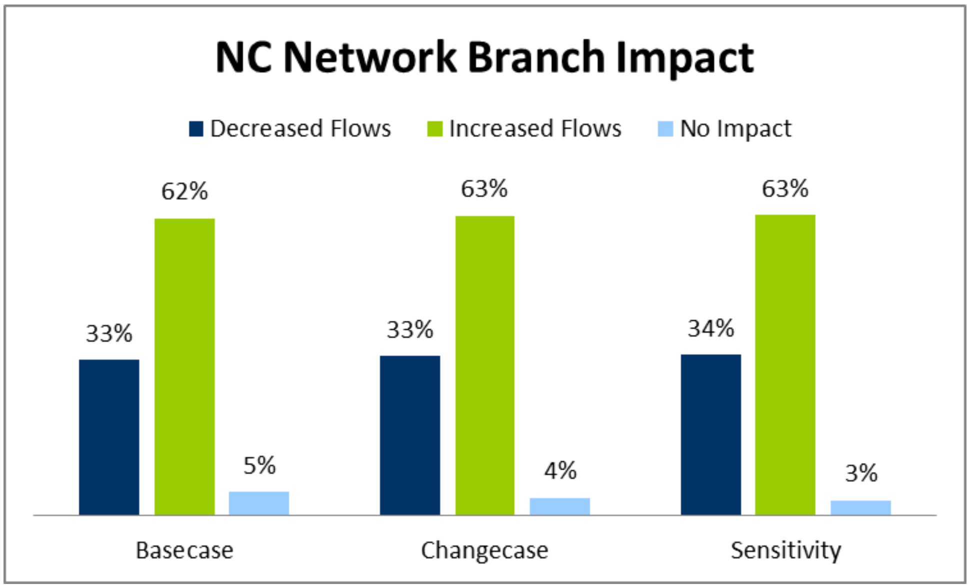
Figure 3-2, shows a bar graph counting the number of DEC and DEP network branches with increased and decreased flow due to each BRA grouping (Base, Change, Sensitivity). The system impact shown is based on the number of network branches in the PSS®E model where flows increased or decreased when compared with the Merged Case. Reading Figure 3-2 below, the PJM 2016/2017 BRA units increase flows in approximately 63% of DEC and DEP branches and decreased flows in approximately 33%, with 4% showing no change.

Only network branches are included in Figure 3-2. Radial branches by their very nature do not carry interregional power flows and were excluded. In addition, many 100 kV and 115 kV network branches are broken into multiple segments in the model to represent the exact location of loads tapped along the lines. Each segment is counted individually in Figure 3-2, meaning that all tapped transmission lines, normally defined breaker to breaker, are counted multiple times in Figure 3-2. On the other hand, all 500 kV lines in CPLE and DUKE and all 230 kV lines in DUKE, except one, have no load taps, and these are the most likely to carry more interregional power flows. Each untapped line is only counted once in Figure 3-2, meaning that the number counts likely include more lower voltage facilities compared to the higher voltages. The fact that there are more lower voltage facilities, however, may be just as likely to inflate the “increases” as it is the “decreases” in flows. Nonetheless the point of this graph is not to present precise counts but to illustrate the potential for BRA resources to produce counter flows as well as add to flows.

Note that transmission planners have to plan for criteria violations on facilities which may be advanced or delayed for increases and decreases in flows.

It should be noted that these graphs do not quantify the MW or mileage impact, but rather show the number of branch segments that are impacted as a rough indicator of impacts. The subsequent sections of this report further explore the MW impacts on the North Carolina facilities.

Figure 3-2 2016/2017 PJM BRA Unit Impact on DEC and DEP Network Branches (normal operation)



3.3 Flow Impact of all BRA Generation on Individual Branches

The flow impact of the PJM 2016/2017 BRA generators as a group on individual North Carolina utilities' transmission lines and transformers was examined. Table 3-2 below shows the branches most impacted. The red numbers represent most impacted branch in each power flow case. The black text numbers are used when the indicated impact was the second highest in the case. Branch 1 is the South Hall to Oconee 500 kV line (tie) between DEC and Southern Company, and Branch 3 is the Carson to Wake 500 kV transmission line (tie) between PJM (Dominion) and DEP. These branch numbers match those in the next section. As in Table 3-1, the flows in Table 3-2 are for the condition with all facilities in service (i.e. N-0) and the columns denote incremental impacts of each grouping of BRA resources (i.e. the "Incremental Change Flow Impact" column depicts the impact from the additional units comprising the Change Case excluding the Base Case units). Note that these branches are not close to their flow limits; they simply carry the most MW flow on a per branch basis due to the PJM 2016/2017 BRA generation groups. Tables 3-2 and 3-3 also show that the North Carolina system flow impacts described in the preceding tables and graphs are predominately carried on the DEC/DEP high-voltage backbone transmission system that connects North Carolina to outside systems.

Table 3-2 Flow Impact on CPLE and DEC Individual Branches from PJM 2016/2017 BRA Generation

	Incremental Base Flow Impact		Incremental Change Flow Impact		Incremental Sensitivity Flow Impact		Change & Sensitivity		Base, Change, & Sensitivity	
Area	MW	PTDF	MW	PTDF	MW	PTDF	MW	PTDF	MW	PTDF
Branch 1	277.6	5.7%	107.3	5.5%	59.7	7.2%	167.0	6.0%	444.6	5.8%
Branch 3	199.3	4.1%	91.2	4.7%	41.6	5.0%	132.8	4.8%	332.1	4.3%
Total Transfer	4889		1940		834		2774		7663	

3.4 Flow Impact of Individual BRA Generators on Individual Branches

The impact of individual PJM 2016/2017 BRA generators on individual branches of the North Carolina utilities can be examined. Because of PJM's confidentiality terms and conditions contained in its governing documents and code of conduct, the PJM 2016/2017 BRA generators and the distribution factors cannot be listed explicitly. However, the heat diagram displayed in Table 3-3 shows the relative impacts of the PJM 2016/2017 BRA generators on the top 29 impacted lines in the study area. The line names are listed below in Table 3-4. As in previous sections, these impacts are with all facilities in service (i.e. N-0). The color shading goes from fully red, indicating a distribution factor of approximately 14%, to fully yellow, indicating a distribution factor of approximately 0% (e.g. the color shading shown for unit 3 Line 6 corresponds to a Power Transfer Distribution Factor (PTDF) value approximately between 5 and 6%). A PTDF is a pre-contingency measure of how a particular element is affected by a specified transfer. A comparison can also be made to the contingency-based thermal impact analysis outlined in Section 4 of this report. This comparison shows that the lines with high flow impacts on Table 3-3 do not correlate with the thermal impacts of Section 4. This is because the lines with more flow impacts are higher-voltage backbone lines with high capabilities.

Looking closely at the statistics provided by Table 3-3, there are approximately 17 power flow branches in the study area with at least one PJM 2016/2017 BRA unit having a 2-5% PTDF and 9 branches with at least one PJM 2016/2017 BRA unit having a 5% or greater PTDF (all of which are 500kV facilities). The remaining branches have more than one PJM 2016/17 BRA unit with PTDF's lower than 2%.

Table 3-3 Flow Impact on CPLE and DUKE Individual Branches from Individual PJM BRA Generators

Branch	KV	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Line 1	500																															
Line 2	500																															
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Line 25	500																															
Line 26	230																															
Line 27	230																															
Line 28	230																															
Line 29	230																															

Table 3-4 Impacted Line Descriptions

Branch	From				To				Circuit
	Area	Bus Num	Bus Name	KV	Area	Bus Num	Bus Name	KV	
Line 1	DUK	306008	8OCONEE	500	SOCO	380011	8S HALL	500	1
Line 2	AEP	242520	05J.FERR	500	DUK	306719	8ANTIOCH	500	1
Line 3	DEP_EAST	304183	WAKE 500 TT	500	DVP	314902	8CARSON	500	1
Line 4	DUK	306719	8ANTIOCH	500	DUK	306546	8MCGUIRE	500	1
Line 5	DUK	306337	8NEWPORT	500	DUK	306008	8OCONEE	500	1
Line 6	DUK	306113	8JOCASSE	500	DUK	308788	8CLFSDTAP	500	1
Line 7	DUK	308788	8CLFSDTAP	500	DUK	306546	8MCGUIRE	500	1
Line 8	DEP_EAST	304183	WAKE 500 TT	500	DEP_EAST	304391	CUMBLND500TT	500	1
Line 9	DUK	306113	8JOCASSE	500	DUK	306008	8OCONEE	500	1
Line 10	DEP_EAST	304377	RICHMON500TT	500	DEP_EAST	304391	CUMBLND500TT	500	1
Line 11	DEP_EAST	304377	RICHMON500TT	500	DUK	306337	8NEWPORT	500	1
Line 12	DUK	306337	8NEWPORT	500	DUK	306546	8MCGUIRE	500	1
Line 13	DEP_EAST	304070	PERSON230 TT	230	DVP	314697	6HALIFAX	230	1
Line 14	DUK	306546	8MCGUIRE	500	DUK	306836	8WOODLF	500	1
Line 15	DUK	306836	8WOODLF	500	DUK	306850	8PL GRDN	500	1
Line 16	DUK	306849	8PARKWOD	500	DUK	306850	8PL GRDN	500	1
Line 17	DUK	306008	8OCONEE	500	DUK	306007	6OCONEE	230	A1
Line 18	DEP_EAST	304451	GREENVILE TT	230	DVP	314574	6EVERETS	230	1
Line 19	DEP_EAST	304417	MCCOLL TAP	230	DEP_EAST	304424	LAURINB230TT	230	1
Line 20	DEP_EAST	304417	MCCOLL TAP	230	DEP_EAST	304708	BENNET SS TT	230	1
Line 21	DEP_EAST	304018	ROB2 230 TT	230	DEP_EAST	304338	CHERAW TAP1	230	1
Line 22	DEP_EAST	304338	CHERAW TAP1	230	DEP_EAST	304348	ROCKHAM230TT	230	1
Line 23	DEP_EAST	304024	ROXSEP230 TT	230	DEP_EAST	304070	PERSON230 TT	230	2
Line 24	DUK	306333	6NEWPORT	230	SCEG	371112	6VCS1_2	230	1
Line 25	DEP_EAST	304054	DURHAM500 TT	500	DEP_EAST	304056	DURHASTR	1	1
Line 26	DEP_EAST	304117	DURHAM230 TT	230	DEP_EAST	304056	DURHASTR	1	1
Line 27	DEP_EAST	304046	WSPOON230 TT	230	DEP_EAST	304682	DILLONMP TAP	230	1
Line 28	DEP_EAST	304663	LATTA SS TT	230	DEP_EAST	304682	DILLONMP TAP	230	1
Line 29	DEP_EAST	304222	ROCKYMT230TT	230	DEP_EAST	304226	PA-RMOUNT#4	230	1

4 Thermal Screening Analysis

The full power flow screening analysis typically performed by DEC and DEP, identifies those branches that are both highly loaded and impacted by the PJM 2016/2017 BRA generation. The processes and results for each utility are discussed below.

4.1 Study Methodology

A full AC Contingency Analysis was performed using the PSS®MUST and PSS®E software. This power flow analysis was performed based on the assumption that thermal limits will be the controlling limit. Voltage, stability, short-circuit, and phase angle studies were not performed.

The study analyses were conducted in a coordinated effort by MISO, NCTPC, and PJM technical staffs, to the extent allowable under the PJM non-disclosure terms and conditions. Sharing of information that would explicitly reveal the generating units that participated in the PJM 2016/2017 BRA was not allowed under PJM's governing documents and code of conduct. To maintain the confidentiality of the PJM 2016/2017 BRA units, PJM performed the analysis using DEC and DEP screening processes. The DEC and DEP processes were tested on the Merged Case in order to ensure that PJM could produce the same results as DEC and DEP. Once it was shown that the results could be duplicated, PJM was able to perform the analysis on the remaining cases and to share the power flow results. The power flow results provided by PJM to MISO and NCTPC only showed pre and post-contingency flows and did not contain any information about what units participated in the BRA.

4.1.1 Method of Analysis

The contingency analysis methods that DEC and DEP use for their internal planning purposes were applied to the Merged Case, Base Case, Change Case, and Sensitivity Case. NERC standards are the minimum standards that ensure system reliability and allow for companies to implement additional criteria for planning. This evaluation included NERC category B N-1 contingency analysis, under scenarios of full generator availability as well as generation maintenance conditions. In addition the analysis included scenarios that modeled generator forced outages, making up power from the Virginia-Carolina (VACAR) Reserve Sharing agreements along with a simultaneous additional single contingency. This can be considered a NERC category C3 contingency since it includes two simultaneous, independent events. The results were reported by showing the limiting network element, the transmission contingency element, and the final thermal loading on the limiting element due to each modeled scenario. Results were reported and reviewed to determine the impact on the planning of the DEC and DEP systems. Results in each scenario case were reviewed to determine the significance of the PJM 2016/2017 BRA unit impacts. The analysis was a reliability screening intended to be indicative of the system capability performance under the specific study conditions.

4.1.1.1 DEC Screening Method

The DEC screening process utilizes an automated script that runs in PSS®E. This script creates cases with various dispatches and simulates line and transformer contingencies for each dispatch. Pre- and post-contingency flows for each branch are reported if they exceed 85% of the facility rating.

Generator maintenance means that a single unit is outaged (e.g. maintenance, refueling, etc.) and other DEC generators are economically dispatched to replace the power. Generator maintenance cases were developed for the following units:

ALLEN 4	ALLEN 5	BAD CREEK 1	BELEWS CREEK 1	CATAWBA 1	CLIFFSIDE 5
CLIFFSIDE 6	BROAD RIVER 1	MILL CREEK 1	JOCASSEE 1	LEE 3	MARSHALL 3
MCGUIRE 1	MCGUIRE 2	NANTAHALA	OCONEE 1	OCONEE 3	BUCK CC
DAN RIVER CC	ROWAN CC	ROCKINGHAM 1	THORPE	LINCOLN 1	

VACAR reserve sharing simulates a loss of various units in other VACAR companies and tests DEC's ability to export power to the following VACAR companies: Dominion Virginia Power (DVP), DEP, South Carolina Electric & Gas (SCE&G), and South Carolina Public Service Authority (SCPSA). DEC maintains 497 MW of non-simultaneous export capability to each of these areas. DEC is typically a net exporter, which is why it tests its export capability. VACAR reserve sharing cases were developed for the loss of the following units:

BATH COUNTY 1 (DVP)	NORTH ANNA 1 (DVP)	BRUNSWICK 1 (DEP)	HARRIS 1 (DEP)
MAYO 1 (DEP)	ROBINSON 2 (DEP)	ROXBORO 4 (DEP)	RICHMOND 1 (DEP)
ASHEVILLE 1 (DEP)	WILLIAMS 1 (SCE&G)	VC SUMMER 1 (SCE&G)	VC SUMMER 2 (SCE&G)
CROSS 3 (SCPSA)			

DEC uses Rates A, B, and C in its transmission planning models. Rate A is a continuous rating and assumes that all lines and transformers are in service. Rate B is a 12-hour rating that is used for contingencies involving lines and single phase transformers. Rate C is a 1-year rating that is used for contingencies involving three phase transformers.

4.1.1.2 DEP Screening Method

DEP's normal transmission screening process was followed in this study. The contingencies simulated in DEP's contingency file represent all transmission lines and transformers (115 kV to 500 kV) associated with the DEP transmission system. Also, contingencies for all common tower lines at least 1 mile in length are simulated (NERC Category C5). DEP plans and builds transmission for these common tower contingencies.

Rate A is monitored with all facilities in service, and Rate B is monitored during contingencies. However, for all but eight DEP transmission facilities, Rate A and Rate B are equal and represent the continuous rating of the facility. DEP uses emergency ratings in only a few special cases.

The DEP transmission system is evaluated with any one major generating unit down simulating a forced outage and the remaining DEP generation scaled back for a total simulated contingency reduction equal to the DEP Transmission Reliability Margin (TRM) requirement (currently 1826 MW emergency import).

DEP's practice is to create TRM cases for the following 5 unit outages:

Brunswick #1
Brunswick #2
Harris
Robinson #2
Roxboro #4

When the above units are taken down, the appropriate unit auxiliary loads are added back to the power flow case. This is because the net (gross - auxiliaries) output of the unit is normally modeled.

The TRM import requirement of 1826 MW is allocated to DEP's interfaces in the following manner:

AEP	100 MW
DEC	773 MW
Dominion	427 MW
SCE&G	200 MW
SCPSA	326 MW
Total	1826 MW

The above TRM values are derived from DEP operations values that are posted on the DEP OASIS. In general, the value calculated for each interface is the larger of the VACAR Reserve Sharing (VRS) component or the collective sum on each interface of inrush values calculated by modeling the most impacting DEP generator outage for each interconnection line. For the PJM interface with DEP, the inrush values are larger than the VRS values. The only PJM contractual commitment for VRS is from Dominion, but DEP also plans for the inrush. DEP's practice is to approximate inrush on the PJM interface by scaling the AEP area load down by the amount shown above to provide for the import flow.

Although this is a standard DEP planning practice, PJM has not studied the reasonableness of these methods for modeling this support from the PJM system.

DEP's TRM cases are created with a Python script that automates this process. AC contingency analysis is performed on all power flow cases using the PSS®MUST software.

4.2 Duke Energy Carolinas Results

Tables 4-1 and 4-2 show the results for DEC. The majority of the issues that DEC identified were in the vicinity of Parkwood Tie, near DEC's eastern interface with DEP.

Certain overloads may be mitigated by performing ancillary upgrades, which are less expensive than major upgrades such as line rebuilds or transformer replacements and can be implemented relatively quickly. Ancillary upgrades may involve pieces of equipment including but not limited to meters and relays. These upgrades can allow for utilization of the full rating of a line or transformer, which can be much higher than the existing rating. Examples of this are the 230 kV lines between Pleasant Garden Tie and Bobwhite Station, which are shown as being loaded to 100.4% of their thermal rating in the Sensitivity Case.

DEC has an operating guide with Yadkin that allows for an overload of either the Tuckertown-Badin 100 kV line or the Tuckertown-High Rock 100 kV line to be mitigated by opening the Tuckertown-High Rock 100 kV line. In Table 4-1 these lines are shown as being loaded 100.5% and 113.1%, respectively, in the Merged Case. In Table 4-2 neither of these lines is overloaded in the Merged Case, but the Tuckertown-High Rock 100 kV line becomes overloaded as the full impact of the BRA is studied. Another operating guide that DEC has that is relevant to the results of this study involves opening a Parkwood 500/230 kV transformer. If the loss of one of the Parkwood 500/230 kV transformers causes the remaining 500/230 kV transformer to overload, there are situations where the remaining transformer can be opened. In Table 4-1 the Merged Case loading for bank 6 is 88.8%, and it only exceeds its rating in the Sensitivity Case (100.5%). For the conditions represented by Table 4-2, the loading on bank 6 ranges from 96.6% in the Merged Case to 107.6% in the Sensitivity Case. As with any operating guide, its viability will continually be evaluated as future system conditions could make the operating guide obsolete.

There are some lines on the DEC system that are conductor limited that may exceed their rating under certain conditions when the impact of the BRA is considered. Loadings on these lines in the Merged Case are at least 89% of their thermal rating. As seen in the Merged Case results, these lines do not exceed their thermal rating before the full impact of the BRA is studied (with the exception of the Glen Raven to Eno 100 kV line in Table 4-2); however, in the Sensitivity Case results where the full impact of the BRA is incorporated into the models, these lines may exceed their rating.

The most significant VRS scenario involves the loss of a Roxboro unit in DEP. Roxboro is a generating facility on DEP's interface with both DEC and DVP. The results show that the increased flow across North Carolina caused by the BRA units contributes to the observed VRS planning criteria violations.

The outage transfer distribution factor (OTDF) is a post-contingency measure of how a particular element is affected by a specified transfer. The OTDFs shown in Tables 4-1 and 4-2 show the contribution of all BRA units without Firm Transmission Service on the flow of each of the facilities listed. It is an industry practice to use OTDF cutoffs, usually in the order of 3-5%, to determine system limitations/violations associated with a particular transfer. In the case of this study, no OTDF cutoffs were used.

Table 4-1 DEC Generator Maintenance + Contingency Analysis Results

Overloaded Branch										Case Loading				Loading Increase	OTDF (Sensitivity – Base)		
										Merged	Base	Change	Sensitivity	(Sensitivity – Base)	Aggregate	Individual Unit (Highest)	
From Bus	Name		To Bus	Name		Circuit	Rating	Case	Contingency	%	%	%	%	%	%	%	Comment [7]
339003	HIGH RCK	100.00	339005	TUCKERTN	100.00	1	103	BEL1GM	GODBEY_W_REA	113.1	116.2	118.6	120.1	3.9	0.1	0.2	OG
306881	ENO	100.00	306897	GLEN RVN	100.00	1	66	OCO3GM	PARKWOOD	99.3	110	115.6	118.7	8.7	0.2	0.3	conductor
306949	PL GARDN	100.00	308766	HOLTRTAP	100.00	1	105	DRCCGM	PARKWOOD	96.4	101.9	104.9	106.7	4.8	0.2	0.2	conductor
339001	BADIN	100.00	339005	TUCKERTN	100.00	1	116	BEL1GM	GODBEY_W_REA	100.5	103.4	105.5	106.7	3.3	0.1	0.2	OG
308766	HOLTRTAP	100.00	308942	SWEPSNVW	100.00	1	105	DRCCGM	PARKWOOD	96.3	101.8	104.8	106.6	4.8	0.2	0.2	conductor
306004	6CENTRAL	230.00	306104	6SHADYTB	230.00	1	464	CLI5GM	FISHERW	98.5	100.7	102.5	103.6	2.9	0.5	0.9	conductor
306004	6CENTRAL	230.00	306105	6SHADYTW	230.00	2	464	CLI5GM	FISHERB	98.5	100.7	102.5	103.6	2.9	0.5	0.9	conductor
306847	6PARKWOD	230.00	306849	8PARKWOD	500.00	5	840	OCO3GM	PARKWOD_TX6	88.8	95.2	98.6	100.5	5.3	1.6	2.2	OG
306848	6PL GRDN	230.00	306850	8PL GRDN	500.00	5	1499	BEL1GM	PARKWOOD	92.1	95.9	97.9	99.6	3.7	2.0	2.5	AEU
306881	ENO	100.00	306897	GLEN RVN	100.00	2	85	OCO3GM	PARKWOOD	-	90.2	94.8	97.4	7.2	0.2	0.3	conductor
306847	6PARKWOD	230.00	306849	8PARKWOD	500.00	6	919	OCO1GM	PARKWOD_TX5	82	87.9	91	92.8	4.9	1.6	2.2	OG

Table 4-2 DEC VACAR Reserve Sharing + Contingency Analysis Results

Overloaded Branch										Case Loading				Loading Increase	OTDF (Sensitivity – Base)		
										Merged	Base	Change	Sensitivity	(Sensitivity – Base)	Aggregate	Individual Unit (Highest)	
From Bus	Name		To Bus	Name		Circuit	Rating	Case	Contingency	%	%	%	%	%	%	%	Comment [7]
306881	ENO	100.00	306897	GLEN RVN	100.00	1	66	STUDYROX4VRS	PARKWOOD	113.1	124.2	130.1	133.5	9.3	0.2	0.3	conductor
306881	ENO	100.00	306897	GLEN RVN	100.00	2	85	STUDYROX4VRS	PARKWOOD	92.8	101.9	106.7	109.5	7.6	0.2	0.3	conductor
306847	6PARKWOD	230.00	306849	8PARKWOD	500.00	5	840	STUDYROX4VRS	PARKWOD_TX6	96.6	102.7	105.9	107.6	4.9	1.5	2.2	OG
339003	HIGH RCK	100.00	339005	TUCKERTN	100.00	1	103	STUDYROX4VRS	GODBEY_W_REA	95.9	99	101.2	102.6	3.6	0.1	0.2	OG
306004	6CENTRAL	230.00	306104	6SHADYTB	230.00	1	464	STUDYASH1VRS	FISHERW	96.8	99.2	100.9	102	2.8	0.5	0.9	conductor
306004	6CENTRAL	230.00	306105	6SHADYTW	230.00	2	464	STUDYASH1VRS	FISHERB	96.8	99.2	100.9	102	2.8	0.5	0.9	conductor
306841	6BOBWH B	230.00	306848	6PL GRDN	230.00	1	416	STUDYHAR1VRS	GODBEY_W_REA	92.2	96.7	99.1	100.4	3.7	0.6	0.5	AEU
306842	6BOBWH W	230.00	306848	6PL GRDN	230.00	2	416	STUDYHAR1VRS	GODBEY_W_REA	92.2	96.7	99.1	100.4	3.7	0.6	0.5	AEU
306949	PL GARDN	100.00	308766	HOLTRTAP	100.00	1	105	STUDYROX4VRS	PARKWOOD	89.4	95.2	98.5	100.4	5.2	0.2	0.2	conductor
308766	HOLTRTAP	100.00	308942	SWEPSNVW	100.00	1	105	STUDYROX4VRS	PARKWOOD	89.5	95.2	98.4	100.3	5.1	0.2	0.2	conductor
306847	6PARKWOD	230.00	306849	8PARKWOD	500.00	6	919	STUDYROX4VRS	PARKWOD_TX5	89.2	94.8	97.8	99.3	4.5	1.5	2.2	OG
306857	BURL T B	100.00	306897	GLEN RVN	100.00	1	305	STUDYROX4VRS	ALAMANCEW	91.8	95.5	97	98.1	2.6	0.3	0.3	conductor
306858	BURL T W	100.00	306897	GLEN RVN	100.00	1	305	STUDYROX4VRS	ALAMANCEB	91.8	95.5	97	98.1	2.6	0.3	0.3	conductor
306844	6ENO	230.00	306848	6PL GRDN	230.00	1	464	STUDYROX4VRS	PARKWOOD	-	89.7	94.1	96.6	6.9	1.2	1.4	conductor
306844	6ENO	230.00	306848	6PL GRDN	230.00	2	464	STUDYROX4VRS	PARKWOOD	-	89.7	94.1	96.6	6.9	1.2	1.4	conductor

[7] "AEU" indicates that an ancillary equipment upgrade could raise facility rating. "Conductor" indicates that a line upgrade is required in order to mitigate the overload. "OG" indicates that an operating guide may relieve the issue.

4.3 Duke Energy Progress Results

The tables below show branches loaded above 85% following contingencies on the Non-TRM cases (Table 4-3) and TRM cases (Table 4-4). Loadings for the Merged, Base, Change, and Sensitivity scenarios are listed.

The largest increase in loading as a percentage of the branch rating is on the Marion – Dillon Tap 115 kV line, where the flows are 97%, 110%, 115%, and 118% for the Merged, Base, Change, and Sensitivity cases, respectively. There is currently an operating guide to open one end of this line if there is a contingency overload possibility. However, as loading increases on this line, the operating procedure may eventually no longer be sufficient.

Some overloads were seen for lines in the West End 230 kV area (Rockingham – Wadesboro Tap 230, West End – Center Church 230, Ellerbe – West End 230). There is currently an operating procedure to open one end of the Rockingham – West End 230 kV West line if there is a contingency overload possibility. However, as loading increases on these lines, the operating procedure may eventually no longer be sufficient.

An outage distribution factor (OTDF), calculated from the Sensitivity and Base cases, is included in the tables based on the flow increase caused by the Change and Sensitivity generation divided by the total of that generation. The largest OTDF is 2%. This type of OTDF is normally calculated for individual transmission service requests and generation interconnection requests, where a cutoff of 3-5% is commonly used. However, this study combines all the PJM 2016/2017 BRA resources, which are spread throughout the Eastern Interconnection, into a single analysis.

It is not contemplated that any equipment upgrades will be needed immediately due to the PJM 2016/2017 BRA.

Table 4-3 DEP Non-TRM Contingency Analysis Results

Monitored Branch	Rating	Case	Contingency Description	Case Loading				Loading Increase	OTDF (Sensitivity – Base)		Comment [7]
				Merged	Base	Change	Sensitivity	(Sensitivity – Base)	Aggregate	Individual Unit (Highest)	
** From bus ** ** To bus ** CKT				%	%	%	%	%	%	%	
304532 VISTA 115 304545 CASTLEH115TT 115 1	179	Non-TRM	304550 CASTLEH230TT 230 304564 SCOTT TAP 230 1	91	93.4	94.9	95.8	2.4	0.2	0.2	conductor
304543 FOLKSTN115TT 115 305061 E9-DAWSON 115 1	152	Non-TRM	304540 GEIGER TAP 230 304542 FOLKSTN230TT 230 1	87.8	91.1	93	94.1	3.0	0.2	0.2	conductor
304532 VISTA 115 305063 E9-HUGHBATTS 115 1	179	Non-TRM	304550 CASTLEH230TT 230 304564 SCOTT TAP 230 1	85.8	88.3	89.7	90.6	2.3	0.2	0.2	conductor
304348 ROCKHAM230TT 230 304638 WADSBOR TAP1 230 1	542	Non-TRM	304348 ROCKHAM230TT 230 304360 WEST END SUB 230 1	<85	86.7	88.8	89.9	3.2	0.6	0.9	OG
304024 ROXSEP230 TT 230 304070 PERSON230 TT 230 2	797	Non-TRM	304024 ROXSEP230 TT 230 304070 PERSON230 TT 230 1	<85	80.1	<85	87	6.9	2.0	2.2	conductor

Table 4-4 DEP TRM Contingency Analysis Results

Monitored Branch	Rating	Case	Contingency Description	Case Loading				Loading Increase	OTDF (Sensitivity – Base)		Comment [7]
				Merged	Base	Change	Sensitivity	(Sensitivity – Base)	Aggregate	Individual Unit (Highest)	
** From bus ** ** To bus ** CKT				%	%	%	%	%	%	%	
304632 MARION115 TT 115 304653 DILLON TAP 115 1	97	TRM Br1 Down	304663 LATTA SS TT 230 304682 DILLONMP TAP 230 1	97	109.7	114.8	117.8	8.1	0.3	0.5	OG
304348 ROCKHAM230TT 230 304638 WADSBOR TAP1 230 1	542	TRM Har Down	304348 ROCKHAM230TT 230 304360 WEST END SUB 230 1	96.4	101.4	103.4	104.7	3.3	0.6	0.9	OG
304361 WESTEND230TT 230 305024 E3-CNTR CRCH 230 1	542	TRM Har Down	304377 RICHMON500TT 500 304391 CUMBLND500TT 500 1	86	94.8	98.6	100.9	6.1	1.2	1.5	OG
304327 ELLERBE 230 304638 WADSBOR TAP1 230 1	512	TRM Har Down	304348 ROCKHAM230TT 230 304360 WEST END SUB 230 1	90.8	96.1	98.3	99.6	3.5	0.7	0.9	OG
304373 SAN GARD TAP 230 305024 E3-CNTR CRCH 230 1	542	TRM Har Down	304377 RICHMON500TT 500 304391 CUMBLND500TT 500 1	<85	92.5	96.4	98.6	6.1	1.2	1.5	OG
304327 ELLERBE 230 304361 WESTEND230TT 230 1	512	TRM Har Down	304348 ROCKHAM230TT 230 304360 WEST END SUB 230 1	86.7	91.9	94.1	95.5	3.6	0.7	0.9	OG
304357 SANFORD US#1 230 304373 SAN GARD TAP 230 1	512	TRM Har Down	304377 RICHMON500TT 500 304391 CUMBLND500TT 500 1	<85	88.9	92.9	95.3	6.4	1.2	1.5	OG
304305 SPRING TAP 115 304307 BISCOFNDRY T 115 1	199	TRM Har Down	304333 PITTSBORO 230 304340 SILERCT230TT 230 1	<85	87.1	90.1	91.9	4.8	0.3	0.4	conductor
304408 BEARD 115 304427 SLOCOMB TAP 115 1	119	TRM Har Down	304183 WAKE 500 TT 500 304391 CUMBLND500TT 500 1	<85	84.5	89.2	91.9	7.4	0.3	0.4	conductor
304630 MULLINS 115 304632 MARION115 TT 115 1	179	TRM Br2 Down	304631 MARION230 TT 230 305001 E1-CHAD PEA 230 1	<85	85.9	89.4	91.4	5.5	0.4	0.6	OG
304348 ROCKHAM230TT 230 304355 HAMLET 230 1	512	TRM Br2 Down	304377 RICHMON500TT 500 304391 CUMBLND500TT 500 1	<85	86.8	89.5	91	4.2	0.8	0.9	conductor
304196 ERWIN230 TT 230 304389 FAYEAST230TT 230 1	478	TRM Har Down	304183 WAKE 500 TT 500 304391 CUMBLND500TT 500 1	<85	82.2	87.4	90.5	8.3	1.4	1.9	conductor
304411 RAEFORD115TT 115 304429 RED SPR TAP 115 1	133	TRM Br1 Down	FAY-HAMLET230_&_RAEFORD-ROCKFISH230	86.2	88.1	89	89.6	1.5	0.1	0.0	conductor
304024 ROXSEP230 TT 230 304070 PERSON230 TT 230 2	797	TRM Br1 Down	304024 ROXSEP230 TT 230 304070 PERSON230 TT 230 1	<85	80.5	85	87.4	6.9	2.0	2.2	conductor
304378 RICHMON230TT 230 304415 RAEFORD230TT 230 1	797	TRM Br1 Down	304377 RICHMON500TT 500 304391 CUMBLND500TT 500 1	<85	83.9	86.2	87.4	3.5	1.0	1.1	AEU

5 Economic Analysis

The economic analysis was conducted in parallel with the reliability study and uses key results of the reliability study as inputs to the economic modeling. The reliability analysis portion of the work is discussed in sections 1 through 5 of this report. The objective of the economic analysis is to determine if the external BRA resources may affect the joint DEC-DEP dispatch in a manner that increases costs for North Carolina customers. The DEC-DEP method for this analysis is based on their zonal production costing model of the DEC and DEP system. The transmission system between DEC and DEP is represented as a bidirectional “pipe” in this model. The reliability study phase of the analysis quantified a range of possible impacts on the bidirectional capability of the DEC-DEP transmission system with and without the BRA unit flows. BRA units impacts on transmission limits between DEC and DEP were quantified during the reliability study for the same set of BRA units considered for the Base, Change, and Sensitivity cases. Production cost simulations were performed to quantify a range of potential impacts of an estimated range of potential transmission capabilities.

Economic analysis was done in parallel by PJM and Duke Energy Progress (DEP). Each entity used its own data and production cost software. The databases used in the DEP study are considered confidential information to Duke Energy, which is outside the NCTPC Planning Working Group (PWG) process. DEP used the production costing software (PROSYM) to conduct the economic analysis.

PJM used the publically available production costing databases and software (PowerBase and PROMOD) to determine the economic impacts of certain incremental flows through the DEC-DEP systems. The database used by PJM are confidential information to Ventyx Inc. and licensed to PJM. PJM performed a data checkout process with DEP to verify the model and performed simulations to mimic the DEP analysis. In addition, for verification, PJM performed various scenario analyses including a nodal analysis with a fully detailed transmission model of the Eastern Interconnection.

5.1 Input Data and Assumptions

The economic analyses done by both Duke Energy and PJM were based on certain input assumptions. The production costing data and assumptions were developed in accordance with the assumptions used in the 2014 Duke Energy Carolinas/Duke Energy Progress Integrated Resource Planning processes. The input assumptions used to conduct this joint economic study include load forecasts, detailed resource data, fuel price forecasts, and transaction assumptions. These input assumptions are described in the following tables. Both Duke Energy and PJM have cross-checked the input data assumptions in each model to ensure the consistency of both data and modeling assumptions to the extent permissible by the applicable confidentiality requirements.

In the zonal production cost model, generation was dispatched for each control area (DEC and DEP) in the cases to meet load. Economic exchange between DEC and DEP were modeled as an exchange at the marginal, i.e. incremental/decremental unit dispatch in each system, subject to a transfer limit constraint between the two systems. Since Duke Energy used a PROSYM model, which does not have a detailed transmission system representation, the limit between the DEC and DEP systems was represented as a single “pipe” or tie between the two systems, with a capacity equivalent to expected Total Transmission Capacity, derived from the first contingency incremental transfer capability (FCITC) transfer study conducted during the reliability phase of the project. This FCITC was determined by identifying the maximum transfer above firm transfer commitments from DEC to DEP-East that can be maintained under single contingency conditions without resulting in overload of any remaining facility. This power flow analysis is based on a single peak load snapshot of the DEC-DEP system. The production costing analyses performed simulation for a full year (8760 hours) of operation. As such, PJM and DEP recognize that the single snapshot simulation may not be representative of the continuously changing system conditions encountered during a full year of operation. Based on this, PJM and DEC-DEP agreed to analyze a range of potential transmission capabilities.

The following input and modeling assumptions are used in the production cost simulations.

5.1.1 Load Forecast:

Table 5-1 Forecast for Peak and Energy

	Peak (MW)					Annual Energy (GWh)		
Months	**DEP-East**	**DEP-West**	**DEC**		**Months**	**DEP-East**	**DEP-West**	**DEC**
JAN	12,036	843	17,637		JAN	5,600	503	8,514
FEB	11,139	841	16,780		FEB	5,035	492	7,929
MAR	9,924	812	14,473		MAR	4,675	439	7,564
APR	8,426	589	13,405		APR	4,226	366	7,100
MAY	10,248	766	15,760		MAY	4,680	438	7,710
JUN	12,041	837	18,130		JUN	5,597	436	8,704
JUL	12,521	827	18,822		JUL	6,172	485	9,428
AUG	12,449	832	18,433		AUG	6,112	455	9,228
SEP	10,707	740	16,829		SEP	5,124	389	8,061
OCT	8,903	605	13,119		OCT	4,448	413	7,037
NOV	9,711	807	14,392		NOV	4,600	439	7,574
DEC	11,568	819	15,608		DEC	5,346	534	8,481
Peak	**12,521**	**843**	**18,822**		**Total**	**61,614**	**5,390**	**97,329**

5.1.2 Resource Mix Data:

Table 5-2 Resource Mix

Resource Type	Max MW
Combined Cycle	4,747
Conventional Hydro	1,363
CT Gas	7,955
CT Oil	451
IC Oil	56
Nuclear	10,838
Pumped Storage Hydro	2,180
Solar PV	519
ST Coal	10,594
ST Renewable	204
Grand Total	**38,906**

5.1.3 Fuel Price Forecast:

The price forecast for different types of fuel used in this 2016 simulation is shown in the following table:

Table 5-3 Fuel Price Forecast

Fuel	Price ($/MMBtu)
Coal	3.65
Natural Gas (Henry Hub)	4.20
Kerosene/Jet Fuel	19.50
Oil#6 - 0.7%	15.15
Oil#2 (Distillate)	18.19
Nuclear	1.00

5.1.4 Transactions Modeling and Associated Load Adjustments

Based on information provided by Duke Energy, there are two key transactions that were modeled for DEC and DEP systems in this study. The first transaction is the modeling of energy entitlement from two nuclear units (Catawba 1 and Catawba 2) which are jointly owned by Duke Energy Carolinas (19.25 %), NCEMC (30.75 %), NCMPA (37.5 %), and Piedmont MPA (12.5 %) respectively. Since the energy entitlement by NCMPA and Piedmont MPA are not represented in load forecast assumptions used in the study, their energy entitlements are modeled as fixed sale transaction, coming right out of these two nuclear units. The amount of energy modeled is 50% (sum of energy entitlement by NCMPA and Piedmont MPA) of energy output from two nuclear units.

The other transaction modeled is the 150 MW firm sale by DEP to both NCEMC and DEC which adds peak load to DEP. The reason that this transaction adds to peak load only is that the firm transaction occurs only on peak hours of DEP zone. While the energy transacted varies by peak hours and by months, the total transacted energy is about 157 GWh. This sale transaction is modeled in DEP as peak builder and interface transfer from DEP to DEC is also modeled to reflect that the energy is transported from DEP to the DEC/NCEMC system.

5.1.5 Pipe Size Assumptions

The various pipe sizes used in this economic study were derived from the reliability studies described in section 6.1. The actual calculated pipe sizes are shown in the following table:

Table 5-4 Pipe Sizes for Different Cases

Pipe Limit (FCITC + Firm)	DEC-DEP		DEP-DEC	
	2%	5%	2%	5%
Merge Case	1,984	3,712	1,531	1,531
Base Case	1,826	3,017	1,748	1,748
Change Case	1,656	2,644	1,855	1,855
Sensitivity Case	1,566	2,432	1,913	1,913

The 2% indicates the “cutoff” applied to facilities limiting the transfer. Only limits that carried 2% or more of the transfer flow were considered valid limits. The 5% columns show the results of the same analysis if the limits are screened to only show those carrying 5% or more of the transfer. The 2% limit is lower than typically used for interregional transfer studies since DEC and DEP are part of a merged entity.

The “cases” described in this table have the same meaning as reported in the reliability portion of this report. The table shows that, from DEC to DEP, for increasing amounts of BRA resource transfers, the transmission capability decreases. Also, from DEP to DEC, for increases in amounts of BRA resource transfers, the transmission capability increases. This result is consistent with a West to East BRA flow impact across the system.

For the analysis reported here the 2% limits were used.

5.2 Study Cases

A set of two annual production costing simulations were performed in each of three study scenarios. A reference case, representing the expected operation of the Joint Dispatch Agreement (JDA) under conditions prior to the transfer of the BRA resources identified in the reliability scope, and an alternate case that models the conditions with the transfer of the identified resources. Four scenarios were simulated. Each scenario included the previously described reference and alternate cases. The scenarios are the previously described Merged, Base, Change, and Sensitivity cases. PJM and DEC-DEP each performed the analysis with their respective tools.

5.3 Results

The following outputs are produced and presented for economic analyses conducted by both Duke Energy and PJM:

A) Total production cost
B) Production cost by fuel type
C) Energy by fuel type

5.3.1 DEC-DEP PROSYM Simulation

A) Total variable production cost for the DEC-DEP PROSYM Scenario is shown in the chart below. The impact of changing the pipe size between DEC and DEP is shown for the 2% cases.

Table 5-5 Variable Production Cost Results of PROSYM Scenario

Variable Production Cost Results for 2016: DEC/DEP PROSYM Scenario: 2% Cases			
Case	**Production Cost ($000)**	**Difference Relative to Min Case ($000)**	**% Difference**
Merge	4,225,736	-	0.00%
Base	4,229,214	3,478	0.08%
Change	4,233,429	7,693	0.18%
Sensitivity	4,234,383	8,647	0.20%

B) Variable production cost by Station Group is shown in the chart below. Again, the 2% cases are represented.

Table 5-6 Variable Production Cost Results by Station Group

Variable Production Cost by Station Group for 2016 ($000) DEC/DEP PROSYM Scenario				
	2 % Cases			
Station Group	Merge	Base	Change	Sensitivity
CC-DEC	207,818	208,242	207,370	205,921
CC-DEP	565,936	566,605	566,494	567,007
Coal-DEC	1,493,435	1,492,996	1,494,186	1,493,278
Coal-DEP	785,204	788,721	787,493	789,846
CT-DEC	45,103	44,021	48,120	47,799
CT-DEP	53,334	52,748	52,584	52,393
DSM-DEC	-	-	-	-
DSM-DEP	-	-	-	-
Future CC-DEC	-	-	-	-
Future CC-DEP	-	-	-	-
Future CT-DEC	-	-	-	-
Future CT-DEP	-	-	-	-
Future Nuc-DEC	-	-	-	-
Future Nuc-DEP	-	-	-	-
Hydro-DEC	2,471	2,471	2,471	2,471
Hydro-DEP	-	-	-	-
Nuclear-DEC	543,000	542,996	542,980	543,001
Nuclear-DEP	202,418	202,418	202,418	202,418
NUG-DEC	26,539	26,371	26,493	26,711
NUG-DEP	85,895	85,895	85,895	85,895
Pumped Stor-DEC	6,402	7,445	7,929	8,330
Purc-Firm-DEC	1,688	1,687	1,688	1,687
Purc-Firm-DEP	54,562	54,666	55,375	55,693
Purc-Mkt-DEC	-	-	-	-
Purc-Mkt-DEP	-	-	-	-
Purc-SEPA-DEC	-	-	-	-
Renewable-DEC	34,116	34,116	34,116	34,116
Renewable-DEP	117,817	117,817	117,817	117,817
Total Variable Generation Cost	4,225,736	4,229,214	4,233,429	4,234,383
Difference Relative to the Merge Case	-	3,478	7,693	8,647

C) Generation by Station Group is shown in the chart below. Again, the 2% cases are represented.

Table 5-7 Generation by Station Group

Generation by Station Group for 2016 (GWH) DEC/DEP PROSYM Scenario				
	2 % Cases			
Station Group	Merge	Base	Change	Sensitivity
CC-DEC	5,750	5,768	5,753	5,718
CC-DEP	16,010	16,037	16,037	16,050
Coal-DEC	38,535	38,552	38,561	38,562
Coal-DEP	18,527	18,624	18,590	18,651
CT-DEC	745	727	796	788
CT-DEP	929	918	915	911
DSM-DEC	31	25	29	30
DSM-DEP	11	10	10	10
Future CC-DEC	-	-	-	-
Future CC-DEP	-	-	-	-
Future CT-DEC	-	-	-	-
Future CT-DEP	-	-	-	-
Future Nuc-DEC	-	-	-	-
Future Nuc-DEP	-	-	-	-
Hydro-DEC	1,622	1,622	1,622	1,622
Hydro-DEP	620	620	620	620
Nuclear-DEC	57,903	57,903	57,901	57,903
Nuclear-DEP	28,639	28,639	28,639	28,639
NUG-DEC	455	451	453	459
NUG-DEP	1,110	1,110	1,110	1,110
Pumped Stor-DEC	2,560	3,021	3,215	3,362
Purc-Firm-DEC	104	104	104	104
Purc-Firm-DEP	950	954	966	972
Purc-Mkt-DEC	-	-	-	-
Purc-Mkt-DEP	-	-	-	-
Purc-SEPA-DEC	1	1	1	1
Renewable-DEC	528	528	528	528
Renewable-DEP	1,753	1,753	1,753	1,753
Total Generation	176,782	177,365	177,603	177,793
Difference Relative to the Merge Case	-	583	821	1,011

5.3.2 DEC-DEP PROMOD Zonal Simulation

PJM ‘s parallel economic simulations were performed to attempt to corroborate the DEC/DEP analysis. The first step was to match modelling inputs as best as we could given the confidentiality of each of the data bases being used. The total loads, generation lists including capacity level and technology type, and transactions were correlated.

Then parallel simulations compared the generation energy results by technology type. The energy comparisons revealed possible differences in maintenance/forced outage, hydro, or fuel cost assumptions. These adjustments were relatively small and enabled tuning of the distribution of the energies among the technology types. The adjustments:

1. Maintenance durations and FOR values of nuclear units in both DEC and DEP.
2. Coal prices for coal-fired generating units in both DEC and DEP.
3. Natural gas prices for gas-fired generating units in both DEC and DEP.
4. Cycle efficiencies for two pumped-hydro units in DEC.

The following table shows the comparison of total energy and dispatch by generator types between Duke’s and PJM’s simulations *before* making the “tuning” adjustments. The pipe sizes used in this table reflect the early test runs accomplished by DEP, which were based on standard DEP pipe assumptions of 1500 MW capability from DEC to DEP and 1200 MW in the reverse direction. PJM then ran PROMOD simulation using the same pipe limits to have a meaningful comparison of energies between the DEP and PJM simulations.

Table 5-8 Generation Comparison between PROSYM and PROMOD Simulations before Adjustments

Generation (GWh)									
Duke Results (Zonal Basecase: DEC-DEP limit 1500/1200)				**PJM Results (Zonal Basecase: DEC-DEP limit 1500/1200)**				**Delta**	
	DEC	DEP			DEC	DEP		DEC	DEP
CC	5,859	15,869	21,728	Combined Cycle	11,254	17,109	28,363	5,395	1,240
Coal	38,442	18,471	56,913	ST Coal	32,333	22,912	55,245	(6,109)	4,441
CT	737	928	1,665	CT Gas	1,486	904	2,390	750	(24)
DSM	31	10	41	Interruptible	1		1	(29)	(10)
Hydro	1,622	620	2,242	Conventional H	1,767	654	2,421	145	34
Nuclear	57,904	28,639	86,543	Nuclear	55,053	27,911	82,965	(2,851)	(728)
NUG	465	1,110	1,575	NUG				(465)	(1,110)
Pumped Stor-DEC	1,882		1,882	Pumped Stor-DEC	1,456		1,456	(426)	0
Renewable	528	1,753	2,281	Renewable	392	1,707	2,099	(136)	(46)
Total	**107,470**	**67,400**	**174,870**	**Total**	**103,743**	**71,197**	**174,940**	(3,726)	3,797

The following table shows the comparison of total energy and dispatch by generator types between Duke’s and PJM’s simulations *after* making ”tuning” adjustments. We can observe that total energy is close between DEC-DEP and PJM in both comparisons. We also see that the totals by technology are closer for combined cycle and nuclear categories after the adjustments. While coal got a little further apart, the discrepancy in DEC is greatly reduced. All of these results differences are considered small. We concluded that reasonable input differences account for the small differences observed and that it was not important to this analysis to spend time creating two sets of identical results. The purpose of independent verification of the DEC-DEP results was accomplished.

Table 5-9 Generation Comparison between PROSYM and PROMOD Simulations after Adjustments

Generation (GWh)									
Duke Results (Zonal Basecase: DEC-DEP limit 1826/1748)				PJM Results (Zonal Basecase: DEC-DEP limit 1826/1748)				Delta	
	DEC	DEP			DEC	DEP		DEC	DEP
CC	5,768	16,037	21,804	Combined Cycle	8,235	12,255	20,490	2,468	(3,782)
Coal	38,552	18,624	57,175	ST Coal	40,424	19,885	60,309	1,872	1,261
CT	727	918	1,646	CT Gas	1,204	690	1,894	476	(228)
DSM	25	10	35	Interruptible	1		1	(23)	(10)
Hydro	1,622	620	2,242	Conventional H	1,767	654	2,421	145	34
Nuclear	57,903	28,639	86,542	Nuclear	57,574	28,360	85,934	(329)	(279)
NUG	451	1,110	1,561	NUG			0	(451)	(1,110)
Pumped Stor-DEC	3,021		3,021	Pumped Stor-DEC	2,872		2,872	(149)	0
Renewable	528	1,753	2,281	Renewable	392	1,707	2,099	(136)	(46)
Total	**108,596**	**67,711**	**176,307**	**Total**	**112,469**	**63,551**	**176,020**	3,873	(4,160)

The following table showed the production cost results from PROMOD scenarios, based on zonal analyses.

Table 5-10 Variable Production Cost Results of PROMOD Scenario

Variable Production Cost Results for 2016: DEC-DEP PROMOD Scenario: 2 % Cases			
Case	**Production Cost ($000)**	**Difference Relative to Min Case ($000)**	**% Difference**
Merge	5,583,518	-	0.00%
Base	5,583,291	(226)	0.00%
Change	5,583,850	333	0.01%
Sensitivity	5,584,332	815	0.01%

5.4 Economic Conclusion

Duke Energy performed a production cost analysis of the specified pipe limits as described above. Production cost impact varied between $3 M and $9 M for the year 2016 as shown in Table 5-5. These results should be considered approximate and will vary with changes to fuel price assumptions.

PJM performed a zonal analysis to corroborate the small percentage economic impacts of the DEC-DEP analysis. The PJM determined production cost impacts are less than $1 M as shown in the Table 5-10 of section 5.3.2. The results reported above for this work indicate that the economic impacts of the studied BRA resources are insignificant. The changes in production costs with and without the modeled transfer of BRA resources is so small as a percentage of total production cost as to be well within the variability that would be expected from small changes in assumptions due simply to the uncertainties in the analysis. In addition PJM performed several sensitivities to changing input assumptions, varying the footprint of the analysis, and changing to a detailed nodal system representation. All the results confirmed the conclusion based on the zonal work that the economic impacts are insignificant.

6 Discussion and Conclusions

This section of the report contains each party's perspective on the analysis and associated results.

6.1 Duke Energy Perspective

NCTPC, PJM, and MISO worked together to analyze the impact of the PJM 2016/2017 BRA on the North Carolina utilities' transmission systems. However, due to confidentiality provisions contained in PJM's governing documents and code of conduct, PJM could not share the individual BRA locations with MISO, Duke Energy, or other members of the NCTPC. This includes not being able to provide access to the "Base", "Change", and "Sensitivity" power flow cases to the other study participants. Not having access to this information and the modeling data makes it virtually impossible for Duke Energy's transmission planners to fully understand any identified issues or to determine appropriate corrective actions. Duke Energy believes that its Transmission Planners have a right and necessity, due to their responsibilities under FERC and NERC rules, to obtain detailed information on all activities that may affect the reliability of Duke Energy's Bulk Electric System. Duke Energy's Transmission Planners operate under FERC's Standards of Conduct which forbid sharing of market information and should have complete access to BRA related information. Notwithstanding the foregoing concern, Duke Energy believes that PJM performed the analysis accurately and conscientiously.

As large balancing areas such as PJM and MISO grow ever larger and less geographically compact, and as they pull resources from the far reaches of North America, traditional interface arrangements among utility neighbors may no longer be sufficient. When utilities were more compact, shared allowance of loop flows was possible. As large balancing areas' resources expand widely, loop flows become unbalanced, with the larger entities making significant use of others transmission systems without an equivalent level of loop flows in the other direction.

Common distribution factor cutoffs of 3-5% make sense for the study of individual transmission service requests and generation interconnection requests, but they are less appropriate for larger, wider-spread groupings of resources analyzed as a single resource. Also, having such low distribution factors limits the likelihood that calling Transmission Loading Reliefs (TLRs) on BRA related generators will be a viable means of relieving congestion in real time. Evaluating all of the PJM BRA generation as a group spreads out the power on a percentage basis, making distribution factors on individual lines smaller. However, the aggregate MW impact of the BRA flows can still be significant on individual lines. Duke Energy does not believe that the small distribution factors seen in this analysis make the impacts on its transmission facilities any less relevant.

This study found that 463 MW of the 2774 MW of PJM 2016/2017 BRA resources that do not have transmission service will flow through DEC and DEP transmission systems. There is a good probability that some or all of these resources will use a transmission service path that does not include Duke Energy, resulting in no means to deny service through the NCTPC footprint or receive compensation.

The study did not find any DEP transmission facilities that will need immediate upgrades due to the PJM 2016/2017 BRA. There were DEC transmission facilities that were identified as not meeting transmission planning requirements that cannot be alleviated by upgrades by 2016. PJM has implemented a Capacity Import Limit into their BRA process and has indicated that the next BRA, 2017/2018, has fewer resources located outside the PJM footprint. These facts lead to the conclusion that follow-up joint operating horizon studies must be performed to more accurately identify impacts and to determine solutions to the identified problems in the DEC area. The BRA resources are based on firm energy contracts and firm transmission service. The NCTPC footprint can incur real time negative reliability impacts without further investigation of the identified issues. Duke Energy is concerned about the reliability impacts on its transmission systems from the growth in large magnitude, long distance power transfers from and to large, geographically diverse balancing areas. Since the BRA resources change from year to year, it may be necessary to repeat this analysis on an annual basis.

6.2 MISO Perspective

As per the North Carolina Utilities Commission's request[8], MISO provided support and assistance to the joint interregional study effort that evaluated the potential impact of capacity imports from MISO to PJM on the North Carolina transmission system. Specifically, MISO provided its latest[9] detailed internal model, used in developing the MISO Transmission Expansion Plan (MTEP), and technical staff resources to support the analysis performed by PJM and the North Carolina Transmission Planning Collaborative utilities.

Due to the confidentiality concerns raised in Sections 2, 4.1, and 6 of this study report, MISO did not have access to information necessary to perform detailed reliability and economic analysis to address the North Carolina Utilities Commission's request[10]. As a result, MISO was not involved in the detailed analysis performed by either PJM or Duke Energy.

MISO appreciates the opportunity to participate in this joint interregional study effort and believes that this process has been effective in evaluating the concerns raised by the North Carolina Utilities Commission in their request[10]. As a 501(c)(4) organization, MISO shares the North Carolina Utilities Commission's goal of assuring the most reliable, lowest cost energy delivered to consumers. MISO looks forward to continue working with the North Carolina utilities via our newly proposed interregional process[11] with the Southeastern Regional Transmission Planning (SERTP).

6.3 PJM Perspective

The results of this reliability analysis for the North Carolina Commission show a single dispatch snapshot of hypothetical operational impacts of the studied PJM BRA resources. As expected, the reliability

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[8] *North Carolina Utilities Commission Letter* at ¶1 and ¶3. See Attachment A: of this study report.
[9] As of May 9th, 2014, the date MISO provided the joint interregional study effort with the MISO model.
[10] *North Carolina Utilities Commission Letter*. See Attachment A: of this study report.
[11] FERC Order #1000 Interregional transmission planning coordination and cost allocation procedures contained in §X of Attachment FF of the MISO Tariff, "Attachment N-1 MISO" of the Duke Energy Joint OATT, & respective SERTP participants OATT.

results show the most significant parallel path effects are realized on North Carolina's interconnected high voltage grid. The study results indicate that the BRA resources cannot be considered a significant adverse impact on North Carolina reliability. Also, the results of the economic analysis show the impacts of the modeled BRA resources to be insignificant.

PJM's capacity market is competitive and open to all eligible resources. PJM limits the clearing of external resources to levels below PJM's determination of the expected capability of the transmission system. Also, PJM external resources accepted as PJM capacity resources are required to adhere to all applicable established North American Electric Reliability Council (NERC) and North American Energy Standards Board (NAESB) requirements and practices. These requirements and practices are the result of many years of development. They are designed to maintain comparable open access to the transmission system while prioritizing transmission uses and ensuring reliability.

PJM's BRA auction is a yearly process that procures capacity resources in a 3 year in advance time frame. Interim BRA auctions are conducted annually allowing participants to adjust their resource plans to accommodate the inevitable system changes that occur. The amount of power procured and location of units cleared in the auction can change from year to year. The 2016/17 auction cleared 7,663MW studied in this analysis for the North Carolina Commission. Since the 2016/17 auction approximately 800 MW of the originally cleared capacity have withdrawn. Also, the subsequent auction for the next delivery year (2017/18) cleared a reduced external capacity of only approximately 4,650 MW (this auction applied the PJM Capacity Import Limits.)

The Eastern Interconnection is voluntarily tightly interconnected with high voltage "backbone" transmission facilities that provide benefits of interconnected operations to all participants in the grid. These include the ability to decrease capacity planning reserve margins and the ability to benefit from opportunistic energy transactions. Loop flows or inadvertent flows are a consequence of this tightly interconnected system. Loop flows are flows of power that follow the laws of electrical physics that, to some extent, may deviate from ownership or contractual entitlements to use of the transmission system. Virtually all systems in the Eastern Interconnection cause and are affected in some degree by loop flows. For example PJM experiences significant loop flows through its system due to the DEC - DEP integrated operations. Long aware of these physical facts, the industry has established business, operational and planning practices that ensure loop flows do not become a reliability issue or cause undue burden to users of the system. In addition, entities may establish operational arrangements that further address specific circumstances.

Loop flows are accounted for in the planning of the interconnected system by embedding long term firm transmission use of the interconnected system into the Eastern Interconnection planning power flows. Through this process each system includes and maintains these granted long term firm uses of the system on a reciprocal basis through its planning for the NERC reliability criteria. Long term planning includes many uncertainties including resource uncertainties. In the near term horizon operational planning and congestion management account for actual outcomes including unexpected events.

The BRA resource contingency impacts that are described in this study are the result of parallel flow effects that are all well below the long accepted industry standard for being cited as a "cause" of any transmission limitations that may be experienced by those facilities. The most often accepted standard in this regard ignores effects when the parallel flow impact on a limiting facility is less than 3% to 5% of a particular transaction. When these "cause" determinations are made, each BRA resource must be treated independently because they each operate separately and each has its own transmission service. For each overload cited in this study, the contribution of flows by any external BRA resource is generally below 1%, with a few exceptions[12]. For the reliability screening results in this study, the contribution to limiting flows due to causes other than BRA resources, is in excess of 85% of the facility rating and most often in excess of 95%. If the BRA resources are considered in aggregate the BRA resource loop flow impacts remain a fraction of a percent impact in most cases.

As summarized in the preceding discussion, the loop flows on the Eastern Interconnection are bounded, managed and controlled to maintain system reliability. PJM nevertheless recognizes that the operation of well-planned transmission systems, particularly at the interfaces, can benefit from coordinated management of operations. PJM manages congestion on most of its interfaces through Joint Operating Agreements. These enable more efficient management of transmission congestion than is possible when systems operate independently. PJM strives to enhance the operations on all of its interfaces.

In addition, PJM coordinates planning with each directly connected transmission planning region pursuant to existing agreements and pending Order No. 1000 interregional planning agreements and tariff provisions. These planning provisions enable PJM to address opportunities to enhance regional plans with interregional plans and to consider mutually agreed to studies, such as this study, addressing identified interface issues.

[12] See Tables 4-1 through 4-4.

Appendix 1

PSS/E Area #	PSS/E Area Name	Company Name	PJM CIL Zone	16/17 BRA MW Cleared	Base Case	Change Case	Sensitivity Case
347	TVA	Tennessee Valley Authority	South				
363	LGEE	Louisville Gas & Electric and Kentucky Utilities Energy	South				
340	CPLE	Carolina Power & Light Company (DEP) – East	South				
341	CPLW	Carolina Power & Light Company (DEP) – West	South				
342	DUK	Duke Energy Carolinas (DEC)	South				
343	SCEG	South Carolina Electric & Gas Company	South				
344	SCPSA	South Carolina Public Service Authority	South				
				1414	**580**	**0**	**834**

PSS®E Area #	PSS®E Area Name	Company Name	PJM CIL Zone	16/17 BRA MW Cleared	Base Case	Change Case	Sensitivity Case
219	ITCT (aka DECO)	International Transmission Company	West 1				
218	METC (aka CONS)	Michigan Electric Transmission Co. LLC	West 1				
217	NIPS	Northern Indiana Public Service Company	West 1				
694	ALTE	Alliant Energy East (ATC)	West 1				
680	DPC	Dairyland Power Cooperative	West 1				
615	GRE	Great River Energy	West 1				
627	ITCM (aka ALTW)	International Transmission Company Midwest	West 1				
697	MGE	Madison Gas and Electric Company (ATC)	West 1				
635	MEC	MidAmerican Energy	West 1				
608	MP	Minnesota Power & Light	West 1				
661	MDU	Montana-Dakota Utilities Co.	West 1				
633	MPW	Muscatine Power & Water	West 1				
620	OTP	Otter Tail Power Company	West 1				
613	SMMPA	Southern Minnesota Municipal Power Association	West 1				
698	UPPC	Upper Peninsula Power Company (ATC)	West 1				
295	WEC	Wisconsin Electric Power Company (ATC)	West 1				
696	WPS	Wisconsin Public Service Corporation (ATC)	West 1				
600	XEL (aka NSP)	Xcel Energy North	West 1				
652	WAPA (aka WAUE)	Western Area Power Administration	West 1				
206	OVEC	Ohio Valley Electric Corporation	West 1				
				2696	**1620**	**1076**	**0**

PSS®E Area #	PSS®E Area Name	Company Name	PJM CIL Zone	16/17 BRA MW Cleared	Base Case	Change Case	Sensitivity Case
357	AMIL	Ameren Illinois	West 2				
356	AMMO	Ameren Missouri	West 2				
314	BREC	Big Rivers Electric Corporation	West 2				
360	CWLP	City of Springfield (IL) Water Light & Power	West 2				
333	CWLD	Columbia	West 2				
208	DEI (aka CIN)	Duke Energy Indiana	West 2				
207	HE	Hoosier Energy Rural Electric Cooperative	West 2				
216	IPL	Indianapolis Power & Light Company	West 2				
361	SIPC	Southern Illinois Power Cooperative	West 2				
210	SIGE	Southern Indiana Gas & Electric Company	West 2				
331	BCA	Batesville	West 2				
336	BUBA	Benton Utilities Balancing Authority	West 2				
502	CLEC	Central Louisiana Electric Company	West 2				
339	DENL (aka NLR)	City of North Little Rock	West 2				
338	DERS	City of Ruston	West 2				
335	CONWAY (aka CWAY)	Conway	West 2				
351	EES	Entergy Electric System	West 2				
327	EES-EAI	Entergy-Arkansas	West 2				
326	EES-EMI	Entergy-Mississippi	West 2				
503	LAFA	Lafayette Utilities	West 2				
504	LEPA	Louisiana Energy and Power Authority	West 2				
332	LAGN	Louisiana Generating Company	West 2				
337	PUPP	Panda Union Power Partners	West 2				
349	SMEPA	South Mississippi Electric Power Association	West 2				
334	WESTMEMP (aka WMU)	West Memphis	West 2				
325	BRAZ	Brazos Electric Power Cooperative, Inc.	West 2				
329	OMLP	City of Osceola	West 2				
328	PLUM	Plum Point Energy Associates	West 2				
				3553	**2689**	**864**	**0**
		Total:		**7663**	**4889**	**1940**	**834**

Attachment A

State of North Carolina
Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

December 11, 2013

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Charlotte, NC 28202

Dear Sirs and Madam,

In May of 2013, PJM Interconnection (PJM), conducted a capacity auction for its 2016/17 delivery year. Subsequently PJM has stated that an unprecedented amount of the capacity that cleared in that auction, 7,483 MW, is from generation resources that are located outside of PJM, primarily in the footprint of the Midcontinent ISO (MISO). I am writing on behalf of the North Carolina Utilities Commission (Commission) to request your support and assistance in conducting a study to determine whether these imports from MISO into PJM could reasonably be expected to exacerbate loop flows on the transmission grid in North Carolina.

The Commission is concerned that these imports could cause congestion on the transmission systems that are owned and operated by Duke Energy Carolinas, LLC (Duke), and Duke Energy Progress, Inc. (Progress). The Commission would like to know: (1) whether such potential congestion would likely require Duke and Progress to alter their joint generation dispatch in a manner that increases costs for North Carolina customers; and (2) whether the planned imports would reduce the reliability of the transmission grid that serves North Carolina.

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Because of these concerns, the Commission is hereby requesting that you assign appropriate leadership and technical resources to a joint study effort that would address these issues as soon as reasonably possible. We are hopeful that such a study could be completed by the end of 2014, thereby leaving your organizations and policymakers adequate time to address any potential problems that surface.

Thank you in advance for your consideration. We appreciate that the study we are requesting is complex, but we believe this issue is important to assuring reliable and economical electric service to North Carolina citizens. To that end, the Commission would very much appreciate a response by early February indicating that your organization is prepared to move forward, and informing us as to whom in your organization will be assigned to this effort. You can reach me at [redacted], or [redacted]

Sincerely,

Edward S. Finley, Jr.
Edward S. Finley, Jr.
Chairman
North Carolina Utilities Commission

Copies:

Acting Chairman Cheryl LeFleur, Federal Energy Regulatory Commission
Chairman G. O'Neal Hamilton, South Carolina Public Service Commission
Mr. Marty Berland, Oversight and Steering Committee Chair, North Carolina Transmission Planning Collaborative
Mr. Gregory Carmean, Executive Director, Organization of PJM States
Mr. Bill Smith, Executive Director, Organization of MISO States