2750 Monroe Blvd
Audubon, PA 19403-2497

October 21, 2014

Mr. Jonathan Feipel
Executive Director
Illinois Commerce Commission
527 East Capitol Avenue
Springfield, Illinois 62701

Dear Mr. Feipel:

This report responds to your September 24 letter requesting that PJM Interconnection analyze the potential impacts of the hypothetical retirements of Illinois nuclear power plants for the Illinois Commerce Commission. You noted that Illinois House of Representatives' Resolution 1146 urges the commission "to prepare a report examining the State's and grid operators' ability to expand transmission to allow Illinois to transport clean electricity to other parts of the nation, as well as any legislative impediments, and the impact on residential, commercial, and industrial electric rates from the premature closing of Illinois nuclear power plants."

This PJM analyses of the reliability, energy market and emissions impacts of the potential retirements of five nuclear generation units at three nuclear power stations is intended to assist the ICC prepare its report to the Illinois House.

The reliability analyses identified significant thermal and voltage violations on the transmission system. It likely would take substantial time to correct these reliability violations, and it is unknown if the corrections could be completed in a timely manner. Some corrections could inconvenience Illinois citizens. The reliability costs would be significant – in the hundreds of millions of dollars or more.

The energy market analysis was based on assumptions about future fuel prices, peak loads and generation mixes for the year 2019. Changes in any of those assumptions could result in different expected impacts. Therefore, PJM also executed sensitivity scenarios based on these assumptions as described in the report.

As a result of the different scenarios and sensitivities performed in these analyses, and, with those caveats in mind, the retirement of all five nuclear units that the Illinois commission asked PJM to evaluate likely would result in:

- Increased carbon dioxide emissions for 2019 of up to 18.9 million tons across the PJM footprint and up to 8.7 million tons for the state of Illinois;
- Locational marginal power price increases for 2019 likely between $2.70 and $3.80 per megawatt-hour in the Commonwealth Edison zone and between $0.90 and $1.50 per megawatt-hour in PJM;
- Load payment increases for 2019 between $307 million and $437 million in the Commonwealth Edison zone and between $752 million and $1.3 billion in PJM; and
- Significant costs, as noted above, to correct reliability violations.

Additionally, all of the scenarios PJM executed assume normal weather conditions. In times of extreme weather, delivered gas prices could be even higher than what PJM analyzed in the higher fuel price sensitivity scenario, which in turn likely would result in higher prices in the retirement scenarios. Likewise, in times of extremely mild weather, delivered gas prices could be lower than what PJM analyzed. PJM has not attempted to quantify those impacts.

Please let me know if you have questions or if we can help further. Please also know that PJM informed its members during the October Transmission Expansion Advisory Committee that it was undertaking this analysis and expects to share the results with members in November.

Sincerely,

Andrew L. Ott
Executive Vice President - Market Services

PJM Response to Illinois Commerce Commission Request to Analyze the Impact of Various Illinois Nuclear Power Plant Retirements

October 21, 2014

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I. Summary

This report responds to a request from the Illinois Commerce Commission requesting that PJM analyze the impacts of hypothetical Illinois nuclear power plant retirements. The request was to assess the reliability, energy market and certain environmental impacts for different nuclear plant retirement scenarios. The analyses were based on assumptions about future fuel prices, peak loads and generation mixes for the year 2019. Changes in any of those assumptions could result in different expected impacts. Therefore, PJM also executed energy market sensitivity scenarios based on these assumptions as described in the report.

II. PJM's role in the Illinois transmission system

PJM is a regional transmission organization with more than 900 members that is operated on a not-for-profit basis. PJM's primary responsibility is to manage and plan the electric transmission system in all or parts of 13 states and the District of Columbia in a safe and reliable manner. In Illinois, PJM manages the transmission system owned by Commonwealth Edison. In real-time operations, PJM must balance electric customer usage (demand) with the available resources (supply), including nuclear generation stations, to provide enough electricity to meet consumer demands. In short, PJM and its members work closely together to "keep the lights on."

PJM's operations are similar to those of air traffic controllers, who are responsible for the safe and reliable operation of airline traffic. Air traffic controllers manage the flow of aircraft through the skies and landings at the nation's airports. Air traffic controllers are regulated by the federal government, do not own the airplanes, the landing rights or the airports but have broad responsibilities for managing air traffic. Likewise, PJM is regulated by the Federal Energy Regulatory Commission, manages the flow of electricity over the electric transmission system for its members but does not own the electricity or the transmission grid.

PJM also operates a trading platform, which may be compared to the Chicago Board of Trade. Through this trading platform, PJM members can buy and sell wholesale energy and related services in day-ahead and real-time markets. PJM also is responsible for securing adequate generating resources to meet future consumer demands and for the long-term planning of the high-voltage transmission system.

These responsibilities place PJM in a unique position to assess the impacts of power plant retirements.

III. Nuclear stations' value to electric transmission grid

PJM values the contribution nuclear power stations, which seldom need refueling and operate with high efficiency, make for a balanced generating portfolio and significantly add to the overall reliability of the power grid. For instance, during the extremely cold weather in Illinois and other states this past January, known as the Polar Vortex, the Byron, Quad Cities and Clinton nuclear power stations operated at or close to full output and provided needed reliability support to PJM as well as to neighboring transmission systems. PJM's records indicate that for the two stations located in the PJM footprint, the Quad Cities nuclear power station operated in January at 100 percent of its rated capacity and the Byron nuclear power station at approximately 97 percent. All three of these nuclear power stations

were critically important in maintaining a safe and reliable transmission system during the record electricity demand served in January. PJM also recognizes that the State of Illinois would rely on low-carbon sources of energy, such as nuclear, to meet carbon dioxide limits proposed by the U.S. Environmental Protection Agency.

IV. The Illinois Commerce Commission request to assume the "unavailability," or retirement of three Illinois nuclear power stations (Byron, Quad Cities and Clinton) in 2019.

Core Request

The ICC asked PJM to model four scenarios concerning the unavailability of nuclear power stations.

Specifically, in September, the commission asked PJM to analyze the following four scenarios using calendar year 2019 as the base year and assuming:

1. All Illinois nuclear power stations are available,

2. All Illinois nuclear power stations, except the Byron station, are available,

3. All Illinois nuclear power stations, except the Byron and Quad Cities stations, are available, and

4. All Illinois nuclear power stations are available except the Byron, Quad Cities and Clinton nuclear power stations.

The commission also noted that a PJM committee, the Transmission Expansion Advisory Committee, had agreed upon and published certain input parameters and forecast assumptions such as customer load growth and transmission upgrades for 2019. The commission asked PJM to use those input parameters and forecast assumptions. In its analysis, PJM recognizes that these assumptions, which are based on the best available data, may change and that any changes could have significant impacts on the ultimate accuracy of the analysis.

Additional Requests

The commission also asked, to the extent feasible, for PJM's analysis of the unavailability of only the Clinton nuclear power station and separately, the unavailability of only the Quad Cities nuclear power station.

Note that due to time limitations, the reliability analysis does not consider the unavailability of only the Quad Cities nuclear power station and contains limited analysis of the unavailability of only the Clinton station.

For each of these scenarios the commission asked PJM to model any new electric transmission system investments that may be necessary to continue to have a reliable electric transmission system in Illinois due the possible retirement of the nuclear power generators. The commission also asked PJM to project the likely impact of the

nuclear power station unavailability on the wholesale prices of energy in Illinois – which are termed wholesale "locational marginal prices."

Finally, the commission asked for estimates of other expenditures necessary to serve customer load and the impacts of nuclear plant unavailability on future carbon dioxide and other power plant emissions, both in Illinois and the PJM region. While the requested analysis was particularly concerned with PJM modeling such scenarios in ComEd's service territory, which is in Northern Illinois, the ICC also requested PJM to analyze what could occur in the Ameren-Illinois service territory, which is in the Mid-Continent Independent System Operator's footprint where the Clinton nuclear power station is situated.

V. Analysis Assumptions

Reliability Analysis Assumptions

The scenarios required PJM to undertake analysis concerning the unavailability – what also could be termed "retirements" – of five nuclear reactor units – two each at Byron and Quad cities and one at Clinton. In the ordinary course of business the PJM planning analysis to evaluate the reliability impact of the unavailability of one generation unit on the PJM-managed transmission system requires at least 30 days to complete. The ICC request asked that the reliability analysis for all five generation units and the energy market impacts of the unavailability of those generators be completed in less than a total of 30 days. As a result of this aggressive timeline, PJM had to make certain assumptions to complete the analyses in the given timeframe.

As noted, the analyses that PJM was asked to complete included both an assessment of the transmission system reliability impact of each of the scenarios, an assessment of the energy market impact of each of the scenarios and the potential emissions levels as well.

The reliability analyses that were completed included the PJM load deliverability testing, generation deliverability testing, common mode outage testing and North American Energy Reliability Corp. category C3 (N-1-1) testing. This NERC testing relates to how reliable the transmission system would be if certain transmission facilities become unavailable at the same time.

Given the time constraints, an exhaustive analysis of all applicable reliability criteria, including the Commonwealth Edison local transmission owner criteria, was not performed. However, historically the analyses that were completed by PJM have driven the majority of the upgrades that are required due to generation retirements. The reliability impacts were evaluated on a 2019 summer peak base case that was modified for each of the retirement scenarios requested by the Illinois commission. Modelling assumptions including transmission topology, loads, generation and interchange were consistent with the assumptions being used for the 2014 PJM Regional Transmission Expansion Plan, or RTEP, which set forth the 2019 base case criteria. It should be noted that severe winter conditions, like the Polar Vortex conditions experienced this past winter, were not studied.

Energy Market Assumptions

The Base Energy Market assumptions used for this analysis were derived from the 2014 Annual PJM RTEP Market Efficiency model for the 2019 study year. Therefore, all base input assumptions were equivalent to the assumptions as posted on the PJM Market Efficiency web page located at the following link:

http://pjm.com/~/media/planning/rtep-dev/market-efficiency/market-efficiency-input-assumptions.ashx

Key energy market input assumptions are provided in Table 1 below.

Table 1: Key Energy Market Input Assumptions

	Study Year 2019
Coal Prices ($/MMBtu)	3.24
Gas Prices ($/MMBtu)	4.79
Peak Load (MW)	165,982
PJM Generation Reserve Requirement (MW)	177,538
PJM Modeled Generation (Includes FSAs) (MW)	198,145
PJM Excess Modeled Generation above Reserve Requirement (MW)	20,607

The key input assumptions for this study include fuel prices, PJM peak load, and modeled generation. Coal and natural gas fuel prices for the 2019 study year were obtained from commercially available databases. PJM's January 2014 Load Forecast Report provided the transmission zone load and energy data. The PJM base generation model includes all existing in-service generation plus actively queued generation with an executed Facilities Service Agreement (FSA), less planned generator deactivations that have given formal notification to PJM of their intent to retire. FSA generation included in the base analysis represents a projection of generation that may or may not proceed forward through the PJM queue process. Inclusion of FSA units is consistent with the RTEP procedures.

The inclusion of FSA units in the generation model in 2019 results in total PJM capacity exceeding the PJM reserve requirement by more than 20,000 megawatts. This is depicted in Table 1. This amount of additional reserve generation, which is considerably greater than historical reserve levels, is significant because this generation will be used in the simulation to replace higher-cost existing generation. Although advanced in the interconnection process, FSA generation has not committed to interconnecting to the transmission system, may not yet be constructed and as such is somewhat speculative. It is added to market efficiency models to ensure reserve requirements are met throughout PJM's 15-year planning horizon and to match the RTEP transmission model, which includes necessary transmission upgrades required to satisfy reliability criteria with the FSA units interconnected. Given the optimistic assumption about FSA generation, and the resulting higher generation reserves, the base energy market impacts noted in this scenario may be less severe (i.e., load payments may increase in the study by a lesser amount) than what may be seen if the plants were to actually retire.

Fuel prices also have a major impact on the results because they directly impact the generation offer bids and consequently the load payments and locational marginal prices. The base analysis utilized the fuel prices from the

PJM 2014 Annual Market Efficiency Cycle. These fuel prices were relatively low for the 2019 study year. In particular, the difference between coal prices and natural gas prices is small, as shown in Table 1, which usually results in more lower-priced gas units displacing coal units in the simulation.

The identified key input assumptions are important because these assumptions have the most impact on the energy market simulation results. These base assumptions were used because they were vetted with stakeholders through the regional PJM RTEP process and are also being used for the 2014/2015 Annual PJM Market Efficiency cycle. However, sensitivities on these key input assumptions may have major impact on the results. Therefore, PJM performed additional sensitivity analysis on two of the key input assumptions to provide a range to help bound the results.

The first sensitivity analysis was to modify the base input generation assumptions to not include the additional FSA units in the analysis. Removal of the additional FSA units in the analysis would be consistent with historical Market Efficiency rules for which FSA units were not included. The reserve requirement will still be achieved because the removal of the FSA units does not result in total modeled generation being under the Reserve Requirement.

The second sensitivity analysis was to modify the sensitivity scenario that modeled sufficient FSA units to meet the Reserve Requirement to include a $1/MMBTU increase in natural gas prices. This sensitivity scenario represents a more updated prediction of natural gas prices and corresponding generation offers.

The 2019 transmission topology used for the energy market simulation was derived from PJM's 2019 RTEP base case, including all upgrades identified as part of PJM's RTEP process up through and including those identified as part of the 2013 RTEP cycle. All backbone lines are included in the 2019 case as well as the PJM-approved Byron-Wayne 345 kV line. Specific transmission constraints were modeled for the analysis. These include thermal constraints and reactive interface constraints. Monitored thermal constraints include facility and contingency elements selected by examining historical PJM congestion events, reviewing other PJM planning studies, or by their representation in the NERC Book of Flowgates. PJM reactive interface limits are thermal limits derived from studying reactive conditions beyond which voltage violations may occur. The modeled interface limits were calculated based on voltage stability analysis, a review of historical values, and the inclusion of approved RTEP upgrades. In addition, only a subset of coordinated PJM/MISO market-to-market flowgates was included in the analysis. This subset of market-to-market flowgates represents historical events and is consistent with the Regional Market Efficiency process.

The energy market impacts were measured using the PROMOD production cost simulation tool that models an hourly security-constrained generation commitment and dispatch. The simulation tool modeled both the PJM and the MISO regions. The MISO model was derived from the 2013 interregional process with the addition of relevant MISO multi-value transmission projects. Due to time constraints, PJM did not have time to work with the MISO to ensure the model was the most current transmission representation for the MISO region.

The model includes multi-party transactions with commitment and dispatch hurdle rates defined between the PJM and MISO pools. This allows for economic transactions to flow between PJM and MISO within the simulation.

Finally, the ownership of the Quad Cities nuclear units was represented similar to the 2014 PJM RTEP Market Efficiency analysis with a shared ownership between PJM and MISO areas with respect to reporting results.

VI. Results

Reliability Impact Results

The reliability analyses identified significant thermal and voltage violations in the transmission systems owned by ComEd, American Electric Power, American Transmission Systems Inc., Duke Energy Ohio, Duke Energy Kentucky, Northern Indiana Public Service Company and Ameren Illinois for the various scenarios. The thermal and voltage violations were primarily on 345 kV and 138 kV facilities.

Thermal violations relate to the limit on the amount of electricity that can be transmitted over the electric transmission lines or related transmission facilities without overheating and degrading system components and potentially causing transmission outages. Voltage violations relate to the ability to maintain system voltages within specified limits to keep power flowing and the system stable. (To use an analogy related to water pressure, voltage violations occur when there is insufficient “pressure” in moving power across the lines leading to a possible voltage collapse, akin to pressure in a water pipe dropping to zero.)

Byron Retirement

The Byron retirement scenario identified 66 potential thermal violations. Of these 66 potential violations, there were 8 potential violations on 345 kV lines, 12 potential violations on 345/138 kV transformers, 44 potential violations on 138 kV lines, 1 138/69 kV transformer and 1 69 kV line. In addition, widespread voltage magnitude and voltage drop violations were identified that would likely require a combination of numerous installations of switched capacitors and dynamic reactive devices such as static VAR compensators, or SVCs.

Byron and Quad Cities Retirement

The Byron and Quad Cities retirement scenario identified 92 potential thermal violations. Of these 92 potential violations, there were 12 potential violations on 345 kV lines, 14 potential violations on 345/138 kV transformers, 64 potential violations on 138 kV lines, 1 138/69 kV transformer and 1 69 kV line. In addition, widespread voltage magnitude and voltage drop violations were identified that would likely require a combination of several thousand MVAR of switched capacitors and dynamic reactive devices such as SVCs.

Byron, Quad Cities and Clinton Retirement

The Byron, Quad Cities and Clinton retirement scenario identified 78 potential thermal violations. Of these 78 potential violations, there were 14 potential violations on 345 kV lines, 14 potential violations on 345/138 kV transformers, and, 50 potential violations on 138 kV lines. In addition, widespread voltage magnitude and voltage drop violations were identified that would likely require a combination of several thousand MVAR of switched capacitors and dynamic reactive devices such as SVCs.

Preliminary Conclusions Regarding Transmission System Reliability

Without very significant and costly transmission system upgrades, PJM's analysis concludes, the transmission system in Northern Illinois would be "unreliable" and would not satisfy mandatory reliability standards for the studied scenarios. Multiple transmission reinforcements would be required to maintain reliability. In general, the number and severity of potential reliability problems and, as a result, the required transmission upgrades, will increase for the scenarios where more generation is removed from the system.

It would likely take substantial time to correct the violations noted above, and it is unknown if the corrections could be completed in a timely manner, i.e. prior to the desired retirement of these facilities. Some corrections would require substantial construction activity and could significantly inconvenience Illinois citizens. Due to the time constraints of completing this analysis, PJM has not had an opportunity to evaluate the costs of the transmission upgrades necessary to have a reliable transmission system that would be required for each of the three scenarios. However, the costs would be significant – in the hundreds of millions of dollars or more.

Energy Market Impact Results

PJM uses PROMOD software to project energy market impacts in future years. The PROMOD production cost simulation tool models an hourly security-constrained generation commitment and dispatch.

Base Results

Table 2 provides the result of the base energy market analysis utilizing the PROMOD tool and the previously described base input assumptions. This table shows the impacts on carbon dioxide, sulfur dioxide, and nitrogen oxides, load payments and load-weighted wholesale locational marginal prices, or LMPs, for different retirement scenarios. These scenario simulations used the 2019 study year from the 2014 annual RTEP market efficiency cycle. The estimated reliability upgrades that would be necessary as a result of the different retirement scenarios have minimal impact on the results. This result is expected because most of the identified reliability upgrades did not impact the transmission facilities included in the model from the Base Market Efficiency case for 2019 study year.

As noted previously, PJM did not perform an exhaustive study of all applicable reliability criteria, including the ComEd criteria. Many of the identified reliability upgrades have minimal impact on the energy market simulation results because they may be local reactive upgrades, local thermal upgrades, or facilities not included in the model utilized in the 2019 market efficiency case. Table 2 shows only results of the different retirement scenarios using the modeled 2019 base study year.

Table 2 shows base results for effluents, in tons, for both the state of Illinois and the total PJM footprint. The increase in tons is significant for the state of Illinois as well as for the entire PJM footprint for each effluent. The impact of Clinton 1 being retired has a smaller impact on the PJM footprint, which is expected since this unit is not part of the PJM grid. In addition, the MISO model utilized in this study has not been thoroughly reviewed by PJM so results may be slightly skewed specifically for the Clinton 1 unit and Ameren-Illinois zone. The unavailability of the Byron, Quad Cities and Clinton units results in the largest increase in effluent tons for the state of Illinois.

Base Results – Load Payments

The impact to load within ComEd, Ameren-Illinois and PJM was also measured with the different retirement scenarios as shown in Table 2. Load payments increased significantly in both the ComEd zone and the PJM footprint as more units were made unavailable. The worst case scenario with the Byron, Quad Cities and Clinton units being unavailable resulted in about a $752 million increase in load payments to the entire PJM footprint and about $307 million increase of load payments in the ComEd zone. Load payments along with load-weighted LMPs in the Ameren-Illinois zone had a smaller impact except for the scenarios for which the Clinton unit retired. The result is expected since the Clinton unit is located in MISO and not in the PJM RTO.

LMPs for the Commonwealth Edison zone were impacted the most for the scenario with the unavailability of the Byron, Quad Cities, and Clinton units. The results also reflect a best-case simulation because the PROMOD tool optimizes the data of the period of the analysis. In other words, although peak conditions, forced outages and unit bid data are represented in the cases, emergency, unpredictable and extreme situations cannot be represented. In addition, as described in the Energy Market Assumptions section of this report, the base simulations include generation that may not yet be in-service but which does have at least a signed Facilities Service Agreement. Not all units with signed FSAs will proceed to final completion, but within the base simulation these units may be dispatched. Therefore, as described in the Energy Market Assumptions section, PJM performed a sensitivity analysis with the FSA units removed from the generation model. In addition, since results can be significantly impacted by fuel prices and specifically natural gas prices, PJM performed a second sensitivity analysis with the natural gas prices increased by $1/MMBTU. This second sensitivity analysis was performed using the generation modeled that does not include FSA units. Results of both sensitivities are described in the next section of this report.

Table 2: 2019 Base Energy Market Impacts

		Nuclear Retirement Scenarios				
Units	Byron 1 and 2	x	x	x		
	Quad Cities 1 and 2		x	x		x
	Clinton 1			x	x	
Delta in Effluent Tons	Illinois CO2 (millions)	2.6	5.6	8.7	3.2	2.7
	Illinois SO2 (thousands)	3.4	6.6	10.5	4.2	3.1
	Illinois NO x (thousands)	2.3	4.4	6.3	2.1	2.0
	PJM CO2 (millions)	11.0	17.4	18.9	1.8	7.0
	PJM SO2 (thousands)	15.3	21.8	24.3	2.7	10.5
	PJM NO x (thousands)	7.7	11.9	13.2	1.6	5.1
Delta in Load Payments ($millions)	AMIL	-$14.3	-$5.8	$23.3	$25.0	-$8.1
	COMED	$198.4	$290.0	$306.8	$13.1	$103.3
	PJM	$447.8	$685.6	$751.9	$13.7	$249.8
Delta in Load Weighted LMP ($/MWh)	AMIL	-0.3	-0.1	0.4	0.4	-0.1
	COMED	1.7	2.5	2.7	0.1	0.9
	PJM	0.5	0.8	0.9	0.0	0.3

Sensitivity Results

Sensitivity Analysis with Removal of Generators with Facilities Service Agreements

Table 3 shows results assuming the first sensitivity as described in this report. This sensitivity was to remove the FSA units from the model. FSA generation, although advanced in the interconnection process, has not committed to interconnecting to the system and as such is somewhat speculative in nature. Inclusion of FSA units in the base analysis is consistent with the PJM Regional Planning Market Efficiency process. It is added to market efficiency models to ensure reserve requirements are met throughout PJM's 15-year planning horizon and to match the RTEP transmission model, which includes necessary transmission upgrades required to satisfy reliability criteria with the FSA units interconnected. However, in the 2019 study year the FSA units are not actually necessary to meet the PJM reserve requirement. Therefore excess generation is being modeled when the FSA units are included.

The result of the analysis with the FSA units removed mainly impacted the Load Payments and LMP prices compared to the original base case with the FSA units included. Effluents, in tons, continue to increase significantly for the state of Illinois as well as for the entire PJM footprint for each effluent. However, the increase is comparable to the base case for which FSA units were included. The removal of the FSA units had a more significant impact on the load payments and LMP prices. The load payments for the Commonwealth Edison zone increased by about $340

million while the load-weighted LMP prices increased by about $3/MWh for the scenario with the Byron, Quad Cities, and Clinton units all retired. In addition, the PJM RTO load payments increased by about $968 million while the load-weighted LMP prices increased by about $1.1/MWh for the scenario with the Byron, Quad Cities, and Clinton units all retired.

Table 3: 2019 Energy Market Impacts with Facilities Service Agreements (FSAs) Removed

		Nuclear Retirement Scenarios				
Units	Byron 1 and 2	x	x	x		
	Quad Cities 1 and 2		x	x		x
	Clinton 1			x	x	
Delta in Effluent Tons	Illinois CO2 (millions)	3.3	6.1	7.9	2.4	3.1
	Illinois SO2 (thousands)	3.7	6.0	7.7	2.9	3.2
	Illinois NO x (thousands)	2.2	3.7	4.5	1.0	1.7
	PJM CO2 (millions)	11.5	17.9	18.2	0.6	7.2
	PJM SO2 (thousands)	13.7	22.0	22.1	0.8	9.1
	PJM NO x (thousands)	7.7	12.1	12.3	0.2	4.9
Delta in Load Payments ($millions)	AMIL	-$6.3	$4.5	$43.1	$39.4	-$2.0
	COMED	$224.2	$322.7	$339.6	$22.0	$108.0
	PJM	$556.1	$932.8	$968.5	$57.4	$283.9
Delta in Load Weighted LMP ($/MWh)	AMIL	-0.1	0.1	0.8	0.7	0.0
	COMED	2.0	2.8	3.0	0.2	0.9
	PJM	0.6	1.1	1.1	0.1	0.3

Sensitivity Analysis with Natural Gas Prices Increased by $1/MMBTU

Table 4 shows results assuming the second sensitivity as described in this report. The second sensitivity analysis was to modify the first sensitivity to include a $1/MMBTU increase in natural gas prices. This sensitivity analysis represents a more updated prediction of natural gas prices and corresponding generation offers. As expected, the results are more significant with the increase in natural gas prices. In particular, the most significant impact was to the load payments and the LMP prices. Effluent tons remain comparable to the original base case. The state of Illinois CO_2 tons increased by about 7 million tons and the PJM CO_2 tons increased by about 16.1 million tons with the increase in natural gas prices. The load payments for the Commonwealth Edison zone increased by about $437 million, while the load-weighted LMP prices increased by about $3.8/MWh for the scenario with the Byron, Quad Cities, and Clinton units all retired. In addition, the PJM RTO load payments increased by about $1.3 billion, while the load-weighted LMP prices increased by about $1.5/MWh for the scenario with the Byron, Quad Cities, and Clinton units all retired.

Table 4: 2019 Energy Market Impacts with Natural Gas Prices increased by $1/MMBTU

		Nuclear Retirement Scenarios				
Units	Byron 1 and 2	x	x	x		
	Quad Cities 1 and 2		x	x		x
	Clinton 1			x	x	
Delta in Effluent Tons	Illinois CO2 (millions)	2.9	5.3	7.0	2.1	2.6
	Illinois SO2 (thousands)	3.6	5.6	7.0	2.6	2.8
	Illinois NO x (thousands)	2.0	3.3	3.9	0.9	1.3
	PJM CO2 (millions)	10.2	15.4	16.1	0.6	6.1
	PJM SO2 (thousands)	10.6	15.8	15.8	(0.3)	6.3
	PJM NO x (thousands)	6.9	10.3	10.4	(0.1)	4.2
Delta in Load Payments ($millions)	AMIL	$12.2	$38.5	$85.9	$57.1	$15.2
	COMED	$302.0	$407.3	$436.8	$46.2	$140.9
	PJM	$806.0	$1,259.4	$1,307.5	$129.7	$421.4
Delta in Load Weighted LMP ($/MWh)	AMIL	0.2	0.7	1.5	1.0	0.3
	COMED	2.7	3.6	3.8	0.4	1.2
	PJM	0.9	1.5	1.5	0.2	0.5

VII. Conclusions

The PJM analyses of both the reliability, energy market and certain environmental impacts of the retirement of up to five nuclear units at three nuclear power stations show significant impacts. The reliability analyses of the potential retirement of five nuclear units identified significant thermal and voltage violations on the transmission system. It would likely take substantial time to correct the reliability violations, and it is unknown if the corrections could be completed in a timely manner. Some corrections could inconvenience Illinois citizens. The reliability costs would be significant – in the hundreds of millions of dollars or more.

The retirement of nuclear units that the Illinois commission asked PJM to evaluate would likely result in 2019 in increased carbon dioxide emissions of up to 18.9 million tons across the PJM region and up to 8.7 million tons for the state of Illinois based on the different scenarios and sensitivities performed in this analysis. Locational marginal prices would likely increase between $2.70 and $3.80 per megawatt-hour in the Commonwealth Edison zone and between $0.90 and $1.50 per megawatt-hour in PJM based on the different scenarios and sensitivities performed for this analysis. In addition, load payments would increase between $307 million and $437 million in the Commonwealth Edison zone and between $752 million and $1.3 billion in PJM based on the different scenarios and sensitivities performed for this analysis.