DNV·GL

SMART WIRES-PJM

Assessment of applicability and cost savings of deploying Smart Wires power flow controls to integrate renewable energy in PJM

Smart Wires, Inc.

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Task and objective:
Extend the PJM Renewable Integration Study (PRIS) to determine the ability of Smart Wires power flow controls (PFCs) to facilitate sourcing 30 percent of annual electricity from renewable energy in the PJM market by 2026.

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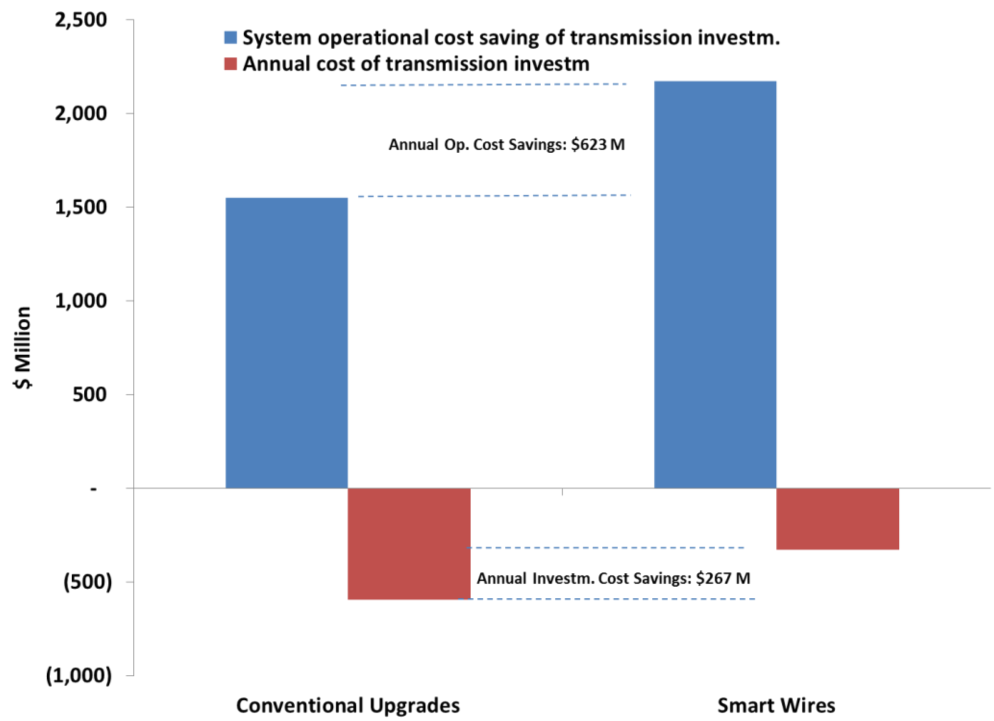
1 EXECUTIVE SUMMARY

DNV GL performed an economic assessment of Smart Wires' power flow control technology for improving transmission capacity on existing high voltage transmission lines in the PJM market (technology henceforth referred to as Smart Wires). Study results show that if Smart Wires is considered as an option in addition to conventional transmission enhancements, transmission cost savings of nearly 50% are possible while at the same time providing equal or better operational performance of the transmission system in terms of power prices, deliverability of renewable energy, transmission congestion and system costs.

The results of the study, summarized in Figure 1, show that the inclusion of Smart Wires technology lowers PJM annual transmission spend by $267M per year plus $623M per year in operational savings for a total of $890M per year in rate payer savings. Additional savings potentially exist, including capacity market savings, reserve market savings and reduced generation buildout.

Figure 1 Summary of cost savings



The study findings are based on a detailed transmission model for the PJM system for 2026 wherein it is assumed that 30% of the annual electrical energy will be supplied by renewable energy from onshore wind, offshore wind, and solar PV. The scenario studied draws on a 2014 study called the PJM Renewables Integration Study (PRIS) that examined costs and benefits of various renewable energy scenarios, including several 30% renewables scenarios. DNV GL used the PRIS as a starting point and benchmark for the analysis but also went beyond the PRIS by determining the optimal transmission enhancements, taking the following alternatives into consideration:

- Transmission enhancements and costs identified in the PRIS
- Conventional transmission line enhancements for all congested transmission lines with a voltage higher than 100 kV
- Smart Wires for all congested transmission lines with a voltage higher than 100 kV

DNV GL followed a three-step approach in determining the optimal investment level for each congested transmission line (and new alternatives). First, the level of transmission congestion was estimated for the year 2026. This estimate was based on data from the 2014 PRIS, transmission system data from PJM's RTEP transmission models, and expected market conditions in 2026 using a production cost simulation. Second, the optimal transmission enhancement portfolio was determined using the capacity expansion capabilities available in the simulation tool PLEXOS (LT Plan). PLEXOS' LT Plan models the trade-off between investment costs and operational cost savings. Third, the identified transmission enhancements were included in a detailed nodal power flow analysis for PJM for the year 2026. The nodal power flow model (DC OPF) is based on a security-constrained economic dispatch (SCED) model in PLEXOS that approximates actual PJM systems operations.

Using the approach described above, DNV GL then estimated the potential investment cost savings and the operational cost savings of Smart Wires by comparing two alternative scenarios:

Conventional Transmission Enhancements. The first scenario considers optimal transmission enhancements and system costs of using only conventional transmission system enhancements to source 30% of annual electricity from renewable energy in the PJM market.

Smart Wires. The second scenario considers *both* conventional transmission enhancements *and* Smart Wires to source 30% of annual electricity from renewable energy in the PJM market.

By comparing results between the two solutions, DNV GL was able to assess the potential value of considering Smart Wires as an option in PJM transmission planning. Table 1 below summarizes the key results.

Table 1 Results Summary

	Conventional Transmission Enhancements	Smart Wires
Renewable energy penetration (percent of annual PJM electrical demand)	30%	30%
Number of monitored lines (lines considered for transmission enhancements and interfaces with neighboring areas)	290	290

Estimated annual investment cost for new transmission lines[1] ($M)	$597	$249
Estimated annual investment cost of Smart Wires[1] ($M)	0	$81
Total annual transmission investment ($M)	$597	$329
Total transmission enhancement cost ($M)	$3,982	$2,199
Annual PJM system operating cost savings[1,2] ($M)	$1,548	$2,171
Total annual cost savings from deploying Smart Wires[1] ($M) (compared to conventional enhancements only)		$890
Renewable energy curtailment	5.5%	5.5%

The results shown in Table 1 and in Figure 1, suggest that the total need for conventional transmission enhancements can be dramatically reduced when Smart Wires is considered, resulting in lower investment costs. The results also suggest that Smart Wires improves overall system performance by offering additional savings in operational costs, mainly because the investment hurdle is lower with Smart Wires and more alternatives are available (for example, a +/- 1 degree Smart Wires device will provide less congestion relief but also has much lower cost and lacks a direct conventional transmission investment substitute)

DNV GL added renewable generation to the model to reflect a 30 percent renewable energy scenario and sought to optimize transmission enhancements. However, some renewable energy curtailment remains in the results, suggesting that further improvements (and likely higher cost savings) could be achieved by further detailed transmission modeling.

One potentially significant category of additional savings of the Smart Wires scenario, which is not captured in this study, is the potential to reduce the up-front and operating costs of new renewable generation. The up-front cost to build the renewable generation of the various PRIS 30% generation scenarios range from $212-344B. The generation scenario selected for this study, 30% Low Offshore and Best Onshore (30% LOBO), has the lowest up-front generation cost and highest transmission investment of all the 30% PRIS scenarios. The Smart Wires transmission scenario enables the 30% LOBO generation scenario with less overall transmission investment and less investment in new and reinforced overhead lines. This reduction in transmission investment may reduce the uncertainty of developing the transmission required to support the 30% LOBO scenario, namely funding, cost allocation, permitting, environmental and schedule uncertainties. To the degree the Smart Wires scenario enables, via uncertainty mitigation, a buildout of a renewable generation portfolio that is more akin to the 30% LOBO scenario than the other scenarios, additional savings as high as $132B could be unlocked by the Smart Wires scenario.

Reaching a 30% renewable energy penetration in PJM by 2026 represents a major change in the resource mix. Figure 2 and Figure 3 shows the 2015 and 2026 expected resource mix, suggesting an increase of

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[1] Nominal 2026 dollars

[2] Compared to PJM system operating costs of the base case that only includes the RTEP transmission enhancements

wind from 4% of total capacity in 2015 to 17% by 2026, and an increase of solar from less than 1% of capacity today to about 7% by 2026. Such dramatic changes will require equally drastic transmission enhancements, much of which is captured in this study.

In order to model the PJM system for year 2026, DNV GL used several data sources, including ABB's North American Reference Case and PJM's Summer 2022 Regional Transmission Expansion Plan (RTEP) model. This data was then converted for use in PLEXOS. The databases include comprehensive cost data for generators, fuel prices, regional load, as well as detailed information for the transmission system at voltage levels above 69 kV. DNV GL added new generation to approximately match the renewable energy assumptions and locations of the 2014 PRIS, and specifically the scenario called "30% LOBO"- with 30% wind and solar energy penetration in PJM, Low Offshore and Best Onshore; 10% of wind resources are offshore, 90% of wind resources are onshore in locations with best wind quality. In addition, DNV GL added new thermal capacity to ensure that local reserve margins remain adequate, using the same methodology as PRIS, and also updated load and fuel prices based on the most recent forecasts available.

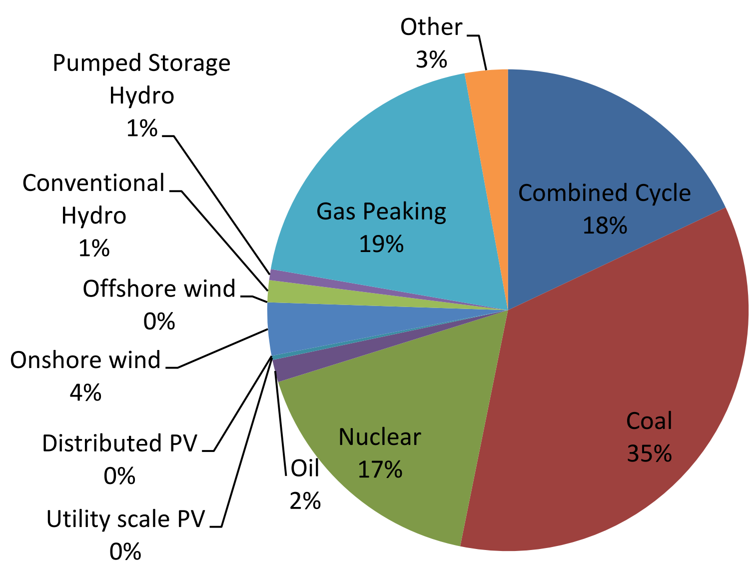


Figure 2 PJM 2015 Capacity Mix

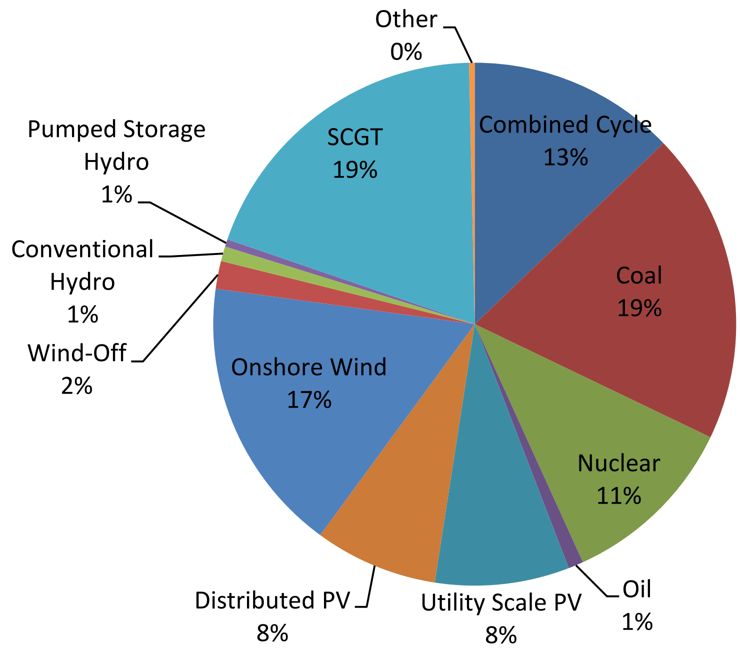


Figure 3 PJM 2026 30% LOBO Capacity Mix

PJM's PRIS analysis focused only on the higher voltage transmission lines. Potentially overloaded elements with a voltage less than 230 kV were ignored. The PRIS analysis included an iterative analysis using GE-MAPS and manual build choices to ensure the reliability and provide acceptable levels of congestion. Conventional transmission enhancements included reconductoring of existing circuits, adding new circuits on existing towers, or construction of completely new circuits (including towers and transformers) in parallel with existing lines. DNV GL's analysis expands on the earlier PRIS by taking a more comprehensive view of potential transmission enhancements that should be considered to successfully integrate up to 30% renewable energy in the PJM market. For each of the transmission circuits considered for enhancement, two alternative solutions were considered: 1. Enhancements based on conventional transmission technologies 2. Smart Wires' flow control technology in addition to the option of conventional transmission enhancements.

The two transmission enhancement scenarios examined, namely "Conventional Transmission Enhancements" and "Smart Wires," both had a similar beneficial impact on locational marginal prices for electricity (LMPs), compared to a situation without any transmission enhancements. The Smart Wires scenario shows slightly lower LMPs in most regions which is consistent with the lower system operational costs shown for the scenario. LMPs were also monitored closely in the modeling process to avoid the occurrence of significant load pockets (very high LMPs) or generation pockets (very low or negative LMPs). The analysis focuses only on the PJM market but surrounding areas were also modeled at a higher degree of aggregation to provide a realistic representation of transmission flows and electricity prices. Figure 4 shows an overview of 2026 LMPs at selected PJM hubs.

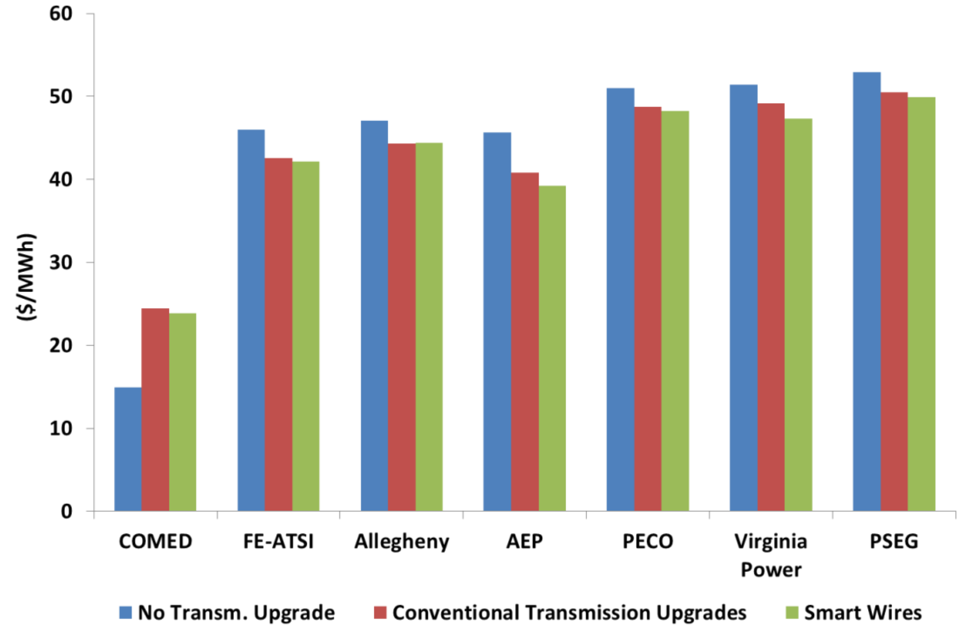


Figure 4 Annual Average Regional LMP for Selected Regions in 2026$

2 METHODOLOGY, DATA AND ASSUMPTIONS

DNV GL developed the modeling data and analytical platform for assessing the performance of Smart Wires' flow control technology on the PJM transmission grid by using a combination of data sources and tools. The study year 2026 was selected in order to be able to compare the study results to PRIS. DNV GL also built the market and renewable energy assumptions to approximate those used in the PRIS. The modeling includes five fundamental building blocks, each of which are described in more detail in this section:

- ABB's North American Reference Case for the eastern interconnection. This database provides detailed unit-by-unit information on installed generation, generation retirements and planned generation additions. The database also includes detailed utility-by-utility load information and a transmission network model, detailed generator model including performance characteristics and operating costs.
- PJM's Summer 2022 RTEP model. PJM's transmission planning model provides information on planned transmission expansion in PJM and also includes a comprehensive transmission network model that was used as a basis for transmission system topology, thermal limits, monitored lines and contingencies.
- Energy Exemplar's PLEXOS nodal market modeling software. This modeling platform allows for optimizing transmission and generation enhancements as well as performing detailed SCED modeling. PLEXOS has been modified at the request of Smart Wires to be able to model the Smart Wires flow control technology.
- PRIS providing renewable capacity allocation by state for 30% LOBO scenario and transmission overlay list used for transmission expansion.
- Detailed performance characteristics of Smart Wires transmission flow control technology

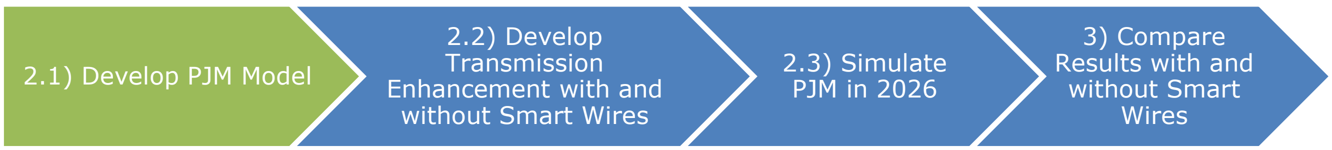
Using the components above, DNV GL developed a unique and comprehensive nodal PLEXOS modeling database for PJM and the neighboring Load Serving Entities that interface with PJM (hereinafter referred to as PJM market model). DNV GL modeled two distinct future scenarios for 2026:

Conventional Transmission Enhancements. The first scenario considers optimal transmission enhancements and system costs of using only conventional transmission system enhancements to facilitate sourcing 30% of annual electricity from renewable energy in the PJM market by 2026.

Smart Wires. The second scenario considers *both* conventional transmission enhancements *and* Smart Wires under the same 30% renewable energy scenario.

By comparing the two scenarios with respect to total system costs of serving load and total annual carrying costs of transmission system enhancements, DNV GL estimated the economic value of Smart Wires transmission technology for PJM for the particular renewable scenario.

The remainder of this chapter explains the methodology in detail. Section 2.1 explains the PJM Import/Export model, including the modeling topology and input assumptions used for the study. Section 2.2 describes the valuation methodology for determining the value of Smart Wires flow control in PJM as well as the approach for modeling the technology on the transmission system. In Section 2.3, the assumptions used in simulating PJM operations in 2026 are explored. Specific results and metrics used to compare two scenarios are provided in Section 3.



2.1 Develop PJM Model

The PJM market is the largest North American power market, covering large parts of the eastern and Midwestern United States (see Figure 5). As a systems operator, PJM operates wholesale electricity markets, capacity markets and manages the high-voltage electricity grid to ensure reliability for more than 61 million people[3]. DNV GL's model of PJM for the year 2026 assumes that the market footprint of PJM will remain unchanged. PJM manages regional planning processes for generation and transmission expansion to ensure continued reliability of the electric system. This process culminates in the PJM annual Regional Transmission Expansion Plan (RTEP).

As part of the effort to perform transmission planning and emulate PJM's day-ahead activities, DNV GL has created a model of PJM's market and transmission network to investigate the economic and operational impacts of a scenario sourcing 30% of annual electricity from renewable energy. In the sections which follow, the power flow assumptions and SCED models used to simulate the PJM market in 2026 are described in Section 2.1.1. In Section 2.1.2, the transmission network managed by PJM on behalf of its members is described and assumptions provided. In Section 2.1.3, study assumptions about member resources used by PJM to meet load obligations are described. In Section 2.1.4, load forecast assumptions are provided. In Section 2.1.5, fuels forecast assumptions are detailed.

[3] Source: www.pjm.com

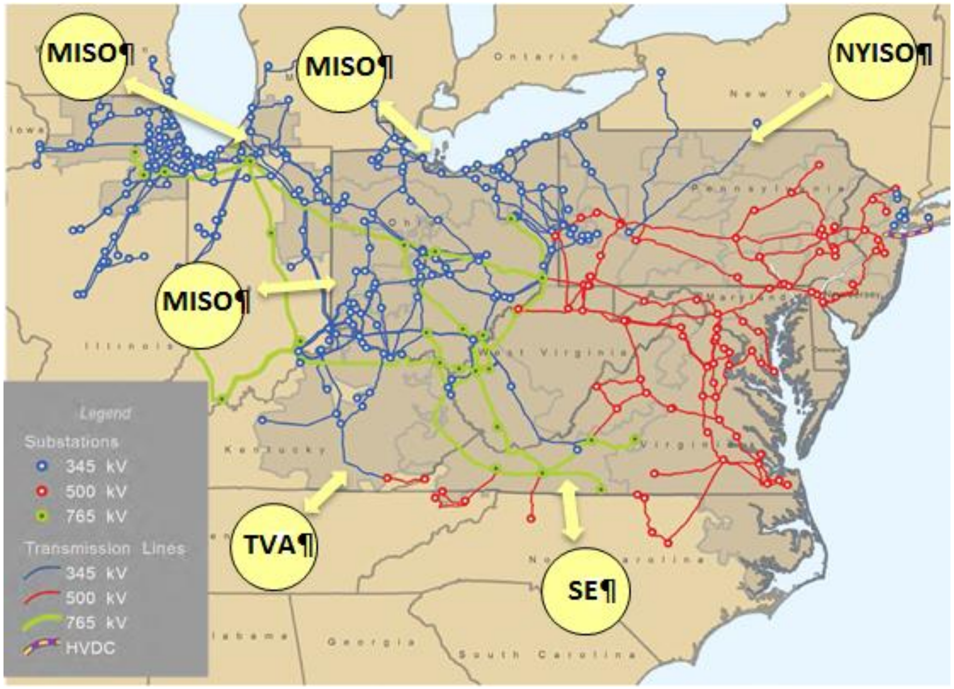


Figure 5 PJM Import/Export Model Footprint

2.1.1 Models Used

To forecast the future state of PJM markets with current operational constraints and market rules, DNV GL collected current information from existing models and DNV GL databases and set up a SCED model to emulate market conditions in PJM using the PLEXOS modeling platform. PLEXOS is software developed and marketed by Energy Exemplar to calculate long-term planning decisions, simulate mid-term decisions such as hydro dispatch and outages and emulate day-ahead and real-time markets. PJM Markets modeled include energy scheduling by resources, load forecasts, balancing, reserves and ancillary services. Capacity Expansion Planning was deployed to calculate the least cost bundle of resources include the Smart Wires configuration including generation resource, transmission line and interface expansion over long timeframes using mixed integer programming. PLEXOS' LT Plan module also allows for optimization of long term investment decisions over time as well as selecting the lowest cost options for meeting a market need. In this study, LT Plan was used to identify cost-effective transmission enhancements. Figure 6 shows the data and modeling process for this study.

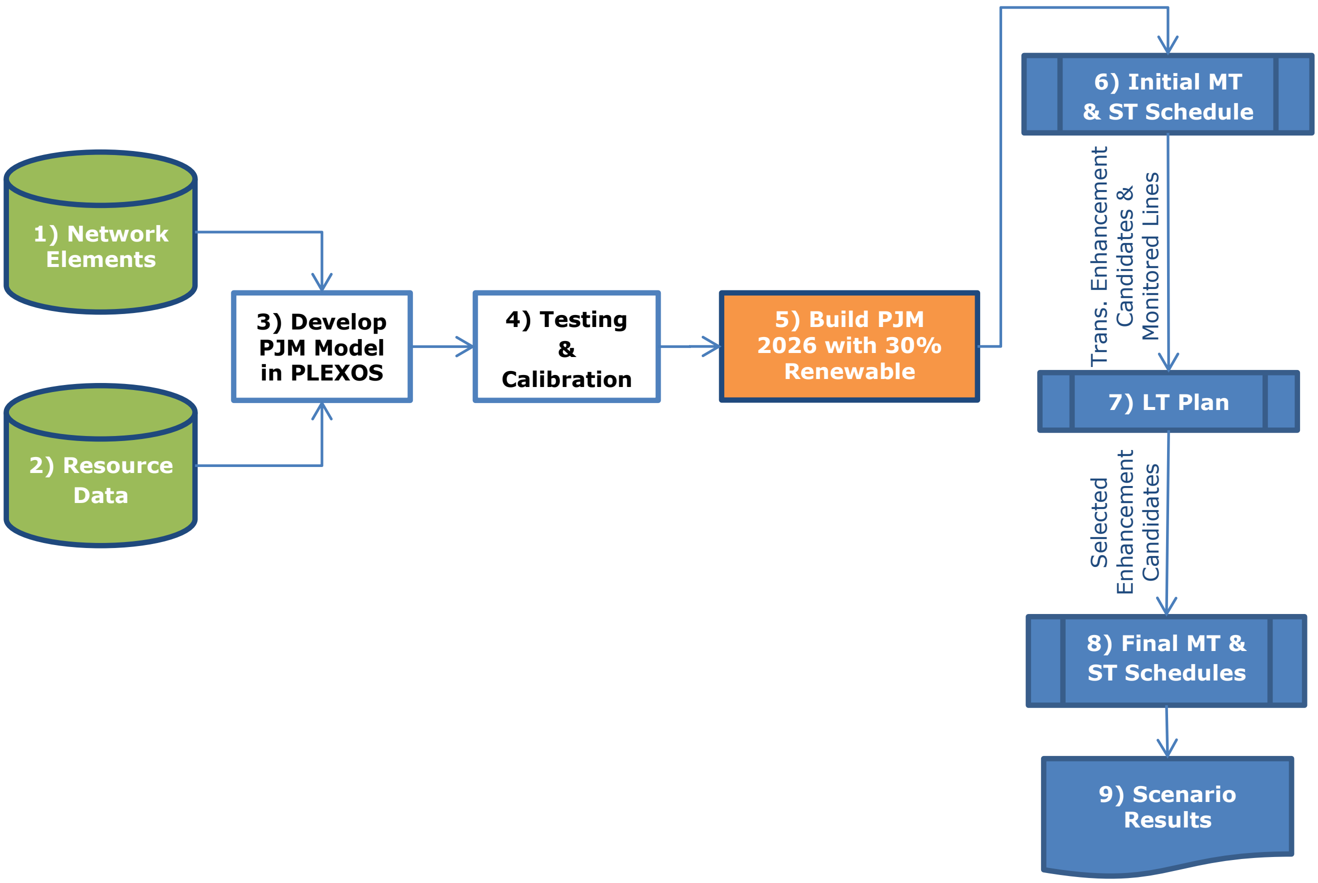


Figure 6 Model Steps

As shown in Figure 6 the underlying data, assumptions and analysis consists of nine main components:

1) **Transmission network elements** from the Eastern Reliability Assessment Group Multiregional Model Working Group data for use in the project, as of summer 2015.
2) **Resource databases** for generators, load and transmission in PJM from ABB's North American Reference Case as well as DNV GL research.
3) **PJM market model.** DNV GL developed a representation of the PJM market in PLEXOS with full nodal transmission detail for the PJM market and a simplified representation for adjacent market areas. Generators in the adjacent areas are aggregated by generator type and fuel to reduce model execution time.
4) **Model calibration.** The PJM model was benchmarked against 2014 and 2015 actual conditions to verify that the market representation aligns with observed prices and transmission flows.
5) **Build PJM 2026 Model:** In this step, planned renewable resources are integrated to PJM Import/Export model. In order to meet 30% LOBO renewable penetration, extra renewable resources are added to the model. In addition, planned transmission enhancements are added to the

model and load profiles and fuel prices are updated. More detail on the enhancement process is provided in sections 2.1.2 and 2.1.3.

6) **Initial Medium Term (MT) & Short Term (ST) Schedule**. The MT schedule optimizes medium to long term decisions, primarily this means managing hydro storage and fuel supply. MT Schedule solves this problem by decomposing medium term constraints, which would otherwise have to be approximated or ignored by ST Schedule, into constraints short enough that ST Schedule can handle. Following the completion of the MT schedule, the full-scale SCED analysis is performed with a full nodal representation of the PJM system. The initial MT and ST schedules are performed to find the potential candidates for transmission enhancements. Also, due to complexity of planning phase, the number of lines with transmission limit enforced needs to be limited. Transmission lines with loading over 85% are considered as transmission enhancement candidates.

7) **Long Term (LT) Plan.** Using PLEXOS LT Plan feature, DNV GL modeled all the transmission enhancement alternatives to find transmission enhancements that are economically viable and that are likely to resolve local and regional congestion, including deploying Smart Wires. The LT Plan allows for a representation of emissions, fuel constraints, and ancillary services that is consistent with MT and ST Schedules. DNV GL's methodology included the use of a partially chronological modeling approach using the load duration curve feature of LT Plan with 24 load blocks, one for each hour, and a total of 12 load duration corves considered, one for each month.

8) **Final MT & ST Schedule**: The transmission enhancement, including conventional and Smart Wires enhancements, selected in LT Plan are added to the model and final set of MT & ST Schedules is performed.

9) **Scenario Results**: Results from the studied scenarios are processed.

2.1.2 Transmission Elements, Operations and Expansion

2.1.2.1 Transmission Elements

DNV GL relied on the North American Power Database provided by ABB to develop a PLEXOS database of load and generation resources in PJM and surrounding areas. Power flow data from PJM's RTEP model was used to develop the PJM network model, including contingencies and monitored lines.

The RTEP transmission network model is managed by PJM on behalf of its members includes transmission lines and elements for voltage levels of 100 kV and above. Transmission less than100 kV[4] are not normally operated in a networked manner and with no capability to do so are considered distribution facilities and are not analyzed in this study.

Detailed modeling of the transmission system can be complex and was therefore simplified for this study by using a Direct Current (DC) power flow model. It is assumed that there are no transient changes in power flow or voltage due to load or generation changes. The system frequency is also assumed to be constant[5].

[4] See www.nerc.com for guidance on transmission/distribution operations.

[5] Wood and Wollenberg, Power Generation Operations and Control. Also, Grainger, J.; Stevenson, W. (1994). Power System Analysis. New York: McGraw–Hill. ISBN 0-07-061293-5.

The modeling topology includes all areas in PJM, including a complete representation of generators, transmission and load. The same detailed representation was also modeled for control areas on the PJM border. Other areas of the eastern interconnect we included in the model but were modeled in a simplified manner by aggregated load and generation within each of these surrounding areas, as shown in Figure 5.

2.1.2.2 Transmission Operations

Transmission elements modeled include branches from substation to substation, resistance, reactance, flow limits, and contingencies (N-1) consistent with the DC model adopted. In the PJM import/export model. The MW flow limit across each branch based upon reactance of the line. Two limits are used: normal operating limit and emergency limit. The NERC-defined term System Operating Limit (SOL) is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria established by the system operator under guidance by the North American Electric Reliability Commission. These criteria include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)[6]

Transmission branch emergency limits (governed under NERC guidelines) are also established for each branch limit to allow short term operations above the normal limit to ensure reliability[7]. In the PJM import/export model, emergency limits are used when checking for violations of line thermal limits post-contingency in the SCED. Thermal limits were enforced only for the transmission lines selected as candidates for expansion and interfaces with neighboring areas (the initial set of candidates was determined based on congestion as described in Section 2.2 of this report).

The PJM import/export model is a full set of time steps during the 2026 Study year for 8760 hours.

2.1.2.3 Transmission Enhancements

The RTEP Transmission Construction Status list[8] is used to add the planned transmission enhancements to the network. The upgrades identified in the RTEP include substations, transmission lines, transformers, circuit breakers and select distribution enhancements. DNV GL incorporated relevant system upgrades into its study, including transmission lines, transformer and substation enhancements above 115 kV planned to be in service by 2026. Projects listed in the RTEP with a status of "pending/hold" were not included in the transmission expansion plan used for the present study.

[6] www.nerc.com. Glossary of reliability terms. Note that the DC representation of the PJM import/export model does not model transients, voltage stability and voltage limits.

[7] www.nerc.com. System Operating Limit Definition and Exceedance Clarification.

[8] http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx

2.1.3 Resources Required to Meet Load Obligations

2.1.3.1 New and retiring fossil generation

DNV GL identified the type and amount of additional thermal generation needed to meet resource adequacy requirements, defined as a 15% reserve margin across PJM. If more generation was needed, Simple Cycle Gas Turbines (SCGT) and Combined Cycle Gas Turbines (CCGT) generation capacity was added in same ratio as the PRIS (85% SCGT and 15% CCGT). New generation was sited by balancing area in proportion to the new generation deployment required in PRIS. When possible, new generation was sited at the locations of power plants that have retired or are scheduled to retire, according to PJM data. The generation sited at each retiring power plant was constrained so as not exceed the highest historical rating of that power plant. If additional generator sites were required, they were sited on the highest voltage buses within the balancing area with no more than 500 MW of new generation per bus[9].

2.1.3.2 Existing and planned wind and solar generation

Total capacity of renewable resources (onshore wind, offshore wind, and solar) was modeled according to the 30% Low Offshore, Best Sites Onshore (LOBO) case of the PRIS. DNV GL allocated and simulated the output of individual plants according to a three-step process.

1. Plants that are currently online were identified in the database of the production cost software PROMOD. Hourly profiles for these plants were simulated by identifying the nearest Eastern Wind Integration and Transmission Study (EWITS) site of the appropriate resource type and scaling the 2006 EWITS profile to the correct plant capacity.

2. All wind/solar plants in the PJM queue were included. Hourly profiles were again generated by scaling the nearest 2006 EWITS profile to plant capacity. Plants were associated with the bus documented in the queue.

3. Additional generic capacity for all types of renewable resources was necessary to fulfill the renewable portfolio modeled in the 30% LOBO PRIS case. No additional capacity was allocated to states whose combined existing and queued generation capacity exceeded the assumed capacity in the PRIS. For states that were not excluded by this condition, the EWITS sites of highest capacity factor were identified and scaled to 500 MW plants for wind and 100 MW plants for solar. EWITS sites were added, in order of capacity factor, up to each state's renewable energy allocation in the PRIS and until the overall renewable energy requirement was met. Since some states had existing and queued capacity that exceeded their renewable allocations in PRIS, other states were assigned less capacity than assumed in PRIS in order to meet the overall renewable energy requirement of the PJM region as a whole.

Based on using the approach explained above, Table 2 shows the resulting renewable energy production for 2026 by state and renewable resource type. A maximum of four 500 MW wind plants were assigned to each bus of over 300 kV, and a maximum of two 500 MW wind plants were assigned to each bus between 100 and 300 kV. Table 2 also shows the development status of the capacity model. Capacity labeled "queue"

[9] In the contingency analysis, two additional analyses were performed, following PJM's transmission planning criteria. A net generation deliverability test was performed to ensure sufficient thermal capacity from injection bus. Secondly, contingency analysis was performed and new monitored lines were added to the final results. In the PJM import/export model, interchange was assumed to follow PRIS assumptions.

indicates that this is a resource under development today and "generic" indicates a new resource that is not yet under development.

Table 2 Renewable Energy Production (in GWh) Assumed for 2026

State	Onshore wind				Solar				Offshore wind		
	Existing	Queue	Generic	**Total**	Existing	Queue	Generic	**Total**	Queue	Generic	Total
DE	0	0	0	**0**	38	13	0	**51**	783	3,294	**4,032**
IL	12,815	3,378	108,920	**125,113**	42	229	0	**271**	0	0	**0**
IN	11,413	1,830	35,788	**49,031**	16	29	0	**29**	0	0	**0**
IA	0	0	19,88	**1,988**	0	0	0	**0**	0	0	**0**
MD	1,029	399	0	**1,428**	80	3240	0	**3,320**	761	0	**761**
MI	0	0	1,771	**1,771**	0	0	0	**0**	0	0	**0**
NC	0	615	0	**615**	70	1731	0	**1,801**	0	4927	**4,927**
NJ	0	0	0	**0**	460	11,084	0	**11,544**	1,284	11,238	**12,522**
OH	1,377	2,007	6,582	**9,966**	46	940	0	**940**	0	0	**0**
PA	4,093	1,437	3,367	**8,896**	52	311	0	**311**	0	0	**0**
VA	0	272	1,712	**1,984**	0	2,358	2,981	**5,339**	35	1,626	**1,661**
WV	1,792	388	3,422	**5,602**	0	0	0	**0**	0	0	**0**

DNV GL used wind and solar profiles by region provided by EWITS. All resources, including renewable energy, load and thermal resources were modeled using a deterministic model.

2.1.3.3 Distributed solar generation

Distributed solar capacity was allocated to each state in PJM using the same capacities as in the PRIS. To model the distributed solar profiles, the EWITS distributed solar profiles were added together for each state and scaled to the capacity assigned for the state in the PRIS report. Distributed solar output was modeled as negative load in order to account for the fact that it is interconnected at lower voltages than modeled in this study. State-level distributed solar capacity was allocated to each area of PJM according to that area's approximate load factor.

2.1.3.4 Other modeling assumptions

Regulation reserves were determined externally to the model using the same methodology as in the PRIS by expressing hourly regulation needs as a function of forecasted load, renewable power output, and total renewable energy capacity. Assumptions on demand-side management/load acting as a resource were adopted from the ABB/Ventyx database, as were planned and forced generation outages.

2.1.4 Load Forecast

To model a projected hourly load profile for 2026, 2014 historical hourly load was scaled to projected peak and average values for 2026 obtained from the North American Reference Case, which in turn is based on load forecasts filed by utilities with the EIA and FERC. Load was scaled according to the following equation:

$$l_i^{2026} = m^{2026} + \frac{\left(\frac{l_i^{2014}}{m^{2014}} - 1\right)(p^{2026} - m^{2026})}{\frac{p^{2014}}{m^{2014}} - 1}$$

in which superscripts indicate years, *l* indicates hourly load, *m* indicates monthly average load, *p* indicates monthly peak load, and subscript *i* indicates hour. This equation produces the correct peak and average loads for 2026 while maintaining the overall hourly load shape of the historical data. Figure 7 shows the expected annual load for 2026 as a load duration curve and Figure 8 provides a monthly overview of PJM total energy demand and monthly peak load for 2026. The annual load forecast for 2026 is 926,150 GWh, slightly lower than the PRIS forecast of 969,596 GWh.

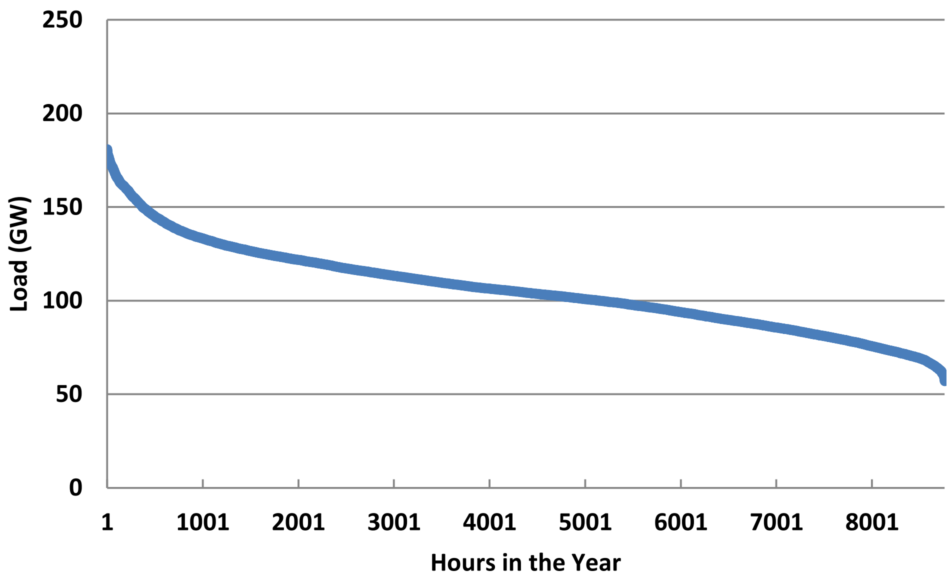


Figure 7 PJM 2026 Load Duration Curve

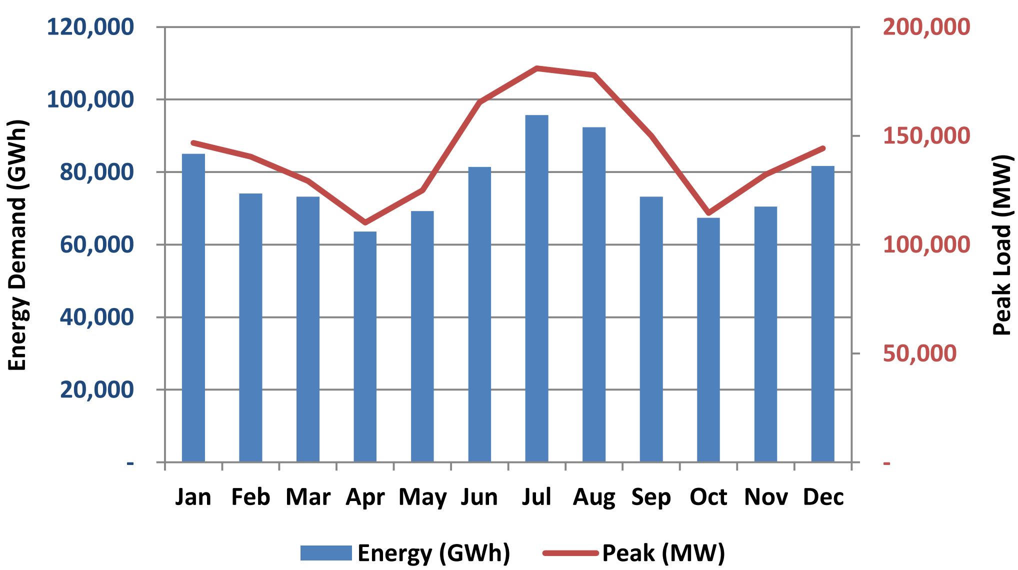


Figure 8 PJM 2026 Monthly Energy and Peak

2.1.5 Fuel Prices

Fuel prices used for the study were based on forecasts from EIA's annual energy outlook for 2015 as well as on the coal, oil and nuclear price forecasts embedded in ABB's North American database. In PJM, coal and natural gas are the key fuel sources for generators on the margin (setting the power price). Table 3 shows the expected Henry Hub gas prices and the average coal price in PJM for 2026. All fuel prices in the modeling database are burner tip prices that include transportation costs in accordance with historical transportation rates and pipeline basis differentials. Figure 9 shows the expected seasonal variation in natural gas prices as well as the difference in regional gas prices within PJM.

Table 3 Fuel Prices

Fuel Type	Nominal Price	Source	Comments
Natural Gas	7.2 ($/MMBtu)	EIA 2015 Annual Energy Outlook	Henry Hub Price; Regional differentials are derived from ABB historical data
Coal	2.60 ($/MMBtu)	ABB Energy Velocity Forecast	Adjusted to reflect regional price differences ($1.15 to $6.48) per ABB historical usage data

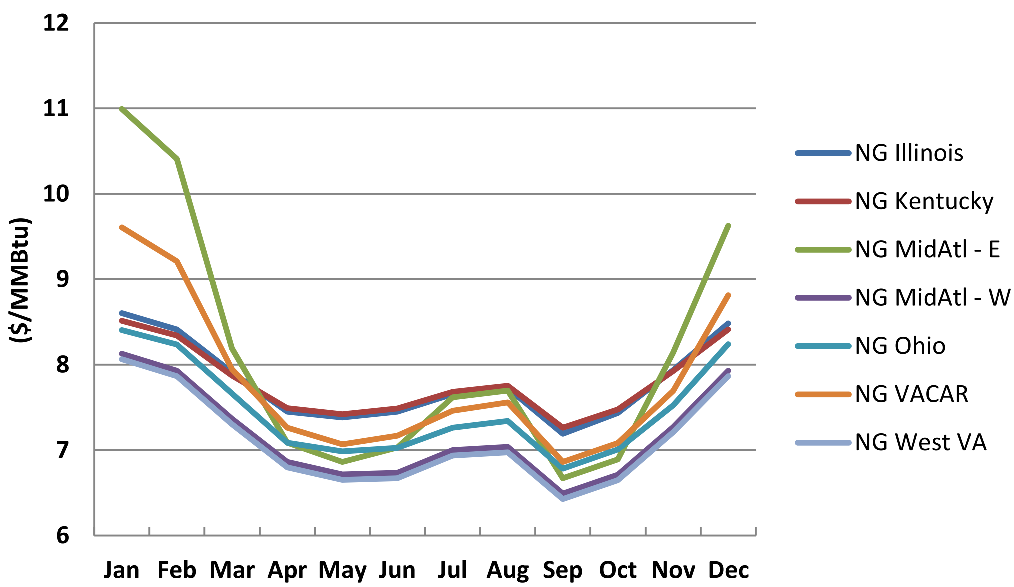


Figure 9 Monthly PJM Natural Gas Prices in Nominal Dollars ($/MMBtu)

2.2 Transmission Enhancements with and without Smart Wires

DNV GL used PLEXOS' LT Planning tool to identify optimal transmission enhancements to minimize the overall combined costs for operating the PJM system and annual transmission investment costs. Enhancements consisted of line uprates, adding additional circuits to an existing line, adding a line in parallel to an existing line and for the Smart Wires case, deploying Smart Wires devices. As part of determining optimal transmission enhancement, DNV GL also modeled the PRIS transmission upgrades and new lines as options that could be selected as part of the optimization. To identify potential candidates to consider for transmission enhancements, DNV GL used the following five steps with the objective of allowing the LT Planning tool to eliminate all major transmission congestion points if cost effective to do so:

- The PLEXOS ST Schedule was used to perform hourly SCED modeling for PJM for one typical week per month, wherein the thermal limits were enforced on all transmission lines and transformers and the most critical historical N-1 contingencies enabled.
- A line with a voltage of 115 kV or above was considered a candidate for transmission enhancement if the pre-contingency flows or the post-contingency flows exceeded the line rating.
- In addition to the transmission enhancements identified per the above methodology, DNV GL also included all of the transmission elements that were identified in the PRIS 30% LOBO scenario as candidates for transmission enhancements. In several cases, these candidates represent new lines between two substations that were not previously served by a direct connection.
- To determine the type of transmission enhancement to be applied for each line, DNV GL used the following criteria:
    - For transmission lines where the existing maximum rating is lower than the average MVA for the voltage class, reconductoring was the only conventional enhancement considered.
    - For existing transmission lines where the existing maximum rating is higher than the average MVA for the voltage class, it was assumed that the upgrading of the line would be done as a second (or third) parallel circuit that utilizes existing transmission infrastructure and therefore has a lower cost than a new transmission line for a new circuit.

The above steps were repeated until the congestion component between two nodes of a constraint was smaller than $5/MWh on an annual average basis, resulting in a final set of 220 transmission lines that were considered as candidates for transmission enhancements.

2.2.1 Transmission Line Construction Costs

The LT Plan input for transmission line enhancements includes capital costs for transmission enhancements (build cost), economic life and the weighted average capital cost (WACC). Although DNV GL ran the LT Plan only for 1 year, the Economic Life and WACC are added as inputs to be consistent with LT Plan data structure. The Economic Life of new transmission assets was assumed to be 30 years and the WACC was assumed to be 15%.

Table 4 shows the transmission enhancement costs that were used in the study. Since there is limited recent transmission cost data available for PJM, DNV GL used a combination of data from recent studies in PJM, ERCOT (for the CREZ projects) and DNV GL's own research and experience from other projects. For transmission enhancement voltages and types where no data was found, DNV GL used inferred values from other voltage classes. The costs were converted to 2026 values using an inflation factor of 1.85%.

Table 4 Transmission Line Build Cost

Source	Year	Voltage	Type	Rural Cost (M$/mile)	Urban Cost (M$/mile)	Base Year Cost (M$/mile)	2026 Build Cost (M$/mile)
PJM[10]	2010	230	New line	-	-	2.00	2.68
DNV GL	2010	230	Add additional circuit to existing right-of-way	-	-	0.50	0.67
DNV GL	2010	230	Add new double circuit	-	-	2.50	3.35
DNV GL	2010	230	Reconductoring of existing line	-	-	0.90	1.21
ERCOT	2012	345	New line	1.95	3.25	2.60	3.36
ERCOT	2012	345	Add additional circuit to existing right-of-way	0.56	0.64	0.60	0.78
ERCOT	2012	345	Add new double circuit	2.44	4.10	3.27	4.23
ERCOT	2012	345	Reconductoring of existing line	0.72	1.43	1.08	1.39
ERCOT	2012	500	New line	2.7	-	2.70	3.49
DNV GL	2012	500	Add additional circuit to existing right-of-way	-	-	0.68	0.87
ERCOT	2012	500	Add new double circuit	2.98	-	2.98	3.85
DNV GL	2012	500	Reconductoring of existing line	1.215	-	1.22	1.57

10 Brattle report for PJM, exact reference TBD

Brattle	2010	765	New line	-	-	6.60	8.85
DNV GL	2010	765	Add new double circuit	-	-	8.25	11.06
DNV GL	2010	765	Add additional circuit to existing row	-	-	1.65	2.21
ERCOT	2012	138	Add additional circuit to existing right-of-way	0.27	0.40	0.34	0.43
ERCOT	2012	138	Reconductoring of existing line	0.59	0.87	0.73	0.94
DNV GL	-	115	Add additional circuit to existing right-of-way	-	-	-	0.36
DNV GL	-	115	Reconductoring of existing line	-	-	-	0.79
DNV GL	-	160	Add additional circuit to existing right-of-way	-	-	-	0.60
DNV GL	-	160	Reconductoring of existing line	-	-	-	1.09

2.2.2 Description of Technology and Modeling

Smart Wires power flow control solutions are built upon two key technologies: The Guardian and the Router. The Guardian injects magnetizing inductance to increase line impedance and “push” power to electrically parallel lines. The Router leverages and builds upon the proven innovations of the Guardian technology – it utilizes the same communications package, transformer, controller and systems protections, but has the added feature of an electronic injection unit (EIU). The EIU produces a variable leading or lagging waveform which is coupled through the transformer to generate a synthesized capacitance or inductance as needed.

Smart Wires products have been operating in the field on utility transmission lines since 2012 and are currently deployed at Pacific Gas & Electric, Tennessee Valley Authority, Southern Company and EirGrid on transmission line voltages of 230 kV, 161 kV, 115 kV and 110 kV respectively.

The Router technology is modeled in PLEXOS as a derivative of the existing Phase Shifter class, with operating limits updated to reflect the capabilities of the Router, namely the ability to modify the level of injection on command without degrading the unit.

Candidate transmission elements for Smart Wires Router deployment were based on the following criteria:

- Candidate element is overhead for at least some fraction of its length, with the criteria the line must be overhead for at least a single span.
- Candidate element is within PJM
- Candidate element has a voltage between 100 kV and 500 kV inclusive

- Candidate element is not a jumper, with jumper defined as an impedance of 0.0002 pu or less
- Candidate element is not a transformer

2.2.3 Calculating Smart Wires Costs

The cost to deploy the Smart Wires Router technology on transmission lines is calculated using a propriety formula that considers the full cost of the deployment. The full cost includes the cost of the devices, deployment method, engineering, installation and commissioning. DNV GL considered four configurations of the Smart Wires technology for the study: +/- 1, +/- 4, +/-8, +/- 16 degree of control. Each of these configurations were considered as enhancement options that can be deployed as a stand-alone option or in combination with other Smart Wires configurations on the same transmission line, resulting in a potential maximum control of +/- 29 degrees on any line that is a candidate for Smart Wires deployment.

2.3 Simulate PJM in 2026

DNV GL followed the steps described in 2.2 to find a set of candidates for transmission enhancement and the build cost related to each enhancement. Summary statistics for the candidate enhancements are summarized in Table 5.

Table 5 LT Plan Candidates Summary

Enhancement Type	Build Cost (k$)	Length (miles)	Count
New 2nd Circuit	1,221,405	1578	97
New 3rd Circuit*	41,060	53	2
Reconductoring of Existing Line	4,405,518	2082	121
New Single Circuit	9,926,911	1260	13
New Double Circuits	5,427,699	522	6

*A transmission enhancement was considered 3rd circuit if the existing double circuit line was congested and therefore a candidate for incremental upgrade

The PLEXOS LT Plan modeling was performed using between 20 and 200 load blocks per month with the objective of minimizing the sum of production cost and annual investment costs of transmission enhancements. Two scenarios were modeled – one scenario where only conventional transmission enhancements are considered and one where both Smart Wires and conventional enhancements are considered. For the scenario without Smart Wires, the build options consist of:

a) All of the transmission elements that were identified in the PRIS 30% LOBO scenario

b) Reconductoring of PJM lines where existing rating is less than average MVA for a line of that voltage class.

c) New parallel transmission line of the same voltage if the existing PJM line rating is higher than average MVA for a line of that voltage. As described in Section 2.2.1, the new parallel line may be adding a new circuit to an existing line or building a new line.

For the second scenario, Smart Wires PFCs with four build options are added to the above transmission lines, except for jumpers and transmission lines above 500 kV. LT Plan finds the optimal set of enhancements candidates among the pool of both conventional transmission enhancements and the Smart Wires build option.

In the LT Plan modeling, contingencies were enforced for transmission elements at or above 230 kV. LT Plan problem size with a full nodal network is for PJM model is too large. To reduce complexity, the number of transmission lines with enforce limit is limited to the enhancement candidates and major interfaces with neighboring areas. In addition, both the LT Plan and the ST Schedule modeling are deterministic and do not account for intermittency or other variability of the renewable resources that were included in the analysis.

3 RESULTS

DNV GL performed a comprehensive analysis for PJM model in 2026, considering 30% LOBO scenario of PRIS, in two phases of planning and operations. For the planning phase, it is assumed that generation expansion is determined to source 30% of annual electricity from renewable sources as described in 2.1.3. Transmission expansion is then optimized to minimize the investment and operational costs. Smart Wires PFCs are added as an alternative for conventional transmission enhancements to further reduce the investment cost. PLEXOS LT Plan tool is used to implement the planning phase. Due to the size of the PJM system, DNV GL performed a large number of iterative modeling attempts to find a balance between simulation feasibility, simulation time and accuracy. A summary of these iterations is provided in the Appendix to this report. As described in Section 2 of this report, two main scenarios were considered:

Conventional Transmission Enhancements. The first scenario considers optimal transmission enhancements and system costs of using only conventional transmission system enhancements to facilitate sourcing 30 percent of annual electricity from renewable energy in the PJM market by 2026.

Smart Wires. The second scenario considers *both* conventional transmission enhancements *and* Smart Wires under the same 30 percent renewable energy scenario.

This chapter summarizes the key findings from the analysis, including potential cost savings of considering Smart Wires as a complementary transmission enhancement option.

3.1 LT Plan Results

LT Plan modeling was performed for the year 2026 to find the optimal combination of transmission enhancements. LT Plan results for the two enhancement scenarios are summarized in Table 6. The candidates are categorized by voltage level. It can be seen that about half of the enhancement candidates are for 138 kV voltage levels that were not considered in PRIS (the PRIS study did not consider reinforcements below 230 kV). Also, the selection of 765 kV has a large impact on the total investment cost.

Table 7 illustrates the LT Plan results summary for the Smart Wires PFCs in the second scenario. DNV GL found that the LT Plan simulation engine is very sensitive to the degree of control assumed for Smart Wires, where simulation time increases dramatically as higher degrees of control are introduced. A comparison of results for two methods to choose the build options is summarized in Appendix.

Transmission enhancement results including cost, number and total length of added lines for both scenarios are summarized in Table 8. For the second scenario, where Smart Wires PFCs replace 26% of conventional enhancement length, the total enhancement cost is decreased by nearly 50% ($1.8B).

Table 6 LT Plan Results Summary for Conventional Enhancements Categorized by Voltage

	Voltage (kV)	Total Build Cost of Selected Lines (k$)	Total Length of Selected Lines (miles)	Number of Candidates	Number of Candidates Selected
Conv. Enhancements	765	$3,363,980	384.58	14	4
	500	$0.00	-	4	-
	345	$313,007	387.76	56	19
	230	$68,836	92.50	27	6
	160	$23,876	39.63	6	4
	138	$204,997	334.83	123	47
	115	$8,157	16.70	10	2
Smart Wires	765	$1,136,803	175.16	14	2
	500	$0.00	-	4	-
	345	$288,020	371.38	56	17
	230	$65,969	90.08	27	4
	160	$23,876	39.63	6	4
	138	$122,305	215.93	123	30
	115	$20,183	34.83	10	5

Table 7 LT Plan Results for Smart Wires PFCs

Build Angle Option	Voltage (kV)	345	230	160	138	115
	Number of Transmission Line Candidates for Smart Wires PFC Deployment	51	26	6	119	10
+/- 1	Number Selected	6	6	6	51	6
	Build Angle	4.55	5.24	5.12	47.16	6
+/- 4	Number Selected	5	2	5	35	4
	Build Angle	16.36	8	20	116.16	11.96
+/- 8	Number Selected	3	2	4	27	2
	Build Angle	14.56	16	32	114.56	13.6
+/- 16	Number Selected	1	1	2	0	0
	Build Angle	0.88	2.72	16.03	0	0

Table 8 Transmission Enhancement Summary

Enhancement Length/Cost	Conventional Enhancements	Smart Wires
Circuit-Miles Reconductored	159	88
Circuit-Miles of New Line Build (Including construction of a new circuit in parallel with an existing circuit)	1,096	838
Number of Lines Reconductored	22	15
Number of New Lines Built	60	47
Number of Lines With Smart Wires Devices Installed	-	173
Total Annual Cost of Conventional Transmission Enhancement (M$)	597	248
Total Annual Cost of Smart Wires PFCs (M$)	-	81
Total Annual Cost of Transmission Enhancement (M$)	597	329
Total Enhancement (M$)	3,982	2,199
of which is Smart Wires PFCs (M$)	-	540

3.2 Location Marginal Price and Congestion in Base Case

The impact of transmission enhancements on average hourly PJM prices for selected areas is illustrated in Figure 10. Higher renewable penetration resulted in reduction is thermal generation and lower marginal prices. However, in the ComEd area, where the majority of onshore wind is located, high congestion in the scenario without transmission enhancements resulted in extreme prices differences and low prices due to high renewable energy generation. With transmission enhancements, the marginal prices are improved as the congestion is reduced.

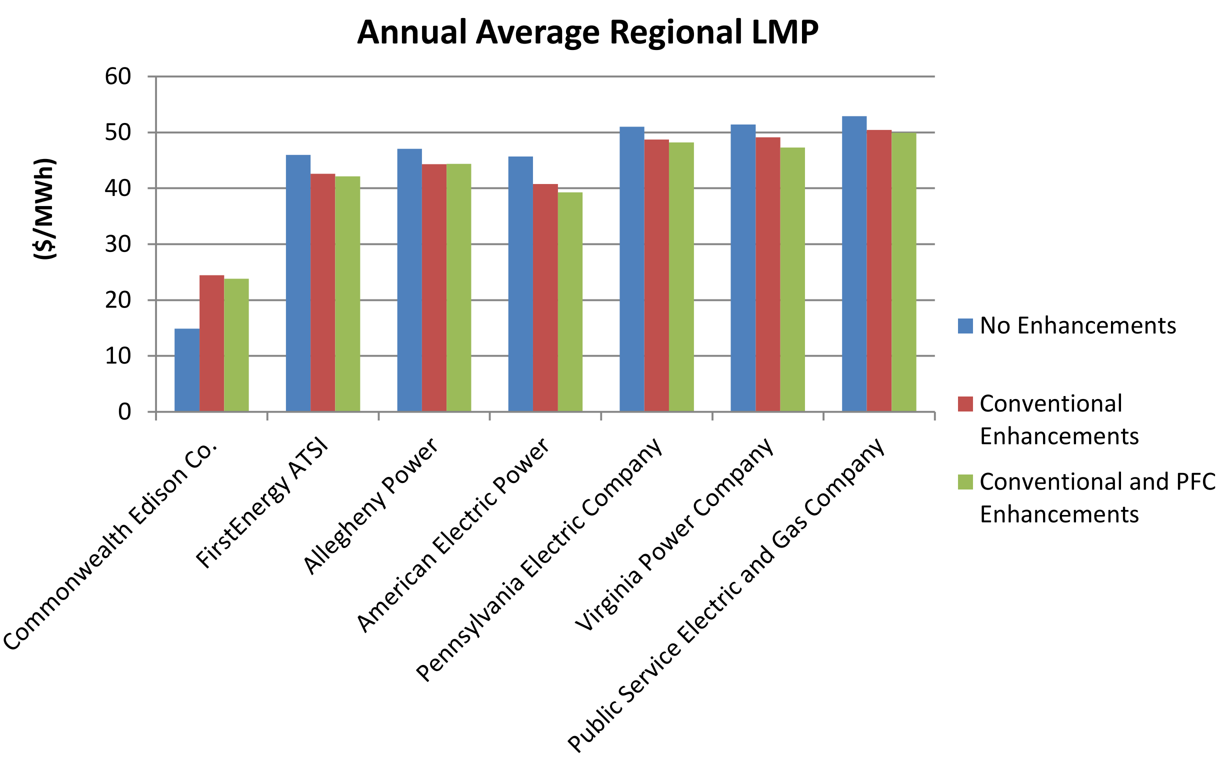


Figure 10 Annual Average Regional LMP for Selected Regions

3.3 Production Cost Savings

The Production Cost and Load Cost for the two enhancements scenarios are compared with the scenario without any transmission enhancements. Investment and operational saving are shown in Figure 11. For the combination of conventional and Smart Wires PFC enhancements, although the investment is 45% less than the conventional enhancement scenario, 3% more saving in Production Cost and 2% more saving in Load Cost is observed.

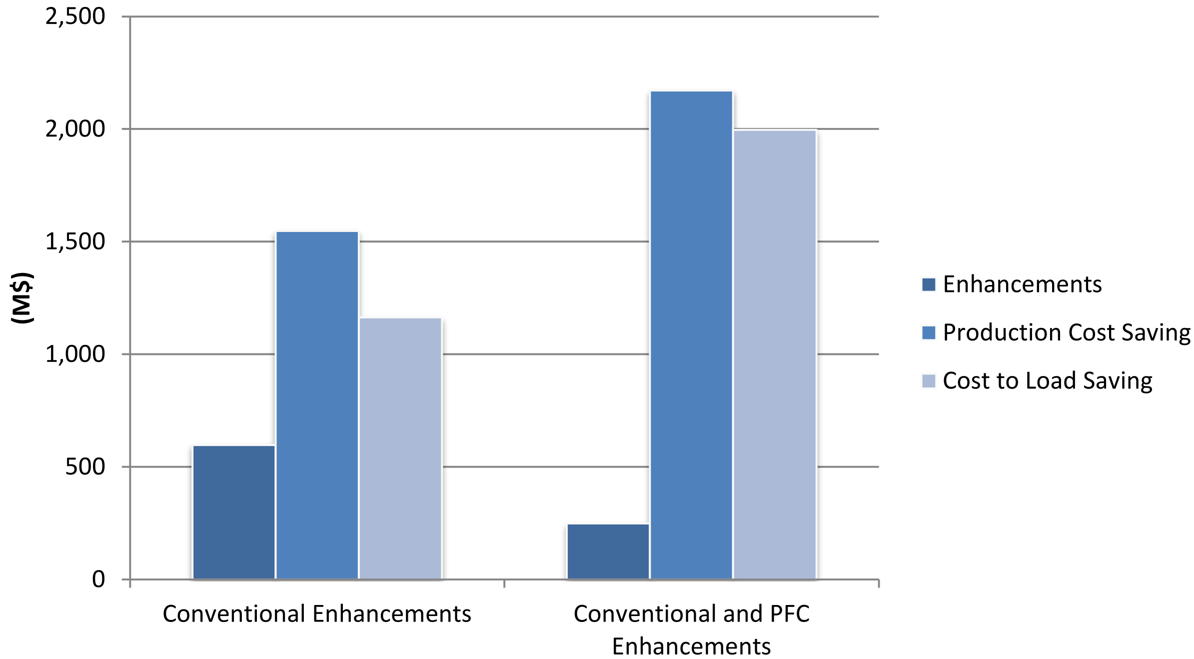


Figure 11 PJM Enhancements and Operation Saving

4 CONCLUSIONS

In this study, DNV GL examined the economic viability and applicability of Smart Wires' power flow controls to relieve transmission congestion in the PJM market model with high penetration of renewables. The study used similar assumptions to those used for the PRIS and assessed the benefits of the Smart Wires controls under a case where 30 percent of annual electricity was sourced from renewable energy in the PJM market in 2026. DNV GL utilized one of the PRIS scenarios as a starting point, the Low Offshore, Best Onshore (LOBO) scenario, which includes onshore and offshore wind as well as significant solar resource developments.

The detailed model for production cost modeling is built considering 2026 system changes announced by PJM and fuel and load forecasts. DNV GL followed PRIS to add extra generation capacity to meet the 30% renewable energy level. To ensure an optimal balance between production cost and transmission investment, transmission enhancements were selected through LT Plan, the PLEXOS optimization tool for planning.

Results show that Smart Wires flow control devices could reduce the investment in transmission system enhancements by 50% or more, resulting in savings of $1.8 B. In addition, despite the finding that the scenario with Smart Wires required 50% less transmission investment, the Smart Wires scenario had an operational cost savings of more than $600 million per year relative to the scenario with conventional transmission enhancements alone. Even though these results suggest the potential for dramatic cost savings when Smart Wires is considered, the estimated savings are likely conservative for a number of reasons:

- A more detailed transmission study is likely to identify additional system enhancements that are cost effective and therefore could contribute to further strengthening the value of Smart Wires flow control technology. For example, the results of this study show that renewable energy is likely to be curtailed for about 6% of its potential energy output, suggesting that further transmission enhancements may be warranted.
- Capacity market savings are not considered

It should be noted that the capacity market was not modeled. Given that wind and solar generation tends to decrease LMPs, capacity markets prices may increase to ensure thermal generation has sufficient revenue to avoid retirement.

DNV GL also notes that the results shown in this report in terms of reducing investment costs and cutting operational costs for PJM are likely to hold for other transmission systems as well, especially in cases where there are options to substitute large high voltage transmission enhancements (345 kV and above) with a larger number of transmission enhancements on lower voltage lines.

APPENDIX

Following are the two methods used to find the LT Plan solution:

1. Four build options (+/-1, +/-4, +/-8, +/-16): in this case 4 PFC candidates are considered for each line. Due to the large number of PFCs with large build angles, the LT Plan complexity is very high. To reduce the complexity, build options are added in 4 steps starting with only +/-1. Next, the lines that are not selected for the first build option are removed from the list of candidates for the higher build options. The same approach is applied for the next options.
2. One build option (+/-30): the number of PFCs is limited to 1 for each line in case, however, the large build option resulted in very complex LT Plan and very time consuming to be solved.

The results for these two approaches are summarized in Table 9. The two methods resulted in approximately the same investment cost for conventional enhancements, while the Smart Wires PFC enhancement cost is about 20% higher for +/-30 build option case. To compare the operational metrics for two methods, ST schedule is performed and the results are summarized in Table 10. Higher investment resulted in more saving in operational costs but the curtailment is increased.

Table 9 LT Plan Results Summary for 2 Smart Wires PFCs Selection Methods

	Enhancement Length/Cost	Smart Wires with +/-1,+/4 ,+/-8,+/-16 Build Options and Conventional Enhancements	Smart Wires with +/-30 Build Option and Conventional Enhancements
a)	Circuit-Miles Reconductored	88.91	111.65
b)	Circuit-Miles of New Line Build (Including Construction of a New Line in Parallel With an Existing Line)	838.10	814.35
c)	Number of Lines Reconductored	15	17
d)	Number of New Lines Built	47	48
e)	Number of Lines With Smart Wires Devices Installed	173	55
f)	Total Annual Cost of Conventional Transmission Expansion (M$)	248.57	249.41
g)	Total Annual Cost of Smart Wires Devices (M$)	81.28	97.83
h)	Total Annual Cost of Transmission Expansion (M$)	329.86	347.24
i)	Total Investment (M$)	2,199.03	2,314.93

Table 10 ST Schedule Results Summary for 2 Smart Wires PFC Selection Methods

Operational Metrics and Investment Cost	Smart Wires with +/- 1,+/4 ,+/-8,+/-16 Build Options and Conventional Enhancements	Smart Wires with +/- 30 Build Options and Conventional Enhancements
Production Cost Saving (M$)	2,170.53	2,309.70
Cost to Load Saving (M$)	1,996.04	2,119.09
Curtailment (%)	5.75	6.03

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