Assessment of Transmission Constraint Costs : Northeast U.S. Case Study

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Abstract

This paper provides a methodology to examine the impact of transmission constraints on the efficient operation of large scale power markets. The Northeast U.S. is presented as a case study. A system model was first constructed using the publicly available U.S. Federal Energy Regulatory Commission (FERC) Form 715 filings to provide a detailed representation of the transmission system. FERC Form 1 data and information from the U.S. Energy Information Administration's (EIA) National Energy Modeling System model were used to represent generator costs. An optimal power flow (OPF) was then used to optimally dispatch a large system consisting of the New England Region (NEPOOL), New York (NYPP), and the NERC MAAC and ECAR regions, both under base case and modified conditions. Using the OPF results, the costs associated with transmission constraints are determined. Finally, given the large amount of data generated by these studies, methods for the efficient visualization of the results are also discussed.

Keywords: Restructuring, Power System Economic Analysis, Power System Visualization

1. Introduction

Electricity markets throughout the world continue to be opened to competitive forces. The underlying objective of introducing competition into these markets is to make them more efficient. Ideally, if fair and equitable market structures are created, which give all market participants incentives to maximize their own individual welfare, then the market as a whole should behave in a manner which maximizes the net welfare to society. However in order to access the efficiency of the markets and to forecast energy prices throughout the market it is expedient to be able to model the expected optimal behavior for these markets.

Deregulation of electric power generation in the United States was partially motivated by persistent regional price differences. For example, the average cost of electricity to residences in New York in 1995 was 11.1 cents a kilowatt hour but was only 6.2 cents in Ohio. For industrial customers the comparison was 5.8 cents in New York and 4.2 cents in Ohio. The cost differences per kilowatt between the adjoining states of Ohio and Kentucky exceeded 2 cents for residences and was 1.3 cents for industrial customers [1]. Regulators hypothesized that increased competition would reduce prices in the high price areas as imports flowed in from relatively low cost areas. In the longer run regulators hoped that competition would lead to a more efficient mix of generators and prices that better reflect marginal costs.

This paper presents a case study examining the impact of the transmission constraints on the optimal dispatch of the Northeast U.S. power market. In particular, the prospects for short run price equalization in the Eastern part of the United States are assessed. The paper estimates the effect on markets in New England and New York of greater exports from ECAR (Michigan, Indiana, Kentucky, Ohio, West Virginia and Northern Virginia) in the Midwest and neighboring PJM (most of Pennsylvania, New Jersey, Maryland). The increased trade would come about from open markets: load would be supplied by the cheapest supplier regardless of its location. The estimates are presented for a base case, "current regulation", and three "competitive trade" alternatives. The base case is the New England FERC Form 715 Summer peak 1997 reference case. The current regulation case represents how a nearly fully loaded system would be dispatched under current regulation. This is contrasted with an optimal, minimum system cost dispatch generated by competitive trade. The sensitivity cases assume ten and twenty percent reductions in ECAR's and PJM's native load and trace the impact of optimal re-dispatch of the freed up capacity on prices in the East.

2. OPF Algorithm

Determination of the optimal solution of power markets requires the need to consider the numerous physical constraints imposed on the market by the transmission system. The solution of this problem requires the use of an optimal power flow (OPF) algorithm. The OPF algorithm was first formulated in the early 1960's [2] and has been an area of active research ever since. The goal of the OPF is the minimization (or occasionally maximization) of some objective function, subject to a variety of equality and inequality constraints. Often the objective function consists of the total generation cost in some set of areas, while the equality and inequality constraints include the power flow

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equations, generation/load balance, generator Mvar limits, branch flow limits, and transmission interface limits.

Over the years a wide variety of different solution approaches have been proposed, with an excellent literature survey recently presented in [3] and a tutorial course in [4]. These approaches can be broadly classified as either linear programming (LP) based methods or non-linear programming based methods. For the case study presented here an LP based approach was used [5]. This section briefly describes this algorithm.

Overall the LP based methods iterate between solving the power flow to take into account system non-linearities and solving an LP to redispatch the control variables subject to certain equality and inequality constraints. The basic steps in the LP algorithm employed here are

1. Solve the power flow equations.
2. Determine constraint violations; linearize the pertinent power flow constraint equations with respect to the control variables.
3. Solve the LP using the Revised Simplex Method with explicit bounds on individual variables in order to get the change in the control variables.
4. Update the control variables and then update the power system state using a linearized network model.
5. If the changes in the control variables are above a tolerance update the LP constraint equations and go to 3; otherwise resolve the power flow equations.
6. If any of the control variables changed during step 3 go to 2. Otherwise the solution has been reached; calculate the final solution cost and the bus/constraint marginal prices.

The key to making the LP OPF fast is to minimize the number of constraints explicitly included in the LP basis. Most of the system constraints are enforced during the power flow solution. These include the power flow equations, generator reactive power limits, and limits on LTC and phase shifter transformer taps. The LP basis then only includes the power balance constraints for the areas on OPF control, and any binding network inequality constraints or any network inequality constraints that are likely to become binding during the iteration.

Once an optimal solution has been determined, the marginal costs for enforcing the different constraints can be determined from the control costs and the final LP basis matrix:

$$\lambda^T = \mathbf{c}_B^T \mathbf{B}^{-1} \qquad (1)$$

where

λ^T = marginal costs of enforcing constraints
$\mathbf{c}_B^T$ = control costs
$\mathbf{B}$ = LP basis matrix

The bus MW marginal costs (also known as the locational marginal prices or LMPs) are then computed as

$$\lambda_{buses}^T = \lambda^T \mathbf{S} \qquad (2)$$

where

λ_{buses}^T = bus MW marginal costs
$\mathbf{S}$ = matrix of sensitivity of bus MW injections to the set of constraints

Similar to what is currently done in the LMP calculation for the PJM system [6], the incremental impact of system losses was not considered here. With this approximation in the absence of transmission system congestion, the bus marginal prices in an entire area would be identical. However, when congestion is present the marginal prices vary depending on the constraint locations; the area no longer has a single marginal price.

3. Contour Visualization of Results

Analysis tools, such as the OPF, yield a wealth of information, but the shear volume of the information makes it difficult and time consuming to interpret. In order to aid the system analyst in finding patterns in the data, the use of contouring for visualization of the bus marginal prices is discussed [7], [8].

Contouring of spatial data is a very common practice in many fields. For example, weather reports on television and in newspapers routinely use a contour map to show temperature differences throughout a region. This section addresses the application of contouring to power system bus data. In order to create a contour map, a technique for drawing the image must be developed since the data only exists at points where a bus is defined [7]. To create the contour image, an imaginary grid is laid across the region, and a *virtual value* is calculated for each point in the grid. These virtual values are then mapped to a color and the resulting contour drawn underneath the power system one-line map, which sometimes only shows the buses. The virtual value is determined by taking a weighted average of the data points throughout the region; that is, data points which are closer to the virtual grid point are weighed more than those further away. These virtual values are then represented by a color in the grid, and the resulting contour plotted.

As an example, Figure 1 shows a contour of the actual LMPs reported by PJM for 2:00 PM on August 20, 1999 (these values are publicly available from the PJM website [6]). In producing Figure 1 a color map was used with red representing higher cost regions and blue representing the lower cost regions. Other color scales, such as a grayscale, could also be used. Of course when this paper is reproduced in black and white the figure will of course be rendered using a grayscale. Note, interested readers can find a color version of this paper in the Document Library at www.powerworld.com/.

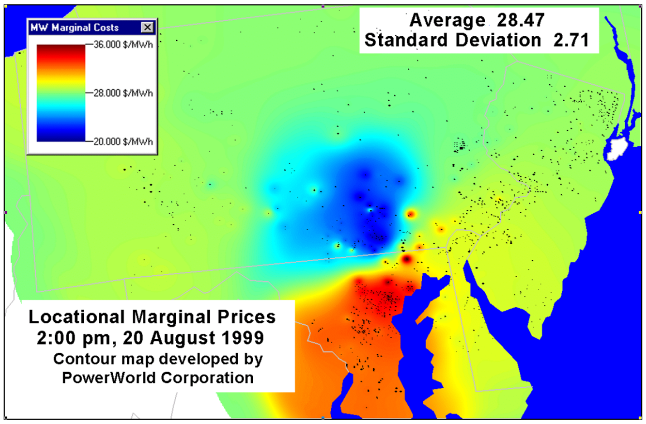

Figure 1: Contour of PJM Locational Marginal Prices

The image produced in Figure 1 is effective but it can be relatively expensive computationally to produce since the computation time is proportional to the number of virtual values in the grid times the number of data points. When contouring several thousands data points with grid resolutions of several hundred in each direction, the contours take on the order of tens of seconds to produce. While such times are certainly acceptable for developing high quality images for publication or slide presentations, when using contouring for interactive data analysis a faster, more approximate method is often desirable.

One such approach to speed up the contour calculation is to recognize that the virtual values are usually only significantly influenced by a relatively small number of nearby data points. Therefore computational time can be reduced by only considering data points that are within a particular influence region, defined as being the set of all points within a distance d_{inf} of the virtual value. This is illustrated in Figure 2. The application of this technique is shown in Figure 3, which contours exactly the same data as Figure 1 but with significantly reduced computational time.

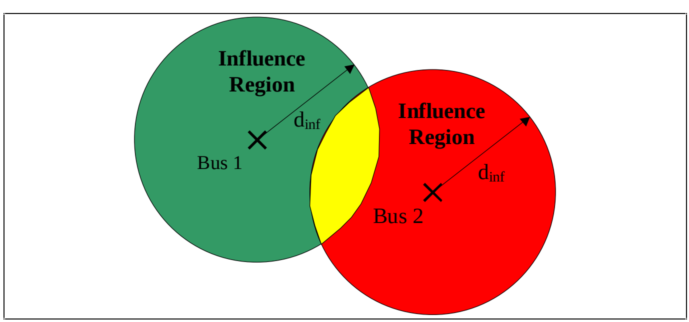

Figure 2: Virtual Value Influence Regions

Figure 3 is effective for quickly showing the regions of low and high price, but has the disadvantage of a somewhat blotchy appearance. In regions with few data points the impact of the influence distance approximation becomes apparent in the appearance of circular regions surrounding each point data point. Also, regions with no data points appear white. Of course the contour user is free to trade off between speed in creating the contour versus display appearance.

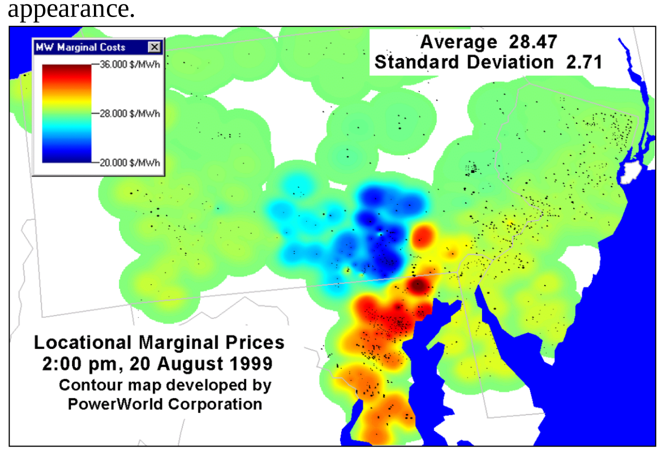

Figure 3: PJM Price Contour with Small Influence Distance

4. Northeast U.S. Case Study Model

The next two sections utilize the OPF and contouring algorithms to present results for a case study examining the Northeast U.S electrical network. The OPF is used to calculate the minimum cost of meeting system loads given the generator costs and the constraints imposed by the electrical network. The dispatch and marginal costs of electricity coming out of this optimization correspond to the equilibrium of a perfectly competitive electricity market. In determining this solution the assumption was that there were no constraints on either access by the generators to the grid or on interregional trade.

The network model used was the FERC Form 715, Annual Transmission Planning and Evaluation Report, for the anticipated 1997 summer peak filed by NEPOOL. This model contains 9270 buses, 4601 loads, 2506 generators, 12 DC lines and 14,840 lines/transformers. The model has a relatively detailed representation of the transmission grid in NEPOOL and NYPP; less detailed, but still adequate models are included for ECAR, PJM and parts of Canada. Total load at the summer peak is 356,274 MW. The study examined the impact of the transmission system on imports from ECAR and PJM (the “export” areas) into NEPOOL and NYPP (the import areas). The initial loads for these regions are NEPOOL: 21,350 MW, NYPP: 25,805 MW, PJM: 47,687 MW, and ECAR: 69,754 MW. Combined these four regions were modeled using 5774 buses. The remaining load of 191,678 MW is spread over the more equivalenced portion of the system representing Canada, MAIN, MAPP, and SERC. Except for the loads in ECAR and PJM, the load is assumed constant throughout the analysis.

EIA staff developed operating cost estimates for most of the on-line generators in the study areas. Generators for which there was no cost estimate were assumed to operate at the level contained in the FERC Form 715 file; that is, they

Table 1. Costed Capacity Using FERC Form 1 Data, by NERC Region (MW)

	Costed Capacity	Hydro, Pumped Storage	Total	% Coverage
Nepool	13,039	1,130	18,083	78.36%
NYPP	17,019	4,245	26,675	79.72%
PJM	39,265	2,031	46,187	89.41%
ECAR	71,125	1,872	74,245	98.32%
Total	140,448	9,278	165,190	90.64%

were not dispatched. The FERC Form 715 filings contain various generator parameters, such as voltage setpoint, and real/reactive power limits. However, they do not include operating costs. Therefore generators reported on the FERC Form 715 were identified and matched with generators reported on other survey Forms such as the FERC Form 1 [9] or the EIA-412 [10] where cost data is collected. Once matched, operating cost data for specific generators was estimated as the product of the heat rate, usually from FERC Form 1, and fuel cost.

The larger units were generally easy to identify and map to other sources of cost data. Although most individual units in NEPOOL and New York could not be matched for costing purposes, many of the unmatched units could be identified as either small hydro and pumped storage facilities. Since these units have low operating costs, they were dispatched using generically low costs. Table 1 reports the capacity for which costs were estimated.

5. Northeast U.S. Case Study Results

The base case, "current regulation", supposes that each region imports or exports the amounts specified in the FERC file[1]. That is, ECAR exports a total of 2277 MW, PJM imports 1408 MW, NYPP imports 1304 MW and NEPOOL imports a total of 2920 MW including 1600 MW from Canada on its DC ties with Hydro Quebec. This assumption reflects the regulated nature of the industry because the FERC 715 scenario indicates the North American Reliability Council's plan for managing peak demand.

The base case was then optimized using the OPF algorithm from Section 2 with the assumption that each of the four areas was dispatched in order to maintain its base case interchange. This resulted in a solution with a total operating cost of $4,555,491 per hour. Because of congestion the bus marginal prices in each of the areas were not identical; the average bus marginal prices for each of the areas are shown in the "Regulated" row of Table 2. In addition, Figure 4 contours the regional variation in the bus MW marginal prices. Overall Figure 4 contours approximately 2000 of the 5774 bus marginal prices; the contoured values corresponded to the higher voltage buses.

[1] The FERC 715 files only specifies the total imports or exports for each area; bilateral transactions are NOT specified.

Note that while most of the locational marginal price variation is due to the area constraints, several areas of price variation due to transmission congestion are visible, such as in Central Maine and Western New York. Bus marginal prices were not determined for areas not included in the study, such as Canada and Southern Virginia; these areas therefor appear white in the contour.

Table 2: Regulated and Competitive Average Bus Marginal Prices ($ / MWh)

	ECAR	PJM	NYPP	NEPOOL
Regulated	31.7	43.7	25.6	49.0
Competitive	35.6	35.4	37.8	37.1

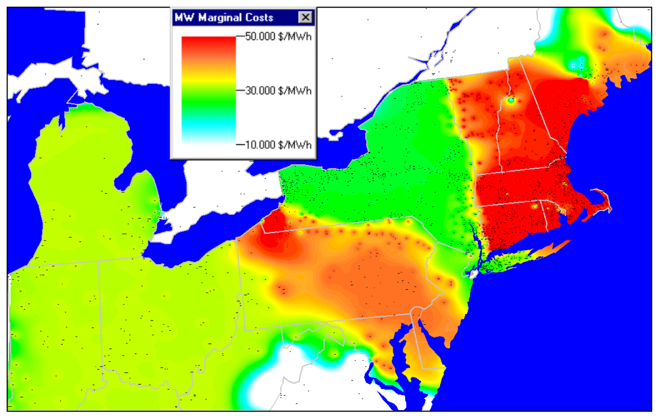

Figure 4: Contour of "Regulated" Bus Marginal Prices

Next, the constraints imposed on transactions between the four areas were relaxed. That is, ECAR, PJM, NYPP and NEPOOL were modeled in the OPF as a single "super area" with no constraints on power transfers between them. Rather just a single constraint on the net real power interchange of this "super area" with the remainder of the system was modeled. This represents what one might expect with perfect competition within these four regions. With this least cost way of meeting demand, the overall operating cost was $4,537,561 per hour, which was only 0.4% below that of the previous solution. However, there is more interregional trade under competitive (optimal) trade. Under competition ECAR exports 2620 MW, PJM imports 2372 MW, NYPP exports 44 and NEPOOL imports 3736 MW.

The price picture is unsettled, with the average bus marginal prices shown in the "Competitive" row of Table 2. The prices in PJM and NEPOOL are lower under competitive trade than under regulation, but the average price in ECAR and New York is higher. This is because of a near equalization in the bus marginal prices; ECAR and NYPP are producing more so their prices go up, while PJM and NEPOOL enjoy the benefits of increased supplies of cheaper power. Figure 5 contours the regional variation in the bus MW marginal prices using the same color key and scale as Figure 4. Note that there is no longer a significant regional variation, although localized price differences due to line congestion are still apparent.

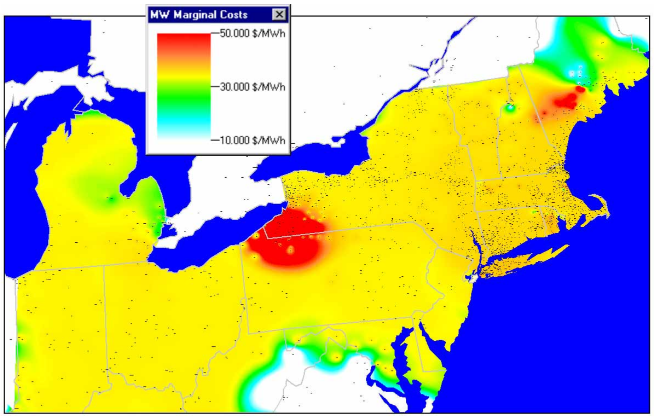

Figure 5: Contour of “Competitive” Bus Marginal Prices

Table 3: Average Competitive Prices with Load Reduction in ECAR and PJM

Load Reduction MW (%)	ECAR	PJM	NYPP	NEPOOL
0 (0 %)	35.6	35.4	37.8	37.1
11,744 (10%)	17.0	18.8	25.1	40.4
23,488 (20%)	15.3	15.8	23.7	39.1

The previous example seems to imply that there are not significant transmission restrictions in moving power from the exporting region (ECAR and PJM) into the importing region (NYPP and NEPOOL). However the base case corresponds to high demand in all regions and hence there is little additional low cost generation in the exporting region available for export. The situation changes considerably if the load in ECAR and PJM is reduced. The results of decreasing the load in ECAR and PJM by first 10% and then 20% are shown in Table 3. The 10% reduction in load frees up 11,744 MW for potential export. While this only amounts to 3.3% of total system load, it is about 25% of the load in NYPPP and NEPOOL. The immediate effect of lower demand is to reduce the average price in ECAR and PJM by about 50%. The increased supplies resulting from the freeing up of capacity in PJM and ECAR also reduce average price in New York by about a third. An additional 10 percent reduction in demand significantly lowers average price in the supplying regions but only reduces the average price in New York an additional 4 percentage points.

Interestingly, New England is almost unaffected by the increase in potential supply from ECAR and PJM. Under the optimal dispatch at peak demand NEPOOL received 1425 MW on its ties with NYPP, but 10% reduced demand in ECAR and PJM actually causes this flow to decrease slightly to 1400 MW. The calculated prices actually increase about 8%! The reason for these differences arises because of congestion in the transmission system. In the case with the 10% load reduction there are actually nine congested lines in NYPP and seven congested lines in NEPOOL. This compares with just four congested lines in NYPP for the base case with again seven in NEPOOL. Of course whether or not congestion occurs and its impact is highly dependent upon both the underlying line limits and the assumed set of controls available to the OPF. For these studies the limits reported in the FERC Form 715 cases were used. Also, only those generators that were modeled as being on-line in the base case and for which we had cost models were assumed to be available as controls. Finally, additional controls, such as phase shifting transformers, were not considered. Figures 6 and 7 show the controls of the bus marginal prices for the 10% and 20% load reductions. Figure 8 plots the variation in the area average bus marginal costs as the ECAR/PJM load is reduced from 100% to 77%.

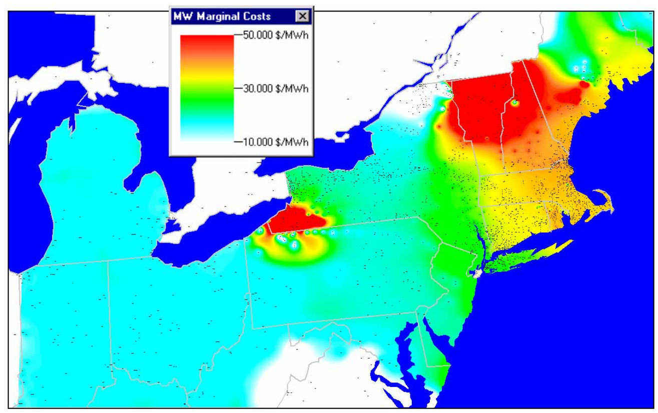

Figure 6: Contour of “Competitive” Bus Marginal Prices with 10% Load Reduction in ECAR and PJM

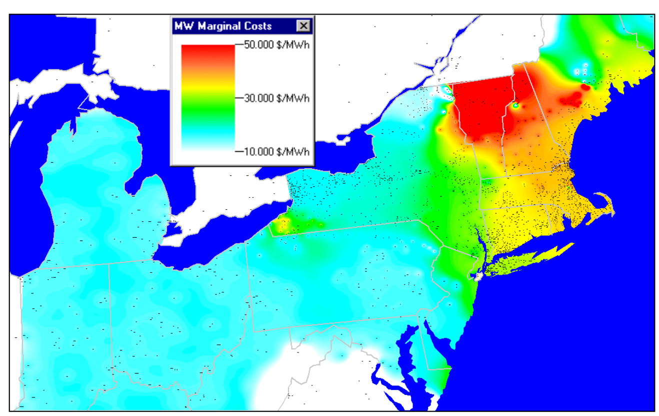

Figure 7: Contour of “Competitive” Bus Marginal Prices with 20% Load Reduction in ECAR and PJM

6. Conclusion

This paper has used a case study examining the Northeast U.S. to present a methodology for studying the impact of transmission constraints on the efficient operation of large scale power markets. The paper first presented an OPF algorithm for studying such large systems, and then introduced a method for visualizing the large number of marginal prices created by such a study. Finally the paper considered the Northeast U.S. power system. The main results of that study are:

1. Reduced native demand in ECAR and PJM greatly reduces the average of prices: a 10% reduction in demand from the summer peak reduces the average price in each region by about 50%. An additional 10 percentage point reduction significantly lowers average price in the regions.
2. Increased supplies resulting from the freeing up of capacity in PJM and ECAR reduce average price in New York: in the 10% case the New York average price falls by about a third. An additional 10 percentage point reduction only reduces price an additional 4 percentage points.
3. New England is almost unaffected by the increase in supply potential from ECAR and PJM because imports through New York are limited to roughly 1450 MWs.

Finally, we would like to mention that these results are certainly not definitive. As in doing any engineering study the final results are dependent upon the input data and assumptions. Some of the assumptions made in this study are 1) generation in the non-studied areas, such as MAIN, Canada, and SERC was assumed to be constant, 2) the effects of voltage support in limiting power transfers was not considered, 3) NERC flowgate limits were not considered, 4) the impacts of contingencies were not considered, 5) the generator cost estimates are preliminary, and 6) the study considered just a single operating point with several variations in the load. Never-the-less it appears that the potential benefits of competition for greatly reducing wholesale prices are significant in New York and limited in New England -- generators in NEPOOL may have substantial protection from distant competitors. For future work the authors plan to relax these assumptions and investigate the effects of grid improvements and generator entry.

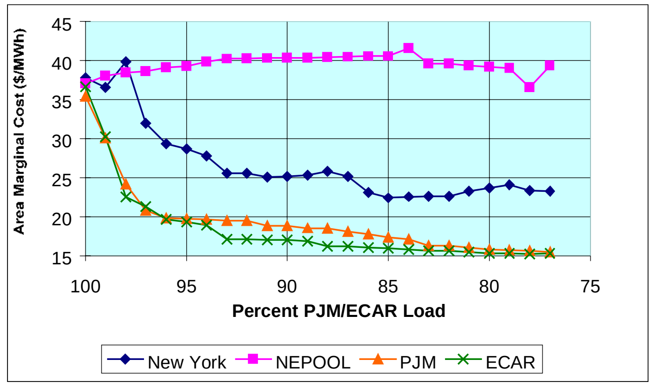

Figure 8: Variation in the Area Average Bus Marginal Costs with Respect to Percentage Base Case Load in ECAR/PJM

7. References

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