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CASE 06-T-0650

STAFF OF THE DEPARTMENT OF PUBLIC SERVICE
INTERROGATORY/DOCUMENT REQUEST
TO NEW YORK REGIONAL INTERCONNECT, INC.
("NYRI")

Request No: DPS-128
Date of Request: March 17, 2009
Reply Date: March 30, 2009
Subject: Production Cost Savings Forecasts
Witness: Lesser-Puga Panel

STATE OF NEW YORK
DEPT. OF PUBLIC SERVICE
DATE 3/31/09
CASE NO. 06-T-0650
285

1. Please provide documentation describing the AuroraXMP (Aurora) model.

Response:

Please see Exhibit DPS-128.1.A, Exhibit DPS-128.1.B, and Exhibit DPS-128.1.C, attached hereto.

2. Please identify proceeding(s) in which the Aurora model has been used to forecast production costs for New York.

Response:

We are not aware of any regulatory proceedings in which Aurora has been used to forecast production costs in New York

3. Please identify whether the Aurora model has been tested for its applicability to New York. If it has, please identify how the testing was done and provide the results from the testing. If not, explain why not.

Response:

EPIS offers and regularly updates a North American power database of the interconnected power systems of the U.S., Canada and Northern Baja California, Mexico, for use by its licensees. EPIS data support team uses multiple data sources to update this database. The data for NYISO was recently updated using the 2009 RNA and the 2008 Goldbook, among other sources. Various Aurora licensees use Aurora to model markets

in which they operate and base multiple business decisions on Aurora outputs. However, their benchmarking is commercially sensitive and thus considered confidential. Platts Power Outlook Research Service relies on the AuroraXMP model to forecast market clearing prices for electric power in the U.S./Canada region, estimating both on-peak and off-peak energy-only values along with "all-hours energy and capacity" composite power values on an aggregated monthly and annual basis for a 20-year forecast period.

4. Have the Aurora model forecasts ever been benchmarked to GE-MAPS forecasts? If so, by whom and what were the results. If not, explain why not.

Response:

We are not aware of any information in the public domain relating to benchmarking of AuroraXMP against GE-MAPS.

5. What geographic region did you simulate for your analysis of the NYRI project's economic benefits?

Response:

In addition to the 11 NYISO zones, we modeled all the key neighboring areas including parts of PJM, MISO, New England, Maine, Connecticut, Ontario, Quebec, and Manitoba. Areas that, due to their distance or weak electrical interconnection, were deemed to have little influence on the NYISO system (such as the WECC, MISO west of RFC-MISO and areas south of Virginia Power, etc.) were turned-off in the model. The region modeled is shown in the zonal diagram in Exhibit DPS-128.5, attached hereto.

6. If the geographic region was greater than just New York, please provide forecasts of production cost savings for each of the control areas simulated:

Response:

No production cost reports were specified for areas outside of NYISO when the model was run.

7. On page 98 (lines 4-8) of your testimony, you state that you used load forecasts for peak demand and annual electric consumption from the NYISO 2009 RNA. Please state the assumptions regarding the impact of EEPS in the forecast for both load and energy consumption (e.g., 100% EEPS).

Response:

Bates White relied on 2009 RNA Base Case demand and energy assumptions. See page 8 of the 2009 RNA for a description of their EEPS assumption:

"Using conservative assumptions appropriate to a baseline reliability analysis, the NYISO determined that there should be a reduction of approximately five percent of peak load from the previously forecasted levels by 2015 based upon currently authorized spending levels. This equates to approximately 30% of the total energy efficiency goals."

Further zone-specific load forecast data was obtained directly from NYISO, as this detailed information was not included 2009 RNA Report. These data have been enclosed in Attachment DPS-128-6.

8. If the response provided to the previous question was less than 100% EEPS, please provide production cost forecast results for an alternative simulation where you assume that 100% of the EEPS targets are achieved for both energy and capacity.

Response:

Although we do not believe the assumption is valid, please refer to Exhibit DPS-128.8, attached hereto.

9. On pages 98-99 of your testimony, you state that you performed a zonal level analysis rather than a nodal-level analysis. Are the interface limits in your analysis assumed to be different in the with NYRI and without NYRI scenarios? If yes, explain how and why they differ. If no, explain why not.

Response:

All limits between zones in the without-NYRI and with-NYRI cases are identical except for the addition of 1200 MW to the interface limit between zones E and G, upon addition of NYRI.

10. Please perform a nodal-level analysis and provide production cost forecast results under these assumptions.

Response:

Bates White does not, at this time, have a completely satisfactory nodal-level representation of the NYISO system for use in its nodal LBMP model. Bates White's approach to nodal LBMP modeling combines the Aurora^{xmp} security-constrained chronological dispatch production cost model with PowerWorld Simulator, an interactive power systems simulation model, via a software bridge which carries information between the two programs.

Although we attempted to perform a nodal-level analysis of the NYISO system, we repeatedly encountered non-convergence issues and unrealistic nodal price solutions, especially in zones H, I, and J. These, we believe, are attributable to the underlying phase angle regulator (PAR) modeling assumptions in the model.

Power flow models often experience difficulties in determining the correct value for discrete and/or limited automatic controls, such as phase shifting transformers tap positions. These problems can be particularly acute in areas in which PARs are actively managed by the system operators, such as is the case of the PARs in the NYC area.

Finally, as discussed in our rebuttal testimony, we believe it was more appropriate to run a zonal model to evaluate the potential long-term benefits of NYRI, which should not be held hostage to certain existing intra-zonal constraints that, ideally, will be addressed by the respective transmission system owners.

11. On page 99-105 of your testimony, you describe generation additions assumed in your analysis for a base case in which the NYRI line is not assumed and for an alternative scenario in which the NYRI line is assumed. Please provide production cost savings forecasts by assuming that the base case supply additions remain unchanged in an alternative scenario in which the NYRI line is assumed.

Response:

As explained in our rebuttal testimony, we do not believe this is a valid analysis. However, please refer to Exhibit DPS-128.11, attached hereto.

12. Please identify how production cost savings are defined in your analysis. Are production cost savings defined as something other than the difference in marginal (running) costs (e.g., fuel and variable O&M costs including environmental allowance costs) between the base case (without the NYRI project) and the alternative case (with the NYRI project)? If so, please identify the dollar value of production cost savings by cost component.

Response:

No. Total production cost in Aurora was calculated as the sum of total fuel cost and total variable O&M cost. Total fuel cost includes emission allowances cost and total variable O&M cost includes unit start-up cost.

13. What is the source of the data included in the Aurora data set underlying your analysis, particularly with regard to generator unit characteristics and transmission system characteristics?

Response:

Generator unit data in the Aurora NYISO database are based on historical EIA-860 data, updated with information sourced in the 2008 NYISO Goldbook, and publicly available data reported in FERC Form 1.

Transmission system characteristics in the Aurora zonal model consists of interzonal and boundary transfer limits published in the 2009 RNA, complemented by other various sources (new projects).

New York Independent System Operator

Table I-2a (2) - 2009 RNA Base Case

Forecast of Annual Energy by Zone - GWh

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2008	15,917	10,025	16,866	6,861	7,944	11,823	10,918	2,706	6,384	54,272	22,960	166,677
2009	16,011	10,067	16,881	7,014	8,020	11,907	11,007	2,748	6,478	54,987	23,008	168,127
2010	16,143	10,162	16,975	7,102	8,066	11,919	11,146	2,786	6,541	55,905	23,002	169,747
2011	16,189	10,154	17,039	7,147	8,109	11,988	11,263	2,817	6,572	56,661	23,015	170,953
2012	16,211	10,157	17,035	7,153	8,117	12,074	11,302	2,830	6,564	57,503	22,981	171,926
2013	16,287	10,210	17,102	7,178	8,127	12,160	11,382	2,871	6,593	58,358	22,888	173,158
2014	16,375	10,323	17,219	7,192	8,171	12,257	11,496	2,884	6,586	59,430	22,866	174,799
2015	16,436	10,410	17,311	7,176	8,202	12,355	11,566	2,903	6,595	60,353	22,870	176,176
2016	16,532	10,519	17,418	7,185	8,228	12,487	11,656	2,928	6,607	61,628	23,062	178,250
2017	16,615	10,615	17,464	7,171	8,238	12,621	11,757	2,954	6,638	62,083	23,127	179,283
2018	16,689	10,703	17,507	7,187	8,244	12,757	11,827	2,985	6,680	62,569	23,278	180,427

Forecast of Coincident Summer Peak Demand by Zone - MW

Before Reductions for Emergency Demand Response Programs

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2008	2,647	1,933	2,872	824	1,382	2,298	2,341	638	1,537	11,964	5,355	33,792
2009	2,657	1,941	2,873	836	1,388	2,299	2,358	644	1,550	12,127	5,386	34,059
2010	2,666	1,949	2,873	847	1,393	2,301	2,375	651	1,561	12,257	5,395	34,269
2011	2,674	1,947	2,884	853	1,401	2,314	2,400	659	1,568	12,361	5,403	34,462
2012	2,678	1,948	2,883	853	1,402	2,331	2,408	662	1,566	12,452	5,403	34,586
2013	2,690	1,958	2,894	856	1,404	2,347	2,425	669	1,567	12,537	5,377	34,725
2014	2,705	1,979	2,914	858	1,412	2,366	2,450	668	1,557	12,627	5,370	34,905
2015	2,715	1,996	2,930	856	1,417	2,385	2,465	671	1,554	12,683	5,358	35,029
2016	2,731	2,017	2,948	857	1,421	2,410	2,484	675	1,554	12,787	5,374	35,258
2017	2,744	2,035	2,956	855	1,423	2,436	2,505	681	1,562	12,879	5,354	35,430
2018	2,757	2,052	2,963	857	1,424	2,462	2,520	688	1,571	12,980	5,383	35,658

Forecast of Coincident Winter Peak Demand by Zone- MW

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2008-09	2,315	1,526	2,619	955	1,334	1,862	1,712	523	916	7,793	3,722	25,278
2009-10	2,328	1,532	2,622	976	1,346	1,875	1,726	531	930	7,896	3,742	25,505
2010-11	2,348	1,547	2,636	989	1,354	1,877	1,748	539	939	8,028	3,744	25,748
2011-12	2,354	1,545	2,646	995	1,361	1,888	1,766	545	944	8,136	3,743	25,924
2012-13	2,357	1,546	2,646	996	1,363	1,901	1,772	548	943	8,257	3,735	26,064
2013-14	2,368	1,554	2,656	999	1,364	1,915	1,785	556	947	8,380	3,718	26,243
2014-15	2,381	1,571	2,674	1,001	1,372	1,930	1,803	558	946	8,534	3,702	26,472
2015-16	2,390	1,584	2,689	999	1,377	1,945	1,814	562	947	8,666	3,688	26,661
2016-17	2,404	1,601	2,705	1,000	1,381	1,966	1,828	566	949	8,849	3,685	26,935
2017-18	2,416	1,616	2,712	998	1,383	1,987	1,844	572	953	8,915	3,687	27,083
2018-19	2,427	1,629	2,719	1,001	1,384	2,009	1,855	578	959	8,985	3,687	27,231

AURORA^{mp}

DECISION POWER.
CONTROL.
RESULTS.

WHY PUBLIC UTILITY COMMISSIONS CHOOSE AURORA

AURORA helps PUC analysts assess the impacts of:

- Fuel price and hydro volatility
- State-wide supply assessments & plans
- Emissions regulations
- Changes to portfolios of individual utilities
- New transmission capacity

"AURORA is easier to use than other models we've seen. The technical support and training provided by EPIS are great. AURORA gives us an extremely powerful tool to use for analyzing a wide variety of utility filings—integrated resource plans, power purchase and sales contracts, PURPA contracts, resource selections in RFPs, and so on.

*—Rick Sterling,
Utilities Engineer, Idaho
Public Utilities Commission*

Across the country, energy market complexity and economic pressures are thrusting state public utility commissions into the spotlight. PUC analysts face many challenges to effective regulation of utilities including: different stages of RTO acceptance, greater environmental considerations, volatile fuel prices, and so on. Additionally, nearly all 50 state governments are facing tremendous budget pressures. Many public utilities commissions are understaffed requiring energy and economic analysts to accomplish more with fewer resources.

PUCs need a fast and easy-to-use tool that can accomplish a wide variety of analysis—rate case, resource planning, environmental studies, production cost modeling, uncertainty analysis, etc.—and be run by minimal staff. They need a transparent tool that helps keep discussions focused on key assumptions and data and not on ideology. **AURORA is a software-based electric market model that accomplishes all of this and much more.**

Several public utility commissions and regulators cite the following reasons why they chose AURORA:

- Ease of Use
- Transparency
- Low Maintenance
- Current North American Database
- Superior Customer Support and Training
- Flexibility with Other Applications
- Comprehensiveness

What regulators say:

"In Washington, we use Aurora in a production cost modeling role and in a resource planning model role. We value the fact that it comes with a current power market database and that it interfaces easily with [other applications]."

"[As a result of using AURORA], the amount of time we need to devote to maintain power economics modeling skills is less than that needed with other models."

AURORA also allows us to focus on the data which reflects the individual companies we regulate. We find it promising that the model's database and reporting system allow the user to create sub-portfolios within a company's portfolio for rate and allocation studies...."

*—Hank McIntosh, Energy Analyst,
Washington Utilities and Transportation
Commission Advocacy Staff*

"As a state commission, we don't have the time or the staff to devote someone full-time to maintaining and operating a cumbersome power supply model. AURORA's ease of use, technical support and training give us the capability to review and analyze utility filings whenever they come in..."

AURORA has features that make preparing output reports and graphs simple and quick. Those are important features in order to overcome the 'black box' perception that often is associated with complex models used in commission proceedings."

*—Rick Sterling, Utilities Engineer,
Idaho Public Utilities Commission*

For more information:

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AURORA: The Industry's Tool of Choice

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AURORA Electric Market Model

Overview



Midwest Power Marketers Conference
Lee A. Barney

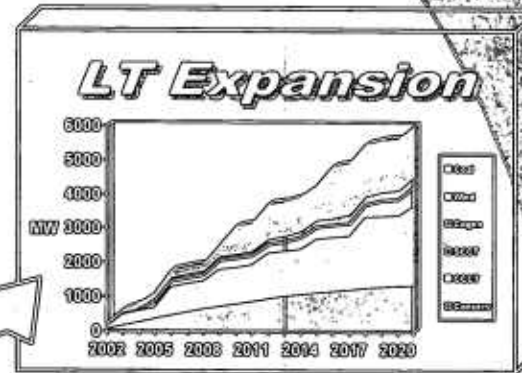
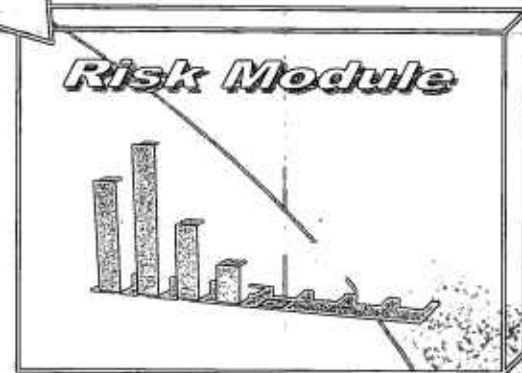
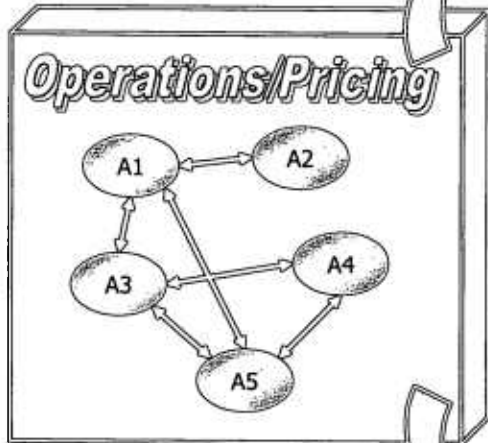
April 25, 2002

AURORA Focus

- Comprehensive:
 - Detailed Production Costing, and
 - Wholesale Price Forecasts
 - Value and Portfolio Analysis
 - Uncertainty Analysis
- Efficiency & Analytical Rigor in solution method



Functional Overview



The Whole Package

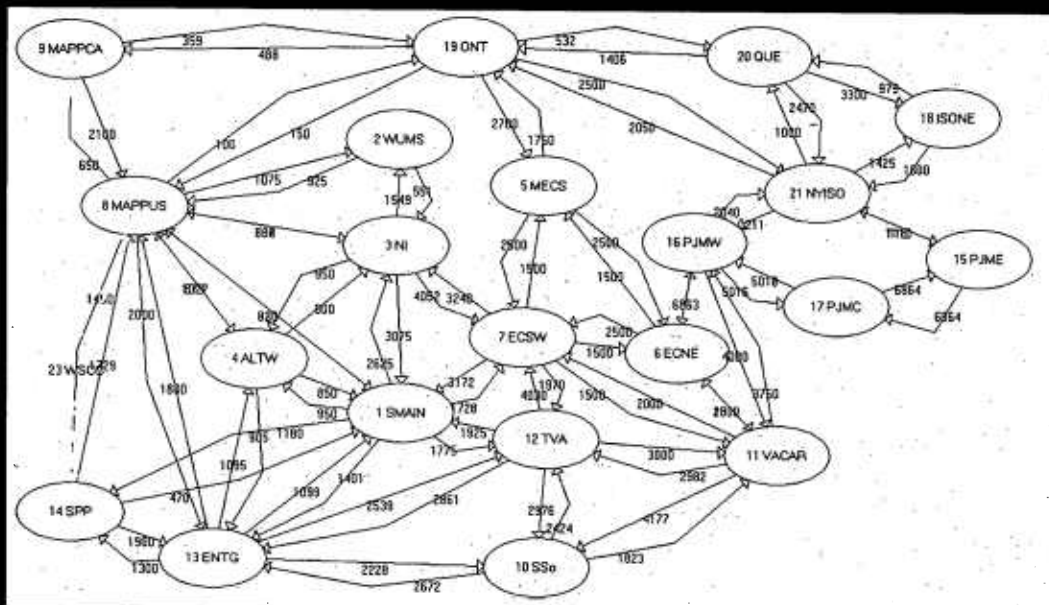
- Complete North American Database

- 9,000 plus generators
- All NERC regions,
60 plus market areas
- Ready to run as delivered,
quarterly updates



- Highly Flexible, Efficient User Interface
- Easily Customizable Interaction with
other Applications
- Strong Customer Support
- Easy Area Consolidation

Select Multiple Areas For Market Studies



Selected Market Areas

- ECAR-MECS
- ECAR-Northeast
- ECAR-Southwest
- MAAC-PJM-Central
- MAAC-PJM-East
- MAAC-PJM-West
- MAIN-ALTW
- MAIN-NI
- MAIN-SMAIN
- MAIN-WUMS
- MAPP-Manitoba
- MAPP-Saskatchewan
- MAPP-US
- NPCC-ISO-NE (11 Areas)
- NPCC-Canada (13 Areas)
- SERC-Entergy
- SERC-South
- SERC-TVA
- SERC-VACAR
- SPP



Operations/Pricing Logic Features

- Hourly Chronological Simulation
 - Multi-Area, Transmission Constrained Dispatch
 - Hourly, Economically Optimized Unit Commitment
- Fundamental or Non-fundamental Based Pricing

Example Detailed Resource Characteristics

- Startup costs, minimum up/down time for unit commitment
- Multiple capacity segments and heat rates
- Peaking operation for SC segment of CC
- Unit ramp rates
- Primary and secondary fuel options with fuel limits
- Flexible emissions definition and pricing
- Bidding factors, shadow bidding specification



Dispatch Engine Speed

- Proprietary, state of the art algorithm
- Much faster than competitors for equivalent detail
 - Full 8760 hour pricing run for all of the Midwest and Eastern US/Canada in under 12 minutes (>5050 units, 20 areas)
 - Annual pricing runs using a quality hour sample set in under two minutes



Dispatch Speed Allows

- Complete integrated risk analysis over time periods of any length
- Long term (20 years or more) economically optimized capacity expansion studies

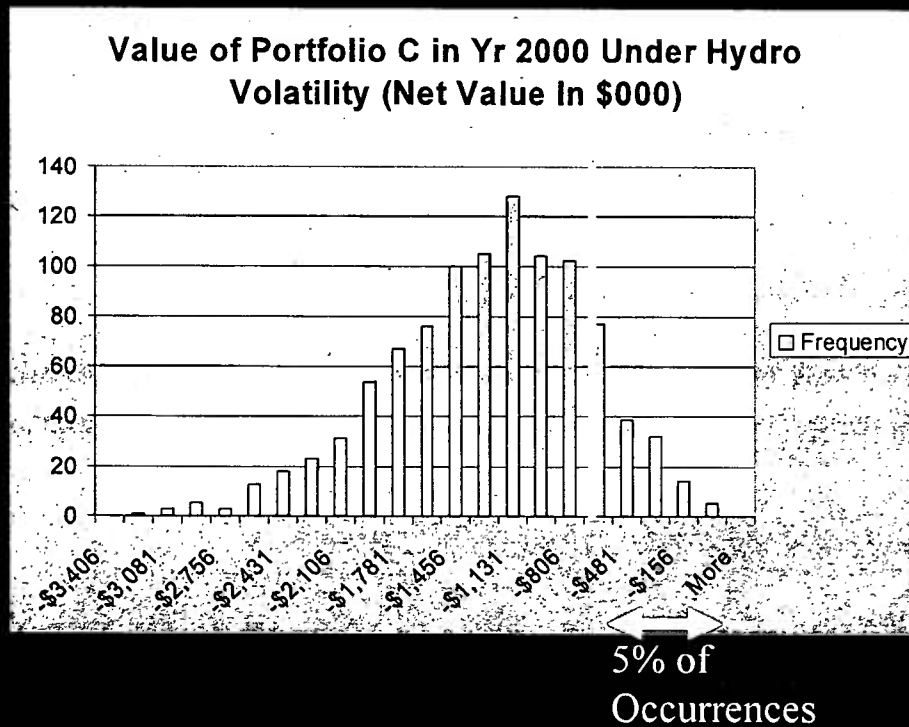


Risk Analysis Capability

- Monte Carlo or Latin Hypercube treatment of price drivers
 - Demand, fuel prices, thermal outage, & hydro generation
 - Built in sampling distributions, or user defined
 - Flexible period definition for stochastic variables
 - Correlated variable specification
- Full output of all variables for all games/iterations available



Case Study: Uncertainty In Resource Portfolio Value



“Profit at Risk” for time interval:

- 95% Confidence Level (5% of Occurrences)
- Worst expected revenue (or loss):
 - Absolute PAR for Portfolio: \$478,000 in Net Revenue
 - PAR Relative to Expected Value: \$870,000

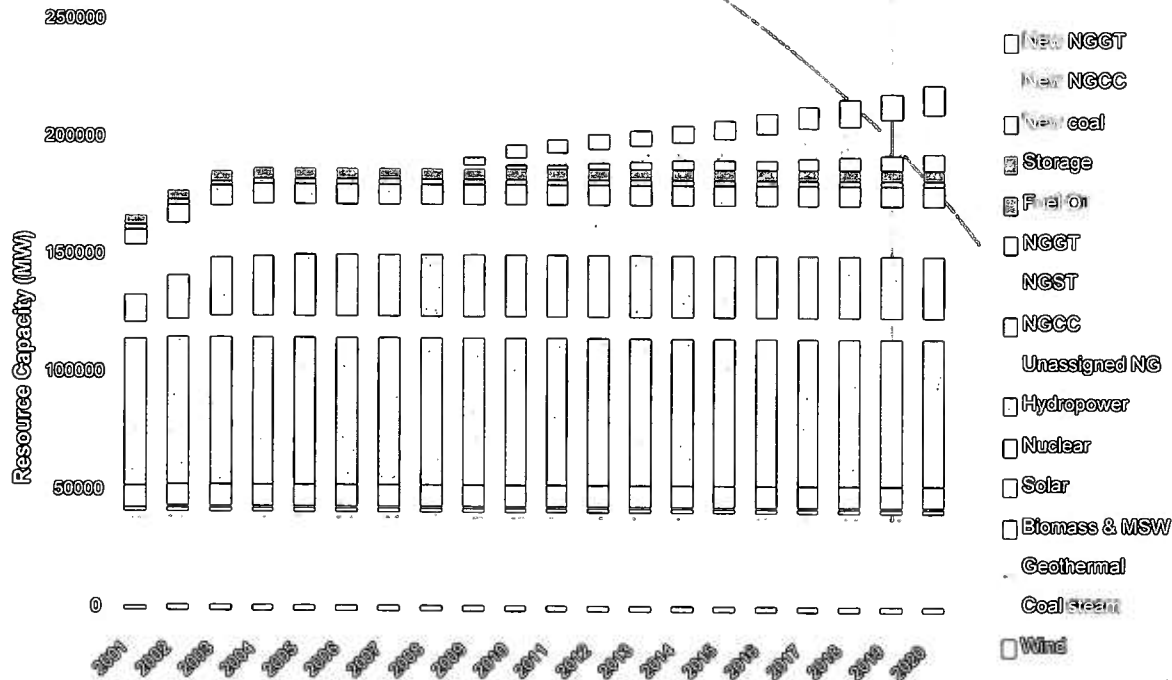


Long Term Expansion Capability

- Decisions to construct or retire based on forward looking market value
 - Constraints allowed on rate of construction and retirements
 - Unlimited definition of supply alternatives
 - Technology vintages accommodated
- Iterative methodology uses hourly core dispatch



Example LT Resource Mix

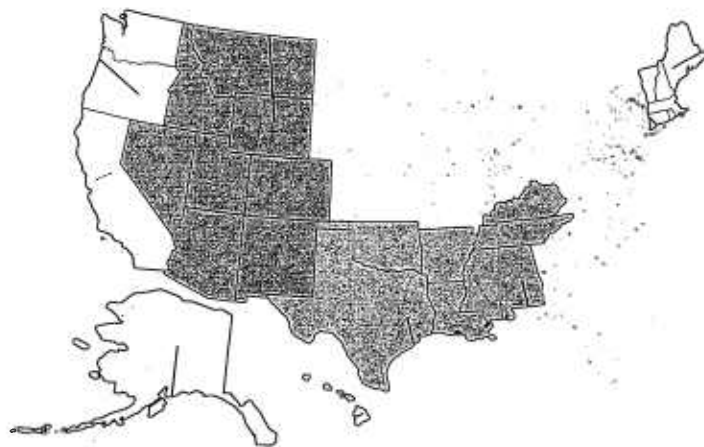


Additional Features

- Sophisticated but flexible hydro algorithm
- Energy storage logic
- Operating reserve treatment
- Interruptible/demand side resource representation
- Flexible fuel module
- Complete emissions logic



Model Emissions by Resource and Region

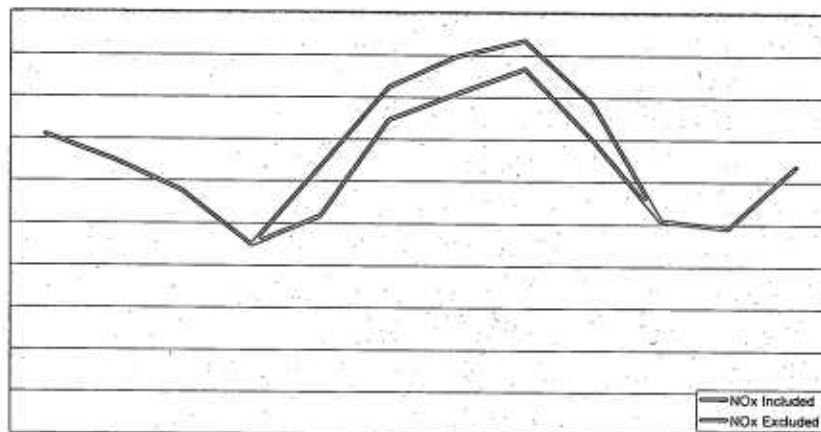


• The resource mix dictates the market clearing price impact of emissions regulations...

• ...and coal-oriented regions will be affected most (areas with much higher coal concentration, shows much more drastic MCP impacts).



Case Study: ECAR 2003 NOx Sensitivity



- NO_x regulation for the SIP Call region in 2003
 - \$ per ton
 - Emissions rates based on current EPA information



Results Focus On

- Prices by area and hub
 - Hourly to any user-defined aggregation period
- Resource operation
 - Complete reporting on all aspects of resource use
 - Area resource stacks
- Resource value
 - Both existing and new projects
- Portfolio value
- Fuel usage
- Transmission use/congestion



Latest Technology in Software Design

- Relational database used for all I/O
- Seamless integration to Microsoft Excel for I/O if desired
- Full automation of study setup, I/O and execution control with VB Scripting
- Complete online/context sensitive help
- Compatible with Windows 98 through Windows XP



Compelling Reasons for AURORA

- *SPEED* without sacrificing detail and accuracy
- *POWER* in risk analysis and long term expansion capability
- *FLEXIBILITY* through automation, the user interface, & output detail
- *COMPREHENSIVE* in geographic coverage, database features, & user support



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AURORAxmp LMP Symposium

Transmission Analysis

Houston, Texas

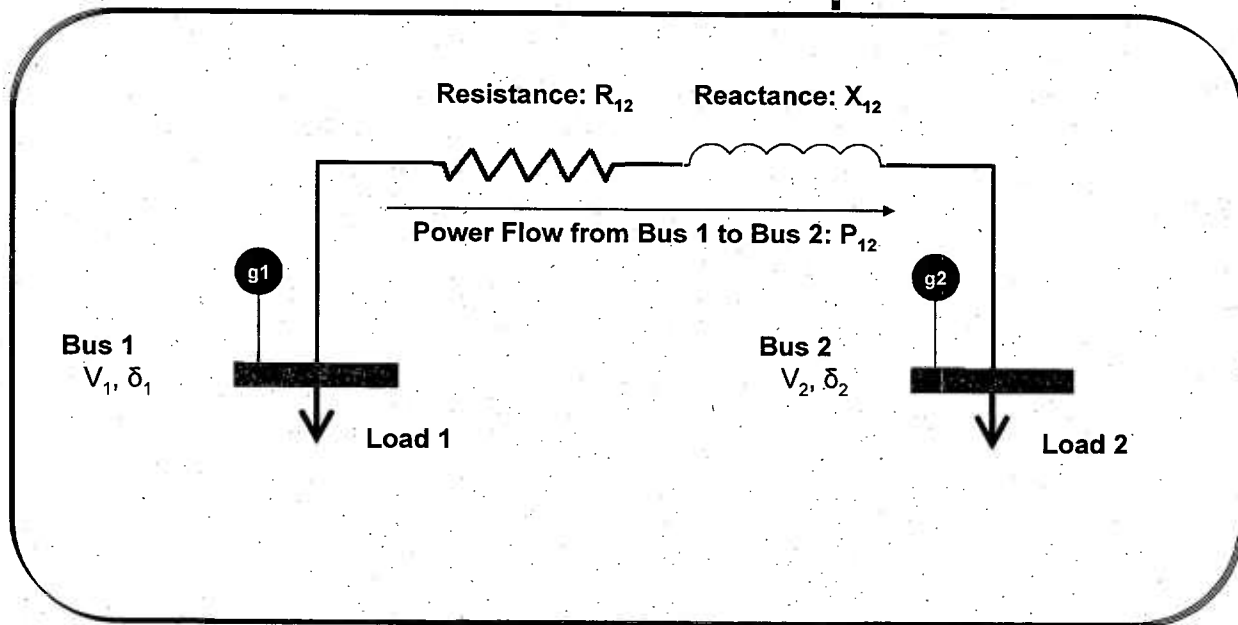
Transmission Analysis

- **AC Loadflow Equations**
- **DC Approximation**
- **Distribution Factors**
- **Determining Appropriate Sub-system(s) to monitor**



AC Loadflow Equations

Two Bus Example



AC Loadflow Equations

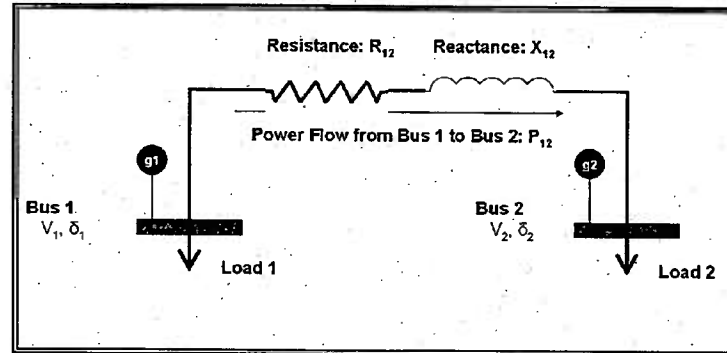
Kirchhoff's first law:

At any point in an electrical circuit the sum of currents flowing towards that point is equal to the sum of currents flowing away from that point.

In power system analysis we use the per-unit system to simplify calculations. One advantage of this is that power and current can be treated identically.



AC Loadflow Equations



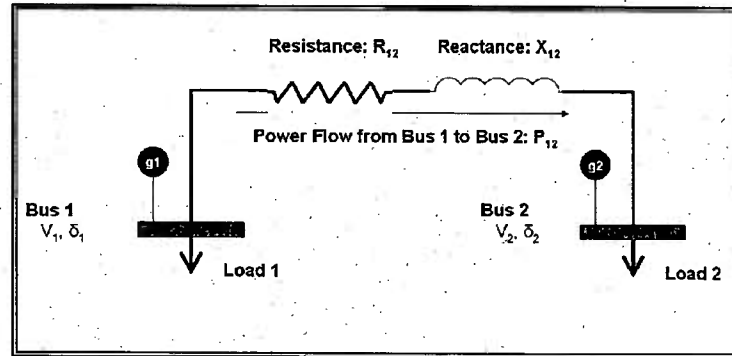
Applying Kirchhoff's law to "Bus 1" yields:

$$G_1 - L_1 - P_{12} = 0$$

Note: An italicized variable such as G denotes a complex number, ie MW + jMVar



AC Loadflow Equations



The equation for P_{12} :

$$P(\text{MW}) = V_1 V_2 (\cos (\delta_1 - \delta_2) / R_{12} + \sin (\delta_1 - \delta_2) / X_{12})$$

$$Q(\text{MVar}) = j(V_1 V_2 (\sin (\delta_1 - \delta_2) / R_{12} - \cos (\delta_1 - \delta_2) / X_{12}))$$



AC Loadflow Equations

Substituting, we get:

$$\mathbf{G}_1 - \mathbf{L}_1 - [V_1 V_2 (\cos (\delta_1 - \delta_2) / R_{12} + \sin (\delta_1 - \delta_2) / X_{12}) + j(V_1 V_2 (\sin (\delta_1 - \delta_2) / R_{12} - \cos (\delta_1 - \delta_2) / X_{12})))] = 0$$

To solve this, we make two assumptions at the reference bus:

$$V_1 = 1.0, \delta_1 = 0.0$$



AC Loadflow Equations

We now have:

$$\mathbf{G}_1 - \mathbf{L}_1 - [V_2(\cos(-\delta_2) / R_{12} + \sin(-\delta_2) / X_{12}) + j(V_2(\sin(-\delta_2) / R_{12} - \cos(-\delta_2) / X_{12})))] = 0;$$

\mathbf{G}_1 , \mathbf{L}_1 , R_{12} and X_{12} are known

V_2 and $-\delta_2$ are unknown.



AC Loadflow Equations

We have two difficulties solving this formula:

- 1. We have one equation with two unknowns,**
- 2. The system is non-linear due to the sine and cosine functions.**



AC Loadflow Equations

AC solutions require an iterative process where 'guesses' are made for each variable and improved during each iteration until an acceptable error occurs. Many methods exist and each have their own merits, but the potential for non-convergence exists with all of them.



DC Approximation

It would be desirable to obtain a closed form solution of the equation:

$$\mathbf{G}_1 - L_1 - [V_2(\cos(-\delta_2) / R_{12} + \sin(-\delta_2) / X_{12}) + j(V_2(\sin(-\delta_2) / R_{12} - \cos(-\delta_2) / X_{12})))] = 0;$$

Can we make reasonable assumptions to simplify this problem?



DC Approximation

The first simplification we make is that each and every $V_n = 1.0$

This assumption is acceptable for a variety of reasons:

- The operation of the power system dictates that V_n is tightly clustered around 1.0 with a range of $0.95 < V < 1.05$
- There are many devices such as generators, capacitors, transformers, etc that we do not truly know the status and/or voltage setpoint within that range.



DC Approximation

Next, we realize that $R \ll X$ for real systems and has minimal impact on real flow; thus we ignore R in our calculations. Then we also realize that in a real power system, $\Delta\delta_n$ is usually very small between connected buses. Thus:

$$\sin(\Delta\delta_n) \sim \Delta\delta_n$$

$$\cos(\Delta\delta_n) \sim 1$$



DC Approximation

Our previous equation:

$$\mathbf{G}_1 - \mathbf{L}_1 - [V_2(\cos(-\delta_2) / R_{12} + \sin(-\delta_2) / X_{12}) + j(V_2(\sin(-\delta_2) / R_{12} - \cos(-\delta_2) / X_{12})))] = 0;$$

reduces to:

$$\mathbf{G}_1 - \mathbf{L}_1 - [1.0(\cos(-\delta_2) / R_{12} + \sin(-\delta_2) / X_{12}) + j(1.0(\sin(-\delta_2) / R_{12} - \cos(-\delta_2) / X_{12})))] = 0;$$



DC Approximation

Finally, recognizing that we are only solving for the real component, P , we arrive at:

$$G_1 - L_1 - (\Delta\delta_{12}) / X_{12} = 0;$$

This equation is easily solved for known G_n and L_n at all buses.



Distribution Factors

The goal of the Optimal Power Flow (OPF) is to find the G_n set that results in the lowest cost for the system, given certain constraints. These constraints include:

- $\Sigma G_n = \Sigma L_n$,
- All operating generators operate within their defined capabilities, and
- All transmission elements of interest operate within their defined capabilities



Distribution Factors

The last of these constraints,

- All transmission elements of interest operate within their defined capabilities

requires that we solve the loadflow. We do not want to solve the loadflow for each possible combination of G_n , therefore we must find a way to minimize the computational overhead.

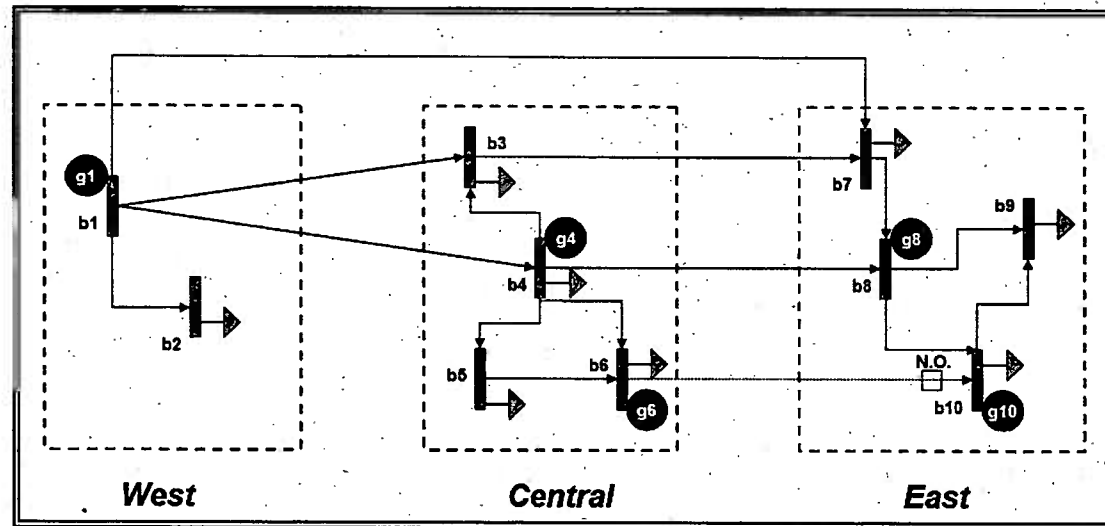


Distribution Factors

Distribution factors are a linearized set of values derived from the DC solution that describe how the flows on a transmission system will be affected by certain elements in the system.



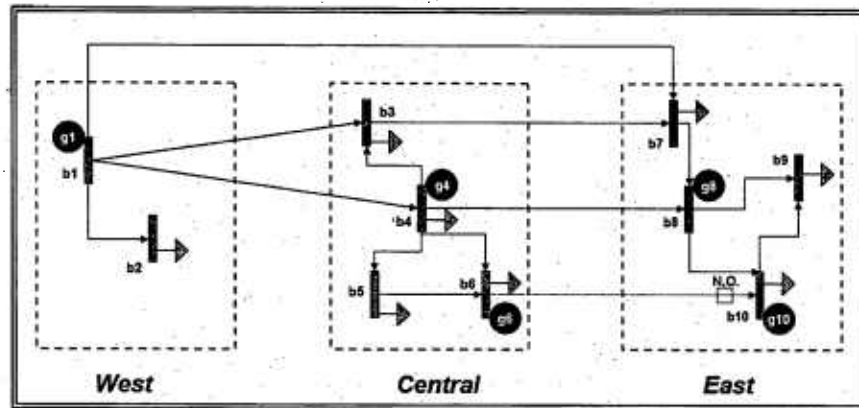
Distribution Factors



- **PTDF's (Power Transfer Distribution Factors) describe how a change in generation or load at a given bus will impact transmission flows. For example, if the generation at bus 1 changed, how would the flow on the line from bus 4 to bus 8 be impacted?**



Distribution Factors



- ODF's (Outage Distribution Factors) describe how a change in the status (open/closed) of an element will impact transmission flows. For example, if the line from bus 4 to bus 8 were open, how would the flows on the line from bus 3 to bus 7 be impacted?



Distribution Factors

By including the distribution factors in the OPF process, we can then satisfy the constraint that all transmission elements remain loaded within acceptable levels under all configurations of interest.



Determining Appropriate Sub-systems to Monitor

As discussed before, the OPF's goal is to minimize the G_n set given certain constraints. The appropriate selection of transmission elements to enforce is therefore critical to achieving a reasonable solution profile for G_n .



Determining Appropriate Sub-systems to Monitor

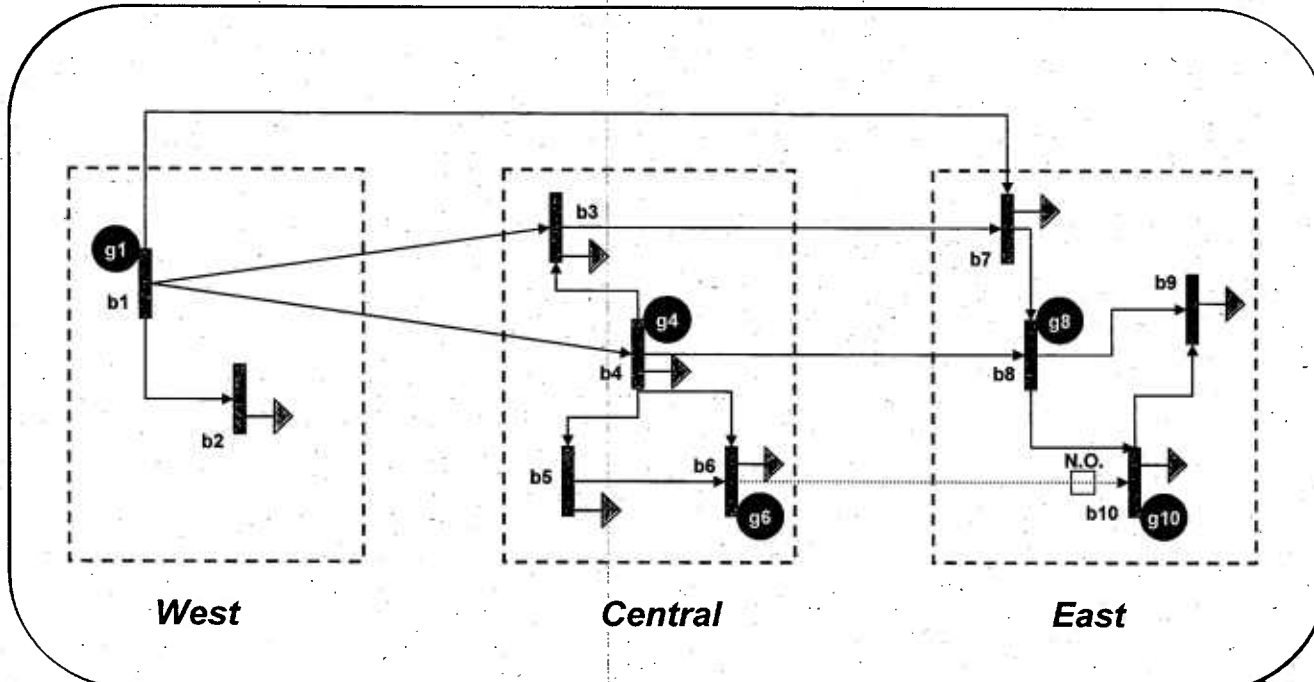
Sub-systems to consider:

- **Radial lines**
- **Voltage (kV) classes**
- **Geographical range**



Modified Ten Bus Example

Radial and Normally-Open Circuits



Determining Appropriate Sub-systems to Monitor

Radial branches are branches that have only one connection to the main grid (such as the radial from bus 1 to bus 2 in the example). By definition these branches must be adequately sized to facilitate transfers to or from the main grid. Including these branches in the OPF solution will result in unnecessary overhead.



Determining Appropriate Sub-systems to Monitor

**The transmission system performs two
functions:**

1. Facilitate the transfer of power between regions (bulk power), and
2. Delivers the power to distribution stations for the end-user.



Determining Appropriate Sub-systems to Monitor

Generally, bulk power facilities will be high voltage facilities, usually 230kV and above. These facilities should be monitored in OPF studies.

The 138kV and below facilities are generally used to transfer power to distribution stations. These facilities often have multiple configurations available to the operator (such as the normally open line from bus 6 to bus 10 in the example) to ensure that service to the distribution stations will remain uninterrupted. Care should be taken not to over-constrain the OPF here.



Determining Appropriate Sub-systems to Monitor

The geographic range of a solution should be considered when doing OPF solutions. The computational and data-management overhead of monitoring distant systems may not be justified when analyzing a local system.



Zonal Price in 2006 Real \$/MWh

NYCA Zone	2012		2015		2018	
	Without NYRI	With NYRI	Without NYRI	With NYRI	Without NYRI	With NYRI
A	\$ 60.60	\$ 61.20	\$ 67.69	\$ 68.39	\$ 76.42	\$ 73.20
B	\$ 62.20	\$ 63.30	\$ 69.63	\$ 70.91	\$ 78.33	\$ 79.04
C	\$ 63.18	\$ 64.20	\$ 70.92	\$ 72.08	\$ 79.86	\$ 80.44
D	\$ 63.52	\$ 64.60	\$ 71.35	\$ 72.58	\$ 80.43	\$ 81.14
E	\$ 64.20	\$ 65.02	\$ 71.98	\$ 72.92	\$ 80.90	\$ 81.51
F	\$ 64.68	\$ 65.20	\$ 72.68	\$ 73.37	\$ 82.15	\$ 82.67
G	\$ 70.72	\$ 70.03	\$ 78.68	\$ 77.67	\$ 87.26	\$ 85.10
H	\$ 72.13	\$ 71.50	\$ 80.39	\$ 79.52	\$ 88.55	\$ 87.01
I	\$ 71.98	\$ 71.45	\$ 80.33	\$ 79.61	\$ 89.22	\$ 88.24
J	\$ 78.61	\$ 78.10	\$ 86.48	\$ 85.67	\$ 92.79	\$ 90.82
K	\$ 78.43	\$ 78.03	\$ 86.23	\$ 85.55	\$ 92.76	\$ 91.05

Note:

Same generation for 2012 and 2015 pre- and post-NYRI cases.

In 2018 the following generation resources were added to both pre- and post NYRI cases to avoid load curtailment.

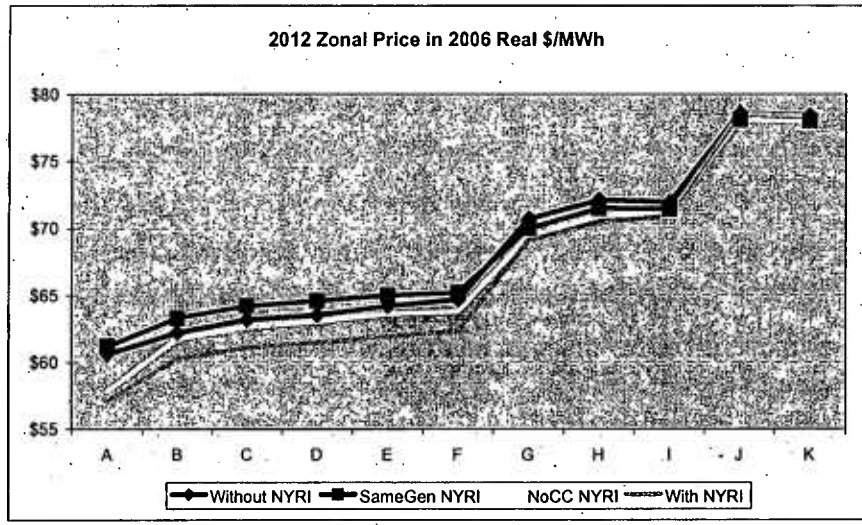
Without NYRI Addtl Resources		
Heat Rate	Capacity (MW)	Area
7,000	1,000	E
7,000	600	G
9,000	230	J
9,000	230	J

w/NYRI Addtl Resources		
Heat Rate	Capacity (MW)	Area
9,000	230	G
9,000	230	G
9,000	230	I
9,000	230	I
9,000	230	J

2012 Zonal Price in 2006 Real \$/MWh

NYCA Zone	Without NYRI	SameGen NYRI	NoCC NYRI	With NYRI
A	\$ 60.60	\$ 61.20	\$ 57.80	\$ 57.09
B	\$ 62.20	\$ 63.30	\$ 61.76	\$ 60.23
C	\$ 63.18	\$ 64.20	\$ 62.62	\$ 61.08
D	\$ 63.52	\$ 64.60	\$ 63.08	\$ 61.47
E	\$ 64.20	\$ 65.02	\$ 63.58	\$ 61.91
F	\$ 64.68	\$ 65.20	\$ 63.79	\$ 62.31
G	\$ 70.72	\$ 70.03	\$ 69.46	\$ 69.14
H	\$ 72.13	\$ 71.50	\$ 70.93	\$ 70.46
I	\$ 71.98	\$ 71.45	\$ 71.09	\$ 70.93
J	\$ 78.61	\$ 78.10	\$ 78.14	\$ 78.59
K	\$ 78.43	\$ 78.03	\$ 77.99	\$ 78.38

Name	Definition
Without NYRI	Without NYRI Case
SameGen NYRI	Add NYRI on Without NYRI Case
NoCC NYRI	Add Wind on SameGen NYRI Case
With NYRI	Add 1000MW CC on NoCC NYRI Case



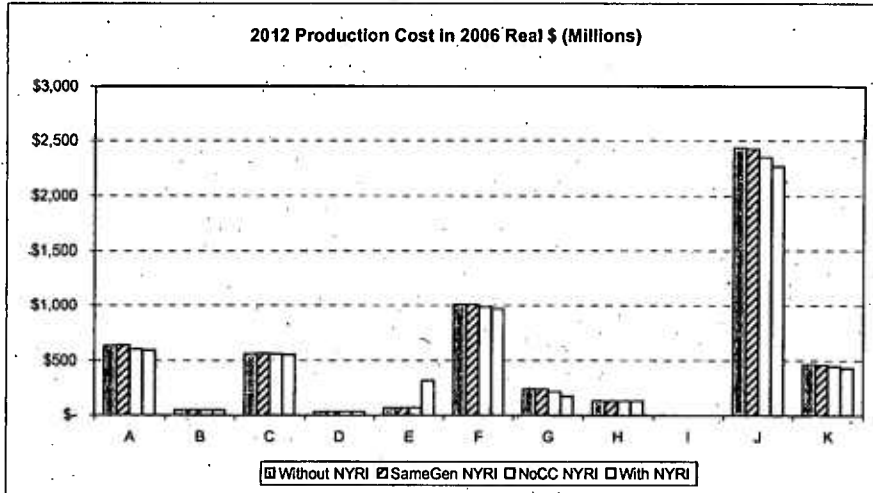
2012 Production Cost in 2006 Real \$ (Millions)

NYCA Zone	Without NYRI	SameGen NYRI	NoCC NYRI	With NYRI
A	\$ 632.54	\$ 635.77	\$ 603.46	\$ 593.59
B	\$ 50.53	\$ 50.70	\$ 50.49	\$ 50.25
C	\$ 561.33	\$ 564.29	\$ 558.67	\$ 552.83
D	\$ 36.28	\$ 36.49	\$ 36.66	\$ 36.43
E	\$ 69.65	\$ 70.04	\$ 70.79	\$ 316.44
F	\$ 1,009.75	\$ 1,012.02	\$ 986.11	\$ 969.30
G	\$ 238.71	\$ 235.21	\$ 213.81	\$ 177.21
H	\$ 134.40	\$ 134.38	\$ 134.35	\$ 134.33
I	\$ 0.01	\$ 0.01	\$ 0.01	\$ 0.01
J	\$ 2,438.62	\$ 2,427.48	\$ 2,350.40	\$ 2,266.35
K	\$ 468.54	\$ 458.48	\$ 444.29	\$ 428.09
Total	\$ 5,640.4	\$ 5,624.9	\$ 5,449.0	\$ 5,524.8

Name	Definition
Without NYRI	Without NYRI Case
SameGen NYRI	Add NYRI on Without NYRI Case
NoCC NYRI	Add Wind on SameGen NYRI Case
With NYRI	Add 1000MW CC on NoCC NYRI Case

Production Cost Savings \$(Millions)

Without NYRI - SameGen NYRI	\$ 15
Without NYRI - NoCC NYRI	\$ 191
Without NYRI - With NYRI	\$ 116

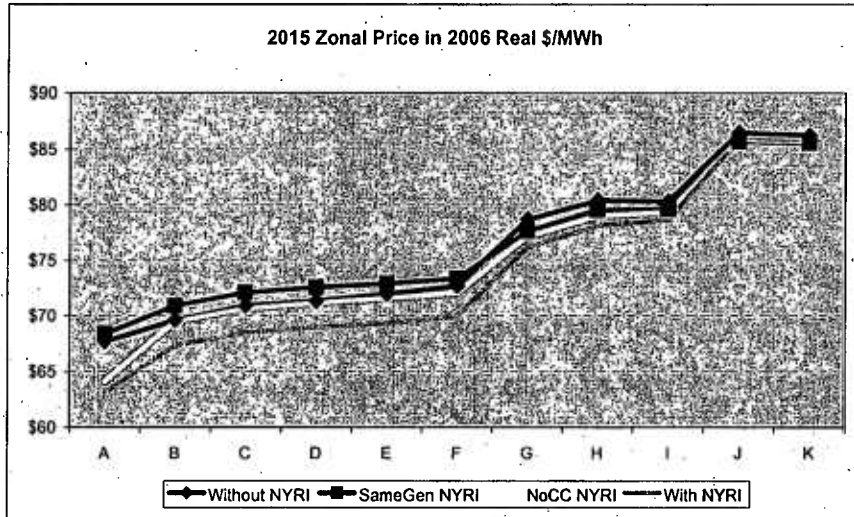


2015 Zonal Price in 2006 Real \$/MWh

NYCA Zone	Without NYRI	SameGen NYRI	NoCC NYRI	With NYRI
A	\$ 67.69	\$ 68.39	\$ 64.11	\$ 63.08
B	\$ 69.63	\$ 70.91	\$ 69.48	\$ 67.33
C	\$ 70.92	\$ 72.08	\$ 70.67	\$ 68.46
D	\$ 71.35	\$ 72.58	\$ 71.20	\$ 68.96
E	\$ 71.98	\$ 72.92	\$ 71.63	\$ 69.33
F	\$ 72.68	\$ 73.37	\$ 72.06	\$ 69.99
G	\$ 78.68	\$ 77.67	\$ 77.21	\$ 76.18
H	\$ 80.39	\$ 79.52	\$ 79.01	\$ 78.09
I	\$ 80.33	\$ 79.61	\$ 79.32	\$ 78.64
J	\$ 86.48	\$ 85.67	\$ 85.91	\$ 85.84
K	\$ 86.23	\$ 85.55	\$ 85.77	\$ 85.66

Name	Definition
Without NYRI	Without NYRI Case
SameGen NYRI	Add NYRI on Without NYRI Case
NoCC NYRI	Add Wind on SameGen NYRI Case
With NYRI	Add 1000MW CC on NoCC NYRI Case

2015 Zonal Price in 2006 Real \$/MWh

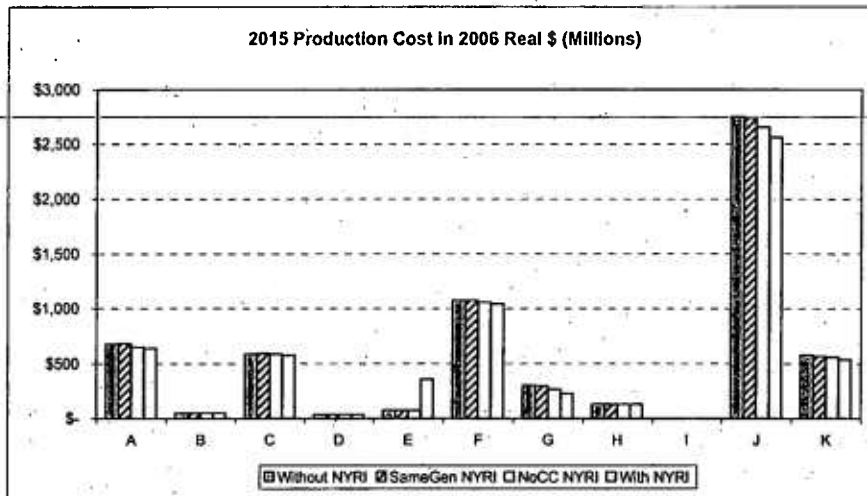


2015 Production Cost in 2006 Real \$ (Millions)

NYCA Zone	Without NYRI	SameGen NYRI	NoCC NYRI	With NYRI
A	\$ 680.40	\$ 682.89	\$ 652.34	\$ 640.90
B	\$ 51.62	\$ 51.80	\$ 51.58	\$ 51.24
C	\$ 587.05	\$ 590.49	\$ 586.12	\$ 576.79
D	\$ 37.44	\$ 37.69	\$ 37.88	\$ 37.51
E	\$ 73.39	\$ 73.69	\$ 74.45	\$ 358.28
F	\$ 1,078.29	\$ 1,079.12	\$ 1,061.03	\$ 1,045.94
G	\$ 303.25	\$ 295.72	\$ 267.29	\$ 229.47
H	\$ 134.33	\$ 134.30	\$ 134.28	\$ 134.24
I	\$ 0.01	\$ 0.01	\$ 0.01	\$ 0.01
J	\$ 2,759.26	\$ 2,747.10	\$ 2,661.62	\$ 2,561.56
K	\$ 577.24	\$ 565.66	\$ 558.90	\$ 535.62
Total	\$ 6,282.3	\$ 6,258.5	\$ 6,085.5	\$ 6,171.6

Name	Definition
Without NYRI	Without NYRI Case
SameGen NYRI	Add NYRI on Without NYRI Case
NoCC NYRI	Add Wind on SameGen NYRI Case
With NYRI	Add 1000MW CC on NoCC NYRI Case

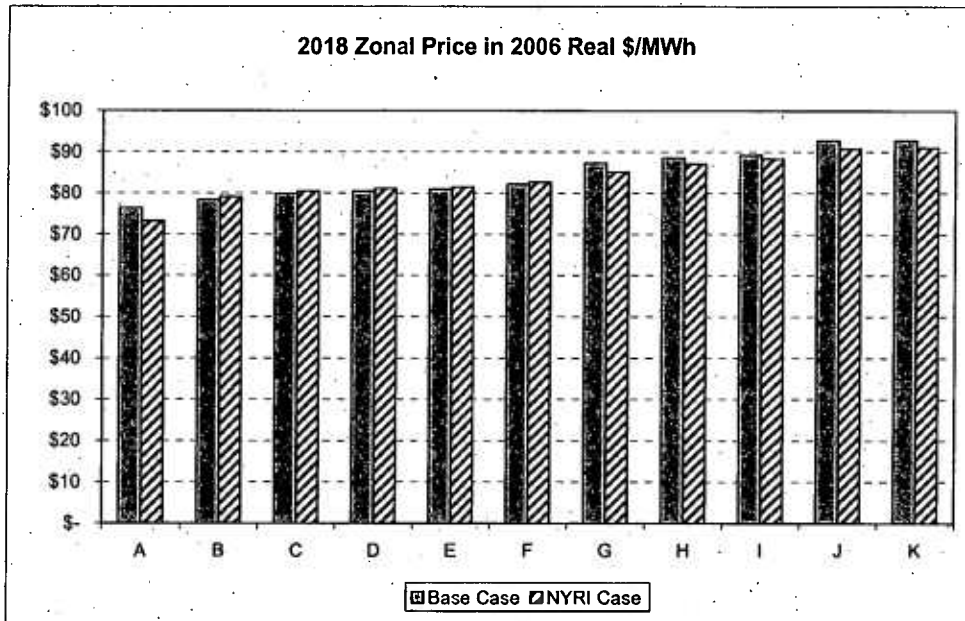
Production Cost Savings \$(Millions)	
Without NYRI - SameGen NYRI	\$ 24
Without NYRI - NoCC NYRI	\$ 197
Without NYRI - With NYRI	\$ 111



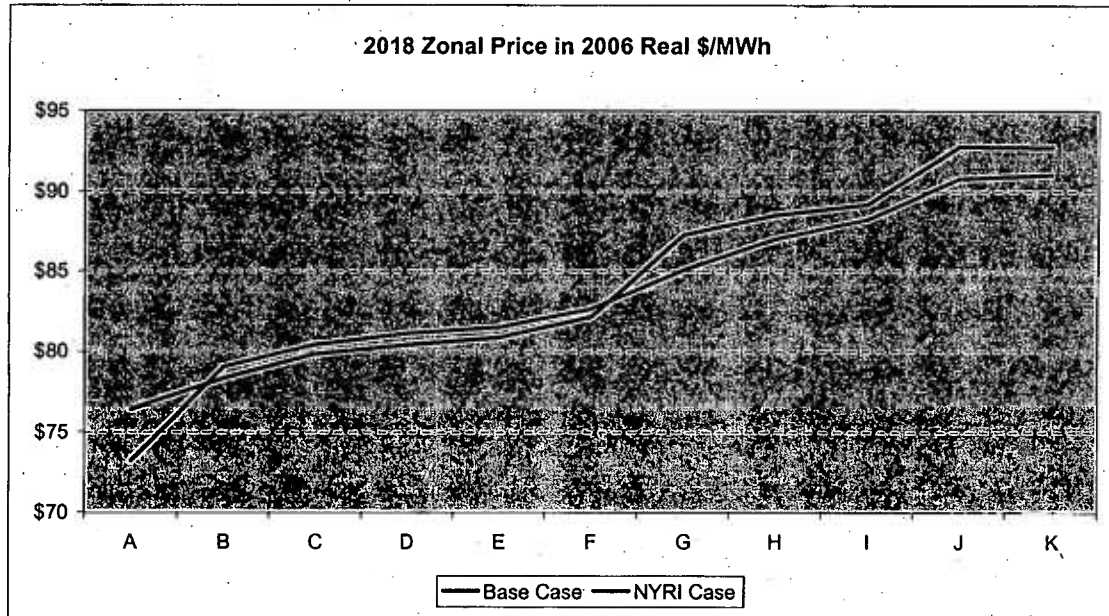
2018 Zonal Price in 2006 Real \$/MWh

NYCA Zone	Base Case	NYRI Case	Change	% Change
A	\$ 76.42	\$ 73.20	\$ (3.22)	-4.2%
B	\$ 78.33	\$ 79.04	\$ 0.71	0.9%
C	\$ 79.86	\$ 80.44	\$ 0.59	0.7%
D	\$ 80.43	\$ 81.14	\$ -0.71	0.9%
E	\$ 80.90	\$ 81.51	\$ 0.61	0.8%
F	\$ 82.15	\$ 82.67	\$ 0.52	0.6%
G	\$ 87.26	\$ 85.10	\$ (2.17)	-2.5%
H	\$ 88.55	\$ 87.01	\$ (1.54)	-1.7%
I	\$ 89.22	\$ 88.24	\$ (0.98)	-1.1%
J	\$ 92.79	\$ 90.82	\$ (1.97)	-2.1%
K	\$ 92.76	\$ 91.05	\$ (1.71)	-1.8%

2018 Zonal Price in 2006 Real \$/MWh



2018 Zonal Price in 2006 Real \$/MWh



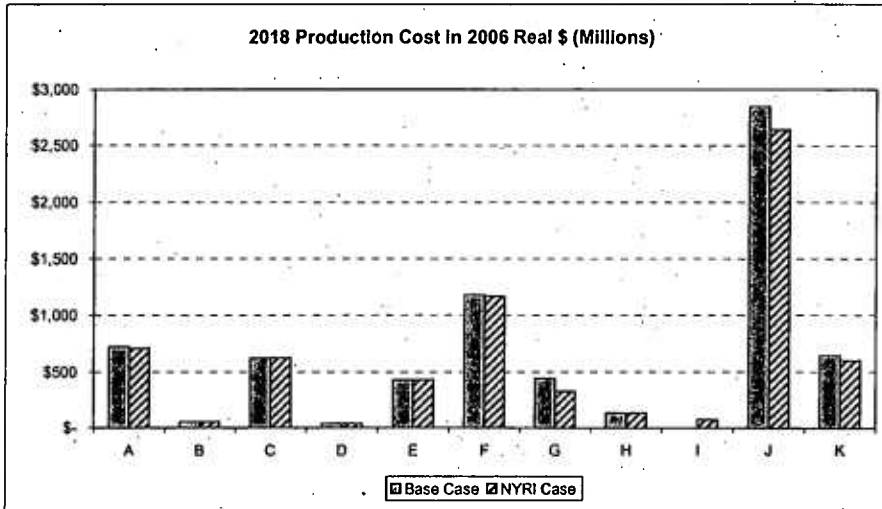
2018 Production Cost in 2006 Real \$ (Millions)

NYCA Zone	Base Case	NYRI Case	Change	% Change
A	\$ 724.82	\$ 708.52	\$ (16.3)	-2.2%
B	\$ 53.26	\$ 53.36	\$ 0.1	0.2%
C	\$ 622.67	\$ 624.62	\$ 1.9	0.3%
D	\$ 39.43	\$ 39.91	\$ 0.5	1.2%
E	\$ 427.91	\$ 432.00	\$ 4.1	1.0%
F	\$ 1,178.54	\$ 1,165.64	\$ (12.9)	-1.1%
G	\$ 445.46	\$ 330.69	\$ (114.8)	-25.8%
H	\$ 134.67	\$ 134.61	\$ (0.1)	0.0%
I	\$ 0.01	\$ 76.69	\$ 76.7	980194.8%
J	\$ 2,849.75	\$ 2,636.87	\$ (212.9)	-7.5%
K	\$ 643.81	\$ 602.64	\$ (41.2)	-6.4%
Total	\$ 7,120.3	\$ 6,805.6	\$ (314.8)	-4.4%

Without NYRI/Added Resources		
Heat Rate	Capacity (MW)	Area
7,000	1,000	E
7,000	600	G
9,000	230	J
9,000	230	J

w/NYRI/Added Resources		
Heat Rate	Capacity (MW)	Area
9,000	230	G
9,000	230	G
9,000	230	I
9,000	230	I
9,000	230	J

2018 Production Cost in 2006 Real \$ (Millions)



**This tab summarizes the overall production cost savings impact of 100% EEPS
The remaining tabs show the price and production cost savings results by
NYCA zones for years 2012, 2025, and 2018**

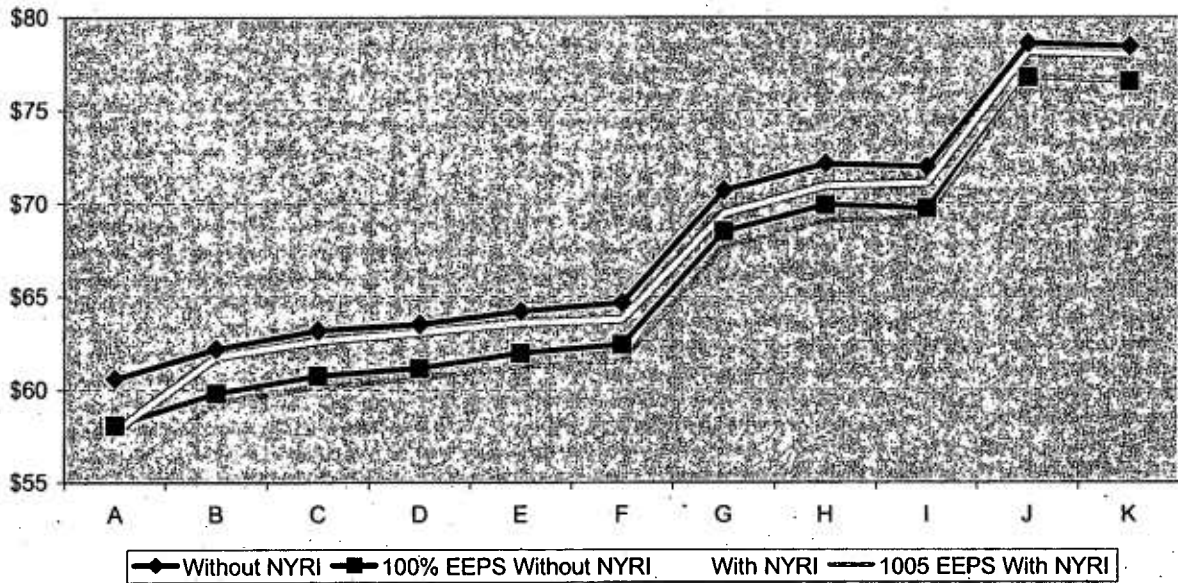
Production Cost Savings \$(Millions)

Year	Base Case	100% EEPS
2012 \$	191.3	\$ 194.0
2015 \$	196.8	\$ 204.1
2018 \$	314.8	\$ 317.7

Zonal Price in 2006 Real \$/MWh

NYCA Zone	Without NYRI	100% EEPS Without NYRI	With NYRI	1005 EEPS With NYRI
A	\$ 60.60	\$ 58.12	\$ 57.80	\$ 55.34
B	\$ 62.20	\$ 59.82	\$ 61.76	\$ 59.31
C	\$ 63.18	\$ 60.76	\$ 62.62	\$ 60.15
D	\$ 63.52	\$ 61.17	\$ 63.08	\$ 60.60
E	\$ 64.20	\$ 61.96	\$ 63.58	\$ 61.23
F	\$ 64.68	\$ 62.44	\$ 63.79	\$ 61.55
G	\$ 70.72	\$ 68.49	\$ 69.46	\$ 67.65
H	\$ 72.13	\$ 69.94	\$ 70.93	\$ 69.04
I	\$ 71.98	\$ 69.73	\$ 71.09	\$ 69.24
J	\$ 78.61	\$ 76.80	\$ 78.14	\$ 76.83
K	\$ 78.43	\$ 76.57	\$ 77.99	\$ 76.62

2012 Zonal Price in 2006 Real \$/MWh



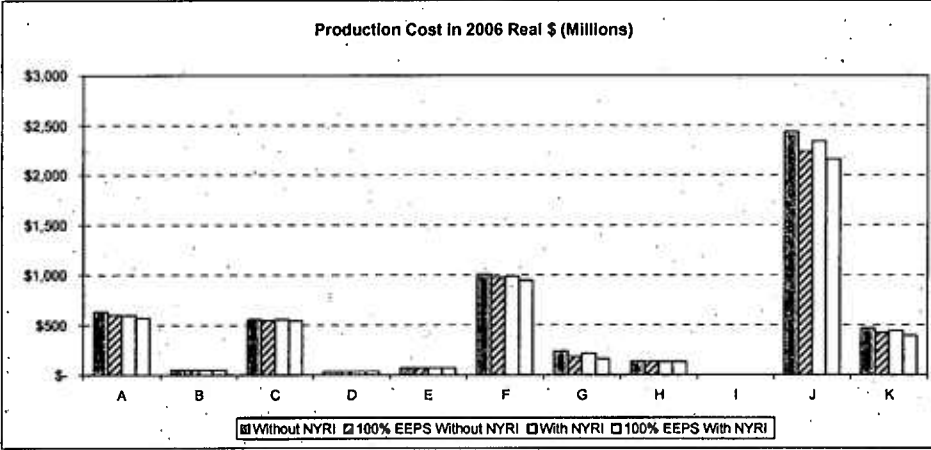
Production Cost in 2008 Real \$ (Millions)

NYCA Zone	Without NYRI	100% EEPS Without NYRI	With NYRI	100% EEPS With NYRI
A	\$ 632.54	\$ 605.71	\$ 603.46	\$ 574.55
B	\$ 50.53	\$ 50.19	\$ 50.49	\$ 50.12
C	\$ 561.33	\$ 551.61	\$ 558.67	\$ 549.04
D	\$ 36.28	\$ 36.12	\$ 36.66	\$ 36.52
E	\$ 69.65	\$ 68.79	\$ 70.79	\$ 70.13
F	\$ 1,009.75	\$ 979.11	\$ 986.11	\$ 948.29
G	\$ 238.71	\$ 180.15	\$ 213.81	\$ 160.93
H	\$ 134.40	\$ 134.31	\$ 134.35	\$ 134.27
I	\$ 0.01	\$ 0.01	\$ 0.01	\$ 0.01
J	\$ 2,438.62	\$ 2,245.25	\$ 2,350.40	\$ 2,159.03
K	\$ 468.54	\$ 423.69	\$ 444.29	\$ 398.01
Total	\$ 5,640.4	\$ 5,274.9	\$ 5,449.0	\$ 5,080.9

Production Cost Savings \$(Millions)

Without NYRI - With NYRI	\$ 191
100% EEPS Without NYRI - 100% EEPS With NYRI	\$ 194

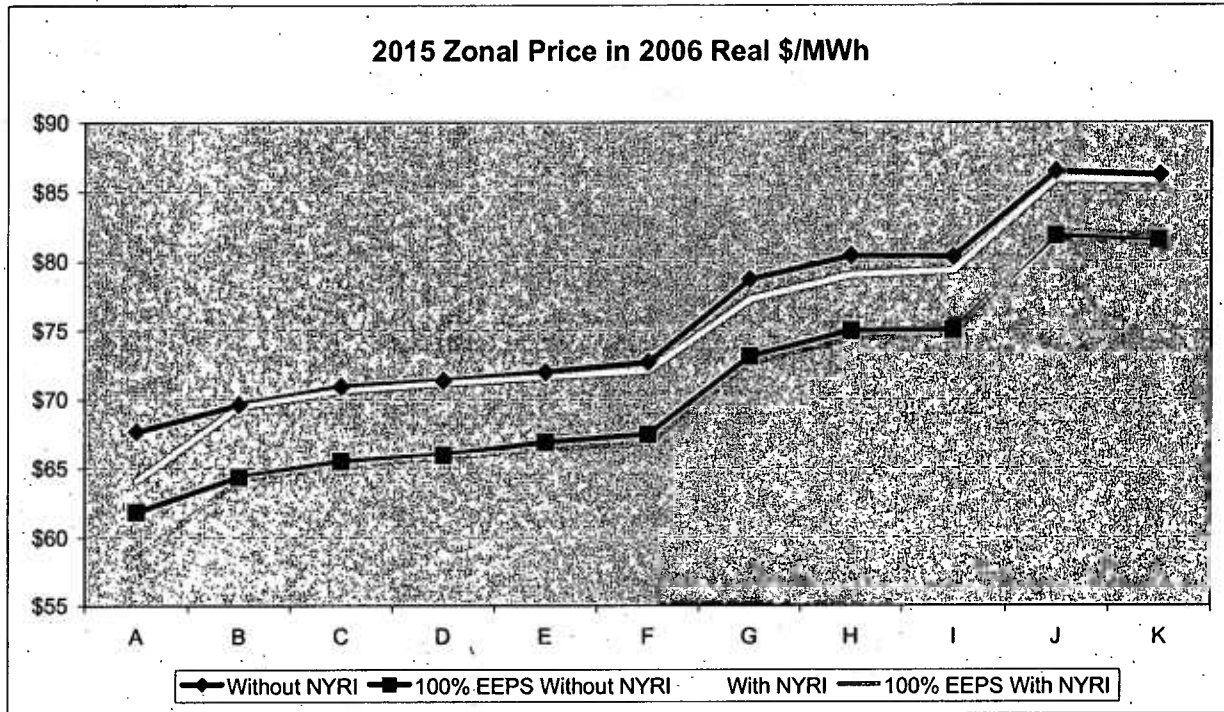
Production Cost in 2006 Real \$ (Millions)



Zonal Price in 2006 Real \$/MWh

NYCA Zone	Without NYRI	100% EEPS Without NYRI	With NYRI	100% EEPS With NYRI
A	\$ 67.69	\$ 61.86	\$ 64.11	\$ 58.64
B	\$ 69.63	\$ 64.39	\$ 69.48	\$ 64.12
C	\$ 70.92	\$ 65.51	\$ 70.67	\$ 65.17
D	\$ 71.35	\$ 65.97	\$ 71.20	\$ 65.79
E	\$ 71.98	\$ 66.89	\$ 71.63	\$ 66.37
F	\$ 72.68	\$ 67.47	\$ 72.06	\$ 66.74
G	\$ 78.68	\$ 73.11	\$ 77.21	\$ 72.59
H	\$ 80.39	\$ 74.98	\$ 79.01	\$ 74.36
I	\$ 80.33	\$ 75.03	\$ 79.32	\$ 74.64
J	\$ 86.48	\$ 81.85	\$ 85.91	\$ 82.18
K	\$ 86.23	\$ 81.57	\$ 85.77	\$ 81.82

2015 Zonal Price in 2006 Real \$/MWh



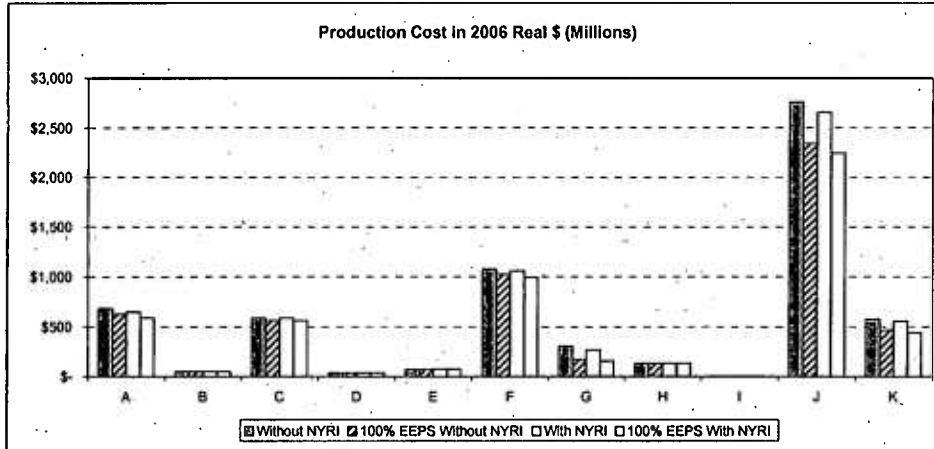
Production Cost in 2006 Real \$ (Millions)

NYCA Zone	Without NYRI	100% EEPS Without NYRI	With NYRI	100% EEPS With NYRI
A	\$ 680.40	\$ 627.13	\$ 652.34	\$ 591.51
B	\$ 51.62	\$ 50.80	\$ 51.58	\$ 50.74
C	\$ 587.05	\$ 566.68	\$ 586.12	\$ 564.06
D	\$ 37.44	\$ 36.79	\$ 37.88	\$ 37.21
E	\$ 73.39	\$ 71.35	\$ 74.45	\$ 72.64
F	\$ 1,078.29	\$ 1,027.23	\$ 1,061.03	\$ 996.31
G	\$ 303.25	\$ 170.76	\$ 267.29	\$ 156.60
H	\$ 134.33	\$ 134.11	\$ 134.28	\$ 134.09
I	\$ 0.01	\$ 0.01	\$ 0.01	\$ 0.01
J	\$ 2,759.26	\$ 2,346.94	\$ 2,661.62	\$ 2,250.18
K	\$ 577.24	\$ 466.24	\$ 558.90	\$ 440.56
Total	\$ 6,282.3	\$ 5,498.0	\$ 6,085.5	\$ 5,293.9

Production Cost Savings \$(Millions)

Without NYRI - With NYRI \$ 197
 100% EEPS Without NYRI - 100% EEPS With NYRI \$ 204

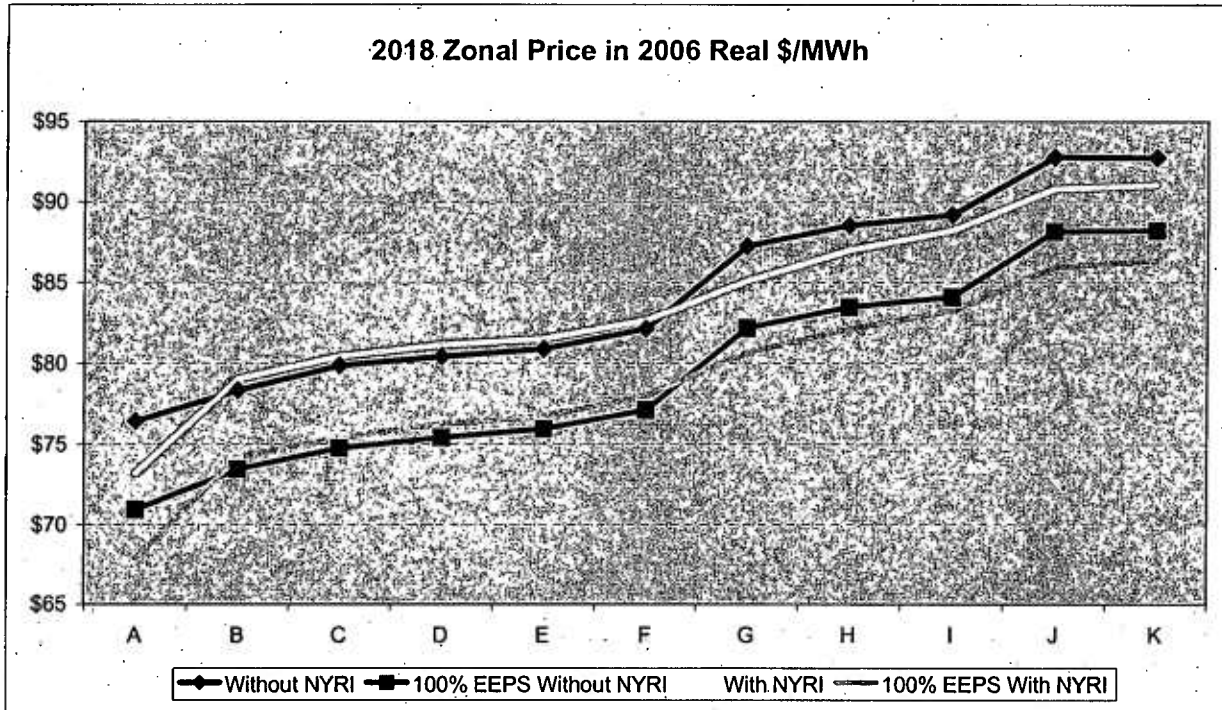
Production Cost in 2006 Real \$ (Millions)



Zonal Price in 2006 Real \$/MWh

NYCA Zone	Without NYRI	100% EEPS Without NYRI	With NYRI	100% EEPS With NYRI
A	\$ 76.42	\$ 70.94	\$ 73.20	\$ 67.94
B	\$ 78.33	\$ 73.45	\$ 79.04	\$ 74.17
C	\$ 79.86	\$ 74.75	\$ 80.44	\$ 75.40
D	\$ 80.43	\$ 75.41	\$ 81.14	\$ 76.26
E	\$ 80.90	\$ 75.96	\$ 81.51	\$ 76.70
F	\$ 82.15	\$ 77.12	\$ 82.67	\$ 77.99
G	\$ 87.26	\$ 82.20	\$ 85.10	\$ 80.69
H	\$ 88.55	\$ 83.51	\$ 87.01	\$ 82.14
I	\$ 89.22	\$ 84.12	\$ 88.24	\$ 83.28
J	\$ 92.79	\$ 88.20	\$ 90.82	\$ 85.97
K	\$ 92.76	\$ 88.22	\$ 91.05	\$ 86.36

2018 Zonal Price in 2006 Real \$/MWh

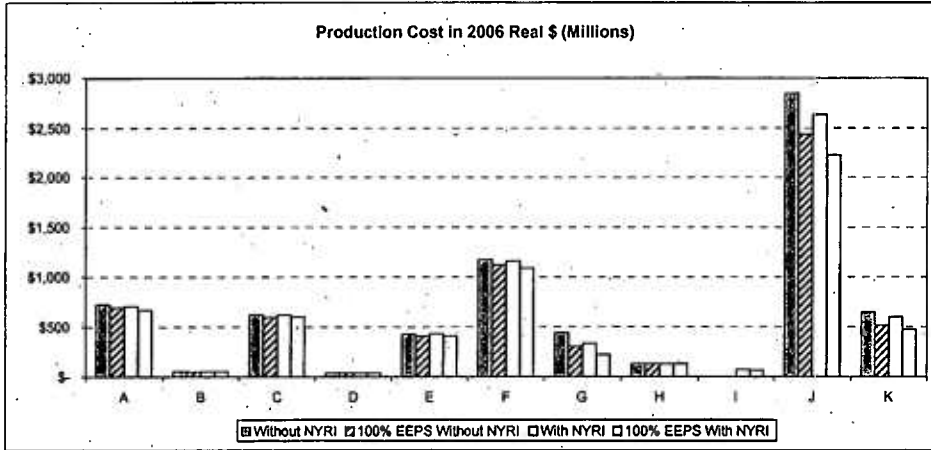


Production Cost in 2006 Real \$ (Millions)

NYCA Zone	Without NYRI	100% EEPS Without NYRI	With NYRI	100% EEPS With NYRI
A	\$ 724.82	\$ 694.42	\$ 708.52	\$ 671.91
B	\$ 53.26	\$ 52.47	\$ 53.36	\$ 52.59
C	\$ 622.67	\$ 600.19	\$ 624.62	\$ 603.10
D	\$ 39.43	\$ 38.66	\$ 39.91	\$ 39.17
E	\$ 427.91	\$ 404.34	\$ 432.00	\$ 407.82
F	\$ 1,178.54	\$ 1,124.50	\$ 1,165.64	\$ 1,090.61
G	\$ 445.46	\$ 302.46	\$ 330.69	\$ 221.21
H	\$ 134.67	\$ 134.46	\$ 134.61	\$ 134.41
I	\$ 0.01	\$ 0.01	\$ 76.69	\$ 68.41
J	\$ 2,849.75	\$ 2,439.79	\$ 2,636.87	\$ 2,226.74
K	\$ 643.81	\$ 516.75	\$ 602.64	\$ 474.38
Total	\$ 7,120.3	\$ 6,308.0	\$ 6,805.6	\$ 5,990.3

Production Cost Savings \$(Millions)
 Without NYRI - With NYRI \$ 315
 100% EEPS Without NYRI - 100% EEPS With NYRI \$ 318

Production Cost in 2006 Real \$ (Millions)



284