Testimony
06-M-0878

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March 7, 2007

Honorable Gerald L. Lynch
Honorable Michelle L. Phillips
NYS Department of Public Service
Three Empire State Plaza
Albany, NY 12223

Re: Case 06-M-0878 – Joint Petition of National Grid plc and KeySpan Corporation for Approval of Stock Acquisition and other Regulatory Authorizations

Dear Judges Lynch and Phillips:

In accordance with the procedural schedule established in the above proceeding, National Grid plc and KeySpan Corporation hereby submit their Prepared Rebuttal Testimony concerning merger-related issues. This testimony responds to the Pre-filed Direct Testimony filed by the Department of Public Service Staff and various intervenors in these proceedings on February 20, 2007.

The Companies' filing herein contains a number of new proposals that are intended to address the concerns raised by the Department of Public Service Staff and other intervenors in their February 20 testimony. Specifically, while the Companies believe that the ten-year rate plan included as part of their initial petition remains the most appropriate way to establish just and reasonable rates for The Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York ("KEDNY") and KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island ("KEDLI") following the merger, the Companies are nonetheless offering an alternative proposal that would fix rates for a three year period while also providing an equitable sharing of the synergy savings derived from the merger over a ten year period. The Companies hope to discuss the merits of their alternative proposals with the parties in order to arrive at a long-term rate plan that is equitable to all parties.

This filing, which is being made in two volumes, includes the Prepared Rebuttal Testimony and exhibits of the following witnesses:

Volume I

- Lawrence J. Reilly and Steven L. Zelkowitz;
- John G. Cochrane and James Read;
- Steven L. Zelkowitz (Redacted);
- Cheryl A. Warren, Keith P. McAfee, David Wright and Scott D. Leuthauser ("Reliability Panel");
- Joseph F. Bodanza, Michael D. Laflamme and James M. Molloy ("Rates Panel");
- Alan V. Feibelman and Richard J. Levin;
- Lee Klosowski and Melissa Nairn;

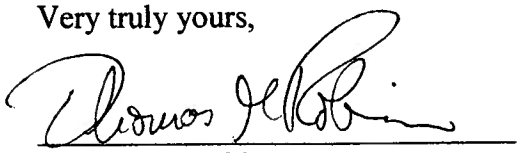
Volume II

- Robert B. Catell;
- Lawrence J. Reilly;
- Masheed Saidi; and
- Peter Fox-Penner.

The stand alone testimony of Steven L. Zelkowitz is being submitted in redacted and unredacted versions. Because this testimony addresses confidential discovery responses to DPS-58, and the follow-up requests DPS-179 and DPS-235, service of the unredacted version is being made in accordance with the December 20, 2006 Second Permanent Protective Order. Consequently, we have distributed the confidential testimony to a single representative of only those parties listed on Appendix 1 to the December 20th Protective Order. For ease of reference, we have attached a copy of the February 16, 2007 Active Parties List, annotated to indicate which parties will receive the unredacted version of Mr. Zelkowitz's testimony. All Active Parties have been sent a copy of the redacted version of this testimony.

Please contact the undersigned if you have any questions or require further information.

Very truly yours,



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Enclosures

cc: Secretary Brilling (40 copies)
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* Parties marked with an asterisk have received unredacted version of confidential testimony.

Case 06-M-0878
National Grid and KeySpan - Merger Petition
Cases 06-G-1185 and 06-G-1186
KeySpan Energy Delivery New York and Long Island - Gas Rates
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Joint Petition of National Grid PLC and
KeySpan Corporation For Approval of Stock
Acquisition and other Regulatory Authorizations
Case 06-M-0878
Rebuttal Testimony and Exhibits
March 7, 2007
VOLUME NO. II

Joint Petition of National Grid plc and KeySpan Corporation For Approval of Stock Acquisition and other Regulatory Authorizations
Case 06-M-0878
Rebuttal Witnesses and Exhibits

	Witness	Identifier Exhibit	Title
	VOLUME I		
1.	Steven L. Zelkowitz/Lawrence J. Reilly	Exhibit No.__(LJR/SLZ-1R)	National Grid and KeySpan Suggested Conditions For Merger Approval
2.	John C. Cochrane/James Read	Exhibit No.__(JGC/JR-1R)	Utilities Ratings
		Exhibit No.__(JGC/JR-2R)	Moodys Investors Service - Global Credit Research
		Exhibit No.__(JGC/JR-3R)	National Grid plc Capital Structure
		Exhibit No.__(JGC/JR-4R)	Response to DPS-158
		Exhibit No.__(JGC/JR-5R)	Response to DPS-111, DPS-198
		Exhibit No.__(JGC/JR-6R)	James A. Read, Jr. - Principal
3.	Steven L. Zelkowitz	No Exhibits	
4.	Cheryl A. Warren/Keith P. McAfee/ David Wright/Scott D. Leuthauser ("Reliability Panel")	Exhibit No.__(Reliability Panel-1R)	Charts, Graphs and Tables
		Exhibit No.__(Reliability Panel-2R)	Summary of Capital Additions Forecast
		Exhibit No.__(Reliability Panel-3R)	Line Workers (1999-2006)
		Exhibit No.__(Reliability Panel-4R)	National Grid - New York - PSC Request 281 - Part 2A

5.	Joseph F. Bodanza/Michael D. Laflamme/ James M. Molloy ("Rates Panel")	Exhibit No.__(Rates Panel-1R)	Three Year Rate Proposal
		Exhibit No.__(Rates Panel-2R)	Calculation of 10 Year Levelized Net Synergy Volume By Year
		Exhibit No.__(Rates Panel-3R)	KEDNY Synergies and CTA
		Exhibit No.__(Rates Panel-4R)	Niagra Mohawk (electric) - Computation of Synergies
6.	Alan V. Feibelman/Richard J. Levin	Exhibit No.__(AVF/RJL-1R)	Corporate Services: Confidence Levels
		Exhibit No.__(AVF/RJL-2R)	Savings Phase-In Rates
		Exhibit No.__(AVF/RJL-3R)	Response To DPS-11
7.	Melissa Nairn/Lee Klosowski	Exhibit No.__(MN/LK-1R)	Illustrative Example of National Grid's and KeySpan's Proposed Opportunity Cost Target
	VOLUME II		
8.	Robert B. Catell	No Exhibits	
9.	Lawrence J. Reilly	No Exhibits	
10.	Masheed Saidi	No Exhibits	
11.	Peter Fox-Penner	Exhibit No.__(PFP-1R)	Visual Evidence of Outages Impacts on Zone J Price
		Exhibit No.__(PFP-2R)	Monthly Prices Graphs of August 2004-July 2005 Backcasting Zones A-K
		Exhibit No.__(PFP-3R)	Backcast Price Summary Statistics for All Zones: Year Ending July 2005
		Exhibit No.__(PFP-4R)	NYISO Transmission Facility Maintenance Outage Impact Report
		Exhibit No.__(PFP-5R)	NYISO Day-Ahead Limiting Constraints Report for June 1, 2006
		Exhibit No.__(PFP-6R)	NYISO Operational Announcements of June 1, 2006
		Exhibit No.__(PFP-7R)	Panels A and B: Generation and Capacity Factor Comparison Between Base Case and Scenario 1 for Hours 8 and 19 on June 8, 2007

PREPARED REBUTTAL TESTIMONY

OF

ROBERT B. CATELL

ON BEHALF OF

NATIONAL GRID plc

AND

KEYSPAN CORPORATION

CASE 06-M-0878

MARCH 7, 2007

ROBERT B. CATELL

Q. Please state your name and business address.

A. My name is Robert B. Catell. My business address is One MetroTech Center, Brooklyn, New York 11201.

Q. By whom are you employed and in what capacity?

A. I am Chairman and Chief Executive Officer of KeySpan Corporation ("KeySpan"). I also serve as Chairman and Chief Executive Officer of The Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York ("KEDNY" or "Brooklyn Union"). I am also Chairman of a number of additional KeySpan affiliates and subsidiaries.

Q. Please describe your education and professional background.

A. I received both my Bachelor's and Master's degrees in Mechanical Engineering from the City College of New York. I am a Registered Professional Engineer in the State of New York. I attended Columbia University's Executive Development Program and the Advanced Management Program at the Harvard Business School. I joined Brooklyn Union in 1958, and have nearly 50 years of experience working at New York utility companies. After holding numerous management positions at Brooklyn Union, I was elected Assistant Vice President in 1974, Vice President in 1977, Senior Vice President in 1981 and Executive Vice President in 1984. In 1986, I was elected Brooklyn Union's Chief Operating Officer, and in 1990, I was elected Brooklyn Union's President. In 1991, I was elected Brooklyn Union's President and Chief Executive Officer. In 1996, I was named Chairman

and Chief Executive Office of Brooklyn Union. In 1998, I assumed my present position.

I am a co-chair of the Board of the Downtown Brooklyn Partnership and chair of the Long Island Association. I am also a member of the Board of Directors of the following industry and business organizations: Business Council of New York State, Colin Powell Center for Policy Studies, Edison Electric Institute, Energy Association of New York State, The Houston Exploration Company, KEYERA Energy Management, New York State Energy Research and Development Authority, NYC Public Private Initiatives, Inc., and the U.S. Energy Association ("USEA").

I am an ex officio Director and Chairman Emeritus of The Partnership for New York City, Inc., a past Chairman of The Houston Exploration Company, the American Gas Association, the USEA and the Advisory Board of the City College of New York's School of Engineering. I am a Vice Chairman of the National Petroleum Council's Natural Gas Committee and also a member of its Finance Committee. I also serve on JP Morgan/Chase's Metropolitan Advisory Board, the advisory Board of HeartShare for Human Services and the advisory board for SUNY Farmingdale.

Q. Please describe your community involvement and community service activities.

A. My community involvement includes serving as a Trustee of the Brooklyn Botanic Garden. I serve as Trustee Emeritus of both the Brooklyn Law School and the Brooklyn Bureau of Community Service. Also, I am a former Chairman of the Brooklyn Chamber of Commerce. I am also a member of many other organizations, including: American Gas Association, Association of Energy Engineers, National Petroleum Council, National Society of Professional Engineers, NYS Society of Professional Engineers, and the New York Building Congress.

Q. Have you ever testified before the New York State Public Service Commission ("the Commission") or any other regulatory commission?

A. Yes. I have testified before the Commission, the Federal Energy Regulatory Commission (and its predecessor the Federal Power Commission) and other administrative and legislative bodies on numerous occasions.

Q. In the event that the pending merger transaction (hereinafter "the Transaction") between KeySpan and National Grid plc ("National Grid") is completed, will you hold a position in the merged organization?

A. Yes. Upon completion of the Transaction, I will become Executive Chairman of National Grid USA and Deputy Chairman of National Grid plc. In that position, I will have significant responsibility for National Grid's operations in the United States, as well as input into the global policies of National Grid.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my testimony is to address the testimony submitted by John D. Stewart, Warren E. Myers and Thomas Coonan ("the Merger Panel") on behalf of the Department of Public Service ("DPS") Staff. Specifically, I will address the Merger Panel's claims that the Transaction is not in the public interest because the Transaction could cause the management of National Gird to be less responsive to the Commission's concerns and the interests of New Yorkers. I also will address the testimony of the Merger Panel and DPS Staff witness David F. Reulet regarding National Grid's service quality in New York.

Q. Do you have any overall comments concerning the DPS Staff's testimony in these proceedings?

A. Yes. I am extremely concerned about the nature of Staff's testimony in opposition to the proposed merger in several respects. Staff's testimony appears to consist largely of a series of speculative assertions about "worst case" possible outcomes. Staff does not appear to consider the extensive testimony demonstrating that the proposed combination of KeySpan and National Grid will create substantial benefits for the customers and communities served by the two companies. In my view, Staff unreasonably ignores and fails to recognize in the public interest determination the real synergy savings that the Transaction will create for New York customers or the track record of both KeySpan and National Grid in completing and implementing mergers and acquisitions in a manner that

has provided significant benefits to the customers and communities served by our operating utilities, including those operating in New York State.

Q. In your opinion, have KeySpan's customers benefited from KeySpan's past mergers and acquisitions?

A. Absolutely. Over the past decade KeySpan has been involved in several utility mergers and acquisitions, including the merger of KEDNY and those assets of the Long Island Lighting Company not acquired by the Long Island Power Authority, including KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island ("KEDLI") in 1998 and the acquisition of Eastern Enterprises ("Eastern") in 2000, have been the primary reason that KEDNY and KEDLI have been able to avoid increasing rates to our utility customers for more than a decade. During that time, KeySpan's utility customers have not only paid stable rates, they have received rate reductions directly as a result of the cost savings that we were able to realize. We have been able to reduce our unit costs, and we have been able to use our larger size and scale to introduce best practices to enhance the quality of our service while at the same time minimizing our costs. As a result, we have not only been able to provide safe and reliable gas distribution services at stable rates, we have also assisted the Long Island Power Authority in providing safe and reliable electric service at a reasonable cost to Long Island consumers and have achieved reliability standards for overhead electric utilities second to none in New York State. The expertise that we have gained in providing both gas and electric

service will serve us well when we combine with National Grid to provide these services on an even greater scale.

Q. Do you believe that National Grid's past acquisitions have also benefited customers in New York?

A. Yes. I have been in the utility business in New York for nearly 50 years, and I recall clearly that at the time National Grid acquired Niagara Mohawk Power Corporation ("NiMo"), that utility faced a number of difficult challenges. National Grid has met those challenges, and has enabled NiMo to attain a level of financial stability that it did not have prior to the acquisition. While it is certainly true that additional challenges remain for both National Grid's and KeySpan's utilities, all of these entities and their customers will benefit from the combination of expertise that will result from the merger of National Grid and KeySpan.

Q. Are the benefits of consolidation of utility operations unique to KeySpan and National Grid?

A. Of course not. Generally, throughout the U.S. utility industry, an era of stable prices is now being followed by upward pressure on rates due to rate base growth resulting from the need to make significant capital investments in new infrastructure and to replace and enhance the existing aging infrastructure. Moreover, productivity gains of the past decade cannot continue *ad infinitum*. We have seen the evidence of that trend in New York, with all energy utilities now back into a cycle of regular rate increases following a period of rate stability.

This pressure on rates can be offset through the continuing consolidation of a fragmented industry in order to provide companies with the economies of scale that can further reduce unit costs. Unfortunately, if the Commission adopts the positions of the Merger Panel concerning this transaction, New York will be unable to participate in any further scale efficiencies because any further utility merger and acquisitions likely will be economically infeasible.

Q. Following completion of the Transaction, does National Grid plan to structure the management of its United States utility operations in a manner that will enable the combined entity to benefit from the expertise of both National Grid and KeySpan?

A. Yes. Although various Staff witnesses express concern over National Grid's historical service quality problems and the impact that may have on the KeySpan Energy Delivery companies, from an operational standpoint, it is far more likely that the Transaction will yield substantial improvements in service quality throughout what will be the combined National Grid US system. The commitment that National Grid is making to increase capital investments in upstate New York has been described by other witnesses and I need not repeat it here. In addition, while the Transaction from a financial standpoint is an acquisition by National Grid of all of the stock of KeySpan, from an operational and organizational perspective, the Transaction is very much a merger of equals with the best management team taken from both companies and adoption of best

practices. Therefore, this is not a situation in which the management of KeySpan will be eliminated. On the contrary, it has already been determined that a number of KeySpan *and* National Grid senior managers will be retained following completion of the Transaction. In fact, the key business teams comprising U.S. based operations will include executive and senior vice presidents selected from both National Grid and KeySpan. This combination ensures that both KeySpan and National Grid will benefit from the depth of experience and knowledge of senior management of both companies and that the best practices of both companies will be implemented. As a result, the combination of National Grid and KeySpan management will result in operational improvements throughout the combined National Grid/KeySpan system, especially in New York.

Q. The Merger Panel suggests that the Transaction could reduce the influence of the Commission on the holding company, which Staff believes could make it more difficult for the Commission to influence the holding company's actions. Do you agree?

A. No, I do not. The Transaction will not in any way affect the Commission's ability to regulate KEDNY and KEDLI or other KeySpan affiliates subject to the jurisdiction of the Commission. If anything, the Transaction will shift the "center of gravity" of National Grid's US business to New York by increasing the number of entities subject to the Commission's jurisdiction that are owned by National Grid, as well as the percentage of National Grid's utility assets that are located in

New York. These entities include not only KEDNY, KEDLI and NiMo, but also a number of entities that are subject to "lighthanded" regulation by the Commission, such as our Long Island and New York City generation assets. Thus, the Merger Panel's suggestion that the transfer of ownership and control of KEDNY and KEDLI from the KeySpan corporate family to the National Grid corporate family would somehow diminish the Commission's influence over these entities is unfounded. The Merger Panel appears to have lost sight of the fact that National Grid has made significant investments in New York State and has stated publicly on many occasions that it will continue to pursue a business strategy focused on growth in the United States. It would be a foolhardy business strategy for National Grid to make a $7.3 billion investment in KeySpan, in addition to its previous investment in NiMo, and then ignore the concerns of the Commission. Such a strategy would jeopardize not only its ability to earn a reasonable return on its investment, but also its ability to implement its growth strategy in New York and other states in the future. The Merger Panel's concerns that National Grid will somehow be impervious to the influence of the Commission are simply illogical.

Q. **In your experience, has the fact that a utility holding company expands its ownership interests into other states or regulatory jurisdictions meant that the influence of any individual state's regulatory authority declines?**

A. No. As a result of the acquisition of Eastern, KeySpan acquired regulated utilities in Massachusetts and New Hampshire. This acquisition did not divert our attention from our obligations to New York or cause us to ignore the concerns of Massachusetts or New Hampshire. Instead, as I described before, the combination of our operations with those of Eastern enabled KeySpan to benefit from the experience of managers employed by both Eastern and KeySpan and resulted in improved service levels throughout the KeySpan system. Moreover, the synergies arising from the Eastern transaction helped us to continue to avoid the need for rate increases in New York well beyond the dates on which the rates under the existing KEDNY and KEDLI rate plans were scheduled to expire.

Q. Are there any other aspects of the KeySpan/National Grid Transaction that should provide assurances to the Commission that the Transaction will not negatively affect New York's customers in the future?

A. Yes. KEDNY and KEDLI will continue to have headquarters in New York and their books and records will continue to be maintained in New York State. Moreover, as I described previously, existing KeySpan managers will continue to play significant roles in the management of the combined entities. Thus, there is no justification for the Merger Panel's concern that the proposed Transaction will diminish the responsiveness of the combined KeySpan/National Grid entity to the policies of the Commission. In addition, as I mentioned earlier in my testimony, I have spent nearly 50 years working at a New York utility and being involved in

the New York State community. During my tenure as Chief Executive of KeySpan, I have always encouraged KeySpan's management to exercise integrity in regulatory affairs, and to work constructively with the Commission, its Staff and the community on issues of all kinds. We have shown that we respect the important role that the Commission and the Staff play in regulating utilities and serving the public interest, and I believe that we have always been responsive to the Commission and its Staff. Following the completion of the Transaction, I will assume the position of US Chairman and will have overall responsibility for external affairs, including regulatory affairs here in the United States. I intend to ensure that the positive approach that KeySpan has taken in the past toward the Commission and Staff will carry over to the post-merger organization. I will continue to be based here in New York and I will continue to encourage our management to maintain its extensive involvement in business and civic affairs in New York. The KeySpan Foundation, which provides grants throughout KeySpan's service territory, will be continued either in its present form or with an expanded scope. Under these circumstances, I see no basis for Staff's assertion that the regulatory influence of the Commission will somehow be diminished by the Transaction.

Q. **Are you aware of any circumstances in which the Commission has been unable to successfully encourage entities subject to its regulations to follow its policies?**

A. No. In my experience the Commission has always been able to encourage utilities to adhere to and follow its policies regardless of whether those utilities were, like New York Telephone Company, owned by a holding company with multi-state operations. The Commission has long exercised national regulatory leadership and ensured that its influence extends well beyond New York State. The notion that the Commission will somehow be unable to influence the practices of KEDNY and KEDLI because they would be owned by National Grid simply does not comport with this experience.

Q. Is it your understanding that the Commission has previously dismissed arguments that it should reject mergers involving holding companies with significant operations outside New York State out of a concern that the Commission's influence will somehow be diminished?

A. Yes. It is my understanding that the Commission rejected similar arguments in the proceedings involving the proposed merger between NYNEX and Bell Atlantic Company. These arguments have no more validity here than they did in that proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

REBUTTAL TESTIMONY

OF

LAWRENCE J. REILLY

ON BEHALF OF

NATIONAL GRID plc AND KEYSPAN CORPORATION

P.S.C. CASE 06-M-0878

March 7, 2007

REBUTTAL TESTIMONY OF LAWRENCE J. REILLY

I. Introduction and Qualifications

Q: Please state your name and business address for the record.

A: My name is Lawrence J. Reilly. I am Executive Vice President and General Counsel of National Grid USA, and my business address is 25 Research Drive, Westborough, Massachusetts 01582.

Q: Have you previously sponsored testimony in this proceeding?

A: Yes. On October 3, 2006, I sponsored testimony with Steven L. Zelkowitz, President of KeySpan Corporation's Energy Assets and Supply Group. On October 27, 2006, I sponsored supplemental testimony addressing vertical market power issues related to the planned merger (the "Transaction") of National Grid plc and KeySpan Corporation ("National Grid" and "KeySpan," collectively "Applicants" or the "Companies").

Q: Is the description of your educational and employment background in your October 3, 2006, testimony still accurate?

A: Yes.

II. Purpose of Testimony

Q: What is the purpose of your rebuttal testimony?

A: The purpose of my rebuttal testimony is to further explain why the

Transaction is in the public interest and specifically to respond to arguments that the Transaction does not comply with the Commission's vertical market power policies.

On February 20, 2007, witnesses for Commission Staff filed testimony claiming that the proposed merger of National Grid and KeySpan (the "Transaction") does not comply with the Commission's vertical market power policies. I respond to certain arguments in the Staff's Merger Policy Panel ("MPP") and Constraints Panel ("CP") related to the potential for the Transaction to create vertical market power concerns. The testimony of Dr. Douglas W. Elfner submitted on behalf of the New York State Consumer Protection Board ("CPB") also briefly addresses vertical market power issues. The Companies' response to Staff testimony on vertical market power issues also fully addresses the issues raised by the CPB.

Specifically my rebuttal testimony: (1) introduces the other witnesses submitting testimony today on vertical market power issues and summarizes our key findings on those issues; (2) explains how the updated analyses provided today demonstrate that the Transaction complies with the Commission's vertical market power policies and applicable precedent; (3) explains why the Staff's concerns about the impacts of the Transaction on New York ISO ("NYISO") governance are misplaced; (4)

describes additional commitments the Companies are nonetheless prepared to make to assure the Commission that any hypothetical ability of the Companies to exercise vertical market power is mitigated, consistent with the Commission's Vertical Market Power Policy Statement; and (5) explains how the proposed Transaction is consistent with prior Niagara Mohawk and National Grid rate plans and will provide benefits to both customers and shareholders.

III. Summary of Rebuttal Testimony on Vertical Market Power Issues

Q: Who are the other witnesses filing rebuttal testimony on vertical market power issues today?

A: In addition to myself, two other witnesses submit rebuttal testimony addressing our findings and recommendations on vertical market power issues.

Dr. Peter Fox-Penner, an economist from the Brattle Group, responds to Staff arguments that the Transaction would "radically increase" the Companies' financial incentive to exercise both short-term and long-term vertical market power ("VMP") and that regulatory controls are insufficient to protect against this increased incentive. Dr. Fox-Penner rebuts Staff's position in a detailed economic analysis of whether the Transaction creates financial incentives to exercise short-term vertical

market power. This analysis uses a state-of-the-art market simulation model similar to the one used to actually dispatch the NYISO market to analyze the effect of the merger on Applicants' projected generation profits for every hour of 2007.

Dr. Fox-Penner's analysis highlights the disparity between the extremely small incremental profits the Companies theoretically could hope to obtain through a scheme to exercise vertical market power – less than $300,000 a year – and the far greater economic consequences of violating the numerous prohibitions on attempting to exercise vertical market power described in my October 27 testimony. In light of Dr. Fox-Penner's analysis, we do not believe that the Commission could conclude that a rational company would subject itself to disgorgement of profits, civil penalties of up to $1,000,000 a day, and revocation of market-based rate authority in return for the prospect of earning a few hundred thousand dollars annually.

In order to address any theoretical concerns about short-term vertical market power, however, the Companies are now proposing to adopt a mitigation mechanism based on Dr. Fox-Penner's economic model that monitors any voluntary transmission outages on the four relevant facilities that are not scheduled at least a month in advance. If an outage from one of these facilities is initiated by National Grid with less than 30

days' notice and results in an increase in Ravenswood's incremental profit exceeding a significant threshold (which Dr. Fox-Penner conservatively sets at $100,000), the Companies would pay any incremental Ravenswood profits to a fund that benefits customers.

Long-term vertical market power issues are addressed by Dr. Fox-Penner and Ms. Masheed H. Saidi, Chief Operating Officer – US Transmission for National Grid USA with responsibility for National Grid's US transmission business. Ms. Saidi addresses concerns that the Transaction will dilute National Grid's focus on transmission issues. Ms. Saidi and Dr. Fox-Penner also explain that Staff's claim that the Companies will have a disincentive to build or upgrade transmission facilities as a result of the Transaction is incorrect for two reasons. Dr. Fox-Penner explains that the argument that National Grid would avoid or delay the construction of economically-beneficial transmission facilities to capture congestion rents for Ravenswood ignores the ability of third parties to construct transmission or generation facilities that could reduce Zone J prices. More importantly, however, concerns about any disincentives the Transaction may create to invest in transmission facilities are more than amply addressed by the Companies' proposal to assume a binding commitment to build economically beneficial transmission projects as described in Ms. Saidi's testimony.

IV. The Commission's Vertical Market Power Policies and Applicable Precedent

Q: Is Staff's testimony consistent with the Commission's Policy Statement on vertical market power?

A: No. Staff suggests that divestiture of the Ravenswood generation plant is an absolute requirement for the Transaction to comply with "established Commission policy." *See, e.g.*, MPP at 185-86. This is contrary to the express terms of the Commission's Statement of Policy Regarding Vertical Market Power, Case 96-E-0900 *et al.* (July 17, 1998) ("Vertical Market Power Policy Statement" or "Policy Statement"). The Commission's Policy Statement establishes only a "rebuttable presumption . . . that ownership of generation by a T&D company affiliate would unacceptably exacerbate the potential for vertical market power." Vertical Market Power Policy Statement at Appendix I, pp. 1-2 (emphasis added). The Policy Statement provides utilities with the ability to overcome this presumption without divestiture of the generation assets by the T&D company.

Staff's testimony, however, suggests that the Policy Statement results in a complete prohibition on the acquisition of market-based generation by a T&D company. This is evidenced by Staff's statements suggesting that National Grid and KeySpan should have known that

divestiture of Ravenswood would be required as part of the merger. MPP at 186. If Staff's position were adopted, it would transform the rebuttable presumption established by the Commission in its 1998 Vertical Market Power Policy Statement into a total prohibition on the acquisition of market-based generation by a T&D company. This is contrary to the plain words of the Policy Statement itself. If the Commission had meant to absolutely exclude such transactions, presumably the Commission would have done so.

Q: What evidence in the Commission's Policy Statement makes it clear that the Commission's vertical market power policies do permit a T&D company to acquire an affiliate with generation assets?

A: The Commission's Vertical Market Power Policy Statement not only states that a utility can rebut the presumption that ownership of generation by a T&D company affiliate would unacceptably exacerbate the potential for vertical market power, but the Policy Statement also identifies three approaches to overcome this rebuttable presumption:

> To overcome the presumption the T&D company affiliate would have to demonstrate that vertical market power could not be exercised [1] because the circumstances do not give the T&D company an opportunity to exercise market power, or [2] because reasonable means exist to mitigate market power. [3] Alternatively, the T&D company would need to demonstrate that substantial ratepayer benefits,

> together with mitigation measures, warrant overcoming the presumption.

Policy Statement at Appendix I, p. 2. The Policy Statement establishes no preference for any of these three alternatives. Our prior testimony in this proceeding, as supplemented by today's filings, including the economic analysis provided by Dr. Fox-Penner and the additional mitigation proposals advanced by the Companies, shows that the Transaction overcomes the rebuttable presumption under each of these alternatives. In particular, the more than one half billion dollars of net synergy savings that would flow to New York electric and gas consumers in the first ten years following the merger, clearly provides the "substantial ratepayer benefits" warranting overcoming the presumption.

Q: Has the Commission permitted a T&D company to acquire generation since the Policy statement was adopted?

A: Yes. On two separate occasions since the Policy Statement was adopted, the Commission has authorized a T&D company to acquire generation. While the facts of these cases differ in some respects from the present case, they demonstrate that the Vertical Market Power Policy Statement is not a complete prohibition on transactions in which a T&D company obtains an interest in generation assets.

In 1998, shortly after the Vertical Market Power Policy Statement

was adopted, the Commission authorized an affiliate of the Consolidated Edison Company ("Con Edison") to bid on generation that Con Edison was divesting subject to mitigation conditions, even though: (1) Con Edison's affiliate would own generation in the same market zone and service territory as Con Edison's transmission and distribution facilities; and (2) there was no demonstration that ownership of the generation by Con Edison's affiliate would provide any customer benefits.[1] The Commission has permitted Con Edison to own generation to this day, including 629 MW of summer-rated capacity that is related to Con Edison's steam-utility operations.[2]

In 2006, the Commission allowed the acquisition of the Lyonsdale generating facility, a Qualifying Facility ("QF") located in New York State, by Central Hudson Enterprises Corporation, an unregulated affiliate of Central Hudson Gas & Electric Corporation. Case 05-E-1423, 2006 WL 162636 (January 20, 2006). Both Central Hudson Enterprises Corporation and Central Hudson Gas & Electric Corporation are subsidiaries of CHEnergy Group. When considering the request, the

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1 Order Authorizing the Process for Auctioning of Generation Plant, Case 96-E-0897 at pp. 20-21 (July 21, 1998); *see also* Vertical Market Power Policy Statement at p. 7.

2 *See, e.g., Triennial Market Power Analysis*, filed November 18, 2004, Docket Nos. ER99-2251, *et al.* at 4.

Commission first found that Lyonsdale was a Qualifying Facility and thus section 70 of the Public Service Law did not directly apply. The Commission found that the acquisition was appropriate under PSL §107 and authorized under Central Hudson's Rate and Restructuring Order. However, the Commission also evaluated the acquisition under the Commission's Vertical Market Power Policy Statement. As the Commission found:

> CHEC's authority to invest in QFs is not necessarily unbounded. In the Statement of Policy Regarding Vertical Market Power (Statement of Policy), it was decided that a holding company, like CHEG, owning a delivery affiliate, like Central Hudson, might take actions to increase profits of its generation affiliates, like CHEC, at an increased cost to captive utility ratepayers. As a result, a rebuttable presumption was created, requiring electric utilities, including CHEG and CHEC, to demonstrate that their investments in generation would not unacceptably exacerbate the potential for market power. The Statement of Policy also provided that its guidelines did not override the terms and conditions of specific Rate and Restructuring Orders.
>
> The Lyonsdale transaction CHEC proposes need not be reviewed under the Statement of Policy. CHEC is investing in a 20 MW QF located in NYISO Zone E while Central Hudson is located in Zone G. The small size of the generation ownership interest CHEC intends to obtain, and the location of the generation and delivery system facilities that will become affiliated as a result of the transaction [emphasis added], could not give rise to market power. As a result, questions related to the effect of the Statement of Policy on utility investments in QFs and the relationship between the Statement of Policy and the Rate and Restructuring Orders, will not be addressed here.

2006 WL 162636, page 2, footnote omitted.

In the instant Transaction, National Grid's transmission facilities are also in different NYISO zones than KeySpan's generation. As Dr. Fox-Penner explains, his analysis shows that the geographic separation of National Grid's transmission facilities from KeySpan's generation limits the impact of National Grid transmission withdrawals on prices earned by KeySpan generation. The mitigation proposal described in Dr. Fox-Penner's testimony is designed to eliminate any remaining short-term vertical market power concerns associated with the Transaction.

Q: Staff believes that the Commission's 1998 Policy Statement implicitly dismissed as ineffective NYISO's control of and authority and oversight over the New York transmission system in detecting, preventing, and deterring attempts by transmission owners to exercise vertical market power. MPP at 138. Do you agree?

A: I do not. For one thing, FERC's decision allowing the New York utilities to proceed with their plan to form an independent system operator was only a few weeks old on the date the Commission issued its Policy Statement. *See Central Hudson Gas & Electric Corp. et al.*, 83 FERC ¶ 61,352 (1998). The NYISO did not begin operations until November 18, 1999, over a year after the Vertical Market Power Policy Statement was issued. *See Central Hudson Gas & Electric Corp. et al.*, 88 FERC ¶

61,229 (1999). The NYISO manuals containing the rules, reporting requirements, and other protections discussed in the direct testimony of Michael L. Schiavone in this proceeding were initially compiled in 1999; and each of these manuals have continued to evolve until the present day. *See* NYISO Outage Scheduling Manual, Revision History; NYISO Transmission and Dispatching Manual, Revision History; Draft NYISO Transmission and Dispatching Manual as of March 10, 2006, Revision History. Accepting Staff's position would require us to attribute to the Commission an irrational intention to analyze the efficacy of rules and procedures that had not yet been promulgated.

V. NYISO Governance

Q: Please address Staff's concern that the proposed Transaction would change National Grid's voting behavior in the NYISO governance process and would "significantly alter the balance of interests at the NYISO Committees and lower-level working groups, making it much more difficult to develop rules and procedures to deal with market power and mitigation"? Constraints Panel at 48-49.

A: Under Section 7.05 of the NYISO Agreement, a NYISO governance participant, together with any affiliate or affiliates, may vote in only one sector and may cast only one vote in the Management Committee. After

the merger, the Companies will cast a single vote in the Transmission Owner sector, reducing the Companies' combined vote in the stakeholder process. National Grid's single vote after the merger is unlikely to swing the results of most stakeholder votes. As Staff notes, the Transmission Owner sector has a total vote of 20 percent in the Management Committee, and National Grid, as one of four voting members of that sector, has a 5 percent vote in the Management Committee.

There is also no reason to conclude that National Grid will vote against beneficial transmission policies. As described in Ms. Saidi's testimony, as a condition to approval of the merger, National Grid is assuming an obligation to propose and construct transmission projects to address both reliability and economic needs. This commitment is further supported by the commitment to continue National Grid's transmission advocacy efforts described in Ms. Saidi's testimony. Moreover, after the merger, National Grid will remain overwhelmingly a T&D company. Once the Transaction is completed, generation interests will be approximately 5 percent of National Grid's enterprise value. National Grid also knows full well that its votes at the NYISO Management Committee will be closely scrutinized by all stakeholders, including the Commission. Together, all of these facts show that National Grid will continue to be a leading proponent of transmission interests at the NYISO.

VI. Commitments to Ensure Compliance with Commission's Vertical Market Power Policies

Q: Staff has suggested that the Transaction can only comply with the Commission's vertical market power policies if certain conditions are satisfied. Have you evaluated their conditions?

A: Yes. As I explain below, we have serious concerns with certain of the conditions suggested by the Staff on the vertical market power issue. Before discussing the conditions proposed by Staff, I would like to summarize the commitments that Companies would suggest to eliminate any question as to whether the Transaction complies with the Commission's vertical market power policies. Although the testimony submitted in this proceeding demonstrates that the Transaction complies with these policies without any conditions, the Companies recognize that it will facilitate the Commission's review of the Transaction to adopt these commitments as a condition to Commission approval of the merger. These commitments would satisfy the second alternative to complying with the Commission's 1998 Policy Statement – a demonstration that reasonable means exist to mitigate any market power which might be created by the merger. These proposed commitments, along with other proposed conditions to approval of the Transaction, are also summarized in Exhibit __(LJR/SLZ-1).

Q: Do the Companies continue to support their previously proposed commitments related to vertical market power?

A: Yes. In the Companies' October 27 testimony on vertical market power issues, the Companies proposed the following commitments to address any hypothetical VMP concerns that the Commission might have.

First, in order to further the visibility of National Grid's transmission operations, the Companies propose to provide the Commission with additional information on transmission outages. Specifically, the Companies propose to provide the Commission with advance notice of emergency (*i.e.*, unscheduled) 230 KV and 345 KV outages as soon as National Grid notifies the NYISO of the need for such outages. The only exception to such advance notification will be when immediate action to take a facility out of service is needed for safety or mechanical protection reasons; in this case, telephone notification to the Commission will take place at the earliest reasonably possible time after the outage is initiated. National Grid will also make operations personnel available to answer questions and offer explanations for operational actions to Commission Staff who request such information. This commitment was discussed in the testimony of Mr. Schiavone. As discussed below, the Companies also are proposing an automatic financial

mitigation mechanism which is designed to eliminate any financial incentive the Companies will have to exercise short-term vertical market power.

To address Staff concerns about the potential impact of the Transaction on National Grid's transmission advocacy efforts, National Grid also commits to continue to support the transmission-related New York policy initiatives and proposals described in Ms. Saidi's testimony through the appropriate stakeholder processes and regulatory proceedings.

To address long-term vertical market power concerns, the Companies also propose, as a condition to approval of the merger, that National Grid assume certain new obligations to propose and build regulated transmission projects with either economic or reliability benefits to New York customers without regard to the impact of such projects on the economics of KeySpan Ravenswood or any other generation interests of the Companies. These commitments are discussed in the initial and rebuttal testimony of Ms. Saidi. As explained in Ms. Saidi's initial and rebuttal testimony and in the rebuttal testimony of Dr. Fox-Penner, the long-term commitments of the Companies to propose and build transmission projects that an independent entity has confirmed will address economic or reliability needs effectively mitigates any long-term vertical market power concerns created by the merger.

Q: Are the Companies offering additional commitments to mitigate the potential of the Transaction to create vertical market power?

A: Yes. The Companies now offer an additional mitigation proposal which is designed to eliminate any financial incentives of the Companies to engage in short-term VMP. The Companies propose to use Dr. Fox-Penner's simulation model (or a similar model) as the basis for an automatic financial mitigation measure. Under this mechanism, whenever National Grid declares a voluntary (*i.e.*, non-forced) outage on one of the four lines identified as Critical Facilities[3] that was not on its month-ahead transmission outage schedule, simulations will be performed with and without this particular outage change. The difference in KeySpan's profits on Zone J generation due to the outage with less than 30 days' notice – if any – will be paid by the Companies into a fund to benefit customers. As Dr. Fox-Penner explains, this mechanism fully removes any incentive for National Grid to intentionally cause an outage on one of the critical transmission facilities with the objective of raising Zone J prices and benefiting Ravenswood generation. The procedure and conditions for

3 The four lines are: Leeds-Pleasant Valley, Leeds-Athens, Athens-Pleasant Valley and Leeds-Hurley.

running these simulations are further discussed in Dr. Fox-Penner's testimony.

Q: What is the Companies' position on Staff's proposal to condition approval of the Transaction on an agreement that National Grid and its affiliates not own additional generation in New York?

A: The Companies are prepared to accept this condition with certain modifications and clarifications. Specifically, unless approved by the Commission, National Grid shall not directly or through an affiliate develop additional generation facilities in New York other than generation capacity specifically requested by the Long Island Power Authority or the New York Power Authority, under a long-term contract. In addition, any generating facilities located in New York that may be acquired by National Grid as part of future transactions must meet the Commission's guidelines on vertical market power through a combination of commitments that address the transmission-owning utility's ability and incentive to exercise vertical market power.

Q: Is the Staff's proposal to require divestiture of the Ravenswood generation facility an appropriate condition to approval of the Transaction?

A: No. Any potential vertical market power concerns created by the Transaction are mitigated by the other commitments the Companies have proposed and by the automatic financial mitigation mechanism described in Dr. Fox-Penner's testimony in particular. As discussed above, the Staff has substantially overstated the requirements of the 1998 Policy Statement by suggesting that the Commission's policies require divestiture of the Ravenswood facility. Moreover, as described in the October 3, 2006, testimony of Mr. John Cochrane, a sale of the KeySpan generation, including Ravenswood, would not only reduce KeySpan's economic value, it would also create a large immediate tax liability that adversely affects the economics of the Transaction. Thus, the substantial ratepayer benefits resulting from the Transaction, *which will not be realized if the Transaction does not move forward,* overwhelm any potential harm to ratepayers if it does, especially in light of the significant mitigation measures proposed by us here.

VII. National Grid's Commitment to Pursue Opportunities That Will Provide Benefits to Customers and Shareholders

Q: Please address Staff's concern that the Transaction is inconsistent with commitments made by Niagara Mohawk in the October 1997 Power Choice Settlement or in the 2001 merger of National Grid and Niagara Mohawk.

A: Staff acknowledges that the express terms of the Power Choice Settlement permit National Grid to seek to acquire generation through a merger. MPP at 144. Staff nonetheless claims that the proposed Transaction is contrary to the "spirit" of that settlement and to statements made in 2001 that National Grid/Niagara Mohawk was exiting the generation business. For the reasons discussed below, although National Grid did not contemplate acquiring generation in 2001, National Grid is not acting contrary to any commitments it has previously made to the Commission, implicit or otherwise.

As I explained in my October 27 testimony, Section 5.1 of Attachment 23 to the Joint Proposal of National Grid USA and Niagara Mohawk Power Corporation, Case 01-M-0075, provides in relevant part:

> **Relationship to Divestiture**
>
> Because the PSC will assert its authority to review merger applications under the Public Service Law, nothing in this Joint Proposal will limit the Company's ability to merge with or be acquired by another entity.

The possibility that further mergers and acquisitions would occur was reflected in the follow-on merger credit to the deferral account in Section 1.2.4.19 of the Joint Proposal in Case 01-M-0075. Nothing in this Joint Proposal suggested that further mergers could not involve utilities owning generation.

Although the Power Choice Settlement was superseded by the Joint Proposal in Case 01-M-0075, the relevant provisions of the Merger Rate Plan are consistent with the Power Choice Settlement itself, and if the Power Choice Settlement remained in effect, it would allow the Transaction to go forward. Page 17 of the Power Choice Settlement provided that: "Because the PSC will review merger applications under the Public Service Law, nothing in this agreement will limit the Company's ability to merge with or be acquired by another entity owning generation." Thus, Power Choice is consistent with the provision in the Merger Rate Plan. The Commission has exercised its authority to review the merger under the Public Service Law, and National Grid is providing information demonstrating its compliance with the Commission's competitive and other policies.

Q: Please address Staff's claim that statements made in 2001 that National Grid and Niagara Mohawk were exiting the generation business have proven to be inaccurate.

A: National Grid's statements that it was exiting the generation business in 2001 were accurate. At that time, National Grid did not envision acquiring generation assets in the foreseeable future.

Q: If National Grid did not envision acquiring generation assets in 2001, how did National Grid decide to pursue the merger with KeySpan?

A: In evaluating whether to go forward with the proposed Transaction, National Grid management considered whether a merger with a company that owns generation would be consistent with National Grid's corporate strategy. National Grid management concluded that, under the specific facts of this Transaction (including the facts that most of KeySpan's generation is subject to long-term contracts and the Ravenswood generation is in a load pocket not directly connected to our transmission assets), the merger with KeySpan was appropriate, especially in light of the benefits to both customers and shareholders from the Transaction.

The testimony of the Companies, and in particular the analysis provided in Dr. Fox-Penner's rebuttal testimony, confirms that National Grid management was correct in concluding that the Transaction would be beneficial to customers and would not create the adverse consequences to customers which might be expected from a comprehensive vertical re-integration of transmission and generation functions. This testimony demonstrates that the Transaction satisfies the Commission's vertical market power policies under the third alternative approach endorsed in the 1998 Policy Statement, which allows a T&D company "to demonstrate that substantial ratepayer benefits, together with mitigation measures,

warrant overcoming the presumption [that vertical market power impacts are unacceptable]."

Q: Thank you. I have no further questions at this time.

REBUTTAL TESTIMONY

OF

MASHEED H. SAIDI

ON BEHALF OF

NATIONAL GRID plc AND KEYSPAN CORPORATION

P.S.C. CASE 06-M-0878

March 7, 2007

REBUTTAL TESTIMONY OF MASHEED H. SAIDI

I. Introduction and Purpose of the Testimony

Q: Please state your name, title, and business address for the record.

A: My name is Masheed H. Saidi. I am Chief Operating Officer – US Transmission for National Grid USA ("National Grid") with responsibility for National Grid's US transmission business. My business address is 25 Research Drive, Westborough, Massachusetts 01582.

Q: Are you the same Masheed H. Saidi who previously filed testimony in this case on October 27, 2006?

A: Yes, I am.

Q: Is the description of your educational and employment background in your October 27, 2006, testimony still accurate?

A: Yes.

Q: What is the purpose of your rebuttal testimony in this case?

A: The purpose of my testimony is to support the Joint Petition of National Grid plc and KeySpan Corporation ("KeySpan") by addressing certain issues related to the Commission's vertical market power policies. On February 20, 2007, witnesses for Commission Staff filed testimony

claiming that the proposed merger of National Grid and KeySpan (the "Transaction") does not comply with the Commission's vertical market power policies. I respond to certain arguments in the Staff's Merger Policy Panel ("MPP") and Constraints Panel ("CP") related to the potential for the Transaction to create long-term vertical market power concerns. Specifically, my testimony addresses arguments that the Transaction: (1) will dilute National Grid's focus on transmission operations, transmission planning, and transmission policy development; and (2) will create a disincentive for the Companies to invest in transmission facilities.

II. National Grid's Focus on Transmission

Q: Please briefly summarize Staff's claim that the Transaction will dilute National Grid's focus on transmission issues.

A: Staff contends that, because the Transaction would result in National Grid having an ownership interest in New York generation, including market-based generators, National Grid's financial incentives would "radically change." CP at 44. Staff claims that, due to this change in incentives, "National Grid's focus on transmission would inevitably be diluted, if not reversed" and "[w]e could no longer count on National Grid assigning its best employees and resources to the management of transmission projects

or the development of transmission proposals at the NYISO." *Id.* at 44-45.

Q: Do you agree with this claim?

A: No. This claim is incorrect. Staff suggests that the Transaction will somehow transform National Grid into a company focused primarily on generation profits. This is not true. As the finance panel explains in its rebuttal testimony, once the Transaction is completed, generation will be a small percentage of National Grid's business, and transmission and distribution will continue to be, by far, our primary business activity. As mentioned in Mr. Reilly's testimony, once the Transaction is completed, generation interests will be approximately 5 percent of National Grid's enterprise value. Given National Grid's extensive involvement in the delivery service business, both in the US and in the UK, our overall business profile supports the conclusion that we will continue to focus on transmission issues.

Q: Are there additional reasons why the Transaction will not result in a diluted focus on transmission issues?

A: Yes. As I have previously testified, National Grid's US transmission business is operated as a separate line of business from National Grid's

electric or gas distribution businesses. After the Transaction is completed, KeySpan Ravenswood and other KeySpan generation assets will be operated separately from the US transmission business that I oversee. Under this organizational structure, employees and resources committed to the US transmission business will not be utilized by the separate business of National Grid's new affiliates with generation facilities. This organizational structure is consistent with FERC's Standards of Conduct, which preclude a sharing of employees between the US transmission business and National Grid's new affiliates with generation facilities.

As the head of National Grid's US transmission business, I want to assure the Commission that National Grid will continue to assign only the most qualified employees to the management of transmission projects and development of transmission proposals.

Q: How do you respond to Staff's arguments that, as a result of the Transaction, the Commission will not be able to count on National Grid to influence the development of New York ISO rules and policies or initiate other policy initiatives that will allow customers to benefit from improved use of and investment in the transmission system?

A: First, these arguments rest on the inaccurate premise that the Transaction will change National Grid's financial incentives so as to favor generation

interests. In my initial testimony, I explained National Grid's commitment to continue as an advocate for policies that will create long term benefits to customers from the efficient operation and expansion of the transmission system. As the head of National Grid's US transmission business, I will be responsible for fulfilling these commitments.

Moreover, National Grid has continued to advocate for proactive transmission policies since the KeySpan merger was announced. For example, National Grid submitted comments in FERC's rulemaking proceeding considering changes to open access transmission tariff regulations (FERC Docket Nos. RM05-25 and RM05-17) in August 2006 that supported requirements for comprehensive transmission planning that take into account both reliability and economic needs. In FERC's Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, issued on February 16, 2007, the FERC adopted the proposal to establish requirements for transmission planning for both reliability and economic needs, consistent with National Grid's comments.

Q: Is Staff correct when they claim that the development of the maintenance incentives reflected in Attachment N to the New York ISO OATT is an example of National Grid pursuing policy initiatives "influenced by its own financial incentives" without regard to the

interests of New York customers?

A: No. This is actually an example of National Grid pursuing a policy that is beneficial to customers, and specifically to National Grid's end-use customers upstate. The goal of the new maintenance incentives in Attachment N was to allocate congestion costs appropriately among utilities. Both before and after the reforms supported by National Grid, these congestion costs are allocated to New York customers. Under Attachment N, transmission congestion revenue shortfalls are assigned to the load of the transmission owner responsible for their incurrence, rather than socialized to the customers of all transmission owners. In the case of National Grid, our customers no longer have to pay a share of congestion revenue shortfalls incurred due to short term outages taken by other transmission owners and vice versa. Thus, the reform was intended to assure appropriate cost allocation to customers and was not driven by the financial incentives of the Company itself. This reform is consistent with National Grid's broader position that customers will benefit from more efficient and proactive transmission policies.

III. National Grid Investment in Transmission Facilities

Q: Is Staff correct in claiming that the Companies will have a disincentive to build or upgrade transmission facilities as a result of

the Transaction?

A: No. This claim is incorrect for two reasons. First, Staff claims that potential profits to KeySpan generation (and specifically profits to the Ravenswood facility, the only KeySpan generation not under long-term contracts) resulting from retaining existing transmission constraints on the National Grid system will necessarily outweigh the financial incentives of investing in transmission upgrades. As discussed by Dr. Fox-Penner, this suggestion assumes that the retention of transmission constraints will necessarily increase generation profits and ignores the ability of third parties to construct transmission or generation facilities that could mitigate Zone J prices. More importantly, however, this argument fails to take into account the Companies' proposal to assume a binding commitment to build economically beneficial transmission projects.

Q: Please summarize the commitment described in your prior testimony.

A: As described in more detail in my initial testimony: (1) If the transmission planning process administered by the New York ISO ("NYISO") identifies either an economic or reliability need for which National Grid is designated as the "Responsible TO," National Grid is prepared to assume an obligation to propose a regulated solution on our system to address identified economic needs in addition to the current obligations with

respect to reliability needs and to assume the obligation to construct that regulated solution to either economic or reliability needs if the Commission determines that National Grid's proposed regulated solution is the preferred solution; and (2) even if National Grid is not designated by the NYISO as the "Responsible TO" to address a given need, National Grid is prepared to assume an obligation to propose an alternative regulated solution if feasible and to assume the obligation to construct any portion of that solution located on its system in New York if the Commission determines that National Grid's proposed alternative regulated solution is the preferred solution. I also wish to clarify that the expansions of the transmission system to address an identified economic need which National Grid commits to construct may be proposed by the Commission itself. More details about the conditions of this proposal are set forth in my initial testimony. I discuss recent developments requiring the development of a transmission planning process that considers economic needs later in my testimony.

Q: How does this commitment address Staff's concerns that the Transaction could result in reduced investment in transmission investment by National Grid?

A: Under this commitment, National Grid will not have the discretion to

determine whether to move forward with an economically beneficial transmission project. If the Commission approves the merger and accepts the commitment described in my initial testimony, National Grid will be subject to a clear obligation that does not exist today to build transmission projects that provide economic benefits to New York customers. Thus, the merger clearly promotes the construction of transmission upgrades and, by doing so, promotes improved competition across New York and improved competition in Zone J in particular.

Q: Is Staff correct that these commitments should be disregarded because the Commission should not "simply trust a utility's promise to ignore the financial incentive that would exist for the utility to act in a manner that would run counter to the public interest"?

A: No. The Companies are not asking the Commission to accept an unsupported promise. Instead, the Companies are proposing that National Grid assume the obligation to propose and build projects to address identified economic needs as a condition to approval of this Transaction. National Grid would have to comply with this obligation as part of its compliance with the Commission's order approving the Transaction. As discussed in my initial testimony, the obligation to propose and build projects to address identified economic needs would also be an expansion

of National Grid's existing obligations with respect to reliability-based transmission projects under the Agreement Between the NYISO and the New York Transmission Owners on the Comprehensive Planning Process for Reliability Needs. National Grid is prepared to enter into an amended or supplemental contract with the NYISO establishing the obligation to propose and build projects to address identified economic needs.

Q: Would this commitment be implemented under terms that have already been put into effect in New York?

A: Yes. The obligation to propose and build projects to address identified economic needs would be subject to the existing terms and conditions set forth in the Agreement Between the NYISO and the New York Transmission Owners on the Comprehensive Planning Process for Reliability Needs. These conditions are set forth in Article 3.0 of that agreement. The Commission and its Staff are familiar with these terms as part of New York's existing transmission planning process.

Q: Will other developments that have occurred since you filed your October 27 testimony facilitate the implementation of the commitment to propose and build projects to address identified economic needs?

A: Yes. The Companies' commitment was premised on a NYISO planning

process that addresses both reliability and economic needs. In Order No. 890, issued by FERC on February 16, the FERC established a requirement that transmission providers comply with certain transmission planning principles, including requirements for economic planning:

> Although planning to maintain reliability is a critical priority, it is not the only one. Planning involves both reliability and economic considerations. . . . Thus, to represent good utility practice and provide comparable service, the transmission planning process under the pro forma OATT must consider both reliability and economic considerations. The purpose of this principle is to ensure that the latter is considered adequately in the transmission planning process.

Order No. 890 at P 542. FERC made it clear that this requirement applies to independent system operators like the NYISO:

> The Commission also disagrees with the contentions of certain RTOs or ISOs that they need not comply with this principle. Although RTO and ISO planning processes tend to be more open and coordinated than the processes used by vertically-integrated transmission providers, this does not mean that RTO or ISO processes adequately address, in all circumstances, investments that are primarily economic in nature.

Id. at P 545. Order No. 890 therefore requires the adoption of a transmission planning process that identifies transmission projects that provide economic benefits to customers. The prerequisite for triggering National Grid's obligation to propose and build economically-driven transmission projects thus now appears likely to be satisfied in the near

term. National Grid looks forward to working with the NYISO, Commission Staff and stakeholders in developing an economic planning process for New York.

Q: Do the requirements of Order No. 890 reduce the value of the Companies' commitment to propose and build economically-driven transmission projects?

A: No. Although Order No. 890 mandates economic transmission planning, it does not require transmission owners to assume an obligation to construct economically-driven transmission projects identified through that process. Thus, the Companies' proposal to mitigate any long-term vertical market power concerns offers New York customers a valuable benefit that they would not obtain solely through the application of Order No. 890.

Q: Has Staff suggested why the Companies' commitment to propose and build economically-driven transmission projects may not fully mitigate long-term vertical market power?

A: Yes. Staff seems to agree that, conceptually, this obligation would address any disincentive to invest in transmission created by the merger. Staff suggests, however, that this commitment may not be effective because

National Grid may attempt to shirk any new obligations to construct economically-driven transmission projects in ways that are difficult to detect. For example, Staff suggests that National Grid may be a "reluctant sponsor" in the siting process. MPP at 153.

Q: Is this a valid criticism of the Companies' proposal?

A: No. As I have discussed in both my initial and rebuttal testimony, National Grid has been a strong supporter of transmission development for both economic and reliability purposes. National Grid views the expansion of the transmission network as a necessary step to support the efficient operation of wholesale and retail markets. Transmission development remains at the core of National Grid's long-term business plan. For all these reasons, we will not alter our long-standing support for needed transmission and will not be a "reluctant sponsor" of necessary transmission improvements.

It is also important to note that the obligations National Grid proposes to construct economically-driven transmission projects are based on the same contractual structure that obligates New York transmission owners to build transmission projects needed for reliability. Commission Staff supported the implementation of this process. There is no evidence that the existing obligation of transmission owners to build reliability

projects is not a real and meaningful commitment.

Q: How will the Companies' proposed commitment ensure that the appropriate solution to a NYISO-identified economic need is pursued?

A: Under the proposed commitment, the Commission will decide whether a National Grid-proposed solution to a NYISO-identified economic need should be pursued. This is based on the Commission's existing role in the Comprehensive Planning Process for Reliability Needs. The Commission Staff has previously explained that they have the technical expertise to make these decisions and resolve disputes in the planning process. For example, in the Commission Staff's September 10, 2004, comments in FERC Docket No. ER04-1144 supporting the NYISO tariff amendments implementing the Comprehensive Planning Process for Reliability Needs, Staff stated:

> The tariff amendments establish a reasonable role for the NYPSC in resolving technical disputes arising under the planning process. While the Commission will resolve disputes pertaining to NYISO's compliance with the tariff amendments, the NYPSC will resolve technical disputes relating to final conclusions or recommendations of the NYISO's Reliability Needs Assessments, as well as disputes concerning whether a proposed solution will meet an identified reliability need. The Commission should adopt this approach because it is pragmatic as well as legally reasonable.

> As a practical matter, the NYPSC's staff ("staff") is intimately familiar with the local and bulk power systems in New York and, therefore, is well-positioned to resolve disputes quickly. Staff understands the design and operation of these systems, monitors them on a day-to-day basis, and knows firsthand where problems tend to surface. Moreover, the NYDPS has committed to developing a process that utilizes stakeholder input.

Staff Comments at pp. 4-5 (citations omitted). National Grid expects that the expertise discussed in these comments also will allow the Staff to determine whether a National Grid-proposed solution to a NYISO-identified economic need should be pursued.

Q: Can you provide specific examples of the types of projects National Grid might propose and construct as part of its obligation to propose and construct economically-driven transmission projects?

A: Yes. As discussed in my initial testimony, in April 2006, National Grid submitted to the NYISO proposals for two different and unrelated alternative regulated solutions to address reliability needs in downstate New York. A copy of these proposals was provided as Exhibit MHS-4, an attachment to my initial testimony. The first proposal consists of reconductoring two 345 kV circuits that run approximately 65 miles from New Scotland to Pleasant Valley. The majority of these facilities are owned by National Grid, with Consolidated Edison Company ("Con Ed")

owning a small portion of the line and the Pleasant Valley termination point. The second proposal consists of a new 345 kV line from the Con Ed Sprainbrook substation in Westchester County to the Rainey substation in New York City of approximately 21 miles. Although these proposals were made in response to reliability needs, both of these proposals are likely to provide economic benefits to customers by increasing the import capabilities of downstate New York from upstate resources, thereby further broadening the market and improving market competitiveness.

Q: Would National Grid agree to pursue these or comparable proposals as part of an economic planning process?

A: Yes. Until the details of the NYISO economic planning process is finalized, I cannot say for certain whether these two proposals would satisfy NYISO-identified economic needs, but as part of its commitment to propose and construct economically-driven transmission projects, National Grid is prepared to pursue these proposals or comparable transmission proposals if National Grid is designated as the "Responsible TO," responsible for building, owing, and operating transmission facilities on our system to address NYISO-identified economic needs.

Q: Thank you. I have no further questions at this time.

REBUTTAL TESTIMONY

OF

PETER FOX-PENNER

ON BEHALF OF

NATIONAL GRID PLC AND KEYSPAN CORPORATION

P.S.C. CASE 06-M-0878

March 7, 2007

REBUTTAL TESTIMONY OF PETER FOX-PENNER

I. Purpose and Summary

Q: Please state your name, address, and position.

A: My name is Peter Fox-Penner. I am a Principal and Co-Chairman of *The Brattle Group*, an economic and management consulting firm with offices in Cambridge, MA, Washington, D.C., San Francisco, CA, London, England, Brussels, and Belgium. My business address is 1850 M Street, NW, Suite 1200, Washington, DC 20036.

Q: Have you previously filed testimony in this proceeding?

A: Yes, my direct testimony in this proceeding was filed before the New York Public Service Commission ("NYPSC" or "the Commission") on October 27, 2006 and my academic credentials and industry experience are set out in my vita which is appended to the October 27 testimony as Exhibit PFP-1.

Q: What is the purpose of this testimony?

A: I have been asked by counsel for National Grid, including its affiliate Niagara Mohawk Power Corporation, ("NG" or "National Grid") and KeySpan Corporation ("KS" or "KeySpan"), together referred to as "the Companies," "Applicants," or "the affiliated Companies," to discuss vertical market power ("VMP") claims raised in the testimony filed by the Merger Policy Panel ("MPP") and the Constraints Panel ("CP") on behalf of the Staff of the New York State Department of Public

Service.[1] Collectively, I refer to these two panels as "DPS Staff," "Staff," or "MPP-CP."

Q: Please summarize your testimony

A: My response to Staff's testimony may be summarized as follows: MPP and CP claim that the proposed merger of NG and KS would "radically increase" the affiliated companies' financial incentive to exercise both short-term and long-term VMP and that regulatory controls are insufficient to protect against this increased incentive.[2] For short-term vertical market power, MPP asserts that NG could take or extend brief planned outages or create frequent unplanned (forced) outages on NG's critical transmission lines so as to increase downstate power prices and increase generation profits.[3] They therefore conclude that Applicants have not rebutted the presumption of VMP as articulated in the Commission's Vertical Market Power Policy Statement.[4]

Staff's conclusion is fatally flawed and should not be relied upon by the Commission. First, Staff has relied on extremely simplistic analyses and computations that fail to address the factors determining the impact of *this* proposed merger on VMP. Their evidence points only to the possibility that *some* vertical merger, involving upstream transmission and downstream generation in the New York power grid *might* create vertical New York market power under some

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1 The vertical market power arguments raised in the Merger Panel testimony are made by Staff Witnesses John D. Stewart, Warren E. Myers, and Thomas Coonan. The vertical market power assertions made in the Constraints Panel testimony are sponsored by Staff Witnesses Thomas Paynter and Edward C. Schrom, Jr.

2 MPP states that "...restrictions on transmission flows...will lead to higher NYC prices, higher revenues for Ravenswood and, thus, an inappropriate incentive for National Grid if it owned the plant." at 130, line 9 to 14. As explained below, this conclusion is incorrect in the wake of my analysis and the proposed mitigation.

3 Testimony of Constraints Panel at 11, and Testimony of Merger Policy Panel at 123.

4 New York Public Service Commission, Case 96-E-0090, *et al.*, *Statement of Policy Regarding Vertical Market Power*, July 17, 1998.

conditions. They examine market behavior only on a single day without determining whether what occurred on that day bears any relationship to what would occur as a result of the merger, or whether that day is representative of conditions generally. Reliance upon such a single carefully selected example is wholly inappropriate and completely insufficient to establish that this particular merger, involving only National Grid's specific transmission lines and KeySpan's specific power plants, would create an incentive for the Companies to exercise VMP.

I provide in Section II of this testimony an extremely detailed analysis of whether the merger creates financial incentives to exercise VMP.[5] This analysis uses a state-of-the-art Locational-Based Marginal Pricing ("LBMP") electric market simulation model similar to the one used to actually dispatch the New York market to analyze the effect of the merger on Applicants' projected generation profits for every hour of 2007. More specifically, the model examines *for every hour of the year* whether the proposed merger would make it profitable for National Grid to remove temporarily one of its transmission lines from service in order to increase prices and profits at KeySpan's generation plants. This is a far more rigorous analysis of whether the merger has the potential to create vertical market power concerns than a single, carefully-selected, non-representative case, and is much more reliable.

My analysis finds that the merger will create no short-term vertical market power possibilities for almost all of the NG transmission system. In other words, with the exception of four lines, any of the transmission lines in National Grid's

5. Applicants provided this analysis to Staff and other parties on December 20, 2006 as a supplemental response to data request DPS-239.

upstate system may be withdrawn from service with no measurable increases in generation profits for KeySpan generation. Only on the four National Grid lines nearest New York City – the lines in the Leeds/Pleasant Valley corridor – could the merger create a small incentive for National Grid to take outages, and then only under specific circumstances when such outages are likely to influence Zone J prices. These circumstances are rare, arising only a projected 16 days in 2007 with only two of these 16 days occurring outside the summer months. Since the New York Independent System Operator ("NYISO") does not ordinarily allow scheduled outages of these transmission lines in summer, the 14 summer outages identified are highly unlikely.

I also find that the types of outages that give rise to VMP incentives are either easily detected or difficult to predict more than a few days in advance. The fact that a rare, poorly predictable combination of market and system conditions is required to create even a small VMP incentive makes the incentive an extremely difficult one to act on in practice. The difficulty of predicting and acting on such an episodic incentive provides an inherent protection against such exercises of vertical market power in the Day-Ahead ("DA") market. Alternatively, real-time ("RT") outages would have to be part of a complex strategy implemented in a manner likely to be easily detected. Nevertheless, as I note below, the Applicants are today proposing a targeted mitigation approach to provide further assurance that the proposed merger will not create opportunities to exercise vertical market power in either DA or RT market.

The MPP argues that the presumption of VMP from this merger cannot be rebutted by relying on the effectiveness of regulations and NYISO requirements that

prevent strategic short-term withdrawals of transmission. It is important to recognize that my analysis does NOT assume that laws, regulations, or NYISO requirements can stop short-term withholding of transmission.[6] My analysis looks at whether the incentive to withhold is increased by the merger *without regard to regulatory prohibitions*. Put differently, and ignoring for the moment the mitigation proposed by the Applicants, I find only a very small incentive to exercise VMP even if one is willing to ignore the strict controls and limits that Federal Energy Regulatory Commission ("FERC") and the NYISO place on National Grid's ability to schedule outages strategically on its transmission facilities, as well as the high risk of detection and the severe consequences to National Grid that would likely result from such actions.

Recognizing that I analyze only whether post-merger *incentives* exist, my analysis shows that these incentives involve only four National Grid transmission facilities, and then only when rare circumstances cause predictable profit increases for the Ravenswood plants due an unexpected outage of these facilities. To remove any possibility that this financial incentive will be present after the merger – again assuming that regulations, NYISO requirements, and other existing controls do not protect against strategic short-term transmission withdrawals – Applicants have agreed to a process that monitors unplanned (defined as not included in NYISO's monthly outage schedules) transmission outages on the four relevant National Grid facilities, and 'give back' all significant incremental Ravenswood profits they earn during such unplanned outages. This process not only mitigates the incentives

[6] Although I agree with Staff that regulation and other applicable controls cannot be counted on to stop all short-term strategic withdrawals where the financial incentives to make such strategic withdrawals is strong, at the same time it is wrong to assert that they cannot prevent any such actions. In reality, I believe these regulations and other controls prevent most if not all such actions in this market.

created by the merger, it could actually over-mitigate them. The over-mitigation could occur because not every relevant unplanned outage could possibly be part of a strategic VMP effort on National Grid's part, and yet every such outage will result in a "give-back" of estimated incremental profits from that outage. The part played by regulatory, NYISO, and other limits and controls, as well as the inherent difficulty of successfully taking strategic outages in the first place, are supplemental to the protections offered by this mitigation process, and they supply additional layers of protection on top of what is already a mechanism that fully mitigates any possible incentive to exercise VMP.

In summary, by (1) analyzing the precise impacts of this merger on Applicants' incentives to exercise short term VMP; (2) not relying on regulation or other requirements to prevent such VMP; and (3) creating a mitigation mechanism that more than removes the small VMP incentive found in my analysis, Applicants have fully rebutted the Commission's policy statement presumption regarding VMP.

Staff's arguments with respect to long-term vertical market power fail on similar grounds. Staff's analysis of this issue is limited to an assertion that NG's incentives to build transmission that adds transfer capacity into Zones J and K will be weakened by the merger, and that NG's commitments to build additional lines cannot be relied upon. In this testimony I explain that NG's incentive to build transmission is not weakened appreciably by the merger. Furthermore, NG has made specific commitments to build transmission described in the testimony of Ms. Masheed H. Saidi and Mr. Lawrence J. Reilly. As in the case of short-term VMP, the presumption of long-term harm in the Commission's policy statement can be

rebutted by relying primarily on the absence of an adverse incentive, with the many applicable rules and processes in the New York market playing a supplemental role.

Q: How is the remainder of your testimony organized?

A: Section II of my rebuttal testimony refutes claims that the proposed NG-KS merger creates a short-term incentive to exercise vertical market power. In this section, I discuss the theory of short-term vertical market power and show that the financial incentive to create temporary transmission constraints on NG's upstate transmission system in order to increase Zone J prices is small and highly episodic, occurring only 16 days a year. In Section III I describe numerous flaws in the Staff's analyses. Section IV examines long-term vertical market power arguments by the Staff; Ms. Masheed H. Saidi also responds to these allegations in her rebuttal testimony.

II. Appropriate Analysis of Vertical Wholesale Market Power

A. The Theory of Vertical Market Power and How can it be Tested?

A.1. Incentive Theory Examined

Q: What is vertical market power?

A: Vertical market power is defined as the ability of a firm involved in both upstream and downstream activities, such as generation and transmission, to use a dominant position in one market to profitably raise prices above competitive levels in a related upstream or downstream market for a sustained period of time. For example, by controlling the transmission system, a vertically integrated utility could have the ability to control the access of generation competitors to the market by

limiting physical access to competitors or potential entrants, or charging them higher prices.

Q: What are the conditions that would have to hold true for the Applicants to profitably exercise VMP?

A: Two primary conditions must hold true for the Applicants to profitably exercise VMP. First, the Companies will take short-term actions that reduce the power transfer capability from upstate New York into Zone J only if they can be reasonably certain that these actions will help to boost profits earned on the affiliated Companies' generation in this zone. For reasons I explain below, given the nature and locations of the generation owned by KeySpan the potential for the merger to create incentives to exercise short-term VMP can be analyzed by examining the potential impact of transmission actions on Zone J prices. That is, the Companies will have the *incentive* to exercise market power (for example, reducing transmission capacity) only if there is a reasonably reliable way to predict the profitability of these actions. If the affiliated Companies cannot tell whether their profits will go up or down if they take these actions, there is no clear VMP incentive created by the merger. I also note that if the expected profits earned as a result of these actions are sufficiently predictable but relatively small, while the risks of being detected and punished by regulatory or antitrust authorities is significant, then the net incentive to take these actions will not exist. As explained elsewhere, my analysis does not rely on the effectiveness of regulation to prevent short-term transmission withdrawals and therefore assumes that the net incentive is not reduced to zero by regulations. The second required condition for VMP is that the Companies must have the *ability* to take the actions necessary to achieve it. The actions that reduce transmission capacity must be within NG's control (as opposed

to the control of the NYISO or some other independent entity) and must not violate reliability rules and/or be easily detected. As just noted, I do not rely on regulation to prevent these actions and therefore assume that the ability exists even though I believe this assumption is extremely conservative. In summary, Applicants must have both the *incentive* and the *ability* to temporarily withdraw transmission capacity in a certain and profitable manner without a significant probability of detection and punishment. As I demonstrate below, given the circumstances of the NYISO markets and the two companies to be merged, the likelihood that these two conditions can be satisfied is remote. Once a mitigation regime is added, the risk of vertical market power is essentially eliminated.

Q: What exactly do you mean by "short-term withdrawal of transmission capacity?"

A: By "short-term withdrawal of transmission capacity," I refer to such actions as taking a line out of service, changing the dates of a scheduled outage, changing reactive power settings, or other actions that temporarily reduce the capacity of the presently-configured transmission system to deliver power downstate. By contrast, long-term transmission incentives to exercise VMP refers to the incentive to avoid identifying or constructing transmission projects that could benefit downstate customers but that could adversely affect the profits of KS-owned units in Zone J.

Q: Does your testimony analyze both the ability and the incentive of the Applicants to exercise vertical market power?

A: As explained in my introduction, I have not assumed that regulation can eliminate VMP, especially in the short-run. Thus, I do not analyze whether Applicants have the ability to take actions that lead to short term transmission withholding – I

assume they can, contrary to my belief. I thus ignore the high risk of detection and the severe adverse consequences to the affiliated companies that would likely result from such actions. I do not assume that their ability to take such actions is unlimited, as this violates common sense, but I assume that some ability exists.

Given this crucial assumption, the overall focus of this testimony is to determine whether the proposed merger provides any short-term incentive to exercise vertical market power without regard to regulatory prohibitions, and if so, how such incentives can be fully mitigated. In particular, I examine whether any possible short-term reductions of transmission capacity in the upstate NG system create a significant and realistic opportunity to increase the profits of KS-owned units in Zones J (New York City or NYC).

Q: Why do you believe that NG has an extremely limited ability to withhold its transmission capacity so as to reduce power transfer capability to Zone J?

A: Mr. Michael L. Schiavone's previously filed testimony in this proceeding explains why such actions are difficult or impossible to undertake due to the NYISO's control over NG's high-voltage transmission lines and the fact that most of NG's transmission-operation actions that could reduce transfer capability are public information and subject to the NYISO's review and approval. Lawrence J. Reilly's supplemental and rebuttal testimony further explains why NG would be highly unlikely to undertake such actions to benefit the generation interests of the Companies after the merger due to the Companies' commitment to comply with applicable regulatory requirements, the potential for financial penalties (including disgorgement of profits, civil penalties and the possible revocation of market-based rate authority), and the damage to the reputation of the Companies that could result

from such action. This notwithstanding, for the purposes of my analysis I make the conservative assumption that there are a set of transmission-related actions that NG could take on its upstate system to reduce the capacity of its lines.

Q: How confident can the Applicants be that a temporary withdrawal of transmission capacity somewhere in upstate New York would have a predictable and significant impact on profits earned by the KeySpan units in NYC?

A: It is difficult to predict with certainty the effect on downstate prices of any temporary withdrawal of transmission capacity in upstate New York by NG. As I show in the rest of this section, NG's upstate transmission system is separated from KS' generation by several zones and interfaces that they do not own or control in any way. The transmission system surrounding the New York metropolitan area is among the most complex and heavily managed transmission systems in the world.

Any intentional NG scheme to withhold transmission in its upstate lines in order to raise prices in NYC in a predictable, significant fashion thus faces extraordinary barriers. The affiliated Companies would have to be confident that, apart from avoiding detection, their transmission withholding would reduce flows into downstate so as to raise prices in Zone J. This would mean, among other things, that the actions of no other generation or transmission supplier closer to or in NYC, nor actions taken by the NYISO, could cancel out, offset, or interfere with the effects of NG's reductions in transmission capacity.

I consider it quite unlikely that any merged company with a geographic footprint like that of the Companies after the merger, with a transmission system operated by an ISO, operating in a complex and highly congested region, could

willfully and profitably pursue such a strategy. Nevertheless, I have performed an analysis of the Companies' incentive to do so, *assuming* they could.

Q: Have you determined the specific actions that could be undertaken by NG to reduce short-term transmission capacity?

A: I am aware of the generic sorts of actions that temporarily reduce transmission capacity, such as declaring an unneeded short-term outage. For the purpose of measuring and mitigating such actions, I need not determine exactly which actions NG could take or how it could take them – I simply assume, conservatively, that NG can find a way to reduce upstate transmission capacity into Zone J, notwithstanding the safeguards described in Mr. Michael L. Schiavone's testimony. As I explain in more detail below, I assume that NG could somehow implement various temporary (one-day) withdrawals of transmission capacity on its lines that might influence flows into and prices in NYC. The impacts of these withdrawals and the resulting profit incentives generally do not depend on exactly what NG hypothetically could do to temporarily reduce capacity, so the actions I examine (one-day unannounced outages) are sufficient for my purposes.

A.2. Incentive Testing Methodology- Overview

Q: You have noted that your analysis examines whether Applicants have a significant incentive to withhold transmission capacity. Generally speaking, on what does this incentive depend?

A: As I mentioned before, the incentive to withhold transmission capacity depends on both the magnitude and the certainty of the potential profits associated with the set of possible actions that temporarily withdraw capacity. The magnitude of potential profits in turn depends on how each transmission-limiting action affects the LBMPs

in Zone J, where KS owns the Ravenswood Facilities. The incentive to exercise short-term VMP by the Applicants increases with the magnitude of the potential profits of these hypothetical market power abuses. In addition, the incentive to manipulate transmission capacity into Zone J decreases if the probability of being detected increases or if the magnitude of the potential punishment increases. However, I do not explicitly consider either the potential for detection or punishment in my incentive analysis.

Q: How do you determine the magnitude of the VMP incentive in Zone J?

A: To examine the magnitude of this hypothetical incentive, I use a detailed simulation model to test the effects of removing from service a wide range of NG transmission lines on prices received by KS generators in Zone J. This process of testing for the incentives involved four major steps. First, I used NYISO information and other data to identify NG's bulk transmission facilities whose outages may affect interface limits (*i.e.*, transmission capacity availability) between upstate New York (including power transmitted from Canada) and NYC. These are the lines I tested. Second, I calibrated a model of DA LBMPs that takes into account all bulk transmission lines and interfaces in the NYISO and adjoining markets. This model is a detailed, hour-by-hour simulation of the entire New York state power grid and the LBMP price-setting mechanism. I calibrated this model by backcasting (benchmarking) against actual 2004-2005 prices. After benchmarking, my third step was to adjust the model to replicate 2007 market supply and demand conditions. To do so, I included new generators and transmission lines that are expected to come on line in 2007, as well as currently projected fuel prices and loads. Finally, I used this model to perform simulations that test the price impact in Zone J of temporarily removing from service candidate "relevant facilities" on the

NG bulk transmission system. These simulations show whether attempted short-term removals of these candidate facilities have any predictably measurable impact on DA LBMPs in Zone J and on Applicants' profitability.[7]

Q: What does your modeling process assume about the geographic markets relevant to this merger?

A: Many market power analyses find or assume fixed boundaries for the relevant geographic markets. My analysis does not fix the boundaries of any geographic markets in advance. Instead, I directly examine whether there is a competitive impact in terms of increased wholesale energy prices and generator profits that result from taking specific transmission lines out of service.

It should be kept in mind that the purpose of defining market boundaries is to simplify the test for price impacts from a merger. In my analysis, through my detailed NYISO transmission simulation model, I effectively define market boundaries and estimate price impacts as one integrated comprehensive process. This is a much more detailed and accurate method of estimating merger impacts because it allows my model to calculate a price impact and market boundary that could differ in each hour of the test year. I contrast my results with Staff's market boundary calculations in a moment.

By directly examining the potential competitive impact of "withholding" (*i.e.*, withdrawing) transmission capacity (through strategically taking lines out of service), my analysis is more consistent with modern antitrust practice and is also consistent with the Department of Justice and Federal Trade Commission *Horizontal Merger Guidelines* (issued April 2, 1992 and revised April 8, 1997).

[7] As explained below, a slightly modified version of the model can estimate the impacts of outages

While I am assessing a vertical merger instead of a horizontal merger in this case, the point remains that a merger is anticompetitive only if it provides an incentive for anticompetitive behavior (*i.e.*, an exercise of VMP), and not merely because it occurs in a concentrated market. For that reason, I directly examine whether there is an incentive for such behavior through the withholding of transmission capacity. My analysis indicates that there is no significant post-merger incentive for the Companies to engage in anticompetitive transmission withholding under the proposed mitigation mechanism.

Q: Why does your withholding analysis focus on price elevation in Zone J only, as opposed to examining price impacts in Zones A through I?

A: I am focusing on NG's incentive to withhold transmission to advantage KeySpan's Ravenswood generation plant. Thus, my analysis examines the increased profits earned by Ravenswood through the use of such a strategy, which is necessarily determined by any resulting price increases in Zone J where Ravenswood is located. I also analyze whether the proposed mitigation removes Ravenswood's ability to profit from hypothetical transmission-withholding behavior instituted by NG.

If transmission withholding subject to the proposed mitigation does not induce an increase in Ravenswood's profits, then there is no incentive for NG to withhold upstate transmission capacity. Without this withholding incentive, there is no anticompetitive price impact in Zone J or any other zone in New York. According to my analysis, there is no incentive to engage in withholding subject to the proposed mitigation because the mitigation removes the ability of Ravenswood to profit from the withholding behavior.

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that affect only the RT market.

In other words, I test for profit incentives by looking at Zone J because (a) this is the only place where price impacts create an incentive for the merged company; and (b) if the incentive is eliminated for Zone J then there will be no price impacts anywhere else. In this sense, it is appropriate and conservative to focus on Zone J.[8]

Q: Do you also examine National Grid's transmission outage impact on Zone K?

A: As I explained in my testimony on this transaction before the FERC, most of the output from its power generators in Zone K has been sold on a long-term basis to Long Island Power Authority ("LIPA"). KeySpan's ability to earn additional profits from this Zone K generation is limited to its share of the profits earned on power that is surplus to LIPA's hourly needs, which KeySpan markets on LIPA's behalf through KeySpan Energy Trading Services.[9] Because this surplus cannot be know with much predictability in advance, and because KeySpan's share of these surplus profits is capped, this does not provide a reliable basis for a vertical withholding incentive.

Q: Is there any other additional reason to limit your VMP incentive analysis to Zone J?

A: Yes. I demonstrated in my FERC testimony that LIPA's operation tends to make Zone K a distinct power system and marketplace from the rest of NYISO. Zone K is least electrically connected to the rest of the New York grid and most reliant on in-zone generation. In 2005, the interfaces leading immediately into Zone K were

[8] My simulation model estimates prices throughout the NYISO. I focus only on Zone J price changes in my analysis for the reasons explained. As discussed further in my results section, short-term withdrawals of transmission in NG's upstate system generally reduce prices in some parts of the New York grid and increase them slightly in others. However, if the incentive to remove transmission is eliminated these impacts are all moot.

congested approximately 65 percent of the time, requiring this zone to rely on internal generation to provide all marginal production. NYISO's local capacity market rules also require that 99 percent of the capacity serving Long Island's ("LI's") peak load come from local generation.[10] These features reduce the possibility that transmission withdrawals can provide any predictable additional generation profits in Zone K. The more isolated and less import-reliant the system, the smaller is the degree of influence that upstate transmission changes will have on Zone K prices. Accordingly, my primary concern remains that Zone J price impacts be modeled correctly, and that this zone serves as the basis for judgments concerning the likelihood and magnitude of transmission withdrawal incentives.

Q: Does your simulation model allow one to mitigate the potential incentive (if any) to exercise VMP in the short run?

A: Yes. As explained further below, my simulation model also offers a method for mitigating the few examples of positive incentives identified. My analysis shows that post-merger incentives involve only four NG transmission facilities and only when rare circumstances cause predictable profit increases for the Ravenswood plants due an unexpected outage of these facilities. To remove any possibility that this financial incentive will be present after the merger, again regardless of how well or poorly regulation and other requirements preclude short-term transmission withdrawals, Applicants have agreed to create a process that monitors their unplanned transmission outages on the relevant corridors that create post-merger incentives and 'give back' all incremental Ravenswood profits they earn during

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9 KeySpan's very limited control over its contracted resources via an energy management agreement is discussed in P.64-72 of my testimony before the FERC in Docket No. EC-06-000, May 23, 2006.

10 *Revised Locational Installed Capacity Requirements Study Covering the New York Control Area For the 2006 – 2007 Capability Year*, NYISO Operating Committee, March 28, 2006. http://www.nyiso.com/public/webdocs/services/planning/resource_adequacy/

such unplanned outages. This not only mitigates the incentives created by the merger, it could actually over-mitigate them, as not every unplanned outage could possibly be part of a strategic VMP effort on NG's part.

A.3. Classifying Outages that Might Cause Impacts

Q: Do all transmission outages have a similar impact on market prices in NYC?

A: No. In general, it is commonly accepted that the effect of transmission outages on market prices depend on how far in advance these outages have been announced. The farther in advance these outages are announced the lower the ability and incentive of the market participants to exercise vertical market power in NYC.

Q: Can you clarify why outages scheduled and announced well in advance are unlikely to have any effect on NYC market prices?

A: For two distinct reasons, the approval and posting of outages well in advance greatly reduces the possibility that such outages can be used to raise NYC prices. First, my modeling efforts (described further below) demonstrate that the ability to predict the price impacts of outages diminishes greatly as the time between the scheduling of the outage and the outage itself. For example, it would not be reliably profitable to decide on September 1, 2006 that one was going to remove a NG transmission line from service on September 1, 2007 purely to raise prices in Zone J. It is virtually impossible to predict this far in advance what load levels, prices, congestion patterns, and other conditions will be on September 1, 2007, and all these factors have large effects on price outcomes in Zone J – typically much larger than the impact of one upstate line outage.[11] The closer in time between the actual

[11] Indeed, my simulations show that outages on the handful of NG facilities whose temporary outages can predictably influence prices in Zone J can often lower Zone J prices as well as raise them. This

analysis of market conditions and the "strategic outage" itself, the more likely it is that profits predicted in an analysis of the impact of the outage will be realized.[12]

The second reason why outages scheduled and announced well in advance are unlikely to raise prices is that other suppliers of energy as well as load can alter their supply plans in response to such outages, and the NYISO can alter its dispatch of the system. My simulation model reflects many of these competitive responses, but it assumes that they are the same regardless of how far in advance the outage information becomes known. In fact, the shorter the notice period between the outage posting and the outage itself, the less action rival suppliers and customers can take to undo any possible price effects.

Q: Does the NYISO classify transmission outages depending on how far in advance they are announced?

A: As Mr. Schiavone describes in his testimony, NYISO classifies transmission outages into four different categories:[13] (1) "Planned" or "Scheduled" outages are outages that are known and approved (for all A-1 facilities) by the NYISO in advance;[14] (2) "Unscheduled" outages are outages that were not part of the "month-

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counter-intuitive outcome occurs when, among other factors, an upstate line outage causes a lower priced unit to commit for service during a given day or week in which the outage occurs. In this case, energy with a lower unit price is available during the outage than would have been available absent the outage.

12 There are undoubtedly periods within a year that are predictably higher in price and congestion, and which therefore would be strong candidates for strategic outages scheduled far in advance. Such a strategy might be profitable over repeated tries and long periods, but my modeling shows that it would be subject to very large year to year variability and also is easy to detect. Accordingly, I do not view such a strategy as having a significant realistic incentive. In addition, the NYISO disfavors transmission owners (TOs) scheduling their maintenance in the summer. See Direct Testimony of Michael. L. Schiavone, Jr. , on behalf of National Grid PLC and KeySpan Corporation, P.S.C. Case 06-M-0878, October 27, 2006, pp. 27, 30-31.

13 Direct Testimony of Michael L. Schiavone, Jr., on behalf of National Grid PLC and KeySpan Corporation, P.S.C. Case 06-M-0878, October 27, 2006, at 11.

14 Under NYISO rules, NG already provides the NYISO with a schedule of all planned transmission element outages (for all A-1 and A-2 facilities) one month prior to the first day of each calendar month. The outages of all A-1 facilities that are on this "month ahead" schedule must be approved by the NYISO.

ahead" schedule and are requested within approximately one week of the outage itself, but do not appear on the "month-ahead" schedule; (3) "Emergency" outages are outages initiated by transmission owners or the NYISO outside the ordinary notice and approval timelines provided in ISO procedures. These Emergency outages are taken for events such as repairing a hot spot to prevent a conductor's failure; and (4) "Fault" or "Forced" outages are outages that occur automatically without operator intervention, such as circuit breaker trips. These are due to events such as severe weather and random equipment failures.

Q: Is there any other relevant dimension to classify transmission outages?

A: Yes. A second relevant dimension to classify outages is the identification of the party requesting or initiating the outage. An outage on NG facilities may be caused by another TO whose facilities are attached to or affected by NG's facilities when that TO takes such affected or attached facilities out of service for maintenance. Similarly, another TO could request that NG take a facility out of service so that this other TO's connected equipment can be serviced.

Q: From the standpoint of your analysis of vertical market power incentives, what kinds of facility outages are relevant to the analysis?

A: For the purpose of my analysis, Fault or Forced outages are not relevant because these are not consciously initiated by NG personnel – they occur automatically in order to preserve equipment or safety. Similarly, outages initiated by parties other than NG cannot be part of a unilateral market power strategy, and I do not examine them in my study. Thus, the types of outages relevant to NG's incentive to withdraw transmission temporarily are its self-initiated Scheduled, Unscheduled,

and Emergency outages.[15] Table 1 summarizes the outage types discussed and analyzed in the remainder of my analysis.[16]

Table 1
Categories of Transmission Outage Types
Relevant to VMP Incentives

Type Of Outage	Outage Initiated By		
	National Grid	Other TOs	NYISO
SCHEDULED	x		
UNSCHEDULED	x		
EMERGENCY	x		
FAULT			

Q: Does your methodology for analyzing short-term vertical incentives include both outages in real-time and day-ahead?

A: Yes. For the purpose of *classifying* whether any outage might create a short-term withdrawal incentive, and therefore is a candidate for mitigation, I make no distinction between whether the outage was known to the DA market or not. It is for this reason that Table 1 above and my analysis in general hinges on what caused the outage, not which markets it may affect.

When simulating the impacts of specific outages, it is necessary to determine which markets these outages affect and simulate those markets. In some cases, outages will affect only the DA market, while in others the outage will affect only

[15] It should be noted that these outages, even if they result in increased prices in Zone J, are not necessarily an attempt to exercise vertical market power. Bulk transmission facility outages are inevitable and it is difficult to schedule them to optimize every conceivable opportunity. The timing of pre-scheduled outages is a function of many considerations, including but not limited to the availability of key resources, permits, weather conditions, and NYISO guidelines, etc.

[16] There is an additional outage descriptor that bears clarification. Some transmission maintenance activities are listed in NG's data base as an "outage" even though the activity does not cause the facility being maintained to leave service or be derated by the NYISO (for example, testing or maintenance that proceeds while the facility is operating). These "outages" are not relevant to my analysis because they do not limit transmission path flows or change interface limits.

the RT market or both markets on different days. For example, an outage declared by a TO with only one hour's notice and that lasts a total of three hours will not ordinarily affect either the DA market on the day the outage occurs or the RT market on the day following the outage. This is because the bids for the DA market were submitted the day before the outage actually occurred, while the bids submitted on the day of the outage (for the next day's DA market) will assume that there is no outage tomorrow. In this example, the only market affected is the RT market within that day.

Q: You testified earlier that – although you believe that the panoply of regulatory prohibitions and market rules are adequate to prevent the exercise of VMP in this proposed merger – you do not assume that they eliminate VMP incentives or ability in your analysis. Does this assumption apply to outages that affect the RT market?

A: Yes, it does. My incentive analysis and mitigation proposal applies to all outages, regardless of which markets they affect. However, I note that outages that occur in RT are even less likely to constitute strategic withdrawals than outages in the DA market. This is true because RT outages are essentially certain to draw regulatory scrutiny, especially if they are repeated during conditions that allow for added profits to Zone J generators. As Mr. Schiavone explains in his testimony, such withdrawals must be documented with the NYISO, making such a strategy highly visible. Furthermore, earning profits from intentionally-caused transmission withdrawals in the RT market is more difficult to implement. It is necessary to model system conditions in the RT quickly enough that accurate simulations can be performed, checked, and then withdrawal and bidding schemes implemented, all within a matter of hours, and all without getting caught. While I do not entirely rule

out the possibility that RT market schemes could occasionally occur, I think it is entirely unrealistic to think that this is a significant source of vertical incentives.

Q: Do you consider your analysis as a proper test for the potential outage impact in upstate transmission facilities on prices in NYC?

A: Yes. In view of the previous considerations, the most significant potential price effects from outages arise from outages that are "surprises" to the market in that they are not known at least 30 days in advance. In fact, I view my analysis as a conservative test for the potential price impacts of outages not shown on the month-ahead schedule, whether they are entirely new outages or new periods into which planned outages are shifted after the month-ahead schedule is posted. I consider my test to be conservative for two main reasons: (1) while outages that change with as much as 60 days advance notice (the maximum notice period within the month-ahead posting schedule) are unlikely to cause significant impacts, the month-ahead schedule provides a conservative, highly-transparent benchmark against which outage changes can be defined, tested, and (if necessary) mitigated; and (2) as noted below, there is a small set of actions that NG might be able to take that temporarily reduce transmission capacity into Zone J with predictable profitability, albeit by very small amounts. Accordingly, I henceforth refer to these actions simply as "outages," even though they could include actions that stop short of being complete removals from service. Given that I assume a complete withdrawal of NG bulk transmission facilities from service in every case rather than a partial withdrawal, the price increase and the theoretical incentive to exercise vertical market power will be over-estimated.

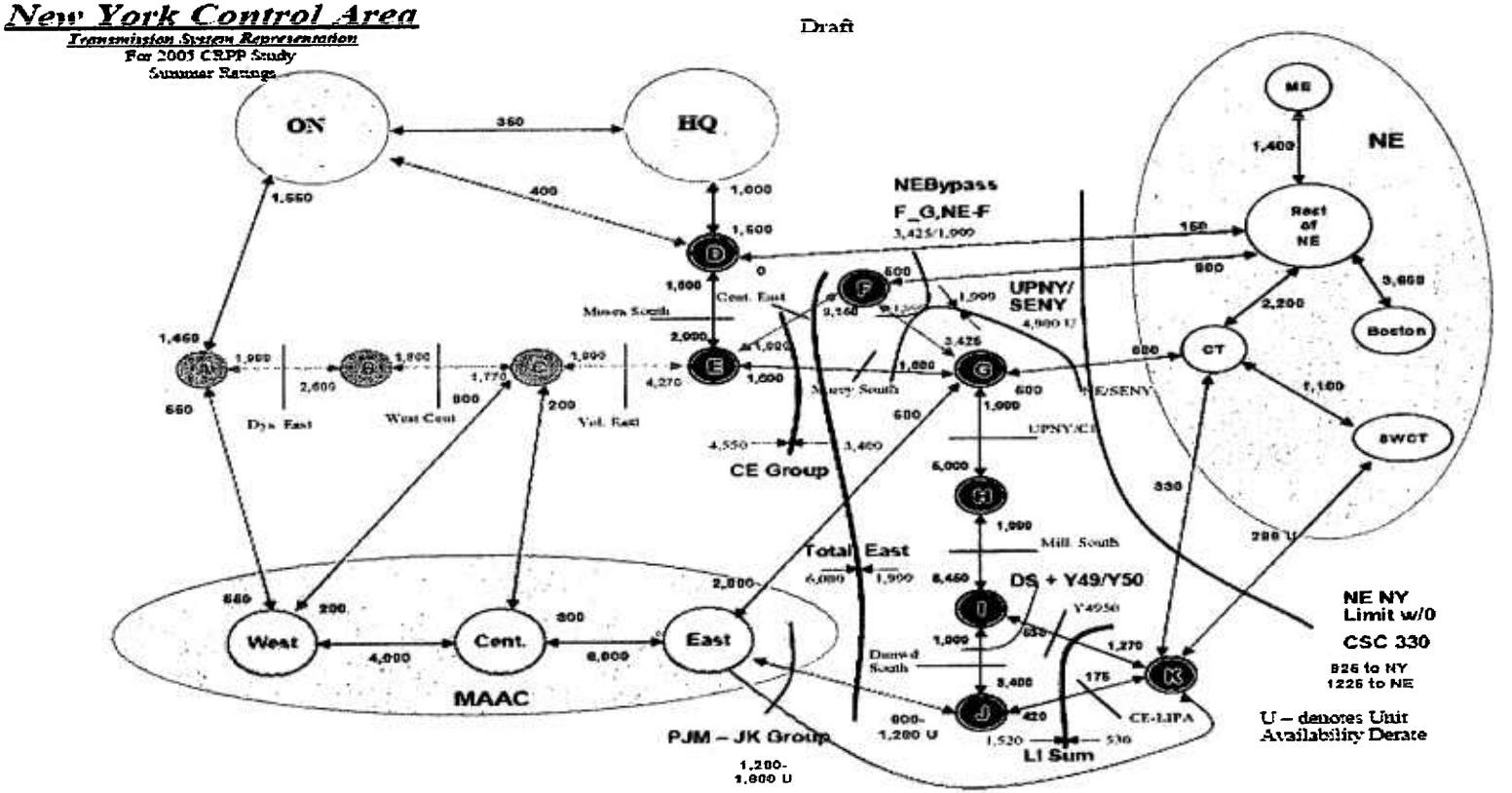
B. THE SIMULATION MODEL AND ITS APPLICATION

B.1. System Background

Q: Please provide an overview of the New York high-voltage transmission system.

A: Figure 1 is a representation of the New York grid reproduced from the NYISO's December, 2005 *Comprehensive Reliability Planning Process Supporting Document and Appendices for the Draft Reliability Needs Assessment*. This figure shows that the NYISO divides the statewide system into 11 geographic zones A through K, each separated by one or more transmission interfaces. In addition to interface limits between each zone, there are several multi-zone interface constraints. The largest interface is Total East, which sets a maximum west-to-east flow across both NY and PJM into eastern NY. The maximum flow limits are shown for each interface in this figure.

Figure 1
Load Zones and Interfaces in
New York Transmission System



Source: New York Independent System Operator, Comprehensive Reliability Planning Process, Supporting Document and Appendices for the Draft Reliability Needs Assessment, December 21, 2005, p. 59.

Q: Please describe National Grid's transmission facilities with respect to this overall system map.

A: As shown by the yellow highlighting in Figure 1, NG's NY transmission facilities are located along the path from Zone A to Zone G. NG does not own any bulk transmission facilities that directly interconnect with Zone J.

Many of National Grid's high voltage lines are part of the NYISO-intra-area transmission interfaces, as summarized in Table 2.[17] For the Dysinger-East Interface, which limits power flows from Zone A to Zone B, NG owns six 115 kV lines: Lockport-Batavia 107, Lockport-N. Akron 108, Lockport-Oakfield 112, Lockport-Sweden 111, Lockport-Sweden 113, and Lockport-Telegraph 114. For the West Central Interface (interface between Zones B and C), NG owns two 115 kV lines: Mortimer-Hook Rd-Elbridge 1/7 and Mortimer–Elbridge 4. For the interface between Zones D and E, Moses South, NG owns 230 kV Adirondack-Chases Lake-Porter 11, Adirondack-Porter 12, 115 kV Dennison-Colton 4 & 5, Alcoa-N. Ogdensburg 13, and Malone-Colton 3. NG's lines that form part of the Central East/Total East interfaces include the 345 kV Edic – New Scotland 14 and Marcy – New Scotland 18 lines, two 230 kV Porter – Rotterdam lines (30 and 31), and 115 kV East Springfield – Inghams 942 lines and the Inghams Bus Tie. For the UPNY-SENY Interface, which limits power flows from Zones F to G, NG owns two 345 kV transmission lines—Leeds-Pleasant Valley and Leeds-Athens-Pleasant Valley connected in parallel. The Leeds-Athens-Pleasant Valley connection is a series connection. In addition, although not a wholly-owned NG facility, the Leeds-Hurley line, which NG jointly owns with Central

Hudson Gas & Electric Corporation ("CHGE"), forms a part of the UPNY-SENY interface.

NG also owns high voltage transmission lines that form part of the NYISO-ISO New England, NYISO-PJM, and NYISO-Ontario interfaces. National Grid's lines that are part of the NYISO and ISO-New England interface include the 345 kV Alps-Berkshire 393 line,[18] the 230 kV Rotterdam-Bear Swamp E205 line, and the 115 kV Hoosick-Bennington 6 and Whitehall-W. Rutland 7 lines. For the NYISO-PJM interface, NG owns the 115 kV Warren-Falconer 171 line and has a minority ownership on the 345 kV Homer City-Stolle Road line, which is operated by New York State Electric & Gas Company ("NYSEG") under the NYISO's operational control. National Grid's 230 kV Beck-Packard 76 line and 115 kV Beck-Lockport 104 line form part of the NYISO – Ontario interface. Table 2 summarizes NG's key transmission lines.

[17] Mr. Schiavone Testimony and Appendix_5.1_Interface_Definitions, *Comprehensive Reliability Planning Process,* NYISO, December 2005.

[18] The NYISO lists this as Alps-Many in its interface definition for NYISO-ISO-New England.

Table 2

National Grid's Transmission Facilities by NYISO Major Interface

Interface	Transmission Facilitity	Voltage (kV)
Dysinger East	Lockport-Batavia 107	115
Dysinger East	Lockport-N.Akron 108	115
Dysinger East	Lockport-Oakfield 112	115
Dysinger East	Lockport-Sweden 111	115
Dysinger East	Lockport-Sweden 113	115
Dysinger East	Lockport-Telegraph 114	115
West Central	Mortimer-Hook Rd- Elbridge 1/7	115
West Central	Mortimer – Elbridge 4	115
Moses South	Adirondack-Chases Lake-Porter 11	230
Moses South	Adirondack-Porter 12	230
Moses South	Dennison-Colton 4 & 5	115
Moses South	Alcoa-N.Ogdensburg 13	115
Moses South	Malone-Colton 3	115
Total East and Central East	Edic-New Scotland 14	345
Total East and Central East	Marcy-New Scotland 18	345
Total East and Central East	Porter-Rotterdam 30 &31	230
Total East and Central East	East Springfield-Inghams 942	115
Total East and Central East	Inghams Tie Bus	115
UPNY-SENY	Leeds-Pleasant Valley	345
UPNY-SENY	Athens-Pleasant Valley	345
UPNY-SENY	Leeds-Hurley (2)	345
NYISO-ISO New England	Alps-Berkshire 393 (1)	345
NYISO-ISO New England	Rotterdam-Bear Swamp E205	230
NYISO-ISO New England	Hoosick-Bennington 6	115
NYISO-ISO New England	Whitehall-W. Rutland 7	115
NYISO-PJM	Warren-Falconer 171	115
NYISO-PJM	Homer City-Stolle Road (2)	345
NYISO-Ontario	Beck-Packard 76	230
NYISO-Ontario	Beck-Lockport 104	115

Source: NYISO 2006 Summer Operating Study, Appendix E, and the Schiavone Testimony

Note: (1) The NYISO lists it as Alps-Many.

(2) National Grid is a minority owner of this facility.

Q: Does National Grid own any significant generation assets?

A: No. NG does not own any significant generation; it provides last resort commodity service to some of its retail customers using power purchased under legacy, long-term contracts and from the NYISO markets on a short-term basis.

Q: Please explain the transmission (if any) and generation assets owned by KeySpan in New York state or adjacent markets.

A: KeySpan is nearly the mirror image of National Grid. It does not own any electric transmission, but it owns several generating plants in Zones J and K (none in Zones A through I). In Zone J, KeySpan owns the Ravenswood facilities, a combination of dual-fuel steam, combined cycle, and gas turbine units totaling approximately 2400 MW. In Zone K, KeySpan owns 55 generating units. All of the output from these Zone K power generators has been sold on a long-term basis to an affiliate of LIPA.

B.2. Confirmatory Visual Evidence of Historical Outages

Q: What is the purpose of this portion of your testimony?

A: Before examining the simulated price impacts resulting from an outage of NG transmission lines, it is useful to consider the ordinary outage frequencies of these facilities and whether actual past outages have had any visually discernible effects on NYC, *i.e.*, Zone J prices. The important question that I explore is whether there is any visual evidence that prices in Zone J rose during periods of outages on NG facilities which are part of the NYISO Interface.

Q: What is the most important conclusion of this visual analysis?

A: By analyzing individual outages and its effect on Zone J prices during the period April 2005 through March 2006, I conclude that there does not appear to be a clear relationship between outages of NG facilities and higher prices in Zone J. The additional profits that the generation units would have earned in NYC as a result of temporarily transmission withdrawals initiated by NG would have been uncertain. Thus, I conclude that the historical incentive to exercise VMP so as to profitably raise prices in Zone J would have been unsystematic and insignificant.

Q: Can you provide some examples that further clarify the methodology you have employed to assess the historical incentive to exercise VMP and raise wholesale prices in NYC?

A: Yes. Exhibit No._(PFP-1R) to my testimony displays plots of actual Zone J DA prices before, during, and after actual NG-initiated outages of its facilities that are considered part of the NYISO key interfaces carrying power to NYC. The exhibit also contains price plots for all of the multi-facility outages and a randomly selected set of individual outages during the period from April 2005 through March 2006. For each of these prices, the outage period is shaded and the graph shows prices for at least one full day before and after each outage. Below the price plot, there is a smaller plot of the Zone J load in each hour shown.

As is typical in electric systems, each day in Zone J has a daily pattern that begins with low loads and prices in the early morning, and a peak in prices and loads sometime during the midday or early evening period. Within this general pattern, however, every day varies significantly.

Starting with the first graph in Exhibit No._(PFP-1R), the chart in this attachment shows two overlapping outages of NG's transmission facilities, the Berkshire-Alps transmission line and the EDIC bus, during the period November 30, 2005 to December 4, 2005. In this case, it can be seen that loads were approximately the same (and rather high) during all three days but peak prices were nearly the same before, during, and after the outage. It is impossible to argue from this particular episode that these particular outages elevated Zone J prices.

In a similar manner, the fourth chart in Exhibit No._(PFP-1R) shows prices and loads during a 36-hour outage of the Athens-Pleasant Valley line on April 24 and April 25, 2005. Prices and loads were essentially the same on April 23 and 24, the day before and the first day of the outage respectively. Prices did increase on the second day of the outage, but so did loads, and from these plots alone we cannot tell whether this April 25 peak period price increase was due to the line outage, higher load, or some other feature. For the day after the outage, we do see that prices declined but loads did not, so we cannot rule out the possibility that the outage contributed to the second-day price increase.

The remainder of the individual-outage price and load plots in Exhibit No._(PFP-1R) follows one of these two patterns. In many instances there is simply no discernible price impact during the outage. In others, there is a higher price in at least part of the outage period, but it cannot be discerned whether that higher price was caused by the outage or something else. It is particularly hard to attribute a price

increase to an outage when the price increase occurs during the second day of the outage but not on the first.

Q: When you consider multi-outage episodes (*i.e.*, those events in which there is an overlap of numerous facilities outages), is there a more clear relationship between outages of NG facilities and higher prices in Zone J?

A: No. Multi-outage episodes do not help to shed any light on the uncertain relationship between outages of NG facilities and higher prices in Zone J. An example of this uncertain relationship can be shown in the graph on May 2, 2005 in Exhibit No._(PFP-1R). During that particular day, an overlap between two candidate facility outages occurred, when a Gilboa-New Scotland 345 kV line outage coincided with a Volney-Marcy outage. As the price plot for this period shows, the overlap periods show no additional price elevation. The same conclusion can be drawn from the overlapping New Scotland – Leeds and Volney – Marcy outages on June 18 and 19.

Q: Is there any visual evidence that higher prices in Zone J can be associated with candidate facility outages that occur during pre-existing outages of other transmission facilities?

A: No. Outages late in 2005 also do not provide visual evidence that elevated prices were associated with candidate facility outages which accompanied pre-existing outages of other candidate facilities. For the November 30 – December 4 series of outages, prices are actually highest outside of the period when Edic – New Scotland is out of service, despite the fact that daily loads are lower on December 3 and 4. The December 6 outage episode yields similar conclusions. On December 14, an added outage of the

Rotterdam-Bear Swamp line clearly had no impact in spite of the fact that the outage occurred in the morning peak period.

Q: As a result of this visual evidence exercise can it be concluded that Applicants will not have any incentive to exercise VMP in the future?

A: No. The visual evidence analysis of candidate facility outages for the period April 2005 through March 2006 does not provide support to either accept or reject the hypothesis that outages on the candidate facilities have a predictable price impact. There certainly is no uniform effect across all facilities, nor is there a uniform effect across all outages. Contrary to expectation, adding a second candidate facility outage atop another one shows little discernible impact. This lends doubt to the hypothesis that individual outages are the causes of the occasional price elevations observed in some of these plots. Although the visual evidence is not sufficient to reject the possibility that there is a predictable relationship between some facility outages and Zone J price, it does show that the relationship is not very prevalent or consistent. This analysis clearly emphasizes the difficulties of accurately forecasting the effects on Zone J prices (and Zone J profits) of a temporary withdrawal of transmission capacity in upstate New York. The incentives to exercise VMP under these circumstances are unquestionably limited and highly situation-specific.

B.3. LBMP Simulation Model

Q: Please provide an overview of your LBMP simulation model.

A: I employ DAYZER, a commercial, state-of-the-art LBMP simulation model made by Cambridge Energy Solutions ("CES"), to test for the effects of outages of candidate transmission facilities on Zone J LBMPs.

The model uses an extensive mathematical description of the state's bulk transmission system, the attributes of all generators[19] in the New York ISO region, and other information such as imports and exports. For every hour in the test period, the model simulates unit commitment and dispatch, and calculates DA LBMPs in much the same way that the NYISO determines them.

Q: Is DAYZER a commonly used model to simulate the effects of transmission outages on market prices in wholesale electricity prices?

A: Yes. DAYZER is extensively used by traders of energy and financial transmission rights and by an academic institution to study and model LMP power markets.

Q: How do you use this model to test for the price impacts of candidate relevant facilities?

A: The model uses a solved load flow case from the New York ISO, and then simulates unit commitment, dispatch, and LBMPs at every New York bus. The model is sufficiently detailed that it can rearrange the flows on the bulk transmission system (including the redispatch of units if necessary) in the wake of a single bulk line being removed. For any given outage, the model recalculates the flow distribution patterns (often referred to as "generation shift factors"), re-simulates the unit commitment and

[19] DAYZER has a generating unit database in which units and their associated capacities in NYISO are based on the NYISO *Load & Capacity Data*. The database also includes unit characteristics such as heat rates, start-up cost, variable cost, etc.

dispatch, and solves for new DA LBMPs, taking into account the new flows and constraints following the outage.[20]

Q: Does a LBMP model of this type perfectly replicate the operation of the NYISO's DA or RT LBMP price-setting process?

A: No, it does not. No model perfectly replicates any real power market or system. However, I have set up and tested the model to simulate actual DA LBMPs and system attributes in New York for the year ending July 2005. The technical term for using a price simulation model to predict actual historic prices is backcasting.

Q: Why did you choose this particular time period for your Backcasting analysis?

A: I chose this period because it was the most recent period for which I had nearly complete NYISO, fuel price, outage and other actual data. On August 25, 2005 Hurricane Katrina landed on the U.S. Gulf Coast. For the remainder of 2005 New York LBMPs became unusually volatile. Benchmarking the model to this unusual period would not be appropriate, so I use the 12 months ending July 2005.

Q: Please provide an overview of the data sources you use in your simulation model.

A: Table 3 provides an overview of the model inputs and the sources for my benchmarked model. As the table shows, essentially all of the inputs come from established and/or public sources. The initial load flow, loads, interface limits, transmission outages, and other transmission information were obtained from the NYISO's reports and database. Certain transmission flows that are required by contracts were obtained from CES and

[20] The model cannot solve for one important variable, the impact of a specific outage on an interface rating, so I use the NYISO's published rating changes as my basis for adjusting interfaces in my tests. *See* Exhibit No._(PFP-4R) to my testimony, NYISO's *2002 Outage Impact Report.*

NYISO. CES, which downloads data from NYISO, FERC, and other sources (listed in its own documentation), provided most of the generator unit attributes (including hydro unit parameters), as well as some fuel price and other information. Unit information was supplemented by Energy Decisions Inc's Velocity Suite Database and the NYISO's 2005 Load & Capacity Data, and some fuel prices came directly from published indices such as NYMEX's gas spot price and Cantor Fitzgerald's daily emission price indices.

Table 3
Overview of Major Data Sources in Price Simulation Model

Data	Data Source for 2004 and 2005 Backcast
Transmission • Physical system • Transmission outages • Flow limits on interfaces • Flow limits on lines, contingencies • Contract flows • Loss factors	• NYISO 2006 Load Flow (2006 FERC Form 715) • Daily outages from NYISO • Hourly interface limits from NYISO • Thermal limits from NYISO 2006 Load Flow • CES* Database • Hourly loss factors from NYISO
Load • Zonal load • Distribution of load among buses	• Hourly RT load by zone from NYISO • NYISO 2006 Load Flow
Generation • Capacity online • Unit characteristics (Heat rate curves, VOM, startup costs, MUT/MDT) • Hydro data • Actual outages	• CES Database, 2005 Load and Capacity Data • CES Database, KeySpan, CEMS data, Global Energy Decisions Inc's Velocity Suite • CES Database with Brattle refinements • IIR, NRC, and CEMS data
Fuel and Emissions Prices • Gas • Oil • Coal • NOx, Sox	• Henry Hub Spot + Basis + LDC charges (ICE and CES) • NYMEX daily product prices • CES Database based on EIA 423 • Cantor Fitzgerald daily prices
Imports and Exports • Scheduled flows • Prices of imports	• Actual DA hourly schedules with PJM, ISO-NE, and IMO from NYISO • PJM market prices in Penn Electric during off-peak

Note: "CES" is Cambridge Energy Solutions, the software and data provider for the Dayzer model

Q: Please summarize the main outputs generated by your price simulation model.

A: The model produces voluminous, extremely detailed outputs. While these outputs are important for diagnosing the behavior of the model and understanding the NYISO power markets, I focus primarily on the models' prediction of DA LBMPs throughout my testimony. Because I am testing for price impacts in Zone J, my primary objective is to produce accurate predictions of these prices as they change with transmission system conditions.

The second type of variable I examine closely is the annual generation of Zone J units, especially the Ravenswood plants. As I explain above, these plants are the only significant source of potential additional profits to the Applicants from vertical market power, and profit calculations involve both quantities and prices.

Q: You say that your focus is on predictions of DA LBMPS. What about changes in vertical incentives involving other markets, such as real-time energy or ancillary services?

A: According to information provided by KeySpan and publicly available Electric Quarterly Reports ("EQRs") filed at FERC, the Ravenswood units have not earned significant revenues for ancillary services when compared to DA and RT energy revenues in the last few years. In addition, as explained above, I believe that it would be exceedingly difficult to construct a transmission withdrawal scheme that could predictably and profitably affect ancillary services prices, as NYISO ancillary service prices are formed for two large zones, eastern and western New York.

With respect to energy revenues, more than 80 percent of Ravenswood's energy payments in 2005 were for DA energy transactions. As noted above, the only way the merged company could have an impact on RT prices that was not already reflected in DA prices would be unexpectedly to withdraw transmission on relevant facilities within 24 hours of the dispatch day, after the DA market had closed.

Moreover, the Ravenswood units are both buyers and sellers at times in the RT market (buying occurs when Ravenswood must offset any shortfall between its DA sales and its actual generation.)[21] Furthermore, to have energy to sell in the RT market, Ravenswood would have had to avoid selling some otherwise available energy in the DA market so it would have additional capacity to offer in RT.[22]

All in all, profiting from a sudden excursion in RT prices via a strategic transmission withdrawal by NG constitutes an exceedingly unrealistic scenario. Such a scenario requires that National Grid would have to (1) model conditions in future downstate DA and RT markets with extraordinary precision; (2) on the basis of this, correctly predict that downstate RT prices were going to spike after withdrawal of the transmission; (3) communicate its intention to make such a withdrawal to Ravenswood generation bidders so they would be certain to be sellers in the RT market during the withdrawal rather than neutral or buyers, thus clearly violating NYISO and FERC rules; and (4) initiate the withdrawal very suddenly (*i.e.*, after the DA market closed),

[21] This contrasts with Staff's implied position that higher RT prices are paid solely by load. See CP Testimony at 33, 2-6.

[22] KeySpan currently hedges up to 50 percent of the on-peak capacity of Ravenswood. See KeySpan Corp, *2006 10K*, February 22, 2007, page 157.

which automatically triggers a high level of scrutiny since the NYISO must approve all such withdrawals, or at least be informed of them.

While I once again do not believe such entirely unannounced withdrawals are the way strategic withholding would occur, the mitigation scheme Applicants propose removes the profit incentives that could arise from the RT as well as the DA markets. The calculation of impacts in the RT markets requires that the simulation begins with market conditions (including unit commitments) initialized as they were in the RT markets when the outage occurred but are otherwise similar to the DA simulations that I describe in this testimony. Because RT incentives cannot properly be measured or removed without initializing the simulation model with that day's conditions, the calculations I perform and report in my testimony refer to the DA market, with RT loads added to DA loads.

B.4. Results of August 2004 through July 2005 Backcast

Q: In the previous section you mentioned that you have tested your model to simulate actual DA LBMPS and system attributes in New York for the year ending July 2005. Please compare the results of your 2005 hourly DA price simulation with actual prices in Zone J over that period.

A: Exhibit No._(PFP-2R) to my testimony shows twelve monthly plots of hourly actual (blue line) and simulated (red line) DA prices for each zone in the NYISO for the August 2004 to July 2005 period (the backcast period). For each month, the top figure presents the comparison of monthly actual and simulated price duration curves, *i.e.*, the ordering of prices from highest to lowest for simulated and actual hourly prices. The

bottom figure presents the chronological hourly prices comparison. These plots show that my backcast tracks actual DA prices quite well. Most importantly, the chronological path of hourly backcasted prices closely follows the time path of actual prices, showing that the model responds properly to hourly changes in loads, unit bids, and outages.

Table 4 compares the monthly average on-peak simulated prices with those of the actual prices for Zone J. On an average annual basis, my simulated on-peak price is approximately $79.5/MWh, while the actual on-peak price is $84.0/MWh, for a difference of $4.6/MWh. The month-by-month averages of simulated on-peak prices are generally below those of the actual on-peak prices. Although the average on-peak price of my backcast is lower than the average actual price, the distribution of the difference between my backcast and actual prices, *i.e.,* my backcast error, indicates that my backcast sometimes overestimates and other times underestimates actual on-peak prices, so there is no uniform bias.

I measure how close my simulated prices perform when compared with the actual Zone J on-peak prices by calculating the mean absolute percent error, as shown in the last column of Table 4. On a monthly basis, my backcast has an average absolute percent error below 12 percent, with the exception of November and December 2004. On an annual basis, the absolute error between my simulated peak prices and actual prices is an average of 10.6 percent. For Zone J's off-peak prices (not shown in Table

4), my simulated prices are higher than actual prices, with annual average off-peak price differential of $1.20/MWh.[23]

Table 4
Comparison of Zone J's Monthly On-Peak Average Prices
Simulated vs. Actual: August 2004 through July 2005

Month	Average Simulated Price *($/MWh)*	Average Actual Price *($/MWh)*	Difference of Average Simulated and Actual Prices *($/MWh)*	Mean Absolute Percent Error *(%)*
August 2004	67.5	70.5	-3.0	9.7%
September 2004	62.1	64.9	-2.8	8.6%
October 2004	70.6	74.1	-3.5	9.2%
November 2004	64.4	73.6	-9.2	12.7%
December 2004	64.7	75.1	-10.3	14.6%
January 2005	86.4	92.0	-5.6	11.4%
February 2005	80.1	83.0	-2.9	11.3%
March 2005	88.6	89.1	-0.5	10.6%
April 2005	84.3	91.0	-6.7	10.9%
May 2005	74.0	76.4	-2.4	7.3%
June 2005	97.2	103.0	-5.8	10.3%
July 2005	115.9	117.7	-1.9	11.0%
Annual Average	**79.5**	**84.0**	**-4.6**	**10.6%**

Q: Did you undertake any other analysis to measure the accuracy of your simulation model?

A: Yes. To further asses the accuracy of the model I also compare the total generation of Ravenswood steam oil/gas units 1-3 and Ravenswood CC with their actual generation for the backcast period.

[23] The simulated price results for Zones A through I and K are also presented in Exhibit No._(PFP-3R) along with their differences from actual prices. As shown in Exhibit No._(PFP-3R), annual average simulated on-peak price differences are generally slightly below the actual prices. Average on-peak

Q: How does the simulated generation of Ravenswood units in 2005 compare to their actual generation?

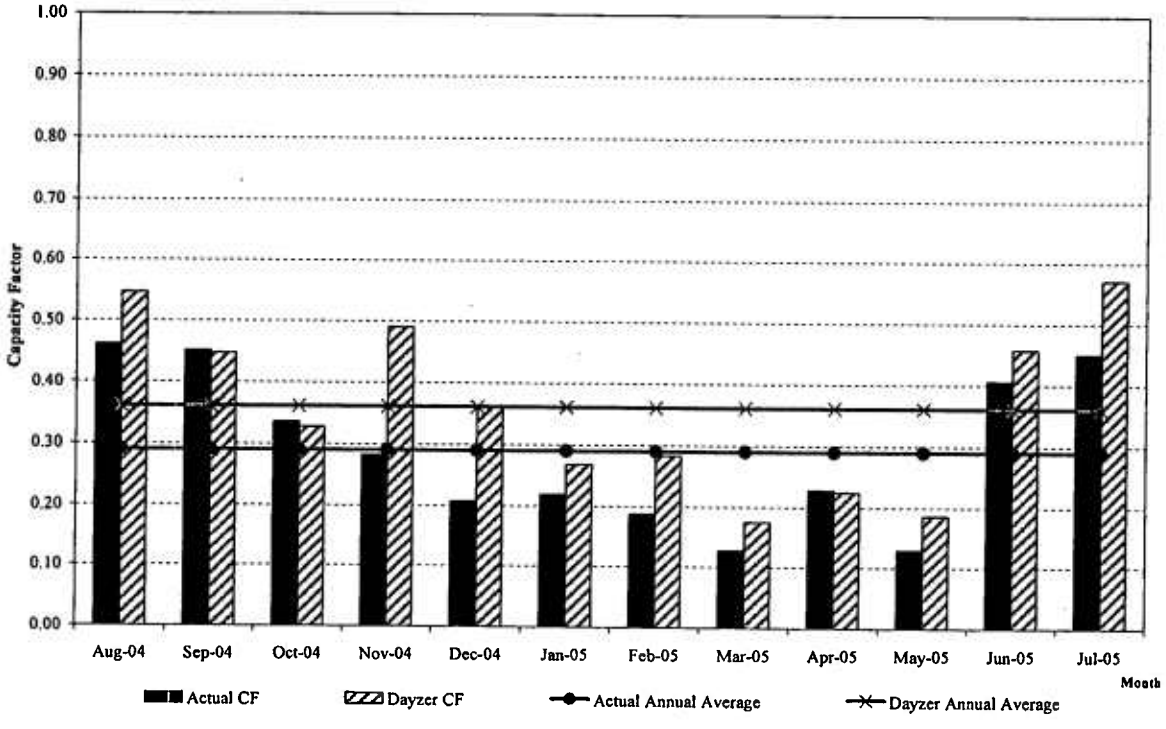
A: The total amounts of simulated and actual generation of these units during the backcast period are approximately 7,287 GWh and 6,224 GWh, respectively. My model overestimates Ravenswood's total generation by approximately 1,000 GWh or 17.1 percent. Figure 2 compares the combined Ravenswood steam oil/gas units 1 to 3 monthly capacity factors from my backcast with the combined actual capacity factor. The combined units' actual monthly capacity factors in August 2004 through July 2005 ranged from 13 percent to 46 percent with annual capacity factors of 29 percent.[24] The simulated monthly capacity factors range from 18 percent to 57 percent with the majority of the months having higher capacity factors when compared to those of the actual capacity factors. On average, the combined capacity factor from the simulation is higher than the actual capacity factor by 7 percent.

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price differentials range from -$2.70/MWh in Zones I and F to $0.20/MWh in Zone K while those of off-peak prices range from -$3.0/MWh in Zone A to $2.50/MWh in Zone K.

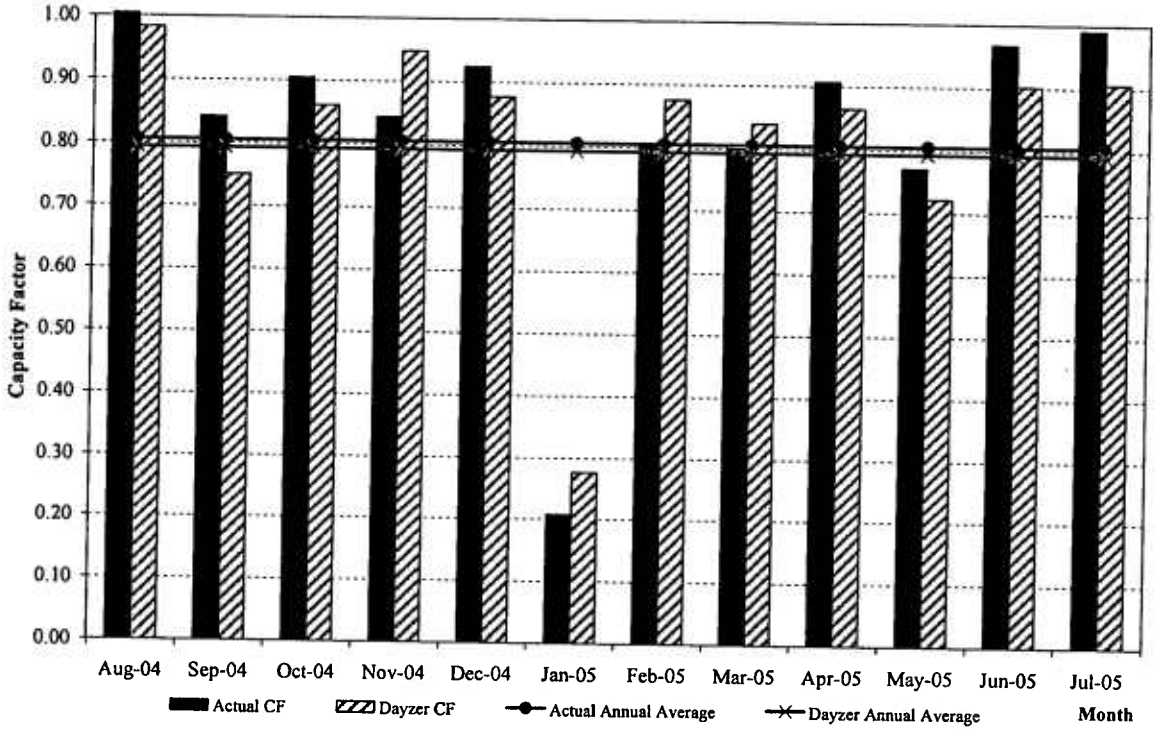
[24] The actual capacity factors of Ravenswood units were calculated using the FERC EQR Database and Energy Velocity Database.

Figure 2
Combined Capacity Factor of Ravenswood Units 1-3
Actual vs. Backcast: August 2004-July 2005



For Ravenswood CC, the simulated total generation is 1,736 GWh, which is just slightly lower than its actual total generation of 1,764 GWh. Figure 3 presents Ravenswood CC's monthly capacity factors comparison for August 2004 to July 2005. The actual annual capacity factor is 81 percent while the simulated capacity factor was about 79 percent. Overall, my model overestimates the total generation of Ravenswood units 1-3 and CC by approximately 17 percent, which is conservative.

Figure 3
Combined Capacity Factor of Ravenswood CC
Actual vs. Backcast: August 2004-July 2005



Q: Do you believe these results are accurate enough to allow for the testing of the price impacts of line outages?

A: Yes, I do. The backcast results confirm that the model reasonably reflects Zone J prices given transmission system conditions. The degree to which the model successfully produced simulated prices close to actual prices, and simulated Ravenswood generation and capacity factors close to actual amounts, confirms the reasonableness of relying on the model to identify NG's relevant transmission facilities and screen for profit impacts.

B.5. Creation of a 2007 Simulation Model

Q: Please summarize the adjustments you make to create a 2007 simulation out of your benchmarked model.

A: My test year for evaluating potential impacts of National Grid's major transmission lines outages on Ravenswood's profit is 2007, the year the merger is expected to close. The adjustments I have made to reflect 2007 conditions include load, fuel prices, emission costs, generation additions and retirements, known generation and transmission outages, hydro availabilities, transfer capability, and the operation of the Neptune cable.

Q: Please explain more carefully the adjustments you have made to estimate load figures in year 2007.

A: The 2007 hourly loads in each zone are derived from the 2005 hourly load pattern (January 2005 through December 2005). I then escalate the historical hourly load data of each NYISO zone by its summer peak, winter peak, and energy growth rates calculated using the NYISO *2006 Load & Capacity Data*.[25]

Q: Please provide an overview of the 2005-2007 fuel price adjustments and the data sources you relied on.

A: CES, the manufacturer of DAYZER, provides estimated 2007 fuel price based on two main sources: Intercontinental Exchange ("ICE") and New York Mercantile Exchange ("NYMEX") price quotes. Natural gas fuel prices delivered in the NYISO markets are calculated based on the NYMEX Henry Hub future gas prices plus basis differentials,

[25] The 2007 energy requirement forecasts for Zones J and K projected in the NYISO *2006 Load & Capacity Data* are lower than the actual 2005 energy requirement, yielding negative energy growth rates

which are calculated based on ICE, and local distribution charges. The 2007 future coal prices are based on NYMEX Central Appalachian future coal prices. Prices of light oil (FO2) and heavy oil (FO6) are forecasted by CES from the NYMEX future prices of crude oil. The 2007 emission costs for sulfur dioxide (SO_2) and nitrogen oxides (NO_x) are obtained from Cantor Fitzgerald.

Q: Do you have to make any adjustments on the generation capacity to accurately reflect 2007 market conditions?

A: Yes, I do. I add approximately 1,160 MW[26] of new generation capacity additions that have been in-service since August 2005 as well as those that are under construction and expected to be on-line in 2007. All of the capacity additions are located in Zone J. I also exclude about 832 MW from the 2007 model, as this capacity was either retired after July 2005 or is scheduled to be retired in 2007. The source for my capacity additions and retirements is the NYISO *2006 Load & Capacity Data Report.*

Q: Please present any further adjustments you have made on generation and transmission outages, hydro generating plant availabilities, transfer capability, and the operation of the Neptune cable.

A: The 2007 planned generation outages for thermal power plants are obtained from Industrial Information Resources ("IIR"). For plants that do not have planned outages reported, CES adjusts their capacity based on past planned and unplanned outage rates by plant size and technology. For hydro power plants, I assume average availabilities based on historical 1996-2005 average capacity factors (but no unplanned outages).

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for both zones. I therefore conservatively assume each of these zones has an annual energy growth rate of positive 0.25 percent.

[26] The number is based on winter capacity ratings.

For 2007 planned transmission outages, I utilize the NYISO's present schedule of transmission line outages listed in its Daily Transfer Limitations report as of December 7, 2006.[27] For transfer capability on major interfaces, unlike my backcast which used the actual DA hourly limits from the NYISO, I utilize the 2007 transfer limits from the NYISO's December 2005 Table 11.1.12 in *Comprehensive Reliability Planning Process Supporting Document and Appendices for the Draft Reliability Needs and Assessment.* The 2007 model also has the Neptune cable entering service in July 2007, increasing Zone K's import capability from PJM by 660 MW.

B.6. Application of the Simulation Model to Determine the Upper Limit of the VMP Incentive

Q: Which National Grid transmission facilities did you test for their ability to influence prices in Zone J via their temporary withdrawal?

A: In order to test the impact of a specific bulk transmission facility's outage on flows into the NYC area it is first necessary to determine how that particular outage affects the transfer capability of the interfaces shown in Figure 1. The management of these interfaces and the determination of specific outage impacts on these interfaces are strictly within the purview of the NYISO, and its software for making such calculations is not public. However, the NYISO analyzes the impact of specific transmission facility outages on its interfaces and publishes these impacts on a *NYISO Transfer Limitation* daily report.[28] Also, the NYISO's *2002 Outage Impact Report,* which we obtained through National Grid, lists maintenance-outage impacts of various

[27] http://mis.nyiso.com/public/pdf/ttcf/

[28] The NYISO publishes *NYISO Transfer Limitation* on a daily basis. The report presents the impacts of the next day's outages on interfaces, but these daily reports are not archived.

transmission facilities on the major NYISO interfaces, as shown in Exhibit No._(PFP-4R).[29] For example, this attachment shows that if the Edic-New Scotland 14 line were to be taken out of service, the Central East interface maximum capacity would be reduced by 1,225 MW by the NYISO during the outage period.

To analyze whether the merger would create an incentive to influence prices in Zone J, I tested all NG facilities identified in this NYISO report as having significant outage impacts on the Central East, Total East, Moses South, and NYISO-ISO-New England interfaces. The NYISO report does not list the impact of lines being out of service on the UPNY-SENY interface, but this interface is part of Central East. To test the lines along this interface, I conservatively assume that outages on NG's transmission facilities that are part of this interface, namely Leeds-Pleasant Valley 92 and Athens-Pleasant Valley 91,[30] will reduce the UPNY-SENY interface by the same amount as listed for the Total East interface. I also test bulk transmission lines for which NG controls only one end, such as the Leeds-Hurley line.

The full list of the tested facilities, which I call "candidate relevant facilities," or simply "candidate facilities," is shown in Table 5 below (as well as in Table 2). There are 21 candidate transmission facilities. Columns [1] to [4] of Table 5 describe my outage scenarios, along with their impact on relevant interface limits (Columns [5] to [9]). Some of these outage scenarios are "nested" within others, *i.e.,* if one scenario passes, another facility must also pass because it has identical or lower interface

[29] NYISO Outage Scheduling Manual (Rev.: 5/30/2002), Appendix, Outage Impact Report rev.: (June 10, 1999).

[30] Leeds also connects to Athens, however, I only analyze the Athens-Pleasant Valley line.

impacts.[31] Accordingly, it is only necessary to test 10 distinct scenarios. These 10 scenarios are listed on Table 6.

I do not analyze the outage impacts of 115 kV lines listed on Table 2 (such as the East Springfield-Inghams 942 or Inghams Tie Bus, Dennison-Colton 4&5 lines) because, consistent with their lower capacity, the NYISO has not reported that they have significant impacts on the major interfaces downstream of Zone G.[32]

[31] Another example of nesting is the Leeds-Athens and Leeds-Pleasant Valley line, which are in series and therefore only one of the two needs to be tested.

[32] I also did not test for the Beck-Packard 76 nor the Beck-Lockport 104 lines, as they do not have an impact on the Total East interface or any other downstream interface in Zone E.

Table 5
List of Candidate Relevant Facilities

Sce. No.	Facility	Description	Station_Equipment in Exhibit No._(PFP-4R)	Impacts on Interface Limits										Source
				Central East		Total East		UPNY-SENY		Moses South		NYISO-NE		
				Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	
[1]	[2]	[3]	[4]	[5]		[6]		[7]		[8]		[9]		[10]
1	Leeds-Pleasant Valley 92	345 kV line from Leeds to Pleasant Valley	LEEDS 345_92			925	400	925	400					[A]
2	Edic-New Scotland 14	345 kV line from Marcy to New Scotland 14	EDIC 345_14-EN (to N Scot)	1225	1225	1225	1225							[A]
3	Marcy-New Scotland 18	345 kV line from Marcy to New Scotland 18	MARCY 345_18 (to N Scot)	1175	1175	1175	1175							[A]
4	New Scotland-Leeds 93 or New Scotland-Leeds-94[1]	345 kV line from Leeds to New Scotland 93 or 94	NEW SCOTL 77_345 93-LN or NEW SCOTL 99_345 94-LN	1175	550	1175	550							[A]
5	Gilboa-Leeds GL3	345 kV line from Leeds to GL3	GILBOA 345_GL3			1100	1100							[A]
6	Athens-Pleasant Valley 91	345 kV line from Athens to Pleasant Valley 91	LEEDS 345_91			925	300	925	300					[A]
7	Adirondack 230 -12AP	345 kV line from ADIRONDACK 230 to 12AP	ADIRONDACK 230_12-AP							500	500			[A]
8	Chases Lake-Porter	345 kV line from Chases Lake to Porter								900	900			[B]
9	Leeds 345 R391 or Leeds 345 R94301	345 kV relays at Leeds Substation	LEEDS 345_301			1300	525							[A]
10	Fitzpatrick-Edic (FE1)	345 kV line from Fitzpatrick to Edic	FITZPATRICK 345_FE1			300	300							[B]
11	Leeds-Hurley (301)	345 kV line from Leeds to Hurley	LEEDS 345_301			625	375	625	375					[A]
12	Porter-Rotterdam (30)	230 kV line from Porter to Rotterdam	PORTER 230_30-PR	250	250	250	250							[A]
13	Porter-Rotterdam (31)	230 kV line from Porter to Rotterdam	PORTER 230_31-PR	250	250	250	250							[A]
14	Lafayette-Oakdale (4-36)	345 kV line from Lafayette to Oakdale	LAFAYETTE 345_4-36			550	550							[A]
15	Volney-Marcy (19)	345 kV line from Volney to Marcy	VOLNEY 345_19			275	275							[A]
16	Gilboa-New Scotland (1)	345 kV line from Gilboa to New Scotland	GILBOA 345_GNS1			375	125							[A]
17	Alps-Many 393	345 kV line from Alps to Berkshire	BERKSHIRE 345_393									450	450	[A]
18	New Scotland-2-AN (Alps)	345 kV line from New Scotland to Alps	NEW SCOTL 77 345_2-AN									325	250	[C]
19	Bearswamp-Rotterdam	230 kV line from Rotterdam to Bear Swamp	BEAR SWP 230_E205W									300	300	[C]
20	Edic-Fraser (EF24-40)	345 kV line from Edic to Fraser	EDIC 345_EF24-40			850	850							[A]
21	Leeds SVC	Leeds Close-Static Var Compensator	LEEDS345_SVC	100	100	100	100							[A]

Source:

[A]: New York ISO Transmission Facility Maintenance Outage Impact Report, Exhibit No._(PFP-4R).

[B]: NYISO, NYISO Transfer Limitations, September 19, 2006.

[C]: NYISO, NYISO Transfer Limitations, October 6, 2006.

[1] Since both are pararell lines, scenario 4 is tested on New Scotland-Leeds 93. The result can be applied to New Scotland-Leeds94 as they have the same outage impacts.

Note: Leeds-Athens is in series with Athens-Pleasant Valley 91 so this line's results are the same as Athens-Pleasant Valley 91.

Table 6
Selected 10 Transmission Outage Scenarios

See. No.	Facility	Description	Station_Equipment in Exhibit No._(PFP-4R)	Impacts on Interface Limits										Source
				Central East		Total East		UPNY-SENY		Moses South		NYISO-NE		
				Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	
[1]	[2]	[3]	[4]	[5]		[6]		[7]		[8]		[9]		[10]
1	Leeds-Pleasant Valley 92	345 kV line from Leeds to Pleasant Valley	LEEDS 345_92			925	400	925	400					[A]
2	Edic-New Scotland 14	345 kV line from Marcy to New Scotland 14	EDIC 345_14-EN (to N Scot)	1225	1225	1225	1225							[A]
3	Marcy-New Scotland 18	345 kV line from Marcy to New Scotland 18	MARCY 345_18 (to N Scot)	1175	1175	1175	1175							[A]
4	New Scotland-Leeds 93 or New Scotland-Leeds-94[1]	345 kV line from Leeds to New Scotland 93 or 94	NEW SCOTL 77_345 93-LN or NEW SCOTL 99_345 94-LN	1175	550	1175	550							[A]
5	Gilboa-Leeds GL3	345 kV line from Leeds to GL3	GILBOA 345_GL3			1100	1100							[A]
6	Athens-Pleasant Valley 91	345 kV line from Athens to Pleasant Valley 91	LEEDS 345_91			925	300	925	300					[A]
7	Chases Lake-Porter	345 kV line from Chaselake to Porter								900	900			[B]
8	Leeds-Hurley (301)	345 kV line from Leeds to Hurley	LEEDS 345_301			625	375	625	375					[A]
9	Porter-Rotterdam (30)	230 kV line from Porter to Rotterdam	PORTER 230_30-PR	250	250	250	250							[A]
10	Alps-Many 393	345 kV line from Alps to Berkshire	BERKSHIRE 345_393									450	450	[A]

Source:

[A]: New York ISO Transmission Facility Maintenance Outage Impact Report, Exhibit No._(PFP-4R).

[B]: NYISO, NYISO Transfer Limitations, September 19, 2006.

[1] Since both are parallel lines, scenario 4 is tested on New Scotland-Leeds 93. The result can be applied to New Scotland-Leeds94 as they have the same outage impacts.

Note: Leeds-Athens is in series with Athens-Pleasant Valley 91 so this line's results are the same as Athens-Pleasant Valley 91

Q: Please describe how you use your adjusted LBMP model to test for the price and profit impacts of candidate facility outages.

A: I use the calibrated simulation model to determine whether a "surprise" outage of any of NG's lines can predictably raise DA prices in Zone J. In my model, I theoretically assume that NG initiates an outage on its key transmission facility by notifying the NYISO a day in advance, *i.e.,* less than the NYISO notification period requirement. Where the model finds that price increases are theoretically achievable from such an action, it simultaneously calculates the predicted amount of increased profit the affiliated Companies might obtain from such a surprise outage. (As I have indicated before, a similar computation can be performed to identify any impacts on RT prices given the correct inputs.)

Q: How do you create the outage scenarios?

A: To create each outage scenario, I begin with the 2007 base case and then remove one candidate facility from service, one day at a time and simultaneously reduce the flow limit on relevant interfaces as specified in Table 6. For example, in Scenario 2, I hypothetically take Edic-New Scotland out of service, one day at a time, for all 365 days of 2007. For each hypothetical outage-day, I examine the difference between the model's predicted profit from sales by the Ravenswood units with and without the outage.

Q: Do you believe the results of your analysis provide an accurate estimation of the magnitude of the incentives of the Applicants to exercise VMP?

A: I believe that this analysis places a conservative upper bound on the magnitude of the incentives of the merged company to exercise VMP. The reasons for this conservatism are twofold. First, I do not think it is remotely possible that the merged company could or would, on the basis of a projection of added generation profits created by unneeded day-long facility outages, take advantage of every such projected opportunity. As Messrs. Reilly and Schiavone explain in their testimonies, such a program would involve substantial willful violations of NG, NYISO and FERC policies, and a consistent pattern of this kind of outage would be nearly certain to be detected by NYISO and others.

The second source of conservatism involves the fact that I test the impact of outages on every day of the year. As explained by Mr. Schiavone, the facilities I examine in my scenarios are all A-1 facilities and are subject to certain NYISO and NG outage guidelines. In particular, the NYISO ordinarily does not allow scheduled outages in the summer, and it also disallows or discourages multiple outages in a single day that affect the same interface.[33] Nevertheless, I do not exclude any days from my test procedures.

C. RESULTS AND MITIGATION DISCUSSION

Q: Please summarize your estimates of daily incremental DA profitability from hypothetical outages for the 10 selected scenarios.

Summary statistics for each of my 10 scenarios, testing one-day outages for the entire calendar year 2007, are shown in Table 7. For each scenario, the table shows the

[33] Michael L. Schiavone Testimony, at 32.

number of days with estimated incremental DA profits exceeding $100,000, the number of days with negative profits, and the median, and maximum daily incremental profit for a hypothetical additional one-day outage of that scenario's facility.

My results in Table 7 show that, for the vast majority of days and candidate facilities, there are no significant added profits obtained by taking additional one-day outages. Using the $100,000 threshold of additional profits per event, I find that there are four NG transmission lines (out of several hundred that NG owns) with Zone J price impacts, but these take place no more than 16 days in 2007. These facilities are the Leeds-Pleasant Valley and Athens-Pleasant Valley lines, and by extension the Leeds-Athens line, which is in series with Athens-Pleasant Valley. I also find that there are two days in which an outage of the Leeds-Hurley line, which NG jointly owns with Central Hudson Gas and Electric, increases KeySpan's profit by more than $100,000. The remaining candidate facilities have no outage impact exceeding my threshold level.

Across all of these facilities, there are only 16 days in 2007 in which an outage on any of these facilities creates a projected DA profit impact. Moreover, 14 of these 16 outage days arise in summer so they could not ordinarily occur under NYISO guidelines. Thus, I find that there are only two non-summer days in which projected profits above my threshold could be predictably earned from two of NG's facilities, Leeds-Pleasant Valley or Athens-Pleasant Valley.

Table 7
Summary of Change in Ravenswood 1-4 Profit By Transmission Outage Scenario

Scenario Number	Scenario	Interface(s) Affected By Outage	No. of Days When Change in Profit Exceeds $100K			No. of Days When Change in Profit is Less than $0	Median Daily Change in Profits	Maximum Daily Change in Profits
			Total	Summer	Non-summer			
Facilities with No Significant Withholding Incentive								
7	Chases Lake-Porter	Moses South	0	0	0	160	$ 1	$ 44,302
10	Alps-Many 393 (Berkshire)	NYISO-NE	0	0	0	131	$ 18	$ 78,693
2	Edic-New Scotland 14	C_E, Total East	0	0	0	96	$ 343	$ 96,525
3	Marcy-New Scotland 18	C_E, Total East	0	0	0	99	$ 300	$ 97,187
4	New Scotland-Leeds 93 or New Scotland-Leeds-94[1]	C_E, Total East	0	0	0	79	$ 71	$ 62,619
5	Gilboa-Leeds GL3	Total East	0	0	0	113	$ 40	$ 67,697
9	Porter-Rotterdam (30)	C_E, Total East	0	0	0	146	$ 9	$ 67,156
Facilities with Small Withholding Incentive								
8	Leeds-Hurley (301)	Total East, UPNY-SENY	2	2	0	87	$ 93	$ 145,945
6	Athens-Pleasant Valley 91[2]	Total East, UPNY-SENY	15	14	1	84	$ 243	$ 315,587
1	Leeds-Pleasant Valley 92	Total East, UPNY-SENY	16	14	2	99	$ 195	$ 315,683

Note: [1] Since both are parallel lines, scenario 4 is tested on New Scotland-Leeds 93. The result can be applied to New Scotland-Leeds94 as they have the same outage impacts.

[2] Leeds-Athens is in series with Athens-Pleasant Valley 91 so this line's results are the same as Athens-Pleasant Valley 91.

Q: Why do you select a $100,000 increase in profits as a significance threshold?

A: I have used my judgment to select $100,000 as a benchmark level of added profits that rises to a reasonable level of significance. This represents about 0.02 percent of Ravenswood's annual 2006 revenue, which is a miniscule fraction of the total annual earnings of either of the Applicants. In view of the risks and uncertainties associated with taking additional outages for "strategic" purposes, I do not believe a utility manager would undertake such behavior for a potential payoff below this level. Indeed, I consider the $100,000 threshold I have chosen to be a level that is quite conservative.

Q: Table 8 reports the number of days with profits greater than $100,000. Is it possible that the merged company could withhold transmission strategically on every one of those high-incentive days?

A: No, it could not. As explained in Mr. Schiavone's testimony, the NYISO prohibits scheduled outages and strongly discourages unscheduled outages on these critical facilities during the summer. Thus, it is extraordinarily unlikely that any summer day can be used to withhold transmission strategically, and all of the summer days with high daily incremental profits belong in a category that is even more unlikely than usual. Similarly, Mr. Schiavone explains that the NYISO does not allow multiple scheduled outages on the same key interface on the same day, and any strategic outages on days that create multiple outages on one interface outages are also extraordinarily unlikely.

Table 8 presents the 16 calendar days that the Companies would earn additional profit exceeding $100K for each of my 10 scenarios. Column [3] of Table 8 presents the

daily upper bound estimate of additional profit that Applicants would earn if they strategically took one of the relevant facilities out of service.

This estimate is highly conservative. As I mentioned above, 14 of these 16 high-incentive days are summer days (June 1 to September 1) and are therefore extraordinarily unlikely to occur. The sum of the short-term incentive to exercise VMP during non-summer period amounts to less than $275,000.

Table 8
Summary of Upper Bound Vertical Incentives

($000)

			Single Outages Scenarios									
			Scenario 1	*Scenario 2*	*Scenario 3*	*Scenario 4*	*Scenario 5*	*Scenario 6*	*Scenario 7*	*Scenario 8*	*Scenario 9*	*Scenario 10*
Date	**Number of Days with Significant Effects**	**Upper Bound Incremental Profits**	Leeds-Pleasant Valley 92	Edic-N. Scotland 14	Marcy-New Scotland 18	Leeds-New Scotland 93 [1]	Gilboa-Leeds GL3	Athens-Pleasant Valley 91 [2]	Chase Lake Porter	Leeds Hurley	Porter Rotterdam	Alps Many
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
27-Mar-07		$ 102	$ 102									
07-Jun-07		$ 160	$ 160					$ 159				
19-Jun-07		$ 122	$ 122					$ 122				
21-Jun-07		$ 123	$ 123					$ 123				
08-Jul-07		$ 149	$ 149					$ 149				
29-Jul-07		$ 102	$ 102					$ 101				
02-Aug-07		$ 316	$ 316					$ 316				
03-Aug-07		$ 159	$ 159					$ 159				
04-Aug-07		$ 182	$ 182					$ 182				
05-Aug-07		$ 190	$ 190					$ 190		$ 114		
10-Aug-07		$ 296	$ 296					$ 295		$ 146		
11-Aug-07		$ 102	$ 102					$ 101				
18-Aug-07		$ 113	$ 113					$ 113				
21-Aug-07		$ 124	$ 123					$ 124				
26-Aug-07		$ 102	$ 102					$ 102				
16-Sep-07		$ 168	$ 168					$ 168				
Total Annual Upper Bound Incremental DA Profits	16	$ 2,510	$ 2,509					$ 2,405		$ 260		
Total Summer Incremental DA Profits (June 1 - September 1)	14	$ 2,239	$ 2,238					$ 2,236		$ 260		
Total Non-Summer Incremental DA Profits [3]	**2**	**$ 271**	**$ 271**					**$ 168**				

Note: [1] Since both are parallel lines, scenario 4 is tested on New Scotland-Leeds 93. The result can be applied to New Scotland-Leeds94 as they have the same outage impacts.

[2] Leeds-Athens is in series with Athens-Pleasant Valley 91 so this line's results are the same as Athens-Pleasant Valley 91.

[3] Non-Summer Incremental Day-Ahead Profits are computed as the sum of March 27th 2007 and September 16th 2007 Incremental Day-Ahead Profits.

Q: From the results that you have presented, do you believe that, as a result of the merger, the Applicants will have an incentive to consistently or randomly schedule transmission outages on any of the critical facilities?

A: No, I do not. One important general observation that emerges from my simulation results is that it is much more common to have no additional profits whatsoever, or even negative profits (*i.e.*, to lose money), from the withdrawal of a candidate facility than it is to have profits exceeding $100,000. This shows that there is no incentive for NG to consistently or randomly schedule transmission outages on any of the Critical Facilities; the only significant incentive would require an elaborate and complex effort to forecast and choose in advance the handful of days where system conditions happen to allow for significant added profits.

Q: Under the unlikely assumption that the Applicants had the ability to manipulate the candidate facilities without a significant probability of detection and punishment, is it your opinion that this small incentive to exercise VMP requires vertical mitigation by the regulatory authorities?

A: No. My results and the constraints on NG's ability to schedule outages on transmission lines indicate that no vertical mitigation is necessary.

Q: Please explain how your model (or any equivalently accurate simulation model) can help to eliminate the incentive to exercise VMP.

A: Use of this model (or any equivalently accurate simulation model) for mitigation is straightforward once the model is properly calibrated. To mitigate any possible withdrawal incentive, whenever NG declares an outage on one of the few identified

Critical Facilities that was not on its month-ahead schedule, one can simply perform a simulation with and without this particular outage change. As discussed above, the simulation would be performed for the markets (DA and/or RT) that are affected by the outage. The difference in KeySpan's profits on Zone J generation – if any – can be paid by the merged company into a fund to benefit customers. This fully removes any incentive for NG to *willfully* cause an outage on any of the facilities that can under some conditions raise Zone J prices.

With this sort of mitigation in place, the merged company would pay only when it changed an outage in the month-ahead schedule on a Critical Facility during a system period where it happened to have the incremental effect of increasing Ravenswood profits. Since the merged company obviously would prefer not to make such payments, its theoretical incentives would actually be reversed – it could be *less* likely to take an outage that raises Zone J prices – even if such an outage was appropriate for reasons other than the incremental profits[34] – than it would prior to the merger. In this sense, the approach discussed here could actually be a small over-mitigation, and Zone J prices might be *lower* in total after the merger than before. Thus, one valuable feature of this mitigation approach is that it *prevents* vertical withdrawals as much as possible rather than simply seeking to forbid or punish them. My calculations show that the likely magnitude of NG's mitigation (deterrent) payments would be about several hundred thousand dollars a year, and possibly none at all in many years.

[34] When the NYISO and National Grid agree that a transmission outage cannot be delayed for reliability reasons, National Grid should be allowed to schedule its outage less than 30 days without mitigation.

Q: In practice, what steps would be required to mitigate the Applicants' small incentives to exercise VMP?

A: The use of a model of this form to mitigate the small VMP incentives in this merger involves four basic steps. First, a current version of the model should be created biannually or each quarter. The model should be adjusted to contain the most accurate available data on fuel prices, planned transmission outages by all transmission owners, and transmission system limits and operating procedures.

Second, outages potentially subject to mitigation would be identified. The model would be used only to test and calculate mitigation payments in the case of outages: (a) on one or more of the four candidate facilities whose outages might impact Zone J prices significantly (*i.e.*, the Leeds-Pleasant Valley, Athens-Pleasant Valley, Leeds-Athens and Leeds-Hurley lines), if (b) the outage diverged from the outages scheduled for these particular lines not shown on NG's month-ahead outage schedule. However, emergency and fault outages, outages initiated by parties other than NG and outage schedule requests that the NYISO and NG agree cannot prudently be delayed, based on reliability concerns would be excluded from mitigation.

Third, the model would be run to compare scenarios with and without the outage for each day and each market (DA and RT) that the outage affected. For example, a rescheduled outage that lasts one day and occurs two days from the day it was changed affects only the DA market on the day the outage is changed to. An outage lasting several hours announced during the same day affects the RT market. The model should

be run using the most current knowledge of transmission and generation outages as of the time of outage change, whether in DA or RT.

Finally, if these simulations show that the outage increased Ravenswood profits by more than $100,000 for that outage, NG would pay the estimated difference in profits earned by the Ravenswood units as calculated by the model into a fund to benefit customers.

Q: Is it your opinion that the implementation of this methodology will fully eliminate the small incentive to exercise VMP by the Applicants?

A: Yes, it will fully eliminate any short-term VMP incentives.

Q: Are the Applicants proposing to put into practice a mitigation mechanism similar to the one you have described?

A: Yes. Mr. Reilly makes this commitment in his testimony.

Q: Please summarize your conclusions regarding short-term VMP.

A: I find that there is no significant incentive to withhold any of the vast majority of transmission facilities owned by NG created by the proposed merger. For four particular NG transmission lines that are parts of key upstate transmission interfaces, I find that the merger would create a small incentive to withhold transmission but only if one is willing to set aside the limits on NG's ability to withdraw these facilities and/or to avoid detection and punishment. I find that there are only two non-summer days in 2007 in which a one-day outage on any of these facilities would predictably increase the merged companies' estimated Zone J generation profits by more than $100,000. However, setting aside all such limits on NG's ability to schedule transmission outages, this small

incentive can be fully removed (and over-mitigated) by using a simulation model to calculate the (estimated) small incremental profits caused by certain types of unscheduled outages on the few NG transmission facilities that can sometimes affect Zone J prices. The amount could then be paid into a fund to benefit customers.

III. Response to Staff's Claims Regarding Short-Term Vertical Market Power

A. Overview of Staff's Claims and Their Irrelevance

Q: Please summarize Staff's claims on short-term vertical market power.

A: Staff disagrees with Applicants' July 2006 assertion that the proposed merger of NG-KS does not create a vertical market power concern, in part because NG's Leeds-Pleasant Valley line is in a different geographic market from KeySpan's generation. Relying on Dr. Liu's geographic market analysis, MPP concludes that National Grid's transmission lines and KeySpan's generators are in the same geographic market over 50 percent of the time. Staff jumps from the finding that the lines and plants are in the same market directly to the conclusion that this fact alone gives NG an incentive to withhold its upstate transmission capacity in order to raise prices in Zones J and K. While Dr. Liu's analysis is interesting and potentially relevant, the factors addressed in her analysis are already taken into account in my more detailed computer simulation model, which reflects the degree of market separation (or lack thereof) based on the state of the markets and transmission system, including pricing.[35]

[35] MPP Testimony at 122.

Q: When a transmission company merges with a generator located in the same geographic market, is it automatically true that such a merger creates vertical market power?

A: No. The fact that a transmission company's transmission system is sometimes in the same geographic market as its merging partner's generator does NOT in itself establish that the merger will create the ability to raise prices through VMP. If this were true, no mergers of any two vertical companies in the same geographic market would be permitted. It is necessary to go well beyond the simple proposition that the geographic market is sometimes common to the two Applicants.

In particular, it is necessary to establish that the market's post-merger structure is sufficiently concentrated, and Applicants' post-merger control over resources is sufficiently strong, that VMP can be profitably exercised. This can be done by a variety of quantitative exercises, such as measuring concentration or simulating price-setting behavior. As noted in my introduction, Staff simply has not attempted the requisite calculations. While I agree with Staff that Applicants' generation and transmission will often be 'within the same geographic market,' I show that the vertical impacts of the merger will be small and fully mitigated.

Q: What evidence does Staff present to claim that the Applicants have an incentive and ability to exercise vertical market power?

A: CP attempts to demonstrate the magnitude of the Applicants' financial incentive to exercise vertical market power in three steps. First, using the NYISO June 17, 2004 supply curve, CP estimates that an average 100-MW reduction in NG's transmission lines

could potentially increase Zone J's prices by $1.76/MWh, assuming that the 100-MW reduction in transfer capability causes the equivalent increase in NYC's generation.[36] As a result, CP argues that Ravenswood's net revenue could increase by $11.3 million per year due to VMP.[37] This calculation is flawed, as I will explain in this section.

Second, to illustrate the congestion impact of NG's transmission line on Zones J and K prices, CP presents a snapshot of the NYISO DA and RT markets on June 1, 2006. CP claims that, on that day, the NYISO recorded NG's Leeds-Pleasant Valley line as moderately congested from hours 12 to 16 (noon to 5 pm). According to posted NYISO prices, the congestion on this line increased DA prices at Ravenswood above those of Zone F (Capital) by an average of $7.66/MWh.[38] In the RT market, when Consolidated Edison called for a ThunderStorm Alert ("TSA"), the RT prices at Ravenswood jumped by over $300/MWh between 1 pm and 10 pm.[39] CP further argues that "[t]he TSA on June 1, 2006, equivalent to an unexpected outage, increased real-time prices in NYC and LI by an average of over $300 per MWh for 9 hours."[40]

In the last step of their analysis, CP estimates the impact on NYC prices when the Leeds-Pleasant Valley line has an outage by using an average price impact of $1.76/MWh per 100-MW increase in NYC generation. Assuming NG's outage reduced transfer capability on the NYISO's Total East interface by 925 MW, and that this reduction led to a one-to-one increase in Zone J generation, CP estimates that the price impact in the day-ahead market could be about $16/MWh ($1.75 per 100 MW x 925

36 CP Testimony at 13.
37 *Id.* at 14, 16-19.
38 *Id.* at 26.
39 *Id.* at 28.

MW) yielding an addition to Ravenswood's net revenue in 2005 of approximately $280,000 per day.[41]

This is a very simplistic and flawed analysis of VMP incentives arising from this transaction. My model shows that CP's analysis is at best irrelevant, as it does not address the specific question of *this* merger's impact on VMP. Instead, it conducts overly simplistic calculations based on a single day example. Consequently, CP's calculations cannot be relied upon. The remainder of Section III examines the flaws in CP's calculations in more detail.

B. CP'S SO-CALLED "REAL-WORLD EXAMPLE" FOCUSING ON JUNE 1, 2006 OVERSTATES APPLICANTS' INCENTIVE TO EXERCISE VERTICAL MARKET POWER

Q: Does CP's example based on June 1, 2006 present sufficient evidence that the Applicants have an incentive to exercise vertical market power?

A: No. The one-day example presented by CP in an attempt to illustrate the impact of strategically removing one of NG's transmission lines on Zones J and K prices is so simplistic, and so seriously confounds the effect of removing NG's transmission facility with many other effects, that it is not a reliable way of analyzing VMP incentives. The one-day event chosen by CP was June 1, 2006, when NG's Leeds-Pleasant Valley line was congested in the DA market, and the NYISO called for a TSA in the RT market. As explained below, market circumstances on this day cannot be considered a representative sample of market conditions generally. At most, this analysis only suggests the

[40] *Id.* at 31, 7-10.

possibility that the proposed merger *might* create vertical market power under extreme conditions on certain hours of certain days of the year.

Q: Is it appropriate and sufficient to estimate potential annual VMP impacts by projecting conditions from one single day?

A: No, it is not. Any illustration of the impact of a merger on incentives must, at a minimum, be based on a representative sample of days, not a single day. Also, the sample must be selected randomly, not picked specifically to support an extreme estimate of VMP incentives.[42] If the principles of proper design of testing samples were applied, it would be obvious that a one-day sample is utterly inadequate. Staff's analysis is like someone taking his heating bill from one of the coldest days of the year, multiplying it by 365, and claiming that the resulting number represents his annual heating bill. Thus, purely on the grounds that the sample is too small and not randomly selected, the Commission should give little or no weight to CP's impact calculation.

Electric system conditions change dramatically over the course of days, weeks, and seasons. This is why the FERC usually uses at least ten representative snapshots, not one, to assess the potential for market power in electric utility mergers.[43] Due to the importance of the rebuttable presumption, my analysis of VMP incentives in Section II did not rely upon a sample of days (much less only a single day), but rather tested for financial impacts using an entire year's worth of days. During this year, as reported on Table 7 in Section II, I found only 16 of 365 days that showed measurable profit

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41 *Id.* at 30, 13-22.

42 Levy, S. Paul and Lemeshow, Stanley, *Sampling of Populations Methods and Applications,* 3rd Edition, John Wiley & Sons, Inc. 1999. Cochran, G. William, *Sampling Technique,* 3rd Edition, 1977, page 4-11.

43 FERC Order 592, Appendix A.

incentives – only 2 days outside of the summer, when NYISO practices preclude National Grid from taking unscheduled outages.

Q: Why is June 1, 2006 not a representative sample of market conditions reflecting vertical market power concerns in the day-ahead market?

A: An examination of system conditions in the DA market on June 1, 2006 reveals that this was an unusual day with many generator and transmission line outages on several utility systems, some of which NG could not have known or predicted in advance, and thus could not have taken advantage of. The jump in DA prices from hours 11 AM to 12 PM or during hours 12 to 5 PM was undoubtedly caused by a number of changes in market conditions, including load, generator outages, transmission outages, and transmission constraints. My examination of the IIR data shows that on June 1, 2006 there were about 600 MW of generator outages in Zone G. Moreover, the NYISO Day Ahead Limiting Constraints Report for June 1, 2006, which I present as Exhibit No._(PFP-5R), indicates that the NYISO not only declared the Leeds-Pleasant Valley line as having a DA constraint, it also recorded constraints on other transmission lines that transmit power into Zones J and K. For example, the Farragut-Hudson Avenue line, was reported to have a constraint starting on hour 9 to hour 18. The Dunwoodie-Shore Road line, a critical transmission facility for both Zones J and K, was also reported to be constrained for almost the entire day. The constraints on these lines would have contributed to higher DA prices in Zones J and K on June 1, 2006.

Q: Staff's discussion of June 1, 2006 also considers RT market. Do you agree with CP's claim on page 28 of their testimony at 14-18 that the impact of the TSA on June 1,

2006 in the NYISO real-time market is "...equivalent to the impact of an unexpected outage on National Grid's Athens-pleasant valley line, caused severe price increases from the Hudson valley south to NYC and LI"?

A: As explained earlier, an increase in prices from one hour to the next in either the DA or RT market could be caused by changes in system conditions (such as load, generator outages, and transmission line outages, *etc*). In the case of the June 1, 2006 RT market, the rise in RT prices in Zone J well above DA prices was, in part, due to deviations between DA load forecasts and real-time load.

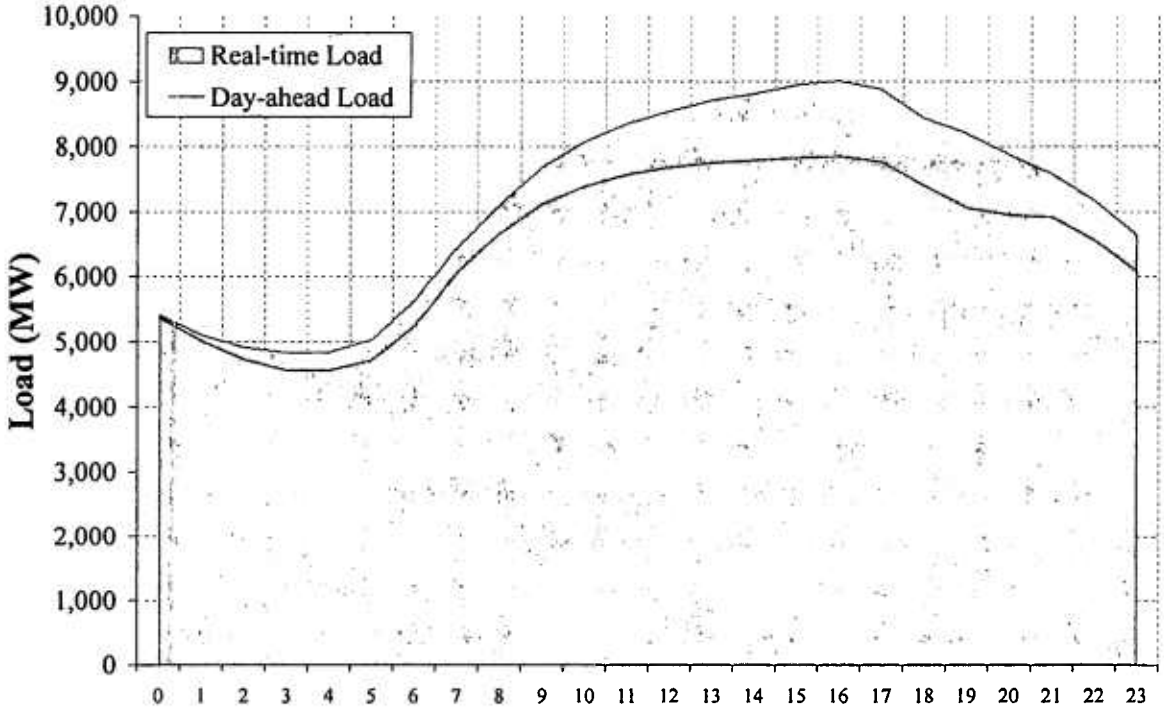
In addition, many transmission lines in Zones J and K were declared out of service only in the RT market on that day. For example, two 138 kV lines connecting the Astoria power plant to the Astoria East substation and the Astoria-Corona 138 kV line were out of service. Moreover, Astoria, a 500-MW combined cycle power plant in Zone J, tripped out of service as recorded in Exhibit No._(PFP-6R), the NYISO Operational Announcements of June 1, 2006 and NG's transmission log at around 11:00 am (when CP notices that "real-time prices began to rise...").[44]

[44] CP Testimony at 27, 2-3.

Figure 4

Zone J Day-Ahead Load Forecast vs. Real-Time Load

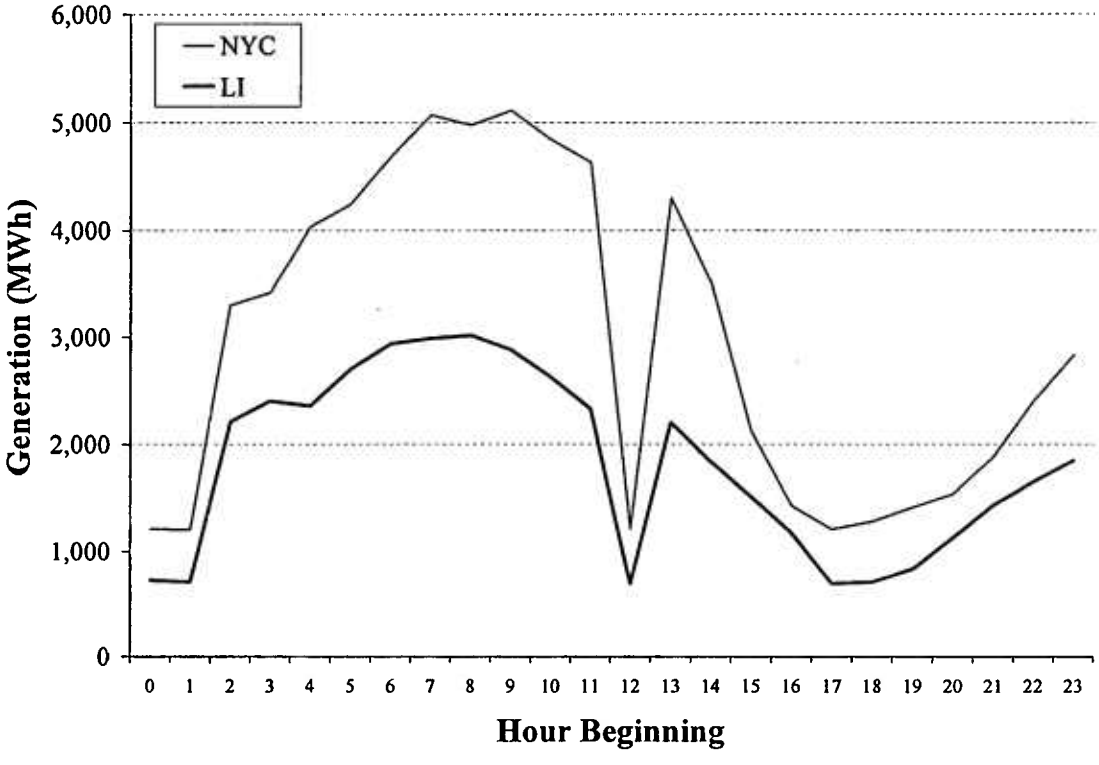
June 1, 2006



By reviewing the CEMS data on this day, I find that the level of generation in both New York City and Long-Island dropped dramatically from hour 11 to hour 12, as shown in Figure 5, confirming the loss of Astoria and possibly other generators in both NYC and LI.

Figure 5

Actual Hourly Generation by Zone: June 1, 2006



This triggered a series of NYISO RT actions in order to maintain system reliability. Exhibit No._PFP-6R) shows that the NYISO requested Gilboa 2, located in Zone F, to commit out of merit for "Loss of 500mw of generation" at 11:36:35. AM. At 12:37:20 the NYISO removed Gilboa 2 out of merit but then recommitted it at 13:24:02, close to the time that CP notes that "…significant congestion appeared on the Leeds-Pleasant Valley line…"[45] At 13:12, NG recorded that the TSA was called by Consolidated Edison, and at 13:40:34 the NYISO requested Astoria 5 to commit out-of-

[45] CP Testimony at 27, 5-7.

merit. According to NG's transmission log, Astoria was tripped again at 14:39, which led the NYISO to call for "large event reserve."

In summary, one cannot treat the June 1, 2006 TSA impact on Zones J and K RT prices as an equivalent to a strategically-planned outage on NG's line. Staff makes much of the fact that, during the TSA, prices in the real time market rise to nearly $500/MWh[46], providing a potential windfall to sellers in this market – presumably including Ravenswood. This is a misleading "illustration" of NG's incentives to take strategic outages following the merger.

Q: What is the significance of your more accurate analysis of the congestion costs of the Leeds-Pleasant Valley line versus Staff's estimate?

A: As the modeling analysis described in Section II explains, there are a limited number of times when withdrawal of the Leeds-Pleasant Valley line raises prices significantly in Zone J. NG has committed to mitigate these impacts during the rare occasions when they occur. While my estimate of these impacts is far more accurate than CP's, because the impacts will be mitigated in any case, in one sense it is immaterial whether Staff's estimate of the impact or my estimate is more accurate. In any event, I provide this more accurate estimate to clarify the record, and to emphasize that calculations of this merger's impact should not be based on oversimplified calculations and vanishingly small sample sizes.

Q: Do you agree with CP's assertion on page 11 that the proposed merger would give National Grid an incentive to weaken its transmission system by allowing its

[46] CP Testimony at 27.

equipment and transmission facilities to deteriorate so as to raise prices on Zones J and K?

A: No. My analysis shows that short term outages on the only lines that ever significantly influence Ravenswood profits do so only during rare, highly specific system conditions. When these specific conditions do not exist, and on all other lines, the profit incentive is insignificant. However, even facilities that have been allowed to deteriorate will rarely automatically trip offline at the precise times when conditions are favorable for generating higher downstate prices, and may never do so.

For this and many other reasons, letting lines deteriorate so they self-initiate outages more frequently but randomly would be a self-defeating strategy. Letting line maintenance deteriorate would quickly create an observable pattern of increasing outages that NYISO, this Commission, and others could scarcely fail to observe sooner or later, however low CP's opinion of their abilities.

C. CP'S OUTAGE IMPACT CALCULATION IS FLAWED

Q: What are the shortfalls in CP's simplified assumptions used to calculate price impacts?

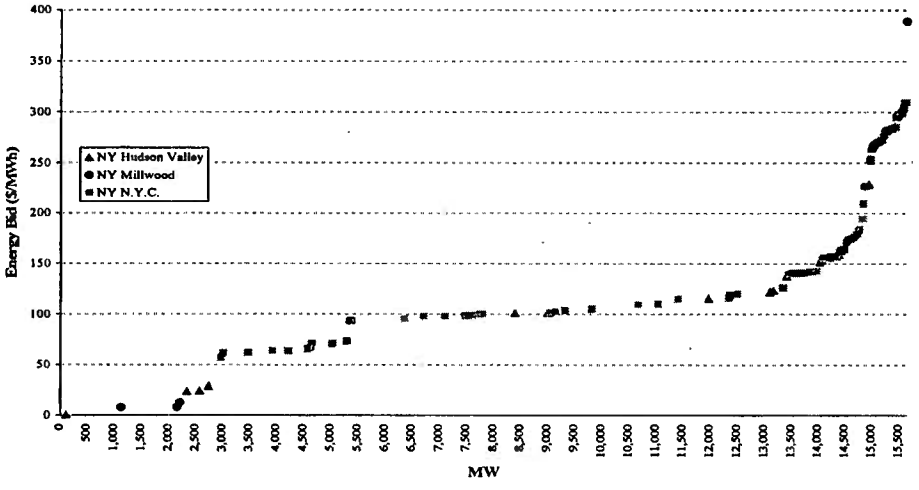
A: First, CP attempts to estimate the impact of a transmission line outage on Zone J prices by assuming that every 100 MW of strategic reduction in NG's transmission capacity will be replaced by a 100 MW increase in Zone J generation. This one-to-one assumption between NG transmission and Zone J generation is a vast over simplification. CP ignores the fact that the degree to which NG's withdrawal would increase the Zone J generation depends on existing market conditions, including power flowing on the interfaces. In

general, a 1 MW reduction on an interface does not automatically imply that there would be a 1 MW reduction in generation upstream of the interface and an increase in 1 MW downstream of the interface. Because the NYISO transmission system interconnects with transmission systems of Ontario, Hydro Quebec, PJM, and ISO-New England, as shown in Figure 1, the flow will often be redirected from the UPNY-SENY and Total East interfaces to PJM, which also link to Zones G and K. Additionally, the reduction in flow from NG's transmission outages can often be replaced by relatively cheaper generation from Zones G (Hudson Valley) and H (Millwood), which are still economical when compared with the operating cost of the NYC units. Although less likely in practice, the lost transmission could also be made up by increased imports from other directions into Zones J or K as well.

An examination of market data and my simulations illustrates this point. As shown in Figure 6, approximately 3,000 MW in Zones G and H come from generating units with relatively lower cost than those in Zone J, while other Zone G and H units have about the same cost as Zone J plants.

Figure 6

Aggregate Supply Curve for Zone G, H, and J



Source: TBG Analysis; Cambridge Energy Solutions.

Exhibit No._(PFP-7R) Panel A presents the change in generation and capacity factors by zone and unit before and after NG's Leeds-Pleasant Valley line is out of service for Hour 8 on June 8, 2007. In this hour before an outage on the Leeds-Pleasant Valley line, the flow on the UPNY-SENY interface was 3,954 MW, lower than the limit of 4,550 MW. With the hypothetical outage, the interface becomes binding, causing a reduction on this interface by 329 MW. In this example, the generation in Zones A-F is reduced by 23 MW while the generation in Zones G-H increases by the same amount. *There are no changes in generation for Zones J and K,* in direct contrast to the assumption that underlies Staff's entire point. My results also show that there is no change in the LMBP at Ravenswood 3 for Hour 8.

An examination of another system condition, Hour 19 on June 8, 2007 (shown in Panel B of this exhibit) again shows that the increase in Zone J generation is not one-for-one with the reduction of National Grid's transfer capacity. This time, the outage on Leeds-Pleasant Valley line causes a re-dispatch of units in the NYISO, so generation in Zone J changes, though still much less than one-for-one.[47] Generators in Zone A-F reduce their generation by 290 MW while downstate generators in both Zone G as well as Zone J increase their generation by a total of 290 MW. Of this total, approximately 196 MW of the added 290 MW comes from Zone G plants. In this case, the LMBP at Ravenswood 3 for Hour 19 increases by $0.23/MWh.

These are only two illustrative days, and as I have explained, I do not think the use of one or two pre-selected days is a valid statistical exercise. As I have also noted, my simulation model does this exact calculation, with and without any hypothetical NG line outage, separately for every line and every day of an entire year, analogous to a yard-by-yard walk-down of a territory that CP can perceive in only a very limited way. Examining the entirety of my results, it is clear that it is a consistent and reliable feature of the New York power market that a reduction in NG's upstate transmission capacity ordinarily causes little or no change in Zone J generation. It is only under the rare circumstances, shown in the Section II results, that Zone J price impacts are significant (including from the increase in zone J marginal costs), and these are the instances the company proposes to mitigate.

[47] The 4,256 MW of power flowing on UPNY-SENY before the outage of the Leeds-Pleasant Valley line is reduced to 3,625 MW after the outage.

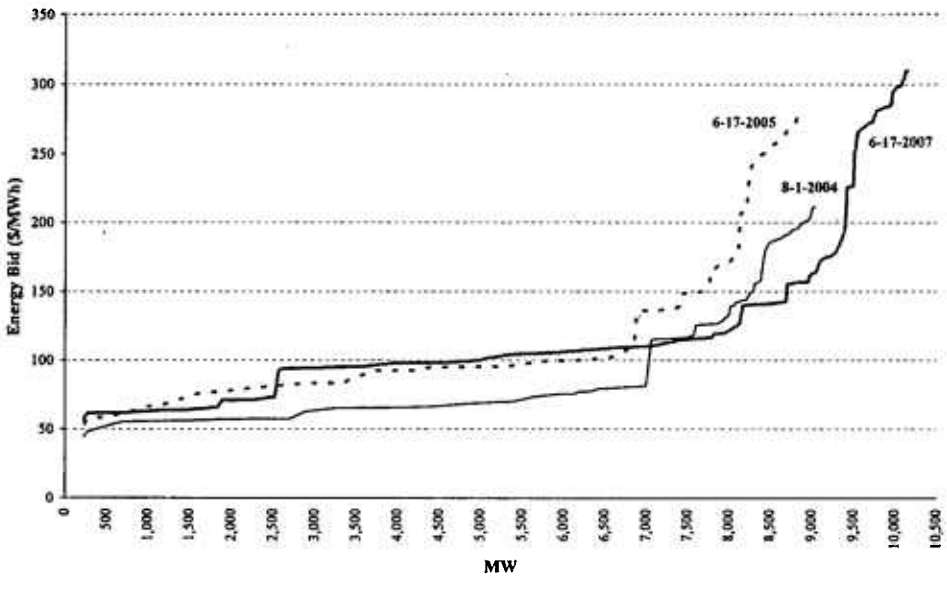
By calculating their impacts based on the NYISO June 17, 2004 supply curve, CP incorrectly assumes that the impact of a reduction in transfer capability would have the same impact in every single hour of every day of every year. The nature of the electricity market is such that it varies significantly from one period to another depending upon transmission system conditions, loads, and available generators. Although CP recognizes that "[t]he potential impacts depend critically on load levels, existing transfer, and the extent to which the outage is forecasted, among other factors," CP estimates the outage impact of National Grid's transmission line on Zone J prices by taking a single day snapshot of the NYISO 2004 supply curve for NYC.[48] Figure 7 compares the local supply curves of Zone J for 2004, 2005, and 2007. The data used in deriving these three supply curves were obtained from my simulation runs. The 2004 supply situation is represented by a single day's supply curve for August 17, 2004. The 2005 supply curve represented by June 17, 2005, lies to the left of the 2004 supply curve, indicating a tighter supply condition in NYC. For 2007, the supply curve shows a shift to the right, of approximately 8,000 MW of new capacity, reflecting the fact that additional supplies have been added.

Since 2005, approximately 1,160 MW of generation has been added in the NYC area. Hence, an impact calculation from the supply curve in 2004 cannot accurately represent 2007 market conditions.

[48] CP Testimony at 13.

Figure 7

Local Supply Curves for Zone J

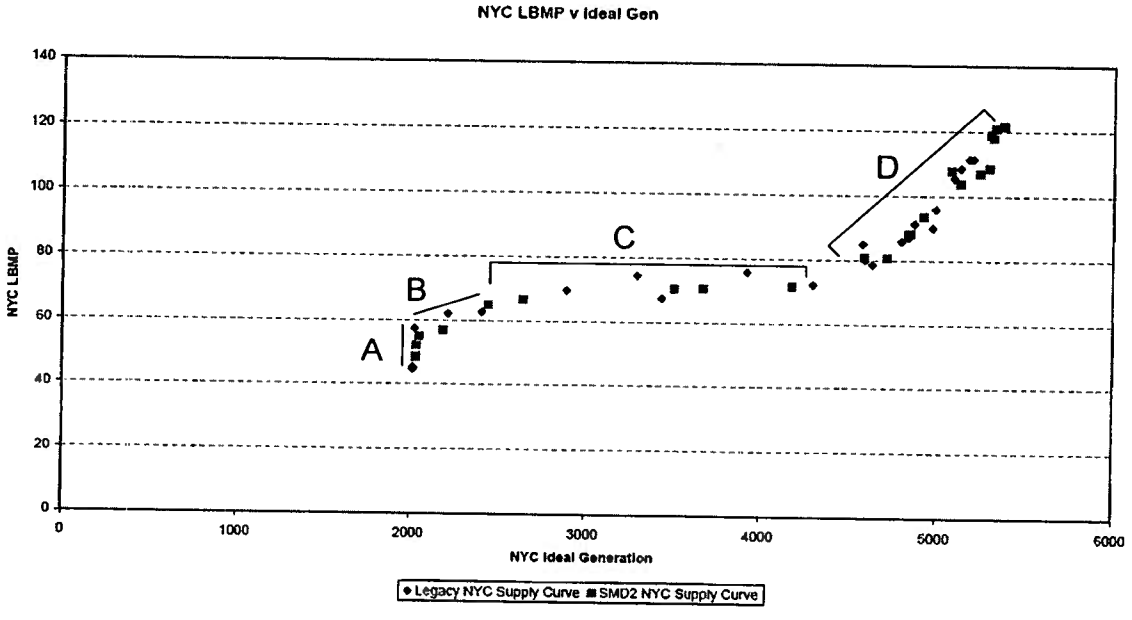


Source: TBG Analysis; Cambridge Energy Solutions.

Even if the supply curve in 2004 were exactly the same as those in other years, CP errs by using a simplistic calculation based on a straight line slope to represent the impact of all hours within that day. As emphasized earlier, market conditions vary greatly. By attempting to measure the amount of transfer capability reduction that would increase NYC prices by $1/MWh, CP ignores the fact that an electricity supply curve is not a smooth upward-sloping function. Rather, as is well known, an electricity supply curve's shape in general is like a stair step with different slopes at different portions of the supply curve.

Figure 8 is the same supply curve that CP used as a base for its impact calculation, the NYC June 17, 2004 supply curve from NYISO's Market Trials VI: DAM Benchmarking. Visually, I can break this supply curve into 4 parts, A through D.

Figure 8
NYC June 17, 2004 Supply Curve



Source: NYISO Market Trials VI: DAM Benchmarking

Figure 8 demonstrates that an outage on one of the four National Grid' lines that affect NYC prices will not always increase those prices. For example, an outage of less than 1,000 MW when NYC local generation is supplying at a level of 3,000 MW is unlikely to increase NYC price at all, as any increase in supply would occur in the "flat portion" of the supply curve (C). The impact, however, would be more significant if the NYC local generation is supplying at a 5,000 MW level prior to the outage. Thus, there will not be a uniform effect across all outages, even of the same transmission line.

My analysis, unlike CP's, systematically examines the outage impact of NG's transmission lines on the Zone J prices in every single hour of 2007, reflecting all of these factors and more. The summary of the result shown in Table 7 indicates that an outage on NG's critical facilities, including the Leeds-Pleasant Valley line, could have a positive, negative, or no impact on Zone J prices under actual, hour-by-hour supply and demand conditions. This is far more reliable and probative than CP's crude calculation.

D. FLAWS IN STAFF'S GEOGRAPHIC MARKET ANALYSIS

Q: In those periods in which upstate New York, Dunwoodie, and NYC are part of the same geographic market, the testimonies of MPP and CP claim that Applicants have both the ability and incentive to exercise VMP through the withholding of transmission resources. Is this a valid claim?

A: No, it is not. The ability and incentive of Applicants to exercise VMP can be assessed only by carefully analyzing the profit impacts that result from withholding transmission capacity under a variety of market conditions. MPP's and CP's testimonies do not provide evidence that Applicants would profit from withholding transmission capacity in those hours when Upstate New York, Dunwoodie (Hudson Valley) and NYC are part of the same geographic market. On the contrary, by systematically simulating market prices and market conditions for every single hour for Year 2007, I am able to conclude that the impact on Ravenswood's profits associated with outages of NG's transmission lines is hardly predictable and certainly quite small under these circumstances. Moreover, the proposed mitigation would remove any hypothetical profits that could be earned through the strategic withholding of transmission capacity if a significant opportunity to earn

profits actually did exist when Upstate New York, Dunwoodie, and NYC are all part of the same relevant market.

Q: Dr. Liu's analysis (as part of the MPP Testimony) concludes that KeySpan's NYC generation is in the same market as some or all of NG's New York transmission and distribution assets for at least 50 percent of the hours in 2006. Does this analysis contradict your claim that Applicants lack the incentive to exercise short-term VMP through strategic transmission withholding?

A: Not at all. Almost by definition, it is certainly confusing to put electric generation in the "same product market" with electricity transmission and distribution. In performing an antitrust analysis, one would not lump them into the same product market because they are inherently different products. It may possibly be true that Applicants' generation in NYC is in the same geographic market as generation in upstate New York during 50 percent of the hours of the year. However, the relevant geographic market for transmission may be quite different than the relevant geographic market for generation.

It is valid to say that electricity transmission is an input into the delivery of electricity power and thus may affect the prices paid to electric generators located in a specified geographic area. Thus, it may be useful under certain circumstances to analyze the "vertical" relationship between electric generation and transmission, and the potential profit impacts associated with the withholding of transmission resources by an entity that also owns generation. This is what I do in Section II of my testimony.

Dr. Liu's analysis provides no evidence as to these profit impacts and thus has limited usefulness. For example, it is quite possible that the market conditions under

which generators in the NYC, Dunwoodie (Hudson Valley), Upstate East, and West zones are in the "same geographic market" are associated with relatively low load levels and ample supply, such as off-peak hours. Withdrawing upstate transmission facilities during these hours may not have any impact on downstate generation prices. My own analysis shows that the price impacts associated with transmission withdrawals are typically nonexistent or quite small when generators in NYC, Dunwoodie (Hudson Valley), Upstate East, and West zones are in the "same geographic market."

Q: The MPP testimony states that NG's attempt to "focus strictly on the Leeds-Pleasant Valley line ... is a gross oversimplification." Do you agree with this statement?

A: No, I do not. My simulation analysis demonstrates that, apart from the Leeds-Pleasant Valley and Athens-Pleasant Valley lines (and by extension Leeds-Athens, which is in series with the Athens-Pleasant line), the only other transmission facility that might have an impact on prices in Zone J is the Leeds-Hurley line. However, whereas I find that a one-day outage on the Leeds-Pleasant Valley and Athens-Pleasant Valley facilities may increase Ravenswood profits by more than $100,000 on 16 days and 15 days in 2007, respectively, a one-day outage of the Leeds-Hurley transmission facility will increase Ravenswood profits by more than $100,000 during two days only. Thus, I have focused particular attention on the Leads-Pleasant Valley and Athens-Pleasant Valley facilities. The other transmission lines in National Grid's upstate system simply have no significant impact on generation prices in New York City on the basis of my analysis.

IV. Long-Term Vertical Market Power

Q: What is long-term vertical market power in the context of this proceeding?

A: Long-term vertical market power refers to a firm's ability and incentive to avoid building transmission so as to benefit its own generation.

Q: Please summarize the Staff's allegation with respect to the Applicants' long-term vertical market power.

A: MPP alleges that the proposed merger would create long-term VMP, in that National Grid will no longer have the incentive to propose and build new transmission in a timely manner.[49] MPP claims that such a disincentive may have a major influence on the constraints of both Southeastern NY and upstate interfaces that would result in NYC becoming a more isolated market.[50] NG Witness Saidi commits that: (1) the acquisition of generation assets as part of the merger will not alter the Company's focus on the US transmission business or its ongoing support for the transmission policies that the Company has pursued for many years; and (2) NG is prepared to assume expanded obligations to develop and construct transmission projects in New York as part of a NYISO planning process that addresses both economic and reliability needs over an appropriate planning horizon as a condition to the merger. The MPP discounts these as something that cannot be relied upon because it alleges that the Applicants would have a financial incentive to act in a manner that would run counter to the public interest.[51] That National Grid's pledges would be in the form of a binding regulatory obligation appears to have no impact on MPP's analysis.

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[49] MPP Testimony at 123-125.

Q: What are the key considerations in analyzing whether the Applicants have incentives to delay or avoid building transmission facilities that relieve congestion downstate?

A: First of all, it is axiomatic that long term market power (*i.e.*, constrained new capacity additions) is possible and profitable only when there are barriers to entry, *i.e.*, when new generation cannot enter the market either by locating within it or by building other transmission lines that bypass NG's transmission. The traditional situation visualized when analyzing long term market power in transmission is a geographic region in which a utility owns all of the transmission pathways in, all of the transmission within the region, and some of the generation inside the region. In this situation, the transmission utility may have the ability to reduce generator entry by (1) not building additional transmission into the region, for which it is essentially the only viable builder; and (2) impeding interconnections to rival generator within the region. Much of the FERC's open access and Generator Interconnection rules are designed to address this situation.[52]

Q: Does National Grid have ability to control or reduce entry into Zones J or K?

A: No, far from it. NG's post-merger generation will be in a region in which National Grid does not control *any* direct pathways in, nor does it control interconnections within the region in any way. Its transmission lines are several zones away upstate. Furthermore, many other transmission lines and rights of way, both actual and potential, lead into NYC both from upstate and other states and regions.

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50 *Id.* at 124-125, 13-23.
51 *Id.* at 142, 15-19.

Moreover, NG neither can prevent anyone else from building transmission into Zones J and K nor impede generators from building within these zones. Additional transmission projects are being built into Zones K and J. The Cross-Sound Cable ("CSC"), a high voltage direct current ("HVDC") transmission cable, is a merchant direct current 330 MW cable system under Long Island Sound. The cable links the New England transmission system in Connecticut to the NYISO transmission system on LI. The Neptune cable, another merchant HVDC line, when complete later this year, will bring up to another 660 MW of power from PJM to Zone K. Hudson Transmission Partners also plans to build a 500-MW alternating current (AC) transmission line between NYC and New Jersey. The project will be completed in 2010 and will enable the New York Power Authority ("NYPA") to bring up to 500 MW of its purchased power into NYC.[53]

Also, there are obviously no strong barriers to generator entry in either Zones J or K because many plants have recently been built in those zones and others are under construction. In NYC, approximately 1,000 MW of new power plants came online in 2006 and 158 MW is expected to come on-line later this year. For Zone K, two new gas combined cycle power plants developed by Calpine and Pinelawn Power LLC have recently come on-line, providing a total of 160 MW to LIPA under long-term contracts. Caithness Energy LLC is also in a process of building the Caithness Long Island Energy Center, a 350 MW natural gas fired combined cycle power plant, on LI, which is

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[52] FERC Order 888, and the more recent FERC Order 890, *Preventing Undue Discrimination and Preference in Transmission Service,* February 16, 2007; 104 FERC ¶ 61,104, *Standardization of Small Generator Interconnection Agreements and Procedures*, July 24, 2003.

[53] *Comprehensive Reliability Planning Process,* NYISO, (5th Draft), February 14, 2007, p. 21.

expected to come on-line in the fourth quarter of 2008. The output of this plant is expected to be under a 20-year power sales agreement with LIPA.[54] Another 140 MW wind farm project is expected to be developed by FPL Energy LLC off the LI coast. The plant is also expected to be on-line by late 2008 and under a long-term sales contract with LIPA.[55]

Q: Post-merger, would National Grid have a financial incentive to delay or avoid proposing and building transmission projects so as to benefit Ravenswood as claimed by MPP?

A: No. This point can be illustrated by looking at the incentives and strategic choices faced by the merged company regarding transmission additions. Suppose there is an economic need for new generation and/or new transmission capacity from upstate to downstate New York. Suppose this translates into National Grid having a choice between building or not building a new line downstate. If NG *does not* build the new line, the potential impact on the profitability of its Zone J generators would be uncertain since competitors may build new lines into NYC or build new plants within the city. My simulations suggest that even under the best possible circumstances and without mitigation or new entry by competitors, KeySpan's generators would likely gain less than National Grid would lose from not building the new transmission line. Thus, in deciding to forbear building a transmission line as part of its core business to benefit its affiliated generation company, NG's managers would have to assume that neither competitive generators nor competitive transmission builders would be able to succeed in replacing the foregone transmission capacity – which would even then yield a speculative long-term added

[54] http://www.caithnesslongisland.com/faq.html.

generation profit far lower (my Section II results) than the essentially certain profit stream from added investment in its core line of business.

In addition, NG, as part of its mitigation, will have the clear obligation to build economic upgrades in accordance with the commitment outlined in Ms. Saidi's earlier testimony. Thus, the merger promotes the construction of transmission upgrades and by doing so, promotes generator competition in Zone J. In summary, Staff's long-term theory of harm is not supported by the facts. Even if we discount NG's commitments to build, there is no adequately specified and sufficiently likely theory of harm that conforms to the reality of added transmission and generation entry.

Q: Thank you. I have no further questions at this time.

[55] Long Island Power Authority, Remarketing Memorandum, March 2006. pp. 2-34.

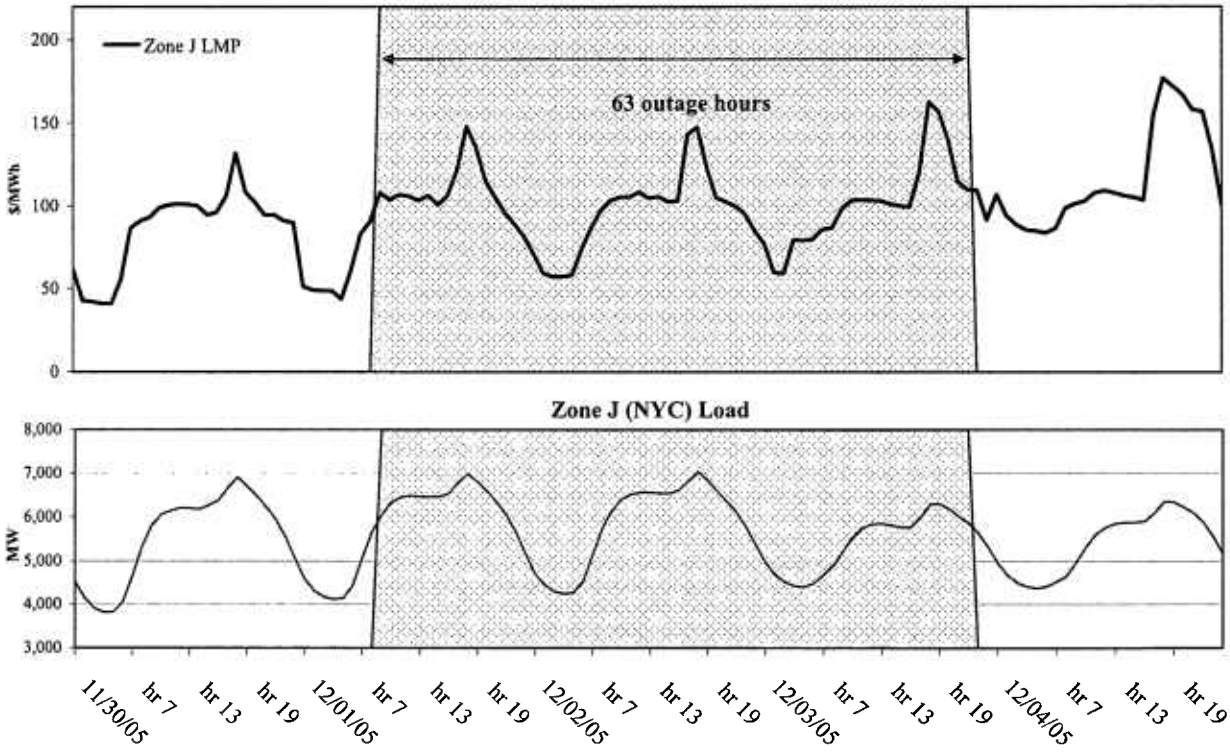
List of Dr. Fox-Penner's Exhibits

Exhibit No.___(PFP-1R) Visual Evidence of Outages Impacts on Zone J Price
Exhibit No.___(PFP-2R): Monthly Prices Graphs of August 2004-July 2005 Backcasting Zones A-K
Exhibit No.___(PFP-3R): Backcast Price Summary Statistics for All Zones: Year Ending July 2005
Exhibit No.___(PFP-4R): NYISO Transmission Facility Maintenance Outage Impact Report
Exhibit No.___(PFP-5R): NYISO Day-Ahead Limiting Constraints Report for June 1, 2006
Exhibit No.___(PFP-6R): NYISO Operational Announcements of June 1, 2006
Exhibit No.___(PFP-7R) Panels A and B: Generation and Capacity Factor Comparison Between Base Case and Scenario 1 for Hours 8 and 19 on June 8, 2007

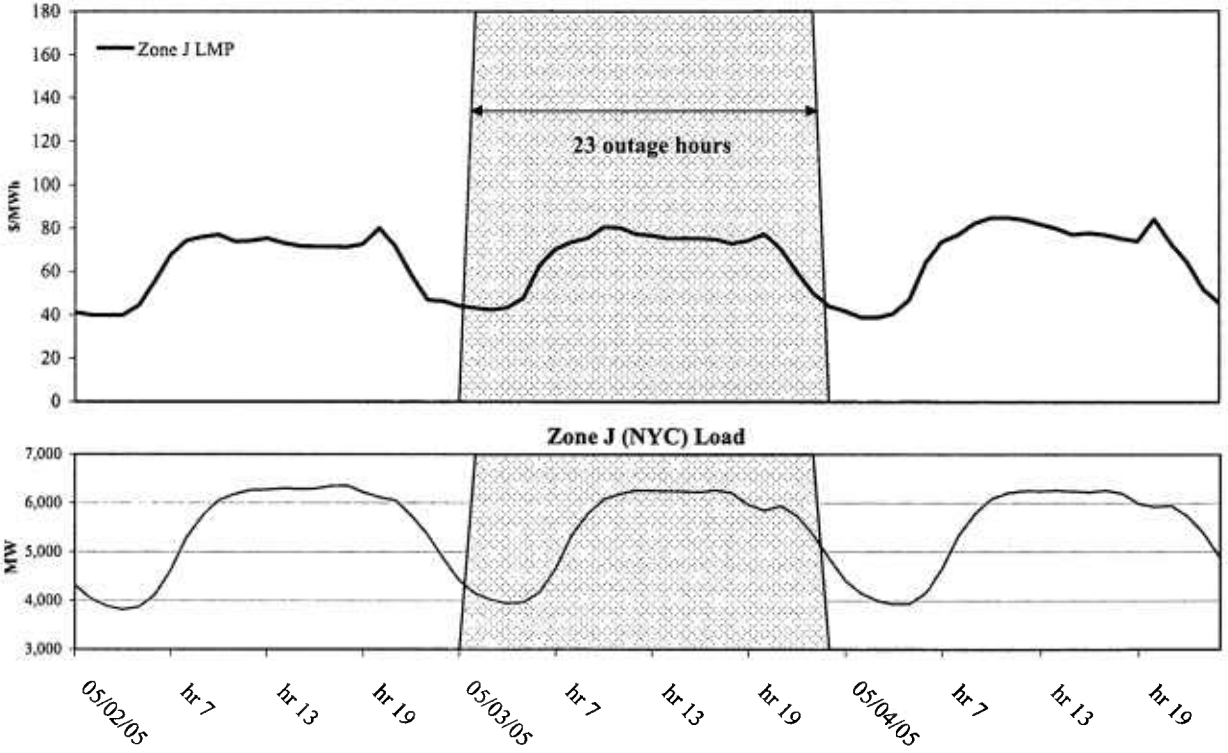
EXHIBIT NO._(PFP-1R)

Visual Evidence of Outage Impacts on Zone J Prices

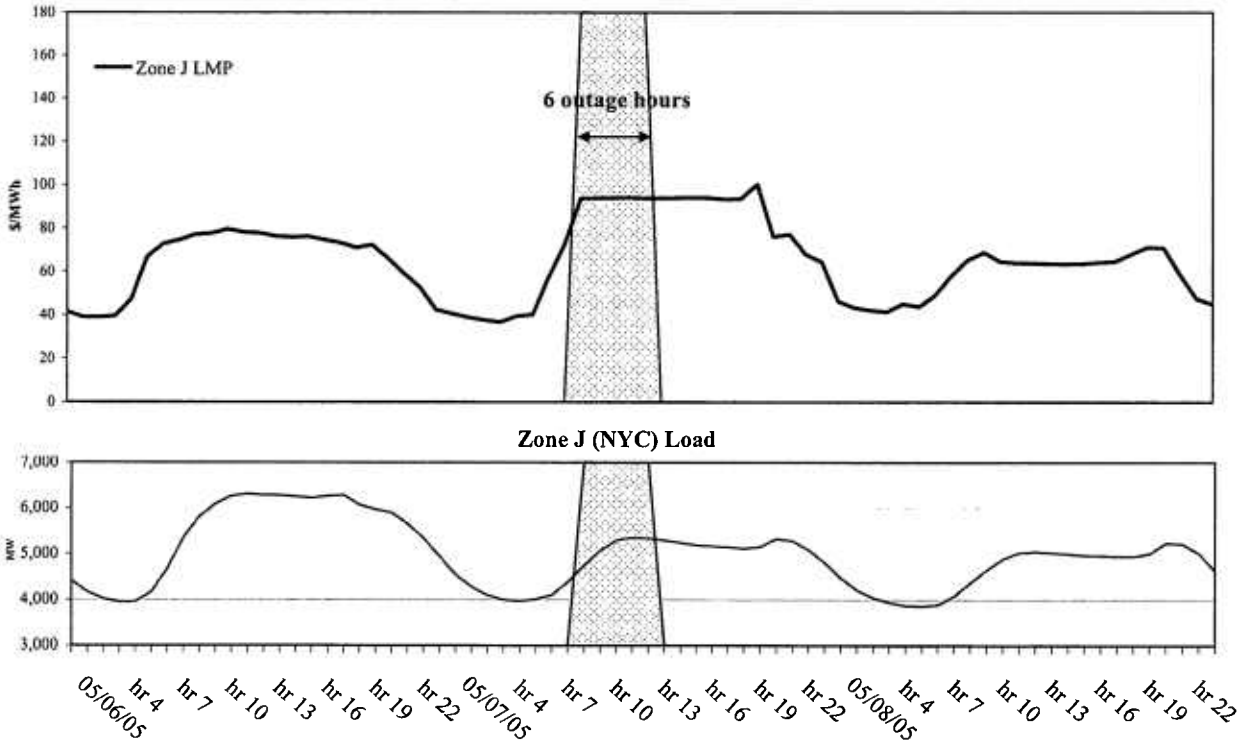
BERKSHIRE-ALPS and EDIC Out
Zone J (NYC) LMP
11/30/05-12/4/05



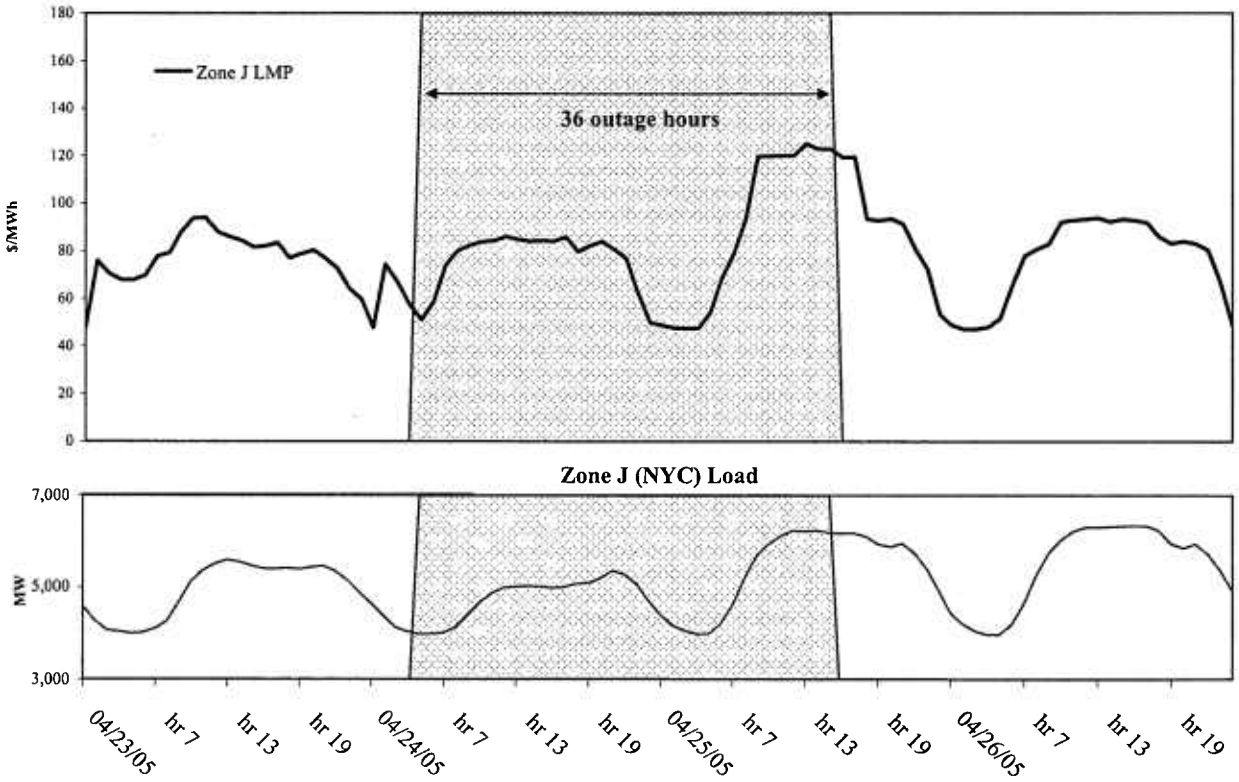
BERKSHIRE-ALPS and EDIC Out
Zone J (NYC) LMP
5/2/05-5/4/05



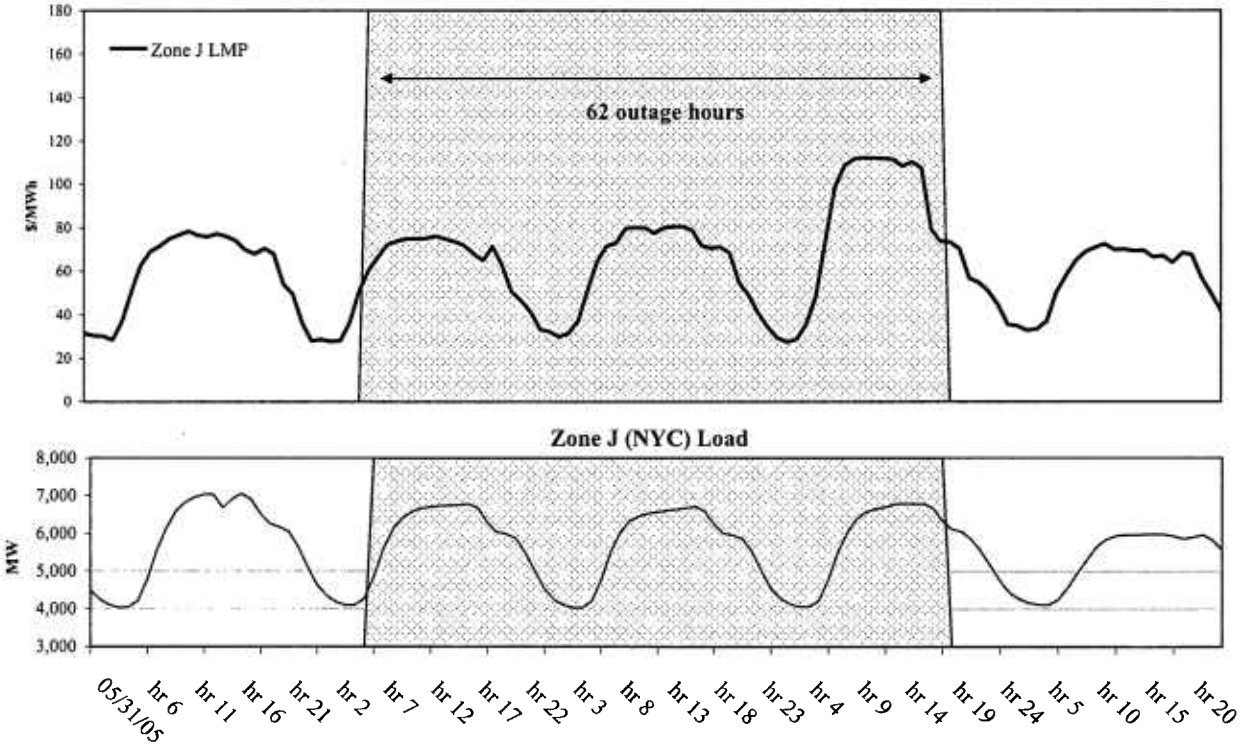
BERKSHIRE-ALPS and NSC-ALPS Out
Zone J (NYC) LMP
5/6/05-5/8/05



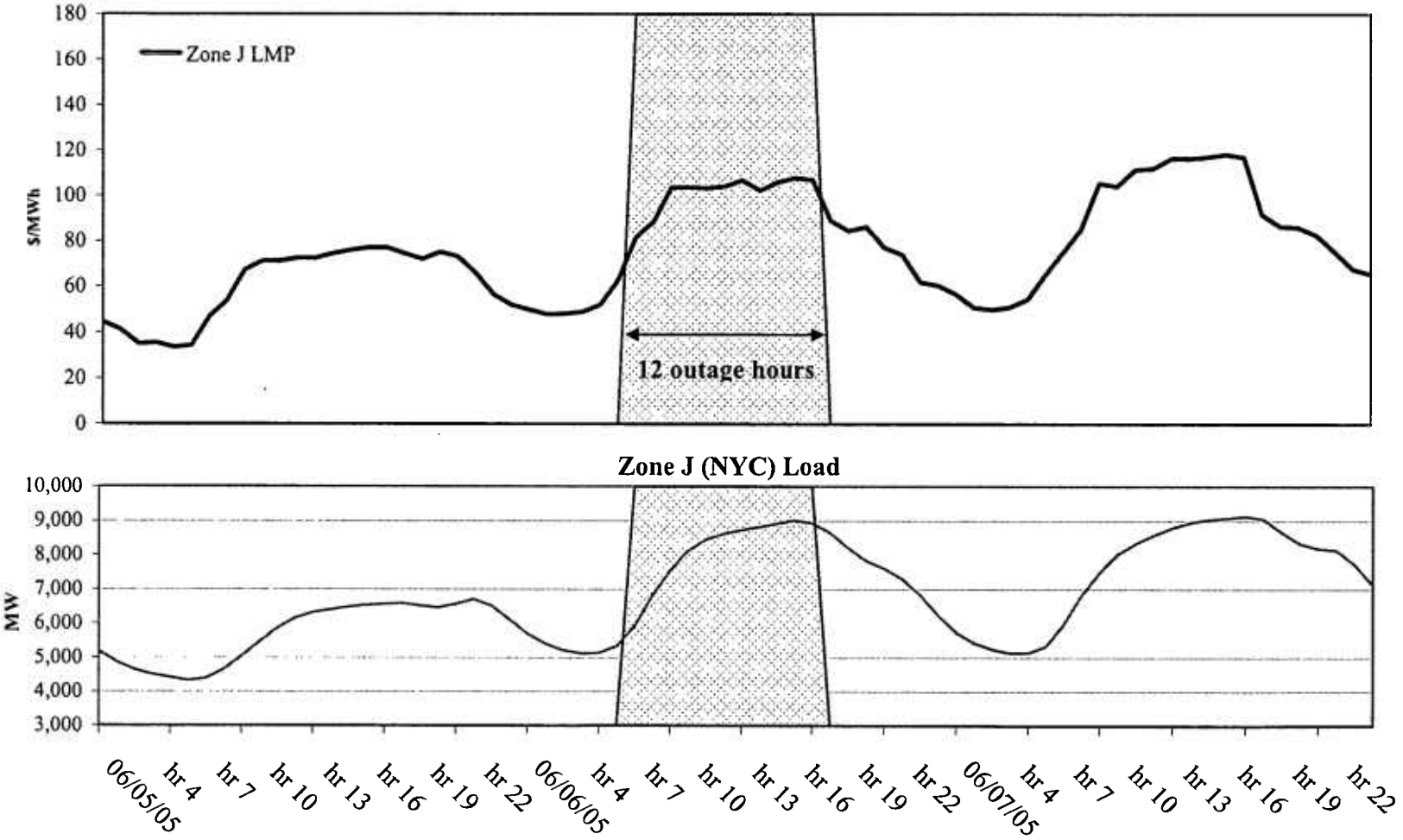
ATHENS-PLEASANT VLY Out
Zone J (NYC) LMP
4/23/05-4/26/05



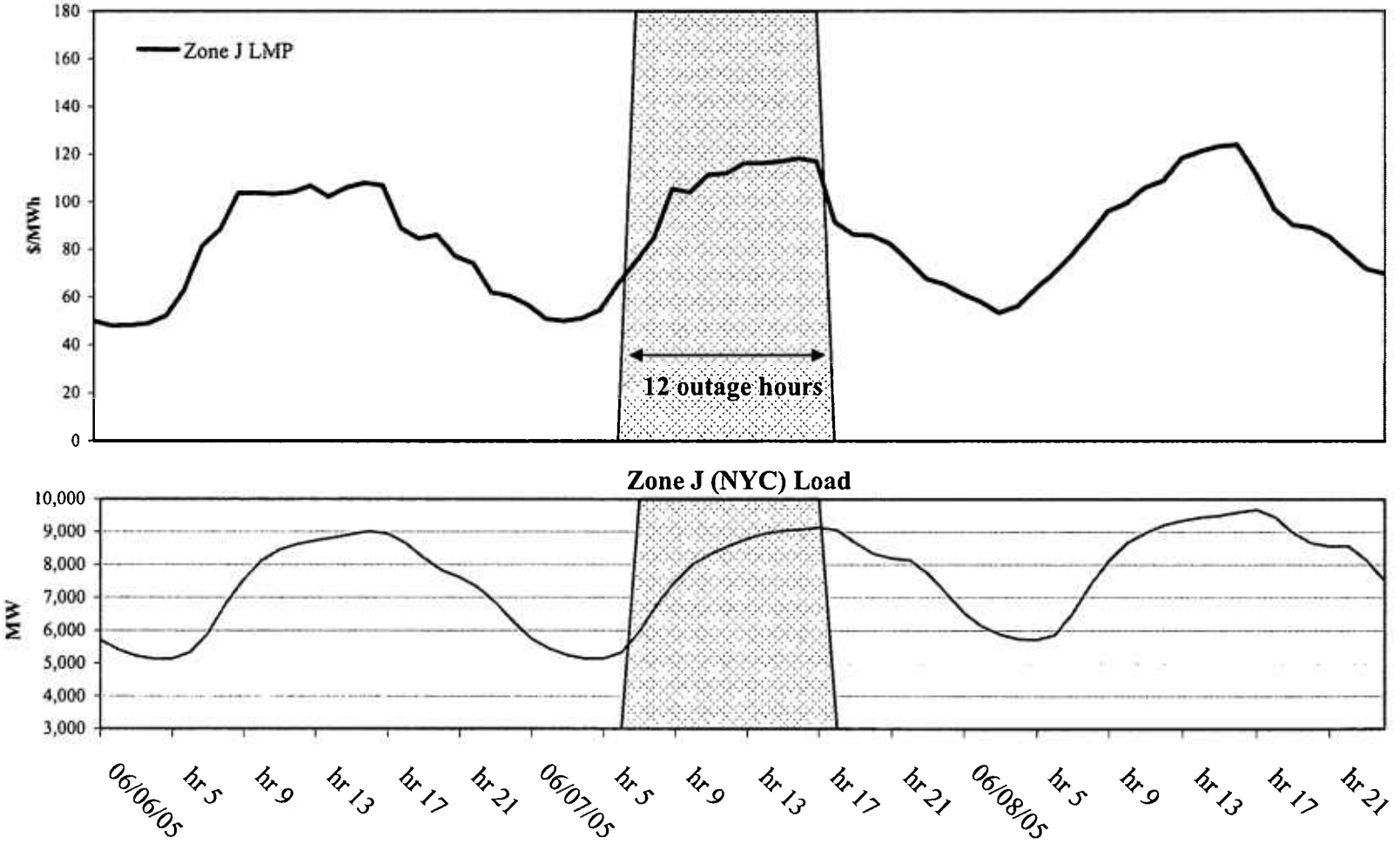
LEEDS-PLEASANT VLY Out
Zone J (NYC) LMP
5/31/05-6/4/05



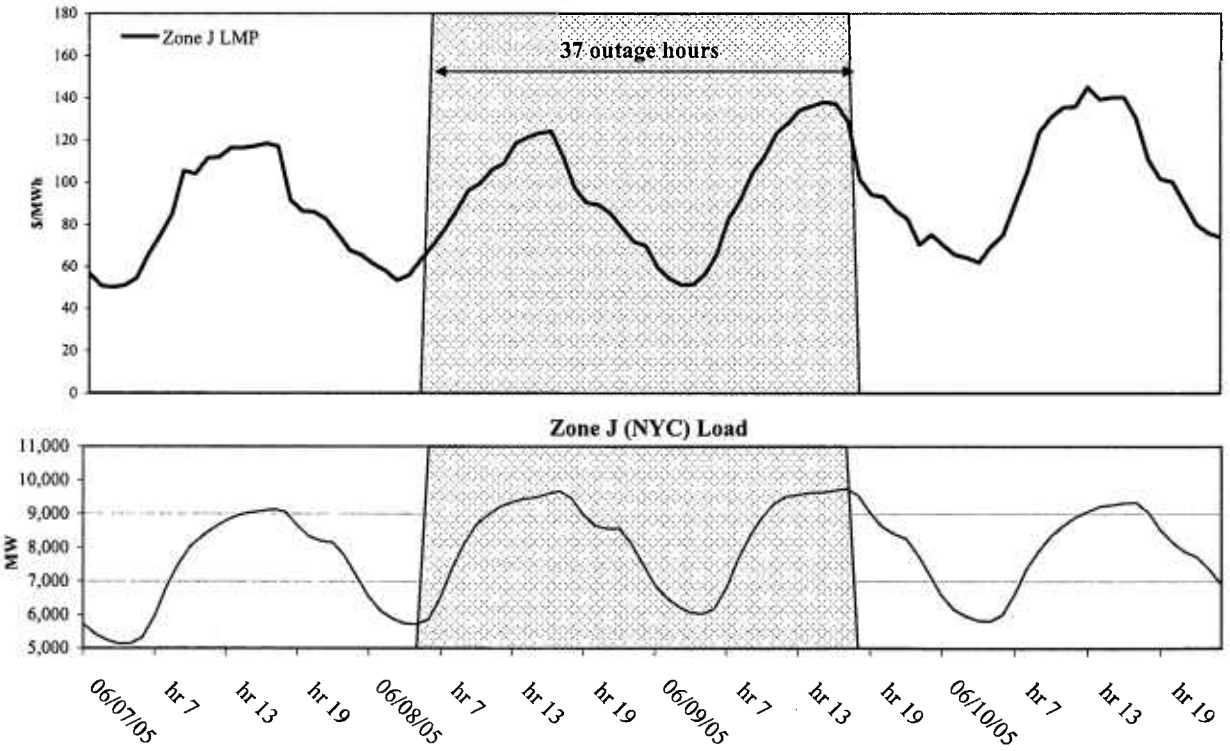
HURLYAVE-LEEDS Out
Zone J (NYC) LMP
6/5/05-6/7/05



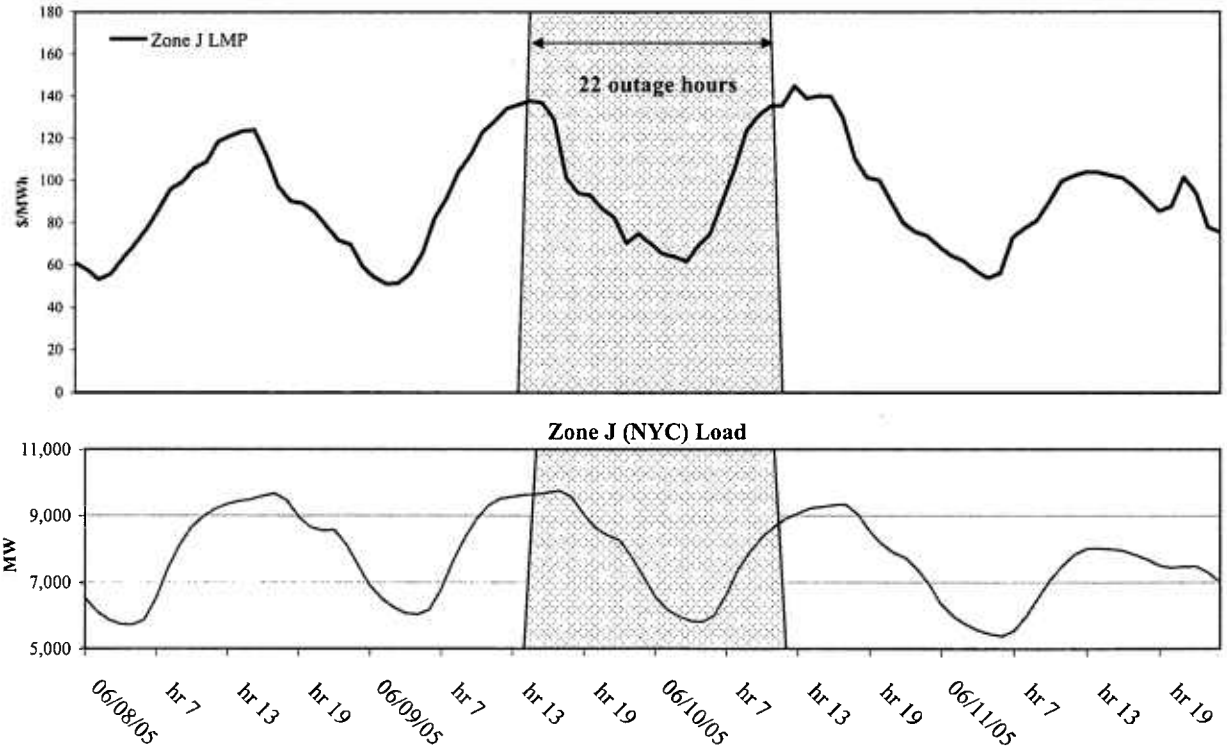
HURLYAVE-LEEDS Out
Zone J (NYC) LMP
6/6/05-6/8/05



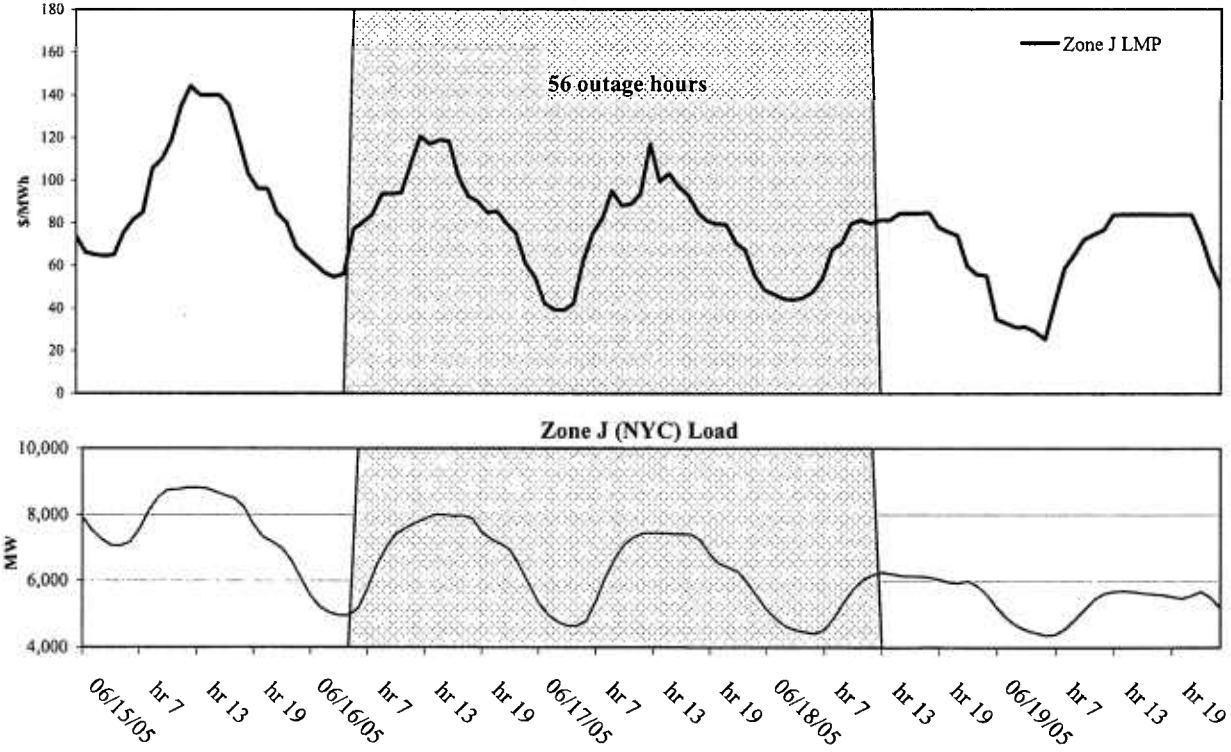
HURLYAVE-LEEDS Out
Zone J (NYC) LMP
6/7/05-6/10/05



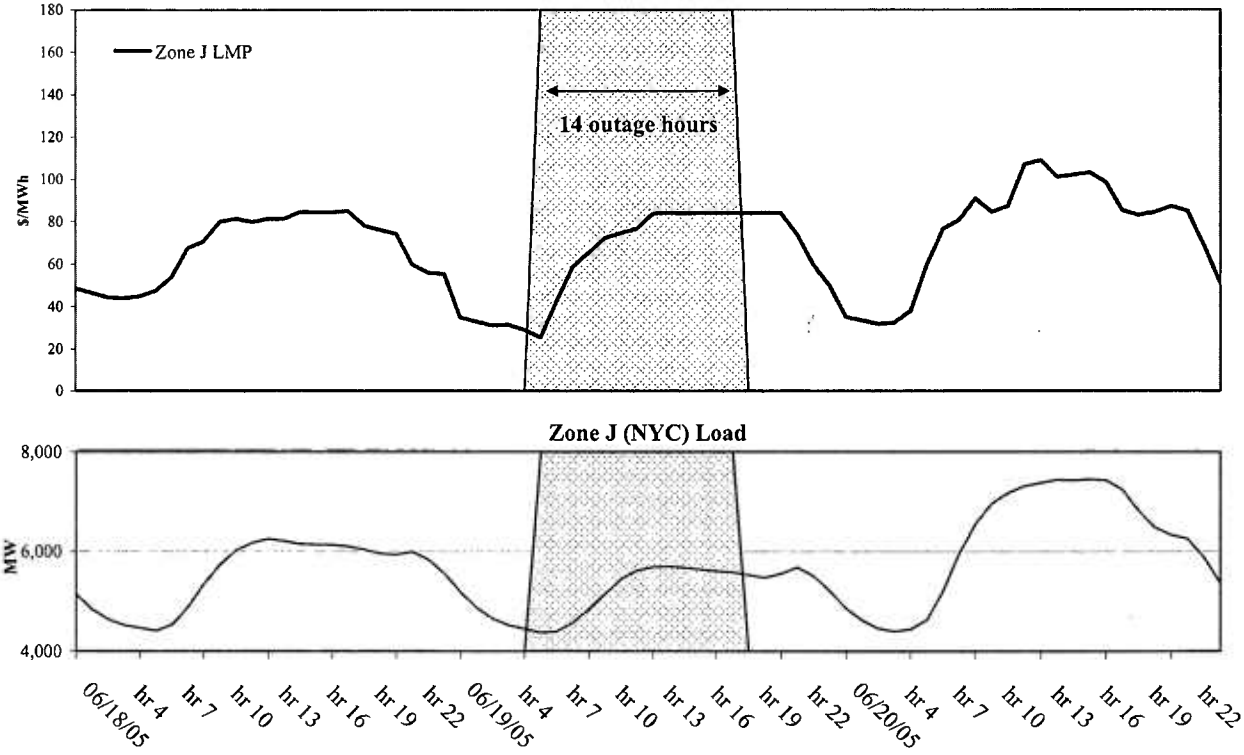
NSC-LEEDS Out
Zone J (NYC) LMP
6/8/05-6/11/05



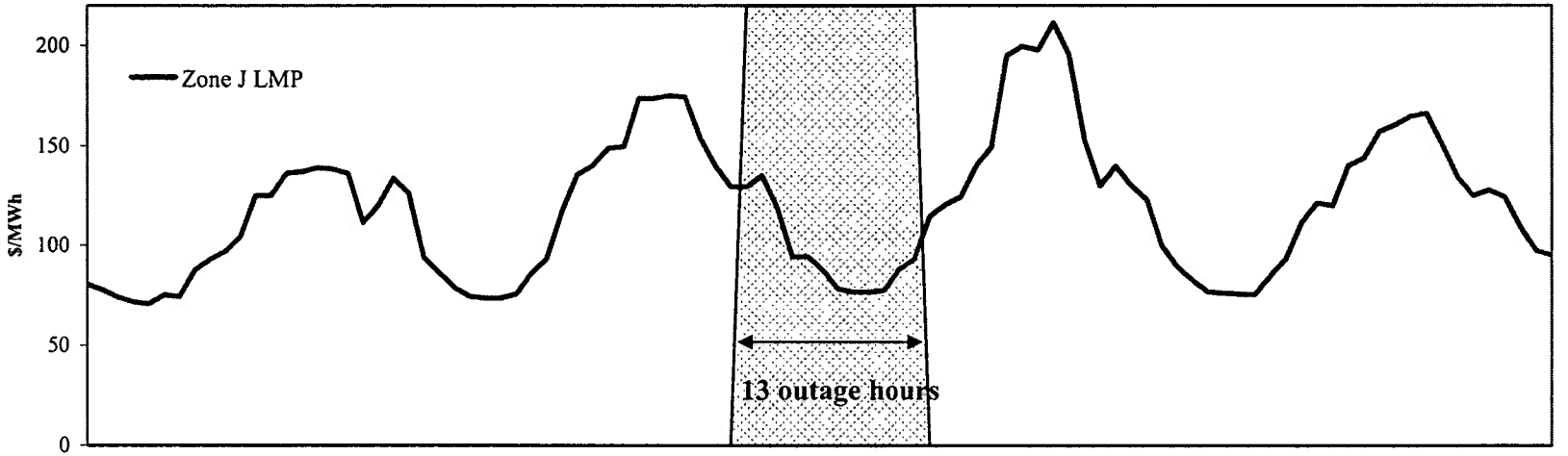
NSC-EDIC Out
Zone J (NYC) LMP
6/15/05-6/19/05



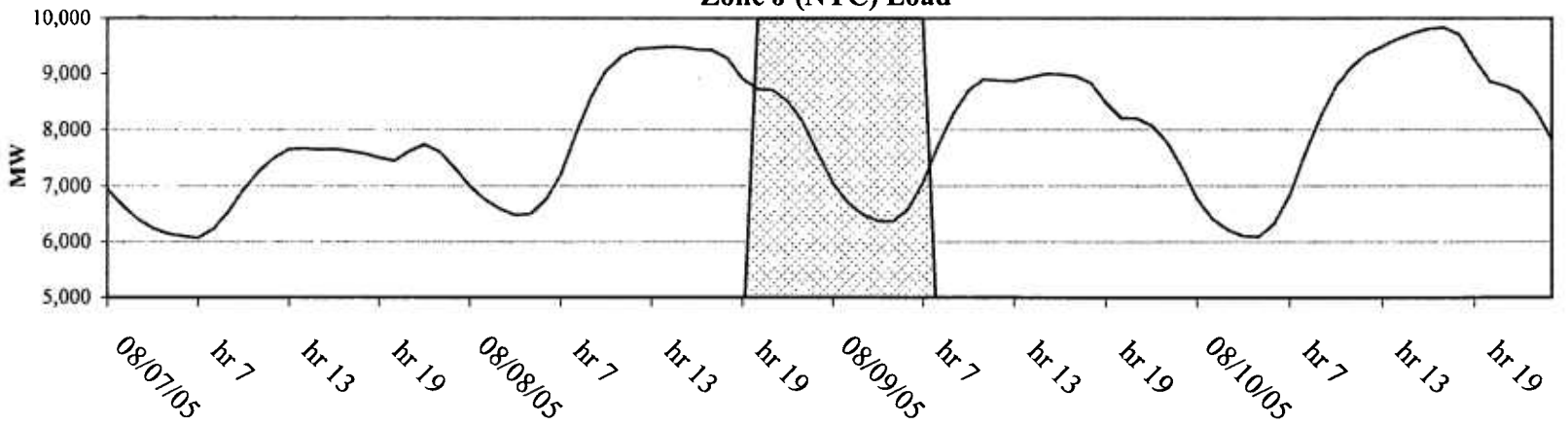
NSC-LEEDS Out
Zone J (NYC) LMP
6/18/05-6/20/05



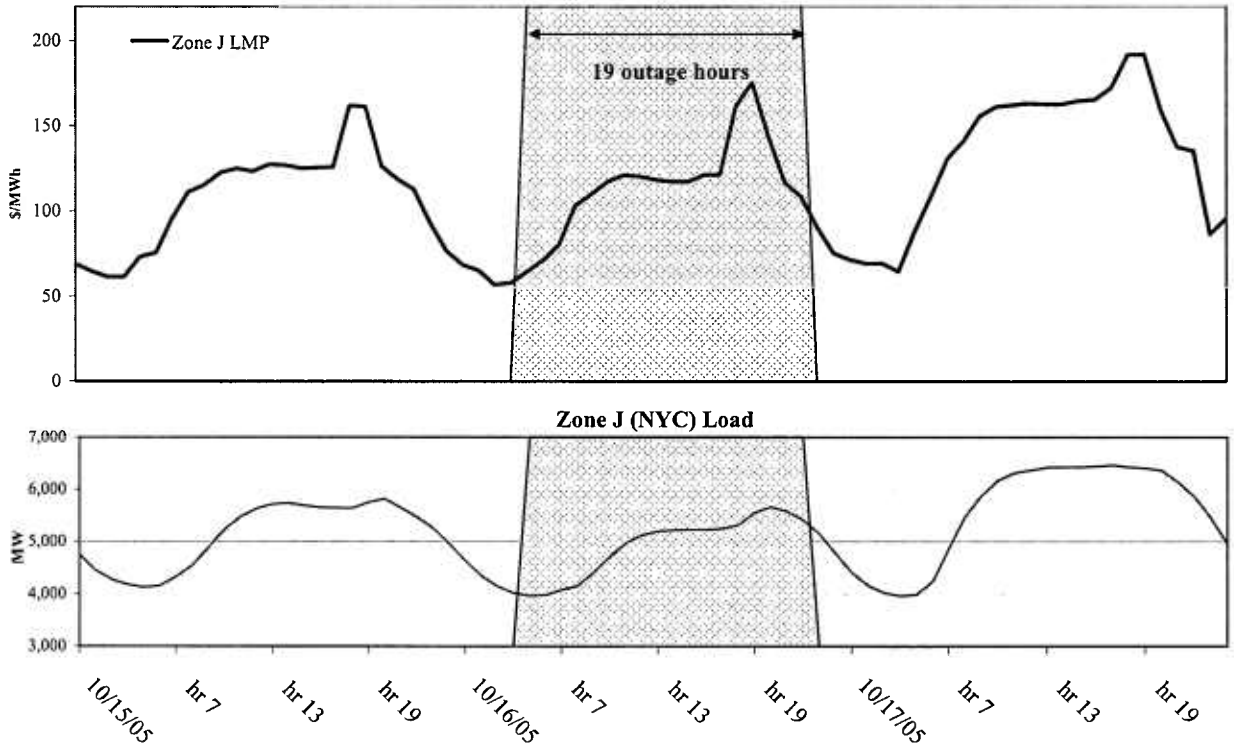
HURLYAVE-LEEDS Out
Zone J (NYC) LMP
8/7/2005-8/10/2005



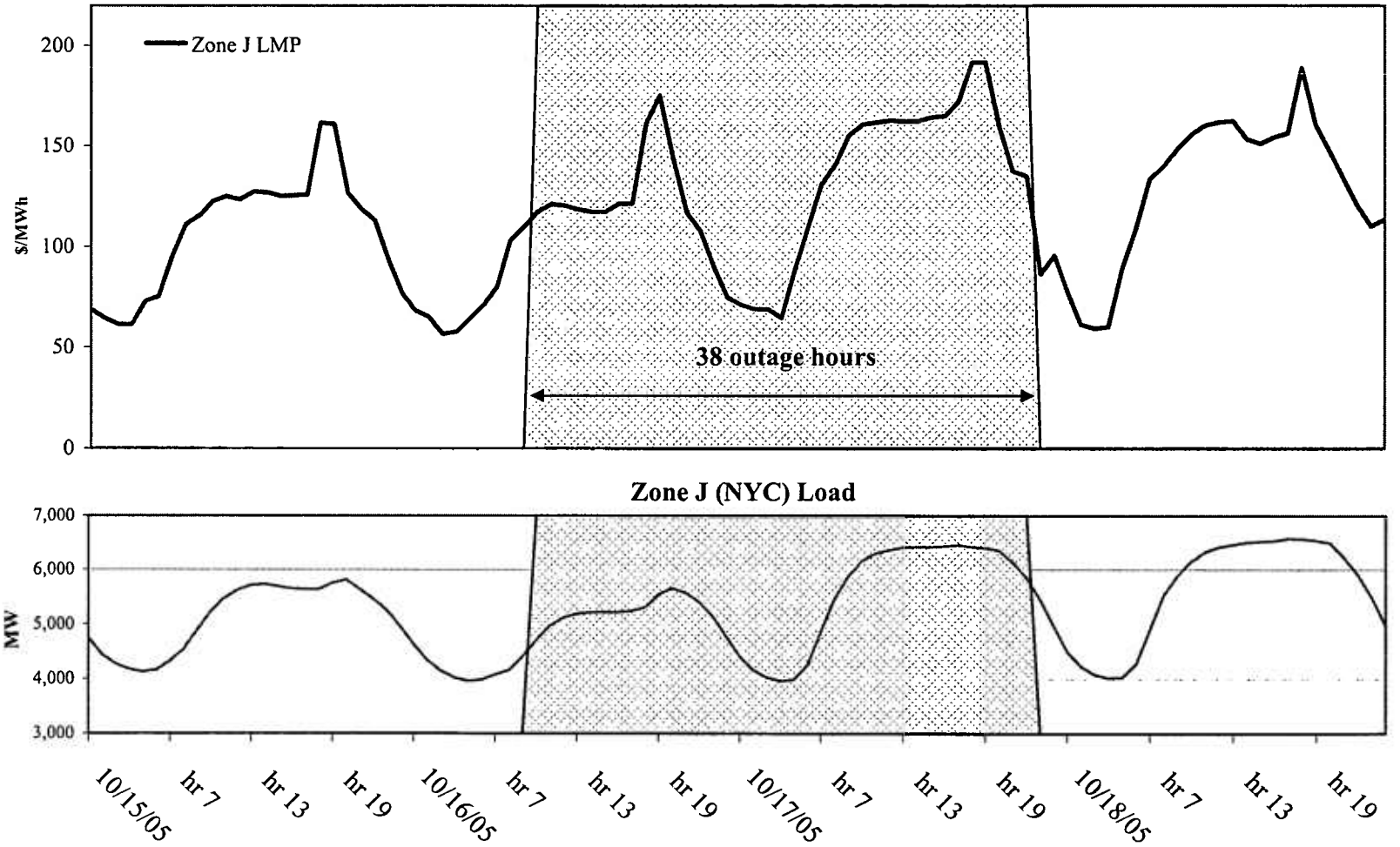
Zone J (NYC) Load



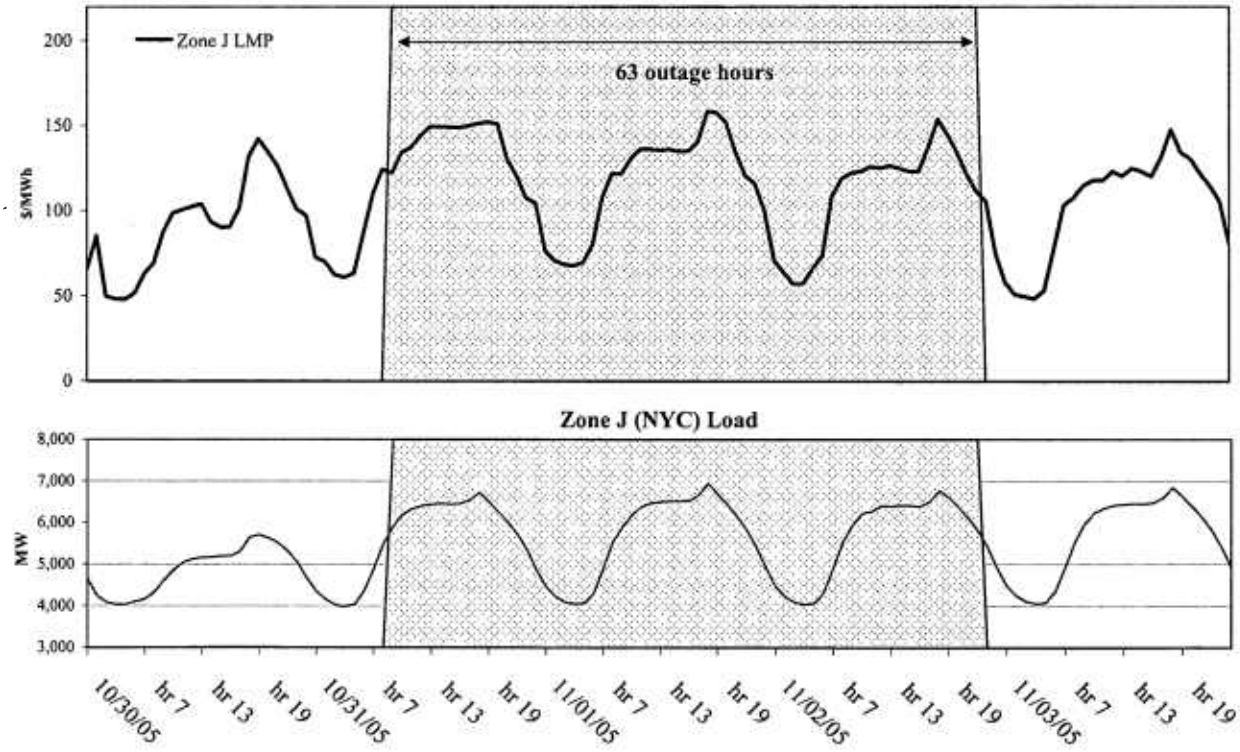
ATHENS-PLEASANT VLY Out
Zone J (NYC) LMP
10/15/05-10/17/05



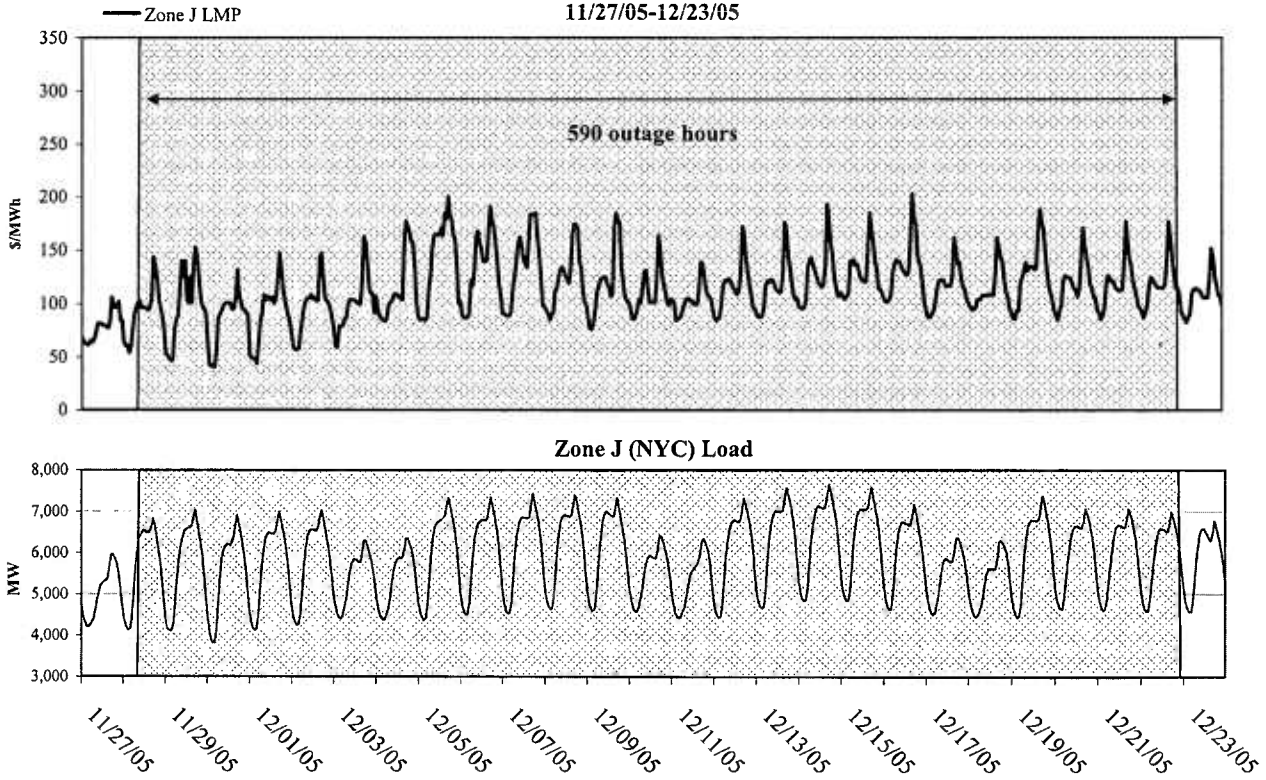
ATHENS-PLEASANT VLY Out
Zone J (NYC) LMP
10/15/05-10/18/05



NSC-EDIC Out
Zone J (NYC) LMP
10/30/05-11/3/05



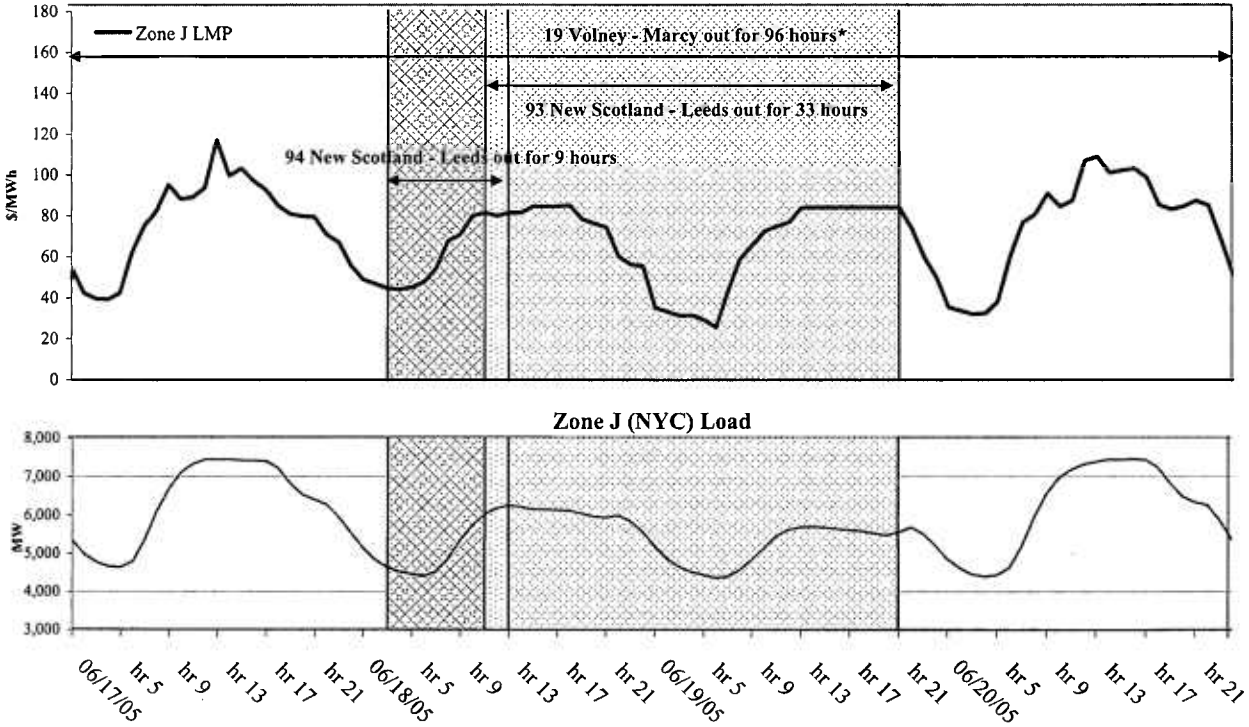
BERKSHIRE-ALPS Out
Zone J (NYC) LMP
11/27/05-12/23/05



VOLNEY-MARCY and NSC-LEEDS Out

Zone J (NYC) LMP

6/17/05-6/20/05

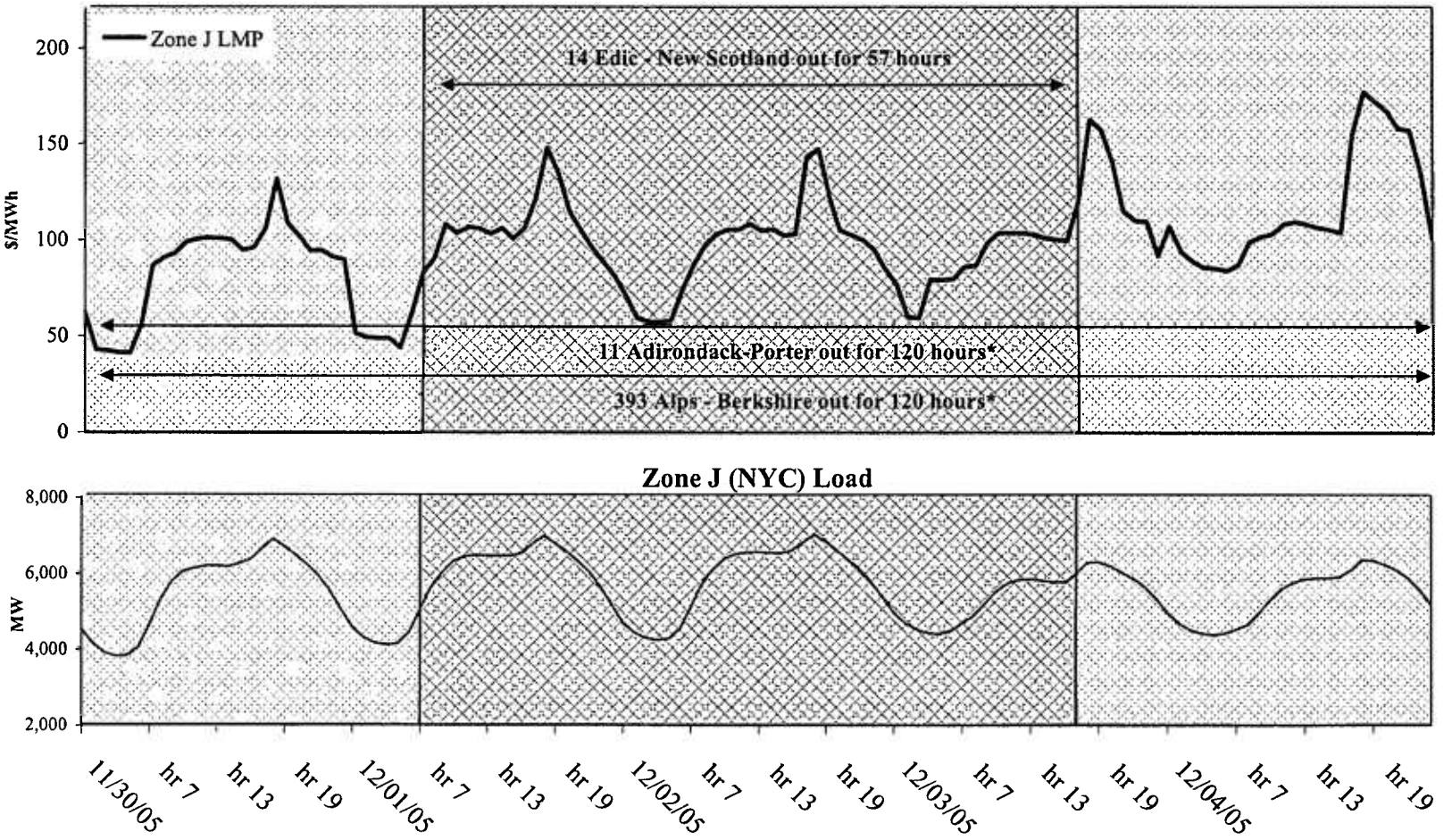


Note: *Volney-Marcy line is out from 5/2/2005 hr 7 to 6/30/2005 hr 15.

ALPS-BERKSHIRE, ADIR-PORTER and EDIC-NSC Out

Zone J (NYC) LMP

11/30/05-12/04/05

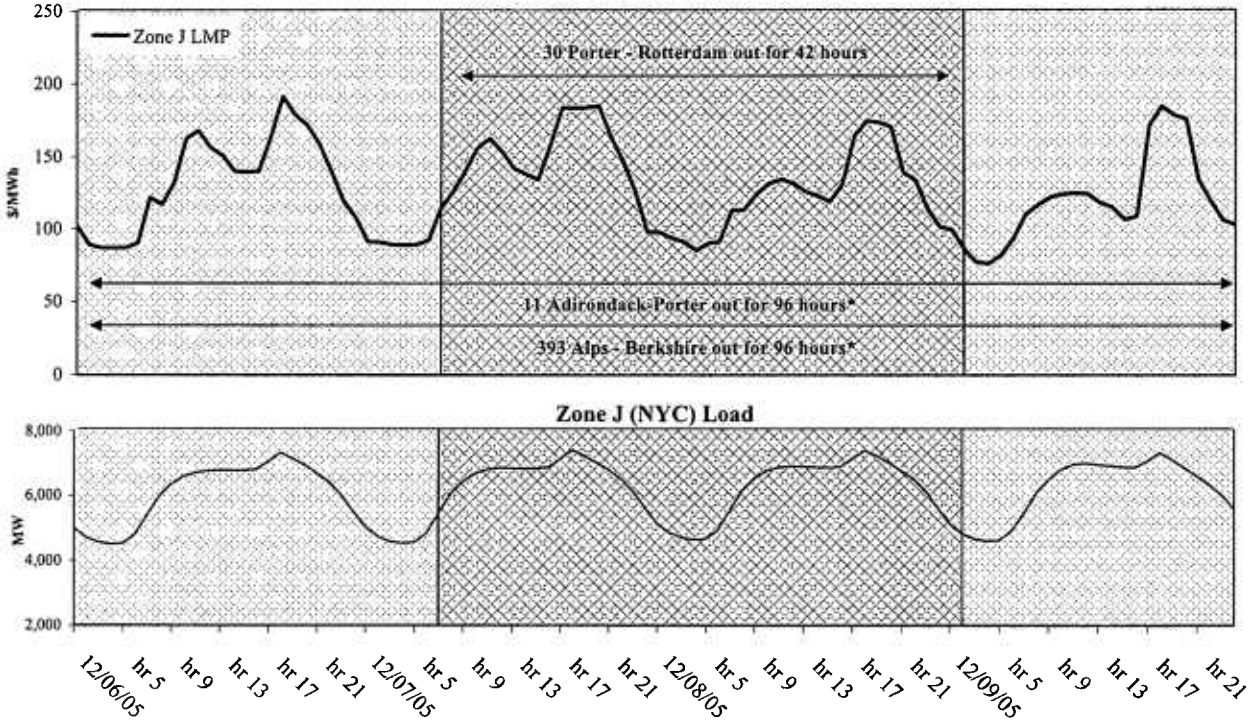


Note: *Alps-Berkshire line is out from 11/28/2005 hr 9 to 12/16/2005 hr 16 and Adirondack-Porter line is out from 11/14/2005 hr 9 to 12/15/2005 hr 17.

ALPS-BERKSHIRE, PORTER-RTDM and ADIR-PORTER Out

Zone J (NYC) LMP

12/06/05-12/09/05

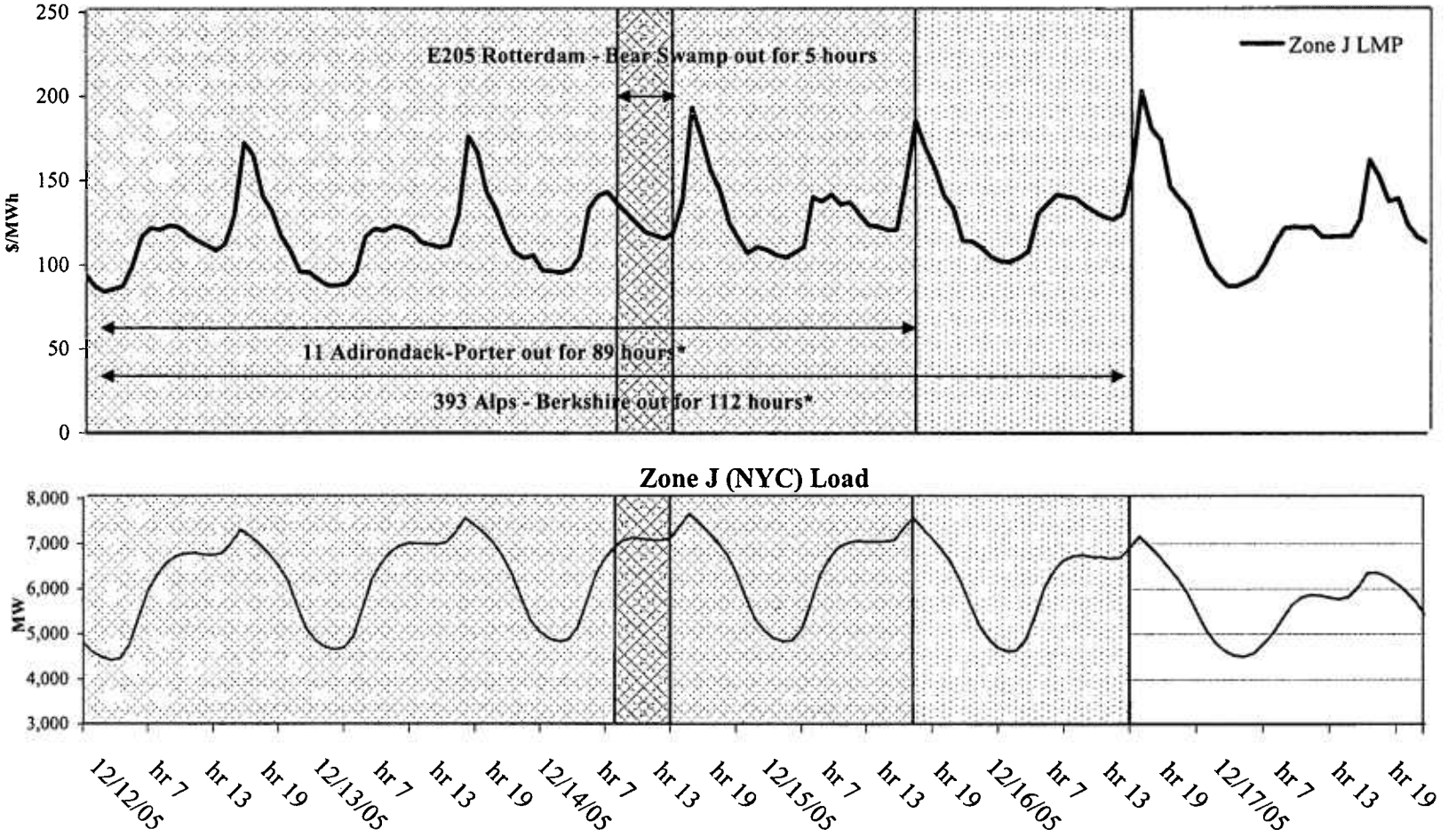


Note: *Alps-Berkshire line is out from 11/28/2005 hr 9 to 12/16/2005 hr 16 and Adirondack-Porter line is out from 11/14/2005 hr 9 to 12/15/2005 hr 17.

ALPS-BERKSHIRE, ADIR-PORTER and RTDM-BEAR SWAMP Out

Zone J (NYC) LMP

12/12/05-12/17/05

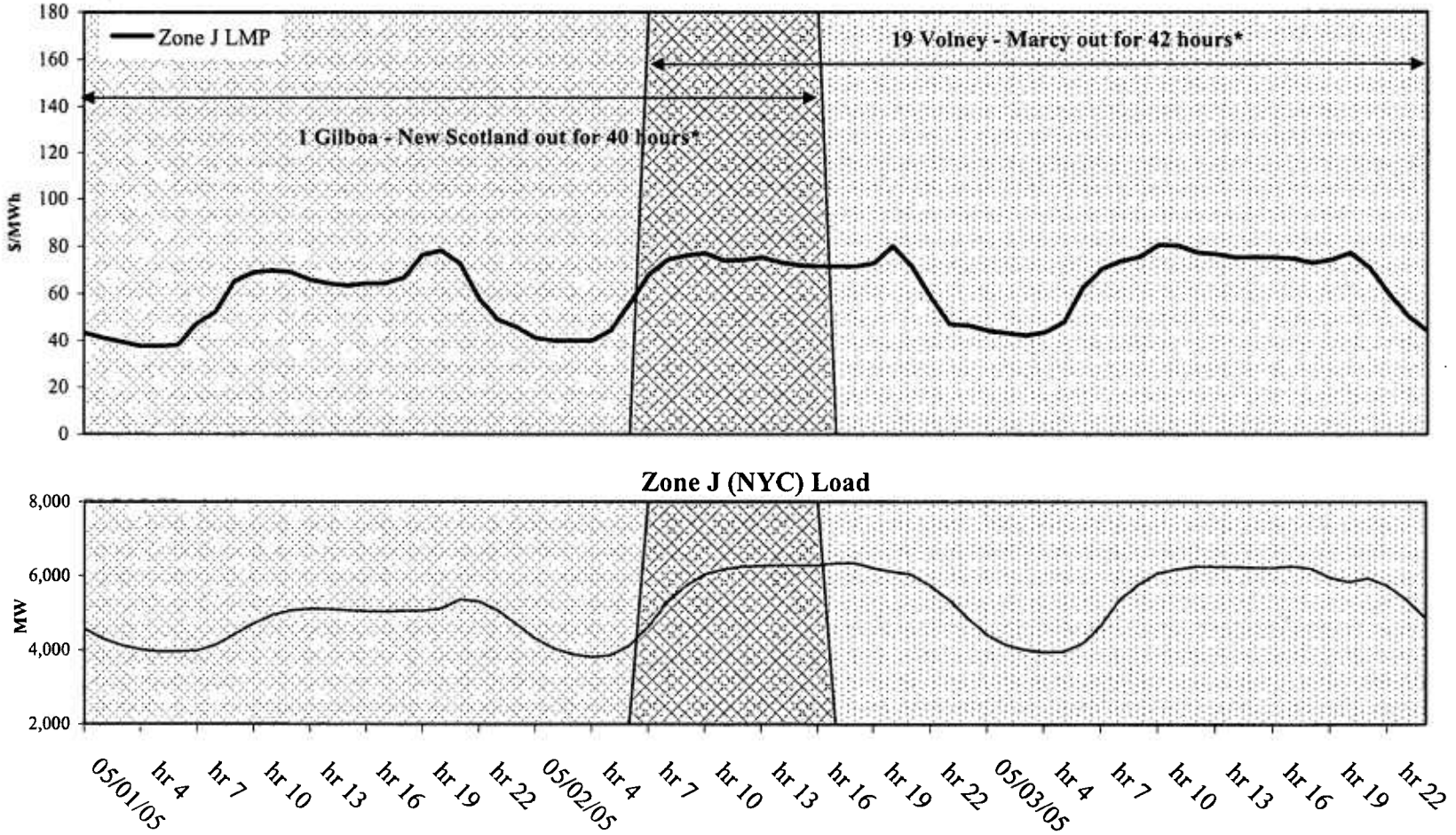


Note: *Alps-Berkshire line is out from 11/28/2005 hr 9 to 12/16/2005 hr 16 and Adirondack-Porter line is out from 11/14/2005 hr 9 to 12/15/2005 hr 17.

VOLNEY-MARCY and GILBOA-NSC Out

Zone J (NYC) LMP

5/1/05-5/3/05

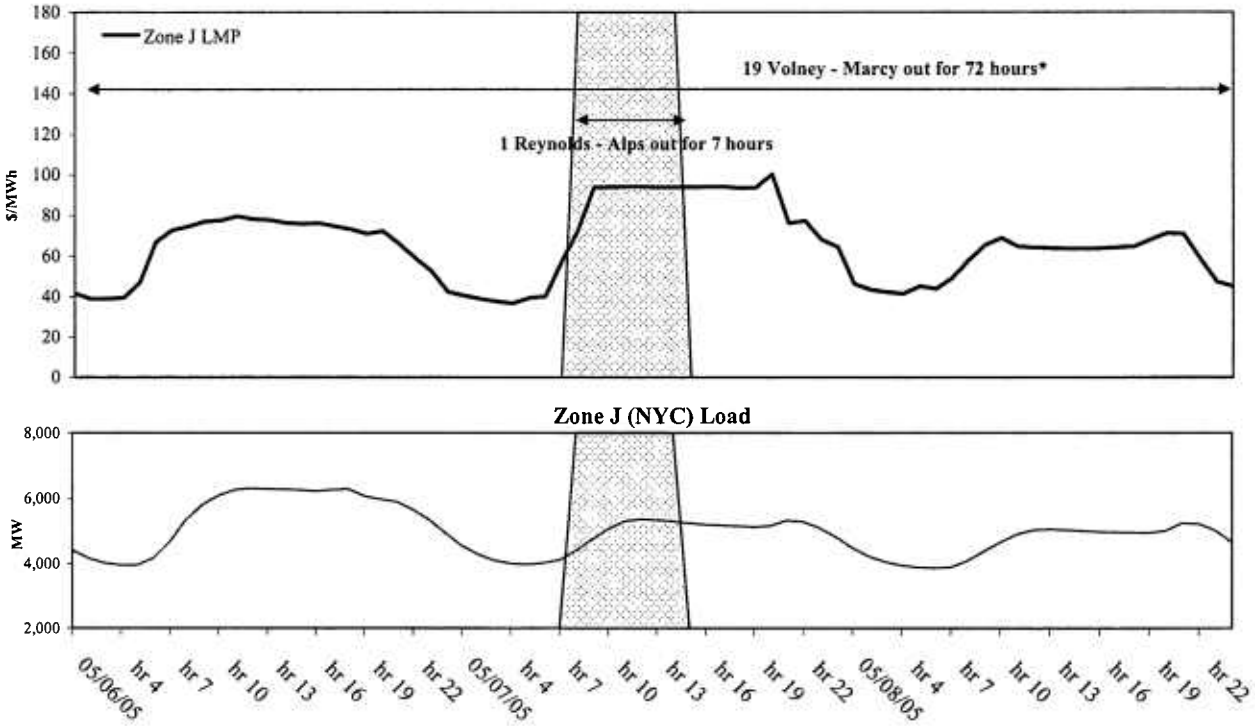


Note: *Volney-Marcy line is out from 5/2/2005 hr 7 to 6/28/2005 hr 15. Gilboa-New Scotland line is out from 4/4/2005 hr 8 to 5/2/2005 hr 16.

VOLNEY-MARCY and REYNOLDS-ALPS Out

Zone J (NYC) LMP

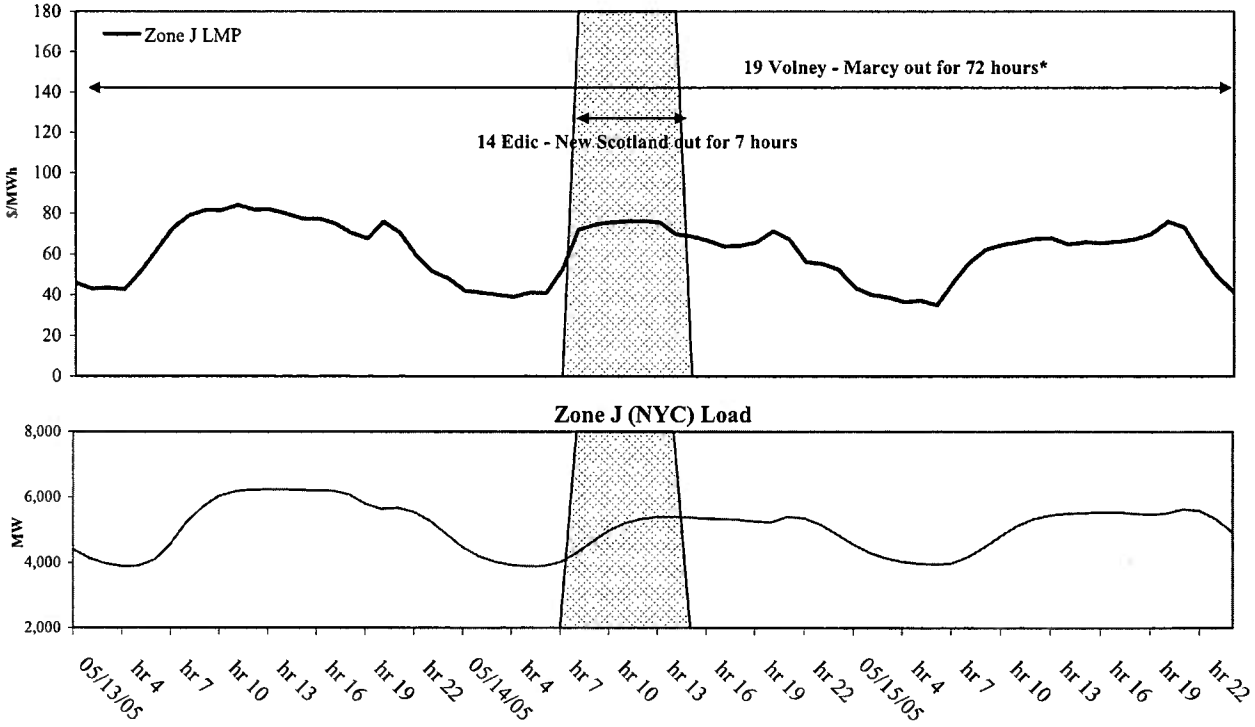
5/6/05-5/8/05



Note: *Volney-Marcy line is out from 5/2/2005 hr 7 to 6/30/2005 hr 15.

VOLNEY-MARCY and EDIC-NSC Out

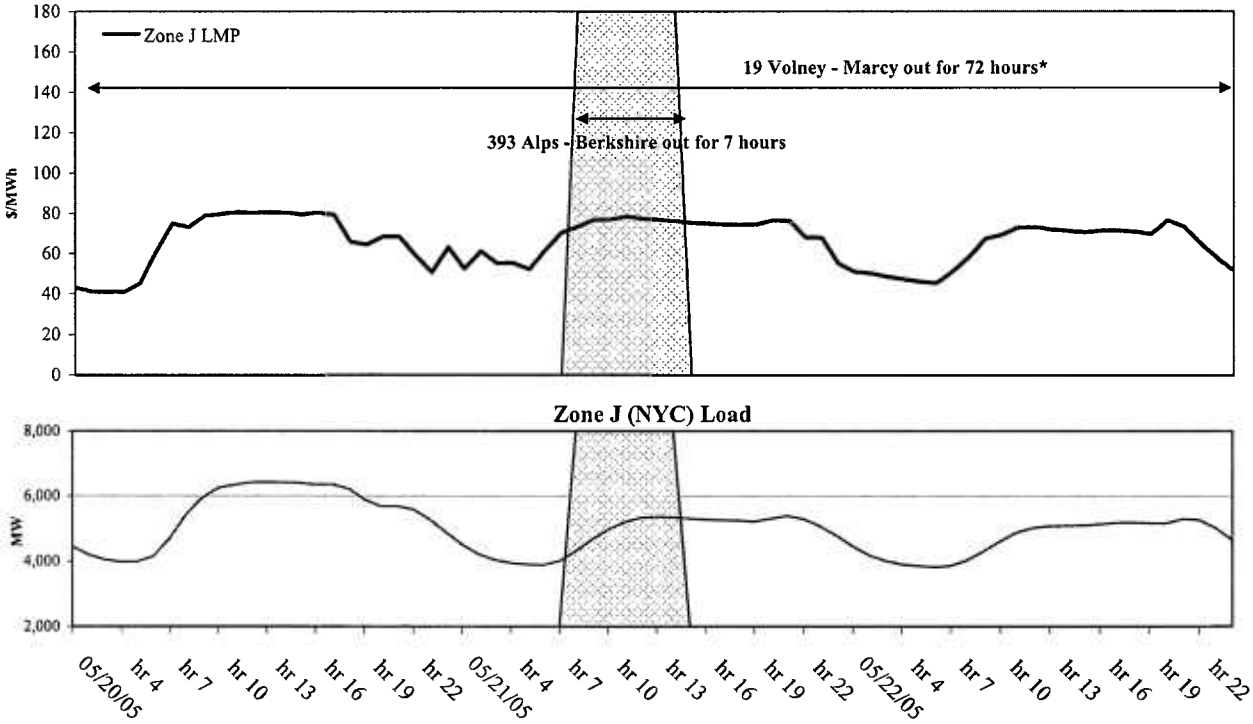
Zone J (NYC) LMP
5/13/05-5/15/05



Note: *Volney-Marcy line is out from 5/2/2005 hr 7 to 6/30/2005 hr 15.

VOLNEY-MARCY and ALPS-BERKSHIRE Out

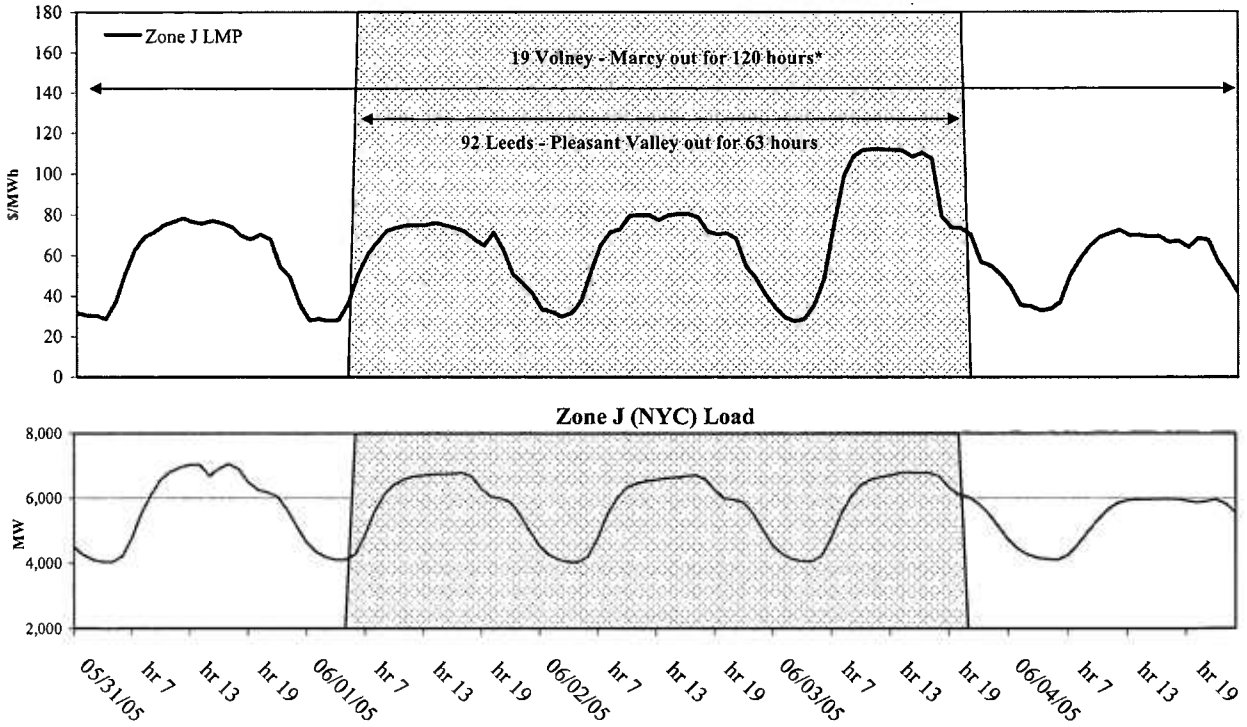
Zone J (NYC) LMP
5/20/05-5/22/05



Note: *Volney-Marcy line is out from 5/2/2005 hr 7 to 6/30/2005 hr 15.

VOLNEY-MARCY and LEEDS-PLEASANT VLY Out

Zone J (NYC) LMP
5/31/05-6/4/05

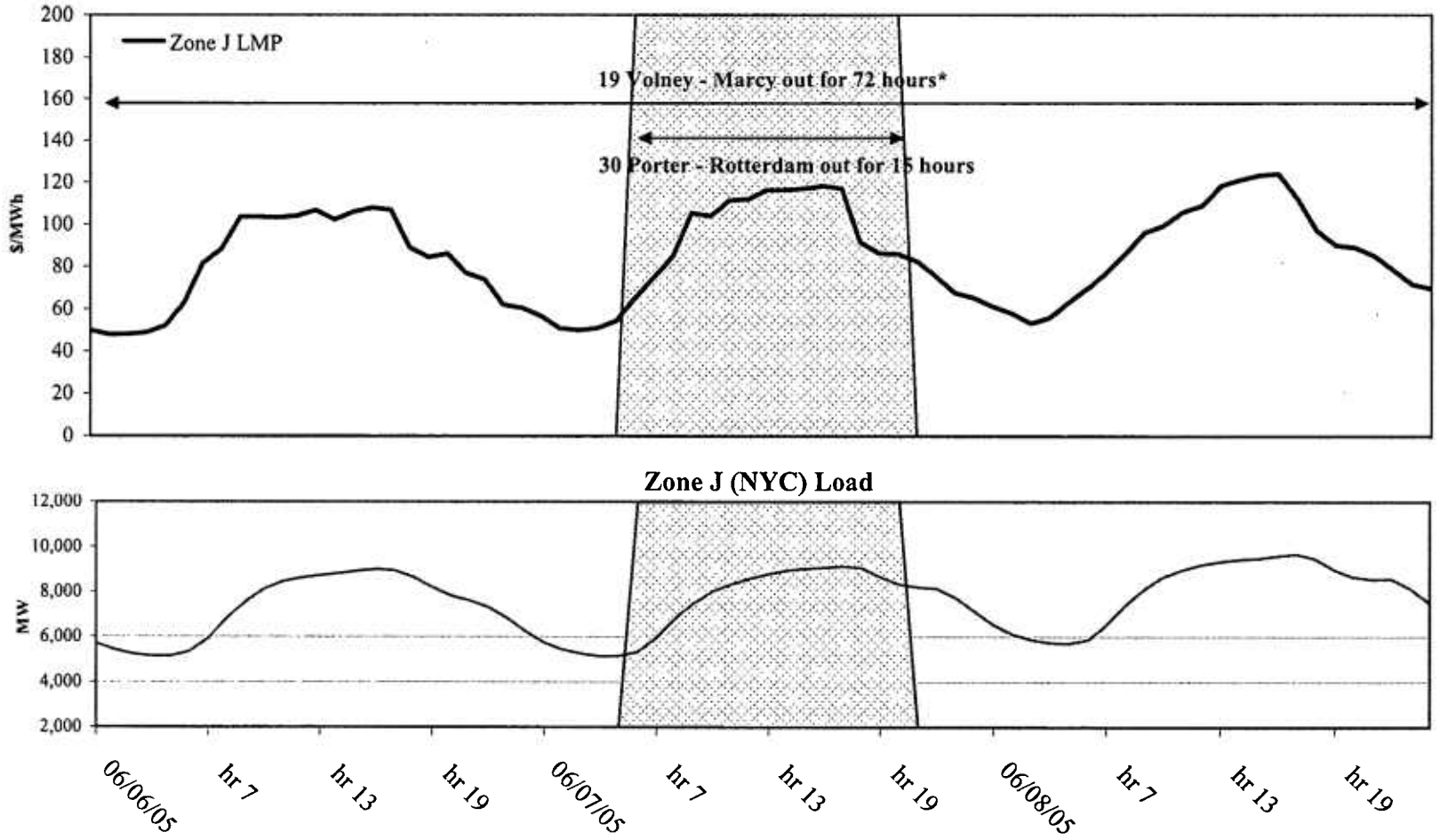


Note: *Volney-Marcy line is out from 5/2/2005 hr 7 to 6/30/2005 hr 15.

VOLNEY-MARCY and PORTER-RTDM Out

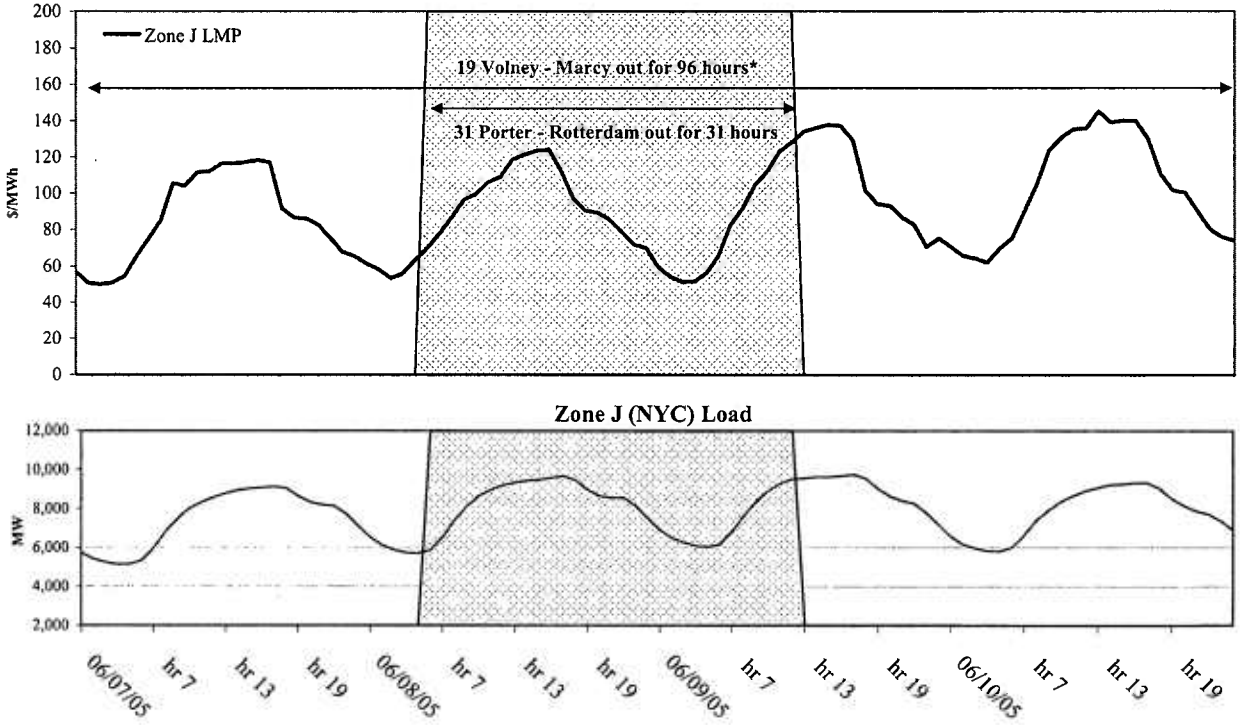
Zone J (NYC) LMP

6/6/05-6/8/05



Note: *Volney-Marcy line is out from 5/2/2005 hr 7 to 6/30/2005 hr 15.

VOLNEY-MARCY and PORTER-RTDM Out
Zone J (NYC) LMP
6/7/05-6/10/05

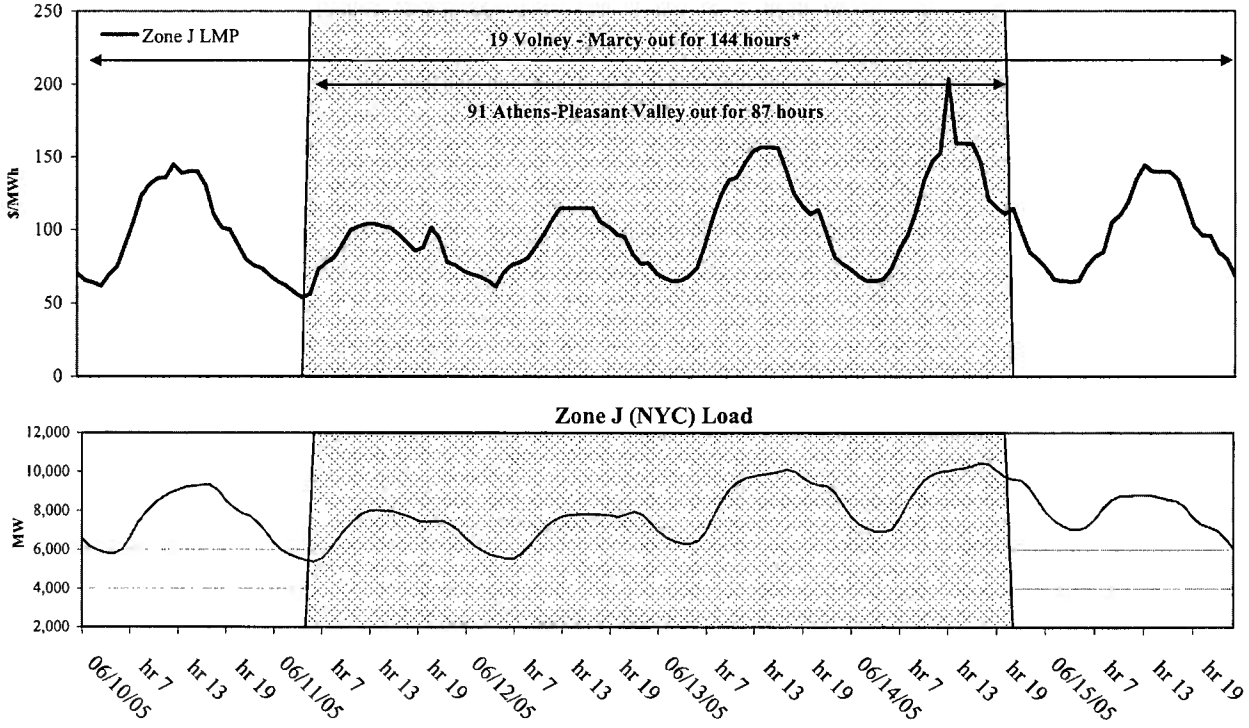


Note: *Volney-Marcy line is out from 5/2/2005 hr 7 to 6/30/2005 hr 15.

VOLNEY-MARCY and ATHENS-PLEASANT VLY Out

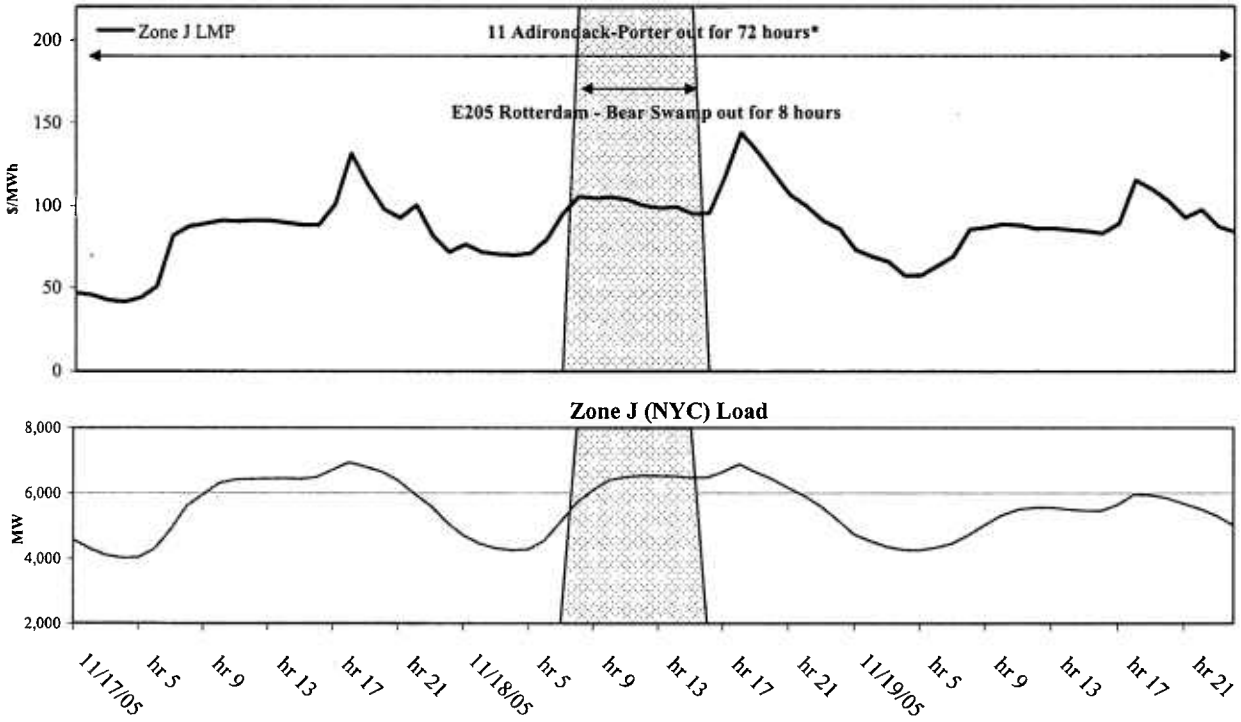
Zone J (NYC) LMP

6/10/05-6/15/05



Note: *Volney-Marcy line is out from 5/2/2005 hr 7 to 6/30/2005 hr 15.

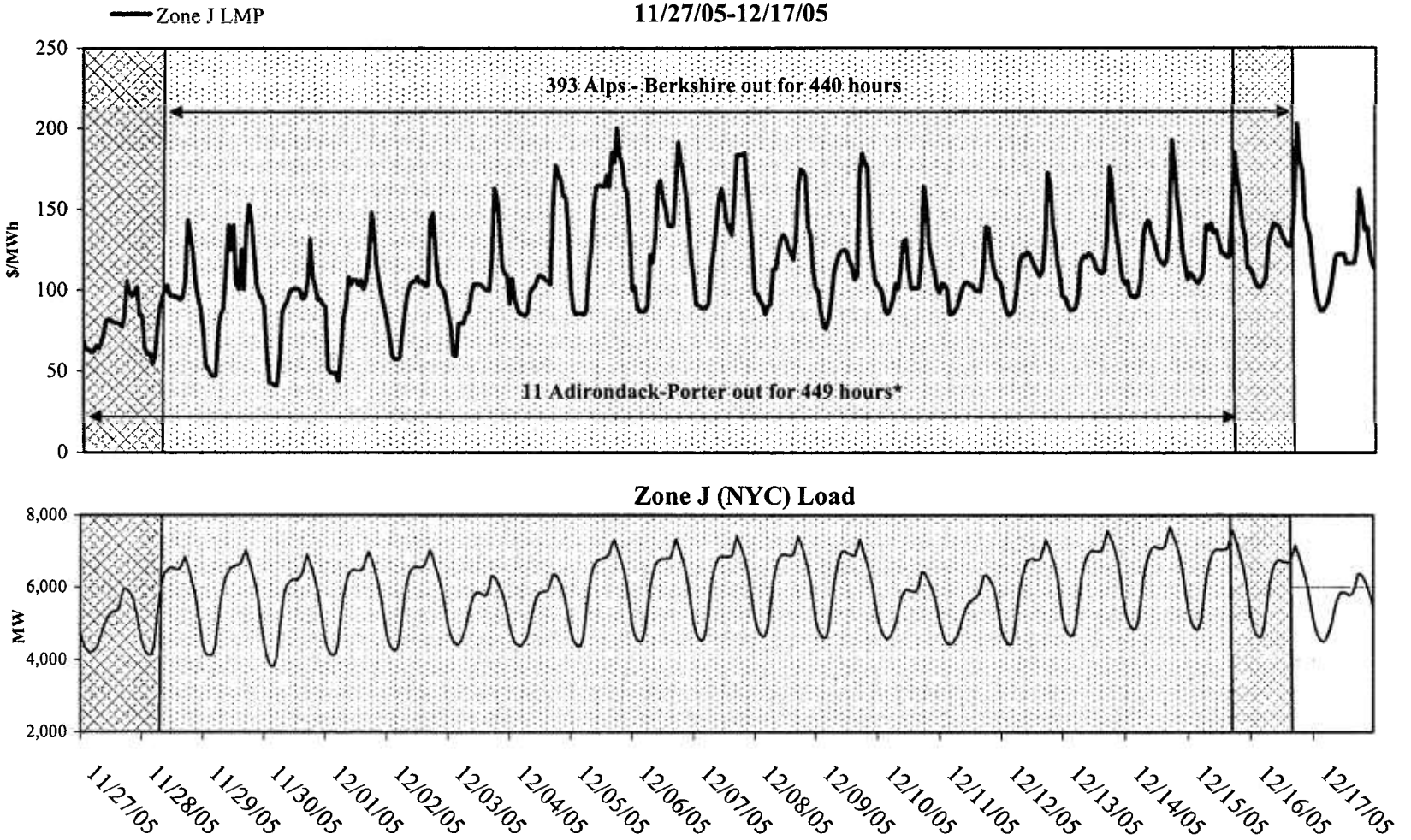
ADIRONDACK-PORTER and RTDM-BEAR SWAMP Out
Zone J (NYC) LMP
11/17/05-11/19/05



Note: *Adirondack-Porter line is out from 11/14/2005 hr 9 to 12/15/2005 hr 17.

ALPS-BERKSHIRE and ADIRONDACK-PORTER Out

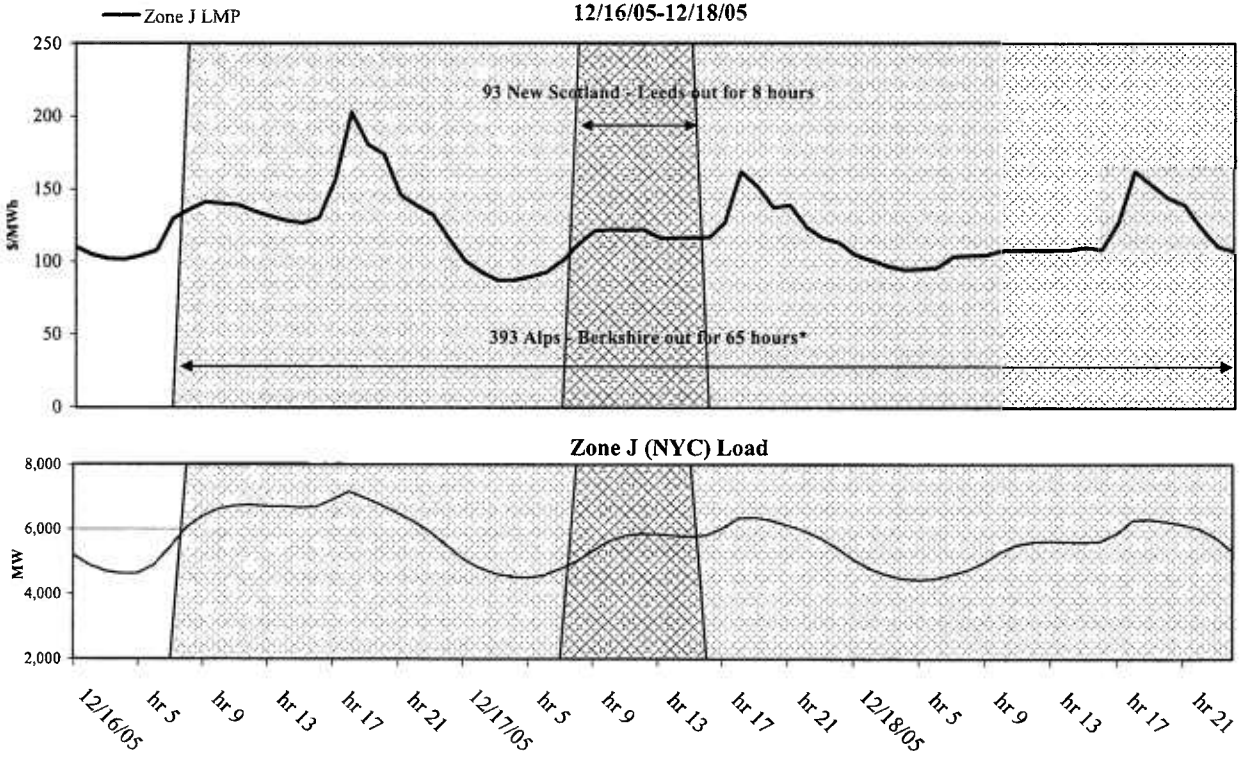
Zone J (NYC) LMP
11/27/05-12/17/05



Note: *Adirondack-Porter line is out from 11/14/2005 hr 9 to 12/15/2005 hr 17.

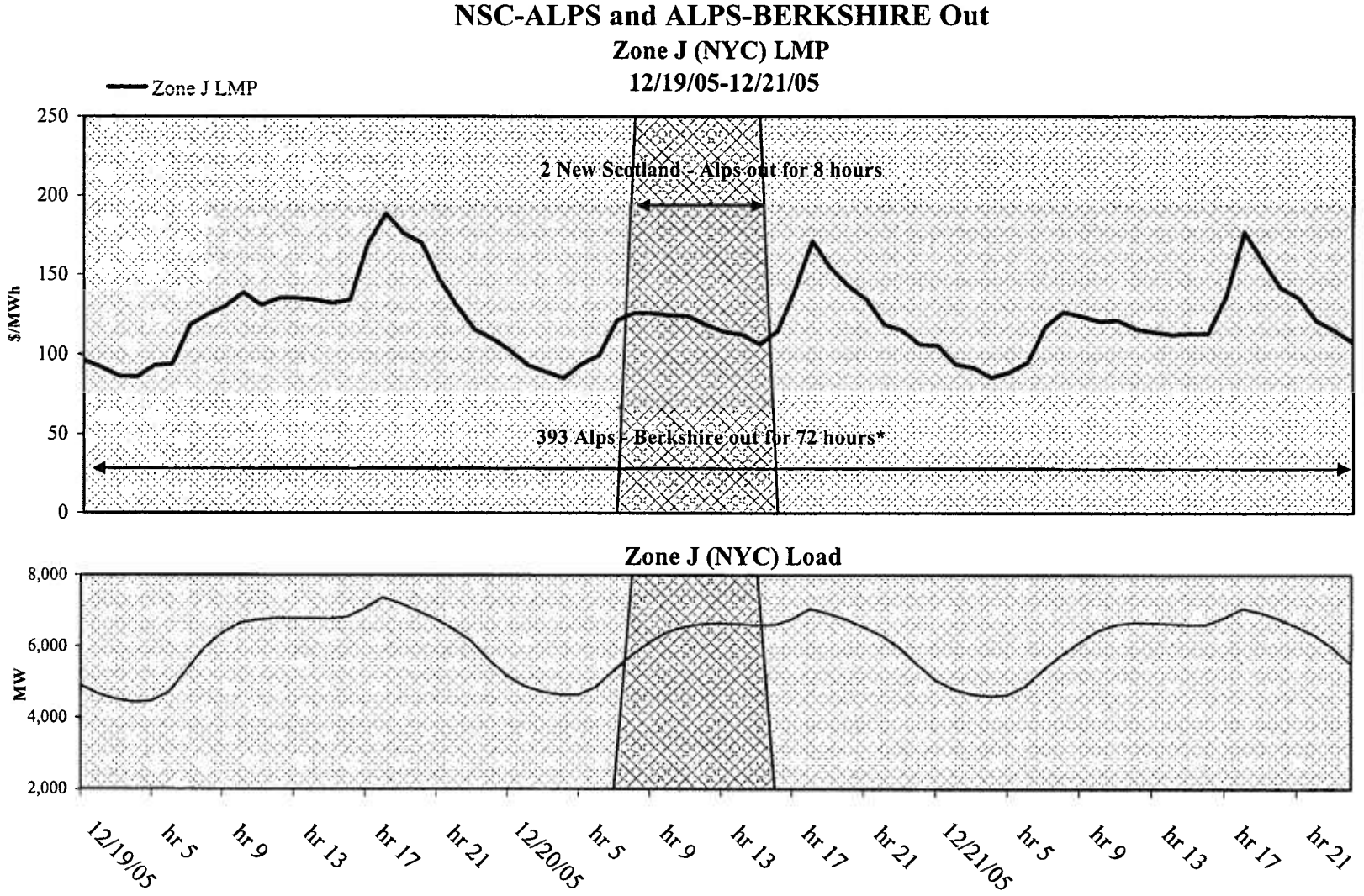
NSC-LEEDS and ALPS-BERKSHIRE Out

Zone J (NYC) LMP
12/16/05-12/18/05



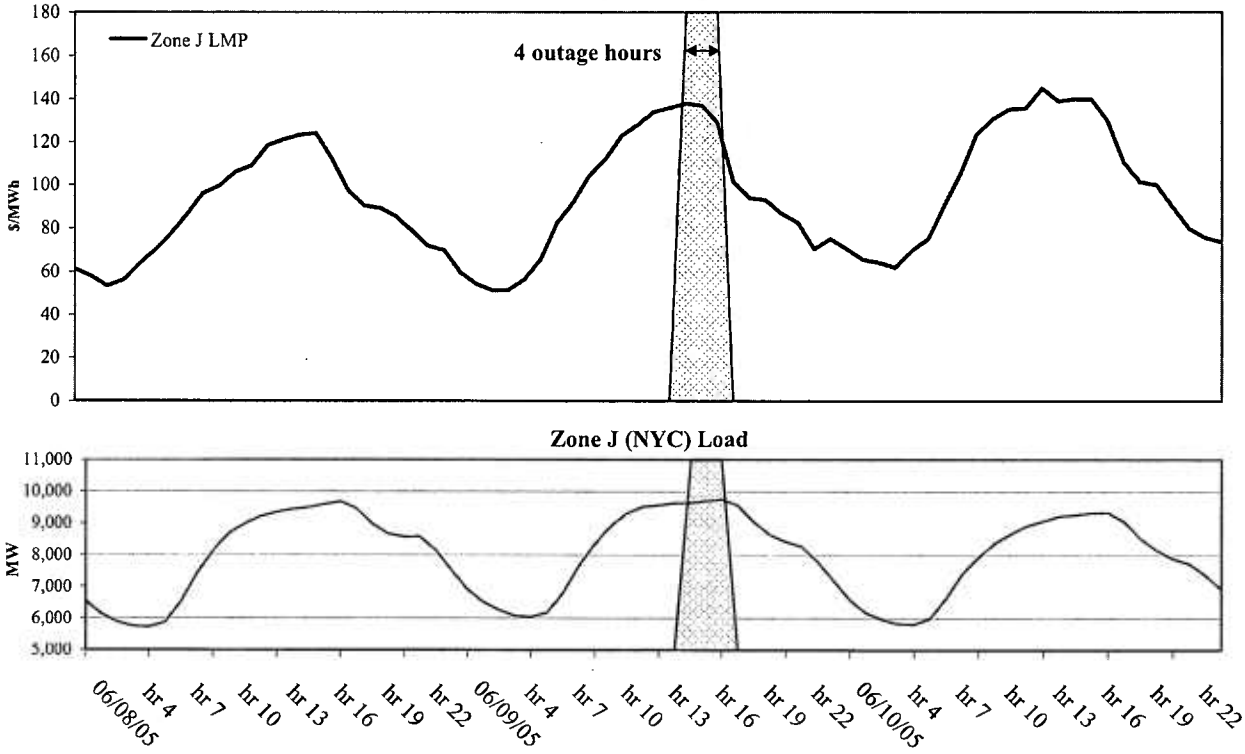
Note: *Alps-Berkshire line is out from 12/16/2005 hr 8 to 12/22/2005 hr 12.

NSC-ALPS and ALPS-BERKSHIRE Out

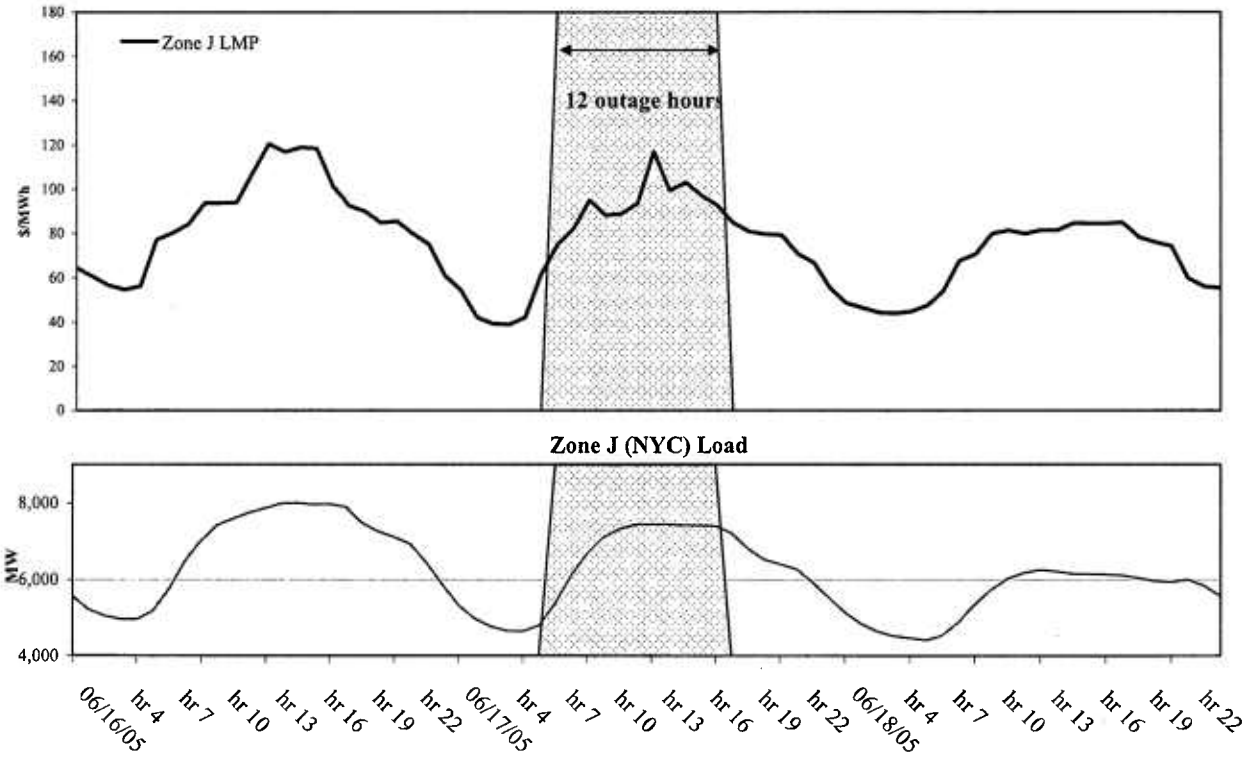


Note: *Alps-Berkshire line is out from 12/16/2005 hr 8 to 12/22/2005 hr 12.

HURLYAVE-LEEDS and NSC-LEEDS Out
Zone J (NYC) LMP
6/8/05-6/10/05



HURLYAVE-LEEDS and NSC-EDIC Out
Zone J (NYC) LMP
6/16/05-6/18/05



HURLYAVE-LEEDS and NSC-EDIC Out
Zone J (NYC) LMP
6/15/05-6/17/05

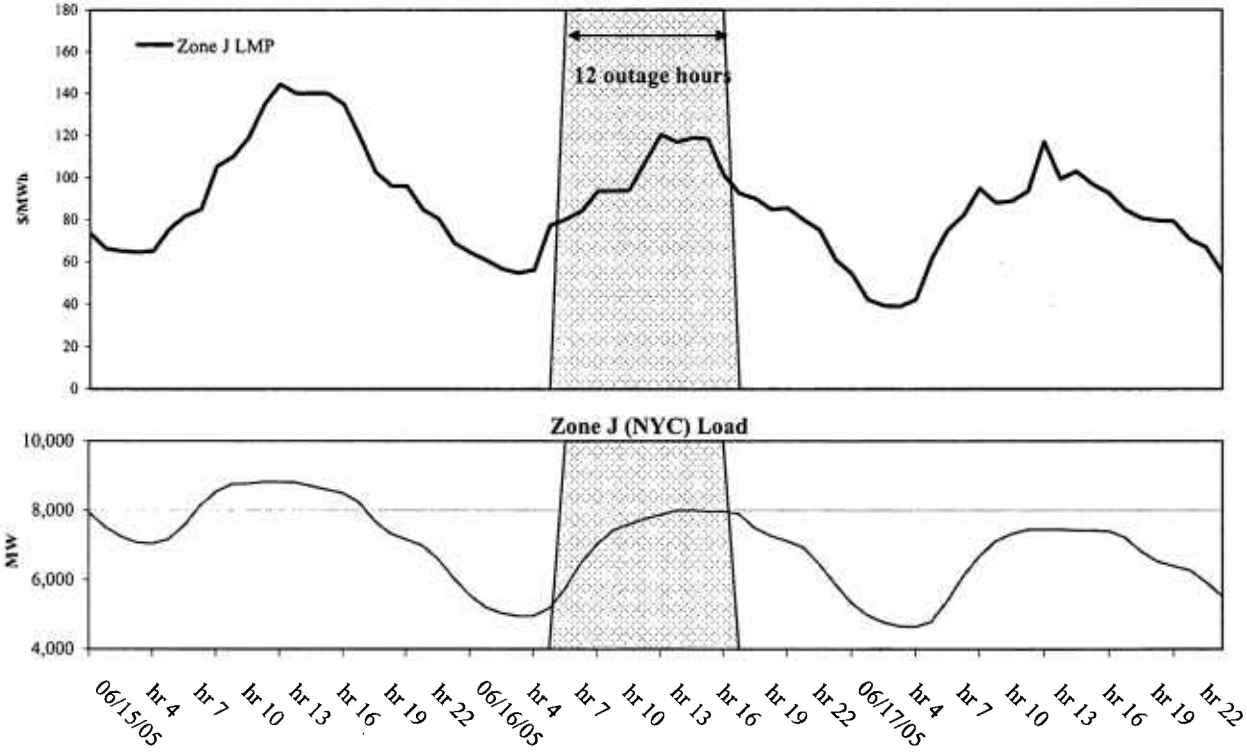
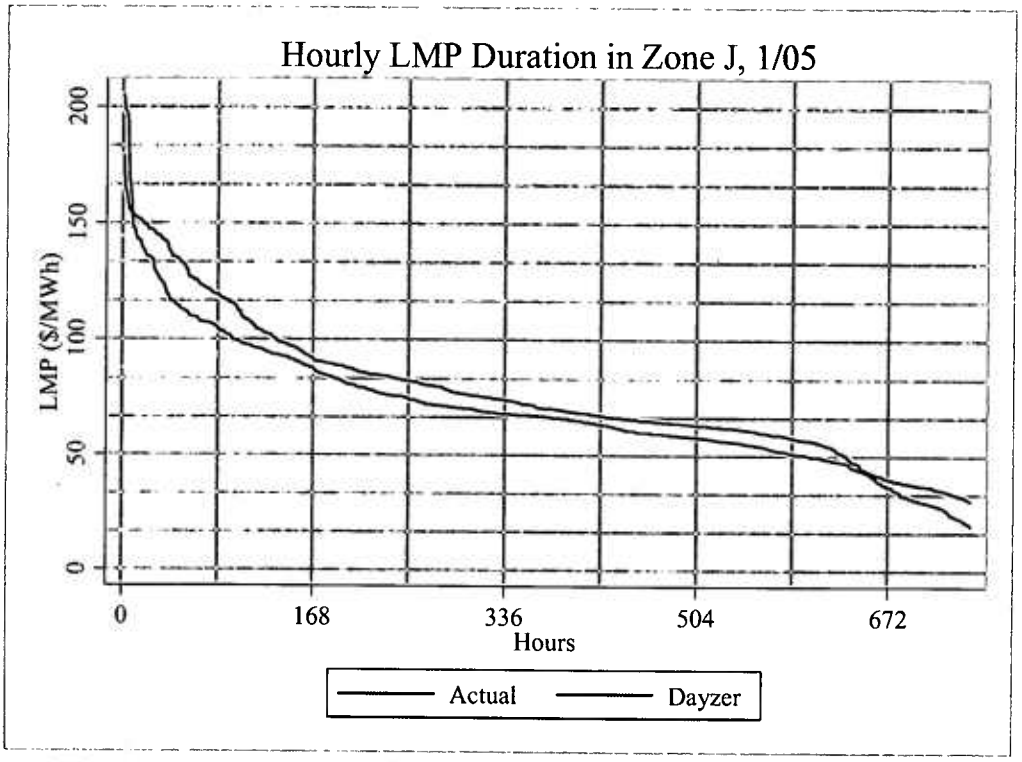
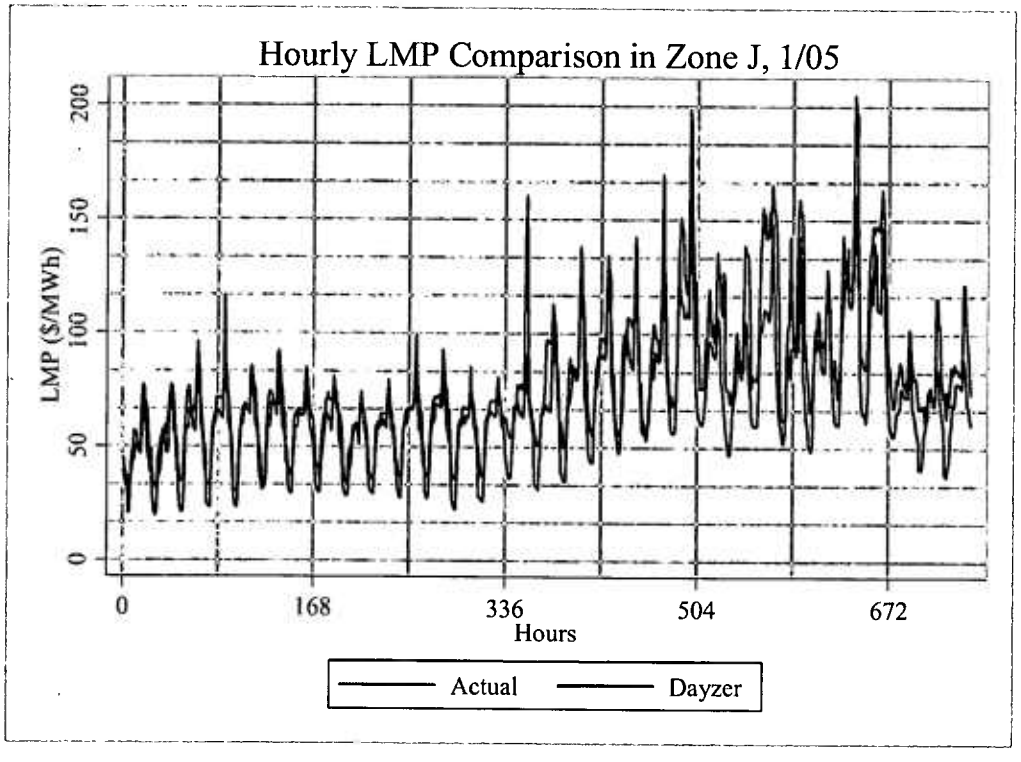


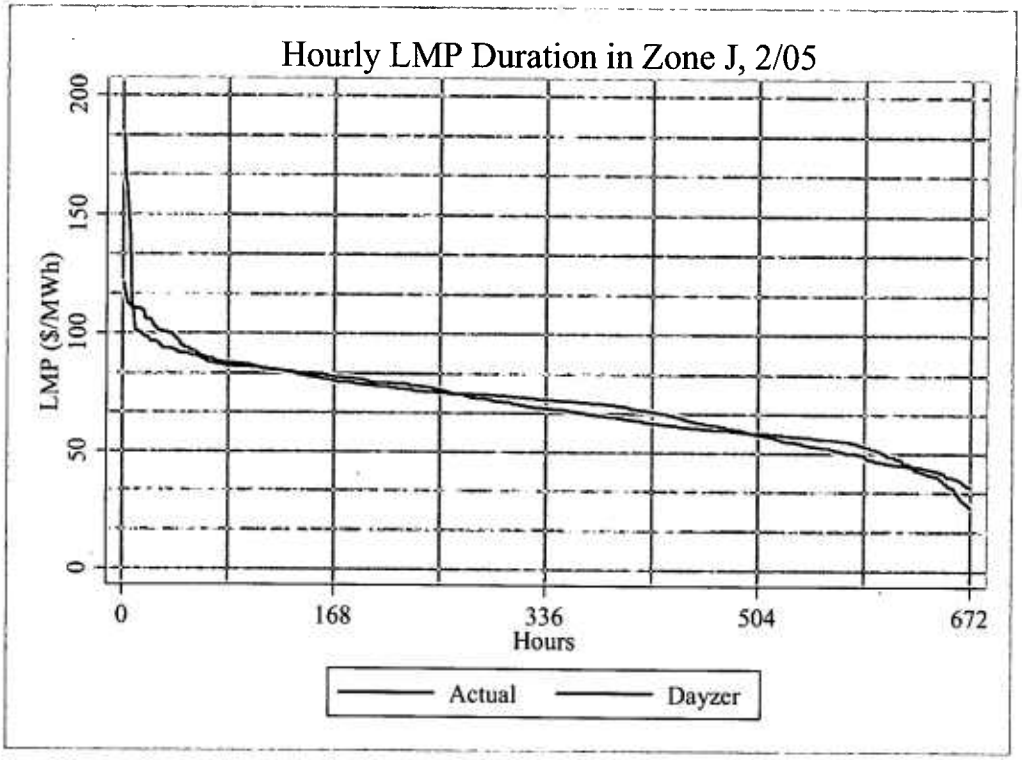
EXHIBIT NO._(PFP-2R)

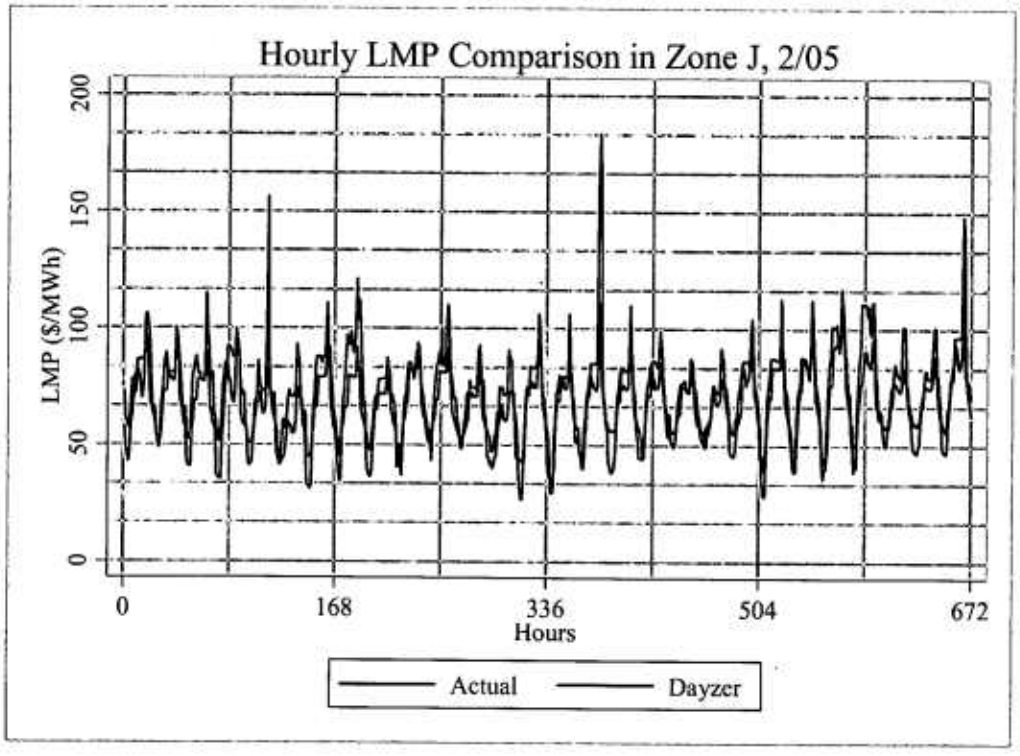
Monthly Price Graphs of August 2004 – July 2005 Backcasting*
Zone A – Zone K

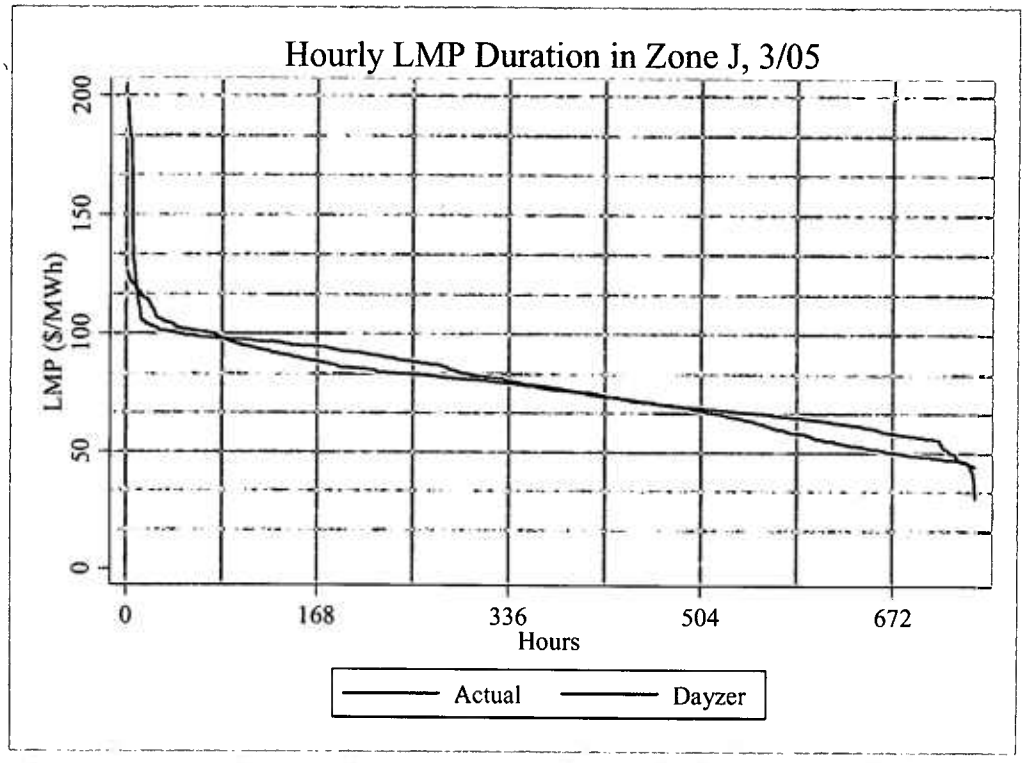
* Graphs of August 2004 – December 2004 follow those of July 2005.

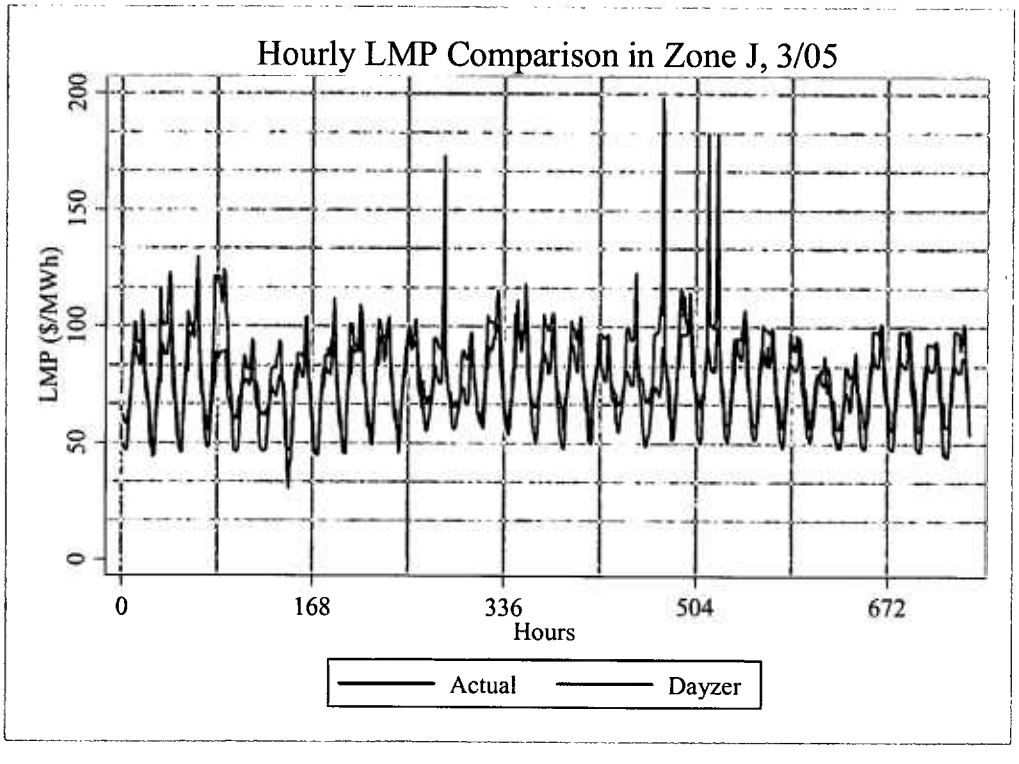

Hourly LMP Duration in Zone J, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

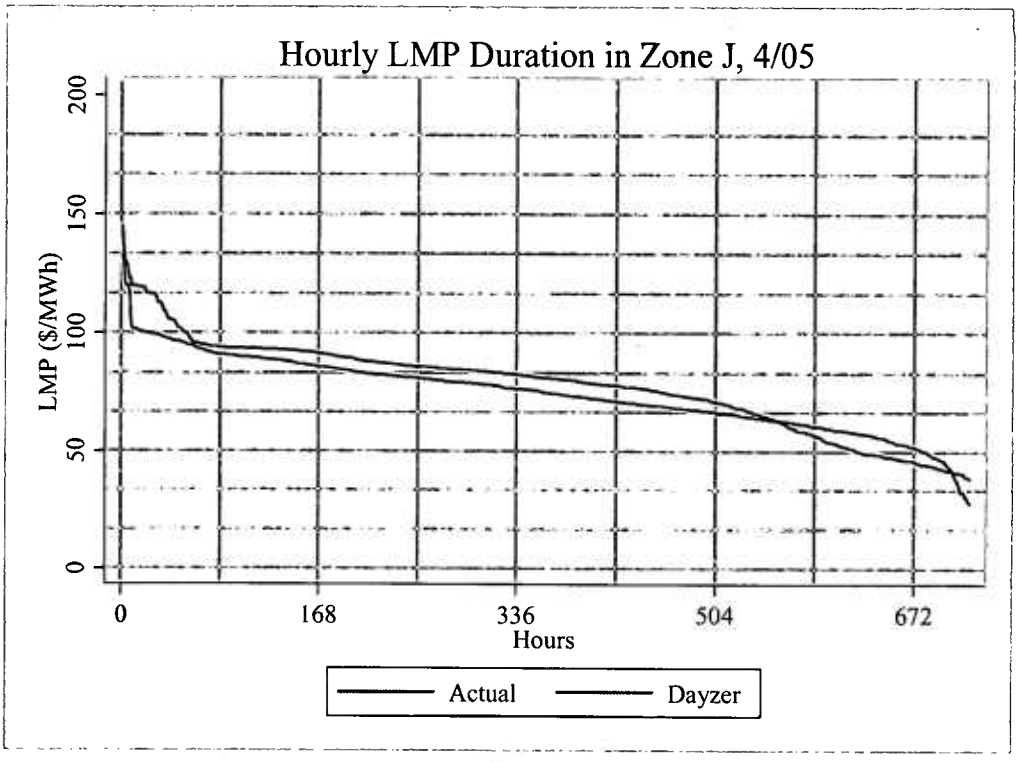

Hourly LMP Comparison in Zone J, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

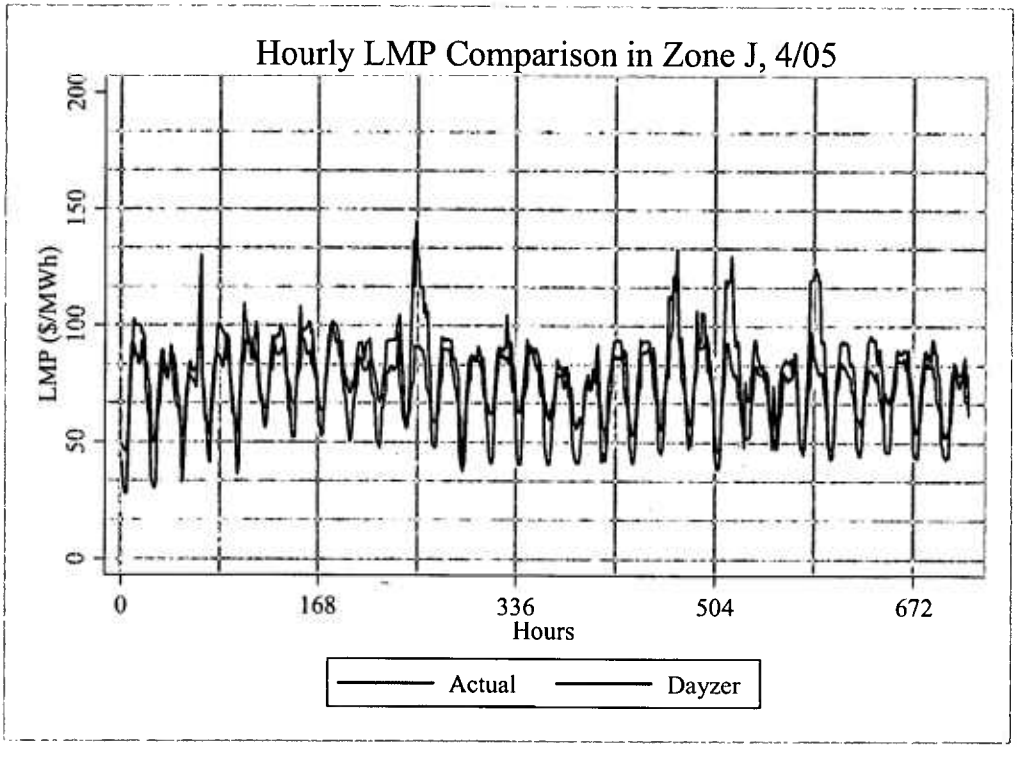

Hourly LMP Duration in Zone J, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

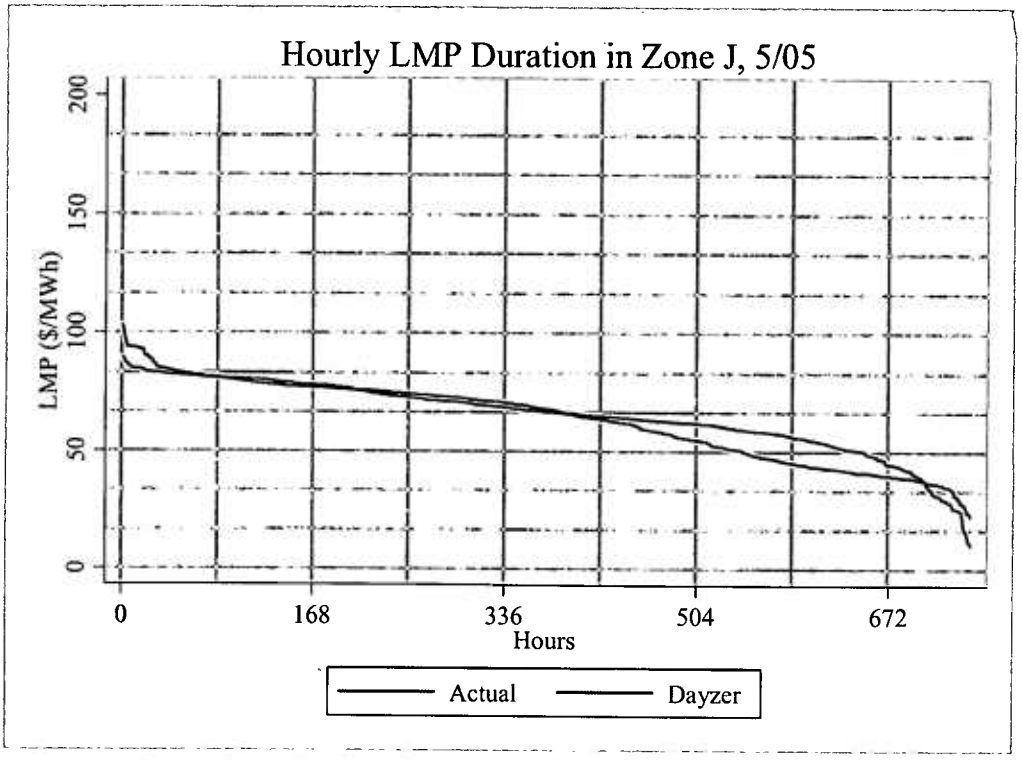

Hourly LMP Comparison in Zone J, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

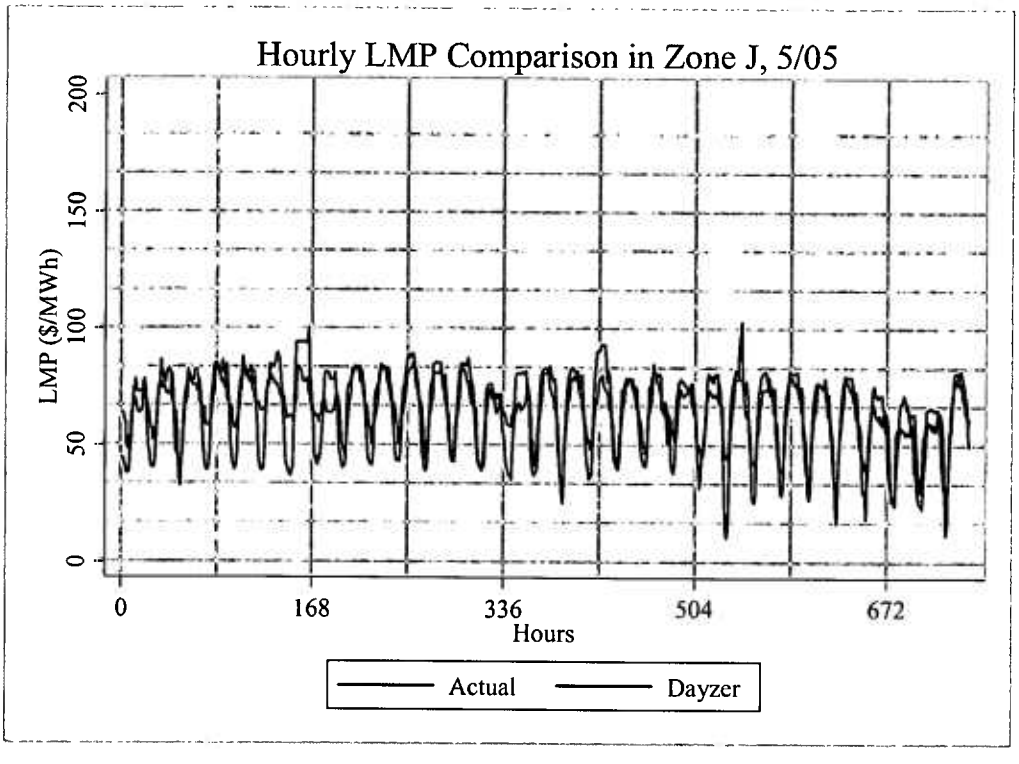

Hourly LMP Duration in Zone J, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

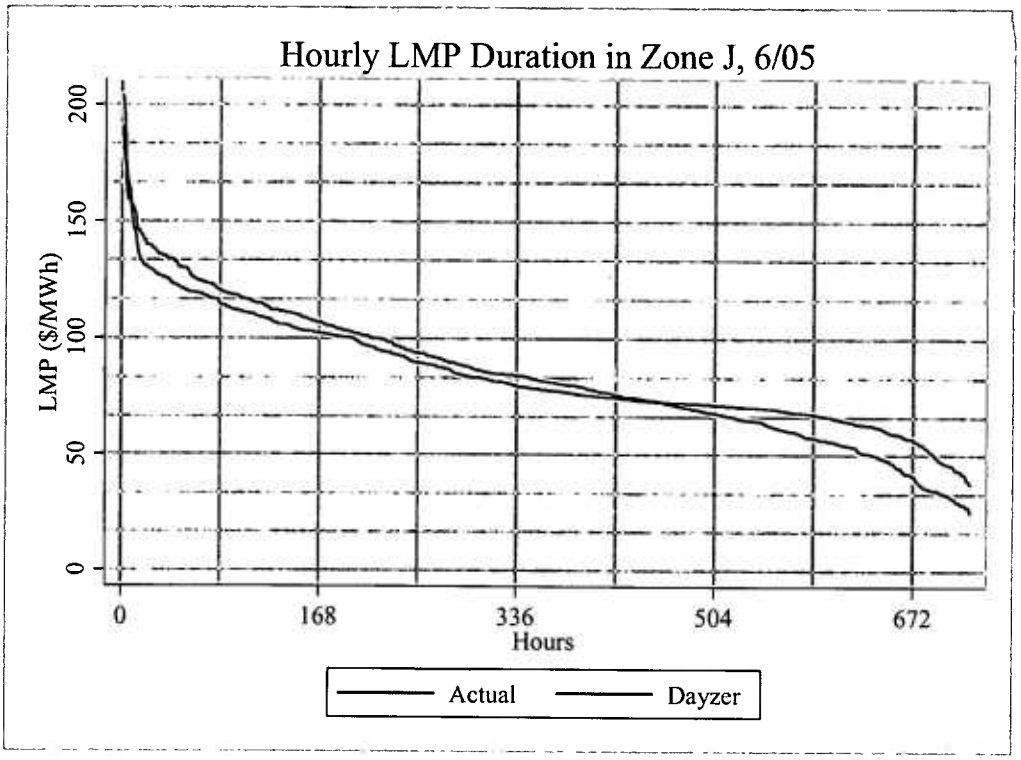

Hourly LMP Comparison in Zone J, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

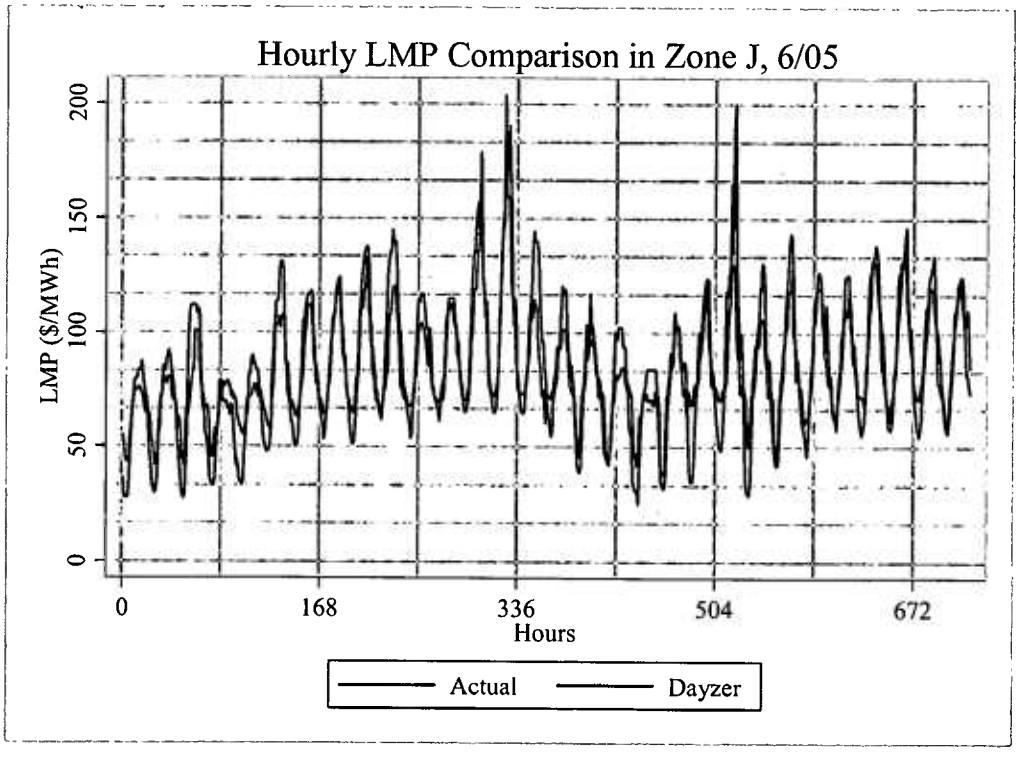

Hourly LMP Duration in Zone J, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

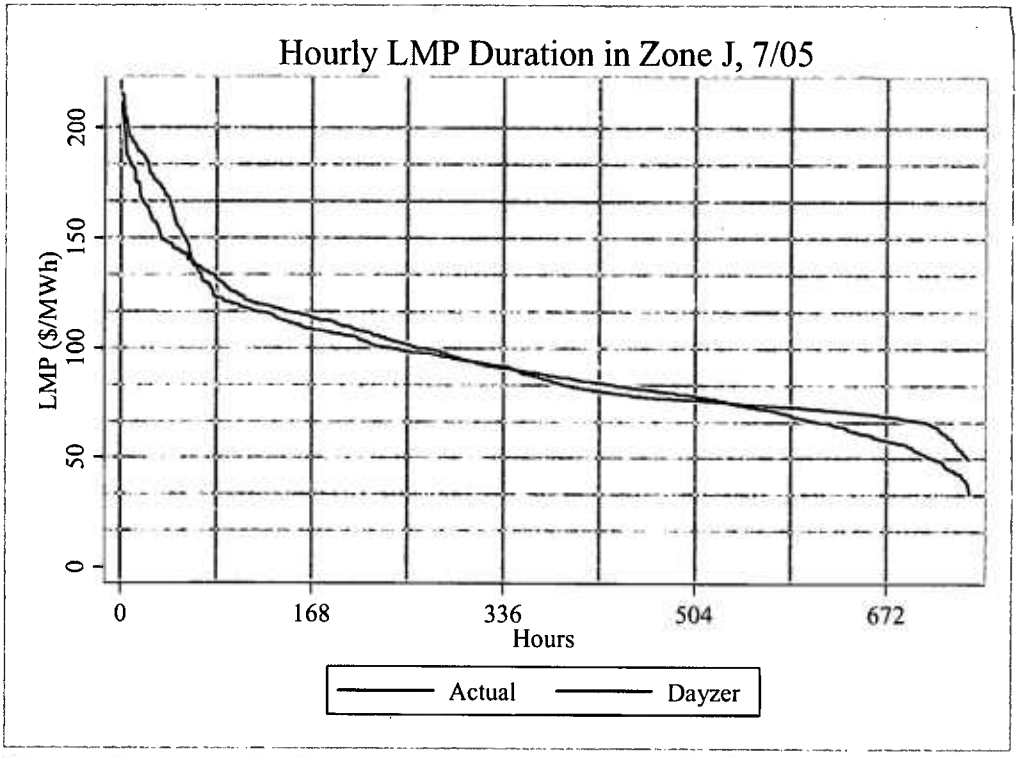

Hourly LMP Comparison in Zone J, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

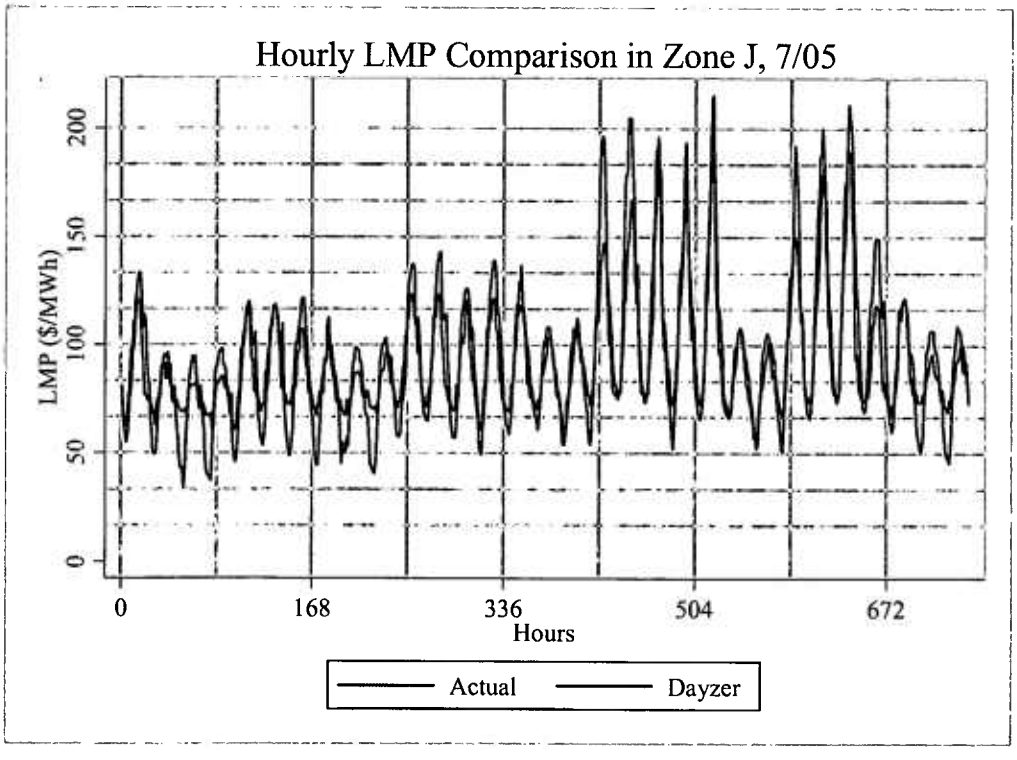

Hourly LMP Duration in Zone J, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

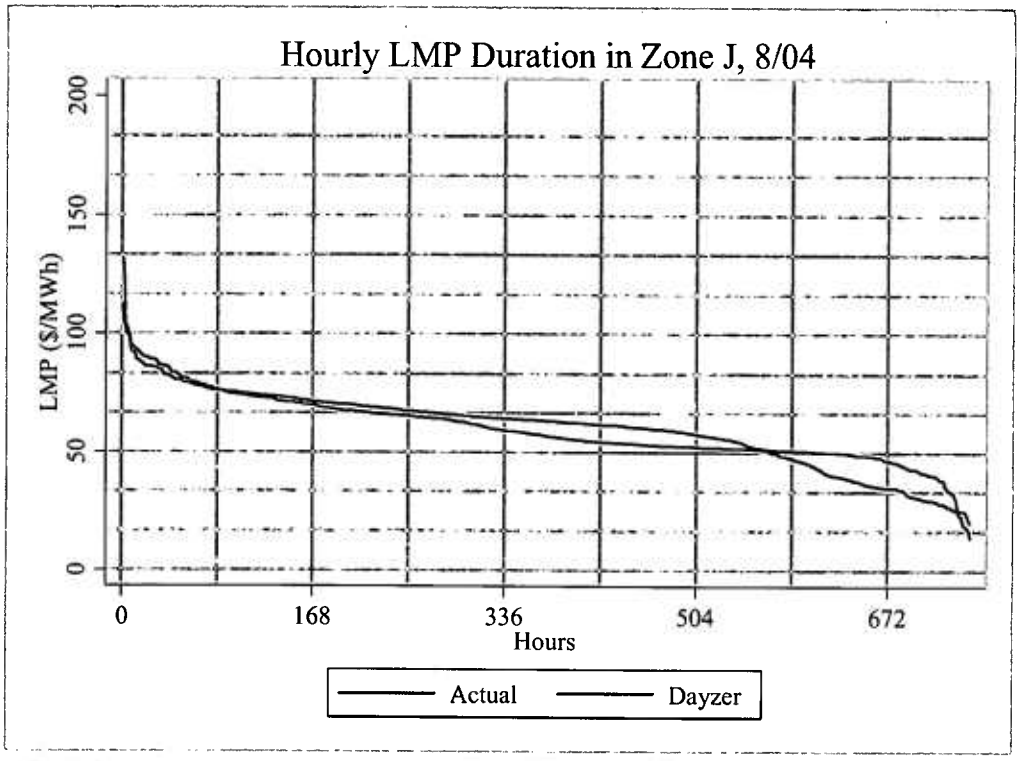

Hourly LMP Comparison in Zone J, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

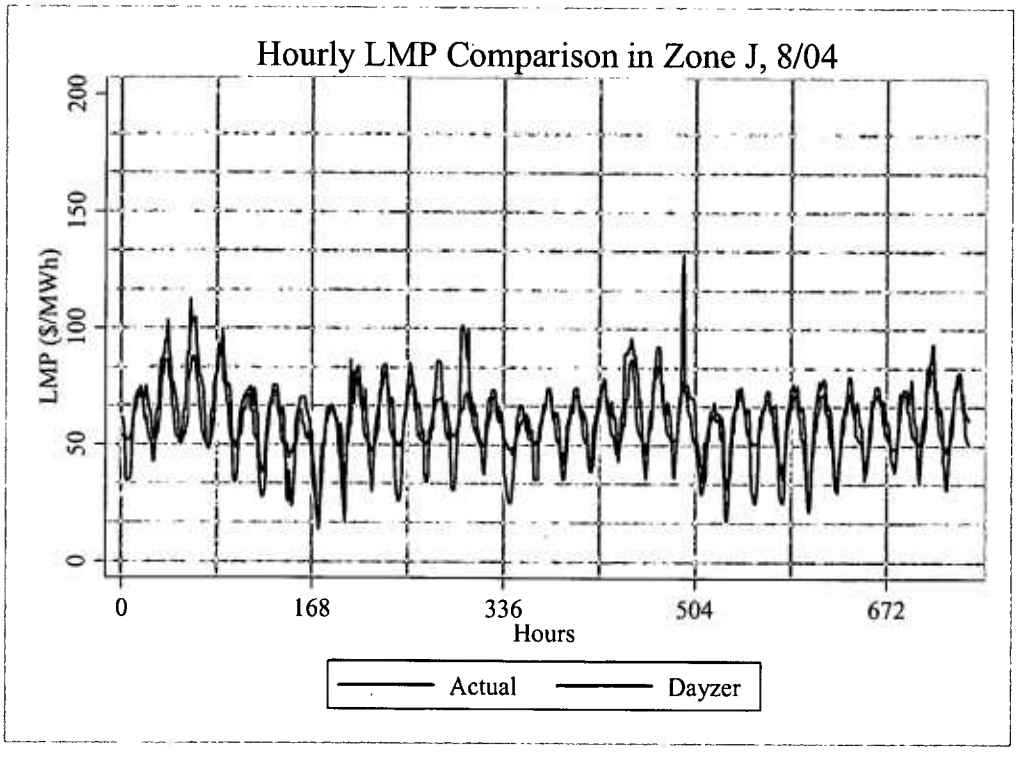

Hourly LMP Duration in Zone J, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

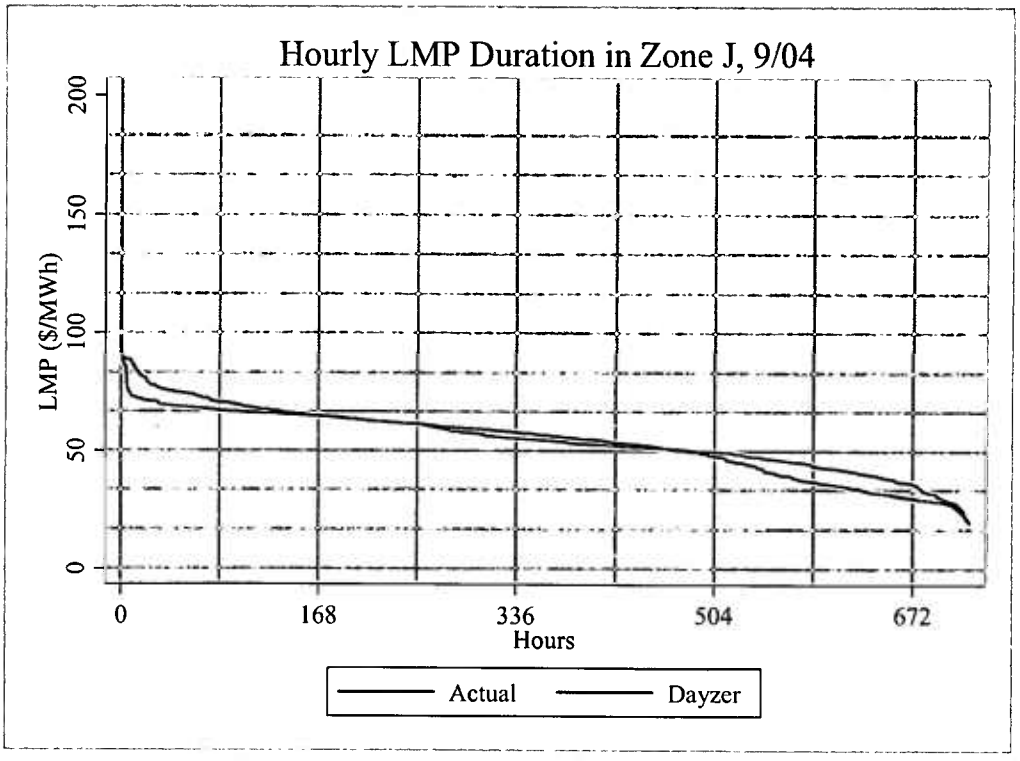

Hourly LMP Comparison in Zone J, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

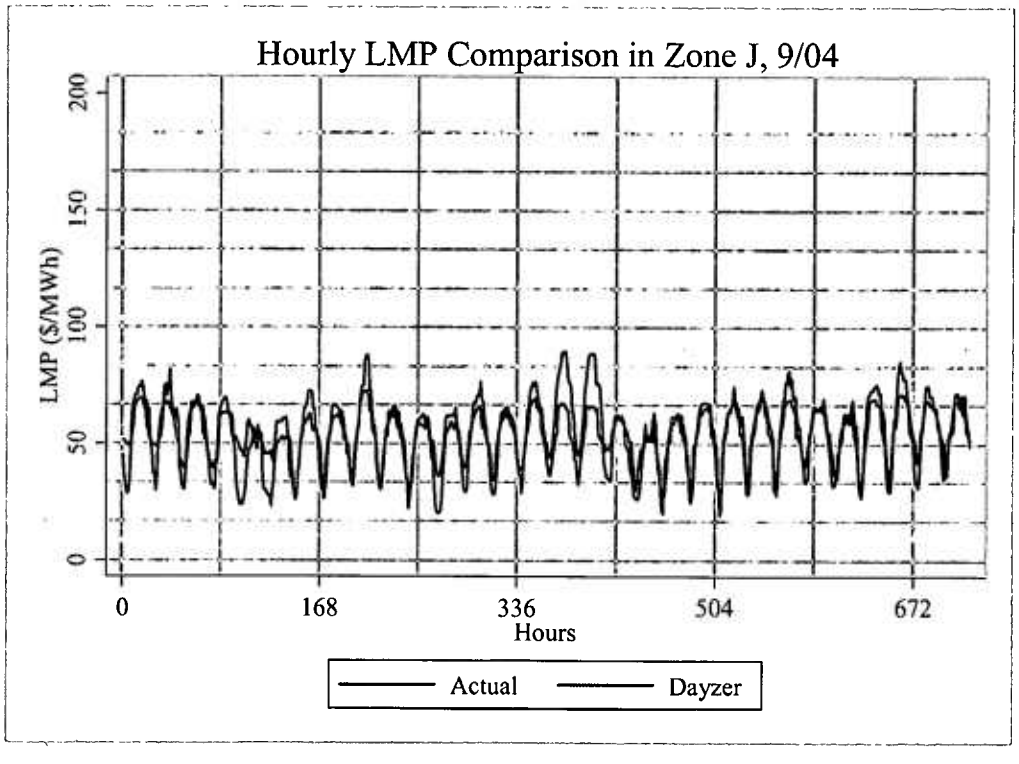

Hourly LMP Duration in Zone J, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

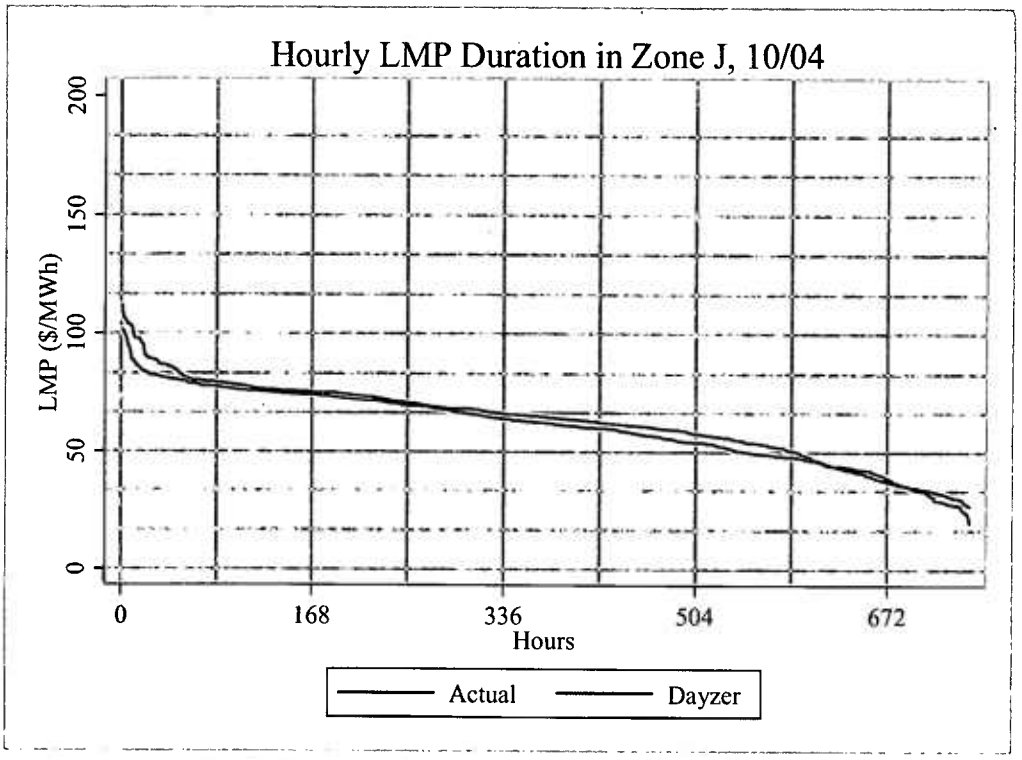

Hourly LMP Comparison in Zone J, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

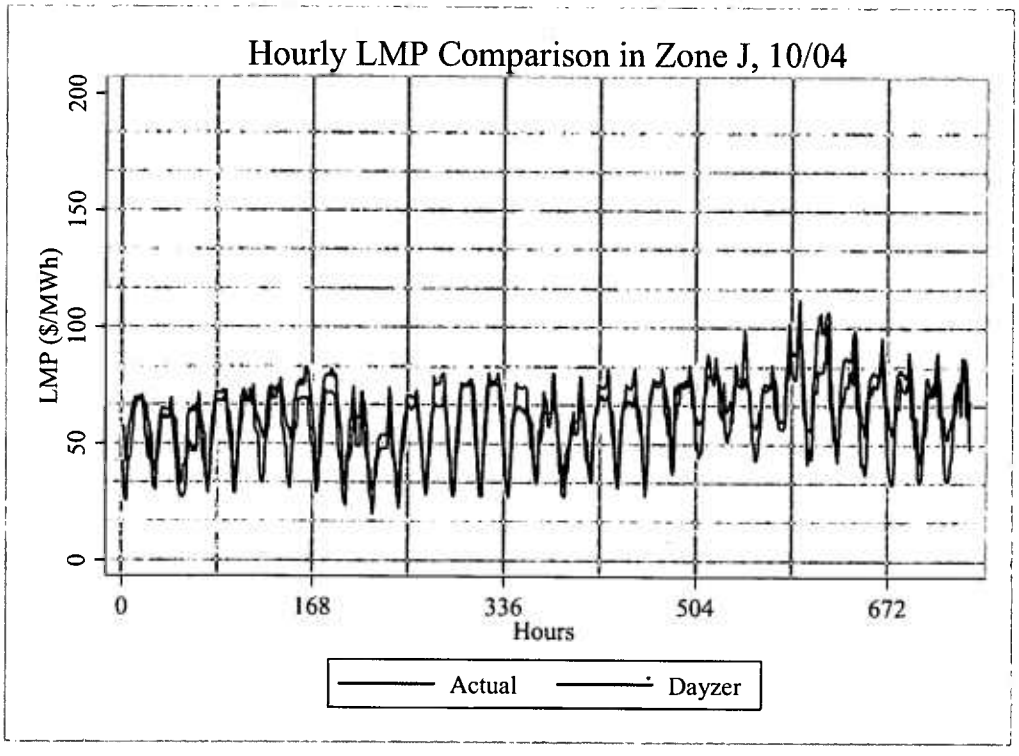

Hourly LMP Duration in Zone J, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

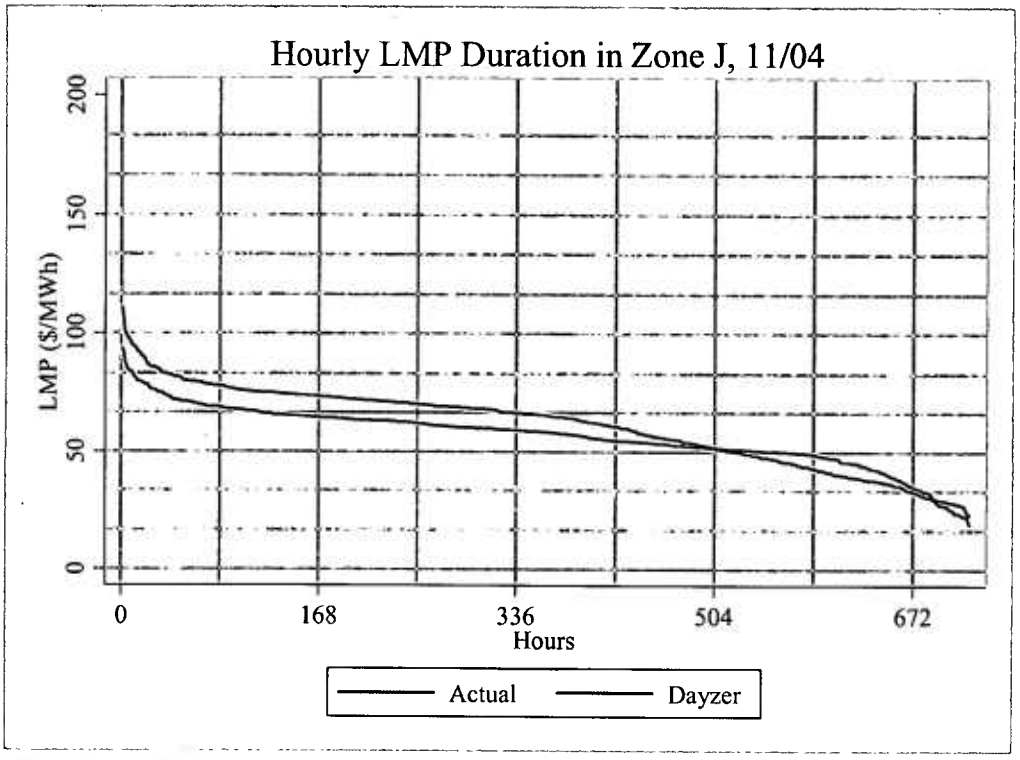

Hourly LMP Comparison in Zone J, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

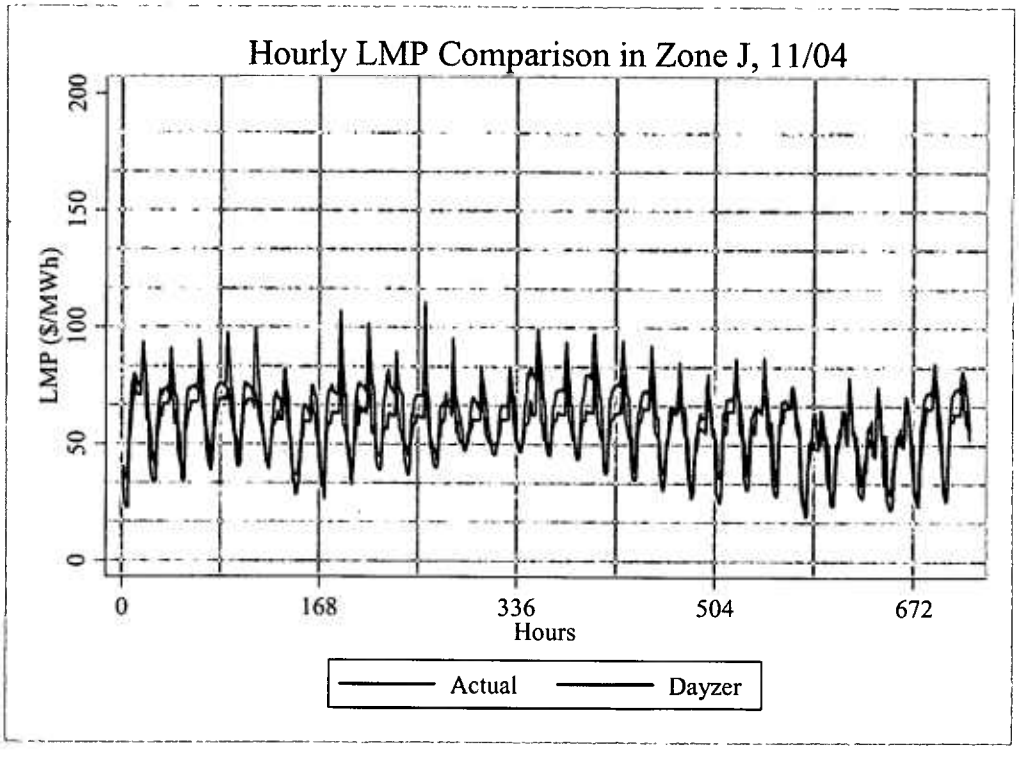

Hourly LMP Duration in Zone J, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

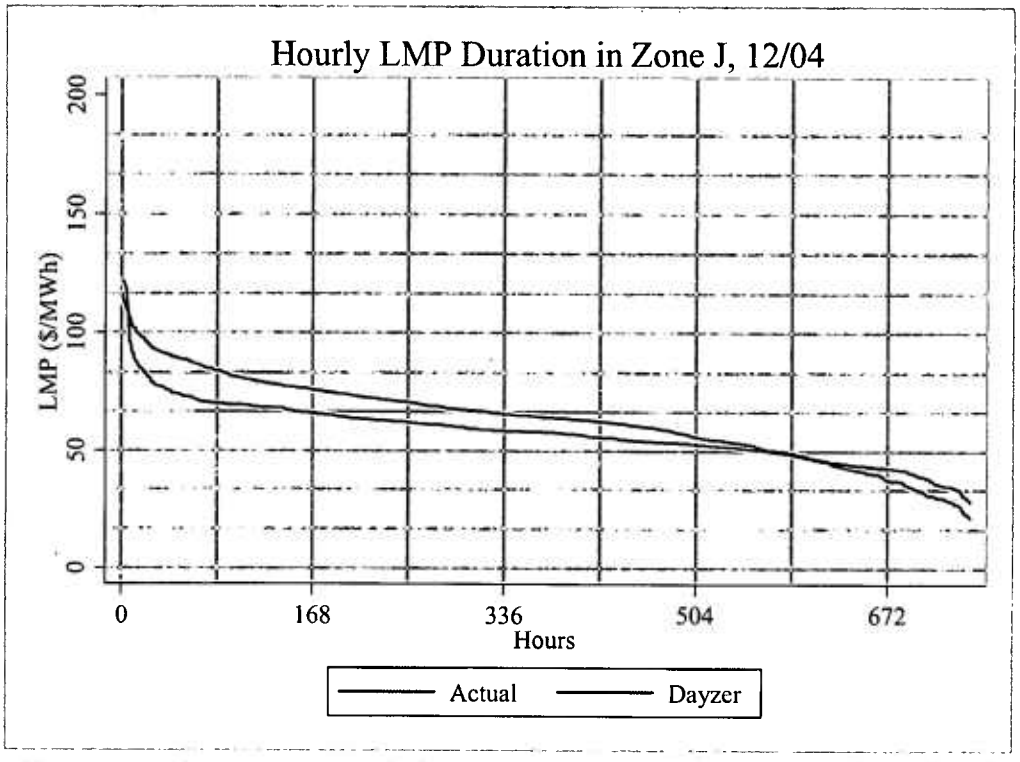

Hourly LMP Comparison in Zone J, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

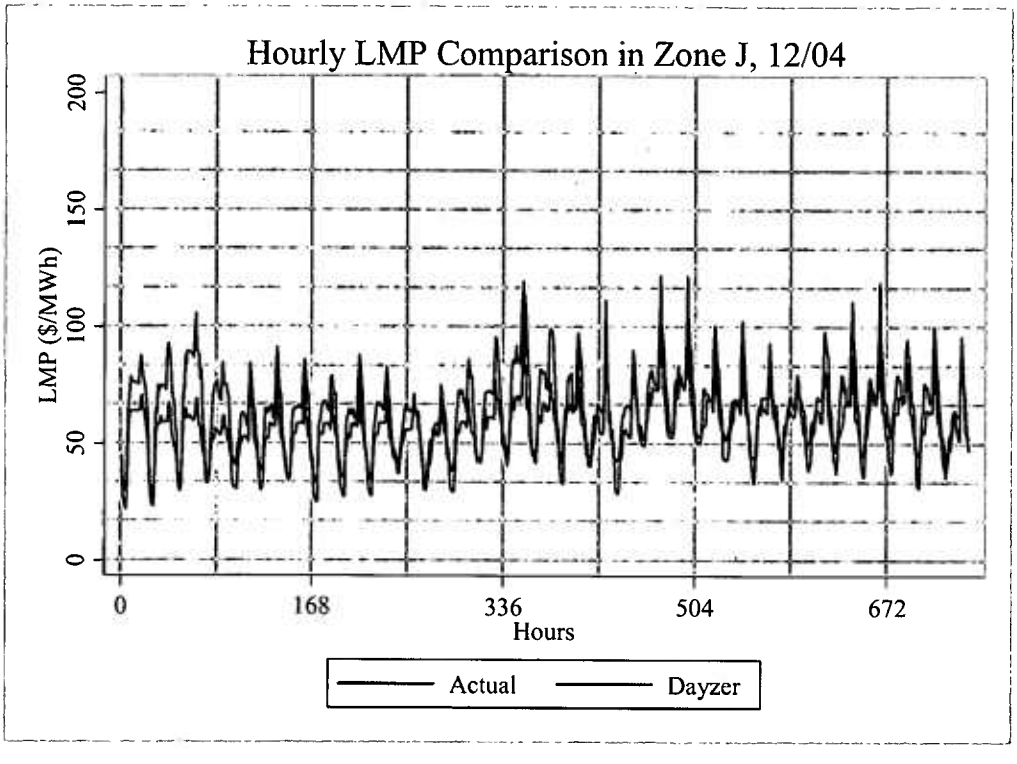

Hourly LMP Duration in Zone J, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

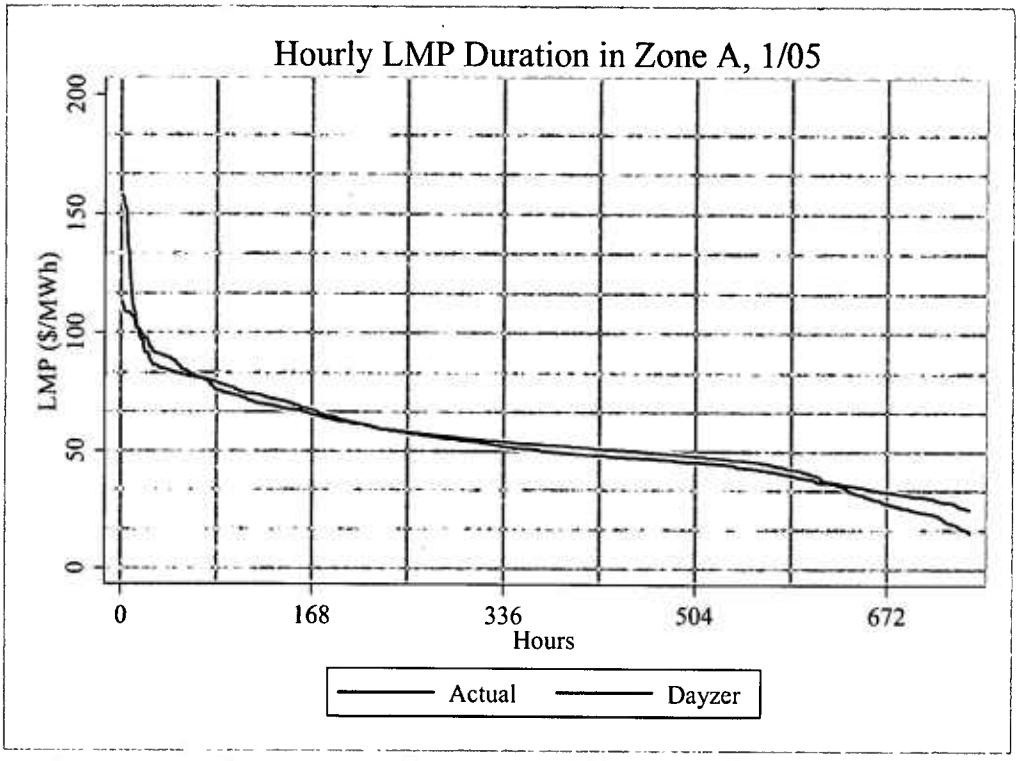

Hourly LMP Comparison in Zone J, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

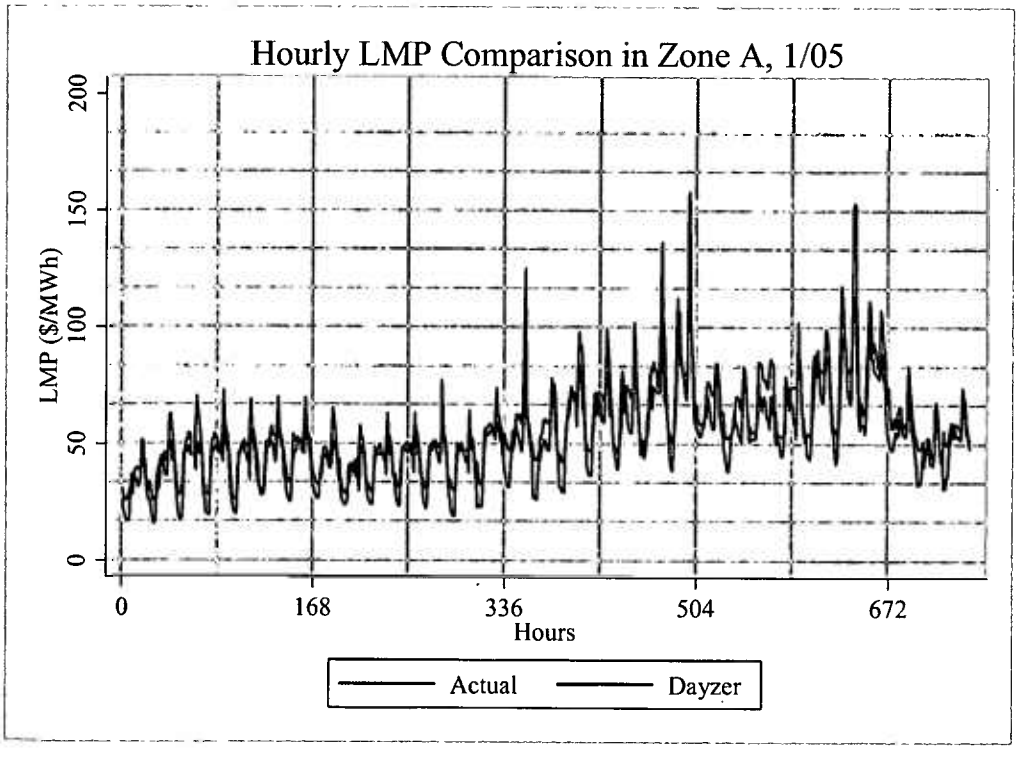

Hourly LMP Duration in Zone J, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

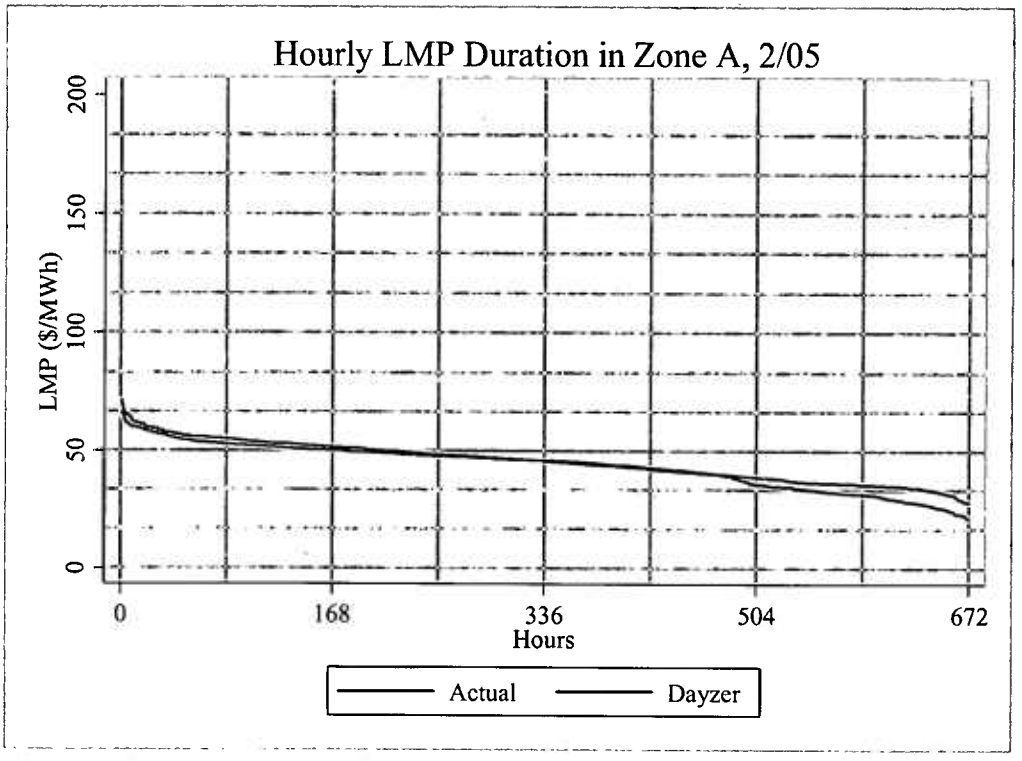

Hourly LMP Comparison in Zone J, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

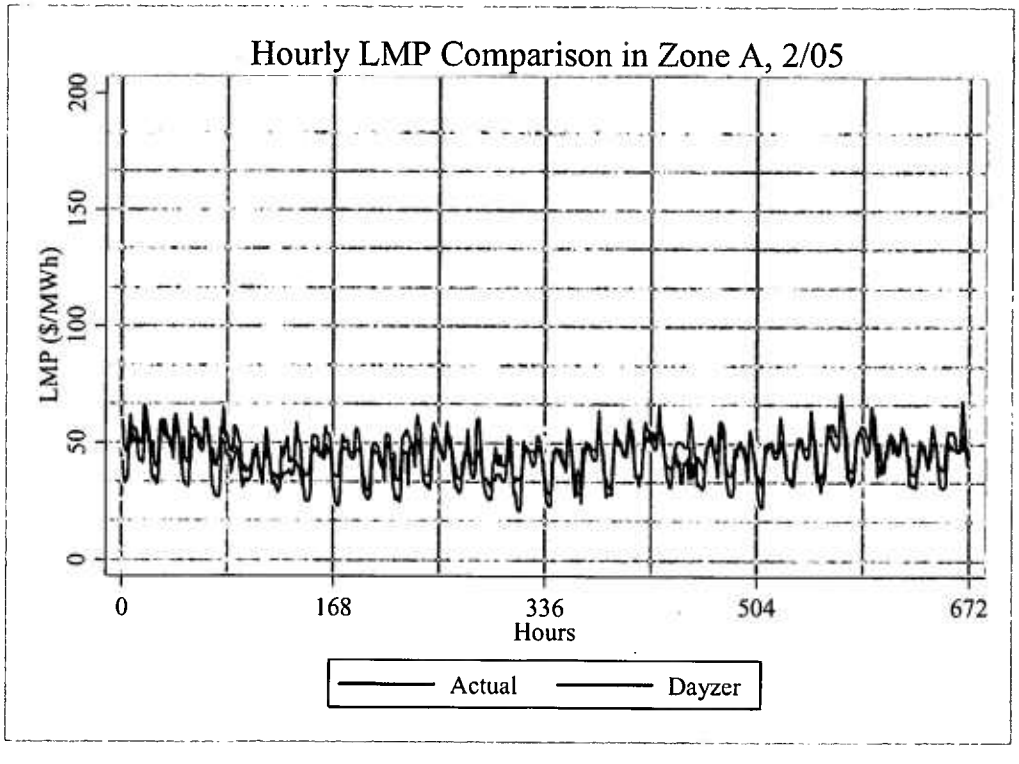

Hourly LMP Duration in Zone J, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

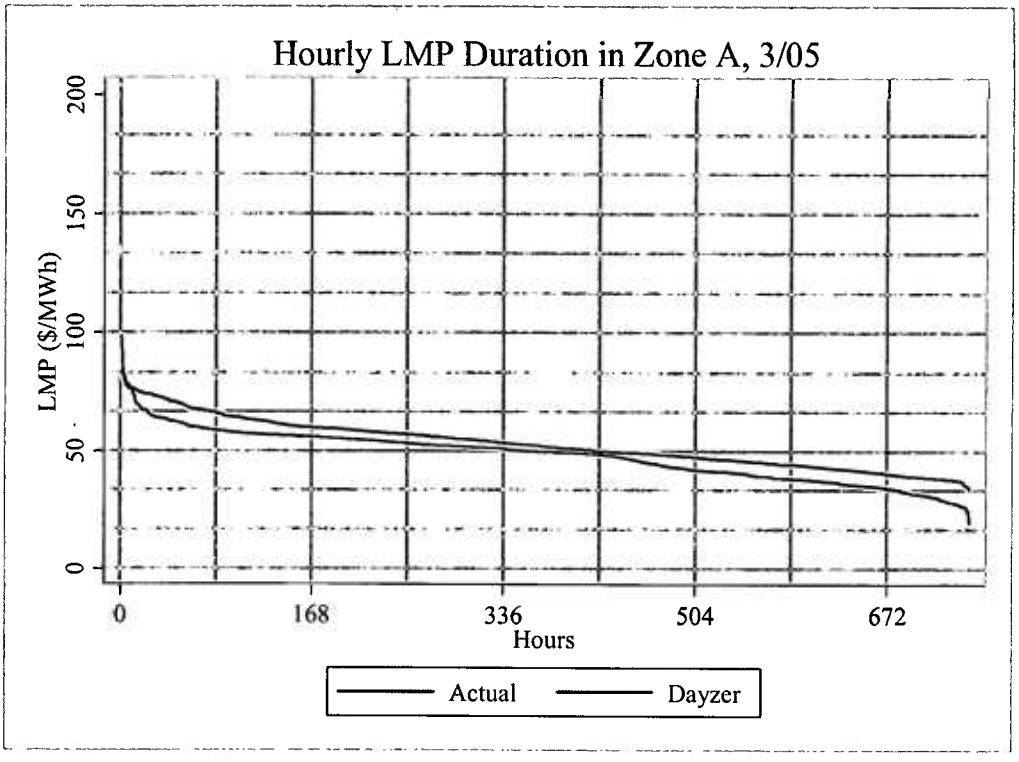

Hourly LMP Comparison in Zone J, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

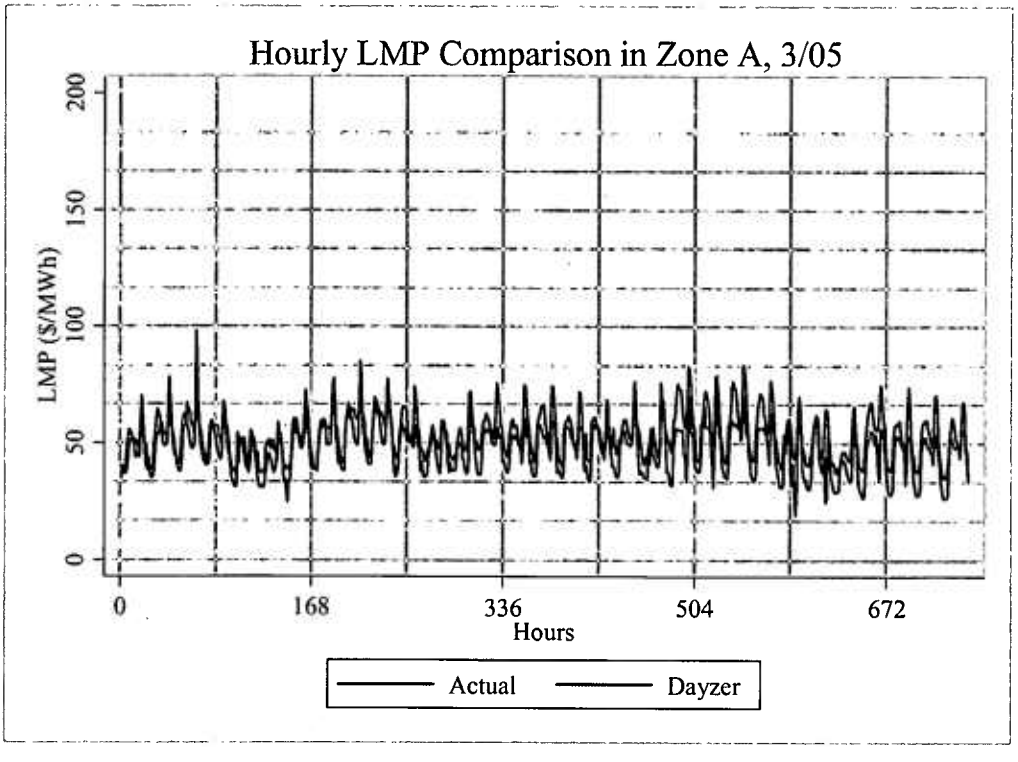

Hourly LMP Duration in Zone A, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

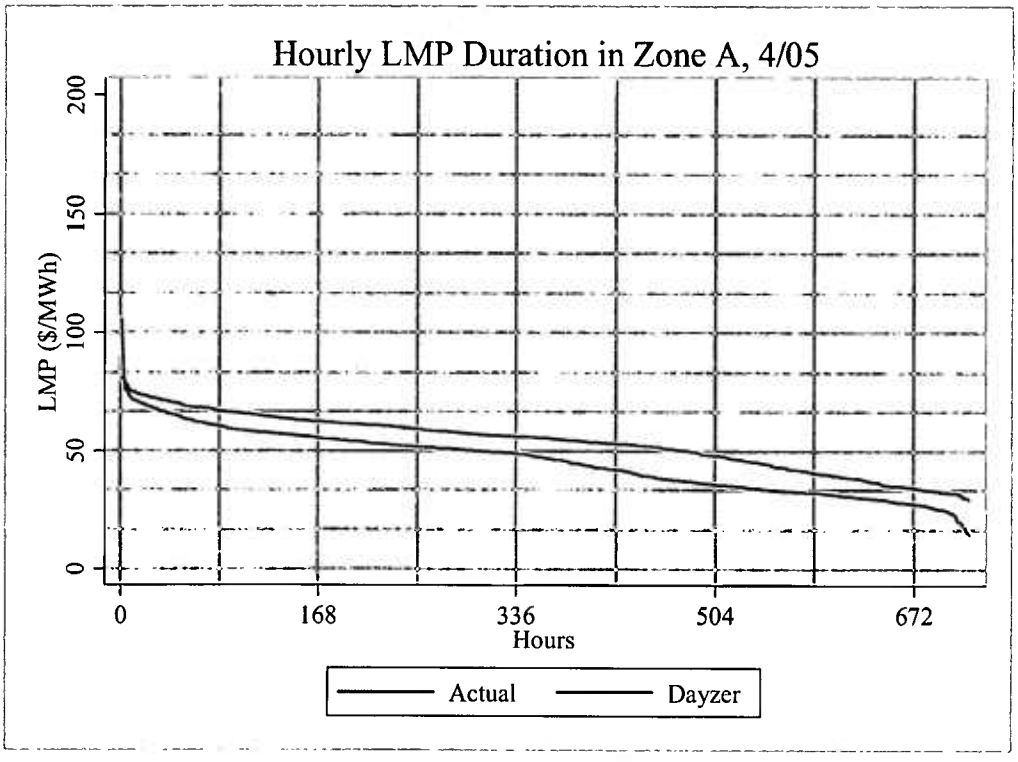

Hourly LMP Comparison in Zone A, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

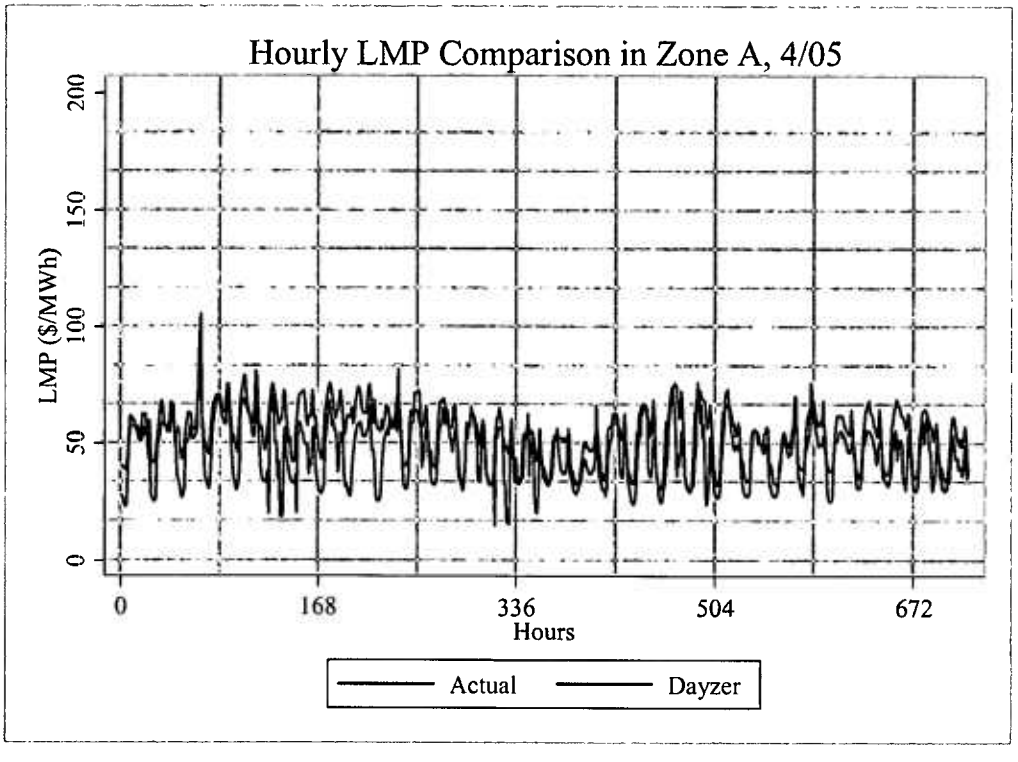

Hourly LMP Duration in Zone A, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

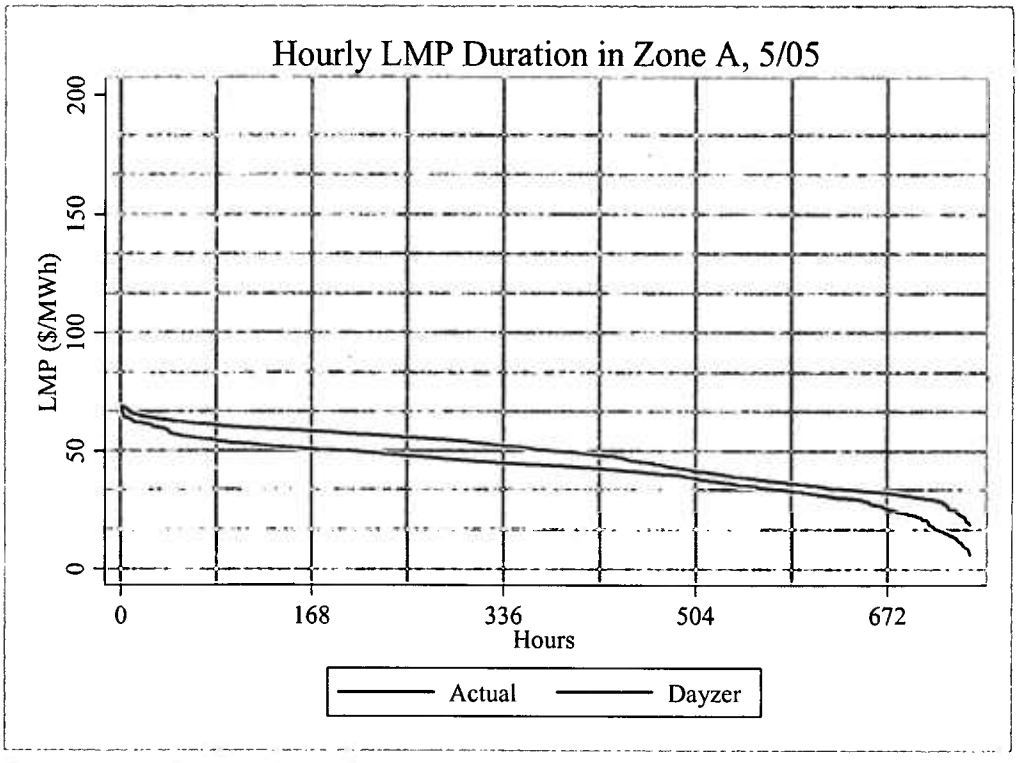

Hourly LMP Comparison in Zone A, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

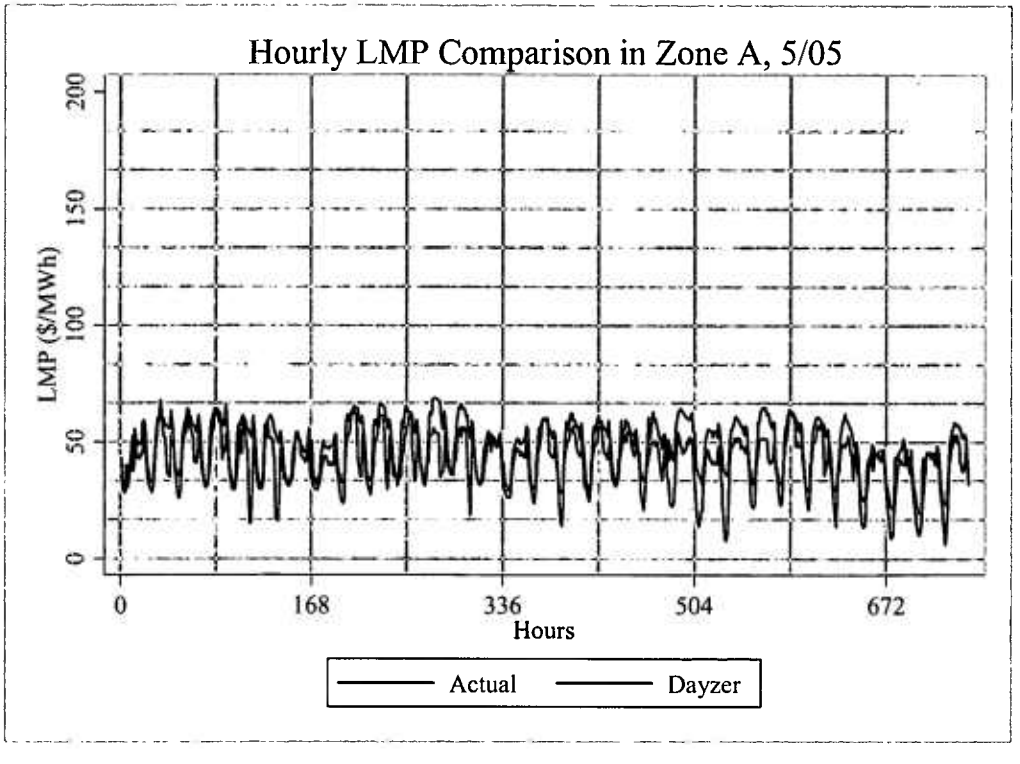

Hourly LMP Duration in Zone A, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

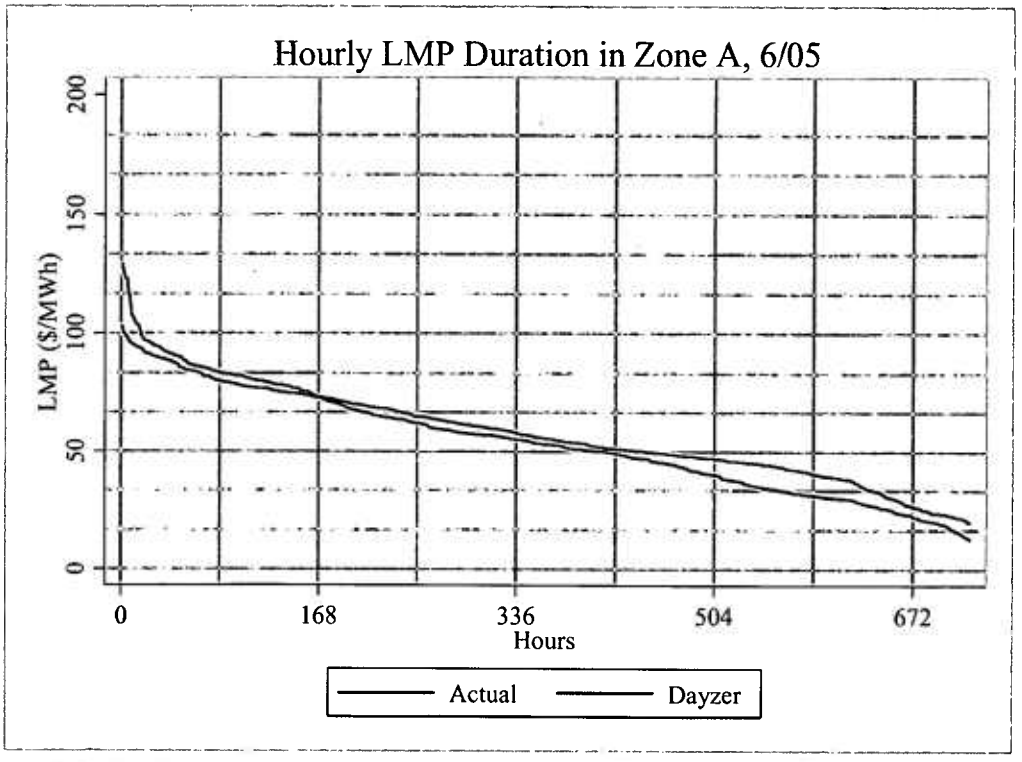

Hourly LMP Comparison in Zone A, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

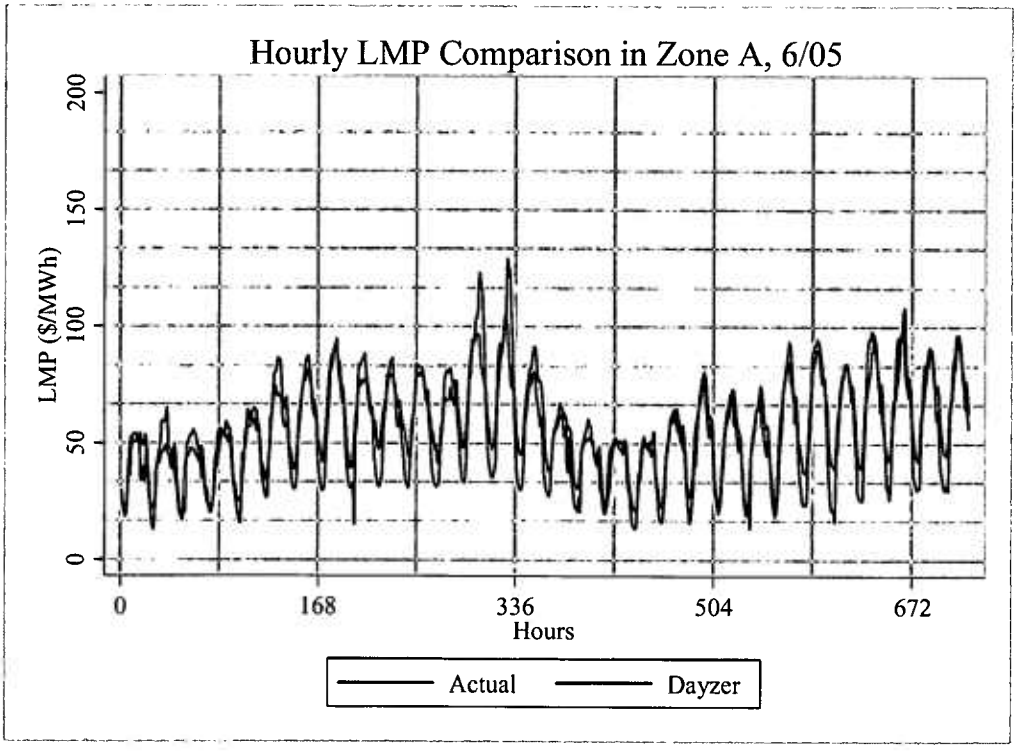

Hourly LMP Duration in Zone A, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

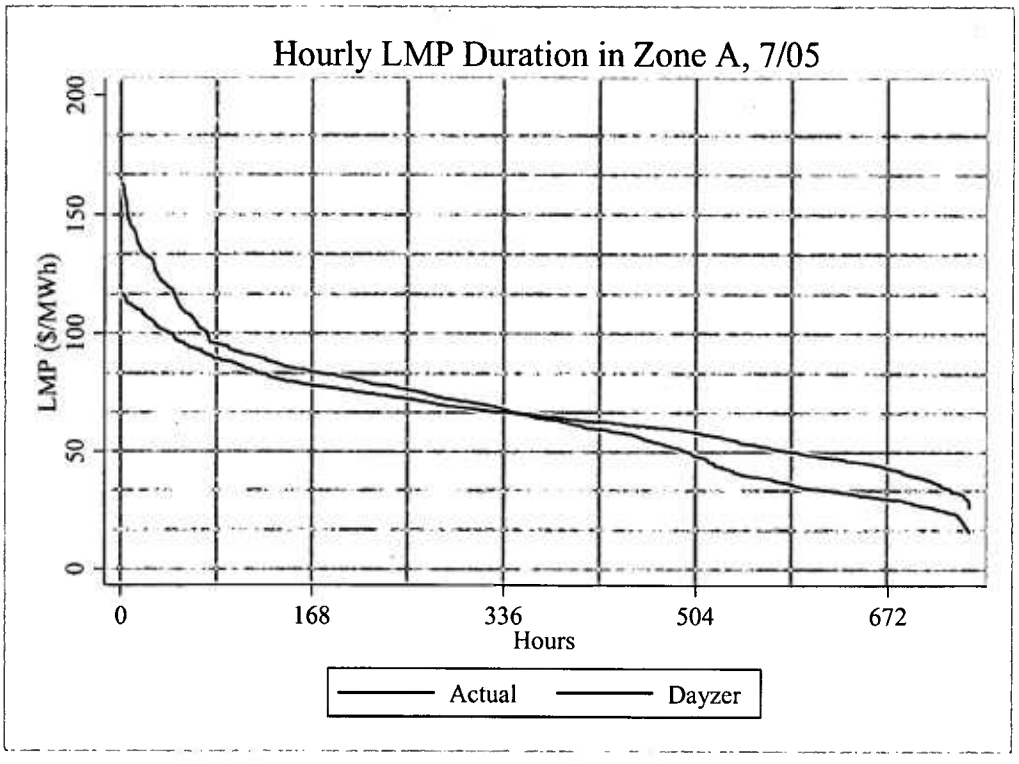

Hourly LMP Comparison in Zone A, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

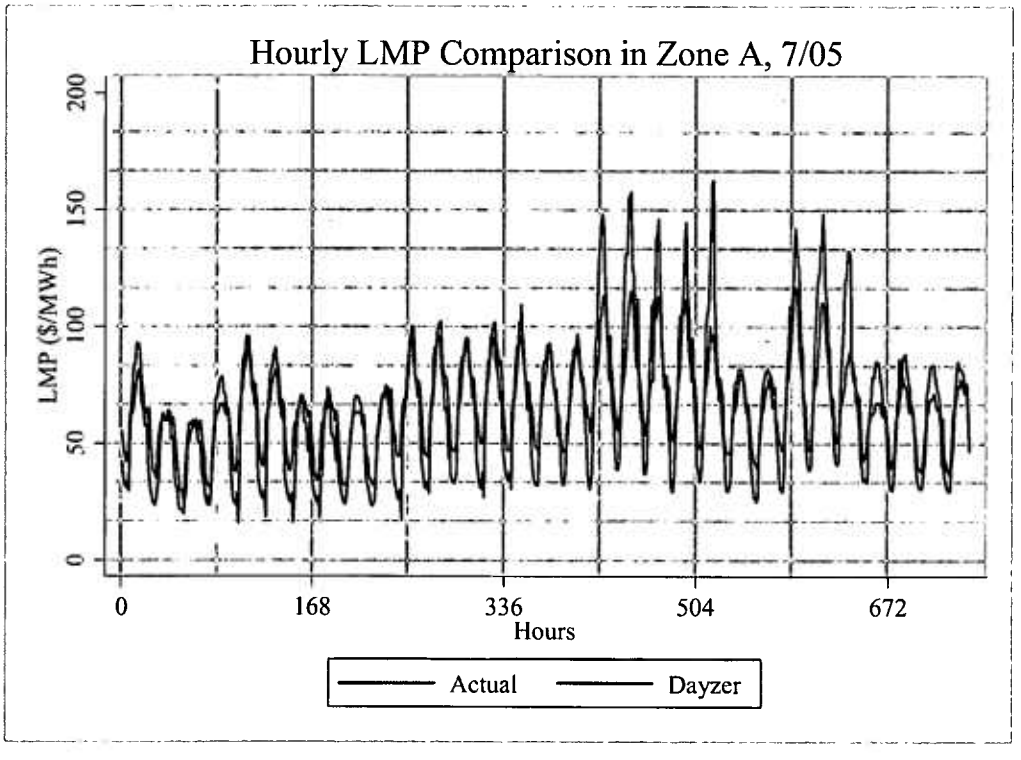

Hourly LMP Duration in Zone A, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

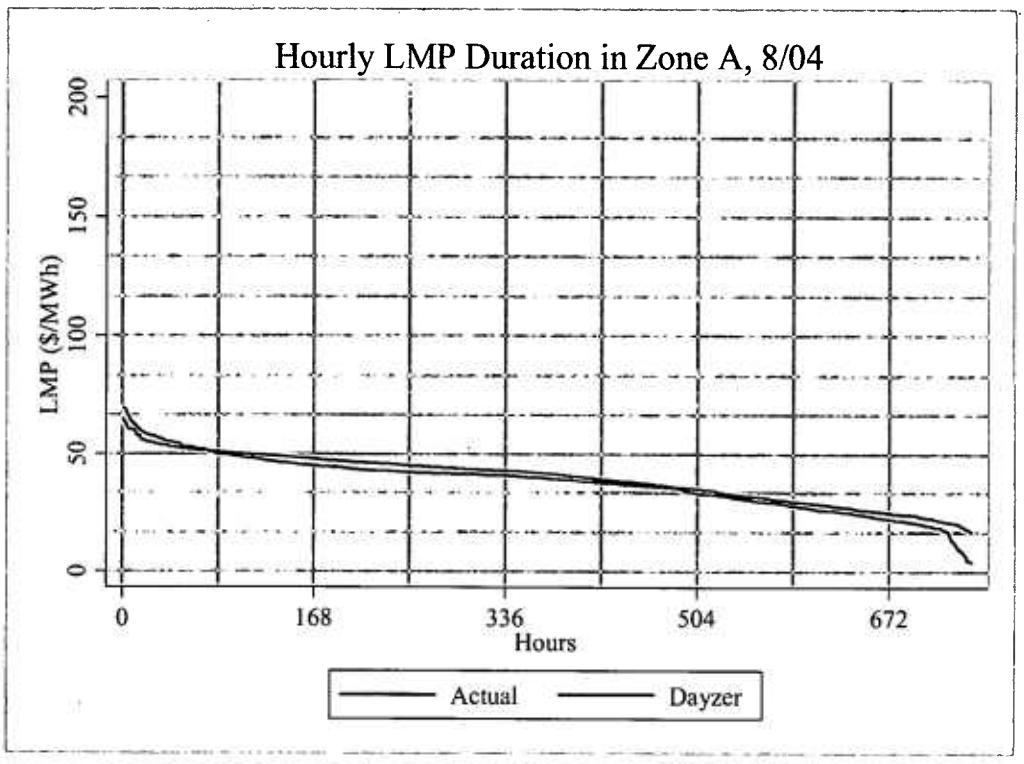

Hourly LMP Comparison in Zone A, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

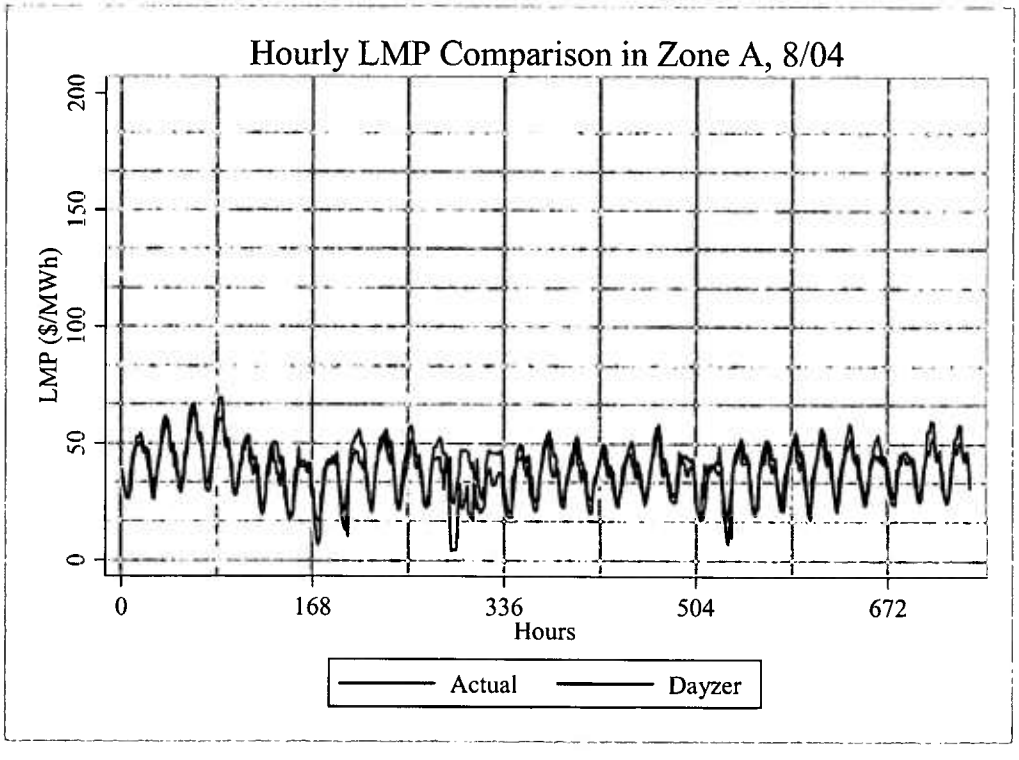

Hourly LMP Duration in Zone A, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

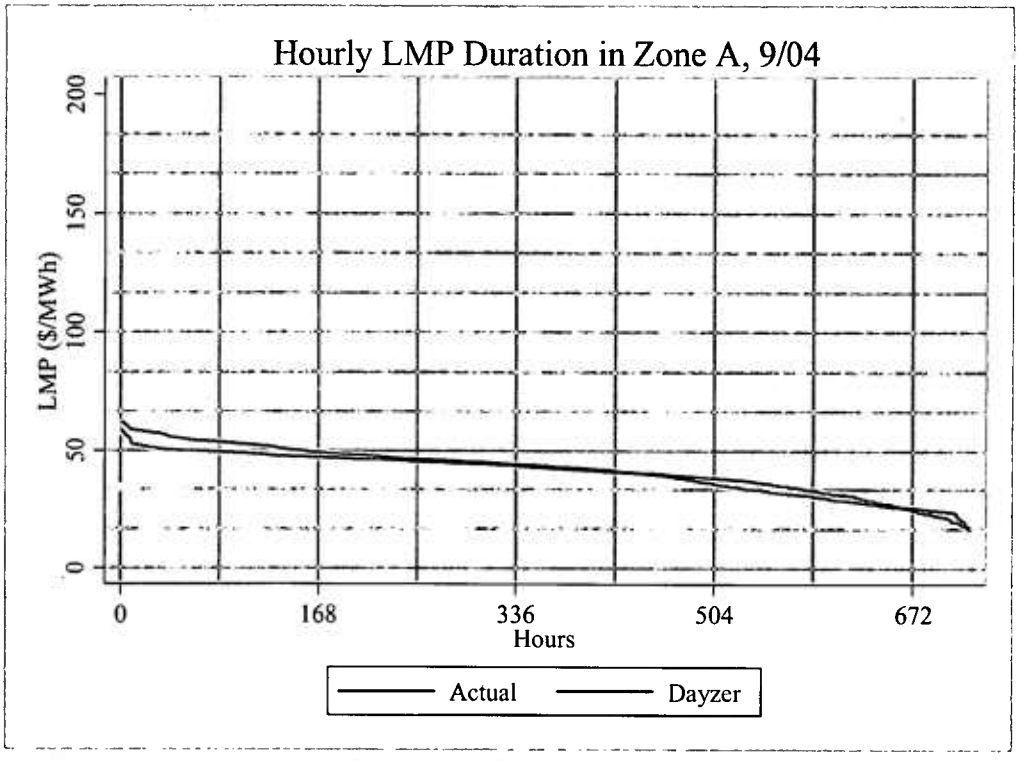

Hourly LMP Comparison in Zone A, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

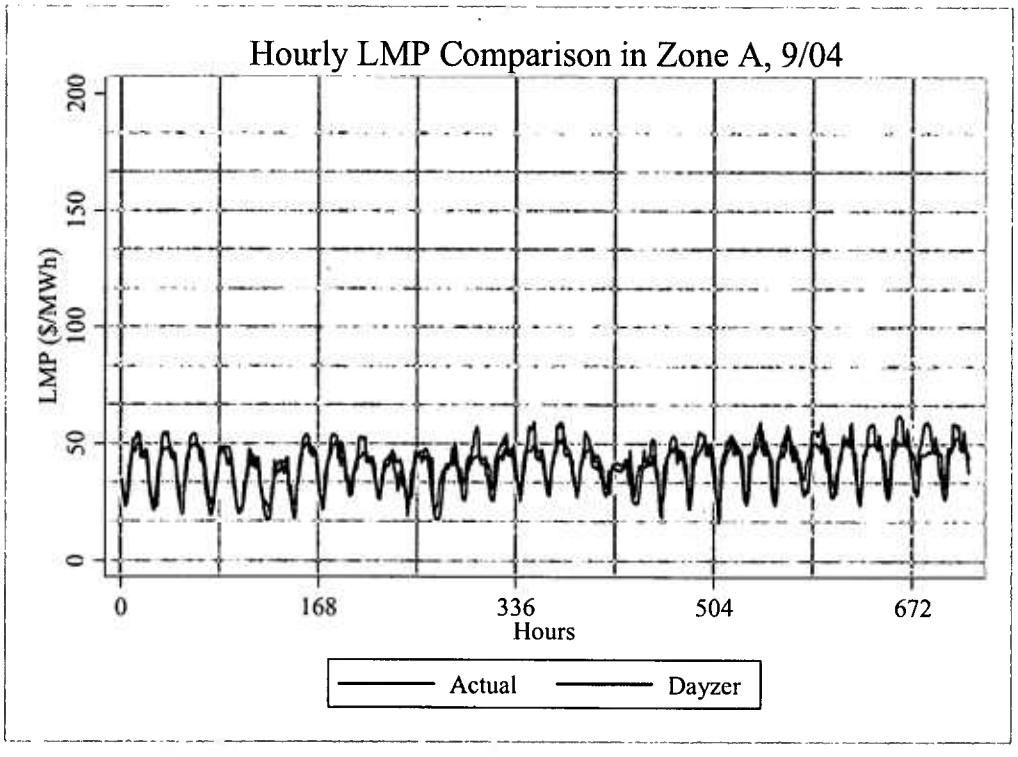

Hourly LMP Duration in Zone A, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

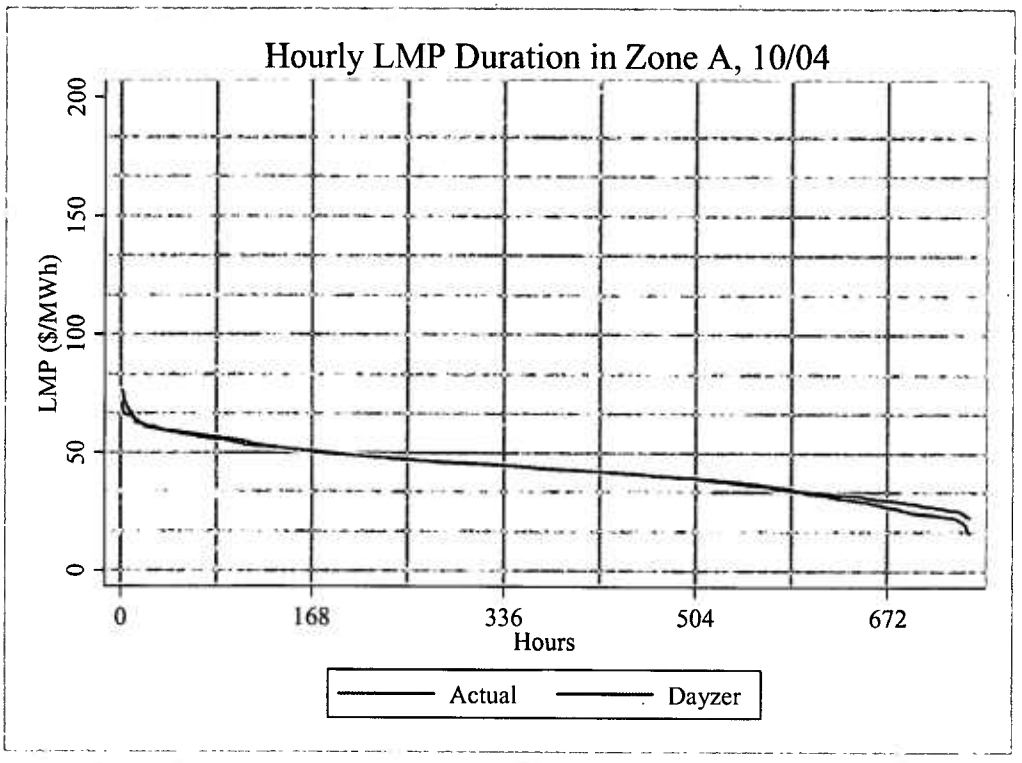

Hourly LMP Comparison in Zone A, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

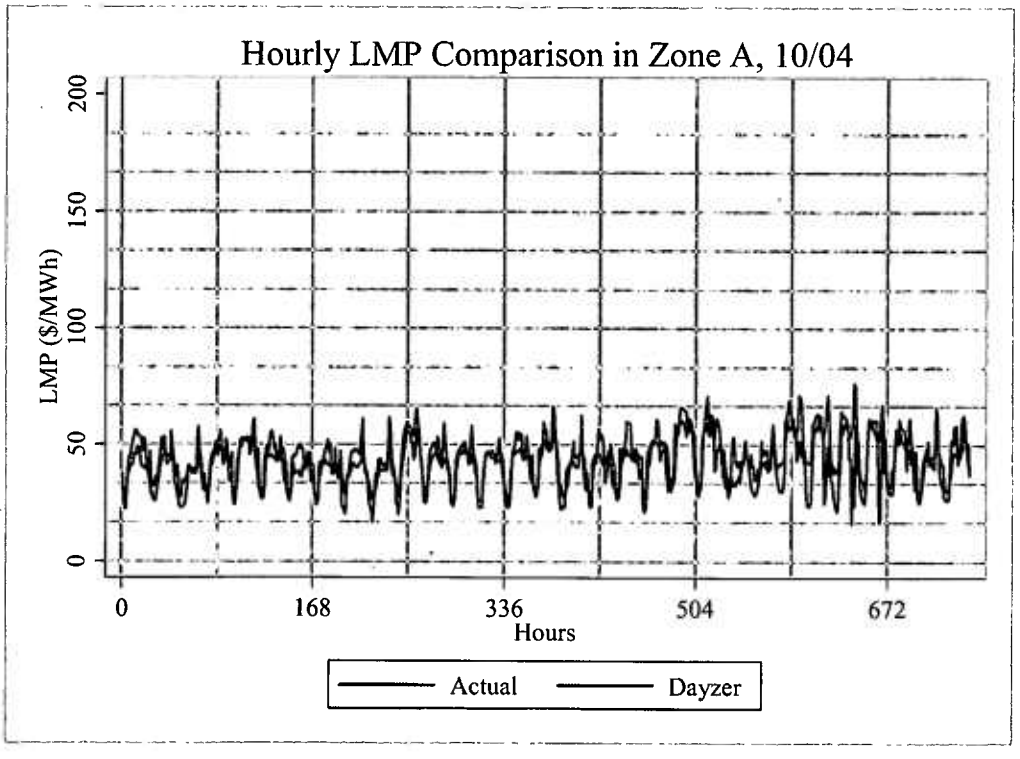

Hourly LMP Duration in Zone A, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

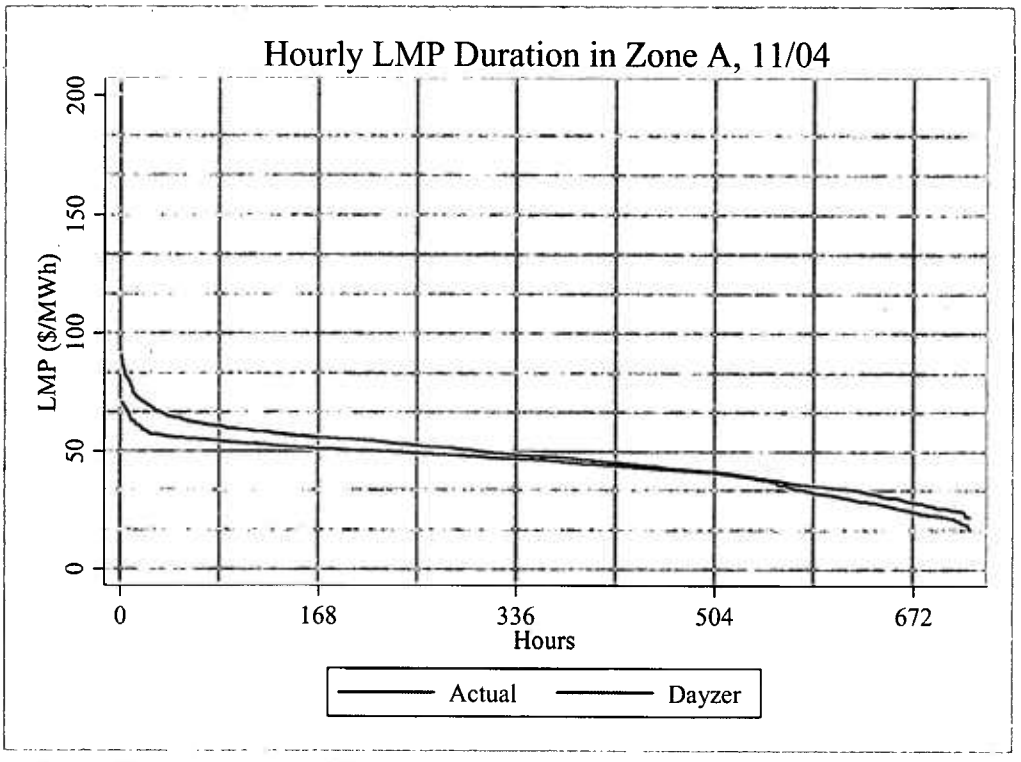

Hourly LMP Comparison in Zone A, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

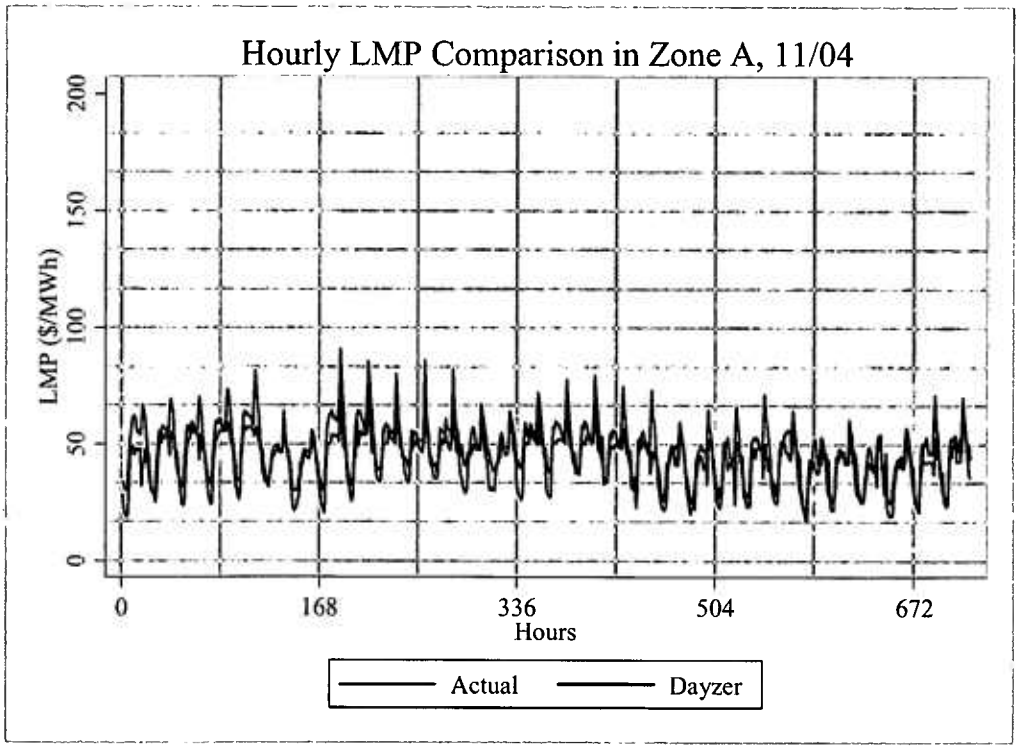

Hourly LMP Duration in Zone A, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

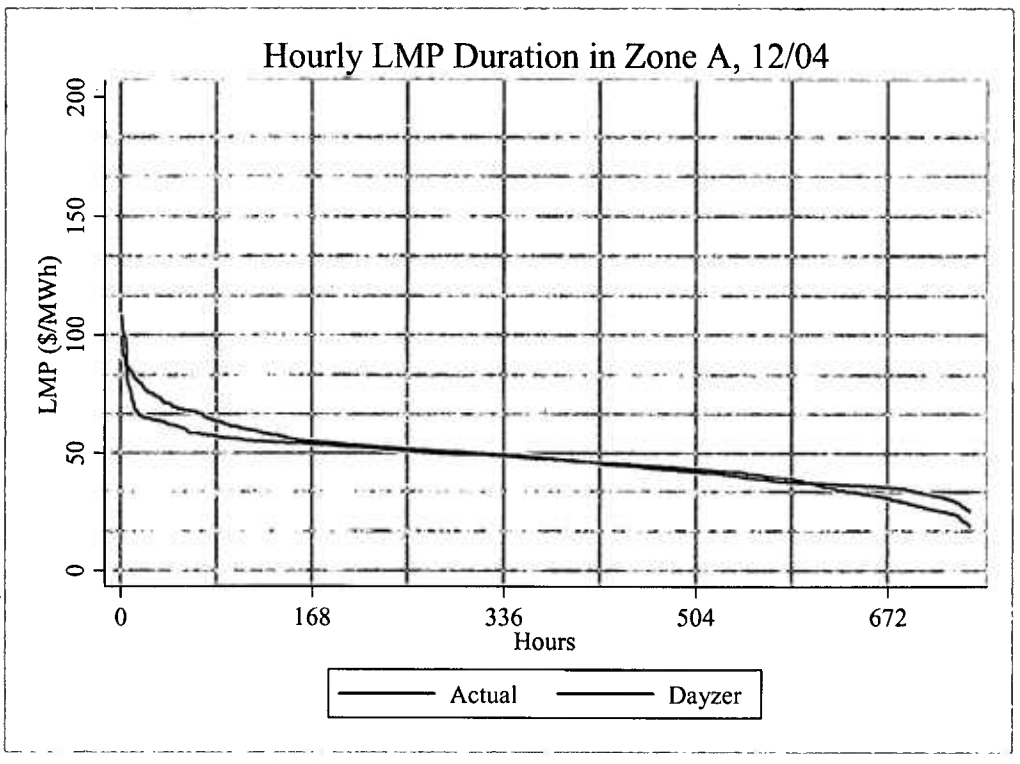

Hourly LMP Comparison in Zone A, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

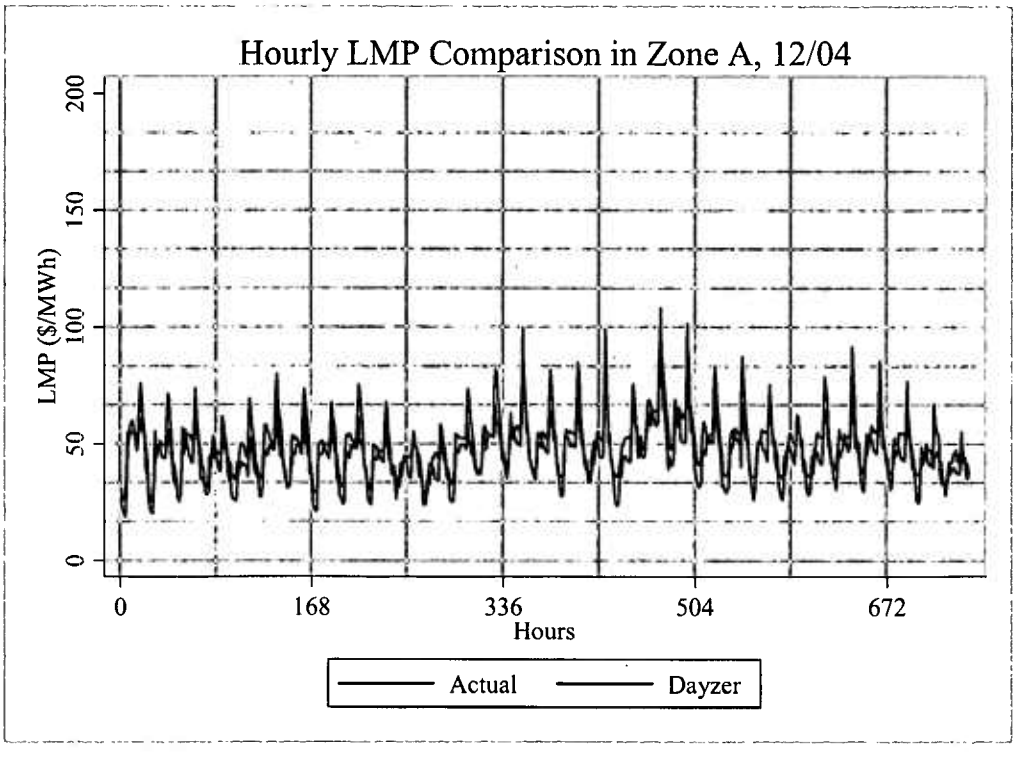

Hourly LMP Duration in Zone A, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

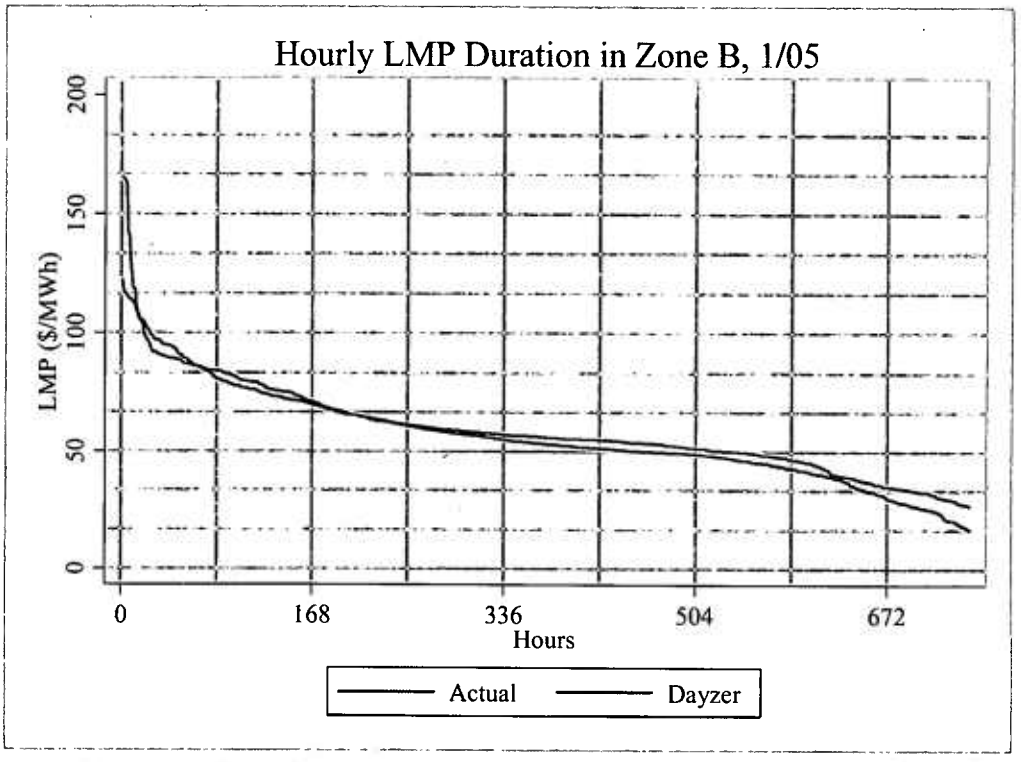

Hourly LMP Comparison in Zone A, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

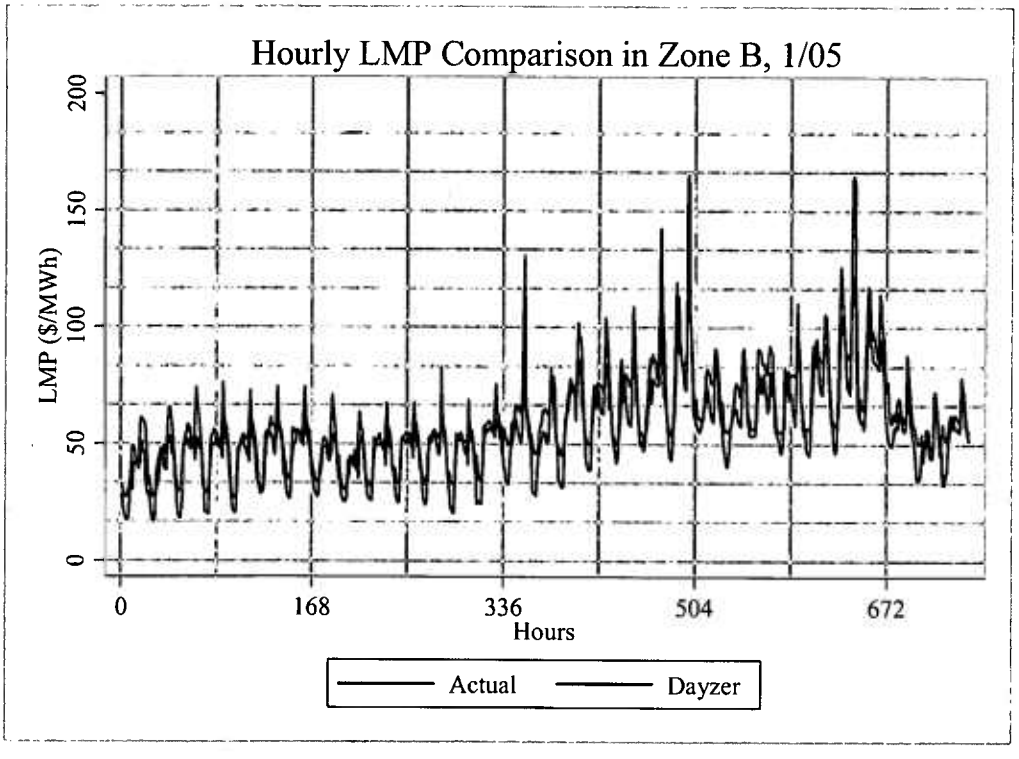

Hourly LMP Duration in Zone A, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

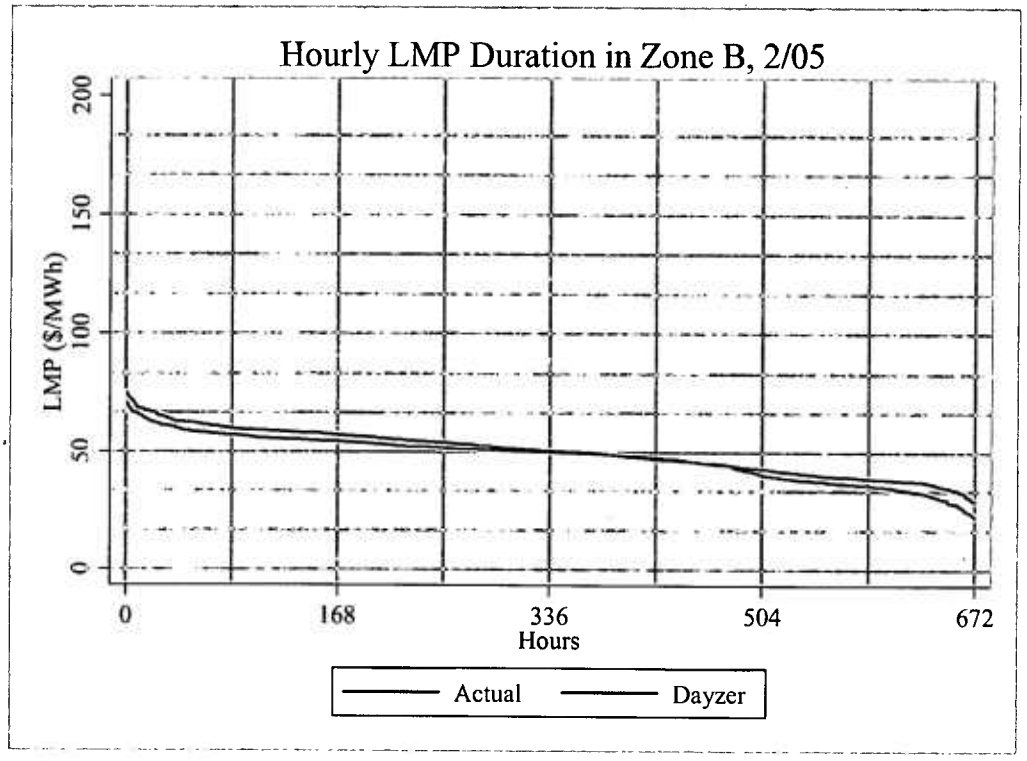

Hourly LMP Comparison in Zone A, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

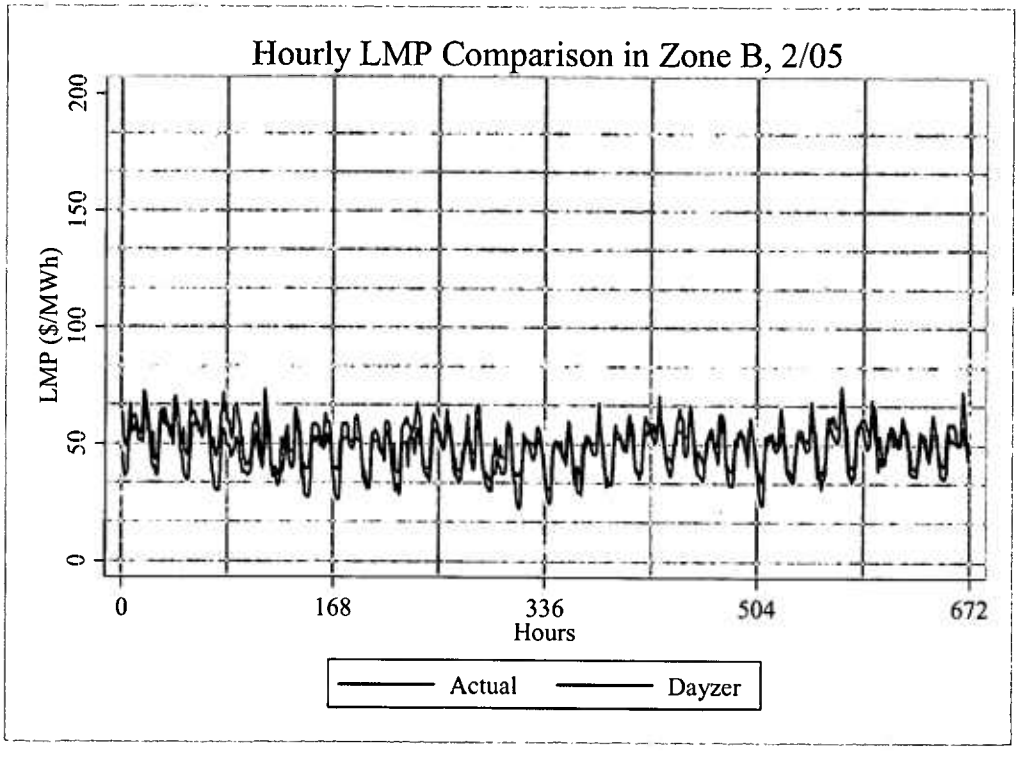

Hourly LMP Duration in Zone A, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

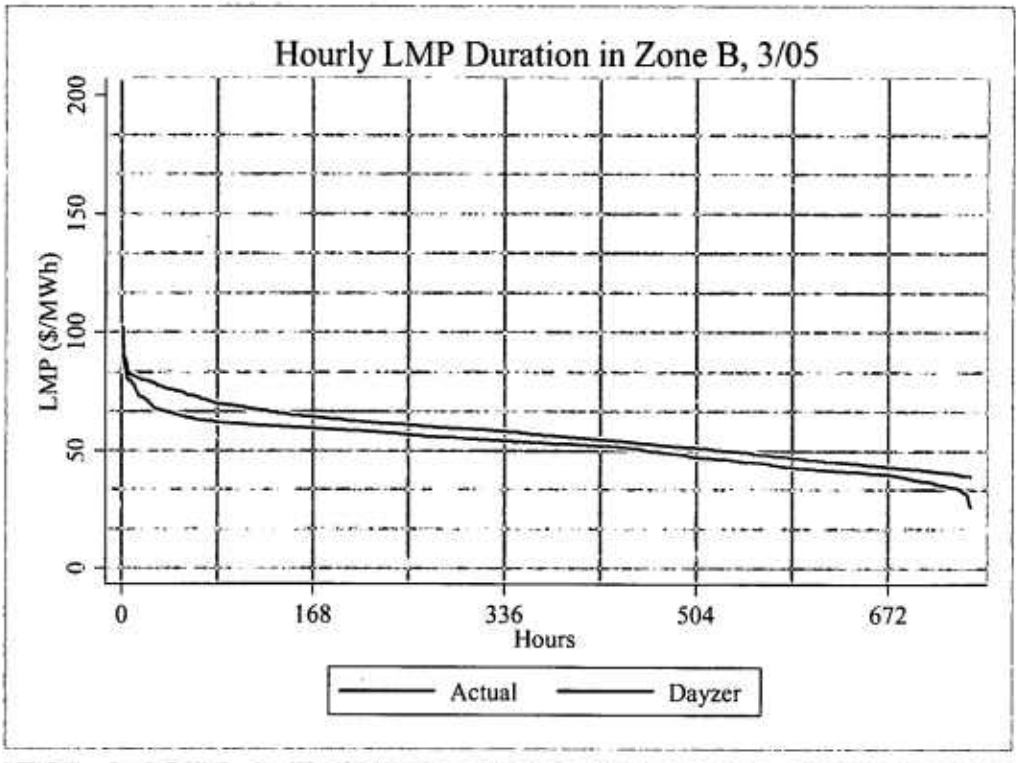

Hourly LMP Comparison in Zone A, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

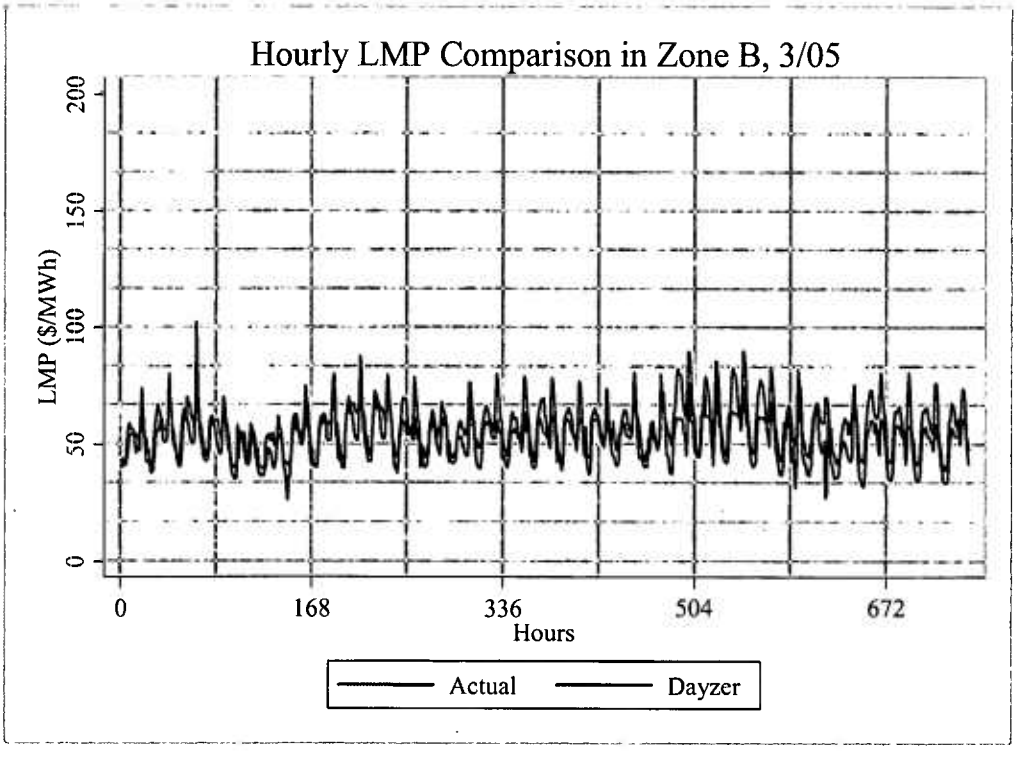

Hourly LMP Duration in Zone B, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

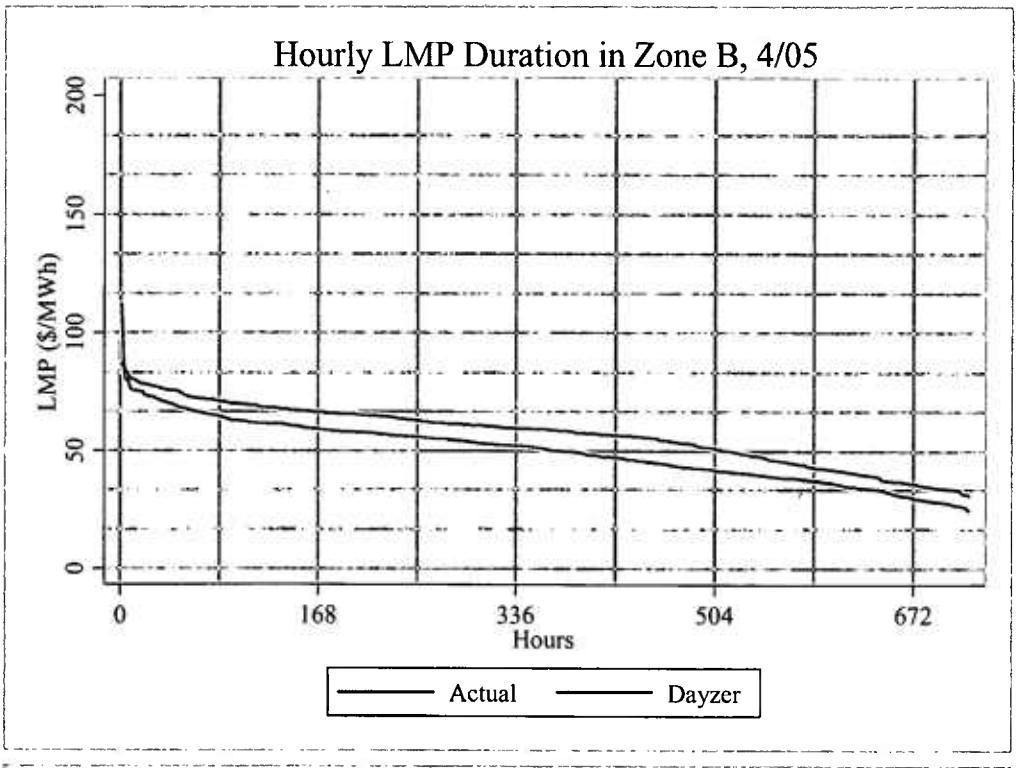

Hourly LMP Comparison in Zone B, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

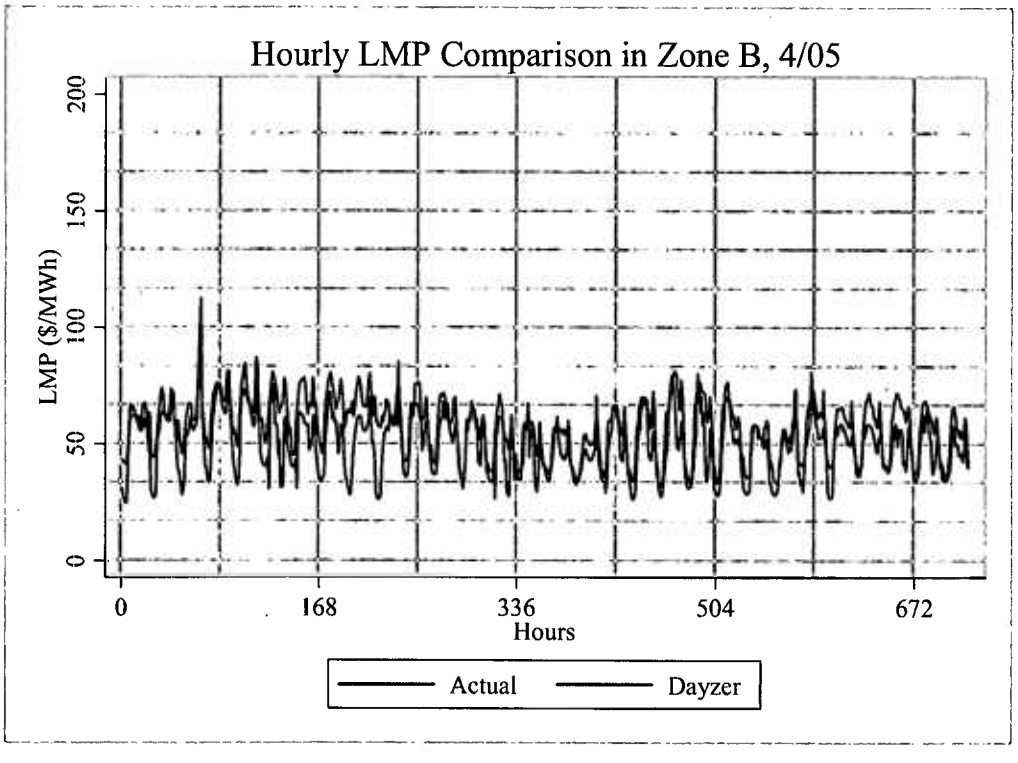

Hourly LMP Duration in Zone B, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

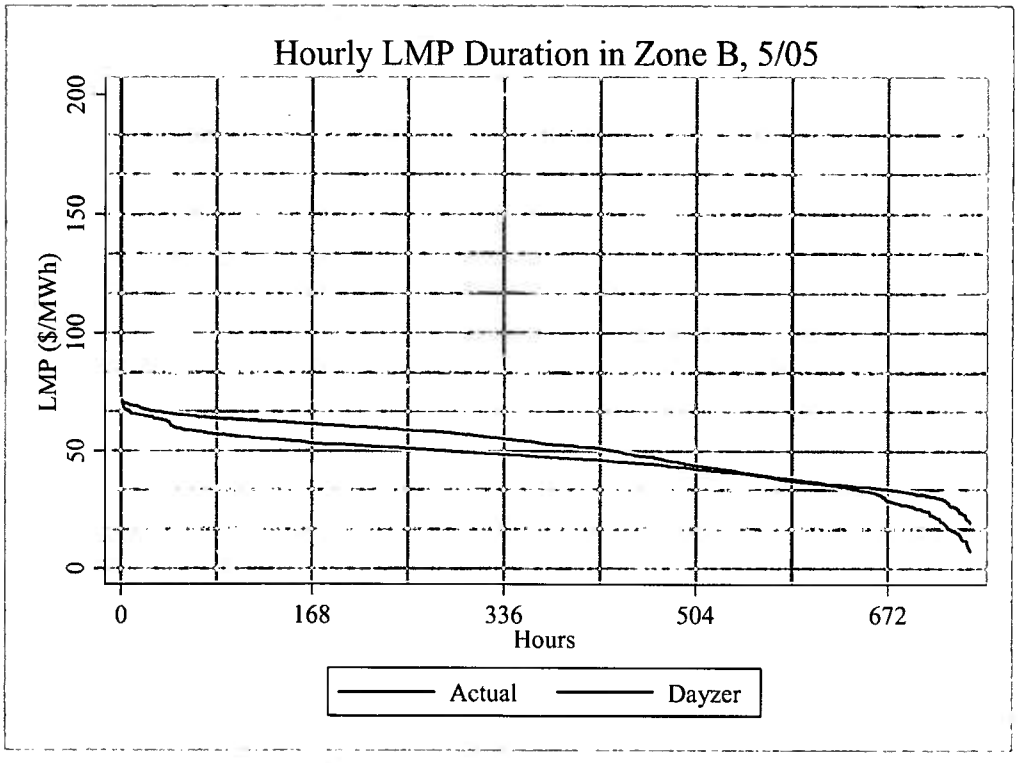

Hourly LMP Comparison in Zone B, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

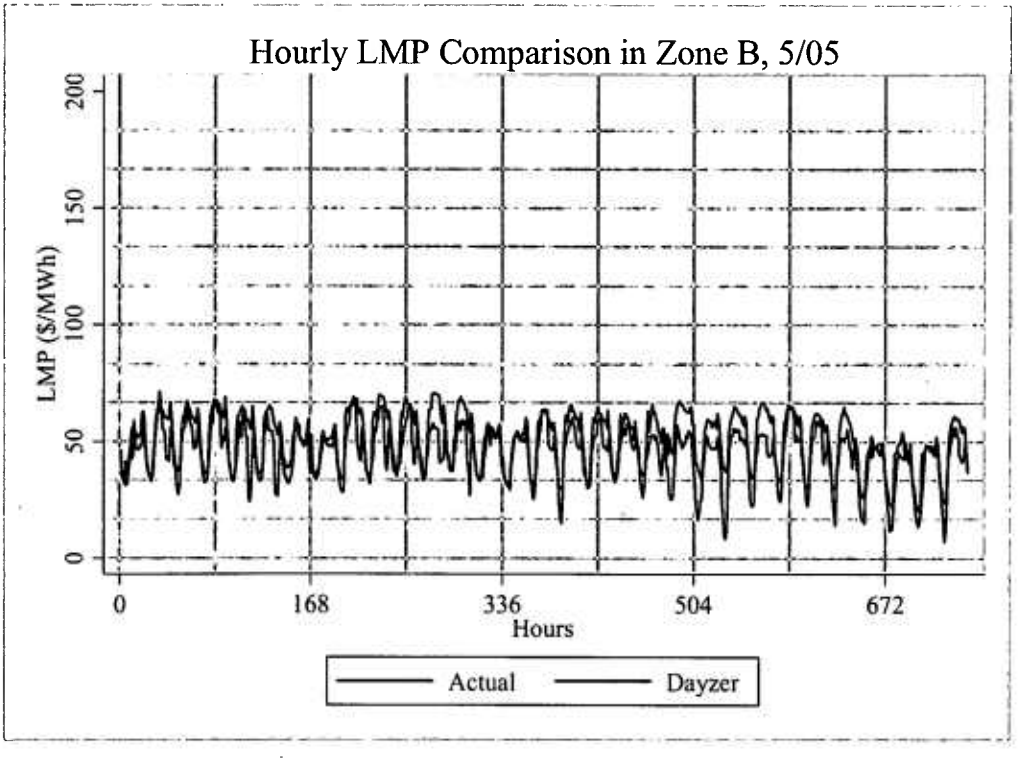

Hourly LMP Duration in Zone B, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

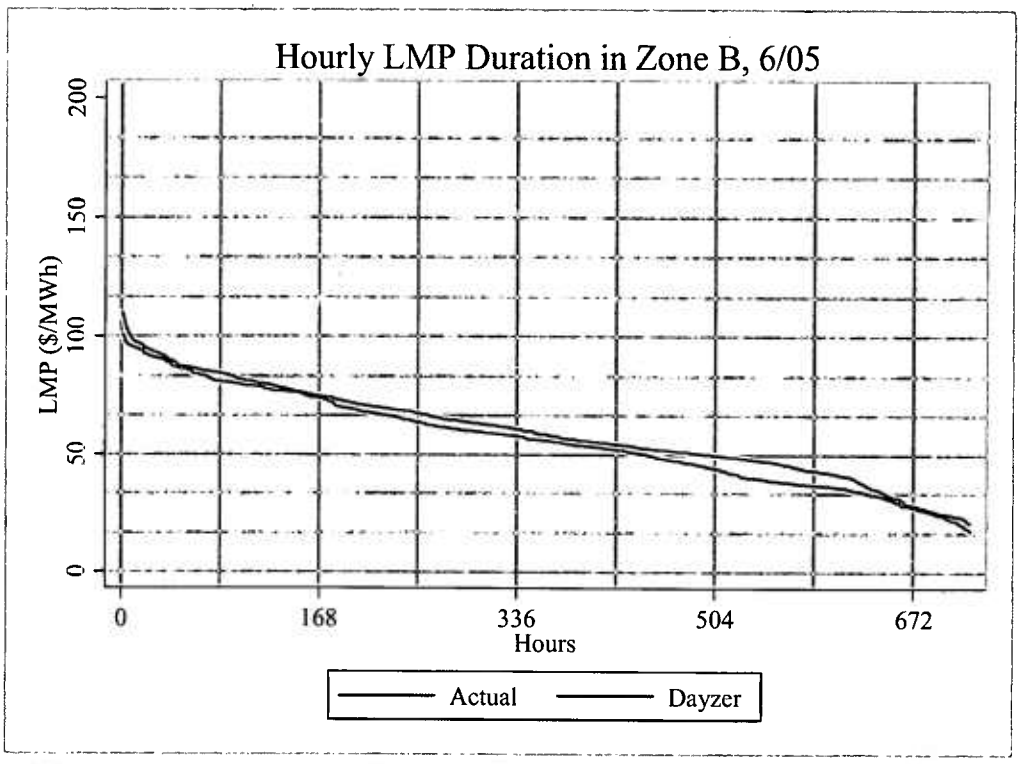

Hourly LMP Comparison in Zone B, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

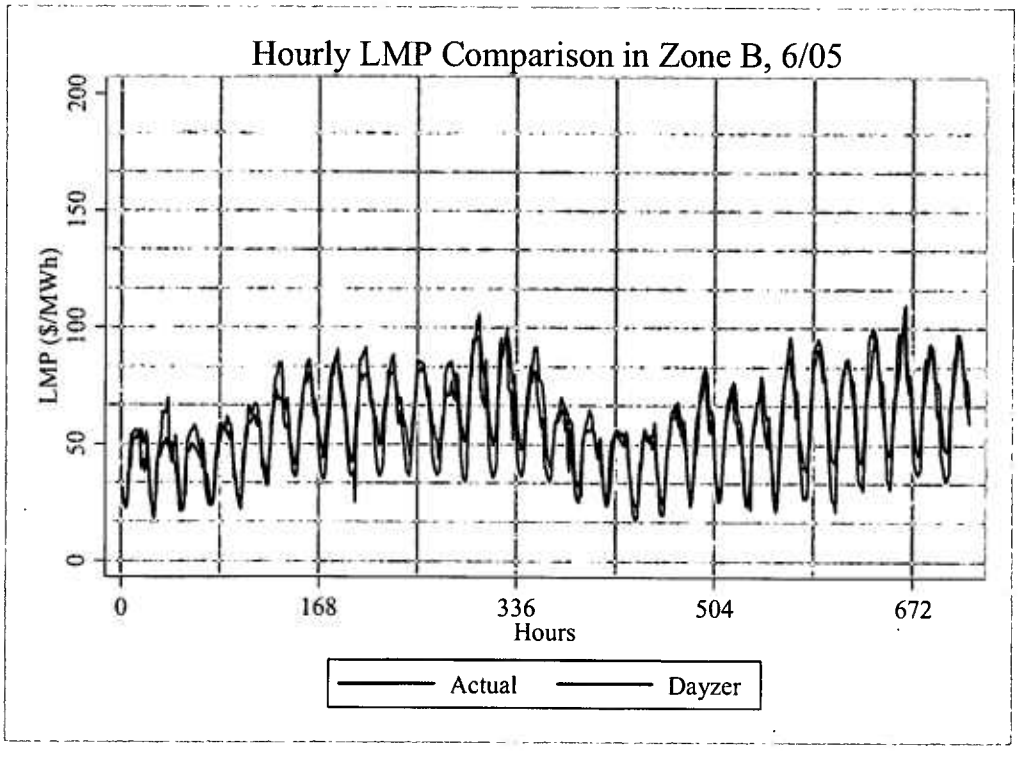

Hourly LMP Duration in Zone B, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

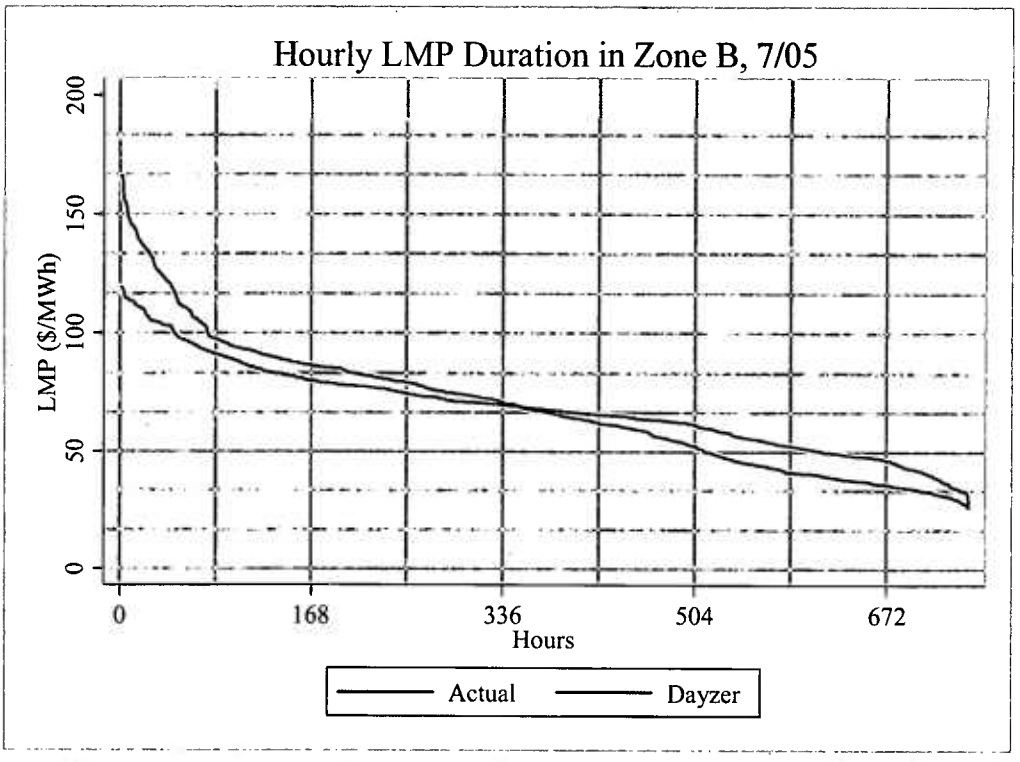

Hourly LMP Comparison in Zone B, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

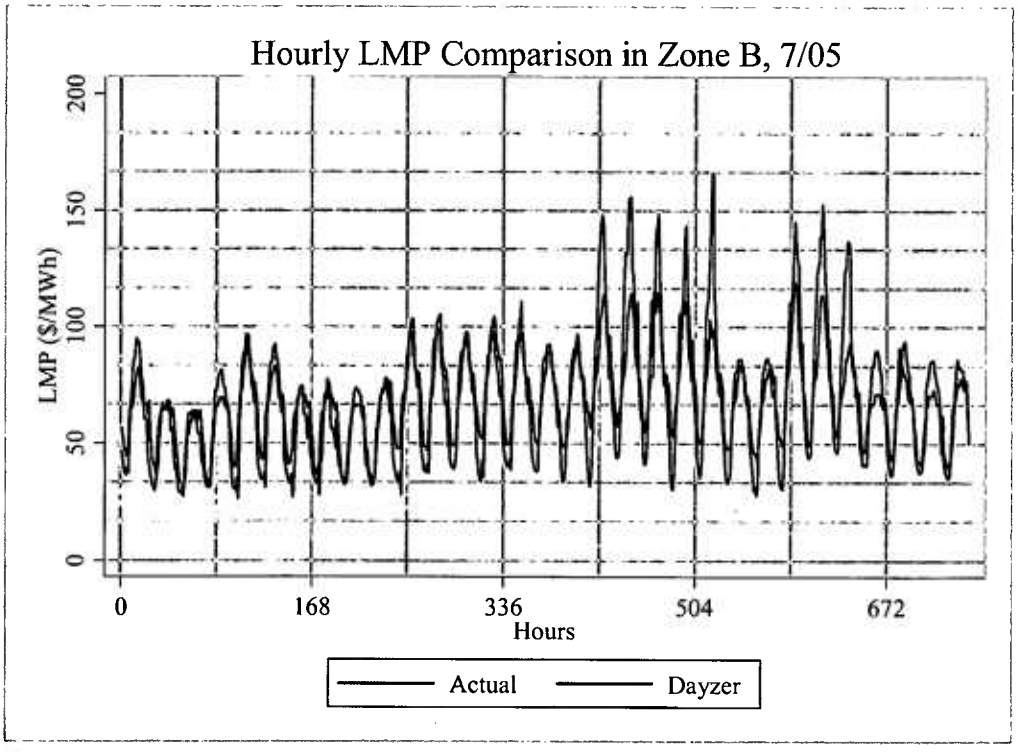

Hourly LMP Duration in Zone B, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

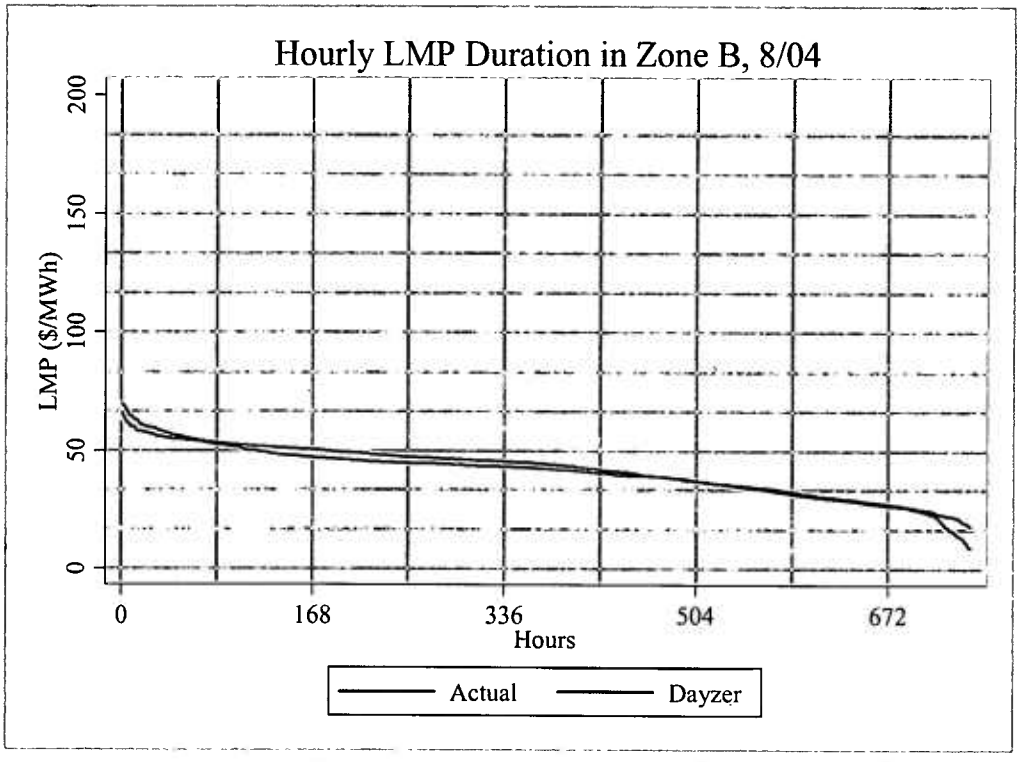

Hourly LMP Comparison in Zone B, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

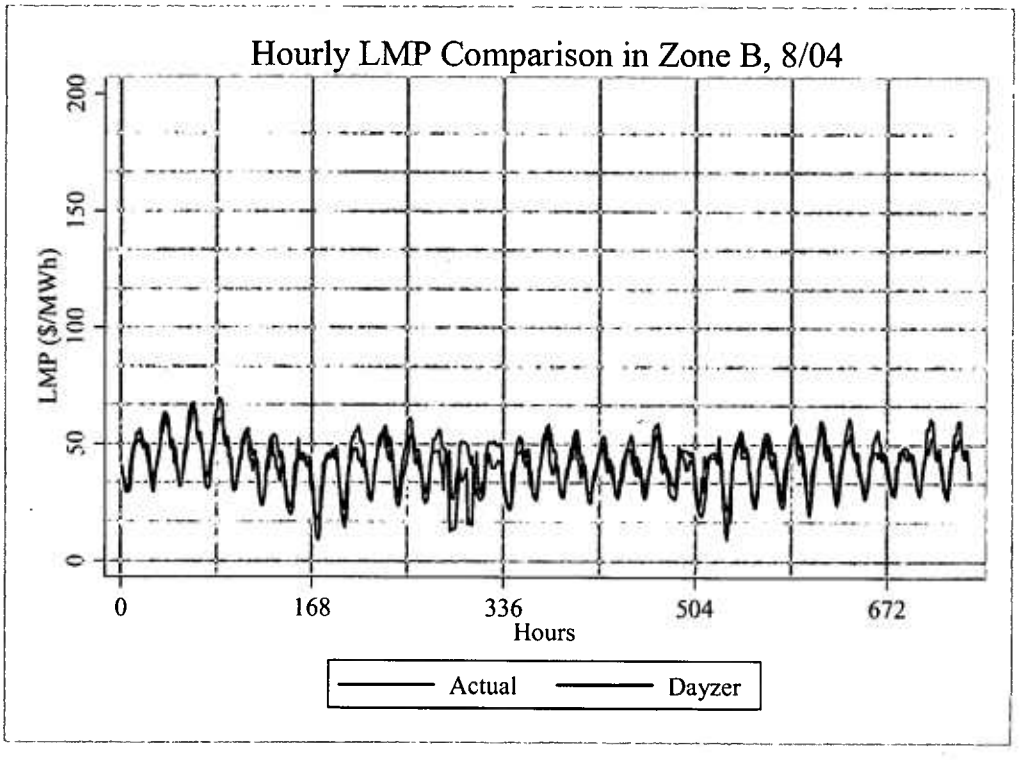

Hourly LMP Duration in Zone B, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

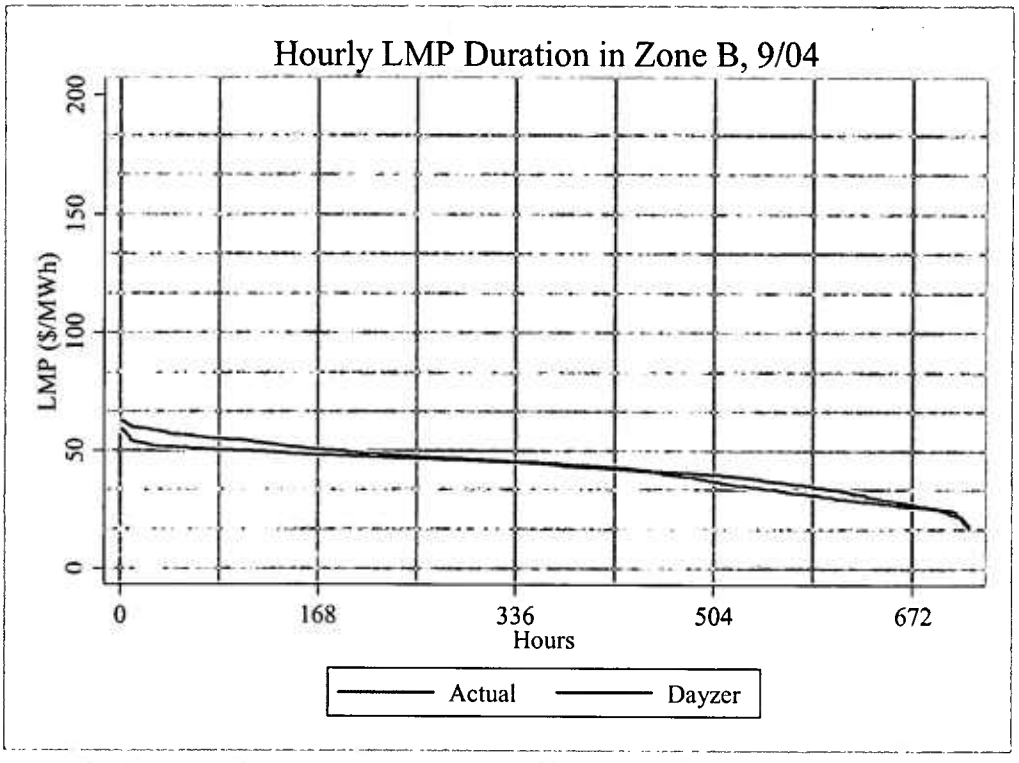

Hourly LMP Comparison in Zone B, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

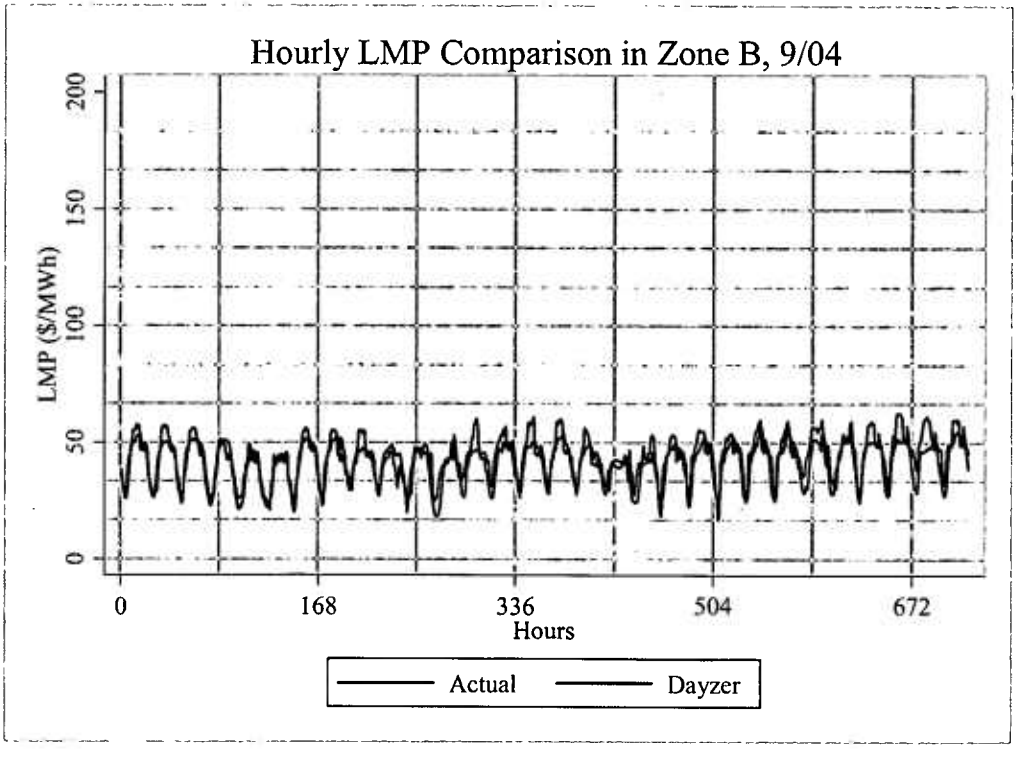

Hourly LMP Duration in Zone B, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

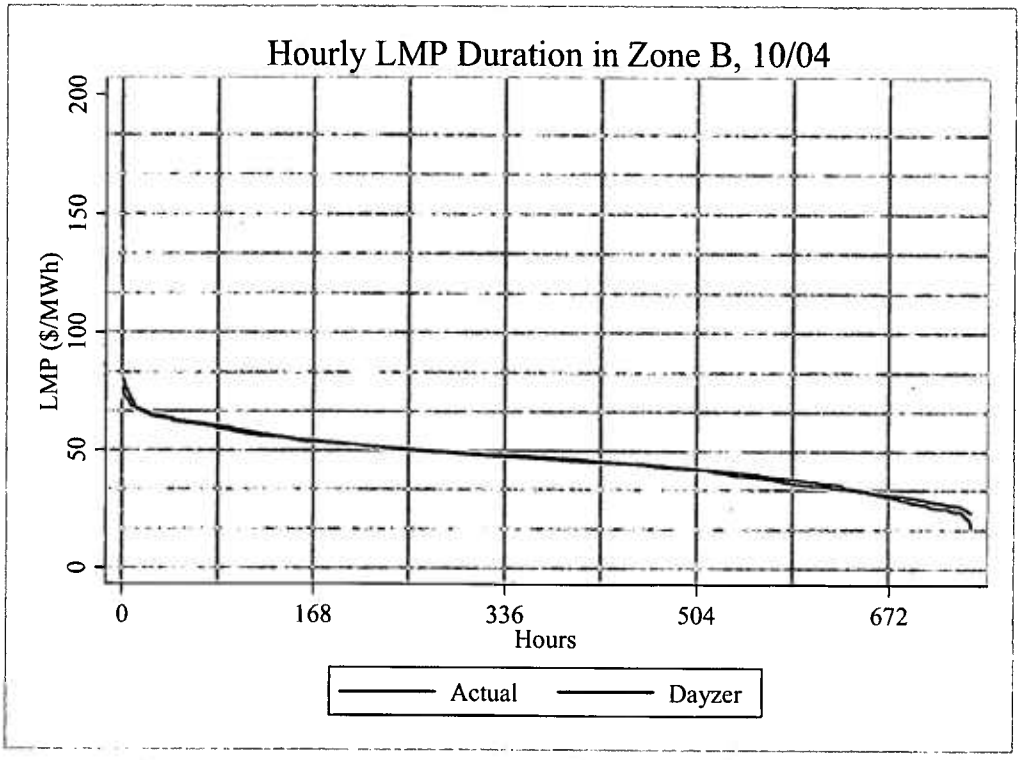

Hourly LMP Comparison in Zone B, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

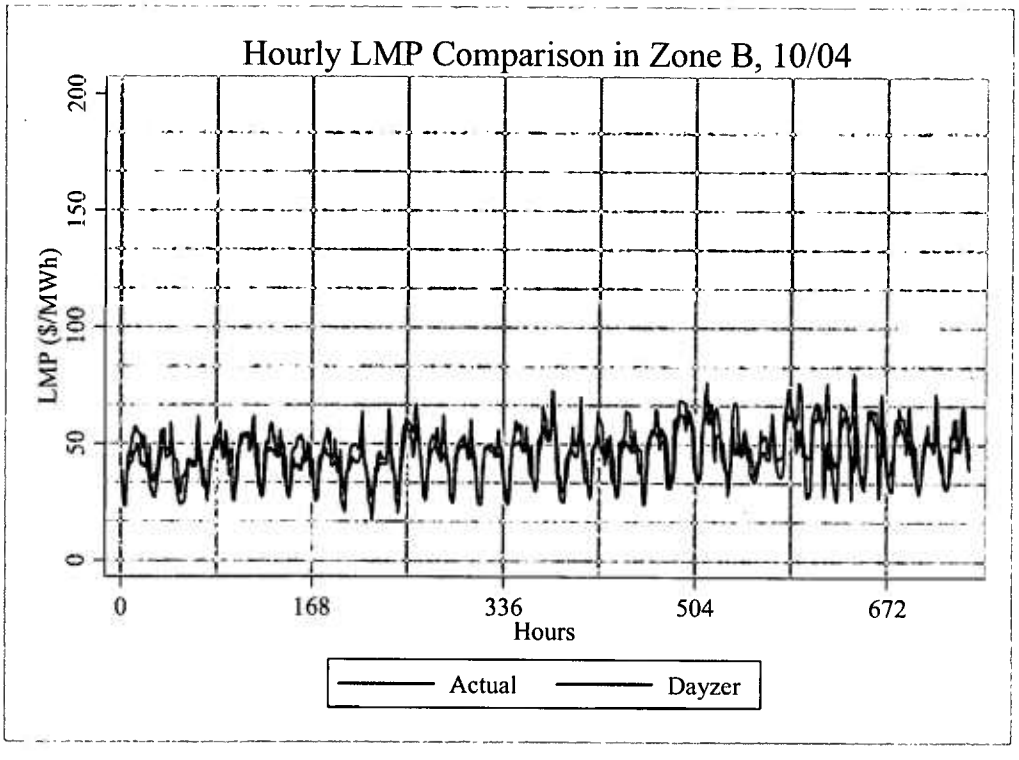

Hourly LMP Duration in Zone B, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

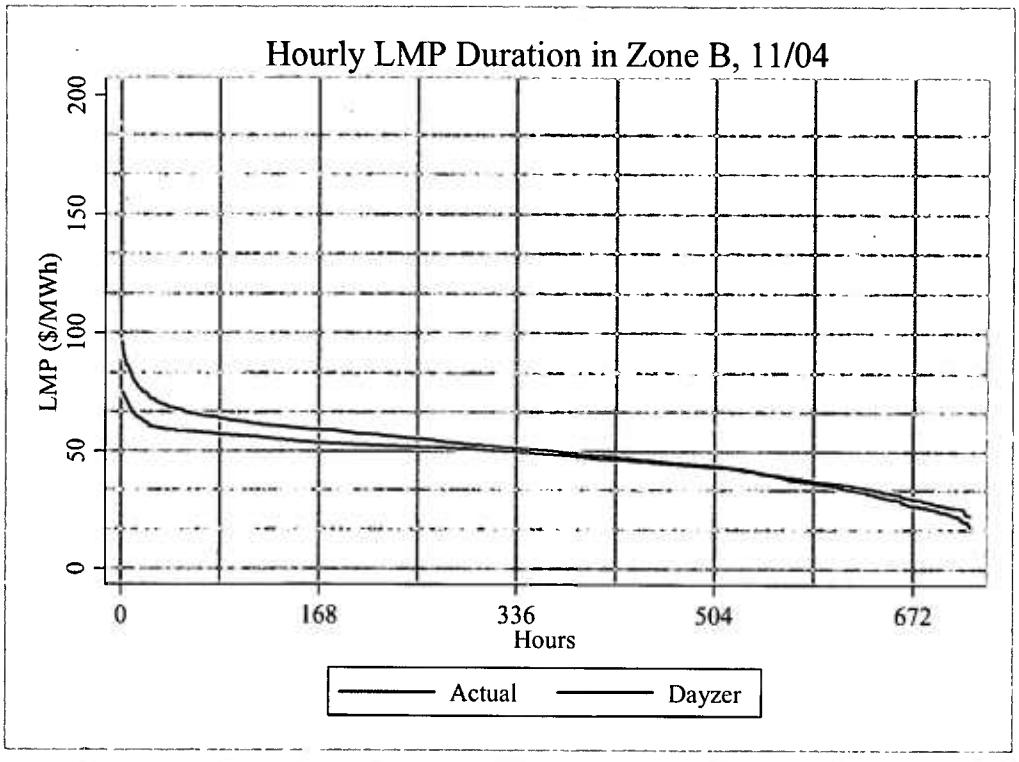

Hourly LMP Comparison in Zone B, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

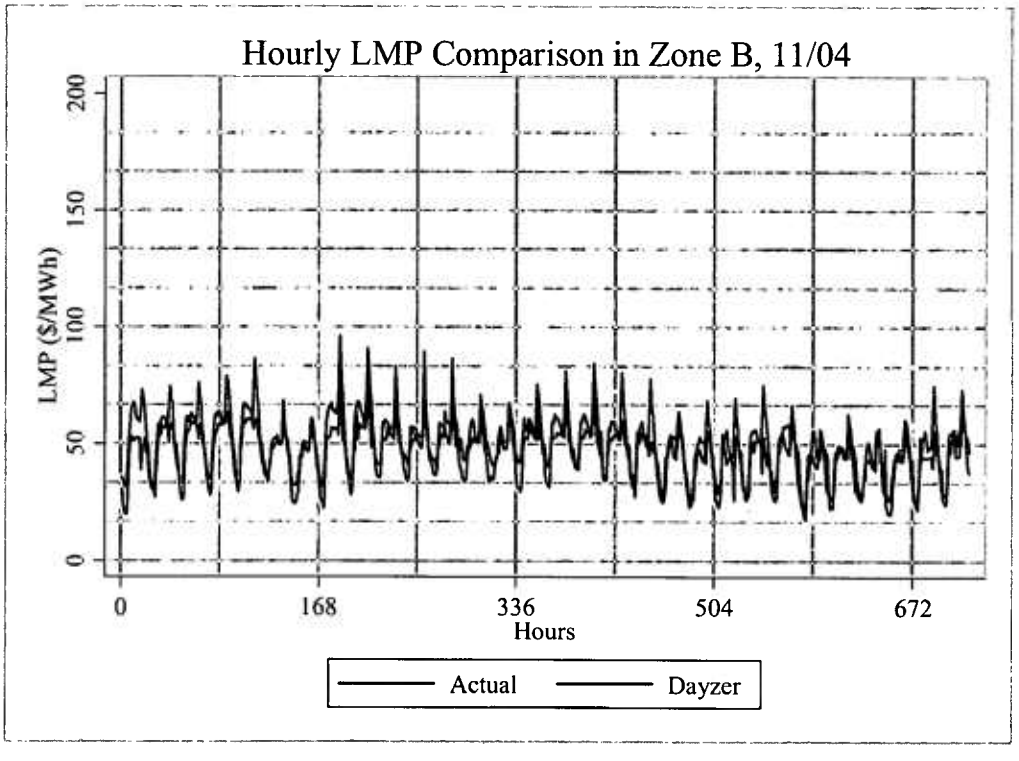

Hourly LMP Duration in Zone B, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

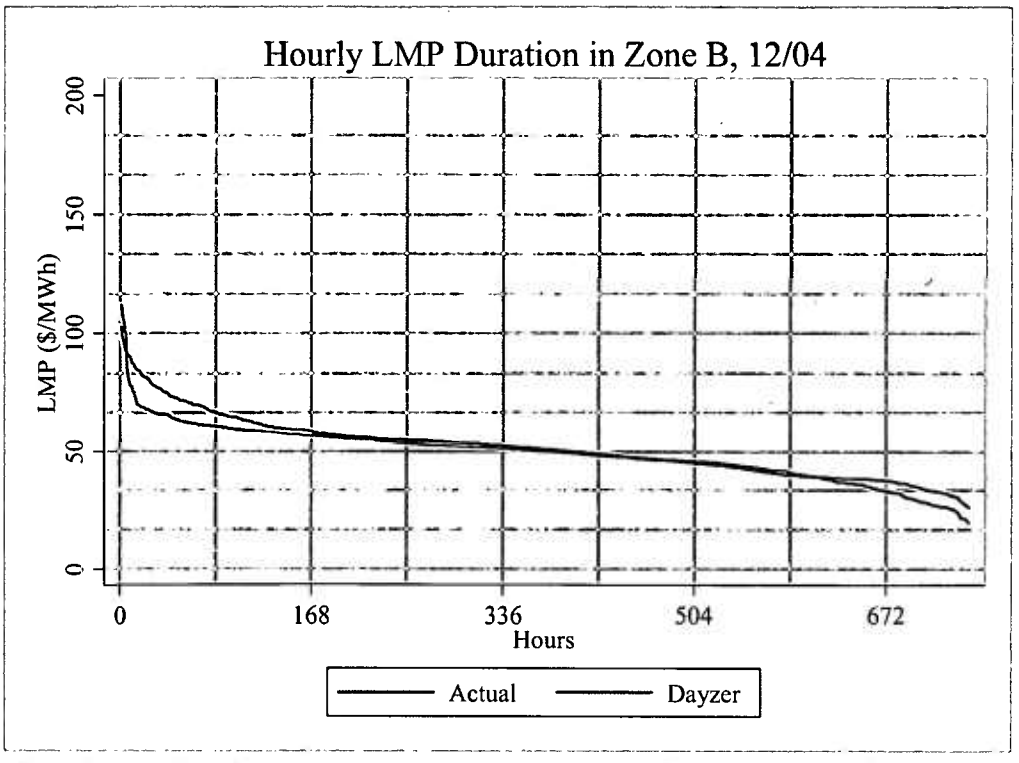

Hourly LMP Comparison in Zone B, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

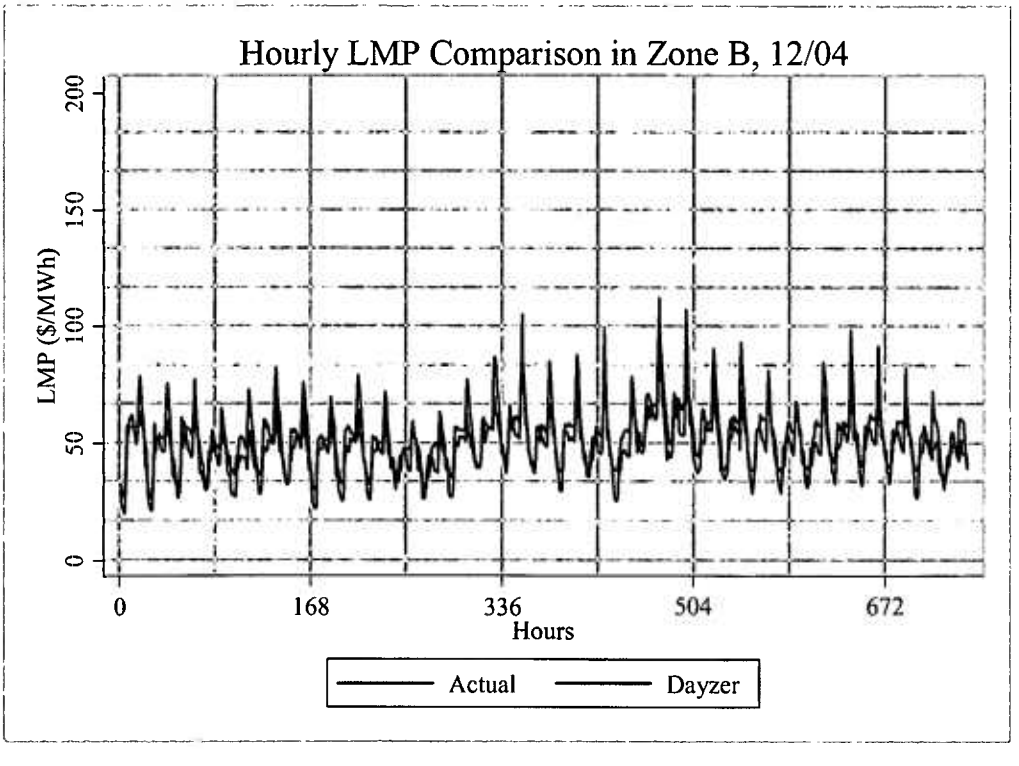

Hourly LMP Duration in Zone B, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

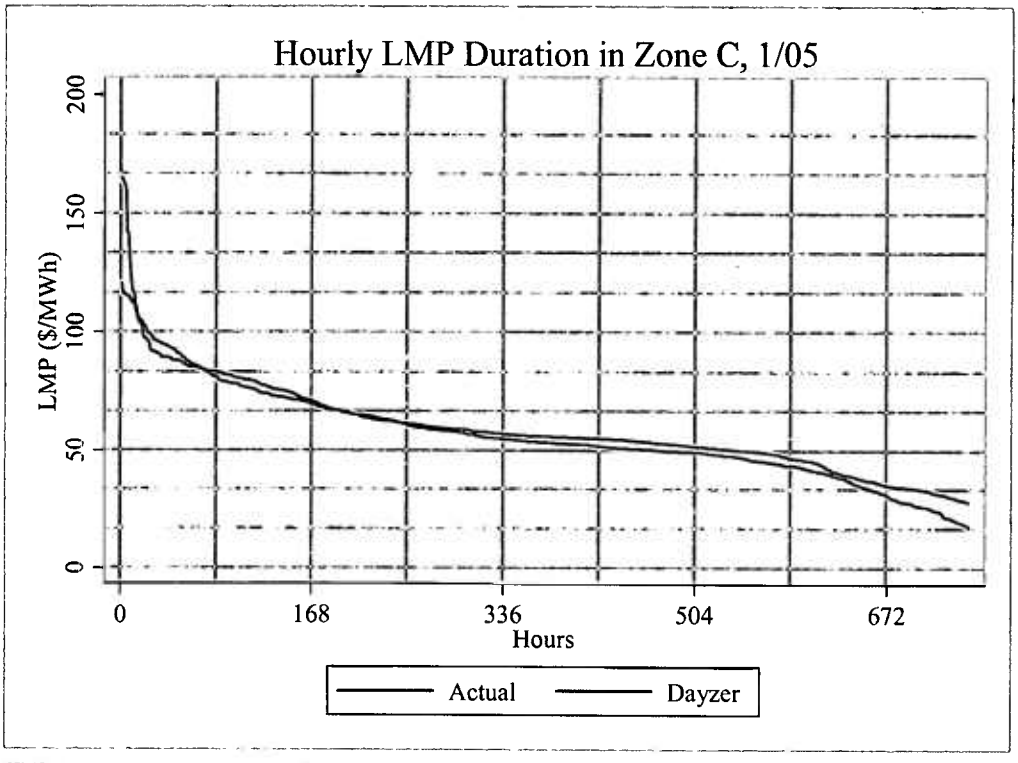

Hourly LMP Comparison in Zone B, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

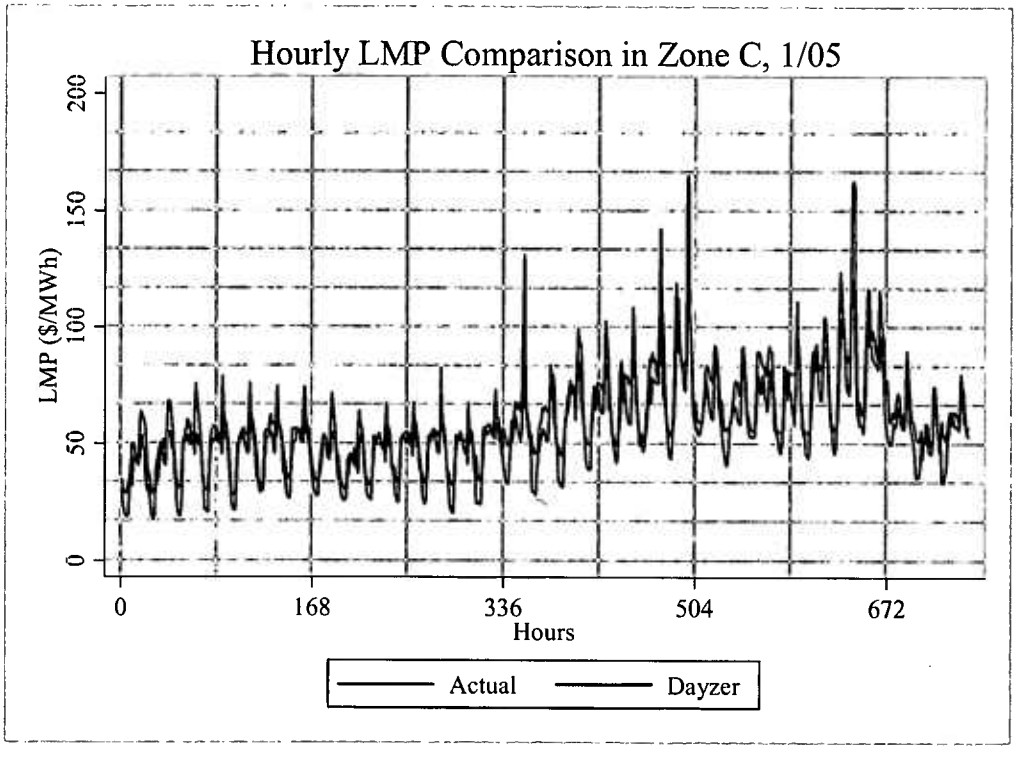

Hourly LMP Duration in Zone B, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

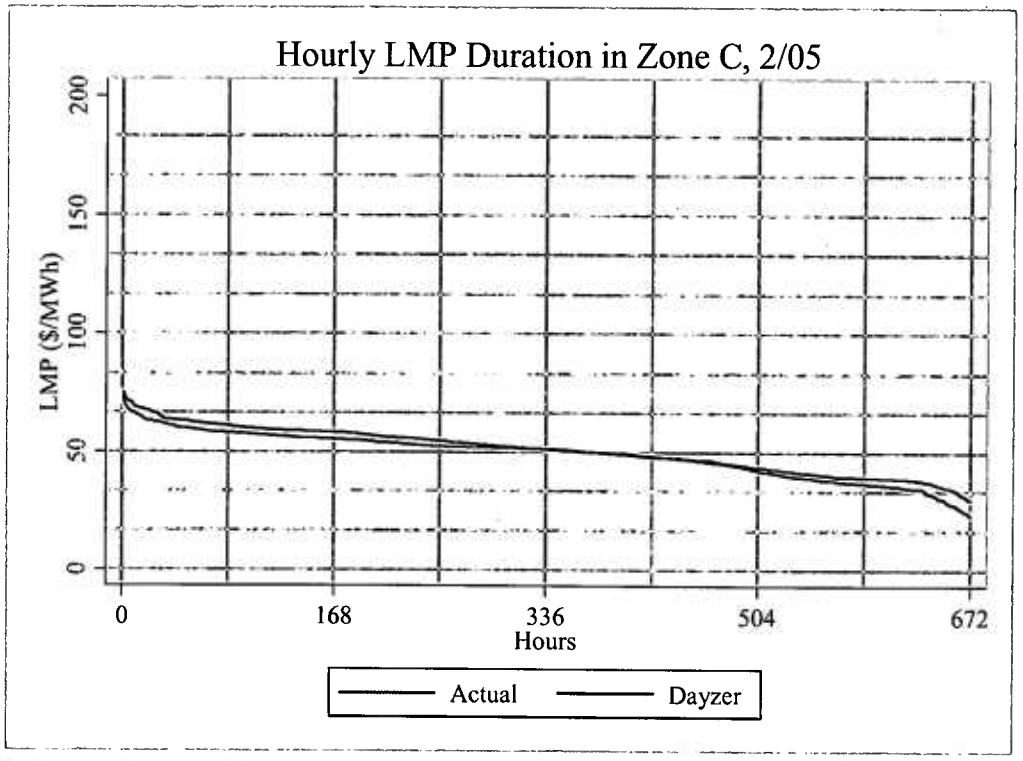

Hourly LMP Comparison in Zone B, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

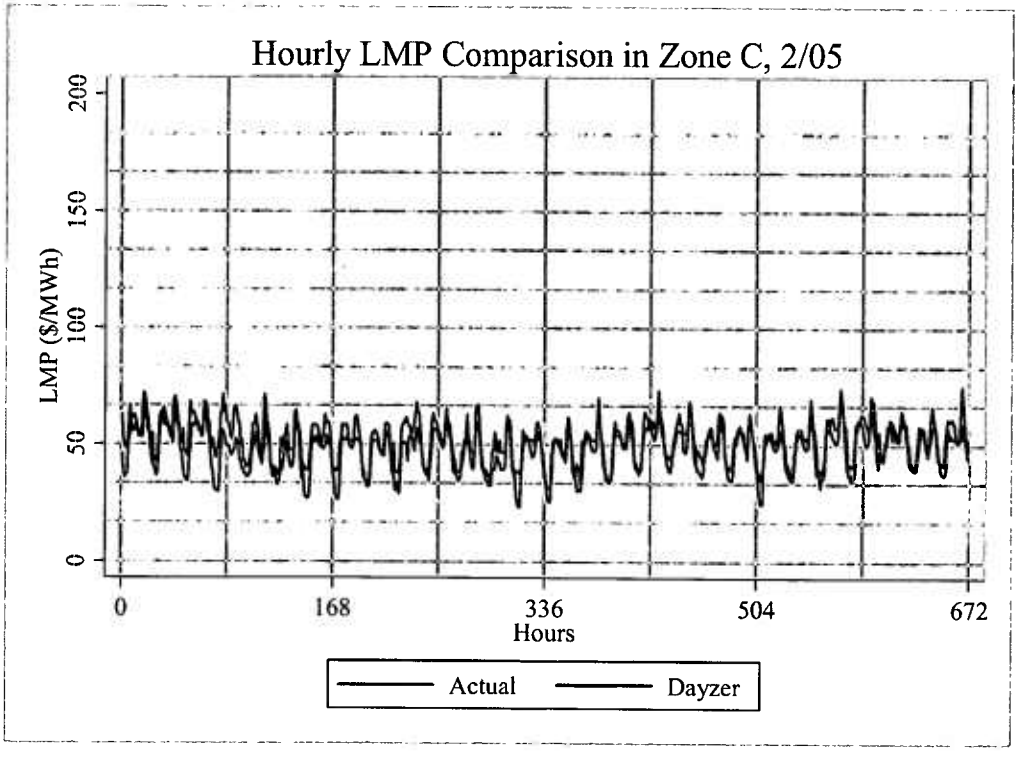

Hourly LMP Duration in Zone B, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

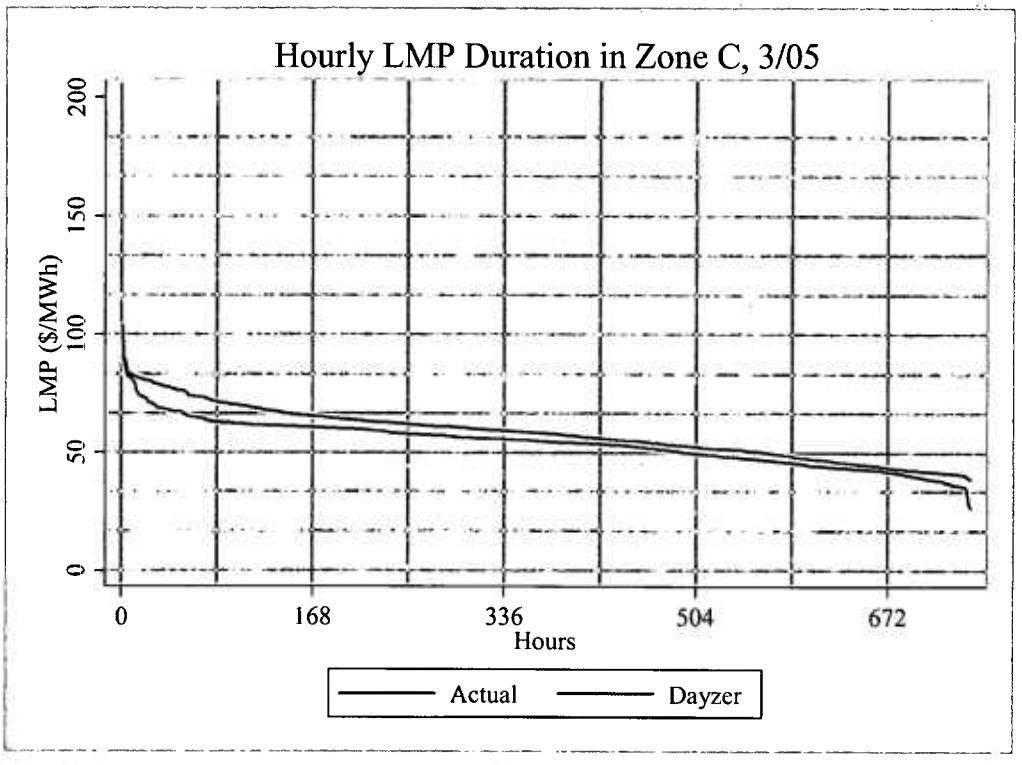

Hourly LMP Comparison in Zone B, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

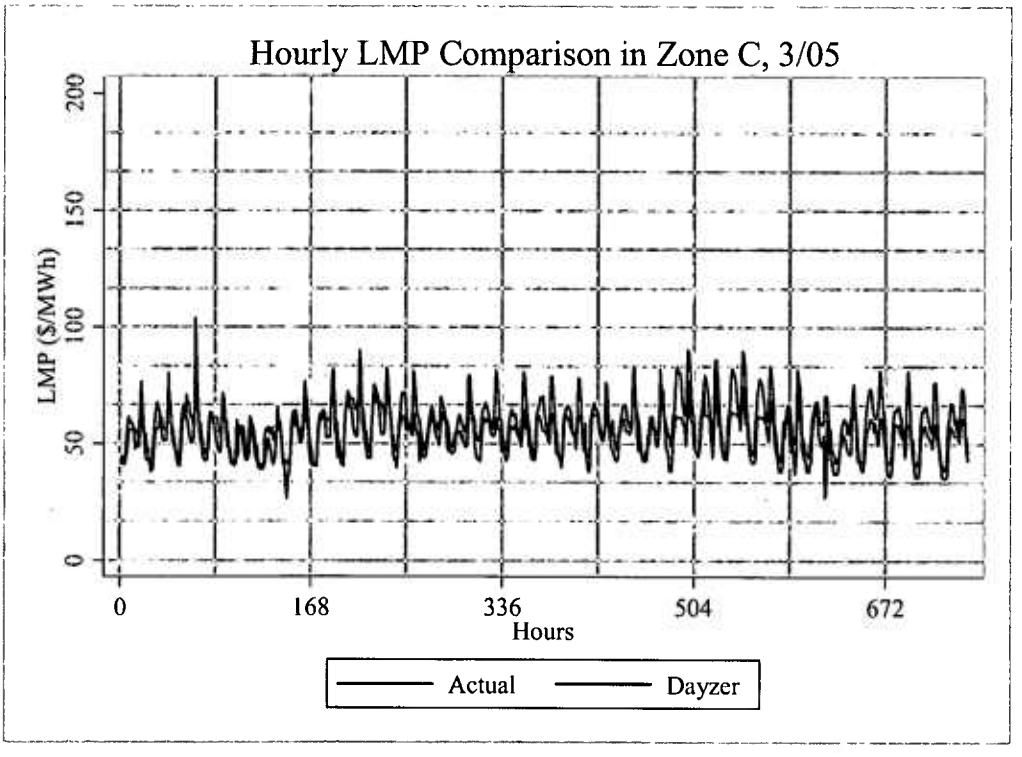

Hourly LMP Duration in Zone C, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

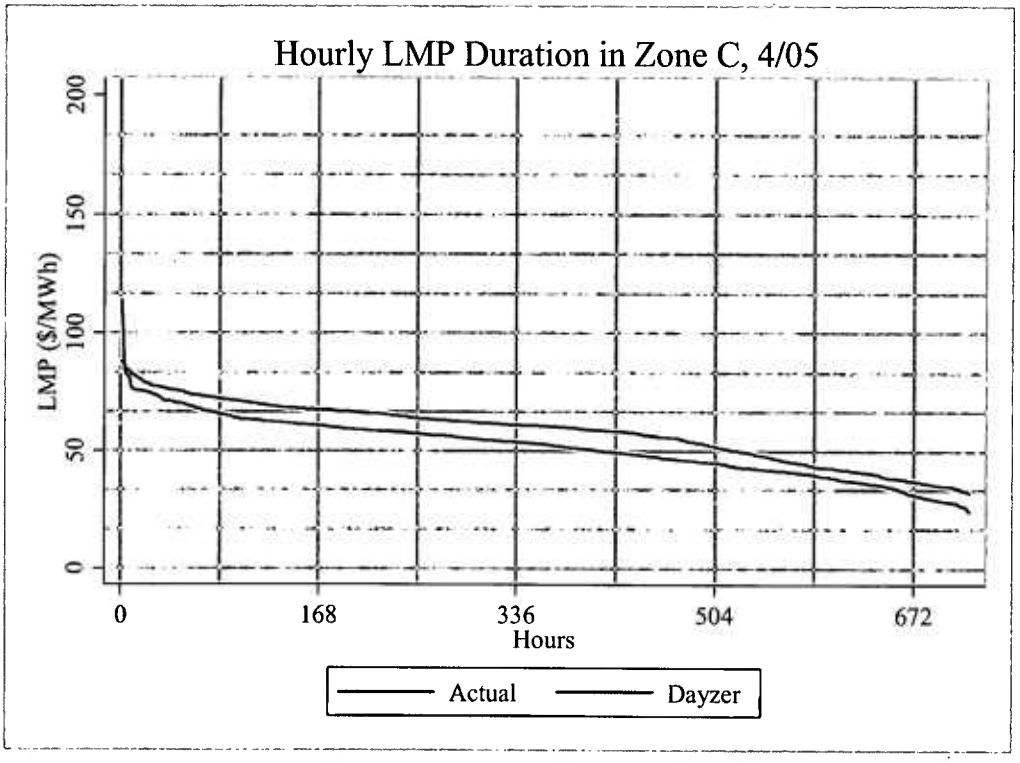

Hourly LMP Comparison in Zone C, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

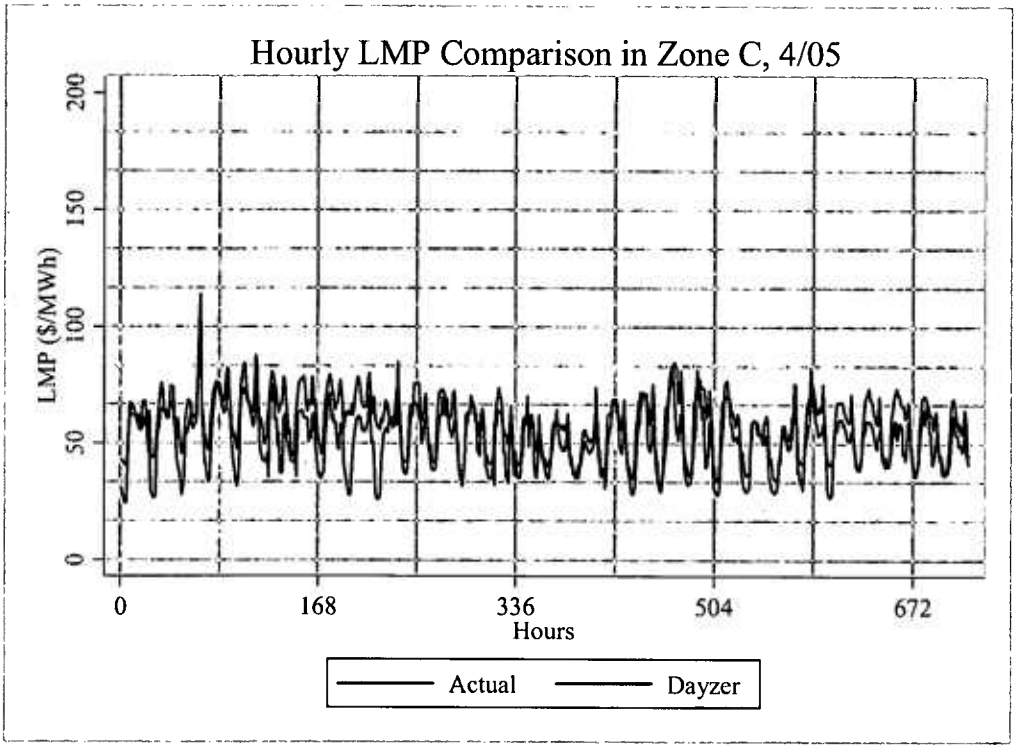

Hourly LMP Duration in Zone C, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

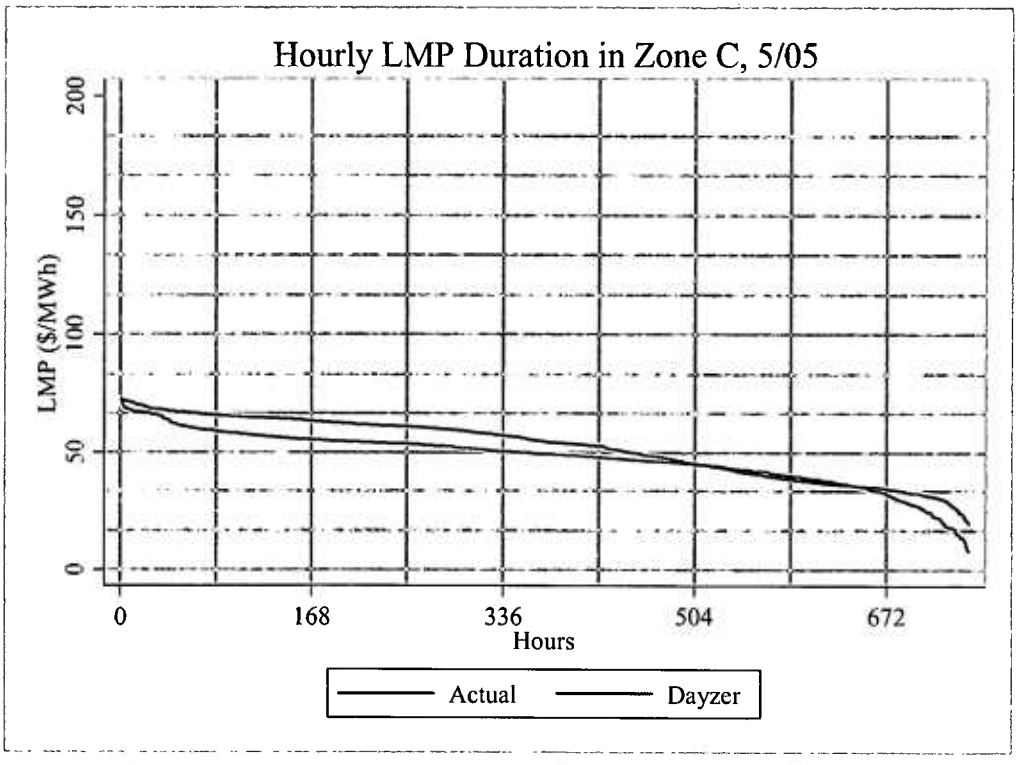

Hourly LMP Comparison in Zone C, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

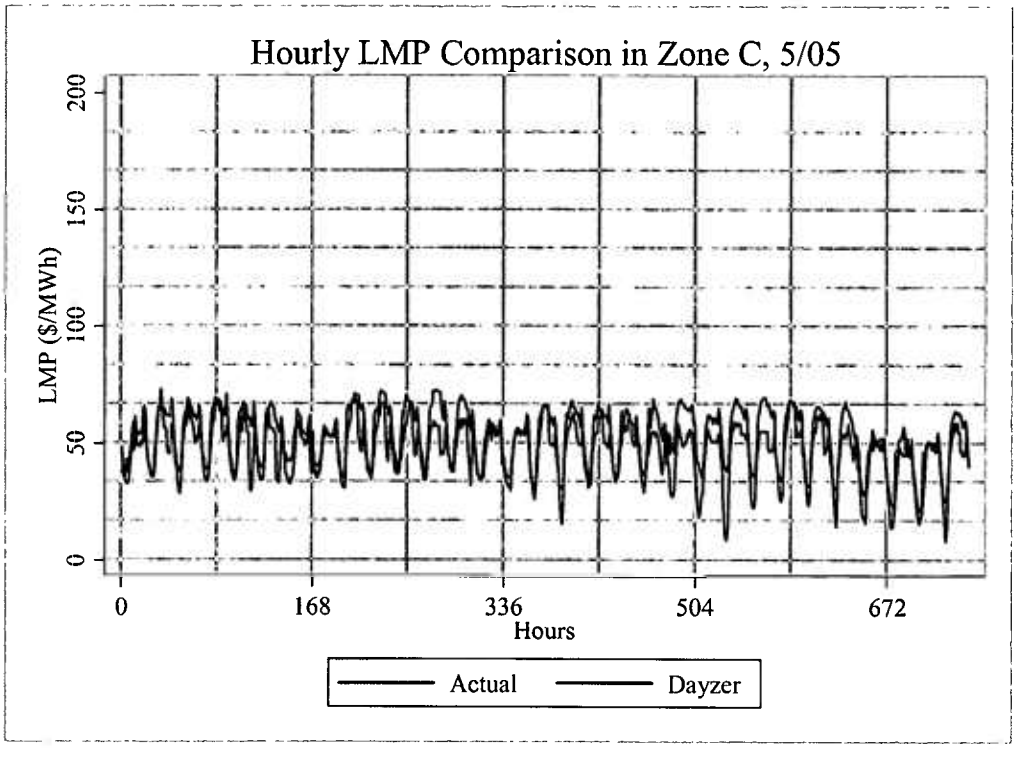

Hourly LMP Duration in Zone C, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

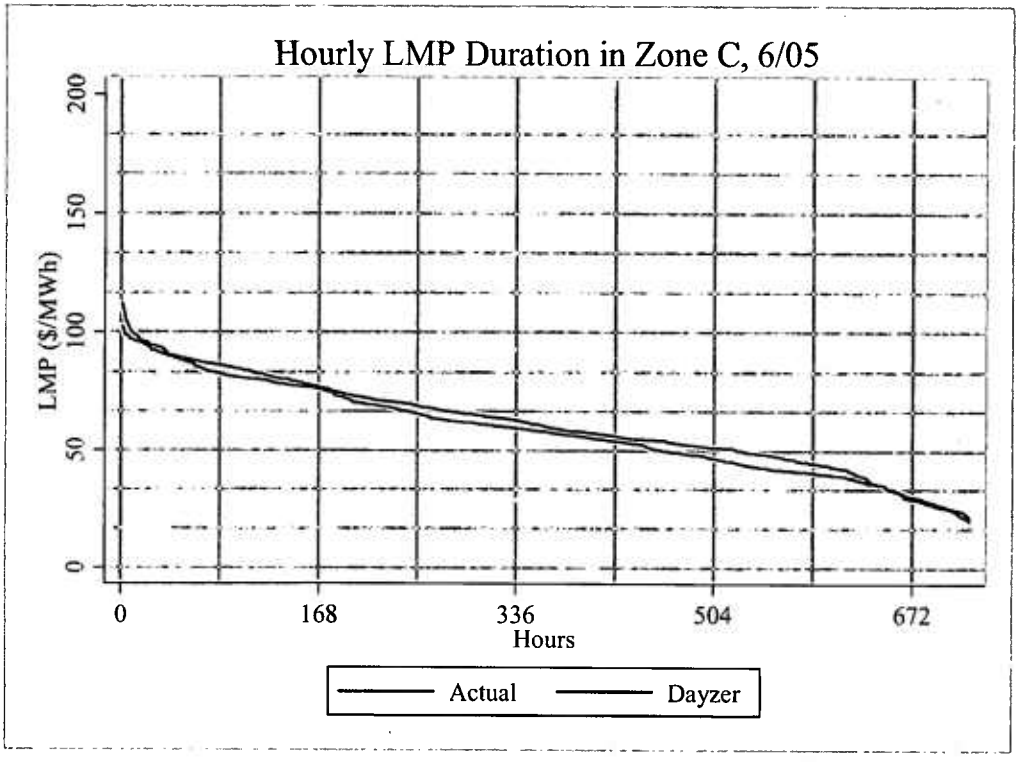

Hourly LMP Comparison in Zone C, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

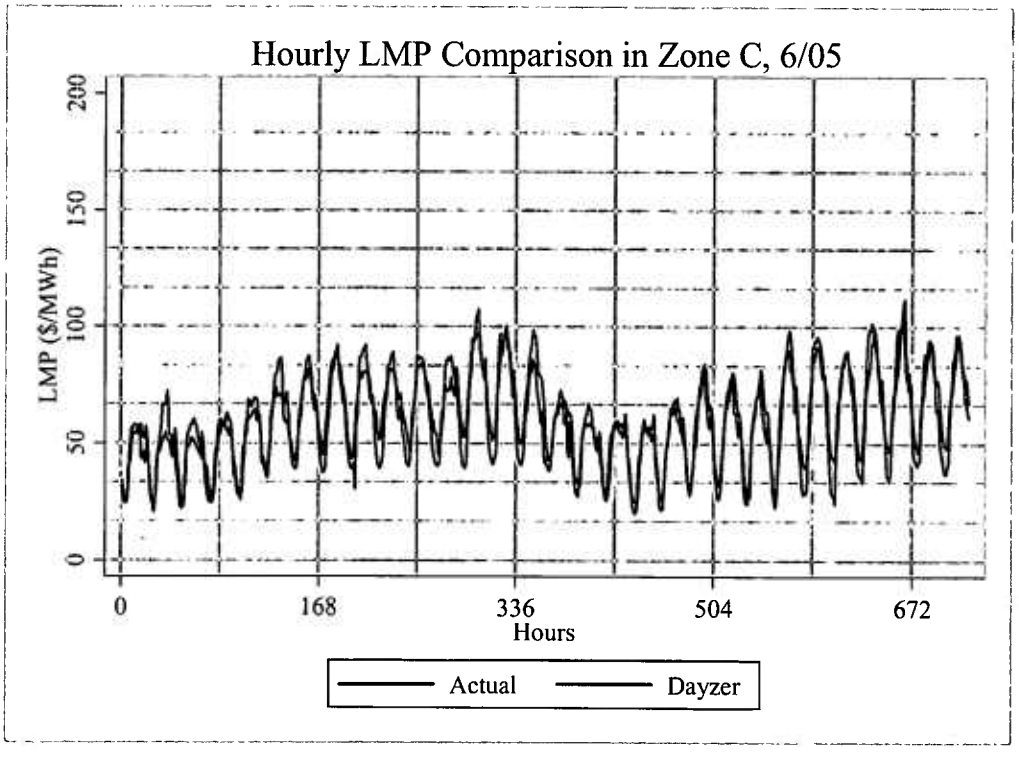

Hourly LMP Duration in Zone C, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

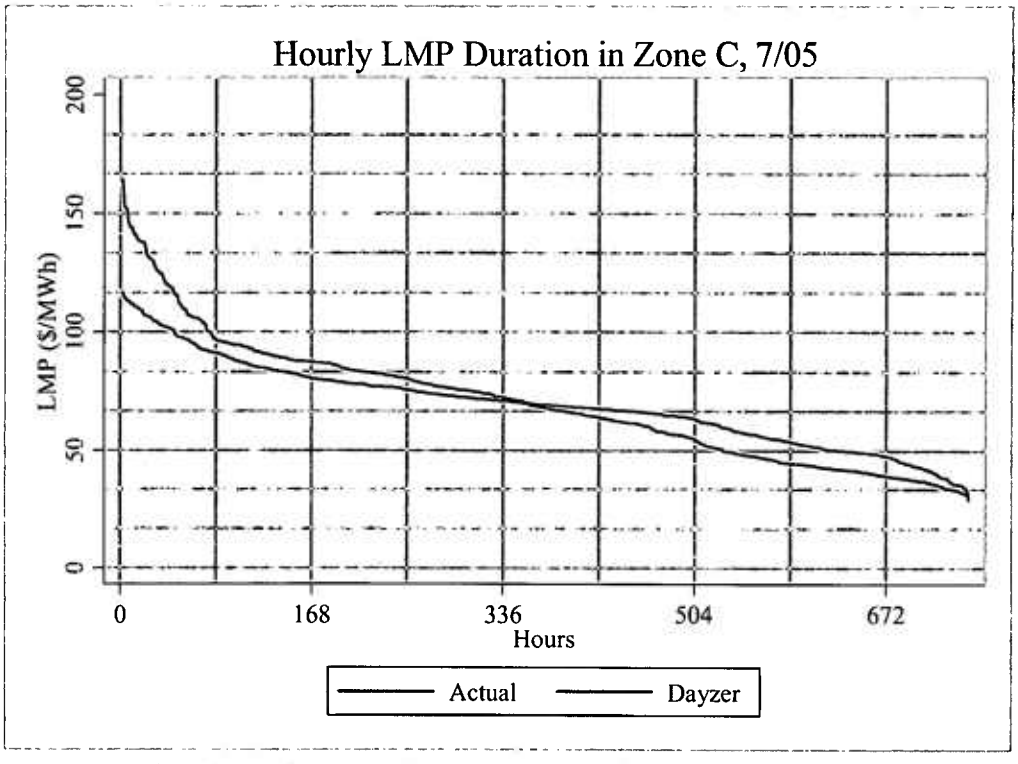

Hourly LMP Comparison in Zone C, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

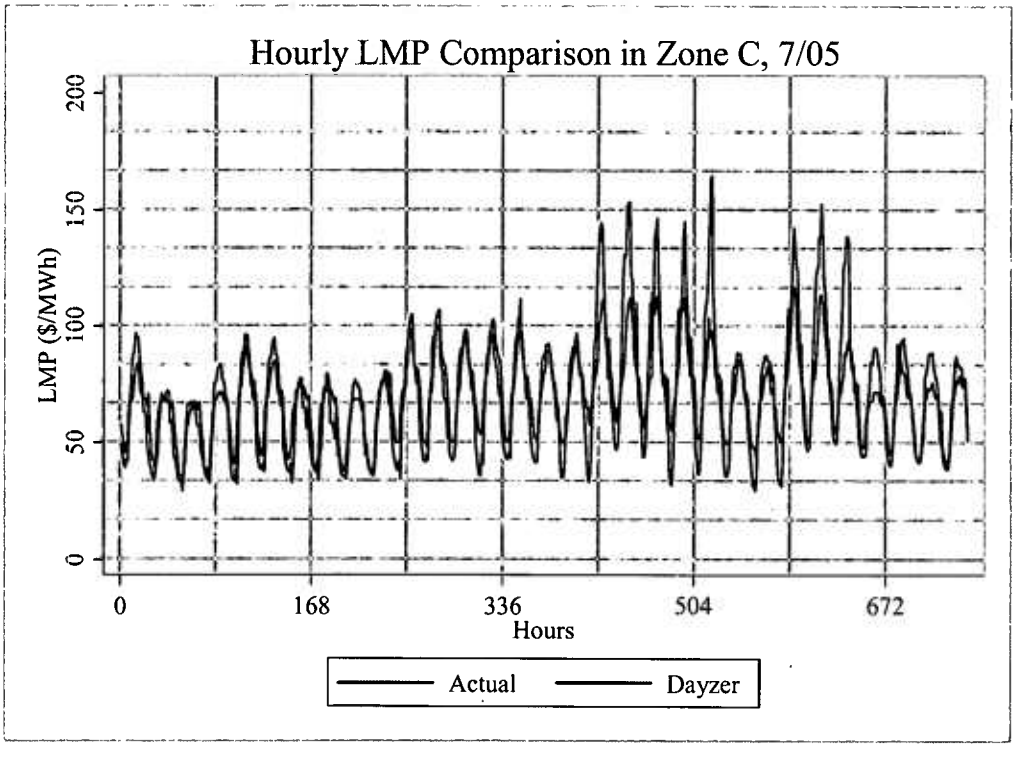

Hourly LMP Duration in Zone C, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

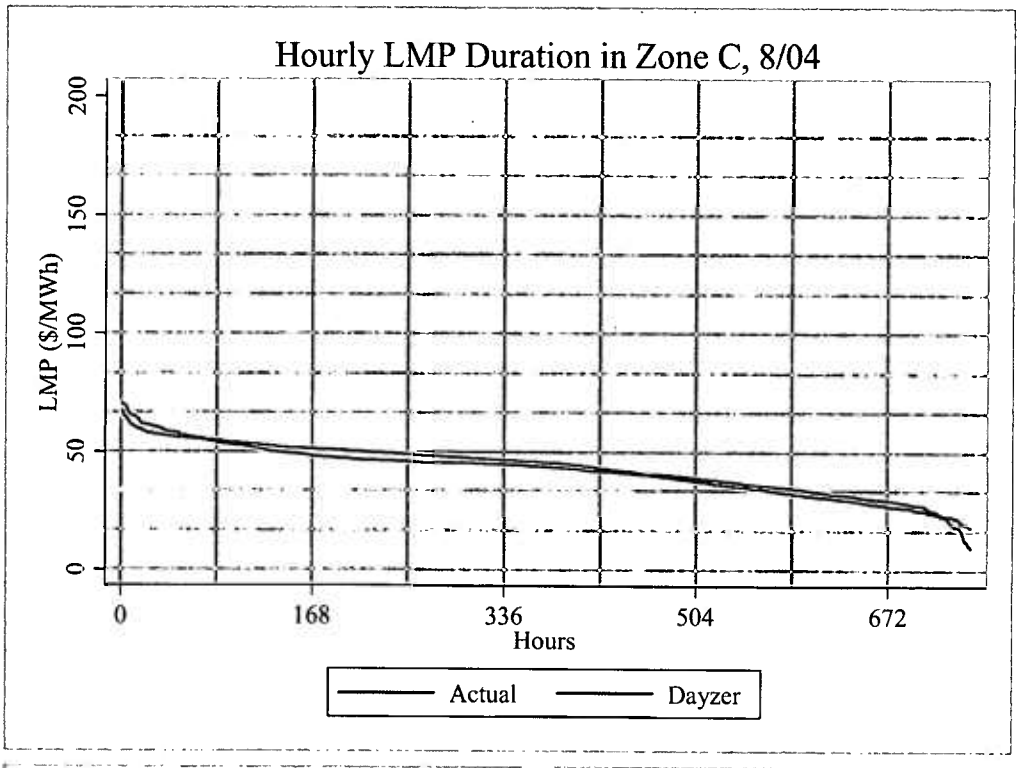

Hourly LMP Comparison in Zone C, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

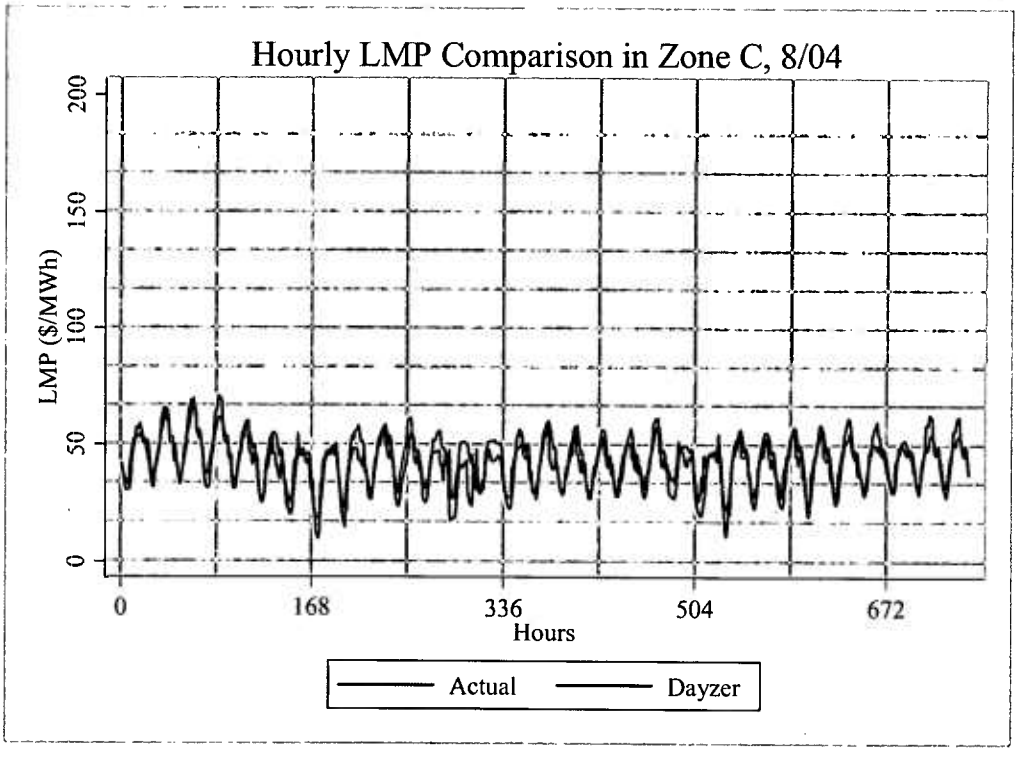

Hourly LMP Duration in Zone C, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

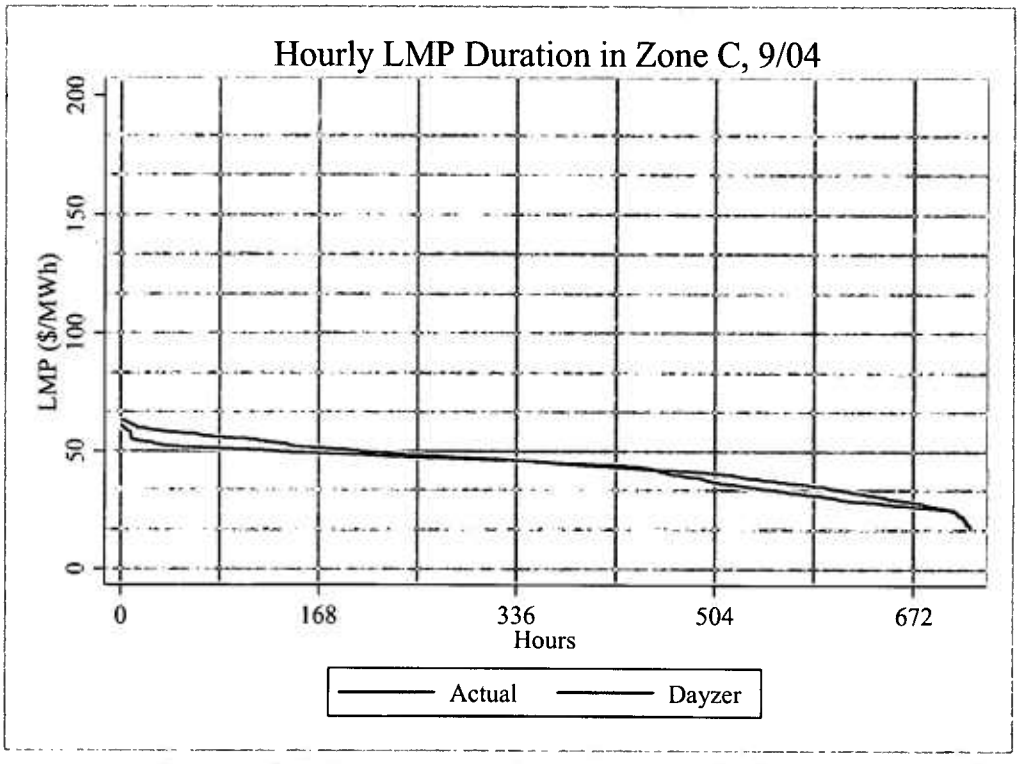

Hourly LMP Comparison in Zone C, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

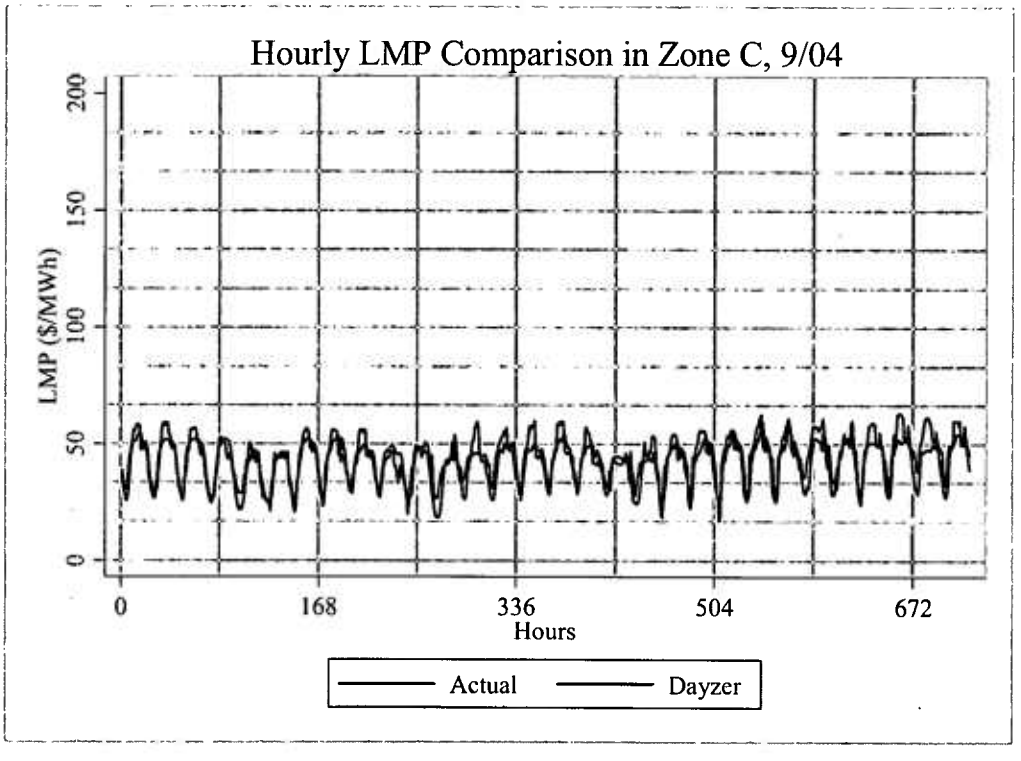

Hourly LMP Duration in Zone C, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

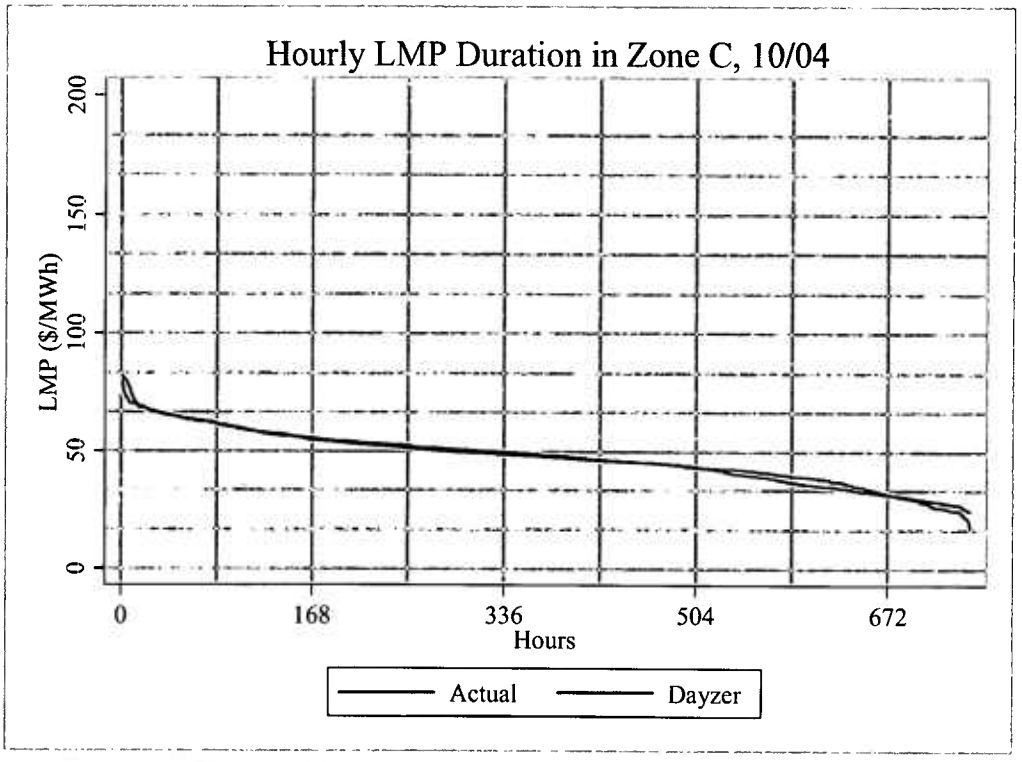

Hourly LMP Comparison in Zone C, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

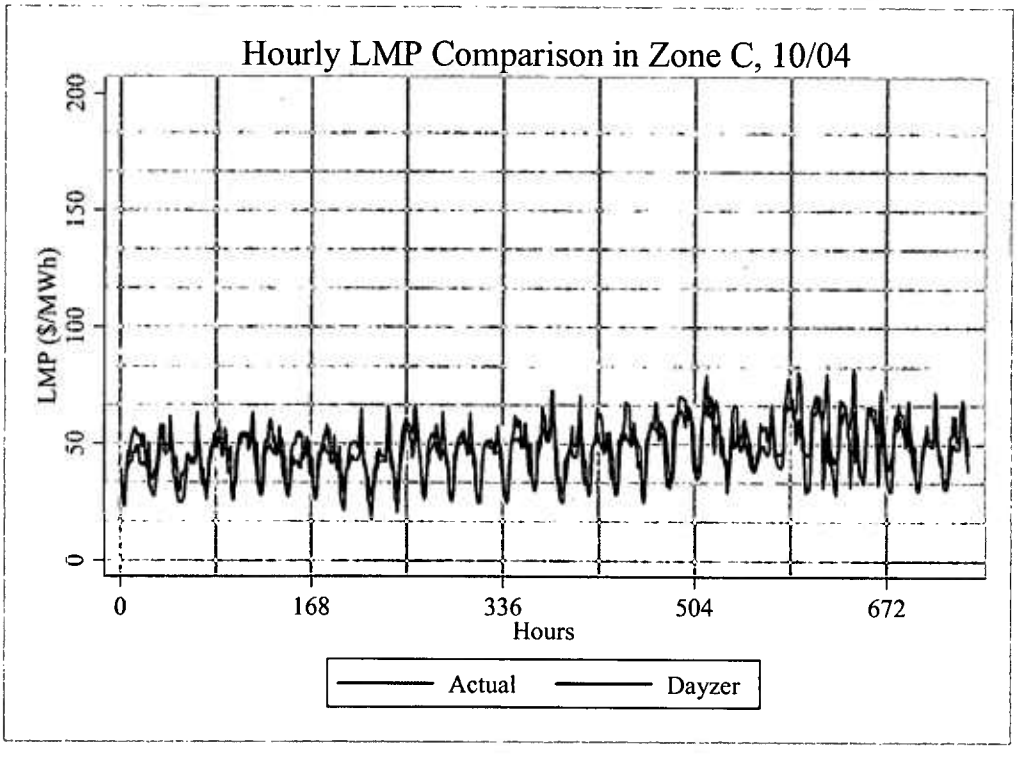

Hourly LMP Duration in Zone C, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

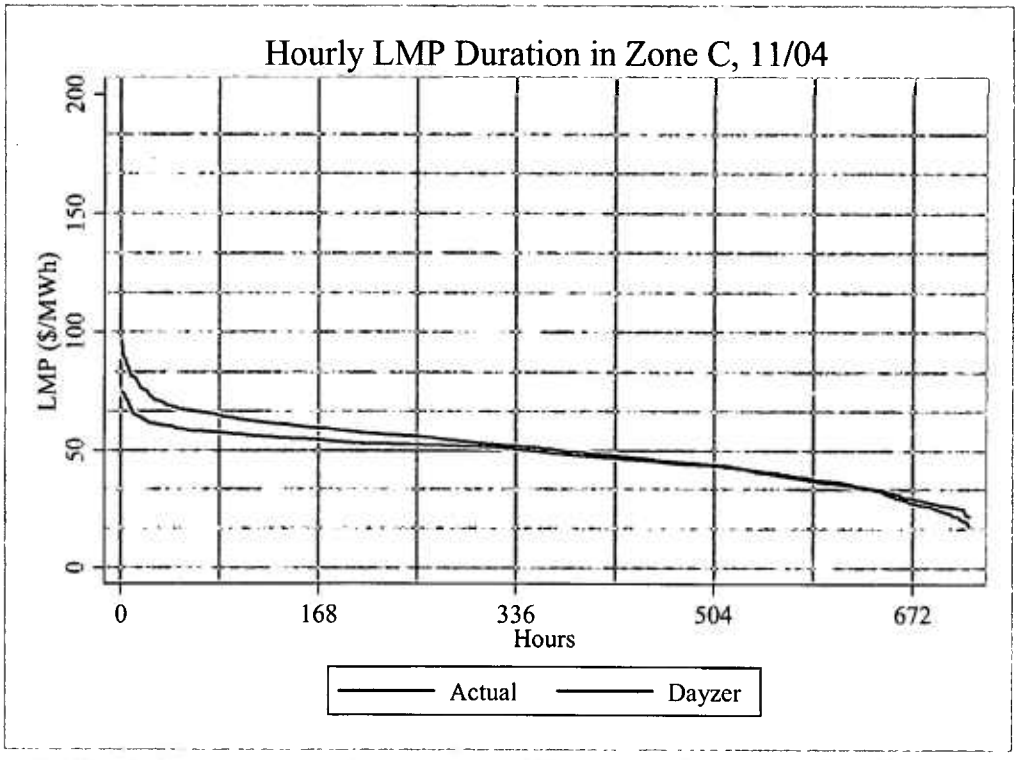

Hourly LMP Comparison in Zone C, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

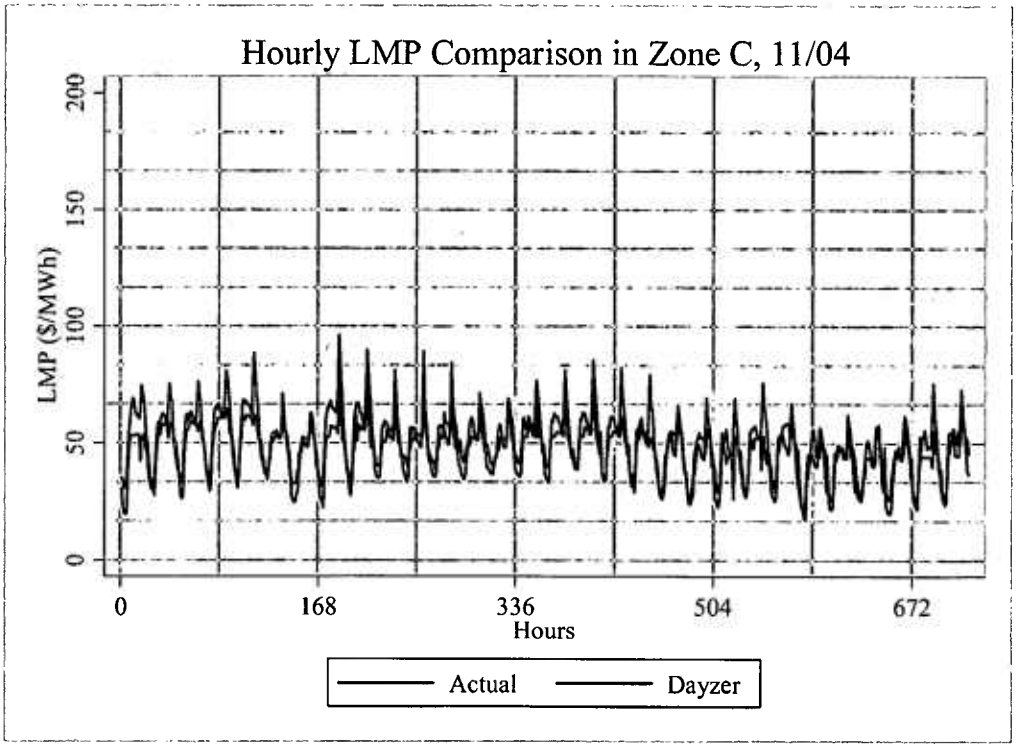

Hourly LMP Duration in Zone C, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

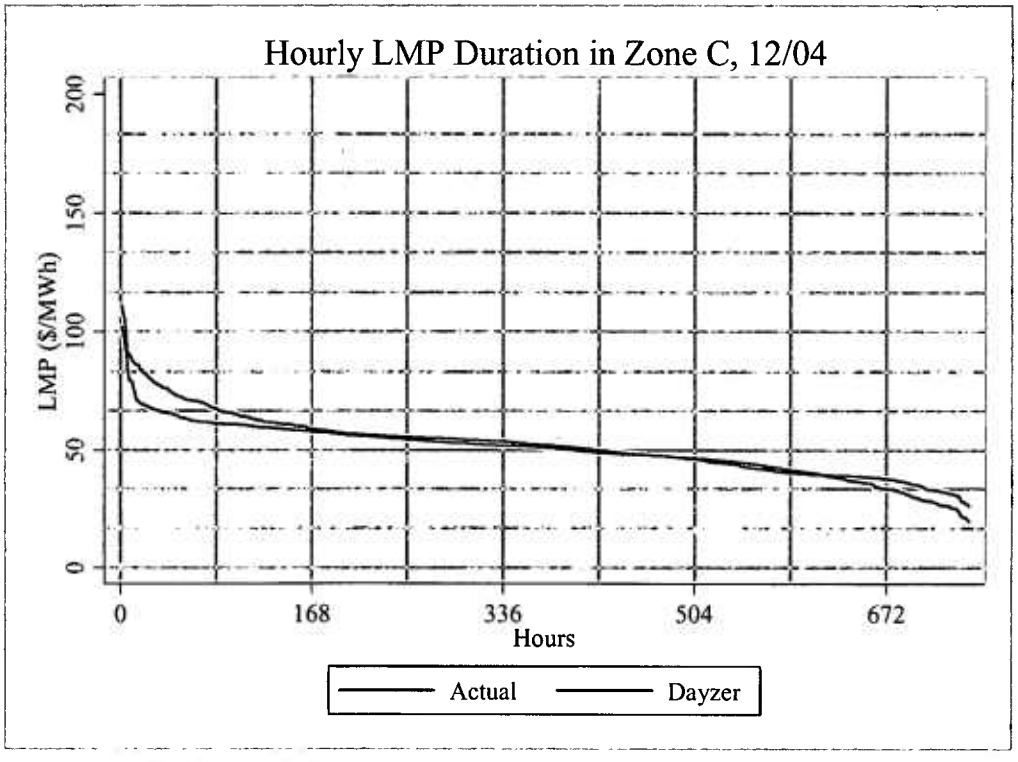

Hourly LMP Comparison in Zone C, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

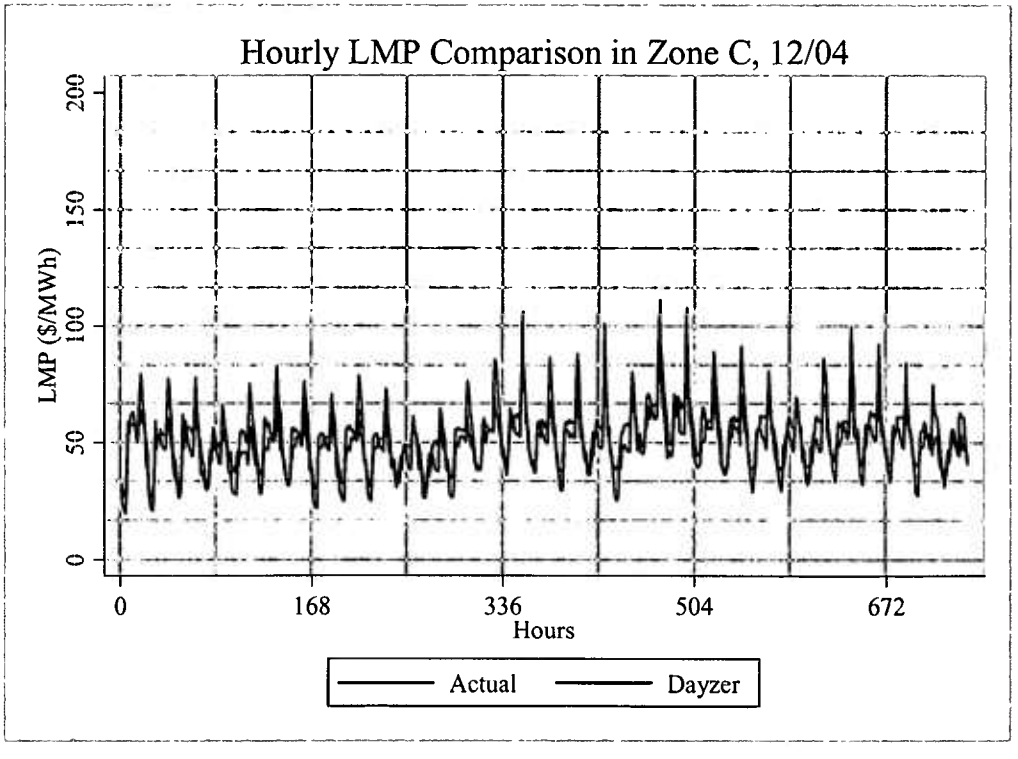

Hourly LMP Duration in Zone C, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

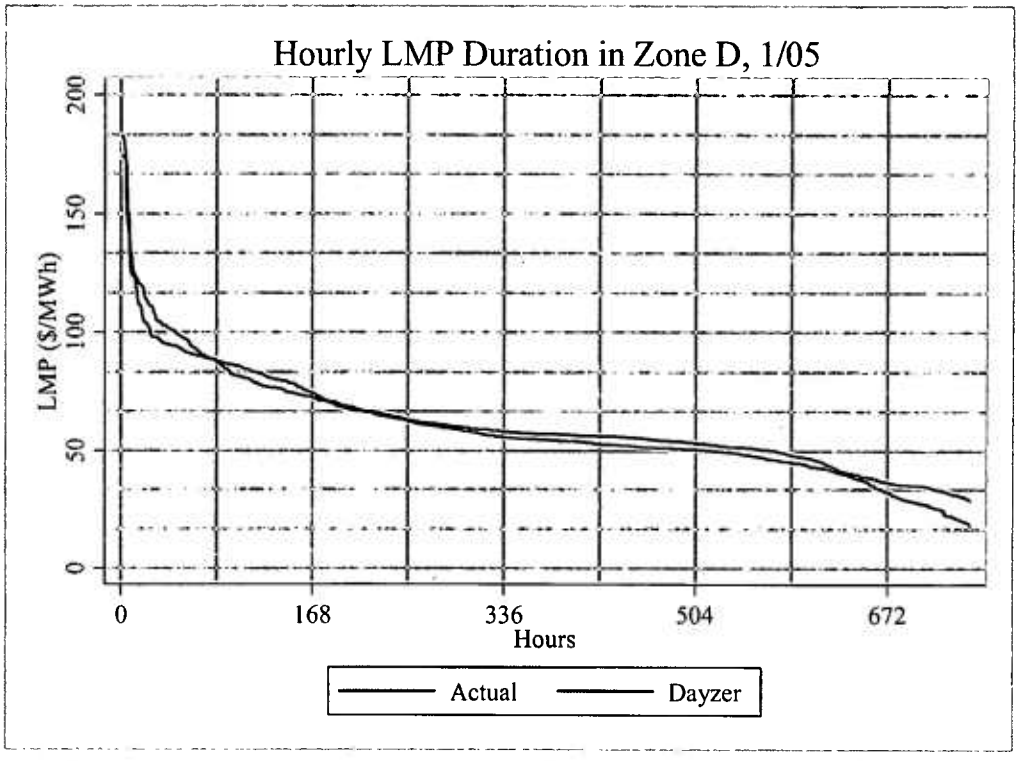

Hourly LMP Comparison in Zone C, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

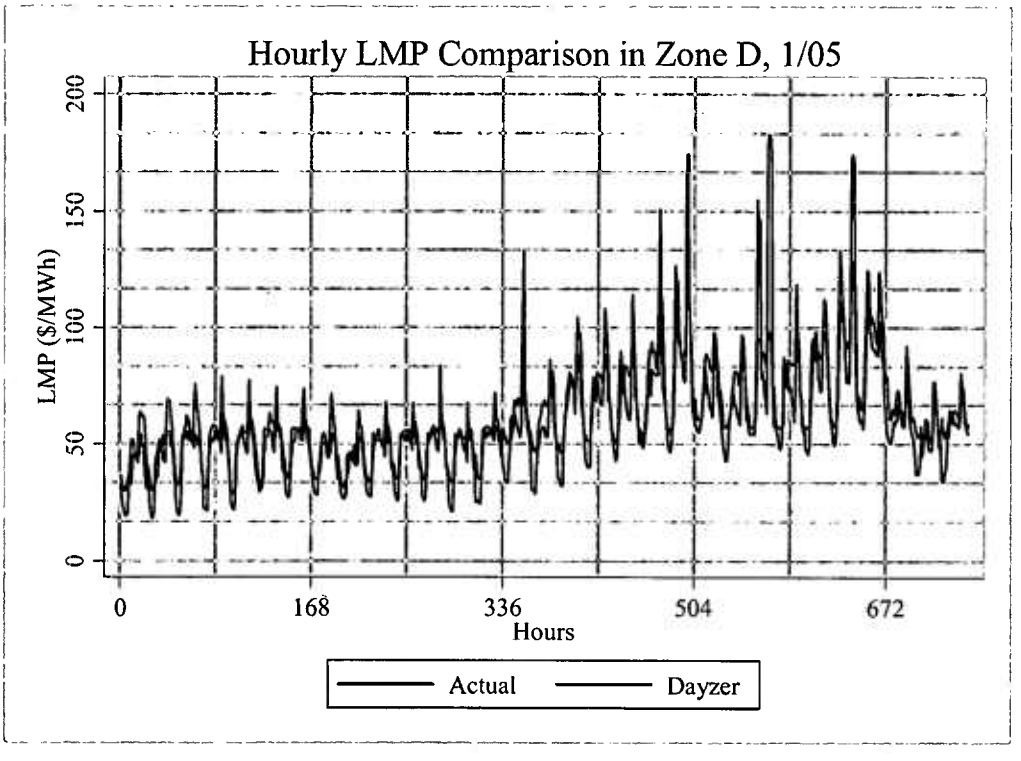

Hourly LMP Duration in Zone C, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

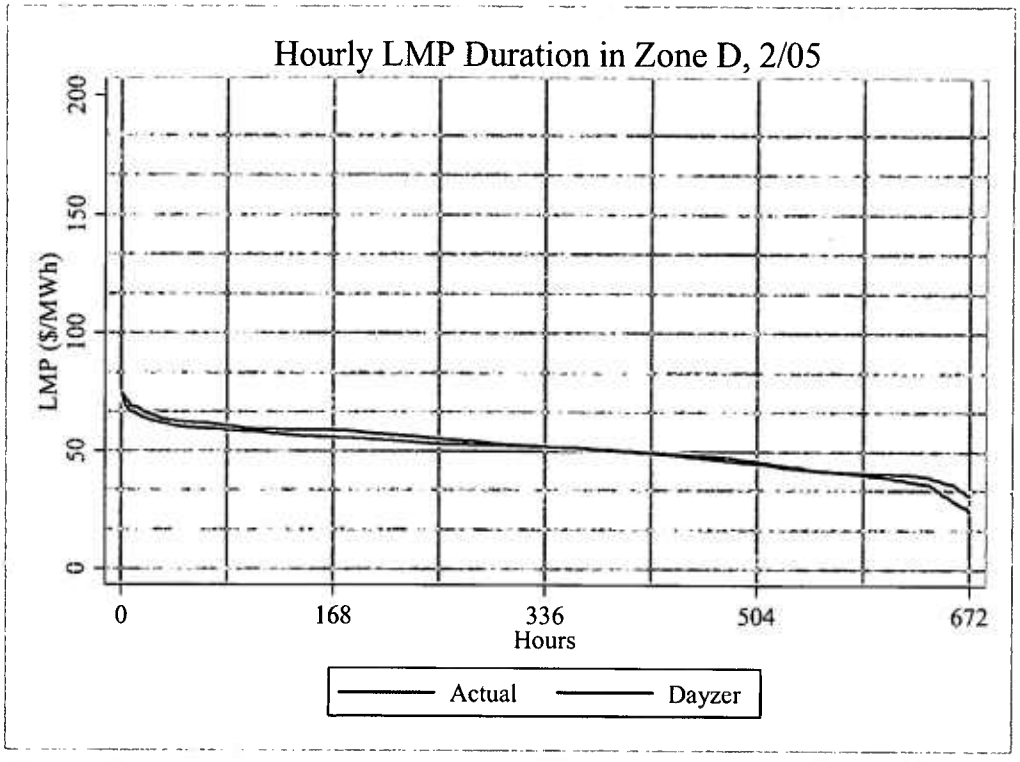

Hourly LMP Comparison in Zone C, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

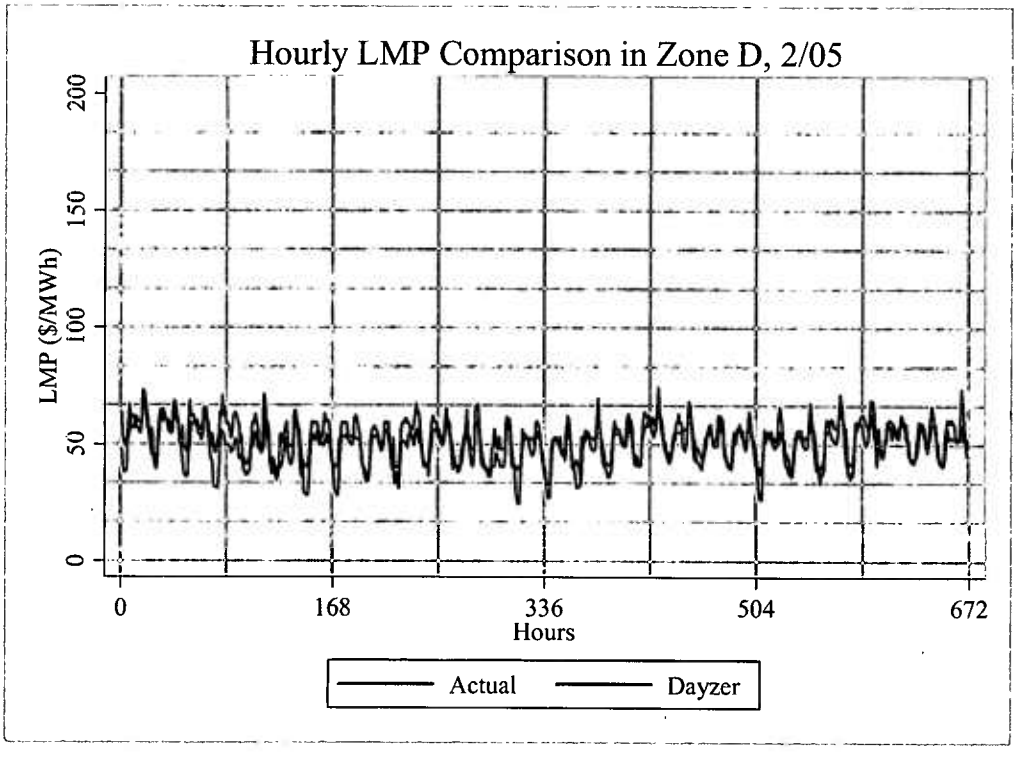

Hourly LMP Duration in Zone C, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

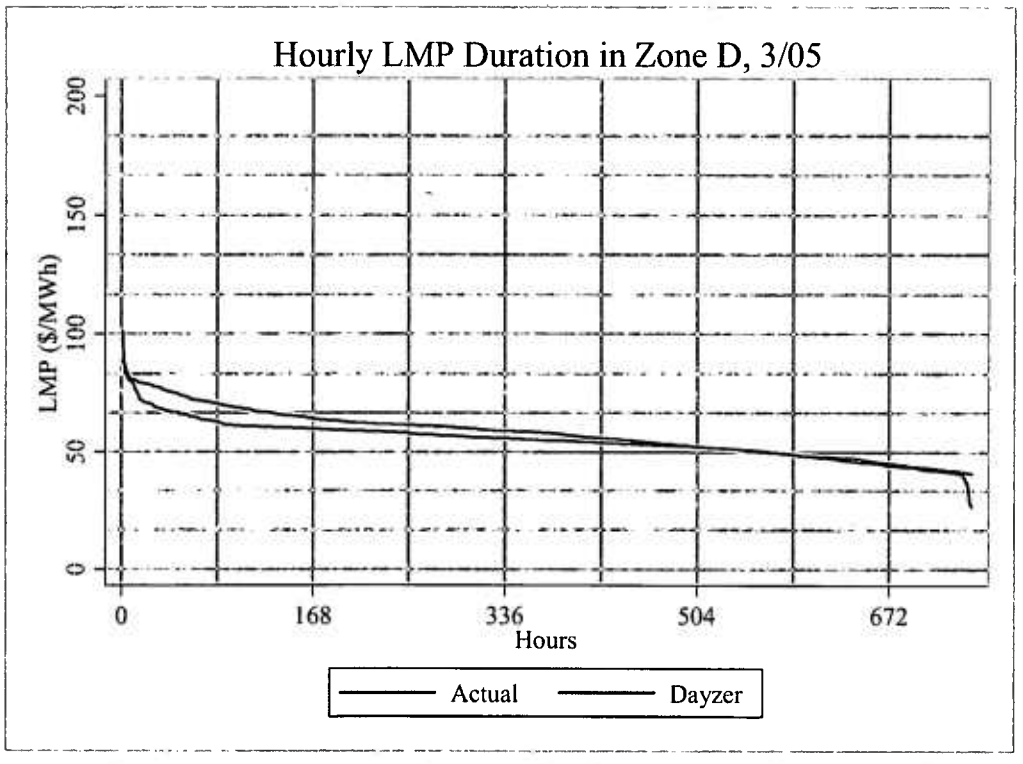

Hourly LMP Comparison in Zone C, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

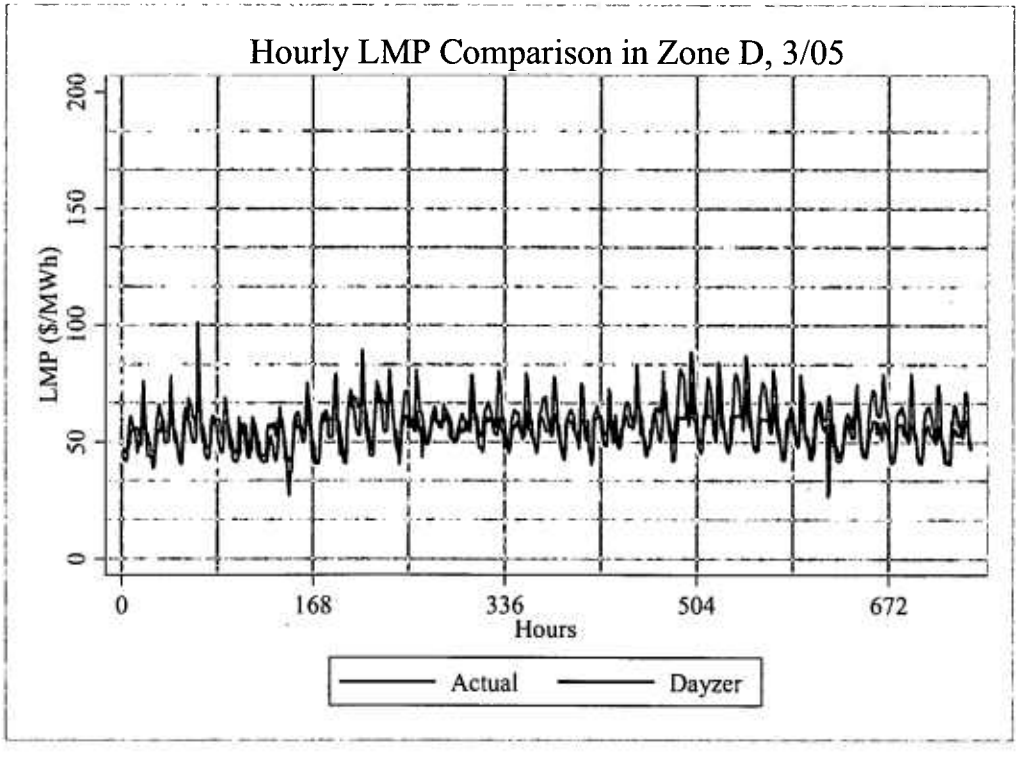

Hourly LMP Duration in Zone D, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

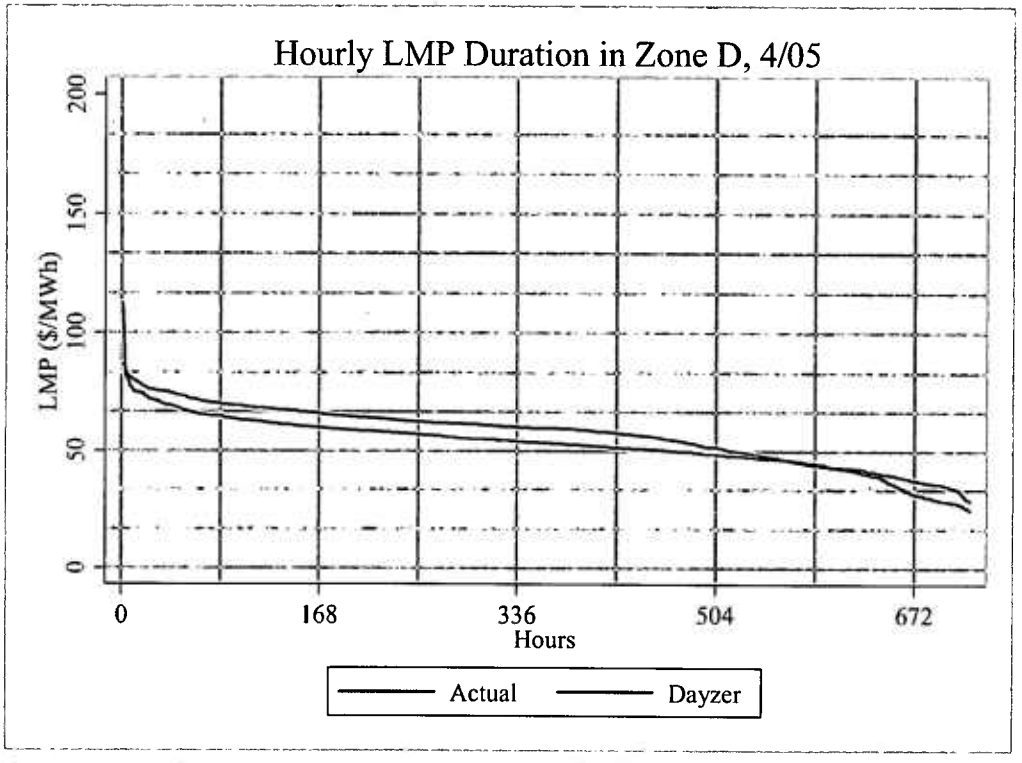

Hourly LMP Comparison in Zone D, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

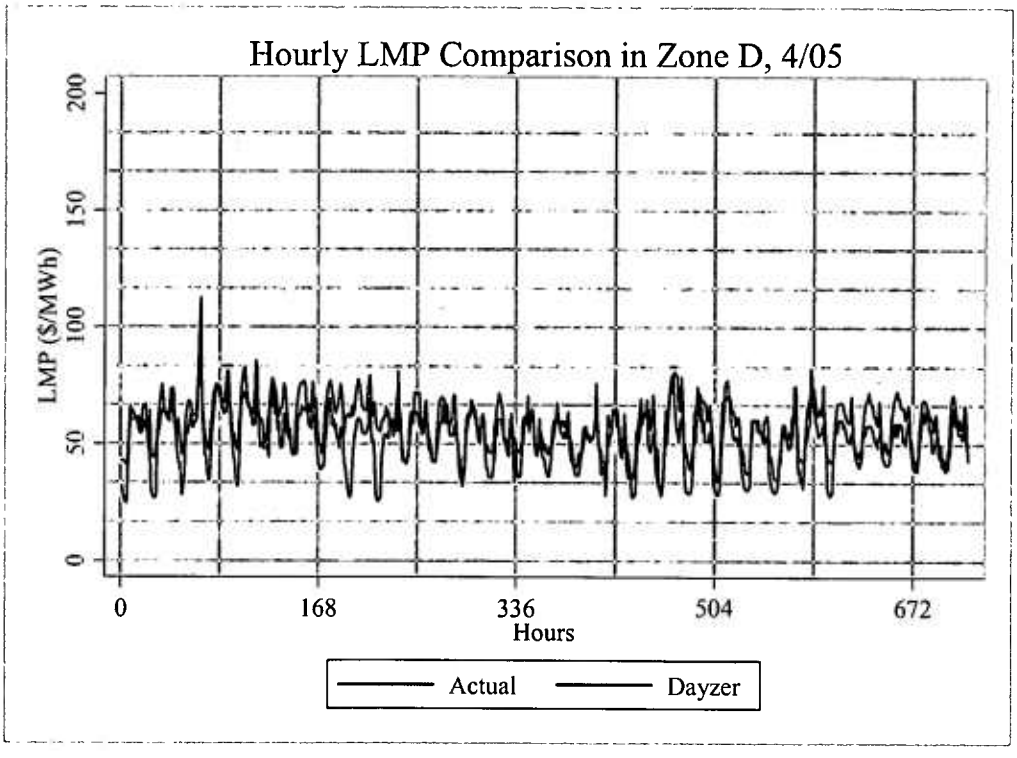

Hourly LMP Duration in Zone D, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

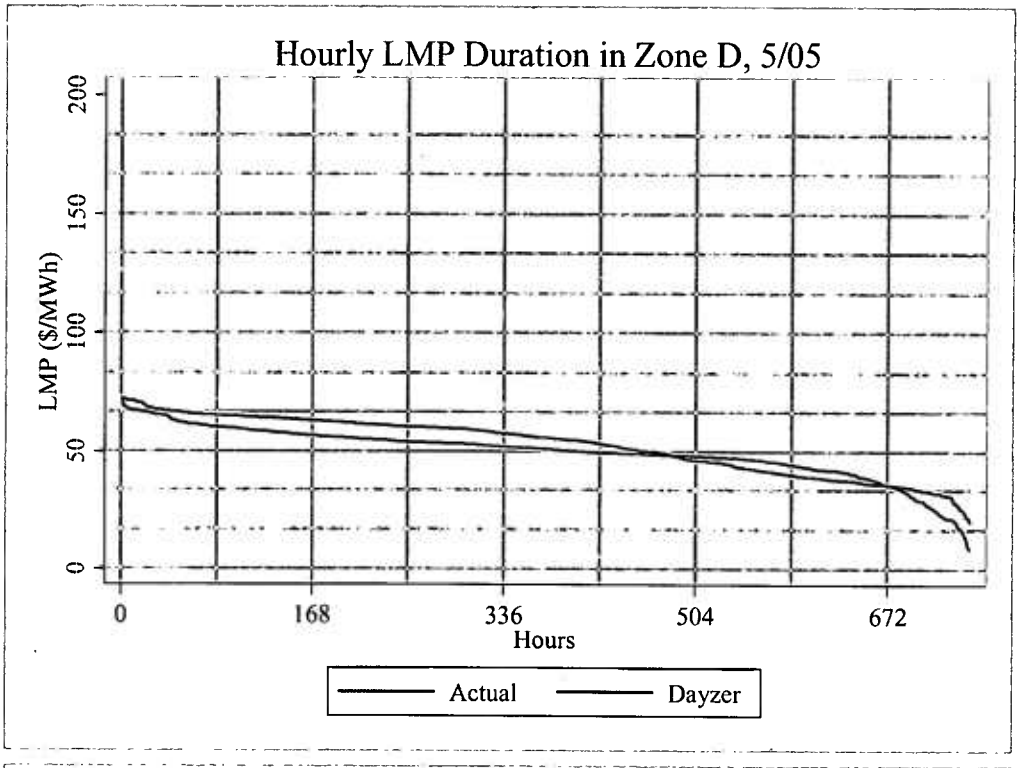

Hourly LMP Comparison in Zone D, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

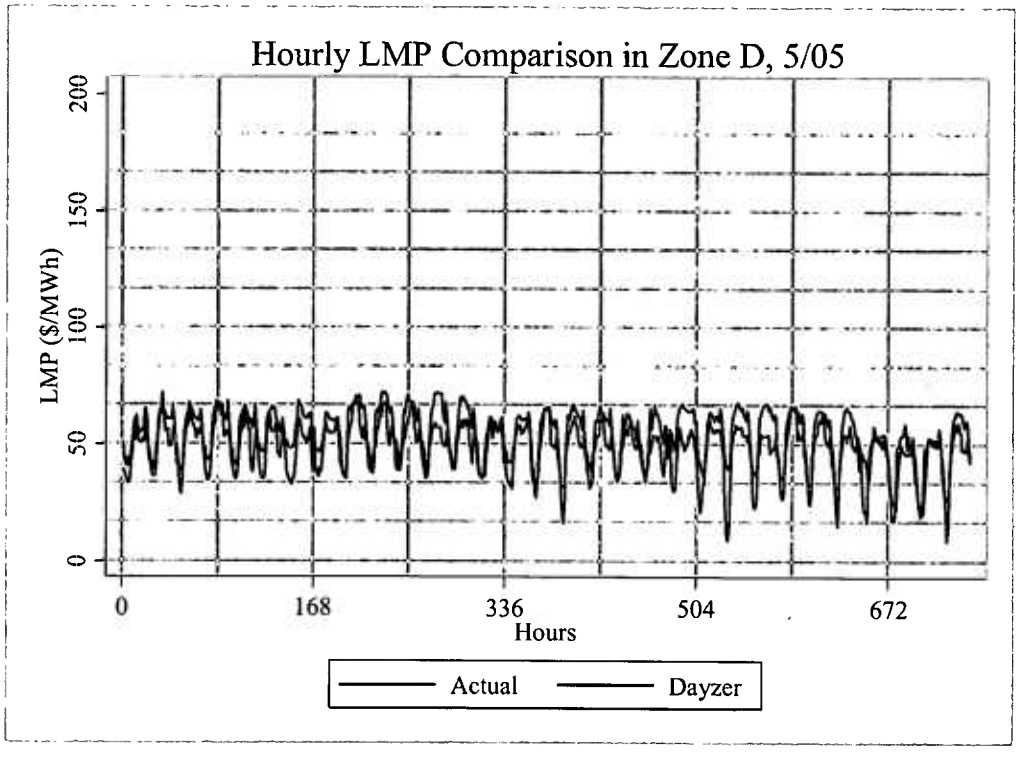

Hourly LMP Duration in Zone D, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

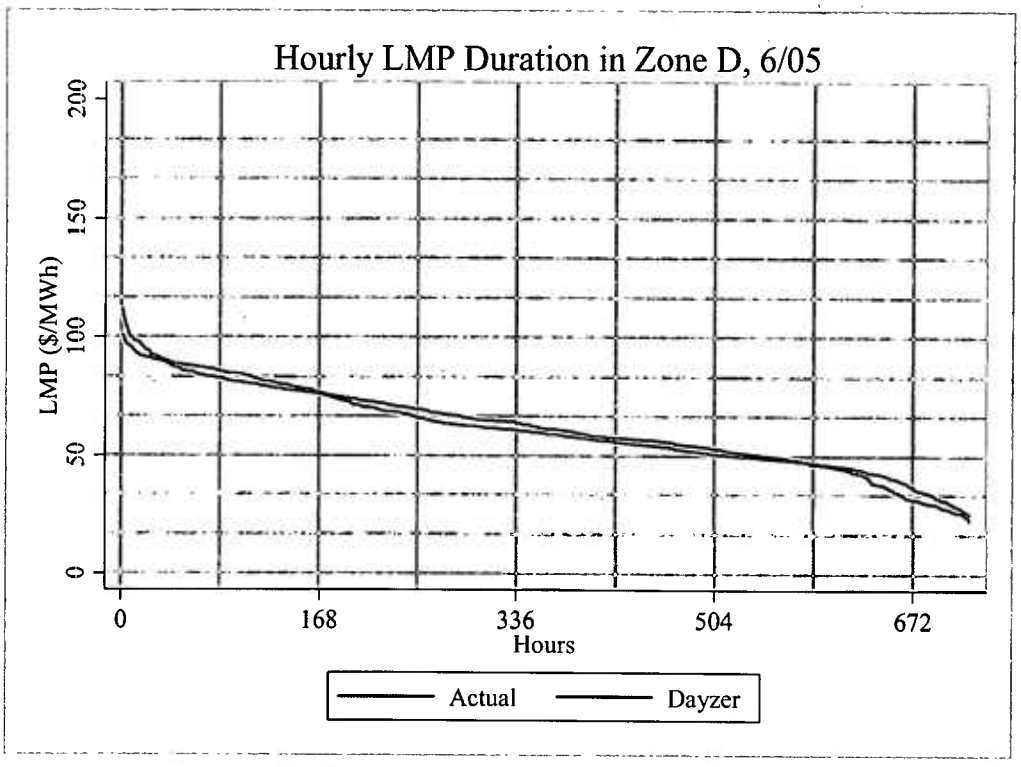

Hourly LMP Comparison in Zone D, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

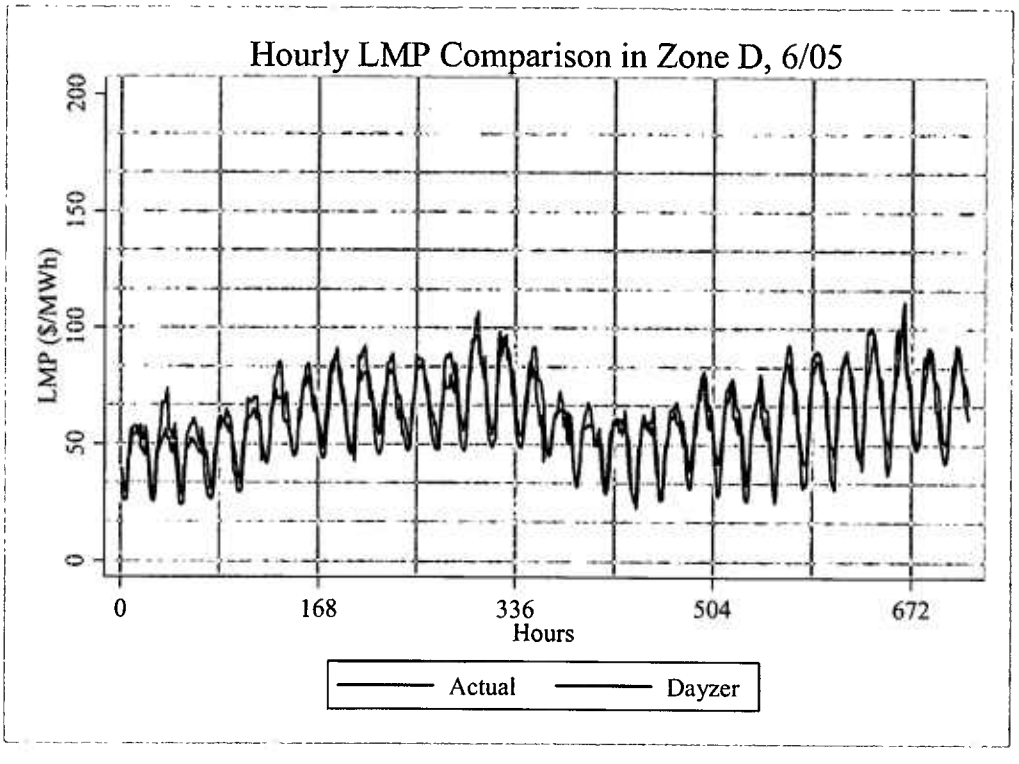

Hourly LMP Duration in Zone D, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

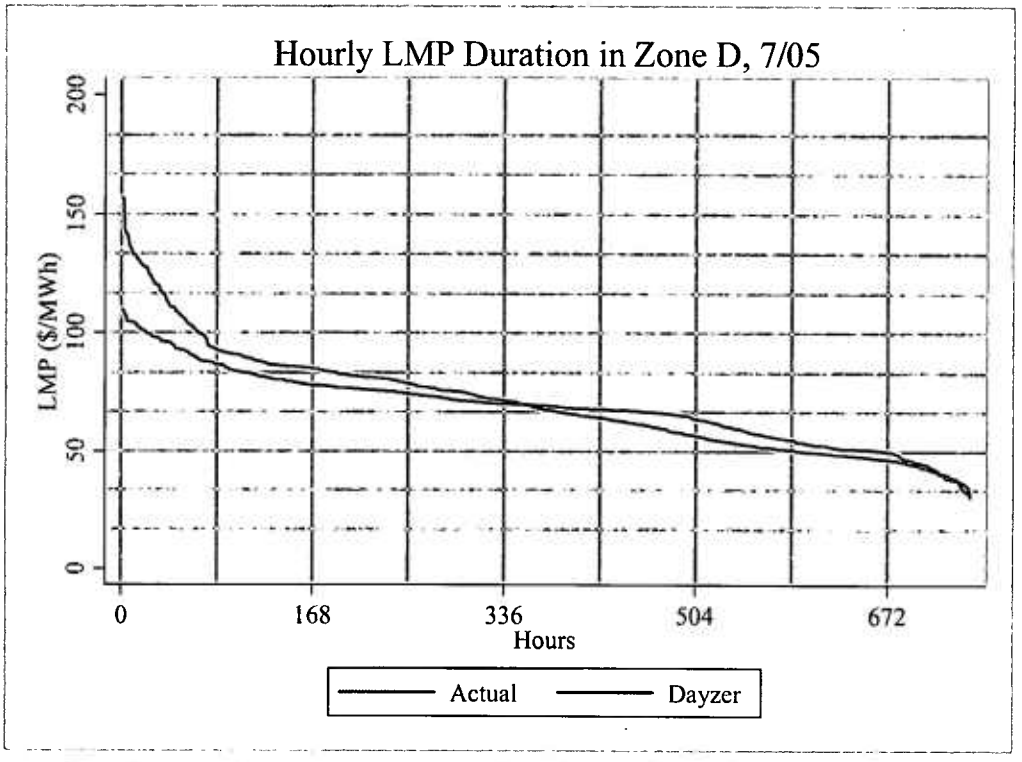

Hourly LMP Comparison in Zone D, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

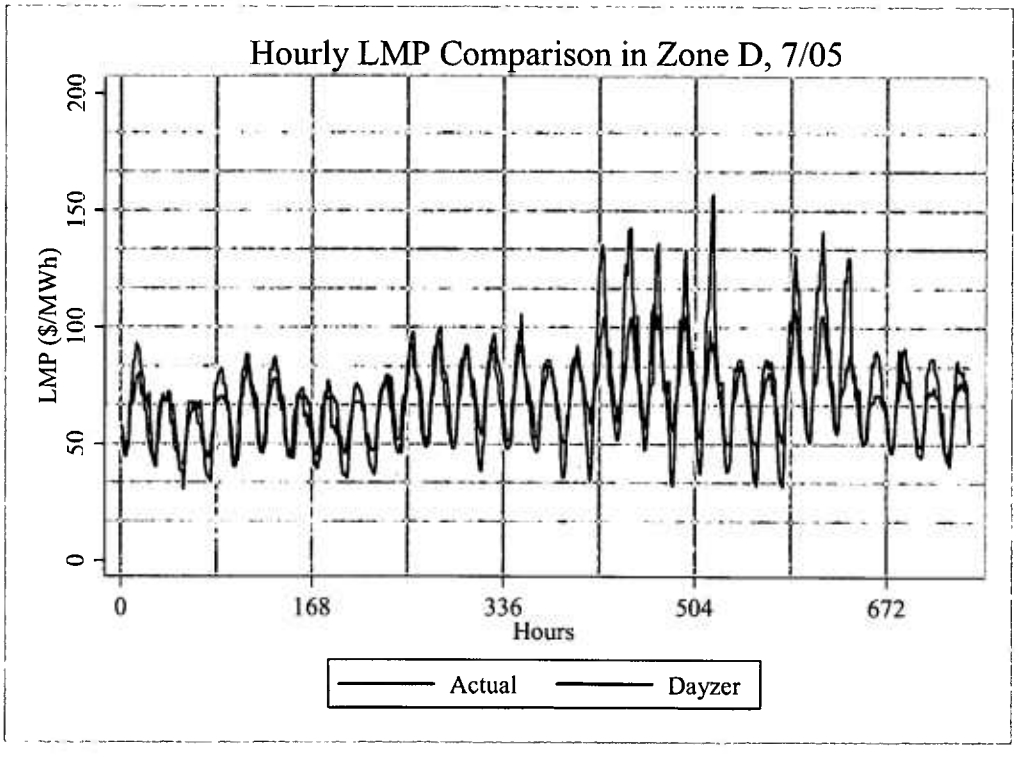

Hourly LMP Duration in Zone D, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

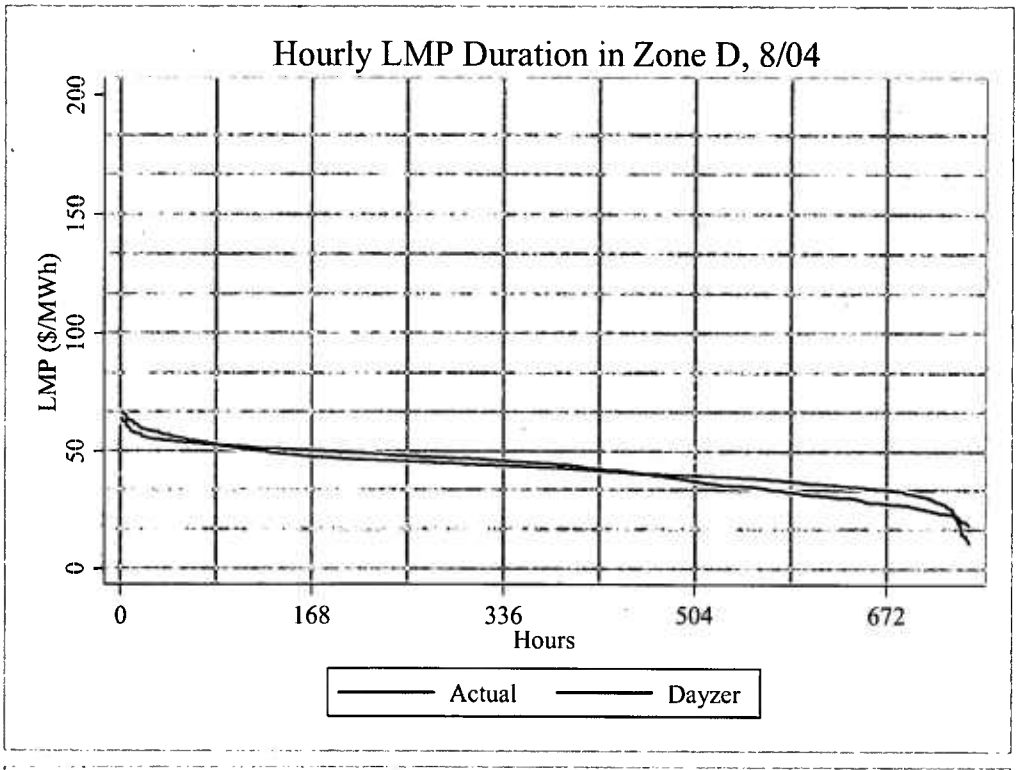

Hourly LMP Comparison in Zone D, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

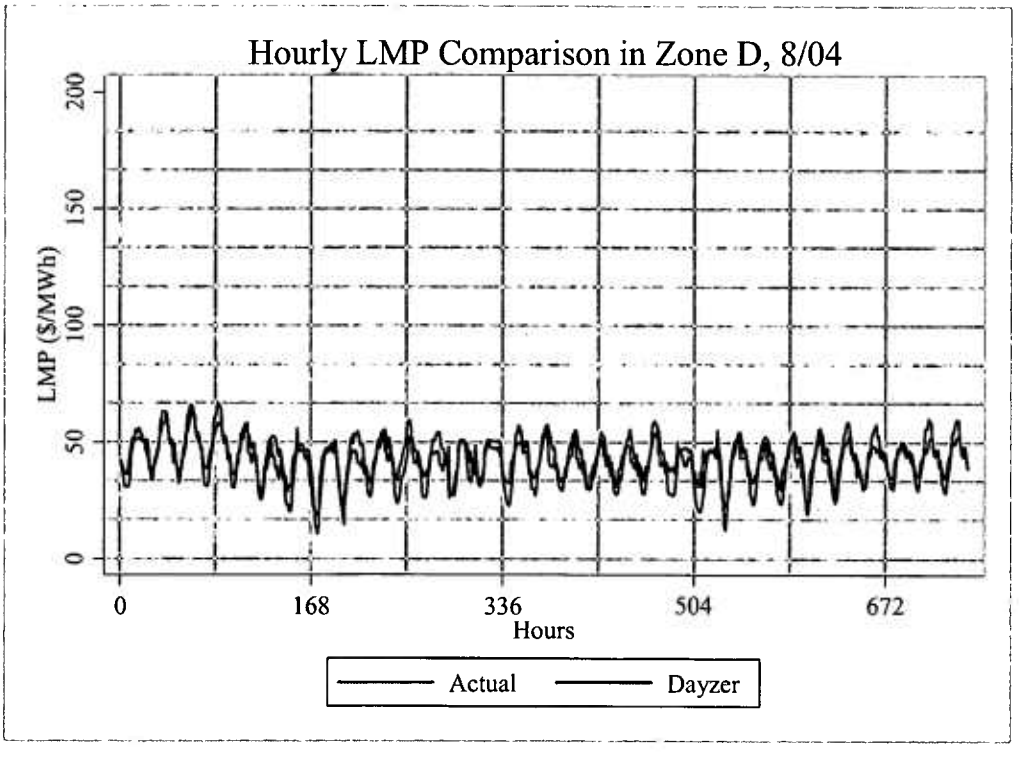

Hourly LMP Duration in Zone D, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

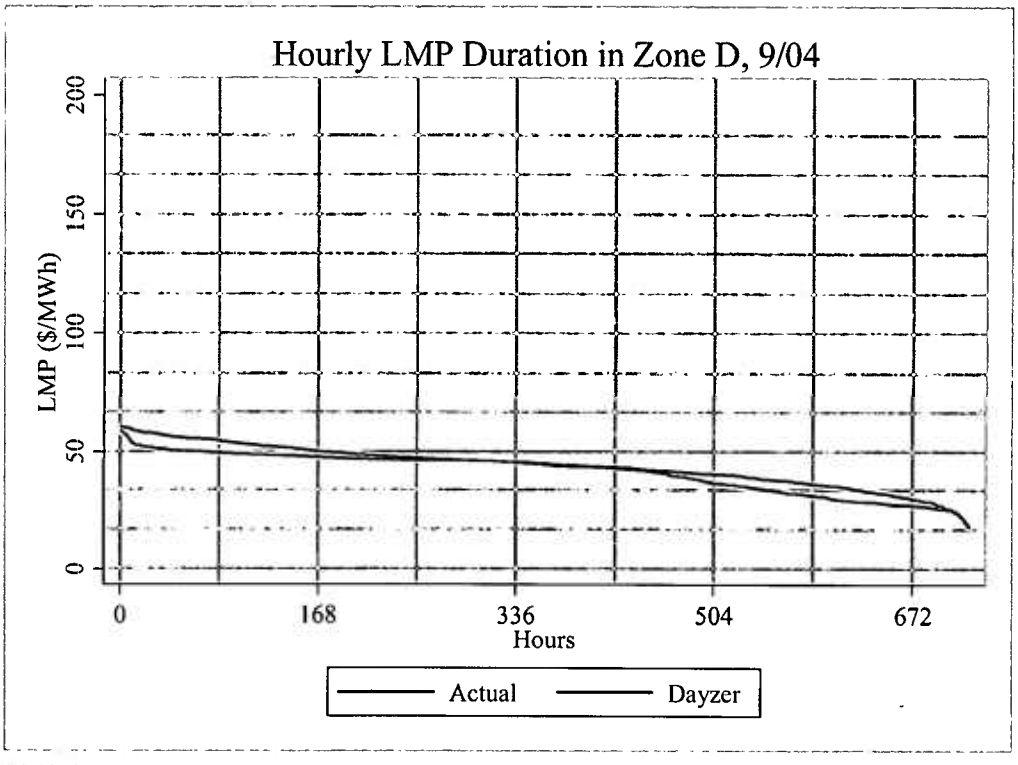

Hourly LMP Comparison in Zone D, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

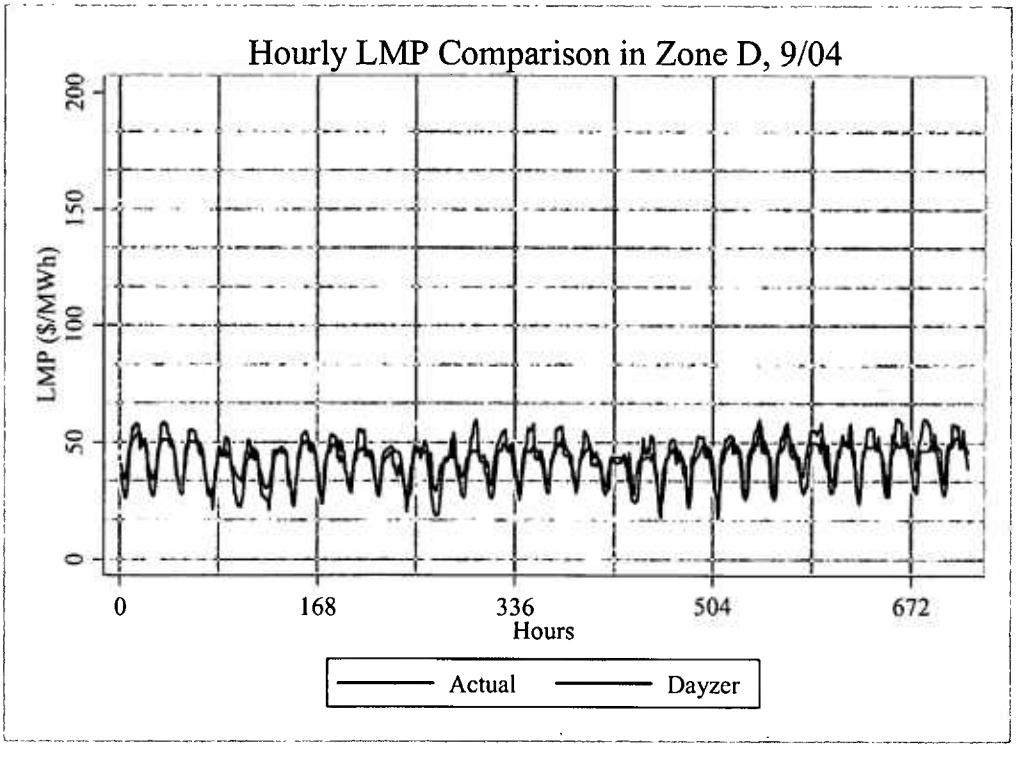

Hourly LMP Duration in Zone D, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

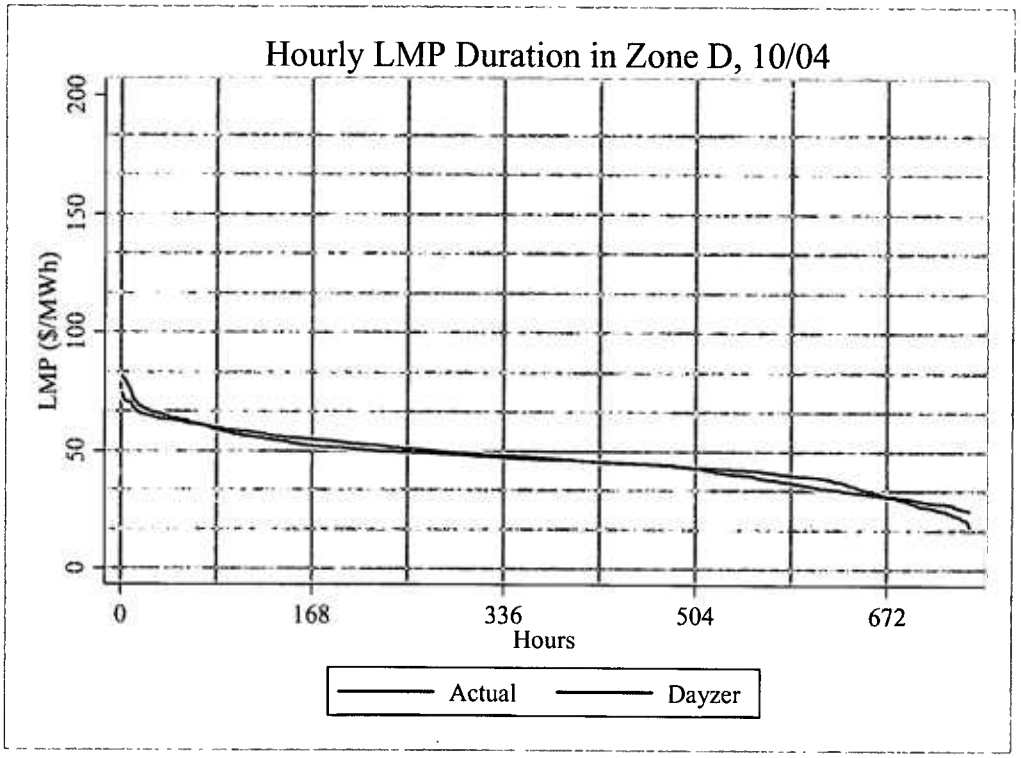

Hourly LMP Comparison in Zone D, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

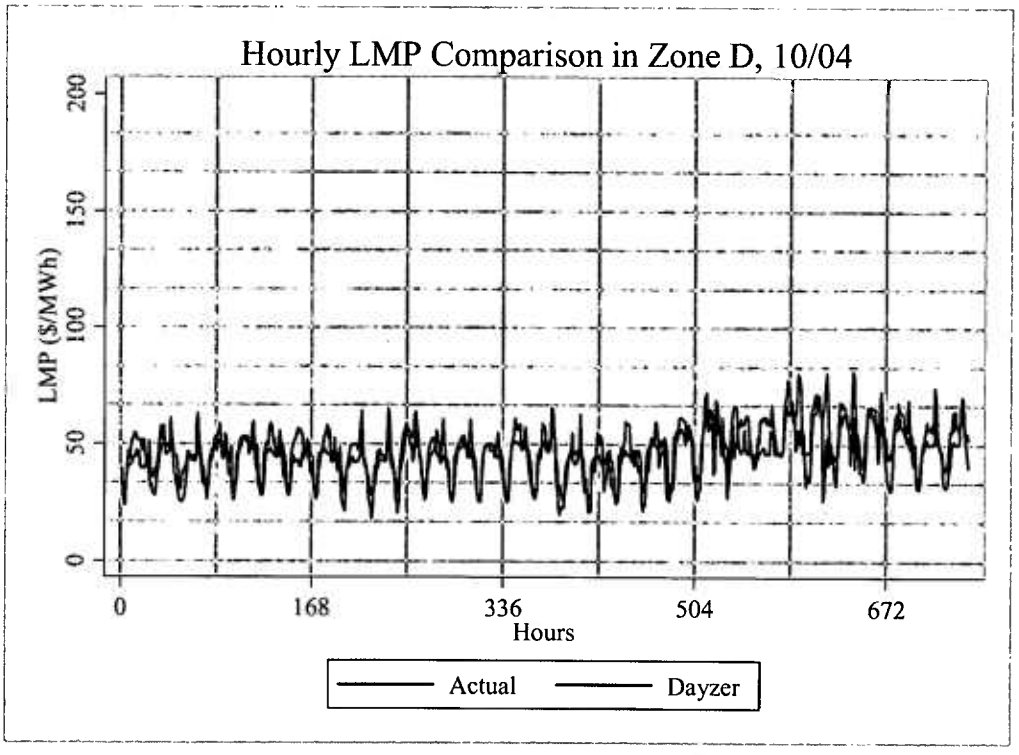

Hourly LMP Duration in Zone D, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

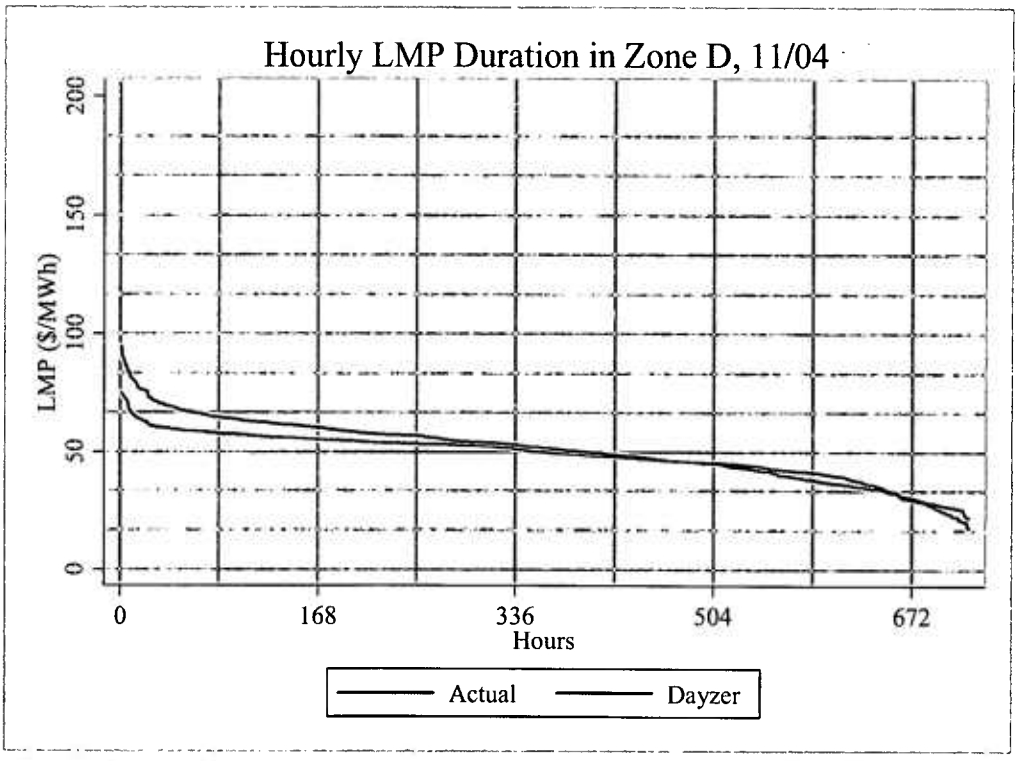

Hourly LMP Comparison in Zone D, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

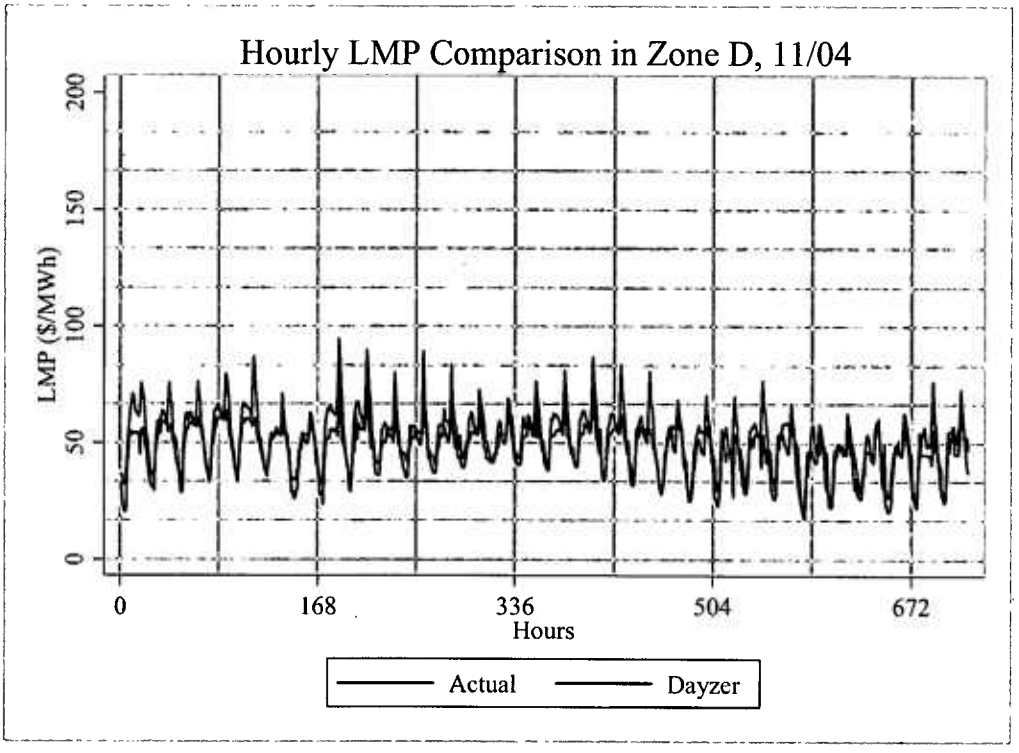

Hourly LMP Duration in Zone D, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

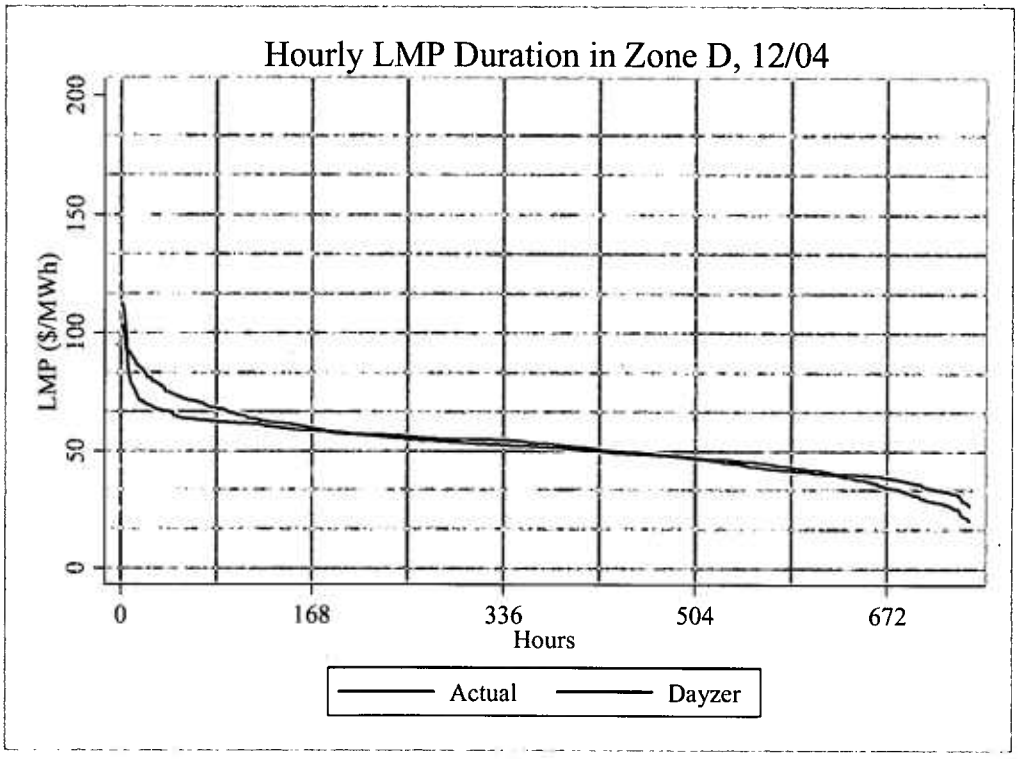

Hourly LMP Comparison in Zone D, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

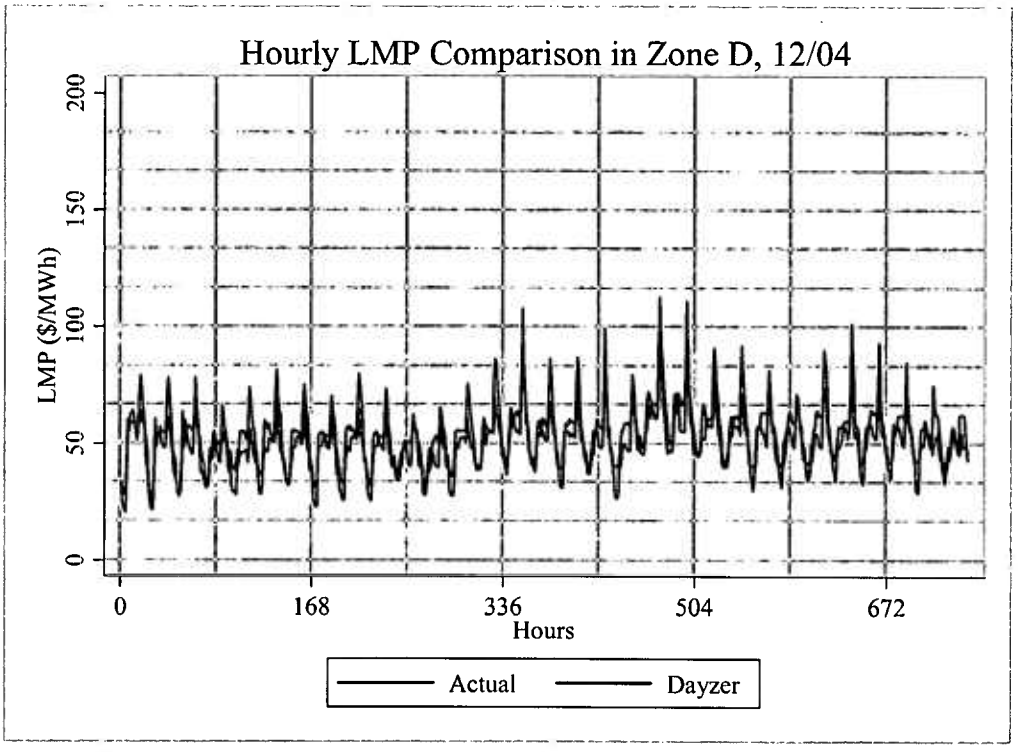

Hourly LMP Duration in Zone D, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

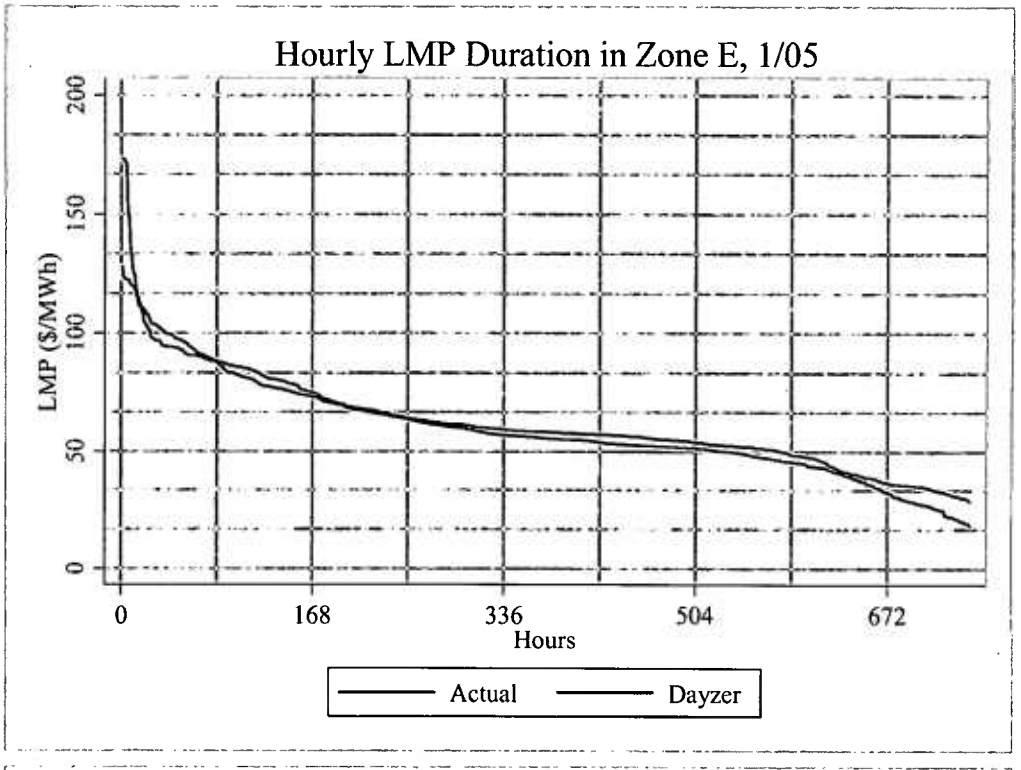

Hourly LMP Comparison in Zone D, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

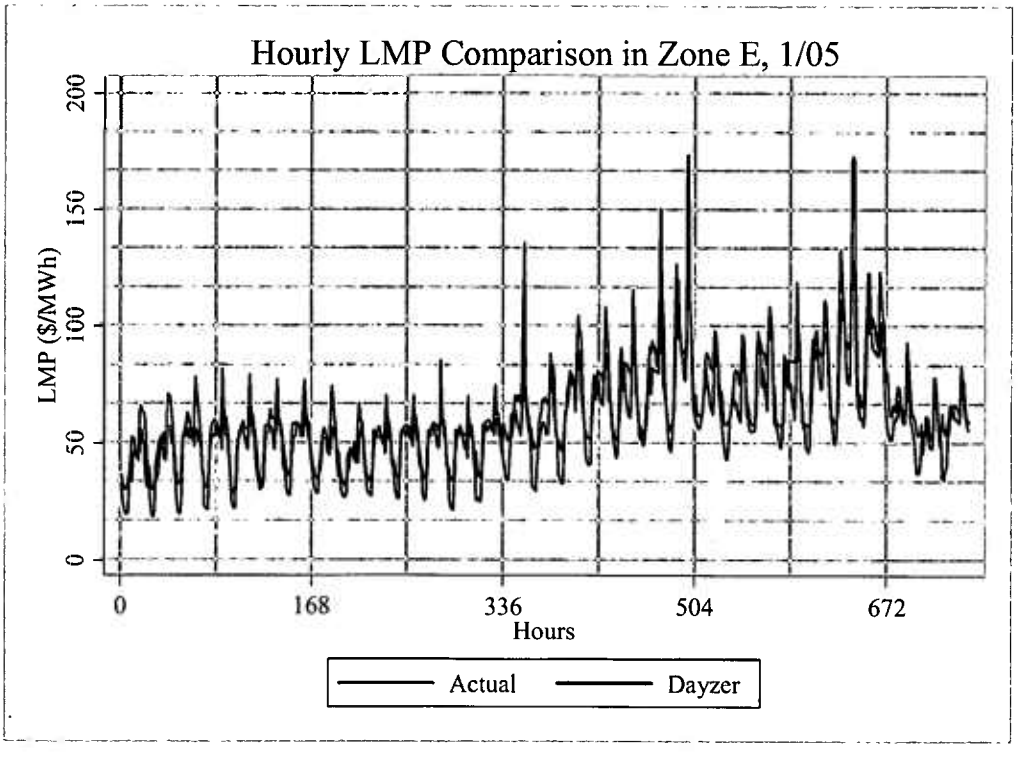

Hourly LMP Duration in Zone D, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

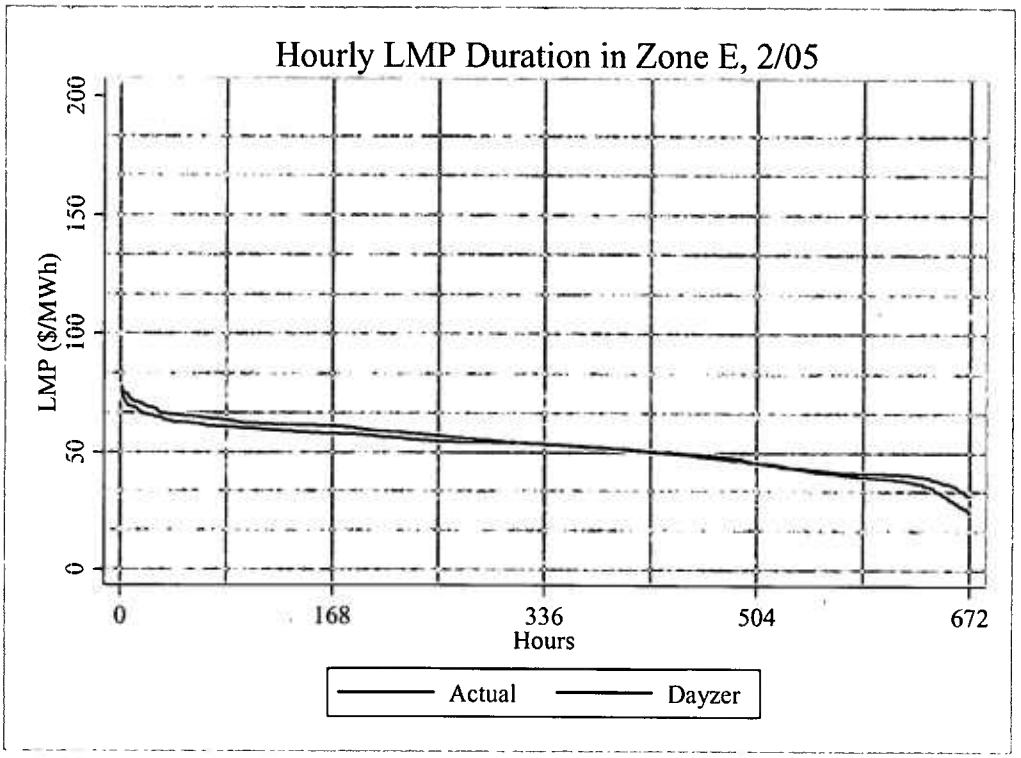

Hourly LMP Comparison in Zone D, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

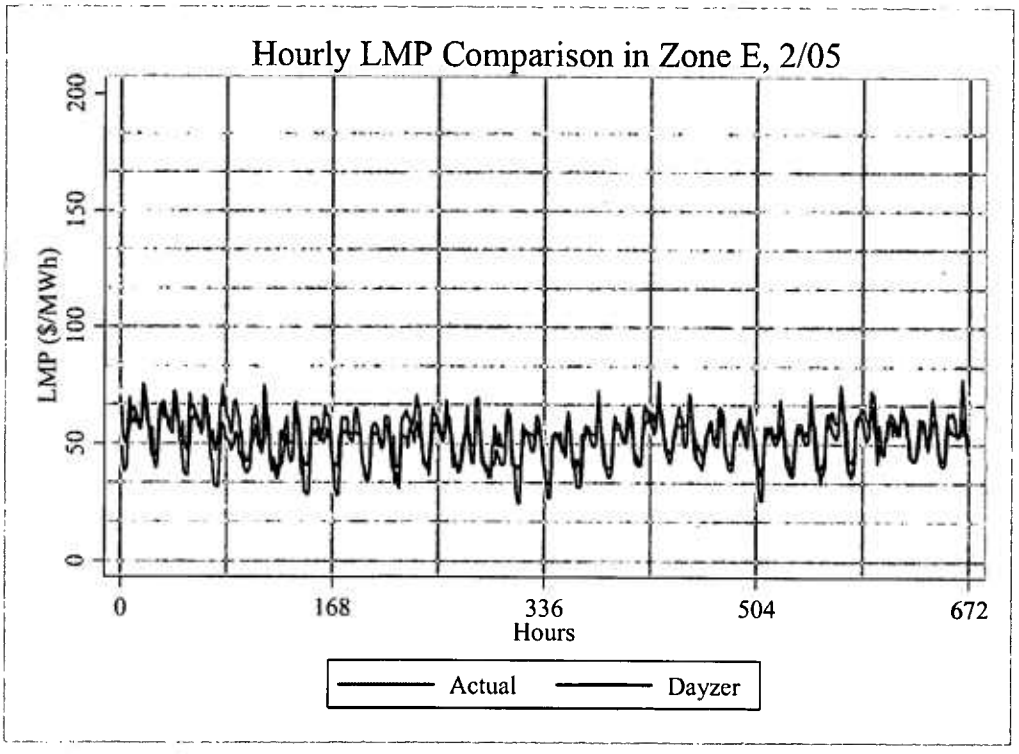

Hourly LMP Duration in Zone D, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

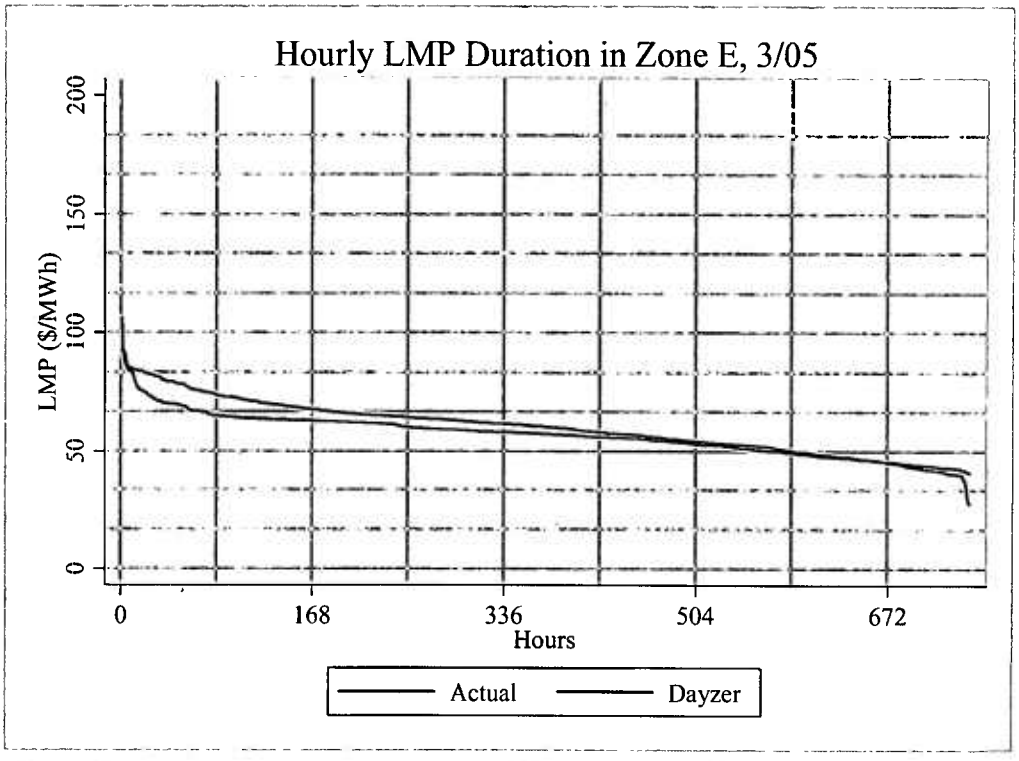

Hourly LMP Comparison in Zone D, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

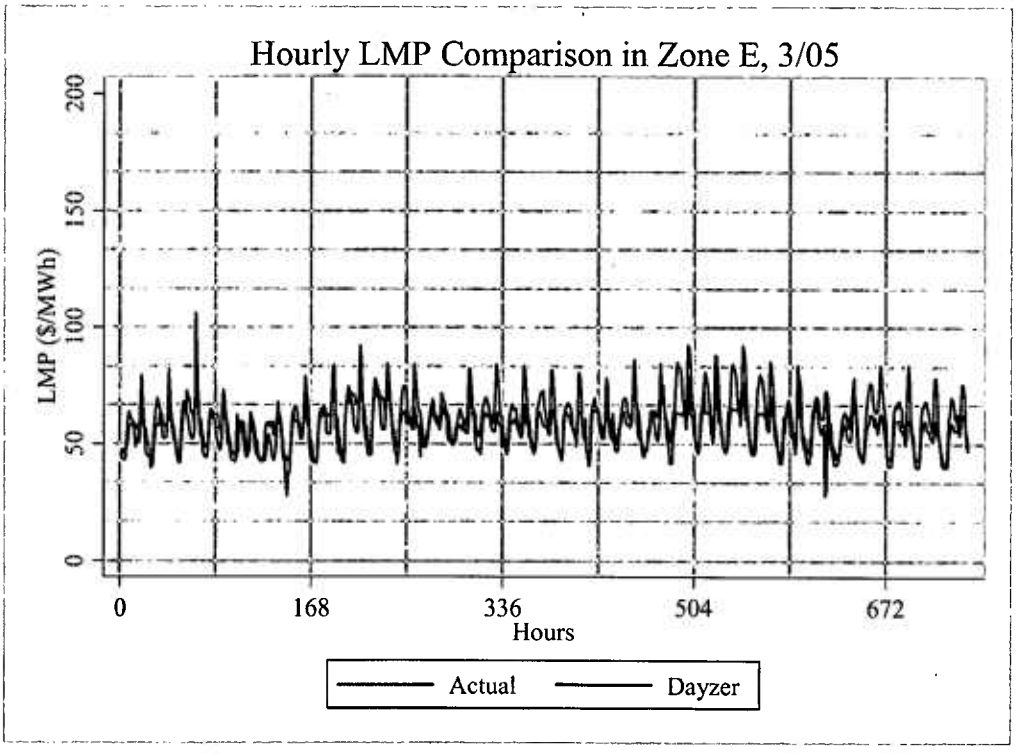

Hourly LMP Duration in Zone E, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

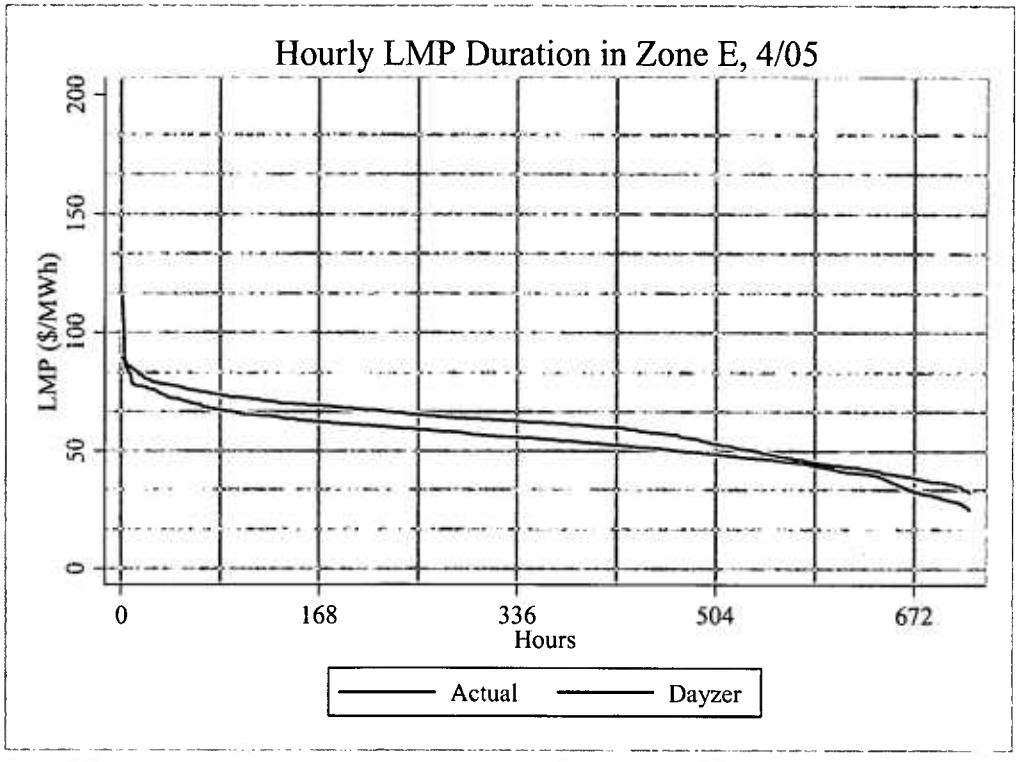

Hourly LMP Comparison in Zone E, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

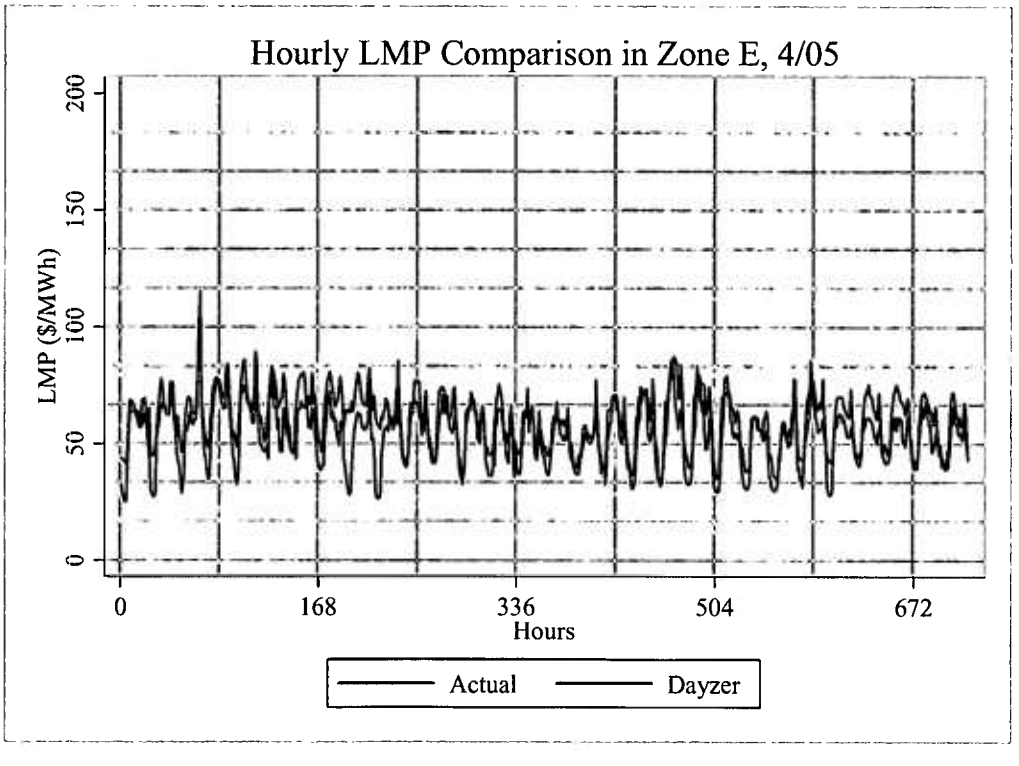

Hourly LMP Duration in Zone E, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

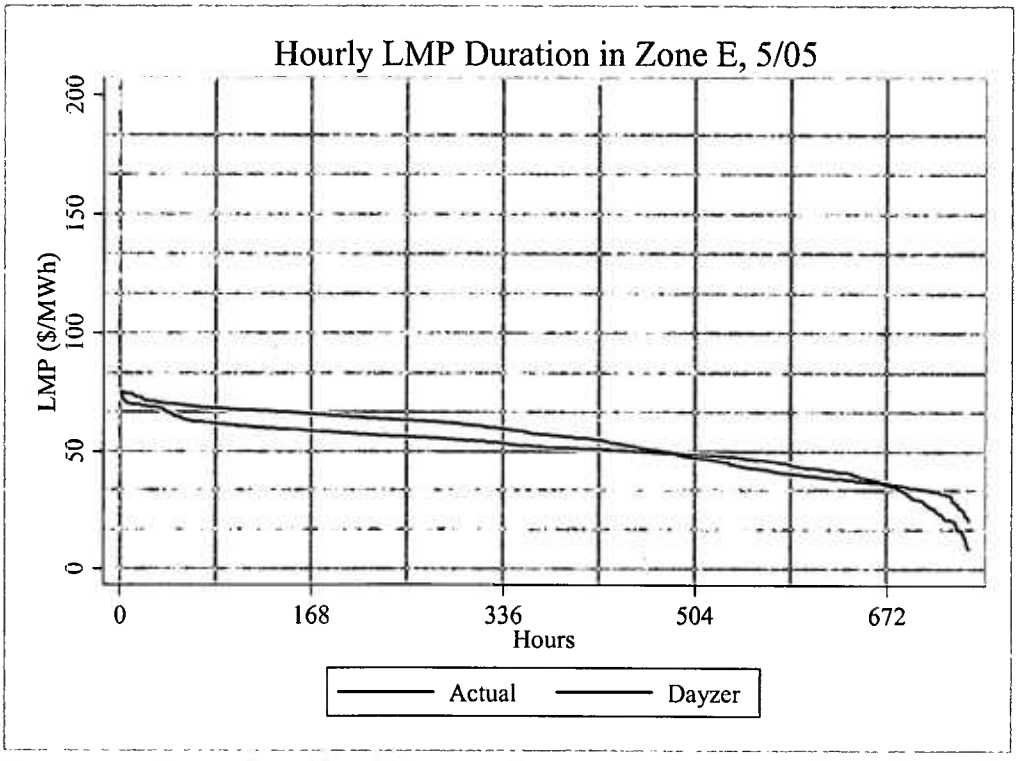

Hourly LMP Comparison in Zone E, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

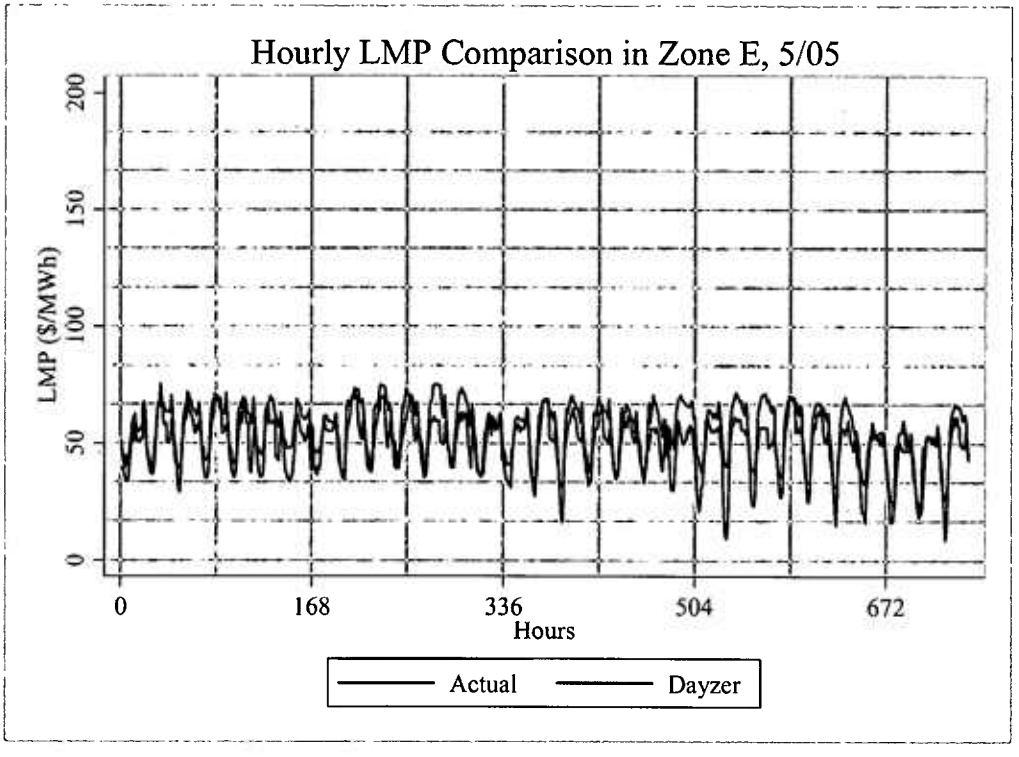

Hourly LMP Duration in Zone E, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

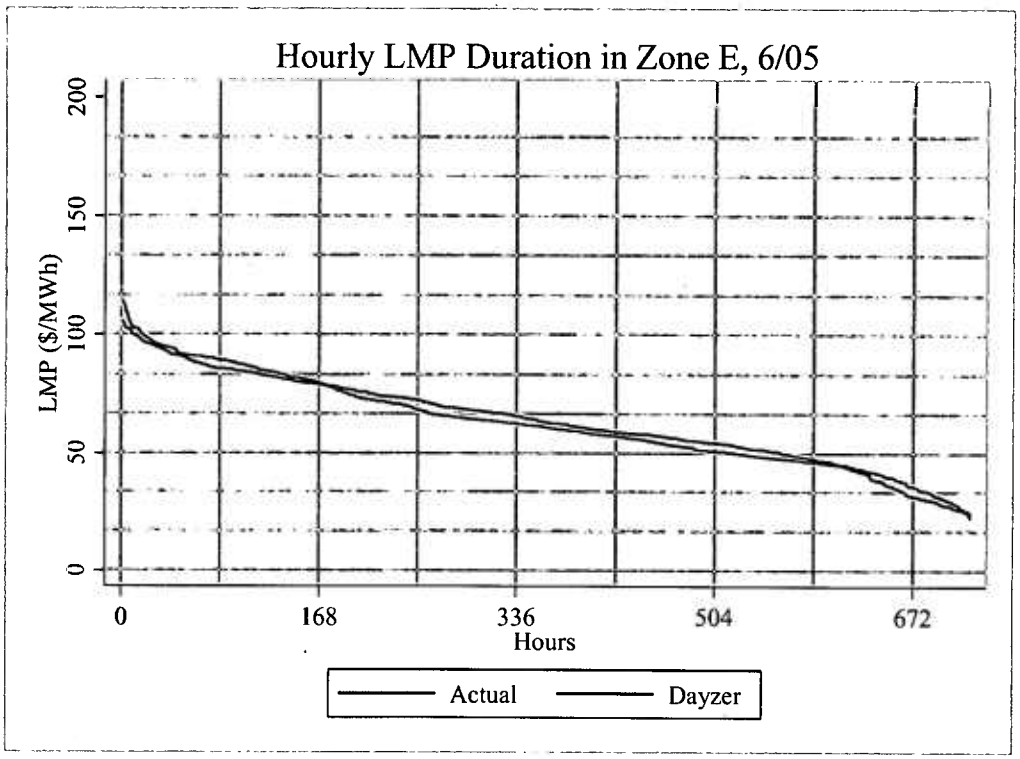

Hourly LMP Comparison in Zone E, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

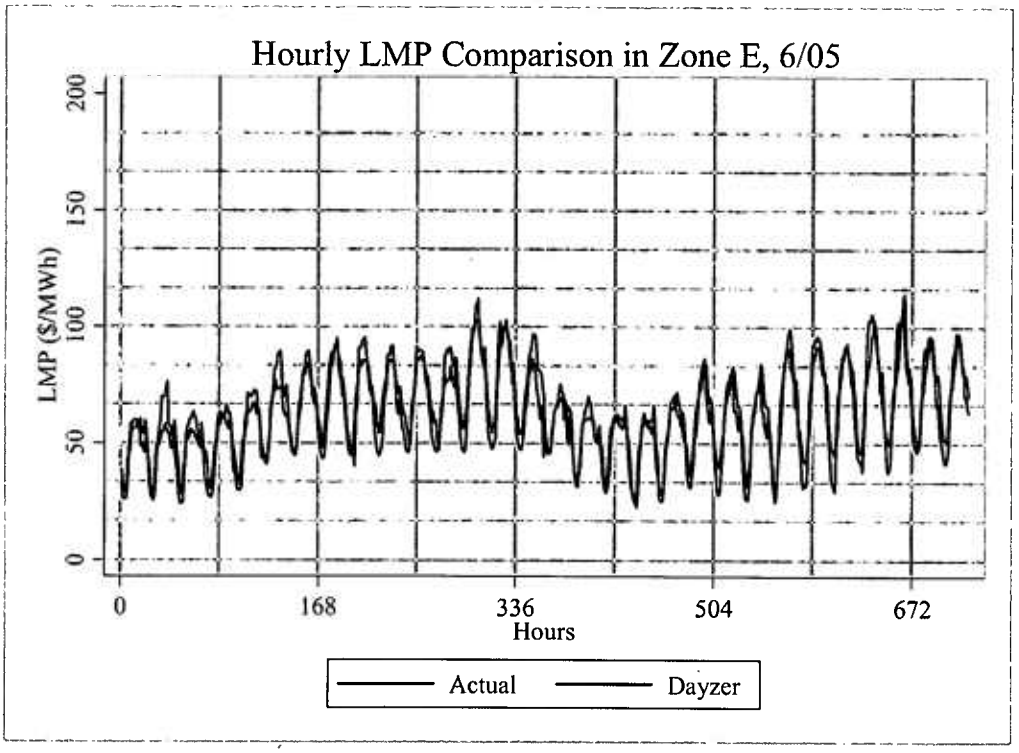

Hourly LMP Duration in Zone E, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

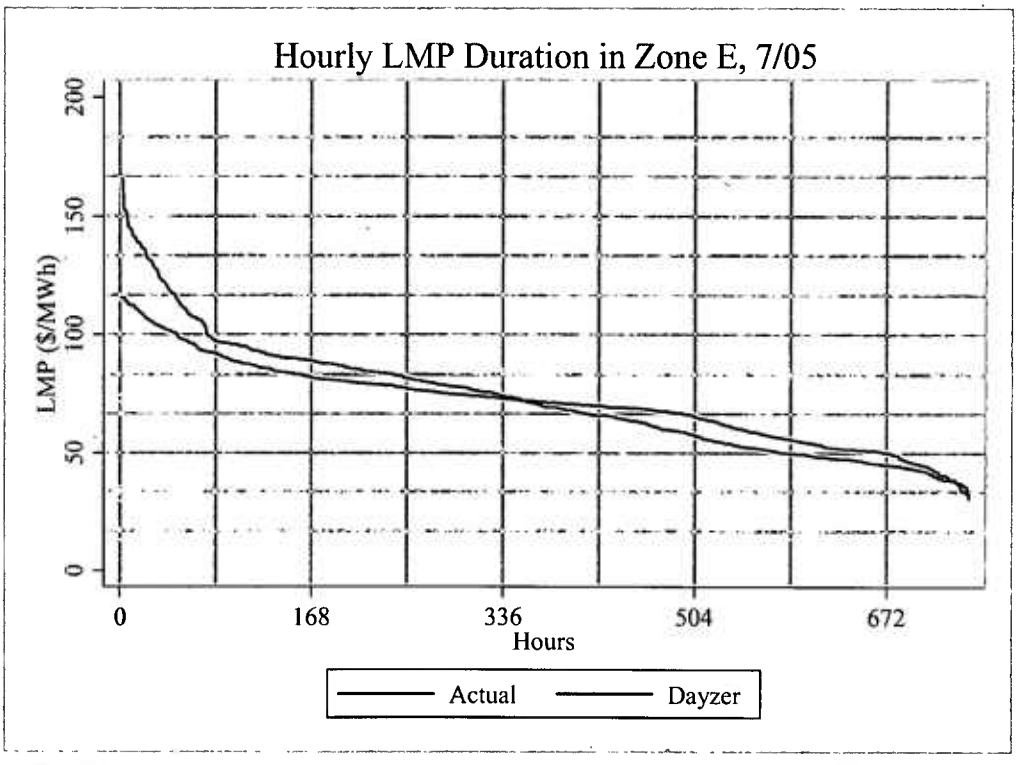

Hourly LMP Comparison in Zone E, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

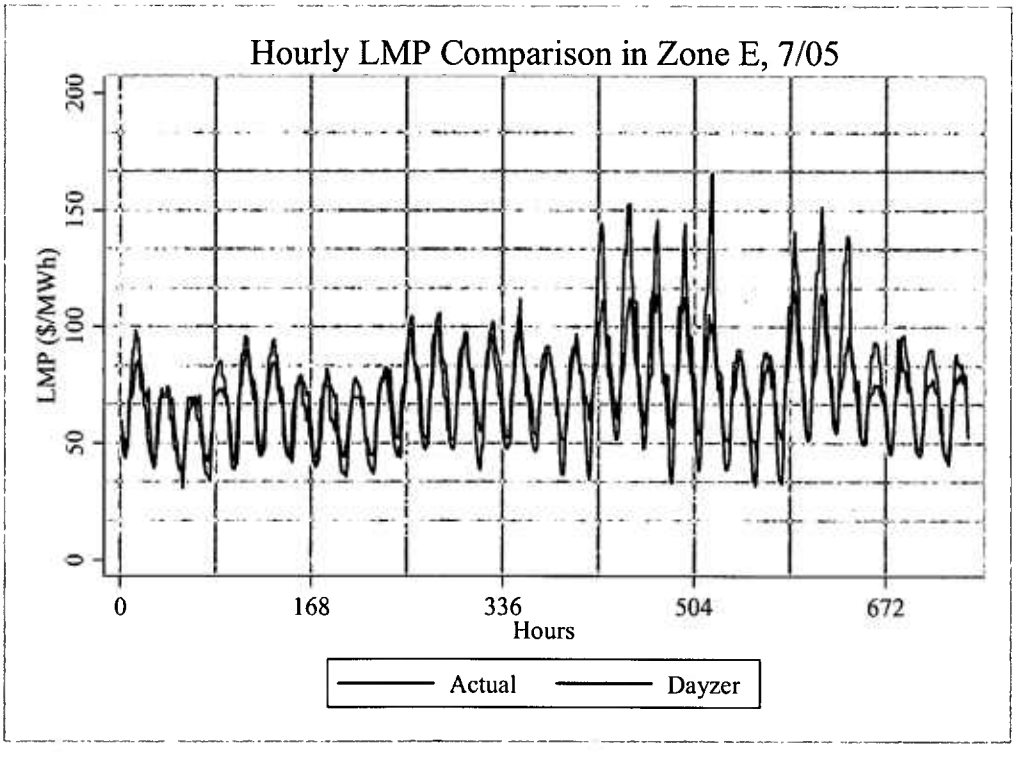

Hourly LMP Duration in Zone E, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

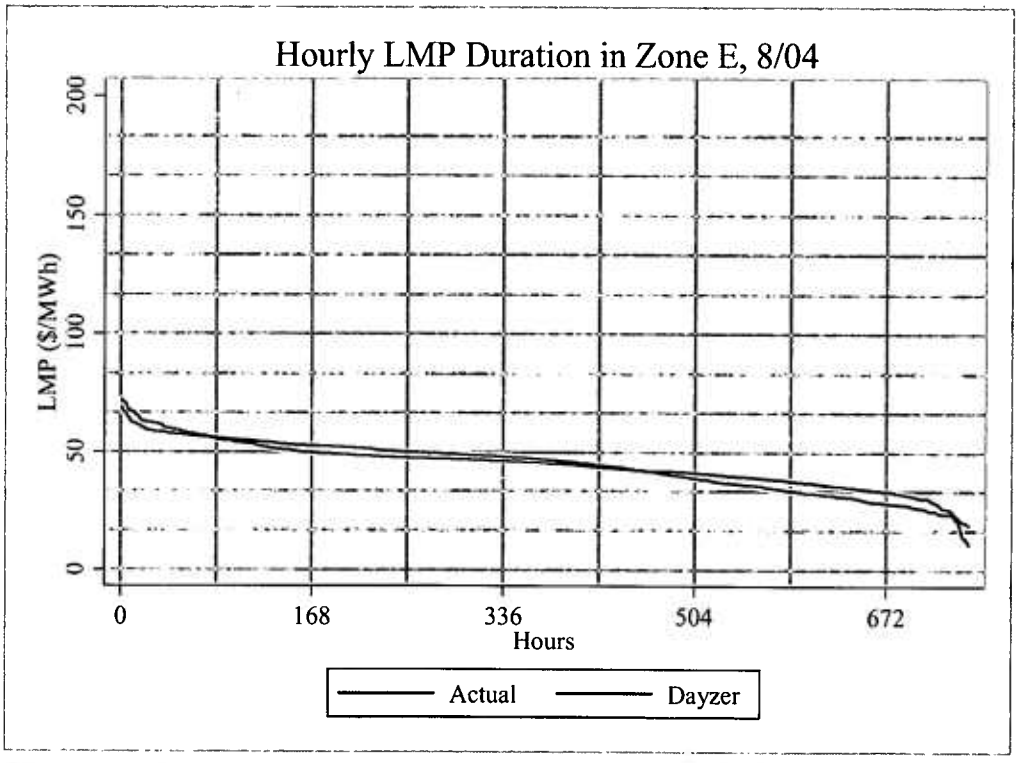

Hourly LMP Comparison in Zone E, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

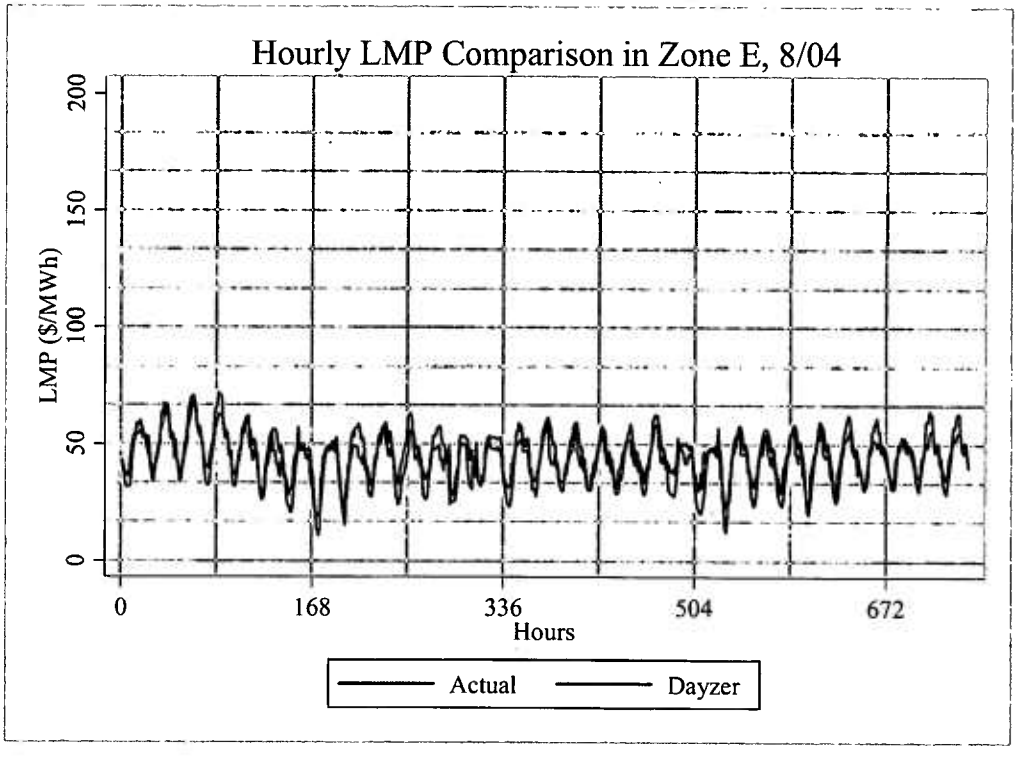

Hourly LMP Duration in Zone E, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

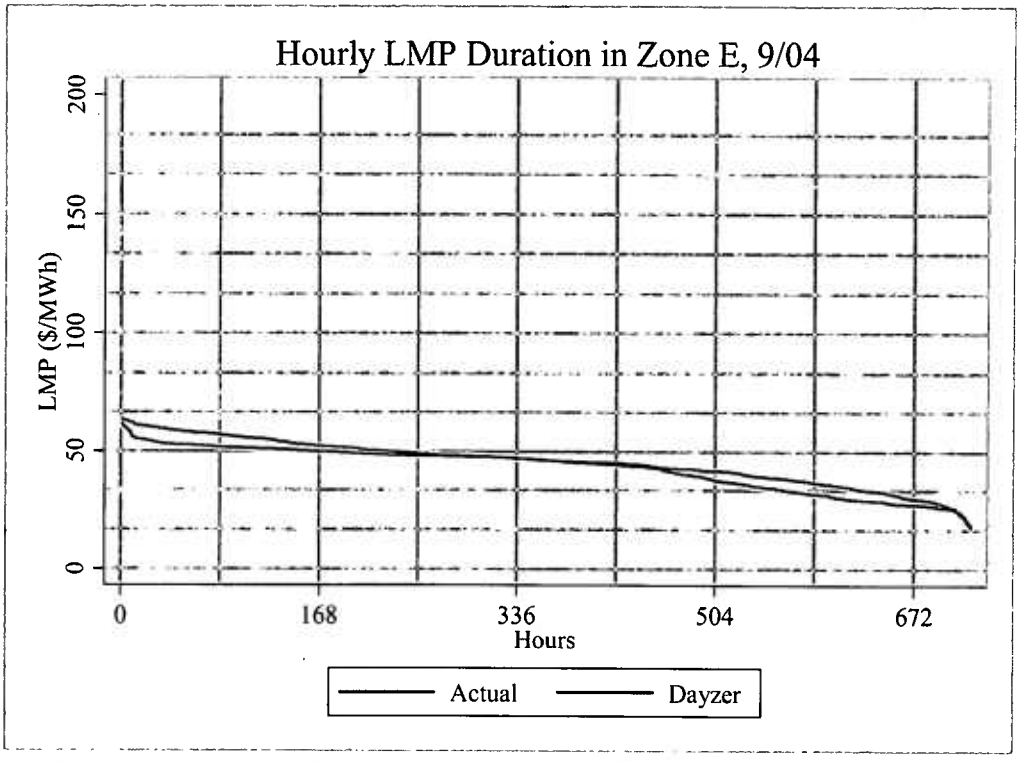

Hourly LMP Comparison in Zone E, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

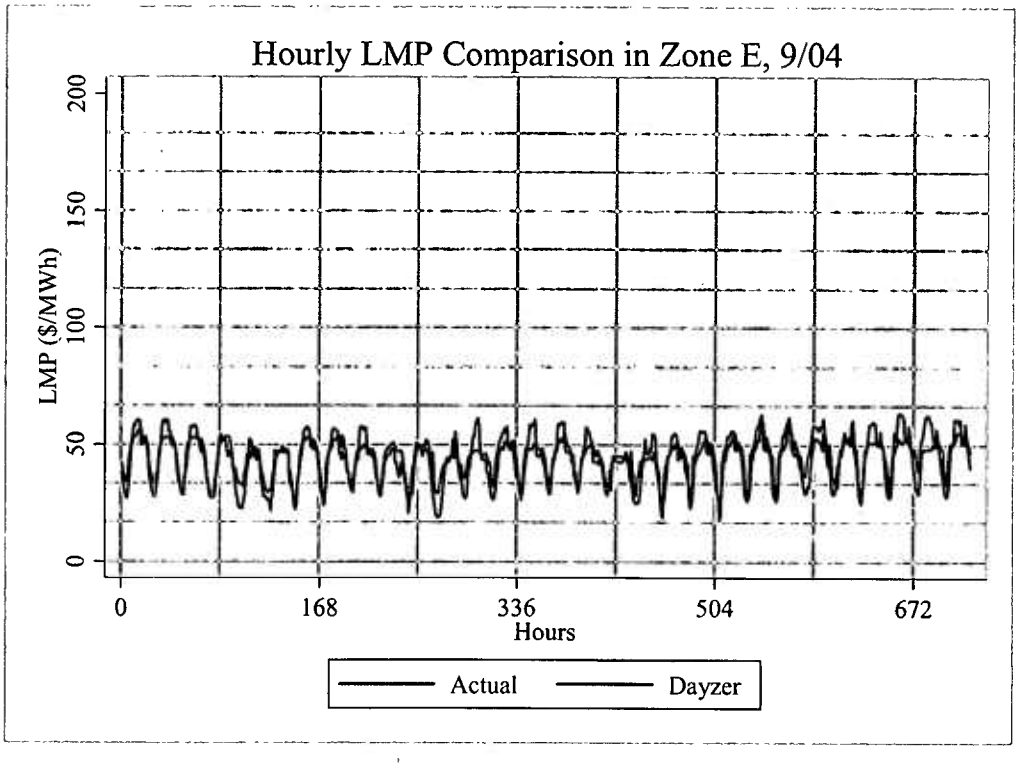

Hourly LMP Duration in Zone E, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

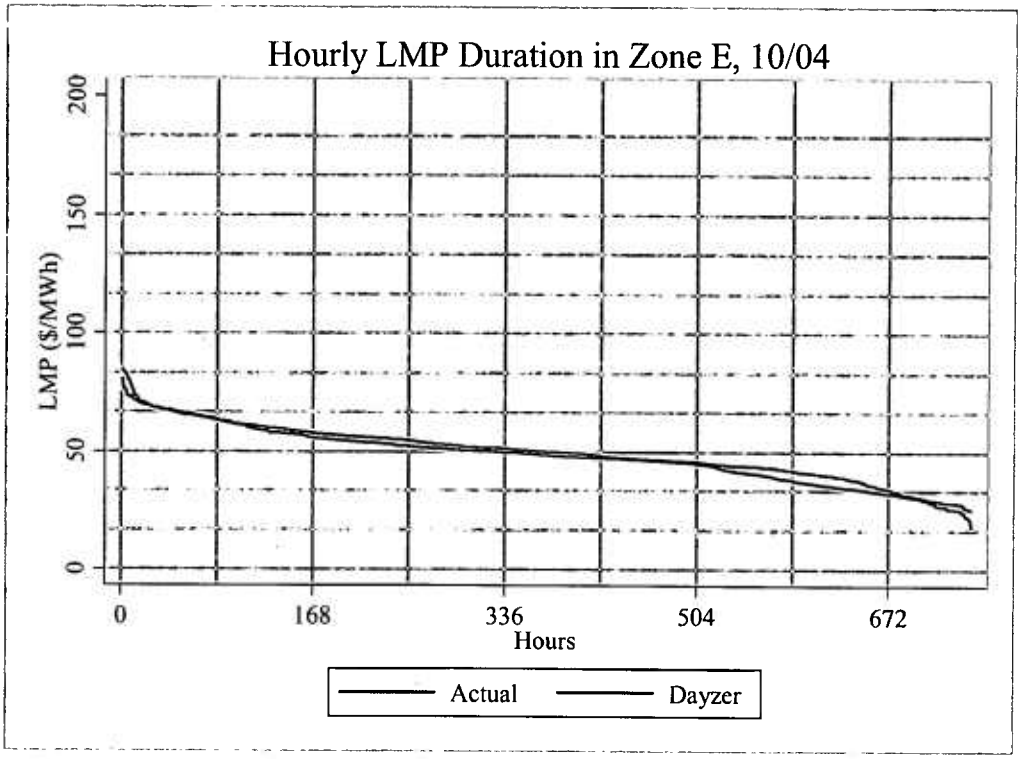

Hourly LMP Comparison in Zone E, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

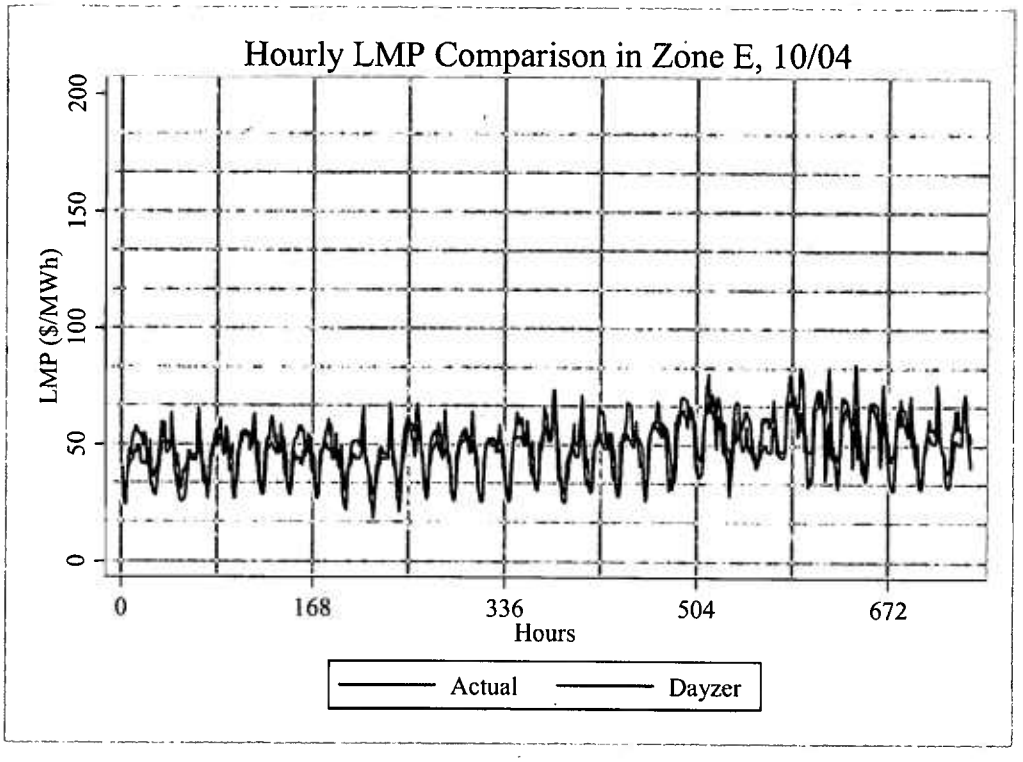

Hourly LMP Duration in Zone E, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

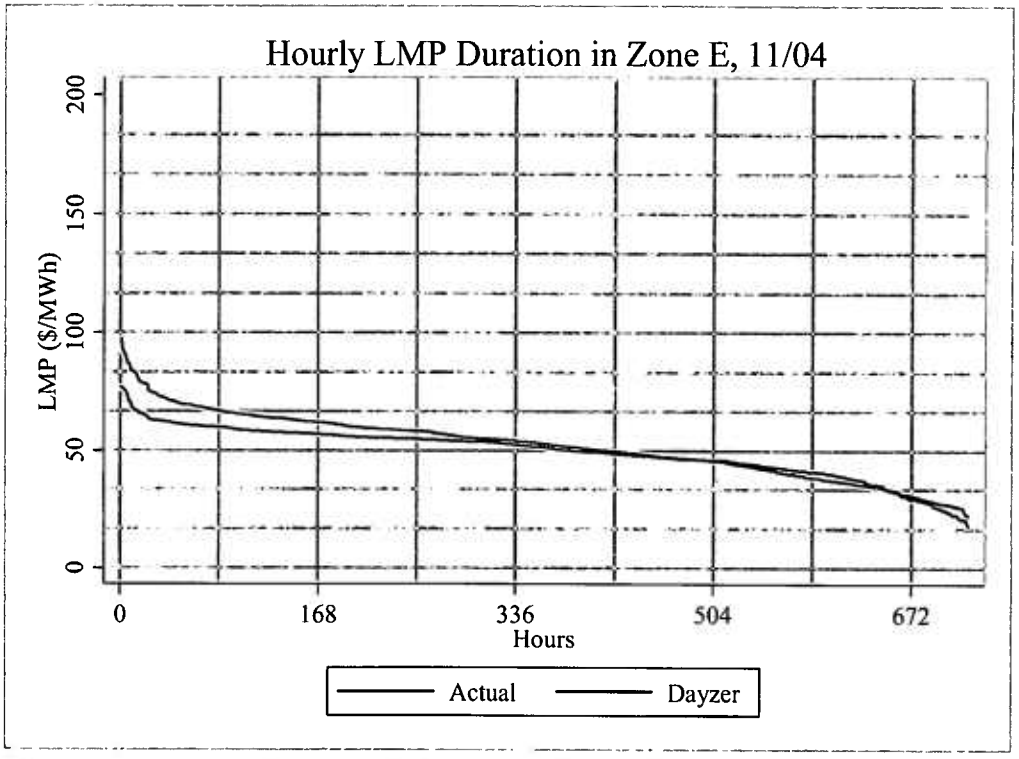

Hourly LMP Comparison in Zone E, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

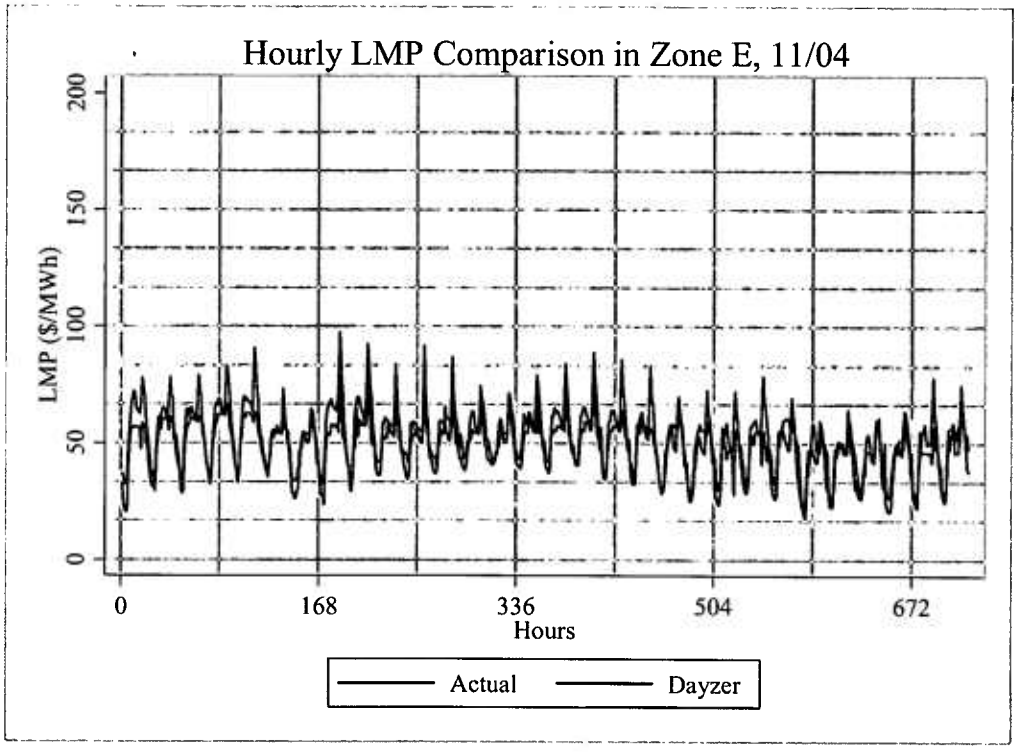

Hourly LMP Duration in Zone E, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

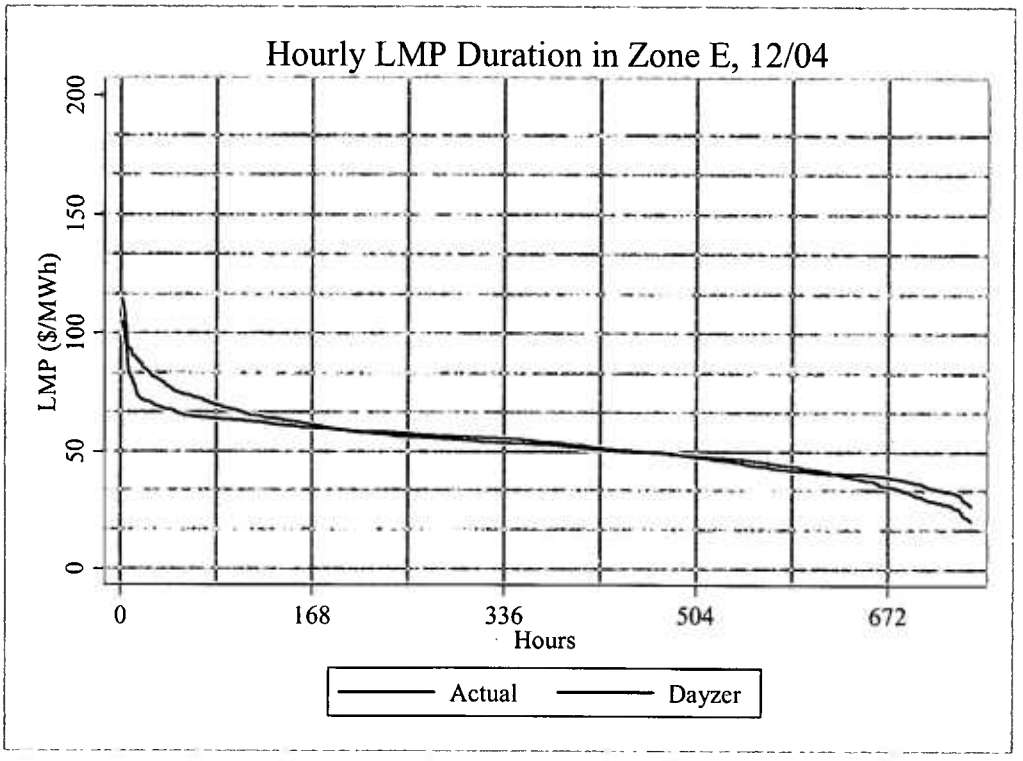

Hourly LMP Comparison in Zone E, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

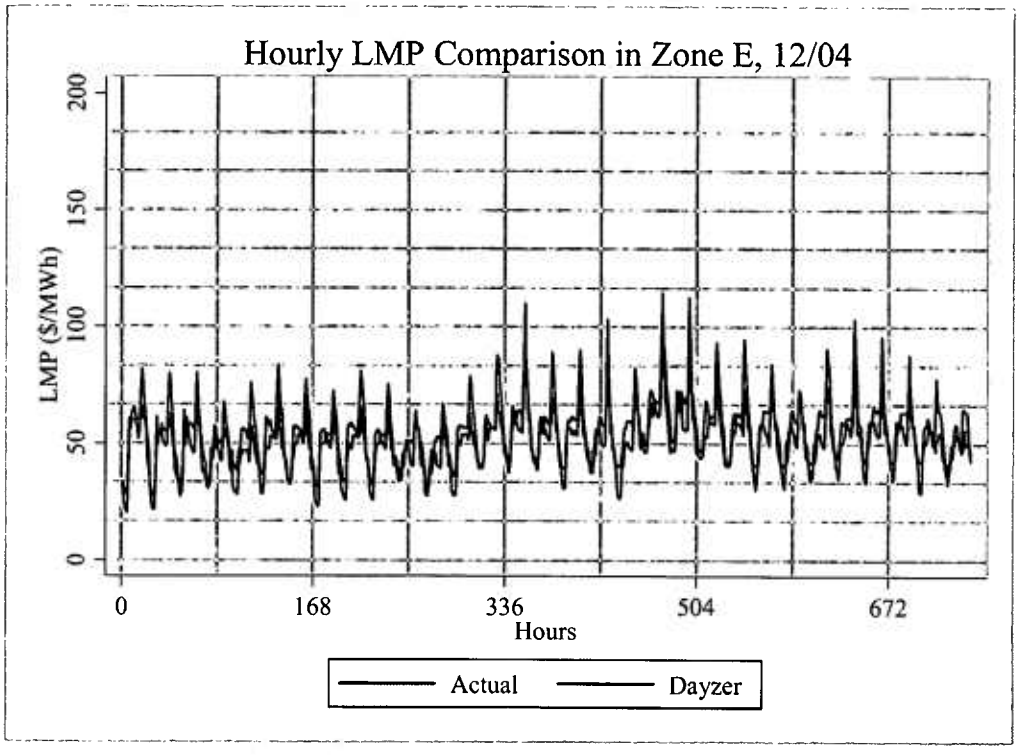

Hourly LMP Duration in Zone E, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

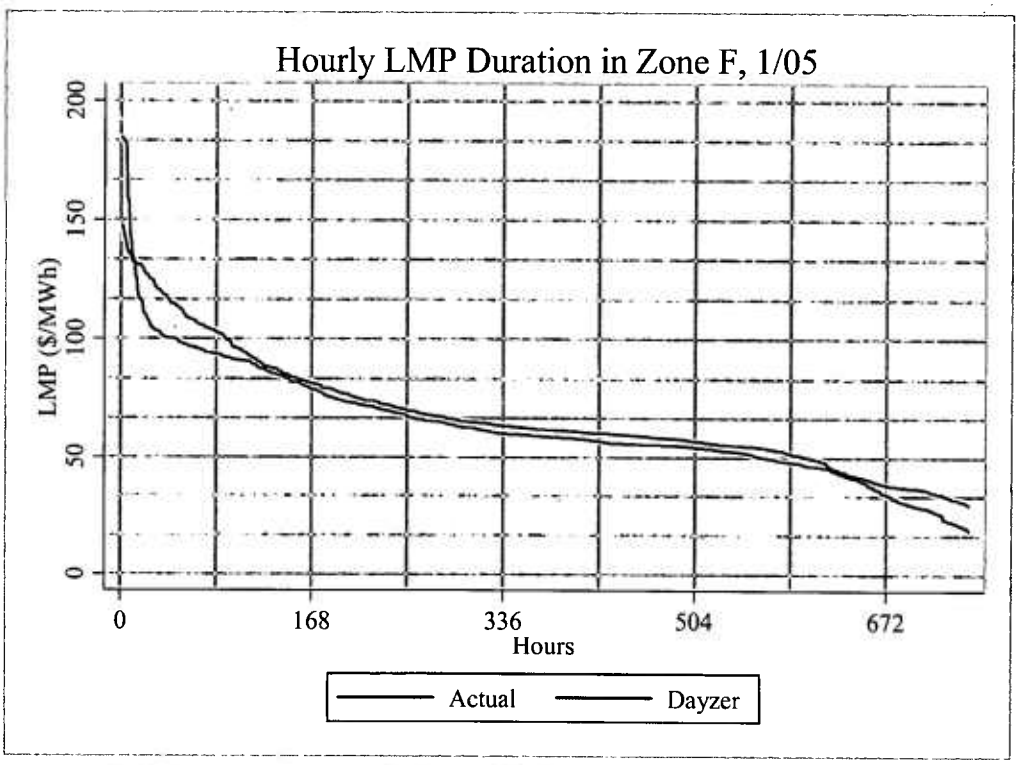

Hourly LMP Comparison in Zone E, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

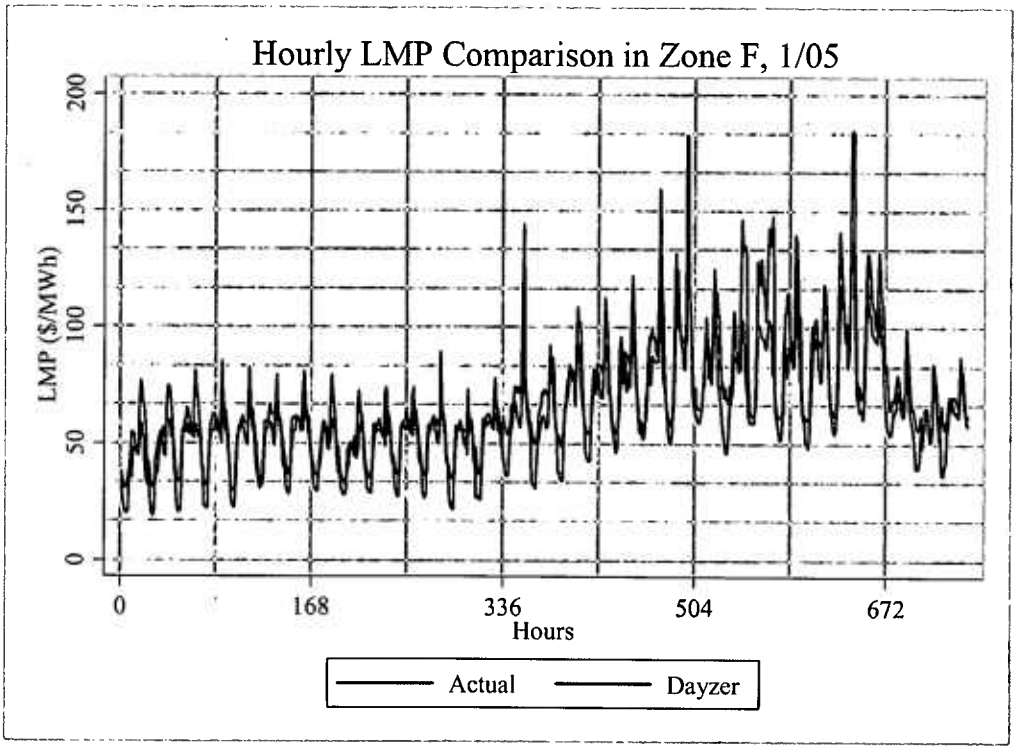

Hourly LMP Duration in Zone E, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

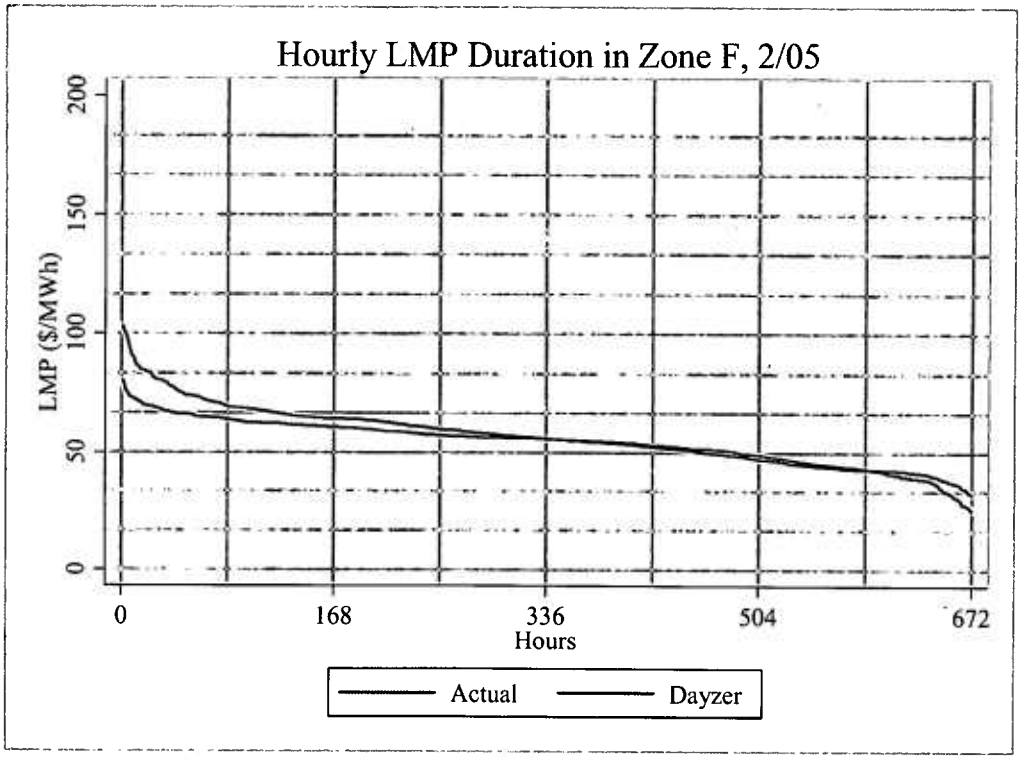

Hourly LMP Comparison in Zone E, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

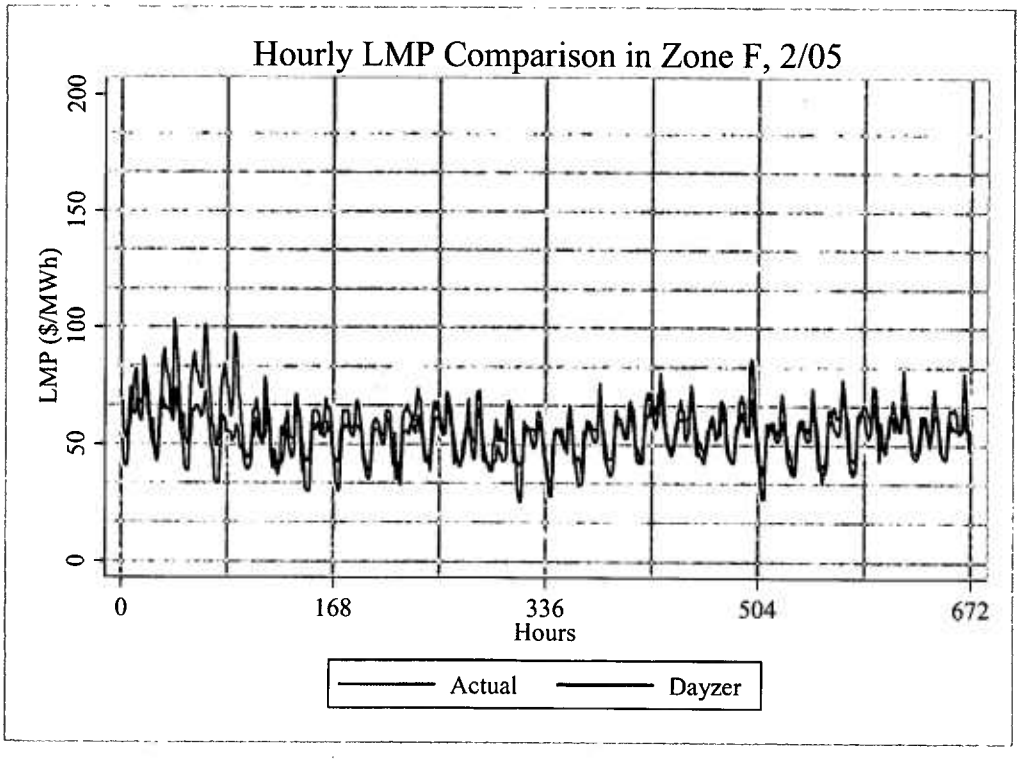

Hourly LMP Duration in Zone E, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

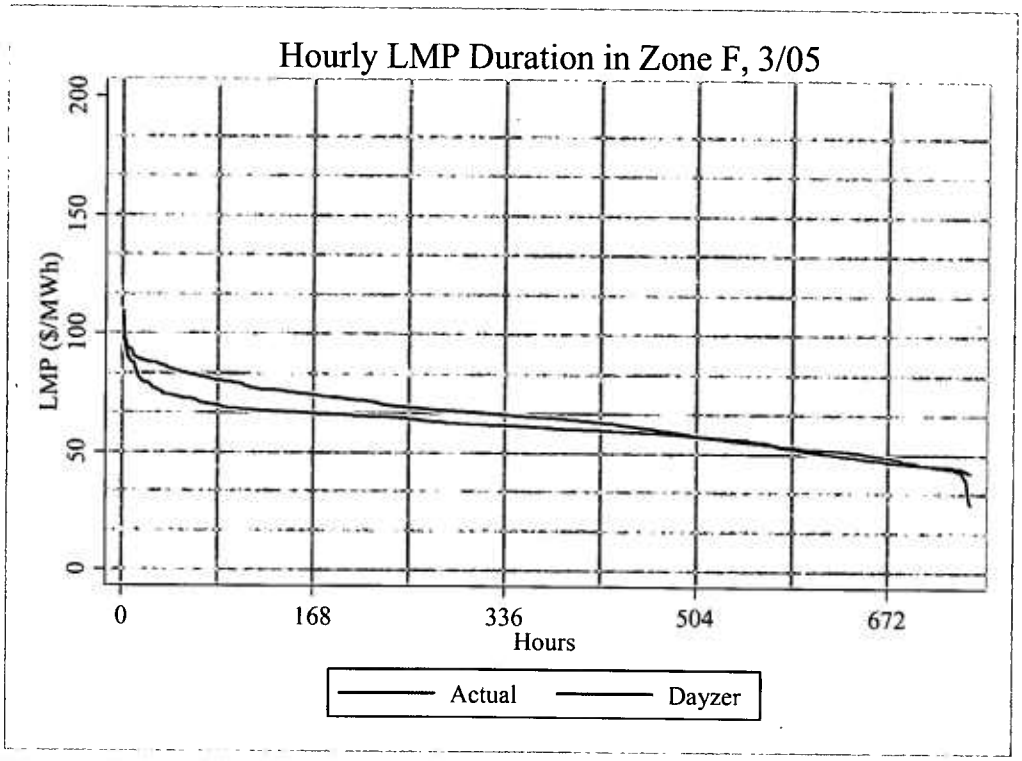

Hourly LMP Comparison in Zone E, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

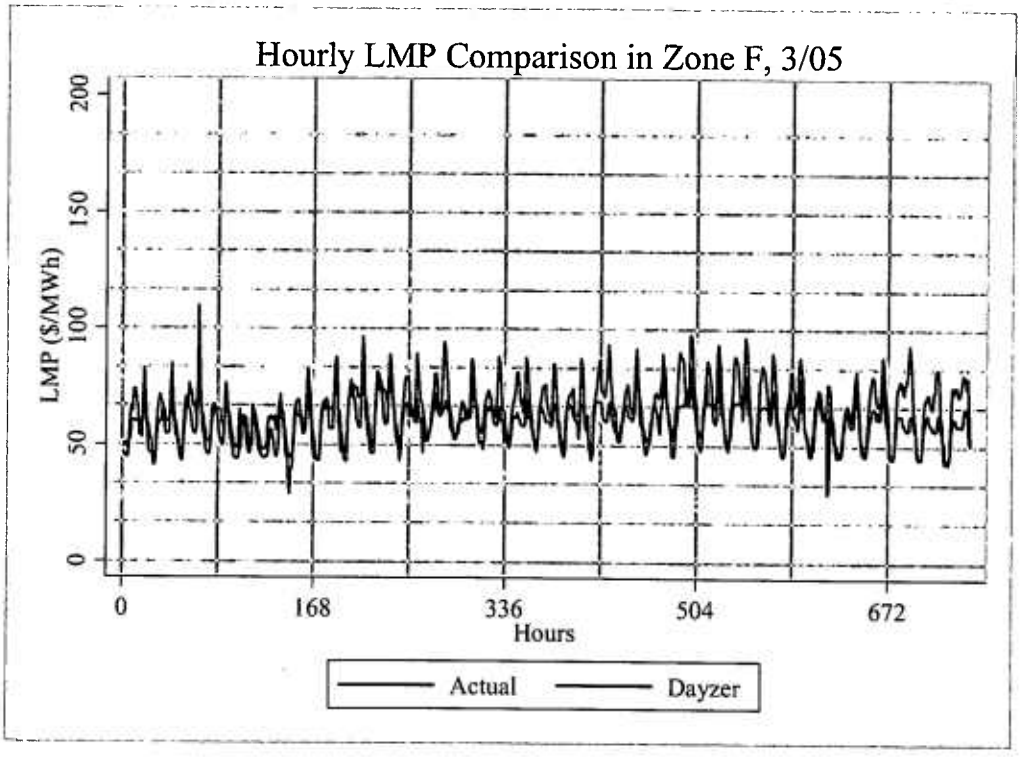

Hourly LMP Duration in Zone F, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

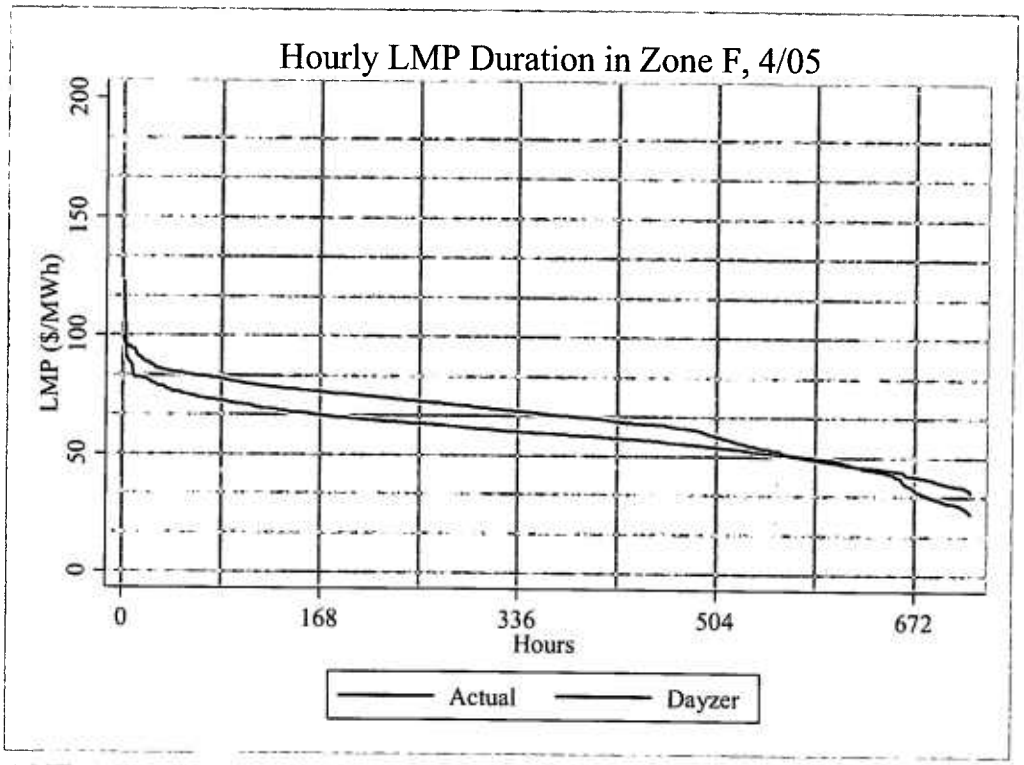

Hourly LMP Comparison in Zone F, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

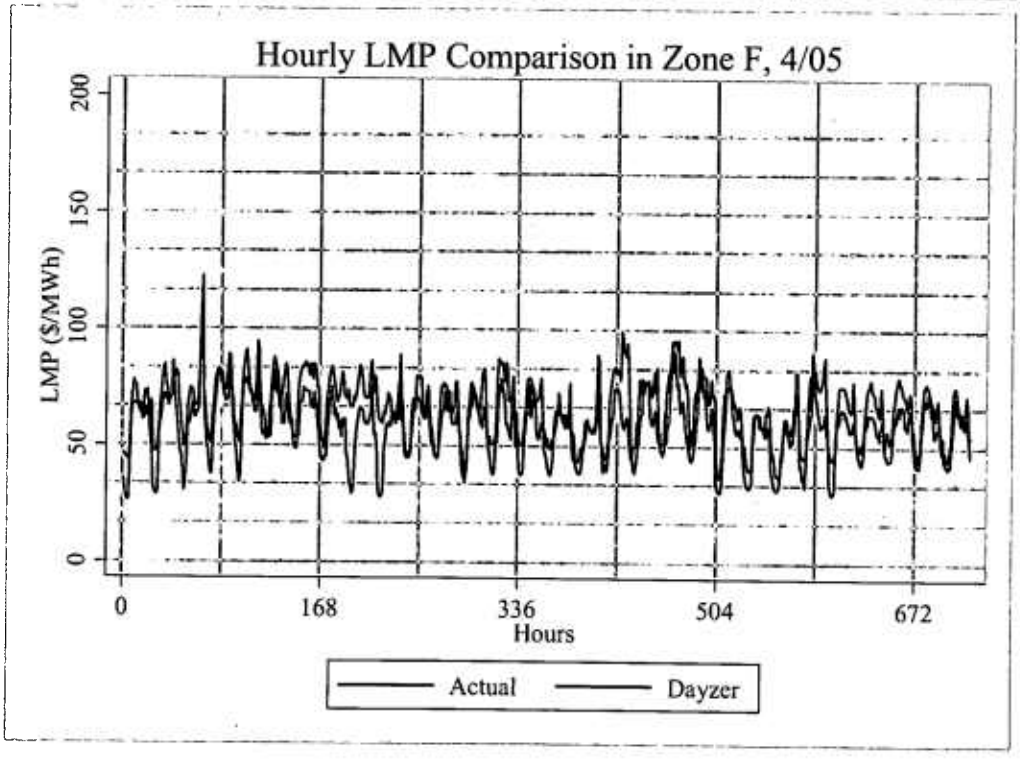

Hourly LMP Duration in Zone F, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

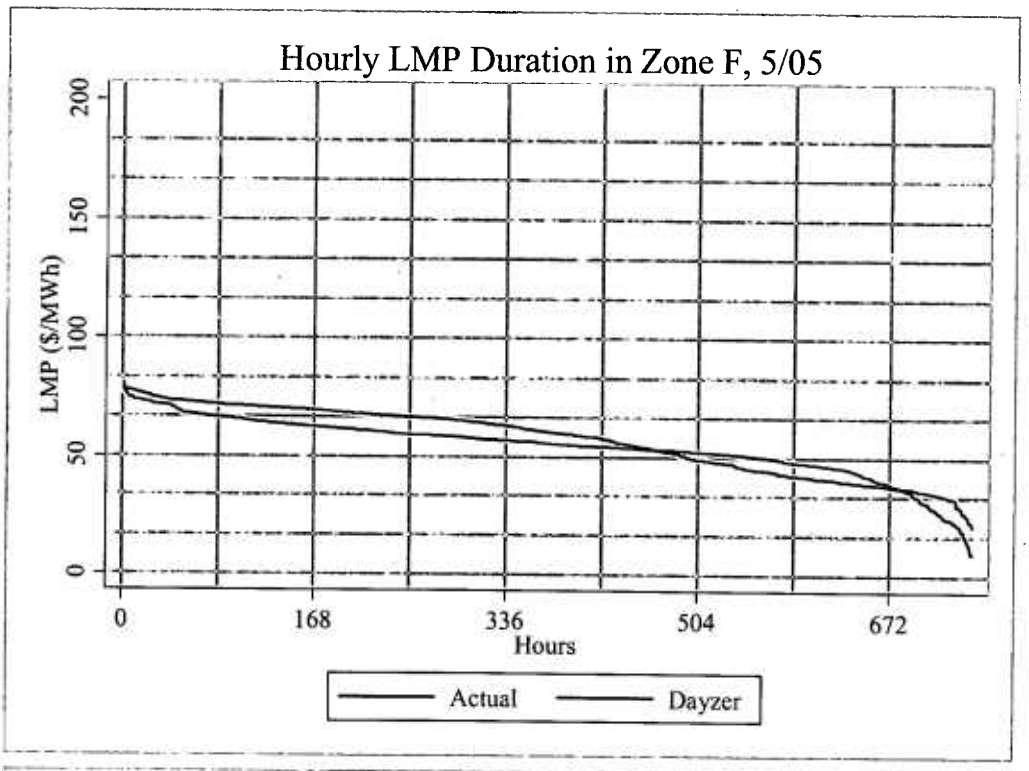

Hourly LMP Comparison in Zone F, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

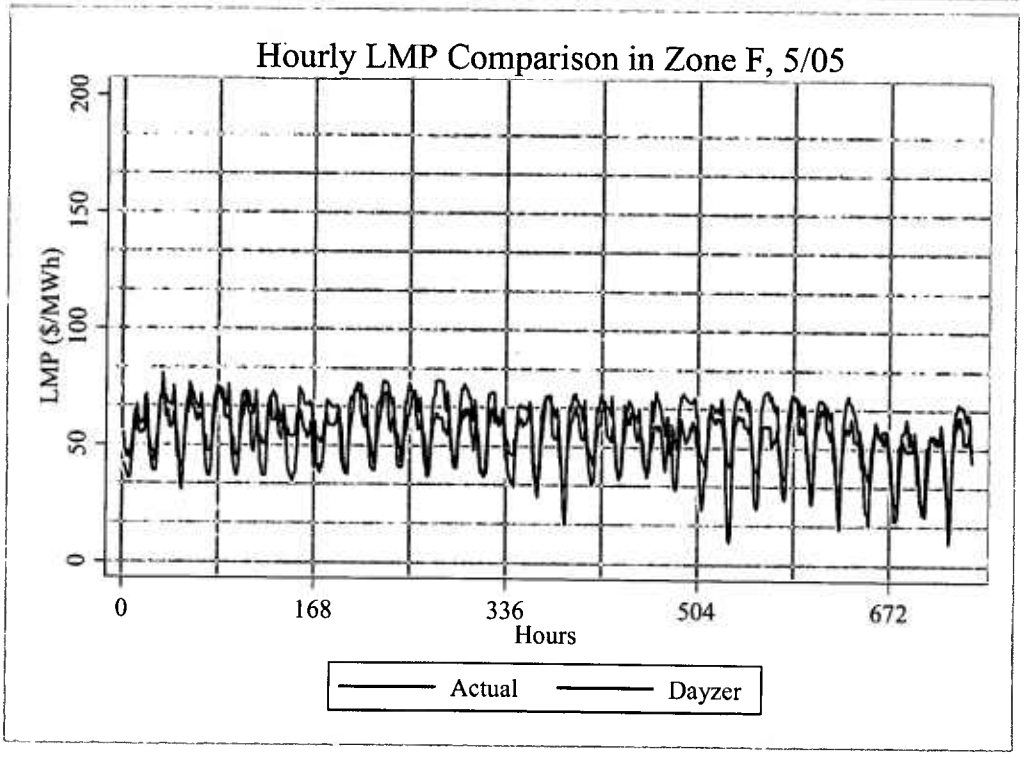

Hourly LMP Duration in Zone F, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

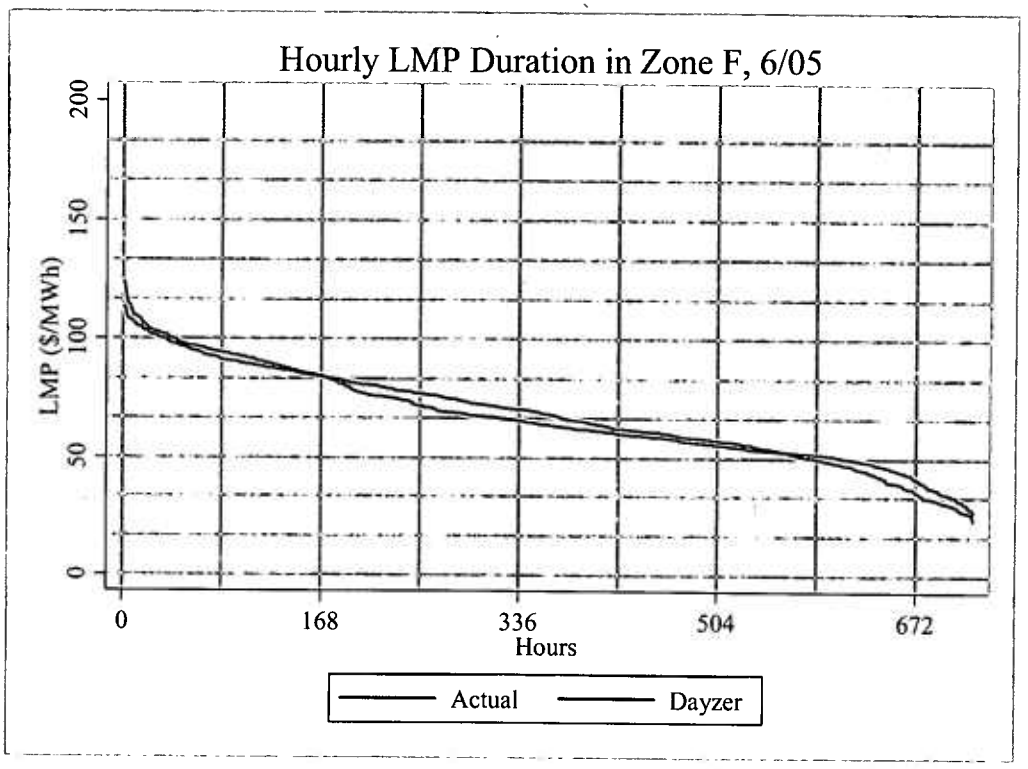

Hourly LMP Comparison in Zone F, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

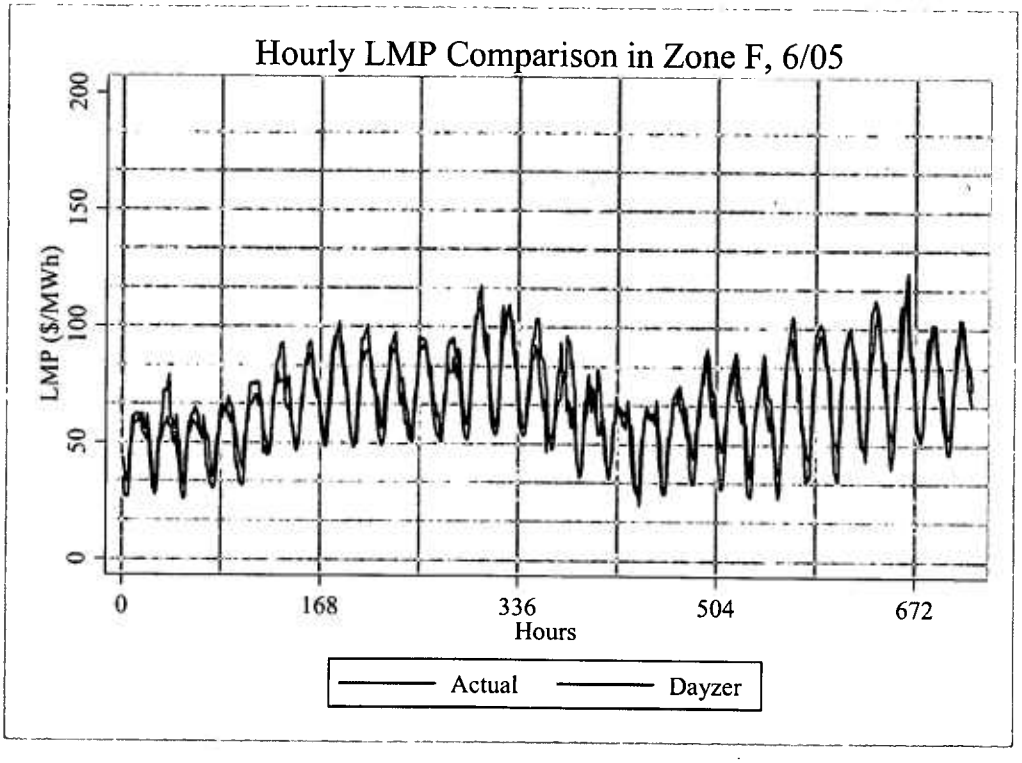

Hourly LMP Duration in Zone F, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

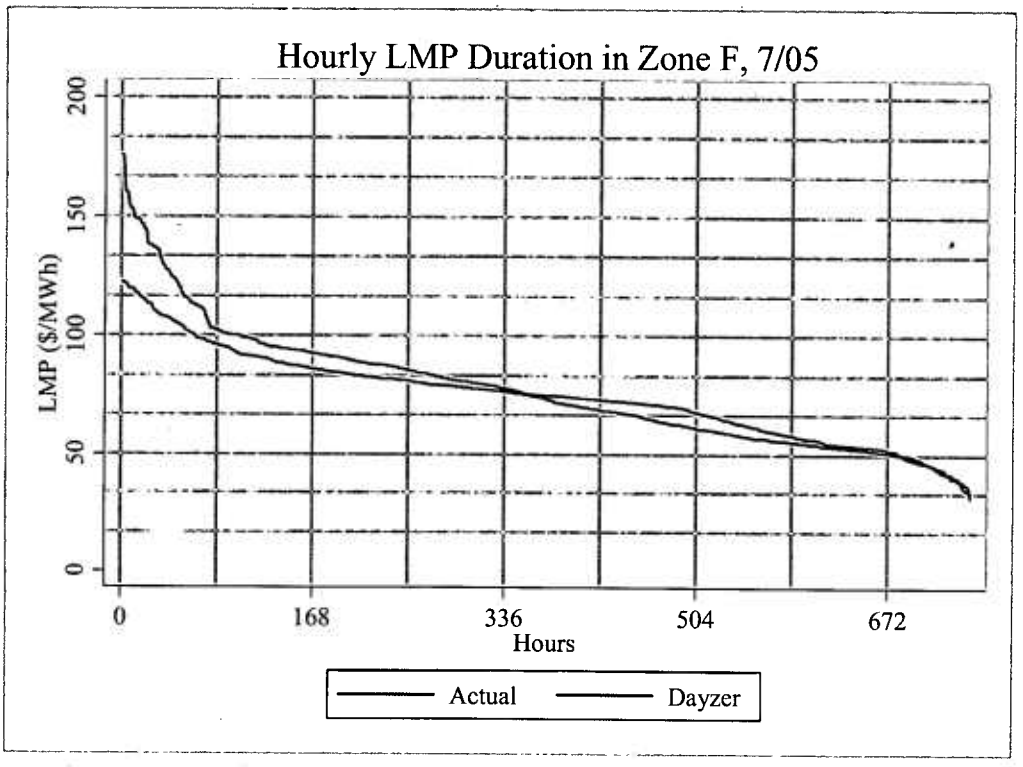

Hourly LMP Comparison in Zone F, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

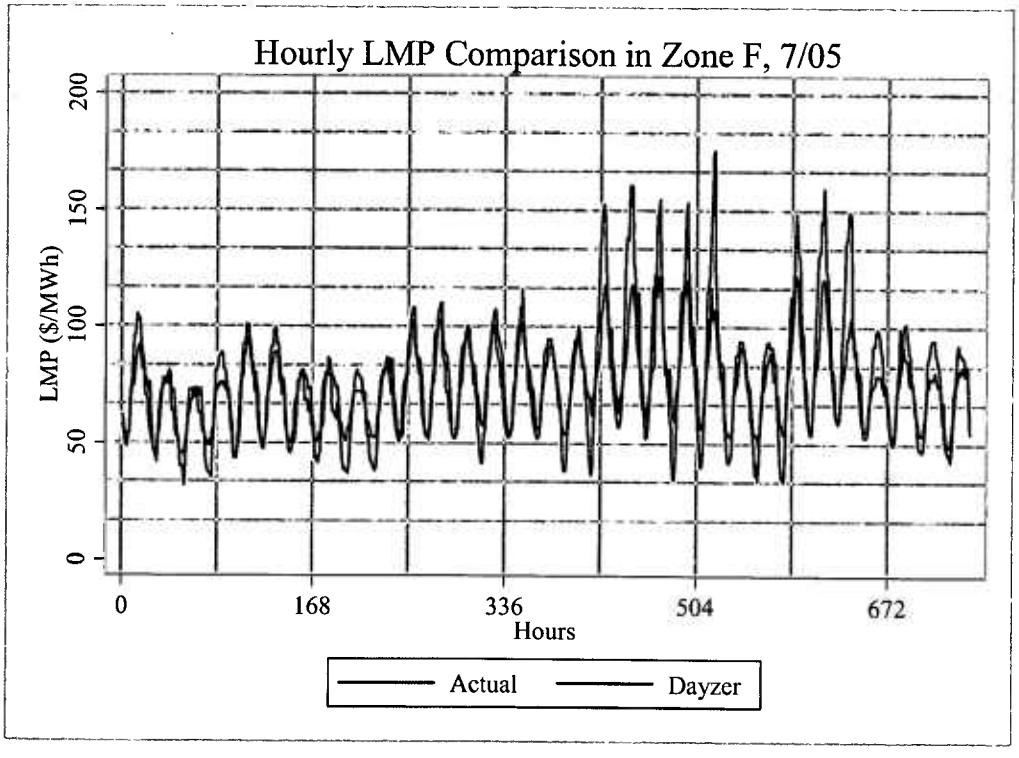

Hourly LMP Duration in Zone F, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

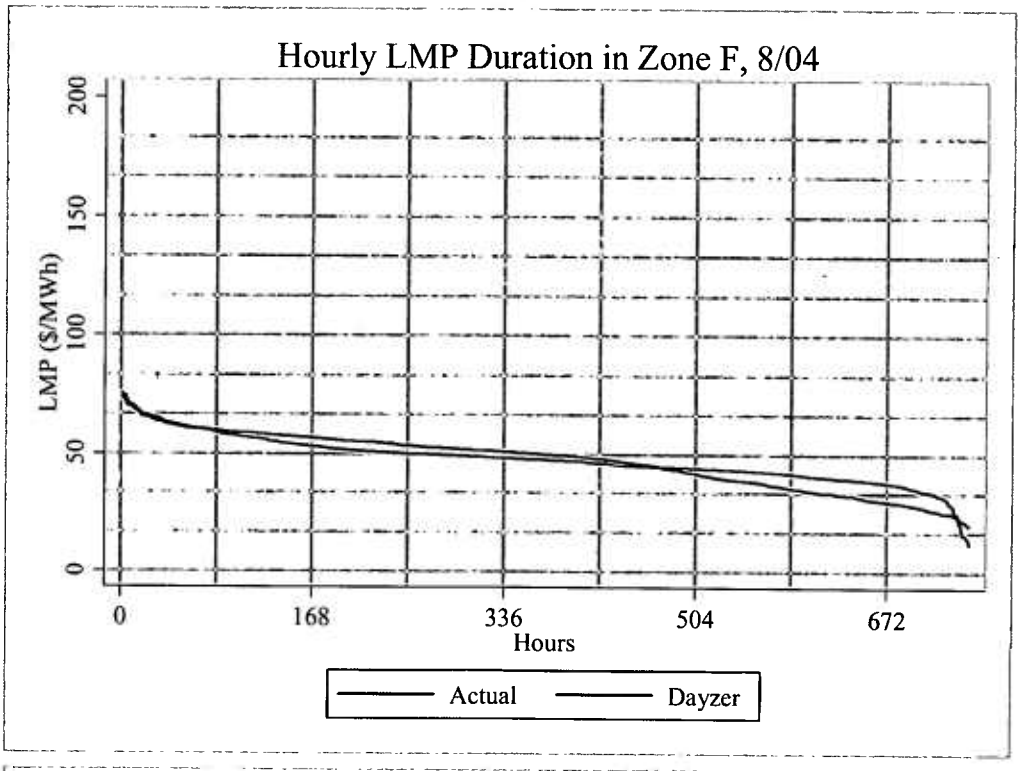

Hourly LMP Comparison in Zone F, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

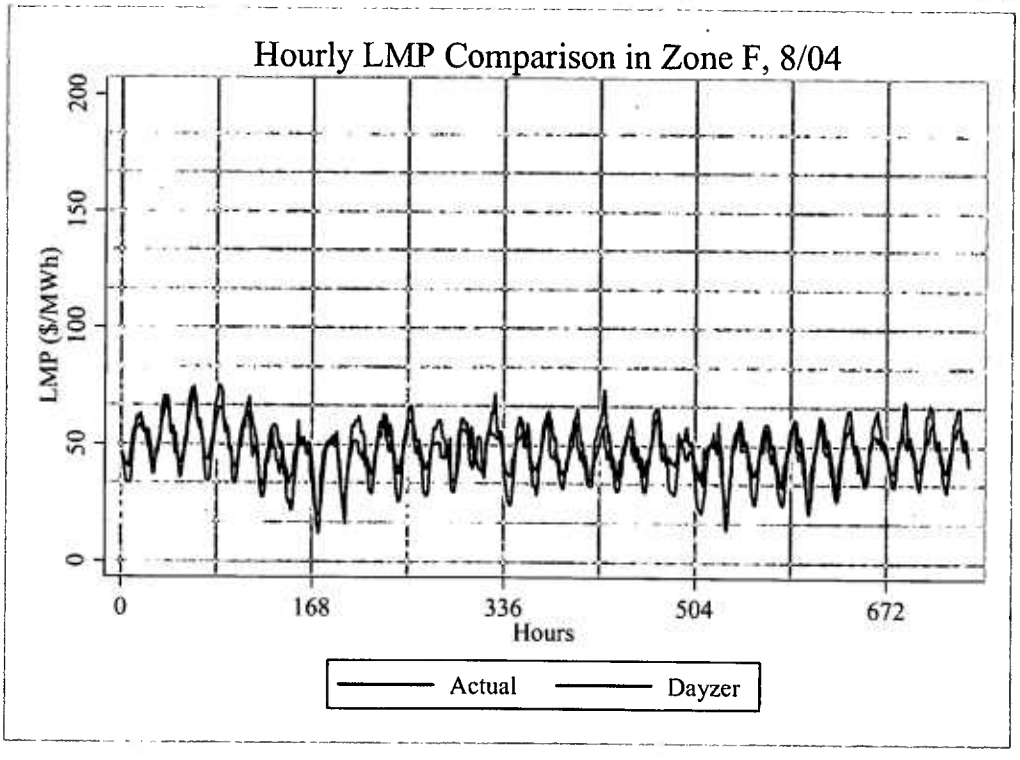

Hourly LMP Duration in Zone F, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

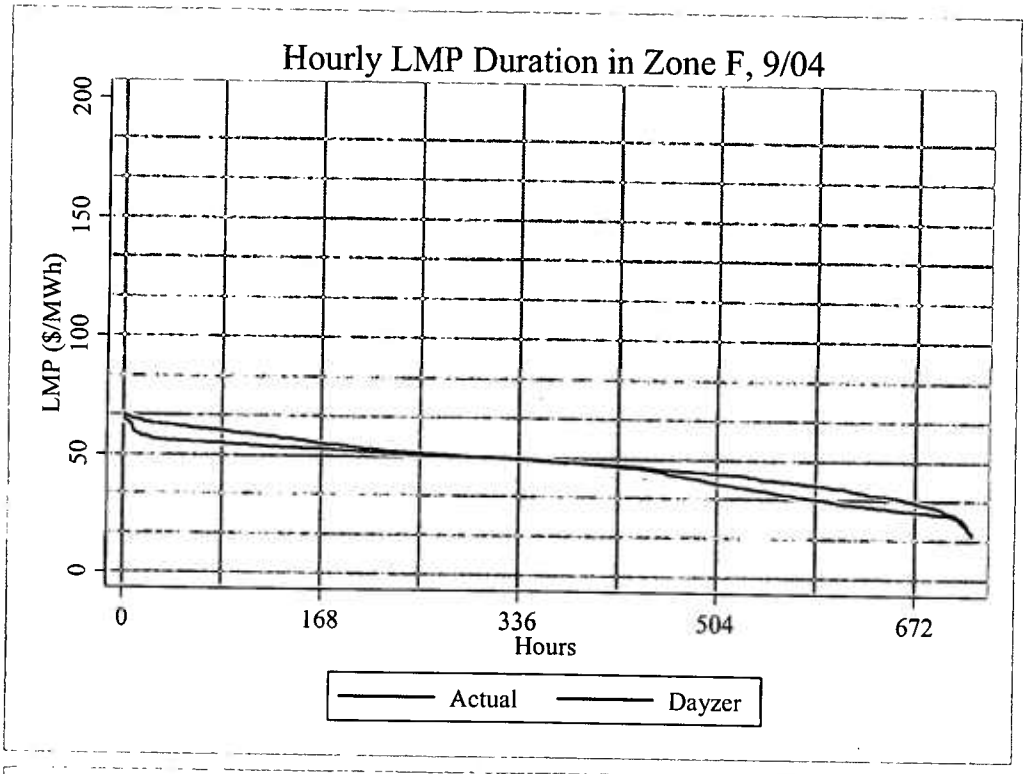

Hourly LMP Comparison in Zone F, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

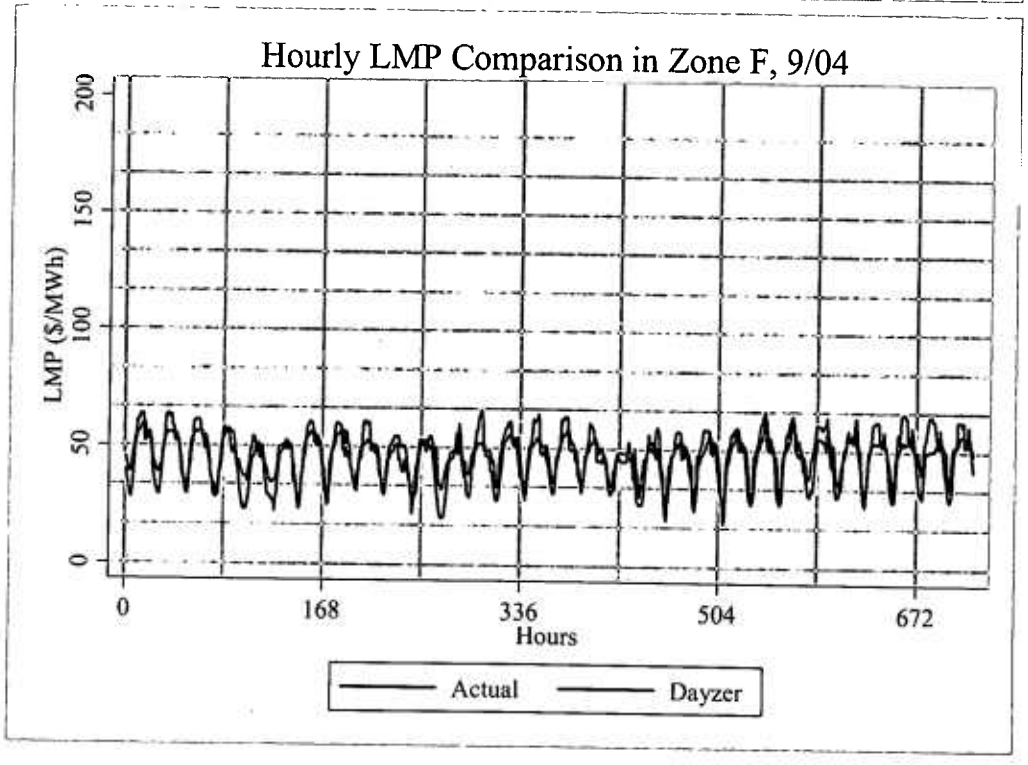

Hourly LMP Duration in Zone F, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

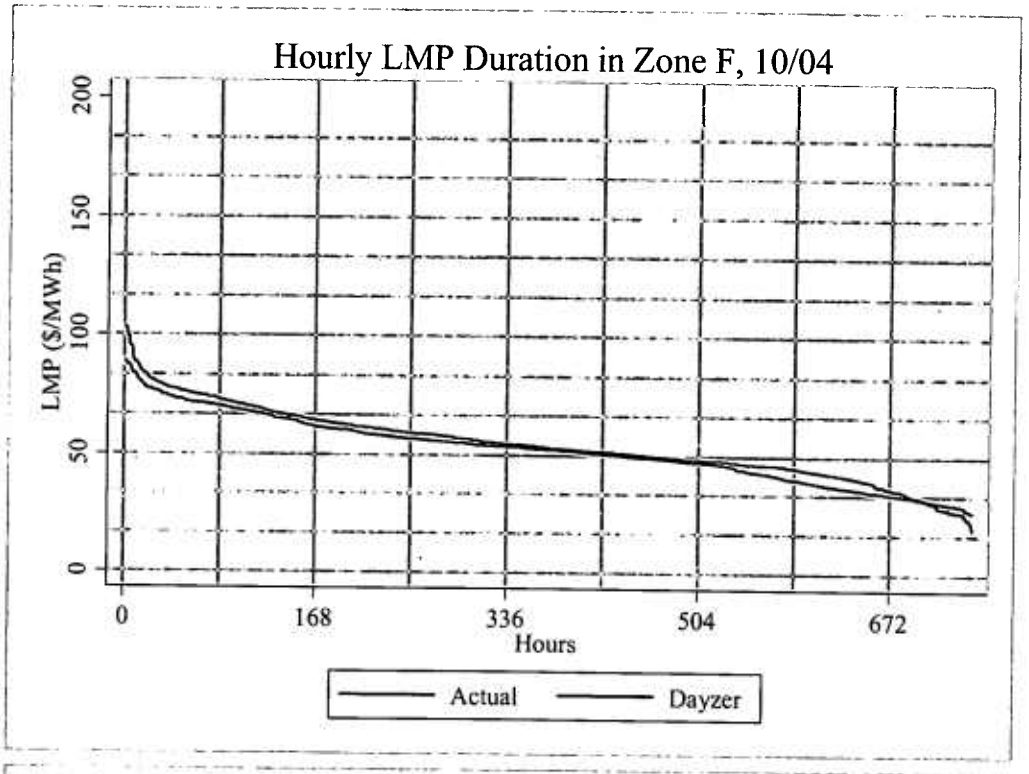

Hourly LMP Comparison in Zone F, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

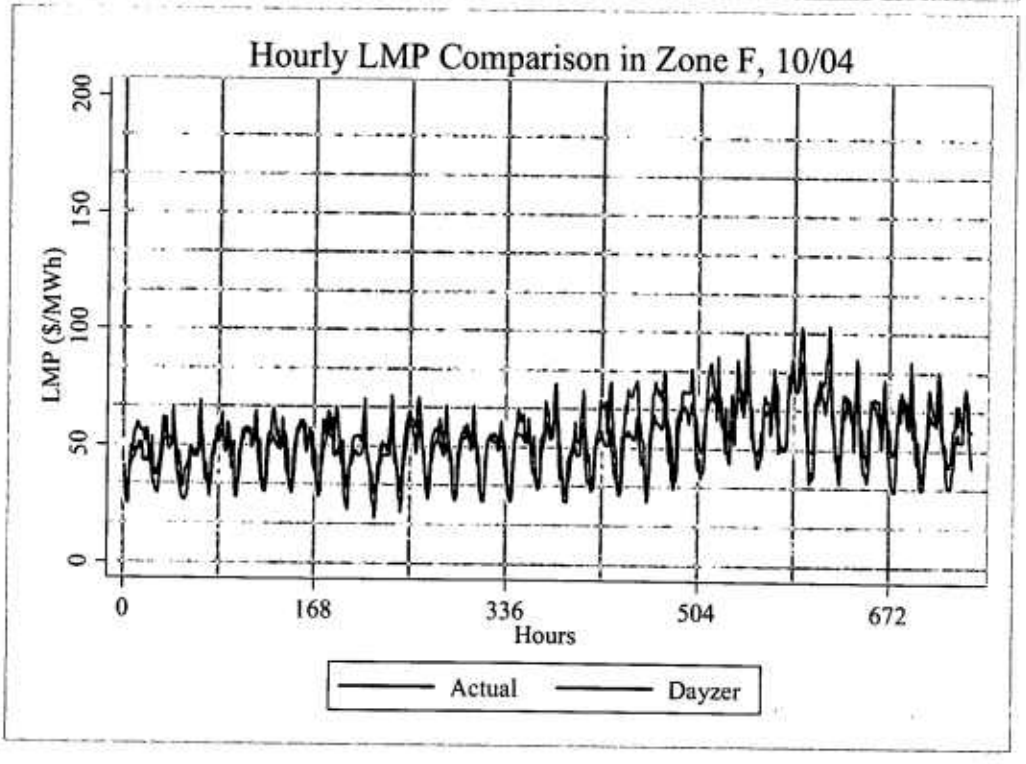

Hourly LMP Duration in Zone F, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

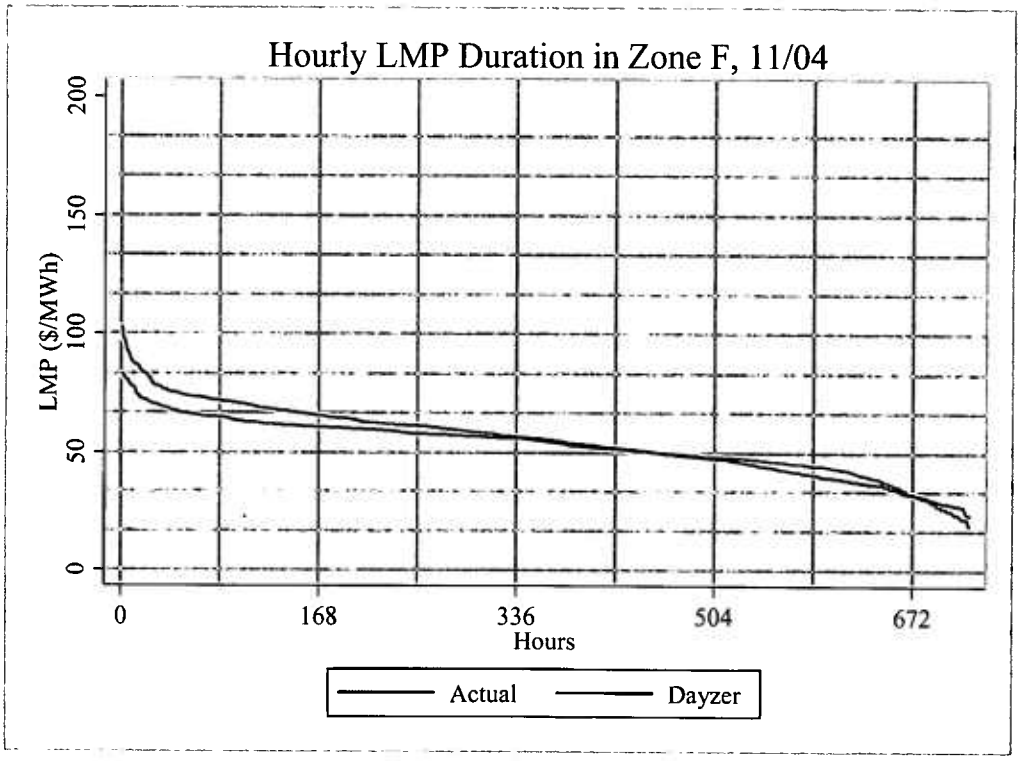

Hourly LMP Comparison in Zone F, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

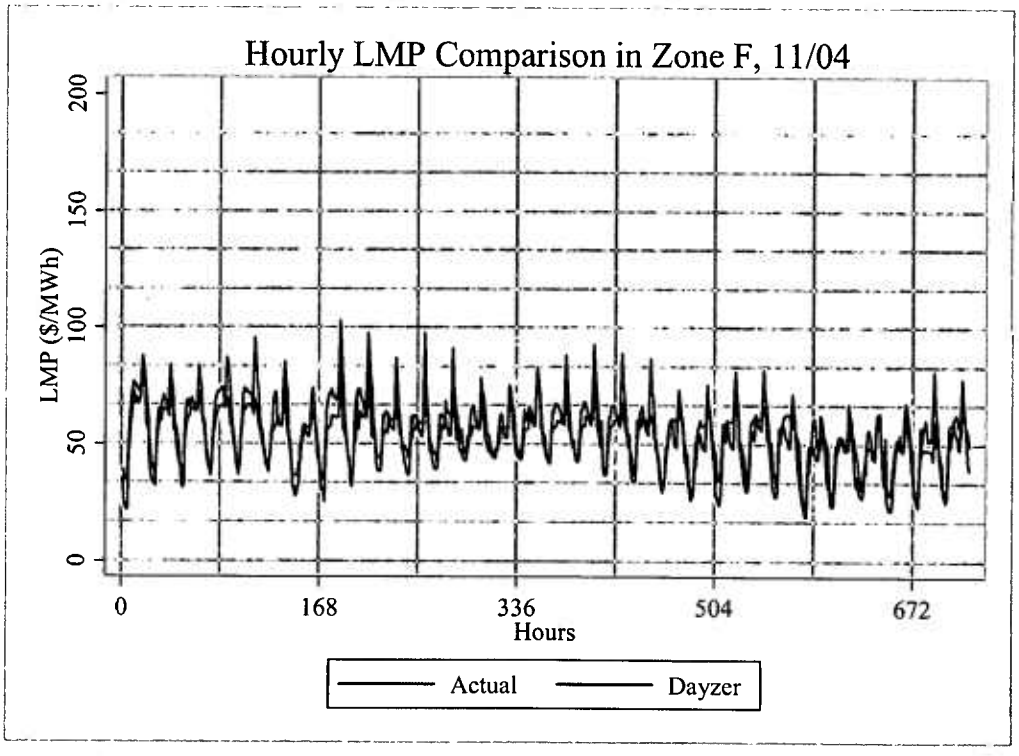

Hourly LMP Duration in Zone F, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

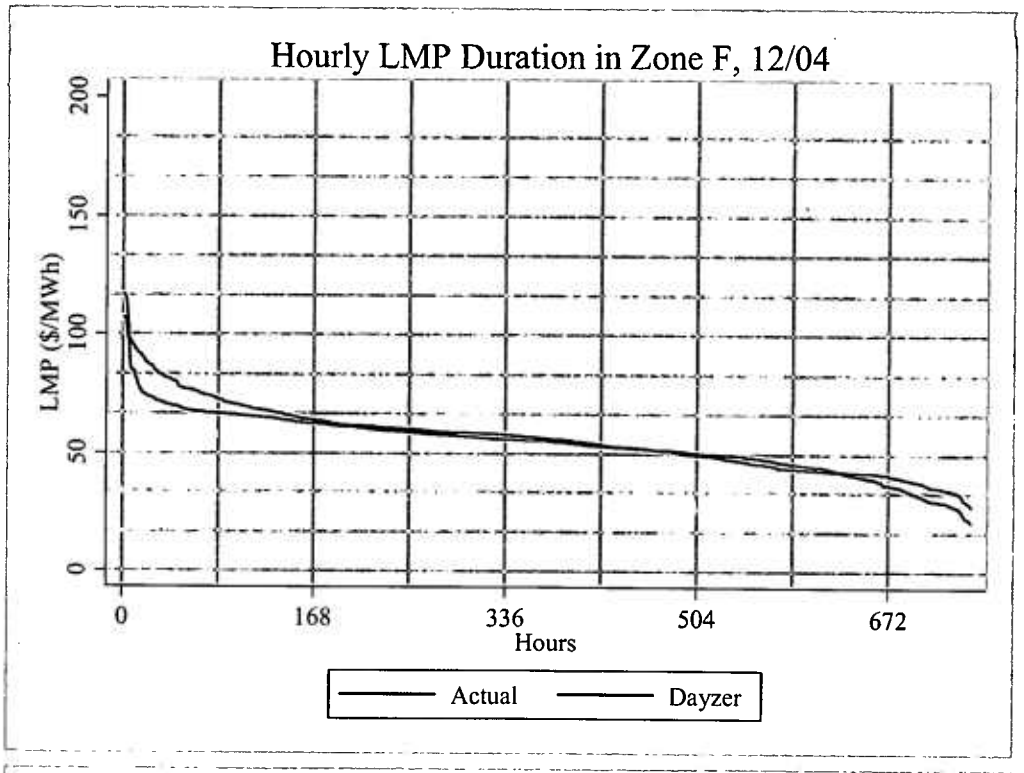

Hourly LMP Comparison in Zone F, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

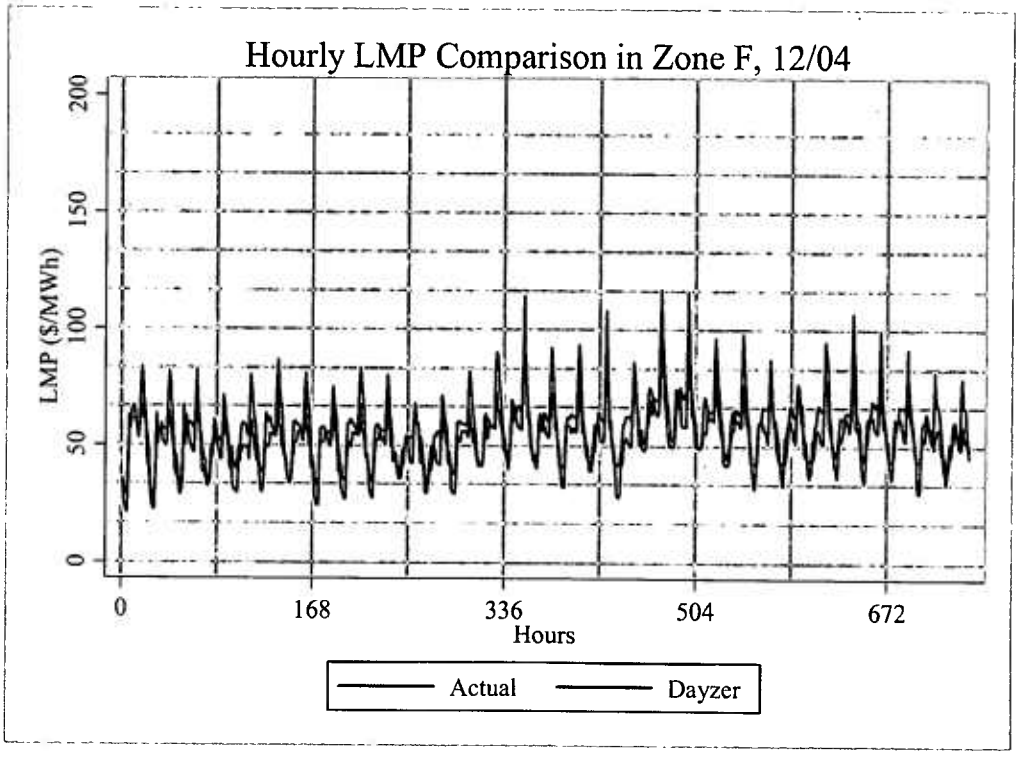

Hourly LMP Duration in Zone F, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

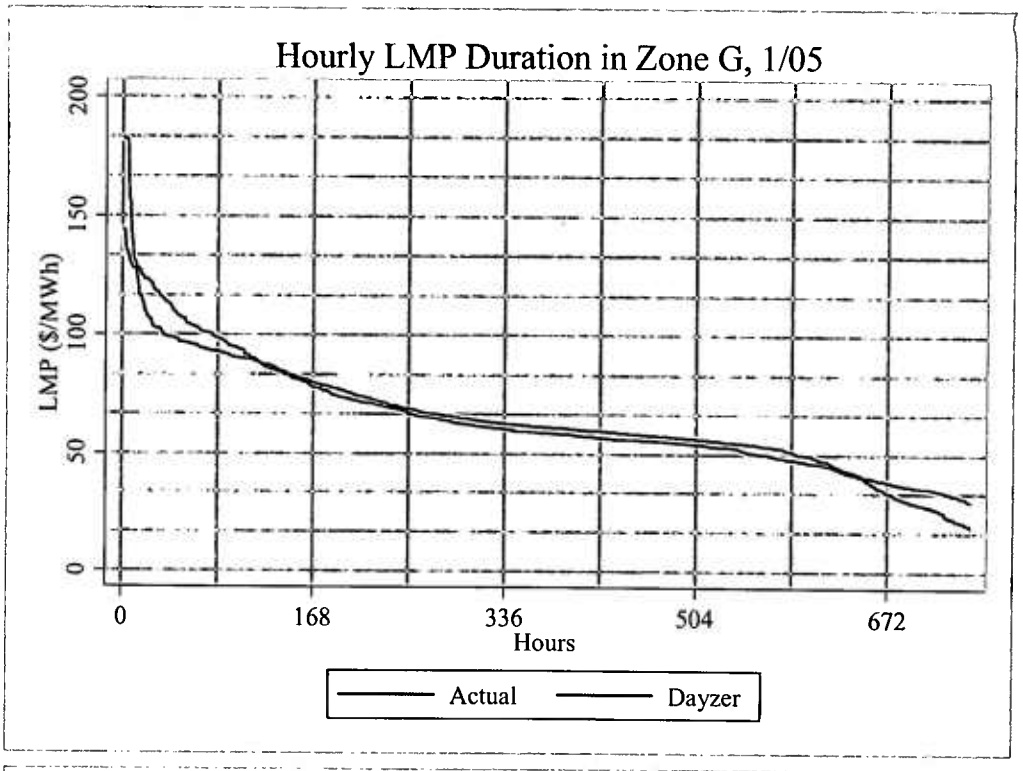

Hourly LMP Comparison in Zone F, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

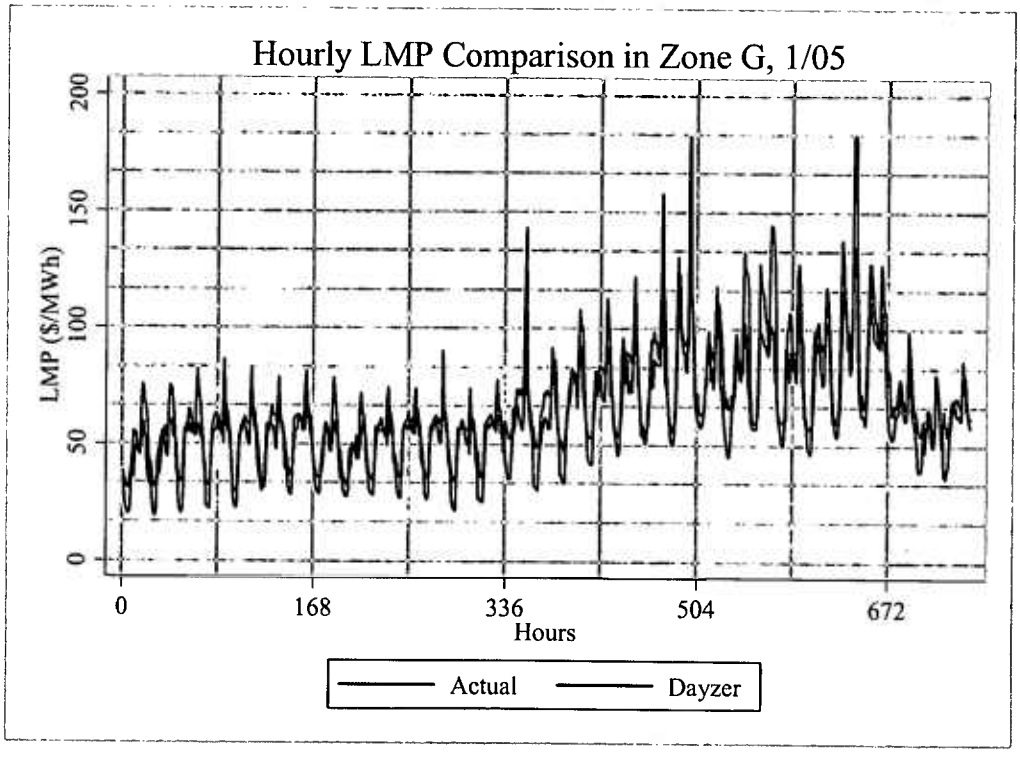

Hourly LMP Duration in Zone F, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

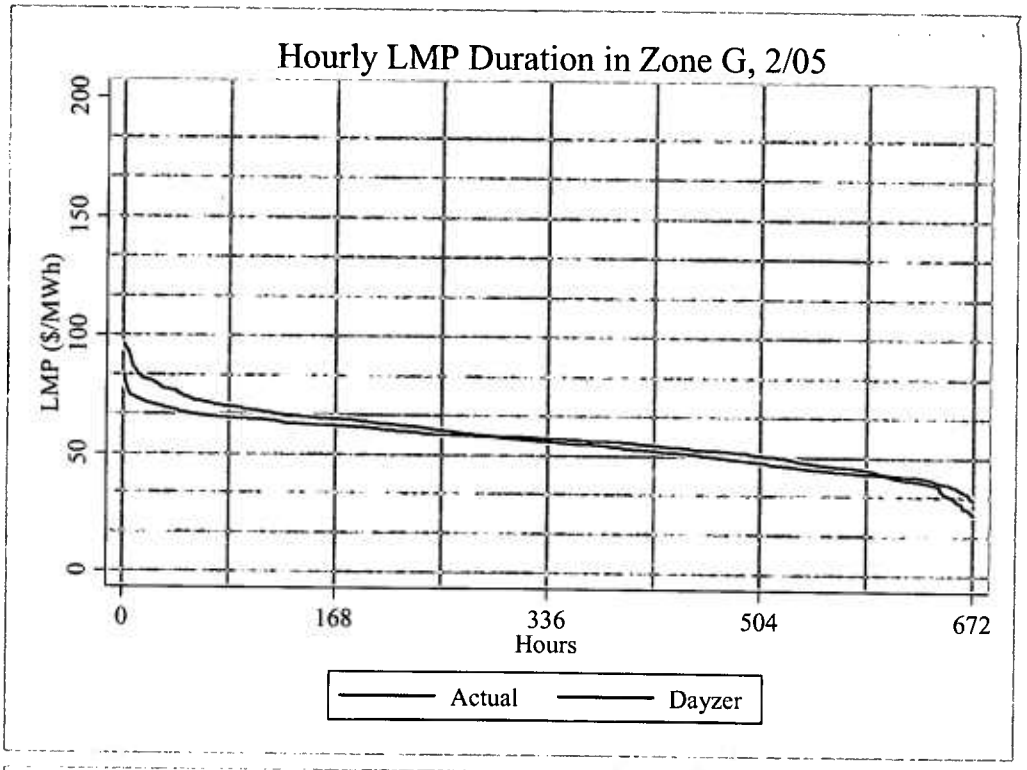

Hourly LMP Comparison in Zone F, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

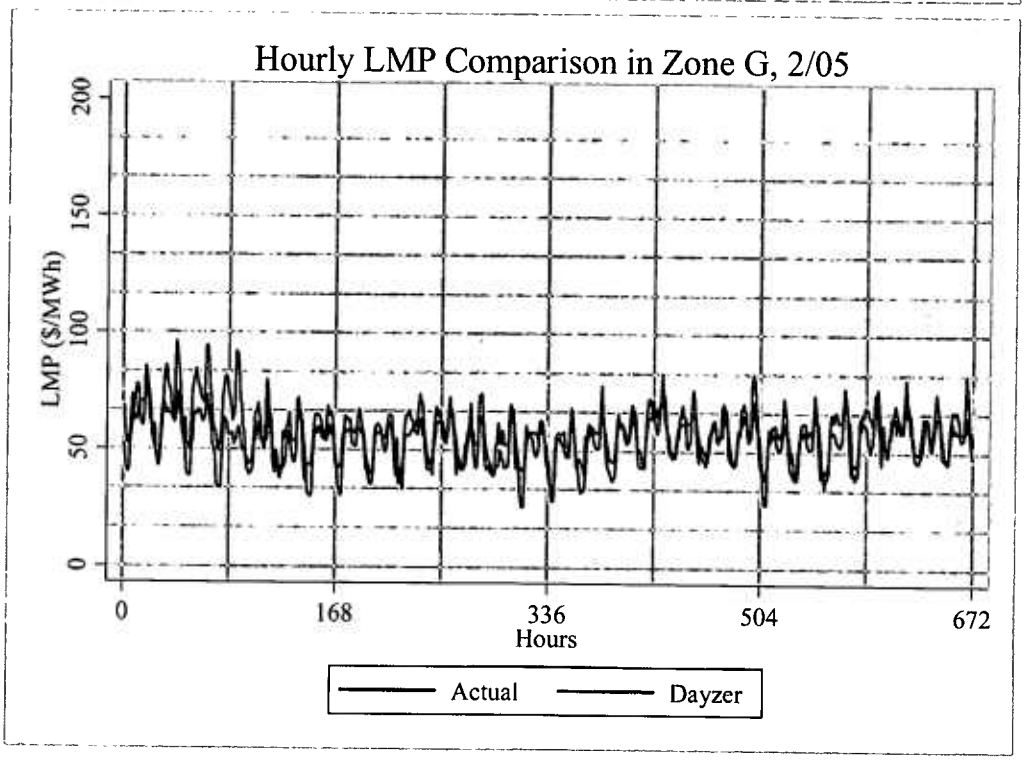

Hourly LMP Duration in Zone F, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

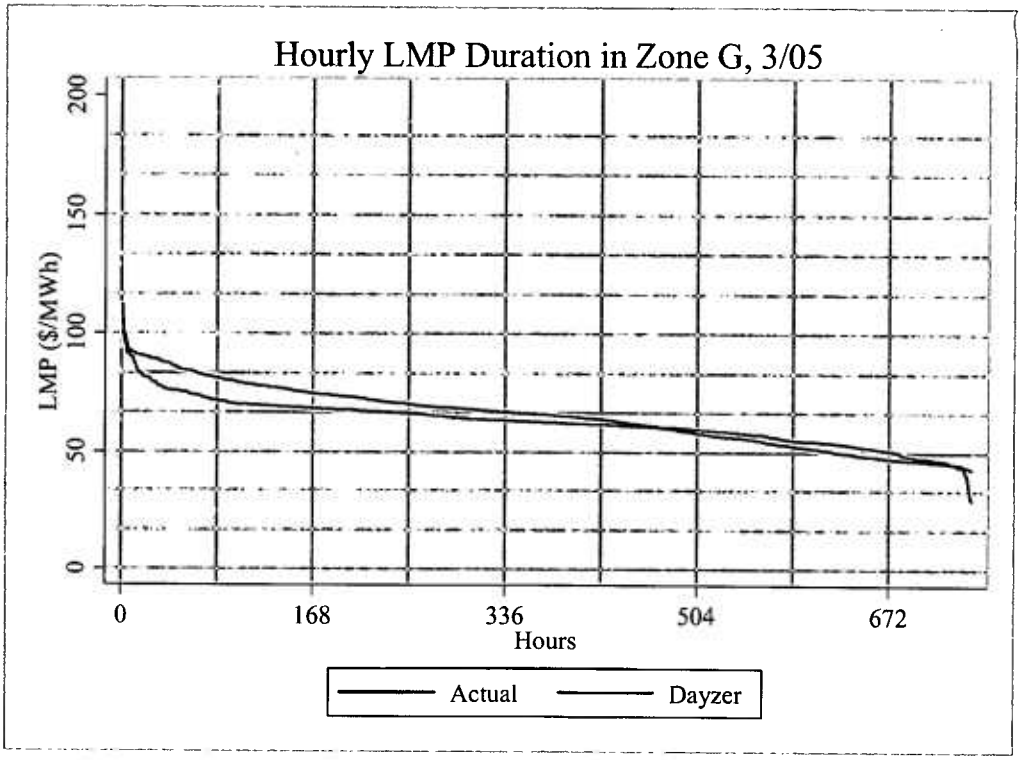

Hourly LMP Comparison in Zone F, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

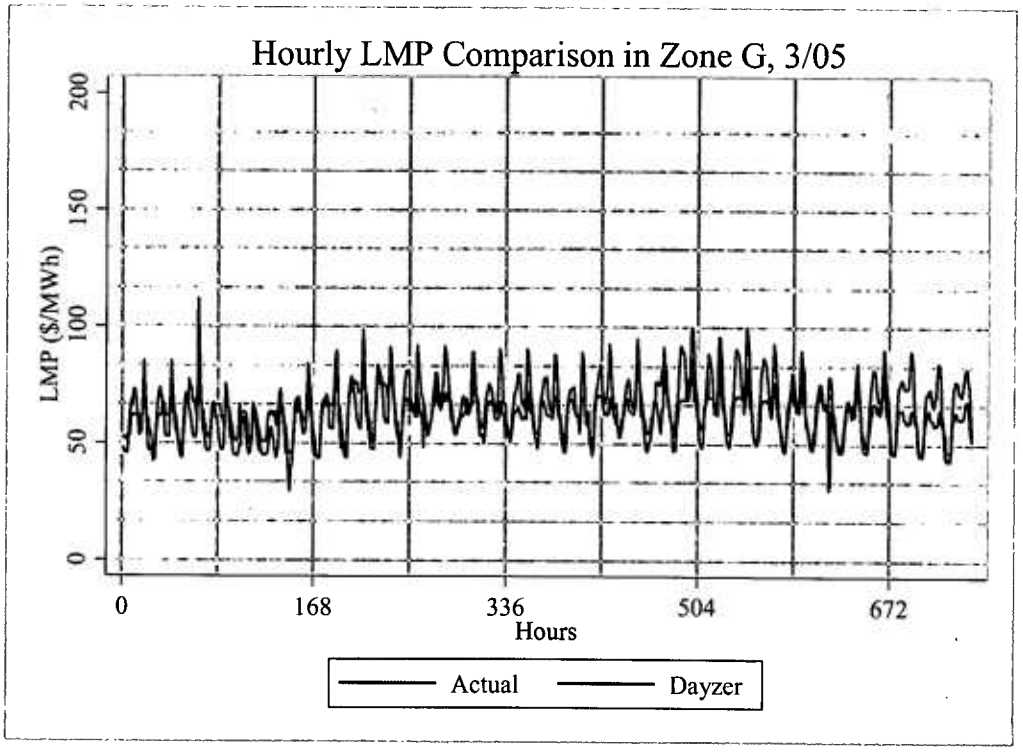

Hourly LMP Duration in Zone G, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

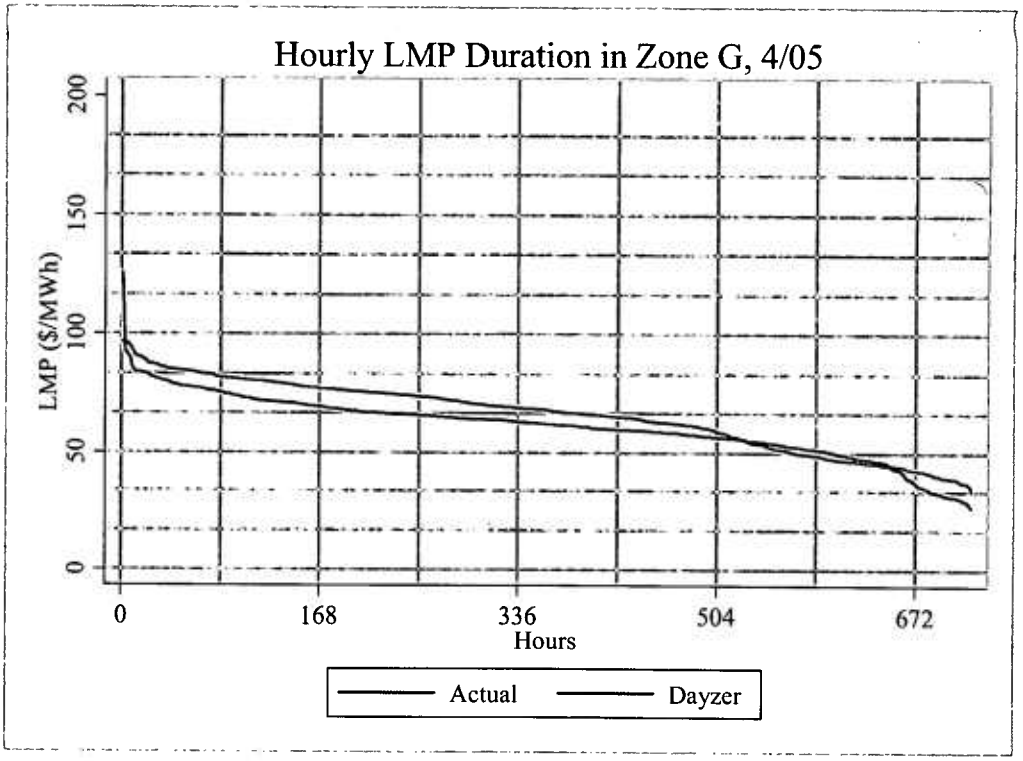

Hourly LMP Comparison in Zone G, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

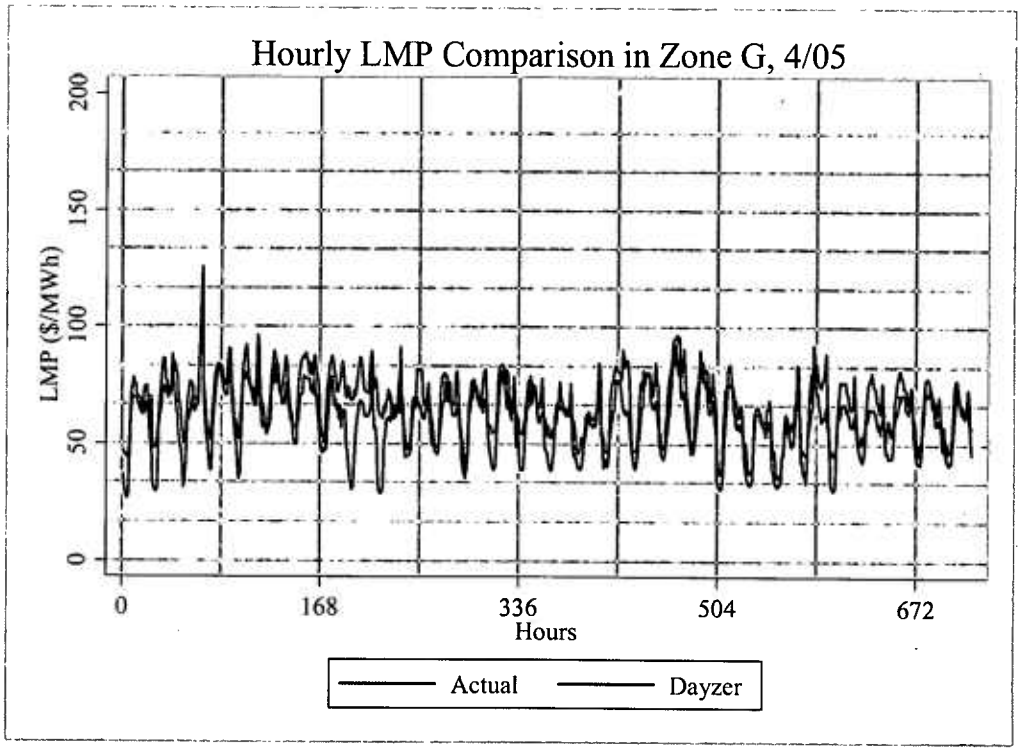

Hourly LMP Duration in Zone G, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

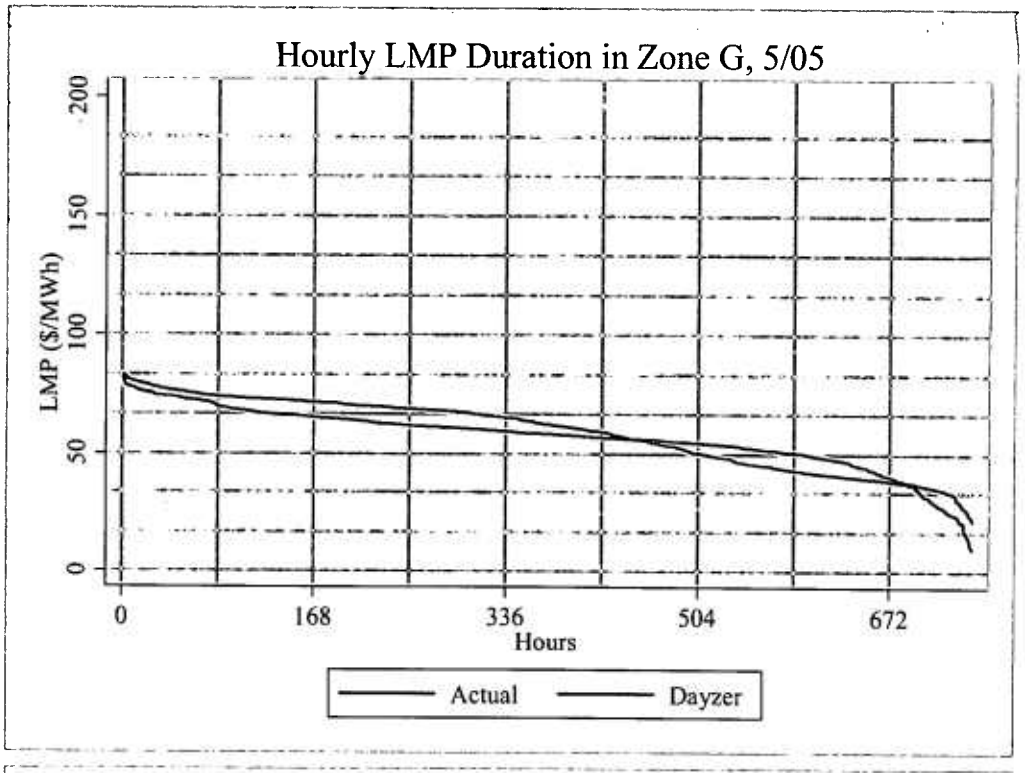

Hourly LMP Comparison in Zone G, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

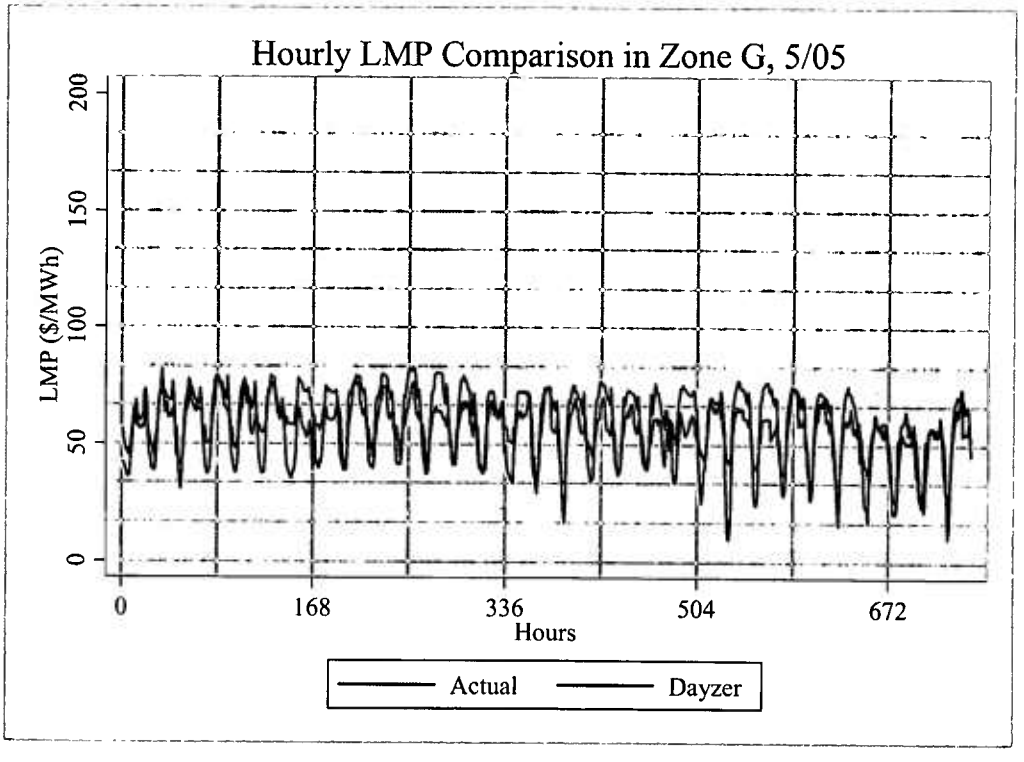

Hourly LMP Duration in Zone G, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

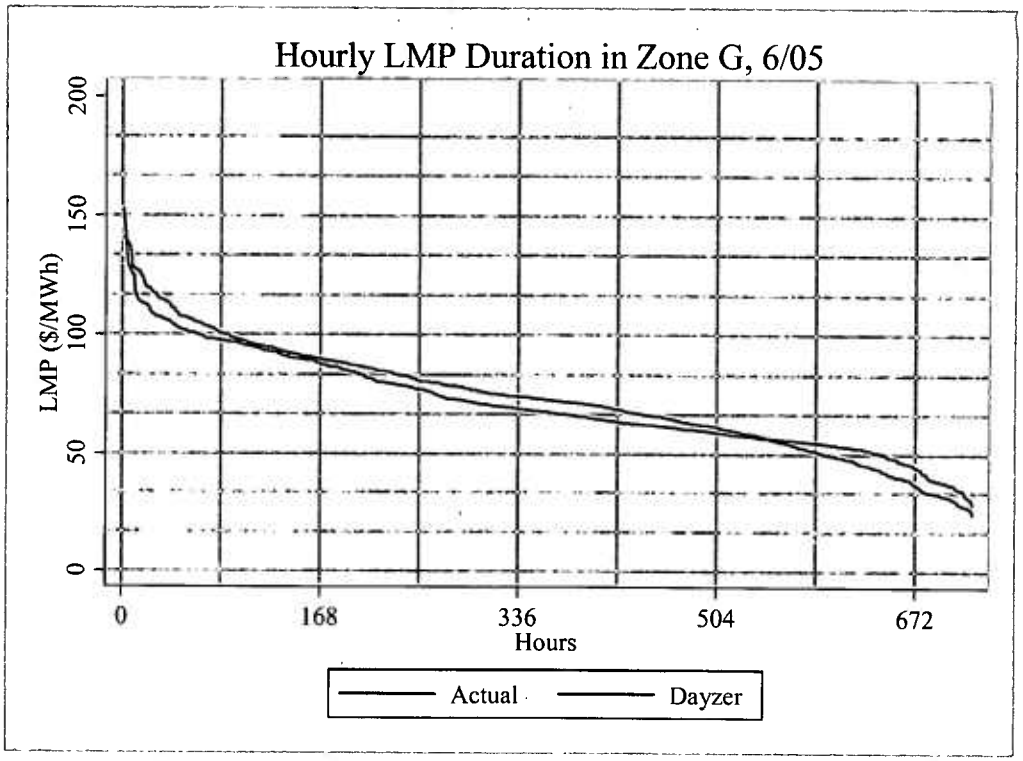

Hourly LMP Comparison in Zone G, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

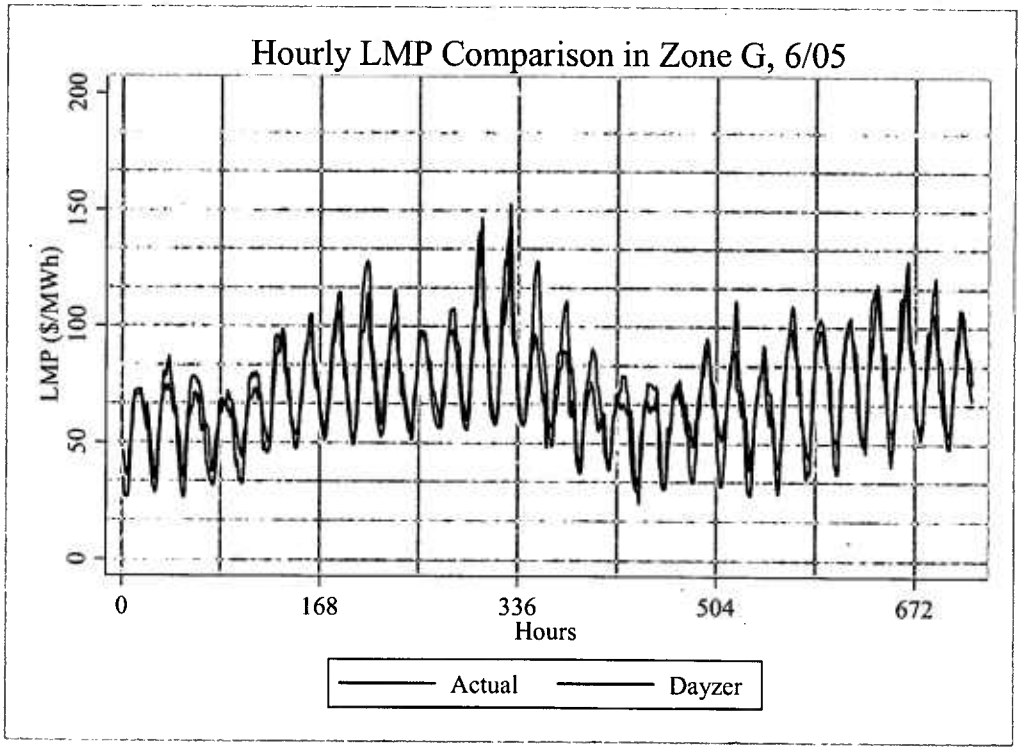

Hourly LMP Duration in Zone G, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

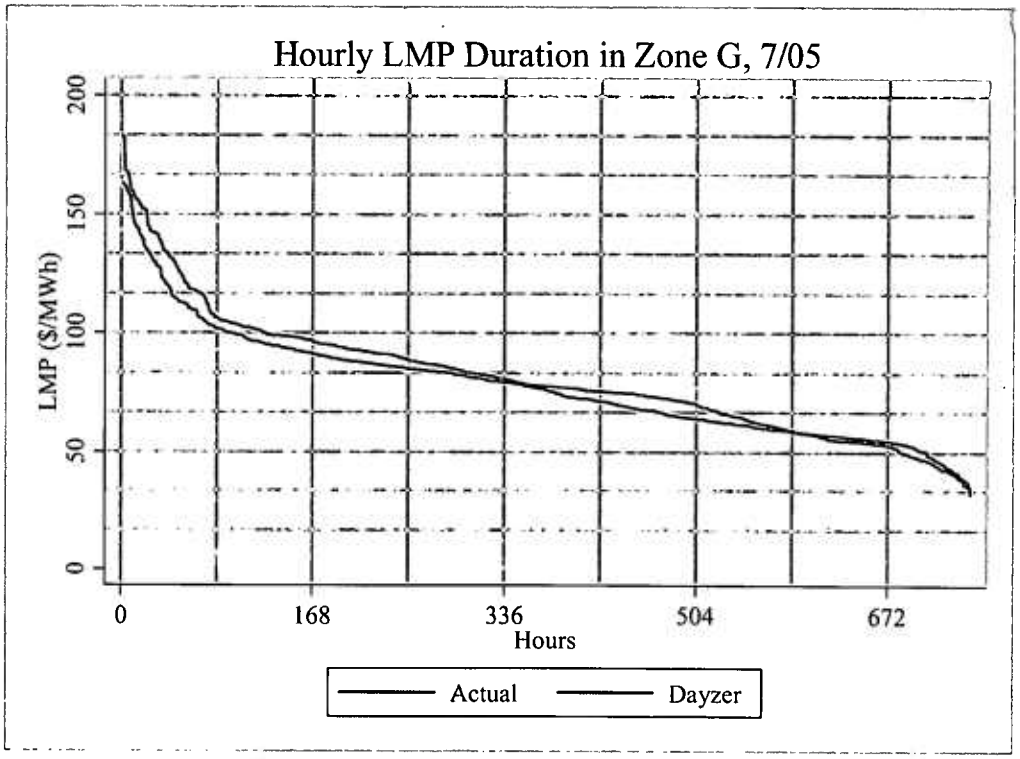

Hourly LMP Comparison in Zone G, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

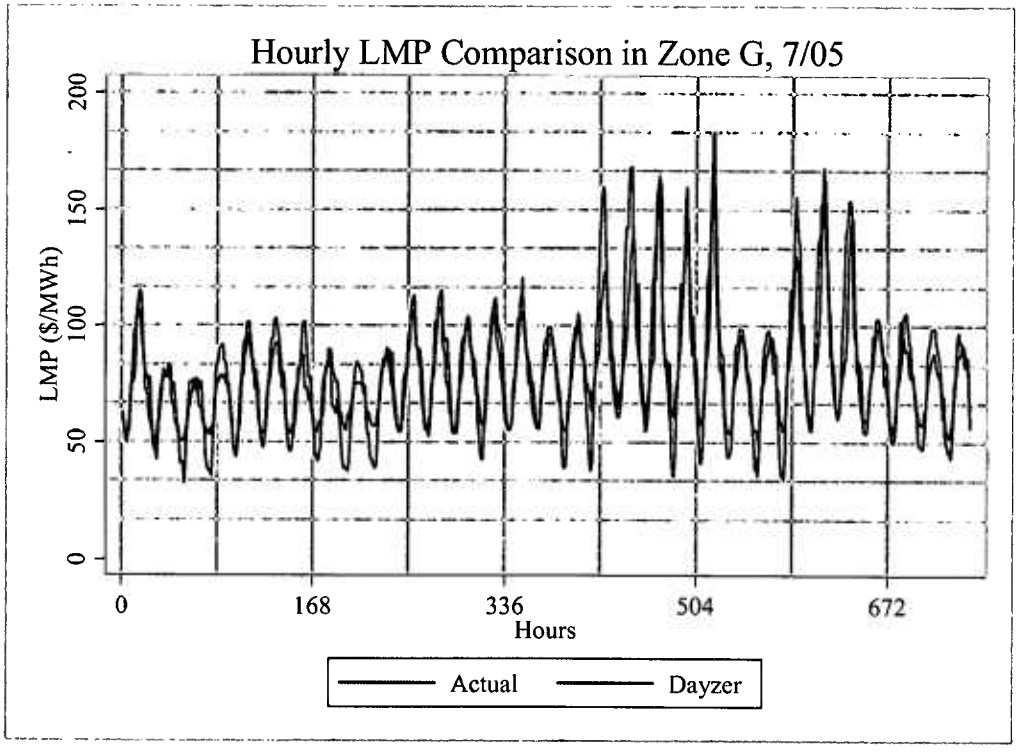

Hourly LMP Duration in Zone G, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

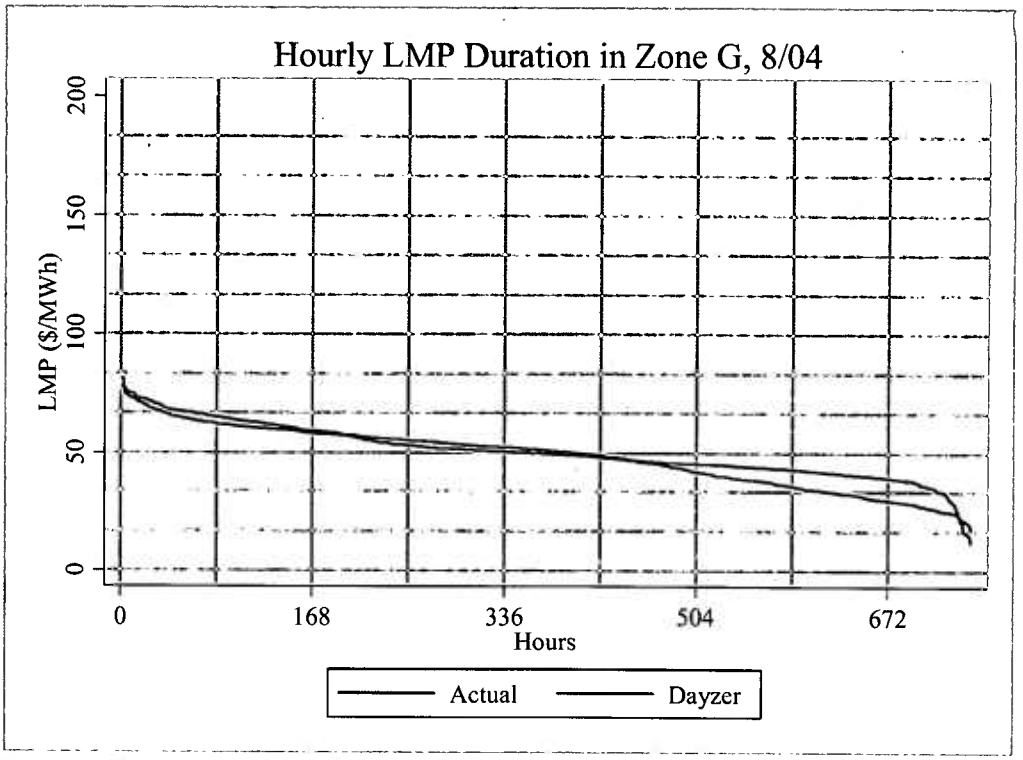

Hourly LMP Comparison in Zone G, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

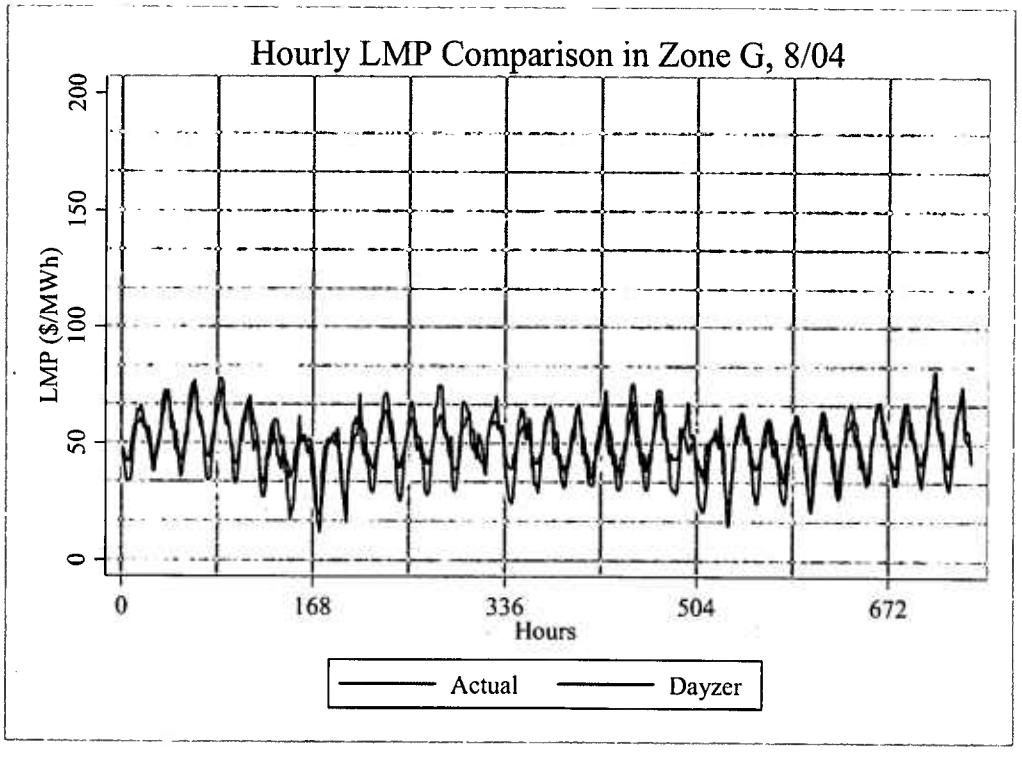

Hourly LMP Duration in Zone G, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

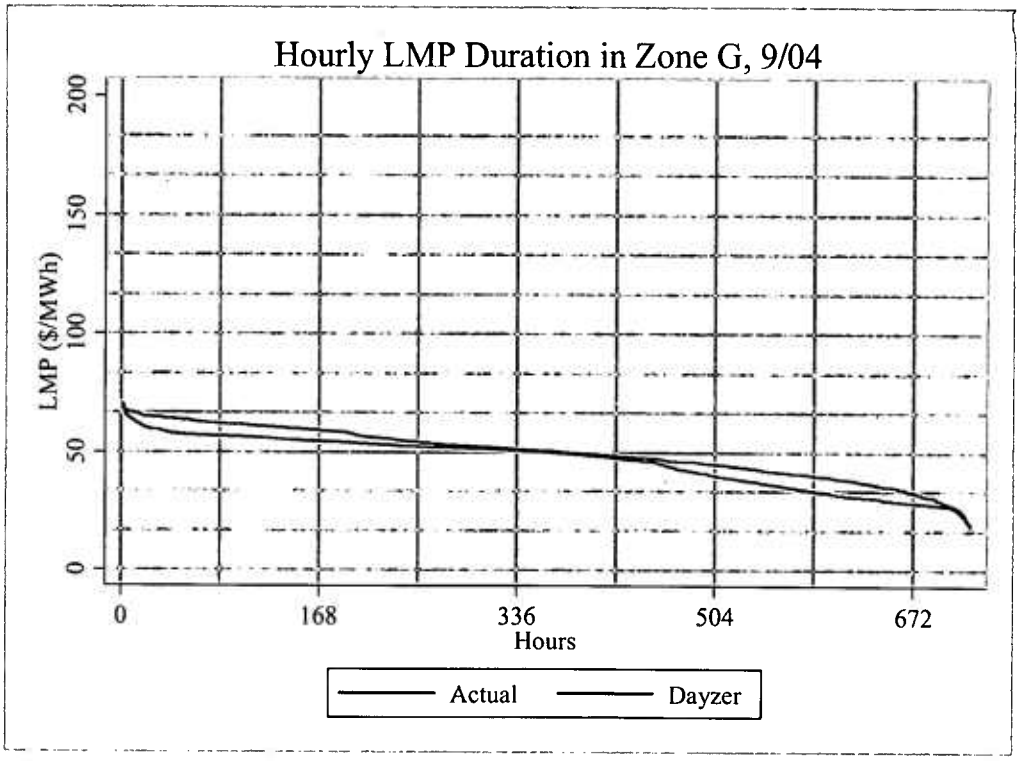

Hourly LMP Comparison in Zone G, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

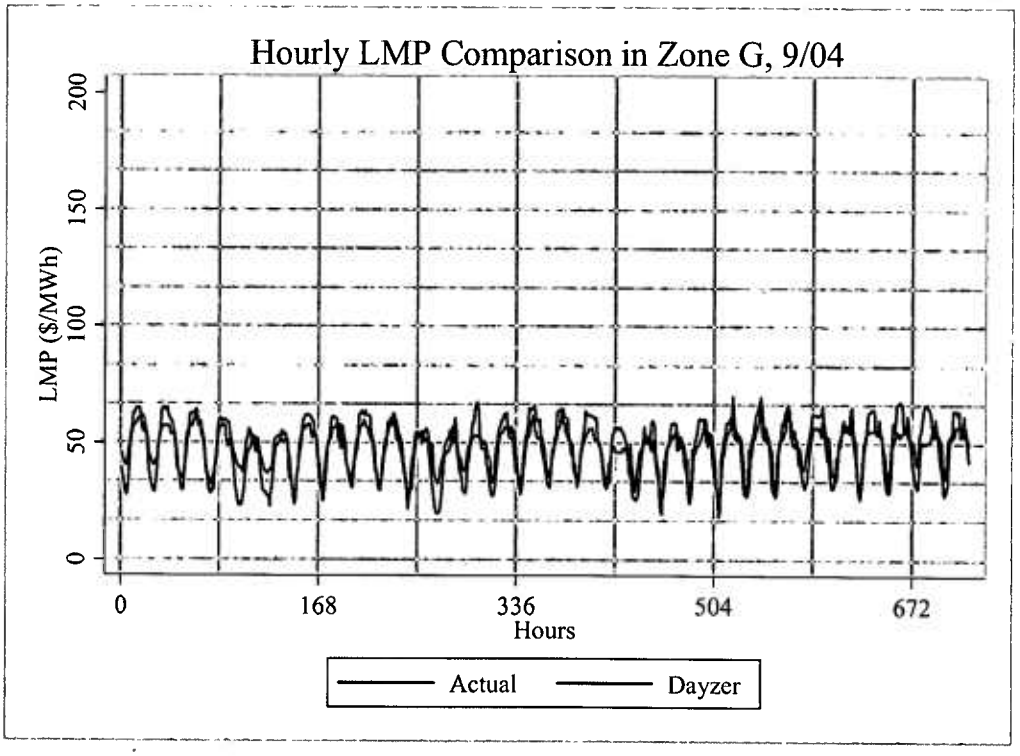

Hourly LMP Duration in Zone G, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

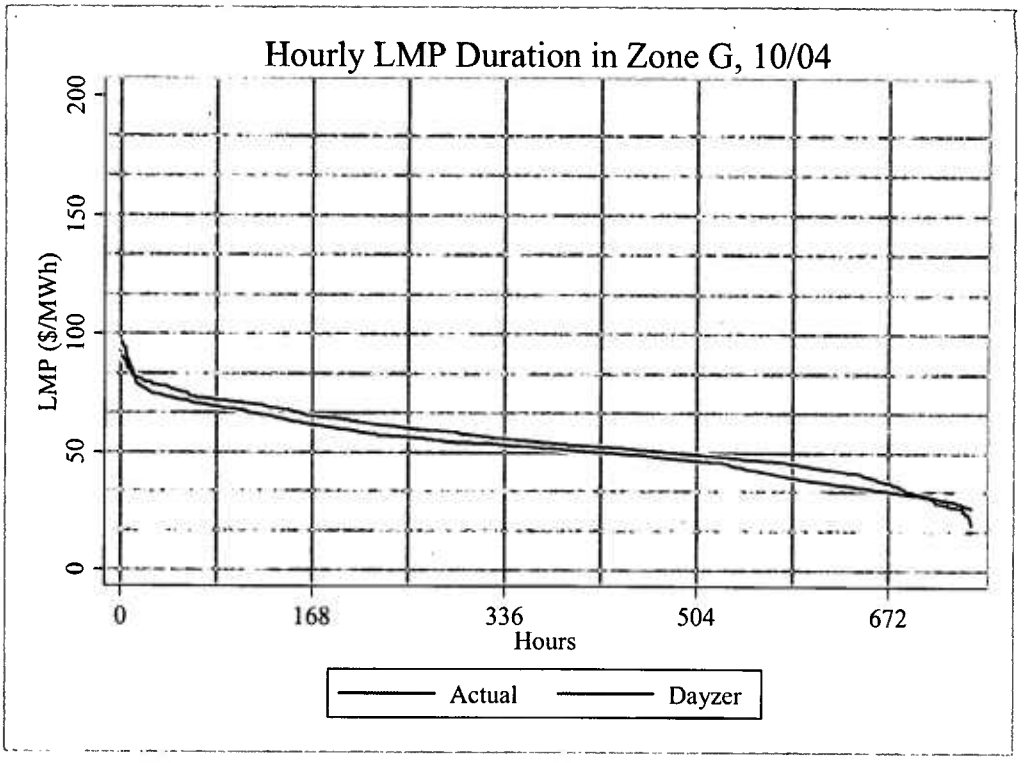

Hourly LMP Comparison in Zone G, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

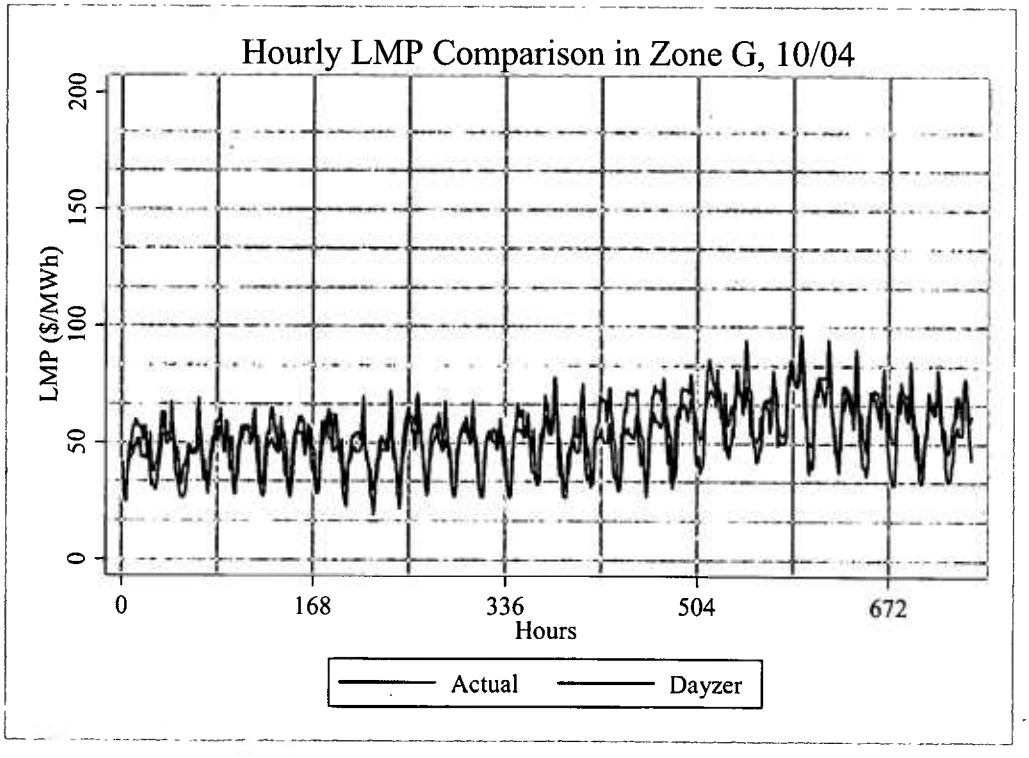

Hourly LMP Duration in Zone G, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

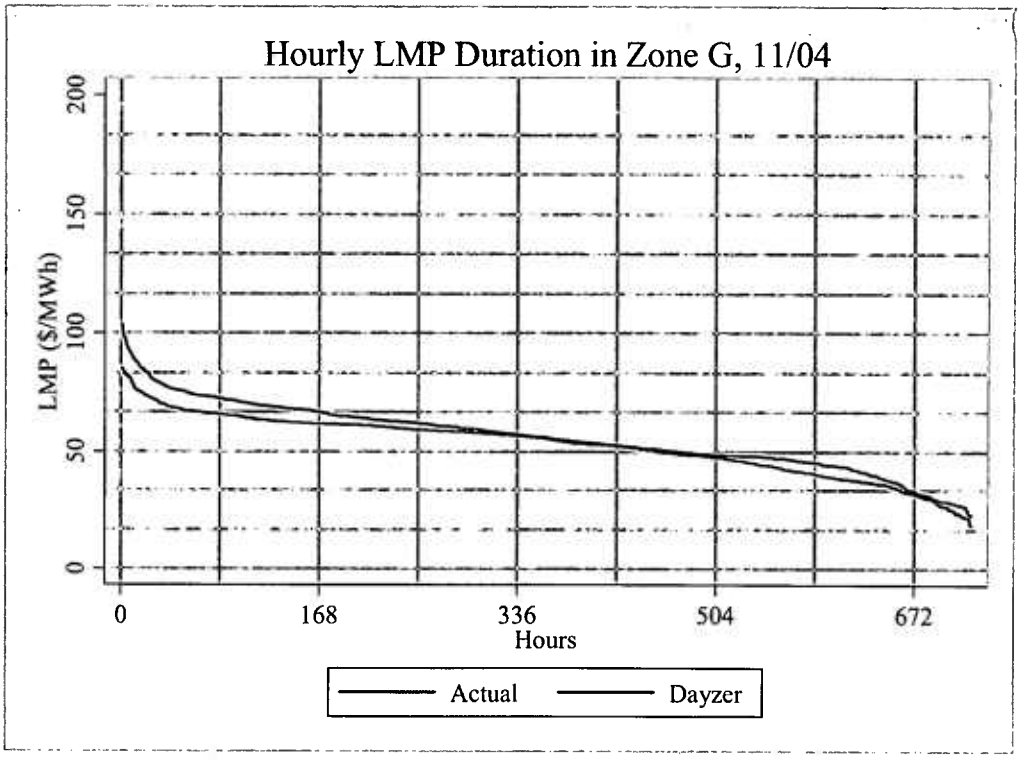

Hourly LMP Comparison in Zone G, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

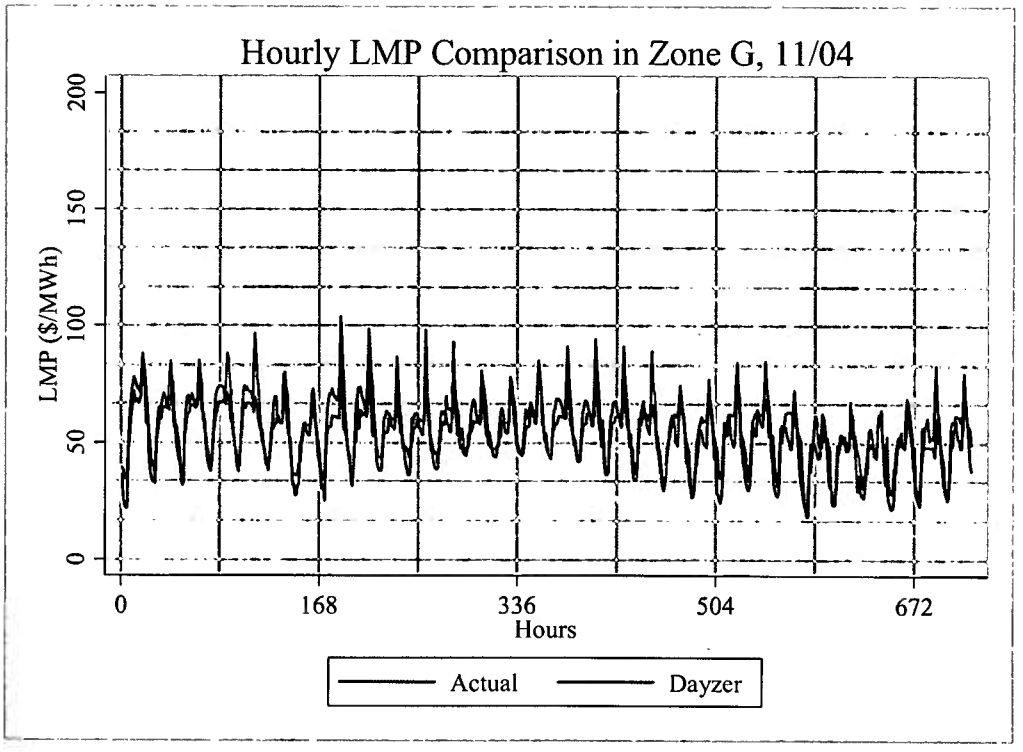

Hourly LMP Duration in Zone G, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

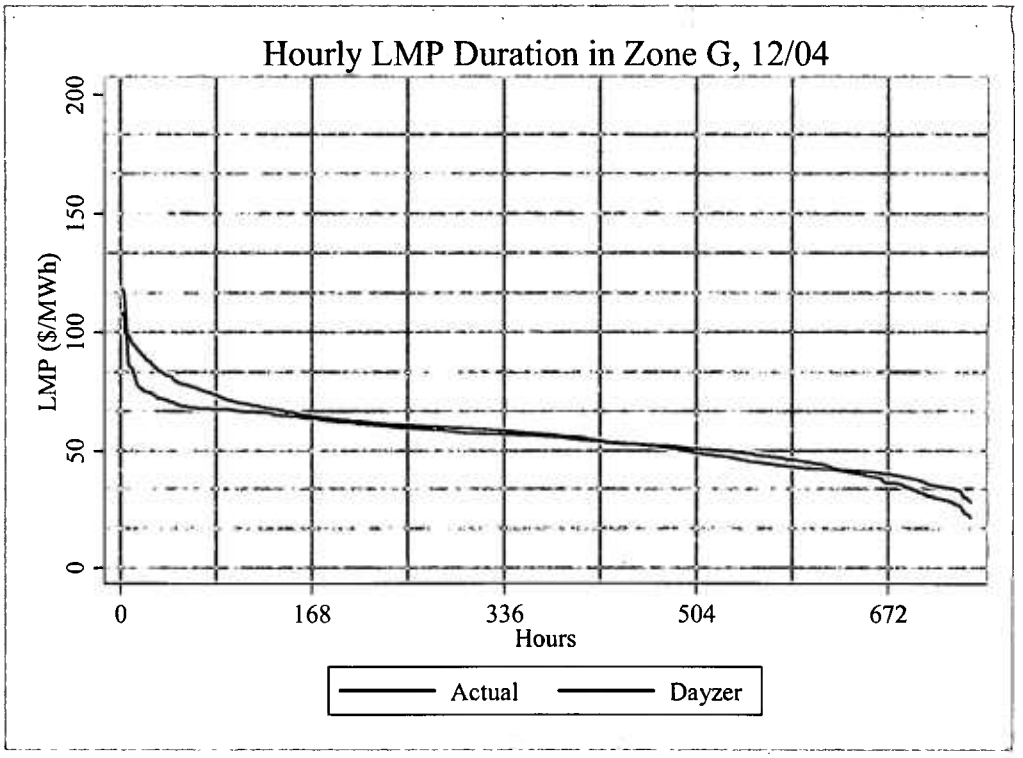

Hourly LMP Comparison in Zone G, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

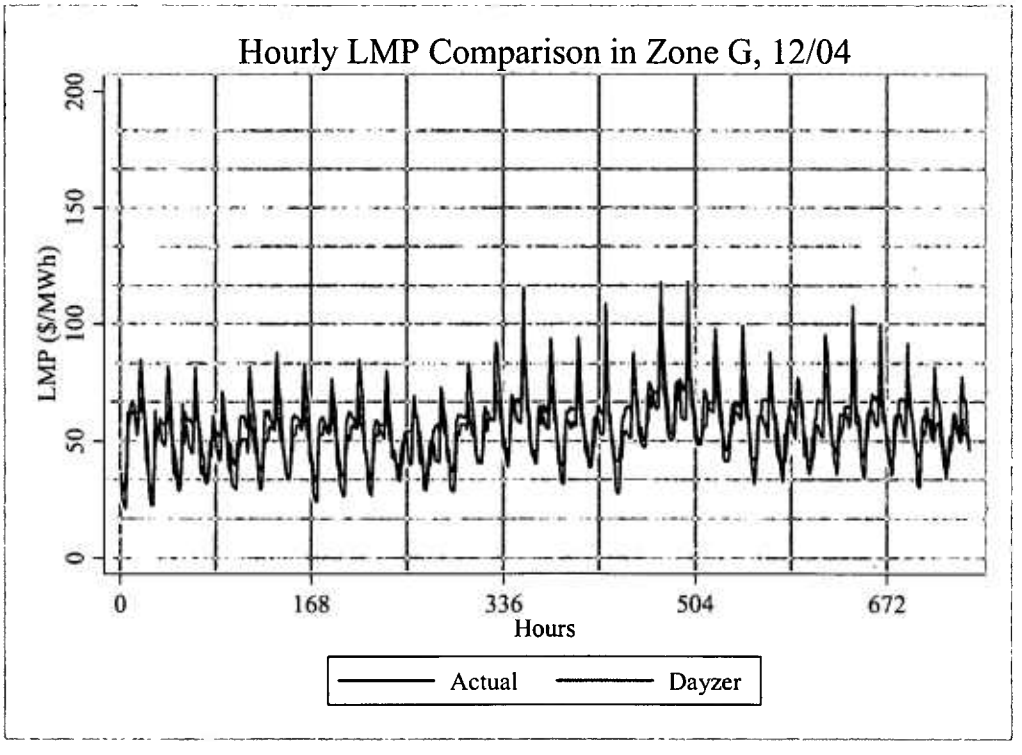

Hourly LMP Duration in Zone G, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

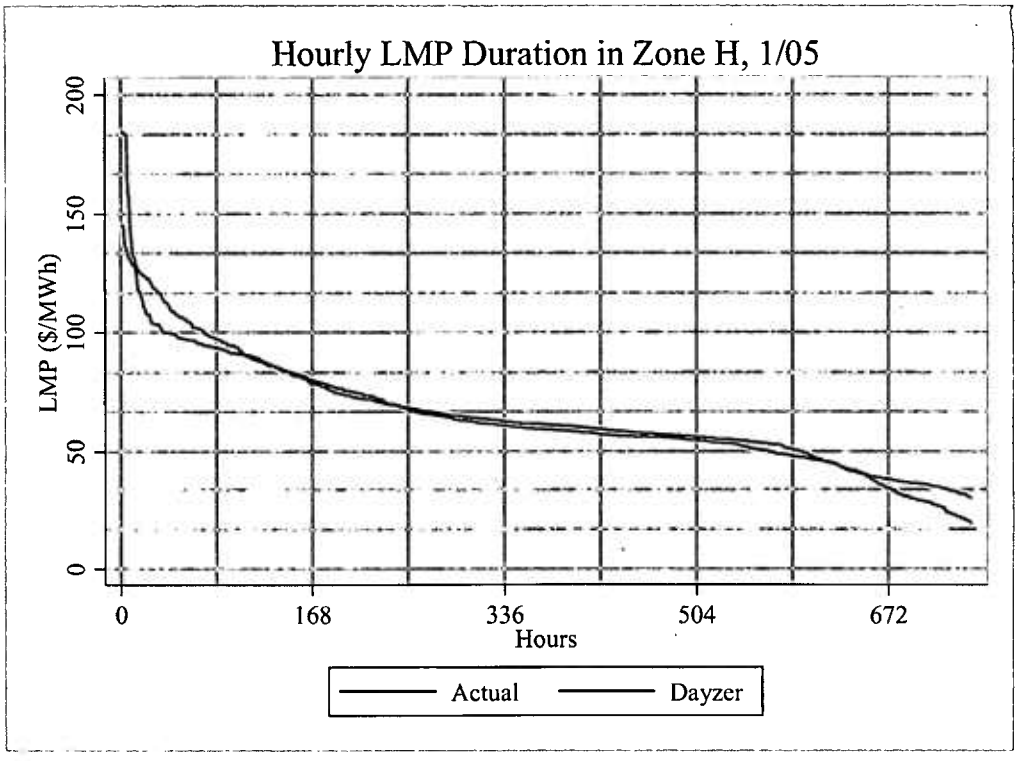

Hourly LMP Comparison in Zone G, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

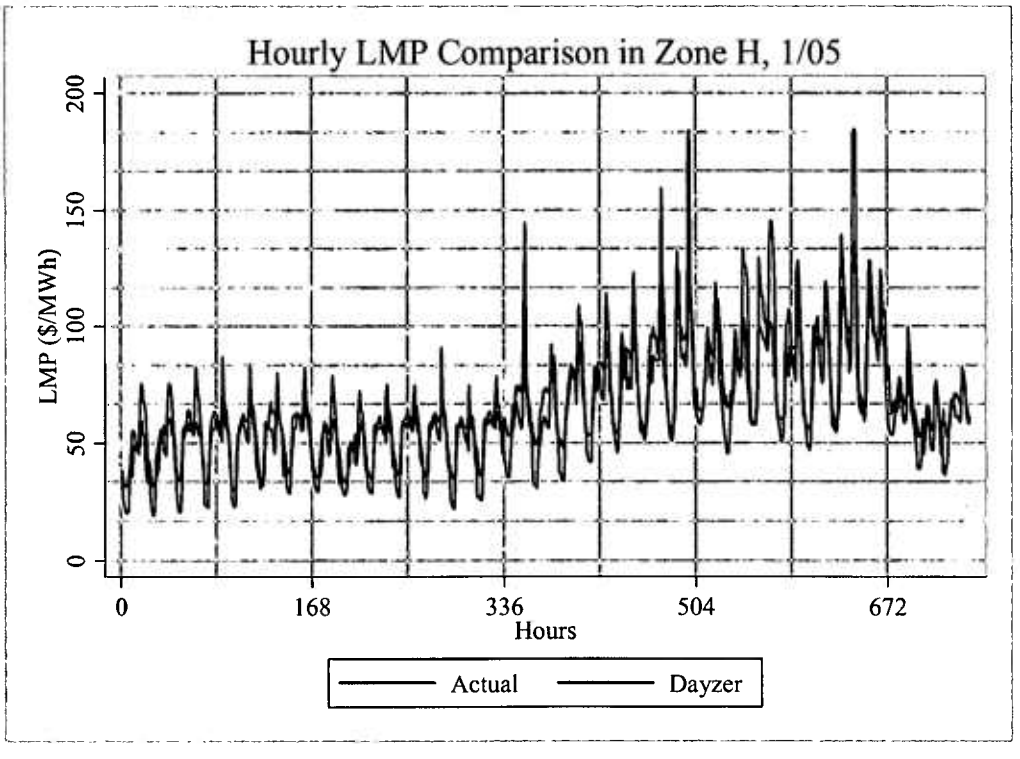

Hourly LMP Duration in Zone G, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

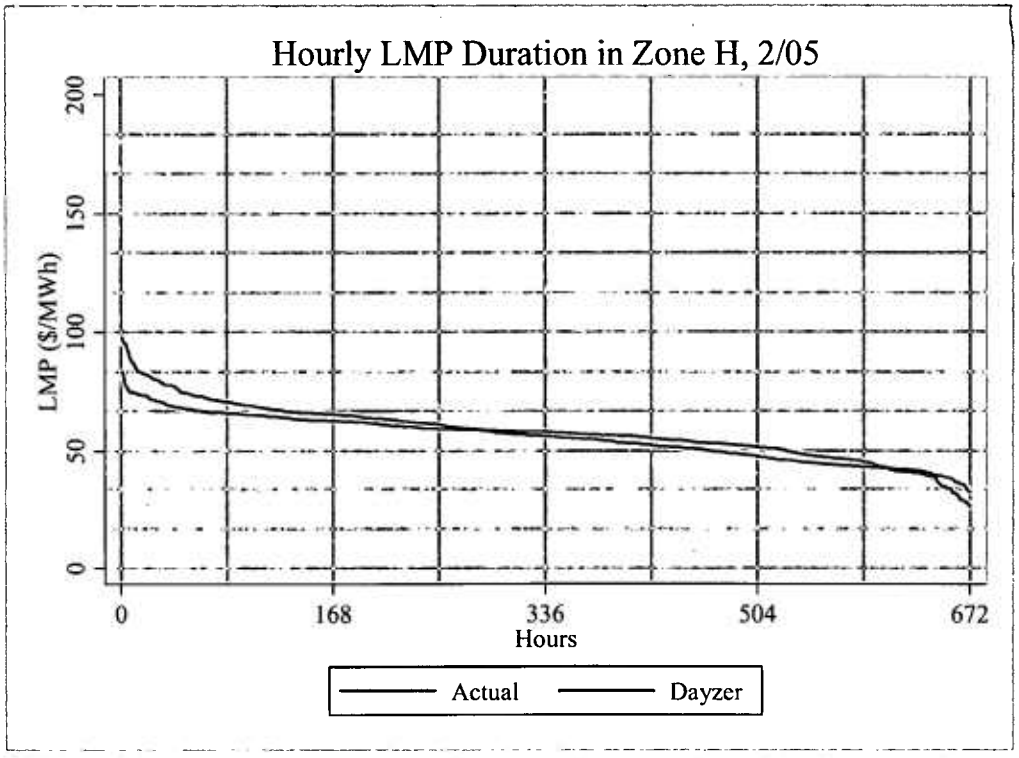

Hourly LMP Comparison in Zone G, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

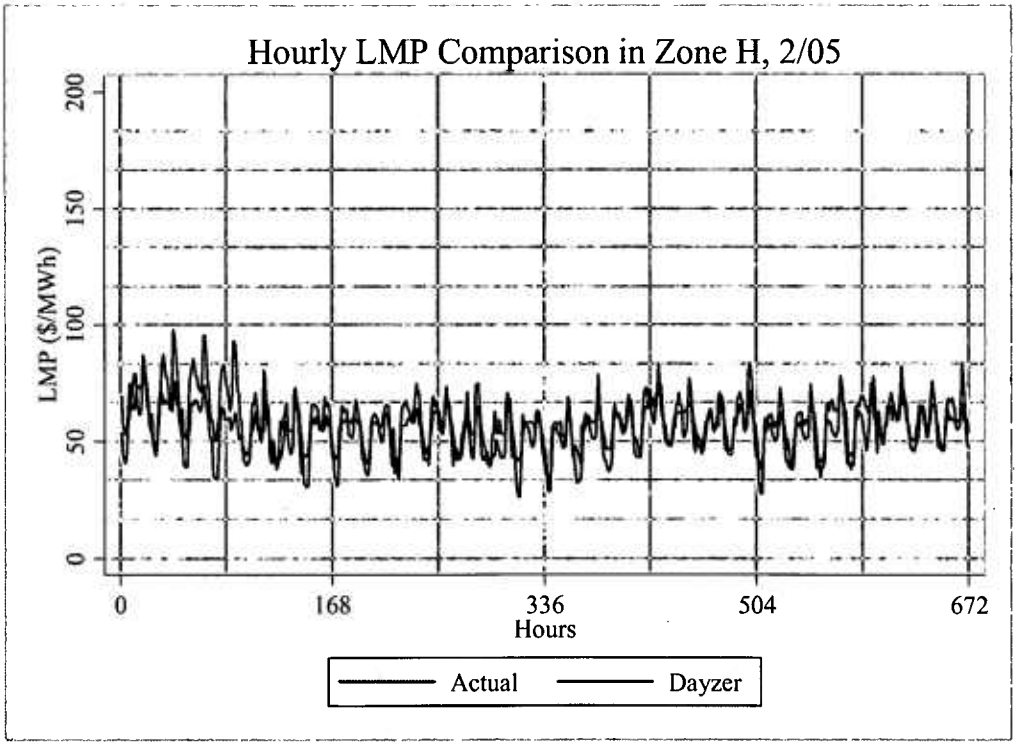

Hourly LMP Duration in Zone G, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

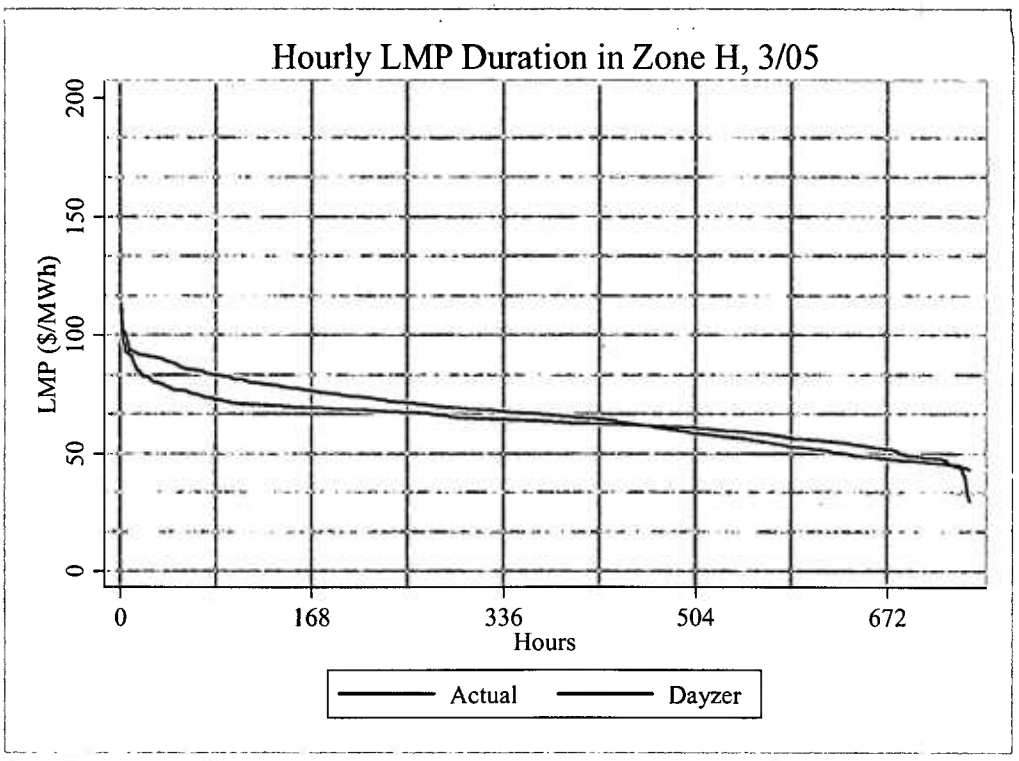

Hourly LMP Comparison in Zone G, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

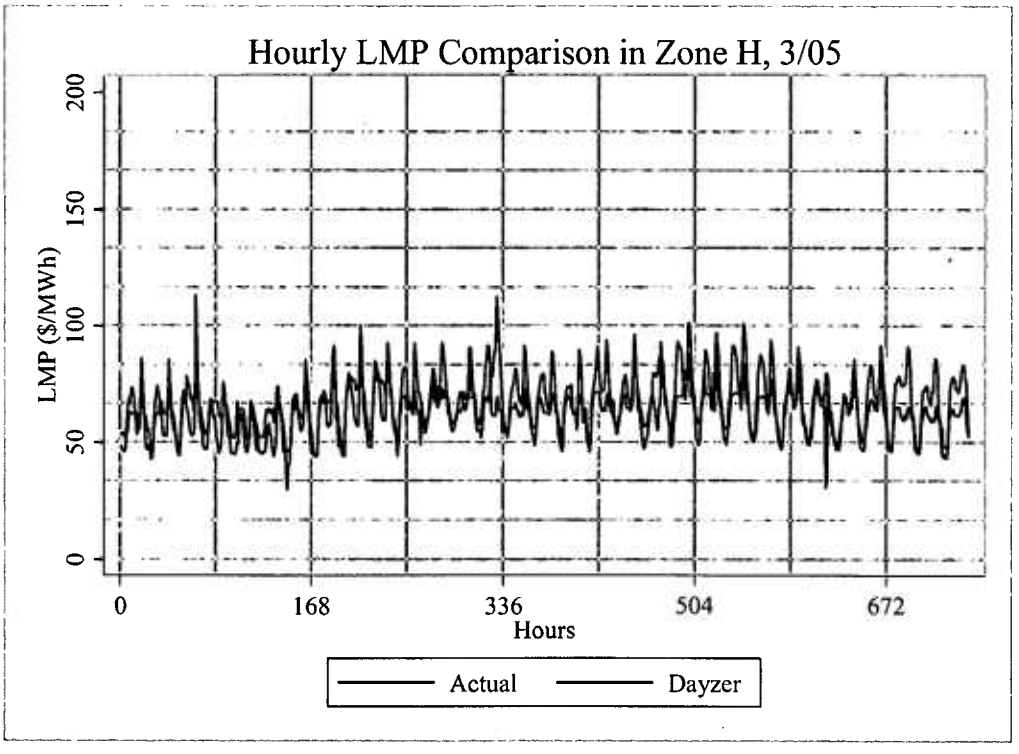

Hourly LMP Duration in Zone H, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

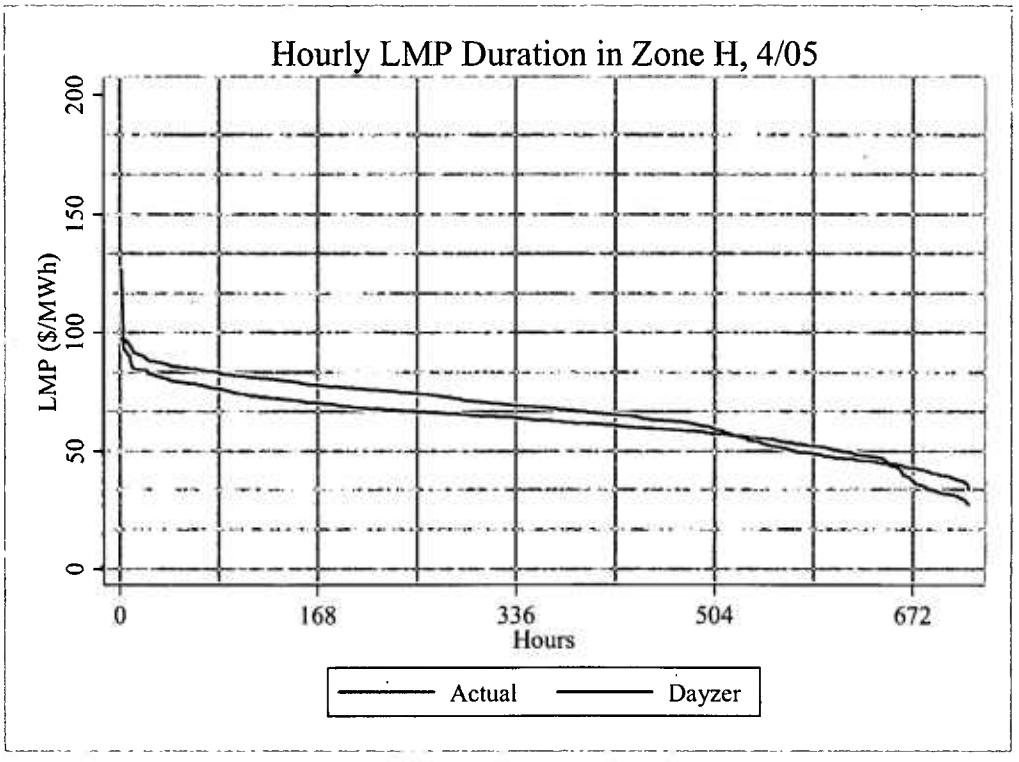

Hourly LMP Comparison in Zone H, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

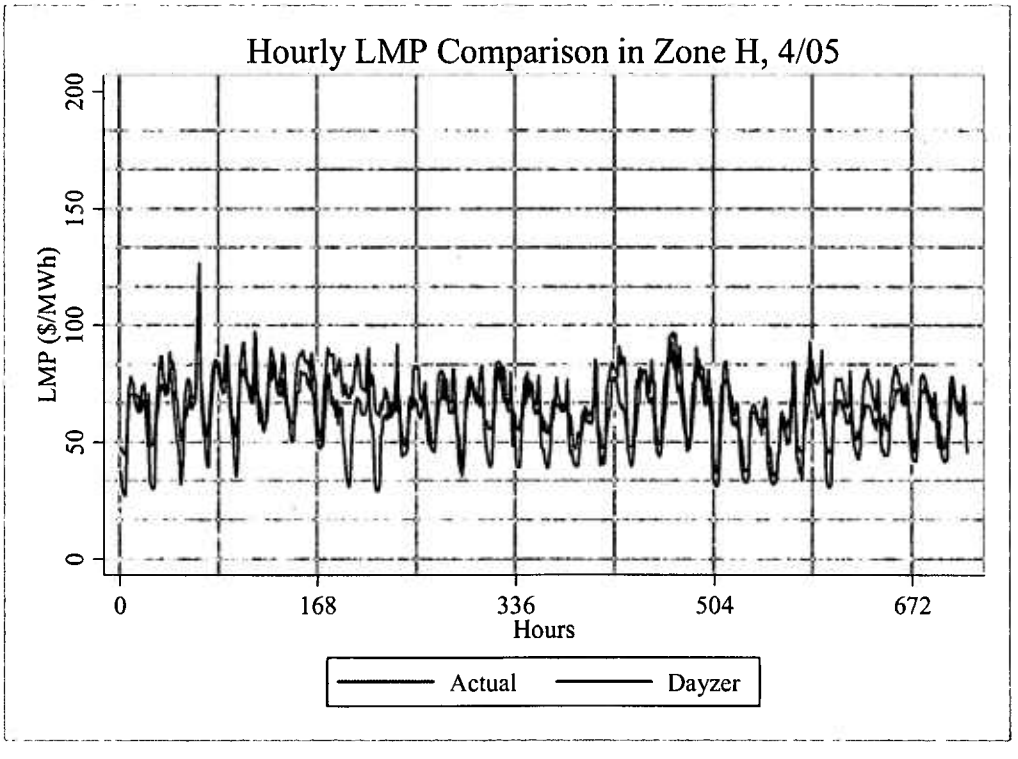

Hourly LMP Duration in Zone H, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

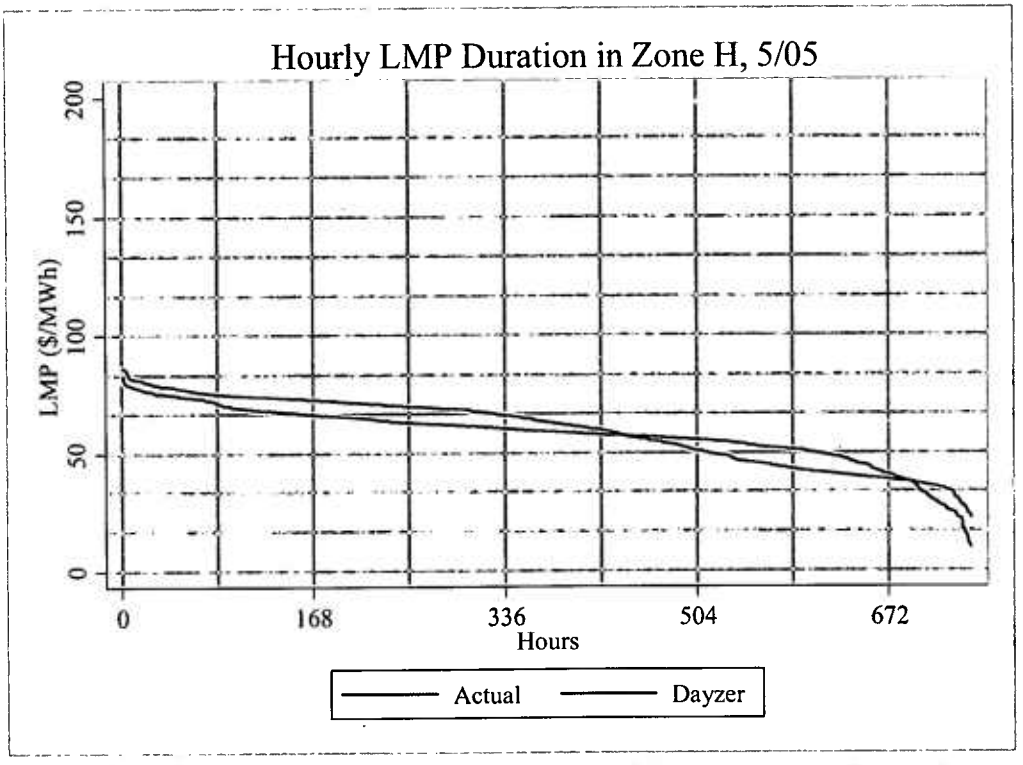

Hourly LMP Comparison in Zone H, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

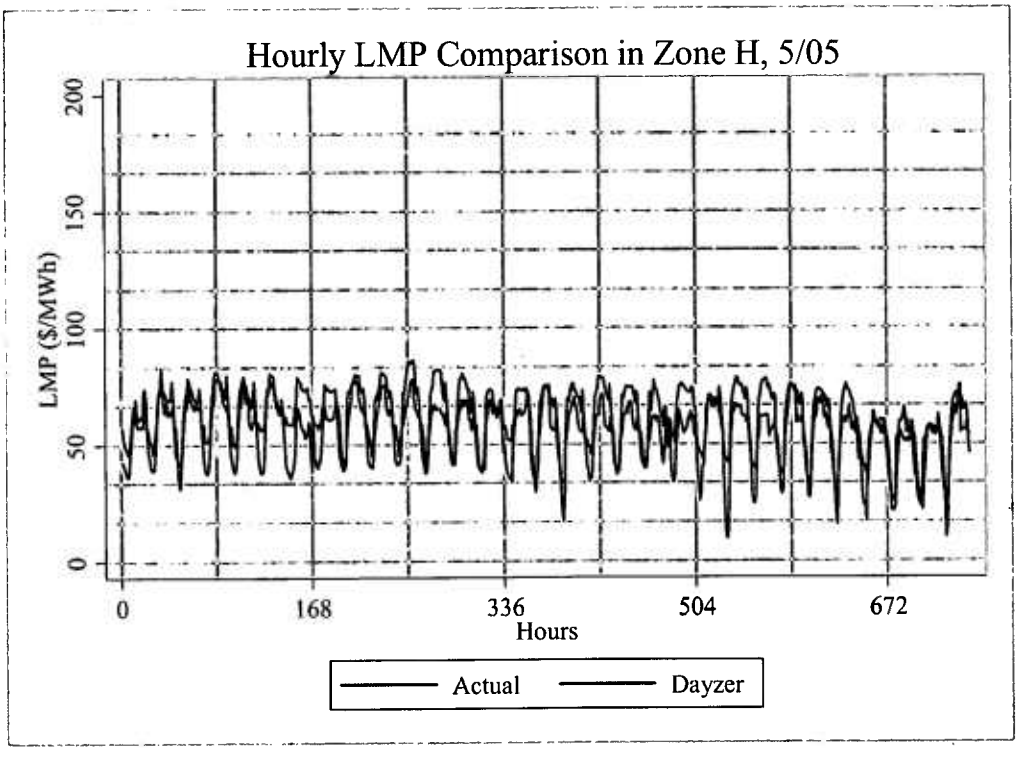

Hourly LMP Duration in Zone H, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

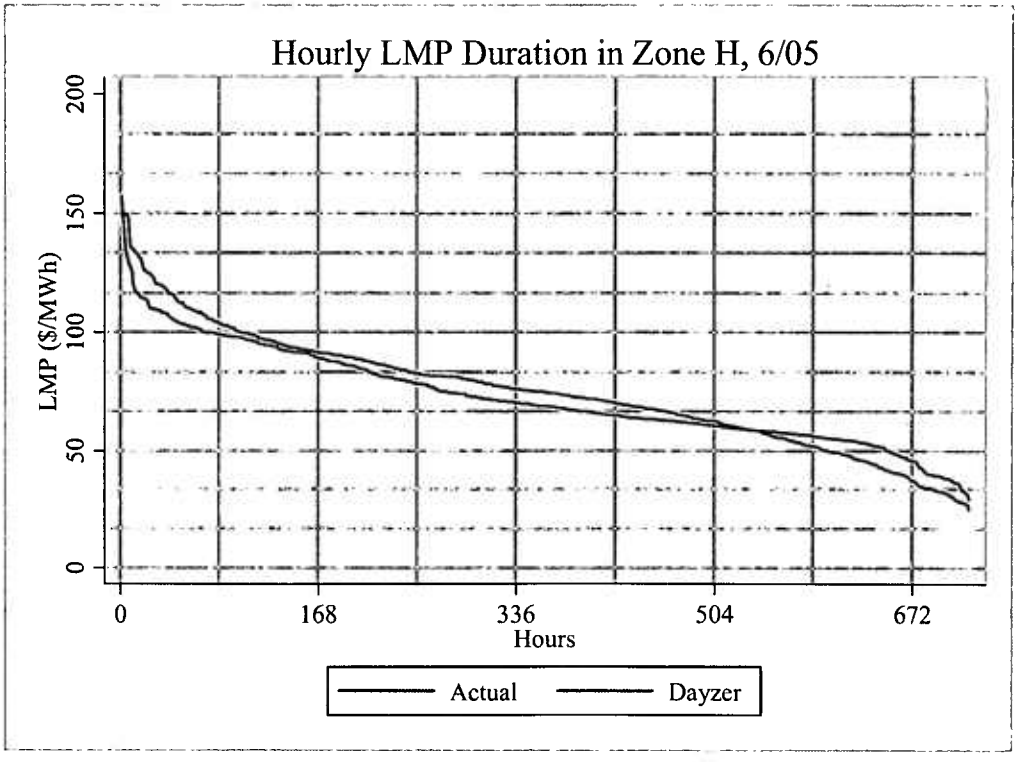

Hourly LMP Comparison in Zone H, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

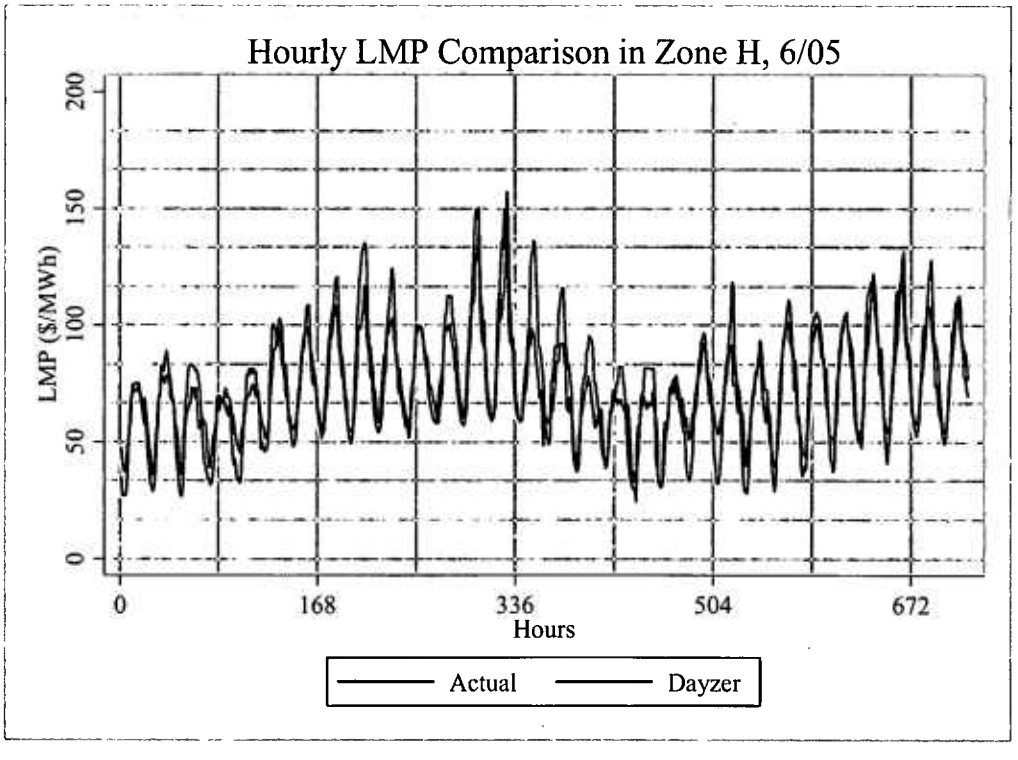

Hourly LMP Duration in Zone H, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

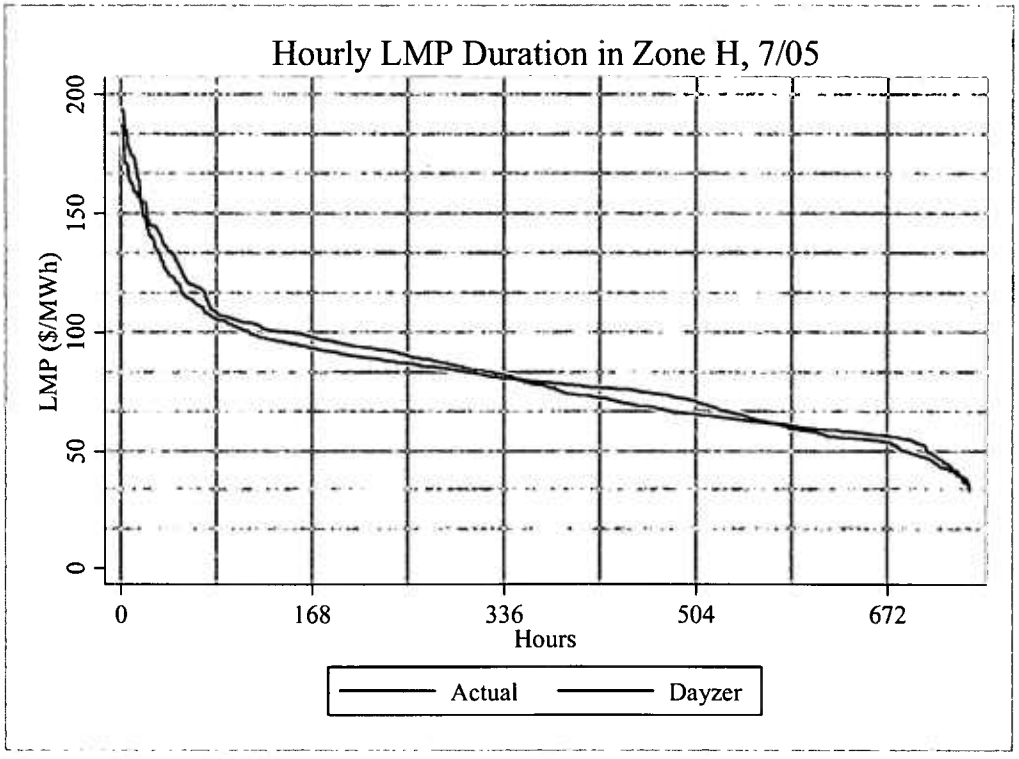

Hourly LMP Comparison in Zone H, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

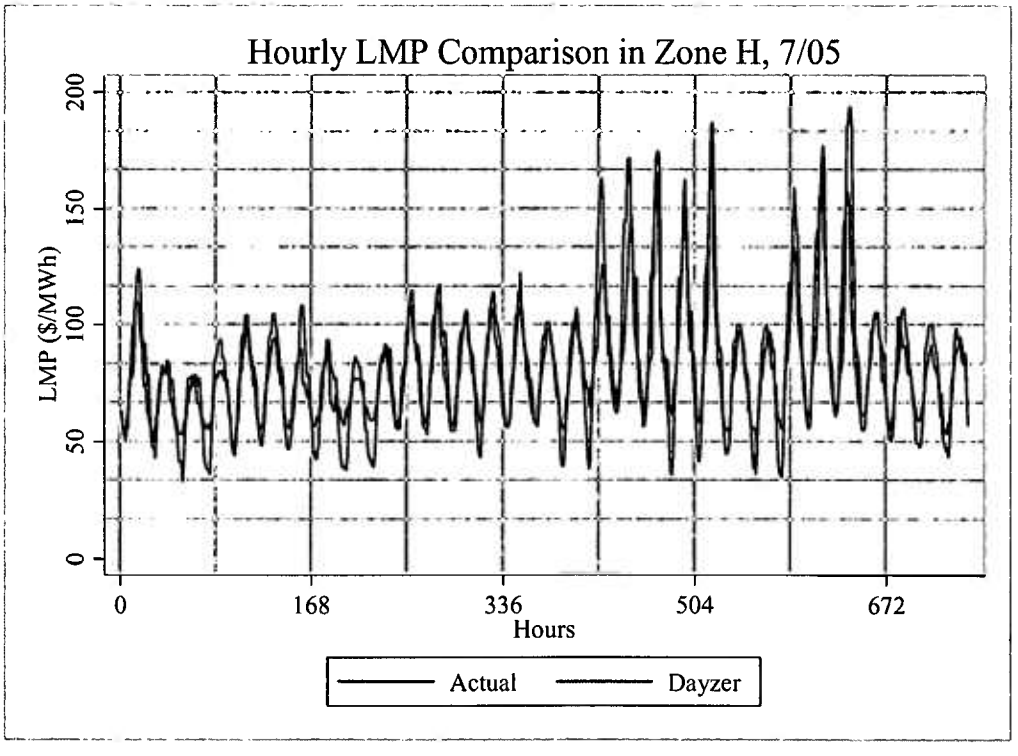

Hourly LMP Duration in Zone H, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

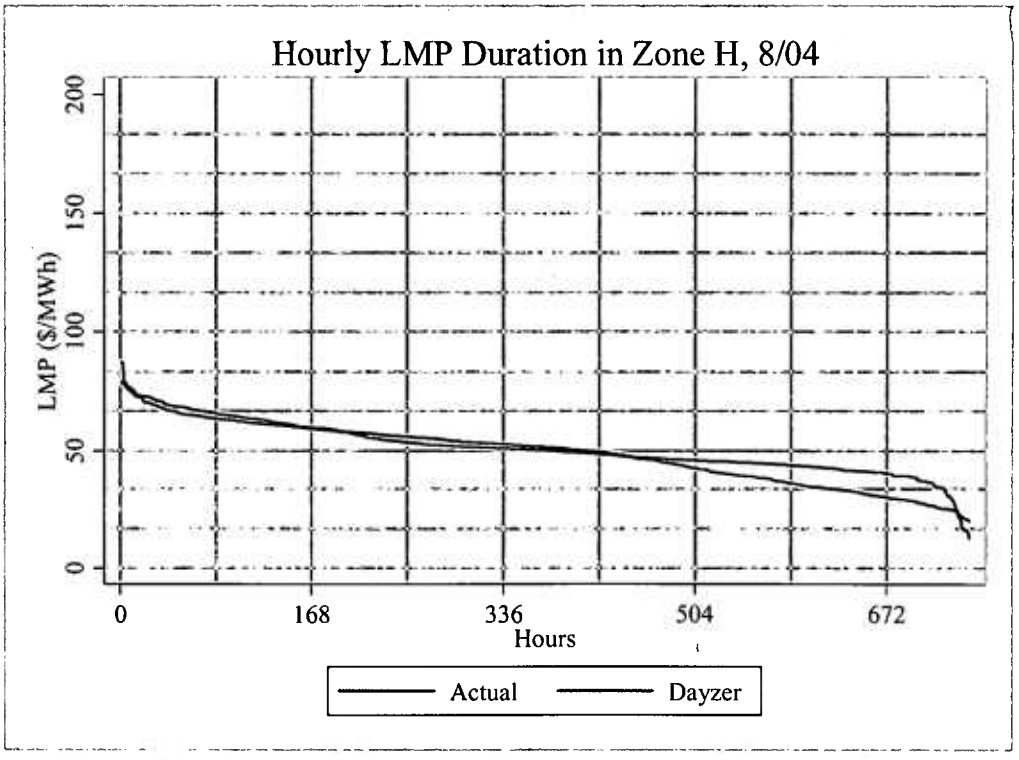

Hourly LMP Comparison in Zone H, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

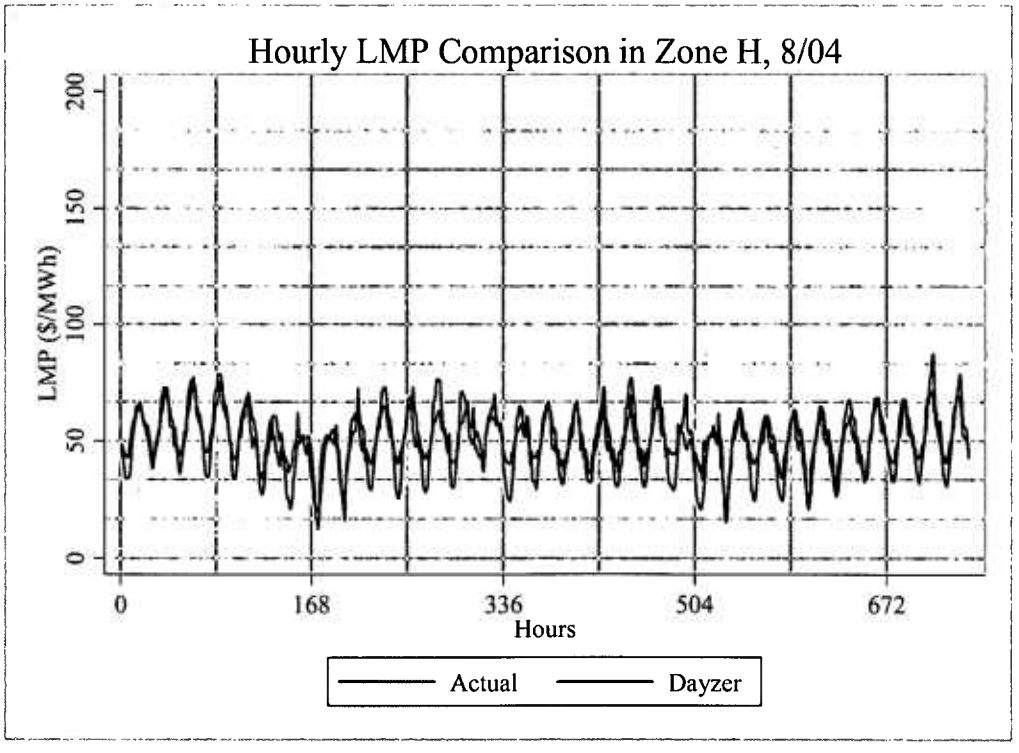

Hourly LMP Duration in Zone H, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

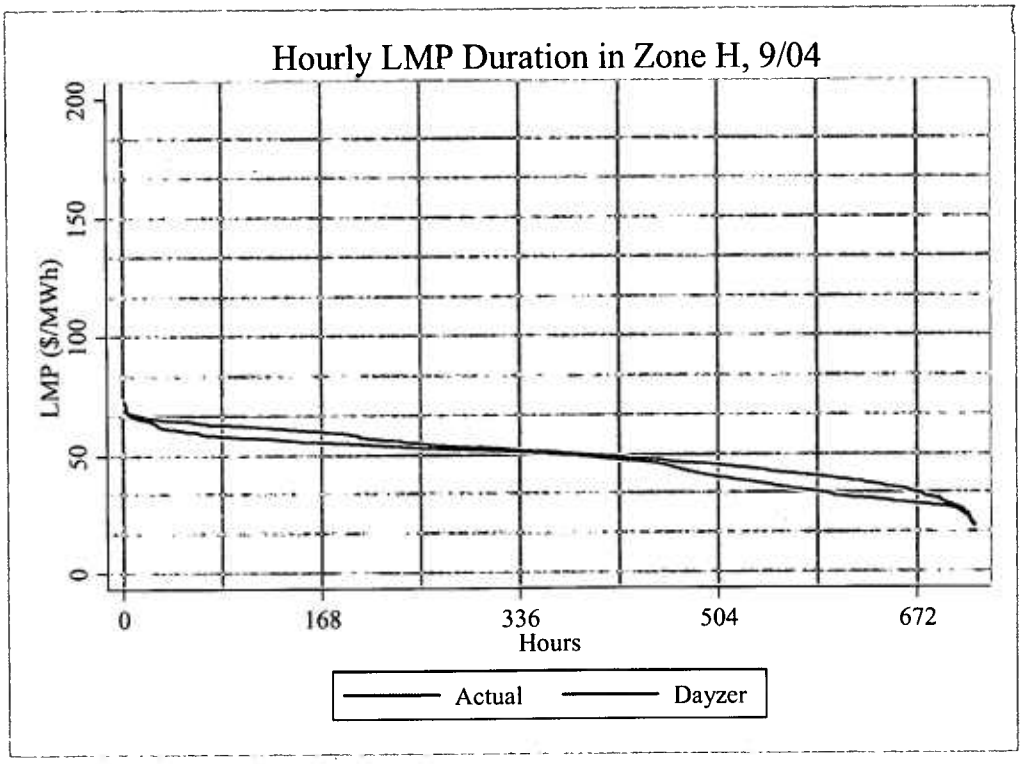

Hourly LMP Comparison in Zone H, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

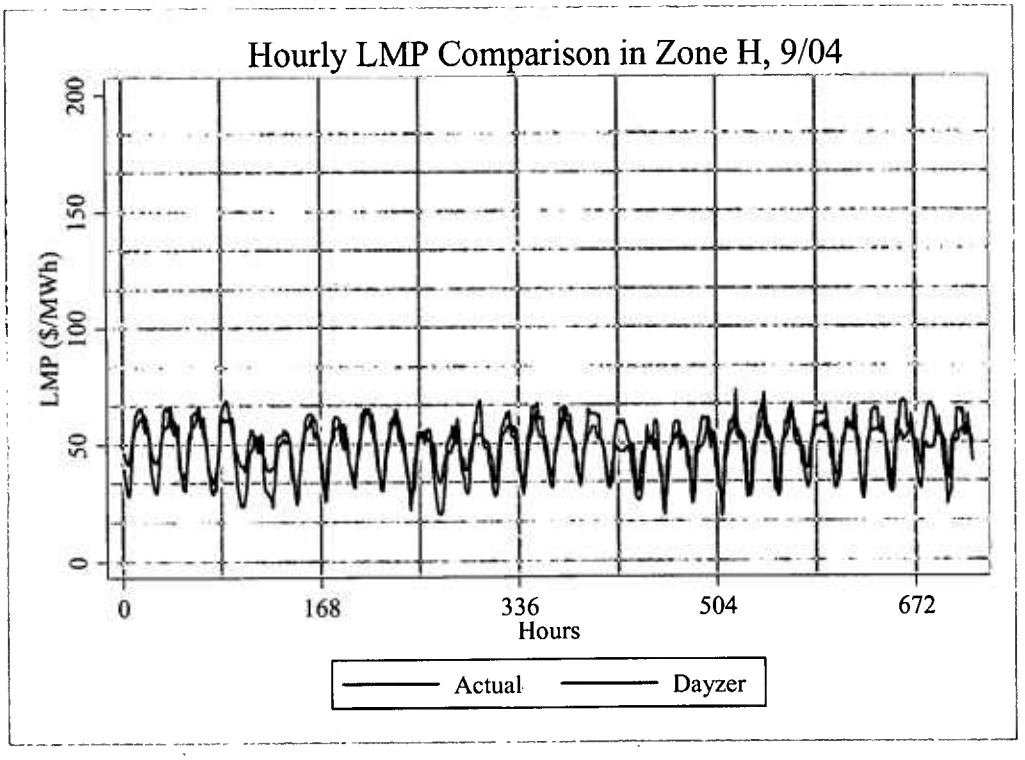

Hourly LMP Duration in Zone H, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

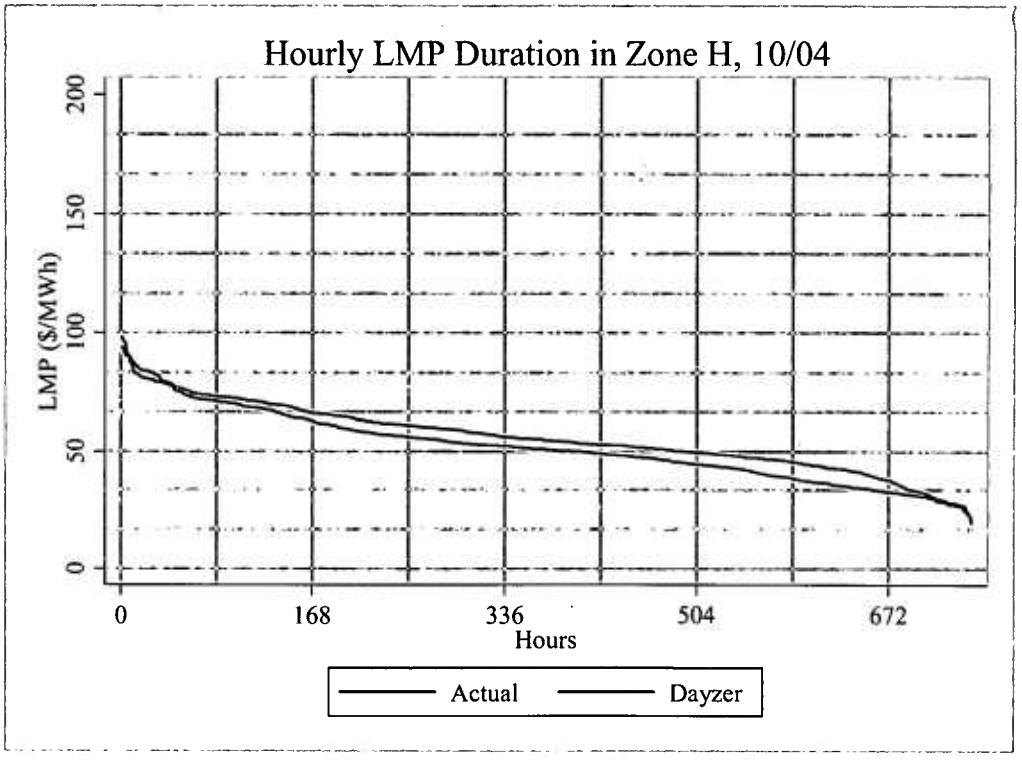

Hourly LMP Comparison in Zone H, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

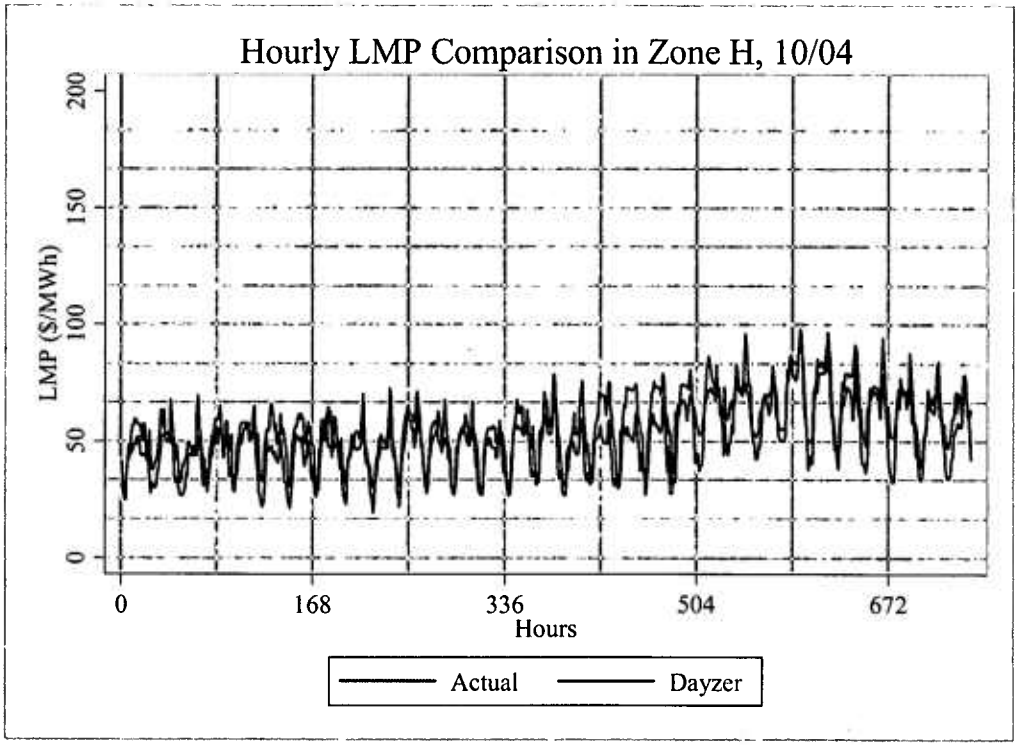

Hourly LMP Duration in Zone H, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

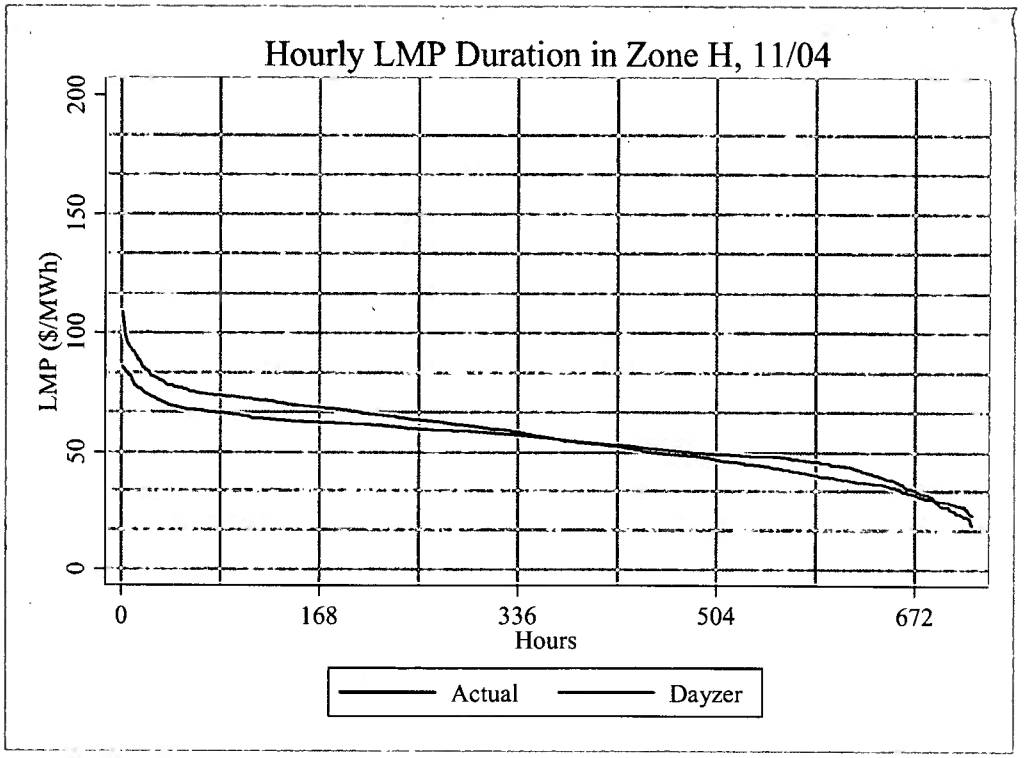

Hourly LMP Comparison in Zone H, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

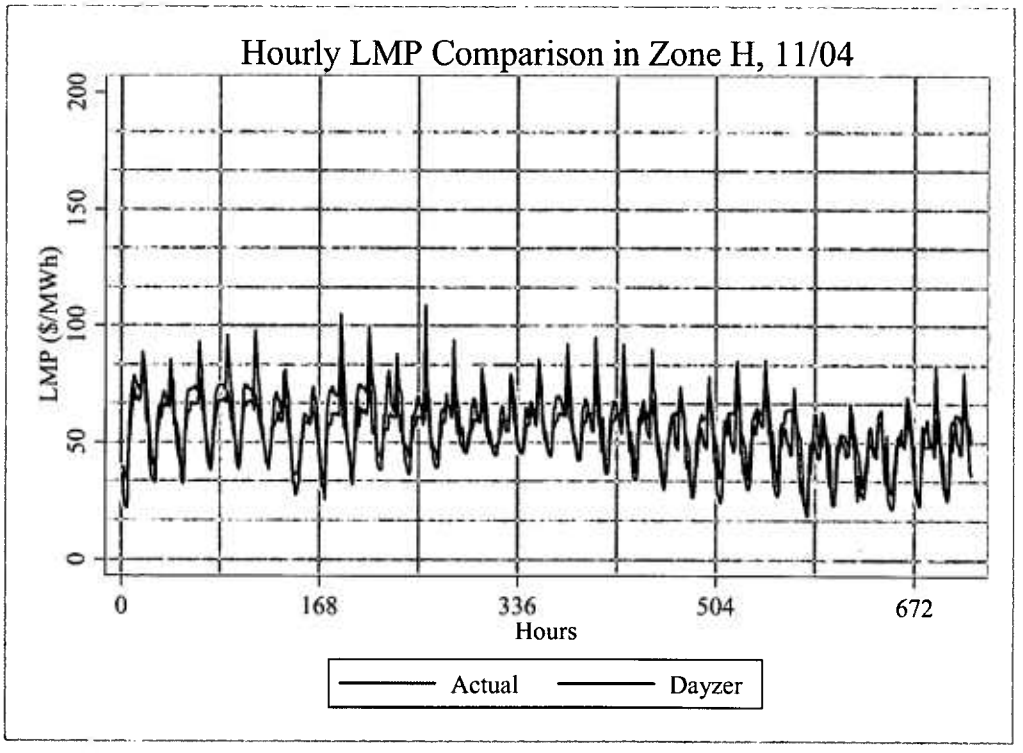

Hourly LMP Duration in Zone H, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

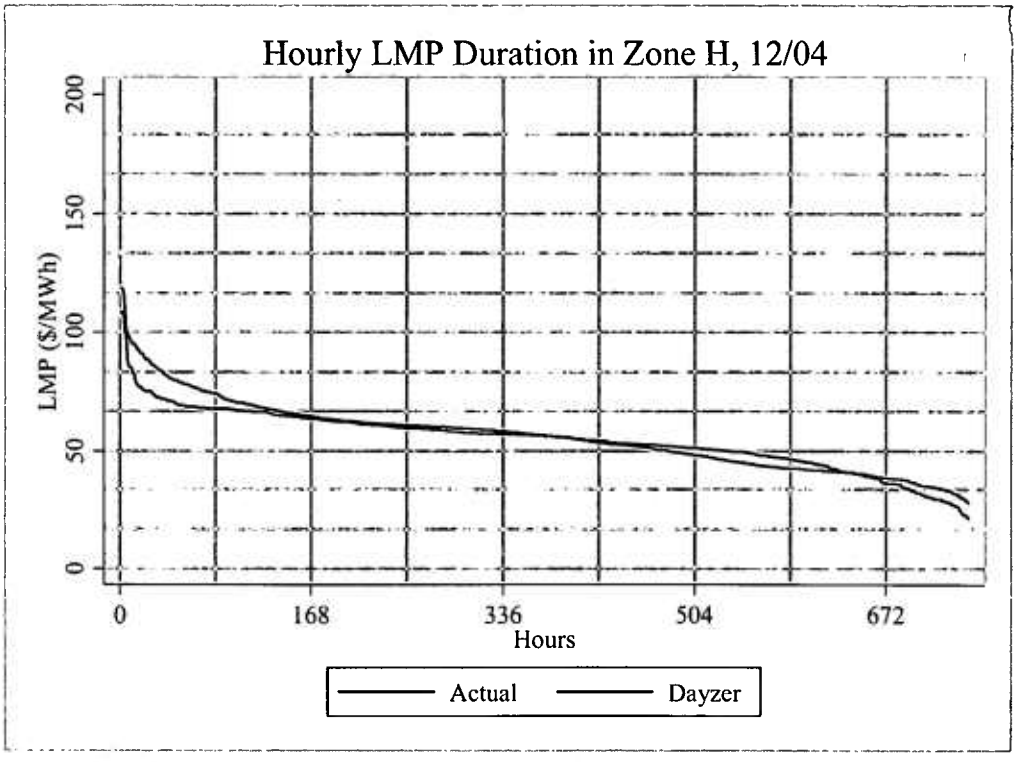

Hourly LMP Comparison in Zone H, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

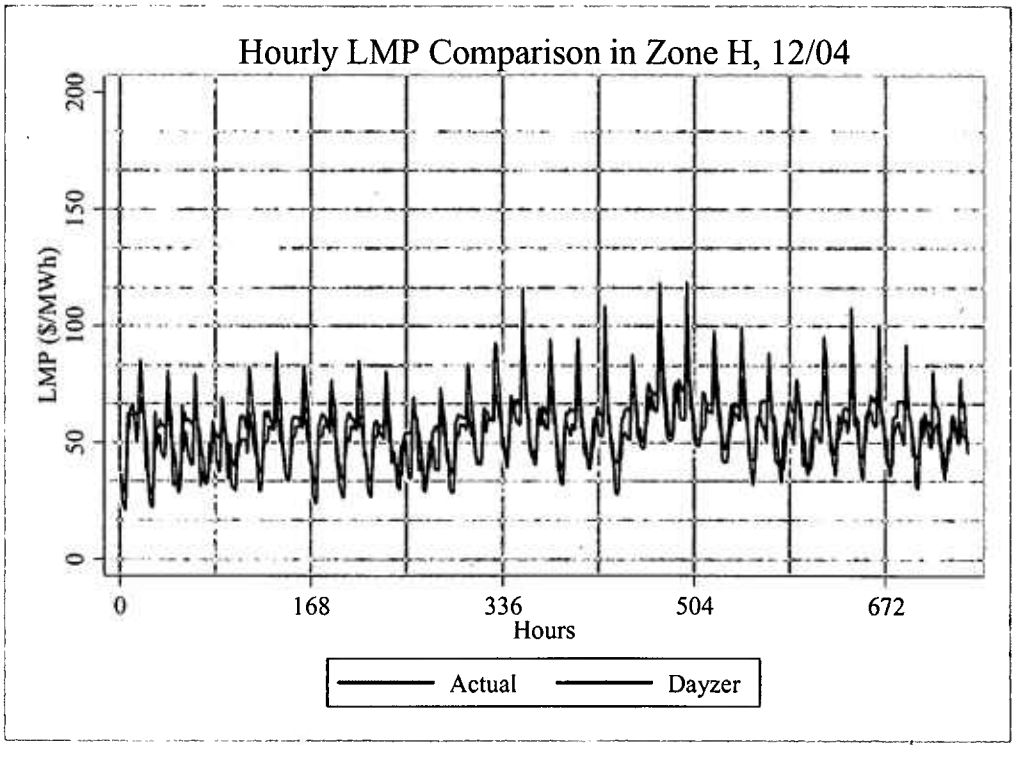

Hourly LMP Duration in Zone H, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

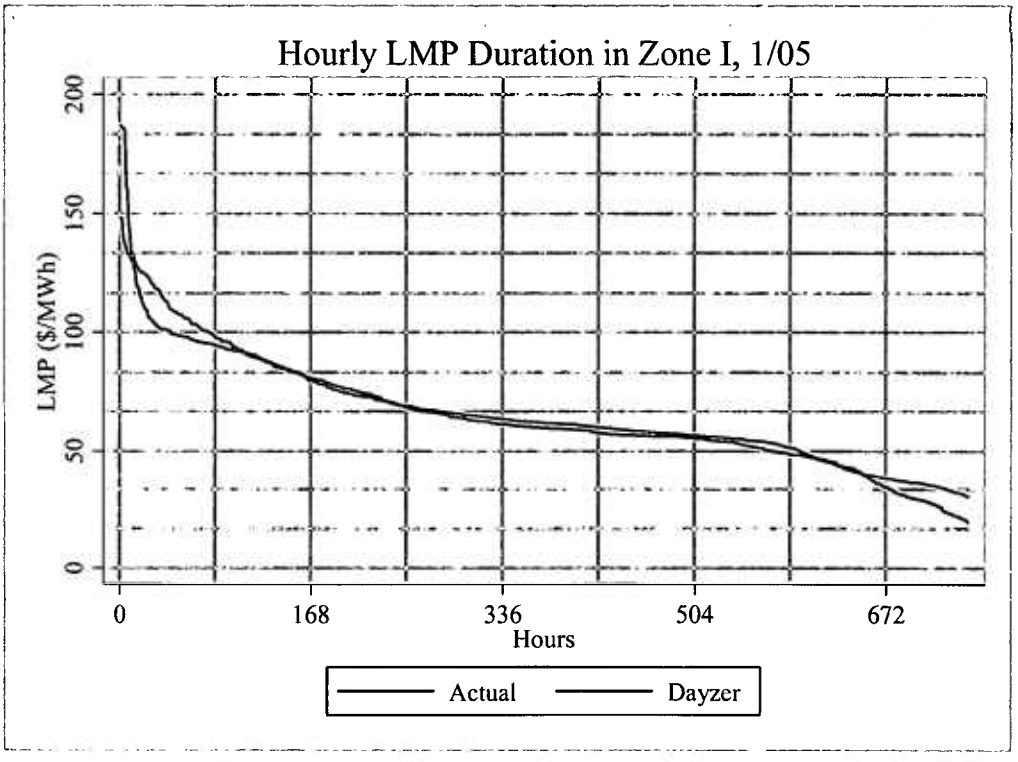

Hourly LMP Comparison in Zone H, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

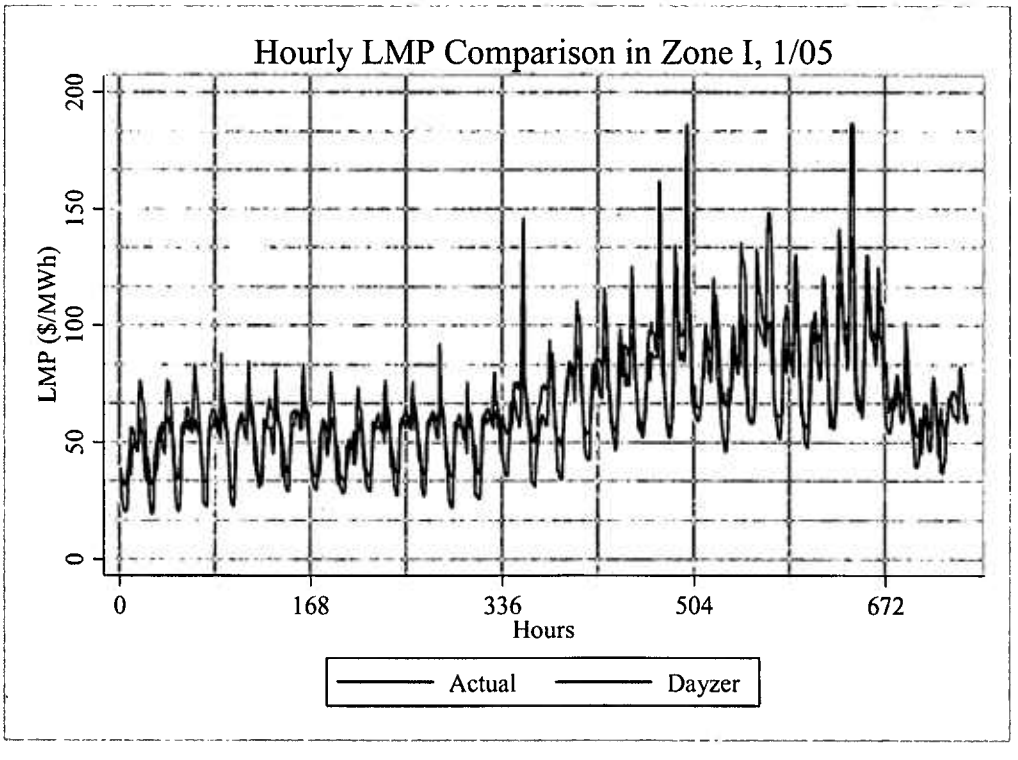

Hourly LMP Duration in Zone H, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

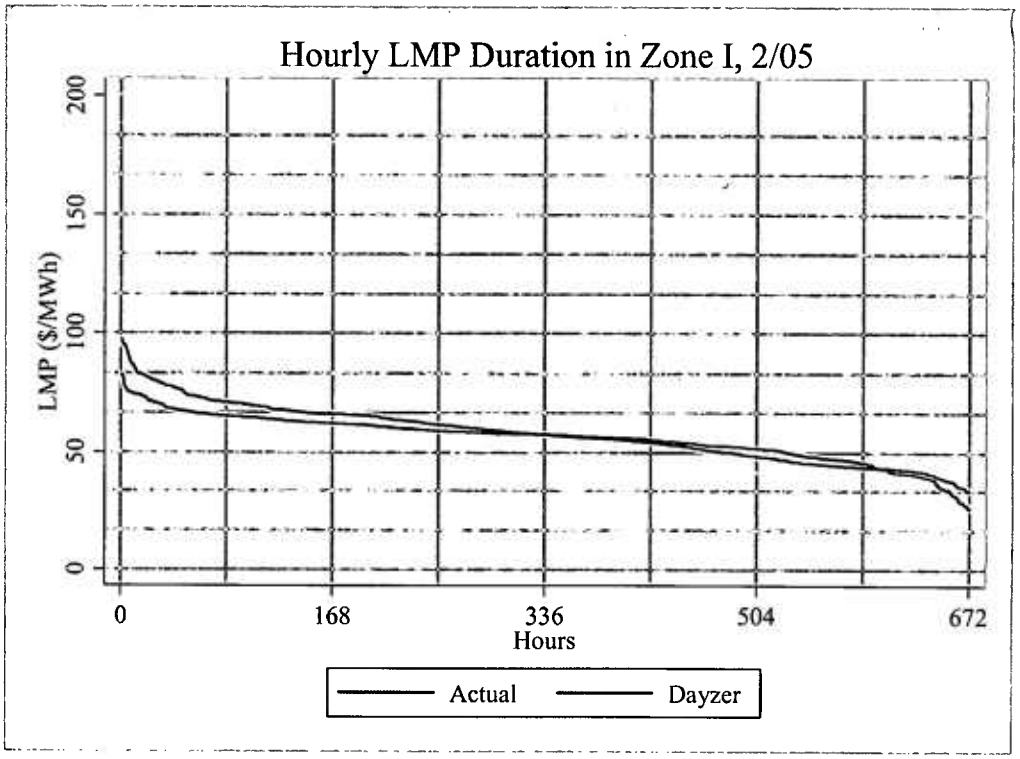

Hourly LMP Comparison in Zone H, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

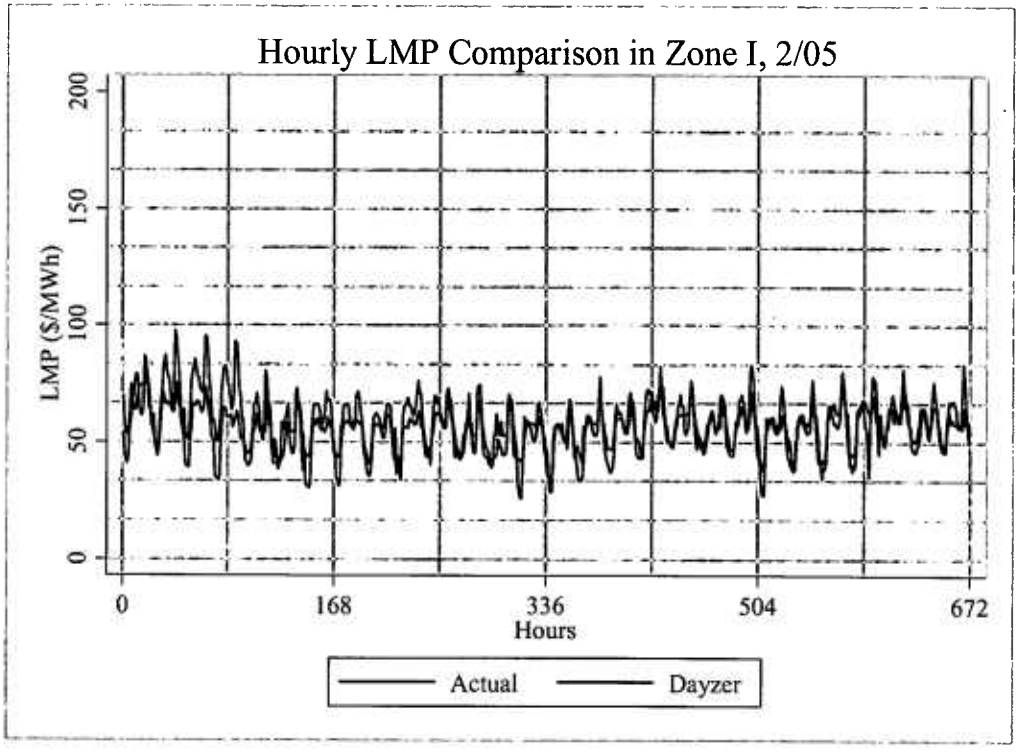

Hourly LMP Duration in Zone H, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

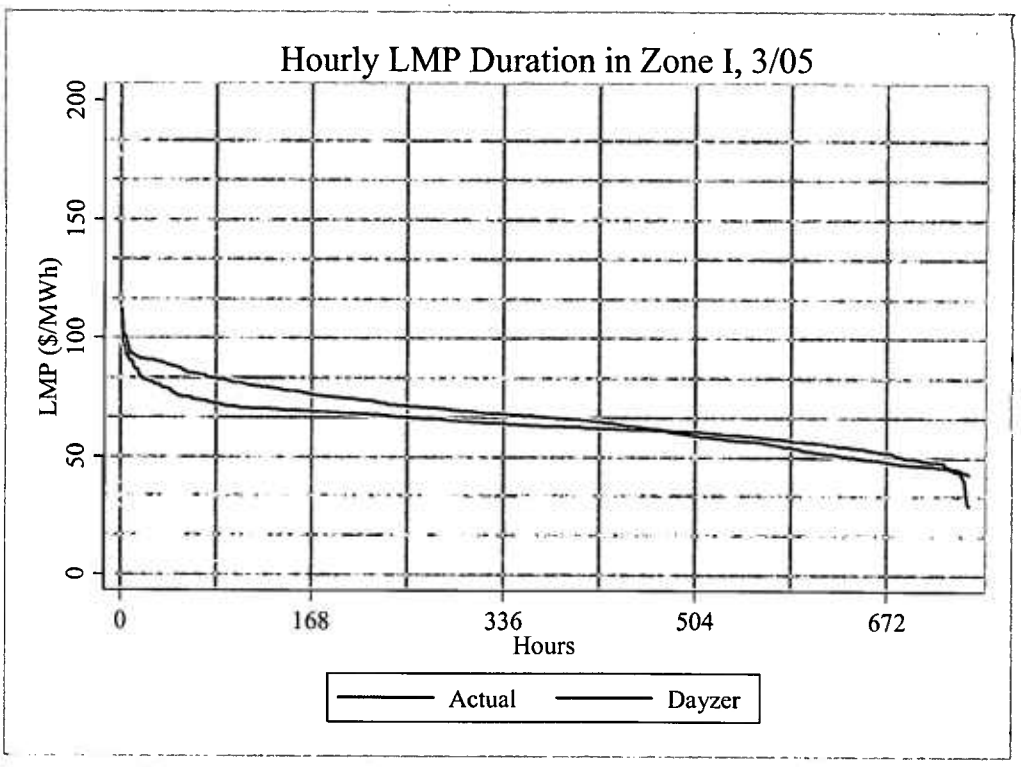

Hourly LMP Comparison in Zone H, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

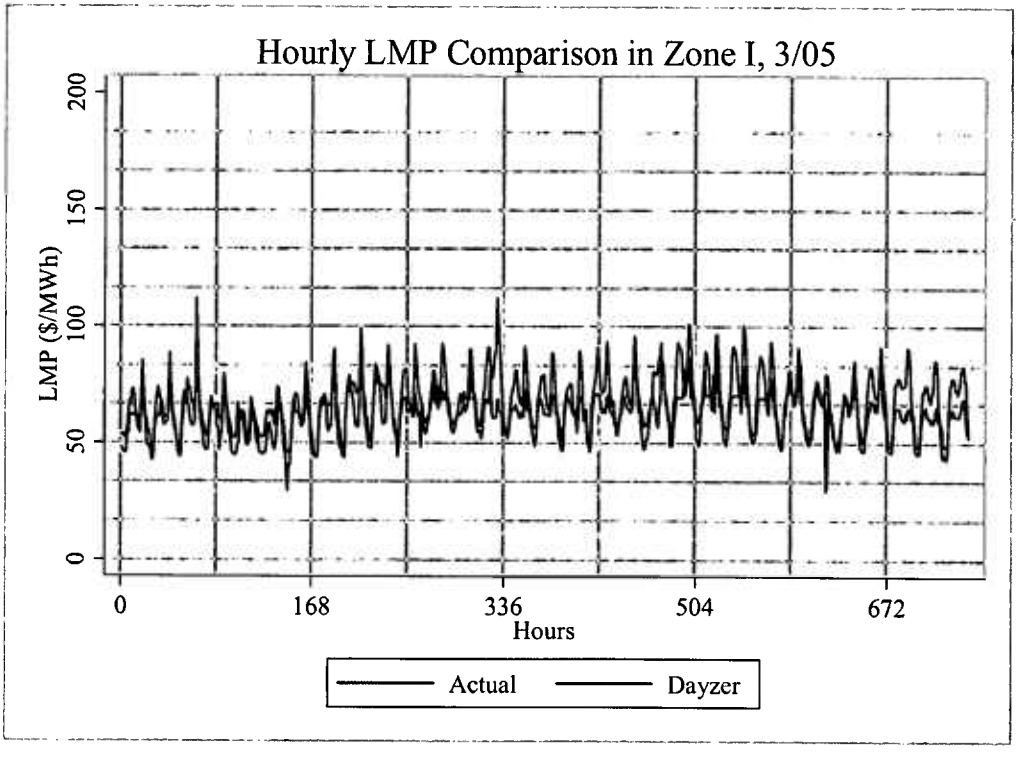

Hourly LMP Duration in Zone I, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

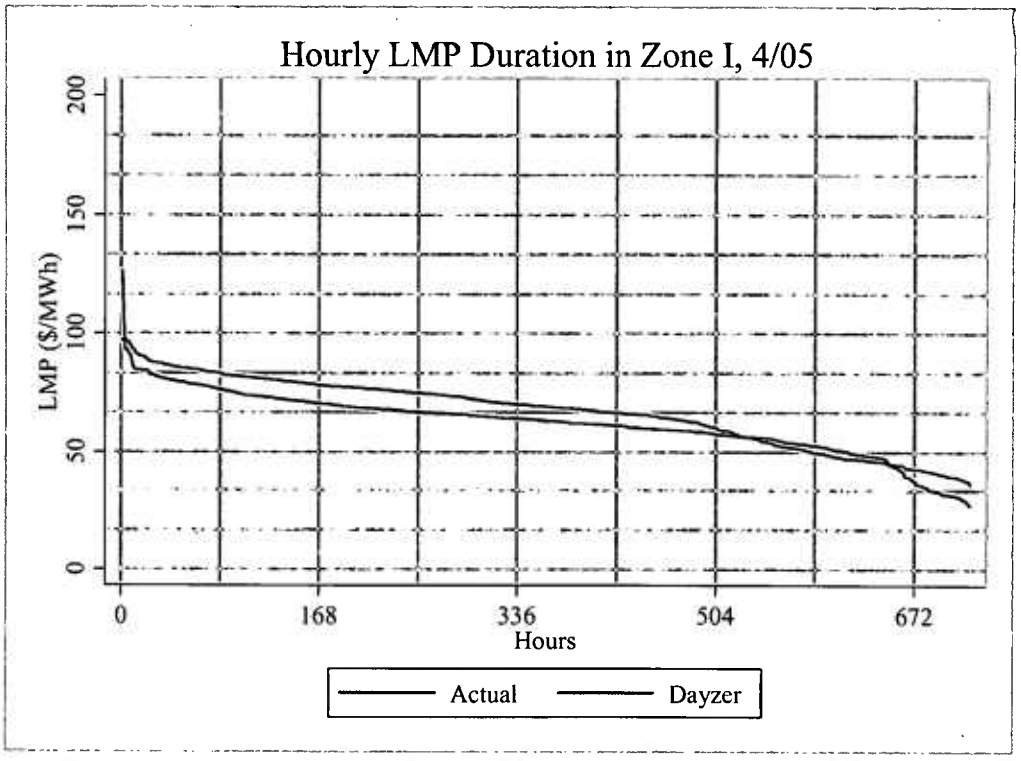

Hourly LMP Comparison in Zone I, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

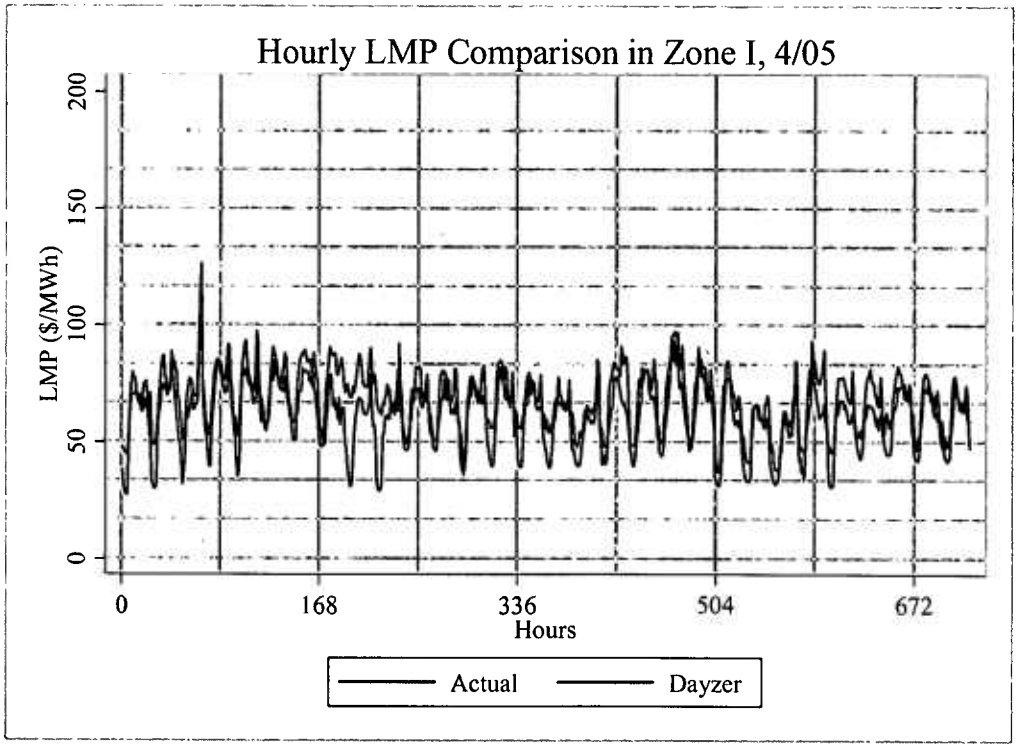

Hourly LMP Duration in Zone I, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

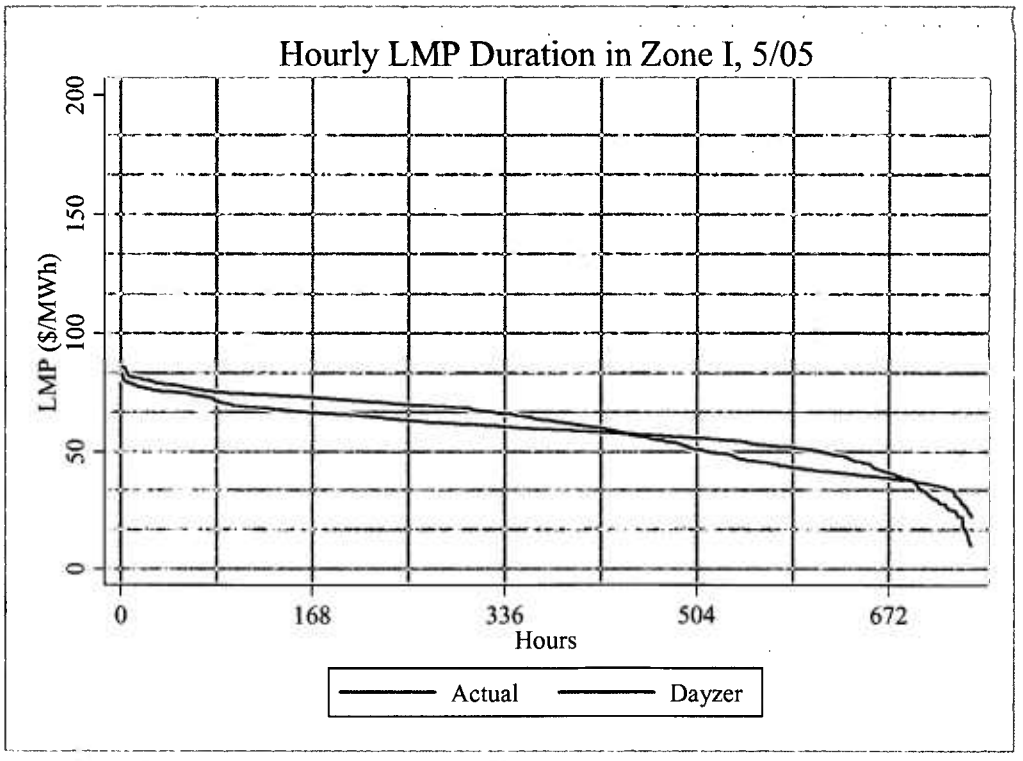

Hourly LMP Comparison in Zone I, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

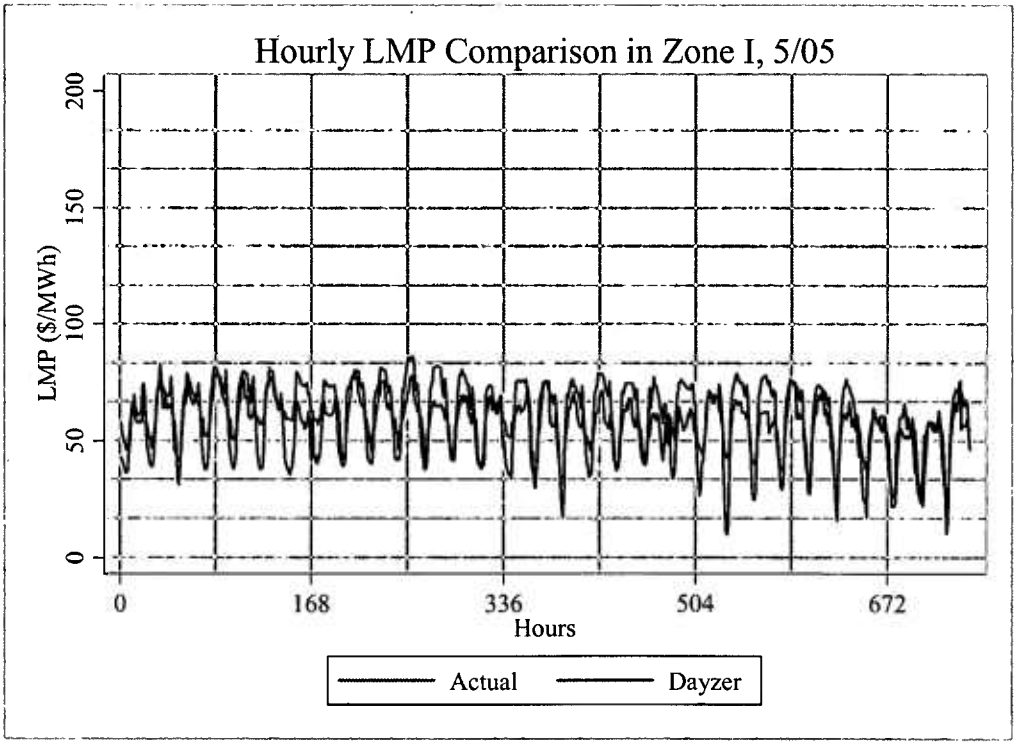

Hourly LMP Duration in Zone I, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

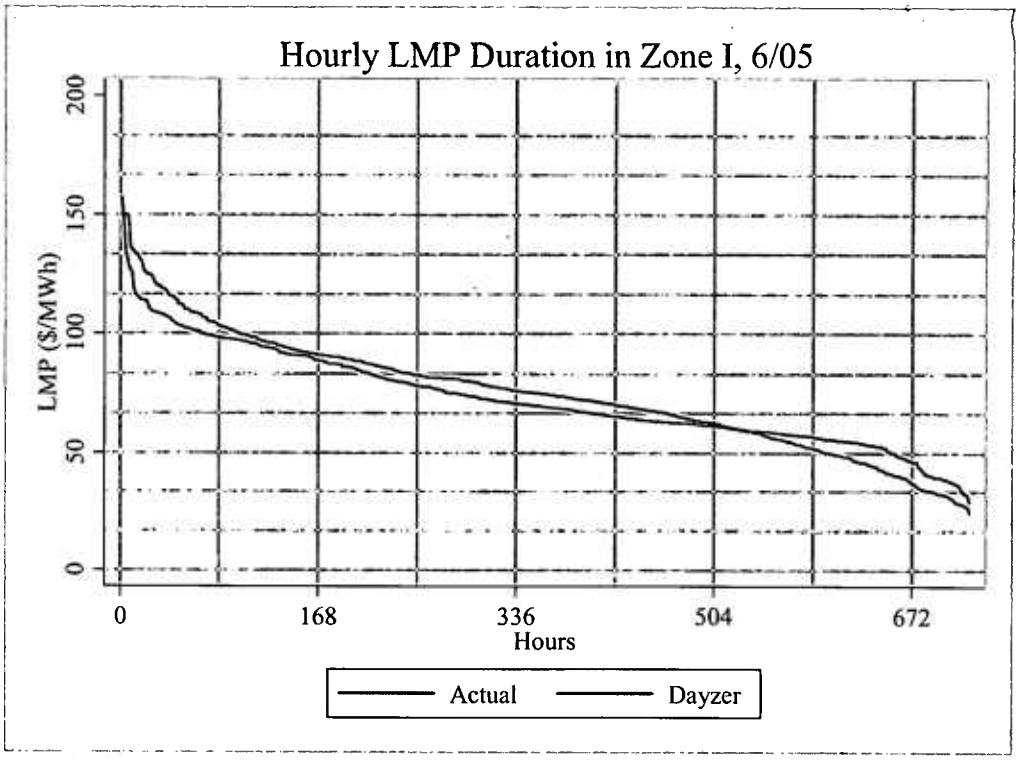

Hourly LMP Comparison in Zone I, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

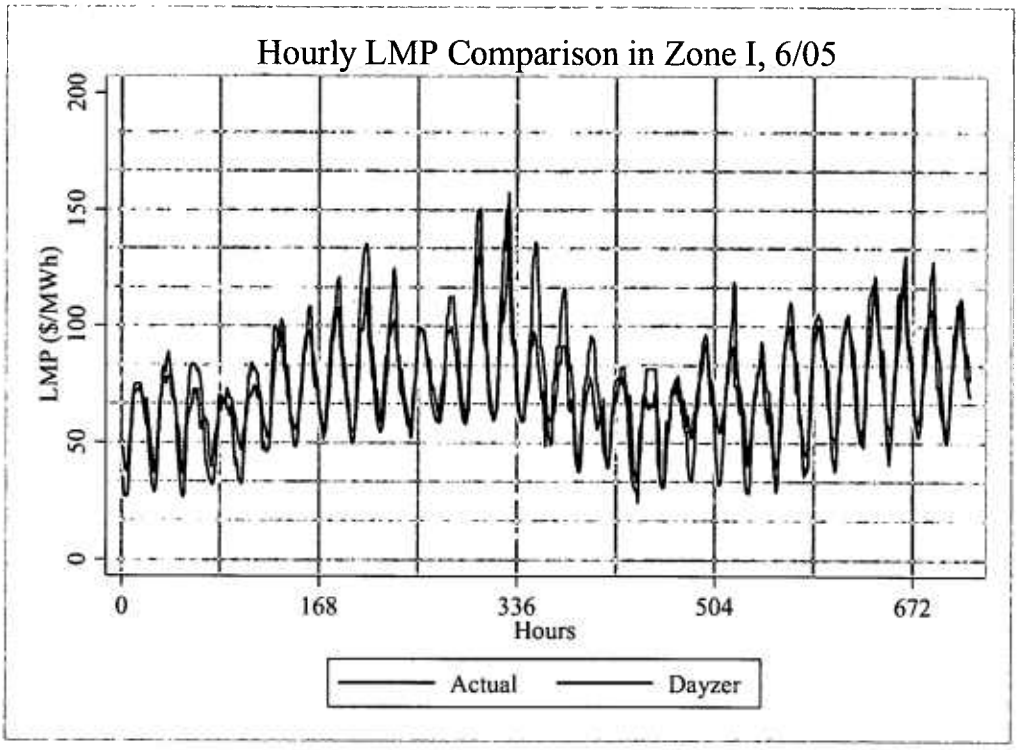

Hourly LMP Duration in Zone I, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

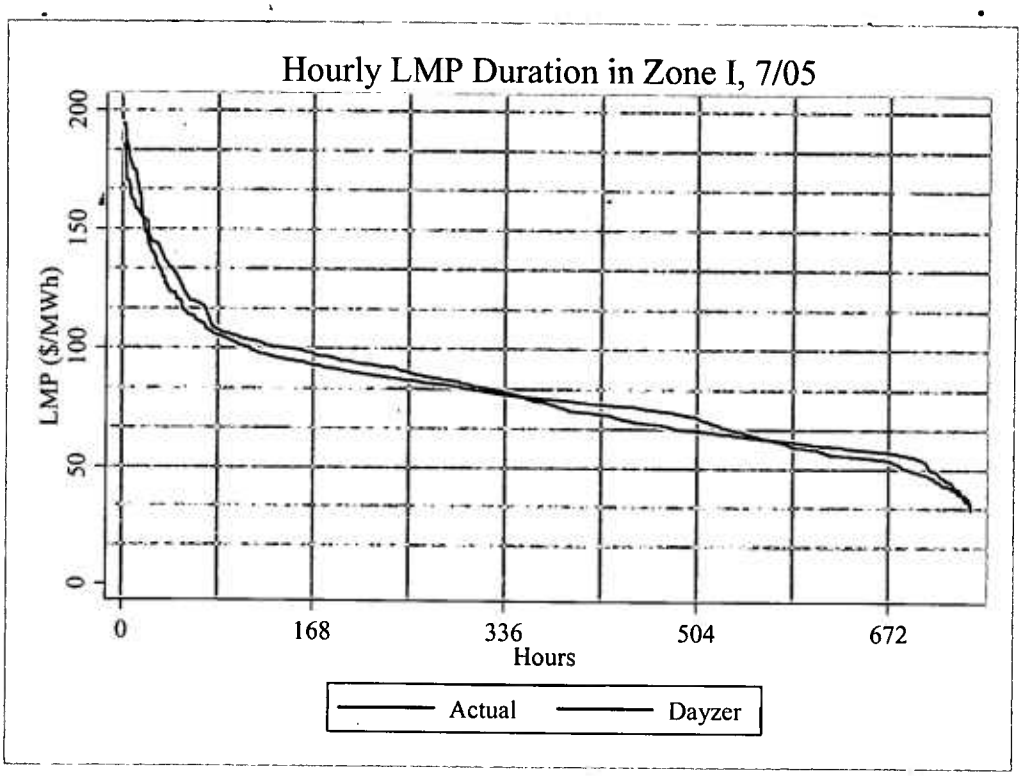

Hourly LMP Comparison in Zone I, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

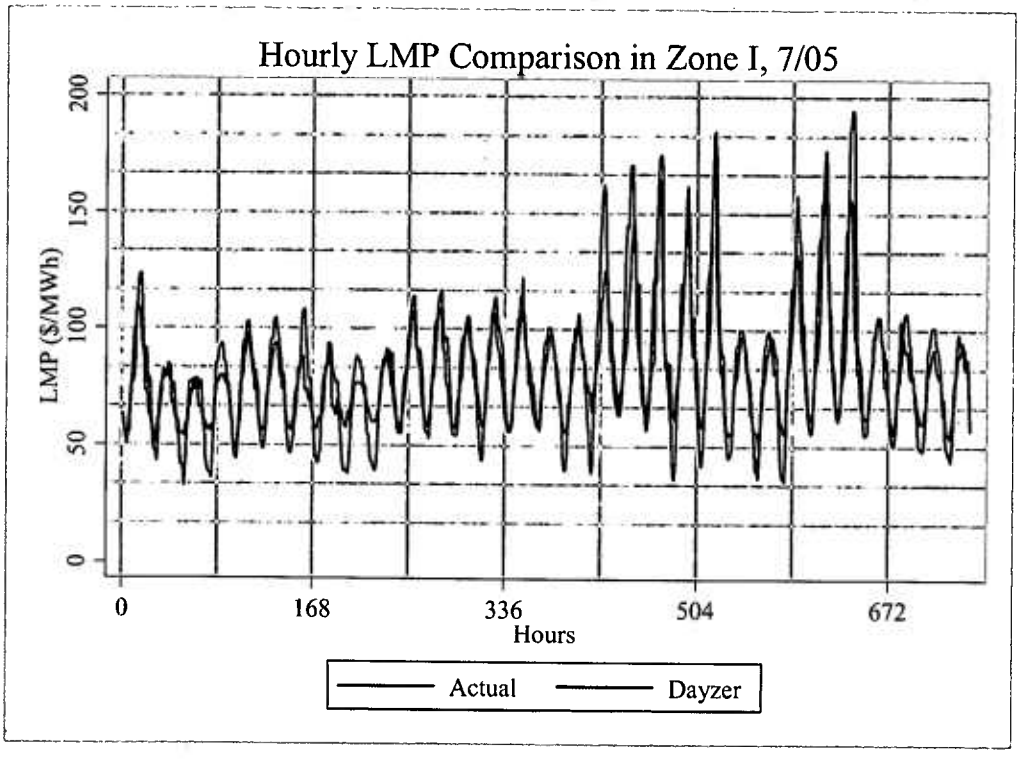

Hourly LMP Duration in Zone I, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

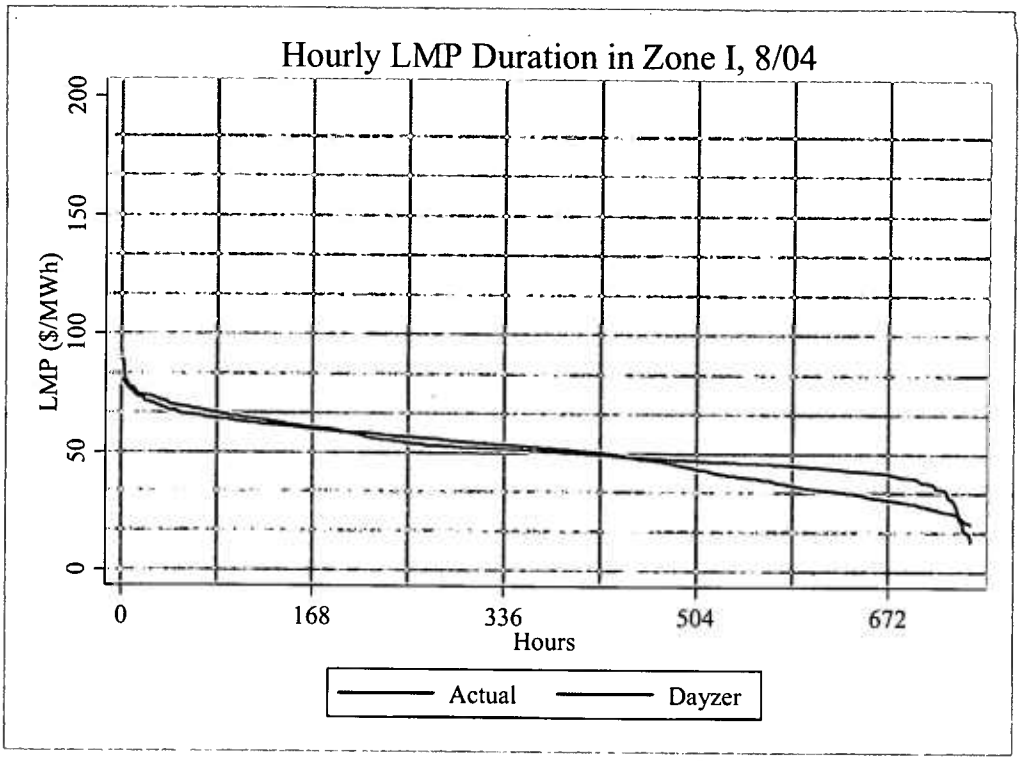

Hourly LMP Comparison in Zone I, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

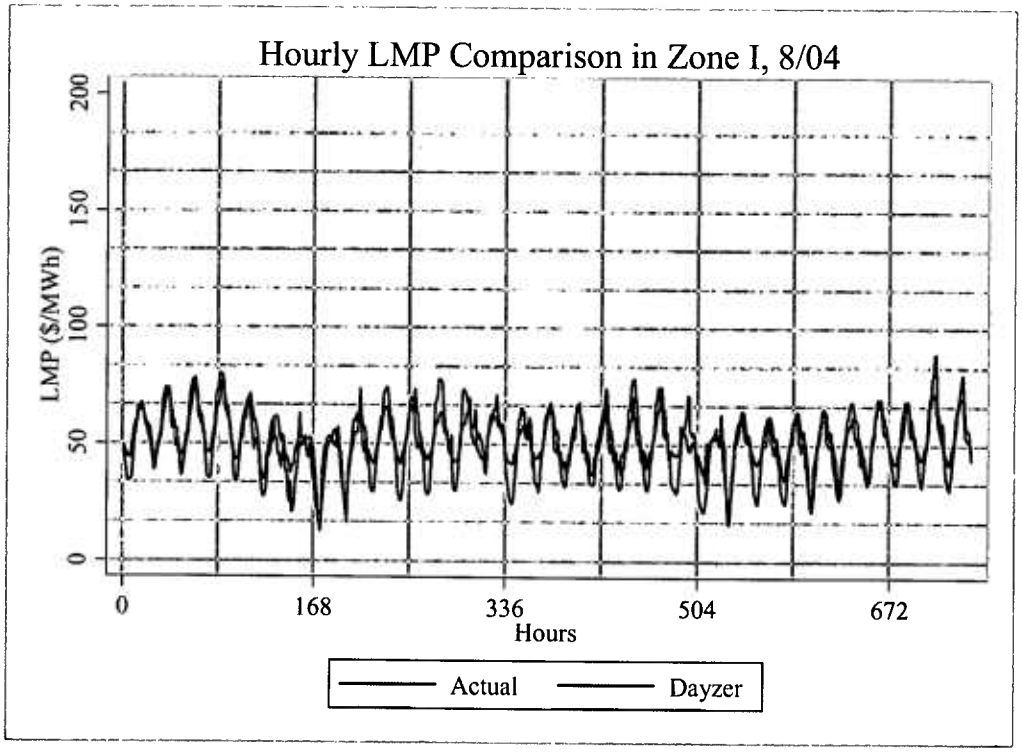

Hourly LMP Duration in Zone I, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

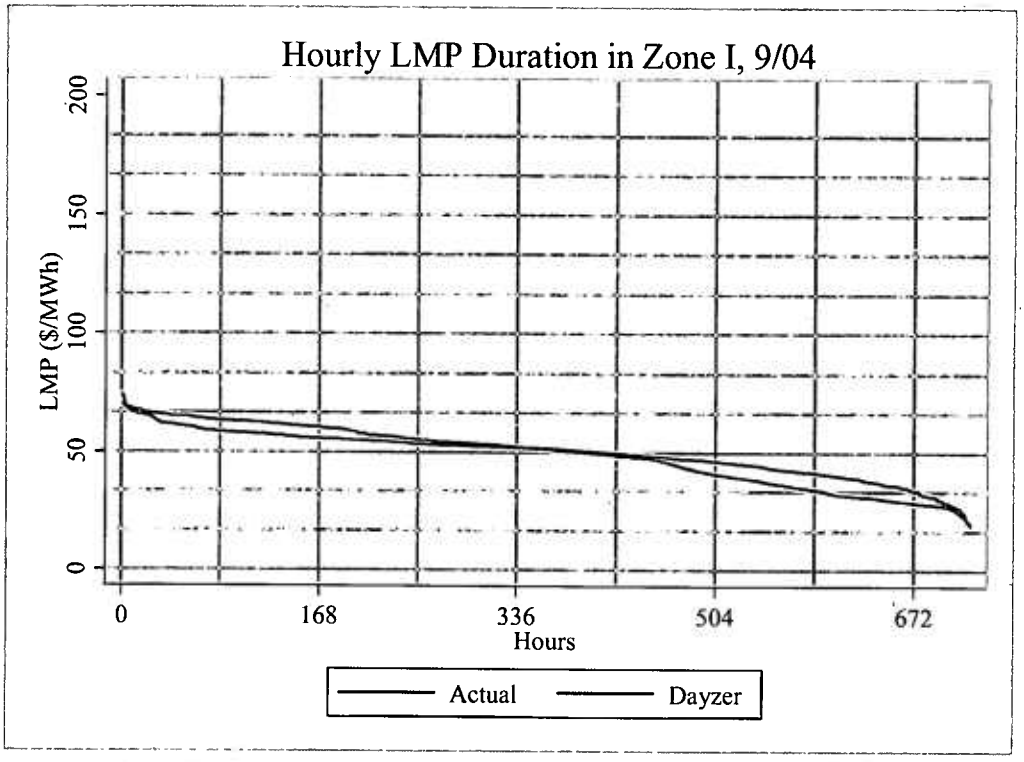

Hourly LMP Comparison in Zone I, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

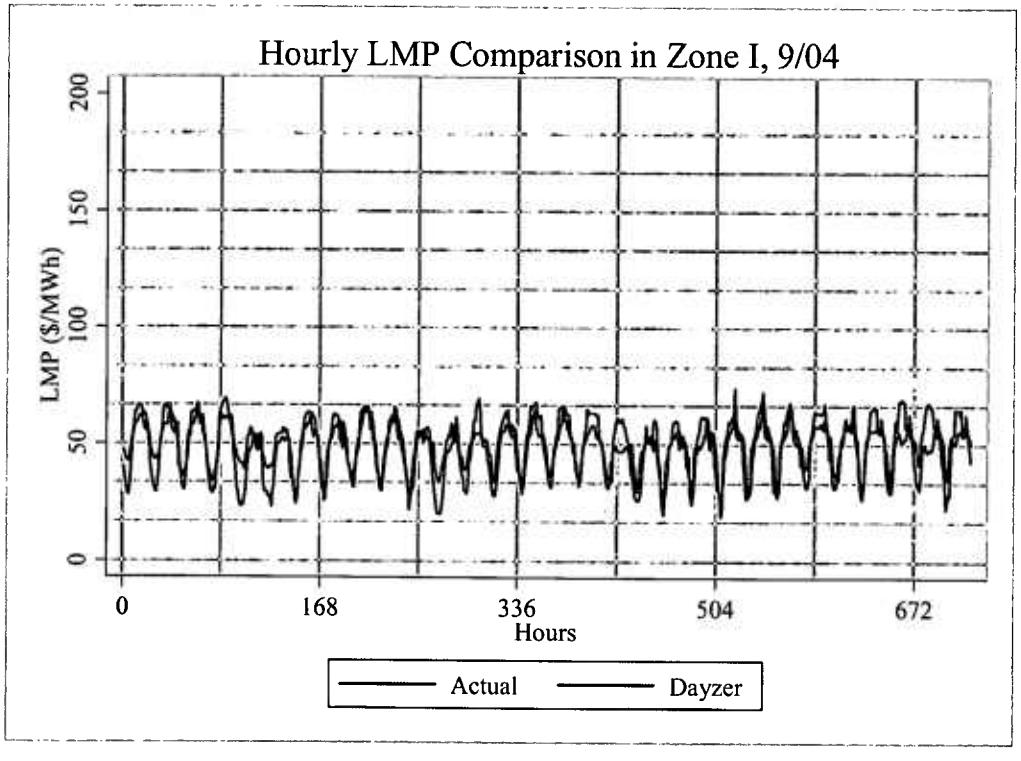

Hourly LMP Duration in Zone I, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

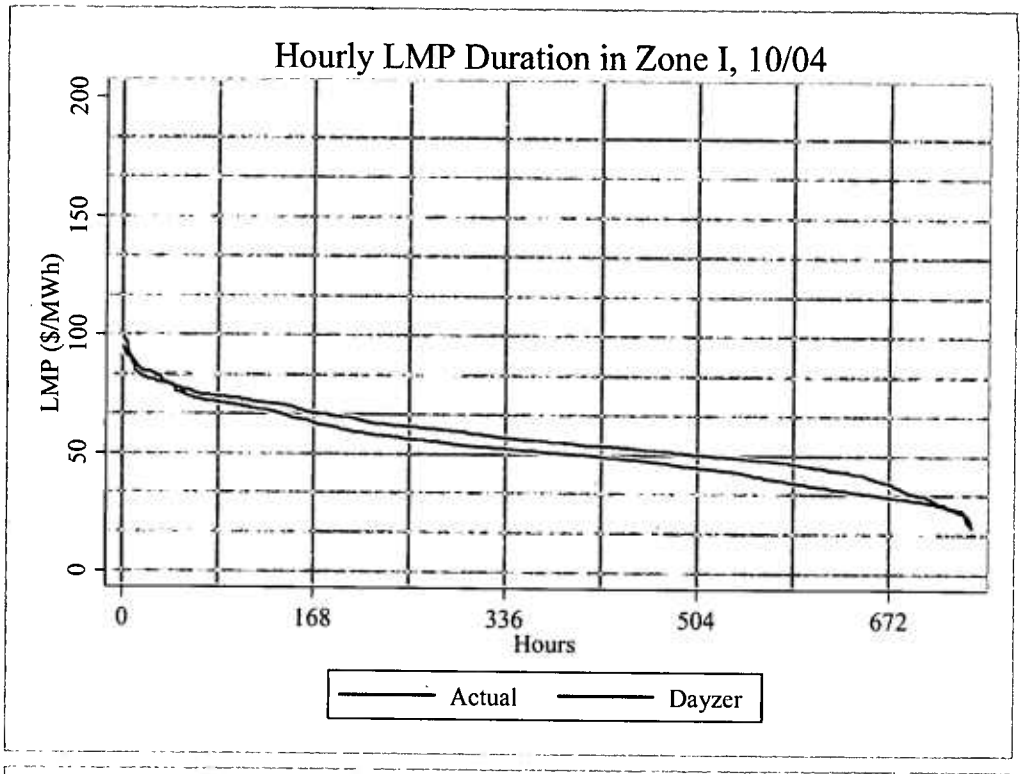

Hourly LMP Comparison in Zone I, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

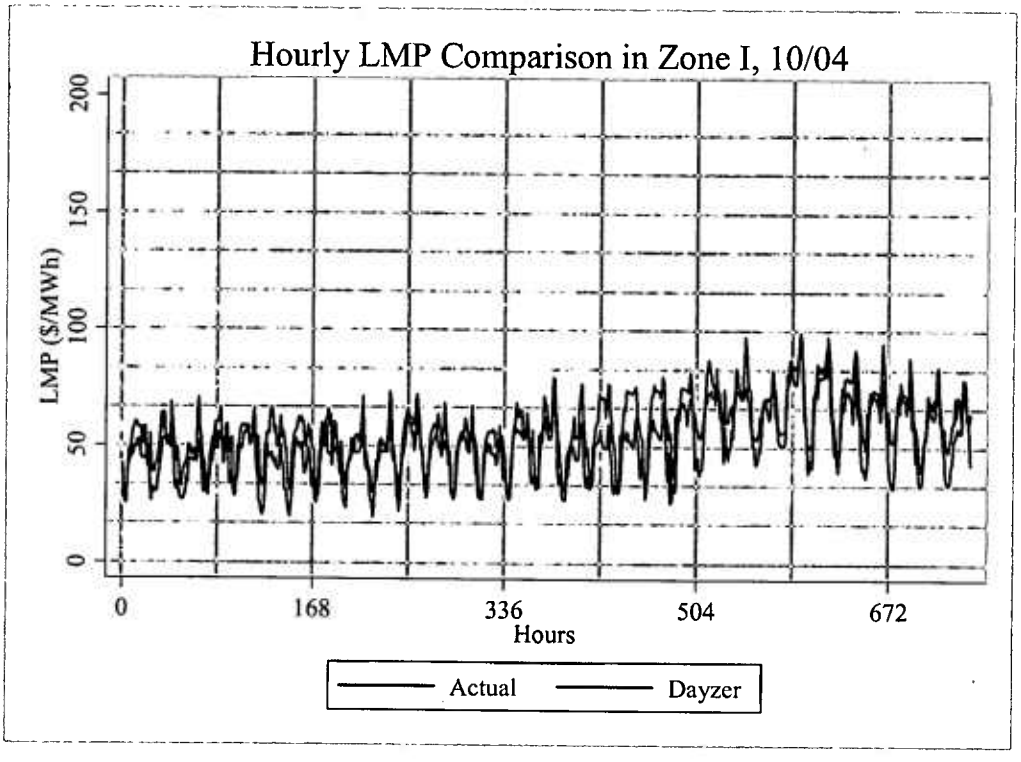

Hourly LMP Duration in Zone I, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

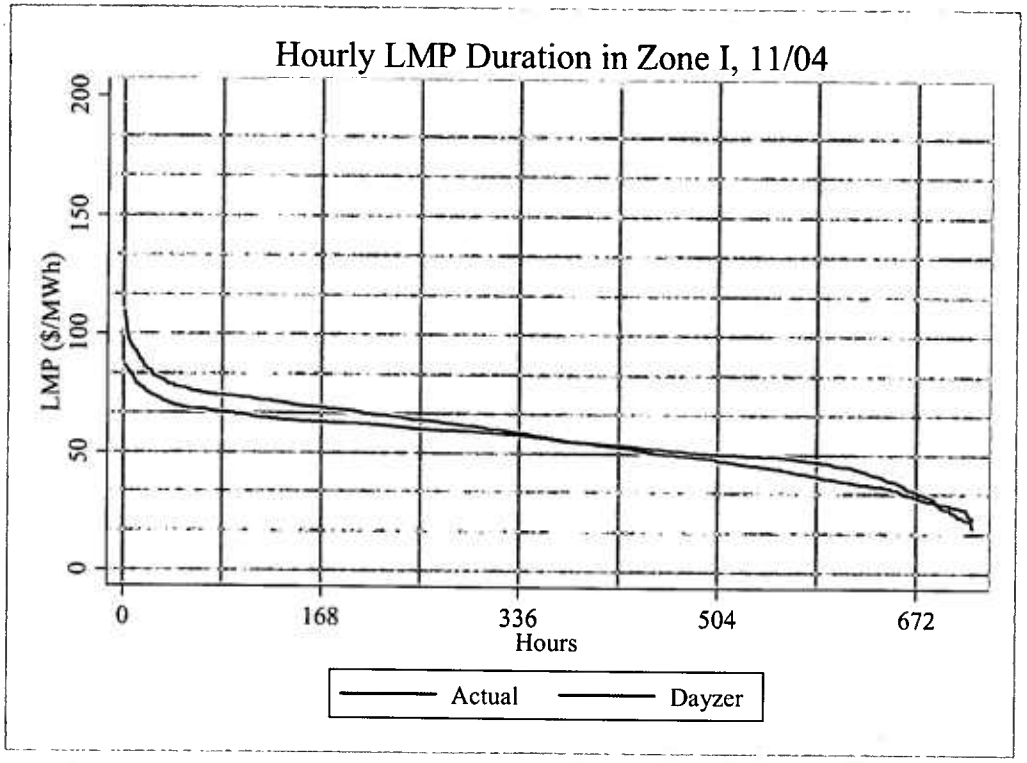

Hourly LMP Comparison in Zone I, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

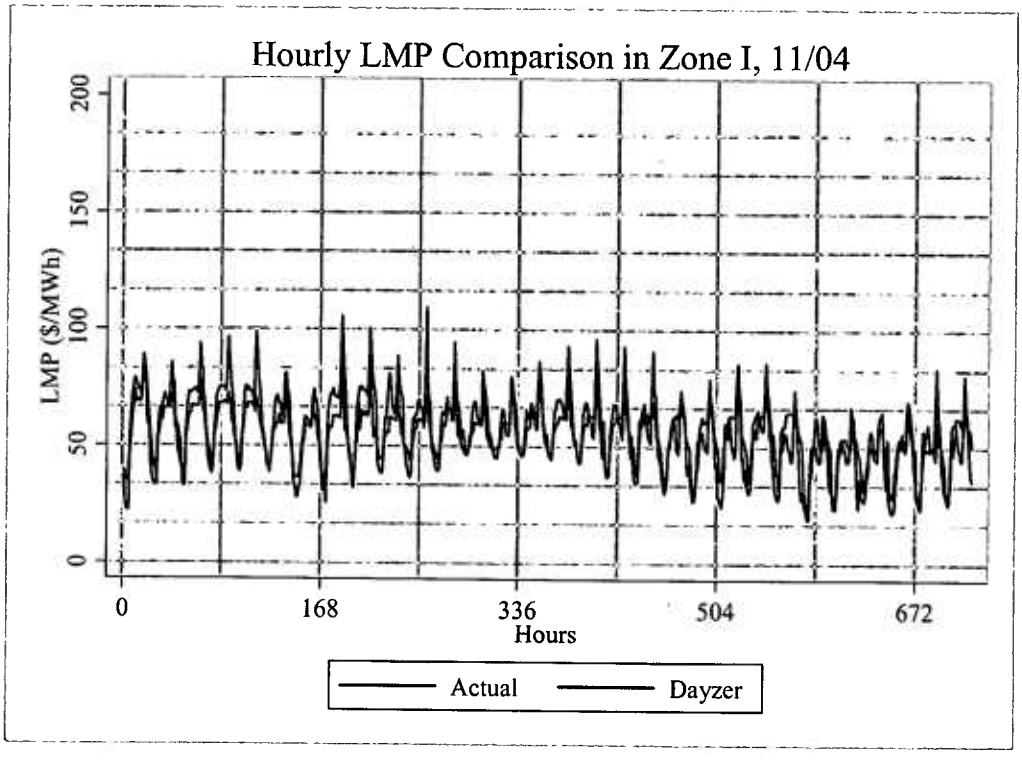

Hourly LMP Duration in Zone I, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

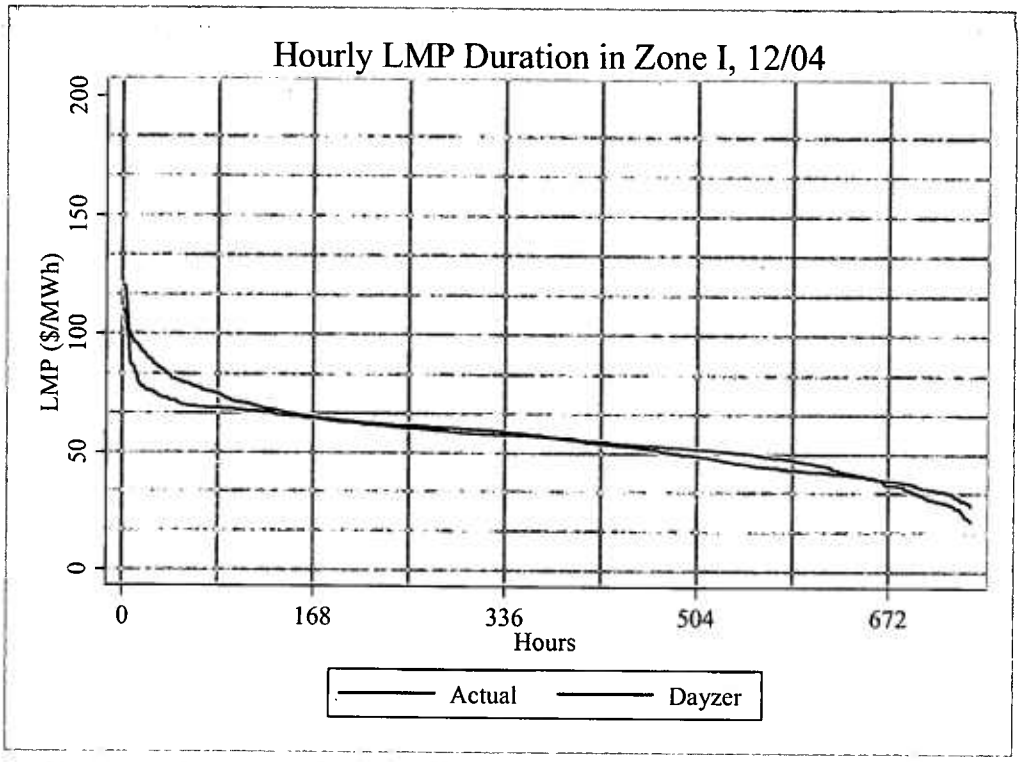

Hourly LMP Comparison in Zone I, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

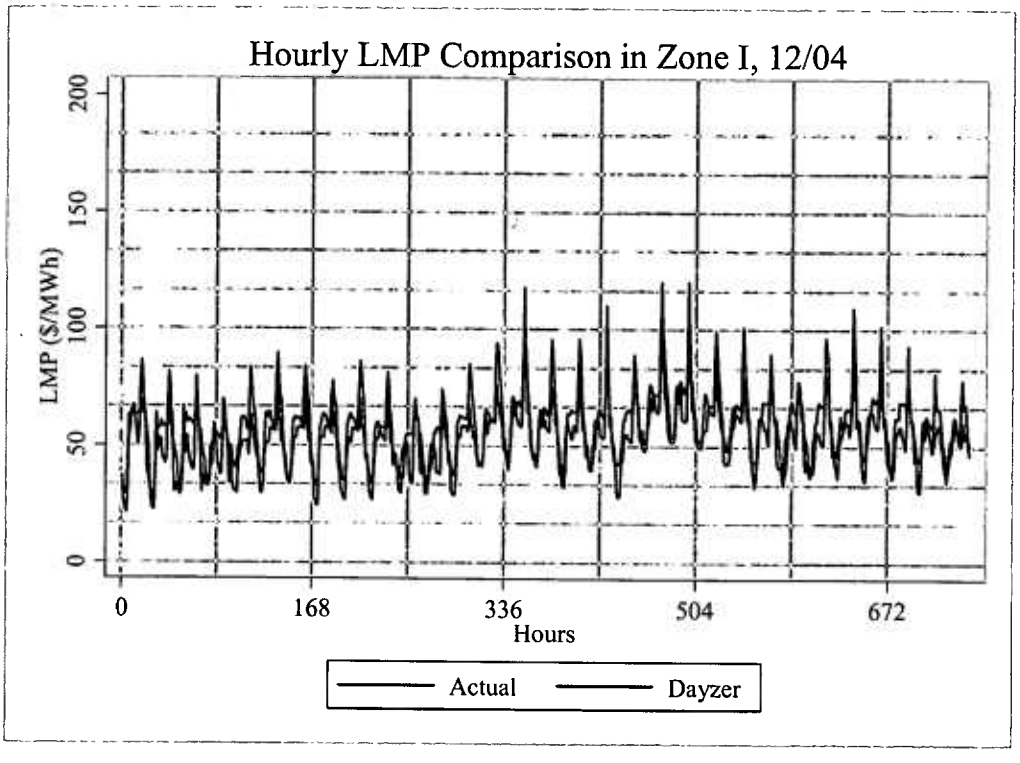

Hourly LMP Duration in Zone I, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

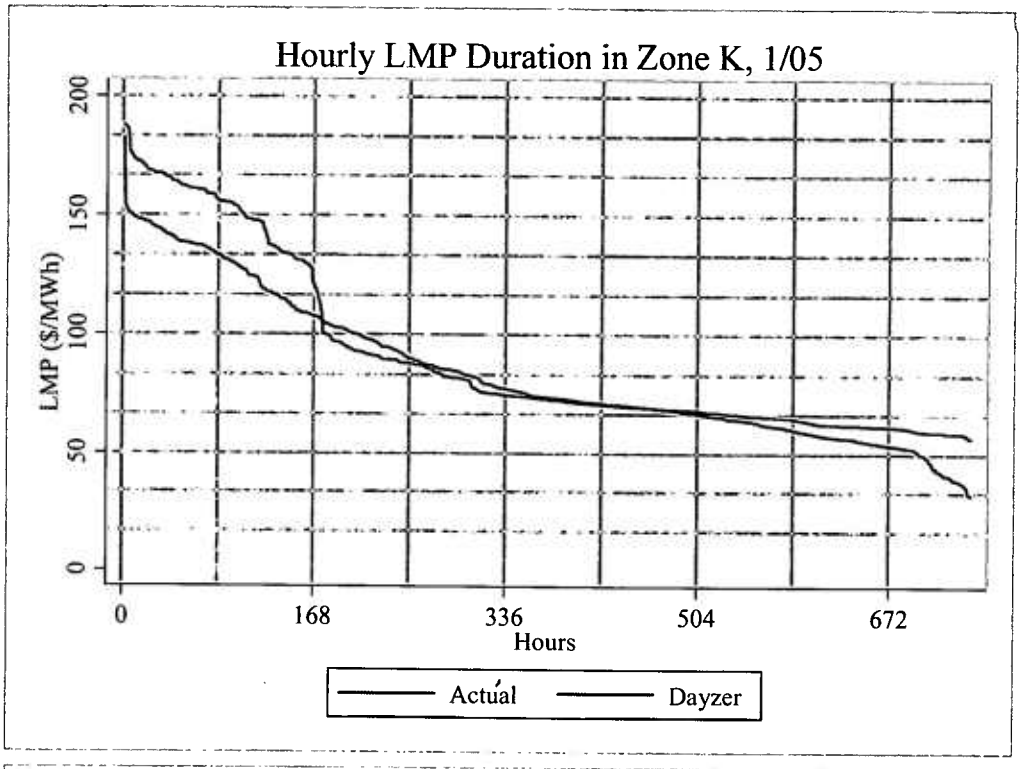

Hourly LMP Comparison in Zone I, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

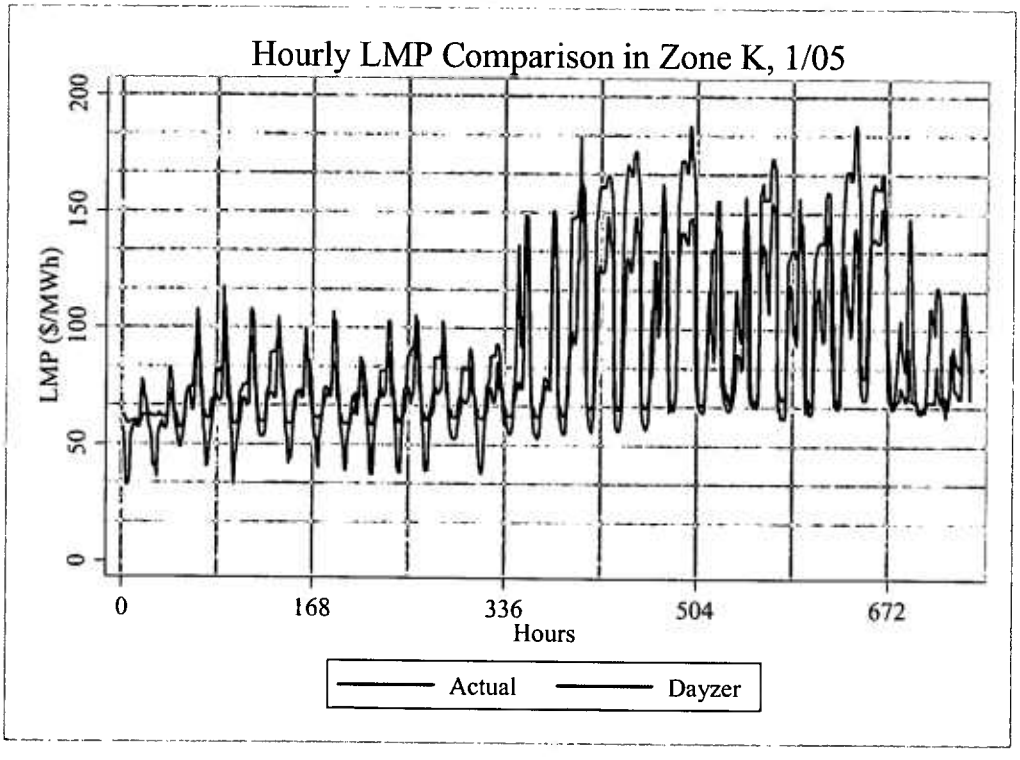

Hourly LMP Duration in Zone I, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

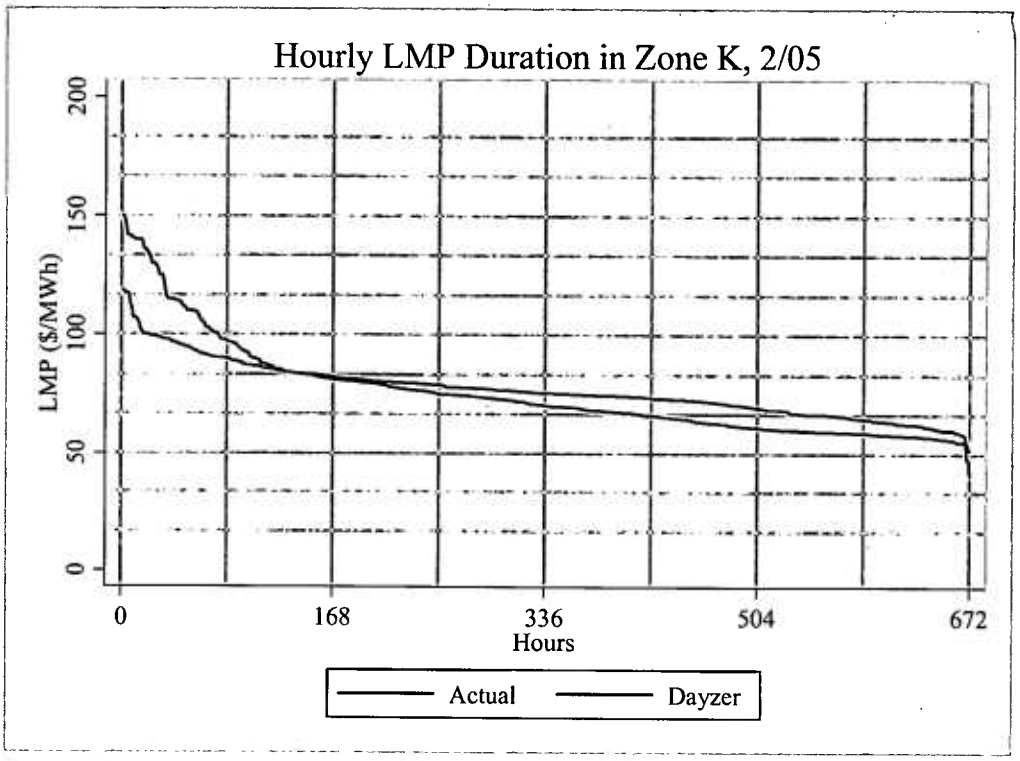

Hourly LMP Comparison in Zone I, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

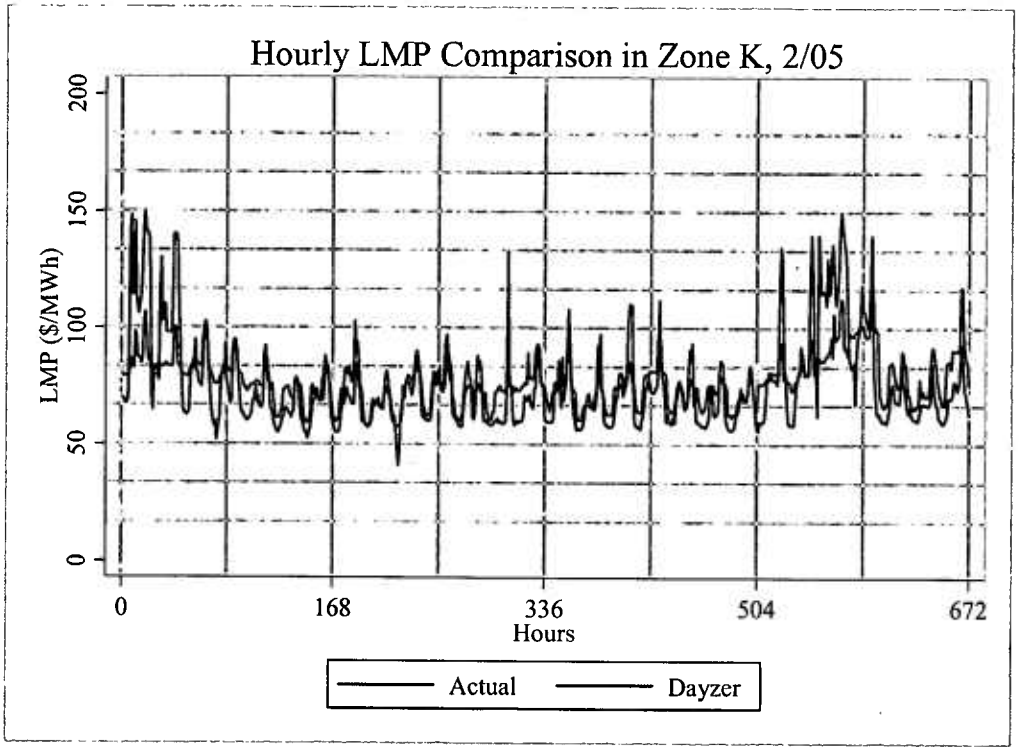

Hourly LMP Duration in Zone I, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

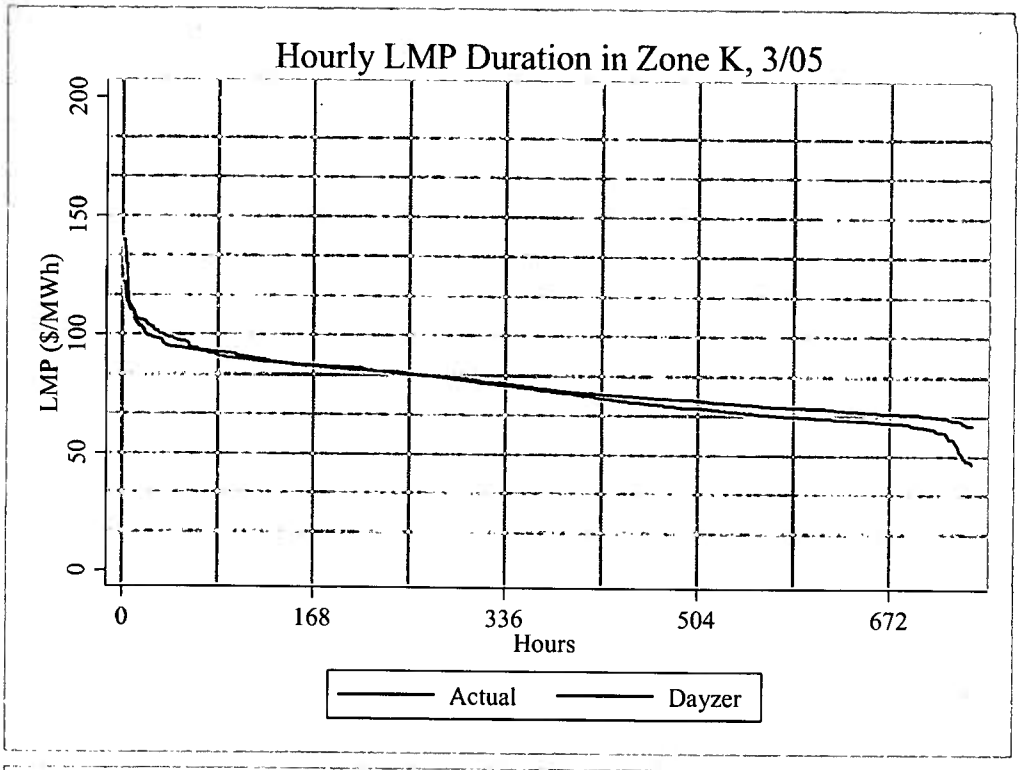

Hourly LMP Comparison in Zone I, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

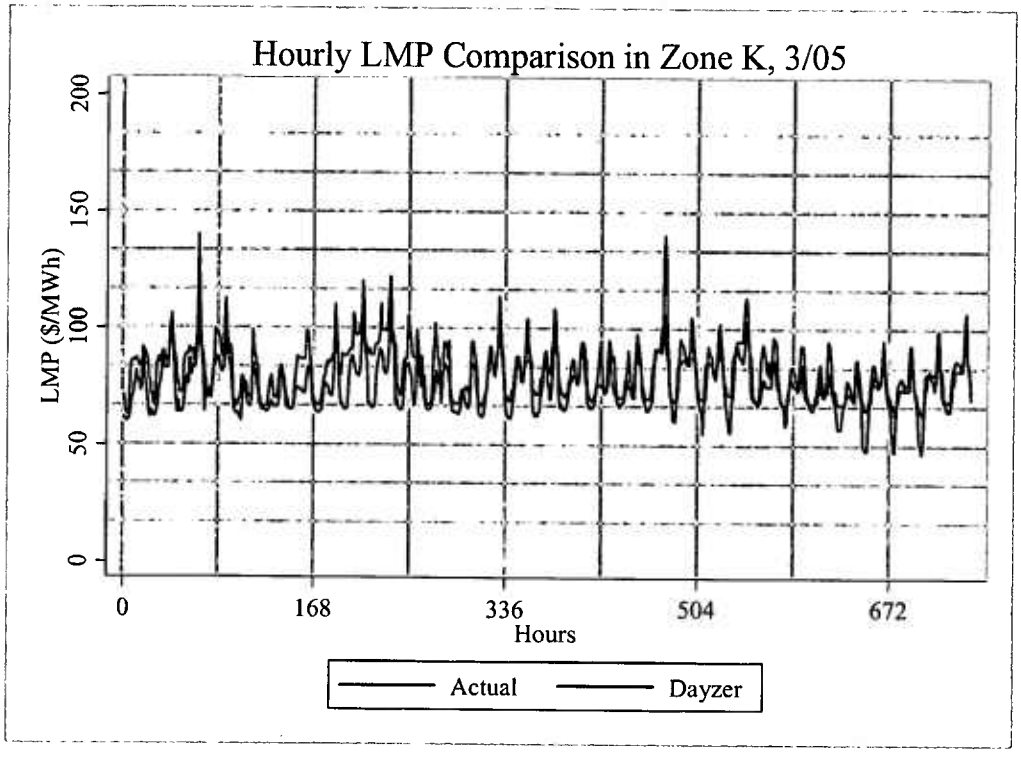

Hourly LMP Duration in Zone K, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

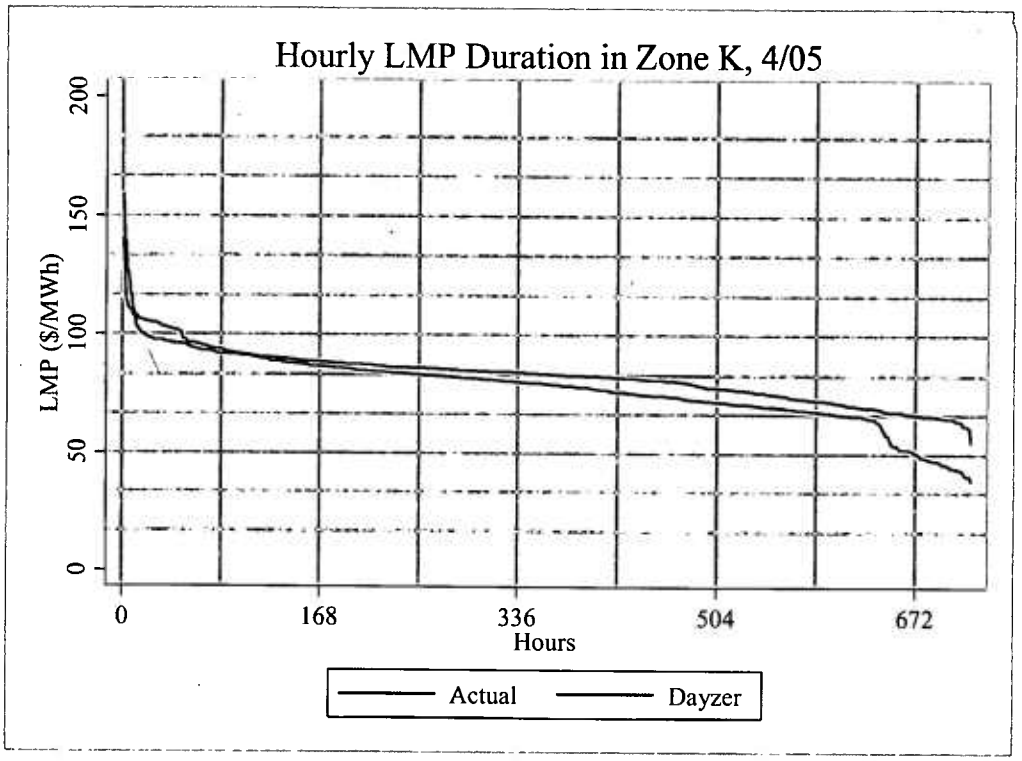

Hourly LMP Comparison in Zone K, 1/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

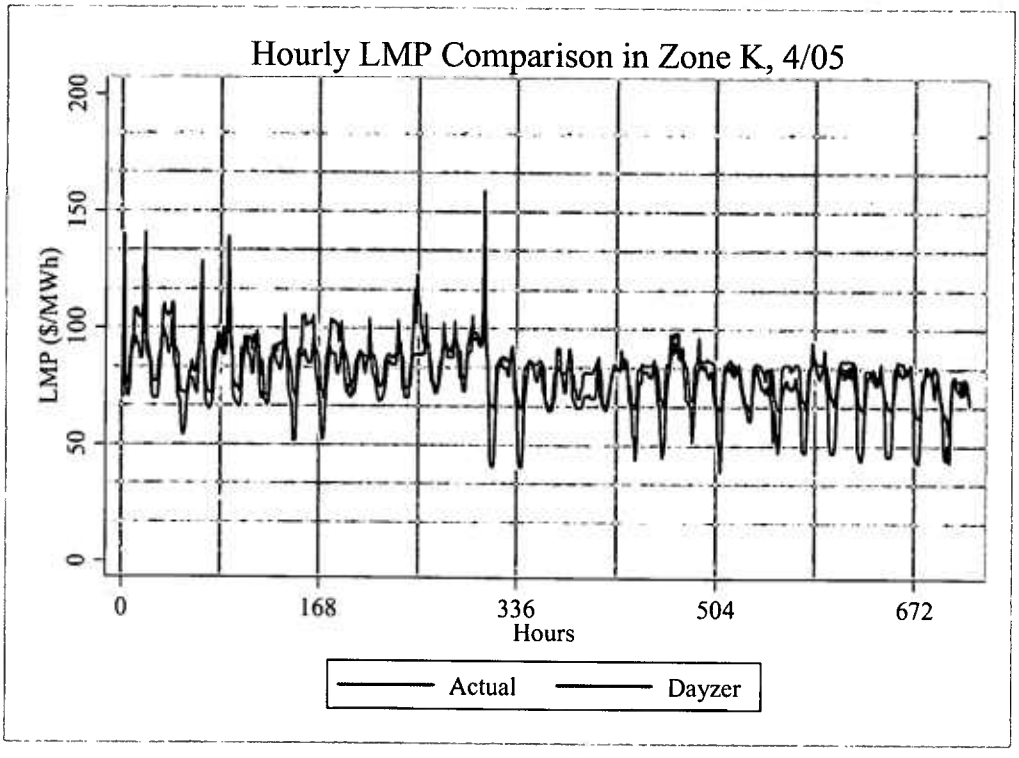

Hourly LMP Duration in Zone K, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

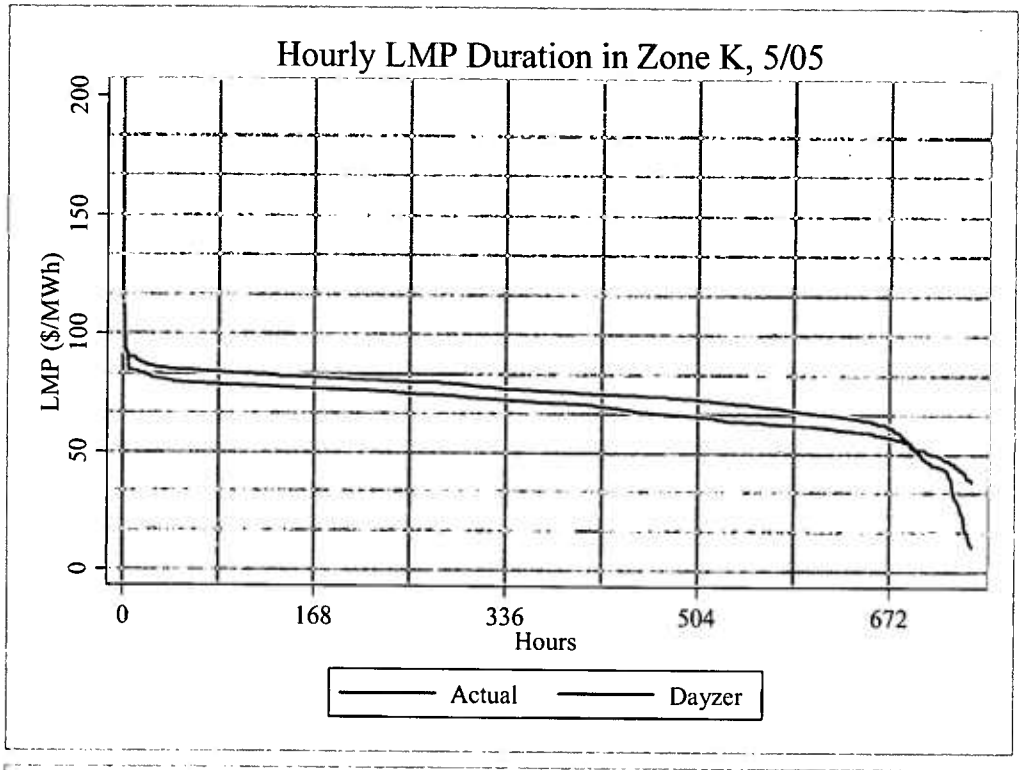

Hourly LMP Comparison in Zone K, 2/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

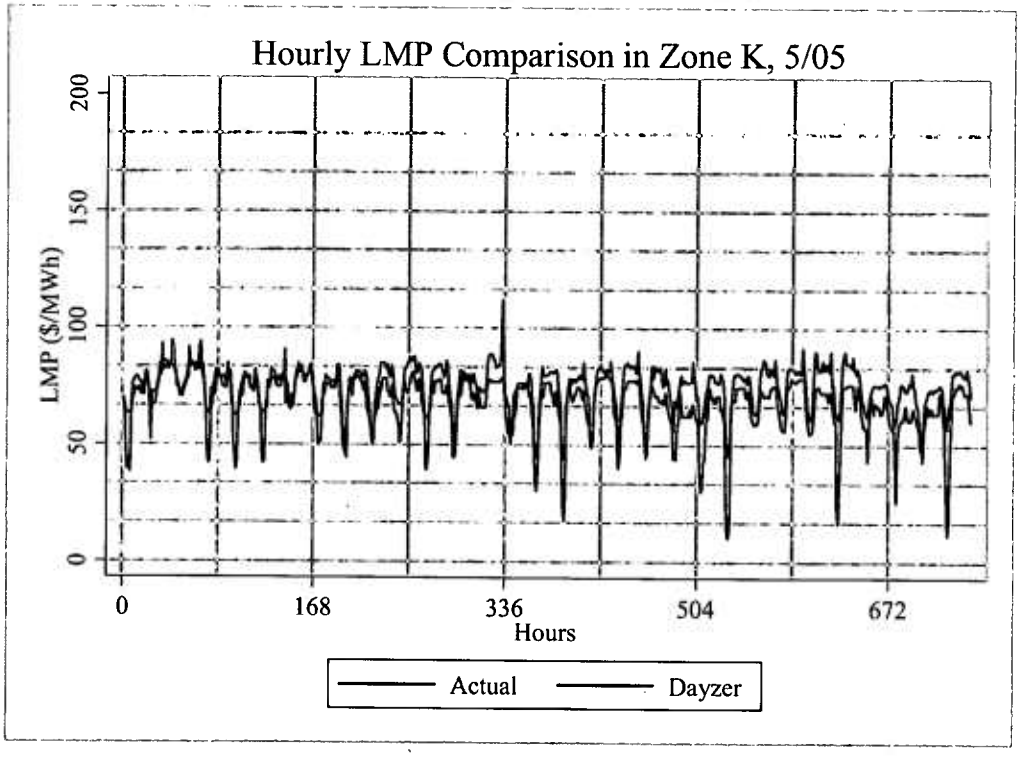

Hourly LMP Duration in Zone K, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

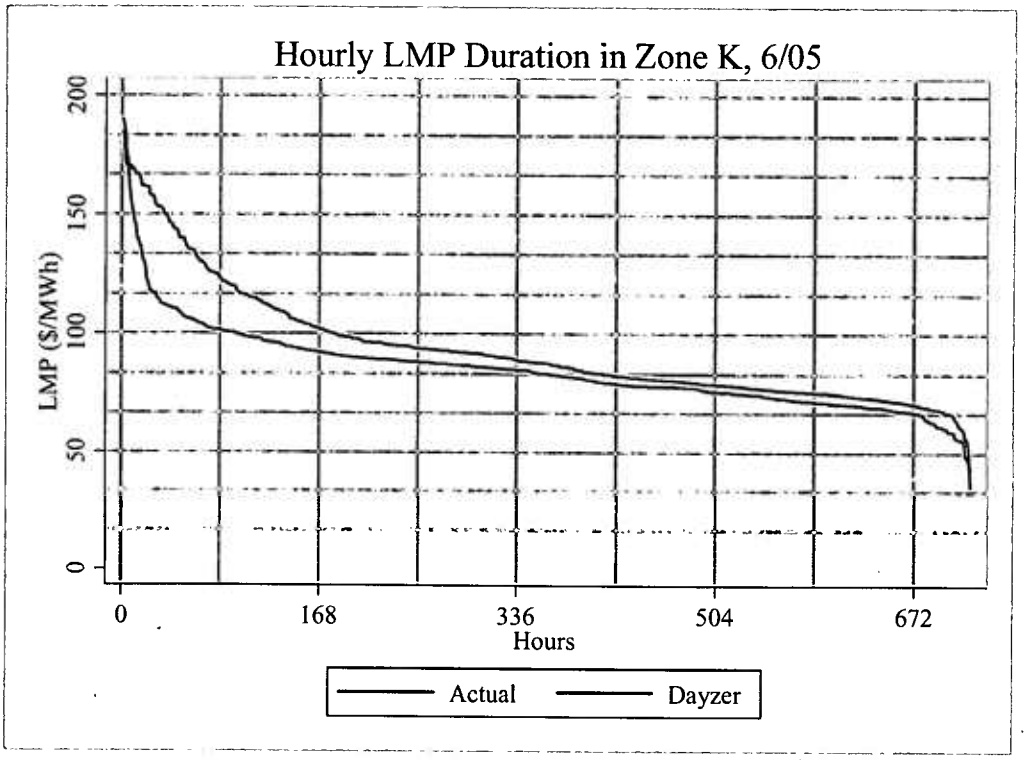

Hourly LMP Comparison in Zone K, 3/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

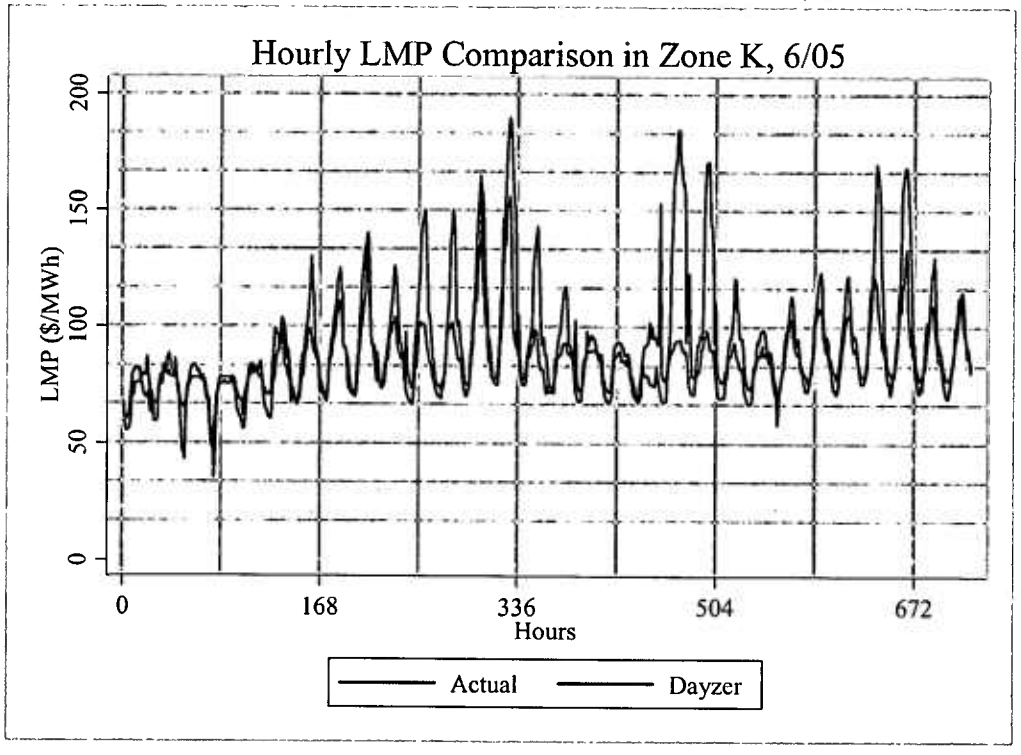

Hourly LMP Duration in Zone K, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

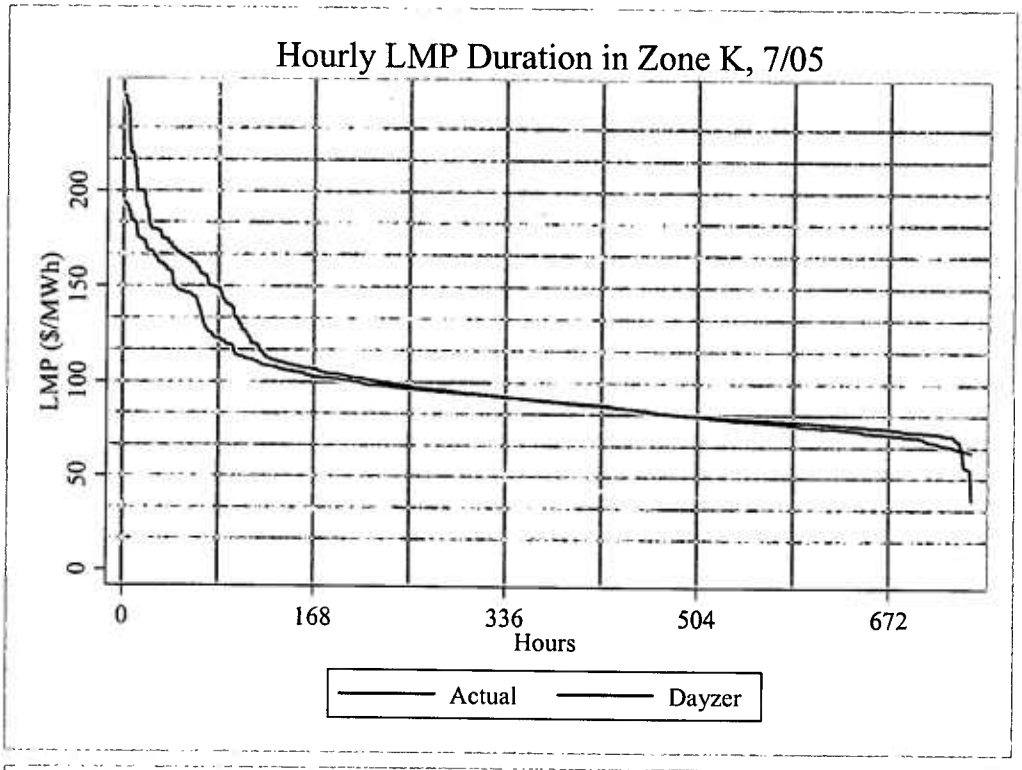

Hourly LMP Comparison in Zone K, 4/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

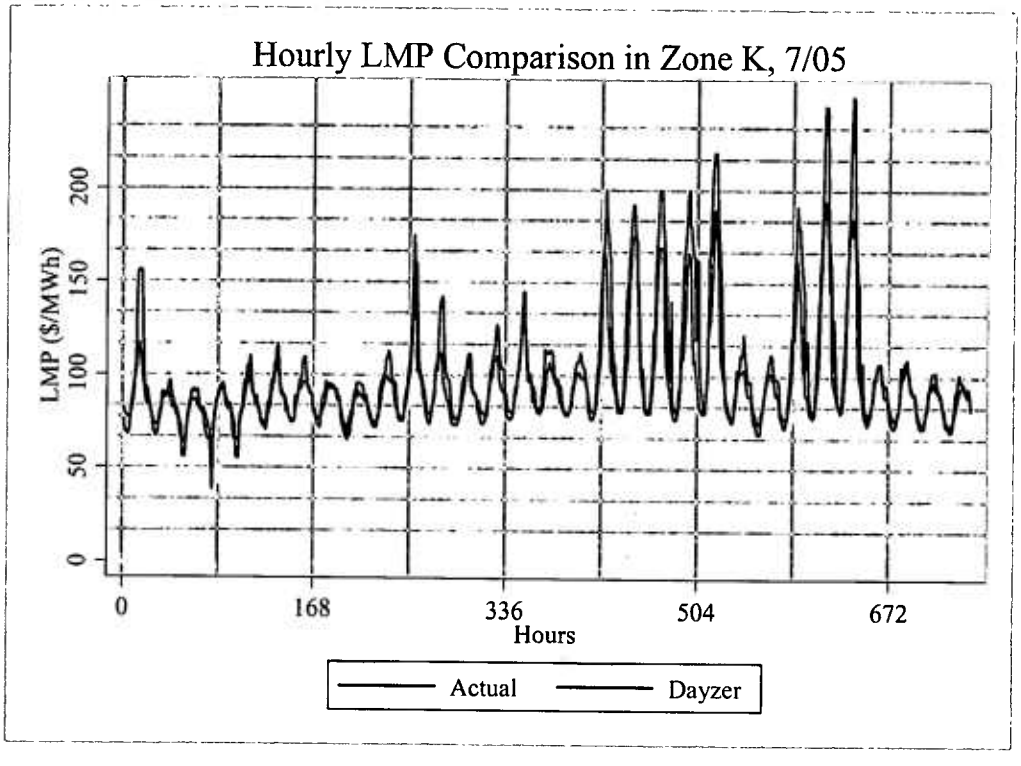

Hourly LMP Duration in Zone K, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

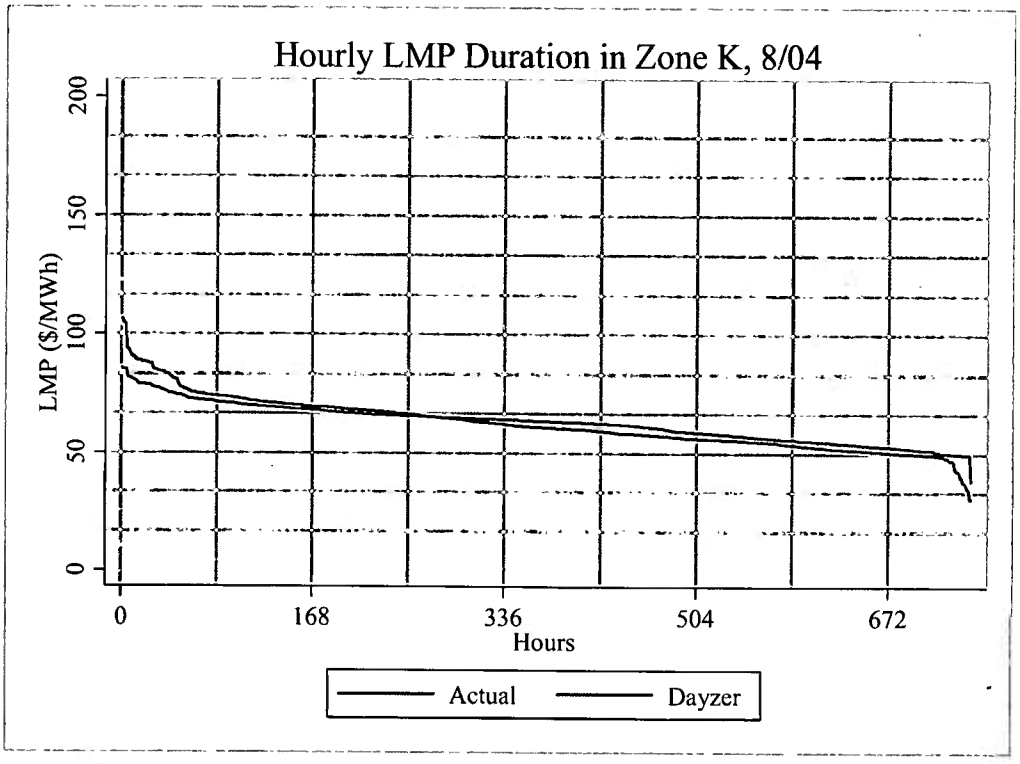

Hourly LMP Comparison in Zone K, 5/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

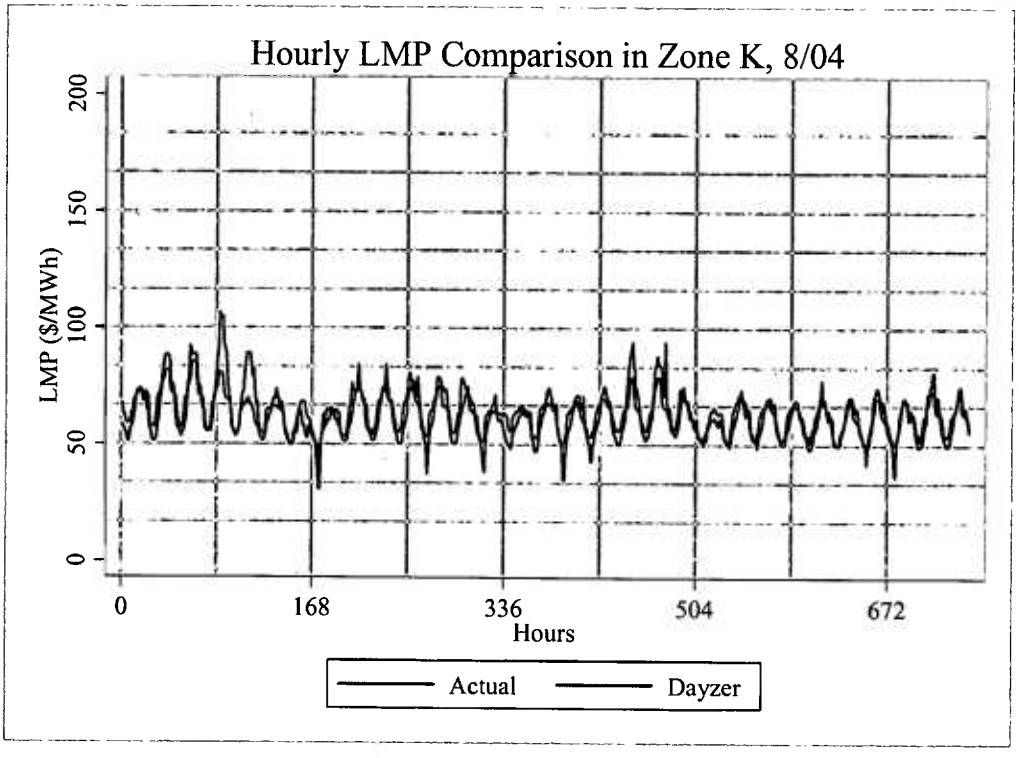

Hourly LMP Duration in Zone K, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

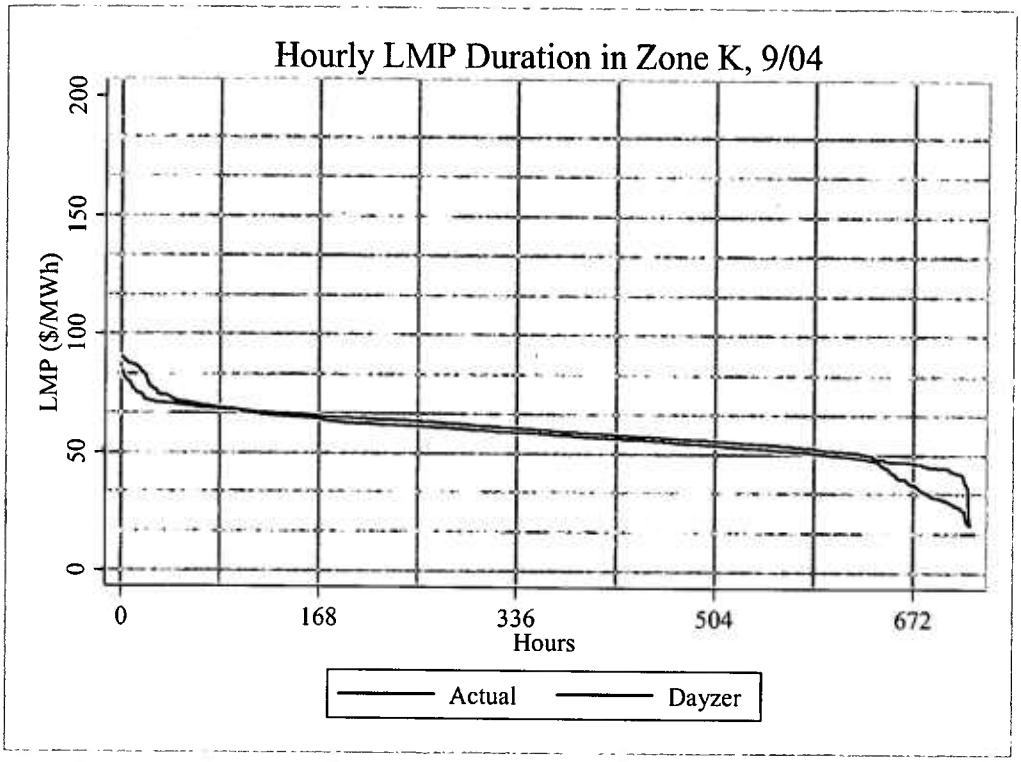

Hourly LMP Comparison in Zone K, 6/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

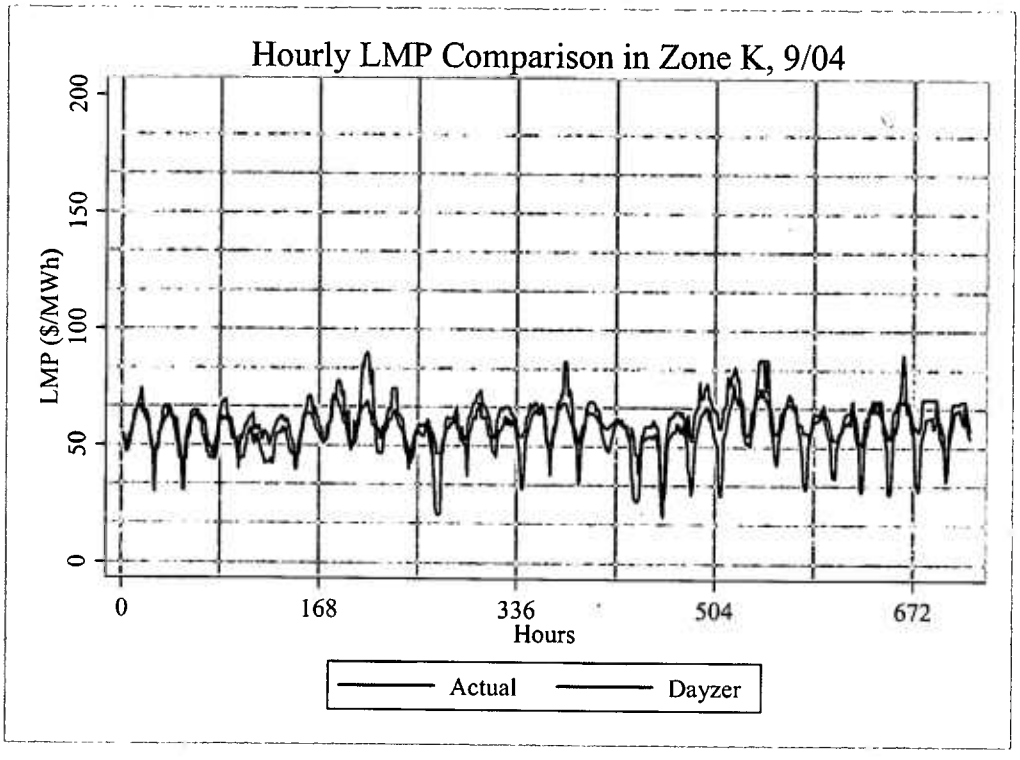

Hourly LMP Duration in Zone K, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

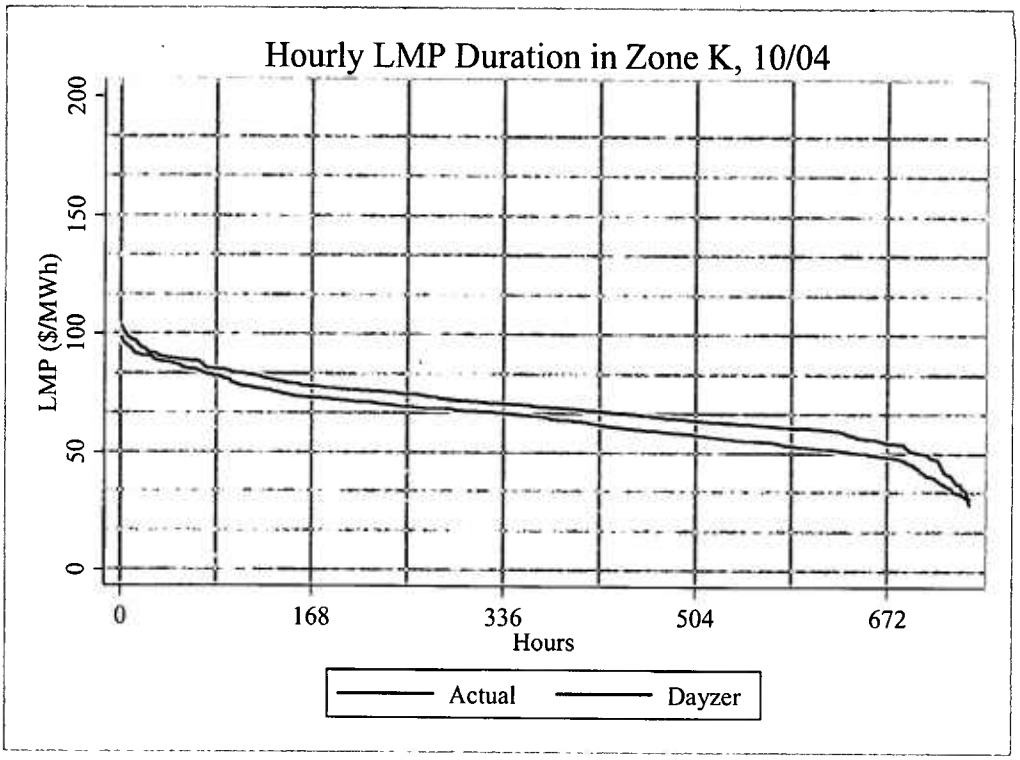

Hourly LMP Comparison in Zone K, 7/05
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

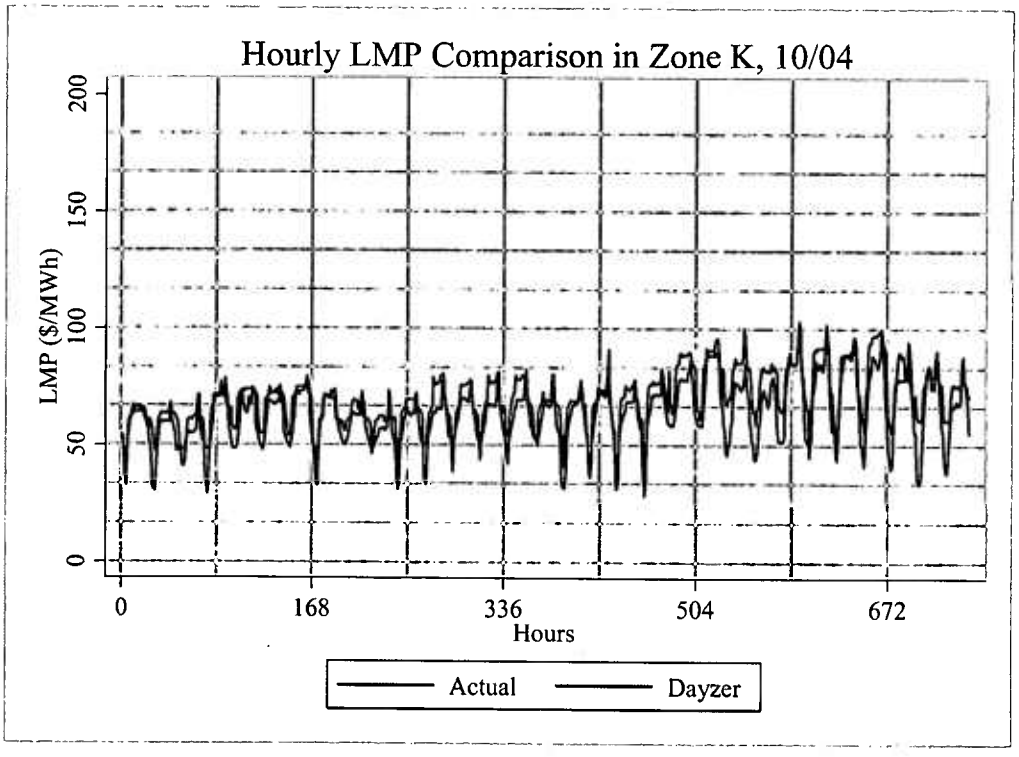

Hourly LMP Duration in Zone K, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

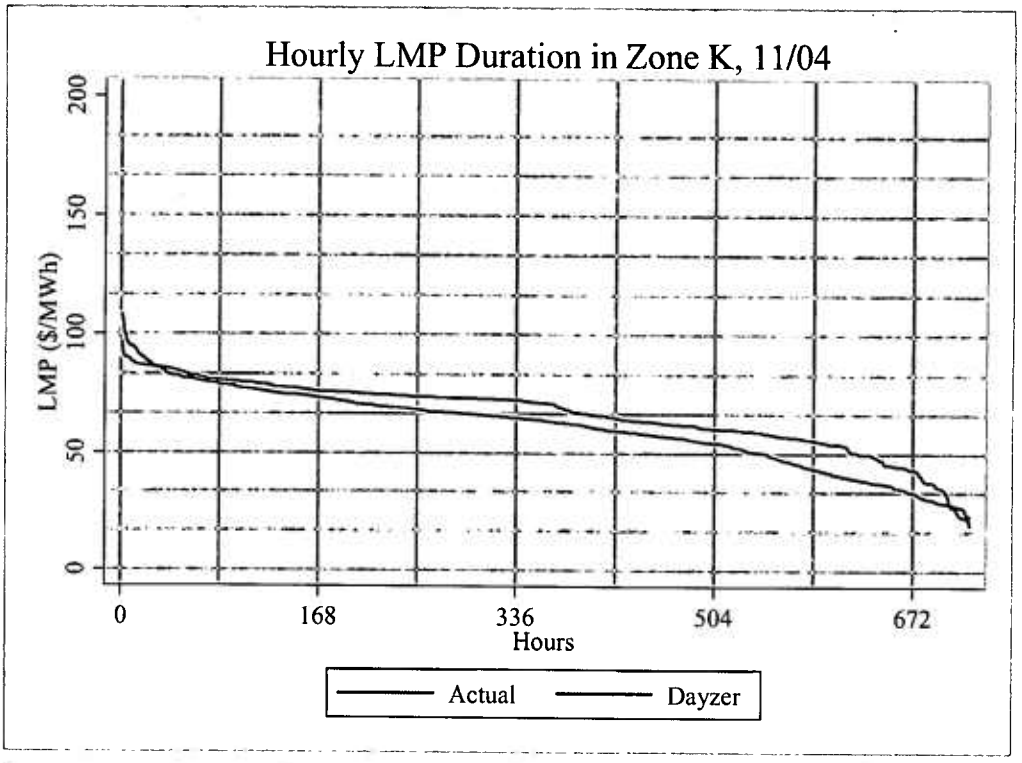

Hourly LMP Comparison in Zone K, 8/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

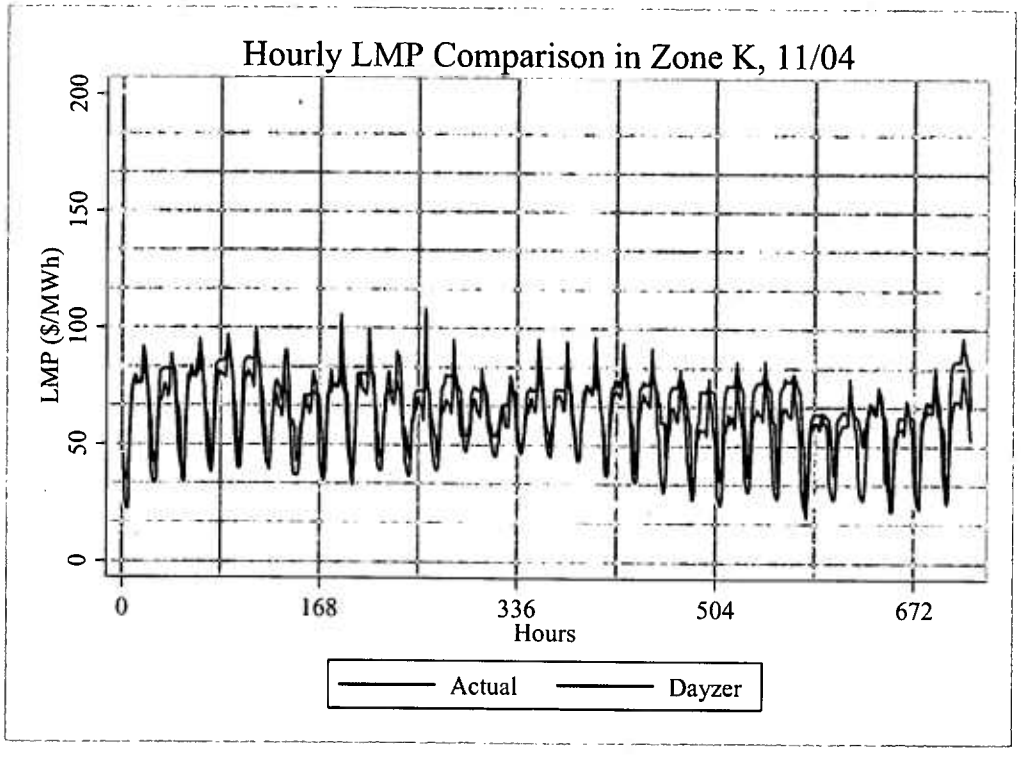

Hourly LMP Duration in Zone K, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

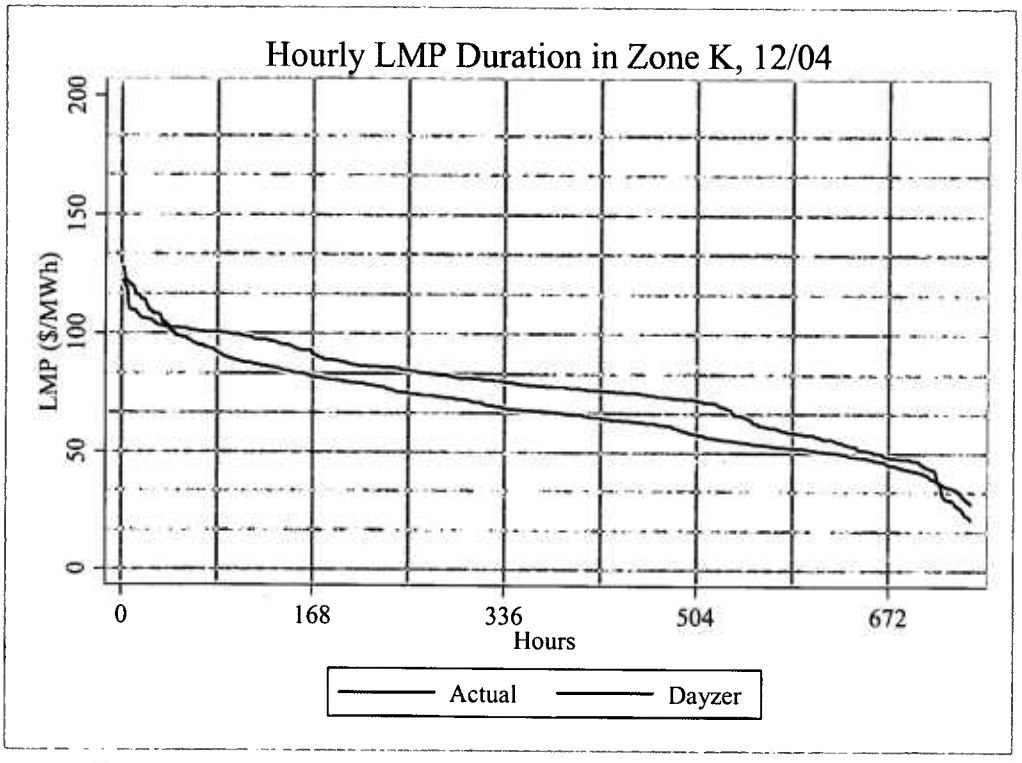

Hourly LMP Comparison in Zone K, 9/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer


Hourly LMP Duration in Zone K, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer


Hourly LMP Comparison in Zone K, 10/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer


Hourly LMP Duration in Zone K, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer


Hourly LMP Comparison in Zone K, 11/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer


Hourly LMP Duration in Zone K, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

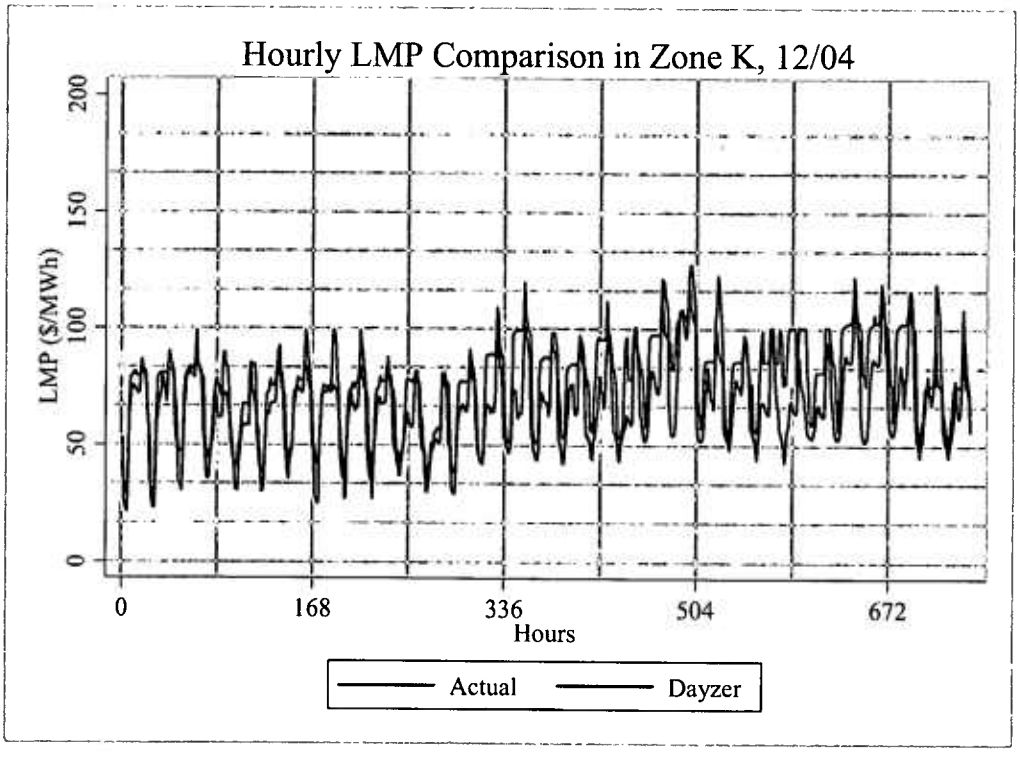

Hourly LMP Comparison in Zone K, 12/04
LMP ($/MWh)
0
50
100
150
200
0
168
336
504
672
Hours
Actual
Dayzer

EXHIBIT NO._(PFP-3R)

Backcasted Price Summary Statistics for All Zones Year Ending July 2005

Comparison of Backcast and Actual Price Differentials

Table 1A: Backcast Average On-Peak LMP by Month ($/MWh)

Zone	Zone Name	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Annual Avg LMP Aug 2004 - Jul 2005
A	WEST	43.8	48.3	48.8	50.6	53.0	64.8	49.1	54.5	51.9	48.8	66.9	85.0	55.4
B	GENESE	46.3	49.7	52.1	53.3	56.0	68.9	53.5	58.3	56.8	52.1	67.7	87.9	58.4
C	CENTRL	47.5	50.4	53.9	53.8	56.7	68.7	54.4	59.5	58.8	54.3	69.7	88.4	59.6
D	NORTH	46.6	49.1	51.4	54.1	57.3	71.7	55.1	58.9	58.8	54.8	70.2	85.6	59.4
E	MHKVL	49.3	51.4	55.5	55.8	58.7	72.3	56.9	61.6	61.3	57.1	72.8	90.0	61.8
F	CAPITL	52.2	54.0	61.8	60.1	61.0	76.4	59.7	65.3	66.1	60.6	77.1	94.7	65.6
G	HUDVL	56.2	56.7	61.7	61.1	61.7	76.1	61.0	67.1	68.7	63.1	82.1	98.5	67.7
H	MILLWD	56.8	57.3	62.3	61.6	62.0	76.7	61.6	68.0	69.6	64.2	83.7	100.2	68.5
I	DUNWOD	57.7	58.0	63.1	62.3	62.8	77.5	61.2	67.6	69.9	64.3	83.5	100.0	68.8
J	NYC	67.5	62.1	70.6	64.4	64.7	86.4	80.1	88.6	84.3	74.0	97.2	115.9	79.5
K	LONGIL	67.5	65.1	76.9	76.4	86.6	113.3	82.2	85.5	88.4	75.4	93.5	111.8	85.1

Table 1B: Actual Average On-Peak LMP by Month ($/MWh)

Zone	Zone Name	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Annual Avg LMP Aug 2004 - Jul 2005
A	WEST	46.0	46.3	50.6	56.2	55.7	64.8	51.0	59.3	61.3	57.7	67.2	79.1	57.9
B	GENESE	48.4	47.7	53.7	59.1	59.4	68.9	55.8	63.4	65.2	60.6	69.1	81.4	61.0
C	CENTRL	49.2	48.4	55.2	59.5	60.0	68.8	56.6	64.6	66.6	62.6	70.6	81.8	61.9
D	NORTH	47.7	47.1	52.9	59.7	60.6	73.3	56.7	63.3	64.7	62.2	70.5	78.9	61.4
E	MHKVL	50.6	49.3	56.3	61.6	62.1	72.5	58.9	66.5	68.1	65.0	73.4	83.2	63.9
F	CAPITL	54.3	51.9	60.2	64.8	64.5	79.6	64.3	72.1	75.4	68.2	78.6	87.3	68.3
G	HUDVL	56.0	53.5	59.7	65.4	65.1	78.3	63.7	72.6	75.8	70.6	86.5	94.5	70.1
H	MILLWD	57.0	54.1	60.0	66.6	64.9	78.1	63.9	73.9	76.4	71.7	89.3	98.4	71.1
I	DUNWOD	57.8	54.7	60.2	67.0	65.6	79.0	65.3	74.4	77.0	71.8	89.1	98.4	71.6
J	NYC	70.5	64.9	74.1	73.6	75.1	92.0	83.0	89.1	91.0	76.4	103.0	117.7	84.0
K	LONGIL	68.7	64.7	73.2	72.6	80.5	99.5	86.1	84.7	86.2	80.7	104.0	119.5	84.9

Table 1C: Monthly Average On-Peak LMP Difference (Backcast-Actual) ($/MWh)

Zone	Zone Name	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Difference of Annual Avg LMP Aug 2004 - Jul 2005
A	WEST	-2.2	2.0	-1.8	-5.6	-2.7	0.0	-1.9	-4.8	-9.4	-8.8	-0.3	6.0	-2.5
B	GENESE	-2.1	2.0	-1.6	-5.7	-3.4	-0.1	-2.3	-5.2	-8.4	-8.5	-1.4	6.5	-2.6
C	CENTRL	-1.7	2.1	-1.3	-5.7	-3.3	-0.1	-2.2	-5.0	-7.8	-8.3	-0.9	6.6	-2.4
D	NORTH	-1.1	2.0	-1.5	-5.6	-3.3	-1.6	-1.7	-4.4	-5.9	-7.3	-0.2	6.8	-2.0
E	MHKVL	-1.3	2.1	-0.8	-5.7	-3.4	-0.2	-2.0	-4.8	-6.8	-7.9	-0.6	6.8	-2.1
F	CAPITL	-2.0	2.1	1.7	-4.7	-3.6	-3.2	-4.7	-6.8	-9.3	-7.6	-1.4	7.4	-2.7
G	HUDVL	0.2	3.3	2.0	-4.4	-3.3	-2.2	-2.7	-5.5	-7.0	-7.5	-4.4	4.0	-2.4
H	MILLWD	-0.1	3.2	2.3	-4.9	-2.9	-1.3	-2.4	-5.9	-6.7	-7.5	-5.5	1.7	-2.5
I	DUNWOD	-0.1	3.3	2.9	-4.7	-2.7	-1.5	-4.1	-6.8	-7.1	-7.4	-5.7	1.6	-2.7
J	NYC	-3.0	-2.8	-3.5	-9.2	-10.3	-5.6	-2.9	-0.5	-6.7	-2.4	-5.8	-1.9	-4.6
K	LONGIL	-1.2	0.4	3.8	3.8	6.1	13.8	-3.9	0.8	2.2	-5.4	-10.5	-7.7	0.2

Table 1D: Average Absolute On-Peak Price Percent Error (%)

Zone	Zone Name	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Annual Avg Aug 2004 - Jul 2005
A	WEST	11.1%	8.9%	11.7%	11.9%	11.7%	11.1%	7.7%	11.8%	17.2%	15.9%	10.7%	15.6%	12.1%
B	GENESE	10.8%	8.9%	11.2%	11.7%	11.6%	10.5%	7.8%	11.4%	14.6%	14.6%	9.6%	14.8%	11.5%
C	CENTRL	10.0%	8.9%	10.8%	11.6%	11.5%	10.7%	7.6%	11.1%	13.5%	13.8%	9.0%	14.4%	11.1%
D	NORTH	9.3%	8.8%	11.1%	11.5%	11.5%	11.4%	7.4%	10.4%	11.1%	12.3%	8.5%	13.7%	10.6%
E	MHKVL	9.4%	8.8%	10.4%	11.4%	11.5%	10.6%	7.4%	10.6%	11.8%	12.7%	8.3%	13.7%	10.5%
F	CAPITL	9.4%	8.7%	11.0%	10.4%	11.5%	10.9%	10.0%	12.3%	13.0%	11.7%	8.6%	13.2%	10.9%
G	HUDVL	8.6%	8.8%	10.9%	10.6%	11.7%	10.6%	10.0%	11.9%	10.7%	11.2%	9.3%	11.1%	10.5%
H	MILLWD	9.0%	9.1%	13.5%	11.9%	12.4%	10.8%	10.2%	12.5%	10.4%	11.1%	10.0%	11.3%	11.0%
I	DUNWOD	9.1%	9.2%	14.5%	12.1%	12.7%	11.1%	9.5%	12.0%	10.3%	11.1%	10.2%	11.4%	11.1%
J	NYC	9.7%	8.6%	9.2%	12.7%	14.6%	11.4%	11.3%	10.6%	10.9%	7.3%	10.3%	11.0%	10.6%
K	LONGIL	7.3%	9.2%	7.9%	10.0%	14.7%	17.5%	11.1%	8.2%	6.8%	7.4%	11.6%	9.3%	10.1%

Comparison of Backcast and Actual Price Differentials

Table 2A: Backcast Average Off-Peak LMP by Month ($/MWh)

Zone	Zone Name	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Annual Avg LMP Aug 2004 - Jul 2005
A	WEST	32.2	36.6	37.9	37.7	40.1	44.5	38.6	41.9	39.8	36.2	42.8	50.0	39.9
B	GENESE	35.9	38.1	41.4	40.5	42.6	47.4	42.7	46.5	43.8	40.1	46.8	54.2	43.4
C	CENTRL	37.5	38.9	42.9	41.3	43.4	47.8	44.0	48.7	45.5	42.2	49.3	56.5	44.9
D	NORTH	39.2	39.1	43.1	43.3	44.6	49.7	46.1	51.4	47.6	45.4	53.4	59.2	46.9
E	MHKVL	40.2	40.3	45.1	43.7	45.2	50.1	46.8	52.1	48.1	45.7	53.7	60.0	47.6
F	CAPITL	43.7	42.8	48.8	46.6	47.6	53.2	49.4	56.0	52.4	49.4	58.3	64.1	51.1
G	HUDVL	45.6	43.6	49.7	47.4	47.8	52.9	50.9	58.2	54.4	51.8	61.2	67.1	52.6
H	MILLWD	46.3	44.2	50.3	48.0	48.1	53.2	51.5	59.4	55.2	52.6	62.5	68.5	53.4
I	DUNWOD	47.2	44.8	51.0	48.6	48.7	54.0	51.5	59.6	55.3	52.9	63.2	69.0	53.9
J	NYC	53.1	47.6	52.7	49.9	49.7	57.4	60.6	70.1	65.9	58.4	73.4	79.6	59.9
K	LONGIL	58.8	54.4	63.6	57.8	66.2	72.7	72.2	74.0	78.2	63.2	77.2	84.1	68.6

Table 2B: Actual Average Off-Peak LMP by Month ($/MWh)

Zone	Zone Name	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Annual Avg LMP Aug 2004 - Jul 2005
A	WEST	33.8	34.8	37.5	39.7	41.6	47.2	40.3	47.0	47.2	40.2	47.8	56.6	42.9
B	GENESE	36.1	35.8	40.3	41.8	43.9	50.6	45.2	50.7	50.0	42.4	50.2	59.2	45.6
C	CENTRL	36.9	36.3	41.0	42.0	44.6	50.9	45.8	52.0	50.9	43.6	51.6	60.6	46.4
D	NORTH	36.9	35.9	40.5	43.1	45.4	52.5	47.0	52.6	51.0	44.9	53.5	61.1	47.1
E	MHKVL	38.3	37.2	42.0	43.8	46.2	53.0	48.0	54.0	52.3	45.6	54.4	62.6	48.2
F	CAPITL	40.9	39.2	46.1	46.2	48.4	58.1	50.1	57.0	56.9	48.1	57.8	65.2	51.3
G	HUDVL	41.4	39.9	45.4	46.4	48.1	56.8	50.5	58.0	57.2	49.2	60.4	67.2	51.8
H	MILLWD	41.8	40.7	45.1	46.9	47.7	56.5	50.9	58.5	57.4	49.6	61.6	68.2	52.1
I	DUNWOD	42.4	41.2	45.3	47.2	48.1	57.1	51.4	58.7	58.1	49.8	61.6	68.4	52.5
J	NYC	52.0	45.0	54.1	50.1	53.4	65.2	59.3	62.9	66.5	53.1	66.9	75.4	58.7
K	LONGIL	56.9	51.4	57.0	50.9	57.1	72.0	66.5	71.0	70.5	69.1	83.7	86.1	66.1

Table 2C: Monthly Average Off-Peak LMP Difference (Backcast-Actual) ($/MWh)

Zone	Zone Name	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Difference of Annual Avg LMP Aug 2004 - Jul 2005
A	WEST	-1.6	1.7	0.4	-2.0	-1.5	-2.7	-1.7	-5.1	-7.4	-4.0	-5.1	-6.6	-3.0
B	GENESE	-0.2	2.3	1.1	-1.3	-1.3	-3.2	-2.4	-4.2	-6.2	-2.3	-3.4	-4.9	-2.2
C	CENTRL	0.6	2.6	1.9	-0.7	-1.2	-3.1	-1.8	-3.3	-5.4	-1.4	-2.4	-4.0	-1.5
D	NORTH	2.3	3.2	2.6	0.2	-0.9	-2.8	-0.9	-1.2	-3.5	0.6	-0.1	-1.9	-0.2
E	MHKVL	1.9	3.1	3.0	-0.1	-1.0	-2.9	-1.2	-2.0	-4.3	0.1	-0.8	-2.6	-0.6
F	CAPITL	2.8	3.5	2.6	0.3	-0.8	-4.9	-0.7	-1.0	-4.4	1.3	0.5	-1.1	-0.2
G	HUDVL	4.3	3.7	4.2	1.0	-0.3	-4.0	0.3	0.2	-2.7	2.6	0.7	-0.1	0.8
H	MILLWD	4.5	3.4	5.2	1.1	0.4	-3.3	0.7	0.9	-2.3	3.0	0.9	0.3	1.2
I	DUNWOD	4.7	3.6	5.7	1.3	0.6	-3.1	0.2	0.8	-2.8	3.2	1.5	0.7	1.4
J	NYC	1.1	2.6	-1.3	-0.2	-3.7	-7.8	1.3	7.2	-0.6	5.4	6.5	4.2	1.2
K	LONGIL	1.9	3.0	6.6	7.0	9.0	0.6	5.7	3.0	7.7	-5.8	-6.5	-2.0	2.5

Table 2D: Average Absolute Off-Peak Price Percent Error (%)

Zone	Zone Name	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Annual Avg Aug 2004 - Jul 2005
A	WEST	13.8%	13.1%	15.2%	13.6%	13.3%	15.7%	15.5%	14.4%	16.9%	15.7%	16.9%	18.0%	15.2%
B	GENESE	12.2%	12.9%	13.6%	12.3%	12.7%	15.7%	12.4%	11.6%	14.9%	13.1%	13.6%	13.9%	13.3%
C	CENTRL	12.4%	13.2%	13.7%	11.7%	12.4%	15.5%	11.7%	9.9%	14.2%	13.1%	12.6%	12.3%	12.8%
D	NORTH	14.4%	14.5%	15.6%	11.2%	12.2%	15.5%	10.8%	8.1%	15.1%	15.0%	12.6%	10.9%	13.0%
E	MHKVL	13.6%	14.1%	15.1%	11.2%	12.2%	15.5%	10.9%	8.5%	14.2%	14.3%	12.4%	11.1%	12.8%
F	CAPITL	16.4%	15.2%	14.8%	11.6%	12.2%	15.7%	11.1%	8.2%	14.9%	16.1%	12.7%	11.0%	13.4%
G	HUDVL	18.2%	16.4%	16.6%	12.0%	12.8%	15.5%	12.0%	8.8%	15.2%	17.8%	13.9%	11.6%	14.3%
H	MILLWD	18.7%	17.1%	19.2%	13.0%	14.2%	15.9%	12.3%	9.3%	15.6%	18.2%	14.8%	12.1%	15.1%
I	DUNWOD	19.1%	17.4%	20.6%	13.4%	14.7%	16.1%	11.5%	9.1%	15.6%	18.3%	15.3%	12.5%	15.4%
J	NYC	19.8%	17.4%	15.9%	13.3%	12.6%	19.0%	13.8%	14.6%	15.8%	20.7%	18.8%	14.2%	16.4%
K	LONGIL	6.5%	17.4%	15.8%	20.6%	22.3%	16.5%	13.5%	9.6%	14.6%	13.9%	8.5%	5.7%	13.7%

Sources and Notes:

Actual LMPs are obtained from The Velocity Suite database, Global Energy Decision Inc., October 2006.

Peak Hours (PK) defined as hours 7 through 22 Monday through Friday, except for NERC holidays and weekends. The rest constitutes Off-Peak (OP) hours.

Annual averages are calculated based on hourly prices.

EXHIBIT NO._(PFP-4R)

NYISO Transmission Facility Maintenance Outage Impact Report

New York ISO Transmission Facility Maintenance Outage Impact Report

STATION / KV	EQUIP.	INTERFACE NAME	OUTAGE IMPACT IN MW SUM	WINTR
O (ONTARIO HYDRO) to A/D (WEST/NORTH) – OH-NYPP				
BECK A 345	PA301	OH to NYPP	700	700
BECK B 345	PA302	OH to NYPP	700	700
BECK 230	PA27	OH to NYPP	400	400
BECK BP76 230	BP76	OH to NYPP	400	400
ST.LAW L33P 230	L33P	OH to NYPP (PA)	150	150
ST.LAW L34P 230	L34P	OH to NYPP (PA)	150	150
A (WEST) to B (GENESEE) - DYSINGER-EAST				
KINTIGH 345	SR-1	DYSINGER EAST	1550	1425
NIAGARA 3 345	NR2	DYSINGER EAST	1525	1400
STOLLE RD 230	67	DYSINGER EAST	725	350
MEYER 230	68	DYSINGER EAST	700	300
B (GENESEE) to C (CENTRAL) - WEST CENTRAL				
ROCHESTER 3 345	RP1	WEST CENTRAL	1300	1025
ROCHESTER 3 345	RP2	WEST CENTRAL	1300	1125
ROCHESTER 3 345	3408	WEST CENTRAL	1300	1300
ROCHESTER 3 345	3508	WEST CENTRAL	1300	1300
CLAY 345	R935	WEST CENTRAL	1250	1250
CLAY 345	R945	WEST CENTRAL	1250	1250
PANNELL RD 345	PC1	WEST CENTRAL	1200	1000
PANNELL RD 345	PC2	WEST CENTRAL	1200	1000
PANNELL RD 345	3808	WEST CENTRAL	1200	1000
PANNELL RD 345	3908	WEST CENTRAL	1200	1000
NIAGARA 3 345	NS1-38	WEST CENTRAL	650	500
CLAY 345	2-15	WEST CENTRAL	200	200
CLAY 345	1-16	WEST CENTRAL	200	200
C (CENTRAL) to E (MOHAWK VALLEY) - VOLNEY-EAST				
M (HYDRO QUEBEC) to D (NORTH) – HQ-NYPP				
CHATEAUGUAY 765	7040	HQ to NYPP (PA)	2350	2350
CHATEAUGUAY 120	120-104	HQ to NYPP (PA)	480	480
CHATEAUGUAY 120	120-103	HQ to NYPP (PA)	480	480
D (NORTH) to E (MOHAWK VALLEY) – MOSES-SOUTH				
MASSENA 7 765	MSU1	MOSES SOUTH	1325	1325
MOSES 230	MA1	MOSES SOUTH	500	500
MOSES 230	MA2	MOSES SOUTH	500	500
ADIRONDACK 230	11-AP	MOSES SOUTH	500	500
ADIRONDACK 230	12-AP	MOSES SOUTH	500	500

STATION / KV	EQUIP.	INTERFACE NAME	OUTAGE IMPACT IN MW SUM	WINTR
D/E (NORTH/MOHAWK VALLEY) to F/N (CAPITAL/NE) – CENTRAL-EAST				
EDIC 345	14-EN (to N Scot)	TOTAL EAST (C-E)	1225	1225
MARCY 345	18 (to N Scot)	TOTAL EAST (C-E)	1175	1175
NEW SCOTL 77	345 93-LN	TOTAL EAST (C-E)	1175	550
NEW SCOTL 99	345 94-LN	TOTAL EAST (C-E)	1175	550
LEEDS 345	SVC	TOTAL EAST (C-E)	100	100
D/E/O (NORTH/MV/PJM) to N/F/G/J (NE/CAP/HV/NYC) – TOTAL-EAST (In Addition to Central-East)				
LEEDS 345	R94301	TOTAL EAST (C-E)	1300	525
LEEDS 345	R391	TOTAL EAST (C-E)	1300	525
GILBOA 345	GL3	TOTAL EAST (C-E)	1100	1100
LEEDS 345	91	TOTAL EAST (C-E)	925	300
LEEDS 345	92	TOTAL EAST (C-E)	925	400
ROSETON 345	305	TOTAL EAST (C-E)	875	450
EDIC 345	EF24-40	TOTAL EAST (C-E)	850	850
MARCY 345	UC2-41	TOTAL EAST (C-E)	850	850
FRASER 345	GF5-35	TOTAL EAST (C-E)	825	825
OAKDALE 345	32	TOTAL EAST (C-E)	775	775
LEEDS 345	301	TOTAL EAST (C-E)	625	375
HURLEY AVE 345	303	TOTAL EAST (C-E)	625	375
LAFAYETTE 345	4-36	TOTAL EAST (C-E)	550	550
FRASER 345	33	TOTAL EAST (C-E)	500	500
GILBOA 345	GNS1	TOTAL EAST (C-E)	375	125
ROCK TAVERN 345	77	TOTAL EAST (C-E)	325	150
FITZPATRICK 345	FE1	TOTAL EAST (C-E)	275	275
VOLNEY 345	19	TOTAL EAST (C-E)	275	275
PORTER 230	30-PR	TOTAL EAST (C-E)	250	250
PORTER 230	31-PR	TOTAL EAST (C-E)	250	250
COOPERS CRN 345	CRT-34	TOTAL EAST (C-E)	175	175
COOPERS CRN 345	CRT-42	TOTAL EAST (C-E)	175	175
FRASER 345	SVC	TOTAL EAST (C-E)	75	75
W.WOODBOUR 115	BK 1	TOTAL EAST	50	50
BRANCHBURG 500	5018	TOTAL EAST (5018/K3411)	1000	1150
RAMAPO S. 345	PAR3500	TOTAL EAST (5018/K3411)	450	575
RAMAPO S. 345	PAR4500	TOTAL EAST (5018/K3411)	450	575
F (CAPITAL) to G (HUDSON VALLEY) – UPNY-SENY				
G (HUDSON VALLEY) to H (MILLWOOD) – UPNY-CONED				
PLEASANT VLY 345	F30	UPNY-CONED	700	600
PLEASANT VLY 345	F31	UPNY-CONED	700	600
PLEASANT VLY 345	F36	UPNY-CONED	700	600
PLEASANT VLY 345	F37	UPNY-CONED	700	600
RAMAPO 345	Y94	UPNY-CONED	550	950
LADENTOWN 345	Y88	UPNY-CONED	550	950
BUCHANAN N. 345	W93	UPNY-CONED	350	750
EASTVIEW 2N 345	W79	UPNY-CONED	350	750
ROSETON 345	311	UPNY-CONED	300	200
RAMAPO 345	W72	UPNY-CONED	300	350

STATION / KV	EQUIP.	INTERFACE NAME	OUTAGE IMPACT IN MW SUM	WINTR
H (MILLWOOD) to I (DUNWOODIE) – MILLWOOD SOUTH				
I (DUNWOODIE) to J/K (NYC/LI) – DUNWOODIE-SOUTH				
SPRAINBROOK 345	Y49 (to E.G.C.)	CONED-LILCO	625	625
DUNWOODIE 345	Y50 (to Shore Rd)	CONED-LILCO	600	600
JAMAICA 138	901L&M	CONED-LILCO	250	250
JAMAICA 138	903	CONED-LILCO	250	250
E.G.C. BNK1 345	BK 1 PAR	CONED-LILCO	175	125
E.G.C. BNK2 345	BK 2 PAR	CONED-LILCO	175	125
E.G.C. = East Garden City				
I/J/N (DUNWOODIE/NYC/NEW ENGLAND) to K (LI) – LONG ISLAND IMPORT				
P (PJM) to A/C/G/J (WEST/CENTRAL/HV/NYC) – PJM-NYPP				
HOMER CTY 345	30	PJM to NYPP	650	650
ERIE S. 230	69	PJM to NYPP	425	425
S.RIPLEY 230	68	PJM to NYPP	425	425
WATERCURE 345	31	PJM to NYPP	300	300
E.TOWANDA 230	70	PJM to NYPP	200	200
WATERCURE 230	71	PJM to NYPP	150	150
HOMER CTY 345	37	PJM to NYPP	100	100
WARREN PJ 115	171	PJM to NYPP	50	50
D/F/G/K (NORTH/CAP/HV/LI) to NEW ENGLAND – NYPP- NEPEX				
NORWALK HAR 138	1385	NYPP to NEPEX (LI)	150	150
LONG MT 345	398	NYPP to NEPEX (CE)	700	700
SMITHFIELD 69	690	NYPP to NEPEX (CH)	28	28
BERKSHIRE 345	393	NYPP to NEPEX (NM)	450	450
NEW SCOTL 77 345	2-AN	NYPP to NEPEX (NM)	375	250
BEAR SWP 230	E205W	NYPP to NEPEX (NM)	100	100
GRAND IS 115	PV20	NYPP to NEPEX (PA)	140	140

Source: **NYISO Outage Scheduling Manual** (Rev.: 5/30/2002), Appendix, Outage Impact Report rev.: (June 10, 1999)

Exhibit No._(PFP-5R)

NYISO Day Ahead Limiting Constraints Report for June 1, 2006

Page Ref: P-511A

Day Ahead Limiting Constraints

[redacted]me Stamp	Time Zone	Limiting Facility	Facility PTID	Contingency	Constraint Cost ($)
06/01/2006 09:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25324	BASE CASE	0.92
06/01/2006 10:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25323	BASE CASE	10.06
06/01/2006 11:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25323	BASE CASE	3.53
06/01/2006 12:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25323	BASE CASE	23.68
06/01/2006 13:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25324	BASE CASE	39.05
06/01/2006 14:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25324	BASE CASE	29.58
06/01/2006 15:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25324	BASE CASE	25.14
06/01/2006 16:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25324	BASE CASE	24.98
06/01/2006 17:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25323	BASE CASE	14.26
06/01/2006 18:00	EDT	ASTORIAE 138 HELLGT_E 138 1	25323	BASE CASE	4.02
06/01/2006 09:00	EDT	E179THST 138 HELLTP_W 138 1	25288	BASE CASE	0.02
06/01/2006 11:00	EDT	E179THST 138 HELLTP_W 138 1	25288	BASE CASE	0.02
06/01/2006 13:00	EDT	E179THST 138 HELLTP_W 138 1	25288	BASE CASE	0.02
06/01/2006 16:00	EDT	E179THST 138 HELLTP_W 138 1	25288	BASE CASE	0.02
06/01/2006 09:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25293	BASE CASE	-0.93
06/01/2006 10:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25292	BASE CASE	-9.94
06/01/2006 11:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25292	BASE CASE	-3.49
06/01/2006 12:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25292	BASE CASE	-23.4
06/01/2006 13:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25292	BASE CASE	-38.58
06/01/2006 14:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25292	BASE CASE	-29.23
06/01/2006 15:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25292	BASE CASE	-24.84
06/01/2006 16:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25292	BASE CASE	-24.69
06/01/2006 17:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25292	BASE CASE	-14.09
06/01/2006 18:00	EDT	FARRAGUT 138 HUDS_AVE 138 1	25292	BASE CASE	-3.98
06/01/2006 06:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.03
06/01/2006 07:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.02
06/01/2006 08:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.02
[redacted]1/2006 09:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.03
[redacted]1/2006 10:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.02
06/01/2006 11:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25320	BASE CASE	0.03
06/01/2006 12:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25320	BASE CASE	0.02
06/01/2006 13:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25320	BASE CASE	0.03
06/01/2006 14:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25320	BASE CASE	0.02
06/01/2006 15:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25320	BASE CASE	0.02
06/01/2006 16:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.03
06/01/2006 17:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.02
06/01/2006 18:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.03
06/01/2006 19:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.03
06/01/2006 20:00	EDT	FRESHKLS 138 WILLWBRK 138 1	25319	BASE CASE	0.03
06/01/2006 11:00	EDT	GOWANUSN 138 GREENWD 138 1	25214	BASE CASE	0.02
06/01/2006 13:00	EDT	GOWANUSN 138 GREENWD 138 1	25214	BASE CASE	0.02
06/01/2006 16:00	EDT	GOWANUSN 138 GREENWD 138 1	25214	BASE CASE	0.02
06/01/2006 18:00	EDT	GREENWD 138 VERNON 138 1	25337	BASE CASE	-0.02
06/01/2006 19:00	EDT	GREENWD 138 VERNON 138 1	25337	BASE CASE	-0.02
06/01/2006 20:00	EDT	GREENWD 138 VERNON 138 1	25337	BASE CASE	-0.02
06/01/2006 21:00	EDT	GREENWD 138 VERNON 138 1	25337	BASE CASE	-0.02
06/01/2006 00:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 01:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 02:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 03:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 04:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 05:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 06:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 09:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 11:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 13:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 16:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
[redacted]/2006 22:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
[redacted]/2006 23:00	EDT	RAINEY 138 VERNON 138 1	25297	BASE CASE	0.02
06/01/2006 00:00	EDT	PJM ACTIVE DNI	994	ACTIVE DNI	2.94

06/01/2006 22:00	EDT	PJM ACTIVE DNI	994	ACTIVE DNI	1.85
06/01/2006 07:00	EDT		990	ACTIVE DNI	-2.36
06/01/2006 22:00	EDT		990	ACTIVE DNI	0.55
06/01/2006 23:00	EDT		990	ACTIVE DNI	3.11
06/01/2006 12:00	EDT	PLSNTVLY 345 LEEDS 345 1	25056	ATHENS__-PLSNTVLY_345_91	-22.16
[redacted]1/2006 13:00	EDT	PLSNTVLY 345 LEEDS 345 1	25056	ATHENS__-PLSNTVLY_345_91	-40.81
[redacted]1/2006 14:00	EDT	PLSNTVLY 345 LEEDS 345 1	25056	ATHENS__-PLSNTVLY_345_91	-26.27
06/01/2006 15:00	EDT	PLSNTVLY 345 LEEDS 345 1	25056	ATHENS__-PLSNTVLY_345_91	-19.42
06/01/2006 16:00	EDT	PLSNTVLY 345 LEEDS 345 1	25056	ATHENS__-PLSNTVLY_345_91	-21.97
06/01/2006 11:00	EDT	ADIRNDCK 230 MOSES 230 1	25270	SIN:MSU1,7040 & HQ GEN,4 BEAU	-0.03
06/01/2006 12:00	EDT	ADIRNDCK 230 MOSES 230 1	25270	SIN:MSU1,7040 & HQ GEN,4 BEAU	-0.03
06/01/2006 13:00	EDT	ADIRNDCK 230 MOSES 230 1	25270	SIN:MSU1,7040 & HQ GEN,4 BEAU	-0.03
06/01/2006 14:00	EDT	ADIRNDCK 230 MOSES 230 1	25270	SIN:MSU1,7040 & HQ GEN,4 BEAU	-0.03
06/01/2006 00:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	21.46
06/01/2006 01:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	24.87
06/01/2006 02:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	25.44
06/01/2006 03:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	27.47
06/01/2006 04:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	27.07
06/01/2006 05:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	27.29
06/01/2006 06:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	19.94
06/01/2006 07:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	11.8
06/01/2006 08:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	7.56
06/01/2006 09:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	6.53
06/01/2006 10:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	7.14
06/01/2006 11:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	7.52
06/01/2006 13:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	12.77
06/01/2006 14:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	16.94
06/01/2006 15:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	21.74
06/01/2006 16:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	21.76
06/01/2006 17:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	40.84
06/01/2006 18:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	45.79
06/01/2006 19:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	16.06
06/01/2006 20:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	16.55
06/01/2006 21:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	11.49
[redacted]1/2006 22:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	17.58
[redacted]1/2006 23:00	EDT	DUNWODIE 345 SHORE_RD 345 1	25091	SPRNBRK_-EGRDNCTR_345_Y49	19.26

EXHIBIT NO._(PFP-6R)

NYISO Operational Announcements of June 1, 2006

NYISO Operational Announcements

Dispatcher Notices
Committed for Reliability
Market Monitor Notices

Dispatcher Notices back to top

Insert Time	Message
01-Jun-2006 00:02:15	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___1 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 00:00 FOR Steam send out.
01-Jun-2006 00:02:31	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___2 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 00:00 FOR CON EDISON STEAM SYSTEM SECURITY..
01-Jun-2006 00:03:26	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___1 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 00:00 FOR Steam send out.
01-Jun-2006 00:03:43	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___2 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 00:00 FOR CON EDISON STEAM SYSTEM SECURITY..
01-Jun-2006 05:06:39	Metering Authority - Consolidated Edison of NY UPDATES BROOKLYN_NAVY_YARD OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 05:00 FOR STEAM SENDOUT.
01-Jun-2006 05:38:10	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___1 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 05:00 FOR Steam send out.
01-Jun-2006 05:38:27	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___2 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 05:00 FOR CON EDISON STEAM SYSTEM SECURITY..
01-Jun-2006 06:06:21	ISO REQUESTS BARRETT___1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 06:00 FOR 262 OVER NORMAL..
01-Jun-2006 06:06:43	ISO REQUESTS BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 06:00 FOR 262 OVER NORMAL..

01-Jun-2006 06:28:45	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___1 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 06:00 FOR Steam send out.
01-Jun-2006 06:29:01	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___2 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 06:00 FOR CON EDISON STEAM SYSTEM SECURITY..
01-Jun-2006 07:00:25	Metering Authority - Consolidated Edison of NY UPDATES BROOKLYN_NAVY_YARD OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 07:00 FOR STEAM SENDOUT.
01-Jun-2006 07:07:40	06/01/2006 07:05:00 NYISO large event reserve pick-up executed.
01-Jun-2006 07:20:33	ISO UPDATES BARRETT___1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 07:00 FOR Post cont loss of 365 & 366 on to 367 over LTE.
01-Jun-2006 07:20:50	ISO UPDATES BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 07:00 FOR Post cont loss of 365 & 366 on to 367 over LTE.
1-Jun-2006 07:24:39	ISO UPDATES BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 07:00 FOR Post cont loss of 365 & 366 on to 367 over LTE.
01-Jun-2006 09:33:34	Metering Authority - Niagara Mohawk UPDATES SITHE___BATAVIA OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 05/31/2006 00:00 FOR SRE entered by TSA (LE) Original record modified: Type: Derate Log: Unit output.
01-Jun-2006 09:41:12	Metering Authority - Long Island Power Authority UPDATES NORTHPORT___3 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 05/31/2006 18:00 FOR SRE entered by TSA (LE) Modified original record Type: Derate Log: Unit off line.
01-Jun-2006 10:27:36	Metering Authority - Consolidated Edison of NY UPDATES EAST RIVER___6 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 10:00 FOR steam system.
01-Jun-2006 11:03:47	Metering Authority - Consolidated Edison of NY UPDATES EAST RIVER___6 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 11:00 FOR steam system.

01-Jun-2006 11:14:34	06/01/2006 11:12:50 NYISO large event reserve pick-up executed.
01-Jun-2006 11:21:20	ISO REQUESTS GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 11:00 FOR Loss of 500mw of generation.
01-Jun-2006 11:36:35	ISO REQUESTS GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 12:00 FOR Loss of 500mw of generation.
01-Jun-2006 12:25:01	Metering Authority - Consolidated Edison of NY UPDATES EAST RIVER___6 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 12:00 FOR steam system.
01-Jun-2006 12:37:20	ISO REMOVES GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 12:00.
01-Jun-2006 13:24:02	ISO REQUESTS GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 13:00 FOR ACE > -500.
01-Jun-2006 13:24:41	06/01/2006 13:22:54 NYISO large event reserve pick-up executed.
01-Jun-2006 13:40:34	ISO REQUESTS ASTORIA___5 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 13:00 FOR 15055, 15054 over normal.
01-Jun-2006 13:41:29	ISO UPDATES BARRETT___1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 13:00 FOR over post contingency 291,292.
01-Jun-2006 13:41:49	ISO UPDATES BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 13:00 FOR over post contingency 291,292.
01-Jun-2006 13:43:27	ISO REQUESTS GILBOA___3 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 13:00 FOR TSA, multiple contingencies.
01-Jun-2006 13:47:06	ISO UPDATES GILBOA___3 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 13:00 FOR TSA, multiple contingencies.
01-Jun-2006 13:47:34	ISO UPDATES ASTORIA___5 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 13:00 FOR 15055, 15054 over normal.
01-Jun-2006 13:57:57	ISO REQUESTS BARRETT___1 OUT OF MERIT.

	COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00 FOR over post contingency 291,292.
01-Jun-2006 13:58:05	ISO REQUESTS BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00 FOR over post contingency 291,292.
01-Jun-2006 14:09:15	ISO UPDATES BARRETT___1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00 FOR over post contingency 291,292.
01-Jun-2006 14:09:26	ISO UPDATES BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00 FOR over post contingency 291,292.
01-Jun-2006 14:15:00	ISO REQUESTS ASTORIA_EAST_ENERGY_CC1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00 FOR Astoria overloads.
01-Jun-2006 14:18:10	ISO UPDATES BARRETT___1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00 FOR over post contingency 291,292.
01-Jun-2006 14:18:24	ISO UPDATES BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00 FOR over post contingency 291,292.
01-Jun-2006 14:33:49	ISO REMOVES GILBOA___3 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00.
01-Jun-2006 14:41:49	ISO REMOVES ASTORIA___5 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00.
01-Jun-2006 14:42:45	06/01/2006 14:39:37 NYISO large event reserve pick-up executed.
01-Jun-2006 14:44:18	ISO REQUESTS GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00 FOR lost 500mw generation.
01-Jun-2006 14:44:29	06/01/2006 14:41:07 NYISO large event reserve pick-up executed.
01-Jun-2006 14:54:37	ISO UPDATES GILBOA___3 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 14:00 FOR lost 500mw generation.
01-Jun-2006 14:54:49	ISO REQUESTS GILBOA___3 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 15:00 FOR lost 500mw generation.
01-Jun-2006 14:55:09	ISO REMOVES GILBOA___2 OUT OF MERIT.

	COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 16:00.
1-Jun-2006 15:21:18	ISO REMOVES GILBOA___3 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 15:00.
01-Jun-2006 15:22:13	Metering Authority - Long Island Power Authority REQUESTS WADING RIVER_IC_1 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 15:00 FOR loss of 138kv 884 & 879 pushes 890 over STE.
01-Jun-2006 15:23:30	Metering Authority - Consolidated Edison of NY REMOVES EAST RIVER___6 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 15:00.
01-Jun-2006 15:41:05	ISO UPDATES GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 16:00 FOR Lost of 500mw of generation.
01-Jun-2006 15:41:22	ISO UPDATES GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 16:00 FOR lost 500mw of generation.
01-Jun-2006 15:41:42	ISO UPDATES GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 16:00 FOR lost 500mw generation.
01-Jun-2006 15:42:55	ISO UPDATES GILBOA___3 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 15:00 FOR OOM cancelled after RTC committed unit.
01-Jun-2006 15:58:04	ISO REMOVES GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 15:00.
01-Jun-2006 16:18:09	ISO REQUESTS GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 16:00 FOR Unit committed by RTC due to OOM record that was later cancelled..
01-Jun-2006 16:58:54	ISO REQUESTS GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 17:00 FOR Unit committed by RTC due to OOM record that was later cancelled..
01-Jun-2006 17:04:32	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___1 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 17:00 FOR Steam send out.
01-Jun-2006 17:04:49	Metering Authority - Consolidated Edison of NY ~~UPDATES EAST_RIVER___2 OUT OF MERIT.~~ OOM FOR TO LOCAL SECURITY AT START

	TIME 06/01/2006 17:00 FOR CON EDISON STEAM SYSTEM SECURITY..
1-Jun-2006 17:11:34	ISO REMOVES GILBOA___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 17:00.
01-Jun-2006 19:01:33	Metering Authority - Consolidated Edison of NY UPDATES BROOKLYN_NAVY_YARD OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 19:00 FOR STEAM SENDOUT.
01-Jun-2006 20:14:22	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___1 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 20:00 FOR Steam send out.
01-Jun-2006 20:14:33	Metering Authority - Consolidated Edison of NY UPDATES EAST_RIVER___2 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 20:00 FOR CON EDISON STEAM SYSTEM SECURITY..
01-Jun-2006 20:49:19	Metering Authority - Long Island Power Authority REMOVES WADING RIVER_IC_1 OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 20:00.
01-Jun-2006 21:21:59	Metering Authority - Consolidated Edison of NY UPDATES BROOKLYN_NAVY_YARD OUT OF MERIT. OOM FOR TO LOCAL SECURITY AT START TIME 06/01/2006 21:00 FOR STEAM SENDOUT.
01-Jun-2006 21:49:25	ISO REMOVES BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 21:00.
01-Jun-2006 21:49:34	ISO REMOVES BARRETT___1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 21:00.
01-Jun-2006 21:52:54	ISO UPDATES BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 21:00 FOR 262 OVER NORMAL..
01-Jun-2006 21:53:03	ISO REQUESTS BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 22:00 FOR 262 OVER NORMAL..
01-Jun-2006 22:10:59	ISO REQUESTS BARRETT___1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 22:00 FOR 262 OVER NORMAL..
01-Jun-2006 22:20:27	ISO REQUESTS BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 23:00 FOR 262 OVER NORMAL..
01-Jun-2006 22:40:02	ISO UPDATES BARRETT___2 OUT OF MERIT.

	COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 22:00 FOR 262 OVER NORMAL..
1-Jun-2006 22:40:16	ISO UPDATES BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 22:00 FOR 262 OVER NORMAL..
01-Jun-2006 22:40:51	ISO UPDATES BARRETT___2 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 22:00 FOR 262 OVER NORMAL..
01-Jun-2006 22:41:00	ISO UPDATES BARRETT___1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 22:00 FOR 262 OVER NORMAL..
01-Jun-2006 22:41:40	ISO UPDATES BARRETT___1 OUT OF MERIT. COMMITED FOR ISO RELIABILITY AT START TIME 06/01/2006 22:00 FOR 262 OVER NORMAL..

Committed for Reliability back to top

Insert Time	Message
01-Jun-2006 11:05:32	Generator: NORTHPORT___3 scheduled for local reliability in DAM market for 06/02/2006 18 Energy = 100 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
1-Jun-2006 11:05:32	Generator: NORTHPORT___3 scheduled for local reliability in DAM market for 06/02/2006 19 Energy = 100 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 11:05:32	Generator: NORTHPORT___3 scheduled for local reliability in DAM market for 06/02/2006 20 Energy = 100 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 11:05:32	Generator: NORTHPORT___3 scheduled for local reliability in DAM market for 06/02/2006 21 Energy = 100 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 11:05:33	Generator: NORTHPORT___3 scheduled for local reliability in DAM market for 06/02/2006 22 Energy = 100 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 11:05:33	Generator: NORTHPORT___3 scheduled for local

	reliability in DAM market for 06/02/2006 23 Energy = 100 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 11:06:39	Generator: NORTHPORT___4 scheduled for local reliability in DAM market for 06/02/2006 23 Energy = 100 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 11:07:26	Generator: BARRETT___2 scheduled for local reliability in DAM market for 06/02/2006 23 Energy = 40 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:17	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/01/2006 21 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:17	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 05 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:17	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 04 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:17	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/01/2006 23 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:17	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 00 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
1-Jun-2006 12:23:17	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 01 Energy =

	63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:17	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 03 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:17	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 02 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:17	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/01/2006 22 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 06 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 08 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 09 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 11 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 13 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0

	MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 15 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 17 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 18 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 16 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 14 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 12 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 10 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:18	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 07 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0

	MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
1-Jun-2006 12:23:19	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 19 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 12:23:19	Generator: INDECK___OLEAN scheduled for local reliability in DAM market for 06/02/2006 20 Energy = 63 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:49:32	Generator: POLETTI____ scheduled for local reliability in DAM market for 06/02/2006 22 Energy = 140 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:49:32	Generator: POLETTI____ scheduled for local reliability in DAM market for 06/02/2006 23 Energy = 140 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:49:53	Generator: RAVENSWOOD___3 scheduled for local reliability in DAM market for 06/02/2006 22 Energy = 150 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:49:53	Generator: RAVENSWOOD___3 scheduled for local reliability in DAM market for 06/02/2006 23 Energy = 150 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:11	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 00 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 01 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0

	MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 02 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 03 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 05 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 07 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 09 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 11 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 10 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 08 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.

01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 06 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:12	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 04 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:13	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 12 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:13	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 15 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:13	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 17 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:13	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 18 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:13	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 16 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:13	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 14 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:13	Generator: ASTORIA___3 scheduled for local

	reliability in DAM market for 06/02/2006 13 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:14	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 19 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:14	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 21 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:14	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 23 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:14	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 22 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.
01-Jun-2006 15:50:14	Generator: ASTORIA___3 scheduled for local reliability in DAM market for 06/02/2006 20 Energy = 75 MW. Regulation = 0 MW. Min10 Spinning = 0 MW. Min10 Nonsynch = 0 MW. Min30 Spinning = 0 MW. Min30 Nonsynch = 0 MW. Operating Cap = 0 MW.

Market Monitor Notices back to top

Insert Time	Message
01-Jun-2006 14:27:41	Prices in the 31 May 2006 Real-Time Market, encompassing Energy, Regulation and Operating Reserves are correct. Prices in the 31 May 2006 Hour-Ahead Market are correct. Prices in the 01 June 2006 Day-Ahead Market are correct.

POWER DISPATCHERS NOTE SHEET
FORM 323-55 N 10-58

Division Security

Day & Date THURSDAY

☑ EST ☑ DST

Sheet No.

TIME	REMARKS
0001	Schenevus - Scranton
0047	N. Canaan - Taylorville & tripped
	and auto reclosed
0233	Dunbar - Gardner Hill tripped and
	auto reclosed
0533	Oneida - Johnsonburg #3 & tripped
	and auto reclosed
0713	PV [illegible] one Stage
0830	Reds Unstrung
0945	Return [illegible] From E. Stark - Carroll Branch 230 kv
10	Sta 80 [illegible] - Oak Grove 230 kv & Branch 230 kv Bypass Bkr 1
1044	Rotunda - Lake [illegible] Line Breakers
1057	Co [illegible] Power Mfg. Sodium Fluoride Co. Installation
	Johnsonburg - Ridgway #1
1102	Alert Starts 1101, Ack 1103, All Secy Reqd 1122
1312	Ack Red Alert Starts
1322	RPH Ack - 455
1323	Alert Ack - 512
1332	Alert Terminated
1439	RPH Ack - 438, Asbury Temp Alert Ack.
1048	Alert Terminated
1631	All Secy Contacted, All Ok, Terminate Alert Ack
	16 Bkrs at Co. Sta. 16 w/ 1
1736	OSW 6 o/s
1749	OSW 345 YAPS NORMAL
1840	Schenevus - Scranton
1950	Closed New Scotland RTU. Ops
	Secretary notified
2004	Cinco - Hunterstown Alert Terminated
2035	P. Carroll Hill Reactor taken OOS by CH

EXHIBIT NO._(PFP-7R)

Generation and Capacity Factor Comparison between
Base Case and Scenario 1 (Leeds-Pleasant Valley Out)
On June 8, 2007 Hour 19 by Unit
Zones A through K

Panels A and B

Panel A

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 8 by Unit

Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Sce1	DIF	Base	Sce1	DIF
	Total	NY West	A	4812	4868	65	64	(0)	3106	3099	(6)
	Total	NY Genese	B	1043	1060	84	84	0	873	873	0
	Total	NY Central	C	6592	6701	65	66	1	4311	4373	61
	Total	NY North	D	1311	1228	76	76	0	998	998	0
	Total	NY Mhk Valley	E	360	397	67	63	(4)	242	227	(15)
	Total	NY Capital	F	4506	4800	53	52	(1)	2388	2325	(63)
	Total	NY Hudson Valley	G	3339	3434	23	23	1	759	783	23
	Total	NY Millwood	H	2141	2173	97	97	0	2085	2085	0
	Total	NY Dunwoodie	I	0	0	0	0	0	0	0	0
	Total	NY N.Y.C.	J	10146	10941	36	36	0	3605	3605	0
	Total	NY Long Island	K	5177	5522	35	35	0	1810	1810	0
	Total	Zones A-F		18624	19054	64	64	(0)	11917	11895	(23)
	Total	Zones G-K		20803	22069	40	40	0	8259	8282	23
	Total	Zones G-I		5479	5606	52	52	0	2844	2867	23
	Total	Zone J		10146	10941	36	36	0	3605	3605	0
	Total	Zone K		5177	5522	35	35	0	1810	1810	0

Panel A
Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 8 by Unit
Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Scel	DIF	Base	Scel	DIF
311	Dunkirk 2	NY West	A	102	99	82	82	0	84	84	0
312	Dunkirk 1	NY West	A	96	100	82	82	0	79	79	0
313	Dunkirk 3	NY West	A	196	206	82	82	0	161	161	0
314	Dunkirk 4	NY West	A	203	196	82	82	0	167	167	0
490	Huntley 67	NY West	A	201	194	82	82	0	165	165	0
491	Huntley 68	NY West	A	200	198	82	82	0	165	165	0
537	Somerset - Kintig	NY West	A	692	692	82	82	0	569	569	0
685	NEW CC	NY West	A	0	1	82	82	0	0	0	0
686	NEW CC	NY West	A	0	1	82	82	0	0	0	0
706	Amer. Ref-Fuel 1	NY West	A	20	21	82	82	0	16	16	0
771	Lockport 1-4 CC Cogen	NY West	A	192	216	41	41	0	79	79	0
823	Oxbow Pwr- N.Tonaw	NY West	A	55	60	41	41	0	22	22	0
824	CHR-Niagara	NY West	A	53	53	0	0	0	0	0	0
1487	Amer. Ref-Fuel 2	NY West	A	20	21	82	82	0	16	16	0
1533	Indeck-Yerkes	NY West	A	48	58	41	41	0	20	20	0
1535	American Brass	NY West	A	62	62	41	41	0	25	25	0
1537	NEPA Energy (Ripley)	NY West	A	81	85	41	41	0	33	33	0
1550	Jamestown 7	NY West	A	37	47	0	0	0	0	0	0
1552	Jamestown 5	NY West	A	23	24	82	82	0	19	19	0
1553	Jamestown 6	NY West	A	22	22	82	82	0	18	18	0
52077	POASHY01	NY West	A	2432	2432	58	58	0	1402	1402	0
1536	Indeck-Olean	NY West	A	78	84	82	74	(8)	64	58	(6)
104	Beebee GT	NY Genese	B	15	18	0	0	0	0	0	0
393	Ginna 1	NY Genese	B	595	595	100	100	0	595	595	0
693	NEW CC	NY Genese	B	0	1	82	82	0	0	0	0
703	Allegany CC (GT-ST)	NY Genese	B	62	62	41	41	0	25	25	0
949	Russell 1	NY Genese	B	45	46	82	82	0	37	37	0
950	Russell 2	NY Genese	B	64	65	82	82	0	53	53	0
951	Russell 3	NY Genese	B	64	65	82	82	0	53	53	0
952	Russell 4	NY Genese	B	76	78	82	82	0	63	63	0
1030	Station 9	NY Genese	B	16	18	0	0	0	0	0	0
1203	Sithe-Batavia	NY Genese	B	54	62	41	41	0	22	22	0
52082	ROGEHY01	NY Genese	B	51	52	48	48	0	24	24	0
866	Oswego 6	NY Central	C	801	835	0	21	21	0	165	165
13	Nine Mile Pt 1	NY Central	C	630	623	100	100	0	630	630	0
14	Nine Mile Pt 2	NY Central	C	1140	1161	100	100	0	1140	1140	0
362	Fitzpatrick 1	NY Central	C	852	856	100	100	0	852	852	0
402	Westover 7	NY Central	C	43	43	82	82	0	35	35	0
403	Westover 8	NY Central	C	83	84	82	82	0	68	68	0
438	Greenidge 3	NY Central	C	54	54	82	82	0	44	44	0

Panel A

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 8 by Unit

Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Sce1	DIF	Base	Sce1	DIF
439	Greenidge 4	NY Central	C	104	107	82	82	0	85	85	0
613	Cayuga 1	NY Central	C	152	152	82	82	0	125	125	0
614	Cayuga 2	NY Central	C	153	155	82	82	0	126	126	0
746	Fulton Cogn Assoc	NY Central	C	43	43	41	41	0	18	18	0
750	Project Orange 1	NY Central	C	41	45	0	0	0	0	0	0
757	Indeck-Oswego	NY Central	C	51	61	41	41	0	21	21	0
790	Onondaga Cogen	NY Central	C	79	81	41	41	0	32	32	0
812	Indeck-Silver Springs Cogen	NY Central	C	53	60	41	41	0	22	22	0
819	CHR-Syracuse	NY Central	C	93	101	82	82	0	76	76	0
820	Carr St.-E. Syr	NY Central	C	97	104	41	41	0	40	40	0
859	Onondaga County	NY Central	C	33	32	82	82	0	27	27	0
865	Oswego 5	NY Central	C	850	852	0	0	0	0	0	0
1488	Project Orange 2	NY Central	C	41	45	0	0	0	0	0	0
1539	Binghamton Cogen	NY Central	C	44	50	41	41	0	18	18	0
1554	Trigen-Syracuse Cogen	NY Central	C	76	78	82	82	0	63	63	0
1007	Sithe-Independence 1	NY Central	C	540	540	82	74	(8)	444	400	(44)
1740	Sithe-Independence 2	NY Central	C	540	540	82	71	(11)	444	385	(59)
806	Saranac Energy 1-3 CC Cogen	NY North	D	240	240	82	82	0	197	197	0
1204	Sithe-Massena	NY North	D	80	90	41	41	0	33	33	0
1555	Chateaugay Power	NY North	D	18	18	82	82	0	15	15	0
52058	MOSESHYD	NY North	D	858	760	81	81	0	697	697	0
52070	ORRUHY01	NY North	D	116	120	48	48	0	56	56	0
709	CHR-Beaver Falls	NY Mhk Valley	E	87	95	82	82	0	71	71	0
718	Lyonsdale Power	NY Mhk Valley	E	20	20	82	82	0	17	17	0
830	Fort Drum	NY Mhk Valley	E	53	53	82	82	0	43	43	0
1205	Sithe-Ogdensburg	NY Mhk Valley	E	78	87	41	41	0	32	32	0
1206	Sithe-Sterling	NY Mhk Valley	E	53	62	41	41	0	22	22	0
1538	Burrws-Little Falls	NY Mhk Valley	E	9	13	82	82	0	7	7	0
724	Carthage Paper	NY Mhk Valley	E	61	67	82	58	(25)	50	35	(15)
82	ATHENS CC1	NY Capital	F	490	540	82	82	0	403	403	0
114	Bethlehem NMPC 1	NY Capital	F	335	375	82	82	0	276	276	0
701	Adir-Resrce Recry	NY Capital	F	12	12	82	82	0	10	10	0
731	Indeck-Corinth Cogen	NY Capital	F	129	137	82	82	0	106	106	0
742	Fort Orange	NY Capital	F	67	73	41	41	0	28	28	0
760	Selkirk-I Cogen	NY Capital	F	85	98	82	82	0	70	70	0
811	Selkirk-II Cogen	NY Capital	F	275	323	82	82	0	226	226	0
1534	NSINS-S Glens Falls	NY Capital	F	61	67	82	82	0	50	50	0
1737	ATHENS CC2	NY Capital	F	490	540	82	82	0	403	403	0
1738	Bethlehem NMPC 2	NY Capital	F	335	375	82	82	0	276	276	0
51002	GILBOA01	NY Capital	F	1170	1170	0	0	0	0	0	0
52062	NEYEHY01	NY Capital	F	364	387	50	50	0	182	182	0
52065	NIMPHY01	NY Capital	F	615	625	48	48	0	296	296	0
802	Rensselaer Cogen	NY Capital	F	79	79	79	0	(79)	63	0	(63)

Panel A
Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 8 by Unit
Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Scel	DIF	Base	Scel	DIF
947	Roseton 1	NY Hudson Valley	G	605	615	21	24	4	124	148	23
121	Bowline 1	NY Hudson Valley	G	568	610	0	0	0	0	0	0
122	Bowline 2	NY Hudson Valley	G	605	608	0	0	0	0	0	0
218	Coxsackie GT	NY Hudson Valley	G	18	24	0	0	0	0	0	0
235	Danskammer 1	NY Hudson Valley	G	60	58	0	0	0	0	0	0
236	Danskammer 2	NY Hudson Valley	G	63	61	0	0	0	0	0	0
237	Danskammer 3	NY Hudson Valley	G	133	133	82	82	0	109	109	0
238	Danskammer 4	NY Hudson Valley	G	232	236	82	82	0	191	191	0
540	Lederle Cogen	NY Hudson Valley	G	15	21	82	82	0	12	12	0
561	Lovett 3	NY Hudson Valley	G	67	67	0	0	0	0	0	0
562	Lovett 4	NY Hudson Valley	G	171	165	82	82	0	141	141	0
743	DCCRA	NY Hudson Valley	G	9	9	82	82	0	7	7	0
946	Roseton 2	NY Hudson Valley	G	605	615	21	21	0	124	124	0
998	Shoemaker GT	NY Hudson Valley	G	36	43	0	0	0	0	0	0
1017	South Cairo	NY Hudson Valley	G	18	22	0	0	0	0	0	0
1547	Hillburn GT	NY Hudson Valley	G	36	47	0	0	0	0	0	0
52015	CEHGHY01	NY Hudson Valley	G	57	57	50	50	0	29	29	0
52051	MECHHY01	NY Hudson Valley	G	43	43	50	50	0	22	22	0
496	Indian Pt GT 3	NY Millwood	H	13	19	0	0	0	0	0	0
498	Indian Pt 2	NY Millwood	H	1016	1026	100	100	0	1016	1016	0
499	Indian Pt 3	NY Millwood	H	1027	1030	100	100	0	1027	1027	0
500	Indian Pt GT 1	NY Millwood	H	13	14	0	0	0	0	0	0
1549	Indian Pt GT 2	NY Millwood	H	20	31	0	0	0	0	0	0
1556	Wheelabrator Westchester	NY Millwood	H	51	53	82	82	0	42	42	0
6	59 St. GT 1	NY N.Y.C.	J	16	23	0	0	0	0	0	0
8	74 St. GT 1	NY N.Y.C.	J	14	16	0	0	0	0	0	0
9	74 St. GT 2	NY N.Y.C.	J	15	18	0	0	0	0	0	0
51	Arthur Kill GT 1	NY N.Y.C.	J	15	17	0	0	0	0	0	0
52	Arthur Kill ST 2	NY N.Y.C.	J	348	348	45	45	0	157	157	0
53	Arthur Kill ST 3	NY N.Y.C.	J	493	493	33	33	0	162	162	0
55	Astoria GT 05	NY N.Y.C.	J	12	16	0	0	0	0	0	0
57	Astoria 2	NY N.Y.C.	J	176	178	0	0	0	0	0	0
58	Astoria 3	NY N.Y.C.	J	370	377	21	21	0	76	76	0
59	Astoria 4	NY N.Y.C.	J	370	377	21	21	0	76	76	0
60	Astoria 5	NY N.Y.C.	J	365	369	21	21	0	75	75	0
61	Astoria GT 07	NY N.Y.C.	J	14	16	0	0	0	0	0	0
62	Astoria GT 08	NY N.Y.C.	J	13	16	0	0	0	0	0	0
63	Astoria GT 09	NY N.Y.C.	J	13	16	0	0	0	0	0	0
64	Astoria GT 10	NY N.Y.C.	J	22	27	0	0	0	0	0	0
65	Astoria GT 11	NY N.Y.C.	J	21	39	0	0	0	0	0	0
66	Astoria GT 12	NY N.Y.C.	J	20	28	0	0	0	0	0	0
67	Astoria GT 13	NY N.Y.C.	J	20	28	0	0	0	0	0	0
68	Astoria GT 2-1	NY N.Y.C.	J	40	48	0	0	0	0	0	0
69	Astoria GT 2-2	NY N.Y.C.	J	40	48	0	0	0	0	0	0
70	Astoria GT 2-3	NY N.Y.C.	J	39	48	0	0	0	0	0	0

Panel A
Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 8 by Unit
Zones A through K

ID	Unit	Zone	Operations								
			Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)			
					Base	Sce1	DIF	Base	Sce1	DIF	
71	Astoria GT 2-4	NY N.Y.C. J	41	48	0	0	0	0	0	0	
72	Astoria GT 3-1	NY N.Y.C. J	39	48	0	0	0	0	0	0	
73	Astoria GT 3-2	NY N.Y.C. J	42	48	0	0	0	0	0	0	
74	Astoria GT 3-3	NY N.Y.C. J	40	47	0	0	0	0	0	0	
75	Astoria GT 3-4	NY N.Y.C. J	39	47	0	0	0	0	0	0	
76	Astoria GT 4-1	NY N.Y.C. J	39	49	0	0	0	0	0	0	
77	Astoria GT 4-2	NY N.Y.C. J	41	49	0	0	0	0	0	0	
78	Astoria GT 4-3	NY N.Y.C. J	41	50	0	0	0	0	0	0	
79	Astoria GT 4-4	NY N.Y.C. J	41	49	0	0	0	0	0	0	
318	East River 6	NY N.Y.C. J	133	135	0	0	0	0	0	0	
405	Gowanus 1-1	NY N.Y.C. J	16	23	0	0	0	0	0	0	
406	Gowanus 1-2	NY N.Y.C. J	15	21	0	0	0	0	0	0	
407	Gowanus 1-3	NY N.Y.C. J	15	21	0	0	0	0	0	0	
408	Gowanus 1-4	NY N.Y.C. J	16	22	0	0	0	0	0	0	
409	Gowanus 1-5	NY N.Y.C. J	15	22	0	0	0	0	0	0	
410	Gowanus 1-6	NY N.Y.C. J	18	23	0	0	0	0	0	0	
411	Gowanus 1-7	NY N.Y.C. J	16	23	0	0	0	0	0	0	
412	Gowanus 1-8	NY N.Y.C. J	18	22	0	0	0	0	0	0	
413	Gowanus 2-1	NY N.Y.C. J	17	21	0	0	0	0	0	0	
414	Gowanus 2-2	NY N.Y.C. J	14	20	0	0	0	0	0	0	
415	Gowanus 2-3	NY N.Y.C. J	15	19	0	0	0	0	0	0	
416	Gowanus 2-4	NY N.Y.C. J	17	21	0	0	0	0	0	0	
417	Gowanus 2-5	NY N.Y.C. J	18	22	0	0	0	0	0	0	
418	Gowanus 2-6	NY N.Y.C. J	17	21	0	0	0	0	0	0	
419	Gowanus 2-7	NY N.Y.C. J	17	20	0	0	0	0	0	0	
420	Gowanus 2-8	NY N.Y.C. J	16	20	0	0	0	0	0	0	
421	Gowanus 3-1	NY N.Y.C. J	14	17	0	0	0	0	0	0	
422	Gowanus 3-2	NY N.Y.C. J	15	22	0	0	0	0	0	0	
423	Gowanus 3-3	NY N.Y.C. J	15	21	0	0	0	0	0	0	
424	Gowanus 3-4	NY N.Y.C. J	18	19	0	0	0	0	0	0	
425	Gowanus 3-5	NY N.Y.C. J	18	22	0	0	0	0	0	0	
426	Gowanus 3-6	NY N.Y.C. J	17	21	0	0	0	0	0	0	
427	Gowanus 3-7	NY N.Y.C. J	18	19	0	0	0	0	0	0	
428	Gowanus 3-8	NY N.Y.C. J	16	20	0	0	0	0	0	0	
429	Gowanus 4-1	NY N.Y.C. J	16	22	0	0	0	0	0	0	
430	Gowanus 4-2	NY N.Y.C. J	17	22	0	0	0	0	0	0	
431	Gowanus 4-3	NY N.Y.C. J	14	20	0	0	0	0	0	0	
432	Gowanus 4-4	NY N.Y.C. J	17	23	0	0	0	0	0	0	
433	Gowanus 4-5	NY N.Y.C. J	16	23	0	0	0	0	0	0	
434	Gowanus 4-6	NY N.Y.C. J	17	23	0	0	0	0	0	0	
435	Gowanus 4-7	NY N.Y.C. J	15	21	0	0	0	0	0	0	
436	Gowanus 4-8	NY N.Y.C. J	15	22	0	0	0	0	0	0	
479	Hudson Ave 3	NY N.Y.C. J	13	17	0	0	0	0	0	0	
480	Hudson Ave 4	NY N.Y.C. J	14	16	0	0	0	0	0	0	

Panel A

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 8 by Unit

Zones A through K

ID	Unit	Zone	Operations							
			Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
					Base	Sce1	DIF	Base	Sce1	DIF
481	Hudson Ave 5	NY N.Y.C. J	13	17	0	0	0	0	0	0
482	Hudson Avenue 10	NY N.Y.C. J	65	65	0	0	0	0	0	0
646	Narrows 1-1	NY N.Y.C. J	17	21	0	0	0	0	0	0
647	Narrows 1-2	NY N.Y.C. J	18	24	0	0	0	0	0	0
648	Narrows 1-3	NY N.Y.C. J	16	20	0	0	0	0	0	0
649	Narrows 1-4	NY N.Y.C. J	19	25	0	0	0	0	0	0
650	Narrows 1-5	NY N.Y.C. J	15	21	0	0	0	0	0	0
651	Narrows 1-6	NY N.Y.C. J	17	22	0	0	0	0	0	0
652	Narrows 1-7	NY N.Y.C. J	17	20	0	0	0	0	0	0
653	Narrows 1-8	NY N.Y.C. J	17	21	0	0	0	0	0	0
654	Narrows 2-1	NY N.Y.C. J	16	22	0	0	0	0	0	0
655	Narrows 2-2	NY N.Y.C. J	16	21	0	0	0	0	0	0
656	Narrows 2-3	NY N.Y.C. J	17	24	0	0	0	0	0	0
657	Narrows 2-4	NY N.Y.C. J	15	20	0	0	0	0	0	0
658	Narrows 2-5	NY N.Y.C. J	16	21	0	0	0	0	0	0
659	Narrows 2-6	NY N.Y.C. J	16	20	0	0	0	0	0	0
660	Narrows 2-7	NY N.Y.C. J	17	22	0	0	0	0	0	0
661	Narrows 2-8	NY N.Y.C. J	18	23	0	0	0	0	0	0
674	NEW CC	NY N.Y.C. J	0	1	82	82	0	0	0	0
713	Bkln Navy Yard	NY N.Y.C. J	260	293	82	82	0	214	214	0
715	Cogen Tech-Linden CC1	NY N.Y.C. J	375	400	82	82	0	308	308	0
758	KIAC (JFK) 1	NY N.Y.C. J	45	45	82	82	0	37	37	0
759	KIAC (JFK) 2	NY N.Y.C. J	45	45	82	82	0	37	37	0
890	Poletti 1	NY N.Y.C. J	855	855	33	33	0	281	281	0
912	Ravenswood 4	NY N.Y.C. J	15	16	0	0	0	0	0	0
913	Ravenswood 5	NY N.Y.C. J	14	19	0	0	0	0	0	0
914	Ravenswood 6	NY N.Y.C. J	15	18	0	0	0	0	0	0
915	Ravenswood 7	NY N.Y.C. J	15	19	0	0	0	0	0	0
916	Ravenswood 8	NY N.Y.C. J	19	24	0	0	0	0	0	0
917	Ravenswood 9	NY N.Y.C. J	20	25	0	0	0	0	0	0
918	Ravenswood 10	NY N.Y.C. J	21	24	0	0	0	0	0	0
919	Ravenswood 11	NY N.Y.C. J	20	23	0	0	0	0	0	0
920	Ravenswood 2-1	NY N.Y.C. J	40	47	0	0	0	0	0	0
921	Ravenswood 2-2	NY N.Y.C. J	38	46	0	0	0	0	0	0
922	Ravenswood 2-3	NY N.Y.C. J	38	42	0	0	0	0	0	0
923	Ravenswood 2-4	NY N.Y.C. J	39	45	0	0	0	0	0	0
924	Ravenswood 3-1	NY N.Y.C. J	38	44	0	0	0	0	0	0
925	Ravenswood 3-2	NY N.Y.C. J	36	45	0	0	0	0	0	0
926	Ravenswood 3-3	NY N.Y.C. J	38	45	0	0	0	0	0	0
927	Ravenswood 3-4	NY N.Y.C. J	38	45	0	0	0	0	0	0
928	Ravenswood GT1	NY N.Y.C. J	11	11	0	0	0	0	0	0

Panel A

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 8 by Unit

Zones A through K

ID	Unit	Zone		Operations								
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)			
						Base	Sce1	DIF	Base	Sce1	DIF	
1126	York-Warbasse 1-2	NY N.Y.C.	J	22	21	0	0	0	0	0	0	
1172	SCS Astoria Energy 1	NY N.Y.C.	J	450	500	82	82	0	370	370	0	
1178	East River Repowering	NY N.Y.C.	J	288	360	82	82	0	237	237	0	
1211	Poletti Expansion	NY N.Y.C.	J	460	500	82	82	0	378	378	0	
1465	Harlem River 1	NY N.Y.C.	J	46	46	0	0	0	0	0	0	
1466	Harlem River 2	NY N.Y.C.	J	46	47	0	0	0	0	0	0	
1467	Hellgate 1	NY N.Y.C.	J	44	47	0	0	0	0	0	0	
1468	Hellgate 2	NY N.Y.C.	J	44	47	0	0	0	0	0	0	
1469	Kent	NY N.Y.C.	J	47	47	0	0	0	0	0	0	
1470	Pouch	NY N.Y.C.	J	47	48	82	82	0	39	39	0	
1490	Cogen Tech-Linden CC2	NY N.Y.C.	J	375	400	82	82	0	308	308	0	
1542	Gowanus 5	NY N.Y.C.	J	46	46	0	0	0	0	0	0	
1543	Gowanus 6	NY N.Y.C.	J	46	47	0	0	0	0	0	0	
1544	Vernon Blvd 2	NY N.Y.C.	J	46	46	82	82	0	38	38	0	
1545	Vernon Blvd 3	NY N.Y.C.	J	46	46	82	82	0	38	38	0	
1747	Kent NYC Energy I	NY N.Y.C.	J	79	79	0	0	0	0	0	0	
84001	Ravenswood 100	NY N.Y.C.	J	385	379	30	30	0	114	114	0	
84002	Ravenswood 200	NY N.Y.C.	J	390	390	28	28	0	109	109	0	
84003	Ravenswood 300	NY N.Y.C.	J	980	980	25	25	0	242	242	0	
84004	Ravenswood 400	NY N.Y.C.	J	225	250	82	82	0	185	185	0	
319	East River 7	NY N.Y.C.	J	183	190	67	67	(0)	122	122	(0)	
85	Barrett 1	NY Long Island	K	197	194	21	21	0	41	41	0	
86	Barrett 2	NY Long Island	K	194	195	74	74	0	144	144	0	
87	Barrett 3	NY Long Island	K	17	20	0	0	0	0	0	0	
88	Barrett 4	NY Long Island	K	17	19	0	0	0	0	0	0	
89	Barrett 5	NY Long Island	K	17	19	0	0	0	0	0	0	
90	Barrett 6	NY Long Island	K	17	19	0	0	0	0	0	0	
91	Barrett 7	NY Long Island	K	17	19	0	0	0	0	0	0	
92	Barrett 8	NY Long Island	K	17	19	0	0	0	0	0	0	
93	Barrett 9	NY Long Island	K	42	48	0	0	0	0	0	0	
94	Barrett 10	NY Long Island	K	44	48	0	0	0	0	0	0	
95	Barrett 11	NY Long Island	K	43	49	0	0	0	0	0	0	
96	Barrett 12	NY Long Island	K	44	50	0	0	0	0	0	0	
97	Barrett GT	NY Long Island	K	17	19	0	0	0	0	0	0	
98	Barrett GT 2	NY Long Island	K	17	19	0	0	0	0	0	0	
183	Flynn	NY Long Island	K	136	164	82	82	0	112	112	0	
297	Babylon (RR)	NY Long Island	K	14	15	82	82	0	12	12	0	
315	East Hampton 1	NY Long Island	K	22	24	0	0	0	0	0	0	
357	Far Rockaway 4	NY Long Island	K	110	106	45	45	0	50	50	0	
394	Glenwood 1	NY Long Island	K	15	18	0	0	0	0	0	0	
395	Glenwood 2	NY Long Island	K	51	64	0	0	0	0	0	0	
396	Glenwood 3	NY Long Island	K	55	62	0	0	0	0	0	0	
397	Glenwood 4	NY Long Island	K	112	108	21	21	0	23	23	0	
398	Glenwood 5	NY Long Island	K	117	96	45	45	0	53	53	0	

Panel A
Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 8 by Unit
Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Sce1	DIF	Base	Sce1	DIF
453	Holtsville 1	NY Long Island	K	54	62	0	0	0	0	0	0
454	Holtsville 2	NY Long Island	K	50	62	0	0	0	0	0	0
455	Holtsville 3	NY Long Island	K	52	62	0	0	0	0	0	0
456	Holtsville 4	NY Long Island	K	56	62	0	0	0	0	0	0
457	Holtsville 5	NY Long Island	K	52	63	0	0	0	0	0	0
458	Holtsville 6	NY Long Island	K	56	66	0	0	0	0	0	0
459	Holtsville 7	NY Long Island	K	52	60	0	0	0	0	0	0
460	Holtsville 8	NY Long Island	K	52	67	0	0	0	0	0	0
461	Holtsville 9	NY Long Island	K	56	65	0	0	0	0	0	0
462	Holtsville 10	NY Long Island	K	55	67	0	0	0	0	0	0
492	Huntington	NY Long Island	K	24	23	82	82	0	19	19	0
678	NEW CC	NY Long Island	K	0	1	82	82	0	0	0	0
754	Bronx Zoo	NY Long Island	K	2	2	0	0	0	0	0	0
775	Hempstead (RR)	NY Long Island	K	69	71	82	82	0	56	56	0
814	Trigen-NDEC Cogen	NY Long Island	K	44	55	82	82	0	36	36	0
818	Bethpage	NY Long Island	K	55	56	82	82	0	45	45	0
839	Northport 1	NY Long Island	K	371	376	58	58	0	214	214	0
840	Northport 2	NY Long Island	K	383	367	33	33	0	126	126	0
841	Northport 3	NY Long Island	K	370	358	70	70	0	259	259	0
842	Northport 4	NY Long Island	K	396	377	33	33	0	130	130	0
843	Northport GT	NY Long Island	K	15	18	0	0	0	0	0	0
893	Port Jefferson 3	NY Long Island	K	189	184	45	45	0	86	86	0
894	Port Jefferson 4	NY Long Island	K	196	192	45	45	0	89	89	0
906	Port Jefferson GT	NY Long Island	K	15	19	0	0	0	0	0	0
999	Shoreham 1	NY Long Island	K	48	62	0	0	0	0	0	0
1000	Shoreham 2	NY Long Island	K	17	21	0	0	0	0	0	0
1018	S Hampton 1	NY Long Island	K	9	14	0	0	0	0	0	0
1024	Southold 1	NY Long Island	K	14	17	0	0	0	0	0	0
1074	West Babylon 4	NY Long Island	K	48	62	0	0	0	0	0	0
1075	Wading River 2	NY Long Island	K	78	97	0	0	0	0	0	0
1076	Wading River 3	NY Long Island	K	81	102	0	0	0	0	0	0
1077	Wading River 1	NY Long Island	K	78	99	0	0	0	0	0	0
1393	Far Rockaway 1	NY Long Island	K	51	61	0	0	0	0	0	0
1394	Far Rockaway 2	NY Long Island	K	54	55	0	0	0	0	0	0
1395	PP& L Pilgrim GT1	NY Long Island	K	37	50	0	0	0	0	0	0
1396	PP& L Pilgrim GT2	NY Long Island	K	37	50	0	0	0	0	0	0
1397	PP&L Shoreham GT3	NY Long Island	K	40	50	82	82	0	33	33	0
1438	PP&L Shoreham GT4	NY Long Island	K	40	50	82	82	0	33	33	0
1439	Port Jefferson GT 2	NY Long Island	K	38	49	0	0	0	0	0	0
1440	Port Jefferson GT 3	NY Long Island	K	39	50	0	0	0	0	0	0
1445	Glenwood GT4	NY Long Island	K	39	47	82	82	0	32	32	0
1446	Glenwood GT5	NY Long Island	K	38	46	0	0	0	0	0	0

Panel A
Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 8 by Unit
Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Scel	DIF	Base	Scel	DIF
1447	Greenport GT1	NY Long Island	K	49	54	0	0	0	0	0	0
1448	Bethpage GT4	NY Long Island	K	49	50	82	82	0	40	40	0
1531	Charles P Keller 10	NY Long Island	K	31	31	0	0	0	0	0	0
1541	Brentwood	NY Long Island	K	47	47	82	82	0	39	39	0
1548	Freeport 2-3	NY Long Island	K	43	43	0	0	0	0	0	0
1557	Islip(RR)	NY Long Island	K	10	9	82	82	0	8	8	0
8777	Bethpage 3	NY Long Island	K	80	80	82	82	0	66	66	0
8878	Pinelawn 1	NY Long Island	K	80	80	82	82	0	66	66	0
84005	Stony Brook GT	NY Long Island	K	9	20	0	0	0	0	0	0
82221	HQ-NYISO			1039	1039	72	72	0	751	751	0
82222	IMO-NYISO			1418	1418	25	25	0	355	355	0
82223	ISONE-NYISO			173	173	226	226	0	391	391	0
82224	PJM-NYISO			991	991	61	61	0	609	609	0
82225	CROSS SOUND NY			305	305	98	98	0	299	299	0
82256	Neptune LI-PJM			660	660	0	0	0	0	0	0

Panel B

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 19 by Unit
Zones A through K

ID	Unit	Zone		Operations								
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)			
						Base	Scel	DIF	Base	Scel	DIF	
	Total	NY West	A	4812	4868	89	86	(3)	4290	4136	(155)	
	Total	NY Genese	B	1043	1060	88	84	(5)	920	873	(48)	
	Total	NY Central	C	6592	6701	68	68	0	4462	4488	26	
	Total	NY North	D	1311	1228	79	76	(3)	1031	998	(33)	
	Total	NY Mhk Valley	E	360	397	82	67	(15)	296	242	(54)	
	Total	NY Capital	F	4506	4800	54	53	(1)	2418	2390	(28)	
	Total	NY Hudson Valley	G	3339	3434	32	38	6	1058	1254	196	
	Total	NY Millwood	H	2141	2173	97	97	0	2085	2085	0	
	Total	NY Dunwoodie	I	0	0	0	0	0	0	0	0	
	Total	NY N.Y.C.	J	10146	10941	45	46	1	4590	4685	95	
	Total	NY Long Island	K	5177	5522	55	55	0	2839	2839	0	
	Total	Zones A-F		18624	19054	72	70	(2)	13417	13127	(290)	
	Total	Zones G-K		20803	22069	51	52	1	10572	10863	290	
	Total	Zones G-I		5479	5606	57	61	4	3143	3339	196	
	Total	Zone J		10146	10941	45	46	1	4590	4685	95	
	Total	Zone K		5177	5522	55	55	0	2839	2839	0	

Panel B
Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 19 by Unit
Zones A through K

ID	Unit	Zone		Operations								
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Sce1	DIF	Base	Sce1	DIF
311	Dunkirk 2	NY West	A	102	99	82	82	0	84	84	0
312	Dunkirk 1	NY West	A	96	100	82	82	0	79	79	0
313	Dunkirk 3	NY West	A	196	206	82	82	0	161	161	0
314	Dunkirk 4	NY West	A	203	196	82	82	0	167	167	0
490	Huntley 67	NY West	A	201	194	82	82	0	165	165	0
491	Huntley 68	NY West	A	200	198	82	82	0	165	165	0
537	Somerset - Kintig	NY West	A	692	692	82	82	0	569	569	0
685	NEW CC	NY West	A	0	1	82	82	0	0	0	0
686	NEW CC	NY West	A	0	1	82	82	0	0	0	0
706	Amer. Ref-Fuel 1	NY West	A	20	21	82	82	0	16	16	0
824	CHR-Niagara	NY West	A	53	53	0	0	0	0	0	0
1487	Amer. Ref-Fuel 2	NY West	A	20	21	82	82	0	16	16	0
1535	American Brass	NY West	A	62	62	41	41	0	25	25	0
1536	Indeck-Olean	NY West	A	78	84	82	82	0	64	64	0
1550	Jamestown 7	NY West	A	37	47	0	0	0	0	0	0
1552	Jamestown 5	NY West	A	23	24	82	82	0	19	19	0
1553	Jamestown 6	NY West	A	22	22	82	82	0	18	18	0
52077	POASHY01	NY West	A	2432	2432	100	100	0	2432	2432	0
1533	Indeck-Yerkes	NY West	A	48	58	82	41	(41)	39	20	(20)
823	Oxbow Pwr- N.Tonaw	NY West	A	55	60	82	41	(41)	45	22	(22)
1537	NEPA Energy (Ripley)	NY West	A	81	85	82	41	(41)	67	33	(33)
771	Lockport 1-4 CC Cogen	NY West	A	192	216	82	41	(41)	158	79	(79)
104	Beebee GT	NY Genese	B	15	18	0	0	0	0	0	0
393	Ginna 1	NY Genese	B	595	595	100	100	0	595	595	0
693	NEW CC	NY Genese	B	0	1	82	82	0	0	0	0
949	Russell 1	NY Genese	B	45	46	82	82	0	37	37	0
950	Russell 2	NY Genese	B	64	65	82	82	0	53	53	0
951	Russell 3	NY Genese	B	64	65	82	82	0	53	53	0
952	Russell 4	NY Genese	B	76	78	82	82	0	63	63	0
1030	Station 9	NY Genese	B	16	18	0	0	0	0	0	0
52082	ROGEHY01	NY Genese	B	51	52	48	48	0	24	24	0
1203	Sithe-Batavia	NY Genese	B	54	62	82	41	(41)	44	22	(22)
703	Allegany CC (GT-ST)	NY Genese	B	62	62	82	41	(41)	51	25	(25)
866	Oswego 6	NY Central	C	801	835	0	21	21	0	165	165
13	Nine Mile Pt 1	NY Central	C	630	623	100	100	0	630	630	0
14	Nine Mile Pt 2	NY Central	C	1140	1161	100	100	0	1140	1140	0
362	Fitzpatrick 1	NY Central	C	852	856	100	100	0	852	852	0
402	Westover 7	NY Central	C	43	43	82	82	0	35	35	0
403	Westover 8	NY Central	C	83	84	82	82	0	68	68	0
438	Greenidge 3	NY Central	C	54	54	82	82	0	44	44	0

Panel B

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 19 by Unit
Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Sce1	DIF	Base	Sce1	DIF
439	Greenidge 4	NY Central	C	104	107	82	82	0	85	85	0
613	Cayuga 1	NY Central	C	152	152	82	82	0	125	125	0
614	Cayuga 2	NY Central	C	153	155	82	82	0	126	126	0
750	Project Orange 1	NY Central	C	41	45	0	0	0	0	0	0
819	CHR-Syracuse	NY Central	C	93	101	82	82	0	76	76	0
859	Onondaga County	NY Central	C	33	32	82	82	0	27	27	0
865	Oswego 5	NY Central	C	850	852	0	0	0	0	0	0
1007	Sithe-Independence 1	NY Central	C	540	540	82	82	0	444	444	0
1488	Project Orange 2	NY Central	C	41	45	0	0	0	0	0	0
1554	Trigen-Syracuse Cogen	NY Central	C	76	78	82	82	0	63	63	0
1740	Sithe-Independence 2	NY Central	C	540	540	82	82	0	444	444	0
812	Indeck-Silver Springs Cogen	NY Central	C	53	60	82	64	(18)	44	34	(9)
746	Fulton Cogn Assoc	NY Central	C	43	43	82	41	(41)	35	18	(18)
1539	Binghamton Cogen	NY Central	C	44	50	82	41	(41)	36	18	(18)
757	Indeck-Oswego	NY Central	C	51	61	82	41	(41)	42	21	(21)
790	Onondaga Cogen	NY Central	C	79	81	82	41	(41)	65	32	(32)
820	Carr St.-E. Syr	NY Central	C	97	104	82	41	(41)	80	40	(40)
806	Saranac Energy 1-3 CC Cogen	NY North	D	240	240	82	82	0	197	197	0
1555	Chateaugay Power	NY North	D	18	18	82	82	0	15	15	0
52058	MOSESHYD	NY North	D	858	760	81	81	0	697	697	0
52070	ORRUHY01	NY North	D	116	120	48	48	0	56	56	0
1204	Sithe-Massena	NY North	D	80	90	82	41	(41)	66	33	(33)
709	CHR-Beaver Falls	NY Mhk Valley	E	87	95	82	82	0	71	71	0
718	Lyonsdale Power	NY Mhk Valley	E	20	20	82	82	0	17	17	0
724	Carthage Paper	NY Mhk Valley	E	61	67	82	82	0	50	50	0
830	Fort Drum	NY Mhk Valley	E	53	53	82	82	0	43	43	0
1538	Burrws-Little Falls	NY Mhk Valley	E	9	13	82	82	0	7	7	0
1206	Sithe-Sterling	NY Mhk Valley	E	53	62	82	41	(41)	44	22	(22)
1205	Sithe-Ogdensburg	NY Mhk Valley	E	78	87	82	41	(41)	64	32	(32)
82	ATHENS CC1	NY Capital	F	490	540	82	82	0	403	403	0
114	Bethlehem NMPC 1	NY Capital	F	335	375	82	82	0	276	276	0
701	Adir-Resrce Recry	NY Capital	F	12	12	82	82	0	10	10	0
731	Indeck-Corinth Cogen	NY Capital	F	129	137	82	82	0	106	106	0
760	Selkirk-I Cogen	NY Capital	F	85	98	82	82	0	70	70	0
802	Rensselaer Cogen	NY Capital	F	79	79	82	82	0	65	65	0
811	Selkirk-II Cogen	NY Capital	F	275	323	82	82	0	226	226	0
1534	NSINS-S Glens Falls	NY Capital	F	61	67	82	82	0	50	50	0
1737	ATHENS CC2	NY Capital	F	490	540	82	82	0	403	403	0
1738	Bethlehem NMPC 2	NY Capital	F	335	375	82	82	0	276	276	0
51002	GILBOA01	NY Capital	F	1170	1170	0	0	0	0	0	0
52062	NEYEHY01	NY Capital	F	364	387	50	50	0	182	182	0
52065	NIMPHY01	NY Capital	F	615	625	48	48	0	296	296	0
742	Fort Orange	NY Capital	F	67	73	82	41	(41)	55	28	(28)

Panel B
Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 19 by Unit
Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Sce1	DIF	Base	Sce1	DIF
947	Roseton 1	NY Hudson Valley	G	605	615	45	74	29	274	448	174
946	Roseton 2	NY Hudson Valley	G	605	615	45	49	4	274	295	21
121	Bowline 1	NY Hudson Valley	G	568	610	0	0	0	0	0	0
122	Bowline 2	NY Hudson Valley	G	605	608	0	0	0	0	0	0
218	Coxsackie GT	NY Hudson Valley	G	18	24	0	0	0	0	0	0
235	Danskammer 1	NY Hudson Valley	G	60	58	0	0	0	0	0	0
236	Danskammer 2	NY Hudson Valley	G	63	61	0	0	0	0	0	0
237	Danskammer 3	NY Hudson Valley	G	133	133	82	82	0	109	109	0
238	Danskammer 4	NY Hudson Valley	G	232	236	82	82	0	191	191	0
540	Lederle Cogen	NY Hudson Valley	G	15	21	82	82	0	12	12	0
561	Lovett 3	NY Hudson Valley	G	67	67	0	0	0	0	0	0
562	Lovett 4	NY Hudson Valley	G	171	165	82	82	0	141	141	0
743	DCCRA	NY Hudson Valley	G	9	9	82	82	0	7	7	0
998	Shoemaker GT	NY Hudson Valley	G	36	43	0	0	0	0	0	0
1017	South Cairo	NY Hudson Valley	G	18	22	0	0	0	0	0	0
1547	Hillburn GT	NY Hudson Valley	G	36	47	0	0	0	0	0	0
52015	CEHGHY01	NY Hudson Valley	G	57	57	50	50	0	29	29	0
52051	MECHHY01	NY Hudson Valley	G	43	43	50	50	0	22	22	0
496	Indian Pt GT 3	NY Millwood	H	13	19	0	0	0	0	0	0
498	Indian Pt 2	NY Millwood	H	1016	1026	100	100	0	1016	1016	0
499	Indian Pt 3	NY Millwood	H	1027	1030	100	100	0	1027	1027	0
500	Indian Pt GT 1	NY Millwood	H	13	14	0	0	0	0	0	0
1549	Indian Pt GT 2	NY Millwood	H	20	31	0	0	0	0	0	0
1556	Wheelabrator Westchester	NY Millwood	H	51	53	82	82	0	42	42	0
84001	Ravenswood 100	NY N.Y.C.	J	385	379	49	74	25	188	285	97
6	59 St. GT 1	NY N.Y.C.	J	16	23	0	0	0	0	0	0
8	74 St. GT 1	NY N.Y.C.	J	14	16	0	0	0	0	0	0
9	74 St. GT 2	NY N.Y.C.	J	15	18	0	0	0	0	0	0
51	Arthur Kill GT 1	NY N.Y.C.	J	15	17	0	0	0	0	0	0
52	Arthur Kill ST 2	NY N.Y.C.	J	348	348	74	74	0	258	258	0
53	Arthur Kill ST 3	NY N.Y.C.	J	493	493	45	45	0	223	223	0
55	Astoria GT 05	NY N.Y.C.	J	12	16	0	0	0	0	0	0
57	Astoria 2	NY N.Y.C.	J	176	178	0	0	0	0	0	0
58	Astoria 3	NY N.Y.C.	J	370	377	21	21	0	76	76	0
59	Astoria 4	NY N.Y.C.	J	370	377	21	21	0	76	76	0
60	Astoria 5	NY N.Y.C.	J	365	369	21	21	0	75	75	0
61	Astoria GT 07	NY N.Y.C.	J	14	16	0	0	0	0	0	0
62	Astoria GT 08	NY N.Y.C.	J	13	16	0	0	0	0	0	0
63	Astoria GT 09	NY N.Y.C.	J	13	16	0	0	0	0	0	0
64	Astoria GT 10	NY N.Y.C.	J	22	27	0	0	0	0	0	0
65	Astoria GT 11	NY N.Y.C.	J	21	39	0	0	0	0	0	0
66	Astoria GT 12	NY N.Y.C.	J	20	28	0	0	0	0	0	0
67	Astoria GT 13	NY N.Y.C.	J	20	28	0	0	0	0	0	0
68	Astoria GT 2-1	NY N.Y.C.	J	40	48	0	0	0	0	0	0

Panel B

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 19 by Unit
Zones A through K

ID	Unit	Zone	Operations								
			Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)			
					Base	Sce1	DIF	Base	Sce1	DIF	
69	Astoria GT 2-2	NY N.Y.C. J	40	48	0	0	0	0	0	0	
70	Astoria GT 2-3	NY N.Y.C. J	39	48	0	0	0	0	0	0	
71	Astoria GT 2-4	NY N.Y.C. J	41	48	0	0	0	0	0	0	
72	Astoria GT 3-1	NY N.Y.C. J	39	48	0	0	0	0	0	0	
73	Astoria GT 3-2	NY N.Y.C. J	42	48	0	0	0	0	0	0	
74	Astoria GT 3-3	NY N.Y.C. J	40	47	0	0	0	0	0	0	
75	Astoria GT 3-4	NY N.Y.C. J	39	47	0	0	0	0	0	0	
76	Astoria GT 4-1	NY N.Y.C. J	39	49	0	0	0	0	0	0	
77	Astoria GT 4-2	NY N.Y.C. J	41	49	0	0	0	0	0	0	
78	Astoria GT 4-3	NY N.Y.C. J	41	50	0	0	0	0	0	0	
79	Astoria GT 4-4	NY N.Y.C. J	41	49	0	0	0	0	0	0	
318	East River 6	NY N.Y.C. J	133	135	0	0	0	0	0	0	
319	East River 7	NY N.Y.C. J	183	190	74	74	0	135	135	0	
405	Gowanus 1-1	NY N.Y.C. J	16	23	0	0	0	0	0	0	
406	Gowanus 1-2	NY N.Y.C. J	15	21	0	0	0	0	0	0	
407	Gowanus 1-3	NY N.Y.C. J	15	21	0	0	0	0	0	0	
408	Gowanus 1-4	NY N.Y.C. J	16	22	0	0	0	0	0	0	
409	Gowanus 1-5	NY N.Y.C. J	15	22	0	0	0	0	0	0	
410	Gowanus 1-6	NY N.Y.C. J	18	23	0	0	0	0	0	0	
411	Gowanus 1-7	NY N.Y.C. J	16	23	0	0	0	0	0	0	
412	Gowanus 1-8	NY N.Y.C. J	18	22	0	0	0	0	0	0	
413	Gowanus 2-1	NY N.Y.C. J	17	21	0	0	0	0	0	0	
414	Gowanus 2-2	NY N.Y.C. J	14	20	0	0	0	0	0	0	
415	Gowanus 2-3	NY N.Y.C. J	15	19	0	0	0	0	0	0	
416	Gowanus 2-4	NY N.Y.C. J	17	21	0	0	0	0	0	0	
417	Gowanus 2-5	NY N.Y.C. J	18	22	0	0	0	0	0	0	
418	Gowanus 2-6	NY N.Y.C. J	17	21	0	0	0	0	0	0	
419	Gowanus 2-7	NY N.Y.C. J	17	20	0	0	0	0	0	0	
420	Gowanus 2-8	NY N.Y.C. J	16	20	0	0	0	0	0	0	
421	Gowanus 3-1	NY N.Y.C. J	14	17	0	0	0	0	0	0	
422	Gowanus 3-2	NY N.Y.C. J	15	22	0	0	0	0	0	0	
423	Gowanus 3-3	NY N.Y.C. J	15	21	0	0	0	0	0	0	
424	Gowanus 3-4	NY N.Y.C. J	18	19	0	0	0	0	0	0	
425	Gowanus 3-5	NY N.Y.C. J	18	22	0	0	0	0	0	0	
426	Gowanus 3-6	NY N.Y.C. J	17	21	0	0	0	0	0	0	
427	Gowanus 3-7	NY N.Y.C. J	18	19	0	0	0	0	0	0	
428	Gowanus 3-8	NY N.Y.C. J	16	20	0	0	0	0	0	0	
429	Gowanus 4-1	NY N.Y.C. J	16	22	0	0	0	0	0	0	
430	Gowanus 4-2	NY N.Y.C. J	17	22	0	0	0	0	0	0	
431	Gowanus 4-3	NY N.Y.C. J	14	20	0	0	0	0	0	0	
432	Gowanus 4-4	NY N.Y.C. J	17	23	0	0	0	0	0	0	
433	Gowanus 4-5	NY N.Y.C. J	16	23	0	0	0	0	0	0	
434	Gowanus 4-6	NY N.Y.C. J	17	23	0	0	0	0	0	0	
435	Gowanus 4-7	NY N.Y.C. J	15	21	0	0	0	0	0	0	

Panel B

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 19 by Unit

Zones A through K

ID	Unit	Zone	Operations							
			Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
					Base	Sce1	DIF	Base	Sce1	DIF
436	Gowanus 4-8	NY N.Y.C. J	15	22	0	0	0	0	0	0
479	Hudson Ave 3	NY N.Y.C. J	13	17	0	0	0	0	0	0
480	Hudson Ave 4	NY N.Y.C. J	14	16	0	0	0	0	0	0
481	Hudson Ave 5	NY N.Y.C. J	13	17	0	0	0	0	0	0
482	Hudson Avenue 10	NY N.Y.C. J	65	65	0	0	0	0	0	0
646	Narrows 1-1	NY N.Y.C. J	17	21	0	0	0	0	0	0
647	Narrows 1-2	NY N.Y.C. J	18	24	0	0	0	0	0	0
648	Narrows 1-3	NY N.Y.C. J	16	20	0	0	0	0	0	0
649	Narrows 1-4	NY N.Y.C. J	19	25	0	0	0	0	0	0
650	Narrows 1-5	NY N.Y.C. J	15	21	0	0	0	0	0	0
651	Narrows 1-6	NY N.Y.C. J	17	22	0	0	0	0	0	0
652	Narrows 1-7	NY N.Y.C. J	17	20	0	0	0	0	0	0
653	Narrows 1-8	NY N.Y.C. J	17	21	0	0	0	0	0	0
654	Narrows 2-1	NY N.Y.C. J	16	22	0	0	0	0	0	0
655	Narrows 2-2	NY N.Y.C. J	16	21	0	0	0	0	0	0
656	Narrows 2-3	NY N.Y.C. J	17	24	0	0	0	0	0	0
657	Narrows 2-4	NY N.Y.C. J	15	20	0	0	0	0	0	0
658	Narrows 2-5	NY N.Y.C. J	16	21	0	0	0	0	0	0
659	Narrows 2-6	NY N.Y.C. J	16	20	0	0	0	0	0	0
660	Narrows 2-7	NY N.Y.C. J	17	22	0	0	0	0	0	0
661	Narrows 2-8	NY N.Y.C. J	18	23	0	0	0	0	0	0
674	NEW CC	NY N.Y.C. J	0	1	82	82	0	0	0	0
713	Bkln Navy Yard	NY N.Y.C. J	260	293	82	82	0	214	214	0
715	Cogen Tech-Linden CC1	NY N.Y.C. J	375	400	82	82	0	308	308	0
758	KIAC (JFK) 1	NY N.Y.C. J	45	45	82	82	0	37	37	0
759	KIAC (JFK) 2	NY N.Y.C. J	45	45	82	82	0	37	37	0
890	Poletti 1	NY N.Y.C. J	855	855	21	21	0	176	176	0
912	Ravenswood 4	NY N.Y.C. J	15	16	0	0	0	0	0	0
913	Ravenswood 5	NY N.Y.C. J	14	19	0	0	0	0	0	0
914	Ravenswood 6	NY N.Y.C. J	15	18	0	0	0	0	0	0
915	Ravenswood 7	NY N.Y.C. J	15	19	0	0	0	0	0	0
916	Ravenswood 8	NY N.Y.C. J	19	24	0	0	0	0	0	0
917	Ravenswood 9	NY N.Y.C. J	20	25	0	0	0	0	0	0
918	Ravenswood 10	NY N.Y.C. J	21	24	0	0	0	0	0	0
919	Ravenswood 11	NY N.Y.C. J	20	23	0	0	0	0	0	0
920	Ravenswood 2-1	NY N.Y.C. J	40	47	0	0	0	0	0	0
921	Ravenswood 2-2	NY N.Y.C. J	38	46	0	0	0	0	0	0
922	Ravenswood 2-3	NY N.Y.C. J	38	42	0	0	0	0	0	0
923	Ravenswood 2-4	NY N.Y.C. J	39	45	0	0	0	0	0	0
924	Ravenswood 3-1	NY N.Y.C. J	38	44	0	0	0	0	0	0
925	Ravenswood 3-2	NY N.Y.C. J	36	45	0	0	0	0	0	0
926	Ravenswood 3-3	NY N.Y.C. J	38	45	0	0	0	0	0	0
927	Ravenswood 3-4	NY N.Y.C. J	38	45	0	0	0	0	0	0
928	Ravenswood GT1	NY N.Y.C. J	11	11	0	0	0	0	0	0

Panel B
Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 19 by Unit
Zones A through K

ID	Unit	Zone	Operations								
			Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)			
					Base	Sce1	DIF	Base	Sce1	DIF	
1126	York-Warbasse 1-2	NY N.Y.C. J	22	21	0	0	0	0	0	0	
1172	SCS Astoria Energy 1	NY N.Y.C. J	450	500	82	82	0	370	370	0	
1178	East River Repowering	NY N.Y.C. J	288	360	82	82	0	237	237	0	
1211	Poletti Expansion	NY N.Y.C. J	460	500	82	82	0	378	378	0	
1465	Harlem River 1	NY N.Y.C. J	46	46	0	0	0	0	0	0	
1466	Harlem River 2	NY N.Y.C. J	46	47	82	82	0	38	38	0	
1467	Hellgate 1	NY N.Y.C. J	44	47	82	82	0	36	36	0	
1468	Hellgate 2	NY N.Y.C. J	44	47	82	82	0	36	36	0	
1469	Kent	NY N.Y.C. J	47	47	0	0	0	0	0	0	
1470	Pouch	NY N.Y.C. J	47	48	82	82	0	39	39	0	
1490	Cogen Tech-Linden CC2	NY N.Y.C. J	375	400	82	82	0	308	308	0	
1543	Gowanus 6	NY N.Y.C. J	46	47	0	0	0	0	0	0	
1544	Vernon Blvd 2	NY N.Y.C. J	46	46	82	82	0	38	38	0	
1545	Vernon Blvd 3	NY N.Y.C. J	46	46	82	82	0	38	38	0	
84002	Ravenswood 200	NY N.Y.C. J	390	390	64	64	0	250	250	0	
84003	Ravenswood 300	NY N.Y.C. J	980	980	82	82	0	806	806	0	
84004	Ravenswood 400	NY N.Y.C. J	225	250	82	82	0	185	185	0	
1747	Kent NYC Energy I	NY N.Y.C. J	79	79	21	21	(0)	17	17	(0)	
1542	Gowanus 5	NY N.Y.C. J	46	46	20	17	(3)	9	8	(1)	
894	Port Jefferson 4	NY Long Island K	196	192	74	82	8	145	161	16	
398	Glenwood 5	NY Long Island K	117	96	74	82	8	87	96	9	
357	Far Rockaway 4	NY Long Island K	110	106	74	82	8	81	90	9	
397	Glenwood 4	NY Long Island K	112	108	74	76	2	83	85	3	
85	Barrett 1	NY Long Island K	197	194	74	74	0	146	146	0	
86	Barrett 2	NY Long Island K	194	195	82	82	0	160	160	0	
87	Barrett 3	NY Long Island K	17	20	0	0	0	0	0	0	
88	Barrett 4	NY Long Island K	17	19	0	0	0	0	0	0	
89	Barrett 5	NY Long Island K	17	19	0	0	0	0	0	0	
90	Barrett 6	NY Long Island K	17	19	0	0	0	0	0	0	
91	Barrett 7	NY Long Island K	17	19	0	0	0	0	0	0	
92	Barrett 8	NY Long Island K	17	19	0	0	0	0	0	0	
93	Barrett 9	NY Long Island K	42	48	0	0	0	0	0	0	
94	Barrett 10	NY Long Island K	44	48	0	0	0	0	0	0	
95	Barrett 11	NY Long Island K	43	49	0	0	0	0	0	0	
96	Barrett 12	NY Long Island K	44	50	0	0	0	0	0	0	
97	Barrett GT	NY Long Island K	17	19	0	0	0	0	0	0	
98	Barrett GT 2	NY Long Island K	17	19	0	0	0	0	0	0	
183	Flynn	NY Long Island K	136	164	82	82	0	112	112	0	
297	Babylon (RR)	NY Long Island K	14	15	82	82	0	12	12	0	
315	East Hampton 1	NY Long Island K	22	24	0	0	0	0	0	0	
394	Glenwood 1	NY Long Island K	15	18	0	0	0	0	0	0	
395	Glenwood 2	NY Long Island K	51	64	0	0	0	0	0	0	
396	Glenwood 3	NY Long Island K	55	62	0	0	0	0	0	0	
453	Holtsville 1	NY Long Island K	54	62	0	0	0	0	0	0	

Panel B

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 19 by Unit
Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Sce1	DIF	Base	Sce1	DIF
454	Holtsville 2	NY Long Island	K	50	62	0	0	0	0	0	0
455	Holtsville 3	NY Long Island	K	52	62	0	0	0	0	0	0
456	Holtsville 4	NY Long Island	K	56	62	0	0	0	0	0	0
457	Holtsville 5	NY Long Island	K	52	63	0	0	0	0	0	0
458	Holtsville 6	NY Long Island	K	56	66	0	0	0	0	0	0
459	Holtsville 7	NY Long Island	K	52	60	0	0	0	0	0	0
460	Holtsville 8	NY Long Island	K	52	67	0	0	0	0	0	0
461	Holtsville 9	NY Long Island	K	56	65	0	0	0	0	0	0
462	Holtsville 10	NY Long Island	K	55	67	0	0	0	0	0	0
492	Huntington	NY Long Island	K	24	23	82	82	0	19	19	0
678	NEW CC	NY Long Island	K	0	1	82	82	0	0	0	0
754	Bronx Zoo	NY Long Island	K	2	2	0	0	0	0	0	0
775	Hempstead (RR)	NY Long Island	K	69	71	82	82	0	56	56	0
814	Trigen-NDEC Cogen	NY Long Island	K	44	55	82	82	0	36	36	0
818	Bethpage	NY Long Island	K	55	56	82	82	0	45	45	0
839	Northport 1	NY Long Island	K	371	376	82	82	0	305	305	0
841	Northport 3	NY Long Island	K	370	358	82	82	0	304	304	0
843	Northport GT	NY Long Island	K	15	18	0	0	0	0	0	0
893	Port Jefferson 3	NY Long Island	K	189	184	82	82	0	155	155	0
906	Port Jefferson GT	NY Long Island	K	15	19	0	0	0	0	0	0
999	Shoreham 1	NY Long Island	K	48	62	0	0	0	0	0	0
1000	Shoreham 2	NY Long Island	K	17	21	0	0	0	0	0	0
1018	S Hampton 1	NY Long Island	K	9	14	0	0	0	0	0	0
1024	Southold 1	NY Long Island	K	14	17	0	0	0	0	0	0
1074	West Babylon 4	NY Long Island	K	48	62	0	0	0	0	0	0
1075	Wading River 2	NY Long Island	K	78	97	0	0	0	0	0	0
1076	Wading River 3	NY Long Island	K	81	102	0	0	0	0	0	0
1077	Wading River 1	NY Long Island	K	78	99	0	0	0	0	0	0
1393	Far Rockaway 1	NY Long Island	K	51	61	0	0	0	0	0	0
1394	Far Rockaway 2	NY Long Island	K	54	55	0	0	0	0	0	0
1395	PP& L Pilgrim GT1	NY Long Island	K	37	50	0	0	0	0	0	0
1396	PP& L Pilgrim GT2	NY Long Island	K	37	50	0	0	0	0	0	0
1397	PP&L Shoreham GT3	NY Long Island	K	40	50	82	82	0	33	33	0
1438	PP&L Shoreham GT4	NY Long Island	K	40	50	82	82	0	33	33	0
1439	Port Jefferson GT 2	NY Long Island	K	38	49	82	82	0	31	31	0
1440	Port Jefferson GT 3	NY Long Island	K	39	50	82	82	0	32	32	0
1445	Glenwood GT4	NY Long Island	K	39	47	82	82	0	32	32	0

Panel B

Generation and Capacity Factor Comparison between Base Case and Scenario 1 (Leeds-Pleasant Valley Out) on June 8, 2007 Hour 19 by Unit
Zones A through K

ID	Unit	Zone		Operations							
				Summer Capacity (MW)	Winter Capacity (MW)	Capacity Factor (%)			Generation (MWh)		
						Base	Sce1	DIF	Base	Sce1	DIF
1446	Glenwood GT5	NY Long Island	K	38	46	82	82	0	31	31	0
1447	Greenport GT1	NY Long Island	K	49	54	82	82	0	40	40	0
1448	Bethpage GT4	NY Long Island	K	49	50	82	82	0	40	40	0
1531	Charles P Keller 10	NY Long Island	K	31	31	0	0	0	0	0	0
1541	Brentwood	NY Long Island	K	47	47	82	82	0	39	39	0
1548	Freeport 2-3	NY Long Island	K	43	43	0	0	0	0	0	0
1557	Islip(RR)	NY Long Island	K	10	9	82	82	0	8	8	0
8777	Bethpage 3	NY Long Island	K	80	80	82	82	0	66	66	0
8878	Pinelawn 1	NY Long Island	K	80	80	82	82	0	66	66	0
84005	Stony Brook GT	NY Long Island	K	9	20	0	0	0	0	0	0
842	Northport 4	NY Long Island	K	396	377	82	81	(1)	326	320	(6)
840	Northport 2	NY Long Island	K	383	367	82	74	(8)	315	284	(32)
82221	HQ-NYISO			1039	1039	77	77	0	801	801	0
82222	IMO-NYISO			1418	1418	11	11	0	157	157	0
82223	ISONE-NYISO			173	173	235	235	0	407	407	0
82224	PJM-NYISO			991	991	40	40	0	397	397	0
82225	CROSS SOUND NY			305	305	99	99	0	302	302	0
82256	Neptune LI-PJM			660	660	0	0	0	0	0	0

Joint Petition of National Grid PLC and
KeySpan Corporation For Approval of Stock
Acquisition and other Regulatory Authorizations
Case 06-M-0878
Rebuttal Testimony and Exhibits
March 7, 2007
VOLUME NO. I

PREPARED REBUTTAL TESTIMONY

OF

LAWRENCE J. REILLY

AND

STEVEN L. ZELKOWITZ

ON BEHALF OF

NATIONAL GRID plc

AND

KEYSPAN CORPORATION

CASE 06-M-0878

MARCH 7, 2007

Joint Petition of National Grid plc and KeySpan Corporation For Approval of Stock Acquisition and other Regulatory Authorizations
Case 06-M-0878
Rebuttal Witnesses and Exhibits

	Witness	Identifier Exhibit	Title
	VOLUME I		
1.	Steven L. Zelkowitz/Lawrence J. Reilly	Exhibit No.__(LJR/SLZ-1R)	National Grid and KeySpan Suggested Conditions For Merger Approval
2.	John C. Cochrane/James Read	Exhibit No.__(JGC/JR-1R)	Utilities Ratings
		Exhibit No.__(JGC/JR-2R)	Moodys Investors Service - Global Credit Research
		Exhibit No.__(JGC/JR-3R)	National Grid plc Capital Structure
		Exhibit No.__(JGC/JR-4R)	Response to DPS-158
		Exhibit No.__(JGC/JR-5R)	Response to DPS-111, DPS-198
		Exhibit No.__(JGC/JR-6R)	James A. Read, Jr. - Principal
3.	Steven L. Zelkowitz	No Exhibits	
4.	Cheryl A. Warren/Keith P. McAfee/ David Wright/Scott D. Leuthauser ("Reliability Panel")	Exhibit No.__(Reliability Panel-1R)	Charts, Graphs and Tables
		Exhibit No.__(Reliability Panel-2R)	Summary of Capital Additions Forecast
		Exhibit No.__(Reliability Panel-3R)	Line Workers (1999-2006)
		Exhibit No.__(Reliability Panel-4R)	National Grid - New York - PSC Request 281 - Part 2A

5.	Joseph F. Bodanza/Michael D. Laflamme/ James M. Molloy ("Rates Panel")	Exhibit No.__(Rates Panel-1R) Exhibit No.__(Rates Panel-2R) Exhibit No.__(Rates Panel-3R) Exhibit No.__(Rates Panel-4R)	Three Year Rate Proposal Calculation of 10 Year Levelized Net Synergy Volume By Year KEDNY Synergies and CTA Niagra Mohawk (electric) - Computation of Synergies
6.	Alan V. Feibelman/Richard J. Levin	Exhibit No.__(AVF/RJL-1R) Exhibit No.__(AVF/RJL-2R) Exhibit No.__(AVF/RJL-3R)	Corporate Services: Confidence Levels Savings Phase-In Rates Response To DPS-11
7.	Melissa Nairn/Lee Klosowski	Exhibit No.__(MN/LK-1R)	Illustrative Example of National Grid's and KeySpan's Proposed Opportunity Cost Target
	VOLUME II		
8.	Robert B. Catell	No Exhibits	
9.	Lawrence J. Reilly	No Exhibits	
10.	Masheed Saidi	No Exhibits	
11.	Peter Fox-Penner	Exhibit No.__(PFP-1R) Exhibit No.__(PFP-2R) Exhibit No.__(PFP-3R) Exhibit No.__(PFP-4R) Exhibit No.__(PFP-5R) Exhibit No.__(PFP-6R) Exhibit No.__(PFP-7R)	Visual Evidence of Outages Impacts on Zone J Price Monthly Prices Graphs of August 2004-July 2005 Backcasting Zones A-K Backcast Price Summary Statistics for All Zones: Year Ending July 2005 NYISO Transmission Facility Maintenance Outage Impact Report NYISO Day-Ahead Limiting Constraints Report for June 1, 2006 NYISO Operational Announcements of June 1, 2006 Panels A and B: Generation and Capacity Factor Comparison Between Base Case and Scenario 1 for Hours 8 and 19 on June 8, 2007

Lawrence J. Reilly
Steven L. Zelkowitz

I. Introduction and Qualifications

Q. Mr. Reilly, please state your name and business address.

A. My name is Lawrence J. Reilly. My business address is 25 Research Drive, Westborough, Massachusetts 01582.

Q. Are you the same Lawrence J. Reilly who provided testimony in this proceeding on October 3, 2006?

A. Yes, I am.

Q. Mr. Zelkowitz, please state your name and business address.

A. Steven L. Zelkowitz, One MetroTech Center, Brooklyn, New York 11201.

Q. Are you the same Steven L. Zelkowitz who provided testimony in this proceeding on October 3, 2006?

A. Yes, I am.

II. Purpose of Testimony and Introduction of other Witnesses

Q. What is the purpose of your testimony?

A. This testimony responds to the positions of the parties as set forth in the testimony filed on February 20, 2007 in this proceeding. Our testimony introduces the other witnesses that will be providing testimony in today's filing, summarizes our response to the conditions suggested by the other parties in the case for the merger between KeySpan and National Grid to go forward, and responds with a series of

proposals to address the concerns raised by the parties in a reasonable fashion that does not undermine the economics of the transaction.

Q. In addition to yourselves, what other witnesses or witness panels will be filing testimony today?

A. We have panels that address each of the key issues that have been identified by the parties who filed testimony on February 20. First, Mr. James Read of Brattle Group and John G. Cochrane ("Finance Panel") will address the impact of this transaction on National Grid's credit rating and financial integrity in response to concerns expressed by the Staff and CPB. The Finance Panel will also explain the capital structure, financing, goodwill, and ring fencing proposals that we are proposing for KEDNY and KEDLI to allow their overall costs of capital to be determined based on their own capital structures. Finally, the Finance Panel explains why KEDNY's and KEDLI's own capital structures should be used when setting their rates. The ring fencing conditions, which we summarize below, respond to the concerns of the parties with regard to financial risk, and are designed to assure the continued financial integrity of KEDNY and KEDLI following the transaction.

Mr. Alan Feibelman and Mr. Richard Levin of Mercer Management Consulting address concerns raised by the parties about the overall level of synergies projected for the transaction and the alleged lack of detail supporting the Companies' estimate of savings. They also address the timing of savings,

estimated costs to achieve and the expected positive impacts of the merger on customer service.

Ms. Melissa Nairn of KeySpan and Mr. Lee Klosowski of National Grid respond to the issues associated with their gas supply synergy savings estimate that were raised by Mr. Wayand of the Staff and Dr. Elfner of the Consumer Protection Board (CPB).

Mr. Michael Laflamme and Mr. James Molloy of National Grid and Mr. Joseph Bodanza of KeySpan ("Rate Panel") address the issues associated with the KEDNY and KEDLI rate plans that have been raised in the direct testimony of the other parties by proposing alternative rate plans that address the concerns expressed by the parties associated with the ten year proposal. As we explain, we believe that a ten year rate plan that postpones and mitigates the rate increases required under the stand-alone KEDNY and KEDLI filings continue to be in the best interests of our customers. However, to move the process forward, the Rate Panel makes a formal proposal for three year rate plans with an early credit to customers from the mergers. Mr. Bodanza provides the details on a proposal for a three year rate plans for KEDNY and KEDLI that are designed to respond to the concerns of the parties in a reasonable fashion. Mr. Laflamme and Mr. Molloy address the allocation of synergy savings among the operating companies on the combined system, and between customers and KEDNY and KEDLI and set forth proposed conditions for the rate plans for KEDNY and KEDLI. We summarize

those proposals later in our testimony. Finally, the Rate Panel compares the actual expenditures on the transmission and distribution system for Niagara Mohawk after its merger with National Grid to the spending levels that occurred prior to the merger and the projections included in the forecasts underlying the Niagara Mohawk rate plan. As their comparisons show, both O&M spending and capital investment in the Niagara Mohawk transmission and distribution system has increased significantly above historical expenditures and rate plan allowances since the merger closed at the beginning of 2002. This analysis addresses directly the contentions of several parties that National Grid has reduced infra-structure spending after the merger.

In response to concerns raised by DPS Staff and several other parties, the Reliability Panel, composed of Ms. Cheryl Warren, and Messrs. David Wright, Kenneth McAfee, and Scott Leuthauser, all from National Grid, addresses in detail the Company's efforts to improve electric system reliability performance in the Niagara Mohawk service area. The panel summarizes the Company's increased maintenance and capital expenditures since the Niagara Mohawk acquisition. It analyzes National Grid's reliability results in the context of similar state- and industry-wide trends. The panel explains the root causes that must be addressed to improve reliability performance and describes the Reliability Enhancement Plan for the distribution system and the transmission capital plan, entailing significant further increases in annual expenditures that we are

implementing in order to achieve the desired improvements. We are proposing to include a commitment to implement that program as a condition to this merger. Under the Niagara Mohawk rate plan, the Company is entitled to request recovery of the revenue requirements associated with major investments of this kind during years seven through ten of that rate plan. The panel also explains the measures the Company takes to ensure an adequate line workforce is available to respond to service interruptions.

We address the vertical market power issues presented by the Staff in testimony by Dr. Peter Fox-Penner of Brattle Group, Ms. Masheed Saidi, Chief Operating Officer--U.S. Transmission for National Grid, and myself [Lawrence J. Reilly] (Vertical Market Power Panel). These witnesses respond to the concerns raised by the Staff constraint and merger policy panels associated with the continued ownership of the Ravenswood Generating Station. Of particular note, Mr. Fox-Penner provides an approach that eliminates any incentive for National Grid to restrict the capacity or availability of its transmission system to increase or otherwise affect the commodity prices received for the output of the Ravenswood Station in New York City. These commitments, together with the commitments made in prior testimony, are designed to respond to the Staff concerns associated with the continued ownership of Ravenswood after the close of the transaction. They are also summarized below. Ms. Saidi also will once again renew National Grid's commitment to expand existing transmission

capacity on its system and to build new transmission capacity to relieve constraints, again addressing the concern that National Grid's ownership of Ravenswood in the future will diminish its desire to make such investments.

Finally, we address the issue of continued management responsiveness to the Commission's policies through the testimony of Robert Catell, Chairman and Chief Executive Officer of KeySpan, and, after the transaction, Executive Chairman of National Grid USA and Deputy Chairman of National Grid plc. Mr. Catell will set forth our commitments to maintain the core management team in New York and to continue our focus on the Commission's policies facing utilities in New York.

III. Response to the Testimony of Staff and other Parties

Q. At the outset, can you comment generally on the positions taken in the Staff filing on the merger?

A. Yes. Frankly, we have both been in the utility industry for many years, most if it spent representing utilities before regulatory commissions in dozens of proceedings, including proceedings such as this. In our opinion, what is remarkable about the Staff positions, taken as a whole, is not that they oppose the transaction as it is currently proposed, because we have come to expect and admire effective and vigorous trial advocacy by the Staff; but rather how far they veer from established policies and practices of this and other commissions, so much so that if the Staff positions in this case are adopted as policy or precedent

by the Presiding Law Judges and the Commission, the practical effect will be to end utility merger and acquisition activity in this State. That may or may not have been the Staff intention in taking the positions it did. While we will not speculate on that intention, we do know that if these positions are adopted, it will be virtually impossible to economically justify any future combinations between utilities in this State, and the substantial ratepayer benefits of such combinations, demonstrated by both the Brooklyn Union – LILCO merger and the National Grid -- Niagara Mohawk merger will be lost to customers forever.

Q. Can you elaborate on some of the positions taken by Staff that you believe are inconsistent with Commission policy and precedent?

A. Yes. They are as follows:

First, although we are attempting to address the Staff's concerns with the proposed merger conditions set forth below, the Merger Panel takes a view on goodwill and goodwill recovery that, to our knowledge, is unknown in the accounting literature. By arguing, as it does, that goodwill allocated to regulated T&D companies must be recovered and amortized over no longer than a five year period through only the shareholder portion of forecast synergy savings, the Merger Panel would have the Commission adopt a standard that effectively would prevent any acquisition of a utility or utility holding company at prices above book value.

Second, the Merger Panel effectively adopts an interpretation of "public interest" under Section 70 of the Public Service Law, which, to our knowledge, has never been applied in this State or in any other state under a comparable statute. Under the Staff theory, not only is it necessary in this case for National Grid and KeySpan to demonstrate the substantial ratepayer and other public interest benefits that will be provided by this transaction, but they also need to demonstrate that the transaction is *more in the public interest* than theoretical alternative transactions that the Board of Directors of the acquired company might have considered. As Mr. Zelkowitz discusses more fully in his rebuttal testimony addressed to the confidential portion of the Merger Panel presentation, this interpretation would effectively put the boards of utilities or utility holding companies in this State in impossible situations given their fiduciary obligations under the Business Corporations Law.

Third, the Merger Panel takes what we can only characterize as an extreme position in its interpretation of the Commission's Policy Statement on Vertical Market Power, effectively converting the clearly stated "rebuttable" presumption" contained in that policy statement into an absolute irrebutable presumption and bar against any transmission owner also owning generation in the State; this notwithstanding the fact that there already is substantial ownership of *in service territory* generation by at least one large transmission owner in the State. And this position is so extreme that, despite the overwhelming facts

presented in this case by National Grid on the vertical market power issue and the commitments made and mitigation measures proposed, nothing short of a binding commitment by *KeySpan* to divest Ravenswood *before the closing of the transaction* will suffice to induce Staff to engage in settlement discussions on the conditions to approval of the merger in this case. Staff's position on vertical market power incorrectly discounts the physical separation of the National Grid transmission system from the New York City market, the operating control of the NYISO that limits National Grid's ability to restrict access to or the availability of transmission capacity in a manner designed to affect commodity prices in New York City, the supervisory authority of the Commission, FERC, and the NYISO to detect and penalize any inappropriate behavior of this kind, and the effect of the commitments that we have made to eliminate any residual incentive that National Grid might have to use the transmission system as a vehicle to increase commodity prices in New York City.

Fourth, the Merger Panel effectively rewrites the Niagara Mohawk ten year rate plan, which clearly sets forth the manner in which forecasted incremental synergies resulting from future mergers and acquisitions entered into by National Grid are to be allocated among the operating units of the National Grid US system and shared between ratepayers and shareholders, by proposing a new allocation methodology and sharing percentage that will make the deal uneconomic and unprecedented, with one exception. And Mr. Zelkowitz will

address that single exception later in this testimony. Moreover, Staff's position on the allocation of synergies ignores the reality that synergy savings will in fact flow to all the operating companies on the system based on the core functions that those companies actually perform. Thus, it is inappropriate to assume that synergy savings will be realized from gas transmission services, which KEDNY and KEDLI do not perform in the first place, or alternatively that synergy savings will not be realized in the electric transmission function, which is an integral service provided by National Grid to regulated customers and by KeySpan to LIPA.

As we explain at length in the accompanying testimony, Staff's position on each of these issues and the other issues raised in its testimony is unsupported by the facts, and, as a result, its conclusion to recommend rejection of the merger is also unsupported. For example, Staff's concerns about the impact of the transaction on National Grid's bond ratings have already been addressed by the ratings agencies themselves, which have reaffirmed National Grid's investment grade ratings after the KeySpan merger. The Staff's doubts about the ability of KEDNY and KEDLI to raise debt on reasonable terms is undermined by the fact that KEDNY and KEDLI have in fact recently raised debt after the transaction was announced at investment grade ratings and at reasonable rates.

Staff's suggestion that the projections for certain costs in the LDAC are understated fails to recognize that the higher costs, prudently incurred for

KEDNY's and KEDLI's customers, as projected by Staff, if they actually occur, will be reflected in gas delivery rates over the next ten years, absent the transaction, but without the mitigation provided by the synergy savings from the transaction.

Staff's position on service quality fails to recognize the significant commitments and the resources that National Grid has devoted to improving the aging infra-structure in up-state New York and its comprehensive reliability enhancement program to improve the performance of its transmission and distribution system across the Northeast.

These issues are all significant and important policy questions for the Commission. However, we believe that they can and should be reasonably addressed by the parties, including Staff, the Presiding Law Judges and the Commission in a manner that allows the transaction to go forward and the benefits of the merger for customers to be realized.

Q. Would you comment on the positions of the other parties who filed testimony?

A. In addition to Staff, testimony was filed by the CPB, the City of New York, Suffolk County, and two unions—IBEW Local 97 and UWUA Locals who are employed by National Grid and KeySpan. The CPB presented testimony by Dr. Elfner who comprehensively reviewed the merger proposals and made several suggestions for modifications to our rate proposals or conditions that should be

implemented as part of the merger. We have incorporated many of his suggestions in this testimony. Mr. Gorman represented New York City and focused primarily on the rate plan. He recommended that KEDNY implement a three year rate freeze following the merger, rather than the rate plan proposed by the Companies.

IV. Conditions Proposed by the Joint Petitioners to Address the Concerns of the Parties

Q. Staff and the other parties have suggested that they could support the merger under certain conditions. Have you evaluated their conditions?

A. Yes. As we explain below, we have serious concerns with several of the conditions suggested by the Staff and other parties. Before discussing the conditions proposed by Staff and the other parties in detail, we would like to set forth and explain the conditions that the Companies would suggest to address the concerns raised by the parties in their February 20, 2007, filings. These proposed conditions are included in Exhibit No. ___ (LJR/SLZ-1R). The conditions will provide our affirmative response to the suggestions of the parties and will provide the context for our response to the specific conditions that each party has proposed. Specifically, we have addressed the issues presented by the parties in a reasonable and comprehensive fashion that preserves the benefits of the transaction for customers and the combined company, in a manner that practically would allow the transaction to go forward.

Q. Please summarize the conditions that the Companies propose regarding financial protections to KEDNY and KEDLI?

A. The financial risks associated with the transaction are discussed at length by the Staff and are addressed in detail by the Finance Panel. The financial conditions that we propose are designed to eliminate any risk or cost to KEDNY or KEDLI associated with the transaction. The conditions are designed to insulate those companies from any financial stress that could be caused by the merger.

Specifically, the first condition commits that no goodwill from this transaction will be reflected on KEDNY's or KEDLI's regulatory accounts. Under the Commission's regulations, we are required to keep separate records to comply with the Commission's accounting and financing policies. The Commission has found in prior cases that these regulatory accounts need not follow Generally Accepted Accounting Principles for the United States (USGAAP). Under USGAAP, we are required to push down goodwill to KEDNY and KEDLI to reflect the fair valuation of their assets in accordance with the requirements of Financial Accounting Standard (FAS) 141. The regulatory treatment that we are proposing does not affect USGAAP financial reporting, which would include any goodwill calculated for KEDNY and KEDLI. However, it keeps all goodwill off of the regulated accounts of the Companies. This approach assures that the regulated balance sheets of KEDNY and KEDLI will

not be affected by the merger and that goodwill will have no affect on the ratemaking for either company.

The exceptions to this approach are the fair value adjustments that will be reflected on KEDNY's and KEDLI's accounts following the merger, for example for pensions and OPEBs. At the time of the merger, we are required to fair value the assets and obligations on KEDNY's and KEDLI's accounts, including pension and OPEB plans to reflect current market values and assumptions. Under condition 2, we will file the fair value studies of KEDNY and KEDLI with the Commission and identify any associated amortizations, regulatory assets, and regulatory liabilities. For example, to assure that this valuation adjustment does not affect ongoing pension or post-retirement benefit expense, we are proposing to amortize any gain or loss associated with the fair value adjustment of these plans over ten years as required in the Commission's Statement of Policy for Pensions and OPEBs. This amortization is proposed for KEDLI, which is currently on the Statement of Policy and for KEDNY, which has proposed to go back on the Statement of Policy.

The third condition commits National Grid to maintain an investment grade bond rating for KEDNY and KEDLI at all times. In the event that this condition is not achieved, KEDNY and KEDLI would be prohibited from paying dividends until the situation is remedied. This assures that KEDNY and KEDLI

will have additional cash to meet debt obligations in the event of a below investment grade rating.

The fourth condition is related to the third. As the Staff Policy Panel has emphasized, the credit rating of a company is related to the amount of equity in its capital structure. We have therefore proposed to continue the conditions in KEDNY's and KEDLI's prior rate plans that limit the ratio of average total debt to average total capital excluding goodwill in KEDNY's and KEDLI's capital structure to no more than 55 percent and 58 percent, respectively. These maximum debt ratios have been in place for the two companies since the merger of Brooklyn Union and LILCO in 1998 and have served well to ensure the financial integrity of KEDNY and KEDLI and therefore should continue to assure that KEDNY and KEDLI, evaluated as a stand-alone credit would have a solid investment grade bond rating. As the Finance Panel explains, it also provides some flexibility for KEDNY and KEDLI to implement efficient capital structures and to respond to conditions in the financial markets. Because we are proposing to use KEDNY's and KEDLI's actual capital structures per the regulatory books of the Commission to set rates, this flexibility will redound to the benefit of KEDNY's and KEDLI's customers.

The fifth condition confirms a commitment that we made in the Joint Petition. It assures that the debt associated with National Grid's acquisition of KeySpan will not be reflected as an obligation of KEDNY or KEDLI. As a result,

neither of those companies will be obligated to the debt holders of National Grid and those debt holders will hold no security interest in the assets of either KEDNY or KEDLI. This condition does not preclude National Grid from loaning funds to KEDNY or KEDLI through the regulated money pool or other vehicles approved by the Commission. Nor does it prevent National Grid from making capital contributions to the Companies when necessary or appropriate to support new investments on the system or otherwise meet the Companies' capital requirements. However, the loans from National Grid are subject to the limit on debt financing in the capital structure established under condition four described above.

The sixth condition also confirms a request that we included in the Joint Petition—that KEDNY and KEDLI be allowed to participate in the regulated money pool on the terms set froth in the Joint Petition. This will assure that KEDNY and KEDLI have ready access to capital at all times.

The final condition suggests that with these commitments, it is appropriate for the Commission to use KEDNY's and KEDLI's own capital structures as reflected on their own regulatory accounts when setting rates. This approach is consistent with Commission precedent. As the Staff Policy Panel recognized, when adequate ring fencing provisions are in place, utilities may use their own capital structures. With the above conditions, KEDNY's and KEDLI's own capital structures will include no goodwill or debt from the transaction, will have

equity ratios and debt ratios adequate to support an investment grade rating, and will have the flexibility to establish those capital structures in a fashion that allows efficient access to capital. This approach also avoids the need to argue about whether the consolidated capital structure of National Grid should be used determine KEDNY's or KEDLI's cost of capital or complications associated with reflecting US and UK capital structures on a consistent basis, which would be required if the National Grid consolidated capital structure were used.

Q. What conditions do you propose associated with the rate plans for KEDNY and KEDLI?

A. First, although we continue to believe that ten year rate plans for KEDNY and KEDLI are in our customers' best interest, we are proposing an alternative rate plan and are willing to begin with the results of the stand-alone rate filings that are now pending in this proceeding. We expect the parties to engage in settlement discussions that would resolve these rate proceedings with rate plans of up to three years in duration. Suggested conditions for the plans are included in the testimony of the Rates Panel. The second condition adopts a suggestion made by Dr. Elfner at pages 47-48 of his testimony that costs to achieve should be amortized over ten years on the books and in rates. However, we continue to propose that supplemental executive retirement payments and related separation costs and the transaction costs associated with the merger be included in the costs to achieve despite Dr. Elfner's recommendation, because the executive separation

costs have been earned over a period of years and are a contractual entitlement. Moreover, the transaction costs, associated with attorneys and underwriters fees, are necessary to implement the transaction and thus give rise to the benefits of the transaction that are being reflected in rates. As Mr. Feibelman and Mr. Levin testify, the $400 million cost to achieve estimate remains reasonable.

Q. How do you propose to treat synergy savings in rates?

A. We propose to implement an immediate credit to KEDNY's and KEDLI's stand-alone rates commencing on the first day of the month following the closing of the transaction. Under our projections, the costs to achieve exceed synergy savings in the first year. We have proposed to amortize the costs to achieve over ten years, reducing the levels recognized in expense at the outset. We also propose to credit customers with 50 percent of KEDNY's and KEDLI's allocated share of synergies for the first three years, which have been levelized, and reduced by 50 percent of the annual amortization of costs to achieve. The calculation is included in the testimony of the accounting panel. For KEDNY, the initial credit to the cost of service totals $5.9 million and for KEDLI, the initial credit totals $3.5 million.

The net synergy credit will offset the rate increases proposed for both KEDNY and KEDLI. The credit would continue until delivery rates are reset. Then over the remainder of the ten year period following the merger, KEDNY and KEDLI would be authorized to add back to the cost of service the amounts

representing the Company's allocation of the forecast synergy savings during the effective period of the rates less the Company's share of the annual amortization of the actual costs to achieve. After the tenth year, the Companies allocation would end and 100 percent of the synergies would flow to KEDNY's and KEDLI's customers.

This approach addresses the concerns of several parties. First, if the actual savings produced following the transaction exceed our estimates as several parties have suggested or more savings are received by KEDNY or KEDLI than we have estimated in our allocations, those greater savings will be automatically flowed through to customers through the lower costs reflected in the cost of service, as early as the fourth year following the merger, after the conclusion of the three year rate plan we propose. Thus, this approach limits the debate about the estimation and allocation of savings among the operating companies. Second, the net synergy saving allowance is front loaded for customers. The recovery of costs to achieve is spread out over ten years. The customers' allocation of synergy savings is based on the assumption that the synergy savings are level over the three year period of the alternative rate plan and realized on day-one after the merger. These features both increase the value of the initial synergy credit above the level originally included in our analysis.

Q. How do you propose to address Staff's concerns associated with vertical market power?

A. This issue of compliance with the Commission's vertical market power policy has been addressed at length in the testimony of the vertical market panel and will not be repeated. Suffice it to say that we have addressed two concerns in our testimony and proposed conditions. As we have explained, the oversights and management of transmission outages by the NYISO and regulators limits our ability to use our up-state transmission facilities to affect New York City prices through continued participation in the NYISO. In addition in our first condition, we have eliminated our incentive to use our up-state transmission facilities to affect New York City prices through an automatic crediting mechanism that captures any increase in margin realized by Ravenswood associated with a transmission constraint caused or exacerbated by an unscheduled National Grid transmission outage or derating, and returns that margin to customers. The second condition assures that the first condition is met by requiring National Grid to report any outage on critical transmission links that could affect commodity prices in New York City and the margins realized by Ravenswood.

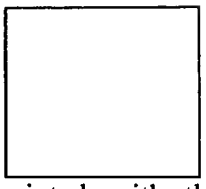
Finally, the third and fourth conditions address the longer term. We assume the additional obligations to propose and build regulated transmission facilities with economic or reliability benefits under the terms described in Ms Saidi's testimony. Finally, absent approval by the Commission, we agree not to develop, directly or through an affiliate, any additional generation facilities in New York, other than facilities specifically dedicated to LIPA or NYPA under

long term contracts. To the extent we acquire ownership of additional generation in New York State through future mergers, we acknowledge that our continued ownership of those assets would be subject to the Commission's approval.

Q. What conditions do you propose associated with service quality?

A. We propose to commit to abide by any service quality standards adopted for KEDNY and KEDLI in their stand-alone rate filings. The Staff has made proposals in those cases for changes to service quality standards and the Companies have responded. The service quality standards will be established as part of that process, whether the merger is approved or it is not. We will abide by those standards.

In addition, National Grid will expand its significant investment in infrastructure in the Niagara Mohawk service territory, as described in the testimony of the Reliability Panel. As explained by the panel, this program is designed to produce concrete improvements in performance across the National Grid system. To provide a concrete benchmark for the program, we have calculated the total projected capital investment for Niagara Mohawk over the five fiscal years from 2007 through 2011 that is contemplated in our current business plan and includes the capital investments associated with the Reliability Enhancement Program. That planned investment totals $1.4 billion. We will make annual reports to the Commission on our actual spending and will explain any significant changes from the $1.4 billion planned amount. As we have indicated, Niagara Mohawk has the



right to request recovery for the revenue requirements associated with the Reliability Enhancement Program in years seven to ten of that rate plan. The request will be made in a separate filing by Niagara Mohawk under its rate plan.

Q. What are the objectives of the conditions that you have set out in the prior section?

A. The conditions are intended to respond in a meaningful fashion to the concerns that have been raised by the parties in their February 20, 2007, filings. We believe that these commitments address these concerns in a meaningful way which allows the transaction to go forward and does not undermine the economic benefits that the transaction provides. We realize that we are not providing all the parties all the commitments that have been requested, and we address our rationale for not doing so in the next portion of our testimony.

V. Response to the Conditions Proposed by Other Parties in Their February 20, 2007, Filings

Q. Would you begin with your response to the conditions proposed by Staff as part of the approval of the merger?

A. Yes. The conditions suggested by the Staff are set forth at pages 183-94 of Merger Policy Panel. Their proposed conditions are discussed in the order that the issues were discussed by Staff and our proposed conditions were developed in response. We will address each of Staff's suggested conditions on the merits, sometimes based on the analysis supplied by the other witnesses in this filing.

Q. Does Staff propose any conditions designed to address their concerns associated with KEDNY's and KEDLI's financial integrity?

A. Yes. The Staff at pages 188-89 and 192-93 of the Policy Panel Testimony proposes that the recording of goodwill be aligned with the present value of synergy savings. As we have explained, we have gone beyond the Staff recommendation to exclude all goodwill from KEDNY's and KEDLI's regulatory accounts provided pursuant to the Commission's accounting regulations. Thus, we are consistent in our conditions on goodwill.

Staff's only recommendation for a condition associated with financing and financial integrity for KEDNY and KEDLI is that National Grid use its consolidated capital structure for determining the cost of capital for KEDNY and KEDLI in rate plans (Policy Panel Testimony, page 188). This approach is not consistent with the concerns articulated by the Staff at the outset of its testimony. As they explained at length, the merger and the additional debt issued to finance it could affect the bond ratings of KEDNY and KEDLI. We structured our conditions to address these concerns directly with commitments designed to maintain a solid capital structure for the two regulated entities and to isolate them from the financial commitments of the parent and the economic effects of the transaction. The logical result of this approach is that the Commission should use the capital structures of the stand-alone companies when setting rates.

Staff has agreed that this approach is appropriate. On page 190 of its testimony (emphasis added), the Merger Policy Panel suggests that a "consolidated capital structure approach would be used to develop the overall rate of return unless extensive ring fencing provisions were put in place to effectively isolate the credit risks of KEDNY and KEDLI from Grid's other businesses." Our proposed conditions are designed to meet these ring fencing requirements.

Q. Did the other parties suggest any conditions directed toward finance issues?

A. Yes. Dr. Elfner suggests at page 10 of his testimony: "CPB recommends that as a condition of approval of the proposed Transaction, KEDNY and KEDLI be precluded from ever including goodwill associated with this Transaction in rate base, earnings base for the Earnings Base/Capitalization analysis or capital structure for ratemaking purposes." Our proposed conditions are consistent with his suggestion.

Dr. Elfner also suggests at page 12: "As a condition of approving the proposed Transaction, the PSC should carefully review the likely impact of recording a large amount of goodwill on the books of KEDNY and KEDLI and, if necessary, take action now to ensure that such approval does not cause an increase in costs to consumers, such as through higher financing costs, either in this case or in the future." Again this recommendation is consistent with and fulfilled by the conditions that we have proposed.

Third, Dr. Elfner proposes that (Testimony, page 13): "Any increase in KeySpan's cost of capital attributable to the Transaction should not be reflected in regulated delivery rates. The Commission should now establish the ratemaking principle, that future regulated rates of the merging entities should not reflect any increase in cost of capital attributable to the merger." We have addressed this concern with our conditions as well.

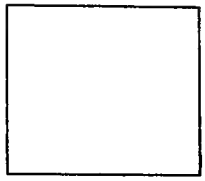
Q. What conditions is the Staff recommending for the rate plans?

A. First, Staff rejects "the use of a ten year rate plan" (Policy Panel, p. 188). Instead the Staff suggests that we enter into negotiations for a much shorter plan, "most likely of three years based upon the typical terms and conditions used in recent two and three year rate plans." (Id) We are in agreement with the Staff's approach. The Staff summarizes at pages 189-90 a set of conditions for a three year rate plan that are generally consistent with those included in the accounting panel's testimony.

Second, Staff would modify the allocation of synergy savings in three ways (Policy Panel, pp. 190-91). First, the Staff proposed to shorten the period of synergy savings. This would limit the net synergy savings included in the sharing mechanism and lower the allowance to the Company for the balance of the ten year period. We disagree with Staff's suggestion and believe that the approach would not lead to a reasonable allocation of the benefits of the merger.

The Staff has also proposed to change the synergy saving allocation to push more synergy savings to KeySpan. As we have explained, our objective is to allocate the synergy savings to the companies where the savings will actually occur. To the extent that our proposed allocation under-estimates the savings that will flow to KEDNY and KEDLI, the under-allocation will be automatically corrected during the ten year sharing period. Under the alternative rate plans, these savings will automatically be reflected in the future cost of service filings that we make for KEDNY and KEDLI. Customers receive 100 percent of actual savings above forecast levels because the Company's allocation is fixed at the outset. Thus, the shorter rate plan also addresses Staff's allocation issue.

The final adjustment suggested by the Staff is to move to a 90%/10% allocation of the savings between customers and the Companies. We believe that the Staff's suggestion ignores the fact that customers receive 100 percent of the synergy savings after the first ten years. On a present value basis, this means that, using our proposed 50%/50% sharing ratio, KEDNY's and KEDLI's customers receive 80 percent of the economic value of the synergy savings realized in the first thirty years after the merger. Using the same allocation method, the Staff's proposal for 90%/10% sharing over a five year period would result in a 98.5 percent allocation of the value to customers and 1.5 percent to the companies. Thus, viewed over a longer period, we believe that our proposal provides



significant benefits to customers and is a reasonable allocation to support the investment necessary to produce the savings.

Q. Mr. Zelkowitz, in its testimony, the Merger Panel cites the 1998 Brooklyn Union-LILCO merger case as precedent for a 90%/10% sharing ratio they have proposed here. Do you think that is an appropriate precedent for this case?

A. Absolutely not. As I have indicated in the rebuttal testimony I submitted with Mr. Bodanza in the stand alone rate cases, I was counsel for Brooklyn Union in that proceeding and was personally involved in both forming the position of the petitioners in their filing in that case, and in the settlement discussions that led to the agreement subsequently approved by the Commission. As the Staff well knows, the Brooklyn Union-LILCO merger was part of a unique three way transaction, including the acquisition of LILCO's electric T&D assets by LIPA, which was designed to produce a specific result – an overall 20% rate decrease for Long Island electric consumers. The refinancing of the LILCO capital structure associated with the assets that LIPA purchased – *i.e.*, the T&D assets, the Shoreham related asset, and LILCO's 18% interest in the Nine Mile 2 Nuclear Generating Station, from a combination of equity and taxable and tax exempt debt to 100% tax exempt debt, produced an 18% rate reduction. Hence, the other 2% had to be produced by the synergies flowing to ratepayers from the Brooklyn Union-LILCO transaction. Those synergies were estimated to be $100 million

per year, and the 90%-10% sharing ratio *fell out of the calculation necessary to produce the additional 2% rate reduction.* To my knowledge, no utility merger before or since has proceeded with a sharing ratio of this nature. Therefore, the unique circumstances surrounding the Brooklyn Union-LILCO-LIPA transaction cannot and should not be used as precedent for this or any other transaction.

Q. Have other parties suggested conditions for the rate plans?

A. Yes. Dr. Elfner of CPB suggests that a ten year rate plan is inconsistent with the Commission's policy and Section 72 of the Public Service Law (Elfner, pp. 15-19). The alternative rate plan addresses that concern. Mr. Gorman for New York City suggests a three year rate freeze (Gorman, pp. 9-14). The alternative rate plan's three year period is consistent with that approach as well.

Dr. Elfner's and Mr. Gorman's positions on sharing of synergy savings and costs to achieve have already been summarized. As explained above, we disagree with these proposals and believe that a ten year sharing of the benefits is reasonable and appropriate to support the resources necessary to produce the synergy savings from the merger.

Q. Would you address the Staff's proposed conditions associated with vertical market power?

A. Yes. The Staff proposes to condition the merger or even discussions about the merger on the divestiture of Ravenswood *pre-closing* (Merger Policy Panel, pp. 185-86). As Staff recognizes (p. 186): "this requirement could affect the

economics of the transaction," but suggests that we should have addressed the market power concern prior to the transaction. Regardless of the timing, we have addressed vertical market power extensively in this proceeding. We believe that we can continue to own and operate Ravenswood on the conditions set forth in Exhibit No. ___ (LJR/SLZ-1R) in complete accord with the Commission's policy guidelines in this area. We are ready to discuss these conditions with the Staff and the other parties. However, we cannot agree to divestiture as a condition for those negotiations.

Q. Have the other parties proposed conditions associated with vertical market power?

A. No.

Q. What are Staff's suggested conditions associated with service quality?

A. The Policy Panel suggests that penalties in place following the Niagara Mohawk merger were not adequate, and therefore recommends "a significant increase" in the size of service quality penalties for KEDNY and KEDLI following the merger (Policy Panel, pp. 184-85). Staff also recommends that National Grid agree to allow the Commission to force divestiture of KEDNY and KEDLI and waive "its ability to challenge the legal basis for the Commission's authority to order divestiture." (Policy Panel, p. 185). The Staff suggests neither a specific increase in the size of service quality penalties beyond those recommended for KEDNY

and KEDLI in their rate proceedings, nor any standards by which the divesture order would be issued.

We disagree with the Staff's recommendations. The reliability performance in the Niagara Mohawk service territory is in line with widely experienced industry trends. As the Reliability Panel documents, National Grid has devoted significant resources to maintaining reliability on its system and has a comprehensive plan to spend significant additional resources in further efforts to enhance reliability. We have focused on our commitments and have paid our penalties. Further increases in penalties would not produce additional investment in infra-structure or a different course than the one that we are following to improve the reliability of Niagara Mohawk's T&D system. Moreover, the commitment to infrastructure improvement is long term. A requirement for divestiture or even the threat of a forced sale would undermine that commitment and affect the ability of Niagara Mohawk to raise the substantial financing that is necessary to rebuild much of the system. As a result, we believe that the Staff's proposals to increase penalties and to threaten forced divestiture are unsupported and inappropriate. Rather, we are proposing to adopt the service quality metrics that are developed in this proceeding for KEDNY and KEDLI as stand-alone companies. We are also committing to a substantial increase in infra-structure investment in Niagara Mohawk's service territory as discussed in the testimony of the Reliability Panel.

Q. Have the other parties suggested conditions on service quality?

A. Dr. Elfner for the CPB suggests that the Commission adopt a condition that requires National Grid to implement its Reliability Enhancement Program and we have adopted that condition. He also suggests that the limitation of doubling of penalties in the Niagara Mohawk rate plan be eliminated. As we have explained, we do not believe that additional penalties are necessary or appropriate. Finally, Dr. Elfner suggests that the CPB recommendations for service quality made in the KEDNY and KEDLI stand-alone cases be adopted. We have agreed to implement the results of those discussions or a Commission order on KEDNY's and KEDLI's service quality standards following the merger.

Mr. Radigan, testifying for Suffolk County suggests that "the Commission should assure that an increase in customer service is a prerequisite to the merger." In addition, he suggests that the Commission should develop penalties "so severe in financial consequence that utility management would never let customer service decrease." Radigan, pp. 4, 11-13. As we have indicated, we will abide by the service quality standard adopted in the KEDNY and KEDLI stand-alone rate proceedings. We also note that the goal of the integration team's efforts is to increase service quality through the combined organization. For example, KeySpan and LIPA have an excellent record of reliability on Long Island, and National Grid has performed well in meeting the customer service and metering standards included in our service quality plans. We intend to bring the best of

both systems together to provide efficient and high quality service to our customers. The efforts of the integration team in this regard are addressed in the testimony of the Synergy Panel.

The Unions also commented extensively on service quality on the National Grid system. Their concerns are addressed by the Reliability Panel. However, the Unions also suggest that the Commission adopt several conditions, specifically related to workforce levels for their membership.

We agree with one point made by UWUA—we should address union concerns at the union bargaining table. We have noted throughout the integration process that we would honor our contracts with the Unions. We reaffirm that commitment in this testimony. However, we believe that the best place to negotiate with our unions is at the bargaining table and not at the Commission. In this case, the UWUA is suggesting a condition that affects personnel outside of New York using a procedure that is outside the normal range of negotiation under established regulations for labor-management relations. We will honor our contractual obligations to the Unions, but following the agreed upon provisions established in our contracts with those Unions. The Commission has long recognized that it should not insert itself into union-management issues that should be resolved through collective bargaining and this case is no different.

Local 97 of IBEW recommends that the Commission consider the staffing, reliability statistics and safety issues. We believe that the condition to implement

the Reliability Enhancement Program in Niagara Mohawk's service territory addresses Local 97's concern. We also believe that commitments regarding the maintenance of books are records proposed by Local 97 are typically provided in the context of a merger. The books and records of KEDNY and KEDLI will continue to be available in New York and will be provided for audit by Staff.

Q. Were other conditions suggested by the parties?

A. Yes. Mr. Radigan, testifying for Suffolk County, has several recommendations that affect both the merger and the KEDNY and KEDLI stand alone filings. Several involve LIPA, which is not a subject for this proceeding. However, several involve KEDNY and KEDLI.

First, Mr. Radigan suggests that the proposed DSM programs for KEDNY and KEDLI be offered by NYSERDA using a systems benefit charge. We have recognized that this is an option and policy choice for the Commission and are willing to consider this option either in the context of merger discussions or in the stand-alone rate proceedings. We also agree with Mr. Radigan that the issue or accurately calculating the impact of lost revenues resulting from incremental DSM programs needs to be a part of the discussion on DSM program implementation. We are also considering revenue decoupling as a means to address this issue.

Mr. Radigan also makes several suggestions about competition and customer choice including a side by side comparison of KEDNY and KEDLI

delivery rates. The data for this comparison is available in the two stand-alone rate proceedings. In both cases, KEDNY and KEDLI are only seeking the recovery of the reasonable costs of providing regulated service in each of their service territories. Cost differences naturally arise from different tax rates, service territory characteristics, customer profiles, and a myriad of other circumstances and obligations that create different costs for the two Companies. Simply stated, the cost to provide regulated gas delivery service is different in Brooklyn, Queens and Staten Island than on Long Island. In both cases, this proceeding should provide reasonable rates based on KEDNY's and KEDLI's cost of providing that service. Moreover, because the rates for delivery service do not depend on the identity of the underlying supplier of the gas, the effects of delivery rate differences between the two systems should not affect retail competition within their service territories.

Mr. Radigan also sets forth Suffolk County's position on repowering. However, any activity on this front requires the consent of LIPA and so his suggestions will not be discussed in detail in this testimony. Nevertheless, we are mindful of the concerns and suggestions of Suffolk County when addressing these issues with LIPA.

Finally, Mr. Radigan addresses the remediation of manufactured gas plant sites in Suffolk County. This issue of cost recovery has been addressed by KeySpan in its rebuttal testimony on the stand alone rate cases. Moreover, we

believe that the issue of remediation plans is best evaluated separately from the issue of cost recovery. National Grid has developed a solid record of remediation of the sites for which it has been responsible. We expect to use this expertise, together with KeySpan's, in the remediation of sites throughout the combined service territories. We both recognize our obligation to remediate the sites in an environmentally sound and safe condition, and the need to complete the work as efficiently as possible. We also expect that the costs of this remediation will be reflected in KEDLI's rates if it is completed reasonably and prudently. The Commission's policy is an essential part of the overall plan. Rate recovery provides the resources necessary to complete the work in an efficient and environmentally sound manner.

Conclusion

Q. Does this conclude your testimony?

A. Yes.

Exhibit No. ___ (LJR/SLZ-1R)

NATIONAL GRID AND KEYSPAN
SUGGESTED CONDITIONS FOR MERGER APPROVAL

National Grid and KeySpan propose the following conditions for the merger approval by the Commission. These conditions are designed to address the issues raised by the parties in the merger proceeding and are above and beyond the conditions and commitments made in the Joint Petition and the prior testimony by the Companies. The conditions would become effective upon closing of the merger, and would continue until the next rate filing by KEDNY or KEDLI or upon notice of an investigation instituted by the Commission.

I. Conditions Associated with Financial Protections for KEDNY and KEDLI

1. Although goodwill may be recorded on KEDNY's and KEDLI's accounts pursuant to USGAAP, no goodwill will be pushed down on the regulatory books maintained by KEDNY or KEDLI pursuant to the Commission's regulations following the transaction. Goodwill will be excluded from rate base and expenses in the determination of KEDNY's and KEDLI's rates and earned returns for regulatory reporting purposes in filings to the Commission.

2. The Companies will file the fair value study for KEDNY and KEDLI and identify all fair value adjustments associated with its implementation. Any amortizations, regulatory assets, and regulatory liabilities will be specifically identified. For example, the unamortized losses or gains recognized as the result of the fair valuation of KEDNY's and KEDLI's pension and OPEB obligations will be offset by a regulatory asset or liability and amortized over ten years following the close of the merger.

3. KEDNY and KEDLI shall be prohibited from paying common dividends if their respective bond ratings fall below an investment grade rating as determined by either Moody's or Standard and Poor.

4. For any twelve month period ending at the end of a quarter, KEDNY's average total debt shall not exceed 55 percent of its total capital excluding goodwill, and KEDLI's average total debt shall not exceed 58 percent of its average total capital excluding goodwill. If the actual debt ratio for either KEDNY or KEDLI exceeds the maximums, KEDNY or KEDLI will have a 15 month period to cure the problem by reducing the debt ratio to levels below the maximums set forth above. In the event that the problem is not cured within the 15 month period and absent an order by the Commission authorizing dividend payments, KEDNY and KEDLI

shall be prohibited from paying common dividends until the maximum debt ratios set forth above are no longer exceeded.

5. No debt associated with National Grid's acquisition of KeySpan shall be reflected as an obligation of either KEDNY or KEDLI, provided, however, nothing in this condition shall prevent KEDNY or KEDLI from borrowing funds from its affiliates under conditions approved by the Commission.

6. KEDNY and KEDLI shall be authorized to participate in the regulated money pool following the merger on the conditions set forth in the Joint Petition.

7. Subject to the above adjustments, KEDNY's and KEDLI's own capital structure as reported on the Commission's regulatory accounts shall be used for determining the cost of capital in rate proceedings, excluding all goodwill as required under point I.1, above.

II. Conditions Associated with the Rate Plans for KEDNY and KEDLI

1. The Joint Petitioners requests for ten year rate plans for KEDNY and KEDLI are withdrawn. KEDNY and KEDLI will complete proceedings on their stand-alone rate cases, either on a litigated basis for rates commencing after the suspension period or through a settlement that will continue for up to three years on terms that are set forth in the rebuttal testimony of the accounting panel.

2 KEDNY and KEDLI shall amortize $400 million of costs to achieve over ten years with a return commencing on the first day of month following the closing of the merger. The amortized costs shall be recoverable in rates.

3. In the first three years of the rate plan developed under point 1, KEDNY and KEDLI shall credit their rates with a net synergy allowance equal to $5.9 million per year for KEDNY and $3.5 million per year for KEDLI as calculated in the rebuttal testimony by the accounting panel. The rate credit equals fifty percent of synergy savings forecast in the first three years after the merger less fifty percent of the annual cost to achieve amortization set forth in point II.2 above. The net synergy allowance shall continue until the effective dates of KEDNY's or KEDLI's next rate filing. The credit shall be implemented on an equal percentage of delivery revenues basis over all rate classes for deliveries on and after the first day of the month following the close of the merger. It will continue until the effective date of new base rates for KEDNY or KEDLI.

4. KEDNY and KEDLI shall include in their costs of service for ratemaking in any subsequent rate filing that becomes effective during the ten years after the close of the merger a synergy allowance equal to fifty percent of the projected synergies for that year as shown in Schedule MDL/JMM-1, page 1 included in the Petitioners' October 3, 2006 filing less fifty percent of the annual amortization of costs to achieve.

III. Conditions Associated with Vertical Market Power

National Grid shall be allowed to retain ownership of KeySpan's existing generation stations under the following conditions:

1. National Grid shall implement the mitigation proposal set forth in the rebuttal testimony of Peter Fox-Penner under which it will pay certain amounts onto a fund to benefit customers. National Grid shall also report to the Commission the existence and amount of all such mitigation payments.

2. National Grid shall provide the Commission with notice of emergency (i.e., unscheduled) 230 kV and 345 kV outages as described in the testimony of Michael Schiavone.

3. National Grid shall assume the additional obligations to propose and build regulated transmission projects with economic or reliability benefits as described in the testimony of Masheed Saidi.

4. Unless approved by the Commission, National Grid shall not directly or through an affiliate own or develop additional generation facilities in New York, other than generation capacity specifically requested by LIPA or NYPA under a long term contract. National Grid also recognizes that any generating facilities located in New York that may be acquired as part of a follow-on transaction must meet the Commission's guidelines on vertical market power through a combination of commitments that limit the transmission owning utility's ability and incentive to restrict transmission capacity affecting prices in the zone in which the generation is located.

IV. Conditions Associated with Service Quality

1. KEDNY and KEDLI shall abide by the service quality plans developed in its stand-alone rate filings following the merger and until the next rate filing.

2. Niagara Mohawk shall implement the Reliability Enhancement plan set forth in the testimony by the reliability panel, which together with other T&D investment contemplates a total capital investment of approximately $1.4 billion over the next five years. National Grid shall make annual

reports on the total capital spending each year in its service territory and shall explain significant changes in the actual or planned spending levels from the $1.4 billion plan.

PREPARED REBUTTAL TESTIMONY

OF

JOHN G. COCHRANE and JAMES READ

ON BEHALF OF

NATIONAL GRID, plc

AND

KEYSPAN CORPORATION

CASE 06-G-1185

THE FINANCE PANEL

MARCH 07, 2007

Q. Please state your name and business address.

A. My name is John G. Cochrane. My business address is 25 Research Drive, Westborough, MA 01581.

Q. Are you the same John G. Cochrane who previously submitted prepared direct testimony in these proceedings?

A. Yes. I am.

Q. Please state your name, business affiliation, and business address.

A. My name is James Read. I am a principal of The Brattle Group, an economics and management consulting firm. My office is located at 44 Brattle Street in Cambridge, Massachusetts.

Q. What are your qualifications?

A. My consulting practice is focused on the electric power and natural gas industries. I have extensive experience in valuation, risk management, capital budgeting, cost of capital, market analysis, and energy trading matters. I have directed the development of software and methods for valuation and risk management for the Electric Power Research Institute (EPRI). I have also written numerous reports for EPRI on the application of financial economics to decision making in the power industry. I am co-author of *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, published by the MIT Press. I hold a B.A. in Economics from Princeton University and an M.S. (Finance) from the Sloan School of Management at Massachusetts Institute of Technology. A detailed

description of my qualifications, including publications and recent testimony, is included as Exhibit No. ___ (JGC/JR-6R).

Q. What is the purpose of your rebuttal testimony?

A. We will address the testimony by Department of Public Service ("DPS") staff Merger Policy Panel and Witnesses John D. Stewart, Warren E. Meyers and Thomas Coonan and the testimony provided by Dr. Douglas W. Elfner on behalf of the New York State Consumer Protection Board ("CPB"), related to the proposed acquisition of KeySpan Corporation ("KeySpan") by National Grid PLC ("National Grid"), Case 06-M-0878.

Specifically we will address our proposed ring-fencing conditions for KEDNY and KEDLI, which protect the financial integrity of those Companies.

Next, we explain that it is appropriate to use the actual stand-alone capital structures of KEDNY and KEDLI to establish rates.

We then explain the financial strength of National Grid, address National Grid's financing of this transaction and its impact on the credit rating of National Grid and KeySpan. Staff's testimony attempts to anticipate how the credit rating agencies will assess National Grid after the acquisition of KeySpan. We reiterate that the rating agencies have already evaluated our credit quality in light of the planned acquisition, and have assigned solid investment grade credit ratings.

Finally we address Staff's concern with recording Goodwill on the books of KEDLI and KEDNY.

Q. Do you sponsor any exhibits as part of your prepared rebuttal testimony?

A. Yes. We sponsor the following exhibits that were prepared and/or compiled under our supervision and direction:

(i) Exhibit No. ___ (JGC/JR- 1R)	Credit ratings chart
(ii) Exhibit No. ___ (JGC/JR-2R)	Moody's Credit rating reports
(iii) Exhibit No. ___ (JGC/JR-3R)	Proforma capital structure for National Grid plc
(iv) Exhibit No. ___ (JGC/JR-4R)	Response to DPS 158
(v) Exhibit No. ___ (JGC/JR-5R)	Response to DPS 11 and DPS-198
(vi) Exhibit No. ___ (JGC/JR-6R)	James Read biographical details

Proposed Ring-Fencing Conditions for KEDNY and KEDLI

Q. What capital structure has Staff proposed to determine KEDNY's and KEDLI's allowed rate of return after the merger?

A. At page 190 of its testimony, Staff suggests that: "A consolidated capital structure approach would be used to develop the overall rate of return unless extensive ring fencing provisions were put into place to effectively isolate the credit risks of KEDNY and KEDLI from Grid's other businesses."

Q. How do you respond to Staff?

A. We are proposing several ring fencing provisions to isolate KEDNY and KEDLI from the other National Grid businesses. These commitments should satisfy the

Staff that it is appropriate to use the actual stand-alone capital structures of KEDNY and KEDLI to be used in setting rates.

Q. What ring-fence provisions are you are proposing?

A. We are proposing the following provisions and conditions that are designed to insulate KEDNY and KEDLI from the effects of the transaction, maintain their financial integrity, and isolate the companies from the other National Grid businesses.

First, although goodwill may be recorded on KEDNY's and KEDLI's financial statements pursuant to US GAAP, no goodwill will be pushed down on the regulatory books maintained by KEDNY or KEDLI pursuant to the Commission's regulations following the transaction. Goodwill will be excluded from rate base and expenses in the determination of KEDNY's and KEDLI's rates and earned returns for regulatory reporting purposes in filings to the Commission.

Second, the Companies will file the fair value study for KEDNY and KEDLI and identify all fair value adjustments associated with its implementation. Any regulatory assets and liabilities and related amortizations will be specifically identified. For example, the unamortized losses or gains recognized as the result of the fair valuation of KEDNY's and KEDLI's pension and OPEB obligations will be offset by a regulatory asset or liability and amortized over ten years following the close of the merger.

Third, KEDNY and KEDLI shall be prohibited from paying common dividends if their respective bond ratings fall below an investment grade rating as determined by either Moody's or Standard and Poor.

Fourth, for any twelve month period ending at the end of a quarter, KEDNY's average total debt shall not exceed 55 percent of its average total capital, excluding goodwill, and KEDLI's average total debt shall not exceed 58 percent of its average total capital, excluding goodwill. If the average debt ratio for either KEDNY or KEDLI exceeds the maximums, KEDNY or KEDLI will have a 15 month period to cure the problem by reducing the debt ratio to levels below the maximums set forth above. In the event that the problem is not cured within the 15 month period and absent an order by the Commission authorizing dividend payments, KEDNY and KEDLI shall be prohibited from paying common dividends until the maximum debt ratios set forth above are no longer exceeded.

Fifth, no debt associated with National Grid's acquisition of KeySpan shall be reflected as an obligation of either KEDNY or KEDLI, provided, however, nothing in this condition shall prevent KEDNY or KEDLI from borrowing funds from its affiliates under conditions approved by the Commission.

Sixth, KEDNY and KEDLI shall be authorized to participate in the regulated money pool following the merger on the conditions set forth in the Joint Petition.

Last, Subject to the above adjustments, KEDNY's and KEDLI's own capital structure as reported on the Commission's regulatory accounts shall be used for determining the cost of capital in rate proceedings, excluding all goodwill as required under point I.1, above.

KEDNY and KEDLI Capital Structures Used to Establish Rates

Q. What issue does this portion of your testimony address?

A. While we believe that our proposed for ring-fencing provisions positively address any concerns the Staff has about the use of the stand-alone capital structures of KEDNY and KEDLI for ratemaking, we need to respond to certain related issues raised by Staff.

In this section, we discuss the appropriateness of rates established on the actual stand-alone capital structures of KEDNY and KEDLI, which are approximately 50 percent debt and 50 percent equity.

The issue before the Commission is not whether the allowed return for KEDNY and KEDLI will recover the cost of the debt used by National Grid to fund its acquisition of KeySpan. The issue, rather, is whether the allowed return will provide investors with an opportunity to earn the cost of capital on investments made by KEDNY and KEDLI.

Staff implies that because the acquisition of KeySpan will be funded by an issue of debt, that cost of debt is the cost of equity capital for KEDNY and KEDLI. Staff refers to the *source* of funds used to acquire KeySpan when it concludes that

ratepayers will pay too much. But this is not correct. The cost of capital depends on how funds will be invested, not on how the funds are raised. In other words, the cost of capital depends on the *use* of funds, not the source. (Brealey, Myers, and Allen emphasize this point early in their textbook, *Principles of Corporate Finance.* See Chapter 2, Section 1, in particular, the discussion under the heading, "A Source of Confusion".)[1]

Q. Has staff proposed a capital structure related to this transaction?

A. On Page 188, Staff states "*We would set the rate of return using Grid's consolidated capital structure based on United States GAAP, consistent with Commission policy*"

Q. Is this appropriate?

A. No. It is appropriate to use the actual capital structures of KEDLI and KEDNY, particularly given our extensive ring-fence proposals.

Q. Would such a capital structure affect the required ROE?

A. Yes. The cost of equity depends on the amount of debt in the capital structure as well as the risk of the underlying assets. This is because debt service entails a fixed stream of cash payments, with a first claim on cash flows and assets. As a result, debt finance amplifies ("leverages") the risk and return on equity—and thus the cost of equity. The greater the amount of debt financing, the higher the required rate of return on equity, other things equal. This is an elementary

[1] Richard A. Brealey, Stewart C. Myers, and Franklin Allen, *Principles of Corporate Finance*, 8th Edition

principle of corporate finance and has been described in Mr. Rosenberg's testimony.

For example, if a 37% equity weighting (the proforma consolidated National Grid equity/debt ratio per Staff testimony MPP 13:12) were to be used in this case, a significant cost of equity adjustment would be necessary.

Q. What other issues are there with Staff's proposal to use National Grid's consolidated capital structure?

First, as we explained in our response to DPS 158 (Exhibit No. ___ (JGC/JR-4R)), the National Grid/KeySpan merger will not change the underlying rate base that exists at KEDLI and KEDNY. As we do not intend to push down any acquisition-related debt to KEDLI and KEDNY, the debt and obligations of these subsidiaries will be exactly the same as before the acquisition. There will be no direct obligation for KEDLI and KEDNY to pay any merger financing costs to the holding company. Because rate base and the companies' obligations are not changing, the capital structure to support the business will not change either. The underlying rate base and regulatory assets and liabilities of KEDNY and KEDLI were financed by the existing capital structure of KEDNY and KEDLI. National Grid is purchasing the equity of KeySpan Corporation from shareholders. The equity and stock of KEDNY and KEDLI will still be owned by KeySpan.

(New York: McGraw-Hill/Irwin, 2006).

Our proposals for ring-fencing would prevent these companies from decreasing their capital ratios to levels indicated by Staff. It is inappropriate to set a capital ratio inconsistent with the capital structure which would be achieved by KEDLI and KEDNY.

In New York, the existing rate plans and earnings sharing filings for Niagara Mohawk, KEDLI and KEDNY, as well as the regulation of KeySpan's generation on Long Island are all based on the capital structure of the entity being regulated. We also believe that this approach is consistent with Commission decisions on this issue. Recently, the Commission adopted in the Central Hudson Gas & Electric rate case the capital structure of the stand-alone utility as provided in the Joint Proposal. See Case 05-E-0934 and 05-G-0935 (Order Establishing Rate Plan, issued and effective July 24, 2006). We believe that it is important to note that the Commission has approved the use of the stand-alone utility capital structures that have been agreed to in Joint Proposals previously brought before the Commission for approval. Additionally, the Commission also allowed a stand-alone structure with respect to Rochester Gas & Electric Corporation. See Cases 02-E-0198 and 03-E-0765. In the Valley Energy Inc. rate case, the Commission found that the use of a hypothetical capital structure was appropriate for Valley Energy, which was a subsidiary of C&T Enterprises, Inc., even though Valley Energy received financing through its parent company. See Case 04-G-0821. Finally, in the St Lawrence Gas Company's rate case, the utility's stand-alone

capital structure was used. The Commission rationale was that the parent company's high debt ratio was "out of line with the industry average" and, thus, the stand-alone utility capital structure was more appropriate than that of the parent company. See Case 99-G-1188 and Case 97-G-0409. As further explained in Staff's Brief Opposing NYSEG's Petition for Rehearing in Case 05-E-1222 dated September 22, 2006, St Lawrence is owned by a "Canadian company whose financial profile is, among other things, governed by Canadian governmental restrictions on its ability to refinance high cost debt" which provided the Commission with a rational basis for approving the stand-alone utility capital structure. Staff Brief at page 12.

Q. Are there any specific factors related to National Grid as an international company that are relevant to this analysis?

A. Yes. First, there are fundamental differences between the financial reporting of the National Grid consolidated financial statements based on International Financial Reporting Standards (IFRS) which the Credit Rating Agencies and others use in their analysis of the Group and reporting those same statements on a US GAAP basis. This is discussed below in the Credit Quality section of our testimony.

In addition, the use of National Grid plc's balance sheet implies that the future regulatory capital structure applicable to KEDLI and KEDNY could be affected by transactions which have no bearing on these businesses. For example, if

National Grid issued equity for a non-US acquisition (as it did in the 2002 Lattice transaction in the UK), or sold unregulated assets at above book value; then the equity portion of National Grid's capital structure would increase.

Staff has referenced cost of equity calculations based on DCF and CAPM. Both of these methodologies depend upon the use of the market value of equity and debt rather than the book value. For National Grid plc, this is easily measurable and so there is no justification for using the "book" consolidated capital structure based on United States GAAP as the leverage measure for the Group. On a market value basis, the equity to total capitalization ratio, at the current share price of £7.50, would be around 50% following completion of the acquisition.

As a largely regulated and international business, National Grid's market valuation is driven by a range of factors, including the regulatory structure and business performance in each of its jurisdictions. Non-U.S. operations make the debt-to-capital ratio even less relevant for National Grid than for utilities with only domestic operations.

The regulation of the National Grid's UK businesses does not utilize the level of capital represented in the US GAAP accounts when setting rates. These accounts, in turn, do not reflect the value of the UK businesses on which the UK regulator allows them to earn a return. The level of capital in the National Grid Group accounts is therefore of less relevance to the credit rating agencies than it might be for a purely US business. Indeed it is our understanding that the credit

agencies place a particularly low weight on the capitalization metric for companies such as National Grid.

The Staff's debt-to-capital analysis does not recognize this fundamental difference in regulation and asset valuation for National Grid's UK assets.

Q. What is the major difference between US and UK regulatory framework?

A. The major difference is that the UK sets rates based on a Regulatory Asset Value (RAV), rather than a net original cost rate base. RAV has no direct relationship to the book value of these businesses and was initially derived from a combination of replacement cost and market value. In addition, the UK regulatory framework increases the RAV every year by inflation.

Q. Is it possible to adjust National Grid's US GAAP balance sheet to take account of the regulatory differences?

A. We continue to believe that it is inappropriate to use the National Grid plc consolidated capital structure in setting the rates of KEDLI and KEDNY. However, if we take the hypothetical case where we use the National Grid plc capital structure as being appropriate for setting KEDLI and KEDNY rates, then it would be necessary to adjust the balance sheet to compare like with like. As explained above, the rates of a UK utility are set using a RAV (which is not directly related to US GAAP book value). In order to ensure that we are comparing like-with-like, it would be necessary to adjust the value of the net assets from their US GAAP book value to the equivalent RAV valuation. If we

make such an adjustment (Exhibit No. ___ (JGC/JR-3R)), the consolidated National Grid plc equity ratio would be 44% instead of the 37% quoted by Staff. National Grid's annual results for 2006/7 will be available in May and we expect that this ratio will rise further when rolled forward to take account of these results.

Financial Capacity of National Grid

Q. **Does National Grid have the financial capacity to fund the acquisition of KeySpan and the future investments required for KEDNY, KEDLI, and its other regulated operations in New York?**

A. Yes. National Grid's ability to raise funds is underpinned by its financial strength. It has access to a very wide range of financing sources, including the very liquid capital markets, driven by its strong financial and business profiles reflected in its credit ratings which are expected to continue to be robust.

National Grid plc's current, senior unsecured, holding company credit rating is (A-/A-/ Baa1) from S&P/Fitch/Moody's) and is strong compared to most other US and international utilities. Exhibit No. ___ (JGC/JR-1R)

The rating agencies have indicated that our senior unsecured holding company rating after the KeySpan acquisition is likely to be BBB+/Baa1, which would still be in the top quartile of credit ratings for similar US utility holding companies (median rating of similar companies is BBB/Baa2).

During the period from the date the KeySpan transaction was announced to the end of February 2007, National Grid plc has raised the equivalent of $6.2 billion

in the international debt capital markets and we have substantial capacity for further debt issuance when required. This debt was raised successfully with full knowledge of the pending acquisition of KeySpan and the potential for a ratings downgrade. The debt has been primarily raised at the holding company level (existing ring-fencing provisions already protect the financial integrity of the regulated utility businesses).

In late 2006, KeySpan's New York and Long Island LDC subsidiaries raised $0.5 billion from the debt markets. These bonds were well received by the markets and in fact were substantially over-subscribed.

Since National Grid's US acquisitions in 2000 and 2002, we have redeemed or retired over $4 billion of National Grid USA's third-party debt and preferred stock.

Niagara Mohawk's (NiMo) credit rating has been raised by 2 notches in this period from a Moodys rating of Baa3 to Baa1, and S&P has assigned a higher rating of A-.

With over 50% of operating profits coming from US regulated businesses, National Grid is strongly committed to the US. Being part of the National Grid group will allow KeySpan and its subsidiaries to gain access to a wider capital market and other sources of funding. For example, National Grid is an active issuer of debt in the UK, US, European, Canadian, Japanese and Australian markets and has benefited from the ability to source funds from different markets.

National Grid's common shares are also listed on both the London and New York stock exchanges.

Our investment in networks takes place at our operating companies which all have strong investment grade credit ratings. This allows these companies ready access to the capital and money markets to finance investment where required. We will not fund any of the KeySpan acquisition costs through our US regulated operating companies. Furthermore, the regulated nature of these companies (and the ring-fencing provisions in place and proposed) means that the addition of further holding company debt would not restrict their access to funding at reasonable terms

Even with the additional debt raised for the KeySpan acquisition, the rating agencies still view our Group as a single A credit which allows the Group, including the holding company and its subsidiaries, ready access to the capital and money markets.

Credit Quality

Q. **Before addressing Staff's analysis of credit quality issues, please describe National Grid's current and expected credit rating.**

A. S&P and Moody's, both rate the National Grid group of companies (the Group) in a similar way. Moody's adopted their revised methodology recently in January 2007. Moody's most recent report is attached as Exhibit No. ___ (JGC/JR-2R). Both agencies determine a business risk profile for the Group by looking at the

business risk profiles of the operating companies. They then look at the Group as a composite of these profiles and assign a "Corporate rating" based on the Group's financial position and composite business risk profile.

National Grid's Corporate rating is currently A2/A. Both agencies have said publicly that they expect these ratings to decrease by a single notch following the acquisition of KeySpan to A3/A-, remaining strong investment grade credit ratings.

"Holdco" (National Grid plc) senior unsecured debt ratings are rated one notch below the National Grid Group Corporate rating.

In the remainder of this testimony, we will refer to either both Corporate and "Holdco" Company ratings as appropriate to the circumstances.

The following table indicates the changes in credit ratings pending the closing of the KeySpan acquisition. While S&P have indicated that they expect all of our UK and US ratings to be downgraded by 1 notch, Moody's has not yet provided the expected ratings outcome for our US subsidiaries.

Agency	Group / Corporate rating	National Grid plc senior unsecured rating ("Holdco")
S&P	A → A-	A- → BBB+
Moody's	A2 → A3	Stay at Baa1
Fitch	A → A-	A- → BBB+

Our credit rating has been assessed by the rating agencies with full knowledge of the investment plans in our current networks, the acquisition of KeySpan, ownership of generation plants and the ongoing investment in the KeySpan infrastructure.

Q. What did the Credit Rating Agencies say?

A. The post-merger National Grid plc ("Holdco") and its operating companies will all retain investment grade ratings. Neither S&P nor Moody's raises concerns about the possibility of loss of investment grade status. The S&P and Moody's reports were provided to Staff in response to DPS-111 and DPS-198. *See* Exhibit No. ___ (JGC/JR-5R).

Q. Should the Commission be concerned about the rating agencies' decisions to downgrade National Grid?

A. The Commission should take notice of the fact that the agencies' announced ratings for the senior unsecured debt of the post-merger National Grid plc at BBB+ (S&P) and Baa1 (Moody's) and these solid, investment grade ratings are indicative of strong credit quality. In fact, these ratings continue to place National Grid plc in the top quartile among regulated utilities in the U.S. (Exhibit No. ___ JGC/JR-1)).

Q. Why did Staff conclude that National Grid was at risk of a junk bond rating while the ratings agencies reach the opposite conclusion?

A. Staff raises four concerns. First, Staff notes that the "debt ratios produced by the proposed transactions suggest a greater downgrade." (MPP at 27:6-8) Second, Staff is concerned that the financial information provided by National Grid and KeySpan to the investment community may not reasonably reflect the impact of the regulatory environment. (MPP at 27:8-21) Third, Staff argued that the business risk profile of National Grid post-merger would be significantly higher than that of the company pre-merger. Fourth, Staff is concerned that the likely future impairment of goodwill could cause the credit rating agencies to further downgrade the merged entity. (MPP at 36-37)

Q. Do you agree with Staff's bond rating assessment?

A. No. As stated earlier the Credit Rating Agencies have already analyzed these issues and have rendered their opinions. Indeed, both S&P and Moody's have analyzed the proposed merger and have issued several reports that take account of the impact of the merger on bond ratings.

Q. What are the key points that you would like to raise regarding Staff's credit impact analysis?

A. Staff's analysis leads to conclusions on potential credit rating impact that directly contradict the conclusions arrived at by the credit rating agencies themselves, who aside from understanding their ratings methodologies the best, are sophisticated financial analysts that express independent opinions on matters of credit quality, They have considered all relevant regulatory and financial implications when they

evaluated the KeySpan transaction. There are two important reasons for staff's departure in its conclusion. First, Staff focuses exclusively on the debt-to-capital ratio, which is only one of the many factors considered by the rating agencies. We would also note that Staff's analysis on leverage contains no information that was not also available to the rating agencies and included in the rating agencies' more comprehensive analysis. Second, the debt-to-capital analyses conducted by Staff contain inappropriate assumptions about the nature of the merged National Grid's business.

Q. The first concern described above is Staff's focus on the debt-to-capital ratio. Why is it unreasonable for Staff to focus solely on the debt-to-capital ratio?

A. Debt-to-capital ratios are only one of many metrics that factor into the rating agencies' analysis. The many qualitative and quantitative factors that the agencies use in assessing Global Power Companies are described in the S&P and Moody's reports that Staff provided in Exhibits MPP-4 and MPP-5.

S&P has published guidelines for three key financial ratios that they use in their assessment of credit ratings for US utilities. However, Staff ignores two of these three ratios - the ratio of funds from operations ("FFO") to interest coverage and the ratio of FFO to total debt. Instead, Staff focuses only on the debt-to-capital ratio. The FFO ratios indicate how much cash is available to meet the debt service obligations (interest expense and principal repayments) of the firm. These metrics

are more indicative of credit quality than the ratio of debt to total capital measured in book value terms.

In fact the debt-to-capital ratio is the least important of the three ratios. S&P has stated (Staff Exhibit No. ___ (MPP-4), page 34)) that "Financial parameters that are increasingly viewed as relevant and reliable are coverage of fixed financial charges by cash flow and cash flow from operations to total debt. Less comparable measures, such as shareholders' equity, leverage and reported earnings, are also reviewed, but de-emphasized."

Staff also ignores the extent to which factors other than these three published financial ratios affect a company's bond rating. In discussing the publication of targets for the three financial ratios, S&P indicated on pages 2-3 of the publication included in Exhibit No. ___ (MPP-3) that:

Although credit ratio analysis is an important part of the ratings process, these three statistics are by no means the only critical financial measures that Standard & Poor's uses in its analytical process. We also analyze a wide array of financial ratios that do not have published guidelines for each rating category... Again, ratings analysis is not driven solely by these financial ratios, nor has it ever been. In fact, the new financial guidelines that Standard & Poor's is incorporating for the specified rating categories reinforce the analytical framework whereby other factors can outweigh the achievement of otherwise acceptable financial ratios.

By looking only at one metric (the debt to capital ratio), Staff's analysis fails to capture the depth of the credit rating process. But even more to the point, S&P and Moody's have already rendered their opinions, which are that National Grid will continue to have strong investment grade ratings after completion of the KeySpan acquisition.

Additionally, National Grid's corporate rating is, in fact, assessed by the rating agencies based on IFRS (International Financial Reporting Standards) financial projections, rather than US GAAP projections. While the cashflows generated by the business will be the same regardless of which accounting standards are used, it is worth noting that under IFRS, National Grid's debt / capitalization ratio at March 2006 is higher than the US GAAP equivalent. The differences between US GAAP and IFRS reporting were addressed in our response to DPS-109 (attached as Exhibit JGC/JR 5R). The differences between US GAAP and IFRS balance sheets reinforce the fact that the agencies focus on cashflow, rather than balance sheet metrics.

Q. It is noted above that the rating agencies consider FFO/interest and FFO/debt to be more important than debt-to-capital. How does the merged entity rate with respect to these ratios?

A. As we note above, the various quantitative and qualitative metrics that the ratings agencies use are assessed together. But, S&P has stated "Standard & Poor's expects National Grid's adjusted funds from operations (FFO) interest coverage to

remain more than 3.5x following the acquisition of KeySpan. Adjusted FFO-to-debt is also expected to remain at more than 15%." [S&P research: National Grid plc 15 May 2006]. To reduce the overall rating of National Grid to below investment grade, we believe that FFO/debt would have to fall to a level below 10%. A fall to 10% FFO/debt from 15% would require a reduction in revenues from the case presented to the credit rating agencies of around $3 billion each year. To put this in context, KeySpan's annual revenues for 2006, excluding gas cost recoveries, total approximately $4 billion.

Q. The Staff in its testimony on page 9 (9-14) states that "The only consideration keeping the rating agencies from downgrading Grid to the full extent suggested by the projected debt ratio levels after the transaction occurs is the cash flow produced by the ten year rate plan on which the merger is premised". Is this statement correct?

A. No. The projections supplied to the rating agencies were based on a business plan prepared by KeySpan prior to the rate filing in this case, adjusted to take account of the merger. The rating agencies have rated KeySpan for a number of years and therefore are able to judge the forecast against their own detailed understanding of the business and regulatory environment in which KeySpan operates.

Also, when making this assertion, Staff appears to recognize the importance of the FFO ratios to the credit ratings process than the simple capital ratios upon which Staff's arguments are based.

Q. The third concern in the Staff's analysis is the level of risk in the merged entity's business. Please elaborate.

A. The level of debt that a company can support is a function of the riskiness of its business. All else equal, companies that have lower business risk can support higher debt levels. The Staff has evaluated the level of the merged entity's debt in the merged business from three perspectives (two S&P measures of risk, one Moody's measure of risk). In these three analyses, however, Staff has overstated the level of business risk in the post-merger National Grid's business. As a result, they conclude incorrectly that the merged entity cannot support an investment grade bond rating given the post-merger debt levels.

Q. How is the level of business risk measured?

A. S&P assigns U.S. investor-owned utilities a business risk profile score between 1 and 10, with 1 being the lowest risk and 10 being the highest. These scores are generally driven by the type of business: transmission and distribution utilities (1-3); vertically integrated power companies (4-6) and generators and other competitive utility businesses (>6). Staff's analysis assumes that the post-merger National Grid will viewed as a typical vertically integrated utility due to the fact that KeySpan owns some generation. As a result, Staff infers that the merged entity has a business risk profile of 5—the middle score for a typical vertically integrated utility. (MPP at 19). This is incorrect.

Q. What are the business profile scores of the KeySpan and National Grid?

A. KeySpan regulated utilities KEDNY and KEDLI have a risk profile of 1. We believe that the risk profile of the regulated utilities will not change as a result of the acquisition. KeySpan Corporation has a risk profile of 4—similar to a low-risk vertically integrated utility. National Grid has a business risk profile of 2—similar to a low to average risk transmission and distribution company.

Q. What will be the business profile score for the merged entity?

A. The most reasonable way to estimate the business profile score for the combined entity is to compute a weighted average of the business profile scores for the underlying companies. On pages 162-163 of Staff's testimony, Staff notes that KeySpan's capitalization is about $8.8 billion, while National Grid, after the merger, would have a consolidated capitalization of about $47.5 billion. Thus, KeySpan would represent about 19 percent of the National Grid capitalization, post-merger, with National Grid comprising the remaining 81% of the combined value. A weighted average therefore suggests that a business profile in the range of 2-3 is appropriate for the merged entity. It is not reasonable to conclude that the combination of a business with a risk profile of 2 and another business with a risk profile of 4 will result in a business with a risk profile of 5.

In addition, National Grid has announced its intention to divest or spin off a number of businesses which are considered to have a higher risk profile (Wireless Infrastructure business in UK and US; Basslink electricity interconnector in

Australia). Following these disposals, National Grid's business (excluding KeySpan) would be expected to have an even lower business risk profile.

Q. What are the implications of this score with respect to the debt-to-capital ratios?

A. This score shows that if National Grid were rated as a US utility, the 63% debt ratio assumed by Staff is consistent with an investment grade rating given the likely business profile score of the companies. The range of debt ratios for a BBB company with scores of 2 and 3 are 58%-68% and 55%-65%, respectively. Thus, a properly estimated business profile score shows that the merged entity's debt ratio is consistent with an investment grade rating for a US utility, even before considering any of the other ratings factors.

Q. Does Staff analyze the debt ratio in any other ways?

A. Yes. Staff recognizes that ratings considerations can differ for international utilities. Thus, they have also analyzed the debt ratio using an S&P approach for global utilities. This approach compares the merged entity's debt rating to median debt ratings of investment grade utilities by type of utility. In this case, Staff assumes that the merged entity is a vertically integrated utility. Based on this analysis, Staff again concludes that the post-merger National Grid has too much debt to be investment grade. (MPP at 20-21).

Q. Is the Staff's methodology sound?

A. No. Based on its assumption that the post-merger National Grid is a vertically integrated utility, Staff concluded that Grid's debt ratio exceeds the median for a BBB utility. From this first conclusion Staff draws a second conclusion, namely, that Grid will have junk bond status. In other words, Staff again relies solely on the debt-to-capital ratio as a metric and its own (rather than S&P's) assessment of business risk to conclude that Grid's credit risk will be below average for BBB utilities. It then concludes that because Grid's debt ratio falls below the median debt ratio of BBB-rated utilities, Grid would be rated "junk". The second conclusion is mysterious because half of *any* population is below the median and half above *by definition*. Thus, Staff seems to imply either that a) all of the companies in a rating category must have identical debt ratios (in which case all would be at the median, not above or below), or b) that half of the companies in any given ratings category should not be in that category

Q. Does Staff consider Moody's ratings procedures in evaluating capital structure?

A. Yes. Staff assumes that Moody's views the post-merger Grid as a medium risk business entity. This conclusion is unreasonable because generation will be only a small percentage of the business. While the ratings procedures used by Moody's and S&P differ, Moody's risk profile is similar to the S&P business profile score. As shown in the analysis of the S&P business profile score, the merger does not shift the S&P score from the low risk to medium risk. Rather, it moves Grid from average low risk to slightly above average low risk.

Q. What do you conclude from this analysis of credit quality?

A. Contrary to Staff's suggestions, the merger of National Grid and KeySpan on the terms proposed will not undermine the investment-grade bond rating of National Grid. Rather, National Grid will continue to have ready access to the capital necessary to maintain and upgrade the larger, combined system. Staff's concerns about the credit quality of the combined firm are unwarranted, and its conclusions are incorrect. The Commission should be assured that the expanded National Grid will have the financial integrity to meet the future financing requirements of Niagara Mohawk, KEDNY, KEDLI, and the other operating companies on the combined National Grid/KeySpan system.

Goodwill

Q. What is staff's position on recording goodwill?

A. On page 43 Staff states generally that they *"oppose recording goodwill"*. They also state that *"in those limited circumstances where it may be appropriate to recognize goodwill, we see it as an asset that would likely be written off over a relatively short time period."*

Q. Are these positions stated by staff consistent with Generally Accepted Accounting Standards (GAAP) or with SEC guidance?

A. No. Statement of Financial Accounting Standards No. 141 (Issued in June 2001) on Business Combinations (FAS 141) requires that the cost of acquiring an entity be allocated to the fair market values of the assets and liabilities with any excess

recorded as goodwill. In addition, Statement of Financial Accounting Standards No. 142 (Issued in June 2001) on Goodwill and Other Intangible Assets (FAS 142) states that "intangible assets with an indefinite useful life should not be amortized, but should be tested for impairment at least annually." As a result of accounting guidance, any goodwill resulting from the fair market value study is required to be recorded, and after the initial allocation of goodwill, should not be amortized but should be tested for impairment.

Q. The Staff suggest that National Grid has avoided questions on the allocation of goodwill and its effect on rates. Is this correct?

A. No. As we have explained (in DPS 28, 35 and 106 and in this testimony), the calculation and allocation of goodwill will be done at completion of the transaction. We have also emphasized that goodwill will have no effect on rates which is further explained by Messrs. Bodanza/LaFlamme/Molloy. As such, the overall amount of goodwill which arises from the transaction and the allocation of such goodwill will have absolutely no effect on customers rates.

Q. Is there anything else you would like to address?

A. Yes

Q. In Staff's testimony, Staff states that the base case valuation analysis done by National Grid with respect to its bid for KeySpan did not assume that National Grid would retain 50% of synergy savings for 10 years and thus

the proposed sharing of the synergy savings occurs over too long a period. How do you respond?

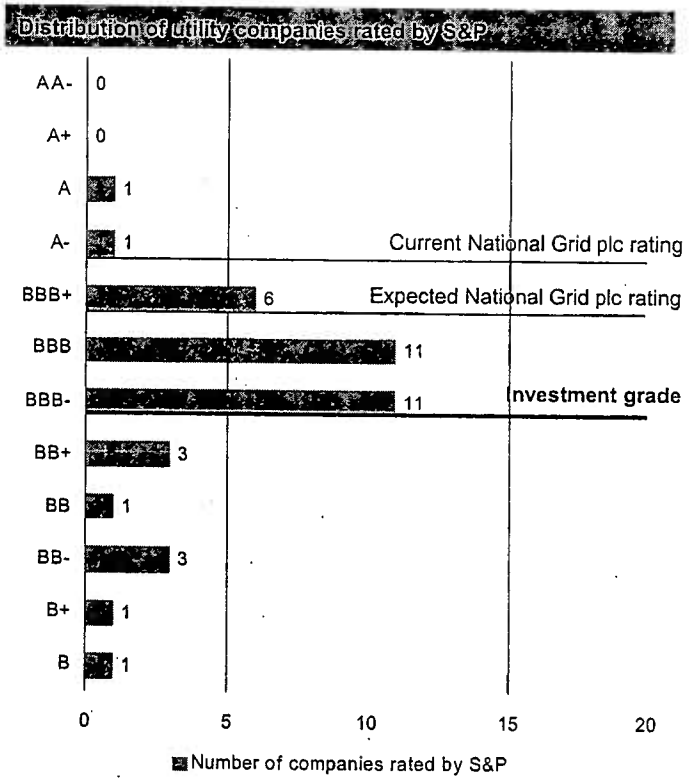
A. National Grid's valuation was based on a range of assumptions for each part of the KeySpan business with sensitivities (up and down) on a number of variables. The case presented to the Board represented one such scenario and reflected the conservative nature of due diligence when making an offer on such a complex transaction. The Board was aware that specific assumptions could change in either direction, but that the various assumptions used could not be isolated and all need to be taken into account when considering the overall value. As explained in Messrs. Bodanza/LaFlamme/Molloy's testimony, the use of a ten year period for the amortization of synergy savings and costs to achieve provides a benefit to the customers of KEDNY and KEDLI, and is consistent with what was approved by the Commission in the Niagara Mohawk rate plan.

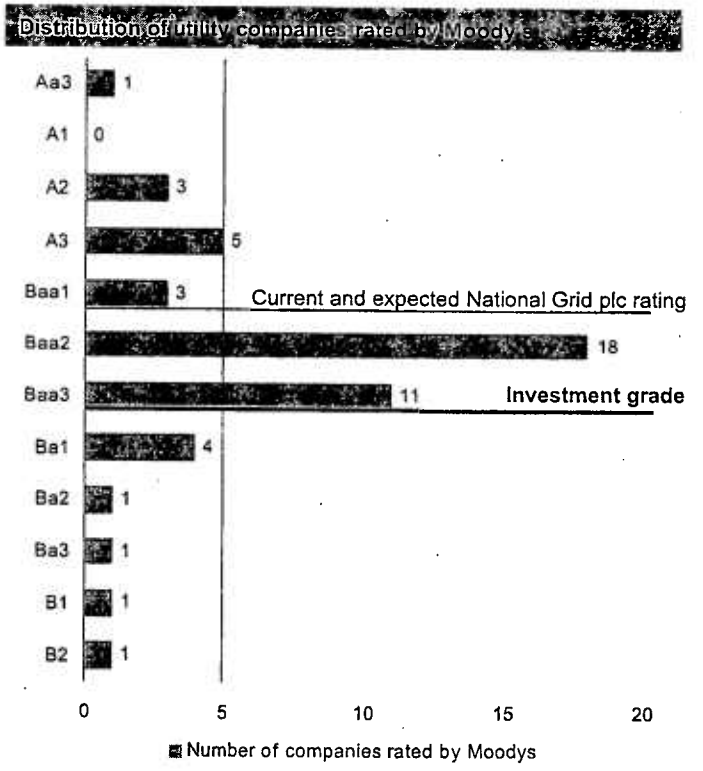
Q. Does this conclude your Testimony?

A. Yes.

Utilities ratings

Utility Credit ratings - Holding Companies





Notes:
(1) Ratings are comprised of holding companies' senior unsecured offerings, where available, or otherwise of issuers
(2) Includes 38 and 49 small, mid and large-cap utility companies rated by S&P and Moody's, respectively
As of March 4, 2007

Credit Opinion: National Grid Plc

National Grid Plc

United Kingdom

Ratings

Category	Moody's Rating
Outlook	Developing
Issuer Rating	Baa1
Senior Unsecured	Baa1
Commercial Paper	P-2
Other Short Term	*P-2
National Grid Electricity Transmission plc	
Outlook	Rating(s) Under Review
Senior Unsecured	**A2
Commercial Paper	**P-1
Other Short Term	**P-1
National Grid Gas Plc	
Outlook	Rating(s) Under Review
Senior Unsecured	**A2
Jr Subordinate MTN	A3
Commercial Paper	**P-1
Other Short Term	**P-1
National Grid Gas Holdings Plc	
Outlook	Stable
Senior Unsecured -Dom Curr	A3

* Placed under review for possible downgrade on February 27, 2006
** Placed under review for possible downgrade on January 12, 2007

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Stuart Lawton/London	

Key Indicators

National Grid Plc

	2005/06	2004/05
EBITA Margin	38.2%	42.1%
Adjusted RCF/ Net Adjusted Debt	12.4%	13.1%
Adjusted FFO Interest Coverage	3.6x	3.9x
Adjusted RCF/Capex + Investments (net of disposals)	81.7%	115.0%
Debt / Book Capitalisation	72.3%	76.2%
FFO / Net Adjusted Debt	18.2%	16.9%

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

National Grid Plc is the holding company for a range of largely regulated businesses, focusing on the ownership and operation of electricity and gas transmission and distribution networks in the UK and the North East of the US representing 62% and 38% of the Group operating profit respectively. Its primary regulated UK subsidiaries include National Grid Gas plc ("NGG") (A2 / P-1) and National Grid Electricity Transmission Plc ("NGET") (A2 / P-1). The Group also operates non-regulated businesses, including a wireless communication infrastructure businesses, metering and meter-reading services, interconnectors between national electricity networks and an LNG terminal on the Isle of Grain.

Rating Rationale

National Grid's rating are based on Moody's Rating Methodology for Global Regulated Electric Utilities, given that National Grid's electricity transmission and distribution represent more than 50% of its consolidated revenues and that the credit characteristics of the company's gas networks which represent the second largest source of operating profit are similar to those of its electricity grid. Accordingly, regulated network utilities are assessed by observing the regulated and unregulated activities in the company business mix and the related quantitative risk factors.

ASSESSMENT OF REGULATED AND UNREGULATED ACITIVITIES IN THE COMPANY'S BUSINESS MIX:

NG's ratings are supported by the cash flows it receives as dividends and other cash inflows from its principal operating companies and the Group's clear and conservative strategy focusing on regulated networks businesses in the UK and US. Regulated activities constitute the vast majority of NG's operations with more than 80% of its operating profits stemming from NGET, NGG and its US regulated activities. The group's business risk profile remains driven by the stability and predictability of its UK and US regulated businesses. These businesses operate within established and transparent regulatory frameworks associated with little regulatory uncertainty. Moody's, which classifies regulatory frameworks on a scale of 1 to 4 with 1 being the most predictable and/or supportive regime, views the UK framework as 1 and the New York, Rhode Island and Massachusetts, where NG operates in the US as marginally less supportive "type 2" environments. Regulated revenues from the UK are based on an 'RPI minus x' formula designed to cover operating cost, capital expenditure and replacement expenditure, as well as to earn an allowed return on their regulatory asset values (RAV). In the US, revenues are based on tariffs approved by the Federal Energy Regulatory Commission (FERC) and the state regulators which are designed to enable them to recover their costs, with a return on capital.

Unregulated activities contribution to revenues and operating profit is low and plays a subordinated role in NG's overall credit quality. In addition, those activities are effectively associated with the Group's role as a network operator; therefore their relative business risk is also low.

Overall, as NG is pursuing a conservative strategy focusing on regulated networks and as NG's receives predictable cash flows by means of dividend streams from its very low risk regulated operating subsidiaries, Moody's views NG's business profile as very low risk.

ASSESSMENT OF QUANTITATIVE RISK FACTORS:

The NG Group exhibits relatively high leverage and moderate debt protection measures, albeit in line with its low-risk business profile with retained cash flow (RCF) to net adjusted debt at 13% for the year ending 31 March 2006. As at 31 March 2006, the group's net adjusted debt position was GBP13.7 billion, including the capitalisation value of operating lease payments (estimated to amount to around GBP720 million) and GBP1.3 billion of under-funded pension liabilities.

If the KeySpan acquisition completes, the expected GBP 6.8 billion of debt that the acquisition will bring (including GBP4.2 billion plus GBP 2.6 billion existing debt at KeySpan) will be added to NG's balance sheet and therefore will result in a deterioration of the financial profile of the company. Whilst Moody's expects the group's retained cash flow to net debt ratios to weaken with the additional debt, it also expects significant additional incremental cash flow generation from KeySpan to partially mitigate the greater debt burden. Also, NG has a strong liquidity profile underpinned by a 364-day MAC-free USD 1.5 billion syndicated credit facility, which expires in November 2007 but benefits from a 12-month term-out option which effectively extends the availability until November 2008.

Structural Considerations

NG's Baa1 / Prime-2 ratings take into account structural subordination of current and future anticipated debt. It thereby reflects bondholders' distance from the operating companies' cash flows, the size of current and anticipated future debt carried by the operating entities and the possible negative consequences of the regulatory ring-fencing applicable to the UK operating companies for bondholders at NG. At the moment, Moody's notches the holding company by one notch down from the consolidated group's credit quality which is currently in the mid single "A" range, but which is likely to fall into the low "A" range once the KeySpan acquisition completes, as reflected in the developing outlook (see below).

Rating Outlook

NG's ratings have a developing outlook (see below).

Recent Developments

In November 2006, Moody's published a Request for Comment, entitled "European Regulated Utility Groups: Methodology Update". The principal proposed change related to the fact that the ratings of wholly-owned regulated issuers would now be allowed to exceed the consolidated rating of the group only in certain circumstances. Following market feedback, Moody's recently published a final version clarifying further the amendments made to its methodology and their rating implications - please refer to Moody's Rating Methodology entitled "European Regulated Utility Groups: Methodology Update".

Drivers of Rating Change

The Baa1 rating of National Grid Plc is based on Moody's new methodology, whereby the notching between holding companies and the consolidated credit quality of the group is normally limited to one notch at firm investment grade rating levels. Consequently, should the acquisition of KeySpan complete under current assumptions whereby the most likely result would be a one notch downgrade of the consolidated group to A3, the holding company would be affirmed at Baa1. Conversely, in the event that the acquisition does not complete, the holding company rating could be upgraded.

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January 2007

Case 06-M-0878
Exhibit No. ___ (JGC/JR-2R)
Page 4 of 11

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European Regulated Utility Groups: Methodology Update

Introduction

Further to the Request for Comment dated Novermber 2006, Moody's is implementing the changes articulated below (and previously discussed in the aforementioned Request for Comment) to its rating methodology for complex regulated utility groups in Europe. These changes are designed to refine and clarify Moody's current methodology in order to ensure a consistent approach to the assignment of ratings for complex European regulated utility groups, which include multiple issuers of debt. Although similar group structures exist in other corporate sectors, having several group entities that access the public financial markets independently is a characteristic feature of utility groups, particularly in the UK.

The principal changes to existing methodology are:

- In normal circumstances, the ratings of wholly-owned regulated issuers within an integrated energy group will no longer be allowed to exceed the consolidated rating of the group. Where the group is itself a component of a larger integrated group, the benchmark, in the majority of cases, will be the consolidated rating of the whole group.
- Ratings of subsidiaries will be principally based on an assessment of their stand-alone financial strength. According to Moody's standard methodology, a Rating Committee may decide that, due to implied parental support, the subsidiary rating should benefit from a degree of uplift, which would typically be one or two notches (but could be more, if warranted).
- The rating differential of regulated subsidiaries within the same regulatory jurisdiction would, however, be typically limited to two or three notches from the consolidated rating.
- Ultimate holding company ratings will, typically, continue to be notched down from the consolidated rating to reflect structural subordination. Intermediate holding company ratings will be derived (notched) from the uncapped, stand-alone ratings of the operating companies, but the rating of an intermediate holding company will not be permitted to exceed the consolidated rating of the group.
- Regulated subsidiaries may nonetheless be rated higher than the consolidated group rating if that rating has reached a level at which the regulators could choose to trigger an existing ring-fence that effectively prevents the upstreaming of funds from operating subsidiaries.

We define complex utility groups as utilities that have: (1) more than one rated entity in the group, commonly within a holding and operating company structure; (2) at least one group entity regulated by ring-fence limitations, with the result that cash flow circulation within the group may be limited by regulatory intervention; and/or (3) a material contribution to total earnings from such subsidiaries (i.e. greater than 40% in total).

Summary Rating Approach

Moody's usually rates corporate groups on the basis of their consolidated credit fundamentals, on the assumption that cash can be transferred freely throughout the group. However, a different approach is required for structures comprising a holding company and one or more operating companies, where the latter are regulated businesses and are thus required to adhere to a certain financial profile or credit rating, thereby limiting (1) the absolute leverage the company can carry, and (2) in certain circumstances, the cash that can be taken out of the subsidiary by the wider group. Although such structures are not limited to the UK, they are an established characteristic of that market because the regulators there place a particular emphasis on regulated companies maintaining a minimum rating (generally at low investment grade).

Europe versus US Regulatory Framework

The approach set out in this document differs from the notching practices for complex utility groups in the U.S. and Canada. This reflects substantial differences in the regulatory framework, and the impact those differences have on financial strategy. In North America, electric utilities and gas distribution utilities are primarily regulated at the state and provincial level. These regulators tend to be more restrictive about financial activities and more parochial in outlook than national regulators found in Europe. Regional regulators are more likely to restrict movements of cash between entities in the same issuer family, and often must approve long-term financing that takes place at the regulated subsidiary. Greater oversight is particularly likely where some subsidiaries are regulated and some are unregulated, or when multiple regulated subsidiaries are subject to different regulatory jurisdictions. Regional regulators usually do not permit loans from regulated utilities to the unregulated parent company, and are more likely to apply pressure that limits the use of larger than normal dividends to support affiliates. Reflecting the stronger emphasis on the financial separateness of each regulated entity, a North American parent company is also less likely to provide a stressed regulated subsidiary with extraordinary support that might undercut regulatory and political pressure for a stand-alone regulatory solution. As a result, a subsidiary facing financial or regulatory stress may be rated lower than the parent company if the parent's other subsidiaries represent the majority of consolidated cash flow. All of these factors result in less cohesion between ratings in complex groups in comparison to what is typically observed in Europe, and the average level of notching between legal entities in a single issuer family is greater in North America.

Consolidated rating of the group is the starting point for the assessment of a complex group

The starting point of Moody's analysis for all ratings of complex regulated utility groups (as defined above) is the consolidated rating (which in essence is equivalent to a Corporate Family Rating). This rating is not necessarily publicly assigned, but in all cases forms the basis of the rating rationale. The consolidated rating is determined by examining the financial profile of the consolidated group in the context of the combined business risk profile of the group, and ignores priority of claim.

The perimeter of this analysis may be restricted to a sub-group, if such sub-group is clearly autonomous from the ultimate parent/wider group such that it should be viewed as an independent group in its own right (e.g. a UK sub-group of a US diversified firm), or it may reach to the ultimate parent if the wider group is managed as an integrated utility group.

In line with Moody's established approach, group subsidiaries are rated on a stand-alone basis, although in most cases the rating is constrained by the group's consolidated rating

Like other subsidiaries of larger groups, the subsidiaries of complex utility groups are assigned ratings on a stand-alone basis, taking into account the specific business and financial risk of these entities. Beyond the external debt assumed by the subsidiary, the rating assessment also factors in the subsidiary's explicit obligations in respect of the servicing of any holding company debt, and also any permanent intercompany loans to which the subsidiary is a long-term borrowing party. It should be noted that, where an intercompany loan is in the form of debt that is pari-passu with external debt at

the subsidiary, this may reduce, on a pro-rata basis, the degree of structural subordination which might otherwise be deemed to exist at the holding company level. Under normal circumstances, stand-alone, wholly-owned subsidiary ratings are constrained or, if weaker, may get a degree of support from the consolidated strength of the group. According to Moody's standard methodology, a Rating Committee may decide that, due to implied parental support, the subsidiary rating should benefit from a degree of uplift, which would typically be one or two notches (but could be more, if warranted). The rating differential of regulated subsidiaries within the same regulatory jurisdiction would, however, be typically limited to two or three notches from the consolidated rating. The rationale for this is Moody's view that any material credit deterioration of a weaker subsidiary would probably be counterbalanced by one or several supporting stronger subsidiaries, thus resulting in a closer alignment of ratings. Moody's recognises that, in many cases, the holding company has the ability to manage the capital structures of its subsidiaries to provide credit support and additional cash where required.

In assessing the rating of an intermediate holding company that may own operating companies, Moody's will take into account for notching purposes the uncapped, stand-alone ratings of the operating companies (prior to any benefit for uplift as described above). Nonetheless, the rating of any such intermediate holding company will not be permitted to exceed the consolidated rating of the group.

Regulated subsidiaries can pierce the group's consolidated rating in certain circumstances

Regulated subsidiaries of utility groups can, under certain circumstances, exceed (or 'pierce') the group's consolidated rating. These circumstances usually occur in the UK when the consolidated rating is Baa2 or lower. In the case of countries with similar regulatory characteristics to the UK, Moody's will apply the same logic. The group's ability to extract cash from regulated subsidiaries may be impaired by regulatory provisions stipulating that the regulated entity maintains a certain financial profile. Such so-called "ring-fence" provisions are commonly embedded in a company's licence (as in the UK water, electricity and gas sectors). In the UK, where a regulatory ring-fence exists, we assume Baa2 as the implied regulatory minimum rating for regulated subsidiaries, thus allowing a margin of error. Accordingly, in a distress situation, regulated subsidiaries are likely to maintain investment grade ratings and could thus pierce the consolidated rating by several notches.

Holding companies are notched from the consolidated rating to reflect structural subordination

Ultimate holding company debt is notched from the consolidated rating of the group to reflect the structural subordination of creditors at this level. Where the consolidated rating is Baa1 or higher, the notching is normally limited to one notch below the consolidated rating (which will, typically, also be the rating of the regulated operating companies, although some may be rated lower, depending on their stand-alone financial strength). Where the consolidated rating is Baa2 or lower, the divergence between the holding company and the regulated operating entities can widen to two or more notches, in order to reflect the risk of cash lock-ups at the regulated subsidiaries that prevent the holding company from accessing their cash flows. This may result in holding company ratings being one or more notches lower than the consolidated rating, while the regulated subsidiaries could pierce the consolidated ratings by one or more notches. Additional holding companies are typically rated one notch lower than the intermediate holding company below them, where debt held by the intermediate holding company is material in relation to the total debt of the group.

Related Research

Rating Methodology:

Global Regulated Electric Utilities, March 2005 (91730)
UK Independent Gas Distribution Companies, March 2004 (87574)
European Electric Utilities, June 1999 (45494)

Special Comments:

UK Water Sector: Key ratios used by Moody's in assessing companies' credit strength, March 2006 (97010)

Industry Outlooks:

European Electric Utilities, October 2005 (94486)
European Gas, February 2006 (96548)

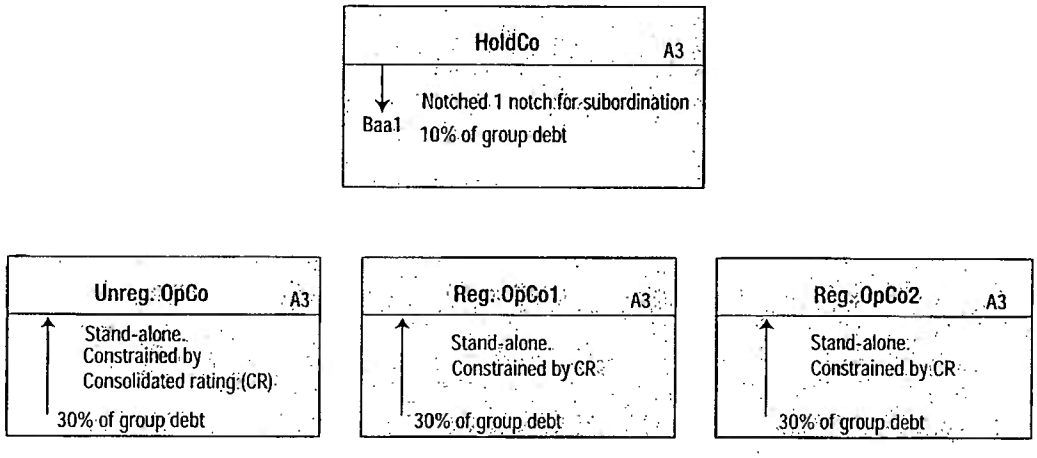
To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Appendix

Examples

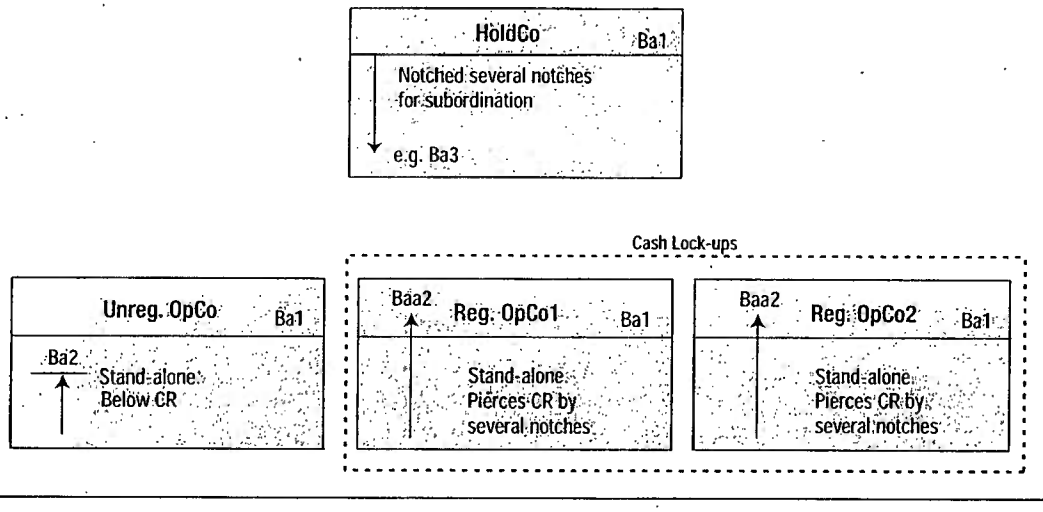
Example 1

Typical Scenario, Consolidated Rating (CR) = A3



Example 2

Meltdown Scenario, Consolidated Rating (CR) = Ba1



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Report Number: 101671

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National Grid PLC
Capital Structure

Case 06-M-0878
Exhibit No. ___ (JGC/JR-3R)

£ in millions	US GAAP Basis March 31, 2006 £	%
Total Capitalization		
Debt, net of cash and marketable securities	10,600	51.99%
Common stockholder's equity	9,747	47.81%
Minority interest in subsidiaries	11	0.05%
Cumulative preferred stock	30	0.15%
Total capitalization	20,388	100.00%

Source: National Grid PLC Annual Report March 31, 2006

£ in millions Proforma - including Keyspan acquisition financing and assumed debt	US GAAP Basis March 31, 2006 £	%
Total Capitalization		
Debt, net of cash and marketable securities	16,645	62.97%
Common stockholder's equity	9,747	36.87%
Minority interest in subsidiaries	11	0.04%
Cumulative preferred stock	30	0.11%
Total capitalization	26,433	100.00%

Information provided in NYC-39

£ in millions Proforma - including Keyspan, Adjusted for RAV acquisition financing and assumed debt	US GAAP Basis March 31, 2006 £	%
Total Capitalization		
Debt, net of cash and marketable securities	16,645	55.94%
Common stockholder's equity (see note)	13,068	43.92%
Minority interest in subsidiaries	11	0.04%
Cumulative preferred stock	30	0.10%
Total capitalization	29,754	100.00%

Note:
Common stockholder's equity adjusted to restate book value of UK regulated utuilities from US GAAP value to RegulatoryAsset Value (RAV)

Cases: 06-M-0878
06-G-1185
06-G-1186

National Grid/KeySpan Merger

Interrogatory/Document Request

Response of National Grid/KeySpan

Re: Capital Structure, Bond Ratings (DPS 111)

Request #: DPS-158

Response Date: October 26, 2006

Respondent: J. Cochrane, J. Bodanza, J. Holodak

Q:

1. Regarding the responses provided to DPS-111:

(a) Does the response to question 1 represent National Grid and KeySpan's entire rationale for why the consolidated common equity ratio of National Grid on a GAAP basis is not used to set rates for KEDNY and KEDLI? If not, provide the entire rationale.

(b) Do petitioners agree that KEDNY and KEDLI's common stock is financed with debt at the National Grid PLC level? If not, explain why.

(c) Does the response to question 2 represent National Grid and KeySpan's entire rationale for why it is reasonable to assume that 50% of KEDNY and KEDLI's assets are financed with common equity if that equity is in fact purchased with cash proceeds generated by National Grid debt? If not, provide the entire rationale.

(d) Does the response to question 3 regarding National Grid as an individual investor represent the company's entire position on why the Commission should treat National Grid as an individual investor? If not, provide the entire rationale.

(e) The response to question 3 indicates that "...it made sense to add debt to the balance sheet in relation to the nature of National Grid's existing international regulated and unregulated assets..."

(i) Describe why this made sense.

(ii) Provide National Grid's total consolidated long and short term debt balance.

(iii) Show the specific National Grid assets financed by its consolidated long and short-term debt balance.

(f) It is unclear how the answer provided to question 4 indicates whether National Grid agrees or disagrees with the statement that "it is ever appropriate to use a holding company's consolidated capital structure to develop the overall cost of capital for the purpose of setting the rates of a utility subsidiary." Please indicate whether National Grid agrees or disagrees with this concept and state why.

(g) The response to question 7 where National Grid classifies goodwill as an intangible asset does not answer the question of whether National Grid believes that goodwill is a regulated or unregulated asset. Provide an answer that responds to the question posed and explain the basis for the answer.

(h) Regarding the responses to questions 10-12:

(i) Does National Grid believe that the implementation of the bond rating actions noted in the recent S&P and Moody's statements for National Grid will have a material effect on its ability or the ability of any of its affiliates to raise capital in the financial markets? Provide the basis for the response, including all studies and analyses which the National Grid has performed to analyze the potential credit quality effects of the merger.

(ii) Does KeySpan believe that the implementation of the bond rating actions noted in the recent S&P and Moody's statements for KeySpan will have a material effect on its ability or the ability of any of its affiliates to raise capital in the financial markets? Provide the basis for the response, including all studies and analyses which the KeySpan has performed to analyze the potential credit quality effects of the merger.

(i) Are there any corporate provisions currently limiting KeySpan's debt ration? If so, describe it and explain how it would apply if the proposed transaction was consummated.

A:

1.

a

As stated in response to DPS – 111, we believe that the existing capital structure at KEDLI and KEDNY (equity /debt of 59%/41% and 51%/49% respectively as of July 31, 2006) is supporting the existing rate base. As we explain in our response to DPS 159, we expect that the KEDLI equity ratio will be around 50% by the end of 2006. There have been a number of information requests regarding the capital structure at both the consolidated level and with the individual subsidiaries. We understand the need to ensure the financial integrity of KEDLI and KEDNY and believe the proposals in the Petition, as further explained in the testimony of John Cochrane, do so.

The National Grid/Keyspan merger will not change the underlying rate base that exists at KEDLI and KEDNY. As we do not intend to push down any acquisition related debt to KEDLI and KEDNY, the debt and obligations of these subsidiaries will be exactly the same as before the acquisition. There will be no direct obligation for KEDLI and KEDNY to pay any merger financing costs to the holding company. Because rate base and the companies' obligations are not changing, the capital structure to support the business should not change as well.

Moreover, the use of a different capital structure for KEDLI and KEDNY that is not in fact supporting the rate base and rates would not improve the financial integrity of these companies. In fact, it would undermine the financial stability of KEDLI and KEDNY by restricting access to and increasing the cost of future equity and debt capital that may be needed. Additionally, the capital structure for the subsidiaries should be used in the calculation of return on equity for the applicable subsidiaries. Looking at the issue more broadly, we believe that the capital structure of the subsidiaries should be used for rate making because the underlying rate base, rates and regulatory assets and liabilities were financed by their existing capital structure.

This is the approach used by FERC and for National Grid and KeySpan's other US subsidiaries. In New York, the existing rate plans and earnings sharing filings for Niagara Mohawk, KEDLI and KEDNY, as well as the regulation of KeySpan's generation on Long Island are all based on the capital structure of the entity being regulated.

We also believe that this approach is consistent with Commission decisions on this issue. Recently, the Commission adopted in the Central Hudson electric and gas rate case the capital structure of the stand-alone utility as provided in the Joint Proposal. See Case 05-E-0934 and 05-G-0935 (Order Establishing Rate Plan, issued and effective July 24, 2006). We believe that it is important to note that the Commission has approved the use of the stand alone utility capital structures that have been agreed to in Joint Proposals that have been previously brought before the Commission for approval Additionally, the

Commission also allowed a stand alone structure with respect to Rochester Gas & Electric Corporation. See Cases 02-E-0198 and 03-E-0765. In the Valley Energy Inc. rate case, Valley Energy was a subsidiary of C&T Enterprises, Inc. and received its financing through the parent company, and the Commission found that the use of a hypothetical capital structure for Valley Energy was appropriate. See Case 04-G-0821. Finally, in the St Lawrence Gas Company's rate cases, the utility's stand-alone debt ratio was used in determining the company's capital structure and the capital structure of the parent company was not used. The Commission rationale was that the stand alone utility capital structure was more consistent with the industry than that of the parent company. See Case 99-G-1188 and Case 97-G-0409. As further explained in Staff's Brief Opposing NYSEG's Petition for Rehearing in Case 05-E-1222 dated September 22, 2006, St Lawrence is owned by a "Canadian company whose financial profile is, among other things, governed by Canadian governmental restrictions on its ability to refinance high cost debt" which provided the Commission with a rational basis for approving the stand alone utility capital structure. Staff Brief at page 12.

Finally, the use of a parent company capital structure would be inappropriate with respect to KEDLI and KEDNY for the further reasons discussed below and because arbitrary assumptions would have to be made about businesses outside New York.

The use of National Grid plc's balance sheet implies that the future regulatory capital structure applicable to KEDLI and KEDNY could be affected by transactions which have no bearing on these businesses. For example, if National Grid issued equity for a non-US acquisition (as it did in the 2002 Lattice transaction in the UK), or sold unregulated (e.g., generation) assets at above book value; then the equity portion of National Grid's capital structure would increase.

As a largely regulated and international business, National Grid's market valuation is driven by a range of factors, including the regulatory structure and business performance in each of its jurisdictions. For our UK electricity and gas delivery businesses, revenues are driven by a regulatory structure which is materially different from the process by which rates are set for US utilities. For example, the closest equivalent to rate base is a Regulatory Asset Value (this has no direct relationship to the book value of these businesses), which was initially derived from a combination of replacement cost and market value and increases with inflation each year.

The consolidated capital structure of National Grid plc should therefore not be used and we believe that this approach is consistent with the rationale that was used in the St Lawrence case, as well as the other cases discussed above.

b.
As answered in DPS 111, Part 2, National Grid is purchasing the equity of KeySpan Corporation. The equity and stock of KEDNY and KEDLI will still be owned by KeySpan. No acquisition debt will be pushed down to KEDNY or KEDLI.

c.

As we explain in Parts 1.a. and 1.b. above, we do not look at the financing of the Transaction in the way the question is phrased.

d.

Please see response to DPS-111 and the response to Parts 1.a. – 1.c. above.

e. (i)

As explained in our response to DPS 104, National Grid felt that it had the financial capacity to pay cash for KeySpan and did not need to issue equity.

Following the sale in 2005 of four UK gas distribution networks for some £5.8 billion, National Grid returned £2 billion of the proceeds to shareholders. A substantial portion of National Grid's shareholders and the equity analysts who follow National Grid expressed a view that following these disposals, National Grid had an overly conservative balance sheet. A selection of such analyst reports on this topic was attached to DPS 104 to demonstrate this point. It therefore was prudent to adjust the National Grid plc balance sheet by funding the acquisition of Keyspan, which itself made sense from a valuation perspective, with cash.

Our response to DPS 26 (confidential) includes our analysis of the expected impact on National Grid's earnings and credit rating as a result of the Keyspan acquisition.

National Grid had the financial capacity to fund the transaction with cash and maintain a strong investment grade credit rating.

e. (ii)

As provided also in response to DPS 109, Question 4

US GAAP Basis.

National Grid PLC
Capital Structure
Fiscal Years Ended March 31, 2006

£ in millions

	US GAAP Basis March 31, 2006 £	%
Total Capitalization		
Debt		
Long-term debt	9,838	
Short-term borrowings, net of cash:		
Short-term borrowings	2,612	
Marketable securities	(384)	
Cash and cash equivalents	(1,466)	
	10,600	52.10%
Common stockholder's equity	9,706	47.70%
Minority interest in subsidiaries	11	0.05%
Cumulative preferred stock	30	0.15%
Total capitalization	20,347	100.00%

Source: National Grid PLC Annual Report March 31, 2006

e. (iii)

We do not manage our capital structure in this way. We manage our capital structure at the Group and subsidiary levels to optimize overall performance. Therefore, we cannot associate specific existing assets with that financing.

f.

We believe that rates should be based on the capital structure of the relevant subsidiary.

g

We answered question 7 to DPS-111 as we understood it.

We are not seeking to include goodwill in rate base or seek recovery of it in this case.

In accordance with the accounting standards, we consider goodwill an intangible asset.

If a regulatory body were to allow recovery of goodwill or acquisition premium, then we would consider it as a regulatory asset and it would not be considered goodwill.

h
(i)

We do not believe that there will be any material impact on the ability of any NG Group company to raise debt finance in the capital markets. The rating agencies have not yet published their final expectations of credit ratings for all companies in the NG Group post the completion of the KeySpan acquisition.

Our response to DPS-26 (confidential) refers to our analysis of the potential impact of alternative financing structures. National Grid proposes to provide these studies to Staff and CPB on a confidential basis. A supplemental motion for confidential treatment will be filed on this material.

Since the KeySpan transaction was announced, NG plc has raised the equivalent of $5.5 billion in the international debt capital markets. This debt was raised successfully with full knowledge that we are in the process of acquiring KeySpan and that the rating agencies have indicated the potential for a ratings downgrade

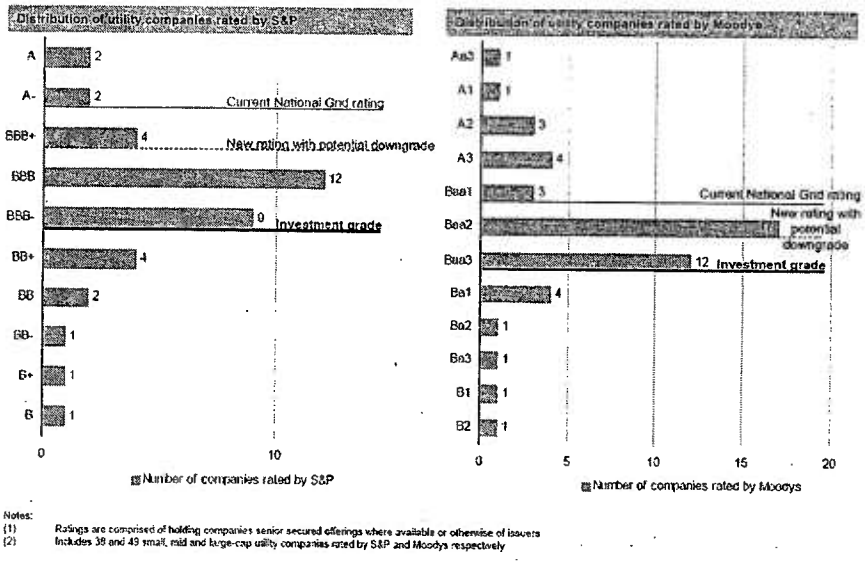
In the event of a single notch downgrade for all of our group businesses, NG plc would have a senior unsecured rating of BBB+/Baa2. The pool of investors available to NG plc at that rating is not materially different than that available to an A-/Baa1 issuer.

The following chart shows the credit rating of National Grid plc and those of US utility companies. In each case, we show the company's (holding company only) most recent senior unsecured debt rating if available or otherwise its issuer rating provided by both Moody's and S&P, if rated. The chart indicates that National Grid plc's rating is in line with the rating of similar companies.

Note that the ratings of utility subsidiaries are typically higher than the holding companies.

Utilities ratings

Utility companies' ratings by S&P and Moodys



Notes:
(1) Ratings are comprised of holding companies senior secured offerings where available or otherwise of issuers
(2) Includes 38 and 49 small, mid and large-cap utility companies rated by S&P and Moodys respectively

(h) (ii).

KeySpan does not believe that the implementation of the bond rating actions noted in the recent S&P and Moody's credit opinions will have a material impact on the Company's and its affiliates' ability to raise capital in the financial markets. In the past when KeySpan was on negative outlook for a possible downgrade the Company has been able to issue bonds and secure credit facilities at favorable interest rates. Both KEDNY and KEDLI are in the process of issuing private placement debt in the amounts of $350 million and $100 million, respectively to term out short term debt. These issuances are currently oversubscribed by more than 2 times and indications are that they will be favorably priced despite the credit opinions made by S&P and Moody's. KeySpan has not performed any analyses to analyze the potential credit quality effects of the merger.

(i).

Yes. KeySpan Corporation's $1.5 billion credit facility requires that Company's consolidated total debt to total capitalization ratio and the ratios of total debt to total capitalization for KEDNY, KEDLI and KEDNE not exceed 65% on the last day of any fiscal quarter. Exceeding this limit is an event of default that gives the lenders the right to terminate the credit agreement if the majority of them vote to do so. If the agreement is terminated, all accrued interest and amounts borrowed must be repaid immediately. A

decision has not yet been made as to whether National Grid will seek to continue, terminate or modify the current credit agreement upon the consummation of the merger.

Case: 06-M-0878

National Grid/KeySpan Merger

Interrogatory/Document Request

Response of National Grid/KeySpan

Re: Financial and Ratemaking Implications of Equity Ratio

Request #: DPS-111

Response Date: October 10, 2006

Respondent: J. Cochrane, J. Bodanza

Q:

1. Explain why the consolidated common equity ratio of National Grid on a GAAP basis is not used to establish KEDNY and KEDLI rates under the terms of the proposed 10 year rate plan?

2. Explain why it would be reasonable to assume that 50% of KEDNY's and KEDLI's assets are financed with common equity if that equity is in fact purchased with cash proceeds generated by National Grid debt.

3. Explain why it is reasonable for the Commission to treat National Grid in the same way it would treat an individual investor by not considering how National Grid financed its purchase of regulated utility common equity.

4. Does National Grid agree that it is ever appropriate to use a holding company's consolidated capital structure to develop the overall cost of capital for the purpose of setting the rates of a utility subsidiary? If yes, explain the circumstances.

5. Does National Grid agree that it is ever inappropriate to use a holding company's consolidated capital structure to develop the overall cost of capital for the purpose of setting the rates of a utility subsidiary? If yes, explain the circumstances.

6. Provide an estimate of the cost of the debt that National Grid will issue to pay for the purchase of KeySpan. Provide all relevant calculations and assumptions.

7. Does National Grid view goodwill as a regulated or unregulated asset?

8. Explain why National Grid believes that it is reasonable to finance goodwill with 100% debt?

9. Explain the bond rating and cost of capital implications of KeySpan choosing today to finance KEDNY and KEDLI with 90% debt and 10% equity.

10. Does KeySpan believe that a bond rating downgrade for KeySpan and its subsidiaries is imminent after the transaction is completed? To the extent the answer is no, provide the complete basis for the response.

11. Does National Grid believe that a bond rating downgrade for KeySpan and its subsidiaries is imminent after the transaction is completed? To the extent the answer is no, provide the complete basis for the response.

12. Does National Grid believe that a bond rating downgrade for its current operations is imminent after the transaction is completed? To the extent the answer is no, provide the complete basis for the response.

13. Are there currently any corporate provisions which limit KEDNY's and KEDLI's debt ratio level? If so, what are they? Provide documentation of their existence. Describe how the proposed transaction would affect these limitations.

A:

1.

The underlying rate base, rates and regulatory assets and liabilities of KEDNY and KEDLI were financed by the capital structure of KEDNY and KEDLI.

2.

National Grid is purchasing the equity of KeySpan Corporation. The equity and stock of KEDNY and KEDLI will still be owned by Keyspan. No acquisition debt will be pushed down to KEDNY or KEDLI.

3.

We understand your reference to "individual investor" and how the "PSC treats an individual investor" to mean that an individual investor can purchase a share of stock in a utility and the financing of that acquisition by this individual investor has no impact.

From the Company's view and from a market perspective it made sense to add debt to the balance sheet in relation to the nature of National Grid's existing international regulated and unregulated assets in combination with an acquisition that made sense from a valuation perspective. National Grid has proposed a reasonable capital structure in the KEDLI and KEDNY rate plans, similar to that which is in place today.

4.

Because the underlying rate base, rates and regulatory assets used as a basis for the proposed rate plans were funded by the capital structures of KEDNY and KEDLI, then the proposed capital structure in our rate plans should be used.

5.

See answer to Part 4 above.

6.

In our October 2, 2006 Motion for Confidential Treatment and Protective Order, National Grid proposed that it would provide Staff with the confidential projections that have been provided to Rating Agencies (DPS-21). The July 2006 Rating Agency presentation contains our interest rate assumptions.

7.

National Grid classifies goodwill as an intangible asset, when recorded on the books of its regulated utilities. The fair value study to be conducted will determine the appropriate accounting for goodwill in the transaction.

8.

National Grid is acquiring KeySpan Corporation for $42 per share. National Grid does not know how much goodwill will be present until after the fair value study has been completed. In the Company's view and from a market perspective it made sense to add debt to the balance sheet in relation to the nature of National Grid's existing international regulated and unregulated assets in combination with an acquisition that made sense from a valuation perspective. Therefore, the Keyspan acquisition is to be financed with debt as part of this overall company capitalization view.

9.

A restructuring of KEDNY's and KEDLI's capitalizations so that they are comprised of 90% debt and 10% equity would have severe negative financial impacts on the utilities and their parent company. We would expect that KEDNY and KEDLI and their parent company would be downgraded by several notches by the credit rating agencies resulting in substantial increases in the cost of new debt and the return on equity required by investors to compensate them for the additional risk resulting from an extremely thin equity ratio. As a result of the severity of the downgrade, the Companies and their parent would most likely no longer have access to certain capital markets such as the commercial paper market.

10.

As the rating agencies have not completed their analysis of the transaction, KeySpan cannot speculate on the outcome. The attached press releases from the rating agencies confirm their latest views.

11.

As the rating agencies have not completed their analysis of the transaction, National Grid cannot speculate on the outcome. The attached press releases from the rating agencies confirm their latest views.

12.

As the rating agencies have not completed their analysis of the transaction, National Grid cannot speculate on the outcome. The attached press releases from the rating agencies confirm their latest views.

13.

The amount of debt at KEDNY and KEDLI is limited by the Settlement Agreement in Case 97-M-0567 as follows: If average total debt to average total capital exceeds 55% for KEDNY and 58% for KEDLI, the Companies have 15 months to reduce the debt ration to below their respective limits, during which time dividends paid to the holding company cannot be increased. If after the cure period the debt ratio still exceeds the restriction, the Company cannot pay any dividends until it is reduced to below the limit for a twelve-month period ending at any quarter.

21:55 27Feb2006 RTRS-Moody's says it may cut KeySpan's debt rating

NEW YORK, Feb 27 (Reuters) - Moody's Investors Service on Monday said it may cut its ratings on KeySpan Corp. <KSE.N>, citing an agreement by Britain's National Grid Plc <NG.L> to buy KeySpan for about $7.3 billion in cash.

The deal to buy KeySpan, the fifth-largest U.S. natural gas distributor, also involves taking on $4.5 billion of debt.

The decision to review the rating for a downgrade reflects concerns that KeySpan's capital structure could be more highly leveraged following the acquisition, Moody's said in a statement.

The ratings may be downgraded several notches, depending on the amount of debt and goodwill that could be pushed down to KeySpan and its subsidiaries, Moody's said.

The acquisition may also face some integration risks and uncertainties about meeting regulatory requirements, Moody's said.

Moody's rates KeySpan's senior unsecured debt "A3," the seventh-highest rating. Earlier on Monday, Standard & Poor's also said it may cut KeySpan's rating, now at the "A" level, the sixth-highest rating.

((Reporting by Dena Aubin; Editing by Dan Grebler; Reuters Messaging: dena.aubin.reuters.com@reuters.net; Tel: 646 223-6325))

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STANDARD &POOR'S RATINGSDIRECT
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RESEARCH

Return to Regular Format

Summary: KeySpan Corp.

Publication date: 25-Apr-2006
Primary Credit Analyst: Dimitri Nikas, New York (1) 212-438-7807; dimitri_nikas@standardandpoors.com

Credit Rating: A/Watch Neg/A-1

Rationale

The ratings on diversified energy company KeySpan Corp. and all its subsidiaries are on CreditWatch with negative implications as a result of the company's agreement to be acquired by National Grid PLC (A/Watch Neg/A-1). If the transaction is funded on an all-cash basis, there is a strong likelihood that the ratings on all the companies will be lowered by one notch. The acquisition of KeySpan would likely lead to a modest deterioration in National Grid's business risk profile.

The ratings on KeySpan reflect the consolidated credit profiles of its regulated gas distribution operations, including KeySpan Energy Delivery New York (KED New York), KeySpan Energy Delivery Long Island (KED Long Island), Boston Gas Co., Colonial Gas Co., its unregulated electricity generation operations, including KeySpan Generation LLC and the Ravenswood plants, and smaller diversified activities.

KeySpan's business risk profile is '4' (strong). (Business risk profiles are ranked from '1' (excellent) to '10' (vulnerable)). Keyspan's business risk profile is supported by the regulated gas distribution operations that provide material stability to cash flow and is further enhanced by the relatively low-risk nature of the power generation contracts with the Long Island Power Authority (LIPA). However, this stability is partly offset by the potential for more volatile cash flows relating to the unregulated electricity generation from the company's Ravenswood facilities. KeySpan's reduced diversified operations and improving financial profile further support credit quality.

KeySpan's gas distribution business contributes about 65% of total cash flow and serves 2.5 million customers in New York, Long Island, and Massachusetts. The customer base has favorable demographics and presents low-cost growth opportunities given the low market-penetration rates in the service territories of KED Long Island and Boston Gas. Regulation in New York and Massachusetts is very supportive of credit quality providing gas cost-adjustment clauses that ensure timely cost recovery, weather-normalization clauses that eliminate exposure to weather conditions, incentive mechanisms, and recovery of pension expenses not captured in rates (KED Long Island and Boston Gas).

KeySpan's power generation operations consist of two major businesses that operate independently of each other. KeySpan Generation provides electricity on a fully contracted basis to LIPA through about 4,200 MW of generation capacity in Long Island, N.Y. by means of long-term contracts that largely mitigate merchant-generation risk. The contracts allow for recovery of all costs while providing KeySpan Generation with the opportunity to earn various incentives. Keyspan and LIPA have agreed to extend the management services agreement (MSA) until 2013 from 2008, matching the expiration date of the two supplementary agreements for power supply and energy management. The new agreement also terminates LIPA's generation purchase

rights agreement, under which LIPA had the option to purchase KeySpan's generation assets in Long Island. The MSA extension supports KeySpan's credit quality by allowing for predictable revenues and cash flows for a longer period of time. At the same time, the pricing on the MSA agreement was revised to consist of a fixed-fee component and a performance-related component based on sales above a minimum level, thereby exposing KeySpan to the potential variability of electricity sales.

Exhibit No. ___ (JJR-5R)
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The fully merchant-generation assets of KeySpan Ravenswood consist of 1,765 MW of steam turbines, 454 MW of peaking dual-fueled units, and a 250 MW combined-cycle peaking unit, all in Long Island City, N.Y. Although KeySpan sells forward the capacity of these plants into the New York Independent System Operator market, it does not pursue long-term contracts for either capacity or energy, introducing revenue variability. As a result, Standard & Poor's ascribes a high level of risk to the Ravenswood operations because the associated cash flows can be more volatile given their full exposure to the vagaries of the wholesale electricity market. Furthermore, the Ravenswood plant represents a resource concentration, and, except for a recent 250 MW addition, the remaining units are old and need regular maintenance.

KeySpan's noncore and diversified activities are not material contributors to cash flow and should not have material capital-spending needs.

During 2005, KeySpan's financial profile continued to improve, in large part due to significant debt redemptions of $515 million as well as the issuance of $460 million through the remarketing of a hybrid security. As a result, adjusted total debt to total capital has improved to 54.7%, which is still high for the rating. Adjusted funds from operations (FFO) interest coverage was about 4.0x, which is adequate for the rating, while FFO to average total debt was about 17.2%.

Short-term credit factors

The short-term rating on KeySpan is 'A-1'. In the near term, cash flow generation should continue to benefit from the stability of the gas distribution and the contracted electric generation operations. KeySpan has adequate liquidity to meet the short-term working-capital funding needs of the gas distribution companies. This liquidity is in the form of two credit facilities totaling $1.5 billion and maturing in 2009 ($580 million) and 2010 ($920 million).

KeySpan's debt maturity profile is favorable with $12 million maturing in 2006, no maturities in 2007, $305 million in 2008, $412.5 million in 2009, and $1.1 billion maturing in 2010.

From 2006 onward, internal cash flow generation is not expected to be sufficient to fund capital-spending needs, dividend payments, and expected contributions to pension funding of about $160 million, necessitating external financing.

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Exhibit No. ___ (JCS/JR-6R)
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London, 27 February 2006 -- Moody's Investors Service has placed the Baa1 rating of National Grid Plc (NG) on review for downgrade following the group's GBP 4.2 billion bid for US utility KeySpan Corporation. Moody's affirmed the ratings of the group's regulated UK operating subsidiaries, but changed the outlook to negative from stable on National Grid Electricity Transmission Plc (NGET).

A full list of ratings affected by today's announcement is given below:

National Grid Plc: Baa1 / Prime-2 on review for downgrade;

NGG Finance Plc (guaranteed by NG): Baa1 on review for downgrade;

National Grid Gas Plc: A2 / Prime-1 affirmed with a negative outlook;

National Grid Gas Holdings Plc: A3 affirmed with a negative outlook;

National Grid Electricity Transmission Plc: A2 / Prime-1 affirmed, outlook changed to negative from stable.

Moody's last rating action on NG and the UK subsidiaries was on 18 November 2004, when all ratings were affirmed.

Moody's states that its decision to place NG's ratings on review for downgrade was determined by the announced all-cash nature of the proposed transaction, which is likely to increase holding company debt by up to GBP 4.2 billion, in addition to around GBP 2.6 billion of existing debt located at various entities of KeySpan. Moody's expects the additional holding company debt to be serviced from cash flows from its enlarged US operations, which will result in a deterioration of the group's overall consolidated credit quality to a low single 'A' range. Moody's adds that it intends to maintain at least two notches between NG's holding company ratings and the implied credit quality of the consolidated group, thereby indicating that NG's ratings are likely to fall by one notch. While the predominantly regulated businesses of KeySpan, which operates gas networks in New York, Massachusetts and New Hampshire and therefore compliments NG's existing activities in the US, are characterised by relatively predictable and thus low-risk cash flow generation, the company generates around 30% of earnings from power generation activities, which Moody's views as higher risk. This risk is partially mitigated by the fact that close to half of KeySpan's generation earnings are linked to long-term contracts with the Long Island Power Authority. Furthermore, following a successful bid, Moody's adds that holding company creditors will be increasingly reliant on non-regulated and US cash flows to service their debt, with the UK regulated businesses's share of the group likely to fall to around 30%.

Moody's intends to finalise the review of NG's ratings once shareholder approval of the transaction has been obtained and there is a strong likelihood of regulatory approval. In the meantime, Moody's will evaluate the likely funding of the transaction, including the possibility of additional refinancing requirements at KeySpan, and the degree to which additional holding company debt is adequately covered by existing and additional US cash flows.

Moody's decision to change the outlook of NGET's ratings to negative reflects the medium term risk of increased leverage required to maintain dividend streams to the holding company in support of additional debt. While at present Moody's does not expect NGET (and National Grid Gas Plc, NGG, whose outlook was already negative) to be called upon for additional debt service, given the relatively stable cash flows from the US, ratings at the UK subsidiaries could come under pressure if access to US cash flows proved less reliable or restricted. This is particularly relevant given that some of KeySpan's regulated subsidiaries benefit from regulatory ring-fence provisions, which could enable the local regulatory authorities to suspend dividends once certain maximum leverage thresholds are reached. Ratings could also be affected, if NG maintained current dividends despite higher future investment requirements not being fully matched by higher regulatory returns in the forthcoming price reviews.

Moody's adds that NGET's A2 rating assumed retained cash flow (RCF)-to-net-adjusted-debt above 9%, funds from operations (FFO) to cover interest payments at least 3.5 times and net debt to regulated asset value (RAV) below 60%. Similarly, NGG's ratings assume RCF-to-net-adjusted-debt above 9%, FFO interest cover above 3.5 times and net debt to RAV not significantly above 50%.

Headquartered in London, England, National Grid Plc (formerly National Grid Transco Plc) is the holding company for a range of international businesses focusing on the ownership and operation of electricity and gas networks. Its two principal geographic areas of activity are the UK and the US.

National Grid Gas Plc (formerly Transco Plc), a wholly owned subsidiary of National Grid Gas Holdings Plc (formerly Transco Holdings Plc), owns and operates the Great Britain natural gas transmission and parts of the distribution network. National Grid Gas Holdings Plc is a wholly owned indirect subsidiary of National Grid.

National Grid Electricity Transmission Plc (formerly National Grid Company Plc), a wholly owned indirect subsidiary of National Grid, owns and operates the high-voltage electricity transmission system in England and Wales.

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16:17 24Feb2006 S&P PUTS NATIONAL GRID ON WATCH NEG ON POTENTIAL KEYSPAN BID
16:22 24Feb2006 S&P MAY CUT NATIONAL GRID 'A' LONG-TERM AND 'A-1' SHORT-TERM CORPORATE CREDIT RATINGS
16:25 24Feb2006 TEXT-S&P on National Grid and KeySpan

(The following statement was released by the rating agency.)

Feb 24 - Standard & Poor's Ratings Services said today that it placed its 'A' long-term and 'A-1' short-term corporate credit ratings, together with its 'A-' senior unsecured debt rating on U.K.-based gas and electricity infrastructure company National Grid PLC, and its subsidiaries, on CreditWatch with negative implications. This follows National Grid's confirmation that it is in discussion concerning the potential acquisition of U.S.-based gas distributor KeySpan Corp. (A/Watch Dev/A-1).

"Should an acquisition go ahead, and assuming it is funded on an all-cash basis, there is a strong likelihood that the ratings would be lowered by one notch," said Standard & Poor's credit analyst Paul Lund.

The acquisition of KeySpan would likely lead to a modest deterioration in National Grid's business profile. The group would need to raise an estimated additional GBP4 billion ($7 billion) of debt to acquire KeySpan's equity.

"In the event that National Grid does not acquire KeySpan, we would likely affirm the ratings and remove them from CreditWatch," added Mr. Lund.

Ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. It can also be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search. Alternatively, call one of the following Standard & Poor's numbers: Client Support Europe (44) 20-7176-7176; London Press Office Hotline (44) 20-7176-3605; Paris (33) 1-4420-6708; Frankfurt (49) 69-33-999-225; Stockholm (46) 8-440-5914; or Moscow (7) 495-783-4017. Members of the media may also contact the European Press Office via e-mail on: media_europe@standardandpoors.com.

((-- U.S. Financial Markets Desk, 646-223-6330))

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Moody's Investors Services

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Global Credit Research
Rating Action
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Rating Action: Massachusetts Electric Company

MOODY'S PLACES RATINGS OF FOUR U.S. SUBSIDIARIES OF NATIONAL GRID PLC UNDER REVIEW FOR POSSIBLE DOWNGRADE

Approximately US$2.1 Billion of Debt Securities Affected

New York, February 27, 2006 -- Moody's Investors Service placed the ratings of four U. S. subsidiaries of National Grid Plc under review for possible downgrade: Niagara Mohawk Power Corporation (NIMO; A3 senior secured), New England Power Company (NEP; A1 senior unsecured), Massachusetts Electric Company (MECO; A1 senior secured), and Narragansett Electric Company (NEC; A1 senior secured). The review for downgrade follows today's announcement that National Grid Plc agreed to acquire KeySpan Corporation through a cash transaction valued at approximately US$7.3 billion.

The review for downgrade reflects Moody's concerns that there may be increased pressure to upstream dividends to the parent, National Grid Plc (NG; Baa1 senior unsecured; under review for downgrade), since the transaction is expected to be funded entirely with debt to be issued by NG. The existing U.S. subsidiaries of NG could become more leveraged if they are treated as a significant source of cash for servicing the debt incurred at NG Plc as part of an expansion in the U.S. The review also considers the already wide rating notching between the ratings of the subsidiaries and the parent and that wider notching would not be consistent with the degree of perceived credit linkage within the family, including significant flexibility to upstream dividends.

The review process will consider several factors whose outcome is still subject to clarification, including any potential change in the funding sources, regulatory conditions, and National Grid's strategy for managing individual subsidiary capital structures and liquidity. Moody's notes that various approvals are required from shareholders and state regulators before this transaction can proceed. Such approvals could take up to a year, which could prolong the review period for these ratings.

Moody's review will also consider the prospects for achieving cost savings and operational synergies and the time frame over which those could be achieved as NG expands its presence in the energy distribution industry throughout the Northeast region of the US. For example, NG expects that integration savings can ultimately reach US$200 million per year over the next four years through the rationalization of overlapping functions and the sharing of best practices.

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Niagara Mohawk Power Corporation, headquartered in Syracuse, New York, is a transmission and distribution utility. New England Power Company, headquartered in Westborough, MA, is a transmission utility. Massachusetts Electric Company, headquartered in Westborough, MA, is a transmission and distribution utility. Narragansett Electric Company, headquartered in Providence, RI, is a transmission and distribution utility. The four companies are all indirect subsidiaries of National Grid Plc, headquartered in London, England.

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Cases: 06-M-0878
06-G-1185
06-G-1186

National Grid/KeySpan Merger

Interrogatory/Document Request

Response of National Grid/KeySpan

Re: DPS 111, 158

Request #: DPS-198

Response Date: November 17, 2006

Respondent: J. Cochrane, J. Bodanza and J. Holodak

Q:

1. Other than the information presented in DPS 158 and 111, are there any other reasons why National Grid and KeySpan believe that National Grid's consolidated common equity ratio should not be used to set rates for KEDNY and KEDLI? If so, provide and discuss these reasons.

2. As requested in DPS 158 question 1(b), do petitioners agree or disagree with the statement that KEDNY and KEDLI's common stock is financed with debt at the National Grid plc level? If petitioners disagree with this premise, state and explain why the equity is not financed by debt..

3. Does the response to question 2 of DPS-111 as augmented by the response to DPS 158 reflect petitioners' complete position regarding why it is reasonable to assume that 50% of KEDNY and KEDLI's assets are financed with common equity even though equity was purchased with cash proceeds generated by National Grid debt?

4. Does the response to question 3 of DPS-111 as augmented by the response to DPS 158 reflect petitioners' complete position regarding why it is appropriate to treat National Grid as an individual investor?

5. Given the response to DPS-158, question 1(g), would National Grid define goodwill as an unregulated asset if the regulatory body did not allow the recovery of goodwill or acquisition premiums because the regulatory body set rates on the basis of the original cost of assets?

6. Is it National Grid's position that both Standard & Poor's and Moody's typically rate utility subsidiaries higher than their holding company parents? If the answer is yes, provide the basis for the response.

A:

1.

We have provided a complete response to this question and have provided the reasons why the capital structures of KEDNY and KEDLI are appropriate for setting rates.

2.

As noted in our response to DPS-158, National Grid is buying the equity of KeySpan Corporation. This purchase is being funded with debt and available cash. In addition, KEDLI and KEDNY will continue to be owned by KeySpan Corporation.

We do not allocate a discrete portion of our holding company debt finance to each part of the group. As noted in our previous responses, we manage the overall capital structure of the Group as an overall portfolio to ensure an efficient overall capital structure, rather than carrying out a hypothetical allocation of holding company debt to each business.

3.

Our testimony and our responses to the referenced interrogatories demonstrate that this is reasonable.

4.

Our testimony and our responses to the referenced interrogatories demonstrate that this is appropriate.

5.

Our description of goodwill as an intangible asset simply reflects the classification of goodwill per the relevant accounting standards. We do not see goodwill as either a regulated or unregulated asset and are not seeking to include goodwill in rate base or seek recovery of it in this case. The allocation of goodwill will be determined by the Fair Value study and by the accounting rules for the allocation of goodwill.

The example we gave reflects how the accounting could work if a regulatory body were to allow recovery of an acquisition premium.

6.

We understand that Moody's and S&P generally rate utility subsidiaries higher than the holding company parent. We have attached publications by each of the two agencies that describe their approach to rating utility holding companies. In addition, we have included below a summary of our ratings, which reflect this higher rating for the utility subsidiaries.

National Grid believes that S&P and Moody's apply a similar methodology to other utility groups but the different fact patterns that inevitably exist from group to group may result in different operating to holding company rating relationships than the National Grid Group situation.

Long term senior unsecured debt and short term debt credit ratings

	Moody's[1]	S&P[2]	Fitch[1]
National Grid plc	Baa1/P2	A-/A1	A-/F2
National Grid Electricity Transmission plc	A2[3]/P1	A/A1	A[5]/F2
National Grid Holdings One plc	—	A-/A1	Not rated
National Grid Gas plc	A2[3]/P1	A/A1	A+/F1
National Grid Gas Holdings plc	A3[3]	A-	A
National Grid USA	—	A-/A1	Not rated
Niagara Mohawk	Baa1	A-	Not rated
Massachusetts Electric Co	A2/P1	A/A1	Not rated
New England Power Co	A1/P1	A/A1	Not rated
Narragansett Electric Co	A2[4]	A[4]	Not rated

[1] All companies on review for downgrade (Moody's) or rating watch negative (Fitch) unless otherwise stated
[2] All companies on credit watch with negative implications
[3] Negative outlook
[4] Issuer Rating
[5] Stable

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Rating Methodology: Global Regulated Electric Utilities

Summary

This rating methodology covers electric utility companies worldwide whose credit profile is significantly affected by the presence of regulation. In order for a company to be included within this classification, at least 40% of its business should derive from regulated electric activities. The methodology thus excludes all other electric and power companies operating in the unregulated market, such as generators or power retailers, and other regulated industries such as water and gas utilities.

Based upon this definition, Moody's rates over 100 companies that either are electric utilities or are the parent holding companies for subsidiaries that operate predominantly in the electric utility business. In addition, Moody's rates a large number of utility operating subsidiaries of the ultimate parent companies. Figure 1 offers a breakdown of the ultimate parent companies by geographic region and rating category as of 1 February 2005:

Figure 1 – Electric Utility Companies Covered By This Methodology - by Geographic Region and Rating Category

	Aaa	Aa	A	Baa	Ba	B	TOTAL
Asia/Pacific		2	8	6	1	1	18
Europe		7	16	9	1		34
Japan		3	6				9
Americas			10	30	10	5	55
Totals	1	12	40	45	12	6	116

Moody's concludes that – despite the considerable number of common characteristics shared by electric utilities on a worldwide basis – country-by-country regulatory differences and cultural and economic considerations make this a local industry seen globally rather than a truly global industry.

In general, regulated electric utilities offer lenders some of the lowest business risks seen amongst corporate entities. However, many of the companies in question may also be active in unregulated businesses, such as speculative trading with exposure to unhedged commodity prices, which can be highly risky and may lead to serious financial difficulties despite the presence of a regulator.

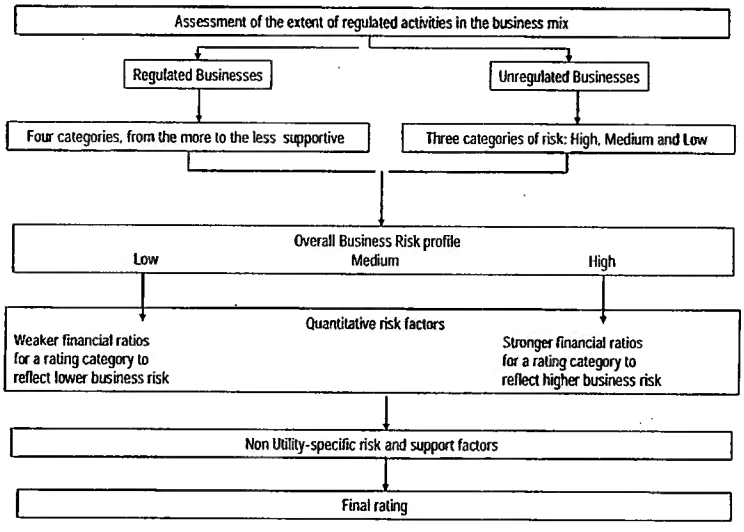
In addition, there is little consistency in the approach and application of regulatory frameworks around the world. Some are highly supportive of the "system" and those that operate within them, often offering implied sovereign support to ensure reliability of supply. Others are designed to protect the end-consumers from abuse of a monopoly supplier – a priority that may work to the detriment of companies operating in the system if they cannot meet regulators' expectations, or if the regulator fails to achieve the appropriate balance in the regulatory framework.

Under this rating methodology, Moody's:

1. Assesses the extent of a "regulated" company's exposure to its unregulated businesses. The strongest credit risk position is enjoyed by a company whose business is wholly regulated. Where non-utility activities are substantial, the main credit driver will be the assessment of these businesses.
2. Assesses the credit support that is gained from operating within a particular regulatory framework.
3. Considers the exact level of risk posed by the unregulated businesses to the overall credit.
4. Looks at six specific financial ratios which are considered the most useful when assessing an electric utility and the adjustments made to calculate these.
5. Considers more generic risk factors that are not specific to utility companies, e.g. the adequacy of liquidity arrangements, appetite for acquisitions.

Figure 2 depicts the broad methodology for regulated utilities:

Figure 2



Profile of Key Characteristics by Rating Category

Figure 3 below describes the key characteristics of regulated electric utilities falling within each rating category.

Figure 3

Rating Category	Ownership	Market and Regulatory Position	Non-Regulatory Risks
Aaa	Wholly owned by a Aaa-rated sovereign with unquestioned support provided	Regulatory framework allows full cost recovery. No evidence of regulatory over-blocking regulated price rises. Large and well-protected service area. Support for the electric transmission system outweighs customer considerations. No or very limited competition. Owned by a Aaa-rated sovereign, the risk is deemed equivalent to that of the Aaa parent.	Zero or immaterial unregulated businesses. Very consistent cashflow with no exposure to commodity risk.
Aa	Wholly or majority owned by a Aaa or Aa-rated sovereign or state-owned with effective monopoly and highly supportive regulation	Regulatory framework allows full cost recovery. No evidence of regulatory over-blocking regulated price rises. Large and well-protected service area. Support for the electric transmission system outweighs user considerations. No or very limited competition. Financially robust under all scenarios with unquestioned access to the financial markets and very strong liquidity. Many companies in this category are either sovereign-owned or are deemed to have certain support from the regulatory system or government in times of stress.	Non-electric utility businesses are predominantly low-risk businesses such as natural gas distribution

Figure 3

Rating Category	Ownership	Market and Regulatory Position	Non-Regulatory Risks
A	Wholly or partially owned by a Aa or A rated sovereign or rating is based on intrinsic strength without factoring in any uplift for sovereign ownership, or investor owned with highly predictable and	Medium to large sized companies where the core operation is a stable, regulated electric utility business. Well capitalized companies with moderately strong financials, that face more business risk and/or have weaker financial metrics than the issuers in the Aa category. If exposed to substantial competition, cost structure and rates are highly competitive for their region. Companies in this category often face greater competitive pressures than those in the Aa rating category. The regulatory environment has above average stability and reliability. Recovery of costs under regulated rates is fairly predictable, with automatic fuel and purchased power recovery provisions in some jurisdictions. Service [illegible] commercial and residential and the most limited potential for harm from loss of important industrial customers. There may be some history of a lack of support by regulators on large spending decisions for the regulated business but any amounts disallowed have had only a modest impact on the issuer's creditworthiness	Larger companies in this category may have substantial non-regulated businesses but the overall profile remains dominated by regulation. Smaller companies in this category are likely to have very limited unregulated activities
Baa	Wholly or partially owned by A or Baa rated sovereign or rating is based on intrinsic strength without factoring in any uplift for sovereign ownership, or investor owned with highly predictable regulation that has modest potential for unexpected rate outcomes	Medium-sized and smaller companies with average to below average capitalization and cash flow [illegible] business risk and have weaker financial metrics than the issuers in the A category. Core operations are dominated by fairly stable integrated electric utility businesses. Issuers may be more exposed to competition, less competitive in costs and rates in their region, and may be at risk for the loss of large industrial customers. There may be substantial competition for wholesale customers and some competition for retail and small commercial customers. The regulatory environment [illegible] reliability. The regulatory environment may sometimes be challenging and politically charged. Recovery of costs under regulated rates is usually predictable with fuel and purchased power recovery provisions in some jurisdictions, but there is a greater tendency for regulatory surprises. There may be some history of regulators disallowing large spending decisions for the regulated business and disallowed amounts may have had a meaningful impact on the issuer's creditworthiness	Issuers may have other utility and energy businesses, especially natural gas distribution. Unregulated non-utility businesses may be substantial in size relative to the regulated business and unregulated businesses may have a higher risk profile than is the case for most issuers in the A category. [illegible] have substantial investments in higher-risk unregulated businesses, including merchant power, energy trading, oil and gas production, real estate, telecom
Ba	Most of the issuers that are rated Ba are holding companies for regulated utility subsidiaries that are rated in the Baa category. Excluding emerging markets, very few regulated utility operating companies have speculative grade senior ratings	Medium-sized and smaller companies with below average capitalization and cash flow coverages, that face more business risk and have weaker financial metrics than the issuers in the Baa category. Core operations may include fairly stable integrated electric utility businesses, but these are offset by substantial debt-financed investments in unregulated activities that are higher risk or have performed poorly Liquidity is likely to be weak, especially at the parent holding company. Bank financing may be secured and the issuer may have limited headroom under its covenants. Some issuers in this rating category are substantially more exposed to competition, less competitive in costs and rates in their region, and may be at risk for the loss of large industrial customers. There may be substantial competition for all types of customers: wholesale, retail, and small commercial. Regulatory environment may be inconsistent, with surprisingly unfavorable rate decisions or regulatory unwillingness to make timely changes to address unexpected market volatili[illegible] Issuer has below-average relationship with regulators. There may be uncertainty of recovery for spikes in costs such as for fuel or purchased power	Compared to those Baa issuers that also have substantial riskier unregulated investments, the investments are proportionately larger in relation to the regulated utility business and have performed more poorly. Issuers may have other utility and energy businesses, especially natural gas distribution. Unregulated businesses have a higher risk profile than is the case for most issuers in the Baa category. Issuers in this rating category usually have substantial investments in higher-risk unregulated businesses, including mer[illegible]ower, [illegible] trading, oil and gas production, real estate, telecom
B	Some issuers in this rating category are majority owned by low-rated sovereign entities	Medium-sized and smaller companies with well below average capitalization and cash flow coverages, that face more business risk and have weaker financial metrics than the issuers in the Ba category. Core operations may include fairly stable integrated electric utility businesses in some cases, but these are outweighed by large highly risky unregulated activities that were debt-financed and have performed extremely poorly Some issuers have very poor regulatory relationships. Regulators may have engaged in second-guessing of spending decisions and denied recovery of amounts that jeopardize the issuer's ability to fund its ongoing business activities Liquidity is likely to be very weak, especially at the parent holding company. Bank financing may be secured and the issuer may have limited headroom under its covenants There is a significant risk of detrimental sovereign actions such as politically motivated interference in the ratemaking process, actions based on social/political needs rather than financial returns. There may be a history of using the utility as a government funding source. These issuers also face higher potential for disruption in power and financial markets. The financial profile of these issuers may be relatively strong but susceptible to rapid deterioration	Unregulated businesses tend to be higher risk activities, including merchant power and energy trading

Stand-Alone Company Credit Risk Factors

QUALITATIVE FACTORS

General rating methodology

Moody's framework for rating regulated electric utilities is constructed around a number of credit risk factors rather than on any one particular metric such as a financial ratio.

The first step is to assess the extent of a "regulated" company's exposure to unregulated businesses. The strongest position is enjoyed by those companies operating in a wholly regulated business. However, the majority of the companies we consider in this sector have additional exposure to unregulated businesses, whether those are unregulated power generation or supply activities or non-electric unregulated businesses.

The second step in the methodology is to assess the credit support that is gained from operating within a particular regulatory framework. Moody's considers each regulatory system and assesses whether there is a high or low expectation of predictability in the system and whether operators can reasonably expect to recover their costs and investments through regulator-approved revenue increases.

The third step is to consider the exact level of risk posed by the unregulated business. Note that a relatively small, but high-risk, unregulated business has the capacity to cause a major credit deterioration for the entity as a whole.

This then leads to an overall assessment of the qualitative business risk of the company's activities.

Each of these steps is now considered in more detail.

Assessment of the extent of regulation around a business

Moody's classifies companies into four categories to determine how much their business risk is influenced by regulated activities.

This is a measure of the relative weight of regulated to unregulated business within a rated entity. Weighting is based on the element of earnings, cashflows and assets that fall within or outside a regulatory framework. In order to define the "unregulated business" percentage, Moody's takes the highest percentage out of the three measures respectively based on earnings, cashflows and assets. This then allows us to derive the regulated business percentage and to assign the entity to one of the four categories as below:

Category 1: A wholly regulated business
Category 2: 80-99% of the business is regulated
Category 3: 60-80% of the business is regulated
Category 4: 40-60% of the business is regulated

Assessment of the supportiveness of the regulatory framework

We also classify entities into the following four categories based on a comparative assessment of the predictability and stability of regulated cashflows for a company operating under a particular regulatory framework – or the Supportiveness of Regulatory Environment (SRE):

SRE 1: Regulatory framework is fully developed, has shown a long track record of being highly predictable and stable and there is a very high expectation of timely recovery of costs and investments.

SRE 2: Regulatory framework is fully developed, is predictable and stable and there is a high expectation of timely recovery of costs and investments.

SRE 3: Regulatory framework is well developed but there is a lower assurance of timely recovery of costs and investments; there may also be evidence of some inconsistency or unpredictability in the way that the regulatory framework has been applied.

SRE 4: Regulatory framework is still being developed, is unclear, is undergoing considerable change or has a history of being unpredictable.

Consideration is given to the substance of a regulatory ringfence including restrictions on dividends, restrictions on capex and investments, separate financings, separate legal structure, and limits on the ability of the regulated entity

to support its parent company. There is more credit uplift if these provisions are contained within a license or clear regulatory rules rather than in financing documents that can be renegotiated.

In general, Moody's sees regulatory frameworks as being fundamentally designed to achieve a balance between supply reliability and service, efficiency, prices, and financial returns to the utilities. All jurisdictions consider all of these factors, but there are regional differences in their application and degree of emphasis, as discussed below:

- Protecting the "system" to ensure a reliable supply. In such cases, the company receives considerable implied support from the government, which may be at the expense of the end-user. Japan is an example of a system that emphasizes these factors more heavily. Other examples would include systems where considerable infrastructure build-out is needed and incentives for investment outweigh the need to control customer prices. Italy and Spain are examples of jurisdictions that emphasize these factors more strongly.
- Protecting consumers from monopoly over-charging or from sudden large rate increases that could be imposed more gradually. When these concerns are more heavily weighted, companies are at financial risk if they cannot economically deliver a service at the regulated price. Some degree of financial deterioration of the utility may be accepted in the interests of protecting consumers from higher prices. California demonstrated a heavier weighting of these factors when wholesale market prices spiked in 2000-2001.
- Attempting to achieve a balance between satisfying the need of companies to be able to provide a return to their stakeholders and endeavoring to encourage efficiency and hold down prices. The regulatory systems of Australia and the UK are good examples of models that consistently stress these factors most heavily.

Examples of regulatory frameworks in each category:

SRE 1:	Australia, Canada, Iceland, Finland, Hong Kong, Japan, UK
SRE 2:	Austria, France, Germany, Italy, New Zealand, Portugal, Netherlands, Norway, Singapore, Spain, Sweden, U.S. states: Alabama, Delaware, District of Columbia, Florida, Georgia, Hawaii, Indiana, Iowa, Kentucky, Maryland, Massachusetts, Michigan, Minnesota, Mississipi, Nebraska, New York, North Carolina, Oklahoma, Oregon, Rhode Island, South Carolina, Tennessee, Utah, Virginia, Washington, Wisconsin
SRE 3:	Chile, Czech Republic, Estonia, Greece, Israel, Korea, Latvia, Malaysia, Taiwan, Thailand, U.S. states: Arizona, Arkansas, California, Colorado, Connecticut, Idaho, Illinois, Kansas, Louisiana, Maine, Michigan, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Dakota, Ohio, Pennsylvania, South Dakota, Texas, Vermont, West Virginia, Wyoming
SRE 4:	Brazil, Bulgaria, China, Colombia, India, Indonesia, Philippines, Romania, South Africa

Assessment of the risk of the unregulated businesses

A key component of Moody's ratings of electric utility companies is an individual assessment of the business risks as well as the financial risks for each company. The regulated activities of electric utility companies generally are more stable and carry lower risk than the business activities of most other corporate entities. As a result, utility companies are rated substantially higher than industrial companies that have a similar financial profile.

However, as noted above, many companies in the electric utility industry have a mix of regulated and unregulated businesses. These companies typically combine a low-risk electric utility business and what is in most cases a higher-risk unregulated business. The risk contribution from the unregulated businesses is determined by:

1) The relative proportion of the total company's business that comprises unregulated activities; and

2) The degree of risk of the particular unregulated activities.

Companies that have substantial unregulated activities that carry high or medium risk require stronger financial ratios to achieve a particular rating level than companies whose unregulated activities are small in size or are low in risk. Note that a company with a low-risk business profile will be rated more highly than a company that has the same financial profile but which has larger or higher-risk unregulated activities. The presence of a high proportion of risky non-regulated businesses could account for as much as a six rating notch differential over another company that was in a wholly regulated business.

Figure 4 shows a broad categorization of the relative riskiness of unregulated activities that are commonly part of the business of electric utility companies. These are grouped into broad categories of high, medium and low business risk. These classifications are general and do not fully capture individual company characteristics or differences in regional markets. For example, uncontracted wholesale power generation is likely to be riskier in the US, where the market is fragmented, than in Germany, where a smaller number of companies have relatively large market shares.

This categorization of the risks of unregulated businesses can be summarized as follows:

Category 1 – High

Category 2 – Medium

Category 3 – Low

Figure 4

High Business Risk
Merchant power generation that is located in highly competitive markets or merchant power generation that is high cost and is not sold under long-term contract to a highly creditworthy counterparty.
Energy trading and marketing that is speculative or market-making in nature.
Investments in unregulated international power assets in unfamiliar markets.
Various investments outside the core area of industry expertise. Frequent areas for such diversified investment include: telecommunications, oil and gas exploration and production, and real estate development.
Medium Business Risk
Merchant power generation in markets in which competition is limited by the large market share of each participant, by geographic isolation, or by the utility's control of critical production and transmission infrastructure, or because the unregulated generation is relatively low-cost.
Affiliated energy generation and supply businesses that sell primarily under contract to the regulated utility or within the utility's core market area.
Energy trading and marketing that is strictly limited to trading around the utility's physical generation and transmission assets, with little or no market-making trading.
Operation of coal mines or natural gas pipelines that are closely integrated with the utility's regulated generation business as the source of fuel for the regulated power plants.
Low Business Risk
Unregulated electricity generation that is wholly sold under long-term contract to highly creditworthy counterparties which assume all risk of fluctuation in the market prices of fuel and electricity.
Unregulated or lightly regulated electricity generation that is very well insulated from competition because of the utility's high market share or its ownership and tight control of the key infrastructure assets that are needed to generate or deliver electricity.
Selling and maintaining customer equipment that is related to the core utility business, or contractual arrangements to manage customers' fuel and electricity needs, under which the customer retains all risk of fluctuation in market prices.

High-Business-Risk Unregulated Activities

This higher business risk category includes merchant generation in highly competitive markets, energy trading and marketing that is speculative or market-making in nature, and unregulated electric generation investments in unfamiliar or poorly developed markets.

Merchant energy is considered to include unregulated power generation for which the output is not sold under long-term contract with a creditworthy counterparty. In the merchant model, power is sold into the competitive or merchant market, and cash flows are subject to market price volatility. The absence of contracts results in less predictable cash flows and higher business risk.

Energy marketing and trading is a related activity that often has a high level of risk associated with it. There can be substantial differences in the riskiness of energy trading and marketing, depending upon the strategy and size of this activity. Speculative trading activity has the potential to produce large swings in income or loss, has limited risk transparency, and may result in large swings in liquidity needs. Trading and marketing activities that are ancillary to a core utility business (trading around the physical assets) are considered to be much less risky than pure proprietary or speculative trading. However, all energy trading is viewed as having a higher business risk profile than regulated activities.

A number of other investments outside the core sector of industry expertise are likely to fall into the high business risk category. Such areas of diversification may include telecommunications, equity investments in leases, oil and gas exploration and production, miscellaneous manufacturing and real estate development.

Some companies have high-risk businesses that are sizeable in comparison to the more stable regulated business. These companies are expected to have financial ratios that are closer to those of an unregulated industrial company in the same rating category, in contrast to the financial ratios typical for a lower-risk regulated utility company. Companies with substantial high-risk activities will need lower leverage, and stronger cash flow coverage ratios to qualify for a particular rating category.

Medium-Business-Risk Unregulated Activities

Unregulated electricity generation may be medium-risk if competition is substantially limited by the structure of the market or by the generators' control over production and transmission infrastructure that is needed to reach customers, or if the unregulated generation has costs that are well below-average.

Also likely to fall into this category is unregulated generation that is largely sold back to the regulated utility without long-term contracts. This activity has a lower risk than merchant sales to third parties if the generating assets are advantageously located for the regulated utility. This is particularly likely when generating assets have been legally separated from the regulated utility. As part of the transition to deregulation, many utilities were required to disaggregate their generation, and these plants were often put into affiliated supply companies under a common parent holding company, but continue to sell a large portion of their output to the affiliated regulated utility.

Medium-risk unregulated generation is likely to have significant exposure to fluctuations in the price of fuel, or capital spending needs to maintain competitiveness or to meet environmental requirements.

Lower-Business-Risk Unregulated Activities

This category includes unregulated generation of electricity that is sold under long-term contract to highly creditworthy counterparties, with the purchaser bearing the risk of any change in the market price of fuel and wholesale power.

Unregulated electricity generation may also be low-risk if there is little competition due to the structure of the market or the generators' exclusive control over critical production and transmission infrastructure that is needed to reach customers.

Below-average costs are not necessarily sufficient for unregulated generation to be classified in the low-risk category. Without other mitigating factors being present, low-cost merchant generation is likely to be classified as medium-risk due to the potential for changes in relative cost competitiveness as market conditions change.

Conclusion on Qualitative factors

This analysis of qualitative factors – the split of regulated versus non regulated activities and the respective risk analysis of those businesses – allows us to determine how stable and predictable we feel the cashflows of the company should be. The lowest business risk will be a company with wholly regulated activities in a supportive regulatory framework. The highest business risk will be a company with a high degree of exposure to non-regulated businesses when those businesses are viewed to be relatively high-risk.

Companies with a lower business risk can have weaker financial metrics than one with higher business risk for the same rating category.

QUANTITATIVE FACTORS

Key ratios

Moody's uses financial ratio analysis as part of our quantitative analysis of all corporates, including electric utilities. Ratio analysis is a helpful way of comparing one company's performance to that of another and the performance in one year to that in another.

However, the importance of ratio analysis can be overstated. No two companies look exactly alike from a qualitative assessment standpoint and each company we rate is constantly changing. It is impossible to assign an accurate credit rating on the basis of financial ratio analysis alone, even less so on the basis of any one ratio. Therefore, Moody's does not have any specific "hurdle rate" to explain which ratio will make the difference between any two rating categories.

Nonetheless, we have identified six core ratios which we consider to be the most useful when looking at an electric utility company. These are supplemented by other ratios which are particularly useful for various local regulatory frameworks.

The six core ratios[1] are as follows:

Primary:

1. Retained Cashflow[2] / Adjusted gross debt[3]
2. FFO / Adjusted gross debt
3. FFO / Interest
4. Adjusted gross debt / Regulated Asset Value[4], or Capitalization

Secondary:

5. EBITDA Margin
6. Retained Cashflow / Capex

While other factors considered in this report may outweigh pure quantitative analysis, it is possible to provide broad guidance on the ratio ranges that may generally be seen at different rating levels.

In general, other factors – such as the degree of likely support from a sovereign – tend to outweigh financial ratios for companies operating in a very low business risk environment such as Japan or Finland. Similarly, considerations such as an undeveloped regulatory framework, potential political risk or relatively opaque corporate governance may outweigh financial ratios for companies operating in a high business risk environment. Our analysis also considers prospective future performance, which may differ from historic ratios.

Financial ratios are more useful for companies operating in a low business risk environment where there is a high degree of regulated activities and a supportive regulatory system. This might include the UK, US transmission and distribution utilities (T&Ds), Canada or many European countries. Medium-business-risk operating environments would include US integrated utilities.

As noted above, this is a local industry found globally rather than one where companies compete with each other outside their own local area. While companies in, say, Japan or in the US or in Germany, all tend to have similar profitability dynamics, there is little global similarity. Hence, measures of profitability are helpful in rank-ordering companies within their own local regulatory operating environment, but not helpful as a global indicator of ratings.

Measures of interest cover, cashflow to debt and balance sheet measures tend to be more consistent across the whole universe of global regulated electric utility companies.

As a guide, the following primary ratios, as set out in Figure 5, might be expected for a utility company without factoring in any uplift for possible sovereign support.

Figure 5

	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Business risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
FFO Int cov. (X)	>5	>5	3.0-5.0	3.0-5.0	2.7-5.0	2.4-5.0	2.5-4.0	<2.5
FFO/Debt (%)	>30	>22	22-30	12-22	13-25	5-13	<13	<5
RCF/Debt (%)	>25	>20	13-25	9-20	8-20	3-10	<10	<8
Debt/Capital (%)	<40	<50	40-60	50-75	50-70	60-75	>60	>70

Other utility-specific issues relevant to quantitative analysis

Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt or to fix the cost of power. While Moody's regards these risk reduction measures positively, some aspects of PPAs may negatively affect the credit of utilities.

1. *Please see Appendix 2 for definitions.*
2. *Retained Cashflow (RCF) is FFO less dividends*
3. *Moody's concentrates on gross debt but will also consider net debt ratios if the cash is clearly being held for future debt maturities or for reasons such as hedging. A good example of this would be a company that has hedged the exchange risk of an overseas investment with the local currency debt despite having surplus cash at the parent level. In such cases, the net ratio will take predominance over the gross ratio.*
4. *The Regulated Asset Value (RAV) or Regulated Asset Base (RAB)*

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge covers the portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments cover debt service and are made irrespective of whether the utility requires the IPP to generate. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also be paid by the utility. Some other arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus analyzed by Moody's as PPAs.

Factors determining the treatment of PPAs

PPAs have a wide variety of financial and regulatory characteristics and are thus each particular circumstance may be treated differently by Moody's. The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized. Factors which determine where on the continuum Moody's treats a particular PPA are as follows:

- Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.
- Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.
- Price considerations: The price of power paid by a utility under a PPA can be substantially below the current spot price of electricity. This will motivate the utility to purchase power from the IPP even if it does not require it for its own customers, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or when the spot price is lower than the PPA price will suffer a financial burden. Moody's will particularly focus on PPAs that have mark-to-market losses that may have a material impact on the utility's cash flow.
- Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. For example, Tenaga, the major Malaysian utility, purchases a large proportion of its power requirement from IPPs under PPAs. PPA payment totalled 42.5% of its operating costs in FY2004. In a high reserve margin environment existing in Malaysia, capacity payment under these PPAs are a significant burden on Tenaga, and some account must be made for these payments in its financial metrics.
- Risk-sharing: Utilities that own plant bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis which of these two sets of risk poses greatest concern from a ratings standpoint.
- Default provisions: In most cases, a default under a PPA will not cross-default to the senior facilities of the utility and thus it is inappropriate to add the debt amount of the PPA to senior debt of the entity. The PPA obligations are not senior obligations of the utility as they do not behave in the same way as senior debt. However, it may be appropriate in some circumstances to add the PPA obligation to Moody's adjusted debt, in the same way as other off-balance sheet items.[5]

5. *See "The Analysis of Off-Balance Sheet Exposures – A Global Perspective", Rating Methodology, July 2004.*

Each of these factors will be weighed by Moody's analysts and a decision made as to the importance of the PPA to the risk analysis of the utility.

Methods of accounting for PPAs in our analysis

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total obligations for the utility using one of the methods discussed below.

Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the obligations of the utility.

Annual Obligation x 8: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of eight. This method is sometimes used in the capitalization of operating leases.[6] This method may be used as an approximation where the analyst determines that the obligation is significant but cannot be quantified otherwise due to limited information.

Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the adjusted obligations of the utility. The discount rate used will be the cost of capital of the utility.

Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the spot price and thus a liability is arising for the utility, Moody's may use a net mark-to-market method, in which the NPV of the net cost to the utility will be added to its total obligations.

Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. Again, if the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the subjective nature of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change. In all methods the Moody's analyst will account for the revenue from the sale of power bought from the IPP. We will focus on the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and the materiality of the PPA obligation to the overall cash flows of the utility in assessing the affect of the PPA on the credit of the utility.

Nuclear liabilities

In several integrated European companies, nuclear power generation form a significant component of their power generation activities. These activities will usually be unregulated but comprise an important element of the analysis of these companies. The analysis is complicated by the lack of consistency in treating nuclear related items in different countries.

In general, nuclear waste management obligations are factored into debt using Moody's methodology for unfunded pensions. This recognizes the uncertainty of final amounts and timing in assessing the likely call on future cash flows. The methodology simulates a pre-funding of the obligation, taking into account access to the equity market and management's probable funding strategy. The existing debt-to-equity mix is generally used as a starting point.

For ratio analysis purposes, Moody's excludes reprocessing provisions from its calculation of total nuclear liability provisions if such provision is expected to remain a permanent component of the nuclear liabilities that will continually be replenished as fuel is used in the production process in line with the expectation that nuclear power will remain an important component of the company's generation portfolio for the foreseeable future.

For nuclear provisions that are recorded and funded on balance sheet, Moody's does consider the impact of their inclusion on adjusted debt ratio. However, we do recognize that their inclusion does understate the company's degree of financial flexibility for meeting financial debt obligations given the long duration of those provisions. This

6. *For further discussion of the methodology of rating lease obligations see "Off-Balance Sheet Leases: Capitalization and Ratings Implications – Out of Sight But Not Out of Mind", October 1999.*

is because the cash outflows for these liabilities will not occur for a number of years and will then extend out in a form similar to operating expenses over a further extended period of time. This is taken into account by looking at both gross and net debt ratios.

U.S. Securitization

Beginning in the late 1990s, legislatively approved stranded cost securitization has become an increasingly used financing technique among investor-owned electric utilities. In its simplest form, a stranded cost securitization isolates a dedicated stream of cash flow into a separate special purpose entity (SPE) and uses that stream of cash flow to provide annual debt service for the securitized debt instrument.

Moody's generally treats securitization debt of industrial and financial issuers as being on-credit debt. The debt that is being securitized usually carries a rating that is higher than that of the issuing entity, and the assets that are being sold to the separate SPE are often of better quality than the assets that remain with the issuer.

Stranded cost securitization differs somewhat from other generic securitizations because the asset being sold is often of poor quality prior to the passage of legislation and the completion of a securitization. In most cases, the asset represents stranded costs that would have been written off by the utility in the absence of legislation allowing for recovery through a surcharge on regulated customers.

Instead, the state regulator – and sometimes the state legislature – establishes the authority for a surcharge on customers' bills, and authorizes the sale of securitized debt. The utility then sells the right to collect a dedicated stream of future cash flows from its regulated customer base that is sufficient to provide debt service on the securitized piece of debt. The issuing utility is typically required to use the proceeds of the debt offering to retire both debt and equity in a manner intended to maintain a predetermined capital structure. The securitization generally has language that enables the tariff to be unilaterally raised in the event that future sales turn out to be lower than originally planned.

Generally speaking, Moody's views stranded cost securitization as being credit-neutral to credit-positive since it typically addresses a major credit overhang, some form of potential stranded costs, and legislatively requires the utilities to use the proceeds for debt and equity reduction in a manner that targets a relatively conservative capital structure.

For the most part, the securitization tariff is separate from the "general tariff" charged to customers and any increase in the size of the securitization tariff is not at the expense of the general tariff. However, in two states, Illinois and Michigan, the utilities operate under a rate freeze, which precludes them from raising rates until the termination of their respective rate freeze. As such, any increase in the securitization tariff is at the expense of revenues and cash flow that would be available to service debt of the remaining creditors of the utility.

Along the same lines, Moody's notes that the size of the securitization tariff relative to the total tariff is an important element in evaluating the credit implications of a securitization because it can impact the future ability of a utility to obtain subsequent rate relief for other costs of service. In effect, customers do not discriminate between the securitization tariff and the general tariff when paying their bills. Consequently, to the extent that the securitization tariff needs to be increased, the financial flexibility and associated credit quality of the utility may be compromised, particularly if the securitization tariff is large relative to the general tariff and if the increase is taken from the cash flow of the utility. As a consequence, Moody's considers the impact that a securitization may have on the ability of the utility to raise rates in the future.

In calculating balance sheet leverage, Moody's treats the securitized bonds as being fully non-recourse to the utility even though accounting guidelines require the debt to appear on the utility's balance sheet. Consistent with this view, all balance sheet capitalization metrics exclude the securitized debt from the capital structure given the legal separateness that exists between the debt of the utility and the debt of the SPE, and the fact that regulators set future rates based upon a capital structure that does not include the securitization debt.

However, in looking at cash flow coverages, Moody's analysis stresses ratios that include the securitized debt in the company's total debt as being the most consistent with the analysis of comparable companies. This recognizes that regulatory approval for recovery of stranded costs and securitization are not always inextricably linked. Many utilities have approval for recovery of stranded costs but do not execute a securitization financing. Regulatory approval of stranded costs can be a credit transforming event when there is substantial doubt about recovery. However, the subsequent completion of a securitization financing does not change the amounts that are expected to be recovered. A securitization transaction does make it extremely unlikely that regulators can later disavow an agreement to allow recovery, and regulatory approval is often packaged together with a securitization with the view that ratepayers will benefit from low borrowing costs.

While our standard credit ratios for funds from operations to total debt and funds from operations interest coverage include the securitization debt, Moody's also looks at these two metrics without the securitization debt, to ensure that the benefits of securitization are not ignored. In making this adjustment, funds from operations is adjusted downward by the amount of principal amortization that is annually paid to the SPE in support of the securitization. Consistent with that adjustment, Moody's excludes the principal amount of securitization debt in the denominator in calculating a company's Adjusted FFO/Adjusted Total Debt and excludes the portion of a company's interest costs relating to the securitized debt when calculating a company's Adjusted FFO/Adjusted Interest. The analytical benefit of making this adjustment helps to determine the amount of residual cash flow (cash flow after satisfying securitization debt service) that is available to service the debt of general creditors.

The recent bankruptcy of Pacific Gas and Electric Company (PG&E) fortifies the strength of the legal separation among cash flows available to the SPE and cash flows available to the utility. Throughout the bankruptcy, funds dedicated to the securitization debt were collected by the utility and transferred on a daily basis to the trustee for the SPE creditors and PG&E's general creditors and the bankruptcy judge never challenged the continued transfer of such funds to the SPE. For this reason, the securitization debt of PG&E remained rated Aaa while the company operated in bankruptcy for more than three years.

ADDITIONAL RISK CONSIDERATIONS

Analysis of Multiple Legal Entities within a Single Issuer Family

Utility companies may have multiple legal entities within a single consolidated organization. This is the prevalent legal structure in the US, even for small utilities. The multiple-entity legal structure is also common in Canada and the UK and is employed by a number of the larger international utilities in other countries. In the US, most utility families have an unregulated holding company. The holding company will have one or more regulated operating subsidiaries, and may have one or more unregulated subsidiaries. Most utility families in the US issue debt at multiple legal entities within the organizational family.

In the case of multiple legal entities within a single issuer family, our approach is to assess each issuer on a stand-alone basis as well as evaluating the creditworthiness of the consolidated entity. We then assess the degree of legal and regulatory insulation that exists between the lower-risk regulated entities and the higher-risk unregulated entities.

The degree of notching (i.e. the rating differential) between entities in a single family of companies depends upon the degree of insulation that exists between regulated and unregulated entities. If the regulatory framework or regulatory practice establishes that there is substantial ring-fencing type insulation for the regulated entity, there may be three or more notches of rating differential between the regulated and the unregulated entities. If there is little or no ring-fencing, there will usually be only a one- or two-notch differential between the unregulated entity (in most cases a holding company) and the regulated entity (in most cases an operating company).

Regulatory ring-fencing for utilities may include minimum equity requirements, limitations on the movement of funds from regulated entities to unregulated entities, and prohibitions against credit support by regulated entities for unregulated entities. This may exist by statute, but most typically takes the form of rules that are established by the regulator. In the United States, where these provisions are most common, the rules may differ for individual utilities in the same state.

Many regulators restrict the ability of utilities to extend intercompany loans, guarantees, or to make payments to unregulated affiliates and parent holding companies. For example, utilities in the state of Wisconsin may only pay dividends to their unregulated holding company (the ultimate parent company in these organizations) in excess of an amount established in each rate case if common equity falls below an authorized level.

Regulators also often have wide discretion to impose new restrictions on regulated entities when the utility appears to be threatened by weakness of its unregulated affiliates. For example, the state regulatory commission in Oregon established tight limitations on any movement of funds by Portland General to its parent company when the parent company filed for bankruptcy protection. These ring-fencing protections were a key reason that Portland General did not default or experience substantial financial distress while its parent was in bankruptcy.

Where regulated utility entities are not well insulated from unregulated affiliates, the ratings of these entities will be notched fairly closely, generally within one or two notches. This will be the case even when one entity has substantially stronger financial ratios than its affiliate, if there is little or no restriction upon movement of funds between the two entities, or if there is a substantial operational interdependence. For example, where the regulated utility is highly dependent upon contractual purchases of power from its unregulated generating affiliate, the ratings of

these two entities will likely be one or two notches apart even if their individual financial profiles would suggest different ratings on a stand-alone basis.

Where regulated utility entities are strongly insulated from unregulated affiliates through prohibitions on loans and credit support, where there are strong regulatory limitations on dividends, and where there is little or no operational interrelationship between regulated and unregulated affiliates, the ratings will be driven more by the stand-alone credit quality of each entity, and may be three or more notches apart.

Non-specific utility risk factors

The majority of the risks considered in this rating methodology are specific to utilities. However, lenders to utilities are also exposed to many of the risks that are common to all industrial companies. These are not covered in detail here as a full analysis can be found in the relevant Moody's research. However, it should be noted that such factors may potentially outweigh the utility-specific considerations covered in depth in this report.

For example, a company that currently shows very strong financial ratios and operates in a supportive regulatory framework could still have a relatively low rating if it had very weak liquidity arrangements or high "event risk" such as if it were pursuing an acquisition policy that was very likely to result in a change in the company's business risk policy going forward.

The generic industrial company risks to which a utility may also be exposed include the following:[7]

- An assessment of the adequacy of the company's liquidity arrangements[8]
- An assessment of the quality of its corporate governance arrangements[9]
- An assessment of the quality of its management – their experience, appetite for risk and ability to fulfill the company's stated strategy
- An assessment of event risk and the probability that this could lead to a change in the company's financial position, business risk profile or its regulatory and political operating environment[10]
- Exposure to off-balance sheet risks[11]
- The potential support of or interference by a sovereign or sub-sovereign entity[12]

Regional Considerations

RATING DIVERGENCE LIMITED AMONG JAPANESE UTILITIES

Japanese electric utilities are rated in a relatively narrow range from Aa3 to A1. This reflects Moody's view that the conservative and predictable regulatory regime, and the individual companies' solidly established franchises in their operating regions, will not lead to major differences in credit risks among the rated utilities. Their financial profiles are more or less comparable, and they have simple corporate structures and limited business diversification exposures.

Moody's rates the three utilities that cover Japan's three largest economic areas at Aa3 (Chubu Electric Power, Kansai Electric Power, and Tokyo Electric Power), and six other utilities at A1 (Chugoku Electric Power, Hokkaido Electric Power, Hokuriku Electric Power, Kyushu Electric Power, Shikoku Electric Power, and Tohoku Electric Power).

Japan's regulator makes the maintenance of supply security its primary policy objective, followed in priority by environmental protection and, finally, allowing market mechanisms to work. This approach preserves utilities' integrated operations and makes them responsible for final supply to users in the liberalized market.

The government is gradually deregulating the industry and expanding the liberalized market. This market, which was partially introduced in 2000, was expanded from about 26% of the total to about 40% in April 2004, and will be

7. *See, for example, "Industrial Company Rating Methodology", July 1998*
8. *See, for example, "Moody's Liquidity Risk Assessments – Q&A", March 2002, "Moody's Analysis of US Corporate Rating Triggers Heightens the Need for Increased Disclosure" and "Rating Triggers in Europe: Limited Awareness but Widely Used Among Corporate Issuers", September 2002*
9. *See, for example, "U.S. and Canadian Corporate Governance Assessment", August 2003 and "Moody's Findings on Corporate Governance in the United States and Canada: August 2003 - September 2004", October 2004*
10. *See, for example, "Event Risk's Four Horsemen of the Apocalypse: Decapitalization, Cash-financed M&A, Litigation, and Accounting Irregularities", November 2000 and "Event Risk For European Corporates 2003 – Still A Credit Risk, Still Part Of Our Analysis", February 2003*
11. *See, for example, "The Analysis Of Off-Balance Sheet Exposures: a Global Perspective", July 2004*
12. *Note: Moody's paper "The Incorporation of Joint-Default Analysis into Moody's Corporate, Financial and Government Rating Methodologies" February 2005 which may effect the ratings of, for example, a municipality supported by a regional or national government.*

further expanded to about 63% in April 2005. However, the pace of deregulation has been set as moderate so that the regulator can monitor the risks and the effects on the power companies, especially in the context of supply security.

The Japanese utilities hold strongly established franchises in their operating regions, maintaining dominant market shares despite the market for large customers being deregulated. Some utilities still hold 100% shares.

Direct competition among integrated utilities has been very limited. This is mainly because: (1) each integrated operator holds a solid franchise in its operating region due to effective regional monopolies; (2) the companies display similar cost positions, and achievement of any meaningful differentiation in pricing is difficult; (3) the utilities are fully aware that an aggressive challenge by one utility in another's franchise would trigger industry-wide competition, which would, in turn, significantly weaken the industry's overall profitability; and (4) all the utilities exhibit similarly leveraged balance sheet positions and place priority on debt reduction, having completed most of their major investments.

In addition, the ability of power producers and suppliers (PPSs) to take utilities' shares has been restrained by limitations on: (1) their ability to purchase power from, for example, captive power plants; (2) their opportunities to build competitive plants on their own; and (3) their marketing abilities.

Although PPSs have been gaining minor shares in some utilities' franchise areas, and some are constructing their own power plants, their aggregate share is expected to remain insignificant over the intermediate term, due to power companies' rate strategies aimed at protecting their franchises and PPSs' ongoing limited access to power sources.

As such, although the rates are to be further lowered through the ongoing deregulation process, we expect the utilities' franchises to remain solid and stable over the intermediate term.

Government energy policy has made nuclear generation a core power source, while leaving actual implementation of the policy – construction and operation of nuclear power plants – to privately owned and managed utilities. Thus, these companies play an important role in the nation's energy policy, although the government remains the main driver by establishing and maintaining their nuclear power operation systems.

The government is now reviewing the economic feasibility of the nuclear fuel cycle, the allocation of back-end costs, and power utilities' reserves for back-end costs. While the outcome of the review could affect utilities' investment, cost, and balance sheet positions to some extent, we do not expect any significant changes in their policy role, business risks or cost competitiveness.

EUROPE

EU policy is the driver for regulatory development in Europe

The EU Electricity Directive of 1999, subsequently amended by the EU Energy Council in 2002, set the roadmap towards full supply liberalization in the European Union as well as addressing issues such as non-discriminatory access to the transmission grid and the granting of new generation licenses. The current aim is to have full liberalization within the EU by 2007.

Despite EU policy, there is a regulatory patchwork across Europe

Despite the EU directive, there is some flexibility in its implementation, leading to different regulatory models. The process has in most cases led to the establishment of an independent regulator, although the degree of independence from government influence varies significantly. In some countries, such as Spain and Greece, the government maintains control for final setting of tariffs and the regulator acts in an advisory capacity, whilst at the other end of the spectrum are those countries where there is a fully independent regulator, such as in the UK.

Having achieved full supply liberalization, the regulator can focus on regulating the monopoly wires activities – transmission and distribution. The UK has adopted an ex-ante approach, with a tight regulatory framework for wires activities. "Ex-ante" means setting the tariffs in advance, normally for a 3-5 year period, and the regulator allows the company to recover operating and capital expenditures as well as a return on capital. Normally the regulator will benchmark companies against their peers and will allow certain revenues (a revenue or price cap), often adjusted for inflation and an efficiency incentive, depending on how efficient the company is perceived to be.

By contrast, Sweden and Finland initially adopted a much lighter "ex-post" system, which allows companies to set their own prices to achieve a reasonable return on a cost-plus basis, with an arbitration mechanism to allow for complaints and remedies. Despite this looser regime, prices in these markets have been some of the lowest in Europe, benefiting no doubt from the overall greater price transparency from a fully liberalized market. However, under

further direction from the EU, Finland and Sweden (and Denmark) are now moving towards an ex-ante regime and this we would expect to become the norm in Europe.

Germany has yet to establish an independent regulator – although it is now moving in this direction – with network tariffs being set within the context of a voluntary agreement between utilities. Access tariffs are set on a negotiated basis, but in practice the German market is difficult and expensive for new entrants to access.

In Moody's view, power shortages in 2003 have led to an easing in regulatory pressure as security of supply displaces cost as a key aim

Regulators initially introduced quite harsh efficiency incentives or tariff caps, with tariffs reduced in real terms as companies have become more efficient. However, recent tariff pressure has been upward, e.g. Spanish tariffs fell in real terms between 1996 and 2002 but the current tariff framework now allows for gradual increases. This can be explained by greater concern over security of supply, with Europe having experiencing blackouts during 2003. Moody's believes that regulators wish to ensure that an incentive to invest remains, particularly as some aged thermo capacity and a number of nuclear plants are earmarked for decommissioning in the next few years.

In Central and Eastern European countries, regulation is following in a similar direction but at a slower pace

Central and Eastern European countries and the Baltic states are following EU directives, but are at an earlier stage of regulatory evolution. Whilst most have put in place at least the first Energy Law, implementation is often at an early stage under an extended implementation timetable or relatively new and untested. Many of these countries have now established an independent regulator although there is still a state-owned incumbent with a dominant or monopoly position.

These countries typically face privatization, structural separation (generation, transmission, distribution and supply), tariff increases and issues concerning cross-subsidization – with accession states such as Romania and Bulgaria aiming to have completed the process by 2007. Electricity market development is often linked to the economic and structural development of the country in which they operate. Indeed, the requirements of the IMF or World Bank may allow for only a gradual increase in tariffs (Romania and Bulgaria).

From a credit perspective, whilst the timely recovery of all costs may be delayed or constrained, the impact of such can be mitigated by the dominant market position of these key utilities and/or their strategic importance to the State and the role they play in the development of the economy.

Rating the UK regulated transmission and distribution companies

The UK electricity system is divided into a number of monopoly areas for the high-voltage transmission and lower-voltage local distribution of electricity. There is one monopoly transmission area and 12 Distribution Network Operators (DNOs) covering England and Wales. Two additional companies have the monopoly rights to transmission and distribution in distinct areas within Scotland. As these businesses are monopolies they are subject to price control regulation primarily aimed at protecting the consumer's interests.

All of these businesses are regulated by the Office of Gas and Electricity Markets (OFGEM). OFGEM itself is an independent body governed by an authority made up of independent, non-executive Directors and an Executive team. OFGEM is not part of the UK government but its duties and powers were established by Acts of Parliament and they must have regard to guidance from the government on issues such as protecting the environment.

The revenue that a monopoly business can earn on its regulated business is restricted by an RPI-X price control formula that is reviewed every five years. The formula is designed to allow a company to increase prices to reflect inflation while encouraging efficiency through a "-X" from the RPI. In addition, at the start of each regulatory period, prices are raised or reduced by a one-off price adjustment known as the P_0 adjustment. In order to calculate the "X" and the "P_0" for each company, OFGEM considers the Regulatory Asset Base of each company and sets a formula to provide a fair rate of return on those assets, typically around 6-7%. The next regulatory period for the transmission companies starts in 2007 and for distribution companies in 2005.

The practical regulation system involves a very detailed analysis of each company's regulated asset base and operating and capital expenditures. The output is a very detailed and highly predictable cashflow forecast for the next regulatory period. If the companies can improve efficiency, then they can retain most of the benefit. However, if they lose efficiency or the regulatory outcome proves unachievable, then this is a risk for the stakeholders in that company.

For Moody's, the ratings of these businesses depend upon two key factors:

1. The projected financial position of the company once the final regulatory outcome is known. This is measured by a number of financial ratios including FFO interest cover and Debt/Regulated Asset Value.
2. The additional burdens placed on the regulated entity's cash flows by its parent, mainly in the form of additional parental debt which needs to be serviced by dividends from the regulated operating company.
3. DNO-specific issues such as unfunded pension deficits unrelated to the distribution business, debt maturity profile and debt capital structure considerations.

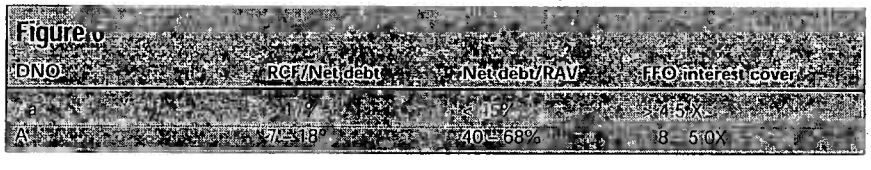
According to OFGEM, after these adjustments, the intention is that all companies will earn the same baselines return of 6.6% on a pre-tax, real basis if they perform in line with the regulator's projections. The main issues are expected to be the need to increase capex to replace network assets and improve network performance, to put a greater emphasis on quality of service, and to respond to the growth in sources of renewable energy. These final determinations for the 2005-2010 price control period will become effective in April 2005.

The main rating implication from these proposals is likely to fall on companies whose overall financial profile is burdened by the need to pay large dividends to service and repay debt at holding company levels. While this can lead to a significant cash drain, the debt at the holding companies is outside the regulatory ringfence and is not protected by the OFGEM framework. One such holding company, Avon Energy Partners, has already defaulted on its debt obligations, while the operating company Midlands Electricity had no financial difficulties, thus illustrating that lending to such holding companies is significantly more risky than lending to the regulated entity itself.

When looking at the financial ratios for regulated UK DNOs, there are a number of important considerations to bear in mind:

1. The Regulated Asset Value (RAV) is an important reference point as allowable revenues and allowable capital expenditures both feed from or into this. Hence, the Debt/RAV ratio is one of the more critical financial ratios to consider.
2. OFGEM's scope of regulation is limited to the regulated entity, while Moody's rating of the DNO also factors in debt which must be serviced by cash flows from the DNO. This means that an RCF number (cashflow after dividends) is an important one for a DNO. It also means that ratios factoring in any "Holdco" debt tend to outweigh pure "stand-alone" DNO ratios. In practice, there are no remaining stand-alone DNOs.
3. Some DNOs retain cash to meet future debt maturities and where this is the case, the emphasis falls on net rather than gross debt numbers.

As a guideline and ignoring other considerations, the following ratios might be expected for UK DNOs at various rating levels, without factoring the need to support other group debt (if there is such debt, stronger ratios would be needed for the same rating level):



AUSTRALIAN T&D RATINGS ARE HIGHER THAN UK RATINGS FOR COMPARABLE ENTITIES

Differences in regulatory philosophy between Australia and the UK mean that Moody's on average rates Australian electricity transmission and distribution (T&D) companies one notch above the ratings of their UK peers, even though both parties may have approximately the same level of debt coverage measures.

Furthermore, the impact of the regulatory differences is such that when Australian and UK companies share the same rating level, the Australian companies conversely exhibit weaker debt coverage measures. Moody's believes that the financial profiles of Australian T&D companies are sustainable within their present ratings, given their benign regulatory environments.

Moody's compared – on a senior unsecured basis – Baa-rated T&D companies in Australia and those in the UK. The projected average financial ratios for Australian T&D companies over the next few years are as follows:



The UK T&D companies – on the other hand – have higher financial ratio hurdles at the Baa rating range. For instance, UK Baa-rated T&D companies are expected to have Debt-to-RAB ratio in the range of 60-90%, RCF-to-Debt 10-15%, and FFO-to-Interest of above 2.8 times.

On one level, the Australian and UK regulatory regimes are close matches. For example, regulators in both countries have adopted similar frameworks for determining revenues and returns. However, on a practical level, regulators in Australia have assumed a more benign stance on requirements for revenues and returns.

Moody's believes that this situation reflects the Australian regulators' approach in the following areas: (1) more generous cost allowances for maintaining minimum levels of service and system reliability for T&D assets; (2) appropriate levels of return for regulated T&D companies; (3) regulators' willingness to allow the retention of efficiency out-performances; and (4) greater certainty in regulatory outcomes at the next resets.

A comparison of recent tariff resets in both countries supports the conclusion that the Australian environment is more benign, a situation which Moody's believes will prevail over the medium term. Consequently, we do not expect an aggressive tariff decision at the next reset, scheduled for 2006 for electricity distributors in the state of Victoria.

In the UK, electricity distributors are undergoing a tariff reset for the five-year period commencing April 2005. The expected outcome for this reset is still evolving. However, the UK electricity distributors' cash flows could come under some pressure as the regulator restricts the ability of distributors to carry through to the next regulatory period the efficiency savings achieved. At the same time, distributors are expected to face higher cash commitments as a consequence of increased tax obligations and capital expenditure requirements to support various policy initiatives. As a result, UK T&D companies would need a more prudent set of financial policies to preserve their credit profiles.

While there is relative certainty in the Australian regulatory environment over the next reset period, it is more difficult to predict with confidence developments in regulatory thinking over the longer term. Consequently, Australian T&D companies must adopt prudent financial policies in readiness for a possible evolution in regulatory thinking at the end of the next regulatory period in 2010.

In this regard, companies that persist with highly leveraged capital structures on a Debt-to-RAB basis – that is, a ratio of over 100% – and exhibit no ability or commitment to de-leverage over the longer term may be more exposed to severe regulatory outcomes.

The ability of a company to de-leverage is indicated by the extent of free cash flow generation – relative to debt levels – after servicing all operational, debt, and dividend obligations.

UNITED STATES

The US electric utilities are characterized by a substantial diversity in both their business models and their regulatory risk. Business models vary from the lowest-risk companies that have purely regulated activities and which operate in states that have supportive regulation, to the highest-risk companies that have substantial unregulated activities and which operate in states that have less supportive or less predictable regulation.

Moody's views the business risk of US utilities as being higher in most cases than that of utilities in some other developed countries, including Japan, Australia, and the United Kingdom. This difference in risk reflects the following factors:

1. State regulation is seen as less predictable than national regulation. State regulation is the primary form of regulation in the US. Compared to national regulators, state regulators represent a smaller economic region. As a result, Moody's believes that state regulators may be more likely to be responsive to the objections of local customers and politicians when a utility seeks a large rate increase to address a large increase in costs or capital expenditures. As noted in the default section in Appendix 3, failure to obtain timely rate increases was a key factor in four recent defaults by US utilities. In addition, various parties may seek to intervene in in U.S. state regulatory proceedings, which can cause delay and increased uncertainty.

2. A large fragmented market structure results in stronger competition in unregulated wholesale power markets. The US electric utility industry is fragmented in comparison to Japan and major countries in Europe. Although the US represents over one fourth of global electricity consumption, none of the US utilities ranks in the top ten in terms of revenues among global utility companies. As portions of the market have become deregulated, US utilities are more vulnerable to changes in wholesale power costs because their market share and market power is more limited than those of comparable utilities in most other countries. Regulators have strived to limit market power to protect consumers, resulting in longstanding legal and regulatory impediments to industry mergers and consolidation.
3. More volatile fuel and wholesale power markets. Natural gas prices are completely unregulated in the US, which can result in rapid and wide swings in prices. There is a large unregulated power market in the US, which responds quickly to changes in fuel costs and passes these changes through to wholesale power prices. This combination of factors can result in more rapid and wider swings in prices than in more controlled markets.
4. Low likelihood of extraordinary political action to support a failing company. Utilities provide an essential service, so financial distress has a high political profile. Governments in the US have broadly demonstrated a reluctance to intervene on behalf of troubled investor-owned utilities when this could be viewed as providing economic assistance to private shareholders. This approach is in sharp contrast to the large US municipal utility sector, in which supportive government action is far more likely. Governments in many other countries (for example, Japan or Canada) are perceived as being more likely to work with regulators and financial institutions to support electric utilities as highly visible entities that provide a critical service.
5. Holding company structures limit regulatory oversight. State regulators only have authority over the regulated operating utility. The vast majority of companies have established unregulated holding companies that have the ability to engage in higher-risk unregulated businesses in the hopes of earning shareholder returns that are higher than the returns provided for the regulated business.
6. Overlapping or unclear regulatory juridisction. The electric utilities industry in the US is characterized by regulation at both the federal and state levels. Traditionally, the federal government has regulated the interstate and wholesale transmission of electricity, while distribution and retail services to consumers have been regulated by the states. Each state exhibits its own unique regulatory characteristics which set the parameters and define the environment in which a particular utility operates. In some instances the jurisdictions can overlap, such as in the case of mergers and transactions with affiliates.

Federal Energy Regulatory Commission (FERC)

The key federal regulatory agency governing utilities in the US is the Federal Energy Regulatory Commission (FERC), an independent agency that regulates the interstate transmission of natural gas, oil, and electricity, as well as natural gas and hydroelectric power projects. In the electric market, the FERC's responsibilities include the approval of rates for the wholesale sale of electricity and transmission on an interstate basis for utilities, power marketers, power pools, power exchanges, and independent system operators. The FERC sets the price for those utility transmission systems that fall within its jurisdiction, although many portions of utility transmission systems fall under the jurisdiction of the state regulatory agencies.

In recent years, FERC has issued several orders aimed at opening the transmission lines of utilities in the US. In 1996, FERC Order 888 provided rules for open access of transmission lines to all suppliers and for competition in the wholesale market and set standards for regional transmission organizations (RTOs). In 1999, FERC Order 2000 encouraged utilities with transmission assets to voluntarily transfer control of their transmission systems to these RTOs, which could either be non-profit independent system operators (ISOs) or for-profit transmission companies. Although some utilities have transferred their transmission assets into RTOs, others have thus far resisted attempts to place their transmission assets under outside control.

Public Utility Holding Company Act (PUHCA)

The most significant piece of legislation governing public utility holding companies at the federal level is the Public Utility Holding Company Act, more commonly known as PUHCA. The Act was passed in 1935 to regulate interstate utility holding companies in response to the financial collapse of a number of such holding companies following the stock market crash of 1929. When utilities in different states combine or merge under a holding company, the new

entity becomes registered under PUHCA, which provides for SEC regulation of their financing activities, including the sale and purchase of securities and assets. PUHCA gives the SEC the power to exercise broad oversight over business combinations that result in functional or geographic diversification of utilities.

Historically, the SEC has severely restricted the types of business activities in which registered holding companies may engage. The National Energy Policy Act of 1992 (NEPA) eased some of the regulatory restrictions imposed by PUHCA by allowing registered holding companies to establish non-utility generating subsidiaries and to purchase foreign utilities without seeking prior SEC approval. However, registered holding companies are still prohibited from owning both electric and gas operations or possessing unregulated businesses without SEC approval. Although there have been a number of attempts over the last few years to repeal PUHCA, most recently as part of comprehensive energy legislation considered but not passed in 2003, it remains a key federal regulatory constraint and limitation for those holding companies registered under PUHCA.

State Regulatory Commissions

The most important regulatory factor affecting the sale of electricity by utilities at the retail level are state agencies generally known as Public Utility Commissions or Public Service Commissions. These commissions comprise elected or appointed officials in each state who determine, among other things, whether utility expenditures are reasonable and how they should be passed on to consumers through their electric rates. They also regulate each utility's rates of return and monitor the quality and reliability of a utility's electric service. The state-level factors that Moody's takes into consideration when evaluating the credit quality of utilities include the following:

- **Status of Deregulation/Retail Access**

Since industry restructuring began in the mid-1990s, states have taken a variety of approaches to the question of whether they should deregulate their electricity markets. Some states have passed comprehensive deregulation legislation and completely restructured. Some have avoided it entirely, while others have introduced some elements of deregulation into their markets. Over the last several years, 18 states have undertaken some form of deregulation or retail open access, while 32 others have elected not to deregulate after studying and debating restructuring initiatives (see Figure 8 for details).

- **Ring-Fencing Provisions**

State commissions sometimes attempt to insulate and protect regulated operating utilities from the often riskier activities of their parent companies or unregulated subsidiaries. Some so-called "ring-fencing" provisions that have been adopted at the state level include: dividend limitations, minimum equity requirements, limits on unregulated activities, credit rating requirements, the maintenance of collateral, limitations on intercompany transactions, and restrictions on asset sales.

- **Transition Periods and Rate Caps**

Some utilities are subject to price limitations or rate freezes which were put in place as states implemented transition plans to deregulate their electric markets. These rates were often thought to be adequate to permit the utilities to both recover stranded costs and earn an adequate rate of return until a fully competitive environment developed. Many of these transition periods and associated rate caps are now ending without a fully competitive market having developed, and the likelihood that these transition periods will be extended is an important credit consideration.

- **Cost Recovery Provisions**

States have various policies with respect to fuel and wholesale power cost recovery, and the recent volatility in commodity prices have made these provisions important elements of a utility's cost management capability. Such provisions make it possible for utilities to quickly adjust rates in the event of an unexpected hike in fuel costs. Although the number of states permitting such recovery has declined, particularly in those that have transitioned to a competitive market, they remain critical risk mitigants to those utilities still operating in regulated environments.

- **Incentive- or Performance-Based Rates (Earnings Sharing)**

Utilities in the US have traditionally operated under "cost of service"-based rates under which revenues were set to permit the utility to cover its costs and provide for an acceptable rate of return. However, a number of state regulatory commissions have implemented incentive- or performance-based rates which give utilities incentives to operate better and more efficiently. Often, these incentives take the form of an earnings sharing mechanism, allowing a utility to keep some of the profits earned above a predetermined range, while returning any excess to ratepayers.

Figure 8 – Regulatory Characteristics of States in The U.S.

State	Deregulation	Rate Cap	Cost Recovery	Earnings Sharing
Alabama			X	X
Alaska	N/A	N/A	N/A	N/A
Arizona	X	X	X	
Arkansas			X	
California	X		X	X
Colorado			X	X
Connecticut	X	X	X	X
Delaware	X	X	X	
DC	X	X		
Florida			X	X
Georgia			X	X
Hawaii			X	
Idaho			X	
Illinois	X	X	X	X
Indiana			X	X
Iowa			X	
Kansas			X	
Kentucky			X	
Louisiana			X	
Maine	X		X	
Maryland	X	X		
Massachusetts	X		X	X
Michigan	X	X	X	
Minnesota			X	
Mississippi			X	X
Missouri			X	X
Montana				
Nebraska	N/A	N/A	N/A	N/A
Nevada			X	
New Hampshire	X	X	X	
New Jersey	X		X	
New Mexico		X		
New York	X		X	X
North Carolina			X	
North Dakota			X	X
Ohio	X	X		
Oklahoma			X	
Oregon			X	
Pennsylvania	X	X		
Rhode Island	X		X	
South Carolina			X	
South Dakota			X	
Tennessee			X	
Texas	X		X	
Utah				
Vermont				
Virginia	X	X		
Washington			X	
West Virginia			X	
Wisconsin			X	
Wyoming			X	

Source: Moody's, Regulatory Research Associates

APPENDICES

Appendix 1 – Three Year Average Ratios and Current Ratings

Company name	Country	Rating	Revenues $bn equiv	EBITA margin %	FFO interest times coverage	FFO/TD %	RCF/TD %	RCF/ Capex %	TD/ Capitalization %
EUROPE									
Landsvirkjun	Iceland	Aaa	0.2	28.2	2.7	6.7	6.4	67.7	68.2
EVN	Austria	Aa3	1.1	11.9	10.3	30.0	26.2	111.8	43.6
Fingrid	Finland	Aa3	0.3	33.9	2.6	8.1	7.5	165.2	78.4
Electricite de France	France	Aa3	45.4	13.4	4.3	20.1	16.9	93.6	64.2
E.on	Germany	Aa3	41.1	12.1	4.7	13.7	9.6	76.2	37.4
Terna	Italy	Aa3	1.2	50.8	3.8	17.7	15.7	43.9	50.0
Statnett	Norway	Aa3	0.5	30.8	3.1	15.6	9.7	92.3	57.6
Scottish & Southern Energy	UK	Aa3	7.2	15.4	8.5	38.6	20.7	94.9	45.3
		hi	7.2	50.8	10.3	38.6	26.2	165.2	78.4
		avg	2.4	24.1	5.3	20.6	15.2	96.9	53.8
		med	1.2	15.4	4.3	17.7	15.7	93.6	50.0
		low	0.2	11.9	2.6	6.7	6.4	43.9	37.4
Verbund	Austria	A1	2.3	21.9	2.1	8.7	7.6	311.4	74.4
RWE	Germany	A1	42.0	11.5	3.6	15.8	13.6	58.3	40.3
ENEL	Italy	A1	38.1	15.1	5.0	21.9	14.7	69.1	53.3
		hi	38.1	21.9	5.0	21.9	14.7	311.4	74.4
		avg	16.2	16.2	3.6	15.5	12.0	146.3	56.0
		med	15.1	15.1	3.6	15.8	13.6	69.1	53.3
		low	1.5	11.5	2.1	8.7	7.6	58.3	40.3
Suez	France	A2	45.2	9.3	2.3	12.0	7.8	42.0	68.8
EWE	Germany	A2	2.9	7.3	22.4	77.5	69.4	100.8	42.9
Essent	Netherlands	A2	8.8	10.4	5.6	28.4	25.5	152.5	61.3
Nuon	Netherlands	A2	4.7	9.4	7.0	28.6	25.2	93.9	40.8
Red Electrica de Espana	Spain	A2	0.5	36.6	8.2	25.2	18.1	37.0	56.9
Iberdrola	Spain	A2	7.0	18.7	3.3	14.4	9.9	72.3	57.9
National Grid Company	UK	A2	2.5	0.4	4.0	0.2	0.1	1.2	0.6
United Utilities Electricity	UK	A2	0.5	53.6	4.5	22.2	14.4	75.8	52.4
		hi	45.2	53.6	22.4	77.5	69.4	152.5	68.8
		avg	10.2	18.2	7.2	26.1	21.3	71.9	47.76
		med	3.9	9.9	5.0	23.7	16.3	74.0	54.6
		low	0.4	0.4	2.3	0.2	0.1	1.2	0.6
Eesti Energia	Estonia	A3	0.3	12.6	10.9	49.6	49.6	71.2	23.3
Energie Baden-Wuerttemberg (EnBW)	Germany	A3	9.7	6.9	2.3	5.8	3.6	21.9	80.3
Electricidade de Portugal	Portugal	A3	8.7	11.8	3.6	10.8	7.3	65.2	58.3
Endesa	Spain	A3	21.0	19.4	3.3	12.7	9.2	-971.8	66.6
Vattenfall	Sweden	A3	13.6	16.5	4.0	15.6	14.0	84.1	53.9
		hi	21.0	19.4	10.9	49.6	49.6	84.1	80.3
		avg	13.4	13.4	4.8	18.9	16.7	-145.9	56.5
		med	12.6	13.6	3.6	12.7	9.2	65.2	58.3
		low	6.9	6.9	2.3	5.8	3.6	-971.8	23.3

Appendix 1 – Three Year Average Ratios and Current Ratings

Company name	Country	Rating	Revenues $bn equiv	EBITA margin %	FFO interest times coverage	FFO/TD %	RCF/TD %	RCF/ Capex %	TD/ Capitalization %
CEZ	Czech Republic	Baa1	2.2	18.7	8.4	50.0	45.6	145.7	21.8
Public Power Corp (PPC)	Greece	Baa1	3.5	19.6	4.9	15.8	14.4	101.6	69.3
Latvenergo	Latvia	Baa1	0.3	11.8	14.6	63.2	59.0	63.0	25.3
Eskom	South Africa	Baa1/A3	3.5	37.3	3.4	24.2	23.8	202.7	53.2
Scottish Power plc	UK	Baa1	9.3	19.5	3.8	16.2	8.7	30.6	56.6
		hi		37.3	14.6	63.2	59.0	202.7	69.3
		avg		21.4	7.0	31.9	30.3	108.7	45.2
		med		19.5	4.9	24.2	23.8	101.6	53.2
		low		11.8	3.4	15.8	8.7	30.6	21.8
Israel Electric Corporation (IEC)	Israel	Baa2	2.6	17.3	2.2	7.5	7.4	65.1	69.9
Union Fenosa	Spain	Baa2	5.6	15.7	2.1	4.4	2.3	54.8	65.1
WPD Holdings UK	UK	Baa3	0.5	47.7	2.4	9.1	6.7	50.0	68.3
CE Electric	UK	Baa3	1.1	36.8	2.6	10.5	8.1	-1.1	75.0
		hi		47.7	2.6	10.5	8.1	65.1	75.0
		avg		29.4	2.3	7.9	6.1	42.2	69.6
		med		27.0	2.3	8.3	7.1	52.4	69.9
		low		15.7	2.1	4.4	2.3	-1.1	65.1
Transelectrica	Romania	Ba3	0.2	-1.4	7.3	77.1	76.4	122.6	10.1
		hi		-1.4	7.3	77.1	76.4	122.6	10.1
		avg		-1.4	7.3	77.1	76.4	122.6	10.1
		med		-1.4	7.3	77.1	76.4	122.6	10.1
		low		-1.4	7.3	77.1	76.4	122.6	10.1
ASIA/PACIFIC									
Singapore Power	Singapore	Aa1	2.6	26.0	7.0	32.0	-8.0	-362.0	48.0
SP PowerAssets		Aa1	0.4	44.0	6.0	8.0	8.0	625.0	61.0
		hi		44.0	7.0	32.0	8.0	625.0	61.0
		avg		35.0	6.5	20.0	0.0	131.5	54.5
		med		35.0	6.5	20.0	0.0	131.5	54.5
		low		26.0	6.0	8.0	-8.0	-362.0	48.0
CLP Holdings		A1	3.4	35.0	14.0	22.0	49.0	94.0	20.0
		hi		35.0	14.0	22.0	49.0	94.0	20.0
		avg		35.0	14.0	22.0	49.0	94.0	20.0
		med		35.0	14.0	22.0	49.0	94.0	20.0
		low		35.0	14.0	22.0	49.0	94.0	20.0
Australian Gas Light Company	Australia	A2	3.8	13.0	4.1	23.0	14.0	96.0	49.0
		hi		13.0	4.1	23.0	14.0	96.0	49.0
		avg		13.0	4.1	23.0	14.0	96.0	49.0
		med		13.0	4.1	23.0	14.0	96.0	49.0
		low		13.0	4.1	23.0	14.0	96.0	49.0

Appendix 1 – Three Year Average Ratios and Current Ratings

Company name	Country	Rating	Revenues $bn equiv	EBITA margin %	FFO interest times coverage	FFO/TD %	RCF/TD %	RCF/ Capex %	TD/ Capitalization %
KEPCO		A3	18.0	24.0	6.0	33.0	31.0	112.0	40.0
Citipower		A3	0.5	39.0	3.0	10.0	7.0	132.0	88.0
ETSA		A3	0.7	42.0	2.0	4.0	-2.0	69.0	64.0
Powercor		A3	0.6	42.0	4.0	12.0	12.0	111.0	51.0
SPI Powernet		A3	0.3	62.0	2.0	10.0	10.0	258.0	71.0
TXU Australia		A3		24.0	3.0	10.0	8.0	171.0	57.0
		hi		62.0	6.0	33.0	31.0	258.0	88.0
		avg		38.8	3.3	13.2	11.0	142.2	61.8
		med		40.5	3.0	10.0	9.0	122.0	60.5
		low		4.0	2.0	4.0	2.0	69.0	40.0
United Energy		Baa1	0.4	32.0	3.0	13.0	7.0	71.0	60.0
Vector		Baa1	0.5	39.0	3.0	8.0	5.0	117.0	67.0
Electranet		Baa1	0.1	46.0	2.0	3.0	3.0	151.0	74.0
Gasnet		Baa1	0.1	61.0	2.0	6.0	4.0	687.0	68.0
		hi		61.0	3.0	13.0	7.0	687.0	74.0
		avg		44.5	2.5	7.5	4.8	256.5	67.3
		med		42.5	2.5	7.0	4.5	134.0	67.5
		low		32.0	2.0	3.0	3.0	71.0	60.0
Tenaga		Baa2	4.1	18.0	3.0	11.0	10.0	82.0	61.0
		hi		18.0	3.0	11.0	10.0	82.0	61.0
		avg		18.0	3.0	11.0	10.0	82.0	61.0
		med		18.0	3.0	11.0	10.0	82.0	61.0
		low		18.0	3.0	11.0	10.0	82.0	61.0
National Thermal Power Corporation		Baa3	4.1	20.5	5.5	31.2	25.7	93.8	29.1
		hi		20.5	5.5	31.2	25.7	93.8	29.1
		avg		20.5	5.5	31.2	25.7	93.8	29.1
		med		20.5	5.5	31.2	25.7	93.8	29.1
		low		20.5	5.5	31.2	25.7	93.8	29.1
Tata Power		Ba1	1.1	17.9	3.6	28.6	25.1	133.3	42.7
		hi		17.9	3.6	28.6	25.1	133.3	42.7
		avg		17.9	3.6	28.6	25.1	133.3	42.7
		med		17.9	3.6	28.6	25.1	133.3	42.7
		low		17.9	3.6	28.6	25.1	133.3	42.7
National Power Corporation		B1	2.1	29.7	2.1	3.6	1.9	129.0	94.5
		hi		29.7	2.1	3.6	1.9	129.0	94.5
		avg		29.7	2.1	3.6	1.9	129.0	94.5
		med		29.7	2.1	3.6	1.9	129.0	94.5
		low		29.7	2.1	3.6	1.9	129.0	94.5

Appendix 1 – Three Year Average Ratios and Current Ratings

Company name	Country	Rating	Revenues $bn equiv	EBITA margin %	FFO interest times coverage	FFO/TD %	RCF/TD %	RCF/ Capex %	TD/ Capitalization %
AMERICAS									
WPS Resources Corp	USA	A1	2.4	9.1	4.1	18.4	11.9	51.1	51.7
		hi		9.1	4.1	18.4	11.9	51.1	51.7
		avg		9.1	4.1	18.4	11.9	51.1	51.7
		med		9.1	4.1	18.4	11.9	51.1	51.7
		low		9.1	4.1	18.4	11.9	51.1	51.7
Consolidated Edison Inc	USA	A2	9.2	16.7	4.1	20.3	14.0	80.3	45.3
FPL Group, Inc.	USA	A2	8.7	17.0	6.0	29.0	23.0	57.0	47.0
Hydro One, Inc	CAN	A2	3.3	25.1	3.0	13.0	9.3	83.3	60.3
NSTAR	USA	A2	2.9	16.0	3.5	16.7	12.8	127.0	52.7
Otter Tail Corporation	USA	A2	0.7	13.3	4.3	17.6	11.9	84.9	53.0
		hi		25.1	6.0	29.0	23.0	127.0	60.3
		avg		17.6	4.2	19.3	14.2	86.5	51.7
		med		16.7	4.1	17.6	12.8	83.3	52.7
		low		13.3	3.0	13.0	9.3	57.0	45.3
Ameren Corporation	USA	A3	4.1	24.3	5.0	19.5	11.1	51.2	44.0
Scana Corporation	USA	A3	3.3	18.3	3.1	13.2	9.7	99.3	54.3
Southern Company (The)	USA	A3	10.7	24.3	4.7	19.7	12.3	67.0	50.0
Wisconsin Energy Corp	USA	A3	3.9	18.1	3.8	15.3	13.1	124.1	60.1
		hi		24.3	5.0	19.7	13.1	124.1	60.1
		avg		21.3	4.2	16.9	11.6	85.4	52.1
		med		21.3	4.2	17.4	11.7	83.2	52.2
		low		18.1	3.1	13.2	9.7	51.2	44.0
Constellation Energy	USA	Baa1	6.1	18.7	3.7	16.3	14.0	135.0	52.0
Dominion Resources	USA	Baa1	11.0	23.0	3.3	14.4	10.3	45.7	54.3
Duke Energy Corp	USA	Baa1	18.7	15.0	3.4	17.3	12.7	166.0	49.3
OGE Energy Corp.	USA	Baa1	3.3	9.2	3.9	16.5	11.4	117.6	53.0
Sempra Energy	USA	Baa1	7.2	15.1	4.0	18.6	18.1	76.3	56.3
Xcel Energy Inc.	USA	Baa1	7.9	15.8	4.6	18.8	14.0	114.3	61.6
		hi		23.0	4.6	18.8	18.1	166.0	61.6
		avg		16.1	3.8	17.0	13.4	109.1	54.4
		med		15.4	3.8	16.9	13.3	116.0	53.7
		low		9.2	3.3	14.4	10.3	45.7	49.3

Appendix 1 – Three Year Average Ratios and Current Ratings

Company name	Country	Rating	Revenues $bn equiv	EBITA margin %	FFO interest times coverage	FFO/TD %	RCF/TD %	RCF/ Capex %	TD/ Capitalization %
Cinergy Corp	USA	Baa2	4.1	22.3	4.2	14.4	9.5	55.8	56.3
DTE Energy Company	USA	Baa2	6.5	24.0	2.8	11.0	7.5	NM	58.0
Emera Inc.	CAN	Baa2	1.0	27.8	2.7	10.5	7.0	151.7	64.9
Empire District Electric Company	USA	Baa2	0.3	21.0	3.0	15.0	8.0	51.0	51.0
Energy East Corporation	USA	Baa2	4.1	16.0	2.6	11.1	8.3	127.0	58.0
Exelon Corp	USA	Baa2	15.2	25.8	4.4	24.7	14.0	86.1	39.9
Great Plains Energy Inc.	USA	Baa2	1.8	16.9	4.3	17.4	11.9	139.1	56.6
IDACORP, Inc.	USA	Baa2	1.0	14.3	4.3	19.7	14.0	98.7	44.0
Northeast Utilities	USA	Baa2	5.7	18.1	2.9	11.0	9.6	124.7	42.9
Pepco Holdings, Inc.	USA	Baa2	5.8	12.5	3.3	10.8	8.4	136.2	56.5
Pinnacle West Capital Corp.	USA	Baa2	2.6	21.7	4.8	18.8	15.3	81.2	50.8
Progress Energy	USA	Baa2	8.3	15.1	3.4	14.4	10.1	68.6	59.1
Public Service Enterprise Group Inc.	USA	Baa2	8.7	23.7	2.4	10.0	6.3	52.7	59.0
		hi		27.8	4.8	24.7	15.3	151.7	64.9
		avg		19.9	3.5	14.5	10.0	97.7	53.6
		med		21.0	3.3	14.4	9.5	92.4	56.5
		low		12.5	2.4	10.0	6.3	51.0	39.9
American Electric Power Co	USA	Baa3	13.5	19.6	3.4	13.2	9.0	208.0	58.5
Cleco Corp	USA	Baa3	0.8	22.0	3.4	16.0	12.0	132.3	57.0
Duquesne Light Holdings	USA	Baa3	1.0	16.9	3.9	18.9	13.4	428.4	54.4
Edison International	USA	(P)Baa3	11.6	33.6	3.0	17.7	17.6	NM	59.8
Entergy Corporation	USA	Baa3	9.0	19.0	4.1	21.1	18.0	100.4	41.3
FirstEnergy Corp.	USA	Baa3	10.8	18.1	3.0	10.9	8.3	108.6	60.1
MidAmerican Energy Holding Co.	USA	Baa3	5.1	25.1	2.2	8.6	8.6	128.4	75.7
PG&E Corporation	USA	Baa3	10.4	28.7	2.9	14.4	14.3	142.4	76.4
PNM Resources, Inc.	USA	Baa3	1.6	11.4	4.4	17.4	14.8	83.0	52.5
PPL Corporation *	USA	Baa3	5.4	21.6	2.5	13.6	11.1	104.5	67.1
UIL Holdings Corporation	USA	Baa3	1.0	12.3	4.0	16.0	10.3	100.7	50.3
		hi		33.6	4.4	21.1	18.0	428.4	76.4
		avg		20.8	3.1	15.3	12.5	153.7	59.4
		med		19.6	3.4	16.0	12.0	118.5	58.5
		low		11.4	2.2	8.6	8.3	83.0	41.3
Avista Corp	USA	Ba1	1.2	15.7	2.3	10.0	8.7	128.0	54.3
Empresa Nacional de Electricidad S.A.	Chile	Ba1	1.5	35.3	2.1	8.2	6.3	217.7	56.0
Enersis S.A.	Chile	Ba1	4.0	17.7	2.3	11.5	9.3	207.0	76.0
Puget Energy, Inc.	USA	Ba1	2.6	15.0	2.8	13.3	10.0	94.7	56.3
TXU Corp	USA	Ba1	10.3	17.0	2.9	13.0	10.0	160.3	62.0
Westar Energy	USA	Ba1	1.4	26.2	2.1	8.9	7.0	93.1	60.7
		hi		35.3	2.9	13.3	10.0	217.7	76.0
		avg		21.1	2.4	10.8	8.5	150.1	60.9
		med		17.3	2.3	11.8	9.0	144.2	58.5
		low		15.0	2.1	8.9	6.3	93.1	54.3

* *Rating on guaranteed debt issued by PPL Capital*

Appendix 1 – Three Year Average Ratios and Current Ratings

Company name	Country	Rating	Revenues $bn equiv	EBITA margin %	FFO interest times coverage	FFO/TD %	RCF/TD %	RCF/ Capex %	TD/ Capitalization %
Centerpoint Energy, Inc.	USA	Ba2	9.4	17.0	2.4	9.7	7.0	90.0	65.0
DPL Inc.	USA	Ba2	1.2	35.8	2.6	12.6	8.1	107.2	67.0
TECO Energy	USA	Ba2	2.6	8.8	2.7	11.0	5.6	24.3	59.4
		hi		35.8	2.6	12.6	8.1	107.2	67.0
		avg		20.5	2.6	11.1	6.9	73.8	63.8
		med		17.0	2.6	11.0	7.0	90.0	65.0
		low		8.8	2.4	9.7	5.6	24.3	59.4
COELCE	Brazil	Ba3	0.3	22.3	6.3	43.5	28.9	113.3	35.8
		hi		22.3	6.3	43.5	28.9	113.3	35.8
		avg		22.3	6.3	43.5	28.9	113.3	35.8
		med		22.3	6.3	43.5	28.9	113.3	35.8
		low		22.3	6.3	43.5	28.9	113.3	35.8
Allegheny Energy Inc.	USA	B1	2.2	2.4	1.9	6.2	4.1	40.6	62.0
CEMIG	Brazil	B1	1.8	16.8	2.4	15.7	11.8	66.7	43.9
CMS Energy Company	USA	B1	7.4	6.5	1.8	5.2	5.2	-46.8	84.0
		hi		16.8	2.4	15.7	11.8	66.7	84.0
		avg		8.6	2.0	9.0	7.0	20.2	63.3
		med		6.5	1.9	6.2	5.2	40.6	62.0
		low		2.4	1.8	5.2	4.1	-46.8	43.9
Sierra Pacific Resources	USA	B2	3.5	5.2	-0.1	-6.3	-7.0	NM	64.7
		hi		5.2	-0.1	-6.3	-7.0	NM	64.7
		avg		5.2	-0.1	-6.3	-7.0	NM	64.7
		med		5.2	-0.1	-6.3	-7.0	NM	64.7
		low		5.2	-0.1	-6.3	-7.0	NM	64.7
EDELNOR	Chile	B3	0.1	6.0	1.8	3.0	3.0	343.6	49.1
		hi		6.0	1.8	3.0	3.0	343.6	49.1
		avg		6.0	1.8	3.0	3.0	343.6	49.1
		med		6.0	1.8	3.0	3.0	343.6	49.1
		low		6.0	1.8	3.0	3.0	343.6	49.1

Note: The listed U.S. issuers are all holding company parent entities. Almost all have regulated operating utility subsidiaries that have higher ratings.

Appendix 1 – Three Year Average Ratios and Current Ratings

Company name	Country	Rating	Revenues $bn equiv	EBITA margin %	FFO interest times coverage	FFO/TD %	RCF/TD %	RCF/ Capex %	TD/ Capitalization %
JAPAN									
Tokyo Electric Power Company, Inc.	Japan	Aa3	46.6	13.1	6.0	15.8	12.3	150.3	92.7
Chubu Electric Power Company, Inc.	Japan	Aa3	20.2	14.5	5.4	17.4	13.5	153.9	81.7
Kansai Electric Power Co., Inc.	Japan	Aa3	24.4	13.5	7.1	19.3	15.4	156.7	77.9
			hi	14.5	7.1	19.3	15.4	156.7	92.7
			avg	13.7	6.2	17.5	13.8	153.7	84.1
			med	13.5	6.0	17.4	13.5	153.9	81.7
			low	13.1	5.4	15.8	12.3	150.3	77.9
Hokuriku Electric Power Co., Inc.	Japan	A1	4.3	15.2	4.8	15.1	13.0	128.1	85.5
Chugoku Electric Power Co., Inc.	Japan	A1	9.3	12.9	5.5	15.9	11.6	167.3	80.7
Tohoku Electric Power Company, Inc.	Japan	A1	15.0	13.1	5.4	18.2	14.0	142.3	80.6
Shikoku Electric Power Company, Inc.	Japan	A1	5.4	13.3	6.6	21.0	17.4	199.7	76.0
Kyushu Electric Power Company, Inc.	Japan	A1	13.4	13.7	6.0	18.2	16.2	154.8	81.6
Hokkaido Electric Power Co., Inc.	Japan	A1	5.0	15.5	5.9	20.3	16.3	137.0	72.1
			hi	15.5	6.6	21.0	17.4	199.7	85.5
			avg	13.9	5.7	18.1	14.7	154.9	79.4
			med	13.5	5.7	18.2	15.1	148.5	80.7
			low	12.9	4.8	15.1	11.6	128.1	72.1

Appendix 2 – Definition of Ratios

FFO Interest cover

(Cash Flow from Operations – Changes in Working Capital + Interest Expense) / (Interest Expense + Capitalized Interest Expense)

FFO / Adjusted gross debt

(Cash Flow from Operations – Changes in Working Capital) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

Retained Cash Flow / Adjusted gross debt

(Cash Flow from Operations – Changes in Working Capital – Common and Preferred Dividends) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

Adjusted gross debt / Regulated Asset Value or Capitalization

(Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) / RAV or (Shareholders' equity + minority interest + deferred taxes + goodwill write-off reserve + Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

EBITA / Sales (margin)

(Net operating income + Equity Earnings of Affiliates + Income from Financial Asset Investments + Goodwill amortization + Interest Component of Operating Lease (1/3 of Rent) + Interest Income – Other expense) / Total revenues

Retained Cash Flow / Capex

(Cash Flow from Operations – Changes in Working Capital – Common and Preferred Dividends) / (Capex + Acquisitions – Divestitures)

Appendix 3 – Description of Utilities Bond Default History

Electric utilities have historically enjoyed a relatively strong credit quality thanks to their stable and predictable cash flows and the tendency of regulators to be supportive when a utility experiences financial stress. Over the past 70 years (since the Great Depression), only five rated investor-owned utilities have experienced bond defaults in highly developed countries; these were all US-domiciled issuers:

1988 Public Service Company of New Hampshire (bankruptcy)

1992 El Paso Electric (bankruptcy)

2001 Pacific Gas & Electric Company (bankruptcy)

2001 Southern California Edison Company (payment default)

2003 Northwestern Corporation (bankruptcy)

Two principal factors contributed to these defaults. In four of the five defaults, a state regulatory commission failed to provide sufficient and timely rate relief for recovery of costs or capital investment in utility plant. This reflected regulatory commission concerns about the impact of large rate increases on customers, as well as debate about the appropriateness of the regulatory relief being sought by the utility. In two of these four cases, transition towards deregulation of the electricity market was a key contributing factor in that it exposed the utilities to dramatic increases in wholesale market prices for purchased power. These two California utilities also lacked long-term contracts such as PPAs, leaving them highly exposed to sharp spikes in market prices. In the remaining case, the default resulted from a failed diversification into unregulated businesses that were totally unrelated to the basic utility business.

These defaults resulted in an average recovery for bondholders that is well above the average for corporate bonds. Holders of secured debt recovered 100% of principal and interest in all five cases. In the case of Pacific Gas & Electric and Southern California Edison Company, 100% of all debt holder claims were ultimately paid.

Figure 9 below lists each of the five bond defaults within the sector and categorizes the reasons for the defaults as the "Principal Factor" or a "Contributing Factor".

Figure 9 – Bond Defaults of US Investor-Owned Utilities: Principal and Contributing Factors

Issuer	Regulators/ Legislators Failed to Respond on a Timely Basis	Transition from a Regulated Environment to a Unregulated Marketplace	Poor-Performing Unregulated Investments
Public Service Company of New Hampshire	Principal Factor		
El Paso Electric Company	Principal Factor		Contributing Factor
Pacific Gas and Electric Company	Principal Factor	Principal Factor	
Southern California Edison Company	Principal Factor	Principal Factor	
Northwestern Corporation			Principal Factor

LESSONS FROM THE ELECTRIC UTILITY INDUSTRY'S DEFAULT HISTORY

Among rated utilities in developed countries, only US utilities have experienced defaults in the last 70 years. In addition to the five US defaulting utilities, several US utilities have narrowly avoided default. In 2002, Allegheny Energy and Centerpoint Energy each experienced a serious liquidity crisis and only avoided defaulting on debt payments due to last-minute agreements with bank lenders that allowed all payments to be made on a timely basis. The greater historic tendency for US companies to default is consistent with Moody's view that regulatory risk is greater in the US than in a number of other highly developed countries.

Related Research

Rating Methodology:

The Analysis of Off-Balance Sheet Exposures – A Global Perspective, Rating Methodology, July 2004, #87408

Off-Balance Sheet Leases: Capitalization and Ratings Implications, October 1999, #48591

Industrial Company Rating Methodology, July 1998, #36188

Special Comment:

Moody's Liquidity Risk Assessments – Q&A, March 2002, #74571

Moody's Analysis of US Corporate Rating Triggers Heightens the Need for Increased Disclosure, July 2002, #75412

Rating Triggers in Europe: Limited Awareness but Widely Used Among Corporate Issuers, September 2002, #76199

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Report Number: 91730

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North American Regulated Gas Distribution Industry (Local Distribution Companies)

Summary

The purpose of this methodology is to provide investors and other interested parties with a clear understanding of how Moody's assigns ratings to issuers and their obligations in the North American local gas distribution (LDC) sector. Our goal is to help the market understand the factors we consider most important for this sector and how they map to specific rating outcomes. Readers should be able to use this report to gauge a company's ratings within two notches.

This rating methodology covers 30 gas utilities in North America (Canada and the United States) all of whom are regulated by their provincial, state or municipal utility commissions. These are relatively small companies that are limited to a particular franchise territory and which ordinarily would not carry investment grade ratings were they not protected through regulation and assured the certainty of a positive gross margin in exchange for the public expectation of a reliable and safe gas distribution service.

Overall, Moody's analysis of gas utility companies focuses on the following core rating factors:

1. Sustainable Profitability
2. Regulatory Support
3. Ring Fencing
4. Financial Strength and Flexibility

In addition Moody's analyzes factors that are common across all industries such as liquidity, corporate governance, event risk, and legal structure.

Moody's Investors Service
Global Credit Research

About the Rated Universe

The focus of this rating methodology is on the "pure" gas LDCs in North America. We note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas utilities owned by parent holding companies that have other non-regulated businesses.

It is anticipated that a separate rating methodology will be forthcoming that would govern the ratings of such "diversified" gas companies including those that may have expanded through non-utility subsidiaries into other non-LDC businesses such as sales of unregulated electric power and gas contracts (energy marketing), gas pipeline transmission and storage, gas gathering and processing, exploration and production, energy trading or businesses that are non-energy related activities (e.g. real estate development or underground construction services).

Additionally, a third rating methodology would also be forthcoming for the gas pipeline companies, completing the three sub-sectors that make up the largely regulated natural gas transmission and distribution industry in North America.

In all Moody's rates 30 companies in the pure gas LDC sector in North America with EBITDA ranging from US$ 32 million to US$ 681 million and total assets ranging from US$ 382 million to US$ 5,974 million. The rated universe stretches from the east coast to the west and ranges in complexity from utilities with jurisdiction in a single state to those with multiple state jurisdictions (such as Atmos Energy Corporation, which has utility operations in 12 states).

Industry Overview

The guiding principle behind gas LDCs is that they are regulated entities within their jurisdictions and are expected to conform to the regulatory framework established by their regulators. The regulatory framework may specify a pre-approved level of capitalization, return on equity, the pass-through of certain cost components and the recognition of a specified level of regulated assets within the base rates established for customers, and the setting of a depreciation schedule based on the average life of plant and equipment. In Canada, regulators may operate at the provincial level. In the United States they might operate at the state or municipal level. As these companies are regulated by local authorities, there are tremendous variances in regulatory frameworks, some more favorable to the utility companies than others.

Allowed rates of return on equity are generally modest (ranging from 9%-12% in most cases depending on cost of capital). This creates certain tradeoffs that are meant to ensure a safe and reliable public service in return for stable and predictable levels of income and cash flow.

HIGHLY SEASONAL DEMAND AND WORKING CAPITAL REQUIREMENTS

The gas distribution business in North America is generally highly seasonal and sensitive to weather variations from one year to another. The vast majority of earnings are derived during the winter heating season (typically, the five months from November through March). In the summer months LDCs usually break even or lose money.

In addition, LDCs are typically subject to vast swings in working capital requirements, with the build-up of natural gas inventory in underground storages occurring during late spring and early summer, reaching a peak in November/December and falling during the course of the winter as gas is consumed. Accounts receivables begin to build in November and generally peak in late December or January. The buildup of short-term debt to meet seasonal working capital needs follows the same winter inventory build-up and accounts receivables financing pattern, with many LDCs completely out of short-term debt by April/May.

In an attempt to standardize the measure of heating days in the year, the industry has adopted the use of "heating degree days," commonly defined as the extent to which the daily average temperature falls below 65 degrees Fahrenheit, (generally assumed to be the point at which individuals would typically heat their homes). The number of heating degree days in a given year are compared against a historical "norm" specified by a regulatory commission in a specific jurisdiction to establish the degree of normalcy within a time frame. This time frame can range anywhere from 10 to 30 years, depending on the formulation approved by the utility regulators.

In some jurisdictions, the earnings impact of weather variations is neutralized through the establishment of weather mitigants as part of fundamental rate design. In its rate applications to the local regulatory commission, the local utility would request protection from weather that is warmer than normal for itself and for its customers when weather is colder than normal. Specifically, weather is compared with current deviations from historical norms as measured in heating degree days. The term often associated with this formal mechanism to compensate a utility for warmer than normal weather (or to compensate a consumer for colder than normal weather) is commonly referred to as a "weather normalization clause" or "WNC."

In jurisdictions that leave LDCs to their own devices, LDCs can either go "naked," or they can purchase weather derivatives or weather insurance to mitigate the effects of margin variations caused by fluctuating weather conditions.

PASS-THROUGH OF NATURAL GAS PRICES

In addition to the fact that gas LDCs are subject to regulation by local authorities, they also operate under the premise that their fixed and variable operating costs are borne by their firm demand customers (usually residential and commercial) who use gas for space heating, cooking, or a combination of both. Under the terms of the LDC operating structure, the LDC is not expected to assume the commodity risk of gas, but is able to pass this cost through to customers in monthly bills. Depending on the gas prices at any given time, the commodity price component of a residential customer's monthly bill could be as high as 80%. The remaining 20% would be the LDC's charge for operating and investing in the infrastructure of its gas distribution system (which are, primarily, its fixed costs of operation).

With the advent of third-party gas commodity marketers, this commodity charge is often provided by gas suppliers to consumers utilizing the LDC's gas delivery network. Under this mechanism of "distribution only" charges, the LDC can sometimes use the gas marketer to bill for its 20% of distribution charges, thereby transferring bad debt and risk of non-collection to the gas marketer. More often however, the LDC bills customers for both the gas marketer's commodity supply charges as well as its own delivery charge, retaining bad debt on its own books.

In several jurisdictions, utility regulators have granted LDCs a "bad debt" tracker, which allows them to recover the costs of non-collection via their customers' rate bases or as part of the PGA (purchase gas adjustment clause). Some states such as Pennsylvania and Tennessee have increased the amount of real-time bad debt that could be passed-through to the customer and are also allowing delivery termination for non-paying or delinquent customers to protect the margins of the LDC.

STABLE AND PREDICTABLE EARNINGS AND CASH FLOW

If weather variations are largely mitigated, cost of gas is a pass-though commodity cost, and regulators permit the company to recover its cost of investment and other operating costs for maintaining the gas distribution system, the earnings of the LDC should, theoretically, be largely predictable and cash flows should be stable year after year.

In reality however, LDCs' earnings are not stable, as customers continually find ways to conserve on heating bills, to purchase more efficient appliances or to build better insulated homes. All of these measures result in gas "conservation" and diminishing earnings (again, revenues are largely dependent on the volume of gas consumed). In areas of high growth — i.e. where the customer base is increasing at rates in excess of 3% p.a. — there is also the added pressure of rising operating and maintenance expenditures as well as the need to catch up with lagging capital investment recoveries. These pressures, coupled with rising cost structures and a volatile energy environment oftentimes require an LDC to file more frequent rate cases requesting cost recoveries or changes in fundamental rate design to account for secular changes in consumer behavior patterns that affect the operating margins of the gas utility.

Key Ratings Issues Going Into the Next Decade

The key rating issues affecting the near and medium term fall into three general areas:

- Rising gas prices
- The push for conservation
- The rise of mergers and acquisitions

RISING GAS PRICES

Gas prices follow many of the pressures that bear on oil prices, but also demonstrate characteristics of their own. Historically, North America was an abundant producer of natural gas. What the US could not supply from its own gas fields could be obtained reliably from Canada. Over the years, Canada has been consuming more of its gas, both to supply its own citizens' needs and to recover heavy oil lodged in sand formations where gas is burned underground to facilitate the oil recovery mechanism.

Also affecting the industry is a change in the pattern of the summer lull in gas prices. This is attributable to the fact that the electric power industry has been building new generation plants fueled by gas, mainly because of gas' clean-combustion characteristics. The vast majority of new electric generating plants built in the past few years have been fired by gas and these power plants burn more summer gas to generate electricity to meet cooling demands. As a consequence, the traditional lull in summer gas prices has become less reliable with the increased volatility in gas commodity pricing.

Rising demand for natural gas has also diminished the supply cushion to the point that hurricane disruptions such as those in the gas producing areas of the Gulf of Mexico in 2005 created logistical delivery disruptions to certain LDCs in the southeastern portion of the US. This confluence of increased gas demand and supply constraints is likely to maintain upward price pressure on natural gas prices over the medium term.

High gas prices have the undesirable effect of causing a rise in bad debt expenses and uncollectible receivables for many gas utilities, creating yet more need for rate design improvements.

THE PUSH FOR CONSERVATION

Another consequence of high gas prices is consumer motivation to burn less gas when possible. We have observed an impetus to reduce consumption in response to rising prices over the past decade. In North America this trend is most noticeable within the most rapidly growing home building areas, where homes are being built with better insulation. Another impetus for conservation is rising gas prices and warmer weather, where it is relatively easy for homeowners to turn-down the thermostat for extended periods of time, reducing gas margins earned by LDCs that are dependent on volumetric gas consumption for cost recoveries.

Conservation is an important component in balancing the region's gas supply and demand equation, but under traditional regulatory frameworks in many jurisdictions, few gas utilities have the incentive to encourage gas conservation or promote education in gas usage efficiencies among their customers. With the likelihood that gas prices will remain high and volatile, conservation will likely become a more formidable influence on gas consumption in the residential and commercial customer segments going forward.

In the US, utility commissioners in various states differ in their approaches to allowing their gas utilities to recover lost margins attributable to conservation-driven variations in consumption. Commissions with more supportive regulatory frameworks tend to allow mechanisms for revenue recoveries and their utilities generally have stronger financial profiles.

As more LDCs become aware of the impact that conservation initiatives have on their customers' gas usage and their own profitability, more are considering applying for the appropriate rate design changes. To do this, however, they must first build understanding and support at the grassroots level. Overall, utility rate designs that compensate gas LDCs for conservation-based margin losses (as with variations due to weather), should help to stabilize utilities' credit metrics and credit ratings. Utilities with these ratemaking mechanisms also tend to carry higher credit ratings.

THE RISE OF MERGERS AND ACQUSITIONS

With the repeal of the Public Utility Holding Company Act (PUHCA) in the US (February 2006) companies are finding fewer obstacles to mergers across state lines. Companies seeking to expand their service territories are now finding it easier to bid for companies seeking an opportunity to cash out (as price multiples are currently attractive for sellers in this industry).

The pace of industry consolidation as well as the introduction of new players could accelerate beyond 2006. From a credit standpoint, however, we note that mergers and acquisitions usually entail taking on more debt, attempts to create new operating synergies, and the need to apply for further rate relief from regulators. Previous periods of heightened mergers and acquisition activity were typically associated with increased numbers of ratings downgrades, as LDC debt levels and operating costs rose and rate recoveries lagged. While it is still early to predict whether past performance will repeat itself in the current merger-driven environment, the denigration of credit metrics remains a possibility.

In This Methodology

To explain Moody's approach to rating gas utility companies, we take the reader through the following steps:

IDENTIFICATION OF KEY RATING FACTORS

To determine the rating of a gas utility company we focus on the following factors:

1. **Sustainable Profitability**
   - Return on Equity
   - EBIT to Customer Base
2. **Regulatory Support**
   - Regulatory Support and Relationship
3. **Ring Fencing**
   - Ring Fencing
4. **Financial Strength and Flexibility**
   - EBIT/Interest
   - Retained Cash Flow/Debt
   - Debt to Book Capitalization (excluding goodwill)
   - Free Cash Flow/Funds from Operations

MEASUREMENT OF THE KEY RATING FACTORS

For each of the core factors cited, we present a set of metrics or "sub-factors" that enable the reader to determine exactly how we measure this factor. Each of the core factors is comprised of between one and four sub-factors, each of which are mapped to a rating or score. For example, we consider four different financial metrics within the Financial Strength and Flexibility Factor.

In total this rating methodology incorporates eight sub-factors. Where possible, we provide quantitative metrics derived from a company's financial statements. For some factors, however, non-statistical observation is necessary to determine the appropriate results. For each of the eight metrics, we assign a weight based on relative importance.[1]

Moody's applies a total weighting of 20% for non-financial observations and 80% for financial. (However, we weigh some sub-factors more heavily than others, as some sub-factors such as the ROE (return on equity) and the ones for Financial Strength and Flexibility weigh more heavily in determining the relative risk of a particular LDC in comparison with its peers). This is because, while regulatory design and support may differ from jurisdiction to jurisdiction, the financial metrics do not. This renders them more easily comparable across political boundaries and more quantifiable. Financial observations also tend to be lagging indicators, as they come at the end of a fiscal reporting period and serve as the final scorecard for the issuer. The two non-financial sub-factors tend to be less definitive and are more subject to interpretation. Applying the sub-factor weightings and scoring the rating assignment for each sub-factor in this manner results in ratings that track our assigned ratings within one or two notches in 93% of the cases.

While Moody's outlooks are forward looking, the rating process does make extensive use of historic financial statements. Historic results help us understand the pattern of a company's results and how it compares to peers. They also provide perspective, helping to ensure that estimated future results are grounded in reality. This document makes use of historic data primarily. However, if an LDC is undergoing a rate case or fundamental business transformation — negating the usefulness of past performance as a guide to future credit standing — we use projected financial results instead.

Where historical financial results are used, metrics are based on an average of the most recent three years. The 2003 through 2005 periods provide a good cross-section of the peaks and troughs that characterize individual company performance over a normalized period.

Where projected financial results are used, metrics are based on an average of the 2006 through 2008 periods, or in some cases, 2007 through 2009, depending on the implementation dates of rate increases or realization of expected merger combinations.

All measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts including under-funded pension obligations, recurring operating leases, and off-balance sheet commitments and contingencies.[2] Moody's Credit Opinion key indicator ratios will also incorporate these standard adjustments.

MAPPING OUR METRICS TO RATING CATEGORIES

After identifying the measurements for each factor, the potential outcomes for each of the eight factors/sub-factors are mapped to a Moody's rating category (i.e. Aaa, Aa, A, Baa, Ba, B, Caa). For example, we specify what level of ROE is generally acceptable for an Aa credit versus an A credit. We provide a range or description for each of the measurement criteria.[3]

COMPANY MAPPING/OUTLIER DISCUSSION

We next assign a rating to each company in our rated universe for each factor. We also show how this rating compares to the company's actual assigned rating. The results of this mapping appear in a summary table located in Appendix B, as well as in the results section under each factor.

We recognize that any given company may perform higher or lower on a specific factor than its actual rating level. These companies are identified as "outliers" for that factor. A company whose performance on a specific factor is more than two rating notches higher than its actual rating is deemed a positive outlier for that factor. A company whose performance is more than two notches below is deemed a negative outlier. We highlight those companies whose factor mapping is more than two notches higher or lower than its rating and offer a discussion of the general reasons for outliers within a given factor.

1. *See Appendices A and B for a summary of sub-factors and weightings for each sub-factor.*
2. Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations — Part I *(US/Canadian GAAP, February, 2006).*
3. *See Appendix D for non-financial sub-factor definitions.*

DETERMINING THE FINAL RATING

To determine the overall rating, each of the eight assigned sub-factor ratings is converted into a numeric value based on the following scale.



Each sub-factor's numeric value is multiplied by an assigned weight (refer to the table below and/or Appendices A and B, for weights), and then summed. For information purposes, the table below also shows sub-totals and how much weight is given to each broad rating factor.

Factor	Sub-Factor	Weighting	Cumulative Weighting of the Relevant Sub-Factors
Sustainable Profitability	ROE	15%	20%
	EBIT/Customer Base	5%	
Regulatory Support	Regulatory Support	10%	10%
Ring Fencing	Ring-Fencing	10%	10%
Financial Strength and Flexibility	EBIT/Interest	15%	60%
	RCF/Debt	15%	
	Debt/Book Capitalization	15%	
	Free Cash Flow/FFO	15%	
Total Weighting		100%	

The total is then mapped to the table below, and an overall alpha-numeric rating is assigned based on where the score falls in the range. The outcome provides a good correlation, with indicated ratings falling at or two notches away from actual ratings.

Indicated Rating	Overall Score
Aaa	1
Aa	1.5
A	4.5 - 7.5
Baa	7.5 - 10.5
Ba	10.5 - 13.5
B	13.5 - 16.5
Caa	16.5

The entire array of scores and mappings for each of the LDC companies is shown in Appendix B.

Factor Discussions

FACTOR 1: SUSTAINABLE PROFITABILITY

Why It Matters

Two subfactors provide good indications of a firm's ability to remain profitable and efficient despite the inherent volatility associated with the sector:

- **Return on equity (ROE),** which is calculated for each year by taking a company's profitability in a given year and dividing it by an average equity of the current and previous year end. ROE serves as barometer of a company's general level of profitability — and when calculated over a period of years, serves as an indicator of its ability to sustain its profitability — and provides a good starting point for understanding the overall efficiency of the operations of the company.
- **Operating Income (EBIT)** relative to customer base provides another indicator of a gas utility's overall operating profitability relative to the number of customers being serviced. The higher this figure, the more each customer contributes to the company's "bottom-line." For purposes of this calculation, only firm demand customers of the residential and commercial categories are included, as industrial customers often have alternate

sources of fuel and are the first to be cut off by a utility in the event of gas pro-rationing (allocation as a percentage of available supply) or shortage.

The former calculates returns on a GAAP basis and the latter serves as a measure of overall operating efficiency. When an average of three years is used as the comparable period, these indicators reveal the company's relative profitability and ability to maintain this profitability and efficiency on a sustainable basis.

LDCs may differ in their rate design, the effectiveness, and the timeliness of rate design, but they ultimately culminate in an ROE scorecard that is an irrefutable indicator of the profitability that the firm has achieved (or in the case of projected figures resulting from a rate case filing or decision, projected profitability) given the business environment in which it operates. Similarly, the EBIT/customer base measures the relative operating efficiency of the company in achieving these operating results.

Among the risk factors reflected in ROE are the presence and effectiveness of the LDC's weather normalization clause (WNC), its ability to increase earnings despite customer gas conservation, the ability of the firm to pass through bad debt expenses, to true-up for underfunded pension liabilities, the frequency and degree of price adjustments for gas cost purchase adjustments, the ability to pass along financial and derivative hedging costs to consumers, to reimburse itself for environmental remediation expenditures, to use forward year test data in factoring in capital expenditure cost recoveries, and its ability to cover rising O&M (operating and maintenance) expenditures. The firm's effectiveness in dealing with these risks is distilled into an ROE calculation. Over time, this calculation provides a profile of the company's ability to generate consistent earnings that are capable of covering the cost of doing business and capable of doing so over an extended period of time. It also provides a benchmark measure of efficiency relative to other LDCs with similar business profiles.

It should be noted that in the use of ROE, the measure of profitability is indifferent as to whether an LDC employs multiple approaches to shielding itself from gas commodity price volatility (such as through use of various forms of financial derivatives) or if it relies primarily on underground gas inventory storage or long-term pipeline deliveries at fixed costs. Similarly, it does not impose a requirement that the LDC have a WNC in place to protect its gas margins against warmer than normal winters, as the company could achieve similar results by employing its own form of weather mitigants through the purchase of weather insurance or derivatives. The importance of achieving a desired target ROE is the fact that it signals management's effectiveness in employing all possible measures to achieve its business goals.

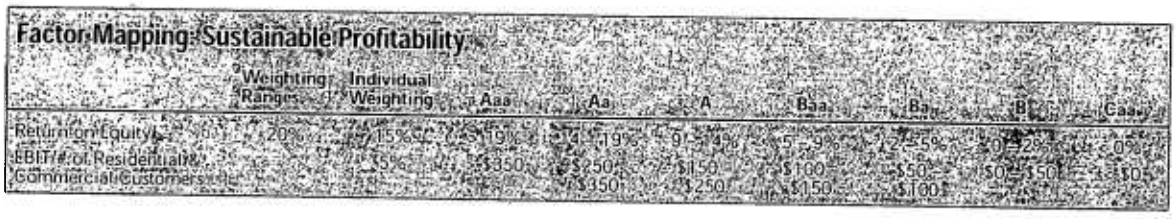
That said, the better the quality of an LDC's rate design or effectiveness in generating operating profits, the greater and more consistent its ROE. Very few businesses are assured a stable and consistent return on their capital by a regulatory body, but LDCs are (in theory, at least). To the extent they employ highly effective rate designs and business solutions in mitigating the known risk factors in the business, the better the ROE and efficiency of its operations.

Despite wide variations in individual utility rate designs therefore, ROE and EBIT/Customer Base appear to capture the level of profitability and efficiency in an LDC's operations and reflect its ability to generate profits over a sustainable period of time.

We note that profitability (ROE), operating income to customer base (EBIT/residential+commercial customers), interest coverage, retained cash flow to debt, debt to capital and free cash flow to funds from operation are the credit metrics that contribute the most to differentiating the stronger LDCs from the weaker ones. These also tend to be the "lagging" indicators as financial results are only available after the close of a fiscal quarter. Thus, they serve as a report card for the close of a given financial period, after all the events of the period have already transpired and all the initiatives of management are either completed or left undone.

Measurement metrics for this factor are as follows:

- **ROE** — profitability in a given year / average equity of the current and previous year.
  Weighting: 15%
- **(EBIT) to Customer Base:** For purposes of this calculation, only firm demand customers of the residential and commercial categories are included, as industrial customers often have alternate sources of fuel and are the first to be cut off by a utility in the event of gas pro-rationing (allocation as a percentage of available supply) or shortage.
  Weighting: 5%



Company Mapping Results: Sustainable Profitability

Issuer Name	Current Senior Unsecured Rating	ROE	Indicated Rating: ROE	EBIT/# of Residential & Commercial Customers	Indicated Rating: Operating Ratio
Alabama Gas Corporation	A1	14 – 19%	Aa	$150 – $250	A
New Jersey Natural Gas Company (Sec Aa3)	A1	9 – 14%	A	$150 – $250	A
Wisconsin Gas	A1	5 – 9%	Baa	$100 – $150	Baa
Boston Gas Company	A2	2 – 5 %	Ba	$150 – $250	A
Brooklyn Union Gas	A2	9 – 14%	A	$150 – $250	A
KeySpan Gas East Corporation	A2	9 – 14%	A	$250 – $350	Aa
Northern Illinois Gas	A2	5 – 9%	Baa	$50 – $100	Ba
North Shore Gas Company (Sec A1)	A2	5 – 9%	Baa	$50 – $100	Ba
Peoples Gas Light and Coke Compa (Sec A1)	A2	5 – 9%	Baa	$100 – $150	Baa
Public Service Co. of North Caro	A2	5 – 9%	Baa	$150 – $250	A
Questar Gas Company	A2	9 – 14%	A	$50 – $100	Ba
Southern California Gas Company	A2	14 – 19%	Aa	$50 – $100	Ba
Washington Gas Light Company	A2	9 – 14%	A	$150 – $250	A
Terasen Gas Inc.	A3	9 – 14%	A	>$350	Aaa
Colonial Gas Company (Sec A2)	A3	2 – 5 %	Ba	$250 – $350	Aa
Northwest Natural Gas Company	A3	9 – 14%	A	$150 – $250	A
Piedmont Natural Gas Company, In	A3	9 – 14%	A	$150 – $250	A
Connecticut Natural Gas	A3	2 – 5 %	Ba	$250 – $350	Aa
UGI Utilities, Inc.	A3	14 – 19%	Aa	$250 – $350	Aa
AGL Resources Inc.	Baa1	14 – 19%	Aa	$150 – $250	A
Cascade Natural Gas Corp.	Baa1	9 – 14%	A	$100 – $150	Baa
Indiana Gas Company, Inc.	Baa1	5 – 9%	Baa	$100 – $150	Baa
Laclede Gas Company	Baa1	9 – 14%	A	$100 – $150	Baa
Southern Connecticut Gas (Sec A3))	Baa1	2 – 5 %	Ba	$150 – $250	A
Laclede Group, Inc. (The)	Baa2	9 – 14%	A	$100 – $150	Baa
South Jersey Gas Company	Baa2	9 – 14%	A	$150 – $250	A
Yankee Gas	Baa2	2 – 5 %	Ba	$150 – $250	A
Atmos Energy Corporation	Baa3	9 – 14%	A	$50 – $100	Ba
Southwest Gas Corporation	Baa3	5 – 9%	Baa	$50 – $100	Ba
SEMCO Energy, Inc.	Ba2	<0%	Caa	$100 – $150	Baa

Positive Outlier
Negative Outlier

Observations and Outliers

ROE

Among the negative outliers are Boston Gas and Colonial Gas, two of six natural gas distribution companies owned by KeySpan Corp. Their low ROE reflects push down accounting relating to KeySpan's acquisition of Eastern Enterprises, whereby a portion of the acquisition debt and goodwill issued by the parent have been allocated to Boston Gas and Colonial Gas. The debt and parent financing of working capital and gas inventory through the utility money pool has resulted in noticeably increased debt and interest expense levels. Additionally, National Grid's recently announced plan to acquire Keyspan raises the possibility of an additional debt servicing burden being "pushed down" to these subsidiaries. The low ROE also reflects the lower efficiency of the rate design in these KeySpan subsidiaries. The lack of

weather mitigation and conservation in the company's rate design leaves it vulnerable to weather and conservation exposure, which are being mitigated in part through the purchase of weather derivatives.

The Connecticut LDCs of Connecticut Natural Gas, Southern Connecticut Gas and Yankee Gas also have low ROEs relative to their assigned ratings, reflecting relatively poor regulatory support from the state commission on weather and conservation protections, and the ability to pass financial hedging costs to rate-payers as a means to mitigate gas price volatility. These LDCs are also smaller subsidiaries within larger electric power utility operations that may require additional forms of parental support for the LDCs.

In the case of Wisconsin Gas the company was approved for a rate base increase, effective January 2006, for an approved ROE of 11.2%, but historical returns had eroded because of a five-year rate freeze.

Among the positive outliers are UGI Utilities, AGL Resources and Atmos. Although UGI has a high ROE relative to its peer group, the overall rating is suppressed because of its affiliation with non-investment grade subsidiaries of the parent.

In the case of AGL and Atmos, the diversified earnings of the group include income from operations such as energy services. These tend to boost the group's returns even though the combined risk may indicate a less stable and predictable earnings stream.

EBIT to Customer Base

Northern Illinois Gas and North Shore Gas Company are negative outliers in this operating efficiency ratio, as they have been suffering from regulatory lag. However, the recent rate increase in the case of Northern Illinois Gas could help narrow the gap in its performance going forward.

On the other extreme, UGI appears to be a very efficient operator and is a positive outlier from a customer base standpoint. Although UGI has strong operating income (being supported by a higher than average customer growth rate — mostly attributable to organic growth), the overall rating is suppressed because of its affiliation with non-investment grade subsidiaries of the parent.

FACTOR 2: REGULATORY SUPPORT

Why It Matters

The fact that LDCs are subject to regulation by local authorities has a direct bearing on the success of their business operations. It is difficult for utilities to function without good community relations, as they depend on their local regulators and on the public's understanding to obtain the rate relief and cost recovery necessary for a gas distribution system's investments.

Of particular importance, regulatory requirements are often delineated not by law or by prescribed statutory requirement or ruling but rather by the expectation that traditional practices will continue and that LDCs — particularly the older and more established ones — will continue to act within established boundaries and in accordance with past practice. This necessitates a strong relationship with regulators who are, ideally, supportive.

Thus, when the regulatory relationship is strong and cooperative, utilities are able to engage in active dialogue with regulatory commissioners and staff to find mutually acceptable solutions to utility problems (such as rising account delinquencies in periods of gas shortages and price increases) or to educate customers about key initiatives such as gas conservation. In a strong relationship, the commission staff might also serve as a technical advisor to the utility commission in facilitating constructive discussions with the company — as opposed to playing the role of "consumer advocate" and countering LDC initiatives.

One very important component of the utility/regulator relationship is the ability of the utility to recoup allowed expenses in a timely manner and its ability to earn its fully-allowed rate of return (without having to file continuously for new rate cases).

Within this metric we also include the utility's relationship — both perceived and actual with the public and its approach to issues of safety, reliability and integrity.

This metric thus helps to define credit impact of the established operational "norms" and the operating framework. It is conceivable for a utility to maintain an investment grade rating with only limited support from its regulators if it has capable management that is able to find alternatives and solutions for its business needs, but the support of regulators on most matters of economic importance enable a company to operate with far more effectiveness. We note that, included in the definition of "regulatory environment" are regulatory staff, commission, interveners, consumer advocates and the public at large.

Measurement metrics for this factor are as follows:

- **Quality of Regulatory Support**: The regulatory relationship is measured on a scale from "Exceptional/ Proactive" to "Inadequate/Weak." To assess the quality of the regulatory support we examine the strength of the regulatory relationship. This will include the speed and degree of willingness with which the regulatory commission approves requests for rate increases, approves and encourages rate design modifications that serve to help a utility recoup its operating and capital investment costs and whether regulators enable utilities to recoup such costs in a timely manner.
  Weighting: 10%

Notes on Measurement Criteria

This sub-factor is important and will have a direct bearing on the ultimate credit rating of the LDC, although it lacks the finality of the more formulaic financial sub-factors (regulatory decisions may be modified or reversed by future regulators or a court action, whereas ROE results, for example, cannot). Because regulatory support is often subject to interpretation and change over time as the actions and views of participants change, it is weighed less heavily than are financial metrics.

Factor Mapping: Regulatory Support

Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
10%	10%	*Exceptional Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service. Utility commission always willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs shareholders and consumers alike. Utility Commission grants all rate designs features to allow LDC to recover costs on a complete and timely basis.	*Very Good Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service. Utility commission highly willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs shareholders and consumers alike. Rate design is near bulletproof. Covers for LDC risks. Requested rate increases tend to be approved in less than 9 months.	*Good Support* by Utility Commission to allow LDCs to amend rate designs. Company gets good support in proposing new solutions to deal with common utility problems such as conservation and weather variables. Differences between LDCs and utility commission are likely to be resolved. Rate filings tend to be approved under 12 months.	*Reasonable support* from Utility Commission to allow LDCs to recoup allowed expenses. Company gets some support in proposing new solutions to deal with common utility problems such as conservation and weather issues. Differences between LDCs and Utility Commission are reasonably resolved in a timely manner and rate cases tend to be approved in 12 – 15 months with at least 50% of LDC's target requests being granted.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses. Utility commissioner and/or staff tends to play the role of consumer advocate that often counters proposals or initiatives advanced by the LDC. Cases often take over 15 months to resolve or LDC is frozen out of rate filings for over 18 months.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses. Utility commissioner often plays the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC. Company is seldom involved with working on special task forces to deal with issues of rising accounts delinquencies or educating customers on conservation or warm weather issues. Utility suffers from increasing regulatory lag and lacks rate relief necessary to earn allowed ROE.	*Inadequate and weak support* from Utility Commission to allow LDCs to recoup allowed expenses. Utility commissioner always plays the role of consumer advocate that tends to counter proposals or initiatives advanced by the LDC. Company is hardly ever involved with working on special task forces to deal with issues relating to utility or customers. Unsupportive commission, state legislature or consumer base. Utility can't earn allowed ROE.

Company Mapping Results: Regulatory Support

Issuer Name	Current Senior Unsecured Rating	Indicated Rating: Regulatory Support
Alabama Gas Corporation	A1	Aaa
New Jersey Natural Gas Company (Sec Aa3)	A1	Aa
Wisconsin Gas	A1	Baa
Boston Gas Company	A2	Baa
Brooklyn Union Gas	A2	Baa
KeySpan Gas East Corporation	A2	Baa
Northern Illinois Gas	A2	Ba
North Shore Gas Company (Sec A1)	A2	Ba
Peoples Gas Light and Coke Compa (Sec A1)	A2	Ba
Public Service Co. of North Caro	A2	Aa
Questar Gas Company	A2	Ba
Southern California Gas Company	A2	A
Washington Gas Light Company	A2	Baa
Terasen Gas Inc.	A3	A
Colonial Gas Company (Sec A2)	A3	Baa
Northwest Natural Gas Company	A3	Aaa
Piedmont Natural Gas Company, In	A3	Aa
Connecticut Natural Gas	A3	Ba
UGI Utilities, Inc.	A3	Baa
AGL Resources Inc.	Baa1	Baa
Cascade Natural Gas Corp.	Baa1	Baa
Indiana Gas Company, Inc.	Baa1	A
Laclede Gas Company	Baa1	A
Southern Connecticut Gas (Sec A3))	Baa1	Baa
Laclede Group, Inc. (The)	Baa2	Aa
South Jersey Gas Company	Baa2	Aa
Yankee Gas	Baa2	Ba
Atmos Energy Corporation	Baa3	Baa
Southwest Gas Corporation	Baa3	Ba
SEMCO Energy, Inc.	Ba2	Ba

Positive Outlier
Negative Outlier

FACTOR 3: RING FENCING

Why it Matters

- **Ring Fencing:** Many LDCs are owned by diversified energy companies engaged in non-regulated activities. For this reason, the degree to which an LDC is "ring-fenced" will have an impact on the quality and degree of protection afforded to the utility's assets and operating cash flows. Whether imposed by regulators, lenders, or by the parent company (self imposed) the ring-fencing must assure that the utility is self-standing and protected from non-regulatory businesses of the diversified parent group[4]. This is a common objective among regulators, lenders and consumers alike. Also, as in the case with weather mitigants, Moody's does not insist that there be explicit written statutes requiring the gas utility to be properly ring-fenced for the utility to be highly rated, as long as this is accomplished in an effective manner through other means.

  Among the contributors to a well ring-fenced utility are limitations on inter-company loans and advances to non-regulated affiliates or prohibitions on the commingling of funds through participation in diversified corporate money pools. These are important in ascertaining that the utility's operating assets and capital expenditures are justifiable to utility ratepayers.

  Other contributors to strong ring fencing are legal or regulatory requirements stipulating maximum leverage ratios for the LDC and requirements that an LDC remain investment-grade to preserve its service

4. *The expectation that non-regulated expenses incurred by affiliates engaged in other businesses will not be passed onto the utility (which would then attempt to seek recovery from its consumers) is intrinsic to the concept of ring fencing. For example, a diversified gas company with a gas trading operation is expected to deal with its regulated utility at arm's length. It is not expected that the company will allow the trading company to determine which entity should receive the best price quotes for gas purchase transactions or which should be chosen to book trading losses.*

franchise. By placing a limitation on leverage, regulators or lenders are implicitly limiting the level of dividends that a diversified parent company might extract from its utility, and discouraging the utility from using its balance sheet to raise debt for the benefit of non-utility affiliates or its diversified parent.

The utility's payment of dividends in excess of what the parent company may require for its public shareholders could also serve as an indication of poor ring fencing, as the surplus funds being paid as dividends by the utility could be viewed as a form of cash support for the parent company's non-utility affiliates. Well ring-fenced utilities typically raise their own funds and handle their own bank accounts, with non-utility affiliates establishing their own credit facilities and funding requirements separate and independent from the utility.

Weighting: 10%

- Less obvious, but also important are the proven resolve of management or a utility's board in erecting operating barriers that isolate the utility from its non-regulated affiliates. This might include, for example, dedicating separate utility gas purchasing agents from the group's energy trading arm or locating utility personnel at separate premises from those of the non-utility affiliates. These good corporate governance attributes are implied in having good ring-fencing measures.

  Utilities sometimes establish their own boards of directors, especially within a larger and more diversified company to ensure that their assets, cash flows and operating funds are properly separated and that attempts by the parent to distribute dividends to the holding company are fair and justified. Any weak corporate governance would typically become evident in reviewing a utility's ring fencing quality and manifest itself through lax policies and procedures in operations as well as in financial dealings, record-keeping and internal controls. Corporate governance therefore, is a related indicator for ring fencing quality.

  While such efforts as creating a permanent body to ensure the operating integrity of the utility could add to the strength of the ring fencing provisions, it is a further indicator that the utility stands on its own and is governed by a board that looks after its interest first rather than using the utility to advance the goals of the parent's diversified group. Ultimately, such efforts can enhance the utility's independent operating performance and credit rating.

  The utility's board may also require that it obtain its own credit facilities, issue its own bonds and only guaranty activities directly related to providing core utility services. Under this framework, the utility serves as its own profit center and allocates any expenses incurred on behalf of non-utility sister companies back to those affiliates for recovery, rather than burdening its own operating staff and the utility ratepayers.

Measurement metrics for this factor are as follows:

- **Ring Fencing**: This metric is assessed on a scale of "excellent ring fencing isolating utility from non-utility" to "inadequate and weak ring fencing: funds always commingled." In determining the degree of commingling of funds, LDCs range from having their own bank accounts and issuing their own debt and commercial paper to participating in combined cash money pools or engaging in making intercompany loans to non-utility affiliates on a frequent basis). Other indicators that we review for quality of ring fencing include: the level of dividends that are upstreamed by the utility to the parent vs. the parent to the public shareholders, the level of intercompany transactions, the ability of various operating entities to raise their own bank and public financing, the extent of any cross-default provisions or cross-guarantees, the presence of utility financial covenants that would enhance their ring fencing and signs of weak corporate governance.
  Weighting: 10%

Factor Mapping: Ring Fencing

Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
10%	10%	*Excellent* ring fencing provisions isolating Utility from Non-Utility. No commingling of funds. Utility cash accounts are separated from rest of company. Inter company loans never permitted between utility and non-utility. No portion of Utility dividend payment to parent ever ends up being allocated to non-utility. Strong Corporate Governance protecting utility interests which are treated as core	*Very Good* ring fencing provisions. Utility and Non-Utility highly unlikely to commingle funds. Separate cash program or own utility money pool. Inter company loans not permitted between utility and non-utility. Utility dividend payment to parent never end up being allocated to non-utility. Very Good Corporate Governance. May lack formal regulatory or creditor leverage which IG requirement for utility, but co an has strong policy of ring fencing utility	*Good* ring fencing provisions. Utility and Non-Utility are unlikely to commingle funds. Separate utility money pool or utility accounts. Inter company loans not permitted between utility and non-utility. Utility dividend payment to parent unlikely to be allocated to non-utility. Good Corporate Governance of utility	*Reasonable* ring fencing provisions. Utility and Non-Utility may need to commingle funds via consolidated corporate money pool. Bond indentures or bank credit agreements may reasonably restrict the utility from financial dealings with non-utility. Inter Company loans between utility and non-utility rare. Satisfactory Corporate Governance. Gas utility contributes less than 50% of consolidated and may not be pri ary gro en ine	*Inadequate* ring fencing provisions. Utility often participates in corporate cash money pool that includes non-utility and funds are often commingled. Regulators usually do not have a requirement that LDCs remain investment grade. Bond indentures or bank credit agreements may not restrict the utility financial dealings with non- utility. Inadequate Corporate Governance p otection for ilit as stand-alone ntity	*Inadequate* ring fencing provisions. Utility often participates in corporate cash money pool that includes non-utility and funds are generally commingled. No requirement for LDCs to remain investment grade. Bond indentures or bank credit agreements usually do not restrict the utility financial dealings with non- utility. Inter company loans between utility and n n-utility common pla e. Inadequate Corporate Governance for utility as a stand alon entity	*Inadequate and weak* ring fencing provisions. Utility and Non-Utility generally always commingle funds. No requirement for LDCs to remain investment grade. Bonds indentures, bank agreements never restrict utility financial dealing with non-utility. Inter company loans between utility and non-utility are common place. Utility dividends to parent may fund non-utility needs. Inadequate and weak Corporate Governance of utility interests

Company Mapping Results: Ring Fencing

Issuer Name	Current Senior Unsecured Rating	Indicated Rating: Ring Fencing
Alabama Gas Corporation	A1	Baa
New Jersey Natural Gas Company (Sec Aa3)	A1	Aaa
Wisconsin Gas	A1	Baa
Boston Gas Company	A2	Baa
Brooklyn Union Gas	A2	Aaa
KeySpan Gas East Corporation	A2	Aaa
Northern Illinois Gas	A2	Baa
North Shore Gas Company (Sec A1)	A2	Baa
Peoples Gas Light and Coke Compa (Sec A1)	A2	Baa
Public Service Co. of North Caro	A2	Aaa
Questar Gas Company	A2	A
Southern California Gas Company	A2	Aaa
Washington Gas Light Company	A2	Aaa
Terasen Gas Inc.	A3	Aa
Colonial Gas Company (Sec A2)	A3	Baa
Northwest Natural Gas Company	A3	Baa
Piedmont Natural Gas Company, In	A3	Aaa
Connecticut Natural Gas	A3	Baa
UGI Utilities, Inc.	A3	A
AGL Resources Inc.	Baa1	Baa
Cascade Natural Gas Corp.	Baa1	Aaa
Indiana Gas Company, Inc.	Baa1	Baa
Laclede Gas Company	Baa1	A
Southern Connecticut Gas (Sec A3))	Baa1	Baa
Laclede Group, Inc. (The)	Baa2	Baa
South Jersey Gas Company	Baa2	Aaa
Yankee Gas	Baa2	Baa
Atmos Energy Corporation	Baa3	Baa
Southwest Gas Corporation	Baa3	Aaa
SEMCO Energy, Inc.	Ba2	Baa

Positive Outlier
Negative Outlier

Observations and Outliers

Ring Fencing

Most of the indicated ring-fencing ratings are compatible with issuer assigned credit ratings. The "Aaa" ring-fencing indicators are typically reserved for those companies whose jurisdictions have established explicit requirements for separation of utility and non-utility businesses, maximum leverage, specific requirements that the LDC remain investment-grade or have placed limitations on dividends to their parent failing certain capitalization requirements. Exceptions might include Washington Gas Light Company, where despite the absence of specific regulatory requirements, the company has a strict policy of not commingling the gas utility funds with those of the non-regulated operations of the parent and the LDC only remits dividends to the parent that are required for distribution to public shareholders, prohibiting its LDC from assisting or supporting the business needs of its non-regulated affiliates.

In the case of Piedmont Natural Gas, Cascade Natural Gas and Southwest Gas Corporation, the utility is the parent company and there is no need for ring-fencing against a diversified non-regulated affiliate.

Negative outlier Alabama Gas results from the LDC having no explicit ring-fencing provisions from regulatory or financing agreements other than broad restrictions under an Alabama state statute.

Regulatory Support

Several "A" rated companies have outstanding regulatory relations and support "Aaa." Some examples include New Jersey Natural Gas Company, Northwest Natural Gas Company and Piedmont Natural Gas Company, where each one of these names have pioneered in the introduction of innovative service concepts and novel rate design concepts such as those for "conservation decoupling" in their respective jurisdictions and all have previously obtained WNC from their

regulators. The regulatory relationship for some of the "Baa" names have also improved to the point where they also scored high in this factor ("Aa"), such as Indiana Gas Company and Laclede Gas Company in Missouri, where these LDCs were the first companies to obtain weather protection mechanisms from their public utility commissions either in the form of formal WNC or through fixed demand charge rate design. Utilities that score high in this factor also tend to be leaders in scoring high on customer satisfaction responses to independent surveys, helping their utility commissioners forge solutions to common utility problems such as dealing with the cost of high gas prices, or providing safety and systems integrity solutions before major problems arise, while maintaining strong community relations.

FACTOR 4: FINANCIAL STRENGTH AND FLEXIBILITY

Why It Matters

Financial strength is an important indicator of an LDC's ability to meet its financial obligations, particularly in light of the volatile nature of the industry's performance[5]. The metrics we use to define this factor include the following:

- **Interest coverage** (EBIT/Interest) is a measure of financial flexibility in an LDC's credit agreement as some lenders require minimum coverage to maintain their credit lines (the concept being that a stable utility should, at a minimum, be able to pay its interest expenses if not amortize its debt over a reasonable time period).

  Interest coverage serves as an indicator of fixed charge coverage. We chose this coverage ratio as it is used in the financial covenants of many LDC bank credit agreements and bond indentures, and is, by extension, both conventional and accessible for comparative purposes. Naturally, the higher this fixed charge coverage, the greater the financial flexibility of the utility.

- **Retained Cash Flow to Debt** (RCF/Debt) is a measure of financial leverage as well as an indicator of the strength of a utility's funds from operations after dividend payments are made to service the debt. It serves as a measure of financial health as well as liquidity to cover debt obligations while also providing a measure of cash available for capital expenditures and to cover working capital needs. RCF/Debt also serves as a measure of leverage relative to operating cash available for debt service.

  The higher the level of retained cash flow relative to debt, the more cash the LDC has after paying dividends to support its capital expenditure programs. The stronger LDCs tend to have sufficient retained cash flow to cover capital expenditure needs, while the weaker ones tend to run cash "deficits" that must be covered through increased equity issuance or debt, or a combination of both. Usually, debt is issued first, followed by occasional equity issuance to meet specific project needs or to strengthen the balance sheet.

- **Debt to Book Capitalization (Excluding Goodwill)** is a more generic measure of financial leverage and has, in the past, been a good barometer with which to gauge the financial flexibility available for a utility to expand and grow in its operations when it has a debt load to service. This measure subtracts goodwill from capitalization because regulators typically do not give credit for premium paid on acquired assets.

  High leverage reduces a firm's operating flexibility not only because it raises interest expense but also because it limits the company's ability to raise additional capital to cushion the impact of poor business conditions. High leverage may also portend the approach of maximum allowed debt capacity under most bank credit agreements, which often set a 65% debt/capitalization borrowing limit for investment grade LDCs.

- **Free Cash Flow as a portion of Funds from Operations** (FCF/FFO) measures the amount of free cash flow as a percentage of funds from operations after dividends are paid, working capital changes are taken into account and capital expenditures are made. While this is a stringent indicator of a utility's cash flexibility, it is a good indicator of cash generating capability and flexibility to deal with unforeseen circumstances or emergencies (gas supply disruptions, production shortages, etc.) — and the accompanying side effect of rapidly rising gas commodity prices — while managing long-term dividend payouts, capital expenditure undertakings and possible upswings in working capital requirements.

  This ratio is generally negative for most LDCs, but it is nonetheless a measure of free cash generated from operating funds (net income + depreciation + deferred taxes +/- other non-cash charges). A ratio that is consistently positive would suggest that the LDC generates surplus cash from its operations. This is rare for LDCs to accomplish on a consistent basis (which is why there are few companies rated Aa or Aaa).

5. *To assess financial strength and flexibility Moody's "smoothes" credit metrics by averaging them over a three-year time horizon whenever possible. The three years chosen are usually in the past, unless the projected years incorporate highly probable events driven by rate changes.*

Measurement metrics for this factor are as follows:

- Interest Coverage: EBIT/interest
  Weighting: 15%
- Retained Cash Flow to Debt
  Weighting: 15%
- Debt to Capitalization (Excluding Goodwill)
  Weighting: 15%
- Free Cash Flow to Funds from Operations
  Weighting: 15%

Factor Mapping: Financial Strength and Flexibility

	Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
EBIT/Interest	15%		> 7x	5 – 7x	3 – 5x	2 – 3x	1 – 2x	0 – 1x	< 0x
RCF/Debt	15%		> 26%	21 – 26%	15 – 21%	10 – 15%	5 – 10%	0 – 5%	< 0%
Debt/Book Capitalization (Excluding Goodwill)	10% – 60%	15%	< 30%	30 – 40%	40 – 50%	50 – 65%	65 – 85%	85 – 90%	> 90%
FCF/FFO	15%		> 10%	10% – (15%)	(15) – (30%)	(30%) – (45%)	(45%) – (60%)	(60%) – (75%)	< (75%)

Company Mapping Results: Financial Strength and Flexibility

Issuer Name	Current Senior Unsecured Rating	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/ Book Capitalization (Excluding Goodwill)	FCF/FFO	Indicated Rating: FCF/FFO
Alabama Gas Corporation	A1	3 – 5x	A	> 26%	Aaa	40 – 50%	A	(15%) – (30%)	A
New Jersey Natural Gas Company (Sec Aa3)	A1	> 7x	Aaa	10 – 15%	Baa	40 – 50%	A	> 10%	Aaa
Wisconsin Gas	A1	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	10% – (15)%	Aa
Boston Gas Company	A2	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(15%) – (30%)	A
Brooklyn Union Gas	A2	5 – 7x	Aa	10 – 15%	Baa	40 – 50%	A	(45%) – (60%)	Ba
KeySpan Gas East Corporation	A2	2 – 3x	Baa	21 – 26%	Aa	40 – 50%	A	10% – (15)%	Aa
Northern Illinois Gas	A2	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
North Shore Gas Company (Sec A1)	A2	3 – 5x	A	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Peoples Gas Light and Coke Compa (Sec A1)	A2	2 – 3x	Baa	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Public Service Co. of North Caro	A2	2 – 3x	Baa	15 – 21%	A	30 – 40%	Aa	(15%) – (30%)	A
Questar Gas Company	A2	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A
Southern California Gas Company	A2	5 – 7x	Aa	21 – 26%	Aa	50 – 65%	Baa	(15%) – (30%)	A
Washington Gas Light Company	A2	5 – 7x	Aa	15 – 21%	A	30 – 40%	Aa	10% – (15)%	Aa
Terasen Gas Inc.	A3	1 – 2x	Ba	5 – 10%	Ba	65 – 85%	Ba	(15%) – (30%)	A
Colonial Gas Company (Sec A2)	A3	3 – 5x	A	15 – 21%	A	50 – 65%	Baa	10% – (15)%	Aa
Northwest Natural Gas Company	A3	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
Piedmont Natural Gas Company, In	A3	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Connecticut Natural Gas	A3	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A

Company Mapping Results: Financial Strength and Flexibility

Issuer Name	Current Senior Unsecured Rating	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/ Book Capitalization (Excluding Goodwill)	FCF/FFO	Indicated Rating: FCF/FFO
UGI Utilities, Inc.	A3	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	Aa
AGL Resources Inc.	Baa1	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	(30%) – (45%)	Baa
Cascade Natural Gas Corp.	Baa1	2 – 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Indiana Gas Company, Inc.	Baa1	2 – 3x	Baa	5 – 10%	Ba	40 – 50%	A	(30%) – (45%)	Baa
Laclede Gas Company	Baa1	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
Southern Connecticut Gas (Sec A3))	Baa1	2 – 3x	Baa	15 – 21%	A	50 – 65%	Baa	(15%) – (30%)	A
Laclede Group, Inc. (The)	Baa2	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
South Jersey Gas Company	Baa2	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	Aa
Yankee Gas	Baa2	1 – 2x	Ba	10 – 15%	Baa	50 – 65%	Baa	< (75%)	Caa
Atmos Energy Corporation	Baa3	2 – 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Southwest Gas Corporation	Baa3	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(45%) – (60%)	Ba
SEMCO Energy, Inc.	Ba2	1 – 2x	Ba	5 – 10%	Ba	> 90%	Caa	(45%) – (60%)	Ba

Positive Outlier
Negative Outlier

Observations and Outliers

Interest Coverage

This ratio is generally compatible with LDCs' assigned credit ratings. Among the positive outliers in the "A" rated names is New Jersey Natural Gas, whose credit measures have proven much stronger than those for most of its peers. During the past few years earnings and cash flow improvements have resulted in higher interest charge coverage and lower leverage for the company. On the other end of the spectrum, Boston Gas Company shows higher interest expense to service relative to other similarly-rated high names.

In the "Baa" rated category we find that South Jersey Gas Company is rated lower than its interest coverage might suggest. This reflects the transitional nature of the company as it contemplates the issuance of additional debt in the future to help fund its capital expenditure requirements.

RCF/Debt

A positive outlier in the "A" rated category is Boston Gas, which has been able to produce strong cash flow under a performance-based rate (PBR) formula approved by regulators in Massachusetts. Negative outliers in the "Baa" category include Laclede Gas Company, where retained cash flow has been negatively affected by a policy of increasing dividend payouts.

Debt to Book Capitalization (Excluding Goodwill)

Low leverage generally correlates with high credit ratings, but there are a few exceptions. The "Ba" leverage factor score for Boston Gas Company and Colonial Gas Company, both subsidiaries of KeySpan, could be explained by the parent's use of push-down accounting. Under this approach, the LDCs were assigned a proportionate share of the cost of their acquisition debt and goodwill when KeySpan purchased them in 2000. The effect of pushing down a portion of the parent company's acquisition debt and goodwill raised financial leverage for these LDCs. This occurred not only because of the added debt burden from the parent but also because the allocated portions of goodwill resulted in a lower capital base (Moody's practice is to subtract the goodwill from equity for the regulated gas sector).

FCF/FFO

The scores for the free cash flow ratio are generally compatible with those of the assigned company ratings. A notable outlier in the "A" category includes Brooklyn Union Gas, which scored a "Ba" in this factor. During the past three years this company has had its cash flows stressed by a combination of high capital expenditures, high working capital uses and high dividend remittances to its parent. Outliers in the "Baa" rated names include South Jersey Gas, which is in transition, and Yankee Gas, which is in need of further rate relief and rate design improvements despite its recent rate filings, especially as it makes capital outlays in advance of rate recovery as in its current capital expenditures for construction of an LNG facility.

Final Considerations

To determine the overall rating, each of the eight assigned sub-factor ratings is converted into a numeric value based on the following scale:

1	3	6	9	12	15	18
Aaa	Aa	A	Baa	Ba	B	Caa

Each sub-factor's numeric point value is then multiplied by an assigned weight (as shown in Appendix A), summed.

Factor	Sub-Factor	Weighting
Sustainable Profitability	ROE	15%
	EBIT/Customer Base	5%
Regulatory Support	Regulatory Support & Relationship	10%
Ring Fencing	Ring-Fencing	10%
Financial Strength and Flexibility	EBIT/Interest	15%
	RCF/Debt	15%
	Debt/Capitalization (Ex. Goodwill)	15%
	FCF/FFO	15%
Total		100%

The total is then mapped to the table below, and an overall alpha-numeric rating is assigned based on where the score falls in the range.

Indicated Rating	Overall Score
Aaa	= 1
Aa	>1 < 4.5
A	3= 4.5 < 7.5
Baa	= 7.5 < 10.5
Ba	= 10.5 < 13.5
B	= 13.5 < 16.5
Caa	>= 16.5

Sample Calculation

	Rating	Rating Score	% of Total	Factor Score
Factor 1: Sustainable Profitability				
Sub-Factor 1	Aa	3	15%	0.5
Sub-Factor 2	Baa	9	5%	0.5
Factor 2: Regulatory Support				
Sub-Factor 3	Baa	9	10%	0.9
Factor 3: Ring Fencing				
Sub-Factor 4	Aaa	1	10%	0.1
Factor 4: Financial Strength and Flexibility				
Sub-Factor 5	A	6	15%	0.9
Sub-Factor 6	Aaa	1	15%	0.2
Sub-Factor 7	A	6	15%	0.9
Sub-Factor 8	A	6	15%	0.9
			100%	4.8
				= A1

If an LDC'S sub-factors sum to a score of 4.8, as shown above, an overall rating of A1 would be assigned. On this scale, a lower score indicates a stronger credit profile than a higher score. If the LDC's sub-factors sum to a total score of 9.0, an overall rating of Baa would be assigned. The LDC would be considered to have an average Baa2 rating profile because it falls in the middle of that category range.

In this methodology we cover 30 gas utility companies. After placing these companies through the rating factor grid,

- 7 companies (23%) map to their assigned ratings
- 14 companies (47%; 70% cumulatively) fall within one notch of their existing ratings.
- 7 companies (23%; 93% cumulatively) have indicated ratings that are within two notches higher or lower than actual ratings
- All but two companies have actual ratings that fall within two notches of their ratings on the grid, with two companies' ratings — those of South Jersey Gas and Boston Gas — falling within three and four notches, respectively, outside of their factor summaries.[6]

South Jersey Gas currently has an assigned rating of Baa2, although the Moody's methodology suggests an A2 rating (reflecting, primarily, that recent past performance may differ from future results). When one factors the company's recent rate case capitalization assumptions with the appropriate adjustments made by Moody's, leverage rises, retained cash flows decline (on account of higher dividend payouts) and coverage ratios are reduced. The company remains solidly in the investment grade category. However, the financial metrics for this company are currently in transition as implied by the methodology and the ratings based on recent historical data may not be applicable for the future.

Boston Gas is rated A2 senior unsecured compared to the model rating of Baa3. This reflects the results of push-down accounting relating to KeySpan's acquisition of Eastern Enterprises, whereby a portion of the acquisition debt and goodwill issued by the parent was allocated to Boston Gas. Additionally, as KeySpan is currently under review for possible downgrade, following the announcement that it is being acquired by National Grid Plc, a UK gas and electricity transmission business, in a transaction valued at $7.3 Billion (£4.2 Billion). The transaction may put pressure on the regulated subsidiary to support the additional debt.

While there may be outliers from time to time under the gas LDC rating methodology, the vast majority of the companies rated by Moody's do fall within the two rating notches targeted by this methodology, and their credit ratings could be explained by the relevant factors. At any given time, we could assume that one or more issuers are in a state of transition and may therefore find themselves positioned as outliers relative to their assigned ratings when compared against the ratings implied under the gas LDC methodology (i.e. the deviations are either higher or lower by more than the two desirable notches).

6. *See Appendix C for Summary Chart on Moody's Public Rating versus Indicated Model Rating.*

Related Research

Special Comments:

Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings, June 2006 (98022)

Update On The Gas Supply and Liquidity Needs of Gas LDCs Post Hurricane Katrina, September 2005 (94440)

Impact Of Conservation On Gas Margins And Financial Stability In The Gas LDC Sector, June 2005 (92787)

Comparative ROE Attributes of US Local Gas Distribution Companies, July 2004 (87301)

Gas Utility Cash Management Practices Reflect the Diversity of their Credit Ratings, October 2003 (79828)

Negative Rating Trend For Local Gas Distribution Companies: Impact Of Diversification And Warm Weather, October 2002 (76344)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Appendix A

CONSOLIDATED GAS UTILITY RATING GRID

		Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
Sustainable Profitability	Return on Equity	80%		> 19%	14% - 19%	9% - 14%	5% - 9%	0% - 5%	< 0%	
	EBIT / # of Residential & Commercial Customers	20%	20.0%	> $350	$250 - $350	$150 - $250	$100 - $150	$50 - $100	$0 - $50	< $0
Regulatory Support	Regulatory Support and Relationship	100%	80.0%	Exceptional Proactive Support by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission always willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Utility Commission grants all rate design features to allow LDC to recover costs on a complete and timely basis.	Very Good Proactive Support by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission highly willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Rate design is near "bullet proof" cover for LDC risks. Requested rate increases tend to be approved in less than 9 months.	Good Support by Utility Commission to allow LDCs to amend rate designs. Company gets good support in proposing new solutions to deal with common utility problems such as conservation and weather variables; Differences between LDCs and utility commission are likely to be resolved. Rate filings tend to be approved under 12 months.	Reasonable support from Utility Commission to allow LDCs to recoup allowed expenses; Company gets some support in proposing new solutions to deal with common utility problems such as conservation and weather issues; Differences between LDCs and Utility Commission are reasonably resolved in a timely manner and rate cases tend to be approved in 12 - 15 months with at least 50% of LDC's target requests being granted.	Inadequate support from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner and/or staff tends to play the role of consumer advocate that often counters propsals or initiatives advanced by the LDC. Cases often take over 15 months to resolve or LDC is frozen out of rate filings for over 18 months.	Inadequate support from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner often plays the role of consumer advocate that tends to counter proposals or initiatives advanced by the LDC. Company is seldom involved with working on special task forces to deal with issues of rising account delinquencies or educating customers on conservation or warm weather issues. Utility suffers from increasing regulatory lag and lacks rate relief necessary to earn allowed ROE.	Inadequate and weak support from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner always plays the role of consumer advocate that tends to counter proposals or initiatives advanced by the LDC. Company is hardly ever involved with working on special task forces to deal with issues of rising concern to utility or customers. Unsupportive commission/state legislature or consumer base. Utility can't earn allowed ROE.

		Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
Ring-Fencing	Ring-Fencing Quality (Regulated or self-imposed)	0% - 10%	0.0%	Excellent ring-fencing provisions isolating Utility from Non-Utility. No commingling of funds. Utility cash accounts are separated from rest of company. Inter-company loans never permitted between utility and non-utility. No portion of Utility dividend payment to parent ever ends up being allocated to non-utility. Strong.	Very Good ring-fencing provisions. Utility and Non-Utility highly unlikely to commingle funds. Separate cash program or own utility money pool. Inter-company loans not permitted between utility and non-utility. Utility dividend payment to parent reviewed up being allocated to non-utility.	Good ring-fencing provisions. Utility and Non-Utility are unlikely to commingle funds. Separate utility money pool or utility accounts. Inter-company loans not permitted between utility and non-utility. Utility dividend payment to parent unlikely to be allocated to non-utility.	Reasonable ring-fencing provisions. Utility and Non-Utility may need to commingle funds via consolidated corporate money pool. Bond indentures or bank credit agreements may reasonably restrict the utility from financial dealings with non-utility. Inter-Company loans between utility and non-utility rare.	Inadequate ring-fencing provisions. Utility often participates in corporate cash money pool that includes non-utility and funds are often commingled. Regulator usually do not have a requirement that LOCs remain investment grade. Bond indentures or bank credit agreements may not restrict the utility financial dealings with non-utility.	Inadequate ring-fencing provisions. Utility often participates in corporate cash money pool that includes non-utility and funds are generally commingled. No requirement for LOCs to remain investment grade. Bond indentures of bank credit agreements usually do not restrict the utility financial dealings with non-utility. Inter-company loans between utility and non-utility common place.	Inadequate and weak ring-fencing provisions. Utility and Non-Utility generally always commingle funds. No requirement for LOCs to remain investment grade. Bonds indentures/ bank agreements never restrict utility financial dealing with non-utility. Inter-company loans between utility and non-utility are common place. Utility dividends to parent may fund non-utility needs.
				Corporate Governance protecting utility interests which are treated as core operation.	Very Good Corporate Governance. May lack formal regulatory or credit or leverage restrictions or IG requirement for utility, but company has strong policy of ring-fencing utility.	Good Corporate Governance of Utility.	Satisfactory Corporate Governance. Gas utility contributes less than 90% of consolidated group EBIT and may not be primary growth engine.	Inadequate Corporate Governance protection for utility as stand alone entity.	Inadequate Corporate Governance for utility as a stand alone entity.	Inadequate and weak Corporate Governance of utility interests.
Financial Strength & Flexibility	EBIT/Interest		15.0%		5 - 7x	3 - 5x	2 - 3x	1 - 2x	0 - 1x	<0x
	CFO/Debt		15.0%	26%	21% - 26%	15% - 21%	10% - 15%	5% - 10%	0% - 5%	<0%
	Debt/ Book Capitalization (Excluding Goodwill)	60.0%	15.0%	30%	30% - 40%	40% - 50%	50% - 65%	65% - 85%	85% - 90%	>90%
	FCF/NFO		0%	10%	10% - 15%	(15) - (30%)	(30%) - (45%)	(45%) - (60%)	(60%) - (75%)	<75%

Appendix B

CONSOLIDATED FACTOR MAPPING RESULTS

Issuer Name	Current Senior Unsecured Rating	ROE	Indicated Rating: ROE	EBIT/# of Residential & Commercial Customers	Indicated Rating: Operating Ratio	Indicated Rating: Regulatory Support	Indicated Rating: Ring Fencing	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/ Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/Book Capitalization (Excluding Goodwill)	FCF/ FFO	Indicated Rating: FCF/FFO
Alabama Gas Corporation	A1	14 – 19%	Aa	$150 – $250	A	Aaa	Baa	3 – 5x	A	> 26%	Aaa	40 – 50%	A	(15%) – (30%)	A
New Jersey Natural Gas Company (Sec Aa3)	A1	9 – 14%	A	$150 – $250	A	Aaa	Aaa	> 7x	Aaa	10 – 15%	Baa	40 – 50%	A	> 10%	Aaa
Wisconsin Gas	A1	5 – 9%	Baa	$100 – $150	Baa	Baa	Baa	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	10% – (15)%	Aa
Boston Gas Company	A2	2 – 5 %	Ba	$150 – $250	A	Baa	Baa	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(15%) – (30%)	A
Brooklyn Union Gas	A2	9 – 14%	A	$150 – $250	A	Baa	Aaa	5 – 7x	Aa	10 – 15%	Baa	40 – 50%	A	(45%) – (60%)	Ba
KeySpan Gas East Corporation	A2	9 – 14%	A	$250 – $350	Aa	Baa	Aaa	2 – 3x	Baa	21 – 26%	Aa	40 – 50%	A	10% – (15)%	Aa
Northern Illinois Gas	A2	5 – 9%	Baa	$50 – $100	Ba	Baa	Baa	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
North Shore Gas Company (Sec A1)	A2	5 – 9%	Baa	$50 – $100	Ba	Ba	Baa	3 – 5x	A	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Peoples Gas Light and Coke Compa (Sec A1)	A2	5 – 9%	Baa	$100 – $150	Baa	Ba	Baa	2 – 3x	Baa	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Public Service Co. of North Caro	A2	5 – 9%	Baa	$150 – $250	A	Aaa	Aaa	2 – 3x	Baa	15 – 21%	A	30 – 40%	Aa	(15%) – (30%)	A
Questar Gas Company	A2	9 – 14%	A	$50 – $100	Ba	Ba	A	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A
Southern California Gas Company	A2	14 – 19%	Aa	$50 – $100	Ba	A	Aaa	5 – 7x	Aa	21 – 26%	Aa	50 – 65%	Baa	(15%) – (30%)	A
Washington Gas Light Company	A2	9 – 14%	A	$150 – $250	A	Baa	Aaa	5 – 7x	Aa	15 – 21%	A	30 – 40%	Aa	10% – (15)%	Aa
Terasen Gas Inc.	A3	9 – 14%	A	>$350	Aaa	Aa	Aaa	1 – 2x	Ba	5 – 10%	Ba	65 – 85%	Ba	(15%) – (30%)	A
Colonial Gas Company (Sec A2)	A3	2 – 5 %	Ba	$250 – $350	Aa	Baa	Baa	3 – 5x	A	15 – 21%	A	50 – 65%	Baa	10% – (15)%	Aa
Northwest Natural Gas Company	A3	9 – 14%	A	$150 – $250	A	Aaa	Baa	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
Piedmont Natural Gas Company, In	A3	9 – 14%	A	$150 – $250	A	Aaa	Aaa	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Connecticut Natural Gas	A3	2 – 5 %	Ba	$250 – $350	Aa	Ba	Baa	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A
UGI Utilities, Inc.	A3	14 – 19%	Aa	$250 – $350	Aa	Baa	A	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	Aa
AGL Resources Inc.	Baa1	14 – 19%	Aa	$150 – $250	A	Baa	Baa	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	(30%) – (45%)	Baa
Cascade Natural Gas Corp.	Baa1	9 – 14%	A	$100 – $150	Baa	Baa	Aaa	2 – 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Indiana Gas Company, Inc.	Baa1	5 – 9%	Baa	$100 – $150	Baa	Aa	Baa	2 – 3x	Baa	5 – 10%	Ba	40 – 50%	A	(30%) – (45%)	Baa

Issuer Name	Current Senior Unsecured Rating	ROE	Indicated Rating: ROE	EBIT/# of Residential & Commercial Customers	Indicated Rating: Operating Ratio	Indicated Rating: Regulatory Support	Indicated Rating: Ring Fencing	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/ Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/Book Capitalization (Excluding Goodwill)	FCF/ FFO	Indicated Rating: FCF/FFO
Laclede Gas Company	Baa1	9 – 14%	A	$100 – $150	Baa	Aa	A	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
Southern Connecticut Gas (Sec A3))	Baa1	2 – 5 %	Baa	$150 – $250	A	Baa	Baa	2 – 3x	Baa	15 – 21%	A	50 – 65%	Baa	(15%) – (30%)	A
Laclede Group, Inc. (The)	Baa2	9 – 14%	A	$100 – $150	Baa	Aa	Baa	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
South Jersey Gas Company	Baa2	9 – 14%	A	$150 – $250	A	Aa	Aaa	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	Aa
Yankee Gas	Baa2	2 – 5 %	Ba	$150 – $250	A	Ba	Baa	1 – 2x	Ba	10 – 15%	Baa	50 – 65%	Baa	< (75%)	Caa
Atmos Energy Corporation	Baa3	9 – 14%	A	$50 – $100	Ba	Baa	Baa	2 – 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Southwest Gas Corporation	Baa3	5 – 9%	Baa	$50 – $100	Ba	Ba	Caa	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(45%) – (60%)	Ba
SEMCO Energy, Inc.	Ba2	<0%	Caa	$100 – $150	Baa	Ba	Baa	1 – 2x	Ba	5 – 10%	Ba	> 90%	Caa	(45%) – (60%)	Ba

Positive Outlier
Negative Outlier

Appendix C

MOODY'S PUBLIC RATING VS. INDICATED MODEL RATING

Summary of LDCs Notch Difference

ACCURACY:			
		0 Notch Difference	7
# of Companies in Methodology Study	30	1 Notch Difference	14
# of Companies within Notching Range	28	2 Notch Difference	7
% Companies within Notching Range	93%	Outliers	2
		Total Companies	**30**

Companies	Public Ratings	Model Ratings	Notch Difference
Alabama Gas	A1	A1	0
New Jersey Natural Gas	A1	Aa3	-1
Wisconsin Gas LLC	A1	A3	2
Boston Gas Company	A2	Baa3	4
Brooklyn Union Gas	A2	A3	1
KeySpan Gas East	A2	A1	-1
Northern Illinois Gas	A2	Baa1	2
NorthShore Gas	A2	Baa1	2
People Gas Light	A2	Baa1	2
Public Service Co of NC	A2	A1	-1
Questar Gas	A2	A3	1
Southern California Gas	A2	A1	-1
Washington Gas Light	A2	Aa3	-2
Colonial Gas	A3	A3	0
Northwest Natural Gas	A3	A3	0
Piedmont Natural Gas	A3	A2	-1
Connecticut Natural Gas	A3	Baa1	1
Terasen Gas Inc.	A3	Baa1	1
UGI Utilities Inc.	A3	A2	-1
AGL Resources Inc.	Baa1	A3	-1
Cascade Natural Gas	Baa1	A3	-1
Indiana Gas Company	Baa1	Baa1	0
Laclede Gas Company	Baa1	Baa1	0
Southern Connecticut Gas	Baa1	Baa1	0
Laclede group Inc	Baa2	Baa1	-1
South Jersey Gas	Baa2	A2	-3
Yankee Gas	Baa2	Ba1	2
Atmos Energy	Baa3	Baa1	-2
Southwest Gas Corp	Baa3	Baa3	0
SEMCO Energy Inc.	Ba2	Ba3	1

Positive Outlier
Negative Outlier

Appendix D

SUMMARY OF NON-FINANCIAL LDC SUB-FACTORS

1. **Regulatory Support & Relationship:** While factor No. 1 measures the adequacy and effectiveness of the LDC's business model, this factor measures both the ***ability*** and ***willingness*** of the utility regulatory commission to grant the necessary support and protection that the LDC requests in its business plans. The utility commission must be willing to help the LDC establish a cooperative framework for discussions, hearings and staff relations with its indigenous utilities as well as have the state constitutional powers to put the necessary regulations or rate designs in place. While the LDC is interested in obtaining flexibility in regulatory growth and risk protection, the commission is usually focused on ensuring a stable utility operation with reliable customer service under reasonable prices. Questions to consider include
   a. Does the Company have good working relationship with the state regulators to recoup allowed expenses and the necessary trust of its regulators that it is doing the right thing for its customers and shareholders alike?
   b. Does the Company maintain an active dialogue with the commissioners and staff in discussing and proposing new solutions to common utility problems and working on special task forces to deal with common industry issues of rising account delinquencies as gas shortages rise and prices increase, or in educating customers as to gas conservation or safety?
   c. What is the role of the commission staff, to serve as a technical advisor to the utility commission in facilitating constructive discussions with the company or does it play the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC in an adversarial atmosphere for dispute resolutions.
   d. How are differences between the LDC and its utility commission typically resolved, do they have a "settlement" approach where various interveners and interested parties are brought together for amicable solutions or do they resort to court actions and counter-actions to achieve their ends?
5. **Ring Fencing Quality:** We find that either regulators or creditors or the companies themselves impose certain ring-fencing parameters on the financial operations of the LDCs. Generally, ring-fencing is a desirable attribute as the utility is assured a certain financial insulation from the non-utility operations of the parent company and is not susceptible to supporting the business of its non-utility affiliates. The greater the degree of ring-fencing, the more separated is the utility from its non-utility affiliates. The strongest ring-fencing requirements tend to come from legislative statutes and regulators, followed by bond indentures and bank creditors. Occasionally, LDCs have self-imposed guidelines that could be just as rigid as those regulated, but this would depend on the analysts' confidence in the utility's strict adherence to its own firewall policies and practices. A utility's self-imposed restrictions on its own operations and its attempts at insulating itself from other non-regulated affiliates could also be evident in its corporate governance policies and practices. Issues to consider include
   a. Are inter-company loans or advances permitted between utility and non-utility operations of the same corporate family?
   b. Does the utility participate in a corporate cash money pool that includes non-utility subsidiaries, such that it is possible for the utility to deposit its surplus funds in general corporate money pool which ends being used by the non-utility affiliates for their WC needs?
   c. Does the utility dividend payment to its parent (perhaps in excess of what the parent needs to pay public shareholders) have a portion that ends up being allocated to non-utility affiliates for their operating or investment needs?
   d. Do the regulators stipulate maximum leverage ratios for the LDC or have a requirement that the LDC remain investment-grade in order to preserve its service franchise?
   e. What is the quality of the LDC's corporate governance?

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Report Number: 99282

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Power Companies

Rating methodology for global power companies

Standard & Poor's rating methodology for global power companies incorporates two basic components: business profile (qualitative analysis) and financial profile (quantitative analysis). The two components are inextricable. A utility with a strong business profile, for example, could have less financial protection than one with a weaker business profile and still achieve the same rating. Conversely, a utility with a weak business profile would require a more robust financial profile than one with a stronger business profile in order to get the same rating. This basic concept is illustrated by the matrix in table 1.

Business profile

Standard & Poor's utilizes business profile assessments to measure a power company's qualitative credit fundamentals. Business profiles are expressed numerically on a scale of 1 (strong) to 10 (weak). To determine a business profile, Standard & Poor's analyzes the key qualitative business or operating characteristics:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Identifying utility types

The weighting or analytical emphasis that each business profile factor receives is strongly influenced by the type of utility. Standard & Poor's has identified four types of utilities *(see table 2)*. The type is determined through analysis of the influence of government ownership (if any), the degree of financial stability derived from the structure of the industry, and the relative competitiveness of the system. There are both investor-owned and government-owned utilities found in all four types, and more than one type may exist within the same country.

Table 1
Global Utility Rating Matrix

Financial Profile	Business Profile		
	Strong	Average	Weak
Strong	AAA	AA	A
Average	AA	A	BBB
Weak	A	BBB	BB

Type I utilities (supported) operate within systems where the utility receives overwhelming government and regulatory support. This support can be explicit, as in cases where a government guarantees a utility's obligations, such as in Canada. Or it can take the form of strong and obvious implicit support, such as in Greece. The government may facilitate the utility's access to external sources of capital, especially where the utility is a direct instrument of government policy. Type I utilities need not be completely owned by government, but government ownership is usually present. Before attributing support from government, Standard & Poor's reviews the track record of assistance, the procedures and timeliness of support mechanisms, the government's policy objectives for utility ownership, and financial policies. Standard & Poor's looks for evidence that the government would stand behind a debtor in time of financial need. Written and oral statements consistently made and significant supportive actions taken over time build credibility. In addition, Standard & Poor's considers the incentives for the government to provide tangible support. Questions asked include: What would be lost if a payment were missed? Would the borrower be able to continue to operate if it defaulted on a debt? Is the name of the borrower closely tied to the government in the market's perception, so that a default by the borrower would cause the government difficulties in the capital markets? What are the political realities?

Type II utilities (sheltered) conduct business where the utility is sheltered from competition and financial variability by the government or regulator. Sheltered utilities are not necessarily owned by government. Japanese investor-owned utilities offer an example. These vertically integrated utilities have historically been insulated from competition and protected by a very cooperative, coordinated rate-setting process. While generally highly leveraged, these utilities' financial results are quite stable. Another example is in the U.S.: municipally owned utilities have traditionally been sheltered from competitive forces and have enjoyed significant rate-setting flexibility. (While categorized as Type II utilities, Standard & Poor's analysis of municipal utilities is evolving, as deregulation measures aimed at investor-owned utilities are pressuring municipal utilities to create competitive markets. Moreover, an increasing number of city councils or other ratemaking bodies are reluctant to make either upward or downward rate adjustments. For example, it may be politically unpalatable to end the subsidization of residential rates by commercial and industrial customers, even if necessary to achieve cost of service rates that are more competitive for the commercial and industrial classes. Similarly, the ability to effect rate reductions necessitated by a more competitive environment may be frustrated by a city's general fund's dependence upon transfers from the electric system.)

Type III utilities (exposed), such as vertically integrated utilities in the U.S. or distribution companies in the U.K. or Victoria, Australia, evidence some regulatory insulation from the forces of competition, mixed with exposure to business risk. Although Type III utilities have certain franchise monopoly characteristics, their financial success may hinge more on their ability to control costs and provide high-quality service.

Finally, Type IV utilities (commodity) are essentially unregulated as to revenue or return. Unregulated generators, such as in Argentina and Chile, owe their success or failure to their ability to operate well at low cost, as they are subject to the sometimes harsh realities of supply and demand.

For Type I utilities, ratings will reflect the credit quality of the entity providing explicit or strong implicit support. For Type II utilities, the business profile factors of regulation and markets are weighted more heavily than competitiveness or management, because of the supportive regulatory umbrella. Conversely, for Type IV utilities, operations, competitiveness, and management are the most heavily weighted factors. Business profile factor weightings for Type III utilities are more evenly distributed.

An important point is that many utilities are gradually transitioning from Type II to Type III and perhaps to Type IV. As many countries' electricity sectors undergo structural reform and introduce competition, Standard & Poor's will weigh more heavily the business profile factors of operations, competitiveness, and management. Business profile assessments will fall and rating downgrades could result, absent offsetting improvement in financial profiles.

Typical business profiles

Large transmission systems and regulated distribution systems (the "wires" business) business profile assessments tend to fall within the 1-4 range. Generators generally receive business profile assessments in the 7-10 range.

The business profile assessment of electric systems with elements of integration—either fully vertically integrated from generation through transmission to distribution or partially integrated—is based on a weighted approach, reflecting the relative importance of each business segment to the overall credit.

Table 2
Utility Types

	Type I	Type II	Type III	Type IV
	Supported	Sheltered	Exposed	Commodity
Example	France, Ontario	Japan, Denmark	U.S., U.K.	Genco
Primary credit determinants	Owner or guarantor	Structural protection, Rate flexibility	Cost control, Service quality	Performance and cost
Debt-servicing capacity	Not limited by stand-alone risks	Usually highly leveraged	Moderate	Limited

Financial Ratio Guidelines

	Funds from operations interest coverage (x)		Funds from operations to total debt (%)		Total debt to total capital (%)	
	A	BBB	A	BBB	A	BBB
Transmission and distribution	3.25	2.0	15	10	55	65
Generators	6.75	4.25	42	27	35	45
Vertically integrated cos.	4.25	2.75	27	18	45	56

Note: Financial ratio medians are derived from Standard & Poor's financial projections for companies rated both publicly and confidentially.

The relative importance of each reflects their contributions of cash flow and operating income and the amount of capital invested. In addition, credit is given for the benefits of integration. For example, a company owning integrated generation and distribution operations benefits from the natural hedge that integration creates for both businesses. Integrated utilities tend to have business profiles in the 3-7 range.

Because of the importance of the different analytical emphasis accorded to the five business profile factors as influenced by the type of utility, the overall business profile assessment can diverge from the general expectations stated above. For example, certain generators can have strong regulatory support, and would therefore be characterized as Type II utilities. Consequently, their business profile assessment could be 3-4, reflecting heavy weighting of the supportive regulatory structure.

Financial profiles

Standard & Poor's measures financial strength by a utility's ability to generate consistent cash flow to service its debt, finance its operations, and fund its investment. Standard & Poor's focuses on a utility's financial results for the last five years and on pro forma, five-year projections.

Because of distortions caused by vastly differing asset valuation practices and depreciation policies around the world, certain leverage and earnings ratios are not particularly useful when conducting comparative analysis. As a consequence, the proper analytical focus should be on "real" stocks and flows, namely, levels of debt, cash, and cash flow. Financial parameters that are increasingly viewed as relevant and reliable are coverage of fixed financial charges by cash flow and cash flow from operations to total debt. Less comparable measures, such as shareholders' equity, leverage, and reported earnings, are also reviewed, but deemphasized.

Tightly regulated transmission and distribution utilities generally face limited business risk and can operate with relatively low operating margins and high leverage. Conversely, generating companies operating in a very competitive environment face much higher business risk and attendant cash flow volatility, and therefore generally can sustain only modest levels of debt. The table above displays guidelines for certain key financial ratios for rated transmission and distribution companies, generators, and vertically integrated utilities. Because of the different types of utilities—supported, sheltered, exposed, commodity—financial ratios for any particular entity may differ significantly from the guidelines. However, the ratios in the table are useful in demonstrating the typical differences in financial standards appropriate due to broad differences in business risk.

Profitability. Profit potential is a critical determinant of credit protection for investor-owned utilities. A company that generates higher profits has a greater ability to generate equity capital internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the firm's assets. Profit is less significant for non-U.S. government-owned utilities, but still relevant because higher operating margins provide additional bondholder protection on a stand-alone basis. For U.S. municipal utilities, Standard & Poor's does not measure "profit" per se, but rather looks at financial health as measured by excess margins on a cash flow basis and their ability to provide coverage of revenue bonds and off-balance-sheet obligations, as measured through fixed-charge coverage.

The more important measures of profitability are:

- Return on average equity,
- Pretax return on capital, and
- Operating margins.

Earnings are also viewed in relation to a company's burden of fixed charges. Otherwise-strong performance can be affected detrimentally by aggressive debt financing, and the opposite also is true. The primary fixed-charge coverage ratio is EBIT interest coverage (pretax income plus interest divided by interest). If preferred stock is outstanding, coverage ratios are calculated both including and excluding preferred dividends, to reflect the company's discretion over paying the dividend when under stress.

To reflect more accurately the ongoing earnings power of the firm, reported profit figures are adjusted. These adjustments remove the effect of foreign-exchange gains and losses, writedowns, and other nonrecurring or extraordinary gains and losses. Unremitted equity earnings of a subsidiary are also excluded. Adjustments are also made for the impact of hyperinflation on nonmonetary assets—gains are subtracted while losses are added back.

Shareholder pressures and accounting standards in certain countries, such as the U.S., can result in companies seeking to maximize profits on a quarter-to-quarter or short-term basis. In other regions, abetted by local tax regulation, it is normal practice to take provisions against earnings in good times to provide a cushion against downturns, resulting in a long run "smoothing" of reported earnings. For example, given local accounting standards, it is common to see a Swiss or German company vaguely report "other income" or "other expenses," which are largely provisions or provision reversals, as large items in a profit and loss account. In its meetings with management, Standard & Poor's delves into provisioning and depreciation practices to see to what extent a company employs noncash charges to reduce or bolster earnings.

There are numerous analytical adjustments to the interest accounts. Interest that has been capitalized is added back. An interest component is computed for debt-equivalents such as operating leases, fixed contractual obligations, and receivable sales. For U.S. utilities, allowance for funds used during construction is removed from income and interest expense.

In some regions, notably Japan and Europe, the local practice is to maintain a high level of debt while holding a large portfolio of cash and marketable securities. Many companies manage their finances on a net debt basis. When a company consistently demonstrates such excess liquidity, interest income may be offset against interest expense in looking at overall financial expenses. Each situation is evaluated on a case-by-case basis, in light of a company's liquidity position, normal working cash needs, nature of short-term borrowings, and funding philosophy.

Capital structure. The principal capital structure ratio analyzed is total debt to total debt plus equity. However, analyzing debt leverage goes beyond the balance sheet and covers quasi-debt items and elements of hidden financial leverage. Noncapitalized leases, debt guarantees, receivables financing, and purchased-power contracts are all considered debt equivalents and are reflected as debt in calculating capital structure ratios. Moreover, adjustments are made to reflect unfunded pension liabilities.

In countries where local practice is to hold significant cash and marketable securities, Standard & Poor's will focus on net debt leverage, which nets out excess liquidity from borrowings.

Most firms use short-term debt as a permanent piece of their capital structure or to bridge to permanent financing. Seasonal, self-liquidating debt is excluded from the permanent debt amount, but this situation is rare—except in the case of natural gas utilities. Given the long life of almost all utility assets, short-term debt exposes these companies to interest-rate volatility, remarketing risk, bank line backup risk, and regulatory exposure that cannot be readily offset. The lower cost of shorter-term obligations (assuming a positively sloped yield curve) partially mitigates the risk of interest-rate variability.

Also important is the term structure of a power company's long-term debt. Amortizing debt is less risky than bullet maturities, and may be more appropriate for certain companies with limited asset lives. Generators, in particular, may have a tendency to rapidly depreciate assets, so they face greater risk of mismatching assets and liabilities when they fund their operations with long-term bullet maturity debt.

What is considered "debt" and "equity" for the purpose of ratio calculation is not always simple. In the case of preferred stock and other hybrid securities, the analysis is based on their features, not the accounting or nomenclature. Pension and retiree health obligations are similar to debt in many respects.

Knowing the true values to assign to a company's assets is important to capital structure analysis. Consequently, assets are examined to identify undervalued or overvalued items. Asset valuation practices differ from country to country, resulting in differences in both a company's reported equity base and its depreciation expense. There is no easy way to compare companies that revalue their assets with those that do not. Rather, Standard & Poor's recognizes that, for all companies, reported asset values often differ from market values. In discussions with management, Standard & Poor's analysts endeavor to gain an appreciation of the realizable values of a company's assets under reasonably conservative assumptions.

Cash flow. Cash flow analysis is critical in all credit rating decisions. Interest or principal obligations cannot be serviced out of earnings, which is just an accounting concept; payment has to be made with cash. Many transactions and accounting entries can affect earnings but not cash, and vice versa. Analysis of cash flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings. Since both common and preferred dividend payments are important to maintain capital market access, Standard & Poor's looks at cash flow measures both before and after dividends are paid. Working capital analysis is typically not a major factor in utility credit analysis given the relatively minor impact on cash flow from period to period. However, such analysis can be critical for certain utilities operating in developing economies—where late payment or nonpayment of bills can drive up receivables.

Cash flow is also measured against fixed contractual obligations, capital expenditures, debt maturities, and shareholder dividends.

Some of the specific ratios considered are:

- Funds from operations/total debt (adjusted for excess liquidity and off-balance-sheet liabilities).
- EBITDA/interest.
- Funds from operations - dividends/capital expenditures.
- Capital expenditures/total capital (debt + equity).

Because of the capital-intensive nature of the power industry and the lengthy periods sometimes necessary to construct facilities—particularly generating plants—utilities require extensive and flexible capital planning. The ability to limit the use of debt also depends on a utility's skill in managing construction projects and completing any new facilities on schedule and within cost estimates. Accordingly, Standard & Poor's reviews capital priorities for the next five years and beyond.

Financial flexibility. Financial flexibility incorporates a utility's financing needs, plans, and alternatives, as well as its flexibility to accomplish its financing program under stress without damaging creditworthiness. External funding capability complements internal cash flow. Especially since utilities are so capital intensive, a firm's ability to tap capital markets on an ongoing basis must be considered. Relationships with banks and the availability of bank lines are also reviewed. A utility's debt capacity reflects all the earlier elements: profitability, capital structure, and cash flow. Market access at reasonable rates is restricted if a reasonable capital structure is not maintained and the company's operational and financial prospects dim.

Standard & Poor's also reviews indenture and bank loan covenants. Certain restrictions, such as a limit on the ability to issue additional debt, provide some comfort, as do provisions that restrict the distribution of dividends unless there is adequate cash flow to provide for projected debt service (interest and principal). Other covenants viewed favorably are those that may reduce default risk, such as a requirement for a funded debt-service reserve. However, very tight covenants can raise default risk by limiting a company's flexibility to raise cash in times of crisis.

For investor-owned utilities, Standard & Poor's assesses a company's capacity and willingness to issue common equity. This is affected by various factors, including stock price, dividend policy, and any regulatory restrictions regarding the composition of the capital structure. For government-owned utilities, analysis focuses on the government's willingness and ability to inject equity as needed or to forgo dividends. An additional measure of financial flexibility important in the analysis of U.S. municipal utilities is ratemaking flexibility, taking into account both political and competitive considerations.

Transmission and distribution qualitative analysis

Reflecting relatively low business risk, electric transmission and distribution companies can be generally expected to have business pro-

file assessments of 1-4. However, few companies receive the top score and some do fall below a 4.

When evaluating electric transmission and distribution companies, Standard & Poor's is most concerned about the predictability and sustainability of financial performance. For typical transmission and distribution companies, regulation, markets, and management are more important factors than operations and competitiveness, although the relative emphasis on the factors may differ depending on the type of system. Regardless of type, the regulatory environment will have great impact. Variations in policies and practices among local and national regulatory bodies are key considerations. Markets and customer composition are also important factors, with weak economic performance and a large industrial sector being less favorable. Importantly, Standard & Poor's evaluates management, especially its leadership qualities and its response to industry changes.

Regulation. Regulation defines the environment in which a utility operates, and has great influence on the company's financial performance. A utility with a marginal financial profile can, at the same time, be considered highly creditworthy due to a supportive regulatory environment. Conversely, unpredictable or antagonistic regulatory action can undermine the financial position of utilities that are very strong from an operational standpoint. To be viewed positively, regulatory treatment should be timely and allow consistent performance from period to period, given the importance of financial stability as a rating consideration. Also important is the transparency of regulatory polices and the length of time that the regulatory framework has been in place. Clearly, there is concern that the mechanics of a recently privatized system could be revisited for fine tuning. Because of this, Standard & Poor's also examines the relative ease with which regulation can be changed. That is, a transparent system that requires legislative action to modify is viewed more favorably than one more subject to the whim of ministerial discretion, as in some Asian countries. Also key is the selection process for membership of a regulatory body.

Evaluation of regulation encompasses the administrative, judicial, and legislative processes involved in local or national regulation. These can affect rate-setting activities and other aspects of the business, such as competitive entry, environmental and safety rules, facility siting, and securities sales. In addition, the terms of a utility's license or franchise often impose obligations to serve any customer and provide a reasonable standard of service, and a variety of other stipulations. Ratings factor in the impact of such constraints and obligations on a utility's operations and financial performance.

Transmission and distribution companies are expected to remain tightly regulated monopolies, with rates set on a cost-plus basis in many circumstances. Under a cost-plus regime, rates are set to recover costs and, for investor-owned utilities, a return on shareholder investment. Under cost-based rates, Standard & Poor's analysis focuses on the predictability of costs and revenues. While a utility may be largely protected from business risk under cost-based rates, the responsiveness of the rate-setting process to changes in a utility's cost structure or to discrepancies between allowed and actual revenues influences the business pressures on the company.

One drawback to cost-based ratemaking is the lack of strong incentive for utilities to control costs. Since rates and earnings are closely linked to the amount of invested capital and the cost of capital, utilities may be rewarded more for justifying costs than for containing them. Consequently, Standard & Poor's believes that performance-based ratemaking will become an increasingly popular form of ratemaking, particularly for the distribution business. Because financial results can vary depending on a company's ability to meet performance challenges, performance-based systems are inherently more risky than cost-based systems. Flexible plans incorporating performance-based rewards or penalties could include market-based rates, price caps, revenue caps, index-based prices or other yardstick measures, and rates premised on the value of customer service.

Markets. Many distribution companies are common carriers. That is, they carry electricity being purchased by customers from independent suppliers, either generating companies or marketers. Other distributors participate in the energy marketing (supply) business by buying, brokering, or generating electricity through an affiliate, and selling the power to a customer. Risks in the marketing business include the significant challenge of matching fuel and power supply with demand. Whether a utility

is involved in the sale or brokering of electricity or merely distributes the commodity, prospects for the stable growth of revenues and cash flow are ultimately related to the strength of the local economy. Customer growth is important for distributors. And, even for utilities involved only in distribution and not in energy marketing, electricity consumption is important—because the typical distributor recovers some portion of its distribution costs through a volumetric, per kWh charge, in addition to any fixed monthly or quarterly customer charge that may be in place. Accordingly, assessing a distributor's markets begins with the economic and demographic evaluation of the area in which distribution services are provided. Strength of long-term demand is examined from a macroeconomic perspective, which enables Standard & Poor's to measure trends in investment, income, and employment as indicators of economic change within the service area. The sustainability of increasing demand is also analyzed. Many emerging economies go through periods of very rapid growth followed by severe contractions. This volatility can contribute to significant and unhealthy swings in a utility's revenues.

The analyst also tries to discern any secular consumption trends and, more importantly, the reasons behind them. Specific items addressed include the size and growth rate of the market, strength of the franchise, historical and projected growth, income levels and trends in population, employment, and per capita income. Other relevant factors include proximity to attractive markets, the quality of public infrastructure, and, particularly in developing countries, the affordability of electricity and customers' ability and willingness to pay their bills.

A distributor with a healthy economy and customer base, as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment, is likely to exhibit greater revenue stability.

For electric distribution utilities, the number and type of customers, revenue analysis, and margin breakdowns are closely scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed cautiously, since the utility may have significant exposure to cyclical volatility. On the other hand, a large residential component produces a stable and more predictable revenue stream. The utility's largest customers are identified to determine their stability and relevance to the bottom line. Sometimes, the loss of just one large customer can have a material effect on the utility's financial position. Credit concerns arise where any one customer plays a dominant role in the overall economic base of the service area. Moreover, large customers may turn to self generation and leave the distribution system altogether, potentially leading to reduced financial protection for the utility.

Similarly, for electric transmission companies, the total number of customers—largely distributors—is evaluated to assess the depth and diversity of the transmission company's customer mix. The transmission company's largest distribution customers are identified to determine their stability and contribution to revenues. Also important to a transmission company is the strength and diversity of the end-use markets of its distribution customers. Accordingly, these end-use markets are evaluated from a macroeconomic perspective in an analysis identical to that described above for a distribution utility.

Another key consideration for a transmission company is the location of its transmission facilities. A transmission company that is strategically located to connect surplus low-cost generation with growth markets is best. On the other hand, a transmission company that connects relatively high-cost generation to a mature or declining area is at risk. Usage and electric growth levels in the end-use markets are compared with transmission capacity utilization. Underutilized transmission lines that serve growth markets have positive implications, while fully utilized lines that serve mature markets have less favorable implications.

Operations. Transmission and distribution operations are typically low risk. To evaluate the operations of a transmission or distribution company, Standard & Poor's focuses on cost, reliability, and quality of service. With gradually increasing competition in all segments of the electric power business, utility managers are under increasing pressure to optimize their use of resources. If utilities are not cost-effective in meeting service standards, compared to the performance of other utilities and administrative benchmarks, stronger regulatory or competitive pressures are likely.

Consequently, emphasis is placed on those areas that require management attention (in terms of time or money) and which, if unresolved, may lead to political, regulatory, or competitive problems.

In addition, the status of utility plant investment is reviewed, with regard to reliability and utilization, as well as for compliance with existing and contemplated environmental and other regulatory standards. The record of outages, system losses, and capacity utilization are examined. Important considerations include the projected capital improvements necessary to provide high-quality and reliable service. Additionally, unique operating challenges could be present that impact costs to a degree where credit quality suffers. Examples of operating challenges include harsh climates, severe storms, and difficult terrain.

Utilities in emerging countries face additional operating challenges, such as the fundamentals of metering and billing. Certain utilities may struggle with accurate and timely metering and billing because they do not have the appropriate technology, computer infrastructure, or control systems in place. Moreover, getting the bills correct and out in a timely fashion is only part of the issue. Collections can be a nagging problem where political or economic realities prevent service cutoff for nonpayment. In addition, outright theft of electricity service can be a big problem.

Assets must be in good physical condition and well maintained. Capital expenditures for system improvements must be at manageable levels, while sufficient to provide for constant renewal and refurbishment of the system. Operating performance, reliability statistics, and efficiency measures are expected to meet industry and regional averages. Having interconnections that provide access to low-cost and diverse power supply sources is viewed favorably, as is limited environmental exposure.

Competitiveness. Competitive pressures in the transmission and distribution businesses are generally quite limited by virtue of franchise monopolies. While introducing competition into the generation business and creating national or international power exchange systems is increasingly popular worldwide, there is near unanimous agreement that transmission and distribution systems should largely remain monopolies. This limited competition is a major factor in the strong business profile assessment for a typical transmission or distribution utility. Franchise monopolies are significant barriers to entry by competitors. Where there are nonexclusive franchises, other barriers to competitors exist, such as siting difficulties caused by public concerns over duplicate utility poles and wires and environmental issues.

Transmission and distribution utilities do face competitive pressures in the form of substitute energy sources and customer self-generation and bypass. Electricity competes with other fuels such as natural gas for certain segments of the market, like space heating, water heating, and cooking. Thus, high electricity prices, which may be caused by inefficient transmission or distribution service, are cause for concern if customers have alternate energy sources. Self-generation has for many years been a significant concern for larger commercial and industrial customers who have been able to take advantage of cogeneration technologies to significantly reduce their reliance on, and, in some cases, disconnect from transmission and distribution systems. In the future, technology could pose a greater threat for transmission and distribution companies. Bypass risk is likely to grow as distributed generation, microgeneration, and self-generation gradually become more economically attractive for smaller and smaller customers. However, these technological evolutions are likely to be gradual, so the currently configured transmission and distribution networks should continue to play a viable role for the foreseeable future.

Management. Owing to the safety net provided by regulation, evaluation of management is less critical for tightly regulated transmission and distribution companies than for generators or energy marketers operating in a very competitive environment. Still, assessing management remains significant, since management's abilities and decisions affect all areas of a company's operations, and ultimately drive the success of a company. Important considerations include strengths and weakness of key members of management, depth and stability of top management, and recent and prospective management changes. Management strategies are also a material determinant in differentiating utilities. Standard & Poor's assesses financial policies, corporate goals, strategies, tactics, and plans for both regulated and diversified businesses, and monitors how effectively they are implemented.

The assessment of management is based on such factors as tenure, industry experience, grasp of industry issues, and knowledge of customers and their needs. Management quality is also indicated by thoughtful balancing of public and private priorities, a record of credibility, and effective communication with the public, regulatory bodies, and the financial community.

Key financial policy considerations include commitment to credit quality. This can be assessed by evaluating accounting and financing practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk taking.

Generation qualitative analysis

Generation is the riskiest segment of the electric utility industry due to complex operating risks and the increasingly competitive nature of the business. Risk may be further heightened by absence of the regulatory umbrella. Because of the higher risks, generators can generally be expected to have business profile assessments in the 7-10 range.

Generation is a commodity business. Electrons are physically indistinguishable from each other and therefore compete primarily on price. However, electricity has some characteristics that make it less like other commodities. Electricity cannot be stored. Electricity must be used instantaneously, as it is produced, and its deliverability can be hampered by transmission constraints. Reliability and deliverability distinguish one generating company from another, and perhaps elicit a premium in the marketplace. Value-added services, such as customization and load-following, can tailor the shape and firmness (or lack of firmness, for example, interruptible service) of electricity delivered to the customer.

Generation also faces unique operating risks. Because electricity cannot be stored, generating plants cannot afford to have unplanned outages. Of course, they are only paid when they run. Furthermore, contractual commitments could force a downed generator into the market to seek replacement power, which could be costly—or unavailable if the outage occurs during a peak usage period. Thus, while low production costs factor heavily into the business profile of a generation company, other criteria are considered when assessing creditworthiness.

Regulation. Some generators may remain highly regulated and achieve superior business profiles due to the more stable revenue stream. Some centralized supply systems derive strength and stability from their highly cohesive nature, stemming, in part, from direct or indirect cross ownership between generators and distributors, and government entities as ultimate owners. However, most global generators operate in deregulated environments, where rates are determined by the market.

Even so, regulatory considerations are still pertinent, and vary among global electric utility systems. Regulation typically establishes the basic framework of the electricity market. The market may be primarily a wholesale, rather than retail, market. The system may mandate that all players bid into a pool or exchange, whereby generators are economically dispatched and the last unit to run sets the market clearing price for all players. A power pool may have rules regarding price bids, dispatch, financial standing of market players, or other factors. Generators may have an obligation to build—or may be limited in building or investing. Furthermore, political stability, legal environment, and contract law influence the generator's operating environment and are examined under this heading. In general, regulation is likely to constrain upside profit potential, while providing little protection on the downside.

Standard & Poor's seeks to determine the regulatory posture toward credit quality. The length of time that the regulatory framework has been in place is noteworthy, given the potential for a relatively new system to be modified. The U.K. is notorious for having touted its competitive power pool, only to have the regulator step in and tamper with the pool's market clearing price.

In the U.S., the Federal Energy Regulatory Commission (FERC) has established regulations for nondiscriminatory interstate transmission pricing. Therefore, a transaction between a generation company and an end user will not be undermined by inflated wheeling fees. But market power issues are still being sorted out. FERC may prohibit mergers where bulking up on generation results in a utility being able to exert market power over its competitors. As a result, regulators may limit size and restrict certain contractual arrangements. Regulators may also set prudence requirements (financial creditworthiness) for entrants to the market. Questions asked include: How

will prices be established? Will there be a power pool or bilateral contracts only? (In bilateral contracts, buyers and sellers negotiate the terms, including cost, of the transaction.) Often times a pool transaction can be hedged to financially simulate a bilateral contract through "contracts for differences."

In some international systems, short-term marginal cost is determined by a pool, but the tariff also includes a charge to cover the long-run marginal cost of the next capital addition. This pricing system offers some greater assurance to the recovery of fixed costs and therefore lowers risk to the generator.

Markets. A generator's market expands as far as it can transport its electrons within physical (transmission) and economic (transportation fees) constraints. It typically has no obligation to serve, and may be free to hand pick its customers and negotiate its own contracts. While it is anticipated that in the U.S. all customers will be able to choose their supplier (retail wheeling), other countries permit retail access to only the very largest industrial entities. Markets in these countries are primarily wholesale. It is anticipated in the U.S. that residential and small customers will initially tend to stick with their local utility distribution company for supply. However, in pilot programs to date, many customers have exercised their option to choose and left their traditional suppliers.

As electricity markets become more liquid, prices become more transparent, and energy marketers and financial derivatives begin to develop. It remains to be seen if marketers can aggregate small customer loads effectively to make them economically desirable.

If a generator sells directly to end users, it is important to know the customer mix, in terms of residential, commercial, and industrial segments. A diverse customer base within a stable, growing economy would be positive from a credit risk perspective. An economy that is driven by only a handful of products or industries introduces concentration risk.

Further market evaluation looks at the economic prospects, inflationary pressures, and electricity consumption patterns within the country or region where the generating company operates. In developing countries, growth prospects would be higher than in a mature economy such as the U.S. However, strong growth could be subject to extreme volatility, due to recessionary or inflationary pressures. If one or a few industries dominate the region, growth prospects could be tied to the fate of that industry.

In terms of supply, who are the other players in the market, and what are the barriers to entry? How much capacity is there relative to demand? Surplus capacity could reduce sales and/or put pressure on margins. A deficit capacity situation would inflate margins over the short term, but encourage other entrants to the market. This would not necessarily be bad, depending on the incremental cost of supply (lower cost would be a threat to existing generators, higher cost would enhance the generating company's competitive position) and the subsequent surplus situation. If transmission constraints are relieved, either through construction or technology, the supply/demand balance changes. Generators may have access to a broader market, but other suppliers will have access to their customers as well.

Operations. An analysis of operations overlaps somewhat with examination of markets and competitiveness. The market within which a generating company is a player (local, regional, national, or international) has implications for how it operates. Transmission interconnections and constraints, as well as the location of a plant relative to customers, provide operating limitations and opportunities. Having a strategic location might necessitate that the plant be run constantly to provide system voltage support. And the efficiency of a generator's operations is directly tied to its competitive position.

Managing production inputs effectively is crucial to competitiveness. Suppliers of fuel, labor, and supplies are sources of economic risk to a generator's ability to produce low-cost power. The generator can be at risk if supplies are disrupted or prices are raised. A generator should diversify risk, as opposed to relying on a few suppliers. What has been the historic growth of operating and maintenance expenditures, and how will they be controlled (or reduced) prospectively? Efficient use of technology enables a generation company to manage its costs more efficiently.

Fuel typically represents about half the cost per kWh. Generators will need to become sophisticated in physical and financial hedging of fuel commodity risk. To the extent that a generation company has contracted to sell its output at a fixed price, it will be necessary to match the length of fuel contracts and hedges

to insure that margins are locked in. Some contracts permit a pass-through of fuel price changes, which might mitigate the necessity of hedging.

Contracts to sell a portion of production output at negotiated prices can protect generators from price and volume risk. Electricity markets are quite volatile, with prices fluctuating as much as 300% daily in U.S. markets. Contracts for differences are a common way to have price settlement around an erratic market clearing price. The mechanics, in very simple terms, are as follows: A buyer and seller agree on a price for power, say, 4 cents per kWh. If the market clears at 5 cents per kWh, the seller sells into the pool and receives 5 cents. The buyer must buy from the pool for 5 cents, which is 1 cent higher than his arrangement. To reconcile their 4 cent agreement, the seller pays the buyer 1 cent. Clearly, strategies will vary depending on how contracts are structured and how much of production is sold under contract versus on the spot market. These strategies are indicative of management's risk appetite.

In addition to these considerations, Standard & Poor's examines key statistical efficiency measures, such as capacity factor, availability factor, and heat rate of individual plants as compared to industry peers. Clearly, it is preferable to achieve parameters which exceed industry standards. Capacity factor measures the degree to which a plant is actually run over a certain period of time, while availability indicates what percent of the time it would have been available to operate. Heat rates measure a power plant's fuel efficiency. A low heat rate indicates less fuel input per unit of output. The average age of the facilities in the portfolio is also important; maintenance expense tends to increase as plants age.

The technologies utilized by a generating company also impact the assessment. New technology is riskier than proven designs. Moreover, nuclear facilities present greater-than-average risk in light of complex technology, additional operating challenges and concerns, and decommissioning costs.

Asset concentration risk is present where any one unit represents a disproportionate share of capital or output in the portfolio. Construction risk is considered in terms of the level of capital expenditures, demonstrated ability to complete projects on time and on budget, and success of start-up. Turnkey projects could transfer construction risks from the generator to the engineering firm. Lastly, environmental risks are evaluated. Imposition of a carbon tax could have significant financial consequences for coal-fired generation.

Diversity of the generation portfolio reduces the risk of dependence on any one unit, or any one fuel. Different fuel sources and the operating characteristics of the facilities (for example, base load versus peaking) further diversify the portfolio, and dual fuel capabilities at individual plants can enhance flexibility. Clearly, a single unit generator is inherently riskier than one with a portfolio of assets. The evolution of the merchant power plant has introduced a certain speculative element to the generation sector. Unlike their independent power producer predecessors, merchant plants are generally constructed without benefit of contractual commitments for the sale of their output. Thus, success depends on their ability to produce power consistently below the market's forward price curve for electricity. Since a merchant plant has less margin for error, it must have superior technological, marketing, finance, management, and operating skills, and be able to manage the risk of uncertain pricing and markets.

For generators selling into spot or short-term contractual markets, reliability is important. Generators who cannot deliver consistently on their commitments will lose credibility—and customers. This risk increases to the extent that the generating company is involved in marketing transactions beyond the sale of its own generation. Standard & Poor's believes that the more successful and higher-rated energy marketers will have leading national or regional market positions and need substantial physical and financial liquidity. Size is important because there are informational economies of scale in marketing, and smaller trading firms can be whipsawed. Generators with hard assets have a perceived advantage over energy traders with no owned assets.

Competitiveness. The first step of an analysis of competitiveness is to compare the generation company's cost of production to those of other market players. Unless there are overriding circumstances (for example, a must-run facility or an environmentally benign power source), a low-cost structure is crucial to a generator's success in a competitive environment. As important as the total cost is the variable cost of production—particularly in markets

with overcapacity. Since generators resemble other commodity industries, with their high capital costs, long-lived assets, and low labor content, they may pursue predatory price strategies in an attempt to gain market share. Thus, a generator's ability to beat its competitors' costs at the margin gives it a significant edge. In addition to analyzing marginal cost, Standard & Poor's compares a generator's average costs against contract prices, spot prices, pool prices, other producers, and new entrant costs.

Comparing costs, however, is not as straightforward as it might appear. The output of a plant greatly affects the cost of a unit of output, as fixed costs are spread over kWhs generated. This can make cost comparisons between base, intermediate, and peaking facilities difficult. The "peakier" the load curve, the higher the price of electricity at peak hours. As a result, a competitive strategy for a load-following generator might be to primarily operate during those more lucrative hours. First Hydro's generating plant in the U.K., a pumped storage hydro facility, has found this strategy to be quite lucrative. It pumps water into a reservoir during off-peak hours, and uses it to generate electricity during high-price peak hours.

Price comparisons will also become difficult as generating companies begin to customize packages for buyers. A package may include a combination of firm and interruptible power, with the interruptible portion being sold many times over. This type of customizing, or load-following, is a value-added service which may command a price premium.

Being competitive also involves strategies for structuring contracts, for deciding what percent of output to contract out versus sell into a spot market or pool, and for limiting the percent of output sold to any one customer. Staying competitive further involves both physical and financial hedging strategies, particularly for fuel.

Competition comes from many sources. Suppliers of new and cheaper power generation represent a threat to existing generating companies. New supplies may come from greenfield projects, renovation of existing facilities, or the opening of transmission pathways. Increasing power supply puts downward pressure on rates. Substitute products, particularly natural gas, also pose a competitive threat. This will become more complex as electric and gas markets "converge." Gas may become a greater threat to electricity usage over time due to the interchangeability of energy sources, as well as technological developments—such as gas-fired air conditioning. And further down the road, remote site applications such as the fuel cell may replace generation-produced power. Threat of these alternatives will depend on pricing, switching costs, availability, political and regulatory barriers, and public policy initiatives.

Management. The high business risk in generation—compared to transmission or distribution—makes management a critical factor in the credit evaluation of generators. In evaluating management, Standard & Poor's attempts to define management's risk appetite, and its overall goals and objectives. What strategies have been utilized to implement these goals, and how effective have they been? This dialogue may also provide insight into the degree of management's credibility to articulate, implement, and achieve its goals. Management's financial and diversification policies, including the appetite for construction of additional plants and/or diversification into international markets, is examined in assessing its risk tolerance.

The degree to which generators engage in energy marketing activities beyond the sale of their own output is also evaluated. Critically important to these activities are the generator's risk management guidelines that provide for the establishment and strict adherence to risk policies, objectives, and limits.

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

Key Credit Factors For U.S. Natural Gas Distributors

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On its surface, analyzing U.S. gas distributors' credit quality would appear straightforward. After all, the core business simply involves distributing a commodity to mainly captive customers within a given service territory under a regulated environment. What could be more uncomplicated or have lower business risk? But, in reality, the universe of local natural gas distribution companies (LDCs) that Standard & Poor's Ratings Services rates has great credit diversity, as evidenced by ratings ranging from 'AA-' to 'BB-'.

Thus, the business risk profile is a defining attribute of an LDC's creditworthiness, as is the case with any corporate issuer. In most cases, Standard & Poor's categorizes pure LDCs as having well above average ('1' and '2') or above average ('3') business profiles (business profiles are categorized from '1' (strong) to '10' (weak)). Nonregulated business segments outside the relatively low-risk gas distribution arena generally weaken a company's business risk profile.

Clearly, higher-risk activities pressure the consolidated profiles and often require stronger financial performance to merit the same rating as a pure LDC. ONEOK Inc. (BBB/Watch Neg/A-2), an extreme example, has gas gathering and processing and energy trading and marketing activities that account for roughly two-thirds of its business mix and elevate the company's business profile to '6'. The inherent volatility of ONEOK's higher-risk businesses dwarfs the relative stability of its regulated gas distribution operations and exposes the company to greater cash flow volatility.

We look at five broad categories when reviewing an LDC's business risk profile: regulation, markets and competition, operations, management, and diversified activities. Below, key factors are highlighted and specific LDCs are identified that demonstrate strong or weak characteristics along these lines.

The business risk profiles of 14 LDCs operating in the U.S. can be seen in table 1.

Table 1

U.S. Gas Distributors Comparison

Company	Rating	Business profile	Gas adjustment mechanism	Supply position	Storage capacity (%)	Hedging policy in place
AGL Resources Inc.	A-/Negative/A-2	4	Yes	4	35	Yes
Cascade Natural Gas Corp.	BBB+/Stable/--	2	Yes	3	25	Yes
New Jersey Natural Gas Co.	A+/Stable/A-1	2	Yes	2	60	Yes
Nicor Inc.	AA/Negative/A-1+	3	Yes	8	55	Yes
Northwest Natural Gas Co.	A+/Stable/A-1	1	Yes	1	58	Yes
ONEOK Inc.	BBB/Watch Neg/A-2	7	Yes	8	15	Yes
Peoples Energy Corp.	A-/Negative/A-2	5	Yes	6	60	Yes
Piedmont Natural Gas Co. Inc.	A/Stable/--	2	Yes	5	50	Yes
SEMCO Energy Inc.	BB-/Stable/--	5	yes	4	35	Yes
South Jersey Gas Co.	BBB+/Neg/--	3	Yes	2	40	Yes
Southern Union Co.	BBB/Negative/--	3	Yes	8	30	Yes

Southwest Gas Corp.	BBB-/Stable/--	3	Yes	6	10	Yes
UGI Utilities Inc.	BBB/Watch Neg/--	4	Yes	3	N.A.	Yes
WGL Holdings Inc.	AA-/Negative/A-1	3	Yes	4	30	Yes

N.A.--Not available.

Regulation

Table 2

Regulatory Comparison

Company	Weather normalization	Allowed ROE (%)	Earnings sharing	Regulatory protection of LDC finances
AGL Resources Inc.	Yes	11 to 11.5	Yes	No
Cascade Natural Gas Corp.	No	11 to 11.5	Yes	No
New Jersey Natural Gas Co.	Yes	> 11.5	Yes	No
Nicor Inc.	Yes	11 to 11.5	No	No
Northwest Natural Gas Co.	Yes	< 11	Yes	No
ONEOK Inc.	Yes	N.A.	No	No
People's Energy Corp.	No	11 to 11.5	No	No
Piedmont Natural Gas Co. Inc.	Yes	> 11.5	No	No
SEMCO Energy Inc.	No	11 to 11.5	No	No
South Jersey Gas Co.	Yes	< 11	Yes	No
Southern Union Co.	No	< 11	Yes	Yes
Southwest Gas Corp.	No	< 11	No	No
UGI Utilities Inc.	No	N.A.	No	Yes
WGL Holdings Inc.	No	< 11	No	No

N.A--Not available. LDC--Local distribution company. > -- Greater than. < -- Less than.

A prolonged period of high natural gas prices without timely reimbursement of deferred gas cost balances will rapidly deplete an LDC's liquidity. Given today's high and volatile natural gas prices, maintaining strong credit quality necessitates that ratepayers bear the responsibility for commodity costs. Automatic pass-through mechanisms linked to gas price indices provide the strongest level of support because they largely remove regulatory risk from the picture. Lesser clauses, including mechanisms that require after-the-fact sign-off by regulators, introduce the potential for disallowance if the regulator deems gas to be purchased at imprudent cost levels. New Jersey LDCs, for instance, can adjust rates up to three times a year without an official rate case. Although this acts as a pressure release valve in high-price environments, it still exposes LDCs to regulatory uncertainty when the price of gas rises above a preset level. In such circumstances, history provides Standard & Poor's with its best guide to regulators' willingness to accommodate LDCs in their jurisdiction.

Due to the extreme volatility and significant increase in gas prices over the past few heating seasons, more state regulators have revised the timing of their gas adjustment clauses by providing monthly gas adjustment clauses rather than the seasonal end of the heating season adjustment. This expedited treatment helps LDCs to reduce any regulatory lag to recover costs and streamline working capital needs, which in turn should allow LDCs to modestly temper rising gas bills to their customers. In today's new cost paradigm, how quickly the purchased-gas adjustment is "trued up" can have a significant bearing on an LDC's credit quality. Slow recovery could impinge on the firm's liquidity as short-term funds are consumed to finance high-cost gas working-capital needs. In turn, this may necessitate a larger bank line that increases borrowing costs or increased debt levels to term out the short-term borrowings with medium-term notes, potentially increasing pressure on a company's financial profile.

However, some companies like Piedmont Natural Gas Co. Inc. (A/Stable/--) have actually begun the new year by requesting the North Carolina Utilities Commission to reduce the wholesale benchmark to calculate its retail rates from an approved $13 per thousand cubic feet (mcf) in December 2005 to $11 per mcf in January, and make the change effective as of Jan. 1, 2006. This unprecedented request is primarily

due to the recent decline in gas prices from peak highs in December 2005 of $15.78 per million Btu to about $7.20 per million Btu today. This represents an example of a working relationship between regulators and LDCs to contain high gas costs and customers' bills.

Weather protection
An LDC's ability to collect a consistent cash stream, regardless of a service territory's weather conditions, provides an important level of stability. Several warmer-than-normal winters or cooler-than-normal summers could significantly change an LDC's financial health unless regulators provide normalization measures. Such protection can be achieved via a normalization clause or rate design. Some jurisdictions such as New Jersey recognize the potential implications of adverse temperatures on unprotected LDCs and provide support accordingly. Other jurisdictions are not as accommodating. SEMCO Energy Inc. and Southwest Gas Corp. have seen their financial profiles weaken partially in response to significant adverse weather conditions.

The growing popularity of weather derivatives serves as an additional avenue for LDCs to pursue weather protection. Regulators that recognize these products as a way to reduce risk for LDCs and their ratepayers tend to allow for derivative cost pass-throughs and do not question the prudence of the strategy.

Earnings sharing
Mechanisms that mandate earnings sharing between shareholders and ratepayers compensate well run LDCs with a share of the profits when companies earn more than their allowed ROE. This gives management an incentive to make their companies' operations more efficient. Sharing also provides downside protection to shareholders and partially shields LDCs during troubled times by, in effect, requiring ratepayers to foot the bill for a portion of lost earnings. AGL Resources Inc., Cascade Natural Gas Corp., Northwest Natural Gas Co., and Southern Union Co. all benefit from earnings sharing in at least a portion of their respective service territories.

Allowed ROE
Like all other for-profit businesses, earning a healthy ROE helps drive success. Fairly set ROEs provide LDCs with capital for system maintenance, growth projects, and capital structure improvement.

Other regulatory mechanisms
Both regulators and LDCs are increasing customer-education programs on energy efficiency and conservation. Lawmakers, state regulators, and LDCs are in preliminary discussions to potentially restructure the current rate structures to encourage these goals of energy conservation and efficiency without hurting an LDC's bottom line and still allow companies to achieve their approved regulated rate of return. In essence, "conservation tariffs" would aim to decouple earnings and rates of return from delivered volumes and should eliminate a current major disincentive for utilities to develop such conservation programs. This would also better align the interest of consumers with utility shareholders by implementing innovative rate designs that would encourage energy conservation and efficiency.

Northwest Natural has a very constructive relationship with the Oregon Public Utility Commission (OPUC) that has resulted in favorable rate design and incentive programs. Northwest Natural is one of the few LDCs that operates under a conservation tariff that insulates its margins from a decline in gas usage levels. Northwest Natural also has a purchased-gas adjustment tariff under which 67% of any difference between actual gas costs and estimated costs (incorporated into rates) will be deferred and charged to customers in subsequent periods, providing protection against commodity price volatility. Finally, Northwest Natural also operates under a weather-normalization tariff that neutralizes 80% of the impact of varying weather patterns on a monthly basis without any dead bands. Oregon regulation also provides for a future test year for ratemaking purposes, thereby minimizing the potential for regulatory lag. All these measures provide for highly stable revenues and margins and contribute to Northwest Natural's solid and very low risk business profile of '1'.

Financial protection from affiliates
Earning a good return provides little benefit if the corporate entity squanders the proceeds. An LDC's credit quality suffers when parent or affiliate companies extract cash proceeds and invest in higher-risk businesses without producing commensurate returns. Regulatory restrictions preventing such dividend flow or mandating minimum equity layers buffer LDCs from more aggressive management teams. Northwest Natural benefits from strong regulatory oversight in Oregon that serves as a template for

protecting an LDC's financial interests. In Missouri, regulators have restricted Southern Union from further investment in Panhandle Eastern Pipe Line LLC subsequent to its significant acquisition of the pipeline from CMS Energy Corp. WGL Holdings Inc.'s LDC must gain prior approval from Virginia's regulators to provide intercompany loans to its parent or affiliates, thus contributing to its credit strength. These protective measures provide an added degree of comfort for bondholders.

Markets And Competition

Table 3

Markets and Competition Comparison

Company	Service territory growth (%)	Service territory saturation (%)	Customer mix* (%)
AGL Resources Inc.	1.5 to 2.5	N.A.	80 to 90
Cascade Natural Gas Corp.	> 2.5	< 60	< 80
New Jersey Natural Gas Co.	> 2.5	> 90	80 to 90
Nicor Inc.	1.5 to 2.0	> 90	< 80
Northwest Natural Gas Co.	> 2.5	< 60	80 to 90
ONEOK Inc.	< 1.5	> 90	> 90
People's Energy Corp.	> 2.5	< 60	80 to 90
Piedmont Natural Gas Co. Inc.	> 2.5	< 60	80 to 90
SEMCO Energy Inc.	1.5 to 2.0	60 to 90	< 80
South Jersey Gas Co.	> 2.5	60 to 90	80 to 90
Southern Union Co.	< 1.5	< 60	80 to 90
Southwest Gas Corp.	> 2.5	< 60	80 to 90
UGI Utilities Inc.	> 2.5	60 to 90	< 80
WGL Holdings Inc.	> 2.5	< 60	80 to 90

*Customer mix defined as residential and commercial margins as % of total gross margins. > -- Greater than. < -- Less than.

Service territory growth

High growth within a service territory due to population influx and new construction could lead to an LDC's greater profitability or rate stability. However, as evidenced by Southwest Gas' struggles, high growth sometimes cuts both ways. Arizona and Nevada benefit from rapid population growth, but the slow pace of regulatory rate adjustments acts as a drag on Southwest Gas' financial ratios because revenues fail to adequately compensate the LDC for its growth capital expenditures on a timely basis. Slower growth in Illinois, on the other hand, provides limited upside for companies, such as Nicor Gas Co. and Peoples Energy Corp., but alleviates the associated regulatory dependence faced by Southwest Gas.

Service territory saturation

Customer saturation refers to the proportion of customers in a given area that use their LDC's services. LDCs that operate in service territories with low growth potential still can grow at healthy rates if a relatively low level of customer saturation permeates the service territory. For example, customers who convert to natural gas from other fuel sources (such as oil) provide growth opportunities to LDCs operating in low population growth service areas. Northwest Natural benefits from its sub-50% saturation rate and good service territory growth, while Peoples Energy faces a disadvantageous combination of a relatively high saturation rate and low service territory growth.

Customer mix

An LDC serving a large proportion of industrial or wholesale customers faces greater instability than an LDC serving only residential customers. Nicor and Peoples Energy, for instance, serve a broad customer base consisting of many small retail users, as opposed to a few large industrial users, which reduces dependence on individual customers. LDCs that depend on the sustainability of a few key industrial users carry not only gas distribution risk, but also business risk associated with the large customers. Furthermore, large users often have greater financial incentive to switch to alternative fuel sources because of extreme input cost sensitivity in certain energy-intensive industries.

Protection against bypass

Due to their proximity to interstate gas pipelines, some large customers have the ability to directly tie into a

transmission line and completely bypass LDCs' services. Although such pipelines provide key sources of gas supply for LDCs, it is important to recognize this bypass risk. Ideally located LDCs have adequate transmission access but have industrial customers far from interstate pipelines.

Wealth demographics

A wealthy customer base reduces the risk of customer nonpayment and often translates into less resistance to distribution rate increases. Furthermore, wealthy customers are less sensitive to their marginal gas consumption, which can lead to higher usage. Suburban areas of New Jersey--outside of New York City and Philadelphia--offer examples of high-wealth customer concentrations that benefit the regional LDCs.

Operations

Supply position

Drawing from a single interstate pipeline or relying on a particular gas basin exposes LDCs to event risk and negative supply shocks, respectively. The ability to access multiple sources of gas supply through multiple pipelines protects LDCs from such disruptions. With its strategic location in Chicago, Ill., Peoples Energy has an ideal supply position. The company has direct interconnections to six major pipelines (Natural Gas Pipeline Co. of America, ANR Pipeline Co., Trunkline Gas Co., Midwestern Gas Transmission Co., Northern Border Pipeline Co., and Alliance Pipeline L.P.) and can draw gas from the Midcontinent, Gulf Coast, and Canada. The numerous pipeline connections allow the company to negotiate gas purchases and storage arrangements at competitive prices.

Storage position

Adequate storage access not only helps supply incremental gas needed to meet peak demand, but also provides opportunities for LDCs without purchased-gas adjustment clauses to arbitrage seasonal pricing fluctuations. LDCs benefit from storage if the cost of buying peak gas exceeds the cost of making off-season purchases and the associated carrying cost. Northwest Natural can meet more than 60% of peak demand with company-owned storage, leased storage, and recall agreements. Such storage has lowered the company's average commodity costs and allowed it to meet peak demand without having to pay for additional transportation costs.

System condition

Outdated systems requiring extensive maintenance and capital expenditures lower LDCs' profitability and efficiency metrics. Newly installed systems mainly consisting of plastic pipe require limited expenditures over the long term compared with older, cast-iron systems that need replacing as they age. In addition, LDCs generate operational efficiencies through the use of new technology. Technology allows Southwest Gas field employees to receive work orders without driving to the office in the morning and read meters without leaving their vehicles. Although often involving material upfront costs, such technological improvements provide significant long-term savings.

Hedging

LDCs can hedge against gas price volatility by using financial instruments and locking in long-term purchase contracts with its suppliers. The hedging of fixed-price purchases reduces exposure to physical market price volatility, preserves the value of storage inventories, and provides risk-management services to a variety of customers. Those companies that have locked in prices through long-term contracts, financial instruments, or both that are below the high average prices over the past three heating seasons have reduced their exposure to high gas prices. Many LDCs' hedging programs need to be preapproved by regulators. We view prudent, consistent hedging programs that have been preapproved by regulators as a credit strength. For example, Piedmont Natural Gas provides a hedging program, which requires preapproval by its regulators.

Management

As in all business segments, ownership structure, management practices, internal controls, corporate governance, and financial disclosure policies fall under the management umbrella and are all regularly examined as part of our ratings methodology for LDCs.

Within the ownership structure analysis, links to parent companies or affiliates are important considerations. Ownership by stronger or weaker parents substantially affects the rated entity's credit

quality. The nature of the owner--holding company or strategically linked business--can also hold significant implications for business and financial aspects of the rated entity. Standard & Poor's deems many LDCs to have the same creditworthiness as other entities within their corporate structure because of strategic linkages and the free flow of funds among the entities.

Assessment of management personnel and practices is an especially significant determinant of a rating. Standard & Poor's analysis considers many factors that pertain to management, including track record and competence, management background and reputation, and management depth and turnover. Business strategies that stray from core competencies, initiatives that bear elevated risk, and actions inconsistent with public or private statements detract from credit quality. We place a higher degree of confidence in management teams that possess significant industry experience, consistently meet or exceed forecast projections, and deal openly with pressing credit issues.

Financial disclosure and management oversight help round out the broader area of governance. Does an impartial board of directors help monitor critical decisions? Are all potential conflicts of interest disclosed in a timely manner? Are all SEC filings on time? The answers to these questions help provide intangibles to the rating process.

Rating Actions

There have been several adverse rating actions in the LDC universe over the past three to four heating seasons (36-40 months) for a variety of reasons, with 10 outlook revisions to negative, five CreditWatch placements with negative implications, and five downgrades. During 2005, there were two outlook revisions (one to negative from stable and one to stable from positive), one CreditWatch placement with negative implications, and one downgrade compared with only one upgrade that occurred in early January 2005. Thus far in 2006, there has been two rating actions, with a negative outlook revision from stable and a CreditWatch placement with negative implications, due to a combination of increased regulatory uncertainty and increased exposure to nonregulated activities.

These adverse rating actions have been due to some combination of the following:

- Sustained high leverage and weaker-than-expected credit protection measures,
- Increased exposure to, or investment in, nonregulated businesses,
- Increased debt-financed acquisitions or capital investments, and
- Weak regulatory mechanisms and support.

Conversely, the favorable rating actions during the past three heating seasons, which have been more modest, have consisted of three upgrades, one outlook revision to positive (which recently was revised back to stable in 2005), and two rating affirmations with an outlook revision to stable from negative. These positive rating actions have been attributable to:

- Increasing customer growth and improving cash flow and financial profile, while maintaining sound liquidity,
- Prudent financings by using a combination of debt and equity as well as the successful integration of acquisitions in certain cases, and
- Demonstrated strength of regulatory support and rate mechanisms during challenging, high natural gas price heating seasons.

The outlook for the LDC universe continues to have some negative pressures with eight out of the 14 rated LDCs possessing a negative outlook or CreditWatch with negative implications, and no company with a positive outlook. The remaining six LDCs have a stable outlook (two of which were recently downgraded in 2005). In general, the majority of the LDCs possess 'A' ratings, a stable outlook, or both which represent our general view of LDCs' cash-flow stability and low business risk profiles.

Nevertheless, current high gas prices will remain a challenge for all LDCs and may further pressure ratings for those LDCs that have a negative outlook and whose financial measures are somewhat stretched for their current ratings. In addition, management's financial policy and commitment to credit quality will also

play an integral role in a company's ability to manage and sustain its credit quality during a fourth consecutive heating season with a higher-than-average natural gas pricing environment.

Table 4

Financial Profile Comparison*

Company	FFO interest coverage (x)	FFO to total debt (%)	Net cash flow/capital expenditures (%)	Discretionary cash flow (mil. $)	Average return on capital 2002-2004 (%)	Total debt to total capital (%)
AGL Resources Inc.	5.0	18.4	86.7	(52.0)	10.5	59.2
Cascade Natural Gas Corp.	4.3	24.5	79.9	(18.3)	9.6	59.8
New Jersey Natural Gas Co.	7.0	19.1	87.3	(157.9)	12.4	56.6
Nicor Inc.	6.6	26.1	96.4	45.3	9.7	58.3
Northwest Natural Gas Co.	4.2	20.0	51.9	67.2	8.8	51.4
ONEOK Inc.	4.8	19.8	169.5	(148.5)	10.5	63.8
People's Energy Corp.	4.9	20.6	63.3	(66.6)	8.8	52.9
Piedmont Natural Gas Co. Inc.	3.8	16.4	58.1	(50.7)	10.9	47.8
SEMCO Energy Inc.	1.8	6.7	101.6	6.0	7.1	71.8
South Jersey Gas Co.	5.3	20.9	89.6	(15.3)	9.8	55.2
Southern Union Co.	3.4	12.3	96.0	(28.6)	2.9	55.0
Southwest Gas Corp.	3.6	18.0	70.3	(180.0)	7.1	66.8
UGI Utilities Inc.	3.5	21.4	204.8	67.8	13.0	65.6
WGL Holdings Inc.	5.5	26.4	131.4	66.4	10.0	46.8

*Financials as of fiscal year-end 2004. FFO--Funds from operations.

We expect many of these companies listed in the table above to either maintain or continue to gradually improve their financial profiles. Still, the outlook for six LDCs is negative. The negative outlook for Southern Union, Nicor Inc., and AGL primarily reflects their increased financial leverage and weakened credit protection measures and their respective near-term challenges to significantly improve their financial profiles. In addition, AGL's and UGI Utilities Inc.'s negative outlooks are also related to their increased exposure to nonregulated operations (i.e., energy marketing and propane business) increasing their business risk profiles and need to generate stronger financial measures commensurate with their respective ratings. Finally, the negative outlook on WGL reflects its absence of weather normalization and increased exposure to its retail energy marketing business, which could further reduce the company's current liquidity cushion.

Cascade Natural Gas has a positive outlook tied to its improving financial profile based on solid customer growth, a reliable purchased-gas adjustment mechanism that ensures full recovery of gas supply costs, and a manageable capital spending program that should allow the company to continue to meet its debt reduction plans in 2006.

The Credit Challenges Ahead

Regulators will always have to balance timely and prudent gas cost recovery with ratepayer resistance to rising gas bills. Continued regulatory support is paramount to credit quality for LDCs, especially during periods of prolonged high natural gas prices and the likely need for LDCs to fund working capital needs

with additional debt. LDCs will remain challenged in this elevated gas price environment to reduce short-term debt balances and avoid creeping debt leverage, which could trigger deterioration in credit quality.

Peoples energy is an example of how an uncertain and challenging regulatory environment can put pressure on a company's credit quality. In February 2006, Standard & Poor's revised the outlook on Peoples Energy to negative from stable due to the challenging regulatory climate in Illinois, which has become highly politicized as the historically supportive gas distribution regulation has become more contentious. In addition, the outlook revision also incorporated the company's continued increased investment in nonregulated diversified businesses, which include oil and gas production, power generation, midstream services, and retail energy services.

In the end, a company's business risk profile must be analyzed in conjunction with its financial risk profile (see table 4). Because investors in the LDC universe rely on stable cash flow, strong financial metrics may simply overpower chinks in the business profile armor. Nicor's stratospheric cash flow ratios drive the company's 'AA' rating despite average regulatory, market, and competition characteristics. Good financial metrics at New Jersey Natural Gas also support that company's strong rating.

More recently, Standard & Poor's has further scrutinized the financial profiles and overall liquidity for companies that have increased their exposure to nonregulated energy trading activities. For example, AGL's credit quality is tempered by the heavy liquidity requirements of its nonregulated businesses (primarily through its subsidiary Sequent, a gas marketing and trading company) and the company's growth strategy that could potentially increase its exposure to unregulated activities (see table 5).

Table 5

Diversified Activities Comparison

Company	Diversified activities as % of consolidated entity	Main areas of focus
AGL Resources Inc.	20	Wholesale and retail services
Cascade Natural Gas Corp.	Less than 5	Retail gas marketing to a small number of large customers
New Jersey Natural Gas Co.	22	Natural gas utility, energy marketing, and pipeline capacity management
Nicor Inc.	10	Shipping
Northwest Natural Gas Co.	9	Interstate gas storage
ONEOK Inc.	70	Gas gathering and processing; energy marketing and trading
Peoples Energy Corp.	10	Gas distribution
Piedmont Natural Gas Co. Inc.	10	Pipelines and retail gas marketing
SEMCO Energy Inc.	90	Propane and retail energy services
South Jersey Gas Co.	30	Natural gas utility, energy marketing, and marina energy (Borgata project in Atlantic City, N.J.)
Southern Union Co.	88	Natural gas pipelines; gas gathering and processing
Southwest Gas Corp.	Less than 10	Construction
UGI Utilities Inc.	50	Propane and retail energy services
WGL Holdings Inc.	2	Retail gas

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Rating Each Issue: Distinguishing Issuers and Issues

Standard & Poor's Ratings Services assigns two types of credit ratings—one to corporate issuers and the other to individual corporate debt issues (or other financial obligations). The first type is called a Standard & Poor's corporate credit rating. It is a current opinion on an issuer's overall capacity to pay its financial obligations—i.e., its fundamental creditworthiness. This opinion focuses on the issuer's ability and willingness to meet its financial commitments on a timely basis. It generally indicates the likelihood of default regarding all financial obligations of the company, because, in most countries, companies that default on one debt type or file under the Bankruptcy Code virtually always stop payment on all debt types. It does not reflect any priority or preference among obligations. In the past, we published the "implied senior-most rating" of corporate obligors—a different term for precisely the same concept. "Default risk rating" and "natural rating" are additional ways of referring to this issuer rating.

Generally, a corporate credit rating is published for all companies that have issue ratings—in addition to those companies that have no ratable issues, but request just an issuer rating. Where it is germane, both a local currency and foreign currency issuer rating are assigned.

Standard & Poor's also assigns credit ratings to specific issues. In fact, the vast majority of credit ratings pertain to specific debt issues. Issue ratings are a blend of default risk (sometimes referred to as "timeliness") and the recovery prospects associated with the specific debt being rated. Accordingly, junior

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debt is rated below the corporate credit rating. Preferred stock is rated still lower *(see "Preferred Stock")*. Well-secured debt can be rated above the corporate credit rating.

Recovery ratings were added in 2003. These ratings address only recovery prospects, using a scale of one to five, rather than the letter ratings.

Notching Down; Notching Up

The practice of differentiating issues in relation to the issuer's fundamental creditworthiness is known as "notching." Issues are notched up or down from the corporate credit rating level.

Payment on time as promised obviously is critical with respect to all debt issues. The potential for recovery in the event of a default—i.e., ultimate recovery, albeit delayed—also is important, but timeliness is the primary consideration. That explains why issue ratings are still anchored to the corporate credit rating. They are notched—up or down—from the corporate credit rating in accordance with established guidelines explained here.

As default risk increases, the concern over what can be recovered takes on greater relevance and, therefore, greater rating significance. Accordingly, the loss-given-default aspect of ratings is given more weight as one moves down the rating spectrum. For example, subordinated debt can be rated up to two notches below a noninvestment grade corporate credit rating, but one notch at most if the corporate credit rating is investment grade. In the same vein, the 'AAA' rating category need not be notched at all, while at the 'CCC' level the gaps may widen.

There is also an important distinction between notching up and notching down. Whenever a financial obligation is judged to have a materially worse recovery prospect than other debt of that issuer—by being unsecured, subordinated, or because of a holding-company structure—the issue rating is notched down. Thus, priority in bankruptcy is considered in broad, relative terms; there is no full-blown attempt to quantify the potential severity of loss. And, because the focus is relative to the various obligations of the issuer, no comparison between unsecured issues of different companies is warranted. For example, the fact that a senior issue of company A is not notched at all does not imply anything about its recovery prospects relative to the junior debt of company B—with the same corporate credit rating—which is notched down.

In contrast, issue ratings are not enhanced above the corporate credit rating unless a comprehensive analysis indicates the likelihood of full recovery—100% of principal—for that specific issue. The degree of confidence of full recovery that results from this more rigorous analysis is reflected in the extent to which the issue is notched up. If the analysis concludes that recovery prospects may be less than 100%, the issue is not deemed deserving of any rating enhancement, even though it can be valuable indeed to realize, say, 80% or 90% of one's investment and avoid a greater loss.

The entire notion of junior obligations—and the related difference it makes with respect to recovery prospects—is specific to the applicable legal system. Notching guidelines are, therefore, a function of the bankruptcy law and practice in the legal jurisdiction that governs a specific instrument. For example, distinguishing between senior and subordinated debt can be meaningless in India, where companies may be allowed to continue paying even common dividends at the same time they are in default on debt obligations; accordingly, notching is not applied in India. The majority of legal systems broadly follow the practices underlying Standard & Poor's criteria for notching—but it always is important to be aware of nuances of the law as they pertain to a specific issue.

Junior Debt: Notching Down

When a debt issue is judged to be junior to other debt issues of the company, and, therefore, to have relatively worse recovery prospects, that issue is assigned a lower rating than—i.e., it is "notched down" from—the corporate credit rating. As a matter of rating policy, the differential is limited to one rating designation in the investment-grade categories. For example, when the

corporate credit rating is 'A', junior debt may be rated 'A-'. In the speculative-grade categories, where the possibility of a default is greater, the differential is up to two rating designations.

Notching relationships are based on broad guidelines that combine consideration of asset protection and ranking. The guidelines are designed to identify material disadvantage for a given issue by virtue of the existence of better-positioned obligations. The analyst does not seek to predict specific recovery levels, which would involve knowing the exact asset mix and values at a point well into the future.

Notching relationships are subject to review and change when actual developments vary from expectations. Changes in notching do not necessarily have to be accompanied by changes in default risk.

Guidelines for Notching

To the extent that certain obligations have a priority claim on the company's assets, lower-ranking obligations are at a disadvantage because a smaller pool of assets will be available to satisfy the remaining claims. One case is when the issue is contractually subordinated—that is, the terms of the issue specifically provide that debt holders will receive recovery in a reorganization or liquidation only after the claims of other creditors have been satisfied. Another case is when the issue is unsecured, while assets representing a significant portion of the company's value collateralize secured borrowings.

A third form of disadvantage can arise if a company conducts its operations through an operating subsidiary/holding-company structure. In this case, if the whole group declares bankruptcy, creditors of the subsidiaries—including holders of even contractually subordinated debt—would have the first claim to the subsidiaries' assets, while creditors of the parent would have only a junior claim, limited to the residual value of the subsidiaries' assets remaining after the subsidiaries' direct liabilities have been satisfied. The disadvantage of parent-company creditors owing to the parent/subsidiary legal structure is known as "structural subordination." Even if the group's operations are splintered among many small subsidiaries, the individual debt obligations of which have only dubious recovery prospects, the parent-company creditors may still be disadvantaged compared with a situation in which all creditors would have an equal claim on the assets *(see table 1)*.

As a rough generic measure of asset availability, we look at the cumulative percentage of priority debt and other liabilities relative to all available assets. When this ratio reaches certain threshold levels, the next, more junior, debt is considered disadvantaged debt, and is rated one or two notches below the corporate credit rating. These threshold levels take into account that it normally takes more than $1 of book assets—as valued today—to satisfy $1 of priority debt. (In the case of secured debt—which limits the priority to the collateral pledged—the remaining assets are still less likely to be sufficient to repay the unsecured debt, inasmuch as the collateral ordinarily consists of the company's better assets and often substantially exceeds the amount of the debt.)

For investment-grade companies with a typical asset mix, the threshold is 20%. That is, if priority debt and liabilities equal 20%

Table 1—Investment-Grade Example

Corporate credit rating: 'A'

		Issue ratings
Assets $100	Priority debt $30	A
	Lower-priority debt $10	A-
	Equity $60	

The lower-priority debt is rated one notch below the corporate credit rating of 'A', because the ratio of priority debt to assets (30 to 100) is greater than 20%.

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or more of the company's assets, the lower-priority debt (unsecured, subordinated, or holding company) is rated one notch below the corporate credit rating *(see table 2)*.

If the corporate credit rating is speculative grade, there are two threshold levels. If priority obligations equal even 15% of the assets, the lower-priority debt is penalized one notch. When priority debt and other liabilities amount to 30% of the assets, lower-priority debt is substantially disadvantaged and is, therefore, differentiated by two notches.

The concept behind these thresholds is to measure material disadvantage with respect to the various layers of debt. At each level, as long as the next layer of debt still enjoys plenty of asset coverage, we do not consider the priority of the top layers as constituting a real disadvantage for the more junior issuers. Accordingly, the nature of the individual company's asset is important: If a company has an atypical mix of assets, the thresholds could be higher or lower to reflect the relative amounts of better or worse assets.

The relative size of the next layer of debt also is important. If the next layer is especially large—in relation to the assets assumed to remain after satisfying the more senior layers—then coverage is impaired. There are numerous LBOs financed with outsized issues just below the senior layers. Although the priority debt issues may be small (below the threshold levels), they pose a real disadvantage for the junior issues, given the paucity of coverage remaining—so the junior debt should be notched down.

Multiple Layers

A business entity can have many levels of obligations, each ranking differently with respect to priority of claim in a bankruptcy. For analytical purposes, debt levels are ranked as follows, from highest priority to lowest:

- Debt secured with higher-quality operating asset collateral;
- Debt secured with lesser-quality operating asset collateral;
- Lease obligations/securitizations;
- Senior debt of the operating company;
- Senior liabilities (ranked pari passu with senior debt);
- Subordinated debt;
- Junior subordinated debt;
- All other operating company liabilities;
- Senior debt of the holding company; and
- Subordinated debt of the holding company.

Once a notching threshold level is crossed—aggregating successive layers of priority claims—notching applies to the remaining, lower-ranking issues *(see chart 1)*.

The reason notching is constrained to one notch for investment-grade companies and two notches for speculative-grade companies is to maintain the important weighting of timeliness in all ratings. Remember, notching pertains only to differentiating recovery prospects: it is presumed a default will interrupt payment on all of a company's debt issues. The very highest-ranking issues receive the corporate credit rating, or sometimes a higher rating, if full recovery is confidently expected; the lowest-ranking issues will never be rated lower than one notch under the investment-grade corporate credit rating, or two notches in the case of noninvestment-grade corporate credit ratings.

This rating convention often results in debt issues of significantly different standing being rated the same. If, for example, a two-notch

Table 2—Speculative-Grade Example

Corporate credit rating: 'BB+'

		Issue ratings
Assets $100	Priority debt $35	BB+
	Lower-priority debt $20	BB-
	Equity $45	

The lower-priority debt is rated two notches below the corporate credit rating of 'BB+', because the ratio of priority debt to assets (35 to 100) is greater than 30%.

distinction is indicated for a senior subordinated issue, that issue and the worse-positioned issues at the holding company are all rated at the same two-notch gap relative to the corporate rating. No distinction is made to highlight the differences between junior issues *(see table 3)*.

Senior Secured Debt

Not all senior secured debt of an issuer is necessarily equally secured. Second-mortgage debt, for example, has only a junior claim to an asset also securing first-mortgage debt, making it inferior to a first-mortgage issue secured by the same asset. The second-mortgage debt issue would receive the corporate credit rating only if the amount of first-mortgage debt outstanding was sufficiently small relative to the assets.

In general, secured debt is notched according to the expected recovery associated with its specific collateral *(see "Bank Loan Methodology" and "Recovery Ratings")*. If the collateral that secures a particular debt issue is of dubious value, while the more valuable collateral is pledged to another loan, even secured debt may be notched down from the corporate credit rating.

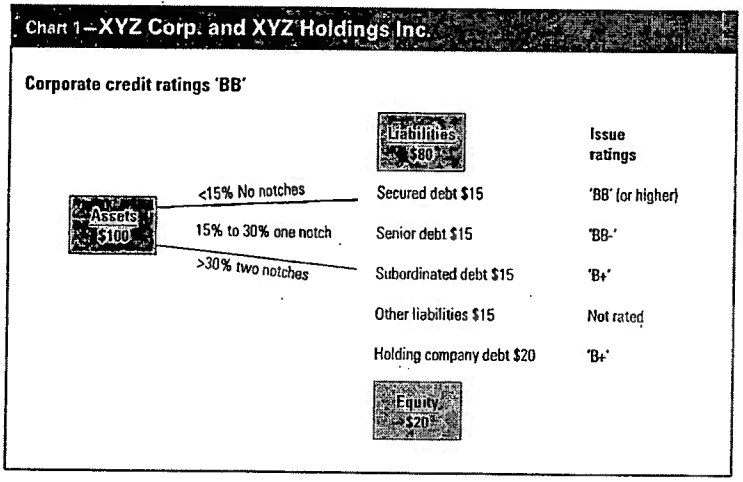
Application of Guidelines

- *Perspective.* Notching takes into account expected future developments. For example, a company may be in the process of refinancing secured debt so that it would have little or no secured debt within a year. If there is confidence that the plan will be carried out, a notching differential should not be needed, even currently. Conversely, if companies have open first-mortgage indentures or the leeway to increase secured borrowings under negative pledge covenants (or if no negative pledge covenants are in place), Standard & Poor's attempts to determine the likelihood that the company will incur additional secured borrowings. But the analyst would not automatically base notching on the harshest assumptions.

If an issuer has a secured bank credit facility, such borrowings would be reflected in notching to the extent that the issuer was expected to draw on the facility. Typically, as a company approaches a financial crisis, it will need to tap its sources of financing. In the absence of expectations to the contrary, Standard & Poor's takes a conservative approach, assuming available bank borrowing capacity is fully utilized. Likewise, if a company typically uses bank borrowings to fund seasonal working capital requirements, we focus on expected peak borrowing levels, rather than the expected average amount.

- *Adjustments.* Book values are used as a starting point; analytic adjustments are made if assets are considered significantly overvalued or undervalued for financial accounting purposes. This analysis focuses on the varying potential of different types of assets to retain value over time and in the default context based on their liquidity characteristics, special-purpose nature, and dependence on the health of the company's business. Goodwill especially is suspect, considering its likely value in a default scenario. In applying the notching guidelines, Standard & Poor's generally eliminates from total assets goodwill in excess of a "normal" amount—10% of total assets. The particular characteristics of specific intangibles, as distinct from goodwill, are considered. (For example, some credit typically is given for the enduring value of well-established brands in the consumer products sector.) We do not, however, perform detailed asset appraisals or attempt to postulate specifically about how market

Chart 1—XYZ Corp. and XYZ Holdings Inc.



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values might fluctuate in a hypothetical stress scenario (except in the case of secured debt).

In applying the guidelines above, lease obligations—whether capitalized in the company's financial reporting or kept off balance sheet as operating leases as priority debt—and the related assets are included on the asset side. Similarly, sold trade receivables and securitized assets are added back, along with an equal amount of priority debt. Other creditors are just as disadvantaged by such financing arrangements as by secured debt. In considering the surplus cash and marketable securities of companies that presently are financially healthy, Standard & Poor's assumes neither that the cash will remain available in the default scenario, nor that it will be totally dissipated, but rather that, over time, this cash will be reinvested in operating assets that mirror the company's current asset base, subject to erosion in value of the same magnitude.

- *Local- and foreign-currency issue ratings.* In determining local-currency issue ratings, the point of reference is the local-currency corporate credit rating: local-currency issue ratings may be notched down one notch from the local-currency corporate credit rating in the case of investment-grade issuers, or one or two notches in the case of speculative-grade issuers. A company's foreign-currency corporate credit rating is often lower than its local-currency corporate credit rating, reflecting the risk that a sovereign government could take actions that would impinge on the company's ability to meet foreign-currency obligations. But junior foreign-currency issues are not notched down from the foreign-currency corporate credit rating, because the government action would apply regardless of the senior/junior character of the debt. Of course, the issue would never be rated higher than if it had been denominated in local currency. For example, if a company's local-currency corporate credit rating were 'BB+' and its foreign-currency corporate credit rating were 'BB-', subordinated foreign currency-denominated issues could be rated 'BB-'. But, if a company's local-currency corporate credit rating were 'BB+' and its foreign currency corporate credit rating were 'BB', subordinated foreign-currency denominated issues would be rated 'BB-', as would subordinated local-currency denominated issues. *(See chart 1).*
- *Short-term ratings.* All short-term ratings, including commercial paper ratings, are linked to the issuer's corporate credit rating. Although commercial paper generally is unsecured, commercial paper ratings focus exclusively on default risk. For example, if an issuer has an 'A' corporate credit

Table 3—Speculative-Grade Example

Corporate credit rating: 'BB+'

		Issue ratings
Assets $100	Priority debt $25	BB+
	Lower-priority debt $15	BB
	Equity $60	

"Here, assuming the issuer was speculative grade, the lower-priority debt might be rated one notch below the corporate credit rating, rather than two notches, although the ratio of priority debt to assets (25 to 100) is close enough to the guideline threshold of 30% to make this a borderline case."

		Issue ratings
Assets $100	Priority debt $25	BB+
	Lower-priority debt $30	BB-
	Equity $45	

In this case, the lower-priority debt should be rated two notches below the corporate credit rating. Although the ratio of priority debt to assets is still 25 to 100, the substantial amount of lower-priority debt would dilute recoveries for all lower-priority debtholders.

rating and secured debt issue rating, and an 'A-' unsecured rating, its commercial paper rating would still be 'A-1'—the commercial paper rating associated with the 'A' issuer default rating—not 'A-2', the commercial paper rating ordinarily appropriate at the 'A-' default risk rating level.

Parents and Subsidiaries: Structural Subordination

At times, a parent and its affiliate group have distinct default risks. The difference in risk may arise from covenant restrictions, regulatory oversight, or other considerations. This is the norm for holding companies of insurance operating companies and banks. In such situations, there are no fixed limits governing the gaps between corporate credit ratings of the parent and its subsidiaries. The holding company has higher default risk, apart from post-default recovery distinctions. If such a holding company issued both senior and junior debt, its junior obligations would be notched relative to the holding company's corporate credit rating by one or two notches.

Often, however, a parent holding company with one or more operating companies is viewed as a single economic entity. When the default risk is considered the same for the parent and its principal subsidiaries, they are assigned the same corporate credit rating. Yet, in a liquidation, holding-company creditors are entitled only to the residual net worth of the operating companies remaining after all operating company obligations have been satisfied.

Parent-level debt issues are notched down to reflect structural subordination when the priority liabilities create a material disadvantage for the parent's creditors, after taking into account all mitigating factors. In considering the appropriate rating for a specific issue of parent-level debt, priority liabilities encompass all third-party liabilities (not just debt) of the subsidiaries—including trade payables, pension and retiree medical liabilities, and environmental liabilities—and any relatively better-positioned parent-level liabilities. (For example, parent-level borrowings collateralized by the stock of the subsidiaries would be disadvantaged relative to subsidiary liabilities, but would rank ahead of unsecured parent-level debt.)

Potential mitigating factors include:

- *Guarantees.* Guarantees by the subsidiaries of parent-level debt (i.e., upstream guarantees) may overcome structural subordination by putting the claims of parent company creditors on a pari passu basis with those of operating company creditors. Such guarantees have to be enforceable under the relevant national legal system(s), and there most be no undue concern regarding potential allegations of fraudulent conveyance *(see "Upstream Guarantees")*. Although joint and several guarantees from all subsidiaries provide the most significant protection, several guarantees by subsidiaries accounting for a major portion of total assets would be sufficient to avoid notching of parent debt issues in most cases.
- *Operating assets at the parent.* If the parent is not a pure holding company, but rather also directly owns certain operating assets, this gives the parent's creditors a priority claim to the parent-level assets. This offsets, at least partially, the disadvantage that pertains to being structurally subordinated with respect to the assets owned by the subsidiaries.
- *Diversity.* When the parent owns multiple operating companies, more liberal notching guidelines may be applied to reflect the benefit the diversity of assets might provide. The threshold guidelines are relaxed (but not eliminated) to correspond with the extent of business and/or geographic diversification of the subsidiaries. For bankrupt companies that own multiple, separate business units, the prospects for residual value remaining for holding company creditors improve as individual units wind up with shortfalls and surpluses Also, holding companies with diverse businesses—in terms of product or geography—have greater opportunities for dispositions, asset transfers, or recapitalization of subsidiaries. If, however, the subsidiaries are operationally integrated, economically correlated, or regulated, the

company's flexibility to reconfigure is more limited.

- *Concentration of debt.* If a parent has a number of subsidiaries, but the preponderance of subsidiary liabilities are concentrated in one or two of these, e.g., industrial groups having finance or trading units, this concentration of liabilities can limit the disadvantage for parent-company creditors. Although the net worth of the leveraged units could well be eliminated in the bankruptcy scenario, the parent might still obtain recoveries from its relatively unleveraged subsidiaries. In applying the notching guideline in such cases, it may be appropriate to eliminate the assets of the leveraged subsidiary from total assets, and its liabilities from priority liabilities. (The analysis then focuses on the assets and liabilities that remain, but the standard notching guideline must be substituted by other judgments regarding recovery prospects.) However, to the extent the company is viewed as one consolidated entity, the presumption that the healthier subsidiaries would remain healthy is questionable. This also would dilute the value of guarantees from individual subsidiaries.
- *Downstream loans.* If the parent's investment in a subsidiary is not just an equity interest, but also takes the form of downstream senior loans, this may enhance the standing of parent-level creditors because they would have not only a residual claim on the subsidiary's net worth, but also a debt claim that would generally be pari passu with other debt claims. Standard & Poor's gives weight to formal, documented

Table 4—Single Economic Entity Example

Parent—corporate credit rating: 'BB+'	
Debt type*	Issue rating
Senior secured	BB-
Senior unsecured	BB-
Subordinated	BB-
Subsidiary—corporate credit rating: 'BB+'	
Debt type*	Issue rating
Senior secured	BB+
Senior unsecured	BB
Subordinated	BB-
Different Default Risk Example	
Parent—corporate credit rating: 'BB+'	
Debt type*	Issue rating
Senior secured	BB+
Senior unsecured	BB
Subordinated	BB-
Subsidiary—corporate credit rating: 'B+'	
Debt type*	Issue rating
Senior secured	B+
Senior unsecured	B
Subordinated	B-

*Debt types are used here merely as illustrative of typical results for different priority debt; notching actually depends on the guidelines explained above. In the first example, because the parent and subsidiary are viewed as having the same default risk, the lowest rating at either is two notches below the single corporate credit rating. If the parent is a holding company without assets other than its ownership interest in the subsidiary, the parent's debt is viewed as junior and notched down. In contrast, in the second example, the parent and subsidiary are viewed as having different default risks, so each has a different corporate credit rating (assumed to be 'BB+' at the parent and 'B+' at the subsidiary), and the two-notch limit is relative to the corporate credit ratings at each entity: there is no limit on the span of ratings that applies across the two legal entities.

loans—not to informal advances, which are highly changeable. (On the other hand, if the parent has borrowed funds from its subsidiaries, the resulting intercompany parent-level liability could further dilute the recoveries of external parent-level creditors.) As with guarantees, the assessment of downstream advances must take into account the applicable legal framework.

- *Adjustments.* Additional adjustments are necessary in assessing structural subordination. We eliminate from the notching calculations subsidiaries' deferred tax assets and liabilities and other accounting accruals and provisions that are not likely to have clear economic meaning in a default *(see table 4)*.

Exceptions to the Rule

If the recovery prospects for a specific junior issue equate to the level associated with senior debt generally, notching is dispensed with. As long as recovery of 80 cents on the dollar reasonably can be anticipated, the junior debt is not notched below the senior debt.

Only a handful of rated junior issues provide for such good recovery prospects. In each case, the junior debt is secured, and the value of the assets that serve as collateral is independent of the fate of the issuer. As in all cases of secured debt, the specific collateral is subjected to analysis of its recovery prospects.

With respect to these and similar cases, we do not presume any specific level of recovery for the senior creditors of the company in question. The senior debt could still, in the end, fare better than the collateralized subordinated issue. The key: As long as the subordinated debt should recover as much as the vast majority of defaulted senior debt, it is not discernibly disadvantaged and does not deserve to be notched down. After all, recovery of 75%-85% would compare favorably with that experienced by roughly three-quarters of senior creditors.

Note that it is not necessary to conclude that holders will be made whole to eliminate the notching down of subordinated obligations. Obligations that are likely to provide full ultimate recovery are rated above the corporate credit rating *(see "Notching Up")*.

Upstream Guarantees

When a subsidiary guarantees the debt of its parent, it commonly is referred to as an upstream guarantee. The object of the exercise is to address the structural subordination that would otherwise apply to parent-company debt if the debt, liabilities, and preferred stock of the operating company are material. Upstream guarantees, if valid, eliminate the rating distinction, since the operating company becomes directly responsible for the guaranteed parent debt. However, the validity of the guarantee is subject to legal risk. An upstream guarantee may be voided in court, if it is deemed to constitute a fraudulent conveyance. The outcome depends on the specific fact pattern, not legal documentation—so one cannot standardize the determination. But, if either the guarantor company received value or was solvent for a sufficiently long period subsequent to issuing the guarantee, the upstream guarantee should be valid. Accordingly, we consider upstream guarantees valid if any of these conditions are met:

- The proceeds of the guaranteed obligation are provided to (downstreamed to) the guarantor. It does not matter whether the issuer downstreams the money as an equity infusion or as a loan. Either way, the financing benefits the operations of the subsidiary, which justifies the guarantee;
- The legal risk period—ordinarily, one or two years from entering into the guarantee—has passed;
- There is a specific analytical conclusion that there is little default risk during the period that the guarantee validity is at risk; or
- The rating of the guarantor is at least 'BB-' in jurisdictions that involve a two-year risk, or at least 'B+' in jurisdictions with one-year risk.

Accordingly, there will be cases where we decline to recognize the upstream guarantee at the time of issuance—because of legal risk—but would upgrade the issue a year (or two) later. Standard & Poor's accepts an upstream guarantee whenever the guar-

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antor obtained value. As long as the guarantor is the recipient of the funds, it meets this test.

Well-Secured Debt: Notching Up

In 1996, Standard & Poor's first published its framework for weighting both timeliness and recovery prospects in a default or bankruptcy scenario when assigning ratings to well-secured debt. The extent of any rating enhancement depends on the following three considerations:

Economics

Will the "second way out" provide 100% recovery? Of principal only, or interest, as well? When the collateral value exceeds the amount of the claim, the creditor could receive postpetition interest. Managing the legal nuances of bankruptcy would be an important aspect of achieving postpetition interest. Although accurately predicting this outcome is extremely difficult, the criteria recognize the potential for such payment. (If all accrued interest, from before and after the default, can be recovered, the length of any delay in recovery is less consequential.)

There can be different degrees of confidence with respect to recovery. For example, excess collateral translates into a greater likelihood that there will be enough value to recover the entire obligation—although obviously, the creditor will never get more than the obligation amount. Subjective judgments are critical in deciding how to stress collateral values in hypothetical postdefault scenarios.

How long will the delay be?

The time it takes to realize ultimate recovery of the loan obligation can be critical. At best, the recovery would be highly valued because of its nearly timely character—almost like a grace period. At worst, we would not give any credit for a very delayed payment. In estimating the length of any delay in recovery, the analysis would focus on:

- *How the legal system resolves bankruptcies or provides access to collateral.* This varies by legal jurisdiction. In the U.S., 18 to 24 months typically is needed to resolve a Chapter 11 filing. (The analysis would identify and differentiate cases that might take longer than usual because of perceived complexities, such as litigation.) In jurisdictions that are more creditor-oriented, the access to collateral may be expedited.
- *The structure of an obligation.* The analysis could distinguish between a bond, a lease obligation, and certificates governed by Section 1110 of the U.S. Bankruptcy Code, which provides specific legal rights to obtain certain transportation assets during a bankruptcy proceeding.
- *The terms of an obligation.* For example, in the case of a guarantee that provided for ultimate—but not necessarily timely—payment, it would be important to know within what period payment must be made.

Weighting

The higher the rating, the more weight one should give to timeliness; the lower the rating, the more it should incorporate a postdefault perspective. (This principle is the basis for the policy of rating junior debt of investment-grade issuers one notch below the issuer credit rating, but differentiating junior debt of speculative-grade borrowers by two notches.) Therefore, the degree of rating enhancement generally depends on the starting point—i.e., the level of the issuer credit rating.

Guidelines for notching

To get even one notch above the corporate rating, a debt issue must have at least reasonable prospects for full recovery. As the prospects improve, based on the nature and/or amount of the collateral, another notch may be added. If the analysis indicates great confidence in full recovery, three or four notches are possible. This reflects the highest expectations for full recovery, following more rigorous stressing of collateral values in various scenarios. This level of strong collateral protection ordinarily would imply decent prospects for recovering post-petition interest, as well.

These guidelines pertain to the speculative-grade portion of the rating spectrum. At the upper end, notching generally is less generous. For example, in the case of first mortgage bonds of investment-grade companies, it

takes greater enhancement to achieve the same notch or two.

With respect to short-term ratings, timeliness of payment is paramount. Accordingly, there is no enhancement of short-term ratings based on ultimate recovery.

To reiterate, the policy of enhancing issue ratings based on ultimate recovery prospects applies only if the expected recovery is 100%. Standard & Poor's does not attempt to differentiate unsecured debt, even though some defaults will result in recovery of 80 cents on the dollar, and others will result in only 30 cents.

Commercial Paper

Commercial paper (CP) consists of unsecured promissory notes issued to raise short-term funds. CP ratings pertain to the program established to sell such notes. There is no review of individual notes. Typically, only companies of strong credit standing can sell their paper in the money market, although there periodically is some issuance of lesser-quality, unrated paper (notably, prior to the junk bond market collapse late in 1989). Alternatively, companies sell commercial paper backed by letters of credit (LOC) from banks. Credit quality of such LOC-backed paper rests entirely on the transaction's legal structure and the bank's creditworthiness. As long as the LOC is structured correctly, credit quality of the direct obligor can be ignored.

Rating criteria

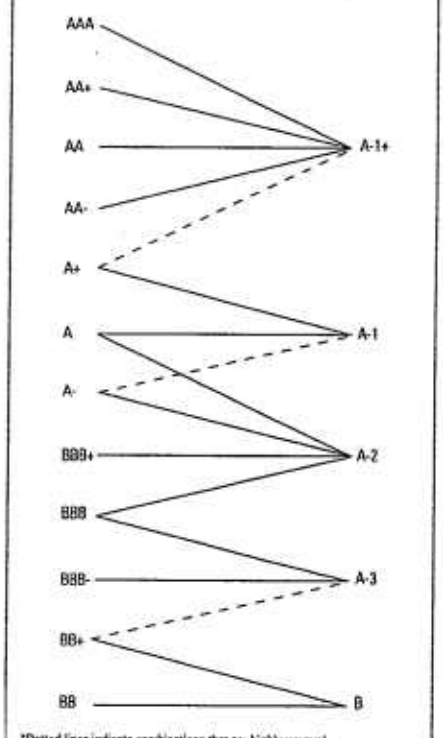
Evaluation of an issuer's commercial paper reflects Standard & Poor's opinion of the issuer's fundamental credit quality. The analytical approach is virtually identical to the one followed in assigning a long-term corporate credit rating, and there is a strong link between the short-term and long-term rating systems *(see chart 2)*.

Indeed, the time horizon for CP ratings is not a function of the typical 30-day life of a commercial-paper note, the 270-day maximum maturity for the most common type of commercial paper in the U.S., or even the one-year tenor typically used to determine which instrument gets a short-term rating in the first place.

To achieve an 'A-1+' CP rating, the company's credit quality must be at least the equivalent of an 'A+' long-term corporate credit rating. Similarly, for commercial paper to be rated 'A-1', the long-term corporate credit rating would need to be at least 'A-'. (In fact, the 'A+'/'A-1+' and 'A-'/'A-1' combinations are rare. Ordinarily, 'A-1' CP ratings are associated with 'A+' and 'A' long-term ratings.)

Conversely, knowing the long-term rating will not fully determine a CP rating, considering the overlap in rating categories. However, the range of possibilities is always narrow. To the extent that one of two CP ratings might be assigned at a given level of long-term credit quality (e.g., if the long-term rating is 'A'), overall strength of the credit within the rating category is the main

Chart 2—Correlation of CP Ratings with Long-Term Corporate Credit Ratings*



*Dotted lines indicate combinations that are highly unusual.

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consideration. For example, a marginal 'A' credit likely would have its commercial paper rated 'A-2', whereas a solid 'A' would almost automatically receive an 'A-1'.

Exceptional short-term credit quality would be another factor that determines which of two possible CP ratings are assigned. For example, a company may possess substantial liquidity—providing protection in the near or intermediate term—but suffer from less-than-stellar profitability, a longer-term factor. Or, there could be a concern that, over time, the large cash holdings may be used to fund acquisitions. (Having different time horizons as the basis for long- and short-term ratings implies either one or the other rating is expected to change.)

Backup policies

Ever since the Penn Central bankruptcy roiled the commercial-paper market and some companies found themselves excluded from issuing new commercial paper, Standard & Poor's has deemed it prudent for companies that issue commercial paper to make arrangements in advance for alternative sources of liquidity. This alternative, backup liquidity protects companies from defaulting if they are unable to roll over their maturing paper with new notes, because of a shrinkage in the overall commercial-paper market or some cloud over the company that might make commercial-paper investors nervous. Many developments affecting a single company or group of companies—including bad business conditions, a lawsuit, management changes, a rating change—could make commercial-paper investors flee the credit.

Given the size of the commercial-paper market, backup facilities could not be relied on with a high degree of confidence in the event of widespread disruption. A general disruption of commercial-paper markets could be a highly volatile scenario, under which most bank lines would represent unreliable claims on whatever cash would be made available through the banking system to support the market. Standard & Poor's neither anticipates that such a scenario is likely to develop, nor assumes that it never will.

Having inadequate backup liquidity affects both the short- and long-term ratings of the issuer because it could lead to default, which would ultimately pertain to all of the company's debt. Moreover, the need for backup applies to all confidence-sensitive obligations, not just rated commercial paper. Backup for 100% of rated commercial paper is meaningless if other debt maturities—for which there is no backup—coincide with those of the commercial paper. Thus, the scope of backup must extend to euro-denominated commercial paper, master notes, and short-term bank notes.

The standard for industrial and utility issuers has long been 100% coverage of confidence-sensitive paper for all but the strongest credits. Backup is provided by excess liquid assets or bank facilities in an amount that equals all such paper outstanding.

While the backup requirement relates only to outstanding paper—rather than the entire program authorization—a company should anticipate prospective needs. For example, it may have upcoming maturities of long-term debt that it may want to refinance with commercial paper, which would then call for backup of greater amounts.

Available cash or marketable securities are ideal to provide backup. (Of course, it may be necessary to "haircut" their apparent value to account for potential fluctuation in value or tollgate taxes surrounding a sale. And it is critical that they be immediately saleable.) Yet the vast majority of commercial paper issuers rely on bank facilities for alternative liquidity.

This high standard for back-up liquidity has provided a sense of security to the commercial-paper market—even though backup facilities are far from a guarantee that liquidity will, in the end, be available. For example, a company could be denied funds if its banks invoked "material adverse change" clauses. Alternatively, a company in trouble might draw down its credit line to fund other cash needs, leaving less-than-full coverage of paper outstanding, or issue paper beyond the expiration date of its lines.

Companies rated 'A-1+' can provide 50%-75% coverage. The exact amount is determined by the issuer's overall credit strength and its access to capital markets. Current credit quality is an important consideration in two respects. It indicates:

- The different likelihood of the issuer's ever losing access to funding in the commercial-paper market; and
- The timeframe presumed necessary to arrange funding should the company lose access. A higher-rated entity is less likely to encounter business reverses of significance and—in the event of a general contraction of the commercial-paper market—the higher-rated credit would be less likely to lose investors. In fact, higher-rated companies could actually be net beneficiaries of a flight to quality.

In 1999, Standard & Poor's introduced a new approach that offers companies greater flexibility regarding the amount of backup they maintain, if they are prepared to match their maturities carefully with available liquidity. The new approach differentiated between companies that are rolling over all their commercial paper in just a few days and those that have a cushion by virtue of having placed longer-dated paper. The basic idea was that companies—if and when they lose access to commercial paper—should have sufficient liquidity to cover any paper coming due during the time they would require to arrange additional funding.

However, companies encountered practical difficulties in implementing the new approach. Moreover, changes in the banking environment have since made us more leery about a company arranging new facilities when under stress. Still, notes that come due only 11-12 months from now do not require backup so far in advance. Companies should begin to actively arrange liquidity backup approximately six months prior to maturity. Similarly, 12-month notes that automatically extend their maturity month by month do not require back-up arrangements from day one. They will be able to arrange backup when and if the extensions stop, leaving a full 12 months to do so *(see table 5)*.

Extendible commercial notes (ECN) provide built-in backup by allowing the issuer to extend for several months if there is difficulty in rolling over the notes; accordingly, there is no need to provide backup for them—i.e., until the extension is effected. However, there is no way to prevent the issuer from tapping backup facilities intended for other debt and use the funds to repay maturing ECNs, instead of extending. This risk is known as leakage. Accordingly, for issuers that provide 100% backup, unbacked ECNs must not exceed 20% of extant backup for outstanding conventional commercial paper.

All issuers—even if they provide 100% backup—must always ensure that the first few days of upcoming maturities are backed with excess cash or funding facilities that provide for immediate availability.

For example, a bank backup facility that requires two-day notification to draw down will be of no use in repaying paper maturing in the interim. The same would hold true if foreign exchange is needed, and the facility requires a few days to provide it. Moreover, if a company issuing commercial paper in the U.S. were relying on a bank facility in Europe, differences in time zones or bank holidays could prevent availability when needed. Obviously, a bank facility in

Table 5—Guidelines for U.S. Industrials and Utilities

	% of total outstanding
A-1+/AAA	50
A-1+/AA	75
A-1	100
A-2	100
A-3	100

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the U.S. would be equally lacking with respect to maturing euro-denominated commercial paper. So-called "swing lines" typically equal 15%-20% of the program size to deal with the maximum amount that will mature in any three- to four-day period.

Quality of backup facilities

Banks offer various types of credit facilities that differ widely regarding the degree of the bank's commitment to advance cash under all circumstances. Weaker forms of commitment, while less costly to issuers, provide banks great flexibility to redirect credit at their own discretion. Some lines are little more than an invitation to do business at some future date.

Standard & Poor's expects all backup lines to be in place and confirmed in writing.

Preapproved lines or orally committed lines are viewed as insufficient. Specific designation for commercial-paper backup is of little significance.

Contractually committed facilities are desirable. In the U.S., fully documented revolving credits represent such contractual commitments. The weaker the credit, the greater the need for more reliable forms of liquidity. As a general guideline, if contractually committed facilities cover 10-15 days' upcoming maturities of outstanding paper, that should suffice.

Even contractual commitments often include "material adverse change" clauses, allowing the bank to withdraw under certain circumstances. While inclusion of such an escape clause weakens the commitment, Standard & Poor's does not consider it critical—or realistic—for most borrowers to negotiate removal of "material adverse change" clauses.

In the absence of a contractual commitment, payment for the facility—whether by fee or balances—is important because it generally creates some degree of moral commitment on the part of the bank. In fact, a solid business relationship is key to whether a bank will stand by its client. Standardized criteria cannot capture or assess the strength of such relationships. We therefore are interested in any evidence—subjective as it may be—that might demonstrate the strength of an issuer's banking relationships. In this respect, the analyst is also mindful of the business cultures in different parts of the world and their impact on banking relationships and commitments.

Dependence on just one or a few banks also is viewed as an unwarranted risk. Apart from the potential that the bank will not have adequate capacity to lend, there is the chance it will not be willing to lend to this issuer. Having several banking relationships diversifies the risk that any bank will lose confidence in this borrower and hesitate to provide funds.

Concentration of banking facilities also tends to increase the dollar amount of an individual bank's participation. As the dollar amount of the exposure becomes large, the bank may be more reluctant to step up to its commitment. In addition, the potential requirement of higher-level authorizations at the bank could create logistical problems with respect to expeditious access to funds for the issuer. On the other hand, a company will not benefit if it spreads its banking business so thinly that it lacks a substantial relationship with any of its banks.

There is no analytical distinction to be made between a 364-day and a 365-day facility.

Even multiyear facilities will provide commitment for only a short time as they approach the end of their terms. It obviously is critical that the company arrange for the continuation of its banking facilities well in advance of their lapsing.

It is important to reiterate that even the strongest form of backup—a revolver with no "material adverse change" clause—does not enhance the underlying credit and does not lead to a higher rating than indicated by the company's own creditworthiness. Credit enhancement can be accomplished only through an LOC or another instrument that unconditionally transfers the debt obligation to a higher-rated entity.

Banks providing issuers with facilities for backup liquidity should themselves be sound. Possession of an investment-grade rating indicates sufficient financial strength for the purpose of providing a commercial-paper issuer with a reliable source of funding. There is no requirement that the bank's credit rating equal the CP issuer's rating.

Nonetheless, Standard & Poor's would look askance at situations where most of a company's banks were only marginally investment grade. That would indicate an imprudent reliance on banks that might deteriorate to weaker, non-investment-grade status.

Documentation for Commercial-Paper Program ratings

- Company letter requesting rating;
- Copy of board authorization for program;
- Indication of authorized amount;
- Indication of program type (e.g., 3(A)3, 4(2), ECN, euro);
- Description of use of proceeds;
- Listing of dealers (unless company is a direct issuer); and
- Description of backup liquidity (including list of bank lines, giving the terms of the facilities, the name of each bank participating, the commitment amount, and the form of the commitment).

Accordingly, we believe the tenor of any backup facility with a hard maturity needs to be at least 180 days. The rating level of the company while it is still issuing commercial paper is not a consideration.

Preferred Stock

Preferred stock carries greater credit risk than debt in two important ways: The dividend is at the discretion of the issuer, and the preferred represents a deeply subordinated claim in the event of bankruptcy. Prior to 1999, Standard & Poor's used a separate preferred stock scale. In February 1999, the debt and preferred stock scales were integrated. Accordingly, now, preferred stock generally is rated below subordinated debt. When a company's corporate credit rating is investment grade, its preferred stock is rated two notches below the corporate credit rating. For example, if the corporate credit rating is 'A+', the preferred stock would be rated 'A-'. (In case of a 'AAA' corporate credit rating, the preferred stock would be rated 'AA+'.) When the corporate credit rating is non-investment grade, the preferred stock is rated at least three notches (one rating category) below the corporate credit rating. Deferrable payment debt is treated identically to preferred stock, given subordination and the right to defer payments of interest.

Financial instruments that have one of these characteristics, but not both (for example, deferrable debt with a senior claim), generally are rated one notch below the corporate credit rating for investment grade credits, and two notches below for speculative grade credits.

There are situations in which the dividend is especially jeopardized, so notching would exceed the guidelines above. For example, state charters restrict payment when there is a deficit in the equity account. This can occur following a write-off, even while the company is healthy and possesses ample cash to continue paying. Similarly, covenants in debt instruments can endanger payment of dividends, even while there is a capacity to pay. Also when there is an unusually large dividend burden, there is greater risk to that dividend. If preferred issues total over 20% of the company's capitalization, it normally would call for greater differentiation of the preferred rating from the corporate credit rating.

On the other hand, the right to defer can in some instances be constrained by virtue of financial covenants. In others, the discretion to defer is limited by the remedy that preferred holders possess to take over the issuing entity and liquidate its assets. Note, however, that such situations are exceptional and normally pertain to negotiated, privately placed transactions. Yet there do exist a handful of preferred issues that are rated pari passu with the company's debt (in some cases, senior debt). In all cases, the risk of deferral of payments is analyzed from a pragmatic, rather than a legal, perspective.

If a company defers a payment or passes on a preferred dividend, it is tantamount to default on the preferred issues. The rating is changed to 'D' once the payment date has passed. The rating usually would be lowered to 'C' in the interim, if nonpayment were predictable—e.g., if the company were to announce that its directors failed to declare the preferred dividend. Whenever a company resumes paying preferred dividends but

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remains in arrears with respect to payments it skipped, the rating is, by definition, 'C'.

Convertible preferred

Securities such as PERCS and DECS/PRIDES provide for mandatory conversion into common stock of a company. Such securities vary with respect to the formula for sharing potential appreciation in share value. In the interim, these securities represent a preferred stock claim. Other offerings package a short-life preferred stock with a deferred common stock purchase contract to achieve similar economics.

These issues are viewed very positively in terms of equity credit—assuming conversion will take place in a relatively short time frame and the imbedded floor price of the shares makes it unlikely the company will regret and reverse its decision to sell new common stock.

Ratings on the issue address only the likelihood of interim payments and the solvency of the company at the time of conversion to enable it to honor its obligation to deliver the shares. These ratings do not address the amount or value of the common stock investors ultimately will receive. (We once highlighted this risk by appending an "r" to the ratings of these hybrid securities, but now rely on the market's familiarity with such instruments and their terms.)

Trust-Preferred stock

When using a trust preferred stock, a company establishes a trust that is the legal issuing entity of the preferred stock. The sale proceeds of the preferred stock are lent to the parent company, and the payments on this intercompany loan are the source for servicing the preferred obligation. In some cases, this financing structure can provide favorable equity treatment for the company, even while the payments enjoy tax-deductibility.

Standard & Poor's rating of trust-preferred securities is based on the creditworthiness of the parent company and the terms of the intercompany loan. Any equity credit that might be associated with these issues also is a function of the terms of the intercompany loan, especially with respect to payment flexibility.

This variety of preferred was introduced in 1995 as trust originated preferred securities (TOPrS). TOPrS represented a structural alternative for deferrable payment hybrids that had been sold since late 1993 under the appellation MIPS—Monthly Income Preferred Securities.

The use of a trust neither enhances nor detracts from the structure compared to the alternative issuing entities. The legal form of the issuing entity can be a business trust, limited partnership, off-shore subsidiary in a tax haven, or on-shore limited liability corporation. What these structures have in common is an intercompany loan with deferral features (typically five years), no cross-default provision, a long maturity, and deep subordination. The preferred dividend is similarly deferrable, as long as common dividends are not being paid. After the deferral period, the trust preferred holders have legally enforceable creditors rights—in contrast to conventional preferreds, which provide only very limited rights. ■

JAMES A. READ, JR. **Principal**

James Read is an expert in valuation, risk management, and capital budgeting. His consulting practice focuses on the electric power and natural gas industries. Mr. Read specializes in the application of option pricing and related methods to analyze the value and risk of derivatives, non-financial contracts, and real assets. He has developed derivatives-based software tools for valuation and portfolio risk management. He has also developed and taught professional training courses on these topics. Prior to joining *The Brattle Group*, Mr. Read was a Principal with Incentives Research Inc., and before that Director of Financial Consulting with Charles River Associates. He holds a B.A. in economics from Princeton University and an M.S. (finance) from the Sloan School of Management at Massachusetts Institute of Technology.

MANAGEMENT CONSULTING

- Conducted an independent review of the hedging policy of a major electric utility in the western U.S.

- Advised numerous electric power companies in connection with their portfolio risk management, including analysis of market data to model and estimate volatility, value non-standard contracts and assets, calculate risk exposures, and assess and manage portfolio risk.

- Worked with a major electric utility to develop a custom methodology for measuring the risk of its power supply portfolio.

- Developed methodology for allocating capital requirements to lines of business in multiple-line insurance companies.

- For the Electric Power Research Institute, directed development of the Energy Book System (EBS), a suite of software tools for valuation and management of energy resources. EBS includes tools for portfolio risk management, valuation and pricing of wholesale contracts and retail service agreements, and valuation and management of thermal and nuclear generation (with project evaluation and capital budgeting capabilities). The EBS exploits concepts and methods of derivative asset valuation to integrate valuation, risk analysis, and asset management.

- Developed and taught professional training courses on the application of derivatives methods for understanding the value and risk of commodity contracts and physical assets. EPRI-sponsored courses include *Value & Risk in Energy Markets*, *Applied Valuation & Risk Management*, and *Generation Asset Valuation*.

- Advised power companies in connection with the valuation of generation assets. Projects entailed development and use of options-based valuation tools as well as development of long-term forward price curves and volatility term structures.

- Developed derivatives-based methodology for estimating the cost of capital for investments in merchant power generation.

- Designed methodology for pricing a new product in the gas pipeline industry that would allow shippers to purchase options on pipeline capacity expansion.

- Developed valuation algorithm for a novel retail electric service that allows supplier to buy back electric energy when wholesale market conditions are tight.

- Developed an options-based valuation and decision-making model of nuclear power plants that explicitly incorporates flexibility to shut down prior to expiration of operating license.

- Advised Tennessee Valley Authority and other companies in connection with their evaluations of bids received in response to power purchase RFPs. These "paper" power plants represented alternatives to conventional capacity expansion. Engagements involved development of models for evaluating option-type bids, formulation of bid selection strategy, and development of forward price and volatility curves.

- Mr. Read is a principal author of the *Utility Capital Budgeting Notebook*, which integrates previous EPRI studies in finance and project evaluation into a single text.

- For EPRI, prepared a report that describes how the theory and methods of option pricing can be exploited to help evaluate investment projects and contracts.

- In a study for EPRI, identified a conceptual problem that arises in the application of the revenue requirements method when utility ratemaking procedures are

inflexible. The study pointed out that there is feedback between demand and rates, which may undermine the logic for cost-based evaluation of projects.

- In a study for EPRI, developed a rigorous procedure for calculating the cost of holding fuel and other commodity inventories. The procedure exploits information in commodity futures and money markets.

- In a study for EPRI, was part of study team that developed theoretical and empirical analysis of a bias that exists in conventional measures of market risk when applied to the shares of public utility companies. It explained why a bias is likely to arise, provided empirical confirmation of the bias, and devised corrected measures of market risk.

- In a study for EPRI, developed a methodology for selecting project-specific discount rates. The methodology is based on the idea that cash flows can be partitioned into risk classes, and hence that the value of an investment project can be found by adding up the values of the parts.

- In a study for EPRI, prepared an exposition of the revenue requirements method. Among other findings, the report concluded that the appropriate risk-adjusted discount rate for calculating the present value of revenue requirements may differ from the discount rate used to calculate net present value. It also identified the logical errors involved in the use of customer discount rates for calculating the present value of revenue requirements.

- Project manager in a study for the U.S. Department of Energy to assess the cost of capital for public and private investments in petroleum stockpiles. The objective of the research was to assess the investment value of private oil stocks and thereby determine the effectiveness of government policies aimed at stimulating private stockpile formation. A major focus of this research was the unusual risk profile of petroleum prices and its implications for investment value.

LITIGATION & REGULATORY SUPPORT

- In a tax matter, prepared an expert report on the economic substance of foreign exchange transactions ostensibly facilitated by a credit agreement with a major financial institution.

- Advised counsel regarding energy trading and risk management practices in an arbitration between participants in an energy marketing and trading company.

- Provided legal counsel with economic analysis of a series of structured finance transactions in a litigation matter involving companies in the energy and financial services industries.

- Prepared an expert report on the determination of settlement prices for certain commodity futures contracts.

- Advised legal counsel in an arbitration that concerned the termination value of power supply contracts written under the WSPP master agreement.

- On behalf of an industry trade group, conducted a preliminary investigation of whether certain commodity futures prices had been manipulated.

- Analyzed gaming practices in the Western power markets during the energy crisis of 2000-2001. Prepared expert testimony for hearings before the Federal Energy Regulatory Commission.

- Assisted in the development of expert testimony in connection with regulatory hearings about the sale of a nuclear power station by a public utility to an unregulated energy company.

- Advised several clients in the electric utility industry in connection with the design, pricing, and risk management of "provider of last resort" and similar retail transition services created as part of industry restructuring.

- Analyzed the impact of credit risk on the pricing of energy contracts. Analysis was performed in the context of a regulatory review of energy procurement decisions.

- Used option pricing methods to estimate the premium over cost required to compensate investors for the long-term nature of investments in railroad assets. Analysis was used in a revenue adequacy proceeding before the Surface Transportation Board.

- For several disputes involving income tax liabilities, prepared economic analyses of complex transaction structures that utilize exotic options and/or other derivatives.

- Prepared testimony on behalf of New York State Electric & Gas in connection with its Price Protection Program. Testimony addressed risk and cost of capital for an electric utility that has sold its generation but continues to have retail service obligations.

- Mr. Read prepared an affidavit on behalf of a natural gas pipeline company that challenged a FERC order on the allowed rate of return. The principal issue in this case concerned the use of *ex post* data to infer the cost of capital.

- In a project for a client in the petroleum industry, Mr. Read worked with an academic expert in finance to develop testimony concerning the value of expropriated oil fields in the Persian Gulf. This testimony was submitted to the Iran-U.S. Claims Tribunal in the Hague.

- In a major antitrust case, Mr. Read worked with an academic expert in finance to critique the damages study submitted by the plaintiff. Among other issues, the critique identified a fundamental conceptual error: the damages were calculated using a mixture of foresight and hindsight.

- In the Penn Central bankruptcy, Mr. Read worked on the valuation of the Intercity Freight Lines. He was responsible for extensive analysis of U.S. capital market data to determine the cost of capital in the railroad industry. In addition, he worked with academic experts in finance theory to evaluate alternative approaches to valuation.

- For a private client involved in antitrust litigation, Mr. Read was responsible for critiquing the testimony of an opposing witness who had used corporate financial data to draw inferences about risk and profitability. The critique identified two major errors, one computational and one conceptual, which, when corrected, reversed the conclusions of the original analysis.

OTHER EXPERIENCE

Financial Analyst, Corporate Financial Staff, General Motors Corporation. Mr. Read worked in forward product programs and corporate transfer pricing.

Staff Economist, Mail Classification Research Division, United States Postal Service. Mr. Read's responsibilities included writing statements of work, technical evaluation of analytical study proposals, and directing contractors in the Postal Service's Long Range Classification Research Program.

Staff Economist, Office of Rates, United States Postal Service. Mr. Read was engaged in the preparation of testimony filed with the Postal Rate Commission in support of requests for changes in rates. His responsibilities included cost analysis, revenue forecasting, econometric analysis of postal markets, and rate design.

PUBLICATIONS

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"Retail Transition Services in Electric Utility Restructuring," Presentation to Illinois Energy Leadership, Chicago, October 29-30, 2001.

"Provider of Last Resort: Retrospect & Prospect," Presentation to Staff Subcommittee on Accounting and Finance, National Association of Regulatory Utility Commissioners, Portland, Maine, October 1, 2001.

"Theory & Methods of Portfolio Risk Management" (with T. Parkinson), Tutorial presented to *Portfolio Risk Analysis & Management*, Infocast, Houston, February 16-18, 2000 and Chicago, October 2-4, 2000.

"Using Option Pricing Formulas," Presentation to *Pricing Wholesale Energy Products & Services*, Infocast, Houston, November 28-30, 2000.

"The Effect of Volatility Modeling on Management Decisions," Presentation to *Market Price Volatility*, Infocast, October 30 - November 1, 2000.

"Option Pricing in a Price Spike World," Presentation to *International Energy Pricing Conference*, EPRI, Washington, D.C., July 26-28, 2000.

"Applications of Portfolio Techniques to Fuel Decisions," Presentation to *Fuel & Power Supply Seminar*, EPRI, Cleveland, November 9-11, 1998.

"Managing Nuclear Generation Assets," Presentation to *Generation Asset Management: Opportunities and Challenges in the Electric Marketplace*, EPRI, Baltimore, July 13-15, 1998.

"Managing the Risks of Generation Assets," Presentation to *Integrating Risk Management for Fuel Supply & Power Sales*, Center for Business Intelligence, Houston, February 5-6, 1998.

"Tactics for Matching Strategy & Market Opportunity through Hedging," Presentation to *Fuel Management: Innovative Fuel Strategies for a Price-Competitive Power Market*, Center for Business Intelligence, Colorado Springs, August 14-15, 1997.

"Implementing Risk Management in Electric Power," Presentation to *European Electricity Trading*, ICM Marketing Ltd., London, January 29-30, 1997.

"Integrating Fuel & Power Price Risk Management," Presentation to *Managing Fuel Risk*, Center for Business Intelligence, Dallas, December 12-13, 1996.

"Lessons From Deregulated Industries," Presentation to *Workshop on New Directions in Electricity Pricing*, EPRI, Palo Alto, May 7, 1996.

"Capacity Prices in a Competitive Power Market," Presentation to *Symposium on The Virtual Utility*, Saratoga Springs, March 31-April 2, 1996.

"Evaluating OPAs: The Art of Pricing Electricity Derivatives," Presentation to *Resource Acquisition in a Competitive Power Market*, International Business Communications, Chicago, October 30-31, 1995.

"Basis Risk in Energy Markets," Presentation to *Achieving Success in Evolving Electricity Markets*, EPRI, Atlanta, October 10-12, 1995.

"Risk and the Revolution in Finance: Implications for Planning," Presentation to *Strategic Resource Planning and Asset Management Forum*, EPRI, St. Petersburg, Florida, December 8-9, 1993.

"Why Small Firms Shun Discounted Cash Flow Analysis," Presentation to the Financial Management Association, Annual Meeting, San Francisco, October 22, 1992.

"Discount Rates in Utility Planning," Lecture to American Gas Association/Edison Electric Institute, Chicago, May 22, 1991.

"Weighted Average Cost of Capital: Before-Tax or After-Tax?" Presentation to the Budgeting and Financial Forecasting Committee, Edison Electric Institute/American Gas Association, Denver, September 10, 1990.

"Economic Evaluation of Utility Projects and Contracts," Seminar sponsored by the Electric Power Research Institute, San Diego, March 2-3, 1989.

"Planning for Utilities: The Value of Service," Paper presented to the Conference of Integrated Value-Based Planning, New Orleans, December 2, 1987.

"Capital Budgeting and the Cost of Capital," Lecture to the Marginal Cost Working Group, Boston, May 6, 1986.

"Capital Budgeting for Electric Utilities," Seminar sponsored by the Electric Power Research Institute, New Orleans, February 26-27, 1986.

"Risk and Capital Budgeting in the Electric Utility Industry," Paper presented to Rutgers University Advanced Workshop in Public Utility Economics and Regulation, New Paltz, New York, May 30, 1985.

"Critique of Rate of Return Methods in Public Utility Rate Cases," Lecture to Advanced Regulatory Studies Program, National Association of Regulatory Utility Commissioners, Williamsburg, Virginia, February 15, 1984.

"Utility Rate Shocks: The Problem and Possible Solutions," Paper presented to the Tenth Annual Rate Symposium, Institute for the Study of Regulation, Washington, DC, February 6, 1984.

EXPERT TESTIMONY

Expert Report and Testimony in Klamath Strategic Investment Fund, LLC v. United States of America, Civil Action No. 5:04-cv-00278-TJW (lead case). United States District Court for the Eastern District of Texas, Texarkana Division, May 2006 and October 2006.

Expert Report and Declaration in re National Westminster Bank PLC v. The United States. United States Court of Federal Claims, No. 95-758 T, March 4, 2005 and July 12, 2005.

Expert Report in re Enron Corp., *et al.* v. Nevada Power Company and Sierra Pacific Power Company. United States Bankruptcy Court, Southern District of New York, February 23, 2005.

Expert Report in re New York Mercantile Exchange, Inc. v. IntercontinentalExchange, Inc. United States District Court, Southern District of New York, August 2004.

Prepared Direct Testimony in re Enron Power Marketing, Inc. and Enron Energy Services, Inc., Docket No. EL03-180-000 *et al.* Federal Energy Regulatory Commission, February 27, 2004 and January 31, 2005.

Prepared Direct Testimony in Case 01-E-0359 (NYSEG Price Protection Plan). State of New York Public Service Commission, August 2, 2001 and September 12, 2001.

PREPARED REBUTTAL TESTIMONY

OF

STEVEN L. ZELKOWITZ

ON BEHALF OF

NATIONAL GRID plc

AND

KEYSPAN CORPORATION

CASE 06-M-0878

Redacted Version

MARCH 7, 2007

Q. Please state your name and business address.

A. My name is Steven L. Zelkowitz. My business address is One Metro Tech Center, Brooklyn, New York 11201.

Q. Are you the same Steven L. Zelkowitz who previously submitted testimony in this proceeding?

A. Yes. I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony of Department of Public Service Staff witnesses John D. Stewart, Warren E. Myers and Thomas Coonan (hereinafter "the Merger Panel"), which asserts that KeySpan Corporation ("KeySpan") did not "reasonably weigh" the interests of customers versus shareholders or the transactional risks associated with the proposal by National Grid, plc ("National Grid") to acquire ownership of KeySpan's Ravenswood generation plan as part of the overall acquisition of KeySpan.

[REDACTED FROM HERE TO PAGE 11]

Q. Does this conclude your rebuttal testimony?

A. Yes. It does.

PREPARED REBUTTAL TESTIMONY

OF

NATIONAL GRID'S RELIABILITY PANEL

CHERYL A. WARREN

DAVID WRIGHT

SCOTT LEUTHAUSER

KEITH MCAFEE

ON BEHALF OF

NATIONAL GRID plc

AND

KEYSPAN CORPORATION

CASE 06-M-0878

MARCH 7, 2007

RELIABILITY PANEL

I. Introduction and Qualifications

Q. Ms. Warren, please state your full name and business address.

A. Cheryl A. Warren, 1125 Broadway, Albany, NY 12201.

Q. Please state your position with the Company.

A. I am the Director of Asset Strategy and Performance in the Distribution Engineering and Asset Management organization within the National Grid USA Service Company, Inc. The Distribution Engineering and Asset Management organization provides support to Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or "Company") on all technical and other support matters. My responsibilities as Director of Asset Strategy and Performance include provision of reliability assessment support, development of the reliability enhancement program (REP), and preparation of reliability results for regulatory filings.

Q. Please describe your educational background and training.

A. I received a Bachelor of Science Degree in Electrical Engineering in 1987 and a Master of Science in Engineering in 1990 from Union College in Schenectady, NY. I have lived in the Capital District region for most of my life.

Q. Please describe your professional experience.

A. I was employed by Central Hudson Gas and Electric from 1987 to 1989 in the System Protection Department where I was responsible for relay coordination on

the distribution system. In 1990, I accepted a position in the Distribution Engineering Group, part of the Consulting Group, with Power Technologies Inc. ("PTI"). My responsibilities included the study and analysis of distribution issues for numerous companies. My primary areas of responsibility were in power quality and reliability studies for clients. During this timeframe, I also assisted on the Rocket Triggered Lightning project that was sponsored by the Electric Power Research Institute ("EPRI"), and taught numerous courses on distribution systems, protection and coordination, and reliability analysis. In 1995, I transferred into the Software Group at PTI and assumed leadership of its distribution power flow software package (PSS/U). In that role I was responsible for all aspects of the program, including design, implementation, testing, training, support, manual creation, sales, marketing and user groups. In 1998, I transferred back to the Consulting Group where I was largely responsible for leading distribution reliability and information technology ("IT") integration engagements for clients. In 1999, I accepted a position as a Senior Engagement Manager with Navigant Consulting in Albany, NY. There I led reliability and IT system integration client engagements. In August 2002, I accepted my present position with National Grid USA.

Q. Please outline your professional activities.

A. I have participated extensively in the Institute of Electrical and Electronics

Engineers, Inc. ("IEEE") activities, which is the electrical engineering standards-making body in the United States. As part of IEEE, I have led the Working Group on System Design that has been renamed to the Working Group on Distribution Reliability ("Working Group") since 1990. This Working Group is the author of IEEE Std. 1366-2003, the *Guide for Electric Power Distribution Reliability Indices*. I am also the Chair of the IEEE Power Engineering Society Distribution Subcommittee. In June 2007, I will receive the IEEE PES Excellence in Power Distribution Award. I have authored and co-authored twenty-eight papers and spoken at numerous conferences on distribution reliability, power quality and IT integration issues.

Q. Have you previously testified before the Commission?

A. No, I have not.

Q. Mr. Wright, please state your full name and business address for the record.

A. My name is David Wright. I am employed by National Grid, and my business address is 25 Research Drive, Westborough, MA 01582.

Q. Please state your position within the Company?

A. I am Vice President Transmission Asset Management. The Transmission Asset Management organization parallels the Distribution Engineering & Asset Management group and provides support to National Grid in New York with respect to transmission assets. In that capacity I am responsible for 115kV and

above assets (69kV and above in New England) on National Grid's transmission system. This includes the development of policies and processes used to manage the transmission system; understanding the condition, age, and life cycle of our assets; planning for the future needs of the transmission system; investment in and maintenance of our transmission system, and evaluating risks to the system to ensure optimum service provision to our customers over the whole lifetime of the asset.

Q. What is your educational background?

A. I was educated in the United Kingdom. I graduated from Birmingham University in 1990 with a Bachelor of Science in Electrical and Electronic Engineering. I am a dual Chartered Engineer in both electricity and gas with the Institute of Engineering and Technology (IET) and the Institute of Gas Engineering Managers (IGEM).

Q. Please summarize your professional experience.

A. I joined National Grid in 1992 as an engineer in Grid System Management in the United Kingdom. In 1994 I was transferred to the national control centre where I undertook a variety of roles including a period on shift as a reactive management engineer. In 1999 I was appointed to my first of three managerial roles as the business was re-organized from a regional to a national model in which I became the Transmission Requirements Manager responsible for the operational planning

of the UK's England and Wales transmission network. In 2003 I transferred to gas and became the Strategy & Support manager for the UK's gas transmission control function. In 2005 I moved into Asset Management as the senior manager for Planning including responsibility for derivation of all work plans, the management of 40,000 annual rental and easement grantors and the management of safety for the system. In 2006 I was appointed to my current position as Vice President for transmission asset management for National Grid's US businesses in New York and New England.

Q. Have you previously testified before the Commission?

A. No, I have not.

Q. Mr. Leuthauser, please state your full name and business address for the record.

A. My name is Scott D. Leuthauser. I am employed by National Grid, and my business address is 300 Erie Blvd West, Syracuse, NY 13202.

Q. What is your educational background?

A. I am a licensed engineer in New York State. I graduated from Clarkson University in 1986 with a Bachelor of Science in Mechanical Engineering. In 1989, I received a Masters of Business Administration from State University of New York at Buffalo and in 2004 received a Masters Certificate in Power Systems Management from Worcester Polytechnic Institute.

Q. In what capacity are you employed at National Grid?

A. I am Vice President Project Management. In that capacity I am responsible for the supervision of professionals who provide management of electric distribution and substation projects for National Grid.

Q. Please summarize your professional experience.

A. I joined National Grid in 1986 as a Junior Engineer in Fossil Generation. In 1987 I was transferred to the C.R. Huntley Steam Station where I served as the station performance engineer and Assistant Station Shift Supervisor. In 1990 I was transferred to work as a Senior Fuel Supply Analyst. In 1993 I became a Senior Supply Planner in Supply Planning and shortly thereafter was promoted to Manager of Supply Planning. In 1997 I became Manager Supply (Power) Contracts, then, in 1998 was promoted to Director of Energy Transactions (power contracts, rates, and load research). In 2002, I was promoted to Vice President Distribution Planning & Engineering and in 2005, to Vice President Distribution Investment Management, and in August 2006 to Vice President Project Management.

Q. Have you previously testified before the Commission?

A. Yes, I have previously testified in proceedings pertaining to Long Run Avoided Costs, several rate case proceedings including supporting testimony to PowerChoice, the Merger Rate Plan, and Standby Service Rates. I submitted

testimony in connection with the Company's March 2006, Petition for Rate Relief in Case 04-M-0159, seeking recovery of costs incurred to implement stray voltage testing and facilities inspection programs, and most recently testified in the Deferral Audit case as part of 01-M-0075.

Q. Mr. McAfee, please state your name and business address for the record.

A. My name is Keith P. McAfee. I am employed by National Grid, and my business address is 1125 Broadway, Albany, NY 12204.

Q. What is your educational background?

A. I am a licensed engineer in New York State. I graduated from Clarkson University in 1985 with a Bachelor of Science in Electrical Engineering. I received a Masters of Business Administration from New Hampshire College in Manchester, New Hampshire in 1991.

Q. In what capacity are you employed at National Grid?

A. I am Director of Customer Operations for the Eastern Division. In that capacity I am responsible for the supervision of professionals and field forces that provide maintenance and construction of the Company's electric infrastructure in that area.

Q. Please summarize your professional experience.

A. I joined National Grid in 1992 as an Account Manager in Buffalo, NY. In 1994, I was promoted to Technical Services Manager in Albany, NY. In 1999, I was

promoted to Regional Manger for the Northeast Region in Glens Falls, NY. In 1999, I was promoted to my present position as Director of Customer Operations for the Eastern Division. Prior to National Grid, I was employed by Central Hudson Gas and Electric from 1985 through 1987 as an Associate Engineer in Newburgh, NY. Between 1987 and 1991, I held various operations management and engineering positions for Public Service Company of New Hampshire in Manchester and Nashua, NH.

Q. Have you previously testified before the Commission?

A. No, I have not.

Q. What exhibits are the Panel Witnesses sponsoring in support of this testimony?

A. The Reliability Panel is sponsoring the following exhibits:

Exhibit No. __ (Reliability Panel-1R) – Charts, Graphs and Tables

Exhibit No. __ (Reliability Panel-2R) – Summary of IR DPS-281

Exhibit No. __ (Reliability Panel-3R) – New York Lineworker Staffing

Exhibit No. __ (Reliability Panel-4R) – Table from IR DPS-281

II. Purpose of Testimony

Q. What is the purpose of the Reliability Panel's testimony as it relates to the Company's filing?

A. The purpose of our testimony is to address various concerns raised by Department

of Public Service Staff regarding electric reliability, electric line workforce, and the maintenance backlog. Similar concerns regarding electric reliability were also raised by the Consumer Protection Board ("CPB"), IBEW Local 97 ("Local 97") and UWUA. In addition, Local 97 also raises concerns regarding system reliability and believes that the degradation in service is due to a reduction in operating staff. Our testimony is organized as follows:

- an explanation of the investment National Grid plans to make in New York and a description of programs that have been implemented by the Company to address the root causes impacting reliability performance;
- an analysis of the Company's performance as measured by CAIDI and SAIFI;
- an analysis of the Company's performance as compared to other utilities' in New York and nationally;
- a response to the assertions made by Witness Reulet concerning the maintenance backlog; and
- the various efforts that have been undertaken post-merger to improve transmission reliability within New York State.

We will also respond to Staff and the Unions' concerns about the electric line workforce, specifically:

- the Company's staffing to respond to customer outage events (herein "trouble") resulting from a typical day's weather and from weather storm

events (e.g., wind, lightning, snow, ice);

- the Company's current staffing levels relative to levels at the time of the merger between Niagara Mohawk and National Grid (more specifically calendar year 2001 versus 2006); and
- the Company's staffing plans and strategies to retain and sustain qualified workers (internal and external) prospectively to respond to trouble and complete the work outlined in the business plan.

III. Reliability Panel Rebuttal to Staff and Union Testimony

Q. Does National Grid recognize that there is an issue with electric reliability with respect to its New York State system?

A. Yes. National Grid recognizes that electric reliability with respect to its New York assets needs to improve. National Grid takes electric reliability very seriously and has spent significant resources on capital investments and maintenance in New York since the merger.

Q. Please explain.

A. From the moment the Niagara Mohawk acquisition was completed, National Grid has been committed to a strong program of investment in and maintenance of its NY Transmission and Distribution ("T&D") infrastructure.

Q. How do these expenditures compare with the merger rate settlement?

A. As summarized in the response to DPS-281, Exhibit No. __ (Reliability Panel-

4R), National Grid's annual capital expenditures in this regard during the first three years after the merger averaged 40% higher than the level that had prevailed in the six years before the merger. Exhibit No. ___ (Reliability Panel-4R) of Mr. Laflamme's and Mr. Molloy's testimony shows that National Grid has invested more capital in the system than was included in the rate plan. Specifically, National Grid's total 2002 to 2006 capital expenditures were more than 55% higher than those anticipated in the rate plan. Similarly, referring to Exhibit No. ___ (Reliability Panel-4R), our total 2002-2006 O&M expenditures were more than11% higher than if we held the expenditures to pre-merger levels, again adjusted for inflation.

Q. Please summarize the approach National Grid is taking to ensure acceptable reliability performance on its electric transmission and distribution system?

A. In addition to this commitment of resources, National Grid needed to improve its reliability results and the way it managed its assets. Dedicated asset management teams were established to improve the long-term performance and health of our assets and in 2004, the Company began to actively develop a program to return service quality to what it believed to be more acceptable levels. The results of these efforts were a Reliability Enhancement Program for distribution ("REP") and a portfolio of asset strategies to improve the reliability performance of the transmission system. Over the five year period starting with the current fiscal

year, the REP will add $360 million of capital and maintenance expenditures to baseline distribution reliability spending of $260 million, producing a total of $620 million committed to the reliability of distribution infrastructure. In addition, asset management strategies have yielded a targeted transmission capital plan of $576 million for the same five year period. When one adds other capital expenditures anticipated for the distribution system and projected transmission maintenance expenditures, the total planned capital investment and maintenance expenditures for the transmission and distribution infrastructure are expected to be $1.82 billion ($1.47 billion capital and $350 million maintenance), compared to an expenditure of $1.0 billion for comparable purposes in the previous five-year period. Exhibit No. __ (Reliability Panel-2R) outlines the year by year history and projections by major category.

These plans are continually being reviewed and updated to improve the efficiency of our investments based on the latest asset condition, reliability performance data and customer satisfaction results.

Q. Before describing National Grid's reliability-related programs in greater detail, please summarize the Company's recent reliability results. Does National Grid agree with the data provided in Witness Reulet's charts at DFR-1 and DFR-2?

A. There are some discrepancies between DFR-1 and DFR-2 and the performance

indices that Niagara Mohawk filed in its annual reliability filings. The reported SAIFI for calendar year 1997 was 0.93 and for 1999 was 0.94. The reported CAIDI for 1998 was 2.03, for 1999 was 1.87, for 2001 was 1.89, for 2003 was 1.99, and for 2005 was 2.33. The differences are minimal, but for the sake of accuracy, please see Figure 1 (Reliability Panel-1R) and Figure 2 (Reliability Panel-1R) below.

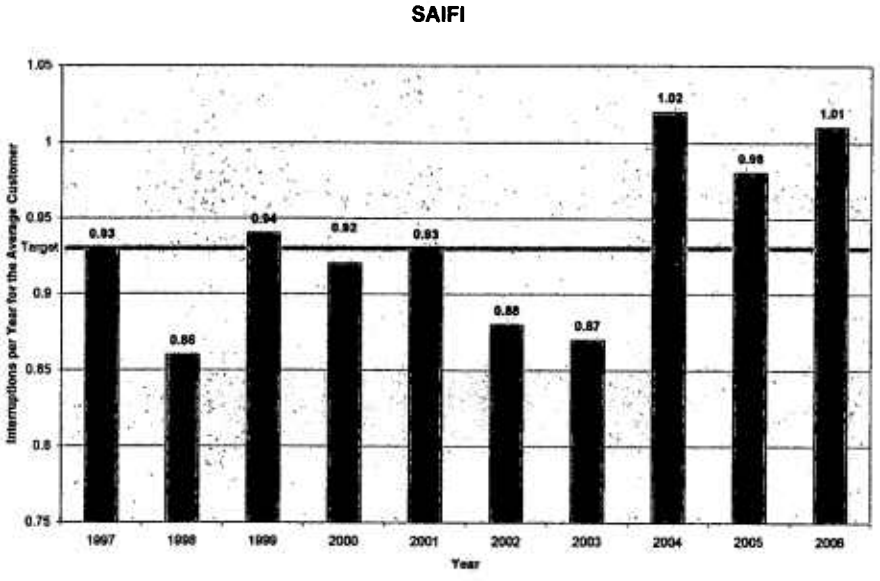


Figure 1. SAIFI - DFR-1

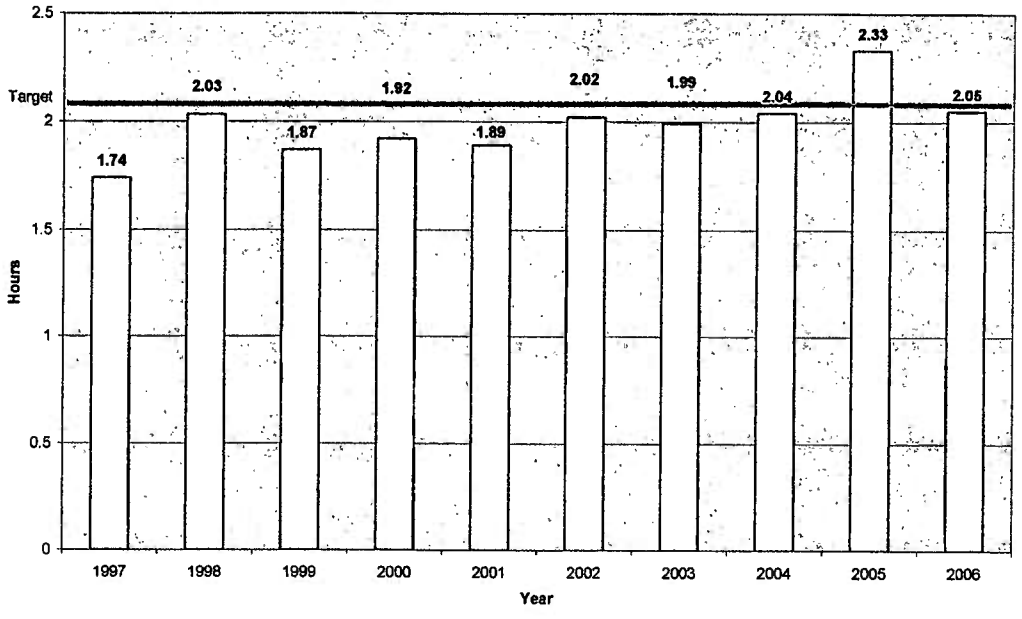


Figure 2. CAIDI - DFR-2

Q. Please provide a brief description of the Company's reliability performance since the time of the merger.

A. Following National Grid's merger with Niagara Mohawk, the Company has met the CAIDI target in all years except 2005, when CAIDI was an abnormally high 2.33 hours.

Notice that in all the other years CAIDI fluctuates around 2.03 hours. While there has been a minor degradation in performance since 2002, there is not a significant increasing trend. In fact, contrary to Witness Reulet at p. 8 lines 10-14, had 2005 not been an abnormal year, the CAIDI trend would have been flat and the five

year average would have been 2.02 hours.

In 2005, the Company experienced numerous subtransmission events on our radial subtransmission lines; two examples are in the Schroon – Chestertown area and in the Old Forge – Racquette Lake area. Because customers are served from radial lines (only one source of power) in these remote Adirondack areas, long duration events occurred.

Even though CAIDI rose to 2.33 in 2005 only, the Company took proactive measures to ensure that better performance results were achieved in 2006. The proactive measures included the implementation of one person crews, alternate off-shift schedules, proactive work practices such as performing extra feeder patrols and fixing the items found, and increased the number of crews held for weather events. The Company also performed additional vegetation management ("VM") activities including tree trimming and hazard tree removal as well as adding 25 more reclosers to the system to improve performance. The Company spent nearly $1.6 million incremental dollars to accomplish the additional VM and nearly $1 million on the additional reclosers.

Q. Why did the Company exceed the SAIFI target in 2004, 2005 and 2006?

A. There were three main reasons the Company exceeded the SAIFI target. They were: (i) increased tree-related and deteriorated equipment/lightning interruptions; (ii) abnormal weather; and (iii) changes in data recording.

Q. Please further describe the impact of the tree-related interruptions, deteriorated equipment/lightning interruptions and weather on SAIFI performance.

A. Reviewing root cause information presented in Figure 3 (Reliability Panel-1R) below, the key performance drivers are interruptions caused by trees, distribution equipment and subtransmission events.

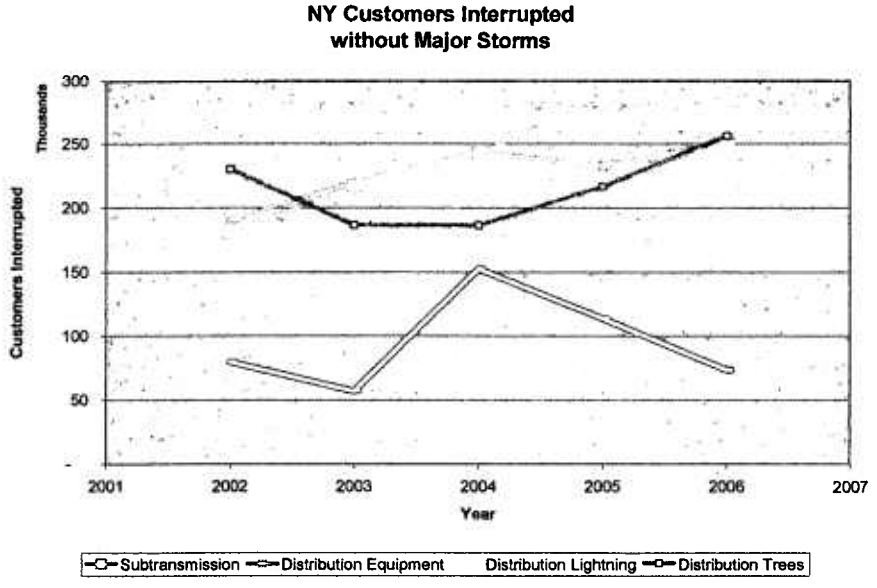


Figure 3. Some of the Major Causes of SAIFI Increase

In 2004 and to some degree in 2005, the Company experienced an abnormally high amount of lightning striking the service territory as can be seen in Figure 4 (Reliability Panel-1R) below.

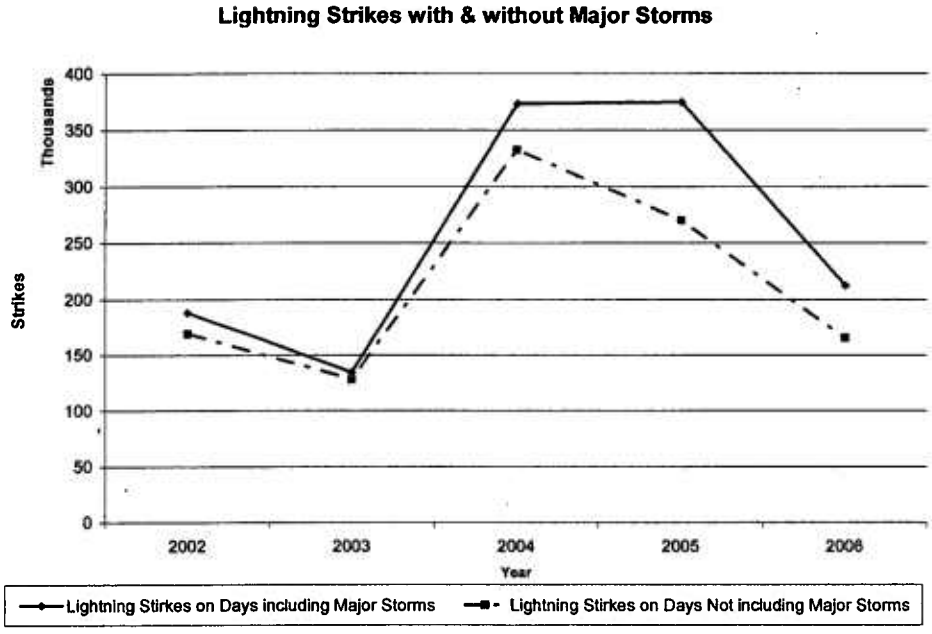


Figure 4. Number of Lightning strikes to the National Grid Service Territory per the Vaisala Lightning Detection Network

Not only was there an abnormally high amount of lightning strikes during major storm events, but also during non-major storm days. Lightning can strike near power system equipment without causing an immediate interruption to customers. In certain cases, these strikes can weaken the infrastructure and ultimately result in conditions that lead to an interruption that occurs at a later time. For example, extruded distribution cables frequently fail during or shortly after a thunder storm.[1] Transformers have also failed after lightning storms.[2] The

1 "Effects of voltage surges on extruded dielectric cable life project update"
Hartlein, R.A. Georgia Power Co., Atlanta, GA, USA ; This paper appears in: Power Delivery, IEEE

subtransmission interruptions was higher than in previous years. The root causes of subtransmission interruptions are shown below in Figure 5 (Reliability Panel-1R).

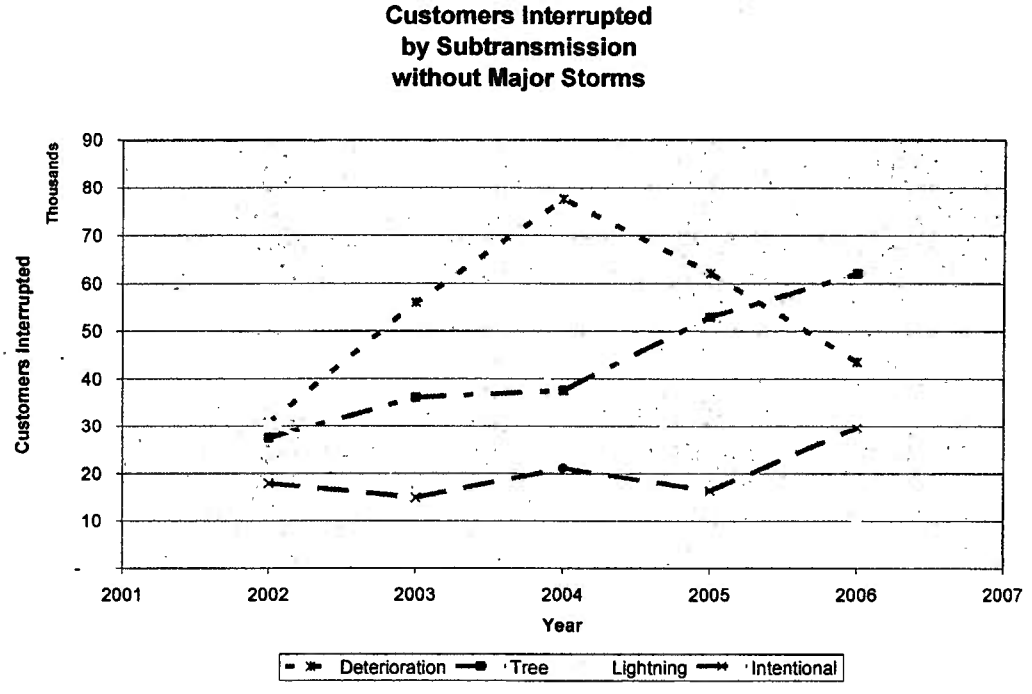


Figure 5. Customers Interrupted by Subtransmission Interruptions

As can be seen, lightning and deterioration are tracking on the same trend in 2004 – 2006. Tree related interruptions have been steadily rising because of the reasons outlined above. The Company is taking a proactive approach to widening the rights of way on the subtransmission system and currently plans to widen about 1,000 miles of subtransmission rights of way by 2011.

Q. Did intentional interruptions (i.e., planned maintenance) contribute to SAIFI in 2006?

A. Yes, the number of customers affected by intentional interruptions increased in 2006. These interruptions are consistent with good utility practice and necessary to complete required work however, they do contribute to the decline in reliability performance. The subtransmission capital budget has been more than doubled above the current rate plan to address load, asset replacement and reliability issues. These projects along with continued widening of the ROWs should make a significant positive impact on reliability over time.

Q. Can changing the interruption data collection methods affect reported performance on reliability indices?

A. Yes. Utilities across the nation that have been changing their outage management processes and their associated IT systems have experienced changes in their reported indices, which are considered inconsistent with their actual underlying reliability performance. Legacy outage management systems were implemented to assist operators with power restoration. As industry restructuring occurred, reliability index tracking became the mainstay of distribution regulation and hence the need for very accurate information from legacy systems became imperative. Since these systems were not originally designed for this purpose, they did not provide this extremely accurate information. As utilities move to improve

processes and replace legacy systems, in most cases they experience an index rise between 25% and 75% from previous numbers. A few have seen even higher rises. The Company does not yet know what impact the enhanced capabilities of the new system will have on future reliability statistics. However, it is possible that National Grid will see increases in reported SAIFI and CAIDI independent of actual underlying system performance, as has been the case at other utilities who have implemented similar systems.

The main sources of error in the legacy systems stem from: (i) missing events – those not captured in the system; (ii) lack of accurate numbers for customers interrupted – many legacy systems were paper-based and relied on field estimates for customers interrupted or did not have fully connected GIS models that help to provide accurate customer counts; (iii) lack of accurate recording of duration of events – legacy systems depend on the time the first customer calls to begin an event and the time the line personnel reports the end of the event; (iv) training – when new systems are implemented there is often a steep learning curve for those using it and the initially collected data often has numerous errors – these are corrected over time with experience and training.

Q. What type of system does National Grid use to collect interruption information?

A. Since 1993, interruption data has been collected in the legacy, paper-based system

interruption reporting (SIR) system. Historical results from this legacy system were used to develop the reliability performance targets contained in National Grid's existing rate plan. SIR is the system used to collect the information that is reported to the Public Service Commission, even today. This system relies on line personnel to: (i) fill out the trouble tickets; (ii) correctly estimate the customers affected; and (iii) report the interruption completed times.

For the reasons stated above, results from the legacy SIR system could have been affected by the types of errors described previously. During the hectic activity surrounding the restoration efforts of major and minor storms, it is possible that interruption tickets may have been misplaced and not entered into the system.

Q. Does National Grid plan to upgrade their paper-based system to a new state-of-the-art system?

A. Yes. National Grid plans to use GE's PowerOn product in the future, although it should be noted that National Grid is not reporting reliability results using this system in 2006. National Grid has been running its SIR system in parallel with its newly implemented PowerOn system, which has been tightly integrated with its interruption disturbance system (IDS) since April, 2004. In this time period, it is likely that some of the more accurate information now more readily available due to the PowerOn system is also being entered into the legacy system thereby

accounting for some of the rise in reported SAIFI.

Q. How does National Grid's SAIFI performance compare with other NY State utility performance?

A. As can be seen below in Exhibit No. ___ (Reliability Panel-1R), National Grid's reliability performance is consistent with that of other NYS utilities.[4] Except in 2002 and 2003, where there is some deviation that is most likely caused by several large storms, National Grid is trending almost exactly with the State average.

SAIFI data for 2006 are provided only for National Grid. The data from the other utilities will not be filed until March 31, 2007 and therefore are not included in this analysis. The State average is provided without including Consolidated Edison Company ("ConEd"). This is done because ConEd is composed of a mostly networked urban downtown area and their SAIFI is usually very small, thus the data are not reasonably comparable with other utilities in the state that do not have such an extensive downtown, underground, urban network.

Q. How does National Grid's CAIDI performance compare with other NY State utilities?

A. As can be seen in Exhibit No. ___ (Reliability Panel-1R) below, National Grid's performance is almost exactly following the trend of the State average utility performance. While the trend is above the other utilities in the state, it has not

4 Based on information obtained from the NY PSC web site.

materially changed over the period. As shown in Exhibit No. ___ (Reliability Panel-1R), the upward deviation experienced by National Grid in 2005 was also experienced by customers served by other utilities in the State.

As with the SAIFI information, a 2006 result is available only for National Grid. The state average is provided without including ConEd, because of the very different characteristics of their operating territory.

Q. Please describe reliability performance trends across the nation.

A. (Reliability Panel-1R) below shows trend performance from an Institute of Electronic and Electrical Engineers ("IEEE") benchmark effort[5] that was conducted across North America. The IEEE is a national standards-making body.

In the 2005 benchmark effort, ninety-four companies provided raw data that were then analyzed by the IEEE Working Group on Distribution Reliability using the IEEE Std. 1366-2003 as the basis for the analysis, as opposed to individual State based criteria. Specifically, the group applied the same criteria (IEEE) across all data sets. Analyzing the data using the same methodology for all companies allows for more accurate comparison of results.

Fifty-eight of the ninety-four companies provided consistent data from 2000-2005. "Large" utilities, as defined in Exhibit No. ___ (Reliability Panel-

5 "Distribution Reliability Benchmarking based on IEEE Std. 1366-2003 – 2005 Survey Results", Accepted by the IEEE Transactions on Power Delivery for publication in 2007 and presentation in Tampa, Fl in June 2007.

1R), are those that serve one million customers or more like National Grid's NY territory; there were twenty-four of those companies in the benchmark effort. Those twenty-four companies served over 51 million customers in 2000 and over 54 million customers in 2005. The results from those companies were used to develop the trend charts shown in Exhibit No. ___ (Reliability Panel-1R).

As can be seen, the trend for reliability performance is worsening over time across the whole benchmark group. There has been considerable discussion about the phenomenon at the IEEE group with no definitive conclusions drawn. Members have suggested that changes in weather patterns, addition or modification of outage management systems, and other factors are likely to be contributing to the changes.

Q. How does National Grid's reliability performance compare to other utilities in the nation?

A. Using the information presented in (Reliability Panel-1R), National Grid's performance has been overlaid onto the national performance as shown in (SAIFI performance) Exhibit No. ___ (Reliability Panel-1R) and (CAIDI performance) Exhibit No. ___ (Reliability Panel-1R) below.

In Exhibit No. ___ (Reliability Panel-1R), with the Company's 2006 results included, it can be seen that the National Grid SAIFI oscillates but is a flat trend overall, while the comparison group of utilities has experienced a modest

deteriorating trend over a similar time period, showing that National Grid is performing better than the industry group.

In Exhibit No. ___ (Reliability Panel-1R), with the Company's 2006 results included, it can be seen that the National Grid CAIDI performance is almost exactly the same as the national average.

Q. What is the Reliability Enhancement Plan as referenced by Witness Reulet (p. 17)?

A. As we noted at the introduction of our testimony, the Company assembled a number of teams in 2004 to develop a program to bring service reliability to a more desired level. One of the products of that effort was the Reliability Enhancement Plan, a five-year program composed of both capital and maintenance spending initiatives. The key elements of the plan include: (i) a targeted program to enhance the worst performing feeders (Feeder Hardening); (ii) an enhanced vegetation management program; (iii) increased asset replacements; and (iv) increased maintenance and inspection.

Because the electric system is dynamic, the plans are also dynamic. The specific feeders and areas where work will be performed for fiscal year ending March 2008 (hereinafter "FY08") have been determined and detailed designs have been created. The potential work for FY09 has been identified and is being researched to ensure it will provide the greatest potential improvement for the

cost. At the end of FY08, the final selected projects will be sent to engineering and design for processing, and then on to operations for completion of the work in FY09. For FY10 and FY11, the broad categories of work are in place as budget place-holders. In FY09, the FY10 work list will be generated.

Q. What are the major underlying causes adversely impacting reliability performance that drove the creation of the REP?

A. Lightning, deteriorating distribution equipment, and tree contacts, in addition to changes in weather patterns and more accurate data collection due to an on-going initiative to implement a new outage management system ("OMS") were the main underlying causes of the change in performance as described previously in this testimony. Exhibit No. ___ (Reliability Panel-1R) shows the performance based on customer minutes interrupted, which is the product of customers interrupted and duration. In Exhibit No. ___ (Reliability Panel-1R), the upward, negative trend for trees, subtransmission, and deteriorated distribution equipment is clear. Lightning has also played a role in the deteriorated equipment interruptions in 2004 and 2005. It can also be seen that transmission (115 kV and above) interruptions were not significant contributors to the negative, upward trend in customer minutes interrupted. Based upon this information, the major programs for the REP were developed. Within the REP, work is evaluated on a dollars per change in customer minute interrupted ("$/Δ CMI").

Q. What is Feeder Hardening as referenced by Witness Reulet at p. 13 line 11 and how is it expected to affect reliability performance?

A. A subset of the REP, the Feeder Hardening Program assesses five year feeder reliability performance, with regard to deteriorated overhead equipment and lightning-caused interruptions, to select those feeders that can be improved through overhead maintenance activities and/or asset replacement. All feeders are ranked on: (i) the number of customers served; (ii) customer minutes interrupted per event; (iii) events per mile; and (iv) a dollars per change in reliability improvement metric allowing the Company to produce the greatest improvement in its reliability performance in the most efficient manner.

In FY07 (April 1, 2006 – March 31, 2007), the Company is hardening close to 600 miles of distribution line. In FY08 the Company plans to complete an additional 1,000 miles. The Feeder Hardening work plan is shown below in. As shown in (Reliability Panel-1R), work is planned across the state.

Q. In addition to the Feeder Hardening Plan, what other activity is the Company undertaking to improve reliability performance?

A. As a part of the REP, the Company also added 98 reclosers on its distribution feeders in FY07 and plans to add another approximately 100 in FY08. A focus has been placed on fusing side taps to improve reliability by further segmenting the circuits and reducing the number of affected customers during outages. This

work is intended to significantly improve overall customer reliability performance.

In addition to Feeder Hardening, the Company is also reviewing the PSC worst performing feeder list using an Engineering Reliability Review ("ERR") process. ERR reviews are evaluated strictly on the internal performance of the feeder itself. Major storms and supply issues are omitted from the study. The goal is to recommend projects that will reduce the number of faults, reduce customer minutes interrupted ("CMI") and/or improve the voltage performance of the feeder. The engineers typically recommend projects such as the installation of reclosers, the addition of side tap fusing, addition of capacitor banks and/or regulators to improve voltage performance and major projects, such as reconductoring or conversion to a different voltage. Major projects for FY08 include the creation of feeder ties, some with automatic loop schemes, and reconductoring from bare wire to tree wire or spacer cable.

Q. What is the distribution asset replacement program and how is it expected to affect reliability performance?

A. As with all utility companies, the Company's assets are deteriorating as they age. Aging alone does not necessitate replacement. In some cases, however, where it is inefficient or ineffective to provide a complete maintenance program, age is the primary indicator that replacement may be required. The Company has and is

continuing to develop asset-based programs to address specific asset classes to optimize the timing of asset replacement programs based on actual equipment condition and performance.

For example, distribution poles are evaluated and considered for replacement based on the following criteria: (i) age of the pole; (ii) type of equipment on the pole; (iii) proximity to the public; (iv) proximity to wetlands; (v) class of the pole; and (vi) condition of the pole. Other asset replacement programs include, but are not limited to: (i) cutouts; (ii) cable; (iii) substation breakers; (iv) transformers, and (v) conductor.

Asset replacement is intended to improve system performance over time.

Q. What is an enhanced vegetation management program and how is it expected to affect reliability performance?

A. The Company has trimmed trees on a cyclical basis since 1979. Starting in 1998, the Company changed its approach to vegetation management by extending the cycle time from five years to an average six year cycle. Some of the savings from this cycle extension were used to start up a new program know as the Tree Outage Reduction Operation or TORO. The program was implemented to remove trees that had a high probability of falling into the power lines, thereby interrupting customers. Based on analysis since the inception of the program, the Company believes that it needs to return to the five year trim cycle and that it must

incorporate the TORO program into this cycle program. To do that, the Company has allocated additional funding to accelerate the program such that by FY12 all circuits will have been trimmed within 5 years.

As I noted earlier, the Company has also refocused its efforts to sub-transmission right-of-way (ROW) widening, and plans to spend approximately $7.5 million between FY07-FY11 to accomplish this task.

Q. Can you please describe the inspection and maintenance ("I&M") program at National Grid?

A. The National Grid I&M program is a comprehensive program that requires inspectors to review 20% of National Grid facilities each year (a five year program) and to record every discrepancy that is found in the field, including those items that are not imminent failure risks or safety only items. In accordance with the Commission's Safety Orders in Case No. 04-M-0159, the Company's I&M program has been augmented for FY08 to have inspectors not only identify condition data but also to identify any deviation from existing internal construction standards.[6] For example, the Company requires arresters to be placed at the end of lines to protect for lightning. Inspectors now actively record where these items are missing. The inspection information directly links to our

6 Case 04-M-0159, Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, "Order Instituting Safety Standards" (January 5, 2005); "Order on Petitions for Rehearing and Waiver" (July 21, 2005) (the "Safety Orders").

asset replacement and reliability improvement processes and assists designers in developing comprehensive construction packages.

Q. What are the priority codes used within the I&M program (in the Computapole database)?

A. As described in DPS 281, defects found during the field inspections are prioritized in the Company's Computapole database in accordance with the following definitions: (i) A Priority - an identified facility/component or tree condition that must be repaired / replaced as soon as practicable; (ii) B Priority – an identified facility/component condition that shall be considered for repair/replacement as the feeder is scheduled for maintenance by Distribution Planning and Engineering. These identified conditions will be corrected as preventive maintenance and or facility life extension; (iii) C Priority – an identified facility/component condition that is being trended and reviewed by Distribution Planning and Engineering that may require replacement through the engineering process. Non-capital conditions identified under this priority will be corrected at the discretion of field operations; (iv) E Priority – an identified facility / component that must be replaced / repaired immediately to address public safety or system reliability; (v) F Priority – an identified forestry condition that should be scheduled as time permits, within the routine right-of-way maintenance and danger tree removal schedules. A

description of these codes has previously been provided to the Dept. of Public Service Staff in accordance with the Commission's Safety Orders.

Priority B and C are not necessarily potential reliability problems. The items that are identified as "B" maintenance items are those that shall be considered for repair/replacement as the feeder is scheduled for maintenance. These items do not require immediate attention and can be prioritized for remediation work. B maintenance items have been collected for numerous reasons including: (i) the existing infrastructure was built to the standards that existed at the time it was installed. As National Grid has evolved, so have the Company's and the Industry's standards, and therefore, during the inspection process items are identified that do not meet current standards. This does not mean that they are unsafe, less reliable, or require immediate attention or that these items are out of compliance with applicable standards (since the original construction standards may continue to apply). Over time these items will be addressed in a planned manner; (ii) the items have a possible safety impact with a very low probability of occurrence, but will have little impact on reliability; (iii) the items are not either safety or reliability related such as pole stenciling; or (iv) the items are good candidates for replacement sometime within the next five years, but, there is a need to review the inspectors' findings and to prioritize and schedule the work.

The items identified as "C" are those facility/component conditions that are being trended and reviewed by engineering that may require replacement through the engineering process over time. C maintenance items do not require immediate attention, but are noted so changes in performance can be tracked during the next inspection cycle. These items provide a broader view of asset condition to the Company and do not represent items that are likely to fail within the inspection cycle period. Only priorities A and E have short-term (within a year) impacts to reliability. The B items may or may not have a reliability impact. The C items are not short-term reliability-related but items for longer-term trending of an asset's condition. If an inspector feels that a specific maintenance item needs immediate attention, they are required to move the priority from B or C up to A or E. The Priority A items must be completed by November 30th of the year in which the item was found so long as it was found prior to November 1st. The Priority E items must be resolved immediately.

Q. Please discuss the testimony of Mr. Reulet with regard to the category B and C priority maintenance.

A. Mr. Reulet expresses concern over the effects on the Company's reliability due to the backlog of items categorized as Priority B or C. In particular, he notes that National Grid does not have any specific timeline to address all category B and C items. His concern is that these items become a reliability problem over time if

not addressed by the Company and, thus, should be addressed under a specified timeline.

Q. What is your opinion of Mr. Reulet's position on these priority B and C issues?

A. The company differs with his opinion that all category B and C items require a specified timeline for remediation. Each time these items are inspected, a new assessment of priority is performed, so items that may have been B or C, will be re-assigned a higher priority as necessary. In addition, certain of these items are being addressed in the context of other programs, such as the Feeder Hardening Program under the REP. Mr. Reulet correctly points out that B and C items are not immediate concerns for reliability but are indications that some conditions may need to be addressed during the next inspection cycle for category B items, and monitored over a longer period for category C items. The Company has category A and E for equipment that requires immediate attention. These must be fixed first. Items in category B and C, by definition do not require a set timeline to remediation.

Categories B and C provide the Company with a view to the condition of its assets and possible problems in the future. As such, they are effective tracking devices for the Company in plotting potential reliability issues. Since items in category B and C do not create an immediate risk to reliability and safety,

flexibility is necessary in handling the issues raised by equipment placed in category B and C. Mr. Reulet does state that the Company's Reliability Enhancement Program will work through some of the backlog of category B and, possibly, category C items. The REP will give National Grid the opportunity to clear some of the backlog for those items that have a greater impact on potential reliability problems in the future. However, the REP will select projects that have the greatest value for customers in terms of reliability impact first. As such category B and C items may remain if they are not causing problems in service.

Q Why is there an apparent backlog in maintenance for overhead lines in Transmission (115kV and above)?

A Table DW-1 Exhibit No. ___ (Reliability Panel-1R) shows a snapshot of transmission overhead line defects as percentages of the total transmission A, B, C, E and F priorities as listed in Computapole on March 1, 2007. As can be seen, only 2% of the defects are outstanding E priority and A priorities.

The current percentages of B priority defects for transmission are listed by category in Table DW-2 Exhibit No. ___ (Reliability Panel-1R).

National Grid's experience has shown that for transmission wood poles (19%) and foundations (1%), it is not cost effective for customers to replace assets on visual inspections alone, as visual inspections are not necessarily an accurate indicator of an imminent reliability risk. National Grid therefore relies on

alternative condition assessment techniques in determining which assets are to be replaced. For foundations, National Grid has a separate on-going program to inspect and repair all foundations on a 20 year cycle. Additionally, National Grid has an instituted program to paint its steel structures on a 15 to 20 year cycle. These alternative strategies for foundation work and tower painting are intended to avoid earlier than necessary expenditures in replacing equipment for our customers, and are hence more efficient.

There are also a number of B transmission maintenance items that do not impact reliability. Two such categories above, which make up 64% of B defects, include "Non-reliability" and "Insulators." The defects in the non-reliability category are issues that do not directly impact reliability such as missing signage. In addition, many of the transmission B maintenance insulator defects are insulators being out of plumb or one or two insulators missing or broken. A string of insulators may be made up of 8 or 9 insulators; although it would show up as a defect if only one insulator is broken or missing, it does not present a reliability risk and may not warrant immediate attention.

Vegetation related defects listed above (4%) are also handled outside of B maintenance work; we have a comprehensive transmission vegetation management program on which we currently spend $3.6 million annually.

The remaining B priority transmission defects (12%), which could impact

reliability and are not resolved through other maintenance programs, are resolved within our annual B maintenance program or capital investment programs.

Q. Staff Witness Reulet (p. 13) says the following, "[h]owever, the timing of this program, in light of the merger petition, raises questions about National Grid's true commitment to this subject." Would you care to comment on the timing of this program and whether it is in any way connected to the timing of the merger?

A. Staff Witness Reulet's statement suggesting that the REP was timed to respond to the merger is based on a misinterpretation of the facts. REP development began in 2004, long before the proposed merger, and thus any implication that the REP was timed to coincide with the merger petition is entirely incorrect.

Q. Staff asserts that the Company appears to have reduced its commitment to the REP from $1B to $750M in the span of a few weeks in September of 2006. Is this accurate?

A. No, there was a misunderstanding of DPS-12 and other statements made by the Company. The Company has committed to undertake the Reliability Enhancement Program described above. The response to Request# DPS-12 question 1(b) states, "[i]n fact, National Grid is committed to investing $750 million in their new electric reliability enhancement program over the next five years. $360 million will be invested in the existing NY electric infrastructure on

reliability programs." The $750 million referred to in DPS-12 is to be spent across all of National Grid's US territory in NY, MA, NH and RI. $360 million is specifically targeted to NY distribution reliability over the next five years to accomplish the distribution REP described above. As noted earlier in this testimony, this commitment adds $360 million to the baseline distribution reliability spending of $260 million yielding a total of $620 million focused on the reliability of distribution infrastructure over a five year period.

A complete summary of the Company's capital and reliability maintenance spending associated with the reliability enhancement program is included in the response to information request DPS-281. The table from that response is summarized and attached in Exhibit No. __ (Reliability Panel-2R). This table shows all components of the Reliability Enhancement Program and the total capital spending for the Niagara Mohawk service territory. The components of reliability spending that were referenced in Mr. Edwards letter (Reulet Exhibit DFR-7) included the total distribution reliability spending of $621 million shown on line 3 plus the transmission capital spending of $576 million shown on line 6. The $360 million of distribution capital spending corresponds to the amount for distribution capital shown on line 1, which together with the $265 million of maintenance expense shown on line 2 provides the total amount of spending on the reliability of the distribution infrastructure. The transmission capital spending

of $576 million over the next five years is also included in that analysis.

We recognize that the presentation of these numbers has created confusion. The problem stems from including both capital and O&M figures in the total spending and including New England and New York together in some cases, and not in others. This confusion will continue as we move forward with the programs, because to track spending we would have to identify specific O&M expenses or capital expenditures as associated with reliability enhancement as distinguished from other functions. To avoid this administrative burden, but still demonstrate our progress in implementing the plan, we are focusing on the total capital spending over the fiscal years ending in March 2007 through March 2011. As shown on the exhibit the total capital spend equals $1,470,000. This figure should be easily verifiable on National Grid's accounts. Thus, in the merger condition that we propose associated with the Reliability Enhancement Program we propose to track total capital spending over the period ending March 2011, and report those expenditures to the Commission. We will also explain any deviations from these levels in the reports to the Commission. In that way, the Commission should be apprised of our progress in the implementation of the Reliability Enhancement Program with an easily verifiable comparison.

Q. Could the level of spending change from the planned number?

A. Yes. The value is drawn from our business plan, and we review that plan

continually. However, in this case, we are committing to maintain at least the level of projected spending over the period to $1.4 billion. Our ability to spend this money will also depend on several factors including the ability to permit the projects and maintain the construction forces necessary to implement the work. The planned spending also depends on the prices and availability of materials. Each of these factors could cause the level or the timing of the spending to change from one year to the next. Nevertheless, our commitment is to implement a sustained investment program of $1.4 billion over the five years of the plan. That is the basis for the condition.

Q. Would you summarize National Grid's structure and processes for asset management across the system?

A. Yes, National Grid implements a focused and proactive approach to asset management across the business. Recognizing that the transmission and distribution functions serve distinctly different purposes, require specialist expertise, and each requires a devoted management focus, the Company has established dedicated Asset Management functions in Transmission and Distribution on each critical function. Distribution, on one hand is made up of many small facilities that distribute power in a radial fashion to many end users. It needs to manage many thousands of similar, small projects each with a relatively small cost (compared to transmission) but higher cost in aggregate.

Transmission on the other hand consists of much larger, more complex, harder to site, higher cost (per item) equipment with "regional impact." The Transmission function must manage a much lower number of higher cost, regionally critical projects. In many cases, different skills and expertise are needed in planning the two systems. Therefore, the Company has established dedicated Asset Management functions in Transmission and Distribution to manage the specific assets and asset types on a portfolio basis. Our approach is a systematic one, where we seek to continually update our understanding of the condition of an asset in a coordinated manner across all our assets. Decisions are made on a risk and criticality basis to maximize the long-term benefit to our customers over the whole lifetime of an asset. This means we not only optimize on asset risk, but we also consider the criticality of the asset to the customer both now and in the future, and optimize our approach to provide the least-cost solution to customers over the whole lifetime of an asset.

Q. How is the Asset Management approach applied at National Grid?

A. This approach is applied through a cyclical process that consists of collecting asset condition data, monitoring network performance, analyzing and developing strategies to address asset conditions and changing power flows, developing a coordinated plan, quantifying resources needed, obtaining approvals as required, and implementing the plan as designed. These programs are combined,

prioritized, put through a rigorous governance process for management approval, and developed into a work plan for execution by our engineering, project management and field forces.

Q. Please explain the time frame over which this current process works.

A. The process itself runs on an annual cycle with a business planning and work plan development process. Within the annual cycle, studies, analyses, project prioritization, and work plan adjustments are constantly undertaken. However, the results of this process may take many years to implement and be realized: in many cases five, ten, or even twenty years. A well thought out and justified transmission project can take three years to go through the stages of conceptual analysis, permitting and licensing to final implementation. Many larger projects on transmission can take ten years or more to go through their project development lives. To be cost efficient, asset condition data are typically collected over several years. For example, some of our line inspections are done on a five year cycle; if we need to find specific information for the entire system, it might take this period to collect all the information we need. Another example is forestry: in transmission we have been cycling our tree trimming and vegetation management programs on a 6-8 year cycle based on the height of the conductors and the distance from the cleared edge of the right-of-way. This cycle differs from the distribution cycle mentioned previously in this testimony. The

transmission cycle is consistent with the Commission's June 20, 2005 Order in Case 04-E-0822.[7] Hence it could take a number of years for a change in vegetation management approach to be fully implemented on the system. Of course, where we identify an immediate need for investment, a project receives top priority and moves ahead in the cycle.

It is also worth noting the condition of an asset tends to change slowly over many years, although there may be a point when the condition starts to deteriorate very quickly. Performance of an asset can change for a number of reasons including changes in the environment it is subjected to, its use over a long period of time, and how it has been maintained. While performance can change rapidly due to some of these factors (and will be addressed on a priority basis if it does), it is more likely that performance degrades slowly with the exact timing of ultimate failure unknown. Therefore the condition and performance of many of the assets on the system today are a result of practices and decisions made over the past twenty years or more. The same holds true for increasing performance. The performance of a given piece of equipment can be changed in a step fashion; however, an increase in the overall performance of the system can not always be turned around quickly and usually evolves with the regular cycle of data

7 Case 04-E-0822, In the Matter of Staff's Investigation into New York State's Electric Utility Transmission Right-of-Way Management Practices, filed in Case 27605, "Order Requiring Enhanced Transmission Right-of-Way Management Practices by Electric Utilities" (June 20, 2005).

collection, engineering, permitting, obtaining access to the system to take lines out of service, and construction phased over many years given the size of the system. Understanding this, one can see that the decisions being made today or even over the past five years, can only be expected to move performance in the right direction and the results might not be able to be seen for a number of years. This is a key element of Asset Management: that the assets that make up the power system are long-lived and decisions typically take some time to yield performance results.

Q. How does National Grid leverage its Asset Management expertise for its customers in New York?

A. National Grid benefits its customers in New York by leveraging its world wide knowledge and experience by sharing and deploying best practices across its businesses and functions. This best practice sharing leads to a diversity of ideas and the identification of common practices from which we can benefit. An example of this best practice sharing is Aerial Laser Survey. This technology has recently been deployed in the US and we are currently surveying the entire 115kV and above New York transmission system. Through best practice sharing National Grid has committed to continually improve its decision-making and mature its Asset Management system so decisions are made on a risk and criticality basis with the long-term consideration over the life of assets. This

approach is designed to deliver the least cost solution for customers to achieve maximum reliability over the whole lifetime of the assets.

Q. Can you give examples of other activities National Grid has undertaken since the merger to improve its management of its assets and thereby provide customer reliability benefits?

A. Directly related to active management of the assets, in 2005 we implemented an Asset Information and Maintenance Management System (AIMMS). This system provides us with the ability to manage planned and unplanned maintenance work on equipment in substations, on relay and telecommunications equipment, and in the HVDC installations. The system keeps track of the maintenance and number of operations of the substation equipment and automatically generates work requests based on maintenance needs calculated daily. The system has significantly enhanced and enabled us to prioritize our substation maintenance practices.

We have also modified our long established ComputaPole application, which is the overhead line inspection system. This system has been improved by, among other upgrades, the use of hand-held devices used by field inspectors to input field data directly into the application reducing the need to key in information later, a process that is inefficient and prone to mistakes in the transfer of data.

Q. What is the benefit to customers from this best practice approach?

A. The benefit to customers is value for money. The aim of this asset management approach is to manage our assets to deliver safe and adequate electric service at the lowest reasonable cost. This is often an area of reasonable engineering and business judgment on the part of decision makers. This is quite different from providing the highest reliability at any cost or the lowest possible cost with poor reliability; it is striking the balance that meets both objectives. The process needs to be applied consistently over the typical lifetime of our assets to achieve long-term customer benefits. Other benefits to customers include increased robustness in the transmission and distribution system to better withstand extreme events (such as storms).

Q. What capital and maintenance investments have National Grid made in the system since the merger?

A. National Grid has funded a program of investment in, and maintenance of, the Niagara Mohawk T&D infrastructure from the beginning of the merger. Exhibit __ (Reliability Panel-4R) of Mr. Laflamme's and Mr. Molloy's testimony shows that National Grid's annual O&M and capital expenditures increased significantly from 2001 to 2006 and its total expenditures in 2006 were $138 million higher than those in 2001 after adjusting for inflation. These numbers include the transmission and distribution investments for both maintenance and capital

investment. These increases in capital and O&M expenditures demonstrate a strong commitment to increasing reliability for National Grid's customers.

Q. Will the performance of the National Grid transmission system as measured by reliability indices (CAIDI and SAIFI) improve as a result of these expenditures?

A. As can be seen from earlier testimony, we are committed to a systematic approach to the management of our assets and improving their long-term performance as measured through these indices. Our objective has been to put in place a portfolio of asset programs which we are now implementing to progressively improve the condition and reliability of our assets in an efficient manner for our customers. Our efforts encompass all different asset types of capital replacement, for example pole and tower replacements, circuit breakers, transformers, spares, lightning performance, etc., and maintenance policies such as tower painting. We are also working to improve our inspection / condition assessment techniques and frequencies. While each targets a specific system need, they all have a different time period over which they will be effective.

As discussed previously, building and maintaining transmission is complex and the full results may not be evident in a short period of time. As an example, if we were to refurbish our top 10 worst performing transmission lines to make them perform comparably to our best performing lines, the cost would be

on the order of $400 million and would decrease the overall transmission system SAIFI by no more than 2.3% and have a negligible affect on CAIDI. This again demonstrates the significant lead time and resources necessary to make even a nominal difference to the improvement of our reliability statistics given the current asset age and condition.

Q. What transmission expenditures are National Grid planning to make that will improve reliability?

A. As shown in Exhibit No. __ (Reliability Panel-2R), we are forecasting to spend approximately $576 million to improve reliability, maintain asset health, accommodate load growth and load shift, and meet regulatory requirements. This level of spending shows we are committed to improving the performance of the system. It is also worth noting that in our capital spending plan provided to the PSC in 2005 we provided a 5-year forecast on transmission. Notwithstanding the comments of Witness Reulet (p. 13) suggesting that efforts to improve reliability are a response to the merger petition, our current spending forecast and the 2005 5-year forecast referenced above show that our capital spending plans have and are continuing to develop over time and are not just a short-term response to the merger filing. Based on our understanding of current and future needs, we believe that this level of spending is required to carry out the work necessary to have a transmission system capable of meeting the needs of consumers. It should also be

noted that, while we intend to spend overall at this level, the actual annual expenditures are periodically updated and might shift based on the latest available data and as a result of other factors such as availability of permits and outages to carry out the underlying work.

Q. What projects do you foresee will be included in future capital expenditure?

A. The future expenditure includes a number of incremental projects and programs developed over the last 5 years that will impact reliability. It includes programmatic replacements of facilities such as steel towers, wood poles, relays, switches, and breakers; it also includes specific major incremental projects such as work to ensure reliability of the 115 kV system following the retirement at the Huntley station, a substantial refurbishment of our two Porter-Rotterdam 230 kV lines (Porter-Rotterdam 30 & 31), and the asset replacement of the Clay 345kV station.

Q. Witnesses Leuthauser and McAfee, can you please provide further discussion regarding Exhibit No. __ (Reliability Panel-3R)?

A. This exhibit presents a tabular comparison of the staffing levels of line workers between 1999 and 2006. It also corrects and updates Reulet Exhibit DFR-3. The internal employees are reflected as a snap-shot of employee count at each calendar year-end, while the contractor count is based upon the average for the year.

Q. In response to Staff Witness Reulet's testimony that the Company fails to

have ample staff to respond to trouble, can you provide a comparison between the staffing for electric operations pre-merger versus today?

A. Yes. As shown in Exhibit No. __ (Reliability Panel-3R), the Company has not made significant cuts to its internal line workforce, i.e., 683 internal plus 0 contractors in 1999, to 663 internal plus 116 contractors in 2006. In fact, the Company has demonstrated its commitment to fill positions once they become vacant, by filling the majority of "Total Line Worker Terminations or Retirement" illustrated at the bottom of the exhibit. This has allowed the Company to maintain adequate levels by continually filling vacancies as well as complementing the workforce with contractor crews for targeted projects. The exhibit highlights that with the addition of contractor crews, the Company has effectively increased its workforce.

Q. What is a "Qualified" lineworker?

A. A "Qualified" lineworker has progressed to a level "C" or higher through on-the-job training and class room training, while levels "A" or "B" or "helper" are considered "Unqualified" lineworkers. The process of progressing from an entry level lineworker to a C lineworker takes about three and a half years. After an additional two years of experience and training, a C lineworker receives the hotstick rating. Contractor crews and other utilities follow a similar progression. Certain tasks require a one-person Qualified crew, while other tasks require a two-

person Qualified crew. As such an Unqualified lineworker is essentially an extra worker in a crew, permitting the crew to do more work in a given period of time. An Unqualified lineworker cannot serve as a substitute for a Qualified lineworker. However, the Company can supplement its complement of Qualified lineworkers with Qualified contractors. While our percentage of Qualified lineworkers is lower than historical levels, our number of Qualified contractors to offset this is considerably higher.

Q. Witness Reulet suggests that using contractors may not be effective and specifically, at page 10 line 2 states, "[a]dditionally, the number of available contractors can vary and hiring additional contractors can be delayed as a result of the bidding process." Do you agree with these assertions?

A. No. To the contrary, the contractor workforce provides select flexibility that is not offered by internal crews. Specifically, contractor crews can be sited in any geographic location and can be increased or decreased more readily. The Company has in place pre-negotiated agreements, referred to as "alliance contracts," which eliminate any delay that might result from continual re-bidding of contracts. Indeed, the time requirement for retaining a Qualified contractor (i.e., the "bidding process") is much quicker than the time it takes to qualify a lineworker. Furthermore, contractors tend to encourage the internal Company employees to remain competitive with respect to cost and productivity. The

Company has found through experience that utilizing a combination of both internal workers and contractors offers the greatest flexibility and ability to efficiently complete the work.

Q. Has the Company made changes to enhance the productivity and coverage of its internal workforce?

A. Yes. The Company has effectively made strategic changes to its workforce complement, including the addition of a new job classification of One Person Line/Trouble Mechanic Crews (OPCs). These OPCs have helped support and maintain outage & trouble response by increasing the availability of crews in the 24 hour day period. Essentially, the addition of the approximate 44 OPCs in New York has increased the coverage for emergency response. In addition the Company has added shifts increasing the use of flexible schedules to cover more hours.

Q. How can you assure the contractor will continue to work for National Grid when contractors are called upon to assist others during trouble or weather events?

A. The contract terms for these services are designed to bind the contractor to the Company, specifically, with the following provision:

"Emergency Assistance

60.1. If the Contractor is notified and requested to provide emergency assistance, by a company other than the Owner [National Grid], the Contractor shall request a

temporary release from the Agreement. It will be the Owner's decision as to whether this request will be granted. If the Owner agrees to temporarily authorize the release of the Contractor from its current obligations, both parties shall sign a Temporary Release Document. This Document will state for whom the Contractor will be working, the anticipated release period, that the Owner will not incur any costs or legal implications due to the Contractor's release and that the release will cause no significant delay in the completion of the Owner's Project."

Q. What are the Company's plans for future hiring for the line workforce?

A. The Company's current plan over the next three years is to add approximately 70 to 80 line worker positions to the New York service territory. The Company also anticipates that it will need to replace approximately 20 to 30 positions due to anticipated retirements over the same period of time. Overall the Company expects the resulting line worker total in New York to be in the range of 730 to 750. While this is the Company's goal, the projection must be considered approximate, given the difficulty in predicting the number of retirements that will actually take place.

The Company feels that at any one time 10 to 20 percent of these workers would be in a progression cycle. This would be an acceptable percentage and would allow the Company to stabilize its workforce attrition over the long-term. The plan is further supported and complemented by the Company's current contracting strategy as discussed earlier in this testimony.

While the Company's plan entails replacing retiring employees, it is extremely challenging to accurately estimate how many employees may choose to

retire at any given point in time. The retirement attrition process is further complicated by recent federal changes to pension reform. These changes have created an uncertainty which has caused employees to retire sooner than they may have otherwise. The Company could not have predicted the passage of new laws or their impact on the Company's workforce. Facing this uncertain attrition, the Company is establishing alliances with local community colleges to establish programs for lineworker training and education. Until such programs mature and retirements stabilize, the Company will continue to rely on the competitive market of Qualified contractors to address this volatility in workforce needs. The Company manages the staffing process to maintain a Qualified workforce presence. The Company recognizes that the percentage of its Qualified workers has been higher in prior years and as a result it needs to supplement its newer workforce with Qualified contractors while these new line mechanics complete the progression and training process.

Q. Do you believe that the integration team's staffing recommendations will adversely affect reliability in upstate New York?

A. No. The integration team's recommendations do not affect lineworker staffing. Estimated FTE reductions are focused on streamlining and consolidating back office, clerical and dispatch operations. In addition, the team has made a number of recommendations related to technology upgrades and adoption of best practices

intended to lead to better service.

Q. Can you elaborate on the Company's ability to respond to weather storm events?

A. The merger of National Grid and Niagara Mohawk expanded the pool of internal labor that is available for response to weather events. Although the number of internal T&D employees in New York is down slightly, the larger company provides a much greater number of internal crews that can respond to trouble and weather events. For example, in the recent storms in Buffalo beginning October 12, 2006, the Company utilized 154 FTEs (73 crews) from our New England operations. Again, in the ice storm beginning January 15, 2007, that plagued the state, especially in our Eastern New York Division, the Company utilized 51 FTEs (22 crews) from our New England operations. In addition, while Exhibit No. __ (Reliability Panel-3R) only shows contract resources in New York, the pool of contractors available during major weather events would include contractors on the Company's property both in New York and New England.

Pre-merger, mutual aid from National Grid - New England to assist customers in New York may not have been a priority. As a result of the merger, affiliated companies can be asked to prepare in advance of a storm, thus minimizing delays in crew movement as well as ensuring support that can now be planned and deployed strategically. With the addition of Keyspan, this will be

further enhanced by their workforce. In fact, with the most recent weather storms in Buffalo and Eastern Division, Keyspan/LIPA crews were used.

The Company utilizes consistent work practices, standards and operating procedures across our system. For example, with common clearance and control policies across the system we do not need to provide local line supervision to ensure that safe and proper tagging is taking place, as these crews are already trained in these work practices. The supervisor resources can now be used to support areas of restoration that have a more significant impact to shortening the restoration effort.

Q Does the contractor work schedule preclude them from being available Fridays or weekends as suggested by Witness Reulet at page 9, line 28?

A. In the event that a storm is predicted to hit on a particular weekend, the Company has the ability to hold contractor crews that would otherwise be completing their planned work for the week and has implemented this practice for all recent storms. Regardless of where the contractor lives, they can be retained to work on National Grid property.

Q. Witness Reulet at page 7 line 10 – 27 comments on the Company's performance in the aftermath of the February 17, 2006 windstorm. Can you comment on the Company's performance in major storms that followed the February 2006 windstorm.

A. Yes. Following the February 2006 Storm, the Company has adopted additional processes to respond to storms. In the more recent storms in Buffalo in October 2006, where approximately 262,800 customers were without power and recently in the Eastern Division starting on January 15, 2007, where approximately 85,000 customers were without power, the Company faced severe system damage and a large number of outages. The Company utilized an increased number of crews from many sources (internal, mutual aid and contractors). Specifically over 800 line crews were used in Buffalo and over 400 in the Eastern Division storm. The Company established centralized staging areas to manage and assign work to the crews. The Company has also reached further into the organization to provide support for field operations. In addition, the Company has enhanced its communication process with local governmental authorities (i.e., local mayors, town supervisors, etc.) by hosting daily conference calls with them. The Company has also used its website to post information on outages and restoration efforts. The Company has placed its communication trailer at readily accessible sites for local leaders to come and communicate with our Business Service personnel to exchange information. Increased communication channels have been implemented with positive feedback received.

Q. Has the Company received any recognition for its efforts to improve weather and storm response?

A. Yes. The Company received positive feedback from the media and the local governmental leaders in both of the recent storms in Buffalo and the Eastern Division. In addition, the Company received several awards over recent years for successful response. In particular, the Company won the Emergency Recovery Award for 2006 (presented in January of 2007) for its response to the October snowstorm in Buffalo, New York. Indeed, in a February 27, 2007, article in the Press Republican, Essex County Officials complimented the Company's restoration of power after storms and emergencies as well as the Company's progress in implementing its reliability enhancement plans for customers in the County.

Q. Do you agree with the assertion of Local 97 that reductions in the operating staff will result in a continual degradation in electric service reliability and safety?

A. No. Local 97 and Witness Reulet suggest that the correlation between reductions in internal line workforce and declining reliability performance is equivalent to causation, i.e., that the reductions cause the declining performance. This is not accurate. As discussed by Witness Warren previously, there are many other factors, not unique to National Grid, contributing to declining performance on the reliability indices. Local 97 provides no empirical or other evidence of a causal connection linking internal staffing directly with performance on the reliability

indices. As discussed previously in my testimony, the Company's commitment to line workforce is unabated. Moreover, the Company seeks to maintain a line workforce adequate to improve and maintain service quality and reliability performance, and to add additional line workers, where appropriate.

Q. Do you have any clarifications that you would like to make regarding Mr. Falleta's testimony pertaining to a December 2006 "Rollins Avenue," Saratoga Springs motor vehicle accident, and in particular regarding the role that concern about "rest time' played in the Company's actions that morning?

A. Yes. I'd like to provide a more complete description of the event in question. Our records indicate that Witness Falleta is referring to a pole strike on "Rowland Street" rather than "Rollins Avenue." At approximately 0230 on Sunday December 17, 2006, a motor vehicle accident (MVA) occurred at pole 63 on Rowland Street, Saratoga. At approximately 0300, a metering services representative was dispatched to the scene to assess the damage. The employee reported back to Eastern Regional Control that the pole had some damage approximately 4 feet above ground line and felt that it could be assigned to a crew that was scheduled to come in later that day. A crew from Glens Falls that was scheduled to work on that day arrived on site at 1100, evaluated the pole and made a decision not to undertake repairs at that time. No consideration of limiting

overtime hours worked was at play, since this crew continued to work until 1800 that day on other scheduled and emergency work. Later that day a supervisor visited pole 63 on Rowland Street to evaluate the pole and determine whether a work order should be created. Unfortunately, he entered the wrong pole number on the work order, and the work was not completed. While this outcome was regrettable, it was not the result of a conscious management decision not to undertake necessary repairs of damaged facilities. It is also worth noting that, at approximately 0830 on the same day, a second MVA occurred at pole 18, Route 9, Malta. Separate crews from Saratoga were called out to effect repairs at the Malta location. In light of the Company's willingness to dispatch crews to respond to these and other events, the Company was not restricting the dispatch of crews to do necessary work because of "rest time" or any other such concerns.

Q. Do you have any clarifications that you would like to make regarding Mr. Falleta's testimony pertaining to a January 6, 2007 pole being struck by a vehicle at approximately 11:00 p.m.?

A. We would like to provide a more complete description of the event in question. We requested information from Local 97, so we could identify the incident in question and provide a more thorough explanation. However, the information was not available in time to research the second incident and prepare a response.

Q. Has the Company implemented a downsizing program of its line workforce

as alluded to by Witness Reulet and Local 97.

A. No. The Company has experienced volatility in retirements as shown on Exhibit No. __ (Reliability Panel-3R). As discussed previously in our testimony, to combat this, the Company has hired additional employees (both Qualified and Unqualified) into the line department, established alliances with community colleges, and retained additional Qualified contractors. In aggregate, the Company has now effectively increased its line workforce since the merger.

Q. Does this conclude the testimony of the Reliability Panel?

A. Yes it does.

CHARTS, GRAPHS AND TABLES

REFERRED TO

REBUTTAL TESTIMONY

OF

NATIONAL GRID'S RELIABILITY PANEL

CHERYL WARREN

DAVID WRIGHT

KEITH MCAFEE

SCOTT LEUTHAUSER

Figure 1. SAIFI – DFR-1

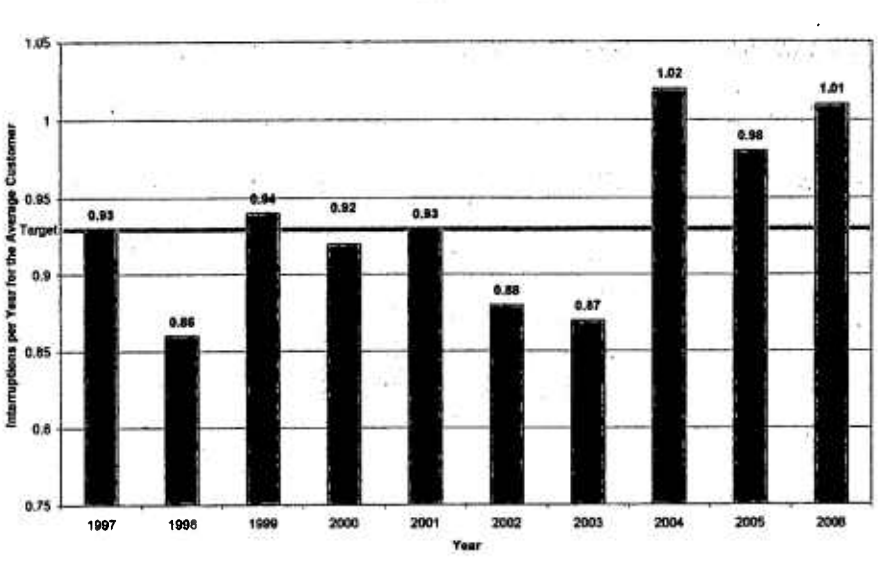


Figure 2. CAIDI – DFR-2

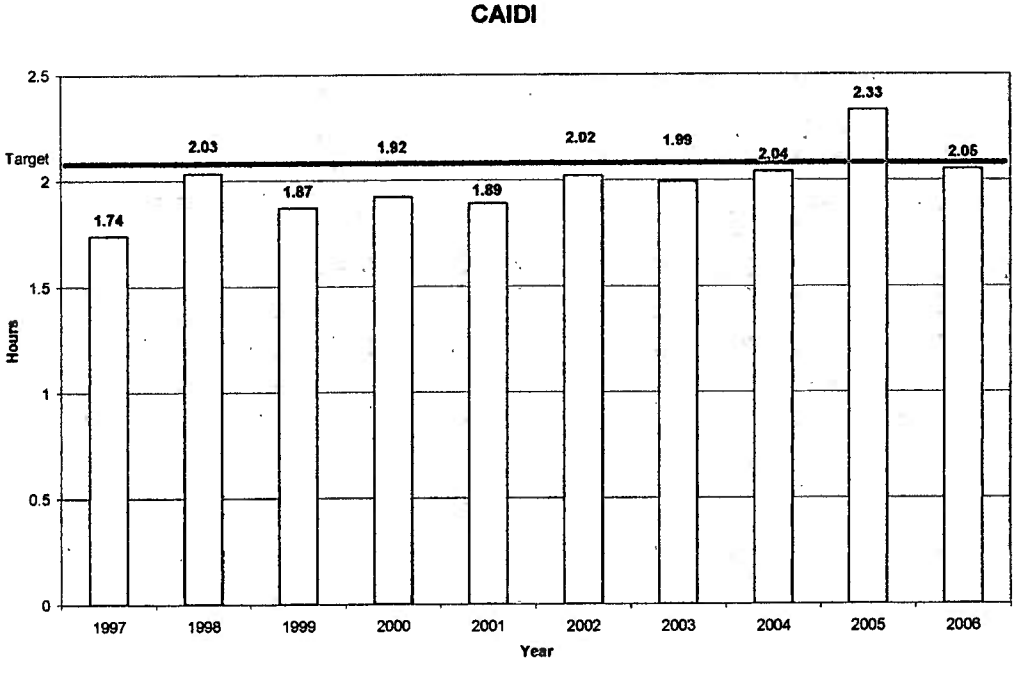


Figure 3. Some of the Major Causes of SAIFI Increase

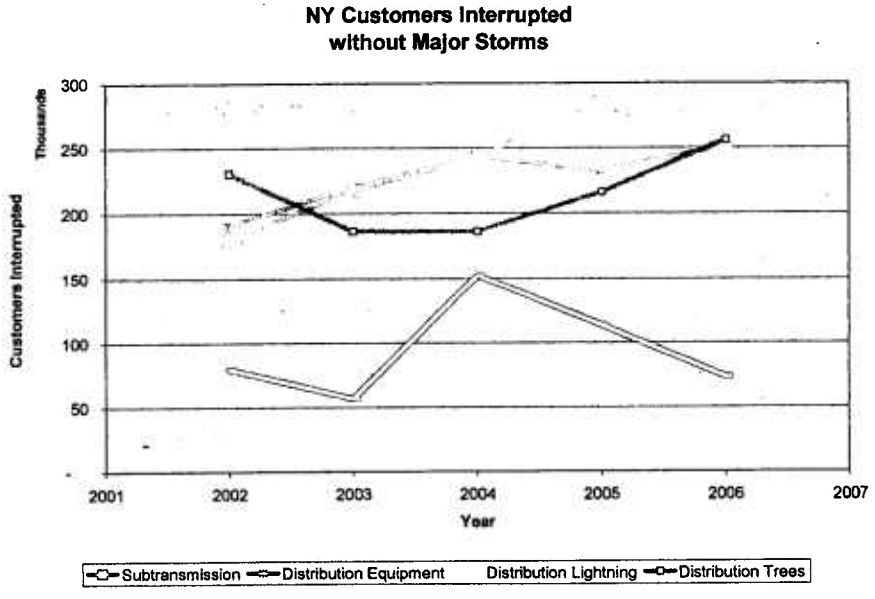


Figure 4. Number of Lightning Strikes to the National Grid Service Territory per the Vaisala Lightning Detection Network

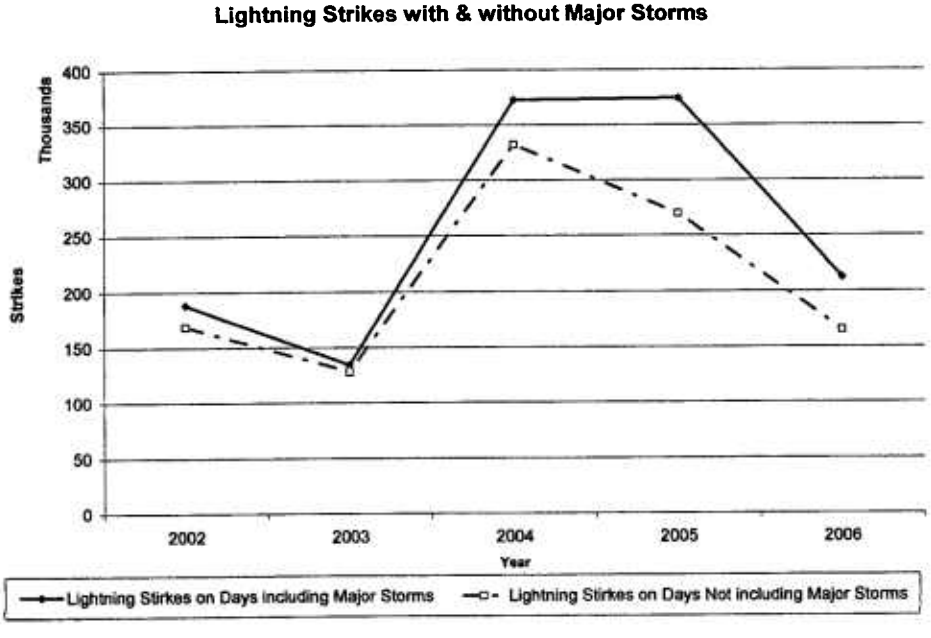


Figure 5. Customers Interrupted by Subtransmission Interruptions

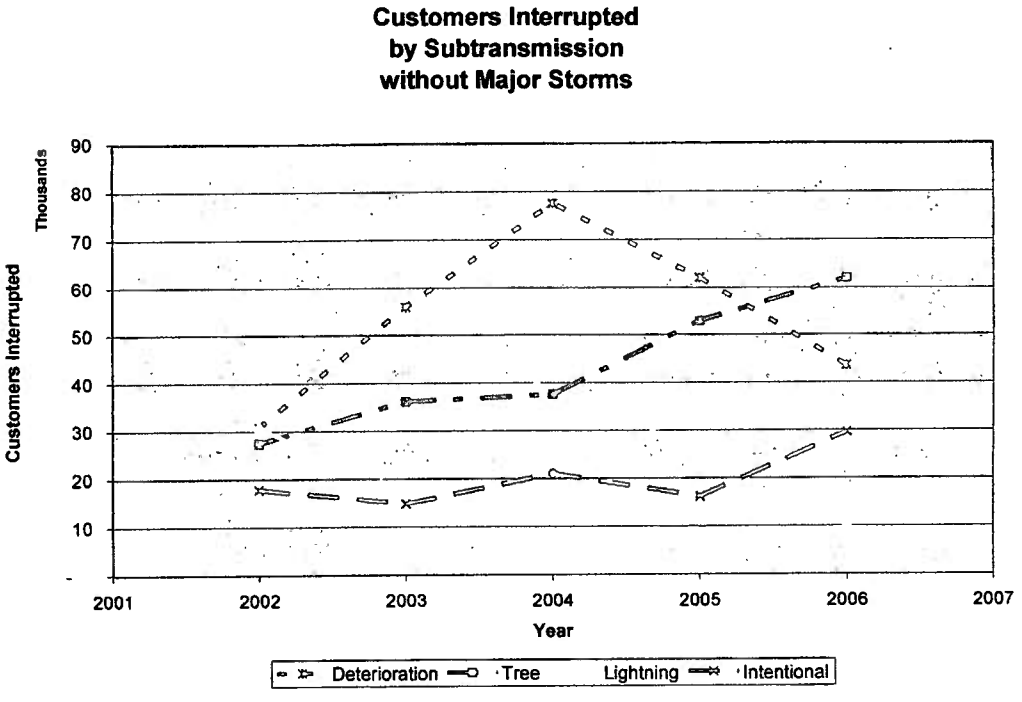


Figure 6. SAIFI performance of NYS Utilities (not including Con Ed)

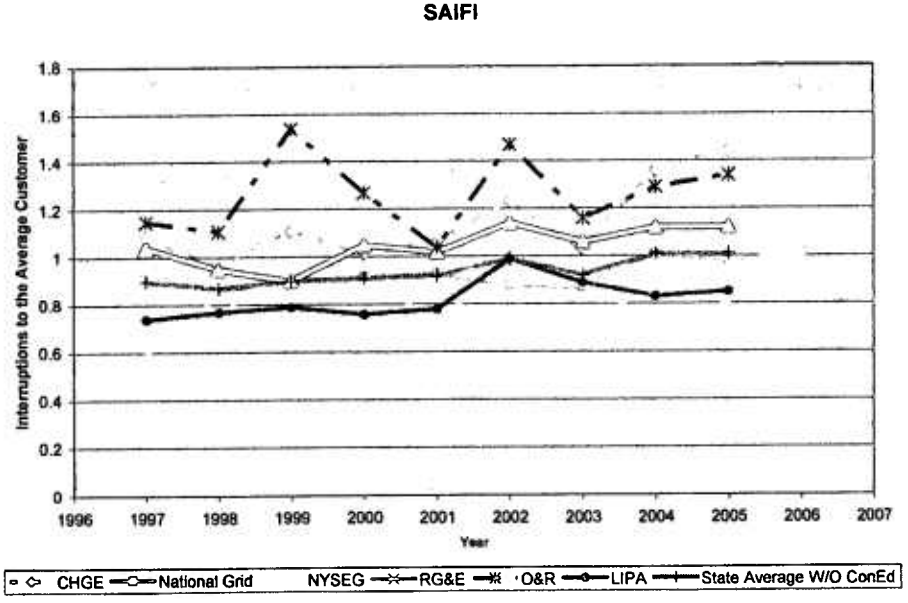


Figure 7. CAIDI performance of NYS Utilities (not including Con Ed)

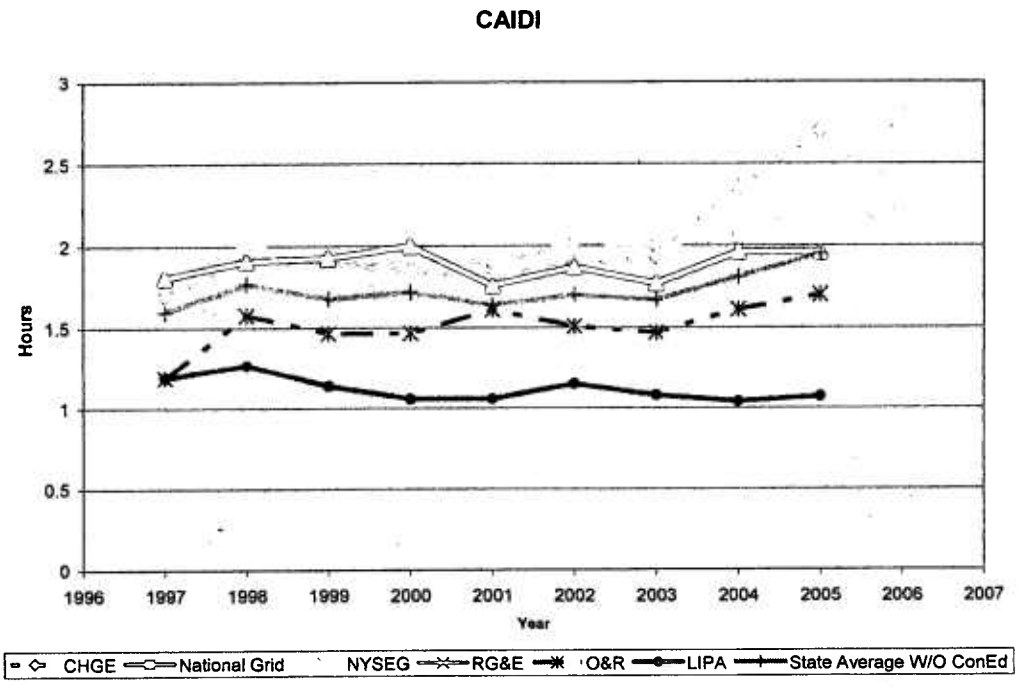


Figure 8. IEEE Reliability Performance Trends

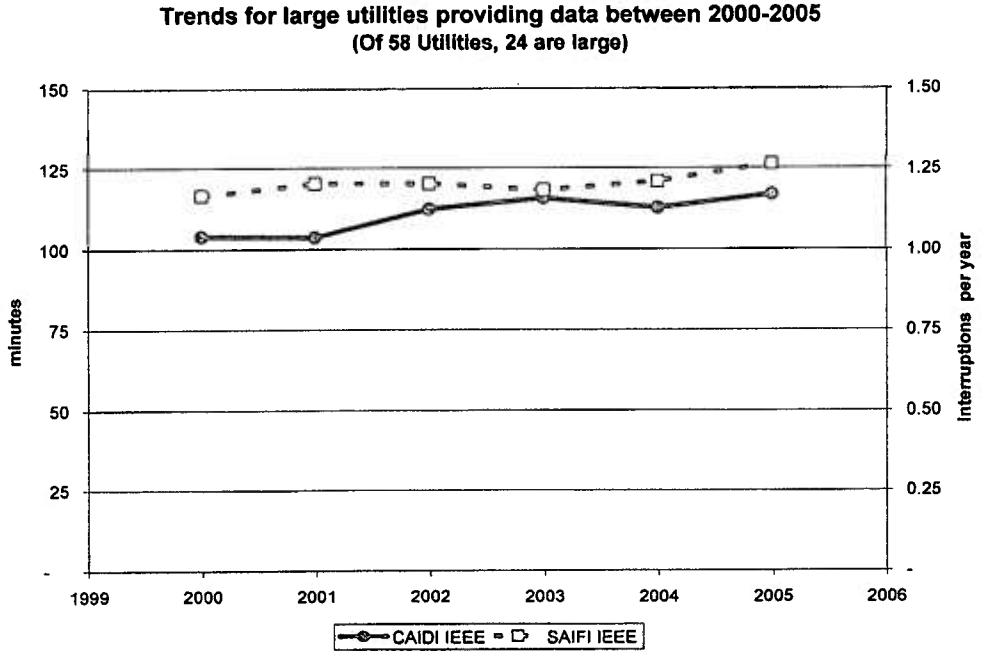


Figure 9. IEEE Reliability SAIFI Performance Trend as compared to National Grid NY's performance

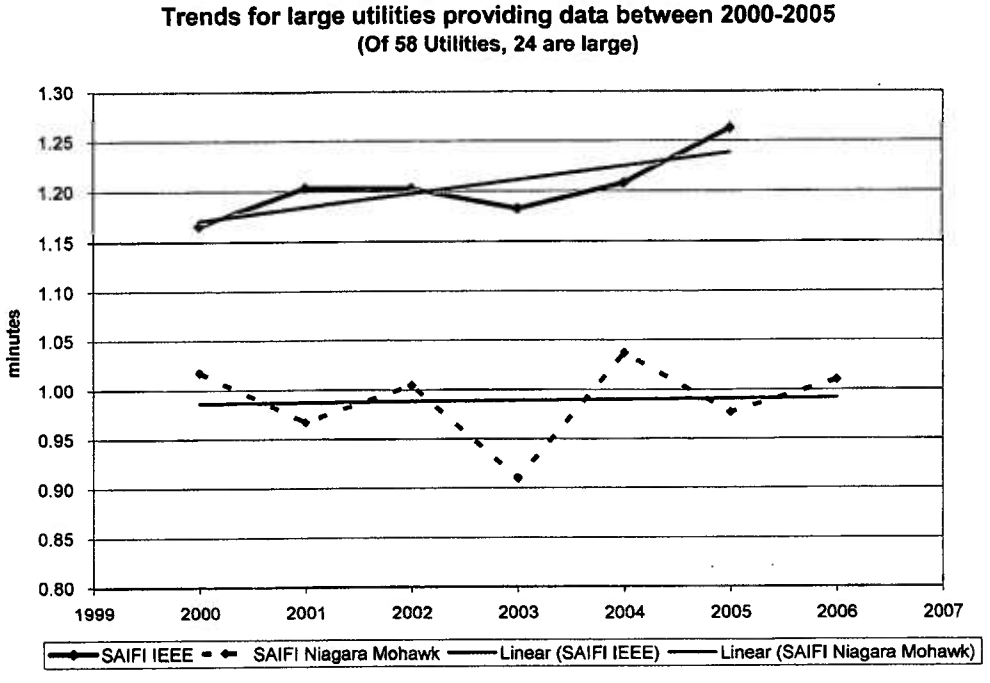


Figure 10.IEEE Reliability CAIDI Performance Trend as compared to National Grid NY's performance

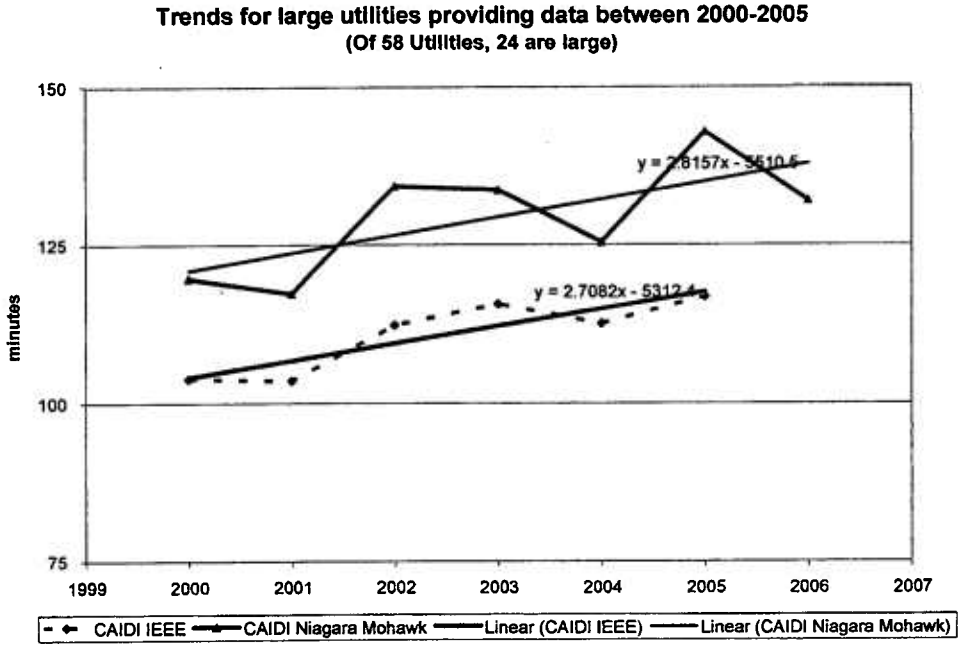


Figure 11. Trend of Underlying Root Causes to worsening performance

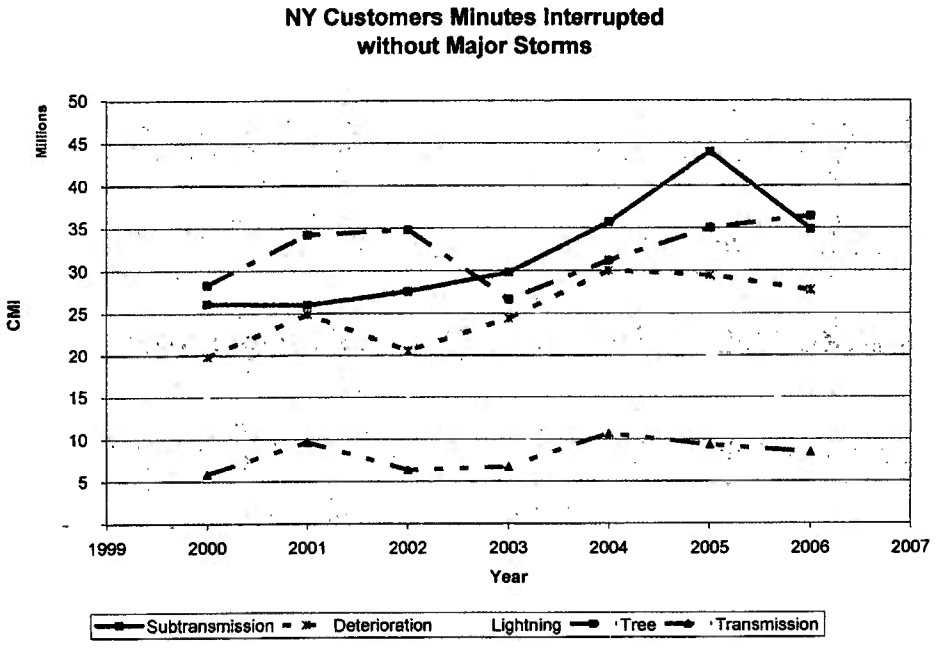


Figure 12. Preliminary FY08 and FY 09 Feeder Hardening plan

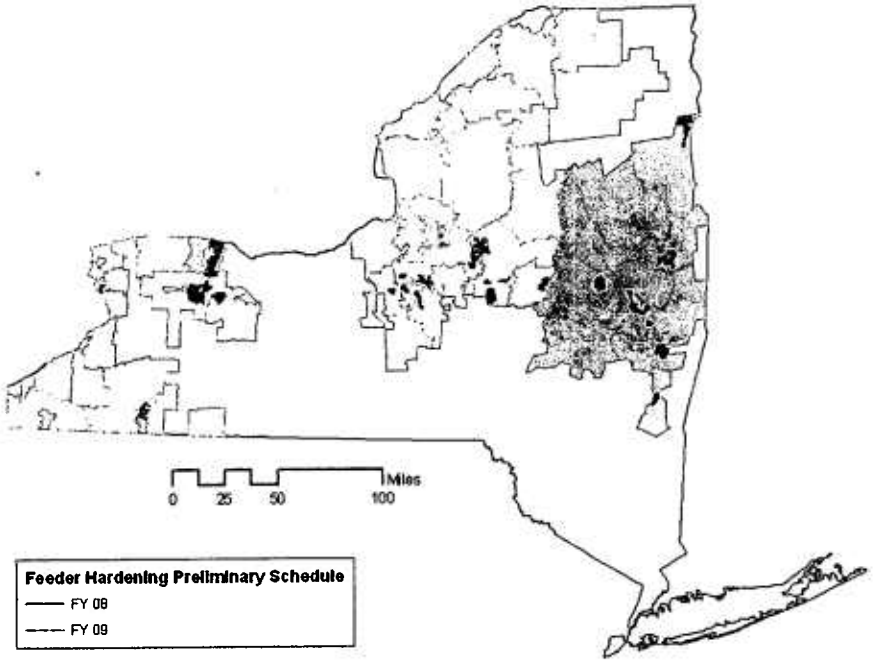


Table DW-1

Priority	Number of Defects
A	558
B	14870
C	15910
E	1
F	2897

Table DW-2

Defect Category	**Percentage of Total B Defects**
Poles	19%
Insulators	14%
Conductors	6%
Towers	2%
Foundations	1%
Grounds	2%
Vegetation	4%
Non-reliability	52%
Totals	100%

Exhibit No. _ (Reliability Panel-2R)
Summary of Capital Additions Forecast

	Fiscal Year					
	2007	2008	2009	2010	2011	Total
1 Distribution Reliability Capital Spending	58,000,000	63,000,000	75,000,000	80,000,000	80,000,000	356,000,000
2 Distribution Non-Reliability Capital Spending	111,000,000	109,000,000	108,000,000	105,000,000	105,000,000	538,000,000
3 Total Distribution Capital Spending	169,000,000	172,000,000	183,000,000	185,000,000	185,000,000	894,000,000
4 Transmission Capital Spending	86,000,000	103,000,000	118,000,000	131,000,000	138,000,000	576,000,000
5 Total T&D Capital Spending	255,000,000	275,000,000	301,000,000	316,000,000	323,000,000	1,470,000,000

Exhibit No. _ (Reliability Panel-2R)
Summary of IR# DPS - 281 Forecast

	Fiscal Year					
	2007	2008	2009	2010	2011	Total
1 Distribution Reliability Capital Spending	58,000,000	63,000,000	75,000,000	80,000,000	80,000,000	356,000,000
2 Distribution Reliability Maintenance Spending	47,000,000	51,000,000	55,000,000	56,000,000	56,000,000	265,000,000
3 Total Distribution Reliability Spending	105,000,000	114,000,000	130,000,000	136,000,000	136,000,000	621,000,000
4 Distribution Non-Reliability Capital Spending	111,000,000	109,000,000	108,000,000	105,000,000	105,000,000	538,000,000
5 Total Distribution Capital Spending	169,000,000	172,000,000	183,000,000	185,000,000	185,000,000	894,000,000
6 Transmission Capital Spending	86,000,000	103,000,000	118,000,000	131,000,000	138,000,000	576,000,000
7 Transmission Maintenance Spending	16,000,000	18,000,000	18,000,000	17,000,000	18,000,000	87,000,000
8 Total Transmission Spending	102,000,000	121,000,000	136,000,000	148,000,000	156,000,000	663,000,000
9 Total T & D Capital Spending	255,000,000	275,000,000	301,000,000	316,000,000	323,000,000	1,470,000,000

1 IR DPS - 281
2 IR DPS - 281
3 Line 1 + Line 2
4 IR DPS - 281
5 Line 3 + Line 4

6 IR DPS - 281
7 IR DPS - 281
8 Line 6 + Line 7
9 Line 3 + Line 8
10 Line 3 + Line 6

Line Workers
1999-2006

Case 06-M-0878
Exhibit No.__(Reliability Panel-3R)

Job Title	Year End 1999	Year End 2000	Year End 2001	Year End 2002	Year End 2003	Year End 2004	Year End 2005	Year End 2006
Qualified Line Workers								
Chief Line Mechanic A Hotstick	300	358	366	351	298	297	287	238
Chief Line Mechanic B Hotstick	0	0	0	0	0	1	1	0
Line Mechanic Hotstick	344	257	228	212	195	161	149	167
Line Mechanic C	15	28	22	21	46	93	99	54
One Person Line/Trouble Mech	0	0	0	0	0	0	47	45
Trouble Mech A Hot Stick	0	0	0	0	1	0	0	0
Trouble Mech B Hot Stick	0	0	0	0	1	0	0	0
Trouble Mech C Hot Stick	3	5	5	4	5	6	4	4
Trouble Mech D Hot Stick	4	4	5	5	9	11	7	5
SubTotal Qualified	**666**	**652**	**626**	**593**	**555**	**569**	**594**	**513**
Avg Age Qualifed	47	47	48	48	47	47	46	46
Unqualified Line Workers								
Line Mechanic A	3	50	66	49	19	47	30	43
Line Mechanic B	3	13	39	95	102	64	65	83
Line Mechanic Helper	11	15	32	6	8	7	22	24
Sub Total Unqualified	**17**	**78**	**137**	**150**	**129**	**118**	**117**	**150**
Avg Age Unqualified	40	39	38	38	37	37	37	
Total Line Workers								
Total	**683**	**730**	**763**	**743**	**684**	**687**	**711**	**663**
Total Line Worker Terminations or Retirements								
Sub-total Qualified	(107)	(29)	(31)	(42)	(59)	(31)	(24)	(81)
Sub-otal Unqualifed	0	0	0	0	(1)	(2)	(6)	0
Total Terminations or Retirements	**(107)**	**(29)**	**(31)**	**(42)**	**(60)**	**(33)**	**(30)**	**(81)**
Line Workers Hired								
Total		**76**	**64**	**22**	**1**	**36**	**54**	**33**
Estimated Contractor Compliment								
Total T&D Contractors	**Approx. 0**							**116.1**
Total T&D Line Workers and Contractors								**779.1**

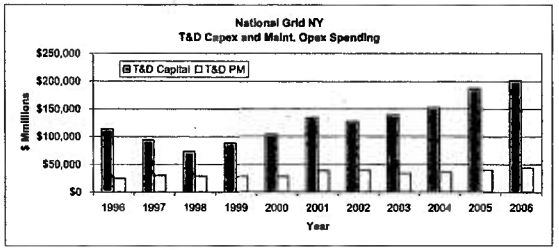
National Grid
New York
PSC Request
DPS-281
Part 2a

T&D Capital and Maint. Spending	Calendar Year 1996	1997	1998	1999	Fiscal Year 2000	2001	2002	2003	2004	2005	2006
Capital - Actual	$113,700	$93,800	$73,400	$88,300	$103,900	$133,500	$127,145	$139,200	$152,400	$185,100	$201,968
Maintenance - Actual	24,500	29,900	28,300	27,600	27,600	37,900	39,600	33,400	35,300	39,500	43,940
Total T&D Capital & Maint. Spending	**$138,200**	**$123,700**	**$101,700**	**$115,900**	**$131,500**	**$171,400**	**$166,745**	**$172,600**	**$187,700**	**$224,600**	**$245,908**

Distribution Reliability Spending	Fiscal Year 2007	2008	2009	2010	2011
Capital	$58,000	$63,000	$75,000	$80,000	$80,000
Maintenance	47,000	51,000	55,000	56,000	56,000
Total D Reliability Spending	**$105,000**	**$114,000**	**$130,000**	**$136,000**	**$136,000**
Non-Reliability Capital Spending	111,000	109,000	108,000	105,000	105,000
Total D Capital & Maint. Spending	**$216,000**	**$223,000**	**$238,000**	**$241,000**	**$241,000**

Transmission Spending	Fiscal Year 2007	2008	2009	2010	2011
Capital	$86,000	$103,000	$118,000	$131,000	$138,000
Maintenance	16,000	18,000	18,000	17,000	18,000
Total T Capital & Maint. Spending	**$102,000**	**$121,000**	**$136,000**	**$148,000**	**$156,000**

T&D Capital & Maint. Spending	Fiscal Year 2007	2008	2009	2010	2011
Capital	$255,000	$275,000	$301,000	$316,000	$323,000
Maintenance	63,000	69,000	73,000	73,000	74,000
Total T&D Capital & Maint. Spending	**$318,000**	**$344,000**	**$374,000**	**$389,000**	**$397,000**



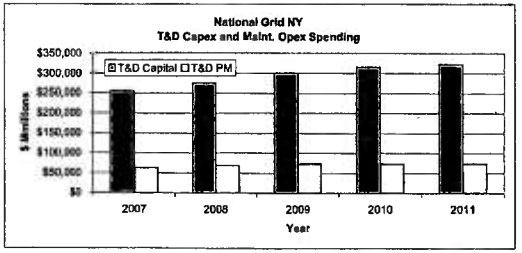


Exhibit ___ (Reliability Panel-4R)

PREPARED REBUTTAL TESTIMONY

OF

JOSEPH F. BODANZA,

MICHAEL D. LAFLAMME

AND

JAMES M. MOLLOY

ON BEHALF OF

NATIONAL GRID plc

AND

KEYSPAN CORPORATION

CASE 06-M-0878

MARCH 7, 2007

Joseph F. Bodanza
Michael D. Laflamme
James M. Molloy

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full names and business addresses.

A. My name is Michael D. Laflamme. My business address is 55 Bearfoot Road, Northboro, Massachusetts 01532.

Q. Are you the same Michael D. Laflamme who previously submitted testimony in this proceeding?

A. Yes, I am.

Q. Please state your full names and business addresses.

A. My name is James M. Molloy. My business address is 25 Research Drive, Westborough, Massachusetts 01582.

Q. Are you the same James M. Molloy who previously submitted testimony in this proceeding?

A. Yes, I am.

Q. Please state your full names and business addresses

A. My name is Joseph F. Bodanza. My business address is One MetroTech Plaza, Brooklyn, New York, 11201.

Q. Are you the same Joseph F. Bodanza who previously submitted testimony in this proceeding?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of this Supplemental testimony?

A. This rebuttal testimony will address the Company's alternative to the 10 year rate plans that it proposed in its initial petition. As explained by Mr. Reilly and Mr. Zelkowitz, although we believe that the ten year rate plans that we initially proposed for KEDNY and KEDLI are in the best interests of our customers, in response to the comments by the parties, we are formally proposing an alternative rate plan of three years, as outlined in the attached Exhibit No. (Rates Panel-1R) and as supported by Mr. Bodanza. As part of this alternative resolution, we are requesting that the Commission authorize KEDNY and KEDLI: (1) to amortize the actual costs to achieve, with a return, over ten years after the close of the merger; (2) to implement a merger credit equal to 50 percent of the net synergy savings, calculated including the 10 year levelized costs to achieve, as a reduction to the stand-alone rates approved for KEDNY and KEDLI in this proceeding; and (3) to authorize KEDNY and KEDLI to include in their costs of service for the ten years after the close of the merger a net synergy savings allowance equal to 50 percent of the net synergies allocated to those Companies in our filing.

In this testimony, we address four items. First, we address the key elements of our proposal for alternative three year rate plans for KEDNY and KEDLI. Second, we provide an explanation of the synergy savings adjustments to

the rates that we summarized above. Third, we address the issues presented by the parties about the allocation of the synergy savings among the companies on the combined systems, the length of the synergy saving period, and the sharing between customers and the Companies. Finally, we respond to the issues raised by several parties with regard to the operation of the Niagara Mohawk rate plan. Specifically, we explain that under the rate plan, Niagara Mohawk has increased spending on operations and maintenance expense and capital for transmission and distribution above the levels that the Company spent prior to the merger and above the allowance in the Niagara Mohawk rate plan. Thus, contrary to the arguments of the Unions and the Staff, Niagara Mohawk has not reduced its focus on the reliability of its infra-structure. Rather, it has significantly increased the resources devoted to T&D operations and infra-structure. As the reliability panel describes, we are planning to increase these resources further in the coming years.

III. THE ALTERNATIVE TO THE PROPOSED RATE PLANS

Q. Has the Company modified its Rate Plan proposals in response to comments filed by the parties on February 20, 2006?

A. Yes we have. The alternative that we propose is a more traditional approach to a multi-year rate plan. The stand-alone rate cases for KEDNY and KEDLI have been subject to review by all parties since their initial filing on October 3, 2006. We propose to work with the parties to settle the cases within the time frame

allowed by the procedural schedule, or failing a settlement, proceed to a litigated outcome. The parties who addressed this issue have all indicated a willingness to discuss rate plans of up to three years, and we are hopeful that we can arrive at a resolution on this basis. The key issues that KEDNY and KEDLI would like to have addressed in the context of a three year settlement are set forth in Exhibit No. __(Rates Panel-1R).

Q. What are the provisions of the three year rate plans proposed by KEDNY and KEDLI?

A. Exhibit No. __ (Rates Panel-1R) provides the framework under which the Company believes a three year rate plan could be negotiated and/or approved by the Commission. As indicated in the exhibit, KEDNY's and KEDLI's rates would be based on each company's stand alone cost of service as determined in cases 06-G-1185 and 06-G-1186, including resolution of issues surrounding the deferral and recovery of certain costs such as SIR, special franchise and real estate taxes, and pension and OPEB expenses. The delivery rates themselves would be fixed for the three year period. The resulting base delivery rates would be reduced by a customer credit based upon the expected net synergies for the three years following the closing of the merger as discussed further in this testimony. The plans would also establish a capital tracker on forecasted non-growth capital additions. These deferral and capital tracker mechanisms are intended to ensure

that customers pay no more or no less than actual expenditures for such deferral and capital items.

Q. What happens if no settlement is reached?

A. We would request the Commission to approve the proposed rate plans. The synergy saving adjustments that we propose in the next section would apply to the stand-alone rates whether determined in a settlement or by the Commission following litigation.

IV. THE TREATMENT OF NET SYNERGY ADJUSTMENTS IN THE ALTERNATIVE PROPOSAL

Q. How does the alternative proposal address synergy savings?

A. We propose that the Commission authorize KEDNY's and KEDLI's rates and cost of service to reflect the net synergy savings adjustment as proposed herein. Under our proposal, a credit equal to 50 percent of the net synergy savings from the merger would be reflected in KEDNY's and KEDLI's cost of service on the effective date of their stand-alone rates,. The adjustment would reduce KEDNY's and KEDLI's cost of service from the stand-alone rate cases by 50 percent of net synergy savings.

Q. How would the amount of the credit be determined?

A. We have calculated a level adjustment for the three year rate plan by first calculating an annual amortization amount for costs to achieve based on the deferral and 10 year recovery of such costs. This annual amortization of costs to achieve would then be subtracted from the annual synergy savings for the three year period in arriving at net synergy savings for the first three years. The resulting net synergies were then levelized over the three year period. The customer credit that would be implemented for customers over the same three year period would equal 50% of this levelized amount. This calculation is shown on Exhibit No. __(Rates Panel-2R). The approach assures that positive savings are allocated to KEDNY's and KEDLI's customers from the outset. The ten-year amortization of costs to achieve eliminates the front loading of these costs, and results in the recognition of net synergies savings in the first year. The synergies for the initial three year period are also levelized to arrive at a fixed customer credit for the three year rate plan. As a result, this approach creates an immediate reduction to KEDNY's and KEDLI's costs of service.

As shown on Exhibit No. __(Rates Panel-2R), this credit will reduce KEDNY's rates by $5.9 million and KEDLI's rates by $3.5 million. It will provide mitigation for the stand alone rate filings. The credit to the cost of service would remain in effect until KEDNY or KEDLI propose new rates. Thus, the

credit will remain in effect through the beginning of year 4 (or later if no filing occurs at that time).

Q. How would net synergies be treated in subsequent filings?

A. If the filing occurs after a three year settlement, the integration process should be complete and the synergies will have been fully realized. These savings will be reflected in lower expenses in KEDNY's and KEDLI's cost of service. We are proposing, however, that in that next rate filing KEDNY and KEDLI would be authorized to include an expense allowance in their costs of service equal to the same 50 percent of the projected net synergy savings that are projected for the effective year of rates as shown on Exhibit No. (Rates Panel-2R). The right to add this 50 percent back to the cost of service would continue for ten years following the close of the merger.

Q. What concerns of the parties does the alternative rate plan address?

A. First, the proposal shortens the rate plan period. All the parties who commented on the rate plan objected to the ten-year term proposed in our initial filing.

Second, the proposal amortizes the costs to achieve to allow positive net synergies to be realized from the outset. As explained in the testimony of the synergy panel the $400 million estimate of costs to achieve remains conservative and reasonable.

Third, the proposal provides a significant up-front credit from the completion of the merger, producing the rate mitigation for KEDNY and KEDLI that we were seeking with our initial rate proposal. This credit provides KEDNY's and KEDLI's customers with concrete and continuing benefits from the merger.

Finally, several parties suggested that our estimate of synergy savings was too low or that the allocation of those savings to KEDNY and KEDLI was insufficient. This proposal assures that, if the savings actually realized at KEDNY and KEDLI are higher than our initial estimate, the incremental benefits will flow to KEDNY's and KEDLI's customers. Under the current proposal, the net synergy saving allowance to KEDNY and KEDLI is fixed at the outset. If we outperform the estimate or if more savings are actually allocated to KEDNY or KEDLI than we have forecast, customers will realize 100 percent of the additional savings from that performance. The additional savings will be automatically reflected in a lower cost of service for KEDNY and KEDLI in future rate proceedings, but the Company's allowance will remain fixed.

V. THE ALLOCATION AND SHARING OF SYNERGY SAVINGS

Q. What are the remaining issues that need to be addressed?

A. 1) The appropriate allocation method, 2) customer and company sharing percentages, and 3) the amount of the synergy savings and costs to achieve. Mr. Fiebelman and Mr. Levin address the issue 3 for the Companies and conclude that the $200 million estimate of synergy savings and the $400 million estimate of costs to achieve remain conservative and reasonable. We do, however, continue to include transaction costs and executive payments in our analysis of costs to achieve, contrary to Dr. Elfner's suggestion. Thus, in this section of our testimony, we only address the first two issues focused on the allocation of synergy savings among the companies and the sharing between KEDNY and KEDLI and their customers.

Q. What are the objectives underlying your proposed allocation methodology of synergy savings among the operating companies on the combined system?

A. We have two objectives. First and foremost, we are seeking an allocation that accurately portrays how the savings will flow among the various companies on the system after the merger. Second, we are seeking consistency among all of the companies on the system. Quite simply, we wish to avoid gaps or overlaps in the allocation methodology.

Q. Does the methodology that you selected meet those objectives?

A. Yes. We believe that an allocation based on delivery revenues of the regulated companies allocates the savings in a manner that will match the flow of synergy

savings as they are realized following the merger. These delivery revenues encompass all of the activities undertaken by the regulated companies. The distribution of the actual experienced savings among the regulated companies is likely to occur in the same pattern as the distribution of the overall costs of service that give rise to the revenue requirements for each entity. We have excluded from the analysis revenues from stranded or commodity costs that do not give rise to the synergy savings being realized. Thus, the remaining costs in the analysis represent the base revenue requirements associated with the delivery services actually performed by the operating companies. As we have explained this is the same approach that we used and the Commission approved in the Niagara Mohawk rate plan. We continue to believe that these revenue requirements will match the flow of synergy savings from the merger.

In the case of LIPA, KeySpan provides much of the services and employees that give rise to synergy savings, but LIPA owns the transmission and distribution plant that is not affected by the integration as much. To better match the likely flow of savings to LIPA under its contracts with KeySpan, we adjusted the revenues under the contracts to reflect the revenue requirements associated with LIPA's T&D investment. In this way, the LIPA allocation of synergy savings is done on a basis that is consistent with the rest of the analysis In

addition, we included the non-commodity revenues associated with unregulated activities.

This approach produces a consistent result across the combined system. The methodology is derived from the Niagara Mohawk rate plan and was approved by the Commission in Case 01-M-0075. We have used the same methodology to forecast synergy savings across the system in all of our regulatory proceedings. For both these reasons, we believe that the allocation methodology represents a reasonable approach for KEDNY, KEDLI, and of course Niagara Mohawk, for which it has already been approved.

Q. Staff raised concerns with the allocation methodology. What is your response to Staff's concerns?

A. Staff ignores the purpose of the allocation methodology. We are not seeking to "allocate more or less" to one company or another; we are seeking to accurately forecast the actual amount of savings that will flow to the different entities on the system. Staff's approach if adopted would not lead to cost based rates for any company on the combined system. For example, suppose we adopted the suggestion to exclude the electric transmission function from the allocation, and instead allocated those savings to KEDNY and KEDLI in the analysis. When the merger closed and the savings were realized, a portion of the savings would actually flow to transmission, rather than to KEDNY and KEDLI, and the electric

transmission cost of service would be over-stated while the gas distribution cost of service would be understated. The incorrect allocation would produce rates that are not cost based. The allocation suggested by Staff is clearly result-oriented, and not designed to produce an equitable allocation methodology. It is inappropriate and should not be adopted.

Q. Would the incorrect allocation have the same effect under the new proposal that it had under the ten year rate plan?

A. Under the ten year rate plan, we were proposing to determine the allocation of synergy savings in advance and fix the share of savings that would be allocated to customers. As a result, Staff's suggestion that incorrectly increased the allocation to KEDNY and KEDLI would have had the effect of allocating more benefits to customers at the outset that would not actually be realized over the ten-year rate plan period. The approach that we are proposing today changes the situation. Staff's over-allocation would benefit customers in the initial credit, but add to KEDNY's and KEDLI's synergy allowance that is included in the later years. An accurate allocation is necessary so that both the customers and the companies are treated appropriately as the actual savings are realized.

Q. Would you respond to the Staff's points on LIPA?

A. Yes. With regard to LIPA, Staff suggests that we should develop a different allocation because we are not required to credit synergy savings from the merger

to LIPA. This is the same issue that we just discussed. The allocation is designed to determine where the synergy savings will actually flow, not how those savings are allocated between the companies and their customers. Following the merger, synergy savings will be reflected in the cost of providing services to LIPA under KeySpan's contracts with that authority. The analysis measures that effect. This is exactly analogous to the situation the Commission faced when approving the Brooklyn Union merger with LILCo. As in that case, the Commission approved a methodology that allocated savings between New York and Long Island gas customers and LIPA's electric customers. The LIPA phase in of such savings was reflected in the terms of the LIPA service agreements.

With regard to the Staff's point on the possible inclusion of inappropriate LIPA revenues associated with the Power Supply Agreement and Nine Mile Point net book value in the allocation, we believe that we have appropriately treated these items. While the Power Supply Agreement might be generation related, it still will receive synergy savings though lower administrative costs. As for the Nine Mile Point costs, we agree that these should not be included in the calculation and have been removed from the current analysis.

Q. Would you summarize CPB's concern with the allocation?

A. Dr. Elfner believes that the Companies had an incentive to understate the allocation to New York (Elfner, pp. 52-53). Based on an early analysis done in

January 27, 2006, Mr. Elfner concludes that the allocation should be made using operation and maintenance expense (id, p. 54).

Q. Do you have a response to Mr. Elfner's concern?

A. Mr. Elfner is correct that we did the analysis mentioned in his testimony. We ultimately concluded that it was not correct, because it did not include LIPA and unregulated operations. As a result, we developed the more inclusive allocation that has been presented in this filing for the reasons that we have already articulated. With regard to the use of O&M and A&G expenses in the January 27, 2006 allocation analysis, this approach was designed to produce a reasonable allocation methodology, because synergies are realized in A&G and O&M expenses. However, most of the synergies are realized in the A&G area, and, thus, Dr. Elfner's suggestion at page 54 to use only O&M expense would miss a significant portion of the allocation. Because both O&M and A&G expenses are included in delivery revenues, and because the delivery revenue approach is consistent with the Niagara Mohawk method, our approach meets both the objective of accuracy and consistency and we continue to recommend it to the Commission.

Q. Would you turn to the second issue presented by the synergy analysis, the sharing between the Companies and their customers and explain the effect of sharing under the new proposal?

A. Under our new proposal, we still propose to include a 50/50 sharing of synergy savings over the ten years following the close of the merger. However, as we have indicated, the net synergy savings, reflecting costs to achieve amortized over ten years, are levelized over the initial three year period, providing a higher initial credit to customers. In addition, customers will receive 100 percent of the savings in the next cost of service that are over and above the forecast of synergies for KEDNY and KEDLI, because they will flow through the cost of service automatically as reduced costs.

Moreover, we should also make clear that the allocation of synergies to KEDNY and KEDLI ends after ten years. As a result, customers receive all the benefits thereafter. The present value of those benefits is significant. As shown on Exhibit No. __(Rates Panel-3), when the present value of the synergy savings over 30 years is calculated, customers receive 78 percent of the net synergy savings from the merger. For KEDNY, the customers' present value benefit is $234 million and for KEDLI the benefit is $128 million. The value of these savings for customers is substantial.

Q. What is your response to the parties proposals on synergy sharing between customers and the Companies?

A. The sharing of synergy savings provides two key benefits to customers. First, it facilitates the transaction in the first place, and the transaction is necessary to

produce the synergies. As we have seen in this transaction, Companies must make significant investments to arrive at a merger. The sharing of synergy savings provides a portion of the resources to support that investment, which with the other rate commitments that we have made assures that customers are better off as a result of the transaction. Second, the sharing provides the incentive to produce the savings following the transaction. This also requires a significant amount of effort by the Company. As with Commission approved incentives to maximize tax refunds or maximize the value of off-system gas sales, synergy sharing provides a concrete mechanism to encourage efficient integration and operation of the combined companies. Both of these features support the Commission's policy for the sharing of synergy savings from mergers of companies with regulated operations.

In this case, as we have explained, the sharing is reasonable, consistent with the Niagara Mohawk rate plan, and supported by the savings that will be produced by the transaction. Under the reformulated proposal, we are also providing a significant up-front credit to mitigate the rate increases that may result in the stand-alone KEDNY and KEDLI filings. For all those reasons, we continue to propose the 50/50 sharing for the first ten years following the merger.

Q. Do you believe the sharing under the Staff's proposal of 90/10 sharing of synergies is reasonable?

A. No. As is shown in Exhibit No. __(Rates Panel-3R), the Staff's proposal would only allocate less than 2% of the total synergies to the Companies ($4.97 million for KEDNY and $2.89 million for KEDLI) and over 98% to Customers ($298.17 million for KEDNY customers and $164.60 million for KEDLI customers). This does not represent a reasonable sharing of merger benefits with the Companies.

VI. NATIONAL GRID SPENDING FOR INFRA-STRUCTURE UNDER THE NIAGARA MOHAWK RATE PLAN

Q. Several parties have suggested that Niagara Mohawk has not placed proper emphasis on infra-structure operation, maintenance and investment since its merger with National Grid in January 2002. Have you analyzed Niagara Mohawk's spending over that period?

A. Yes. The analysis is included in Exhibit No. ____(Rates Panel-4R). That exhibit compares Niagara Mohawk's actual spending in various electric accounts for the period from 2001 (the last year before the merger) through today. Page 1 of the Exhibit includes all of Niagara Mohawk's FERC accounts from 560 through 598. These accounts include the operation and maintenance costs for both the transmission and distribution system. As the analysis shows, in 2001 prior to the merger, Niagara Mohawk was spending about $175 million per year on operation and maintenance expense. This is consistent with spending in prior years excluding the effects of the costs of the 1998 ice storm and its associated recoveries in 2000. Since the merger with National Grid in 2002, the operation

and maintenance expenses have continually increased from $175 million in 2001 to $239 million in 2006. The increases in nearly every account have been significant. The incremental spending from 2001 levels adjusted for inflation is shown on line 37. As that comparison shows, Niagara Mohawk in 2006 spent $41 million, or 21%, more than the 2001 value adjusted for inflation. This exhibit thus demonstrates that National Grid has added resources to the reliability effort, not reduced them.

Q. Has Niagara Mohawk achieved synergy savings in other areas of the business?

A. Yes, page two of the exhibit does the same comparison for A&G and customer service expense, which are included in the 900 accounts. As that comparison shows, National Grid has consistently under-spent the 2001 level of expenses adjusted for inflation. In 2001, the spending in the 900 accounts, excluding bad debts and the reconciling account that includes the Systems benefit charge, totaled $392 million. In 2006, this value was reduced to $313 million, or $131 million below the level of the inflation adjusted 2001 value of $441 million. The savings in A&G relate to the consolidation of functions and elimination of duplication, which are traditional synergy targets. In addition, we realized significant savings in customer service from consolidating operations and implementing automated meter reading. It is important to note that in these areas,

where significant savings were realized, the performance as measured under our service quality plan has improved.

Q. Have you performed similar comparisons for Niagara Mohawk's capital expenditures for the period?

A. Yes. A comparison with historical capital expenditures on the transmission and distribution system is shown on page 4 of the Exhibit. During 2001 before the merger, Niagara Mohawk's capital spending, composed of capital additions and changes in CWIP balances was $140 million as shown on Line 26. The actual outlay after the merger has climbed to $255 million in 2006. The actual outlays are compared to the 2001 outlay, escalated for inflation on Line 29. As that comparison shows, National Grid's capital outlays exceed the inflated 2001 level by $96 million. Cumulatively over the period since the merger the capital outlay has exceeded the inflated base year by $218 million. Again more resources have been invested in the system after the merger than before.

Lines 30-33 compare the actual capital outlays from 2002 through 2006 to the allowances in the rate plan. As that exhibit shows, we have outspent the rate plan by $135 million in 2006, and by $370 million cumulatively over the period since the merger. Our plans for future investment are discussed by the reliability panel.

VII. CONCLUSION

Q. Does that conclude your testimony?

A. Yes it does.

Three-Year Rate Proposal

Once KEDNY and KEDLI's (collectively, "Companies") rates are set as provided below, the Companies would commit to refrain from filing an application to increase overall net revenues with rates going into effect before September 1, 2010.

A. Basis of Rates

KEDNY's and KEDLI's rates as of September 2, 2007 will be based on those approved by the Commission in their stand-alone rate proceedings in Cases 06-G-1185 and 06-G-1186, as adjusted for the multi-year feature of this proposal discussed below. Whether such new rates arise from a settlement or litigation, they must fully resolve all cost of service and service quality issues raised in the direct and rebuttal testimony filed in those cases, including recovery of outstanding deferrals of SIR costs, special franchise taxes, and pension and other post-employment benefit ("OPEB") expense.

B. Second and Third Year Base Rate Levels

KEDNY's and KEDLI's base rates as set forth above will remain frozen for the second and third rate years of the three year plan. To achieve the two year rate freeze, the plan shall provide for the cost deferrals described in Section C below and rates that are based on approved annual levels of O&M expenditures, payroll taxes and sales taxes that have been levelized over the three year period of the plan. The three year levelized amounts for O&M expenditures, payroll taxes and sales taxes shall be established by escalating the year one expenditure levels approved by the Commission by approved labor and non-labor escalation factors to determine the respective operating expense levels for years two and three of the plan. The expense levels for rate years one, two and three of the plan will then be reduced by the annual level of net synergy savings allocable to customers, and the resulting levels for years two and three discounted on a present value basis to year one at KEDNY's and KEDLI's overall cost of capital. The sum total of these expenses for the three year period will be converted to levelized annuities to establish the fixed base rate levels for the three year period of the plan. The levelized O&M expenses shall not include pension and OPEB expenses since these costs will be eligible as described below.

C. Authorized Deferrals and Amortization

KEDNY and KEDLI will be authorized to defer for future recovery the following cost items to the extent they exceed or fall below the level of such costs included in rates during the twelve months ending September 1, 2008 ("First Rate Year"):

- Pension and OPEB expense;
- Special Franchise and Real Property Tax expense;
- Site Investigation and Remediation ("SIR") expense;
- Revenue Requirement of non-growth capital additions.

In addition, KEDNY and KEDLI will amortize the customers' share of the costs to achieve the synergy savings over a ten-year period as described in the testimony of Michael D. Laflamme and James M. Molloy.

D. GAC/TAC changes

KEDNY and KEDLI will be entitled to recover commodity-related uncollectible expense and purchased gas working capital through the GAC and the return requirement for gas in storage through the GAC/TAC (collectively, "commodity-related costs"). Commodity-related costs will be recovered through the GAC/TAC as a fixed experience factor applied to estimated and actual gas costs in the routine reconciliation of the GAC/TAC mechanisms. Such fixed experience factors are as follows.

1. Commodity-related uncollectible expense – the fixed experience factors set forth below will be applied to total estimated gas costs (including TC gas costs) and reconciled to actual gas costs in the GAC:

KEDNY - Residential 1.84% KEDLI – Residential .77%
Non-Residential 1.38% Non-Residential .71%.

2. Commodity related working capital: will have a fixed lead-lag percentage and a fixed return requirement percentage that is applied to total estimated gas costs (including TC gas costs) and reconciled to actual gas costs in the GAC.

KEDNY lead-lag = xx% KEDLI lead-lag=xx%.

The fixed return requirement for both KEDNY and KEDLI is xx%.

3. The return on storage will be recovered through the GAC/TAC as a fixed return requirement percentage applied to estimated storage inventory costs and reconciled to actual inventory costs (per the GAC reconciliation method). The fixed return requirement for KEDNY and KEDLI is xx%.

Calculation of 10 Year Levelized Net Synergy Value by Year

		1	2	3	4	5	6	7	8	9	10
	KEDNY										
1	Synergies	$ 13,600,941.43	$ 18,588,046.23	$ 23,815,919.95	$ 29,293,452.64	$ 30,025,788.96	$ 30,776,433.68	$ 31,545,844.53	$ 32,334,490.64	$ 33,142,852.91	$ 33,971,424.23
2											
3	Cost to Achieve	$ 20,940,009.43	$ 8,323,776.16	$ 8,160,564.86	$ 3,688,575.32	$ 3,955,153.77	$ 3,247,904.81	$ 2,518,894.35	$ 1,153,359.83	$ 1,186,002.09	$ 1,224,084.73
4	NPV $43,019,419.01										
5	Levelized	6,600,377.19	$ 6,600,377.19	$ 6,600,377.19	$ 6,600,377.19	$ 6,600,377.19	$ 6,600,377.19	$ 6,600,377.19	$ 6,600,377.19	$ 6,600,377.19	$ 6,600,377.19
6											
7	Net Synergy Savings - 100%	$ 7,000,564.25	$ 11,987,669.05	$ 17,215,542.76	$ 22,693,075.46	$ 23,425,411.77	$ 24,176,056.50	$ 24,945,467.34	$ 25,734,113.45	$ 26,542,475.72	$ 27,371,047.04
8											
9	Net Synergy Savings - 50%	$ 3,500,282.12	$ 5,993,834.52	$ 8,607,771.38	$ 11,346,537.73	$ 11,712,705.89	$ 12,088,028.25	$ 12,472,733.67	$ 12,867,056.73	$ 13,271,237.86	$ 13,685,523.52
10	NPV $15,010,279.20										
11	3 Year Levelized	5,892,928.71	$ 5,892,928.71	$ 5,892,928.71							
	KEDLI										
12	Synergies	$ 8,075,488.70	$ 11,036,556.41	$ 14,140,579.41	$ 17,392,836.15	$ 17,827,657.05	$ 18,273,348.48	$ 18,730,182.19	$ 19,198,436.75	$ 19,678,397.66	$ 20,170,357.61
13											
14	Cost to Achieve	$ 12,433,022.40	$ 4,942,199.08	$ 4,845,293.22	$ 2,190,072.54	$ 2,348,352.11	$ 1,928,426.70	$ 1,495,580.51	$ 684,801.44	$ 704,182.61	$ 726,793.98
15	NPV $25,177,515.18										
16	Levelized	3,966,439.11	$ 3,966,439.11	$ 3,966,439.11	$ 3,966,439.11	$ 3,966,439.11	$ 3,966,439.11	$ 3,966,439.11	$ 3,966,439.11	$ 3,966,439.11	$ 3,966,439.11
17											
18	Net Synergy Savings - 100%	$ 4,109,049.60	$ 7,070,117.30	$ 10,174,140.31	$ 13,426,397.04	$ 13,861,217.95	$ 14,306,909.37	$ 14,763,743.09	$ 15,231,997.64	$ 15,711,958.56	$ 16,203,918.50
19											
20	Net Synergy Savings - 50%	$ 2,054,524.80	$ 3,535,058.65	$ 5,087,070.15	$ 6,713,198.52	$ 6,930,608.97	$ 7,153,454.69	$ 7,381,871.54	$ 7,615,998.82	$ 7,855,979.28	$ 8,101,959.25
21	NPV $8,743,604.76										
22	Levelized	3,469,603.61	$ 3,469,603.61	$ 3,469,603.61							

Line Notes:

1 From Page 3 of 6, Line 11
3 From Page 3 of 6, Line 28
4 NPV of annual Cost to Achieve discounted at weighted average cost of capital of 8.65%
5 10 Year levelized payment of Line 4 Cost to Achieve NPV at 8.65%
7 Line 1 minus Line 7
9 Line 7 times 50%
10 NPV of Line 9 for years 1, 2 and 3 discounted at weighted average cost of capital of 8.65%
11 3 Year Levelized payment of Line 10 NPV at 8.65%

12 From Page 3 of 6, Line 12
14 From Page 3 of 6, Line 29
15 NPV of annual Cost to Achieve discounted at weighted average cost of capital of 9.25%
16 10 Year levelized payment of Line 15 Cost to Achieve NPV at 9.25%
18 Line 12 minus Line 16
20 Line 18 times 50%
21 NPV of Line 20 for years 1, 2 and 3 discounted at weighted average cost of capital of 9.25%
22 3 Year Levelized payment of Line 21 NPV at 9.25%

Illustrative Calculation of Synergy Value - Net Synergy by Year

	1	2	3	4	5	6	7	8	9	10	Total
SYNERGIES (Page 2 Column C Times Page 4 Column B)											
1 Massachusetts Electric	$ 9,927,989.07	$ 13,568,319.57	$ 17,384,399.02	$ 21,382,716.71	$ 21,917,284.63	$ 22,465,216.74	$ 23,026,847.16	$ 23,602,518.34	$ 24,192,581.30	$ 24,797,395.83	$ 202,265,268.39
2 Nantucket Electric	$ 121,326.58	$ 165,813.83	$ 212,448.84	$ 261,310.92	$ 267,843.70	$ 274,539.79	$ 281,403.28	$ 288,438.36	$ 295,649.32	$ 303,040.56	$ 2,471,815.18
3 New England Power	$ 3,565,498.53	$ 4,872,872.36	$ 6,243,363.96	$ 7,679,303.88	$ 7,871,286.48	$ 8,068,068.64	$ 8,269,770.36	$ 8,476,514.62	$ 8,688,427.48	$ 8,905,638.17	$ 72,640,744.48
4 Essex Gas	$ 545,760.00	$ 745,875.72	$ 955,652.70	$ 1,175,447.65	$ 1,204,833.84	$ 1,234,954.68	$ 1,265,828.55	$ 1,297,474.26	$ 1,329,911.12	$ 1,363,158.90	$ 11,118,897.42
5 Colonial Gas	$ 1,825,441.20	$ 2,494,782.12	$ 3,196,437.67	$ 3,931,601.04	$ 4,029,891.06	$ 4,130,638.34	$ 4,233,904.30	$ 4,339,751.91	$ 4,448,245.70	$ 4,559,451.85	$ 37,190,145.19
6 Boston Gas	$ 6,543,106.78	$ 8,942,290.65	$ 11,457,303.02	$ 14,092,420.71	$ 14,444,731.23	$ 14,805,849.51	$ 15,175,995.75	$ 15,555,395.64	$ 15,944,280.53	$ 16,342,887.54	$ 133,304,261.36
7 Granite State Electric	$ 422,443.05	$ 577,341.73	$ 739,718.64	$ 909,849.93	$ 932,596.18	$ 955,911.08	$ 979,808.86	$ 1,004,304.08	$ 1,029,411.68	$ 1,055,146.97	$ 8,606,532.21
8 EnergyNorth Gas	$ 804,508.81	$ 1,099,500.88	$ 1,408,734.65	$ 1,732,736.00	$ 1,776,054.40	$ 1,820,455.76	$ 1,865,967.15	$ 1,912,616.33	$ 1,960,431.74	$ 2,009,442.53	$ 16,390,448.25
9 Niagara Mohawk Electric	$ 20,220,680.88	$ 27,635,068.71	$ 35,407,410.55	$ 43,550,923.35	$ 44,639,696.43	$ 45,755,688.84	$ 46,899,581.06	$ 48,072,070.59	$ 49,273,872.35	$ 50,505,719.16	$ 411,960,711.93
10 Niagara Mohawk Gas	$ 5,214,526.56	$ 7,126,555.26	$ 9,130,893.45	$ 11,230,949.53	$ 11,511,723.27	$ 11,799,516.35	$ 12,094,504.26	$ 12,396,866.87	$ 12,706,788.54	$ 13,024,458.25	$ 106,236,782.36
11 KEDNY	$ 13,600,941.43	$ 18,588,046.23	$ 23,815,919.95	$ 29,293,452.64	$ 30,025,788.96	$ 30,776,433.68	$ 31,545,844.53	$ 32,334,490.64	$ 33,142,852.91	$ 33,971,424.23	$ 277,095,195.20
12 KEDLI	$ 8,075,488.70	$ 11,036,556.41	$ 14,140,579.41	$ 17,392,836.15	$ 17,827,657.05	$ 18,273,348.48	$ 18,730,182.19	$ 19,198,436.75	$ 19,678,397.66	$ 20,170,357.61	$ 164,523,840.41
13 LIPA	$ 19,015,726.02	$ 25,988,288.84	$ 33,297,475.10	$ 40,955,714.16	$ 41,979,607.02	$ 43,029,097.19	$ 44,104,824.62	$ 45,207,445.24	$ 46,337,631.37	$ 47,496,072.15	$ 387,411,881.72
14 Unregulated	$ 3,146,847.76	$ 4,300,713.44	$ 5,510,285.78	$ 6,777,621.69	$ 6,947,062.23	$ 7,120,738.79	$ 7,298,757.26	$ 7,481,226.19	$ 7,668,256.85	$ 7,859,963.27	$ 64,111,473.26
15 Narragansett	$ 4,001,694.80	$ 5,469,010.23	$ 7,007,165.16	$ 8,618,775.22	$ 8,834,244.60	$ 9,055,100.72	$ 9,281,478.23	$ 9,513,515.19	$ 9,751,353.07	$ 9,995,136.90	$ 81,527,474.11
16 Providence Gas	$ 2,968,019.81	$ 4,056,314.02	$ 5,197,149.22	$ 6,392,465.41	$ 6,552,277.05	$ 6,716,083.98	$ 6,883,986.07	$ 7,056,085.73	$ 7,232,487.87	$ 7,413,300.07	$ 60,468,169.22
17 Total	$ 100,000,000.00	$ 136,667,350.00	$ 175,104,937.13	$ 215,378,125.00	$ 220,762,578.13	$ 226,281,642.58	$ 231,938,683.64	$ 237,737,150.73	$ 243,680,579.50	$ 249,772,593.99	$ 2,037,323,640.70
COST TO ACHIEVE (Page 3 Column C Times Page 4 Column A)											
18 Massachusetts Electric	$ (15,285,131.97)	$ (6,075,929.31)	$ (5,956,793.44)	$ (2,692,470.64)	$ (2,887,059.22)	$ (2,370,803.79)	$ (1,838,663.58)	$ (841,893.47)	$ (865,720.65)	$ (893,519.02)	$ (39,707,985.09)
19 Nantucket Electric	$ (186,794.41)	$ (74,251.87)	$ (72,795.95)	$ (32,903.77)	$ (35,281.77)	$ (28,972.79)	$ (22,469.68)	$ (10,288.49)	$ (10,579.68)	$ (10,919.39)	$ (485,257.81)
20 New England Power	$ (5,489,441.54)	$ (2,182,085.10)	$ (2,139,299.12)	$ (966,963.20)	$ (1,036,846.97)	$ (851,441.05)	$ (660,330.33)	$ (302,354.28)	$ (310,911.47)	$ (320,894.87)	$ (14,260,567.92)
21 Essex Gas	$ (840,252.09)	$ (334,005.12)	$ (327,456.00)	$ (148,010.11)	$ (158,707.01)	$ (130,327.49)	$ (101,074.75)	$ (46,280.45)	$ (47,590.27)	$ (49,118.40)	$ (2,182,821.68)
22 Colonial Gas	$ (2,810,449.28)	$ (1,117,170.02)	$ (1,095,264.72)	$ (495,059.65)	$ (530,838.30)	$ (435,915.36)	$ (338,071.71)	$ (154,797.41)	$ (159,178.47)	$ (164,289.71)	$ (7,301,034.64)
23 Boston Gas	$ (10,073,767.21)	$ (4,004,381.35)	$ (3,925,864.07)	$ (1,774,490.56)	$ (1,902,735.45)	$ (1,562,493.90)	$ (1,211,783.38)	$ (554,855.46)	$ (570,558.91)	$ (588,879.61)	$ (26,169,809.90)
24 Granite State Electric	$ (650,393.33)	$ (258,535.15)	$ (253,465.83)	$ (114,566.56)	$ (122,846.44)	$ (100,879.40)	$ (78,236.45)	$ (35,823.17)	$ (36,837.03)	$ (38,019.87)	$ (1,689,603.24)
25 EnergyNorth Gas	$ (1,238,621.77)	$ (492,359.39)	$ (482,705.29)	$ (218,182.79)	$ (233,951.16)	$ (192,116.70)	$ (148,995.03)	$ (68,222.35)	$ (70,153.17)	$ (72,405.79)	$ (3,217,713.45)
26 Niagara Mohawk Electric	$ (31,131,760.29)	$ (12,375,056.70)	$ (12,132,408.53)	$ (5,483,848.66)	$ (5,880,174.00)	$ (4,828,698.59)	$ (3,744,870.10)	$ (1,714,713.74)	$ (1,763,243.37)	$ (1,819,861.28)	$ (80,874,635.26)
27 Niagara Mohawk Gas	$ (8,028,285.09)	$ (3,191,290.25)	$ (3,128,715.94)	$ (1,414,179.60)	$ (1,516,384.32)	$ (1,245,228.94)	$ (965,730.32)	$ (442,191.85)	$ (454,706.72)	$ (469,307.39)	$ (20,856,020.43)
28 KEDNY	$ (20,940,009.43)	$ (8,323,776.16)	$ (8,160,564.86)	$ (3,688,575.32)	$ (3,955,153.77)	$ (3,247,904.81)	$ (2,518,894.35)	$ (1,153,359.83)	$ (1,186,002.09)	$ (1,224,084.73)	$ (54,398,325.36)
29 KEDLI	$ (12,433,022.40)	$ (4,942,199.08)	$ (4,845,293.22)	$ (2,190,072.54)	$ (2,348,352.11)	$ (1,928,426.70)	$ (1,495,580.51)	$ (684,801.44)	$ (704,182.61)	$ (726,793.98)	$ (32,298,724.61)
30 LIPA	$ (29,276,611.78)	$ (11,637,624.33)	$ (11,409,435.61)	$ (5,157,064.90)	$ (5,529,773.13)	$ (4,540,955.37)	$ (3,521,712.46)	$ (1,612,533.57)	$ (1,658,171.31)	$ (1,711,415.34)	$ (76,055,297.80)
31 Unregulated	$ (4,844,886.80)	$ (1,925,870.83)	$ (1,888,108.65)	$ (853,425.11)	$ (915,103.33)	$ (751,467.24)	$ (582,796.20)	$ (266,852.69)	$ (274,405.12)	$ (283,216.30)	$ (12,586,132.28)
32 Narragansett	$ (6,161,009.31)	$ (2,449,037.22)	$ (2,401,016.88)	$ (1,085,259.63)	$ (1,163,692.85)	$ (955,604.72)	$ (741,113.88)	$ (339,343.72)	$ (348,947.79)	$ (360,152.53)	$ (16,005,178.51)
33 Providence Gas	$ (4,569,563.30)	$ (1,816,428.12)	$ (1,780,811.89)	$ (804,926.97)	$ (863,100.16)	$ (708,763.13)	$ (549,677.27)	$ (251,688.08)	$ (258,811.33)	$ (267,121.78)	$ (11,870,892.03)
34 Total	$ (153,960,000.00)	$ (61,200,000.00)	$ (60,000,000.00)	$ (27,120,000.00)	$ (29,080,000.00)	$ (23,880,000.00)	$ (18,520,000.00)	$ (8,480,000.00)	$ (8,720,000.00)	$ (9,000,000.00)	$ (399,960,000.00)
NET SYNERGIES (Synergies Plus Cost To Achieve)											
35 Massachusetts Electric	$ (5,357,142.90)	$ 7,492,390.26	$ 11,427,605.58	$ 18,690,246.08	$ 19,030,225.41	$ 20,094,412.95	$ 21,188,183.59	$ 22,760,624.87	$ 23,326,860.65	$ 23,903,876.82	$ 162,557,283.30
36 Nantucket Electric	$ (65,467.82)	$ 91,561.96	$ 139,652.89	$ 228,407.15	$ 232,561.92	$ 245,567.00	$ 258,933.60	$ 278,149.87	$ 285,069.65	$ 292,121.16	$ 1,986,557.38
37 New England Power	$ (1,923,943.01)	$ 2,690,787.26	$ 4,104,064.84	$ 6,712,340.68	$ 6,834,439.51	$ 7,216,627.59	$ 7,609,440.03	$ 8,174,160.34	$ 8,377,516.01	$ 8,584,743.30	$ 58,380,176.55
38 Essex Gas	$ (294,492.09)	$ 411,870.61	$ 628,196.70	$ 1,027,437.54	$ 1,046,126.83	$ 1,104,627.20	$ 1,164,753.80	$ 1,251,193.82	$ 1,282,320.85	$ 1,314,040.50	$ 8,936,075.74
39 Colonial Gas	$ (985,008.07)	$ 1,377,612.10	$ 2,101,172.95	$ 3,436,541.38	$ 3,499,052.76	$ 3,694,722.98	$ 3,895,832.59	$ 4,184,954.49	$ 4,289,067.23	$ 4,395,162.14	$ 29,889,110.55
40 Boston Gas	$ (3,530,660.42)	$ 4,937,909.30	$ 7,531,438.95	$ 12,317,930.15	$ 12,541,995.77	$ 13,243,355.61	$ 13,964,212.37	$ 15,000,540.18	$ 15,373,721.62	$ 15,754,007.93	$ 107,134,451.47
41 Granite State Electric	$ (227,950.27)	$ 318,806.58	$ 486,252.81	$ 795,283.37	$ 809,749.74	$ 855,031.68	$ 901,572.41	$ 968,480.91	$ 992,574.65	$ 1,017,127.10	$ 6,916,928.97
42 EnergyNorth Gas	$ (434,112.96)	$ 607,141.48	$ 926,029.36	$ 1,514,553.21	$ 1,542,103.24	$ 1,628,339.05	$ 1,716,972.12	$ 1,844,393.98	$ 1,890,278.57	$ 1,937,036.74	$ 13,172,734.80
43 Niagara Mohawk Electric	$ (10,911,079.40)	$ 15,260,012.01	$ 23,275,002.02	$ 38,067,074.69	$ 38,759,522.43	$ 40,926,990.25	$ 43,154,710.96	$ 46,357,356.85	$ 47,510,628.98	$ 48,685,857.88	$ 331,086,076.67
44 Niagara Mohawk Gas	$ (2,813,758.53)	$ 3,935,265.01	$ 6,002,177.52	$ 9,816,769.93	$ 9,995,338.95	$ 10,554,287.41	$ 11,128,773.94	$ 11,954,675.02	$ 12,252,081.82	$ 12,555,150.86	$ 85,380,761.93
45 KEDNY	$ (7,339,068.00)	$ 10,264,270.08	$ 15,655,355.09	$ 25,604,877.33	$ 26,070,635.19	$ 27,528,528.87	$ 29,026,950.17	$ 31,181,130.81	$ 31,956,850.81	$ 32,747,339.50	$ 222,696,869.84
46 KEDLI	$ (4,357,533.70)	$ 6,094,357.32	$ 9,295,286.19	$ 15,202,763.61	$ 15,479,304.94	$ 16,344,921.78	$ 17,234,601.68	$ 18,513,635.30	$ 18,974,215.05	$ 19,443,563.62	$ 132,225,115.80
47 LIPA	$ (10,260,885.76)	$ 14,350,664.51	$ 21,888,039.48	$ 35,798,649.27	$ 36,449,833.89	$ 38,488,141.82	$ 40,583,112.16	$ 43,594,911.67	$ 44,679,460.06	$ 45,784,656.81	$ 311,356,583.91
48 Unregulated	$ (1,698,039.05)	$ 2,374,842.61	$ 3,622,177.13	$ 5,924,196.58	$ 6,031,958.91	$ 6,369,271.55	$ 6,715,961.06	$ 7,214,373.50	$ 7,393,851.72	$ 7,576,746.97	$ 51,525,340.98
49 Narragansett	$ (2,159,314.51)	$ 3,019,973.02	$ 4,606,148.28	$ 7,533,515.59	$ 7,670,551.75	$ 8,099,496.00	$ 8,540,364.36	$ 9,174,171.47	$ 9,402,405.28	$ 9,634,984.36	$ 65,522,295.60
50 Providence Gas	$ (1,601,543.49)	$ 2,239,885.90	$ 3,416,337.33	$ 5,587,538.44	$ 5,689,176.89	$ 6,007,320.84	$ 6,334,308.81	$ 6,804,397.65	$ 6,973,676.54	$ 7,146,178.28	$ 48,597,277.20
51 Total	$ (53,960,000.00)	$ 75,467,350.00	$ 115,104,937.13	$ 188,258,125.00	$ 191,682,578.13	$ 202,401,642.58	$ 213,418,683.64	$ 229,257,150.73	$ 234,960,579.50	$ 240,772,593.99	$ 1,637,363,640.70

Illustrative Calculation of Synergy Value - Synergy

		Revenues (A)		Percent (B)		Synergies (C)
1	Massachusetts Electric	$	534,184,464	9.93%	$	19,855,978.14
2	Nantucket Electric	$	6,528,087	0.12%	$	242,653.17
3	New England Power	$	191,844,885	3.57%	$	7,130,997.06
4	Essex Gas	$	29,365,112	0.55%	$	1,091,519.99
5	Colonial Gas	$	98,219,521	1.83%	$	3,650,882.41
6	Boston Gas	$	352,057,800	6.54%	$	13,086,213.57
7	Granite State Electric	$	22,729,932	0.42%	$	844,886.11
8	EnergyNorth Gas	$	43,287,327	0.80%	$	1,609,017.63
9	Niagara Mohawk Electric	$	1,087,992,090	20.22%	$	40,441,361.76
10	Niagara Mohawk Gas	$	280,572,335	5.21%	$	10,429,053.12
11	KEDNY	$	731,811,000	13.60%	$	27,201,882.87
12	KEDLI	$	434,509,000	8.08%	$	16,150,977.40
13	LIPA	$	1,023,158,400	19.02%	$	38,031,452.05
14	Unregulated	$	169,319,000	3.15%	$	6,293,695.51
15	Narragansett	$	215,314,821	4.00%	$	8,003,389.59
16	Providence Gas	$	159,697,000	2.97%	$	5,936,039.62
17	Total	$	5,380,590,774	100.00%	$	200,000,000.00
18	Synergy				$	200,000,000.00

(A) High Level Estimated T&D Revenue (Rather than adjust the $200 million, Unregulated is included)
(B) Column A / Column A Line 17
(C) Line 18 * Column B

Illustrative Calculation of Synergy Value - Cost to Achieve

		Revenues (A)	Percent (B)		Cost to Achieve (C)
1 Massachusetts Electric	$	534,184,464	9.93%	$	39,711,956.28
2 Nantucket Electric	$	6,528,087	0.12%	$	485,306.34
3 New England Power	$	191,844,885	3.57%	$	14,261,994.12
4 Essex Gas	$	29,365,112	0.55%	$	2,183,039.98
5 Colonial Gas	$	98,219,521	1.83%	$	7,301,764.82
6 Boston Gas	$	352,057,800	6.54%	$	26,172,427.14
7 Granite State Electric	$	22,729,932	0.42%	$	1,689,772.22
8 EnergyNorth Gas	$	43,287,327	0.80%	$	3,218,035.25
9 Niagara Mohawk Electric	$	1,087,992,090	20.22%	$	80,882,723.53
10 Niagara Mohawk Gas	$	280,572,335	5.21%	$	20,858,106.24
11 KEDNY	$	731,811,000	13.60%	$	54,403,765.74
12 KEDLI	$	434,509,000	8.08%	$	32,301,954.80
13 LIPA	$	1,023,158,400	19.02%	$	76,062,904.09
14 Unregulated	$	169,319,000	3.15%	$	12,587,391.02
15 Narragansett	$	215,314,821	4.00%	$	16,006,779.18
16 Providence Gas	$	159,697,000	2.97%	$	11,872,079.23
17 Total	$	5,380,590,774	100.00%	$	400,000,000.00
18 Cost to Achieve (Page 2 Line 18 times 2)				$	400,000,000.00

(A) Page 4 Column A
(B) Column A / Column A Line 17
(C) Line 18 * Column B

Illustrative Calculation of Synergy Value - Phase in Rates

	Cost to Achieve		Synergy Multiplier		Inflation		Phase-In
	(A)		(B)		(C)		(D)
Year 1	38.49%	Year 1	50.00%	Year 1	1	Year 1	50%
Year 2	15.30%	Year 2	68.33%	Year 2	1.0250	Year 2	67%
Year 3	15.00%	Year 3	87.55%	Year 3	1.0506	Year 3	83%
Year 4	6.78%	Year 4	107.69%	Year 4	1.0769	Year 4	100%
Year 5	7.27%	Year 5	110.38%	Year 5	1.1038	Year 5	100%
Year 6	5.97%	Year 6	113.14%	Year 6	1.1314	Year 6	100%
Year 7	4.63%	Year 7	115.97%	Year 7	1.1597	Year 7	100%
Year 8	2.12%	Year 8	118.87%	Year 8	1.1887	Year 8	100%
Year 9	2.18%	Year 9	121.84%	Year 9	1.2184	Year 9	100%
Year 10	2.25%	Year 10	124.89%	Year 10	1.2489	Year 10	100%

(A) Attachment 10
(B) Column (C) * Column (D)
(C) Assumed Inflation Growth of 2.50%
(D) Attachment 10

	KEDNY Synergies and CTA	
	50/50 10 Year	90/10 5 Year
1 NPV over 30 years	$290,821,965	$290,821,965
2 Company Share	$62,520,230	$4,851,281
3 Customer Share	$228,301,735	$285,970,684
4 Customer Percent	78.50%	98.33%
5 Discount Rate	8.65%	8.65%

	KEDLI Synergies and CTA	
	50/50 10 Year	90/10 5 Year
1 NPV over 30 years	$160,538,870	$160,538,870
2 Company Share	$35,825,583	$2,815,207
3 Customer Share	$124,713,287	$157,723,663
4 Customer Percent	77.68%	98.25%
5 Discount Rate	9.25%	9.25%

Years	KEDNY Synergies	KEDNY CTA	Net Synergies
1	(13,265,639)	20,423,777	7,158,139
2	(18,129,797)	8,118,571	(10,011,226)
3	(23,228,788)	7,959,383	(15,269,405)
4	(28,571,284)	3,597,641	(24,973,643)
5	(29,285,566)	3,857,648	(25,427,918)
6	(30,017,705)	3,167,835	(26,849,871)
7	(30,768,148)	2,456,796	(28,311,351)
8	(31,537,351)	1,124,926	(30,412,425)
9	(32,325,785)	1,156,764	(31,169,022)
10	(33,133,930)	1,193,907	(31,940,022)
11	(33,962,278)		(33,962,278)
12	(34,811,335)		(34,811,335)
13	(35,681,618)		(35,681,618)
14	(36,573,659)		(36,573,659)
15	(37,488,000)		(37,488,000)
16	(38,425,200)		(38,425,200)
17	(39,385,830)		(39,385,830)
18	(40,370,476)		(40,370,476)
19	(41,379,738)		(41,379,738)
20	(42,414,232)		(42,414,232)
21	(43,474,587)		(43,474,587)
22	(44,561,452)		(44,561,452)
23	(45,675,488)		(45,675,488)
24	(46,817,375)		(46,817,375)
25	(47,987,810)		(47,987,810)
26	(49,187,505)		(49,187,505)
27	(50,417,193)		(50,417,193)
28	(51,677,623)		(51,677,623)
29	(52,969,563)		(52,969,563)
30	(54,293,802)		(54,293,802)

Years	KEDLI Synergies	KEDLI CTA	Net Synergies
1	(7,876,404)	12,126,512	4,250,108
2	(10,764,473)	4,820,360	(5,944,114)
3	(13,791,973)	4,725,843	(9,066,130)
4	(16,964,052)	2,136,081	(14,827,971)
5	(17,388,153)	2,290,458	(15,097,695)
6	(17,822,857)	1,880,885	(15,941,972)
7	(18,268,429)	1,458,710	(16,809,719)
8	(18,725,139)	667,919	(18,057,220)
9	(19,193,268)	686,822	(18,506,445)
10	(19,673,100)	708,876	(18,964,223)
11	(20,164,927)		(20,164,927)
12	(20,669,050)		(20,669,050)
13	(21,185,777)		(21,185,777)
14	(21,715,421)		(21,715,421)
15	(22,258,307)		(22,258,307)
16	(22,814,764)		(22,814,764)
17	(23,385,133)		(23,385,133)
18	(23,969,762)		(23,969,762)
19	(24,569,006)		(24,569,006)
20	(25,183,231)		(25,183,231)
21	(25,812,812)		(25,812,812)
22	(26,458,132)		(26,458,132)
23	(27,119,585)		(27,119,585)
24	(27,797,575)		(27,797,575)
25	(28,492,514)		(28,492,514)
26	(29,204,827)		(29,204,827)
27	(29,934,948)		(29,934,948)
28	(30,683,321)		(30,683,321)
29	(31,450,404)		(31,450,404)
30	(32,236,665)		(32,236,665)

Niagara Mohawk (Electric)
Computation of Synergies

National Grid and KeySpan
KEDNY & KEDLI Rate Plan
Exhibit No. ___ (Rates Panel-4R)

			2001	2002	2003	2004	2005	2006
1	560000	Trans Oper-Supervision & Eng	165,340	1,143,708	3,110,543	2,730,842	1,885,670	1,800,998
2	561000	Trans Oper-Load Dispatching	3,869,375	2,945,485	1,351,266	3,772,372	4,051,031	4,672,659
3	562000	Trans Oper-Substations	4,213,031	3,757,315	3,985,426	3,165,234	2,461,201	2,481,497
4	563000	Trans Oper-Overhead Lines	809,838	907,135	790,020	1,619,934	2,141,130	1,508,546
5	564000	Trans Oper-Underground Lines	596,973	486,229	439,408	616,568	95,296	75,795
6	565000	Trans Oper-Wheeling	2,328,352	2,791,240	2,784,356	2,784,226	3,027,308	2,870,741
7	566000	Trans Oper-Misc Expenses	298,365	323,334	1,416,759	4,585,047	5,991,542	6,193,842
8	567000	Trans Oper-Rents	13,419,078	11,625,708	12,861,432	9,871,295	8,948,044	9,193,796
9	568000	Trans Maint-Supervision & Eng	237,801	203,362	533,027	1,088,002	1,932,902	1,654,022
10	569000	Trans Maint-Buildings	255,863	303,276	177,253	142,913	224,758	1,123,642
11	570000	Trans Maint-Substations	9,686,558	9,061,136	9,984,057	7,723,829	5,078,917	6,353,620
12	571000	Trans Maint-Overhead Lines	8,405,133	6,694,547	9,295,645	9,585,849	7,906,020	15,889,966
13	572000	Trans Maint-Underground Lines	134,452	199,597	230,934	465,528	364,622	236,022
14	573000	Trans Maint-Misc Expenses	3,464	3,676	2,669	22,059	29,053	28,674
15	580000	Dist Oper-Supervision & Eng	696,735	4,264,900	11,313,051	7,416,654	3,582,107	4,740,376
16	581000	Dist Oper-Load Dispatching				5,436,789	7,905,337	10,031,860
17	582000	Dist Oper-Substations	5,406,151	4,716,859	3,761,881	4,185,110	3,252,072	5,120,219
18	583000	Dist Oper-Overhead Lines	9,019,762	9,343,429	9,361,311	6,660,356	(834,077)	5,431,539
19	584000	Dist Oper-Underground Lines	2,861,223	3,283,150	3,420,496	4,217,345	5,221,653	4,830,272
20	585000	Dist Oper-Outdoor Lighting	635,028	489,484	432,646	1,529,792	1,143,835	794,849
21	586000	Dist Oper-Electric Meters	8,388,850	8,262,340	8,301,441	9,051,626	8,974,006	8,408,444
22	587000	Dist Oper-CustomerInstallation	4,670,447	4,827,009	4,811,773	4,384,786	4,804,809	4,753,916
23	588000	Dist Oper-Misc Expenses	7,402,177	6,769,760	7,537,355	31,299,239	41,926,840	38,339,311
24	589000	Dist Oper-Rents	678,291	627,158	971,380	124,421	452,785	549,267
25	590000	Dist Maint-Supervision & Eng	2,282,811	3,407,111	1,154,565	192,017	182,371	234,565
26	591000	Dist Maint-Structures	127,467	256,958	307,227	1,145,200	1,556,144	950,981
27	592000	Dist Maint-Substations	6,086,957	6,794,007	7,346,344	7,212,741	5,882,447	7,046,513
28	593000	Dist Maint-Overhead Lines	70,990,857	86,536,353	83,955,108	62,883,838	63,641,614	83,860,834
29	594000	Dist Maint-Underground Lines	3,023,401	2,290,263	2,889,102	4,769,008	2,791,226	1,992,655
30	595000	Dist Maint-Line Transformers	2,454,484	1,935,245	1,872,129	2,855,659	2,329,620	1,765,091
31	596000	Dist Maint-Outdoor Lighting	3,597,155	3,854,562	3,084,782	4,252,684	4,977,958	5,052,373
32	597000	Dist Maint-Electric Meters	1,821,975	1,768,727	1,910,412	3,548,304	1,122,085	959,767
33	598000	Dist Maint-Misc Distr Plant	39,794	46,214	60,567	188,409	393,481	378,488
34	Total Electric O&M		174,607,188	189,919,277	199,454,365	209,527,676	203,443,807	239,325,139
35	Inflation			1.75%	2.13%	2.84%	3.03%	2.95%
36	Inflated 2001		174,607,188	177,659,763	181,439,993	186,588,576	192,240,166	197,909,352
37	Implied Synergies		-	(12,259,514)	(18,014,372)	(22,939,100)	(11,203,641)	(41,415,787)

Niagara Mohawk (Electric)
Computation of Synergies

			2001	2002	2003	2004	2005	2006
1	901000	Cust Acct-Supervision	2,438,741	2,657,113	2,648,638	2,455,862	3,164,972	2,966,858
2	902000	Cust Acct-Meter Reading Exp	11,264,453	11,165,519	10,096,808	8,078,132	6,135,358	5,864,592
3	903000	Cust Records & Collection	31,888,877	32,889,233	36,668,834	39,086,898	36,083,949	34,953,004
4	904000	Uncollectible Accounts	45,839,069	66,619,701	50,400,250	32,237,382	38,076,256	25,220,719
5	905000	Cust Acct-Misc Expenses	37,245	57,898	32,244	1,114,740	754,473	170,071
6	907000	Cust Service-Supervision	1,153,343	1,129,918	2,033,304	1,381,098	1,597,976	469,818
7	908000	Cust Assistance Expenses	9,548,743	46,887,541	49,325,606	46,796,517	48,238,456	57,148,972
8	909000	Info&Instruct Advertising Exp	(3,276)	111,410	44,326	265,881	515,295	620,695
9	910000	Cust Service-Misc Expenses	923,224	908,119	3,185,192	3,630,500	4,544,075	4,892,033
10	911000	Sales Expense-Supervision	12,100	34,842	31,797	9,091	46	
11	912000	Demo & Selling Expenses	78,432	20,721	1,116		159	
12	913000	Sales-Misc Expenses	240,763	178,895	40,181	9,621	1,128	1,365
13	920000	A&G-Salaries	95,619,268	90,299,971	57,347,943	46,999,764	47,690,131	44,991,703
14	921000	A&G-Office Supplies	27,195,314	34,298,796	34,081,870	39,017,856	39,540,162	36,428,116
15	922000	Admin Expense Transferred-CR	-	-	-	377	7,151	3,736
16	923000	A&G-Outside Services Employed	45,623,984	49,047,884	33,971,568	17,552,115	6,758,132	8,016,385
17	924000	Property Insurance	(2,239,973)	(2,692,456)	(2,271,475)	(1,873,964)	3,246,128	2,841,526
18	925000	Injuries & Damages Insurance	8,831,729	15,187,967	16,454,791	16,269,253	17,214,755	18,250,280
19	926000	Employee Pensions & Benefits	104,901,379	148,769,392	130,569,063	85,761,574	99,508,678	106,795,887
20	927000	Franchise Requirements	-	-	1,204	940	3,134	212
21	928000	Regulatory Comm Expenses	8,471,515	8,941,955	9,811,249	9,519,229	11,869,256	12,075,253
22	929000	Duplicate Charges-Credit	(1,565,018)	(1,157,348)	(318,066)	(161,829)	-	1,772
23	930200	A&G-Misc Expenses	(1,100)	8,677	3,629	5,826	-	
24	930210	A&G-Research & Development	35,273,744	(6,586,460)	13,258,797	12,433,568	16,457,498	16,685,407
25	931000	A&G-Rents	11,112,490	9,765,551	10,841,433	12,447,352	13,148,932	14,181,387
26	932000	A&G-Maint-General Plant-Gas						
27	935000	A&G Maint-General Plant-Elec	10,617,088	10,358,506	11,190,693	5,432,614	821,622	2,797,579
28	Total Customer and A&G		447,262,134	518,903,345	469,450,995	378,470,397	395,377,722	395,377,370
29	Less: DSM, SBC, RPS (908000)		9,548,743	46,887,541	49,325,606	46,796,517	48,238,456	57,148,972
30	Less: Bad Debt (904000)		45,839,069	66,619,701	50,400,250	32,237,382	38,076,256	25,220,719
31	Total Less Adjustments		391,874,322	405,396,103	369,725,139	299,436,498	309,063,010	313,007,679
32	Inflation			1.75%	2.13%	2.84%	3.03%	2.95%
33	Inflated 2001		391,874,322	398,725,275	407,209,321	418,764,384	431,448,358	444,171,824
34	Implied Synergies		-	(6,670,828)	37,484,182	119,327,886	122,385,348	131,164,145

Niagara Mohawk (Electric)
Computation of Synergies

National Grid and KeySpan
KEDNY & KEDLI Rate Plan
Exhibit No. ___ (Rates Panel-4R)

		2002	2003	2004	2005	2006
1	OPEB	2,766	2,766	2,766	2,766	2,766
2	SIR	10,200	10,200	10,200	10,200	10,200
3	Miscelleous	28,172	28,172	28,172	28,172	28,172
4	Labor 53 Week	490	490	490	(2,666)	490
5	Departmental	529,239	538,924	550,619	563,284	577,028
6	Increased Departmental	6,300	6,300	6,300	6,300	6,300
7	Other	8,499	9,009	9,550	10,123	10,731
8	Subtotal	585,666	595,861	608,097	618,179	635,687
9	Less SBC	15,616	15,704	15,777	15,831	15,839
10	Total Joint Proposal Cost	570,050	580,157	592,320	602,348	619,848
11	Actual Costs (less SBC & RPS)	595,315	569,180	508,964	512,507	552,333
12	Total Achieved Savings	(25,265)	10,977	83,356	89,841	67,515
13	Forecasted Synergies	(58,246)	(79,082)	(100,635)	(122,812)	(125,809)
14	Forecasted Cost to Achieve	52,444	20,851	20,440	9,241	9,910
15	Over/(Under) Achieved Synergies	(31,067)	(47,254)	3,161	(23,730)	(48,384)

Niagara Mohawk (Electric)
Computation of Capital Additions

			2001	2002	2003	2004	2005	2006
	Transmission							
1	350000	Land and Land Rights	152,452	88,955	262,680	54,316	20,258	210,250
2	352000	Structures and Improvements	789,250	316,559	(8,716)	733,293	365,298	299,949
3	353000	Station Equipment	18,576,943	21,241,973	5,434,717	15,590,091	28,749,003	36,989,013
4	354000	Towers and Fixtures	3,243,667	-	10,334	4,105	1,509,992	981,047
5	355000	Poles and Fixtures	24,349,411	4,732,484	4,194,751	6,672,448	7,383,335	17,593,899
6	356000	Overhead Conductors and Devises	7,807,839	3,472,235	1,522,532	2,428,938	9,756,232	7,941,368
7	357000	Underground Conduit	2,707,958	104,461	40,789	57,256	199,018	34,042
8	358000	Underground Conductors and Devises	3,561,006	1,628,090	2,473,499	1,700,521	2,851,620	2,077,637
9	359000	Roads and Trails	2,242,293	2,040	(1,326)	22,255	29,380	-
	Distribution							
10	360000	Land and Land Rights	922	69,553	80,546	104,491	6,066,214	3,023,294
11	361000	Structures and Improvements	368,627	589,604	927,353	219,816	173,331	-
12	362000	Station Equipment	9,856,380	10,233,568	6,263,498	7,574,743	20,262,072	25,352,458
13	363000	Storage Battery Equipment	-	-	-	-	-	-
14	364000	Poles, Towers and Fixtures	38,912,077	31,229,290	32,416,931	36,769,456	32,812,598	26,056,587
15	365000	Overhead Conductors and Devises	27,207,021	25,826,706	24,097,853	26,560,865	34,656,564	57,546,181
16	366000	Underground Conduit	4,037,101	4,125,206	2,864,196	3,653,291	4,096,471	3,951,616
17	367000	Underground Conductors and Devises	14,835,603	16,214,597	15,315,535	20,187,636	22,636,490	21,485,186
18	368000	Line Transformers	21,709,866	24,252,958	23,936,364	11,761,338	41,112,453	44,890,806
19	369000	Services	11,661,239	14,803,301	16,742,855	7,447,934	12,296,049	7,448,785
20	370000	Meters	3,844,839	3,426,160	40,543,003	1,170,276	34,188,061	4,671,658
21	371000	Installations on Customer Premises	408,472	284,741	452,905	574,879	415,296	309,208
22	372000	Leased Property on Customer Premises	-	-	-	-	-	-
23	373000	Street Lighting and Signal Systems	13,916,064	9,694,950	7,340,880	7,893,029	8,050,160	9,198,728
24	Total Electric Capital Additions		210,189,030	172,337,431	184,911,179	151,180,977	267,629,895	270,061,712
25	CWIP		165,891,737	137,119,289	90,509,503	153,650,562	104,431,643	89,597,333
26	Capital Outlay in Year (Line 24 + Change in CWIP)		140,292,089	143,564,983	138,301,393	214,322,036	218,410,976	255,227,402
27	Inflation			1.75%	2.13%	2.84%	3.03%	2.95%
28	Inflated 2001 (Prior Year times Line 27, except for 2001 which is Line 24)		140,292,089	142,744,749	145,782,061	149,918,806	154,459,703	159,014,739
29	Additional Capital Spending (Line 24 - Line 28)		-	820,234	(7,480,668)	64,403,230	63,951,273	96,212,663
30	Rate Plan Transmission Capital Expenditures (Workpapers pgs 353-373)		20,172,000	20,443,000	20,227,000	20,086,000	20,944,000	21,153,000
31	Rate Plan Distribution Capital Expenditures (Workpapers pgs 353-373)		113,512,000	117,790,000	116,964,000	110,700,000	112,437,000	113,561,000
32	Rate Plan Trans and Dist Capital Expenditures		133,684,000	138,233,000	137,191,000	130,786,000	133,381,000	134,714,000
33	Difference Between Actuals and Rate Plan (Line 24 - Line 32)		76,505,030	34,104,431	47,720,179	20,394,977	134,248,895	135,347,712

PREPARED REBUTTAL TESTIMONY

OF

ALAN V. FEIBELMAN AND RICHARD J. LEVIN

ON BEHALF OF

NATIONAL GRID plc

AND

KEYSPAN CORPORATION

CASE 06-M-0878

MARCH 7, 2007

I. Introduction

Q. Mr. Feibelman, please state your full name and business address for the record.

A. My name is Alan V. Feibelman. My business address is 200 Clarendon Street, Boston, MA 02116. I am a Director of Mercer Management Consulting.

Q. Mr. Levin, please state your full name and business address for the record.

A. My name is Richard J. Levin. My business address is 200 Clarendon Street, Boston, MA 02116. I am a management consultant with Mercer Management Consulting.

Q. Mr. Feibelman, have you previously submitted testimony in this proceeding?

A. Yes. On December 14, 2006, I co-sponsored (along with Mr. Levin) testimony that presented an updated merger savings estimate. This estimate was based on the work of the Companies' merger integration team.

Q. Mr. Levin, have you previously submitted testimony in this proceeding?

A. Yes. In addition to the testimony referenced above, on October 3, 2006, I co-sponsored (along with David J. Hoffman of Mercer) testimony supporting Exhibit 1 to the July 20, 2006 joint petition that provided an initial estimate of potential savings from the merger of National Grid and KeySpan.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to comment on the testimonies submitted by the Department of Public Service witnesses Mr. Stewart, Mr. Myers and Mr. Coonan (the Merger Policy Panel); the Consumer Protection Board witness, Dr. Elfner; the International Brotherhood of Electrical Workers, Local 97 witnesses Mr. Falletta and Mr. Koda; and the Utility Workers Union of America witness Mr. Sullivan.

Q. How is the remainder of this testimony organized?

A. The remainder is organized into four sections that discuss the above-mentioned testimonies as they relate to:

- Estimated annual synergy savings;
- Estimated timing of savings;
- Estimated costs to achieve; and
- Potential impacts on customer service quality.

II. Estimated Annual Synergy Savings

Q. Please summarize the Companies' synergy savings analyses.

A. The Companies' initial estimate of synergy savings in this proceeding was presented in Exhibit 1 contained in the July 20, 2006 joint petition and supported by the testimony of Mr. Hoffman and Mr. Levin filed October 3, 2006. That testimony discussed a range of annual savings of $165 million to $210 million (page 1). On December 14, 2006, we submitted an updated analysis, based on the work of the National Grid-KeySpan integration team, which estimated annual

savings at $153 million to $208 million (page 8 and Exhibit No.__ (AVF/RJL-1)). Both estimates confirmed the reasonableness of the Companies' use of $200 million in annual savings in its proposed Rate Plan.

While the team has continued to investigate cost-saving opportunities and refine its work since the December 2006 filing, no significant change has occurred in its estimate of savings. Moreover, given the integration team's work to date, the Companies continue to recommend that $200 million in annual savings (somewhat above the midpoint of the range) be adopted in this proceeding.

Q. What issues have been raised about the Companies' synergy savings analyses?

A. The testimonies of the other parties have focused on three issues: methodology and documentation; the status of the integration team's analysis; and the estimated level of savings.

Q. Please discuss the methodology and documentation issue.

A. With respect to the integration team's updated synergy savings analysis, the Merger Policy Panel testimony states that: "Once again the company provided no clear and succinct description of how it identified and quantified the synergy savings. Therefore, the validity and accuracy of the synergy savings presented by the companies is dubious" (page 89).

Q. Do you agree with the Merger Policy Panel's assessment?

A. No. The Panel provided only a generalized criticism and did not identify specific information or analyses that have not been provided. The updated synergy savings analysis was based on a rigorous methodology, was detailed and well documented, and has been appropriately communicated through testimony and responses to data requests. Information that has been provided includes:

- A five-page discussion of the methodology used by the integration team contained in our December 14, 2006 testimony (see pages 3 through 8). This discussion describes the nine functional teams responsible for identifying savings, the specific cost-savings changes identified by the teams (e.g., organizational consolidation, consolidation of information technology operations, optimization of facilities, elimination of duplicative costs), and the methodology used to quantify labor and non-labor savings;
- Exhibit No.__ (AVF/RJL-1), an overall summary of the team's synergy savings estimate with details regarding estimated FTE reductions and savings by component (labor and non-labor);
- Exhibit No.__ (AVF/RJL-2), an eighteen-page document that provides additional details about the savings estimate and FTE reductions for each of the nine functional teams; and
- The response to DPS-314, question 8 (dated January 9, 2007), a thirty-one page document that provides further detail on the team's synergy estimate, specifically line-item savings estimates for more than 150 individual cost-saving initiatives

developed by the nine functional teams. Details are provided for labor savings by function and specific non-labor savings, such as IT savings, procurement savings, facilities savings and A&G savings. The document is attached as Exhibit No.__ (AVF/RJL-1R).

In fact, the level of detail provided in this proceeding far exceeds the level of detail provided in support of the approved Niagara Mohawk and the Eastern Utilities Associates mergers. In addition, based on our review of testimonies submitted in other transactions since 1999, we have not identified any synergy savings estimate that is based on as detailed an analysis as the integration team's work.

Q. Please compare the methodology supporting the team's estimate in this merger with your prior merger experience.

A. The methodology supporting the integration team's savings estimates is consistent with methodologies used in prior mergers, including the National Grid-Niagara Mohawk merger. Nine functional teams, comprised of individuals from the two merging companies, have spent the last eight months developing detailed plans for integrating National Grid and KeySpan. These teams have involved over 200 managers and staff from both companies in (1) understanding and assessing both companies' operations, (2) identifying best practices, policies, processes and systems to utilize in the future merged entity, (3) designing organization structures, and (4) estimating the savings associated with the combination of the

two companies. Individuals who are knowledgeable and experienced with particular functions have been responsible for developing the integration plans and savings estimates associated with those functions. Using such a large integration planning effort, which involves leaders, managers and staff from the functions being integrated, is consistent with our prior merger experience.

Q. What concerns were raised about the status of the team's analysis?

A. The Merger Policy Panel states (at pages 89-90) that "the usefulness of such a review is questionable because the estimate is by Grid's own admission is incomplete and not final."

Q. Do you agree?

A. No. The Companies' have presented a substantial and detailed record that supports the estimate of $200 million in annual savings. The validity of this estimate has not changed during the course of this proceeding. The fact that the Companies do not yet have answers to some questions prior to the merger close (e.g., the future location of all workers, the specific number of FTE reductions related to a specific union) is not unusual in this type of proceeding.

Q. With respect to the level of estimated annual savings, has any other party developed an independent estimate?

A. No other party has presented an estimate of overall savings based on the integration of National Grid and KeySpan operations. In addition, no other party

offers any specific dollar adjustments to the cost savings estimates developed by the team overall or in any of the nine functional areas considered.

Q. Dr. Elfner states on page 41 of his testimony that "Petitioners include a smaller estimate of synergy savings in their filings in this case than were presented to National Grid's Board of Directors to justify the Transaction and that those different estimates have not been reconciled." Are the team's estimate and the estimates presented to the Board in January and February 2006 inconsistent?

A. No. On the contrary, the estimates, excluding bad debt reduction, are close. In fact, the five analyses cited by Dr. Elfner (the high-level 2004 Mercer study that was provided in response to CPB-214; the two high-level Board presentations; the more detailed October 2006 initial filing; and the very detailed December 14, 2006 integration team update) each support the conclusion that $200 million is a realistic estimate of annual O&M savings. The range provided by the integration team is the most rigorous and detailed analysis available and provides the best estimate of savings for this transaction.

III. Estimated Timing of Savings

Q. Please discuss the timing or phase-in of merger savings incorporated into the Companies' alternative rate plan.

A. The Companies' alternative rate plan (discussed by Mr. Bodanza, Mr. Laflamme and Mr. Molloy in their rebuttal testimony) assumes that savings would be

achieved over a four-year period with 50% of the $200 million in savings achieved in the first year, 67% of savings achieved in the second year, 83% of savings achieved in the third year and 100% of savings achieved in the fourth year. Under the alternative rate plan, savings are then levelized over a ten-year period. The phase-in percentages are the same percentages adopted in the settlement agreement related to the National Grid-Niagara Mohawk merger.

Q. Dr. Elfner recommends that the National Grid-Niagara Mohawk achieved phase-in percentages be adopted in this proceeding (testimony at page 49). Please compare the percentages proposed by the Companies with the percentages achieved in the Niagara Mohawk merger.

A. The phase-in percentages proposed by the Companies and the percentages achieved in the Niagara Mohawk merger are comparable overall. As shown on Exhibit No. ___ (AVF/RJL-2R), savings ramp up over a four-year period in both cases. The percentage of savings achieved in year 1 are actually higher in the Companies' rate plan (50% versus 26% achieved in the Niagara Mohawk merger). Annual savings average 75% of fully-phased-in savings in the Companies' rate plan over the four-year period. The comparable figure in the Niagara Mohawk merger is 71%.

Achieving savings at a faster rate would be difficult in this merger. Compared to the Niagara Mohawk merger, this merger will involve:

- Two larger-scale operations, as measured by number of employees, number of customers, number of office locations and size of service territories;
- The integration of both gas operations organizations and electric T&D organizations (National Grid did not have gas operations prior to the Niagara Mohawk merger);
- More dependencies, including a larger number of unions; and
- The services agreements with Long Island Power Authority (LIPA).

Q. Please summarize your testimony related to the timing of savings.

A. The timing of savings incorporated into the Companies' alternative rate plan is a reasonable estimate and should be adopted in this proceeding.

IV. Estimated Costs to Achieve

Q. Please discuss the estimated costs to achieve incorporated into the Companies' alternative rate plan.

A. The Companies' alternative rate plan is based on estimated costs to achieve of $400 million with future adjustments to rates based on actual costs incurred. We believe that $400 million is a conservative estimate of costs to achieve for the following reasons:

- Mercer has previously estimated costs to achieve at $400 million, based on annual savings of $200 million and costs at 2 times savings, as discussed in

Exhibit 1 of The Joint Petition at pages 1 and 10 of 17. The 2 times ratio is at the low end of the range (2.0 to 2.7 times) of other transactions reviewed; and

• National Grid staff has estimated costs to achieve of $477 million (supplemental response to DPS-11, part (b), Attachment A). As noted in that response, the estimate excludes certain costs that will be incurred in order to capture the savings identified by the integration team, such as facilities consolidation costs. This response is attached to our testimony as Exhibit No. ___(AVF/RJL-3R).

Q. Do you agree with Dr. Elfner's recommendation (page 47 of his testimony) that transaction costs and executive compensation costs should be excluded from recoverable costs to achieve?

A. No. We believe that both transaction costs and executive compensation costs should be included, because they are costs that will be incurred in order to complete the merger and capture the merger benefits. Transaction costs include fees for professional services that must be incurred in order to successfully complete a merger, to gain the necessary regulatory approvals and to achieve regulatory compliance.

Q. Please summarize your testimony related to costs to achieve.

A. The $400 million cost to achieve estimate incorporated into the rate plan is conservative. Recoverable costs to achieve should include both transaction costs and executive compensation costs.

V. Potential Impacts on Customer Service Quality

Q. Have you reviewed the concerns raised in Staff and intervenor testimonies related to customer service quality?

A. Yes. We have reviewed the concerns and will discuss issues related to two significant customer service functions: call taking (telephone contact centers) and meter reading.

Q. Do you believe that customer service quality will be adversely affected if the merger is approved?

A. No. On the contrary, we believe that the merger will improve contact center service quality and meter reading performance and will create a more positive experience for customers. At the same time, the implementation of cost-saving initiatives developed by the integration team will lead to lower costs of providing these services. Cost reduction and service quality improvement do not have to be a "trade-off," and we believe that the merger will not result in one.

Q. Will estimated cost savings related to the contact center function negatively impact response time for answering calls and service quality?

A. No. Cost savings will primarily result from the following three strategies that will enhance or maintain service quality:

- **Reducing the number of calls that will need to be handled by customer service representatives:** this will be accomplished by increasing the functionality and convenience of customer self-service options available through the Web and

interactive voice response (IVR) systems. The use of these channels will be voluntary and will improve the customer service experience for customers;

- **Reducing the average cost per call taken:** this can be accomplished by working with the relevant unions to reduce labor costs associated with representatives, by employing lower-cost vendors to take calls, or by some combination of the two. To the extent that a vendor is used, the combined company will continue the practice of closely managing the vendor relationship and ensuring that call takers are well trained, are handling calls appropriately and are meeting expected service levels; and
- **Consolidating contact centers and linking the centers (virtualization):** again, while reducing costs, consolidation and virtualization will allow the combined company to better utilize call takers and handle overflow and emergency calls between centers, thereby improving response time and service.

Q. Why do you believe that meter reading performance and related customer satisfaction will improve post-merger?

A. The integration team has recommended that automated meter reading (AMR) be expanded in the KEDNY and KEDLI service territories. AMR, a proven technology in the utility industry, will bring a number of operating and customer benefits including:

- Improved meter reading and billing accuracy;

- Fewer estimated bills due to more frequent reads and a higher percentage of meters read;
- Fewer high-bill complaints and quicker resolution of complaint calls due to more accurate and frequent reads; and
- Greater convenience for customers due to reduced need to read their own meters or provide access to inside meters.

National Grid's experience with AMR illustrates these benefits. Pre-AMR, meters not read or estimated for regular billing were approximately 10% of total reads. Since the installation of AMR, estimated meter reads have fallen to approximately 2%. In Massachusetts, the average billing adjustment dropped from approximately $30 per 1,000 residential customers to $3 in 2005 (see the 2005 Massachusetts Electric Results of Service Quality Plan submitted to the Massachusetts DTE and contained in Exhibit GS-16).

Because AMR has already been widely implemented by National Grid in New York and New England and by KeySpan in New England and portions of New York, the post-merger company will be able to utilize the combined expertise of the companies in more effectively installing and managing the meters.

Q. Will customers see any other benefits from the merger?

A. Yes. In addition to the benefits discussed above, the team has recommended converting KEDNY bi-monthly accounts to monthly billing, which will levelize

winter bills. The team also recommends increasing customer awareness of electronic bill presentation and payment (EBPP), a convenient way to pay bills.

Q. Please summarize your testimony regarding the impact of the merger on post-merger customer service quality.

A. We expect positive impacts on contact center and meter reading performance as a result of the merger. The merger will produce costs savings, improved or maintained service levels, expanded offerings and higher customer satisfaction in the customer service functions.

VI. Conclusion

Q. Does that complete your testimony?

A. Yes, it does.

Corporate Services: Confidence Levels

Potential O&M Savings

Certainty

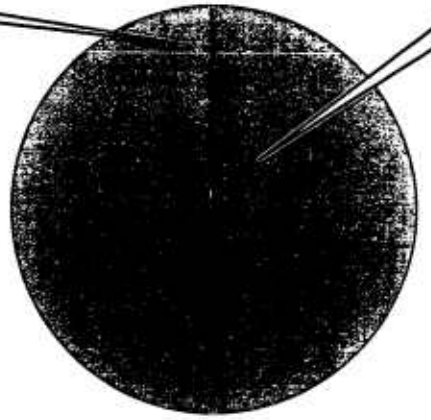
Items in this category include:

- Improve utilization of outside counsel
- Eliminate overlap in lobbying function
- Improve utilization of other professional services
- Eliminate duplicate legal research services
- Eliminate KS annual report, annual meeting
- Consolidate functions: legal, corporate communications, regulatory affairs, claims, records management, governmental affairs
- Eliminate KS outside board of directors
- Optimize mix of in-house vs. outside legal resources

High confidence

Items in this category include:

- Consolidate functions: records management
- Implement common approach to records management



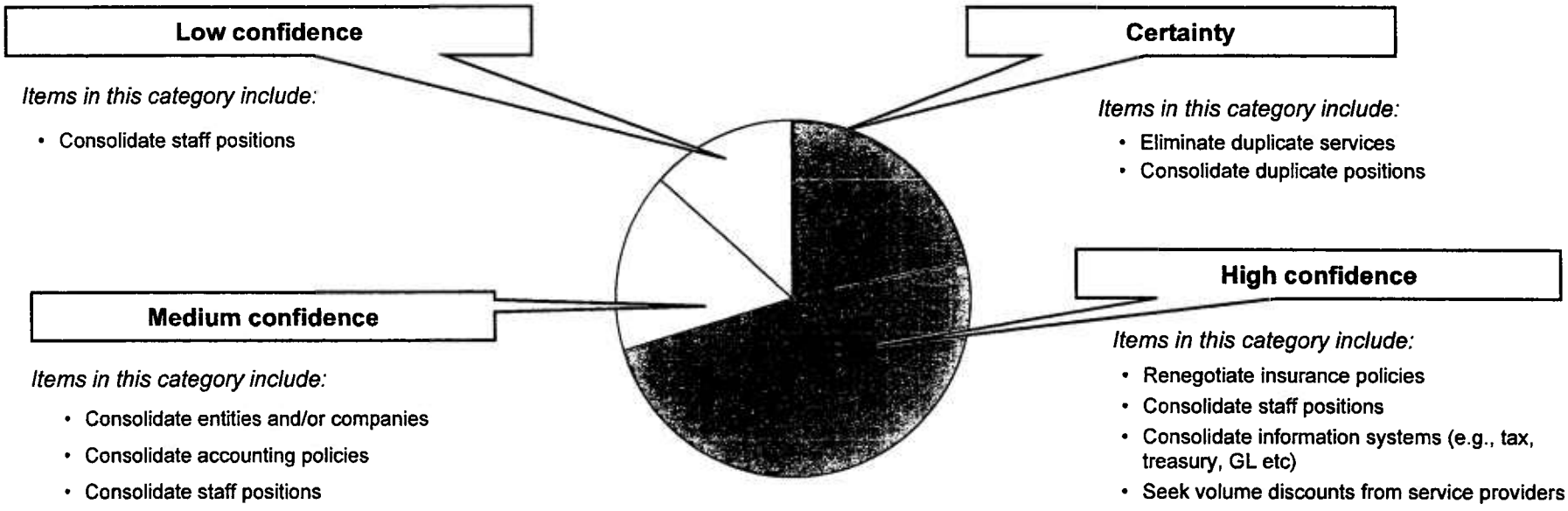
Confidence Levels	Probability to Achieve		FTEs	O&M Savings ($M)		
				Labor Savings	Non-Labor Savings	Total
Certainty	■	100%	45	6.5	5.6	12.1
High Level of Confidence	☐	75-100%	2 - 3	0.3 - 0.4	0 - 0	0.3 - 0.4
Medium Level of Confidence	☐	50-75%	0 - 0	0 - 0	0 - 0	0 - 0
Low Level of Confidence	☐	0-50%	0 - 0	0 - 0	0 - 0	0 - 0
TOTAL			47 - 48	6.9 - 7	5.6 - 5.6	12.5 - 12.6

Initiative		External Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (Y/N)	Regulatory Dependencies (Y/N)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Corporate Services	Consolidation of overlap staff				Certain	45.0	45.0	6.5	6.5	0.0	0.0
Corporate Services	Reduction in outside professional services				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Corporate Services	Reduction in advertising costs				Certain	0.0	0.0	0.0	0.0	0.3	0.3
Corporate Services	Re-bidding of printing contract				Certain	0.0	0.0	0.0	0.0	0.1	0.1
Corporate Services	Elimination of KS Annual Meeting/Printing and Mailing of Annual Report				Certain	0.0	0.0	0.0	0.0	0.5	0.5
Corporate Services	Elimination of KS Corporate Secretary non-labor costs				Certain	0.0	0.0	0.0	0.0	0.1	0.1
Corporate Services	Elimination of KS External Board of Directors				Certain	0.0	0.0	0.0	0.0	1.6	1.6
Corporate Services	Reduction in outside professional services				Certain	0.0	0.0	0.0	0.0	3.8	3.8
Corporate Services	Consolidation of online research				Certain	0.0	0.0	0.0	0.0	0.1	0.1
Corporate Services	Consolidation of library publications				Certain	0.0	0.0	0.0	0.0	0.1	0.1
Corporate Services	Implement electronic invoicing KeySpan Legal Dept				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Corporate Services	Hire outside counsel for targetted services				Certain	0.0	0.0	0.0	0.0	-0.9	-0.9
Corporate Services	Coordination of regulatory policy and compliance requirements				Certain	0.0	0.0	0.0	0.0	0.0	0.0
Corporate Services	Integration of Gas and Electric support functions				Certain	0.0	0.0	0.0	0.0	0.0	0.0
Corporate Services	Additional outside counsel for auditing				Certain	0.0	0.0	0.0	0.0	-0.5	-0.5
Corporate Services	Optimize Records Management department	Collective bargaining			High	2.3	3.0	0.3	0.4	0.0	0.0
					Totals	47.3	48.0	6.9	7.0	5.6	5.6
					Certain	45.0	45.0	6.5	6.5	5.54	5.54
					High	2.3	3.0	0.3	0.4	0.03	0.04

Initiative		External Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (title)	Regulatory Dependencies (title)	Other Dependencies	Overall confidence	FTEs ($ low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
					Medium	0.0	0.0	0.0	0.0	0.0	0.0
					Low	0.0	0.0	0.0	0.0	0.0	0.0

Finance and Accounting: Confidence Levels

Potential O&M Savings



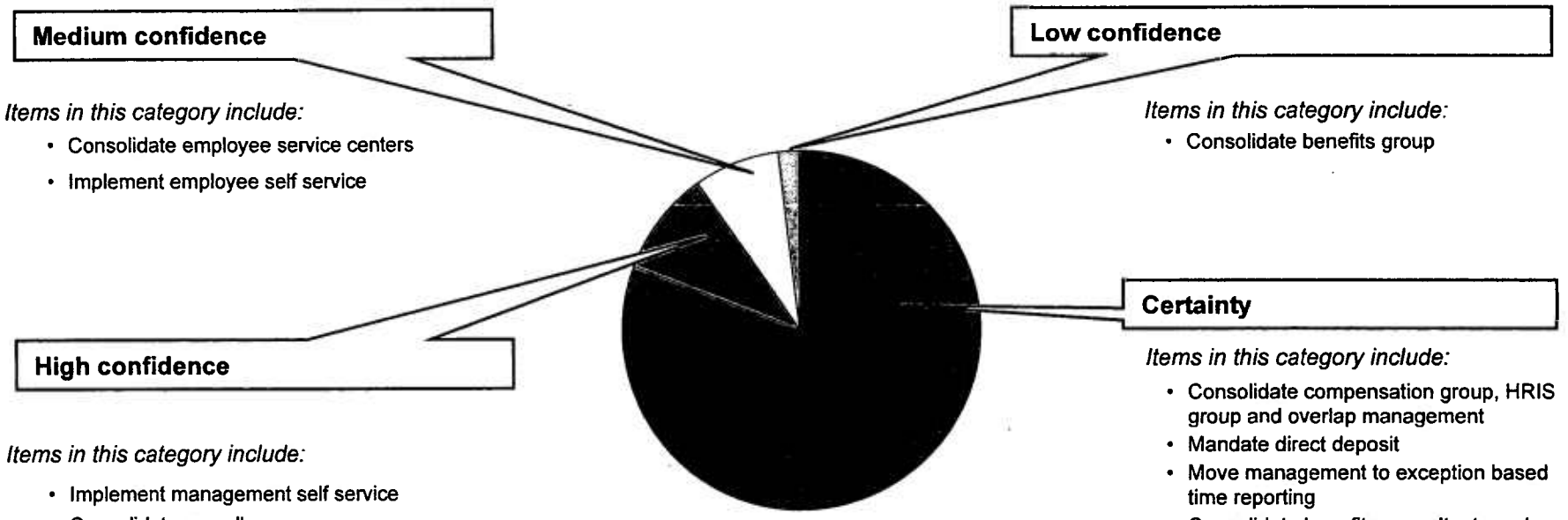
Confidence Levels	Probability to Achieve		FTEs	O&M Savings ($M)		
				Labor Savings	Non-Labor Savings	Total
Certainty	■	100%	17	1.9	7.6	9.4
High Level of Confidence	□	75 – 100%	39 - 52	4.3 - 5.7	2.4 - 3.2	6.7 - 8.9
Medium Level of Confidence	□	50 – 75%	20 - 30	2.2 - 3.3	0 - 0.1	2.2 - 3.3
Low Level of Confidence	□	0 – 50%	0 - 12	0 - 1.3	0 - 0	0 - 1.3
TOTAL			76 - 110	8.3 - 12.1	10 - 10.8	18.3 - 22.9

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (IBEW)	Regulatory Dependencies (DPS)	Other Dependencies	Overall Confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Finance & Accounting	Consolidation of Global CFOs				Certain	1.0	1.0	0.1	0.1	0.4	0.4
Finance & Accounting	Consolidate professional service firms and vendors				Certain	1.0	1.0	0.1	0.1	6.0	6.0
Finance & Accounting	Consolidate staff positions				Certain	13.0	13.0	1.4	1.4	0.1	0.1
Finance & Accounting	Transfer services from Citibank to Remitco				Certain	0.0	0.0	0.0	0.0	0.3	0.3
Finance & Accounting	Negotiate walk-in payment agent contract - Western Union				Certain	0.0	0.0	0.0	0.0	0.1	0.1
Finance & Accounting	Negotiate Lockbox Contracts (Regulus/Mellon Financial)				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Finance & Accounting	Elimination of Treasurer & CRO position				Certain	2.0	2.0	0.2	0.2	0.0	0.0
Finance & Accounting	Eliminate transfer agent fees				Certain	0.0	0.0	0.0	0.0	0.4	0.4
Finance & Accounting	Elimination of NYSE listing fees				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Finance & Accounting	Consolidate Financial Policies and Reporting		Regulatory consultation		High	10.5	14.0	1.2	1.5	0.0	0.0
Finance & Accounting	Consolidation of global staff positions				High	9.8	13.0	1.1	1.4	1.2	1.7
Finance & Accounting	Consolidate staff positions				High	14.5	19.0	1.5	2.0	0.4	0.6
Finance & Accounting	Consolidate staff positions	Collective bargaining			High	4.3	6.0	0.6	0.8	0.6	0.9
Finance & Accounting	Bank account consildation				High	0.0	0.0	0.0	0.0	0.1	0.1
Finance & Accounting	Implementation of treasury workstation		Regulatory consultation required		High	0.0	0.0	0.0	0.0	0.0	0.0
Finance & Accounting	Consolidate staff positions	Collective bargaining, some positions			Medium	19.8	29.6	2.2	3.3	-0.2	-0.2
Finance & Accounting	Equipment replacement and licensing fee avoidance - Revenue Accounting				Medium	0.0	0.0	0.0	0.0	0.2	0.3
Finance & Accounting	Optimize Revenue Accounting	Collective bargaining			Low	0.0	11.8	0.0	1.3	0.0	0.0
					Totals	75.8	110.4	8.3	12.1	10.0	10.8
					Certain	17.0	17.0	1.9	1.9	7.6	7.6
					High	39.0	52.0	4.3	5.7	2.4	3.2

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor [illegible]	Regulatory Dependencies (if any)	Other Dependencies	Overall Confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M [illegible]	[illegible] Value $M (High)
					Medium	19.8	29.6	2.2	3.3	0.0	0.1
					Low	0.0	11.8	0.0	1.3	0.0	0.0

Human Resources: Confidence Levels

Potential O&M Savings



Items in this category include:

- Consolidate employee service centers
- Implement employee self service

Items in this category include:

- Consolidate benefits group

Items in this category include:

- Implement management self service
- Consolidate payroll group

Items in this category include:

- Consolidate compensation group, HRIS group and overlap management
- Mandate direct deposit
- Move management to exception based time reporting
- Consolidate benefits consultants and contractors

Confidence Levels	Probability to Achieve		FTEs	O&M Savings ($M)		
				Labor Savings	Non-Labor Savings	Total
Certainty		100%	28	4.1	1.5	5.6
High Level of Confidence		75-100%	4 - 5	0.3 - 0.5	0 - 0	0.3 - 0.5
Medium Level of Confidence		50-75%	2 - 3	0.2 - 0.3	0 - 0	0.2 - 0.3
Low Level of Confidence		0-50%	0 - 1	0 - 0	0 - 0	0 - 0
TOTAL			34 - 37	4.6 - 4.9	1.5 - 1.5	6.1 - 6.4

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Concentration (HR)	Regulatory Dependence (HR)	Other Dependencies	Overall Confidence	FTEs (Low)	FTEs (High)	Labor Value ($M) (Low)	Labor Value ($M) (High)	Non-Labor Value ($M) (Low)	Non-Labor Value ($M) (High)
HR	Consolidate consultants and contractors				Certain	0.0	0.0	0.0	0.0	1.4	1.4
HR	Consolidate HRIS				Certain	4.0	4.0	0.4	0.4	0.0	0.0
HR	Consolidate overlap staff (1)				Certain	20.0	20.0	3.3	3.3	0.0	0.0
HR	Implement exception based time reporting				Certain	2.0	2.0	0.2	0.2	0.0	0.0
HR	Mandatory direct deposit and electronic payroll				Certain	2.0	2.0	0.2	0.2	0.1	0.1
HR	Consolidate overlap staff (2)				High	3.0	4.0	0.3	0.4	0.0	0.0
HR	Implement employee self service				High	0.8	1.0	0.0	0.1	0.0	0.0
HR	Consolidate overlap staff (3)	Collective bargaining			Medium	1.5	2.3	0.2	0.2	0.0	0.0
HR	Implement management self service	Collective bargaining			Medium	0.5	0.8	0.0	0.1	0.0	0.0
HR	Consolidate overlap staff (4)	Collective bargaining			Low	0.0	0.5	0.0	0.0	0.0	0.0
					Totals	33.8	36.5	4.6	4.9	1.5	1.5
					Certain	28.0	28.0	4.1	4.1	1.5	1.5
					High	3.8	5.0	0.3	0.5	0.0	0.0
					Medium	2.0	3.0	0.2	0.3	0.0	0.0
					Low	0.0	0.5	0.0	0.0	0.0	0.0

Information Services: Confidence Levels

Potential O&M Savings

Medium confidence

Items in this category include:

- Renegotiate vendor contracts
- Consolidate business applications and related infrastructure
- Reduce the number of contractors
- Consolidate staff positions

Low confidence

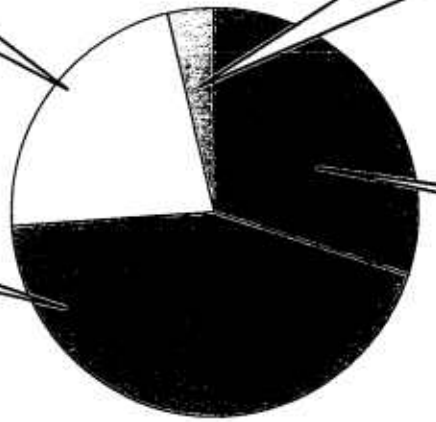
Items in this category include:

- Consolidate staff positions

High confidence

Items in this category include:

- Consolidate business applications
- Consolidate assets and infrastructure
- Negotiate contracts with vendors
- Optimize use of contractors



Certainty

Items in this category include:

- Reduce managers and internal project related staff

Confidence Levels	Probability to Achieve		FTEs	O&M Savings ($M)		
				Labor Savings	Non-Labor Savings	Total
Certainty		100%	91	8.6	0.0	8.6
High Level of Confidence		75 – 100%	69 - 91	8.4 - 11.1	7.2 - 9.6	15.6 - 20.7
Medium Level of Confidence		50 – 75%	18 - 27	2.3 - 3.5	2.9 - 4.4	5.3 - 7.9
Low Level of Confidence		0 – 50%	0 - 8	0 - 0.7	0 - 0	0 - 0.7
TOTAL			177 - 217	19.3 - 23.9	10.1 - 14	29.4 - 37.9

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (FTEs)	Regulatory Dependencies (FTEs)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Information Services	Consolidation of Customer Application staff			Dependent on LOB consolidating their applications	Certain	10.0	10.0	1.1	1.1	0.0	0.0
Information Services	Consolidation of Application Services staff			Dependent on LOB consolidating their applications	Certain	4.5	4.5	0.5	0.5	0.0	0.0
Information Services	Consolidation of Corporate Applications staff - vacancies			Dependent on LOB consolidating their applications	Certain	4.0	4.0	0.4	0.4	0.0	0.0
Information Services	Consolidation of Trans/Gen Applications staff - vacancies			Dependent on LOB consolidating their applications	Certain	0.0	0.0	0.0	0.0	0.0	0.0
Information Services	Consolidation of Operations Applications staff - management			Dependent on LOB consolidating their applications	Certain	2.0	2.0	0.4	0.4	0.0	0.0
Information Services	Consolidation of Infrastructure management			Dependent on LOB consolidating their applications	Certain	1.0	1.0	0.3	0.3	0.0	0.0
Information Services	Consolidation of Telecom Services - Management			Dependent on LOB consolidating their applications	Certain	1.5	1.5	0.2	0.2	0.0	0.0
Information Services	Consolidation of Network Engineering staff			Dependent on LOB consolidating their applications	Certain	2.0	2.0	0.3	0.3	0.0	0.0
Information Services	Consolidation of Distributed Computing - Vacancies			Dependent on LOB consolidating their applications	Certain	7.5	7.5	0.9	0.9	0.0	0.0
Information Services	Consolidation of Data Center staff			Dependent on LOB consolidating their applications	Certain	8.5	8.5	1.1	1.1	0.0	0.0
Information Services	Consolidation of Strategy & Business management staff - Vacancies				Certain	50.0	50.0	3.4	3.4	0.0	0.0
Information Services	Consolidation of Corporate Applications staff			Dependent on LOB consolidating their applications	High	22.5	30.0	2.6	3.5	0.0	0.0
Information Services	Consolidation of Application Services staff			Dependent on LOB consolidating their applications	High	8.3	11.0	0.9	1.2	0.0	0.0
Information Services	Consolidation of Trans/Gen Applications staff			Dependent on LOB consolidating their applications	High	5.3	7.0	0.6	0.8	0.0	0.0

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (IBT)	Regulatory Dependencies (IBT)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Information Services	Consolidation of Operations Applications staff			Dependent on LOB consolidating their applications	High	9.8	13.0	1.0	1.4	0.0	0.0
Information Services	Consolidation of Data Center staff			Dependent on LOB consolidating their applications	High	6.8	9.0	0.9	1.2	0.0	0.0
Information Services	Consolidation of Energy Management staff			Dependent on LOB consolidating their applications	High	1.5	2.0	0.2	0.3	0.0	0.0
Information Services	Consolidation of Network Engineering staff			Dependent on LOB consolidating their applications	High	0.8	1.0	0.1	0.1	0.0	0.0
Information Services	Consolidation of Distributed Computing staff			Dependent on LOB consolidating their applications	High	9.8	13.0	1.2	1.6	0.0	0.0
Information Services	Consolidation of Strategy & Business management staff			Dependent on LOB consolidating their applications	High	3.8	5.0	0.7	0.9	0.0	0.0
Information Services	Reduction in non-labor costs from consolidation of corporate systems			Dependent on LOB consolidating their applications	High	0.0	0.0	0.0	0.0	4.7	6.3
Information Services	Reduction in contractors from the consolidation of systems			Dependent on LOB consolidating their applications	High	0.0	0.0	0.0	0.0	2.5	3.3
Information Services	Consolidation of Data Center staff	Collective Bargaining		Dependent on LOB consolidating their applications	Medium	4.0	6.0	0.6	0.8	0.0	0.0
Information Services	Consolidation of Telecom Services staff	Collective Bargaining		Dependent on LOB consolidating their applications	Medium	2.0	3.0	0.3	0.4	0.0	0.0
Information Services	Consolidation of Network Engineering staff			Dependent on LOB consolidating their applications	Medium	1.8	2.6	0.2	0.4	0.0	0.0
Information Services	Consolidation of Distributed Computing staff			Dependent on LOB consolidating their applications	Medium	6.3	9.4	0.8	1.2	0.0	0.0
Information Services	Consolidation of Strategy & Business management staff			Dependent on LOB consolidating their applications	Medium	4.0	6.0	0.5	0.7	0.0	0.0
Information Services	Reduction in non-labor costs from consolidation of corporate systems			Dependent on LOB consolidating their applications	Medium	0.0	0.0	0.0	0.0	2.3	3.4

Intiative		Dependencies				Expected O&M Impact					
Area	Initiative Name	Labor Dependencies (IBT)	Technology Dependencies (IBT)	Other Dependencies	Overall confidence	Pre-Tax Low	Pre-Tax High	Labor Value $/ (Low)	Labor Value $/ (High)	Non-Labor Value $/ (Low)	Non-Labor Value $/ (High)
Information Services	Reduction in contractors from the consolidation of systems			Dependent on LOB consolidating their applications	Medium	0.0	0.0	0.0	0.0	0.7	1.0
Information Services	Optimize network of data centers	Collective Bargaining		Savings dependent on other functions moving out of facility	Low	0.0	7.5	0.0	0.7	0.0	0.0
					Totals	177.3	216.5	19.3	23.9	10.1	14.0
					Certain	91.0	91.0	8.6	8.8	0.0	0.0
					High	68.3	91.0	8.4	11.1	7.2	9.6
					Medium	18.0	27.0	2.3	3.5	2.9	4.4
					Low	0.0	7.5	0.0	0.7	0.0	0.0

Customer Service and Marketing: Confidence Levels

Low confidence

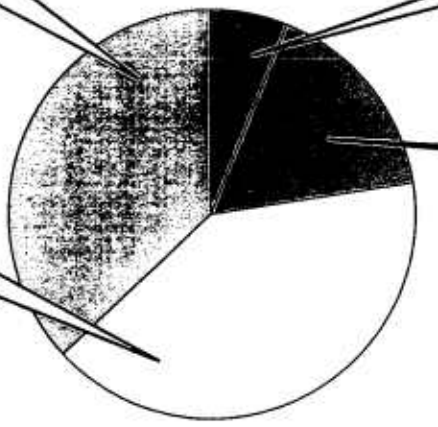
Items in this category include:

- Leverage call taking vendor to reduce average cost per call
- Consolidate contact center and back office
- Virtualize contact centers

Medium confidence

Items in this category include:

- Consolidate contact center, back office, and account management
- Migrate to CSS from CAS and CRIS
- Combine gas and electric meter work
- Virtualize contact centers
- Deploy AMR



Certainty

Items in this category include:

- Consolidate functions

High confidence

Items in this category include:

- Increase utilization of electronic bill presentation and payment (EBPP)
- Expand self-service opportunities for customers through the Web and IVR

Confidence Levels	Probability to Achieve		FTEs	O&M Savings ($M)		
				Labor Savings	Non-Labor Savings	Total
Certainty		100%	30	3.1	0.4	3.5
High Level of Confidence		75-100%	32 - 42	3.9 - 5.2	3.1 - 4.2	7 - 9.4
Medium Level of Confidence		50-75%	177 - 265	12.7 - 19.1	-1.1 - -1.7	11.6 - 17.4
Low Level of Confidence		0-50%	0 - 180	0 - 13.6	0 - -3.1	0 - 10.5
TOTAL			238 - 517	19.7 - 40.9	2.5 - -0.1	22.1 - 40.8

Initiative		Dependencies				Expected O&M Impact					
Type	Initiative Name	Labor Dependencies (Y/N)	Regulatory Dependencies (Y/N)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Customer and Marketing	Consolidate overlap Community Relations staff				Certain	4.0	4.0	0.5	0.5	0.0	0.0
Customer and Marketing	Consolidated Meter Purchasing Power				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Customer and Marketing	Consolidated AMR Purchasing Power				Certain	0.0	0.0	0.0	0.0	0.1	0.1
Customer and Marketing	Improved efficiency within existing KeySpan growth model				Certain	20.0	20.0	2.0	2.0	0.0	0.0
Customer and Marketing	Process Improvement				Certain	6.0	6.0	0.5	0.5	0.0	0.0
Customer and Marketing	Discontinuation of targetted vendor contract				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Customer and Marketing	Determine most efficient and effective operating model for large accounts				High	3.0	4.0	0.6	0.8	0.0	0.0
Customer and Marketing	Create a corporate Economic Development approach				High	0.8	1.0	0.1	0.1	0.0	0.0
Customer and Marketing	Allocate Account Managers time to DSM				High	0.0	0.0	0.4	0.5	0.0	0.0
Customer and Marketing	Convert KeySpan bi-monthly billed accounts to monthly billing		Regulatory consultation		High	0.0	0.0	0.0	0.0	0.4	0.5
Customer and Marketing	Consolidate management of Retail Choice programs (Electric and Gas) across the combined companies.			LIPA: Service Agreement	High	1.5	2.0	0.2	0.3	0.0	0.0
Customer and Marketing	Increase customer utilization of Electronic Bill Presentment and Payment (EBPP) and shift customers to lower-cost payment options				High	0.0	0.0	0.0	0.0	0.5	0.7
Customer and Marketing	Increased Self-Service IVR (1a)				High	3.8	5.0	0.3	0.4	0.8	1.1
Customer and Marketing	Increased Self-Service Web (2a)				High	1.5	2.0	0.1	0.2	0.7	0.9
Customer and Marketing	CSR Training/Support				High	7.5	10.0	0.7	0.9	0.0	0.0
Customer and Marketing	Recall past obligations from vendor				High	-0.8	-1.0	-0.1	-0.1	0.8	0.9

Initiative		Dependencies				Expected O&M Impact					
Theme	Initiative Name	Labor Dependencies (Title)	Regulatory Dependencies (Title)	Other Dependencies	Overall confidence	FTE's (Low)	FTE's (High)	Labor Value ($) (Low)	Labor Value ($) (High)	Non-Labor Value ($) (Low)	Non-Labor Value ($) (High)
Customer and Marketing	Adoption of common platform and operating processes for field force	Collective bargaining	Regulatory consultation		High	9.8	13.0	0.8	0.8	0.1	0.1
Customer and Marketing	Technology Improvement				High	4.5	6.0	1.0	1.3	0.0	0.0
Customer and Marketing	Determine most efficient model for managing New Construction Orders	Collective bargaining			Medium	8.5	12.8	1.0	1.4	0.0	0.0
Customer and Marketing	Centralize back office and support activities for non-managed accounts	Collective bargaining	Coordinate CIAC reconciltions across jurisdictions		Medium	4.0	6.0	0.4	0.7	0.0	0.0
Customer and Marketing	CIS System Consolidation				Medium	4.5	6.8	0.4	0.6	0.0	0.0
Customer and Marketing	Consolidate Bill print and mail function for the combined company				Medium	6.5	9.8	0.0	0.0	0.2	0.3
Customer and Marketing	Contact Center Consolidation (a)	Collective bargaining			Medium	22.0	33.0	2.1	3.1	0.1	0.1
Customer and Marketing	Move Calls to Competitve Cost Structure (a)	Collective bargaining			Medium	31.0	46.5	2.1	3.2	-1.1	-1.6
Customer and Marketing	Virtualization (a)	Collective bargaining			Medium	10.0	15.0	0.8	1.2	0.0	0.0
Customer and Marketing	Back Office Consolidation (a)	Collective bargaining			Medium	16.5	24.8	1.3	2.0	0.0	0.0
Customer and Marketing	Back Office Consolidation (c)	Collective bargaining			Medium	0.0	0.0	0.3	0.5	0.0	0.0
Customer and Marketing	Adopt Pos ID systemwide				Medium	-1.5	-2.3	-0.1	-0.2	-0.1	-0.2
Customer and Marketing	Improve replevin process				Medium	0.0	0.0	0.0	0.0	0.4	0.7
Customer and Marketing	Migrate to fewer and more effective DSM vendors				Medium	2.3	3.4	0.2	0.3	-0.5	-0.7
Customer and Marketing	Adopt system wide outbound calling strategy	Collective bargaining			Medium	15.5	23.3	0.6	0.8	-0.5	-0.8
Customer and Marketing	Gas DSM Program Expansion		Regulatory consultation		Medium	0.0	0.0	0.0	0.0	0.0	0.0
Customer and Marketing	Expand AMR	Collective bargaining			Medium	36.0	54.0	2.4	3.6	0.2	0.3

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (title)	Regulatory Dependencies (title)	Other Dependencies	Overall confidence	FTE (Low)	FTE (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Customer and Marketing	Consolidate gas and electric workforce in overlap territories	Collective bargaining		LIPA: Service Agreement	Medium	21.5	32.3	1.4	2.0	0.2	0.2
Customer and Marketing	Contact Center Consolidation(b)	Collective bargaining		LIPA: Service Agreement	Low	0.0	11.5	0.0	1.0	0.0	0.0
Customer and Marketing	Move Calls to Competitive Cost Structure (b)				Low	0.0	72.5	0.0	5.9	0.0	-3.0
Customer and Marketing	Virtualization (b)	Collective bargaining			Low	0.0	10.0	0.0	0.8	0.0	0.0
Customer and Marketing	Increased Self-Service IVR (1b)				Low	0.0	7.0	0.0	0.6	0.0	0.0
Customer and Marketing	Back Office Consolidation (b)	Collective bargaining			Low	0.0	5.0	0.0	0.4	0.0	0.0
Customer and Marketing	Reduce Traffic to Customer Offices	Collective bargaining			Low	0.0	1.5	0.0	0.1	0.0	0.0
Customer and Marketing	Adopt system wide policy of collecting 100% on field visits				Low	0.0	0.0	0.0	0.0	0.0	-0.5
Customer and Marketing	Adopt risk-based segmentation strategy system wide				Low	0.0	1.3	0.0	0.1	0.0	0.0
Customer and Marketing	Customer Satisfaction Program			Vendor: contract	Low	0.0	0.0	0.0	0.0	0.0	0.0
Customer and Marketing	Consolidate regulatory relations on customer issues				Low	0.0	1.5	0.0	0.1	0.0	0.0
Customer and Marketing	Expand AMR	Collective bargaining		LIPA: Service Agreement	Low	0.0	70.0	0.0	4.6	0.0	0.3
					Totals	238.3	517.4	19.7	40.9	2.5	-0.1
					Certain	30.0	30.0	3.1	3.1	0.4	0.4
					High	31.5	42.0	3.9	5.2	3.1	4.2
					Medium	176.8	265.1	12.7	19.1	-1.1	-1.7
					Low	0.0	180.3	0.0	13.6	0.0	-3.1

Gas Operations: Confidence Levels

Potential O&M Savings

Low confidence

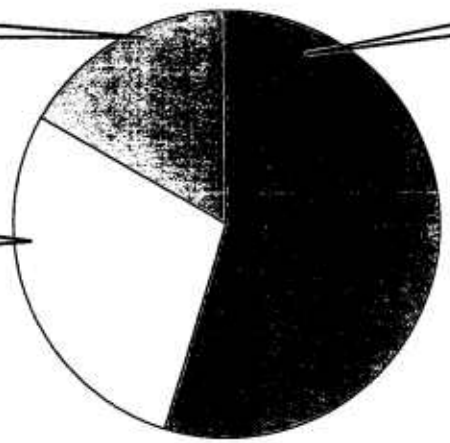
Items in this category include:

- Explore competitive pricing opportunities for locating and cast iron monitoring

Medium confidence

Items in this category include:

- Improve field performance by increasing supervisor time spent in field
- Consolidate control centers
- Standardize design/mapping processes
- Implement first responder leak process



High confidence

Items in this category include:

- Consolidate organizational structure
- Implement KeySpan's leak tracking system at National Grid
- Adopt common systems (e.g., GIS, work management, SCADA)
- Roll out GPS/AVLS
- Rationalize contractor usage to reduce unit costs and increase service levels
- Standardize material specifications to increase purchasing leverage (pipe, meters, vehicles, etc.)
- Optimize equipment management (right sizing, utilization of excess resources, inventory centralization)

Confidence Levels	Probability to Achieve		FTEs	O&M Savings ($M)		
				Labor Savings	Non-Labor Savings	Total
Certainty	■	100%	0	0.0	0.0	0.0
High Level of Confidence	□	75-100%	22 - 29	1.8 - 2.4	6.3 - 8.3	8.1 - 10.8
Medium Level of Confidence	□	50-75%	25 - 38	1.4 - 2.1	1.4 - 2.1	2.8 - 4.2
Low Level of Confidence	□	0-50%	0 - 16	0 - 1.6	0 - 0	0 - 1.6
TOTAL			47 - 82	3.2 - 6.2	7.6 - 10.4	10.9 - 16.6

Initiative		Dependencies				Expected O&M Impact					
Area	Initiative Name	Labor Dependencies (Title)	Regulatory Dependencies (Title)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Gas Operations	Standardize material specifications		Regulatory approval		High	0.0	0.0	0.0	0.0	0.2	0.3
Gas Operations	Enhance regulatory presence				High	0.0	0.0	0.0	0.0	0.2	0.3
Gas Operations	Organizational consolidation				High	7.5	10.0	0.6	0.7	0.1	0.1
Gas Operations	Governance on design change				High	2.3	3.0	0.2	0.3	0.0	0.0
Gas Operations	Adopt Process Ownership model				High	0.0	0.0	0.0	0.0	3.8	5.0
Gas Operations	Roll out GPS to KeySpan / AVLS	Collective bargaining		Training	High	9.0	12.0	0.4	0.6	0.0	0.0
Gas Operations	Standardization to code compliance for Transmission line leak survey/patrol Explore competitive pricing for surveys				High	0.0	0.0	0.5	0.7	0.0	0.0
Gas Operations	Standardization to code compliance for Business District leak survey Explore competitive pricing for surveys	Collective bargaining			High	0.0	0.0	0.1	0.1	0.0	0.0
Gas Operations	Common leak tracking system				High	0.0	0.0	0.0	0.0	0.0	0.0
Gas Operations	Electronic field data capture for leak process			Training	High	0.0	0.0	0.0	0.0	0.0	0.0
Gas Operations	Standardization of investigation and classification practices and reporting criteria for leak process Migrate to a similar leak data capture to afford data transparency, better planning & scheduling and overall better management of leaks.		Regulatory approval	Training	High	1.5	2.0	0.1	0.1	0.0	0.0
Gas Operations	Opportunity to eliminate site visits and shorten cycle time within NG.	Collective bargaining		Training; municipal considerations	High	2.3	3.0	0.0	0.1	0.0	0.0
Gas Operations	Utilizing the KeySpan Sales Fulfillment model in NG to enhance customer satisfaction and efficiencies	Collective bargaining		Training	High	0.0	0.0	0.0	0.0	0.0	0.0

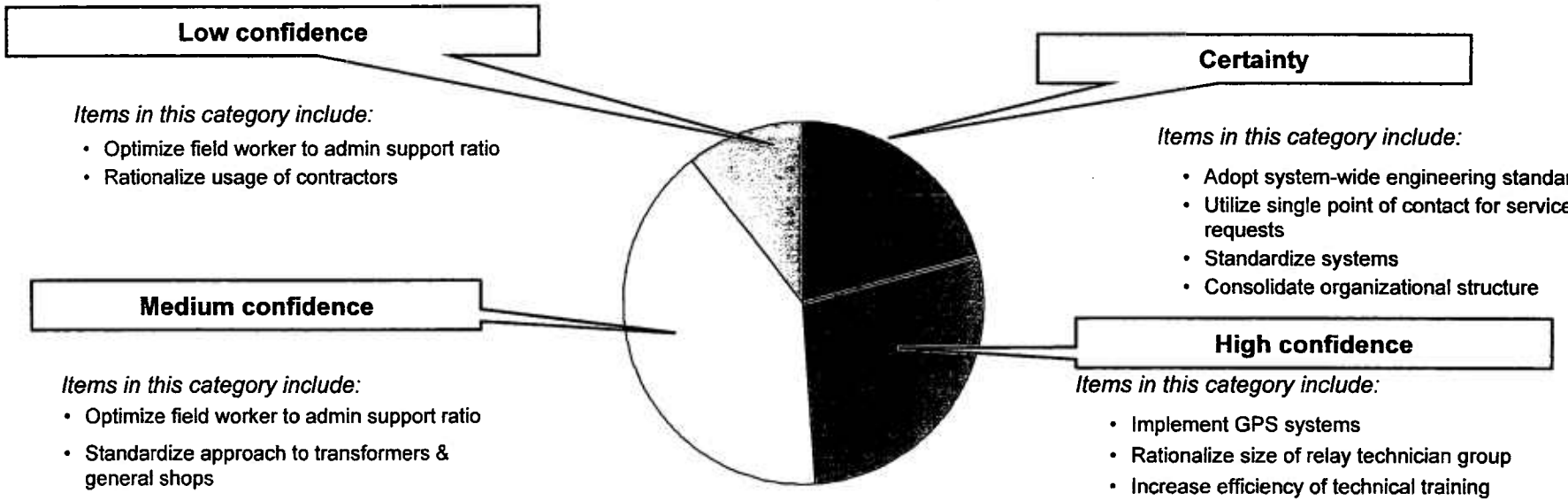
Initiative		Dependencies				Expected O&M Impact					
Type	Initiative Name	Labor Dependencies (IBs)	Regulatory Dependencies (IBs)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Gas Operations	Service retirement/ relocation policy for maintenance activity		Regulatory consultation		High	0.0	0.0	0.0	0.0	0.4	0.6
Gas Operations	Spoil Recycling			Municipal considerations	High	-2.3	-3.0	-0.1	-0.1	0.5	0.7
Gas Operations	Standardize vehicle specs				High	0.0	0.0	0.0	0.0	0.3	0.4
Gas Operations	Excavation Equipment Right Sizing				High	0.0	0.0	0.0	0.0	0.5	0.7
Gas Operations	Reduce underutilized excess vehicles and equipment				High	0.0	0.0	0.0	0.0	0.3	0.3
Gas Operations	Continued synergies within business processing	Collective bargaining		Training	High	1.5	2.0	0.0	0.0	0.0	0.0
Gas Operations	Standardize odorization		In MA		High	0.0	0.0	0.0	0.0	0.1	0.1
Gas Operations	Standardized processes for design/mapping				Medium	6.5	9.8	0.0	0.1	0.0	0.0
Gas Operations	Encroachment criteria for public works projects		Regulatory consultation		Medium	2.8	4.2	0.3	0.4	0.2	0.3
Gas Operations	Implement common system for tracking potential customers				Medium	0.0	0.0	0.0	0.0	0.0	0.0
Gas Operations	Standardize leak management system (leak classification process in Operations Subteam)			Training	Medium	0.0	0.0	0.3	0.4	0.3	0.4
Gas Operations	Work mgt and records in corrosion engineering			Operations, electric & power plants	Medium	0.3	0.4	0.0	0.1	0.0	0.0
Gas Operations	Field performance improvement / Supervisor Enablement, increase productivity				Medium	1.8	2.6	0.1	0.1	0.0	0.0
Gas Operations	Installation of Field Data Capture units				Medium	3.5	5.3	0.2	0.3	0.0	0.0
Gas Operations	Avoidance of restoration costs by utilizing appropriate tools and equipment	Collective bargaining		Materials inventory management	Medium	0.0	0.0	0.0	0.0	0.3	0.4

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (HBs)	Regulatory Dependencies (HBs)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Gas Operations	Consistent response practices; crew-type for leak process (2 person; live gas)	Collective bargaining			Medium	4.0	6.0	0.0	0.0	0.0	0.0
Gas Operations	Execution of repair by first responder for leak process	Collective bargaining	Regulatory consultation		Medium	3.0	4.5	0.3	0.4	0.0	0.0
Gas Operations	Reduce restoration costs associated with service retirements		Regulatory approval	"Live stub" safety considerations	Medium	0.0	0.0	0.0	0.0	0.1	0.2
Gas Operations	Standardization to code compliance for valve inspection		Coordinate across jurisdictions		Medium	0.3	0.4	0.0	0.0	0.0	0.0
Gas Operations	Excavation Equipment Optimization				Medium	0.5	0.8	0.0	0.0	0.1	0.2
Gas Operations	Consolidation of control centers - New York region		Verify Two County rule		Medium	2.5	3.8	0.2	0.3	0.4	0.6
Gas Operations	Standardization to code compliance for Distribution leak survey/patrol	Collective bargaining	Regulatory consultation		Low	0.0	0.0	0.0	0.2	0.0	0.0
Gas Operations	Explore competitive pricing for surveys										
	Create Education and Implementation Plan for General Public				Low	0.0	0.0	0.0	0.0	0.0	0.0
Gas Operations	Explore competitive pricing for locating (New England)	Collective bargaining			Low	0.0	0.0	0.0	0.8	0.0	0.0
Gas Operations	Explore competitive pricing for locating (New York)	Collective bargaining			Low	0.0	0.0	0.0	-0.1	0.0	0.0
Gas Operations	Explore competitive pricing for cast iron monitoring (New England)	Collective bargaining			Low	0.0	0.0	0.0	0.2	0.0	0.0
Gas Operations	Explore competitive pricing for cast iron monitoring (New York)	Collective bargaining			Low	0.0	0.0	0.0	0.0	0.0	0.0
Gas Operations	Replacement Main and Service Installation Process: 1. Optimize the use of Low Dig Technologies / 2. Outsourcing opportunities for conventional and low dig technologies	Collective bargaining		Contractor availability	Low	0.0	2.5	0.0	0.1	0.0	0.0
Gas Operations	New Main and Service Installation Process: 1. Optimize the use of HDD / 2. Outsourcing opportunities for HDD, Optimize customer prepared trenching opportunity (Excavation/backfill by others)	Collective bargaining		Contractor availability	Low	0.0	10.9	0.0	0.3	0.0	0.0

Initiative		Dependencies				Expected O&M Impact					
Area	Initiative Name	Labor Dependencies (Yes)	Regulatory Dependencies (Yes)	Other Dependencies	Overall confidence	Total (Low)	Total (High)	Labor Value ($ Low)	Labor Value ($ High)	Non-Labor Value ($ Low)	Non-Labor Value ($ High)
Gas Operations	URD/EUD Installation: Review and Optimize the use of Contractors - 2 Maximize opportunities for installation of joint utilities in a common trench	Collective bargaining		Contractor availability	Low	0.0	2.3	0.0	0.1	0.0	0.0
Gas Operations	Explore competitive pricing for tapping process (ie.live gas, tie-ins, cut outs, large diameter drillings),	Collective bargaining		Contractor availability	Low	0.00	0.00	0.00	0.03	0.00	0.00
					Totals	47	82	3.2	6.2	7.6	10.4
					Certain	0	0	0.0	0.0	0.0	0.0
					High	22	29	1.8	2.4	6.3	8.3
					Medium	25	38	1.4	2.1	1.4	2.1
					Low	0	16	0.0	1.6	0.0	0.0

Electric Transmission and Distribution: Confidence Levels

Potential O&M Savings



Items in this category include:

- Optimize field worker to admin support ratio
- Rationalize usage of contractors

Items in this category include:

- Adopt system-wide engineering standards
- Utilize single point of contact for service requests
- Standardize systems
- Consolidate organizational structure

Items in this category include:

- Optimize field worker to admin support ratio
- Standardize approach to transformers & general shops
- Consolidate EMS/IT support group

Items in this category include:

- Implement GPS systems
- Rationalize size of relay technician group
- Increase efficiency of technical training
- Standardize policies and procedures
- Rationalize usage of contractors

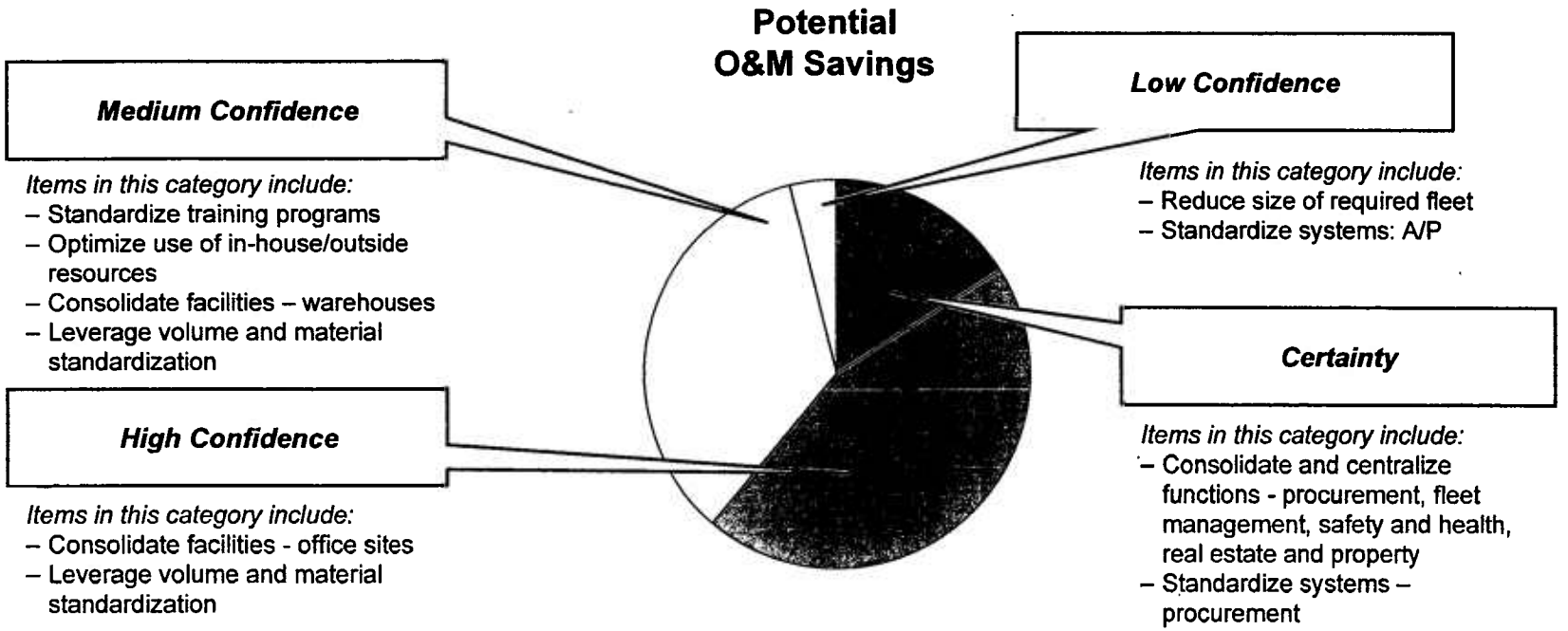
Confidence Levels	Probability to Achieve	FTEs	O&M Savings ($M)		
			Labor Savings	Non-Labor Savings	Total
Certainty	100%	14	2.3	1.1	3.4
High Level of Confidence	75 – 100%	19 - 25	0.9 - 1.2	2.6 - 3.4	3.5 - 4.6
Medium Level of Confidence	50 – 75%	47 - 70	3.1 - 4.6	0.3 - 0.5	3.4 - 5.1
Low Level of Confidence	0 – 50%	0 - 8	0 - 0.5	0 - 0.4	0 - 0.9
TOTAL		79 - 117	6.3 - 8.7	4 - 5.4	10.3 - 14.1

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (IBEW)	Regulatory Dependencies (IBEW)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Electric T&D	Optimize Organizational Structure				Certain	8.0	8.0	2.0	2.0	0.0	0.0
Electric T&D	Single point of accountability Project Management structure; Functional Consolidation with KeySpan			Coordination with USBR	Certain	3.0	3.0	0.0	0.0	0.0	0.0
Electric T&D	Implement Automated Contractor Invoicing System (ACIS)			ACIS Phase 2 at National Grid	Certain	0.0	0.0	0.0	0.0	0.1	0.1
Electric T&D	Evaluate distribution automation for National Grid				Certain	0.0	0.0	0.0	0.0	0.0	0.0
Electric T&D	Adopt best paractices relative to Work Methods/ Construction Unit/Macro estimating units				Certain	0.0	0.0	0.0	0.0	0.4	0.4
Electric T&D	Adopt GIS/design system at KeySpan				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Electric T&D	Consolidate engineering standards			LIPA: Service Agreement	Certain	2.0	2.0	0.2	0.2	0.0	0.0
Electric T&D	Evaluate single point of contact for requests for service				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Electric T&D	Rationalize Project Portfolios				Certain	1.0	1.0	0.1	0.1	0.0	0.0
Electric T&D	Automate Equipment History				Certain	0.0	0.0	0.0	0.0	0.1	0.1
Electric T&D	Consolidate software licenses				Certain	0.0	0.0	0.0	0.0	0.1	0.1
Electric T&D	Consolidate KS and NG bare ground treatments			Vendor: contracts	Certain	0.00	0.00	0.00	0.00	0.02	0.02
Electric T&D	Implement National Grid technology (ARCOS and AVLS) at KeySpan				High	0.0	0.0	0.0	0.0	0.2	0.3
Electric T&D	Adopt best practices relative to permanent connections. (ie., utilize electricians to make permanent taps; designers/planners for meter sets.)	Collective bargaining		Training; Safety	High	0.0	0.0	0.0	0.0	0.5	0.6
Electric T&D	Standadize GIS Platform				High	0.0	0.0	0.0	0.0	0.1	0.1
Electric T&D	Consider installing GPS at KS	Collective bargaining		LIPA: Service Agreement	High	0.0	0.0	0.0	0.0	0.8	1.0
Electric T&D	Technical training on inclement days	Collective bargaining			High	0.0	0.0	0.0	0.0	0.4	0.6
Electric T&D	Explore usage of cost data reports			Coordinate with USBR	High	0.0	0.0	0.0	0.0	0.1	0.1
Electric T&D	Explore installing a productivity measurement system			Coordinate with USBR	High	0.0	0.0	0.0	0.0	0.1	0.1

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (If Any)	Regulatory Dependencies (If Any)	Other Dependencies	Overall Confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Electric T&D	Optimize Organizational Structure	Collective bargaining		LIPA: Service Agreement; Training	High	18.8	25.0	0.9	1.2	0.0	0.0
Electric T&D	Develop uniform standards and material specs				High	0.00	0.00	0.00	0.00	0.01	0.02
Electric T&D	Investigate inventory sharing with LIPA			LIPA: Service Agreement	High	0.0	0.0	0.0	0.0	0.0	0.1
Electric T&D	Exclude service drop trimming on cycle projects and customer requests		Regulatory consultation	Vendor: contracts; customer communication	High	0.0	0.0	0.0	0.0	0.2	0.3
Electric T&D	Adopt vine growth gap spec at KS			Vendor: contracts	High	0.00	0.00	0.00	0.00	0.03	0.04
Electric T&D	Reduce size of NE Unit Price areas			Vendor: contracts	High	0.00	0.00	0.00	0.00	0.02	0.03
Electric T&D	Establish Transmission Lump sum danger tree removals at NGRID			Vendor: contracts	High	0	0	0.0	0.0	0.2	0.2
Electric T&D	Optimize System Operations Computing and EMS/IT support and systems				Medium	1.5	2.3	0.1	0.2	0.0	0.0
Electric T&D	Use common Transmission Outage Application (TOA) Program				Medium	0.0	0.0	0.0	0.0	0.1	0.2
Electric T&D	Gas and Electric System Operations Dispatch (SOD)/Standardize SOD functions/SOD Consolidation				Medium	6.5	9.8	0.4	0.6	0.0	0.0
Electric T&D	Control Consolidation	Collective bargaining		LIPA: Service Agreement	Medium	6.0	9.0	0.7	1.0	0.0	0.0
Electric T&D	Issue jobs not requiring design directly to field	Collective bargaining			Medium	0.0	0.0	0.0	0.0	0.1	0.2
Electric T&D	Standardize the field worker to support worker ratio across the company	Collective bargaining		LIPA: Service Agreement	Medium	31.0	46.5	1.8	2.7	0.0	0.0
Electric T&D	Standardize acceptance testing of key electric hardware				Medium	1.5	2.3	0.1	0.2	0.0	0.0
Electric T&D	Evaluate transformer shop and general shops			Training	Medium	0.0	0.0	0.0	0.0	0.1	0.1
Electric T&D	Provide cross support and leverage specialized expertise				Medium	0.00	0.00	0.00	0.00	0.01	0.01
Electric T&D	Modify NE NGRID customer contact for vegitation management		Coordinate across jurisdictions	Customer communication; Veridor contracts	Medium	0.00	0.00	0.00	0.00	0.03	0.04
Electric T&D	Implement National Grid technology (ARCOS and AVLS) at KeySpan				Low	0.0	0.0	0.0	0.0	0.0	0.1
Electric T&D	Standardize the field worker to support worker ratio across the company	Collective bargaining		LIPA: Service Agreement	Low	0.0	8.0	0.0	0.5	0.0	0.0

Initiative		Dependencies				Expected O&M Impact					
Area	Initiative Name	Labor Dependencies (Units)	Signif Dependencies (Dist)	Other Dependencies	Degree of confidence	FTEs (Low)	FTEs (High)	Labor Value ($) (Low)	Labor Value ($) (High)	Non-Labor Value ($) (Low)	Non-Labor Value ($) (High)
Electric T&D	Exclude service drop trimming on cycle projects and customer requests		Regulatory consultation	Customer communication; Vendor contracts	Low	0.0	0.0	0.0	0.0	0.0	0.1
Electric T&D	Modify NE NGRID customer contact for vegitation management		Coordinate across jurisdictions	Customer communication; Vendor contracts	Low	0.0	0.0	0.0	0.0	0.0	0.1
Electric T&D	Adopt vine growth gap spec at KS			Vendor: contracts	Low	0.00	0.00	0.00	0.00	0.00	0.02
Electric T&D	Reduce size of NE Unit Price areas			Vendor: contracts	Low	0.00	0.00	0.00	0.00	0.00	0.03
Electric T&D	Establish Transmission Lump sum danger tree removals at NGRID			Vendor: contracts	Low	0	0	0.0	0.0	0.0	0.1
					Totals	79.3	116.8	6.3	8.7	4.0	5.4
					Certain	14.0	14.0	2.3	2.3	1.1	1.1
					High	18.8	25.0	0.9	1.2	2.6	3.4
					Medium	46.5	69.8	3.1	4.8	0.3	0.5
					Low	0.0	8.0	0.0	0.5	0.0	0.4

Shared Services: Confidence Levels



Confidence Levels	Probability to Achieve		FTE	O&M Savings ($M)		
				Labor Savings	Non-Labor Savings	Total
Certainty	■	100%	96	8.7	1.6	10.3
High Level of Confidence	□	75 – 100%	67 - 89	4.7 - 6.3	16.4 - 21.8	21.1 - 28.1
Medium Level of Confidence	□	50 – 75%	8 - 11	0.4 - 0.5	10.7 - 16.1	11.1 - 16.6
Low Level of Confidence	□	0 – 50%	0 - 1	0 - 0.1	0 - 1	0 - 1.1
TOTAL Unadjusted			170 - 197	13.8 - 15.6	28.7 - 40.5	42.4 - 56.1

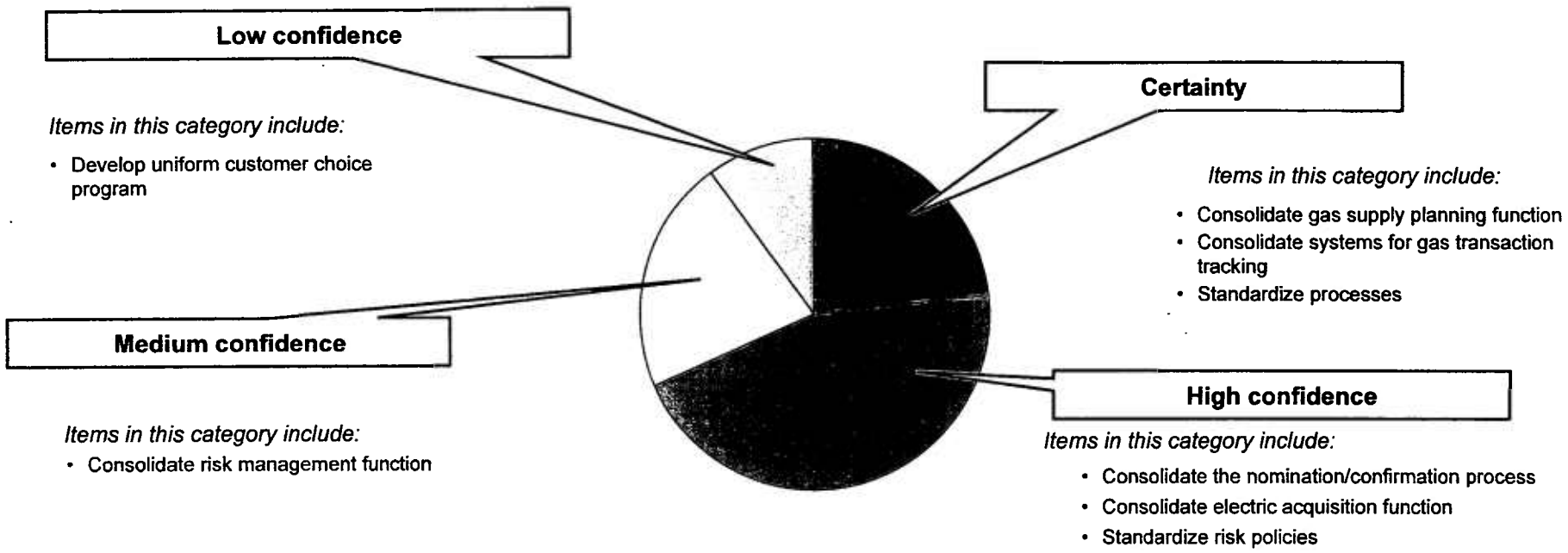
Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (Title)	Non-Labor Dependencies (Title)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value $M (Low)	Labor Value $M (High)	Non-Labor Value $M (Low)	Non-Labor Value $M (High)
Shared Services	Facilities Consolidation				High	0.0	0.0	0.0	0.0	4.5	6.0
Shared Services	Standardize O&M - Facilities Services				High	0.0	0.0	0.0	0.0	-0.4	-0.6
Shared Services	Reduce the size of the fleet			LIPA Service Agreement	High	0.0	0.0	0.0	0.0	0.5	0.6
Shared Services	Vehicle auction process				High	0.0	0.0	0.0	0.0	0.2	0.3
Shared Services	Joint Buying/Leveraged Spend			LIPA Service Agreement	High	0.0	0.0	0.0	0.0	11.6	15.5
Shared Services	Facilities Consolidation				Medium	0.0	0.0	0.0	0.0	3.0	4.5
Shared Services	Standardize O&M - Facilities Services				Medium	0.0	0.0	0.0	0.0	-0.3	-0.4
Shared Services	Joint Fleet commodity procurement				Medium	0.0	0.0	0.0	0.0	0.1	0.1
Shared Services	Joint Buying/Leveraged Spend			LIPA Service Agreement	Medium	0.0	0.0	0.0	0.0	7.8	11.6
Shared Services	Joint vehicle procurement				Low	0.0	0.0	0.0	0.0	0.0	0.7
Shared Services	Standardize company supplied vehicle program			LIPA Service Agreement (possibly)	Low	0.0	0.0	0.0	0.0	0.0	0.2
Shared Services	Consolidate Medical Services - NE				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Shared Services	Use a single procurement card and system				Certain	1.0	1.0	0.1	0.1	0.0	0.0
Shared Services	Use a single T&E card and system				Certain	0.5	0.5	0.0	0.0	0.0	0.0
Shared Services	Extend use of online ordering of office supplies				Certain	0.0	0.0	0.0	0.0	0.0	0.0
Shared Services	Environmental Policy and Management Process: Organizational Integration				Certain	2.0	2.0	0.6	0.6	0.0	0.0
Shared Services	Environmental Licensing and Complaince Process: Organizational Integration				Certain	4.0	4.0	0.4	0.4	0.0	0.0

Initiative		Dependencies				Expected O&M Impact					
Theme	Initiative Areas	Union Dependencies (Low)	Union Dependencies (High)	Other Dependencies	Overall Confidence	FTE (Low)	FTE (High)	Labor Value ($) (Low)	Labor Value ($) (High)	Non-Labor Value ($) (Low)	Non-Labor Value ($) (High)
Shared Services	Technology Transition				Certain	0.0	0.0	0.0	0.0	0.9	0.9
Shared Services	Sale of Non-Regulated, Non-Operating Surplus Land				Certain	0.0	0.0	0.0	0.0	0.0	0.0
Shared Services	Lease of regulated non operating surplus vacant land				Certain	0.0	0.0	0.0	0.0	0.2	0.2
Shared Services	Reduce O&M budget				Certain	0.0	0.0	0.0	0.0	0.1	0.1
Shared Services	Functional Consolidation				Certain	3.0	3.0	0.5	0.5	0.0	0.0
Shared Services	Security Reporting Function				Certain	0.0	0.0	0.0	0.0	0.0	0.0
Shared Services	Organizational Consolidation	Collective Bargaining (some items)		LIPA Service Agreement (some items)	Certain	85.0	85.0	7.2	7.2	0.1	0.1
Shared Services	Integrated Disability Management				High	0.0	0.0	0.0	0.0	0.1	0.1
Shared Services	Consolidate Contracted Medical Services Vendors				High	0.0	0.0	0.0	0.0	0.1	0.1
Shared Services	Standardize O&M - Facilities Services				High	21.0	28.0	1.7	2.3	0.0	0.0
Shared Services	Facilities Consolidaiton				High	6.0	8.0	0.5	0.6	0.0	0.0
Shared Services	Exit Metropolitan Lease				High	0.0	0.0	0.0	0.0	0.1	0.2
Shared Services	Standardize Training Offerings				High	2.3	3.0	0.3	0.3	-0.1	-0.1
Shared Services	Optimize Training Delivery				High	0.8	1.0	0.1	0.1	0.0	0.0
Shared Services	Optimize Trainer Cost Model				High	3.0	4.0	0.3	0.4	-0.1	-0.2
Shared Services	Warehouse Consolidation	Collective Bargaining (some items)	Multi-state, multi-company transfers of assets		High	13.5	18.0	0.3	0.3	0.0	0.0
Shared Services	Organizational Consolidation	Collective Bargaining (some items)		LIPA Service Agreement (some items)	High	20.3	27.0	1.6	2.1	-0.2	-0.2

Initiative		Dependencies				Expected O&M Impact					
Form	Initiative Name	Labor Dependencies (Y/N)	Regulatory Dependencies (Y/N)	Other Dependencies	Current Initiatives	FTEs (Low)	FTEs (High)	Labor Value ($M) (Low)	Labor Value ($M) (High)	Non-Labor Value ($M) (Low)	Non-Labor Value ($M) (High)
Shared Services	Consolidate Bank Accounts and Business Units into single paying company				Medium	0.5	0.8	0.0	0.1	0.0	0.0
Shared Services	Analytical Services Process: Optimize insource/outsource mix	Collective Bargaining (some items)			Medium	1.5	2.3	0.1	0.1	0.1	0.1
Shared Services	Optimize Waste Management, Environmental Outreach and Spill Response Process:	Collective Bargaining (some items)		LIPA Service Agreement	Medium	0.5	0.8	0.0	0.0	0.0	0.0
Shared Services	Standardize Real Estate systems				Medium	0.0	0.0	0.0	0.0	0.0	0.0
Shared Services	Addition of Security Personnel- 1 Technician				Medium	-0.5	-0.8	0.0	-0.1	0.0	0.0
Shared Services	Optimize Training Offerings				Medium	1.5	2.3	0.2	0.3	0.0	0.0
Shared Services	Warehouse Consolidation			LIPA Service Agreement	Medium	4.0	6.0	0.1	0.1	0.0	0.0
Shared Services	Optimize use of e-commerce technology				Low	0.0	1.5	0.0	0.1	0.0	0.0
Shared Services	Expand Inv recovery to Key Span				Low	0.0	-1.0	0.0	0.0	0.0	0.0
Shared Services	Contract Guards Staffing Reduction				Low	0.0	0.0	0.0	0.0	0.0	0.2
					Totals	169.8	196.3	13.8	15.7	28.6	40.3
					Certain	95.5	95.5	8.8	8.8	1.6	1.6
					High	66.8	89.0	4.7	6.3	16.3	21.8
					Medium	7.5	11.3	0.4	0.5	10.6	16.0
					Low	0.0	0.5	0.0	0.1	0.0	1.0

Generation and Energy Supply: Confidence Levels

Potential O&M Savings



Confidence Levels	Probability to Achieve	FTEs	O&M Savings ($M)		
			Labor Savings	Non-Labor Savings	Total
Certainty	100%	2	0.2	0.0	0.2
High Level of Confidence	75 – 100%	3 - 4	0.4 - 0.5	0 - 0	0.4 - 0.5
Medium Level of Confidence	50 – 75%	1 - 1	0.1 - 0.2	0 - 0	0.1 - 0.2
Low Level of Confidence	0 – 50%	0 - 1	0 - 0.1	0 - 0	0 - 0.1
TOTAL		6 - 7	0.7 - 0.9	0 - 0	0.7 - 0.9

Initiative		Dependencies				Expected O&M Impact					
Team	Initiative Name	Labor Dependencies (IBT)	Regulatory Dependencies (IBT)	Other Dependencies	Overall confidence	FTEs (Low)	FTEs (High)	Labor Value ($M) (Low)	Labor Value ($M) (High)	Non-labor Value ($M) (Low)	Non-labor Value ($M) (High)
Generation and energy Supply	Optimize gas supply planning functions				Certain	2.0	2.0	0.2	0.2	0.0	0.0
Generation and energy Supply	Move the nomination/confirmation process from Gas Operations				High	1.5	2.0	0.2	0.2	0.0	0.0
Generation and energy Supply	Consolidate Administration of PPA contracts		Coordinate across different jurisdictions	LIPA: Service Agreement	High	0.8	1.0	0.1	0.1	0.0	0.0
Generation and energy Supply	Develop consistent risk policies and procedures.				High	0.8	1.0	0.1	0.2	0.0	0.0
Generation and energy Supply	Develop consistent risk policies and procedures.				Medium	0.5	0.8	0.1	0.2	0.0	0.0
Generation and energy Supply	Move the nomination/confirmation process from Gas Operations				Low	0.0	0.5	0.0	0.1	0.0	0.0
					Totals	5.5	7.3	0.7	0.9	0.0	0.0
					Certain	2.0	2.0	0.2	0.2	0.0	0.0
					High	3.0	4.0	0.3	0.5	0.0	0.0
					Medium	0.5	0.8	0.1	0.2	0.0	0.0
					Low	0.0	0.5	0.0	0.1	0.0	0.0

Savings Phase-In Rates

	National Grid-Niagara Mohawk Settlement Agreement	National Grid-Niagara Mohawk Achieved (1)
Achieved 1st Year	50%	26%
Achieved 2nd Year	63%	63%
Achieved 3rd Year	87%	94%
Achieved 4th Year	100%	100%
4 Year Average	75%	71%

(1) Based on data provided in response to DPS-314, question 2

National Grid/KeySpan Merger

Interrogatory/Document Request

Response of National Grid/KeySpan

Re: Cost to Achieve

Request #: DPS 11
Response Date: November 20, 2006
Respondent: T McCormick

Q

1. The Companies estimates that the cost to achieve is $400 million (2 times annual total savings of $200 million).

   (a) Please provide all work papers associated with the calculation of the cost to achieve.

   (b) Please provide any studies performed by National Grid or performed on behalf of National Grid before the merger was announced which quantify cost to achieve the expected savings as a result of this transaction.

   (c) Please indicate the basis and source of the personnel related synergy savings estimates for each of the mergers listed above.

   (d) What are the actual personnel related synergy savings achieved in the mergers listed above?

A:

This response supplements National Grid's response to DPS 11, part (b).

The table in Attachment A below was prepared by the National Grid staff who produced the estimate of potential savings described in our response to DPS 3. Please note that this table does not include merger transition costs, such as costs related to integration efforts; facilities consolidation; customer, employee and corporate communications initiatives; director and officer tail liability insurance coverage; and regulatory filings and compliance.

Attachment A

Cost to Achieve (CTA) Components	Estimate
HR/Compensation	Low Case
VERO Programs	100
Voluntary Severance	50
Retention Agreements	15
sub-total HR/Compensation	**165**
IT Infrastructure	
Infrastructure Consolidations (Data Centers, Network, Desktop etc.)	10
IT Applications Consolidations	
Finance/Supply Chain (Oracle-to-PeopleSoft)	10
HR/Payroll (PeopleSoft Conversion)	1
Fixed Assets & Tax (PowerPlant/PowerTax Conversion)	1
GIS (ESRI-to-Smallworld)	5
Customer Systems (CAS/CRIS-to-Customer/1)	25
Outage Mgmt (CARES-to-PowerOn)	1
Field Force (MDSI-to-FFE/WorkSuite)	3
Work Management (Maximo-to-Worksuite)	1
Electric EMS (TBD; Bass has GE, Grid has ABB)	15
Gas EMS (TBD: We have homegrown system)	10
All Others	20
sub-total IT	**102**
Sub Total - Deductible / Recoverable	**267**
Bankers/Lawyers	75
Exec Chutes	60
Exec Options	75
Sub Total - Non deductible	**210**
Grand Total	**477**

PREPARED REBUTTAL TESTIMONY

OF

MELISSA NAIRN

AND

LEE KLOSOWSKI

ON BEHALF OF

NATIONAL GRID plc

AND

KEYSPAN CORPORATION

CASE 06-M-0878

MARCH 7, 2007

Melissa Nairn
Lee Klosowski

Q. Please state your name and business address.

A. My name is Melissa Nairn. My business address is One MetroTech Center, Brooklyn, New York 11201.

Q. Are you the same Melissa Nairn who previously submitted prepared direct and rebuttal testimony in these proceedings?

A. Yes. I am.

Q. Please state your name and business address.

A. My name is Lee Klosowski. My business address is 300 Erie Blvd, West Syracuse, New York 13202.

Q. Are you the same Lee Klosowski who previously submitted prepared direct testimony in these proceedings?

A. Yes. I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of our rebuttal testimony is to respond to Department of Public Service Staff Witness Michael Wayand's claims that:

(i) the savings associated with lowering KEDNY and KEDLI's (KeySpan's) peak day reserve margin should not be considered a benefit of the merger;

(ii) the savings associated with the proposed sale of National Grid's available off-peak winter season supply to KeySpan are speculative and could be performed without a merger;

(iii) the assignment of supply contracts to an unregulated affiliate will impede information provided to the Public Service Commission, and DPS Staff, and negatively impact supply reliability and price.

In addition, we will respond to Consumer Protection Board ("CPB") Witness Douglas Elfner's claims that:

(i) none of the estimated gas cost savings is a benefit of the merger of National Grid and KeySpan ("Companies");

(ii) KeySpan has no need for any operating reserve margin and that savings associated with reducing the reserve should not be attributed to the merger; and

(iii) the proposed seasonal sale is a straightforward commercial transaction not attributed to the merger.

Q. Does your testimony include any exhibits?

A. Yes. Our testimony includes one exhibit, which was prepared under our supervision and direction, Exhibit No.___ (MN/LK-1R) "Illustrative Example of The Companies' Proposed Opportunity Cost Target."

Q. Does the fact that the merger-related gas supply synergy savings identified in your direct testimony are not guaranteed mean that they are unlikely to be achieved?

A. No. We believe that the gas cost savings that we have identified to date are conservative and readily achievable over the ten-year period following the

merger. KeySpan has a proven track record in achieving gas cost synergy savings for its customers and has contracted more efficiently for incremental supply and capacity by leveraging the complementary features of the KEDNY and KEDLI supply portfolios.

For example, in gas year 2006/07, KeySpan realized approximately $20 to $25 million in gas cost savings for its customers by deferring the need for nearly 71,000 dt per day of incremental supply and capacity to meet new load growth. KEDLI, which has proportionately more winter season than peak day supply capability, helped KEDNY reduce its need to contract for incremental winter season supply to meet new load growth. Conversely, KEDNY, which has proportionately more daily deliverability than winter season supply, helped KEDLI reduce its need to contract for incremental peaking capability to meet new load growth.

This approach mirrors the one we plan to implement under the proposed National Grid and KeySpan merger. By managing the portfolios on a combined basis, National Grid and KeySpan will be able to leverage the complementary features of their demand and supply portfolios to reduce gas demand costs, as well as to realize reliability benefits.

Q. Do you agree with CPB Witness Elfner's contention that KeySpan has no need for any operating reserve margin?

A. No. As Ms Nairn explains in her rebuttal testimony filed February 21, 2007 in Cases 06-G-1185 and 06-G-1186, KeySpan's current 5% operating reserve, equal to approximately 110,000 dt per day in the Rate Year ending March 31, 2008, provides additional peak day capacity to KEDNY and KEDLI to:

(i) offset the effects of a force majeure supply disruption by pipelines and suppliers due to compressor failures, well freeze-offs and other unforeseen events; and

(ii) manage situations where customer demand is higher than predicted as a result of error in KEDNY and KEDLI's predictive sendout equations.

Q. Please describe why KeySpan will be able to reduce its operating reserve margin from 5% to 2.5% as a result of the proposed merger.

A. The Companies will each realize significant reliability benefits by combining their gas supply portfolios given the increased scale, diversity and storage flexibility of the combined portfolio, as well as the increased geographic diversity of the service territories and customer demand centers.

As a result of the proposed merger, both National Grid and KeySpan will benefit from enhanced opportunities to mitigate the impact of force majeure supply disruptions and handle potential situations in which customer demand is higher than predicted on a peak day. KeySpan proposes to reduce its peak day reserve margin to 2.5%, which equates to a 55,000 dt per day reduction in the Rate Year.

This volumetric reduction is equivalent to the supply assistance that could be provided by National Grid to KeySpan on its Iroquois Gas Transmission System ("Iroquois"), Texas Gas Transmission LLC ("Texas Gas") and Dominion Transmission Inc ("Dominion") contracts on non-coincident peak days and, in some instances, on coincident peak days.

Q. Would National Grid be able to provide supply assistance to KeySpan if the Companies were to simultaneously experience peak days?

A. Yes. In the event that KeySpan's gulf coast supply deliveries to its Texas Eastern Transmission System ("Texas Eastern") firm transportation contract were interrupted, National Grid could divert up to 52,000 dt per day of its Texas Gas supply to KeySpan's Texas Eastern receipt point at Lebanon, Ohio to offset the loss. National Grid would then be able to purchase replacement supplies at Dominion South Point, a liquid gas hub, without any net impact to its peak day supply deliverability.

Q. Do you agree with Witness Wayand's determination that KeySpan and National Grid have experienced coincident or near coincident peak day temperatures 75% of the time over the last 36 years?

A. No. We believe that Mr. Wayand's 75% factor is not representative of the past 36 years' experience, nor is it indicative of the prospective risk of simultaneous peak day temperatures across National Grid's and KeySpan's service territories.

National Grid's design day temperature is -10°F, equivalent to 75 heating degree days (HDDs). For National Grid to experience a systemwide design day, it must experience -10°F simultaneously at its two weather stations in Albany and Syracuse. A -10°F temperature at either weather station would not constitute a design day. Therefore, we do not agree that it is valid to compare KeySpan's Central Park temperatures against either one of National Grid's weather stations individually.

The incidence of simultaneous peak day temperatures at Syracuse and Albany is 42% (15 times over the past 36 years) due to the geographic dispersion of National Grid's service territory. Implying that the overall risk of coincident peak day temperatures increases with the inclusion of a third weather station in Central Park is illogical because the geographic diversity of the service territories is enhanced with the addition of the KeySpan service territory. The risk of simultaneous peaks across three weather stations cannot be any higher than the risk of simultaneous peaks across National Grid's two weather stations. Therefore, we stand by our original analysis, which shows a 22% risk of the Companies experiencing coincident peaks.

Q. Could National Grid sell its off-peak seasonal supply to KeySpan as a commercial transaction without the benefit of the proposed merger?

A. It would be highly unlikely that KeySpan and National Grid would be able to combine the management of their supply portfolios to take advantage of the

complementary features of their gas assets and increase the overall utilization of their available supply and capacity in the absence of a merger.

National Grid's ability to maximize its sale of up to 60,000 dt/day available off-peak seasonal supply to KeySpan is in turn dependent on National Grid' ability to leverage KeySpan's daily deliverability flexibility. Although National Grid has available capacity on a seasonal basis, its daily supply deliverability is constrained. Consequently, its ability to maximize sales of available seasonal supply is limited by its need to maintain adequate daily deliverability, particularly late in the winter heating season when storage withdrawal ratchets are implemented and storage deliverability is reduced.

KeySpan, on the other hand, has proportionately more daily deliverability than seasonal supply because its two LNG peakshaving facilities have a high ratio of daily LNG vaporization capability to on-site LNG storage capacity. KeySpan has the flexibility to vaporize, on any day, more LNG than is needed to meet daily demand.

As a result, National Grid is able to maximize the amount of seasonal supply it sells to KeySpan, as opposed to a third party, because KeySpan will stand ready to provide National Grid daily supply deliverability to offset the potential effects of storage withdrawal ratchets. Operationally, KeySpan would deliver the daily supply to National Grid at pipeline points the two Companies have in common,

such as Iroquois Croghan, Iroquois Boonville, Canajoharie, Dominion South Point and Leidy.

The Companies' enhanced ability to optimize the use and value of their gas portfolio assets under the proposed merger is not dissimilar from the benefits New York State derives from having a single entity, the New York Independent System Operator ("NYISO"), optimize the dispatch the state's power generators. With centralized oversight, the NYISO is able to ensure that the electric transmission system and power plants statewide are managed and dispatched efficiently, reliably and economically. While the scheduling and operation of a natural gas transmission network may differ in detail from the operations of an electric system, it is nonetheless true that both systems are better optimized through centralized management than they would be through individual commercial arrangements among users with competing interests.

Moreover, absent the merger, National Grid's ability to sell available seasonal supply on a commercial basis to off-system markets would be constrained by its contractual footprint. National Grid's reach would be limited primarily to customers in upstate New York who are attached directly to the Dominion system, where the value of the capacity is typically less than what the capacity constrained market in downstate New York would be willing to pay.

By modifying its Dominion contracts, National Grid is able to extend its reach to include KeySpan's downstate markets. National Grid would likely need to enter

into a long-term contractual agreement (e.g.10 years) with Dominion for incremental deliverability to Leidy. Without a commitment from KeySpan, National Grid would consider such a transaction speculative and would not make the necessary contract modifications with Dominion. It is unlikely that National Grid and KeySpan would make such a long-term commitment absent the merger. Nor is it likely that National Grid would find an off-system customer willing to make such a long-term commitment as part of a typical commercial transaction.

Q. Will National Grid's customers bear the incremental costs of the new long-term contractual agreement with Dominion?

A. No. As explained in our direct testimony, KeySpan's customers will fully compensate National Grid's customers for any incremental costs incurred to modify National Grid's Dominion contracts. At the same time, KeySpan's customers will realize gas cost savings because they will avoid the demand costs of more expensive incremental capacity. In sum, all customers will benefit from increased revenue credits and savings generated through the more efficient management and utilization of the combined supply portfolio.

Q. Do you agree with Witness Wayand that the Companies' proposed target mechanism would be difficult to develop and that its assumptions, estimates and results would be uncertain and subject to interpretation?

A. No. We are confident that National Grid and KeySpan will be able to readily implement the proposed target mechanism ("Opportunity Cost Target") as

described in our direct testimony. The Opportunity Cost Target enables us to estimate the revenue that would be realized by National Grid if it were to optimize its available supply on its own (or through an asset manager) absent the proposed merger with KeySpan. At the end of each year, the actual revenue credits generated by the transaction with KeySpan, as well as any additional credits generated by National Grid via off-system sales transactions, would be compared to the Opportunity Cost Target. If the sum of the credits generated from both the KeySpan transaction and any further off-system sales transactions is less than the Opportunity Cost Target, then KeySpan's customers would pay the difference to National Grid's customers. Conversely, if total credits exceed the Opportunity Cost Target, KeySpan's customers would be credited the difference by National Grid's customers.

Q. **Please describe Exhibit No. ___ (MR/LK-1R) "Illustrative Example of National Grid's and KeySpan's Proposed Opportunity Cost Target."**

A. Exhibit No.__(MR/LK-1R) shows an example of how the Companies would first compute the Opportunity Cost Target, reconcile actual revenues against the Opportunity Cost Target, and than allocate credits among the Companies' customers. The Companies would file the calculation with DPS Staff prior to implementation.

For illustrative purposes, Exhibit No.___ (MR/LK-1R) computes the November – March Opportunity Cost Target for National Grid's approximately 8,000 dt per

day Transco firm transportation contract. As shown on Section 1 of the Exhibit, the Opportunity Cost Target for the November – March period is computed to be $1,510,000. This represents the amount of revenue credits that National Grid could generate for its customers on a stand-alone basis, absent the proposed merger with KeySpan, using its 8,000 dt per day Transco firm transportation agreement to sell firm supply to off-system customers. To replace the Transco supply sold off-system, National Grid would in turn purchase a like amount of supply at Dominion North Point and deliver that supply to its customers. Section 2 of the Exhibit shows how revenue credits totaling $820,000 would be computed under the proposed merger from two types of transactions. First, National Grid would sell its Transco supply to KeySpan as required. It is assumed that the sale would be conducted over 100 days of the 151-day winter heating season and would generate a total of $320,000 revenue credits. The $320,000 paid by KeySpan's customers represents the approximately $0.40 per dt unitized demand cost of the Transco capacity. Second, National Grid would seek to sell its Transco supply to off-system customers on those days that KeySpan does not need the supply. This sale is assumed to be conducted to off-system customers over 51 days and would generate a total of $510,000 additional revenue credits.

Section 3 of the Exhibit computes the difference between the Opportunity Cost Target and the revenue credits and determines that in this example National

Grid's customers are owed $680,000 additional credits from KeySpan's customers.

Q. Have you quantified additional economic benefits of the reliability, operational and flexibility enhancements realized by combining the portfolios?

A. No, our analysis, to date, has conservatively focused on fixed gas cost savings that would be realized by implementing two specific cost saving strategies across the New York State Companies alone. We believe that there are additional opportunities to further reduce gas demand costs, reduce gas variable costs and increase optimization credits for customers in New York. Further, we believe that there are potential synergies with the New England LDCs that will provide further benefits to customers of all of the National Grid gas utilities.

Q. Please comment on Witness Wayand's concerns regarding the proposal to transfer its gas supply, transportation and storage contracts from the regulated utilities to an unregulated affiliate.

A. This proposal is directed at simplifying and streamlining the administration of the KEDNY and KEDLI (and following the merger – National Grid) gas supply, transportation and storage contracts ("supply portfolio contracts") by conveying those contracts to a single affiliated entity. The Companies are not seeking to diminish the Commission's oversight authority. Under KeySpan's existing structure, an unregulated service company is responsible for the administration,

planning and management of KEDNY and KEDLI's supply portfolio contracts pursuant to an agreement between the regulated LDCs and the service company. The service company is not directly subject to the Commission's jurisdiction. Under the Companies' proposal, the same type of structure would be employed: an unregulated service company would continue to perform those functions on behalf of the regulated LDCs, would continue to adhere to all requirements currently in effect and would be as responsive to Commission Staff as we have been in the past.

The same is true with respect to the KeySpan unregulated service company that is responsible for purchasing and scheduling gas supplies, capacity releases, off-system sales, and gas price hedging activities. The unregulated service company would continue to perform those functions following the conveyance of the supply portfolio contracts to a single entity. Under our proposal, DPS Staff would have the same access to our gas supply records and contracts as exists today. The sole purpose of the Companies' proposal is to simplify administration of our gas supply contracts.

The administration of the KEDNY and KEDLI supply portfolio contracts is burdensome, inefficient and results in unintended credit risk because each utility must hold separate and distinct contracts with various counterparties (i.e. suppliers, transporters, and storage providers). Inefficiencies arise because of KeySpan's inability to net and set-off across entities, exposure to greater credit

risk, greater demands for guarantees or other forms of credit support, increased manpower requirements in connection with contract negotiation and execution, invoicing and data entry, and scheduling and optimization inefficiencies caused by FERC's "shipper-must-have-title rule."

Q. Please describe how FERC's "shipper-must-have-title" rule hinders the KeySpan Companies' ability to optimize their supply portfolio contracts.

A. Under FERC's shipper-must-have title-rule, shippers must have title to the gas transported on their pipeline transportation contracts, as well as to the gas stored pursuant to their storage service agreements. This rule impedes the operational flexibility of KeySpan to dispatch the KEDNY and KEDLI portfolios on a combined basis.

For example, because of the shipper-must-have-title rule, KEDNY is unable to deliver its gas supply on KEDLI's pipeline transportation contracts or to inject its supply into KEDLI's storage contracts. If on warm days KEDNY needs to balance demand at its city gate by injecting gas into storage, it is prevented from injecting its supply into KEDLI storage services even if KEDNY's storage were full and KEDLI would benefit from the additional inventory. KEDNY would first need to sell its supply to KEDLI in order to convey title and KEDLI would need to inject the gas into its storage as a separate transaction.

Aside from the increased transaction complexity, the rule also increases KeySpan's administrative burden because KEDNY and KEDLI must each enter

and maintain supply contracts with the same counterparties. This redundancy results in duplicative negotiation and execution of contracts, as well as duplicative entry into KeySpan's contract data base and transaction systems. Further, because KEDNY and KEDLI have separate contracts with the same counterparties, they are unable to net transactions across those agreements to streamline the invoicing, accounting and payment for those transactions.

Q. Please explain why KEDNY and KEDLI are exposed to increased credit risk when they separately maintain and manage their gas portfolio contracts.

A. KEDNY and KEDLI are unable to set-off transactions across their individual agreements with the same counterparty to minimize financial exposure in the event of a contract dispute with the counterparty or if the counterparty declares bankruptcy. For example, if KEDNY had a payable to a supplier and KEDLI had a receivable from that same supplier, if that supplier went bankrupt, KEDNY would be required to make payment while KEDLI's receivable would be at risk pending resolution of the bankruptcy proceeding. If the payable and receivable were both with the proposed affiliated entity, one could be set off against the other, thereby increasing and accelerating recovery of the receivable. Moreover, KEDNY and KEDLI individually are likely to have a lower credit threshold than the proposed affiliated entity, thereby increasing the likelihood and magnitude of the credit assurance that either KeySpan utility would be required to provide to its counterparty in the event our proposal is not accepted. Conversely,

because KeySpan establishes credit thresholds for its counterparties on an enterprise-wide basis, each KeySpan affiliate would need to divide that counterparty's credit threshold among their redundant contracts, thereby reducing the credit available under any one contract and perhaps limiting each KeySpan entity's ability to do business with that counterparty.

Q. Will the Companies' proposal to convey the supply portfolio contracts to an unregulated entity reduce supply reliability or negatively impact the cost of gas to the Companies' customers?

A. No. The proposal will enhance gas supply reliability by facilitating the utilization of the available assets of one LDC for the benefit of another when necessary. The proposal would not increase costs but, rather, would reduce them through more efficient management and utilization of the assets.

The proposal is intended only to achieve the numerous benefits that will result from combining KEDNY and KEDLI's, as well as National Grid's, supply portfolio contracts into a single portfolio. These benefits will ultimately accrue to the benefit of customers. Moreover, this proposal will not affect DPS Staff's ability to review the Companies gas supply practices.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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Exhibit No.__(MN/LK-1R)

Illustrative Example of National Grid's & KeySpan's Proposed Opportunity Cost Target

Section 1. Compute Opportunity Cost Target (Stand Alone)

Daily Volume of Transco Capacity Available for Sale		8,000	dt per day
Period of Sale (Nov 1 to Mar 31)		151	days
Unit Margin of Sale			
Sales Price (Transco Zone 6 Non-NY)	$	9.00	per dt
Replacement Price (Dominion North Point)	$	7.75	per dt
Unit Margin	$	1.25	per dt
Opportunity Cost Target	**$**	**1,510,000**	

Section 2. Compute Revenue Credits From KeySpan Sale & Additional Off-System Sales by National Grid

a) Compute Revenue Credits Generated from Sale to KeySpan

Daily Volume of Transco Capacity Sold to KeySpan		8,000	dt per day
No Days of Sale		100	days
Unit Margin of Sale			
Sales Price	$	8.15	per dt
Replacement Price (Dominion North Point)	$	7.75	per dt
Unit Margin	$	0.40	per dt
Revenue Credits from KeySpan	**$**	**320,000**	

b) Compute Revenue Credits from Additional Off-System Sales by National Grid

Daily Volume of Transco Capacity Sold Off-System		8,000	dt per day
No Days of Sale		51	days
Unit Margin of Sale			
Sales Price (Transco Zone 6 Non-NY)	$	9.00	per dt
Replacement Price (Dominion North Point)	$	7.75	per dt
Unit Margin	$	1.25	per dt
Optimization Revenue Credits from Off-System Sales	**$**	**510,000**	

Total Revenue Credits from KeySpan Sale and Additional Off-System Sales	**$**	**830,000**

Section 3. Determine Revenue Credit Allocation

Opportunity Cost Target	**$**	**1,510,000**
Total Revenue Credits from KeySpan Sale and Additional Off-System Optimization	**$**	**830,000**
Difference to be Paid by KeySpan Customers to National Grid Customers	**$**	**680,000**