MINUTES OF THE REGULAR MEETING
OF THE
POWER AUTHORITY OF THE STATE OF NEW YORK

November 15, 2011

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November 15, 2011

Minutes of the Regular Meeting of the Power Authority of the State of New York held at the Clarence D. Rappleyea Building, 123 Main Street, White Plains, New York at approximately 11:00 a.m.

The Members of the Board present were:

Michael J. Townsend, Chairman
Jonathan F. Foster, Vice Chairman
D. Patrick Curley, Trustee
John S. Dyson, Trustee
R. Wayne LeChase, Trustee
Eugene L. Nicandri, Trustee
Mark O'Luck, Trustee

Gil C. Quiniones	Acting President and Chief Executive Officer
Judith C. McCarthy	Acting General Counsel
Donald Russak	Acting Chief Financial Officer
Thomas Antenucci	Senior Vice President – Power Supply Support Services
Steve DeCarlo	Senior Vice President – Transmission
Thomas DeJesu	Senior Vice President – Public, Governmental and Regulatory Affairs
Paul Finnegan	Senior Vice President – Public, Governmental and Regulatory Affairs
James Pasquale	Senior Vice President – Marketing and Economic Development
Joan Tursi	Senior Vice President – Corporate Support Services
Paul Belnick	Vice President – Energy Services – Energy Services and Technology
John Canale	Vice President – Project Management
Thomas Davis	Vice President – Financial Planning and Budgets
Dennis Eccleston	Vice President – Information Technology/Chief Information Officer
Michael Huvane	Vice President – Marketing – Business and Municipal Marketing
John Kahabka	Vice President – Environmental, Health and Safety
Joseph Leary	Vice President – Community and Government Relations
Lesly Pardo	Vice President – Internal Audit
Scott Scholten	Vice President and Chief Risk Officer – Energy Risk Assessment and Control
John Suloway	Vice President – Project Development, Licensing and Compliance
Lori Alesio	Assistant General Counsel – Human Resources and Labor Relations
Vincent Esposito	Assistant General Counsel – Legislative and Regulatory Affairs
Karen Delince	Corporate Secretary
Brian McElroy	Treasurer
Jill Anderson	Director – Business Integration
John Brennan	Director – Strategy and Governance
Robert Knowlton	Director – Civil/Structural Engineering
Mike Lupo	Director – Marketing Analysis and Administration
Michael Saltzman	Director – Media Relations
Lynn Hait	Regional Manager Central NY – Site Administration, B-G
Gary Schmid	Manager – Network Services Infrastructure
Kevin O'Keeffe	Manager – Video Production Services – Media Relations
Meg Smilowitz	Manager – SAP Portfolio, Application Services
Ali White	Senior Attorney I – Human Resources and Labor Relations
Tannille Santos	Conservation Engineer – Energy Services and Technology
Trish Hennessy	Photographer – Video and Photographic Services
Michael Schneider	Contractor – Media Relations
Lorna M. Johnson	Assistant Corporate Secretary
Sheila Baughman	Senior Secretary – Corporate Secretary's Office

Mikey Wade	Intern
Kenneth F. Deon	Managing Partner, KPMG LLP
Brendan Kennedy	Senior Manager, KPMG LLP

Chairman Townsend presided over the meeting. Corporate Secretary Delince kept the Minutes.

Introduction

Chairman Michael Townsend welcomed the Trustees and staff to the meeting.

1. ***Approval of the November 15, 2011 Meeting Agenda***

On motion made and seconded, the agenda for the meeting was approved as amended.

2. <u>Consent Agenda</u>

On motion made and seconded, the Consent Agenda was approved. Trustee Curley recused himself as regards the vote on item #2c – Expansion Power Contracts with Moog, Inc. and Try-It Distributing Co., Inc. – Transmittal to the Governor.

a. <u>Approval of the Minutes</u>

The Minutes of the Regular Meeting held on October 25, 2011 were unanimously adopted.

b. Inclusion of Independent Not-for-Profit Institutions of Higher Education in the Statewide Energy Services Program

The Acting President and Chief Executive Officer submitted the following report:

SUMMARY

"The Trustees are requested to authorize the inclusion of independent not-for-profit colleges and universities within New York State as eligible participants in the Statewide Energy Services Program ('Statewide ESP'). As deemed feasible and advisable by the Trustees, pursuant to a recent amendment to Chapter 477 of the Laws of 2009 (Public Authorities Law §1005(17)) recently signed by Governor Cuomo, the Authority was authorized to finance and design, construct, implement, provide and administer energy related projects, programs and services for this group of prospective customers. If authorized by the Trustees, all Authority costs will be recovered directly from each participating not-for-profit college or university.

BACKGROUND

"Since the 1980s, the Authority, through its Energy Services Programs ('ESP'), has offered various types of energy services and clean energy technology programs to participants throughout the State to help them lower their energy usage and/or achieve cleaner and more energy-efficient use of energy and natural resources.

"As an outgrowth of the State's continuing efforts in the areas of energy efficiency and clean energy technologies (e.g., its 45x15 goal to meet 45% of the State's electricity needs through improved energy efficiency and renewable sources by 2015 and Executive Order No. 111, which requires agencies to reduce energy consumption while transitioning to renewable energy sources), the State signed into law Chapter 477 of the Laws of 2009 on September 16, 2009. Governor Cuomo amended Section 1005 of the Public Authorities Law by adjusting subsection 16 (now 17) which enhanced the Authority's ability to provide energy efficiency, clean energy and green building programs and services to reduce energy consumption and mitigate environmental impacts from energy usage and eliminated the sunset date originally designated. Subsequently, he signed into law, effective August 31, 2011, the Authority's ability to carry out energy efficiency and clean energy projects for independent, not-for-profit colleges and universities.

"The amendment now authorizes the inclusion of this new customer group of independent not-for-profit institutions of higher learning for energy efficiency services consistent with the State's energy and environmental policies.

DISCUSSION

"There are more than100 independent not-for profit colleges and universities in the State. The addition of these institutions as eligible participants in the Statewide ESP would assist these institutions to address critical energy efficiency concerns, help them to reduce their energy costs, free up monies for capital expenses, which in turn could have a favorable impact on tuition and fees. All Authority costs will be recovered directly from each participating institution.

"Assisting these institutions of higher education has benefits for the State:

- The facilities in the new market serve over 450,000 undergraduate and graduate students. More than 300,000 of these students are New York residents. Fifty-four percent of the baccalaureate degrees, seventy-three percent of the master's degrees and seventy-nine percent of the doctoral and first professional degrees earned in the State are from these institutions;

- Boost local economy – the schools in nine of the State's counties provide five percent or more of those counties' total local employment;

- These institutions contribute $54 billion to the economy, employ 174,000 people and sponsor 500 research centers and institutes that are available to businesses and local communities.

"If approved by the Trustees, the Statewide ESP projects, programs and services will be available to not-for-profit colleges and universities that sign a cost-recovery agreement and commit to repay the Authority for the costs associated with any financing provided for eligible ESP project(s).

FISCAL INFORMATION

"No additional funding is requested for the implementation of energy-related projects, programs and services to be included in the Statewide ESP for the benefit of the independent not-for-profit institutions. Funding will be provided through Authority financing options previously approved by the Trustees for Statewide ESP. In addition, projects may be funded, in part, with monies from the Petroleum Overcharge Restitution ('POCR') fund. All Authority costs, including Authority overheads, excluding any grant of POCR funds, will be recovered from the individual participating institution, similar to other Energy Services and Technology programs. The Authority will continue to evaluate each applicant in order to best mitigate risk of loss to the Authority.

RECOMMENDATION

"The Vice President – Energy Services and Technology recommends that the Trustees approve the inclusion of independent not-for-profit colleges and universities in the Statewide Energy Services Program.

"For the reasons stated, I recommend the approval of the above-requested action by adoption of a resolution in the form of the attached draft resolution."

The following resolution, as submitted by the Acting President and Chief Executive Officer, was unanimously adopted.

RESOLVED, That the Trustees authorize inclusion of independent not-for-profit colleges and universities into the Statewide Energy Services Program as described in the foregoing report of the Acting President and Chief Executive Officer; and be it further

RESOLVED, That the funding for the energy related projects, programs and services for the benefit of the independent not-for-profit institutions be provided through Authority financing options previously approved by the Trustees for Statewide Energy Services Programs;

Commercial Paper Program/ Operating Fund/POCR	Statewide ESP Authorization
Previously Authorized	$833 million
Additional Funding	$ 0 million
Total Amount Authorized	$833 million

AND BE IT FURTHER RESOLVED, That the Vice President – Energy Services and Technology is authorized to determine which projects in the Statewide Energy Services Programs will be deemed to be energy services projects within the meaning of Section (7) of Part P of Chapter 84 of the Laws of 2002 (the "Section (7) POCR Legislation") to be funded, in part, with Petroleum Overcharge Restitution ("POCR") Funds allocated pursuant to the Section (7) POCR Legislation; and be it further

RESOLVED, That POCR funds allocated to the Authority by the Section (7) POCR Legislation may be used to the extent authorized by such legislation, in such amounts as may be deemed necessary or desirable by the

Vice President – Energy Services and Technology to finance Statewide Energy Services Program projects; and be it further

RESOLVED, That the Chairman, the Vice Chairman, the Acting President and Chief Executive Officer, the Acting Chief Operating Officer and all other officers of the Authority are, and each of them hereby is, authorized on behalf of the Authority to do any and all things and take any and all actions and execute and deliver any and all certificates, agreements and other documents to effectuate the foregoing resolution, subject to the approval of the form thereof by the Acting General Counsel.

c. Expansion Power Contracts with Moog, Inc. and Try-It Distributing Co., Inc. – Transmittal to the Governor

The Acting President and Chief Executive Officer submitted the following report:

SUMMARY

"The Trustees are requested to approve the proposed agreements ('Agreements') for the sale of Expansion Power to Moog, Inc. ('Moog') and Try-It Distributing Co., Inc. ('Try-It') and to authorize their transmittal to the Governor. The proposed Agreements with Moog and Try-It are attached as Exhibits '2c-A' and '2c-B,' respectively.

BACKGROUND

"At their July 26, 2011 meeting, pursuant to criteria set forth in §1005 (13) of the Public Authorities Law ('PAL'), the Trustees approved 300 kilowatt ('kW') and 200 kW Expansion Power allocations to Moog and Try-It, respectively, each for a term of five years. The Trustees also authorized a public hearing, pursuant to §1009 of the PAL, on the proposed Agreements to effectuate the sale of power and energy for the allocation to the companies.

"In return for the 300 kW allocation, Moog, a designer and manufacturer of precision motion control equipment, committed to invest $13 million to build and equip a new, two-story, 68,000 square-foot corporate shared services building at its East Aurora campus. As a result of this project, the company would commit to creating 70 new jobs in addition to the nearly 2,500 existing high-quality jobs.

"In return for the 200 kW allocation, Try-It, a wholesale beverage distributor located in Depew, New York, committed to invest a total of $14.0 million to expand its existing office and warehouse facility by over 100,000 square feet. A majority of the new space will be climate controlled warehousing operations. As a result of this expansion project, the company would commit to creating 23 new jobs above its existing 242 jobs.

"Regarding the proposed Agreements, firm electric service will be equivalent to that provided to all other Authority firm hydropower customers and subject to pro-rata curtailment when there is insufficient generation at the Niagara and St. Lawrence/FDR facilities to meet the energy requirement of the firm hydropower customers. The allocations will be subject to enforceable employment commitments. The Agreements include an annual job reporting requirement with a job compliance threshold of 90%. Should the ratio of actual jobs reported to jobs committed fall below the compliance threshold, the Authority have the right to reduce the hydropower allocation on a pro-rata percentage basis.

"Electricity will be sold directly to the customers ('direct service'), with delivery service provided by New York State Electric and Gas, the local distribution company. The rates, terms, and conditions for direct EP sales, as applicable to all other direct service EP allocations, are contained in the 'Schedule of Rates for Sale of Expansion Power – Service Tariff No. EP-1,' that is effective through June 30, 2013. Thereafter, sales for these Agreements and all EP and Replacement Power allocations will be served under the 'Schedule of Rates for Sale of Firm Power to Expansion and Replacement Customers located In Western New York – Service Tariff No. WNY-1.'

"Regarding the status of the individual expansion projects, both Moog and Try-It's projects have commenced and are progressing as planned. If the Agreements are approved by the Trustees and the Governor, the individual customer agreements will only be executed after a project review is completed by and to the satisfaction of the Authority.

DISCUSSION

"A public hearing on the Agreements was held on October 4, 2011 at the Niagara Power Project's Power Vista Visitor Center in Lewiston. There were no oral statements made at the public hearing and no written statements were submitted. The official transcript of the public hearing is attached as Exhibit '2c-C.' As such, the Agreements are submitted for final approval as proposed.

RECOMMENDATION

"The Manager – Business Power Allocations and Compliance recommends that the Trustees approve the proposed Agreements for the sale of Expansion Power to Moog, Inc. and Try-It Distributing Co., Inc. and authorize the transmittal of the Agreements to the Governor for approval.

"For the reasons stated, I recommend the approval of the above-requested action by adoption of a resolution in the form of the attached draft resolution."

The following resolution, as submitted by the Acting President and Chief Executive Officer, was unanimously adopted.

> **RESOLVED, That the Expansion Power agreements for the sale of hydroelectric power and energy generated by the Authority for sale to Moog, Inc. and Try-It Distributing Co., Inc., respectively, are in the public interest and should be submitted to the Governor for approval and that the agreements, along with the record of the public hearing thereon, be forwarded to the Speaker of the Assembly, the Minority Leader of the Assembly, the Chairman of the Assembly Ways and Means Committee, the Temporary President of the Senate, the Minority Leader of the Senate and the Chairman of the Senate Finance Committee; and be it further**
>
> **RESOLVED, That the Chairman and the Corporate Secretary be authorized and directed to execute such agreements in the name of and on behalf of the Authority after it has been approved by the Governor; and be it further**
>
> **RESOLVED, That the Senior Vice President – Marketing and Economic Development, or his designee, be, and hereby is, authorized, subject to the approval of the form thereof by the Acting General Counsel, to negotiate and execute any and all documents necessary or desirable to implement the agreements with the companies as set forth in the foregoing report of the Acting President and Chief Executive Officer; and be it further**
>
> **RESOLVED, That the Chairman, the Vice Chairman, the Acting President and Chief Executive Officer, the Acting Chief Operating Officer and all other officers of the Authority are, and each of them hereby is, authorized on behalf of the Authority to do any and all things, take any and all actions and execute and deliver any and all agreements, certificates and other documents to effectuate the foregoing resolution, subject to the approval of the form thereof by the Acting General Counsel.**

3. Discussion Agenda

a. Report of the Acting President and Chief Executive Officer

Acting President and Chief Executive Officer Quiniones discussed the Authority's performance, as reflected in the performance matrix developed by Authority staff, and highlighted some of the key initiatives. He said that the Authority is performing well operationally and financially.

Key Issues

Governor's Energy Efficiency Initiative

Acting President and Chief Executive Officer Quiniones said that because of the Authority's success in its energy efficiency program, Authority staff is assisting the Governor's office staff in their effort to accelerate the implementation of energy efficiency initiatives in public buildings around the state.

Recharge New York

Acting President and Chief Executive Officer Quiniones said that, to date, staff has received 133 completed applications for power under the new Recharge New York ("RNY") Program with approximately 600 additional applications in progress in the online system. Staff from Marketing and Public and Governmental Affairs continue to visit stakeholders around the State in order to explain the program and the application process.

Proposed Hydro Rate Increase

Acting President and Chief Executive Officer Quiniones said that based on comments received at the public forum to consider the hydropower rate increase, staff will be recommending that the rates be modified downward from the initial proposal. He thanked Trustee Dyson for his input in identifying measures to reduce the Authority's expenses, adding that these measures will continue with the objective of achieving ten percent reductions in overhead expenses in keeping with the Governor's goal.

In response to a question from Trustee Nicandri, Acting President and Chief Executive Officer Quiniones said that two employees have been assigned to support the Governor's office with regard to its energy efficiency initiative. He said the assignment will be for approximately six months and they will be providing technical expertise for the development of the program.

In response to a question from Trustee LeChase, Acting President and Chief Executive Officer Quiniones said that the number of applications received, to date, for the RNY program is less than anticipated;

but it is expected additional applications will be submitted. He added that RNY is a very valuable program, and, eventually, the number of potential customers applying for the program will increase.

In response to a question from Chairman Townsend, Acting President and Chief Executive Officer Quiniones said that although customers who were a part of the Power for Jobs ("PFJ") or Energy Cost Savings Benefit ("ECSB") programs are more aware of the new program because of the Authority's outreach activities, the Authority is expecting to receive applications from new businesses that are not a part of the PFJ or ECSB program.

In response to a question from Trustee Curley, Acting President and Chief Executive Officer Quiniones said that under the Recharge New York program, applications go through the Central Funding Application ("CFA") process and that the Regional Economic Development Councils have access to the applications submitted through the CFA. In response to further question from Trustee Curley, Acting President and Chief Executive Officer Quiniones said that no applications have been rejected by the Authority; staff reviews the applications and if they are incomplete, staff will contact the applicant and assist them with the application.

b. Report of the Acting Chief Operating Officer

Senior Vice President – Power Supply Support Services, Mr. Thomas Antenucci, provided highlights of the report to the Trustees.

Performance Measures

- ***Net Generation exceeded projections; transmission reliability measures exceeded its target and there were no significant transmission events in October.***

Key Issues

Forced Outages

- ***500 MW Plant – two forced outages from problems on Unit 7B which tripped out of service on September 27 and had an oil leak on October7th. The unit was repaired and returned to service on October 7 and 10, respectively.***
- ***Y-49 feeder located near the east Garden State substation – reason for outage has been located and the unit is in the process of being repaired.***

Planned Maintenance Outages

- ***Richard M. Flynn Power Plant – scheduled to return to service by the end of November.***
- ***Niagara-Lewiston Plant – replacement of the generator step-up transformer to be completed in December.***
- ***Blenheim-Gilboa Project – Unit #3 expect to return to service by the end of the week.***

Technical Compliance – NERC Reliability Standards

- ***The Northeast Power Coordinating Council ("NPCC") conducted a Culture of Compliance Survey of its 350 registered entities. On October 18, the Authority received a letter from NPCC stating that the Authority has demonstrated that it meets or exceeds all minimum characteristics for a favorable culture of compliance.***

c. <u>Report of the Acting Chief Financial Officer</u>

Acting Chief Financial Officer, Mr. Donald Russak, provided highlights of the report to the Trustees. He said that the Authority continues to perform well financially. For the period ended October 30, 2011, Net Income was $19 million, which is $7 million above budget. Net Income through October 31, 2011 is $211 million; this amount is $62 million above budget.

In response to a question from Vice Chairman Foster, Mr. Russak said that the lower capacity prices in the marketplace have a greater effect on the Blenheim-Gilboa ("B-G") Power Plant than the Niagara and St. Lawrence-FDR Plants because B-G receives a higher percentage of its revenues from the capacity market. In response to a question from Trustee Nicandri, Mr. Russak said that the overall revenue impact at B-G is the result of a combination of the lower capacity prices and the reduced on-peak and off-peak price differentials in the energy market.

Mr. Russak continued that the Operating Fund balances for October increased temporarily because of the proceeds from the 2011 bond sale; this will be used to refund the 2001 series bonds during November. Mr. Russak ended by stating that the 2012 budget briefing package is being prepared for the Trustees' review. Staff will also set up individual briefings with the Trustees to answer any questions they may have. In response to a question from Trustee Nicandri, Mr. Russak said that the 2012 budget will be presented to the Trustees for approval at the December meeting. In response to a question, from Trustee O'Luck, Mr. Russak said that last year the Authority did have a flat budget, however, later in the year, staff sought and received approval from the Trustees for an adjustment to that budget.

4. Hydroelectric Preference Power Rates - Notice of Adoption

The Acting President and Chief Executive Officer submitted the following report:

SUMMARY

"The Trustees are requested to adopt a final rule with respect to the preference power rates supplied from the Niagara and St. Lawrence/FDR Hydroelectric Projects (individually, 'Niagara Project' and 'St. Lawrence Project,' and collectively, the 'Hydro Projects'). The rates have been modified downward from the change proposed at the July 26, 2011 meeting of the Trustees as a result of the public comment process. Such rates apply to the Authority's hydroelectric sales to forty-seven municipal electric systems and four rural electric cooperative customers located in-state (collectively, the 'NY Munis & Coops'), the neighboring states customers ('NS Customers')[*], three upstate investor-owned utilities (for the benefit of their residential customers) and the Niagara Project relicensing customers.[†] Under the 41-month final rate plan proposed by Authority staff, new rates would commence December 1, 2011, with subsequent increases starting May 2012, 2013 and 2014, and concluding on April 30, 2015. The commencement of new rates would be delayed one month from staff's original proposal as a result of the Authority's decision to extend the end of the public comment period from October 3, 2011 to October 24, 2011. This proposal would increase rates for a typical municipal system residential customer by less than 60 cents per month for each year of the phase-in period, which cost represents less than 1% of the total bill, and by less than 5 cents per month for each year of the phase-in period for a typical utility residential customer, which is also well below 1%.

"The Trustees are also requested to authorize the Corporate Secretary to publish a Notice of Adoption in the *New York State Register* ('*State Register*') regarding the final rate plan.

BACKGROUND

"At their meeting of July 26, 2011, the Trustees authorized publication in the *State Register* of a Notice of Proposed Rulemaking ('NOPR') to increase the preference power rates. The proposed rate plan was prepared by Authority staff and explained in its July 2011 report on 'Preliminary Staff Report, Hydroelectric Production Rates, Rate Modification Plan – Rate Years 2011-2014' (referred to herein as the 'Preliminary Staff Report' and included in Appendix '4-B' to this report). The proposed rate plan was based on the results of staff's preliminary 2011 hydroelectric cost-of-service ('Hydro CoS' or 'CoS') study. The July NOPR sought to increase the effective rates to $11.42 per MWh for the 2011 rate year as compared to the 2008 rate level of $10.71 per MWh at the time the rates were frozen in April 2009, and added gradual increases from the 2012 through 2014 rate years with a proposed final effective rate of $13.87 per MWh.

"The current rates, which end on November 30, 2011, are based on the ratemaking methodologies adopted by the Trustees at their meetings approving earlier increases to the preference rate in 2003 and 2007, which are also reflective of the same cost-of-service principles agreed to by the NY Munis & Coops, the NS Customers and the Niagara Project relicensing customers through either settlements or in their purchase contracts with the Authority. Except as noted below, those same CoS principles are continued in this Preliminary Staff Report.

"The customers were provided with written notice of the Preliminary Staff Report and notice of three public forums shortly after July 26, 2011. The NOPR was published in the *State Register* on August 17, 2011 together with notices of public forums on this rate proposal to be held for the purpose of obtaining the views of interested parties.

"After issuing the Preliminary Staff Report, Authority staff met with various customer groups and elected officials and entertained extensive discovery regarding the proposed rate plan. Staff responded to 128 data requests from the following parties: the Municipal Electric Utilities Association ('MEUA,' 35 requests), the New York

[*] These customers are certain municipal utility systems in the states of Connecticut, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island and Vermont.
[†] These customers include the seven 'host communities' (*e.g.* cities, towns and school districts) located in the vicinity of the Niagara Project and the Tuscarora Nation.

Association of Public Power ('NYAPP,' 64 requests) and the NS Customers (29 requests). Many requests were answered with work papers supporting the CoS calculations, but several others required detailed explanations, sometimes with attachments of financial or Hydro Project data.

"Public forums were held in Syracuse, Niagara Falls and Massena on September 19, 20 and 22, respectively. The forums were conducted in accordance with the terms of the 'Policy and Procedures – Public Forum on Rate Proposals' adopted by the Authority's Trustees at their meeting of November 27, 1990. Authority staff spoke at the forums to explain the procedures and summarize the results of the CoS and proposed rates. Representatives of various customers attended, as well as elected officials and residents of New York State. Customers included representatives from the NS Customers, MEUA, NYAPP, Niagara Power Coalition, Inc. ('NPC,' an organization representing the Niagara Relicensing host communities), Jamestown Board of Public Utilities, Town of Massena Electric Department and the Plattsburgh Municipal Lighting Department. Elected officials included Assemblyman John D. Ceretto, William L. Ross, Chairman of the Niagara County Legislature (and also NPC Chairman), and Renae Kimble, Niagara County Legislator. Mr. Charlie McGrath, a St. Lawrence Project-area citizen, also commented. In addition to oral or written comments delivered at the public forum, written comments were received through October 24, 2011, the end of an extended public comment period.

"The Authority received written comments from MEUA, NYAPP, the NS Customers, and NPC as well as numerous letters from elected officials and other parties concerning the rate proposal.[‡]

"All of the public comments were evaluated by Authority staff. The Staff Analysis, a detailed description of the issues raised and staff's recommendations, is contained in Appendix '4-A.' A summary of staff's analysis of the major issues and final recommendations are set forth below. (The transcript of the public forums and all written comments are included in Appendix '4-C' to this report.)

DISCUSSION

STAFF ANALYSIS OF PUBLIC COMMENTS

Requests to Delay Implementation Date and Extend Review Period: There were several comments which requested that NYPA delay implementation of the new rates until May 1, 2012. MEUA requested that for future Authority rate proceedings, the review time be extended to allow for at least four months between publication of the Notice and the comment due date. Many parties cited the need for more time to consider responses to data requests and to file comments. As the Staff Analysis explains in more detail, there was sufficient time to review the data supporting the pending rate action, including the responses to the significant amount of data requests received. By operation of the extended due date that the Authority granted for the filing of comments, the Authority has consented to delay the implementation date for new rates, which was originally scheduled to become effective on November 1, 2011. Staff does not find convincing the arguments to delay implementation of the new rates or to permanently alter the review time which is done in accordance with state law. The proposed rates should be implemented one month later than originally proposed, to be effective December 1, 2011.

Proposed Preference Rates and their Conformance With the 'Lowest Possible Rate' Standard: Many customers argued that the proposed rates do not conform with the statutory standard that preference customers be served at the 'lowest possible rate' as set forth in the Public Authorities Law. They claim that various adjustments are needed including the enlargement of the demand charge allocator and several changes to NYPA's calculation of unforced capacity ('UCAP') sales credits used in the CoS and in the Rate Stabilization Reserve ('RSR') reconciliation mechanism,[§] all to lower customers' rates.

"The attached Staff Analysis discusses the merits of these proposals in detail. However, as amply explained in the Staff Analysis, staff finds there is no compelling argument that any of these adjustments are

[‡] The letters received by the Authority are included in Appendix 'C' to this Report.

[§] Each year, in accordance with the terms of the affected customer contracts, an annual reconciliation is performed whereby any differences between actual costs incurred and cost-based rate revenues collected are accumulated in a Rate Stabilization Reserve ('RSR'). Should the RSR balance exceed a ±$25 million bandwidth, a credit or surcharge is applied to the affected customers' bills to return or collect, as appropriate, the excess amount.

required to satisfy the 'lowest possible rate' standard. The rate methodologies used in the July 2011 Preliminary Staff Report are virtually identical to the methodologies adopted by the Trustees in 2003, which were later agreed to by all the preference customers in contracts or settlement, and used again in 2007 when the Trustees authorized the last preference rate increase. Further, MEUA, NYAPP and the NS Customers have ignored the provisions in their long-term hydropower contracts or settlements that specifically permit NYPA to employ the rate methodologies adopted by the Authority's Trustees in 2003. In addition, as the courts have recognized, the Authority possesses 'broad discretion' in determining what comprises the 'lowest possible rate' pursuant to the *Auer* decisions and the *Auer* Settlement, both of which have long-provided guidance on NYPA's preference power ratemaking. None of the customers has alleged, nor can they allege, that NYPA has somehow abandoned its agreements that set forth NYPA's rate methodologies.

Requests to Increase the Demand Allocator: NYAPP argues that the denominator used to set the demand rate should be based on the MW-months of NYPA's contract demand plus the MW-months of the Authority's average UCAP sales from the Projects. MEUA makes a similar claim, in that NYPA does not calculate the demand rate by spreading the cost over 'all users' of Hydroelectric Projects' capacity. The NS Customers reach the same conclusion.

"The billing determinant methodology used for the proposed 2011-2014 hydroelectric production rates is the same methodology used in both the 2003 and 2007 production rates proposals and is entirely consistent with the contracts and settlements reached with various preference power customers. According to standard ratemaking principles, the firm power contract customers are responsible for the cost recovery of the assets developed to serve them. NYPA adheres to this principle when it undertakes its cost recovery through production rates that are developed by using the total *firm* demands of its hydroelectric customers.

"As explained in detail in the Staff Analysis, NYPA does not find compelling the argument to increase the denominator used to calculate the demand charge. However, to provide the preference customers with the timing benefits of NYPA's UCAP sales, staff proposes to include a UCAP credit, based on projected ISO sales revenue, into the annual rate development for each of the 2011-2014 rate years. Any differences in the estimated UCAP credit and actual UCAP sales would be reconciled in future annual RSR computations. By making this adjustment, NYPA would reduce the Hydro CoS by $1.6 million in Rate Year ('RY') 2011, $3.7 million in RY 2012, $5.1 million in RY 2013 and $6.5 million in RY 2014.

Claims That the UCAP Credit be Cost-Based and Applied Directly to the RSR Balance: The RSR contains a UCAP Credit which is designed as a credit to the preference power rates to account for sales of UCAP for the hydroelectric projects that is above the needs of the contract hydro customers. Both NYAPP and MEUA request that prior RSR annual calculations be revised to reflect a cost-based rate for the UCAP. NYAPP contends that NYPA is incorrectly crediting UCAP sales based on the lower of market prices or costs and that a cost-based UCAP credit would be consistent with applicable precedents and its settlement with NYPA.

"As explained in the Staff Analysis, consistent with staff's determination not to expand the billing determinants to include estimated short-term UCAP sales, staff finds unconvincing NYAPP's proposal that the UCAP credits be re-valued at cost. As these NYISO customers are not receiving the same product, service or benefits as NYPA firm contract customers, staff affirms that it is unsound ratemaking to apply the same cost of service rate to these transactions.

NYPA's UCAP Credit Calculation Applied to the RSR and Claims that Preference Customers Cross-Subsidize Non-Preference Customers: NYAPP states that a flaw in NYPA's UCAP calculation used in the RSR causes actual capacity sales to be understated because NYPA's UCAP sales crediting methodology leaves the difference between the forecasted demand and the actual demands out of the equation. Preference customers are charged for the costs of those MW-months but cannot use them. Nevertheless, preference customers are not granted a dollar credit when NYPA sells these MW-months, either in the UCAP credit to the RSR or in the calculation of the demand rate. MEUA argues that cross-subsidization can occur between the rates charged to preference customers and non-preference customers, and has observed that the drop in demand of Reynolds Metals (*i.e.*, now ALCOA's East Plant) over 2009-10 is a major factor in this regard.

"As explained in the Staff Analysis, the comments concerning the cross-subsidization issue have some merit and staff has reconsidered its UCAP sales credit methodology. Staff recommends that the actual UCAP sales be used in the annual RSR calculations for 2005 through 2010. The dollar effect of the change is a reduction of $13.5 million in the RSR negative balance.

Treatment of 455 MW Preference Power Redirected to the Recharge New York Power Program: NYAPP and NS Customers voiced concerns over the withdrawal of 455 MW from preference power allocations to the Recharge New York Program, and its effect on the demand rate. Staff has continued to include the 455 MW withdrawn from the R&D customers in the total billing demands of the hydroelectric project CoS, which is consistent with the Customers' view. Staff also recognizes that the withdrawn power may no longer be classified as preference power thus, its proportional share of the RSR balance should be excluded. Staff recommends reducing the RSR balance by 30.17% or $10.5 million to reflect this adjustment. This amount is expected to be recovered through the sales made under the Recharge New York Power Program.

Annual RSR Report Procedures: MEUA points out that the RSR is a 'full, after the fact reconciliation of NYPA's rate year costs and revenues.' MEUA requests the right to review the annual RSR calculations and the establishment of a public process, with an opportunity for information sharing, discovery and comment. While other customers did not provide written comments on the specific issue of RSR review, NYAPP and the NS Customers made this concern known to NYPA staff at in-person meetings. NYPA staff agrees that transparency in the Hydro CoS process, including the annual RSR computation, is a worthwhile goal. NYPA staff agrees to provide the preference customers with the annual reconciliation to the RSR by June 1 of each year and to meet over the ensuing months to discuss relevant issues and provide needed data to customers, but does not believe a public comment process is warranted as the RSR mechanism is provided for in customer contracts.

Increased Credit for Ancillary Services Production: NS Customers assert that its current ancillary services credit is insufficient, as it only credits the costs associated with the amount of regulation necessary for contract loads, and not the actual regulation service sales. As explained in the Staff Analysis, the NS Customers' claim is inconsistent with their Authority hydro contracts in which their members agreed that certain methodologies and principles adopted by the Authority in 2003 would continue to be used without objection when the Authority sets future hydro rates.

"However, staff does recommend that the ancillary services credit for the 2011-14 be increased by a total of $2.2 million from that shown in the preliminary CoS. This change stems from an adjustment to the 2009 test year billing determinants to reflect average annual usage for the ALCOA East plant, which was shut down for much of that year.

Request for Credits Based on Authority Investment Income: NS Customers argue that they should receive a credit for investment income in the CoS since much of the Authority's investment income is generated from the operations at the Hydro Projects. This argument runs counter to the ratemaking principles established in the preference customer contracts. As explained in the Staff Analysis, a claim for a share of the Authority's investment income would produce preference rates that are below cost and in violation of settled law and applicable ratemaking principles. Staff recommends no credit be provided for investment income.

2009-2010 Deferred Rate Increases: NYAPP asserts that Authority costs associated with 2009-10 increases at the hydroelectric projects should not be allocated to ratepayers, due to the fact that the March 2009 rate increase proceeding was cancelled by the Trustees. NYAPP claims that they had no 'notice' that 2009 and 2010 costs would be deferred and that they expected those costs to be forgiven. NYAPP also claims that the Authority's proposal in this regard demonstrates a lack of 'transparency.' At the March, 2009 Trustee Meeting, the Trustees gave clear notice that 2009 and 2010 costs '[would] be deferred and recovered over appropriate, subsequent years(s).' All deferred amounts are being captured in the contractually agreed-upon RSR reconciliation mechanism. Therefore, Staff does not recommend any changes to the RSR mechanism that would fail to recognize the cost deferrals related to the 2009 and 2010 rate years.

Contributions to the New York State Treasury: MEUA commented that NYPA's expenditures used to make contributions to the State Treasury have been 'properly excluded' from Hydro CoS. However, NYAPP noted the size of the voluntary transfers to the State and requested that the Authority adopt 'detailed metrics' for measuring its creditworthiness at the time it considers making voluntary contributions to the State, and registered its concern about

the Authority's future financial strength. NPC commented that the Authority should use surplus funds pledged to the State Treasury to offset the entire rate increase. As the Staff Analysis explains, staff has reviewed existing policies and concludes that the Authority has developed an in-depth review process to ensure that these transfers are 'feasible and advisable' and will not result in preference power rate increases beyond those necessary to provide power at cost. There is no cause to provide the relief requested by the NPC, as the inclusion of such 'surplus funds' in the Hydro CoS would lower the preference rate below cost. No changes are recommended.

Inclusion of Charitable Contributions within the CoS: MEUA has requested that charitable contributions and sponsorships not directly assigned to the hydroelectric projects be removed from the cost of service. Staff concurs with this request, and recommends that all costs for such contributions and sponsorships be removed from the preference customer CoS in the total amount of $483,000 over the 41-month rate plan period.

Recovery of Costs for Parks Neighboring the St. Lawrence Power Project: NYAPP seeks clarification concerning payments made to the Robert Moses and Coles Creek State Parks ('Parks') located in the direct vicinity to the St Lawrence Power Project. The Federal Energy Regulatory Commission license issued for the St. Lawrence Project on October 23, 2003 incorporates these Parks as project recreational facilities and, under the terms of the license, the Authority has the ultimate responsibility to fund the O&M costs of the Parks. However, as part of a 2009 Memorandum of Understanding between the State of New York and the Authority, the Authority was relieved of these annual payments to the Office of Parks, Recreation and Historic Preservation ('OPRHP') for the state fiscal years 2011 through 2017. In reviewing accounting data for past years, staff discovered that in 2008, $8 million charged to the Miscellaneous and General Expenses Account for the Niagara and St. Lawrence Projects for Parks reimbursement had not been backed out of financial information used in the 2008 actual hydroelectric CoS. The CoS did include a separate entry for $800,000 attributable to the Parks. The removal of the $8 million charge from the CoS resulted in positive adjustment to the cumulative RSR of about $3 million. Staff recommends that the $800,000 cost for the Parks not be included in the RSR true-up and confirms that it is not in the CoS for Rate Years 2011-14 covered under this rate proceeding.

Shared Services Expenses within the CoS: NYAPP indicated that the Authority did not provide sufficient information as to what it includes in Shared Services within the CoS, and generally requested additional information describing what is included in this category of expenses. Staff responded to several data requests regarding the allocation of shared services costs. It was staff's understanding that the responses were sufficient, as there was no receipt of any further requests for follow-up information concerning shared services expenses. The final rate recommendation reflects certain overhead cost-cutting measures undertaken by staff in the last few months including an approximate $5 million reduction for RY 2012-2014 resulting from the Trustees approval of a revised funding plan for the Other Post-Employment Benefits ('OPEB') Trust at their October 2011 meeting.

SUMMARY OF FINAL RATE PROPOSAL

"For the reasons summarized above and described in detail in the Staff Analysis, Authority staff recommends that the demand rates originally proposed in the July 2011 Preliminary Staff Report be amended and approved as shown below. The proposed final demand and energy rates and the overall effective rates at a typical 70% load factor are shown below:

Rate Year[**]	**Demand Rate $/kW-month**	**Energy Rate $/MW-hour**	**RSR-related Surcharge $/MW-hour**	**Effective Rate**[††] **$/MW-hour**
2011	3.26	4.92	-	11.30
2012	3.57	4.92	-	11.91
2013	3.91	4.92	-	12.57
2014	4.07	4.92	up to 0.40	13.28

[**] Except for 2011, the preference power rate year runs from May 1 of the calendar year indicated to April 30 of the following year. Because the final rule in this NOPR proceeding is proposed to be adopted on November 15, 2011, the RY 2011 would extend from December 1, 2011 to April 30, 2012.
[††] Effective rate at 70% load factor.

"Also, as noted and recommended in the Staff Analysis of public comments, the RSR balance must be altered and lowered from the -$51.3 million balance cited in the NOPR to account for 1) $13.5 million in additional revenues tied to the total annual UCAP sales and internal transfers; 2) a reduction of $3 million in the 2008 RSR calculation resulting from a correction of charges included in the 2008 CoS related to payments to OPRHP; and 3) a 30.17% reduction in the revised RSR balance to account for the withdrawing of 455 MW of firm hydroelectric power formerly allocated to the upstate utilities for their residential customers and which is now allocated to the Recharge New York Power Program. The remaining RSR balance equals -$24.5 million.

"As a result, staff retracts its recommendation that a $0.50/MWh surcharge begin in 2014, but rather, should the RSR balance exceed the $25 million threshold the surcharge would be no greater than $0.40/MWh

FISCAL INFORMATION

"Implementation of the proposed schedule of rate increases would allow the Authority to recover its costs associated with serving the preference power customers. For the 2011 rate year, the estimated revenue increase would be about $2.1 million. For the 41-month period from December 2011 through April 30, 2015, the estimated cumulative base rate revenue increases would be about $45.8 million with the additional RSR surcharge of $2.7 million being collected from preference power customers for the period May 1, 2014 to April 30, 2015.

RECOMMENDATION

"The Vice President – Financial Planning and Budgets recommends that the Trustees: (1) adopt the conclusions of the Staff Analysis attached hereto as Appendix '4-A'; (2) approve the hydroelectric preference rates for the 41-month plan commencing December 1, 2011, as set forth above; and (3) include in the Authority's records the Preliminary Staff Report contained Appendix '4-B,' and the transcripts of the public forums, written public comments and letters contained in Appendix '4-C.'

"It is also recommended that the Secretary be authorized to publish a Notice of Adoption of the above-described preference rates in the *State Register*, including notice of the availability of the Final Rate Modification Plan and other materials included in the record of these proceedings.

"It is also recommended that the Senior Vice President – Marketing and Economic Development, or his designee, be authorized to issue written notice of the final action, including a copy of the revised tariff leaves, as necessary, to the affected customers.

"For the reasons stated, I recommend the approval of the above-requested action by adoption of a resolution in the form of the attached draft resolution."

Mr. Thomas Davis presented highlights of staff's recommendation to the Trustees. In response to a question from Trustee Nicandri, Mr. Davis said that the billing determinants associated with the allocation of power to the RNY customers will remain in the calculation of future hydropower Cost Of Service rate actions.

Trustee Dyson added that the Authority is required by law to "break even" and that is why it has undertaken this process. After consideration of comments from customers, the Authority has agreed to lower the amount of the increase in the rates, which will be phased-in over a number of years to lessen the impact on the customers. The Authority was able to consider this further reduction in rates because of the more than $3 million cut in spending, which the Authority has undertaken as part of Governor Cuomo's overall goal of 10% cuts in spending. Trustee Dyson thanked staff for the thorough and professional job done in putting the elements

of the recommendation together. Chairman Townsend also thanked Trustee Dyson for his role in assisting staff in this effort.

The following resolution, as submitted by the Acting President and Chief Executive Officer, was unanimously adopted.

> **WHEREAS, on July 26, 2011, the Authority authorized the Secretary to file a Notice of Proposed Rulemaking for publication in the *New York State Register* of its intention to increase the hydroelectric preference power rates; and**
>
> **WHEREAS, such notice was duly published in the *New York State Register* on August 17, 2011 and more than 45 days have elapsed since such publication; and**
>
> **WHEREAS, Public Forums were held on September 19, 20 and 22 of 2011 and staff received and responded to both oral and written comments and data requests as set forth in the attached Final Rate Modification Plan; and**
>
> **WHEREAS, the proposed rate action should be modified, in accordance with the changes contained in the foregoing report of the Acting President and Chief Executive Officer, and as explained in detail in the Staff Analysis contained in Appendix "4-A";**
>
> **NOW THEREFORE BE IT RESOLVED, That the rates for sale of power and energy to Authority customers receiving the preference power rate, as recommended in the foregoing report of the Acting President and Chief Executive Officer, are hereby approved effective December 1, 2011; and be it further**
>
> **RESOLVED, That the Senior Vice President – Marketing and Economic Development or his designee be, and hereby is, authorized to issue written notice as required by contract with respect to the modification in rates, including applicable tariff leaves; and be it further**
>
> **RESOLVED, That the Corporate Secretary of the Authority be, and hereby is, directed to file a Notice of Adoption with the Secretary of State for publication in the *New York State Register* and to submit such other notice as may be required by statue or regulation; and be it further**
>
> **RESOLVED, That the Chairman, the Vice Chairman, the Acting President and Chief Executive Officer, the Acting Chief Operating Officer and all other officers of the Authority are, and each of them hereby is, authorized on behalf of the Authority to do any and all things, take any and all actions and execute and deliver any and all agreements, certificates and other documents to effectuate the foregoing resolution, subject to the approval of the form thereof by the Acting General Counsel.**

5. Massena Substation 765/230 kV Autotransformer Replacement
Capital Expenditure Authorization and Contract Award

The Acting President and Chief Executive Officer submitted the following report:

SUMMARY

"The Trustees are requested to authorize capital expenditures in the amount of $4.4 million for the engineering, design, procurement, installation and testing of a new 765/230 kV auto-transformer to be used as a replacement of a failed 765/230 kV autotransformer at the Massena Substation, Massena, NY. The Trustees are also requested to approve the award of a multi-year contract in the amount of $3.1 million to Smit Transformers, Nijmegen, Netherlands, to furnish, deliver, and install this autotransformer at the Massena Substation.

BACKGROUND

"Section 2879 of the Public Authorities Law and the Authority's Guidelines for Procurement Contracts require the Trustees' approval for procurement contracts involving services to be rendered for a period in excess of one year. In accordance with the Authority's Expenditure Authorization Procedures, the award of non-personal services contracts exceeding $3,000,000 require the Trustees' approval.

"The Massena Autotransformers No. 1 and No. 2, consist of seven single-phase autotransformers, three each for each bank and one designated as a spare to be put into service in the event of a failure. On July 8, 2008 Transformer 2A from autotransformer bank No. 2 failed and it was replaced with the existing spare autotransformer. This event left the Massena Substation without a spare to handle a contingency failure in either of the autotransformer banks.

"The autotransformers are critical long-lead time electrical components required for successful operation and functioning of the substation. Failure of a single autotransformer can result in loss of service. A spare autotransformer is essential to maintaining the operation of the substation and will mitigate the impacts should one of the existing autotransformers fail. With the installation of this new autotransformer, the current spare would still be used as the spare autotransformer for the facility.

DISCUSSION

"The scope-of-work under this contract includes the design, fabrication, delivery, installation, assembly and testing of one 765/230 kV single-phase autotransformer.

"The Authority issued an advertisement to procure bids in the New York State *Contract Reporter* and bid packages were available as of May 26, 2011. The bid documents were downloaded by 68 potential bidders.

"The following seven proposals were received on July 26, 2011:

BIDDER	LOCATION	BID WITH OPTIONS	EVALUATED BID
Smit	Nijemgen, Netherlands	$3,068,912.00	$4,346,912.00
TBEA	Shenyang, PR China	$2,893,648.00	$4,409,648.00
Hyundai	Ulsan, Korea	$3,420,296.00	$4,495,296.00
ABB	Varennes, QC, Canada	$3,966,976.00	$4,808,976.00
BTW	Hebei, China	$3,870,000.00	$5,345,000.00
XD	Jiangsu, China	$4,574,315.00	$5,912,315.00
Alstom	Stafford, England	$4,800,000.00	$6,435,000.00

"The proposals were reviewed by an evaluation committee comprising staff from Engineering, Procurement, Project Site, Quality Assurance and Project Management. The evaluated cost took into account the technical and commercial evaluation factors as detailed in the bid documents. Authority staff recommends the contract award to Smit Transformers, the lowest evaluated price and technically acceptable bidder. The evaluated bid price shown above also includes optional prices for spare parts and extended warranty. The evaluated cost took into account operational characteristics of the autotransformer: no load losses, load losses and auxiliary losses.

"The project work will be performed over a three-year period with design and fabrication taking place during 2012 and 2013. Delivery, installation, and field testing would be completed in 2014.

"The total project cost to purchase and install this autotransformer is estimated at $4.4 million as follows:

Engineering		$ 341,000.00
Procurement		$ 3,225,000.00
Construction		$ 230,000.00
Authority Direct and Indirect		$ 631,000.00
	Total:	$ 4,427,000.00

FISCAL INFORMATION

"Payment associated with this project will be made from the Authority's Capital Fund.

RECOMMENDATION

"The Executive Vice President and Chief Engineer – Power Supply, the Senior Vice President – Power Supply Support Services, the Vice President – Project Management, the Vice President – Engineering, the Vice President – Procurement, the Project Manager and the Regional Manager – Northern New York recommend that the Trustees approve the award of a contract to Smit Transformers, in the amount of $3.1 million, to furnish a 765/230 kV autotransformer for Massena Substation and authorize the capital expenditure of $4.4 million for the project.

"For the reasons stated, I recommend the approval of the above-requested action by adoption of a resolution in the form of the attached draft resolution."

Mr. John Canale presented highlights of staff's recommendation to the Trustees. In response to a question from Chairman Townsend, Mr. Canale said that the replacement autotransformer is being manufactured in the Netherlands; the Authority did not receive any bids from firms in the United States. In response to a question from Trustee Nicandri, Mr. Canale said that the Authority has been operating without a back-up autotransformer for approximately three years. In response to a question from Trustee O'Luck, Mr. Canale said that the original equipment was purchased in 1977 and that the Autotransformers, Nos. 1 and 2, (7 total: 3 in each bank and 1 designated spare) at the Massena Substation are the same age as the one that failed. In response to further question from Trustee O'Luck, Mr. Russak said that staff is including costs for a series of autotransformer replacements at the facilities in the 2012 budget. In response to a question from Chairman Townsend, Mr. Canale said that the autotransformers are about 35 years old however, they typically last for approximately 45 - 50 years, and the cause of the failure of the autotransformer being replaced has not been

determined. He said that staff is also taking steps to ensure that the other autotransformers do not experience a similar failure.

Acting President and Chief Executive Officer Quiniones added that an evaluation of a Life Extension and Modernization ("LEM") program is currently being performed on the Authority's entire transmission system; the Trustees will be provided with an update of the LEM condition assessment of the Authority's transmission system in January.

In response to a question from Vice Chairman Foster, Mr. Canale said that staff is taking extra precautions by conducting weekly monitoring and analysis of the autotransformers. Mr. Antenucci added that it is not industry practice and has not been the Authority's practice to have a spare autotransformer on every site; however, in order to reduce the Authority's vulnerability to similar events, the Authority has initiated a program to reduce its vulnerability by selectively purchasing spares ahead of time.

The following resolution, as submitted by the Acting President and Chief Executive Officer, was unanimously adopted.

RESOLVED, That pursuant to the Authority's Expenditure Authorization Procedures, additional capital expenditures in the amount of $4.4 million are hereby authorized as recommended in the foregoing report of the Acting President and Chief Executive Officer;

Capital	**Expenditure Approval**
Engineering, Procurement, Installation **Authority Direct & Indirect**	**$4.4 million**

AND BE IT FURTHER RESOLVED, That pursuant to the Guidelines for Procurement Contracts adopted by the Authority, approval is hereby granted to award a contract to Smit Transformers, in the amount of $3.1 million to provide an autotransformer for use at the Massena Substation, as recommended in the foregoing report of the Acting President and Chief Executive Officer;

Contractor	**Contract Approval**
Smit Transformers **Nijmegen, Netherlands**	**$3.1 million**

AND BE IT FURTHER RESOLVED, That the Chairman, the Vice Chairman, the Acting President and Chief Executive Officer, the Acting Chief Operating Officer and all other officers of the Authority are, and each of them hereby is, authorized on behalf of the Authority to do any and all things and take any and all actions and execute and deliver any and all agreements, certificates and other documents to effectuate the foregoing resolution, subject to the approval of the form thereof by the Acting General Counsel.

6. Selection of President and Chief Executive Officer

The Chairman submitted the following report:

SUMMARY

"The Trustees are requested to consider the selection of Mr. Gil C. Quiniones of New York, New York as President and Chief Executive Officer of the Authority, effective as stated below.

BACKGROUND AND DISCUSSION

"Under the Public Authorities Law ('PAL') and the Authority's By-Laws, the Trustees have the authority to select the President and Chief Executive Officer, subject to confirmation by the Senate. Section 2852 of the PAL provides that the Senate shall vote to confirm any appointment within 60 days of its submission to the Senate during session. If submission is made when Senate is not in session, confirmation shall be made within 7 days of the convening for session. If the Senate fails to vote to confirm any such appointment within the prescribed time, the appointment is deemed confirmed without further Senate action.

"On July 26, 2011, Mr. Richard M. Kessel resigned from his position as President and Chief Executive Officer of the Authority. At that time, the Trustees designated Mr. Gil C. Quiniones as Acting President and Chief Executive Officer of the Authority, effective September 7, 2011. On October 31, 2011, Governor Andrew M. Cuomo recommended Mr. Gil C. Quiniones to be President and Chief Executive Officer of the New York Power Authority. The Trustees, after due consideration, have elected to appoint Mr. Quiniones for the office of President and Chief Executive Officer.

RECOMMENDATION

Pursuant to Section 1004 of the Public Authority Act and Article IV, Section 2 of the Authority's By-Laws, 'Election of Non-Statutory Officers,' adopted December 18, 1984 and last amended on July 26, 2011, the Trustees recommend that, based on his substantial knowledge of Authority matters, management skills, strong expertise and record of exemplary service to the Authority, Mr. Gil C. Quiniones be elected as President and Chief Executive Officer, subject to confirmation by the New York State Senate. The Trustees further recommend that Article IV, Section 2 of the Authority's By-Laws be amended to permit the election of the President and Chief Executive Officer and all other non-statutory officers to occur at 'any regular or special meeting of the Trustees.' The current version of this section reads as if such elections may only occur at the Trustees' annual meeting.

"For the reasons stated, I recommend the approval of the above-requested action by adoption of a resolution in the form of the attached draft resolution."

Chairman Townsend said that the Governor recommended that Mr. Gil C. Quiniones of New York be nominated as President and Chief Executive Officer of the Authority. On behalf of the Trustees, he is pleased to present the motion today to appoint Mr. Quiniones to the position. He added that the Governance Committee, which met earlier, recommended that Mr. Quiniones be appointed to the position. The recommendation is subject to Senate confirmation. Vice Chairman Foster, Trustees Nicandri, LeChase, Curley, Dyson and O'Luck endorsed the selection of Mr. Quiniones as President and Chief Executive Officer of the Authority.

Mr. Quiniones expressed sincere thanks to the Governor for recommending him and to the Board of Trustees for appointing him for the position of President and Chief Executive Officer of the Authority, subject to

approval by the New York State Senate. He felt honored by the Board's confidence in him and was looking forward to working with the Trustees and staff to carry out the Authority's mission to advance the state's energy and economic development goals.

The following resolution, as submitted by the Chairman, was unanimously adopted.

> **RESOLVED, That pursuant to Article IX, Section 1, "Amendments," of the Authority's By-Laws, which give the Trustees the power to amend any provision of the By-Laws, Article IV, Section 2, "Election of Non-Statutory Officer," of the Authority's By-Laws, is hereby amended to permit the election of the President and Chief Executive Officer and all other non-statutory officers to occur at "any annual, regular or special meeting of the Trustees"; and be it further**
>
> **RESOLVED, That pursuant to Section 1004 of the Public Authorities Law and amended Article IV, Section 2, "Election of Non-Statutory Officer," of the Authority's By-Laws, Mr. Gil C. Quiniones is hereby elected and appointed as President and Chief Executive Officer of the Authority, subject to confirmation by the New York State Senate, and shall hold such office pursuant to Article IV, Section 3 of the Authority's By-Laws.**

7. Election of Executive Vice President and General Counsel

The Chairman submitted the following report:

SUMMARY

"The Trustees are requested to consider the election of Ms. Judith C. McCarthy of Westchester County, New York as Executive Vice President and General Counsel of the Authority.

BACKGROUND AND DISCUSSION

"Article IV, Section 2 of the Authority's By-Laws provides for the election of certain non-statutory officers by the Trustees. Ms. Judith C. McCarthy was appointed First Deputy General Counsel on January 31, 2011 and serves as Acting General Counsel since that time. She has rendered exceptional service to the staff and Board of Trustees of the Authority.

RECOMMENDATION

"It is recommended that, pursuant to Article IV of the By-Laws, adopted December 18, 1984, and last amended November 15, 2011, Ms. Judith C. McCarthy be elected as Executive Vice President and General Counsel of the Authority effective immediately.

"For the reasons stated, I recommend the approval of the above-requested action by adoption of a resolution in the form of the attached draft resolution."

Chairman Townsend said that the Trustees are being asked to consider the election of Ms. Judith McCarthy of Westchester, as Executive Vice President and General Counsel of the Authority. He said that Ms. McCarthy has performed admirably as Acting General Counsel and will be a great asset to the Authority. He is confident she will do a good job and look forward to working with her. He added that the Governance Committee also recommended the election of Ms. McCarthy to the position. Trustee Nicandri said that, as Chair of the Governance Committee, he worked with Ms. McCarthy and she was very helpful in providing legal counsel to the Committee and will vote in favor of the motion to elect her. The other Trustees endorsed the recommendation.

Ms. McCarthy said that she appreciated the vote of confidence and also the support given to her over the past ten months. She also thanked Mr. Quiniones for his support and Governor Cuomo for giving her the opportunity to work at the Authority.

The following resolution, as submitted by the Chairman, was unanimously adopted.

> **RESOLVED, That pursuant to Article IV, Section 2 of the Authority's By-Laws, Ms. Judith C. McCarthy is hereby elected as Executive Vice President and General Counsel of the Authority effective immediately.**

8. Resolution – Paul F. Finnegan

WHEREAS, Paul F. Finnegan has been a highly valued employee at the New York Power Authority for more than 17 years, including his most recent position as senior vice president of Public, Governmental and Regulatory Affairs in which he spearheaded NYPA's engagement with members of Congress, the executive and legislative branches of New York State government and local government entities; and

WHEREAS, Mr. Finnegan, who joined NYPA in 1994 as a state legislative liaison, has provided sage advice and counsel over the years to the NYPA Board of Trustees and senior management on countless matters of significance that reflect the Power Authority's broad reach and influence on the state's electric power system, economy, local communities and environment; and

WHEREAS, Mr. Finnegan's impact on the Power Authority's intergovernmental relations has included his major role in the Authority's successful federal relicensing of its St. Lawrence-Franklin D. Roosevelt and Niagara power projects, in 2003 and 2007, respectively, and the attendant carrying out of wide ranging commitments under agreements that he helped make possible for major recreational, environmental and economic benefits in Northern and Western New York; and

WHEREAS, the practical good sense and judgment that Mr. Finnegan brought to bear on a wide range of matters have made him an influential voice, with those qualities exhibited every day in his contributions to the Power Authority's sound decision-making; and

WHEREAS, Mr. Finnegan's quick wit and marvelous sense of humor have advanced his ability to transcend partisan politics in reinforcing the Power Authority's positive relations with federal, state and local elected officials, for the effective undertaking of the Authority's programs and initiatives; and

WHEREAS, Mr. Finnegan's warm and vibrant personality and self-effacing demeanor have furthered the admiration and affection that the NYPA Board of Trustees and his co-workers have for him and have made him a valued confidant of NYPA chairmen, presidents and other senior executives; and

WHEREAS, the wayfaring requirements of the positions held by Mr. Finnegan, including vice president of Intergovernmental and Community Relations, called for frequent travels to NYPA facilities and numerous communities around the state, at the expense of being away from his family, at great personal sacrifice; and

WHEREAS, Mr. Finnegan's peripatetic ways will now be divided between his home in Lake Pleasant, in Adirondack Park, Hamilton County, and a new residency in the sun-splashed environs of Ventura, California;

NOW THEREFORE BE IT RESOLVED, that the Trustees of +the Power Authority of the State of New York extend their deepest appreciation to Paul Finnegan for his dedicated service and varied contributions to NYPA and wish him; his wife, Jeannie; their two beloved golden retrievers, Cedar and Riley; and the large extended Finnegan family of brothers, sisters, nieces and nephews much health, happiness and success.

November 15, 2011

Acting President and Chief Executive Officer Quiniones read the resolution honoring Mr. Paul Finnegan's service to the Authority.

Mr. Finnegan said that this is an opportunity for him to take on new challenges. He said that he appreciated the support and opportunities granted to him by the Authority. He will always have fond memories of the Authority and will miss everyone.

9. <u>Motion to Conduct an Executive Session</u>

Mr. Chairman, I move that the Authority conduct an executive session pursuant to the Public Officers Law of the State of New York section §105 to discuss matters leading to the appointment, employment, promotion, demotion, discipline, suspension, dismissal or removal of a particular person or corporation. On motion made and seconded, an Executive Session was held.

10. <u>Motion to Resume Meeting in Open Session</u>

Mr. Chairman, I move to resume the meeting in Open Session. On motion made and seconded, the meeting resumed in Open Session.

11. <u>Next Meeting</u>

The next regular meeting of the Trustees will be held on **Thursday, December 15, 2011, at 11:00 a.m., at the Clarence D. Rappleyea Building, White Plains, New York,** unless otherwise designated by the Chairman with the concurrence of the Trustees.

Closing

On motion made and seconded, the meeting was adjourned by the Chairman at approximately 1:30 p.m.

Karen Delince
Corporate Secretary

November 15, 2011

EXHIBITS

For

November 15, 2011

Trustees' Meeting

November 15, 2011
Exhibit “2c-A”

POWER AUTHORITY

OF THE

STATE OF NEW YORK

30 South Pearl Street
10th Floor
Albany, New York 12207-3425

AGREEMENT FOR THE SALE

OF EXPANSION POWER AND ENERGY

(MOOG INC.)

The POWER AUTHORITY OF THE STATE OF NEW YORK ("Authority"), created pursuant to Chapter 772 of the New York Laws of 1931 and existing under Title I of Article V of the New York Public Authorities Law ("PAL"), having its office and principal place of business at 30 South Pearl Street, 10th Floor, Albany, New York 12207-3425, hereby enters into this Agreement for the Sale of Expansion Power and energy ("Agreement") with MOOG INC. ("Customer"), with facilities at Jamison Road and Seneca Street, East Aurora, New York 14052. The Authority and the Customer are from time referred to in this Agreement as "Party" or collectively as "Parties" and agree follows:

RECITALS

WHEREAS, the Authority is authorized to sell hydroelectric power produced by the Niagara Power Project, Federal Energy Regulatory Commission ("FERC") Project No. 2216, known as "Expansion Power" (or "EP"), as further defined in this Agreement, to qualified businesses in New York State in accordance with PAL § 1005(5) and (13);

WHEREAS, EP consists of 250 megawatts ("MW") of firm hydroelectric power and associated firm energy produced by the Niagara Power Project;

WHEREAS, the Authority is authorized pursuant to PAL § 1005(13)(a) to award EP based on, among other things, the criteria listed in the PAL, including but not limited to an applicant's long-term commitment to the region as evidenced by the current and planned capital investment; the type and number of jobs supported or created by the allocation; and the state, regional and local economic development strategies and priorities supported by local units of governments in the area in which the recipient's facilities are located;

WHEREAS, PAL § 1005(11) provides that the Authority is authorized to "[t]o exercise all the powers necessary or convenient to carry out and effectuate the purposes and provisions of … title [1 of article 5 of the PAL] … and as incidental thereto to . . . sell … electric power, and generally to do any and every thing necessary or convenient to carry out the purposes of … title [1 of article 5 of the PAL] …";

WHEREAS, the Customer is party to another agreement with the Authority entitled "Agreement for the Sale of Expansion and/or Replacement Power and Energy," dated February 8, 2011 (the "WNY Contract Extension") covering various allocations of Expansion Power (or "EP") as provided for in the WNY Contract Extension;

WHEREAS, the Customer applied to the Authority for an allocation of EP for use by the Customer at its facilities (defined in Section I of this Agreement as the "Facility);

WHEREAS, on July 26, 2011, the Authority's Board of Trustees ("Trustees") approved a 300, kilowatt ("kW") allocation of EP to the Customer for a five (5) year term (defined in Section I of this Agreement as the "Allocation") as further described in this Agreement;

WHEREAS, on July 26, 2011, the Trustees authorized the Authority to, among other things, take any and all actions and execute and deliver any and all agreements and other documents necessary to effectuate its approval of the Allocation;

WHEREAS, the Customer has completed the expansion of the Facility and has requested that the Allocation be made available to the Customer beginning on___, 2011;

WHEREAS, NYPA staff has confirmed that the expansion of the Facility is complete;

WHEREAS, the provision of Electric Service (defined in Section I of this Agreement) associated with the Allocation is an unbundled service separate from the Authority's sale of power and energy to the Customer, which will be performed by New York State Electric & Gas Corporation ("NYSEG");

WHEREAS, such transmission and delivery service will be made in accordance with a separate agreement between the Customer, the Authority and NYSEG (defined in Section I of this Agreement as the "Supplemental Agreement"), and NYSEG tariffs as applicable;

WHEREAS, on ___, 2011, the Parties executed an Interim Agreement for the Sale of Expansion Power and Energy (defined in Section I of this Agreement as the "Interim Agreement"), to enable the Customer to receive the Allocation pending the execution of a long-term agreement, or___, 2011, whichever first occurs;

WHEREAS, in accordance with the Supplemental Agreement, the Authority, the Customer and NYSEG, on ___, 2011 executed the "Interim Sale Agreement Appendix," which is attached to the Interim Agreement as Exhibit A;

WHEREAS, the Parties have reached an agreement on a long-term contract governing the sale of the Allocation to the Customer as set forth in this Agreement;

WHEREAS, the Parties intend that this Agreement will govern the terms and conditions of the sale of the Allocation through June 30, 2013, and that on and after July 1, 2013 the Allocation will be governed by the WNY Contract Extension for the remainder of the term of the Allocation;

WHEREAS, the Authority has complied with requirements of PAL § 1009 which specifies the approval process for contracts negotiated by the Authority; and

WHEREAS, the Governor of the State of New York has approved the terms of this Agreement pursuant to PAL § 1009(3).

NOW THEREFORE, in consideration of the mutual covenants herein, the Authority and the Customer agree as follows:

NOW THEREFORE, the Parties hereto agree as follows:

I. Definitions

A. **Agreement** means this Agreement.

B. **Allocation** refers to the allocation of 300 kW of EP awarded to the Customer for a five (5) year term as specified in Schedule A.

C. **Contract Demand** is as defined in the Service Tariff.

D. **Electric Service** is the Firm Power and Firm Energy associated with the Allocation and sold by the Authority to the Customer in accordance with this Agreement, the Service Tariff and the Rules.

E. **Expansion Power** (or **EP**) is 250 MW of Firm Power and associated Firm Energy from the Project eligible to be allocated by the Authority for sale to businesses pursuant to PAL § 1005 (5) and (13).

F. **Facility** means the Customer's facilities at Jamison Road and Seneca Street, East Aurora, New York 14052.

G. **Firm Power** is as defined in the Service Tariff.

H. **Firm Energy** is as defined in the Service Tariff.

I. **FERC** means the Federal Energy Regulatory Commission (or any successor organization).

J. **FERC License** means the first new license issued by FERC to the Authority for the continued operation and maintenance of the Project, pursuant to Section 15 of the Federal Power Act, which became effective September 1, 2007 after expiration of the Project's original license which became effective in 1957.

K. **Hydro Projects** is a collective reference to the Project (defined below) and the Authority's St. Lawrence-FDR Project, FERC Project No. 2000.

L. **Interim Agreement** means the Interim Agreement for the Sale of Expansion Power and Energy, executed by the Parties on ___, 2011.

M. **Load Serving Entity (or LSE)** means an entity designated by a retail electricity customer (including the Customer) to provide capacity, energy and ancillary services to serve such customer, in compliance with NYISO Tariffs, rules, manuals and procedures.

N. **NYISO** means the New York Independent System Operator or any successor organization.

O. **NYISO Tariffs** means the NYISO's Open Access Transmission Tariff or the NYISO's Market Administration and Control Area Services Tariff, as applicable, as such tariffs are modified from time to time, or any successor to such tariffs.

P. **NYSEG** has the meaning set forth in the eighth recital.

Q. **Project** means the Niagara Power Project, FERC Project No. 2216.

R. **Replacement Power** (or **RP**) is 445 MW of Firm Power and associated Firm Energy from the Project eligible to be allocated by the Authority for sale to businesses pursuant to PAL § 1005(5) and (13).

S. **Rules** are the applicable provisions of Authority's rules and regulations (Chapter X of Title 21 of the Official Compilation of Codes, Rules and Regulations of the State of New York), as applicable, as may be modified from time to time by the Authority.

T. Sales Agreement Appendix refers to the form Sales Agreement Appendix that is Attachment B to the Supplemental Agreement

U. **Service Tariff means th**e Authority's Service Tariff No. EP-1, establishing rates, terms and other conditions for the sale of EP, as may be modified or superseded from time to time.

V. **Schedule A** refers to the Schedule A entitled "Expansion Power Allocations" which is attached to and made part of this Agreement.

W. **Schedule B** refers to the Schedule B entitled "Expansion Power Commitments" which is attached to and made part of this Agreement.

X. **Substitute Energy** means energy sold to the Customer at its request which the Authority procures from markets administered by the NYISO to replace hydroelectricity that would otherwise have been supplied to the Customer under this Agreement.

Y. **Supplemental Agreement** means an agreement entitled "Supplemental Agreement for the Delivery of Power Allocations between Power Authority of the State of New York and New York State Electric & Gas Corporation," made as of July 18, 2007.

Z. **Unforced Capacity** (or **UCAP**) means the electric capacity required to be provided by LSEs to serve electric load as defined by the NYISO Tariffs, rules, manuals and procedures.

II. Electric Service

A. The Authority shall make available Electric Service to enable the Customer to receive the Allocation commencing ___, 2011 (or on such later date as this Agreement becomes effective) in accordance with this Agreement, the Service Tariff and the Rules.

B. The Authority shall provide UCAP in amounts necessary to meet the Customer's NYISO UCAP requirements associated with the Allocation in accordance with the NYISO Tariffs.

C. The Contract Demand for the Customer's Allocation may be modified by the Authority if the amount of Firm Power and Firm Energy available for sale as EP or RP from the Project is modified as required to comply with any ruling, order, or decision of any regulatory or judicial body having jurisdiction, including but not limited to FERC. Any such modification will be made on a pro rata basis to all EP and RP customers, as applicable, based on the terms of such ruling, order, or decision.

D. The Contract Demand may not exceed the Allocation.

III. Rates, Terms and Conditions

A. Electric Service shall be sold to the Customer based on the rates, terms and conditions determined in accordance with this Agreement, the Service Tariff and the Rules.

B. The Customer may not resell or permit any other person to use any quantity of the EP it has purchased from the Authority under this Agreement.

C. Electric Service sold to the Customer pursuant to this Agreement may only be used by the Customer at the Facility.

D. Notwithstanding any other provision of this Agreement to the contrary, the power and energy rates for Electric Service shall be subject to increase by the Authority at any time upon 30 days prior written notice to the Customer if, after consideration by the Authority of its legal obligations, the marketability of the output or use of the Project and the Authority's competitive position with respect to other suppliers, the Authority determines in its discretion that increases in rates obtainable from any other Authority customers will not provide revenues, together with other available Authority funds not needed for operation and maintenance expenses, capital expenses, and reserves, sufficient to meet all requirements specified in the Authority's bond and note resolutions and covenants with the holders of its financial obligations. The Authority shall use its best efforts to inform the Customer at the earliest practicable date of its intent to increase the power and energy charges pursuant to this provision. Any rate increase to the Customer under this subsection shall be on a non-discriminatory basis as compared to other Authority customers after giving consideration to the factors set forth in the first sentence of this subsection. With respect to any such increase, the Authority shall forward to the Customer with the notice of increase, an explanation of all reasons for the increase, and shall also identify the sources from which the Authority will obtain the total of increased revenues and the bases upon which the Authority will allocate the increased revenue requirements among its customers. Any such increase in rates shall remain in effect only so long as the Authority determines such increase is necessary to provide revenues for the purposes stated in the preceding sentences.

IV. Expansion Power Commitments

Schedule B sets forth the Customer's specific "Expansion Power Commitments." The commitments agreed to in Schedule B are in addition to any other rights and obligations of the Parties provided for in the Agreement.

V. Rules and Service Tariff

The Service Tariff, as may be modified or superseded from time to time by the Authority in its discretion, is hereby incorporated into this Agreement with the same force and effect as if set forth herein at length. In the event of any inconsistencies, conflicts or differences between the provisions of the Service Tariff and the Rules, the provisions of

the Service Tariff shall govern. In the event of any inconsistencies, conflicts or differences between the provisions of this Agreement and the Service Tariff, the provisions of this Agreement shall govern.

VI. Transmission and Delivery of Firm Power and Firm Energy; Responsibility for Charges

A. The Customer will pay NYSEG for transmission and delivery service associated with the Allocation in accordance with the Supplemental Agreement, and all applicable tariffs, rulemakings, and orders, in order to deliver to the Customer the Allocation of Firm Power and Firm Energy supplied by the Authority under this Agreement. To the extent the Authority incurs transmission and delivery service charges or other costs associated with the Allocation during the term of this Agreement, the Customer agrees to compensate the Authority for all such charges and costs incurred.

B. Each Party hereby represents that nothing in this Agreement conflicts with the Supplemental Agreement, and the event of any such conflict, the terms of the Supplemental Agreement shall control.

C. The Customer understands and acknowledges that delivery of the Allocation will be made over transmission facilities under the control of the NYISO. The Authority will act as the LSE with respect to the NYISO, or arrange for another entity to do so on the Authority's behalf. The Customer agrees and understands that it shall be responsible to the Authority for all costs incurred by the Authority with respect to the Allocation for the services established in the NYISO Tariff or other applicable tariff ("NYISO Charges"), as set forth in the Service Tariff or any successor service tariff, regardless of whether such NYISO Charges are transmission-related. Such NYISO Charges shall be in addition to the charges for power and energy.

VII. Billing and Billing Methodology

A. The billing methodology for the Allocation shall be determined on a "load factor sharing" basis consistent with the Supplemental Agreement.

B. The Authority will render bills by the 10th business day of the month for charges due for the previous month. Such bills shall include charges for Electric Service, NYISO Charges associated with the Allocation (subject to adjustment consistent with any later NYISO re-billings to the Authority), and other applicable charges.

C. All other provisions with respect to billing are set forth in the Service Tariff.

VIII. Hydropower Curtailments and Substitute Energy

A. If, as a result of reduced water flows caused by hydrologic conditions, there is insufficient energy from the Hydro Projects to supply the full power and energy requirements of the Authority's firm power customers served by the Authority from the Hydro Projects, curtailments (*i.e.* reductions) in the amount of Firm Power and Firm Energy associated with the Allocation to which the Customer is entitled shall be applied

on a *pro rata* basis to all firm power and energy customers served from the Hydro Projects, consistent with the Service Tariff as applicable.

B. The Authority shall provide reasonable notice to Customer of any curtailments referenced in Section VII.A of this Agreement that could impact Customer's Electric Service under this Agreement. Upon written request by the Customer, the Authority will provide Substitute Energy to the Customer to replace the Firm Power and Firm Energy that would otherwise have been supplied pursuant to this Agreement.

C. For each kilowatt-hour of Substitute Energy supplied by the Authority, the Customer will pay the Authority directly during the billing month: (1) the difference between the market cost of the Substitute Energy and the charge for firm energy as provided for in this Agreement; and (2) any NYISO charges and taxes the Authority incurs in connection with the provision of such Substitute Energy. Billing and payment for Substitute Energy shall be governed by the Billing and Payments provision of the Authority's Rules (Section 454.6) and shall apply directly to the Substitute Energy service supplied to the Customer.

D. The Parties may enter into a separate agreement to facilitate the provision of Substitute Energy, provided, however, that the provisions of this Agreement shall remain in effect notwithstanding any such separate agreement. The provision of Substitute Energy may be terminated by the Authority or the Customer on fifteen (15) days' prior written notice.

IX. Effectiveness, Term and Termination

A. This Agreement shall become effective and legally binding on the Parties: (1) upon execution of this Agreement by the Authority and the Customer; and (2) upon execution of a Sales Agreement Appendix by the Parties and NYSEG unless otherwise agreed to by the Parties and NYSEG pursuant to the Supplemental Agreement.

B. Once initiated, Electric Service under the Agreement shall continue until the earliest of: (1) termination by the Customer with respect to its Allocation upon ninety (90) days prior written notice to the Authority; (2) termination by the Authority pursuant to this Agreement, the Service Tariff, or the Rules; (3) termination of the Supplemental Agreement or the Sales Agreement Appendix as provided for in the Supplemental Agreement and the Sales Agreement Appendix; or (4) June 30, 2013.

C. The Customer may exercise a partial termination of the Allocation upon at least thirty (30) days notice prior written notice to the Authority. The termination shall be effective commencing with the first billing period as defined in the Service Tariff.

D. The Authority may cancel service under this Agreement or modify the quantities of Firm Power and Firm Energy associated with the Allocation: (1) if such cancellation or modification is required to comply with any final ruling, order or decision of any regulatory or judicial body of competent jurisdiction (including any licensing or re-licensing order or orders of the FERC or its successor agency); or (2) as otherwise provided in this Agreement, the Service Tariff or the Rules.

X. Transition of Allocation to WNY Contract Extension

Beginning July 1, 2013, the provision of the Allocation will be governed by the WNY Contract Extension (and the Authority's Service Tariff No. WNY-1 and the Rules as provided in the WNY Contract Extension). To facilitate the transition of the Allocation to the WNY Contract Extension, the Authority will (i) modify Schedule A to the WNY Contract Extension to add the Allocation, (ii) modify Schedule B to the WNY Contract Extension to add the Customer's Employment Commitments under this Agreement, and (iii) provide a revised/supplemental Schedule A and Schedule B to the Customer. Such transition shall not otherwise effect the Allocation, including the term of the Allocation, or otherwise modify the terms of the WNY Contract Extension. Notwithstanding Article XV of the WNY Contract Extension, further consent of the parties shall not be required to effectuate the transition described in this Section, provided, however, that nothing in this Section shall preclude the Parties from agreeing to additional modifications of the WNY Contract Extension to facilitate such transition.

XI. Notification

A. Correspondence involving the administration of this Agreement shall be addressed as follows:

To: The Authority

New York Power Authority
123 Main Street
White Plains, New York 10601
Email:
Attention: Mr. Michael J. Huvane, Vice President, Marketing

To: The Customer

Moog Inc.
Jamison Road and Seneca Street
East Aurora, New York 14052
Email:
Attention: Timothy P. Balkin, Treasurer

The foregoing notice/notification information pertaining to either Party may be changed by such Party upon notification to the other Party pursuant to Section IX.B of this Agreement.

B. Except where otherwise herein specifically provided, any notice, communication or request required or authorized by this Agreement by either Party to the other shall be deemed properly given: (1) if sent by U.S. First Class mail addressed to the Party at the address set forth above; (2) if sent by a nationally recognized overnight delivery service, two (2) calendar days after being deposited for delivery to the appropriate address set forth above; (3) if delivered by hand, with written confirmation of receipt; (4) if sent by facsimile to the appropriate fax number as set forth above, with written confirmation of

receipt; or (5) if sent by electronic mail to the appropriate address as set forth above, with written confirmation of receipt. Either Party may change the addressee and/or address for correspondence sent to it by giving written notice in accordance with the foregoing.

XII. Applicable Law

This Agreement shall be governed by and construed in accordance with the laws of the State of New York to the extent that such laws are not inconsistent with the FERC License and the Niagara Redevelopment Act (16 U.S.C. §§836, 836a).

XIII. Venue

Each Party consents to the exclusive jurisdiction and venue of any state or federal court within or for Albany County, New York, with subject matter jurisdiction for adjudication of any claim, suit, action or any other proceeding in law or equity arising under, or in any way relating to this Agreement.

XIV. Assignments and Transfers

The Customer may not assign or otherwise transfer an interest in this Agreement without written approval of the Authority.

XV. Previous Agreements and Communications

A. This Agreement shall constitute the sole and complete agreement of the Parties hereto with respect to the sale, transmission and delivery of the Allocation and supersedes all previous communications and agreements between the Parties hereto, either oral or written, with reference to said Allocation, including the Interim Agreement.

B. Except as otherwise provided in this Agreement, no modification of this Agreement shall be binding upon the Parties hereto or either of them unless such modification is in writing and is signed by a duly authorized officer of each of them.

XVI. Severability and Voidability

A. If any term or provision of this Agreement shall be invalidated, declared unlawful or ineffective in whole or in part by an order of the FERC or a court of competent jurisdiction, such order shall not be deemed to invalidate the remaining terms or provisions hereof.

B. Notwithstanding the preceding paragraph, if any provision of this Agreement is rendered void or unenforceable or otherwise modified by a court or agency of competent jurisdiction, the entire Agreement shall, at the option of either Party and only in such circumstances in which such Party's interests are materially and adversely impacted by any such action, be rendered void and unenforceable by such affected Party.

XVII. Waiver

A. Any waiver at any time by either the Authority or the Customer of their rights with respect to a default or of any other matter arising out of this Agreement shall not be deemed to be a waiver with respect to any other default or matter.

B. No waiver by either Party of any rights with respect to any matter arising in connection with this Agreement shall be effective unless made in writing and signed by the Party making the waiver.

XVIII. Execution

To facilitate execution, this Agreement may be executed in as many counterparts as may be required, and it shall not be necessary that the signatures of, or on behalf of, each Party, or that the signatures of all persons required to bind any Party, appear on each counterpart; but it shall be sufficient that the signature of, or on behalf of, each Party, or that the signatures of the persons required to bind any Party, appear on one or more of the counterparts. All counterparts shall collectively constitute a single agreement. It shall not be necessary in making proof of this Agreement to produce or account for more than a number of counterparts containing the respective signatures of, or on behalf of, all of the Parties hereto. The delivery of an executed counterpart of this Agreement by email as a PDF file shall be legal and binding and shall have the same full force and effect as if an original executed counterpart of this Agreement had been delivered.

[SIGNATURES FOLLOW ON NEXT PAGE]

AGREED:

MOOG INC.

By: _____

Title: _____

Date: _____

AGREED:

POWER AUTHORITY OF THE STATE OF NEW YORK

By: _____

Title: _____

Date: _____

SCHEDULE A TO AGREEMENT FOR THE SALE OF EXPANSION POWER AND ENERGY TO MOOG INC.

EXPANSION POWER ALLOCATIONS

Customer: MOOG INC.

Facility: The Facility (located at Jamison Road and Seneca Street, East Aurora, New York 14052)

	Type of Allocation	Allocation (kW)	Expiration Date	Extended Expiration Date
1.	EP	300		N/A
TOTALS:		300 kW		

SCHEDULE B TO AGREEMENT FOR THE SALE OF EXPANSION POWER AND ENERGY TO MOOG INC.

EXPANSION POWER COMMITMENTS

I. Employment Commitments

A. Employment Levels

The provision of Expansion Power to the Customer hereunder is in consideration of, among other things, the Customer's creation and/or maintenance of the employment level set forth in Appendix A of this Schedule (the "Base Employment Level"). Such Base Employment Level shall be the total number of full-time positions held by: (1) individuals who are employed by the Customer at Customer's facilities identified in Appendix A to this Schedule, and (2) individuals who are contractors or who are employed by contractors of the Customer and assigned to the facilities identified in such Appendix A (collectively, "Base Level Employees"). The number of Base Level Employees shall not include individuals employed on a part-time basis (less than 35 hours per week); provided, however, that two individuals each working 20 hours per week or more at such facilities shall be counted as one Base Level Employee.

The Base Employment Level shall not be created or maintained by transfers of employees from previously held positions with the Customer or its affiliates within the State of New York, except that the Base Employment Level may be filled by employees of the Customer laid off from other Customer facilities for *bona fide* economic or management reasons.

The Authority may consider a request to change the Base Employment Level based on a claim of increased productivity, increased efficiency or adoption of new technologies or for other appropriate reasons as determined by the Authority. Any such change shall be within Authority's sole discretion.

B. Employment Records and Reports

A record shall be kept monthly by the Customer, and provided on a calendar year basis to the Authority, of the total number of Base Level Employees who are employed at or assigned to the Customer's facilities identified in Appendix A to this Schedule, as reported to the

United States Department of Labor (or as reported in such other record as agreed upon by the Authority and the Customer). Such report shall separately identify the individuals who are employed by the Customer, and the individuals who are contractors or who are employed by contractors of the Customer, and shall be certified to be correct by an officer of the Customer, plant manager or such other person authorized by the Customer to prepare and file such report and shall be provided to the Authority on or before the last day of February following the end of the most recent calendar year. The Authority shall have the right to examine and audit on reasonable advance written notice all non-confidential written and electronic records and data concerning employment levels including, but not limited to, personnel records and summaries held by the Customer and its affiliates relating to employment in New York State.

II. Reductions of Contract Demand

A. Employment Levels

If the year-end monthly average number of employees is less than 90% of the Base Employment Level set forth in this Schedule B, for the subject calendar year, the Authority may reduce the Contract Demand subject to Article II.D of this Schedule. The maximum amount of reduction will be determined by multiplying the Contract Demand by the quantity one minus the quotient of the average monthly employment during the subject calendar year divided by the Base Employment Level. Any such reduction shall be rounded to the nearest fifty (50) kW. In the event of a reduction of the Contract Demand to zero, the Agreement shall automatically terminate.

B. Power Utilization Levels

A record shall be kept monthly by the Customer, and provided on a calendar year basis to the Authority on or before the last day of February following the end of the most recent calendar year, of the maximum demand utilized each month in the facilities receiving the power covered by the Agreement. If the average of the Customer's six (6) highest Billing Demands (as such term is described in Service Tariff No. EP-1) for Expansion Power is less than 90% of the Customer's Contract Demand in such calendar year the Authority may reduce the Contract Demand subject to Article II.D of this Schedule. The maximum amount by which the Authority may reduce the Contract Demand shall be determined by multiplying the Contract Demand by the quantity one minus the quotient of the average of the six (6) highest Billing Demands for in such calendar year divided by the Contract Demand. Any such reduction shall be rounded to the nearest fifty (50) kW. In the event of a

reduction of the Contract Demand to zero, this Agreement shall automatically terminate.

C. Capital Investment Levels

The Customer has completed the Capital Investment set forth in the Appendix to this Schedule B. No other Capital Investment commitments are applicable to the Allocation.

D. Notice of Intent to Reduce Contract Demand

In the event that the Authority determines that the Contract Demand will be wholly or partially reduced pursuant to this Schedule , the Authority shall provide the Customer with at least thirty (30) days prior written notice of such reduction, specifying the amount of the reduction of Contract Demand and the reason for the reduction, provided, however, that before making the reduction, the Authority may consider the Customer's scheduled or unscheduled maintenance or facilities upgrading periods when such events temporarily reduce plant employment levels or electrical demand as well as business cycle.

III. Energy Efficiency Audits; Information Requests

The Customer shall undergo an energy efficiency audit of its facilities and equipment at which the Allocation is consumed at the Customer's expense at least once during the term of this Agreement. The Customer will provide the Authority with a copy of the audit or, at the Authority's option, a report describing the results of the audit, and provide documentation requested by the Authority to verify the implementation of any efficiency measures implemented at the facilities.

The Customer agrees to cooperate to make its facilities available at reasonable times and intervals for energy audits and related assessments that the Authority desires to perform, if any, at the Authority's own expense.

The Customer shall provide information requested by the Authority or its designee in surveys, questionnaires and other information requests relating to energy efficiency and energy-related projects, programs and services.

The Customer may, after consultation with the Authority, exclude from written copies of audits, reports and other information provided to the Authority under this Article trade secrets and other information which if disclosed would harm the competitive position of the Customer.

APPENDIX TO SCHEDULE B

Base Employment Level

In consideration of receiving the Allocation, the Customer agrees to attain a Base Employment Level of 2,567 persons at the Customer's Facility within 3 years of commencement of Electric Service under the Agreement and to maintain such Base Employment Level thereafter for the term of the allocation in accordance with Article I of Schedule B. The Base Employment Level is derived from (1) a stipulation by the Customer that there exists 2,497 jobs at the Facility at the time of the award of the Allocation by the Authority, and (2) a commitment by the Customer to create 70 new jobs at the Facility.

Capital Investment Level

In consideration of receiving the Allocation, the Customer has made a capital investment of approximately $13.0 million in the Facility, adding a new 68,000 square foot corporate headquarters/ shared services building. The new building is designed to enable co-location of various administrative functions across the campus into one facility, freeing up space needed by manufacturing / operating business units.

November 15, 2011
Exhibit “2c-B”

POWER AUTHORITY

OF THE

STATE OF NEW YORK

30 South Pearl Street
10th Floor
Albany, New York 12207-3425

AGREEMENT FOR THE SALE

OF EXPANSION POWER AND ENERGY

(TRY-IT DISTRIBUTING CO., INC.)

The POWER AUTHORITY OF THE STATE OF NEW YORK ("Authority"), created pursuant to Chapter 772 of the New York Laws of 1931 and existing under Title I of Article V of the New York Public Authorities Law ("PAL"), having its office and principal place of business at 30 South Pearl Street, 10th Floor, Albany, New York 12207-3425, hereby enters into this Agreement for the Sale of Expansion Power and energy ("Agreement") with TRY-IT DISTRIBUTING Co., INC. ("Customer"), with facilities at 4155 Walden Avenue, Lancaster, New York 14086. The Authority and the Customer are from time referred to in this Agreement as "Party" or collectively as "Parties" and agree follows:

RECITALS

WHEREAS, the Authority is authorized to sell hydroelectric power produced by the Niagara Power Project, Federal Energy Regulatory Commission ("FERC") Project No. 2216, known as "Expansion Power" (or "EP"), as further defined in this Agreement, to qualified businesses in New York State in accordance with PAL § 1005(5) and (13);

WHEREAS, EP consists of 250 megawatts ("MW") of firm hydroelectric power and associated firm energy produced by the Niagara Power Project;

WHEREAS, the Authority is authorized pursuant to PAL § 1005(13)(a) to award EP based on, among other things, the criteria listed in the PAL, including but not limited to an applicant's long-term commitment to the region as evidenced by the current and planned capital investment; the type and number of jobs supported or created by the allocation; and the state, regional and local economic development strategies and priorities supported by local units of governments in the area in which the recipient's facilities are located;

WHEREAS, PAL § 1005(11) provides that the Authority is authorized to "[t]o exercise all the powers necessary or convenient to carry out and effectuate the purposes and provisions of … title [1 of article 5 of the PAL] … and as incidental thereto to . . . sell … electric power, and generally to do any and every thing necessary or convenient to carry out the purposes of … title [1 of article 5 of the PAL] …";

WHEREAS, the Customer applied to the Authority for an allocation of EP for use by the Customer at its facilities (defined in Section I of this Agreement as the "Facility);

WHEREAS, on July 26, 2011, the Authority's Board of Trustees ("Trustees") approved a 200 kilowatt ("kW") allocation of EP to the Customer for a five (5) year term (defined in Section I of this Agreement as the "Allocation") as further described in this Agreement;

WHEREAS, on July 26, 2011, the Trustees further authorized the Authority to, among other things, take any and all actions and execute and deliver any and all agreements and other documents necessary to effectuate its approval of the Allocation;

WHEREAS, the Customer has completed an expansion of its Facility and has requested that the Allocation be made available beginning ____;

WHEREAS, NYPA staff has confirmed that the expansion of the Facility is complete;

WHEREAS, the provision of Electric Service (defined in Section I of this Agreement) associated with the Allocation is an unbundled service separate from the Authority's sale of power and energy to the Customer, which will be performed by New York State Electric & Gas Corporation ("NYSEG");

WHEREAS, such transmission and delivery service will be made in accordance with a separate agreement between the Customer, the Authority and NYSEG (defined in Section I of this Agreement as the "Supplemental Agreement") and NYSEG tariffs as applicable;

WHEREAS, on ___, 2011, the Parties executed an Interim Agreement for the Sale of Expansion Power and Energy (defined in Section I of this Agreement as the "Interim Agreement"), to enable the Customer to receive the Allocation pending the execution of a long-term agreement, or until ___, whichever first occurs;

WHEREAS, in accordance with the Supplemental Agreement, the Authority, the Customer and NYSEG, on ___, executed the "Interim Sale Agreement Appendix," which is attached to the Interim Agreement as Exhibit A;

WHEREAS, the Parties have reached an agreement on a long-term contract governing the sale of the Allocation to the Customer as set forth in this Agreement;

WHEREAS, the Parties intend that this Agreement will govern the terms and conditions of the sale of the Allocation to the Customer;

WHEREAS, the Authority has complied with requirements of PAL § 1009 which specifies the approval process for certain contracts negotiated by the Authority; and

WHEREAS, the Governor of the State of New York has approved the terms of this Agreement pursuant to PAL § 1009(3).

NOW THEREFORE, in consideration of the mutual covenants herein, the Authority and the Customer agree as follows:

NOW THEREFORE, the Parties hereto agree as follows:

I. Definitions

A. **Agreement** means this Agreement.

B. **Allocation** refers to the allocation of 200 kW of EP awarded to the Customer for a five (5) year term as specified in Schedule A.

C. **Contract Demand** is as defined in the Service Tariffs.

D. **Electric Service** is the Firm Power and Firm Energy associated with the Allocation and sold by the Authority to the Customer in accordance with this Agreement, the Service Tariffs and the Rules.

E. **Expansion Power** (or **EP**) is 250 MW of Firm Power and associated Firm Energy from the Project eligible to be allocated by the Authority for sale to businesses pursuant to PAL § 1005 (5) and (13).

F. **Facility** means the Customer's the Customer's place of business located at 4155 Walden Avenue, Lancaster, New York 14086.

G. **Firm Power** is as defined in the Service Tariffs.

H. **Firm Energy** is as defined in the Service Tariffs.

I. **FERC** means the Federal Energy Regulatory Commission (or any successor organization).

J. **FERC License** means the first new license issued by FERC to the Authority for the continued operation and maintenance of the Project, pursuant to Section 15 of the Federal Power Act, which became effective September 1, 2007 after expiration of the Project's original license which became effective in 1957.

K. **Hydro Projects** is a collective reference to the Project (defined below) and the Authority's St. Lawrence-FDR Project, FERC Project No. 2000.

L. **Interim Agreement** means the Interim Agreement for the Sale of Expansion Power and Energy, executed by the Parties on ___.

M. **Load Serving Entity (or LSE)** means an entity designated by a retail electricity customer (including the Customer) to provide capacity, energy and ancillary services to serve such customer, in compliance with NYISO Tariffs, rules, manuals and procedures.

N. **NYISO** means the New York Independent System Operator or any successor organization.

O. **NYISO Tariffs** means the NYISO's Open Access Transmission Tariff or the NYISO's Market Administration and Control Area Services Tariff, as applicable, as such tariffs are modified from time to time, or any successor to such tariffs.

P. **NYSEG** has the meaning set forth in the eighth recital.

Q. **Project** means the Niagara Power Project, FERC Project No. 2216.

R. **Replacement Power** (or **RP**) is 445 MW of Firm Power and associated Firm Energy from the Project eligible to be allocated by the Authority for sale to businesses pursuant to PAL § 1005(5) and (13).

S. **Rules** are the applicable provisions of Authority's rules and regulations (Chapter X of Title 21 of the Official Compilation of Codes, Rules and Regulations of the State of New York), as may be modified from time to time by the Authority.

T. **Sales Agreement Appendix** refers to the form Sales Agreement Appendix which is Attachment B to the Supplemental Agreement, a completed and executed copy of which is annexed to this Agreement as Exhibit A.

U. **Service Tariffs** is a collective reference to the Authority's Service Tariff No. EP-1 and Service Tariff No. WNY-1, as applicable.

V. **Service Tariff No. EP-1** means the Authority's Service Tariff No. EP-1, establishing rates, terms and other conditions for the sale of EP, as may be modified or superseded from time to time. Service Tariff No. EP-1 shall be applicable to Electric Service provided prior to July 1, 2013.

W. **Service Tariff No. WNY-1** means the Authority's Service Tariff No. WNY-1, as may be modified from time to time by the Authority. Service Tariff No. WNY-1 shall be applicable to Electric Service provided on and after July 1, 2013.

X. **Schedule A** refers to the Schedule A entitled "Expansion Power Allocations" which is attached to and made part of this Agreement.

Y. **Schedule B** refers to the Schedule B entitled "Expansion Power Commitments" which is attached to and made part of this Agreement.

Z. **Substitute Energy** means energy sold to the Customer at its request which the Authority procures from markets administered by the NYISO to replace hydroelectricity that would otherwise have been supplied to the Customer under this Agreement.

AA. **Supplemental Agreement** means an agreement entitled "Supplemental Agreement for the Delivery of Power Allocations between Power Authority of the State of New York and New York State Electric & Gas Corporation," made as of July 18, 2007.

BB. **Unforced Capacity** (or **UCAP**) means the electric capacity required to be provided by LSEs to serve electric load as defined by the NYISO Tariffs, rules, manuals and procedures

II. Electric Service

A. The Authority shall make available Electric Service to enable the Customer to receive the Allocation commencing ___ (or on such later date as this Agreement becomes effective) in accordance with this Agreement, the Service Tariffs and the Rules.

B. The Authority shall provide UCAP in amounts necessary to meet the Customer's NYISO UCAP requirements associated with the Allocation in accordance with the NYISO Tariffs.

C. The Contract Demand for the Customer's Allocation may be modified by the Authority if the amount of Firm Power and Firm Energy available for sale as EP or RP from the Project is modified as required to comply with any ruling, order, or decision of any regulatory or judicial body having jurisdiction, including but not limited to FERC. Any such modification will be made on a pro rata basis to all EP and RP customers, as applicable, based on the terms of such ruling, order, or decision.

D. The Contract Demand may not exceed the Allocation.

III. Rates, Terms and Conditions

A. From the effective date of this Agreement through and including June 30, 2013, Electric Service shall be sold to the Customer based on the rates, terms and conditions determined in accordance with this Agreement, Service Tariff No. EP-1 and the Rules.

B. From July 1, 2013 until the termination of this Agreement, Electric Service shall be sold to the Customer based on the rates, terms and conditions determined in accordance with this Agreement, Service Tariff No. WNY-1 and the Rules.

C. The Customer may not resell or permit any other person to use any quantity of the EP it has purchased from the Authority under this Agreement.

D. Electric Service sold to the Customer pursuant to this Agreement may only be used by the Customer at the Facility.

E. Notwithstanding any other provision of this Agreement to the contrary, the power and energy rates for Electric Service shall be subject to increase by the Authority at any time upon 30 days prior written notice to the Customer if, after consideration by the Authority of its legal obligations, the marketability of the output or use of the Project and the Authority's competitive position with respect to other suppliers, the Authority determines in its discretion that increases in rates obtainable from any other Authority customers will not provide revenues, together with other available Authority funds not needed for operation and maintenance expenses, capital expenses, and reserves, sufficient to meet all requirements specified in the Authority's bond and note resolutions and covenants with the holders of its financial obligations. The Authority shall use its best efforts to inform the Customer at the earliest practicable date of its intent to increase the power and energy charges pursuant to this provision. Any rate increase to the Customer under this subsection shall be on a non-discriminatory basis as compared to other Authority customers after giving consideration to the factors set forth in the first sentence of this subsection. With respect to any such increase, the Authority shall forward to the Customer with the notice of increase, an explanation of all reasons for the increase, and shall also identify the sources from which the Authority will obtain the total of increased revenues and the bases upon which the Authority will allocate the increased revenue requirements among its customers. Any such increase in rates shall remain in effect only so long as the Authority determines such increase is necessary to provide revenues for the purposes stated in the preceding sentences.

IV. Expansion Power Commitments

Schedule B sets forth the Customer's specific "Expansion Power Commitments." The commitments agreed to in Schedule B are in addition to any other rights and obligations of the Parties provided for in the Agreement.

V. Rules and Service Tariffs

The Service Tariffs, as may be modified or superseded from time to time by the Authority in its discretion, are hereby incorporated into this Agreement with the same force and effect as if set forth herein at length. In the event of any inconsistencies, conflicts or differences between the provisions of the Service Tariffs and the Rules, the provisions of the Service Tariffs shall govern. In the event of any inconsistencies, conflicts or differences between the provisions of this Agreement and the Service Tariffs, the provisions of this Agreement shall govern.

VI. Transmission and Delivery of Firm Power and Firm Energy; Responsibility for Charges

A. The Customer will pay NYSEG for transmission and delivery service associated with the Allocation in accordance with the Supplemental Agreement, and all applicable tariffs, rulemakings, and orders, in order to deliver to the Customer the Allocation of Firm Power and Firm Energy supplied by the Authority under this Agreement. To the extent the Authority incurs transmission and delivery service charges or other costs associated with the Allocation during the term of this Agreement, the Customer agrees to compensate the Authority for all such charges and costs incurred.

B. Each Party hereby represents that nothing in this Agreement conflicts with the Supplemental Agreement, and the event of any such conflict, the terms of the Supplemental Agreement shall control.

C. The Customer understands and acknowledges that delivery of the Allocation will be made over transmission facilities under the control of the NYISO. The Authority will act as the LSE with respect to the NYISO, or arrange for another entity to do so on the Authority's behalf. The Customer agrees and understands that it shall be responsible to the Authority for all costs incurred by the Authority with respect to the Allocation for the services established in the NYISO Tariff or other applicable tariff ("NYISO Charges"), as set forth in the Service Tariffs or any successor service tariff, regardless of whether such NYISO Charges are transmission-related. Such NYISO Charges shall be in addition to the charges for power and energy.

VII. Billing and Billing Methodology

A. The billing methodology for the Allocation shall be determined on a "load factor sharing" basis consistent with the Supplemental Agreement.

B. The Authority will render bills by the 10th business day of the month for charges due for the previous month. Such bills shall include charges for Electric Service, NYISO

Charges associated with the Allocation (subject to adjustment consistent with any later NYISO re-billings to the Authority), and other applicable charges.

C. All other provisions with respect to billing are set forth in the Service Tariffs.

VIII. Hydropower Curtailments and Substitute Energy

A. If, as a result of reduced water flows caused by hydrologic conditions, there is insufficient energy from the Hydro Projects to supply the full power and energy requirements of the Authority's firm power customers served by the Authority from the Hydro Projects, curtailments (*i.e.* reductions) in the amount of Firm Power and Firm Energy associated with the Allocation to which the Customer is entitled shall be applied on a *pro rata* basis to all firm power and energy customers served from the Hydro Projects, consistent with the Service Tariffs as applicable.

B. The Authority shall provide reasonable notice to Customer of any curtailments referenced in Section VII.A of this Agreement that could impact Customer's Electric Service under this Agreement. Upon written request by the Customer, the Authority will provide Substitute Energy to the Customer to replace the Firm Power and Firm Energy that would otherwise have been supplied pursuant to this Agreement.

C. For each kilowatt-hour of Substitute Energy supplied by the Authority, the Customer will pay the Authority directly during the billing month: (1) the difference between the market cost of the Substitute Energy and the charge for firm energy as provided for in this Agreement; and (2) any NYISO charges and taxes the Authority incurs in connection with the provision of such Substitute Energy. Billing and payment for Substitute Energy shall be governed by the Billing and Payments provision of the Authority's Rules (Section 454.6) and shall apply directly to the Substitute Energy service supplied to the Customer.

D. The Parties may enter into a separate agreement to facilitate the provision of Substitute Energy, provided, however, that the provisions of this Agreement shall remain in effect notwithstanding any such separate agreement. The provision of Substitute Energy may be terminated by the Authority or the Customer on fifteen (15) days' prior written notice.

IX. Effectiveness, Term and Termination

A. This Agreement shall become effective and legally binding on the Parties: (1) upon execution of this Agreement by the Authority and the Customer; and (2) upon execution of a Sales Agreement Appendix by the Parties and NYSEG unless otherwise agreed to by the Parties and NYSEG pursuant to the Supplemental Agreement.

B. Once initiated, Electric Service under the Agreement shall continue until the earliest of: (1) termination by the Customer with respect to its Allocation upon ninety (90) days prior written notice to the Authority; (2) termination by the Authority pursuant to this Agreement, the Service Tariffs, or the Rules; (3) termination of the Supplemental Agreement or the Sales Agreement Appendix as provided for in the Supplemental Agreement and the Sales Agreement Appendix; or (4) ___.

C. The Customer may exercise a partial termination of the Allocation upon at least thirty (30) days notice prior written notice to the Authority. The termination shall be effective commencing with the first billing period as defined in the Service Tariffs.

D. The Authority may cancel service under this Agreement or modify the quantities of Firm Power and Firm Energy associated with the Allocation: (1) if such cancellation or modification is required to comply with any final ruling, order or decision of any regulatory or judicial body of competent jurisdiction (including any licensing or re-licensing order or orders of the FERC or its successor agency); or (2) as otherwise provided in this Agreement, the Service Tariffs, or the Rules.

X. Notification

A. Correspondence involving the administration of this Agreement shall be addressed as follows:

To: The Authority

New York Power Authority
123 Main Street
White Plains, New York 10601
Email:
Attention: Mr. Michael J. Huvane, Vice President, Marketing

To: The Customer

Try-It Distributing Co., Inc.
4155 Walden Avenue
Lancaster, New York 14086
Email:
Attention:

The foregoing notice/notification information pertaining to either Party may be changed by such Party upon notification to the other Party pursuant to Section IX.B of this Agreement.

B. Except where otherwise herein specifically provided, any notice, communication or request required or authorized by this Agreement by either Party to the other shall be deemed properly given: (1) if sent by U.S. First Class mail addressed to the Party at the address set forth above; (2) if sent by a nationally recognized overnight delivery service, two (2) calendar days after being deposited for delivery to the appropriate address set forth above; (3) if delivered by hand, with written confirmation of receipt; (4) if sent by facsimile to the appropriate fax number as set forth above, with written confirmation of receipt; or (5) if sent by electronic mail to the appropriate address as set forth above, with written confirmation of receipt. Either Party may change the addressee and/or address for correspondence sent to it by giving written notice in accordance with the foregoing.

XI. Applicable Law

This Agreement shall be governed by and construed in accordance with the laws of the State of New York to the extent that such laws are not inconsistent with the FERC License and the Niagara Redevelopment Act (16 U.S.C. §§836, 836a).

XII. Venue

Each Party consents to the exclusive jurisdiction and venue of any state or federal court within or for Albany County, New York, with subject matter jurisdiction for adjudication of any claim, suit, action or any other proceeding in law or equity arising under, or in any way relating to this Agreement.

XIII. Assignments and Transfers

The Customer may not assign or otherwise transfer an interest in this Agreement without written approval of the Authority.

XIV. Previous Agreements and Communications

A. This Agreement shall constitute the sole and complete agreement of the Parties hereto with respect to the sale, transmission and delivery of the Allocation and supersedes all previous communications and agreements between the Parties hereto, either oral or written, with reference to said Allocation, including the Interim Agreement.

B. Except as otherwise provided in this Agreement, no modification of this Agreement shall be binding upon the Parties hereto or either of them unless such modification is in writing and is signed by a duly authorized officer of each of them.

XV. Severability and Voidability

A. If any term or provision of this Agreement shall be invalidated, declared unlawful or ineffective in whole or in part by an order of the FERC or a court of competent jurisdiction, such order shall not be deemed to invalidate the remaining terms or provisions hereof.

B. Notwithstanding the preceding paragraph, if any provision of this Agreement is rendered void or unenforceable or otherwise modified by a court or agency of competent jurisdiction, the entire Agreement shall, at the option of either Party and only in such circumstances in which such Party's interests are materially and adversely impacted by any such action, be rendered void and unenforceable by such affected Party.

XVI. Waiver

A. Any waiver at any time by either the Authority or the Customer of their rights with respect to a default or of any other matter arising out of this Agreement shall not be deemed to be a waiver with respect to any other default or matter.

B. No waiver by either Party of any rights with respect to any matter arising in connection with this Agreement shall be effective unless made in writing and signed by the Party making the waiver.

XVII. Execution

To facilitate execution, this Agreement may be executed in as many counterparts as may be required, and it shall not be necessary that the signatures of, or on behalf of, each Party, or that the signatures of all persons required to bind any Party, appear on each counterpart; but it shall be sufficient that the signature of, or on behalf of, each Party, or that the signatures of the persons required to bind any Party, appear on one or more of the counterparts. All counterparts shall collectively constitute a single agreement. It shall not be necessary in making proof of this Agreement to produce or account for more than a number of counterparts containing the respective signatures of, or on behalf of, all of the Parties hereto. The delivery of an executed counterpart of this Agreement by email as a PDF file shall be legal and binding and shall have the same full force and effect as if an original executed counterpart of this Agreement had been delivered.

[SIGNATURES FOLLOW ON NEXT PAGE]

AGREED:

TRY-IT DISTRIBUTING CO., INC.

By: _____

Title: _____

Date: _____

AGREED:

POWER AUTHORITY OF THE STATE OF NEW YORK

By: _____

Title: _____

Date: _____

SCHEDULE A TO AGREEMENT FOR THE SALE OF EXPANSION POWER AND ENERGY TO TRY-IT DISTRIBUTING CO., INC.

EXPANSION POWER ALLOCATIONS

Customer: TRY-IT DISTRIBUTING CO., INC.

Facility: The Facility (located at 4155 Walden Avenue, Lancaster, New York 14086)

	Type of Allocation	Allocation (kW)	Expiration Date	Extended Expiration Date
1.	EP	200		N/A
TOTALS:		200 kW		

SCHEDULE B TO AGREEMENT FOR THE SALE OF EXPANSION POWER AND ENERGY TO TRY-IT DISTRIBUTING CO., INC.

EXPANSION POWER COMMITMENTS

I. Employment Commitments

A. Employment Levels

The provision of Expansion Power to the Customer hereunder is in consideration of, among other things, the Customer's creation and/or maintenance of the employment level set forth in Appendix A of this Schedule (the "Base Employment Level"). Such Base Employment Level shall be the total number of full-time positions held by: (1) individuals who are employed by the Customer at Customer's facilities identified in Appendix A to this Schedule, and (2) individuals who are contractors or who are employed by contractors of the Customer and assigned to the facilities identified in such Appendix A (collectively, "Base Level Employees"). The number of Base Level Employees shall not include individuals employed on a part-time basis (less than 35 hours per week); provided, however, that two individuals each working 20 hours per week or more at such facilities shall be counted as one Base Level Employee.

The Base Employment Level shall not be created or maintained by transfers of employees from previously held positions with the Customer or its affiliates within the State of New York, except that the Base Employment Level may be filled by employees of the Customer laid off from other Customer facilities for *bona fide* economic or management reasons.

The Authority may consider a request to change the Base Employment Level based on a claim of increased productivity, increased efficiency or adoption of new technologies or for other appropriate reasons as determined by the Authority. Any such change shall be within Authority's sole discretion.

B. Employment Records and Reports

A record shall be kept monthly by the Customer, and provided on a calendar year basis to the Authority, of the total number of Base Level Employees who are employed at or assigned to the Customer's facilities identified in Appendix A to this Schedule, as reported to the United States Department of Labor (or as reported in such other record

as agreed upon by the Authority and the Customer). Such report shall separately identify the individuals who are employed by the Customer, and the individuals who are contractors or who are employed by contractors of the Customer, and shall be certified to be correct by an officer of the Customer, plant manager or such other person authorized by the Customer to prepare and file such report and shall be provided to the Authority on or before the last day of February following the end of the most recent calendar year. The Authority shall have the right to examine and audit on reasonable advance written notice all non-confidential written and electronic records and data concerning employment levels including, but not limited to, personnel records and summaries held by the Customer and its affiliates relating to employment in New York State.

II. Reductions of Contract Demand

A. Employment Levels

If the year-end monthly average number of employees is less than 90% of the Base Employment Level set forth in this Schedule B, for the subject calendar year, the Authority may reduce the Contract Demand subject to Article II.D of this Schedule. The maximum amount of reduction will be determined by multiplying the Contract Demand by the quantity one minus the quotient of the average monthly employment during the subject calendar year divided by the Base Employment Level. Any such reduction shall be rounded to the nearest fifty (50) kW. In the event of a reduction of the Contract Demand to zero, the Agreement shall automatically terminate.

B. Power Utilization Levels

A record shall be kept monthly by the Customer, and provided on a calendar year basis to the Authority on or before the last day of February following the end of the most recent calendar year, of the maximum demand utilized each month in the facilities receiving the power covered by the Agreement. If the average of the Customer's six (6) highest Billing Demands (as such term is described in the Service Tariffs) for Expansion Power is less than 90% of the Customer's Contract Demand in such calendar year the Authority may reduce the Contract Demand subject to Article II.D of this Schedule. The maximum amount by which the Authority may reduce the Contract Demand shall be determined by multiplying the Contract Demand by the quantity one minus the quotient of the average of the six (6) highest Billing Demands for in such calendar year divided by the Contract Demand. Any such reduction shall be rounded to the nearest fifty (50) kW. In the event of a

reduction of the Contract Demand to zero, this Agreement shall automatically terminate.

C. Capital Investment Levels

The Customer has completed the Capital Investment set forth in the Appendix to this Schedule B. No other Capital Investment commitments are applicable to the Allocation.

D. Notice of Intent to Reduce Contract Demand

In the event that the Authority determines that the Contract Demand will be wholly or partially reduced pursuant to this Schedule , the Authority shall provide the Customer with at least thirty (30) days prior written notice of such reduction, specifying the amount of the reduction of Contract Demand and the reason for the reduction, provided, however, that before making the reduction, the Authority may consider the Customer's scheduled or unscheduled maintenance or facilities upgrading periods when such events temporarily reduce plant employment levels or electrical demand as well as business cycle.

III. Energy Efficiency Audits; Information Requests

The Customer shall undergo an energy efficiency audit of its facilities and equipment at which the Allocation is consumed at the Customer's expense at least once during the term of this Agreement. The Customer will provide the Authority with a copy of the audit or, at the Authority's option, a report describing the results of the audit, and provide documentation requested by the Authority to verify the implementation of any efficiency measures implemented at the facilities.

The Customer agrees to cooperate to make its facilities available at reasonable times and intervals for energy audits and related assessments that the Authority desires to perform, if any, at the Authority's own expense.

The Customer shall provide information requested by the Authority or its designee in surveys, questionnaires and other information requests relating to energy efficiency and energy-related projects, programs and services.

The Customer may, after consultation with the Authority, exclude from written copies of audits, reports and other information provided to the Authority under this Article trade secrets and other information which if disclosed would harm the competitive position of the Customer.

APPENDIX TO SCHEDULE B

Base Employment Level

In consideration of receiving the Allocation, the Customer agrees to attain a Base Employment Level of 265 persons at the Customer's Facility within 3 years of commencement of Electric Service under the Agreement and to maintain such Base Employment Level thereafter for the term of the allocation in accordance with Article I of Schedule B. The Base Employment Level is derived from (1) a stipulation by the Customer that there exists 242 jobs at the Facility at the time of the award of the Allocation by the Authority, and (2) a commitment by the Customer to create 23 new jobs at the Facility.

Capital Investment Level

The Customer is a wholesaler of beer and non-alcoholic beverages. In consideration of receiving the Allocation, the Customer has made a capital investment of $14.0 million in the Facility, to expand its warehousing operations. The 106,000 square foot expansion will be adjoined to the Customer's existing building and will include climate control equipment, such as ceiling and exhaust fans, and refrigeration units.

1 POWER AUTHORITY OF THE STATE OF NEW YORK

2 _____

3 PUBLIC HEARING

4 Tuesday, October 4, 2011 - 3:00 P.M.

5

6 Niagara Power Project
Lewiston, New York

7

8 PROPOSED EXPANSION POWER CONTRACTS WITH MOOG INC. and TRY-IT DISTRIBUTING CO., INC.

9 _____

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11 Public Hearing held at the

12 Niagara Power Project, Community Room, Lewiston,

13 New York on October 4, 2011 at 3:00 P.M.

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1 PRESENT: FOR THE POWER AUTHORITY OF THE
STATE OF NEW YORK,
2
KAREN DELINCE,
3 Corporate Secretary,
123 Main Street,
4 White Plains, New York 10601.

5 JAMES PASQUALE,
Senior Vice President of Marketing &
6 Economic Development at the New
York Power Authority.
7
LORNA JOHNSON,
8 Assistant Corporate Secretary.

9
REPORTED BY: METSCHL & ASSOCIATES,
10 BY: DAWN M. SITERS,
1098 Ellicott Square Building,
11 295 Main Street,
Buffalo, New York 14203,
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1 KAREN DELINCE: Good
2 afternoon. My name is Karen Delince, and I'm the
3 Corporate Secretary of the New York Power Authority.
4 This public hearing is being
5 conducted by the Power Authority to provide an
6 overview and receive public comment on the proposed
7 Expansion Power Contracts with Moog, Inc. and Try-It
8 Distributing Company, Inc.
9 Pursuant to Section 1009 (1) of
10 the Public Authorities Law, notice of this hearing
11 was published in the following six newspapers once a
12 week for the four weeks leading up to the hearing:
13 Buffalo News, Niagara Gazette, Buffalo First, Albany
14 Times Union, Post Standard and The Journal News.
15 During the thirty-day period prior
16 to today's hearing, copies of the proposed contracts
17 have been available for inspection at the
18 Authority's office in White Plains, as well as on
19 the Authority's website.
20 Also pursuant to Section 1009 (1)
21 of the Public Authorities Law, notice of this
22 hearing, and copies of the proposed contracts were
23 sent to: Governor Andrew Cuomo; President Pro Tem

1 of the New York State Senate, Dean G. Skelos;
2 Speaker of the Assembly, Sheldon Silver; Chairman of
3 the Senate Finance Committee, John A. DeFrancisco;
4 Chairman of the Assembly Ways and Means Committee,
5 Herman Farrell; Senate Minority Leader, John L.
6 Sampson and Assembly Minority Leader, Brian M. Kolb.
7 If you plan to make an oral
8 statement at this hearing, and have not yet filled
9 out the form at the sign-in desk, please do so now.
10 We ask that you give copies of your original
11 statement to the reporter and Lorna Johnson. While
12 your written statement may be of any length, we ask
13 those presenting an oral statement to limit their
14 remarks to five minutes. If your oral statement
15 summarizes a written statement, both will appear in
16 the record of the hearing.
17 The record of this hearing will
18 remain open through the close of business on
19 Wednesday, October 7 for the submission of any
20 additional comments or statements. These should be
21 addressed to the Authority's Corporate Secretary at
22 123 Main Street, 15-M, White Plains, New York 10601;
23 or may be faxed to (914) 390-8040; or e-mailed to

1 secretarys.office@nypa.gov. Please see Lorna
2 Johnson at the sign-in table if you have additional
3 questions.
4 A complete transcript of the
5 hearing will be submitted to the Authority's
6 Trustees, along with all the written submissions,
7 for review. The transcript will also be made
8 available to the public for review at the
9 Authority's White Plains office, and on the
10 Authority's website, www.nypa.gov.
11 At this point, I will turn the
12 microphone over to James Pasquale, NYPA's Senior
13 Vice President of Marketing and Economic
14 Development, who will provide additional details on
15 the proposed contract extensions.
16 I will then call on speakers as
17 they arrive. Thank you.
18 JAMES PASQUALE: Thank you, Ms.
19 Delince. Good afternoon. My name is James F.
20 Pasquale, and I am the Senior Vice President for
21 Marketing and Economic Development at the New York
22 Power Authority.
23 I am here today to present an

1 overview of a proposed contract with two companies;
2 Moog, Inc. and Try-It Distributing Company, Inc. for
3 the sale of three hundred kilowatts and two hundred
4 kilowatts of Expansion Power, respectively, from the
5 Niagara Power Project.
6 Under Section 1005, Subsection 13
7 of the Power Authority Act, as amended by Chapter
8 313 of the Laws of 2005, the Authority may contract
9 to allocate two hundred fifty megawatts of firm
10 hydroelectric power, known as Expansion Power, or
11 EP, to businesses within thirty miles of the Niagara
12 Power Project. Each application for an allocation
13 of EP must be evaluated under the criteria that
14 includes, but need not be limited to, those set
15 forth in the Public Authorities Law Section 1005,
16 Subsection 13, paragraph A, which details general
17 eligibility requirements.
18 Among the factors to be considered
19 when evaluating a request for an allocation of
20 hydropower are the number of jobs created as a
21 result of the allocation; the business' long-term
22 commitment to the region as evidenced by the current
23 and/or planned capital investment in the business'

1 facilities in the region; the ratio of the number of
2 jobs to be created to the amount of power requested;
3 the types of jobs created, as measured by wage and
4 benefit levels, and the type and cost of buildings,
5 equipment and facilities to be constructed, enlarged
6 or installed.
7 At their meeting of July 26, 2011,
8 the Power Authority Trustees approved an allocation
9 of three hundred kilowatts of Expansion Power to
10 Moog for a term of five years. Approval of the
11 allocation was based on an evaluation of the
12 company's application for hydropower, in which it
13 proposed to invest thirteen million dollars to
14 construct a new sixty-eight thousand square foot
15 corporate shared services building at its East
16 Aurora campus location. Moog has comitted to create
17 seventy new jobs, in addition to its existing two
18 thousand four hundred and ninety-seven jobs. The
19 contract includes an enforceable employment
20 commitment of two thousand five hundred and
21 sixty-seven jobs, an annual job reporting
22 requirement, and job compliance threshold of ninety
23 percent. Should Moog's average annual employment

1 fall below the compliance threshold of ninety
2 percent of the employment commitment, the Authority
3 has the right to reduce the allocation on a pro rata
4 basis.
5 At their meeting of July 26, 2011,
6 the Trustees also approved an allocation of two
7 hundred kilowatts of Expansion Power to Try-It
8 Distributing for a term of five years. Approval of
9 the allocation was based on an evaluation of the
10 company's application for hydropower, in which it
11 proposed to invest fourteen million to expand its
12 Lancaster facility. The proposed project would add
13 roughly one hundred thousand square feet of
14 warehousing space, along with associated
15 climate-control and refrigeration equipment.
16 Try-It has committed to create
17 twenty-three new jobs, in addition to the existing
18 two hundred and forty-two jobs. The contract
19 includes an enforceable employment commitment of two
20 hundred and sixty-five jobs, an annual job reporting
21 requirement, and job compliance threshold of ninety
22 percent. Should Try-It's average annual employment
23 fall below the employment threshold of ninety

1 percent of the employment commitment, the Authority
2 has the right to reduce the allocation on a pro rata
3 basis.
4 The Authority will provide firm
5 electric service from the Niagara Plant, consisting
6 of firm power capacity and energy service. The
7 service is subject to pro rata curtailment when
8 there is insufficient generation at the Niagara and
9 St. Lawrence/FDR facilities to meet all its firm
10 load requirements. The power and energy will be
11 sold on a direct sale basis. Delivery will be
12 provided by the local utility; NYSEG, and billed
13 directly to the customers. The rates, terms and
14 conditions for the sale are contained in the
15 relevant Expansion Power Service Tariff EP-1.
16 Effective July 1, 2013, Service Tariff WNY-1 will
17 become effective for all EP allocations.
18 The contracts also require that an
19 energy-efficiency audit be performed not less than
20 once during the term of electric service.
21 The contract is subject to a
22 public hearing and approval by the Governor, as set
23 forth in Section 1009 of the Public Authorities Law.

As Ms. Delince stated earlier, the Authority will accept your comments on the proposed contracts until the close of business on October 7, 2011.

I will now turn the hearing back over to Ms. Delince.

KAREN DELINCE: Thank you, Mr. Pasquale. We will remain here until seven o'clock for speakers.

(Off the record until seven o'clock.)

KAREN DELINCE: There being no speakers present today, this hearing is now officially closed.

* * * *

Acting President & Chief Executive Officer Report
Gil Quiniones

November 15, 2011

Board of Trustees Meeting

New York Power Authority

Acting President & CEO Report Overview

- Corporate Performance Measures
- Key Issues
  - Governor's Energy Efficiency Initiative
  - ReChargeNY Implementation
  - Proposed Hydro Rate Increase

Corporate Performance Measures

NYPA OVERALL PERFORMANCE

OCTOBER 2011

CORPORATE MEASURE	OWNER	YTD TARGET	YTD ACTUAL	STATUS Aug	STATUS Sep	STATUS Oct
POWER SUPPLY OPTIMIZATION						
Generation Market Readiness (%)	ED WELZ	99.4	**99.8**			
Transmission System Reliability* (%) * Reflects *monthly* performance	STEVE DECARLO	86.54	**86.67**			
Installed MWs to Meet Demand (MWs)	JOHN SULOWAY		New	Annual Measure		
FINANCIAL STRENGTH						
O&M Budget Performance ($ Millions)	BOB HOPKINS	262	**253.5**			
ENTERPRISE RISK AND COMPLIANCE						
Enterprise Risk (% Milestones achieved)	SCOTT SCHOLTEN	100	**70**			
Compliance Reporting (%)	JOE GRYZLO	75	**50**			
Compliance Training (%)	JOE GRYZLO	75	**50**			
Environmental Incidents (Units)	JOHN KAHABKA	23	**31**			
ECONOMIC DEVELOPMENT						
Jobs Created/Retained (# Jobs)	JIM PASQUALE	**1778**	**2020**			
ENERGY EFFICIENCY						
Energy Efficiency (MWHs)	PAUL BELNICK	62,500	**63,900**			
RENEWABLES						
Renewable Energy (MWHs)	BILL NADEAU	144,800	**157,330**			
WORKFORCE RENEWAL						
Succession Preparedness (% Milestones)	BUSINESS UNITS	80	**60**			
SAFETY						
Recordable Incidence Rate** (Index) **Results based on 12 month rolling average	JOHN KAHABKA	1.00	**1.49**			
SUSTAINABILITY						
Sustainability Profile (Milestones met)	BRIAN ROSS	8	**11**			

LEGEND: Meeting Target / Needs Monitoring / Missing Target

Strategic Initiative Deliverables: YTD due: 69 YTD completed: 52

New York Power Authority

Key Issues

- Energy Efficiency Support for the Governor's Office
  - NYPA staff are fully engaged in supporting the Governor's office on their efforts to expand energy efficiency in public buildings, including two dedicated employees.

- ReChargeNY
  - As of November 10, 133 applications have been submitted and 675 are in progress.
  - Presentations in Kingston and Utica organized by Assemblyman Cahill's and Senator Griffo's offices.

- Proposed Hydro Rate Increase
  - The rate action is expected to reflect a downward adjustment in the rates proposed at the July meeting of the Trustees.

123 Main Street
White Plains, NY 10601-3170

914.681.6675
Edward.Welz@nypa.gov

Edward Welz
Acting Chief Operating Officer

TO: NYPA BOARD OF TRUSTEES

FROM: EDWARD WELZ, ACTING CHIEF OPERATING OFFICER

DATE: NOVEMBER 15, 2011

SUBJECT: MONTHLY REPORT FOR THE BOARD OF TRUSTEES

****

This report covers performance of the Operations group in October.

Power Supply

Plant Performance

Systemwide net generation[1] was 2,196,660 megawatt-hours[2] (MWh) in October, compared to projected net generation of 2,033,537 MWh. Year-to-date net generation is 22,811,323 MWh, compared to the target of 21,038,091 MWh.

The fleet availability factor[3] was 91.0 percent in October and is 96.5 percent for the year. Generation market readiness factor[4] was 100.0 percent in October, compared with the monthly target of 99.4 percent. Year-to-date generation market readiness factor is 99.8 percent.

There were two significant unplanned generation events[5] in October, both of which occurred on the 500-MW Combined Cycle Plant's Unit 7B. First, repair of the 7B exciter[6], which failed on September 27, ended on October 5. Also, an oil leak on Unit 7B turning gear occurred on October 7.

Generation revenue in October was $167.1 million, with $0.35 million revenue lost from unscheduled outages. Year-to-date lost opportunity cost is $2.31 million, about 0.14 percent of year-to-date generation revenue of $1,710.0 million.

River flows at the Niagara Power Project were greater than forecast in October, and are forecast to be above average through the beginning of 2012. At the St. Lawrence-FDR Power Project, flows were also greater than forecast in October, and are expected to be at historical average levels in 2012.

Transmission Performance

Transmission reliability[7] in October was 86.67 percent, which was above the target of 86.54 percent. Year-to-date transmission reliability is 97.14 percent, below the target of 97.47 percent.

There were no significant unplanned transmission events[8] in October.

Environmental

There were two reportable events for October. At the Poletti Power Project, while excavating to determine the cause of a ground subsidence, approximately 1-2 gallons of oil were released from a broken pipe feeding the oil water separator at the former 825 MW facility.

The second event took place at the Clark Energy Center where, when preparing equipment for auction, a contractor hooked up to a NYPA owned gooseneck trailer and, while in the process, pressurized a hydraulic hose on the trailer which failed, releasing 1-2 pints of oil to the stone surface.

Year-to-date number of recordable environmental incidents is 31; the 2011 target is 27.

Relicensing – Niagara Power Project

Two Requests for Proposals (RFP) were issued for excavation and plant cultivation/installation for the Motor Island Habitat Improvement Project (HIP), and the NYS Department of State issued a letter concurring that the project met Coastal Zone Management Policy consistency requirements. The ninety percent design for the Frog Island HIP was presented to the Ecological Standing Committee.

Construction work continued at Reservoir State Park on landscaping, interior work and utilities at the new comfort station and Winter Pavilion; roofing at new open pavilions; drilling of softball diamond no. 1 lighting foundations; and final surface treatments at new and refurbished ball courts. Landscaping work was completed at the Niagara intakes, with shelter and kiosk fabrication for the intakes area still ongoing.

Relicensing – St. Lawrence-FDR Power Project

An RFP for construction was issued for the Little Sucker Brook Habitat Improvement Project. The U.S. Army Corps of Engineers permit Public Notice for the Nichols Island HIP was issued with a closing date of November 4. We anticipate this will result in a permit for construction shortly. The construction of the pumphouse on the Wilson Hill Causeway has commenced. This is the last element to complete the water management system at the Wilson Hill Wildlife Management Area. Perras Excavating is expected to begin construction in November of two new fishing piers in Waddington that will be compliant with the Americans with Disabilities Act.

Technical Compliance – NERC Reliability Standards

In October, NYPA successfully completed the Northeast Power Coordinating Council[9] (NPCC) self-certifications associated with the Critical Infrastructure Protection[10] (CIP) Standards CIP-002-3 through CIP-009-3. All of NYPA's 2011 NPCC self-certifications of reliability standards compliance are now complete.

NPCC developed and conducted a Culture of Compliance Survey of its approximately 350 North American Electric Reliability Corporation[11] (NERC) registered entities and expects to have all results compiled by the end of 2011. In a letter NYPA received on October 18, NPCC concluded that NYPA clearly has demonstrated that it meets or exceeds all minimum characteristics of a favorable culture of compliance. Entities will be given credit with regard to penalties and sanctions if an effective compliance program is in place.

In October, the industry cast ballots and submitted comments for the revised Bulk Electric System (BES) Definition and the Technical Principles for Demonstrating BES Exceptions. The industry approved the new BES Definition, but rejected the Technical Principles for Demonstrating BES Exceptions. Final recirculation ballots for these are expected in November and adoption of both is expected in January 2012. With the adoption of the new BES Definition NYPA will have to provide NPCC with a Transition Plan for applying the NERC Reliability Standards to all transmission and generation elements, if any, according to the new definition. In NYPA's case, additional transmission elements will become part of the BES. NYPA's Transition Plan will need to be submitted to NPCC in December 2011.

Research & Technology Development

Three Kelman multiple gas analyzers were installed (for a total of six) on the Massena substation's 765kV transformers. These gas analyzers monitor the transformers and warn if failure is imminent, preventing spillage of the transformer oil. This information will be available to St. Lawrence and Asset Management staff.

A new project was initiated entitled "New Integrated Digital Fault Record (DFR) / Phasor Measurement Unit (PMU)" at Marcy. This equipment will provide additional networking capabilities which are beneficial in anticipation of potential future NERC requirements. This equipment will replace old DFRs at the Marcy substation and provide additional Phasor Measurement Unit capabilities.

The Chief Technology Officer made a presentation entitled "NYPA – Academia R&D Collaboration" to the IEEE Central Area Industry Day Conference. This conference provided a platform for the exchange of information across multiple disciplines regarding technical exchanges and collaboration between academia and industry.

Energy Resource Management

NYISO Markets

In October, Energy Resource Management (ERM) bid more than 2.1 million MWh of NYPA generation into the NYISO markets, netting $40.0 million in power supplier payments to the Authority. Year-to-date net power supplier payments are $470.3 million.

Fuel Planning & Operations

In October, NYPA's Fuels Group transacted $12.9 million in natural gas and oil purchases, compared with $12.8 million in October 2010. Year-to-date natural gas and oil purchases are $220.2 million, compared with $181.8 million at this point in 2010. The total year-to-date $38.4 million increase is mainly attributed to the start up of Astoria Energy II Plant (+$34.1 million), increased fuel cost at the 500-MW Combined Cycle Plant (+$4.0 million), and increased generation at the Small Clean Power Plants (+$6.8 million) and the Richard M. Flynn Power Plant (+$6.1 million), which was offset by cessation of operations at the Poletti Power Project (-$12.6 million, the last day of operations was January 31, 2010).

GLOSSARY

[1] **Net Generation** – The energy generated in a given time period by a power plant or group of plants, less the amount used at the plants themselves (station service) or for pumping in a pumped storage facility. Preliminary data in the COO report is provided by Accounting and subject to revision.

[2] **Megawatt-hour (MWh)** – The amount of electricity needed to light ten thousand l00-watt light bulbs for one hour. A megawatt is equal to 1,000 kilowatts and can power about 800 homes, based on national averages.

[3] **Availability Factor** – The Available Hours of a generating unit over the Period Hours (hours in a reporting period when the unit was in an active state). Available Hours are the sum of Service Hours (hours of generation), Reserve Shutdown Hours (hours a unit was not running but was available) and Pump Hours (hours a pumped storage unit was pumping water instead of generating power).

[4] **Generation Market Readiness Factor** – The availability of generating facilities for bidding into the New York Independent System Operator (NYISO) market. It factors in available hours and forced outage hours that drive the results.

[5] **Significant Unplanned Generation Events** – Forced or emergency outages of individual generator units of duration greater than 72 hours, or with a total repair cost of greater than $75,000, or resulting in greater than $50,000 of lost revenues.

[6] **Exciter** – The system used to regulate the machine speed and voltage output.

[7] **Transmission Reliability** – A measurement of the impact of forced and scheduled outages on the statewide system's ability to transmit power.

[8] **Significant Unplanned Transmission Events** –Forced or emergency outages of individual transmission lines that directly affect the reliability of the state's transmission network, or affect the availability of any component of the state's transmission network for greater than eight hours, or have a repair cost greater than $75,000.

[9] **Northeast Power Coordinating Council (NPCC)** – The Northeast Power Coordinating Council, Inc. (NPCC) is the cross-border regional entity and criteria services corporation for Northeastern North America. NPCC's mission is to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in Northeastern North America pursuant to an agreement with the Electric Reliability Organization (ERO) which designates NPCC as a regional entity and delegates authority from the U.S. Federal Energy Regulatory Commission (FERC), and by Memoranda of Understanding with applicable Canadian Provincial regulatory and/or governmental authorities. The ERO to which NPCC reports is the North American Electric Reliability Corporation (NERC).

[10] **Critical Infrastructure Protection (CIP)** – The Critical Infrastructure Protection (CIP) program coordinates all of the North American Electric Reliability Corporation's (NERC) efforts to improve physical and cyber security for the bulk power system of North America, as it relates to reliability. These efforts include standards development, compliance enforcement, assessments of risk and preparedness, disseminating critical information via alerts to industry, and raising awareness of key issues.

[11] **North American Electric Reliability Corporation (NERC) –** The organization that develops and enforces mandatory reliability standards for the bulk power system in the United States, issues long-term and seasonal reliability forecasts and monitors the power system. (NERC standards are also mandatory and enforceable in parts of Canada.)

New York Power Authority

Report of the Acting Chief Financial Officer

For the Ten Months Ended October 31, 2011

New York Power Authority

Report of the Acting Chief Financial Officer
For the Ten Months Ended October 31, 2011
Executive Summary

Results of Operations

Net income for the ten months ended October 31, 2011 was $210.8 million which was $61.8 million higher than budgeted. Positive variances attributable to higher net margins on sales ($50.0 million), lower O&M ($10.6 million) and higher non-operating income ($39.2 million) were partially offset by higher other operating expenses ($39.0 million).

Net margins were higher primarily at St. Lawrence ($32.5 million) and Niagara ($30.3 million) due to higher generation and higher prices on market-based sales. Net generation at Niagara and St. Lawrence was 22% higher than budgeted for the month of October and 13% higher than budgeted for the year-to-date. These positives were partially offset by a lower net margin at Blenheim-Gilboa ($9.5 million) primarily due to lower prices on capacity sales. Lower O&M resulted primarily from lower payroll related costs associated with the high number of vacant positions, lower IT computer hardware and software costs, and the delayed start of the commercial operation date of Astoria Energy II. Non-operating income included a mark-to-market gain on the Authority's investment portfolio ($12.8 million), lower interest costs ($16.2 million) and the settlement of the spent nuclear fuel claim ($11 million) against the United States Department of Energy not included in the budget. The mark-to-market gain and lower interest costs resulted primarily from lower than budgeted market interest rates. Other operating expenses were higher due to additional Power for Jobs related voluntary contributions to New York State ($12.5 million) and the recognition of residential consumer discounts ($24.9 million) included in the Recharge New York (RNY) Power Program legislation. The additional Power for Jobs voluntary contribution includes $7.5 million relating to 2010 paid in June and accrual of a portion of the amount for 2011. On June 28, 2011, the Authority's Trustees authorized the use of revenues from the sale of withdrawn hydropower under the RNY legislation into the wholesale market or, as necessary, internal funds to fund the residential consumer discount program for its first six months.

Net income through October 2011 ($210.8 million) was $42.3 million higher than the comparable period in 2010 ($168.5 million). Lower voluntary contributions to New York State ($82 million) were partially offset by lower net operating income ($12.2 million) and lower non-operating income ($27.6 million) during the period. Year-to-date voluntary contributions were $65 million in 2011 compared to $147 million through October 2010. Net operating income was lower primarily due to higher retiree health benefits and higher Power for Jobs related contributions to New York State. Non-operating income in 2011 reflected a lower mark-to-market gain on the Authority's investment portfolio and higher interest costs (primarily Astoria II) than the comparable period in 2010.

Year-end Projection

Year-end net income is projected to be $235 million, or $56 million above the 2011 budget of $179 million. The year-end projection is up from the prior projection due mainly to significant rainfall over Lakes Erie and Ontario over the past two months. The current forecast of 21.3 TWh of hydro generation for 2011 represents an increase of 12% over the 19.1 TWh in the budget, contributing approximately $67 million to net income.

Additional factors affecting net income positively include a $9 million increase due to higher energy prices, an $11 million settlement received by NYPA from the Department of Energy regarding the spent nuclear fuel claim, and a $12 million increase in the market valuation of the Authority's investment portfolio.

Partially mitigating these gains are a $15 million negative impact due to lower capacity prices, $8.5 million higher voluntary contributions related to the Power for Jobs Program, $5 million in additional operating and maintenance expenses and an estimated $5 million due to the overall effect of the Recharge New York program for 2011.

Cash & Liquidity

The Authority ended the month of October with total operating funds of $1,329 million as compared to $1,069 million at the end of 2010. The increase includes $79 million in proceeds from the sale of the 2011A Revenue Bonds that will be used to retire the outstanding 2000A Revenue Bonds on November 15, 2011. The balance of the increase ($181 million) is primarily attributable to net cash from operations and payments received from Entergy partially offset by voluntary contributions to New York State and scheduled debt service payments.

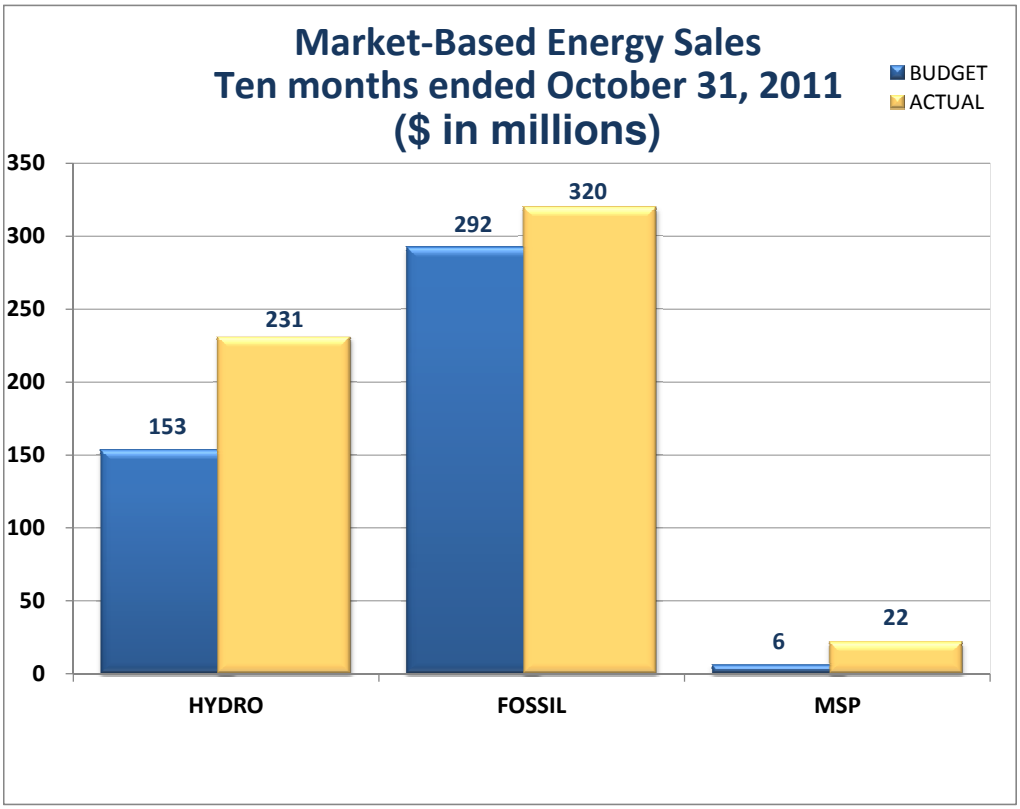
New York Power Authority

RESULTS OF OPERATIONS

Net Income
Ten Months ended October 31, 2011
($ in millions)

	Actual	Budget	Variance
Niagara	$91.3	$67.7	$23.6
St. Lawrence	42.5	24.3	18.2
Blenheim-Gilboa	(13.2)	(3.5)	(9.7)
SENY	34.0	32.1	1.9
SCPP	20.9	17.8	3.1
Market Supply Power	(45.0)	(33.4)	(11.6)
Flynn	7.9	2.0	5.9
Transmission	30.3	28.6	1.7
Non-facility	42.1	13.4	28.7
Total	**$210.8**	**$149.0**	**$61.8**

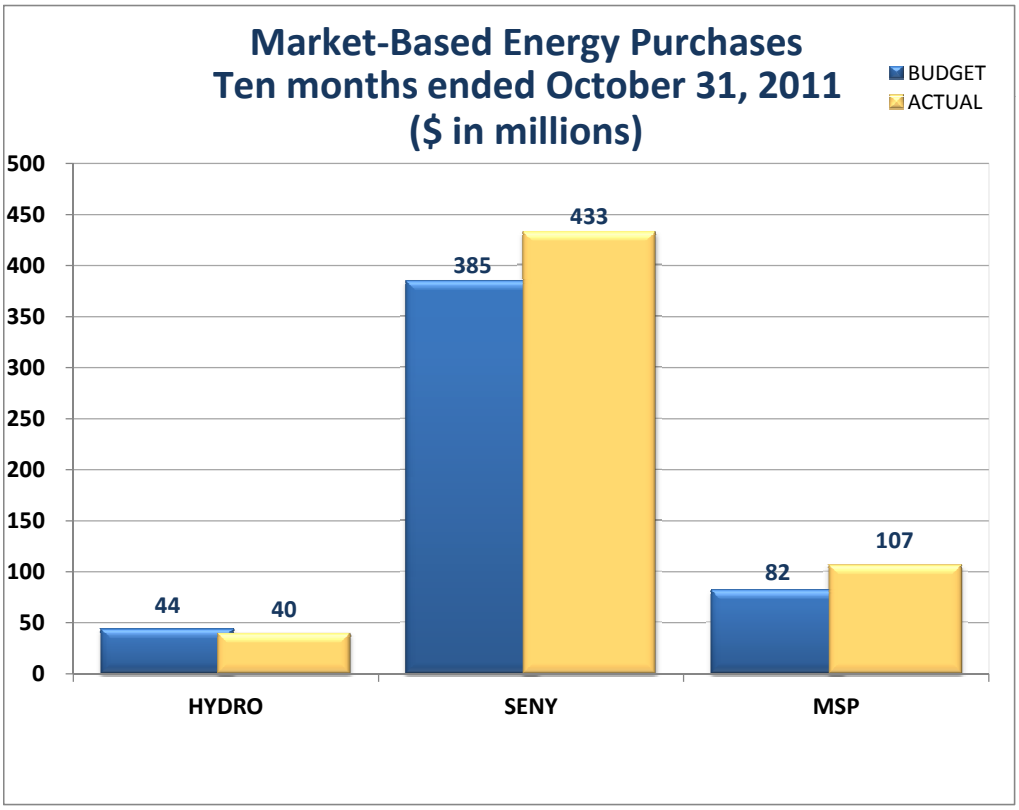
Major Factors	**Better (Worse)**
Niagara Primarily higher net margin on sales and lower O&M. Net margins were higher ($30.3) due to higher market based sales (12% higher net generation) partially offset by higher purchased power costs to support customer loads . Purchased power costs were higher due to an extended outage at an upstate transmission line early in the year. Lower O&M due to timing underruns in non-recurring projects were substantially offset by hydro subsidies related to the Recharge NY Power Program.	$23.6
St. Lawrence Higher net margin ($32.5) resulting from 16% higher generation and higher prices on market sales ($39/mwh vs $36/mwh), partially offset by hydro subsidies related to the Recharge NY Power Program ($13.8).	18.2
Blenheim-Gilboa Lower prices on capacity sales into the market.	(9.7)
Market Supply Power Primarily accruals and payment of voluntary contributions ($12.5) not in budget (extension of Power for Jobs program).	(11.6)
Flynn Primarily lower fuel costs due to lower prices and lower outage costs due to timing.	5.9
Other facilities Positive variances at the SCPP's ($3.1) due to higher production and prices and at the Transmission facility ($1.7) due to lower O&M and other expenses.	6.7
Non-facility (including investment income) Mark-to-market gain on the Authority's investment portfolio ($12.8) due to lower than budgeted market interest rates during the period and settlement of spent nuclear fuel claim ($11.0).	28.7
Total	**$61.8**



REVENUES		
SALES (MWH)		
	BUDGET	ACTUAL
Hydro*	3,070,432	5,236,597
Fossil	4,510,863	4,503,183
MSP	185,330	480,424
TOTAL	7,766,625	10,220,204
PRICES ($/MWH)		
Hydro*	$41.04	$42.28
Fossil	$56.95	$62.36
MSP	$34.83	$44.87
AVERAGE	$50.13	$51.25

** Includes Niagara, St. Lawrence, B-G, and Small Hydro.*

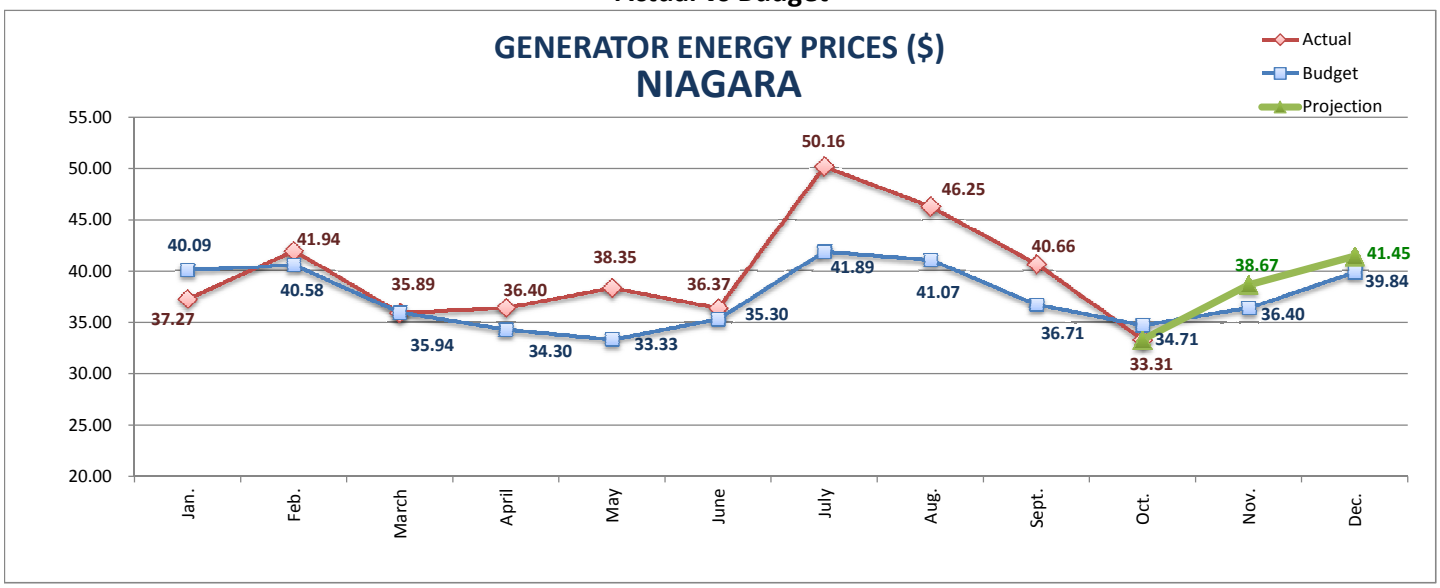
REVENUES		
SALES (MWH)		
	BUDGET	ACTUAL
Niagara	1,369,596	3,055,360
St. Law.	1,046,658	1,827,381
PRICES ($/MWH)		
Niagara	$39.03	$40.45
St. Law.	$36.14	$39.13

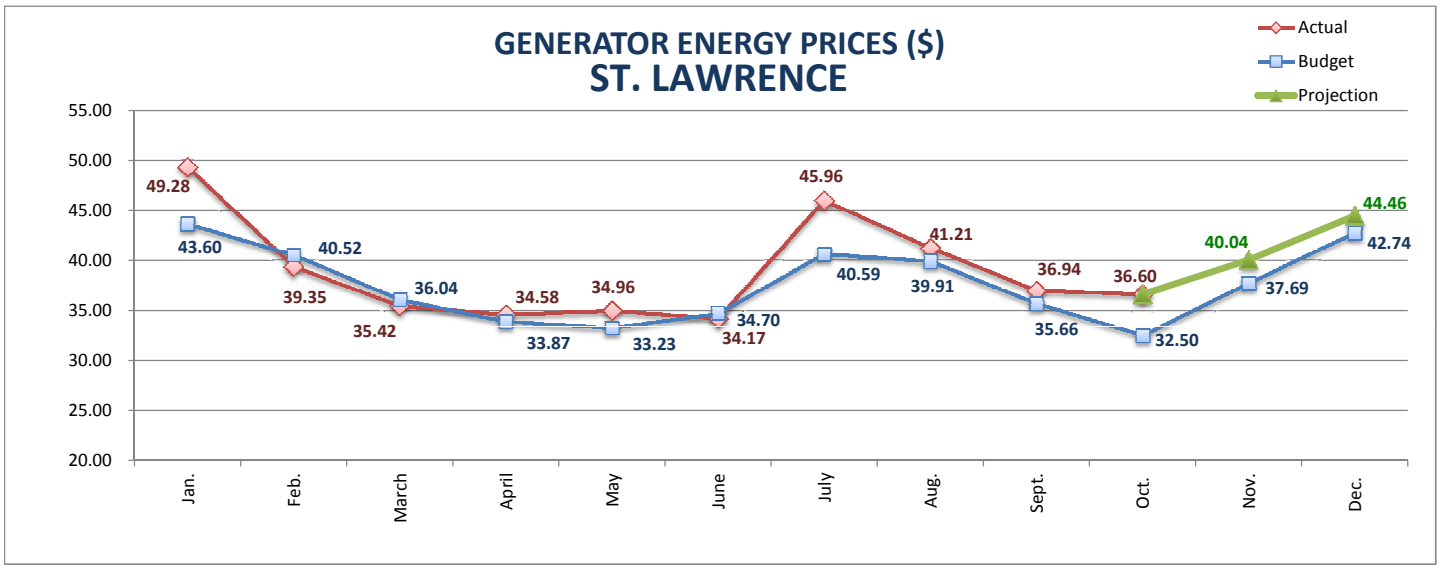


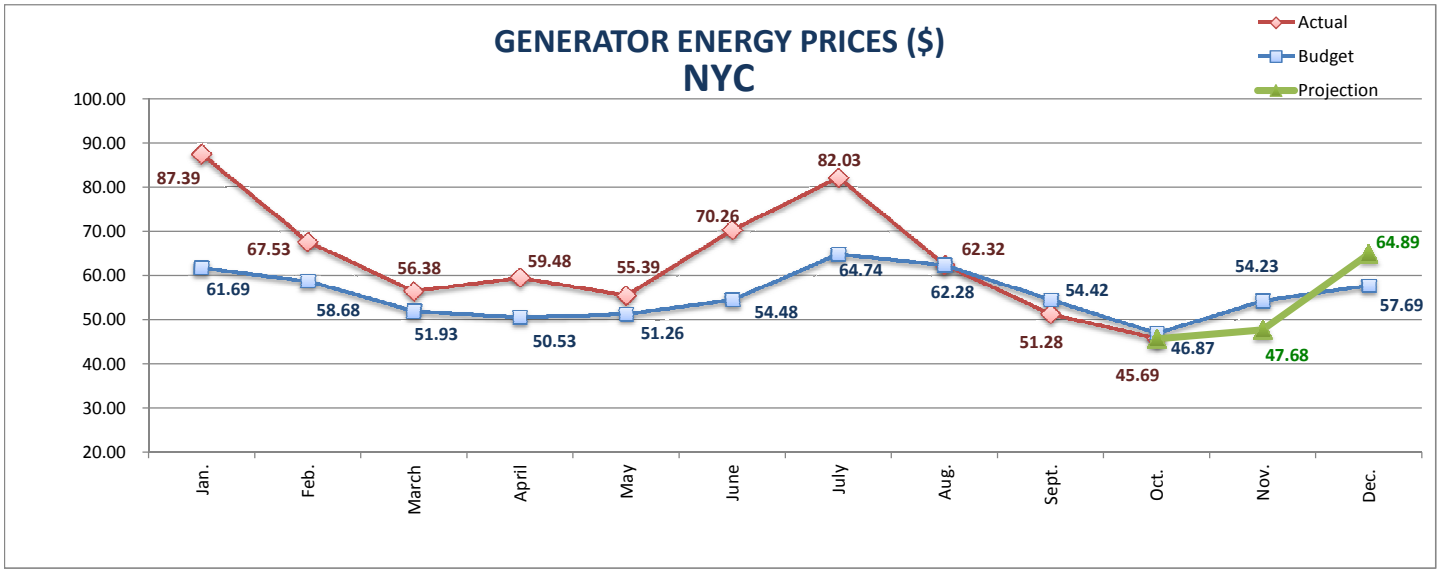
COSTS		
PURCHASES (MWH)		
	BUDGET	ACTUAL
Hydro	1,780,989	1,168,987
SENY	7,469,108	7,920,557
MSP	2,230,259	2,474,192
TOTAL	11,480,356	11,563,736
COSTS ($/MWH)		
Hydro	$24.85	$33.88
SENY	$51.54	$54.65
MSP	$36.56	$43.60
AVERAGE	$44.49	$50.19

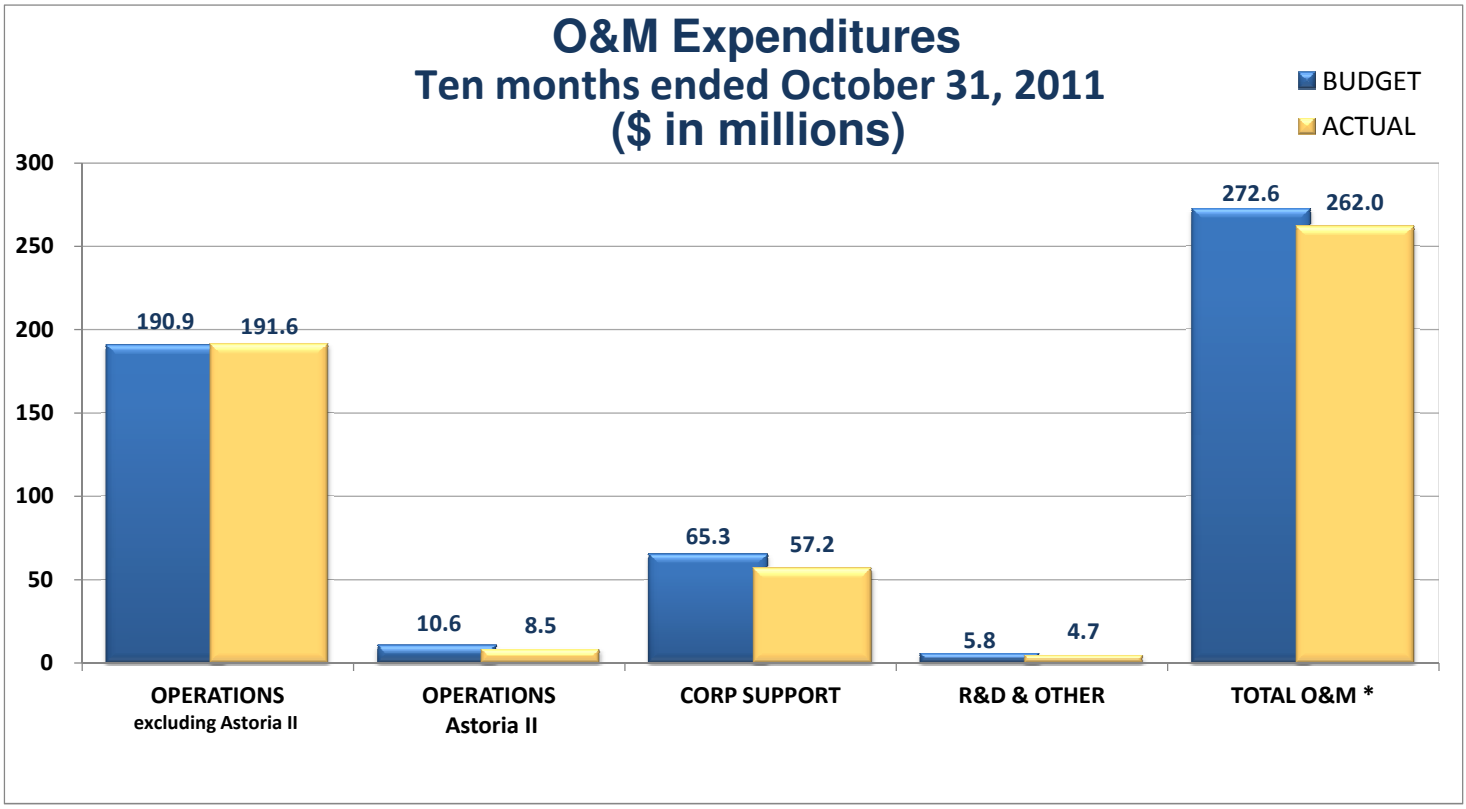
New York Power Authority

RESULTS OF OPERATIONS
Market Energy Prices
Actual vs Budget







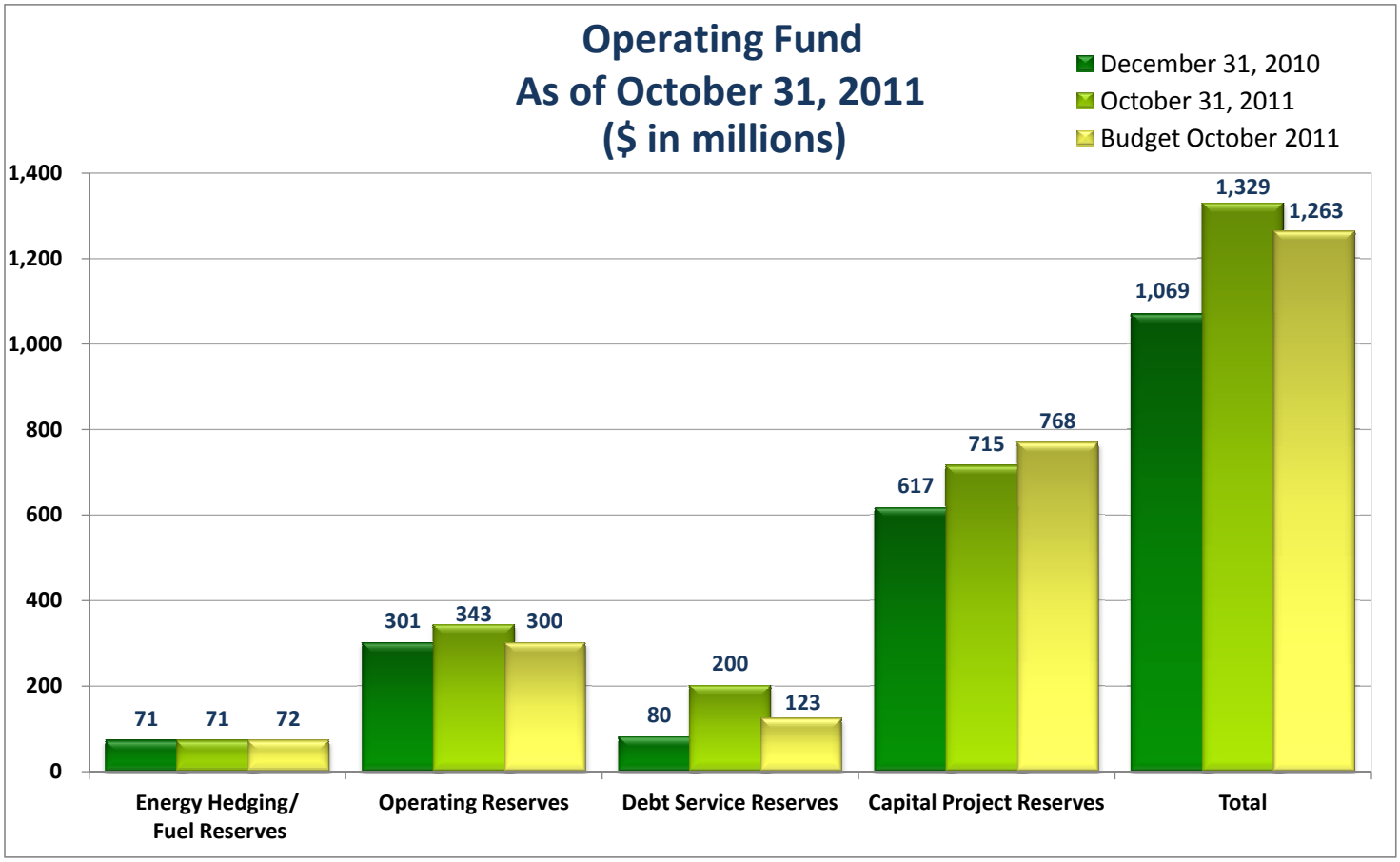


- Through October, O&M expenses were $10.6 lower than the budget.

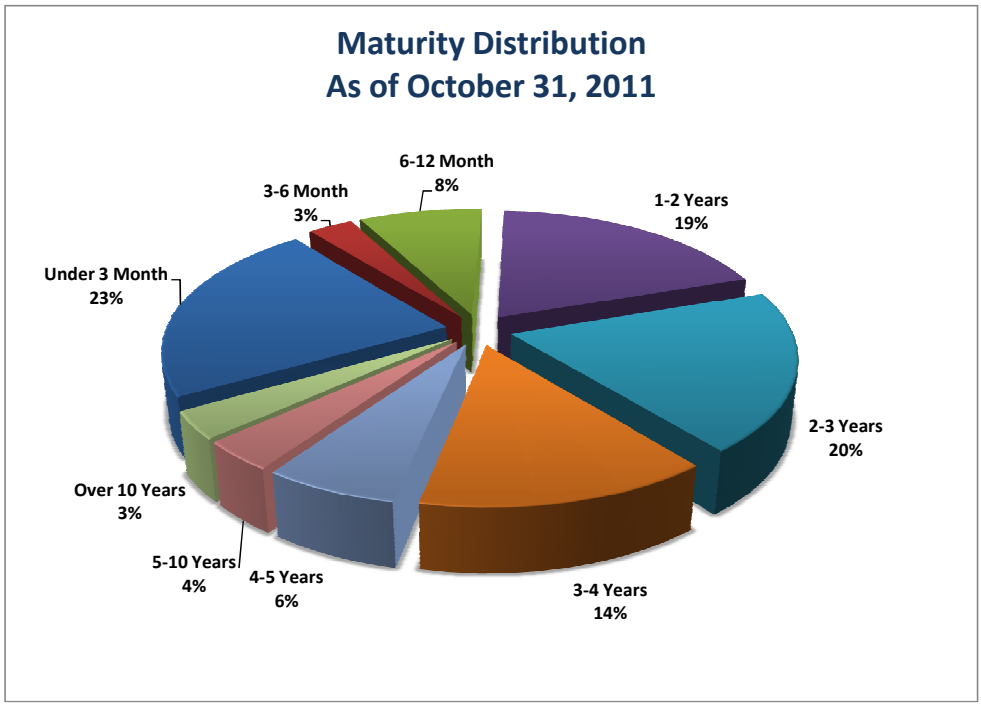
- HQ Corporate Support was under budget by $8.1 due to lower than expected expenses for Human Resource contract services and employment agency fees, WPO building operations, computer software, hardware and services, and fuel cell maintenance.

- Operations expenditures excluding Astoria II were slightly higher than budgeted. Overruns totaling $9.6 at the Small Clean Power Plants and Operations Shared Services were offset by under-runs at Niagara and Flynn ($6.0). Higher than anticipated expenditures at the SCPP's resulted from emergent work (Harlem River Step Up Transformer and Pouch Blade Repair). Operations Shared Services reflected less than anticipated labor charged to capital projects. These negatives were offset by timing under runs in non-recurring projects at Niagara and timing related to the Flynn outage (budget assumed all work completed in October; outage work to be completed in November). Under runs in recurring maintenance at St. Lawrence and the Small Hydro facilities ($2.1, timing) added to the positives. In addition, operations O&M was lower by $2.1 as a result of a one-month delay in the commercial operation date for Astoria II.

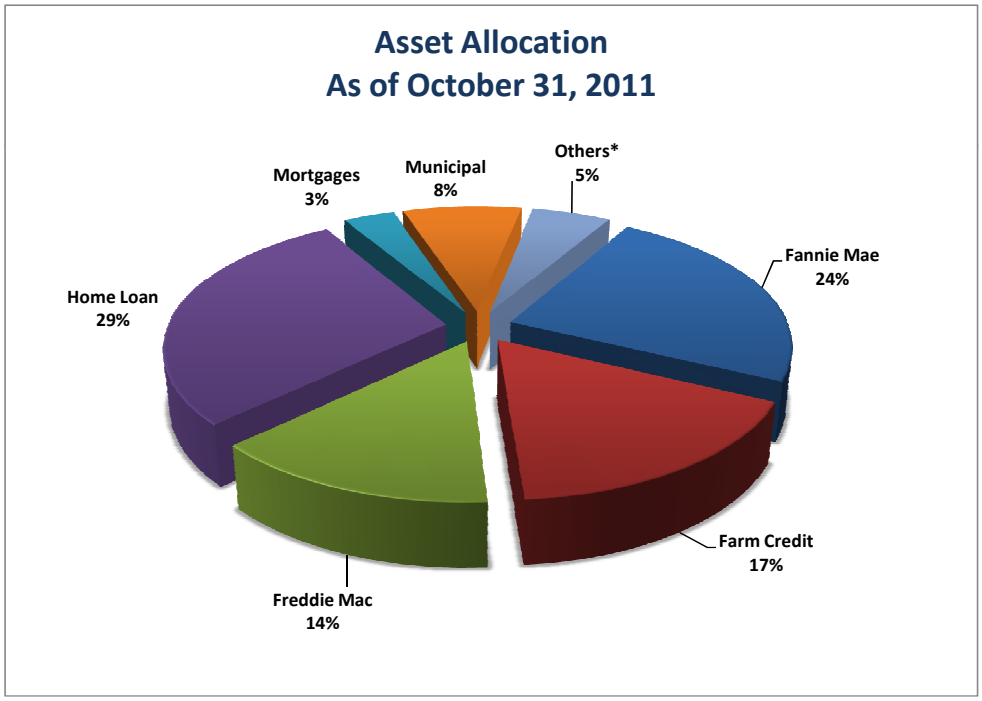
***** In September, the Trustees approved an additional $9.6 primarily for emergent work at the SCPP's and the transmission facilities. This amount is not included in the budgeted amounts above.



The increase of $260 in the Operating Fund (from $1,069 to $1,329) includes $79 in bond proceeds from the issuance of 2011A Revenue Bonds which will be used to retire the 2000A Revenue Bonds on 11/15/11. The remaining $181 increase was primarily attributable to positive net cash provided by operating activities, the payments received from Entergy ($82) and the settlement of the spent nuclear fuel claim ($11), substantially offset by voluntary contributions to New York State ($73) and repayments on commercial paper ($106) and ART Notes ($8).

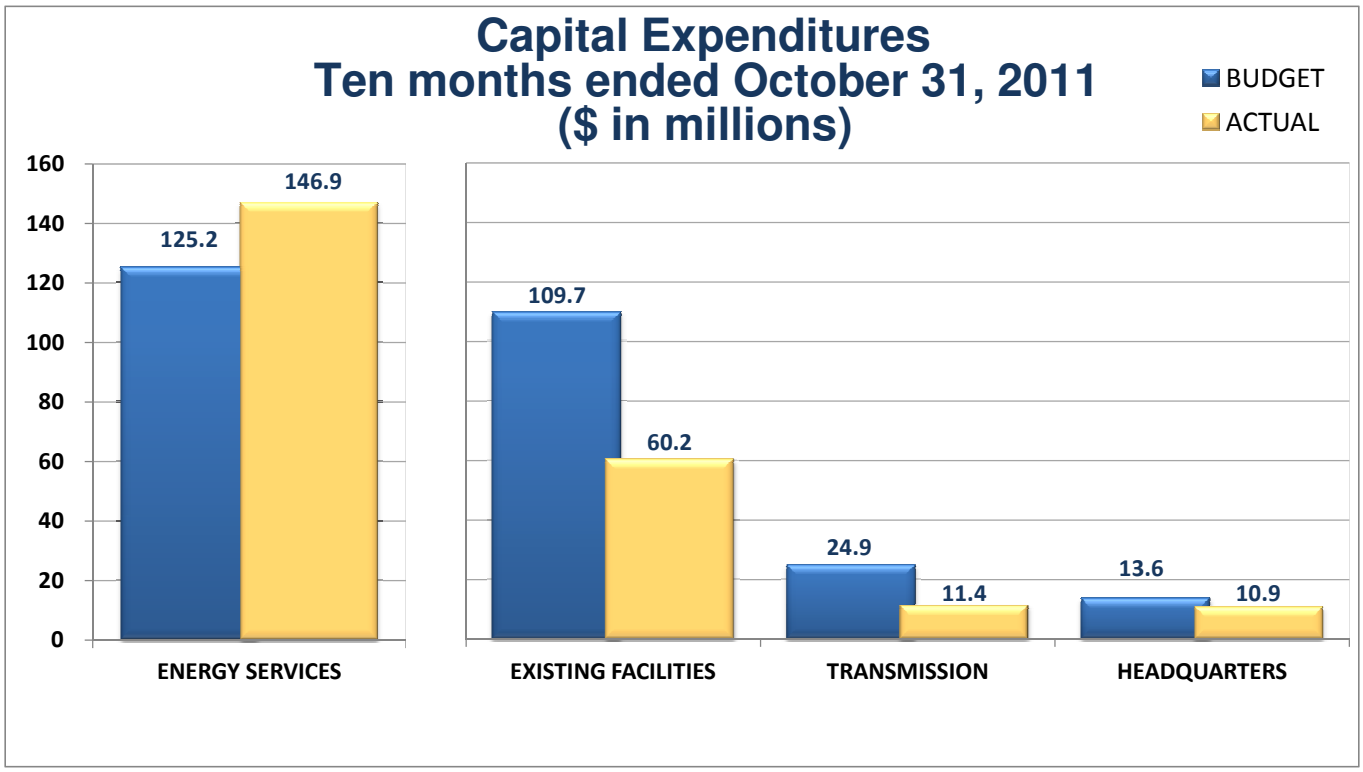


MATURITY DISTRIBUTION	
($ in millions)	
Under 3 Month	$326.2
3-6 Month	43.8
6-12 Month	119.9
1-2 Years	275.8
2-3 Years	281.3
3-4 Years	203.7
4-5 Years	93.3
5-10 Years	52.5
Over 10 Years	47.9
Total	**$1,444.4**



ASSET ALLOCATION	
($ in millions)	
Fannie Mae	$344.4
Farm Credit	241.6
Freddie Mac	201.0
Home Loan	414.3
Mortgages	49.5
Municipal	116.8
Others*	76.8
Total	**$1,444.4**

*Includes CDs and Repos



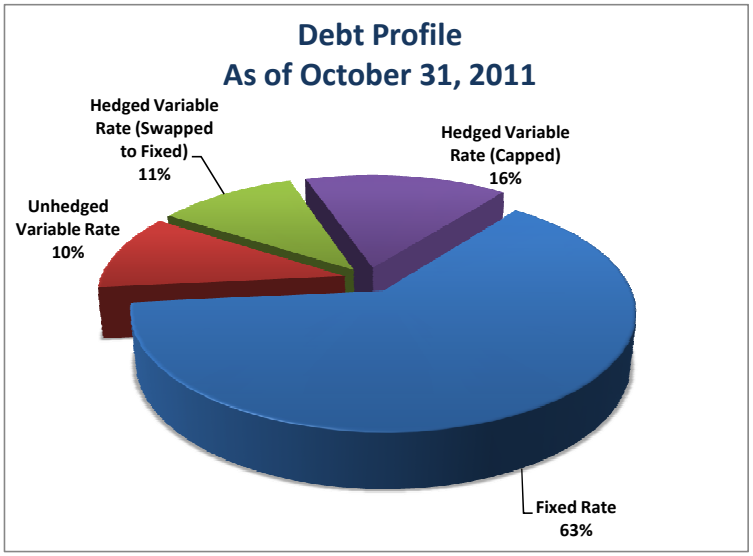
• Energy Services expenditures were over budget primarily due to accelerated construction activity in the Governmental Services Program (primarily Queens Supreme Court-Chiller).

• Existing facilities expenditures were under budget by $49.5 primarily due to the delays in permitting for projects related to the Niagara and St. Lawrence Relicensing Implementation and Compliance.

• Transmission expenditures were less than anticipated due to timing for several projects, primarily the 765 kv transmission line relay and switch replacements.

• Headquarters expenditures were less than budgeted due to timing for several IT projects.

• Under the Expenditure Authorization Procedure, the President has authorized new expenditures on budgeted capital projects of $22.1 for 2011. New authorizations in October include the BG protective relay replacement ($2.6), the BG transfer switch replacement ($2.6) and the RMNPP CO2 exhaust system upgrade ($0.8).



DEBT PROFILE	
($ in millions)	
Fixed Rate	$1,201.1
Unhedged Variable Rate	203.1
Hedged Variable Rate (Swapped to Fixed)	204.8
Hedged Variable Rate (Capped)	300.0
Total	**$1,909.0**

On September 21, 2011, the Authority priced and sold the Series 2011 A Bonds. The proceeds will be used to current refund $77.2 of the Series 2000A bonds on November 15, 2011 and advance refund, on November 15, 2012, $41.7 of the Series 2002A bonds. The refunding transaction will result in $19.4 in present value savings or 16.3% of the par amount of bonds refunded. The transaction closed on October 6, 2011.

New York Power Authority

ENERGY DERIVATIVES

Results

Year-to-date, energy derivative settlements have resulted in a net loss of $59.9 million. Gains and losses on these positions are substantially passed through to customers as resulting hedge settlements are incorporated into and recovered through customer rates.

Year-to-Date 2011 Energy Derivative Settlements & Fair Market Valuation of Outstanding Positions

($ in Millions)

	Settlements	Fair Market Value				
	YTD[1]	2011	2012	>=2013	Total
NYPA	$ 0.25	$ 0.21	$ -	$ -	$ 0.21
Customer Contracts	$ (60.16)	$ (12.67)	$ (85.00)	$ (77.32)	$ (174.98)
Total	**$ (59.91)**	**$ (12.46)**	**$ (85.00)**	**$ (77.32)**	**$ (174.77)**

[1]*Reflects October 2011 preliminary settlements.*

At the end of October, the fair market value of outstanding positions was valued at an unrealized loss of $174.8 million for positions extending through 2017.

Market Summary

Exhibit 1 shows the average price of January to December 2012 futures contracts and how they have traded since the beginning of 2010, while Exhibit 2 illustrates the average price of futures contracts for entire year 2013 since 11/30/2010.

Exhibit 1: Average January to December 2012 Forward Price

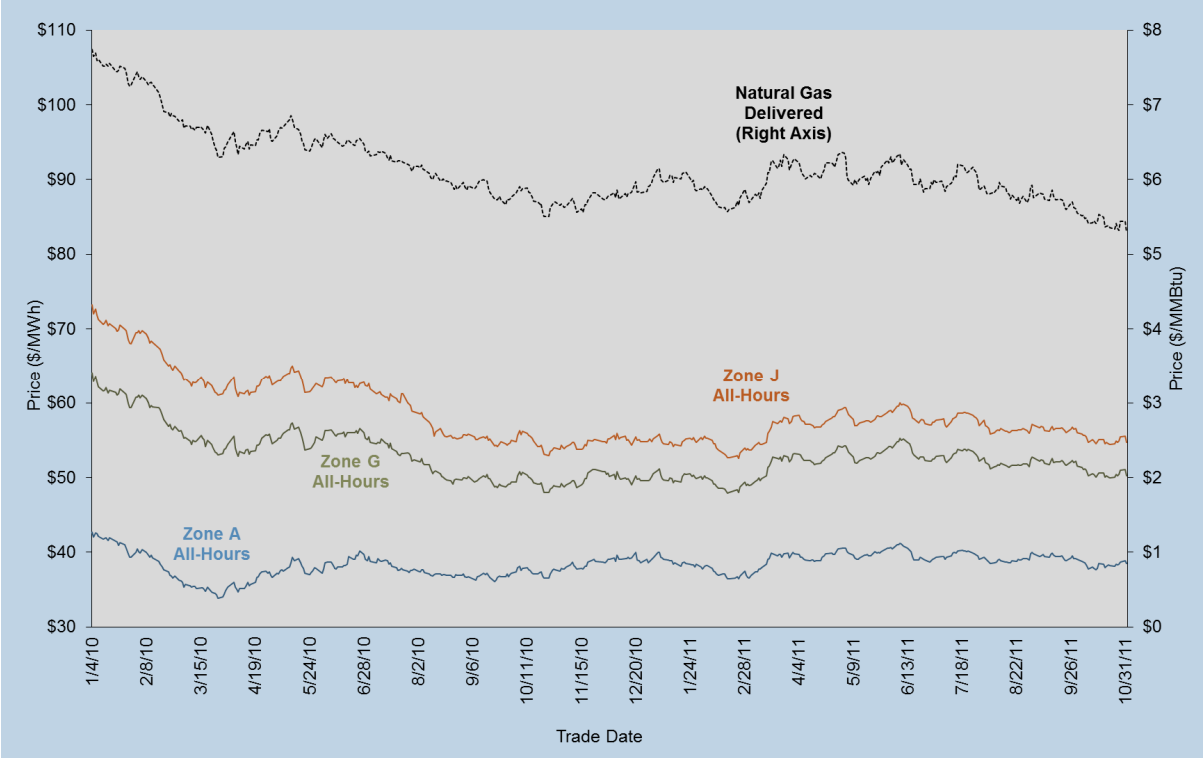
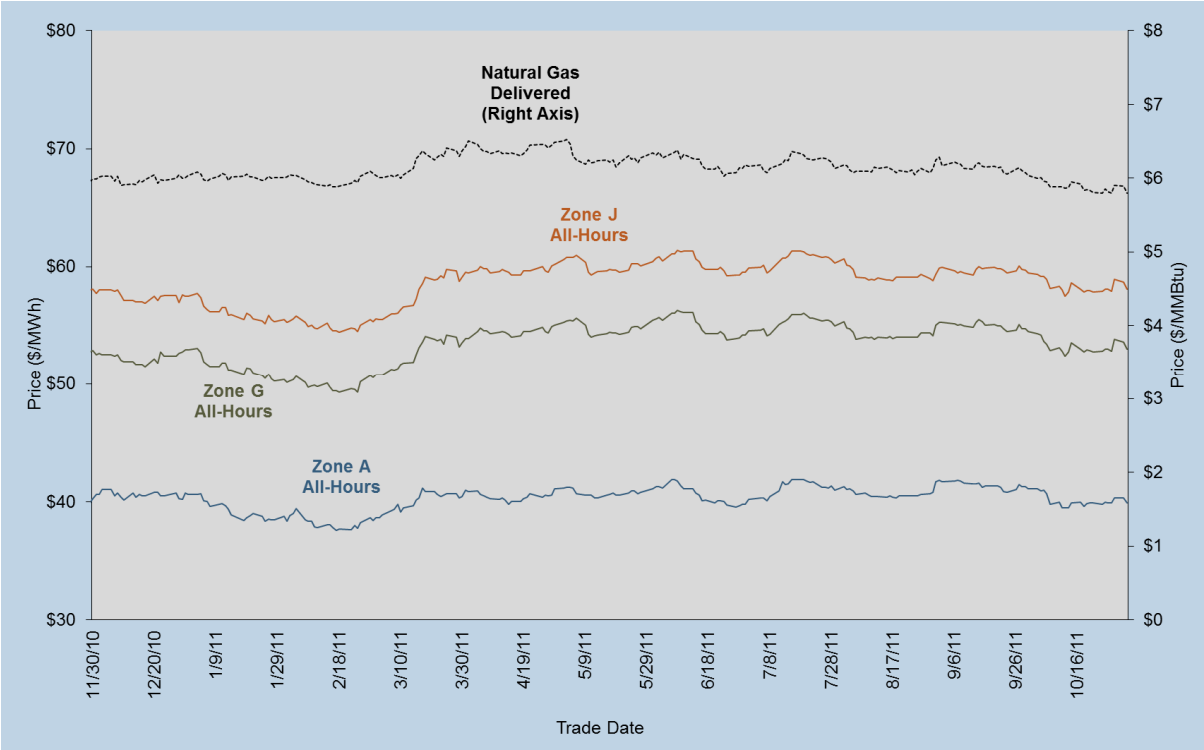


Exhibit 2: Average January to December 2013 Forward Price



STATEMENT OF NET INCOME
For the Ten Months Ended October 31, 2011
($ in millions)

Annual Budget		Actual	Budget	Variance Favorable/ (Unfavorable)
	Operating Revenues			
$2,070.5	Customer	**$1,660.2**	**$1,733.1**	**($72.9)**
463.4	Market-based power sales	476.5	389.1	87.4
30.6	Ancillary services	21.2	22.4	(1.2)
114.9	NTAC and other	93.1	96.1	(3.0)
608.9	Total	**590.8**	**507.6**	**83.2**
2,679.4	**Total Operating Revenues**	**2,251.0**	**2,240.7**	**10.3**
	Operating Expenses			
804.7	Purchased power	704.2	682.5	(21.7)
295.6	Fuel consumed - oil & gas	220.1	241.7	21.6
108.2	Ancillary services	47.7	89.9	42.2
543.4	Wheeling	466.6	464.3	(2.3)
327.1	Operations and maintenance	262.0	272.6	10.6
194.9	Depreciation and amortization	154.4	158.5	4.1
135.5	Other expenses	153.0	113.9	(39.1)
(10.9)	Allocation to capital	(5.9)	(9.0)	(3.1)
2,398.5	**Total Operating Expenses**	**2,002.1**	**2,014.4**	**(12.3)**
280.90	**Net Operating Income**	**248.9**	**226.3**	**22.6**
	Nonoperating Revenues			
88.0	Post nuclear sale income	85.4	85.4	-
39.9	Investment income	31.8	32.8	(1.0)
(7.0)	Mark to market - investments	7.5	(5.3)	12.8
-	Other income	11.2	-	11.2
120.9	**Total Nonoperating Revenues**	**135.9**	**112.9**	**23.0**
	Nonoperating Expenses			
65.0	Contributions to New York State	65.0	65.0	-
157.5	Interest and other expenses	109.0	125.2	16.2
222.5	**Total Nonoperating Expenses**	**174.0**	**190.2**	**16.2**
$179.3	**Net Income**	**$210.8**	**$149.0**	**$61.8**

COMPARATIVE BALANCE SHEETS
October 31, 2011
($ in millions)

Assets		October 2011	October 2010	December 31, 2010
Current Assets				
	Cash	$0.1	$0.1	$0.1
	Investments in government securities	1,356.9	1,108.3	1,091.1
	Interest receivable on investments	5.5	5.8	5.5
	Accounts receivable - customers	242.3	222.2	204.0
	Materials and supplies, at average cost:			
	Plant and general	80.3	77.4	75.1
	Fuel	23.2	17.4	15.3
	Prepayments and other	150.5	176.4	190.5
	Total Current Assets	**1,858.8**	**1,607.6**	**1,581.6**
Noncurrent Assets				
Restricted Funds	Investment in decommissioning trust fund	1,079.7	1,017.0	1,032.4
	Other	81.0	88.0	83.3
	Total Restricted Funds	**1,160.7**	**1,105.0**	**1,115.7**
Capital Funds	Investment in securities and cash	101.5	147.0	144.8
	Total Capital Funds	**101.5**	**147.0**	**144.8**
Net Utility Plant	Electric plant in service, less accumulated depreciation	3,405.5	3,302.5	3,344.1
	Capital lease, less accumulated amortization	1,017.6	-	-
	Construction work in progress	95.8	147.8	123.3
	Net Utility Plant	**4,518.9**	**3,450.3**	**3,467.4**
Other Noncurrent Assets	Receivable - NY State	318.0	318.0	318.0
	Deferred charges, long-term receivables and other	609.7	669.8	604.6
	Notes receivable - nuclear plant sale	160.5	174.3	157.1
	Total other noncurrent assets	**1,088.2**	**1,162.1**	**1,079.7**
	Total Assets	**$8,728.1**	**$7,472.0**	**$7,389.2**
Liabilities and Net Assets				
Current Liabilities	Accounts payable and accrued liabilities	$902.5	$902.3	$881.7
	Short-term debt	353.1	304.9	323.2
	Total Current Liabilities	**1,255.6**	**1,207.2**	**1,204.9**
Noncurrent Liabilities				
Long-term Debt	Revenue bonds	1,228.6	1,190.7	1,151.2
	Adjustable rate tender notes	122.9	130.5	130.5
	Commercial paper	231.8	344.1	336.5
	Total Long-term Debt	**1,583.3**	**1,665.3**	**1,618.2**
Other Noncurrent Liabilities	Nuclear plant decommissioning	1,079.7	1,017.0	1,032.4
	Disposal of spent nuclear fuel	216.2	216.1	216.1
	Capital lease obligation	1,125.4	-	-
	Deferred revenues and other	256.0	377.5	316.5
	Total Other Noncurrent Liabilities	**2,677.3**	**1,610.6**	**1,565.0**
Net Assets	Accumulated Net Revenues - January 1	3,001.1	2,820.4	2,820.4
	Net Income	210.8	168.5	180.7
	Total Net Assets	**3,211.9**	**2,988.9**	**3,001.1**
	Total Liabilities and Net Assets	**$8,728.1**	**$7,472.0**	**$7,389.2**

SUMMARY OF OPERATING FUND CASH FLOWS
For the Ten Months Ended October 31, 2011
($ in millions)

Operating Fund	
Opening	$1,069.2
Closing	1,329.1
Increase/(Decrease)	**259.9**
Cash Generated	
Net Operating Income	248.9
Adjustments to Reconcile to Cash Provided from Operations	
Depreciation & Amortization	154.4
Net Change in Receivables, Payables & Inventory	(78.9)
Other	(4.8)
Net Cash Generated from Operations	**319.6**
(Uses)/Sources	
Utility Plant Additions	(48.5)
Debt Service	
Issuance of 2011A Bonds	123.3
Defeasance of 2002A Bonds	(46.0)
Commercial Paper 2	(44.8)
Commercial Paper 3 & Extendible Municipal Commercial Paper 1	(61.6)
ART Notes	(7.6)
Investment Income	19.5
Entergy Value Sharing Agreement	72.0
Entergy IP2 Purchase Agreement	10.0
Voluntary Contributions to NY State	(72.5)
Other	(3.5)
Total (Uses)/Sources	**(59.7)**
Net Increase in Operating Fund	**$259.9**

New York Power Authority

Staff Analysis of Public Comments and Recommendations

Rate Modification Plan – Rate Years 2011 to 2014

Including:

Revised Cost of Service

Appendix A

November 2011

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Part I: Introduction

This Staff Analysis of Public Comments and Recommendations ("Staff Analysis") is being issued by the New York Power Authority ("Authority" or "NYPA") in November 2011 to analyze the comments received in the Authority's hydroelectric preference rate proceeding for the 2011 to 2014 Rate Years, and to support the final rates requested to be approved by the Authority's Trustees. Part I of this Staff Analysis provides background on the July 2011 proposed rulemaking, the public comment period and the proposed final rates. Part II contains the Authority staff's analysis and disposition of the issues raised in the public comments.

A. Background

1. July 2011 Proposed Rulemaking

At their meeting of July 26, 2011, the Trustees authorized a notice of proposed rulemaking ("NOPR") for a 3½-year rate plan to increase the rates for hydroelectricity applicable to preference power customers. The Authority proposed new rates to cover the period from November 1, 2011 to April 30, 2015. The proposed rate plan was prepared by the Authority staff and explained in its "Preliminary Staff Report, Hydroelectric Production Rates, Rate Modification Plan – Rate Years 2011 to 2014" ("Preliminary Staff Report"). Preference power is the hydroelectricity sold from the Authority's Niagara Project and St. Lawrence Project (collectively, the "Hydro Projects") for "domestic and rural" use as defined under New York Public Authorities Law § 1005(5) ("PAL") and the Niagara Redevelopment Act, 18 U.S.C. § 836(b)(1) (2011) ("NRA"). NYPA's sales of hydroelectricity at the preference power rate apply to forty-seven in-state municipal electric systems and four rural electric cooperatives (collectively, "NY Munis & Coops"), three upstate investor-owned utilities ("IOUs"),[1] the

[1] Until August 1, 2011 the residential customers served by the three upstate IOUs received 455 MW of firm preference power. These allocations were withdrawn in accordance with New York State law that redirects such power and energy for the Recharge New York power program. These IOUs, however, will continue to receive their allocations of "firm peaking" preference power.

neighboring states customers ("NS Customers")[2] and the Niagara Project Relicensing Host Communities ("Host Communities") and other entities who received hydropower allocations as part of the Niagara Project relicensing process (collectively, with the Host Communities, the "Relicensing Customers").[3]

2. Ratemaking Principles

The Hydroelectric Cost-of-Service ("Hydro CoS" or "CoS") in the Preliminary Staff Report is based on an update of the cost elements using the same ratemaking principles and methodologies employed by the Authority when setting preference power rates in 2003 and included in the January 2003 Report on Hydroelectric Production Rates ("January 2003 Report"). Subsequent to the 2003 rate action, such principles and methodologies were later agreed to by all the NY Munis & Coops, the bargaining agents for the NS Customers and the Relicensing Customers. Each of these customers agreed through either a long-term contract or settlement agreement with the Authority that it would not object to those ratemaking principles and methodologies in subsequent Authority rate increases for the term of their contracts or settlement agreements.

In 2007, the Authority proposed, and later adopted, a preference rate increase based on updated cost information and the ratemaking principles that had already been agreed to by the aforementioned customers.

The key agreed-upon principles and methodologies from the January 2003 Report include:

i. The principles set forth in the March 5, 1986 Settlement Agreement (Appendix B to this Agreement) settling *Auer v. Dyson*, No. 81-124 (Sup. Ct. Oswego

[2] The NS Customers are certain municipal utility systems in the seven neighboring states of Connecticut, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island and Vermont.

[3] The Host Communities consist of the City of Niagara Falls, NY; Lewiston Porter Central School District; Niagara County; School District of the City of Niagara Falls, NY; Niagara Wheaton Central School District; Town of Lewiston, NY; and Town of Niagara, NY. The two other Relicensing Customers are Niagara University and the Tuscarora Nation.

Co.), *Auer v. Power Authority*, Index No. 11999-84 (Sup. Ct. N.Y. Co.) and *Delaware County Electric Cooperative, Inc. v. Power Authority*, 82 Civ. 7256 (S.D.N.Y.) (the "*Auer* Settlement").

ii. Recovery of capital costs using Trended Original Cost and Original Cost methodologies.

iii. Treatment of sales to third parties, including the New York Independent System Operator ("NYISO").

iv. Allocation of Indirect Overheads.

v. Melding of costs of the Niagara Power Project and St. Lawrence-FDR Power Project for ratemaking.

vi. Post-employment benefits other than pensions (*i.e.*, retiree health benefits and now referred to as Other Postemployment Benefits, or OPEBs).

vii. Rate Stabilization Reserve ("RSR") methodology.

3. Proposed Rates

To set the rates for the four future rate periods, staff used projected calendar year data. The Preliminary Staff Report proposed the following rates:

Rate Year[4]	**Demand Rate $/kW-month**	**Energy Rate $/MW-hour**	**RSR-related Surcharge $/MW-hour**	**Effective Rate**[5] **$/MW-hour**
2011	3.32	4.92	-	11.42
2012	3.70	4.92	-	12.16
2013	4.12	4.92	-	12.98
2014	4.32	4.92	0.50	13.87

The Preliminary Staff Report included a CoS study which set out the calculations supporting the proposed rates and explained the additional costs of production of hydroelectricity at the Hydro Projects. These costs include: (1) the Authority's capital

[4] Except for 2011, the preference power rate year runs from May 1 of the calendar year indicated to April 30 of the following year. Because of the timing of the initial proposal, the Authority had proposed that the 2011 rate year of the period would be from November 1, 2011 to April 30, 2012.

[5] Effective rate at 70% load factor.

costs including upgrades and life extension and modernization costs at both Hydro Projects; (2) the Authority's costs related to Federal Energy Regulatory Commission ("FERC") relicensing for the Hydro Projects; (3) operation and maintenance ("O&M") costs for the Hydro Projects; and (4) indirect overhead costs.

B. Public Comment Period

Written notice and a copy of the Preliminary Staff Report were mailed to all affected customers on or about July 26, 2011. The written notice stated that customers could contact the Authority for further information, for answers to questions concerning the rate proposal or to meet with NYPA staff to discuss details of the proposal. The notice also informed customers of three separate public forums on the proposed rates for the purpose of obtaining the views of interested persons: September 19, 2011 in Syracuse, New York; September 20, 2011 in Niagara Falls, New York; and September 22, 2011 in Massena, New York. Notice of the proposed rulemaking was published in the *New York State Register* ("*State Register*") on August 17, 2011. Such notice also announced the dates and locations of the public forums. The *State Register* notice also established an October 3, 2011 deadline to submit written comments on the proposed rulemaking.[6] The public comment period end date was subsequently extended three weeks, from October 3, 2011 to October 24, 2011, based on customers' feedback.

Following the Trustees' action on July 26, 2011, Authority staff made itself available to affected customers and their organizations on a number of occasions for the purpose of answering questions about the proposed rate revisions. The Authority staff held meetings with representatives of the Municipal Electric Utilities Association ("MEUA"), which represents 40 municipal utility systems in New York State; the New York Association of Public Power ("NYAPP"), which represents a total of thirteen municipal utility systems and rural electric cooperative systems; the NS Customers; and with a number of elected officials.

[6] The October 3, 2011 deadline was in accordance with the 45-day comment period for rulemakings required by the New York State Administrative Procedure Act.

Interested parties submitted voluminous and substantive data requests concerning the Preliminary Staff Report. Staff responded to a total of 128 data requests: 35 from MEUA, 64 from NYAPP, and 29 from the NS Customers. Many of these data requests had multiple subparts, so these numbers understate the amount of material staff provided. Many data requests sought the workpapers in support of the calculations underlying the proposal.

The three public forums were conducted in accordance with the terms of the "Policy and Procedures – Public Forums on Rate Proposals" adopted by the Authority's Trustees in November 1990. Such Policy and Procedure provides for the holding of public forums on all proposed Authority production and transmission rate increases of two percent or more.

A panel of Authority representatives was available at the public forums to explain the basis for the proposed rate revisions and to listen to issues raised by concerned members of the public. The Authority had invited parties to submit written comments at the public forums. Various customer groups, as well as elected officials and residents of New York State, attended. Customers included representatives from the NS Customers, MEUA, NYAPP, the Niagara Power Coalition, Inc. ("NPC," an organization representing the Host Communities), Jamestown Board of Public Utilities, Town of Massena Electric Department and the Plattsburgh Municipal Lighting Department. Elected officials included Assemblyman John D. Ceretto, William L. Ross, Chairman of the Niagara County Legislature (and also NPC Chairman), and Renae Kimble, Niagara County Legislator. Mr. Charlie McGrath, a St. Lawrence Project-area citizen, also commented. In addition to oral or written comments delivered at the public forums, written comments were received through October 24, 2011, the end of the public comment period.

NYPA received written comments from MEUA,[7] NYAPP,[8] the NS Customers, and NPC as well as numerous letters from elected officials and other parties concerning the rate proposal. All such written comments and letters submitted in the proceeding, as well as the transcripts from the three public forums, are included in the accompanying Appendix C. All of the public comments received were evaluated by Authority staff. A detailed description of the issues raised and the proposed disposition of each are contained in Part II of this Staff Analysis.

C. Summary of Final Proposed Rates

Based on our analysis of the written comments and other information received, Authority staff recommends a series of adjustments which results in proposed rates representing a decrease from the initial proposal. The major driver in the rate adjustments is the introduction of a forward looking capacity credit as part of the Hydro CoS computation. This capacity credit, which is based on NYPA's unforced capacity sales into the NYISO market, has always been incorporated in the annual Rate Stabilization Reserve ("RSR"), a contractual mechanism that reconciles actual costs and with tariff-based revenues. By estimating and incorporating the NYISO capacity sales as part of the CoS, the customers will receive the up-front rate-reducing effect of these sales. The reasons for the various adjustments are explained fully in Part II of this Staff Analysis. The revised rates, which represent a phase-in to fully cost-based rates, are as follows:

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[7] MEUA's comments also included the affidavit and exhibits of Frank W. Radigan. Page references to these comments will be designated as "MEUA at [page #]"; references to Mr. Radigan's affidavit will be designated as "Radigan at [page #]."

[8] NYAPP's comments also included the affidavit of Whitfield A. Russell. Page references to these comments will be designated as "NYAPP at [page #]"; references to Mr. Russell's affidavit will be designated as "Russell at ¶ [#]."

Rate Year[9]	Demand Rate $/kW-month	Energy Rate $/MW-hour	RSR-related Surcharge $/MW-hour	Effective Rate[10] $/MW-hour
2011	3.26	4.92	-	11.30
2012	3.57	4.92	-	11.91
2013	3.91	4.92	-	12.57
2014	4.07	4.92	up to 0.40	13.28

These rates reflect a 6 cents/kW-month reduction in the demand rate for the 2011 rate year, a 13 cents/kW-month reduction for the 2012 rate year, a 21 cents/kW-month reduction for the 2013 rate year and a 25 cents/kW-month reduction for the 2014 rate year. For 2014, the RSR-related surcharge was adjusted downward, and would be no higher than $0.40/MWh. Based on the above, rates for a typical municipal system residential customer would increase by less than 60 cents per month for each year of the phase-in period, which is less than 1% of their total electric bill, and by less than 5 cents per month for each year of the phase-in period for a typical residential customer of the IOUs, which is also well below 1% of their total electric bill.

In addition, the RSR will be adjusted to produce a year-end 2010 balance of negative $24.5 million for reasons explained fully in Part II of this Staff Analysis.

Exhibit A contains the revised Hydro CoS, and the Exhibit B shows a summary of bill impacts, both of which are attached to this Staff Analysis. Also attached are revised Tables 1 through 5 supporting the cost-based credit associated with the production of ancillary services.

[9] As a result of the extended comment period granted by the Authority, the 2011 rate year will commence on December 1, 2011, rather than November 1, 2011 as originally proposed. The other rate years will extend from May 1 of the calendar year indicated to April 30 of the following year.

[10] Effective rate at 70% load factor.

Part II: Public Comments, Staff Analysis and Recommendations

A. Issue: Requests to Delay Implementation Date and Extend Review Period

Public Comments:

Several commenters, including the NS Customers and NYAPP, requested that NYPA delay implementation of the new rates until May 1, 2012. NYAPP (at 2) stated that NYPA's "fiscal integrity" will be "unaffected" by such delay. Senators Young, *et al.* and Senator Fuschillo also requested a May 1, 2012 effective date. MEUA requested that the review time for future NYPA rate proceedings be extended to allow for at least four months between publication of the *State Register* notice and the comment due date. Many parties cited the need for more time to consider responses to data requests. NPC criticized NYPA's rate-setting process as not allowing it or any other party to "test" the proposed rates.

Staff Analysis:

The current rate implementation defers the rate increase that NYPA staff had expected to implement effective May 1, 2011. Further delays of this action would only compress the time period in which the phase-in of a rate increase can occur. Following the initial rate increase on December 1, 2011, subsequent increases will be effective on May 1, 2012, 2013 and 2014.

NYAPP is incorrect to suggest that this rate matter should be based on an evaluation of NYPA's current fiscal condition. Rather, NYPA's obligation is to ensure that the preference rate is based on cost, which is the focus of this proceeding.

Subsequent to the July 26, 2011 Trustee action, the Authority promptly sent copies to its customers of the Preliminary Staff Report, filed all appropriate notices in the *State Register*, and made staff available to the customers and/or their representatives on a number of occasions to answer questions regarding the proposed rate revisions. The proposed rate action employs the same principles and methodologies agreed to by the customers and adopted by the Trustees in the 2003 rate action. Meetings and telephone calls were held with representatives from MEUA,

NYAPP, the NS Customers, NPC and a number of elected officials to discuss the proposal. Staff responded to a total of 128 data requests, many of which contained multiple sub-parts.

Based on letters and comments received at the public forums, NYPA agreed to extend the comment period an additional three weeks, until October 24, 2011. Such extension was unprecedented for NYPA hydro rate proceedings. It is important to note that the Authority held three public forums (instead of one, as in past proceedings) throughout New York State in order to better engage stakeholders during the present rate case.

The time initially allotted for review and comment on the proposed rate action follows the timetable the Authority used for the 1992, 2003 and 2007 rate actions, and meets the standard set forth for rulemakings under the State Administrative Procedure Act ("SAPA"). Extending the review time to at least four months between publication of the NOPR and comment due date would result in an unprecedented six-month time period between the notice of the rate action and its final implementation.

Staff acknowledges the complexity of the data and issues involved in this proceeding, but also understands that affected parties always desire more time to review data in rate proceedings. Moreover, based on the extensive amount of data shared with customers and the meetings held in this case, which included multiple technical conferences, staff believes that there was sufficient time to review the proposed rate action.

Recommendation:

By operation of the extended due date granted for the filing of comments, the Authority has consented to delay the implementation date for new rates, which was originally scheduled to become effective on November 1, 2011. The proposed rates should be implemented one month later than originally proposed, to be effective December 1, 2011. NYPA recommends no changes regarding the review period for future hydro rate proposals.

B. Issue: Proposed Preference Rates and their Conformance With the "Lowest Possible Rate" Standard

Public Comments:

MEUA, NYAPP and the NS Customers all argue that the Authority staff's proposed rates do not conform with the statutory standard that preference customers be served at the "lowest possible rate" as set forth in PAL § 1005(5). The federal Niagara Redevelopment Act ("NRA") provides for similar rate treatment, as it prescribes that the preference power shall be made available at the "lowest rates reasonably possible." 18 U.S.C. § 836(b)(1) (2011).

These parties claim that various adjustments to NYPA's proposed rate plan are needed in order to make NYPA's rates consistent with this standard. The adjustments requested include the following:

(1) Enlarging the allocator used to derive the demand charge to include all sales from the Hydro Projects, not merely those made to firm contract customers. *See, e.g.,* MEUA at 9-10, NYAPP at 3-4; NS Customers at 5-6. Under this theory, it would be appropriate for NYPA to allocate costs to non-firm customers who are not able to receive electricity at the preference rate and whose purchases are uncertain, rather than to perform the traditional allocation costs based on sales to firm contract customers.

(2) That NYPA's estimates of its capacity or "UCAP"[11] sales credits should be used to directly lower the Hydro CoS, rather than employed in the RSR reconciliation process. NS Customers at 11-12.

[11] In New York State, UCAP or "unforced capacity" refers to electric capacity that is needed to meet the reliability needs of customers as required under the NYISO tariff. In the context of this proceeding, NYPA's UCAP sales refers to capacity sold into the NYISO capacity markets or capacity internally transferred to non-hydroelectric customers at the NYISO UCAP rate. These UCAP transactions (which form the basis for the UCAP credit) are above the capacity needs of NYPA's firm hydroelectric power contract customers who receive this capacity product as part of the bilateral transaction between NYPA and the customer.

(3) All UCAP sales into the NYISO markets should be credited to the preference customers by lowering the energy charges collected under RSR rather than to the reconciled Hydro CoS used in the RSR calculation. NYAPP at 7, 9. Under this theory, UCAP sales into the NYISO would be a benefit realized exclusively by preference power customers, rather than attributed to the Hydro Projects as a whole.

(4) UCAP credits should be made at cost, even if the NYISO market price for NYPA's UCAP sales is below NYPA's cost. NYAPP at 8; Russell at ¶¶ 23-24; Radigan at 30. Under this proposed reform, NYPA's sales into short-term NYISO capacity markets would somehow be recognized as containing the same benefits as long-term firm sales to contract customers.

(5) NYPA's UCAP credit should be enlarged to include all capacity sales above the actual capacity demands from the Hydro Projects, rather than using the sales that exceed the "base level" of demand that NYPA uses to determine the demand rate. Radigan at 26-28; NYAPP at 24; Russell at ¶ 25.

Staff Analysis:

The requested rate adjustments noted in (1) – (5) above are discussed separately on their merits (see the Staff Analysis of Issues C, D and E, below), but first we addresses the notion, raised by some customers, that if a proposed modification reduces the rate, NYPA is *required* to adopt it in order to satisfy the "lowest possible rate" standard found in PAL §1005(5). That notion, however, is not mandated by law and, equally important, is inconsistent with specific rate methodologies agreed to by the customers in their long-term contracts and settlement agreements with NYPA.

Both the law and the customers have long recognized NYPA's "[b]road discretion . . . to determine the components of its costs" and that NYPA is not required or authorized to set the preference rate at "less than cost." *Auer v. Dyson*, 110 Misc. 2d 943, 948-49 (Sup. Ct. Oswego Co. 1981) ("*Auer*"). In fact, the preference customers have agreed to abide by the principles set out in the *Auer* cases and the *Auer* Settlement ending those litigations.

In subsequent long-term contracts and settlement agreements those principles have been further defined to include specific agreed-upon methodologies. Those methodologies include the recovery of capital costs, the treatment of sales of ancillary services or surplus energy to third parties and the creation and administration of the RSR. In addition, the application of these agreed-upon methodologies was fully explained and illustrated in the January 2003 Report, made available to all customers and specifically referenced in later contractual arrangements.

The truth is that some of the now-challenged methodologies are virtually identical to the methodologies adopted by the Trustees in 2003 and again in 2007 when the last preference rate increase was adopted. By way of example, NYPA's calculation of the demand allocation, the UCAP credit and the RSR adjustments in the July 2011 proposal are thoroughly consistent with these methods, which were expressly agreed to by customers.

Two final points are worth noting. First, the customers' reliance on the *Bergen* case is misplaced. *Village of Bergen v. Power Auth. of State of N.Y.*, 249 A.D.2d 902 (4th Dep't 1998), *appeal den'd,* 97 N.Y.2d 606 (2001). The issue there – NYPA's method for allocating indirect overheads – was not specifically covered by any agreement between NYPA and the customers. Here, however, the now-criticized methodologies concerning such items as UCAP crediting and RSR adjustments were previously employed in the January 2003 Report and consistent with the principles and methodologies contained in the customer agreements.

Second, the claim that NYPA *must* accept any customer suggestion which yields a lower rate is totally at odds with NYPA's acknowledged "broad discretion" in determining its costs. To accept that argument, NYPA would effectively cede all discretion to any customers who could suggest a cost calculation that yields a lower rate.

Recommendation:

Although the Authority is not mandated to accept any particular customer proposal, we have always been receptive to reasonable suggestions concerning the

development of the preference rate. In this case, the customers have raised some valid considerations. Accordingly, NYPA will, as described further below, adopt certain adjustments which should address the customers' concerns.

C. Issue: Requests to Increase the Demand Allocator

Public Comments:

NYAPP argues that denominator used to set the demand rate should be based on the MW-months of NYPA's contract demand plus the MW-months of the Authority's average UCAP sales from the Hydro Projects. In other words, the demand rate must be calculated using billing demands of 41,000 MW-months rather than the lower 34,000 to 36,000 MW-months the Authority has proposed to use in 2011-2014 based on estimated firm customer contract demands. NYAPP at 2-4. NYAPP states that this adjustment is necessary to achieve the lowest possible rate. *Id.* at 5-6. MEUA makes a similar claim. Though Mr. Radigan (MEUA's consultant) states that he does not take issue with NYPA's proposed revenue requirement, he believes that the rate design does not result in the lowest possible rate because it ignores "critical" billing determinants in the calculation of the demand rate. Radigan at 19. Mr. Radigan objects to NYPA not calculating the demand rate by spreading the cost over "all users" of the Hydro Projects' capacity. *Id.* at 22.

The NS Customers raise the demand allocator issue in a slightly different context. They first argue that NYPA's non-preference energy sales into the NYISO markets justify a customer credit based on the capacity costs associated with such sales. NS Customers at 5. But, the NS Customers further state that they would be happy with an alternative form of relief obtained by increasing the denominator used to calculate the demand charge. *Id.* at 5-6.

Staff Analysis:

The billing determinant methodology used for the proposed 2011-2014 hydroelectric production rates is the same methodology used in both the 2003 and 2007 production rates proposals and is entirely consistent with the contracts and settlements reached with various preference power customers.

According to standard ratemaking principles, the firm power contract customers are responsible for the cost recovery of the assets developed to serve them. NYPA

adheres to this principle when it undertakes its cost recovery through production rates that are developed by using the total *firm* demands of its hydroelectric customers.

These customers incorrectly equate NYPA's month-to-month and capability period-to-capability period sales of excess hydroelectric capacity into the NYISO market with long-term firm demand that is used in the derivation of the demand rate. To base the demand rate on the full capacity sales from the Hydro Projects pre-supposes that the clearing price of the NYISO UCAP market will always at least equal or exceed the cost-based demand rate developed with the increased billing determinants. Otherwise, NYPA would be at risk of adopting a rate recovery approach that leads to the under-recovery of its costs. In fact, the NYISO UCAP Rest of State clearing price has often been lower than the demand rate that would result from the customers' proposed method. The customers' proposed approach would very likely lead to the application of a less than cost-based rate.

The conventional method of developing a demand charge is to spread the fixed costs of a project to the firm users of the project and then to provide firm users with a demand credit from the non-firm use of the project's excess capacity. This is just the approach NYPA uses when it provides a UCAP credit in the annual RSR calculation. Through the UCAP credit computation the preference customers receive their allocated share of the Hydro Projects' UCAP sales as a credit to the actual cost of service. In its review of its Hydro CoS, staff recognizes that it can enhance the UCAP credit in a manner consistent with the rate methodologies in the January 2003 Report. In particular, and consistent with the NS Customers' suggestion (at 11-12), staff finds that it would be appropriate to provide the preference customers with the direct CoS benefit of forecasted UCAP sales, rather than incorporating the credit solely at the time of the RSR reconciliation process.

Recommendation:

NYPA does not find compelling the argument to increase the denominator used to calculate the demand charge. As shown, there is risk that NYPA would not recover its costs. However, to provide the preference customers with the timing benefits of the

UCAP sales, staff proposes to build a UCAP credit, based on NYPA's projected NYISO capacity sales revenue, into the annual rate development for each of the 2011-2014 rate years. Any differences in the estimated UCAP credit and actual UCAP sales would be reconciled in future annual RSR computations. By making this adjustment, NYPA would reduce the Hydro CoS by $1.6 million in Rate Year ("RY") 2011, $3.7 million in RY 2012, $5.1 million in RY 2013 and $6.5 million in RY 2014.

D. Issue: Requests that the RSR Should Reflect a UCAP Credit Based on Cost and Be Applied to the RSR Balance Directly

Public Comments:

As noted in Issue C, *supra*, the annual RSR reconciliation process contains a UCAP Credit which is designed as a credit to the preference power customers to account for market sales of capacity from the Hydro Projects that is above the needs of NYPA's contract hydropower customers. Both NYAPP and MEUA request that prior RSR annual calculations be revised to reflect the use of the cost-based rate for the UCAP credits. NYAPP at 7; Radigan at 30.

NYAPP refers to the "Global Settlement Agreement"[12] concerning the application of the UCAP credit, noting that it is explicit in the determination of the MW-months of capacity above a base level of capacity sales, but does not indicate the method for converting MW-months to a dollar credit, nor whether that dollar credit is to be spread to all contract customers or be applied only to the preference customers. Russell at ¶ 21. NYAPP contends that NYPA is incorrectly crediting UCAP sales based on the lower of market prices or costs and that revising the calculation to use a cost-based UCAP is necessary under the Global Settlement and applicable precedents.

Staff Analysis:

Consistent with the staff determination that the proposed rates for 2011-2014 should not be recalculated based on billing determinants that have been expanded to include estimated short-term UCAP sales, staff similarly disagrees with the NYAPP's proposal that the UCAP credit in prior annual RSR computations be re-valued at cost. Staff does not agree that its current approach of crediting the RSR for UCAP sales based on market prices conflicts with the Global Settlement Agreement and applicable precedents.

[12] The Global Settlement Agreements are long-term contract extensions entered into between NYPA and all NY Munis & Coops in 2003 which set forth the RSR crediting methodology and all other rate setting principles and methodologies regarding preference rates that were adopted by the Trustees in 2003.

There is no sound basis to equate the UCAP sales NYPA makes to NYISO customers as being the equivalent firm power service that the contract customers receive through the application of a rate that is at the lowest possible cost. By paying their rates, NYPA's firm contract customers are receiving long-term firm electric power and energy that is among the least expensive in the country. In contrast, the NYISO customers that purchase short-term UCAP from NYPA in a competitive market are merely meeting the unforced capacity requirements on a month-to-month or a capability period-to-capability period basis that are set for reliability purposes by the NYISO. As these NYISO customers are not receiving the same product, service or benefits as NYPA's firm contract customers, it does not make sense to apply the same cost of service rate to these transactions.

Rates are designed based upon the cost of providing service with the cost causer being the cost payer. NYPA correctly assigns this cost of service to its firm contract customers and correctly credits their cost of service through an application of a UCAP credit. However, NYPA will make a slight modification to its UCAP crediting practices to include in RSR balances the actual sales revenues it receives, rather than the lower of market revenues or cost. The market cost more properly reflects the service that the UCAP purchaser receives, and this change ensures that the preference customers will get that benefit when the market price exceeds the cost-based price for capacity.

Additionally, NYPA rejects the proposal that UCAP credit should be applied to the RSR balances only rather than deducted from the Hydro CoS, as suggested by NYAPP. Because the UCAP credit derives from the operation of Hydro Projects as a whole, it is appropriate for staff to continue to deduct these dollars from the actual Hydro CoS and not apply it to the preference power customers only. (Of course, consistent with NYPA's recommendation in Issue C, the UCAP credit applied to the CoS in the RSR process would consist of the reconciliation between the forecasted and actual UCAP sales.) This is consistent with the NYPA's rate methodologies that it has employed since 2003.

Recommendation:

Staff believes its dollar valuation of the UCAP credit at market prices is appropriate and should be retained, and that the UCAP credit made in the RSR calculation should be applied to the Hydro CoS.

E. Issue: NYPA's UCAP Credit Calculation Applied to the RSR and Claims that Preference Customers Cross-Subsidize Non-Preference Customers

Public Comments:

NYAPP states that a flaw in NYPA's UCAP calculation used in the RSR causes MW-months of actual capacity sales to be understated because NYPA's UCAP sales crediting methodology leaves the difference between the forecasted demand (the "base level" of approximately 36,000 MW-months) and the actual demands (ranging from 32,000-35,000 MW-months in recent years) out of the equation. Preference customers are charged for the costs of those MW-months but cannot use them. Nevertheless, preference customers are not granted a dollar credit when NYPA sells these MW-months, either in the UCAP credit to the RSR or in the calculation of the demand rate. Russell at ¶ 25.

MEUA argues that cross-subsidization can occur between the rates charged to preference customers and non-preference customers. In view of 2010 data, MEUA points out that actual billed demand of 32,711 MW is 10% less than the amount used in development of the current demand charge. They pinpoint the cause of the differential as being that the former Reynolds Metals (*i.e.*, now ALCOA's East Plant) saw its demand of 2,568 MW-months in 2007 reduced to 0 MW-months in 2010. ALCOA is a non-preference customer and its inclusion in the RSR calculation can cause cross-subsidization because the demand from the industrial customers can vary from year to year, while the demand of the preference power customers is more stable. If demand from the non-preference customers is down, the demand revenues collected go down, and the amount of money that needs to be collected in the RSR's energy charge goes up. Radigan at 26-28.

Staff Analysis:

Staff finds a certain level of merit in the public comments concerning the cross-subsidization issue and has reconsidered its UCAP sales credit methodology.

Beginning with the 2005 RSR calculation, the UCAP credit has been based on:

1) actual demand of Hydro Project contract customers;
2) plus UCAP sales to others in the NYISO market (= total sales of capacity);
3) minus the base level of capacity used to develop the demand rate;
4) equals the net amount of capacity used for the UCAP credit calculation.

In general, when actual demand was consistent with forecasted demand, the RSR calculation produced reasonable and expected UCAP credit results. However, in 2009 and 2010 ALCOA's East Plant was out of service for significant periods due to prevailing economic conditions. NYPA's base level of capacity approach did not leave the flexibility to account for the capacity reduction and did not make allowance for the greater amount of UCAP market sales that resulted with the absence of the East Plant's capacity needs.

Since the firm contract customers are paying for the embedded and operating costs of the hydroelectric projects, it is in accordance with traditional ratemaking standards that they be provided with the value produced by the UCAP sales made for each year from the time the UCAP credit was first implemented via the Global Settlement Agreement in 2003. Staff finds that such a methodological change can substantially remedy the problem of any cross-subsidization between the preference and non-preference customers that might have resulted in the RSR calculation as the increased UCAP sales will mitigate lost non-preference customer (*i.e.*, ALCOA) demand revenues.

Recommendation:

Staff recommends that the actual UCAP sales be used in the annual RSR calculations for 2005 through 2010. The dollar effect of the change is a $13.5 million positive movement in the 2010 RSR negative balance.

F. Issue: Treatment of the 455 MW Redirected to the Recharge New York Power Program

Public Comments:

NYAPP stated that the 455 MW withdrawn from the rural and domestic ("R&D") customers of the three upstate IOUs to implement the Recharge New York Power Program enacted into law in 2011 must remain in the billed demands used to calculate the demand rate. NPC registered the similar concern that its members not pay for RSR balances related to withdrawn preference power. NS Customers noted that the Authority should confirm its plan to reduce the RSR balance by a historical ratio of MWh usage of the utilities' R&D customers to the total preference power customers' MWh usage.

Staff Analysis:

The Preliminary Staff Report noted that the RSR balance might need to be altered as a result of the reduction in the portion of the hydropower sales made at preference power rates resulting from the newly created Recharge New York Power Program. Staff reviewed the billing determinants and contributions to the RSR balance for several years to determine an appropriate reduction in the cumulative RSR balance.

Recommendation:

Staff recommends that the 455 MW withdrawn from the R&D customers of the IOUs continue to be included in the billing demands used in the Hydro CoS. The withdrawn power, however, would no longer be classified as preference power and would be excluded from the calculation of the annual contribution to the RSR. Staff also recommends that the RSR balance as of December 31, 2010 (as adjusted) be reduced by 30.17%. This percentage represents the average MWh for these R&D customers out of the total preference MWh for the period 2008 through 2010 (see table below).

Year	IOU residential firm MWh	Total Preference MWh	IOU / Total
2008	2,981,500	9,980,801	29.87%
2009	2,964,533	9,759,304	30.38%
2010	2,982,171	9,848,105	30.28%
Total	8,928,204	29,588,210	30.17%

Using this 30.17% ratio results in a $10.5 million positive movement in the 2010 RSR negative balance.

G. Issue: Annual RSR Report Procedures

Public Comments:

MEUA points out that the RSR is a "full, after the fact reconciliation of NYPA's rate year costs and revenues." Though it concedes that the RSR process is a "mutually agreed upon" revenue requirement reconciliation set out in the preference customers' contracts with NYPA, MEUA requests the right to review the annual RSR calculations and the establishment of a public process, with an opportunity for information sharing, discovery and comment. MEUA at 4-5. While other customers did not provide written comments on the specific issue of RSR review, NYAPP and the NS Customers made this concern known to NYPA staff at in-person meetings.

Staff Analysis:

NYPA staff agrees that transparency in the Hydro CoS process, including the annual RSR computation, is a worthwhile goal. NYPA staff has regularly provided the annual RSR computation and supporting documentation to customers, but this process has not been done at consistent intervals. The receipt of customer comments and other formal procedures (as in a SAPA-style rulemaking proceeding) are unnecessary, however, as NYPA's administration of the RSR computation is already provided for as a matter of contract. Staff believes that the distribution of the RSR computation on an annual basis will allow for critical detailed information to be provided to preference customers and, coupled with follow-up meetings or conference calls, this should provide adequate opportunity for the customers to better understand the expenses and revenues that form the basis of the annual RSR computation. Such a process would be mutually beneficial to both NYPA and its preference customers.

Recommendation:

NYPA staff agrees to provide the preference customers with the annual reconciliation to the RSR by June 1st of each year and to meet over the ensuing few months to discuss relevant issues and provide needed data to customers. In light of NYPA's contractual rights and obligations concerning the RSR, no formal public process is necessary.

H. Issue: Increased Ancillary Services Credit

Public Comments:

NS Customers assert that the preference customers' current cost-based ancillary services credit used in the development of the Hydro CoS is insufficient, as it only credits the costs associated with the amount of regulation service necessary for contract loads, and not the actual regulation service sales. They refer to their contract to claim that they are entitled to receive an ancillary services credit based not on their contract demands, but rather based on the total amount of Authority ancillary services sales on the NYISO markets. NS Customers at 7-10.

Staff Analysis:

The NS Customers' claim is inconsistent with their Authority contracts and settlements. In their contracts with the Authority for preference power, their members agreed that certain methodologies and principles adopted by the Authority in 2003 could continue to be used without objection when the Authority sets future hydro rates.[13] One of those principles is "(iii) Treatment of sales to third parties, including the New York Independent System Operator." Although NS Customers interpret this provision as requiring *all* sales to third parties be used in the Hydro CoS crediting mechanism, they completely ignore the portion of Article X[14] of their preference power contract, which states that the customer waives any challenges to the methodologies and principles employed by the Authority in 2003 that are used to set new rates.

Thus, under the terms of their preference contracts, the NS Customers have already consented to the continued use of the 2003 methodology, and their claims to

[13] Each of NS Customers agreed to these methodologies and principles in their long-term contracts with the Authority executed in 2006.

[14] NS Customers have quoted a provision from Article X of their contract, entitled "Agreement for the Sale of Niagara Project Power and Energy," but have mistakenly referred to the "Relicensing Settlement Agreement Addressing Allocation of Niagara Project Power and Energy to Neighboring States" from 2005. No specific rate provisions are included in that document.

enlarge the “cost-based” production credit in the derivation of the base hydro rate and to reduce the Hydro CoS accordingly have no merit.

Recommendation:

Because there is no basis to accept customer claims that the cost-based credit should be increased, staff does not recommend this adjustment. However, for other reasons staff does recommend an increase in the cost-based credit for rate years 2011-14. Due to an upward adjustment to the 2009 test year billing determinants to reflect average annual usage for the ALCOA East plant (which happened to be shut down for much of that year), the ancillary services credit of $61.9 million shown in the preliminary CoS is proposed to be increased by a total of $2.2 million over the proposed rate plan. This is reflected in the revised Hydro CoS in Exhibit A.

I. Issue: Request for Credits Based on Authority Investment Income

Public Comments:

The NS Customers argue that they should receive a credit for investment income in the CoS since much of the Authority's investment income is generated from the operations at the Hydro Projects. They state that the failure to provide such credits is tantamount to including tax payments in the CoS, but failing to recognize tax refunds. NS Customers at 10-11.

Staff Analysis:

The NS Customers' tax refund analogy runs counter to the ratemaking principles established in the preference customer contracts. The preference rates are cost-based where no working capital charge is included and no real rate of return is earned. A portion of the Authority's investment income is derived from the Hydro Projects, but the Authority's investments are not analogous to tax refunds for which interest must be credited to the preference customers. As the *Auer* Settlement instructs, after the cost-based rate is established, revenues from the Hydro Projects can go into NYPA's general revenue fund. *Auer* Settlement ¶ 10. A claim for a share of the Authority's investment income would produce preference rates that are below cost and in violation of *Auer* Settlement principles. Yet, that is exactly the result if investment income derived from such excess revenues is used as a credit to the CoS.

Recommendation:

Staff recommends that no credits be provided to the Hydro CoS for investment income.

J. Issue: 2009-10 Deferred Rate Increases

Public Comments:

NYAPP asserts that the Authority's uncollected costs associated with the rate increases previously proposed for RYs 2009 and 2010 should not be allocated to ratepayers because that rate proceeding was cancelled by the Trustees in March 2009. NYAPP bases its argument on a March 24, 2009 Press Release issued by the Authority that announced the cancellation of the 2009 proposed rate, as well as the March 31, 2009 Trustees' decision to "withdraw" the proposed rates and "extend" the rates in effect in 2008. NYAPP claims that it had no "notice" that 2009-10 costs would be deferred and recovered through the RSR mechanism, and expected those costs to be forgiven. NYAPP also claims that the Authority's proposal in this regard demonstrates a lack of "transparency." NYAPP at 9-11.

Staff Analysis:

The contractually agreed-upon RSR mechanism is used to make annual calculations of the RSR balance, regardless of whether the Trustees decide to suspend any applicable RSR-related surcharge in addition to withdrawing a preference rate increase proposal. In essence, it is *always* appropriate for the Authority to record under-recovery of costs (as well as over-recoveries) through the RSR pursuant to customer contracts.

The 2009 suspension of the RSR surcharge did not indicate that prospective RSR calculations would be abandoned nor its balance forgiven; rather, it solely indicates that the costs accrued (including any potential surcharges) would be deferred until such date when the Trustees authorize the Authority to make such recoveries.

Moreover, the March 31, 2009 Memorandum to the Trustees gave clear notice that 2009 and 2010 costs would be deferred, not forgiven. The Memorandum states the following:

> The expected revenue increase resulting from the 2009 Rate Year Increase was nearly $10 million. *Those revenues will be deferred and recovered over appropriate, subsequent year(s). By deferring*

> *the collection of revenues, the Authority will comply with the requirement that preference rates be established on the basis of costs.* (emphasis supplied)

As shown above, the Authority correctly and openly stated that 2009-2010 rate year costs would not lapse, but rather that recovery would be postponed.

It is important to note that 2009-10 rate year costs would not be recovered until the rate year 2014 under the rate plan proposal. Based on the adjustments to the RSR balance now being recommended to the Trustees, an RSR-related surcharge to collect 2009-10 costs would be capped at $0.40/MWh in RY 2014. Authority staff will continue to monitor the RSR balance annually in order to evaluate the necessity of including 2009-10 costs within the preference rate.

Recommendation:

Staff does not recommend any changes to the RSR mechanism that would fail to recognize the cost deferrals related to the 2009 and 2010 rate years.

K. Issue: Contributions to New York State Treasury

Public Comments:

Certain parties raised concerns regarding NYPA's voluntary contributions to the State, but such comments were not uniformly critical. At the public forums, numerous parties remarked that it was inappropriate for NYPA to request a preference power rate increase in light of the large contributions to the State Treasury that the Authority has made in recent years.[15]

However, MEUA commented that it has reviewed the materials provided during the discovery process in this proceeding and concludes that NYPA's expenditures used to make contributions to the State Treasury have been "properly excluded" from the Hydro CoS. MEUA at 5-6.

NYAPP noted the size of the voluntary transfers and requested that the Authority adopt "detailed metrics" for measuring its creditworthiness at the time it considers making voluntary contributions to the State. NYAPP at 13-14. NYAPP is concerned that NYPA maintain its financial strength, particularly in light of "planned and needed upgrades of the hydro Projects" and that NYPA not become subject to "more stringent covenants in future lending agreements" that may require NYPA to increase hydroelectric rates in greater amounts than would otherwise be needed. Russell at ¶ 39.

Finally, NPC commented that the Authority should redirect the funds it would contribute to the State and instead use such "surplus funds" to offset the "entire proposed rate increase." NPC at 9-11.

Staff Analysis:

Despite the concerns raised, no party has argued that the Authority included the expenditures related to NYPA's contributions to the State in the Hydro CoS. Indeed, as

[15] *See* Statement of Assemblyman John D. Ceretto at 1-2; Statement of William L. Ross on behalf of NPC at 7-8; Statement of Niagara County Legislator Renae Kimble at 2-3 (all dated September 20, 2011, Niagara Falls public forum); Comments of Mr. Charlie McGrath, Tr. 17 (September 22, 2011, Massena public forum).

MEUA has verified during the discovery process, NYPA's documentary support for the production costs of the Hydro Projects indicates that no costs related to such contributions are included in NYPA's rate development. This is appropriate because such expenditures are unrelated to the costs of the operation of the Hydro Projects.

To address NYAPP's concerns, as demonstrated in the discovery phase of this proceeding, NYPA currently has existing metrics and engages in an in-depth review process to determine whether any transfer of surplus funds to the State is feasible and advisable. As shown in NYPA's responses to, *e.g.,* Data Requests MEUA 26 and NYAPP 1-23, the Trustees have set forth their criteria to determine whether these transfers were feasible and advisable.

Before a transfer can be considered it must (1) be authorized by the Legislature; (2) be approved by the Trustees "as feasible and advisable" and (3) satisfy the requirements of the Authority's General Resolution Authorizing Revenue Obligations dated February 24, 1998, as amended and supplemented ("Bond Resolution"). The Bond Resolution's requirements to withdraw monies "free and clear of the lien and pledge created by the [Bond] Resolution" are as follows: such withdrawals (a) must be for a "lawful corporate purpose as determined by the Authority," and (b) the Authority must determine, taking into account among other considerations anticipated future receipt of revenues or other moneys constituting part of the Trust Estate, that the funds to be so withdrawn are not needed for (i) payment of reasonable and necessary operating expenses, (ii) an Operating Fund reserve for working capital, emergency repairs or replacements, major renewals or for retirement from service, decommissioning or disposal of facilities, (iii) payment of, or accumulation of a reserve for payment of, interest and principal on senior debt or (iv) payment of interest and principal on subordinate debt.

Before any such transfer is made, a full review of the Authority's finances is conducted, and may include meetings and extensive communication with the Authority's financial advisor, bond counsel, and the rating agencies. The Authority reviews the effects that these transfers will have considering its current and future financial

obligations, and before the actual transfer is made, it is reaffirmed by the Trustees utilizing the most recent updated financial information available. The Trustees have developed a process to ensure that these any such transfers are "feasible and advisable" and will not result in preference power rate increases beyond those necessary to provide power at cost. Moreover, at their meeting on May 24, 2011, the Trustees adopted a Policy Statement establishing a "2.0 times debt service" coverage ratio shall be used as a reference point in considering any such transfer.

Lastly, NPC's insistence that NYPA is obligated to redirect funds it has contributed (or will contribute in the future) to the State to lower the preference rate was firmly rejected in a recent decision of the Appellate Division, Fourth Department. The court concluded that as long as NYPA has based the preference rate on cost "there is nothing in the Public Authorities Law prohibiting [NYPA] from contributing surplus funds to the State." *Niagara County v. Power Auth. of N.Y.*, 82 A.D.3d 1597, 1601 (4th Dep't), *appeal den'd*, 17 N.Y.3d 838 (2011).

Recommendation:

Staff has reviewed the Trustees' decision making criteria regarding contributions to the State Treasury and recommends no changes. Further, staff confirms that expenditures related to such contributions are unrelated to, and not included in, the Hydro CoS.

L. Issue: Relicensing Settlement Agreement with Host Communities

Public Comments:

NPC posits that the proposed rate increase will "diminish the value" of the allocations to its Host Community members obtained as part of its relicensing settlement with NYPA. NPC further states that it understood that the "value of the overall transaction would increase," and that the NYPA proposal "violates the spirit" of that settlement agreement because the allocations "could readily become worthless" from the rate increase. NPC at 5-6.

Staff Analysis:

The sale of hydropower at preference rates to the Host Communities, whose allocations now total 28 MW, began in 2007 under long-term contracts extending through September 1, 2025 as a result of the "Host Community Relicensing Settlement Agreement Addressing Non-License Terms and Conditions" executed on June 27, 2005. Before these allocations were made, the Host Communities paid the market price for all of their electricity. As a result of their hydro allocations, they receive some of the least expensive electricity in the United States for a portion of their loads.

NPC incorrectly implies that NYPA has somehow failed to live up to its settlement agreement commitments by making this rate proposal. However, Section 6.2(d) of the settlement agreement sets forth that the Host Communities shall pay NYPA the same cost-based rate for Niagara Project power that is paid by preference customers. NYPA never committed to freeze the preference rate, and parties understood that NYPA makes preference rate adjustments from time to time.

Recommendation:

Staff rejects NPC's complaints as unfounded and maintains that this rate proposal is completely consistent with the settlement agreement. Accordingly, staff makes no specific recommendations to the proposed rate plan to address NPC's complaints. Staff points out, however, that the rate adjustments recommended in this Staff Analysis should address some of NPC's concerns.

M. Issue: Shared Services, Charitable Contributions and Other Post-Employment Benefits Expenses

Public Comments:

NYAPP indicated that the Authority has not provided sufficient information as to what is included in Shared Services within the CoS and requests additional information regarding this category of expenses.

MEUA requested that charitable contributions not directly assignable to the Hydro Projects be removed from the CoS, as they do not direct benefit Hydro Project operations. MEUA takes no issue with CoS inclusions of charitable contributions that directly benefit the Hydro Projects, and which are directly assigned.

Staff Analysis:

During the discovery process, the Authority responded to several data requests regarding the allocation of Shared Services costs, including requests MEUA 8, 12, 29 and 31, NYAPP 1-5 and 3-5, and NS 14 and 28. Staff received no further inquiries regarding Shared Services expenses.

To provide further clarity regarding the responses previously provided, costs included in the Shared Services category are in support of NYPA-wide initiatives that are not directly chargeable to any specific project or facility. These costs include such items as general overhead to maintain NYPA operations, programs and facilities, including headquarters payroll, employee benefits, contractor and consultant support, information technology expenses, corporate finance and controller expenditures, corporate support including the maintenance of all facilities, equipment and grounds, marketing costs, general law department expenditures, Energy Resource Management and Energy Risk Management.

Shared Services expenses are allocated based on labor ratios, which, in turn, is based on the percent of total direct costs charged to each facility.

Concerning charitable contributions, staff's analysis indicates that all charitable contributions and sponsorships should be removed from the Hydro CoS. These include both directly assigned charitable contributions, as well as those included in Shared Services. The total value of the cost proposed to be removed for RYs 2011-14 is $483,000. Because this amount is *de minimis*, it will have little impact on the preference rate and will not affect the safe and reliable operation of the Hydro Projects.

Staff points out that its analysis resulted in an adjustment to its Other Post-Employment Benefits ("OPEB") expense which, though not part of Shared Services, is allocated in the same manner. Certain overhead cost-cutting measures undertaken by staff in the last few months, including an approximate $5 million reduction for RY 2012-2014 resulting from the Trustees' approval of a revised funding plan for the OPEB Trust at their October 2011 meeting, will lower the Hydro CoS.

Recommendation:

Staff recommends that any prospective charitable contributions or sponsorships be removed from the Hydro CoS. This would remove $483,000 for the 2011-14 rate years and lower, to some extent, the Shared Services component. Staff also recommends a $5 million downward adjustment to the OPEB expense be reflected in the Hydro CoS.

N. Issue: Recovery of Costs for Parks Near the St. Lawrence Power Project

Public Comments:

NYAPP seeks clarification concerning payments made to the Robert Moses and Coles Creek State Parks located in the direct vicinity to the St. Lawrence Power Project.

Staff Analysis:

In the Preliminary Staff Report, the Authority discussed its assumption of responsibility for operations at the New York State Robert Moses and Coles Creek Parks. The Authority developed these parks as part of the St. Lawrence Project, and through a series of agreements with state officials, assigned O&M responsibilities for these parks to the New York State Office of Parks, Recreation and Historic Preservation ("OPRHP"). The FERC license issued for the St. Lawrence Project on October 23, 2003 incorporates these facilities as project recreational facilities and, under the terms of the license, the Authority has the ultimate responsibility to fund the O&M costs of both parks. However, as part of a 2009 Memorandum of Understanding between the State of New York and the Authority, the Authority was relieved of these annual payments to OPRHP for the state fiscal years 2011 through 2017. Therefore, the Authority included no parks-related expenses within the CoS beyond the rate year 2010.

In reviewing accounting data for past years in response to customer data requests, staff discovered that in 2008, $8 million charged to the Miscellaneous and General Expenses Account for the Niagara and St. Lawrence Projects for Parks reimbursement had not been backed out of financial information used in the 2008 actual Hydro CoS used in the RSR calculation for that year. The CoS did include a separate entry for $800,000 attributable to the Parks.

Recommendation:

Based on the analysis above, staff recommends that the $800,000 cost for the Robert Moses and Coles Creek Parks not be included in either the RSR true-up or the Hydro CoS for RYs 2011-2014 covered under this proposed rate plan. The removal of the $8 million charge from the CoS results in a positive adjustment to the cumulative RSR of about $3 million.

O. Issue: Lewiston Pump Generation Project Life Extension and Modernization Program Costs

Public Comments:

Niagara County Legislator Renae Kimble questioned the “feasibility of the $460 million dollar Life Expectancy Project upgrade” at the Lewiston Pump Generation Plant (“LPGP”) at the Niagara Project, and its consequent effect on preference power rates. She claimed that this expense is unwarranted, and that it should not be included in the current rate modification plan.

Staff Analysis:

The Niagara Project has been operating for over 50 years, mostly with original equipment. Life extension and modernization (“LEM”) work is entirely prudent. The Authority's staff participates in industry research organizations from which we obtain a broader understanding of how plant systems degrade and when replacement is prudent, and consequently, the Authority has conducted overhauls to maintain the equipment and to replace or repair components as needed. Those overhauls provided the Authority's engineering and maintenance staff with the information to develop an understanding as to how components and systems were aging, and how long they could reasonably be expected to operate with the reliability needed at this critical project. It is important to note, however, that the basic control systems, including, but not limited to, wiring, hydraulic systems, breakers, transformers, exciters, governors and motor-generators are original.

While the cost of the LPGP LEM program may appear high, it must be viewed in the context of work over a nine year period. This is due to both an allowance for associated escalation risks, and work taking place one unit at a time so that NYPA can continue to meet its power commitments. The LEM project is necessary for the Authority to continue to meet its customers’ electricity demand both currently and prospectively.

In the alternative, a choice to retire the LPGP rather than upgrade it would cause a reduction in the firm power capability of the Niagara Project on the order of several hundred megawatts, which would cause a significant reduction in sales to all hydropower customers.

Recommendation:

Based on the analysis stated, staff does not recommend any changes to the Hydro CoS relating to expenses associated with the LPGP LEM project.

P. Issue: Control Systems at the Niagara Facility

Public Comments:

Legislator Kimble made two claims concerning the safety of the Niagara Project's control systems. First, she alleged that the replacement of the Project's original analog gauges with current industry-standard digital gauges poses a risk both to the operation of the Project, as well as to the electricity grid itself. Also, she alleged that the newer gauges represent excessive spending, as she claims they will not last as long as the original equipment. Second, Legislator Kimble alleges that the replacement of the analog gauge system with a digital system might pose a cyber security risk, and potentially subject the Niagara Project to a malicious attack by "hackers."

Staff Analysis:

Safety of Digital Gauges

Many of the gauges and associated components in the plant have been replaced or re-built as part of normal maintenance over the past 50 years. There is no evidence to show that new systems will not last as long as the originals, and periodic replacement of gauges and other components is routine. Making a change to digital equipment is undertaken cautiously, and the risk of lack of availability of analog equipment and the industry expertise to maintain such systems is itself a driver in moving to modern digital systems.

Safety of the Power Projects' Cyber Network

The North American Energy Reliability Corporation provides for extensive cyber-security procedures, to which all utilities, including the Authority, must adhere and be subject to audit. Further, control systems at the Hydro Projects are not part of a conventional business network, but rather are a secure closed network.

Recommendation:

Based on the analysis stated, staff does not recommend any changes to the Niagara Project's program of control system modernization.

Q. Issue: Sale of Capacity on the NYISO Market

Public Comments:

Legislator Kimble claims that the Authority sales of excess capacity are violative of the Authority's mandate to provide electricity at the "lowest possible rate" to its customers. She alleges that the sale of such electricity on the NYISO market enriches the Authority at the expense of the preference power customers.

Staff Analysis:

As directed by statute and case law, the Authority provides electricity to its preference power customers at the lowest possible rate. The preference power rate is cost-based, and the Authority charges preference customers only as much as it costs the Authority to produce. Further, the NYISO market clearing price has no bearing whatsoever on the preference customer rate, which is set by contract.

Recommendation:

Staff does not recommend any changes in response to this comment.

Exhibits and Tables

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
FINAL PRODUCTION COST OF SERVICE

($000)

Line	Description	(Per 2007 CoS) 2008	2011	2012	2013	2014	Difference 2011 vs 2008 *
	Operations & Maintenance/Administrative & General						
1	Operations & Maintenance/A&G	61,941	71,655	72,063	74,540	76,238	9,714
2	Amortized Roadwork	2,983	212	-	-	-	(2,771)
3	Subtotal O&M/A&G (line 1 + line 2)	64,924	71,866	72,063	74,540	76,238	6,942
	Indirect Overheads						
4	Shared Services	41,329	44,888	45,829	46,555	47,226	3,559
5	Research & Development	3,780	2,523	2,598	2,650	2,703	(1,257)
6	Project Study Debt Service	846	-	-	-	-	(846)
7	Y2K Debt Service	2,874	237	237	237	237	(2,637)
8	Subtotal Indirect Overheads (sum lines 4-7)	48,829	47,648	48,664	49,442	50,166	(1,181)
9	**St. Law. Relicensing, amortization**	2,000	2,000	2,000	2,000	2,000	-
10	**Niagara Relicensing, amortization**	12,000	12,700	12,700	12,700	12,700	700
11	**Other Post -Employment Benefits (OPEB)**	13,608	10,348	9,532	9,388	9,234	(3,261)
12	**O&M Cost of Service** (sum lines 3,8, 9, 10,11)	**141,361**	**144,562**	**144,959**	**148,070**	**150,338**	**3,201**
	Capital Costs						
13	Total Depreciation	35,350	40,984	43,422	45,309	47,204	5,634
14	Interest on Debt	21,453	30,322	33,205	35,104	37,386	8,869
15	Inflation Compensation	21,521	28,697	30,428	32,182	34,069	7,176
16	Subtotal Capital Costs (sum lines 13-15)	78,324	100,003	107,055	112,595	118,659	21,679
17	**Total Cost of Service** (line 12 +line 16)	**219,685**	**244,565**	**252,014**	**260,665**	**268,997**	**24,880**

* 2008 data is from 2007 CoS and was based on data and projections available at that time.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
FINAL PRODUCTION COST OF SERVICE

($000)

Line	Description		(Per 2007 CoS) 2008	2011	2012	2013	2014	Difference 2011 vs 2008 *
1	**Total Cost of Service**	**($000)**	**219,685**	**244,565**	**252,014**	**260,665**	**268,997**	**24,880**
2	**Credits for ancillary services**	($000)						
3	Black Start, O&M		81	69	72	74	76	(12)
4	Voltage Support, O&M		332	213	219	225	232	(119)
5	Remaining O&M (page 1, line 12 - (line 3+line 4)		140,948	144,280	144,668	147,771	150,030	3,332
6	Operating Reserves, O&M		4.82%	4.62%	4.60%	4.55%	4.52%	
7	Regulation, O&M		0.57%	0.57%	0.57%	0.56%	0.56%	
8	Subtotal OR, Reg. O&M		5.39%	5.19%	5.17%	5.11%	5.08%	
9	Op. Res.+ Reg. O&M credit (line 8 * line 5)	($000)	7,597	7,488	7,479	7,551	7,622	(109)
10	**Capital Reductions**							
11	All ancillary services		6.85%	6.92%	6.98%	6.99%	7.03%	
12	Subtotal capital reductions (page 1, line 16 * line 11)	($000)	5,365	6,920	7,472	7,870	8,342	1,555
13	Total Ancillary Credits (sum lines 3,4,9,12)	($000)	13,375	14,690	15,243	15,721	16,271	1,315
14	UCAP Credit	($000)		1,554	3,741	5,094	6,493	1,554
15	**Adjusted Cost of Service** (line 1 - (line 13 + line 14))	**($000)**	**206,310**	**228,321**	**233,030**	**239,851**	**246,233**	**22,011**
16	Billing Demand	MW	36,137	34,086	35,035	35,871	36,100	(2,051)
17	Billing Demand Allocated Costs (line 15 - line 22)	($000)	106,822	128,858	133,567	140,388	146,770	22,035
18	Billed Demand Rate (line 17 / line 16)	$/kW/mo	2.96	3.78	3.81	3.91	4.07	
19	LTA Generation	GWh	20,221	20,216	20,216	20,216	20,216	(5)
20	Annual Generation	GWh	20,012	20,456	20,148	20,409	20,435	444
21	Billing Energy Rate	$/MWh	4.92	4.92	4.92	4.92	4.92	
22	Costs Allocated to Energy Rate (line 19 * line 21)	$/MWh	99,487	99,463	99,463	99,463	99,463	(25)

* 2008 data is from 2007 CoS and was based on data and projections available at that time.

EXHIBIT "B"

NEW YORK POWER AUTHORITY
ESTIMATED AVERAGE ANNUAL CUSTOMER IMPACTS
Prices ($/MWh) include demand and energy components

		Current *	2011	2012	2013	2014
MUNIS/COOPS FULL REQUIREMENTS						
CURRENT HYDRO PRODUCTION RATES	$/MWh		10.36	10.42	10.41	10.41
PROPOSED HYDRO PRODUCTION RATES	$/MWh		10.91	11.55	12.17	12.87
INCREASES FROM CURRENT	$/MWh		0.55	1.13	1.76	2.46
END USE RESIDENTIAL IMPACTS						
SYSTEM RESIDENTIAL RATE	$/MWh	80.51	80.72	81.46	82.00	82.59
INCREASES FROM CURRENT	$/MWh		0.21	0.95	1.49	2.08
SYSTEM RESIDENTIAL AVG. BILL	$/mo	79.98	80.18	80.92	81.46	82.05
INCREASES FROM CURRENT	$/mo		0.21	0.94	1.48	2.07
MUNIS/COOPS PARTIAL REQUIREMENTS						
CURRENT HYDRO PRODUCTION RATES	$/MWh		10.61	10.69	10.68	10.68
PROPOSED HYDRO PRODUCTION RATES	$/MWh		11.18	11.88	12.53	13.24
INCREASES FROM CURRENT	$/MWh		0.58	1.19	1.85	2.56
END USE RESIDENTIAL IMPACTS						
SYSTEM RATE	$/MWh	59.27	59.51	60.38	61.01	61.69
INCREASES FROM CURRENT	$/MWh		0.24	1.12	1.74	2.42
SYSTEM RESIDENTIAL AVG. BILL	$/mo	64.87	65.14	66.09	66.78	67.52
INCREASES FROM CURRENT	$/mo		0.27	1.22	1.91	2.65
RESIDENTIAL UTILITY CUSTOMERS (PEAKING ONLY)						
END USE RESIDENTIAL IMPACTS						
SYSTEM RATE	$/MWh	135.58	135.61	135.71	135.79	135.83
INCREASES FROM CURRENT	$/MWh		0.03	0.13	0.21	0.25
SYSTEM RESIDENTIAL AVG. BILL	$/mo	88.94	88.96	89.03	89.07	89.10
INCREASES FROM CURRENT	$/mo		0.02	0.09	0.14	0.16

* Current is the most recent Energy Information Adminstration data, which is 2009.

Table 1
EMBEDDED COSTS FOR ANCILLARY SERVICES FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
Voltage Support O&M Cost Reduction ($)	[1]	212,522	218,897	225,464	232,228
Voltage Support Capital Share (%)	[2]	1.74%	1.85%	1.92%	1.98%
Black Start O&M Cost Reduction ($)	[3]	69,445	71,528	73,674	75,884
Black Start Capital Share (%)	[4]	0.074%	0.071%	0.069%	0.067%
Regulation O&M Share (%)	[5]	0.57%	0.57%	0.56%	0.56%
Regulation Capital Share (%)	[6]	0.57%	0.57%	0.56%	0.56%
Operating Reserve O&M Share (%)	[7]	4.62%	4.60%	4.55%	4.52%
Operating Reserve Capital Share (%)	[8]	4.62%	4.60%	4.55%	4.52%
Ancillary Service O&M Cost ($)	[9]	281,966	290,425	299,138	308,112
Ancillary Service O&M Share (%)	[10]	5.20%	5.17%	5.11%	5.09%
Ancillary Service Capital Share (%)	[11]	6.92%	6.98%	6.99%	7.03%

Notes and Sources:
[1]-[2]: Table 2.
[3]-[4]: Table 3.
[5]-[6]: Table 4.
[7]-[8]: Table 5.
[9]: [1] + [3]
[10]: [5] + [7]
[11]: 1 - { 1 - ([2]+[4]) } * { 1 - ([6]+[8]) }

Table 2
EMBEDDED COSTS FOR VOLTAGE SUPPORT FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
Voltage Fraction of Gross Capital (Niag. & St. L.)	[1]	**1.74%**	**1.85%**	**1.92%**	**1.98%**
Voltage O&M Expense : Niagara ($)	[2]	172,800	177,984	183,324	188,823
Voltage O&M Expense : St. Lawrence ($)	[3]	39,722	40,913	42,141	43,405
Total Voltage O&M Expense ($)	[4]	**212,522**	**218,897**	**225,464**	**232,228**

Notes and Sources:
[1]: From Workpaper 5.3. Fraction is Beginning-of-Year value (equal to End-of-Year value for previous year).
[2] and [3]: From Workpaper 2.2.
[4] = [2] + [3].

Table 3

EMBEDDED COSTS FOR BLACK START FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
Black Start Fraction of Gross Capital (Niag. & St. L.)	[1]	**0.074%**	**0.071%**	**0.069%**	**0.067%**
Inflation Factor	[2]	106.6%	103.0%	103.0%	103.0%
Black Start O&M Expense ($)	[3]	**69,445**	**71,528**	**73,674**	**75,884**

Notes and Sources:
[1]: From Workpaper 7. Fraction is Beginning-of-Year value (equal to End-of-Year value for previous year).
[2] = From Workpaper 1
[3]: Sum of Test Year Training costs for Niagara and St. Lawrence, plus O&M Cost allocated to Black Start from Workpaper 6 and adjusted by Inflation Factor in line [2].

Table 4
EMBEDDED COSTS FOR REGULATION FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
NYCA Peak Load	[1]	33,160	33,367	33,737	33,897
Total NYCA Regulation Requirement (MW)	[2]	223	223	223	223
Required regulation per MW of peak load (MW)	[3]	0.007	0.007	0.007	0.007
Peak load of all contract customers of Niagara and St. Lawrence (MW)	[4]	2,761	2,761	2,761	2,761
Required regulation for all contract customers of Niagara and St. Lawrence (MW)	[5]	19	18	18	18
Niagara & St. Lawrence Summer Generation Capacity (MW)	[6]	3,241	3,241	3,241	3,241
Share of regulation for all contract customers of Niagara and St. Lawrence in generation capacity (%)	[7]	0.57%	0.57%	0.56%	0.56%

Notes and Sources:
[1]: From Workpaper 8. Test year peak equals 2009 peak.
[2]: From Workpaper 8.
[3] = [2] / [1].
[4]: From Workpaper 8.
[5] = [3] * [4].
[6]: NYPA, "2009 Annual Report".
[7] = [5] / [6].

Table 5
EMBEDDED COSTS FOR OPERATING RESERVE FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
NYCA Peak Load	[1]	33,160	33,367	33,737	33,897
Total NYCA Reserve Requirement (MW)	[2]	1,800	1,800	1,800	1,800
Required reserve per MW of peak load (MW)	[3]	0.054	0.054	0.053	0.053
Peak load of all contract customers of Niagara and St. Lawrence (MW)	[4]	2,761	2,761	2,761	2,761
Required reserve for all contract customers of Niagara and St. Lawrence (MW)	[5]	150	149	147	147
Niagara & St. Lawrence Summer Generation Capacity (MW)	[6]	3,241	3,241	3,241	3,241
Share of required reserve for all contract customers of Niagara and St. Lawrence in generation capacity (%)	[7]	4.62%	4.60%	4.55%	4.52%

Notes and Sources:
[1]: From Workpaper 8. Test year peak equals 2009 peak.
[2]: From Workpaper 8.
[3] = [2] / [1].
[4]: From Workpaper 8.
[5] = [3] * [4].
[6]: NYPA, "2009 Annual Report".
[7] = [5] / [6].

New York Power Authority

July 2011 Preliminary Staff Report

Hydroelectric Production Rates

Rate Modification Plan – Rate Years 2011 to 2014

Including:

Cost-of-Service

Appendix B

November 2011

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Exhibit A - Production Cost of Service

Exhibit B – Estimated Average Annual Customer Impacts

Table 1 - Embedded Costs For Ancillary Services

Table 2 - Embedded Costs For Voltage Support

Table 3 - Embedded Costs For Black Start

Table 4 - Embedded Cost For Regulation

Table 5 - Embedded Costs For Operating Reserve

New York Power Authority
2011 Preliminary Staff Report

Executive Summary

At their April 2007 meeting, the Trustees approved a two-year (2007 and 2008 Rate Years) rate plan applicable to the Authority's preference power customers. The final rate year under this plan was to terminate on April 30, 2009. In January 2009, the Trustees authorized the publication of a proposed new rate action for Rate Years 2009 and 2010. That proposal called for increasing revenues in the 2009 rate year by $9.7 million as compared to the 2008 rate year, and increasing revenues in the 2010 rate year by another $14.6 million as compared to the 2008 rate year. Based on public comments and in consideration of the national economic downturn and the extent to which the downturn had adversely affected the region's customers, the Trustees in March 2009 approved the withdrawal of the proposed rate action, deferring the recovery of the costs until a subsequent period of time. The deferred recovery was necessary since under federal and state statutes and court precedents governing preference power sales the preference rate must be at the lowest possible rate but not lower than cost.

The currently effective rates consist of a demand charge of $2.96/kW-mo. and an energy charge of $4.92/MWh. At an indicative load factor of 70% these rates equal $10.71/MWh, which compares favorably to the $39.22/MWh average hourly market rate for 2010 in the New York Independent System Operator ("NYISO") Zone A located in western New York.

Authority staff is proposing a 42-month rate plan covering the remaining portion of the 2011 rate year plus the 2012, 2013 and 2014 rate years ending April 30, 2015. By the 2013 rate year the preference rates will be phased back up to full cost. Starting with the 2014 rate year, the suspension of the Rate Stabilization Reserve ("RSR") would be lifted and the Authority would begin to collect deferred hydroelectric costs stemming mainly from the withdrawn rate action for the 2009 and 2010 rate years.

A preliminary Cost of Service ("CoS") has been completed to determine the adequacy of the current rates. This analysis has resulted in a projected increase in hydroelectric rate to $12.45 per MWh for the 2011 rate year as compared to the 2008 rate level of $10.71 per MWh at the time the rates were frozen. Thereafter, gradual increases for the 2012 through the 2014 rate years are projected with the final year rate at $13.37 per MWh. These projected increases in rates are before any recovery of the deferred amounts. The principal cost driver responsible for the increase is the ongoing capital investments in the facilities, including: relicensing expenditures at Niagara and St. Lawrence, the life extension and modernization ("LEM") for the St. Lawrence Project and the LEM for the Lewiston Pump-Generating Plant ("LPGP") at the Niagara Project. The LEM program at the St. Lawrence Project, which began in 1998, is expected to be completed in 2013. The LEM program at LPGP, expected to begin in 2012 and be completed in 2020, is estimated to cost $460 million. During the two years of the rate freeze and the four years of the proposed rate plan period, the Authority will have invested over $490 million in the Hydro Projects.

The proposed rate plan incorporates continuation of the ratemaking and CoS methodologies adopted in the April 2003 final rate action approved by the Trustees and agreed to by the preference power customers as part of the "global" settlement agreements with the Authority.

Discussion

The attached preliminary CoS sets forth in detail the estimated costs required to serve the preference power customers from the Authority's St. Lawrence and Niagara Projects. The preference power customer class consists of 47 municipal electric systems and four rural electric cooperatives ("M&C" customers), residential customers of three upstate investor-owned utilities, the Neighboring State customers[1] and the Niagara Project relicensing host communities.

Ratemaking methodologies incorporated in this CoS were adopted in the April 2003 final rate action approved by the Trustees and agreed to by preference power customers who were active parties to the 2003 rate proceeding as part of the "global" settlement agreements. These methodologies and principles include:

(a) The "labor/labor" method (*i.e.* labor ratios) adopted by the Authority's Trustees on December 18, 2001 and incorporated into the January 2003 Report on Hydroelectric Production Rates ("January 2003 Report") for the allocation of Indirect Overheads.

(b) A capital cost recovery method as described in the January 2003 Report reflecting the equity investment in and new debt issued related to the Hydro Projects.

(c) Melding of St. Lawrence Project and Niagara Project costs for ratemaking purposes.

(d) Recovery in rates of all prudent Hydro Project relicensing, life extension and modernization costs incurred by the Authority in the exercise of its broad discretion.

(e) Amortization over 20 years by the Authority of its actuarial estimate of its Other Postemployment Benefits ("OPEBs") liability as described in the January 2003 Report.[2]

(f) Use of the RSR for any under-collection or over-collection of the Authority's hydroelectric CoS. The RSR calculations will be done in a manner consistent with the hydroelectric CoS study contained in the January 2003 Report.

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[1] These customers consist of certain municipal utilities located in Connecticut, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island and Vermont.

[2] The January 2003 Report used the equivalent term Post Retirement Benefits Other than Pensions ("PBOPs") for this analysis.

(g) The Authority will continue to credit the cost-based revenues from hydro energy sales in the hydroelectric CoS in the same manner as in the hydroelectric CoS study contained in the January 2003 Report. The credit will be based on the preference power tariff energy charge, as it changes from time to time. Also, all sales of capacity above the base level of capacity sales in the hydroelectric CoS study will be credited to the RSR.

Cost of Service Components

The major categories and significant drivers of the proposed rate action are summarized below. The CoS is detailed in the attached Exhibit "A" and Tables 1 to 5. Exhibit "B" shows estimated average annual customer impacts of the proposed rate modification plan.

Operations & Maintenance/Administrative & General Expenses

Operations & Maintenance ("O&M")/Administrative & General ("A&G") (Exhibit "A", Page 1, Line 1) – These costs consist of the site and direct O&M as well as the A&G expenses for the Hydro Projects which include the day-to-day operations of the projects and ongoing expenses associated with major maintenance programs and non-capital modifications.

Included in the Operations & Maintenance/A&G category of the CoS are payments reflecting the Authority's assumption of responsibility for operations at the New York State Robert Moses and Coles Creek Parks.

The Authority developed Robert Moses and Coles Creek State Parks as part of the St. Lawrence Project, and through a series of agreements assigned O&M responsibilities for these parks to the New York State Office of Parks, Recreation and Historic Preservation. The Federal Energy Regulatory Commission ("FERC") license issued for the St. Lawrence Project on October 23, 2003 incorporates these facilities as project recreational facilities and, under the terms of the license, the Authority has the ultimate responsibility to fund the O&M costs of both parks. Approximately half of the total $800,000 annual cost for these facilities is recovered from the preference power customers each year.

Added to the O&M for ratemaking purposes only (Exhibit "A", Page 1, Line 2) is the amortization of the $51.3 million of Niagara Project roadwork incurred from 1991 to 1996. Each year's expense was amortized over 15 years. The last year for recovery of these costs is 2011.

Indirect Overheads

Indirect Overheads (Exhibit "A", Page 1, Lines 4-7) consists of: Shared Services, the allocated share of headquarters costs associated with providing support for the St. Lawrence and Niagara Projects based on labor ratios consistent with the methodology adopted in the April 2003 final rate action; the cost of Research & Development ("R&D") initiatives; and, debt service associated with the Y2K readiness program. Included in the CoS is 41% of the total projected Shared Services for the 2011 through 2014 rate years.

St. Lawrence & Niagara Relicensing

Included in current rates are certain relicensing costs related to the Niagara and St. Lawrence Projects (Exhibit "A", Page 1, Lines 9-10). At their meeting of November 25, 2003, the Trustees formally accepted the new license issued for the St. Lawrence Project by FERC. The total cost of compliance and implementing the provisions of a new license and associated settlement agreements was estimated to be $210 million including relicensing process costs, the expenses associated with relicensing studies, support for settlement discussions and the public outreach. Of this amount, some $173 million is capitalized and will be recovered over the 50-year term of the new license. Part of the compliance cost is a $2 million annual payment to local communities, shown as an expense in Exhibit "A" (Page 1, Line 9).

At their meeting of May 22, 2007, the Trustees formally accepted the new license issued for the Niagara Project by FERC. The costs of a new license and the associated settlement agreements was estimated to be $494 million dollars, of which some $182 million is capitalized and recovered over the 50-year term of the new license. As part of the relicensing, the Authority is committed to providing amounts of some $19.7 million per year to the surrounding host

communities. Of the $19.7 million annual amount, $12.7 million will be drawn from the Authority's Operating Fund and is shown as an expense in Exhibit "A" (Page 1, Line 10). The remaining amount will be funded through the monetization of 29 MW of Niagara Project power.

Other Post-Employment Benefits ("OPEBs")

The existing rates reflect accrual treatment of OPEBs[3] which mainly include retiree health benefit costs. Prior to the current ratemaking methodology the plan costs were treated on a cash basis. In anticipation of a change in accounting standards, the Authority switched to accrual accounting in 2002. The liability has been updated since then. The revised charge has resulted in a decrease from the projected 2008 level of $13.6 million to a range of $10.3 to $11.4 million per year over the period 2011-2014, primarily due to the Authority funding an independent trust to partially meet the OPEB obligation. (See Exhibit "A", Page 1, Line 11).

Capital Costs

Since the retirement in 1981 of the original bonds issued to fund the Hydro Projects, cash (or "equity") funding was used to finance plant additions (Exhibit "A", Page 1, Lines 13-15). With the increased capital investments in the Hydro Projects related to plant modernization, upgrades and relicensing, beginning in 2000 the Authority has issued new debt associated with these facilities. As in past rate formulations, and as agreed to in various customer contracts, equity-type funding will be recovered using the Trended Original Cost ("TOC") methodology. Under TOC only the inflation component or return "of" the investments is captured. The return "on" the investment is foregone. The inflation component uses the Handy-Whitman Index ("HWI") as the measure for inflation. The HWI increased by 7.9% and 7.8% in 2007 and 2008, respectively, offset by a 1.2% decline in 2009. In 2010 the HWI increased 3.5%. For the 10-year period through 2010 the average annual increase in the HWI was about 3.7%.

[3] The January 2003 Report used the equivalent term Post Retirement Benefits Other than Pensions ("PBOPs") for this analysis.

The capital costs (both debt- and equity-funded investments) during the rate years covered by the proposal under consideration total $438 million, including $100 million, $107 million, $113 million and $119 million, in each of the rate years 2011 to 2014, respectively. (See Exhibit "A", Page 1, Line 16.) In addition, in the two years that the rates were frozen, the capital costs totaled $186 million. As noted above, these costs include the capital investments in the St. Lawrence and Niagara Projects, as well as the costs of relicensing. In the April 2003 final rate action the Trustees adopted a "hybrid" approach to capital cost recovery, reflecting the use of the TOC method for that portion of the Hydro Projects' capital cost funded with equity and the more conventional debt-service method that applies to the portion funded with debt. This hybrid method, developed by The Brattle Group in 2003, is used in the CoS here.

Credits For Ancillary Services

The proposed hydroelectric rates exclude certain O&M and Capital costs associated with the production of ancillary services at the Hydro Projects, namely Regulation Service, Operating Reserves, Voltage Support and Black Start Service (Exhibit "A", Page 2, Lines 3-13). These services are sold to the NYISO. Consistent with the ratemaking methodologies adopted in the April 2003 final rate action, the Authority has included a reduction in the CoS that represents the embedded costs of producing these services. The results of applying these methodologies to develop the 2011-14 cost-based credits are shown in Exhibit "A" (Page 2, Line 13). Tables 1-5 include the detailed data supporting the estimated credits. The 2011-14 credits to the CoS are about $14.1 million, $14.7 million, $15.2 million and $15.7 million, respectively.

Rate Design

From the inception of the Hydro Project preference rates in 1958 through April 30, 2003, the demand charge was held constant at $1.00/kW-month. All costs above those captured by the $1.00/kW-month demand charge were recovered in the energy rate. Because the majority of the costs identified in the CoS do not vary with the energy production from the Hydro Projects, but are in the nature of fixed costs, it was determined in the April 2003 final rate action approved by

the Trustees that the increased revenue requirement should be collected in the hydroelectric demand (or "fixed") charge. The demand charge was increased for the rate year beginning May 2003, and each year thereafter, while the energy rate was held constant at $4.92/MWh. For the last year of the plan, May 1, 2008 to April 30, 2009 and continuing to the present as a result of the rate freeze, the demand charge is currently $2.96/kW-month. It is proposed that this rate design policy be continued for the proposed rate plan, and that costs not collected in the current $4.92/MWh energy charge be recovered through the demand charge. (See Exhibit "A" Page 2, Line 17.)

As discussed in the January 2003 Report (which supported the April 2003 final rate action approved by the Trustees), the cost structure for a hydroelectric plant is largely fixed in nature and does not vary by output in the short term. The vast majority of the total Hydro Projects' costs, including the majority of O&M, indirect costs (Shared Services, R&D, and Indirect Debt Service), Relicensing, and Capital Costs, are fixed, and therefore, should appropriately be allocated to the demand charge. For the proposed rate design, the initial step is to allocate a portion of the total Hydro Projects' costs to the energy function by multiplying the current energy rate of $4.92/MWh times the generation. (See Exhibit "A", Page 2, Line 21). The result is energy allocated costs of $99.5 million in each rate year. The remaining Hydro Projects' costs to be recovered through the demand charge are $131.1 million (2011), $139.2 million (2012), $147.8 million (2013) and $156.1 million (2014). (See Exhibit "A", Page 2, Line 16). Dividing the demand charge costs by the total Hydro Projects' billed demands yields the demand charges of $3.85/kW-month (2011), $3.97/kW-month (2012), $4.12/kW-month (2013) and $4.32/kW-month (2014). The result of the cost allocation procedure allocates somewhat more costs to the demand function (57% in 2011) than to the energy function (43%).

The total Hydro Projects' costs, net of the ancillary service credits, are $230.6 million, $238.6 million, $247.3 million and $255.6 million for the 2011 to 2014 calendar years, respectively. (Refer to Exhibit "A" Page 2, line 14). If applied in a manner consistent with past ratemaking practice, the Rate Year beginning November 1, 2011 would be based on the calendar year 2011 costs. Similarly, the rate years beginning May 1, 2012 to 2014 would be based on calendar year

2012 to 2014 costs, respectively. The demand and energy rates for the 42-months covered by this rate plan and the overall rates at the 70% load factor, if set on this basis, are shown below.

Rate Year[4]	Demand Rate $/kW-month	Energy Rate $/MW-hour	Effective Rate[5] $/MW-hour
2011	3.85	4.92	12.45
2012	3.97	4.92	12.69
2013	4.12	4.92	12.98
2014	4.32	4.92	13.37

Rate Stabilization Reserve (RSR)

The RSR, established in 1987, was designed to capture the under-recovery or over-recovery of costs relative to the costs collected in the fixed demand and energy charges, due to differences in net generation and actual cost incurrence. By design, if the RSR balance exceeds a range of -$25 million to +$25 million, a surcharge or credit will be assessed against the preference power hydro rate over the ensuing 12-month period. Authority staff's calculations show the RSR balance as of December 31, 2010 to be about -$51.3 million, indicating a $26.3 million shortfall beyond the -$25 million threshold. Most of this $26.3 million shortfall is attributable to the deferred 2009 and 2010 rate increases.

Staff proposes that, given the increased level of costs forecast, the suspension of the RSR surcharge should be lifted no later than May 2014, and customers would pay an RSR surcharge during the fourth rate year under this proposal.

[4] Except for 2011, the preference power rate year runs from May 1 of the calendar year indicated to April 30 of the following year. Because of the timing of this Notice of Proposed Rulemaking ("NOPR"), the 2011 rate year the period would be from November 1, 2011 to April 30, 2012.

[5] Effective rate at 70% load factor.

Based on the current negative RSR balance, staff anticipates that RSR surcharges will need to continue in the rate years subsequent to the years covered by the proposed rate plan in order to bring the RSR balance back to the -$25 million level. Staff will keep the Trustees informed regarding the RSR balance and will make further recommendations as appropriate.[6]

Rate Phase-in Proposal

At their March 31, 2009 meeting the Authority's Trustees approved the withdrawal of a Notice of Proposed Rulemaking affecting hydroelectric preference power rates. This action included a rate freeze of the existing preference rates, a suspension of the rate surcharge of the RSR for preference power customers and a requirement to collect the costs deferred as a result of such action "over appropriate, subsequent year(s)."

Staff recommends phasing rates up to current costs by the 2013 rate year. A phase-in of rates would result in an under-recovery of costs of $12 million in 2011 and $4 million in 2012. Staff also recommends that, starting with the 2014 rate year, the suspension of the RSR would be lifted and the Authority would begin to collect deferred hydroelectric costs stemming from the 2009 and 2010 foregone rate increases. To mitigate cost impacts to the preference customers, staff recommends that the RSR surcharge be limited to $0.50/MWh in 2014. Based on the current negative RSR balance, staff anticipates the proposed RSR surcharges will need to continue in the rate years subsequent to the years covered by the proposed rate plan in order to bring the RSR balance back to the -$25 million level.

[6] By the time new preference rates are made effective in November 2011, the RSR balance may need to be altered due to the loss of a portion of the hydropower sales made at preference power rates. As a result of Chapter 60 (Part CC) of the Laws of 2011, which directs NYPA to implement the Recharge New York power program, NYPA will be withdrawing 455 MW of firm hydropower currently allocated to upstate utilities which is priced at the preference power rate. To the extent staff anticipates that such withdrawal will affect the RSR balance and the RSR surcharge in a material manner, staff will inform the Trustees and adjust the rate proposal accordingly when it is submitted for final approval in October 2011.

The proposed demand and energy rates for the four rate years and the overall rates at the 70% load factor are shown below.

Rate Year[7]	Demand Rate $/kW-month	Energy Rate $/MW-hour	RSR-related Surcharge $/MW-hour	Effective Rate[8] $/MW-hour
2011	3.32	4.92	-	11.42
2012	3.70	4.92	-	12.16
2013	4.12	4.92	-	12.98
2014	4.32	4.92	0.50	13.87

Final Staff Report

Authority staff intends to present a final report at the October 2011 Trustee meeting, and would issue it to the public shortly thereafter. The final report will reflect public comments and staff analysis, as well as Trustee action, on the proposed rate plan.

[7] Except for 2011, the preference power rate year runs from May 1 of the calendar year indicated to April 30 of the following year. Because of the timing of this NOPR, the 2011 rate year the period would be from November 1, 2011 to April 30, 2012.

[8] Effective rate at 70% load factor.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
PROPOSED PRODUCTION COST OF SERVICE

($000)

Line	Description	(Per 2007 CoS) 2008	2011	2012	2013	2014	Difference 2011 vs 2008 *
	Operations & Maintenance/Administrative & General						
1	Operations & Maintenance/A&G	61,941	71,762	72,174	74,654	76,355	9,821
2	Amortized Roadwork	2,983	212	-	-	-	(2,771)
3	Subtotal O&M/A&G (line 1 + line 2)	64,924	71,973	72,174	74,654	76,355	7,049
	Indirect Overheads						
4	Shared Services	41,329	44,897	45,837	46,564	47,235	3,568
5	Research & Development	3,780	2,523	2,598	2,650	2,703	(1,257)
6	Project Study Debt Service	846	-	-	-	-	(846)
7	Y2K Debt Service	2,874	237	237	237	237	(2,637)
8	Subtotal Indirect Overheads (sum lines 4-7)	48,829	47,656	48,672	49,451	50,176	(1,173)
9	**St. Law. Relicensing, amortization**	2,000	2,000	2,000	2,000	2,000	-
10	**Niagara Relicensing, amortization**	12,000	12,700	12,700	12,700	12,700	700
11	**Other Post -Employment Benefits (OPEB)**	13,608	10,348	10,720	11,051	11,424	(3,261)
12	**O&M Cost of Service** (sum lines 3,8, 9, 10,11)	**141,361**	**144,677**	**146,266**	**149,856**	**152,654**	**3,316**
	Capital Costs						
13	Total Depreciation	35,350	40,984	43,422	45,309	47,204	5,634
14	Interest on Debt	21,453	30,322	33,205	35,104	37,386	8,869
15	Inflation Compensation	21,521	28,697	30,428	32,182	34,069	7,176
16	Subtotal Capital Costs (sum lines 13-15)	78,324	100,003	107,055	112,595	118,659	21,679
17	**Total Cost of Service** (line 12 +line 16)	**219,685**	**244,680**	**253,321**	**262,451**	**271,313**	**24,995**

* 2008 data is from 2007 CoS and was based on data and projections available at that time.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
FINAL PRODUCTION COST OF SERVICE

($000)

Line	Description		(Per 2007 CoS) 2008	2011	2012	2013	2014	Difference 2011 vs 2008 *
1	**Total Cost of Service**	**($000)**	**219,685**	**244,680**	**253,321**	**262,451**	**271,313**	**24,995**
2	**Credits for ancillary services**	($000)						
3	Black Start, O&M		81	69	71	73	75	(12)
4	Voltage Support, O&M		332	213	219	225	232	(119)
5	Remaining O&M (page 1, line 12 - (line 3+line 4)		140,948	144,395	145,976	149,558	152,347	3,447
6	Operating Reserves, O&M		4.82%	4.40%	4.37%	4.33%	4.31%	
7	Regulation, O&M		0.57%	0.55%	0.54%	0.54%	0.53%	
8	Subtotal OR, Reg. O&M		5.39%	4.95%	4.91%	4.87%	4.84%	
9	Op. Res.+ Reg. O&M credit (line 8 * line 5)	($000)	7,597	7,148	7,167	7,283	7,374	(450)
10	**Capital Reductions**							
11	All ancillary services		6.85%	6.68%	6.74%	6.75%	6.79%	
12	Subtotal capital reductions (page 1, line 16 * line 11)	($000)	5,365	6,680	7,216	7,600	8,057	1,315
13	Total Ancillary Credits (sum lines 3,4,9,12)	($000)	13,375	14,110	14,673	15,182	15,738	734
14	**Adjusted Cost of Service** (line 1 - line 13)	**($000)**	**206,310**	**230,570**	**238,648**	**247,270**	**255,576**	**24,261**
15	Billing Demand	MW	36,137	34,086	35,035	35,871	36,100	(2,051)
16	Billing Demand Allocated Costs (line 14 - line 21)	($000)	106,822	131,108	139,186	147,807	156,113	24,285
17	Billed Demand Rate (line 16 / line 15)	$/kW/mo	2.96	3.85	3.97	4.12	4.32	
18	LTA Generation	GWh	20,221	20,216	20,216	20,216	20,216	(5)
19	Annual Generation	GWh	20,012	20,456	20,148	20,409	20,435	444
20	Billing Energy Rate	$/MWh	4.92	4.92	4.92	4.92	4.92	
21	Costs Allocated to Energy Rate (line 18 * line 20)	$/MWh	99,487	99,463	99,463	99,463	99,463	(25)

* 2008 data is from 2007 CoS and was based on data and projections available at that time.

EXHIBIT "B"

NEW YORK POWER AUTHORITY
ESTIMATED AVERAGE ANNUAL CUSTOMER IMPACTS
Prices ($/MWh) include demand and energy components

		Current *	2011	2012	2013	2014
MUNIS/COOPS FULL REQUIREMENTS						
CURRENT HYDRO PRODUCTION RATES	$/MWh		10.38	10.42	10.41	10.41
PROPOSED HYDRO PRODUCTION RATES	$/MWh		11.04	11.79	12.56	12.93
INCREASES FROM CURRENT	$/MWh		0.66	1.37	2.15	2.52
END USE RESIDENTIAL IMPACTS						
SYSTEM RESIDENTIAL RATE	$/MWh	80.51	80.81	81.67	82.33	82.65
INCREASES FROM CURRENT	$/MWh		0.30	1.15	1.82	2.14
SYSTEM RESIDENTIAL AVG. BILL	$/mo	79.98	80.27	81.12	81.78	82.10
INCREASES FROM CURRENT	$/mo		0.30	1.15	1.80	2.12
MUNIS/COOPS PARTIAL REQUIREMENTS						
CURRENT HYDRO PRODUCTION RATES	$/MWh		10.61	10.69	10.68	10.68
PROPOSED HYDRO PRODUCTION RATES	$/MWh		11.30	12.14	12.94	13.33
INCREASES FROM CURRENT	$/MWh		0.69	1.44	2.26	2.65
END USE RESIDENTIAL IMPACTS						
SYSTEM RATE	$/MWh	59.27	59.62	60.62	61.40	61.77
INCREASES FROM CURRENT	$/MWh		0.35	1.35	2.13	2.50
SYSTEM RESIDENTIAL AVG. BILL	$/mo	64.87	65.26	66.35	67.20	67.61
INCREASES FROM CURRENT	$/mo		0.38	1.48	2.33	2.74
RESIDENTIAL UTILITY CUSTOMERS (PEAKING ONLY)						
END USE RESIDENTIAL IMPACTS						
SYSTEM RATE	$/MWh	135.58	135.62	135.74	135.83	135.87
INCREASES FROM CURRENT	$/MWh		0.04	0.16	0.25	0.29
SYSTEM RESIDENTIAL AVG. BILL	$/mo	88.94	88.97	89.04	89.10	89.13
INCREASES FROM CURRENT	$/mo		0.03	0.11	0.17	0.19

* Current is the most recent Energy Information Adminstration data, which is 2009.

Table 1
EMBEDDED COSTS FOR ANCILLARY SERVICES FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
Voltage Support O&M Cost Reduction ($)	[1]	212,522	218,897	225,464	232,228
Voltage Support Capital Share (%)	[2]	1.74%	1.84%	1.91%	1.98%
Black Start O&M Cost Reduction ($)	[3]	69,081	71,154	73,288	75,487
Black Start Capital Share (%)	[4]	0.074%	0.071%	0.069%	0.067%
Regulation O&M Share (%)	[5]	0.55%	0.54%	0.54%	0.53%
Regulation Capital Share (%)	[6]	0.55%	0.54%	0.54%	0.53%
Operating Reserve O&M Share (%)	[7]	4.40%	4.37%	4.33%	4.31%
Operating Reserve Capital Share (%)	[8]	4.40%	4.37%	4.33%	4.31%
Ancillary Service O&M Cost ($)	[9]	281,603	290,051	298,753	307,715
Ancillary Service O&M Share (%)	[10]	4.95%	4.92%	4.86%	4.84%
Ancillary Service Capital Share (%)	[11]	6.68%	6.74%	6.75%	6.79%

Notes and Sources:
[1]-[2]: Table 2.
[3]-[4]: Table 3.
[5]-[6]: Table 4.
[7]-[8]: Table 5.
[9]: [1] + [3]
[10]: [5] + [7]
[11]: 1 - { 1 - ([2]+[4]) } * { 1 - ([6]+[8]) }

Table 2
EMBEDDED COSTS FOR VOLTAGE SUPPORT FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
Voltage Fraction of Gross Capital (Niag. & St. L.)	[1]	**1.74%**	**1.84%**	**1.91%**	**1.98%**
Voltage O&M Expense : Niagara ($)	[2]	172,800	177,984	183,324	188,823
Voltage O&M Expense : St. Lawrence ($)	[3]	39,722	40,913	42,141	43,405
Total Voltage O&M Expense ($)	[4]	**212,522**	**218,897**	**225,464**	**232,228**

Notes and Sources:
[1]: From Workpaper 5.3. Fraction is Beginning-of-Year value (equal to End-of-Year value for previous year).
[2] and [3]: From Workpaper 2.2.
[4] = [2] + [3].

Table 3

EMBEDDED COSTS FOR BLACK START FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
Black Start Fraction of Gross Capital (Niag. & St. L.)	[1]	**0.074%**	**0.071%**	**0.069%**	**0.067%**
Inflation Factor	[2]	106.1%	103.0%	103.0%	103.0%
Black Start O&M Expense ($)	[3]	**69,081**	**71,154**	**73,288**	**75,487**

Notes and Sources:
[1]: From Workpaper 7. Fraction is Beginning-of-Year value (equal to End-of-Year value for previous year).
[2] = From Workpaper 1
[3]: Sum of Test Year Training costs for Niagara and St. Lawrence, plus O&M Cost allocated to Black Start from Workpaper 6 and adjusted by Inflation Factor in line [2].

Table 4
EMBEDDED COSTS FOR REGULATION FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
NYCA Peak Load	[1]	33,160	33,367	33,737	33,897
Total NYCA Regulation Requirement (MW)	[2]	223	223	223	223
Required regulation per MW of peak load (MW)	[3]	0.007	0.007	0.007	0.007
Peak load of all contract customers of Niagara and St. Lawrence (MW)	[4]	2,628	2,628	2,628	2,628
Required regulation for all contract customers of Niagara and St. Lawrence (MW)	[5]	18	18	17	17
Niagara & St. Lawrence Summer Generation Capacity (MW)	[6]	3,241	3,241	3,241	3,241
Share of regulation for all contract customers of Niagara and St. Lawrence in generation capacity (%)	[7]	0.55%	0.54%	0.54%	0.53%

Notes and Sources:
[1]: From Workpaper 8. Test year peak equals 2009 peak.
[2]: From Workpaper 8.
[3] = [2] / [1].
[4]: From Workpaper 8.
[5] = [3] * [4].
[6]: NYPA, "2009 Annual Report".
[7] = [5] / [6].

Table 5
EMBEDDED COSTS FOR OPERATING RESERVE FOR NIAGARA AND ST. LAWRENCE

		2011	2012	2013	2014
NYCA Peak Load	[1]	33,160	33,367	33,737	33,897
Total NYCA Reserve Requirement (MW)	[2]	1,800	1,800	1,800	1,800
Required reserve per MW of peak load (MW)	[3]	0.054	0.054	0.053	0.053
Peak load of all contract customers of Niagara and St. Lawrence (MW)	[4]	2,628	2,628	2,628	2,628
Required reserve for all contract customers of Niagara and St. Lawrence (MW)	[5]	143	142	140	140
Niagara & St. Lawrence Summer Generation Capacity (MW)	[6]	3,241	3,241	3,241	3,241
Share of required reserve for all contract customers of Niagara and St. Lawrence in generation capacity (%)	[7]	4.40%	4.37%	4.33%	4.31%

Notes and Sources:
[1]: From Workpaper 8. Test year peak equals 2009 peak.
[2]: From Workpaper 8.
[3] = [2] / [1].
[4]: From Workpaper 8.
[5] = [3] * [4].
[6]: NYPA, "2009 Annual Report".
[7] = [5] / [6].

New York Power Authority

New York Power Authority

Public Forum Transcripts and Written Comments

Rate Modification Plan – Rate Years 2011 to 2014

Appendix C

November 2011

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TAB 1

1 ----------
2 NYPA PUBLIC FORUM
3 IN THE MATTER OF THE PROPOSED INCREASE
4 IN HYDROELECTRIC PREFERENCE POWER RATES
5 FROM THE NIAGARA AND ST. LAWRENCE
6 HYDROELECTRIC PROJECTS
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12 DATE: September 19, 2011
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14 TIME: 3:00 p.m. to 7:00 p.m.
15
16 LOCATION: Schine Student Center
Syracuse University
17 303 University Place
Syracuse, NY 13244
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24 REPORTED BY:
SUSAN M. BYRNE
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SUSAN M. BYRNE
(315) 243-7560

1 APPEARANCES

2

3 FOR NEW YORK POWER AUTHORITY:

4 KAREN DELINCE, ESQ.
Corporate Secretary, Law Department
5 JAMES F. PASQUALE
Senior Vice President
6 Marketing & Economic Development

7 NEW YORK POWER AUTHORITY
123 Main Street
8 White Plains, New York 10601

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10

11 SPEAKERS:

12 JOHN P. COYLE

13 BUTCH SOLOMON

14 TONY MODAFFERI

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1 MS. DELINCE: Good afternoon. My name

is Karen Delince, and I'm the Corporate Secretary of the New York Power Authority.

This public forum in Syracuse is being conducted pursuant to the Power Authority policy adopted by the Trustees in 1990. Another forum will be conducted tomorrow in Niagara, and a third on Thursday in Massena.

These forums are not required by law and are held in addition to the State Administrative Procedure (SAPA) process. The SAPA process provides a 45-day public comment period, which began on August 17 with the publication of a notice in the State Register and will end on October 3.

The purpose of this forum is to offer affected customers and the general public an opportunity to present data, views and positions for the Trustees to consider prior to taking final action on the proposed hydroelectric preference power rate increase.

A complete transcript of the proceeding will be taken and provided to the Authority's Trustees, along with any written comments submitted by October 3.

If you plan on making an oral statement at this forum and have not yet filled out a card, please see Lorna Johnson at the sign-in desk in

the back. We ask that you give copies of your written statement to the reporter and Lorna Johnson before or after you deliver your remarks.

Your written statement may be any length you like, but we ask those presenting an oral statement to limit their remarks to five minutes. If your oral statement summarizes your written statement, both will appear in the record of the forum.

If you would like to submit additional comments, send them to the Corporate Secretary at the New York Power Authority, 123 Main Street, 11P, White Plains, New York, 10601. It may be faxed to (914) 390-8040, or you may e-mail it to secretarys.office@nypa.gov.

If you have any additional questions, please see Lorna Johnson in the back.

Once complete, the transcript of the forums will be made available to the public for review at the Authority's office in White Plains and on the Authority's web site, www.nypa.gov.

At this point, I will turn the proceedings over to Mr. James Pasquale, the Authority's Senior Vice President of Marketing and Economic Development, who will provide additional details on the proposed rate increase.

6 I will then call on speakers.

7 MR. PASQUALE: Thank you, Ms. Delince.

8 Good afternoon. My name is James Pasquale.

9 I am the Senior Vice President of Marketing

10 and Economic Development at the New York

11 Power Authority. I am here today to

12 present an overview of the modifications to

13 the hydroelectric preference power rates.

14 In summary, by this rate action, the

15 Authority is proposing a 42-month phase-in rate

16 plan covering the remaining portion of the 2011

17 rate year, plus the 2012, 2013 and 2014 rates

18 years ending April 30, 2015.

19 By the 2013 rate year, the preference rate

20 will be phased back up to full cost. Starting

21 with the 2014 rate year, the suspension of the

22 Rate Stabilization Reserve (RSR) would be

23 lifted, and the Authority would begin to collect

24 deferred hydroelectric costs stemming mainly

25 from the withdrawal rate action for the 2009 and

1 2010 rate years.

2 The proposed rate plan would allow rates to

3 return to cost-based rate levels in accordance

4 with the methodologies adopted in the April 2003

5 final rate action approved by the Authority

6 Trustees. Such methodologies were also agreed

7 to by the Municipal and Cooperatives customers

8 as part of the 2003 global settlement agreement
9 reached with the Authority.
10 The overall production phase-in rates
11 proposed at a 70% load factor are $11.42/MWh,
12 $12.16/MWh, $12.98/MWh, and $13.87/MWh for rate
13 years 2011, 2012, 2013 and 2014 respectively.
14 The public comment period and this forum
15 are intended as opportunities for customer input
16 into the Authority's rate-making process, in
17 accordance with established Authority
18 rate-making policies and consistent with the
19 State Administrative Procedure Act.
20 To that end, the Authority has received
21 numerous customer inquiries, to which Authority
22 staff has been and is working hard to respond
23 to in a timely and thorough manner. Staff shall
24 diligently consider all relevant comments and
25 queries raised during this public comment

1 period, including those heard today during this
2 public forum. The staff will present their
3 analysis, findings and recommendations to the
4 Trustees at the conclusion of the public comment
5 period.
6 I will now provide some background on the
7 Authority's preference rates -- recent history
8 and the cost components that make up the rate.
9 After that, I'll describe in more detail the

10 current rate proposal, including the primary
11 drivers of the rate increase.
12 The Authority's proposed preference
13 rates apply to the customers that purchase
14 hydroelectric preference power supplied from
15 the Authority's Niagara and St. Lawrence
16 Hydroelectric Projects. The major customer
17 groups are the 47 municipal electric systems,
18 4 rural electric cooperatives, three upstate
19 investor-owned utilities, the Neighboring States
20 customers, and the Niagara Project relicensing
21 host communities.
22 In their April 24, 2007 meeting, the
23 Trustees adopted a two-year rate plan for the
24 2007 and 2008 rate years which extended from
25 May 1, 2007 to April 30, 2009. No increase to

1 these rates has occurred since May 2008, the
2 start of the final rate year under the two-year
3 plan.
4 In January 2009, the Trustees authorized
5 a Notice of Proposed Rule Making, also called a
6 NOPR, to increase the preference power rates for
7 rate years 2009 and 2010. That proposal called
8 for increasing revenues in the 2009 rate year by
9 $9.7 million, as compared to the rates in effect
10 in the 2008 rate year, and increasing revenues
11 in the 2010 rate year by $14.6 million, as

12 compared to the rates in effect in the 2008 rate
13 year.
14 Based on public comments, consideration of
15 the national economic downturn, and the extent
16 to which the downturn had adversely affected the
17 region's customers, the Trustees, on March 2009,
18 approved the withdrawal of the NOPR, deferring
19 the recovery of costs until a subsequent period
20 of time.
21 The deferred recovery was necessary since
22 under federal and state statutes and court
23 precedents governing preference power sales the
24 preference rate must be at the lowest possible
25 rate but not lower than cost. This action also

1 included a suspension of the RSR, a contractual
2 rate adjustment for preference power customers,
3 to ensure that the tariff rates do not
4 over-collect or under-collect costs.
5 The current overall production rate at a
6 70% load factor is $10.71/MWh, which compares
7 favorably to the $39.22/MWh average hourly
8 market rate for 2010 in the New York Independent
9 System Operator Zone A located in western
10 New York.
11 The preliminary Cost of Service sets forth
12 the estimated costs required to serve the
13 preference power customers from the Authority's

14 Hydro Projects and continues the rate-making
15 methodologies adopted by the Trustees at their
16 April 2003 meeting.
17 Based on the Cost of Service methodology,
18 the total Hydro Projects' costs, net of the
19 ancillary service credits, are $230.6 million,
20 $238.6 million, $247.3 million, and $255.6
21 million for the 2011 through 2014 calendar
22 years, respectively.
23 The principal cost driver responsible for
24 the increases is the ongoing capital investments
25 at the facilities, including the Niagara and

1 St. Lawrence relicensing expenditures, and the
2 life extension and modernization for both the
3 St. Lawrence Project and the Lewiston
4 Pump-Generating Plant at the Niagara Project.
5 During the two years of rate freeze and the four
6 years of the proposed rate plan period, the
7 Authority will have invested over $490 million
8 in the Hydro Projects.
9 Consistent with past rate-making practice,
10 the costs used to set new rates starting in 2011
11 will be based on projected calendar year 2011
12 costs, although the 2011 rate year would extend
13 only from November 1, 2011 through April 30,
14 2012.
15 For the subsequent rate years in this

16 proposed plan, Authority staff proposed to adopt
17 its traditional rate year approach, under which
18 the new rate year will begin May 1st of 2012,
19 2013 and 2014 and will be based on projected
20 calendar year costs for 2012, 2013 and 2014,
21 respectively.
22 The phase-in of the rates would result
23 in an under-recovery of costs during the two
24 rate years ending April 30, 2013. These
25 under-recovery amounts are estimated to be

1 $12 million in 2011 and $4 million in 2012, and
2 would contribute to making the current RSR
3 balance more negative. By the 2013 rate year,
4 the proposed increase would bring rates up to
5 the current costs estimated for calendar year
6 2013.
7 Starting with the 2014 rate year, the
8 suspension of the RSR would be lifted, and the
9 Authority would begin to pay down the negative
10 RSR balance through the collection of an RSR
11 surcharge.
12 To mitigate costs impacts to the preference
13 customers, staff recommends that the RSR
14 surcharge be limited to $0.50MWh in 2014.
15 Based on the current negative RSR balance,
16 staff anticipates that RSR surcharges will need
17 to continue in the rate years subsequent to the

18 years covered by the proposed rate plan in
19 order to bring the RSR balance back to the
20 $25 million threshold.
21 It is proposed that the rate design policy
22 approved by the Trustees in the April 2003 final
23 rate action be continued for the proposed rate
24 plan and that costs not collected in the current
25 $4.92/MWh energy charge be recovered through the

1 demand charge. Therefore, the resulting
2 proposed demand charge is $3.32/kW/mo for 2011,
3 $3.70/kW/mo for 2012, $4.12/kW/mo for 2013 and
4 $4.32/kW/mo for 2014.
5 Included in the Trustee Item for the Notice
6 of Proposed Rule Making is the Preliminary Staff
7 Report documenting the Cost of Service. Copies
8 are available here today for your review.
9 As Ms. Delince stated earlier, the
10 Authority will accept your comments on the
11 proposed rates until October 3, 2011. I will
12 now turn the forum back over to Ms. Delince.
13 MS. DELINCE: Thank you, Mr. Pasquale.
14 I will now call on speakers. When called,
15 please come up to the podium and state your
16 full name and company you represent, if
17 any, for the record.
18 Butch Solomon?
19 MR. SOLOMON: We're actually a team.

20 MR. COYLE: Good afternoon,
21 Ms. Delince, Mr. Pasquale. My name is John
22 Coyle, C-O-Y-L-E. I am appearing today as
23 counsel to the Neighboring States of
24 Connecticut, Massachusetts, New Jersey,
25 Ohio, Pennsylvania, Rhode Island and

1 Vermont.
2 The Neighboring States are currently
3 allocated an aggregate of approximately 266.6MW
4 of hydroelectric power from the Authority's
5 Niagara and St. Lawrence projects. And
6 approximately 34.5 MW of that amount comes from
7 the St. Lawrence project under the facility's
8 current FERC hydroelectric license, and
9 approximately 232.1 MW of that amount comes from
10 the Niagara Project under the terms of the
11 federal Niagara Redevelopment Act and the
12 current FERC hydro license for that facility.
13 Under the terms of both Section 1005(5)
14 of the Public Authorities Law, and the Niagara
15 Redevelopment Act, the standard, as Mr. Pasquale
16 mentioned in his remarks, is the lowest possible
17 cost, but not below cost, and we fully subscribe
18 to that principle.
19 We think, based on our analysis of the
20 data, responses that we have received to date
21 from staff -- and we applaud staff's efforts and

22 diligence in responding to our discovery. We
23 have identified several areas in the Preliminary
24 Staff Report and the accompanying cost of
25 service study that we believe warrant

1 adjustments that would have the effect of
2 bringing the proposed rates into closer
3 conformity with the requirements for cost-based,
4 lowest possible rates established by the
5 principles adopted by the Authority in the March
6 1986 Settlement Agreement in Auer v. Dyson, and
7 the 2003 global settlement agreement between the
8 Authority and its preference customers.
9 At the outset, we would also like to note
10 that we support the September 13, 2011 request
11 of the New York Association of Public Power to
12 defer implementation of any proposed change in
13 the Authority's hydroelectric rates until May 1,
14 2012, the start of the next rate year.
15 Like our New York based colleagues,
16 the Neighboring States, we wish to pursue an
17 informed and deliberate dialogue with the
18 Authority's rate staff, aimed at achieving close
19 conformity between the Authority's rate proposal
20 and the statutory and settlement principle-based
21 requirements that govern it.
22 And I am going to turn the microphone over
23 now to my colleague, Butch Solomon, who'll

24 review the costs of service adjustments that we
25 believe are appropriate based on our review of

1 the data to date. We have additional copies of
2 our statements. I have given two to
3 the reporter and two to the Authority's
4 representative. If anybody needs any more, we
5 have extras.
6 MS. DELINCE: Thank you.
7 MR. SOLOMON: Thank you. My name is
8 Butch Solomon, and as Mr. Coyle noted, I
9 too work for the Neighboring States group.
10 The major concerns that we have identified
11 to date all fall in the category of proper
12 cost of service credits for the costs
13 associated with the use of the hydro
14 facilities to make sales into the New York
15 ISO markets and credit for the investment
16 income that is generated from investable
17 cash that accrues from the operations of
18 the hydro facilities.
19 The full cost of owning and operating the
20 hydro units are included in the cost of service
21 that is used to determine the rates to be
22 charged the hydro preference customers.
23 However, some of the costs are related to the
24 use of the facilities to make non-preference
25 sales into the New York ISO markets.

1 The Authority recognizes that cost of
2 service credits must be made in order to
3 eliminate costs associated with making those
4 non-preference sales, but we believe there are a
5 couple of areas where the staff credits are
6 insufficient to reflect either the full costs
7 associated with the sales or the full quantity
8 of the sales that are made.
9 The first is the credit for energy sales
10 into the New York ISO market. The cost of
11 service divides into two components, the total
12 cost. One is energy related, the other is
13 demand related.
14 Both types of costs must be incurred to
15 provide the ability to make these market sales,
16 but the cost of service in the preliminary
17 report only provides credit for what has been
18 classified as energy-related costs and does not
19 provide credit for the demand-related costs.
20 Thus, full cost-based credit is not provided for
21 the energy sold into the New York ISO market.
22 The additional credit that we propose would
23 only amount to approximately $7 per megawatt
24 hour and would still leave the vast majority of
25 the $40 to $50 per megawatt hour market-based

1 sales price that the Authority receives to
2 contribute to the net income earned by the
3 Authority.
4 The second area where we believe
5 insufficient credit has been provided is for
6 the sales of regulation ancillary services. In
7 this area also the preliminary cost of service
8 provides a credit, but one that we believe falls
9 far short of the cost to provide the volume of
10 regulation service being sold by the Authority.
11 The credit provided is only for the volume
12 of regulation service needed to meet the needs
13 of the preference customer contract sales.
14 When, in fact, the regulation sales that are
15 made into the New York ISO market are for much
16 larger volume.
17 For example, the 2008 cost of service in
18 the report provides a regulation sales service
19 credit of only approximately one and a quarter
20 million dollars, while information provided in
21 response to data requests shows the actual 2008
22 regulation sales service revenue were over 40
23 million dollars.
24 While part of the reason for this large
25 discrepancy is the full sales made were made at

1 market-based prices and not at cost-based
2 prices, the quantity sold certainly also has
3 been substantially greater than that for which
4 cost of service credit has been provided.
5 For the forecast rate period, 2011 through
6 2014, the annual credit that has been given in
7 the cost of service is about 1.5 million dollars
8 per year, while the staff estimates annual
9 regulation service sales ranging from 12 to 32
10 million dollars over the rate planning horizon.
11 We believe annual cost based credit for the
12 full amount of regulation sales should be in the
13 range of 3 to 8 million dollars per year.
14 Credits in this range would obviously still
15 leave large margins from such sales to accrue to
16 the net income of the Authority.
17 The third area is the lack of credit for --
18 from earnings from investment funds that arise
19 from the Niagara and St. Lawrence Projects.
20 Obviously, substantial net revenues and free
21 cash flows are generated for the Power Authority
22 through the hydro projects.
23 In addition to the profits from the market
24 sales of energy and ancillary services into the
25 New York ISO market, cash is generated from the

1 collection of depreciation expenses and the
2 extra capital costs recovered through the use of

3 the TOC capital cost recovery methodology.
4 Such amounts arise directly as a result of
5 the project operations, and fully cost-based
6 rates for the output of those projects would
7 reflect the credits for the investment income
8 generated as part of those operations.
9 Through investment of its available cash,
10 the Authority had investment income of 71
11 million in 2008, 32 million in 2009, and 41
12 million for 2010. For the 2010 to 2014 period,
13 the Power Authority's Approved Financial Plan
14 projects investment income to climb from 32.4
15 million in 2011 to 88.3 million in 2014, with an
16 annual average of 58.4 million per year over the
17 four-year period.
18 An appropriate portion of this investment
19 income that is clearly generated in large
20 part out of the cash flow from Niagara and
21 St. Lawrence operations should be credited
22 against the hydro cost of service.
23 The report of the Chief Financial Officer
24 for the years ending December 31, 2009 and 2010
25 show that Niagara and St. Lawrence contributed

1 81% and 82%, respectively, of the Authority's
2 total net income for those years. If the
3 projected income were allocated conservatively
4 as only 50% attributable to Niagara and

5 St. Lawrence, the cost of service credit would
6 range from 16.2 million in 2011 to 44.2 million
7 in 2014, and would be an annual average of 29.2
8 million over the four-year period.
9 Neighboring States do not seek a resulting
10 price that is below cost, rather, the income
11 generated by cash supplied by hydro customers
12 for hydro power is a necessary input to the
13 calculation of the cost of that power.
14 Failing to reflect investment income
15 associated with hydro revenues in calculating
16 the hydro cost is akin to including tax payments
17 in a cost of service but refusing to consider
18 any tax refunds obtained.
19 The fourth area is estimated UCAP sales
20 and the associated credit that we believe should
21 be included in calculating the initial rates
22 as they are forecast. The Power Authority
23 recognizes that it is appropriate to include the
24 credit for UCAP sales in determining the actual
25 after-the-fact cost of service for purposes of

1 RSR calculations.
2 Such credits for 2008, 2009 and 2010
3 were 11,079,000, 6,625,000 and 7,209,000
4 respectively. The same methodology should apply
5 to the development of the rates to be charged in
6 the first instance, not just in the calculation

7 of the after-the-fact actual cost of service for
8 RSR purposes.
9 A conservative estimate of such annual
10 sales credits for the 2011 to 2014 period would
11 be the average of the 2008 through 2009 actual
12 sales, or $8,304,000. This would make the
13 projected rates more realistic and yet would
14 still provide the ability to adjust to the
15 actual credit amounts in the RSR cost of service
16 calculations.
17 And then, finally, we would like to
18 mention today the proposed RSA treatment or the
19 potential treatment of the withdrawal of the
20 455 megawatts from upstate utilities resulting
21 from the implementation of the Recharge New York
22 Power Program.
23 Footnote 6 on page 10 of the report states
24 that to the extent that staff anticipates that
25 the withdrawal of the 455 megawatts from upstate

1 utilities to implement the Recharge New York
2 power program will affect the RSR balance and
3 the RSR surcharge in a material manner, then
4 staff will inform the Trustees and adjust the
5 rate proposal accordingly when it is submitted
6 for final approval in October 2011.
7 Since at this point we don't know what
8 conclusions the staff will draw, nor whether it

9 will propose any adjustment in the RSR balance
10 of surcharge, we can't comment except to urge
11 the staff to collaborate with the customers in
12 their deliberations on the issue and to allow
13 customer input before making any ultimate
14 decision.
15 Any adjustments should assure that the
16 remaining customers do not have any prior
17 shortfall in collections associated with the
18 455 megawatts rolled over onto them.
19 That concludes our statement. Thank you
20 very much.
21 MS. DELINCE: Thank you, Mr. Solomon.
22 Next we have Tony Modafferi.
23 MR. MODAFFERI: Good afternoon,
24 Mr. Pasquale, Ms. Secretary, and NYPA staff
25 members. Tony Modafferi, Executive

1 Director of the Municipal Electric
2 Utilities Association of New York State.
3 We represent 40 municipal electric
4 utilities that receive hydroelectric
5 preference power.
6 NYPA and MEUA both know public power
7 imposes a public duty. According to state law,
8 hydroelectric power for domestic and rural use
9 should be sold at the lowest possible rate, and
10 at the lowest possible price.

11 It is clear, just like the MEUA systems,
12 NYPA has had a public duty to control the
13 cost of providing that power. Whether it
14 is relicensing of the Niagara Project, or
15 instituting new rates, we have an obligation to
16 control costs. NYPA and MEUA are partners in
17 this duty.
18 Over the years, the MEUA has participated
19 in many programs with NYPA. We are committed to
20 exploring new opportunities as we have done in
21 NYPA sponsored programs such as Industrial
22 Economic Development, the Alternative Electric
23 Partnership Program MAP, the Global Settlement
24 Agreement of 2003, the recent solar initiative
25 both for large and small applications, and

1 MEUA's Energy Efficiency Program, and the Home
2 Insulation Program demonstrates that the
3 municipals do not take their preference power
4 allotments for granted.
5 The Authority may pursue to revise its
6 rates based on costs. The current rate study is
7 an explanation of NYPA's costs. The MEUA has
8 retained qualified analysts to examine that
9 study. NYPA has presented a multi-year rate
10 program which would allow for municipalities to
11 plan and adjust accordingly for years to come as
12 far as rates are concerned.

13 This increase was first announced July 26
14 with the public hearings announced August 19th
15 for today, tomorrow and Thursday. NYPA
16 officials will then make a recommendation to
17 the NYPA Board of trustees, and the rate
18 increase is scheduled to be possibly voted on
19 at the trustees meeting in October.
20 Two weeks after the proposed rate increase
21 was announced, the MEUA submitted a series of
22 questions concerning the cost study. To date,
23 the answers to these questions are still being
24 worked on by NYPA officials.
25 And I do want to possibly clarify that. In

1 talking with Gary a few minutes ago before the
2 meeting started, he did mention he thought that
3 all the questions had been answered late last
4 week. I was out of town all last week, have not
5 seen a copy of them, but so the record is
6 straight, if they have been, we will be
7 reviewing them and getting back to you.
8 Anyway, this does not allow much time for
9 review and submission of written comments to
10 NYPA. Out of fairness to all parties involved,
11 the MEUA requests an extension of time to allow
12 our consultants the proper time to analyze the
13 cost study and submit MEUA's written comments.
14 If the true extent of the law is to be

15 followed as far as costs are concerned, then
16 please allow more time for review of the costs
17 before moving forward with the increase.
18 When the Authority decides this matter, we
19 urge them to make a statement recognizing and
20 offering its duty to control costs and provide
21 power at the lowest possible price.
22 The MEUA looks forward to a continued
23 working relationship with the Power Authority in
24 the interest of our public power partnership.
25 With that, I thank you.

SUSAN M. BYRNE
(315) 243-7560

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1 MS. DELINCE: Thank you,
2 Mr. Modafferi. Is there anyone else
3 present who would like to make a statement?
4 (No response)
5 All right. We will be here until 7:00.
6 (Off-the-record)
7 MS. DELINCE: There being no
8 additional speakers this afternoon, I
9 declare this forum officially closed.
10 (Time: 7 o'clock)
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1 CERTIFICATION
2
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4 STATE OF NEW YORK
5 COUNTY OF ONONDAGA
6
7
8 I, SUSAN M. BYRNE, do certify that as a Notary
9 Public in the State of New York, I attended and
10 reported the above-entitled proceedings; that I have
11 compared the foregoing with my original minutes taken
12 therein, and that it is a true and correct transcript
13 of the testimony thereof.
14
15
16
17 _____
18 SUSAN M. BYRNE
19 Notary Public in and for the

State of New York

My Commission Expires
July 31, 2014

TAB 2

1 POWER AUTHORITY OF THE STATE OF NEW YORK

2 _____

3 PUBLIC HEARING

4 Tuesday, September 20, 2011 - 3:00 P.M.

5

6 Niagara Power Project
Lewiston, New York

7 PROPOSED INCREASE IN HYDROELECTRIC PREFERENCE

8 POWER RATES FROM NIAGARA AND ST. LAWRENCE

9 HYDROELECTRIC PROJECTS

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13 Public Hearing held at the

14 Niagara Power Project, Community Room, Lewiston,

15 New York on September 20, 2011 at 3:00 P.M.

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1 PRESENT: FOR THE POWER AUTHORITY OF THE
STATE OF NEW YORK:
2
KAREN DELINCE,
3 Corporate Secretary,
123 Main Street,
4 White Plains, New York 10601.

5 JAMES PASQUALE,
Senior Vice President of Marketing &
6 Economic Development at the New
York Power Authority.
7
LORNA JOHNSON,
8 Assistant Corporate Secretary.

9
REPORTED BY: METSCHL & ASSOCIATES,
10 BY: DAWN M. SITERS,
1098 Ellicott Square Building,
11 295 Main Street,
Buffalo, New York 14203,
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1 KAREN DELINCE: Good
2 afternoon. This is a public forum on the proposed
3 increase in hydroelectric preference power rates
4 from the Niagara and St. Lawrence Hydroelectric
5 Projects. My name is Karen Delince, and I'm the
6 Corporate Secretary of the New York Power Authority.
7 This public forum is being
8 conducted pursuant to a Power Authority policy
9 adopted by the Trustees in 1990. Another forum was
10 conducted yesterday in Syracuse, and one will be
11 conducted Thursday in Massena, New York.
12 These forums are not required by
13 law, and are held in addition to the State
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15 The SAPA process provides a forty-five day public
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23 action on the proposed hydroelectric preference

1 power rate increase.
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3 proceeding will be taken and provided to the
4 Authority's Trustees, along with any written
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6 If you plan to make an oral
7 statement at this forum, and you have not yet filled
8 out a card, please see Lorna Johnson at that table.
9 If you have copies of your statement, please give
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11 While your written statement may
12 be whatever length you'd like, we ask those
13 presenting an oral statement to limit their remarks
14 to five minutes. If your oral statement summarizes
15 your written statement, both will appear in the
16 record of this forum.
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18 additional comments after today, you may mail them
19 to the Corporate Secretary at the New York Power
20 Authority, 123 Main Street, 11P, White Plains, New
21 York, 10601; or fax it to (914) 390-8040; or e-mail
22 it to secretarys.office@nypa.gov.
23 If you have any additional

1 questions, please see Ms. Johnson.
2 A complete transcript of the forum
3 will be available to the public for review at the
4 Authority's office in White Plains, and on the
5 Authority's website, www.nypa.gov.
6 At this point, I will turn the
7 proceedings over to Mr. James Pasquale, the
8 Authority's Senior Vice President of Marketing and
9 Economic Development, who will provide additional
10 details on the proposed rate increase.
11 JAMES PASQUALE: Thank you,
12 Ms. Delince. Good afternoon, everyone. My name is
13 James F Pasquale. I am the Senior Vice President of
14 Marketing and Economic Development at the New York
15 Power Authority.
16 I am here today to present an
17 overview of the modifications to the hydroelectric
18 preference power rates. In summary, by this rate
19 action, the Authority is proposing a forty-two month
20 phase-in rate plan covering the remaining portion of
21 the 2011 rate year, plus the 2012, 2013 and 2014
22 rate years, ending April 30, 2015. By the 2013 rate
23 year, preference rates will be phased back up to

1 full cost. Starting with the 2014 rate year, the
2 suspension of the Rate Stabilization Reserve would
3 be lifted, and the Authority would begin to collect
4 deferred hydroelectric costs stemming mainly from
5 the withdrawal rate action for the 2009 and 2010
6 rate years.
7 The proposed rate plan would allow
8 rates to return to cost-based levels, in accordance
9 with the methodologies adopted in the April 2003
10 final rate action approved by the Authority
11 Trustees. Such methodologies were also agreed to by
12 Municipal and Cooperative customers as part of the
13 2003 global settlement agreement reached with the
14 Authority.
15 The overall production phase-in
16 rates proposed at a seventy percent load factor are
17 eleven dollars and forty-two cents a megawatt hour,
18 twelve dollars and sixteen cents a megawatt hour,
19 twelve dollars and ninety-eight cents a megawatt
20 hour, and thirteen dollars and eighty-seven cents a
21 megawatt hour for rate years 2011, 2012, 2013 and
22 2014, respectively.
23 The public comment period and this

1 forum are intended as opportunities for customer
2 input into the Authority's ratemaking process, in
3 accordance with established Authority ratemaking
4 policies, and consistent with the State
5 Administrative Procedure Act. To that end, the
6 Authority has received numerous customer inquiries,
7 to which the Authority's staff has been, and is,
8 working hard to respond in a timely and thorough
9 manner. Staff shall diligently consider all
10 relevant comments and queries raised during this
11 public comment period, including those heard today
12 during this public forum. Staff will present their
13 analysis, findings and recommendations to the
14 Trustees at the conclusion of the public comment
15 period.
16 I will now provide some background
17 on the Authority's preference rates; recent history,
18 and the cost components that make up the rate.
19 After that, I'll describe in more detail the current
20 rate proposal, including the primary drivers of the
21 rate increase.
22 The Authority's proposed
23 preference rates apply to the customers that

1 purchase hydroelectric preference power supplied
2 from the Authority's Niagara and St. Lawrence
3 Hydroelectric Project. The major customer groups
4 are the forty-seven municipal electric systems, four
5 rural electric cooperatives, three Upstate
6 investor-owned utilities, the Neighboring States
7 customers and the Niagara Project relicensing host
8 communities.
9 At their April 24, 2007 meeting,
10 the Trustees adopted a two-year rate plan for the
11 2007 and 2008 rate years, which extended from May 1,
12 2007 to April 30, 2009. No increase to these rates
13 has occurred since May of 2008, the start of the
14 final rate year under the two-year plan.
15 In January of 2009, the Trustees
16 authorized a Notice of Proposed Rule Making to
17 increase the preference power rates for the rate
18 years 2009 and 2010. That proposal called for
19 increasing revenues in the 2009 rate year by nine
20 point seven million dollars, as compared to the
21 rates in effect in the 2008 rate year; and
22 increasing revenues in the 2010 rate year by
23 fourteen point six million dollars, as compared to

1 the rates in effect in the 2008 rate year.
2 Based on public comments,
3 consideration of the national economic downturn, and
4 the extent to which the downturn has adversely
5 affected the region's customers, the Trustees, in
6 March 2009, approved the withdrawal of the Notice of
7 Proposed Rule Making, deferring the recovery of
8 costs until a subsequent period of time. The
9 deferred recovery was necessary, since under federal
10 and state statutes, and court precedents governing
11 the preference power sales, the preference rate must
12 be at the lowest possible rate, but not lower than
13 cost. This action also included a suspension of the
14 Rate Stabilization Reserve, a contractual rate
15 adjustment for preference power customers, to ensure
16 that the tariff rates do not over-collect or
17 under-collect costs.
18 The current overall production
19 rate, at a seventy percent load factor, is ten
20 dollars and seventy-one cents a megawatt hour, which
21 compares favorably to the thirty-nine dollar and
22 twenty-two cent megawatt hour average hourly market
23 rate for 2010 in the New York Independent System

1 Operator Zone A, located in Western New York.
2 The preliminary Cost of Services
3 sets forth the estimated costs required to serve the
4 preference power customers from the Authority's
5 Hydro Projects, and continues the ratemaking
6 methodologies adopted by the Trustees at their April
7 2003 meeting.
8 Based on the Cost of Service
9 methodology, the total Hydro Projects' cost, net of
10 the ancillary service credits, are two hundred and
11 thirty point six million; two hundred and
12 thirty-eight point six million; two hundred and
13 forty-seven point three million; and two hundred and
14 fifty-five point six million for the 2011 through
15 the 2014 calendar years. The principal cost driver
16 responsible for the increases is the ongoing capital
17 investments at the facilities, including the Niagara
18 and St. Lawrence relicensing expenditures, and the
19 life extension and modernization for both the St.
20 Lawrence Project and the Lewiston Pump-Generating
21 Plant at the Niagara Project. During the two years
22 of the rate freeze, and the four years of the
23 proposed rate plan period, the Authority will have

1 invested over four hundred and ninety million
2 dollars in the Hydro Projects.
3 Consistent with past ratemaking
4 practice, the costs used to set new rates starting
5 in 2011 will be based on projected calendar year
6 2011 costs, although the 2011 rate year will extend
7 only from November 1, 2011 through April 30, 2012.
8 For the subsequent rate years in this proposed plan,
9 Authority staff proposed to adopt its traditional
10 rate year approach, under which the new rate year
11 will begin May 1st of 2012, 2013 and 2014, and will
12 be based on projected calendar year costs for 2012,
13 2013 and 2014, respectively.
14 The phase-in of the rates would
15 result in an under-recovery of costs during the two
16 rate years ending April 30, 2013. These
17 under-recovery amounts are estimated to be twelve
18 million in 2011, and four million in 2012, and would
19 contribute to making the current Rate Stabilization
20 Reserve balance more negative. By the 2013 rate
21 year, the proposed increase would bring rates up to
22 the current costs estimated for calendar year 2013.
23 Starting with the 2014 rate year,

1 the suspension of the Rate Stabilization Reserve
2 would be lifted, and the Authority would begin to
3 pay down the negative Rate Stabilization Reserve
4 balance through the collection of a Rate
5 Stabilization Reserve surcharge. To mitigate cost
6 impacts to the preference customers, staff
7 recommends that the Rate Stabilization Reserve
8 surcharge be limited to fifty cents per megawatt
9 hour in 2014. Based on the current negative Rate
10 Stabilization Reserve balance, staff anticipates
11 that the Rate Stabilization Reserve surcharges will
12 need to continue in the rate years subsequent to the
13 years covered by the proposed rate plan in order to
14 bring the Rate Stabilization Reserve balance back
15 into the twenty-five million dollar threshold.
16 It is proposed that the rate
17 design policy approved by the Trustees in the April
18 2003 final rate action be continued for the proposed
19 rate plan, and that costs not collected in the
20 current four dollar and ninety-two cent megawatt
21 hour energy charge be recovered through the demand
22 charge. Therefore, the resulting proposed demand
23 charge is three dollars and thirty-two cents a

1 kilowatt month for 2011; three dollars and seventy
2 cents a kilowatt month for 2012; four dollars and
3 twelve cents a kilowatt month for 2013; and four
4 dollars and thirty-two cents a kilowatt month for
5 2014.
6 Included in the Trustee Item for
7 the Notice of Proposed Rule Making is the
8 Preliminary Staff Report, documenting the Cost of
9 Service. Copies are available here today for your
10 review.
11 As Ms. Delince stated earlier, the
12 Authority will accept your comments on the proposed
13 rates until October 3, 2011.
14 I will now turn the forum back
15 over to Ms. Delince.
16 KAREN DELINCE: Thank you, Mr.
17 Pasquale. I will now call on the speakers who have
18 signed in. When I call your name, please come to
19 the podium to deliver your statement, and state your
20 name, your affiliation, if any, for the record.
21 We'll start with Assemblyman John
22 D. Ceretto.
23 ASSEMBLYMAN CERETTO: First of

1 all, I'd like to say thank you for having this
2 public hearing here. I'm very appreciative that you
3 are taking our opinions here in Lewiston.
4 I appear before this panel on
5 behalf of my constituents to say enough is enough.
6 The residents and small business owners in Niagara
7 County should not be subject to rate hikes at a time
8 when the economy remains stagnant, and when Niagara
9 County has given so much to the NYPA system.
10 In my interactions with NYPA,
11 there are always numbers being tossed around. This
12 time, it is four hundred million dollars -- four
13 hundred and eighty million dollars needed for plant
14 improvements in Lewiston for efficiency upgrades.
15 I'm not here to suggest the plants couldn't use the
16 upgrades; but let's not forget that in 2010 five
17 hundred million dollars was swept out of the NYPA
18 system by majorities in both the Senate and the
19 State Legislature to plug a gaping hole in the state
20 budget. Now, I don't have to tell anyone here the
21 tremendous role the Niagara Power Project plays in
22 revenue generation for NYPA, but to those in Niagara
23 County, it felt like Niagara, Niagara County -- it

1 felt like Albany was using Niagara County as a
2 piggybank to cover its own failures. Like many, I
3 was outraged.
4 What was even outrageous was that,
5 despite needing to raid NYPA for five hundred fifty
6 million dollars, Albany found a way to bail out the
7 Metro Transit Authority to the tune of thirty
8 billion dollars; give thirty billion to New York
9 City, while taking five hundred and fifty million
10 from Upstate.
11 So here we are, less than two
12 years later, and NYPA needs now four hundred and
13 eighty million dollars. That four hundred and
14 eighty million dollars should not come out of the
15 pockets of preferred power customers here in Niagara
16 County.
17 Until Albany can repay that money,
18 and clean up its act, and until NYPA can live within
19 its means, and not spend hundreds of thousands of
20 dollars on lavish parties, I strongly object to any
21 rate increases on the citizens of New York State,
22 Western New York and Niagara County. Thank you.
23 KAREN DELINCE: Thank you.

1 William L. Ross.

2 CHAIRMAN ROSS: Thank you

3 very much. Good afternoon. William L. Ross. I

4 am the chairman of the Niagara County Legislature.

5 In that role, I also serve as Niagara County's

6 representative on the Board of the Niagara Power

7 Coalition, Incorporated, known as the NPC, and am

8 currently the chairman of that Board.

9 I appreciate the fact that the New

10 York Power Authority is holding a public hearing on

11 its proposed rate increase, and I'm pleased to be

12 speaking to you today on behalf of the Niagara Power

13 Coalition.

14 My purpose in speaking to you is

15 to urge you to reconsider the proposed multi-year

16 rate increase announced in July of this year.

17 The NPC consists of seven members.

18 In addition to Niagara County, the members are; the

19 City of Niagara Falls, the Towns of Lewiston and

20 Niagara; the three school districts, the Niagara

21 Falls City School District, the Lewiston-Porter and

22 the Niagara-Wheatfield School District. Among their

23 other ties, these seven bodies are linked by the

1 fact that they are the hosts to the Power
2 Authority's Niagara Power Project. For that reason,
3 they known as the host communities.
4 As the hosts to the Power Project,
5 beginning more than fifty years ago, their residents
6 and taxpayers have borne the impact of the Project's
7 footprint, including the loss of tax base and land
8 that could no longer be developed. While there were
9 some modest benefits of hosting the Project, most of
10 the impacts were negative, or at best, neutral.
11 While low-cost hydropower benefited some people and
12 industries in New York and neighboring states, the
13 Niagara Power Project was a net burden on the host
14 communities.
15 In the late 1990s, as the Project
16 was in the last decade of the original FERC license,
17 the host communities formed the NPC to represent
18 their interests in the relicensing process. Our
19 goal was to ensure that any burdens the host
20 communities would continue to bear as a result of
21 relicensing the Project for another fifty years
22 would not go unrecognized, and thus, uncompensated.
23 Our citizens and taxpayers are the only ones who

1 truly gave up anything to permit the Project to be
2 built, and they would be the only ones to continue
3 doing so if the Project were relicensed. Therefore,
4 the NPC and our members negotiated with the Power
5 Authority for benefits for our citizens and our
6 taxpayers to help offset the ongoing burden imposed
7 by the Project over the next fifty years.
8 Our negotiations with the Power
9 Authority culminated in a settlement agreement
10 signed in 2005 that provided three kinds of benefits
11 that were allocated to, and among, the NPC members
12 based on a formula that was worked out during the
13 negotiations.
14 The first benefit is an annual
15 payment of five million dollars into the Host
16 Communities Fund, to be used for capital projects
17 and infrastructure that benefit the general public,
18 and promote economic development, public health and
19 safety.
20 The second benefit is an annual
21 payment of the three million into the Host Community
22 Greenway Recreation/Tourism Fund for the
23 construction and rehabilitation of parks,

1 recreation, and related facilities, for the purposes
2 of redefining the Niagara riverfront, promoting
3 tourism, enhancing the environment, and advancing
4 the economic revitalization of the Niagara River
5 Greenway within Niagara County.
6 The third benefit is the
7 commitment of twenty-five megawatts of firm power
8 and associated energy for sale to the host
9 communities, to be allocated according to the NPC
10 bylaws. I want to focus on this last benefit,
11 because it is the one directly affected by the
12 proposed rate increase.
13 To implement the power allocation
14 portion of the settlement agreement, the members of
15 the NPC entered into individual contracts with the
16 Power Authority. I want to emphasize, the host
17 communities pay for the power allocated to them;
18 it's not simply given to them. Under their
19 contracts they pay the preference power rate, which
20 is the same rates that muni electrical systems, and
21 certain domestic and rural customers pay for Power
22 Authority hydropower. This rate is below the cost
23 of electricity that would otherwise be available to

1 the host communities and their citizens.
2 It benefits them in two different
3 ways. First, it saves the host communities
4 themselves on electric bills, because they would
5 otherwise have to purchase electricity at higher
6 rates from National Grid or the New York State
7 Electric & Gas Corporation.
8 Second, because the host
9 communities sell the electricity they do not use
10 into the market, they receive revenues from any
11 sales that are made at a price above their cost.
12 I would just add that one NPC
13 member, the Town of Lewiston, made an alternative
14 arrangement by which electric customers within the
15 Town are credited directly for net revenues from
16 sales in the market.
17 A rate increase affects the host
18 communities in two corresponding ways. It requires
19 them to pay more for the power and the energy they
20 use directly, and it reduces the revenues they
21 otherwise would realize on sales into the market.
22 This is a double hit, a double whammy. It is why we
23 are concerned about the multi-year increase the

1 Power Authority is proposing.
2 Any way you slice it, the proposed
3 rate increase is enormous, and I believe
4 unprecedented. Even using the data and assumptions
5 in the Preliminary Staff Report dated July 2011, the
6 increase amounts to approximately thirty percent
7 over two and a half years, from October 31, 2011 to
8 May 1, 2014. That is, the rates we pay right now
9 will be thirty percent higher in May 2014. That is
10 an average annual increase of twelve percent in
11 rates.
12 To illustrate what this increase
13 means to the Host Communities, I would like you to
14 consider the impact on just Niagara County. The
15 County has an allocation of nine megawatts, as a
16 result of the settlement agreement. Using the same
17 assumptions that are included in the proposed rate
18 increase, the County, over the period covered by the
19 Power Authority's rate plan, November 1, '11 to
20 April 30, '15, will pay approximately four hundred
21 thousand more for the electricity it receives. That
22 is an average yearly increase of a hundred and
23 fourteen thousand. More importantly, in the last

1 rate year, from May 1, 2014 to April 30, 2015, and
2 every year after that, the Power Authority will be
3 collecting an additional hundred and seventy-four
4 thousand from the County, compared with what it
5 charges the County now.
6 In addition to this direct cost,
7 the County, like other host communities, will suffer
8 an erosion of revenues for the resale of its surplus
9 electricity in the market, unless the market price
10 increases at a faster pace than the Power
11 Authority's increases. Given the magnitude of the
12 Authority's rate increases, and the current state of
13 the market, we believe that it is unrealistic to
14 expect the spread between the two prices to remain
15 the same or to be greater. Thus, it seems likely
16 that net revenues will decline.
17 The impacts I have just described
18 diminish the value of that 2005 settlement
19 agreement, June 27, 2005, between the host
20 communities and the Power Authority. When the host
21 communities bargained with the Power Authority and
22 agreed to accept allotments of preference power,
23 rather than entirely cash benefits, it was with the

1 understanding that the value of the overall
2 transaction would increase, or at the very least,
3 not diminish over time. By diluting the value of
4 the settlement's power allocation, the rate increase
5 the Power Authority is considering here would
6 certainly violate the spirit of the settlement. The
7 settlement agreement was intended to provide
8 compensatory benefits to the host communities for
9 fifty years into the future.
10 If the rate increases proposed by
11 the Authority are not modified to that level that
12 would preserve the value of electricity allocations
13 over time, that important feature of the settlement
14 agreement could readily become worthless to the Host
15 communities, because the power and the energy
16 allocations to the host communities offset costs
17 that would otherwise be borne by the taxpayers. Any
18 reduction in the value of the power allocations
19 through a rate increase results in a greater burden
20 on taxpayers.
21 We appreciate the explanation in
22 the Preliminary Staff Report of the various
23 components of the rate increase; but a narrative

1 description of these components does little to
2 justify their reasonableness. Unfortunately, the
3 process by which the Power Authority sets its rates
4 does not lend itself to the kind of opportunity for
5 detailed examination that parties would have, for
6 example, in the case of an investor-owned electric
7 company, or a muni electric system asking for a rate
8 increase from the New York Power -- Public Service
9 Commission. While we have no reason to believe that
10 the Power Authority is misrepresenting historical
11 data, or other facts, our ability to test the
12 proposed rates is so limited that it's almost
13 nonexistent. In particular, the time available is
14 not adequate for anything even approaching a full
15 analysis.
16 Even with that constraint, we have
17 identified some major concerns. The amount of the
18 increases, whether you look at them year by year, or
19 over a four-year period, are so far above the
20 current rate of inflation that they raise questions
21 as to their reasonableness.
22 We understand the Power Authority
23 has major capital improvement projects under way,

1 and that those projects may drive costs above the
2 rate of inflation. By the same token, however, if
3 costs in one area are going up, it seems to the host
4 communities that it is incumbent upon the Power
5 Authority to control, and even reduce costs in other
6 areas to offset the increases as much as possible.
7 We have not seen any evidence of this type of
8 effort.
9 For the host communities,
10 belt-tightening is a way of life. We are
11 continuously faced with unfunded mandates that drive
12 up our costs, but we simply cannot raise taxes at
13 will. In fact, as I'm sure the Power Authority is
14 aware, the State now has imposed -- the State now
15 has imposed a limit on property tax increases,
16 capping them at two percent, or the rate of
17 inflation, whichever is less. To comply with that
18 restriction, while simultaneously meeting our
19 mandatory obligations, our members are forced to
20 make hard choices, and to cut back on expenditures
21 that would otherwise be entirely appropriate. As a
22 result, over the past few years, our budgets have
23 remained nearly flat, and in some cases have

1 actually declined, despite the unfunded mandates,
2 and other cost increases we face in nearly every
3 category of expense. Unlike the host communities'
4 unfunded mandates and other uncontrollable costs
5 that make up a large portion of their budgets, the
6 expenditures that apparently drive the Power
7 Authority's proposed rate increase are largely, if
8 not entirely, within the control of the Power
9 Authority.
10 In times like this, we do not see
11 how the Power Authority can justify the increases it
12 is proposing without demonstrating that it's made
13 every possible effort to cut costs.
14 It troubles us -- what troubles us
15 is that, despite all the capital improvements the
16 Power Authority is undertaking at the Niagara Power
17 Project, as well as the St. Lawrence Project,
18 there's no reduction in operation and maintenance,
19 and administrative and general expenses. Instead,
20 there's a substantial increase. According to the
21 July 2011 Preliminary Staff Report, those costs
22 would increase by almost sixteen percent in just the
23 first year of the rate plan. Over the four-year

1 period they would increase by over twenty-three
2 percent.
3 The host communities are puzzled
4 by the notion that a series of upgrade projects that
5 are supposed to increase the efficiency of the
6 Niagara Power Project are apparently doing
7 nothing to reduce operation and maintenance and
8 administrative and general costs. If the Power
9 Authority believes that the capital improvements are
10 going to reduce these costs, then that outcome does
11 not appear to be reflected in the rate proposal.
12 An additional concern of the host
13 communities is how the Power Authority intends to
14 deal with recovery of the Rate Stabilization
15 Reserve, the RSR, balances following the withdrawal
16 of the firm hydropower that was allocated to the
17 three Upstate electric utilities; National Grid, New
18 York State Electric & Gas Corporation, and the
19 Rochester Gas & Electric Corporation. According to
20 the Preliminary Staff Report, the Power Authority
21 staff has not completed its analysis of the effect
22 that withdrawal may have, but plans to inform the
23 Trustees, and adjust the rate proposal accordingly

1 when it is submitted for final approval in October.
2 Our concern is that, with the withdrawal of the
3 Upstate electric companies and their customers as
4 recipients of preference power, the RSR balances
5 that accumulated prior to withdrawal might be
6 included in the rates charges to the host
7 communities and other customers who continue to
8 receive firm hydropower. In other words, our
9 citizens might be forced to bear the costs that were
10 incurred by the departed customers. That would be
11 unfair. Accordingly, the Power Authority should
12 make clear that whatever disposition is ultimately
13 made of those RSR balances, now or in the future,
14 they will not be collected from the host communities.
15 The host communities are also
16 troubled by the fact that while the Power Authority
17 is seeking to implement a major multi-year rate
18 increase, it is able to make so-called voluntary
19 contributions of hundreds of millions of dollars to
20 the State Treasury. We belive that before such
21 payments are made to the State, some portion of that
22 surplus should be used to mitigate the proposed rate
23 increase. The host communities are aware that when

1 the issue of payments to the State was litigated
2 recently, the Power Authority took the position that
3 using the surplus to offset rates to preference
4 power customers would result in lowering those rates
5 below cost. The court agreed that the Public
6 Authorities Law did not require a reduction below
7 cost; but at the same time, it did not conclude that
8 the law precluded an offset. The host communities
9 believe that even if the Power Authority is not
10 required to use surplus funds as an offset to part
11 or all of the proposed rate increases, it has the
12 discretion to do so.
13 Exercising that discretion here
14 would be appropriate. Using surplus funds as an
15 offset would mitigate what we believe is the
16 greatest increase that has ever been proposed. It
17 would preserve the intent and economic value of the
18 settlement agreement power allocations. It would
19 also recognize the role of the firm hydropower
20 customers in supporting the Niagara Power Project
21 and the St. Lawrence Project, which are the backbone
22 of the Power Authority's business, and have enabled
23 it to achieve surplus revenues.

1 At the same time, this use of
2 surplus funds would not impair the Power Authority's
3 ability to carry out any of its functions. I would
4 just add that if the Power Authority believes that
5 it lacks the authority it use surplus funds in this
6 way, it should seek legislation expressly
7 authorizing such use.
8 While we would like to see the
9 Power Authority use its surplus funds to offset the
10 entire proposed rate increase, we believe there is a
11 middle ground that would serve the interests of the
12 Authority and the host communities. Consistent with
13 the State's legislation and policies limiting
14 property tax increases to the lesser of two percent
15 or the rate of inflation, the Power Authority could
16 increase its rates by up to two percent per year.
17 The Authority would rely on surplus funds to make up
18 any remaining revenue shortfall. This approach
19 would provide an incentive to the Authority to
20 minimize increases in rates, thereby helping to
21 preserve the value of the June 27, 2005 settlement
22 agreement, maintaining its viability of a fifty-year
23 term.

1 The host communities respectfully
2 urge the Trustees of the New York Power Authority
3 not to implement the proposed rate increase as
4 presented. Instead, the proposal should be
5 reconsidered and modified consistent with these
6 remarks.
7 And we thank you very much for the
8 time. Sorry about the five minutes. Thank you.
9 KAREN DELINCE: Thank you,
10 Mr. Ross. Next we have Renae Kimble.
11 LEGISLATOR KIMBLE: Good
12 afternoon. Thank you for holding public comments on
13 NYPA's proposed increases in hydropower preference
14 reduction rates. I am Niagara County Legislator,
15 Renae Kimble. I represent the Second Legislative
16 District in the City of Niagara Falls.
17 According to New York Power
18 Authority's preliminary staff report, hydroelectric
19 production rates, on page two, and I quote; the
20 principal cost driver responsible for the increase
21 is the ongoing capital investments in the
22 facilities, including relicensing expenditures at
23 Niagara and St. Lawrence, the life extension and

1 modernization, LEM, for the St. Lawrence Project,
2 and LEM for the Lewiston Pump Generating Plant at
3 the Niagara Project.
4 The LEM program at the St.
5 Lawrence project, which began in 1998, is expected
6 to be completed in 2013. The LEM program at the
7 Lewiston Pump Generating Plant is expected to begin
8 in 2012, and be completed in 2020, and is estimated
9 to cost four hundred and sixty million dollars.
10 During the two years of the rate freeze, and the
11 four years of proposed rate plan period, the
12 Authority will have invested over four hundred
13 ninety million in the Hydro Projects; end of quote.
14 NYPA is a public benefit
15 corporation formed under the New York State Public
16 Authorities Law. This not-for-profit entity owns
17 two thousand nine hundred acres of property in
18 Niagara County, primarily in Lewiston, and is
19 assessed at one point eight billion dollars.
20 NYPA is exempt from paying local,
21 state and federal taxes. It is exempt from paying
22 property taxes. NYPA pays nothing for the water it
23 uses to produce low-cost power.

1 NYPA received over one hundred
2 million dollars in net revenues last year.
3 Throughout NYPA's existence, it
4 has transferred millions of dollars to the General
5 Fund of the State of New York for the purpose of
6 assisting the State in balancing its budget.
7 Recently, from 2008 to 2010, NYPA transferred seven
8 hundred fifty million dollars to assist the State
9 during one of its most mammoth financial crisis in
10 recent history. This amount includes the infamous
11 five hundred forty-four million dollar sweep of funds.
12 In 2009 NYPA purchased waterfront
13 property at 32 Fuhrmann Boulevard to moor the Power
14 Authority's barge, icebreaker and tugboat at, a cost
15 of four point four million dollars.
16 In November 2009, NYPA opened a
17 satellite office on Perry Street in Buffalo.
18 In February 2010, NYPA negotiated
19 an accelerated payment schedule with Buffalo and
20 Erie County for fifty-five million dollars in net
21 new funding toward waterfront development.
22 Regarding the relicensing
23 agreement, NYPA made assurances during the

1 relicensing negotiations that the proposed
2 settlement agreement that was entered into between
3 NYPA and the Niagara Power Coalition would not
4 result in any rate increase for any NYPA customers.
5 In 2008, NYPA made a proposal to
6 increase the rates for NYPA customers, which was
7 tabled until now, due to the outcry of elected
8 officials and ratepayers.
9 NYPA continues on a quest to gouge
10 its ratepayers, even though it pays no taxes, the
11 water it uses to product electricity is free, and it
12 has a statutory obligation to provide the lowest
13 possible rates to preferred power users, including
14 the residents of Niagara County, and to charge
15 preferred users of power generated by the Niagara
16 Power Project at cost.
17 NYPA provides free power, or loose
18 juice, as it's called, which is not contractually
19 allocated to Economic Development Power and Low Cost
20 Power. This loose juice is sold on the grid because
21 electricity cannot be stored. This electricity is
22 sold at the highest bidder's rate.
23 Pursuant to the New York State

1 Independent Systems Operators, or better known at
2 the ISO, which is a private non New York State
3 authority, which regulates the power on the grid,
4 leads to NYPA to an exorbitant revenue stream, in
5 which ratepayers wind up paying the highest utility
6 rates around, as NYPA continues to reap a
7 significant profit the ratepayers' expense, in spite
8 of its statutory obligation to provide the lowest
9 possible rates to preferred power users.
10 I would like to give you an
11 example as to how this loose juice bidding process
12 operates, so that we can have a clear picture of how
13 the ratepayers are being ripped off.
14 The ISO states that it needs three
15 hundred megawatts of power for a customer. NYPA
16 informs them that they have two hundred and fifty
17 megawatts of power at a cost of, let's say,
18 twenty-five dollars a megawatt. National Grid
19 informs the ISO that it has ten megawatts of power
20 at a hundred and fifty dollars a megawatt, and
21 Rochester Electric & Gas says that it has the
22 remaining forty megawatts of power at five hundred
23 dollars a megawatt. NYPA is paid five hundred

1 dollars a megawatt for its two hundred and fifty
2 megawatts of power, instead of only twenty-five
3 dollars a megawatt. So the customer pays a hundred
4 and twenty-five thousand dollars for the two hundred
5 and fifty megawatts of power from NYPA at the
6 upgraded rate of five hundred dollars per megawatt.
7 The other fifty megawatts of power from National
8 Grid and Rochester Electric equals an additional
9 twenty-five thousand, so the customer pays a total
10 of a hundred and fifty thousand dollars for three
11 hundred megawatts of power, instead of the former
12 blended rate, which would add the cost for each
13 megawatt of power as originally bidded upon. What a
14 rip off.
15 Under the former blended-rate
16 scenario, the cost would have amounted only to six
17 thousand one hundred dollars for two hundred
18 megawatts of power from NYPA at twenty-five dollars
19 a megawatt; or one thousand five hundred dollars for
20 ten megawatts of power, at a hundred and fifty
21 dollars per megawatt from National Grid; and twenty
22 thousand for the forty megawatts of power, at five
23 hundred dollars per megawatt from Rochester

1 Electric; for a total cost to the ratepayer of only
2 twenty-seven thousand six hundred dollars. What a
3 tremendous difference in the price.
4 So my question here today is why
5 is NYPA asking to raise rates an additional three
6 dollars a megawatt, when NYPA is already receiving
7 prime dollar rates for its power? I say no way, no
8 way. Operate within your means. Trust me, your
9 means are very, very good from where I sit. We
10 are being ripped off, and this is all due to
11 deregulation.
12 But now, I do not want to digress
13 regarding deregulation. I would like to address the
14 need for the massive upgrade at the Lewiston Pump
15 Plant. I believe that the Project Management
16 Department that runs the Power Authority no longer
17 has engineers on site to upgrade these units. I
18 believe that all of the engineers are located in
19 White Plains, and that they make their decisions top
20 down, instead of bottom up. Their decisions are
21 based on theory instead of actual hands-on
22 experience with each and every plant. They are not
23 making plant-specific recommendations, but

1 recommendations that they want each plant to carry
2 out, or standardized recommendations.
3 There have been problems with NYPA
4 spending millions of dollars on equipment that
5 doesn't last as long as the original equipment,
6 which, in many instances, works better than the new
7 equipment that they have replaced the old equipment
8 with.
9 The NYPA engineers have made
10 changes with analog gauges to digital gauges for the
11 generating units to monitor the temperature of the
12 units. Due to the EMF, the electrical magnetic
13 field, that is given off by the generators, the new
14 digital gauges do not last as long as the former
15 analog gauges, which results in additional costs in
16 repair. This is just one example of NYPA's attempt
17 to standardize things at all of its plants, costing
18 additional money.
19 Massive upgrades at the Pump
20 Plant, which are being suggested, make everything to
21 run electronically and computer-operated, and that
22 has significant problems. I feel that it has not
23 been adequately thought through for the amount of

1 money that NYPA is being asked to spend, and raise
2 our rates.
3 Have you thought of what would
4 happen if someone were to hack into the computer
5 system? The Power Authority operators and workers
6 would have absolutely no control of that generating
7 unit. With no control, there is a great possibility
8 that blackouts, shutdowns, and significant damage
9 would occur to the equipment, which would affect the
10 grid and power production, as well as leave those
11 who receive the power vulnerable to all types of
12 security problems.
13 It seems to me that the Power
14 Authority has lost sight of what it was originally
15 created to do; and that is to ensure the reliability
16 of producing the lowest costing, most reliable power
17 for its low-cost power customers, the businesses who
18 need cheap power, and all those individuals who rely
19 on NYPA power for operating their businesses safely
20 and efficiently, without glitches.
21 When the blackout of August 15,
22 2003 occurred, from Cleveland, Detroit, Toronto,
23 sections of New Jersey, Massachusetts, Pennsylvania,

1 Connecticut and New York, including Albany, the
2 Catskills, Syracuse, New York City and beyond, it
3 cost NYPA customers millions of dollars when the St.
4 Lawrence and Blenheim Gilboa plants went off line.
5 The Niagara Project was the only
6 one to remain online, and that was due to the fact
7 that the plant was built with a backup system that
8 the operators could rely on, and that was manual
9 operation of the generators. They were able to put
10 the generators on manual control, they controlled
11 the units by hand. If the electronic control
12 operation system on the generators had been in
13 effect, as it is being proposed today, the power on
14 the grid would have been adversely affected, the
15 businesses who rely on NYPA for power allocations
16 would have been adversely affected, and the Niagara
17 Plant would have been off line too, and not
18 operational during the blackout.
19 I have to question the feasibility
20 of the four hundred and sixty million dollar Life
21 Expectancy Project upgrade that is before the Board
22 of Trustees for the Lewiston Pump Plant today, which
23 is the impetus for the request for this ill-timed

1 unnecessary rate increase.

2 If I were you, I would revisit

3 this, and go back to the drawing board. NYPA built

4 into its current system safeguards to operate the

5 system in case of an emergency. If the current

6 proposal goes forth as is currently presented, there

7 will be absolutely no control over the system, and

8 no safeguards. If the system fails, it can cause a

9 catastrophic chain of events; explosions, fire,

10 equipment damage, damage to the power grid itself,

11 and even death. The employees will be placed in

12 harm's way. We could have a major disaster of

13 calamitous proportions.

14 We all know that we would like the

15 Power Authority to update equipment when needed, but

16 the top down approach, as to the way the Authority

17 currently operates, is not working, but is causing a

18 financial drain on the Power Authority's resources,

19 which is tantamount to waste, fraud and abuse. This

20 whole scheme needs to be investigated thoroughly

21 before any decision is made; before any rate is

22 hiked, and before any security breach. This is one

23 rate increase in which we cannot afford on so many

1 different levels.

2 I sincerely hope that before any

3 decision is made by the Board of Trustees, that

4 every concern that I have raised here today is

5 reviewed, researched and resolved. Unfortunately,

6 you do not have the time to really know what is

7 really needed at each facility, you have to take the

8 word of bureaucrats, who usually have very little

9 hands-on experience or knowledge regarding each and

10 every facility.

11 And we, in Niagara County,

12 continue to suffer the continuing saga of having the

13 facility which produces the greatest amount of

14 power, and providing the most profits for NYPA, but

15 with very little to show for it. We continue to

16 have taxation without representation on the NYPA

17 Board. After all, who would know better than a

18 Niagara County representative what the Lewiston Pump

19 Plant needs, because it is obvious to me that you

20 have much more work to do before you can make a

21 knowledgeable decision regarding spending four

22 hundred sixty million dollars on the Lewiston Pump

23 Plant by implementing the proposed rate increase,

1 which is unwarranted, and a significant deterrent to
2 economic development and job creation, which is
3 still desperately needed in Niagara County, and
4 throughout the rest of the region.
5 Again, thank you for the
6 opportunity to address my concerns.
7 KAREN DELINCE: Thank you,
8 Legislator Kimble.
9 Next we have Tom Rudebusch.
10 THOMAS RUDEBUSCH: Thank you.
11 Thank you for the opportunity to be here today. My
12 name is Tom Rudebusch. I represent the New York
13 State Association of Public Power, also known as
14 NYAPP. NYAPP is comprised of nine municipal
15 electric systems, and four rural electric
16 cooperatives; and are all eligible customers under
17 the Niagara Redevelopment Act.
18 I have seven points I want to make
19 today.
20 Point number one; NYAPP supports
21 the deferral of any proposed rate increase to May 1,
22 2012, and an extension of the comment period to
23 December 1, 2011. NYAPP, and other customers, are

1 actively reviewing the proposed rate increase and
2 are conducting discovery. The customers need this
3 additional time to complete their review.
4 It has been customary for the
5 staff's Preliminary Report to be made available to
6 customers five or six months in advance of the start
7 of the rate year on May 1. In this case, customers
8 were provided with the Preliminary Report two months
9 before the deadline for written comments. Staff is
10 doing a good job of responding to discovery
11 requests, but the issue isn't whether the staff
12 answers the requests before the comment date; the
13 issue is how much time do the customers have to
14 review the responses. NYAPP has had productive
15 discussions with staff. Additional time for
16 discussion will allow for a better understanding of
17 the interests of both sides, and reduce any friction
18 caused by a compressed timetable. An extension of
19 time to December 1, 2011 for written comments would
20 be much appreciated.
21 NYAPP has also requested a
22 deferral of any rate increase until May 1, 2012,
23 which is the start of the next rate year for NYAPP.

1 At the Trustees' June 28, 2011
2 meeting, the Chief Financial Officer noted that the
3 Authority, quote; continues to be in a strong
4 financial position, end quote. Because hydro flows
5 and precipitation and higher than normal, the Chief
6 Financial Officer predicted that end-of-year net
7 income will be one hundred and ninety-seven million,
8 which would be seventeen million dollars above the
9 2011 budget. For the period November 1, 2011 to
10 April 30, 2012, the proposed preference power rate
11 increase would produce approximately three million
12 dollars additional revenue for the Authority from
13 all the municipal and cooperative customers in New
14 York State. Deferral of any rate increase until the
15 start of the next rate year will not affect the
16 Authority's fiscal integrity. Put simply, you don't
17 need the money now.
18 Point number two; NYAPP opposes
19 the retroactive collection of cancelled rate
20 increases for 2009 and '10. In 2009, the staff
21 proposed to increase rates for the 2009 and 2010
22 rate years. Instead, the Trustees voted to, quote,
23 withdraw, unquote; the proposed rate increases, and

1 they, quote, extended, unquote, the rates that were
2 in effect in 2008. That's the language in the
3 Trustees' motion. The March 24, 2009 press release
4 was titled: NYPA Cancels Proposed Rate Increase for
5 Hydropower Customers. But now, the Authority
6 proposes to go back and collect approximately
7 twenty-five million dollars for 2009 and 2010. This
8 violates the expectations of customers. They expect
9 that when the Authority cancels a rate increase,
10 it's gone. The staff cannot say we meant we were
11 going to defer the rate increases and not cancel
12 them. It's a shock. What controls is the language
13 of the Trustees' motion, not prefatory language --
14 KAREN DELINCE: Sir, can you
15 repeat that?
16 THOMAS RUDEBUSCH: What controls
17 is the language of the Trustees' motion, not
18 prefatory language leading up to the motion.
19 Collecting costs incurred in the
20 past is also not proper ratemaking. The rates in
21 the Service Tariffs are stated rates. They are a
22 fixed number per unit of service. They are to be
23 based on the cost of service. But once billed by

1 the Authority, and paid for by the customers, that
2 is the end of it. Changes to the rates are only
3 prospective, or forward-looking. You cannot go back
4 in time and say, our costs were really such and
5 such, and we are going to change the stated rate
6 from the past and collect the amounts due from
7 current customers. That is called retroactive
8 ratemaking, and it is not permissible.
9 The Public Service Commission
10 knows how to collect deferred amounts; it does it
11 up front. The PSC issues an order that says; these
12 costs are being incurred, but for some good public
13 policy reason, we are not going to collect them now,
14 and we direct the utility to put the amounts in a
15 deferral account to be collected at a date certain
16 in the future. That is how you do it; with notice
17 to customers.
18 The PSC puts it all in an order.
19 It does not say we are cancelling the rate increase,
20 leaves the stated rate in place, and then comes back
21 two years later and say, we are changing the rate
22 retroactively.
23 Besides stated rates, there's

1 another mechanism called formula rates, where the
2 stated rate in the tariff is a formula, not a fixed
3 number. There is no formula in the Service Tariff.
4 The Authority's attorneys know what a formula rate
5 is, because some of the Transmission Owners use them
6 for transmission charges. The formula usually goes
7 on for pages. The formula details how annual values
8 in the numerous accounts are incorporated in charges
9 to customers. The numbers in those accounts are
10 verified by being filed with the Federal Energy
11 Regulatory Commission on an annual FERC Form 1. If
12 the Authority wants to consider implementing a
13 formula rate for hydro production costs, we can
14 discuss what that might involve.
15 The Service Tariffs do include a
16 hydro flow adjustment calculation called the Rate
17 Stabilization Reserve, or RSR. And I'll talk more
18 about the RSR later. But the purpose of the RSR
19 was to smooth out the effect of fluctuations in
20 annual hydro flows, it was to provide rate stability
21 so that the rates did not change every year. The
22 purpose was the opposite of what a rate formula
23 does, which is to allow for periodic frequent

1 variations in the rates.
2 We do have a statutory standard
3 that the preference power shall be sold at the
4 lowest rate reasonably possible. But that is a
5 guide for setting rates, it is not a formula. The
6 Authority, in the past, has not used that standard
7 as a formula. When the court, in the Bergen case,
8 said rates should be set using a labor ratio
9 allocator, the Authority made the change only
10 prospectively, and did not change the rates in the
11 past. When customers pointed out that the Authority
12 used the wrong year to start the Handy-Whitman Index
13 for Depreciation, the Authority said, we can't go
14 back and change rates, those were established
15 practices. Put simply, the Authority cannot have it
16 both ways; heads, we win; tails, customers lose.
17 Point three; NYAPP is concerned
18 about the rate impact of the four hundred and
19 fifty-five megawatts of reallocated power under the
20 Recharge New York Program. Under the Recharge New
21 York Program, the Authority withdrew four hundred
22 and fifty-five megawatts of hydropower from its
23 rural and domestic and customers on August 1, 2011,

1 and will reallocate that power to eligible
2 businesses to promote economic development. Since
3 the R&D customers did not pay the proposed rate
4 increases in 2009 and '10, other NYPA customers will
5 pay more if retroactive rate increases are allowed.
6 This is exactly one of the problems with retroactive
7 ratemaking. If the rates had been increased in 2009
8 and '10, the R&D customers would have paid their
9 share of the increase, or about six million dollars.
10 Since those customers are no longer customers, if
11 the Authority seeks to implement a twenty-five
12 million dollar retroactive rate increase, that
13 leaves a hole that needs to be filled. Other
14 Authority customers should not have to make up the
15 difference.
16 Going forward, the four hundred
17 and fifty-five megawatts should continue to be
18 included in the demand components of the rate
19 calculation, because the new customers should be
20 allocated the costs of the hydro projects.
21 In addition, the Authority has not
22 yet stated how it proposes to treat the reality of
23 this, which is another reason to defer any proposed

1 rate increases.

2 Point four; NYAPP is concerned

3 about increasing Authority costs.

4 In a March 2009 press conference

5 announcing the withdrawal of the rate increases, the

6 then NYAPP Chairman committed to reducing the

7 Authority's costs. He said, quote; we will find

8 ways to bring our costs down, through cutting our

9 own costs, or better productivity, more efficiency,

10 you know, fewer cars, whatever it takes to bring

11 down our costs, we will do that; end quote.

12 Some measures have been taken to

13 bring down costs, including a wage and salary

14 freeze, which is not an item that NYPA has -- that

15 NYAPP has endorsed, by the away.

16 But the Authority's rates continue

17 to increase. There were rate increases of five

18 point three percent in 2007; five point nine percent

19 in 2008; and the proposed increase of eight point

20 two percent in 2009. Going forward, the Authority

21 is proposing increases of six point six percent in

22 2011; six point five percent in 2012; six point

23 seven percent in 2013, and six point nine percent

1 in 2014.

2 These are dramatic increases,

3 especially at the same time that the Authority is

4 making large voluntary contributions to the State

5 Treasury. In June, the Trustees approved a

6 contribution to the State Treasury of forty million

7 dollars. This is in addition to the twenty-five

8 million dollar contribution they approved in

9 January; as well as a seven point five million

10 dollar contribution to the Gross Receipts Tax

11 Credit. The current budget legislation authorized

12 an additional sixty million dollar contribution to

13 be made by January 2012. Wage freezes for

14 employees; rate increases for customers; and

15 continued large contributions to the State Treasury;

16 that sounds like a problem.

17 At a public hearing in 2009, I

18 said that the Authority had an image problem;

19 proposing rate increases while paying bonuses for

20 senior management -- that's what we opposed -- and

21 making large contributions to the State.

22 Well, the Authority still has an

23 image problem. Preference power rates are supposed

1 to be based on costs, and costs do not include large
2 contributions to the State Treasury. Simply put, we
3 have a hard time explaining to our customers why
4 their power rates should go up, while the Authority
5 continues to make the large contributions. This is
6 another reason why the proposed rate increase should
7 be deferred until after January 2012, when the next
8 payment is due.
9 Point five; NYAPP supports the
10 allocation of the Niagara Project costs to all
11 users. Niagara Project costs should be allocated to
12 all users of the Project's capacity.
13 Currently, all of the costs of the
14 Project are allocated to contract customers,
15 including preference power customers, even though
16 substantial capacity is being used to make sales to
17 the NYISO markets.
18 For the years 2011 through 2014,
19 the Authority forecasts billing demands of about
20 thirty-six thousand megawatt months, based on sales
21 to contract customers. These demands are used to
22 allocate costs -- the cost of the Project. At the
23 same time, the Authority has routinely made sales

1 based on forty-one thousand megawatt months, as
2 reflected in the recent annual calculations of the
3 RSR, the Rate Stabilization Reserve. This capacity
4 is the source of the energy sold into the state's
5 ISO markets. These sales are the main source of the
6 Authority's profits, the two hundred million net
7 income number I mentioned earlier.
8 Again, we have an image problem.
9 The contract customers are allocated all of the
10 costs of the Niagara Project, and support all of the
11 capacity of the Project. Meanwhile, a substantial
12 part of Project capacity is used to make the
13 highly-profitable sales to the ISO markets. We are
14 not looking for a revenue credit, but we think the
15 Niagara Project costs should be allocated to all
16 users.
17 Point six; NYAPP supports the UCAP
18 Credit based on a cost-based rate.
19 In addition to energy, the
20 Authority sells capacity, called UCAP, into the ISO
21 markets. Preference power customers currently get a
22 credit that is based on the lower of the UCAP market
23 price or the cost-based rate of the UCAP.

1 Preference power customers should get a credit based
2 solely on the cost of the capacity, because these
3 are cost-based rates. This is an area where NYAPP
4 has had discussion with the staff. An extension of
5 the comment period, and a deferral of the effective
6 date of any rate increase, would be helpful and
7 potentially productive.
8 Point seven; NYAPP supports
9 calculating the RSR balance with a UCAP credit.
10 The Rate Stabilization Reserve,
11 the RSR, is an annual calculation meant to provide
12 rate stability when there are variations in annual
13 hydro flows. Under the global settlement reached in
14 2003, sales of capacity above the base level used in
15 rating setting should be credited to the RSR
16 balance, not to the cost of service. In other
17 words, the UCAP credit should be applied to
18 preference power customers, as parties of the
19 settlement, and not to other contract customers, who
20 are not part of the settlement. Thank you.
21 KAREN DELINCE: Thank you.
22 Next we have David Gustafson.
23 DAVID GUSTAFSON: Hello, my name

1 is Dave Gustafson. I'm with the Jamestown Board of
2 Public Utilities. Thank you for the opportunity to
3 speak here today.
4 The Jamestown Board of Public
5 Utilities is one of the largest NYPA customers
6 located in Western New York. While we recognize the
7 value of the services that NYPA provides to our
8 community, a thirty percent rate increase over a
9 three-year period is pretty significant.
10 We are a member of the New York
11 Association of Public Power, and merely wish to
12 express our support of the issues that Mr. Rudebusch
13 raised. Thank you.
14 KAREN DELINCE: Thank you.
15 Do we have any additional speakers? We do not.
16 We'll be here until seven o'clock.
17 (Off the record until seven o'clock.)
18 KAREN DELINCE: There being
19 no additional speakers, I declare this forum to be
20 closed.
21
22
23 * * * *

TAB 3

NYPA PUBLIC FORUM

IN THE MATTER OF THE

PROPOSED INCREASE IN HYDROELECTRIC PREFERENCE POWER RATES

FROM THE NIAGARA AND ST. LAWRENCE HYDROELECTRIC PROJECTS

NEW YORK POWER AUTHORITY

DATE: September 22, 2011

TIME: 2:00 p.m. to 6:00 p.m.

LOCATION: Frank S. McCullough, Jr.
Hawkins Point Visitor Center
21 Hawkins Point Road
Massena, New York 13662

COPY

1 APPEARANCES

2

3 FOR NEW YORK POWER AUTHORITY:

KAREN DELINCE, ESQ., Corporate Secretary, Law

4 Department

JAMES F. PASQUALE, Senior Vice President of Marketing &

5 Economic Development

New York Power Authority

6 123 Main Street

White Plains, New York 10601

7 (914) 390-8085

8

9 SPEAKERS:

James Shaw

10 Andy McMahon

Charlie McGrath

11 William Treacy

12

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1 MS. DELINCE: Good afternoon. This is a New York
2 Power Authority public forum on a Proposed Increase in
3 Hydroelectric Preference Power Rates from the Niagara
4 and St. Lawrence Hydroelectric Projects. My name is
5 Karen Delince and I'm the corporate secretary of the
6 Power Authority. This public forum is being conducted
7 pursuant to an Authority policy adopted in 1990. Two
8 other forums on this issue ~~was~~ were conducted earlier in the
9 week in Syracuse and Niagara.
10 These forums are not required by law and are held
11 in addition to the State Administrative Procedure Act or
12 SAPA process. The SAPA process provides a 45-day public
13 comment period, which began on August 17th with the
14 publication of a notice in the State Register and will
15 end on October 3rd. The purpose of this forum is to
16 offer affected customers and the general public an
17 opportunity to present data, views and positions to
18 assist the Trustees in evaluating the rate proposal
19 prior to making final -- prior to taking final action.
20 A complete transcript of the proceeding will be
21 taken and provided to the Authority's Trustees along
22 with any written comments submitted by October 3rd.
23 If you plan to make an oral statement at this forum

1 and have not filled out a card, please see Lorna Johnson
2 at the sign-in desk. If you have copies of your
3 statement, please give one to the reporter and one to
4 Lorna Johnson. If you have both a written statement and
5 will make an oral statement, both will appear in the
6 record of this forum.
7 If you would like to submit additional comments
8 after today, you may mail them to the Corporate
9 Secretary at the New York Power Authority, 123 Main
10 Street, 11-P, White Plains, New York 10601; or fax to
11 (914) 390-8040; or e-mail to secretarys.office@nypa.gov.
12 If you have any additional questions, please see
13 Ms. Johnson.
14 The complete transcript of the forums will be made
15 available to the public for review at the Authority's
16 office in White Plains and on the Authority's website,
17 nypa.gov. At this point, I will turn the proceedings
18 over to Mr. James Pasquale, the Authority's Senior Vice
19 President of Marketing and Economic Development, who
20 will provide additional detail on the proposed rate
21 increase. I will then call on speakers. Thank you.
22 MR. PASQUALE: Thank you, Ms. Delince. Good
23 afternoon. My name is James F. Pasquale, I am Senior

1 Vice President of Marketing and Economic Development at
2 the New York Power Authority. I am here today to
3 present an overview of the modifications to the
4 hydroelectric preference power rates.
5 In summary, by this rate action, the Authority is
6 proposing a 42-month phase-in rate plan covering the
7 remaining portion of the 2011 rate year plus the 2012,
8 2013 and 2014 rate years ending April 30th, 2015. By
9 the 2013 rate year, the preference rates will be phased
10 back up to full cost. Starting with the 2014 rate year,
11 the suspension of the Rate Stabilization Reserve, known
12 as an RSR, would be lifted and the Authority would begin
13 to collect preferred hydroelectric costs stemming mainly
14 from the withdrawal rate action for the 2009 and 2010
15 rate years.
16 The proposed rate plan would allow rates to return
17 to cost-based levels in accordance with the
18 methodologies adopted in the April 2003 final rate
19 action approved by the Authority Trustees. Such
20 methodologies were also agreed to by the municipal and
21 electric cooperative customers as part of 2003 global
22 settlement reached with the Authority. The overall
23 production phase-in rates proposed at a 70 percent load

1 factor are $11.42 a megawatt hour, $12.16 a megawatt
2 hour, $12.98 a megawatt hour and $13.87 a megawatt hour
3 for the rate years 2011, 2012, 2013 and 2014
4 respectively.
5 The public comment and this forum are intended as
6 opportunities for customer input into the Authority's
7 ratemaking process in accordance with established
8 Authority ratemaking policies and consistent with the
9 State Administrative Procedure Act. To that end, the
10 Authority has received numerous customer inquiries to
11 which Authority staff has been and is working on to
12 respond to in a timely and thorough manner. Staff shall
13 diligently consider all relative comments and queries
14 raised during this comment period, including those heard
15 today during this public forum. Staff will present
16 their analyses, findings and recommendations to the
17 Trustees at the conclusion of the public comment period.
18 I will now provide some background on the
19 Authority's preference rates, recent history and the
20 cost components that make up the rate. After that, I'll
21 describe in more detail the current rate proposal,
22 including the primary drivers of this rate increase.
23 The Authority's proposed preference rates apply to

1 customers that purchase hydroelectric preference power
2 supplied from the Authority's Niagara and St. Lawrence
3 hydroelectric projects. The major customer groups are
4 the 47 municipal electric systems, four rural electric
5 cooperatives, three upstate investor-owned utilities,
6 the Neighboring States customers and the Niagara Project
7 relicensing host communities.
8 At their April 24th, 2007, meeting, the Trustees
9 adopted a two-year rate plan for the 2007 and 2008 rate
10 years, which extended from May 1, 2007, to April 30th,
11 2009. No increase to these rates has occurred since May
12 2008, the start of the final rate year under the
13 two-year plan.
14 In January 2009, the Trustees authorized a Notice
15 of Proposed Rulemaking, also known as a NOPR, to
16 increase the preference power rates for rate years 2009
17 and 2010. That proposal called for increasing revenues
18 in the 2009 rate year by $9.7 million as compared to the
19 rates in effect in the 2008 rate year, and increasing
20 revenues in the 2010 rate year by $14.6 million as
21 compared to the rates in effect in the 2008 rate year.
22 Based on public comments, consideration of the
23 national economic downturn and the extent to which the

1 downturn had adversely affected the region's customers,
2 the Trustees in March 2009 approved the withdrawal of
3 the NOPR, deferring the recovery of costs until a
4 subsequent period of time. The deferred recovery was
5 necessary since under federal and state statures and
6 court precedents governing preference power sales the
7 preference rate must be at the lowest possible rate but
8 not lower than cost. This action also included a
9 suspension of the RSR, a contractual rate adjustment for
10 preference power customers to ensure that the tariff
11 rates do not over-collect or under-collect costs.
12 The current overall production rate at a 70 percent
13 load factor is $10.71 a megawatt hour, which compares
14 favorably to the $39.22 a megawatt hour average hourly
15 market rate for 2010 in the New York Independent System
16 Operator Zone A located in Western New York. The
17 preliminary Cost of Service sets forth the estimated
18 costs required to serve the preference power customers
19 from the Authority's Hydro Projects and continues the
20 ratemaking methodologies adopted by the Trustees at
21 their April 2003 meeting.
22 Based on the Cost of Service methodology, the total
23 Hydro Projects' costs, net of the ancillary service

1 credits, are $230.6 million, $238.6 million, $247.3
2 million and $255.6 million for the 2011 through
3 2014 calendar years respectively. The principal cost
4 driver responsible for the increase is the ongoing
5 capital investments at the facilities, including the
6 Niagara and St. Lawrence relicensing expenditures and
7 the life extension and modernization for both the St.
8 Lawrence Project and Lewiston Pump-Generating Plant at
9 the Niagara Project. During the two years of rate
10 freeze and the four years of the proposed rate plan
11 period, the Authority will have invested over $490
12 million in the Hydro Projects.
13 Consistent with past ratemaking practice, the costs
14 used to set new rates starting in 2011 will be based on
15 projected calendar year 2011 costs, although the 2011
16 rate year would extend only from November 1, 2011,
17 through April 30, 2012. For the subsequent rate years
18 in this proposed plan, the Authority staff proposed to
19 adopt its traditional rate year approach under which the
20 new rate year will begin May 1st, 2012, 2013 and 2014
21 and will be based on projected calendar year costs for
22 2012, 2013 and 2014 respectively.
23 Phasing of the rates would result in an

1 under-recovery of costs during the two years, the two
2 rate years ended April 30th, 2013. These under-recovery
3 amounts are estimated to be $12 million in 2011 and $4
4 million in 2012 and would contribute to making the
5 current RSR balance more negative. By the 2013 rate
6 year, the proposed increase would bring rates up to the
7 current costs estimated for calendar year 2013.
8 Starting with the 2014 rate year, the suspension of the
9 RSR would be lifted and the Authority would begin to pay
10 down the negative RSR balance through the collection of
11 an RSR surcharge.
12 To mitigate cost impacts to the preference
13 customers, staff recommends that the RSR surcharge be
14 limited to 50 cents a megawatt hour in 2014. Based on
15 the current negative RSR balance, staff anticipates that
16 RSR surcharges will need to continue in the rate years
17 subsequent to the years covered by the proposed rate
18 plan in order to bring the RSR balance back to the
19 $25 million threshold.
20 It is proposed that the rate design policy approved
21 by the Trustees in the April 2003 final rate action be
22 continued for the proposed rate plan and the costs not
23 collected in the current $4.92 a megawatt hour energy

1 charge be recovered through the demand charge;
2 therefore, resulting proposed demand charge is $3.32 a
3 kilowatt-month for 2011, $3.70 a kilowatt-month for
4 2012, $4.12 a kilowatt-month for 2013, and $4.32 a
5 kilowatt-month for 2014.
6 Included in the Trustee item for the notice of
7 proposed rulemaking is the Preliminary Staff Report
8 documenting the Cost of Service. Copies are available
9 here today for your review. As Ms. Delince stated
10 earlier, the Authority will accept your comments on the
11 proposed rates until October 3rd, 2011. I will now turn
12 the forum back over to Ms. Delince.
13 MS. DELINCE: Thank you, Mr. Pasquale. I will now
14 call on speakers. When called, please come to the
15 podium to deliver your statement and state your full
16 name and affiliation, if any, for the record. James
17 Shaw.
18 MR. SHAW: Good afternoon. I'm James Shaw,
19 Chairman of the Massena Electric Board, and we're one of
20 your major principal municipal customers. I'm here to
21 express my Board's concern with regard to the proposed
22 rate increase, particularly the aggressive time schedule
23 you are proposing. Our rate experts have, after

1 reviewing your information, raised many questions and
2 issues that need to be resolved. I choose not to list
3 them as I believe in discussions our experts have
4 brought these questions and issues to your staff's
5 attention. We believe that you should allow adequate
6 time for these questions to be answered to both party's
7 satisfaction; therefore, we believe the proposed
8 timetable is inappropriate and should be extended to
9 allow for this resolution of these issues. Thank you
10 for allowing me to speak and for having the meeting in
11 Massena.
12 MS. DELINCE: Thank you, Mr. Shaw. Next we have
13 Andy McMahon.
14 MR. McMAHON: Good afternoon. My name is Andy
15 McMahon, and I'm the Superintendent of the Massena
16 Electric Department. I'm here to make comments on the
17 NYPA's proposed rate increase as put forward in August
18 2011. My comments on the proposal are brief.
19 Primarily, I wish to offer my support to the well
20 researched and thoughtful efforts put forward by the
21 rate specialists working for the municipals in New York
22 state. I believe a dialog has begun and I hope NYPA
23 will listen and make appropriate and fair decisions on

1 the recommendations put forward.

2 I recognize the importance and rational behind

3 cost-based rates. I agree with the concept that a

4 utility must recover their legitimate expenses. In

5 reviewing NYPA's proposal, I am confident that there

6 will be the typical questions related to the appropriate

7 cost allocations and the appropriateness of certain

8 expenses that will no doubt be resolved in due time.

9 However, I have multiple concerns with pressing forward

10 with a rate increase at this point for reasons more

11 related to philosophical disconnects in ratemaking.

12 There are vagaries involved in this case that lead to

13 significantly different mathematical results which need

14 to be fully addressed and understood in advance of the

15 application of a new rate plan.

16 Given the upgrades at the Niagara Project, the

17 advent of the ISO and other changes which have occurred

18 in recent years, the ratemaking exercise is more than

19 just plugging numbers into formulas. Given these

20 changes and the unique dynamics it has caused, it seems

21 to me that there are some policy questions that may take

22 some time to be properly resolved.

23 Application of the UCap to the RSR is an issue that

1 will take some time to fully understand and resolve. In
2 one calculation I have seen, the UCap application would
3 obviate the need for any rate increase. At a minimum,
4 it would dramatically reduce the size of the Rate
5 Stabilization Reserve, which NYPA is using as an
6 indicator of the need to revise rates. We need to take
7 adequate time and diligence to assure that we have an
8 appropriate cost-based methodology that all parties
9 agree is fair.
10 Understanding the impact of Recharge New York on
11 preference power rates must also be understood. It is a
12 significant variable that has yet to be resolved. I
13 strongly encourage you to take time and defer
14 implementation of this increase, and, if required,
15 address these questions in a fair and prudent manner.
16 In the past there have been questions raised on
17 these types of rate policy matters that I do not believe
18 received proper consideration. By way of example, I
19 cite the issues surrounding the Handy Whitman Index on
20 depreciation. NYPA implemented an initiation date on
21 the index that some municipal rate experts still believe
22 is incorrect. The difference of six months in the
23 application of this index has had a long lasting and

1 profound financial impact on the RSR and the rates which
2 NYPA charges. Now, when questioned on the Handy Whitman
3 Index, the explanation from NYPA staff is essentially
4 that it is too hard to go back. Given that logic, let
5 us not go forward until we are relatively confident that
6 we are going forward with a deep understanding that we
7 have applied proper cost-based ratemaking principles.
8 I appreciate the time you've taken to listen to
9 these comments on this very important matter, and I
10 further appreciate that as a host community to one of
11 your greatest assets you have made the host -- that we
12 were made a host to these very important sessions.
13 Thanks.
14 MS. DELINCE: Thank you, Mr. McMahon. Charlie
15 McGrath.
16 MR. McGRATH: Good afternoon. My name is Charlie
17 McGrath. I'm certain some of you have heard my name in
18 this area. I've been trying to pay attention for the
19 last 13 years on what's been going on with the
20 relicensing and the increase in rates from the Power
21 Authority.
22 During the relicensing you'll remember that the
23 Towns of Louisville and Massena and the Village of

1 Massena agreed to accept approximately $500,000 per year
2 as one of the payments for the relicensing cash
3 payments. Since 2003 the rates to Massena Electric for
4 our 22 megawatts, approximately, have gone up about
5 $500,000 a year. So just from a citizen standpoint, it
6 looks to me like we're getting nothing again. We're
7 taking money from the Power Authority that they have
8 taken out of our pocket prior to giving it to us, and it
9 always happens just before Christmas so it looks like
10 we're receiving some great gift. And I know that in the
11 relicensing agreement there was no clause called the
12 Santa clause, but I think that we're looking at that
13 relicensing agreement and that check just like we're
14 getting a gift from Santa.
15 From a citizen standpoint, looking at it from the
16 first 50 years, NYPA was allowed to purchase the
17 property along the river, and now the community has got
18 no taxes, no school taxes, no ability to develop along
19 the shoreline of the river. We've had limited access to
20 this river, and that's one of our biggest problems is we
21 need greater access to this river.
22 I've heard from sources within the Power Authority
23 that "we need this land." I take exception to that you

1 really need that land to produce power. Somehow the
2 local host communities should be able to be granted
3 access, but this is about the rate increases. And right
4 now it seems that the Power Authority has the ability to
5 transfer hundreds of millions of dollars to Albany, so
6 that says to me you really don't need that money for
7 operation. And so, if you have enough money to transfer
8 to Albany for God knows what reason, whether it's a loan
9 or a voluntary contribution I believe it's called,
10 that's still an awful lot of money, and we're looking at
11 taking those dollars out of the ratepayer's pockets and
12 redistributing them to Albany so that those folks in
13 Albany can redistribute based upon whatever basis they
14 choose.
15 So I don't like the fact that you're raising rates
16 again to pay for the cost of relicensing because -- and,
17 again, we're so dumb up here that we didn't realize that
18 part of the cost of the relicensing was the two million
19 dollar check that we get every Christmas, so we believed
20 that there was -- we were going to get something in
21 exchange for what we lost during the first 50 years,
22 and, once again, we're getting nothing for the next 50
23 years. So I don't see the need for the Power Authority

1 to raise rates next year or any time soon. If they
2 could change their policy of handing money over to
3 Albany, and I know there's a lot of political pressure
4 for the Power Authority to perform and produce a lot of
5 money so that they can send it to Albany, but we need to
6 take those people out of the mix and leave the monies
7 with the host communities. And thank you.
8 MS. DELINCE: Thank you, Mr. McGrath. Is there
9 anybody else present who would like to give a statement?
10 All right. Not at this time. We will be accepting
11 additional statements until 6:00 this evening.
12 (A recess was taken to wait for testimony.)
13 MS. DELINCE: Bill --
14 MR. TREACY: Treacy.
15 MS. DELINCE: Treacy?
16 MR. TREACY: Yes.
17 MS. DELINCE: Okay.
18 MR. TREACY: All right. I'm Bill Treacy,
19 representing the Plattsburgh Municipal Lighting
20 Department from the City of Plattsburgh, New York, and
21 I'm representing the Mayor and the City Council, who
22 believe and have looked at the stated rate increase that
23 NYPA is asking for and believe it is unwise at this time

1 to be asking for such an increase based on the current
2 state of the economy.
3 Things have been pretty tough in Plattsburgh. For
4 example, two years -- two years ago we had about 800
5 people that are receiving HEAP allowances. That has
6 increased in the last two years to now well over 1,200
7 and probably will increase. And with the talk of the
8 economy possibly going into another recession or a
9 double-dip recession, the city -- the city fathers
10 believe it is not time to do a rate increase, that it
11 would be better for NYPA to put it off until some time
12 in the future until things in the economy turn around.
13 MS. DELINCE: Thank you, Mr. Treacy.
14 MR. TREACY: Thanks.
15 (A recess was taken to wait for testimony.)
16 MS. DELINCE: Okay. Seeing no additional speakers,
17 I declare this forum officially closed.
18 (The public forum concluded at 6:00 p.m.)
19
20
21
22
23

STATE OF NEW YORK)

COUNTY OF ST. LAWRENCE)

C E R T I F I C A T E

I, Erica Bedford, Court Reporter, do hereby certify that the foregoing has been a true and correct transcript of the testimony as taken by me, to the best of my ability, at the time and place noted in the heading hereof.

Erica Bedford

Erica Bedford, Notary Public

State of New York

County of St. Lawrence

My commission expires: 5/11/14

TAB 4

Statements Submitted at Public Forums

TAB 4-A

Statement From Tony Modafferi

Representing MEUA

Municipal Electric Utilities Association of New York State

6652 Hammersmith Drive, East Syracuse, New York, 13057
Phone: 315/453-7851 Fax: 315/453-7849
Email: info@meua.org web site: www.meua.org

Statement of Tony Modafferi, Executive Director of the Municipal Electric Utilities Association at the NYPA hearing September 19, 2011

Good afternoon, my name is Tony Modafferi. I am the Executive Director of the Municipal Electric Utilities Association (MEUA) which represents 40 of the municipal electric utilities in New York State that receive hydroelectric preference power.

NYPA and the MEUA both know public power imposes a public duty. According to State law the hydroelectric power for domestic and rural use should be sold at the lowest possible rate and for the lowest possible price.

It is clear that just like the MEUA systems, NYPA has a public duty to control the cost of providing that power. Whether it is relicensing the Niagara Project, or instituting new rates, we have an obligation to control costs. NYPA and the MEUA are partners in this duty.

Over the years, the MEUA has participated in many programs with NYPA. We are committed to exploring new opportunities as we have done in NYPA sponsored programs such as Industrial Economic Development, the alternate vehicle partnership program (MAPP), the Global settlement agreement of 2003, the recent solar incentive both large and small applications, the MEUA's Energy Efficiency Program and the home insulation program demonstrates that the municipals do not take their preference power allotment for granted.

The authority may pursue to revise its rates based on costs. The current rate study is an examination of NYPA's costs. The MEUA has retained qualifed analysts to examine that study. NYPA has presented a multi-year rate plan. This will allow the municipalities to plan and adjust accordingly for years to come.

This increase was first announced July 26 with the public hearings announced August 19th for today September 19, tomorrow Sept. 20th and Thursday September 22nd. NYPA officials will then make a recommendation to the NYPA Board of Trustees and the rate increase is scheduled to be possibly voted on at the Trustee's October meeting. Two weeks after the proposed rate increase was announced, the MEUA submitted a series of questions concerning the cost study. To date, the answers to these questions are still being worked on by NYPA officials. This does not allow much time for review and submission of written comments to NYPA.

Out of fairness to all parties involved, the MEUA requests an extension of time to allow our consultants the proper time to analyze the cost study and submit it's written comments. If the true extent of the law is to be followed as far as costs are concerned, then please allow more time for the review of the costs before moving forward with this increase.

When the Authority formally decides this matter, we urge the Authority to make a statement recognizing and offering its duty to control costs and provide power at the lowest possible price. The MEUA looks forward to a continued working relationship with the Power Authority in the interest of our Public Power Partnership.

Thank you

TAB 4-B

Statement from Butch Solomon and John Coyle Representing Neighboring States

PRELIMINARY ISSUES
FOR SEPTEMBER 19, 2011 PUBLIC COMMENTS OF
NEIGHBORING STATES PREFERENCE CUSTOMERS
CONCERNING
NEW YORK POWER AUTHORITY'S 2011 HYDROELECTRIC RATE MODIFICATION PLAN
(New York Register Rulemaking I.D. No. PAS-33-11-00001-P)

The Neighboring States (Connecticut, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island and Vermont) are currently allocated an aggregate of approximately 266.6 MW of hydroelectric power from the Power Authority's Niagara and St. Lawrence projects. Approximately 34.5 MW of that amount comes from the St. Lawrence Project under that facility's current FERC hydroelectric license, and approximately 232.1 MW of that amount comes from the Niagara Project under the terms of the federal Niagara Redevelopment Act (16 U.S.C. § 836) and the terms of the FERC hydroelectric license for that facility.

Under the terms of both Section 1005(5) of New York's Public Authorities Law -- the statute under which the Authority is proposing to modify its rates in this proceeding -- and the federal Niagara Redevelopment Act, the Neighboring States are entitled to the same rate making protections that are afforded to New York municipal utilities who receive hydroelectric power allocations from the Authority. The relevant standard, as the Authority is aware, requires that power generated by the Authority's hydroelectric facilities be sold to in-state municipal utilities and to the Neighboring States "at prices representing cost of generation, plus capital and operating charges, plus a fair cost of transmission, all as determined by the trustees, and subject to conditions which shall assure the resale of such power at the lowest possible price." Similarly, the Niagara Redevelopment Act (16 U.S.C. § 836(b)(1)) requires that power generated by the Authority's hydroelectric plants "shall be made available at the lowest rates reasonably possible and in such manner as to encourage the widest possible use."

These are the standards against which the Authority's proposal to increase its hydropower rates by approximately 37 percent is required to be assessed. Based on initial analysis of data responses received to date, we have identified several areas in the July 2011

Preliminary Staff Report (the Report) and accompanying cost of service study (CoS) that we believe warrant adjustments that would have the effect of bringing the proposed rates into closer conformity with the requirements for cost-based, "lowest possible" rates established by the principles adopted by the Authority in the March 5, 1986 Settlement Agreement in *Auer v. Dyson* and 2003 "global" settlement agreements between the Authority and its preference customers.

At the outset, we support the September 13, 2011, request of the New York Association of Public Power that the Authority defer the implementation of any proposed change in its hydroelectric rates until May 1, 2012, the start of the Authority's next rate year. Like our New York-based colleagues, the Neighboring States wish to pursue an informed and deliberate dialogue with the Authority's rate staff, aimed at achieving closer conformity between the Authority's rate proposal and the statutory and settlement principle-based requirements that govern it.

The Neighboring States seek to apply more correctly the *Auer v. Dyson* and 2003 settlement principles based upon the understanding of the Authority's hydro costs and operations gleaned from the Preliminary Staff Report and the Authority's responses to Neighboring States information requests and to those of other interested parties. None of the suggested adjustments seek any "market-based" credits. The adjustments proposed by the Neighboring States would leave in the hands of the Authority's Trustees the discretion to use surplus margins earned through market-based sales from the Niagara and St. Lawrence projects. However, the cost-based, lowest possible rates principles that are the bedrock of the *Auer v. Dyson* Settlement and 2003 settlements must be applied in a way that provides credit for the full costs associated with participation in the NYISO markets not just a portion of the costs. The Neighboring States believe that when these principles are correctly applied and their impacts evaluated, the results demonstrate that the Authority's existing rates are fully compensatory. Actual experience shows that, even in the difficult economic times we have

experienced since 2008, the existing rates have enabled the Authority not only to secure sufficient revenues to meet all of its costs, but have also earned margins from market transactions that have proven sufficiently substantial to enable the Authority to make significant transfers to the State's general fund and add significantly to its operating funds balances.

The cost-of-service issues identified thus far are:

1. Failure to Provide Fully Cost-Based Credit for Hydro Energy Sales Into the NYISO Markets – While the ratemaking methodology used to determine the hydro R&D rates does provide a credit for the energy-related portion of the cost of producing the energy sold into the NYISO markets, this $4.92/MWH energy cost credit does not reflect the capacity-related cost incurred to produce such sales, and, therefore, it does not fulfill the Power Authority's commitment to provide cost-based credit for the sales. In response to Neighboring States data request item 11, the Staff provided forecasted sales of Niagara and St. Lawrence energy into the NYISO markets. While these forecasted sales for 2011-2014 average only 2,629,004 MWH per year as compared to the 4,555,142 MWH average for the last three years (2008-2010), they still may be used as a basis for determining at least a minimal credit for the demand-related costs of producing such energy. A reasonable contribution to the cost of the capacity used in generating these NYISO energy market sales may be calculated by dividing the annual capacity-related costs included in the CoS divided by the long-term average generation of 20,216,000 MWH used for each year. The average cost over the four-year rate plan horizon is $7.10/MWH and when applied to the average forecasted NYISO energy sales, results in an average annual CoS credit of $18,563,000. See the attached rate impact workpaper for the actual annual adjustments. Of course, this adjustment, as well as the others suggested by the Neighboring States, should also be reflected in the annual RSR calculations.

   When the Neighboring States raised this issue in the 2007 rate determination, the Staff incorrectly assumed it was a request for a market-based level of credits for such sales and rejected it on that basis. That is not the issue being raised, and it should not be mistaken as a request for credits for the NYISO market sales based on the market prices actually received for such sales. Neighboring States simply seek credit for the full, capacity as well as energy, cost basis for such sales. Such proper crediting of the full

cost associated with making these sales would still leave the vast majority of the market prices received (approximately $40/MWH and often much more) to contribute to the net revenues of the Power Authority.

2. Insufficient Credit for the Regulation Ancillary Service Sales into the NYISO Markets – Historically, the Power Authority has sold much, much more regulation ancillary services into the NYISO markets than have actually been required to meet the needs of its hydro power contract customers, yet it has provided credit only up to the level of its contract customers' needs. The July 2011 Report provides a regulation ancillary service credit for the forecasted 2008 CoS of approximately $1.25 million, whereas, the Staff response to Neighboring States data request item 12 and NYAPP 1-21 shows actual 2008 regulation service revenues of $40.489 million. While a part of the reason for this large discrepancy is that the actual revenues are those received from market based sales, it certainly must also be attributable to the actual sale of a much larger quantity of regulation service sales than is reflected in the CoS. The forecasted rate period credits are similarly lopsided with hydro CoS credits of approximately $1.5 million or less each year and forecasted regulation service sales (pursuant to the Staff response to Neighboring States data request item 12) ranging from $12 million in 2011 to $32 million in 2014.

   The use only of costs associated with the amount of regulation needs of the contract loads is not relevant, because the actual sales volumes greatly exceed these amounts. It is important to remember that one of the principles agreed upon in the Relicensing Settlement Agreement Addressing Allocation of Niagara Project Power and Energy to Neighboring States (at Article X) was "(iii) Treatment of sales to third parties, including the New York Independent System Operator." Since the stated principle does not exclude any sales to third parties, conformity with the stated principle requires that ***all*** sales to third parties be included in the crediting process. Accordingly, the credits should be increased to reflect the full quantity of regulation services sold into the NYISO markets, not just the amount sold related to the contract load.

   While we do not have sufficient information to calculate the most precise adjustment to reflect the higher level of expected regulation sales, even if only one quarter of the expected sales revenues were due to the larger quantity of regulation services sold than is reflected in the CoS, the cost-based credits for such sales would range from $3 to $8

million per year over the rate period horizon. Such annual credits would still fall far short of the expected sales revenues that are in the $12 to $32 million per year range and would leave huge contributions toward the overall net revenues of the Power Authority.

3. No CoS Credit Provided for Investment Income From Investment Funds Arising Out of the Niagara and St. Lawrence Project Operations – Obviously, substantial net revenues and free cash flows are generated for the Power Authority through the hydro projects. In addition to the profits from the market sales of energy and ancillary services into the NYISO market, cash is generated from the collection of depreciation expenses and the extra capital costs recovered through the use of the TOC capital cost recovery methodology. Such amounts arise directly as a result of the project operations, and fully cost-based rates for the output of those projects would reflect the credits for the investment income generated as part of those operations. Through investment of its available cash, the Power Authority had investment income of $71 million in 2008, $32 in 2009, and $41 million for 2010. For 2011-14 the Power Authority's Approved Financial Plan projects investment income to climb from $32.4 million in 2011 to $88.3 million in 2014, with an annual average of $58.4 million over the four-year period. An appropriate portion of this investment income that is clearly generated in large part out of the cash flow from Niagara and St. Lawrence operations should be credited against the hydro cost of service. The Report of the Chief Financial Officer for the years ending December 31, 2009 and 2010 show that Niagara and St. Lawrence contributed 81% and 82%, respectively, of the NYPA total Net Income for those years. If the projected investment income were allocated conservatively as only 50% attributable to Niagara and St. Lawrence, the CoS credit would range from $16.2 million in 2011 to $44.2 in 2014 and would be an annual average of $29.2 million over the four-year period. Neighboring States do not seek a resulting price that is below cost; rather, the income generated by cash supplied by hydro customers for hydro power is a necessary input to the calculation of the cost of that power. Failing to reflect investment income associated with hydro revenues in calculating the hydro "cost" is akin to including tax payments in a cost of service but refusing to consider any tax refunds obtained.

4. An Estimated UCAP Sales Credit Should Be Included in Calculating the Rates – The Power Authority recognizes that it is appropriate to include a credit for UCAP sales in determining the actual, after-the-fact cost of service for purposes of the RSR

calculations. Such credits for 2008, 2009 and 2010 were $11,079,000, $6,625,000 and $7,209,000, respectively. The same methodology should apply to the development of the rates to be charged in the first instance, not just in the calculation of the after-the-fact actual cost of service for RSR purposes. A conservative estimate of such annual sales credits for 2011-2014 would be the average of the 2008-2010 actual sales, or $8,304,000. This would make the projected rates more realistic, and yet, would still provide the ability to adjust to the actual credit amounts in the RSR CoS calculations.

5. Proper RSR Treatment of the Withdrawal of 455 MW From Upstate Utilities Resulting From Implementation of the Recharge New York Power Program – Footnote 6 on page 10 of the Report states that to the extent that staff anticipates that the withdrawal of the 455 MW from upstate utilities to implement the Recharge New York power program will affect the RSR balance and the RSR surcharge in a material manner, staff will inform the Trustees and adjust the rate proposal accordingly when it is submitted for final approval in October 2011. Since at this point, we don't know what conclusions the staff will draw nor whether it will propose any adjustment in the RSR balance or surcharge, we can't comment except to urge the staff to collaborate with the customers in their deliberations on the issue and to allow customer input before making any ultimate decision. Any adjustments should assure that the remaining customers do not have any prior shortfall in collections associated with the 455 MW rolled over onto them.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
PROPOSED PRODUCTION COST OF SERVICE
AS ADJUSTED BY NEIGHBORING STATES - September 16, 2011

($000)

Line	Description	(Per 2007 CoS) 2008	2011	2012	2013	2014	Difference 2011 vs 2008 *
	Operations & Maintenance/Administrative & General						
1	Operations & Maintenance/A&G	61,941	71,762	72,174	74,654	76,355	9,821
2	Amortized Roadwork	2,983	212	-	-	-	(2,771)
3	Subtotal O&M/A&G (line 1 + line 2)	64,924	71,973	72,174	74,654	76,355	7,049
	Indirect Overheads						
4	Shared Services	41,329	44,897	45,837	46,564	47,235	3,568
5	Research & Development	3,780	2,523	2,598	2,650	2,703	(1,257)
6	Project Study Debt Service	846	-	-	-	-	(846)
7	Y2K Debt Service	2,874	237	237	237	237	(2,637)
8	Subtotal Indirect Overheads (sum lines 4-7)	48,829	47,656	48,672	49,451	50,176	(1,173)
9	**St. Law. Relicensing, amortization**	2,000	2,000	2,000	2,000	2,000	-
10	**Niagara Relicensing, amortization**	12,000	12,700	12,700	12,700	12,700	700
11	**Other Post -Employment Benefits (OPEB)**	13,608	10,348	10,720	11,051	11,424	(3,261)
12	**O&M Cost of Service** (sum lines 3,8, 9, 10,11)	**141,361**	**144,677**	**146,266**	**149,856**	**152,654**	**3,316**
	Capital Costs						
13	Total Depreciation	35,350	40,984	43,422	45,309	47,204	5,634
14	Interest on Debt	21,453	30,322	33,205	35,104	37,386	8,869
15	Inflation Compensation	21,521	28,697	30,428	32,182	34,069	7,176
16	Subtotal Capital Costs (sum lines 13-15)	78,324	100,003	107,055	112,595	118,659	21,679
17	**Total Cost of Service** (line 12 +line 16)	**219,685**	**244,680**	**253,321**	**262,451**	**271,313**	**24,995**

* 2008 data is from 2007 CoS and was based on data and projections available at that time.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
FINAL PRODUCTION COST OF SERVICE
AS ADJUSTED BY NEIGHBORING STATES - September 16, 2011

($000)

Line	Description		(Per 2007 CoS) 2008	2011	2012	2013	2014	Difference 2011 vs 2008 *
1	**Total Cost of Service**	**($000)**	**219,685**	**244,680**	**253,321**	**262,451**	**271,313**	**24,995**
2	**Credits for ancillary services**	($000)						
3	Black Start, O&M		81	69	71	73	75	(12)
4	Voltage Support, O&M		332	213	219	225	232	(119)
5	Remaining O&M (page 1, line 12 - (line 3+line 4)		140,948	144,395	145,976	149,558	152,347	3,447
6	Operating Reserves, O&M		4.82%	4.40%	4.37%	4.33%	4.31%	
7	Regulation, O&M		0.57%	0.55%	0.54%	0.54%	0.53%	
8	Subtotal OR, Reg. O&M		5.39%	4.95%	4.91%	4.87%	4.84%	
9	Op. Res.+ Reg. O&M credit (line 8 * line 5)	($000)	7,597	7,148	7,167	7,283	7,374	(450)
10	**Capital Reductions**							
11	All ancillary services		6.85%	6.68%	6.74%	6.75%	6.79%	
12	Subtotal capital reductions (page 1, line 16 * line 11)	($000)	5,365	6,680	7,216	7,600	8,057	1,315
13	Total Ancillary Credits (sum lines 3,4,9,12)	($000)	13,375	14,110	14,673	15,182	15,738	734
14	**Other Credits Pursuant to Comments of the Neighboring States ($000)**							
15	Demand Cost Credit for Sales Into NYISO Energy Market			19,098	18,890	18,039	18,227	
16	Credit for Larger Quantities of Regulation Service Sales			3,004	6,355	7,636	8,063	
17	Investment Income Credit			16,200	23,400	33,000	44,200	
18	Credit for Sales Into NYISO UCAP Market			8,304	8,304	8,304	8,304	
19	Total Other Credits (sum lines 15-18)			46,606	56,949	66,979	78,794	(46,606)
20	**Adjusted Cost of Service** (line 1 - line 13 - line 19)	**($000)**	**206,310**	**183,964**	**181,699**	**180,291**	**176,782**	**(22,345)**
21	Billing Demand	MW	36,137	34,086	35,035	35,871	36,100	(2,051)
22	Billing Demand Allocated Costs (line 20 - line 27)	($000)	106,822	84,502	82,237	80,828	77,319	(22,321)
23	Billed Demand Rate (line 22 / line 21)	$/kW/mo	2.96	2.48	2.35	2.25	2.14	(0.48)
24	LTA Generation	GWh	20,221	20,216	20,216	20,216	20,216	(5)
25	Annual Generation	GWh	20,012	20,456	20,148	20,409	20,435	444
26	Billing Energy Rate	$/MWh	4.92	4.92	4.92	4.92	4.92	
27	Costs Allocated to Energy Rate (line 24 * line 26)	$/MWh	99,487	99,463	99,463	99,463	99,463	(25)

* 2008 data is from 2007 CoS and was based on data and projections available at that time.

TAB 4-C

Statement from Niagara County Legislator Renae Kimble

Renae Kimble
Niagara County Legislator
2nd District

3302 Hyde Park Blvd.
Niagara Falls, New York
14305
(716) 282-1618

REMARKS ON NYPA'S PROPOSED INCREASES IN HYDROPOWER PREFERENCE PRODUCTION RATES

By Niagara County Legislator Renae Kimble

Thank you for holding public comments on NYPA's proposed increases in Hydropower Preference Production Rates. I am Niagara County Legislator Renae Kimble. I represent the Second District in the City of Niagara Falls, New York.

According to the New York Power Authority's preliminary staff report Hydroelectric Production Rates on page 2, "The principal cost driver responsible for the increase is the ongoing capital investments in the facilities, including: relicensing expenditures at Niagara and St. Lawrence, the life extension and modernization ("LEM") for the St. Lawrence Project and the LEM for the Lewiston Pump Generating Plant ("LPGP") at the Niagara Project. The LEM program at the St. Lawrence Project, which began in 1998, is

expected to be completed in 2013. The LEM program at LPGP, expected to begin in 2012 and be completed in 2020, is estimated to cost $460 million. During the two years of the rate freeze and the four years of the proposed rate plan period, the Authority will have invested over $490 million in the Hydro Projects."

NYPA is a public benefit corporation formed under the New York State Public Authorities Law. This not-for-profit entity owns 2,900 acres of property in Niagara County, primarily in Lewiston and is assessed at $1.8 billion dollars.

NYPA is exempt from paying local, state and federal taxes. It is exempt from paying property taxes.

NYPA pays absolutely nothing for the water it uses to produce low cost power. NYPA received over $100 million dollars in net revenues last year.

Throughout NYPA's existence, it has transferred millions of dollars to the General Fund of the State of New York for the purpose of assisting the state in balancing its budget. Recently, from 2008 -

2010, NYPA transferred $750 million dollars to assist the state during one of its most mammoth financial crisis in recent history. This amount includes the infamous $544 million dollar sweep of funds.

In 2009 NYPA purchased waterfront property at 32 Fuhrmann Boulevard to moor the Power Authority's barge, ice breaker and tug boat at a cost of $4.4 million dollars.

In November 2009, NYPA opened a satellite office on Perry Street in Buffalo.

In February 2010, NYPA negotiated an accelerated payment schedule with Buffalo and Erie County for $55 million dollars in net new funding toward waterfront development.

Regarding the Relicensing Agreement, NYPA made assurances during the Relicensing negotiations that the proposed settlement agreement that was entered into between NYPA and the Niagara Power Coalition would not result in any rate increase for NYPA customers.

In 2008, NYPA made a proposal to increase the rates for NYPA customers which was tabled until now, due to the outcry of elected officials and ratepayers.

NYPA continues on a quest to gouge its ratepayers even though it pays no taxes, the water it uses to produce electricity is free, and it has a statutory obligation to provide the "lowest possible rates" to preferred-power users including the residents of Niagara County and to charge preferred users of power generated by the Niagara Power Project at cost.

NYPA provides free power or loose juice as it is called which is not contractually allocated to Economic Development Power and Low Cost Power. This loose juice is sold on the grid because electricity cannot be stored. This electricity is sold at the highest bidder's rate.

Pursuant to the New York State Independent Systems Operators or better known as the ISO, which is a private non-NYS authority which regulates the power on the grid; leads NYPA to an

exorbitant revenue stream, in which rate payers wind up paying the highest utility rates around as NYPA continues to reap a significant profit at the rate payer's expense in spite of its statutory obligation to provide the "lowest possible rates" to preferred-power users.

I would like to give you an example as to how this loose juice bidding process operates, so that we can have a clear picture of how the rate payers are being ripped off.

The ISO states that it needs 300 megawatts of power for a customer. NYPA informs them that it has 250 megawatts of power at a cost of $25 dollars a megawatt. National Grid informs the ISO that it has 10 megawatts of power at $150 dollars a megawatt. Rochester Electric and Gas says it has the remaining 40 megawatts of power at $500 dollars a megawatt. NYPA is paid $500 dollars a megawatt for its 250 megawatts of power instead of only $25 dollars a megawatt. So the customer pays $125,000 for the 250 megawatts of power from NYPA at the upgraded rate of $500 per megawatt. The other 50 megawatts of power from National Grid and

Rochester Electric equals an additional $25,000 so the customer pays a total of $150,000 dollars for 300 megawatts of power, instead of the former blended rate which would add the cost for each megawatt of power as originally bided. What a rip off.

Under former blended rate scenario the cost would have amounted to only $6,100 for 250 megawatts of power from NYPA, at $25 dollar a megawatt, $1,500 for 10 megawatts of power at $150 dollars per megawatt from National Grid, and $20,000 for 40 megawatts of power at $500 dollars per megawatt from Rochester Electric for a total cost to the rate payer of only $27,600. What a tremendous difference in price.

So my question here today is why is NYPA asking to raise the rates an additional $3.00 a megawatt when NYPA is already receiving prime dollar rates for its power? I say no way, no way.

Operate within your means, and trust me your means look very, very good from where I sit.

We are being ripped off and this is all due to deregulation.

Now not to digress regarding deregulation, I would like to address the need for the massive upgrade at the Lewiston Pump Plant.

I believe that the Project Management Department that runs the Power Authority no longer has engineers on site to upgrade the units. I believe that all of the engineers are located in White Plains and they make their decisions top down instead of bottom up. Their decisions are based on theory instead of actual hands on experience with each and every plant. They are not making plant specific recommendations but recommendations that they want each plant to carry out or standardized recommendations.

There have been problems with NYPA spending million dollars on equipment that doesn't last as long as the original equipment which in many instances works better than the new equipment that they have replaced the old equipment with.

The NYPA engineers have made changes with analog gages to digital gages for the generating units to monitor the temperature of

the units. Due to the EMF, Electrical Magnetic Field that is given off by the generators, the new digital gages do no last as long as the former analog gages which results in additional costs in repair. This is just one example of NYPA's attempt to standardize things at all of its plants costing additional money.

Massive upgrades at the Pump Plant which are being suggested making everything run electronically and computer operated has significant problems and I feel have not been adequately thought through for the amount of money that NYPA is being asked to spend and raise our rates.

Have you thought of what would happen if someone were to hack into the computer system? The Power Authority operators and workers would have absolutely no control of that generating unit. With no control there is a great possibility that black outs , shut downs and significant damage would occur to the equipment which would affect the grid and power production, as well as leave those who receive the power vulnerable to all types of security problems.

It seems to me that the Power Authority has lost sight of what it was originally created to do and that is to ensure the reliability of producing the lowest costing, most reliable power for its low cost power customers, the businesses who need cheap power and all of those individuals who rely on NYPA power for operating their businesses safely and efficiently without glitches.

When the "Black out" of August 15, 2003 occurred, from Cleveland, Detroit, Toronto, sections of New Jersey, Massachusetts, Pennsylvania, Connecticut and New York State, including Albany, Catskills, Syracuse, New York City and beyond, it cost NYPA customers millions of dollars when the St. Lawrence and Blenheim Gilboa plants went off line.

The Niagara Project was the only one to remain on line and that was due to the fact that the plant was built with a backup system that the operators could rely on, and that was manual operation of the generators. They were able to put the generators on manual control, they controlled the units by hand. If the

electronic control operation system on the generators had been in effect as is being proposed today, the power on the grid would have been adversely affected, the businesses who rely on NYPA for power allocations would have been adversely affected and the Niagara Plant would have been off line too, and non-operational during the black out.

I have to question the feasibility of the $460 million dollar Life Expectancy Project upgrade that is before the Board of Trustees for the Lewiston Pump Plant today which is the impetus for the request for this ill timed, unnecessary rate increase.

If I were you, I would revisit this and go back to the drawing board. NYPA built, into its current system safeguards to operate the system in case of an emergency. If the current proposal goes forth as is currently presented, there will be absolutely no control over the system, and no safeguards. If the system fails, it can cause a catastrophic chain of events, explosions, fire, equipment damage, damage to the power grid itself and even death. The employees will

be placed in harm's way. We can have a major disaster of calamitous proportions.

We know that we would like the Power Authority to update equipment when needed but this top down approach as the way the authority currently operates is not working but is causing a financial drain on the Power Authority's resources which is tantamount to waste, fraud and abuse. This whole scheme needs to be investigated thoroughly before any decision is made, before any rate is hiked and before any security breached.

This is one rate increase in which we cannot afford on so many different levels.

I sincerely hope that before any decision is made by the Board of Trustees that every concern that I have raised here today is reviewed, researched and resolved. Unfortunately, you do not have the time to really know what is really needed at each facility, you have to take the word of bureaucrats who usually have very little hands on experience or knowledge regarding each and every facility.

And we in Niagara County continue to suffer the continuing saga of have the facility which produces the greatest amount of power and providing the most profits for NYPA but with very little to show for it. We continue to have taxation without representation on the NYPA Board. After all, who would know better than a Niagara County representative what the Lewiston Pump plant needs because it is obvious to me that you have much more work to do before you can make a knowledgeable decision regarding spending $460 million dollars on the Lewiston Pump Plant by implementing the proposed rate increase which is unwarranted and a significant deterrent to economic development and job creation which is still desperately needed in Niagara County and throughout the rest of the region.

Again, thank you for the opportunity to address my concerns.

Renae Kimble
9/20/11

TAB 4-D

Statement from State Assemblyman John D. Ceretto

JOHN
Ceretto
STATE ASSEMBLYMAN

Assemblyman John D. Ceretto
Testimony to NYPA
September 20, 2011

I appear before this panel on behalf of my constituents to say enough is enough. The residents and small business owners in Niagara County should not be subject to rate hikes at a time when the economy remains stagnant and when Niagara County has given so much to the NYPA System.

In my interactions with NYPA there are always numbers tossed around. This time it is $480 million. $480 million needed for plant improvements in Lewiston for efficiency upgrades. I'm not here to suggest the plant couldn't use upgrades. But let's not forget that in 2010 $550 million was swept out of the NYPA system by majorities in both houses of the State Legislature to plug a gaping hole in the State Budget. Now I don't have to tell anyone here the tremendous role the Niagara Power Project plays in revenue generation for NYPA, but to those in Niagara County, it felt like Albany was using Niagara County as a piggy bank to cover its own failures. Like many, I was outraged.

What was even more outrageous was that, despite needing to raid NYPA for $550 million, Albany found a way to bail out the Metro Transit Authority to the tune of $30 billion. Give $30 billion to New York City, while taking $550 million from upstate.

So here we are less than 2 years later and NYPA needs $480 million. That $480 million should NOT come out of the pockets of "preferred power customers" in Niagara County.

Until Albany can repay that money and clean up its act and until NYPA can live within its means and not spend hundreds of thousands of dollars on lavish parties I strongly object to any rate increases on the citizens of New York State, Western New York and Niagara County.

Thank You.

TAB 4-E

Statement from William L. Ross representing Niagara Power Coalition, Inc.

STATEMENT OF
WILLIAM L. ROSS
ON BEHALF OF THE
NIAGARA POWER COALITION, INC.

September 20, 2011

Good afternoon, I am William L. Ross. I am the Chairman of the Niagara County Legislature. In that role, I also serve as Niagara County's representative on the Board of the Niagara Power Coalition, Inc. (NPC) and am currently the Chairman of that Board. I appreciate the fact that the New York Power Authority is holding this public hearing on its proposed rate increase and I am pleased to be speaking to you today on behalf of the NPC.

My purpose in speaking to you is to urge you to reconsider the proposed multi-year rate increase announced in July of this year.

The NPC consists of seven members. In addition to Niagara County, the members are the City of Niagara Falls, the Towns of Lewiston and Niagara, and three School Districts, the Niagara Falls City School District, the Lewiston-Porter School District, and the Niagara-Wheatfield School District. Among their other ties, these seven bodies are linked by the fact that they are the hosts to the Power Authority's Niagara Power Project. For that reason, they are known as the Host Communities. As the hosts to the Power Project, beginning more than 50 years ago, their residents and taxpayers have borne the impact of the Project's footprint, including the loss of tax base and land that could no longer be developed. While there were some modest benefits of hosting the Project, most of the impacts were negative or, at best, neutral. While low-cost hydropower benefited some people and industries in New York and neighboring states, the Niagara Power Project was a net burden on the Host Communities.

In the late 1990s, as the Project was in the last decade of its original FERC license, the Host Communities formed the NPC to represent their interests in the relicensing process. Our goal was to ensure that any burdens the Host Communities would continue to bear as a result of relicensing the Project for another 50 years would not go unrecognized and thus uncompensated. Our citizens and taxpayers are the only ones who truly gave up anything to permit the Project to be built and they would be the only ones to continue doing so if the Project were relicensed. Therefore, the NPC and our members negotiated with the Power Authority for benefits for our citizens and taxpayers to help offset the ongoing burden imposed by the Project over the next 50 years.

Our negotiations with the Power Authority culminated in a Settlement Agreement signed in 2005 that provided three types of benefits that are allocated to and among the NPC members based on a formula that was worked out during the negotiations. The first benefit is an annual payment of $5 million into a Host Communities Fund, to be used for "capital projects and infrastructure that benefit the general public and promote economic development, public health, and safety." The second benefit is an annual payment of $3 million into a Host Community Greenway Recreation/Tourism Fund to "support the construction and/or rehabilitation of parks, recreation and related facilities, for the purpose of redefining the Niagara riverfront, promoting tourism, enhancing the environment, and advancing the economic revitalization of the Niagara River Greenway within Niagara County." The third benefit is the commitment of 25 Megawatts of firm power and associated energy for sale to the Host Communities, to be allocated according to the NPC by-laws. I want to focus on this last benefit because it is the one directly affected by the proposed rate increase.

To implement the power allocation portion of the Settlement Agreement, the members of the NPC entered into individual contracts with the Power Authority. I want to emphasize that the Host Communities pay for the power allocated to them; it is not simply given to them. Under their contracts, they pay the "Preference Power" rate, which is the same rate that municipal electric systems and certain "domestic and rural" customers pay for Power Authority hydropower. This rate is below the cost of electricity that would otherwise be available to the Host Communities and their citizens. It benefits them in two different ways. First, it saves the Host Communities themselves on their electric bills because they would otherwise have to purchase electricity at higher rates from National Grid or New York State Electric & Gas Corporation. Second, because the Host Communities sell the electricity they do not use into the market, they receive revenues from any sales that are made at a price above their cost. I would just add that one NPC member, the Town of Lewiston, made an alternative arrangement by which electric customers within the Town are credited directly for net revenues from sales in the market.

A rate increase affects the Host Communities in two corresponding ways. It requires them to pay more for the power and energy they use directly and it reduces the revenues they otherwise would realize on sales into the market. This is a "double whammy" and it is why we are concerned about the multi-year rate increase the Power Authority is proposing.

Any way you slice it, the proposed rate increase is enormous and I believe unprecedented. Even using the data and assumptions in the Preliminary Staff Report dated July 2011, the increase amounts to approximately 30 percent over two and a half years, from October 31, 2011 to May 1, 2014. That is, the rates we pay right now will be 30 percent higher in May, 2014. That is an average annual increase of 12 percent in rates.

To illustrate what this increase means to the Host Communities, I would like you to consider the impact on just Niagara County. The County has an allocation of 9 Megawatts as a result of the Settlement Agreement. Using the same assumptions that are included in the proposed rate increase, the County, over the period covered by the Power Authority's rate plan – November 1, 2011 through April 30, 2015 – will pay approximately $400,000 more for the electricity it receives. That is an average yearly increase of $114,000. More importantly, in the last rate year, from May 1, 2014 through April 30, 2015 and every year after that, the Power Authority will be collecting an additional $174,000 from the County, compared with what it charges the County now.

In addition to this direct cost, the County, like other Host Communities, will suffer an erosion of revenues from re-sale of its surplus electricity in the market, unless the market price increases at a faster pace than the Power Authority's increases. Given the magnitude of the Authority's rate increases and the current state of the market, we believe that it is unrealistic to expect the spread between the two prices to remain the same or to be greater. Thus, it seems likely that net revenues will decline.

The impacts I have just described diminish the value of the 2005 Settlement Agreement between the Host Communities and the Power Authority. When the Host Communities bargained with the Power Authority and agreed to accept allotments of Preference Power rather than entirely cash benefits, it was with the understanding that the value of the overall transaction would increase or, at the very least, not diminish over time. By diluting the value of the Settlement's power allocation, the rate increase the Power Authority is considering here would certainly violate the spirit of the Settlement. The Settlement Agreement was intended to provide compensatory benefits to the Host Communities for 50 years into the future.

If the rate increases proposed by the Authority are not modified to a level that would preserve the value of the electricity allocations over time, that important feature of the Settlement Agreement could readily become worthless to the Host Communities. Because the power and energy allocations to the Host Communities offset costs that would otherwise be borne by the taxpayers, any reduction in the value of the power allocations through a rate increase results in a greater burden on taxpayers.

We appreciate the explanation in the Preliminary Staff Report of the various components of the rate increase; but a narrative description of those components does little to justify their reasonableness. Unfortunately, the process by which the Power Authority sets its rates does not lend itself to the kind of opportunity for detailed examination that parties would have, for example, in the case of an investor-owned electric company or a municipal electric system asking for a rate increase from the New York Public Service Commission. While we have no reason to believe that the Power Authority is misrepresenting historical data or other facts, our ability to test the proposed rates is so limited as to be almost non-existent. In particular, the time available is not adequate for anything even approaching a full analysis.

Even with that constraint, we have identified some major concerns. The amount of the increases, whether you look at them year-by-year or over a four-year period, are so far above the current rate of inflation that they raise questions as to their reasonableness. We understand that the Power Authority has major capital improvement projects under way and that those projects may drive costs above the rate of inflation. By the same token, however, if costs in one area are going up, it seems to the Host Communities that it is incumbent upon the Power Authority to control and even reduce costs in other areas to offset the increases as much as possible. We have not seen any evidence of this type of effort.

For the Host Communities, belt-tightening is a way of life. We are continuously faced with unfunded mandates that drive up our costs; but we cannot simply raise taxes at will. In fact, as I am sure the Power Authority is aware, the State has now imposed a limit on property tax increases, capping them at two percent or the rate of inflation, whichever is less. To comply with that restriction, while simultaneously meeting our mandatory obligations, our members are forced to make hard choices and to cut back on expenditures that would otherwise be entirely appropriate. As a result, over the past few years, our budgets have remained nearly flat, and in some cases have actually declined, despite the unfunded mandates and other cost increases we face in nearly every category of expense. Unlike the Host Communities' unfunded mandates and other uncontrollable costs that make up such a large portion of their budgets, the expenditures that apparently drive the Power Authority's proposed rate increase are largely, if not entirely, within the control of the Power Authority. In times like these, we do not see how the Power Authority can justify the increases it is proposing without demonstrating that it has made every possible effort to cut costs.

It troubles us is that, despite all of the capital improvements the Power Authority is undertaking at the Niagara Power Project, as well as at the St. Lawrence Project, there is no reduction in Operation and Maintenance and Administrative and General expenses. Instead, there is a substantial increase. According to the July 2011 Preliminary Staff Report, those costs would increase by almost 16 percent in just the first year of the rate plan. Over the four-year period they would increase by over 23 percent. The Host Communities are puzzled by the notion that a series of upgrade projects that are supposed to increase the efficiency of the Niagara Power Project are apparently doing nothing to reduce Operation and Maintenance and Administrative and General costs. If the Power Authority believes that the capital improvements are going to reduce these costs, then that outcome does not appear to be reflected in the rate proposal.

An additional concern of the Host Communities is how the Power Authority intends to deal with recovery of Rate Stabilization Reserve (RSR) balances following the withdrawal of the firm hydropower that was allocated to the three upstate electric utilities, National Grid, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation. According to the Preliminary Staff Report, the Power Authority Staff has not completed its analysis of the effect that withdrawal may have, but plans to "inform the Trustees and adjust the rate proposal accordingly when it is submitted for final approval in October." Our concern is that, with the withdrawal of the upstate electric companies and their customers as recipients of Preference Power, the RSR balances that accumulated prior to withdrawal might be included in the rates charged to the Host Communities and other customers who continue to receive firm hydropower. In other words, our citizens might be forced to bear the costs that were incurred by the departed customers. That would be unfair. Accordingly, the Power Authority should make clear that, whatever disposition is ultimately made of those RSR balances, now or in the future, they will not be collected from the Host Communities.

The Host Communities are also troubled by the fact that, while the Power Authority is seeking to implement a major, multi-year rate increase, it is able to make so-called "voluntary" contributions of hundreds of millions of dollars to the State Treasury. We believe that, before such payments are made to the State, some portion of the surplus should be used to mitigate the proposed rate increase. The Host Communities are aware that, when the issue of payments to the State was litigated recently, the Power Authority took the position that using the surplus to offset rates to Preference Power customers would result in lowering those rates below cost. The court agreed that the Public Authorities Law did not <u>require</u> a reduction below cost; but, at the same time, it did not conclude that the law <u>precluded</u> an offset. The Host Communities believe that, even if the Power Authority is not required to use surplus funds as an offset to part or all of the proposed rate increases, it has the discretion to do so.

Exercising that discretion here would be appropriate. Using surplus funds as an offset would mitigate what we believe is the greatest increase that has ever been proposed. It would preserve the intent and economic value of the Settlement Agreement power allocations. It would also recognize the role of firm hydropower customers in supporting the Niagara Power Project and the St. Lawrence Project, which are the backbone of the Power Authority's business and have enabled it to achieve surplus revenues. At the same time, this use of surplus funds would not impair the Power Authority's ability to carry out any of its other functions. I would just add that, if the Power Authority believes that it lacks the authority to use surplus funds in this way, it should seek legislation expressly authorizing such use.

While we would like to see the Power Authority use its surplus funds to offset the entire proposed rate increase, we believe that there is a middle ground that would serve the interests of the Authority and the Host Communities. Consistent with the State's legislation and policy limiting property tax increases to the lesser of two percent or the rate of inflation, the Power Authority could increase its rates by up to two percent per year. The Authority would then rely on surplus funds to make up any remaining revenue shortfall. This approach would provide an incentive to the Authority to minimize increases in rates, thereby helping to preserve the value of the 2005 Settlement Agreement, maintaining its viability over its 50-year term.

The Host Communities respectfully urge the Trustees of the New York Power Authority not to implement the proposed rate increase as presented. Instead, the proposal should be reconsidered and modified consistent with these remarks.

Thank you.

TAB 4-F

Statement from Andy McMahon representing Massena Electric Department

MASSENA ELECTRIC DEPARTMENT
71 E. Hatfield Street • PO Box 209 • Massena, New York 13662
Office: (315) 764-0253 • Fax: (315) 764-1498
www.massenaelectric.com

Good Afternoon.

My name is Andy McMahon and I am the Superintendent of the Massena Electric Department.

I am here to make comments on the NYPA's proposed rate increase as put forward in August of 2011.

My comments on the proposal are brief. Primarily, I wish to offer my support to the well researched and thoughtful efforts put forward by the rate specialists working for the municipals in NYS. I believe a dialogue has begun and I hope NYPA will listen and make appropriate and fair decisions on the recommendations put forward.

I recognize the importance and rational behind cost based rates. I agree with the concept that a utility must recover their legitimate expenses.

In reviewing NYPA's proposals I am confident that there will be the typical questions related to appropriate cost allocations and the appropriateness of certain expenses that will no doubt be resolved in due time.

However, I have multiple concerns with pressing forward with a rate increase at this point for reasons more related to philosophical disconnects in rate making. There are vagaries involved in this case that lead to significantly different mathematical results which need to be fully addressed and understood in advance of the application of a new rate plan.

Given the upgrades at the Niagara project, the advent of the NYISO and other changes which have occurred in recent years, the rate making exercise is more than just plugging numbers into formulas.

Given these changes and the unique dynamics it has caused, it seems to me that there are some policy questions that may take some time to be properly resolved.

Application of the UCap to the RSR is an issue that will take some time to fully understand and resolve. In one calculation I have seen, the UCap application would obviate the need for any rate increase. At a minimum, it would dramatically reduce the size of the Rate Stabilization Reserve, which NYPA is using as an indicator of the need to revise rates. We need to take adequate time and diligence to assure that we have an appropriate cost based methodology that all parties agree is fair.

Understanding the impact of Recharge NY on preference power rates must also be understood. It is a significant variable that has yet to be resolved.

I strongly encourage you to take time and defer implementation of this increase if required while you address these questions now in a fair and prudent manner. In the past, there have been questions raised on these types of rate policy matters that I do not believe received proper consideration. By way of example I cite the Handy Whitman Index on depreciation. NYPA implemented an initiation date on the index that some municipal rate experts still believe is incorrect. The difference of 6 months in the application of this index has had a long lasting and profound financial impact on the RSR and the rates which NYPA charges. Now, when questioned on the HWI, the explanation from NYPA staff was essentially that "it was too hard to go back". Given that logic, let us not go forward until we are relatively confident that we are going forward with a deep understanding that we have applied proper cost based rate making principles.

I appreciate that you have taken the time to listen to comments on this very important matter. I further appreciate that as a host community to your greatest assets you have also made us a host to these very important sessions.

TAB 4-G

Statement from James Shaw representing Massena Electric Department

Good afternoon.

I am James Shaw Chairman of the Massena Electric Board. We are one of your major municipal customers. I am here to express my Boards concern with regard to your proposed rate increase particularly the aggressive timetable you are proposing. Our rate experts have, after reviewing your information, raised many questions and issues that need to be resolved. I choose not to list them here as I believe in discussions our experts have brought these questions and issues to your staffs attention. We believe that you should allow adequate time for these questions to be answered to both parties satisfaction. Therefore, we believe the purposed timetable is inappropriate and should be amended to allow for resolution of the issues.

Thank you for allowing me to speak and for having a hearing in Massena.

James M. Shaw
Chairman Massena Electric Board
Massena Electric Department
71 East Hatfield
Massena, NY 13662
315-764-0253

TAB 5

WRITTEN COMMENTS

TAB 5-A

Letter from Senator Joseph Griffo

JOSEPH A. GRIFFO
SENATOR, 47TH DISTRICT

THE SENATE
STATE OF NEW YORK

ALBANY OFFICE:
[illegible]
LEGISLATIVE OFFICE BUILDING
ALBANY, NEW YORK 1[illegible]
[illegible]
FAX [illegible]

UTICA OFFICE:
[illegible] SEE STREET
UTICA, NEW YORK [illegible]
[illegible]
FAX [illegible]

EMAIL ADDRESS:
[illegible]

July 29, 2011

Chairman Michael J. Townsend
New York Power Authority
123 Main Street
10-B
White Plains, NY 10601-3170

Dear Chairman Townsend:

It is with disappointment and concern that I read of the Power Authority's plan to increase power rates for hydroelectric power supplied to several groups of customers. Although I understand that the Power Authority has announced that it is also undertaking cost-cutting measures, the very hard truth of our current economic picture is that cost-cutting that allows for a rate increase is not cost-cutting that has gone anywhere near deep enough. Likewise, comparison of hydropower rates against other forms of power does not address the major concern of the people I represent: with the economy struggling, wages frozen if not in peril and families already at or beyond the point of fiscal breaking, there is no money to pay higher rates.

Throughout this year, the state Senate has worked hard to reduce and restrain the costs of providing essential government services through a budget that makes tough choices and the creation of a tax cap that also makes tough choices when it comes to spending money. This is a time when hard decisions need to be made and decisive action needs to be taken to avoid making hard-pressed families and employers pate higher taxes, rates, fees or any other charge.

For the sake of the people who will ultimately be facing the difficulty of paying for this rate increase proposal, I strongly encourage the New York Power Authority to reconfigure its options and avoid this rate increase.

Sincerely,

Joseph A Griffo

Joseph A. Griffo
Senator

TAB 5-B

Letter from Senator James L. Seward

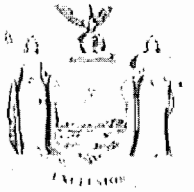
LEGISLATOR
ALBANY, NEW YORK 12247
[illegible]

MAIL: [illegible]
OSWEGO, NEW YORK 13126
[illegible]

E-MAIL
SEWARD@SENATE.GOV

WEBSITE
SEWARD@SENATE.GOV

THE SENATE
STATE OF NEW YORK



JAMES L. SEWARD
SENATOR 50TH DISTRICT

September 16, 2011

ASSISTANT MAJORITY LEADER ON
CONFERENCE OPERATIONS

CHAIRMAN
[illegible] COMMITTEE

COMMITTEES
[illegible]
[illegible]
[illegible]
[illegible]
[illegible]
[illegible]
[illegible]

RECEIVED
SECRETARY'S OFFICE

SEP 28 2011

Michael J. Townsend, Chairman
New York Power Authority
30 S. Pearl Street
Albany, New York 12207

RE: Remington Arms, Ilion, NY

Dear Chairman Townsend:

I am enclosing a letter from the mayor of the Village of Ilion relative to its extension of municipal power to Remington Arms, a major employer in the Mohawk Valley and in fact, all of New York.

I understand that the letter has been under review for over a month, but I have not received a satisfactory response and am again requesting that you review and address the mayor's concerns as soon as possible.

The rate increase advanced by NYPA is totally inappropriate and needs to be revisited. I would appreciate your reviewing the letter and responding to the mayor and me.

Thank you for your cooperation.

With best wishes, I remain

Sincerely yours,

James L. Seward

JAMES L. SEWARD
State Senator

JLS:ddjt
Enc.
Cc: Hon. John P. Stephens, Mayor
Hon. Marc Butler, NYS Assembly

AUG 11 2011

VILLAGE MAYOR
John P. Stephens

VILLAGE TRUSTEES
Joanne L. Moore
Kim R. Conley
Barbara Collea
Beth A. Neale

Village of Ilion
49 Morgan Street
Ilion, NY 13357
Phone: 315-895-7449
TDD 711

VILLAGE TREASURER
Connie S. Gagliardi

VILLAGE CLERK
Linda B. Coffin

VILLAGE ATTORNEY
J. K. Hage

August 9, 2011

Honorable James Seward
New York State Senator
41 S. Main St.
Oneonta, NY 13820

Senator Seward,
On July 1, 2011, the Village of Ilion and Remington Arms, LLC entered into an historic agreement which for the first time in history has allowed the oldest firearms manufacturer in America and the Mohawk Valley's largest employer to take advantage of low cost municipal hydro electric power to continue to operate its manufacturing facility in New York State. The Village of Ilion received an allocation of additional hydropower from the New York Power Authority (NYPA) through NYPA's Economic Development Program to support this provision of electric service to Remington. The Village and Remington publicly announced this historic event on July 27, 2011, with NYPA and other representatives in attendance.

Unbeknown to the negotiating teams from the Village and Remington, NYPA Trustees adopted a resolution on July 26, 2011 directing the Authority to provide written notice to affected customers of proposed increases over the next 3 ½ years totaling over 26%! I am sure you understand my concern with this issue because none of this was ever mentioned while in talks with Remington, even though NYPA was integral to those negotiations. We assured our ratepayers that bringing Remington onto municipal power would not increase their electric rates and we confirmed this publicly at the July 27, 2011 press conference. Any rate increase now will be ill received by Village ratepayers and likely perceived by such as being caused by the addition of Remington.

The NYPA notice indicated that it would conduct a series of public forums for interested parties to provide input and comments prior to the Trustees' final action on October 25, 2011. Because of the recent events, I have asked the folks from NYPA to hold one of their informational sessions in the Village of Ilion. I was told by their Vice President of Marketing, Michael Huvane, that NYPA would be holding only 3 public forums and that I should attend the forum in Syracuse which, according to Mr. Huvane, is the most convenient given my location. This is obviously not the answer I was looking for and his reply was extremely evasive, uninformative and non-committal. Syracuse is nearly 1 ½ hours away from Ilion! That is not convenient for Village ratepayers who just two weeks ago were told their rates wouldn't increase.

I am asking for your support in blocking this rate increase, or at the very least getting NYPA to hold one of the rate forums in Ilion to address why this issue was never mentioned during all of the discussions/negotiations with Remington Arms. It's an insult to all who worked endless hours on this

issue to never have brought it to the table and I hope they wont further add to it by saying they had no idea it was coming.

Thank you for your anticipated assistance,

John P. Stephens – Mayor
Village of Ilion

Cc:
Governor Andrew M. Cuomo
Assemblyman Marc Butler
NYPA Chairman Michael Townsend
NYPA President Richard Kessel
MEUA General Mgr. Tony Modafferi
Herk.Co. Leg. Leonard Hendrix
Herk.Co. Leg. Jean Maneen
Herk.Co. Leg. Jeff Stone

TAB 5-C

Letter from Senator Fuschillo

THE SENATE
STATE OF NEW YORK

CHAIRMAN
COMMITTEE ON TRANSPORTATION

DEPUTY MAJORITY WHIP

SENATOR
CHARLES J. FUSCHILLO, JR.
8TH SENATE DISTRICT

COMMITTEE MEMBER
CIVIL SERVICE & PENSIONS
CODES
COMMERCE, ECONOMIC DEVELOPMENT & SMALL BUSINESS
CONSUMER PROTECTION
ENERGY & TELECOMMUNICATIONS
FINANCE
HEALTH
JUDICIARY

September 27, 2011

RECEIVED
SECRETARY'S OFFICE
OCT 3 · 2011

Mr. Michael Townsend, Chairman
New York Power Authority
123 Main Street
White Plains, New York 10601

Dear Chairman Townsend:

I am writing to you with regard to NYPA's rate increase proposal.

Under NYPA's Notice of Proposed Rulemaking published in the State Register on August 17, 2011, the public comment period on NYPA's proposed rate increase will close on October 1, 2011, and any approved rate increase would take effect on November 1, 2011.

Giving the public, which will be forced to pay increases of 6.6% in 2011, 6.5% in 2012, 6.7% in 2013, and 6.9% in 2014 under this proposal, less than two months to review and comment on this proposal is unacceptable. NYPA should extend the public comment period until December 1, 2011, so that those who will be forced to pay dramatically more under this rate increase proposal have more time to review and comment on it.

There is no reason for NYPA to rush through this process. According to the New York Association of Public Power, NYPA's fiscal integrity would not be adversely affected if NYPA forgoes implementing a rate increase before its next rate year, which begins May 1, 2012. Increasing rates prior to this date would also negatively affect the implementation of the provision of the "Recharge NY" Power Program that will ultimately impact the preference power rates.

I strongly oppose these rate increases because of the negative impact they will have on NYPA ratepayers and urge you to reconsider them. In addition, NYPA should extend the public comment period to ensure that ratepayers have every opportunity to voice their concerns about this proposal.

Sincerely,

CHARLES J. FUSCHILLO, JR.
New York State Senator

District Office: 5550 Merrick Road, Suite 202, Massapequa, NY 11758-6248 • (516) 882-0630 • Fax (516) 882-0636
Albany Office: Room 609, Legislative Office Building, Albany, NY 12247 (518) 455-3341 • Fax (518) 426-6823
fuschill@nysenate.gov • fuschillo.nysenate.gov

TAB 5-D

Letter from Senator Young, *et al.*

New York State Senate

Office of:
Senator Catharine M. Young
~~513~~ 307 Legislative Office Bldg.
Albany, NY 12247

Phone: (518) 455-3563
FAX: (518) 426-6905
Email: cyoung@senate.state.ny.us

Memorandum

TO: Chairman Townsend, NYPA
FAX: 914-390-8040
FROM: Jess Jenne, Office of Senator Young
PAGES (w/cover): 3
DATE: 9/27/11
RE: NYPA's Proposed rate increase & comment period

★ Your immediate ATTENTION is requested.

Please see the attached joint letter from Legislative Members which will also be sent via regular mail today.

Thank You.

NEW YORK STATE LEGISLATURE

September 27, 2011

Mr. Michael Townsend
Chairman
New York Power Authority
123 Main Street
White Plains, NY 10601

RE: REQUEST FOR TIME DEFERRAL OF WRITTEN COMMENTS/IMPLEMENTATION OF PROPOSED RATE INCREASE (I.D. No. PAS-33-11-00001-P)

Dear Chairman Townsend:

We are writing with regard to the Notice of Proposed Rulemaking ("NOPR") published in the State Register on August 17, 2011 on the proposed increase in the hydroelectric preference power rates of the Power Authority of the State of New York ("Authority"). This NOPR provides that written comments on the proposal are due on October 1, 2011 and that if implemented, the proposed rate increase will become effective on November 1, 2011.

While the Authority has traditionally provided the public and the preference power customers five or six months to review the Authority Staff Preliminary Reports detailing previous proposed rate increases, in this case this information was provided less than two months prior to the time when written comments are due. This is certainly insufficient time when considering a proposed cumulative 26% increase in rates over a three and a half (3 ½) year period.

A two- month extension of the written comment period (to December 1st) is warranted to facilitate meaningful input on this rate increase proposal. This additional time is necessary to enable the Members of the Legislature, the public and the preference power customers the ability to thoroughly review this proposal, continue discussions with the Authority staff, review responses to discovery requests and will further enable the Authority staff to respond to the outstanding discovery requests.

In addition, we support the deferral of the effective date of any rate increase resulting from the NOPR until May 1, 2012, the beginning of the Authority's traditional rate year. Deferring the rate increase until May 1st is consistent with past practice and would not have an adverse impact on the Authority's fiscal integrity. In addition, the delay of the effective date of the rate increase until May 1 is necessary

PRINTED ON RECYCLED PAPER

to allow the implementation of the provisions of the "Recharge NY" Power Program that ultimately will impact the preference power rates.

On behalf of our constituents and all New Yorkers impacted by this proposed preference power rate increase, we urge you to extend these timelines to facilitate the comprehensive review and response required by this proposal.

Sincerely,

Senator Catharine M. Young
57th District

Senator Mark Grisanti
60th District

Senator David J. Valesky
49th District

Senator Joseph A. Griffo
47th District

Senator Thomas O'Mara
53rd District

Assemblyman William Magee
111th District

CC: Karen Delince, Corporate Secretary, NYPA

TAB 5-E

Letter re Niagara County Legislaturere Resolutions

NIAGARA COUNTY LEGISLATURE
NIAGARA COUNTY COURTHOUSE
175 HAWLEY STREET
LOCKPORT, NY 14094-2470

WILLIAM L. ROSS
Chairman

MARY JO TAMBURLIN
Clerk

(716) 439-7000
(716) 439-7124 Fax

October 6, 2011

James F. Pasquale
Senior Vice President
New York Power Authority
123 Main St., Mail Stop 10-H
White Plains, NY 10601

Dear Senior Vice President Pasquale:

On behalf of the Niagara County Legislature I have enclosed copies of Resolution #s IL-057-11 and IL-058-11 which were approved during the Niagara County Legislature Meeting on Tuesday, October 4, 2011. If you have any questions regarding these resolutions please feel free to contact me.

Sincerely,

Mary Jo Tamburlin
Clerk of the Legislature

Enclosure

MJT/cls

NIAGARA COUNTY LEGISLATURE

FROM: Legislator Renae Kimble, et al. DATE: 10/04/11 RESOLUTION # IL-057-11

APPROVED BY CO. ATTORNEY	REVIEWED BY CO. MANAGER	COMMITTEE ACTION	LEGISLATIVE ACTION
			Approved: Ayes ____ Abs. ____ Noes 0
			Rejected: Ayes ____ Abs. ____ Noes ____
			Referred: ____

RESOLUTION REQUESTING THE NEW YORK POWER AUTHORITY'S BOARD OF TRUSTEES TO REJECT THE PROPOSED HYDROELECTRIC PRODUCTION RATE INCREASE

WHEREAS, the New York Power Authority (NYPA) is a public benefit corporation established in 1931, and

WHEREAS, NYPA owns 2,900 acres of property in Niagara County, primarily in Lewiston and is assessed at $1.8 billion dollars, and

WHEREAS, NYPA is exempt from paying local, state and federal taxes; NYPA is also exempt from paying property taxes, and

WHEREAS, NYPA pays absolutely nothing for the water that it uses to produce electricity, and

WHEREAS, NYPA received over $100 million dollars in net revenues last year, and

WHEREAS, throughout NYPA's existence, it has transferred millions of dollars to the General Fund of the State of New York for the purpose of assisting the state in balancing its budget; recently, from 2008-2010, NYPA transferred $750 million dollars to assist the state during one of its most mammoth financial crisis in recent history, which included the $544 million dollar "sweep" of funds, and

WHEREAS, on July 26, 2011, the NYPA Board of Trustees adopted a resolution directing the authority to provide written notice of its intent to increase hydropower preference production rates from November 1, 2011 to April 30, 2015, and

WHEREAS, according to the NYPA Preliminary Staff Report dated July 2011, the proposed rate increase would amount to approximately thirty percent (30%) over the next two and a half years, from November 1, 2011 to May 1, 2014, with an annual average rate increase of twelve percent (12%), and

WHEREAS, the proposed thirty percent (30%) rate hike is astronomical and believed to be unprecedented, which would have a chilling effect upon the production and service cost for businesses, which will in turn be passed on to customers, raising prices for Niagara County's consumers, and

WHEREAS, the NYPA Preliminary Staff Report also states that, "The principal cost driver responsible for the increase is the ongoing capital investments in the facilities, including relicensing expenditures at Niagara and St. Lawrence, the life extension and modernization ("LEM") for the St. Lawrence Project and the LEM for the Lewiston Pump Generating Plant ("LPGP") at the Niagara Project", and

WHEREAS, the Preliminary Staff Report states that the life extension and modernization ("LEM") for the Lewiston Pump Generating Plant at the Niagara Project is expected to begin in 2012 and be completed in 2020, for an estimated cost of $460 million dollars, and

WHEREAS, the Preliminary Staff Report further states that the costs of the Relicensing agreement for the Niagara Power Project is approximately $494 million dollars, and

WHEREAS, NYPA made assurances during the Relicensing negotiations that the proposed settlement agreement that was entered into between NYPA and the Niagara Power Coalition would not result in any rate increase for NYPA customers, and

WHEREAS, the $750 million dollars that was transferred to the General Fund of the State of New York could have more than covered the cost of the ("LEM") life extension and modernization for both the Lewiston Pump Plant at the Niagara Project and the St. Lawrence Project totaling $490 million dollars, or even used to assist in mitigating this proposed rate increase, and

WHEREAS, at a time when all state municipalities and state agencies are cutting costs, taxes are being capped at two percent (2%) or the rate of inflation, whichever is less, NYPA has failed to show that it has made substantial efforts to cut or try to control its operating costs, and

WHEREAS, NYPA's proposed rate increase would exacerbate a statewide climate that is unfriendly to businesses and job creation, now, therefore, be it

RESOLVED, that the Niagara County Legislature does hereby oppose NYPA's proposed changes to its Hydroelectric Production Rates, and be it further

RESOLVED, that the Niagara County Legislature respectfully requests the Board of Trustees of NYPA to reject the proposed rate increase, and be it further

RESOLVED, that the Niagara County Legislature calls upon NYPA to begin to look at other cost cutting measures to reduce its operation, maintenance, administrative and general expense, and be it further

RESOLVED, that the Niagara County Legislature calls upon NYPA to also look to use surplus funds that it has at its disposal to minimize any rate increase, and be it further

RESOLVED, that the County of Niagara shall forward copies of this Resolution to our local state delegation, Governor Andrew M. Cuomo, Senate Majority Leader Dean G. Skelos, Senator George D. Maziarz, Chairman, Energy and Telecommunications Committee, Senator Mark Grisanti, Senator Michael Ranzenhofer, Senator Patrick Gallivan, Senate Minority Leader John L. Sampson, Senator Timothy Kennedy, Assembly Speaker Sheldon Silver, Assemblyman John Ceretto, Assemblyman Robin Schimminger, Assemblywoman Crystal Peoples-Stokes, Assemblyman Dennis Gabryszak, Assemblyman Mark J.F. Schroeder, Assemblyman Sean Ryan, Assemblyman Kevin Cahill, Chairman of the Energy Committee, Assembly Minority Leader Brian Kolb, Assemblyman Stephen Hawley, and Assemblywoman Jane Corwin, be it further

RESOLVED, that a copy of this resolution be forwarded to Michael J. Townsend, Chairman, New York Power Authority Board of Trustees, Jonathan F. Foster, Vice Chairman, D. Patrick Curley, Eugene L. Nicandri, Mark O'Luck, John S. Dyson, and R. Wayne LeChase members of the New York Power Authority Board of Trustees, and be it further

RESOLVED, that a copy of this resolution be forwarded to Gil C. Quiniones, Acting President and CEO, Edward A. Welz, Acting Chief Operating Officer and Executive Vice President and Chief Engineer Power Supply, and James F. Pasquale, Senior Vice President, marketing and Economic Development, and be it further

RESOLVED, that a copy of this resolution be forwarded to Senator Charles E. Schumer, Senator Kirsten Gillibrand, Congresswoman Louise M. Slaughter, Congressman Brian Higgins and Congresswoman Kathy Hochul, and that a response be requested from each elected and each appointed official.

LEGISLATOR RENAE KIMBLE

LEGISLATOR BRITTANY L. CATCHPOLE

LEGISLATOR CHERÉE J. COPELIN

LEGISLATOR KARI ANN BULLMAN

LEGISLATOR PAUL B. WOJTASZEK

LEGISLATOR GERALD K. FARNHAM

LEGISLATOR WILLIAM L. ROSS

LEGISLATOR PETER E. SMOLINSKI

LEGISLATOR RICHARD F. SOLURI

LEGISLATOR PHILLIP R. RIZZO

LEGISLATOR MICHAEL A. HILL

LEGISLATOR JOHN SYRACUSE

LEGISLATOR RICHARD A. MARASCO

LEGISLATOR RICHARD E. UPDEGROVE

LEGISLATOR WM. KEITH MCNALL

LEGISLATOR ANTHONY J. NEMI

LEGISLATOR DENNIS F. VIRTUOSO

LEGISLATOR DAVID E. GODFREY

LEGISLATOR CLYDE L. BURMASTER

NIAGARA COUNTY LEGISLATURE

FROM: Legislator Renae Kimble, et al. DATE: 10/04/11 RESOLUTION # IL-058-11

APPROVED BY CO. ATTORNEY	REVIEWED BY CO. MANAGER	COMMITTEE ACTION	LEGISLATIVE ACTION
			Approved: Ayes ____ Abs. ____ Noes 0
			Rejected: Ayes ____ Abs. ____ Noes ____
			Referred: ____

10/4/11

RESOLUTION REQUESTING AN AUDIT OF THE NEW YORK POWER AUTHORITY BY THE OFFICE OF THE NEW YORK STATE COMPTROLLER

WHEREAS, the New York Power Authority (NYPA) is a public benefit corporation established in 1931, and

WHEREAS, NYPA has been charged with the responsibility of developing the Niagara River and the Saint Lawrence River for the development of hydroelectric power, in order to generate, transit and sell electricity primarily at wholesale cost to its customers, and

WHEREAS, many Niagara County companies that provide good family-supporting jobs in an economy that has been in a major downturn, continue to struggle with high electricity and other utility rates that are adversely affecting their ability to remain in business, and

WHEREAS, NYPA owns 2,900 acres of property in Niagara County, primarily in Lewiston and is assessed at $1.8 billion dollars, and

WHEREAS, NYPA is exempt from paying local, state and federal taxes; NYPA is also exempt from paying property taxes, and

WHEREAS, NYPA pays absolutely nothing for the water that it uses to produce electricity, and

WHEREAS, NYPA received over $100 million dollars in net revenues last year, and

WHEREAS, throughout NYPA's existence, it has transferred millions of dollars to the General Fund of the State of New York for the purpose of assisting the state in balancing its budget; recently, from 2008-2010, NYPA transferred $750 million dollars to assist the state during one of its most mammoth financial crisis in recent history, which included the $544 million dollar "sweep" of funds, and

WHEREAS, in June 2010, the NYPA Board of Trustees approved the investment of $460 million dollars in the Life Extension and Modernization Program ("LEM") for the Lewiston Pump Generating Plant at the Niagara Project, and

WHEREAS, on July 26, 2011, the NYPA Board of Trustees adopted a resolution directing the authority to provide written notice of its intent to increase hydropower preference production rates from November 1, 2011 to April 30, 2015, and

WHEREAS, according to the NYPA Preliminary Staff Report dated July 2011, the proposed rate increase would amount to approximately thirty percent (30%) over the next two and a half years, from November 1, 2011 to May 1, 2014, with an annual average rate increase of twelve percent (12%), and

WHEREAS, the proposed thirty percent (30%) rate hike is astronomical and believed to be unprecedented, which would have a chilling effect upon the production and service cost for businesses, which will in turn be passed on to customers, raising prices for Niagara County's consumers, and

WHEREAS, the NYPA Preliminary Staff Report also states that, "The principal cost driver responsible for the increase is the ongoing capital investments in the facilities, including relicensing expenditures at Niagara and St. Lawrence, the life extension and modernization ("LEM") for the St. Lawrence Project and the LEM for the Lewiston Pump Generating Plant ("LPGP") at the Niagara Project", and

WHEREAS, the Preliminary Staff Report states that the life extension and modernization ("LEM") for the Lewiston Pump Generating Plant at the Niagara Project is expected to begin in 2012 and be completed in 2020, for an estimated cost of $460 million dollars, and

WHEREAS, according to a newspaper article in the September 27, 2011 edition of the Niagara Gazette, NYPA awarded a contract in support of the refurbishing and modernizing of the Niagara Project's Lewiston Pump Generating Plant to Eaton Corporation of Leroy, New York as part of the Life Extension and Modernization program at the plant, for nine years and is valued at $10.9 million dollars, and

WHEREAS, there have been problems in the past regarding NYPA spending millions of dollars on equipment that does not have the same estimated useful life as the original equipment installed, equipment not working properly which results in additional repair costs, and

WHEREAS, NYPA plans to replace the original electro-mechanical devices with modern digital technology, without any back- up system which could lead to computer hacking, black outs, shut downs, security breaches, no manual control of the units by the NYPA employees, and

WHEREAS, this modernization could result in the plant going off line and becoming non operational during a black out, which happened to the St. Lawrence and Blenheim Gilboa plants when the "Black Out" of August 15, 2003 occurred, costing NYPA customers millions of dollars; the Niagara Plant was the only plant to remain on line due to the back- up manual system which allowed the operators to control the generators manually, and

WHEREAS, the Preliminary Staff Report states that the costs of the Relicensing agreement for the Niagara Power Project is approximately $494 million dollars, and

WHEREAS, NYPA made assurances during the Relicensing negotiations that the proposed settlement agreement that was entered into between NYPA and the Niagara Power Coalition would not result in any rate increase for NYPA customers, and

WHEREAS, the $750 million dollars that was transferred to the General Fund of the State of New York could have more than covered the cost of the ("LEM") life extension and modernization for both the Lewiston Pump Plant at the Niagara Project and the St. Lawrence Project totaling $490 million dollars, or even used to assist in mitigating this proposed rate increase, and

WHEREAS, at a time when all state municipalities and state agencies are cutting costs, taxes are being capped at two percent (2%) or the rate of inflation, whichever is less, NYPA has failed to show that it has made substantial efforts to cut or try to control its operating costs, or to use surplus funds that it has at its disposal to minimize any rate increase, and

WHEREAS, NYPA's proposed rate increase would exacerbate a statewide climate that is unfriendly to businesses and job creation, and

WHEREAS, the Office of the New York State Comptroller since 1991 has been required by state law to perform at five year intervals a comprehensive audit of NYPA's management and operations, and

WHEREAS, upon information and belief a comprehensive audit of NYPA was conducted by the Office of the New York State Comptroller beginning in 1996, and in 2001, 2006, and 2010, and

WHEREAS, NYPA received another selected management and operating practices audit in 2010, it is not comprehensive enough, now, therefore, be it

RESOLVED, that the Niagara County Legislature respectfully requests the Office of the New York State Comptroller to conduct a comprehensive audit of NYPA's management and operations in accordance to state law, and be it further

RESOLVED, that the audit examine and review the need for the proposed Hydroelectric Production Rate increase for the Life Extension and Modernization of the Lewiston Pump Plant, Niagara Project and the St. Lawrence facility; that there be no wasteful spending on equipment which may lead to a shut down, or security breach, and be it further

RESOLVED, that if a need exists for a rate increase, alternative methods to finance the costs that will not be passed on to the rate payers, such as cost cutting measures, or use of surplus by NYPA, and be it further

RESOLVED, that the County of Niagara shall forward copies of this Resolution to our local state delegation, New York State Comptroller Thomas P. Di Napoli, Governor Andrew M. Cuomo, Senate Majority Leader Dean G. Skelos, Senator George D. Maziarz, Chairman, Energy and Telecommunications Committee, Senator Mark Grisanti, Senator Michael Ranzenhofer, Senator Patrick Gallivan, Senate Minority Leader John L. Sampson, Senator Timothy Kennedy, Assembly Speaker Sheldon Silver, Assemblyman John Ceretto, Assemblyman Robin Schimminger, Assemblywoman Crystal Peoples-Stokes, Assemblyman Dennis Gabryszak, Assemblyman Mark J.F. Schroeder, Assemblyman Sean Ryan, Assemblyman Kevin Cahill, Chairman of the Energy Committee, Assembly Minority Leader Brian Kolb, Assemblyman Stephen Hawley, and Assemblywoman Jane Corwin, be it further

RESOLVED, that a copy of this resolution be forwarded to Michael J. Townsend, Chairman, New York Power Authority Board of Trustees, Jonathan F. Foster, Vice Chairman, D. Patrick Curley, Eugene L. Nicandri, Mark O'Luck, John S. Dyson, and R. Wayne LeChase members of the New York Power Authority Board of Trustees, and be it further

RESOLVED, that a copy of this resolution be forwarded to Gil C. Quiniones, Acting President and CEO, Edward A. Welz, Acting Chief Operating Officer and Executive Vice President and Chief Engineer Power Supply, and James F. Pasquale, Senior Vice President, marketing and Economic Development, and be it further

RESOLVED, that a copy of this resolution be forwarded to Senator Charles E. Schumer, Senator Kirsten Gillibrand, Congresswoman Louise M. Slaughter, Congressman Brian Higgins and Congresswoman Kathy Hochul, and that a response be requested from each elected and each appointed official.

LEGISLATOR RENAE KIMBLE

LEGISLATOR BRITTANY I. CATCHPOLE

LEGISLATOR CHERÉE J. COPELIN

LEGISLATOR KARI ANN BULLMAN

LEGISLATOR PAUL B. WOJTASZEK

LEGISLATOR GERALD K. FARNHAM

LEGISLATOR WILLIAM L. ROSS

LEGISLATOR PETER E. SMOLINSKI

LEGISLATOR RICHARD F. SOLURI

LEGISLATOR PHILLIP R. RIZZO

LEGISLATOR MICHAEL A. HILL

LEGISLATOR JOHN SYRACUSE

LEGISLATOR RICHARD A. MARASCO

LEGISLATOR RICHARD E. UPDEGROVE

LEGISLATOR WM. KEITH MCNALL

LEGISLATOR ANTHONY J. NEMI

LEGISLATOR DENNIS F. VIRTUOSO

LEGISLATOR DAVID E. GODFREY

LEGISLATOR CLYDE L. BURMASTER

TAB 5-F

Letter from Chautauqua County Chamber of Commerce Manufactures Association of the Southern Tier

Chautauqua County Chamber of Commerce

MAST
MANUFACTURERS ASSOCIATION
OF THE SOUTHERN TIER

Together, we're Leading Businesses. Leading Communities. ™

October 21, 2011

Mr. Michael Townsend
Chairman
New York Power Authority
123 Main Street
White Plains, NY 10601

Mr. Townsend:

The Chautauqua County Chamber of Commerce and the Manufacturers Association of the Southern Tier represent 1,200 businesses and over 20,000 employees in Chautauqua County. Within our County many of our businesses depend on hydroelectric power allocations. In a County where our property taxes are among the highest in the nation, the lower cost power available to several of our communities and our members is helping keep many of our businesses and the jobs they provide, here in New York State.

We are concerned about the proposed rate increase outlined in the Notice of Proposed Rulemaking ("NOPR") published in the State Register on August 17, 2011. We are requesting an extension of the comment period to better understand the impact of this rate increase on our members. In that the proposal recommends a cumulative 26% increase in rates over a three and half year period we believe that an extension of the comment period is justified.

Thank you for your consideration.

Sincerely,

Todd J. Tranum
President/CEO, Chautauqua County Chamber of Commerce
Executive Director, Manufacturers Association of the Southern Tier

Cc: Senator Cathy Young
Assemblyman Joseph Giglio
Assemblyman Andrew Goodell

Chautauqua County Chamber of Commerce / Manufacturers Association of the Southern Tier
Dunkirk Branch 10785 Bennett Road / Dunkirk, New York 14048 / 716-366-6200 / Fax 716-366-4276
Jamestown Branch 101 West Fifth Street / Jamestown, New York 14701 / 716-484-1101 / Fax 716-487-0785
MTI Branch 512 Falconer Street / Jamestown, New York 14701 / 716-483-1833 / Fax 716-487-9599
website: www.chautauquachamber.org / email: cccc@chautauquachamber.org

TAB 5-G

Letter from Municipal Electric Utilities Association (MEUA) requesting extension of time

READ AND LANIADO, LLP
ATTORNEYS AT LAW
25 EAGLE STREET
ALBANY, NEW YORK 12207-1901

(518) 465-9313 MAIN
(518) 465-9315 FAX
www.readlaniado.com

KEVIN R. BROCKS
DAVID B. JOHNSON
SAM M. LANIADO

KONSTANTIN PODOLNY

RICHARD C. KING
HOWARD J. READ
Of Counsel

Via Electronic Mail and Overnight Delivery

September 22, 2011

Ms. Karen Delince
Corporate Secretary
New York Power Authority
123 Main Street, 15M
White Plains, NY 10601

Re: MEUA Request for Extension of Time to Submit Comments

Dear Ms. Delince:

On or about July 26, 2011, the New York Power Authority ("NYPA") initiated the public phase of its proposal to increase it hydroelectric preference power rates. NYPA has set a deadline of October 1, 2011 for written comments.

The purpose of this letter is to request a one month extension of the deadline for written comments. This request is submitted on behalf of the Municipal Electric Utilities Association ("MEUA"), an association of 40 New York municipal electric utilities.

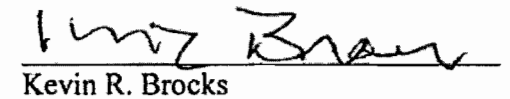
The MEUA has retained the Hudson River Energy Group (Mr. Frank Radigan, Principal) to assist it in analyzing NYPA's rate report. We have submitted questions to NYPA, and examined the discovery conducted by other interested parties. Some questions have not yet been answered. Some very important questions, such as the effect of the "Recharge New York" program, have not yet been answered. While the analysis has been rigorous and ongoing, we are running out of time.

NYPA's schedule does not allow sufficient time for the MEUA and other interested members of the public to provide meaningful comments on NYPA's multi-year rate plan. As Mr. Modafferi, the MEUA's Executive Director, explained at Monday's and Tuesday's public hearings, the MEUA has been diligently pursuing its inquiry. But to allow less than two months for analysis of such an important and technically challenging matter is simply unreasonable. We have in the past brought to NYPA's attention that the time allowed for comments in connection with NYPA rate increases has been inadequate. It is especially true in this case.

Extending the comment period will allow NYPA's preference customers and the interested public a meaningful opportunity to comment. At the same time, it costs NYPA nothing. The RSR deferral account captures any shortfalls in revenue from NYPA's preference customers, so NYPA will ultimately collect, and the preference customers will ultimately pay, through the RSR surcharge, all legitimate charges. Under the circumstances, we ask NYPA to afford the MEUA and the public a modest extension of the comment period.

Respectfully submitted,

READ and LANIADO, LLP
Attorneys for the Municipal Electric Utility
Association of New York

By: 
Kevin R. Brocks

KRB:kak

cc: Mr. Modafferi
Mr. Quinones
Mr. Huvane
Mr. Catalino
Mr. Falvey
Mr. Levenson
Mr. Pasquale

TAB 5-H

Comments of MEUA

NEW YORK POWER AUTHORITY

2011 RATE MODIFICATION PLAN

COMMENTS OF THE MUNICIPAL ELECTRIC UTILITIES ASSOCIATION OF NEW YORK STATE

Kevin R. Brocks
READ AND LANIADO, LLP
Attorneys for the Municipal Electric
Utilities Association of New York State
25 Eagle Street
Albany, New York 12207
Telephone: (518) 465-9313
Fax: (518) 465-9315
krb@readlaniado.com

Dated: October 24, 2011
Albany, New York

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COMMENTS OF THE MUNICIPAL ELECTRIC UTILITIES ASSOCIATION OF NEW YORK STATE

Introduction

These comments are submitted on behalf of the Municipal Electric Utilities Association of New York State ("MEUA"), an 80 year old organization of 40 of New York State's municipal electric utilities.

On July 27, 2011, the New York Power Authority ("NYPA") provided notice that NYPA was proposing an increase to its "preference power" rates. We were provided a copy of the "Preliminary Staff Report" ("Staff Report") dated July 2011, concerning "Hydroelectric Production Rates – Rate Modification Plan – Rate Years 2011 to 2014." The rate plan would increase rates over the next 3 ½ years by about 7% in four steps each, or a total of about 30%. According to the Staff Report, increased rates would be phased in and would remain slightly under cost until 2013. The plan also would commence amortizing the negative balance in the "Rate Stabilization Reserve" ("RSR") in the year 2014.[1] According to the Staff Report, the present negative balance of about $51 million is largely attributable to the 2009 rate "freeze." The plan proposes to amortize the RSR at the rate of 5/100th of a cent (*i.e.*, one-half mill) per kWh.

The MEUA retained the Hudson River Energy Group, Mr. Frank Radigan, Principal, to assist it in reviewing NYPA's Staff Report. The Testimony and Affidavit of Frank Radigan are attached to and forms a part of these comments. The MEUA asked, and NYPA Staff answered, many discovery questions. We reviewed the extensive discovery of other interested parties. We

[1] The Staff Report mentions that "Recharge New York" will have an impact on the cost of service and the RSR. Staff has stated that it will share its analysis when completed, and the parties will have an opportunity to comment.

examined NYPA's system of accounts, trial balances, budgets, operating budgets, RSR calculations, and many other documents. NYPA Staff shared interactive spreadsheets and workpapers. We also met with NYPA Staff at NYPA's White Plains office.[2] We have compared NYPA's Staff Report to prior rate plans and have sought to reconcile the data in the Staff Report and other documentation to RSR balances.

I. Preliminary Comments

A. The Review Time was Too Short.

The time afforded to interested parties to provide comments was too short. As we and most if not all the other parties have noted in connection with prior NYPA preference power rate proceedings, NYPA's procedural schedule is unreasonably abbreviated.

> As we have had occasion to note before, the time allowed for customer analysis and comment on this topic is inadequate. … Even with the diligent and professional attention of NYPA Staff, there simply was not enough time allowed by NYPA for the proper examination of a matter of such complexity and of such importance, not only to the municipal electric system customers of NYPA, but to the people of New York State. The public interest demands that NYPA not truncate the examination of the study, to the prejudice of the customers' due process rights.
>
> MEUA Comments, April 3, 2007

The slight extension provided in this case was helpful and appreciated, but still inadequate. For example, in New York Public Service Commission rate proceedings, parties have usually at least four months from the date of the utility filing—filings much more informative and detailed than NYPA's "Preliminary Staff Report"—before their testimony is due, and then at least two more months before their written comments (briefs) are due. In

[2] We wish to thank Gary Levenson, Tom Davis, Kevin Falvey, David Applebaum, Lenny Davito and Gina Harwood for meeting with us.

contrast, NYPA in this matter has afforded us less than three months from start to finish. The effective time was less, given the initial slow reaction time to party discovery requests. In the next rate plan, and all RSR reviews, NYPA should allow at least four months between publication of the notice and the comment due date.

B. NYPA and the MEUA are Partners in Public Power.

The New York Power Authority is by law and license the public power instrumentality of the people of New York State. NYPA's organic statute—the "Power Authority Act" (PAL § 1000 *et seq.*)—refers to the hydroelectric assets of NYPA as for the use of domestic and rural customers at "the lowest possible rate." Federal law imposes on NYPA the duty to provide the hydroelectric power of Niagara Falls at "the lowest rate reasonably possible."

In the case of *Auer v. Dyson*, 110 Misc. 2d 943 (Sup. Ct. Oswego County, 1981), and its progeny, the Court affirmed that the "lowest rate reasonably possible" does not mean less than cost. The MEUA has agreed with that formulization. However, NYPA also has an affirmative duty to assure that its rates are the "lowest possible." NYPA must set its rates to the lowest possible, consistent with capturing its cost of service. It cannot calculate the cost of service in a way that overestimates the cost. It must affirmatively choose reasonable allocations and assignments of costs that produce a lower rate. It does not have unbridled discretion to determine what the lowest possible rate is.

> We reject the contention of PASNY that it has broad discretion to establish rates and that, as long as its indirect overhead expenses are allocated reasonably, PASNY has complied with its statutory mandate. Even though a rate-setting methodology may be reasonable, it may not result in the lowest possible rate required by Public Authorities Law § 1005(5).
>
> *Bergen v. PASNY*, 249 A.D.2d 902. (4th Dept.,1998)

These principles are enshrined in the April 2003 "NYPA MEUA Global Settlement." In that settlement, the MEUA and NYPA worked diligently and in good faith to address some of the concerns and resolve some of the issues raised by the restructuring of the electricity markets. In connection with NYPA rates, the parties tried to map out the fair rate treatment for several items. Of course, the signatories could not resolve everything or every rate setting detail.

These MEUA comments herein adhere to the Global Settlement and the law that underlies it.

C. NYPA's Rates are Fully Reconciled through the RSR.

NYPA's preference power ratemaking methodology is in many ways unusual and in some ways unique. For example, in 2009, NYPA decided to "withdraw" its pending revised rate plan, and hold rates steady rather than increase rates at that time. Some people assumed that meant NYPA was foregoing recovery of its preference power revenue requirement. However, NYPA was not foregoing recovery, but only deferring recovery, through the mechanism of the Rate Stabilization Reserve ("RSR"). The current Staff Report states that the increase in the negative balance of the RSR is primarily driven by the rate freeze, because while rates did not go up, costs did. The RSR is a full, after the fact reconciliation of NYPA's rate year costs and revenues. Once the RSR balance gets above a certain level ($25 million), a surcharge is imposed in rates to recover the deferred revenue (such a surcharge is proposed in this case). It is a thorough and mutually agreed upon after the fact revenue requirement reconciliation. This has several consequences.

First, NYPA's rate plans are based on forecasts and projections. Rates are set prospectively, but through the RSR NYPA reviews its costs retrospectively and charges customers actual costs. Customers will eventually pay the actual cost through the after the fact RSR reconciliation. Therefore, the preference customers are entitled to review the annual RSR calculations in the detail warranted by the circumstances. The RSR calculations really establish what customers will eventually pay. We address this in more detail below. NYPA and its customers need to develop a process for customer review of the RSR calculations. There should be a public process, with an opportunity for information sharing, discovery and comment.

Second, after the fact reconciliation methods such as the RSR are generally disfavored in regulatory circles because they are perceived to provide no incentive for cost control, and indeed provide a "blank check." NYPA must demonstrate that it is indeed controlling costs and striving to achieve the "lowest possible rates." In a typical utility rate proceeding, the company is required to demonstrate its cost and quality control efforts. Utility regulators often adjust utility rates downward to encourage such efforts. NYPA's "Preliminary Staff Report" is devoid of any reference to cost control efforts. The Report does not demonstrate or even assert that the rates proposed are the lowest possible rates.

D. NYPA Has Properly Excluded Its Governmental Contributions.

NYPA has made a series of payments to the State of New York pursuant to various budget legislation (*see, e.g.*, L 2009, Ch 2, Part A; NYPA's 2008 Annual Report, p. 23-24). NYPA's decision to make those special payments, pursuant to law, has been upheld by the courts (*Niagara County v. New York Power Authority*, 82 A.D.3rd 1597 (3rd Dept., 2011). Over the last several years NYPA has many times assured the MEUA that the special payments to the

state are not included in the hydroelectric revenue requirement, and hence are not in preference rates. NYPA reiterated that position in the recent *Niagara County v. New York Power Authority* case, and again in the course of discovery in this proceeding. It therefore appears NYPA has properly excluded those expenditures from the cost of hydroelectric service and preference rates.

E. NYPA's Ratemaking Methodology.

As Mr. Radigan explains in his testimony (Radigan, pp. 16-19), the Preliminary Staff Report employs a multi-step methodology to determine the cost attributable to the hydroelectric projects. Costs with a strong nexus to a particular facility are "directly assigned." Other "indirect costs" are "allocated" across NYPA's various projects.

Costs are "directly assigned" to one of NYPA's project, such as Niagara or St. Lawrence, or Blenheim-Gilboa or the CTs when the cost is clearly and wholly attributable to a certain project and only to that project. For example, relicensing costs, on-site payroll or capital costs booked directly to Niagara and St. Lawrence are "directly assigned" in the cost of service study to those projects. Certain O&M, amortizations and capital costs are directly attributable to certain projects and are "directly assigned" to those facilities.

Other costs are not booked directly to a specific project, but are "allocated" on some basis to the various projects. Indirect overheads, such as shared services, headquarters cost, etc., are allocated to the various projects based upon the labor ratio. Pursuant to that approach, approximately 41% of these "indirect overheads" are allocated to the hydroelectric cost of service, and hence to the preference power cost.

Other adjustments are then made to the cost of service to, for example, subtract the embedded costs of producing ancillary services. The result is a "revenue requirement" for

the hydroelectric projects. A portion of that "revenue requirement" is allotted to the preference power customers.

This basic approach to determining the revenue requirement is loosely consistent with the "global settlement" (Radigan, p. 19). What is not consistent with the global settlement—and also fundamentally wrong—is the methodology of allocating the resulting cost of hydroelectric service to the preference customers.

II. NYPA's Cost of Service Study Violates the "Lowest Possible Rate" Standard

While the overall revenue requirements may be reasonable, the rate calculation is not. There are problems with Staff's Preliminary Report, and also with the way NYPA reconciles its actual results, through the RSR, to Preference Power Rates (Radigan, pp. 19-20).

The Niagara and St. Lawrence project customers can be (are) divided into three classes: (1) Rural and Domestic ("R&D") (the preference power customers), (2) non-R&D customers (at Niagara, mainly Expansion and Replacement; at St. Lawrence, special contract customers, such as Alcoa, etc.), and (3) "NYPA Use" (sales by NYPA into the market) (Radigan, pp. 13-14). The purpose of the Cost of Service Study is to determine the cost properly attributable to the "preference power" customers.

The Hudson River Energy Group's analysis has uncovered several major flaws in the Cost of Service Study.

First, some context. The preference power R&D customers' use of the hydroelectric projects is remarkably steady. As can be readily seen in Mr. Radigan's Testimony (Radigan, pp. 21; 27-28), the R&D "preference power" customers' demand and energy use is remarkably

steady. The other two customer categories vary year to year. The preference power R&D customers purchase about 45% of the Niagara project's energy output. Those same preference customers purchase about 50% of the project capacity. The Staff Report cost of service, however, imposes approximately 55% of the total cost of the project on the R&D preference customers (Radigan, p. 29). The total annual cost of service for 2011 is about $230 million. The Staff study allocates 55%, or $127 million, to the R&D customers' cost of service. The R&D customer allocation should match the R&D customers' proportionate usage of the plant, which is about 45% (energy) or 50% (capacity). The revenue requirement attributable to the R&D preference customer should be approximately in the range of $104 million to $115 million, depending upon whether the cost share is based on capacity or energy. (We will detail the rate comparisons and calculations below.) (Radigan, pp. 5-7). The overcharge to the preference customers is on the order of $12 million to $23 million. Again, this is based on the proper allocation of costs. The MEUA is seeking a proper accounting of costs, not a share of revenues. NYPA is budgeting net revenue (earnings) of $93 million from Niagara and $25 million from St. Lawrence (Radigan, p. 10). Under the Global Settlement and *Auer* principle NYPA is entitled to keep those revenues, so long as it properly allocates the cost of production to the preference customers.

The Staff Report divides rates into two categories—demand rates (KW) and energy rates (kWh). The rates needed to recover the cost of service of course depend upon the quantities projected to be sold (or in the case of the RSR, actual sales). These units sales projections are called "billing determinants." The Staff Report treats those determinants differently for energy and demand.

In the energy rate calculation, the Staff Report starts with long-term average generation (Radigan, p. 20). Of that total energy generation projected for 2011, "NYPA Use" accounts for 11% of total projected energy. NYPA sells that output into the market. It is indeed the source of a great deal of NYPA's total profit. NYPA budgeted $117 million in profit from those sales for the year 2011. The MEUA takes no exception to NYPA's profits from those sales and does not seek those revenues.

When NYPA makes its energy rate calculation it uses the whole of the energy (kWh output) in the billing determinants, including the "NYPA Use." This has the effect of giving the preference customers a "cost based" credit for the "NYPA Use," and is proper.

However, the Staff Report does not treat "demand" (KW) the same way (Radigan, pp. 21-25). As discussed above, the Staff Report spreads all energy, including "NYPA Use," over the total energy output (that is, the billing determinant is total sales, as it should be). It does not spread demand over the total project demand (that is, the billing determinant is not "total demand"). The only billing determinants used for demand are those for "preference" and "non-preference"—the "NYPA Use" is completely ignored. In 2010, total sale of capacity was 41,539 MW. Demand from customers (both "preference" and "non-preference") was 32,711 MW. "NYPA Use" is sold by NYPA into the market (6,954 MW) or "transferred" to other NYPA projects (1,874 MW). That "NYPA Use" accounts for approximately 20% of the capacity output of the plant (Radigan, pp. 22-23).

In doing its demand rate calculation, NYPA ignores this use. Therefore, unlike on the energy side, NYPA is not accounting for all the capacity when it sets it rates. The billing determinants for demand are wrong. NYPA is spreading the cost over only 32,711 MW of

demand, rather than 41, 539 MW. The obvious result is that the demand charge is higher, by about 20%, than the actual cost. Through this ratemaking, preference customers do not get a proper cost based credit and are being overcharged.

III. The Demand Charge Error Infects the RSR Calculation

A significant consequence of reduced sales to either "preference" or "non-preference" customers is that NYPA has much more to sell into the market. NYPA profits handsomely. NYPA profits—which is fine under the Global Settlement. But by a further quirk in the RSR calculation the shortfall of sales to "non-preference" customers is reflected as a revenue shortfall to the preference customers' RSR. As Mr. Radigan explains, if demand from the Non-Preference Power customers is down, the demand revenues collected go down, and the amount of money that needs to be collected in the energy charge goes up. But since the energy charge reconciliation is only done for the Preference Power customers, only the Preference Power customers are making up the shortfall of revenues that were not received from the Non-Preference Power customers (Radigan, p. 29).

The RSR, as noted above, is a complete revenue and expense reconciliation. The RSR applies only to preference customers (Radigan, p. 23-29). While preference power customers have a very steady demand, the non-preference customer demand varies dramatically (Radigan, p. 26). When NYPA does its RSR calculations, it includes the "non-preference" customer demands, while ignoring "NYPA Use" demand. The effect is that the "billing determinants" used to spread the demand costs show a drop in demand, and an imputed shortfall in demand revenue. That "shortfall" becomes a charge, a liability, upon preference customers.

This calculation is not only inconsistent with the (proper) treatment of plant energy, it is also obviously wrong. It explains why preference customers use 45% of plant energy, 50% of plant capacity, but pay 55% of plant costs.

There are two ways to fix it. First, "NYPA Use" could be included in the billing determinants for the demand charge. That would address the problem. (Radigan, p. 30).

The second, and more straight forward fix, would be to exclude all the extraneous and overly complex computations and simply allocate the revenue requirement to preference customers based on their proportionate share of the project. Preference power customers take 45% of the plant's energy output (Radigan, pp. 22; 30). That is what they should be charged for.

The comparison of the NYPA method, and the two alternatives, is set out below:

Item	Current Method	Option 1 –Use Full Demand Output for All Calculations	Option 2 – Allocate Plant on Energy Output
2011Total Revenue Requirement ($Millions)	$230,570	$230,570	$230,570
2011R&D Revenue Requirement ($Millions)	$126,861	$114,555	$103,757
R&D Share of Revenue Requirement	55%	50%	45%
Energy Rate ($/MWH)	$4.92	$4.92	$4.92
Demand Rate ($/kW/mo.)	$3.85	$3.23	$3.16
RSR Balance $Millions	($51,267)	$922	$32,829

Correcting the rate calculation is only step one. The RSR balance must be fixed as well. For the last few years the RSR has been calculated improperly. The preference customers do not owe NYPA $51 million. Under the first option (using total demand) the RSR is essentially even.

Under the second option (allocation based on energy output) NYPA owes preference customers $33 million (Radigan, p. 31).

In the 2003 "Global Settlement," the MEUA members foreswore ancillary service profits, and the profits from surplus hydroelectric energy and capacity sales, in exchange for cost based credits and cost based rates. NYPA's Staff Study fails to do that. It improperly allocates a disproportionate share of the plant's cost to preference customers.

IV. Certain Expenses are Improperly Allocated to Hydroelectric Cost of Service

Expenditures that have a nexus to the hydroelectric projects, such as a contribution to the local fire department for the fire district that serves the plant, is "directly assigned" to the cost of service for the hydroelectric projects. Other A&G and indirect overheads are "allocated" to the projects, using the labor ratio.

During the process of discovery (Radigan, p. 31), we observed a number of items under "shared services" that should be completely excluded from the "shared services" pot and should not be allocated to the hydroelectric cost of service. Two items stand out.

First, NYPA makes community and charitable contributions. If such contributions bear a direct relationship to operations at the hydroelectric plant, they are "directly assigned" to the cost of service. MEUA members pay for those charges and do not object because they bear a rational causal relationship to hydroelectric operation. If, however, there are such payments that are not directly tied to the plant, they are contained in "shared services." But unlike overhead, like office expense, contributions to *e.g.*, a downstate chamber of commerce are not a proper element of the hydroelectric cost of service. Since there is no nexus to hydroelectric operations, they should be subtracted from the expense pool before costs are allocated to the hydroelectric cost of

service. There are two reasons to exclude those costs. First, it is questionable whether any such contributions should be made that are not directly assignable to any particular plant (*see,* letter from New York State Attorney General to NYPA President dated March 22, 2011). Second, it is contrary to all accepted ratemaking principles to charge customers for the costs of charitable contributions. NYPA is welcome to make contributions as it sees fit. It certainly has funds to do so, in very large part derived from the profits it reaps from "NYPA use" of the hydroelectric plants, *i.e.*, from market-based sales. But there is no ratemaking theory or practice that would countenance assigning such unrelated expenditures to the preference power cost of service. Clearly it fails the "lowest possible rate" test (*see, Bergen v. PASNY, supra.*).

The Hudson River Energy Group's analysis revealed a number of other items of questionable relevance to the hydroelectric projects. For example, there are expenses of discontinued demand side and alternate energy projects. There is no basis to allocate any such costs to the hydroelectric cost of service.

During the course of discovery NYPA Staff stated that no such costs are projected for rate purposes. We could not confirm that. Staff did say, however, that such costs could well be included in the RSR, and hence in rates, at year end. That would be improper, and a clear violation of the "lowest possible rate" standard.

Conclusion

The Preliminary Staff Report outlines a rate plan to run through 2014. It is therefore important that this rate plan get it right. But, as we have explained herein, the annual RSR calculation is every bit as important as the base rate plan. The affected parties should be afforded an opportunity to examine and comment on the RSR computations.

The MEUA and NYPA are partners in public power. The Global Settlement of 2003 was a significant milestone, and set the stage for further cooperation between MEUA and NYPA to advance the benefits of public power in New York State. The Global Settlement reaffirmed the *Auer* principle. The "lowest possible rate" means rates at cost, neither above nor below cost. Adjustments offered herein would bring the Staff Report into line with those principles.

Respectfully submitted,

READ AND LANIADO, LLP
Attorneys for the Municipal Electric Utilities
Association of New York State

By: /s/_____
Kevin R. Brocks

TAB 5-H

Part 1

Affidavit of Frank W. Radigan on behalf of MEUA

NEW YORK STATE POWER AUTHORITY
2011 MODIFICATION PLAN

DIRECT TESTIMONY OF
FRANK W. RADIGAN
ON BEHALF OF THE MUNICIPAL ELECTRIC UTILITIES ASSOCIATION
OF NEW YORK STATE

VERIFICATION

STATE OF NEW YORK	)	
	)	SS.:
COUNTY OF ALBANY	)	

I, Frank Radigan state that I have prepared the attached Testimony dated October 24, 2011, and hereby verify that it is accurate and true to the best of my knowledge.

Frank W. Radigan

Sworn to before me this 24 day
of October, 2011.

KONSTANTIN PODOLNY
Notary Public, State of New York
Qualified in Albany County
No. 02PO6230727
Commission Expires Nov. 08, 2014

Notary Public

NEW YORK POWER AUTHORITY

2011 RATE MODIFICATION PLAN

DIRECT TESTIMONY OF

FRANK W. RADIGAN

ON BEHALF OF THE

MUNICIPAL ELECTRIC UTILTIES ASSOCIATION OF NEW YORK STATE

OCTOBER 24, 2011

1 **Q. MR. RADIGAN, WOULD YOU PLEASE STATE YOUR FULL NAME,**
2 **OCCUPATION AND BUSINESS ADDRESS.**
3 A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy
4 Group, a consulting firm providing services regarding utility industries and
5 specializing in the fields of rates, planning and utility economics. My office
6 address is 237 Schoolhouse Road, Albany, New York 12203.
7
8 **Q. WOULD YOU PLEASE SUMMARIZE YOUR EDUCATION AND**
9 **BUSINESS EXPERIENCE?**
10 A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson
11 College of Technology in Potsdam, New York (now Clarkson University) in 1981.
12 I received a Certificate in Regulatory Economics from the State University of New
13 York at Albany in 1990. From 1981 through February 1997, I served on the Staff
14 of the Department of Public Service, the staff arm of the New York State Public
15 Service Commission. I served in the Rates and System Planning sections of the
16 Power Division and in the Rates Section of the Energy and Water Division. My
17 responsibilities included resource planning and the analysis of rates, depreciation
18 rates and tariffs of electric, gas, water and steam utilities in the State and
19 encompassed rate design and performing embedded and marginal cost of service
20 studies, as well as depreciation studies.
21
22 Before leaving the Commission, I was responsible for directing all engineering
23 staff during major proceedings, including those relating to rates, integrated

resource planning and environmental impact studies. In February 1997, I left the Commission and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own company.

In my 30 years of experience, I have testified as an expert witness in utility rate proceedings on more than 100 occasions before various utility regulatory bodies, including the Arizona Corporation Commission, the Connecticut Department of Utility Control, the Delaware Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the New York State Public Service Commission, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Public Service Commission of the District of Columbia, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board and the Federal Energy Regulatory Commission.

I currently advise a variety of regulatory commissions, consumer advocates, municipal utilities and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. A summary of my qualifications and experience is included as Exhibit __(FWR-1).

1 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

2 A. I am testifying on behalf of the Municipal Electric Utilities Association of New
3 York State ("MEUA"). The MEUA was formed in 1930 and contains 40
4 municipal utilities in the State. The object of this association is to foster and
5 advance the efficient operation of publicly owned and operated electric systems,
6 including the production, distribution, conservation and prudent use of electric
7 power and energy for public service.
8

9 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

10 A. I have been asked to review the reasonableness of the New York Power
11 Authority's ("NYPA") Preliminary Staff Report on Hydroelectric Production
12 Rates for the Rate Years 2011 to 2014 that was issued on July 27, 2011 (the "Staff
13 Report"). The Staff Report sets forth in detail the estimated costs required to
14 serve NYPA's "Preference Power" customers that take power from the
15 Authority's St. Lawrence and Niagara Hydroelectric Projects[1] ("Hydroelectric
16 Projects" or "Projects"). NYPA uses the Preference Power rate for more than
17 strictly the Preference Power class. The Preference Power customers consist of
18 47 municipal electric systems and four rural electric cooperatives, residential
19 customers of three upstate investor-owned utilities, the Neighboring State
20 customers and the Niagara Project relicensing host communities.

[1] Section 836 (b) (1) of the Niagara Redevelopment Act (NRA; Public Law 85-159; 16 USC Section 836) creates a preference for public power entities for 50% of the Niagara Project output in order to serve "domestic and rural" customers at "the lowest rates possible." Preference power customers are sometimes also referred to as R&D customers.

1 **Q. COULD YOU PLEASE SUMMARIZE THE FINDINGS OF YOUR**
2 **REVIEW?**
3 A. Yes. As I will explain in more detail later, the goal of the rate setting process for
4 the Hydroelectric Production Rates is to develop a rate which represents the
5 lowest possible cost of obtaining power from the Project. The Staff Report does
6 not result in the lowest possible cost as it ignores critical billing determinants in
7 the calculation of the demand rate. Further, the mechanism used in the
8 calculation of the Rate Stabilization Reserve[2] ("RSR") can result in cross
9 subsidization by the Preference Power customers to Non-Preference Power
10 customers, and this needs to be revised. Because of this I conclude that the
11 current Staff Report does not abide by good ratemaking practices, it violates the
12 principles of the Global Settlement and the *Auer* Decisions (both of these terms
13 will be explained *infra*).
14
15 The unfairness of the current rate setting process is obvious in that it allocates a
16 disproportionate share, 55%, of the cost of the Project to the Preference Power
17 Customers, even though they only are allocated 50% of the demand and use only
18 45% of the energy output. Rectification of this infirmity does not require a
19 change in the means by which the revenue requirement is determined, but rather
20 how the revenue requirement is allocated between Preference Power customers
21 and Non-Preference Power customers. There are two means by which the

[2] A mechanism designed to reconcile revenues and costs.

infirmity could be rectified. The first option is to include all demand output in the calculation of the demand charge and use all demand output in the calculation of the RSR. The second option, and the preferable one, would be to simply allocate the revenue requirement between the Preference Power customers and others (Non-Preference Power and "NYPA Use"). Specifically, as the Project's main value is the low cost energy they produce I recommend that the fair share be based on the energy output associated with the Preference Power customer's allotted share of the plant.[3]

The use of a different methodology for calculating the RSR balance also requires that current RSR balance be recalculated beginning from the last time rates were set (2007).

The table below shows the difference between the current methodology and my proposed methodologies:

[3] The Preference Power customers use 45% of the plant's energy output.

Item	Current Method	Option 1 –Use Full Demand Output for All Calculations	Option 2 – Allocate Plant on Energy Output
2011Total Revenue Requirement ($Millions)	$230,570	$230,570	$230,570
2011R&D Revenue Requirement ($Millions)	$126,861	$114,555	$103,757
R&D Share of Revenue Requirement	55%	50%	45%
Energy Rate ($/MWH)	$4.92	$4.92	$4.92
Demand Rate ($/kW/mo.)	$3.85	$3.23	$3.16
RSR Balance $Millions	($51,267)	$922	$32,829

A final recommendation is in regards to the RSR calculation. Currently the RSR is just updated and during rate cases NYPA states what its intentions are for crediting or surcharging any existing balances. NYPA has taken a position that the RSR is not an issue to be discussed or reviewed during the review of hydroelectric production rates. There are millions of dollars that are charged to expenses in a given year and not all of them should be charged to Preference Power customers through the RSR. The Preference Power customers have a concern that the charges to the RSR require some type of audit review before they are charged to the RSR. Indeed, as the RSR is a reconciliation account only charged to Preference Power customers, the RSR calculation is every bit as important as the hydroelectric production rate itself. This needs to be rectified by either an annual review process, increased reporting requirements, review of RSR balances in the hydroelectric production cost rate setting process or some combination of the above.

1 **Q. COULD YOU PLEASE DISCUSS YOUR REVIEW AND THE**
2 **RATEMAKING PHILOSOPHY THAT YOU EMPLOYED IN YOUR**
3 **REVIEW?**
4 A. Yes. The means for setting Hydroelectric Production Rates incorporates several
5 ratemaking methodologies and principles that have been agreed to, and
6 incorporated in this Staff Report, over the years and are part of a April 2003
7 NYPA MEUA Global Settlement ("Global Settlement") agreement.
8
9 In that Global Settlement, the MEUA and NYPA worked diligently and in good
10 faith to address some of the concerns and resolve some of the issues raised by the
11 restructuring of the electricity markets. In connection with NYPA rates, the
12 parties tried to map out the fair rate treatment of ancillary services, surplus
13 hydroelectric energy sales and capacity credits. For example, NYPA sells
14 ancillary services into the competitive electric market. It does not credit to
15 customers the revenues received from those sales, but rather credits the Preference
16 Power customers the embedded cost for the machinery that allows the ancillary
17 services to be produced. Another example, which I will discuss in more detail
18 later, is the fact that MEUA has agreed not to make any claim on revenues from
19 sales that NYPA may make into the energy market which is overseen by the New
20 York State Independent System Operator ("NYISO"). Of course, the signatories
21 could not resolve everything or every rate setting detail, and this requires periodic
22 review to ensure that the current methodology continues to meet good ratemaking
23 practices.

To accomplish this review we asked many discovery questions and reviewed the extensive discovery of other interested parties. I examined NYPA's system of accounts, trial balances, workpapers, budgets, operating budget, RSR calculations, many other documents, and met with NYPA Staff. I also compared the Staff Report to prior rate plans and have sought to reconcile the data in the Staff Report and other documentation to RSR balances.

Q. COULD YOU PLEASE GIVE SOME SENSE OF THE SIZE OF THE PROJECTS AND WHAT THEY MEAN TO NYPA'S OPERATIONS?

A. Yes. The Niagara Project is comprised of the Robert Moses Niagara Power Plant on the Niagara River, which is a run-of-the river design and the Lewiston Pump Generating Plant, which is a pumped storage project whereby energy is used to pump water up into the Lewiston reservoir during low load hours, and then the reservoir water is released during the day to produce energy that is more valuable. This plant has a rated capacity of approximately 2,700 MW. The St. Lawrence Project is on the St. Lawrence River and is a run-of-the-river plant with a rated capacity of approximately 860 MW. Together these Projects create power from the outflow of the five great lakes and have a total capacity of 3,560 MW and produce 20.1 TWH of energy per year. To put this into perspective the Hoover Dam is only 2,080 MW and produces on average 4.2 TWH per year. By producing low cost power to New York State these two Projects help employ thousands of New Yorkers and are true gems to the State.

1 If the Hydroelectric Projects are gems to New York State, they are the crown
2 jewels to NYPA. Exhibit__ (FWR-2) is a section of the 2011 NYPA Operating
3 Budget, which is the day-to-day budget that NYPA uses for its operations. The
4 Operating Budget provides forecast revenues and expenses for each of NYPA's
5 various projects. As can be seen in the last column of Exhibit__(FWR-2), for
6 2011 NYPA is forecasting it will have revenues of $2.7 billion with operating
7 expenses of $2.4 billion for a net operating revenue of $0.3 billion. After making
8 contributions to the State of $65 million and other charges to operating income,
9 NYPA forecasts that it will have a net income for the year of approximately
10 $180 million.
11
12 The Hydroelectric Projects make up the vast share of the NYPA profits and as
13 shown on Exhibit__(FWR-2), the Niagara Project is forecast to earn $93 million
14 in net income and the St. Lawrence Project $25 million for a total of $118 million,
15 or 65% of total net income.[4]
16
17 The fact that 11 cents out of each dollar is going towards contributions to the state
18 or as profit to NYPA is quite impressive for a not-for-profit entity. I had this in
19 mind when I began my review of the Staff Report.
20

[4] Reports from the NYPA Chief Financial Officer show that for 2009 and 2010 Niagara and St. Lawrence accounted for 81% and 82%, respectively of the total NYPA Net Income in those years.

Q. COULD YOU PLEASE GIVE SOME BACKGROUND ON THE NIAGARA AND ST. LAWRENCE PROJECTS AND THE ALLOCATION OF THEIR POWER OUTPUT?

A. Yes. There is a wide variety of data sources that detail the hydroelectric power projects and their history and operation. A very useful report regarding the history of the projects, their power allocation and the rate setting process is Volume I of the Niagara Power Project Relicensing entitled Niagara Power Project Power Allocation, Rates and Opportunities, Niagara Power Project FERC No. 2216, prepared for the New York Power Authority by the Brattle Group, which is attached as Exhibit__(FWR-3).

The Niagara and St. Lawrence Rivers have long been recognized for their power potential.

Works for harnessing the power potential of the Niagara River with its high head and flow rate date back to the early 1800s with the first hydroelectric power generation project dating back to 1881. Plans for developing the low head high flow St. Lawrence River Rapids date back as far as 1909 with efforts to develop a hydroelectric dam on the river starting in the 1920s.

The legal basis for the power allocation and rates for the current hydroelectric projects rests primarily on the Niagara Redevelopment Act and the Power Authority Act. NYPA applied to the Federal Power Commission in 1956 for a license to develop the Niagara River for hydroelectric power. This application

1 was submitted just three months after a rock slide caused an existing power plant,
2 the Schoellkopf Plant, to topple into the River. The Niagara Redevelopment Act
3 (NRA; Public Law 85-159; 16 USC Section 836) was enacted in 1957 and
4 authorized construction and operation of a power project.
5
6 Three sections of the NRA govern the allocation of power. Section 836 (b) (1)
7 created a class of customer called Preference Power customers who used their
8 allocation to serve "domestic and rural" customers. Section 836 (b) (2) called for
9 a reasonable portion to be made available to neighboring states. Section 836 (b)
10 (3) allocates 445 MW of the project power to Niagara Mohawk Power
11 Corporation for resale to customers that were formerly served by the Schoellkopf
12 Plant. The remaining power was sold to public and private utility companies for
13 sale to domestic and rural customers.
14
15 The Power Authority Act ("PAA") was signed into law in 1931, and its purpose
16 was to develop hydroelectric power on the St. Lawrence River. Elements of the
17 PAA were incorporated in the Public Authorities Law ("PAL") of 1951, which
18 outlines the powers and duties of NYPA. The PAL also called for development
19 of hydroelectric power for domestic and rural customers, but the PAL contains no
20 percentage requirement for the allocation of power. The Preference Power
21 customers of the St. Lawrence Project are some neighboring states and investor-
22 owned utilities who resell the power to domestic and rural customers. The

remaining power from the plant is sold to certain high load factor industrial customers under contracts.

Q. COULD YOU PLEASE DISCUSS THE OPERATION OF THE HYDROELCTRIC PROJECTS?

A. As noted above, the hydroelectric projects are divided into two main types of allocations: Preference Power (sales to New York municipal utilities, sales to New York rural electric cooperatives, sales to neighboring states, and power sold to investor-owned utilities for resale to residential customers) and Non-Preference Power (Replacement Power, Expansion Power and power sold under contracts with individual entities). The allocation of the Project's power is expressed in capacity with energy delivered per terms of the individual contracts.

The Hydroelectric Projects have been designed to specifically generate power when most valuable within the constraints of existing treaties over water use and the physical availability of water. The generation of power from the Projects is not constant over time, nor is the customer demand for the power. Thus, actual operation power generated does not always perfectly match contractual load factors. When the power generated from the Projects exceeds contract demand NYPA is able to use the power for its own purposes (to sell into deregulated electric power market as administered by the New York Independent System Operator, the "NYISO", or transfer to other projects for use by other NYPA

customer classes). The use by NYPA, therefore, creates a third customer group which uses the Projects power, *i.e.*, "NYPA's Use."

Q. COULD YOU PLEASE DISCUSS THE RATE SETTING BASIS FOR PREFERENCE POWER CUSTOMERS?

A. Yes. Section 836 (b) (1) of the NRA states that the Preference Power was to serve domestic and rural customers at the lowest rates reasonably possible. The PAL has similar language to pricing. Neither law gives an exact definition to the term lowest rates. The PAL does state that the price should represent the cost of generation, plus capital and operating charges, plus a fair cost of transmission.[5] With such inexact language it is not surprising that there have been a series of legal cases over the last 50 years.

The legal cases most notable to the rate setting process are what are known as the *Auer* Decisions.[6] Under these decisions the elements of the costs that go into the rate were more clearly defined, as well as the fact that Preference Power customers are not entitled to rates below costs that result from the excess revenues derived from selling the "NYPA Use" power into the market.

[5] Which is now recovered separately under the Transmission Adjustment Clause as administered by the NYISO.

[6] Auer I - *Auer vs. Dyson*, 110 Misc. 2d 943, 444 N.Y.S.2d 513 (Sup. Ct. Oswego Co. 1981) and Auer II - *Auer vs. Dyson*, 125 Misc. 2d 274, 479 N.Y.S.2d 102 (Sup. Ct. Oneida Co. 1984), 112 A.D. 2d 803, 491 N.Y.S.2d 1022 (4th Dept. 1985).

In the late 1990s, another lawsuit further defined the rate setting process, and it addressed the allocation of shared, or indirect, services.[7] Indirect services are now allocated on a labor ratio, whereby each NYPA project is assigned a share of headquarters costs in proportion of its share of labor costs to the total labor costs for all NYPA projects.

Together, the results of these past legal actions and past rate proceedings have defined a set of ratemaking principles. These principles were included in the Global Settlement.

The principle rate setting methodologies and principles included in the Global Settlement are:

(a) Melding of St. Lawrence Project and Niagara Project costs for ratemaking purposes;

(b) A means by which NYPA is allowed to recover the capital and cost of capital related debt related to the Hydro Projects;

(c) The use of a "labor/labor" method for the allocation of Indirect Overheads;

(d) Recovery in rates of all prudent Hydro Project relicensing, life extension and modernization costs incurred by NYPA in the exercise of its broad discretion;

(e) Amortization over 20 years by NYPA of its actuarial estimate of its Other Postemployment Benefits liability;

[7] *Bergen v. PASNY*, 249 A.D.2d 902. (4th Dept. 1998).

(f) Use of the Rate Stabilization Reserve ("RSR") for any under-collection or over-collection of the NYPA's revenue requirement for the hydroelectric projects; and

(g) By law and license NYPA's is to price its power for the domestic and rural customers at "the lowest possible rate" and at the lowest possible price (this is sometimes known as the *Auer* Principle).

Q. HAVE YOU REVIEWED THE PRELIMINARY STAFF REPORT IN THIS CASE?

A. Yes. The revenue requirement of the Hydroelectric Project included the above described ratemaking principles and methodologies. Costs are grouped into a four categories. The first is direct costs and is known as Operations & Maintenance ("O&M")/Administrative & General ("A&G"). These costs consist of direct O&M for each hydroelectric project plus A&G expenses that are directly incurred for the Hydroelectric Projects (as example of this later term a study or legal action directly related to one of the projects). Direct O&M includes the day-to-day operations of the projects and ongoing expenses associated with major maintenance programs and non-capital modifications.

The next cost category is Indirect Overheads and consists of the allocated share of headquarters costs associated with providing support for the hydroelectric based on the labor ratio discussed above. The current labor ratio results in approximately 41% of the indirect overheads being allocated to Hydroelectric Projects.

The next group of cost relates to certain cost elements related to the relicensing of the Projects and accrual treatment of OPEBs, which mainly include retiree health benefit costs. The relicensing costs reflect an amortization of the cost to relicense the Hydroelectric Projects and a NYPA change in accounting for OPEBs where it now uses accrual accounting to reflect the liability. These cost categories and their rate treatment were all included in the Global Settlement.

The final group of costs is known as Capital Costs and reflects that fact that since the retirement of the original construction bonds in 1981, the recovery of costs for new capital programs has to be addressed. New capital investments have been made in the Hydroelectric Projects related to plant modernization, upgrades and relicensing. The method for funding them is to use the Trended Original Cost ("TOC") methodology. NYPA continues to recover interest on debt and depreciation which represents the return of capital. Under the TOC only the inflation component or return "of" the investments is captured, and the equity return "on" the investment is foregone. The inflation component uses the Handy-Whitman Index as the measure for inflation. This method has been agreed to by the parties in the Global Settlement.

There is one final element in the revenue requirement setting process for the Hydroelectric Projects, and that is a crediting for ancillary service costs. The proposed hydroelectric rates exclude costs associated with the production of ancillary services (Regulation Service, Operating Reserves, Voltage Support and

Black Start Service at the Hydroelectric Projects). These services are sold to the NYISO, and NYPA is allowed to keep the revenues associated with them. In the Global Settlement, Preference Power customers agreed that they would not lay claim to the revenues, but in return would receive a cost based credit associated with cost of the equipment at the Projects associated with their production.

As shown on Appendix A of the Preliminary Staff Report, the revenue requirement of the Hydroelectric Projects for 2011 is $244,680,000 with a credit for Ancillary Services of $14,110,000 for a net revenue requirement of $230,570,000. NYPA considers this revenue requirement as the cost of the plant which needs to be recovered from customers. NYPA uses this same cost allocation process to determine the revenue requirements for 2012, 2013 and 2014, and they are shown on Exhibit A, page 2 of 2 of the Preliminary Staff Report.

Q. COULD YOU PLEASE DISCUSS THE RATE DESIGN THAT NYPA PROPOSES?

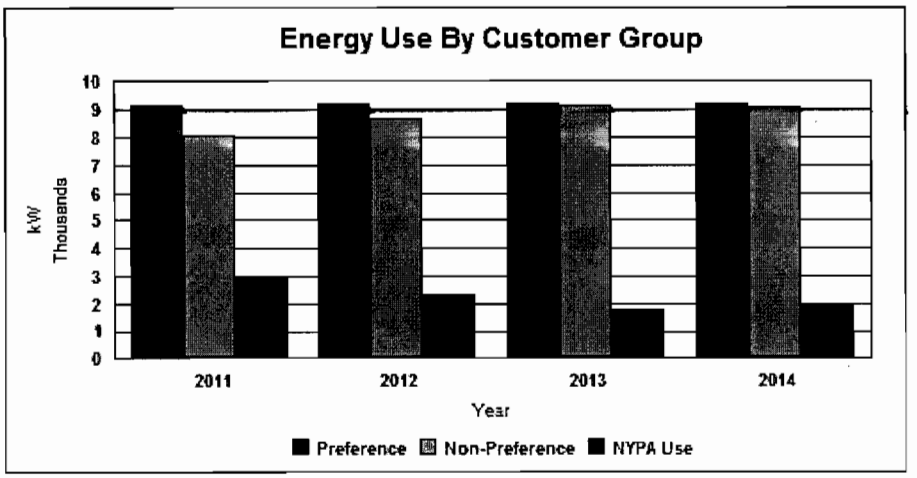
A. Yes. NYPA proposes to keep the energy rate at the existing level of $4.92 per MWH and recover the remaining charges though the demand charge. NYPA recovers the revenue requirement for the Hydroelectric Projects by first multiplying the long-term average generation of the projects by the existing energy rate, which results in a revenue recovery of $99,463,000 out of the $230,570,000 revenue requirement.

1 Once the revenue recovery from the energy charge is determined the remaining
2 revenue requirement is then recovered from the billing demand of 34,086 MW,
3 which results in the proposed demand rate of $3.85 per kW. NYPA proposes to
4 use this same rate design methodology for the 2012, 2013 and 2014 rate years,
5 and the resultant rates are shown on Exhibit A, page 2 of 2 of the Preliminary
6 Staff Report.
7
8 **Q. DO YOU AGREE WITH THE PROPOSED METHOD FOR**
9 **DETERMINING REVENUE REQUIREMENT AND THE PROPOSED**
10 **RATE DESIGN?**
11 A. By and large I do not take issue with the determination of revenue requirement at
12 this time as it does comport with the terms and principals of the Global
13 Settlement. I do take issue with the determination of the revenue requirement
14 used in the calculation of the RSR, which I will discuss *infra*.
15
16 As to the proposed rate design, I disagree completely with NYPA as its proposed
17 methodology does not result in the lowest possible rate. It ignores critical billing
18 determinants in the calculation of the demand rate. Because of this I conclude
19 that the current methodology does not abide by good ratemaking practices. It
20 violates the principals of the Global Settlement and the *Auer* Decisions.
21
22 Exhibit __(FWR-4) is the NYPA workpaper that shows the billing determinants
23 which it uses in setting the proposed rate. This information was provided in

1 response to a MEUA discovery question. As can be seen on Exhibit__(FWR-4),
2 NYPA shows the billing determinants for each of the customers that take output
3 from one of the Hydroelectric Projects. The billing determinants are shown for
4 both demand (expressed in kW) and energy (expressed in MWH). For example,
5 on the energy side, it is shown that Alcoa is forecast to use 1,174,148 MWH in
6 2011 (Alcoa is a non-Preference Power customer of the St. Lawrence Project).
7 Similarly, the New York State municipals are forecast to use 1,861,891 kW in
8 2011 (the municipal customers are Preference Power customers).
9
10 Exhibit__(FWR-4) also gives some insight into the ratemaking principal the
11 NYPA states it uses in developing its proposed rates. For example, the total
12 energy billing determinants show that for 2011 the Preference Power and Non-
13 Preference Power customers are forecast to use 17,232,383 MWH of energy. As
14 noted before, this is not the same amount of energy used in the rate design of the
15 Preliminary Staff Report. As shown on Exhibit A, page 2 of 2, line 18, the Long-
16 Term Average ("LTA") Generation of the Hydroelectric Projects is 20,216 GWH
17 or 20,216,000 MWH. As explained *supra,* the difference in the energy use is
18 attributable to the third customer group, which I discussed before, the "NYPA
19 Use." As discussed before, due to the inexact generation of the Projects and the
20 demand from the Projects, at times there is energy which is produced and NYPA
21 is allowed to use for its own purposes. NYPA includes that energy use in its
22 computations. Including the "NYPA Use" in the development of the cost to serve

is consistent with the ratemaking principle that the rate developed in this case is the rate which recovers the lowest possible cost.

The graph below shows the NYPA forecast of energy use by customer group. On average "NYPA Use" accounts for approximately 11% of project capacity and the sale of that power into the NYISO market accounts for the forecast profits in NYPA's operating budget.



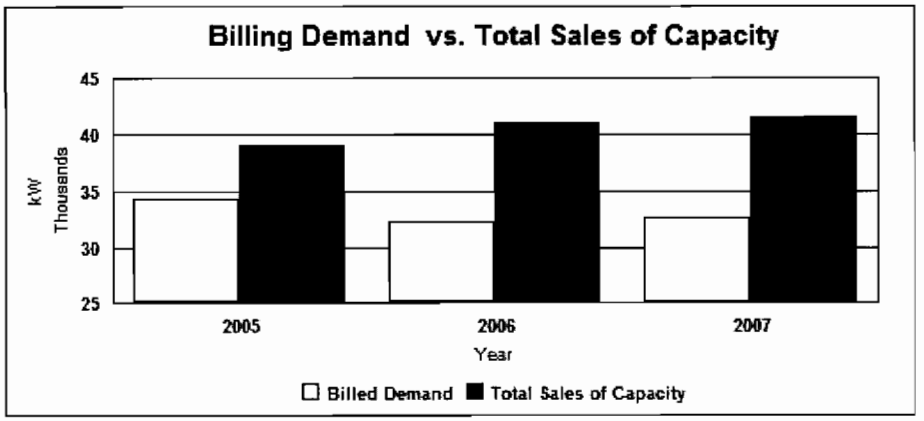
When one turns to the development of the demand rate, however, NYPA is not consistent with the lowest possible cost ratemaking concept which is required under the *Auer* Principle. As shown on Exhibit__(FWR-4), the billing determinant for the Preference Power and Non-Preference Power customers is forecast to be 34,085,651 kW in 2011 and nowhere in Exhibit__(FWR-4) is the demand forecast to be used by the customer group that I have termed "NYPA Use." Yet, the

34,085,651 kW, which is also equal to 34,086 MW, is shown on Exhibit A, page 2 of 2, line 15 of the Preliminary Staff Report. NYPA ignores this use when it calculates demand charges. Thus, NYPA is being inconsistent in spreading costs across all energy users but not spreading costs over all users of the capacity.

Through discovery I have been able to obtain the capacity sales that NYPA has made from the Projects when the Preference Power and Non-Preference Power customers are not using it. For example, Exhibit__(FWR-5) is the response to a discovery question by the Neighboring States which shows the contract demand for the system, as well as the total demand output of the Hydroelectric Projects. As shown, the actual demand from customers in 2010 was 32,711 MW, while the total sale of capacity out of the Projects was 41,539 MW. The difference of 8,828 MW was either sold by NYPA into the market, 6,954 MW, or transferred to other NYPA projects, 1,874 MW.[8]

To illustrate the magnitude of the demand that is not being used in the calculation of the hydroelectric production rate and the actual demand output of the plant I plotted the data on the graph below.

[8] Other discovery responses show the relative distribution of capacity use of the plant. For the 2008-2010 periods, the "NYPA Use" accounted for approximately 20% of all capacity output.



By excluding this demand from the calculation of the demand charge, NYPA is effectively recovering costs from a pool of customers smaller than the total, and thereby overstating costs. NYPA is not recognizing the cost offset for the 20% of the plant capacity it uses—it sells—for itself. This is in direct violation of the NRA, the PAL and the *Auer* Decisions, which all require that rates be set at the lowest possible cost. By not including all demand in the denominator NYPA is effectively overstating the demand rate. The Global Settlement is silent on the mechanics of the calculation of the demand rate in the rate setting process of the hydroelectric production rates.

Q. WHAT WOULD BE THE IMPACT OF RECOVERING THE REVENUE REQUIRMENT FROM ALL USERS OF THE PROJECTS?

A. If the current rate design method were employed, *i.e.*, keeping the existing energy rate as is and recovering the remaining revenue requirement from the demand charge by including the "NYPA Use" demand into the calculation, it would result

in a reduction in the demand charge from the proposed level of $3.85 per kW to 3.23 per kW as shown in the table below.[9]

	NYPA Method	Corrected Method
Revenue Requirement	$230,570	$230,570
LTA Generation (GWH)	20,221	20,221
Energy Rate ($/MWH)	$4.92	$4.92
Energy Revenues ($)	$99,487	$99,487
Demand Revenue Requirement ($)	$106,822	$106,822
Demand (kW)	36,137	40,537
Demand Rate ($/kW)	$3.85	$3.23

If no other changes were to be made, at a minimum this change would need to be done. Before that change is made, however, we need to consider how the choice of the rate design impacts the RSR calculations and balances.

Q. PLEASE DISCUSS YOUR REVIEW OF THE RSR CALCULATION.

A. The RSR calculation is the means by which NYPA reconciles any deviations from the forecast revenue requirement as compared to that used in the rate setting process. It should be noted that the RSR calculation and any balances contained in it only impact the Preference Power customers. My review of the calculation shows that cross-subsidization can occur between the rates charged to Preference Power customers and Non-Preference Power customers. In order to understand

[9] Assuming that the "NYPA Use" customers use 20% of the capacity output of the Projects.

how cross subsidization can occur, one needs to first understand how the RSR calculation is made. I will first explain how the RSR calculation works, and then explain the problems with it. To understand that I have attached the 2010 RSR calculation to this testimony as Exhibit__(FWR-6), and I present the summary calculation from the Exhibit below.

EXHIBIT II

Page 1 of 6

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
RURAL & DOMESTIC
COST-BASED RATES
2010 CALENDAR YEAR COSTS

LINE NO.	DESCRIPTION	AMOUNT ($000) (1)	BILLING DETERMINANTS DEMAND (MW) 4/ (2)	ENERGY (GWH) 5/ (3)	RATE (4)
1	PRODUCTION COST OF SERVICE 1/	250,251			
2	DEMAND COMPONENT 2/	108,928	32,711		3.33
3	ENERGY COMPONENT 3/	141,323		20,210	6.99 mills/kWh

The first step in this summary calculation is to take the actual revenue requirement of the Hydroelectric Projects after the calendar year ends. In this case, that is $250,251,000. Line 2 of the table shows how much of the revenue requirement was recovered through the demand charge based on actual billed demand in the year of 32,711 MW. The difference between the amount of money recovered in the demand charge and the actual cost to serve in a year is the amount that must be recovered in the energy charge, which in this case is $141,323,000. These figures carry over to another table in Exhibit__(FWR-6),

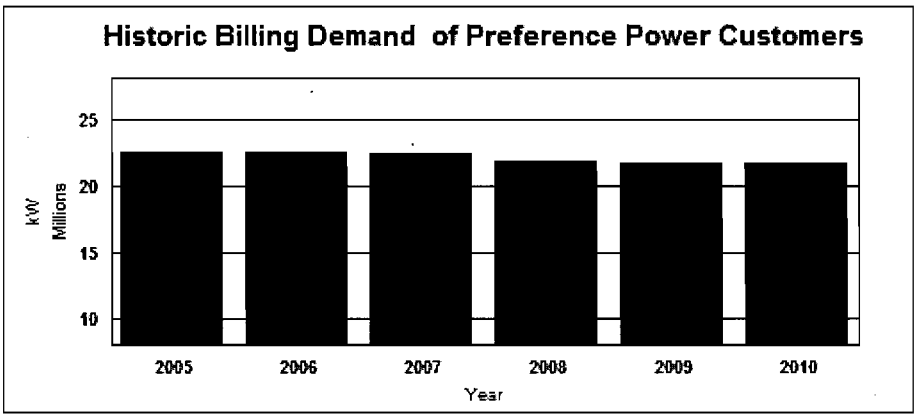
which compares actual energy revenues versus the actual energy revenues and goes on to complete the reconciliation of actual revenues to the cost of service for the year. Notice though that the RSR charges only the R&D customers the difference. Preference customers make up for the non-preference so called "shortfall."

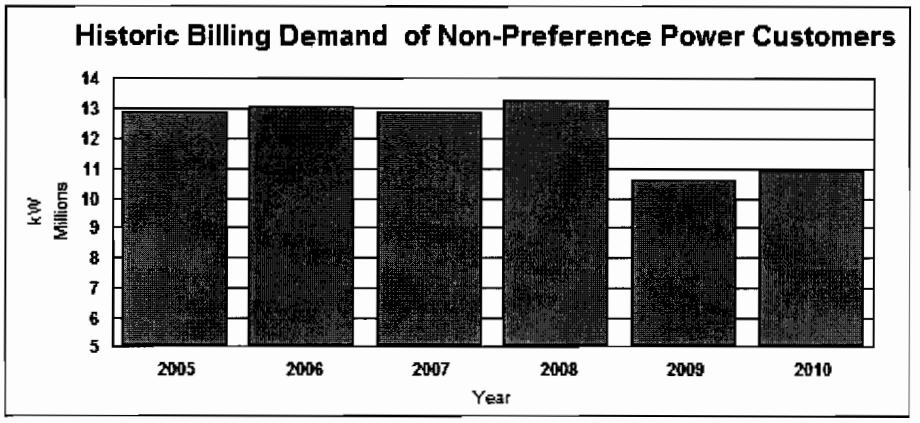
What is important in this calculation is that it uses actual billed demand for 2010, which is considerably less than both the billing demand that was included in the determination of the current demand charge, 36,137 MW and the actual capacity sales from the Projects, 41,539 MW. The actual billing demand of 32,711 MW is approximately 10% less than the amount used in the development of current rates. The actual billed demand for 2010 is shown below.

ACTUAL BILLING DEMANDS
2010 CALENDAR YEAR

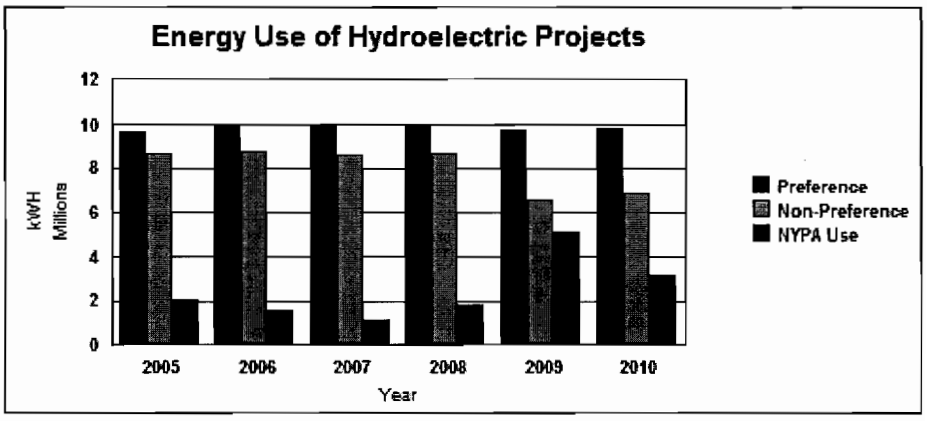
LINE NO.	CUSTOMER	MW
1	NIAGARA MOHAWK	10,283.8
2	NEW YORK STATE ELECTRIC & GAS	4,370.8
3	ROCHESTER GAS & ELECTRIC	1,608.0
4	MUNICIPALS & COOPERATIVES	8,305.9
5	OUT OF STATE	3,199.2
6	ALUMINUM COMPANY OF AMERICA (ALCOA)	2,892.0
7	REYNOLDS COMPANY	0.0
8	ENERGY COST SAVINGS BENEFIT - 2005 LEGISLATION	752.8
9	WESTER NEW YORK ECONOMID DEV. FUND	375.2
10	GENERAL MOTORS CORPORATION	15.0
11	MARCY SUBSTATION	7.5
12	NYC METROPOLITAN TRANSPORTATION AUTHORITY	120.0
13	NIAGARA FRONTIER TRANSPORTATION AUTHORITY	36.7
14	NIAGARA RELICENSING POWER AND OTHER	744.0
15	TOTAL	32,711

As can be seen from this table, a sizable portion of the demand is used by industrial customers, such as Alcoa with a demand of 2,892 MW. The Reynolds Company used 0 MW in 2010. This compares to Reynolds demand of 2,568 MW in 2007. Both Alcoa and Reynolds are Non-Preference Power customers, and it is their inclusion in the RSR calculation which can cause cross subsidization because the demand from the industrial customers can vary from year to year, while the demand of the Preference Power customers is more stable. To illustrate this fact I have prepared the following two graphs which show the demand of the Preference Power customers over the last six years, and another which shows the demand of the Non-Preference customers.





As one can see from the graphs above, the demand by the Non-Preference Power customers has decreased dramatically over the last few years. The graph below shows energy use form the Projects by customer group and it shows the same phenomenon of consistent use by Preference Power customers and varying use by the Non-Preference Power customers.



By using the demand for both Preference Power customers and Non-Preference Power customers in the calculation of the RSR cross subsidization can occur. If

demand from the Non-Preference Power customers is down, the demand revenues collected go down, and the amount of money that needs to be collected in the energy charge goes up. But since the energy charge reconciliation is only done for the Preference Power customers, only the Preference Power customers are making up the shortfall of revenues that were not received from the Non-Preference Power customers. Moreover, as shown in the graph above, NYPA also benefits because when the energy use of the Non-Preference Power customers goes down it has more energy available to sell into the energy market, of which, as I explained *supra*, NYPA gets to keep 100%.

Q. WHAT SHOULD BE DONE?

A. The Preference Power customers should have a revenue requirement that does not cross subsidize Non-Preference Power customers and is based on the cost to serve. The unfairness of the current rate setting process is obvious in that it allocates a disproportionate share of the plant to the Preference Power Customers as shown in the table below.

Year	Demand Rate ($/kW)	Pref Pwr. Demand (MW)	Demand Revs. ($000)	Energy Rate ($/MWH)	Pref. Pwr. Energy (GWH)	Energy Revenues ($000)	Pref. Pwr. Total Rev ($000)	Total Revenue Req. ($000)	Share of Rev. (%0)
2011	3.85	21,455	82,600	4.92	9,180	45,165	127,765	230,570	55%
2012	3.97	21,490	85,314	4.92	9,225	45,387	130,701	238,648	55%
2013	4.12	21,523	88,676	4.92	9,215	45,335	134,011	247,270	54%
2014	4.32	21,557	93,128	4.92	9,232	45,421	138,549	255,576	54%

This does not require a change in the means by which the revenue requirement is determined, but rather how the revenue requirement is allocated between Preference Power customers and Non-Preference Power customers. There are two means by which this could be fixed. The first option is to include all demand output in the calculation of the demand charge and use all demand output in the calculation of the RSR. The second option would be to simply allocate the revenue requirement between the Preference Power customers and others (Non-Preference Power and "NYPA Use"). Specifically, as the Projects' main value is the low cost energy they produce, I recommend that the fair share be based on the energy output associated with the Preference Power customer's allotted share of the plant.[10] A third option would be to develop a credit based on costs and not on revenues, which is what is done with UCAP sales from the Projects and credited to the RSR.[11] One way to do this would be to calculate total cost of the project on either energy or capacity sales (MW or MWH and credit cost on that basis).

Q. DOES THIS AFFECT THE RSR?

A. Yes. Use of a different methodology for calculating the RSR balance also requires that the current RSR balance be recalculated beginning from the last time rates were set (2007). The impact is shown in the table below.

[10] The Preference Power customers use 45% of the plant's energy output.

[11] Crediting of revenues is a violation of the *Auer* Principles. If credits are to be applied, then revenue credits should be made for energy sales as well and eliminate the tariff based credit for energy sales that are currently made.

Item	Current Method	Option 1 –Use Full Demand Output for All Calculations	Option 2 – Allocate Plant on Energy Output
2011Total Revenue Requirement ($Millions)	$230,570	$230,570	$230,570
2011R&D Revenue Requirement ($Millions)	$126,861	$114,555	$103,757
R&D Share of Revenue Requirement	55%	50%	45%
Energy Rate ($/MWH)	$4.92	$4.92	$4.92
Demand Rate ($/kW/mo.)	$3.85	$3.23	$3.16
RSR Balance $Millions	($51,267)	$922	$32,829

Q, DO YOU HAVE ANY OTHER COMMENTS ON THE RATE SETTING PROCESS?

A. Yes. There is a need for an ability to examine and comment on the inputs used in the RSR calculation. Currently, the RSR is just updated and during rate cases NYPA states what its intentions are for crediting or surcharging of any existing balances. There is adiscovery response where NYPA states that charges for cancelled capacity projects that have nothing to do with the Hydroelectric Projects are expenses to A&G. While the discovery response (attached as Exhibit__(FWR-7)), states that none of these charges are included in the costs used to develop the proposed rates in this case, the fact remains that those costs could be charged to the Preference Power customers in the RSR. This is a serious concern because there are some very large charges to A&G. For example a

1 review of the trial balance for 2010 shows that there were over $36 million in
2 consulting fees, almost $2 million in grants and $2.5 million in cancelled DSM
3 projects (a selected potion of Trial Balance for 2010 attached as Exhibit__(FWR-
4 8). The Preference Power customers have a concern that these charges require
5 review before they are or could be charged to the RSR, and the current process
6 does not do that. Indeed, as the RSR is a reconciliation account only charged to
7 Preference Power customers, the RSR calculation is every bit as important as the
8 hydroelectric production rate itself. This needs to be rectified by either an annual
9 review process, increased reporting requirements, review of RSR balances in the
10 hydroelectric production cost rate setting process or some combination of the
11 above.
12

13 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

14 A. Yes, it does.

TAB 5-H

Part 2

Exhibits of Frank W. Radigan

EXHIBIT_FWR-1

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY** -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York -- Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Jurisdictional Cost of Service – Mississippi Power Company – On behalf of the Staff of the Mississippi Public Utilities Staff prepared a report on the reasonableness of the Company's jurisdictional cost of service study. 2010

Rate Case Cost of Service Study – Heritage Hills Water Works – For small water company, performing cost of service study for the preparation of a full cost of service study before the New York Public Service Commission. 2009

Rate Case Cost of Service Study – Stowe Electric Department, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Study – Hudson River Black River Regulating District -- For regulating body performed detailed cost of service allocation in order to allocate costs among beneficiaries of water regulation.

Rate Case Cost of Service Study – Village of Greene, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Bath, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Richmondville, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – **Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002**

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with

environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 09-E-0715 – New York State Electric and Gas Corporation -- On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed construction program, revenue allocation, rate design and decoupling mechanism. 2010

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of a Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast 2010

Docket No. 09-01299 – Utilities. Inc. of Central Nevada - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the appropriate level of rate case expense, and allocation of corporate salaries. 2010

Docket No. 09-12-11 – Connecticut Water Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed Water Conservation Adjustment Mechanism. 2010

Case 9217 – Potomac Electric Power Company – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed jurisdictional cost of service study, revenue allocation and rate design. 2010

Docket No. 09-12-05 – Connecticut Light & Power Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed depreciation rates, revenue allocation and rate design. 2010

Case 09-S-0794 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 09-G-0795 – Consolidated Edison – Gas Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 10-S-0001 – Project Orange Associates, LLC -- On behalf of Project Orange Associates testified to the reasonableness of whether the steam customers of Syracuse University could benefit if a steam transportation tariff were adopted by the New York Public Service Commission. 2009

Docket No. E-7, Sub 900 – Duke Energy Carolinas, LLC – On behalf of the Sierra Club, Southern Alliance for Clean Energy testified on the reasonableness of the Company's request to recover construction work in progress in rate base and to comment on whether the costs incurred by the Company for the supercritical coal plant Cliffside Unit 6 are reasonable and prudent. 2009

D.P.U. 8-64 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the accuracy of the Company's accounting data as it related to affiliate transaction with the parent Company. 2009

Formal Case No. 1027 – Washington Gas Light Company – On behalf of the Office of People's Counsel fo the District of Columbia testified to the reasonableness of the Company's use of mechanical couplings and problems related thereto. 2009

Docket No. G-04204A-08-0571 -- UNS Gas, INC. -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, and proposed rate design. 2009

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2009

Docket No. 09-0407 – Commonwealth Edison – On behalf of the People of the State of Illinois testified to the reasonableness of Company's Chicago Area smart Grid Initiative. 2009

Docket No. E-01345A-08-0172 – Arizona Public Service – On behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Case 9182 – Maryland Water Service, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed bulk purchased water rate increase. 2009

Case 9182 – Artesian Water Maryland, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed advance fees to connect new water customers in the Whitaker Woods subdivision. 2009

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes. and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in deprecation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 – Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company - On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design and its for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger. customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power

purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association, Northeast Public Power Association and New York State ISO.

EXHIBIT_FWR-2

New York Power Authority
Operating Budget for Total NYPA
For the Year ended December 31, 2011
($ in 000's)

	Niagara	St. Lawrence	B-G	SENY	SCPP	Market Supply Power	Flynn	Transmission	Eliminations & Adjustments	Total
Operating Revenues:										
Customer Revenues	$225,349	$110,256	$10,251	$1,450,290	$8,668	$151,617	$90,250	$59,042	($37,026)	$2,068,696
NYISO	$105,890	$42,947	$51,898	$281,734	$71,595	$7,801	$0	$114,897	($55,847)	$620,915
Total Operating Revenues	**$331,239**	**$153,203**	**$62,149**	**$1,732,024**	**$80,263**	**$159,418**	**$90,250**	**$173,939**	**($92,873)**	**$2,689,610**
Operating Expenses:										
Purchased Power	$10,271	$28,649	$26,627	$635,757	$1,626	$117,195	$0	$0	($98,634)	$721,492
Ancillary Services	$25,966	$14,802	$113	$56,260	$106	$10,926	$0	$0	$0	$108,173
Transmission Congestion	$24,813	$5,323	$0	$50,215	$0	$13,089	$0	$0	$0	$93,440
Fuel Consumed - Oil & Gas	$0	$0	$0	$203,062	$30,625	$0	$61,884	$0	$0	$295,572
Wheeling	$6,979	$979	$0	$525,963	$0	$9,089	$360	$0	$0	$543,369
Site O&M and Administrative Expenses	$81,586	$34,513	$30,535	$70,919	$14,056	$2,070	$19,037	$74,420	$0	$327,136
Other Expenses	$25,339	$9,466	$3,023	$13,262	$360	$44,845	$1,746	$7,960	$29,450	$135,450
Depreciation & Amortization	$31,905	$17,655	$8,891	$66,885	$19,060	$803	$5,256	$44,463	$0	$194,917
Allocation to Capital	($3,128)	($1,377)	($1,316)	($1,673)	($157)	($98)	($332)	($2,803)	$0	($10,883)
Total Operating Expenses	**$203,731**	**$110,010**	**$67,873**	**$1,620,650**	**$65,677**	**$197,919**	**$87,951**	**$124,039**	**($69,184)**	**$2,408,666**
Net Operating Revenues	**$127,508**	**$43,193**	**($5,724)**	**$111,374**	**$14,586**	**($38,502)**	**$2,299**	**$49,899**	**($23,689)**	**$280,945**
Non-Operating:										
Investment Income and Realized Gains	$0	$0	$0	$0	$0	$0	$0	$0	$39,427	$39,427
Entergy Time Payments	$0	$0	$0	$0	$0	$0	$0	$0	$87,954	$87,954
Mark to Market Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	($7,000)	($7,000)
Other Income	$0	$0	$0	$0	$0	$0	$480	$0	$0	$480
Total Non-Operating Income	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$480**	**$0**	**$120,381**	**$120,861**
Contributions to State	$0	$0	$0	$0	$0	$0	$0	$0	$65,000	$65,000
Interest and Other Expenses	$34,090	$18,592	($75)	$71,643	$10	$5	$20	$15,865	$17,311	$157,460
Total Non- Operating Expenses	$34,090	$18,592	($75)	$71,643	$10	$5	$20	$15,865	$82,311	$222,460
Net Income (loss)	**$93,418**	**$24,601**	**($5,649)**	**$39,731**	**$14,576**	**($38,506)**	**$2,760**	**$34,034**	**$14,380**	**$179,345**

EXHIBIT_FWR-3

NIAGARA POWER PROJECT

RELICENSING

NIAGARA POWER PROJECT POWER ALLOCATIONS, RATES, AND OPPORTUNITIES

Volume 1: Public

Niagara Power Project FERC No. 2216

Prepared for:

New York Power Authority

Prepared by:

The Brattle Group

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New York Power Authority

August 2005

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ABBREVIATIONS

Agencies

ENCRPB	Erie and Niagara Counties Regional Planning Board
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
NYISO	New York Independent System Operator
NYPA	New York Power Authority
PASNY	Power Authority of the State of New York

Units of Measure

cfs	cubic feet per second
fps	feet per second
G	giga (prefix for one billion)
GW	gigawatt
GWh	gigawatt-hour
k	kilo (prefix for one thousand)
kV	kilovolt

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kVA	kilovolt-ampere
kW	kilowatt
kWh	kilowatt-hour
M	mega (prefix for one million)
mgd	million gallons per day
MV	megavolt
MVA	megavolt-ampere
MW	megawatt
V	volt
W	watt
Wh	watt-hour

Regulatory and Legal

CFR	Code of Federal Regulations
FPA	Federal Power Act
PAA	Power Authority Act
PAL	Power Authority Law

Miscellaneous

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DEIS	Draft Environmental Impact Statement
EA	Environmental Assessment
EIS	Environmental Impact Statement
FSCR	First Stage Consultation Report
IOU	Investor-Owned Utility
MEUA	Municipal Electric Utilities Association of New York
NMPC	Niagara Mohawk Power Corporation
NYSEG	New York State Electric & Gas
RG&E	Rochester Gas and Electric

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EXECUTIVE SUMMARY

This report describes the legal and institutional framework that governs allocations of Niagara Project power, explains ratemaking methodologies and outcomes, and discusses current and future opportunities for utilizing project power. The Niagara Redevelopment Act authorized the New York Power Authority (NYPA) to build a hydroelectric project that would use the United States share of water made available for power generation under the 1950 Niagara River Water Diversion Treaty. The allocation of this power is governed primarily by Federal and State law, as administratively and judicially interpreted, with discretion given to NYPA regarding allocation and contracts once legal requirements are met.

Niagara Project power is divided among four basic types of allocations – Preference Power, Replacement Power, Expansion Power and contract sales to three upstate investor-owned utilities for resale to residential customers. As currently allocated, 50% of Firm Power (940 MW) is allocated to Preference customers, which are municipal electric and rural cooperative utilities (40% in New York and 10% out-of state), 445 MW to Replacement Power, 250 MW to Expansion Power, and the remaining power to investor-owned utilities. The allocation has remained fairly constant throughout the term of the project, with the primary exception being the Preference Power allocation rising to serve the growing needs of eligible municipal and rural cooperative systems, while the allocation to investor-owned utilities fell.

The customer base that ultimately uses the power provided by the Niagara Project varies considerably – both geographically and in uses of the power – depending upon the class of power and the entity purchasing the power from NYPA. Preference Power provides the most geographically distributed benefit of Niagara Project power, but also is quite concentrated in terms of the relatively small proportion of customers and loads that it serves within those broad geographic regions. The share of residential retail sales to total retail sales for the New York Preference customers averages 40%, and Preference Power serves about 2% of New York State residential customers. Replacement Power and Expansion Power serves only industrial customers that are heavily concentrated in Niagara County (Replacement Power) or in Niagara, Erie, and Chautauqua counties (Expansion Power). Power deliveries to three upstate investor-

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owned utilities are dedicated to residential customers, which together serve 2.4 million customers in 54 of New York's 62 counties.

The rates on Niagara power remained constant from 1961 to 1981, when court decisions mandated a change to cost based rate making. Preference Power and energy sold to upstate investor owned utilities for residential customers are sold at cost, while Replacement and Expansion Power are sold at below market rates. The cost-based rates are determined using a unique version of the "Trended Original Cost" method of rate regulation in which the rate of return on capital is not included.

Due to statutory, judicial and contractual restraints, opportunities for new utilizations of project power are limited. The Niagara project is fully allocated, except for quantities of Replacement and Expansion Power that are underutilized, voluntarily relinquished by or withdrawn from recipients. There are established procedures for eligible business applicants to apply for and receive an allocation from the blocks of unallocated Replacement and Expansion Power. The New York State Legislature on June 23, 2005 passed legislation that provides a state statutory basis for the continued sale of 445MW of Replacement Power to businesses within 30 miles of the Project. (S5866/A8960). The legislation, which will be sent to the Governor for his approval, also provides for the use of a portion of unallocated Replacement Power for the purpose of Energy Cost Savings Benefits to be granted by the New York State Economic Development Allocation Board, consistent with current contractual obligations.

The contracts with the upstate investor-owned utilities for resale to residential customers expire at the end of the current license (August 31, 2007). Except for the general priority for residential use under state law, there are no statutory restrictions that prohibit this portion of Niagara Project Power from being reallocated to other recipients. However, there are no requirements on the power authority to alter the existing arrangements. Finally, the Niagara Project Upgrade will provide an estimated 35 MW of additional firm power, of which one-half will be made available to preference customers as required by the NRA. The other half will be used as a source for a portion of the power to be allocated for the benefit of the Host Communities.

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1.0 INTRODUCTION

This report addresses the historic, current, and potential future allocation and pricing of power from the Niagara Power Project. The report describes the legal and institutional framework that governs allocations of Niagara Project power, explains ratemaking methodologies and outcomes, and discusses current and future opportunities for utilizing project power.

The power allocation and ratemaking issues addressed by The Brattle Group in this report span the era from before the project's inception to the post-relicensing phase. The report reviews the historic statutory framework and the relevant case law and contracts to explain how that legal and contractual framework has impacted and will continue to impact power allocation and rates. The report presents several opportunities for power allocations that are possible in the context of the existing legal framework.[1]

1.1 Brief History of the Niagara Power Project

The Niagara River has been utilized for hydroelectric power generation since the first privately-owned facility was built in 1881. Transmission lines to Buffalo were built in 1896, and additional privately-owned generating stations were built during the early 20th Century, with the largest – the 365 MW Schoellkopf Power Plant – built at the turn of the Century by the Niagara Mohawk Power Company. Because the Niagara River serves as a border between the U.S. and Canada, the allocation of water rights is a matter of international treaty. Among other things, the Niagara River Water Diversion Treaty of 1950 provides a minimum daytime water flow over Niagara Falls during the tourist season and allocated the water rights for hydroelectric power production equally between the U.S. and Canada.

[1] While we believe that the legal framework described is accurate, it is important to recognize and appreciate that The Brattle Group is a firm of economic consultants and not lawyers and that nothing herein is intended to provide, nor should any stakeholder infer that the report provides, legal advice regarding such opportunities identified.

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While Congress was debating the proper way to develop the U.S. share of hydropower rights on the Niagara River, a rockslide effectively destroyed the Schoellkopf Power Plant on June 7, 1956, an event which threatened disruption in power supplies for industry in Western New York. In response, the U.S. Congress passed the Niagara Redevelopment Act (NRA) in 1957, directing the Federal Power Commission to issue a hydropower license to the Power Authority of the State of New York (PASNY) for a facility large enough to utilize the U.S. share of the Niagara River water resource. PASNY, now conducting business as the New York Power Authority (NYPA), was created in 1931 by the New York Power Authority Act (PAA) for the purpose of developing hydropower in the state, and NYPA was, in fact, building the Saint Lawrence-Franklin D. Roosevelt project in the St. Lawrence River when the NRA was signed into law.[2] The 50-year project license for the Niagara Power Project, incorporating the power allocation and other requirements of the NRA, became effective September 1, 1957, and expires on August 31, 2007. Construction commenced in 1958, and the plant began operation in February 1961.

The legal basis for power allocations and rates – primarily the Niagara Redevelopment Act and the Power Authority Act – provided an exceptionally stable platform for power allocations and rates for the first two decades of the plant's operation. However, the profound changes in energy and power markets that occurred during the 1970s, such as higher fossil energy costs, cost overruns in nuclear construction programs, and the impact of stricter environmental regulations, combined with rising demands from eligible Preference customers, spawned a significant series of legal actions in the 1980s that challenged the established allocations and ratemaking procedures. The resolution of these protracted legal struggles altered allocations and rate-setting and will continue to influence power delivery and prices. As power markets in New York and the eastern U.S. continued to evolve during the 1990s, the establishment of the New York Independent System Operator (NYISO). the deregulation of the wholesale generation market and the introduction of retail customer choice further altered the relationship between the physical provision of power and the financial terms under which customers received electric supply.

[2] This report will use NYPA to designate the Power Authority, except for historical references and quotations (such as statutory references and legal decisions) that explicitly refer to PASNY.

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1.2 Description of the Niagara Power Project

1.2.1 Physical Description

The primary project components are the twin intakes located 2.6 miles above Niagara Falls, the conduits that carry water to the 1.8 billion gallon forebay on the east bank of the Niagara River, the Robert Moses Niagara Power Plant (RMNPP) – the main generating plant – housing 13 Francis-type turbines, the Lewiston Pump Generating Plant (LPGP), housing 12 Francis-type reversible pump-turbines, the 22-billion-gallon Lewiston Reservoir, and the switchyard that conveys the electrical power to the state electrical grid.

The Niagara Power Project integrates two different types of hydroelectric facilities – the RMNPP run-of-river diversion type plant and the LPGP pumped-storage peaking facility. Hydroelectric plant capacity measures vary substantially under assumed water flow conditions; the current Net Dependable Capacity under adverse flow conditions has been established at 2,400 MW. As discussed later, measures of physical capability also can differ somewhat from the amount of capacity allocated under regulation as well as contractual obligations for Project Power. The current capacity of the Niagara Power Project for the purposes of establishing allocations under federal law was set by the FERC at 2,280 MW (1,880 MW of firm power and 400 MW of firm peaking power).

1.2.2 Economic and Operational Description

The project is designed specifically to generate power when most valuable, within the constraints of legally and physically available water flows. The project operates on dual weekly and daily cycles designed to maximize the amount of energy produced during the periods of peak demand while minimizing the waste of water available for power production. The dual cycles achieve these goals by storing water that would otherwise be lost for generation in the Lewiston Reservoir when dispatch by the NYISO is less than the generating capacity of the project and by utilizing the stored water when flow is insufficient to serve the generation called for by NYISO.

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The daily cycle compensates for the variation between demand in the daytime and the nighttime and includes four distinct periods: the daytime, the nighttime change-over, the nighttime, and the morning change-over. During the daytime period – particularly in tourist season – demand is usually greater than the energy generated from the allowable flow through the Robert Moses Plant. Thus, in order to generate the necessary contracted energy, water is released from the Lewiston Reservoir, flowing through both the Lewiston and Robert Moses plants. When load is reduced sufficiently to allow the Robert Moses Plant to meet load without the additional flow from the Lewiston Reservoir, generation at the Lewiston Plant ceases and pumping begins. This is the nighttime change-over. During tourist season the nighttime change-over coincides with the Niagara River Water Diversion Treaty reduction in mandated flow over Niagara Falls from 100,000 cfs to 50,000 cfs at 10 p.m. (between April 1 and September 15) or 8:00 pm (between September 16 and October 31).

Following the nighttime change-over is the nighttime period which is characterized by the pumping of excess flow into the Lewiston Reservoir for use in the daytime. The pumps are powered by surplus energy from the Robert Moses Plant except under low flow conditions in which case the energy for the pumps are supplied by open market purchases. The nighttime period is followed by the morning change-over in which pumping at the Lewiston Plant is stopped and generation recommences. During tourist season, the morning change-over occurs at 8 a.m. when the Niagara Falls flow returns to 100,000 cfs. Otherwise, the morning change-over occurs when the load exceeds the generating capacity without additional releases from the Lewiston Reservoir – typically occurring between 7 and 8 a.m.

In addition to the daily cycle, the weekly cycle further compensates for the variation between demand on weekdays and weekends. Weekday power demands are sufficiently large so that nighttime pumping is inadequate to fully replace the water released during the weekday time period. However, on weekends load is significantly lower than weekdays and can be met from the Robert Moses Plant alone, allowing additional pumping into the Lewiston Reservoir during the daytime period on weekends. Thus, the gradual drawdown of the Lewiston Reservoir during the week is compensated by the complete replenishment on the weekends. The reservoir is completely filled at the Monday morning change-over, is gradually drawn down to a minimum level at the Friday nighttime change-over, and is refilled over the weekend.

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2.0 LEGAL AUTHORITIES GOVERNING NIAGARA POWER PRODUCTION AND ALLOCATION

2.1 1950 Niagara River Water Diversion Treaty

The 1950 Niagara River Water Diversion Treaty between the U.S. and Canada dictates the amount of water available for hydroelectric development for each country. It supercedes the allocations set forth in the 1909 Boundary Waters Treaty (between the U.S. and Great Britain).

The preamble to the treaty cited the need for greater utilization of water for hydroelectric purposes on both sides of the border, but the parties recognized "their primary obligation to preserve and enhance the scenic beauty of the Niagara Falls and River and, consistent with that obligation, their common interest in providing for the most beneficial use of the waters of that River." By its terms, therefore, the treaty balances the need to expand hydroelectric utilization with the obligation to preserve a substantial natural resource.

Article III of the treaty defines the water available for hydroelectric power. Article IV of the treaty reserves "sufficient amounts of water in the Niagara River for scenic purposes" by establishing minimum flows over Niagara Falls at 100,000 cubic feet per second (cfs) between 8:00 AM and 10:00 PM (EST) each day during the period April 1 through September 15; 100,000 cfs between 8:00 AM and 8:00 PM each day during the period September 15 through October 31; and 50,000 cfs during any other time.[3] Article V simply states "all water specified in Article III of this treaty in excess of water reserved for scenic purposes in Article IV may be diverted for power purposes." Article VI divides the water available for power purposes equally between the U.S. and Canada.

[3] The 50,000 cfs rate can be increased when additional water is required for flushing ice above the Falls or through the rapids below the Falls.

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The Treaty was signed on February 27, 1950, and ratified by the Senate on August 9, 1950. However, in ratifying the Treaty, the Senate expressed the following reservation:

> The United States on its part expressly reserves the right to provide by Act of Congress for the redevelopment, for the public use and benefit, of the United States' share of the waters of the Niagara River made available by the provisions of the Treaty, and no project for redevelopment of the United States' share of such waters shall be undertaken until it be specifically authorized by Act of Congress.

President Truman signed the Treaty, incorporating the above reservation, on October 30, 1950. The Senate reservation meant that the Power Authority of the State of New York could not pursue hydroelectric development on the Niagara River without first obtaining specific authorization by the U.S. Congress.[4] This situation sparked the Congressional debates of the 1950s, which were effectively interrupted by the destruction of the Schoellkopf Plant in June 1956.

2.2 The Niagara Redevelopment Act

The demise of the Schoellkopf Plant created an immediate need to resolve the issues surrounding the development of the Niagara River for hydroelectric power.[5] This need was met with the Niagara Redevelopment Act (NRA; Public Law 85-159; 16 USC § 836), enacted on August 21, 1957. Section 836 (a) provides:

> The Federal Power Commission is expressly authorized and directed to issue a license to the Power Authority of the State of New York for the construction and operation of a power project with capacity to utilize all of the United States share of the water of the Niagara River permitted to be used by international agreement.

[4] In Exhibit E of the initial license application, the General Counsel of the Power Authority opined that the Senate reservation had no force of law, and did not impede the Power Authority from applying for a license under Section 4(e) of the Federal Power Act prior to explicit Congressional authorization.

[5] The Power Authority of the State of New York submitted an initial license application for the Niagara Project to the Federal Power Commission on August 20, 1956, less than three months after the Schoellkopf Plant disaster.

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This gave the Power Authority the right to build a hydroelectric project that would use the entire water resource made available under the 1950 Treaty. In addition to the requirements for hydroelectric facility license normally required under Section 4 (e) of the Federal Power Act (FPA), the NRA established certain requirements concerning the disposition of project power. These rules reflected Congressional concerns regarding how the benefits of publicly-owned hydropower might be realized and distributed among various classes of customers in New York and other states.

Three sections of the NRA govern the licensee's obligations to allocate power to specific classes of customers. Section 836 (b) (1) creates a preference for public power entities for 50 percent of the project output in order to serve "domestic and rural consumers" at "the lowest rates reasonably possible." Section 836(b) (2) ensures that a "reasonable portion" of the preference power defined above is made available to consumers in neighboring States "within reasonable economic transmission distance;" this provision, however, "shall not be construed to require more than 20 per centum of the project power subject to preference provisions to be made available for use in such States." Section 836(b) (3) allocates 445 MW of the project power to Niagara Mohawk Power Corporation for resale to customers formerly served by the Schoellkopf Plant. The entire NRA language was incorporated into the FPC license for the Niagara Power Project (no. 2216) in Articles 20 – 26.[6] Although part of the existing license, the provisions of the NRA control, and will continue to control, the terms under which the re-licensed project will operate. Because these statutory provisions have figured prominently in subsequent legal actions, they are reproduced in their entirely below, with emphasis added on phrases that have been subject to specific disputes.

2.2.1 NRA Preference Power

Section 836 (b) (1) states:

> In order to assure that *at least 50 per centum* of the project power shall be available for sale and distribution primarily for the benefit of the

[6] The 50-year project license was approved on January 30, 1958, with an effective date of September 1, 1957.

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> *people as consumers*, particularly *domestic and rural consumers*, to whom such power shall be made available at the *lowest rates reasonably possible* and in such manner as to *encourage the widest possible use*, the licensee in disposing of 50 per centum of the project power shall give *preference and priority to public bodies and nonprofit cooperatives within economic transmission distance*. In any case in which project power subject to the preference provisions of this paragraph is sold to utility companies organized and administered for profit, the licensee shall make *flexible arrangements and contracts providing for the withdrawal* upon reasonable notice and fair terms of enough power to meet the *reasonably foreseeable needs* of the preference customers.

Several observations are warranted regarding this section. First, the emphasis on "domestic and rural" consumers was common language from earlier statutes and now refers generally to the class of residential customers.[7] However, the notion that 50 percent of the Project Power be available for sale to residential customers has been construed as a Congressional expectation, not a mandate.[8] Second, the section grants preference and priority to "public bodies and nonprofit cooperatives" within "economic transmission distance" but does not define those terms. Third, to the extent that project power that qualifies for such preference status is instead marketed through traditional investor owned utilities (IOUs), there must be sufficient flexibility in those marketing arrangements to reallocate those sales to public bodies and nonprofit cooperatives if and when the need arises to satisfy the preference obligation.

2.2.2 NRA Preference Power Out of State

Section 836 (b) (2) states:

> The licensee shall make *a reasonable portion of the project power subject to the preference provisions* of paragraph (1) of this subsection available for use within *reasonable economic transmission distance in neighboring States*, but this paragraph shall not be construed to require

[7] The "rural" aspect of this language has been diminished over time, as it originally signified rural customers who did not have access to electric power. However, it was still an important concept when the NRA was enacted.

[8] In particular, there is no restriction on the type of customer to which public bodies and nonprofit cooperatives can resell Niagara power. See Power Authority of the State of New York v. FERC, 743 F.2d 93,104 (2d Cir. 1984).

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> more than 20 per centum of the project power subject to such preference provisions to be made available for use in such States. The licensee shall cooperate with the appropriate agencies in such States to insure compliance with this requirement. In the event of disagreement between the licensee and the power-marketing agencies of any of such States, the Federal Power Commission [now Federal Energy Regulatory Commission] may, after public hearings, determine and fix the applicable portion of power to be made available and the terms applicable thereto: Provided, That if any such State shall have designated a bargaining agency for the procurement of such power on behalf of such State, the licensee shall deal only with such agency in that State. The arrangements made by the licensee for the sale of power to or in such State shall include observance of the preferences in paragraph (1) of this subsection.

This section ensures that a limited portion of the benefits of this Congressionally-mandated project utilizing the U.S. share of an international resource is realized outside the State of New York. The "reasonable portion" in this section applies to the 50% of project power made available to preference customers established in Section 836 (b) (1), but no more than 20% of the 50% (or 10%) of total project power is required to be allocated to out-of-state recipients, who also must conform to the preference criteria outlined in the previous section.

2.2.3 NRA Replacement Power

Section 836 (b) (3) states:

> The licensee shall contract, with the approval of the Governor of the State of New York, pursuant to the procedure established by New York law, to sell to the licensee of Federal Energy Regulatory Commission project 16 for a period ending *not later than the final maturity date of the bonds initially issued to finance the project* works herein specifically authorized, *four hundred and forty-five thousand kilowatts of the remaining project power*, which is equivalent to the amount produced by project 16 prior to June 7, 1956, *for resale generally to the industries which purchase power produced by project 16* prior to such date, or their successors, in order as nearly as possible to restore low power costs to

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> such industries and for the same general purposes for which power from project 16 was utilized...[9]

This establishes the basis for what has become known as "Replacement Power" *i.e.*, the terms and conditions under which the former recipients of power (and their successors) from the Schoellkopf and Adams plant receive power from the Niagara Power Project. The allocation level here is quite specific (445 MW) to be resold by the former licensee of Project 16 (Niagara Mohawk Power Corporation) "generally to the industries" that purchased power from the Schoellkopf and Adams Plants, at rates "in order as nearly as possible to restore low power costs to such industries." Because the final maturity date of the bonds initially issued to finance the project is December 31, 2005, both the NRA and the conforming license provide a terminal (or "sunset") date for this requirement.[10] The New York State Legislature on June 23, 2005 passed legislation that provides a state statutory basis for the continued sale of 445MW of Replacement Power to businesses within 30 miles of the Project. (S5866/A8960). The legislation, which will be sent to the Governor for his approval, also provides for the use of a portion of unallocated Replacement Power for the purpose of Energy Cost Savings Benefits to be granted by the New York State Economic Development Allocation Board, consistent with current contractual obligations.

2.2.4 Modifications to the Original NPP License

Several amendments and revisions to the project license have occurred. The most important of these was the proposed upgrade and expansion of both the RMNPP and the LPGP submitted to the FERC on November 29, 1984. The upgrade of the RMNPP and the upgrade/expansion of the LPGP were approved in an Order Amending License issued on March 31, 1989. However, the Power Authority later

[9] Additional clauses related to the surrender of license ("project 16") for the Schoellkopf (365 MW) and Adams (80 MW) plant, which in fact occurred, are not included here. Although the Adams Plant was not damaged in the rockslide, it was obsolete by 1956, and thus abandoned in favor of the NPP, bringing the total Replacement Power allocation to 445 MW. A legislative history of the replacement power provision is reported in Occidental Chem. Corp. v. Power Auth. of N.Y., 786 F. Supp. 316 (W.D.N.Y. 1992).

[10] Members of the New York State Legislature have introduced bills to ensure that such allocations survive as a matter of state law, as discussed later.

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decided to abandon the plans to expand and upgrade the LPGP, and FERC approved the proposed license amendment on April 5, 1995, incorporating only the RMNPP upgrades.

2.3 New York State Law: Power Authority Act (PAA)

2.3.1 Introduction and Purpose of PAA

On April 7, 1931, Governor Franklin D. Roosevelt signed the Power Authority Act (PAA) into law, creating the Power Authority of the State of New York to develop hydropower on the St. Lawrence river. The original elements of the PAA and subsequent amendments, including the addition of the Niagara Project authorization in 1951, are reflected in the New York Public Authorities Law (PAL). PAL § 1001 declares: "those parts of the Niagara and St. Lawrence rivers within the boundaries of the state of New York are hereby declared to be natural resources of the state for the use and development of commerce and navigation in the interest of the people of this state and the United States." In order to implement the policies outlined in Section 1001, PAL § 1002 (1) creates the Power Authority of the State of New York as "a corporate municipal instrumentality of the state" and as "a body corporate and politic, a political subdivision of the state, exercising governmental and public powers, perpetual in duration, capable of suing and being sued..."

2.3.2 Preference Power under PAL § 1005

PAL § 1005 outlines the powers and duties of the authority, creates the legal framework for constructing facilities, producing and delivering electricity from Power Authority projects and establishes certain principles for charging rates. PAL § 1005 (5) authorizes the Power Authority to develop, maintain, manage and operate hydroelectric projects (meaning both the St. Lawrence-FDR and Niagara Projects) and that:

> ...in the development of hydro-electric power there from such projects shall be considered primarily as for the *benefit of the people of the state as a whole and particularly the domestic and rural consumers* to whom the power can economically made available, and accordingly that *sale to and use by industry shall be a secondary purpose*, to be utilized

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> principally to secure a sufficiently high load factor and revenue returns to permit *domestic and rural use at the lowest possible rates* and in such manner as to encourage increased domestic and rural use of electricity. In furtherance of this policy and to secure a wider distribution of such power and use of the greatest value to the general public of the state, the authority shall in addition to other methods which it may find advantageous make provision so *that municipalities and other political sub-divisions of the state now or hereafter authorized by law to engage in the distribution of electric power may secure a reasonable share* of the power generated by such projects, and shall sell the same or cause the same to be sold to such municipalities and political subdivisions *at prices representing cost of generation, plus capital and operating charges, plus a fair cost of transmission, all as determined by the trustees, and subject to the conditions which shall assure the resale of such power to domestic and rural consumers at the lowest possible price*, provided, however, that in disposing of hydro-electric power pursuant to and in furtherance of the aforementioned policy and purposes, appropriate provision may also be made to *allocate a reasonable share of project power to agencies created or designated by other states and authorized to resell the power to users* under the same terms and conditions as power is disposed of in New York state.

PAL § 1005 (5) contains no percentage requirement for the allocation of St. Lawrence and Niagara Project hydropower to either residential consumers or municipal and rural cooperative systems. There is a general direction that power is intended primarily for direct consumer use and that "sale to and use by industry shall be a secondary purpose, to be utilized principally to secure a sufficiently high load factor and revenue returns to permit domestic and rural use at the lowest possible rates and in such manner as to encourage increased domestic and rural use of electricity." Moreover, that same provision of law allows for the provision of a "reasonable share" of the power from such projects for "municipalities and other political sub-divisions of the state now or hereafter authorized by law to engage in the distribution of electric power." As discussed later, this definition of preference customers under PAL § 1005 (5) is somewhat broader than the definition used in the NRA.

2.3.3 Power Rates under PAL § 1005

PAL § 1005 (5) provides additional guidance on Preference Power rates by defining prices as reflective of costs and giving the Trustees authority to calculate the costs. Sales are made "at prices representing cost of generation, plus capital and operating charges, plus a fair cost of transmission, all as

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determined by the trustees, and subject to the conditions which shall assure the resale of such power to domestic and rural consumers at the lowest possible price." Notwithstanding the "lowest possible price" for domestic and rural customers, contracts for the sale, transmission and distribution of power from the NYPA projects shall provide for "(a) payment of all operating and maintenance expenses of the project [and] (b) Interest on and amortization and reserve charges sufficient within fifty years of the date of issuance to retire the bonds of the power authority issued for the project."

In addition, PAL § 1005 (5) gives the Power Authority the right to stipulate the conditions of resale of the power in its contracts without review by the New York Public Service Commission:

> g. That the rates, services and practices of the purchasing, transmitting or distributing public agencies shall be governed by the provisions and principles established in the contract, and not by the regulations of the public service commission or by general principles of public service law regulating rates, services and practices and that in the event that any public agencies or companies which purchase power from the authority shall sell any such power for resale, such sale for resale shall be made at rates no higher than those at which the power was purchased from the authority.
>
> h. The rate structures agreed upon in such contract may provide different rates for different localities, classes of consumers, and amounts of current consumed, and for changes in the rates resulting from variation in operating costs and fixed charges.

These statutory provisions give NYPA substantial authority to set rates, negotiate contracts, and otherwise determine the terms and conditions under which project power is resold to ultimate customers.

2.3.4 Expansion Power under PAL § 1005

In addition to the 445 MW of Replacement Power defined by the NRA, PAL § 1005 (13) allocates 250 MW of Niagara project power to businesses located generally within 30 miles of the Niagara Project switchyard. This "Expansion Power" is designed to retain and expand business in the Niagara Frontier region of western New York. The Expansion Power provisions of PAL § 1005 (5) were

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added in 1987, preserving allocations to customers in Chautauqua County that lie outside of the 30 mile limit.[11] The current statutory definition and eligibility criteria are found at PAL § 1005 (13) [as amended]:

> Notwithstanding any other provision of law to the contrary but subject to the terms and conditions of federal energy regulatory commission licenses, to allocate or reallocate directly or by sale for resale, two hundred fifty megawatts of firm hydroelectric power as "expansion power" to businesses within the state located within thirty miles of the Niagara project provided that the amount of power allocated to businesses in Chautauqua county on January first, nineteen hundred eighty-seven shall continue to be allocated in such county. Provided, however, the authority shall negotiate contracts on reasonable terms and conditions to renew or extend every permanent contract allocation of expansion power in effect on the effective date of this subdivision and provided further, to the extent consistent with such contracts, the authority shall negotiate contracts on reasonable terms and conditions to extend or renew all other allocations or allotments of such power in effect on such date. Contracts entered into pursuant to this subdivision shall be long-term and shall contain reasonable provisions providing for the partial or complete withdrawal of the power in the event the recipient fails to maintain mutually agreed levels of employment and power utilization.

The 250 MW allocation of Expansion Power is concentrated in Niagara and Erie counties. Additional language of PAL § 1005 (13) regarding relinquishment and criteria for re-allocation are discussed later.

[11] Chapter 32, Laws of New York, "Allocation of Low-Cost Electric Power to Promote Economic Development" approved April 21, 1987.

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3.0 ALLOCATION AND DELIVERY OF NIAGARA POWER PROJECT POWER

3.1 Overview of Project Power Allocation and Energy Deliveries

Niagara Project power is divided among four main types of allocations – Preference Power, Replacement Power, Expansion Power and power sold under contracts with three upstate investor-owned utilities (IOUs) for resale to residential customers. Preference customers are 51 municipal electric and rural cooperative utilities in New York and, through bargaining agents, such entities in 7 neighboring states. Replacement and Expansion Power is sold to upstate IOUs for resale to business customers.

The firm allocations from the Niagara Power Project are expressed in capacity terms (megawatts), while energy delivered is measured in megawatthours.[12] Neither power generation nor demand is constant over time, and thus contracts must account for these fluctuations by establishing "load factors" to describe the percent of total potential energy actually delivered over a given time period. In actual operation, delivered power does not always perfectly match contractual load factors. For example, firm peaking power is sold at 12.5% load factor (corresponding roughly to the capacity factor of LPGP), but averages 11.9% load factor as delivered.

In addition to capacity and energy, the NPP produces and sells "ancillary services" into the NYISO, such as voltage support and various types of operating reserves. Prior to wholesale market restructuring, these services used to be bundled into various contracts, but now are sold separately ("unbundled") and are procured by load-serving entities from the NYISO. The Power Authority

[12] A megawatt (MW) is a measure of instantaneous electric power or demand. Generating capacity and allocations are measured in MW. A megawatt-hour (MWh) is a measure of energy equal to one MW continuously supplied or consumed over one hour. Electricity sales are often expressed in MWh or gigawatt-hours (GWh, equal to 1,000 MWh). A load factor is the percentage of MWh delivered over a period of time compared to the maximum amount of MWh under a capacity allocation. A capacity factor measures the percentage of MWh generated compared to the maximum MWh generated from a given plant based on its measured generating capacity. A megawatt is 1,000 kilowatts (kW) and a megawatt-hour is 1,000 kilowatt-hours (kWh).

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conducts ancillary service transactions with the NYISO in accordance with market rules as is the case with other wholesale generators.

3.1.1 Allocations, Contracts and Energy Delivery of Project Power by Type

Preference Power can be subdivided into in-state preference customers (municipal electric and rural cooperatives) and out-of-state preference customers. Firm contracts with three upstate New York investor-owned utilities (Niagara Mohawk, New York State Electric and Gas and Rochester Gas & Electric) account for the remaining firm power sales. Project Power allocations are either "Firm Power" generally at the customers' load factors or "Firm Peaking Power" at much lower load factors. Finally, at any point in time, due to underutilization, recapture or relinquishment of allocations, sales of Replacement and Expansion Power to business users are typically somewhat lower than the full allocation (445 and 250 MW, respectively). Table 3.1.1-1 summarizes the 2003 allocations, contracts and deliveries by each of these classifications. It also displays the various measurements of Niagara Project Power relevant to measuring power allocation and energy deliveries. In the first two columns, the table shows the Project Power as established by the Federal Energy Regulatory Commission at 1,880 MW of Firm Power and 400 MW of Firm Peaking Power for total Project Power allocations of 2,280 MW.[13] As allocated, 50% of Firm Power is allocated to Preference customers (40% in New York and 10% out-of state), 37% of Firm Power is allocated to Expansion and Replacement Power and the remaining 13% is allocated to upstate IOUs for resale to residential customers. Only investor-owned utilities and out-of-state Preference customers receive Firm Peaking allocations (360 MW and 40 MW, respectively).

The next set of columns show the overall power allocations available for contract, which total 2,336 MW. The difference between this total and the 2,280 MW total is comprised of an additional 56 MW of Firm Power contracts with the upstate IOUs. The next set of columns show actual contracts for power as of December 31, 2003, which total nearly 2,252 MW. These figures reflect the fact that not all Replacement and Expansion Power allocations are fully subscribed by eligible business customers at any

[13] These totals were established in Vt. Pub. Serv. Bd. v. Power Auth. of N.Y., 55 F.P.C. 1109 (May 15, 1975).

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given moment. At year-end 2003, 90% of Replacement Power was under contract and 87% of Expansion Power was under contract. All together, about 77 MW of Replacement and Expansion Power was available at the end of 2003 (a figure that has increased slightly to 115 MW by July 1, 2004 due to relinquishments exceeding reallocations in the first half of 2004).

Finally, the "Contract Sales" columns in the table show actual sales under each contract category and the associated (as-delivered) load factors for each type of Project Power. About 41% of the project's energy sales go to Replacement and Expansion Power while the remaining 59% goes to the Preference Power customers and upstate IOUs for residential customers. Because load factors for Preference customers are somewhat lower than Replacement and Expansion power customers in terms of energy delivery, Preference customers (in New York and out-of-state) received about 43% of total energy delivered from the Niagara project in 2003.

Generation from the Niagara Power Project does not always perfectly coincide with hourly contractual demands. When NPP generation exceeds contract demand NYPA sells excess generation into the ISO spot markets, and when generation is insufficient to cover firm contract demand NYPA purchases electricity from the ISO market. During calendar year 2003, sales from the Niagara Power Project were roughly 12.4 million megawatt hours, while generation was only 11.9 million megawatt hours. The contract sales in excess of generation were made up by 507,148 MWh of net system purchases.

The net purchase position reflects lower than average water flows in recent years. The resulting decline in energy production was greater than the reduced contract load from unallocated power. Until water flows return to normal, the present level of unallocated power will not provide a sufficient basis for net energy sales over contract demands from the Niagara Project.

When project output is reduced due to low-water flows NYPA provides recipients of reduced project power with the option of purchasing substitute power. Substitute power is *not* a NPP product, but rather ISO market power purchased through the ISO by NYPA that is resold at cost as a substitute for power normally delivered under firm hydroelectricity contracts received in years without low-flow

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restrictions. Alternately, in years when water flow conditions are favorable, NYPA makes available interruptible energy as required by contract to certain purchasers from the Project.

3.1.2 Allocation and Energy Delivery of Project Power by Region

Each class of power allocation has a different customer base and thus geographic distribution of power. As such, the benefits of Niagara power are concentrated in distinct geographic areas depending on the power class as shown in Table 3.1.2-1 and Table 3.1.2-2.

All Replacement and Expansion Power is delivered into Western New York. The most geographically concentrated power is Replacement Power: 76% of Replacement Power is allocated within the host communities of the City of Niagara Falls, the Town Niagara, and the Town of Lewiston and 99% is allocated within the Niagara Frontier region of Niagara and Erie Counties.[14] Expansion Power is similarly concentrated, although the benefits are diffused somewhat more broadly in Western New York. 34% of Expansion Power allocations are to businesses in the host communities, and 41% to firms in Niagara County. 50% of Expansion Power allocations are given to firms in Erie County.

In contrast to the allocations of both Replacement and Expansion Power, Preference Power is distributed throughout New York and to neighboring states. About 2% of Preference Power is allocated to two municipal agencies in the Niagara Frontier region – the Villages of Akron and Springville in Erie County. About 16% of Preference Power allocations (18% of energy sales) are in Western New York, with 77% of allocations and 79% of sales in New York State. Out-of-state municipals and cooperatives receive 20% of Firm Power Preference allocations and account for 21% of Preference Power energy deliveries. Contracts with three upstate investor-owned utilities also distribute Project Power to residential customers throughout Upstate New York, with 17% of power going to Niagara and Erie Counties and 22% to Western New York, with the remainder going to mid- and upstate counties in New York.

[14] There is a small allocation of Replacement Power for a firm located in western Orleans County, within the 30-mile zone from the Niagara switchyard.

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3.1.3 Allocation and Energy Delivery of Project Power to Domestic and Rural Customers

The customer base that ultimately uses the power provided by the Niagara Project varies considerably depending upon the class of power and the entity purchasing the power from NYPA for resale to ultimate customers. Expansion Power is resold exclusively to industrial and commercial customers as is nearly all Replacement Power.[15]

Sales of Project Power (exclusive of Replacement and Expansion Power) to the three upstate investor-owned utilities are designated for residential customer use. These energy deliveries account for an average of 12% of the three utilities' total residential customer kWh sales. Municipal electric and rural cooperative utilities who receive Preference Power serve residential, commercial and industrial customers in varying proportions, and are not obligated to flow the entire benefit of preference power to domestic and rural (i.e. residential) customers. Residential sales as a percentage of total retail sales for the New York Preference customers ranges from 12% to 98%, averaging 40% (based on 2002 figures). Using the actual residential customer sales proportions for each New York Preference customer to estimate geographic delivery of Preference Power to residential customers, we can estimate the geographic distribution of energy sales of Preference Power to domestic and rural customers. Combining this with an estimate of county-by-county residential sales from the three IOUs, we estimate the total Niagara Project Power energy sales that flow to domestic and rural customers. Table 3.1.3-1 shows this estimate, and provides a geographic breakdown of all energy sales to domestic and rural customers.

According to this estimate, 5,500 gigawatt-hours (GWh) of electric energy was supplied to domestic and rural customers, or 44% of overall Niagara sales of 12,446 GWh in 2003. It is worth noting that this percentage is wholly determined by factors outside of NYPA's range of control, i.e. the percentage of residential sales by the preference customers. In total, the amount of electricity supplied to residential customers by Preference Power recipients in New York and out-of-state (2,719 GWh) was

[15] The portion of Replacement Power energy sold to Niagara Mohawk (at 95% load factor) that is in excess of the energy requirements of the industrial customers is distributed by Niagara Mohawk to residential customers. For the years 1999, 2000, 2001, 2002 and 2003 this excess amounted to 623,957 MWh, 626,383 MWh , 427,694 MWh , 1,320,596 MWh and 648,451 MWh , respectively. .

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nearly identical to the amount supplied to the upstate IOUs under contracts (2,781 GWh). Niagara County received about 2% of the Project deliveries to residential customers, while Erie County received about 9%. Because both Preference customers and the three upstate IOUs serve loads across the state, Niagara Project Power for residential customers is not concentrated in Western New York, where only 19% of Project Power for residential customers is delivered. About 82% of Project Power that flows to residential customers flows to New York households and 18% flows to out-of-state residential customers.

3.2 Preference Power Allocation

Throughout the history of the Niagara Power Project – including during the Congressional debates of the mid 1950s – the role of Preference Power has engendered the most controversy and contention. The history of the NPP is intertwined with the history of public power, federal hydropower, and rural electrification in the U.S. during the 20th Century. Allocations of Preference Power have increased over time – in part through design – but also as a result of a series of legal challenges which have increased the power allocated to municipal electric and rural cooperative customers (both in New York and out-of-state). The increase in Preference Power allocation and sales has been accompanied by a reduction in the amount of power marketed to the upstate IOUs. This can be seen in Table 3.2-1, which shows the difference in allocations between 1982 and 2003 among various types of power customers.

As the table demonstrates, the Preference Power allocation for New York municipals and cooperatives increased 63% from 461 MW in 1982 to 752 MW in 2003, while power sales from the Niagara Project to investor-owned utilities (exclusive of Replacement and Expansion Power) dropped 50% from 600 MW in 1982 to 301 MW in 2003.[16] Smaller shifts occurred as the amount of firm peaking power to IOUs fell 40 MW between 1982 and 2003, with 5 MW of firm peaking power and 43 MW of firm power added to out-of-state preference power customers during that time.

[16] A portion of the reduction was restored by sales of St. Lawrence-FDR hydropower to the investor-owned utilities.

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3.2.1 Relevant Legal and Regulatory Precedents on Preference Power Allocation

The legal history of Preference Power involves concepts dating back to the early 20th century political movements and jurisprudence. Many principles in the NRA and PAL have been tested in the courts with respect to Preference Power allocations, and resulting case law defines the discretion that NYPA has to alter Preference Power allocations.

3.2.1.1 Withdrawn Power and "Reasonably Foreseeable Needs"

When the original contracts for preference power were signed with the investor-owned utilities in 1961, they provided for some power to be withdrawn over time (from the portion designated for domestic and rural customers served by the IOUs) to meet the "reasonably foreseeable needs" of expected load growth of the Preference customers as per the NRA.[17] The projections that estimated the likely amount of withdrawable power were made through 1985, but the contracts with IOUs themselves extended through the end of 1989. However, resulting demand growth (primarily non-residential) in municipal and cooperative systems proved to be higher than expected, in part due to the low rates they charged commercial and industrial customers. By 1978, all of the withdrawable power was already transferred from IOUs to Preference customers. From the late 1950s, prior to the operation of the Niagara Project, some power from the St. Lawrence-FDR project was used to satisfy NPP preference customers' requirements. Later, the St. Lawrence Power was replaced with equal amounts of Niagara Preference Power.

On May 12, 1978, the Municipal Electric Utilities Association of New York (MEUA) filed a complaint against the Power Authority at FERC, beginning a series of legal actions that culminated in a 2nd Circuit decision issued on August 15, 1984.[18] In the interim, several FERC decisions were issued,

[17] In the original 1961 Niagara Mohawk contract (NS-1) the 447 of firm power designated for residential use was divided into 250 MW of non-withdrawable power and 197 MW of withdrawable power.

[18] Power Auth. of N.Y. v. FERC, 743 F.2d 93 (2d Cir. 1984), aff'g and modifying 23 FERC ¶ 61,031 (Apr. 6, 1983) (Opinion 151A), modifying 21 FERC ¶ 61,021 (Oct. 13, 1982) (Opinion 151).

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and appealed to the courts. The initial ALJ decision found that the Power Authority had failed to provide for the reasonably foreseeable needs of Preference Power customers when it entered into contracts with the IOUs, declared the contracts void and ordered the Power Authority to revise the contracts to comply with the NRA and the Project license.[19] On hearing, the FERC issued Opinion 151, which found that preference customers were entitled to receive all their current needs up to 40% of the project output, and thus upheld the voiding of the contracts.[20] However, upon rehearing, the Commission partially reversed itself and limited the remedy to the 1985 – 1990 period, ordering the Power Authority to increase the preference allocation from its current level of 586 MW to 697 MW.[21] These orders were appealed to the Circuit Court in PASNY v. FERC. The Court generally agreed with the imposed remedy, but allowed NYPA to fulfill the increase with identically-priced power from the St. Lawrence-FDR project. If it failed to accomplish this requirement, the contracts with IOUs were to be voided and reallocations demanded (including reallocation from Expansion Power if necessary).[22] The contracts were not voided and new contracts with IOUs were entered into as of February 22, 1989.

3.2.1.2 Requirements and Criteria for Receiving Preference Power

Under the NRA, Preference Power recipients are "public bodies and nonprofit cooperatives within economic transmission distance" while PAL § 1005 identifies "municipalities and other political sub-divisions of the state now or hereafter authorized by law to engage in the distribution of electric power" as having priority for receiving a "reasonable share" of project power at the "lowest possible price." These eligibility criteria are not identical.

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[19] Mun. Elec. Utils. Ass'n v. Power Auth. of N.Y., 13 FERC ¶ 63,020 (Oct. 22, 1980) Birchman Decision (Phase I).

[20] 21 FERC ¶ 61,021 (Oct. 13, 1982) (Opinion 151).

[21] 23 FERC ¶ 61,031 (Apr. 6, 1983) (Opinion 151A). In re Mun. Elec. Utils. Ass'n, No. 85-3027 (2d Cir. June 10, 1985)

[22] Power Auth. of N.Y. v. FERC, 743 F.2d 93 (2d Cir. 1984); also, In re Mun. Elec. Utils. Ass'n, No. 85-3027 (2d Cir. June 10, 1985) .

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In 1985, NYPA began to sell Niagara Preference Power to "municipal distribution agencies" (MDAs), which various jurisdictions established under State Law in order to qualify for allocations of Preference Power, under the presumption that such entities were "public bodies" within the meaning of NRA § 836 (b) (1) and thus entitled to preference and priority in NPP power allocations.[23] MDAs (sometimes called "paper munis") were public agencies that purchased power at wholesale and then distributed it to retail customers of investor-owned utilities through "lease and operating agreements" (LOAs) that gave them limited rights to the utilities' distribution network. When these arrangements were challenged, New York courts upheld the position of the Power Authority that these MDAs complied with the legal requirements and qualified as public bodies under New York State law.[24] However, a series of subsequent FERC and Federal court cases eventually determined that none of these entities qualified as public bodies under the NRA. and therefore that they were not entitled to receive Preference Power. The FERC and Federal Courts found that such agencies were not equivalent to municipal and cooperative (M&C) systems that owned and controlled the distribution network, which traditionally were understood to furnish "yardstick competition" in the electricity market. These decisions had the effect of limiting Preference Power to municipal electric and rural cooperative distribution utilities.

The theory of yardstick competition emerged in the 1930s, and the theory was implemented through various tax advantages for cooperatives and a preference for municipal electric and rural cooperative systems to receive Federal hydropower. The primary goal of yardstick competition was to provide an alternative form of utility organization, one that would enjoy inherent cost advantages and challenge the rate structures and practices of the investor-owned utilities. This created a way to discipline IOU costs and rates through the threat of losing large customers to existing M&C systems or even communities organizing their own power delivery systems by purchasing IOU assets ("municipalization"). As the matter was brought before FERC, the issue regarding whether MDAs were public bodies under the NRA focused on whether an MDA could perform as a yardstick competitor,

[23] In addition, NYPA sold preference power from the St. Lawrence-FDR project to the Metropolitan Transit Authority and to the Vermont Department of Public Service at preference rates.

[24] See Vaisey v. Power Auth. of N.Y., No. 16497/85 (Sup. Ct. N.Y. Co. Oct. 17, 1985) (unreported decision), aff'd, 120 A.D.2d 996, 502 N.Y.S.2d 316 (1st Dep't 1986).

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rather than simply pass on savings to IOU customers. FERC found that MDAs were not capable of performing a yardstick competition function, and voided the allocations.[25]

3.2.1.3 Out-of-State Preference Power Allocations

Niagara project power is sold to Preference customers outside of New York under the NRA. However, the actual amount has risen over time as a result of litigation, and as a wider area came within "economic transmission distance." In a 1975 case, the Federal Power Commission (now FERC) decided that the NRA does not require allocation of a full 10 percent of project power to out-of-state entities, and that preference power is not limited to firm power.[26] A later decision noted that FERC has the authority to review the Power Authority's determination of what constitutes a "reasonable portion" of project power allocated to out-of-state entities.[27] In 1985, however, FERC stated in a footnote that the full 10% should be allocated to out of state preference customers, as there was sufficient demand within economic transmission distance to satisfy the Congressional intent that up to 20% of Preference Power be allocated out of state.[28] In the same decision, FERC ruled that the most reasonable method of apportioning Project power among out-of-state preference customers is based on the number of residential customers served by each preference customer.[29]

The entities receiving out-of-state Preference Power has also changed over time, as transmission costs declined (and became more economic relative to electricity generation) and as allocation formulas were clarified. Recently, the composition of out-of-state Preference Power changed as a result of the

[25] See Mun. Elec. Utils Ass'n, 42 FERC ¶ 63,018 (Feb. 16, 1988) Leventhal Decision and Mun. Elec. Utils. Ass'n v. Power Auth. of N.Y., 48 FERC ¶ 61,124 (July 28, 1989) Opinion No. 329.

[26] Vt. Pub. Serv. Bd. v. Power Auth. of N.Y., 55 F.P.C. 1109 (May 15, 1975).

[27] Mass. Mun. Wholesale Elec. Co. v. Power Auth. of N.Y., 14 FERC ¶ 61,128 (Feb. 13, 1981), on reh'g, 18 FERC ¶ 61,217 (Mar. 4, 1982).

[28] *MMWEC*, 32 FERC ¶ 61,194 at 61,452 n.16 (1985) ("*Opinion No. 229-A*")

[29] Mass. Mun. Wholesale Elec. Co. v. Power Auth. of N.Y., 22 FERC ¶ 63,087 (Mar. 9, 1983) Lewnes Decision.

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Buckeye Cooperative in Ohio qualifying to receive Niagara Project power. This has caused NYPA to re-allocate some preference power from other states' allocations.

Although delivered to specific municipal electric and rural cooperative systems in the neighboring states, both the NRA and PAA envision and permit such states to designate a single bargaining agent to represent the preference customers in that state, which can include a preference customer, the Public Utility Commission, or other body. NYPA's contract is with the bargaining agent; however, that agent does not resell the power (or its portion of the power) at retail unless it also is a municipal or cooperative distribution utility.[30]

3.2.1.4 Preference Power and Domestic and Rural Customers

Several cases have addressed Preference Power resales to domestic and rural (i.e. residential) customers. Nothing in the NRA or PAL prohibits a municipal or cooperative preference customer from selling preference power to industrial or commercial customers. Although the general intent of the preference provisions is to favor domestic and rural consumption, an allocation of preference power does not restrict resale to any particular type of customer.[31]

3.2.1.5 Geographic Allocation of Preference Power and Energy Deliveries

Although Preference Power is the most spatially distributed benefit of Niagara project power – reaching 51 municipal electric and rural cooperative utilities across New York and additional systems in 7 neighboring states – it is also quite concentrated in terms of the relatively small proportion of customers

[30] Several decisions relating to MDAs also addressed the eligibility of the Vermont Public Service Board as a Preference customer, declaring it a wholesaler and not a retail entity (it now serves as the bargaining agent for the State of Vermont). See. Mun. Elec. Utils. Ass'n v. Power Auth. of N.Y., 48 FERC ¶ 61,124 (July 28, 1989) Opinion No. 329 and Allegheny Elec. Coop., Inc. v. FERC, 922 F.2d 73 (2d Cir. 1990), aff'g 48 FERC ¶ 61,124 (July 28, 1989).

[31] Power Auth. of N.Y. v. FERC, 743 F.2d 93 (2d Cir. 1984); also, Mun. Elec. Utils. Ass'n v. Power Auth. Of N.Y. , 23 FERC ¶ 61,302 (May 27,1983).

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and loads that it serves within those broad geographic regions. When the Niagara Power Project began delivering power in 1961, not all municipal and cooperative systems had a need for power or were within "economic transmission distance," and, therefore, allocations gradually were made available to all municipal electric and rural cooperative utilities in New York and increased to initial Preference Power recipients. Jamestown, currently the largest Preference customer, only received its allocation in 1971 (to augment its own coal-fired generation), and three municipalities in Long Island began receiving Preference Power in 1976. Appendix A shows a summary of New York Preference Power allocations and kWh sales for 2003, and Table 3.2.2-1 shows the geographic allocation of preference power for 2003.

Two percent (2%) of Preference Power is delivered into Niagara and Erie Counties. Western New York receives 18% of overall Preference Power, or roughly 22% of Preference Power delivered into New York. Out of state Preference customers receive 21% of Preference Power.

3.2.2 Out-of-State Preference Power

As seen in Table 3.2.2-1, 228 MW of Niagara Project Power was allocated to out of state recipients in 2003, with 1,149 GWh of energy delivered. Table 3.2.3-1 provides a breakdown of these allocations and deliveries by recipient state. In 2003, Massachusetts received the most – about 34% – of out-of-state Preference Power energy deliveries, with Ohio and Pennsylvania following with 28% and 20%, respectively.

Although out-of-state Preference Power allocations have remained steady at a total of 228 MW of Firm and Firm Peaking Power, the composition of state recipients can change as new entities become eligible to receive power. Recently, the inclusion of the Buckeye Electric Cooperative in Ohio as an eligible recipient has caused out-of state allocations to shift to Ohio from the other six neighboring states, roughly in proportion to their current allocations. Table 3.2.3-2 shows the shift in allocations that occurred in the Spring of 2004 in both Firm and Firm Peaking Power.

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In order to increase the overall Ohio allocation, other states' allocations were reduced by roughly 20%-30%. Owing to this re-allocation, Ohio now receives the most out-of-state Preference Power – at 46% of the total, with Massachusetts' share declining to 23% and Pennsylvania falling to 17%.

3.2.3 Preference Power to Domestic and Rural Customers

Appendix B shows the 2002 energy deliveries to Preference customers in New York, combined with data on their number of residential customers and residential kWh sales from the Energy Information Administration (2002 is shown because that is the most recent EIA data available on retail electricity suppliers). In 2002, the 51 municipal electric and rural cooperative utilities in New York received 4,340 GWh of Niagara Project Power, and sold 4,566 GWh at retail to all customers (residential, commercial and industrial).[32] The share of residential retail sales to total retail sales for the New York Preference customers ranges from 12% to 98%, with an average of 40%. All together, these M&C Preference customers served 153,000 residential retail customers. Table 3.2.4-1 allocates Preference Power deliveries in 2003 between residential and other (industrial & commercial) sectors, by region, using factors derived from the 2002 data.[33]

This estimate shows that 50% of Preference Power is allocated to domestic and rural customers. About 20% of Preference Power sales attributed to domestic and rural customers in New York are in Western New York, and, thus, 80% of the benefit of Preference Power that flows to residential customers in New York accrues to areas outside of the western region. Two percent (2%) of the residential customer benefit from Preference Power deliveries remains in the Niagara Frontier region.

[32] Project sales can exceed retail sales as a result of transmission losses to the recipient and distribution losses to retail customers.

[33] Customer sales share data is fairly stable over time, so applying the 2002 share factors to 2003 data does not create any material distortion in the figures.

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3.3 Replacement Power Allocation

Replacement Power allocation has not varied since its inception, with 445 MW of firm power granted to Niagara Mohawk for sales to industrial customers on the Niagara Frontier. As of July 1, 2004, there were 68 companies receiving Replacement Power with a total contract demand of 378 MW (23 of these also received Expansion Power allocations). Appendix C shows the list of industrial customers receiving Replacement Power and their kW allocations as of July 1, 2004. (It also shows the allocations as of December 31, 2003, which provide Replacement Power contract totals used in calculations based on calendar 2003 data.)

3.3.1 Requirements and Criteria for Receiving Replacement Power

All of the NPP replacement power is sold through Niagara Mohawk pursuant to Niagara Contract NS-1 under service tariff NP-F1.[34] In the original NS-1 (February 10, 1961) Replacement Power was defined in Article I (h) as "Project firm power made available by Authority to Contractor [Niagara Mohawk] pursuant to Public Law 85-159 [NRA] to replace power formerly produced by Contractor in its Adams and Schoellkopf plants. The industrial customers to whom such power is sold by Contractor and the amounts sold to each shall be approved by Authority." Although the NRA § 836 (3) provided for 445 MW of Niagara Project Power "*for resale generally to the industries which purchase power produced by project 16* prior to such date, *or their successors*, in order as nearly as possible to restore low power costs to such industries *and for the same general purposes for which power from project 16 was utilized*," the NMPC originally allocated the full 445 MW to local industries, even though some were not formerly recipients of power from Project 16. NS-1 Article IV (1) states: "Contractor shall resell the replacement power made available to it to industrial customers in accordance with Public Law 85-159." There were no specific references to the method by which the Power Authority or NMPC should reallocate any replacement power that might be made available due to the original recipients closing or downsizing

[34] Customers who received a Replacement Power allocation after May 1, 1994 are billed at the Expansion Power rate, which currently is about 17% higher (at 80% load factor) than the current Preference Power rate. See "New York Power Authority Operations Data for 2003" and later discussion on ratemaking.

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industrial facilities. Finally, NS-1 Article II (1)(b)(i) gives the Power Authority the right to restrict energy deliveries below 95% load factor to Replacement Power customers. The delivered energy that represents the difference between actual Replacement Power load factor and 95% load factor is credited to the residential customers of Niagara Mohawk.

The New York State Legislature on June 23, 2005 passed legislation that provides a state statutory basis for the continued sale of 445MW of Replacement Power to businesses within 30 miles of the Project. (S5866/A8960). The legislation, which will be sent to the Governor for his approval, also provides for the use of a portion of unallocated Replacement Power for the purpose of Energy Cost Savings Benefits to be granted by the New York State Economic Development Allocation Board, consistent with current contractual obligations. The bill treats reallocations of Replacement Power in the same manner and under the same criteria as currently apply to the allocation of Expansion Power. (PAL §1005(13))

3.3.2 Relinquished and Re-Allocated Replacement Power

By the late 1970s, about 110 MW of the Replacement Power allocation had been relinquished by the original recipients as they discontinued or reduced operations, and NMPC was using the relinquished power for general system requirements.[35] Several customers filed a breach of contract suit against the Power Authority and NMPC to restore power allocations that they believed should be granted to industrial customers. (the "Airco" case).[36] The Airco case was settled with the parties to the dispute agreeing to an allocation of relinquished Replacement Power and a method for allocating future relinquishments among industrial customers. Another case soon followed, with Bethlehem Steel suing

[35] The term "general system requirements" is from the Airco decision. The *Report of the Temporary Commission on Allocation of Power Authority Hydroelectric Power* (February 29,1984; the "Millonzi Commission") indicates that 1.7 million kWh out of 3.7 million kWh (46%) of Replacement Power was distributed to Niagara Mohawk residential customers. In an attached dissent (no attribution) a table of Replacement Power customers indicates only 367 MW were allocated in 1983, with 75 MW awaiting allocation contingent on planned facility expansions.

[36] See Airco Alloys Div., Airco, Inc. v. Niagara Mohawk Power Corp., 76 A.D.2d 68, 430 N.Y.S.2d 179 (4th Dep't 1980).

(footnote continued)

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the Power Authority and NMPC.[37] In that case, the court concluded that (a) Niagara Mohawk and NYPA had broad discretion to select those entities that would receive initial Replacement Power allocations, with no specific company entitled to receive an allocation; (b) Replacement Power relinquished during the term of the contract (NS-1) had to be reallocated to the industries as a group but no specific company was entitled to a portion of such relinquished power; and (c) while Niagara Mohawk (but not NYPA) breached the contract when it refused to allocate relinquished Replacement Power, plaintiff had not proven its contractual right to a specific allocation of relinquished Replacement Power or damages for the failure to allocate that power. The Bethlehem case was settled with all parties agreeing to additional allocations of relinquished Replacement Power and a method for allocating future relinquishments.

The current framework for re-allocations of relinquished Replacement Power is an outgrowth of a process established by a 1988 Settlement Agreement between NYPA, Niagara Mohawk and the industrial customers.[38] Under the settlement, relinquished Replacement Power was held by Niagara Mohawk until it reached 10 MW, or 18 months have expired, whichever occurs first. The availability of Replacement Power was published in local newspapers and industry then submits requests based on their expansion needs. Customers receive Replacement Power allocations under criteria similar to those for Expansion Power, including the number of jobs created per MW and the level of new investment. Recently, Niagara Mohawk, NYPA, and Western New York economic development entities streamlined the reallocation procedures to ensure that there is a continuing allocation process as Replacement and Expansion Power becomes available for reallocation. This new process provides greater opportunity to match available power with a prospective customer.[39] Note that the new state legislation concerning Replacement Power, discussed above, would replace any inconsistent allocation methods established by the Airco and Bethlehem settlements, which expire on January 1, 2006.

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[37] Bethelehem Steel Corp. v. Niagara Mohawk Power Corp., No. H-10963 (Sup. Ct. Erie Co. Oct. 30, 1989) (unreported decision), aff'd no opinion, 179 A.D.2d 1095, 580 N.Y.S.2d 902 (4th Dep't 1992).

[38] "Agreement for allocation and transfer of Replacement Power pursuant to Niagara Contract NS-1, dated April 4, 1988"

[39] "Memorandum of Understanding Regarding Western New York Hydropower" dated October 22, 2003.

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3.3.3 Geographic Distribution of Replacement Power Allocations and Associated Energy Deliveries

Because of its historic association with the Schoellkopf and Adams plants, Replacement Power is geographically concentrated in the Niagara Frontier region. Although not specifically stipulated in the NRA or the PAL, Contract NS-1 requires that all of the Replacement Power recipients be located within 30 miles of the Niagara switchyard. The new legislation changes the radius for Replacement Power to be 30 miles from the Project. Appendix D provides a breakdown of current Replacement Power customers by the investor-owned utility serving those customers and region. Table 3.3.3-1 shows the geographic distribution of Replacement Power allocations and associated energy deliveries by the Host Communities and the counties of Niagara and Erie.[40] Over three-quarters (76%) of all Replacement Power is allocated to industries located in the Host Communities, with nearly all of the remainder in Erie County

3.3.4 Expiration of Replacement Power Allocation

Under the NRA the Replacement Power requirement and allocations expire on December 31, 2005.[41] The new legislation mentioned above that has passed both houses of the New York State Legislature, and which is expected to be signed by the Governor (S5866/A8960) operates to provide a statutory base for replacement power sales independent of the Niagara Redevelopment Act. The bill would extend the Replacement Power allocations as a matter of state law by amending PAL § 1005 (13), and basically merge Replacement Power with Expansion Power allocation rules.

The remainder of PAL § 1005 (13) is largely unchanged except for additional investment criteria added to the allocation methods. Expansion Power Allocation

[40] Energy deliveries are assumed at the average Replacement Power load factor.

[41] Technically, NS-1 expires at 12:01 AM January 1, 2006. The agreement was extended by agreement of NYPA and Niagara Mohawk until the end of the current Niagara Project license on August 31, 2007."

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Up to 250 MW of firm Project Power has been allocated to three load-serving entities: Niagara Mohawk (174.7 MW) New York State Electric and Gas (38.7 MW) and City of Jamestown (3.1 MW). As of December 31, 2003 there were only 217 MW actually under contract, with the rest available for allocation under the rules outlined in PAL § 1005 (13); by July 1, 2004 there were 202 MW of Expansion Power contracts with 68 companies. Appendix C also shows the industrial customers served by the current allocation of Expansion Power and their kW allocations.

3.3.5 Requirements and Criteria for Receiving Expansion Power

Expansion Power is defined by New York State law, and designed to elicit new or expanded business in the Niagara Frontier region. As outlined in PAL § 1005 (13), the requirements for receiving Expansion Power are business customers within 30 miles from the Niagara Power Plant switchyard (or Chautauqua County allocations as of 1987). The trustees of the Power Authority have authority to determine which customers receive Expansion Power and the amount of any such allocation. Actual customer's allocations are decided by the trustees under the criteria outlined in PAL § 1005 (13).

The rules regarding Expansion Power are explicit regarding relinquished and re-allocated power. PAL § 1005 (13) states:

> Expansion power relinquished or withdrawn after the effective date of this subdivision shall be allocated directly or by sale for resale by the authority to businesses within the state located within thirty miles of the Niagara project provided, that the amount of power allocated to businesses in Chautauqua county on January first, nineteen hundred eighty-seven shall be allocated in such county. These allocations shall be made in accordance with criteria established by the trustees. Such criteria shall address the expansion of industry and employment pursuant to paragraph (a) of this subdivision and the revitalization of existing industry pursuant to paragraph (b) of this subdivision.

The criteria for allocating relinquished power are the same as eligibility for Expansion Power, and were furnished by the 1987 Expansion Power law:

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(a) Criteria for eligibility for expansion power. Each application for an allocation for expansion power shall be evaluated by the trustees under criteria which shall include but need not be limited to:

(1) the number of jobs created as a result of an expansion power allocation;

(2) the business` long term commitment to the region as evidenced by the current and/or planned capital investment in business` facilities in the region;

(3) the ratio of the number of jobs to be created to the amount of expansion power requested;

(4) the types of jobs created, as measured by wage and benefit levels, security and stability of employment;

(5) the type and cost of buildings, equipment and facilities to be constructed, enlarged or installed;

(6) the extent to which expansion power will affect the overall productivity or competitiveness of the business and its existing employment;

(7) the extent to which an allocation of expansion power may result in a competitive disadvantage for other business;

(8) the growth potential of the business facility and the contribution of economic strength to the area in which the business facility is or would be located;

(9) the extent of the business` willingness to make jobs available to persons defined as eligible for services under the federal job training partnership act of nineteen hundred eighty-two and the extent of the business` willingness to satisfy affirmative action goals;

(10) the extent to which an allocation of expansion power is consistent with state, regional and local economic development strategies and priorities and supported by local units of government in the area in which the business is located; and

(11) the impact of the allocation on the operation of any other facilities of the business, on other businesses within the region, and upon other electric ratepayers.

(b) Revitalization. In addition to the criteria provided in paragraph (a) of this subdivision the trustees shall establish special criteria for the evaluation of applications for power allocated for the revitalization of industry. Such criteria shall include, but need not be limited to:

(1) that the business is likely to close, partially close or relocate resulting in the loss of a substantial number of jobs;

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(2) that the business is an important employer in the community and efforts to revitalize the business are in long-term interests of both employers and the community;

(3) that a reasonable prospect exists that the proposed allocation of expansion power will enable the business to remain competitive and become profitable and preserve jobs for a substantial period of time;

(4) that the applicant demonstrates cooperation with the local electricity distributor and other available sources of assistance to reduce energy costs to the maximum extent practicable, through conservation and load management; and

(5) that the allocation will not unduly affect the cost of electric service to customers of the local electricity distributor.

The new legislation affecting Replacement Power amends these criteria in minor respects regarding capital investment.

3.3.6 Geographic Distribution of Expansion Power Allocations and Energy Deliveries

Appendix D shows the geographic allocation of Expansion Power by utility. Table 3.4.2-1 shows the geographic distribution of Expansion Power and the associated energy deliveries (assuming average load factors apply across geographic boundaries). As in Replacement Power, all Expansion Power is delivered into Western New York, but Expansion Power is less concentrated in the Host Communities, where 34% is currently allocated. Expansion Power customers in Erie County account for half of the current allocation, and about 10% of Expansion Power allocation goes to customers in Western New York outside of Niagara and Erie Counties.

3.4 Upstate Investor-Owned Utilities

Project Power designated for domestic and rural (i.e. residential) customers and sold at Preference rates is delivered under contract with three upstate investor-owned utilities: Niagara Mohawk (NMPC) New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E). Contracts for 310 MW of Firm Power (and 360 MW of Firm Peaking Power) are allocated to IOUs, with the Firm Power allocated as: 126 MW to NMPC, 110 MW to NYSEG and 65 MW to RG&E.

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These three IOUs collectively serve almost 2.4 million residential accounts in all or parts of 54 counties in New York (out of 62 counties), and Niagara Project Power accounted for 12% of total their residential sales in 2002.[42] Table 3.5-1 displays the power delivered to these IOUs in 2002, and shows that Niagara Project Power accounted for 21% of RG&E retail residential sales, 14% of NYSEG's residential sales, and 9% of NMPC's residential sales.

The geographic distribution of this power is shown on Table 3.5-2, which allocates residential power deliveries based on approximate numbers of households in the counties served by the three IOUs (also see Appendix E). This power is broadly distributed through Upstate New York, with 22% in Western New York and 78% in the remainder of the state, although none is allocated to the downstate urban counties.

[42] The service territories of the three upstate IOUs encompass all or part of 54 counties.

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TABLE 3.1.1-1

NPP SCHEDULE OF DEMAND AND ENERGY SALES, YEAR ENDED DECEMBER 31, 2003

Customer Type	Allocated Power		Power Available for Contract		Contracted Power		Contract Sales		Load Factor
	kW	% of Total	kW	% of Total	kW	% of Total	MWh	% of Total	
Firm Power									
Investor Owned Utilities	245,000	13.0%	301,000	15.5%	301,000	16.2%	1,757,526	15%	66.7%
In-State Preference	752,000	40.0%	752,000	38.8%	752,000	40.4%	4,232,694	35%	64.3%
Out-of-State Preference	188,000	10.0%	188,000	9.7%	188,000	10.1%	1,107,123	9%	67.2%
Replacement Power	445,000	23.7%	445,000	23.0%	401,749	21.6%	3,494,739	29%	99.3%
Expansion Power	250,000	13.3%	250,000	12.9%	216,522	11.6%	1,436,069	12%	75.7%
Subtotal Firm Power Sales	1,880,000	100.0%	1,936,000	100.0%	1,851,905	100.0%	12,028,151	100.0%	74.1%
Firm Peaking Power									
Investor Owned Utilities	360,000	90.0%	360,000	90.0%	360,000	90.0%	376,722	90.2%	11.9%
Out-of-State Preference	40,000	10.0%	40,000	10.0%	40,000	10.0%	41,585	9.8%	11.9%
Subtotal Firm Peaking Sales	400,000	100.0%	400,000	100.0%	400,000	100.0%	418,307	100.0%	11.9%
Total Sales							12,446,458		
Purchases							(507,148)		
Generation	2,280,000		2,336,000		2,259,271		11,939,310		60.3%

Source: 2003 Report on the Sale and Distribution of Niagara Power and NYPA.
Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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TABLE 3.1.2-1

2003 GEOGRAPHIC SUMMARY OF PROJECT POWER

Region	Preference Power		Replacement Power		Expansion Power		Upstate IOU's Residential		Total Project Power	
	MW	% of Total	MW	% of Total	MW	% of Total	MW	% of Total	MW	% of Total
Western New York & Subregions										
Host Communities	0	0%	304	76%	73	34%	7	1%	384	17%
Remaining Niagara County	0	0%	1	0%	15	7%	16	2%	32	1%
Niagara County Subtotal	0	0%	305	76%	88	41%	23	3%	417	18%
Erie County	17	2%	94	23%	107	50%	95	14%	313	14%
Niagara Frontier Subtotal	17	2%	399	99%	195	90%	118	18%	730	32%
Western New York Subtotal	160	16%	402	100%	217	100%	155	23%	933	41%
State Regions										
New York	752	77%	402	100%	217	100%	661	100%	2,031	90%
Out-of-State	228	23%	0	0%	0	0%	0	0%	228	10%
Total	980	100%	402	100%	217	100%	661	100%	2,259	100%
Percent of Project Power	43%		18%		10%		29%		100%	

Sources: "2003 Report on the Sale and Distribution of Niagara Power" and NYPA.

Capacity figures include firm and firm peaking allocations. Niagara Frontier includes Niagara and Erie Counties; western New York includes Niagara, Erie, Genesee, Orleans, Wyoming, Chautauqua, Cattaraugus, and Allegany Counties. Includes both firm and firm peaking power. Replacement and Expansion totals reflect power contract levels as of 12/31/03 and are thus lower than total statutory allocations.

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TABLE 3.1.2-2

2003 GEOGRAPHIC SUMMARY OF NPP ENERGY SALES

Region	Preference Sales		Replacement Sales		Expansion Sales		Upstate IOU's Residential		Total Energy Sold	
	GWh	% of Total	GWh	% of Total	GWh	% of Total	GWh	% of Total	GWh	% of Total
Western New York & Subregions										
Host Communities	0	0%	2,646	76%	485	34%	22	1%	3,153	25%
Remaining Niagara County	0	0%	11	0%	100	7%	47	2%	159	1%
Niagara County Subtotal	0	0%	2,657	76%	585	41%	69	3%	3,311	27%
Erie County	98	2%	816	23%	711	50%	289	14%	1,914	15%
Niagara Frontier Subtotal	98	2%	3,473	99%	1,297	90%	358	17%	5,225	42%
Western New York Subtotal	946	18%	3,495	100%	1,436	100%	476	22%	6,352	51%
State Regions										
New York	4,251	79%	3,495	100%	1,436	100%	2,134	100%	11,316	91%
Out of State	1,149	21%	0	0%	0	0	0%	0%	1,149	9%
Total	5,400	100%	3,495	100%	1,436	100%	2,134	100%	12,465	100%
Percent of Project Power	43%		28%		12%		17%		100%	

Percentages for subregions are of Project total.
Niagara Frontier includes Niagara & Erie Counties; Western New York includes Niagara, Erie, Genesee, Orleans, Wyoming, Chautauqua, Cattaraugus, and Allegany Counties. Includes both firm and firm peaking.
Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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TABLE 3.1.3-1

GEOGRAPHIC DISTRIBUTION OF 2003 DOMESTIC AND RURAL SALES

Region	Preference Sales to Domestic & Rural Customers (GWh)	Replacement Sales to Domestic & Rural Customers (GWh)	Upstate IOU's Sales to Domestic & Rural Customers (GWh)	Total Sales to Domestic & Rural Customers (GWh)	Percent of Domestic & Rural Sales in Region
Western New York & Subregions					
Host Communities	0	15	22	37	1%
Remaining Niagara County	0	16	47	63	1%
Niagara County Subtotal	0	31	69	100	2%
Erie County	37	144	289	470	9%
Niagara Frontier Subtotal	37	176	358	570	10%
Western New York Subtotal	352	221	476	1,048	19%
State Regions					
New York	1,735	646	2,134	4,516	82%
Out-of-State	984	0	0	984	18%
Total	2,719	646	2,134	5,500	100%

Sources: "2003 Report on the Sale and Distribution of Niagara Power," "New York Power Authority Operations Data for 2003," and NYPA.

Niagara Frontier includes Niagara & Erie Counties; Western New York includes Niagara, Erie, Genesee, Orleans, Wyoming, Chautauqua, Cattaraugus, and Allegany Counties. Includes both firm and firm peaking power. Out-of-State preference domestic and rural sales are calculated as the percentage of in-state preference domestic and rural sales times out-of-state preference sales.

Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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TABLE 3.2-1

NIAGARA POWER PROJECT SCHEDULE OF DEMAND, 1982 AND 2003

Class	1982		2003	
	Demand (MW)	Percent of Total	Demand (MW)	Percent of Total
Firm Power				
Investor Owned Utilities	600	32%	301	16%
In-State Preference	461	24%	752	39%
Out-of-State Preference	145	8%	188	10%
Replacement Power	445	23%	445	23%
Expansion Power	250	13%	250	13%
Subtotal Firm Power	1,901	100%	1,936	100%
Firm Peaking Power				
Investor Owned Utilities	400	92%	360	90%
Out-of-State Preference	35	8%	40	10%
Subtotal Firm Peaking	435	100%	400	100%
Total	2,336		2,336	

Sources: "Report of the Temporary Commission on Allocation of Power Authority Hydroelectric Power" and "2003 Report on the Sale and Distribution of Niagara Power."

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TABLE 3.2.2-1

PREFERENCE POWER GEOGRAPHIC ALLOCATION AND SALES

Region	Preference Power Allocation (MW)	Preference Sales (GWh)	Region Percent of Preference Sales
Western New York Subregions			
Host Communities	0	0	0%
Remaining Niagara County	0	0	0%
Niagara County Subtotal	0	0	0%
Erie County	17	98	2%
Niagara Frontier Subtotal	17	98	2%
Western New York Subtotal	160	946	18%
State Regions			
New York	752	4,251	79%
Out-of-State	228	1,149	21%
Total	980	5,400	100%

Sources: "2003 Report on the Sale and Distribution of Niagara Power" & "New York Power Authority Operations Data for 2003."

Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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TABLE 3.2.3-1

OUT-OF-STATE 2003 PREFERENCE ALLOCATIONS AND SALES

Entity	Preference Power Allocation (kW)	Preference Sales (GWh)	Percent of Preference Sales
Allegheny Electric Cooperative, Pennsylvania	47,900	228.5	19.9%
City of Cleveland, Ohio	63,800	317.9	27.7%
Connecticut Municipal Electric Energy Coop.	15,500	82.7	7.2%
Public Power Association of New Jersey	13,800	63.9	5.6%
Massachusetts Department of Telecommunications and Energy	72,200	385.2	33.5%
Rhode Island Public Utilities Commission	800	4.1	0.4%
Vermont Department of Public Service	14,000	66.5	5.8%
Total	228,000	1,149	100%

Sources: "2003 Report on the Sale and Distribution of Niagara Power" and "New York Power Authority Operations Data for 2003."

Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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TABLE 3.2.3-2

NPP OUT-OF-STATE PREFERENCE POWER, JANUARY 1, 2004, AND APRIL 1, 2004

Entity	January 1, 2004 Allocation		April 1, 2004 Allocation	
	NPP Allocation (kW)	Percent of NPP Out-of-State Allocation	NPP Allocation (kW)	Percent of NPP Out-of-State Allocation
Connecticut Municipal Electric Energy Coop.	15,500	6.8%	10,500	4.6%
Massachusetts Department of Telecommunications and Energy	72,200	31.7%	53,000	23.2%
Public Power Association of New Jersey	13,800	6.1%	9,600	4.2%
City of Cleveland, Ohio	63,800	28.0%	104,400	45.8%
Allegheny Electric Cooperative, Pennsylvania	47,900	21.0%	38,700	17.0%
Rhode Island Public Utilities Commission	800	0.4%	600	0.3%
Vermont Department of Public Service	14,000	6.1%	11,200	4.9%
Total	228,000	100%	228,000	100%

Sources: NYPA.

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TABLE 3.2.4-1

GEOGRAPHIC DISTRIBUTION OF 2003 DOMESTIC AND RURAL PREFERENCE SALES

Region	Preference Sales to Domestic and Rural Customers (GWh)	Preference Sales to Non-Rural and Domestic Customers (GWh)	Total Preference Sales
Western New York Subregions			
Host Communities	0	0	0
Remaining Niagara County	0	0	0
Niagara County Subtotal	0	0	0
Erie County	37	61	98
Niagara Frontier Subtotal	37	61	98
Western New York Subtotals	352	594	946
State Regions			
New York	1,735	2,516	4,251
Out-of-State	984	165	1,149
Total	2,719	2,681	5,400

Sources: "2003 Report on the Sale and Distribution of Niagara Power," "New York Power Authority Operations Data for 2003," and NYPA.

Niagara Frontier includes Niagara & Erie Counties; western New York includes Niagara, Erie, Genesee, Orleans, Wyoming, Chautauqua, Cattaraugus, and Allegany Counties. Out-of-State preference domestic and rural sales are calculated as the percentage of in-state preference domestic and rural sales times out-of-state preference sales.

Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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TABLE 3.3.3-1

2003 REPLACEMENT POWER GEOGRAPHIC ALLOCATION AND SALES

Region	Replacement Power (MW)	Replacement Sales (GWh)	Region Percent of Replacement Sales
Western New York & Subregions			
Host Communities	304	2,646	76%
Remaining Niagara County	1	11	0%
Niagara County Subtotal	305	2,657	76%
Erie County	94	816	23%
Niagara Frontier Subtotal	399	3,473	99%
Western New York Subtotal	402	3,495	100%
State Regions			
New York	402	3,495	100%
Out-of-State	0	0	0%
Total	402	3,495	100%

Sources: "2003 Report on the Sale and Distribution of Niagara Power" and NYPA.

Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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TABLE 3.4.2-1

2003 EXPANSION POWER GEOGRAPHIC ALLOCATION AND SALES

Region	Expansion Power (MW)	Expansion Sales (GWh)	Region Percent of Expansion Sales
Western New York Subregions			
Host Communities	73	485	34%
Remaining Niagara County	15	100	7%
Niagara County Subtotal	88	585	41%
Erie County	107	711	50%
Niagara Frontier Subtotal	195	1,297	90%
Western New York Subtotal	217	1,436	100%
State Regions			
New York	217	1,436	100%
Out-of-State	0	0	0%
Total	217	1,436	100%

Sources: "2003 Report on the Sale and Distribution of Niagara Power" and NYPA.

Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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TABLE 3.5-1

DISTRIBUTIONS TO DOMESTIC AND RURAL CUSTOMERS FROM UPSTATE IOU'S 2002 SALES

Entity	Power Contracted (MW)	Niagara Sales (GWh)	Residential Customers	Retail Sales to Residential Customers (GWh)	Niagara Sales as Percent of Residential Sales
Niagara Mohawk Power Corp	301	941	1,369,959	10,120	9%
New York State Electric & Gas Corp	260	836	715,299	5,544	15%
Rochester Gas and Electric Corporation	100	466	281,565	2,156	22%
Total	661	2,243	2,366,823	17,820	13%

Sources: 2002 EIA Form 861, Tables 14 - 17, "New York Power Authority Operations Data for 2002," and "2003 Report on the Sale and Distribution of Niagara Power."

Power contracted includes both firm and firm peaking power. Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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TABLE 3.5-2

2003 UPSTATE IOU'S GEOGRAPHIC RESIDENTIAL POWER AND SALES

Region	Upstate IOU's - Residential Power (MW)	Upstate IOU's - Residential Sales (GWh)	Region Percent of Upstate IOU's - Residential Sales
Western New York Subregions			
Host Communities	7	22	1%
Remaining Niagara County	16	47	2%
Niagara County Subtotal	23	69	3%
Erie County	95	289	14%
Niagara Frontier Total	118	358	17%
Western New York	155	476	22%
State Regions			
New York	661	2,134	100%
Out-of-State	0	0	0%
Total	661	2,134	100%

Sources: US Census, NYPA, "New York Power Authority Operation Data for 2003," and 2002 EIA Form 861, Table 17.

Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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4.0 RATE-SETTING METHODOLOGY AND IMPACT OF RELICENSING COSTS

4.1 History and Overview of Ratemaking Principles Applicable to Niagara Power Project

The initial rates for firm power for the Niagara Power Project were established when the plant went into operation in 1961. This initial rate included a one dollar per kilowatt per month demand charge and a 2.67 mills per kWh energy charge applicable to all firm power deliveries – Preference, Replacement, Expansion and power delivered to IOUs. These rates remained steady through 1981 when the Trustees decided to retire the remaining bonds issued under the Authority's 1954 Bond Resolution for the St. Lawrence and Niagara hydro projects. At that time, the Trustees decided to conduct a comprehensive study to determine an appropriate rate level. A decision by the New York Supreme Court in the Auer et al v. Dyson et al case in 1981 addressed how project costs and revenues were to be handled in the rate setting process. Specifically, the court said that revenues from the Niagara and St. Lawrence hydro projects could not be diverted to finance other projects until the statutory obligation to provide domestic and rural customers with the lowest possible rate was met. The court went on to state that in setting the "lowest possible rate:"

> ...the Authority has broad discretion, in setting such rates, to determine the components of its costs, and it is not required to guarantee any specific rate. It may include a reasonable charge for depreciation of the Niagara and St. Lawrence projects and such other factors which the exercise of business accounting principles would allow.

Following this decision, the trustees adopted a five percent rate decrease for the domestic and rural customers on June 29, 1982 retroactive to January 1, 1982. Also, rates were to be based on a 1982/1983 cost-of-service study including only those costs tied to the hydro projects. Costs to be considered included operating and maintenance expenses, administrative and general expenses, indirect overhead costs, depreciation, and inflation compensation. Indirect overhead costs were to be allocated according to generating capacity. These indirect costs include headquarters office administrative expenses, debt service expenses related to non-revenue producing facilities and research & development expenses.

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NYPA is required to provide service from its hydroelectric facilities at cost to "preference rate customers," which include municipalities, cooperatives and investor-owned electric utilities.[43] In addition to the Auer Decision, Section 1005 (5) of the New York Power Authority Act provides a general guideline that, in determining hydroelectric rates the New York Power Authority: "shall sell the same or cause the same to be sold to such municipalities and political subdivisions at prices representing cost of generation, plus capital and operating charges, plus a fair cost of transmission, all as determined by the trustees, and subject to conditions which shall assure the resale of such power to domestic and rural consumers at the lowest possible price."[44] The Power Authority Act, in Section 1005 (5) (h), allows varying rates based on "different localities, classes of customers, and amounts of current consumed" and allows for rate adjustments as a result of changes in operating costs and fixed charges. However, from the inception of the Niagara project through 1981 uniform and constant rates were charged for all customer classes (Figure 4.1-1).

The Auer Decision also explicitly stated that preference customers are not entitled to rates below cost as a result of revenues from other project energy sales:

> There is nothing in Subdivision 5 of Section 1005 of the Public Authorities Law which requires or authorizes the furnishing of hydroelectric power to rural or domestic users at less than cost. In fulfilling its statutory requirements that the rate to domestic and rural customers be the lowest possible rate, the Authority has broad discretion, in setting such rates, to determine the components of its costs, and it is not required to guarantee any specific rate. It may include a reasonable charge for depreciation of the Niagara and St. Lawrence projects and such other factors which the exercise of business accounting principles would allow.
>
> Once the lowest possible rate for domestic and rural consumers of the Niagara and St. Lawrence projects has been established excess revenues derived from the sale of power from the Niagara and St. Lawrence projects may be added to the general fund of the authority.[45]

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43 IOUs receive power at the preference rate for distribution to residential customers.

44 Power Authority Act of the State of New York Section 1005 (5)

45 Auer v. Dyson, 110 Misc. 2d 943, 444 N.Y.S.2d 513 (Sup. Ct. Oswego Co. 1981)

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4.1.1 Auer I Decision

The plaintiffs in this case sued the Power Authority, claiming that the 1974 bond resolution, known as the General Purpose Bond Resolution and the Ninth Supplemental General Purpose Bond Resolution were in violation of sections 1001 and 1005 of the Public Authorities Law, the Niagara Redevelopment Act and the Federal Power Commission license of St. Lawrence. The General Purpose Bond Resolution provided that NYPA revenues from all projects, including the hydroelectric projects, be used to pay off the 1974 series bonds as well as any new bond series issued after the retirement of the Niagara and St. Lawrence bonds and the refinancing of the Fitzpatrick and Blenheim-Gilboa projects (the 1970 bonds). Plaintiffs argued that the use of hydroelectric revenues to pay off bonds associated with capital investments in other projects throughout the state would result in an illegal rate for the domestic and rural customers and thus violate subdivision 5 of section 1005 of the Public Authorities Law. NYPA argued that such an interpretation would lead to NYPA default on the bonds as this narrow interpretation of the Public Authorities Act would not be consistent with the Bond Covenant.

The court focused on several sections of the Public Authority Act in its decision. First, under subdivisions 5 and 6 of section 1005 of the Public Authority Law, the hydroelectric projects are to benefit "the people of the state as a whole" and "particularly the domestic and rural consumers at the lowest possible rates." Second, though there is no definition of "lowest possible rates" in the Act, the court asserted that "an interpretation that would permit the lowest possible rate to be less than cost would be absurd, and it must be presumed that the Legislature never intended such a result" where costs are defined as "cost of generation, plus capital and operating charges, plus a fair cost of transmission." Further, the decision found NYPA's duty in sales to industry as "the responsibility of the authority to seek contracts of sale to industry as a secondary purpose "to secure a sufficiently high load factor and revenue returns" to facilitate [the lowest possible rate]." Therefore, once it is established that preference customers are receiving the lowest possible rate there is nothing in the Public Authority Act preventing hydroelectric revenues from being included in a general fund.[46]

[46] Auer v. Dyson, 110 Misc. 2d 943, 444 N.Y.S.2d 513 (Sup. Ct. Oswego Co. 1981)

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4.1.2 Auer II Decision

Following the Auer I Decision, NYPA established a cost based rate that included a debt service charge from certain non-hydro projects. The plaintiffs argued that this was in violation of the initial court decision. In the second Auer Decision, the court stated that cost based rates used to establish the lowest possible rate must be set first, i.e., before NYPA could determine whether there would be excessive revenue to use in a general fund. Therefore, the decision required NYPA to remove the non-hydro project debt service charges and refund these to the domestic and rural customers.

The Auer II Settlement established several rules for the recovery of capital expenditures and debt charges. In addition to a charge for hydroelectric project depreciation (return *of* capital), NYPA could also include an adjustment for inflation. However, with the exception of debt interest, NYPA was not allowed to earn a return *on* capital through a real rate of return charge.[47]

4.2 Treatment of Capital Cost

Two key features of Auer in regard to capital charges were its treatment of inflation and the lack of a return on capital. Auer capital charges are based on a partial implementation of "Trended Original Cost" (TOC) method. As traditionally implemented, TOC is a cost-based method of rate regulation that tracks the cost of investment outlays for property, plant and equipment and gives the companies making those investments a fair opportunity both to (1) recover the capital they have invested, through subsequent depreciation and amortization charges, and (2) earn a fair rate of return on the capital while it remains unrecovered. In this, it is like the Original Cost ("OC") method widely used to set rates for investor-owned utilities in North America. It differs from OC in that inflation compensation under TOC comes through an increase in the value of the assets employed, not through an inflation premium in the allowed rate of return on those assets. However, the starting present values of the capital charges are the same and

[47] Auer v. Dyson, 125 Misc. 2d 274, 479 N.Y.S.2d 102 (Sup. Ct. Oneida Co. 1984), 112 A.D.2d 803, 491 N.Y.S.2d 1022 (4th Dep't 1985)

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equal the initial amount invested.[48] Thus, both methods exactly recover the cost of the investment from customers over time, albeit in different patterns.

The second key feature of Auer in regard to capital recovery is that the method deviates from a normal application of TOC as it does not include the rate of return on capital. Under Auer, NYPA recovers less from its capital investments than a private firm or regulated IOU might expect to earn as it omits the return on capital. This makes the present value of the capital charges under this version of TOC less than that recovered under a traditional TOC methodology. For example, Figure 4.2-1 compares the cost recovery found under traditional OC and TOC, which have present values equal to a $1,000 initial investment, with the Auer cost recovery method, which has a present value of only $631. Since NYPA's assets have much longer lives than the example's assets, the actual present value from full cost recovery for NYPA will be a lower percentage of the initial investment than this. For example, with a 50-year asset and the assumptions otherwise unchanged, NYPA gets back only $373 in present value under Auer-style TOC, well below half of the actual cost of the investment. As a result, the cost-of-service based rate is lower than would be expected under traditional capital charge recovery methods.

Despite earning no return on its capital investments, NYPA is bound by the principles under the Auer settlement, which does permit the collection of the interest expense on the debt NYPA issues for the new investments. Since the total cost of capital of those investments, debt and equity combined, will exceed the interest expense on the debt-financed part of the investments, this means NYPA charges less than standard TOC for the capital employed on behalf of preference rate customers on the new investments as well as the old ones.

[48] "Capital charges" in this context equal the sum of depreciation and amortization plus the return on capital. Sometimes "capital charges" for privately owned rate-regulated companies are defined to include income taxes. However, NYPA does not pay income taxes.

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4.3 Treatment of Operational Costs

Variable costs included in rates are site O&M, Niagara roadwork, Headquarters overhead allocation and research & development expenses. The Niagara roadwork, completed between 1991 and 1996, is included as O&M for rate making purposes and is being amortized on a 15 year schedule for this purpose.[49] These annual variable expenses, in addition to capital costs associated with both new and existing investments, less revenue from demand charges, are then divided by forecasted annual generation (or the long term average) in order to determine an estimated energy production cost.

4.3.1 Combining Costs of Niagara and St. Lawrence for Ratemaking

Though the contracts distinguish between Niagara and St. Lawrence, the rate calculations track costs and output for both projects together. Total costs less revenue from demand charges are divided by the combined capacities of both Niagara and St. Lawrence projects in order to estimate the energy production charge. Total costs are a combination of variable costs and capital costs from both the projects and the portion of Headquarters allocated to the hydroelectric projects. The generation capacity is based on long term average water flows.

4.4 NYPA Cost of Service Methodology for Setting Hydro Rates

The cost of service method combines capital and variable expenses from both the Niagara and St. Lawrence hydroelectric projects in order to calculate an energy production cost. In addition, the component of headquarters capital costs allocated to Niagara and St. Lawrence is factored into the hydro cost of service model. Since depreciation rates and financing differ between the two hydro projects, Niagara and St. Lawrence capital expenditures are tracked separately. However, after depreciation, interest and the inflation component have been calculated these capital costs are combined for the final cost calculations. In this respect, Niagara and St. Lawrence are not tracked on a project-by-project basis.

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Likewise, the headquarters capital expenses are not allocated to Niagara and St. Lawrence individually but rather to the two projects as a whole. Finally, these total capital and variable expenses for the two projects are summed together. After subtracting out the demand charge revenues (from both preference and non-preference customers), the total costs are divided by the net generation capacity in order to determine the energy production cost.

4.5 Ancillary Services

The move to competitive generation markets and the start of operations by the New York Independent System Operator ("NYISO", or "ISO") have fundamentally changed the nature of the electric industry in the New York Control Area ("NYCA"). One change is that electric service has now been unbundled into separate component products. Prior to the new market structure, the incumbent utility provided customers with all aspects of electric power, bundling generation (capacity and energy) together with all of the network support services that are necessary to deliver it reliably. Now, the ISO's new market structure distinguishes and charges separately for these network support services. The ISO acquires these support services from competitive suppliers, and passes the cost of each unbundled service or product through to customers, as an item separate from the cost of generation.

The embedded costs for these four ancillary services are not new costs, nor are the services themselves new. Rather, in the past all services and costs have been bundled together, but now the new market separates them. The total cost of service of the NYPA hydro facilities is first determined (which in total supports the provision of all electric services) and then the relevant costs associated with ancillary services are allocated in the appropriate portion. After deducting the costs of these ancillary services, the remainder of the total cost of service associated with generation is used to develop the cost-based generation rates for NYPA's preference rate customers. The unbundling does not change NYPA's total costs; it merely allocates these costs among energy and the ancillary services identified.

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[49] New York Power Authority Hydroelectric Production Rates 1998 Calendar Year Production Related Cost of Service Study & Rate Stabilization Reserve (RSR) Computation, pg 2 of Exhibit 1.

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4.6 Preference Power Rates

Section 1005 of the Public Authority Act states that preference customers are to receive power at the "lowest possible rate" consistent with the cost-reflective principles outlined therein From 1961 through 1981 this meant a constant rate with a demand charge of one dollar per kilowatt per month and an energy charge of 2.67 mills per kWh. The Auer I decision prompted the move towards cost-based rate making which resulted in a decrease in the energy charge. The demand charge remained constant at one dollar per kW-month until May 2003 when annual increases began. The energy charge was set at 4.92 mills per kWh in May 1994 (Figure 4.6-1). Finally, in the case of *Village of Bergen v. Power Authority of New York*, the court ruled that labor ratios as opposed to capacity ratios were to be used in the allocation of indirect overhead in calculating a lowest possible rate.[50]

4.7 Expansion Power Rates

From the beginning of Niagara operations in 1961 through the end of 1987, expansion rates were the same as those for replacement power. Demand charges were one dollar per kW per month and energy charges were 2.67 mills per kWh (see Figure 4.7-1).

The 1987 amendments to the New York Power Authority Act specified that "net" revenues from the expansion power sales were to be used for "industrial incentive rewards."[51] Expansion rates were negotiated during a period from 1987 through 1989 and were set at a uniform rate for all expansion customers. The rates were set above the preference power rate and are adjusted through time according to an industrial energy cost-based inflation index.

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[50] Village of Bergen v. Power Auth. of N.Y., 249 A.D.2d 902, 672 N.Y.S.2d 595 (4th Dep't 1998), leave to appeal dismissed, 92 N.Y.2d 940, 681 N.Y.S.2d 469 (1998).

[51] Allocation of Low-Cost Electric Power to Promote Economic Development, Laws of New York, 1987, Approved April 21, 1987.

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4.8 Replacement Power Rates

Replacement power was allocated initially to Niagara Mohawk for resale to the former customers of the Adams and Schoellkopf plants. The destruction of the Schoellkopf plant in 1956 threatened the industries which had developed in the region., These industries faced substantial increases in electricity costs resulting from the purchasing of power from Canadian hydro plants. Unlike preference power rates, replacement power rates need not be sold at the lowest possible cost. As is shown in Figure 4.8-1, Replacement power had been sold at $1.00 per kW per month and 2.67 mills per kWh up to 1990. At that point, NYPA increased the demand charge to $1.47 per kW per month while the energy charge was decreased to 2.51 mills per kWh. NYPA wished to use these additional revenues for such projects as funding the Niagara expansion or retiring debt early. This brought about a legal challenge (the Occidental Chemical case) protesting that the Niagara Redevelopment Act did not allow for NYPA to increase replacement power rates above the cost of production.

In the Occidental Chemical case a number of industrial replacement power customers claimed that replacement power rate increases were contrary to the Niagara Redevelopment Act. The NRA called for power to be sold to previous customers of the destroyed Schoellkopf dam in order to restore "low power costs." Plaintiffs felt this should be interpreted as to mean rates set at cost. In 1992, the court found that "costs" referred to the customers' costs, not NYPA's production costs. As a result, the court ruled that NYPA had the authority to set replacement power rates greater than the actual production cost:

> ...the phrase requiring PASNY to sell Replacement Power to Niagara Mohawk for resale "in order as nearly as possible to restore low power costs to such industries" meant that PASNY should provide low-cost power to these industries. The phrase "low power costs" means what it says: low-cost power. It does not mean "at cost" power.[52]

[52] Occidental Chem. Corp. v. Power Auth. of N.Y., 786 F. Supp. 316 (W.D.N.Y. 1992), aff'd, 990 F.2d 726 (2d Cir. 1993), cert. denied, 510 U.S. 947 (1993).
The NRA [16 U.S.C.A. § 836(b)(3)]

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4.9 Retail Ratemaking Procedures of Project Power Recipients

The three upstate IOUs receiving project power at preference rates are required to include these purchases to residential customers at the cost of service, in effect flowing through the benefit of lower-cost hydro resources only to that customer class.[53] Likewise, Replacement and Expansion Power allocated to specific industrial customers is passed through with no markup from the distribution utility (other than delivery charges). Thus, the benefit of low-cost hydropower is targeted to specific customers and classes.

Ratemaking in municipal electric and rural cooperative utilities receiving Preference Power, whether by NYPA (for customers whose full requirements are served by NYPA) or the New York Public Service Commission (for systems whose needs are partially met from sources other than NYPA) is premised on the across-the-board distribution of the benefits of the hydropower to the various classes.

4.10 Current Revenues and Usage

As of 2002, Preference customers and the three upstate investor-owned utilities receiving electricity at preference rates from Niagara accounted for approximately 35% of New York residential customers. The average residential sales revenue per kilowatt hour for the upstate investor-owned utilities and preference customers is 12.2 and 4.8 cents, respectively. The state average is 13.2 cents per kilowatt hour (See Table 4-10-1). Of course, there are other factors which keep the rates low for the municipal power providers which make up the preference customer base. For example, these entities have access to tax exempt financing, do not require a return for shareholders and generally have lower overhead expenses. Nevertheless, the relatively low Preference Power rates charged help to keep these New York municipal providers' retail power rates below the national average for public power.

[53] Section 1005.5.g of the New York Power Authority Act states that "in the event any such public agencies or companies which purchase power from the authority shall sell any such power for resale, such sale for resale shall be made at rates no higher than those at which the power was purchased from the authority." Section 1005.5.h further states that contracts "may provide different rates for different localities, classes of consumers, and amounts of current consumed..."

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4.11 Rate Setting and the Cost of Relicensing

4.11.1 Types of Relicensing Costs and Ratemaking Treatment

Relicensing costs factored into the cost of service include procedural and administrative relicensing expenses (treated as capital expenditures) and potential capital and O&M expenses related to new license conditions. In addition to these expenses, other costs related to relicensing are factored into the cost of service through other such accounts as operating & maintenance variables expenses or "general plant" capital charge accounts. The relicensing account capital expenses are depreciated over a period of 50 years. As a result, the capital charges are calculated using both the original cost and trended original cost methodologies to determine depreciation, interest and inflation charges.

4.11.2 Cost of Service Impact of Relicensing

Once known and accounted for, the costs of relicensing will have a direct impact on the cost of service. Changes to variable and capital expenses will affect future energy production costs. This will include any changes to the estimated procedural and administrative expenses, expensed variable costs, and any future capital investments or increased operating & maintenance expenses resulting from the new license.

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TABLE 4.10-1

COMPARISON OF RESIDENTIAL SALES BY SELLER TYPE, 2002

	Number of Residential Customers	% of State Total	Residential Sales (MWh)	% of State Total	Residential Revenues (000 $)	% of State Total	Average cents / kWh	Average kWh / Customer
Investor Owned Utilities								
NIMO	1,369,959	19%	10,119,984	22%	$1,254,200	21%	12.4	7,387
NYSEG	715,299	10%	5,544,411	12%	$682,849	11%	12.3	7,751
RGE	281,565	4%	2,156,036	5%	$228,753	4%	10.6	7,657
Upstate IOU Totals	2,366,823	33%	17,820,431	39%	$2,165,802	36%	12.2	7,529
Other New York IOU's*	4,005,592	56%	24,007,859	52%	$3,635,185	60%	15.1	5,994
New York State IOU Totals	6,372,415	88%	41,828,290	91%	$5,800,987	95%	13.9	6,564
Preference Customers	153,253	2%	1,829,522	4%	$86,957	1%	4.8	11,938
Retail Electricity Providers	675,003	9%	2,542,672	6%	$194,115	3%	7.6	3,767
New York State Totals/Averages	**7,200,671**		**46,200,484**		**$6,082,059**		**13.2**	**6,416**

Source: Energy Information Administration
* Includes LIPA

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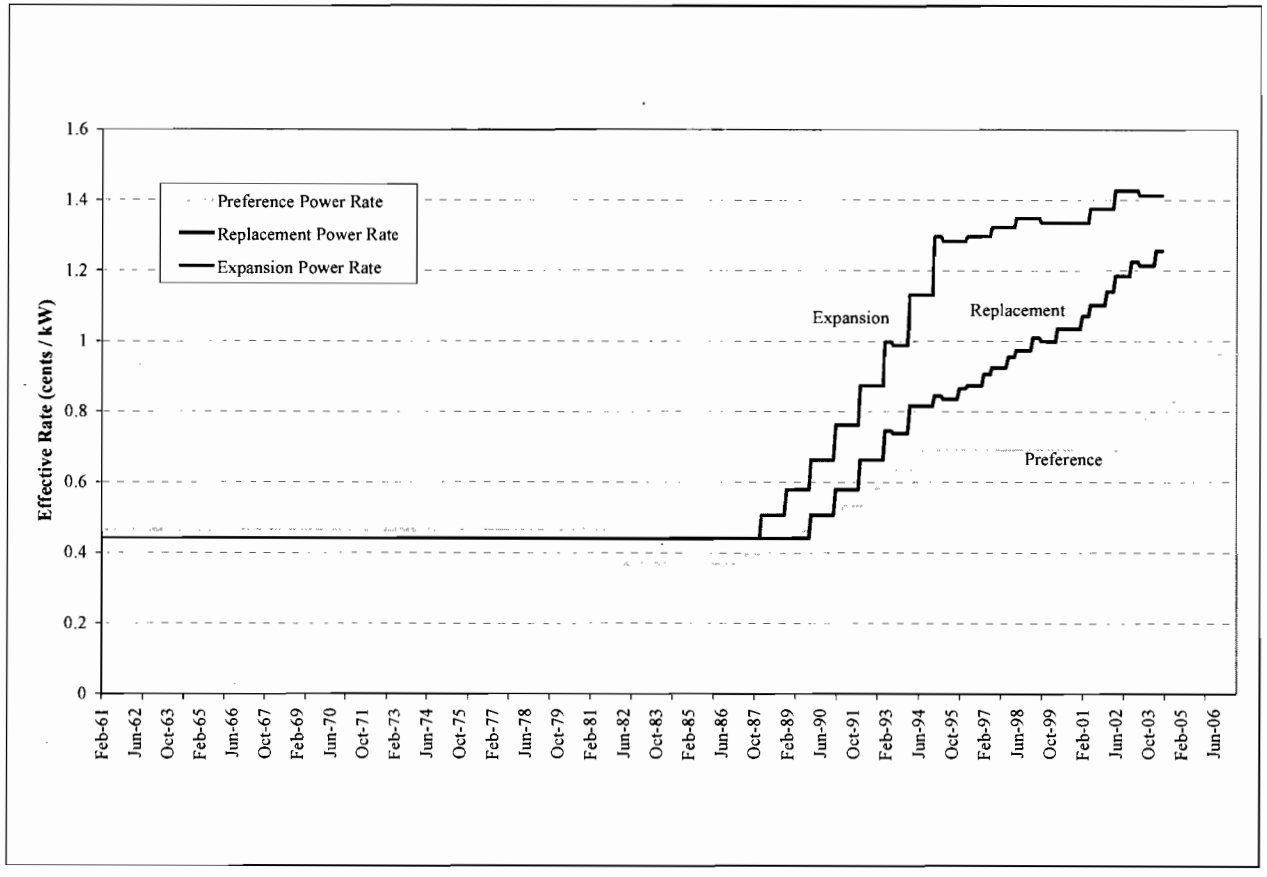
FIGURE 4.1-1

NIAGARA EFFECTIVE RATES BY CUSTOMER CLASS



Notes: Load factors are from the New York Power Authority Operations Data for 2003 report. Preference load factor is assumed to be 70%. Replacement and expansion load factors are 80%.

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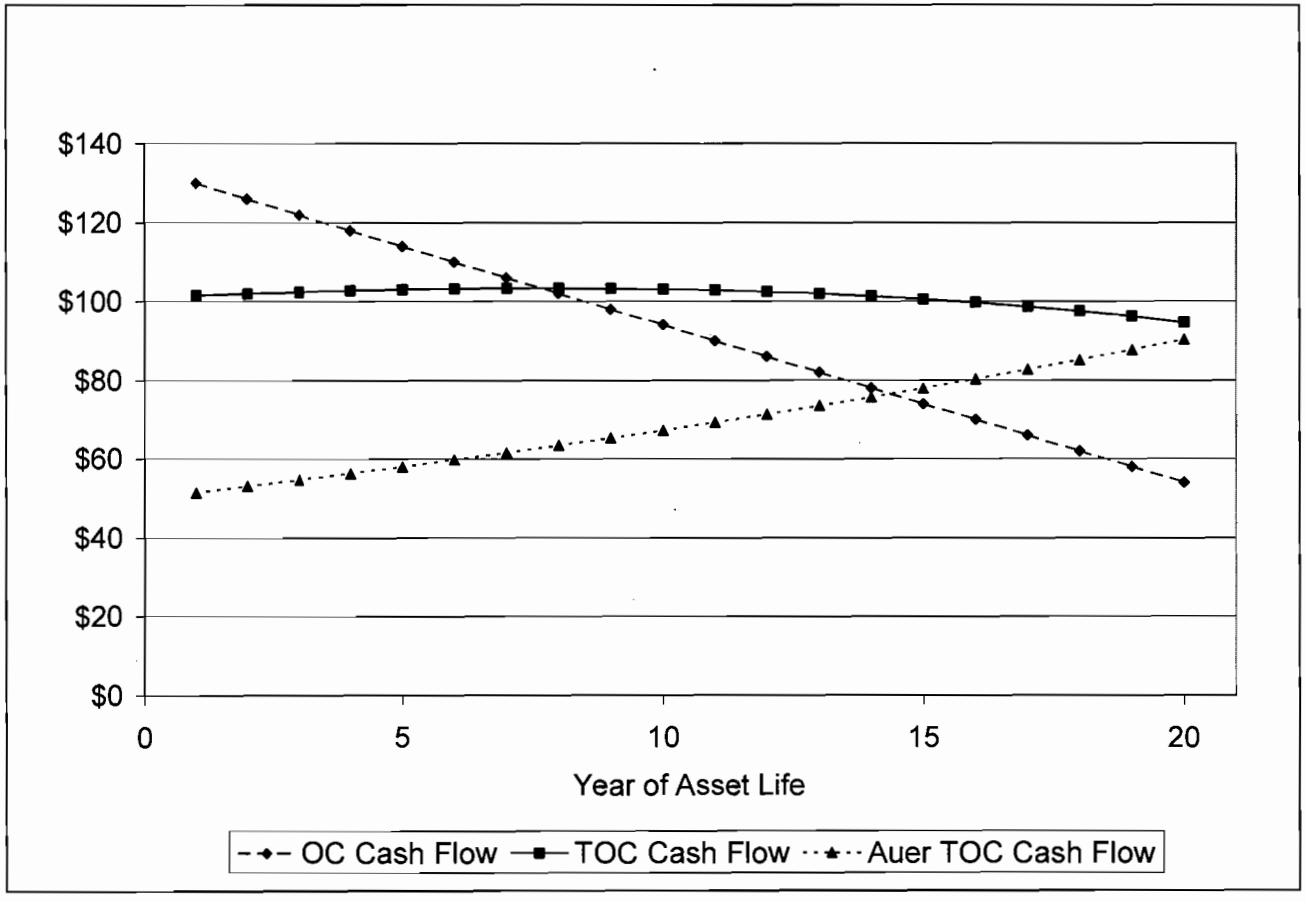
FIGURE 4.2-1

ANNUAL CASH FLOWS UNDER OC VS. TOC VS. AUER VERSION OF TOC



$1,000 investment, 20-year life, 8% nominal cost of capital, 3% inflation

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FIGURE 4.6-1

PREFERENCE CUSTOMERS DEMAND AND ENERGY CHARGES

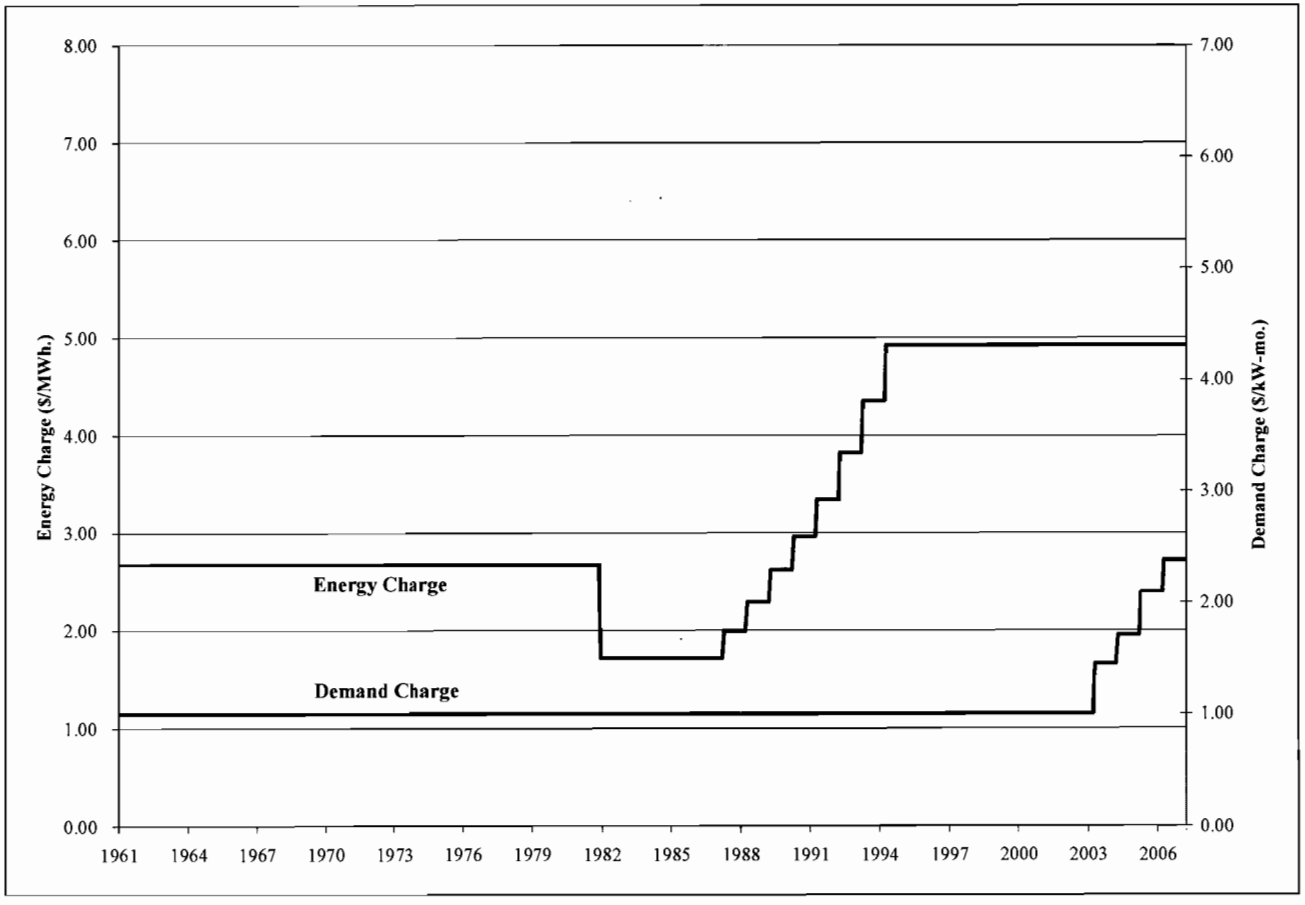

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FIGURE 4.7-1

EXPANSION CUSTOMERS DEMAND AND ENERGY CHARGES

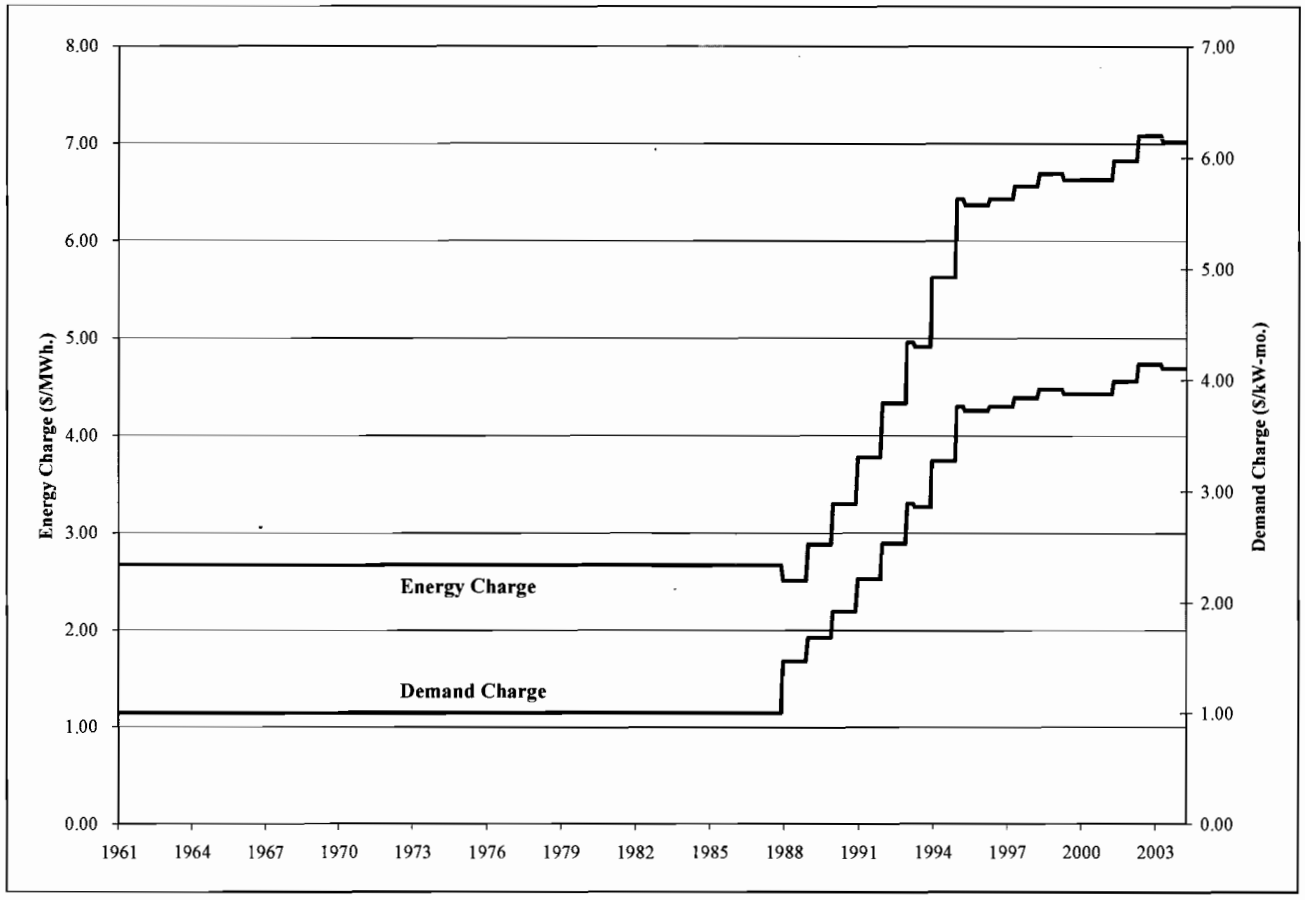

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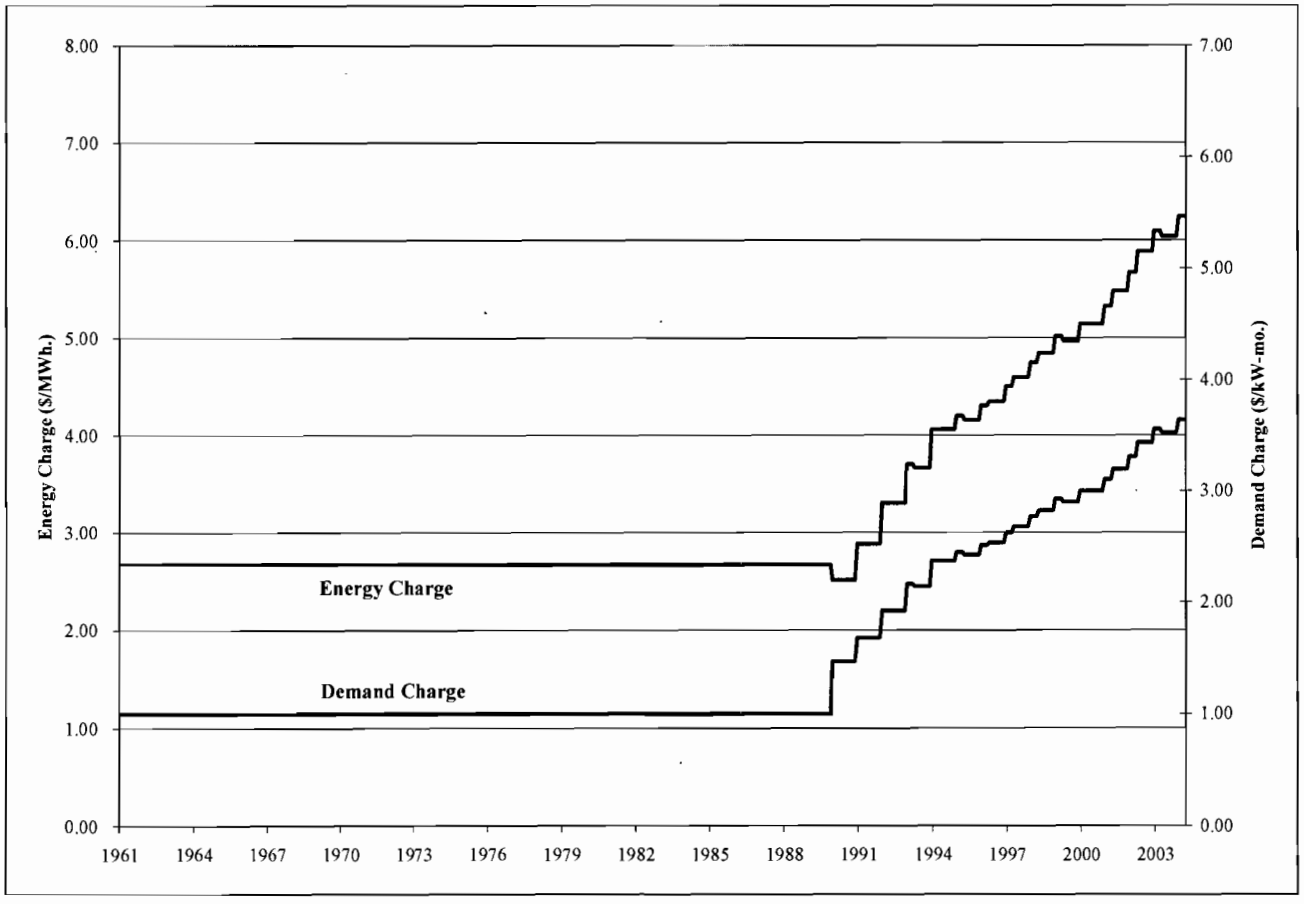
FIGURE 4.8-1

REPLACEMENT CUSTOMERS DEMAND AND ENERGY CHARGES



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5.0 OPPORTUNITIES FOR UTILIZING PROJECT POWER

Over a third of all New York residential customers receive some benefit from Niagara's supply of inexpensive power. Residential customers served by Preference Power recipients number about 153,000, or about 2% of the total New York State residential customer base. In 2002, the residential customers of Preference Power recipients used about 1.8 million MWh, 4% of the state total residential retail sales. In addition, another 2.4 million up-state investor-owned utility customers, or 33% of the state's residential customers, receive at least some portion of their electricity at preference power rates. They consumed 17.8 million MWh in 2002 (39% of total New York residential sales). All recipients of Niagara Project power receive power at prices well below New York State's average price thus providing an electricity cost advantage over competitors.

Niagara Project power provides a very inexpensive source of electricity for New York and the surrounding states, which understandably promotes interest in obtaining access to this resource. In any event, opportunities to obtain new allocations will continue to be governed and constrained by the NRA, state legislation, court rulings, and present contracts.

5.1 Available Expansion and Replacement Power

As Replacement and Expansion Power becomes available over time, allocations to qualified applicants are made according to legal and legislative requirements. As of July 2005 there are approximately 75 MW of Replacement Power and 44 MW of Expansion Power available for qualified recipients. While temporarily available, this power cannot be reallocated to alternative recipients on a long-term basis because it must be reserved for those industrial and commercial customers for whom it is intended under Federal and State law.

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5.2 Expiring Power Contracts and Allocations

The Replacement Power allocation requirement under the NRA will expire on December 31, 2005. However, many of the allocations are subject to extension to 2013 provided the Project is relicensed and NYPA is legally authorized to do so. See Sections 3.3.1 and 3.3.4 above for a discussion of new state legislation expected to be approved which would govern the reallocation and use of unallocated RP.

Out-of-state preference contracts currently expire at the end of the current license on August 31, 2007. These contracts account for 10% of project power (228 MW). However, under the NRA (as currently interpreted by FERC and the courts) out-of-state preference customers will continue to be entitled to up to 10% of Project power, and thus no portion of this allocation would become available for alternative use within New York. In-State Preference Power and Expansion Power allocations are not due to expire until September 2025 and June 2013, respectively, provided the Project license is renewed on terms allowing such extensions.

The contracts with three upstate investor-owned utilities expire at the end of the current license on August 31, 2007. Currently, these contracts allocate 301 MW of firm power and 360 MW of firm peaking power to the residential customers of Niagara Mohawk, New York State Electric & Gas and Rochester Gas & Electric. Except for the general priority for residential use in the Power Authority Act, there are no statutory restrictions that prohibit this portion of Niagara Project Power from being reallocated to other recipients, nor are there any requirements on the Power Authority to alter the existing arrangements.

5.3 RMNPP Upgrade

There is presently a turbine upgrade program in process at the Niagara Project. However, this is not going to result in significant increased firm capacity. It is estimated that about 35 MW of new firm power will be available, one-half of which will have to be made available to Preference customers (in-

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state and out of state) under the NRA requirements. The other half has been earmarked for use by the Host Communities.

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TABLE 5.4-1

CONTRACTS FOR PROJECT POWER

Power Type	Contract Number	Contract Date	Expiration Date	Power Available for Contract (MW)	Notes
In-State Preference	Multiple	11/24/1986	09/01/2025	752 Firm	Contracts were executed 11/24/1986 with additional amendments executed 8/16/1991 and 3/30/2004. Service ending beyond NPP license expiration subject to FERC license renewal. Covers 40% of Project power.
Out-of-State Preference	Multiple	02/28/1990	08/31/2007	188 Firm 40 Firm Peaking	Power totaling 228 MW was supplied to Out-of-State preference customers beginning 7/1/1985. Covers 10% of Project power.
Replacement	NS-1	02/10/1961	12/31/2005	445 Firm	Under NRA Replacement Power (445 MW) expires at the term of original project bonds. Bills in New York Legislature would extend the authority under PAL § 1005.
Expansion	NS-1 NS-11	02/22/1989	06/30/2013	250 Firm	Many of the allocations are subject to extension to 2013 provided the Project is relicensed and NYPA is legally authorized to do so. Allocation is 250 MW. Expiration date subject to renewal of NPP license.
Upstate Utilities – Residential	NS-1 NS-11 NS-13	02/22/1989	08/31/2007	301 Firm 360 Firm Peaking	All sales passed on to domestic and rural consumers.

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APPENDICES

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APPENDIX A

Table A-1 (next page) shows the allocations and sales of each New York municipal electric and rural cooperative utilities that receives preference power. The investigation area was determined from either U.S. Census data or the NYPA associated websites. The allocation and full/partial requirements data were reported in 2003 Report on the Sale and Distribution of Niagara Power while the sales data are compiled in New York Power Authority Operations Data for 2003.

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Table A-1
Summary of 2003 Municipal and Cooperative Power Agencies Preference Allocations and Sales

Entity	Investigation Area	Full Requirement or Partial Requirement Contract	Preference Power Allocation (kW)	Preference Sales (kWh)
Bath Electric Gas & Water Sys	NY	PARTIAL	13,380	74,508,109
City of Plattsburgh	NY	PARTIAL	102,755	509,910,823
City of Salamanca	WNY	PARTIAL	12,820	75,894,552
City of Sherrill	NY	FULL	11,800	64,274,218
Delaware County Elec Cooperative, Inc	NY	FULL	9,520	53,237,396
Jamestown Board of Public Util	WNY	PARTIAL	72,280	450,444,000
Lake Placid Village, Inc	NY	FULL	28,750	144,645,626
Mohawk Municipal Comm	NY	PARTIAL	4,260	21,042,098
Oneida-Madison Elec Coop, Inc	NY	FULL	3,500	18,821,359
Otsego Electric Coop, Inc	NY	FULL	7,900	45,339,866
Steuben Rural Elec Coop, Inc	NY	FULL	12,600	70,635,289
Town of Massena	NY	PARTIAL	22,460	131,797,460
Village of Akron	EC	PARTIAL	7,730	42,592,096
Village of Andover	NY	PARTIAL	1,400	7,292,671
Village of Angelica	NY	PARTIAL	1,600	7,818,415
Village of Arcade	WNY	PARTIAL	25,030	131,218,130
Village of Bergen	WNY	PARTIAL	2,400	15,877,417
Village of Boonville	NY	PARTIAL	12,730	64,622,513
Village of Brocton	WNY	PARTIAL	2,840	13,918,353
Village of Castile	WNY	PARTIAL	1,500	7,369,065
Village of Churchville	NY	PARTIAL	3,540	17,192,460
Village of Endicott	NY	PARTIAL	9,220	51,298,780
Village of Fairport	NY	FULL	76,540	421,948,431
Village of Frankfort	NY	PARTIAL	3,495	19,570,995
Village of Freeport	NY	PARTIAL	37,910	226,678,000
Village of Green Island	NY	PARTIAL	2,500	13,870,835
Village of Greene	NY	PARTIAL	6,690	32,496,569
Village of Greenport	NY	FULL	5,240	29,512,282
Village of Groton	NY	PARTIAL	4,400	21,823,628
Village of Hamilton	NY	PARTIAL	10,670	58,666,974
Village of Holley	WNY	PARTIAL	4,300	24,702,027
Village of Ilion	NY	PARTIAL	12,720	62,540,988
Village of Little Valley	WNY	PARTIAL	3,800	21,795,307
Village of Marathon	NY	FULL	4,250	20,087,950
Village of Mayville	WNY	FULL	4,470	25,840,925

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Table A-1 (cont.)

Entity	Investigation Area	Full Requirement or Partial Requirement Contract	Preference Power Allocation (kW)	Preference Sales (kWh)
Village of Penn Yan	NY	PARTIAL	12,890	74,635,682
Village of Philadelphia	NY	PARTIAL	2,070	9,795,563
Village of Richmondville	NY	PARTIAL	2,670	14,129,226
Village of Rockville Centre	NY	PARTIAL	28,460	163,309,000
Village of Rouses Point	NY	PARTIAL	14,600	98,664,275
Village of Sherburne	NY	PARTIAL	13,180	66,372,842
Village of Silver Springs	WNY	PARTIAL	900	5,038,275
Village of Skaneateles	NY	PARTIAL	5,050	27,753,589
Village of Solvay	NY	FULL	54,260	401,940,694
Village of Spencerport	NY	PARTIAL	12,460	57,799,761
Village of Springville	EC	PARTIAL	9,240	55,083,630
Village of Theresa	NY	PARTIAL	1,500	6,906,925
Village of Tupper Lake	NY	FULL	19,070	90,665,798
Village of Watkins Glen	NY	FULL	6,140	44,291,857
Village of Wellsville	NY	PARTIAL	10,200	59,278,020
Village of Westfield	WNY	FULL	12,510	76,120,427
Total			**752,200**	**4,251,071,171**

Sources: "2003 Report on the Sale and Distribution of Niagara Power" and "New York Power Authority Operations Data for 2003."

Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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APPENDIX B

Table B-1 (next page) uses retail sales data from EIA Form 861 and Niagara sales data from New York Power Authority Operations Data for 2003 to calculate the approximate percentage of Niagara power ultimately sold to residential customers. Using the EIA data, the percentage of residential to total retail sales for each municipal or cooperative agency is calculated. The percentage of residential sales is then multiplied by the entity's residential sales percentage to approximate the Niagara sales to residential customers. Accounting for the fact that the Niagara sales to residential customers cannot be larger than the actual residential retail sales, the proportion of Niagara sales to residential customers to total Niagara purchases approximates the percentage of Niagara sales sold to residential customers.

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Table B-1
Distributions to Domestic and Rural (i.e. Residential) Customers from Municipal and Cooperative Agencies, 2002 Sales

Entity	Full or Partial Requirements	Niagara Sales (GWh)	Total Retail Sales (GWh)	Niagara Sales as a Percentage of Total Retail Sales	Number of Residential Customers	Retail Sales to Residential Customers (GWh)	Percent of Total Sales to Residential Customers	Estimated Percentage of Niagara Sales to Residential Customers
Bath Electric Gas & Water Sys	PARTIAL	77.3	75.1	103%	3,767	39.1	52%	51%
City of Plattsburgh	PARTIAL	537.6	523.1	103%	7,814	142.9	27%	27%
City of Salamanca	PARTIAL	77.4	87.7	88%	2,963	39.4	45%	45%
City of Sherrill	FULL	65.7	67.2	98%	813	20.8	31%	31%
Delaware County Elec Cooperative, Inc	FULL	50.9	49.2	103%	4,781	40.2	82%	79%
Jamestown Board of Public Util	PARTIAL	472.8	523.6	90%	16,876	153.6	29%	29%
Lake Placid Village, Inc	FULL	148.8	147.8	101%	3,562	63.1	43%	42%
Mohawk Municipal Comm	PARTIAL	22.2	20.9	106%	1,217	12.8	61%	58%
Oneida-Madison Elec Coop, Inc	FULL	18.4	18.4	100%	1,725	18.0	98%	98%
Otsego Electric Coop, Inc	FULL	43.7	43.8	100%	3,932	38.7	88%	88%
Steuben Rural Elec Coop, Inc	FULL	67.0	61.2	109%	5,788	53.8	88%	80%
Town of Massena	PARTIAL	141.3	168.0	84%	7,985	89.6	53%	53%
Village of Akron	PARTIAL	45.4	52.1	87%	1,411	16.3	31%	31%
Village of Andover	PARTIAL	7.5	7.3	104%	491	4.8	66%	63%
Village of Angelica	PARTIAL	8.2	8.1	102%	632	5.7	71%	70%

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Table B-1 (cont.)

Entity	Full or Partial Requirements	Niagara Sales (GWh)	Total Retail Sales (GWh)	Niagara Sales as a Percentage of Total Retail Sales	Number of Residential Customers	Retail Sales to Residential Customers (GWh)	Percent of Total Sales to Residential Customers	Estimated Percentage of Niagara Sales to Residential Customers
Village of Arcade	PARTIAL	136.8	144.7	95%	3,382	60.9	42%	42%
Village of Bergen	PARTIAL	17.2	28.9	59%	578	8.1	28%	28%
Village of Boonville	PARTIAL	67.4	68.6	98%	2,675	42.3	62%	62%
Village of Brocton	PARTIAL	15.0	15.1	99%	777	9.3	62%	62%
Village of Castile	PARTIAL	8.0	7.8	103%	514	5.4	69%	67%
Village of Churchville	PARTIAL	18.5	17.9	103%	775	9.5	53%	52%
Village of Endicott	PARTIAL	54.1	50.8	107%	2,770	20.0	39%	37%
Village of Fairport	FULL	411.5	402.3	102%	14,570	230.2	57%	56%
Village of Frankfort	PARTIAL	20.6	27.0	76%	1,495	13.8	51%	51%
Village of Freeport	PARTIAL	230.4	268.2	86%	13,015	115.9	43%	43%
Village of Green Island	PARTIAL	13.8	16.2	85%	1,325	8.5	53%	53%
Village of Greene	PARTIAL	34.5	35.3	97%	1,102	15.2	43%	43%
Village of Greenport	FULL	28.7	26.8	107%	1,645	11.5	43%	40%
Village of Groton	PARTIAL	23.3	23.2	100%	918	13.8	59%	59%
Village of Hamilton	PARTIAL	61.9	59.9	103%	1,202	19.9	33%	32%
Village of Holley	PARTIAL	25.9	25.7	101%	817	9.8	38%	38%
Village of Ilion	PARTIAL	65.0	59.2	110%	3,469	37.9	64%	58%
Village of Little Valley	PARTIAL	22.1	24.6	90%	1,055	11.4	46%	46%
Village of Marathon	FULL	19.5	17.9	109%	669	9.9	55%	51%
Village of Mayville	FULL	24.9	30.2	83%	901	14.7	49%	49%

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Table B-1 (cont.)

Entity	Full or Partial Requirements	Niagara Sales (GWh)	Total Retail Sales (GWh)	Niagara Sales as a Percentage of Total Retail Sales	Number of Residential Customers	Retail Sales to Residential Customers (GWh)	Percent of Total Sales to Residential Customers	Estimated Percentage of Niagara Sales to Residential Customers
Village of Penn Yan	PARTIAL	77.8	76.8	101%	2,614	26.2	34%	34%
Village of Philadelphia	PARTIAL	10.3	9.5	108%	633	6.6	69%	63%
Village of Richmondville	PARTIAL	14.8	16.4	90%	865	10.3	63%	63%
Village of Rockville Centre	PARTIAL	167.4	185.1	90%	8,939	82.2	44%	44%
Village of Rouses Point	PARTIAL	103.3	131.2	79%	1,086	22.7	17%	17%
Village of Sherburne	PARTIAL	72.6	75.5	96%	1,619	26.9	36%	36%
Village of Silver Springs	PARTIAL	5.3	5.8	91%	358	3.2	55%	55%
Village of Skaneateles	PARTIAL	28.6	29.2	98%	1,217	14.2	49%	49%
Village of Solvay	FULL	381.4	440.0	87%	4,805	54.8	12%	12%
Village of Spencerport	PARTIAL	60.2	61.9	97%	2,299	40.2	65%	65%
Village of Springville	PARTIAL	57.0	57.2	100%	2,082	22.7	40%	40%
Village of Theresa	PARTIAL	6.9	5.9	118%	401	4.4	75%	64%
Village of Tupper Lake	FULL	90.9	88.2	103%	3,267	51.4	58%	57%
Village of Watkins Glen	FULL	42.5	51.2	83%	984	9.5	19%	19%

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Table B-1 (cont.)

Entity	Full or Partial Requirements	Niagara Sales (GWh)	Total Retail Sales (GWh)	Niagara Sales as a Percentage of Total Retail Sales	Number of Residential Customers	Retail Sales to Residential Customers (GWh)	Percent of Total Sales to Residential Customers	Estimated Percentage of Niagara Sales to Residential Customers
Village of Wellsville	PARTIAL	63.5	62.5	102%	2,236	18.4	29%	29%
Village of Westfield	FULL	74.4	65.4	114%	2,437	29.5	45%	40%
Total		**4,340**	**4,566**	**95%**	**153,253**	**1,830**	**40%**	**40%**

Note: The column representing the "Estimated Percentage of Niagara Sales to Residential Customers" is calculated by multiplying the percentage of each entity's residential sales compared to total sales (from EIA Form 861) by the total Niagara Sales (capped at Retail Sales to Residential Customers) divided by the total Niagara Sales. The cap is necessary in order to account for Niagara sales in some cases exceeding total retail sales possibly due to transmission losses or a variety of other possible reasons. Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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Table B-2
Out-of-State 2003 Preference Allocations and Sales

Entity	Preference Power Allocation (kW)	Preference Sales (GWh)	Percent of Out-of-State Preference Sales	Rule or Practice to Deliver Power to Domestic & Rural Customers	Percentage for Domestic & Rural Customers	Approximate Sales to Residential & Domestic Customers (GWh)
Allegheny Electric Cooperative, Pennsylvania	47,900	228.5	19.9%	Yes	100.0%	228.5
City of Cleveland, Ohio	63,800	317.9	27.7%	No	77.0%	244.7
Connecticut Municipal Electric Energy Coop.	15,500	82.7	7.2%	No	33.0%	27.3
Public Power Association of New Jersey	13,800	63.9	5.6%	No	46.5%	29.7
Massachusetts Department of Public Utilities	72,200	385.2	33.5%	Yes	100.0%	385.2
Rhode Island Public Utilities Commission	800	4.1	0.4%	No	53.8%	2.2
Vermont Department of Public Service	14,000	66.5	5.8%	Yes	100.0%	66.5
Total	228,000	1,148.7	100.0%		85.7%	984.1

Sources: "2003 Report on the Sale and Distribution of Niagara Power," "New York Power Authority Operations Data for 2003," and EIA. Sources for rule or practice columns from stakeholder comments and NYPA survey. New Jersey and Rhode Island percentage of domestic and rural customers calculated by dividing the sales to residential customers by the total sales by all publicly owned and cooperative systems in the state (energy sales from EIA). Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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APPENDIX C

Table C-1 (next page) provides a list of expansion and replacement customers and their respective allocations, along with the area in which each customer operates based upon location data provided by NYPA.

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Table C-1
Allocation of Replacement And Expansion Power by Customer, January 1, 2004

Customer	Replacement Power Allocation (kW)	Expansion Power Allocation (kW)	Total Allocation (kW)	Investigation Area
3M		1,500	1,500	EC
ADM Milling	1,900	1,500	3,400	EC
Al-Ag Corp	500		500	HC
Allied Signal Inc	300		300	EC
American Axle & Manufacturing	3,200	3,000	6,200	EC
American Axle & Manufacturing - Tonawanda	3,900	3,250	7,150	EC
American Pharmaceutical Partners	1,500		1,500	EC
Avery	250		250	EC
Bioconvergence	1,250		1,250	HC
BOC Gases		11,250	11,250	EC
Bristol Myers Squibb	250	750	1,000	EC
Brunner Inc	2,500	1,800	4,300	WNY
Buffalo Color Corp	2,216		2,216	EC
Buffalo Newspress Inc		250	250	EC
Buffalo Tungsten Inc	2,050		2,050	EC
C&S Wholesale Grocers Inc		300	300	EC
Caplugs LLC		250	250	EC
Ceres Corp	4,600		4,600	HC
Client Logic		250	250	EC
Cliffstar Corp		500	500	WNY
Confer Plastics	550		550	NC
Coyne Textile Services		350	350	EC
Curtis Screw Co. Inc	650		650	EC
Dunkirk Specialty Steel LLC		6,800	6,800	WNY
Goodyear Dunlop Tire North America Ltd.	5,541	6,000	11,541	EC
EI Dupont DE Nemours & Co	2,475	1,800	4,275	EC
EI Dupont DE Nemours & Co	31,700	1,450	33,150	HC

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Table C-1 (cont.)

Customer	Replacement Power Allocation (kW)	Expansion Power Allocation (kW)	Total Allocation (kW)	Investigation Area
Fairbank Reconstruction Co		700	700	WNY
Ferro Electronic Materials Inc	11,115	3,000	14,115	HC
Fieldbrook Farms Ice Cream		3,000	3,000	WNY
FMC Corp-Inorganic Chemical	6,250		6,250	EC
Ford Motor Company - Buffalo S		7,200	7,200	EC
Freezer Queen Foods Inc	360	1,050	1,410	EC
General Mills Inc	4,100	1,000	6,100	EC
General Motors Powertrain	2,725	15,700	18,425	EC
Gibralter Metals	550		550	EC
Globe Metallurgical Inc	20,000	23,000	43,000	HC
Graphic Controls	250		250	EC
Habasit	250		250	EC
Hydro Air Components Inc		250	250	EC
I Squared R Element Co	500		500	EC
Ingram Micro Inc		900	900	EC
International Imaging Material	250	2,750	3,000	EC
International Steel Group-ISG Corp	25,750	9,650	35,400	EC
Invitrogen Corp	400		400	EC
IsleChem. LLC	325		325	EC
Ivaco	260		260	EC
Kanthal Globar	2,100		2,100	HC
Lockheed Martin	250		250	HC
MacNail Polymers		250	250	EC
Metallics Systems Co LP	1,000		1,000	HC
Nestle Purina Petcare		2,900	2,900	WNY
Niacet Corp	1,400		1,400	HC
Niagara Ceramics Corp	1,100		1,100	EC

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Table C-1 (cont.)

Customer	Replacement Power Allocation (kW)	Expansion Power Allocation (kW)	Total Allocation (kW)	Investigation Area
Niagara Falls Wastewater Treatment	1,644		1,644	HC
Niagara Falls Water Treatment	2,000		2,000	HC
Niagara Lasalle Corp	700		700	EC
Norampac Industries Inc.		1,600	1,600	HC
North American Hoganas Inc	1,000	4,000	5,000	HC
Now-Tech Industries	250		250	EC
Nuttall Gear Corp		350	350	HC
Occidental Chemical Corp	65,400	38,700	104,100	HC
Olin Corp	77,160		77,160	HC
Olin Corp	2,290		2,290	HC
Outokumpu American Brass	10,460		10,460	EC
Praxair Inc	48,450		48,450	HC
Praxair Inc-Linde Div	2,750	4,450	7,200	EC
PrecIOU's Plate Inc	800		800	HC
Precision Electro Minerals Co	1,550		1,550	HC
Republic Engineered Products LLC	2,000	7,400	9,400	EC
Rich Products Corp	1,000		1,000	EC
Russer Foods - Div of Zemco I		2,250	2,250	EC
Saint-Gorbain Abrasives Co	2,200		2,200	HC
Saint-Gorbain Corp	3,070		3,070	EC
Saint-Gorbain Corp	3,750		3,750	HC
Saint-Gorbain Corp	1,850		1,850	HC
Saint-Gorbain Corp	900		900	HC
SGL Carbon	9,658		9,658	HC
Sherwood, Harsco Corp		400	400	HC
Sherwood, Harsco Corp - Lockport		240	240	NC
Sorento Lactalis Inc	250		250	EC

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Table C-1 (cont.)

Customer	Replacement Power Allocation (kW)	Expansion Power Allocation (kW)	Total Allocation (kW)	Investigation Area
Special Metals Div Al Ludlum		1,000	1,000	WNY
Stollberg Inc		300	300	HC
Sun Orchard Fruits	700		700	NC
The Carriage House Companies		750	750	WNY
The Carriage House Companies, Inc		500	500	WNY
Treibacher Schleifrittel	750		750	HC
Trico Products Corp		250	250	EC
Tulip Corp	1,200	300	1,500	HC
Unifrax Corp	5000		5,000	EC
Viking Industries, LLC	1,000	500	1,500	EC
Viking Lockport, LLC		300	300	NC
Washington Mills Electro Miner	9,700		9,700	HC
Monofrax		2,082	2,082	WNY
Valeo Engine Cooling		1,000	1,000	WNY
American Axle		250	250	EC
Atlas Cold Storage America		500	500	EC
C&S Wholesale - Tops Markets		550	550	EC
Carleton Tech.		700	700	EC
Delphi Automotive Systems, LLC		14,300	14,300	WNY
International Multifoods		300	300	NC
LEICA, Inc.		450	450	EC
McGard		250	250	EC
Moog, INC.		4,250	4,250	EC
Motorola		4,600	4,600	EC
Quebecor Buffalo		5,000	5,000	EC
Rosina		400	400	EC

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Table C-1 (cont.)

Customer	Replacement Power Allocation (kW)	Expansion Power Allocation (kW)	Total Allocation (kW)	Investigation Area
Servotronics Inc.		500	500	EC
Steuben Foods		5,750	5,750	EC
Total	**401,749**	**216,522**	**618,271**	
Changes Between January 1, 2004 and July 1, 2004 Allocation				
Buffalo Color Corp	700	0	700	EC
Certain Teed Corp†	0	3,500	3,500	EC
General Mills Inc	1,000	0	1,000	EC
GEICO†	0	1,600	1,600	EC
Gibralter Metals	(550)	0	(550)	EC
Globe Metallurgical Inc*	(20,000)	(23,000)	(43,000)	HC
International Imaging Material	0	(500)	(500)	EC
Ivaco Steel Processing*	(260)	0	(260)	EC
Nestle Purina Petcare	0	500	500	WNY
NFB Carbon Products†‡	3,342	0	3,342	HC
Niacet Corp	0	500	500	HC
Niagara Ceramics Corp	(250)	250	0	EC
Niagara Lasalle Corp	700	0	700	EC
Norampac Industries Inc.	300	0	300	HC
Occidental Chemical Corp	(9,400)	0	(9,400)	HC
Outokumpu American Brass	1,100	0	1,100	EC
Plesh Industries, Inc†	200	0	200	EC
Praxair Inc	(2,400)	0	(2,400)	HC
Praxair Inc-Linde Div	0	(450)	(450)	EC
Soteck Inc/Beirlix Ind, Inc	100	0	100	EC
Sun Orchard Fruits*	(700)	0	(700)	NC
Sweeny Steel Services - Buffalo†	450	0	450	EC

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Table C-1 (cont.)

Customer	Replacement Power Allocation (kW)	Expansion Power Allocation (kW)	Total Allocation (kW)	Investigation Area
Sweeny Steel Services - Tonawanda†	1,750	0	1,750	EC
Time Release Sciences, Inc†	600	0	600	EC
Trico Products Corp*	0	(250)	(250)	EC
American Axle	0	800	800	EC
Upstate Farms†	0	1,000	1,000	EC
Current (July 2004) Total	378,431	201,972	580,403	

† New customer
* Customer's allocations eliminated
‡ NFB Carbon acquired SGL Carbon's facility including replacement allocation

Source: NYPA.

Replacement and Expansion totals do not equal the total capacity set aside due to unallocated power.

HC: City of Niagara Falls, Town of Lewiston (includes Village of Lewiston), and the Town of Niagara. NC: Niagara County. EC: Erie County. WNY: Western New York, including the counties of Niagara, Erie, Genesee, Orleans, Wyoming, Chautauqua, Cattaraugus, and Allegany Counties.

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APPENDIX D

Table D-1 (next page) combines NYPA data indicating the location of and the entity serving the contracted recipients of expansion and replacement power, and the replacement and/or expansion allocation data. Note, the allocations are cumulative for regions containing previously defined areas, *i.e.*, the allocation for Western New York includes the allocations for Niagara and Erie counties and thus, columns to not equal the sum of all listed allocations.

Table D-2 aggregates the Replacement and Expansion Power allocations from Table D-1 to provide a summary geographic distribution table of Replacement and Expansion Power.

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Table D-1
2003 Expansion and Replacement Power Geographic Distributions

Region	Replacement Power Allocation (kW)	Expansion Power Allocation (kW)	Total Allocation (kW)
NIAGARA MOHAWK			
Niagara Frontier and Subregions			
Host Communities	304,217	72,700	376,917
Remaining Niagara County	1,250	0	1,250
Niagara County Subtotal	305,467	72,700	378,167
Erie County	93,782	84,050	177,832
Niagara Frontier Subtotal	399,249	156,750	555,999
Remaining Western New York	2,500	17,950	20,450
Niagara Mohawk Total	**401,749**	**174,700**	**576,449**
NEW YORK STATE ELECTRIC & GAS			
Western New York Subregions			
Host Communities	0	400	400
Remaining Niagara County	0	15,140	15,140
Niagara County Subtotal	0	15,540	15,540
Erie County	0	23,200	23,200
Niagara Frontier Subtotal	0	38,740	38,740
Remaining Western New York	0	0	0
NYSEG Total	**0**	**38,740**	**38,740**
OTHER			
Niagara Frontier and Subregions			
Host Communities	0	0	0
Remaining Niagara County	0	0	0
Niagara County Subtotal	0	0	0
Erie County	0	0	0
Niagara Frontier Subtotal	0	0	0
Remaining Western New York	0	3,082	3,082
Total Other	**0**	**3,082**	**3,082**
TOTAL	**401,749**	**216,522**	**618,271**

Source: NYPA. Niagara Frontier includes Niagara & Erie Counties. Western New York includes Niagara, Erie, Genesee, Orleans, Wyoming, Chautauqua, Cattaraugus, and Allegany Counties. Replacement and Expansion totals do not equal the total capacity set aside due to unallocated power. "Other" is 3,082 kw of power allocated to EP customers located in the City of Jamestown.

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Table D-2
Expansion and Replacement Power Geographic Distributions

Region	Replacement Power Allocation (kW)	Expansion Power Allocation (kW)	Total Allocation (kW)
Western New York & Subregions			
Host Communities	304,217	73,100	377,317
Remaining Niagara County	1,250	15,140	16,390
Niagara County Subtotal	305,467	88,240	393,707
Erie County	93,782	107,250	201,032
Niagara FrontierSubtotal	399,249	195,490	594,739
Remaining Western New York	2,500	21,032	23,532
Total	**401,749**	**216,522**	**618,271**

Source: NYPA

Niagara Frontier includes Niagara and Erie Counties. Western New York includes Niagara, Erie, Genesee, Orleans, Wyoming, Chautauqua, Cattaraugus, and Allegany Counties. Replacement and Expansion totals do not equal the total capacity set aside due to unallocated power.

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APPENDIX E

Since county-by-county data for the distribution of Niagara power to Upstate IOUs is unavailable, the Table E-1 (next page) uses estimates based on U.S. Census, EIA, and NYPA data. The distribution of IOU residential customers was estimated using the U.S. Census, EIA data, and IOU maps of service territory. The share of each New York counties electric customers is approximated with the total approximating the total customers and population served and the percentage of each Upstate IOUs customers in each geographic region is approximated. These percentages are then multiplied by the allocations and the energy sales to create the geographic distribution of Upstate IOU sales to residential customers. Table E-2 aggregates the three IOU residential customer estimates from Table E-1 to provide a summary geographic distribution table of IOU residential customers served by Niagara Project Power.

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Table E-1
Geographic Distribution of Upstate IOU's - Residential Power & Sales by Upstate IOU

Region	Number of Residential Customers	Upstate IOU's - Residential Power (MW)	Upstate IOU's - Residential Sales (GWh)
NIAGARA MOHAWK			
Niagara Frontier and Subregions			
Host Communities	32,281	7	22
Remaining Niagara County	34,236	8	23
Niagara County Subtotal	66,517	15	45
Erie County	305,463	67	205
Niagara Frontier Subtotal	371,980	82	249
Western New York	468,184	103	314
New York	1,369,959	301	919
Niagara Mohawk Total	1,369,959	301	919
NEW YORK STATE ELECTRIC & GAS			
Niagara Frontier and Subregions			
Host Communities	0	0	0
Remaining Niagara County	22,623	8	24
Niagara County Subtotal	22,623	8	24
Erie County	77,918	28	84
Niagara Frontier Subtotal	100,540	37	108
Western New York	128,612	47	138
New York	715,299	260	770
NYSEG Total	715,299	260	770
ROCHESTER GAS & ELECTRIC			
Niagara Frontier and Subregions			
Host Communities	0	0	0
Remaining Niagara County	0	0	0
Niagara County Subtotal	0	0	0
Erie County	0	0	0
Niagara Frontier Subtotal	0	0	0
Western New York	14,572	5	23
New York	281,565	100	445
RG&E Total	281,565	100	445
TOTAL	**2,366,823**	**661**	**2,134**

Sources: US Census, NYPA, "New York Power Authority Operation Data for 2003," and 2002 EIA Form 861, Table 14.
Niagara Frontier includes Niagara and Erie Counties. Western New York includes Niagara, Erie, Genesee, Orleans, Wyoming, Chautauqua, Cattaraugus, and Allegany Counties.
Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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Table E-2
Geographic Distribution of Upstate IOU's - Residential Power & Sales

Region	Upstate IOU's - Residential Power (MW)	Upstate IOU's - Residential Sales (GWh)	Number of Customers
Western New York & Subregions			
Niagara County			
Host Communities	7	22	32,281
Remaining Niagara County	16	47	26,858
Niagara County Subtotal	23	69	89,140
Erie County	95	289	383,380
Niagara Frontier Subtotal	118	358	472,520
Western New York	155	476	611,368
New York	661	2,134	2,366,823
Total	**661**	**2,134**	**2,366,823**

Sources: US Census, NYPA, "New York Power Authority Operation Data for 2003," and 2002 EIA Form 861, Table 17.

Niagara Frontier includes Niagara and Erie Counties. Western New York includes Niagara, Erie, Genesee, Orleans, Wyoming, Chautauqua, Cattaraugus, and Allegany Counties.

Data underlying table include substitute energy sales. Substitute energy sales are not a Niagara Power Project product. Substitute energy accounts for approximately 1% of sales and does not substantially affect project allocations.

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EXHIBIT_FWR-4

Demand (KW)	Total 2011	Total 2012	Total 2013	Total 2014
RP & EP	6,841,703	7,083,056	7,497,563	8,029,728
Full (w/Peaking) Munis (Hydro)	1,861,891	1,868,904	1,876,412	1,885,568
Partial (w/Peaking) Munis (Hydro)	6,490,466	6,518,482	6,544,662	6,569,653
R&D (Niagara - Firm & Peaking)	6,756,000	6,756,000	6,756,000	6,756,000
R&D (St. Lawrence - Firm)	2,990,400	2,990,400	2,990,400	2,990,400
NS (Niagara - Firm & Peaking)	2,785,200	2,785,200	2,785,200	2,785,200
NS (St. Lawrence - Firm)	414,000	414,000	414,000	414,000
Miscellaneous (Marcy, NFTA & MTA)	156,614	156,614	156,614	156,614
ALCOA (Firm & Interruptible)	2,445,076	2,415,583	2,665,424	2,653,583
Reynolds (Firm & Interruptible)	1,893,646	2,596,550	2,746,454	2,739,350
GM	12,000	12,000	0	0
Relicensing Customers (Power)	300,000	300,000	300,000	300,000
Relicensing Customers (Monetized)	384,000	384,000	384,000	384,000
RP -> ECSB (Monetization)	319,056	319,056	319,056	0
NS -> Brookhaven (Monetization)	0	0	0	0
Brookhaven (Niagara - Firm Hydro)	12,000	12,000	12,000	12,000
Brookhaven (St. Lawrence - Firm Hydro)	168,000	168,000	168,000	168,000
Preservation Power	15,600	15,600	15,600	15,600
Massena Monetized	240,000	240,000	240,000	240,000
	34,085,651	**35,035,446**	**35,871,385**	**36,099,696**

Energy MWH	Total 2011	Total 2012	Total 2013	Total 2014
RP & EP	4,162,859	4,300,078	4,513,381	4,820,499
Full (w/Peaking) Munis (Hydro)	1,005,290	1,011,828	1,012,255	1,016,590
Partial (w/Peaking) Munis (Hydro)	3,333,950	3,358,621	3,361,644	3,374,601
R&D (Niagara - Firm & Peaking)	1,659,859	1,664,536	1,659,859	1,659,859
R&D (St. Lawrence - Firm)	1,627,075	1,631,698	1,627,075	1,627,075
NS (Niagara - Firm & Peaking)	1,274,360	1,278,161	1,274,360	1,274,360
NS (St. Lawrence - Firm)	218,113	218,767	218,113	218,113
Miscellaneous (Marcy, NFTA & MTA)	61,216	61,404	61,216	61,216
ALCOA (Firm & Interruptible)	1,745,178	1,732,990	1,913,598	1,909,163
Reynolds (Firm & Interruptible)	1,369,577	1,874,371	1,985,527	1,984,991
GM	3,592	3,601	0	0
Relicensing Customers (Power)	153,294	153,714	153,294	153,294
Relicensing Customers (Monetized)	196,224	196,762	196,224	196,224
RP -> ECSB (Monetization)	186,329	186,839	186,329	0
NS -> Brookhaven (Monetization)	0	0	0	0
Brookhaven (Niagara - Firm Hydro)	6,990	7,036	7,008	7,008
Brookhaven (St. Lawrence - Firm Hydro)	97,866	98,510	98,112	98,112
Preservation Power	7,972	7,993	7,972	7,972
Massena Monetized	122,640	122,976	122,640	122,640
	17,232,383	**17,909,884**	**18,398,607**	**18,531,716**

EXHIBIT_FWR-5

NYPA Responses to Data Requests
of
The Neighboring States (NS)

NS 18:

Provide the Rate Stabilization Reserve calculations and related workpapers for each of the years 2008, 2009 and 2010.

Response:

The Rate Stabilization Reserve calculation is contained in the COS files provided in the response to NS 9 above. Additional files being sent in response to this request are the calculation of the UCAP credit for each of the years 2008, 2009, 2010. These files are contained in the attached file:

"UCAP Credit 2008-10.zip

2010 UCAP CREDIT - GLOBAL SETTLEMENT AGREEMENT

	MW
2010 Actual Demand - customers	**32,711**
2010 UCAP Auction	6,954
NYPA internal net UCAP transfers	1,874
Total sales of capacity	41,539
2010 - base level of capacity sales per 2007 rate case	**36,137**
Net amount - capacity	5,402
Average rate per kW	1.33
Amount of credit (000s)	$ 7,209

EXHIBIT_FWR-6

Tab Color Scheme:

	Data Entry Required
	NO Entry Required
	Copy/Paste from GPIS Model

Cost of Service Year (Enter as text):		2010	
Cost of Service Year (Enter as number):		2010	
UCAP Credit (000s):	2010	(7,209)	transfers to Exh III 1

Expansion Power Rates in effect for:

2010	Demand $/kW	Energy Mills/kWh	
(Jan-Apr)	5.17	8.84	transfers to Exh IV 1
(May-Dec)	5.17	8.84	

Debt Service (000s) for:		Principal	Interest	Total	
Greene County				-	transfers to Exh IV 1
Arthur Kill				-	transfers to Exh IV 2
Projects' Study				-	transfers to Sched 3
WPO Debt & Y2K	2010		572.3	572.3	transfers to Sched 3
R&D Expense:	2010			9,699.0	transfers to Sched 3

Production Labor Ratio for functionalization:		2010	75%	transfers to Sched 3
Production Labor Ratio for allocation:				
3-year total amount:	NIA Production	39.8%	85,188	transfers to Sched 4
	STL Production	17.3%	39,092	transfers to Sched 4
	Total Production	58.1%	213,930	transfers to Sched 4

Other Postemployment Benefits (OPEB) in thousands:

Unfunded Liability @ 1/1/2010		$	181,440
Annual OPEB Cost - Buck Report		$	32,067
Normal Cost (Beg. Of Year)			7,906
Amount to be allocated using labor	2010		24,161
NIA production functionalization x allocation		29.9%	7,224
STL production functionalization x allocation		13.0%	3,141
		43.6%	10,365

LTA generation Schedule 10 for:		2010	20,210	GWH	
	Number used in:				
	Ex II 1 (line 3)				
	Exh III 1 (line 6)				
	Exh IV 1 (line 2)				
Annual generation from system generation report:		2010	19,853	GWH	19,853

Tabs that require data input:

Ex II 1	Weighted average demand rate before Ancillary Services credit
Ex II 4	Pasted from GPIS model (same as Sched 1)
Exh III 2	Historical data is manually entered
Exh IV 2	Historical data is manually entered; current year has formula
Sched 1	Pasted from GPIS model (same as Ex II 4)
Sched 2	Data from Accounting
Sched 6	Data from Accounting
Sched 7	Historical data -- does not change; Inflation Factors from GPIS model
Sched 8,8a,8b,9,9a & 9b	Data feeds from NIA Sales and STL Sales tabs
Sched 10	NIA and STL net generation from billing group report: "MONTHLY SYSTEM GENERATION AND SUMMARY REPORTS"

EXHIBIT II

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
RURAL & DOMESTIC
COST-BASED RATES
2010 CALENDAR YEAR COSTS

LINE NO.	DESCRIPTION	AMOUNT ($000) (1)	BILLING DETERMINANTS DEMAND (MW) 4/ (2)	ENERGY (GWH) 5/ (3)	RATE (4)
1	PRODUCTION COST OF SERVICE 1/	250,251			
2	DEMAND COMPONENT 2/	108,928	32,711		3.33
3	ENERGY COMPONENT 3/	141,323		20,210	6.99 mills/kWh

1/ Exhibit II, Page 3.
2/ Col. (2) demand x weighted average demand rate per kW/Month.
The demand charge is inclusive of the Ancillary Services costs as calculated by the Brattle Group (see April 2003 Rate Modification Plan Appendix A, Exhibit 1, page 2, line 13) and by NYPA Staff (see April 2007 Rate Modification Plan Appendix A, Exhibit A, page 2, line 13).
By including the A/S costs in the demand charge as a revenue component, it is consistent with the cost side of the equation where they are also included.
3/ Line (1) less (2).
4/ Exhibit II, Page 2.
5/ Generation at long-term average.

EXHIBIT II

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
ACTUAL BILLING DEMANDS
2010 CALENDAR YEAR

LINE NO.	CUSTOMER	MW
1	NIAGARA MOHAWK	10,283.8
2	NEW YORK STATE ELECTRIC & GAS	4,370.8
3	ROCHESTER GAS & ELECTRIC	1,608.0
4	MUNICIPALS & COOPERATIVES	8,305.9
5	OUT OF STATE	3,199.2
6	ALUMINUM COMPANY OF AMERICA (ALCOA)	2,892.0
7	REYNOLDS COMPANY	0.0
8	ENERGY COST SAVINGS BENEFIT - 2005 LEGISLATION	752.8
9	WESTER NEW YORK ECONOMID DEV. FUND	375.2
10	GENERAL MOTORS CORPORATION	15.0
11	MARCY SUBSTATION	7.5
12	NYC METROPOLITAN TRANSPORTATION AUTHORITY	120.0
13	NIAGARA FRONTIER TRANSPORTATION AUTHORITY	36.7
14	NIAGARA RELICENSING POWER AND OTHER	744.0
15	TOTAL	32,711

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
ACTUAL PRODUCTION COST OF SERVICE
2010 CALENDAR YEAR

($000)

LINE NO.	DESCRIPTION	TOTAL
1	OPERATION & MAINTENANCE 1/	67,992
2	ADMINISTRATIVE & GENERAL 2/	5,139
3	O&M & A&G	73,131
4	MISCELLANEOUS 3/	25,065
5	INDIRECT OVERHEADS/SHARED SERVICES	58,089
6	DEPRECIATION 4/	38,858
7	INFLATION: TOC 4/	26,885
8	RETURN ON DEBT 4/	28,223
9	TOTAL CAPITAL	93,966
10	TOTAL COST OF SERVICE (Sum lines 3 thru 8)	250,251

1/ Exhibit II, Page 5.
2/ Exhibit II, Page 6.
3/ Includes Other Postemployment Benefits Accrual and relicensing grant payments.
4/ Exhibit II, Page 4.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
CAPITAL COST REQUIREMENTS
2010 CALENDAR YEAR

(1) Year	(2) Cumulative Investments	(3) Cumulative Retirements	(4) Depreciation	(5) Return on Debt	(6) Inflation Component	(7) Total Capital 1/
1981	958,836	100,153	13,719	-	21,684	35,403
1982	6,736	2,165	117	-	164	281
1983	2,829	429	116	-	150	265
1984	7,433	1,683	159	-	191	351
1985	2,849	1,019	86	-	95	181
1986	2,482	864	62	-	63	125
1987	5,734	2,107	139	-	135	274
1988	6,504	1,378	208	-	196	404
1989	7,021	2,388	200	-	167	367
1990	3,028	883	81	-	63	144
1991	8,402	738	183	-	140	323
1992	4,776	1,003	135	-	96	231
1993	42,429	812	1,046	-	710	1,756
1994	3,881	482	133	-	82	215
1995	20,648	580	524	-	290	814
1996	27,523	762	690	-	348	1,038
1997	26,248	377	625	-	304	929
1998	22,981	347	713	-	315	1,028
1999	47,027	2,750	1,090	334	398	1,822
2000	33,434	1,061	977	1,042	187	2,206
2001	41,167	790	924	1,302	107	2,334
2002	81,823	382	1,910	3,174	135	5,219
2003	77,187	362	1,949	2,611	224	4,784
2004	43,981	132	1,083	1,831	75	2,989
2005	136,149	119	3,181	5,626	206	9,013
2006	63,169	474	1,458	2,621	72	4,151
2007	165,921	(266)	4,364	6,561	260	11,184
2008	40,379	(187)	1,163	1,343	41	2,547
2009	74,136	-	1,823	1,778	(13)	3,587
Total	1,964,713	123,787	38,858	28,223	26,885	93,965

1/ Sum cols (4), (5), (6)

EXHIBIT II

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
PRODUCTION OPERATION AND MAINTENANCE EXPENSE
2010 CALENDAR YEAR

($000)

FERC ACCOUNT NUMBER	DESCRIPTION	TOTAL
535	OPERATION/SUPERVISION/ENGINEERING	4,955
537	HYDRAULIC EXPENSES	121
538	ELECTRIC EXPENSES	6,378
539	MISC HYDRAULIC POWER GENERATION	20,931
541	MAINTENANCE-SUPERVISION/ENG	3,276
542	MAINTENANCE-STRUCTURES	8,296
543	MAINTENANCE-RESERV/DAM/WATER	4,493
544	MAINTENANCE-ELECTRICAL PLANT	8,761
545	MAINTENANCE-MISC HYDRAULIC PLANT	8,495
	NYS PARKS PAYMENT-ST. LAWRENCE PROJECT	800
	AMORTIZED ROADWORK 1/	1,486
	PRODUCTION TOTAL	67,992

1/ Roadwork undertaken from 1993-1996 that is amortized over 15 years.

EXHIBIT II

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
PRODUCTION ADMINISTRATION & GENERAL EXPENSES
2010 CALENDAR YEAR

($000)

FERC ACCOUNT NUMBER	DESCRIPTION of A&G PRODUCTION EXPENSES	TOTAL
920	ADMINISTRATIVE & GENERAL SALARIES	0
921	OFFICE SUPPLIES/EXPENSES	0
923	OUTSIDE SERVICES EMPLOYED	0
924	PROPERTY INSURANCE	2,237
925	INJURIES & DAMAGES	0
926	BENEFITS DISTRIBUTED	0
928	REGULATORY COMMISSION EXPENSES	2,153
930	MISC. & GENERAL EXPENSES	725
931	RENTS	0
935	MAINTENANCE GENERAL PLANT	24
	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	5,139

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
RATE STABILIZATION RESERVE (RSR) COMPUTATION
@ DECEMBER 31, 2010

EXHIBIT III

LINE NO.	DESCRIPTION	YEAR ENDING 2009	CURRENT YEAR 2010
	COST OF SERVICE (COS) ($000)		
1	TOTAL COS		250,251
2	UCAP CREDIT		(7,209)
3	NET COS		243,042
4	DEMAND 1/		108,928
5	ENERGY 2/		134,114
	GENERATION (GWH)		
6	@ LONG TERM AVERAGE		20,210
7	ANNUAL NET GENERATION		19,456
	ENERGY RATE (MILLS/KWH)		
8	@ LONG TERM AVERAGE GENERATION 3/		6.64
9	@ ANNUAL NET GENERATION 4/		6.89
10	RATE IN EFFECT (MILLS/KWH)		4.92
11	ANNUAL R & D SALES (GWH)		9,848
12	TOTAL FOR YEAR 5/		(19,401)
13	RSR BALANCE @ YEAR END 6/	(31,866)	(51,267)

1/ See EXHIBIT II, Page 1. The demand charge is a weighted average of the January-April and May-December periods, inclusive of the projected ancillary services costs that were removed using the methodology from the 2003 rate action.
2/ Line (3) - line (4)
3/ Line (5) / (6).
4/ Line (5) / (7).
5/ (Line (10) - (9)) * (11).
6/ Line (12) + line (13) [Prior-year balance]

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
HISTORIC COST OF SERVICE & RATE STABILIZATION RESERVE (RSR) COMPUTATION
1981 - 2009

($000)

EXHIBIT III
Page 2 of 2

LINE NO.	DESCRIPTION	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002 5/	2003	2004	2005	2006	2007	2008	2009
1	COST OF SERVICE ($000) 1/		61 987	75 612	77 488	78 291	82 604	85 429	92 818	95 239	110 532	117 753	117 805	115 992	120 567	131 816	132 395	133 415	134 617	132 274	139 805	143 679		151 131	167 023	180 125	192 355	212 401	223 527	222 164
2	DEMAND		34 445	34 902	35 007	35 008	35 169	35 173	34 642	34 415	34 152	34 249	34 227	34 527	34 592	34 586	34 900	35 019	35 877	35 787	35 491	35 172		92 180	96 241	79 408	92 133	101 418	109 058	107 609
3	ENERGY		27 542	40 910	42 484	43 283	47 415	48 306	57 976	60 824	76 380	83 504	83 578	81 465	84 975	96 924	97 493	104 396	99 243	96 471	104 134	108 507		58 951	101 182	100 717	99 622	110 983	114 469	114 555
	GENERATION (GWH)																													
4	LONG TERM AVERAGE		19 820	19 956	19 934	20 040	20 100	20 146	20 153	20 153	20 151	20 161	20 189	20 222	20 233	20 241	20 258	20 268	20 278	20 307	20 157	20 258		20 224	20 222	20 221	20 218	20 210	20 210	20 216
5	ANNUAL NET		22 134	22 038	23 154	23 916	25 311	24 030	20 726	20 285	21 460	21 367	21 534	20 313	21 510	20 713	21 594	24 214	23 239	18 322	18 746	17 207		17 531	19 996	20 093	19 924	19 359	20 150	21 016
	ENERGY RATE (MILLS/KWH)																													
6	UNDER LTA GENERATION 2/		1 38	2 04	2 12	2 16	2 36	2 40	2 88	3 02	3 78	4 14	4 12	4 01	4 69	4 79	4 81	5 14	4 88	4 75	5 14	5 36		4 89	5 00	4 98	4 93	5 40	5 66	5 08
7	UNDER ANNUAL NET GEN 3/		1 24	1 78	1 83	1 81	1 87	2 01	2 80	3 00	3 56	3 90	3 87	3 49	4 37	4 69	4 45	4 31	4 27	5 27	5 72	6 30		5 55	5 08	5 01	5 00	5 73	5 68	5 45
	RATE IN EFFECT																													
8	January-April		1 71	1 71	1 71	1 71	1 71	1 71	1 99	2 39	2 62	2 96	3 34	3 82	4 35	4 92	4 92	4 92	4 92	4 92	4 92	4 92		4 92	4 92	4 92	4 92	4 92	4 92	4 92
9	May-December		1 71	1 71	1 71	1 71	1 71	1 90	2 20	2 62	2 96	3 34	3 82	4 35	4 92	4 92	4 92	4 92	4 92	4 92	4 92	4 92		4 92	4 92	4 92	4 92	4 92	4 92	4 92
	R&D SALES (GWH)																													
10	January-April							2 874	3 656	3 442	3 383	4 214	3 378	3 038	3 481	3 487	3 507													
11	May-December							8 151	6 522	6 552	6 459	6 180	6 263	7 369	6 914	6 616	6 096													
12	TOTAL SALES (GWH)		9 754	9 407	11 244	11 098	13,105	12 125	10 180	9 994	9 842	10 394	9 639	10 398	10 095	10 103	10 603	11 307	10 882	9 736	9 607	9 239		9 282	9 749	9 754	9 930	9 938	9 981	9 759
	RATE STABILIZATION RESERVE ($000)																													
13	RSR SURPLUS/ (DEFICIENCY) 4/		4 584	(672)	(1 343)	(1 119)	(2 097)	(1 355)	(9 289)	(4 504)	(7 051)	(7 421)	(2 102)	7 437	3 568	2 425	4 936	6 952	7 040	(3 307)	(7 546)	(12 750)		(6 910)	(1 305)	(873)	(794)	(8 051)	(7 586)	(5 172)
14	ADJUSTMENTS											452						(1 034)		(394)	335	253				(300)				
15	RSR BALANCE - YEAR END	21 195	25 779	25 107	23 764	22 645	20 55*	19 195	12 697	7 973	912	(6 042)	(8 144)	(707)	2 861	5 288	10 186	16 114	23 174	19 380	11 172	(725)		(7 635)	(9 000)	(10 263)	(11 057)	(19 108)	(26 694)	(31 866)

1 See NYPA's Actual Calendar Year Production Related COS Studies and Rate Stabilization Reserve (RSR) Computations
2 Line (3) / Line (4)
3 Line (3) / Line (5)
4 (Rate in Effect (lines 8 9) - Rate at annual gen (line 7)) * R&D sales (line 10,11 or line 12)
5 The RSR mechanism was not used to reconcile actual costs for the period from December 18, 2001 to December 31 2002

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
EXPANSION POWER NET REVENUES
2010 CALENDAR YEAR

LINE NO.	DESCRIPTION	($000) DEMAND (1)	ENERGY (2)	TOTAL (3)	NET GEN (GWH) (4)	DEMAND ($/KW) (5)	ENERGY (MILLS/KWH) (6)
1	PRODUCTION COST OF SERVICE 1/	108,928	141,323	250,251			
2	LONG TERM AVERAGE GENERATION 2/				20,210		
3	COST BASED RATES @ LT AVG GENERATION					3.33	6.99
4	GREENE COUNTY/ARTHUR KILL DEBT SERVICE 3/			0			
5	NON-R&D ENERGY SALES (GWH) 4/				9,608		
6	GREENE COUNTY/ARTHUR KILL ENERGY RATE 5/						0.00
7	NON-R&D COST BASED RATE					3.33	6.99

	EXPANSION POWER	DEMAND (Jan-April)	DEMAND (May-Dec.)	ENERGY (Jan-April)	ENERGY (May-Dec.)	TOTAL ($000)
8	BILLING DETERMINANTS (KW, MWH)	711,954	1,553,064	380,931	842,888	
9	PRODUCTION RATES ($/KW, MILLS/KWH)	5.17	5.17	8.84	8.84	
10	GROSS REVENUES 6/	3,681	8,029	3,367	7,451	22,528
11	PRODUCTION COSTS 7/					16,097
12	NET PRODUCTION REVENUES 8/					6,431

1/ Exhibit II, Page 1.
2/ Exhibit III, Page 1.
3/ Allocated share to production function, Non-R&D customers only.
4/ Total Non-R&D sales; total generation less preference sales.
5/ Line (4) / Line (5).
6/ Line (8) * Line (9).
7/ Line (7) * Line (8).
8/ Line (10) - Line (11).

EXHIBIT IV

Page 2 of 2

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
EXPANSION POWER NET REVENUES
1987 - 2010

($000)

	1987 (1)	1988 (2)	1989 (3)	1990 (4)	1991 (5)	1992 (6)	1993 (7)	1994 (8)	1995 (9)	1996 (10)	1997 (11)	1998 (12)	1999 (13)	2000 (14)	2001 (15)	2002 (16)	2003 (17)	2004 (18)	2005 (19)	2006 (20)	2007 (21)	2008 (22)	2009 (23)	2010 (24)	TOTAL (25)
PRODUCTION REVENUES	6 734	7 713	8 837	10 178	10 773	11 800	13 785	16 646	20,744	20 221	20.481	20,880	20 345	22 057	20 044	20.044	19 706	18 704	19 700	20 495	22 958	23 437	22 265	22,528	398 547
PRODUCTION COSTS	6,871	7,633	7,883	9,064	8,560	8,316	8,283	9,700	11,089	10,605	11,315	10,523	11,390	12,332	10,823	10,837	11,525	11,731	12,904	13,146	15,245	15,035	14,688	16,097	249,998
NET PRODUCTION REVENUES	(137)	80	954	1,114	2,213	3,484	5,502	6,946	9 655	9,616	9,166	10 357	8,955	9,725	9,221	9,207	8 181	6,973	6,896	7 349	7,713	7,802	7,577	6,431	148,549

EXHIBIT_FWR-7

Request MEUA 13:

Please provide an explanation of the accounting methodology used to track expenses for the following NYPA initiatives:

a. The 100 MW Solar Project;
b. The Great Lakes Offshore Wind Project; and
c. Long Island - NYC Off Shore Wind Project.

Please provide an explanation of how shared services are allocated to these initiatives and the expenditures made to date.

Response:

WBS projects were created to track the cost of these initiatives. However, these costs are considered preliminary investigations and are being expensed. Expenditures are excluded from the base for shared services allocation. See below for expenditures through 7-31-2011.

Projects:

HQ-PI-2-ER-001- 100MW Solar Project - $363,712

HQ-PI-2-DD- The Great Lakes Offshore Wind Project - $1,778,455

HQ-PI-2-DN- Long Island – NYC Offshore Wind project - $90,726

EXHIBIT_FWR-8

Operating Expenses				
Operations & Maintenance				
650600 County Fees	650600	7 623 68	5 607 52	2 016 16
651100 American Public Power Association	651100	168.687 36	165 497 59	3 189 77
651200 Maintenance of Public Facilities	651200	597 140 76	547 083 73	50 057 03
651300 PILOT (Payment in lieu of taxes) Payments	651300	1 760 758 53	1.849 861 49	-89 102 96
651400 Non-Nuclear Industry Fees	651400	457 690 91	422.978 76	34 712 15
651600 Research & Development Industry Dues	651600	5.775.829 25	2 490 658 42	3 285 170 83
651700 Employee Fees	651700	179.978 43	164.072 21	15 906 22
651800 Other Industry Dues	651800	495.221 16	675 797 32	-180 576 16
651900 MTA Regional Payroll Tax	651900	262.578 64	215 835 01	46 743 63
665200 Ads-Newspaper/Periodical	665200	264 685 73	179 603 72	85 082 01
665300 Ads-T V /Radio	665300	27 295 69	11 284 00	16 011 69
666200 Contributions	666200	203.145 80	236 824 39	-33 678 59
666201 Sponsorships	666201	57 425 00	169 250 00	-111 825 00
666300 Petty Cash	666300	1 090 93	1 788 55	-697 62
666400 Land Owner Settlements	666400	247 937 05	159 242 34	88 694 71
666401 Real Property	666401	4 416.231 37	1 039.313.14	3 376 918 23
666500 Community Grants	666500	16.005 989 00	22 050 00	15 983 939 00
666900 Printing & Photo	666900	128.649 12	75 197 22	53 451 90
667000 Employment Agency Fees	667000	58 195 97	0 00	58 195 97
672500 Aircraft Services	672500	452 098 93	812 434 24	-360 335 31
672600 Medical Services	672600	245.983 98	216 969 25	29 014 73
672700 Warranty Expense	672700	179 521 05	151 364 40	28 156 65
675000 Other Outside Services	675000	8.821 278 35	11 438 459 93	-2 617 181 58
681100 Accountants/Auditors-Consulting Services	681100	427 720 99	396 299 50	31 421 49
681200 Economists-Consulting Services	681200	461 897 29	0 00	461 897 29
681400 Underwriting/Bond-Consulting Services	681400	60 142 00	0 00	60 142 00
682100 Outside Counsel-Consulting Services	682100	2.136 039 98	2 085 242 86	50 797 12
682200 Legal Appraisal-Consulting Services	682200	800 00	2 700 00	-1 900 00
683100 Design Engineering-Consulting Services	683100	8 139 385 06	4 480 203 76	3 659 181 30
683200 Construction Management-Consulting Services	683200	7.153 695 15	3 342 132 05	3 811 563 10
683300 Licensing - Consulting Services	683300	61 174 80	10 886 85	50 287 95
683400 Environmental - Consulting Services	683400	2 654 310 06	3 462 194 77	-807 884 71
683500 Fuel-Consulting Services	683500	0 00	13.818 75	-13 818 75
683600 Surveying & Mapping - Consulting Services	683600	410.954 96	279 237 62	131.717 34
689100 Management - Consulting Services	689100	4 706.779 45	6 224 562 02	-1.517 782 57
689200 Computer-Consulting Services	689200	1 524 172 68	3 122 556.32	-1 598 383 64
689300 Training - Consulting Services	689300	404 907 57	157 723 86	247 183 71
689900 Other Consultants - Consulting Services	689900	8 478 779 29	5 906 574 64	2 572 204 65
692100 Charges to Agencies/Utilities	692100	-10 853 154 94	-8.827 208 18	-2.025 946 76
694501 Co - Funding	694501	11 730 90	-40 835 00	52 565 90
715662 IOU Payments	715662	1 468 154 00	1.458 035 00	10 119 00
729300 Obsolete/Excess Inventory Write Off	729300	507.257 00	1 045 499 51	-538 242 51
729303 Inventory Physical Count Adjustments	729303	117 596 74	237 365 65	-119 768 91
729304 Gain/Loss on Price Difference	729304	24.549 24	-11.577 20	36 126 44
729306 Transfer/Return to Inventory	729306	-221.642 21	-359 875 03	138 232 82
729309 Miscellaneous Expense	729309	234 107.390 67	190 052.712 14	44 054 678 53
729313 Industrial Incentive Awards	729313	5.356 296 40	147.495 04	5 208 801 36
729314 North Country Temporary Power Discount Program	729314	9 299 381 74	1 662 230 80	7 637 150 94
729318 Project Close out adjustments	729318	27.009 86	54 300 81	-27.290 95
729319 DSM overhead adjustment re costing sheet	729319	0 00	46 722 87	-46 722 87
729320 ES&T Grants	729320	1 964 026 97	2 437 326 34	-473 299 37
729323 DSM cancelled Projects	729323	2 447 312 39	683 380.63	1 763 931 76

TAB 5-I

Comments and Exhibit of Neighboring States

BEFORE THE
POWER AUTHORITY OF THE STATE OF NEW YORK

Proposed Rulemaking to Increase Hydroelectric Preference Power Rates	x : : x	NY Register ID No. PAS-33-11-00001-P

COMMENTS OF
NEIGHBORING STATES PREFERENCE CUSTOMERS
CONCERNING NEW YORK POWER AUTHORITY'S
2011 HYDROELECTRIC RATE MODIFICATION PLAN

(October 24, 2011)

The Neighboring States (Connecticut, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island and Vermont) are currently allocated an aggregate of approximately 266.6 MW of hydroelectric power from the Power Authority's Niagara and St. Lawrence projects. Approximately 34.5 MW of that amount comes from the St. Lawrence Project under that facility's current FERC hydroelectric license, and approximately 232.1 MW of that amount comes from the Niagara Project under the federal Niagara Redevelopment Act (16 U.S.C. § 836) and the terms of the FERC hydroelectric license issued pursuant to the Niagara Redevelopment Act for that facility.

INTRODUCTION

Under Section 1005(5) of New York's Public Authorities Law -- the statute under which the Authority is proposing to modify its rates in this proceeding -- the federal Niagara Redevelopment Act, and Article X of their contracts with the Authority, the Neighboring States are entitled to the same rate making protections that are afforded to New York municipal utilities who receive hydroelectric power allocations from the Authority. The relevant standard, as the Authority is aware, requires that power generated by the Authority's hydroelectric facilities be

sold to in-state municipal utilities and to the Neighboring States "at prices representing cost of generation, plus capital and operating charges, plus a fair cost of transmission, all as determined by the trustees, and subject to conditions which shall assure the resale of such power at the lowest possible price." Similarly, the Niagara Redevelopment Act (16 U.S.C. § 836(b)(1)) requires that power generated by the Authority's hydroelectric plants "shall be made available at the lowest rates reasonably possible and in such manner as to encourage the widest possible use."

These are the standards against which the Authority's proposal to increase its hydropower rates by approximately 37 percent between 2011 and 2014 must be assessed. Based on our analysis of the Authority's responses to data requests during the course of this rulemaking, we have identified several areas in the July 2011 Preliminary Staff Report (the "Report") and accompanying cost of service study (the "Cost of Service") that we believe must be adjusted in order to bring the rates proposed by the Authority in this proceeding into conformity with the requirements for cost-based, "lowest possible" rates established by Public Authorities Law § 1005(5) and the principles adopted by the Authority in the March 5, 1986 Settlement Agreement in *Auer v. Dyson.*

II. COMMENTS

A. Support for NYAPP Request to Defer Implementation of New Rates

We support the September 13, 2011, request of the New York Association of Public Power that the Authority defer the implementation of any proposed change in its hydroelectric rates until May 1, 2012, the start of the Authority's next rate year. Like our fellow preference customers the New York municipal utility members of NYAPP, the Neighboring States believe that deferral of any change in rates until the beginning of the Authority's next rate year would create the opportunity for an informed and deliberate dialogue with the Authority's rate staff,

aimed at pursuing closer conformity between the Authority's rate proposal and the statutory and settlement principle-based requirements that govern it.

B. Applicable Principles

The Neighboring States seek to apply faithfully the *Auer v. Dyson* settlement principles based upon the understanding of the Authority's hydro costs and operations gleaned from the Preliminary Staff Report and the Authority's responses to information requests submitted by the Neighboring States and other interested parties. None of our suggested adjustments seek any "market-based" credits, and none of those adjustments contravene the waiver of objection set forth in Article X of our current contracts with the Authority. The adjustments proposed by the Neighboring States leave to the discretion of the Authority's Trustees the application of surplus margins earned through market-based sales from the Niagara and St. Lawrence projects. However, the cost-based, lowest possible rates principles that are the bedrock of the *Auer v. Dyson* settlement and the understanding of Public Authorities Law § 1005(5) on which that settlement rests, must be applied in a way that provides credit for the full costs associated with participation in the NYISO markets -- not just a portion of the costs.

The Neighboring States believe that when these principles are correctly applied and their impacts evaluated, the results demonstrate that the Authority's existing rates are already fully compensatory. Actual experience shows that, even in the difficult economic times we have experienced since 2008, the existing rates have enabled the Authority not only to secure sufficient revenues to meet all of its costs, but have also earned margins from market transactions that have proven sufficiently substantial to enable the Authority to make significant transfers to the State's general fund and add significantly to its operating funds balances.

The major concerns identified by the Neighboring States fall into the category of proper Cost of Service credits for the costs associated with use of the hydro facilities to make sales into the NYISO markets and credit for the investment income that is generated from investable cash that accrues directly from the operations of the hydro facilities. The full costs of owning and operating the hydro facilities are included in the Cost of Service used to determine the rates to be charged the hydro preference customers. However, some of those costs are related to the use of the facilities to make non-preference sales into the NYISO markets. The Authority has recognized that Cost of Service credits must be made in order to eliminate the costs associated with making those non-preference sales. However, in some areas, the credits incorporated into the staff's preliminary Cost of Service are insufficient to reflect either the full costs associated with the sales or the full quantity of sales expected to be made.

C. Cost-Of-Service Issues

The Neighboring States have identified the following deviations from the statutory, lowest-possible-price standard (Public Authorities Law § 1005(5)), and the implementation of that standard in the principles adopted in the *Auer v. Dyson* settlement. The Neighboring States urge the Trustees to correct these deviations prior to the implementation of the proposed modified rates.

1. The Authority's Proposed Rates Fail to Provide Fully Cost-Based Credit for Hydro Energy Sales Into the NYISO Markets

The Authority has made significant sales from the hydro facilities into the NYISO energy market, and continues to project that it will make substantial amounts of such sales during the 2011-2014 rate modification planning horizon. Although the ratemaking methodology used in the Report to determine the proposed hydroelectric production rates provides a "credit" for the energy-related portion of the cost of producing the energy sold into the NYISO markets, this

$4.92/MWH energy cost credit does not reflect the capacity-related cost that is incurred in order to make such sales possible. The proposed credit therefore does not fulfill the Power Authority's commitment to provide cost-based credit for the sales.

In response to Neighboring States Data Request No. 11, the Staff provided historical and forecasted sales of Niagara and St. Lawrence energy into the NYISO markets. The Authority has forecast sales for 2011-2014 averaging only 2,629,004 MWH per year for purposes of establishing the proposed rates, in contrast to the 4,555,142 MWH per year actual average sales for the previous three years (2008-2010). The Authority's forecast may nevertheless be used as a basis for determining at least a minimal credit for the capacity-related costs of producing such energy. A reasonable contribution to the cost of the capacity used in generating these NYISO energy market sales may be calculated by dividing the annual capacity-related costs included in the Cost of Service by the long-term average generation of 20,216,000 MWH used for each year. The average cost over the four-year rate plan horizon is $7.10/MWH and when applied to the average forecasted NYISO energy sales, results in an average annual Cost of Service credit of $18,563,000. (The actual annual adjustments are shown on page 2 of the attached adjusted Cost of Service). Of course, this adjustment, as well as the others suggested by the Neighboring States, should also be reflected in the annual RSR calculations.

The crux of this issue is that the Authority's preliminary Cost of Service and proposed rate design attributes to preference customers costs that in fact are incurred in order to make non-preference sales into the NYISO markets. The Neighboring States propose to remedy this oversight by including a capacity-related cost credit in the calculation of the preference customer cost of service. However, the Neighboring States recognize that this problem could also be corrected in another way. The full MW generating capability, or at least the full estimated (or

experienced for RSR purposes) hourly maximum MW output of the hydro facilities for each year could be used as the denominator in calculating the preference power demand charge. The Neighboring States would not object to correcting the fundamental problem in either way, but note that correct application of the *Auer* principles requires that the problem be remedied in one way or the other. As the Appellate Division observed in *Village of Bergen v. Power Auth.*, 249 A.D.2d 902, 903, 672 N.Y.S.2d 595, 596 (App. Div. 4th Dept. 1998), "Even though a rate-setting methodology may be reasonable, it may not result in the lowest possible rate required by Public Authorities Law § 1005 (5)." Here, the mismatch between the costs incorporated into the cost of service and the demand over which those costs are allocated precludes any argument that the rate-setting methodology used to develop the Authority's currently proposed rates even qualifies as "reasonable."

When the Neighboring States raised this issue in the 2007 rate determination, the Staff incorrectly asserted that Neighboring States were requesting a market-based level of credits for such sales, and urged rejection of Neighboring States' proposed adjustment on that basis. Staff's position at that time mischaracterized the issue being raised, and the Neighboring States' comment on this point should not be mistaken as a request for revenue credits for the NYISO energy market sales based on the market prices actually received for such sales. Neighboring States simply seek credit for the full cost basis -- capacity as well as energy -- for such sales. Such proper crediting of the full cost associated with making these sales would still leave the vast majority of the market prices received (approximately $40/MWH and often much more) to contribute to the net income of the Power Authority.

2. The Authority's Proposed Rates Provide Insufficient Credit for Regulation Ancillary Service Sales into the NYISO Markets

Historically, the Authority has sold significantly more regulation ancillary service into the NYISO markets than have actually been required to meet the needs of its hydro power contract customers. Notwithstanding the fact that the Authority includes the *entire* cost associated with these sales in the development of the proposed rates, the Authority has provided Cost of Service credit only up to the level of its contract customers' needs. The Report provides a regulation ancillary service credit for the forecasted 2008 Cost of Service of approximately $1.25 million, whereas, the Staff response to Neighboring States data request item 12 and NYAPP 1-21 shows actual 2008 regulation service revenues of $40.489 million. While a part of the reason for this large discrepancy between the credit provided and the sales revenues received is that the actual revenues are based on market prices received from sales made in the NYISO ancillary services market, the discrepancy is unquestionably attributable in significant part to the actual sale of a much larger quantity of regulation service sales than is reflected in the Cost of Service credit. The comparison of the forecasted rate period credits to anticipated sales revenues is similarly lopsided, with hydro Cost of Service credits of approximately $1.5 million or less each year and forecasted regulation service sales revenues ranging from $12 million in 2011 to $32 million in 2014.[1/]

The crediting only of costs associated with the amount of regulation needs of the contract loads is not sufficient, because the actual regulation service sales volumes greatly exceed the amount of regulation service needed for the contract loads. In evaluating this issue, it is important to remember that one of the principles agreed upon in the Relicensing Settlement Agreement Addressing Allocation of Niagara Project Power and Energy to Neighboring States

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1/ This data appears in Authority Staff's response to Neighboring States Data Request No. 12.

(at Article X) was "(iii) Treatment of sales to third parties, including the New York Independent System Operator." As the stated principle does not exclude any sales to third parties, conformity with the stated principle requires that ***all*** sales to third parties be included in the crediting process. Accordingly, the Cost of Service credits should be increased to reflect the full quantity of regulation services sold into the NYISO markets, not just the lesser amount needed solely to meet the needs of the contract loads.

Moreover, as explained in the January 22, 2003 report of the Authority's consultant, Frank C. Graves of the Brattle Group, that was incorporated into the January 2003 Report on Hydroelectric Production Rates as Appendix B, the costs associated with making the ancillary service sales should not be classified as generation-related costs and should not be included in the development of "cost-based generation rates for NYPA's preference rate customers." In explaining why such costs must be removed from the generation Cost of Service used in developing the hydro generation rates, Mr. Graves explained (emphasis supplied):[2/]

> The move to competitive generation markets and the start of operations by the New York Independent System Operator ("NYISO", or "ISO") have fundamentally changed the nature of the electric industry in the New York Control Area ("NYCA"). One change is that **electric service has now been unbundled into separate component products**. Prior to the new market structure, the incumbent utility provided customers with all aspects of electric power, bundling generation (capacity and energy) together with all of the network support services that are necessary to deliver it reliably. Now, the ISO's new market structure distinguishes and charges separately for these network support services. **The ISO acquires these support services from competitive suppliers, and passes the cost of each unbundled service or product through to customers, separate from the cost of generation.**
>
> These changes in the industry unbundle the components of electric service, and **thus it is appropriate that NYPA unbundle its**

2/ *See* New York Power Authority January 2003 Report on Hydroelectric Production Rates, Rate Modification Plan Appendix B, Report of Frank C. Graves, January 22, 2003 at pages 2-3, emphasis added.

> **costs, separating out from its hydro cost of service the embedded cost[] that are associated with these ancillary services.** I have been asked by NYPA to perform this unbundling of ancillary service costs in support of developing hydro generation rates. The ancillary services I consider are 1) Voltage Support, 2) Black Start, 3) **Regulation**, and 4) Operating Reserve. A brief description of each of these services is given in Section III of this report.
>
> The embedded costs that I identify for these four ancillary services are not new costs, nor are the services themselves new. Rather, in the past all services and costs have been bundled together, but now the new market separates them. **Starting with the total cost of service of the NYPA hydro facilities (which in total supports the provision of all electric services)**, I identify the relevant ancillary services that are distinct from generation, and allocate the appropriate portion of total costs to these ancillary services. **After deducting the cost of these ancillary services, the remainder of the total cost of service is associated with generation, and will be used going forward to develop the cost-based generation rates for NYPA's preference rate customers.** The unbundling does not change NYPA's total costs; it merely allocates these costs among energy and the ancillary services identified.

Of course, Mr. Graves only evaluated the removal of the minimum costs that must be removed from the hydro generation costs – those directly related to the ancillary service needs of the hydro contract customers – since those services would now have to be purchased by those customers from the NYISO rather than being supplied by the Authority. However, the same principle applies to the cost of all the additional amounts of ancillary service sales made by the Authority in the NYISO ancillary services markets; i.e., the costs related to making such sales are not generation costs, but rather are ancillary service costs. Those costs must be removed from the generation Cost of Service in order to develop the cost-based generation rates for the Authority's preference rate customers. The Authority's proposed rates cannot meet the cost-based requirement of Public Authorities Law § 1005(5) and its amplification in the Auer principles so long as costs unrelated to generation remain in the Cost of Service. Therefore, not only the costs related to the ancillary service needs of the hydro contract customers must be

removed from the generation Cost of Service, but the costs related to the additional ancillary service sales volumes the Authority makes in the NYISO markets must also be removed. As explained by Mr. Graves, such costs are not generation costs and should not be included in developing generation service rates.

Neither the discovery process in this proceeding, nor public information otherwise available to the Neighboring States, has revealed sufficient information to enable the Neighboring States to calculate the most precise adjustment required to reflect the higher level of expected regulation sales. However, even if only twenty-five percent of the Authority's forecasted sales revenues were attributable to the excess of actual sales of regulation service sold over the amounts reflected in the Cost of Service, the cost-based credits for such sales would range from $3 to $8 million per year over the rate planning period horizon. That level of annual credits would still fall far short of the anticipated sales revenues, which are in the range of $12 to $32 million per year, and would leave significant margins available to contribute toward the overall net income of the Power Authority.

3. The Authority's Proposed Rates Fail to Provide Cost of Service Credit for Investment Income From Investment Funds Arising Out of the Niagara and St. Lawrence Project Operations

Obviously, substantial free cash flows are generated for the Power Authority through the operation of the hydro projects. In addition to the profits from the market sales of energy and ancillary services into the NYISO markets, cash is generated from the collection of depreciation expenses and the extra capital costs recovered through the use of the TOC capital cost recovery methodology. Such amounts arise directly as a result of the project operations, and fully cost-based rates for the output of those projects would reflect the credits for the investment income generated as part of those operations. NYPA annual financial reports show that through

investment of its available cash, the Power Authority had investment income of $71 million in 2008, $32 in 2009, and $41 million for 2010. For 2011-14 the Power Authority's Approved Financial Plan projects investment income to climb from $32.4 million in 2011 to $88.3 million in 2014, with an annual average of $58.4 million over the four-year period. An appropriate portion of this investment income that is clearly generated in large part out of the cash flow from Niagara and St. Lawrence operations should be credited against the hydro cost of service. The Report of the Chief Financial Officer for the years ending December 31, 2009 and 2010 show that Niagara and St. Lawrence contributed 81% and 82%, respectively, of the NYPA total Net Income for those years. If the projected investment income were allocated conservatively as only 50% attributable to Niagara and St. Lawrence, the Cost of Service credit would range from $16.2 million in 2011 to $44.2 in 2014 and would be an annual average of $29.2 million over the four-year period. Neighboring States do not seek a resulting price that is below cost; rather, the income generated by cash supplied by hydro customers for hydro power is a necessary input to the calculation of the cost of that power. Failing to reflect investment income associated with hydro revenues in calculating the hydro "cost" is akin to including tax payments in a cost of service but refusing to consider any tax refunds obtained. This aspect of the Authority's rate proposal therefore also fails to adhere to the statutory lowest-possible-cost requirement, and must be adjusted by an appropriate level of rate credit before the proposed rates may be placed into effect. *Village of Bergen v. Power Auth.*, *supra*, 249 A.D.2d at 903, 672 N.Y.S.2d at 596.

4. The Authority's Proposed Rates Should Include an Estimated UCAP Sales Credit

The Authority recognizes that it is appropriate to include a credit for UCAP sales in determining the actual, after-the-fact cost of service for purposes of the RSR calculations. Such credits for 2008, 2009 and 2010 were $11,079,000, $6,625,000 and $7,209,000, respectively.

The same methodology should be applied *a priori* to the development of the rates, and not simply in the calculation of the after-the-fact actual cost of service for RSR purposes. A conservative estimate of such annual sales credits for 2011-2014 would be the average of the 2008-2010 actual sales, or $8,304,000. This would make the projected rates more closely approach the statutorily-required actual cost basis for rate setting, but would continue to afford the Authority the ability to adjust to the actual credit amounts in the RSR Cost of Service calculations.

5. The Authority Should Confirm Its Plan for Treatment of the 455 MW Redirected to the Recharge New York Power Program in Determining the Rate Stabilization Reserve Prior to Placing the Proposed Rates Into Effect

Staff's September 28, 2011, Supplemental Response to MEUA Data Request No. 7 states that, with respect to the redirection of 455 MW of "state preference" power to the "Recharge New York" power program, Staff:

> intends to recommend to its Board that it approve a *pro rata* reduction in the RSR balance due to the withdrawal of the 455 MW from the preference power program. Specifically, staff will recommend that the RSR balance be reduced by a historical ratio of the MWh usage of the upstate utilities' rural & domestic customers to the total preference power customers' MWh usage. In the context of the current negative RSR balance, this adjustment will make the RSR balance less negative. Going forward, the RSR balance would reflect a smaller preference power customer base. Staff will issue a revised RSR balance calculation before the close of the public comment period.

Neighboring States do not object in principle to Staff's proposed resolution of this issue. However, as of October 21, there has been no revised RSR balance calculation provided in order to permit review of the impact of Staff's proposed adjustment. In these circumstances, the Authority should (i) hold the public comment period open for a reasonable time after Staff formally presents its proposal and revised RSR balance calculation, in order to permit further

comment by affected customers of the Authority, and (ii) defer the implementation of this element of any proposed change in rates until the Trustees have had the opportunity to review public comment on Staff's proposal.

CONCLUSION

For the foregoing reasons, the Trustees should direct Staff to reformulate the proposed modification of the Authority's hydroelectric rates in accordance with the foregoing comments, and take such other steps as may be necessary to ensure that any modified hydroelectric rates that are actually implemented conform to the requirements of Public Authorities Law § 1005(5) and the principles set forth in the *Auer v. Dyson* settlement agreement.

Respectfully submitted,

/s/ John P. Coyle

John P. Coyle
DUNCAN & ALLEN
Suite 300
1575 Eye Street, N.W.
Washington, D.C. 20005-1175
Telephone: (202) 289-8400
Facsimile: (202) 289-8450
e-mail: jpc@duncanallen.com

Counsel for the Bargaining Agents for the Neighboring States of Connecticut, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island and Vermont

Dated: October 24, 2011.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
PROPOSED PRODUCTION COST OF SERVICE
AS ADJUSTED BY NEIGHBORING STATES - September 16, 2011

($000)

Line	Description	(Per 2007 CoS) 2008	2011	2012	2013	2014	Difference 2011 vs 2008 *
	Operations & Maintenance/Administrative & General						
1	Operations & Maintenance/A&G	61,941	71,762	72,174	74,654	76,355	9,821
2	Amortized Roadwork	2,983	212	-	-	-	(2,771)
3	Subtotal O&M/A&G (line 1 + line 2)	64,924	71,973	72,174	74,654	76,355	7,049
	Indirect Overheads						
4	Shared Services	41,329	44,897	45,837	46,564	47,235	3,568
5	Research & Development	3,780	2,523	2,598	2,650	2,703	(1,257)
6	Project Study Debt Service	846	-	-	-	-	(846)
7	Y2K Debt Service	2,874	237	237	237	237	(2,637)
8	Subtotal Indirect Overheads (sum lines 4-7)	48,829	47,656	48,672	49,451	50,176	(1,173)
9	**St. Law. Relicensing, amortization**	2,000	2,000	2,000	2,000	2,000	-
10	**Niagara Relicensing, amortization**	12,000	12,700	12,700	12,700	12,700	700
11	**Other Post -Employment Benefits (OPEB)**	13,608	10,348	10,720	11,051	11,424	(3,261)
12	**O&M Cost of Service** (sum lines 3,8, 9, 10,11)	**141,361**	**144,677**	**146,266**	**149,856**	**152,654**	**3,316**
	Capital Costs						
13	Total Depreciation	35,350	40,984	43,422	45,309	47,204	5,634
14	Interest on Debt	21,453	30,322	33,205	35,104	37,386	8,869
15	Inflation Compensation	21,521	28,697	30,428	32,182	34,069	7,176
16	Subtotal Capital Costs (sum lines 13-15)	78,324	100,003	107,055	112,595	118,659	21,679
17	**Total Cost of Service** (line 12 +line 16)	**219,685**	**244,680**	**253,321**	**262,451**	**271,313**	**24,995**

* 2008 data is from 2007 CoS and was based on data and projections available at that time.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
FINAL PRODUCTION COST OF SERVICE
AS ADJUSTED BY NEIGHBORING STATES - September 16, 2011

($000)

Line	Description		(Per 2007 CoS) 2008	2011	2012	2013	2014	Difference 2011 vs 2008 *
1	**Total Cost of Service**	**($000)**	**219,685**	**244,680**	**253,321**	**262,451**	**271,313**	**24,995**
2	**Credits for ancillary services**	($000)						
3	Black Start, O&M		81	69	71	73	75	(12)
4	Voltage Support, O&M		332	213	219	225	232	(119)
5	Remaining O&M (page 1, line 12 - (line 3+line 4)		140,948	144,395	145,976	149,558	152,347	3,447
6	Operating Reserves, O&M		4.82%	4.40%	4.37%	4.33%	4.31%	
7	Regulation, O&M		0.57%	0.55%	0.54%	0.54%	0.53%	
8	Subtotal OR, Reg. O&M		5.39%	4.95%	4.91%	4.87%	4.84%	
9	Op. Res.+ Reg. O&M credit (line 8 * line 5)	($000)	7,597	7,148	7,167	7,283	7,374	(450)
10	**Capital Reductions**							
11	All ancillary services		6.85%	6.68%	6.74%	6.75%	6.79%	
12	Subtotal capital reductions (page 1, line 16 * line 11)	($000)	5,365	6,680	7,216	7,600	8,057	1,315
13	Total Ancillary Credits (sum lines 3,4,9,12)	($000)	13,375	14,110	14,673	15,182	15,738	734
14	Other Credits Pursuant to Comments of the Neighboring States ($000)							
15	Demand Cost Credit for Sales Into NYISO Energy Market			19,098	18,890	18,039	18,227	
16	Credit for Larger Quantities of Regulation Service Sales			3,004	6,355	7,636	8,063	
17	Investment Income Credit			16,200	23,400	33,000	44,200	
18	Credit for Sales Into NYISO UCAP Market			8,304	8,304	8,304	8,304	
19	Total Other Credits (sum lines 15-18)			46,606	56,949	66,979	78,794	(46,606)
20	**Adjusted Cost of Service** (line 1 - line 13 - line 19)	**($000)**	**206,310**	**183,964**	**181,699**	**180,291**	**176,782**	**(22,345)**
21	Billing Demand	MW	36,137	34,086	35,035	35,871	36,100	(2,051)
22	Billing Demand Allocated Costs (line 20 - line 27)	($000)	106,822	84,502	82,237	80,828	77,319	(22,321)
23	Billed Demand Rate (line 22 / line 21)	$/kW/mo	2.96	2.48	2.35	2.25	2.14	(0.48)
24	LTA Generation	GWh	20,221	20,216	20,216	20,216	20,216	(5)
25	Annual Generation	GWh	20,012	20,456	20,148	20,409	20,435	444
26	Billing Energy Rate	$/MWh	4.92	4.92	4.92	4.92	4.92	
27	Costs Allocated to Energy Rate (line 24 * line 26)	$/MWh	99,487	99,463	99,463	99,463	99,463	(25)

* 2008 data is from 2007 CoS and was based on data and projections available at that time.

TAB 5-J

Comments and Exhibit of Niagara Power Coalition, Inc. (NPC)

NIAGARA POWER COALITION, INC.

William L. Ross, Chairman

Niagara County . City of Niagara Falls . Town of Lewiston . Town of Niagara
Niagara-Wheatfield Central School District . Lewiston Porter Central School District . Niagara Falls School District

October 21, 2011

VIA ELECTRONIC AND FIRST CLASS MAIL

Ms. Karen Delince
Corporate Secretary
Power Authority of the State of New York
123 Main Street, 11-P
White Plains, New York 10601

RE: SAPA I.D. No. PAS-33-11-00001-P – Rates for Sale of Power and Energy – Proposed Increase in Hydroelectric Preference Power Rates

Dear Ms. Delince:

Enclosed please find the Comments of the Niagara Power Coalition, Inc. (the "NPC") regarding the above-referenced proposed rate increase. As indicated above, these comments are being submitted in response to the Notice published in the August 17, 2011 issue of the ***New York State Register***, as modified by the Notice appearing in the October 19, 2011 issue.

As discussed in the Comments, the Niagara Power Coalition respectfully urges the New York Power Authority (the "Authority") not to adopt the multi-year rate increase as proposed and, instead, to re-examine the reasonableness of the proposed increase in light of current economic conditions and other factors. To the extent that any increase is warranted, the NPC requests that the Authority utilize surplus funds as a complete or partial off-set to such increase. Avoidance or meaningful mitigation of the proposed increase is critical to maintaining the value and integrity of the 2005 Settlement Agreement that helped to facilitate the successful relicensing of the Niagara Power Project.

Should you have any questions regarding these comments, or this matter generally, please contact me.

Very truly yours,

William L. Ross

Enclosure

cc: Niagara Power Coalition Members
Stanley W. Widger, Jr., Esq., NPC Counsel

Vantage Center
6311 Inducon Corporate Drive
Sanborn, NY 14132

PHONE (716) 278-8760
FAX (716) 278-8769

POWER AUTHORITY
OF THE
STATE OF NEW YORK

SAPA I.D. NO. PAS-33-11-00001-P – Rates for Sale of Power and Energy – Proposed Increase in Hydroelectric Preference Power Rates

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COMMENTS
OF
NIAGARA POWER COALITION, INC.

NIAGARA POWER COALITION, INC.
Vantage Center
6311 Inducon Corporate Drive
Suite One
Sanborn, New York 14132

October 21, 2011

POWER AUTHORITY
OF THE
STATE OF NEW YORK

SAPA I.D. NO. PAS-33-11-00001-P – Rates for Sale of Power and Energy – Proposed Increase in Hydroelectric Preference Power Rates

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COMMENTS
OF
NIAGARA POWER COALITION, INC.

I. INTRODUCTION

Pursuant to the Notice of Proposed Rulemaking appearing in the *New York State Register* on August 17, 2011, as modified by a subsequent Notice appearing on October 19, 2011, the Niagara Power Coalition, Inc. (the "NPC"), on behalf of its members and their residents, urges the New York Power Authority (the "Authority") not to adopt the proposed multi-year electric rate increase announced in July of this year.[1] The proposed increase has not been shown to be reasonable, especially in light of current economic reality, and undercuts fundamental understandings that underlie the relicensing of the Authority's Niagara Power Project (the "Niagara Project" or the "Project"). In particular, by reducing the value of power and energy allocations to NPC members, the proposed rate increase, if adopted, will impose a substantial burden on taxpayers. To the extent that any portion of the proposed increase is based on justifiable and reasonable cost increases, the Authority has at its disposal the means of funding those increases without imposing a rate increase on the NPC's members or other Preference Power customers.

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[1] *New York Power Authority, Preliminary Staff Report, Hydroelectric Production Rates, Rate Modification Plan – Rate Years 2011-2014* (July 2011) (the "Preliminary Report").

II. BACKGROUND

The NPC consists of seven members: Niagara County, the City of Niagara Falls, the Towns of Lewiston and Niagara, the Niagara Falls City School District, the Lewiston-Porter School District, and the Niagara-Wheatfield School District. These seven bodies are the hosts (the "Host Communities") to the Niagara Project. As the hosts to the Project, beginning more than 50 years ago, their residents and taxpayers have borne the impact of the Project's footprint, including the loss of tax base and land that could no longer be developed. Notwithstanding some modest benefits of hosting the Project, most of the impacts were negative or, at best, neutral. While low-cost hydropower benefited some people and industries in New York and neighboring states, the Niagara Project was a net burden on the Host Communities.

In the late 1990s, as the Project was in the last decade of its original Federal Energy Regulatory Commission ("FERC") license, the Host Communities formed the NPC to represent their interests in the relicensing process. The NPC's goal was to ensure that any burdens the Host Communities would continue to bear as a result of relicensing the Project for another 50 years would not go unrecognized and thus uncompensated. Host Community citizens and taxpayers are the only ones who truly gave up anything to permit the Project to be built and they would be the only ones to continue doing so if the Project were relicensed. Therefore, the NPC and its members negotiated with the Authority for benefits for local residents and taxpayers to help offset the ongoing burden that would be imposed by the Project over the next 50 years.

Negotiations with the Authority culminated in a Settlement Agreement signed in 2005[2] that provided three types of benefits that are allocated to and among the NPC members based on a formula that was worked out during the negotiations. The first benefit is an annual payment of $5 million into a Host Communities Fund, to be used for "capital projects and infrastructure that

[2] Host Community Relicensing Settlement Agreement Addressing Non-License Terms and Conditions (June 27, 2005) (the "Settlement Agreement").

benefit the general public and promote economic development, public health, and safety."[3] The second benefit is an annual payment of $3 million into a Host Community Greenway Recreation/Tourism Fund to "support the construction and/or rehabilitation of parks, recreation and related facilities, for the purpose of redefining the Niagara riverfront, promoting tourism, enhancing the environment, and advancing the economic revitalization of the Niagara River Greenway within Niagara County."[4] The third benefit is the commitment of 25 Megawatts ("MW") of firm power and associated energy for sale to the Host Communities, to be allocated according to the NPC by-laws.[5] The focus of these Comments is on the last benefit enumerated here because it is the one most directly affected by the proposed rate increase.

To implement the power allocation portion of the Settlement Agreement, the members of the NPC entered into individual contracts with the Authority. Under those contracts, the Host Communities pay the Preference Power rate for their allocations of Authority hydropower. The Host Communities and their citizens benefit from their allocations in two different ways. First, the allocations save the Host Communities themselves on their electric bills because they would otherwise have to purchase electricity at higher rates from National Grid or New York State Electric & Gas Corporation. Second, because the Host Communities sell the electricity they do *not* use into the market, they receive revenues from any sales that are made at a price above their cost.[6]

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3 *See* Settlement Agreement §4 ("Host Communities Fund").

4 *See* Settlement Agreement §7 ("Greenway Recreation/Tourism Fund in the Host Communities").

5 *See* Settlement Agreement §6 ("Power Allocation"). The allocation is set forth in Exhibit 1 to the Settlement Agreement. In addition, the Authority was authorized to allocate up to an additional 3 MW of power to the Town of Lewiston. Settlement Agreement §6.5, App. C.

6 One NPC member, the Town of Lewiston, made an alternative arrangement by which electric customers within the Town are credited directly for net revenues from sales in the market. For purposes of these Comments, the difference between the Lewiston approach to providing benefits and that employed by the other six Host Communities is immaterial.

A rate increase for Preference Power affects the Host Communities in two corresponding ways. It requires them to pay more for the power and energy they use directly *and* it reduces the revenues they otherwise would realize on sales into the market. This compounded disadvantage is the major reason why the NPC is concerned about the multi-year rate increase the Authority is considering.

III. COMMENTS

A. IF ADOPTED, THE PROPOSED INCREASE WILL HAVE SIGNIFICANT DETRIMENTAL IMPACTS ON THE HOST COMMUNITIES AND THEIR CITIZENS.

The proposed rate increase amounts to nearly 30 percent over two and a half years, from October 31, 2011 to May 1, 2014.[7] That is, the rates the Host Communities pay right now will be approximately 30 percent higher in May, 2014. This is an average annual increase of 12 percent in rates. Such an increase, the Host Communities believe, is not only unprecedented for the Authority, but it would be unheard of for an investor-owned utility in the State of New York.[8] The facile response to this point is that the Host Communities are fortunate to be receiving low-cost power and energy and, even with the proposed increase, the cost will remain well below that of any alternative sources. Such an argument ignores the very real impact of the proposed increase and the damage it would do to legitimate understandings and expectations.

Niagara County (the "County"), which receives the largest allocation of power and energy – 9.0 MW – under the Settlement Agreement, illustrates the impact of the proposed increase on the Host Communities. As shown in Appendix A to these Comments, which uses the

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7 The current rate, at an indicative load factor of 70 percent, is $10.71 per Megawatthour ("MWH"). Preliminary Report at 1. Effective May 1, 2014, the rate will be $13.87 per MWH, including the $0.50 per MWH Rate Stabilization Reserve ("RSR") surcharge. *Id.* at 11. ($13.87 - $10.71 = $3.16; $3.16 ÷ $10.71 = .295 or 29.5 percent.)

8 In what appears to be the only recent New York Public Service Commission ("PSC") decision to allow a single-year percentage rate increase nominally in double digits, the increase was offset by the elimination of certain surcharges, resulting in a bill increase of 1.9 percent for total electric bills. *See Orange and Rockland Utilities, Inc.*, 291 PUR 4th 349, 358 (2011).

same assumptions that are included in the proposed rate increase, the County, over the period covered by the Authority's rate plan – November 1, 2011 through April 30, 2015 – will pay approximately $400,000 more for the electricity it receives.[9] That is an average yearly increase of $114,000. More importantly, in the last rate year, from May 1, 2014 through April 30, 2015 and every year after that, the Authority will be collecting an additional $174,000 from the County, compared with what it charges the County now.

In addition to this direct cost, the County, like other Host Communities, will suffer an erosion of revenues from re-sale of its surplus electricity in the market, unless the market price increases at a faster pace than the Authority's rate increases. Given the magnitude of the Authority's rate increases and the current state of the market, however, it is unrealistic to expect the spread between the two prices to remain the same or to be greater.[10] Thus, it is highly likely that net revenues to the Host Communities will decline.

The aforementioned impacts diminish the value of the Settlement Agreement to the Host Communities. When the Host Communities bargained with the Authority and agreed to accept allotments of Preference Power rather than entirely cash benefits, it was with the understanding that the value of the overall transaction would increase or, at the very least, not diminish over time. By diluting the value of the Settlement Agreement's power allocation, the rate increase the Authority is considering here would certainly violate the spirit of the Settlement Agreement. The Settlement Agreement was intended to provide compensatory benefits to the Host Communities for 50 years into the future. If the rate increases proposed by the Authority are not modified to a level that would preserve the value of the electricity allocations over time, that important feature of the Settlement Agreement could readily become worthless to the Host

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9 Appendix A was prepared by the County's energy consultant, Fluent Energy Corporation.

10 The NPC is aware of no projection of changes in market prices that would even approach the increases proposed for Preference Power.

Communities. Because the power and energy allocations to the Host Communities offset costs that would otherwise be borne by the taxpayers, any reduction in the value of the power allocations through a rate increase results in a greater burden on taxpayers.

B. THE AUTHORITY'S RATE-SETTING PROCESS SEVERELY LIMITS THE ABILITY OF CUSTOMERS TO EXAMINE AND QUESTION THE PROPOSED RATE INCREASE.

A rate increase having as broad and deep an impact as the current proposal ought to be thoroughly and transparently justified before it is adopted. While the Host Communities appreciate the summary descriptions in the Preliminary Report of the various components of the rate increase, a brief narrative of those components does little to justify their reasonableness.[11] Unfortunately, the process by which the Authority sets its rates does not lend itself to the kind of opportunity for detailed examination that parties would have, for example, in the case of an investor-owned electric company or a municipal electric system asking for a rate increase from the PSC.[12] While the NPC has no reason to believe that the Authority is misrepresenting historical data or other facts, the ability of the NPC or any other party to test the proposed rates is so limited as to be almost non-existent. In particular, the time available is not adequate for anything even approaching a full analysis.

The Host Communities acknowledge that, even if there were more time within which to examine the proposed rate increase, they are contractually limited as to the issues they can address. Like certain other customers, they are precluded by their respective service agreements with the Authority from challenging the key methodologies used by the Authority to set rates.[13]

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[11] The Host Communities also appreciate the visit made by Authority officials to the NPC's offices for an informal question-and-answer session.

[12] PSC procedures include suspension of proposed rate increases for up to 11 months and broad discovery throughout rate proceedings, as well as evidentiary hearings in which witnesses are examined under oath. *See, e.g.*, 16 NYCRR Parts 3, 4, 5, 61.

[13] *See, e.g.*, the Agreement for the Sale of Niagara Project Power and Energy between the County and the Authority (August 2007) §V (Rates). While the Host Communities understand why the Authority might be

(Footnote continued on next page)

Accordingly, the absence of comment on various issues should not be construed as endorsement of the Authority's position on those issues.

C. THE JUSTIFICATION FOR THE PROPOSED INCREASE IS INCOMPLETE AND REQUIRES RE-EXAMINATION.

Notwithstanding the limitations, described above, on the ability of Authority customers to challenge the proposed rate increase, the NPC has nevertheless identified some major concerns that should be addressed by the Authority's Staff and Trustees.

1. The Reasonableness of the Proposed Increase has not Been Established.

As suggested at the outset, the amount of the increases, whether viewed year-by-year or over a four-year period, are so far above the current rate of inflation that they raise questions as to their reasonableness. The Host Communities are well aware that the Authority has major capital improvement projects under way and that the increased level of activity associated with those projects may drive total costs above the rate of inflation. By the same token, however, if costs in one area are increasing, it is incumbent upon the Authority to control and even reduce costs in other areas to offset the increases as much as possible. We have not seen any evidence of this type of effort.[14]

For the Host Communities, belt-tightening is a way of life. They are continuously faced with unfunded mandates that drive up costs; but they cannot simply raise taxes at will. In fact, such increases are now out of the question. The State has now imposed a limit on property tax increases, capping them at two percent or the rate of inflation, whichever is less.[15] To comply

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(Footnote continued from previous page)

reluctant to relitigate certain issues that had been particularly contentious, declaring them off-limits, potentially for the next 50 years, seems unnecessarily heavy-handed. Moreover, the Host Communities are aware of no other such restrictions in the rate-setting processes of the PSC, FERC or any other jurisdiction.

[14] If the Authority chooses not to undertake such cost-reduction efforts in other areas, then it should look to other sources of funds, as suggested later in this discussion, to avoid having to raise rates.

[15] *See* L. 2011, ch. 97.

with that restriction, while simultaneously meeting their mandatory obligations, the NPC's members are forced to make hard choices and to cut back on expenditures that would otherwise be entirely appropriate. As a result, over the past few years, the Host Communities' budgets have remained nearly flat, and in some cases have actually declined, despite the unfunded mandates and other cost increases they face in nearly every category of expense. Unlike the Host Communities' unfunded mandates and other uncontrollable costs that make up such a large portion of their budgets, the expenditures that appear to drive the Authority's proposed rate increase are largely, if not entirely, within the control of the Authority. In times like these, the Host Communities do not see how the Authority can justify the increases it is proposing without demonstrating that it has made every possible effort to cut costs.

In particular, it greatly concerns the Host Communities that, despite all of the capital improvements the Authority is undertaking at the Niagara Project, as well as at the St. Lawrence Project, there is no reduction in Operation and Maintenance and Administrative and General ("O&M/A&G") expenses. Instead, there is a substantial increase. According to the Preliminary Report, those costs would increase by almost 16 percent in just the first year of the rate plan.[16] Over the four-year period, they would increase by over 23 percent.[17] The Host Communities are puzzled by the notion that a series of upgrade projects that are supposed to increase the efficiency of the Niagara Project are apparently doing nothing to reduce O&M/A&G costs. If the Authority believes that the capital improvements are going to reduce these costs, then that outcome does not appear to be reflected in the rate proposal.

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[16] Preliminary Report, Ex. A, p. 1.

[17] *Ibid.*

2. RSR Balances Attributable to Other Customers Should not be Imposed on the Host Communities.

The Host Communities are greatly concerned as to how the Authority intends to deal with recovery of RSR balances following the withdrawal of the firm hydropower that was allocated to the three upstate electric utilities, National Grid, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation. According to the Preliminary Report, the Authority Staff has not completed its analysis of the effect that withdrawal may have, but plans to "inform the Trustees and adjust the rate proposal accordingly when it is submitted for final approval in October."[18] The Host Communities are concerned that, with the withdrawal of the upstate electric companies and their customers as recipients of Preference Power, the RSR balances that accumulated prior to withdrawal might be included in the rates charged to the Host Communities and other customers who continue to receive firm hydropower. In other words, the citizens of the Host Communities might be forced to bear the costs that were incurred by the departed customers. Such a result would be patently unfair. Accordingly, the Authority should make clear that, whatever disposition is ultimately made of those RSR balances, now or in the future, they will not be collected from the Host Communities.

3. Surplus Funds Should be Used to Moderate any Rate Increase That is Otherwise Warranted.

The Host Communities are troubled by the fact that, while the Authority is seeking to implement a major, multi-year rate increase, it is able to make so-called "voluntary" contributions of hundreds of millions of dollars to the State Treasury. The NPC members believe that, before such payments are made to the State, some portion of the surplus should be used to mitigate the proposed rate increase. The Host Communities are aware that, when the issue of payments to the State was litigated recently, the Authority took the position that using

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[18] *Id.* at 10, fn. 6.

the surplus to offset rates to Preference Power customers would result in lowering those rates below cost. The Appellate Division agreed that the Public Authorities Law did not *require* a reduction below cost; but, at the same time, it did not conclude that the law *precluded* an offset.[19] The Host Communities submit that, even if the Authority is not required to use surplus funds as an offset to part or all of the proposed rate increases, it has the discretion to do so.

Exercising that discretion under these circumstances would be appropriate. Using surplus funds as an offset would mitigate what the Host Communities understand to be the greatest increase that has ever been proposed for Authority rates. It would preserve the intent and economic value of the Settlement Agreement power allocations. It would also recognize the role of firm hydropower customers in supporting the Niagara Project and the St. Lawrence Project, which are the backbone of the Authority's business and have positioned it to achieve surplus revenues. At the same time, this use of surplus funds would not impair the Authority's ability to carry out any of its other functions. If the Authority truly believes that it lacks the statutory authority to use surplus funds in this way, it should seek legislation expressly authorizing such use.

The members of the NPC would like to see the Authority use its surplus funds to offset the entire proposed rate increase, thereby preserving the value of the Settlement Agreement that facilitated the relicensing of the Niagara Project. To the extent that the Authority concludes, after due deliberation, that keeping rates flat is not possible, there is a potential middle ground that would serve the interests of the Authority and the Host Communities. Consistent with the State's legislation and policy limiting property tax increases to the lesser of two percent or the rate of inflation, the Authority could increase its rates by up to two percent per year. The Authority would then rely on surplus funds to make up any remaining revenue "shortfall." This

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[19] *Niagara County v. Power Authority*, 82 A.D. 3d 1597, 1601 (4th Dep't), *app. den.*, 2011 N.Y. LEXIS 2138 (Sept. 13, 2011).

approach would provide an incentive to the Authority to minimize increases in rates, thereby helping to preserve the value of the Settlement Agreement and maintaining its viability over its 50-year term.

IV. CONCLUSION

The Host Communities respectfully urge the Trustees of the New York Power Authority not to implement the proposed rate increase as presented. Instead, the proposal should be reconsidered and modified consistent with the foregoing comments.

Respectfully submitted,

NIAGARA POWER COALITION, INC.

Vantage Center
6311 Inducon Corporate Drive
Suite One
Sanborn, NewYork 14132
Phone: (716) 278-8759
Fax: (716) 278-8769
E-mail: william.ross@niagaracounty.com

Dated: October 21, 2011

SAPA I.D. NO. PAS-33-11-00001-P

COMMENTS
OF
NIAGARA POWER COALITION, INC.

Appendix A

Illustrative Impact of Proposed Rate Increase

Niagara County

prepared by Fluent Energy 8.11.11

Impact of Proposed NYPA Hydro Preference Rate Increases

NYPA Allocation (MW) **9**

NYPA Preference Rate History

Power Year	Period	Demand $/kW/month	Energy $/MWh	RSR Surcharge	Effective Unit Rate ($/MWh)	% Increase (from prior period)	Average Monthy Invoice ($)	Approx. Period Invoice ($)	Period Invoice @ current hydro rates	cost increase compared to current rates
2007	9/1/07 - 4/30/08	$2.65	$4.92	$0.00	$10.11	5.52%	$ 46,477	$ 371,817		
2008	5/1/08 - 4/30/09	$2.96	$4.92	$0.00	$10.71	6.00%	$ 49,267	$ 591,205		
2009	5/1/09 - 4/30/10	$2.96	$4.92	$0.00	$10.71	0.00%	$ 49,267	$ 591,205		
2010	5/1/10 - 4/30/11	$2.96	$4.92	$0.00	$10.71	0.00%	$ 49,267	$ 591,205		
2011	5/1/11 - 10/31/11	$2.96	$4.92	$0.00	$10.71	0.00%	$ 49,267	$ 295,602		
2011	11/1/11 - 4/30/12	$3.32	$4.92	$0.00	$11.42	6.58%	$ 52,507	$ 315,042	$ 295,602	$ 19,440
2012	5/1/12 - 4/30/13	$3.70	$4.92	$0.00	$12.16	6.51%	$ 55,927	$ 671,125	$ 591,205	$ 79,920
2013	5/1/13 - 4/30/14	$4.12	$4.92	$0.00	$12.98	6.76%	$ 59,707	$ 716,485	$ 591,205	$ 125,280
2014	5/1/14 - 4/30/15	$4.32	$4.92	$0.50	$13.87	6.87%	$ 63,807	$ 765,679	$ 591,205	$ 174,474
										$ 399,114

Notes:

Invoice ($) amounts are approximate and assume no hydro shortfalls

TAB 5-K

Letter of New York Association of Public Power (NYAPP) requesting deferral of rate increase

Law Offices
Duncan, Weinberg, Genzer & Pembroke, P.C.

WALLACE L. DUNCAN (1937-2008)
EDWARD WEINBERG (1918-1995)
ROBERT WEINBERG
JEFFREY C. GENZER
THOMAS L. RUDEBUSCH
MICHAEL R. POSTAR
ELI D. EILBOTT*
LISA S. GAST
PETER J. SCANLON
KATHLEEN L. MAZURE
DEREK A. DYSON
BHAVEETA K. MODY
KRISTEN CONNOLLY McCULLOUGH
SETH T. LUCIA
JOSHUA E. ADRIAN
MATTHEW R. RUDOLPHI
JASON T. GRAY
NATALIE M. KARAS

RICHMOND F. ALLAN+
JAMES D. PEMBROKE+
TANJA M. SHONKWILER+
TERRY E. SINGER+

SUITE 800
1615 M STREET, N.W.
WASHINGTON, DC 20036

(202) 467-6370
FAX (202) 467-6379
www.dwgp.com

California Offices
SUITE 1410, 915 L STREET
SACRAMENTO, CA 95814
(916) 498-0121
SEAN M. NEAL

SUITE 501
100 W. SAN FERNANDO STREET
SAN JOSE, CA 95113
(408) 288-2080
BARRY F. McCARTHY+
C. SUSIE BERLIN+

Northeast Regional Office
2700 BELLEVUE AVENUE
SYRACUSE, NY 13219
(315) 471-1318
THOMAS J. LYNCH+

*REGISTERED TO PRACTICE BEFORE U.S. PATENT AND TRADEMARK OFFICE

+OF COUNSEL

September 13, 2011

By E-mail and Overnight Express

Karen Delince
Corporate Secretary
New York Power Authority
123 Main Street, 15M
White Plains, New York 10601

RE: **NYAPP Request for Deferral to May 1, 2012 of any Rate Increases Resulting from the Proposed Rulemaking On Increasing Hydroelectric Preference Power Rates, Issued on August 17, 2011**

Dear Ms. Delince:

Enclosed please find the New York Association of Public Power's ("NYAPP") Request for Deferral to May 1, 2012 of any rate increases resulting from the Proposed Rulemaking on increasing hydroelectric preference power rates.

Sincerely,

Thomas L. Rudebusch

Thomas L. Rudebusch

Enclosure

Before the
POWER AUTHORITY OF THE STATE OF NEW YORK

Proposed Rulemaking to Increase Hydroelectric Preference Power Rates	)))	I.D. No. PAS-33-11-00001-P

Request of the New York Association of Public Power for Deferral to May 1, 2012 of Any Rate Increases Resulting from the Proposed Rulemaking on Increasing Hydroelectric Preference Power Rates

To: The Trustees

On August 17, 2011, a Notice of Proposed Rulemaking ("NOPR") was published in the State Register to increase the hydroelectric preference power rates of the Power Authority of the State of New York ("Authority"), with a proposed effective date of November 1, 2011. The New York Association of Public Power ("NYAPP") represents nine municipal electric utilities and four rural electric cooperatives which are preference power customers of the Authority. NYAPP respectfully requests that the Authority defer until May 1, 2012 the effective date of any rate increase resulting from the Proposed Rulemaking. In addition, NYAPP requests that the date for written comments on the proposal be extended from October 1, 2011 to December 1, 2011. In support, NYAPP states as follows:

A. May 1, 2012 is the start of the Authority's next Rate Year.

The Authority's traditional rate year commences May 1 and concludes April 30 of the following year. It would be appropriate and consistent with past practice to defer the effective date of any rate increase resulting from the Proposed Rulemaking until the start of the next Rate Year.

In 2007, NYAPP submitted a request for an extension of the effective date of a proposed rate increase from May 1 until July 1, because of the lack of time to adequately review the proposed new rates. One of the reasons cited in denying that request was that rate changes must always happen in conjunction with the start of the Rate Year on May 1. Consistency requires that that practice continue, especially where, as here, there is not an immediate need for the increased revenue.

B. Deferral of the effective date to May 1, 2012 will not affect the Authority's fiscal integrity.

The NOPR states that the purpose of the Proposed Rulemaking is to maintain the Authority's fiscal integrity. NYAPP's members currently pay a demand charge of $2.96/kW-month, which is proposed to increase to a rate of $3.32/kW-month on November 1, 2011 (a 12% increase). For the period November 1, 2011 to April 30, 2012, the proposed increase would produce additional revenues of approximately $3.0 million from all of the municipal and cooperative customers in New York State. Deferral of the effective date for any rate increases to May 1, 2012 will not affect the Authority's fiscal integrity.

At the Trustees' June 28, 2011 meeting, the Authority's Chief Financial Officer presented a financial report, noting that the Authority "continues to be in a strong financial position."[1] She reported that the Authority has $1.1 billion in cash and liquidity. At the end of the reporting period, the Authority's net income was $86.8 million, which was $7.1 million more than budgeted. Because hydro flows and precipitation are higher than normal, the Chief Financial Officer predicted that end of year net income will be $197 million, which would be $17 million above the 2011

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[1] Approved Minutes of the June 28, 2011 Trustee Meeting at 26.

budget. Therefore, deferral of any preference power rate increase until the start of the next Rate Year on May 1, 2011 will not affect the Authority's fiscal integrity.

C. The contribution of funds to the State Treasury also demonstrates the fiscal integrity of the Authority.

At the June 28, 2011 meeting, the Trustees also approved a contribution to the State Treasury of $40 million for the State's fiscal year 2011-12 ("SFY").[2] This is in addition to the $25 million contribution to the SFY 2010-11 budget approved in January 2011, as well as a $7.5 million contribution to the Gross Receipts Tax credit approved retroactively for 2010-11.

The SFY 2011-12 Budget legislation authorizes an additional $60 million contribution to the State Treasury to be made by January 2012. According to the legislation, the contributions are to be made by the Authority as deemed "feasible and advisable by its trustees."[3] The fact that the Trustees have deemed these contributions of funds to the state to be "feasible and advisable" demonstrates the fiscal integrity of the Authority. Deferral of any increase in the preference power rates should not affect the Authority's contributions to the state.[4]

D. Deferral of any increase in preference power rates to May 1, 2012 is necessary to allow implementation of the Recharge NY program.

The proposed preference power rate increases are discussed in the Preliminary Staff Report on Hydroelectric Production Rates, Rate Modification Plan – Rate Years 2011 to 2014, dated July 2011 ("Preliminary Report"). The Preliminary Report states that important elements of the cost of service are not yet decided related to the

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2 *Id.* at 53-54.

3 *Id.*

4 Preference power rates are by statute based on the hydroelectric production cost of service. Contributions to the State Treasury are not to be included in the cost of service.

implementation of the Recharge NY power program. As of August 1, 2011, 455 MW of firm hydropower previously sold to certain investor-owned utility companies for the benefit of their rural and domestic customers was withdrawn by the Authority. Beginning July 1, 2012, the 455 MW of hydropower will be sold to eligible customers under the Recharge NY program.

Deferral of any increase in the preference power rates until May 1, 2012 is appropriate and necessary to allow implementation of the Recharge NY program. Specifically, the Preliminary Report states that:

> [t]o the extent that such withdrawal [of the 455 MW] will affect the R[ate] S[tabilization] R[eserve] balance and the RSR surcharge in a material manner, the staff will inform the Trustees and adjust the rate proposal accordingly when it is submitted for final approval in October 2011.[5]

The RSR balance and the RSR surcharge, if any, are important elements of the preference power customers' rates. It would be unfair if the customers had no notice of the impact the Recharge NY program may have on their rates.

The public hearings on the rate proposal are scheduled for the week of September 19, and written comments are due on October 1, 2011. Yet, staff is proposing to wait until after those dates before it informs the Trustees of adjustments it may make to the rate proposal to account for the implementation of the Recharge NY program. Deferral of any increase in the preference power rates is required to provide proper notice and opportunity for comment to the Authority's customers.

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[5] Preliminary Report at 10, n.6. The RSR is the mechanism provided in the Service Tariffs to make the Flow Adjustment Calculation, which compensates for variations in annual hydro flows.

E. Deferral of the date for written comments until December 1, 2011 is appropriate to allow customers time to review the rate proposal.

NYAPP and other customer representatives are actively reviewing the proposed rate increase, including conducting discovery. The customers need additional time to conduct their review.

In the past, it was customary for the staff's Preliminary Report to be made available to customers five or six months in advance of the May 1 effective date. In this case, customers were provided the Preliminary Report two months before the deadline for written comments.

NYAPP has had productive discussions with the staff, and has been conducting discovery. As of this date, the staff has responded to just over half of NYAPP's discovery requests, with 28 of 62 still outstanding in whole or part. An extension of time to December 1, 2011 for written comments would allow time for customers to complete their review, allow for continuation of discussions with the staff, and allow staff more time to respond to discovery requests.

WHEREFORE, for the foregoing reasons, NYAPP requests the deferral of the

any increases in the preference power rates to May 1, 2012, and an extension of the deadline for written comments to December 1, 2011.

Dated: September 13, 2011

Respectfully submitted,

Jeffrey C. Genzer
Thomas L. Rudebusch
DUNCAN, WEINBERG, GENZER
& PEMBROKE, P.C.
1615 M Street, N.W., Suite 800
Washington, D.C. 20036
(202) 467-6370
tlr@dwgp.com

Attorneys for the
New York Association of Public Power

TAB 5-L

Comments of NYAPP

Law Offices
Duncan, Weinberg, Genzer & Pembroke, P.C.

WALLACE L. DUNCAN (1937-2008)
EDWARD WEINBERG (1918-1995)
ROBERT WEINBERG
JEFFREY C. GENZER
THOMAS L. RUDEBUSCH
MICHAEL R. POSTAR
ELI D. EILBOTT*
LISA S. GAST
PETER J. SCANLON
KATHLEEN L. MAZURE
DEREK A. DYSON
BHAVEETA K. MODY
KRISTEN CONNOLLY McCULLOUGH
SETH T. LUCIA
JOSHUA E. ADRIAN
MATTHEW R. RUDOLPHI
JASON T. GRAY
NATALIE M. KARAS

RICHMOND F. ALLAN+
JAMES D. PEMBROKE+
TANJA M. SHONKWILER+
TERRY E. SINGER+

SUITE 800
1615 M STREET, N.W.
WASHINGTON, DC 20036

(202) 467-6370
FAX (202) 467-6379
www.dwgp.com

California Offices
SUITE 1410, 915 L STREET
SACRAMENTO, CA 95814
(916) 498-0121
SEAN M. NEAL

SUITE 501
100 W. SAN FERNANDO STREET
SAN JOSE, CA 95113
(408) 288-2080
BARRY F. McCARTHY+
C. SUSIE BERLIN+

Northeast Regional Office
2700 BELLEVUE AVENUE
SYRACUSE, NY 13219
(315) 471-1318
THOMAS J. LYNCH+

*REGISTERED TO PRACTICE BEFORE U.S. PATENT AND TRADEMARK OFFICE

+OF COUNSEL

October 24, 2011

By E-mail and Overnight Express

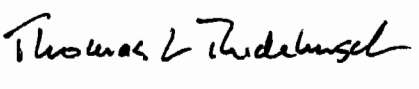
Karen Delince
Corporate Secretary
New York Power Authority
123 Main Street, 15M
White Plains, New York 10601

RE: **Comments of the New York Association of Public Power on the Proposed Rulemaking to Increase Hydroelectric Production Rates, Issued August 17, 2011**

Dear Ms. Delince:

Enclosed please find Comments of the New York Association of Public Power in the above-referenced matter. Please contact me with any questions.

Sincerely,



Thomas L. Rudebusch

Enclosure

Before the
POWER AUTHORITY OF THE STATE OF NEW YORK

Proposed Rulemaking to Increase Hydroelectric Preference Power Rates	)))	I.D. No. PAS-33-11-00001-P

Comments of the New York Association of Public Power on the Proposed Rulemaking to Increase Hydroelectric Production Rates

To: The Trustees

The New York Association of Public Power ("NYAPP") respectfully files these Comments on the Notice of Proposed Rulemaking to increase the hydroelectric preference power rates of the Power Authority of the State of New York ("Authority" or "PASNY"), published in the State Register on August 17, 2011.[1] NYAPP is concerned about the impact of a cumulative 29.5 percent rate increase on rural and domestic consumers and the amounts of Authority spending that increase reflects.[2] NYAPP requests that the Trustees take the following actions:

- Defer the effective date of any rate increase resulting from the Proposed Rulemaking until May 1, 2012, and allow time to consider the increases.
- Allocate costs to all capacity sales from the Projects to produce the statutory "lowest possible rate" going forward.
- Looking backward, credit all sales of Project capacity above the base level used in ratemaking directly to the Rate Stabilization Reserve ("RSR") Balance, and calculate the credit using a cost-based rate.
- Affirm that the canceled rate increases proposed for 2009-2010 were indeed canceled and are not to be recovered in the future.
- Confirm that the 455 MW withdrawn from domestic and rural consumers for the Recharge NY Power Program will remain in the demand component of the rate calculation.
- Use appropriate metrics when considering whether future transfers to the State Treasury are "feasible and advisable," and confirm that revenues

[1] NYAPP's members, which are municipal electric utilities and rural electric cooperatives, are preference power customers of the Authority.
[2] The rate increases are discussed in the Preliminary Staff Report on Hydroelectric Production Rates, Rate Modification Plan – Rate Years 2011 to 2014, dated July 2011 ("Preliminary Report").

from the sale of preference power are in no way being used to fund the transfers.

In support, NYAPP has sponsored the affidavit of Whitfield A. Russell, which is attached to these Comments. Further, NYAPP states as follows:

A. The Effective Date of any Proposed Rate Increases Should Be May 1, 2012 Which Is the Start of the Authority's Next Rate Year.

The Authority's traditional Rate Year commences May 1 and concludes April 30 of the following year.[3] It would be appropriate and consistent with past practice to defer the effective date of any rate increase resulting from the Proposed Rulemaking until the start of the next Rate Year. The Notice states that the purpose of the Proposed Rulemaking is to maintain the Authority's fiscal integrity. A deferral will not affect the Authority's fiscal integrity. The Authority's Chief Financial Officer has predicted that end-of-year net income will be $197 million, which would be $17 million above the 2011 budget. For the period November 1, 2011 to April 30, 2012, the proposed rate increase would produce additional revenues of approximately $3.0 million from all of the preference power customers in New York State. Deferral of the effective date for any rate increases to May 1, 2012 will not materially affect the Authority's fiscal integrity and will be in the public interest.

B. Project Costs Must Be Allocated to All Capacity Sales to Achieve the Lowest Possible Rate for Sales of Preference Power.

Niagara Project costs must be allocated to all users of the Project's capacity to achieve the lowest possible rate. Currently, all the costs of the Project are allocated only to contract customers, including preference power customers, even though substantial capacity is being used to make in sales the New York Independent System Operator

[3] For more, see NYAPP's Request for Deferral of Any Rate Increases, submitted on September 13, 2011.

("NYISO") capacity market or transferred to other Authority customers. These customers, and customers in the NYISO market, rely on the capacity to meet their reliability requirements in the same manner as contract customers. All Load Serving Entities in New York must demonstrate they meet the Unforced Capacity ("UCAP") requirements established by the NYISO.[4] For cost allocation purposes, there is no basis for distinguishing capacity sales to the contract customers from sales into the NYISO market or transfers to other Authority customers.

For the years 2011-2014, the Staff's Preliminary Report forecasts Billing Demands of about 36,000 MW-months, based on sales to the contract customers. These demands are used to allocate the costs of the Project. At the same time, the Authority has routinely made total annual capacity sales of about 41,000 MW-months as reflected in the recent calculations of the RSR.[5] Under the Authority's Cost of Service ("CoS") methodology, all increases in costs are recovered through an increase in the demand rate.[6] Obviously, a key element in determining the demand rate is the estimated billing demand expressed in MW-months. By using higher billing demand, the Authority produces a lower demand rate. Conversely, using lower billing demand produces a higher demand rate.

To produce the lowest possible rates, the denominator used to set the demand rate should be the MW-months of contract customer demand and the MW-months based on the Authority's average UCAP sales from the Projects. In other words, the demand rate must be calculated using Billing Demands of 41,000 MW-months, rather than the much

---

[4] *See* NYISO's Installed Capacity Manual, *e.g.*, §§ 2.6 and 3.4.
[5] *See* Russell Affidavit at ¶¶5-6.
[6] The demand rate is determined by subtracting expected energy revenues from the total revenue requirement and then dividing the result by the estimated billing demand.

lower 34,000 to 36,000 MW-months the Authority is proposing to use in 2011-2014. If the Authority uses Billing Demands of 41,000 MW-months to set the prospective rates for 2011-2014, the revised rate increase for the entire period would equal 15.6 percent, compared to the 29.5 percent increase arising from the projected phased-in rates of the Authority.[7] NYAPP members would bear additional increases of $7.2 million when the rate increase is calculated based upon 41,000 MW-months of Billing Demands, compared to the $13 million in additional increased payments they would bear under the Authority's proposed phase-in plan.[8]

The Authority is required to provide service from the Projects at cost to preference power customers. The statutory requirement is contained in Section 1005(5) of the Public Authorities Law, which requires that in selling preference power the Authority:

> shall sell the same or cause the same to be sold to such municipalities and political subdivisions at prices representing cost of generation, plus capital and operating charges, plus a fair cost of transmission, all as determined by the trustees, and subject to conditions which shall assure the resale of such power to domestic and rural consumers *at the lowest possible rate*.[9]

The statutory policy was explained by the *Auer* court: "[t]he policy is that hydroelectric projects shall benefit 'the people of the state as a whole' and 'particularly the domestic and rural consumers *at the lowest possible rates*'...."[10] Moreover: "to further that policy,

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[7] *See* Russell Affidavit at ¶15 for detail on rate changes.
[8] *Id.* at ¶16.
[9] Public Authorities Law, §1005(5), emphasis supplied. The complementary standard in federal law is "the lowest rate reasonably possible," in the Niagara Redevelopment Act, 16 U.S.C. 836(b)(2).
[10] *Auer v. Dyson*, 110 Misc. 2d 943, 948, 444 N.Y.S.2d 513 (Sup. Ct. Oswego Co. 1981) ("*Auer*"), *quoting* PAL §1005(5) (emphasis in original).

the authority is also mandated to furnish a reasonable share of hydroelectric power to 'municipal and political subdivisions' at a price based on costs."[11]

In *Auer*, retail customers of Niagara Mohawk Power Corporation contended that the Authority was violating the lowest possible rate requirement because revenues from the Projects were pledged to general purpose bonds.[12] The Authority argued that the requirement did not apply to domestic and rural consumers who were customers of an investor-owned utility. The *Auer* court disagreed: "[H]ydropower furnished for the use domestic and rural consumers whether direct from the authority, from a municipal or political subdivision or an investor-owned utility must be sold by the authority at the lowest possible rates...."[13]

The Authority also argued that the requirement applied only to sales to industry. The *Auer* court again disagreed:

> The court cannot agree with PASNY's argument that the phrase "lowest possible rate" is solely for the purpose of establishing a condition for sales to industry. Broad discretion is given to the authority to determine the components of its costs, and it is not required to guarantee any specific rate. ... *However, the authority must be able to establish that the rate to domestic and rural consumers is as low as possible....*[14]

The *Auer* court did find a limitation on the statutory requirement, finding that:

> An interpretation that would permit the lowest possible rate to be less than cost would be absurd, and it must be presumed that the Legislature never intended such a result. Once there is evidence that the lowest possible rate within this limitation has been established, PASNY will have fulfilled its statutory obligation.[15]

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[11] *Id.*
[12] Wholesale preference power customers were not parties to the *Auer* cases.
[13] *Auer*, 110 Misc. at 950.
[14] *Id.* at 948 (emphasis supplied).
[15] *Id.* at 949 (citation removed).

The issue of whether the "lowest possible rate" requirement applied in setting preference power rates was confirmed in the *Bergen* case. In that case, preference power customers argued that the Authority should allocate indirect overhead costs using a ratio based on labor expenses rather than generation capacity, because this would comply with the "lowest possible rate" requirement of the Public Authorities Law. The court agreed and ordered the Authority to recalculate the preference rate using the labor ratio.

The Authority appealed, arguing that it had "broad discretion" in setting rates. The Appellate Division disagreed:

> The issue before the court was whether PASNY, in calculating the preference power rate for municipal customers, complied with the statutory mandate to set the "lowest possible rate" when it included therein indirect overhead expenses based on capacity rather than labor costs. We reject the contention of PASNY that it has broad discretion to establish rates and that, as long as its indirect overhead expenses are allocated reasonably, PASNY has complied with its statutory mandate. Even though a rate-setting methodology may be reasonable, it may not result in the lowest possible rate required by Public Authorities Law § 1005(5).[16]

Importantly, the *Bergen* case is consistent with the decision in *Auer*. While the Authority has broad discretion in setting rates, that discretion is subject to the "lowest possible rate" statutory requirement in setting preference power rates.

In this proceeding, the Trustees must abide by the statutory mandate to allocate costs to produce the "lowest possible rate." As demonstrated above, and in the attached affidavit of Mr. Russell, that result is reached if the demand rate is calculated using Billing Demands of 41,000 MW-months, rather than the lower 34,000 to 36,000 MW-months that Staff is proposing to use in 2011-2014.

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[16] *Bergen v. Power Auth. of St. of New York*, 249 A.D.2d 902, 672 N.Y.S.2d 595 (N.Y. App. Div. 1998) (citations removed). The case was remanded in order to determine the "lowest possible rate."

C. The RSR (Rate Stabilization Reserve) Must Reflect a UCAP Credit Based on Cost and That Is Applied To the RSR Balance Directly.

The Service Tariffs, which set forth the fixed demand and energy rates at issue in this rulemaking, contain a Flow Adjustment Computation, which is a credit or surcharge to be applied in a rate year following a calendar year when the RSR exceeds a bandwidth of $+/-25 million. The purpose of the RSR is to ensure rate stability and cost recovery in the face of variations in annual water flows and hydro generation.[17] NYAPP supports the general purpose of the Flow Adjustment Computation.

The RSR contains a "UCAP Credit" which is designed as a credit to the preference power rates to account for the 24 percent of the Project capacity that is used for sales into the NYISO's UCAP market and transfers to meet the reliability needs of other Authority customers. As discussed above, going forward in 2011-14, the Trustees should approve rates that allocate costs to all users of the Project capacity, which would substantially reduce the need for the UCAP Credit. For prior periods, the RSR balance should (1) be adjusted to reflect a cost-based rate and (2) be applied directly to the RSR balance, as discussed in the attached affidavit of Whitfield A. Russell.

The Staff's Preliminary Report states that the RSR balance is currently $-51 million. To remedy the negative imbalance, it proposes that the Trustees implement a surcharge on preference power customers of $0.50/MWh in 2014.[18] The surcharge is unnecessary, however. The adjustments that NYAPP recommends to the Trustees would substantially reduce the negative RSR balance.

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[17] "The RSR was established in 1987 . . . and is designed to capture over or under recovery of costs relative to the costs collected in the fixed demand and energy charges, due to differences in net generation and actual cost incurrence." April 2003 Rate Modification Plan, Appendix B, p 21.

[18] The Staff Preliminary Report states that over $25 million of the shortfall is related to the "deferred" rates proposed for 2009-10. This "deferral" is discussed in Section D, *infra*.

First, the RSR should be adjusted in two ways to properly reflect the lowest possible cost-based rate. Under the Authority's rate design, preference power customers receive a credit that is based on the *lower* of the UCAP market price or the cost-based rate for the UCAP. This credit should instead be based on the cost of that capacity because these are cost-based rates.[19] Obviously, the lowest rate would be achieved by using the *higher* of market prices or cost-based rated, but that result would be inconsistent with the *Auer* decision that rates be based on costs. The consistent approach would be to base the UCAP Credit on costs. In years when the NYISO market prices are above cost (which has occurred), there are excess revenues for the Authority. In years when the market prices are below cost (which has also occurred), the *Auer* decision requires that the credit be based on cost. Using a cost-based credit reduces the RSR underfunding by $13.8 million.[20]

In addition, the UCAP Credit calculation causes the MW-months of actual capacity sales to be understated because the methodology leaves the difference between the forecasted demand (the "base level" of approximately 36,000 MW-months) and the actual demands (ranging from 32,000-35,000 MW-months in recent years) out of the equation. From 2005 through 2010, NYPA has derived a dollar UCAP credit based - not upon its total sales of capacity into the UCAP market and internal transfers - but upon a lesser, net amount of capacity ("Net Capacity") times the UCAP market price ("Market Rate"). The product of Net Capacity times Market Rate is subtracted from the Actual CoS.[21] It is significant that the Authority did not limit the megawatts of UCAP and

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[19] *See* Russell Affidavit at ¶¶15-16.
[20] *Id.* at ¶24. This correction results in the RSR balance being reduced from $-51.3 million to $-37.4 million.
[21] *Id.* at ¶¶ 27-30.

internal transfers that it credited to the RSR in 2003 and 2004, the first years after the Global Settlement. In these years, the UCAP credit was calculated correctly, and the Authority should return to its initial interpretation of the 2003 Global Settlement Agreement in order to produce the lowest possible rate.

Calculating the UCAP Credit at the cost-based demand rate for the full amount of (a) capacity transferred internally plus (b) capacity sold into the NYISO's UCAP market results in a reduction in the RSR underfunding of $32.3 million.[22]

Second, the Authority deducts the UCAP Credit from the Cost of Service, which means all contract customers benefit from the credit. However, the UCAP Credit was a bargained-for right obtained in the Global Settlement. Only the preference power customers that executed the Global Settlement should be entitled to the UCAP Credit. This can be achieved by deducting the UCAP Credit directly from the RSR balance, as Mr. Russell recommends.[23]

Making these adjustments in tandem reduces the RSR imbalance by $48 million and results in there being no need for a surcharge in 2014.

D. Costs, If Any, Associated with the Withdrawn Rate Increases from 2009-10 Should Not Be Collected from Future Ratepayers.

In 2009, the Staff proposed to increase rates for the 2009 and 2010 Rate Years. Instead, the Trustees voted to "withdraw" the proposed rate increases, and they "extended" the rates that were in effect in 2008.[24] The March 24, 2009 Press Release issued by the Authority was titled: "NYPA Cancels Proposed Rate Increase For

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[22] *Id.* at ¶¶ 30-31. The two corrections together result in the RSR underfunding being reduced from $-51.3 million to $-19 million.
[23] *Id.* at ¶ 32. The three corrections together result in the RSR underfunding being reduced from $-51.3 million to $-3 million.
[24] That is the language from the Trustees' motion.

Hydropower Customers." Now the Staff proposes to go back and collect in excess of $25.0 million for 2009-10 through the $0.50/MWh surcharge proposed for 2014. As demonstrated above, if the Trustees make the adjustments to the UCAP credit recommended by NYAPP, there is no need for the surcharge. However, costs, if any, associated with the 2009-10 increases should stay "canceled" and not be recovered from future ratepayers.

For the Staff to now say we meant we were going to "defer" the rate increases and not "cancel" them is a shock to customers. The Public Service Commission knows how to collect "deferred" amounts – it does it up front. The PSC issues an order that states: "these costs are being incurred, but for some good public policy reason, we are not going to collect them now, and we direct the utility to put the amounts in a deferral account to be collected at a date certain in the future." That is how a deferral is handled, with notice to customers.

The Staff proposes to collect the amounts from 2009-10 through the RSR, the true-up mechanism intended to provide rate stability for variations in annual hydro flows. The Authority did not announce it was going to use the RSR to collect the "deferred" amounts, instead it suspended providing customers with the annual statement of the calculation of the RSR balance, thereby hiding the fact that the RSR bandwidth may have been exceeded. The 2009-10 RSR Statements were not provided to customers until the Preliminary Report was issued, showing a RSR balance of $-51.3 million. This is a sleight-of-hand maneuver and is not evidence of candor in dealing with customers.

For formula rates, the "rate" in the tariff is a formula, not a fixed number. The formula details how annual values in numerous accounts are incorporated in charges to

customers. Typically, the numbers in those accounts are verified in filings with the Federal Energy Regulatory Commission. Without a similar requirement, there is no way to verify the Authority's actual costs. If the Trustees want to establish a formula rate for the hydro production costs, consideration needs to be given as to how the costs can be verified. Currently, there is a lack of transparency involving the Authority's costs that make it difficult to verify the appropriateness of costs.

There is the statutory standard that the preference power should be sold at the lowest possible rates. But that is a guide for setting rates at cost. It is not a formula rate. The Authority has not in the past used the standard as a formula. When the court in the *Bergen* case said rates should be set using a labor ratio allocator, the Authority made the change only prospectively, and it did not change rates in the past (other than through refunds for those systems that filed suit). When customers pointed out that the Authority used the wrong year to start the Handy-Whitman Index for depreciation, the Authority said it could not go back and change rates, because those were established practices. The Authority cannot have it both ways.

E. The 455 MW Withdrawn from Domestic and Rural Consumers to Implement the Recharge NY Power Program Must Remain in the Demand Component of the Rates.

The Preliminary Report states that important elements of the cost of service are not yet decided related to the implementation of the Recharge NY Power Program. On August 1, 2011, the Authority withdrew 455 MW of hydropower previously sold to investor-owned utilities for the benefit of domestic and rural consumers. In the future, the 455 MW of hydropower will be sold to eligible businesses under the Recharge NY Power Program. Until eligible entities are allocated the power, the Authority will sell the

power into the NYISO markets and use the proceeds to mitigate the rate shock to the former customers.

However, the Preliminary Report states that:

> [t]o the extent that such withdrawal [of the 455 MW] will affect the RSR balance and the RSR surcharge in a material manner, the staff will inform the Trustees and adjust the rate proposal accordingly when it is submitted for final approval in October 2011.[25]

The RSR balance and the RSR surcharge are important elements of the preference power customers' rates. It is unfair that customers have no notice of the impact the Recharge NY program may have on their rates.

There are two adjustments that the Trustees must ensure are made to the preference power rates related to the Recharge NY program. First, the 455 MW must continue to be reflected in the Billing Demands used for calculating the demand rate for preference power customers. Those MW-months also need to continue to be included in the actual contract demands used in the RSR calculation. Preference power customers should not have to assume the burden of all costs of the Projects in the event that qualifying businesses do not emerge to take power, or if such businesses do not take the full amount of capacity withdrawn from the domestic and rural consumers. As Mr. Russell recommends, the 455 MW must remain in the production rate denominator (Billing Demands) and in the calculation of Actual Demands used in the RSR calculation in order to produce the lowest possible cost-based rate.[26] Importantly, Staff agrees with this recommendation.[27]

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[25] Preliminary Report at 10, n.6.
[26] Russell Affidavit at ¶ 35.
[27] In a September 28, 2011, Staff response to Request NYAPP 1-16, NYPA stated:

Second, the Staff's Preliminary Report recommends that the RSR balance include over $25 million related to the "deferred" rate increases in 2009 and 2010. If the rates had been increased in 2009-10, the customers associated with the 455 MW would have paid their share of the increase, approximately $6 million. Since the power has been withdrawn, those customers can no longer be charged for what they were proposed to have paid in higher rates during that period. However, it would be unfair to remaining preference power customers to be assessed the share of costs associated with the 455 MW. The remaining Authority customers must not be assessed the difference.

F. The Trustees Must Use Appropriate Metrics When Considering Whether Transfers Are "Feasible and Advisable," and Confirm That Revenues from Preference Power Sales Are Not Funding the Transfers.

NYAPP is concerned about rising costs of the Authority. There were rate increases of 5.3 percent in 2007, 5.9 percent in 2008, and the proposed increase of 8.2 percent in 2009. Going forward, the Authority is proposing increases of 6.6 percent in 2011, 6.5 percent in 2012, 6.7 percent in 2013, and 6.9 percent in 2014. These are dramatic increases, especially at the same time that the Authority is making large transfers, or "Sweeps," to the State Treasury.

The Authority's voluntary transfers will amount to approximately $775 million between 2002 and January of 2011. In addition, the Authority made "temporary transfers" totaling $318 million from the Authority's spent nuclear fuel reserve fund and

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NYPA has not removed the 455 MW of firm hydropower from the demand and energy billing determinants used to calculate the Hydroelectric COS. Despite the removal of the 455 MW from the amount of MWs sold at the preference power rate in order to be used for the new Recharge New York Power Program, NYPA still considers these MWs part of the firm billing demands of the Hydroelectric Projects, and therefore, has included them as part of the billing determinants used in the COS.

future construction funds, for total transfers in excess of $1 billion.[28] In June, the Trustees approved a contribution to the State Treasury of $40 million. This is in addition to the $25 million contribution approved in January 2011, as well as a $7.5 million contribution to the Gross Receipts Tax credit. The coverage calculation presented at that meeting assumed that the Authority's $396 million in 2011 cash flow would cover $170 million in debt by 2.7 times and that its coverage would drop to 2.1 times after the Authority contributed $97.5 million to the State Treasury.

As Mr. Russell testifies, a more appropriate test would call for the Authority to apply the methodology on a *pro forma* basis to future periods and future planned financings and to include sensitivity studies assuming levels of cost increases and sales declines experienced during the recent recession.[29] The Authority must establish and publish detailed metrics for measuring its present and projected creditworthiness when confronting the Sweeps.

The current budget legislation authorizes an additional $60 million contribution to be made by January 2012. NYAPP requests that the Trustees exercise their "feasible and advisable" judgment in considering any future transfers and only approve the coming $60 million transfer based upon studies of *pro forma* results showing the metrics of the Authority's financial strength.

NYAPP also requests that the Trustees confirm that none of the revenue from preference power customers contributes to the transfers, since this would be a violation of the *Auer* decision, the holding of which was that the Authority is prohibited from using Project revenues for other purposes unless and until it has satisfied its statutory obligation

[28] *Id.* at ¶ 37.
[29] *Id.* at ¶ 40.

to provide power at the lowest possible rates to domestic and rural consumers. Finally, NYAPP requests that the Trustees confirm that any replenishment of the spent nuclear fuel waste fund will not come out of preference power rates, since NYAPP's members already contributed to this fund when they paid incremental power rates in the past.

WHEREFORE, for the foregoing reasons, NYAPP requests that the Trustees:

1. Defer the effective date of any rate increase resulting from the Proposed Rulemaking until May 1, 2012, and allow time to consider the increases.
2. Allocate costs to all capacity sales from the Projects to produce the statutory "lowest possible rate" going forward.
3. Looking backward, credit all sales of Project capacity above the base level used in ratemaking directly to the RSR Balance, and calculate the credit using a cost-based rate.
4. Affirm that the canceled rate increases proposed for 2009-2010 were indeed canceled and are not to be recovered in the future.
5. Confirm that the 455 MW withdrawn from domestic and rural consumers for the Recharge NY program will remain in the demand component of the rate calculation.
6. Use appropriate metrics when considering whether future transfers to the State Treasury are "feasible and advisable," and confirm that revenues from the sale of preference power are in no way being used to fund the transfers.

Dated: October 24, 2011

Respectfully submitted,

Jeffrey C. Genzer
Thomas L. Rudebusch
DUNCAN, WEINBERG, GENZER
& PEMBROKE, P.C.
1615 M Street, N.W., Suite 800
Washington, D.C. 20036
(202) 467-6370
tlr@dwgp.com

Attorneys for the
New York Association of Public Power

TAB 5-L

Part 1

Affidavit of Whitfield A. Russell & Exhibit on behalf of NYAPP

AFFIDAVIT OF WHITFIELD A. RUSSELL

NEW YORK POWER AUTHORITY'S 2011 HYDROELECTRIC RATE MODIFICATION PLAN

(New York Register Rulemaking I.D. No. PAS-33-11-00001-P)

INTRODUCTION

1. My name is Whitfield A. Russell. I am a public utility consultant and principal in Whitfield Russell Associates. I hold a Bachelor of Science degree in Electrical Engineering from the University of Maine at Orono, a Master of Science degree in Electrical Engineering from the University of Maryland, and a Juris Doctor degree from Georgetown University Law Center. I have been accepted as an expert on bulk power systems in more than 150 proceedings before State and Federal courts, administrative agencies and other tribunals in approximately 30 States and in two Canadian provinces. My complete resume and a description of cases on which I have worked are attached as Exhibit No. 1 to this Affidavit.

PURPOSE AND ORGANIZATION OF AFFIDAVIT

2. This proceeding involves the appropriate rates for bulk power service that the New York Power Authority ("NYPA") will render in the 2011-2014 rate years to municipal and cooperative preference customers from NYPA's Niagara and St. Lawrence Projects. NYPA is proposing an increase in its Adjusted Cost of Service ranging from $230.57 million in 2011 to $255.576 million in 2014. See the NYPA Preliminary Staff Report on Hydroelectric Production Rates, Rate Modification Plan – Rate Years 2011 to 2014, dated July 2011 ("2011 Staff Report") at Exhibit A, page 2 of 2, line 14. Starting from the Adjusted Cost of Service of $206.31 million for 2008, NYPA proposes to increase the Adjusted Cost of Service in annual steps, by 11.7% over the 2008 level in 2011 and by 23.9% over the 2008 level in 2014. From the current rates that were in effect since 2008, the proposed rates will increase on average 6.7% annually from 2011 to 2014 for a total increase of 29.5%.

3. I have reviewed the proposed rates and Adjusted Cost of Service on behalf of the New York Association of Public Power ("NYAPP"). My affidavit addresses the issues arising from my review, and first addresses the allocation of costs to insufficient amounts of capacity. In addition, NYPA has deprived its customers of a fair and equitable credit for actual sales of capacity by means of its calculation of the UCAP credit in its Rate

Stabilization Reserve ("RSR") true-up.[1] Next, I discuss concerns that involve the newly-passed Recharge New York Power Program legislation and how the Staff's 2011 preliminary Cost of Service ("CoS") will allocate costs to the Megawatts ("MW") of capacity used in this program. Finally, I address concerns involving the "Sweeps" of funds from NYPA to the New York State government, funds for State Parks, and Shared Service costs.

CAPACITY ALLOCATION

4. Under NYPA's cost of service methodology, all increases in costs are recovered through an increase in the demand rate. The demand rate is determined by subtracting expected energy revenues from the total revenue requirement and then dividing the result by the estimated billing demand. Obviously, a key element in determining the demand rate is the estimated billing demand expressed in MW-months. By using a higher billing demand, NYPA produces a lower demand rate. Conversely, using a lower billing demand produces a higher demand rate.

5. For the years 2011 through 2014, NYPA has forecast a billing demand of approximately 36,000 MW-months although the forecast is lower at 34,086 MW-months in 2011 and 35,035 MW-months in 2012. Exhibit A, page 2 of 2, line 15. A billing demand of 36,000 MW-months reflects an expectation that NYPA has 3,000 MW to sell in each month (36,000 MW-months divided by 12 months).

6. A billing demand of 36,000 MW-months represents an unreasonably low expectation given (1) that NYPA has sold about 41,000 MW-Months as reflected in recent annual true-ups of the RSR and (2) that the Dependable Maximum Net Capacity ("DMNC") of the two projects is now approximately 3,540 MW (equivalent to a billing demand of 42,480 MW-months).[2] The DMNC has increased because capacity of the Hydro Projects has increased as a result of upgrades made at the plants. The costs of these upgrades are included in the CoS. Because NYPA possesses over 3,500 MW of capacity for sale from the Hydro Projects, its Billing Demand should be closer to 42,000 MW-months. By

[1] UCAP stands for Unforced Capacity, as defined in Section 2.21 of the New York Independent System Operator ("NYISO") Market Administration and Control Area Services Tariff.

[2] DMNC and UCAP values are taken from NYPA's response to NYAPP-13(b) and (c). DMNC is the amount of Project output which annual tests determine can be sustained for at least four hours during on-peak conditions. See the 2007 Appendix A Staff Report at 19. The combined installed capacity of the Projects is even higher at 3,842 MW (2930 MW at Niagara with maximum head at the Lewiston Pump Generating Plant and 912 MW at St. Lawrence).

unreasonably suppressing its forecast of Billing Demands, NYPA has set an unduly high demand rate.

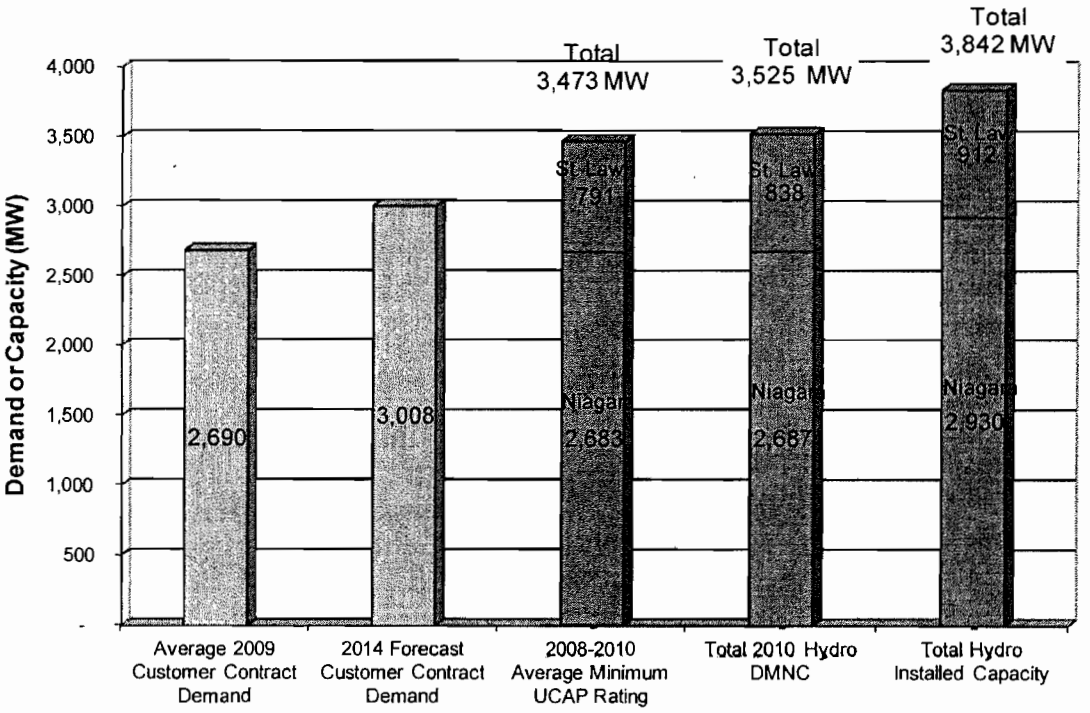
7. Niagara and St. Lawrence Project costs should be allocated to all users of the Projects' capacity. Currently, all the costs of the Projects are allocated only to contract customers, including preference power customers, even though substantial capacity is being used to make sales to the New York Independent System Operator ("NYISO") markets. Customers in the NYISO markets rely on the capacity to meet their reliability requirements in the same manner as do contract customers. In response to Request NYAPP 2-5 (b), NYPA admits that Project DMNC is sold into the NYISO's markets to provide capacity to NYISO customers. NYPA's response to Request NYAPP 2-5 (b) states:

> To the extent hydrologic flows at the Projects make such generation available, the differential between Summer Generation Capacity and peak load of all contract customers would be available for sales of UCAP or other NYISO ancillary services, such as operating reserves and regulation. The Authority is obligated to bid its generation into the UCAP and ancillary services markets in accordance with NYISO rules, and such bids are accepted based on market needs.

NYPA has chosen to allocate costs only to contract customers, and then provide a revenue credit for (a) UCAP sales into NYISO markets and (b) internal NYPA capacity transfers. This methodology is not correct because all customers of capacity should be allocated the costs of the capacity. In order for NYPA to set the lowest possible rates, NYPA must allocate those costs correctly.

8. The chart below demonstrates the difference between (1) the contract customers' demands used to allocate costs during 2009 and the demands proposed to be used to allocate costs in 2011-2014 (the two left-most bars) and (2) the much greater UCAP, DMNC and installed capacity for the Niagara and St. Lawrence Projects for which customers pay (the three right-most bars). As discussed below, I propose allocating costs based upon an average of the last three years of capacity sales, which is close to the minimum UCAP rating of the two plants (the middle bar) with a true-up based upon actual contract demands and UCAP sales and transfers in the RSR balance.

Comparison of Customer Demand to Niagara and St. Lawrence Hydro Capacity



9. Note that, in 2009, monthly contract demands of contract customers were about 800 MW less on average than the DMNC of the Projects. Contract demands averaged 2,690 MW (76% of average DMNC).[3] Average contract customer demands are projected to increase to 3,008 MW in 2014, indicating that those demands are expected to remain about 500 MW below the DMNC of the Projects.[4] The minimum UCAP ratings for the plants over the 2008-2010 period was 3,473 MW. The average DMNC for the Hydro Projects in 2010 was set at 3,525 MW, the sum of Niagara (2,687 MW) and St. Lawrence (838 MW).[5] Installed capacity, on the other hand, is about 300 MW higher at 3,842 MW.[6]

10. For 2010, NYPA used Billing Demands of 36,137 MW-months to set the demand rate (the same amount used since the rate was set in 2008). However, NYPA admits that it made capacity sales of 41,539 MW in 2010. This amount was made up of the following:
    (a) 32,711 MW-months sold to contract customers,
    (b) 6,954 MW-months sold in the NYISO's UCAP market and

[3] AS_Cost_Workpapers-2011-14-MEUA#1-1, WORKPAPER 9.2
[4] Billing_Determinants-2011-14-MEUA#1-1
[5] NYAPP Responses13b_13c_2-9
[6] NYPA report entitled "Capacity and Energy Production Achievable at the Niagara Project, March 2007" and FERC Order Approving Settlement Agreements, Dismissing Complaint, and Issuing New License, Project 2000-036, October 23, 2003, P9.

(c) 1,874 MW-months transferred internally to other NYPA customers.[7]

11. In my opinion, it is unreasonable that NYPA allocates 100% of the costs of the Niagara and St. Lawrence Project costs to contract customers yet sold only 76% of Project capacity to those customers. The remaining 24% is sold in NYISO's UCAP markets, transferred internally to other NYPA customers (e.g., Southeast New York governmental customers) and/or is sold as ancillary services. In order to produce the lowest possible rates, the denominator used in deriving the demand rate should be the MW-months of contract customer demand plus the MW-months of NYPA's average UCAP sales and internal transfers from the Projects. Based upon recent data (2008-2010), the average Billing Demands from the Projects total approximately 41,000 MW-months. If NYPA sets the demand rate based upon these Billing Demands, the CoS methodology will still allow a true-up to actual costs and usage. Use of this amount will also correct the double recovery of costs associated with the RSR UCAP credit, as discussed below.

12. If NYPA uses Billing Demands of 41,000 MW-months to set the preference power rates for 2011-2014, the revised rate increase for the entire period would equal 15.6%, compared to the 29.5% increase arising from the projected phased-in rates of NYPA. The table below shows the annual increases.

ACTUAL with 41,000 MW-Months BDs

Year	Demand $/kW-mo.	Energy $/MWh	Base $/MWh	% Change
2010	2.96	4.92	10.71	
2011	3.20	4.92	11.18	4.4%
2012	3.39	4.92	11.55	3.3%
2013	3.61	4.92	11.98	3.7%
2014	3.81	4.92	12.38	3.3%

13. As the Table below shows, the NYAPP members would bear additional increases of only $7.2 million with use of my proposed rate increases based upon 41,000 MW-months of Billing Demands, compared to the $13 million in additional increased payments under NYPA's proposed phase-in plan.

[7] See Response to NS-18.

Impacts of Rate Increases on NYAPP Members

NYPA PHASE-IN

Year	Demand $/kW-mo.	Energy $/MWh	Base $/MWh	% Change	Revenues	Annual Revenues Increase	Accum. Revenues Increase
2010	2.96	4.92	10.71		$ 18,347,079		
2011	3.32	4.92	11.42	6.6%	$ 19,558,337	$ 1,211,258	$ 1,211,258
2012	3.70	4.92	12.16	6.5%	$ 20,832,251	$ 2,485,172	$ 3,696,430
2013	4.12	4.92	12.98	6.8%	$ 22,240,261	$ 3,893,182	$ 7,589,612
2014	4.32	5.42	13.87	6.9%	$ 23,767,282	$ 5,420,203	$ 13,009,815

ACTUAL with 41,000 MW-Months BDs

Year	Demand $/kW-mo.	Energy $/MWh	Base $/MWh	% Change	Revenues	Annual Revenues Increase	Accum. Revenues Increase
2010	2.96	4.92	10.71		$ 18,347,079		
2011	3.20	4.92	11.18	4.4%	$ 19,152,226	$ 805,147	$ 805,147
2012	3.39	4.92	11.55	3.3%	$ 19,786,066	$ 1,438,987	$ 2,244,134
2013	3.61	4.92	11.98	3.7%	$ 20,522,690	$ 2,175,611	$ 4,419,745
2014	3.81	4.92	12.38	3.3%	$ 21,207,922	$ 2,860,842	$ 7,280,587

Difference between NYPA Phase-In Rates and NYAPP Proposed Rates

Year	Demand $/kW-mo.	Energy $/MWh	Base $/MWh	% Change	Revenues	Annual Revenues Increase	Accum. Revenues Increase
2010	0.00	0.00	0.00		$ -		
2011	-0.12	0.00	-0.24	-2.2%	$ (406,110)	$ (406,110)	$ (406,110)
2012	-0.31	0.00	-0.61	-3.2%	$ (1,046,185)	$ (1,046,185)	$ (1,452,296)
2013	-0.51	0.00	-1.00	-3.0%	$ (1,717,572)	$ (1,717,572)	$ (3,169,867)
2014	-0.51	-0.50	-1.49	-3.5%	$ (2,559,361)	$ (2,559,361)	$ (5,729,228)

RSR CALCULATION

14. As discussed above, my recommendation is that costs be allocated to all capacity sold from the Projects, including sales of UCAP into the NYISO market and capacity transferred from the Projects to NYPA customers other than contract customers of the Projects. NYPA acknowledges does not deny that it sells considerable UCAP to parties that are not contract customers. NYPA claims it provides sufficient recognition for those UCAP sales by granting preference customers a credit through the RSR for Project capacity that it sells in NYISO's UCAP market and transfers internally.

15. NYPA does indeed grant preference customers a credit for UCAP sales and internal transfers. This credit is not reflected before the fact when NYPA is setting production rates for the Projects but is instead reflected after the fact in determining the RSR balance. However, in determining that credit, NYPA shortchanges preference customers

in two ways—first, by valuing extra capacity sales at the lower of the UCAP market price or the cost-based demand rate and, second, by limiting the MW of UCAP that it credits.

16. As to the first issue, the UCAP market price has been substantially lower than the cost-based demand rate in recent years as shown at lines j and k in the Table entitled "UCAP CREDIT - GLOBAL SETTLEMENT AGREEMENT" at paragraph 30, *infra*. The UCAP credit should be based on the full cost per kW of Project capacity (e.g., the cost-based demand rate) and should be applied to all kWs of Project capacity made available for UCAP sales and internal transfers. By granting a below-cost credit for UCAP sales and internal transfers of Project capacity to other customers, NYPA runs afoul of the *Auer* finding that "PASNY is specifically prohibited from diverting revenue from the restricted hydropower unless it has met the policy requirement [to furnish hydropower at the lowest possible rate to domestic and rural consumers]."[8] NYPA also runs afoul of the *Bergen* standard to set the lowest rates possible.

17. The RSR calculation is as follows: For each year, NYPA starts by truing up the Cost of Service that it previously forecast to the Actual Cost of Service. From the Actual CoS, NYPA subtracts out a dollar UCAP credit. Next, NYPA subtracts out a demand component, which it bases upon actual contract demands multiplied by the demand rate. NYPA then adjusts the RSR for the amount by which actual energy production differs from Long Term Average energy production, and thus recovers its full costs by means of an adjusted energy rate. Any over- or under-recovery is placed into the RSR balance until it exceeds a set limit ($+/-25 million), at which time NYPA will begin crediting/charging customers for the imbalance.

18. The UCAP or capacity credit was first added to the RSR calculation in connection with the 2003 rate proceeding and has since been applied to the capacity that is sold in the NYISO's UCAP market and the capacity that is transferred internally to other, non-contract, NYPA customers.[9] Prior to the 2003 Global Settlement, NYPA offered no credit for capacity it transferred internally or sold in the NYISO market. The parties addressed the issue by agreeing to a capacity credit as part of the Global Settlement.

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[8] This was stated in the context of the Court's discussion of PASNY's attempt to pool all the revenue from all the projects which the Court characterized as ". . . PASNY's attempt to extend its authority and use its revenue from financially successful projects to underwrite high cost or loss items." The Court noted that "This may be a worthy purpose but it is simply not authorized."

[9] "The RSR was established in the [sic] 1987 in response to public comment that short-term rather than long-term hydro generation forecasts should be used to set current rates . . . and is designed to capture over or under recovery of costs relative to the costs collected in the fixed demand and energy charges, due to differences in net generation and actual cost incurrence." April 2003 Rate Modification Plan, Appendix B, p 21.

19. With respect to capacity credits, the Global Settlement provides:

> (f) Use of the Rate Stabilization Reserve for any under- or over-collection of NYPA's hydroelectric cost of service. The RSR calculations will be done in a manner consistent with the 2003 Hydroelectric cost of service study. All sales of capacity above the base level of capacity sales in the Hydroelectric Cost of Service Study (e.g., in the 2003 Hydroelectric cost of service study, see, NYPA-1, page 2 of 2 line 15) will be credited to the RSR.

20. Note that "Sales of capacity" under the Global Settlement are expressed in terms of MW-months and are credited in amounts "above the base level of capacity sales in the Hydroelectric Cost of Service Study." Further, the line cited from the NYPA 2003 Hydroelectric CoS study references MW-Months, not dollars.

21. These MW-months of capacity sales must be converted into a dollar amount before those dollars can "be credited to the RSR." The Global Settlement does not indicate the method for converting MW-months to a dollar credit, nor does it indicate whether that dollar credit is to be spread to all contract customers or is to be applied solely to preference power customers. Accordingly, neither NYPA's methodology for crediting capacity sales, nor NYPA's decision to value the MW-months at the lesser of cost or market price, was dictated by the Global Settlement.

22. In the face of that ambiguity, NYPA has given this provision of the Global Settlement an interpretation that minimizes the value of the credit to preference customers. That is, once it executed the Global Settlement, NYPA chose both (a) to understate the MW-months sold and transferred and (b) to understate the rate applicable to those MW-months. Neither of these choices produces the lowest possible rate to preference power customers.

23. After reviewing data responses in this proceeding and participating in a September 7, 2011, technical conference with NYPA personnel, I understand that NYPA has been crediting the RSR for UCAP sales based on the *lower* of market prices or costs.[10] NYPA's reasoning seems to be that market prices represent "cost" whenever UCAP market prices are below the cost-based demand rate. NYPA is being inconsistent because NYPA has steadfastly refused to grant a market-based revenue credit for the ancillary services it sells from the hydro Projects into the NYISO markets, citing the *Auer*

[10] See Response to NS-18, annual UCAP Credit Calculation files.

requirement for setting hydro rates based on cost and the Global Settlement Agreement. A cost-based UCAP credit would be consistent with the *Auer* decisions, the *Bergen* standard and the Global Settlement.

24. When I corrected NYPA's use of the UCAP market price instead of the demand rate, I found that NYPA has over-stated the underfunding of the RSR by $13.8 million. This correction results in the RSR balance being reduced from -$51.3 million to -$37.4 million.

25. The other flaw in NYPA's UCAP calculation causes the MW-months of actual capacity sales to be understated because NYPA's UCAP crediting methodology leaves the difference between the forecasted demand (the "base level" of approximately 36,000 MW-months) and the actual demands (ranging from 32,000-35,000 MW-months in recent years) out of the equation.[11] Preference customers are charged for the costs of those MW-months but cannot use them. Nevertheless, preference customers are not granted a dollar credit when NYPA sells these MW-months, either in the UCAP credit to the RSR or in the calculation of the demand rate. NYPA is recovering costs of the capacity differential twice by charging two sources for the same capacity: (1) the contract customers who pay 100% of the cost and (2) the NYISO market from which NYPA obtains UCAP market prices.[12]

26. NYPA did not limit the megawatts of UCAP and internal transfers that it credited to the RSR in 2003 and 2004, the first years in which it provided UCAP credits. In these years, the UCAP credit was calculated correctly, based on the total MW-months that NYPA sold into the UCAP market and transferred internally - over and above the MW-months NYPA actually sold to the contract customers. There was no netting against the forecast sales of capacity to the contract customers used initially in setting the Capacity Rate (the "base level"). NYPA should return to its initial interpretation of the Global Settlement Agreement in order to produce the lowest possible rate.

27. Beginning with the 2005 RSR calculation, NYPA began employing a new methodology to calculate the UCAP credit. Since 2005, the UCAP credit has been based on:
    1. Actual Demand of Hydro project contract customers

[11] Under NYPA's initial interpretation of the 2003 Global Settlement (in 2003 and 2004), those MW-months were not left out of the equation.

[12] NYPA recovers more than once the costs it incurs in providing the block of MW-months between (a) its forecast of 36,000 MW-months of billing demand and (b) the actual demands of contract customers.

2. + UCAP sales to others in the NYISO market + internal transfers of hydro capacity to other NYPA customers
3. = Total Sales of Capacity
4. - (less) Forecasted amount of capacity used initially to develop the Capacity rate (the "base level")
5. = net amount of capacity used in the UCAP credit calculation.

28. Thus, from 2005 through 2010, NYPA has derived a dollar UCAP credit based - not upon its total sales of capacity into the UCAP market and internal transfers - but upon a lesser, net amount of capacity ("Net Capacity") times the UCAP market price ("Market Rate"). The product of Net Capacity times Market Rate is subtracted from the Actual CoS.

29. After applying the UCAP dollar credit to the Actual CoS, NYPA backs out the demand costs recovered from contract customers. In order to do so, NYPA takes the Actual Demand of contract customers (the starting point in step No. 1 of the UCAP calculation above) and multiplies this actual amount times the demand rate (adjusted to include projected ancillary services costs removed under the 2003 rate methodology) to obtain a demand dollar calculation (See RSR calculations of CoS files, Exhibit II page 1 of 6 and Exhibit III line 4). These demand dollars are then subtracted from the trued-up revenue requirement in order to obtain a net amount of CoS to be recovered through the energy charge component of the rate.

30. A proper UCAP crediting process that produces the lowest rate reasonably possible must use the Total Capacity of the Projects, not the Net Capacity. The table below shows how NYPA changed its UCAP credit methodology. In the table shown below, line g shows the amount of Net Capacity that NYPA used to calculate the UCAP credit. However, line h shows the amount of capacity that should have been used for preference customers to receive a proper capacity credit that reflects all MW-months sold in capacity markets. With the recession occurring in 2009-2010, the difference between Net Capacity (line g) and Total Capacity above Actual Demand (line h) has increased to approximately 3,600 MW-months— which should have produced a credit of $12 million per year (based upon the demand rate) that the preference customers have not received in each of the last two years.

UCAP CREDIT - GLOBAL SETTLEMENT AGREEMENT

		2005 MW-Mo.	2006 MW-Mo.	2007 MW-Mo.	2008 MW-Mo.	2009 MW-Mo.	2010 MW-Mo.
Actual Demand - customers	a	35,473	35,126	34,852	34,295	32,342	32,711
Capacity sales to NY Municipal Power Agency 1/	b	142	201	155			
UCAP Market Capacity	c	1,493	-	2,649	4,449	4,696	6,954
NYPA internal net UCAP transfers	d	966	3,213	1,677	2,336	1,954	1,874
Total Sales of Capacity (Total Capacity)	e=a+b+c+d	38,074	38,540	39,334	41,080	38,992	41,539
Base level of capacity sales per rate cases	f	36,000	36,073	36,210	36,137	36,137	36,137
Net Capacity (Total Capacity minus Base Capacity)	g=e-f	2,074	2,467	3,124	4,943	2,855	5,402
Total Capacity above Actual Demand	h=b+c+d	2,601	3,414	4,482	6,785	6,650	8,828
Market Rate $/kw-Month	j	$ 0.74	$ 1.62	$ 2.20	$ 2.24	$ 2.32	$ 1.33
R&D Demand Rate $/kW-month	k	$ 2.29	$ 2.64	$ 2.91	$ 3.18	$ 3.33	$ 3.33

1/ Agreement expired 10/31/07.

31. Correcting NYPA's understatement of the MW-months of credits for UCAP and internal transfers required crediting the CoS at the demand rate for the full amount of (a) capacity transferred internally plus (b) capacity sold into the NYISO's UCAP market. I have calculated a corrected UCAP credit by starting with the difference between the total sales of capacity less the actual demand, and then multiplying this difference by the demand rate. This change results in the RSR underfunding being reduced from $-51.3 million to $-19 million, a reduction in underfunding of $32.3 million.

32. Under a literal application of the Global Settlement language, the amount of UCAP credit can be applied only to the preference power customer load (as opposed to being credited against the CoS itself). Applying the UCAP credit to the RSR balance itself reduces the $-51 million accumulated balance by $48 million to $-3.1 million. This is illustrated by the RSR calculation below.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
RATE STABILIZATION RESERVE (RSR) COMPUTATION

10/19/2011 8:57

EXHIBIT III

Page 1 of 2

Net Sales Capacity and R&D Demand Rate as a RSR Credit

LINE NO.	DESCRIPTION	2001	2003	2004	2005	2006	2007	2008	2009	2010
	COST OF SERVICE (COS) ($000)									
1	TOTAL COS		151,519	169,763	181,661	196,339	219,276	234,606	228,789	250,251
2	UCAP CREDIT		-	-	-	-	-	-	-	-
3	NET COS OF CAPACITY SALES		151,519	169,763	181,661	196,339	219,276	234,606	228,789	250,251
4	DEMAND 1/		52,180	66,741	79,408	92,733	101,419	109,058	107,699	108,928
5	ENERGY 2/		99,339	103,022	102,253	103,606	117,857	125,548	121,090	141,323
	GENERATION (GWH)									
6	@ LONG TERM AVERAGE		20,224	20,222	20,221	20,218	20,210	20,210	20,216	20,210
7	ANNUAL NET GENERATION		17,831	19,986	20,093	19,924	19,359	20,150	21,016	19,456
	ENERGY RATE (MILLS/KWH)									
8	@ LONG TERM AVERAGE GENERATION 3/		4.91	5.09	5.06	5.12	5.83	6.21	5.99	6.99
9	@ ANNUAL NET GENERATION 4/		5.57	5.15	5.09	5.20	6.09	6.23	5.76	7.26
10	RATE IN EFFECT (MILLS/KWH)			4.92	4.92	4.92	4.92	4.92	4.92	4.92
10A	JANUARY - APRIL		4.58							
10B	MAY - DECEMBER		4.92							
11A	JANUARY - APRIL		3,125							
11B	MAY - DECEMBER		6,157							
11	ANNUAL R & D SALES (GWH)		9,282	9,749	9,704	9,930	9,939	9,981	9,759	9,848
12	TOTAL FOR YEAR 5/		(7,096)	(2,242)	(1,650)	(2,780)	(11,629)	(13,075)	(8,198)	(23,044)
12A	ADJUSTMENT				(390)					
12B	**Sales of Capacity above the base level credited to RSI**		**$ 633**	**$ 3,514**	**$ 4,749**	**$ 6,512**	**$ 9,090**	**$ 15,718**	**$ 9,505**	**$ 17,987**
13	RSR BALANCE EOY 6/		**$ (725)**	**$ (7,188)**	**$ (5,916)**	**$ (3,206)**	**$ 526**	**$ (2,013)**	**$ 630**	**$ 1,937**	**$ (3,119)**
	NYPA RSR BALANCE @ YEAR END (lesser of)		**$ (725)**	**$ (7,635)**	**$ (9,000)**	**$ (10,263)**	**$ (11,057)**	**$ (19,108)**	**$ (26,694)**	**$ (31,866)**	**$ (51,267)**

Amount of RSR Reduction = 48,148

1/ See EXHIBIT II, Page 1. The demand charge is a weighted average of the January-April and May-December periods, inclusive of the projected ancillary services costs that were removed using the methodology from the 2003 rate action.
2/ Line (3) - line (4)
3/ Line (5) / (6).
4/ Line (5) / (7).
5/ (Line (10) - (9)) * (11), except for 2004 which is (Line (10A) x Line (11A) + Line (10B) x Line (11B) - Line (9) x Line (11))
6/ Line (12) + line (12A) + line (12B)+ line (13) [Prior-year balance].

THE RECHARGE NEW YORK POWER PROGRAM

33. Footnote 6 at page 10 of the 2011 Staff Report stated that "NYPA will be withdrawing 455 MW of firm hydropower currently allocated to upstate utilities which is priced at the preference power rate." NYAPP asked NYPA to describe this 455 MW withdrawal, and NYPA provided the following response to NYAPP 1-15:

> Legislation enacted into law on March 31, 2011 (Chapter 60 of the Laws of 2011) establishes the "Recharge New York Power Program" ("RNYPP"). The RNYPP is a new, permanent power program, administered by the Authority and the EDPAB, which has as its central benefit up to 910 MW of power comprised of 455 MW of hydropower from the Niagara and St. Lawrence-FDR Projects

(currently used by the upstate utilities) and up to 455 MW of other power procured or produced by the Authority for allocation to eligible businesses and non- for-profit corporations. This legislation also temporarily extends the Power for Jobs and ECBD Programs through June 30, 2012 at which time the programs will end and be replaced by the new "Recharge New York Power Program." The 455 MW of hydropower was withdrawn by the Authority on August 1, 2011.

34. The law authorizes removing the 455 MW of firm power sales, and allocating this power to eligible businesses as they apply and qualify for the power. Initially, NYPA plans to monetize the 455 MW by selling the power into the NYISO markets and apply the revenues from such sales as credits over a multi-year period in order to lessen the rate shock on domestic and rural consumers of the investor owned utilities.

35. There are two main issues related to the 455 MW related to the Recharge New York Power Program:

    a. The 455 MW previously sold to investor-owned utilities needs to be reflected in the Billing Demands used for calculating the demand rate for preference power customers, both before and after the power is allocated to Recharge New York business customers. Those MW-months also need to continue to be included in the actual contract demands used in the RSR calculation. Preference power customers should not have to assume the burden of all costs of the Projects in the event that qualifying businesses do not emerge to take power, or if such businesses do not take the full amount of withdrawn capacity. The 455 MW must remain in the production rate denominator (Billing Demands) and in the calculation of Actual Demands used in the RSR calculation in order to produce the lowest rate reasonably possible.[13]

    b. Both the capacity and energy billing determinants for the 455 MW now being withdrawn contributed to the buildup of the large negative balance in the RSR. If no reduction of the RSR's negative balance is made in order to account for the disappearance of those loads and the associated billing determinants,

[13] NYPA agrees with NYAPP's recommendation that it retain the billing determinants. In a September 28, 2011, Staff response to Request NYAPP 1-16, NYPA stated:

> NYPA has not removed the 455 MW of firm hydropower from the demand and energy billing determinants used to calculate the Hydroelectric COS. Despite the removal of the 455 MW from the amount of MWs sold at the preference power rate in order to be used for the new Recharge New York Power Program, NYPA still considers these MWs part of the firm billing demands of the Hydroelectric Projects, and therefore, has included them as part of the billing determinants used in the COS.

responsibility for recovery of the negative RSR balance will fall entirely on the preference customers. My recommendation is that NYPA commit to provide a credit to the RSR balance that will remove the amount of negative balance attributable to the R&D customer loads of the New York investor-owned utilities. Failure to do so would mean that the preference customers are paying rates in excess of the lowest rates reasonably possible.

THE "SWEEPS"

36. NYPA has been under pressure from the State of New York to provide revenues to help close budget deficits, and NYPA has responded by transferring hundreds of millions of dollars to the State from its cash reserves. The transfers, also known as "Sweeps," increased substantially starting in 2009 as a result of the recession. NYPA's financial position has enabled it to carry out these transfers to date, but NYPA must take steps to ensure that such transfers do not weaken its financial position or make it susceptible to market shocks. The program was summarized in minutes of a February 3, 2009, meeting of NYPA's Trustees:

> Legislation enacted into law as part of the 2000-01 State budget, and other legislative enactments in subsequent years, authorized the Authority 'as deemed feasible and advisable by the trustees' to make a number of 'voluntary contributions' into the State treasury. From December 2002 through January 2009, the Authority has made such voluntary contributions to the State in an aggregate amount of $603 million, the most recent of which were payments of $100 million for 2007, $90 million for 2008 and $119 million in January 2009. [14]

37. It is apparent from the minutes above and information provided in response to data requests NYAPP 1-15 and 1-24 that NYPA's voluntary transfers will amount to approximately $775 million between 2002 and the end of 2011.[15] In addition, NYPA made "temporary transfers" totaling $318 million from NYPA's spent nuclear fuel reserve fund and future construction funds, for total transfers in excess of $1 billion. The high level of actual and planned transfers to the State treasury in comparison to NYPA's net income makes NYPA susceptible to adverse turns in volatile wholesale power markets upon which NYPA relies for much of its net income. For example, NYPA's sales to the NYISO markets fell $100.7 million below budget in 2010. This $100.7 million drop represented the bulk of NYPA's total $126 million shortfall from the $308

[14] "Temporary Transfer of Funds to the State Treasury" at http://www.nypa.gov/trustees/2009%20minutes/feb3/feb.pdf

[15] Approved Minutes of the June 28, 2011 Trustee Meeting at 53-54 and Approved Minutes of a Special February 3, 2009 Trustee Meeting at 5.

million of net income it budgeted for 2010. See Report of NYPA's Chief Financial Officer for the Year Ended December 31, 2010, at 1. By comparison, NYPA contributed in excess of $100 million to the State treasury in several years ($119 million in 2009 with $107 million originally budgeted for 2010 and $603 million from December 2002 to January 2009). The State's fiscal year ("SFY") 2011-12 Budget legislation authorizes an additional $60 million contribution to the State Treasury to be made by January 2012. According to the legislation, the contributions are to be made by the Trustees as deemed "feasible and advisable by its trustees."[16]

38. Clearly, the Trustees have first-hand knowledge from NYPA's 2010 operations that past results are no guarantee of future performance.. At the June 28, 2011, meeting, the Trustees approved a contribution to the State Treasury of $40 million for SFY 2011-12. The coverage calculation presented at that meeting assumed that NYPA's $396 million in 2011 cash flow would cover $170 million in debt by 2.7 times and that its coverage would drop to 2.1 times after NYPA contributed $97.5 million to the State Treasury. However, the calculation made no provision for a repeat of 2010's precipitous plunge of $100.7 million in margins. See Response to NYAPP 1-15, Exhibit "10-A" to the June 28, 2011 Board minutes.

39. These transfers are not accounted for as State debt. The temporary transfers from the spent nuclear fuel fund and the construction fund are repayable by the State under terms that are contingent upon NYPA's first demonstrating a need for a return of the funds it transferred. There is no assurance that NYPA will be repaid in full or on a timely basis. I am concerned that NYPA's diversion of funds from its reserves to the State Treasury will undermine the creditworthiness of NYPA and potentially cause it to borrow money for planned and needed upgrades of hydro Projects and transmission facilities that it would otherwise meet from internal sources, to defer needed upgrades or routine maintenance, to run afoul of covenants in lending agreements, to incur more stringent covenants in future lending agreements, to pay a premium when rolling over existing borrowings or issuing additional debt, and to require NYPA to increase hydro rates earlier or in greater amounts than would otherwise be the case.

40. Given the volatility in NYPA's free cash flow, "2.1 times Debt Service" is not an exceptionally stringent coverage test. A more appropriate test would call for NYPA to apply the methodology on a *pro forma* basis to future periods and future planned financings and to include sensitivity studies assuming levels of cost increases and sales

[16] Approved Minutes of the June 28, 2011 Trustee Meeting at 53.

declines experienced during the recent recession. NYAPP seeks further assurance that, if NYPA's creditworthiness is nevertheless degraded by the Sweeps, hydro rates will be held harmless from the adverse impacts of that degradation.

41. In my opinion, the Trustees should direct NYPA to:

a. Conduct studies that determine whether its creditworthiness has been or could be degraded as a result of the Sweeps,
b. Establish and publish detailed metrics for measuring its present and projected creditworthiness,
c. Exercise their "feasible and advisable" judgment in considering the coming $60 million transfer,
d. Only approve the coming $60 million transfer based upon studies of *pro forma* results showing the metrics of NYPA's financial strength ,
e. Confirm that none of the revenue from hydro preference customers contributes to the Sweeps, and
f. Confirm that the replenishment of the spent nuclear fuel waste fund will not come out of preference rates.

STATE PARK PAYMENTS - RELIEF

42. NYPA has been inconsistent in its responses concerning the $8 million in state park payments that NYPA was relieved from making to the State as part of the Memorandum of Understanding governing the 2009 Sweeps. Although NYPA had previously stated (in 2009 data responses) that it would remove the amount of this payment from the Hydro CoS beginning in 2011, the Preliminary Report at page 4 stated that NYPA was including "approximately half of the $800,000 annual cost for the Robert Moses and Coles Creek State Parks." In response to a follow-up data request, NYPA stated that these costs were not included in the CoS.[17] However, the $800,000 annual payment has been included in the RSR true-up, not the CoS. NYAPP seeks a commitment that NYPA will remove this $800,000 cost from both the cost of service and the RSR calculations going forward through 2017.

43. In an October 7, 2011, response to Request NYAPP 3-23, NYPA reduced its prior calculation of the RSR balance by $3 million in order to reflect a late-discovered overstatement of A&G expense related to its NYS Parks payment. NYAPP's request

[17] Response to NYAPP 1-10.

asked why A&G Expenses in the RSR files (Cos-08-Exhibits I, II and III.pdf and others) fluctuated from $12.2 million in 2008 to $6.7 million in 2009 and $5.1 million in 2010 and increased for the 2011-2014 period. NYPA responded (emphasis added):

> A review of Account 930 revealed that the accrual for the NYS Parks payment should have been backed out of the amounts used in the 2008 CoS, while the $800,000 payment for the St. Lawrence parks was properly included in a separate line in the production section under O&M expenditures. With this adjustment, the revised A&G expenses for 2008 would have been $6.1 million, rather than [$]12.2 million. **The net effect of this change will be to move the RSR balance by approximately $3 million in the positive direction.**

SHARED SERVICE COSTS

44. Nearly 20% ($44.897 million) of the 2011 Adjusted Final Production Cost of Service ($230.57 million) is attributable to Shared Services.[18] Workpapers and data responses offered in support of the claimed Shared Savings convey little about what home office activities or categories of outlays are associated with the claim. In spite of receiving numerous data requests seeking underlying support for the amount of Shared Service costs allocated to the Hydro CoS and the reasoning for those allocations, NYPA has yet to provide sufficient information. As of September 16, 2011, NYPA first provided underlying calculations of its labor allocator, which allocated 41.39% of all Indirect Overhead costs to the Hydro CoS. However, NYPA has yet to provide information as to the type of expenses that are included in the Shared Service costs, beyond listing five categories of costs:[19]

Total Overhead	2011	2012	2013	2014
Power Supply HQ	19,194	19,371	19,450	19,361
Executive Offices	24,714	25,347	25,854	26,371
Business Services	11,893	12,197	12,441	12,690
Enterprise Shared Sevices	34,184	35,060	35,762	36,477
Energy Mktg. & Business Dev.	10,987	11,269	11,494	11,724
	100,972	103,245	105,001	106,623

NYAPP and other preference customers can have no assurance that NYPA's claims for Shared Services are appropriate unless and until NYAPP receives information describing the types of services that are included in these categories.

45. This concludes my affidavit.

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[18] Exhibit A, page 1, line 4 and page 2, line 14.
[19] Response to MEUA-29.

NEW YORK POWER AUTHORITY'S 2011 HYDROELECTRIC RATE MODIFICATION PLAN

(New York Register Rulemaking I.D. No. PAS-33-11-00001-P)

AFFIDAVIT
OF
WHITFIELD A. RUSSELL

I, Whitfield A. Russell, certify that the attached Affidavit on behalf of the New York Association of Public Power, which bears my name, was prepared by me or under by direct supervision and is true and accurate to the best of my knowledge and belief formed after a reasonable inquiry.

Whitfield A. Russell

Subscribed and sworn to before me this 24th day of October, 2011, by Whitfield A. Russell.

City of Alexandria
Commonwealth of Virginia

Notary Public: Tara K. Parker-Johnson

Notary Registration Number: 333663

My Commission Expires: November 30, 2015

TARA K. PARKER-JOHNSON
Notary Public
Commonwealth of Virginia
333663
My Commission Expires Nov 30, 2015

WHITFIELD A. RUSSELL

Whitfield A. Russell is an electrical engineer, attorney and President of Whitfield A. Russell and Associates, P.C., a corporate Partner of Whitfield Russell Associates. He holds a Bachelor of Science degree in Electrical Engineering from the University of Maine at Orono, a Master of Science in Electrical Engineering from the University of Maryland, and a Juris Doctor degree from Georgetown University Law Center.

Mr. Russell is experienced in electric utility system planning (transmission and generation), ratemaking and bulk power contracts. He has been qualified as an expert witness in 27 states (as well as in the Provinces of Ontario, Alberta and Manitoba and the District of Columbia) and has been accepted as an expert in approximately 150 proceedings before state and federal courts, arbitration panels, public service commissions, the Federal Energy Regulatory Commission and numerous other administrative agencies. Mr. Russell's clients have included public power utilities, state and federal power marketing agencies, investor- owned utilities, independent power producers, and state regulatory bodies and their staffs. He has written and spoken extensively on matters relating to regulated electric utilities.

Mr. Russell founded Whitfield Russell Associates in 1976.[1] Prior to that, from 1972 to 1976, he served as Engineer and eventually Chief Engineer for the Securities and Exchange Commission's Division of Corporate Regulation. That Division, in administering the Public Utility Holding Company Act of 1935, regulated registered pubic utility holding company systems representing approximately 20% of the gas and electric industries in the United States.

From 1971 to 1972, Mr. Russell was on the staff of the Federal Power Commission. He served as a consultant to staff attorneys in proceedings, and as an expert witness in an administrative proceeding before the Atomic Energy Commission.

From 1969 to 1971, Mr. Russell served as an Associate Engineer in the System Planning Division of the Potomac Electric Power Company. At PEPCO, he conducted system studies of load flows and stability. He was also a member of numerous study groups concerned with planning and operation of the Pennsylvania-New Jersey-Maryland Interconnection.

[1] Whitfield Russell Associates is located at 4232 King Street Alexandria, VA 22302. (703) 894-2200

PROCEEDINGS IN WHICH WHITFIELD A. RUSSELL HAS TESTIFIED

1. Anaheim v. Kleppe, U.S. District Court, Arizona (Civil No. 74-542 PHX-WEC), concerning the availability of transmission capacity in the Pacific Southwest.

2. In re: Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 7004, concerning the need for proposed 500 kV transmission lines in the Washington, D.C. area.

3. In re: Baltimore Gas and Electric Company, and Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 6984, involving the same transmission lines mentioned in the preceding case.

4. Perry v. The City of Monroe, Louisiana (State of Louisiana, Parish of Ouachita, Fourth District Court; Nos. 111145, 111146, 111147) regarding the necessity of Monroe's disposing of its municipal utility system; Filed August 16, 1977.

5. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, in Case No. 685, concerning the system planning of the Potomac Electric Power Company and the PJM Pool.

6. In re: Generic Hearings on Rate Structure, before the Colorado Public Utilities Commission, Case No. 5693, regarding the engineering aspects of marginal cost pricing and power pooling in Colorado; Filed October 1980.

7. In re: Pacific Gas and Electric Company, FERC Docket No. ER76-532, regarding the proper level of rates to be charged by PG&E to the Central Valley Project for transmission service; Filed April 1978, revised January 1979.

8. In re: Pacific Power and Light Company, FERC Docket No. E-7796, regarding the Seven Party Agreement and related matters; Filed May 1978.

9. In re: Pacific Gas and Electric Company, FERC Docket No. E-7777 (II), concerning the provisions of numerous bulk power arrangements governing electric utilities in California; Filed October 1978.

10. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case No. 7055, concerning the need for a 230 kV transmission line in Montgomery County, Maryland.

11. In re: Delmarva Power and Light Company, before the Maryland Public Service Commission, Case Nos. 7239F, 7239G, 7239H, 7239I, 7239J, 7239K, 7239L, 7239M and 7239N concerning fuel rate adjustments; Filed June 17, 1980, March 17, 1981, August 19, 1981 and November 20, 1981.

12. In re: Baltimore Gas and Electric Company, before the Maryland Public Service Commission, Case Nos. 7238G, 7238H, 7238I, 7238J, 7238L and combined dockets 7238P, Q, R and S, concerning fuel rates; Filed June 20, 1980, November 2, 1980, April 14, 1981, July 17, 1981 and September 14, 1981.

13. In re: Potomac Electric Power Company, before the Maryland Public Service Commission, Case Nos. 7240A, 7240B, 7240C, 7240D, 7240E, 7240F and 7240G, concerning fuel rate adjustments; Filed October 1980.

14. In re: Florida Power & Light Company, FERC Docket No. E-9574, concerning system planning for the City of Vero Beach, Florida. FP&L withdrew its application to acquire the Vero Beach system.

15. In re: Oklahoma Gas and Electric Company, FERC Docket No. ER77-465, concerning rates for energy banking and transmission services rendered to the Western Farmers Electric Cooperative; Filed October 20, 1978.

16. In re: Idaho Power Company, before the Idaho Public Utility Commission, Case No. U-1006-158, concerning the value of interruptible industrial loads and Idaho Power Companies entitlement to Federal secondary energy; Filed March 1980.

17. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, Case No. 737, concerning the Company's construction program; Filed October 27, 1980.

18. In re: Virginia Electric and Power Company, before the Virginia State Corporation Commission, Case No. PUE 800006, concerning construction of transmission lines in the Charlottesville, Virginia area; Filed 1982.

19. In re: Pacific Gas and Electric Company, FERC Project Nos. 2735 and 1988, concerning the Helms Project, a pumped storage generating unit; Filed August 24, 1979.

20. Southeastern Power Administration v. Kentucky Utilities Company, FERC Docket No. EL 80-7, concerning SEPA's attempt to obtain a FERC wheeling order under the Public Utility Regulatory Policies Act of 1978; Filed October 6, 1980.

21. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 81-105, concerning construction and transmission planning; Filed June 29, 1981.

22. In re: Virginia Electric and Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 257, concerning production cost simulation and normalized fuel adjustment clause formula; Filed June 9, 1981.

23. In re: the Investigation of the Capital Expansion For Electric Generation, before the New Mexico Public Service Commission, Case No. 1577, concerning construction

programs of the Public Service Company of New Mexico and El Paso Electric Company; Filed July 2, 1981.

24. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case Nos. 7241A, 7241B, 7241C and 7241D, concerning fuel rate adjustments and productivity of generating units; Filed March 13, 1981.

25. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case No. 7528, concerning the method of calculating Potomac Edison's fuel rate.

26. In re: Delmarva Power & Light Company, before the Maryland Public Service Commission, Docket No. 7570, concerning transmission loss allocation methodology; Filed October 30, 1981.

27. In re: Nebraska Public Power District, before the South Dakota Public Utilities Commission, Docket No. F-3371, concerning proposed construction and operation of the 500 kV MANDAN Transmission Facility; Filed September 29, 1981.

28. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 81-660, concerning construction and transmission planning; Filed January 4, 1981.

29. In re: Kentucky Utilities Company, FERC Docket Nos. ER-81-341-000 and ER81-267-000, concerning construction planning and the market for short term power; Filed February 26, 1982 and May 7, 1982.

30. In re: Kentucky Power Company et al., before the Kentucky Public Service Commission, Case No. 8566, concerning cogeneration and avoided costs; Filed September 16, 1982.

31. In re: Appalachian Power Company, before the West Virginia Public Service Commission, Case No. 82-162-42T, concerning the wholesale market and short-term power sales; Filed October 19, 1982.

32. In re: Central Maine Power Company, before the Maine Public Utility Commission, Docket No. 82-137, concerning the application of Central Maine Power Company to reorganize in the form of a holding company; Filed October 25, 1982.

33. In re: Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 4712, concerning rates to be paid to cogenerators and small power producers; Filed February 28, 1983.

34. In re: Dow Chemical Company, before the Public Utility Commission of Texas, Docket Nos. 4802, 5050 and 5062, concerning rates for interruptible service; Filed September 26, 1983.

35. In re: Nevada Power Company, before the Nevada Public Service Commission, Docket No. 83-707, concerning the Reid Gardner No. 4 Participation Agreement, Filed October 11, 1983.

36. Dow Chemical Company vs. Houston Lighting & Power Company, before the District Court of Brazoria County, Texas, 149th Judicial District, No. 79-F-2620, regarding the custom and usage of contract terms in the electric utility industry. Live direct testimony in a jury trial. No transcript available.

37. In re: The Montana Power Company and the Confederated Salish and Kootenai Tribes of the Flathead Reservation, Project Nos. 5-004 and 2776-000, concerning the Tribes' intention and ability to sell its output to one or more entities in the Western states, if obtaining the license to the Kerr Project; Filed July 15, 1983.

38. In re: the Dow Chemical Company vs. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-16038, concerning cogeneration and small power production; Filed October 28, 1984.

39. In re: Petition of the Dow Chemical Company, before the Public Utility Commission of Texas, Docket No. 5651, for an order compelling Houston Lighting & Power Company to comply with the Commission Order concerning cogeneration and small power production; Filed December 10, 1984.

40. In re: Oklahoma Gas and Electric Company, before the Oklahoma Corporation Commission, Cause No. 29017, concerning priority for recognition of capacity costs to Qualifying Facilities; Filed January 1985.

41. In re: Kansas City Power & Light Company of Kansas City, Missouri, before the Missouri Public Service Commission, Case Nos. ER-85-128 and EO-85-185, regarding rate design and allocation of production-related costs for the Company's Wolf Creek Generating Station on behalf of the United States Department of Energy; Filed May 3, 1985.

42. In re: Kansas City Power and Light Company, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning operating problems caused by excess capacity, mitigation measures and regulatory requirements, on behalf of Johnson County Joint Intervenors; Filed May 6, 1985.

43. In re: Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-7, Sub 391, concerning the Company's use of an Extended Cold Shutdown program to mitigate its excess capacity situation resulting from the Catawba Units, on behalf of the Department of Justice for the State of North Carolina; Filed June 26, 1985.

44. Sierra Pacific Power Company, before the Public Service Commission of the State of Nevada, Docket No. 85-430, on behalf of the State of Nevada Attorney General's

Office of Advocate for Customers of Public Utilities, concerning the effects upon retail rates of placing Valmy Unit No. 2 in service; Filed August 26, 1985.

45. United States of America Department of Energy, before the Bonneville Power Administration, on behalf of the City of Vernon, California, concerning the 1985 Proposed Firm Displacement Power Rate; Filed November 8, 1985.

46. In re: City of Anaheim, et al., v. Southern California Edison, Docket No. 78-0810, on behalf of five partial requirements wholesale customers of Southern California Edison Company, making claims under Federal antitrust laws for access to the Pacific Northwest-Pacific Southwest Intertie.

47. In the Matter of the Application of Sierra Pacific Power Company for Approval of its 1986-2006 Electric Resource Plan, Docket No. 86-701, on behalf of the State of Nevada Attorney General's Office of Advocate for Customers of Public Utilities, concerning efforts of Sierra Pacific Power Company to develop a new interconnection (the SMUD Tie) with the Sacramento Municipal Utility District; Filed September 8, 1986.

48. The Federal Executive Agencies, Complainant v. Public Service Company of Colorado, before the Public Utilities Commission of the State of Colorado, Case No. 6551, on behalf of the Federal Executive Agencies concerning the feasibility of wheeling federal preference power to the Government's facilities at Rocky Flats, the Lowry Air Force Base, the Rocky Flats Technical Center and the Denver Federal Center; Filed December 15, 1986 and February 10, 1987.

49. Commonwealth Edison Company, before the State of Illinois, Illinois Commerce Commission, Docket Nos. 87-0043, 87-0044 and 87-0057 Consolidated, on behalf of Intervenor, Citizen's Utility Board of Illinois, concerning Edison's proposal to form a generating subsidiary.

50. Nevada Power Company, before the Nevada Public Service Commission, Docket No. 87-750, concerning a 345 kV transmission line proposed to connect Nevada Power Company to Utah Power and Light Company; Filed September 28, 1987, October 8, 1987 and October 24, 1987.

51. Utah Power & Light Company, PacifiCorp, PC/UP&L Merging Corporation, FERC Docket No. EC88-2-000, establishing conditions for the proposed merger; also challenging PP&L's/UP&L's assertion that the claimed coordination benefits would not be attainable through power pooling or by contract; Filed February 12, 1988.

52. Rosemount Cogeneration Joint Venture, Biosyn Chemical Corporation and Oxbow Power Corporation vs. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GG-88-491, on behalf of Petitioners, Rosemount Cogeneration Joint Venture, Biosyn Chemical Corporation and Oxbow Power Corporation, concerning a contract between Northern States Power and Biosyn Chemical Corporation covering the 50 MW output of a yet-to-

be-constructed power plant based on the forecast costs of Sherburne County Unit #3 ("Sherco Unit 3"); Filed October 24, 1988.

53. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, Case No. 869, on behalf of the District of Columbia Office of the People's Counsel, concerning the prudence of off-system purchases; Filed June 6, 1988.

54. In re: Wisconsin Public Power Inc. System, Advance Plan 5, before the Public Service Commission of the state of Wisconsin, on behalf of the Wisconsin Public Power System, Inc., concerning transmission planning in the state of Wisconsin; Filed August 15, 1988.

55. In re: Nevada Power Company, before the Public Service Commission of Nevada, Docket No. 88-701, on behalf of the Attorney General's Office of Advocate for Customers of Public Utilities, concerning NPC's 1988 Resource Plan; Filed August 29, 1988.

56. In re: Commonwealth Edison Company, before the Illinois Commerce Commission, Docket Nos. 87-0427, 87-0169, 88-0189 and 88-0219, on behalf of the Citizens Utility Board, concerning rejection of an unfair, Staff-proposed rate order; Filed September 12, 1988.

57. In re: Dow Chemical Company vs. Houston Lighting & Power Company, before the Texas Public Utilities Commission, Docket No. 8425, 8431, on behalf of The Dow Chemical Company, concerning application of Houston Lighting & Power Company for authority to change rates; Fuel Reconciliation, Revenue Requirements and Rate Design; Filed March 15, 1989.

58. Dow Chemical Company vs. Houston Lighting & Power Company, before the Texas Public Utilities Commission, Docket No. 8555, on behalf of The Dow Chemical Company, concerning rate discrimination, cost to serve and class load characteristics; Filed August 7, 1989.

59. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 89-676, on behalf of the Attorney General's Office of Advocate for Customers of Public Utilities, concerning Sierra's system planning; Filed August 18, 1989.

60. In re: Northern California Power Agency vs. Pacific Gas and Electric Company, before the Federal Energy Regulatory Commission, Docket No. EL89-4-000, on behalf of the Northern California Power Agency ("NCPA"), concerning the Interconnection Agreement between Pacific Gas & Electric Company and NCPA; Filed October 3, 1989.

61. In re: M-S-R Public Power Agency vs. Tucson Electric Power Company, before the United States District Court of Arizona, No. CIV-86-521-TUC-ACM, on behalf of M-S-R, concerning TEP's breach of contract.

62. In re: Southern California Edison Company and San Diego Gas & Electric Company, before the Federal Energy Regulatory Commission, Docket No. EC89-5-000, on behalf of the City of Vernon, California concerning expected effects of the proposed merger on competition, system operation and transmission access; Filed January 3, 1990 and March 12, 1990.

63. In re: Farmers Electrical Cooperative Corporation and City Water & Light Plant of the City of Jonesboro, Arkansas, v. Arkansas Power & Light Company, No. LR-C-86-118. Presented deposition testimony on AP&L's liability and assisted in settlement negotiations of treble damage claims for transmission line foreclosure made by plaintiffs, City Water and Light Department of Jonesboro, Arkansas and the Farmers Electric Cooperative.

64. In re: Southern California Edison Company and San Diego Gas & Electric Company, before the California Public Utilities Commission, Docket No. 88-12-035, on behalf of the City of Vernon, California concerning expected effects of the proposed merger on competition, system operation and transmission access; Filed April 1990.

65. In re: Northeast Utilities Service Company and Public Service Company of New Hampshire, before the Federal Energy Regulatory Commission, Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000, ER90-145-000 and EL90-9-000, on behalf of Massachusetts Municipal Wholesale Electric Company, concerning the effect of a proposed merger on competition and transmission access; Filed May 25, 1990.

66. Report to the Public Utilities Board of Manitoba concerning 1990 Manitoba Hydro Capital Projects Review: Generation and Transmission Requirements. Whitfield Russell Associates was appointed to report to The Public Utilities Board on matters regarding the economic consequences to the domestic customers of the Manitoba Hydro capital program; Filed August 28, 1990.

67. In re: Northeast Utilities Service Company, before the Federal Energy Regulatory Commission, Docket Nos. ER90-373-000, et al., on behalf of the Massachusetts Municipal Wholesale Electric Company, evaluating the Preferred Transmission Service Agreement between MMWEC and Northeast Utilities Service Company, for the transmission of MMWEC's power purchase from the New York Power Authority; Filed November 27, 1990.

68. In re: New Hampshire Electric Cooperative Rate Plan Proposal, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation; Filed December 11, 1990.

69. Tampa Electric Company v. Zeigler Coal Company. This was an arbitration held in August 1991, concerning provisions of a coal contract in which Mr. Russell offered testimony for Zeigler to the effect that Tampa Electric was not suffering a hardship by measures commonly used in the electric utility industry.

70. In re: The Long Range Forecast of Ohio Power Company, before the Ohio Public Utilities Commission, Docket No. 90-660-EL-FOR (Phase II). Mr. Russell presented and defended testimony on behalf of Ormet Aluminum Corporation concerning Ormet's right to allowances to emit sulfur dioxide from the Kammer Power Plant of Ohio Power Company under the Clean Air Act Amendments of 1990 and the propriety of Ohio Power's Compliance Plan; Filed July 17, 1991.

71. In re: Application of Tex-La Electric Cooperative to Increase Rates. Mr. Russell presented testimony in 1991, demonstrating that Tex-La was prudent in selling its entitlement in a nuclear plant and in settling its 1988 claims against Texas Utilities concerning Texas Utilities' fraud and imprudence in the construction of the Comanche Peak Nuclear Plant; Filed June 1991.

72. In re: Southern California Edison Company, before the Federal Energy Regulatory Commission, Docket No. ER88-83, on behalf of the City of Vernon, California concerning expected effects of Edison's administration of its transmission network on competition, system operation and transmission access; Filed June 1991.

73. In the Matter of the Application of the Public Service Company of New Mexico for Approval to Construct, Own, Operate and Maintain the Ojo Line Extension and for Related Approvals before the New Mexico Public Service Commission, Case No. 2382, on behalf of the United States Department of Energy, concerning transmission line construction programs of the Public Service Company of New Mexico; Filed November 8, 1991.

74. In re: Wisconsin Public Power Inc. System et al., Advance Plan 6, before the Public Service Commission of the state of Wisconsin, Docket No. 05-EP-6, concerning Eastern Wisconsin Utility Joint Transmission System and Interface Study; Filed December 31, 1991.

75. In re: MidAtlantic Energy v. Monongahela Power Company and the Potomac Edison Company, before the Public Service Commission of West Virginia, Case No. 89-783-E-C, on behalf of MidAtlantic Energy, concerning need for capacity and the appropriate avoided cost; Filed January 6, 1992, June 8, 1992 and February 13, 1992..

76. In re: Northeast Utilities Service Company, before the Federal Energy Regulatory Commission, Docket No. EL91-36-000, on behalf of the Massachusetts Municipal Wholesale Electric Company evaluating the tie-line adjustment charge borne by MMWEC that arose under a Transmission Service Agreement between New England Power Company and Northeast Utilities; Filed May 1, 1992 and August 24, 1992.

77. In re: Application of Houston Lighting & Power Company for a Certificate of Convenience and Necessity for the DuPont Project, before the Public Utility Commission of Texas, Docket No. 11000, on behalf of Destec Energy, Inc; Filed September 28, 1992, June 24, 1993 and June 29, 1993.

78. In re: Investigation on the Commission's Own Motion into Barriers to Contracts Between Electric Utilities and Nonutility Cogenerators and Certain Related Policy Issues, before the Public Service Commission of the state of Wisconsin, Docket No. 05-EI-112, on behalf of JOINT PARTIES: DESTEC Energy, Inc., EnerTran Technology Company, LS Power Corporation, The AES Corporation, LG&E Development Corporation, National Independent Energy Producers, and Citizens' Utility Board, concerning appropriate QF contract provision; Filed November 23, 1992.

79. In re: Application of Cap Rock Electric Cooperative, Inc. for a Certificate of Convenience and Necessity, before the Public Utility Commission of Texas, Docket No. 11248, on behalf of Cap Rock Electric Cooperative, Inc., concerning its proposed transmission system improvements; Filed December 30, 1992.

80. In re: Application of Texas Utilities for Authority to Change Rates, before the Public Utility Commission of Texas, Docket No. 11735, on behalf of Cap Rock Electric Cooperative, Inc., concerning standby rates, wholesale rate contracts and terms and conditions of the Power Sales Agreement, Filed May 18, 1993.

81. In re: Determination of Houston Lighting & Power Company's Standard Avoided Cost Calculation for the Purchase of Firm Energy and Capacity from Qualifying Facilities Pursuant to P.U.C. Subst. R. 23.66(H)(3), before the Public Utility Commission of Texas, Docket No. 10832, on behalf of Destec Energy, Inc; Filed August 11, 1993.

82. In re: Complaint of Phibro Refining, Inc. v. HL&P, Docket No. 11989, before the Public Utility Commission of Texas, on behalf of Phibro Energy, USA, Inc., concerning electric service contracts and terms and conditions of HL&P's industrial rate schedule; Filed August 3, 1993.

83. In re: Application of Texas Utilities Electric Company for Authority to Implement Economic Development Service, General Service Competitive Pricing, Wholesale Power Competitive Pricing, and Environmental Technology Service, Docket No. 13100, before the Public Utility Commission of Texas, on behalf of Rayburn Country Electric Cooperative, Inc., concerning TU Electric's so-called "competitive rates."; Filed August 8, 1994

84. In re: Complaint of Kenneth D. Williams v. HL&P, Docket No. 12065, on behalf of Destec before the Public Utility Commission of Texas; Filed January 10, 1995.

85. In re: Rebuttal testimony in a Complaint of Tex-La v. TUEC, Docket No. 12362, on behalf of Rayburn County Electric Coop. before the Public Utilities Commission of Texas; Filed March 6, 1995.

86. In re: Application for Authorization and Approval of Merger Between Wisconsin Electric Power Company, Northern States Power Company (Minnesota), Northern States Power Company (Wisconsin), and Cenergy, Inc., in Docket No. EC-95-16-

000, before the Federal Energy Regulatory Commission (on behalf of Certain Intervenors, including Madison Gas & Electric Company, Wisconsin Public Service Corporation, Minnesota Power & Light Company, Otter Tail Power Company and the Lincoln Electric System), in Docket Nos. 6630-UM-100 and 4220-UM-101, before the Wisconsin Public Service Commission and Docket No. 6-2500-10601-2 before the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (both on behalf of Madison Gas & Electric, Wisconsin Industrial Energy Group, Wisconsin Federation of Cooperatives and the Citizen's Utility Board), concerning the effect upon transmission access of the merger of NSP and WEPCO into Primergy; Filed May 10, 1996.

87. In re: Merger of The Washington Water Power Company and Sierra Pacific Power Company, Docket Nos. EC94-23-000 and ER95-808-000, before the Federal Energy Regulatory Commission, on behalf of Truckee Donner Public Utility District, concerning ancillary services and single system transmission rates; Filed May 22, 1996.

88. In re: Alberta Electric Utilities 1996 Tariff Application before the Alberta Energy And Utilities Board, on behalf of the Industrial Power Consumers Association of Alberta concerning calculation of charges for ancillary services; Filed June 3, 1996.

89. In re: Surrebuttal Testimony in Docket Nos. EC95-16-000, ER95-1357-000 and ER95-1358-000, on behalf of Madison Gas & Electric Company, Citizens Utility Board and Wisconsin Electric Cooperative Association; Filed June 10, 1996.

90. In re: City Public Service Board of San Antonio Filing in Compliance with Subst. Rule 23.67, Docket No. 15613, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; Filed September 5, 1996.

91. In re: City of Austin Filing in Compliance with Subst. Rule 23.67, Docket No. 15645, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; Filed September 5, 1996.

92. In re: Central Power and Light and West Texas Utilities Filing in Compliance with Subst. Rule 23.67, Docket No. 15643, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; Filed September 5, 1996.

93. In re: Texas Utilities Electric Company, Filing in Compliance with Subst. Rule 23.67, Docket No. 15638, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; Filed September 18, 1996.

94. In re: Docket No. 15840, Regional Transmission Proceeding to Establish Postage Stamp Rate and Statewide Load Flow Pursuant to P.U.C. Subst. Rule. 23.67 on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; Filed August 30, 1996.

95. In re: Application of Wisconsin Energy Corporation, Wisconsin Electric Power Company, Northern, States Power Company, and Northern States Power Company-Wisconsin for Approval of a Series of Transactions by Which Northern States Power Company-Wisconsin is merged into Wisconsin Electric Power Company, Northern States Power Company becomes a Subsidiary of Wisconsin Energy Corporation, and Wisconsin Energy Corporation is Renamed Primergy Corporation: Direct Testimony, Rebuttal Testimony and Surrebuttal Testimony on behalf of The Wisconsin Industrial Energy Group ("WIEG"), The Citizens' Utility Board ("CUB"), The Wisconsin Federation of Cooperatives ("WFC") and Madison Gas and Electric ("MG&E") in Docket Nos. 6630-UM-100 and 4220-UM-101 before the Public Service Commission of Wisconsin. The purpose of the direct testimony was to address Certain Intervenors' Transmission System Control Agreement and ISO Bylaws; October 8, 1996. The purpose of the rebuttal testimony was to address Applicants' Unilateral Settlement Offer which was submitted to FERC in their FERC merger proceeding; October 24, 1996. The purpose of the surrebuttal testimony was to address two sets of Rebuttal testimony of Jose Delgado and the Rebuttal Testimonies of Malcolm Bertsch of the Applicants and Don Carlson of Minnesota Power and Light; Filed November 5, 1996.

95a. In re: In the Matter of Northern States Power Company's Petition for Approval to Merge with Wisconsin Energy Corporation; OAH Docket No. 6-2500-10601-2: Direct Testimony and Exhibits and Rebuttal Testimony and Exhibits on behalf of Madison Gas and Electric ("MG&E"), The Wisconsin Federation of Cooperatives ("WFC"), and The Citizens' Utility Board ("CUB") in Docket No. E,G-002 and PA-95-500 before the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission. The purpose of the direct testimony is to remedy a Wisconsin Energy Corporation merger, in order to prevent anti-competitive effects with an Independent System Operation which actually operates the transmission system and which is truly independent of the proposed Primergy; October 21, 1996. The purpose of the rebuttal testimony is to address the direct testimony of Dr. Eilon Amit of Minnesota Department of Public Service and Dan Carlson of Minnesota Power and Light; Filed November 8, 1996.

95b. In re: Joint Application of WPL Holdings, Inc. and Wisconsin Power & Light Company for all Requisite Approvals in Connection with a Series of Related Transactions by which Interstate Power Company Becomes a Subsidiary of WPL Holdings, Inc., IES Industries, Inc. is Merged into WPL Holdings, Inc. and is Renamed Interstate Power Corporation and for Certain Related Transactions and Matters: Direct Testimony and two Surrebuttal Testimonies on behalf of Badger Cooperative Group ("BCG"), The Citizens' Utility Board ("CUB"), Madison Gas and Electric ("MG&E"), The Wisconsin Federation of Cooperatives ("WFC"),

Wisconsin Industrial Energy Group ("WIEG") and Municipal Wholesale Power Group ("MWPG") in Docket No. 6680-UM-100 before the Public Service Commission of Wisconsin. The purpose of the direct testimony was to discuss the characteristics of an appropriate ISO and present the ISO recommended by Certain Intervenors; May 7, 1997. The purpose of surrebuttal testimony #1 was to answer the rebuttal testimony of WP&L's witness Rodney Frame, Arnold Kehrli and Scott Wallace; May 30, 1997. The purpose of surrebuttal testimony #2 was to address the rebuttal testimony of WP&L's witness Arnold Kehrli; Filed May 30, 1997.

96. In re: Houston Lighting & Power Company Filing in Compliance with Subst. Rule 23.67, Docket No. 15639, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; Filed September 30, 1996.

97. In re: IES Utilities, Inc., Interstate Power Company, Wisconsin Power & Light Company, South Beloit Water, Gas & Electric Company, Heartland Energy Services, and Industrial Energy Applications, Inc., Docket Nos. EC96-13-000, ER96-1236-000, and ER96-2560-000, before the Federal Energy Regulatory Commission, on behalf of Wisconsin Intervenors ("WI"). Mr. Russell simultaneously filed 2 sets of testimony; the first, sponsored by the intervenors listed above as well as by Wisconsin Public Service Corporation ("Pub Service"), and Dairyland Power Cooperative. ("Dairyland") analyzed engineering and operating problems created by the merger of WP&L, IPW and IES. The second set of testimony discusses how the IEC Independent System Operator ("ISO") fails in general to meet the rigorous and comprehensive ISO standards promulgated by the Wisconsin Public Service Commission (WPSC). Both sets of testimony (Engineering and ISO) were filed before the Federal Energy Commission; Filed March 27, 1997.

98. In re: Joint Application of WPL Holdings, Inc. and Wisconsin Power & Light Company for all Requisite Approvals in Connection with a Series of Related Transactions by which Interstate Power Company Becomes a Subsidiary of WPL Holdings, Inc., IES Industries, Inc. is Merged into WPL Holdings, Inc. and is Renamed Interstate Power Corporation and for Certain Related Transactions and Matters, in Docket No. 6680-UM-100, before the Public Service Commission of Wisconsin; Filed May 7, 1997.

99. In re: City of College Station, FERC Docket No. TX 96-2-000, concerning transmission rates; Filed November 7, 1997.

100. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, in Docket No. R-00973981 on behalf of Mid-Atlantic Power Supply Association, before the Pennsylvania Public Utility Commission; Filed November 7, 1997.

101. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, in Docket No. R-00974104 on behalf of Mid-Atlantic Power

Supply Association, before the Pennsylvania Public Utility Commission; Filed November 7, 1997.

102. In re: New England Power Company, FERC Docket No. OA96-74-000, concerning proposed formula rates for Tariffs No. 9 and 4, on behalf of the Massachusetts Municipals; Filed December 12, 1997.

103. In re: Sierra Pacific Power Company before the Federal Energy Regulatory Commission in Docket Nos. ER97-3593-000, ER97-3779-000, ER97-4462-000 on behalf of Truckee Donner Public Utility District, addressing lack of comparable access to transmission systems; Filed February 23, 1998.

104. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, in Docket Nos. 97-11018 and 97-11028, before the Public Service Commission of Nevada; Filed February 1, 1998.

105. In re: Southern California Edison Company before the Federal Energy Regulatory Commission in Docket No. ER97-2355-000 on behalf of Department of Water Resources of the State of California, regarding lower pricing for off-peak transmission services; Filed April 1998.

106. In re: Response to Procedural Order Number Three Load Pockets, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, Docket Number 97-8001, before the Public Utilities Commission of Nevada; Filed May 15, 1998.

107. In re: Supplemental Testimony in an Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, Docket Numbers 97-11018 and 97-11028, before the Public Utilities Commission of Nevada, Filed May 22, 1998.

108. In re: Southern California Edison Company, on behalf of The Department of Water Resources of The State of California, Docket No. ER97-2355, before FERC in reference to Transmission Revenue Balancing Account Adjustment ("TRBAA"); Filed November 16, 1998.

109. In re: Ormet Primary Aluminum Corporation, on behalf of Ormet Primary Aluminum Corporation, Arbitration Number 55-199-0051-94, before the American Arbitration Association, concerning the relationship between AEP and other power systems within NERC and ECAR; Filed July 14 1998.

110. In re: Rebuttal Testimony in response to Mr., Walter R. Kelley and Mr. Thomas Kennedy, on behalf of Ormet Primary Aluminum Corporation, Arbitration Number 55-199-0051-94, before the American Arbitration Association; Filed September 2, 1998.

111. In re: Application No. RE95081 – TransAlta Utilities Corp., on behalf of Albchem Industries Ltd., CXY Chemicals and Dow Chemicals Canada Ltd., before the

Alberta Energy & Utilities Board addressing ACD's interest in providing interruptible service; Filed October 1998.

112. In re: Tri-State Generation and Transmission Assoc., Inc., in Arbitration No. 77 Y 181 0023097 before the American Arbitration Association; Filed September 14, 1998.

113. In re: Joint Application for Approval of Merger, Docket No. 98-7023 on behalf of The Staff of the Public Utilities Commission, before the Public Utilities Commission of Nevada; Filed November 9, 1998.

114. In re: Independent System Administrator, Docket No. 97-8001 on behalf of The Staff of the Public Utilities Commission, before the Public Utilities Commission of Nevada; Filed December 11, 1998.

115. In re: Petition for Order Concerning Delineation of Transmission and Local Distribution Facilities, Docket No. 98-0894 on behalf of The City of Chicago, before the Illinois Commission in reference to re-functionalization; Filed April 2, 1999.

116. In re: Consolidated Edison Company, Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for the breach of contract to provide firm service on a non-discriminatory basis; Filed July 22, 1999, August 3, 1999, August 18, 1999 and September 9, 1999.

117. In re: Wisconsin Public Power, Inc. Docket No. 05-EI-119 on behalf of Wisconsin Transmission Customer Group (WTCG"), before the Public Service Commission of Wisconsin to address the concerns of municipally-owned utilities within Wisconsin; Filed March 6, 2000.

118. In re: Joint Application of Utilicorp United Inc. & St. Joseph Light & Power Co., Docket No. EM-2000-292 on behalf of Springfield (MO) City Utilities before the PSC of the State of Missouri to address why the merger between the two is detrimental to the public interest; Filed May 1, 2000.

119. In re: Utilicorp United Inc. and Empire District Electric Co. Docket No. EM-2000-369 on behalf of Springfield (MO) City Utilities before the Public Service Commission of the State of Missouri to explain why the merger between the two is detrimental to the public interest; Filed June 19, 2000.

119A. In re: Mobil Oil Corporation vs. Southern California Edison, Oral Testimony in a jury trial before the Superior Court of the State of California for the County of Los Angeles in Docket No. BC 175784, on behalf of Mobil Oil Corporation. The purpose of the testimony was to explain how Southern California Edison's actions contributed to substantial damage to equipment at Mobil's Torrance, California refinery during the cascading blackout on August 10, 1996; Testimony on July 17, 2000.

120. In re: Arrowhead - Westin Transmission Line Project, Docket No. 05-CE-113 on behalf of the Wisconsin Public Service Corporation ("WPSC"), before the Public Service Commission of the State of Wisconsin to provide support for the transmission project as proposed by WPSC and Minnesota Power; Filed November 22, 2000.

121. In re: Kansas Municipal Energy Agency ("KMEA"), Docket No. ER00-2644-000 on behalf of the Kansas Municipal Energy Agency ("Kansas Municipal"), before the Federal Energy Regulatory Commission ("FERC") to review, assess and comment on the actions taken by the Southwest Power Pool in connection with two transmission service requests made by the Kansas Municipal Energy Agency aggregating 39 MW of contract demand; Filed December 8, 2000.

122. In re: Arrowhead - Weston 345 kV Transmission Line, Rebuttal testimony in Docket No. 05-CE-113 on behalf of the Wisconsin Public Service Corporation ("WPSC"), before the Public Service Commission of the State of Wisconsin to address matters set forth in the direct testimony of Dr. Richard A. Rosen on behalf of Save Our Unique Lands ("SOUL"), Mr. David Schoengold on behalf of Wisconsin's Environmental Decade, and Mr. George R. Edgar on behalf of the Citizens' Utility Board ("CUB"); Filed December 18, 2000.

123. In re: Ethyl Corporation verses Gulf States Utilities Company, Civil Docket No. M, live direct testimony in a dispute over direct assignment of substation facilities; Filed April 2001.

124. In re: Joint Application of Entergy Louisiana, Inc. and Entergy Gulf States, Inc., Docket No. U-25533 on behalf of Occidental Chemical Corporation ("OxyChem"), before the Louisiana Public Service Commission for authorization to participate in contracts for the purchase of capacity and electric power for the Summer of 2001; Filed May 3, 2001.

125. In re: Petitioners' Joint Proposal for Merger & Rate Plan, testimony in Case No. 01-M-0075 on behalf of Alliance for Municipal Power before the New York State Public Service Commission. The purpose of this testimony is explain (1) the inappropriateness of Rule 52 in the post merger competitive energy markets; (2) to have stranded transmission cost and distribution costs expunged; and (3) to show how merged Companies exacerbates the incentive to abuse Rule 52 against newly formed municipal utilities; Filed November 5, 2001.

126. In re: Northeast Utilities Service Company Transmission Line Project, direct testimony in Docket No, 217 before the Connecticut Siting Council of the State of Connecticut on behalf of the Attorney General, State of Connecticut for the purpose of (1) Whether there is a need for the 345 f transmission line from Plum-tree to Norwalk; (2) whether the proposed transmission system design is the best option based on current transmission design and (3) whether any approval of the project by the Siting Council should be conditioned upon CL&P and NU's agreement; Filed March 12, 2002.

127. In re: Alliance Companies, et al., Affidavit in Docket Nos. RM01-12-000, RT01-87-000 and RT01-88-000, before the Federal Energy Regulatory Commission on behalf of the Ormet Primary Aluminum Corporation, for the purpose of providing relevant engineering fundamentals related to the proper design of methodology for quantifying transmission losses and for allocating such losses to the customers of regional transmission organizations; Filed March 12, 2002.

128. In re Cannon Power Corporation:, Affidavit in Docket No. ER02-2189-000, before the Federal Energy Regulatory Commission on behalf of Whitewater Hill Wind Partners, LLC developing a 66 MW wind power project to be interconnected to Southern California Edison Company; Filed July 29, 2002.

129. In re Cannon Power Corporation:, Affidavit in Docket No. ER02-1764, before the Federal Energy Regulatory Commission on behalf of Cabazon Wind Partners, LLC developing a 66 MW wind power project to be interconnected to Southern California Edison Company; Filed August 2, 2002.

130. In re: Response to Pacificorp's Motion: Affidavit in Response to Pacificorp's Daubert Motion Regarding Richard Slaughter and Supplemental Expert Report on behalf of Snake River Valley Electric Association; Filed September 10, 2002.

131. In re: Pacific Gas & Electric Company : Direct Testimony in Docket No. ER01-2998, before the Federal Energy Regulatory Commission on behalf of Northern California Power Agency to explain what level of firmness is required of transmission service under the Stanislaus Commitments; Filed December 20, 2002.

132. In re: American Electric Power Corp.: Affidavit in Docket No. ER03-242, before the Federal Energy Regulatory Commission on behalf of Ormet Primary Aluminum Corp. to respond to AEP's proposed electric transmission rates to be included in the OATT of the PJM Interconnection; Filed December 24, 2002.

133. In re: Application of the CT Light & Power Company: Supplemental Direct Testimony in Docket No. 217, before the State of CT Siting Council on behalf of The Attorney General, State of CT as a follow-up to the direct testimony filed on March 12, 2002 and to address various studies and reports that have been filed since that original testimony; Filed January 14, 2003.

134. In re: Pacific Gas & Electric: Rebuttal Testimony before the Federal Energy Regulatory Commission in Docket No. ER01-2998 on behalf of Northern California Power Agency ("NCPA") to respond to testimony from witnesses Judi K. Mosley, Kevin J. Dasso, Dr. Roy Shanker and Linda Patterson; Filed April 1, 2003.

135. In re: Order Instituting Investigation into implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply: Direct testimony before the Public Utilities Commission of California on behalf of Oak Creek Energy Systems. The purpose of the testimony is to provide comments on and recommendations with respect to the Tehachapi

Transmission Conceptual Facility Study ("Tehachapi CFS" or "TCFS"), performed by Southern California Edison ("SCE" or "Edison"); Filed April 22, 2003.

136. In re: Order Instituting Investigation into implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply: Rebuttal testimony before the Public Utilities Commission of California on behalf of Oak Creek Energy Systems. The purpose of the testimony is to rebut the testimony of Mr. Jorge Chacon and Mr. Melvin Stark on behalf of Southern California Edison Company, taking into account the testimony of Mr. Robert Sparks filed on behalf of the California Independent System Operator ("CA ISO" or "ISO"); Filed May 13, 2003.

137. In re: California Independent System Operator Corporation: Direct testimony before the Federal Energy Regulatory Commission in Docket No. ER00-2019 on behalf of State Water Contractors and the Metropolitan Water District of Southern California. The purpose of the testimony is to provide a critical analysis of ISO's proposed Transmission Access Charge; Filed June 2, 2003.

138. In re: Ameren Services Company, et al.: Affidavit in Docket No. EL03-212-000, before the Federal Energy Regulatory Commission on behalf of Ormet Primary Aluminum Corp. to respond to AEP's Submission in Response to the Commission's Section 206 Investigation; Filed September 2, 2003.

139. In re: Pacific Gas and Electric Company: Direct Testimony in Phase I before the Federal Energy Regulatory Commission in Docket Nos. ER00-565-000, ER00-565-003, and ER00-565-007 on behalf of the Northern California Power Agency. The purpose of the testimony is to explain the nature of the costs for which Pacific Gas and Electric Company seeks recovery through its Scheduling Coordinator Service Tariff; Filed September 15, 2003.

140. In re: California Independent System Operator Corporation: Surrebuttal Testimony before the Federal Energy Regulatory Commission in Docket Nos. ER00-2019-006, ER01-819-002, and ER03-608-000 on behalf of State Water Contractors and the Metropolitan Water District of Southern California. The purpose of the testimony is to respond to the Prepared Rebuttal Testimony of Mr. Johannes P. Pfeifenberger on behalf of the ISO; Filed October 20, 2003.

141. In re: Midwest Independent Transmission System Operator, Inc. and Public Utilities With Grandfathered Agreements in the Midwest ISO Region: Prepared Testimony before the Federal Energy Regulatory Commission in Docket Nos. ER04-691-000 and EL04-104-000 on behalf of Marshfield Electric & Water District. The purpose of the testimony is to review Marshfield Electric & Water District's transmission arrangements in order to respond to the Commission's May 26, 2004 Order in this proceeding; Filed June 25, 2004.

142. In re: Pacific Gas and Electric Company: Direct Testimony in Phase II before the Federal Energy Regulatory Commission in Docket Nos. ER00-565-000 and

ER00-565-003 on behalf of the Northern California Power Agency ("NCPA"). The purpose of the testimony is to discuss PG&E's propriety in passing through ISO Charge Type costs as Scheduling Coordinator Service charges to NCPA under the terms of the NCPA-PG&E Interconnection Agreement; Filed September 13, 2004.

143. In re: Southern California Edison Company: Prepared Direct Testimony before the Federal Energy Regulatory Commission in Docket No. ER02-2189-003 on behalf of Whitewater Wind Hill Partners. The purpose of the testimony is to provide support for Whitewater's request that the Commission revise the Interconnection Facilities Agreement ("IFA") between Whitewater and Southern California Edison Company ("SCE or Edison"); Filed September 14, 2004.

144. In re: Cabazon Wind Partners, LLC Complainant vs. Southern California Edison Company Respondent: Affidavit in Docket No. EL04-137 before the Federal Energy Regulatory Commission on behalf of Cabazon Wind Partners, LLC ("Cabazon"). This Affidavit provides support for Cabazon's request that Southern California Edison Company ("SCE") grant Cabazon reimbursement, in the form of a transmission credit or otherwise, for the cost of certain upgrades Cabazon has borne to interconnect its generation to SCE; Filed September 27, 2004.

145. In re: Southern California Edison Company: Cross Answering Testimony before the Federal Energy Regulatory Commission in Docket No. ER02-2189-003 on behalf of Whitewater Hill Wind Partners. The purpose of the testimony is to respond to testimony filed on October 28, 2004, in this proceeding by Commission Staff witnesses, Ms. Tania Martinez Navedo and Mr. Edward W. Mills. As discussed in my prior testimony, the issue in this case involve the designation of disputed upgrades contained in the IFA between Whitewater and Southern California Edison Company; Filed November 22, 2004.

146. In re: Pacific Gas and Electric Company: Direct and Answering Testimony before the Federal Energy Regulatory Commission in Docket No. ER01-1639-006 on behalf of Northern California Power Agency. The purpose of this testimony is to explain 1) PG&E's failure to justify the pass-through of Reliability Service charges to Western and PG&E's additional failure to "unbundle the rates in its ETCs and provide a full cost of service analysis supporting the unbundled rates," 2) PG&E's attempt to pass-through Scheduling Coordinator Service Charges to Western, and 3) The inappropriateness of PG&E's imposition of interest charges; Filed November 23, 2004.

147. In re: Petition for a Declaratory Order or Advisory Opinion as to the Applicability of the Commission's Decision in Docket No. 03-10003, Plant Project in Orange County, California: Affidavit in Docket No. 04-10023, before the Public Utilities Commission of Nevada on behalf of Ridgewood Renewable Power, LLC ("Ridgewood") with respect to a landfill methane gas powered electric generating project located at the Olinda/ Alpha landfill in Orange County, California; Filed December 30, 2004.

148. In re: Southern California Edison Company and Cabazon Wind Partners, LLC: Prepared Direct Testimony before the Federal Energy Regulatory Commission in Docket No. EL04-137, on behalf of Cabazon Wind Partners, LLC. The purpose of this testimony is to provide support for Cabazon's request that Southern California Edison ("SCE") grant Cabazon reimbursement, in the form of transmission credit or otherwise, for the cost of certain upgrades Cabazon has borne to interconnect generation to SCE; Filed February 4, 2005.

149. In re: Pacific Gas and Electric Company: Phase II Answering Testimony to PG&E's Supplemental Testimony; Cross Answering Testimony; and Errata of Whitfield A. Russell before the Federal Energy Regulatory Commission in Docket No. ER00-565-000, et al and ER04-1233-000, on behalf of Northern California Power Agency. The purpose of this testimony is to respond to Mr. Bray's contention that the SCS Tariff is a formula rate, to respond to aspects of the Prepared Direct and Answering Testimony of Ms. Linda M. Patterson on behalf of the Federal Energy Regulatory Commission Staff and to provide updates to my previously filed testimony, Filed March 8, 2005.

150. In re: Southern California Edison Company: Affidavit before the Federal Energy Regulatory Commission in Docket No. EL05-80-000, on behalf of the California Wind Energy Association ("CalWEA"). The purpose of this affidavit is to explain how and why the proposed Antelope-Tehachapi 230 kV line will be integrated into the regional transmission grid and thereby constitute a network upgrade facility; Filed April 14, 2005.

151. In re: American Electric Power Service Corporation: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER05-751-000, on behalf of Ormet Primary Aluminum Corporation. The purpose of this affidavit is to respond to American Electric Power Corporation's (AEP's) request (a) to increase its annual Network Integration Transmission Service (NTS) revenue requirements to $486 million per year and (b) to increase the NTS rates; Filed April 29, 2005.

152. In re: Southern California Edison Company and Cabazon Wind Partners, LLC: Prepared Rebuttal Testimony before the Federal Energy Regulatory Commission in Docket No. EL04-137, on behalf of Cabazon Wind Partners, LLC. The purpose of this testimony is to respond to direct testimony filed on March 14, 2005 and cross answering testimony filed on May 3, 2005 by Mr. Daniel J. Allstun, the witness of Southern California Edison and to respond to testimony filed on April 14, 2005 by Commission Staff witness, Ms. Emily White; Filed May 20, 2005.

153. In re: In the Matter of the Arbitrations between PG&E Energy Trading-Power, LP Claimant, Counter-Respondent and Southaven Power, LLC, and Caledonia Generating, LLC, Respondents, Counter-Claimants: Expert Report and litigation before the American Arbitration Association in AAA Nos. 16-198-00206-03 & 16-198-00207-03, on behalf of Williams & Connolly LLP (counsel of Southaven Power, LLC) and Bingham McCutchen LLP (counsel for Caledonia Generating, LLC). The purpose of this expert report was to provide my opinion on certain

elements of the matters in dispute between PG&E Energy Trading-Power, L.P., on the one hand, and each of Southaven and Caledonia, on the other hand. These disputes have arisen in connection with two similar tolling agreements, each titled "Dependable Capacity and Conversion Services Agreement;" Filed September 8, 2005.

154. In re: Midwest Independent Transmission System Operator, Inc: Pre-Filed Answering Testimony before the Federal Energy Regulatory Commission in Docket No. ER05-6-001, et al, on behalf of Ormet Primary Aluminum Corporation. The purpose of this testimony is to analyze the proposed SECA rate design as it relates to Ormet; Filed October 24, 2005.

155. In re: Berkshire Power Company, LLC: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER05-1179-001, on behalf of Massachusetts Municipal Wholesale Electric Company, Chicopee Municipal Lighting Plant, and South Hadley Electric Light Department. The purpose of this affidavit is to review the engineering analysis performed by ISO New England in support of its determination of the system reliability for the Springfield, Massachusetts area in Western Massachusetts and, more specifically, the ISO's analysis of the reliability need for two units in that area: (1) the 245 MW Berkshire facility operated by Berkshire Power Company; and (2) the 107 MW West Springfield Unit 3 operated by Consolidated Edison Energy Massachusetts, Inc.; Filed November 7, 2005.

156. In re: Consolidated Edison Energy Massachusetts, Inc.: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER05-903-002, on behalf of Massachusetts Municipal Wholesale Electric Company, Chicopee Municipal Lighting Plant, and South Hadley Electric Light Department. The purpose of this affidavit is to review the engineering analysis performed by ISO New England in support of its determination of the system reliability for the Springfield, Massachusetts area in Western Massachusetts and, more specifically, the ISO's analysis of the reliability need for two units in that area: (1) the 245 MW Berkshire facility operated by Berkshire Power Company; and (2) the 107 MW West Springfield Unit 3 operated by Consolidated Edison Energy Massachusetts, Inc.; Filed November 10, 2005.

157. In re: Pittsfield Generating Company, LP: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER06-262-000, on behalf of Massachusetts Municipal Wholesale Electric Company, Chicopee Municipal Lighting Plant, and South Hadley Electric Light Department. The purpose of this affidavit is to review the engineering analysis performed by ISO New England in support of its evaluation of the system reliability for the Pittsfield, Massachusetts area of Western Massachusetts and, more specifically, the ISO's analysis of the reliability need for the 160 MW facility operated by Pittsfield Generating Company, L.P.; Filed December 21, 2005.

158. In re: Mystic Development LLC: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER06-427-000, on behalf of Massachusetts Municipal Wholesale Electric Company, Wellesley Municipal Light Plant, Reading

Municipal Light Department and Concord Municipal Light Plant. The purpose of this affidavit is to (a) respond to portions of the testimony offered by Mystic witnesses Messrs. Theodore Horton, Robert B. Stoddard, and Alan C. Heintz; and (b) review the engineering analysis of the December 7, 2004, "Need for Mystic Units 7, 8 and 9 for System Reliability," performed by ISO New England ("ISO") and included by Mystic in its filing as support for the assertion that Mystic Units 8 and 9 are needed to ensure system reliability in the Northeast Massachusetts/Boston Area load pocket; Filed January 19, 2006.

159. In re: In the Matter of the Application of Ohio Power Company for Approval of a Special Contract Arrangement with Ormet Primary Aluminum Corporation, In the Matter of the Joint Petition of Ohio Power Company and South Central Power Company for Reallocation of Territory, In the Matter of: Ormet Primary Aluminum Corporation and Ormet Primary Mill Products Corporation v. South Central Power Company and Ohio Power Company: Pre-Filed Testimony before the Public Utilities Commission of Ohio in Docket Nos. 96-999-EL-AEC, 96-1000-EL-PEB and 05-1057-EL-CSS, on behalf of Ormet Primary Aluminum Corporation. The purpose of this testimony is to analyze: (a) the effect upon the ratepayers of South Central and Buckeye of requiring South Central to serve Ormet and (b) the effect upon the ratepayers and stockholders of Ohio Power Company ("OPCO") of requiring OPCO to serve Ormet's full requirements under OPCo's retail GS-4 rate schedule; Filed September 8, 2006.

160. In re: Mystic Development, LLC: Direct Testimony before the Federal Energy Regulatory Commission in Docket No. ER06-427-000, on behalf of Massachusetts Municipal Wholesale Electric Company, Reading Municipal Light Department Wellesley Municipal Light Plant and Concord Municipal Light Plant. The purpose of this testimony is to assess whether a cost-of-service ("COS"), Reliability Must-Run ("RMR") Agreement is needed in order to keep Mystic Development LLC's ("Mystic's") Units 8 and 9 available to provide reliability service and if, contrary to my testimony, the Commission finds that a COS RMR agreement is needed to keep Mystic Units 8 and 9 available to provide reliability service, the Commission would be required to determine a just and reasonable COS rate to be imposed on customers under the RMR agreement. I testify regarding adjustments that need to be made to Mystic's proposed COS rates in order to render them just and reasonable; Filed November 9, 2006.

161. In re: Hydroelectric Production Rates and Rate Modification Plan-2007 and 2008 Rate Years: Direct Testimony and Supporting Exhibits before the New York Power Authority, on behalf of the New York Association of Public Power. The purpose of this testimony is to address the understatement of capacity at the Niagara and St. Lawrence Projects of the New York Power Authority ("NYPA") and how that understatement of capacity improperly reduces the amount of capacity made available to preference customers of the Niagara Project and improperly increases the rates applicable to capacity sold to those customers; Filed April 9, 2007.

162. In re: ISO New England Inc: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER08-190-000, on behalf of Massachusetts Municipal Wholesale Electric Company ("MMWEC"). The purpose of this testimony is to review the engineering analysis performed by ISO New England Inc. in support of its determination that MMWEC's Phase II Stony Brook Unit is not qualified to participate in the first Forward Capacity Market auction, scheduled to be held in February 2008; Filed November 21, 2007.

163. In re: Columbus Southern Power Company and Ohio Power Company: Affidavit before the Public Utilities Commission of Ohio in Case Nos. 07-1132-EL-UNC, 07-1191-EL-UNC, 07-1278-EL-UNC, and 07-1156-EL-UNC, on behalf of Ormet Primary Aluminum Company. The purpose of this affidavit is in the matter of the Application of Columbus Southern Power Company and Ohio Power Company for approval of an additional generation service rate increase pursuant to their post-market development period rate stabilization plans and to update each company's transmission cost recovery rider; Filed February 28, 2008.

164. In re: Niagara Mohawk Power Corporation: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER08-552-000, on behalf of the New York Association of Public Power and several of its members which include Green Island Power Authority, Jamestown Board of Public Utilities, City of Salamanca Board of Public Utilities, City of Sherrill Power & Light and Oneida-Madison Electric Cooperative, Inc. The purpose of this affidavit is review the filing by NMPC for Amendments to its Wholesale Transmission Service Charge for Point-to-Point Transmission service and Network Integration Transmission Service; Filed March 17, 2008.

165. In re: Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas and Electric Department and Taunton Municipal Light Plant v. ISO New England Inc.: Direct Testimony and Exhibits before the Federal Energy Regulatory Commission in Docket No. EL08-48-000, on behalf of the individually municipally-owned power systems serving the Massachusetts communities of Hull, Mansfield, Middleborough, Taunton, Braintree and Hingham. The purpose of this testimony is to provide technical support for the MPS complaint; Filed March 28, 2008.

166. In re: Entergy Nuclear Operations Inc. and Entergy Nuclear Palisades, Inc. (Palisades Nuclear Plant), Entergy Nuclear Operations Inc. and Entergy Nuclear Fitzpatrick, Inc. (James A. Fitzpatrick Nuclear Power Plant), Entergy Nuclear Operations Inc. and Entergy Nuclear Generation Company (Pilgrim Nuclear Power Station), Entergy Nuclear Operations Inc. and Entergy Nuclear Vermont Yankee, Inc. (Vermont Yankee Nuclear Power Station), Entergy Nuclear Operations Inc.; Entergy Nuclear Indian Point 2, LLC; and Energy Nuclear Indian Point 3, LLC (Indian Point Nuclear Generating Unites Nos. 1, 2, and 3), and Entergy Nuclear Operations Inc. and Entergy Nuclear Palisades, LLC. (Big Rock Point): Affidavit before the Nuclear Regulatory Commission in Docket Nos. 50-255-LT and 72-7-LT, 50-333-LT and 72-12-LT, 50-293-LT, 50-271-LT,

50-003-LT, 50-247-LT and 50-286-LT and 50-155-LT and 72-43-LT, on behalf of the Locals 369 and 590, Utility Workers Union of America, AFL-CIO. The purpose of this affidavit is to provide support for the April 15, 2008 Reply of Locals 369 and 590, Utility Workers Union of America, AFL-CIO to Answer of Energy Nuclear Operations, Inc. Opposing Petitions for Leave to Intervene, Request for Hearing, and Related Requests for Relief; Filed April 15, 2008.

167. In re: ISO New England, Inc.: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER08-633-000, on behalf of The Connecticut Department of Public Utility Control. The purpose of this affidavit is to review the reliability analyses performed by the ISONE on the need to retain NRG's Norwalk Harbor Units 1 and 2 as listed Capacity Resources in the Forward Capacity Market for the 2010/2011 Capacity Year; Filed April 17, 2008.

168. In re: In the Matter of the Ontario Energy Board Act, 1998, S.O. 1998, C.15 (Sched. B); In the Matter of an Application by Hydro One Networks Inc. pursuant to section 92 of the Act, for an Order or Orders granting leave to construct a transmission reinforcement project between the Bruce Power Facility and Milton Switching Station, all in the Province of Ontario: Affidavit and Exhibits before the Ontario Energy Board in Docket No. EB-2007-0050, on behalf of the Saugeen Ojibway Nations. The purpose of this affidavit is to review the analyses performed by the Ontario Power Authority, Hydro One and the Independent Electric System Operator of Ontario in support of the application to construct a proposed Bruce-to-Milton double circuit 500 kV transmission line project; Filed April 18, 2008.

169. In re: Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas and Electric Department and Taunton Municipal Light Plant v. ISO New England Inc.: Second Affidavit before the Federal Energy Regulatory Commission in Docket No. EL08-48-000, on behalf of the individually municipally-owned power systems serving the Massachusetts communities of Hull, Mansfield, Middleborough, Taunton, Braintree and Hingham. The purpose of this affidavit is to responds to the testimony of Messrs. Peter Brandien and Gregory Sullivan, which are part of the respective responses to the Complaint submitted by Independent System Operator New England, Inc and NSTAR Energy Company; Filed May 23, 2008.

170. In re: In the Matter of sections 25.30 and 25.31 of the Electricity Act and In the Matter of an Application by Ontario Power Authority for review and approval of its integrated power system plan and approval of its proposed procurement process. Affidavit and Exhibits before the Ontario Energy Board in Docket No. EB-2007-0707, on behalf of the Saugeen Ojibway Nations. The purpose of this affidavit is to review the Integrated Power System Plan ("IPSP") prepared by the Ontario Power Authority, and discuss that Plan as it relates to the concerns of the Saugeen Objiway Nations; Filed August 1, 2008.

171. In re: Ashburnham Municipal Light Plant, Boylston Municipal Light Department, Chester Municipal Electric Light Department, Groton Electric Light, Holden Municipal Light Department, Holyoke Gas & Electric Department, Paxton Municipal Light Department, Princeton Municipal Light Department, Shrewsbury Electric Light and Cable, Sterling Municipal Light Department, Templeton Municipal Light, West Boylston Municipal Light Plant, Westfield Gas & Electric, Chicopee Municipal Lighting Plant, Hudson Light & Power Department, South Hadley Electric Light Department and the Massachusetts Municipal Wholesale Electric Company, Complainants, v. Berkshire Power Company, LLC, and ISO New England Inc., Respondents. Affidavit and Exhibits before the Federal Energy Regulatory Commission in Docket No. EL09-3, on behalf of Ashburnham Municipal Light Plant, et al. The purpose of this affidavit is to present the results of an analysis I conducted concerning whether Berkshire Power Company, LLC ("Berkshire"), the operator of the Massachusetts-based Berkshire Plant, is earning sufficient revenues in the market to cover its "facility costs." The Berkshire Unit is currently operated pursuant to a Reliability Must Run ("RMR") Agreement between Berkshire and ISO New England Inc; Filed October 8, 2008.

172. In re: Missouri River Energy Services and Midwest Independent Transmission System Operator, Inc. and Missouri River Energy Services and Western Minnesota Municipal Power Agency. Rebuttal Testimony before the Federal Energy Regulatory Commission in Docket No. ER08-370-008 and EL08-22-006, on behalf of Missouri River Energy Services and the Western Minnesota Municipal Power Agency. The main purpose of my testimony is to respond to portions of Mr. Alan Heintz's Prefiled Answering Testimony, Cross Answering Testimony and Corrections to Testimony on behalf of Otter Tail Power Company ("OTP") and of Mr. Lotfy N. Sidrak's Prepared Answering Testimony on behalf of the Commission Staff; Filed October 9, 2009.

173. In re: Southwest Power Pool, Inc. Affidavit before the Federal Energy Regulatory Commission in Docket No. ER10-1069-000 on behalf of Nebraska Public Power District, Omaha Public Power District, City Utilities of Springfield, Missouri, Lincoln Electric System and The Empire District Electric Company. The purpose of this affidavit is respond to Southwest Power Pool, Inc.'s "Submission of Tariff Revisions to Modify Transmission Cost Allocation Methodology," and, in particular, the Prepared Direct Testimony of Mr. Leslie E. Dillahunty; Filed May 17, 2010.

174. In re: Southwest Power Pool, Inc. Affidavit before the Federal Energy Regulatory Commission in Docket No. ER10-1269-000 on behalf of Nebraska Public Power District. The purpose of this affidavit is to respond to SPP's Integrated Transmission Plan filing in Docket No. ER10-1269 on May 17, 2010 and the prepared testimony of Mr. Bruce Rew, which summarizes and purports to provide a justification for SPP's modified transmission planning process, the Integrated Transmission Plan ("ITP"); Filed June 7, 2010.

175. In re: In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Populus to Ben Lomond

Transmission Line and the Dunlap 1 Wind Project. Testimony before the Public Service Commission of Utah in Docket No. 10-035-89 on behalf of The Utah Industrial Energy Consumers. The purpose of this testimony is to explain Why present method of allocating costs of PacifiCorp's transmission system should be changed to a method that tracks cost causation and is aligned with PacifiCorp's transmission planning; Filed October 26, 2010.

176. In re: The Connecticut Light and Power Company, The Connecticut Transmission Municipal Electric Energy Cooperative. Affidavit before the Federal Energy Regulatory Commission in Docket No. EC11-31 on behalf of the Connecticut Transmission Municipal Electric Energy Cooperative. The purpose of this affidavit is to explain how CTMEEC intends to account for, and recover the transmission revenue requirement associated with, the 345 k V and 115 k V PTF assets that it is acquiring from CL&P; Filed December 15, 2010.

177. In re: Connecticut Transmission Municipal Electric Energy Cooperative. Affidavit before the Federal Energy Regulatory Commission in Docket No. ER11- on behalf of the Connecticut Transmission Municipal Electric Energy Cooperative. The purpose of this affidavit is to file Connecticut Transmission Municipal Electric Energy Cooperative proposed localized costs, revenue requirements and Schedule 21; Filed April 29, 2011.

178. In re: MidAmerican Energy Company. Answering testimony before the Federal Energy Regulatory Commission in Docket No. ER09-823-001 on behalf of Clipper Windpower Development Company, Inc. The purpose of this testimony is to answer and respond to the testimony filed in this proceeding by MidAmerican Energy Company ("MEC") witness Dehn A. Stevens and by Federal Energy Regulatory Commission Staff witnesses Antonio Maceo and Edward R. Gross; Filed May 2, 2011.

179. In re: Duke Energy Corporation and Progress Energy, Inc. Affidavit before the Federal Energy Regulatory Commission in Docket No. EC11-60-000, ER11-3306-000 and ER11-3307-000 on behalf of the Cities of New Bern and Rocky Mount, North Carolina. The purpose of this affidavit it to report on my analyses of several elements of the proposed merger of Duke Energy Corp. and Progress Energy, Inc.; Filed June 3, 2011.