New York Power Authority

Preliminary Staff Report

Hydroelectric Production Rates

Rate Modification Plan – Rate Years 2011 to 2014

Including:

Cost-of-Service

July 2011

Table of Contents

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("RSR") would be lifted and the Authority would begin to collect deferred hydroelectric costs stemming mainly from the withdrawn rate action for the 2009 and 2010 rate years.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	64,924	71,973	72,174	74,654	76,355	7,049
	(line 1 + line 2)						
	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	48,829	47,656	48,672	49,451	50,176	(1,173)
	(sum lines 4-7)						
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**	**141,361**	**144,677**	**146,266**	**149,856**	**152,654**	**3,316**
	(sum lines 3,8, 9, 10,11)						
	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	78,324	100,003	107,055	112,595	118,659	21,679
	(sum lines 13-15)						
17	**Total Cost of Service**	**219,685**	**244,680**	**253,321**	**262,451**	**271,313**	**24,995**
	(line 12 +line 16)						

* 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].