Board Staff Interrogatories
2009 Electricity Distribution Rates
Northern Ontario Wires Inc. ("NOW")
EB-2008-0238

ECONOMIC ASSUMPTIONS

1. Ref: N/A

a. Given the general economic situation in Ontario has NOW assessed the situation and identified any specific issues that may have a material impact on its load and revenue forecasts and bad debt expense forecast?

Northern Ontario Wires Inc is continually assessing the impact of the current economic situation in Ontario, specifically the Northern region and the lumber industry. NOW Inc has two lumber mills which contribute significantly to our distribution revenues. One of these mills is expected to close for a period of 5 months (December 2007 to April 2008) and re-open in the spring. The second mill is continuing to operate at partial capacity and has not indicated any plans to shut down. We have not made any adjustments to load and revenue forecasts and bad debt expense since the impact is expected to be short term at this time.

b. If so, please indicate if NOW will be updating its current application, in whole or in part, to address any material impacts. If yes, please provide an estimate of the timing of the update.

Accordingly NOW does not consider it necessary to update its current application since the impact is expected to be short term at this time.

2. Ref: E 2 / T 3 / S 1, 2 and E 4 / T 2 / S 3

a. Please provide a list of criteria and the rationale that NOW has used in the prioritization and selection of 2009 maintenance and capital projects in its application.

NOW is continually inspecting and assessing its system to determine deteriorating components that require maintenance or replacement. Criteria used to determine these projects include asset condition and reliability, efficiency, safety and cost benefits analysis.

Furthermore, in 2006 NOW engaged the services of EnerSpectrum Group to complete a system study to assess overall system losses and identify opportunities for mitigation investment. This was part of our CDM plan. The results of this study have been used in part to prioritize and select 2009 maintenance and capital projects.

b. Please identify, individually, maintenance and capital programs, if any, that NOW may consider as a candidate for a deferral, cut, or partial adjustment, given the current economic situation. Please identify these programs, if any, in a ranking order that NOW would consider, using a ranking of "1" as the first suitable candidate, ranking of "2" as the second suitable candidate, ranking of "3" as the third suitable candidate, etc.

Our 2009 Capital Budget is relatively low in comparison to annual depreciation and has been very conservative in recent years, with capital spending and depreciation being significantly different. The table below summarized our capital spending and depreciation in recent years.

Capital Expenditure And Depreciation Expense by year

	Capital Expenditure	Depreciation Expense
2003	$ 63,390	$ 371,004
2004	$ 113,179	$ 372,597
2005	$ 167,266	$ 363,348
2006	$ 183,655	$ 329,835
2007	$ 404,275	$ 337,216
2008 foreacast (excluding smart meters)	$ 615,250	$ 363,270
2009 forecast (excluding smart meters)	$ 391,000	$ 404,740

With little capital expenditure in recent years, our infrastructure is in need of upgrading and has been reflected in our capital budget. Some of the re-building projects can be deferred until the following year although this will shift more costs into operations

c. Please identify the rationale for the selection of these maintenance and capital programs and projects.

Please see chart below.

CAPITAL BUDGET BY PROJECT - RATIONALE

Project Description - 2008	Amount	Rationale
Iroquois Falls voltage conversion & pole changes	$30,000	Re-building, converting to higher voltage to reduce line losses. Identified by EnnerSpectrum study
Cochrane - 4th street pole change	$25,000	Re-building, converting to higher voltage to reduce line losses. Internally identified need
Cochrane - feeder reclosure	$18,000	Replace old inefficient reclosures, reliability issues. Internally Identifed need
Cochrane - wholesale meter point	$20,000	Required by IESO
Kapuskasing - pole change	$35,000	Re-building, converting to higher voltage to reduce line losses. Internally identified need
Regular Meter Replacement	$10,000	As required
Building Renovations (Iroquois Falls)	$2,000	Required Upgrade to old facility
Bucket Truck	$240,000	Replace old equipment, costly to operate and increasing repair costs, more than fully depreciated
Pickup Truck	$27,500	Replace old equipment, costly to operate and increasing repair costs, more than fully depreciated
Misc. Tools	$23,050	As required
Computer hardware	$39,665	As described in Rate Application , current system no longer supported in 2009
Computer Software - billing change	$145,000	As described in Rate Application , current system no longer supported in 2009
Annual Total	**$615,215**	

Project Description - 2009	Amount	
Iroquois Falls - conversion continuation	$30,000	Re-building, converting to higher voltage to reduce line losses. Identified by EnnerSpectrum study
Cochrane - 4th street pole change	$25,000	Re-building, converting to higher voltage to reduce line losses. Internally identified need
Cochrane - misc works	$15,000	Re-building, replacing old place, reliability issue, Internally identified need
Kapuskasing - pole change & overhead change	$30,000	Re-building, converting to higher voltage to reduce line losses. Internally identified need
Cochrane sub - pole & overhead replacement	$10,000	Re-building, replacing old place, reliability issue, Internally identified need
Regular Meter Replacement	$10,000	As required
Kapuskasing - building purchase	$200,000	Currently rent one bay in a bus depot. Arrangement has significant drawbacks. Identified need to have appropriate "service centre" in our Kap service area
Concrete pads for transformers	$7,000	asset appropriate storage, maintain asset conditions and security
Misc. Tools	$45,000	Includes Pole Trailer $25,000 and other tools/equipment as required
Computer hardware	$11,500	Replace older workstations and equipment
Computer Software	$7,500	As required
Annual Total	**$391,000**	

d. Please describe the expected impacts on NOW's revenue requirement, operations and service quality and reliability to customers if the identified programs are reduced, deferred or cut during the economic downturn.

Service quality and reliability impact – As mentioned above, we have had limited capital upgrades in recent years and therefore our infrastructure is in need of upgrading. Deferring such upgrades may result in increased power outages and further defer the reduction of line losses that result from some of the voltage conversion work planned.

Revenue requirements impact -we must furthermore recognize that our capital maintenance and replacement programs are for the most part completed using our own workforce. Therefore any reduction in planned capital work will result in increases operating costs. With such a small staff and safety and service reliability issues it is impossible to reduce our qualified workforce.

OPERATING COSTS

General

3. Ref: E 4 / T 1 / S 1

The figures in the table below are taken directly from the public information filing in the Reporting and Record-keeping Requirements ("RRR") initiative of the OEB. The figures are available on the OEB's public website. Please confirm the utility's agreement with the numbers for OM&A, which are summarized in the table below.

	2002	2003	2004	2005
Operation	$ 236.221	$ 206,447	$ 283,318	$ 229,355
Maintenance	$ 105,955	$ 109,748	$ 91,322	$ 127,990
Billing and Collecting	$ 453,857	$ 574,011	$ 614,895	$ 535,294
Administrative and General Expenses	$ 1,129,056	$ 850,771	$ 801,133	$726,337
Total OM&A Expenses	**$ 1,929,498**	**$ 1,743,139**	**$ 1,791,444**	**$ 1,621,576**

NOW Inc is in agreement for the most part with the OM&A numbers as reported above. We have identified an inconsistency with "Administration and General Expenses" whereby the figures as reported above exclude A/C#6035 Other Interest Expense. Our figures for 2006 to 2009 do include A/C#6035 Other Interest Expense in the OM&A Category "Administration and General Expenses". The 2002 to 2005 numbers for A/C#6035 Other Interest Expense are as follows:

	2002	2003	2004	2005
Other Interest Expense	$ (31,855)	$ 41,111	$ 40,891	$ 82,073

OEB Question #12 requested details of the 2009 figure for A/C#6035 – Other Interest Expense. The major items in this expense account for 2002 to 2005 includes regulatory interest on variance accounts (i.e.: carrying charges), customer deposit interest and IESO Letter of Guarantee costs. The 2003 credit balance is the result of carrying charges.

Please note there are also a few non-material variances (under $10,000) related to the grouping of accounts.

4. Ref: E4 / T2 / S1

Please identify the inflation rate used for the 2009 OM&A forecast and the source document for the inflation assumptions.

NOW Inc used a 3% inflation rate for its 2009 OM&A Forecast. For compensation costs we used 3% based on the contract negotiation results of similar local distribution companies. For materials and expenses we refer to the Consumer Price Index for June and July 2008 which indicates a 3.1% and 3.4% respectively increase over the previous year.

5. Ref: E4 / T2 / S6 / p1

The impact of an aging workforce is an operating issue for many utilities. Is an aging workforce an issue for NOW? If so, please provide a description of the utility's plan to address the aging workforce issue.

An aging workforce is not a significant issue for NOW. We have included a small provision in 2009 to accommodate the replacement of our Electric Superintendant whom is expected to retire in 2010. Recent discussions and analysis of options suggests that these transition costs will be higher than originally forecasted. We now expect to bring in a replacement for the last half of 2009 (likely internal promotion) and will need to replace this lineman. Total cost is expected to be $60,000 for 2009 and 2010 or $30,000 for each 2009 and 2010. For rate application purposes this will increase annual revenue requirements by $20,000 for the three year rate period

6. Ref: E4 / T1/ S1

Are there any cost efficiency programs at the utility that are in place now or contemplated in the test year? If so, please describe the programs and include a cost benefit analysis.

NOW does not have any specific cost efficiency programs identified. Capital costs are being spent on system optimization to lower loss factors and annual budgeting process considers bottom line costs to rate payers.

Non-Recurring Items

7. Ref: E4 / T 2 / S3

The evidence in the above reference indicates that approximately $62,000 of the $185,000 or 8.7% increase between 2007 actual OM&A and 2008 Bridge is due to nonrecurring expenditure items in 2008.

a. Please confirm that this is correct; if not please provide the correct amount of non-recurring costs budgeted in 2008.

This is correct.

b. Please clarify whether or not NOW eliminated these non-recurring work or expenditure items in its 2009 OM&A forecast.

2008 Non-Recurring Expenditure has been removed for the 2009 OM&A Forecast.

c. The 2009 OM&A forecast is little changed from the 2008 bridge. Please identify the new work activities or items in 2009 which are utilizing the funds in 2008 related to non-recurring activities.

There are no significant new work activities or items in 2009. The change between 2008 and 2009 is summarized as follows:

2009 Expenditure Change

	Detail	Total
2008		
2008 Bridge Year Total OM&A	$ 2,322,354	
2008 Bridge Year Amortization	$ 363,270	
2008 Bridge Year PILS	$ 53,924	
2008 TOTAL	$ 2,739,548	$ 2,739,548
2009 Changes		
reductions		
remove 2008 non-recurring		$ (62,000)
Net other changes between 2008 and 2009		$ (4,998)
increases		
3% Inflation on OM&A		$ 57,000
Amortization		$ 41,000
PILS		$ 6,000
TOTAL		$ 2,776,550
2009		
2009 Bridge Year Total OM&A	$ 2,311,307	
2009 Bridge Year Amortization	$ 404,740	
2009 Bridge Year PILS	$ 60,503	
	$ 2,776,550	$ 2,776,550
Unreconciled Difference		$ -

d. Please identify any non-recurring expenditure items (in excess of $10,000) that are included on the 2009 OM&A forecast.

There are no non-recurring expenditure items in excess of $10,000 included in the 2009 OM&A forecast.

Shared Services

8. Ref: E4 / T2 / S4 / p1

The evidence indicates that NOW has a Services Agreement with its affiliate, Cochrane Telecom Services ("CTS") and that on January 1, 2007, five management positions were moved from CTS to NOW while NOW's remaining labour requirements continue to be provided by CTS.

a. Please explain what prompted the transfer of the five management positions from CTS to NOW.

The five management positions were transferred from CTS to NOW to provide for better separation in order to facilitate compliance with the Affiliate Relationships Code. It also provides for better reporting and accountability between the management of NOW and it's Board of Directors.

b. Please confirm that CTS is the only affiliate from whom NOW purchases services.

CTS is the only affiliate from whom NOW purchases significant services. NOW purchases gas from the Town of Cochrane at bulk rates. We had a similar agreement with the Town of Kapuskasing until they removed their pumps a few years ago. We had unsuccessfully pursued a similar arrangement with the Town of Iroquois Falls as well.

c. Please provide a copy of the current Services Agreement between NOW and CTS.

Due to the size of this file, it is being provided to all registered interveners on a CD or electronically via email along with a copy of the Cost allocation model and the Board decisions requested in VECC IR # 3.

d. Please confirm that there are no corporate service costs allocated to NOW.

There are no corporate service costs allocated to NOW.

e. Please confirm whether NOW provides services to its affiliate(s). If so, please elaborate.

Two of NOW's management personnel continue to provide services to CTS. This provides for the sharing of expertise and costs between the two organizations. The allocation of time and costs is continually reviewed and reflects actual services incurred by either organization.

NOW also provides inventory and truck/vehicle requirements to Northern Ontario Energy. Northern Ontario Energy is a retail affiliate and primarily provides streetlight maintenance services to local communities. NOW charges to NOE are the same as for its arms length customers.

Compensation

9. E4 / T2 / S7 / p1

The two tables in the above reference show the number of full time equivalents ("FTE") for 2009 at 4.2 for NOW and at 12.3 for CTS. The evidence indicates that five management positions were transferred to NOW. Please explain why the total FTEs for NOW is shown to be 4.2

As indicated in the answer to 8 e), two of NOW's management personnel continue to provide services to CTS. This translates into .4 of the CEO position and .4 of a Non-Unionized position. Accordingly the FTE is calculated to be 4.2 (5 less .8)

10. Ref: E4 /T2 / S7 / p1

Please provide the base salary percentage increases budgeted for 2008 and 2009 broken down by major employee grouping (e.g., executive, management, unionized workers).

The base salary percentage increase budgeted for 2008 and 2009 for all employee groupings is 3%.

We are scheduled for negotiations in January 2009 and have been advised that our lineman are seeking an increase to achieve parity with the industry. Our research indicates that we are approximately $2 to $3 per hour less than similar sized LDCs. Accordingly we expect to have to make some concession in this area and provide an increase to the lineman over and above the 3% we have already budgeted. This is essential in retaining and attracting such skilled workers. We have experienced difficulty in the past with this issue. A $2/hour increase represents an additional $20,000 annually in lineman wages and benefits. This has been reflected in the summary of changes to costs and impact on revenue requirements.

Furthermore, our Electric Superintendant is scheduled for retirement in 2010. For succession planning we expect to bring in his replacement for training in 2009. This will result in an additional $30,000 for both 2009 and 2010 and have reflected this addition in the summary of changes to costs and impact on revenue requirements.

Regulatory Costs

11. Ref: E4 / T2/ S2 / p4

Evidence indicates that there is $17,875 for regulatory expenses in the 2009 OM&A. Please indicate whether any or all of the $17,875 reflects the amortized portion of (i) actuals from previous years, (ii) cost forecasted to be incurred in 2008 (iii) costs forecasted to be incurred in 2009. If so, please specify the amortization periods.

2009 OM&A Regulatory expenses represent the OEB quarterly and Annual Fees. Rate application costs are tracked through outside services and are not anticipated to be above the historical consulting costs utilized annually by NOW (i.e. no increase to regulatory expenses associated with rate application).

NOW has realized that we have not included any costs for Intervener activities in this application. In reviewing other 2008 cost awards NOW is estimating $15,000 in costs from interveners. NOW will be including $5,000 as an annual cost, in the final submission for this application.

Miscellaneous

12. Ref: E4 / T2 / S1 / p1

NOW's OM&A forecast appears to include $87,576 for "Other Interest Expense". Please elaborate on the nature of this expense and clarify whether it is included in NOW's calculation of its revenue requirement for 2009.

Please see summary chart below.

Other Interest Expense

IESO Letter of Guarantee Fee ($525/month)	$ 6,300
Regulatory Interest (on Variance Accounts)	50,943
Truck Loan Interest - Digger Truck (purchased in 2007)	11,000
Truck Loan Interest - Bucket Truck (purchased in 2008)	13,214
Customer Deposit Interest Expense	6,119
	$ 87,576

NOW has included the 2009 forecast for the above expenditures within the applied for 2009 revenue requirement.

RATE BASE AND CAPITAL EXPENDITURES

General

13. Ref: E2

Please provide information for the period 2006 to 2009 in the following table format:

	2006 Actual	**2007 Actual**	**2008 Bridge**	**2009 Test**
Allowed Return on Equity (%) on the regulated rate base	$250,137 50% @ 9%	$233,461 50% @ 9%	$216,785 46.7% @ 8.68	$217,283 43.3% @ 8.68
Actual Return on Equity (%) on the regulated rate base	$117,097	$175,819	Not Available	Not Available
Retained Earnings	($1,098,321)	($922,502)	Not Available	Not Available
Dividends paid to shareholders	Nil	Nil	Nil	Nil
Sustaining capital expenditures (excluding smart meters)	$183,655	$404,175	$615,215	$391,000
Development capital expenditures (excluding smart meters)	Nil	Nil	Nil	Nil
Operations capital expenditures	Nil			
Smart Meters capital expenditures (Note 1 below)	Nil	Nil	$24,450	$1,353,277
Other capital expenditures (please specify)	Nil	Nil	Nil	Nil
Total capital expenditures (including smart meter meters)	$183,655	$404,175	$639,665	1,744,277
Total capital expenditures (excluding smart meters)	$183,655	$404,175	$615,215	$391,000
Construction Work in Progress				
Depreciation expense (see reconciliation table below)	$329,835	$337,216	$363,270	$404,740
Rate Base	$5,427,348	$5,293,198	$5,364,907	$5,480,429
Number of Customer Additions	(97)	(29)	(22)	(15)
- Residential	(54)	(14)	(39)	(10)
- General Service < 50 kW	(28)	(14)	17	(5)
- General Service > 50 kW, Intermediate and Large Use	(15)	(1)	0	0
Number of Customers (total, December 31)	6,123	6,094	6,072	6,057
- Residential	5,263	5,249	5,210	5,200
- General Service < 50 kW	787	773	790	785
- General Service > 50 kW, Intermediate and Large Use	70	69	69	69

Depreciation Reconciliation	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Total Depreciation	$329,835	$337,216	$363,270	$404,740
Less: Depreciation recorded to clearing accounts and is therefore included in various OM&A accounts (applies to 2006 and 2007)	(12,612)	(38,081)	(57,732)	(70,375)
Net Depreciation shown as " Depreciation Expense" per Audited Financial Statements accounts (applies to 2006 and 2007)	$317,223	$299,135	$305,538	$334,365

Note 1 – The smart meters capital budget was excluded from the original application pending further direction for the OEB.

Transportation Equipment

14. Ref: E2 / T2 / S2 and E2 / T2 / S3

On page 2 of the first reference above, NOW shows an increase in gross fixed assets in account 1930 – Transportation Equipment of about $220,000 in 2007. This is followed by an increase in 2008 of $267,500, which NOW has documented on page 4 of the second reference above ($225,000 corresponds to a new bucket truck and a new pickup truck). In the 2009 test year, NOW forecasts expenditures in this account of $25,000. Please provide documentation on the capital expenditures of $220,000 in 2007 in this asset category.

<u>1930 Transportation Equipment - $221,551</u>

This variance is a result of the replacement of a 1985 Digger Derrick Truck with a new one. The age of the vehicle was causing high repair/maintenance and operating costs and it was deemed more economical to replace it. The new truck was purchased from Wajax Industries and the details are as follows"

Terex Utilities C-4047 Digger Derrick, mounted on a 2007 International 4400 Cab & Chassis

Asset Management

15. Ref: E2 / T3 / S4 / p2

At the above reference, NOW provides a very brief description of an annual capital budget planning process. Please provide further description of NOW's processes, by providing the following:

a. Does NOW's annual capital budgeting process assess and prioritize projects beyond the next budget year? If not, why not?

NOW's annual capital budgeting process reviews capital projects and expenditure for a three year period. For smart meters we have a five year capital budget

b. How does NOW assess the condition of assets? Does NOW formally conduct, or have someone else conduct on NOW's behalf, asset condition studies?

c. How do analyses of asset condition, reliability performance and other parameters, factor into NOW's capital budget planning?

Answer for B & C

Typically NOW assesses the conditions of our own assets and determines upgrade/replacement requirements. This assessment includes a review of system/equipment's condition, reliability, efficiency and safety as well as performing a cost/benefit analysis when appropriate. In 2006 NOW engaged the services of EnerSpectrum Group to complete a system study to assess overall system losses and identify opportunities for mitigation investment. This was part of our CDM plan. The results of this study have been used in part to prioritize and select future capital projects.

d. What, if any, capital projects for 2008 and 2009 have been budgeted and prioritized based on asset condition and asset management analyses and results?

See summary chart below.

CAPITAL BUDGET BY PROJECT - Projects that are budgeted and prioritized based on asset condition and asset management analyses and results - YES

Project Description - 2008	Amount	Assessed as per above	More Detail
Iroquois Falls voltage conversion & pole changes	$30,000	YES	Ennerspectrum study
Cochrane - 4th street pole change	$25,000	YES	Re-building, converting to higher voltage to reduce line losses. Internally identified need
Cochrane - feeder reclosure	$18,000	YES	Replace old inefficient reclosures, reliability issues. Internally Identifed need
Cochrane - wholesale meter point	$20,000		Required by IESO
Kapuskasing - pole change	$35,000	YES	Re-building, converting to higher voltage to reduce line losses. Internally identified need
Regular Meter Replacement	$10,000		As required
Building Renovations (Iroquois Falls)	$2,000		Required Upgrade to old facility
Bucket Truck	$240,000	YES	Replace old equipment, costly to operate and increasing repair costs, more than fully depreciated
Pickup Truck	$27,500	YES	Replace old equipment, costly to operate and increasing repair costs, more than fully depreciated
Misc. Tools	$23,050		As required
Computer hardware	$39,665		As described in Rate Application , current system no longer supported in 2009
Computer Software - billing change	$145,000		As described in Rate Application , current system no longer supported in 2009
Annual Total	**$615,215**		

Project Description - 2009	Amount		
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Cochrane - misc works	$15,000	YES	Re-building, replacing old place, reliability issue, Internally identified need
Kapuskasing - pole change & overhead change	$30,000	YES	Re-building, converting to higher voltage to reduce line losses. Internally identified need
Cochrane sub - pole & overhead replacement	$10,000	YES	Re-building, replacing old place, reliability issue, Internally identified need
Regular Meter Replacement	$10,000		As required
Kapuskasing - building purchase	$200,000		Currently rent one bay in a bus depot. Arrangement has significant drawbacks. Identified need to have appropriate "service centre" in our Kap service area
Concrete pads for transformers	$7,000		asset appropriate storage, maintain asset conditions and security
Misc. Tools	$45,000	YES	Includes Pole Trailer $25,000 and other tools/equipment as required
Computer hardware	$11,500	YES	Replace older workstations and equipment as required
Computer Software	$7,500		As required
Annual Total	**$391,000**		

Service Reliability

16. Ref: N/A

a. Please provide reliability performance data for NOW's service area in the following table format.

NOW service reliability performance data for 2003 to 2005 were calculated incorrectly. We have recalculated the data for 2005 and 2006 and reported them in the second table below.

As originally submitted in RRR Filings (2006 and prior incorrect calculations)

YEAR	All Causes of Interuuption			All Interruptions Except Loss of Supply (Cause Code 2)		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	cannot locate					
2003	0.00161	0.00016	9.97500			
2004	0.00145	0.00016	8.97500			
2005	0.03600	0.03600	1.00000			
2006	NOW failed to file for 2006					
2007	4.7	3.4	1.4	2.4	2.2	1.1

Revised Calculations (2005 and 2006 only)

YEAR	All Causes of Interuuption			All Interruptions Except Loss of Supply (Cause Code 2)		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	info not available to re-calculate					
2003	info not available to re-calculate					
2004	info not available to re-calculate					
2005	4.4	2.1	2.2	4.4	2.1	2.2
2006	3.9	1.1	3.4	3.9	1.1	3.4
2007	4.7	3.4	1.4	2.4	2.2	1.1

b. Please indicate any reliability indicator and year where performance was out of standard, meaning that it was higher than the range of the previous years. For any such case, please provide an explanation for the decreased reliability and the actions taken by, or being taken by, NOW to address the issue.

Please see summary charts provided in part a) of this response.

Working Capital Allowance

17. Ref: E2 / T4 / S1

a. Please provide a derivation of the cost of power expense used in the determination of the working capital allowance. Please identify the commodity price, wholesale market service charge and retail transmission charges used in the calculation.

Please see summary chart below.

	Determinants		Commodity		WMS		RTR – Network		RTR -Connection	
	kWs	kWhs	Rate	$	Rate	$	Rate	$	Rate	$
Residential		41,1611457	0.0545	2,243,299	0.0052	214,040	0.0044	181,110	0.0042	172,878
GS < 50 kW		21,858,575	0.0545	1,191,292	0.0052	113,665	0.0040	87,434	0.0038	83,063
GS > 50 kW	173,388	68,558,740	0.0545	3,736,451	0.0052	356,505	1.6425	284,791	1.4944	259,112
Unmetered Load		121,104	0.0545	6,600	0.0052	630	0.0040	484	0.0038	460
Street Light	5,014	1,778,469	0.0545	96,927	0.0052	9,248	1.2388	0	1.1553	0
Total	**178,402**	**133,478,344**		**7,274,569**	**0.0052**	**694,088**		**553,819**		**515,513**

Please notice that the above is colour coded, in an effort to assist with the calculations. The two cells in red omitted any RTR charges built into the working capital portion of the application. They should have values of Street Light Network = $6,211.34 and Street Light Connection = $5,792.67, totaling $12,004.01 and a working capital adjustment of $1,800.60.

b. Does NOW concur that the working capital allowance should be updated at the time of the Board’s decision based on the most current RPP price then available? If not, please explain.

NOW does agree that the WCA should be adjusted to incorporate not only the most recent RPP pricing but also should include updates for the RTR rates as well.

Short Term Debt

18. Ref: E6 / T1 / S4

In the table shown under Item 2 “Weighted Average Cost of Capital”, NOW has not included a short-term debt component in the proposed capital structure for the 2009 Test Year for the purposes of calculating the Weighted Average Cost of Capital (“WACC”).

Section 2.1.1 of the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario’s Electricity Distributors* (the “Board Report”) states that:

> “The Board has determined that short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors. **The short-term debt amount will be fixed at 4% of rate base**.” [Emphasis in Original]

The Board Report states the following in section 2.2.2:

> **The Board has determined that the deemed short-term debt rate will be calculated as the average of the 3-month bankers’ acceptance rate plus a fixed spread of 25 basis points.** This is consistent with the Board’s method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts. The Board will use the 3-month bankers’ acceptance rate as published on the Bank of Canada’s website, for all business days of the same month as used for determining the deemed long-term debt rate and the ROE.
>
> For the purposes of distribution rate-setting, the deemed short-term debt rate will be updated whenever a cost of service rate application is filed. The deemed short-term debt rate will be applied to the deemed shortterm debt component of a distributor’s rate base. Further, consistent with updating of the ROE and deemed long-term rate, the deemed short-term debt rate will be updated using data available three full months in advance of the effective date of the rates.” [Emphasis in original]

a. If NOW is proposing not to include a short term debt component in the 2009 Test Year for the purposes of setting its revenue requirement and distribution rates, please provide the reasons that NOW is proposing to deviate from the Board Report.

NOW did not intend to deviate from the Board Report, a more detailed derivation of the WACC below shows that the 4% short-term debt was utilized, however, the same return rate was utilized and this was summarized in Exhibit 6, Tab 1, Schedule 4, Page 1. NOW will incorporate the actual debt / equity rates when finalizing the application process.

2009 Test Year	**Deemed**	**Percentages**
Rate Base	$5,482,230	
Equity Portion	$2,375,450	43.33%
Debt Portion Long Term	$2,887,490	52.67%
Debt Portion Short Term	$219,289	4.00%
Equity Return	$206,189	8.68%
Debt Return Long Term	$145,422	5.04%
Debt Return Short Term	$11,044	5.04%
Proposed Return	**$362,655**	

b. If NOW is proposing to comply with the Board Report, please provide NOW's estimate of the short-term debt rate, showing the calculations, data used and identifying in detail the sources of the data used.

The debt rate will be finalized during the approval process in early 2009 and updated prior to submitting for an approved schedule of rates and tariffs.

c. Please identify if NOW is proposing that the deemed short-term debt rate would be updated based on January 2009 *Consensus Forecasts* and Bank of Canada data, in accordance with the methodology documented in section 2.2.2 of Board Report. If NOW is not proposing to follow the methodology documented in section 2.2.2 of the Board Report, please provide NOW's reasons for varying from the Board Report.

NOW is proposing to use the updated Jan 2009 values.

d. Please provide a calculation of the WACC as shown in the table in Exhibit 6 / Tab 1 / Schedule 4, using a long-term debt component of the deemed capital structure of 52.7%, a deemed short-term debt component of 4.0% and a short-term debt rate of 4.47%, and an equity component of 43.3%.

See updated chart from part b) of this question.

2009 Test Year - Board Staff Rework

	Deemed	**Percentages**
Rate Base	$5,482,230	
Equity Portion	$2,375,450	43.33%
Debt Portion Long Term	$2,887,490	52.67%
Debt Portion Short Term	$219,289	4.00%
Equity Return	$206,189	8.68%
Debt Return Long Term	$145,422	5.04%
Debt Return Short Term	$9,802	4.47%
Proposed Return	**$361,414**	

SMART METERS

Rate Adder

19. Ref: E1 / T1 / S6

At the above reference, NOW states:

> Northern Ontario Wires has not included any costs with respect to smart metering in this rate application. In its current rates NOW has approval for $0.26 per customer per month to cover the costs for Smart Metering. NOW was unsure of how these costs were to be handled in this rate process and requests that the Board approve the appropriate change in rates for this initiative.

On October 22, 2008, the Board issued Guideline G-2008-0002 – Smart Meter Funding and Cost Recovery, providing information to distributor and other parties with information on finding and cost recovery related to authorized smart meter activities.

a. Please confirm whether NOW is seeking approval for continuation of its existing smart meter rate adder of $0.26 per month per metered customer.

NOW is not seeking to extend the $0.26 charge currently approved for a smart meter recovery. Alternatively (as discussed in part b) of this IR, NOW is applying for the generic smart meter recovery adder.

b. If NOW is not seeking approval for continuation of the smart meter rate adder of $0.26 per month per metered customer, please clarify what approval NOW is seeking with respect to smart meter funding or cost recovery. Please provide supporting explanation for NOW's proposal and detailed calculations of the proposed smart meter rate adder, if applicable. Such support should comply with the filing requirements documented in G-2008-0002.

At time of filing the NOW 2009 application there was much confusion on the Smart Meter funding. OEB document G-2008-0002 has clarified this to some degree. As NOW is an "Implementing Utility" we are applying for the generic $1.00 per customer per month charge (filing requirement are below in this IR response). It is important to note that NOW's smart meter consultants have identified an average annual cost of $4.05 per customer per month for capital and operating costs, once smart meters are fully deployed. The $1.00 is "seed money" only.

NOW is approved for Smart Meter spending under the London Hydro RFP option.

- Filing requirements
  - Estimated number of meters to be installed in 2009 – 6,140
  - Estimated cost per installed meter - $239.12 (capital costs only)
  - Estimated total cost of meters installed - $1,468,196
  - Minimum functionality – only using minimum functionality meters
  - SME associated costs
    - Ongoing SME annual operating cost of
      - $31.11 per meter
      - $191,015.40 total

c. Please confirm whether or not NOW's proposed distribution rates documented in Exhibit 9 / Tab 1 / Schedule 5 include the existing smart meter rate adder of $0.26 per month for metered customer classes.

The schedule referenced currently includes the $0.26 smart meter rate adder. Please see revised rate schedules below incorporating $1.00 smart meter rate adder. The schedule below does not adjust for any other Interrogatory either from Board Staff or Interveners. NOW has assumed that the $1.00 standard charge will be applied to all metered customers (Residential, GS < 50 and GS > 50).

Northern Ontario Wires Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge		$ 18.50
Distribution Volumetric Rate	$/kWh	0.0179
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge		$ 0.25

General Service Less Than 50 kW

Service Charge		$ 24.00
Distribution Volumetric Rate	$/kWh	0.0156
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0038
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge		$ 0.25

General Service 50 to 4,999 kW

Service Charge		$ 206.00
Distribution Volumetric Rate	$/kW	0.9450
Retail Transmission Rate – Network Service Rate	$/kW	1.6425
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4944
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge		$ 0.25

Unmetered Scattered Load

Service Charge		$ 12.00
Distribution Volumetric Rate	$/kWh	0.0409
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0038
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge		$ 0.25

Northern Ontario Wires Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

Service Charge		$ 6.25
Distribution Volumetric Rate	$/kW	6.6742
Retail Transmission Rate – Network Service Rate	$/kW	1.2388
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1553
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge		$ 0.25

Specific Service Charges

Customer Administration

Arrears Certificate	$ 15.00
Returned Cheque charge (plus bank charges)	$ 15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$ 30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$ 30.00
Non-Payment of Account	
Late Payment - per month	% 1.50
Late Payment - per annum	% 19.56
Collection of Account Charge – no disconnection	$ 30.00
Disconnect/Reconnect at Meter - during Regular Hours	$ 65.00
Disconnect/Reconnect at Meter - after Regular Hours	$185.00
Specific Charge for Access to the Power Poles – per pole/year	$ 22.35

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW (0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	% (1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$ 100.00
Monthly Fixed Charge, per retailer	$ 20.00
Monthly Variable Charge, per customer, per retailer	$ 0.50
Distributor-consolidated billing charge, per customer, per retailer	$ 0.30
Retailer-consolidated billing credit, per customer, per retailer	$ (0.30)

Northern Ontario Wires Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Service Transaction Requests (STR)

Request fee, per request, applied to the requesting party	$ 0.25
Processing fee, per request, applied to the requesting party	$ 0.50

Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party :

- Up to twice a year no charge
- More than twice a year, per request (plus incremental delivery costs) $ 2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	%1.0433
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	%1.0328
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

TAXES AND PAYMENTS IN LIEU OF INCOME TAXES (“PILS”)

PILs Calculation

20. Ref: E4 / T3 / S1

For all years shown, please provide a detailed breakdown of “Other Additions” and “Other Deductions” shown in the table of Income Tax Calculations.

	Other Addition		Other Deduction	
	Value	Details	Value	Details
2006 Approved	$ 131,461	Deemed interest to be recovered (calculated by OEB Tax Model)	$ 205,891	Anticipated Interest (from OEB 2006 Tax model)
2006 Actual	$ 131,461	Deemed interest	$ 101,338	Actual Interest
2007 Actual	$ 127,037	Deemed Interest	$ 103,161	Actual Interest
2008 Bridge	$ 143,906	Deemed Interest (short & long term combined)	$ 114,122	Forecast interest expense
2009 Test	$ 156,466	Deemed Interest (short & long term combined)	$ 105,262	Forecast interest expense

Audited and Pro Forma Financial Statements

21. Ref: E1 / T3 / S1 and E1 / T3 / S2

NOW’s Audited Financial Statements for 2007, with 2006 restated, and pro forma financial statements for 2008 bridge and 2009 test years show the following actual and forecasted financial performance for NOW:

	2007 Audited Financial Statements		Pro forma Financial Statements	
	2006 Restated	2007 Actual	2008 Bridge	2009 Test
Net Income from Operations before Taxes	$ 141,737	$ 216,737	-$ 160,957	$ 266,624
PILS	$ 24,640	$ 40,972	$ 55,811	$ 60,503
Net Income (loss)	$ 117,097	$ 175,819	-$ 216,768	$ 206,121

Please provide further explanation of NOW’s forecasted operating loss for the 2008 bridge year, and the factors contributing to this loss.

The 2008 results show a Net Loss due to the fact that the increase in expenses have not yet been incorporated into the distribution rates (this cost of service application process updates the rates to include 2009 expenditure levels). As an example, total revenue from operations is $453,843 (2009 = $3,139,087 while 2008 = $2,685,248) higher in 2009 than in 2008.

The differences between actual expenses and the revenue generated from rates based on 2004 expenses drive this 2008 loss.

LOAD FORECAST

General

22. Ref: N/A

Please provide the following information regarding the accuracy of NOW's previous load forecasts:

What was the forecast error of NOW's load forecast in 2004, 2005, 2006, 2007 and year-to-date 2008 (i.e. variance and percent variance between total normalized actual load and forecast load, by rate class if available)?

NOW has historically not utilized a formal load forecast for budget purposes, alternatively, we adjust prior year numbers to align with our economic and environmental assumptions. As a result, the requested information is not available.

A chart of the historical actual consumptions are located in Exhibit 3, Tab 2, Schedule 2, Page 3 the "Non-Normalized Consumption" chart at the top of the page.

Customer Connections

23. Ref: E3/ T2 /S2 / p1

a. At the above reference, NOW states "Over all the three communities serviced by NOW Inc. are not growing. Cochrane and Kapuskasing are relatively stagnant while Iroquois Falls has experienced a decrease and continues to experience a slow decrease...".

Please provide any external reports or forecasts (for example, regional economic forecasts from the national Banks or Housing Outlook reports from CMHC) used to support the above claim.

This is a statement of observation by NOW management that also utilized the historical customer counts. We do not have any external reports to prove this thought.

b. Please explain the methodology and assumptions used to forecast the number of customers in the Residential, GS<50 and GS 50 to 4999 rate classes in the Bridge and Test years. If these assumptions are based on factors such as housing or population trends then please provide the studies/reports supporting the assumptions.

2008 Bridge year, we utilized the actual counts as of July 3, 2008 (most recent value available at time of filing). For the 2009 test year, NOW's manager of finance utilized current LDC trends and economic information to estimate the reduction of 10 residential customers, 5 GS < 50 customers and stagnant customer counts for GS > 50, Street Light and Unmetered customer classes.

Official (with supporting documentation) Housing / Population trends were not utilized.

c. Please prepare a test year customer forecast for the Residential, GS<50 and GS 50 to 4999 rate classes, using a linear trend method with customer data from 2002 to 2007. Please also provide the impact on the proposed test year load and revenue forecast if this alternate forecast is adopted.

Submitted Customer Counts

CUSTOMER COUNT FORECAST TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Bridge	Variance from 2007 Actual	2008 Bridge	2009 Test	Variance from 2008 Actual
Residential	5,268	5,263	-5	5,263	5249	-14	5249	5210	-39	5210	5200	-10
GS<50	861	787	-74	787	773	-14	773	790	17	790	785	-5
GS>50 to 499 kW	55	70	15	70	69	-1	69	69	0	69	69	0
Unmetered Scattered Load	48	15	-33	15	15	0	15	15	0	15	15	0
Street Lighting	1,732	1,737	5	1,737	1737	0	1737	1737	0	1737	1737	0
	7,964	**7,872**	**-92**	**7,872**	**7843**	**-29**	**7,843**	**7,821**	**-22**	**7,821**	**7,806**	**-15**

Linear Trend Counts

CUSTOMER COUNT FORECAST TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Bridge	Variance from 2007 Actual	2008 Bridge	2009 Test	Variance from 2008 Actual
Residential	5,268	5,263	-5	5,263	5249	-14	5249	5151	-98	5151.4	5100	-51
GS<50	861	787	-74	787	773	-14	773	764	-9	764.2	748	-17
GS>50 to 499 kW	55	70	15	70	69	-1	69	74	5	73.8	78	4
Unmetered Scattered Load	48	15	-33	15	15	0	15	15	0	15	15	0
Street Lighting	1,732	1,737	5	1,737	1737	0	1737	1737	0	1737	1737	0
	7,964	**7,872**	**-92**	**7,872**	**7843**	**-29**	**7,843**	**7,741**	**-102**	**7,741**	**7,678**	**-63**

Revenue Forecast Impact:

- Submitted Total Revenue = $3,119,866
- Linear Trend Total Revenue = $3,124,040

Load Forecast Impact:

- Residential
  - 2009 kWh – Submitted = 41,161,457
  - 2009 kWh – Linear = 40,371,699
- GS < 50 kW
  - 2009 kWh – Submitted = 21,858,575
  - 2009 kWh – Linear = 20,815,569
- GS > 50 kW
  - 2009 kWh – Submitted = 68,558,740
  - 2009 kWh – Linear = 77,671,516
  - 2009 kW – Submitted = 173,388
  - 2009 kW – Linear = 196,435

Weather Normalization

24. Ref: E3/ T2 /S1 / p1

a. At the above reference, the evidence indicates that the IESO weather correction factors are adjusted by a “NOW Factor” of 2.101. Please explain how the “NOW factor” was derived and the reasons for the adjustment.

The NOW factor is simply a ratio of weather sensitive load compared to total load (based on Hydro One 2004 Load Study utilized for cost allocation purposes). The attempt was to adjust the IESO average weather normalization for the specific proportions of weather sensitive load in NOW distribution territory.

b. A number of applicant distributors have adopted the Hydro One weather correction factors to normalize load in recent Cost of Service rate applications. Please explain NOW's rationale for using IESO factors rather than Hydro One weather correction factors.

NOW has utilized the IESO approach due to the fact that the 2004 Hydro One weather correction is from 2004 and is based on data previous to the 2004 date. It was thought that using the IESO reports on load growth for 2005, 2006 & 2007 would be an appropriate way to estimate future load patterns that would incorporate a more recent history of Ontario load characteristics (economic outlook, incorporation of CDM activities, etc…).

In reviewing many OEB decisions on 2008 rebasing utilities, there were repeated comments on updating load characteristics and cost allocation methodologies. It was NOW's view that this was an economically efficient way of attempting to meet the OEB wishes.

c. Please develop a test year weather normal forecast using a linear trend method based on 20 years (1988 – 2007) of weather data from an appropriate weather station that reflects the weather in NOW's service area. Please prepare an econometric test year load forecast for the Residential, GS<50 and GS 50 < 4999 rate classes, using appropriate explanatory variables and the above weather normalization. Please identify the impact on the proposed test year load and revenue forecast if this alternate forecast is adopted.

NOW did not use an econometric approach to load forecasting in the 2009 rate application. As this is the case, the requested information can not be efficiently (considering time) organized and calculated. Considering this factor, NOW is not is a position to respond to this question.

NOW would like to bring to the Board and Board Staff attention, that research was performed to attempt to answer this question, however, a more detailed response could not be produced within the timeframe of the IR responses.

Load and Revenue Forecast

25. Ref: N/A

Please provide the 2006 Board-approved load and revenue forecast.

Please see excerpt from 2006 approved EDR.

Amount allocated on this sheet:-- *Base Revenue Requirement B.R.R. #1* **$2,237,164**	Number of Customers (Connections)	kWh per Customer			Calculated kWh per Customer	Calculated kWh	kW per Customer			Calculated kW per Customer	Calculated kW
	2004 Customer count	2002	2003	2004	3 yr average per customer	2004 cust. count x 3 yr average per cust.	2002	2003	2004	3 yr average per customer	2004 cust. count x 3 yr average per cust.
RESIDENTIAL											
Regular	5,268	8,037.2	7,776.1	7,790.9	7,868.1	41,449,024	0.0	0.0	0.0	0.0	0
Less than 50 kW	861	40,467.0	30,660.2	30,838.3	33,988.5	29,264,110	0.0	0.0	0.0	0.0	0
Greater than 50 kW (to 3000 kW)	55	1,164,142.9	1,257,420.2	1,234,558.0	1,218,707.0	67,028,886	3,406.1	3,006.4	3,040.7	3,151.1	173,309
Unmetered Scattered Load	48	2,489.0	2,489.0	2,489.0	2,489.0	119,472	0.0	0.0	0.0	0.0	0
Street Lighting	1,732	341.6	1,161.4	1,161.4	888.1	1,538,235	1.2	3.4	2.9	2.5	4,324
TOTALS	7,964					139,399,727					177,634

26. Ref: E3 / T1 / S2 /p1

Please explain with detailed calculations the derivation of the 2008 and 2009 distribution revenue forecast provided at the above reference. If available, please file the electronic worksheets.

2008 Distribution revenue is comprised of the current fixed charges multiplied by the mid-year customer count value multiplied by 12 plus the current variable charge multiplied by the 2008 customer forecast. The calculations are provided below.

2008 Distribution Reveue Build-Up

	Customer Counts			Number of Bills	Fixed Rate (excl.Smart Meters)	Fixed Revenue	Annual kWh / kW	Variable Rate	Variable Revenue	Total Revenue
	2008	2007	Mid-year							
Residential	5,210	5,249	5,230	12	$ 16.33	$ 1,024,773	41,240,613	0.0108	$ 445,399	$ 1,470,171
GS < 50 kW	790	773	782	12	$ 21.45	$ 201,158	21,997,802	0.0102	$ 224,378	$ 425,536
GS > 50 kW	69	69	69	12	$ 208.23	$ 172,414	173,388	2.0476	$ 355,030	$ 527,445
Unmetered Load	15	15	15	12	$ 10.96	$ 1,973	121,104	0.0102	$ 1,235	$ 3,208
Street Light	1,737	1,737	1,737	12	$ 1.04	$ 21,678	5,014	3.3746	$ 16,920	$ 38,598
Total										**$ 2,464,958**

The 2009 distribution revenue is derived throughout the application and ends up at the $2,890,752 indicated in Exhibit 1, Tab 3, Schedule 2, Page 2. The specific allocation of revenue to customer class is based on the cost allocation methodology discussed in Exhibit 8. This is derived by the table below. OM&A, Amortization and PILS expenses can bee found @ Ex. 4, Tab 1, Sch. 1, Pg. 1. Return is calculated and can be found in the response to Interrogatory 18a) above. Revenue off-set can be found in Ex. 3, Tab 1, Sch. 2, Pg. 1.

Calculation of Revenue Requirement

	2006 EDR	2009 Test
OM&A	$2,029,551	$2,311,307
Amortization	$331,372	$404,740
Return	$381,627	$362,536
PILS	$59,377	$60,503
Revenue Offset	-$339,555	-$297,503
Base Revenue Requirement	$2,462,371	$2,841,584
Transformer Allowance		$49,168
Revenue Requirement		$2,890,752

27. Ref: E3 / T2 / S2 /p1

At the above reference NOW states, “The residential class utilized the full historical bandwidth (2002-2007) to generate the weighted average consumption profile”.

a. Please explain the reasons for the significant decline in Residential load in 2003.

The 2002 to 2004 consumption figures were obtained from the information submitted in the 2006 EDR. NOW experienced some difficulties in billing in 2002 and 2003 as a result there were delays in billing resulting in inconsistent consumption figures. Calculations for unbilled revenues at year ends were performed on dollar basis only therefore the consumption figures are based on billed consumption. The billing delays and limited unbilled revenues calculation essentially renders the load figures reported for 2002 to 2004 as somewhat unreliable.

b. Please provide the impact on the test year Residential load and revenue forecast if the 2003 load and customer data are excluded from the multi-year trend analysis.

Excluding the 2003 residential loads and customer counts changes the submitted 2009 load profile from 41,161,457 to an adjusted 41,419,248, a difference of 257,791 kWh or 0.6% (an increase in kWh). The revenue requirement (less misc. revenue) forecast for the residential class changes from $1,827,862 to $1,827,997, a difference of $135.

c. The average growth from 2002 to 2007 in Residential normalized use per customer is 1.3% or an average annual increase of 100 kWh. The 2009 test year Residential average normalized use per customer is forecast to be 7,916 kWh. This represents a 3% decline from 2007 or a decrease of 229 kWh. Please explain the reasons for the significant forecasted decline in the test year normalized average use compared to 2007.

The outcome is simply a result of normalization (or averaging). For reference, please see augmented table from Ex. 3, Tab, 2, Sch. 2, page 4 (adding the annual average consumption values).

	2002	2003	2004	2005	2006	2007	Total
kWh	42,860,054	40,454,974	41,211,165	42,736,273	43,154,148	42,750,091	253,166,706
Counts	5,608	5,278	5,268	5,317	5,263	5,249	31,983
Weighted Average Usage (total kWh / total count)							7,916
2008 Count							5,210
2008 Usage							41,240,613
2009 Count							5,200
2009 Usage							41,161,457
Average Consumption	7,643	7,665	7,823	8,038	8,200	8,144	

It is shown that the annual consumption as been on the rise from 2002 to 2006 with a slight decline in 2007. As NOW's process for load forecasting adjusted for weather on an annual basis and then utilized the average (2002 to 2007) of the total usage by class divided by the average customer count (2002 to 2007) multiplied by the 2009 forecasted customer count, the 2009 estimated average usage per customer has been weighted down from the 2005 to 2007 value of around 8,000 kWh by the 2002 to 2004 value of around 7,700. As the 2007 average has started to decline, this was deemed a reasonable approach from NOWs perspective.

28. Ref: E3 / T2 / S2 /p2 and p4

At the above reference, NOW states "Essentially, NOW created a multi-year average consumption per customer (customer class specific) and applied that average consumption to forecasted customers." [Emphasis added] Further, at the second reference above NOW provides the derivation of the Residential rate class multi-year average consumption per customer used to develop the load forecast.

Please provide the multi-year average consumption per customer for the GS<50 and GS 50 to 4999 rate classes, used to forecast the test year load.

Please see tables below

General Service < 50 kW - Weather Normalized (note only 2006 & 2007 was utilized for average load profile)

	2002	2003	2004	2005	2006	2007	2002 - 2007 Total	2006 & 2007 Total (utilized)
kWh	32,054,130	26,171,785	26,660,992	26,221,167	22,563,293	20,875,404	154,546,770	43,438,697
Counts	833	866	861	815	787	773	4,935	1,560
Weighted Average Usage (total kWh / total count)							31,316	27,845
2008 Count							790	790
2008 Usage							24,740,010	21,997,802
2009 Count							785	785
2009 Usage							24,583,427	21,858,575

General Service > 50 kW - Weather Normalized (note only 2006 & 2007 was utilized for average load profile)

	2002	2003	2004	2005	2006	2007	2002 - 2007 Total	2006 & 2007 Total (utilized)
kWh	53,135,570	66,928,966	68,180,015	60,547,314	70,527,710	67,583,375	386,902,950	138,111,084
Counts	48	54	55	55	70	69	351	139
Weighted Average Usage (total kWh / total count)							1,102,288	993,605
2008 Count							69	69
2008 Usage							76,057,845	68,558,740
2009 Count							69	69
2009 Usage							76,057,845	68,558,740

29. Ref: E3 / T2 / S2 /p2

At the above reference NOW states, "The GS<50 and GS 50 to 4999 customer classes had some significant re-categorization between these classes at the end of the fiscal year 2005, as a result a two year weighted average normalized consumption and load forecast has been created." [Emphasis added]

Please prepare a test year load forecast for the GS<50 and GS 50 to 4999 rate classes using multi-year data from 2002 to 2007. What is the impact on the proposed test year load and revenue forecast for GS<50 and GS 50 to 4999 rate classes if this alternate forecast is adopted?

2009 - GS < 50 kW Load Forecast

- Submitted (original) = 21,858,575
- Proposed = 24,583,427

2009 - GS < 50 kW Load Forecast

- Submitted kWh(original) = 68,558,740
- Proposed kWh = 76,057,845
- Submitted kW (original) = 173,388
- Proposed kW = 194,942

Revenue Requirement Summary

	Original (submitted)	Proposed	Difference
Residential	1,827,862	1,833,222	5,360
GS < 50 kW	558,441	560,089	1,648
GS > 50 kW	333,592	334,428	836
Unmetered	7,119	7,140	21
Street Light	163,739	164,232	493
Total	**2,890,752**	**2,899,111**	8,359

30. Ref: E3 / T2 / S2 /p3

From the above reference, please explain how the "2009 Non-Normalized Weighted Average" values were identified and calculated and how these have been used in the calculation of the test year load forecast.

The non-normalized weighted average summed the 2002 to 2007 kWh by class and divided by the summed customer counts by class (for the same period). As these are non-normalized results, and as indicated in Ex. 3, Tab 2, Sch. 2 Pg. 3, these were not utilized in the process. They have been provided to show a reference between weather adjusted and non-weather adjusted consumption.

Revenue Offsets

31. Ref: E3 / T1 / S2 / p1

The "Other Distribution Revenue" item decreases from 2007 actual to the bridge year by an amount of $51,896. Please explain the reason for this expected decrease in 2008, and describe how it affects the forecast of Other Distribution Revenue in 2009 if at all.

Account	2007 Actual	2008 Bridge	Variance	Variance %
Other Electric Revenue	$202,398	$150,502	($51,896)	-26%

Removal of 2007 non-recurring items as identified above:

Hydro One Meter Exit Rebate	($17,100)
Proceeds from disposal of old transformers	(11,130)

Other items:

Discontinuance of Billing Services to the Town of Iroquois Falls	($15,000)
Effective Sept 2007	($20,000 annually)
Interest Earned on Bank – lower rates	($9,000)
Total Identified above	**($52,230)**

32. Ref: E3 / T1 / S2 / p1 and E3 / T3 / S1

A history and projection of "Miscellaneous Service Revenue" is shown in the last row of the referenced table in Tab 3. The same data entries are found in the row for Specific Service Charges in the referenced table in Tab 1.

a. Please clarify whether this is the revenue from Specific Service Charges in both tables. If not revenue from Specific Service Charges, please provide a brief description of the revenue items included as Miscellaneous Service Revenue.

Yes, these revenues are Specific Service Charges.

b. The amount approved in the 2006 revenue requirement (EB-2005-0020/EB-2005-0398) for Specific Service Charges is included in the referenced tables as "Other Distribution Revenue" or "Other Electric Revenues". Please confirm that this item is the revenue from Specific Service Charges. Alternatively, please provide a brief description of the nature of revenue described as "Other Distribution Revenue" or "Other Electric Revenues".

NOW confirms that both of the referenced "Revenues" are Specific Service Charges.

33. Ref: E9 / T1 / S5

NOW provided its proposed list of specific service charges for 2009 as part of its proposed rate schedule in the reference above.

> a. Please explain why the proposed specific service charges identified at the above reference do not include the $2,000 general administration fee for unauthorized energy use identified at section 2.4.6 in NOW's Conditions of Service.

This was an omission on NOW's part. This charge did not appear on the last (2008) rate order and was not included in this request.

> b. Please provide a description of when the $2,000 general administration fee would be applied, how the level of the charge was determined and the amount of revenue associated with the charge on an annual basis from 2002 to 2007.

The $2,000 general administration fee is intended to compensate for the administration costs associated with handling a situation where there is unauthorized use of power. Section 2.4.6 indicates that all direct costs incurred by NOW would be charged to the responsible party. Since administration costs are indirect costs and would not be recorded as separately identifiable to this situation, accordingly the $2,000 general administration fee would apply. NOW has never applied this fee and therefore the revenues associated with this fee from 2002 to 2007 are nil.

COST ALLOCATION AND RATE DESIGN

Low Voltage

34. Ref: E2 / T4 / S1 / p3

The forecast cost of LV Charges in Account 4750 is $219,054.56, unchanged from the 2007 actual cost.

> a. Please describe the services received, if other than Shared Lines, and please provide the annual kW amounts billed to NOW in 2007.

The only charges and services from Hydro One is the HVDS-Low charges representing shared line services.

Please see billed kW chart below:

NOW - LV Billings

		Iroquois Falls DS F1 PME	Iroquois Falls DS F2 PME	Total
Jan	**2007**	1,810.87	2,533.09	4,343.96
Feb	**2007**	1,794.54	2,596.69	4,391.23
Mar	**2007**	1,721.44	2,511.70	4,233.14
Apr	**2007**	1,576.55	2,381.59	3,958.14
May	**2007**	1,442.03	2,059.03	3,501.06
June	**2007**	1,442.03	2,059.00	3,501.03
July	**2007**	1,462.56	1,995.51	3,458.07
Aug	**2007**	1,703.29	2,352.61	4,055.90
Sept	**2007**	1,655.98	2,249.14	3,905.12
Oct	**2007**	1,458.29	2,136.43	3,594.72
Nov	**2007**	1,373.63	2,132.15	3,505.78
Dec	**2007**	1,531.64	2,244.69	3,776.33
Total	**2007**	18,972.85	27,251.63	46,224.48

b. Please confirm that the cost forecast is made on the basis of the prices that prevailed in 2007.

NOW confirms that the forecast has been made on 2007 pricing.

c. Please provide an update of the forecast cost using rates that may be expected to prevail in 2009, for example the applicable sub-transmission rates applied for by Hydro One in EB-2007-0681 if these are applicable.

Method uses 12 most recent months (Nov 2007 to Oct 2008) multiplied by proposed Hydro One Sub-Transmission rates.

Month	Year	Units	Variable Rate	Variable Charge	Fixed Charge	Total Charge
Nov	**2007**	3,505.78	$ 2.66	$ 9,325.37	$ 376.00	$ 9,701.37
Dec	**2007**	3,776.33	$ 2.66	$ 10,045.04	$ 376.00	$ 10,421.04
Jan	**2008**	4,369.80	$ 2.66	$ 11,623.67	$ 376.00	$ 11,999.67
Feb	**2008**	4,444.23	$ 2.66	$ 11,821.65	$ 376.00	$ 12,197.65
Mar	**2008**	4,458.77	$ 2.66	$ 11,860.33	$ 376.00	$ 12,236.33
Apr	**2008**	4,130.65	$ 2.66	$ 10,987.53	$ 376.00	$ 11,363.53
May	**2008**	3,752.66	$ 2.66	$ 9,982.08	$ 376.00	$ 10,358.08
June	**2008**	3,517.82	$ 2.66	$ 9,357.40	$ 376.00	$ 9,733.40
July	**2008**	3,337.59	$ 2.66	$ 8,877.99	$ 376.00	$ 9,253.99
Aug	**2008**	3,097.18	$ 2.66	$ 8,238.50	$ 376.00	$ 8,614.50
Sept	**2008**	2,759.66	$ 2.66	$ 7,340.70	$ 376.00	$ 7,716.70
Oct	**2008**	3,705.29	$ 2.66	$ 9,856.07	$ 376.00	$ 10,232.07
12 Month Total						$123,828.32

Assumes:

- Monthly Service Charge of $188.00 per delivery point
- Variable charges of $2.66 per kW
- Does not use the temporary charge of $0.633 per kW as this has not historically been billed to NOW

35. Ref: E3 / T1 / S1

The description of operating revenue includes Low Voltage Wheeling. Please describe the revenue that is included under this description, and whether it is gained from NOW's customers or from any embedded distributor(s).

NOW's written submission is confusing, the LV wheeling revenue should be written similar to the PILS section directly before, where we discuss the PILS recovery amount. Essentially, the LV expenses have been incorporated into the working capital calculation and the expense have been recorded in 5665 – Miscellaneous General Expenses to ensure revenue recovery.

36. Ref: 2006 Electricity Distribution Rates – RP-2005-0020/EB-2005-0398

In NOW's previous re-basing, rate adders were approved for NOW's distribution rates for the purpose of recovering Low Voltage costs. For example, the volumetric rate for the Residential class included a rate adder of $0.0018 per kWh (shown in Worksheet 8-2 'Low Voltage/Wheeling Adjustments' in the 2006 EDR model). The Uniform System of Accounts provides Account 4075 to record revenue from this source, and the total should match as closely as possible the amount in Account 4750 which is forecast to be $219,055.

Please provide the amounts recorded by NOW in 2006 and 2007 in Account 4075 "Billed – LV", and the balances if any in Account 1550 "LV Variance Account". (If these accounts were not used, please describe how the amounts were recorded and the amounts that would have been recorded in accounts 4075 and 1550 if they had been used.)

See chart below.

Low Voltage Details

	A/C#4075-0000	A/C#4750-0000	A/C#1550-0000	A/C#1550-0001
	Recovered from Customers	LV Billed from Hydro One	LV Variance Account	LV Variance Interest
2006 (2006 Rate Approval effective July 16/06)				
monthly entries (starts July 16/06)	$ (100,675)	$ 105,695	$ -	
quarterly interest entries				$ (281)
Year End - clear to variance	$ 100,675	$ (105,695)	$ 5,020	
Balance Dec 31/06	$ -	$ -	$ 5,020	$ (281)
2007				
monthly entries	$ (219,055)	$ 178,478	$ -	
quarterly interest entries				$ (1,465)
Year End - clear to variance	$ 219,055	$ (178,478)	$ (40,577)	
Balance Dec 31/07	$ -	$ -	$ (35,557)	$ (1,746)
2008 - to Sept 30				
monthly entries	$ (154,689)	$ 136,846	$ -	
Hydro One Phase 1 Extended (6 x $9,787/month)		$ 58,722		
quarterly interest entries				$ (1,657)
Year End - clear to variance				
Balance Sept 30/08	$ (154,689)	$ 195,568	$ (35,557)	$ (3,403)

37. Ref: N/A

NOW's application does not appear to address how the cost of LV charges will be recovered from its customers.

a. Please identify the LV adder that is included in this application for each rate class.

In the original application, a specific LV adder was not requested as the LV charges were included in the expense lines of the budget used to derive the revenue requirements. Specifically the charges are currently located in USoA 5665 in the A&G expenses. If a unique rate adder is to be generated and used then the 2009 A&G expenses will be reduced by $219,055. Proposed rate adder to be calculated in part c) of this IR.

b. Please provide the amount billed to each rate class in the account 4068 "Billed --CN" in a recent year, and calculate the proportion billed to each class.

See summary chart below:

Billed Connection Charges (4068)

	2007		2008		Two Year Weighted Average
	$	%	$	%	
Residential	212,126	36.7%	248,738	39.2%	38.0%
GS < 50 kW	69,987	12.1%	71,851	11.3%	11.7%
GS > 50 kW	289,191	50.1%	308,136	48.5%	49.3%
Street Lights	6,111	1.1%	6,589	1.0%	1.0%
Total	577,415		635,314		100.0%

note: unmetered loads included in GS < 50 kW class.

c. Please confirm whether the forecast cost of LV service (Account 4750) will be allocated to the rate classes in these same proportions. If not, please describe how the cost is intended to be allocated.

NOW proposes to use the above weighted average allocation of billed connection costs to allocate the LV charges in an effort to determine the class specific LV rate adders. In this IR response NOW will be using the $219,055 originally calculated as the 2009 estimated LV charges. The value will be updated upon finalization of the application and determination of the tariff sheets. Below is a table calculating the specific LV adders by class.

LV Rate Adder Calculations

	Allocation Factor	Allocated Expense	2009 Billing Determinant		2009 LV Rate Adder	
Residential	38.0%	83,246	41,161,457	kWh	0.0020	per kWh
GS < 50 kW	11.7%	25,620	21,979,679	kWh	0.0012	per kWh
GS > 50 kW	49.3%	107,895	173,388	kW	0.6223	per kW
Street Lights	1.0%	2,294	5,014	kW	0.4575	per kW
Unmetered	0	-		kWh	0.0012	per kWh
Total		219,055				

Note: unmetered loads uses the GS < 50 kW rate, the billing determinants for the GS class are based on the combination of the Unmetered loads and GS < 50 kW from the load profile included in the NOW application.

Cost Allocation

38. Ref: E10 / T1 / S2

a. Please provide for the record of this application an electronic copy of NOW's cost allocation study EB-2007-0003 (rolled-up Informational Filing). Please provide Run 1 or Run 2, whichever is more relevant to this application.

Please see attached file (on CD or via email included with this response). The NOW cost allocation study is a Run 2 version.

b. Please compare the proposed Monthly Service Charge for the GS 50 – 4999 kW class with the ceiling amount in Sheet O2 'Fixed charge\Floor\Ceiling'. In light of this comparison, please provide the rationale for decreasing the Monthly Service Charge for this class by less than 2%, while decreasing the volumetric charge by 54%.

Sheet O2 of the 2nd Run Cost Allocation model has a fixed charge ceiling of $168.30 for the GS 50 to 4,999 kW class, which gets grossed up to $201.96 (using the 120% of ceiling guidelines provided by Board Staff). NOW is applying for a fixed charge of $205.26 which is approximately 2% higher than the Board Staff guidelines.

The rationale for the proposed fixed charge was based on a goal to keep fixed charges relatively close to current fixed charges approved. The approved 2008 fixed charge for this customer class is $209.32. Note, that the fixed / variable split for this class at the proposed rates is approximately 50% fixed ($169,740) and 50% variable ($163,852).

NOW is not opposed to a different rate design for this class and submits the following as an alternative (for illustrative purposes). The following is based on a charge @ 100% of the ceiling ($168.30) and provides for a fixed charge revenue of $139,352 representing 41.8% of class revenue. The resulting variable rates are $1.1203 / kW and provides for variable revenues of $194,239 representing 58.2% of class revenue. Please see summary impacts below.

Class	Consumption kWh	Consumption kW	May 2008 Bill	May 2009 Bill	Difference $	Bill Impact %	Max	Min
General Service 50 to 4,999 kW	25,000	50	$ 2,345.85	$ 2,253.94	$ (91.91)	-3.9%	-2.5%	-3.9%
	40,000	75	$ 3,593.36	$ 3,476.88	$ (116.47)	-3.2%		
	50,000	100	$ 4,471.65	$ 4,330.62	$ (141.03)	-3.2%		
Average Customer	82,800	209	$ 7,505.82	$ 7,257.32	$ (248.50)	-3.3%		
	250,000	500	$ 21,478.06	$ 20,944.10	$ (533.96)	-2.5%		

As seen in comparing Exhibit 8, Tab 1, Schedule 2, Page 3 from the original application to the above summary of impacts under the new scenario, we have moved the average impacts (%) slightly and have increased customers with consumption higher than the average a few more dollars while decreasing the monthly costs to customers consuming less than the average customer. Please note, a total of 15 customers are contained within this customer class.

39. Ref: E8 / T1 / S2 and E9 / T1 / S8

a. NOW proposes to lower the revenue to cost ratio for Unmetered Scattered Load from 127% to 103%, yet the calculated impact on the Delivery sub-total for this class in Exhibit 9 is an increase of 93%. In contrast, the Residential class would have an increase in its revenue to cost ratio from 98% to103% and would experience an impact of only 22% (1000 kWh, Delivery sub-total). Please confirm that the calculations underlying these situations are accurate, and if they are accurate please provide an explanation of the seeming contradiction (i.e. the class whose revenue to cost ratio is increasing has a smaller impact than the class whose ratio is decreasing).

On the surface NOW agrees that these numbers are extremely suspect. A disconnect occurs due to the fact that the cost allocation model is based on the 2006 EDR model which utilizes the customer information from 2002 to 2004. If we review the table in Exhibit 3, Tab 2, Schedule 2 Page 1 we can see that in 2006 the number of customers (bills per month) was 48 customers, this has dropped to 15 customers in 2008 and projected 2009..

A drop of 33 customers represents $4,356 ($11.00 /customer / month * 33 customers * 12 months). This $4,356 has remained associated to the unmetered class (in the proposed treatment) and is recovered via the variable charge. A summary chart is provided to assist with this analysis.

Unmetered Load Summary

2004 Customer Count and Load Profile @ 2008 Rates

Customers		48
Fixed Rate	$	11.00
Months / Year		12
Fixed Revenue	**$**	**6,336.00**
kWh		119,472
Variable Rate	$	0.0102
Variable Revenue	**$**	**1,218.61**
Total Revenue	**$**	**7,554.61**

2009 Customer Count and Load Profile @ 2008 & 2009 Rates

		2008	2009
Customers		15	15
Fixed Rate	$	11.00	12
Months / Year		12	12
Fixed Revenue	**$**	**1,980.00**	**$ 2,160.00**
kWh		121,104	121,104
Variable Rate	$	0.0102	0.0409
Variable Revenue	**$**	**1,235.26**	**$ 4,953.15**
Total Revenue	**$**	**3,215.26**	**$ 7,113.15**

As this customer class is not associated with a large portion of distribution revenue, if an alternative allocation methodology is mandated, the impact to the residential and both general service customer classes would be marginal.

b. Please provide a calculation of the revenue to cost ratio for the GS 50 - 4999 kW class that would result if the rate for Street lighting is lower than proposed, such that the revenue to cost ratio for Street lighting is 50%, and the rate for the GS 50 - 4999 kW class is higher than proposed so that it compensates for the lower revenue from Street lighting.

While this is not a proposed treatment and is directly against Board Staff guidelines the results are as follows:

- GS > 50 kW customers
  - Submitted RC% = 102.76%
  - Adjusted RC% = 120.03%
  - Submitted class revenue requirement = $333,592
  - Adjusted class revenue requirement = $386,417
- Streetlight customers
  - Submitted RC% = 70%
  - Adjusted RC% = 50%
  - Submitted class revenue requirement = $163,739
  - Adjusted class revenue requirement = $110,913

c. Please provide a calculation of the bill impact for Street lighting and a representative customer in the GS 50 – 4999 kW class resulting from the hypothetical rates in part b.

See impact summary chart below.

	kWh	kW	2008 Bill	2009 Bill	$	%		
General Service 50 to 4,999 kW	25,000	50	$ 2,345.85	$ 2,299.26	$ (46.59)	-2.0%	-1.9%	-2.4%
	40,000	75	$ 3,593.36	$ 3,525.61	$ (67.75)	-1.9%		
	50,000	100	$ 4,471.65	$ 4,382.74	$ (88.91)	-2.0%		
Average Customer	82,800	209	$ 7,505.82	$ 7,324.31	$ (181.51)	-2.4%		
	250,000	500	$ 21,478.06	$ 21,050.58	$ (427.48)	-2.0%		
Street Lighting - Avg Customer (579 connections)	49,402	139	$ 5,540.01	$ 7,647.24	$ 2,107.22	38.0%		

Retail Transmission Rates

40. Ref: ***Electricity Distribution Retail Transmission Service Rates, Guideline G-2008- 0001,*** **October 22, 2008**

Under the Board's Guideline, NOW is expected to file an update to its Cost of Service application with evidence to support a change in its retail transmission service rates ("RTSRs"). The adjustment in RTSRs is intended to eliminate future growth in the Applicant's variance accounts that are related to the pass-through of transmission costs.

a. Please file a table showing two years of NOW's wholesale Network and Connection costs, and its retail billings for Network and Connection service to its retail customers.

Network

Opening Balance (principle) 64,297

	2007											
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Expenses	56,905	70,844	69,918	66,909	53,326	51,496	53,698	55,458	57,862	54,898	48,199	50,217
Revenues	69,325	72,291	67,615	67,624	55,534	53,664	54,632	54,279	49,711	52,401	52,901	61,890
Monthly Difference	(12,420)	(1,448)	2,304	(715)	(2,209)	(2,168)	(935)	1,179	8,151	2,497	(4,702)	(11,674)
Cummulative Principle Balance	51,877	50,430	52,733	52,019	49,810	47,642	46,707	47,886	56,037	58,534	53,833	42,159

	2008											
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Expenses	50,458	53,369	51,053	46,902	42,874	45,264	37,686	37,159	40,198	-	-	-
Revenues	60,056	89,421	26,911	55,983	50,310	40,954	50,494	43,139	33,651	-	-	-
Monthly Difference	(9,598)	(36,052)	24,143	(9,081)	(7,435)	4,309	(12,808)	(5,980)	6,548	-	-	-
Cummulative Principle Balance	32,561	(3,491)	20,651	11,570	4,135	8,444	(4,364)	(10,344)	(3,796)			

Connection

Opening Balance (principle) (1,449,085)

	2007											
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Expenses	56,905	70,844	69,918	66,909	53,326	51,496	53,698	55,458	57,862	54,898	48,199	50,217
Revenues	69,325	72,291	67,615	67,624	55,534	53,664	54,632	54,279	49,711	52,401	52,901	61,890
Monthly Difference	(12,420)	(1,448)	2,304	(715)	(2,209)	(2,168)	(935)	1,179	8,151	2,497	(4,702)	(11,674)
Cummulative Principle Balance	(1,461,505)	(1,462,952)	(1,460,649)	(1,461,363)	(1,463,572)	(1,465,740)	(1,466,674)	(1,465,496)	(1,457,345)	(1,454,848)	(1,459,549)	(1,471,223)

	2008											
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Expenses	46,229	46,732	45,697	42,869	31,840	30,753	30,036	29,199	30,496			
Revenues	48,650	71,401	20,523	45,306	41,491	38,892	47,662	40,867	31,876	-	-	-
Monthly Difference	(2,421)	(24,669)	25,174	(2,437)	(9,651)	(8,140)	(17,626)	(11,668)	(1,380)	-	-	-
Cummulative Principle Balance	(1,473,644)	(1,498,314)	(1,473,140)	(1,475,577)	(1,485,228)	(1,493,367)	(1,510,993)	(1,522,661)	(1,524,041)			

b. Please provide an analysis of the variances between costs and the corresponding revenues, and any trends in these amounts.

Over the 2 year period (2007 & 2008) the network balance has moved from a receivable (owed money from customers) balance of approximately $65,000 to a payable (owing to customers) balance of approximately $4,000. A total change of approximately $70,000 (collecting more from customers than the charged expenses) resulted in the 2 year period. The history shows a fairly consistent over collection.

The connection balance has moved from a payable (owing to customers) balance of approximately $1,450,000 to a payable balance of approximately $1,525,000. A total change of approximately $125,000 resulted in the 2 year period.

NOWs is of the belief that the reduction in rates applied for in part c) of this response, will ensure that the annual variance between revenues and expenses will not increase from the reduction in wholesale charges. The total over collection (more revenue than expenses) over the 2007 / 2008 period is approximately $195,000. During this period the expenses have been $2,118,274. This indicates that the over collection is around 9.2%. NOW would not be opposed to a further 5% reduction in retail transmission rates, if deemed necessary by the Board panel.

c. Please file proposed RTSR rates for each customer class that are an adjustment to the currently approved RTSRs and would recover the wholesale cost of transmission service assuming that the Interim rates charged by Hydro One to embedded distributors effective May 1, 2008 had been in effect during the 2-year period in part a). Please provide the calculations used to derive the proposed RTSR rates.

As NOW has received approval for the 2008 IRM, which adjusted the RTR to the 2008 level, see summary chart below that follows the 2009 2nd Generation IRM methodology (decreasing the RTR rates the same amount as the wholesale charges for 2009).

Northern Ontario Wires
Retail Transmission Rates Adjustment Model

Network

	2008	2009	% Change
Wholesale Rate	2.31	2.57	11.26%

Retail Rates

	Current Rate	Adjustment Factor	Proposed 2009 Rate
Residential	0.0044	11.26%	0.0049
GS < 50 kW	0.0040	11.26%	0.0045
GS > 50 kW	1.6425	11.26%	1.8274
Unmetered Load	0.0040	11.26%	0.0045
Street Light	1.2388	11.26%	1.3782

Connection

	2008	2009	% Change
Wholesale Line	0.59	0.70	
Wholesale Tranformation	1.61	1.62	
Wholesale Total	2.2	2.32	5.45%

Retail Rates

	Current Rate	Adjustment Factor	Proposed 2009 Rate
Residential	0.0042	5.45%	0.0044
GS < 50 kW	0.0038	5.45%	0.0040
GS > 50 kW	1.4944	5.45%	1.5759
Unmetered Load	0.0038	5.45%	0.0040
Street Light	1.1553	5.45%	1.2183

Deferral and Variance Accounts

41. Ref: E5 / T1 / S1

NOW is not applying for disposition of balances of any deferral or variance accounts, and has not filed the balances in any accounts.

> a. Please provide a continuity schedule for the above accounts using the Excel spreadsheet attached. (Please note that forecasting principal transactions beyond December 31, 2007 and the interest on those transactions in columns AM – AP is optional.)

We have completed the continuity schedule including forecasts to April 30, 2009.

There is a difference in the allocation of the 2006 approved recoveries between the original worksheet filing for Regulatory Asset Balances at Dec 31, 2004 and what we have recorded in our books and on the continuity schedule. We discovered a number of errors in the input cells of the original worksheet. These errors primarily included the reporting of interest balances in the principle columns and the consolidation of the RSVA balances 1580 to 1588 at Dec 31/04 reported as account 1584-Deferred Rate Impact Amount. We also failed to report the accrued interest on Qualifying Transition Costs from Jan 1/05 to Apr 30/06 which has been adjusted on the revised worksheet as well. We recreated the worksheet using the balances as they should have been input and the difference in total claim was negligible and is summarized as follows:

Summary of Revision to 2004 Regulatory Asset Worksheet

	Original	Revised	Difference
Total Claim	1,455,929	1,456,130	(201)
Net = Grand Total Claimed	1,421,086	1,419,217	1,869
Write off difference(10% Transition Costs)	34,843	36,913	(2,070)

Accordingly we recorded the 2006 recoveries as they should have been and as per the revised worksheet.

Please recognize we also failed to report accrued interest to Dec 31/04 on the Pre-Market opening variance account # 1571 and did not include this in the revised worksheet since it would have resulted in a significant variance from the original filing This amounted to $50,975 and is reflected in the current continuity schedule.

> b. The continuity schedule provides a sub-total for the accounts: 1508, 1518, 1525, 1548, 1570, 1571, 1572, 1574, 1582, 1590, 1592, 1595, and 2425. Please provide rate riders that would dispose of the net balance of the accounts listed. Please include details of how the individual balances would be allocated to customer classes and the length of time over which the rate rider would be charged or rebated.

The total projected variances balances (1508, 1518, 1525,1548, ,1571,1582, 1580 to 1588, 1590) at April 30, 2009 is $(655,945).The continuity schedule balance column excludes the balance for Smart Meters. We have summarized the smart meters variance account forecasts as follows:

Smart Meters Variance Balances

	A/C#1555-0000 Smart Meter Capital & Recovery	A/C#1556-0000 Smart Meter OM&A	TOTAL	A/C#1550-0001 Smart Meters Variance Interest	TOTAL Principle and Interest
Forecast Balance Dec 31/08	**$ (47,619)**	**$ 31,427**	**$ (16,191)**	**$ (1,523)**	
2009 Forecast Jan to April 30/09					
2009 recoveries Jan - April	$ (6,240)		$ (6,240)		
2009 costs	$ 600,000	$ 4,000	$ 604,000		
quarterly interest entries				$ 1,968	
Forecast Balance April 30, 2009	**$ 546,141**	**$ 35,427**	**$ 581,569**	**$ 445**	**$ 582,013**
2009 Forecast May to Dec 2009					
2009 recoveries May - June (assume minimum $1/account)	$ (48,000)		$ (48,000)		
2009 costs	$ 746,000	$ 75,000	$ 821,000		
quarterly interest entries				$ 29,000	
Forecast Balance Dec 31, 2009	**$ 1,244,141**	**$ 110,427**	**$ 1,354,569**	**$ 29,445**	**$ 1,384,013**

Forecast Balance of Total Variances April 30/09

Per Continuity Schedule at April 30/09, excluding smart meters	$ (656,000)
add Forecast Smart Meters Balance April 30/09	$ 582,013
Total Forecast Variance Balances April 30/09	**$ (73,987)**
increase to smart meters variance forecast May to Dec 2009	$ 802,000
Total Forecast Variance Balances December 31, 2009	**$ 728,013**

When we include the smart meters variance balance forecast to April 30, 2009 the total variance is forecast to be ($73,987). With another $802,000 in smart meters spending from May to December 2009 the net variances total is expected to be over $700,000.

Accordingly NOW is not applying to dispose of its variance accounts as part of this rate application.

We have also revised the regulatory interest (interest on deferral and variance accounts) included in our rate application to account for the smart meters spending forecast in 2009. The changes are summarized as follows:

Deferral and Variance Accounts Regulatory Interest

Total 2009 expense included in Revenue Requirements	$ 50,943
Revised 2009 interest forecast	$ 10,000
Reduction in 2009 Forecast Variance accounts interest	**$ (40,943)**

This reduction is included in our summary or changes to revenue requirements.

Loss Factors

42. Ref: E4 / T2 / S9

a. Please clarify whether electricity is delivered directly to NOW from a transformer station operated by Hydro One Transmission, or alternatively whether the power is delivered to NOW through an LV line(s) operated by Hydro One Distribution.

NOW is comprised of 3 distribution areas. The specific supply arrangements are listed below:

- Iroquois Falls Is fed from a Hydro One distribution station transformer at 12.5 KV
- Cochrane is fed from the 115 KV grid with our own transformers. (LV supplied)
- Kapuskasing is fed from a Hydro One transformer station at 25KV.

b. If the latter, please confirm whether the kWh amounts shown in the first row of the referenced table are described by Hydro One as “total kWh with losses” or simply “total kWh”.

NOW is not sure how Hydro One would describe the kWhs referenced. The data for this table comes from IESO purchases and NOW sales.

c. The approved loss factor for Hydro One Distribution to apply to its deliveries to embedded distributors is 1.034. Please confirm that this factor is not included in the total loss factors requested in this application.

Total loss factor as applied for consist of NOW distribution loss factor (DLF) and the Hydro One supply facilities loss factor (SFLF) as has been calculated since market opening.