Topic

Rates Resulting From Phase I Decision

Reference

NTPC Letter dated October 1, 2007

Preamble

NTPC's refiling letter makes no reference to the implementation of new rates resulting from the Board's Phase I (Re-filing) Decision. The Board wishes to know how and when NTPC proposes to give effect to new rates resulting from Phase I of the proceedings and how any revenue deficiency/excess by community resulting from the rates that were in place from April 2006 to January 2007 and the interim rates effective February 1, 2007 would be dealt with.

Requests

a) Please indicate the effective date for implementation of new rates resulting from the Board's Phase I (Re-filing) Decision for 2006/07 and 2007/08.

b) If the new rates are to be dealt with as part of the Phase I (Re-filing) Decision please provide proposed rates and detailed rate calculations by community in support of the proposed rates. Attachment BR.NTPC.1 provides a guide to the details to be included in determining new rates (interim pending completion of Phase II) by community; it has been assumed for purposes of illustration January 1, 2008 would be the effective date for new rates:

   i. Schedule 1-Determination of 2006/07 core revenue under/ over recovery
   ii. Schedule 2-Determination of 2007/08 core revenue under/ over recovery
   iii. Schedule 3-Determination of change in interim rider and rider revenues resulting from Phase I refiling
   iv. Schedule 4-Determination of change in revenue resulting from annualized change in interim rider, recovery of 2006/07 and 2007/08 under/ over recovery and fuel rider

c) If new rates are to be dealt with as part of a forthcoming application please provide the date when NTPC expects to file that application.

Response

(a), (b) and (c)

It is not possible to determine the level of rider adjustments required to finalize 2006/07 rates and set a 2007/08 interim rate without a final revenue requirement being approved. NTPC will provide its application for new rates reflecting the Board's Phase I decision as soon as possible following a final Phase I Revenue Requirement decision. Assuming the required decisions proceed in an expeditious manner, it is possible that the new rates could be in place for January 1, 2008.

Topic

Sinking Fund Interest and Effective Cost of Long Term Debt

Reference

Directives 5 and 6

Preamble

Requests

a) Please provide the supporting calculations for the effective cost of long term debt.

Response

a) Please refer to the response to HC.NTPC-1.

Topic

Sales Forecast

Reference

Directive 19

Preamble

The review of the average use per Customer method indicates that on the whole, the Corporation's test year forecasts for Residential sales are reasonable with only three communities outside of an 8% tolerance. For General Service, the Corporation maintains that for reasons discussed below, the average use per Customer method is not a good measure of forecast accuracy. The Corporation's refiling therefore does not reflect any adjustment to the forecast sales for Residential or General Service Customers.

Requests

a) Please provide all the analysis that was undertaken (include supporting calculations and regression analysis in Excel format) by NTPC to assess the impact on sales forecast following Board directive 19. Please confirm normalized sales were used to determine average use per customer. If normalized sales were not used please provide the analysis based on normalized sales.

b) Please provide a schedule comparing the number of customers, sales and sales revenues by community and rate class showing the results of the analysis in response to Directive 19 and the original forecast and the percentage differences. (Provide response in Excel format)

c) With respect to each community where differences are shown in response to b) above, please provide NTPC's reasons as to why the sales should, or should not, be adjusted in response to Directive 19.

d) Please provide an estimate of the impact on the community costs (through the impact on fuel costs) and revenues if (i) the residential sales forecasts and (ii) the general service sales forecasts were adjusted in accordance with the results following the analysis under directive 19 irrespective of the percentage differences between the original forecasts and Directive 19 forecasts. Please use a preliminary Phase II cost of service study if available or the community costs used in the interim Decision 2-2007 for this analysis. Include Excel spreadsheets showing all supporting calculations.

Response

a) The analysis that was undertaken by the Corporation to prepare its response to Directive 19 is provided in response to BR.NTPC-4 (b) below.

The Corporation did not undertake any regression analysis based on heating degree days or any other weather related indicator in preparing its response to Directive 19. The analysis provided in BR.NTPC-4 (b) reflects a simple 4-year average of average use per customer. The Corporation does not have a method for normalizing sales due to weather (ie. temperature, precipitation, etc) from actual years to correct for variations due to weather and could not develop one in the short time period available for the re-filing. As such the Corporation cannot provide the analysis on the basis of weather normalized sales.

In preparing its response to Directive 19, the Corporation also undertook a review of its customer count method for previous years. Prior to 2002, the Corporation reported customer counts in regulatory filings and load forecasts using a simple method that counted the number of active accounts at a single point in time each year. Beginning part way through the 2002/03 fiscal year, the Corporation introduced a new method for collecting customer count data. The new method takes the 12-month average of accounts that are active on the 15th of each month. In the Corporation's view, the new method provides a more accurate customer count.

Given the importance of an accurate and consistent method for obtaining customer counts in calculating a meaningful average-use-per-customer index, the Corporation has updated its customer counts for 2002/03 to reflect the newer method. The customer counts for 2003/04, 2004/05 and 2005/06 continue to reflect the same counts previously filed during the proceeding. However, the differences in customer count method prior to 2002/03 mean that the Corporation cannot rely on an average use per customer calculation for years prior to 2002/03 without considerable additional effort to restate prior year customer counts to be consistent with the new customer count method. In the Corporation's view, it would be advantageous to examine whether an average should be based on 4 years or some larger data set, however, such an analysis could not be undertaken during the short time period available for the re-filing. In the event this data is intended to develop new weather normalization variables, 4 years is entirely insufficient and 10 years is likely to be required.

b) Please refer to the attached Table 1, BR.NTPC-4 b through to Table 4, BR.NTPC-4 b. The tables compare the Corporation's sales forecasts in the October 1, 2007 re-filing with two 4 year averages. A simple average of use per

customer for each of the previous 4 years and a weighted average use per customer, with a weighting of 4 assigned to the most recent year, 3 to the second most recent year, 2 to the third most recent year and 1 to the fourth most recent year. The customer counts are the same for both methods.

c) In the refiling, the Corporation employed the average use per customer analysis as a test of reasonableness of its load forecasting method. As stated in the Corporation's response to Directive 19, the review of the average use per customer method indicated that on the whole, the Corporation's test year forecasts for Residential sales are reasonable. As such, the Corporation did not make any adjustments to its test year sales forecasts. Further, as noted in the Corporation's response to Directive 19, the 4 year average use per customer methodology has not been tested and subject to appropriate scrutiny due to severe limitations in the amount of time available to prepare the re-filing. In particular the Corporation has concerns with respect to how to apply the 4-year average use per customer method to General Service Customers as an extra factor beyond the notable issues identified for the Residential class.

Load forecasting methodology must account for a number of factors, only one of which is weather. The method of a simple average of 4 previous years may or may not properly reflect other variables or customer usage patterns, and should not, in the Corporation's view be solely relied upon to prepare a test year sales forecast.

For the current proceeding, given that the average use per customer method was first proposed by the HC in its argument, and the short time period available to the Corporation to prepare its Phase I re-filing, the Corporation cannot recommend that the average use per customer method be adopted as the prime forecasting method for Residential and General Service customers in the 2006/08 Phase I General Rate Application. As a cross check on the methods applied by the Corporation, this approach may be suitable. Using this approach as a cross check, the analysis indicates that the Corporation's 2006/07 and 2007/08 sales forecasts are reasonable and should be approved.

The Corporation remains open to testing and evaluating different load forecasting methods following this GRA, such as the average use per customer method that may be simpler to apply and understand. If directed by the Board, the Corporation will undertake to review the average use per customer method for both Residential and General Service customers as a load forecasting method for its next Phase I General Rate Application.

d) Please refer to the attached Table 5, BR.NTPC-4 d through to Table 12, BR.NTPC-4 d. The following should be noted with respect to the attached tables:

- The tables are provided for illustrative purposes only.
- The revenue requirements and miscellaneous revenues consistent with the Corporation's October 1st Re-filing have been broken out by community or system using the same method as described in the Corporation's interim rate proposal. The Corporation has not completed a preliminary Phase II Cost-of-Service Study. The community revenue requirements are presented for illustrative purposes only and do not reflect the Corporation's proposal for Phase II cost of service allocations.
- In Table 5, BR.NTPC-4 d through to Table 8, BR.NTPC-4 d, the Incremental Sales (column A) represent the increase or decrease in sales (kW.h) comparing the simple 4-year average method described in part b above with the sales forecasts in the October 1, 2007 re-filing. Table 9, BR.NTPC-4 d through to Table 12, BR.NTPC-4 d illustrates that same information but for the 4-year weighted average method.
- The Incremental Line Losses (column B) show the line-losses that would be incurred with the Incremental sales in column A.

The results of the analysis indicate that, even if either the 4-year average sales forecasts were adopted without regard for the variance from the GRA forecasts, there would be relatively little impact on the overall revenue requirement and resulting rates to be collected from customers (per column O in each respective Table 5 through 12).

Table 1, BR.NTPC-4 b
Northwest Territories Power Corporation
Sales and Revenue Forecast Comparison
Rate Application to Average Use Per Customer Methodology
Residential Customer Class
2006/07

Plant No.	Plant Name	Sales Forecast from Application	Sales Forecast 4-Year Simple Average User Per Customer	4-Year Simple Average	Sales Forecast 4-Year Weighted Average Use Per Customer	4-Year Weighted Average	Forecast Customer	Revenue Forecast from Application	Revenue Forecast 4-Year Simple Average	4-Year Simple Average	Revenue Forecast 4 - Year Weighted Average	4-Year Weighted Average
	Units	(kWh)	(kWh)	Variance	(kWh)	Variance	Count	($000s)	($000s)	Variance	($000s)	Variance
104	Wha Ti	817,363	827,749	1.3%	819,623	0.3%	125	655	663	1.2%	657	0.3%
105	Gameti	437,619	457,102	4.5%	449,466	2.7%	79	379	395	4.3%	389	2.6%
108	Behchoko	3,334,309	3,818,855	14.5%	3,741,768	12.2%	463	762	858	12.6%	842	10.6%
109	Dettah	599,368	613,270	2.3%	607,684	1.4%	87	138	140	2.0%	139	1.2%
110	Lutsel K'e	704,966	759,145	7.7%	732,264	3.9%	120	463	497	7.3%	480	3.7%
201	Ft Smith	9,207,225	10,133,174	10.1%	9,965,885	8.2%	983	1,329	1,441	8.5%	1,421	6.9%
203	Ft Resolution	1,387,458	1,408,143	1.5%	1,398,442	0.8%	211	240	243	1.2%	242	0.6%
205	Ft Simpson	2,887,829	2,934,470	1.6%	2,887,681	0.0%	491	1,169	1,186	1.5%	1,169	0.0%
206	Ft. Liard	1,043,948	1,029,699	-1.4%	1,020,149	-2.3%	171	455	449	-1.3%	445	-2.1%
207	Wrigley	275,977	277,317	0.5%	274,012	-0.7%	52	227	228	0.5%	225	-0.7%
208	Nahanni Butte	156,512	153,218	-2.1%	157,729	0.8%	36	158	154	-2.0%	159	0.7%
209	Jean Marie River	120,528	118,632	-1.6%	115,532	-4.1%	22	107	105	-1.5%	102	-4.0%
301	Inuvik	8,878,668	9,563,810	7.7%	9,201,537	3.6%	1,410	3,742	4,008	7.1%	3,867	3.3%
304	Norman Wells	2,875,134	2,793,164	-2.9%	2,851,869	-0.8%	370	967	941	-2.6%	959	-0.7%
305	Tuktoyaktuk	2,074,185	2,077,369	0.2%	2,061,862	-0.6%	325	1,348	1,350	0.1%	1,341	-0.6%
306	Ft. McPherson	1,519,692	1,556,329	2.4%	1,554,330	2.3%	275	863	882	2.2%	881	2.1%
307	Aklavik	1,255,147	1,353,884	7.9%	1,348,819	7.5%	245	773	829	7.3%	826	7.0%
308	Deline	1,148,722	1,148,137	-0.1%	1,164,670	1.4%	207	709	709	0.0%	719	1.3%
309	Ft. Good Hope	1,231,649	1,177,812	-4.4%	1,187,453	-3.6%	191	829	795	-4.2%	801	-3.4%
310	Tulita	1,013,946	997,185	-1.7%	1,013,231	-0.1%	161	849	836	-1.6%	849	-0.1%
311	Paulatuk	490,549	547,398	11.6%	542,510	10.6%	88	482	535	11.1%	531	10.2%
312	Sachs harbour	266,425	264,448	-0.7%	259,578	-2.6%	53	272	270	-0.7%	265	-2.5%
313	Tsiigehtchic	370,559	360,870	-2.6%	356,019	-3.9%	71	383	374	-2.5%	369	-3.8%
314	Colville Lake	140,967	146,526	3.9%	148,576	5.4%	35	383	398	3.9%	404	5.3%
315	Ulukhatok	770,604	787,655	2.2%	795,647	3.2%	149	590	602	2.1%	608	3.1%
	Total	**43,009,351**	**45,305,360**	**5.3%**	**44,656,333**	**3.8%**	**6,419**	**18,271**	**18,889**	**3.4%**	**18,690**	**2.3%**

Table 2, BR.NTPC-4 b
Northwest Territories Power Corporation
Sales and Revenue Forecast Comparison
Rate Application to Average Use Per Customer Methodology
Residential Customer Class
2007/08

Plant No.	Plant Name	Sales Forecast from Application	Sales Forecast 4-Year Simple Average Use Per Customer	4-Year Simple Average	Sales Forecast 4-Year Weighted Average Use Per Customer	4-Year Weighted Average	Forecast Customer	Revenue Forecast from Application	Revenue Forecast 4-Year Simple Average	4-Year Simple Average	Revenue Forecast 4-Year Weighted Average	4-Year Simple Average
	Units	(kWh)	(kWh)	Variance	(kWh)	Variance	Count	($000s)	($000s)	Variance	($000s)	Variance
104	Wha Ti	829,623	836,676	0.9%	836,949	0.9%	128	665	670	0.8%	671	0.8%
105	Gameti	444,183	454,994	2.4%	453,820	2.2%	80	385	394	2.3%	393	2.1%
108	Behchoko	3,601,507	3,813,879	5.9%	3,783,263	5.0%	469	816	858	5.2%	852	4.4%
109	Dettah	598,769	626,784	4.7%	623,116	4.1%	89	138	144	4.0%	143	3.5%
110	Lutsel K'e	723,176	750,204	3.7%	736,580	1.9%	122	475	492	3.5%	484	1.8%
201	Ft Smith	9,299,298	10,231,686	10.0%	10,124,129	8.9%	1,004	1,345	1,458	8.4%	1,445	7.4%
203	Ft Resolution	1,363,999	1,374,655	0.8%	1,391,068	2.0%	210	237	238	0.6%	241	1.6%
205	Ft Simpson	2,896,091	2,940,394	1.5%	2,902,732	0.2%	497	1,173	1,189	1.4%	1,176	0.2%
206	Ft. Liard	1,037,262	1,024,615	-1.2%	1,018,168	-1.8%	171	452	447	-1.1%	445	-1.7%
207	Wrigley	255,880	273,217	6.8%	271,705	6.2%	52	211	224	6.4%	223	5.9%
208	Nahanni Butte	155,840	154,017	-1.2%	159,335	2.2%	35	157	155	-1.1%	160	2.1%
209	Jean Marie River	122,938	122,048	-0.7%	117,845	-4.1%	22	109	108	-0.7%	105	-4.0%
301	Inuvik	9,056,746	9,818,366	8.4%	9,429,393	4.1%	1,454	3,821	4,116	7.7%	3,965	3.8%
304	Norman Wells	2,952,355	2,865,211	-3.0%	2,902,425	-1.7%	376	992	965	-2.7%	976	-1.6%
305	Tuktoyaktuk	2,123,186	2,082,274	-1.9%	2,072,500	-2.4%	328	1,379	1,354	-1.8%	1,348	-2.3%
306	Ft. McPherson	1,515,429	1,574,421	3.9%	1,572,432	3.8%	278	861	892	3.6%	891	3.5%
307	Aklavik	1,255,524	1,346,944	7.3%	1,351,378	7.6%	246	773	826	6.8%	828	7.1%
308	Deline	1,151,740	1,174,460	2.0%	1,188,351	3.2%	210	712	725	1.8%	733	3.0%
309	Ft. Good Hope	1,255,079	1,204,479	-4.0%	1,208,430	-3.7%	193	845	812	-3.8%	815	-3.5%
310	Tulita	1,039,310	1,026,896	-1.2%	1,038,973	0.0%	164	870	860	-1.1%	870	0.0%
311	Paulatuk	500,235	562,000	12.3%	558,809	11.7%	91	491	550	11.9%	547	11.2%
312	Sachs harbour	265,166	256,180	-3.4%	255,014	-3.8%	53	271	262	-3.2%	261	-3.7%
313	Tsiigehtchic	384,538	361,451	-6.0%	358,018	-6.9%	72	397	374	-5.8%	371	-6.6%
314	Colville Lake	141,314	150,463	6.5%	151,367	7.1%	35	384	409	6.3%	411	7.0%
315	Ulukhatok	816,779	794,363	-2.7%	803,028	-1.7%	149	624	607	-2.6%	614	-1.6%
	Total	**43,785,966**	**45,820,677**	**4.6%**	**45,308,830**	**3.5%**	**6,531**	**18,582**	**19,130**	**2.9%**	**18,965**	**2.1%**

Table 4, BR.NTPC-4 b
Northwest Territories Power Corporation
Sales and Revenue Forecast Comparison
Rate Application to Average Use Per Customer Methodology
General Service Customer Class
2007/08

Plant No.	Plant Name	Sales Forecast from Application (kWh)	Sales Forecast 4-Year Simple Average Use Per Customer (kWh)	4-Year Simple Average Variance	Sales Forecast 4-Year Weighted Average Use Per Customer (kWh)	4-Year Weighted Average Variance	Forecast Customer Count	Revenue Forecast from Application ($000s)	Revenue Forecast 4-Year Simple Average ($000s)	4-Year Simple Average Variance	Revenue Forecast 4-Year Weighted Average ($000s)	4-Year Weighted Average Variance
104	Wha Ti	721,509	884,770	22.6%	880,331	22.0%	36	542	657	21.4%	654	20.8%
105	Gameti	387,572	422,611	9.0%	410,105	5.8%	22	410	446	8.7%	433	5.6%
108	Behchoko	2,846,072	2,773,671	-2.5%	2,820,341	-0.9%	90	834	816	-2.2%	828	-0.8%
109	Dettah	227,476	234,195	3.0%	227,480	0.0%	22	71	73	2.4%	71	0.0%
110	Lutsel K'e	696,640	727,060	4.4%	738,362	6.0%	40	421	439	4.1%	445	5.6%
201	Ft Smith	11,581,412	11,627,261	0.4%	11,682,146	0.9%	218	1,400	1,404	0.3%	1,408	0.6%
203	Ft Resolution	1,126,614	1,150,106	2.1%	1,144,752	1.6%	66	186	188	1.5%	188	1.1%
205	Ft Simpson	4,533,753	4,195,870	-7.5%	4,257,675	-6.1%	151	1,522	1,421	-6.6%	1,439	-5.4%
206	Ft. Liard	1,358,930	1,427,777	5.1%	1,419,399	4.4%	54	539	562	4.3%	560	3.8%
207	Wrigley	315,549	345,186	9.4%	335,372	6.3%	31	286	311	8.8%	303	5.9%
208	Nahanni Butte	137,737	183,114	32.9%	181,765	32.0%	16	188	247	31.5%	245	30.5%
209	Jean Marie River	110,845	111,066	0.2%	107,721	-2.8%	16	144	144	0.2%	140	-2.7%
301	Inuvik	18,642,829	18,269,110	-2.0%	18,413,770	-1.2%	461	6,615	6,495	-1.8%	6,542	-1.1%
304	Norman Wells	5,043,212	4,917,670	-2.5%	4,895,282	-2.9%	148	1,518	1,485	-2.2%	1,479	-2.6%
305	Tuktoyaktuk	1,682,401	1,638,846	-2.6%	1,633,023	-2.9%	82	980	957	-2.4%	954	-2.7%
306	Ft. McPherson	1,550,291	1,495,670	-3.5%	1,501,917	-3.1%	60	772	747	-3.3%	750	-2.9%
307	Aklavik	1,190,340	1,293,981	8.7%	1,286,432	8.1%	75	703	760	8.0%	755	7.5%
308	Deline	1,173,978	1,164,805	-0.8%	1,159,231	-1.3%	53	673	668	-0.7%	666	-1.2%
309	Ft. Good Hope	1,331,825	1,281,059	-3.8%	1,294,300	-2.8%	51	782	754	-3.6%	762	-2.6%
310	Tulita	821,009	852,290	3.8%	848,456	3.3%	61	675	700	3.6%	697	3.1%
311	Paulatuk	661,999	650,734	-1.7%	663,930	0.3%	36	611	601	-1.6%	613	0.3%
312	Sachs harbour	473,779	543,440	14.7%	532,776	12.5%	22	442	505	14.1%	495	11.9%
313	Tsiigehtchic	361,828	366,404	1.3%	365,078	0.9%	27	331	334	1.2%	333	0.9%
314	Colville Lake	134,230	110,557	-17.6%	111,131	-17.2%	10	323	267	-17.4%	269	-16.9%
315	Ulukhatok	974,350	982,926	0.9%	974,340	0.0%	50	681	687	0.8%	681	0.0%
	Total	**58,086,181**	**57,650,182**	**-0.8%**	**57,885,117**	**-0.3%**	**1,895**	**21,652**	**21,668**	**0.1%**	**21,709**	**0.3%**

Table 3, BR.NTPC-4 b
Northwest Territories Power Corporation
Sales and Revenue Forecast Comparison
Rate Application to Average Use Per Customer Methodology
General Service Customer Class
2006/07

Plant No.	Plant Name	Sales Forecast from Application (kWh)	Sales Forecast 4-Year Simple Average Use Per Customer (kWh)	4-Year Simple Average Variance	Sales Forecast 4-Year Weighted Average Use Per Customer (kWh)	4-Year Weighted Average Variance	Forecast Customer Count	Revenue Forecast from Application ($000s)	Revenue Forecast 4-Year Simple Average ($000s)	4-Year Simple Average Variance	Revenue Forecast 4 - Year Weighted Average ($000s)	4-Year Weighted Average Variance
104	Wha Ti	729,345	823,812	13.0%	815,979	11.9%	33	546	613	12.3%	607	11.3%
105	Gameti	400,550	424,879	6.1%	413,181	3.2%	22	424	448	5.8%	436	3.0%
108	Behchoko	2,925,170	2,795,532	-4.4%	2,878,690	-1.6%	91	855	822	-3.9%	843	-1.4%
109	Dettah	227,704	252,556	10.9%	235,708	3.5%	22	71	78	8.9%	73	2.9%
110	Lutsel K'e	686,345	700,117	2.0%	707,684	3.1%	38	414	422	1.9%	426	2.9%
201	Ft Smith	11,466,745	11,663,272	1.7%	11,691,400	2.0%	219	1,392	1,409	1.2%	1,411	1.4%
203	Ft Resolution	1,110,883	1,147,964	3.3%	1,132,848	2.0%	66	184	188	2.4%	186	1.4%
205	Ft Simpson	4,423,201	4,218,373	-4.6%	4,265,944	-3.6%	152	1,490	1,428	-4.1%	1,443	-3.2%
206	Ft. Liard	1,446,067	1,497,844	3.6%	1,480,793	2.4%	56	571	588	3.1%	583	2.0%
207	Wrigley	342,632	350,636	2.3%	338,777	-1.1%	30	310	317	2.2%	306	-1.1%
208	Nahanni Butte	154,989	179,151	15.6%	176,952	14.2%	15	210	241	15.0%	239	13.6%
209	Jean Marie River	108,672	108,956	0.3%	106,144	-2.3%	15	141	141	0.2%	138	-2.2%
301	Inuvik	18,458,246	18,152,620	-1.7%	18,455,951	0.0%	463	6,558	6,459	-1.5%	6,557	0.0%
304	Norman Wells	4,849,242	4,811,300	-0.8%	4,877,821	0.6%	147	1,467	1,457	-0.7%	1,474	0.5%
305	Tuktoyaktuk	1,695,709	1,639,290	-3.3%	1,642,337	-3.1%	82	989	958	-3.1%	960	-2.9%
306	Ft. McPherson	1,594,999	1,522,849	-4.5%	1,531,882	-4.0%	61	794	761	-4.2%	765	-3.7%
307	Aklavik	1,186,779	1,251,620	5.5%	1,272,231	7.2%	74	700	736	5.0%	747	6.7%
308	Deline	1,172,806	1,164,349	-0.7%	1,174,939	0.2%	54	673	669	-0.7%	674	0.2%
309	Ft. Good Hope	1,335,543	1,306,166	-2.2%	1,317,254	-1.4%	52	785	769	-2.1%	775	-1.3%
310	Tulita	828,621	845,670	2.1%	842,738	1.7%	60	681	694	1.9%	692	1.6%
311	Paulatuk	649,301	655,986	1.0%	667,834	2.9%	37	600	606	1.0%	617	2.7%
312	Sachs harbour	494,576	530,625	7.3%	525,842	6.3%	22	461	493	7.0%	489	6.1%
313	Tsiigehtchic	351,631	363,547	3.4%	365,426	3.9%	27	322	332	3.2%	334	3.7%
314	Colville Lake	131,598	112,506	-14.5%	114,973	-12.6%	10	317	272	-14.3%	278	-12.4%
315	Ulukhatok	934,558	983,290	5.2%	975,130	4.3%	50	656	688	4.9%	682	4.1%
	Total Sales	**57,705,912**	**57,502,911**	**-0.4%**	**58,008,458**	**0.5%**	**1,898**	**21,610**	**21,589**	**-0.1%**	**21,736**	**0.6%**

Table 5, BR.NTPC-4 d
Northwest Territories Power Corporation
Cost and Revenue Implications of Simple Average Use per Customer Load Forecasting
Residential Customers
2006/07

			Cost Component								Revenue Component						
		Column	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Line no.	Plant No.	Plant Name	Incremental Sales	Incremental Line Losses	Total Incremental Generation	GRA Fuel Efficiency	GRA Fuel Price	Incemental Fuel Expense	GRA Revenue Requirement per Refiling	Revenue Requirement with 4-year Avg Sales Adjustment	Other Revenues	Revenue At Existing Rates	Revenue with 4-year Average Sales at Existing Rates	Shortfall per Refiling	Shortfall with 4-year Avg Sales Adjustment	Change in Shortfall	Change in Shortfall as % of Community Revenue Requirement
		Units	(kWh)	(kWh)	(kWh)	(kWh/L)	($/L)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	(%)
		Calculation			A+B			C/D x E		F+G				G-I-J	H-I-K	L - M	
1	101	Snare	498,447	18,357	516,804	n/a	n/a	$ -	$ 26,888	$ 26,888	$ 138	$ 22,587	$ 22,686	$ 4,163	$ 4,064	$ 99	0.4%
2	104	Wha Ti	10,387	789	11,176	3.711	0.891	$ 3	$ 1,265	$ 1,267	$ 13	$ 1,227	$ 1,235	$ 25	$ 20	$ 5	0.4%
3	105	Gameti	19,483	974	20,457	3.398	0.904	$ 5	$ 1,025	$ 1,030	$ 13	$ 822	$ 838	$ 190	$ 179	$ 11	1.0%
4	108	Behchoko	484,546	17,845	502,390	n/a	n/a	$ -	n/a	n/a						$ -	
5	109	Dettah	13,901	512	14,413	n/a	n/a	$ -	n/a	n/a						$ -	
6	110	Lutsel K'e	54,179	3,433	57,612	3.778	0.847	$ 13	$ 1,026	$ 1,039	$ 7	$ 909	$ 943	$ 110	$ 90	$ 21	2.0%
7	201	Taltson	946,633	73,114	1,019,747	n/a	n/a	$ -	$ 6,369	$ 6,369	$ 121	$ 4,832	$ 4,947	$ 1,417	$ 1,302	$ 115	1.8%
8	201	Ft Smith	925,949	71,516	997,465	n/a	n/a	$ -	n/a	n/a						$ -	
9	203	Ft Resolution	20,685	1,598	22,282	n/a	n/a	$ -	n/a	n/a						$ -	
10	205	Ft Simpson	46,640	2,799	49,440	3.755	0.817	$ 11	$ 4,736	$ 4,747	$ 50	$ 2,717	$ 2,734	$ 1,969	$ 1,963	$ 6	0.1%
11	206	Ft. Liard	(14,249)	(1,083)	(15,333)	3.725	0.843	$ (3)	$ 1,682	$ 1,678	$ 13	$ 1,060	$ 1,054	$ 608	$ 610	$ (2)	(0.1%)
12	207	Wrigley	1,340	92	1,431	3.525	0.865	$ 0	$ 858	$ 858	$ 10	$ 571	$ 572	$ 277	$ 276	$ 1	0.1%
13	208	Nahanni Butte	(3,294)	(261)	(3,555)	2.511	0.816	$ (1)	$ 612	$ 610	$ 6	$ 385	$ 382	$ 221	$ 223	$ (2)	(0.3%)
14	209	Jean Marie River	(1,895)	(150)	(2,046)	2.749	0.802	$ (1)	$ 449	$ 448	$ 5	$ 266	$ 264	$ 178	$ 179	$ (1)	(0.2%)
15	301	Inuvik - Gas	650,884	43,762	694,646	3.399	0.430	$ 88	$ 13,602	$ 13,698	$ 288	$ 10,428	$ 10,693	$ 2,886	$ 2,717	$ 169	1.2%
16		Inuvik - Diesel	34,257	2,303	36,560	3.635	0.792	$ 8									
17	304	Norman Wells	(81,970)	(6,202)	(88,172)	n/a	0.279	$ (25)	$ 3,108	$ 3,084	$ 32	$ 2,485	$ 2,460	$ 592	$ 592	$ (1)	(0.0%)
18	305	Tuktoyaktuk	3,183	250	3,434	3.697	0.929	$ 1	$ 2,482	$ 2,483	$ 94	$ 2,396	$ 2,398	$ (8)	$ (9)	$ 1	0.0%
19	306	Ft. McPherson	36,638	1,691	38,329	3.609	0.889	$ 9	$ 2,173	$ 2,183	$ 21	$ 1,693	$ 1,712	$ 459	$ 449	$ 10	0.5%
20	307	Aklavik	98,737	6,244	104,981	3.475	0.895	$ 27	$ 1,288	$ 1,315	$ 20	$ 1,516	$ 1,573	$ (247)	$ (277)	$ 30	2.3%
21	308	Deline	(585)	(45)	(629)	3.546	0.835	$ (0)	$ 1,633	$ 1,632	$ 14	$ 1,399	$ 1,399	$ 219	$ 220	$ (0)	(0.0%)
22	309	Ft. Good Hope	(53,837)	(3,139)	(56,976)	3.576	0.948	$ (15)	$ 1,743	$ 1,727	$ 12	$ 1,658	$ 1,624	$ 72	$ 92	$ (19)	(1.1%)
23	310	Tulita	(16,761)	(1,327)	(18,087)	3.634	0.886	$ (4)	$ 1,638	$ 1,633	$ 13	$ 1,564	$ 1,551	$ 61	$ 70	$ (9)	(0.6%)
24	311	Paulatuk	56,849	4,447	61,295	3.492	1.107	$ 19	$ 1,342	$ 1,361	$ 9	$ 1,109	$ 1,163	$ 224	$ 190	$ 34	2.5%
25	312	Sachs harbour	(1,977)	(105)	(2,082)	3.189	0.948	$ (1)	$ 944	$ 943	$ 7	$ 766	$ 764	$ 171	$ 172	$ (1)	(0.1%)
26	313	Tsiigehtchic	(9,689)	(723)	(10,412)	3.537	0.944	$ (3)	$ 755	$ 753	$ 10	$ 733	$ 723	$ 12	$ 19	$ (7)	(0.9%)
27	314	Colville Lake	5,559	422	5,980	2.957	0.795	$ 2	$ 624	$ 626	$ 6	$ 736	$ 751	$ (118)	$ (131)	$ 13	2.1%
28	315	Ulukhatok	17,051	1,029	18,080	3.616	1.102	$ 6	$ 1,270	$ 1,276	$ 13	$ 1,269	$ 1,281	$ (12)	$ (19)	$ 7	0.5%
29		**Total**	**2,296,009**	**146,671**	**2,442,680**			**$ 139**	**$ 77,511**	**$ 77,650**	**$ 914**	**$ 63,128**	**$ 63,747**	**$ 13,468**	**$ 12,989**	**$ 480**	**0.6%**
								Increase in Revenue Requirement		**$ 139**							

Table 6, BR.NTPC-4 d
Northwest Territories Power Corporation
Cost and Revenue Implications of Simple Average Use per Customer Load Forecasting
Residential Customers
2007/08

			Cost Component								Revenue Component						
		Column	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Line no.	Plant No.	Plant Name	Incremental Sales	Incremental Line Losses	Total Incremental Generation	GRA Fuel Efficiency	GRA Fuel Price	Incemental Fuel Expense	GRA Revenue Requirement per Refiling	Revenue Requirement with 4-year Avg Sales Adjustment	Other Revenues	Revenue At Existing Rates	Revenue with 4-year Average Sales at Existing Rates	Shortfall per Refiling	Shortfall with 4-year Avg Sales Adjustment	Change in Shortfall	Change in Shortfall as % of Community Revenue Requirement
		Units	(kWh)	(kWh)	(kWh)	(kWh/L)	($/L)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	(%)
		Calculation			A+B			C/D x E		F+G				G-I-J	H-I-K	L - M	
1	101	Snare	240,386	10,024	250,410	n/a	n/a	$ -	$ 28,200	$ 28,200	$ 138	22,739	$ 22,787	$ 5,323	$ 5,275	$ 48	0.2%
2	104	Wha Ti	7,053	536	7,589	3.711	0.897	$ 2	$ 1,320	$ 1,322	$ 13	1,234	$ 1,239	$ 73	$ 70	$ 4	0.3%
3	105	Gameti	10,811	541	11,352	3.398	0.927	$ 3	$ 1,073	$ 1,076	$ 13	814	$ 823	$ 246	$ 240	$ 6	0.5%
4	108	Behchoko	212,372	8,855	221,227	n/a	n/a	$ -	n/a	n/a						$ -	
5	109	Dettah	28,015	1,168	29,183	n/a	n/a	$ -	n/a	n/a						$ -	
6	110	Lutsel K'e	27,028	1,713	28,741	3.778	0.896	$ 7	$ 1,091	$ 1,098	$ 7	929	$ 945	$ 156	$ 146	$ 10	0.9%
7	201	Taltson	943,045	72,760	1,015,805	n/a	n/a	$ -	$ 6,681	$ 6,681	$ 141	4,877	$ 4,992	$ 1,663	$ 1,549	$ 115	1.7%
8	201	Ft Smith	932,389	71,938	1,004,327	n/a	n/a	$ -	n/a	n/a						$ -	
9	203	Ft Resolution	10,656	822	11,478	n/a	n/a	$ -	n/a	n/a						$ -	
10	205	Ft Simpson	44,303	2,659	46,962	3.755	0.862	$ 11	$ 5,252	$ 5,263	$ 50	2,749	$ 2,766	$ 2,453	$ 2,447	$ 6	0.1%
11	206	Ft. Liard	(12,647)	(961)	(13,608)	3.725	0.877	$ (3)	$ 1,707	$ 1,704	$ 13	1,025	$ 1,020	$ 668	$ 670	$ (2)	(0.1%)
12	207	Wrigley	17,337	1,187	18,524	3.525	0.885	$ 5	$ 886	$ 890	$ 10	532	$ 545	$ 344	$ 335	$ 9	1.0%
13	208	Nahanni Butte	(1,823)	(144)	(1,968)	2.511	0.877	$ (1)	$ 632	$ 631	$ 6	363	$ 361	$ 264	$ 265	$ (1)	(0.2%)
14	209	Jean Marie River	(890)	(70)	(961)	2.749	0.858	$ (0)	$ 484	$ 484	$ 5	271	$ 270	$ 208	$ 208	$ (0)	(0.1%)
15	301	Inuvik - Gas	723,540	48,647	772,187	3.399	0.430	$ 98	$ 14,471	$ 14,578	$ 288	10,563	$ 10,858	$ 3,620	$ 3,432	$ 188	1.3%
16		Inuvik - Diesel	38,081	2,560	40,641	3.635	0.797	$ 9									
17	304	Norman Wells	(87,144)	(6,598)	(93,742)	n/a	0.279	$ (26)	$ 3,236	$ 3,210	$ 32	2,562	$ 2,535	$ 642	$ 643	$ (1)	(0.0%)
18	305	Tuktoyaktuk	(40,912)	(3,223)	(44,135)	3.697	1.001	$ (12)	$ 2,645	$ 2,633	$ 22	2,418	$ 2,393	$ 205	$ 218	$ (13)	(0.5%)
19	306	Ft. McPherson	58,992	2,723	61,714	3.609	0.926	$ 16	$ 2,250	$ 2,266	$ 21	1,670	$ 1,701	$ 560	$ 545	$ 15	0.7%
20	307	Aklavik	91,419	5,781	97,201	3.475	0.914	$ 26	$ 1,678	$ 1,704	$ 20	1,520	$ 1,572	$ 138	$ 111	$ 27	1.6%
21	308	Deline	22,720	1,743	24,463	3.546	1.015	$ 7	$ 1,792	$ 1,799	$ 14	1,401	$ 1,414	$ 376	$ 370	$ 6	0.3%
22	309	Ft. Good Hope	(50,600)	(2,950)	(53,550)	3.576	1.001	$ (15)	$ 1,800	$ 1,785	$ 12	1,670	$ 1,638	$ 117	$ 134	$ (17)	(1.0%)
23	310	Tulita	(12,414)	(983)	(13,397)	3.634	0.905	$ (3)	$ 1,684	$ 1,680	$ 13	1,579	$ 1,569	$ 91	$ 98	$ (7)	(0.4%)
24	311	Paulatuk	61,765	4,825	66,590	3.492	1.090	$ 21	$ 1,374	$ 1,395	$ 9	1,129	$ 1,188	$ 235	$ 198	$ 37	2.7%
25	312	Sachs harbour	(8,986)	(479)	(9,465)	3.189	1.075	$ (3)	$ 1,008	$ 1,005	$ 7	746	$ 737	$ 254	$ 260	$ (6)	(0.6%)
26	313	Tsiigehtchic	(23,087)	(1,723)	(24,810)	3.537	0.985	$ (7)	$ 815	$ 808	$ 10	755	$ 732	$ 49	$ 65	$ (16)	(2.0%)
27	314	Colville Lake	9,148	692	9,841	2.957	1.133	$ 4	$ 684	$ 688	$ 6	743	$ 767	$ (65)	$ (85)	$ 21	3.0%
28	315	Ulukhatok	(22,416)	(1,352)	(23,768)	3.616	1.111	$ (7)	$ 1,310	$ 1,302	$ 13	1,328	$ 1,312	$ (32)	$ (23)	$ (9)	(0.7%)
29		**Total**	**2,034,710**	**137,906**	**2,172,616**			**129**	**$ 82,070**	**$ 82,199**	**$ 862**	**$ 63,618**	**$ 64,166**	**$ 17,590**	**$ 17,171**	**$ 419**	**0.5%**
								Increase in Revenue Requirement		**$ 129**							

Table 7, BR.NTPC-4 d
Northwest Territories Power Corporation
Cost and Revenue Implications of Simple Average Use per Customer Load Forecasting
General Service Customers
2006/07

			Cost Component								Revenue Component						
		Column	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Line no.	Plant No.	Plant Name	Incremental Sales	Incremental Line Losses	Total Incremental Generation	GRA Fuel Efficiency	GRA Fuel Price	Incemental Fuel Expense	GRA Revenue Requirement per Refiling	Revenue Requirement with 4-year Avg Sales Adjustment	Other Revenues	Revenue At Existing Rates	Revenue with 4-year Average Sales at Existing Rates	Shortfall per Refiling	Shortfall with 4-year Avg Sales Adjustment	Change in Shortfall	Change in Shortfall as % of Community Revenue Requirement
		Units	(kWh)	(kWh)	(kWh)	(kWh/L)	($/L)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	(%)
		Calculation			A+B			C/D x E		F+G				G-I-J	H-I-K	L - M	
1	101	Snare	(104,786)	(3,859)	(108,645)	n/a	n/a	$ -	$ 26,888	$ 26,888	$ 138	$ 22,587	$ 22,560	$ 4,163	$ 4,189	$ (27)	(0.1%)
2	104	Wha Ti	94,467	7,180	101,647	3.711	0.891	$ 24	$ 1,265	$ 1,289	$ 13	$ 1,227	$ 1,294	$ 25	$ (18)	$ 43	3.4%
3	105	Gameti	24,329	1,217	25,546	3.398	0.904	$ 7	$ 1,025	$ 1,031	$ 13	$ 822	$ 847	$ 190	$ 172	$ 18	1.7%
4	108	Behchoko	(129,638)	(4,774)	(134,412)	n/a	n/a	$ -	n/a	n/a						$ -	
5	109	Dettah	24,852	915	25,767	n/a	n/a	$ -	n/a	n/a						$ -	
6	110	Lutsel K'e	13,772	873	14,644	3.778	0.847	$ 3	$ 1,026	$ 1,029	$ 7	$ 909	$ 917	$ 110	$ 106	$ 5	0.4%
7	201	Taltson	233,609	18,043	251,652	n/a	n/a	$ -	$ 6,369	$ 6,369	$ 121	$ 4,832	$ 4,853	$ 1,417	$ 1,395	$ 21	0.3%
8	201	Ft Smith	196,528	15,179	211,707	n/a	n/a	$ -	n/a	n/a						$ -	
9	203	Ft Resolution	37,081	2,864	39,945	n/a	n/a	$ -	n/a	n/a						$ -	
10	205	Ft Simpson	(204,828)	(12,294)	(217,122)	3.755	0.817	$ (47)	$ 4,736	$ 4,689	$ 50	$ 2,717	$ 2,656	$ 1,969	$ 1,983	$ (14)	(0.3%)
11	206	Ft. Liard	51,777	3,937	55,714	3.725	0.843	$ 13	$ 1,682	$ 1,694	$ 13	$ 1,060	$ 1,077	$ 608	$ 603	$ 5	0.3%
12	207	Wrigley	8,004	548	8,552	3.525	0.865	$ 2	$ 858	$ 860	$ 10	$ 571	$ 578	$ 277	$ 272	$ 5	0.5%
13	208	Nahanni Butte	24,162	1,913	26,075	2.511	0.816	$ 8	$ 612	$ 620	$ 6	$ 385	$ 416	$ 221	$ 198	$ 23	3.8%
14	209	Jean Marie River	284	22	306	2.749	0.802	$ 0	$ 449	$ 449	$ 5	$ 266	$ 266	$ 178	$ 177	$ 0	0.1%
15	301	Inuvik - Gas	(290,345)	(19,521)	(309,866)	3.399	0.430	$ (39)	$ 13,602	$ 13,559	$ 288	$ 10,428	$ 10,330	$ 2,886	$ 2,942	$ (56)	(0.4%)
16		Inuvik - Diesel	(15,281)	(1,027)	(16,309)	3.635	0.792	$ (4)									
17	304	Norman Wells	(37,942)	(2,871)	(40,813)	n/a	0.279	$ (11)	$ 3,108	$ 3,097	$ 32	$ 2,485	$ 2,475	$ 592	$ 591	$ 1	0.0%
18	305	Tuktoyaktuk	(56,419)	(4,439)	(60,858)	3.697	0.929	$ (15)	$ 2,482	$ 2,467	$ 94	$ 2,396	$ 2,366	$ (8)	$ 7	$ (15)	(0.6%)
19	306	Ft. McPherson	(72,150)	(3,330)	(75,480)	3.609	0.889	$ (19)	$ 2,173	$ 2,154	$ 21	$ 1,693	$ 1,660	$ 459	$ 474	$ (15)	(0.7%)
20	307	Aklavik	64,840	4,101	68,941	3.475	0.895	$ 18	$ 1,288	$ 1,306	$ 20	$ 1,516	$ 1,551	$ (247)	$ (265)	$ 18	1.4%
21	308	Deline	(8,457)	(649)	(9,106)	3.546	0.835	$ (2)	$ 1,633	$ 1,630	$ 14	$ 1,399	$ 1,394	$ 219	$ 222	$ (2)	(0.1%)
22	309	Ft. Good Hope	(29,377)	(1,713)	(31,090)	3.576	0.948	$ (8)	$ 1,743	$ 1,734	$ 12	$ 1,658	$ 1,642	$ 72	$ 80	$ (8)	(0.5%)
23	310	Tulita	17,049	1,349	18,399	3.634	0.886	$ 4	$ 1,638	$ 1,642	$ 13	$ 1,564	$ 1,577	$ 61	$ 52	$ 9	0.5%
24	311	Paulatuk	6,685	523	7,208	3.492	1.107	$ 2	$ 1,342	$ 1,344	$ 9	$ 1,109	$ 1,115	$ 224	$ 220	$ 4	0.3%
25	312	Sachs harbour	36,050	1,922	37,972	3.189	0.948	$ 11	$ 944	$ 955	$ 7	$ 766	$ 798	$ 171	$ 150	$ 21	2.2%
26	313	Tsiigehtchic	11,916	889	12,805	3.537	0.944	$ 3	$ 755	$ 759	$ 10	$ 733	$ 743	$ 12	$ 5	$ 7	0.9%
27	314	Colville Lake	(19,092)	(1,448)	(20,540)	2.957	0.795	$ (6)	$ 624	$ 619	$ 6	$ 736	$ 691	$ (118)	$ (78)	$ (40)	(6.4%)
28	315	Ulukhatok	48,731	2,940	51,671	3.616	1.102	$ 16	$ 1,270	$ 1,286	$ 13	$ 1,269	$ 1,301	$ (12)	$ (28)	$ 16	1.3%
29		**Total**	**(203,001)**	**(5,695)**	**(208,696)**			**$ (38)**	**$ 77,511**	**$ 77,472**	**$ 914**	**$ 63,128**	**$ 63,108**	**$ 13,468**	**$ 13,450**	**$ 18**	**0.0%**
								Decrease in Revenue Requirement		**$ (38)**							

Table 8, BR.NTPC-4 d
Northwest Territories Power Corporation
Cost and Revenue Implications of Simple Average Use per Customer Load Forecasting
General Service Customers
2007/08

			Cost Component								Revenue Component						
		Column	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Line no.	Plant No.	Plant Name	Incremental Sales	Incremental Line Losses	Total Incremental Generation	GRA Fuel Efficiency	GRA Fuel Price	Incemental Fuel Expense	GRA Revenue Requirement per Refiling	Revenue Requirement with 4-year Avg Sales Adjustment	Other Revenues	Revenue At Existing Rates	Revenue with 4-year Average Sales at Existing Rates	Shortfall per Refiling	Shortfall with 4-year Avg Sales Adjustment	Change in Shortfall	Change in Shortfall as % of Community Revenue Requirement
		Units	(kWh)	(kWh)	(kWh)	(kWh/L)	($/L)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	(%)
		Calculation			A+B			C/D x E		F+G				G-I-J	H-I-K	L - M	
1	101	Snare	(65,682)	(2,739)	(68,420)	n/a	n/a	$ -	$ 28,200	$ 28,200	$ 138	22,739	$ 22,722	$ 5,323	$ 5,339	$ (17)	(0.1%)
2	104	Wha Ti	163,261	12,408	175,669	3.711	0.897	$ 42	$ 1,320	$ 1,362	$ 13	1,234	$ 1,349	$ 73	$ 0	$ 73	5.6%
3	105	Gameti	35,039	1,752	36,791	3.398	0.927	$ 10	$ 1,073	$ 1,083	$ 13	814	$ 850	$ 246	$ 220	$ 26	2.4%
4	108	Behchoko	(72,400)	(3,019)	(75,419)	n/a	n/a	$ -	n/a	n/a						$ -	
5	109	Dettah	6,719	280	6,999	n/a	n/a	$ -	n/a	n/a						$ -	
6	110	Lutsel K'e	30,420	1,927	32,348	3.778	0.896	$ 8	$ 1,091	$ 1,099	$ 7	929	$ 946	$ 156	$ 146	$ 10	0.9%
7	201	Taltson	69,342	5,350	74,692	n/a	n/a	$ -	$ 6,681	$ 6,681	$ 141	4,877	$ 4,884	$ 1,663	$ 1,657	$ 7	0.1%
8	201	Ft Smith	45,849	3,537	49,387	n/a	n/a	$ -	n/a	n/a						$ -	
9	203	Ft Resolution	23,493	1,813	25,305	n/a	n/a	$ -	n/a	n/a						$ -	
10	205	Ft Simpson	(337,883)	(20,280)	(358,163)	3.755	0.862	$ (82)	$ 5,252	$ 5,170	$ 50	2,749	$ 2,648	$ 2,453	$ 2,471	$ (19)	(0.4%)
11	206	Ft. Liard	68,847	5,234	74,081	3.725	0.877	$ 17	$ 1,707	$ 1,724	$ 13	1,025	$ 1,049	$ 668	$ 662	$ 6	0.3%
12	207	Wrigley	29,637	2,029	31,666	3.525	0.885	$ 8	$ 886	$ 894	$ 10	532	$ 557	$ 344	$ 327	$ 17	1.9%
13	208	Nahanni Butte	45,377	3,594	48,970	2.511	0.877	$ 17	$ 632	$ 649	$ 6	363	$ 422	$ 264	$ 222	$ 42	6.6%
14	209	Jean Marie River	220	17	238	2.749	0.858	$ 0	$ 484	$ 484	$ 5	271	$ 271	$ 208	$ 208	$ 0	0.0%
15	301	Inuvik - Gas	(355,032)	(23,871)	(378,903)	3.399	0.430	$ (48)	$ 14,471	$ 14,419	$ 288	10,563	$ 10,443	$ 3,620	$ 3,688	$ (68)	(0.5%)
16		Inuvik - Diesel	(18,686)	(1,256)	(19,942)	3.635	0.797	$ (4)									
17	304	Norman Wells	(125,542)	(9,506)	(135,048)	n/a	0.279	$ (38)	$ 3,236	$ 3,198	$ 32	2,562	$ 2,528	$ 642	$ 638	$ 4	0.1%
18	305	Tuktoyaktuk	(43,555)	(3,431)	(46,986)	3.697	1.001	$ (13)	$ 2,645	$ 2,633	$ 22	2,418	$ 2,395	$ 205	$ 216	$ (11)	(0.4%)
19	306	Ft. McPherson	(54,621)	(2,521)	(57,142)	3.609	0.926	$ (15)	$ 2,250	$ 2,236	$ 21	1,670	$ 1,644	$ 560	$ 570	$ (11)	(0.5%)
20	307	Aklavik	103,642	6,554	110,196	3.475	0.914	$ 29	$ 1,678	$ 1,707	$ 20	1,520	$ 1,576	$ 138	$ 111	$ 28	1.6%
21	308	Deline	(9,173)	(704)	(9,877)	3.546	1.015	$ (3)	$ 1,792	$ 1,789	$ 14	1,401	$ 1,396	$ 376	$ 378	$ (2)	(0.1%)
22	309	Ft. Good Hope	(50,766)	(2,960)	(53,726)	3.576	1.001	$ (15)	$ 1,800	$ 1,785	$ 12	1,670	$ 1,642	$ 117	$ 130	$ (13)	(0.7%)
23	310	Tulita	31,282	2,476	33,758	3.634	0.905	$ 8	$ 1,684	$ 1,692	$ 13	1,579	$ 1,604	$ 91	$ 76	$ 16	0.9%
24	311	Paulatuk	(11,265)	(880)	(12,145)	3.492	1.090	$ (4)	$ 1,374	$ 1,370	$ 9	1,129	$ 1,119	$ 235	$ 242	$ (6)	(0.4%)
25	312	Sachs harbour	69,661	3,714	73,375	3.189	1.075	$ 25	$ 1,008	$ 1,032	$ 7	746	$ 809	$ 254	$ 217	$ 38	3.7%
26	313	Tsiigehtchic	4,576	342	4,917	3.537	0.985	$ 1	$ 815	$ 816	$ 10	755	$ 759	$ 49	$ 46	$ 3	0.3%
27	314	Colville Lake	(23,673)	(1,792)	(25,464)	2.957	1.133	$ (10)	$ 684	$ 674	$ 6	743	$ 686	$ (65)	$ (18)	$ (46)	(6.8%)
28	315	Ulukhatok	8,576	517	9,093	3.616	1.111	$ 3	$ 1,310	$ 1,312	$ 13	1,328	$ 1,334	$ (32)	$ (34)	$ 3	0.2%
29		**Total**	**(435,998)**	**(24,023)**	**(460,022)**			**(62)**	**$ 82,070**	**$ 82,008**	**$ 862**	**$ 63,618**	**$ 63,635**	**$ 17,590**	**$ 17,512**	**$ 78**	**0.1%**
								Decrease in Revenue Requirement		**$ (62)**							

Table 9, BR.NTPC-4 d
Northwest Territories Power Corporation
Cost and Revenue Implications of Weighted Average Use per Customer Load Forecasting
Residential Customers
2006/07

			Cost Component								Revenue Component						
		Column	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Line no.	Plant No.	Plant Name	Incremental Sales	Incremental Line Losses	Total Incremental Generation	GRA Fuel Efficiency	GRA Fuel Price	Incemental Fuel Expense	GRA Revenue Requirement per Refiling	Revenue Requirement with 4-year Weighted Avg Sales Adjustment	Other Revenues	Revenue At Existing Rates	Revenue with 4-year Weighted Average Sales at Existing Rates	Shortfall per Refiling	Shortfall with 4-year Weighted Avg Sales Adjustment	Change in Shortfall	Change in Shortfall as % of Community Revenue Requirement
		Units	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	(%)
		Calculation			A+B			C/D x E		F+G				G-I-J	H-I-K	L - M	
1	101	Snare	415,774	15,312	431,087	n/a	n/a	$ -	$ 26,888	$ 26,888	$ 138	$ 22,587	$ 22,669	$ 4,163	$ 4,080	$ 82	0.3%
2	104	Wha Ti	2,260	172	2,432	3.711	0.891	$ 1	$ 1,265	$ 1,265	$ 13	$ 1,227	$ 1,229	$ 25	$ 24	$ 1	0.1%
3	105	Gameti	11,847	593	12,440	3.398	0.904	$ 3	$ 1,025	$ 1,028	$ 13	$ 822	$ 832	$ 190	$ 183	$ 6	0.6%
4	108	Behchoko	407,459	15,006	422,465	n/a	n/a	$ -	n/a	n/a						$ -	
5	109	Dettah	8,315	306	8,622	n/a	n/a	$ -	n/a	n/a						$ -	
6	110	Lutsel K'e	27,297	1,730	29,027	3.778	0.847	$ 7	$ 1,026	$ 1,032	$ 7	$ 909	$ 926	$ 110	$ 100	$ 10	1.0%
7	201	Taltson	769,644	59,444	829,088	n/a	n/a	$ -	$ 6,369	$ 6,369	$ 121	$ 4,832	$ 4,926	$ 1,417	$ 1,323	$ 94	1.5%
8	201	Ft Smith	758,660	58,596	817,256	n/a	n/a	$ -	n/a	n/a						$ -	
9	203	Ft Resolution	10,984	848	11,832	n/a	n/a	$ -	n/a	n/a						$ -	
10	205	Ft Simpson	(149)	(9)	(158)	3.755	0.817	$ (0)	$ 4,736	$ 4,736	$ 50	$ 2,717	$ 2,717	$ 1,969	$ 1,969	$ (0)	(0.0%)
11	206	Ft. Liard	(23,799)	(1,810)	(25,609)	3.725	0.843	$ (6)	$ 1,682	$ 1,676	$ 13	$ 1,060	$ 1,050	$ 608	$ 612	$ (4)	(0.2%)
12	207	Wrigley	(1,965)	(135)	(2,100)	3.525	0.865	$ (1)	$ 858	$ 857	$ 10	$ 571	$ 569	$ 277	$ 278	$ (1)	(0.1%)
13	208	Nahanni Butte	1,216	96	1,312	2.511	0.816	$ 0	$ 612	$ 612	$ 6	$ 385	$ 386	$ 221	$ 220	$ 1	0.1%
14	209	Jean Marie River	(4,996)	(396)	(5,392)	2.749	0.802	$ (2)	$ 449	$ 447	$ 5	$ 266	$ 262	$ 178	$ 180	$ (3)	(0.6%)
15	301	Inuvik - Gas	306,725	20,623	327,348	3.399	0.430	$ 41	$ 13,602	$ 13,647	$ 288	$ 10,428	$ 10,553	$ 2,886	$ 2,807	$ 80	0.6%
16		Inuvik - Diesel	16,143	1,085	17,229	3.635	0.792	$ 4									
17	304	Norman Wells	(23,265)	(1,760)	(25,025)	n/a	0.279	$ (7)	$ 3,108	$ 3,101	$ 32	$ 2,485	$ 2,478	$ 592	$ 592	$ (0)	(0.0%)
18	305	Tuktoyaktuk	(12,323)	(970)	(13,293)	3.697	0.929	$ (3)	$ 2,482	$ 2,479	$ 94	$ 2,396	$ 2,388	$ (8)	$ (4)	$ (4)	(0.2%)
19	306	Ft. McPherson	34,638	1,599	36,237	3.609	0.889	$ 9	$ 2,173	$ 2,182	$ 21	$ 1,693	$ 1,711	$ 459	$ 450	$ 9	0.4%
20	307	Aklavik	93,672	5,924	99,596	3.475	0.895	$ 26	$ 1,288	$ 1,314	$ 20	$ 1,516	$ 1,570	$ (247)	$ (276)	$ 28	2.2%
21	308	Deline	15,948	1,223	17,171	3.546	0.835	$ 4	$ 1,633	$ 1,637	$ 14	$ 1,399	$ 1,408	$ 219	$ 214	$ 5	0.3%
22	309	Ft. Good Hope	(44,196)	(2,577)	(46,772)	3.576	0.948	$ (12)	$ 1,743	$ 1,730	$ 12	$ 1,658	$ 1,630	$ 72	$ 88	$ (16)	(0.9%)
23	310	Tulita	(715)	(57)	(772)	3.634	0.886	$ (0)	$ 1,638	$ 1,638	$ 13	$ 1,564	$ 1,563	$ 61	$ 61	$ (0)	(0.0%)
24	311	Paulatuk	51,961	4,064	56,025	3.492	1.107	$ 18	$ 1,342	$ 1,360	$ 9	$ 1,109	$ 1,158	$ 224	$ 193	$ 31	2.3%
25	312	Sachs harbour	(6,847)	(365)	(7,212)	3.189	0.948	$ (2)	$ 944	$ 942	$ 7	$ 766	$ 759	$ 171	$ 175	$ (5)	(0.5%)
26	313	Tsiigehtchic	(14,540)	(1,085)	(15,625)	3.537	0.944	$ (4)	$ 755	$ 751	$ 10	$ 733	$ 719	$ 12	$ 22	$ (10)	(1.4%)
27	314	Colville Lake	7,609	577	8,186	2.957	0.795	$ 2	$ 624	$ 626	$ 6	$ 736	$ 756	$ (118)	$ (136)	$ 18	2.9%
28	315	Ulukhatok	25,043	1,511	26,554	3.616	1.102	$ 8	$ 1,270	$ 1,278	$ 13	$ 1,269	$ 1,287	$ (12)	$ (22)	$ 10	0.8%
29		**Total**	**1,646,982**	**104,790**	**1,751,773**			**86**	**$ 77,511**	**$ 77,596**	**$ 914**	**$ 63,128**	**$ 63,547**	**$ 13,468**	**$ 13,135**	**$ 334**	**0.4%**
								Increase in Revenue Requirement		**$ 86**							

Table 10, BR.NTPC-4 d
Northwest Territories Power Corporation
Cost and Revenue Implications of Simple Average Use per Customer Load Forecasting
Residential Customers
2007/08

			Cost Component								Revenue Component						
		Column	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Line no.	Plant No.	Plant Name	Incremental Sales	Incremental Line Losses	Total Incremental Generation	GRA Fuel Efficiency	GRA Fuel Price	Incemental Fuel Expense	GRA Revenue Requirement per Refiling	Revenue Requirement with 4-year Weighted Avg Sales Adjustment	Other Revenues	Revenue At Existing Rates	Revenue with 4-year Weighted Average Sales at Existing Rates	Shortfall per Refiling	Shortfall with 4-year Weighted Avg Sales Adjustment	Change in Shortfall	Change in Shortfall as % of Community Revenue Requirement
		Units	(kWh)	(kWh)	(kWh)	(kWh/L)	($/L)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	(%)
		Calculation			A+B			C/D x E		F+G				G-I-J	H-I-K	L - M	
1	101	Snare	206,103	8,594	214,697	n/a	n/a	$ -	$ 28,200	$ 28,200	$ 138	22,739	$ 22,780	$ 5,323	$ 5,282	$ 41	0.1%
2	104	Wha Ti	7,326	557	7,883	3.711	0.897	$ 2	$ 1,320	$ 1,322	$ 13	1,234	$ 1,239	$ 73	$ 70	$ 4	0.3%
3	105	Gameti	9,637	482	10,119	3.398	0.927	$ 3	$ 1,073	$ 1,075	$ 13	814	$ 822	$ 246	$ 240	$ 5	0.5%
4	108	Behchoko	181,756	7,579	189,335	n/a	n/a	$ -	n/a	n/a						$ -	
5	109	Dettah	24,347	1,015	25,362	n/a	n/a	$ -	n/a	n/a						$ -	
6	110	Lutsel K'e	13,404	849	14,253	3.778	0.896	$ 3	$ 1,091	$ 1,094	$ 7	929	$ 937	$ 156	$ 151	$ 5	0.5%
7	201	Taltson	851,901	65,728	917,628	n/a	n/a	$ -	$ 6,681	$ 6,681	$ 141	4,877	$ 4,981	$ 1,663	$ 1,559	$ 104	1.6%
8	201	Ft Smith	824,831	63,639	888,471	n/a	n/a	$ -	n/a	n/a						$ -	
9	203	Ft Resolution	27,069	2,089	29,158	n/a	n/a	$ -	n/a	n/a						$ -	
10	205	Ft Simpson	6,642	399	7,040	3.755	0.862	$ 2	$ 5,252	$ 5,254	$ 50	2,749	$ 2,752	$ 2,453	$ 2,452	$ 1	0.0%
11	206	Ft. Liard	(19,093)	(1,452)	(20,545)	3.725	0.877	$ (5)	$ 1,707	$ 1,702	$ 13	1,025	$ 1,018	$ 668	$ 671	$ (3)	(0.2%)
12	207	Wrigley	15,826	1,084	16,909	3.525	0.885	$ 4	$ 886	$ 890	$ 10	532	$ 544	$ 344	$ 336	$ 8	0.9%
13	208	Nahanni Butte	3,495	277	3,772	2.511	0.877	$ 1	$ 632	$ 633	$ 6	363	$ 366	$ 264	$ 262	$ 2	0.3%
14	209	Jean Marie River	(5,093)	(403)	(5,496)	2.749	0.858	$ (2)	$ 484	$ 482	$ 5	271	$ 267	$ 208	$ 210	$ (3)	(0.5%)
15	301	Inuvik - Gas	354,014	23,802	377,817	3.399	0.430	$ 48	$ 14,471	$ 14,523	$ 288	10,563	$ 10,707	$ 3,620	$ 3,528	$ 92	0.6%
16		Inuvik - Diesel	18,632	1,253	19,885	3.635	0.797	$ 4									
17	304	Norman Wells	(49,930)	(3,781)	(53,710)	n/a	0.279	$ (15)	$ 3,236	$ 3,221	$ 32	2,562	$ 2,547	$ 642	$ 643	$ (0)	(0.0%)
18	305	Tuktoyaktuk	(50,687)	(3,993)	(54,679)	3.697	1.001	$ (15)	$ 2,645	$ 2,631	$ 22	2,418	$ 2,387	$ 205	$ 221	$ (16)	(0.6%)
19	306	Ft. McPherson	57,003	2,631	59,634	3.609	0.926	$ 15	$ 2,250	$ 2,266	$ 21	1,670	$ 1,700	$ 560	$ 545	$ 15	0.7%
20	307	Aklavik	95,854	6,062	101,916	3.475	0.914	$ 27	$ 1,678	$ 1,705	$ 20	1,520	$ 1,575	$ 138	$ 110	$ 28	1.7%
21	308	Deline	36,611	2,808	39,419	3.546	1.015	$ 11	$ 1,792	$ 1,803	$ 14	1,401	$ 1,422	$ 376	$ 366	$ 10	0.6%
22	309	Ft. Good Hope	(46,648)	(2,720)	(49,368)	3.576	1.001	$ (14)	$ 1,800	$ 1,786	$ 12	1,670	$ 1,641	$ 117	$ 133	$ (16)	(0.9%)
23	310	Tulita	(337)	(27)	(364)	3.634	0.905	$ (0)	$ 1,684	$ 1,683	$ 13	1,579	$ 1,579	$ 91	$ 91	$ (0)	(0.0%)
24	311	Paulatuk	58,574	4,576	63,149	3.492	1.090	$ 20	$ 1,374	$ 1,393	$ 9	1,129	$ 1,185	$ 235	$ 200	$ 36	2.6%
25	312	Sachs harbour	(10,153)	(541)	(10,694)	3.189	1.075	$ (4)	$ 1,008	$ 1,004	$ 7	746	$ 736	$ 254	$ 261	$ (6)	(0.6%)
26	313	Tsiigehtchic	(26,519)	(1,979)	(28,499)	3.537	0.985	$ (8)	$ 815	$ 807	$ 10	755	$ 729	$ 49	$ 67	$ (18)	(2.3%)
27	314	Colville Lake	10,053	761	10,813	2.957	1.133	$ 4	$ 684	$ 688	$ 6	743	$ 769	$ (65)	$ (87)	$ 23	3.3%
28	315	Ulukhatok	(13,750)	(829)	(14,580)	3.616	1.111	$ (4)	$ 1,310	$ 1,305	$ 13	1,328	$ 1,318	$ (32)	$ (26)	$ (5)	(0.4%)
29		**Total**	**1,522,863**	**104,137**	**1,627,000**			**78**	**$ 82,070**	**$ 82,149**	**$ 862**	**$ 63,618**	**$ 64,001**	**$ 17,590**	**$ 17,286**	**$ 304**	**0.4%**
								Increase in Revenue Requirement		**$ 78**							

Table 11, BR.NTPC-4 d
Northwest Territories Power Corporation
Cost and Revenue Implications of Weighted Average Use per Customer Load Forecasting
General Service Customers
2006/07

			Cost Component								Revenue Component						
		Column	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Line no.	Plant No.	Plant Name	Incremental Sales	Incremental Line Losses	Total Incremental Generation	GRA Fuel Efficiency	GRA Fuel Price	Incemental Fuel Expense	GRA Revenue Requirement per Refiling	Revenue Requirement with 4-year Weighted Avg Sales Adjustment	Other Revenues	Revenue At Existing Rates	Revenue with 4-year Weighted Average Sales at Existing Rates	Shortfall per Refiling	Shortfall with 4-year Weighted Avg Sales Adjustment	Change in Shortfall	Change in Shortfall as % of Community Revenue Requirement
		Units	(kWh)	(kWh)	(kWh)	(kWh/L)	($/L)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	(%)
		Calculation			A+B			C/D x E		F+G				G-I-J	H-I-K	L - M	
1	101	Snare	(38,476)	(1,417)	(39,893)	n/a	n/a	$ -	$ 26,888	$ 26,888	$ 138	$ 22,587	$ 22,577	$ 4,163	$ 4,173	$ (10)	(0.0%)
2	104	Wha Ti	86,634	6,585	93,219	3.711	0.891	$ 22	$ 1,265	$ 1,287	$ 13	$ 1,227	$ 1,288	$ 25	$ (14)	$ 39	3.1%
3	105	Gameti	12,632	632	13,263	3.398	0.904	$ 4	$ 1,025	$ 1,028	$ 13	$ 822	$ 835	$ 190	$ 180	$ 9	0.9%
4	108	Behchoko	(46,480)	(1,712)	(48,192)	n/a	n/a	$ -	n/a	n/a						$ -	
5	109	Dettah	8,004	295	8,299	n/a	n/a	$ -	n/a	n/a						$ -	
6	110	Lutsel K'e	21,338	1,352	22,690	3.778	0.847	$ 5	$ 1,026	$ 1,031	$ 7	$ 909	$ 921	$ 110	$ 103	$ 7	0.7%
7	201	Taltson	246,620	19,048	265,668	n/a	n/a	$ -	$ 6,369	$ 6,369	$ 121	$ 4,832	$ 4,854	$ 1,417	$ 1,395	$ 22	0.3%
8	201	Ft Smith	224,656	17,351	242,007	n/a	n/a	$ -	n/a	n/a						$ -	
9	203	Ft Resolution	21,965	1,696	23,661	n/a	n/a	$ -	n/a	n/a						$ -	
10	205	Ft Simpson	(157,257)	(9,439)	(166,696)	3.755	0.817	$ (36)	$ 4,736	$ 4,700	$ 50	$ 2,717	$ 2,670	$ 1,969	$ 1,980	$ (11)	(0.2%)
11	206	Ft. Liard	34,727	2,640	37,367	3.725	0.843	$ 8	$ 1,682	$ 1,690	$ 13	$ 1,060	$ 1,072	$ 608	$ 605	$ 3	0.2%
12	207	Wrigley	(3,855)	(264)	(4,119)	3.525	0.865	$ (1)	$ 858	$ 857	$ 10	$ 571	$ 568	$ 277	$ 279	$ (2)	(0.3%)
13	208	Nahanni Butte	21,963	1,738	23,701	2.511	0.816	$ 8	$ 612	$ 619	$ 6	$ 385	$ 414	$ 221	$ 200	$ 21	3.4%
14	209	Jean Marie River	(2,528)	(200)	(2,728)	2.749	0.802	$ (1)	$ 449	$ 448	$ 5	$ 266	$ 263	$ 178	$ 180	$ (2)	(0.5%)
15	301	Inuvik - Gas	(2,180)	(147)	(2,327)	3.399	0.430	$ (0)	$ 13,602	$ 13,602	$ 288	$ 10,428	$ 10,427	$ 2,886	$ 2,887	$ (0)	(0.0%)
16		Inuvik - Diesel	(115)	(8)	(122)	3.635	0.792	$ (0)									
17	304	Norman Wells	28,579	2,162	30,741	n/a	0.279	$ 9	$ 3,108	$ 3,117	$ 32	$ 2,485	$ 2,493	$ 592	$ 593	$ (1)	(0.0%)
18	305	Tuktoyaktuk	(53,372)	(4,199)	(57,571)	3.697	0.929	$ (14)	$ 2,482	$ 2,467	$ 94	$ 2,396	$ 2,367	$ (8)	$ 6	$ (14)	(0.6%)
19	306	Ft. McPherson	(63,117)	(2,913)	(66,030)	3.609	0.889	$ (16)	$ 2,173	$ 2,157	$ 21	$ 1,693	$ 1,664	$ 459	$ 472	$ (13)	(0.6%)
20	307	Aklavik	85,452	5,404	90,856	3.475	0.895	$ 23	$ 1,288	$ 1,312	$ 20	$ 1,516	$ 1,563	$ (247)	$ (271)	$ 23	1.8%
21	308	Deline	2,134	164	2,298	3.546	0.835	$ 1	$ 1,633	$ 1,633	$ 14	$ 1,399	$ 1,400	$ 219	$ 219	$ 1	0.0%
22	309	Ft. Good Hope	(18,289)	(1,066)	(19,355)	3.576	0.948	$ (5)	$ 1,743	$ 1,737	$ 12	$ 1,658	$ 1,648	$ 72	$ 77	$ (5)	(0.3%)
23	310	Tulita	14,117	1,117	15,234	3.634	0.886	$ 4	$ 1,638	$ 1,642	$ 13	$ 1,564	$ 1,575	$ 61	$ 54	$ 7	0.4%
24	311	Paulatuk	18,532	1,450	19,982	3.492	1.107	$ 6	$ 1,342	$ 1,348	$ 9	$ 1,109	$ 1,125	$ 224	$ 214	$ 10	0.7%
25	312	Sachs harbour	31,266	1,667	32,933	3.189	0.948	$ 10	$ 944	$ 954	$ 7	$ 766	$ 794	$ 171	$ 152	$ 18	1.9%
26	313	Tsiigehtchic	13,795	1,030	14,824	3.537	0.944	$ 4	$ 755	$ 759	$ 10	$ 733	$ 745	$ 12	$ 4	$ 8	1.1%
27	314	Colville Lake	(16,624)	(1,261)	(17,886)	2.957	0.795	$ (5)	$ 624	$ 619	$ 6	$ 736	$ 697	$ (118)	$ (83)	$ (35)	(5.6%)
28	315	Ulukhatok	40,572	2,447	43,019	3.616	1.102	$ 13	$ 1,270	$ 1,283	$ 13	$ 1,269	$ 1,296	$ (12)	$ (25)	$ 14	1.1%
29		**Total**	**302,546**	**26,523**	**329,069**			**$ 37**	**$ 77,511**	**$ 77,548**	**$ 914**	**$ 63,128**	**$ 63,255**	**$ 13,468**	**$ 13,379**	**$ 89**	**0.1%**
								Increase in Revenue Requirement		**$ 37**							

Table 12, BR.NTPC-4 d
Northwest Territories Power Corporation
Cost and Revenue Implications of Simple Average Use per Customer Load Forecasting
General Service Customers
2007/08

			Cost Component								Revenue Component						
		Column	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Line no.	Plant No.	Plant Name	Incremental Sales	Incremental Line Losses	Total Incremental Generation	GRA Fuel Efficiency	GRA Fuel Price	Incemental Fuel Expense	GRA Revenue Requirement per Refiling	Revenue Requirement with 4-year Weighted Avg Sales Adjustment	Other Revenues	Revenue At Existing Rates	Revenue with 4-year Weighted Average Sales at Existing Rates	Shortfall per Refiling	Shortfall with 4-year Weighted Avg Sales Adjustment	Change in Shortfall	Change in Shortfall as % of Community Revenue Requirement
		Units	(kWh)	(kWh)	(kWh)	(kWh/L)	($/L)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	(%)
		Calculation			A+B			C/D x E		F+G				G-I-J	H-I-K	L - M	
1	101	Snare	(25,727)	(1,073)	(26,799)	n/a	n/a	$ -	$ 28,200	$ 28,200	$ 138	22,739	$ 22,732	$ 5,323	$ 5,329	$ (7)	(0.0%)
2	104	Wha Ti	158,822	12,070	170,893	3.711	0.897	$ 41	$ 1,320	$ 1,361	$ 13	1,234	$ 1,346	$ 73	$ 2	$ 71	5.4%
3	105	Gameti	22,533	1,127	23,660	3.398	0.927	$ 6	$ 1,073	$ 1,079	$ 13	814	$ 837	$ 246	$ 229	$ 16	1.5%
4	108	Behchoko	(25,731)	(1,073)	(26,803)	n/a	n/a	$ -	n/a	n/a						$ -	
5	109	Dettah	4	0	4	n/a	n/a	$ -	n/a	n/a						$ -	
6	110	Lutsel K'e	41,722	2,644	44,365	3.778	0.896	$ 11	$ 1,091	$ 1,102	$ 7	929	$ 952	$ 156	$ 143	$ 13	1.2%
7	201	Taltson	118,873	9,172	128,044	n/a	n/a	$ -	$ 6,681	$ 6,681	$ 141	4,877	$ 4,888	$ 1,663	$ 1,652	$ 11	0.2%
8	201	Ft Smith	100,734	7,772	108,506	n/a	n/a	$ -	n/a	n/a						$ -	
9	203	Ft Resolution	18,139	1,399	19,538	n/a	n/a	$ -	n/a	n/a						$ -	
10	205	Ft Simpson	(276,078)	(16,570)	(292,648)	3.755	0.862	$ (67)	$ 5,252	$ 5,185	$ 50	2,749	$ 2,667	$ 2,453	$ 2,468	$ (15)	(0.3%)
11	206	Ft. Liard	60,468	4,597	65,065	3.725	0.877	$ 15	$ 1,707	$ 1,722	$ 13	1,025	$ 1,046	$ 668	$ 663	$ 5	0.3%
12	207	Wrigley	19,823	1,357	21,180	3.525	0.885	$ 5	$ 886	$ 891	$ 10	532	$ 549	$ 344	$ 333	$ 12	1.3%
13	208	Nahanni Butte	44,028	3,487	47,515	2.511	0.877	$ 17	$ 632	$ 648	$ 6	363	$ 420	$ 264	$ 223	$ 41	6.4%
14	209	Jean Marie River	(3,124)	(247)	(3,372)	2.749	0.858	$ (1)	$ 484	$ 483	$ 5	271	$ 267	$ 208	$ 211	$ (3)	(0.6%)
15	301	Inuvik - Gas	(217,606)	(14,631)	(232,236)	3.399	0.430	$ (29)	$ 14,471	$ 14,439	$ 288	10,563	$ 10,489	$ 3,620	$ 3,662	$ (42)	(0.3%)
16		Inuvik - Diesel	(11,453)	(770)	(12,223)	3.635	0.797	$ (3)									
17	304	Norman Wells	(147,930)	(11,201)	(159,131)	n/a	0.279	$ (44)	$ 3,236	$ 3,191	$ 32	2,562	$ 2,522	$ 642	$ 638	$ 5	0.1%
18	305	Tuktoyaktuk	(49,378)	(3,890)	(53,268)	3.697	1.001	$ (14)	$ 2,645	$ 2,631	$ 22	2,418	$ 2,392	$ 205	$ 217	$ (12)	(0.5%)
19	306	Ft. McPherson	(48,374)	(2,233)	(50,607)	3.609	0.926	$ (13)	$ 2,250	$ 2,237	$ 21	1,670	$ 1,647	$ 560	$ 569	$ (9)	(0.4%)
20	307	Aklavik	96,092	6,077	102,169	3.475	0.914	$ 27	$ 1,678	$ 1,705	$ 20	1,520	$ 1,572	$ 138	$ 113	$ 26	1.5%
21	308	Deline	(14,747)	(1,131)	(15,878)	3.546	1.015	$ (5)	$ 1,792	$ 1,787	$ 14	1,401	$ 1,393	$ 376	$ 380	$ (3)	(0.2%)
22	309	Ft. Good Hope	(37,525)	(2,188)	(39,713)	3.576	1.001	$ (11)	$ 1,800	$ 1,789	$ 12	1,670	$ 1,650	$ 117	$ 126	$ (10)	(0.5%)
23	310	Tulita	27,447	2,173	29,620	3.634	0.905	$ 7	$ 1,684	$ 1,691	$ 13	1,579	$ 1,601	$ 91	$ 77	$ 14	0.8%
24	311	Paulatuk	1,931	151	2,082	3.492	1.090	$ 1	$ 1,374	$ 1,374	$ 9	1,129	$ 1,131	$ 235	$ 234	$ 1	0.1%
25	312	Sachs harbour	58,997	3,145	62,142	3.189	1.075	$ 21	$ 1,008	$ 1,029	$ 7	746	$ 799	$ 254	$ 222	$ 32	3.2%
26	313	Tsiigehtchic	3,250	243	3,493	3.537	0.985	$ 1	$ 815	$ 815	$ 10	755	$ 758	$ 49	$ 47	$ 2	0.2%
27	314	Colville Lake	(23,098)	(1,748)	(24,847)	2.957	1.133	$ (10)	$ 684	$ 674	$ 6	743	$ 688	$ (65)	$ (19)	$ (45)	(6.6%)
28	315	Ulukhatok	(10)	(1)	(10)	3.616	1.111	$ (0)	$ 1,310	$ 1,310	$ 13	1,328	$ 1,328	$ (32)	$ (32)	$ (0)	(0.0%)
29		**Total**	**(201,064)**	**(9,441)**	**(210,505)**			**(45)**	**$ 82,070**	**$ 82,025**	**$ 862**	**$ 63,618**	**$ 63,675**	**$ 17,590**	**$ 17,488**	**$ 102**	**0.1%**
								Decrease in Revenue Requirement		**$ (45)**							

Topic

Sales Forecast

Reference

Directive 19

Preamble

Prior to considering whether an average use per Customer is an appropriate method or an appropriate test of reasonableness for the General Service Customer sales forecast, the Corporation would need to consider the following:

- Diversity of load patterns among General Service Customers;
- Relative influence on General Service Customers of weather compared to other factors;
- Historical performance of regression based forecast methods compared to average use per Customer methods;

Requests

a) Does the corporation have any evidence to indicate diversity of load patterns or the relative size of general service customers have contributed to variability in average use per customer from year to year within a given community. Provide examples.

b) What other factors besides weather would impact general service customers contributing to variability in average use per customer from year to year.

c) Please confirm that the original regression analysis regressed historical sales against number of commercial customers having regard to temperature. If not identify the variables used in the original regression analysis to forecast commercial customer sales.

d) Explain why NTPC believes a regression analysis conducted using the variables identified in c) above would produce materially different results than one based on average use per customer analysis; identify the factors giving rise to such differences and how the two approaches can be reconciled.

Response

a) Yes the Corporation has evidence to indicate diversity of load patterns or the relative size of general service customers have contributed to variability in average use per customer from year to year within a given community. In many of the communities, the number of General Service customers is less than thirty which makes the sample size very small and the average will be susceptible to skewing from one or two results at the extremes. Please refer to the examples below, which are prevalent in most NWT communities served by NTPC:

- In Tsiigehtchic during the first half of 2007/08, the new Northern Store consumed twice the annual average energy per General Service customer and is on track to consume approximately four times the annual average by the end of the year. Using an average would have understated the sales for that customer group.
- In Deline, from 2004/05 to 2005/06 the number of General Service customers decreased by 4% however the average use per customer increased by 1%. This would suggest that smaller unit sales customers left the system resulting in an increase in the average use per customer left on the system. There is a wide range of General Service customers in any community for example the Co-op store in Deline consumes approximately 192 MW.h per year (16% of the total General Service sales in Deline) versus the Deline Pizza Deli which consumes approximately 10 MW.h per year. The loss of either of these two customers would have differing impacts on the average use per customer statistics and would tend to skew the forecast for future additions or reductions in customers.
- In Fort Simpson, the Snack Shop consumes 0.9 MWh per year as compared to a Northern Store that consumes 500 MWh per year. The average consumption for General Service customers in this community was approximately 30 MWh in 2005/06. This result demonstrates that even in a community such as Fort Simpson where the number of General Service customers is close to 150, the average can be skewed by such a large variance in use between customers.
- In the last GRA, NTPC forecast the average use per General Service customer in Fort Liard at 36 MWh. With the downturn of oil and gas activity in that area, the actual average use per customer was 10 MWh lower or 26MWh, a decrease of 28%. Therefore, the economy can also have a significant impact on the average use per customer.

b) In addition to weather some other ‘Top-Down’ variables that would impact General Service customers contributing to variability in average use per customer from year to year are:

- Non-homogeneous operations as illustrated by the examples provided in BR.NTPC-5a)
- Rate of uptake of more energy efficient technologies.
- Rate of uptake of more electrical equipment.
- State of the local economy, construction activity, employment, etc.
- General Service customers have less incentive to conserve if they have the ability to pass costs onto their customers.
- Conformity to current building codes and new technology. For example, the new hospital in Inuvik is a larger consumer of energy than the old hospital. Although the building is built to a higher energy efficiency standard, the air handling systems, lighting, coupled with more requirements to meet current codes for such things as electronic diagnostic equipment, etc. increase the energy consumed.

Therefore in considering these variables, forecasting General Service sales based on the average use per customer is not appropriate.

c) Not confirmed. As discussed in the Corporation's response to BR.NTPC-4 from the Phase I proceeding, both the weather regression and the trend regression consider monthly aggregated sales by customer class (i.e. Residential and General Service). Those analyses did not consider number of customers.

d) As discussed in the Corporation's response to Directive 19 from Decision 13-2007, the Corporation has not had the time to do a complete analysis of different forecasting methods. Please refer to response Re-filing BR.NTPC-4.

However, the Corporation is aware that some utilities use an average use per Customer approach for Residential customers and a different approach for General Service customers. As an example, Manitoba Hydro uses a forecasting method for Residential customers based on an average use per customer and a forecasting method for General Service customers that reviews its top consumer forecasts individually and uses a form of regression analysis for all other General Service customers.

Given the small customer base NTPC communities have, the Corporation maintains a more dynamic approach that considers all the relevant variables discussed in part a) and b) above is required. The Corporation remains open to testing and evaluating different load forecasting methods, such as the method used by Manitoba Hydro that may be simpler to apply and understand. If directed by the Board, the Corporation will undertake this review at the time of its next Phase I General Rate Application.

Topic

Diesel Fuel Required for Forced Outages

Reference

Direction 21; P31, Table 1

Preamble

The Corporation would require on average, 2.97 GW.h of additional diesel generation in 16 2006/07 and 3.02 GW.h of additional diesel generation in 2007/08 based on the forecast hydro generation to be utilized. This is the simplest method the Corporation could develop in the time available that would be suitable to apply and test in future General Rate Applications.

Requests

a) Please provide the hydro unit outage calculation in Table 1 showing the forced outage percentages and corresponding Gwh, by hydro unit. Identify the inherent limitations of this method of forecasting diesel generation due to outages and provide an assessment of the potential error that may result from the proposed method of forecasting diesel generation due to outages.

b) Please confirm every time there is a hydro unit outage it does not necessarily result in a corresponding increase in diesel generation. Can NTPC provide a probabilistic estimate of the percentage of time when diesel generation is required to replace hydro generation when a hydro unit experiences forced outage.

c) Please provide an estimate of the diesel generation in each of the last 3 years as a result of:

- Forced outages of hydro units and or transmission lines;
- Outages of hydro units and or transmission lines due to capital projects;
- Regularly planned maintenance outages of hydro units and or transmission lines
- Normal generation dispatch

Explain and provide support for how the estimates were derived.

d) Based on the analysis of historical diesel generation due to hydro unit or transmission forced outages in c) above please comment of NTPC's proposed

method of determining the diesel generation required to replace hydro generation as a result of forced outages.

Preamble

The Corporation has maintained a water stabilization account for the Snare/Yellowknife system since the 1995/98 Phase I General Rate Application. The mechanics of the water stabilization fund, as agreed to by the parties to the 1995/98 Phase I negotiated settlement and approved by the Board in Decision 1-1997 are based on the theoretical long-term average hydro generation built into rates and the actual Snare-Yellowknife hydro and diesel generation. There has never been a provision in the fund for discretion with respect to whether or not diesel generation is included in the calculation of the balance in the fund. Actual hydro and diesel generation are, by definition, influenced by forced outages, capital projects planned and unplanned maintenance as well as normal generation dispatch (including peaking and exercising).

The current fund mechanics have the advantages of being transparent, eliminates judgment, easy to apply and understand and reduced sensitivity resulting in recovering the correct amount of diesel fuel expense. This allows difficult to forecast diesel generation requirements to be smoothed over time as they occur, rather than subjecting customers to the forecasting risk associated with highly irregular and difficult to forecast diesel generation requirements. This treatment is also consistent with the Board's views on the appropriateness of the use of deferral accounts where the Board has previously stated "In principle, the Board considers deferral accounts should be used to record amounts over which the utility has no control or where the amount cannot be forecast with reasonable accuracy."[1] Clearly forced outages meet the test of being difficult to forecast with reasonable accuracy.

In order to implement a discretionary aspect to the fund, that is to determine that some diesel generation will flow through to the fund while other diesel generation will be excluded, requires a degree of judgment and subjectivity. It simply is not possible to say with absolute certainty in all occasions whether a kW.h of diesel generation was incurred as the result of a forced outage at a hydro unit, or as a result of normal generation dispatch or is exercising the unit. It is also extraordinarily difficult to forecast diesel generation requirements on the basis of whether it will be required as the result of a forced outage or a normal generation dispatch requirement in any meaningful way.

The Corporation continues to believe that its proposed treatment of diesel fuel expenses for the Snare Yellowknife systems is transparent, consistent with the operating rules of the stabilization funds agreed to by the parties to the 1995/98 Phase I Negotiated Settlement and results in the Corporation fairly recovering diesel fuel costs required to

[1] Page 55, Decision 9-2006.

maintain safe and reliable service to its customers. Any alternative that requires the Corporation to distinguish between diesel generation requirements as the result of forced outages, capital projects, planned maintenance outage and normal generation dispatch requirements, on both an actual and forecast basis, will be necessarily subjective and controversial. This is a core and unavoidable limitation of any method for operating the fund that requires a discretionary aspect to adjusting the actual hydro or diesel generation recorded in the fund. For further discussion on this topic please refer to the Corporation's response for HC.NTPC-6.

Response

a) The Corporation did not prepare its hydroelectric generation forecasts for the General Rate Application on a unit by unit basis. As a result the requested table cannot be provided. The forecast diesel generation requirements related to forced outages were prepared considering the system total forecast hydro-electric generation and the forced outage rate ("FOR") which is a system average FOR for the Snare-Yellowknife hydro units.

b) It is confirmed that at the system loads forecast in the test years, a hydro unit outage does not necessarily result in the need for additional diesel generation. It is also possible that the loss of a unit can require diesel generation of $40,000 per day. It is dependent on the load, water availability and the availability of the other hydro units and how quickly these units can be returned to service. The Corporation considered this factor by using the forecast hydro generation requirement in the test years, rather than the long-term average hydro generation.

   NTPC has undertaken no analysis to support a probabilistic estimate of the percentage of time when diesel generation is required to replace hydro generation when a hydro unit experiences a forced outage. Due to the highly irregular and unpredictable nature of these types of outages, the Corporation does not believe that such an analysis would provide a useful or meaningful method for predicting the future diesel generation requirements due to forced outage.

c) Please refer to Table 1, BR.NTPC-6 below.

Table 1, BR.NTPC-6
Diesel Generation MW.h

	2004/05	2005/06	2006/07	NTPC's understanding where these amounts will be charged in Re-filing, as per Board order
Forced outages of hydro units and/or T-line	84	1,728	462	O&M and Revenue Requirement
Outage of hydro units and/or T-line due to capital projects	0	748	0	Capital Projects
Regularly planned maintenance outages of hydro units and/or T-line	30	126	217	O&M and Revenue Requirement
Normal generation dispatch	29,466	808	1,449	Water Stab. Fund if hydro output is below long term average. If hydro out put is above long term average, amounts will go to O&M and Revenue Requirement
Total	**29,580**	**3,410**	**2,128**	

The Corporation's SCADA system records generation by unit which provides a list of the diesel generation on an hourly basis on log sheets.

Forced Outages

Outage reports are prepared for each outage providing the date and duration of the outage. The log sheets for all the outages were reviewed for diesel generation during the outage. The amount of diesel generation was estimated by

taking the total diesel generation during the outage period and reducing it by any diesel generation immediately before the outage.

Capital Projects

The Corporation knows the time period hydro was unavailable for capital upgrades to the hydro units, transmission line or substations. The log sheets were reviewed for the periods that any of the hydro units, transmission line or substations were down for capital upgrades. Any diesel generation during these periods was attributed to capital if it would not have been required if the hydro units were available.

Regular Planned Maintenance

The Corporation knows when hydro units, transmission lines or substations are down for planned maintenance. The log sheets were reviewed for the periods that any of the hydro units or transmission line or substations were down for a planned maintenance. Any diesel generation during these periods was attributed to planned maintenance if it would not have been required if the hydro units were available.

Normal Generation Dispatch

The Corporation knows the total amount of diesel generation from the SCADA system. Normal generation is the difference of total diesel generation less the diesel generation attributed to the above categories. This generation is required to meet customer load, exercise the units and for operation as part of daily maintenance. For example, after the repair of a pump on a diesel unit it is run for several hours to ensure it is fully operational.

d) Based on the analysis presented in part c) above, it is clear that the Corporation's diesel generation requirements for forced outages can vary dramatically from year to year. Clearly forced outages are irregular and would be difficult to forecast with reasonable accuracy.

In the Corporation's view, the simplest method for addressing diesel generation requirements due to forced outages is to retain the current treatment of the water stabilization fund. Any treatment that requires a discretionary aspect to when diesel generation is flowed through the fund will be inherently difficult to forecast and is likely to result in the Corporation significantly either under or over-collecting its requirement for diesel fuel expense.

Topic

Diesel Fuel Required for Forced Outages

Reference

Direction 21; P33

Preamble

The Corporation has retained an amount of diesel generation for exercising and peaking requirements. As this generation is not related to outages, it will continue to be recovered via the water stabilization fund. This results in revised forecast diesel generation on the Snare system of 4.237 GW.h in 2006/07 and 4.398 GW.h in 2007/08.

Requests

a) Please provide an analysis of the components of diesel generation that are included in the diesel generation forecast in the refiling schedules 3.3.1 and 3.3.2 and provide support showing how each component was calculated.

b) Please describe what is meant by exercising and peaking and explain why this component is proposed to be recovered via the water stabilization fund.

c) Please reconcile the diesel generation for Snare Yellowknife shown in Schedules 3.3.1 and 3.3.2 of the original filing with the diesel generation in the refiling as shown in the corresponding schedules showing how each component was calculated.

d) Please explain why the fuel price per liter for Snare Yellowknife shown in Schedules 3.3.1 and 3.3.2 of the original filing differs from the fuel price per liter in the refiling

Response

a) Please refer to the responses to HC.NTPC-6 (e) and HC.NTPC-6 (f).

b) Please refer to response HC.NTPC-6 (g).

c) Please refer to the responses to HC.NTPC-6 (e) and HC.NTPC-6 (f).

d) Please refer to the response to BR.NTPC-2.

Topic

Diesel Fuel Required for Forced Outages

Reference

Direction 21; Table 2

Preamble

Requests

Please provide an illustrative example showing how the diesel generation due to outages in Table 2 Line 8 will be calculated in practice. Identify the inherent limitations of this method of estimation, on an actual basis, and provide an assessment of the potential error that may result from the proposed method of calculating diesel generation due to outages.

Response

Outage reports are prepared that record the date and duration of each outage. The amount of diesel generation required as a result of the outage would be estimated by taking the total diesel generation during the outage period and subtracting any diesel generation occurring in the hour immediately preceding the outage. For example, if 2 MW of diesel was running before the outage, and 6 MW was required to be dispatched to address the outage, the 4 incremental MW would be assumed to be diesel generation related to the outage.

There are a variety of limitations to this method. The most serious limitation is that it is difficult at best and at times not a meaningful exercise to attempt to attribute the use of diesel generation to a particular cause at any given point in time. This would make it a difficult and often subjective exercise in practice to determine whether a kW.h of diesel generation should be an operations and maintenance expense, charged to the water stabilization fund, part of a capital project or charged to the reserve for injuries and damages. In any event, the treatment is likely to be at least partially subjective, as well as difficult to explain and interpret.

Critical errors that may arise under this approach may be quite material. These may arise as NTPC's system is far more complicated than a simple situation like NUL Hay River (where hydro is simply either on or off) and be simple unintended consequences of weaknesses in this hybrid design. For example, the following situation would appear to result in NTPC in effect paying twice for the same diesel generation:

- If NTPC has a transmission outage during normal water conditions, it would be required to burn diesel which under the new approach would be charged to O&M. NTPC's normal operational response would be to store water on the Snare system during this event, so as not to waste it when the hydro system cannot generate power to serve Yellowknife. This stored water would then be used to enhance the system output at a future time period, as a benefit to the overall system.
- This extra water would be used in a future month, resulting in hydro generation in that month that would be above the typical long-term average in that month.
- Under the system as now being debated, in the month with enhanced hydro generation, this "extra hydro generation" would be considered by the water stabilization fund as a surplus compared to long-term average (for example, by getting 21 GWh in that month rather than the normal 20 GWh). The water stabilization fund tracks such variances, and effectively considers all such positive variances as being from higher than average flows. As NTPC's revenue requirement is based on average flows, these higher than average flows are portrayed by the fund as a "savings" to NTPC compared to having to run diesel generation. The fund in effect requires NTPC to pay to the fund the calculated "savings" it achieves.
- Consequently, at the end of this exercise, the approach as now proposed would appear to result in NTPC having to, in effect, pay twice for this diesel it burns – once when it is actually used by paying for the actual diesel, and once when the water shows up by paying amounts to the Water Stabilization Fund. This is clearly not the intended outcome.
- In order to avoid such double payment, it would be necessary to also make subjective adjustments to the water stabilization fund hydro generation, in months outside when the outages actually occur, to neutralize this effect. There has been insufficient time to consider how this might be done, if it is at all possible on any defensible basis, but clearly the extent of subjectivity and difficulty for the Board and Intervenors to review all such adjustments are a substantial concern.

The situation noted above is but one type of error introduced into the regulatory system by this Directive; it is not known how many other situations that cannot yet be identified may give similarly counter-intuitive results. It is not at all possible to quantify the precise magnitude or potential frequency of this type of error, but it can clearly be material.

Topic

Reference

Directives 5 and 6

Preamble

NTPC was directed to use a 6% sinking fund return for each of the test years for purposes of calculating the effective cost of debt and was to calculate its effective cost of debt based on the formula prescribed by the Board. NTPC indicates that it has reflected these changes in Schedules 3.5 and 3.6. The HC are unable to confirm the cost rates for long-term debt based on the information provided. The HC wish to review the calculations of these changes by debt issue.

Requests

a) Please provide an updated Schedule 3.7.

b) Please break down Schedule 3.7 to each of the debt issues comprising the Cost of Long Term Debt to demonstrate the application of the Board formula as directed at page 26.

Response

a) Please refer to the attached Schedule 3.7.

b) Please refer to the attached Schedules.

NORTHWEST TERRITORIES POWER CORPORATION

Schedule 3.7
Revised Oct 2007

COST OF LONG-TERM DEBT

(in thousands of dollars)

Line No.		2004/05 Actual	2005/06 Actual	2006/07 Forecast	2007/08 Forecast
1	**MID-YEAR DEBT BALANCE (MAD)**	105,200	124,534	131,367	130,700
	SINKING FUND				
2	Opening Balance	24,082	28,850	37,804	43,202
3	Closing Balance	28,850	37,804	43,202	48,922
4	**Mid Year Sinking Fund Balance (SFI)**	26,466	33,327	40,503	46,062
	DEBT FINANCING COSTS				
5	Beginning Financing Costs O/S	1,678	1,890	1,704	1,578
6	Additions	188	0	0	0
7	Less: Amortization	(86)	(185)	(126)	(124)
8	Ending Financing Costs O/S	1,779	1,704	1,578	1,454
9	**Average Financing Costs Outstanding (UFC)**	1,729	1,797	1,641	1,516
10	AVERAGE PROCEEDS	77,006	89,409	89,222	83,122
	INTEREST & AMORTIZATION OF FINANCING COSTS				
11	Interest Expense Amount **(I)**	9,060	10,286	10,778	10,755
12	Less: Interest Revenue Amount **(SFE)**	(1,354)	(3,145)	(2,214)	(2,535)
13	Amortization of Finance Costs **(AFC)**	86	185	126	124
14	Total Interest and Amortization	7,792	7,326	8,691	8,344
15	**EFFECTIVE COST OF LONG TERM DEBT (I+AFC-SFE)/(MAD - UFC - SFI)**	10.119%	8.194%	9.740%	10.038%

NORTHWEST TERRITORIES POWER CORPORATION
PHASE 1 REFILING
EFFECTIVE COST OF LONG TERM DEBT
2004/05 Actual
(in thousands of dollars)

Line No.									
1	Loan #	**2**	**3**	**4**	**6**	**7**	**10**	**11**	
2	Loan Amount	**$ 20,000**	**$ 15,000**	**$ 20,000**	**$ 8,700**	**$ 10,000**	**$ 20,000**	**$ 25,000**	**TOTAL**
3	Interest Rate	**11.000%**	**11.125%**	**10.750%**	**8.41%**	**6.330%**	**6.420%**	**5.955%**	**ALL**
4	Issue Date	**9/Mar/89**	**6/Jun/91**	**28/May/92**	**27/Feb/96**	**27/Oct/98**	**18/Dec/02**	**15/Dec/04**	**LOANS**
5	Balance from Beginning of Year to Day of Issue	20,000	15,000	20,000	8,700	10,000	19,333	-	
6	Balance from Day of Issue to End of Year	20,000	15,000	20,000	8,700	10,000	18,667	25,000	
7	**Mid-Year Balance (MAD) [(L5+L6)/2]**	**20,000**	**15,000**	**20,000**	**8,700**	**10,000**	**19,000**	**12,500**	**105,200**
8	**Sinking Fund**								
9	Opening Balance	11,031	6,075	6,681		296			
10	Closing Balance	13,272	7,076	7,895		607			
11	**Mid Year Balance [(L9+L10)/2] (SFI)**	**12,151**	**6,575**	**7,288**		**451**			**26,466**
12	**DEBT FINANCING COSTS**								
13	Beginning Financing Costs O/S	38	68	58	44	79	1391	0	
14	Additions							188	
15	Less Amortization	8	9	9	3	5	49	3	
16	Ending Financing Costs O/S	30	58	49	41	74	1343	185	
17	**Average Financing Costs Outstanding [(L13+L16)/2] (UFC)**	**34**	**63**	**53**	**43**	**76**	**1,367**	**92**	**1,729**
18	**AVERAGE PROCEEDS [L13-L17-L23]**	**7,815**	**8,362**	**12,659**	**8,657**	**9,472**	**17,633**	**12,408**	**77,006**
19	**INTEREST & AMORTIZATION OF FINANCING COSTS**								
20	Interest Expense Amount [L7*L3] (I)	2,200	1,669	2,150	732	633	1,241	435	
21	Less Interest Revenue Amount (SFE)	594	350	388	0	21	0	0	
22	Amortization of Finance Costs (AFC)	8	9	9	3	5	49	3	
23	Total Interest and Amortization	1,613	1,328	1,771	734	617	1,290	438	7,792
	EFFECTIVE COST OF LONG TERM DEBT (I + AFC - SFE)/(MAD - UFC - SFI)								**10.119%**

NORTHWEST TERRITORIES POWER CORPORATION OCT 16, 2007

PHASE 1 REFILING

EFFECTIVE COST OF LONG TERM DEBT

2005/06 Actual

(in thousands of dollars)

Line No.										
1	Loan #	**2**	**3**	**4**	**6**	**7**	**10**	**11**	**12**	
2	Loan Amount	**$ 20,000**	**$ 15,000**	**$ 20,000**	**$ 8,700**	**$ 10,000**	**$ 20,000**	**$ 25,000**	**$ 15,000**	**TOTAL**
3	Interest Rate	**11.000%**	**11.125%**	**10.750%**	**8.41%**	**6.330%**	**6.420%**	**5.955%**	**5.000%**	**ALL**
4	Issue Date	**9/Mar/89**	**6/Jun/91**	**28/May/92**	**27/Feb/96**	**27/Oct/98**	**18/Dec/02**	**15/Dec/04**	**16/Dec/05**	**LOANS**
5	Balance from Beginning of Year to Day of Issue	20,000	15,000	20,000	8,700	10,000	18,667	25,000	-	
6	Balance from Day of Issue to End of Year	20,000	15,000	20,000	8,700	10,000	18,000	25,000	15,000	
7	**Mid-Year Balance (MAD) [(L5+L6)/2]**	**20,000**	**15,000**	**20,000**	**8,700**	**10,000**	**18,334**	**25,000**	**7,500**	**124,534**
8	**Sinking Fund**									
9	Opening Balance	13,272	7,076	7,895	0	607				
10	Closing Balance	18,384	8,544	9,728	171	977				
11	**Mid Year Balance [(L9+L10)/2] (SFI)**	**15,828**	**7,810**	**8,812**	**86**	**792**				**33,327**
12	**DEBT FINANCING COSTS**									
13	Beginning Financing Costs O/S	30	58	49	41	74	1343	185	110	
14	Additions									
15	Less Amortization	8	9	9	3	5	143	6	2	
16	Ending Financing Costs O/S	22	49	40	39	68	1200	178	109	
17	**Average Financing Costs Outstanding [(L13+L16)/2] (UFC)**	**26**	**53**	**44**	**40**	**71**	**1,271**	**181**	**110**	**1,797**
18	**AVERAGE PROCEEDS [L13-L17-L23]**	**4,146**	**7,137**	**11,144**	**8,574**	**9,137**	**15,951**	**24,819**	**7,390**	**89,409**
19	**INTEREST & AMORTIZATION OF FINANCING COSTS**									
20	Interest Expense Amount [L7*L3] (I)	2,200	1,669	2,150	732	633	1,198	1,489	216	
21	Less Interest Revenue Amount (SFE)	1359	804	910	1	71	0	0	0	
22	Amortization of Finance Costs (AFC)	8	9	9	3	5	143	6	2	
23	Total Interest and Amortization	849	874	1,250	733	567	1,341	1,495	217	7,326
	EFFECTIVE COST OF LONG TERM DEBT (I + AFC - SFE)/(MAD - UFC - SFI)									**8.194%**

NORTHWEST TERRITORIES POWER CORPORATION OCT 16, 2007

PHASE 1 REFILING

EFFECTIVE COST OF LONG TERM DEBT

2006/07 Forecast

(in thousands of dollars)

Line No.										
1	Loan #	**2**	**3**	**4**	**6**	**7**	**10**	**11**	**12**	
2	Loan Amount	**$ 20,000**	**$ 15,000**	**$ 20,000**	**$ 8,700**	**$ 10,000**	**$ 20,000**	**$ 25,000**	**$ 15,000**	**TOTAL**
3	Interest Rate	**11.000%**	**11.125%**	**10.750%**	**8.41%**	**6.330%**	**6.420%**	**5.955%**	**5.000%**	**ALL**
4	Issue Date	**9/Mar/89**	**6/Jun/91**	**28/May/92**	**27/Feb/96**	**27/Oct/98**	**18/Dec/02**	**15/Dec/04**	**16/Dec/05**	**LOANS**
5	Balance from Beginning of Year to Day of Issue	20,000	15,000	20,000	8,700	10,000	18,000	25,000	15,000	
6	Balance from Day of Issue to End of Year	20,000	15,000	20,000	8,700	10,000	17,333	25,000	15,000	
7	**Mid-Year Balance (MAD) [(L5+L6)/2]**	**20,000**	**15,000**	**20,000**	**8,700**	**10,000**	**17,667**	**25,000**	**15,000**	**131,367**
8	**Sinking Fund**									
9	Opening Balance	18,384	8,544	9,728	171	977				
10	Closing Balance	20,552	9,720	11,244	354	1,333				
11	**Mid Year Balance [(L9+L10)/2] (SFI)**	**19,468**	**9,132**	**10,486**	**263**	**1,155**				**40,503**
12	**DEBT FINANCING COSTS**									
13	Beginning Financing Costs O/S	22	49	40	39	68	1200	178	109	
14	Additions									
15	Less Amortization	8	9	9	3	5	80	6	6	
16	Ending Financing Costs O/S	15	39	31	36	63	1119	172	103	
17	**Average Financing Costs Outstanding [(L13+L16)/2] (UFC)**	**19**	**44**	**35**	**37**	**66**	**1,159**	**175**	**106**	**1,641**
18	**AVERAGE PROCEEDS [L13-L17-L23]**	**513**	**5,824**	**9,479**	**8,400**	**8,780**	**15,501**	**24,825**	**14,894**	**89,222**
19	**INTEREST & AMORTIZATION OF FINANCING COSTS**									
20	Interest Expense Amount [L7*L3] (I)	2,200	1,669	2,150	732	633	1,156	1,489	750	
21	Less Interest Revenue Amount (SFE)	1041	511	591	14	57	0	0	0	
22	Amortization of Finance Costs (AFC)	8	9	9	3	5	80	6	6	
23	Total Interest and Amortization	1,167	1,167	1,568	721	582	1,236	1,495	756	8,691
	EFFECTIVE COST OF LONG TERM DEBT (I + AFC - SFE)/(MAD - UFC - SFI)									**9.740%**

NORTHWEST TERRITORIES POWER CORPORATION OCT 16, 2007

PHASE 1 REFILING

EFFECTIVE COST OF LONG TERM DEBT

2007/08 Forecast

(in thousands of dollars)

Line No.										
1	Loan #	**2**	**3**	**4**	**6**	**7**	**10**	**11**	**12**	
2	Loan Amount	**$ 20,000**	**$ 15,000**	**$ 20,000**	**$ 8,700**	**$ 10,000**	**$ 20,000**	**$ 25,000**	**$ 15,000**	**TOTAL**
3	Interest Rate	**11.000%**	**11.125%**	**10.750%**	**8.41%**	**6.330%**	**6.420%**	**5.955%**	**5.000%**	**ALL**
4	Issue Date	**9/Mar/89**	**6/Jun/91**	**28/May/92**	**27/Feb/96**	**27/Oct/98**	**18/Dec/02**	**15/Dec/04**	**16/Dec/05**	**LOANS**
5	Balance from Beginning of Year to Day of Issue	20,000	15,000	20,000	8,700	10,000	17,333	25,000	15,000	
6	Balance from Day of Issue to End of Year	20,000	15,000	20,000	8,700	10,000	16,667	25,000	15,000	
7	**Mid-Year Balance (MAD) [(L5+L6)/2]**	**20,000**	**15,000**	**20,000**	**8,700**	**10,000**	**17,000**	**25,000**	**15,000**	**130,700**
8	**Sinking Fund**									
9	Opening Balance	20,552	9,720	11,244	354	1,333				
10	Closing Balance	22,849	10,966	12,850	547	1,710				
11	**Mid Year Balance [(L9+L10)/2] (SFI)**	**21,701**	**10,343**	**12,047**	**451**	**1,521**				**46,062**
12	**DEBT FINANCING COSTS**									
13	Beginning Financing Costs O/S	15	39	31	36	63	1119	172	103	
14	Additions									
15	Less Amortization	8	9	9	3	5	78	6	6	
16	Ending Financing Costs O/S	7	30	22	33	57	1042	166	98	
17	**Average Financing Costs Outstanding [(L13+L16)/2] (UFC)**	**11**	**35**	**26**	**34**	**60**	**1,080**	**169**	**101**	**1,516**
18	**AVERAGE PROCEEDS [L13-L17-L23]**	**-1,711**	**4,623**	**7,927**	**8,215**	**8,419**	**14,987**	**24,831**	**14,899**	**83,122**
19	**INTEREST & AMORTIZATION OF FINANCING COSTS**									
20	Interest Expense Amount [L7*L3] (I)	2,200	1,669	2,150	732	633	1,133	1,489	750	
21	Less Interest Revenue Amount (SFE)	1171	581	681	24	77	0	0	0	
22	Amortization of Finance Costs (AFC)	8	9	9	3	5	78	6	6	
23	Total Interest and Amortization	1,037	1,097	1,478	710	561	1,210	1,495	756	8,344
	EFFECTIVE COST OF LONG TERM DEBT (I + AFC - SFE)/(MAD - UFC - SFI)									**10.038%**

Topic

Reference

Directive 7

Preamble

NTPC was directed to include a capital lease rate that reflected the Board approved rates of return on equity less 25 basis points. The HC are unable to precisely replicate the mid-year cost rates based on the information provided.

Requests

Please provide supporting calculations for the 9.55% and 9.59% shown in schedule 3.5.

Response

Please refer to Table 1 below.

Table 1, HC.NTPC-2
NORTHWEST TERRITORIES POWER CORPORATION
CALCULATION OF SNARE CASCADES
CAPITAL LEASE COST RATE

Line No.		2006/07	2007/08
1	Mid-Year Capitalization ($ 000)	22,261	21,858
2	Mid-Year Equity percentage	6.79%	6.74%
3	Mid-Year Equity	1,512	1,473
4	Return on Equity	8.75%	9.00%
5	Mid-Year Debt percentage	93.21%	93.26%
6	Mid-Year Debt	20,749	20,385
7	Mid-Year Debt Rate	9.61%	9.63%
8	Mid-Year Capital Lease Cost Rate ((l3 x l4) + (l7 x l6))/(l 1)	**9.55%**	**9.59%**

Topic

Reference

Directive 17

Preamble

The Board identified a very large difference between the accumulated reserve for site restoration as of fiscal year-end 2004/2005 of $37.154 million as compared to estimated soil remediation costs of $12.959 million in 2005 dollars, or some $24 million. In response to Directive 17, NTPC indicated that there are substantial requirements for FRSR for hydro plant, transmission lines and distribution systems but did not quantify those amounts. Although NTPC suggests that there may be changes to negative salvage and asset lives, there is no evidence on the record in this proceeding to support that suggestion.

Requests

Please provide the future removal costs or negative net salvage for each of hydro plant, transmission lines and distribution systems based on the most recently approved negative net salvage rates as of fiscal year-end 2004/2005.

Response

Table 1, HC.NTPC-3 illustrates net liability established from accumulated amortization during the initial depreciation study for the 1995/98 GRA as well as the net accumulated balances since that time using the PUB approved rates for negative salvage and site restoration (including soil remediation) as of March 31, 2005.

Table 1, HC.NTPC-3
Future Removal and Site Restoration Provision
As of March 31, 2005 ($000's)

Description	
Total Hydro Plant	6,164
Total Diesel Plant	12,156
Total Transmission Plant	13,125
Total Distribution Plant	5,654
Total General Plant	55
Total Depreciable Plant	37,154

As indicated in the Phase I re-filing, soil remediation was only added at the 2001/03 GRA. At that time, the target amount incorporated into amortization rates pending further analysis was $5 million. As a result, future soil remediation cost is underrepresented in terms of the amount collected to date and the updated estimated cost to remediate the soil (est. $12.959 million in 2005 dollars). All else being equal, this would equate to a shortfall in the future removal and site restoration provision.

Since the future removal and site restoration provision is established to fund the removal and disposal of assets, above ground site clean up and soil remediation, the Corporation's next deprecation study will focus on the estimated future cost to remove and dispose of assets and an updated estimate of the above ground clean up cost. As part of the next depreciation study the estimated total liability for negative salvage will be re-estimated along with the review of the useful lives of assets.

Topic

Reference

Directive 18

Preamble

NTPC defines Deferred Costs as costs incurred over a short period of time, where expenditures would be significant from a rate impact viewpoint and where the benefits are spread over a number of years. The HC seek further clarity respecting this definition.

Requests

a) Please define and quantify in dollars what level of expenditure NTPC would consider "significant from a rate impact point of view".

b) NTPC has noted the Job Evaluation System and Depreciation Studies as examples of Deferred Costs which it would propose to defer and amortize over 5 years. Please provide a more complete list of examples that may fall into this category in the future.

Response

a) In Decision 2-94 the PUB ruled from a capital perspective that anything over $1,000 is material for rate purposes. NTPC proposes that any expenditure that meets the test of a "deferred cost" and has a one-time impact of $10,000 or greater should be considered significant from a rate impact point of view.

b) In addition to the examples provided in the re-filing, other expenditures that could be treated as deferred costs include franchise renewal costs, load forecast remodeling, alternative energy funding studies, weather normalization models, investigation of station service and investigations of line losses. As indicated in the re-filing, deferred costs are costs incurred for intangible assets, generally incurred over a short period of time, that create a long-term or enduring benefit to Customers. They are similar to fixed assets in that they benefit more than one year, with the exception of their intangible nature. Treating these types of expenditures as O&M will result in them being built into rates in a test year buy not incurred on an on-going basis. Any given item that is deferred is not expected to occur annually, they generally occur once in a very broad period of time if they are ever repeated at all.

Topic

Reference

Directive 19

Preamble

At page 134 of Decision 13-2007, the Board specifically directed NTPC, "as part of its Phase I refiling, to adjust the Test Year sales forecasts by community having regard to historical normalized use per customer and any other relevant factors considered in the top down and bottom up approaches." Although the Board referred to the illustration provided by the HC in relation to Fort Smith as an example of the use of historical averages, NTPC did not provide any adjustments to the Fort Smith, Behchoko or Dettah usage per customer in Directive 19. The HC communities require further information.

Requests

a) Please provide a complete copy of the "comparison of the most recent 4-year simple average use per customer by community for residential customers."

b) Please provide all temperature or Degree-Day Deficiency data considered in that comparison.

c) Please provide specific reasons why the 4 year average use per residential customer in Fort Smith, Behchoko and Dettah as shown at pages 10 and 11 of the HC Argument which reflect near normal temperatures over a 4 year period was not factored into any adjustments for at least those communities.

d) Please provide the results of the preliminary review conducted for General Service Customers.

Response

a) Please refer to the Corporation's response to BR.NTPC-4 (b).

b) & c)

BR.NTPC-4 (b), as noted in that response does not rely upon Heating Degree Day data. As noted in that response, NTPC does not have the developed methods to weather normalize sales at the individual customer (or average use per customer) level. The only "consideration" of HDD data was in determining whether the four year period 2002/03 to 2005/06 was sufficiently representative of typical weather as to be an appropriate basis for comparison. In this regard, Table 1, HC.NTPC-5 to Table 3, HC.NTPC-5 below set out the HDD data for Fort Smith, Yellowknife and Inuvik which confirms this most recent four year period of available data (2002/03 to 2005/06) is appropriate for the present analysis.

In its argument, the HC proposed that the Fort Smith Residential and General Service sales forecasts should rely on a 4-year average of sales for the period 2001/02 through 2004/05. The HC felt that the 2005/06 actual data should be removed from the calculation on the basis that it was an unusually mild year and that the 4 year average HDD data for that period was lower than the 30 year normal. The HC preferred to use the four year period from 2001/02 through 2004/05 on the basis that the four year average HDD figure for that period was closer to the 30 year Normal.

Tables 1 through 3 provide the heating degree day (HDD) data for Fort Smith, Yellowknife and Inuvik respectively. Each table shows the 30 Year Normal as reported by Environment Canada, a calculated 20 year and 10 year average and calculated four year rolling averages from 1987/88 through 2006/07. The 4 year rolling averages are based on the actual HDD data from the 4 years prior.

In comparing the HDD data for each of the communities against the historical averages there are two points to note. First, the 30 year Normal reported by Environment Canada is the average based on 1971 through 2000, and is therefore not a complete reflection of 30 year average temperature conditions up to 2005/06, the year in question. Next, for each of the three communities, the 10 year averages are less than the 20 year averages which in turn fall below the 30 year Normal. This would seem to indicate that each of these communities have been experiencing a warming trend through the past 30 years.

In order to determine whether the four year average used in the analysis prepared for the response to Directive 19, the Corporation reviewed the four-year average Heating Degree Day (“HDD”) summarized in Tables 1 through 3. Table 1 summarizes the rolling 4-year average HDD data for

Fort Smith for 1987/88 through 2006/07[1]. A review of Table 1 indicates the following:

- Using the data for 2001/02 through 2004/05 (the period recommended by the HC) returns the highest four year rolling average for any period from 1995/96 through 2005/06.

- While the 4-year average from 2001/02 through 2004/05 is relatively close to the 30-year Normal (1971 through 2000), it is appreciably higher than either the 20-year average (1986/87 through 2005/06) or the 10 year average (1996/97 through 2005/06).

- The four year average from 2002/03 through 2005/06 is a better fit to both the 20 year average and the 10 year average.

The Corporation reviewed similar information it had available for Yellowknife and Inuvik. These data are summarized in Table 2 and Table 3.

A review of Table 2 indicates that for Yellowknife, like Fort Smith, the HDD data four-year average from 2001/02 through 2004/05 is the highest during the 1992/93 through 2005/06 period. For Yellowknife, the 4-year average from 2002/03 through 2005/06 is also a better fit to the 20 year average and 10 year average data, compared to the 2001/02 through 2004/05 period. For Inuvik, the 2001/02 through 2004/05 data are very similar to the 2002/03 through 2005/06 data (less than 1 per cent different).

Based on this review, the Corporation does not think it is reasonable to reject the 2005/06 actual data. While weather is certainly one factor that could influence average use per customer, there are others, including the uptake of different types of energy efficient technologies. The Corporation considers that the most recent data available is likely to reflect best these other factors. Therefore, in its consideration of the 4-year average use per customer metric, the Corporation based its review on the 4-year average using the most recently available actuals – the years 2002/03 through

[1] It should be noted that in some cases the HDD data vary very slightly from the information summarized by the HC in their argument. These differences in most cases reflect revisions to the HDD data by Environment Canada in the period between when the Corporation originally obtained the data and the present. The differences are in all cases small and not material to the analysis.

2005/06 for the 2006/07 test year, not 2001/02 through 2004/05 as suggested by the HC in their argument.

Please refer to the Corporation's response to BR.NTPC-4 for more information.

d) The results of the analysis of adopting a 4-year average forecasting method for General Service customers are provided in the Corporation's response to BR.NTPC-4.

Please refer to the response to BR.NTPC-4 and BR.NTPC-5 for more information.

Table 1, HC.NTPC-5 – Fort Smith Heating Degree Day Data and Four Year Rolling Averages

Fiscal Year Heating Degree Days

	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	30 Year Normal 1971-2000	20 year Avg 1986/87 - 2005/06	10 year Avg 1996/97 - 2005/06
Apr	550	402	587	620	480	562	607	566	513	602	466	577	620	606	598	379	477	599	553	772	512	612	454	429	552	559	556
May	449	311	268	265	274	389	315	296	222	327	331	265	296	356	370	207	303	339	323	479	297	488	330	234	296	324	349
Jun	134	115	143	175	138	88	112	110	105	160	154	85	87	115	99	74	141	148	98	89	130	156	122	66	122	119	117
Jul	67	57	102	79	79	72	54	68	63	85	79	21	106	37	25	35	99	20	20	57	50	41	71	52	70	58	45
Aug	89	89	184	139	188	90	86	141	90	145	156	86	151	90	93	68	83	152	82	140	91	175	141	83	127	119	111
Sep	336	350	359	293	223	296	313	283	311	379	341	269	274	275	224	281	247	342	201	289	284	341	313	191	306	289	279
Oct	523	615	614	546	527	545	537	625	714	547	550	481	543	618	614	454	516	530	561	676	447	600	470	548	554	555	548
Nov	714	1023	1039	1051	792	920	1061	1101	971	746	875	889	1003	962	728	742	762	783	775	832	872	844	724	1034	891	872	802
Dec	1320	1394	1125	1019	981	1194	1294	1380	1185	1239	1106	1099	1155	1188	943	1075	1078	1328	1153	947	1040	1278	877	932	1207	1,128	1,090
Jan	1325	1197	1227	1055	1314	1314	1315	1302	1204	1173	1502	1085	1429	1300	1300	1307	1265	981	1252	1278	1349	1296	1079	1128	1304	1,255	1,241
Feb	984	1282	1063	893	1177	998	1197	1005	1067	1011	1282	1132	1088	1005	847	877	917	1067	988	1172	1009	1034	929	1129	1069	1,035	985
Mar	924	857	941	978	824	1150	818	988	859	731	807	980	1100	1035	876	728	786	905	1108	1007	964	873	785	1008	941	915	907
Total	**7414**	**7691**	**7653**	**7112**	**6997**	**7619**	**7709**	**7864**	**7304**	**7144**	**7649**	**6968**	**7853**	**7586**	**6717**	**6225**	**6672**	**7192**	**7114**	**7739**	**7043**	**7738**	**6293**	**6835**	**7,439**	**7,227**	**7,032**

Four Year Rolling Averages

	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
4-year Average:					1983/84 - 1986/87	1984/85 - 1987/88	1985/86 - 1988/89	1986/87 - 1989/90	1987/88 - 1990/91	1988/89 - 1991/92	1989/90 - 1992/93	1990/91 - 1993/94	1991/92 - 1994/95	1992/93 - 1995/96	1993/94 - 1996/97	1994/95 - 1997/98	1995/96 - 1998/99	1996/97 - 1999/00	1997/98 - 2000/01	1998/99 - 2001/02	1999/00 - 2002/03	2000/01 - 2003/04	2001/02 - 2004/05	2002/03 - 2005/06
Apr					540	522	562	567	554	562	572	537	539	566	567	600	551	515	513	502	600	609	612	588
May					323	280	299	311	318	305	290	294	286	305	312	322	307	309	305	293	361	360	397	399
Jun					142	143	136	129	112	104	122	132	126	122	110	97	94	107	115	115	119	116	118	124
Jul					76	79	83	71	68	64	67	74	62	73	61	47	51	49	45	44	49	37	42	55
Aug					125	150	151	126	127	102	116	133	119	135	121	105	100	83	99	96	114	116	122	137
Sep					335	307	293	281	279	301	322	329	325	316	290	260	263	256	273	268	270	279	279	307
Oct					574	575	558	539	558	605	606	609	573	530	548	564	557	551	529	515	571	553	571	548
Nov					957	976	951	956	969	1013	970	923	870	878	932	895	859	798	754	765	788	816	831	818
Dec					1214	1129	1080	1122	1212	1263	1274	1227	1157	1150	1137	1096	1,090	1,071	1,106	1,158	1,126	1,117	1,104	1,035
Jan					1201	1198	1227	1249	1311	1284	1248	1295	1241	1297	1329	1278	1,334	1,293	1,213	1,201	1,194	1,215	1,294	1,250
Feb					1055	1103	1033	1066	1094	1067	1070	1091	1123	1128	1127	1018	954	911	927	962	1,036	1,059	1,051	1,036
Mar					925	900	973	942	945	954	849	846	844	905	981	998	935	856	823	882	951	996	988	907
Total					**7467**	**7363**	**7345**	**7359**	**7547**	**7624**	**7505**	**7490**	**7266**	**7404**	**7514**	**7281**	**7,095**	**6,800**	**6,702**	**6,801**	**7,179**	**7,272**	**7,409**	**7,204**
Difference from Actual					471	-255	-364	-505	243	480	-144	522	-586	-182	797	1056	423	-392	-412	-938	136	-466	**1115**	369

Table 2, HC.NTPC-5 – Yellowknife Heating Degree Day Data and Four Year Rolling Averages

Fiscal Year Heating Degree Days

	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	30 Year Normal 1971-2000	20 year Avg 1986/87 - 2005/06	10 year Avg 1996/97 - 2005/06
Apr	697	552	761	798	633	685	732	682	685	789	570	740	757	745	702	530	652	735	697	886	620	801	613	597	699	703	698
May	591	331	375	374	369	532	430	411	342	424	375	330	399	447	463	259	395	397	420	555	402	606	459	307	386	419	440
Jun	156	129	171	211	152	149	130	158	137	195	167	116	109	133	140	86	153	137	134	133	167	189	165	81	142	148	144
Jul	67	50	113	57	66	77	58	60	52	83	73	10	110	35	39	26	101	21	48	62	46	50	84	59	62	58	51
Aug	103	104	200	133	191	88	81	184	118	146	107	71	148	107	95	85	101	173	122	170	117	178	155	85	128	128	130
Sep	378	359	372	304	278	329	315	334	353	437	319	283	322	283	231	281	310	365	227	309	290	373	364	244	328	315	303
Oct	605	686	662	585	555	608	590	655	743	611	558	518	584	680	695	483	594	605	613	671	480	681	547	582	611	603	605
Nov	719	1049	1110	1104	923	1046	1147	1159	1056	816	688	912	1039	913	823	743	822	871	880	879	937	989	812	1063	955	928	867
Dec	1360	1527	1220	1130	1002	1272	1366	1462	1305	859	1150	1196	1281	1300	1050	1154	1189	1445	1230	993	1118	1383	967	1015	1293	1,193	1,183
Jan	1415	1273	1358	1137	1408	1462	1432	1392	1324	905	1580	1191	1479	1375	1432	1384	1320	1130	1342	1364	1470	1376	1239	1221	1389	1,337	1,343
Feb	1096	1377	1126	991	1279	1025	1310	1170	1227	829	1350	1222	1200	1163	1109	967	1024	1155	1165	1288	1139	1140	994	1205	1169	1,137	1,114
Mar	1086	1051	1112	1104	959	1269	973	1145	1026	649	994	1163	1187	1207	1016	905	965	1062	1229	1165	1151	1027	896	1180	1093	1,055	1,062
Total	**8271**	**8486**	**8580**	**7926**	**7813**	**8541**	**8564**	**8810**	**8367**	**6741**	**7930**	**7752**	**8615**	**8387**	**7795**	**6902**	**7627**	**8095**	**8105**	**8475**	**7936**	**8793**	**7292**	**7639**	**8,256**	**8,023**	**7,941**

Four Year Rolling Averages

	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
4-year Average:					1983/84 - 1986/87	1984/85 - 1987/88	1985/86 - 1988/89	1986/87 - 1989/90	1987/88 - 1990/91	1988/89 - 1991/92	1989/90 - 1992/93	1990/91 - 1993/94	1991/92 - 1994/95	1992/93 - 1995/96	1993/94 - 1996/97	1994/95 - 1997/98	1995/96 - 1998/99	1996/97 - 1999/00	1997/98 - 2000/01	1998/99 - 2001/02	1999/00 - 2002/03	2000/01 - 2003/04	2001/02 - 2004/05	2002/03 - 2005/06
Apr					702	686	719	712	683	696	722	682	696	714	703	736	684	657	655	653	742	734	751	730
May					418	362	412	426	436	429	402	388	367	382	388	410	392	391	378	368	442	443	496	505
Jun					167	166	171	160	147	143	155	164	154	147	131	124	117	128	129	127	139	143	156	163
Jul					72	71	78	64	65	62	63	67	54	69	57	48	52	50	47	49	58	44	51	60
Aug					135	157	153	123	136	118	132	139	110	118	108	105	109	97	113	120	142	146	147	155
Sep					353	328	321	306	314	333	360	361	348	340	302	280	279	276	297	296	303	298	300	334
Oct					634	622	603	585	602	649	650	642	607	568	585	619	610	613	594	574	621	592	611	595
Nov					995	1047	1046	1055	1069	1102	1044	930	868	864	888	922	879	825	815	829	863	891	921	904
Dec					1309	1220	1156	1192	1275	1351	1248	1194	1127	1121	1231	1207	1,196	1,173	1,210	1,255	1,214	1,197	1,181	1,115
Jan					1296	1294	1341	1359	1423	1402	1263	1300	1250	1289	1406	1369	1,418	1,378	1,317	1,294	1,289	1,327	1,388	1,362
Feb					1147	1193	1105	1151	1196	1183	1134	1144	1157	1150	1234	1174	1,110	1,066	1,064	1,078	1,158	1,187	1,183	1,140
Mar					1088	1056	1111	1076	1086	1103	948	953	958	998	1138	1143	1,079	1,023	987	1,040	1,105	1,152	1,143	1,060
Total					**8316**	**8201**	**8215**	**8211**	**8432**	**8571**	**8121**	**7962**	**7698**	**7759**	**8171**	**8137**	**7,925**	**7,678**	**7,605**	**7,682**	**8,075**	**8,153**	**8,327**	**8,124**
Difference from Actual					503	-340	-348	-599	65	1830	190	210	-917	-627	376	1235	298	-417	-500	-792	139	-640	**1035**	485

Table 3, HC.NTPC-5 – Inuvik Heating Degree Day Data and Four Year Rolling Averages

Fiscal Year Heating Degree Days

	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	30 Year Normal 1971-2000	20 year Avg 1986/87 - 2005/06	10 year Avg 1996/97 - 2005/06
Apr	933	934	1117	1088	1072	849	822	771	786	998	839	908	764	976	860	583	995	972	887	912	804	888	907	977	923	884	878
May	748	516	515	660	645	540	542	509	375	608	529	466	396	569	549	361	534	686	675	518	566	601	507	504	559	542	557
Jun	194	137	205	207	162	161	178	205	232	203	167	230	169	184	178	144	197	164	218	248	231	193	246	148	207	196	200
Jul	114	180	245	150	118	95	83	106	178	134	95	31	119	138	120	73	205	135	168	179	133	110	235	120	134	130	150
Aug	208	267	257	250	239	227	99	257	276	196	218	132	251	314	158	137	193	302	198	300	237	211	226	170	222	221	228
Sep	517	417	411	367	400	429	383	444	414	581	414	505	307	534	315	349	397	456	351	353	414	470	425	307	429	415	406
Oct	948	842	872	796	655	885	810	788	787	886	691	724	744	955	839	733	866	833	767	722	638	804	734	669	813	783	789
Nov	1007	1295	1162	1319	1191	1384	1379	1347	1264	1108	1072	1225	944	1121	940	1009	1152	1070	1091	942	1062	1190	1181	1150	1168	1,150	1,076
Dec	1285	1497	1226	1291	1222	1195	1368	1447	1463	1326	1275	1334	1341	1288	1288	1187	1380	1371	1232	1038	1321	1429	1158	1131	1356	1,298	1,269
Jan	1437	1282	1540	1316	1383	1563	1572	1334	1446	1266	1528	1290	1386	1413	1499	1425	1281	1185	1324	1398	1476	1256	1407	1295	1414	1,387	1,366
Feb	1523	1388	1183	1279	1246	864	1464	1302	1340	1101	1267	1232	1197	1194	1145	1199	1208	1543	1278	1195	1357	1195	965	1313	1267	1,228	1,228
Mar	1347	1167	1370	1251	1168	1286	1065	1290	1058	1117	1238	1333	1145	1326	1040	1291	1290	1357	1170	1280	1395	1185	1320	1404	1276	1,230	1,265
Total	**10260**	**9921**	**10103**	**9972**	**9500**	**9478**	**9765**	**9799**	**9617**	**9521**	**9335**	**9410**	**8763**	**10012**	**8931**	**8489**	**9696**	**10074**	**9357**	**9085**	**9636**	**9532**	**9310**	**9186**	**9,767**	**9,464**	**9,412**

Four Year Rolling Averages

	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
4-year Average:					1983/84 - 1986/87	1984/85 - 1987/88	1985/86 - 1988/89	1986/87 - 1989/90	1987/88 - 1990/91	1988/89 - 1991/92	1989/90 - 1992/93	1990/91 - 1993/94	1991/92 - 1994/95	1992/93 - 1995/96	1993/94 - 1996/97	1994/95 - 1997/98	1995/96 - 1998/99	1996/97 - 1999/00	1997/98 - 2000/01	1998/99 - 2001/02	1999/00 - 2002/03	2000/01 - 2003/04	2001/02 - 2004/05	2002/03 - 2005/06
Apr					1018	1053	1032	958	879	807	844	848	883	877	872	877	796	853	852	859	942	894	873	878
May					609	584	590	597	559	491	508	505	494	500	490	495	469	503	532	564	603	611	590	548
Jun					186	178	184	177	177	194	204	201	208	192	187	190	169	176	171	181	207	215	223	230
Jul					172	173	152	112	101	116	125	128	109	95	96	102	113	134	133	145	172	154	148	164
Aug					245	253	243	204	205	215	207	237	206	199	229	214	215	200	198	208	248	259	236	243
Sep					428	399	402	395	414	417	455	463	478	452	440	415	376	399	379	388	389	394	397	415
Oct					864	791	802	787	785	818	818	788	772	761	779	816	818	848	818	800	797	740	733	725
Nov					1196	1242	1264	1318	1325	1344	1275	1198	1167	1088	1091	1058	1,004	1,056	1,043	1,081	1,064	1,041	1,071	1,094
Dec					1324	1309	1233	1269	1308	1368	1401	1377	1349	1319	1309	1313	1,276	1,286	1,306	1,292	1,255	1,240	1,255	1,237
Jan					1394	1381	1451	1459	1463	1479	1404	1393	1382	1368	1404	1397	1,431	1,404	1,347	1,303	1,297	1,346	1,363	1,384
Feb					1343	1274	1143	1213	1219	1242	1302	1252	1235	1199	1223	1192	1,184	1,186	1,274	1,307	1,306	1,343	1,256	1,178
Mar					1284	1239	1269	1192	1202	1175	1132	1176	1187	1208	1261	1211	1,201	1,237	1,244	1,277	1,274	1,301	1,258	1,295
Total					**10064**	**9874**	**9763**	**9679**	**9635**	**9665**	**9675**	**9568**	**9471**	**9257**	**9380**	**9279**	**9,049**	**9,282**	**9,298**	**9,404**	**9,553**	**9,538**	**9,402**	**9,391**
Difference From Actual					564	396	-1	-120	18	143	341	158	707	-755	449	790	-647	-792	-59	319	-82	6	**92**	204

Topic

Directive 2 – Aklavik Plant

Reference

October 1, 2007 Refiling, Page 3-5

Preamble

Further details are required to understand the adjustment proposed by the Corporation.

Requests

a) Please provide copies of the Major Permit Application demonstrating the original cost of $3.5 million and the $0.8 million related to AFUDC and Overhead costs.

b) Please confirm the final project permit approval costs are $4.9 million which includes $0.5 million related to AFUDC and OH costs.

c) The original project budget reflected an addition of AFUDC and OH costs of $0.8 million to the $3.5 million project costs estimate (AFUDC/OH about 19% of total project cost of $4.3 million, $0.8/4.3 million). However, the amount approved in Decision 11-2006 reflect AFUDC and OH costs of $0.5 million and project estimate costs of $4.4 million (AFUDC/OH about 10% of total project cost of $4.9 million, $0.5/4.9 million). Please explain the reduction from 19% to the 10% in the AFUDC and OH costs.

d) Please explain why the adjustment proposed in Table 1 (page 4 of Re-Filing) is not calculated in reference to the difference between the $0.5 million amount approved for AFUDC and OH costs as approved in Decision 11-2006 and the amount of AFUDC and OH costs proposed in the 2006/08 GRA of $0.9 million. Please provide Table 1 recomputed using these differences (i.e. of $0.4 million in AFUDC and OH Costs).

Response

a) Please find attached a copy of the Major Project Permit Application for the Aklavik plant addition. This application mentions the original project estimate of $3.5 million (excluding AFUDC and overheads) at page 5, paragraph 1. This estimate was very preliminary and once NTPC went out for tenders, it was clear that the project cost would be closer to the $5 million threshold that requires a major project permit approval. The original estimate of $0.8 million related to AFUDC and overheads was not addressed in the major project permit application

however the TGC.NTPC-1 Table 1 below illustrates the calculation of the $0.8 million in AFUDC and overheads for this original budget estimate.

TGC.NTPC-1 Table 1 New Modular Power Plant - Aklavik
Original Budget Estimate ($000's)

Description	2003/04 Actual	2004/05 Budget	2005/06 Budget	2006/07 Budget	Total Project
Labour	41	45	280	18	384
Construction	12	565	1,830	135	2,542
Freight	-	-	125	-	125
Contingency	-	90	300	22	412
Project Sub-Total	**53**	**700**	**2,535**	**175**	**3,463**
Overhead	12	84	304	21	421
AFUDC	11	39	194	158	402
Project Total	**76**	**823**	**3,033**	**354**	**4,286**

b) & c) Confirmed. PUB Decision 11-2006 approved the final project permit application for the Aklavik plant addition at $4.9 million. The project cost before AFUDC and overheads was $4.4 million therefore the total cost included approximately $0.5 million related to AFUDC and overheads. TGC.NTPC-1 Table 2 illustrates how the $4.9 million was compiled.

TGC.NTPC-1 Table 2 New Modular Power Plant - Aklavik
Budget Estimate as per Project Permit Application ($000's)

Description	2003/04 Actual	2004/05 Actual	2005/06 Acutal	2006/07 Budget	Total Project
Labour	55	26	395	140	615
Construction	12	566	664	2,185	3,427
Freight	-	3	1	164	168
Contingency	-	-	-	175	175
Project Sub-Total	**67**	**595**	**1,060**	**2,664**	**4,385**
Overhead	12	71	133	238	454
AFUDC	11	19	16	15	61
Project Total	**90**	**685**	**1,209**	**2,917**	**4,900**

Upon review, it was determined that the $4.9 million included incorrect numbers for the forecast AFUDC for 2005/06 and 2006/07. The forecast AFUDC for the third and fourth year should have been $92,000 and $137,000 respectively. This error resulted in an understatement of AFUDC equal to $198,000, bringing the

total for AFUDC and overheads to $0.7 million. TGC.NTPC-1 Table 3 illustrates the correction for AFUDC in 2005/06 and 2006/07.

TGC.NTPC-1 Table 3 New Modular Power Plant - Aklavik
Budget Estimate as per Project Permit Application (Corrected) ($000's)

Description	2003/04 Actual	2004/05 Actual	2005/06 Acutal	2006/07 Budget	Total Project
Labour	55	26	395	140	615
Construction	12	566	664	2,185	3,427
Freight		3	1	164	168
Contingency				175	175
Project Sub-Total	**67**	**595**	**1,060**	**2,664**	**4,385**
Overhead	12	71	133	238	454
AFUDC	11	19	92	137	259
Project Total	**90**	**685**	**1,285**	**3,039**	**5,098**

Correcting for the error, the AFUDC and overheads ($0.7 million) based on the estimated project timeline in the major project permit application was still lower than the original budget estimate ($0.8 million). The forecast AFUDC was lower due to a shifting of the timeline to complete the project such that most of the costs would be incurred in year four (Table 3) as opposed to year three (Table 1) of a 4-year project.

d) As per Directive 2 from Decision 13-2007, Table 1 of the Phase 1 re-filing calculates the difference in AFUDC and overheads from the original project budget ($4.3 million with AFUDC and overheads) to the capital addition in the 2006/08 GRA ($5.3 million with AFUDC and overheads). The comparison from original budget to the 2006/08 GRA application is the appropriate point of comparison as it addresses the Board's concern over the additional costs in AFUDC and overheads from when the project was first planned. This approach includes any inflationary impacts while NTPC undertook additional community consultation and temporary redeployed resources to address the emergency plant rebuild in Fort McPherson.

NTPC maintains that the additional costs were warranted given the circumstances. The additional community consultation was necessary in order for the project to proceed on a new site with lower risk of flooding than the current site. As well, NTPC acted prudently in delaying the Aklavik plant rebuild while resources were shifted to complete the emergency rebuild of the Fort McPherson plant, which was destroyed by fire.

NORTHWEST TERRITORIES POWER CORPORATION

Dept. of Finance, 4 Capital Drive, Hay River NT X0E 1G2 Phone (867) 874-5234 Fax (867) 874-5229 www.ntpc.com

February 28, 2006

Mr. John Hill, Chairman
Northwest Territories Public Utilities Board
203-62 Woodland Drive
PO Box 4211
HAY RIVER, NT X0E 0R0

Dear Mr. Hill,

Re: Application for Major Project Permit – Aklavik Modular Genset Power Plant

The Northwest Territories Power Corporation ("NTPC" or "the Corporation") has identified a need for a new powerplant in Aklavik. NTPC has reviewed several options for addressing this need and has had extensive consultation with the community to understand their requirements and receive their feedback on potential options. This application sets out the approvals requested; the background related to the project; the impact of the project on rates; the public need for the project; and the impact on the reliability of the utility.

Approvals Requested

NTPC is seeking approval of the Public Utilities Board ("PUB") for a Project Permit in accordance with section 54 of the *Public Utilities Act* to prepare the new plant site, purchase, transport and install pre-built modules and convert the community's distribution system to the 4160 volt standard from its current non-standard 2400 volt system. The estimated cost to undertake the project is $4.9 million. Though this estimate is below the $5 million threshold for a Major Project Permit as outlined in the *Public Utilities Act*, the estimate is close to the threshold and would be a material portion of the rate base for the community.

Background

The Hamlet of Aklavik is located in the Mackenzie District of the Northwest Territories, about 50-km west of Inuvik. The Hamlet is situated on a bend of the Peel Channel and has a population of approximately 900 people. The Northwest Territories Power Corporation (NTPC) operates a diesel-fuelled power plant, in Aklavik with an installed capacity of 1,780 kW. The plant was built in 1976. Since that time, the community has developed in the area around the plant. With the

increased development in the vicinity there have been increased complaints from local residents related to plant noise and air emissions.

Over the years since its construction, the powerhouse floor, building, and radiator racks have been experiencing differential settlements and seasonal movements, requiring constant shimming and leveling of the gensets. All electrical and mechanical equipment, except a Cat 3508 genset installed in 1999, is relatively old. By 1978, settlement of the building slab had reached levels to warrant mudjacking to re-level the floor. Micro-piles were installed then in 1981 to support the slab surrounding the gensets and the slab was again re-leveled by means of mudjacking. The powerhouse is situated below extreme flood level, in contravention of requirements for a post-disaster structure.

Gygax Engineering Associates Ltd. (GEA) completed a Plant Condition Assessment on behalf of the Corporation, in association with Kerr Wood Leidal Associates Ltd. (KWL). NTPC's engineering staff reviewed the report and recommended that a new power plant be constructed.

Alternatives Considered

Several options for addressing the deficiencies in the existing plant were considered by the Corporation's engineers. It should be noted that natural gas will not be available in the Community for the foreseeable future. The current natural gas activity is to the east of Inuvik. While a Mackenzie gas pipeline is planned for construction within 10 years, there are no plans for a pipeline across the Mackenzie Delta to Aklavik. There is no exploration in the immediate vicinity of Aklavik. Natural gas supply options were therefore not considered among the alternatives. The options reviewed by the Corporation's engineers and as part of a consultation process with the Aklavik Town Council are described below.

Option 1 Replace Powerhouse at Existing Site

This option would provide a completely new plant on the existing site and would address the following concern with the existing plant:

- It would satisfy all code requirements, and provide a service life exceeding 40 years.
- Full (jacket-water and exhaust gas) heat recovery could be accommodated.
- The plant floor would be above designated flood level.

- The Hamlet's concerns about noise, aesthetics, and cultural impacts would be addressed.

- Local trucking of fuel could be eliminated if a tank farm were built on land beside the plant

This option is the most costly for providing a new power plant for the community. Additionally the cost benefit of providing residual heat to the community is marginal at best. This option also does not address the Hamlet's concerns regarding the location of generation facilities in the town or near residential areas.

Option 2 Transmission Line from Inuvik

This option would involve constructing a transmission line from Inuvik to Aklavik for primary power supply with perhaps only stand-by generation available in the community. Crossing the Mackenzie Delta with a transmission line requires specialized foundations for the power poles. The route from Inuvik to Aklavik would also involve two major river crossings. These crossings must account for navigable waters and provide clearance for boat passage. In addition, the rivers experience significant flooding during spring break-up and significant ice scouring. These factors contribute to very high costs for the transmission line. In addition, this option would require additional generating capacity in Inuvik. Therefore the Corporation does not consider this option to be viable or cost effective.

Option 3 New modular power house at Imperial Oil tank farm and distributed generation near the school.

This option consists of constructing a smaller modular genset power station constructed at the Imperial Oil (IOL) tank farm and one generator module at or very near the school to provide residual heat for that facility. The new power station at IOL would have three genset modules and a switchgear/controls module situated in a fenced area.

This option was the second most costly of the new plant options but was designed to address the community's interest in investigating the potential for the use of residual heat. However, the installation of a single generating unit in the community separate from the main plant would make fuelling and power plant control issues more complex. This option would introduce an element of noise and air emissions in the school environment. The Corporation was also concerned that this option may put it at risk for unnecessary environmental liability. For these reasons the Corporation and the community did not prefer this approach despite the potential for residual heat use.

Option 4 **Design and construct a new modular genset power station located at the Imperial Oil Tank Farm.**

This option involved constructing a modular genset power station at the Imperial Oil tank farm. The new power station would be composed of four genset modules and a switchgear/controls module situated in a fenced area. This was the least costly of the options reviewed. However, this option required a site lease with IOL that NTPC was not able to negotiate successfully.

Option 5 **Design and construct a new modular genset power station located in the Industrial Area**

This option consists of a modular genset power station constructed on new lots in the community's industrial area. The new power station would be composed of four genset modules and a switchgear/controls module situated in a fenced area. This option has the second lowest capital cost of all the options reviewed, addresses all the structural and code deficiencies and addresses the Hamlet's request for the power generation facilities to be located outside the residential core. This option is therefore NTPC's preferred option. Further, this option has received support from the community by way of a Town Council motion.

Overview of Project

The project involves constructing a modular genset power station on new lots in the community's industrial area. The new power station would contain four genset modules and a switchgear/controls module situated in a fenced area. The use of modular gensets (i.e. each genset housed in an individual enclosure) is proposed as a cost saving measure. Modular gensets are proving to be more cost effective than a traditional or modular powerhouse.

The 2004/05 peak load for Aklavik was approximately 725 KW. The peak is forecast to remain at approximately this level through 2010/11. With the planned installation of four Detroit Diesel Series 60 320 KW units the peak load that could be supplied by the plant is 872 KW. This is the best mix of units available in standard size gensets to serve the forecast peak load.

The Series 60 generating units are very efficient (3.9 kW.h/litre). This compares very favourably with the units being replaced. It is estimated there will be a reduction in fuel consumption and exhaust emissions compared to the existing plant.

The preliminary estimate for the project was approximately $3.5 million, well below the threshold required for a project permit under the *Public Utilities Act*. Therefore NTPC did not apply for a project permit when initially considering the project.

However, work on the project was delayed from the original schedule due to on-going consultation with the community and the fire at the Fort McPherson plant, which required the immediate attention of NTPC's engineering staff. Also, due to increases in the price of steel and other materials, the tenders received for supply of the gensets and other materials were significantly higher than originally estimated.

The project has proceeded on the basis of earlier cost estimates and approximately $2.2 million will be spent by the end of 2005/06 with the remainder being spent in 2006/07. The revised budget for the project is now $4.9 million. As the revised budget for the project is close to the $5 million threshold NTPC is applying for a project permit. The budget figures are attached as Appendix A to this application

Basis for Project Permit

The *Public Utilities Act* sets out 3 specific matters for the Board to review with respect to applications for project permits: impact of the project on rates, the public need for the project, and the reliability of the public utility.

A. Impact of the Project on Rates

The construction of the new power plant at Aklavik will have no impact on rates until the time of the Corporation's next General Rate Application. Once the power plant is approved as a part of the Corporation's rate base, the primary impact on the community's rates will be increases to the return on ratebase and amortization expense. It is anticipated that these increases will be offset somewhat by a reduction in fuel expense due to the higher fuel efficiency of the newer engines.

Table 1 provides an estimate of the impact of the project on the 2002/03 community revenue requirement, had the project been in rate base in the 2002/03 test year. Table 1 indicates that the impact of the project in the 2002/03 test year would have been a $447,000 (approximately 30 per cent) increase in the revenue requirement for Aklavik.

Table 1. Estimate of Project Impact on 2002/03 test year Revenue Requirement

Category	2002/03 COSA	2002/03 COSA with New Plant Estimate	Change ($)
Rate Base ($)	1,064,000	5,361,000	4,297,793
Return on Rate Base ($)	102,000	516,000	413,448
Production Fuel Expense ($)	696,000	612,000	-84,130
Diesel Production Amort. Expense ($)	75,000	193,000	118,002
Total Revenue Requirement ($)	**1,517,000**	**1,964,000**	**447,000**

B. The Public Need for the Project

The project is required in order to maintain safe and reliable electric service to the community. In order to develop a project that meets the utility's requirements for a safe and reliable power supply at a reasonable cost as well as the needs of the community, NTPC has undertaken extensive consultations with the town council. The community indicated a need to have the power station located away from residential areas of the community, as well as an interest in pursuing cogenerative heating options. After reviewing several options with the town leadership, the modular genset power plant project as described in this application was judged by NTPC and the town council to be the most appropriate solution to meet the needs of the Corporation and the community. The project has received the support of the town council through approval of a council motion.

C. The Reliability of the Public Utility

Over the years since its construction, the powerhouse floor, building, and radiator racks have been experiencing differential settlements and seasonal movements, requiring constant shimming and levelling of the gensets. By 1978, settlement of the building slab had reached levels to warrant mudjacking to re-level the floor. Micro-piles were installed then in 1981 to support the slab surrounding the gensets and the slab was again re-levelled by means of mudjacking. All electrical and mechanical equipment, except a Cat 3508 genset installed in 1999, is approximately 30 years old. Independent engineering consultants and the Corporation's engineers have reviewed the condition of the existing plant and found that there are significant deficiencies. The project is essential to ensure the ongoing reliability and safety of electricity supply to the community.

In summary, the current plant in Aklavik does not meet the Corporation or the community's requirements for a safe and reliable power supply. Several options have been reviewed and the modular genset plant project as described in this application was judged by both the Corporation and the community to be the preferred option. The Corporation therefore submits that the project is in the public interest, and respectfully requests approval of a Major Project Permit for the Aklavik Modular Genset Power Plant as outlined in this application.

If you have any questions, please contact me at (867) 874-5234.

Sincerely,

Judith Goucher
Director, Finance and CFO

Appendix A:
Proposed Budget and Schedule for Aklavik Modular Genset Power Plant

Table A. Project Budget*

Description	2003/04 Actual $	2004/05 Actual $	2005/06 Budget $	2006/07 Budget $	Total Project $
Salaries	38,500	26,000	82,000	40,000	**186,500**
Transportation & Accommodation	16,000	0	10,000	94,500	**120,500**
Engineering Studies & Design			215,000	20,000	**235,000**
Consultants - Expenses			45,000	28000	**73,000**
Land Cost		**90,000**			**90,000**
Subtotal Engineering	**54,500**	**116,000**	**352,000**	**182,500**	**705,000**
Site Preparation	12,000		230,000	65,000	**307,000**
Building Civil		0	285,000	100,000	**385,000**
Mechanical		420,000	200,000	1,000,000	**1,620,000**
Electrical		65,000	200,000	760,000	**1,025,000**
Subtotal Construction	**12,000**	**485,000**	**915,000**	**1,925,000**	**3,337,000**
Freight		3,000	3,000	162,000	**168,000**
Contingency 15%			60,000	115,000	**175,000**
TOTAL	**66,500**	**604,000**	**1,330,000**	**2,384,500**	**4,385,000**

* With AFUDC and overheads project budget is $4,900,000.

Topic

Directive 3

Reference

October 1, 2007 Refiling, Page 7; Schedules 5.5 to 5.9

Preamble

Further information is needed to understand the increases in Cash Working Capital amounts.

Requests

a) The Cash working capital requirements have increased from $1 million to $1.188 million in 2006/07 and from $1.040 million to $1.249 million in 2007/08. Please confirm this increase is due entirely to the separate recognition of net lag lead (lag) days for each expense item.

b) Please explain why insurance is shown as a separate line item. Confirm if this item was previously included with Supply and Services in the original 2006-08 GRA.

Response

a) Not confirmed. The cash working capital of $1 million in 2006/07 and $ 1.040 million in 2007/08 referenced in the question are from the November 24, 2006 application. The Corporation revised its cash working capital forecasts as part of the May 16, 2007 refiling (exhibit 13 to the Phase I proceeding). The adjustments to cash working capital were explained in the cover letter of the May 16, 2007 re-filing and the Corporation's response to TGC.NTPC-46 (c) of the Phase I proceeding.

   The cash working capital forecasts in the May 16, 2007 re-filing were $1.275 million in 2006/07 and $1.327 million in 2007/08. The cash working capital forecasts in the October 1, 2007 re-filing are $1.188 million for 2006/07 and $1.249 million for 2007/08. These represent slight decreases relative to the May 16, 2007 re-filing ($0.087 million decrease in 2006/07 and $0.078 million decrease in 2007/08). The decreases are primarily the result of two factors:

   - changes to the Corporation's Operations and Maintenance expenses to reflect the Board's directions in Decision 13-2007.

- calculation of cash working capital using the specific expense lags for each expense category.

b) It is confirmed that Insurance was included with the supplies and services expenses used to calculate the cash working capital forecast in the November 24, 2006 application.

As noted in Table 7 of the Corporation's response to TGC.NTPC-46 (e) from the Phase I proceeding, Insurance has a different expense lag associated with it than other supplies and services. In order to implement Board Directive 4 from Decision 13-2007 "…to provide a computation of its cash working capital for the test years using the net lead or lag associated with each expense item" it is necessary to show Insurance as a separate expense item from other supplies and services.

Topic

Directive 9 – Losses

Reference

October 1, 2007 Refiling, Page 12

Preamble

Additional details are needed to ensure compliance with Board directions.

Requests

a) NTPC states the revised 2006/07 and 2007/08 losses reflect the Board direction "to apply a 7% cap on losses." However, it is not evident from an examination of Schedules 2.1-2.3 of the Re-filing how this has been achieved. Please provide a schedule that identifies, for each community, the derivation of the losses for community, for each of the test years, and reconcile the totals to Schedule 2.1-2.3 of the re-filing. Please identify all communities for which a 7% cap has been applied.

Response

a) Please see the Table 1, TGC.NTPC-3 below, which summarizes line losses from the Phase I Application and the October 1, 2007 Phase I Re-filing by community. For an explanation of how line losses were derived in the Application, please refer to page 2-17 of the Application.

Table 1, TGC.NTPC-3
Losses by Community

		2006/07 Losses from Application	2006/07 Losses from Re-Filing	2007/08 Losses from Application	2007/08 Losses from Re-Filing
101 Snare/Yellowknife	(MW.h)	6,643	6,637	7579	7,573
	(% of Generation)	3.4%	3.4%	3.9%	3.9%
104 Wha Ti	(MW.h)	135	119	135	119
	(% of Generation)	7.8%	**7.0%**	7.8%	**7.0%**
105 Gameti	(MW.h)	43	43	42	42
	(% of Generation)	4.5%	4.5%	4.3%	4.5%
110 Lutsel K'e	(MW.h)	90	90	92	92
	(% of Generation)	5.7%	5.7%	5.7%	5.7%
201 Taltson	(MW.h)	6742	4,447	6818	4,493
	(% of Generation)	10.2%	**7.0%**	10.2%	**7.1%**
205 Ft Simpson	(MW.h)	446	446	453	453
	(% of Generation)	5.5%	5.5%	5.5%	5.5%
206 Ft. Liard	(MW.h)	254	193	244	186
	(% of Generation)	9.0%	**7.0%**	9.0%	**7.0%**
207 Wrigley	(MW.h)	45	45	41	41
	(% of Generation)	6.2%	6.2%	6.2%	6.2%
208 Nahanni Butte	(MW.h)	37	25	35	24
	(% of Generation)	9.4%	**7.0%**	9.4%	**7.0%**
209 Jean Marie River	(MW.h)	63	19	65	19
	(% of Generation)	19.0%	**7.0%**	19.0%	**7.0%**
301 Inuvik	(MW.h)	1854	1,854	1880	1,880
	(% of Generation)	6.0%	6.0%	6.0%	6.0%
304 Norman Wells	(MW.h)	1121	594	1157	614
	(% of Generation)	12.4%	**7.0%**	12.4%	**7.0%**
305 Tuktoyaktuk	(MW.h)	480	302	485	305
	(% of Generation)	10.6%	**7.0%**	10.6%	**7.0%**
306 Ft. McPherson	(MW.h)	146	146	144	144
	(% of Generation)	4.2%	4.2%	4.2%	4.2%
307 Aklavik	(MW.h)	158	158	158	158
	(% of Generation)	5.7%	5.7%	5.7%	5.7%
308 Deline	(MW.h)	242	180	243	181
	(% of Generation)	9.1%	**7.0%**	9.1%	**7.0%**
309 Ft. Good Hope	(MW.h)	153	153	154	154
	(% of Generation)	5.3%	5.3%	5.3%	5.3%
310 Tulita	(MW.h)	181	149	183	150
	(% of Generation)	8.3%	**7.0%**	8.3%	**7.0%**
311 Paulatuk	(MW.h)	109	91	112	93
	(% of Generation)	8.2%	**7.0%**	8.3%	**7.0%**
312 Sachs Harbour	(MW.h)	42	42	41	41
	(% of Generation)	4.8%	4.8%	4.5%	4.8%
313 Tsiigehtchic	(MW.h)	55	55	57	57
	(% of Generation)	6.6%	6.6%	6.6%	6.6%
314 Colville Lake	(MW.h)	54	21	55	21
	(% of Generation)	16.2%	**7.0%**	16.3%	**7.0%**
315 Ulukhatok	(MW.h)	104	104	110	110
	(% of Generation)	5.5%	5.5%	5.5%	5.5%
Total Losses (MW.h)		**19,197**	**15,915**	**20,283**	**16,952**
Total Losses per Schedule 2.1 (MW.h)		**19,197**	**15,915**	**20,283**	**16,952**

Topic

Directive 10 – Station Service

Reference

October 1, 2007 Refiling, Page 10

Preamble

Additional details are needed to ensure compliance with Board directions.

Requests

a) NTPC states the revised 2006/07 and 2007/08 station loss amounts and percentages reflect the Board direction "to calculate station service using the same procedure used for fuel efficiencies." However, it is not evident from an examination of Schedules 2.1-2.3 of the Refiling how the three years of actual data has been deployed to arrive the one line number of station service on Schedule 2.3, L27 (for example, for 2007/08, the original FC was 3,274 Mwh and per Refiling, it is 3,068 Mwh). Please provide a schedule that identifies, for each community, the derivation of the station loss for that community for each of the test years and reconcile the totals to Schedule 2.1-2.3 of the refiling. Please identify all communities for which the 5% cap has been applied.

b) Please provide the station service data requested above for Fort Resolution, Normal Wells and Fort McPherson.

Response

a) and b)

Please see Table 1, TGC.NTPC-4 below. For a description on how station service was calculated in the Application, please refer to page 2-17 of the Application. For a description on how station service was calculated in the Re-filing, please refer to the Corporation's response to Directive 10, from Decision 13-2007.

Table 1, TGC.NTPC-4
Station Service by Community

		2006/07 Station Service from Application	2006/07 Station Service from Re-filing	2007/08 Station Service from Application	2007/08 Station Service from Re-filing
101 Snare/Yellowknife	(MW.h)	5,982	5,938	6,137	6,015
	(% of Generation)	3.1%	3.1%	3.1%	3.1%
104 Wha Ti	(MW.h)	23	23	23	23
	(% of Generation)	1.4%	1.4%	1.3%	1.3%
105 Gameti	(MW.h)	85	47	85	47
	(% of Generation)	8.7%	5.0%	8.7%	5.0%
110 Lutsel K'e	(MW.h)	96	79	96	81
	(% of Generation)	6.0%	5.0%	5.9%	5.0%
201 Taltson	(MW.h)	1,665	1,796	1,665	1,753
	(% of Generation)	2.5%	3.4%	2.4%	3.3%
203 Fort Resolution*	(MW.h)	111	111	111	111
	(% of Generation)	4.1%	4.1%	4.2%	4.2%
205 Ft Simpson	(MW.h)	231	254	231	244
	(% of Generation)	2.8%	3.1%	2.8%	3.0%
206 Ft. Liard	(MW.h)	33	38	33	37
	(% of Generation)	1.2%	1.4%	1.2%	1.4%
207 Wrigley	(MW.h)	27	25	27	25
	(% of Generation)	3.7%	3.5%	4.0%	3.7%
208 Nahanni Butte	(MW.h)	33	18	33	17
	(% of Generation)	8.4%	5.0%	8.8%	5.0%
209 Jean Marie River	(MW.h)	31	14	31	14
	(% of Generation)	9.3%	5.0%	9.1%	5.0%
301 Inuvik	(MW.h)	1,612	1,548	1,612	1,570
	(% of Generation)	5.2%	5.0%	5.1%	5.0%
304 Norman Wells	(MW.h)	101	81	101	89
	(% of Generation)	1.1%	0.9%	1.1%	1.0%
305 Tuktoyaktuk	(MW.h)	226	193	226	200
	(% of Generation)	5.0%	4.5%	4.9%	4.6%
306 Ft. McPherson	(MW.h)	153	153	153	153
	(% of Generation)	4.4%	4.4%	4.5%	4.5%
307 Aklavik	(MW.h)	117	98	117	109
	(% of Generation)	4.2%	3.6%	4.2%	4.0%
308 Deline	(MW.h)	56	57	56	57
	(% of Generation)	2.1%	2.2%	2.1%	2.2%
309 Ft. Good Hope	(MW.h)	76	101	76	93
	(% of Generation)	2.7%	3.5%	2.6%	3.2%
310 Tulita	(MW.h)	122	107	122	108
	(% of Generation)	5.6%	5.0%	5.5%	5.0%
311 Paulatuk	(MW.h)	53	52	53	51
	(% of Generation)	4.0%	4.0%	3.9%	3.8%
312 Sachs Harbour	(MW.h)	96	44	96	43
	(% of Generation)	10.3%	5.0%	10.6%	5.0%
313 Tsiigehtchic	(MW.h)	39	42	39	41
	(% of Generation)	4.7%	5.0%	4.5%	4.7%
314 Colville Lake	(MW.h)	2	4	2	3
	(% of Generation)	0.6%	1.2%	0.6%	1.0%
315 Ulukhatok	(MW.h)	62	64	62	64
	(% of Generation)	3.3%	3.4%	3.1%	3.2%
Total Losses (MW.h)		**10,921**	**10,777**	**11,076**	**10,836**
Total Losses per Schedule 2.1 (MW.h)		**10,921**	**9,838**	**11,076**	**9,919**

Note: *Fort Resolution station service is included in the total for Plant 201 Taltson station service.

Topic

Directive 19 – Sales Forecasts

Reference

October 1, 2007 Refiling, Page 25-28

Preamble

The Corporation agrees with the Board that average use per Customer can be a helpful test of reasonableness for Residential sales forecasts. The Corporation undertook a comparison of the most recent 4-year simple average use per Customer by community for Residential Customers. Corporation wide, the average use per Customer measure produced similar results to the Corporation's existing method (5% variance at the Customer class level). [Page 26, Refiling].

Requests

a) Please provide details of the above noted most recent 4-year simple average use per customer by community for Residential and GS customers on a community basis.

b) Compare the results of the data resulting from (a) above to the sales forecast in the GTA (for each test year) and provide comment on the differences and why the 4-year average use should not be used in this Application.

c) Please discuss the merits of using a weighted average as opposed to the use of a simple average, and explain how NTPC would apply a weighted average and the pros and cons of using a weighted average approach.

Response

a), b) and c)

Please refer to IR Response BR.NTPC-4.

Topic

Directive 22 – Fuel Stabilization Accounts

Reference

October 1, 2007 Refiling, Page 35-36

Preamble

The Corporation has reviewed the Board's directive and comments in Decision 13-2007. In the Corporation's view, the most practical way to implement the recommendation of the Board is to develop a community specific index for the fuel rider that recognizes differences in fuel efficiency, line losses and station service. Table 1 below shows the calculation of the fuel rider index for 2006/07. Table 2 shows the calculation of the fuel rider index for 2007/08.

Requests

a) Please provide details of any other options considered in response to the Board direction for "determining future fuel stabilization riders triggered by fuel price changes as part of the refiling." [Decision 13-2007, page 146]

b) Please explain how the proposed index reflects the Board's finding "that under community based rates, the fuel riders should follow the community costs as closely as possible." [Decision 13-2007, page 145]

c) Please provide a hypothetical example of how the proposed index would operate and impact each of the thermal communities affected by the Fuel Stabilization Fund. For purposes of this example, please assume there has been no change to the Landed Cost, Fuel Service Charge, Fuel Tax, but there has been a significant increase in the cost of the Delivery Charge. The TGC is trying to ascertain how changes in cost inputs that vary as amongst communities (primarily shipping/distribution costs) are recognized with the proposed index and the impact on the subsequent FSF rider.

d) Please provide the data provided in Tables 1 and 2 of the Oct 1, 2007 Re-filing in electronic format using Excel.

Response

a), b), and c)

The full text of Board Decision 13-2007 on this topic reads:

> "The Board agrees with the TGC that under community based rates, the fuel riders should follow the community costs as closely as possible. The Board notes the increase or decrease in fuel costs that are passed through to customers via the fuel rider would be approximately the same incremental costs per kWh for each community resulting from a common change in the reference price for crude oil. However, given the differences in fuel efficiencies by community as well as differences in station service and line losses by community, the fuel riders to pass through a given cost change can vary by community. For example, a community with a relatively low average fuel efficiency would require a higher fuel rider compared with one with a relatively high fuel efficiency in order to pass through a given cents per kWh increase or decrease in fuel costs. The present fuel stabilization rider mechanism does not recognize these differences by community.
>
> The Board notes NTPC's concern respecting material costs for maintaining separate fuel stabilization accounts by community. However, the Board considers the premise of community based rates can be maintained if the change in fuel cost following a change in the reference price of oil can result in different fuel riders for each community based on the forecast efficiencies and station service/losses for that community. Since the change in the fuel cost on a per kWh basis could be expected to be approximately the same for all communities, there will be no requirement to maintain separate fuel stabilization accounts by community. The reconciliation of revenues and costs recorded in the fuel stabilization account could be carried out as at present using a single fund. The Board directs NTPC to consider these comments and propose a procedure for determining future fuel stabilization riders triggered by fuel price changes as part of the refiling."[1]

In the Corporation's view the method it proposed is the only one that could address the Board's concern with respect to different fuel efficiency, line losses and station service by community while maintaining a single fuel stabilization account. Therefore the Corporation did not consider any other methods.

The indexing method proposed by the Corporation in its response to Directive 22 addresses the concern by the Board that the present method for calculating the

[1] Decision 13-2007 pages 145-146.

fuel rider does not address differences in fuel efficiency, line losses and station service by community.

The indexing method does not attempt to make any adjustments to the way changes in fuel price is calculated in the fund. This is consistent with the Board's finding that "Since the change in the fuel cost on a per kWh basis could be expected to be approximately the same for all communities, there will be no requirement to maintain separate fuel stabilization accounts by community".

A hypothetical comparison of the calculation of the fuel price change described in the TGC's question is presented below. It should be noted that the Corporation is providing this table for illustrative purposes only.

Table 1, TGC.NTPC-6 shows a hypothetical calculation of the Fuel Stabilization Fund Balance for a hypothetical period. The columns show the following values:

- Column A – the approved fuel price for 2007/08.
- Column B – a hypothetical actual fuel price excluding delivery charges
- Column C – a hypothetical delivery charge, largely consistent with the delivery charges provided in the response to TGC.NTPC – 40.
- Column D – the calculation of the hypothetical fuel price variance.
- Column E – hypothetical generation for illustrative purposes
- Column F – the approved 2007/08 fuel efficiency
- Column G – litres of fuel required
- Column H – Fuel price (draw)/contribution
- Column I – the 2007/08 Fuel Rider Index per the Corporation's response to Directive 22
- Column J – illustrative proposed diesel fuel riders by community that would result from the hypothetical scenario.

In this scenario, the deficiency of $39,857 is proposed to be collected over forecast sales of 2.8 GW.h resulting in a proposed fuel rider of 1.42 cents/kW.h. The community specific fuel riders in column J are the community specific fuel rider indices in Column I multiplied by the fuel rider of 1.42 cents/kW.h. In this scenario the Corporation would apply the riders until total collections approached the balance to be collected ($39,857) with the Fuel Stabilization Fund being credited for actual collection. The result is that communities with a higher Fuel Rider Index would contribute a proportionately greater amount per kW.h of sales, in recognition of their different fuel efficiency, line losses and station service.

Table 2, TGC.NTPC-6 shows the same information, except that in one community, Fort Simpson, a drastically higher fuel delivery price is assumed

(17.40 cents/litre instead of 8.70 cents/litre). All other variables are the same as Table 1, TGC.NTPC- 6.

The table shows that the total deficiency to be collected by the fuel rider increases and as a result the proposed fuel rider also increases. The community specific riders in Column J also increase proportionally. In short, the indexing method does not flow through the delivery charge solely to Fort Simpson.

d) Please refer to the attached Excel file.

Northwest Territories Power Corporation
TABLE 1, TGC.NTPC-6
Hypothetical Diesel Community Fuel Stabilization Fund Balance - Scenario 1

LINE NO.	PLANT NO.	PLANT	A APPROVED FUEL PRICE ($/litre)	B ACTUAL FUEL PRICE EXC. DELIVERY ($/litre)	C ACTUAL FUEL PRICE DELIVERY ($/litre)	D=A-(B+C) FUEL PRICE VARIANCE ($/litre)	E ACTUAL GENERATION (kW.h)	F APPROVED EFFICIENCY (kW.h/litre)	G=E/F APPROVED FUEL REQ (litres)	H=D x F FUEL PRICE (DRAW)CONTR ($)	I FUEL RIDER INDEX	J COMMUNITY FUEL RIDER ($/kW.h)
1	104	Wha Ti	0.8966	0.8000	0.1219	(0.0253)	100,000	3.711	37,275	(943)	1.010	0.0144
2	105	Gameti	0.9269	0.8000	0.1519	(0.0250)	100,000	3.398	23,891	(597)	1.118	0.0159
3	110	Lutsel K'e	0.8958	0.8000	0.1222	(0.0264)	100,000	3.778	34,742	(917)	1.018	0.0145
4	205	Fort Simpson	0.8616	0.8000	0.0870	(0.0254)	600,000	3.755	168,175	(4,277)	1.000	0.0142
5	206	Fort Liard	0.8773	0.8000	0.1026	(0.0253)	200,000	3.725	63,932	(1,618)	1.007	0.0143
6	207	Wrigley	0.8846	0.8000	0.1099	(0.0253)	50,000	3.525	17,662	(447)	1.083	0.0154
7	208	Nahanni Butte	0.8750	0.8000	0.1026	(0.0276)	30,000	2.511	12,020	(331)	1.556	0.0221
8	209	Jean Marie River	0.8582	0.8000	0.0838	(0.0256)	20,000	2.749	5,469	(140)	1.421	0.0202
9	305	Tuktoyaktuk	1.0011	0.8000	0.2249	(0.0238)	400,000	3.697	102,447	(2,434)	1.051	0.0150
10	306	Fort McPherson	0.9256	0.8000	0.2293	(0.1037)	250,000	3.609	89,723	(9,306)	1.043	0.0149
11	307	Aklavik	0.9142	0.8000	0.2182	(0.1040)	250,000	3.475	62,608	(6,509)	1.095	0.0156
12	308	Deline	1.0146	0.8000	0.2389	(0.0243)	200,000	3.546	62,413	(1,514)	1.067	0.0152
13	309	Fort Good Hope	1.0008	0.8000	0.2989	(0.0981)	200,000	3.576	59,606	(5,849)	1.051	0.0150
14	310	Tulita	0.9051	0.8000	0.1313	(0.0262)	200,000	3.634	45,392	(1,188)	1.075	0.0153
15	311	Paulatuk	1.0896	0.8000	0.3110	(0.0214)	100,000	3.492	29,967	(641)	1.104	0.0157
16	312	Sachs Harbour	1.0752	0.8000	0.2967	(0.0215)	100,000	3.189	25,454	(548)	1.195	0.0170
17	313	Tsiigehtchic	0.9847	0.8000	0.2093	(0.0246)	50,000	3.537	20,547	(505)	1.096	0.0156
18	314	Colville Lake	1.0993	0.8000	0.3919	(0.0926)	50,000	2.957	11,591	(1,074)	1.263	0.0180
19	315	Ulukhaktok	1.1107	0.8000	0.3319	(0.0212)	200,000	3.616	48,099	(1,018)	1.041	0.0148
20						**Total**	**3,200,000**		**921,013**	**(39,857)**		

Deficiency to Collect ($)	**39,857**
Forecast Sales (kW.h)	**2,800,000**
Proposed Fuel Rider ($/kW.h)	**0.0142**

Northwest Territories Power Corporation
TABLE 2, TGC.NTPC-6
Hypothetical Diesel Community Fuel Stabilization Fund Balance Scenario 2

PLANT NO.	PLANT	A APPROVED FUEL PRICE ($/litre)	B ACTUAL FUEL PRICE EXC. DELIVERY ($/litre)	C ACTUAL FUEL PRICE DELIVERY ($/litre)	D=A-(B+C) FUEL PRICE VARIANCE ($/litre)	E ACTUAL GENERATION (kW.h)	F APPROVED EFFICIENCY (kW.h/litre)	G=E/F APPROVED FUEL REQ (litres)	H=D x F FUEL PRICE (DRAW)CONTR ($)	I FUEL RIDER INDEX	J COMMUNITY FUEL RIDER ($/kW.h)
104	Wha Ti	0.8966	0.8000	0.1219	(0.0253)	100,000	3.711	37,275	(943)	1.010	0.0197
105	Gameti	0.9269	0.8000	0.1519	(0.0250)	100,000	3.398	23,891	(597)	1.118	0.0218
110	Lutsel K'e	0.8958	0.8000	0.1222	(0.0264)	100,000	3.778	34,742	(917)	1.018	0.0198
205	Fort Simpson	0.8616	0.8000	0.1740	(0.1124)	600,000	3.755	168,175	(18,908)	1.000	0.0195
206	Fort Liard	0.8773	0.8000	0.1026	(0.0253)	200,000	3.725	63,932	(1,618)	1.007	0.0196
207	Wrigley	0.8846	0.8000	0.1099	(0.0253)	50,000	3.525	17,662	(447)	1.083	0.0211
208	Nahanni Butte	0.8750	0.8000	0.1026	(0.0276)	30,000	2.511	12,020	(331)	1.556	0.0303
209	Jean Marie River	0.8582	0.8000	0.0838	(0.0256)	20,000	2.749	5,469	(140)	1.421	0.0277
305	Tuktoyaktuk	1.0011	0.8000	0.2249	(0.0238)	400,000	3.697	102,447	(2,434)	1.051	0.0205
306	Fort McPherson	0.9256	0.8000	0.2293	(0.1037)	250,000	3.609	89,723	(9,306)	1.043	0.0203
307	Aklavik	0.9142	0.8000	0.2182	(0.1040)	250,000	3.475	62,608	(6,509)	1.095	0.0213
308	Deline	1.0146	0.8000	0.2389	(0.0243)	200,000	3.546	62,413	(1,514)	1.067	0.0208
309	Fort Good Hope	1.0008	0.8000	0.2989	(0.0981)	200,000	3.576	59,606	(5,849)	1.051	0.0205
310	Tulita	0.9051	0.8000	0.1313	(0.0262)	200,000	3.634	45,392	(1,188)	1.075	0.0209
311	Paulatuk	1.0896	0.8000	0.3110	(0.0214)	100,000	3.492	29,967	(641)	1.104	0.0215
312	Sachs Harbour	1.0752	0.8000	0.2967	(0.0215)	100,000	3.189	25,454	(548)	1.195	0.0233
313	Tsiigehtchic	0.9847	0.8000	0.2093	(0.0246)	50,000	3.537	20,547	(505)	1.096	0.0213
314	Colville Lake	1.0993	0.8000	0.3919	(0.0926)	50,000	2.957	11,591	(1,074)	1.263	0.0246
315	Ulukhaktok	1.1107	0.8000	0.3319	(0.0212)	200,000	3.616	48,099	(1,018)	1.041	0.0203
					Total	**3,200,000**		**921,013**	**(54,488)**		

Deficiency to Collect ($)	**54,488**
Forecast Sales (kW.h)	**2,800,000**
Proposed Fuel Rider ($/kW.h)	**0.0195**

Table 1. Calculation of 2006/07 Community Fuel Rider Index

		A	B	C	D	E
PLANT NO.	PLANT	GRA Fuel Efficiency (kW.h/l)	GRA Line Losses (per cent of generation)	GRA Station Service (per cent of generation)	Litres Fuel Required per kW.h Sales	Indexed
104	Wha Ti	3.711	7.0%	1.4%	0.294	1.009
105	Rae Lakes	3.398	4.5%	5.0%	0.325	1.116
110	Lutsel K'e	3.778	5.7%	5.0%	0.296	1.017
305	Tuktoyaktuk	3.697	7.0%	4.5%	0.305	1.048
306	Fort McPherson	3.609	4.2%	4.4%	0.303	1.041
307	Aklavik	3.475	5.7%	3.6%	0.317	1.089
308	Deline	3.546	7.0%	2.2%	0.310	1.066
309	Fort Good Hope	3.576	5.3%	3.5%	0.307	1.053
310	Tulita	3.634	7.0%	5.0%	0.313	1.073
311	Paulatuk	3.492	7.0%	4.0%	0.322	1.103
312	Sachs Harbour	3.189	4.8%	5.0%	0.348	1.193
313	Tssigehtchic	3.537	6.6%	5.0%	0.320	1.097
314	Colville Lake	2.957	7.0%	1.2%	0.368	1.264
315	Holman	3.616	5.5%	3.4%	0.304	1.042
205	Fort Simpson	3.755	5.5%	3.1%	0.291	1.000
206	Fort Liard	3.725	7.0%	1.4%	0.293	1.006
207	Wrigley	3.525	6.2%	3.5%	0.314	1.078
208	Nahanni Butte	2.511	7.0%	5.0%	0.452	1.552
209	Jean Marie River	2.749	7.0%	5.0%	0.413	1.419

Table 2. Calculation of 2007/08 Community Fuel Rider Index

		A	B	C	D	E
PLANT NO.	PLANT	GRA Fuel Efficiency (kW.h/l)	GRA Line Losses (per cent of generation)	GRA Station Service (per cent of generation)	Litres Fuel Required per kW.h Sales	Indexed
104	Wha Ti	3.711	7.0%	1.3%	0.294	1.010
105	Rae Lakes	3.398	4.5%	5.0%	0.325	1.118
110	Lutsel K'e	3.778	5.7%	5.0%	0.296	1.018
305	Tuktoyaktuk	3.697	7.0%	4.6%	0.306	1.051
306	Fort McPherson	3.609	4.2%	4.5%	0.303	1.043
307	Aklavik	3.475	5.7%	4.0%	0.319	1.095
308	Deline	3.546	7.0%	2.2%	0.310	1.067
309	Fort Good Hope	3.576	5.3%	3.2%	0.306	1.051
310	Tulita	3.634	7.0%	5.0%	0.313	1.075
311	Paulatuk	3.492	7.0%	3.8%	0.321	1.104
312	Sachs Harbour	3.189	4.8%	5.0%	0.348	1.195
313	Tssigehtchic	3.537	6.6%	4.7%	0.319	1.096
314	Colville Lake	2.957	7.0%	1.0%	0.367	1.263
315	Holman	3.616	5.5%	3.2%	0.303	1.041
205	Fort Simpson	3.755	5.5%	3.0%	0.291	1.000
206	Fort Liard	3.725	7.0%	1.4%	0.293	1.007
207	Wrigley	3.525	6.2%	3.7%	0.315	1.083
208	Nahanni Butte	2.511	7.0%	5.0%	0.453	1.556
209	Jean Marie River	2.749	7.0%	5.0%	0.413	1.421

^

Topic

Directive 51 – Generation using sources other than diesel

Reference

Not addressed

Preamble

The Board directed NPTC as follows:

> The Board directs NTPC to provide the Board with biannual reports that discuss the following:
>
> 1. The efforts and progress of NTPC and its affiliates in pursuing alternative energy, demand side management and energy efficiency projects;
> 2. Justification for any projects being pursued by NTPC's affiliates rather than NTPC;
> 3. Funding programs that are, or will be, available and any efforts and progress by NTPC and its affiliates in obtaining funding. [Decision 13-2007, page 177]

While compliance with Directive 51 is not part of the Oct 1, 2007 Refiling, the TGC submits it in the interest of all parties to get a sense of what types of information will be included in the proposed biannual reports. Clarification of the nature and extent of information to be provided will hopefully avoid this debate when NTPC files biannual reports in compliance with Direction 51.

Requests

a) Please explain how and when NTPC is expecting to comply with the foregoing direction? More specifically, please provide when the Board (and intervenors) may expect the first of these biannual reports and what details NTPC plans to include in these reports. For example, will NTPC provide details that include the following:

   (i) Availability of all federal and other funding available to kick start the "green" energy projects in thermal communities;
   (ii) Efforts made by NTPC to secure private/public funding;
   (iii) Updates on the status of all "green projects" identified in the 2006-08 GRA and projects identified subsequently;
   (iv) Changes made in the Corporation's resource planning to specifically include costs of carbon emissions;

(v) Details of market developments related to valuation and trading of greenhouse gas emissions (GHG)
(vi) Efforts to secure GHG credits arising from both new "green" projects or from prior such projects already in place;
(vii) Discussions with thermal communities with a view to assisting the communities to get the required funding;
(viii) Rationale for any new green projects being undertaken by non-regulated affiliates as opposed to by NTPC (see discussion of Board concerns in Decision 13-2007, page 165)
(ix) How NTPC has managed risk considerations "through appropriate business arrangements with third parties" [Decision 13-2007,page 165]
(x) Details of all "green" projects undertaken by NTPC's affiliates and why these were not, or could not be undertaken by NTPC.

To the extent NTPC is not prepared to file details in respect to any one of the foregoing, please provide a complete explanation to help understand NTPC's position.

Response

a) NTPC is in the process of completing its Phase I re-filing and responding to near term directives. The order in which the directives are actioned is driven by the dates set by the Board. A Phase II application and the inter-affiliate information will take precedence over Directive 51 with regard to producing a report for submission. Given the workload to complete the short term directives, NTPC is planning to submit a report to the PUB in the first half of 2008/09.

In the meantime, the Corporation is working with the communities of Wrigley and Norman Wells to facilitate their submission for funding to offset the cost of changing out streetlights to more efficient lighting. The Corporation has supplied the information on how to apply and has made numerous attempts to encourage these communities to apply for funding however to date we are not aware of any applications being submitted. The Corporation has had success with most of its thermal communities in getting them to apply for funding assistance to mitigate the cost of the streetlight change-outs and these are the only two communities remaining. We will continue our efforts in this area and the streetlight projects in these communities will proceed in 2007/08.

The Corporation is also in the process of sending out a request for proposals for the supply of wind power. Once responses to the proposal call are reviewed the Corporation will work over the next several months with the private sector to encourage the development of wind power in the NWT.