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A REVIEW OF COST PRESSURES FACING THE NORTHWEST TERRITORIES POWER CORPORATION

PREPARED BY
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Executive Summary

This report on the Northwest Territories Power Corporation's (NTPC) revenue requirements and cost pressures affirms and augments the relevant findings of earlier utility, policy, and governance reviews. All share the common goal of putting NTPC on a solid financial footing going forward, so it can generate and deliver electricity efficiently, reliably, and at reasonable rates.

It is worth noting that the GNWT considers electricity an essential service for northern communities. The NTPC system operates in a harsh environment, with very small loads in widely dispersed communities. NTPC's ongoing challenge will be to find and implement cost saving measures without affecting safety and reliability.

Through the course of our investigation and analysis, we have found that NTPC's costs are reasonable, given the challenges of providing electricity in the NWT. Electricity utilities across Canada are facing cost pressures, and many are experiencing rate increases that have outpaced those of NTPC over the last five years. The Utility is to be commended for reducing its staff to 2007 levels, and keeping its O&M budget increase in line with inflation.

As NTPC had not filed a General Rate Application (GRA) for five years, we found that there was a significant degree of "catch-up" required with respect to the revenue requirement. The revenue requirement increase from $87.1 million to $101.6 million, is substantial, especially if implemented in one year. At the outset of our review, we were made aware of a proposal being developed by NTPC and the GNWT Department of Finance to limit rate increases to no more than seven per cent per year. This appears reasonable as a fundamental principle of rate design is the avoidance of "rate shock". As well, revenue to cost ratios in all rate zones are reasonable, so simple "across the board" percentage increases to the zone-based rates make sense.

Projected cost impacts for NTPC customers for the next three years (2012-13 to 2014-15) are reflected in the tables below:

Figure I Forecasted Residential Rate Increases

Anticipated Monthly Power Bill Increases (Winter) Residential Ratepayers (1000kWh/month)				
Zone	**2012/13**	**2013/14**	**2014/15**	**Total**
NTPC Thermal	$11	$12	$13	$36
NTPC Taltson	$12	$13	$14	$39
NTPC Snare	$11	$12	$13	$36

*These are projections of monthly bills for January 1st of target years.

Figure II Forecasted Commercial Rate Increases

Anticipated Monthly Power Bill Increases (Winter) Commercial Ratepayers (3000kWh/month)				
Zone	**2012/13**	**2013/14**	**2014/15**	**Total**
NTPC Thermal	$89	$95	$101	$285
NTPC Taltson	$28	$30	$33	$91
NTPC Snare	$66	$70	$75	$211

*These are projections of monthly bills for January 1st of target years.

To keep rate increases to a maximum of seven per cent per year requires a GNWT contribution in the range of $18 million over two years. It should be noted that these figures do not reflect an additional $15 million in diesel costs over the next three years, related to diminishing natural gas supply in Inuvik. Just prior to the finalization of our report, we were informed that there is the potential for these costs to remain ongoing and that they would likely need to be included in the revenue requirement. A discussion of these additional costs was not included in our review. However, the impact on the proposed annual revenue requirement is clear - $107 million will be required. To keep rate increases to a seven per cent maximum and still attain the $107 million revenue requirement, an additional year would need to be added to the annual seven per cent rate increases. As well, GNWT support during this transition phase would need to increase to approximately $33 million.

We understand that government support to this level, accompanied by rate increases of seven per cent for the next four years, is challenging. However, the cost pressures are immediate, and the Utility does need to attain its $107 million revenue requirement, beginning in 2012-13.

In light of these cost pressures, we have presented our recommendations in two streams, short term and long term. The short term recommendations identify some immediate actions that could be considered although we have found that there are few substantive savings to be found. In the long term, our recommendations should be considered as potential strategies to contain future costs and ensure rates keep up with inflation.

Short-term Recommendations

The Petroleum Products Division (PPD) provides diesel fuel to NTPC for electricity generation under a Fuel Services Agreement. As diesel use has increased, so have PPD's revenues from this agreement. These revenues appear to have outpaced costs. Therefore:

1. NTPC, PPD, and other government officials should attempt to reach a consensus on the cost of the service PPD provides to NTPC and whether fuel sales in communities served by PPD are indirectly being subsidized by the PPD charges on diesel fuel used for electricity generation.

We have found that the regulatory process is expensive and have provided a number of suggestions for change to be considered in the long term. Acceptance of these recommendations and reflecting them in the GRA to be filed will reduce costs in the short term.

2. In order to streamline the examination of diesel fuel prices and price forecasts in GRA reviews, NTPC should establish a diesel fuel price forecast methodology and submit it to the Public Utilities Board (PUB) for approval. This methodology should be clear, easy for consumers to understand, and substantially reduce or eliminate detailed discussion on fuel prices during periodic GRA reviews.

   Further, the diesel fuel price forecast should be incorporated into rates on a semi-annual basis in October and April, ensuring that fuel is treated as a "pass through" item. The rider for the Consolidated Stabilization Fund should also be reset each October and April with a two year recovery and there should no longer be a threshold limit before NTPC could apply.

3. In the General Rate Application, NTPC should propose a streamlined process to the PUB that includes no debate of capital structure, return on equity, or development of a detailed cost of service study. The GNWT should consider supporting this position through a submission to the PUB explaining the intent of the proposed government support.

4. Recognizing the 2010 Electricity Policy and the desire to keep rates low, NTPC should consider seeking approval for an Return on equity (ROE) in the 8 to 8.5% range on NTPC's actual equity of just over 40%, to provide a meaningful discount against the benchmark ROE awarded in Alberta.

Finally, consideration could be given to phasing in new depreciation rates for the reasons we discuss in our report. During this time of substantially increased cost pressures, the increased costs associated with a recent depreciation study may not need to be implemented immediately.

5. NTPC should consider advancing its condition assessment for its main assets, use the findings to update its recent depreciation study, and seek PUB approval for its updated depreciation rates through a separate written hearing process for implementation in 2013/14 or later.

Long-term Recommendations (and Strategies)

As found in previous reviews, there needs to be greater communication between the GNWT and the Utility, the mandate and expectations related to NTPC need to be clarified and performance measures will ensure that the interests of the Utility and the government are aligned.

1. The GNWT and NTPC should implement a regular planning and reporting structure centered on a Shareholder's Letter of Expectations, and a subsequent NTPC report back to the GNWT. As well, the GNWT should revisit the Strategic Direction issued in 2002 and the NTPC Act to ensure they are consistent with the current corporate structure of NTPC and there is clarity with respect to NTPC's mandate.
2. NTPC should expand its use of standard industry safety and reliability indexes by setting measurable targets, reporting results at the community, zone, and system level, and comparing its results with those of similar utilities.
3. A comprehensive listing of performance measures should be prepared by NTPC that permit it to assess corporate performance in the context of shareholder expectations, customer interests and corporate priorities.
4. NTPC should calculate "GW.h Produced per Employee" as a useful "Key Performance Indicator" (KPI) to reveal trends at a glance in the future. (Note: This is about 1.89 GW.h/employee with 169 staff in 2012/13, and given recent staff reductions, is trending in a favourable direction).

We have also provided a number of suggestions for the GNWT to consider with respect to the regulatory process. A more detailed review is required.

5. The GNWT should consider undertaking a review of the *Public Utilities Act* and the current GRA process with a view to streamline the process and control costs. This review could either be done by Government or through an undertaking of the Board.

Both NTPC and the GNWT undertake borrowing but ultimately all of the borrowing falls under the GNWT debt limit. We believe there will be efficiencies in combining this approach.

6. GNWT and NTPC should examine the potential savings, advantages, and disadvantages of having GNWT issue debt on NTPC's behalf.

The largest challenge in the NWT is the lack of economies of scale. Increasing sales will reduce the per-unit cost of electricity for everyone.

7. NTPC and the GNWT should explore ways to increase sales where there is a surplus in hydro generation capacity. Electric heating or industrial customers appear to be the greatest opportunity.

While not specifically addressed in this review, continued collaboration among NTPC, GNWT, educators, and unions will be needed to recruit talented staff. Electricity sector retirement rates are among the highest of any Canadian industry: 45,000 new and replacement staff will need to be hired in the next five years. NTPC can attract new workers with favourable career and training opportunities, competitive salaries and benefits, and job security.

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1.0

1.0 Introduction

NOTE: This review and analysis has been prepared at the request of the Government of the Northwest Territories (GNWT) based on the draft General Rate Application (GRA) information compiled by Northwest Territories Power Corporation (NTPC). The information provided for analysis was received no later than mid-February 2012 and, as a result, does not address any changes or adjustments that may have been made to the draft GRA materials after that date.

Northwest Territories Power Corporation (NTPC, the Utility, the Corporation) is a regulated Territorial Crown Corporation serving about 8800 customers directly. It also sells electricity to Northland Utilities for distribution to customers in Hay River and Yellowknife. Revenues in 2010/11 were $82.8 million, close to the average over the last five years of $82.3 million. Seventy-four percent of NTPC's electricity is generated hydraulically; diesel fuel and natural gas account for the remainder. NTPC sells about 314,000 MW.h of electricity annually at an average unit cost in the 26 cents/kW.h range.

There has been no GRA filed by NTPC since 2007/08, when the Utility's revenue requirement was about $80 million. Since then, NTPC's costs have increased significantly in some areas and there have been significant rate changes due to the establishment of rate zones, changes to the Territorial Power Subsidy Program (TPSP), and other GNWT policy decisions.

NTPC is preparing a new GRA that is expected to seek approval for revenues of around $97.3 million in 2012/13 and $101.6 million in 2013/14. Thanks to an anticipated GNWT contribution of about $18.2 million over two years, the rate impact on customers may be reduced to 7% over each of the next three fiscal years, or some variation thereto.

Given the public interest in the cost of living in the Northwest Territories (NWT), the essential role electricity plays in public health and safety, and the substantial government contribution to soften rate impacts, the GNWT decided that a third party review of NTPC's revenue requirements and cost pressures should be completed as a matter of due diligence.

It is important to note that this review does not replace the more detailed GRA examination that will be conducted by the Public Utilities Board (PUB). This being said, we do suggest ways the PUB's review may be streamlined to reduce unnecessary regulatory costs for this and future applications.

We would like to thank staff from NTPC, InterGroup Consultants, the Department of Industry, Tourism and Investment (ITI) and several others who participated in this review, for their cooperation and contributions.

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2.0

2.0 Objectives, Approach, and Scope

The objective of this report is to evaluate and make recommendations about NTPC's expected revenue requirements, including its main cost drivers, with a view to identifying opportunities for savings. In particular, it is to:

- Provide an overview of cost pressures of other electricity utilities, including utilities similar in size and scope as NTPC;
- Review the cost pressures facing NTPC in the context of historical and projected NTPC budgets, generally identify areas where some operational efficiencies may be realized, and provide an opinion on whether the costs appear to be reasonable, given the challenge of providing electricity services in the NWT;
- Identify strategies to mitigate potential rate increases, including continuing GNWT financial support, approaches to cost drivers, and implementation of identified efficiencies. Specifically:
  - the level of net income
  - dividend and dividend policy
  - the debt/equity ratio
  - depreciation rates of NTPC assets
  - costs associated with PUB reviews
  - fuel costs, including NTPC's contract with the Petroleum Products Division (PPD)
  - the balances in NTPC's deferral accounts

The consultants were supported by a small review team that included representatives from NTPC, InterGroup Consultants Ltd., and ITI. NTPC officials cooperated fully, which was of utmost importance in completing the report in the allotted time.

During our work, we reviewed background government or government-initiated reports, including:

- "Energy For the Future: An Energy Plan for the NWT" (March 2007, 61 pages)
- "A Review of Electricity Regulation, Rates, and Subsidy Programs in the NWT" (December 2008, 11 pages)
- "Electricity Review: A Discussion with Northerners about Electricity" (June 2009, 38 pages)
- "Northwest Territories Energy Report" (May 2011, 52 pages)
- Draft NWT Hydro Strategy Executive Summary (2008, 18 pages) and Draft NWT Hydro Strategy (61 pages)

We also reviewed three additional reports which guide the GNWT's policy direction in relation to the NWT electricity system. These additional reports include: *Creating a Brighter Future: A Review of Electricity Regulation, Rates, and Subsidy Programs in the NWT* (frequently referred to as the "*Electricity Review*", 2009); *The Report of the NTPC Review Panel* (frequently referred to as the "*NTPC Review*", 2010); and the GNWT's policy document "*Efficient, Affordable, and Equitable: Creating a Brighter Future for the NWT Electricity System*" (referred to in this report as the *2010 Electricity Policy*) which summarized the GNWT's response to the earlier independent review documents.

We also:

- Examined NTPC's recent Annual Reports, and NTPC's October 2011 "Strategic Plan 2012—14"
- Met with the President and Chief Executive Officer of NTPC, and the Board's Vice Chairperson, and spoke with the Chairperson of the PUB
- Interviewed senior GNWT finance and public works officials
- Held a workshop with the review team and invited government officials in Yellowknife on January 24 and 25, 2012, to discuss cost pressures, possible ways to reduce NTPC's revenue requirement, options around rate design, regulatory review options, and potential strategies for the future.

Electricity as an Essential Service: Safety and Reliability

As a result of its recent examination of the NWT electricity system, the GNWT has stated that the provision of electricity is seen as essential to the residents of the Northwest Territories. It has also directed NTPC, as a Crown agency, to focus its efforts on ensuring electricity is provided safely and reliably to the communities that it serves. As a result, NTPC has established a vision stating that it wishes to be regarded as an exceptional utility, up to the challenge of delivering safe, reliable, and fairly priced power through a territory-wide system that is efficient and sustainable.

Unlike southern utilities, there is no flexibility in the NTPC system to import power from the North American interconnected transmission grid. Back up generation capacity is in place in communities to meet emergency power demands. Examination of indices used to measure utilities suggest that NTPC's operation is generally reliable and safe when compared to other utilities. (See Appendix1).

Our review and recommendations are not intended to compromise NTPC's safety and reliability priorities and initiatives. Similarly, when considering future proposals for cost reductions or deferrals, the paramount criterion should be to ensure safety and reliability will not be unduly eroded.

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3.0

3.0 Background to the NTPC's 2012-14 General Rate Application

NTPC's 2012-14 GRA submission represents the first full application submitted for regulatory review since 2006. Since then, there have been material changes in a number of the Utility's cost drivers. As well, as a result of GNWT action, there have been substantial changes to the electricity rate structure.

This chapter briefly summarizes key activities that have occurred since the last GRA filing. A more complete chronology of main GRA related events during this timeframe is attached as Appendix 2.

3.1 2006-08 Revenue Requirements Application and Decision

The 2006-08 NTPC GRA (Phase I) was filed during November, 2006 - 8 months into the test year which began April 1, 2006. NTPC delayed filing the GRA until November as it sought ways to mitigate the rate impacts that were forecast in its initial work. The PUB did not accept a request from NTPC for a negotiated settlement, and a full oral hearing took place.

In its GRA submission NTPC sought increases of:

- $15.9 million for 2006/07 (from $64 million to $79.9 million); and
- $19.9 million for 2007/08 (to $84.3 million).

The final Phase I GRA decision was over 200 pages and had over 50 "directives", many of which were to be addressed at the "next GRA". The PUB's combined decisions reduced the revenue requirement to $76.6 million in 2006/07 and to $81.1 million in 2007/08. The main effect of the PUB's approvals on NTPC's revenue requests were to:

- Reduce return on equity by $1.7 million
- Debt cost recalculation of $0.7 million
- Reduce fuel costs and volumes of $0.2 million
- Reduce salary costs by $0.3 million, by excluding half of bonuses
- Reduce operating and maintenance costs by $0.4 million
- Increase forecast revenues by $0.4 million

The rate riders designed to collect GRA shortfalls and fuel costs were slow to be fully recovered.

3.2 Phase II Application and Fuel Riders

NTPC filed its Phase II application in August 2008 to address cost of service, rate design, and fuel rate riders. ("Rate riders" are meant to capture variances in key cost drivers–usually over which a utility has little or no control between what was forecast when rates were set, and what actually occurs. Amounts either owed back to or owing from ratepayers accumulate in regulatory or stabilization accounts.) Diesel fuel prices had increased dramatically since the 2006 filing and the Phase I GRA shortfalls had not yet begun to be collected.

During Phase II, NTPC sought approval for a revised method to recover stabilization account amounts: in short, it proposed that twice a year the riders would be "trued up" to target a zero balance within twelve months. The PUB generally accepted this new approach, but ordered NTPC to lower the diesel fuel price forecast and target a zero balance over eighteen months, not twelve. Diesel fuel price increases were having a dramatic negative effect on the fuel stabilization account. Subsequently, two payments from the GNWT of $3 million each in 2010/11 and 2011/12 reduced the balance in the Consolidated Stabilization Fund. An additional $1 million contribution in September 2011 reduced the Consolidated

Stabilization Fund balance to $1.5 million. However, given the current fuel price, the balance of this Fund is expected to grow to $4.6 million by March 2012.

In 2009, the GNWT commissioned the NTPC Review and Electricity Review, described below. In consultation with the GNWT, NTPC concluded it could adopt a "zero/zero/zero" percent rate increase plan, with no increase in revenue requirements for 2009/10, 2010/11, and 2011/12. As well, the GNWT also agreed to forego collecting its dividend pending completion of the reviews.

3.3 Review of Rates, Regulation, and Subsidies

The GNWT announced its review of rates, regulation, and subsidies in the 2007 *Energy Plan*. An independent panel completed its work in 2009 and its report (the Electricity Review) was tabled in the Legislative Assembly in November of that year. It called for a renewed focus by all utilities on customer service, and recommended a series of changes to:

- The structure of the electricity system (e.g. consolidation to increase economies of scale)
- The rate structure (e.g. establish three cost of service zones and a thermal zone rate; GNWT to set the rate of return for NTPC's assets in the hydro zones; eliminate the dividend to the GNWT; reduce use of rate riders and replace them with a territorial rider to share costs related to fuel and low water; revise the TPSP and review the subsidy for residents of public housing)
- The regulatory processes (e.g. amend the *Public Utilities Act* to to permit the GNWT to provide policy direction to the PUB; streamline review processes; limit participant funding)
- The role of the GNWT (e.g. improving the lines of authority and accountability for electricity related matters)

This report and its recommendations were reviewed by the Government. A response to the report was issued in 2010 (see sub-section 3.5, below).

3.4 Report of the NTPC Review Panel

The independent NTPC Review Panel was established in 2009 and was tasked with examining the operations, corporate structure, and mandate of NTPC. The Panel did not identify any opportunities for major cost savings in NTPC operations. Their report indicated that NTPC was operating with reasonable efficiency and there were limited opportunities to significantly affect the corporation's cost structure. The Panel made several recommendations concerning operational efficiency (e.g. fuel handling, safety), corporate efficiency (e.g. capital project cost estimation, travel, salaries), and mandate (e.g. NTPC's role in conservation and alternative energy, public engagement, regulatory process delays and costs). Many of the recommendations are currently being implemented.

3.5

3.5 Government Response: 2010 Electricity Policy

The GNWT considered both the NTPC Review and the Electricity Review and issued a comprehensive response in May 2010. As a result of the direction established in the Government's response, rate policy guidelines were issued to the PUB in July 2010 with respect to the approach to NTPC rates. Based upon these guidelines, seven rate zones were established, with no rate increases to any customers (i.e. when rates were compared to what customers paid in October 2009) and significant rate reductions (down to a residential rate of 47.3 cents/kW.h) for NTPC Thermal Zone customers. This was achieved by:

- Ending the 2006/2008 GRA rider that was fully collected by that time;
- A GNWT payment of $6 million to pay down the balances in stabilization funds; and
- The GNWT foregoing the annual NTPC dividend of $3.5 million for 2010/11 and again in 2011/12.

NTPC filed a Rate Rebalancing Application consistent with the rate policy guidelines, and final rates were put in place for December 2010. The rates were designed based on 2007/08 costs and loads, with the exception of items changed by policy, notably a $1.2 million annual decrease in returns from thermal communities. (NTPC returns in thermal communities are now limited to an interest coverage ratio of 1.5 times interest expense, which is very close to simple cost recovery plus a small profit.) The new rates were introduced at the same time as all stabilization fund riders ended.

4

4.0

4.0 Cost Pressures, Rates, and Rate Increases: Other Jurisdictions

As a whole, the electricity utility sector is facing ever increasing cost pressures, with electricity rates rising world-wide due to growing demand, higher fuel costs, operating costs to maintain aging systems, and capital expenditures to sustain and expand them. In fact, many utilities are finding that significant portions of their generation and transmission systems, built during high growth periods in the 1960s and 70s, have reduced reliability, pose safety and environmental risks and are in need of rehabilitation.

NTPC's operations have a number of unique characteristics. However, like NTPC, some utility companies across Canada provide electricity services in locations that are not connected to electricity grids and serve small, often isolated populations.

To assist in the examination of NTPC's proposed GRA we examined the provision of electrical generation, transmission and distribution in Yukon, British Columbia, Alaska, Manitoba and Newfoundland / Labrador. Detailed findings related to these jurisdictions can be found in Appendix 3.

A summary of our findings can be found in the subsections below.

4.1 Cost Pressures

A utility's operating costs relate to day-to-day operations and maintenance activities, such as costs for labour, pension expense, materials, travel, supplies and fuel. Utilities face operating cost pressures due to inflation, customer growth, changing customer service levels, maintenance activities, and public and employee safety.

Operating and maintenance (O&M) costs usually make up between 20 and 40% of a utility's revenue requirements and represent the largest category of "controllable" cost drivers. An example of a largely uncontrollable cost is the price of fuel – in NTPC's case, the cost of diesel fuel for its primary and backup generators.

Comparison of cost pressures, in particular those cost pressures that are controllable, suggests that NTPC has done relatively well in controlling its cost growth. Table 4.1 illustrates that NTPC fares well, particularly when compared to utilities where future year O&M cost information is available.

Figure 4.1 Non-Fuel O&M Costs, NTPC and Other Utilities (All costs indexed to 2003)

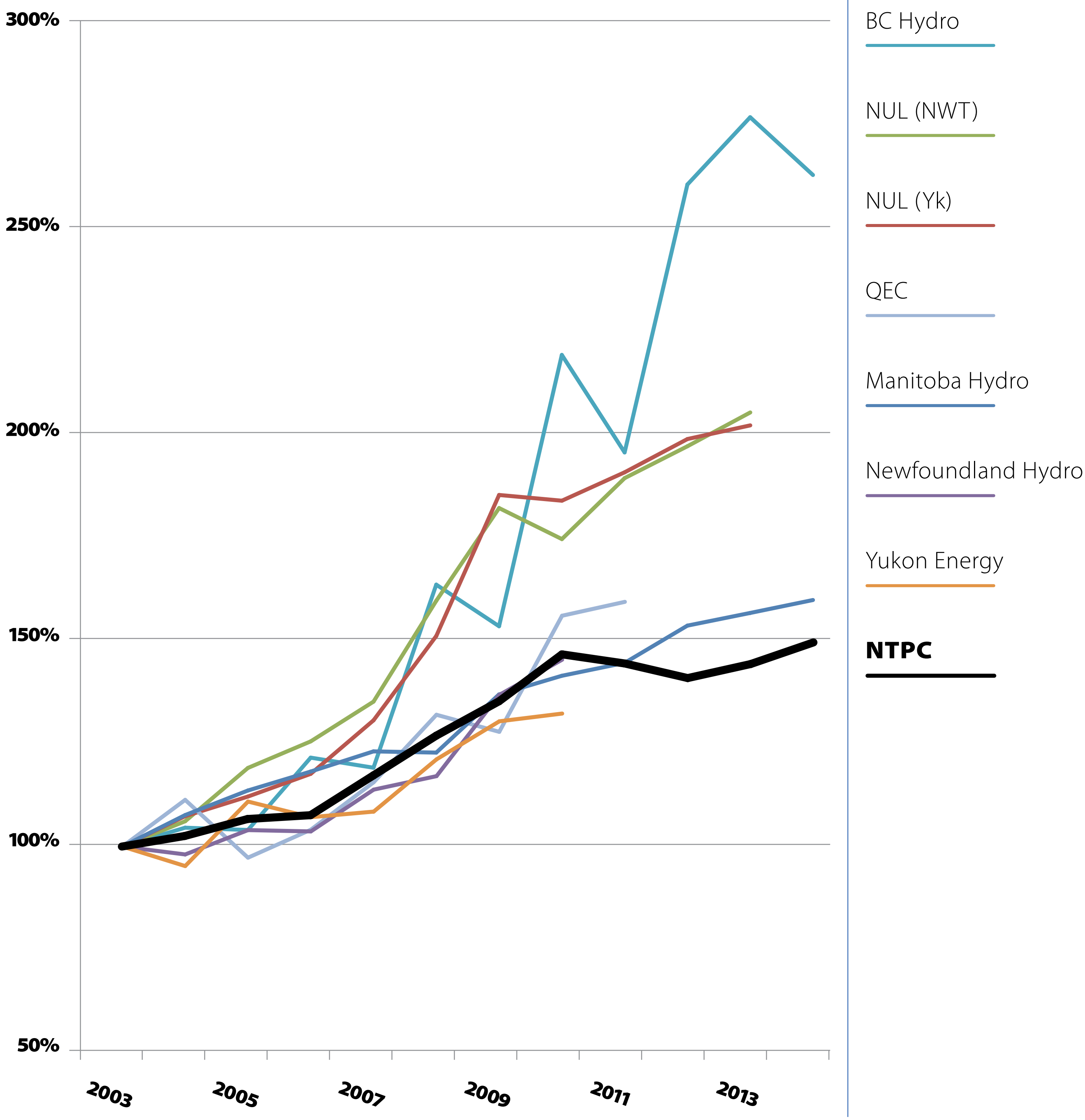
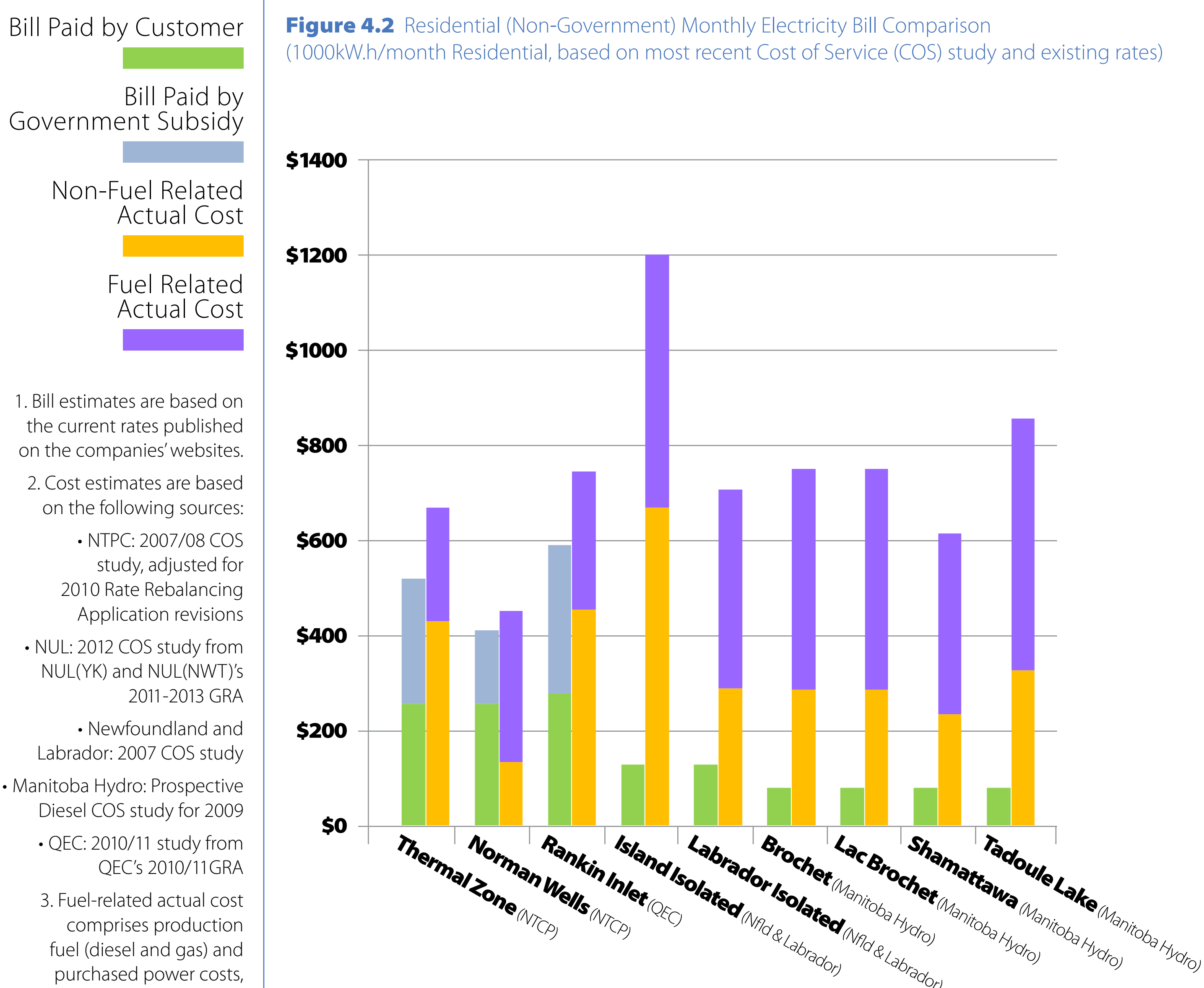


Figure 4.2 below compares actual costs and bills for NTPC thermal communities with off-grid diesel communities in Nunavut (Rankin Inlet), Newfoundland, Labrador, and Manitoba. The bottom left (green) portion is the amount a customer pays. The other three portions show the actual cost (broken into non fuel and fuel components), the cross subsidies from other customers, and for the NWT and Nunavut examples, the government subsidies. Newfoundland, Labrador, and Manitoba actual generation costs are higher, and their customers' bills lower, than in NWT communities. Unlike Manitoba and Newfoundland and Labrador where lower cost integrated grid customers subsidize a small minority of diesel off grid customers, in the NWT and Nunavut it falls primarily to governments to help make electricity more affordable.

Figure 4.2 Residential (Non-Government) Monthly Electricity Bill Comparison (1000kW.h/month Residential, based on most recent Cost of Service (COS) study and existing rates)



1. Bill estimates are based on the current rates published on the companies' websites.

2. Cost estimates are based on the following sources:

- NTPC: 2007/08 COS study, adjusted for 2010 Rate Rebalancing Application revisions
- NUL: 2012 COS study from NUL(YK) and NUL(NWT)'s 2011-2013 GRA
- Newfoundland and Labrador: 2007 COS study
- Manitoba Hydro: Prospective Diesel COS study for 2009
- QEC: 2010/11 study from QEC's 2010/11GRA

3. Fuel-related actual cost comprises production fuel (diesel and gas) and purchased power costs, where applicable.

4.2

4.2 Rates and Rate Increases

Rates are largely determined by costs associated with the operation of a utility. As electricity rates are regulated, only costs that are approved by the regulator (in the NWT this is the PUB) can be included when the utility revenue requirements are finalized. Approved costs depend, to some extent, on the organizational structure and government policies that define the Utility's operating environment.

Governments also play a significant role in determining the amount that consumers pay for electricity. In other jurisdictions, rates are influenced by government subsidies and cross subsidization between rate zones.

Because of the complexity of approaches taken in various jurisdictions to set electricity rates, it is useful to monitor the changes in rates over time. Examination of rate change provides a perspective on revenue requirement changes and on the changing impact of rates on customers. Table 4.1 compares the monthly residential bill for 1000 kW.h of consumption for Inuvik, Yellowknife, and several cities across Canada in April 2008 and again in April 2011. The Inuvik and Yellowknife bills include the 2006-08 GRA final rates and riders, implemented in January 2008.

4.2

Sources: Hydro Quebec, 2008 and 2011 Comparison of Electricity Prices in Major North American Cities (rates in effect April 1); InterGroup Consultants Ltd. personal communication; www.bankofcanada.ca /rates

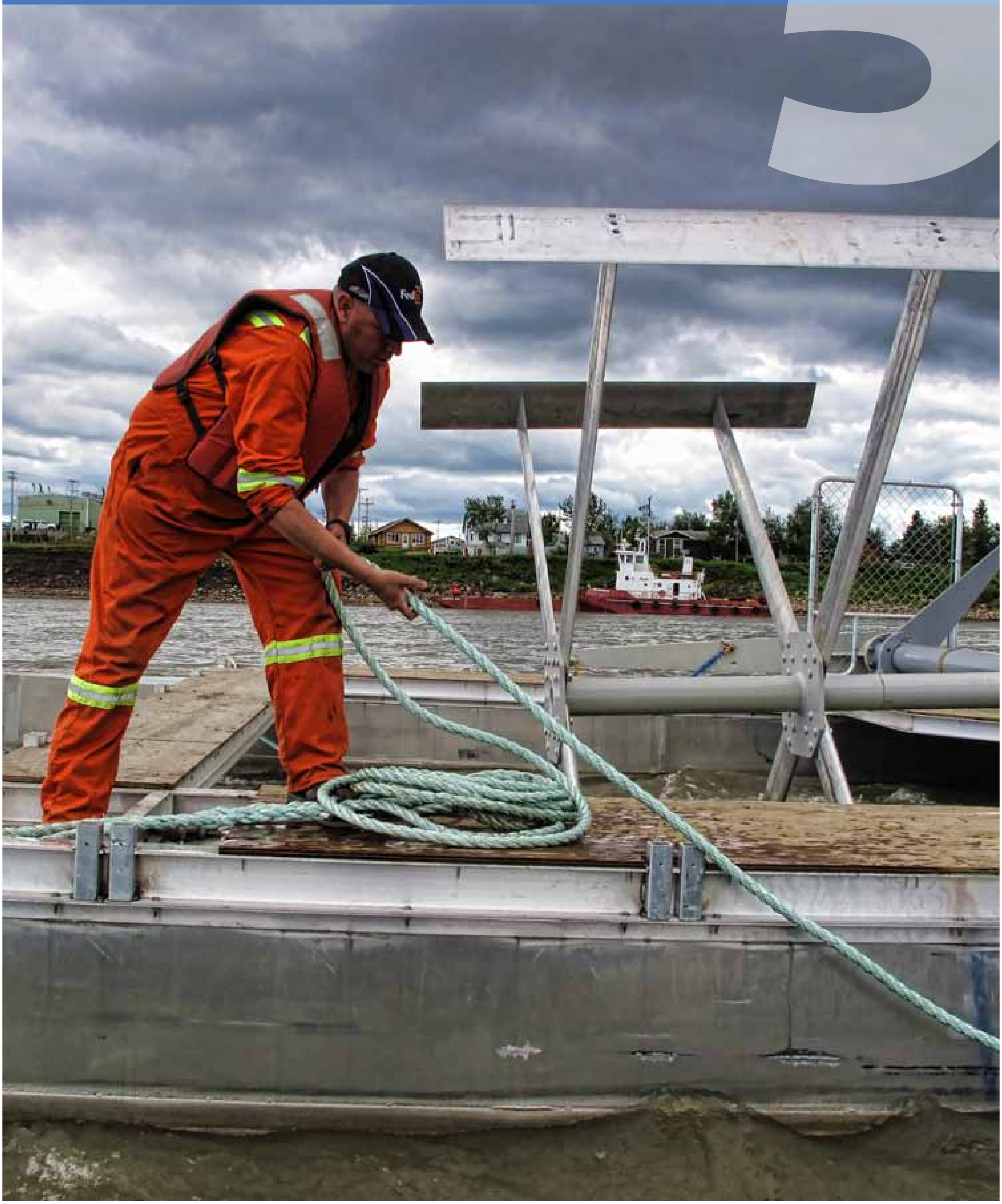
Table 4.1 Comparison of Monthly Bills ($Cdn): 1000 KW.h Consumption

City	April 2008	April 2011	Average Annual Change (%)
Regina	109.11	137.92	8.12%
Edmonton	134.51	164.04	6.84%
Ottawa	106.07	124.37	5.45%
Halifax	117.53	136.23	5.04%
Toronto	111.66	129.01	4.93%
Winnipeg	64.41	73.05	4.29%
Vancouver	69.78	76.81	3.25%
Yellowknife (NUL)	**237.58**	**256.62**	**2.60%**
St. John's	104.31	109.86	1.84%
Moncton	115.13	118.23	0.89%
Montreal	68.12	68.21	0.04%
Charlottetown	148.07	145.07	-0.68%
Inuvik	**425.12**	**246.02**	**-16.67%**
Canadian CPI, All Items (2002=100)	**113.5**	**119.8**	**1.80%**

Note: Inuvik bill is winter season (1000 kW.h TPSP threshold); Yellowknife bill information has been estimated.

For most Canadians, electricity rate increases have exceeded growth in the Consumer Price Index (CPI) during the time period. In fact, only four cities identified in the table have seen rate increases that have been lower than the rise in the CPI. Further, while it is no surprise that Yellowknife's bills are higher than those in southern cities (due to operational costs, limited economies of scale, etc.), the rate of increase over the last three years in Yellowknife is lower than all but Montreal and three cities in Atlantic Canada. It is also important to note that, as a result of the rate restructuring carried out in 2010, the rates for Inuvik have declined by almost 17% per year.

5



5.0

5.0 Cost Pressures, Rates, and Rate Increases: NTPC

The earlier sections of this report have provided a context for the upcoming NTPC GRA. This section examines the main cost drivers described in the 2012-14 GRA, including NTPC's load forecast, the impact of possible GNWT financial support and the proposed approach to rate increases over the next few years.

5.1 Overview

In general, utility sales are influenced by economic growth, population growth, and weather. Economic activity in the NWT has been steady or declining, and prospects for significant new electricity loads are limited. This being said, there may be possibilities for some industrial growth in the mid to long-term.

The recently released 2011 Canada Census reported that the NWT's population did not change between 2006 and 2011. The Census also reported that the number of occupied private dwellings in the NWT has risen by 3.3%, from 14,224 in 2006 to 14,700. This suggests a modest rise in residential customer loads.

NTPC forecasts a 2012/13 revenue requirement of about $97.3 million. While this is a significant increase over the previously approved revenue level, it is clear that NTPC has had recent success in bringing its operating and maintenance costs in line with inflation, which must remain a priority in an operating environment of no or minimal load growth. Most other components of the revenue requirement are harder to influence, or are entirely beyond NTPC's ability to control.

5.2 Load Forecast

Table 5.1 provides a summary of NTPC's load changes from 2007/08 through to 2013/14. The forecast is broken down by zone (including wholesale sales) and is normalized for recent weather variations.

Table 5.1 Summary of NTPC Load Changes (MW.h)

Zones	2007/08 GRA	2010/11 Actual	% Change 07/08 to 10/11	2013/14 Forecast	% Change 07/08 to 13/14
Snare Zone (includes Yellowknife)	181,740	182,126	+0.2%	186,525	+2.6%
Taltson Zone (includes Hay River)	58,702	58,473	-0.4%	58,987	+0.5%
Thermal Zone	72,729	73,950	+1.7%	74,655	+2.6%
Totals	**313,171**	**314,549**	**+0.4%**	**320,167**	**+2.2%**

Most utilities benefit from system sales growth, but NTPC is facing very low growth overall. As well, based on available information, NTPC is expecting reduced sales for some of the 19 diesel communities in the Thermal Zone. The 2010 establishment of the NTPC Thermal Zone will shield the individual communities with declining sales from further rate increases as long as the overall sales growth in the Thermal Zone remain, as projected, to be slightly positive. If overall sales in the Thermal Zone decline, then rates would rise, as the allocated costs of the Utility would need to be spread over reduced consumption.

We see no reason not to accept NTPC's load forecast for the purpose of this review. However, it is important to remember that actual weather in any year can cause significant variations in actual sales when they are compared to normalized forecasts.

In reviewing the NTPC sales forecast, new revenues will be added starting in 2012/13 to account for interruptible sales to four government customers for electric heating in Fort Smith ($113,000 by 2013/14). Later in this report we have provided additional context and a recommendation aimed at increasing sales.

5.3

5.3 Breakdown of Cost Components and Overview of Potential Efficiencies

Table 5.2 is a summary of the preliminary 2013/14 revenue requirement, compared to the 2007/08 approved revenue requirement and includes actual costs for 2010/11. This table illustrates the trends among the main cost components.

Table 5.2 Preliminary Revenue Requirement Summary ($Millions, Rounded to Nearest $100,000)

Cost Components	2007/08 Test Year	Actual 2010/11	Forecast 2013/14	% Change (Six Years)	% Change (Average Annual)
Salaries and Wages	$18.3	$21.2	$23.5	28%	4.3%
Non Production Fuel	$0.7	$0.9	$1.0	43%	6.1%
Supplies & Services	$10.6	$13.0	$11.9	12%	1.9%
Travel & Accommodation	$2.2	$2.2	$2.2	0%	0%
Total O&M	**$31.8**	**$37.3**	**$38.6**	**21%**	**3.3%**
Production Fuel	$17.3	$17.9	$22.7	31%	4.6%
Depreciation/ Amortization	$12.6	$14.8	$21.5	71%	9.3%
Interest	$10.4	$9.6	$11.6	12%	1.8%
Return on Equity	$9.0	$7.5	$7.2	-20%	-3.7%
Total	**$81.1**	**$87.1**	**$101.6**	**25%**	**3.8%**

NTPC's draft GRA presents cost information that is reasonable and defensible. This being said, there is some room for further examination and the possibility of some policy-based alterations to the reporting of depreciation and return on equity. As well, examination of mitigating actions that could be taken to reduce costs related to the purchase of production fuel and obtaining the best rates when borrowing money also warrant discussion. Sections 6 and 7 provide further discussion of these matters.

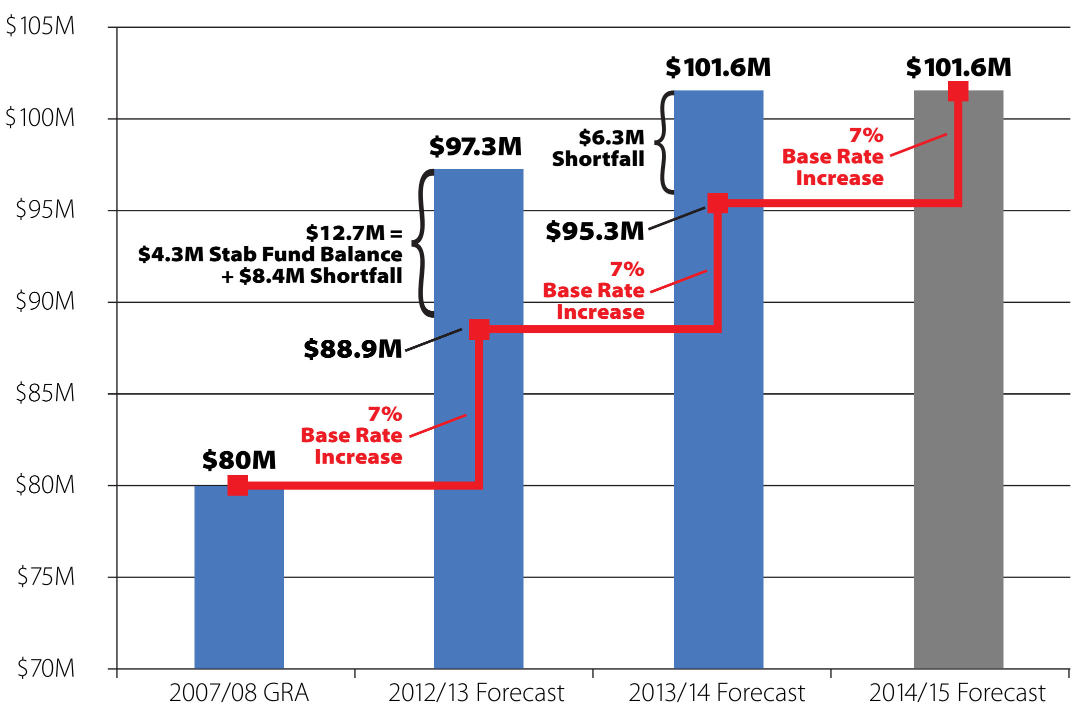
5.4 The Proposed 7/7/7 Rate Increase Scenario

During the course of our review we were informed that the GNWT is considering direct financial support to mitigate the impact of the required rate increases on customers, keeping the impact to no more than 7% per year in most cases. We have developed our report based on the implementation of the proposed 7/7/7 rate increase scenario. This scenario is expected to include the following aspects:

- Energy rates (cents/kW.h) are to increase by 7% in all communities other than Norman Wells – this includes wholesale and retail (residential, general service, and street lighting customers);
- Government customers are expected to face the same 7% rate changes on energy as other customers; and
- No change is expected to customers' demand charges (the fixed $/month component of the bill).

Figure 5.3 below illustrates the revenue forecast from sales under proposed rate increases and the resulting shortfall in relation to the revenue requirement for 2012/13 – 2014/15 fiscal years. The graph is based in part on the information provided in Table 5.2.

Figure 5.3 NTPC Revenue Requirement and Estimated Sales Revenue



While the wholesale energy rate is increasing by 7%, the wholesale demand charge is not. Therefore, the net cost for wholesale power to NUL in Yellowknife is increasing by something less than 7%. In addition, NTPC's cost changes do not affect the distribution component of the Yellowknife bills, which also form the basis for the TPSP calculations. As a result, the net effect on TPSP-eligible bills from NTPC's application is less than 7% each year.

5.5

5.5 Possible GNWT Financial Support

In order to reduce the immediate impacts of the increased revenue requirement on electricity rates, NTPC is proposing a deferred implementation of rate changes over three years. This would result in the smoothing of rate increases. NTPC has therefore proposed that it will seek GNWT contributions of $18.2 million, spread over two years. This contribution, combined with a 7% rate increase in each of the next three years would permit NTPC to generally meet its revenue requirement and eliminate the current balance in the Consolidated Stabilization Fund.

In considering this proposal for financing the revenue requirement of NTPC, it will be important that GNWT decision-makers keep in mind:

- The requirement to establish a timely, efficient way to refund or recover deferral account balances in the future; and
- How inflationary increases will be managed in 2014/15: at this point, there is limited room to address inflation costs within NTPC's cost structure.

The impact on customers is a key issue. The tables below provide an estimate on the impacts of residential (at a thousand kilowatt hours per month) and commercial customers (at 3,000 kilowatt hours per month).

Table 5.4 Electricity Bill Impacts for Residents, 1000 kWh Consumption

Anticipated Monthly Power Bill Increases (Winter) Residential Ratepayers (1000kWh/month)				
Zone	**2012/13**	**2013/14**	**2014/15**	**Total**
NTPC Thermal	$11	$12	$13	$36
NTPC Taltson	$12	$13	$14	$39
NTPC Snare	$11	$12	$13	$36

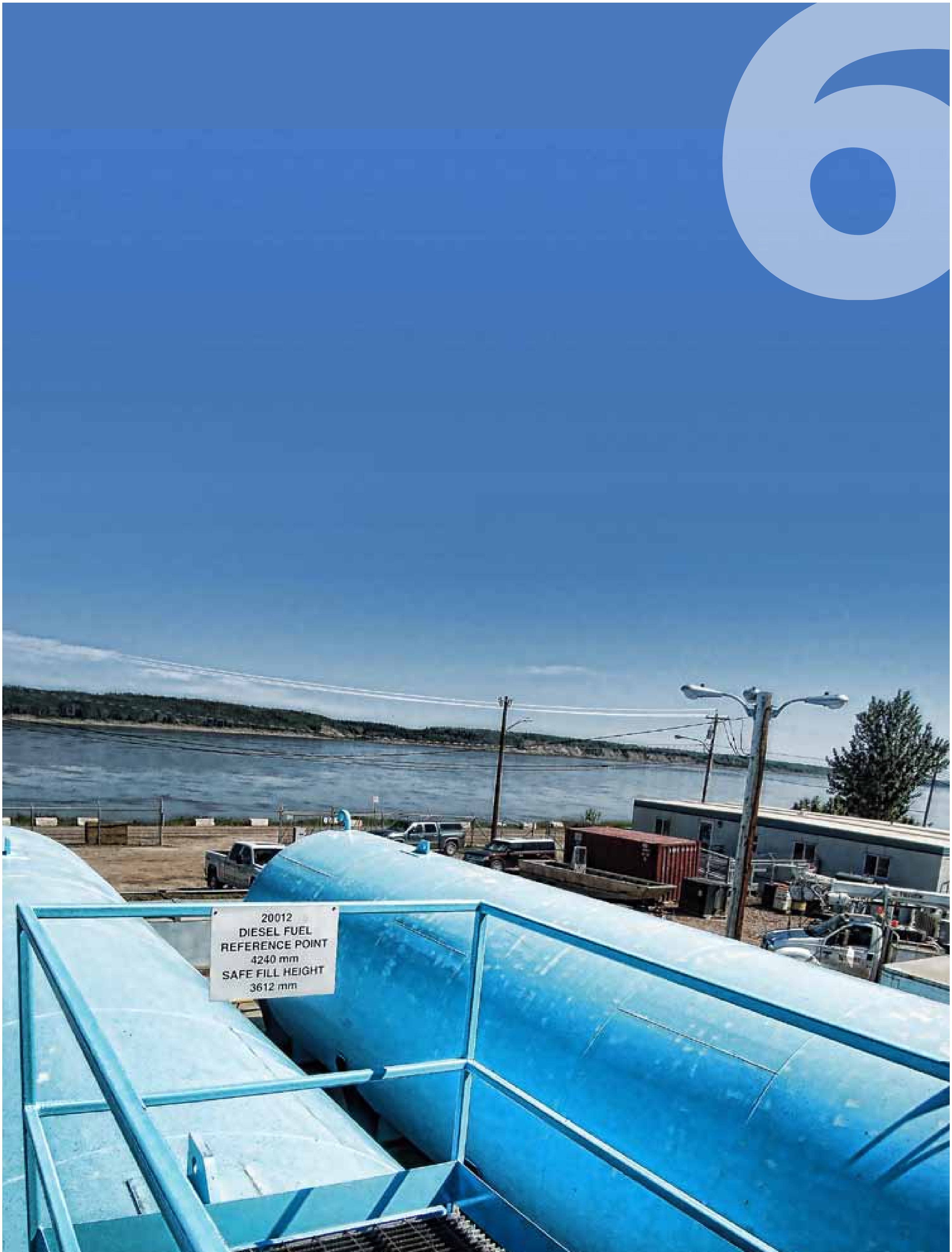
*These are projections of monthly bills for January 1st of target years.

Table 5.5 Electricity Bill Impacts for Businesses, 3000 kWh Consumption

Anticipated Monthly Power Bill Increases (Winter) Commercial Ratepayers (3000kWh/month)				
Zone	**2012/13**	**2013/14**	**2014/15**	**Total**
NTPC Thermal	$89	$95	$101	$285
NTPC Taltson	$28	$30	$33	$91
NTPC Snare	$66	$70	$75	$211

*These are projections of monthly bills for January 1st of target years.

6


20012
DIESEL FUEL
REFERENCE POINT
4240 mm
SAFE FILL HEIGHT
3612 mm

6.0

6.0 Finding Efficiencies: Strategies to Manage Short Term Rate Increases

The next two sections of this report examine NTPC's GRA and the GRA process. Section 6 provides comments and recommendations related to key aspects of NTPC's current draft GRA. Section 7 discusses actions that could be taken in the longer term, to contain NTPC and overall system costs.

Although the GRA submission that we reviewed is preliminary and subject to refinement, there are a number of matters and observations related to NTPC's cost categories that we believe warrant some consideration.

6.1 Salaries and Wages

NTPC has taken significant steps to minimize the impact of salaries and wages on the proposed revenue requirements. It has flattened the organization structure and eliminated nine positions, including three senior management positions. As well, senior management bonuses were not paid in 2010/11, and going forward, all management bonus pay will conform to GNWT bonus program policies.

The net effect of the restructuring actions by NTPC is to reduce staffing approximately to 2007/08 levels, with the exception of apprentices. This would seem appropriate recognizing the minimal growth in sales and customers. It will be important for NTPC to avoid new staffing when the system is static and there are growing cost pressures from capital investment and fuel costs.

The expected increase in NTPC salaries and wages in the six year period since 2007/08 is $5.2 million, or an average of 4.3% per year. This is reasonably good performance in a period when electric utilities throughout Canada have faced a shortage of skilled labour and upward salary cost pressures in excess of inflation. NTPC is hoping to develop a northern apprenticeship program to train northerners to fill future job vacancies, a good objective given the growing shortage of technical personnel within the industry.

There are a couple of additional factors related to salaries and wages that impact the revenue requirement that should receive some further consideration. The first is related to Overhead Capitalized (overhead and administrative costs related to capital projects). For most utilities the trend has been to decrease the Overhead Capitalization Rate as they have fewer new capital expenditures and recent accounting policy changes encourage expensing of overhead rather than capitalization. The draft GRA submission indicates that NTPC has recently increased its Overhead Capitalization Rate from 10% to 18%. While this may be higher than the rate used by some (but not all) other utilities, NTPC's large capital program justifies a higher Overhead Capitalized Rate.

The impact of a higher Capitalization Rate is to decrease the revenue requirement in the near term as more expenses are capitalized. Over the longer term the higher rate base of capital projects (including the Overhead Capitalized) attracts greater depreciation expense and utility return. Therefore, it will be desirable to reduce the Overhead Capitalization Rate in the future if the capital program winds down.

A second issue to consider is the cost of pension and other post-retirement benefits. For most utilities these costs have been growing rapidly in recent years. One large factor driving this growth has been the actuarial reduction in the retirement plan discount rate, the impact of which is to increase the funding obligation of corporations.

An on-going issue for most utilities is whether to include some or all of employee bonus payments in the pension obligations and whether these costs should be funded by ratepayers or shareholders. In the last PUB Decision only 50% of NTPC's management bonuses were allowed for funding by ratepayers. Since then, NTPC has revised its management bonus levels to be consistent with that of the GNWT. It is not clear how this corporate policy change impacts the appropriateness of ratepayer versus shareholder funding of this part of the pension.

6.2 Operations & Maintenance (O&M) Cost Components

The draft GRA also includes Other O&M cost components. Our review of the information provided suggests that estimated costs in O&M are generally well contained. General comments related to these cost components can be found below.

Non Production Fuel is fuel for NTPC's vehicles and for heating NTPC's buildings. The target is to keep fuel consumption volumes the same as the amounts approved in the 2007/08 GRA.

Supplies and Services include materials, insurance, property taxes, and grants in lieu of taxes. These costs have decreased since peaking in 2009/10 to an average increase of 1.9% per year since 2007/08.

Travel and Accommodation costs have stabilized at $2.2 million. Increases in air charter costs to fly power line technicians to trouble spots have been offset by greater use of technology, especially teleconferencing and tele-control, which remotely monitors NTPC's isolated plants.

Taken together, NTPC's estimated expenses for its O&M cost components result in a relatively modest average annual increase of 3.3 % per year between 2007/08 and 2013/14. Based on the research done for this review it is important to note that few utilities are managing to keep O&M cost increases to a level this low.

6.3 Cost of Production Fuels

The cost of fuel (diesel fuel and natural gas) used for the generation of electricity is a major cost category in the NTPC revenue requirements. It is the second largest area of cost increase (following depreciation expense) since the last GRA revenue requirements review in 2007/08. Costs have risen from just over $17.3 million (including Norman Wells) in 2007/08 to a forecast of just under $23 million in the proposed 2012/13 GRA submission. This increased cost creates a shortfall of $5 million that makes up one-third of the total revenue requirements cost difference between 2007/08 and the proposed 2012/13 GRA. (Note: The NTPC forecast does not include impacts that may develop in Inuvik due to reduced natural gas deliverability).

Figure 6.1 shows the changes in diesel production fuel costs to NTPC since 2007, along with the diesel fuel reference price from the 2007/08 GRA.

6.2

Actual Diesel

2007/08 GRA

Figure 6.1 Historical Diesel Fuel Prices since the 2007/08 GRA

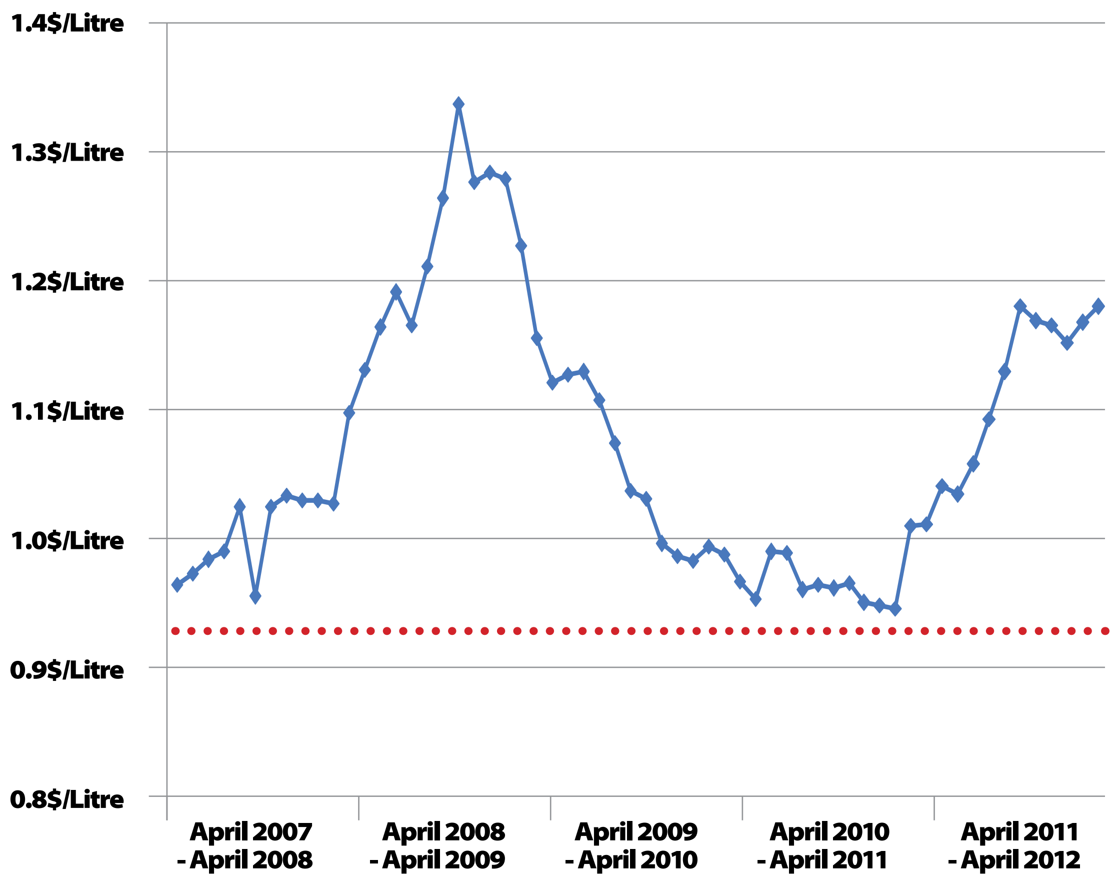


Figure 6.1 demonstrates the extreme volatility in petroleum products costs and the low reference price included in rates back in 2007/08. The impact of not adjusting the reference price quickly enough over the last five years has been large transfers to the diesel rate stabilization fund.

The total of $7 million in payments from the GNWT (and a possible further $4.6 million in future) to pay down the Stabilization Fund balances is a major benefit to ratepayers. The payments have reduced pressure on revenue requirements as well as "clearing" much of the account balances. These payments and a proposed additional $4.6 million payment in 2012/13 will assist in stabilizing rates going forward, as long as an efficient mechanism is established and used in a timely manner to revise the reference price of production fuel.

The Fuel Services Agreement with the Petroleum Products Division

NTPC now purchases all its diesel fuel from the GNWT's Petroleum Products Division (PPD) under a 2005 Fuel Services Agreement. PPD arranges for the purchase and delivery of diesel fuel to the storage tanks in NWT communities, and invoices NTPC for the actual cost of the fuel, plus a charge per litre to cover PPD's own costs for transportation, storage, and administration. The Agreement between NTPC and PPD appears to have been beneficial to both parties as PPD has realized economies of scale in its diesel fuel procurement and transportation, and NTPC receives fuel at competitive prices with low overheads.

When negotiated in 2005, the Agreement identified approximately $400,000 in costs that needed to be recovered by PPD. NTPC's diesel fuel use has increased since the Agreement was signed. As a result, PPD can expect to receive revenues of over $1.1 million per year during the period covered by the draft GRA. This figure includes new revenue of $210,000 that PPD will receive when NTPC reverts to diesel fuel use in Inuvik. The $400,000 in costs identified by PPD in the 2005 Agreement are likely substantially understated in 2012, but they are unlikely to be as high as $1.1 million.

The current Fuel Services Agreement ends in December 2015, but there may be an opportunity to renegotiate it before then. There is significant value to the services PPD provides to NTPC, but it is difficult to see that PPD incurs direct costs of over $1 million. In our view, since both parties benefit from the economies of scale in purchasing, delivery and storage of the diesel fuel, it would seem fair that the PPD mark up should not be more than the actual cost of the service provided to NTPC. If the mark-up is greater than the actual cost of the service being provided by PPD, then electricity rates would be subsidizing PPD fuel sales. This may be the objective of the GNWT, but nonetheless, should be considered from a government policy perspective.

No potential cost saving to NTPC from a renegotiated agreement has been factored into our analysis.

Hedging

Both PPD and NTPC appear to have authority to hedge diesel fuel prices to control volatility. However, an unfortunate hedge in the early 2000s led to considerable criticism of PPD when the hedge went negative, and PPD is now less likely to hedge future purchases. NTPC also has the ability to hedge prices to minimize price fluctuations but is equally reluctant to do so.

NTPC should remain alert to financial hedging options to smooth prices but we agree that fuel price hedges should not be used frequently.

Recommendation

NTPC, PPD, and other government officials should attempt to reach a consensus on the cost of the service PPD provides to NTPC and whether fuel sales in communities served by PPD are indirectly being subsidized by the PPD charges on diesel fuel used for electricity generation.

6.2

Recommendation

In order to streamline the examination of diesel fuel prices and price forecasts in GRA reviews, NTPC should establish a diesel fuel price forecast methodology and submit it to the PUB for approval. This methodology should be clear, easy for consumers to understand, and substantially reduce or eliminate detailed discussion on fuel prices during periodic GRA reviews.

Further, the diesel fuel price forecast should be incorporated into rates on a semi-annual basis in October and April, ensuring that fuel is treated as a "pass though" item. The rider for the Consolidated Stabilization Fund should also be reset each October and April with a two year recovery and there should no longer be a threshold limit before NTPC could apply.

The Consolidated Stabilization Fund

There are many factors that have led to the significant increase in revenue requirements since 2007/08. However, the infrequent updates to the diesel fuel reference price into rates and the build up in the fuel rider, and now the Consolidated Stabilization Fund, are matters that need not reoccur. NTPC had an approved methodology to act on both these diesel fuel price matters, but for various reasons the fund balance has continued to increase. Now that territorial energy policy matters and rate design issues are being resolved, it is timely to address mechanisms to avoid rate shock from diesel fuel price escalation and volatility in the future.

The issue of rising and volatile petroleum and natural gas prices is not new and most jurisdictions in Canada have approved methods to deal with them. For example, in B.C. the natural gas utilities adjust their commodity prices each quarter based on a forward estimate of natural gas prices from NYMEX. At the end of each year the differences in actual versus forecast costs held in a deferral account are set for recovery over a three-year period and a natural gas cost rider is adjusted up or down as necessary. The regulator reviews these applications for accuracy but no regulatory proceeding occurs. The advantage of quarterly price adjustments is that prices reflected in rates are never far out of the market and the benefit of the three-year cost recovery is that the volatility in the market is smoothed out for ratepayers.

The circumstances in NWT are similar and a mechanism could be tailored to the fuel purchase and delivery patterns in NWT. We found, during our review, that the existing mechanism of adjusting prices every six months in October and April will work best with the purchasing practices of PPD. Adjusting the Consolidated Stabilization Fund rate rider also in October and April seems appropriate, although instead of a one year recovery, a two or more year recovery would help to smooth out the volatility that will occur in market prices.

Perhaps the most important feature of a revised approach to diesel fuel price setting and changes to any associated rider is that the mechanism should be automatic - with the regulator reviewing and approving the changes after due diligence checks, but without an extended and formal regulatory process. This approach seems reasonable in that there is no "winning" or "losing" involved in the regulatory review of fuel price changes; the prudently incurred costs will be recovered without profit or loss.

As well, it is important to recognize that automatic semi-annual adjustments, as a regular feature of rate setting, will ensure deferral accounts remain manageable and there would be less need for government intervention.

6.4

6.4 Regulatory Considerations

Everyone we spoke to had views on the state of regulation in NWT. Virtually all are disappointed with the high cost of PUB hearings and the length of time to get Decisions from the Board. The last GRA proceeding in 2007/08 cost approximately $2.5 million in direct costs for consultants, lawyers, intervener funding and proceeding expenses. This is a cost of about $130 for every retail electricity customer, or $60 for every resident in the NWT. For a large utility in the south the cost of a full oral hearing would likely range from one to several dollars per residential customer. In addition to monetary costs, there is a cost to the operating efficiency of the Utility as management attention is diverted to the hearing process.

In its last Decision the PUB issued some 50 Directives to the Utility. Thirty remain outstanding, to be answered in the upcoming GRA. This is a trend that we have also seen by regulatory tribunals across Canada. However, it should be remembered that responding to these directives diverts Utility personnel from their primary task of operating a safe and reliable electricity system. No doubt some directives are necessary but all regulators should weigh the benefit of each directive against its cost in terms of time and expense. In the end the ratepayers will pay for all direct and indirect costs.

The PUB will review many of the critical factors and reach its own conclusion as to whether a streamlined process is appropriate. For example, as discussed in the next section, if NTPC proposes to the PUB a reduced return on equity, there will be little to debate on these issues at a public hearing.

NTPC has also largely reduced staffing to 2007 levels and revised management bonuses so that salaries and wages costs are not much more than inflation since 2007. Fuel costs are largely a pass through from PPD. If there is no change to depreciation rates then the depreciation expense is a matter of verification rather than debate. Add to this the fact that the GNWT intends to provide direct funding to NTPC to reduce the impact of the upcoming GRA on consumers and a very good case can be made to the PUB to implement a streamlined process.

NTPC had forecast $1.6 million as its cost to prepare its application and participate in the regulatory process. This allocation may drop to below $1.2 million assuming the PUB accepts the case for a streamlined process and:

- Removes ROE matters from discussion at a public hearing (savings of at least $300,000);
- Determines that a full Cost of Service study is not required (if the GNWT does propose to provide funding to facilitate "across the board" increases to zone-based rates); and
- Agrees to a combined hearing for Phases I and II (savings of at least $100,000).

With a decline from $1.6 to $1.2 million in GRA regulatory costs, assuming these costs are recovered over four years, the amount being built into rates drops from about $400,000 per year to $300,000 per year.

Government should consider presenting these views to the PUB to support the case for a streamlined process. NTPC, as the agent of GNWT, could make this case in its application, but given its role as proponent, it might not have as much weight with the Board as it would if it is a Government position.

Recommendation

In the General Rate Application, NTPC should propose a streamlined process to the PUB that includes no debate of capital structure, return on equity, or development of a detailed cost of service study. The GNWT should consider supporting this position through a submission to the PUB explaining the intent of the proposed government support.

6.5

6.5 Capital Structure and Return on Equity (ROE)

A regulated investor-owned utility earns its profit based on the awarded ROE on the portion of rate base funded by shareholder equity. The rate base is the depreciated value of all the approved capital assets on the books of the Utility. At the time of the last rate setting for the 2007/08 fiscal year NTPC was awarded an ROE of 9.25% on the actual Capital Structure of 51.4% debt and 48.6% equity. As well, the cost of debt was funded at its actual cost. Since then there have been major energy policy and structural changes that impact NTPC's Capital Structure and effective returns of the Utility.

All of the recent changes result in a new paradigm facing NTPC. The *2010 Electricity Policy* makes it clear that NTPC is to remain owned by GNWT and that reliable and affordable electricity supply is an essential service. The new rate structure creates a new NTPC Thermal Zone with a reduced effective utility return (1.5 times-interest-coverage) while maintaining the existing ROE and Capital Structure rate setting methodology for the hydro zones. Even with these changes, as noted above, the GNWT is facing a significant injection of funds to keep the proposed rate increases to reasonable levels.

In our discussions we heard how NTPC was once structured like an investor-owned utility and that the substantial dividends provided by NTPC to the GNWT were used to fund the Territorial Power Subsidy Program (TPSP). The TPSP subsidizes the initial consumption levels of residents living in what is now the Thermal Zone. However, the link between the amount of the dividend paid and the cost of the TPSP has now been broken as the TPSP now costs far more than the amount provided by the dividend. Further, the 2010 Electricity Policy set new limits to the consumption that will be subsidized by government. As a result of all of these changes it seems fair to say that the TPSP can now be viewed as a social and an economic program of GNWT and not tied to the NTPC dividend.

All of the changes noted above create an opportunity to revisit the Capital Structure and ROE of NTPC. For example, if the dividend is no longer tied to the TPSP, is it reasonable to ask if there is a need for NTPC to have as large a ROE? The ROE drives up the revenue requirement - each percentage point drop in ROE equals a reduction of approximately $0.8 million in the revenue requirement.

Should changes to the ROE structure be contemplated it will be important to recognize the current structure of NTPC rate setting. If one reduces the ROE in the Capital Structure, the impact will be to reduce costs and rates in the hydro zones which then leads to higher costs to government to subsidize the Thermal Zones' initial block consumption down to the now lower "Yellowknife" rate.

In looking at the near term circumstances, we considered the level of equity needed by NTPC and the ROE. In this context we also considered the regulatory costs and time to have the issue adjudicated in an oral public hearing before the PUB. Generally, the issues of Capital Structure and ROE are hotly contested and very expensive when canvassed at a revenue requirements hearing. There are the high costs of experts and an inordinate amount of time consumed in public hearings, often followed by lengthy delays before a tribunal renders a Decision. These issues are usually acrimonious, which reduces opportunities for utilities to work harmoniously with their customers.

Establishing an Appropriate Rate of Return

A suggested in the discussion above, for a Crown utility like NTPC there may be less need to maximize shareholder returns. Rather, there may be a greater desire to keep costs low for ratepayers. An early version of NTPC's draft GRA requests a market ROE of 9% on an actual equity component of just over 40% of rate base. This follows what appears to be a fairly traditional approach. However, there are alternatives. The Alberta regulator has recently awarded its benchmark investor-owned utilities an ROE of 8.75% for 2012.

All parties we spoke to, including NTPC, seem to support setting the ROE below the maximum that could be awarded by the PUB – although no specific level of discount was agreed upon. While reducing NTPC's revenues, this action would likely simplify approval, reduce regulatory costs and provide lower rates to ratepayers.

One option that was suggested was to set the ROE at perhaps 8-8.50%, which is below the level likely to be awarded to a low risk investor-owned utility anywhere in Canada. If the ROE were to be set at this level then there would be no reason to review this in a public hearing since the Utility would be accepting a return less than the regulator would otherwise be obligated to award. With the current low interest rates already existing, the proposed ROE would likely remain below market levels into the future. An alternative could be to prescribe a discount below the annual ROE benchmark set by Alberta's regulator. The discount would need to be meaningful to avoid calls for expert evidence: perhaps a discount of 0.5 to 1.0% would suffice.

The PUB has historically recognized the actual level of equity held by NTPC. Elsewhere it is not uncommon for regulators to deem a level of equity if it is felt that the actual equity component is too high. If the deemed equity for NTPC was set below the actual level of equity, it would mean that NTPC would receive only the weighted average debt percentage return on the portion of equity deemed to be funded by debt. However, in NTPC's case, as the current actual level of equity is close to the 40% there may not be much to be gained by artificially adjusting the equity component.

Interest Coverage

Another area to consider is the mandated 1.5 times-interest-coverage margin that is currently applied to debt servicing costs for assets in the NTPC Thermal Zone. The application of interest coverage, rather than establishing a ROE, helps reduce rates in the thermal communities. The overall result of the application of interest level coverage in the Thermal Zone will also be a lower level of government subsidy.

The use of 1.5 times interest coverage makes some sense when one considers typical debt covenants on borrowings. This being said, it is not clear that the interest level coverage is set at an optimal level, recognizing the ROE and equity thickness in the NTPC hydro zones.

We believe that the 1.5 times interest coverage should be continued for NTPC's thermal zones. This action reduces the overall revenue requirement when compared to a full commercial type ROE.

Recommendation

NTPC should consider seeking approval for an ROE at a level in the 8.0 to 8.5% range on NTPC's actual equity component of just over 40%, to provide a meaningful discount against the benchmark ROE awarded in Alberta.

6.6

6.6 Fixed Asset Amortization (Depreciation Expense)

The depreciation expense on fixed assets is a significant driver in the 2013/14 forecast revenue requirement. Since the last rate setting in 2007/2008, NTPC forecasts that the annual depreciation expense will need to increase by $8.9 million to about $21.7 million. A significant portion of this additional cost relates to increases in the amortization of the deferred costs for things like water licenses and generation plant and equipment overhauls. This deferred cost portion makes up $3.2 million of the $8.9 million increase. Much of the remaining $6.7 million increase can be attributed to new capital additions which result in an increase in the net rate base to which the individual asset's depreciation is applied.

NTPC's draft GRA also provides for the implementation of revised depreciation rates resulting from a recent review of the Corporation's assets by an experienced depreciation firm (the "depreciation study"). No depreciation study was completed for the last GRA, so the most recently completed study is from the year 2000. NTPC's auditors have indicated an updated study is needed. It is our understanding that the net effect of the proposed new depreciation rates is about a $1.6 million increase in depreciation expense compared to the currently approved rates.

The proposed increase in depreciation expense suggested by the depreciation study arises from a combination of changes to estimates of the lives of assets and the treatment of the cost of asset retirement (negative salvage). The largest increases relate to updated estimates of the life of diesel generating assets ($1.7 million, with the remainder of asset classes yielding a net $0.1 million reduction in costs).

Depreciation studies are highly technical and are subject to considerable judgment, so that the approval process for changes to depreciation rates could be involved and lengthy. Changes in depreciation rates are not normally allowed on an interim basis, and it is unlikely the new rates would be approved in time for the upcoming 2012/13 fiscal year.

Negative Salvage

NTPC's depreciation consultants have advised the Corporation that its provision for "negative salvage" is excessive when compared to actual costs for equipment retirement. The negative salvage balance is about $40 million and today's rates include about $2 million/year to build up this balance. The depreciation study concludes the appropriate balance should be $21 million and that $1.5 million should be set aside each year. To remedy this situation, NTPC proposes to stop collecting negative salvage from ratepayers at this time (i.e, put $0/year in rates) until the balance is more appropriate. This reduces overall depreciation expense by about $2 million per year compared to existing rates.

Notwithstanding NTPC's proposed approach to the matter, there are many options for dealing with the issue of negative salvage and the reduction in the "over-collection". In some jurisdictions energy utilities are not approved to collect negative salvage at all. The thinking in support of this perspective is that an asset, like a diesel generator, that has reached its end of life, will be replaced by another generator at the same site and the net cost of removal of the old generator becomes part of the capital cost of installing the new generator. This has not been the practice in NWT.

The options available to the regulator in approving new depreciation rates range from a temporary halt in collecting negative salvage (as proposed by NTPC) to a more aggressive approach based on drawing down some or all of the current negative salvage balance (either the excess or the full amount).

Determining the Life of Assets

The second proposed change in depreciation expense results from an overall reduction in expected asset lives. This change would increase NTPC's depreciation expense by about $3.8 million per year.

A major source of the increased depreciation expense is the proposed reduction in expected life of diesel generation assets in 3 categories:

- Structures (plants) from 40 years to 30 years
- Engines from 25 to 20 years
- Diesel Generation Electrical Equipment from 28 to 21 years.

These changes are very significant and it can be expected that they will be challenged during the regulatory process.

In our view, NTPC should reassess expected diesel life by size of unit and by unit status (i.e. primary use versus back up use units). For example, it is hard to imagine that the average life of the large diesels backing up Yellowknife would only be 20 years. Conversely, a very small primary generator in a small community might have a shorter life. NTPC's 2011 Strategic Plan notes the need to complete a condition assessment for its main assets to help prioritize overhauls, upgrades, and replacements.

NTPC would like to file its depreciation study with the PUB and move forward to regulatory review and approval of updated depreciation rates for implementation in 2013/14. This seems prudent due to the auditor's direction to do so, but this should occur only after the condition assessment is completed. Presumably this could be done as a separate application and reviewed in a written hearing process, perhaps with an initial workshop for the Corporation to explain its study findings and final proposal.

Recommendation

NTPC should consider advancing its condition assessment for its main assets, use the findings to update its recent depreciation study, and seek PUB approval for its updated depreciation rates through a separate written hearing process for implementation in 2013/14 or later.

7

7.0

Recommendation

The GNWT and NTPC should implement a regular planning and reporting structure centered on a Shareholder's Letter of Expectations, and a subsequent NTPC report back to the GNWT. As well, the GNWT should revisit the Strategic Direction issued in 2002 and the NTPC Act to ensure they are consistent with regard to the current corporate structure of NTPC and there is clarity with respect to NTPC's mandate.

7.0 Closing the Revenue Gap: Long-Term Cost Containment Strategies

It is important to recognize that not all opportunities for cost containment and revenue enhancement will be realized immediately. Nevertheless, there is considerable value in identifying those activities that will be of highest priority, in the longer-term, in controlling costs and then establishing a plan for further study and future decisions.

If we consider the period 2012 to 2014 as "transition years", then action related to the subjects discussed below can provide potential ways to reinforce a stable financial foundation for NTPC (and the GNWT) in the post-GRA era.

7.1 Governance Structure: The Shareholder-Utility Relationship

The *NTPC Act* mandates its Board to "act in accordance with the directions and policy guidelines that may from time to time be issued or established by the Executive Council". That *Act* also mandates NTPC to prepare long-term generation and transmission plans, update these plans annually, and to undertake programs to conserve energy.

As well, in 2002 the GNWT issued an "expectations document" to NTPC. The document included a listing of priorities that must now be reconsidered in light of GNWT recent policy changes. The priorities listed in the document included direction that NTPC:

- Aggressively pursue alternative generation technologies
- Aggressively pursue new domestic and export markets with a view to expanding the electrical sales base
- Aggressively pursue partnerships and joint ventures with northern parties
- Maximize the value of NTPC through profitable expansion and diversification

With the subsequent creation of Northwest Territories Hydro Corporation and its business development subsidiaries, NTPC's focus is now correctly on the provision of safe, reliable power at fair, regulated rates. However by doing so it is technically straying from its statutory mandate.

7.2

7.2 Direction to NTPC – Regular Issuance of Shareholder's Letter of Expectations

Long-term efficiencies are more likely to be achieved if there is well developed two-way reporting and communication between GNWT and NTPC. Both the *NTPC Review* and the *Electricity Review* discussed the need to improve this relationship. With new executive leadership in both organizations, changes have already occurred and both are eager to take further positive steps.

NTPC is a corporate structure and the GNWT is its sole shareholder. Both GNWT and NTPC officials expressed support for a "Shareholder's Letter of Expectations" (SLE). Every year or two, a SLE would be prepared by the GNWT and sent to NTPC. The SLE would describe GNWT's perspective on NTPC's priorities and performance expectations for the period covered by the letter. The SLE would provide a way for NTPC to be formally advised of changing government priorities and policies. For the SLE process to be most effective it would be important that NTPC have input into the preparation of the SLE.

NTPC would be expected to submit reports to the GNWT, outlining its successes in achieving stated priorities and describing the corporate results in relation to any performance measures in the SLE. The establishment of a SLE, and an appropriate reporting mechanism, may reduce the temptation for the GNWT to "micromanage" NTPC operations, reduce misunderstandings and miscommunications and encourage cooperation.

Measurement of Corporate Performance

The SLE and NTPC's response should include performance measures and targets. NTPC already refers to the need to develop and implement a set of KPIs in its *2011 NTPC Strategic Plan*. As well, its annual reports have, for some time, summarized trends in customer satisfaction, worker safety and reliability, and may be a source for information leading to the creation of some of the desired KPIs.

NTPC's performance measures should involve target setting by all employees. They should summarize the service, safety, and reliability of the system, and include industry standard measures to enable comparisons with peer utilities. Selected performance measures should also be "SMART": specific, measurable, actionable, repeatable, and targeted. The performance measures could be developed in consultation with the GNWT, industry associations, interested parties and customers.

In addition to the traditional reliability and safety performance measures, we have seen instances where customers want statistics on the average speed with which utility representatives answer complaints or emergency calls and the results of customer satisfaction surveys. Finally, while there is merit in benchmarking to similar utilities, customers often want to see that their utility is improving its performance statistics year over year. In Performance Based Regulation a utility is generally not able to share in financial incentives unless it meets its performance targets.

The performance measures will also prove helpful in communicating with and demonstrating to customers and ratepayers that their utility is providing safe and reliable service at reasonable costs.

Recommendation

NTPC should expand its use of standard industry safety and reliability indexes by setting measurable targets, reporting results at the community, zone, and system level, and comparing its results with those of similar utilities.

Recommendation

A comprehensive listing of performance measures should be prepared by NTPC that permit it to assess corporate performance in the context of shareholder expectations, customer interests and corporate priorities.

Recommendation

NTPC should calculate "GW.h Produced per Employee" as a useful "Key Performance Indicator" (KPI) to reveal trends at a glance in the future. (Note: This is about 1.89 GW.h/employee with 169 staff in 2012/13, and given recent staff reductions, is trending in a favourable direction).

7.3 Long Term Approach to Regulation

While criticisms of the PUB costs and process exist, there appears to be continuing public support for and trust of the PUB. This is an important finding since a regulatory tribunal relies on its independence and public trust to remain effective.

An overall goal of governments, regulators and utilities is to keep GRA review timelines and costs down, while respecting the meaningful role of the regulator. The 2006-08 NTPC GRA review, which cost ratepayers around $2.5 million on an $80 million application, is not a preferred regulatory model to pursue.

Addressing Intervener Costs

The *Public Utilities Act* gives the PUB the authority to require a utility applicant to pay interveners' costs. NTPC paid over $300,000 to fund interveners in the 2006-08 GRA process. As the *Electricity Review* noted, interveners and information requests (over a thousand for the last GRA) are significant expenses and the costs for these elements of the regulatory process are passed on to customers.

The *Electricity Review* recommended that cost awards should be limited to non-tax-based communities and non-profit organizations. The 2010 Electricity Policy (Action 9) stated the PUB would be directed to develop cost recovery guidelines that will outline eligible costs and standard reimbursement rates. Most provincial utility regulators have prepared similar guidelines, which can serve as models to consider.

Addressing the Costs of the Regulatory Process

Upon the completion of the current GRA, the GNWT may wish to undertake a review of the current legislation, the process, and the government's role in that process, and consider additional ways to ensure regulatory costs are low and proceedings are streamlined.

In discussion with the Board Chair, he is open to more efficient regulatory methods while maintaining the integrity of the Board. He has also identified that NTPC is likely to face future pressures as costs of the Bluefish dam enter the rate base and costs are incurred related to declining natural gas in Inuvik and Norman Wells.

With fewer than 9,000 NTPC customers, the regulatory regime must be tailored to minimize regulatory costs while maintaining effectiveness. There are many options that should be considered, including:

- Written hearings and other streamlined application protocols for less substantive applications;
- Establishing intervener budgets and perhaps having Board Counsel assist interveners on procedural matters so that other lawyers are not required;
- Establishing defined time limits for the regulatory process;
- Setting targets for application "turnaround" times and reporting results;
- Establishing multi-year rate setting with some inflationary components; and
- Negotiated settlement processes, and multi-year performance based rate setting.

For example, if NTPC had an on-going mechanism to revise diesel fuel costs and clear out variances, a stretch inflation (inflation less productivity) component for variable costs, a fixed ROE and automatic adjustments to annual depreciation for the completion of previously approved capital projects, NTPC could likely avoid hearings for many years. Most of these items need only be verified by the regulator rather than open to debate.

Establishing a process to adjust rates due to inflation is comparable to the simplified rate adjustment mechanism that was in place in New Brunswick for most of the last two decades. Utilities were required to file a summary package with the PUB for their information within some deadline after the rate change occurred (e.g., 90 days). If so desired by the Minister, the PUB may be asked to provide comments on the package, which would become part of the consideration as to the need for any further adjustments in subsequent years.

A more substantial change could be to adopt some aspects of the Saskatchewan model and change the quasi-judicial approach of the PUB to one more along the lines of an advisory council. The merits of such an approach should be studied in depth as to how it could be applied to the unique circumstances in the NWT. This includes the structure of the industry in the NWT and the fact that there are both public and private utilities, a complicating factor. Changes in regulatory oversight for investor owned utilities are often (justifiably) viewed differently than for government owned utilities.

The recent amendment to the *Public Utilities Act* enables the Minister to request that the Board perform undertakings on behalf of the Government. Therefore, at the Minister's request, the PUB itself could undertake a review and provide recommendations to Government on the opportunities to streamline the GRA process.

The GNWT likely does not have the legislative authority to issue direction specific to a GRA. Section 12 of the *Public Utilities Act* gives the Executive Council the authority to issue directives to the PUB respecting:

"(1) (a) policies to be applied by the Board in the determination of its orders, decisions and rules; and

(b) the general performance of the duties of the Board.

(2) The Board shall ensure that directives of the Executive Council are implemented promptly and efficiently."

Many jurisdictions have this directive-making power in their utility regulator's enabling legislation. The extent to which such directives can legally intrude on the normal powers of the regulator is a theme visited frequently by legal advisors. Notwithstanding the recent changes made to the PUB legislation, the GNWT should explore making further changes that consider the options for change discussed above.

Recommendation

The GNWT should consider undertaking a review of the Public Utilities Act and the current GRA process with a view to streamline the process and control costs. This review could either be done by Government or through an undertaking of the Board.

7.4 Capital Structure and Dividend Policy

In the medium to long-term it appears that there may be the need for some substantial policy changes as established in the 2010 Electricity Policy. Most notably, the new Thermal and Hydro Rate Zones have return requirements that seem at odds with each other. Also, breaking the link between the NTPC dividends as a funding source for the TPSP calls into question the need for substantial dividends to government. The two issues are interlinked and should be considered together.

Consideration of recapitalization options may require consideration by the GNWT because of their potential impact on NTPC and GNWT debt ratings - those provided by debt rating agencies. It is well beyond the scope and timing of this review but we offer some comment since it would be to everyone's benefit to simplify the understanding of the Utility funding and rates.

Comparing the Diesel and Hydro Zone Rates of Return

There is currently a difference in the approach to setting a return for the Thermal and Hydro Zones. The current approach does not make much sense except to reduce the overall costs in the Thermal Zone while maintaining higher costs in the Hydro Zones (due to the use of a different approach to return on equity, or setting required reserve levels).

The investor-owned type Capital Structure and ROE structure that existed for NTPC has been mandated for some other Crown-owned energy utilities in Canada, and not for some others. Two examples of alternate approaches can help illustrate the matter.

In the early 1990s the Government of B.C. mandated that the rates of BC Hydro (a Crown Corporation) be set on a notional Capital Structure and that the pre-tax ROE be equal to the return of the most comparable investor-owned energy utility. Prior to that time BC Hydro had been funded almost entirely by government debt and rates were set at cost. BC Hydro had one of the lowest rate structures in Canada and the government saw an opportunity to receive large dividends from BC Hydro by changing its approach. Even now that BC Hydro rates are rising rapidly due to large capital investments and purchased supply contracts, the B.C. government is reluctant to decrease its dividends.

In contrast to B.C., the Province of Manitoba has not created an investor-owned type Capital Structure and ROE for Manitoba Hydro. That Crown utility has traditionally operated on a cost recovery basis with very low reserves or "equity" levels and no dividend paid to the owner (with one exception, in 2003). Starting in the early 1990s, with a ratio of 95% debt and 5% equity or reserves, Manitoba Hydro began to build up equity in order to improve its ability to withstand adverse events such as droughts. Manitoba Hydro generates nearly all of its electricity from hydraulic sources, and exports substantial proportions of this energy (up to 40% of revenues come from export customers). The result is that Manitoba continues to have some of the lowest electricity rates in North America.

One might also wish to consider the effective tax incidence when considering charging an ROE to customers that then becomes a dividend revenue source to government. Typically the income tax system is more progressive than collecting government revenue via the electricity rates.

There are a host of options the GNWT could consider, including maintaining the existing separation between the capital recovery in the Thermal versus Hydro Zones. One radical idea might be to move the NTPC to a debt basis with an interest coverage target and direct that some or all the interest coverage be recovered from the Hydro Zones. This would lower NTPC rates in the thermal communities to a cost only basis and maintain rates in the hydro communities for interest coverage on debt purposes. A reduction in the differential between the zones could reduce the cost of the TPSP subsidy program.

7.5

7.5 Cost of Borrowing

NTPC will need to borrow funds over the next few years to finance its significant capital programs. Crown-owned electricity utilities in western Canada generally borrow money through their provincial government shareholder in an effort to minimize interest payments on utility debt. NTPC's borrowing costs may be reduced if it borrowed through the GNWT's Department of Finance, assuming the GNWT can borrow in capital markets at lower costs than NTPC could achieve on its own. NTPC may also realize some O&M savings by simply utilizing GNWT resources to obtain its financing requirements. As an example, from 2003 to 2010 GNWT's Department of Finance loaned funds to NTPC at short-term floating rates with an interest saving estimated by Finance at $1.2 million over the commercial cost of funds.

As well, centralizing borrowing activities for both NTPC and other government entities may lower the overall cost of GNWT debt by increasing the amount of GNWT debt in the market.

However, the GNWT has its own cash and borrowing constraints, and as NTPC's borrowings are included in the GNWT's debt cap, it is important to ensure NTPC's future debt requirements are well understood. Any further savings from this area may be small as NTPC's debt is already guaranteed by the GNWT.

Recommendation

GNWT and NTPC should examine the potential savings, advantages, and disadvantages of having GNWT issue debt on NTPC's behalf.

7.6 Revenue Growth Opportunities

NTPC receives about $1.2 million per year in non-power revenues, including connection fees, contract work, pole rentals, and heat sales.

NTPC's diesel and natural gas power plants are heated using residual heat, and partnerships have been developed in three NWT communities to heat adjacent buildings. For example, the Fort Liard heat recovery system, funded by GNWT with a contribution from NTPC, connects several buildings to that community's diesel plant.

Residual heat projects often have high up-front costs and extended payback periods, but will become more feasible as oil prices rise. NTPC's ratepayers should share in the revenues from these projects, based on the value of the heat and the way the project was funded. NTPC and GNWT might be able to sell greenhouse gas emission reduction (carbon) credits as a way to improve residual heat recovery project economics: at an emission factor of 0.00276 tonnes of CO2e per litre, the 63,000 litres per year saved at Fort Liard has a value of $4,400 per year at $25 per tonne.

As discussed earlier in this report, NTPC is currently selling interruptible power from the Taltson generation plant to government customers in the Town of Fort Smith. NTPC should ensure these interruptible revenues continue to be included in its revenue forecasts: any such sales in the hydro zones will make a small but positive contribution, given that short-term firm load growth is expected to be minimal.

In the Snare Zone, there is a small surplus capacity of hydro-generated power during the summer months. This is interruptible power, but could be sold through NUL to larger facilities in Yellowknife that wish to install duel fuel heating systems. (As with residual heat, selling carbon credits might help offset costs). Should this occur, NTPC may increase its sales of wholesale power. There are also more lucrative revenue possibilities from the proposed Yellowknife Community Energy System and Giant Mine remediation project.

In the NTPC Taltson Zone there is five to eight megawatts of surplus hydro generation capacity and it is our view that greater efforts should be made to sell this surplus electricity, either through electric heating, or through marketing efforts aimed at potential resource development in the area. Higher sales improve economies of scale, allowing NTPC to spread its overhead across more units of electricity sold, and ultimately reducing the cost of electricity for everyone.

Recommendation

NTPC and the GNWT should explore ways to increase sales where there is a surplus in hydro generation capacity. Electric heating or industrial customers appear to be the greatest opportunity.

7.7

7.7 Demand Side Management

Demand Side Management (DSM) encompasses GNWT's and NTPC's initiatives to reduce electricity consumption on the customer's side of the meter. DSM electricity savings are the difference between the actual amount of electricity consumed and the amount that would have been consumed in the absence of DSM programs. For utilities with growing loads, DSM resources are logical alternatives to supply-side additions as the cost per kW.h saved is usually lower than the cost of constructing new generation. In addition, most DSM programs have employment and environmental benefits.

Even though NTPC has a strong public mandate through its legislation to undertake programs to conserve energy, given its flat load growth and modest summer hydro surplus, it is arguably not in NTPC's interest to have its revenues reduced due to DSM investments. Rather, opportunities lie with the GNWT to use DSM programs to reduce the amounts budgeted for electricity subsidies. For example, about $5.2 million is spent annually to reduce NWT Housing Corporation tenants' electricity rates down to six cents/kW.h. Since 2008, NWT Housing has undertaken energy retrofits in about 175 units. The pace of energy retrofits could be expanded and seasonal jobs created, perhaps funded by a redesign of the electricity benefit portion of the Housing Support program. Electricity bills for tenants of retrofitted housing could remain unchanged, with reduced consumption offsetting a reduced subsidy.

A "back to the basics" theme underpins much of NTPC's recent strategic planning and messaging to its shareholder and customers. DSM programs should be evaluated in an effort to balance the costs and benefits among the competing interests of ratepayers, taxpayers, the utilities, and the GNWT. As a general principle, if NTPC is to invest in DSM programs, funding should come from governments, not ratepayers.

NTPC should also continue to pursue initiatives to reduce corporate energy use, examples being gas and diesel generator efficiencies, vehicle fleet fuel consumption, and line losses in its transmission and distribution grids. The 2011 Strategic Plan references NTPC's need to lead by example in a northern conservation culture, noting initiatives to reduce its environmental footprint and proposing a Five Year Environmental Plan. It will be useful to develop performance measures and targets to help fully engage NTPC staff in reducing "in house" energy consumption. As discussed above, the nature and degree of NTPC's responsibilities to promote electricity efficiency and conservation should be clarified.

7.8 Other Minor Cost Saving Opportunities

In 2010/11, NTPC contributed $152,000 to 68 organizations and events around the NWT as an investment in building NTPC's positive reputation in communities. It is important to note that these amounts are not built into the revenue requirements of the Corporation. While this amount is fairly insignificant to the overall revenue requirement (16/100 of one percent) it is proportionately higher than some larger utilities (e.g. BC Hydro's is 4/100 of one percent). This higher proportion may well be justified; nevertheless NTPC should ensure these expenditures are aligned with core operational requirements. NTPC expects to complete an assessment of its Donations and Sponsorship Policy in mid 2012.

As noted in Section 6.2, NTPC's budget for non-production fuel (fuel for vehicles and space heating) is about $1 million per year, up about 5% per year since 2007/08. NTPC expects fuel consumption to stay relatively constant; the increase shown in the cost components of the Corporation is due to the rise in the price per litre.

NTPC may wish to consider joining a fleet management program. "Fleetsmart" is a component of Natural Resources Canada's ecoENERGY for Fleets program, offering free advice. The "E-3 Fleet" (Energy Environment Excellence) is another Canada-wide program that helps 120 public and private organizations operating 50,000 vehicles. It offers fleet reviews, fleet ratings, and ways to help increase fuel efficiency and reduce emissions through driver training, idling reduction, vehicle "right-sizing", maintenance, and trip planning. Fees are scaled by fleet size and designed to be affordable. Cost savings average around 10% per fleet, which could translate into order of magnitude savings of $50,000 per year assuming vehicles account for half of the $1 million non-production fuel budget.

7.9 Liquefied Natural Gas Potential

Liquefied natural gas (LNG) may offer material reductions in long-term electricity rate increases in the larger centres of Inuvik and Norman Wells (which are natural gas ready) and perhaps for smaller Thermal Zone communities that could be converted to natural gas as diesel generators need to be replaced or retrofitted. LNG is natural gas, cooled to minus 160 degrees Celsius to keep it in liquid form. LNG has been safely used and transported around the world for fifty years. It is a relatively stable fuel: if LNG spills, it will warm, rise, and dissipate into the air. Across North America there is renewed interest in LNG as the price differential between natural gas and fuel oil has increased so markedly. For example, at current market prices, LNG fuel costs 40% less than marine diesel fuel. Work is underway in the north to examine LNG as a potential option in Yukon.

Yukon Energy Corporation is examining LNG as a transition fuel away from diesel, and has released a background paper "LNG Transition Option" (www.yukonenergy.ca/energy/public_engagement/lng/) for an LNG workshop in Whitehorse in January 2012. This report concludes:

- LNG liquefaction facilities in Kitimat or Fort Nelson can supply cost competitive LNG by truck to Yukon.
- A potential LNG liquefaction facility at Spectra Energy's Fort Nelson gas processing plant would cost around $26 million, but take advantage of cheaper gas supplies; trucking distances are also lower than Kitimat-sourced LNG.
- Subject to securing LNG supplies, natural gas power plants can be relatively easily integrated into the Yukon grid as conversions or replacements for existing diesel plants.
- At either $9/mmbtu for LNG at Kitimat or $6/mmbtu at Fort Nelson, and diesel at $0.89/litre ($26/mmbtu), LNG is more cost effective than diesel for the various Yukon power generation options and locations that were examined.
- Estimated power generation costs from LNG single or combined cycle generators ranged from 14.2 to 17.9 cents/kW.h (8% cost of capital, capital costs assume a 20 year economic life).

Given the current cost of diesel electricity the potential to introduce LNG solutions at the scale needed for NWT Thermal Communities with either barge or road access merits further study. The cost of permitting and developing the supply chain for sourcing, transporting, storing, re-gasifying and distributing natural gas is unknown, but much can be learned from other jurisdictions.

The Province of BC has released "Liquefied Natural Gas: A Strategy for BC's Newest Industry" (www.gov.bc.ca/ener/natural_gas_strategy.html). The province has committed to having three new LNG facilities in operation by 2020 as part of its goals for clean energy and climate change. Provided the supply chain infrastructure can be put in place, LNG could become the fuel of choice, displacing diesel in stationary power and perhaps transportation uses across the North. As well, Fortis BC Energy Inc. is mid-way through a BCUC-approved pilot program to provide LNG for truck fleets, which could present a viable option for Inuvik, via the Dempster Highway. Barging solutions for communities along the Mackenzie River may also be possible. **To help advance the LNG option, GNWT and NTPC should consider pursuing more detailed feasibility analyses in conjunction with governments, gas industry, and utility interests in BC, Yukon, and Nunavut.**

8

8.0

8.0 Conclusion

This report on NTPC's revenue requirements and cost pressures affirms and augments the relevant findings of earlier utility, policy, and governance reviews. All share the common goal of putting NTPC on a solid financial footing going forward, so it can generate and deliver electricity efficiently, reliably, and at reasonable rates.

All electricity utilities are facing cost pressures, and as detailed in our report, many are experiencing revenue requirement and rate increase percentages outpacing those of NTPC.

For NTPC, there are no "silver bullets". We have identified areas in both the short and long term where savings can be realized. In the short-term:

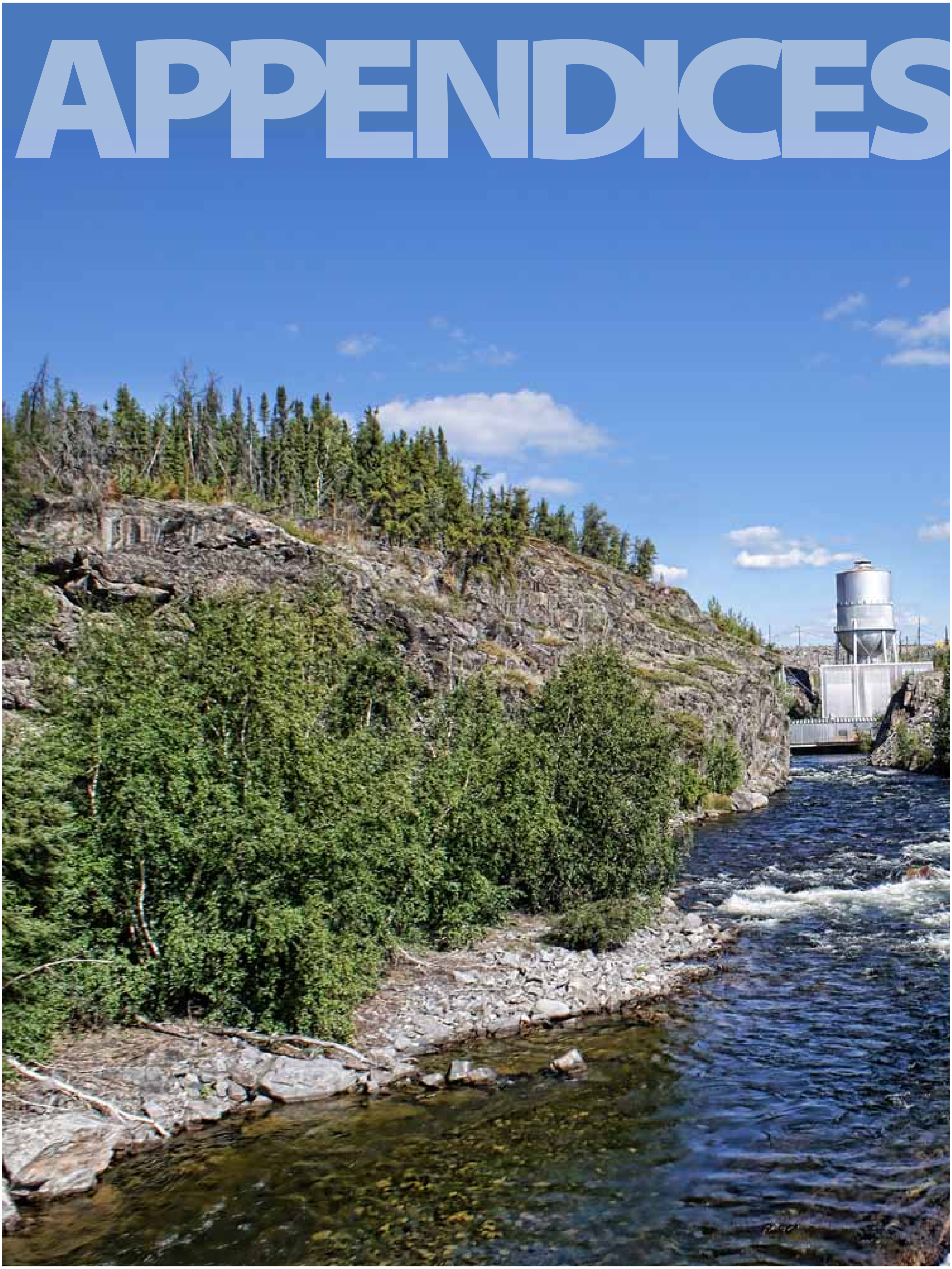
- Reducing the return on equity requested by NTPC and taking other measures to streamline the GRA process will result in savings of several hundred thousand dollars;
- There are likely potential savings from a review of PPD's administration charges to NTPC; and
- There are savings in deferring implementation of the new depreciation rates for at least 2012-13.

In the long-term, we have identified a number of steps to be taken to ensure NTPC does not "fall behind" again, including:

- A review of the regulatory system to ensure a simplified, predictable regulatory and rate setting regime that secures modest annual inflationary increases and routinely manages deferral accounts;
- The possible transfer of NTPC's borrowing function to GNWT's Department of Finance;
- The development of new sources of revenue from the sale of interruptible hydro and sales to potential industrial developments; and
- A number of recommendations aimed at performance measurement, results reporting, and enhanced communication between the Utility and the GNWT as the shareholder.

While not specifically addressed in this review, continued collaboration among NTPC, GNWT, educators, and unions will be needed to recruit talented staff. Electricity sector retirement rates are among the highest of any Canadian industry: 45,000 new and replacement staff will need to be hired in the next five years. NTPC can attract new workers with favourable career and training opportunities, competitive salaries and benefits, and job security.

APPENDICES



APPENDIX 1

Safety and Reliability Indices for Utilities

The January 2010 Report of the NTPC Review Panel concluded that NTPC's safety policies and procedures rate highly. One measure of safety is the industry standard of accident severity, measured using worker days lost due to accidents. The five year rolling average (2007-2011) of days lost by NTPC employees per 200,000 hours worked is 14.1, very close to the Canadian Electricity Association (CEA) five year rolling average (2007-2010) of 15.5 days lost per 200,000 hours worked. NTPC's 2011 Strategic Plan notes that NTPC already has a strong safety program and now needs to improve the safety "culture" by considering safety as a life value, not as a set of rules to be followed.

Reliability indexes are important in helping to identify aging assets or deficient maintenance: as with all utilities, NTPC needs to invest in its assets so they can continue to provide reliable service. NTPC's outage statistics usually meet or are better than industry averages for two of the three standard reliability indexes:

- Customer Average Interruption Duration Index (CAIDI) is the average interruption in hours per interrupted customer. NTPC fares well, with an average outage duration of 0.44 hours (i.e. 26 minutes) in 2008/09, compared to a CEA average of 2.42 hours.
- System Average Interruption Duration Index (SAIDI) indicates the percent of time in a year the lights are on or out. For the average NTPC customer, power was available 99.93% of the time in 2010/11. Put another way, in 2008/09 the power was out an average of 2.43 hours, comparing favourably with the CEA average of 5.21 hours per year in the last three years, and 7.0 hours for the CEA's "Region 2" utilities in 2010. Region 2 utilities tend to have less favourable SAIDI scores as they have both urban and rural service areas.
- System Average Interruption Frequency Index (SAIFI) measures the number of interruptions per customer per year. In 2008/09, the power went out on 5.6 occasions for the average NTPC customer, compared to the CEA average of 2.2 times and the CEA Region 2 average of 2.5 times.

NTPC's SAIFI index is higher because the system lacks the redundancy of an integrated grid. More importantly though, when a community loses its primary generation source, NTPC has the back-up capability in place to minimize risks to life, health, and public safety.

As noted in the NTPC Strategic Plan, being able to compare NTPC's performance to peer utilities will help meet customer expectations over reliability and cost, and benchmarking will help in discussions with the PUB and GNWT.

APPENDIX 2

Table A2.0 NTPC Rate Application and Rate Change Chronology since the 2006/08 GRA

Fiscal Year	Date	Rates	GNWT
2006/07	APR '06	Start of first 2006/08 GRA test year. Application not yet filled	
	NOV '06	NTPC files 2006/08 Phase I GRA, as well as application to implement interim GRA rates, and increase fuel riders	
	JAN '07	PUB Decision on Interim Refundable GRA rates and Fuel Rider changes; New Fuel Riders implemented	
	FEB '07	2006/07 Interim Refundable GRA Riders implemented	
	MAR '07		Release Energy Plan; indicate intention to review rates, regulation, subsidies
2007/08	MAY '07	2006/08 GRA hearing - 3 days	
	AUG '07	PUB First decision on Phase I GRA matters	
	DEC '07	PUB First decision on Phase I refiling matters	
	JAN '08	Final GRA Phase I rates and riders implemented	
2008/09	MAY '08		Initiate review of rates, regulation, subsidies
	AUG '08	NTPC files 2006/08 GRA Phase II Application	
	NOV '08	Final GRA Phase II rates and riders implemented plus increases to fuel riders	
	DEC '08		Appoint commission and initiate independant review of rates, regulation and subsidies
	FEB '09	Fuel rider application filed - proposed no change - largely on track for March 2010 target	
2009/10	JUN '09		Appoint independent team and initiate review of NTPC operational efficiency
	AUG '09	Fuel rider application filed - proposed no change despite no longer being on track for March 2010 target	Independent team completed review rates, regulation and subsidies
	JAN '10		Independent team completes review of NTPC operational efficiency
	FEB '10	2010/11 Business Plan Prepared - targets 0-0-0; no GRA for 2010/11 or 2011/12	
	APR '10	Fuel rider update filed - not on track for March 2011 - no changes proposed	
2010/11	MAY '10		GNWT releases response to independent review
	JUL '10	PUB received rate policy guidelines; initiates rate rebalancing process	GNWT issues rate policy guidelines to PUB
	AUG '10	NTPC files application for rate rebalancing	
	NOV '10	PUB releases decision on rate rebalancing and recommendations to GNWT regarding revisions to rate policy	
	DEC '10	New "rebalanced" rates in effect; ultimately declared final in March 2011	
	JAN '11	NTPC files rate stabilization fund update - notes no need for riders due to GNWT payment	
	FEB '11		GNWT issues revised rate policy reflecting PUB recommendations
2011/12	APRI '11		Issue final payment of $6 million contribution stabilization fund balances
	SEP '11	Fuel rider update - balance below trigger until January - no rider propsed	

APPENDIX 3

Comparisons of Rates and Costs in Selected Jurisdictions

The sections below describe the current situation in other selected jurisdictions and identify a variety of approaches used by governments and utilities to manage costs and rates.

Yukon

Similar to the NWT, two utilities generate and distribute electricity in Yukon. Yukon Energy Corporation (YEC), owned by the Yukon Government, generates and transmits most of the Territory's electricity. The Yukon Electrical Company Ltd. (YECL), a private utility owned by ATCO Electric Ltd., distributes electricity to most Yukon customers.

Table A3.1 Installed Capacity (MW): Yukon and Northwest Territories

	Yukon	NWT
Hydro	76.7	55.0
Natural Gas	0	22.2
Diesel	53.4	74.3
Wind	0.8	0
Total	130.9	151.5

There are about 17,500 electricity customers in Yukon. YEC directly serves about 1800 of them, mostly in the Dawson City-Mayo area. YECL buys wholesale power from YEC and sells it to retail customers in most other communities, including Whitehorse. YECL generates and distributes its own diesel-generated electricity in five communities away from the Whitehorse-Aishihik-Faro (WAF) transmission grid, a situation similar to the four NWT communities in the NUL (NWT) Thermal Zone.

Many of Yukon's diesel facilities are stand-by or backup plants to the hydro stations that power the WAF and Mayo-Dawson systems. So, while hydro accounts for less than 60% of Yukon's installed capacity, over 93% of its electric energy is generated by hydro. Yukon has reduced its diesel fuel dependence: in the mid 1990s the hydro/diesel energy split was about 60/40. Diesel's contribution is further reduced with the completion of YEC's Mayo-Carmacks-Stewart Crossing Transmission Project, and "Mayo B" hydro expansion project. These two projects are 50% funded by the Federal Government (up to $71 million) as a "Green Energy Legacy Project". The integration of the two hydro grids will allow Yukon to maximize its hydro usage.

Operations of both utilities are regulated by the Yukon Utilities Board (YUB). Each utility filed a GRA in 2008 for forecast revenue requirements for 2008 and 2009. The main components of the 2009 consolidated revenue requirements, totaling $52.3 million, are:

- Fuel $5.8 million.
- Operations and Maintenance $22.2 million.
- Depreciation $9.9 million.
- Income tax $0.2 million.
- Return on rate base-debt $7.4 million.
- Return on rate base-equity $6.8 million.

APPENDIX 3

Yukon is divided into four rate zones: Hydro, Small Diesel; Large Diesel, and Old Crow. Each has its own set of rates for customer classes, although there are very few rate differences across these zones. 2011 rates for the "Non Government Residential" customer class, comprising 98% of the 14,380 residential customers, are set in three inclining blocks. The following rates include all riders, rebates, and GST:

Table A3.2 Yukon Electricity Rates

	Hydro; Small Diesel; Large Diesel	Old Crow
Basic Charge/month	$15.27	$15.27
First 1000 kW.h/month	$0.1023/kW.h	$0.1023/kW.h
1000-2500 kW.h/month	$0.1373/kW.h	$0.1373/kW.h
Over 2500 kW.h/month	$0.1495/kW.h	$0.3244/kW.h

Rates for the 800 customers in the federal and territorial government residential and government general service classes are significantly higher.

The consolidated cost of incremental diesel generation is about 28 cents/kW.h, and is spread across all zones so Hydro Zone customers subsidize those in diesel communities. However the cost of fuel makes up only 11% of the utilities' revenue requirements, so the impact on rates is considerably less than in the NWT, where fuel costs comprise about a quarter of NTPC's revenue requirements. A Fuel Adjustment Rider –currently a surcharge of 0.352 cents/kW.h on all consumption—is meant to cover changes in the cost of fuel. Given the large swings in the account's balance, the YUB has directed the utilities to provide a written policy on how the rider can be better managed and understood by customers.

Rate design is emerging as an issue in Yukon. Under Orders in Council (OIC) since the mid 1990s, the portion of revenue requirements paid by various customer classes was set by government, not the YUB. For example, non-government residential customers pay only about 79% of their true costs; government customers pay 144%. In a December 2010 Decision, the YUB directed the two utilities to file a joint Cost of Service Study and rate design proposals to correct these imbalances after the current OIC expires at the end of 2012. If acceptable to both the regulator and government, residential rates could rise to over $0.15/kW.h, and higher if a government rebate of $0.0266/kW.h on the first 1,000 kW.h per month is discontinued.

Alaska

Diesel fuel powers 16% of Alaska's electricity generation, slightly higher than NTPC's 12%. Hydroelectricity supplies 17%, natural gas 61%, and coal 6%. As in the NWT, generation varies by region, with rural communities in western and interior Alaska relying mostly on diesel fuel. Wood generates both heat and electricity in community-level thermal facilities in about ten communities, mostly in the southeast Alaska panhandle.

There are about 100 separate electricity utilities servicing Alaska, a mixture of investor-owned utilities, municipal utilities, and rural cooperatives. Ownership and size dictate regulatory status with the Regulatory Commission of Alaska (RCA): in general, rates are regulated for co-ops and investor-owned utilities if revenues exceed $50,000 per year.

Communities in southeast Alaska that rely primarily on hydroelectricity from almost fully depreciated assets have rates as low as $0.10/kW.h. Residents of Anchorage and other communities with gas fired generation pay around $0.15/kW.h. Alaskans relying on diesel fuel have the most expensive electricity, mostly between $0.50 and $1.00/kW.h. The State's Power Cost Equalization Program (PCE) subsidizes bills in most diesel communities.

The average rate paid by Alaska residential customers in 2009 was $0.162/kW.h (before PCE subsidies), up from $0.112/kW.h in 1999. This 45% increase over the decade is double the Canadian CPI increase of 23% over the same period.

Alaska's PCE Program was established in 1984 to subsidize rural residents at the same time state funds were being used to subsidize major generation and transmission projects servicing urban communities. In 2010, 183 communities served by 84 utilities benefited from the PCE Program; about 78,000 people live in these communities. Payments totaled $30.6 million, a per capita subsidy of $392. Without PCE, electricity bills would be 2.5 to three times higher. PCE Program rules are complex. The RCA determines utility eligibility and calculates the amount of PCE per kW.h payable to the Utility, which reduces each eligible customer's bill by that amount for up to 500 kW.h per month. A formula is used to determine the PCE rate, to a maximum of $0.82/kW.h. Utilities must meet diesel generation efficiency and line loss standards.

British Columbia

After being frozen by the Provincial Government through the late 1990s, BC Hydro's residential rates have increased from 6.46 cents/kW.h in 2001 to 8.50 cents/kW.h in 2011. This 31.6% increase outpaced the rise of 22.3% in the CPI for the same period.

In March 2011 BC Hydro applied to the BC Utilities Commission (BCUC) for rate increases of 9.73% for each of the next three years, a cumulative total of 32%. Concerns were expressed about the impact the rate increases would have on customers. The B.C. government ordered a review of BC Hydro, seeking recommendations and options for reducing the increases.

The review panel of three Deputy Ministers was supported by a consulting team of twenty, working on site at BC Hydro for several weeks. The 124 page June 2011 report, "Review of BC Hydro" made several recommendations about governance, operating costs, procurement, and electricity policy. It was particularly critical of BC Hydro's operating costs, which make up 22% of BC Hydro's $3.6 billion annual revenue requirement and have been increasing by over 10% per year. Staffing levels rose from 3796 to 5615 employees over the four years ending in 2010.

As recommended by the review panel, BC Hydro filed an amended Application with the BCUC for rate increases of 8%, 3.9%, and 3.9% per year, or 17% over three years. Cost reductions totaling $818 million were comprised of:

- Operating cost decreases, $163 million.
- Deferred capital projects, $54 million.
- Lower than forecast capital projects in service for 2010/11, $61 million.
- Higher export income, $175 million.
- Extended Demand Side Management (DSM) amortization and reduced DSM spending, $127 million.
- Lower than forecast interest rates, $161 million.
- Regulatory account refunds, $27 million.
- Reduced taxes, increased miscellaneous revenues, $50 million.

BC Hydro has eliminated 550 positions and plans to eliminate another 150 over the next three years.

The BCUC has approved interim increases of 8% for 2011/12 and 3.9% for 2012/13. It has also ordered that the deferral accounts rate rider rise from 2.5% to 5.0% for 2012/13. With compounding, this represents an increase in 2012/13 rates of 7.1%. The BCUC concluded that BC Hydro's deferral account balances are continuing to grow, and that doubling the rider is consistent with BC Hydro's approved mechanism to reduce account balances.

Separate from the BC Hydro Review, in October 2011 the Auditor General of British Columbia released a report, "BC Hydro: The Effects of Rate-Regulated Accounting" that criticized BC Hydro's use of regulatory or deferral accounts. It recommended that the Provincial Government determine how BC Hydro will recover the net deferred costs totaling $2.16 billion in 27 regulatory accounts, either through rate increases, operating efficiencies, or cash infusions.

The BC Auditor General's report also recommended that BC Hydro's financial statements be prepared fully in accordance with Canadian Generally Accepted Accounting Principles (GAAP). Rate regulated deferral accounting is not permissible under International Financial Reporting standards (IFRS), and Canada will be adopting IFRS as a Canadian GAAP for business enterprises. Starting in 2012/13, the full costs of operating expenses are to be shown in the year they are incurred, rather than being deferred to future years. The B.C. government has rejected this recommendation, stating that retaining rate regulated accounting is a policy decision made to maintain rate stability, and one that is also being made in other jurisdictions. Regulatory deferral accounts will continue to be used by Manitoba Hydro, Ontario Power Generation, Hydro One, Hydro Quebec, Nova Scotia Power, New Brunswick Power, Newfoundland Power, Fortis BC, Fortis Alberta, Enbridge Gas, and TransCanada.

BC Hydro operates off-grid diesel generation systems in 17 communities, mostly in northern BC. Revenues cover about one-quarter of costs. Rates for the first 1500 kW.h per month are the same as the integrated system (7.84 cents/kW.h for energy) but rise to 13.47 cents thereafter, to discourage electric space heating.

BC Hydro is expanding service to additional communities through its Remote Community Electrification Program. Its goals are to offer BC Hydro electricity to up to forty more communities, and to build sustainable relations with First Nations. Twenty-one First Nations communities receive electricity from diesel generators operated by Aboriginal and Northern Development Canada, which has agreed in principle to transfer funding to BC Hydro where BC Hydro takes over operations and billing. A complementary provincial initiative, the Remote Community Implementation Program, helps subsidize supply and demand side clean energy projects for off grid communities.

NWT electricity interests should keep apprised of BC Hydro activities in the Fort Nelson area. Natural gas producers are planning to install new natural gas gathering and processing capacity in the Horn River region, about 90 km northeast of Fort Nelson and 120 km south of Trout Lake. Industry is increasingly interested in grid-supplied electricity instead of self supply, particularly as expectations rise for mandated or voluntary greenhouse gas emission reductions. BC Hydro is considering a double circuit 287kV line from the south Peace to meet the combined needs of Fort Nelson and Horn River regions.

Manitoba

Manitoba Hydro is a Crown utility serving all electricity customers in Manitoba. Rates have traditionally been low and stable. However, since 2004/05, rates began to steadily increase, rising by approximately 20% by the end of 2010/11, or over 3% per year on average. Going forward, Manitoba Hydro's long term business plan is based on rate increases typically at the 3.5% per year level for the next ten years. Major new generation and transmission is planned over the next decade. Consistent with current practice, Manitoba Hydro is expected to continue to operate on a cost recovery basis, with no dividends being paid to the shareholder over this period.

The recent period of increases in rates has corresponded with major increases in the costs to operate Manitoba Hydro. In the five years from 2007 to 2012, Manitoba Hydro's O&M costs increased by more than 30%. Staff levels have increased by more than 10%, from approximately 6000 staff to almost 6700.

Manitoba Hydro serves four small diesel communities, where costs to serve residential customers average about 15% higher than NTPC's costs to operate in its Thermal Zone. Despite these costs, the rates paid by non-government customers in these communities are the same as those paid by Manitoba Hydro's integrated grid customers.

Newfoundland and Labrador

Crown-owned Newfoundland and Labrador Hydro (NLH) provides power at a wholesale level to the investor-owned distribution utility, Newfoundland Power, and a number of industrial customers, plus provides retail electricity directly to over 36,000 rural customers in Newfoundland and Labrador.

Of the directly served customers, approximately 3500, representing 48 GW.h of generation, are in isolated diesel communities either on the island (900 customers) or in Labrador (2600 customers). Average costs to serve these areas in 2006 was over 70 cents/kW.h (approximately 63 cents/kW.h in Labrador, and $1.07/kW.h on the island). However customers in these isolated areas only pay 17-29% of these costs, with the remainder allocated to non-industrial customers on the interconnected system.

Similar to Manitoba Hydro, NLH was previously (pre-2001) regulated on the basis of a very low equity ratio, and with no formal Return on Equity. This was changed by legislation to require NLH to target a commercial type return in all areas other than the rural and isolated service areas (which have traditionally earned no ROE). At that time NLH had very low levels of reserves that it had begun classifying as equity (below 20%). The Provincial Government suspended dividend payments starting in 2006/07 to aid in bringing the equity levels up to a target range (at that time equity levels were at approximately 14% of total capital, and the company was targeting equity at 20% of total capital). The Government also contributed $100 million as a new equity contribution to NLH. This was the first time such an equity injection had occurred, although Government had played a role in the past by paying off balances in the Rate Stabilization Plan to minimize impacts on customers. At present, NLH has exceeded their new target equity ratio of 25% of total capital, and has resumed paying dividends when this does not drop the equity levels below the target.

APPENDIX 4

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Yukon Housing Corp.: www.housing.yk.ca

Yukon Utilities Board: www.yukonutilitiesboard.yk.ca

APPENDIX 5

Abbreviations

BCUC: British Columbia Utilities Commission
CAIDI: Customer Average Interruption Duration Index
CEA: Canadian Electricity Association
CO2e: Carbon Dioxide equivalent
CPI: Consumer Price Index
DSM: Demand Side Management
GAAP: Generally Accepted Accounting Principles
GRA: General Rate Application
GNWT: Government of the Northwest Territories
IFRS: International Financial Reporting Standards
ITI: NWT Department of Industry, Tourism and Investment
KPI: Key Performance Indicator
kW.h: Kilowatt hour
LNG: Liquefied Natural Gas
mcf: thousand cubic feet
MW: Megawatt
MW.h: Megawatt hour
NLH: Newfoundland and Labrador Hydro
NTPC: Northwest Territories Power Corporation
NUL: Northland Utilities Ltd.
NYMEX: New York Mercantile Exchange
PCE: Power Cost Equalization Program (Alaska)
PPD: Petroleum Products Division
PUB: Northwest Territories Public Utilities Board
QEC: Quilliq Energy Corporation
RCA: Regulatory Commission of Alaska
ROE: Return on Equity
SAIDI: System Average Interruption Duration Index
SAIFI: System Average Interruption Frequency Index
SLE: Shareholder's Letter of Expectation
TPSP: Territorial Power Subsidy Program
WAF: Whitehorse-Aisihik-Faro
YEC: Yukon Energy Corporation
YECL: Yukon Electrical Company Ltd.
YUB: Yukon Utilities Board

Biographies

Peter Ostergaard, B.A.(Hons.), M.A., MCIP

Peter Ostergaard was an Assistant Deputy Minister with the Government of British Columbia's Ministry of Energy, Mines, and Petroleum Resources for fourteen years, most recently with responsibility for electricity and alternative energy policies, plans, and governance. He was also Chair and Chief Executive Officer of the BC Utilities Commission between 1998 and 2003.

After retiring in 2008, he now consults on energy and land use planning matters, including assignments with the BC Energy Ministry, the Fraser Basin Council, Columbia Basin Trust, and an independent power company. He has also served as Chair of Canada's Electricity Sector Council's "Building Connectivity" Steering Committee, and on the Board of Directors of the Western Electricity Coordinating Council.

Peter has degrees from Queen's and the University of BC, and is a Member of the Canadian Institute of Planners. In the 1970s he spent two summers in the southwestern NWT mapping surficial geology to assist in route selection for the Mackenzie Valley Pipeline. He also completed his graduate thesis in urban geography on Yellowknife's livability.

William Grant, B.Sc. (Eng.), MBA, CFA

Bill Grant was employed by the BC Utilities Commission and its predecessor, the BC Energy Commission, for 30 years. For 15 years he was Executive Director of the Commission. He has consulted to other regulators and governments in Canada, the USA, Australia, and Argentina on regulatory reform, including the Yukon Government on electricity matters. He continues to mediate Negotiated Settlement Processes and Performance Based Regulatory proceedings, primarily for the BCUC.

Bill has initiated or been involved in the development of many energy policy and regulatory initiatives, including:

- Natural gas commodity competition and unbundling of utility tariffs
- An automatic return on equity adjustment mechanism
- A multi year performance –based ratemaking process
- Alternative dispute resolution techniques

Bill completed a Master of Business Administration degree immediately following his undergraduate Bachelor of Science degree. He has been a Professional Engineer in Ontario and British Columbia, and he returned to academic study to obtain a Chartered Financial Analyst designation from the University of Virginia. In 2006 he received the Canadian Association of Members of Public Utility Tribunals award for Innovation in Public Utility Regulation and Process.