

**NORTHWEST TERRITORIES POWER CORPORATION
2006/07 AND 2007/08 GENERAL RATE APPLICATION
PHASE I**

**REBUTTAL EVIDENCE OF
THE NORTHWEST TERRITORIES POWER CORPORATION**

April 23, 2007

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1 **1.0 INTRODUCTION**

2 The purpose of this rebuttal evidence is to respond from the Northwest Territories Power Corporation's
3 ("NTPC" or the "Corporation") perspective to certain assertions made in the following testimony submitted
4 in respect of the Corporation's 2006/07 and 2007/08 GRA Phase I filing:
5

6 § Dr. Lawrence Kryzanowski and Dr. Gordon S. Roberts, on behalf of the Hydro Communities
7 ("HC"), regarding NTPC's determination of its capital structure and cost of capital.

8 § Mr. Azad Merani, on behalf of the Thermal Generation Communities ("TGC"), regarding affiliate
9 transactions, generation using sources other than diesel fuel, the fuel stabilization fund, and the
10 fuel efficiency rate for Inuvik.
11

12 This evidence is intended to supplement the rebuttal evidence of Ms. Kathleen McShane, the
13 Corporation's cost of capital expert, which is being filed concurrently with this evidence and addresses a
14 number of the points raised in the HC evidence.

15 **2.0 SINKING FUNDS (HC)**

16 Drs. Kryzanowski and Roberts set out in section 5 of their evidence comments in regards to NTPC's
17 sinking funds. Three of those matters are addressed in this rebuttal evidence.

18 **2.1 SINKING FUND TERMS AND CONDITIONS**

19 Drs. Kryzanowski and Roberts claim that "...NTPC implemented risk management practices that were not
20 'best practice'..." in respect the first three issues of sinking fund debentures.¹ As noted in Ms. McShane's
21 rebuttal, this is not correct.
22

23 NTPC further notes that in each case NTPC's debt was placed in an arms length third party transaction
24 using professionals in institutional lending, who marketed the borrowing to a number of potential lenders.
25 The ultimate placement terms and rates reflect what the market required in the particular circumstances
26 of NTPC at the time. At the time this debt was issued NTPC was restricted in its options for placing debt
27 essentially to insurance companies. Particularly in the late 1980s and 1990s insurance companies had
28 ample opportunity to purchase government debt reflecting the underlying deficits occurring in many
29 provinces and with the Federal government at the time. Consequently the universe of potential
30 purchasers interested in purchasing NTPC's debt offerings was very limited.

31 **2.2 SINKING FUND INVESTMENT PERFORMANCE**

32 Drs. Kryzanowski and Roberts claim that NTPC's sinking fund has an "annual compound return on the
33 sinking fund of nearly 7%" and that as a result, compared to the performance benchmarks set by the
34 Corporation, the sinking fund manager has "underperformed three of the four benchmarks and has

¹ HC evidence, pages 97 and 98.

1 underperformed the most relevant benchmark by about 40 basis points annually.”² This claim is not
2 correct.

3
4 First, as noted in NTPC’s response to HC.NTPC-23, the actual annual compound return achieved by AMI
5 on the sinking fund noted in Table 3 of that response was 7.1%, not “nearly 7%”. Second, the sinking
6 fund managers have met or exceeded all four of the benchmarks set by NTPC.³

7
8 As background, NTPC notes that to monitor the performance of the sinking fund returns, the Corporation
9 uses four benchmarks: one based on passive investment management, two based on simple financial
10 market measures, and one based on active investment management. The first benchmark (passive) was
11 selected to ensure that, over time, Fund Managers obtain higher earnings than what the Corporation
12 could obtain using a conservative approach to investment, such as buying and holding fixed income
13 investments with minimum trade activity (such as was required by the legislation that existed prior to the
14 2001 changes noted in the HC evidence). The second and third benchmarks (market measures) were
15 selected as additional cross-checks against financial markets. The fourth benchmark (active) was
16 selected to encourage sinking fund returns beyond the passive management approach by measuring the
17 performance of an actively managed mix of investments (fixed income and equity) within Policy
18 constraints that are set by the Corporation.

19 **2.3 SINKING FUND EARNINGS FORECASTS**

20 Drs. Kryzanowski and Roberts indicate that NTPC’s sinking fund earnings are “3.62% for the test year
21 2006/07 and 3.68% for test year 2007/08, which are considerably below Ms. McShane’s long Canada
22 forecasts for those test years”.⁴

23
24 The sinking fund returns stated in the HC evidence are incorrect. The sinking fund return based on a
25 simple mid-year calculation is 3.97% in 2006/07⁵ and 3.99% in 2007/08⁶. However, as noted in Ms.
26 McShane’s evidence, a refined approach to this calculation would “weight” the sinking fund balances by
27 contribution date compared to a simple mid-year balance. Under that approach the returns are 3.96% in
28 2006/07 and 3.99% in 2007/08. NTPC also notes that use of such a weighted calculation to address Drs.
29 Kryzanowski and Roberts’ concerns over “asymmetrical” calculations would result in a revised revenue
30 requirement that is \$2,000 higher for the 2006/07 test year and \$4,000 higher for the 2007/08 test year (a
31 change of approximately 0.0099% in 2006/07 and approximately 0.0184% in 2007/08, which is not
32 material).

² HC evidence, page 105.

³ Note that HC.NTPC-23 as filed indicated the managers had met only 3 of the 4 benchmarks. The Corporation has noted an error in the sinking fund policy that was submitted in HC.NTPC-23. The benchmark asset allocation weighting stated is incorrect, as the fixed income weight should be 75% and the equity weight should be 25%, rather than 70% and 30%, respectively. These are the “Policy” levels that the Fund Manager uses to guide investment weighting. Although a temporary upside of 30% equity investment is within the maximum investment parameters, the Fund Manager is not expected to invest at that level on a sustained basis and it would be punitive to measure performance that is outside of the Fund Manager’s normal investment parameters. A correction to HC.NTPC-23 will be provided.

⁴ HC evidence, page 105.

⁵ \$1.592 million in earnings per HC.NTPC-23 Table 1 divided by \$40.122 million mid-year balance per Schedule 3.7.

⁶ \$1.792 million in earnings per HC.NTPC-23 Table 2 divided by \$44.858 million mid-year balance per Schedule 3.7.

1 NTPC's forecast of sinking fund returns is based primarily on market forecasts from 2005 when the
2 2006/07 budgets were being prepared. Similar to other items in NTPC's budgets, these were not
3 continually updated during the GRA preparation, with the notable exception of including 2005/06 actual
4 results into the 2006/07 opening balances. As a result of the 2005/06 closing balances being higher than
5 was forecast at the time the 2006/07 budget was prepared, the GRA is based on forecast sinking fund
6 earnings that are greater than NTPC's budgets for the test year 2006/07 by approximately \$265,000 (in
7 contrast to the asserted "move to lower sinking fund expectations" set out by Drs. Kryzanowski and
8 Roberts⁷).

9 **3.0 CAPITAL LEASE FOR SNARE-CASCADES (HC)**

10 Drs. Kryzanowski and Roberts in section 5 of their evidence are critical of the manner in which NTPC has
11 treated the capital lease for capital structure purposes.⁸

12
13 It needs to be appreciated that the costs reflected in NTPC's revenue requirement, in respect of the
14 capital lease, are costs actually incurred under this arms-length arrangement, which was approved by the
15 Board, and are costs that were reasonably and necessarily incurred by the Corporation to fulfill its
16 obligations to the Dogrib Power Corporation ("DPC") and to secure the rights to the hydro facility known
17 as Snare-Cascades, which is owned by DPC.

18
19 Ratepayers have derived substantial value from the arrangement that gave rise to the capital lease and
20 the development of Snare-Cascades. For example, as set out in the Snare-Cascades feasibility studies
21 provided in the 1995/98 GRA (when the project was approved for inclusion in rate base), the project was
22 forecast to save 26.3 GW.h of fuel by 2006/07, for a saving of \$3.22 million.⁹ In 2006/07 test year
23 forecasts, the value of this 26.3 GW.h of fuel cost saving will be more than \$4.82 million, an increase of
24 approximately 50%. In addition, the cost of the lease reflected in the Revenue Requirement is lower than
25 had been forecast due to the project weighted average cost of capital being below the 11.22% forecast at
26 the time for 2006/07. With such massive benefits accruing to ratepayers from the project, it is not
27 apparent how the lease could be considered to be either too costly or somehow unfair to ratepayers after
28 the arrangement was approved by the Board, negotiated at arms length, and fully executed and
29 implemented.

30
31 Were the Board to adopt the recommendations of Drs. Kryzanowski and Roberts, it is important to note
32 the impacts that would arise. The Power Acquisition Agreement between the DPC and NTPC provides
33 that the DPC will pay to NTPC the amount of all Disallowed Costs. Under that agreement, "Disallowed
34 Costs" means amounts payable by NTPC under the agreement which the Board does not permit NTPC to
35 recover in its rates, tolls and charges.¹⁰ The lease was structured to ensure that regulatory risk for
36 recovery of the costs of the project from ratepayers was a risk that DPC bore, not NTPC. Ultimately, it is
37 DPC that would be directly and adversely impacted were the Board to accept HC's recommendations.
38 Additional risks arise related to the potential for DPC to default on the loans it secured, and potential
39 consequent DPC insolvency or loss of the facility, depending on the degree of impact.

⁷ HC evidence, page 105.

⁸ HC evidence, page 110 and following.

⁹ BR.NTPC-50(b) page 19.

¹⁰ Power Purchase Agreement dated March 18, 1993 between the DPC and NTPC, sections 4.3 and 1.1.

1
2 From a public interest perspective, the capital lease with DPC represents a cutting edge relationship
3 between a public utility and a First Nation in Canada. No other public utility NTPC is aware of has to date
4 managed to structure a deal that allows for full ratepayer benefits from the development of a generation
5 project simultaneous with 100% community ownership. If retroactive adverse impacts arise with respect
6 to DPC's finances from this proceeding, NTPC has a significant concern that any future opportunities to
7 develop hydro in NWT will be near impossible as they will entail unacceptable counter-party risks for the
8 local communities in question.

9 **4.0 AFFILIATE TRANSACTIONS AND CODE OF CONDUCT (TGC)**

10 **4.1 NTPC AFFILIATE TRANSACTIONS**

11 The Corporation's affiliate (also called non-utility or non-regulated) operations were identified and
12 discussed in the Corporation's response to TGC.NTPC-6(a). As noted in that response, the Corporation
13 wholly owns:

- 14
- 15 • NWT Energy Corporation ("NTEC");
- 16 • NWT Energy Corporation (03) Ltd. ("NTEC(03)");
- 17 • Sahdae Energy Ltd. ("Sahdae"); and
- 18 • 5383 N.W.T. Ltd.
- 19

20 The nature and scope of the non-utility operations conducted by the above NTPC subsidiaries were also
21 discussed in TGC.NTPC-6(a) as follows:

22

23 NWT Energy Corporation Ltd., under the authority of the Northwest Territories Power
24 Corporation Act, financed the Dogrib Power Corporation in 1996 for the construction of a
25 4.3 MW hydro facility. The NWT Energy Corporation (03) Ltd. has three operations: the
26 operation, management and shared ownership of one residual heat project in Fort
27 McPherson [Aadrii Limited], the development of business opportunities outside the
28 regulated business including development of hydroelectric projects and an investment in
29 Deze Energy Corporation Ltd. a company involved in the expansion of the Taltson hydro
30 system, started in 2006. Sahdae Energy Ltd. began operations in 2005. Its mandate is to
31 pursue a hydro development project on the Great Bear River to provide power to the
32 potential Mackenzie Valley pipeline. 5383 NWT Ltd. is an inactive company.

33

34 The future hydro projects referred to above are not expected to materialize during the 2006/08 test years.

35

36 As part of the annual budgeting process, the Corporation budgets for both the regulated operations and
37 the non-regulated operations. The operational subsidiaries (NTEC(03) and Aadrii) provide their budgets
38 to NTPC to consolidate. NTPC prepares budgets for the remaining subsidiaries based on expected
39 operations for the budget year. The Corporation reports to its Board of Directors on regulated operations
40 as well as consolidated operations on a quarterly basis. The Revenue Requirement applied for in the
41 Corporation's Application does not include costs related to non-regulated operations.

1
2 Mr. Merani states in his evidence that “[w]ithout adequate checks and balances to ensure transactions
3 with affiliates are transparent and will not impair the operations of the regulated entity, having the NTPC
4 affiliates engaged in operations similar to those provided by the regulated arm can be problematic.”¹¹ He
5 concludes that “NTPC needs to develop a comprehensive code of conduct to govern its transactions with
6 these and other affiliates.”¹² Mr. Merani provides an example of a detailed Code of Conduct approved by
7 the Alberta Energy and Utilities Board (“AEUB”) for several utilities in Alberta.

8
9 First, it should be noted that the ATCO Group Code of Conduct referenced by Mr. Merani makes a
10 specific distinction between “shared service” transactions – which should be allocated on a cost recovery
11 basis; and “for profit affiliate service” transactions – which should be provided between affiliates at fair
12 market value.¹³ NTPC’s affiliate transactions are of the “shared service” variety and not the types of
13 transactions between core business streams of its affiliates appropriate to be considered “for profit
14 affiliate service”, such as outsourced retail customer services provided by ATCO Singlepoint or IT support
15 from ATCO I-Tek. NTPC’s affiliate transactions involve sharing of financial reporting, purchasing, IT
16 support and senior management services with NTEC, NTEC(03) and Sahdae. In sharing such services,
17 NTPC maximizes the utilization of its utility resources and recovers a component of the costs (on a cost
18 recovery basis) from its affiliates that would otherwise be charged to ratepayers. As discussed below,
19 such shared services are appropriately allocated to the Corporation and its affiliates by direct charges or
20 overhead allocations.

21
22 Further, Mr. Merani’s conclusion does not account for the various “checks and balances” which NTPC has
23 implemented to ensure that there is no cross-subsidization between the Corporation’s regulated
24 operations and affiliate operations. It also appears that Mr. Merani disregards the structure and relative
25 size of the electric utility industry in the Northwest Territories (vertically integrated and regulated
26 generation, transmission, distribution and retail functions) as compared to Alberta. Both of those matters
27 are addressed below.

28 **4.2 NTPC AFFILIATE COST TRACKING**

29 For cost tracking purposes, NTPC maintains different plant numbers for each of its non-regulated
30 subsidiaries to identify transactions related to non-regulated companies. It also maintains different plant
31 numbers for each community and head office to track the regulated operations of the Corporation. For
32 capital assets or long term projects undertaken by the non-regulated subsidiaries, specific projects
33 accounts are set up to separate these costs from regulated operations, as well as non-regulated
34 operational expenses.

35
36 There are two ways in which costs are allocated to non-regulated operations:

- 37
38 1. **Direct charge** – time and supplies are directly coded to the non-regulated plants for those costs
39 that are readily identifiable as non-regulated transactions. This would include such costs as:

¹¹ Page 3, Pre-filed Testimony of Azad P. Merani.

¹² Page 4, Pre-filed Testimony of Azad P. Merani.

¹³ See for example Section 3.3.4 of Appendix 5 of AEUB Decision 2003-040 which describes cost recovery of shared services and section 4.1 of the same appendix which describes for profit affiliate services.

- a. direct employees whose salaries are separated from the regulated operations and directly charged to the non-regulated operations via timesheets;
- b. time spent to build assets or perform operational on a periodic basis for the non-regulated operations – these costs would be charged through timesheets;
- c. interest expenses on debt held by the non-regulated operations;
- d. daily operational costs (ie. rent, office supplies, hiring costs, advertising, etc.) for non-regulated operations are directly charged to the appropriate plant through service agreements or purchase orders; and
- e. travel is itemized and coded using travel claims.

2. **Overhead allocations** – for costs that are incurred in small increments or are not readily identifiable as non-regulated transactions, the Corporation applies an overhead allocation from regulated operations to non-regulated operations. This overhead allocation is reviewed on an annual basis to ensure the rates are applicable for the non-regulated activity expected each year. This would include such costs as time for financial reporting, purchasing and IT spent on producing financial statements, purchasing supplies and maintaining computers for the non-regulated operations.

Shared services transactions are tracked throughout the year. Financial statements are produced annually at which time the accounts are reconciled and shared services transactions involving those subsidiaries are checked to ensure they are correct.

In the Corporation's 2005/06 financial statements, there were:

- \$0.6 million in operating and administration expenses related to non-regulated operations;
- \$0.8 million in labour and related costs charged to non-regulated activities;
- \$0.01 million in shared services associated with non-regulated activities including computer usage, financial reporting & management services; and
- \$0.1 million in net interest expenses related to non-regulated debt.

4.3 AFFILIATE COST TRACKING IN OTHER CROWN UTILITIES

NTPC is aware of at least two other Crown electric utilities that have similar cost tracking measures in place for transactions with affiliated or subsidiary companies. In the case of these two utilities:

1. the cost tracking guidelines are far simpler than those in the ATCO Group code of conduct;
2. the scale of affiliate transactions is larger than experienced by NTPC; and
3. the method for tracking costs between affiliates has been reviewed and accepted by the regulator.

Newfoundland and Labrador Hydro

Newfoundland and Labrador Hydro ("NLH") has procedures in place to separate costs related to non-regulated operations from its regulated operations that are similar to the methods used by NTPC. Non-regulated activities undertaken by NLH include:

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9
- all activities associated with the subsidiary companies Churchill Falls (Labrador) Corporation Limited (“CF(L)Co”), Lower Churchill Development Corporation Limited, and Gull Island Power Company Limited;
 - export sales;
 - new business development;
 - activities/costs associated with the Labrador Hydro Project negotiations and activities regarding the Lower Churchill hydroelectric developments; and
 - other specific non-regulated costs.¹⁴

10
11 Methods used by NLH to allocate costs to the non-regulated operations include:

- 12
13
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17
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19
- non-regulated affiliates having their own direct employees whose salaries are separated from the regulated operations;
 - cost tracking using specific work orders related to non-regulated operations;
 - salary cost tracking using timesheets; and
 - ratios developed based on non-regulated operation salary costs as a percentage of total department costs.

20 NLH also calculates a regulated weighted average cost of capital that is based on the relative proportions
21 of debt to equity in a regulated context.¹⁵

22
23 In its 2006 GRA NLH reported the following costs that had been excluded from its 2007 regulated
24 revenue requirement and charged to non-regulated operations:

- 25
26
27
28
29
30
31
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33
- \$2.2 million in cost recoveries from CF(L)Co for administrative services;
 - \$0.4 million in labour and related costs charged to non-regulated activities;
 - \$0.2 million in shared services associated with non-regulated activities including office space, telephones and computer usage;
 - \$0.3 million relating to donations and a portion of advertising costs; and
 - costs associated with export sales of recall power to Hydro Quebec and costs allocated to the supply of power to non-regulated customers.¹⁶

34 Manitoba Hydro

35
36 In 1999 Manitoba Hydro purchased Centra Gas – a natural gas distribution utility. Following the purchase
37 of Centra Gas, Manitoba Hydro fully integrated the electric and gas operations. With the integration came
38 the requirement to allocate costs, including administrative and indirect costs, to electric or gas operations.

39
40 In its 2004 GRA, Manitoba Hydro described the key aspects of its integrated cost methodology as follows:
41

¹⁴ Page 2, Newfoundland and Labrador Hydro Non-Regulated Activities. December 2002.

¹⁵ Page 17, Finance and Accounting Evidence. Newfoundland and Labrador Hydro 2006 General Rate Application.

¹⁶ Pages 18 and 19. Finance and Accounting Evidence. Newfoundland and Labrador Hydro 2006 General Rate Application.

- 1 • Work that is clearly in direct support of either electric or gas functions is identified and costs
2 are accumulated on the basis of direct disbursements and time spent. Time charged to this
3 work is costed at an activity rate that is calculated to recover all related costs of carrying out
4 that work.
- 5 • Work for integrated functions is identified, accumulated and charged to electric and gas
6 operations based upon an appropriate cost driver.
- 7 • Corporate overhead is added to activity charges at a standard percentage rate and charged
8 to electric and gas operations along with the activity charges. Where overhead is directly
9 attributable to either electric or gas operations, but not both, it is allocated only to the
10 operation to which it pertains.¹⁷

11
12 In its 2004 GRA, Manitoba Hydro forecast that for the 2003/04 fiscal year there would be approximately
13 \$54.6 million in operating and administration expenses charged to Centra Gas.¹⁸

14 **4.4 CONFIDENTIAL CUSTOMER INFORMATION AND PREFERENTIAL ACCESS TO UTILITY** 15 **SERVICES**

16 Mr. Merani also states that “[a] properly structured code of conduct will ensure: ... c) confidentiality of
17 customer information is protected; and d) no preferential access to utility services is provided to the non-
18 regulated operations.”¹⁹

19
20 With respect to the protection of customer information, the AEUB heard concerns from intervenors about
21 the possibility of a utility being able to provide a non-regulated affiliate with proprietary customer
22 information that could give the affiliate an advantage over existing competitors or potential market
23 entrants in a competitive marketplace.²⁰ While it is understandable that intervenors would be concerned
24 about that issue in Alberta, where the generation and retail functions are non-regulated, it is not a concern
25 in the Northwest Territories. NTPC simply does not hold proprietary customer information that it could
26 provide to one of its non-regulated affiliates to give that affiliate an advantage over an existing or potential
27 competitor. NTPC’s non-regulated affiliates discussed above are not businesses involved in a legislated
28 competitive marketplace.

29
30 The concern of no preferential access being provided to utility services is provided to the non-regulated
31 operations was also addressed in the ATCO Group case. In that regard, the AEUB clarified the concern
32 as follows:

33
34 [t]o the extent that ATCO’s actions interfere with or inhibit the development of a
35 competitive market, the Board considers that utility customers could be harmed. Utility
36 customers are paying the utility to provided regulated service on an equal basis in
37 exchange for monopoly purposes. The Board considers that it is inappropriate for a utility
38 to use its position to unfairly advance the interests of its affiliates.²¹

¹⁷ Page 13, lines 15 through 24 of Tab 3. Manitoba Hydro 2004 General Rate Application.

¹⁸ Schedule 4.1. Page 3 of Tab 4. Manitoba Hydro 2004 General Rate Application.

¹⁹ Page 4, Pre-filed Testimony of Azad P. Merani.

²⁰ AEUB Decision 2003-040, p. 95.

²¹ AEUB Decision 2003-040, p. 87.

1
2 That concern does not arise in the Northwest Territories and certainly not in relation to NTPC and its
3 affiliates. As discussed above, the businesses in which NTPC's affiliates are involved do not involve a
4 legislated competitive market.

5 **5.0 GENERATION SOURCES OTHER THAN DIESEL FUEL (TGC)**

6 Mr. Merani states that "Customers expect NTPC to take an aggressive and proactive position in pursuit of
7 whatever external funding is available for any green projects...".²² Mr. Merani seems to suggest that this
8 could help achieve lower rates as well as environmental and greenhouse gas emissions benefits. This
9 section provides more discussion on NTPC's experience with alternative energy projects and efforts to
10 secure external funding.

11 **5.1 NTPC EXPERIENCE WITH ALTERNATIVE ENERGY PROJECTS AND FUNDING**

12 NTPC has spent over \$2 million on alternative energy projects (refer to TGC-NTPC.9 for a list of some of
13 these projects) and NTPC has more experience with alternative energy technology in the NWT than other
14 companies. None of the alternative energy projects undertaken by the Corporation would be considered
15 successful as defined by reliability and cost savings objectives. Alternative energy faces considerable
16 challenges in the Corporation's operating environment including the extreme climate and the lack of
17 technical support and limited supplier market for smaller size alternative energy technology more suitable
18 for use in NWT.

19
20 For example, when NTPC was looking to install wind generation in Sachs Harbour, only two
21 manufacturers supplied the size of wind technology that NTPC required. Currently, a new federal
22 program is being developed to fund wind generation but the current criteria requires a minimum size of 1
23 MW and the subsidy is 1 cent per kWh produced by wind. The generator size criteria exceed the needs
24 of most NTPC communities and the subsidy is so small as to have limited impact for NTPC Customers.
25 Further, the results from testing wind potential in six NWT communities indicate that only one or two may
26 have potential given current wind technology and both require further study. The impact of integrating
27 wind generation resources on the current system is greater in the NWT than it is for southern utilities due
28 to the small size of the system in each diesel community. Based on experience in southern Canada,
29 there is concern that if wind energy provides a substantial percentage of system power, stability can be
30 adversely affected, which results in power quality issues. Access to technical expertise is a significant
31 issue both from a cost and reliability perspective and can severely impact the economics of a wind
32 project, even if the asset was funded entirely by a third party. The Corporation is not aware of any
33 Canadian isolated diesel electric system that has successfully integrated wind power into its generation
34 mix other than test or pilot projects.

35
36 These experiences have lead to the conclusion that currently available alternative energy technology
37 does not work well in the NWT at the present time. It appears that not only NTPC has come to that
38 conclusion. All of the diamond mines in the NWT have installed diesel generation as their primary source
39 of power. As well, there are very few entrepreneurs in the Northwest Territories that are pursuing

²² Page 8, Pre-filed Testimony of Azad P. Merani.

1 alternative energy supply. Both examples are a good indication that alternative energy initiatives are not
2 economically viable or can be practically applied, given current technology, in the NWT.

3
4 Even if alternative energy projects were economically viable in the NWT diesel communities, it would be
5 incorrect to assume that costs would be materially lowered. Most current costs would not go away with
6 the exception of variable diesel costs. The cost to maintain unfamiliar technology can be high depending
7 on whether specialized skills are required and the location of the technology can further drive costs if
8 maintenance people need to be flown in for regular maintenance or to make repairs. Therefore to lower
9 rates, the cost of an alternative energy project would need to be less than the cost of diesel fuel. This
10 would be difficult to achieve even if the capital was free (e.g. funding obtained from third party).

11
12 It is NTPC's position that the most effective way to be involved with alternative energy technology is to
13 support private industry in the development of alternative energy technology by agreeing to purchase
14 power or sell surplus hydro, providing data and connection assistance but otherwise leaving the
15 construction and operational risk with the private sector. Past examples of where NTPC has attempted to
16 assist private industry with alternative energy projects include a request for proposals for wind energy, the
17 Cambridge Bay wind proposal, the excess hydro request for proposal and application for a rate for a
18 district heating system (which was proposing to eventually introduce biomass boilers) and the hydrogen
19 electrolyser. None of these systems were ever developed by private industry, due in part to a low
20 appetite for investment risk.

21
22 NTPC's experience has also been that it is easier for local governments, aboriginal organizations and
23 private businesses, than it is for a Crown Corporation, to access third party funding for alternative energy
24 projects. Typically third parties structure their programs on a "matching" basis which means that even if
25 an applicant is successful at obtaining funding for a project, there will still be initial and ongoing costs. In
26 NTPC's view, Customers are better served by corporate efforts to increase diesel efficiencies, install
27 residual heat distribution systems and provide services to assist Customers achieve energy efficiencies
28 (e.g. energy audits) than they would be by having NTPC invest time and resources in unproven and to
29 date unreliable alternative energy projects, such as wind, photo voltaic solar power, and biofuels.

30
31 NTPC supports the concept of applying for third party funding for alternative energy projects whether
32 funding is obtained by NTPC or communities, as the end result is that it helps to offset costs to
33 Customers. It must be recognized, however, that the amount of time and effort required to apply for third
34 party funding can vary. Some programs require considerable information and emphasis is on the
35 applicant to compile and provide that information. In addition to the application process, third party
36 funding typically has a reporting process which can be onerous and not cost effective depending on the
37 amount of funding acquired.

38
39 NTPC has made significant efforts to date in pursuit of third party funding. Appendix A provides a list of
40 the alternative energy project third party funding applications in which NTPC has been involved. To the
41 extent that Mr. Merani's proposition would require NTPC to aggressively pursue alternative energy
42 funding beyond its current efforts and report quarterly on its efforts to the PUB, NTPC does not have
43 sufficient resources to fulfill this request. NTPC maintains that the current level of effort to acquire third
44 party funding either directly or through assisting communities to obtain funding is appropriate and that
45 quarterly reporting on these efforts would be done at the expense of using resources to successfully

1 acquire funding. If Customers in the diesel communities determine that this is a high priority, NTPC would
2 be willing to amend its 2006/08 rate application to include a position to aggressively and proactively
3 pursue alternative energy funding and make reports to the Board on a full time basis.

4 **5.2 SUMMARY COMMENTS ON ALTERNATIVE ENERGY**

5 Corporate-wide, NTPC provides close to eighty percent of its power from renewable hydro power. The
6 installation of gas engines in those communities accessible to gas has further reduced emissions. Diesel
7 fuel required by NTPC to serve NWT communities has declined from a high of 57 million litres (NWT only)
8 to 12-13 million litres annually. Further, NTPC tested all of its diesel plants for emission levels to
9 determine if investment in emission reducing infrastructure was necessary from a regulatory perspective.
10 Emissions were found to be below the federal and territorial standards. The potential exists for short term
11 emissions concerns in Yellowknife if the Jackfish diesel plant becomes fully operational again, which is
12 being monitored.

13
14 Generally hydro communities do not support investment by NTPC in alternative energy technology.
15 Consequently, the cost of such projects would be borne by individual diesel communities which would
16 cause rates to increase beyond the current levels proposed in the 2006/08 general rate application.

17
18 Both the Federal and Territorial governments are developing alternative energy programs for 2007/08.
19 NTPC is actively involved with the GNWT and will apply to access funds either directly or indirectly under
20 any of the programs that will help customers to conserve energy. Alternative energy funding applications
21 will be made in consideration of the "all in" costs including operation and maintenance, impact on system
22 (power quality) and reliability of technology.

23 **6.0 FUEL STABILIZATION FUND (TGC)**

24 **6.1 BACKGROUND**

25 In response to a directive from the Board in Decision 12-94 to develop a proposal for a low water
26 stabilization fund, the Corporation applied for water and fuel stabilization funds in its 1995/98 Phase I
27 Application. During the 1995/98 Negotiated Settlement,²³ certain changes were made to the stabilization
28 fund proposal. These changes were outlined in the 1995/98 Negotiated Settlement and included the
29 following:

- 30
31 (f)
- 32 (i) A Fuel Stabilization Fund would be in place for the diesel communities if, and only if,
33 a single Fund is established for all of the diesel communities. If the Board
34 determines that it is inappropriate to have a single Fuel Stabilization Fund for all of
35 the diesel communities, the Corporation and Intervenors agreed that fuel adjustment
36 clauses would be established for each diesel zone.
- 37

²³ It should be noted that the Town of Inuvik was a party to the 1995/98 Phase I GRA Negotiated Settlement, PUB Decision 1-97.

1 (g) The Corporation and Intervenors agreed that it would not be necessary to track the
2 contributions of specific contributors to the Fund.²⁴
3

4 In Decision 1-97, the Board discussed the provisions of the Negotiated Settlement related to the
5 Stabilization Funds. On the particular issue of a single Fuel Stabilization Fund for the diesel communities
6 the Board stated:
7

8 The Board also considered the prudence of having only one fund for all diesel
9 communities. The Board appreciates that while there are significant differences in fuel
10 prices among communities it believes that any incremental rise or fall in fuel prices would
11 affect all communities equally. The Board therefore accepts this parameter of the
12 proposal as being reasonable as well.²⁵

13 **6.2 OPERATION OF THE FUEL STABILIZATION FUND**

14 Mr. Merani states in his evidence that:
15

16 Assuming the forecast consumption and price per litre turns out to be exactly the same
17 as the actual price and assuming a nil opening balance in the Diesel Fuel Stabilization
18 Account at the beginning of fiscal 2006/07, there should be no build up in this account.
19 Effectively, under this hypothetical scenario, the actual results are identical to forecast.
20 However, using the current fuel stabilization method, each community is charged the
21 averaged or pooled fuel rate. Attachment APM-3 demonstrates the expected results.²⁶
22

23 Mr. Merani's understanding of the operation of the Fuel Stabilization Fund as outlined in his Attachments
24 APM-3(1) and APM-3(2) is incorrect. Specifically, each community is *not* charged the averaged or pooled
25 fuel price.
26

27 Fuel expense at GRA fuel prices is included in the final revenue requirement approved for each
28 community. These community based revenue requirements form the basis of the final rates approved for
29 each community. It is therefore incorrect to state that each community is charged the averaged or pooled
30 fuel rate. Column H of Mr. Merani's Attachments APM-3(1) and APM-3(2) therefore is not an accurate
31 representation of the calculation of the charges to the Fuel Stabilization Fund.
32

33 The Fuel Stabilization Fund tracks only the difference between GRA forecast fuel prices and actual fuel
34 prices. In the scenario described by Mr. Merani – where the actual fuel prices and consumption unfolded
35 exactly as forecast, there would be no charges to the Stabilization Fund and no Fuel Stabilization Rider.
36

37 When fuel prices vary from GRA forecasts, the charges to the fund are calculated by comparing the
38 community based forecast and community based actual fuel prices. A sample calculation of the fuel price

²⁴ Page 5, 1995/98 Phase I Negotiated Settlement.

²⁵ Page 28, Board Decision 1-97.

²⁶ Page 11, lines 4 through 9. Prepared Testimony of Mr. Azad Merani.

1 difference portion of the Fuel Stabilization Fund for September 2006, the most recent actual month
2 provided in the Corporation's filing dated December 4, 2006, is provided in Table 1.

3
4 **Table 1**
5 **Calculation of Diesel Fuel Stabilization Fund Charges for September 2006**
6

PLANT NO.	PLANT	A APPROVED FUEL PRICE (\$/litre)	B ACTUAL FUEL PRICE (\$/litre)	C=A-B FUEL PRICE VARIANCE (\$/litre)	D ACTUAL GENERATION (kW.h)	E APPROVED EFFICIENCY (kW.h/litre)	F=D/E APPROVED FUEL REQ (litres)	G=CxF FUEL PRICE (DRAW)CONTR (\$000)	H INCR FUEL EXPENSE PER LITRE (\$)/KWH
104	Wha Ti	0.7150	0.8504	(0.1354)	129,500	3.147	41,150	(6)	0.0430
105	Gameti	0.5210	0.7066	(0.1856)	74,550	3.464	21,521	(4)	0.0536
110	Lutsel K'e	0.4900	1.0445	(0.5545)	119,345	3.793	31,465	(17)	0.1462
205	Fort Simpson	0.4080	0.7435	(0.3355)	573,944	3.763	152,523	(51)	0.0892
206	Fort Liard	0.4270	0.8190	(0.3920)	194,400	3.665	53,042	(21)	0.1070
207	Wrigley	0.4430	0.8538	(0.4108)	49,500	3.617	13,685	(6)	0.1136
208	Nahanni Butte	0.4240	0.8317	(0.4077)	32,054	2.311	13,870	(6)	0.1764
209	Jean Marie River	0.3990	0.7580	(0.3590)	28,640	2.520	11,365	(4)	0.1425
305	Tuktoyaktuk	0.5460	0.8911	(0.3451)	367,500	3.581	102,625	(35)	0.0964
306	Fort McPherson	0.6090	0.8672	(0.2582)	258,350	3.381	76,412	(20)	0.0764
307	Aklavik	0.8510	1.0767	(0.2257)	215,111	3.428	62,751	(14)	0.0658
308	Deline	0.5030	0.8742	(0.3712)	203,200	3.471	58,542	(22)	0.1069
309	Fort Good Hope	0.5750	0.8715	(0.2965)	195,467	3.556	54,968	(16)	0.0834
310	Tulita	0.7890	0.8876	(0.0986)	208,184	3.587	58,038	(6)	0.0275
311	Paulatuk	0.8100	1.2732	(0.4632)	97,716	3.397	28,765	(13)	0.1364
312	Sachs Harbour	0.5700	0.8308	(0.2608)	56,100	3.281	17,098	(4)	0.0795
313	Tsiigehtchic	0.6080	0.8521	(0.2441)	53,025	3.286	16,137	(4)	0.0743
314	Colville Lake	0.8150	0.7957	0.0193	25,275	2.414	10,470	0	-0.0080
315	Ulukhaktok	0.7650	1.1117	(0.3467)	155,600	3.579	43,476	(15)	0.0969
					3,037,461		867,906	(264)	0.0869

7
8 Table 1 indicates that for this month, in all communities except one (Colville Lake) actual fuel prices were
9 higher than GRA fuel prices included in the community based revenue requirements. In the specific case
10 of Fort Simpson and Fort Liard, the actual fuel price variance on a per kW.h of generation basis was
11 slightly higher than the average. Since the charges to the Fuel Stabilization Fund are calculated with
12 reference to the GRA approved fuel price on a community by community basis, there is no basis to
13 assert, as Mr. Merani does, that some communities are perpetually subsidizing others in the Diesel Fuel
14 Stabilization Fund.

15 **6.3 FUEL EFFICIENCIES IN THE FUEL STABILIZATION FUND**

16 With respect to the use of forecast or actual fuel efficiency in the Fuel Stabilization Fund, Mr. Merani
17 states:

18
19 In Attachment APM-5, it analyzes a scenario wherein there is an improvement in the
20 heat rate from 3.50 (forecast basis) to 4.00 (actual). All other parameters used in the
21 determination of the forecast and actual cost of fuel per KW.h are held constant. The
22 results indicate the volume of fuel required is reduced. In particular, 35,714 litres less
23 is required than forecast in this example. As the forecast and actual price per litre did
24 not change, there is no price variance as such. Therefore, the only variance is related
25 to the volume variance of \$26,786, and represents the excess fuel costs paid by
26 customers.
27

1 Accordingly, my recommendation is when the FSF is trued up, NTPC should replace
2 the forecast (last approved by the Board) with the actual heat rate for the most recent
3 year.²⁷
4

5 The Corporation notes that the change suggested by Mr. Merani would remove the Corporation's risk
6 related to fuel efficiency on the portion of the fuel price that is different from the GRA forecast included in
7 the community based rates.²⁸ Regardless of the treatment in the fund, NTPC is at risk of efficiency
8 variations for the GRA forecast price of fuel.
9

10 The following simple hypothetical example illustrates the mathematics of Mr. Merani's proposal. If the
11 forecast load is 1000 kW.h at an efficiency of 5 kW.h/litre, the community would be forecast to use 200
12 litres. If the forecast fuel price is \$1/litre, the fuel forecast would be \$200. If the actual load is similarly
13 1000 kW.h and the efficiency has dropped to 4 kW.h/litre then the community will require 250 litres. If the
14 actual price of fuel is \$1.10/litre, the total cost will be \$275. This \$275 is really made up of 4 components:
15

- 16 a) \$200 as forecast in rates;
17 b) \$50 due to lower efficiency at the GRA price (pure efficiency variation);
18 c) \$20 due to increased price at GRA volumes (pure price variation); and
19 d) \$5 due to the higher price applying to the extra 50 litres needed due to the lower efficiency
20 (compounded efficiency and price variation).
21

22 The Corporation would recover \$200 in base rates (component (a)). Regardless of the approach to the
23 Fuel Stabilization Fund, the Corporation is at risk for the \$50 related to pure fuel efficiency (component
24 (b)). The Fuel Stabilization Fund in any case (both under current operation and under Mr. Merani's
25 proposed changes) will provide the \$20 due to pure price variation (component (c)). The impact of Mr.
26 Merani's proposed change is that the Corporation would recover the extra \$5 (component (d)) from the
27 Fuel Stabilization Fund. Under the current approach, the Corporation is at risk for the extra \$5
28 (component (d)). Consequently, Mr. Merani's proposal is of minimal consequence.

29 **7.0 FUEL EFFICIENCY RATE FOR INUVIK (TGC)**

30 Mr. Merani's evidence suggests that an increase to the fuel efficiency rate for Inuvik is warranted. He
31 appears to arrive at this conclusion by relying on two factors:
32

- 33 • the forecast efficiency is lower than the manufacturer's stated test efficiency rating; and
34 • because replacing diesel engines in other communities has resulted in improved fuel
35 efficiency.²⁹
36

²⁷ Page 10, lines 3-13 Prepared Testimony of Mr. Azad Merani.

²⁸ It should be noted that this position appears to be contrary to the position put forward by Fort Simpson in the 2001/03 Phase I GRA where the Hamlet's expert witness Mr. Bellows indicated that he believed the Corporation should be at greater risk for fuel expense than it is currently. See for example Mr. Bellows' discussion on Question 21 of his testimony from the 2001/03 Phase I General Rate Application on the issue of fuel efficiencies.

²⁹ Pages 13-14, Prepared Testimony of Mr. Azad Merani.

1 In the Corporation's view neither of these factors is a valid reason for adjusting the forecast gas plant
2 efficiency in Inuvik.

3
4 The manufacturer's efficiency rating is seldom, if ever, achievable in practice. Actual operating conditions
5 influence the efficiency achieved. The forecast fuel efficiencies used to calculate fuel expense reflect the
6 overall efficiency of all units in a plant. The plant efficiencies are impacted by the operating loads; the
7 efficiency of individual units; how the units are dispatched; and percentage loading on the individual
8 engines. Also, fuel efficiencies calculated by the manufacturer do not include fuel consumed during unit
9 start-up and cool down periods. It is therefore not reasonable to adjust the forecast gas plant efficiency
10 based on the manufacturer's rated efficiency. Rather, the more accurate measure of fuel efficiency is to
11 consider recent historical performance of the actual unit when available and, if not available, recent
12 historical performance of similar units at the same generation plant.

13
14 Mr. Merani's evidence cites instances where replacing older diesel engines with newer diesel units
15 improved the fuel efficiency at the plant.³⁰ In the Corporation's view, comparing the efficiency
16 improvements observed as a result of replacing older diesel engines with newer diesel engines to the
17 installation of the 3rd gas genset in Inuvik is not a reasonable basis to suggest that the gas plant efficiency
18 in Inuvik should be adjusted.

19
20 Newer diesel engines typically have electronic controls and/or electronic fuel injection – where the
21 primary target is to produce as much power as possible while utilizing the least amount of fuel. This
22 contrasts with the much older technology typically being replaced in diesel plants. In these situations fuel
23 efficiency often is observed to improve. However, it should be noted that this may not continue to be the
24 case in the future as current diesel technology has largely maximized fuel efficiency to the extent
25 possible. Further, it should be noted that diesel engine manufacturers are in many cases faced with
26 competing design objectives of fuel efficiency and reduced emissions. In some newer diesel engines,
27 fuel efficiency is actually lower than previous technologies, in order to maximize emissions reduction
28 objectives.

29
30 By contrast, the new natural gas genset in Inuvik is only 4-5 years newer than the existing natural gas
31 gensets (it was manufactured in 2001). The new unit has the same engine control system/fuel system
32 and the same efficiency ratings as the other 2 units. The 3rd gas genset was not justified based on
33 improving efficiency but rather on displacing consumption of diesel fuel. In the Corporation's view there is
34 no reasonable basis to expect that the 3rd gas genset will materially affect the gas plant efficiency in
35 Inuvik.

³⁰ Mr. Merani cites for example improved fuel efficiency at the new Fort McPherson plant as well as an adjustment made to the forecast fuel efficiency at the Fort Providence plant operated by Northland (NWT).

Appendix A

The following is a list of the alternative energy project third party funding applications that NTPC has been involved with:

- Assisted communities to write proposals to access funding for 50% of their streetlight conversion upgrade costs from the Department of Energy and Natural Resources (“ENR”) Energy Conservation Program. The funded communities were: Sachs Harbour (\$8,400 in 2004/05), Fort McPherson (\$20,600 in 2004/05), Aklavik (\$19,400 in 2004/05), Deline (\$10,800 in 2004/05), Tuktoyaktuk (\$13,265 in 2005/06), Fort Good Hope (\$13,895 in 2005/06), Inuvik (\$20,880 in 2005/06, up to \$20,880 in 2006/07), Behchoko (up to \$14,200 in 2006/07), and Fort Liard (up to \$13,260 in 2006/07). Conversions completed in 2006/07 are still being closed-out, therefore the total job cost and the subsequent funding from ENR have not yet been finalized.
- NTPC has, either through direct application or by assisting/encouraging communities to apply, directed efforts to mini hydro potential in the NWT. Three communities (Wha Ti, Deline and Lutsel K’e) have applied to the eco-Trust fund in 2007/08 for \$1,000,000 funding for feasibility studies.
- Applied in 2000/01 for funding from Natural Resources Canada (“NRCan”) Technology Early Action Measures (TEAM) for the Arviat heat distribution system. Received \$325,000 with 50% repayable over 5 years.
- Applied in 2000/01 for funding from TEAM for Rankin Inlet (now in Nunavut) wind project, no funding was approved.
- Assisted Fort Simpson to obtain a matching grant in 1996 for a district heating study. Fort Simpson received half of the estimated \$17,600 study cost. A second community study in 2004 also received funding from Indian and Northern Affairs Canada, through the GNWT Department of Resources, Wildlife and Economic Development (“RWED”). NTPC is not privy to the amount of funding provided.
- Applied in 1999 to TEAM for Fort McPherson district heating installation. Received \$35,000, with 50% repayable over 5 years.
- Applied for federal funding for feasibility studies for Wha Ti and Lutsel K’e for mini hydro in 2005/06. Received approval for \$575,000 however approval was withdrawn when the Liberal Party was defeated.
- Applied for/supported \$100,000 for commercial energy assessments/audits from the GNWT under the Energy Plan. Approved in principle. Awaiting Legislative Assembly approval.
- Assisted in solar power installation in Jean Marie River. This project was funded by the ENR however NTPC is not privy to the amount of funding provided. NTPC provided in-kind contributions – helped to set up project by participating in initial discussions with ENR and Jean Marie River Band; did interconnection review and approval; continue to do periodic site-checks of the monitoring system to ensure the system is operating.

- 1
- 2 • Assisted in Stirling engine proposed installation in Norman Wells. This project was originally funded
- 3 by the Energy Secretariat, and then taken over by ENR. NTPC is not privy to the amount of funding
- 4 that was received, however is aware that funding was supposed to come from NRCan to the GNWT
- 5 once the system was commissioned. However, because the system was never commissioned, the
- 6 GNWT never received funding. NTPC provided in-kind contribution – reviewed and approved
- 7 interconnection drawings.
- 8
- 9 • In 2002/03, NTPC was successful in obtaining \$63,540 from Indian and Northern Affairs Canada's
- 10 Aboriginal and Northern Climate Change Program and \$12,000 from the Energy Secretariat for the
- 11 Residential Energy Efficiency Program. A second proposal for program funding under the
- 12 replacement program, the Aboriginal and Northern Climate Action Plan, was not successful.
- 13
- 14 • Assisting in gathering wind monitoring info with the Aurora Research Institute ("ARI"). This project
- 15 was led by ARI and funded by ENR. NTPC is not privy to the amount of funding provided. NTPC
- 16 provided in-kind contributions – provided storage space in some of the Beaufort communities;
- 17 provided the tower for monitoring equipment erection in Yellowknife; provided the pole-climbers and
- 18 electronic technician to install the Yellowknife monitoring equipment; download Yellowknife data and
- 19 send to consultant on a monthly basis.
- 20
- 21 • Founding Member of Arctic Energy Alliance.
- 22
- 23 • In the winter of 2005/06, NTPC received \$75,000 under the Energy Conservation Action Plan for a
- 24 Residential Energy Efficiency Assessment Program in the South Slave Region (Fort Smith, Fort
- 25 Resolution and Lutsel K'e). The official contribution agreement was with ENR.
- 26
- 27 • NCP/NTPC received federal funding of \$1 million for a wind project in Cambridge Bay (now in
- 28 Nunavut) from the mid 1980s. This project was unsuccessful and shut down in the early 1990s
- 29 (about 1994).
- 30
- 31 • Reached verbal agreement to develop two wind sites in a one-third partnership with NRCan and
- 32 RWED (GNWT) in the mid to late 1990s. After the equipment was ordered, both parties backed out of
- 33 the agreement leaving NTPC with the expense of completing the projects.
- 34
- 35 • In 2002, NRCan provided \$20,000 to fund the capital purchase of a microturbine for the Inuvik
- 36 recreation centre. In 2004, 2005, and 2006, NRCan provided funding support in the range of \$2,000
- 37 to \$3,500 each year for NTPC staff to attend and make a presentation at the Annual Microturbine
- 38 Applications Workshop. In 2004 to 2007, NRCan entered into a contribution agreement with NTPC
- 39 for \$25,500 to train NTPC staff to operate and repair the microturbine, set-up remote monitoring of
- 40 the system, and to support on-going scheduled maintenance on the system.
- 41
- 42 • NTPC examined several possible applications for the federal government Wind Power Production
- 43 Incentive ("WIPPI") and other federal government renewable energy incentive programs. The
- 44 Corporation had numerous conversations with the federal government on potential applications for

- 1 this funding, however, the efforts were not successful in developing a project. With the change in the
2 federal government many of these programs either no longer exist or have been drastically altered.
3
4 • From about 1993-1996 NTPC had a position located in Yellowknife who did energy audits and
5 provided demand side management information.
6
7 • In 2007 the Territorial Farmers Association provided \$30,000 to study the potential for using biofuels
8 in the Corporation's operations.