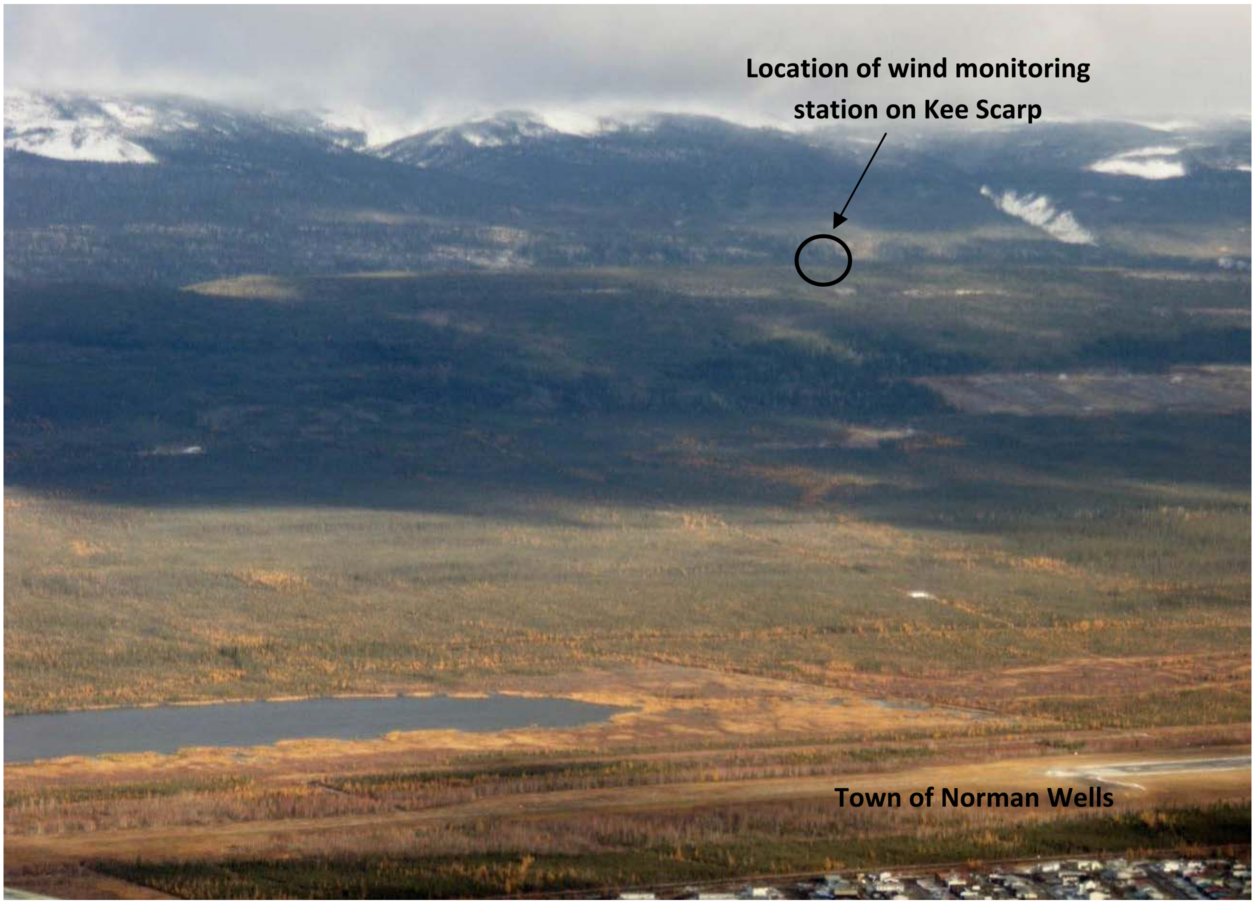
Norman Wells Wind Energy Pre-feasibility Update



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Executive Summary

This study updates the prefeasibility study completed in early 2008 on a possible wind project for the community of Norman Wells, specifically on Kee Scarp 5 km northeast of town. There is now actual wind data available from Kee Scarp, and the wind turbine options and costs for a project have been updated in some detail.

The community of Norman Wells has a population of about 800 whose power is provided by Northwest Territories Power Corporation (NTPC). The current electrical load is about 10,000 megawatt hours (MWh) per year, and almost all of the power is purchased by NTPC and generated by natural gas.

A wind monitoring station on Kee Scarp ran for two years and the measurements show that this site has a projected long-term mean wind resource of 5.0 m/s at 40 m above ground level (AGL). The long-term mean wind speeds are also estimated to be 5.5 m/s at 50 m AGL, and 6.3 m/s at 80 m AGL.

The community and its electrical load are large enough to allow some economies of scale in a wind project. To perform an economic assessment of a possible wind energy project in Norman Wells, the 100 kilowatt (kW) NorthWind 100 (37 m, tallest tower available) and Aeronautica (formerly Norwin) 225kW (50 m tallest tower) wind turbines were considered. Wind energy projects of about 400/450 kW and 900 kW were estimated to cost from $4.24 to $4.75 million and from $6.69 to $8.28 million, respectively, depending on the wind turbine considered.

The levelized cost of energy produced from an unsubsidized wind project with a 20 year life was estimated to cost from $0.572 per kWh for a 900 kW project, to $0.967 for the 400/450 kW project. The 20-year levelized cost of diesel generation is $0.380 per kWh for fuel costing $1.00 per litre and $0.467 per kWh for fuel costing $1.25 per litre. The wind project will become competitive when diesel costs $1.60 per litre. A 400/450 kW wind project would reduce greenhouse gas (GHG) emissions in Norman Wells by over 425 tonnes per year, and a 900 kW project would reduce GHG emissions by over 958 tonnes per year.

Larger wind turbines (e.g. 800 kW and up) with taller towers (60 - 80 m typical) are available for this project. A larger scale wind project was outside the scope of this study as this implies a more complex power and energy control system which has not been implemented to any great extent in Canada. These high penetration systems are being used in Alaska however, and should be considered as a future phase.

In the North, the impact of capital costs on the cost of wind energy is very significant. The authors have provided capital and operating cost estimates on the basis that experienced developers and operators will be completing and operating the projects. Cost estimates do not make allowances for this project being a first in the territory and thus incurring extra costs. However, the authors also believe that with experience there is still room to lower the capital costs for wind projects in Northwest Territories.

The Canadian Wind Energy Association (CanWEA) continues to make the proposed Northern and Remote Community Wind Incentive Program a very high priority. Any other factors such as reduced capital cost, reduced operating cost, or increased diesel fuel cost (or revenue from carbon credits or green attribute sales) would serve to further increase the competitiveness of a wind project.

Background

JP Pinard, P.Eng., PhD. and John Maissan, P.Eng. (Leading Edge Projects Inc.), have been retained by the Aurora Research Institute (ARI) to conduct a pre-feasibility study for wind energy generation in Norman Wells. This study examines wind data from the ARI wind monitoring station, the weather balloon (upper-air) station, the airport meteorological station, as well as information from maps and satellite images of the community to identify potential wind monitoring sites. In addition, the project group has consulted with the Hamlet of Norman Wells, NTPC and Imperial Oil about the current and future power systems in Norman Wells. This study provides the following information:

1) An analysis of wind data to estimate long-term mean wind speed and direction.
2) Estimates of the wind speeds around the hamlet generated with computer models.
3) A list of possibleareas for a wind project.
4) A description of the power system in the hamlet which includes the size, capacity and condition of present system.
5) An analysis of the potential wind energy production from different wind turbine models.
6) Preliminary estimates of the cost of wind generation for the hamlet.
7) Estimates of power production and fuel displacement through the integration of wind power.
8) An outline of next steps needed to pursue the integration of wind power in the hamlet.

Introduction

Norman Wells has a population of about 800 people and is located 700 km northwest of Yellowknife on the east shore of the Mackenzie River. The community is accessible by plane year round, by barge during the summer, and connects to NWT's highway system during the winter on a winter road.

With the nearby gas fields in decline, the solution for community energy demands appears to be the utilization of diesel to generate power. So with the likely introduction of diesel generation in the community, wind energy could become a favourable compliment to keeping diesel consumption to a minimum. In the fall of 2006, preliminary work was carried out to investigate wind energy potential in Norman Wells, and the following factors were identified:

- The abundance of technical (human) resources in the community;
- The large 13 megawatt (MW) gas plant run by Imperial Oil (the plant will shut down and loads will be reduced as industrial activity drops);
- The presence of a promising wind resource (long-term mean above 6 m/s was estimated) and anelevated site located near town; and
- The Mackenzie River location being ideal for barging large project components and machinery.

Following recommendation from a pre-feasibility report (Pinard and Maissan, 2008) a wind monitoring campaign was carried out near Norman Wells over the period of two years, from September 2008 to September 2010. The wind monitoring station was set up on Kee Scarp directly east and overlooking the town of Norman Wells. A progress report (Pinard, 2010) using 15 months of wind measurements revealed a long-term wind speed of 4.8 m/s at 40 m above ground level (AGL); projected to higher levels above the stations, the estimates of long-term annual mean wind speeds were 5.5 m/s at 60 m and 6 m/s at 80 m AGL. This report will provide an update on these numbers, provide a wind flow model of the area of interest and provide an updated economic assessment of wind energy for Norman Wells based on the new measurements.

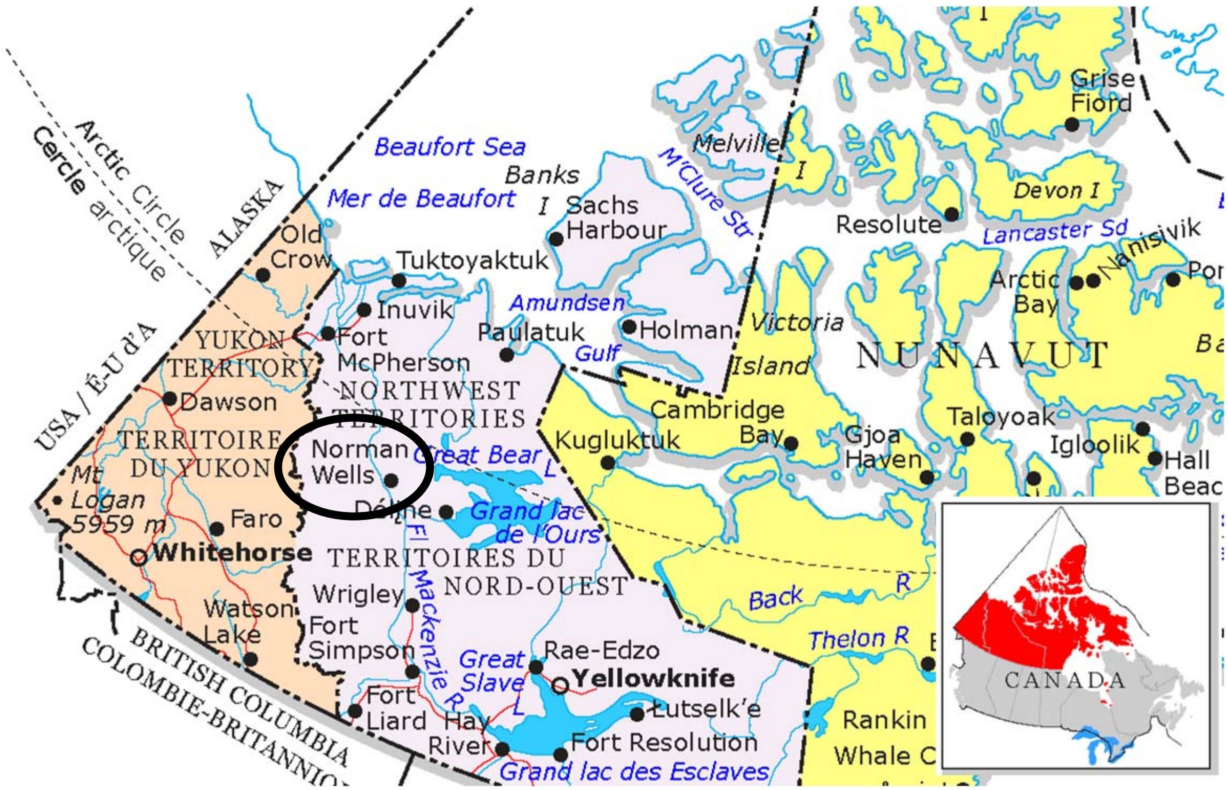

Figure 1: Norman Wells is located on the shore of the Mackenzie River 700 km northwest of Yellowknife.

Area of Wind Energy Study

The town site of Norman Wells is on the northeast shore of the Mackenzie River at an elevation of 60 m above sea level (ASL). The town is in a 50 km wide river valley between the Mackenzie Mountains and the Norman Range. The Carcajou Range (Mackenzie Mountains) is 40 km to the southwest, and the Norman Range is 10 km to the northeast. The Norman Range has elevations in excess of 1000 m ASL, and would appear to be an appropriate ridge to install a wind park. The ridge, however, has steep slopes making it difficult to access. Being 10 km from the town is also problematic for building a wind project there, as power line installation and road construction would become prohibitively expensive.

The nearest accessible hill to Norman Wells is Kee Scarp, which sits 5 km from town towards the Norman Range. Kee Scarp peaks at about 347 m ASL, or 275 m above the town site. The hill is narrow with the long axis oriented west-northwest, parallel to the Norman Range. Because of its accessibility and relatively high surface elevation above the town, the hill was chosen as the site for the initial wind monitoring and it is still likely the best location for a wind project for the community.

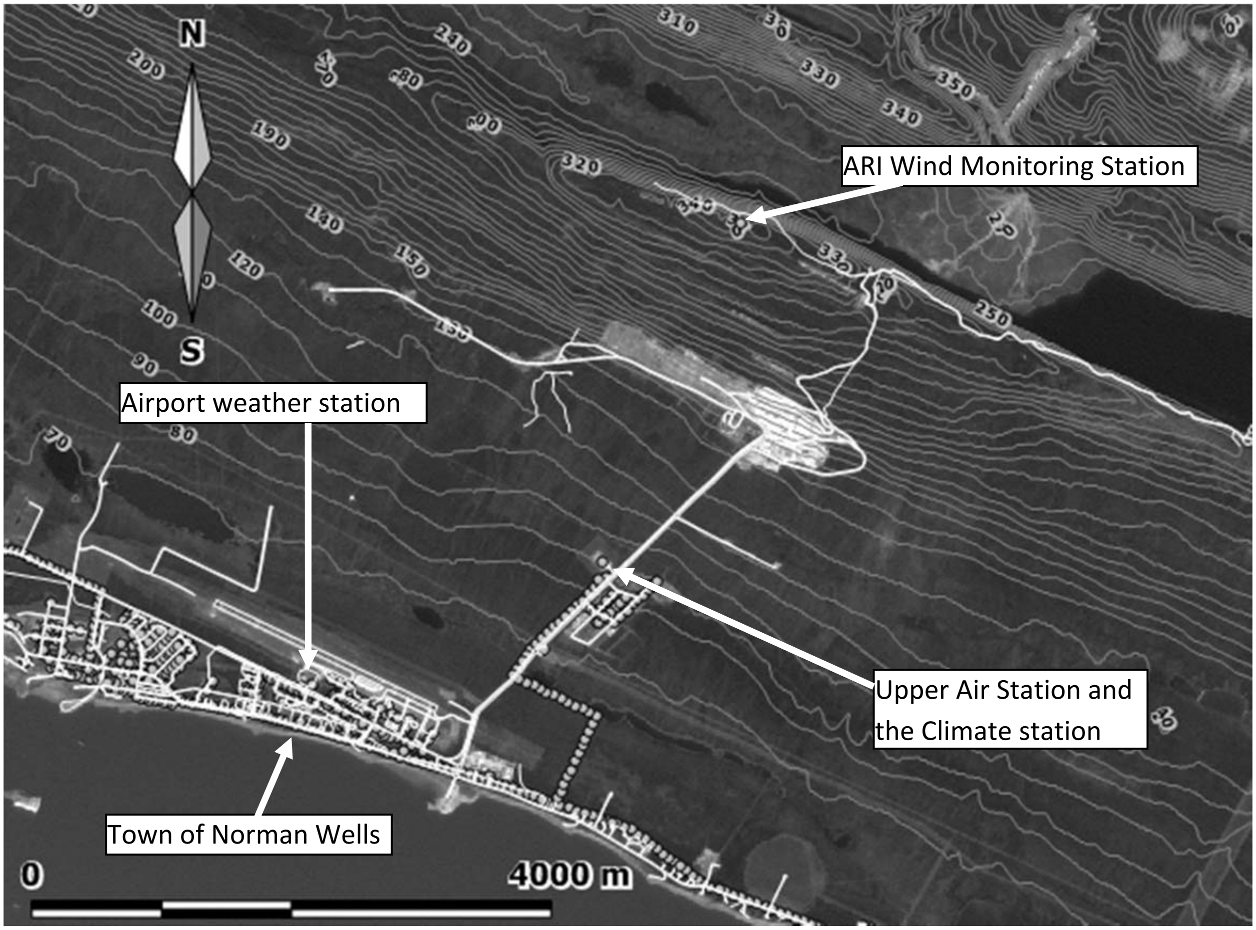

Figure 2: Map of Norman Wells area including Kee Scarp. Contour interval is 10 m.

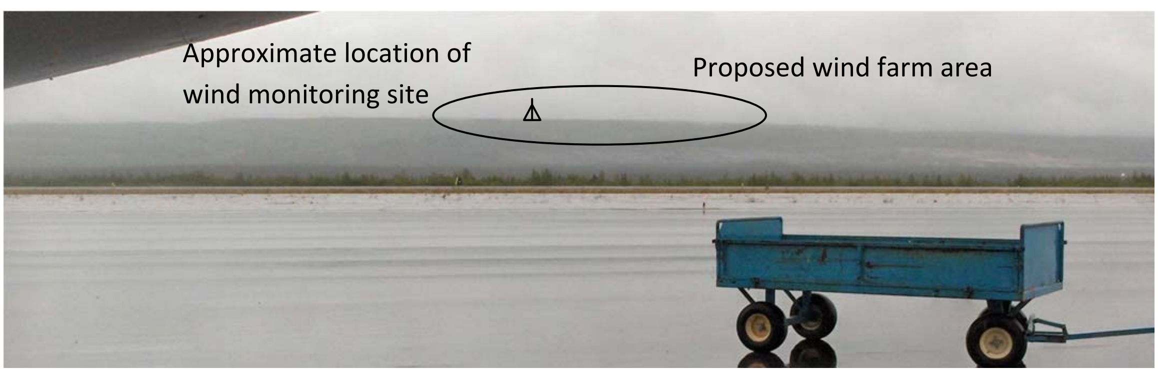

Figure 3: View of Kee Scarp from the airport.

The wind monitoring tower installed by the Aurora Research Institute(ARI) was located at about 345 m ASL and was 40 m tall. The tower was installed on Kee Scarp's ridgeline about 300 m southeast of the highest point (see Figure 4). When the tower installation began, a number of challenges arose that changed the location and the height of the tower. First, the location that was initially chosen (the highest point of Kee's Scarp) was narrow; the land was too uneven and too forested to allow proper and safe installation of the anchors and the tower. The new area was again uneven but had fewer trees and the site allowed for the proper installation of the anchors. The ground itself was also weak, revealing a muddy soil below the vegetation layer. As a result and out of concern for safety, only the lower 40 m of the 60-m tower was installed.

Analysis of Wind Measurements

In the following analysis, the measurements from the wind monitoring station at Kee Scarp (at 345 m ASL) are compared to those of the upper air and the meteorological station (both Environment Canada's) for the same period.

A comparison of monthly average wind speeds for the three sites is shown in Figure 4 below. The graph shows that the wind speed at Kee Scarp closely follows but is about 78% of the wind speed measured by the upper air sensors at a roughly similar elevation (ASL). Measurements from the surface climate station (associated with the upper air station, 94 m ASL) and the airport station (73 m ASL) follow the other two measures well during the summer but are notably lower during the winter months (under the winter temperature inversion).

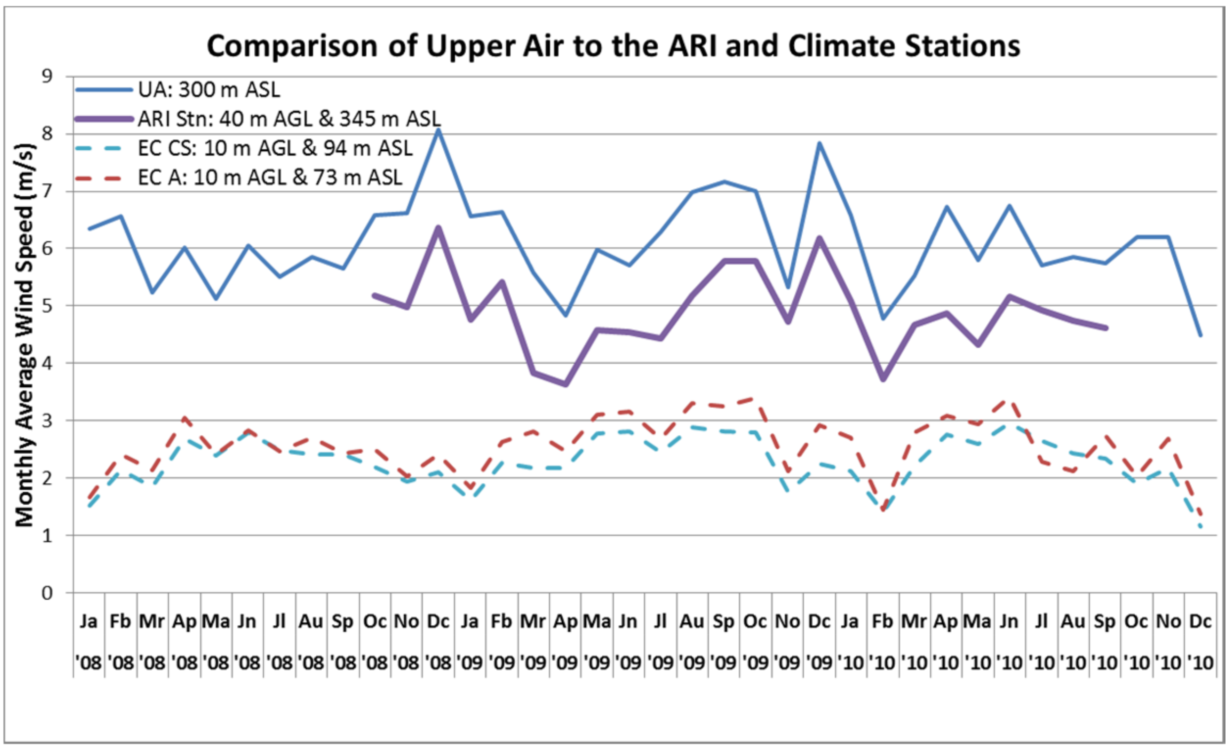

Figure 4: Comparing the wind speed between the ARI wind monitoring station on Kee Scarp ("ARI Stn"), the upper air measurements at 300 m ASL ("UA"), the climate station ("EC CS"), and the airport station ("EC A"). The locations of these stations are shown in Figure 2.

For the period of September 2008 to September 2010, the measured average wind speeds were 4.7 m/s at 40 m, 4.4 m/s at 35 m, and 3.9 m/s at 25 m AGL. It appearsthat some icing affected the sensors during the periods when temperatures fell below freezing point. The data was carefully analyzed to filter out those icing periods. With the data filtered of icing, the mean wind speeds improves slightly to 4.9 m/s at 40 m, 4.7 m/s at 35 m, and 4.1 m/s at 25 m AGL.

The wind speeds at the ARI wind monitoring station are correlated to those of the upper air for the same two-year period. At 300 m ASL (or 205 m above the ground at the weather balloon station) the upper air wind speed is6.3 m/s. A height of 300 m ASL is about 45 m below the top of Kee Scarp where the ARI station is located. The correlation coefficient of the monthly average between the upper air (300 m ASL) and the Kee Scarp wind monitoring station is 0.91, which is considered to be an excellent correlation. The ten-year (2001-2010) mean for the upper air measurements at 300 m ASL was 6.5 m/s, which is about 3% higher than the 2-year monitoring period.

The short-term wind speed measured at the Kee Scarp site is adjusted to a ten-year mean using the MCP method of **M**easuring, **C**orrelating, and **P**redicting the long-term mean winds. The formula is:

$$E_s = \mu_s + \frac{R \cdot \sigma_s}{\sigma_r}(E_r - \mu_r),$$

where E_s is the estimated long term wind speed at the site of the wind monitoring station, μ_s is the measured wind speed at the site, μ_r is the measure reference wind speed, and E_r is the measured long-term mean wind speed at the reference station. The other variables in the equation are the correlation coefficient R and the standard deviation for the reference station, σ_r, and the wind monitoring site, σ_s. These values are listed in Table 1. From the above formulae the ten-year (2001-2010) projected mean of the Kee Scarp site is 5.0 m/s at 40 m AGL.

Table 1: Details of values in the evaluation of the long-term mean wind speed of the wind monitoring station at Kee Scarp using the MCP method. The Kee Scarp station (ARI) is the "site" and the upper air station is the "reference".

Measure-Correlate-Predict	Values	units	Height AGL
Estimated Long-term mean at site Es =	**5.0**	m/s	40 m
Measured Long-term mean at reference Er =	6.5	m/s	205 m
Measured short-term site u_s =	4.9	m/s	40 m
Measured short-term reference u_r =	6.3	m/s	205 m
Ratio between long- and short-term =	1.03		
Measured cross-correlation coefficient R =	0.91		
measured standard deviation at site $theta_s$ =	0.69	m/s	40 m
measured standard deviation at reference $theta_r$ =	0.84	m/s	205 m

Table 2 shows summary values of wind speeds for the upper air and the Kee Scarp sites. The Kee Scarp numbers include wind projected to higher levels above ground. These numbers were obtained by using natural log law formulation which is as follows.

Turbulent air flow over rough surfaces tends to generate a vertical profile of horizontal winds that are fairly predictable. The wind speed profile near the ground is dependent on neutral well mixed air conditions and the roughness of the ground surface. This vertical profile can be defined by the natural log law equation:

$$u_2 = u_1 \frac{\ln(z_2/z_o)}{\ln(z_1/z_o)}$$

where u_1 is the known wind speed at z_1 (typically at 10 m AGL), and is projected to u_2 at the height z_2. The surface roughness is defined by z_o which as a rule of thumb is 1/10 the height of the grass, brush, or ground undulations surrounding the site where the measurements are made. This equation is considered most accurate up to approximately 100 m above the surface. The surface roughness z_o can be categorised by the type and size of vegetation as well as the hilliness of the ground itself. If we know the wind speeds at two heights of say 10 and 30 m then we can also find the value of z_o, look the value up on a roughness chart and compare the land description to the actual ground surrounding the station. With the known z_o we can use the log equation to predict the wind speed at higher elevations.

Around the Kee Scarp wind monitoring site the land surface is typically forested with undulating terrain. The surface roughness based on the measurement is estimated to be z_o = 2.5 m, this would represent a surface roughness of a dense tall forest which is not the case here. The forest on Kee Scarp has a surface roughness closer to 0.5m. Two other factors increase the perceived surface roughness on Kee Scarp: the stability of the atmosphere causes the wind speeds to decrease dramatically towards the surface; the large undulating ground surfaces causes a more turbulent and slower wind closer to the surface of the hill.

Table 2: Details of measurements and their projection to longer term and to higher elevations. Bold values indicate the estimated long-term (10-years, 2001-2010) mean wind speed at the Kee Scarp (Norman Wells) ARI wind monitoring station.

Location and measurement period	Height	Wind speed	
Upper Air station, Oct 2008 to Sept 2010:	205 m AGL	6.3	m/s
Kee Scarp Station, Oct 2008 to Sept 2010:	25 m AGL	4.1	m/s
	35 m AGL	4.7	m/s
	40 m AGL	4.9	m/s
Upper Air station, 2001 to 2010:	205 m AGL	6.5	m/s
Ratio of 2-year to 10-year mean at UA station:		1.03	
Kee Scarp site projected to ten years:	10 m AGL	**2.5**	m/s
	25 m AGL	**4.2**	m/s
	30 m AGL	**4.8**	m/s
	37 m AGL	**4.9**	m/s
	40 m AGL	**5.0**	m/s
	50 m AGL	**5.5**	m/s
	60 m AGL	**5.8**	m/s
	70 m AGL	**6.1**	m/s
	80 m AGL	**6.3**	m/s

Wind direction must also be taken into account when considering a wind energy project. A wind rose provides an indication of where the dominant wind energy is from in the area and is very useful for planning the location of a wind project to ensure the wind's maximum energy capture. In Figure 5 below, the wind rose for Norman Wells has a solid shaded area that represents the relative wind energy by direction. The wind energy by direction is calculated as the frequency of occurrence of the wind in a given direction sector multiplied by the cube of the mean wind speed in the same direction. The given wind energy in each direction is a fraction of the total energy for all directions. According to the wind rose below, the wind energy at Norman Wells comes from mainly the southeast with a lesser component from the northwest following the valley axis. According to this wind rose, a wind energy project established in the region should have good exposure to the southeast as well as the northwest. Information from the wind rose and the wind speed and direction data are used to run a wind flow model that helps visual where the best wind sites might be for the Norman Wells area.

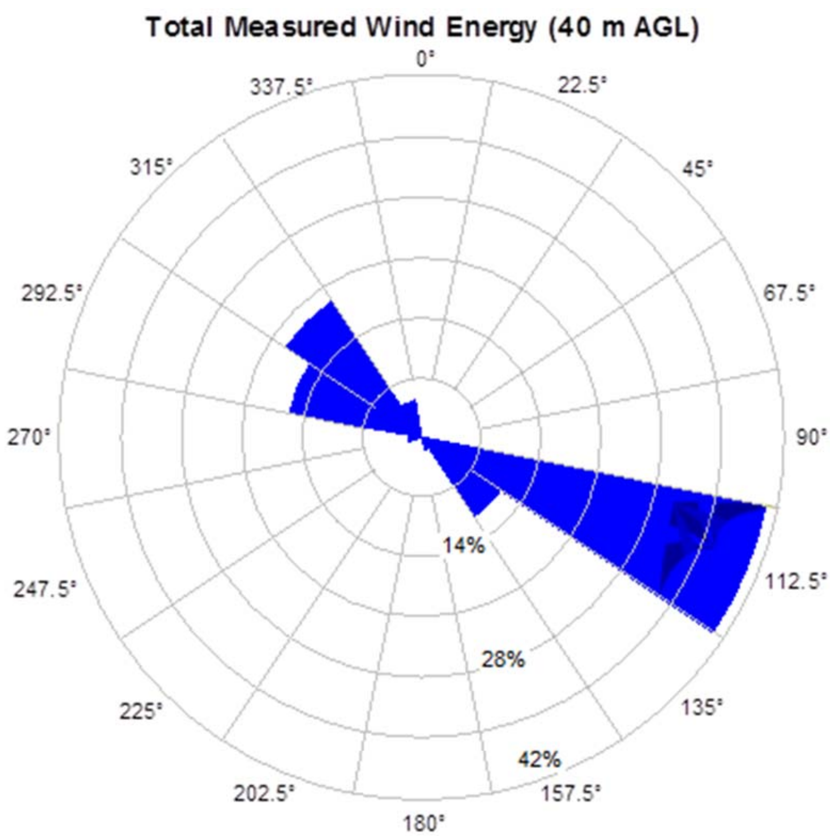

Figure 5: Wind energy rose showing the wind energy by direction for Kee Scarp. This rose shows that the dominant wind direction is from the Southeast, with a lesser component from the northwest.

Fine-Scale Wind Modelling of the Kee Scarp Area

The wind model used to create the wind map for the Kee Scarp area is OpenWind by AWS Truewind (www.awstruewind.com). OpenWind uses a mass-consistent wind flow model to project winds from one location to another. As input, the model uses surface elevation data, surface roughness, and a table of wind speed distribution by direction. The elevation data is obtained in part from the Geobase website (http://www.geobase.ca), and from the MACA (Municipal and Community Affairs) website. The surface roughness is assumed to be z_o = 0.5 m, which is representative of the area's forest type and density. The table of wind speed distribution is derived from the two-year wind speed data set (Sept 2008 to Sept 2010) from the ARI wind monitoring station on Kee Scarp.

The wind flow modeling portion of OpenWind creates a wind map for each wind flow direction. The wind speeds in the wind maps are directly associated to the table of wind speed distributions. The OpenWind wind speed map in Figure 6 shows the summarized wind speed contours over a satellite image of LutselK'e. One possible location is suggested for turbine placements. The area outlined by a rectangle in Figure 6 is about 120 by 700 metres across the top of Kee Scarp has wind speeds above 5 m/s (at 40 m above ground). There is probably room to install up to ten Aeronautica A225, depending on the ground conditions and further feasibility studies.

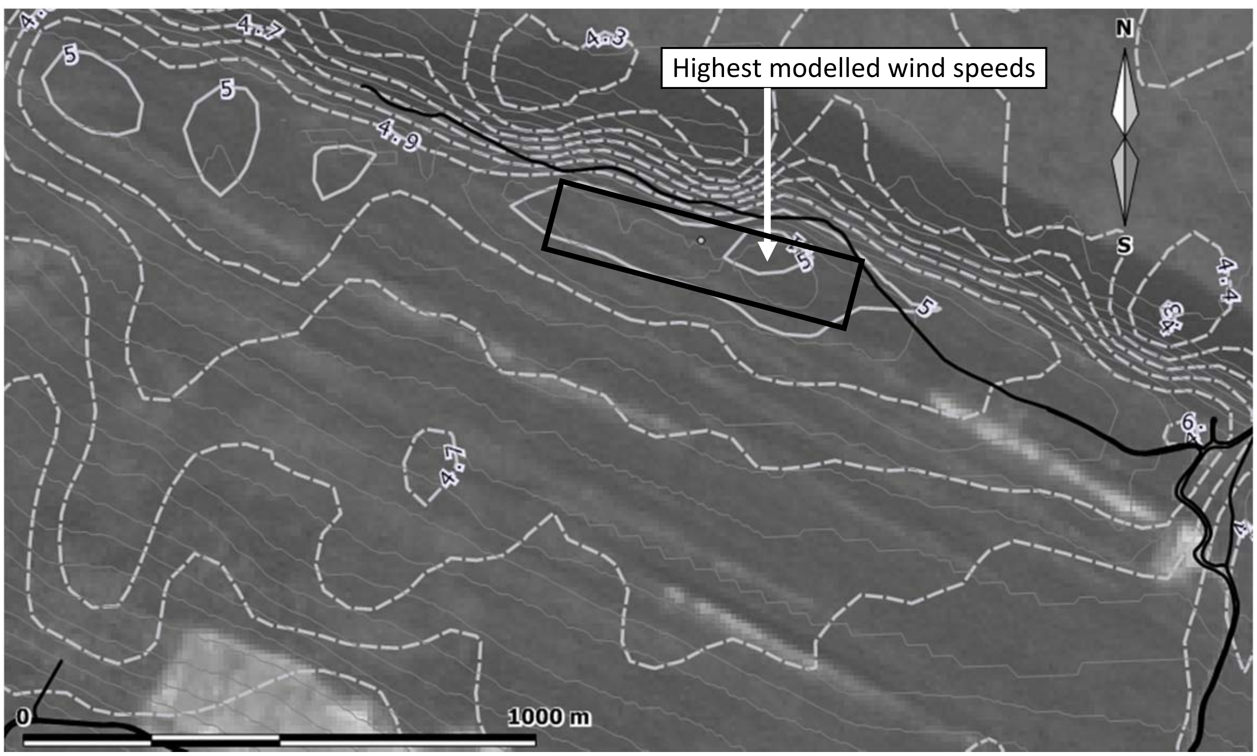

Figure 6: An aerial image of the Kee Scarp area superimposed by a contour line of modelled wind speeds at 40 m above the surface. The wind speed contour interval is 0.1 m/s. The highest wind speed contour is 5.1 m/s and it appears just east of where the ARI wind monitoring station was located.

Power Requirements and Costs

The community of Norman Wells has two power suppliers: Imperial Oil operates a 13 MW gas fired power plant to serve the oil related industrial loads in the area and sells power to NTPC for distribution to serve the local community's residential and general service loads and street lights; and NTPC owns and operates a diesel plant composed of a Caterpillar 3516 rated at 1,400 kW and a Caterpillar D399 rated at 720 kW. This plant provides a small amount of diesel generated power to augment the power purchased from the gas power plant.

The 2007/8 actual power requirement in the community was 9,683 MWh of which 99% was purchased from Imperial Oil at a general rate application (GRA) forecasted price of $0.279 per kWh (indexed to the price of diesel) and the remainder was at a GRA forecasted $0.246 per kWh ($0.841 per litre and 3.414 kWh per litre). Relevant excerpts of the GRA are attached as Appendix 1.

The 2011 annual energy requirement has been conservatively estimated (by the authors) at 10,000 MWh which indicates an average load of 1.142 MW and a peak load estimated at 1.700 MW (a load factor of 65.1% was forecasted in the GRA). Based on these figures the minimum load is estimated to be about 600 kW. For this prefeasibility study, a smaller wind energy project size of about 400 to 450 kW and a larger project size of about 900 kW were considered and are consistent with a low and medium penetration levels. This study did not examine a high penetration project as the authors feel that more experience with simpler wind-diesel projects in NWT is required before the more technically complicated high penetration systems are taken on.

The authors understand that the supply of gas may be running low and that NTPC may be required to supply all of the community power demand from diesel generation in the future. For the purposes of this prefeasibility study it has been assumed that the industrial loads would continue to be served by privately owned power plants and are thus not included in this study. It has also been assumed that NTPC would install a state of the art diesel power plant that would generate 3.7 kWh per litre of diesel fuel. This diesel plant would produce energy at a levelized cost of $0.380 per kWh over 20 years with diesel fuel starting at $1.00 per litre ($0.467 per kWh with diesel fuel starting at $1.25 per litre). Other relevant assumptions are: variable diesel O&M expense is $0.03 per kWh (the Yukon Utilities Board accepted cost in Yukon for Yukon Energy and Yukon Electrical Company Limited); and diesel fuel inflates at 3% per year while general inflation is 2%.

Wind Power Project Costs

Developer – Operator

For the purpose of this report it was assumed that a wind project will be only large enough to displace significant electrical diesel consumption without compromising the quality of the electric grid. A larger wind project will require a more complex power and energy control system to divert the excess wind energy. This creates an opportunity to utilise the excess wind energy for space heating (and eventually, local transportation) which will add greater benefits to the community at large.This level of high contribution (high penetration) has however, not been implemented to any great extent in Canada. High penetration systems are being used in Alaska and Australia and should be considered as a future phase for this community.

For this report it is also assumed that if a wind project were to be developed in Norman Wells it would be done by a developer with some amount of wind project experience in the NWT. There is no allowance in the project cost estimates for overcoming a learning curve for inexperienced developers/operators. If a project were to be developed by an inexperienced firm the capital costs would likely be higher. In the opinion of the authors, the ideal project developer/operator would be NTPC as they already own the diesel power plant, have significant technical resources, and have experience in construction in the remote communities. As well, the integration of the wind and diesel plants (including power purchase agreement issues) would be relatively seamless.

Wind Turbines

Based on other recent work by the authors, two wind turbine models were selected for consideration in Norman Wells. These include Northern Power Systems' NorthWind 100 which has a 21 meter rotor and a 37 meter tower, and Aeronautica's 225kW (the design of the former Danish manufacturer Norwin, of which there are many in operation) which has a 29 meter rotor and a 50 meter tower. The NorthWind 100 has available an option for operation down to -40°C (included in the authors' pricing), but the Aeronautica standard very low temperature option only permits operation down to -30°C. However, based on discussions with the supplier it may be possible to extend this range at some additional cost. At this time no extra cost has been included in this study as a detailed wind energy-temperature analysis would need to be undertaken to determine whether this modification would be necessary. The advantages of the Aeronautica 225 is its 50 meter tower, which reaches up into far better wind speeds than the 37 meter NorthWind tower, and economies of scale – meaning fewer larger turbines. The Aeronautica 225 is also a lower cost turbine per unit nameplate capacity. For convenience, the NorthWind 100 is referred to as the NW100 in this report and the Aeronautica (Norwin) turbine is referred to as the A225.

The tower heights of these two wind turbines are the maximum heights available for each model. Considering the wind climate on Kee Scarp taller towers would be preferred as the wind energy available increases sharply as a function of wind speed (wind energy is proportional to the cube of the wind speed). There are larger turbines that are available on the market, for example the EWT 900 kW wind turbine is available with a 75 m tower. There is an EWT 900 kW operating in Delta Junction, Alaska which has a similar climate as Norman Wells. This size of turbine is large and more expensive to install and so would require some economy of scale by installing more than one. There is also an Enercon E53 800kW turbine that would fit this community that is to be used in a wind-diesel project in northern Quebec. This then causes the wind project to become a higher wind energy contributor to the community grid which adds more complexity that is beyond the scope of this study. A larger project utilizing larger turbines has the potential to lower wind energy costs. This also creates (and requires) an opportunity for wind energy to provide spacing heating in the community, but again, this will require more detailed analysis which is beyond the scope of this study.

Energy Production

The annual energy production from each of the two selected wind turbines is calculated using the HOMER model. HOMER was developed by the National Renewable Energy Laboratory of the US Government and is now distributed and supported by HOMER Energy (www.homerenergy.com). HOMER is a power system analysis and optimization model. The energy model uses published wind turbine power curves, diesel plant production specifications, and a one-year hourly time series measurements of both wind speed and community power load to model the energy output of various power generators.

The inputs for the HOMER model consists of the diesel generators described earlier, the wind system and the community load estimated from the average, maximum and minimum load of the community. The wind resource data used as input for the HOMER is a one-year data set based on on-site wind mast measurements at Kee Scarp projected to the ten-year (2001-2010) mean. As shown in the wind flow model results in Figure 6, the wind speed at the top of Kee Scarp are expected to be above 5 m/s at 40 m AGL for an area large enough to fit up to 10 wind generators.

The energy produced by the NW100 and A225 turbines are based on the published power curves, less 5% to adjust for a turbine availability of 95%. An additional 10% of the production is then subtracted to account for losses (turbulence losses, array losses, mechanical losses, cold and icing performance losses, transformer losses, and transmission line losses) to arrive at the net energy production available to displace diesel energy. Appendix 2 presents a table of energy production from the two different wind farm sizes using each of the two wind turbine models described. Often there is an adjustment for increased production at higher air densities due to cold temperatures which, in this case, would likely be 5% or a bit higher. However, to be conservative no air density adjustments were made in this study.

The calculations indicate that the net energy production at the annual average wind speed at the turbine hub height represents a capacity factor of about 15.0% for the NW100 and 16.9% for the A225. The A225 has a higher capacity factor largely because of its taller 50-m tower compared to the NW100 at 37 m. Net generation is the HOMER calculated ideal generation less availability and other losses (total 15% of ideal generation).

Capital Costs

The estimated capital costs for the 400/450 kW and 900 kW projects are presented in some detail in Appendix 3 and are summarized below.

1. A 400 kW project based on four NW100 turbines was estimated to cost about $4.751 million or $11,877 per kW;
2. A 450 kW project based on two A225 turbines was estimated to cost about $4.240 million or $9,423 per kW;
3. The estimate for a 900 kW project based on nine NW100s was $8.284 million or $9,205 per kW; and
4. The estimate for a 900 kW project based on four A225s was $6.686 million or $7,429 per kW.

The unit cost reduction in scaling up from a 400/450 kW project to a 900 kW project ranged from about $2,000 per kW for the A225 based projects to about $2,600 per kW for the NW100 based projects.

The most significant fixed cost items (not directly a function of project size) are the power line estimated at $900,000 (4.5 km at $200,000 per km), the mobilization and demobilization of a crane at $100,000 to $150,000, the foundation design and the associated geotechnical work at about $130,000 to $170,000, and the integration with the diesel plant/power system estimated at about $100,000 to $200,000.

A power line to the proposed wind farm area closely following the road would have to be 5.5 km long. A straight line from Kee Scarp to the nearest power line could reduce the power line distance to 3.5 km, but to be prudent a straight alignment in two segments generally following the road (one to Kee Scarp and one along Kee Scarp) to the middle of the proposed development site was chosen and the estimated 4.5km provides for power collection from the turbines. As the power line is a major cost component of any project, it would be important to examine cost reduction alternatives carefully.

The capital costs of a wind project are a major energy cost driver, so it is critical for any developer to pay considerable attention to all capital cost components. For the same reason larger projects provide economies of scale that reduce costs per unit of installed capacity and for this reason the authors chose relatively larger projects for this study.

Operating and Maintenance Costs

The annual operating and maintenance (O&M) costs were based on other recent work by the authors. For a project of about 400kW in size based on four NW100s, the O&M was estimated to be about $45,000 per year, and for a 450kW project based on two A225s was estimated to be $50,000 per year. For a 900kW project employing either nine NW100s or four A225s the annual O&M was estimated to be $95,000. This cost is based on the simple requirements to keep a project running and does not include costs that may be associated with establishing and running a corporation for the wind project only. The effective assumption is that the wind project is owned and operated by an appropriate existing organization.

The operating and maintenance cost is intended to include all overhead, insurance, lease, and tax costs as well as the actual maintenance costs. The estimated costs fall between $0.07 and $0.09 per kWh.

For the economic analysis (presented in the following subsection) the cost of capital was assumed to be 7.5%, which represents a regulated utility. Incorporated in the cost of capital is a return on equity which would be earned by the project owners and is separate and distinct from the annual operating and maintenance costs. The authors believe that funding assistance would likely be necessary to interest a wind project developer and this would increase the effective return on equity or reduce the cost of debt. A project developer would need to calculate the economics of a project based on their own circumstances.

Cost of Wind Energy and Economic Analyses

In order to compare an energy project to another we calculate the average annual or levelized cost of energy, which is the net present value of total life cycle costs of the project divided by the quantity of energy produced over the system life. The levelized cost of wind energy over a 20 year project life was calculated for each of the four project configurations and compared to the levelized cost of diesel generation over 20 years. Appendix 4 presents the economic model outputs of the levelized cost of wind energy for the four project variations. Appendix 5 presents the economic model outputs for continued diesel generation with different starting prices for diesel fuel. The variables and assumptions used in the economic model include the project capital cost, its capacity in kW, its annual diesel displacing energy production, the useful life of a project (20 years), the cost of capital (7.5%), the general inflation rate (2%), and the annual operating costs. The model calculates the levelized cost of energy over the life of the projects.

For continued diesel generation the assumptions include a variable operating and maintenance cost of \$0.03 per kWh, a plant efficiency of 3.7 kWh per litre of diesel, and diesel fuel is assumed to inflate at 3% per year while general inflation is 2% per year. As the authors were unable to obtain present diesel fuel pricing from NTPC, present fuel prices of \$1.00 per litre and \$1.25 per litre were considered. The economic model outputs for diesel generation are contained in Appendix 5.

The levelized incremental (or variable) cost of diesel energy over 20 years with diesel fuel commencing at \$1.00 per litre was calculated by the model to be \$0.380 per kWh, and for fuel starting at \$1.25 per kWh was calculated to be \$0.467 per kWh.

The 400 kW project composed of four NW100s was projected to produce a levelized cost of energy of \$0.967 per kWh over its life, and the 450 kW project composed of two A225 turbines was projected to produce energy at a levelized cost \$0.777 per kWh over its life. A 900 kW project composed of nine NW100s was projected to produce power at a levelized cost of \$0.766 per kWh over its life and a 900 kW project composed of four A225s was projected to produce energy at a levelized cost of \$0.572 per kWh over its life.

The above analyses show that electrical energy from wind power projects would be more expensive than electrical energy from diesel generation. The analyses also show two other important things. The first is that larger wind projects produce electrical energy at a far lower cost than smaller projects – economies of scale do make a big difference. In this case doubling the project size from 400-450kW to 900kW reduced the cost of electrical energy by \$0.20 per kWh for both turbine types.

The second thing is that taller wind towers can make a significant difference to the cost of electrical energy. In this project case, the A225 turbine outperforms the NW100 turbine despite having a smaller swept area per kW of capacity and a less attractive power curve than the NW100. The difference is that the NW100 has a tower height of 37 meters and harvests energy at a wind speed of 4.9m/s whereas the A225 has a tower 50 meters in height and harvests wind energy at a wind speed of 5.5m/s. Since the energy in wind is proportional to the cube of the wind speed, this makes big difference, and reduces the cost of wind energy by about \$0.20 per kWh.

In order to make wind energy economic, one of two things must happen (or a combination of the two could happen). The first is that the cost of diesel fuel would need to increase to about $1.60 per litre (and still inflate at 3% per year relative to inflation at 2% per year) in which case the 20 year levelized of energy would be about $0.58 per kWh – just over the cost of energy from a 900kW wind project with four Aeronautica turbines.

The second thing that could happen is that the Canadian Wind Energy Association's (CanWEA) proposed Northern and Remote Community Wind Incentive Program (NoRWIP) could be adopted by the federal government. The proposed program would subsidize the project cost by 30% to a maximum of $4,000 per kW of installed capacity. This would reduce the levelized cost of energy from the 900kW A225 project to about $0.426 per kWh – comparable to diesel-generated electrical energy with fuel prices somewhere between $1.00 and $1.25 per litre. Applying NoRWIP to the 900kW project composed of nine NW100 turbines would reduce the levelized cost of energy to about $0.565 per kWh – still above the cost of diesel fuel starting at $1.25 per litre. Appendix 6 provides the economic model outputs of these two cases.

Table 3 below summarizes the economic model outputs for Norman Wells.

Table 3: 20 year levelized cost of energy for wind projects and continued diesel generation.

Project Configuration	20 year levelized cost of energy ($ per kWh)	
	Without subsidies	With NoRWIP subsidy
Four NW 100s (400kW)	$0.967	
TwoA225s (450kW)	$0.777	
NineNW 100s (900kW)	$0.766	$0.565
Four A225s (900kW)	$0.572	$0.426
Diesel generation, $1.00/L	$0.380	
Diesel generation, $1.25/L	$0.467	

Greenhouse Gas Reductions

Table 4 outlines the diesel fuel and greenhouse gas (GHG) reductions that would be achieved by the four project configurations examined in this report. The calculations are based on a diesel plant efficiency of 3.7 kWh per litre, and GHG emissions of 3.0 kg carbon dioxide (CO_2) equivalent per litre of diesel fuel consumed.

If natural gas were being displaced, the GHG reductions would be reduced to about 63.4% those of the diesel GHG reductions, based on the Inuvik plant efficiency of 3.399 kWh per cubic meter of gas and CO_2 equivalent of 1.9 kg per cubic meter consumed.

Table 4: Annual GHG reductions from modelled wind projects.

Project Configuration	Diesel Electricity Displaced (kWh)	Diesel Fuel Saved (L)	GHG Reductions (kg CO_2 equivalent)
Four NW100s	525,129	141,927	425,780
TwoA225s	666,537	180,145	540,435
Nine NW100s	1,181,539	319,335	958,005
Four A225s	1,315,409	355,516	1,066,548

Conclusions

1. Kee Scarp has potential as a wind development site. It is within 5 km of the community and has road access via a 6-km of all-weather road and 4X4/ATV trails.
2. Based on two years of site monitoring correlated to local airport and local weather balloon data as well as on site wind monitoring over two years, the long term annual average wind speed at 37m AGL at Kee Scarp is calculated to be 4.9 m/s and at 50m AGL is calculated to be 5.5 m/s.
3. The present NTPC diesel plant serves as a back-up plant as more than 99% of the approximate 10,000 MWh annual load (residential, general service, and streetlights) is served by gas generated power purchased from Imperial Oil's 13 MW gas power plant (at a price tied to diesel fuel cost). The gas power plant also serves an industrial load. The peak NTPC load is 1.700 MW, the average load is 1.124 MW (65.1% load factor) and the minimum load is estimated by the authors to be about 600 kW.
4. The available information indicates that the gas supply is limited and may be running low, while the population and NTPC power loads are forecasted to grow. The 2007/8 NTPC actual load information was used in this study. This project did not consider NTPC's power load growth beyond this or industrial loads in the calculations.
5. Costs for 400 kW (four NW100s) and the 450 kW (two A225s) wind projects were estimated to be about $4.751 million ($11,877 per kW) and $4.240 million ($9,423 per kW), respectively. The costs for the 900 kW projects were estimated to be $8.284 million or $9,205 per kW (nine NW100s), and $6.686 million or $7,429 per kW (four A225s).
6. Projects of 400/450 kW would produce power at a cost of $0.967per kWh (400 kW with four NW100s) and $0.777 per kWh (450kW with two A225s). The 900kW project with nine NW100s would produce power at $0.766 per kWh and the 900kW project of four A225s would produce power at $0.572 per kWh. No subsidies were assumed in these calculations.
7. Both wind project size and tower height are very important factors in the cost of wind energy with larger projects and taller turbine towers resulting in lower costs for wind energy.

8. Diesel generation over twenty years would have a levelized cost of $0.380 per kWh with diesel fuel starting at $1.00 per litre and $0.467 per kWh with diesel fuel starting at $1.25 per litre.
9. The proposed NoRWIP subsidies of up to 30% of capital cost or to a maximum of $4,000 per kW installed would reduce the energy costs from a 900kW project to $0.426 per kWh if A225 turbines are used and to $0.565 per kWh if NW 100 turbines are used. A 900kW A225 wind project would thus be competitive with diesel generation when diesel fuel is between $1.00 and $1.25 per litre.
10. Diesel generation with fuel costing about $1.60 per litre would cost about the same as an unsubsidized 900 kW wind project using A225 turbines.
11. GHG reductions on an annual basis would range from over 425 tonnes per year to over 540 tonnes of CO_2 equivalent for the 400/450kW wind project and over 958 tonnes to over 1,066 tonnes of CO_2 equivalent per year for the 900kW wind project.

Next Steps

1. A preliminary review of the land tenure at Kee Scarp should take place to confirm if the site could be available for development.
2. Discussions should be initiated with Imperial Oil and NTPC to determine with greater certainty the situation with respect to gas availability and future power loads.
3. Seek out funding that may be available from Indian and North Affairs to carry out more detailed studies and to seek permitting that will advance this potential wind project. Funding may also be available from the GNWT to aid the feasibility work.
4. If the CanWEA's NoRWIP proposal is adopted by the federal government, a 900kW or larger wind farm may become economic. A detailed feasibility study should be carried out if this transpires and if there is a desire to do a wind project in Norman Wells. Particular attention would be required to minimize the capital costs of such a project and to find the most appropriate size wind turbines with towers as tall as possible.

Reference

Pinard, J.P., and J.F. Maissan, 2008. Norman Wells Wind Energy Pre-feasibility Report. Prepared for the Aurora Research Institute, Inuvik, NT.

Pinard, J.P., 2010. Progress Report on the Norman Wells Wind Monitoring.Prepared for the Aurora Research Institute, Inuvik, NT.

Appendix 1

NORTHWEST TERRITORIES
POWER
CORPORATION

Department of Finance, 4 Capital Drive, Hay River, NT X0E 1G2; Phone (867) 874-5200 Fax (867) 874-5251

November 24, 2006

John Hill, Chair
Northwest Territories Public Utilities Board
203-62 Woodland Drive
Box 4211
Hay River, NT

Dear Mr. Hill,

Enclosed are seven copies of Northwest Territories Power Corporation's ("NTPC's") 2006/07 and 2007/08 Phase I General Rate Application and supporting materials ("Phase I Application"). The Phase I Application sets out the forecast costs to supply customers for the two test years, the revenues that are forecast to arise at existing rates, and a consequent shortfall requiring changes to rates.

The Phase I Application addresses company-wide costs, revenues and investments required to determine the NTPC overall revenue requirement. Also included in the Phase I Application is the NTPC's response to various directives of the Northwest Territories Public Utilities Board ("PUB" or "Board") related to revenue requirement matters.

Community-specific revenue requirements and resulting final rate proposals will be addressed as part of NTPC's Phase II Application. In addition, the Phase II Application is expected to address three remaining Board directives from the 2001/03 GRA[1].

[1] Board Directive 10 from Decision 3-2003 regarding time of use rates, Directive 2 from Decision 7-2003 regarding legacy assets in cost-of-service and Directive 3 from Decision 7-2003 regarding cost-of-service for Rae/Edzo (now Behchoko) and Dettah are all properly cost-of-service or rate design topics and are more properly suited to a Phase II filing.

1.2 CHALLENGES AND OPPORTUNITIES FACING THE CORPORATION

It has been 4 years since the last NTPC General Rate Application test year in 2002/03. In the intervening years, NTPC's has faced challenges associated with cost pressures associated from normal ongoing inflation of typically about 2-3% per year[1]. On top of these normal cost pressures, NTPC and its customers are dealing with challenging times with respect to the costs and/or availability of resources to operate, maintain and invest in the company, notably:

Diesel Fuel: prices have increased dramatically, as high as 75% in some communities. This is causing major rate pressures in communities that rely on diesel for their generation. This concern extends primarily to communities that are either served entirely by diesel, or served by other power sources priced based on an index to diesel fuel (Norman Wells, Inuvik). These fuel price increases are currently being recovered from customers by way of fuel riders[2]. Although NTPC has pursued efforts to reduce fuel costs in the thermal communities, most notably by installation of a third gas engine in Inuvik, there are practical limits to the ability to reduce or curb consumption in these communities. This Application seeks approval to incorporate new current day fuel prices into base electrical rates.

[1] In the four years since the last GRA, the CPI for Yellowknife has been 2.9%, 2.4%, 1.4% and 2.3% respectively. The Yellowknife CPI reflects higher percentage increases for costs related to transportation than for most other goods and services. As a result it is expected that the price index increases reflective of the more remote NWT communities (which are not measured by Statistics Canada) is considerably higher. Also, wage inflation in the north has been notably in excess of simple CPI in the last few years.

[2] At the time of filing, NTPC has fuel riders in place to address balances in the Diesel Communities Diesel Stabilization Fund, the Inuvik Fuel Stabilization Fund, the Norman Wells Fuel Stabilization Fund and the Taltson Fuel Stabilization Fund.

Generation

Total forecast generation for 2006/07 compared to 2002/03 Negotiated Settlement levels is shown in Table 2.4.

TABLE 2.4

SYSTEM GENERATION - 2002/03 NEGOTIATED SETTLEMENT COMPARED TO 2006/07

	2002/2003 Negotiated Settlement	% of Total	2006/2007 Forecast	% of Total	Average Annual Growth
Total Generation (MWh)	349,943		339,440		-0.76%
Generation By Source					
Hydro (MWh)	239,436	68%	256,200	75%	1.71%
Diesel (MWh)	77,212	22%	45,284	13%	-12.49%
Gas (MWh)	25,966	7%	29,397	9%	3.15%
Purchased (MWh)	7,350	2%	8,559	3%	3.88%

The Corporation's forecast generation mix has changed markedly since the negotiated settlement. Hydro generation is forecast to increase from 68% to 75% of total generation, reflecting the acquisition of the Bluefish Hydro Generating Station. Gas Generation is also forecast to increase, reflecting the addition of the third gas engine in Inuvik. Diesel production is forecast to decline in absolute terms by over 40%, and as a percentage of total generation from 22% to 13%. This forecast decrease results primarily from the dual impact of the addition of Bluefish to the Snare system concurrent with overall load reductions on that system.

Taltson, Snare-Yellowknife and Diesel communities). The funds have been routinely reviewed by the PUB and intervenors since they were first put in place in the 1995/98 GRA.

At this time, NTPC is proposing no material changes to the various stabilization funds compared to how they have operated in recent years. A number of modest changes are required to reflect the proposals in this GRA, as follows:

- For the Snare-Yellowknife Water Stabilization Fund, a long-term average hydro generation of 220 GW.h per year, consistent with the addition of Bluefish to the fund (Bluefish as 42.5 GW.h per year and the remaining Snare at 177.5 GW.h per year).
- For the Taltson Water Stabilization Fund, an active fund without a specific long-term average water value required, as the system is well below the level of hydro generation possible from the Taltson system so the long-term average generation value is not relevant to the calculations.
- For the Norman Wells Stabilization Fund – The Town of Norman Wells relies on Natural Gas from Imperial Oil for electricity (through NTPC) and heating purposes. Future availability of natural gas for the Town's heating purposes is in decline. In order to free up the available natural gas for the Town's heating requirements, the Town has requested NTPC to operate the local standby diesel plant for periods during the winter of 2006/07 for electrical purposes in lieu of purchasing electricity from Imperial Oil. NTPC and the Town of Norman Wells

acknowledge that while the Corporation will save the purchased price of power from Imperial Oil under the current Purchase Power Agreement, NTPC will incur diesel fuel costs in operating the diesel plant to serve the Town's load. As a result, the Town and NTPC are in discussions related to an agreement that these diesel costs will form part of the costs attributable to the Norman Wells Fuel Stabilization Fund, by incorporating the diesel costs into the calculation of recoverable/refundable costs by rider for the Norman Wells Fuel Stabilization Fund.

- For the various Fuel Stabilization Funds, updated efficiencies and fuel prices as reflected in this GRA.

The methods for determining collection of Stabilization Fund balances are related to the topic of rate design. As such, to the extent the procedures for determining fund balances are required to be updated, NTPC will address those changes at the time of its Phase II GRA filing.

Schedule A.16

Northwest Territories Power Corporation
2006/07 - 2007/08 General Rate Application
Summary of Generation, Sales, and Revenue
304 Norman Wells

Line no.	Description	2002/03 Negotiated Settlement	2004/05 Actual	2005/06 Actual	2006/07 Forecast @ Existing Rates	2007/08 Forecast @ Existing Rates
	SALES AND REVENUE					
	Residential					
1	Sales (MWh)	2,546	2,839	2,779	2,875	2,952
2	Customers	377	362	365	370	376
3	Av. MWh Sales/Cust.	6.76	7.84	7.61	7.77	7.86
4	Revenue (000s)	867	955	937	967	992
5	Cents /kWh	34.04	33.63	33.70	33.62	33.59
	General Service					
6	Sales (MWh)	3,978	4,646	4,715	4,849	5,043
7	Customers	114	136	144	147	148
8	Av. MWh Sales/Cust.	34.84	34.16	32.74	33.03	34.17
9	Revenue (000s)	1214	1,399	1,479	1,467	1,518
10	Cents /kWh	30.52	30.12	31.36	30.25	30.11
	Wholesale					
11	Sales (MWh)					
12	Customers					
13	Revenue (000s)					
14	Cents /kWh					
	Industrial					
15	Sales (MWh)					
16	Customers					
17	Av. MWh Sales/Cust.					
18	Revenue (000s)					
19	Cents /kWh					
	Streetlights					
20	Sales (MWh)	159	146	146	131	114
21	Revenue (000s)	57	52	52	52	52
22	Cents /kWh	36.17	35.82	35.84	39.75	45.55
	Total Community					
23	**Sales (MWh)**	**6,683**	**7,632**	**7,640**	**7,855**	**8,110**
24	Customers	**491**	**498**	**509**	**517**	**523**
25	Revenue (000s)	**2138**	**2,407**	**2,468**	**2,485**	**2,562**
26	Cents /kWh	31.99	31.53	32.30	31.64	31.59
	GENERATION (MWh)					
27	**Total Station Service**	152	67	101	101	101
28	**Total Losses**	515	1,256	1,232	1,121	1,157
29	***Losses - % of Gen.***	*7.0%*	*14.0%*	*13.7%*	*12.4%*	*12.4%*
30	**Total Generation**	**7,350**	**8,955**	**8,973**	**9,077**	**9,368**
	Source (MWh)					
31	Hydro Generation					
32	Gas Generation					
33	Gas Efficiency					
34	*Cubic Meters (000s)*					
35	Diesel Generation		63	407	518	63
36	Diesel Efficiency		3.277	3.506	3.414	3.414
37	*Liters (000s)*	*10*	*19*	*116*	*152*	*18*
38	Purchased Power	7,350	8,892	8,566	8,559	9,305
39	Total Generation	7,350	8,955	8,973	9,077	9,368
	% of Total Generation					
40	Hydro					
41	Gas					
42	Diesel		*0.7%*	*4.5%*	*5.7%*	*0.7%*
43	Purchased	*100.0%*	*99.3%*	*95.5%*	*94.3%*	*99.3%*
	Peak (kW)					
44	Total Peak	1,548	1,580	1,580	1,512	1,643
45	Load Factor	54.2%	64.7%	64.8%	68.6%	65.1%

NORTHWEST TERRITORIES POWER CORPORATION — Schedule 3.3.2

2007/08 FORECAST PRODUCTION FUEL COST

Line No.	Plant No.		Generation (kWh)	Plant Efficiency (kWh/L)	Fuel Required (Litres)	Fuel Price ($/L)	Fuel Cost ($000's)
1	101	Yellowknife	1,379,000	3.500	394,000	0.755	297
2	104	Wha Ti	1,730,422	3.711	466,256	0.897	418
3	105	Gameti	975,320	3.398	287,008	0.927	266
4	108	Behchoko	21,125	3.250	6,500	0.778	5
5	110	Lutsel K'e	1,637,723	3.778	433,468	0.896	388
6	201	Fort Smith	465,700	3.277	142,102	0.793	113
7	203	Fort Resolution	60,000	3.459	17,345	0.860	15
8	205	Fort Simpson	8,238,565	3.755	2,193,767	0.862	1,890
9	206	Fort Liard	2,719,334	3.725	730,105	0.877	641
10	207	Wrigley	667,892	3.525	189,491	0.885	168
11	208	Nahanni Butte	372,594	2.511	148,360	0.877	130
12	209	Jean Marie River	339,598	2.749	123,547	0.858	106
13	301	Inuvik Power - D	1,675,500	3.635	460,935	0.797	367
14	304	Norman Wells - D	63,000	3.414	18,451	0.841	16
15	305	Tuktoyaktuk	4,584,515	3.697	1,240,016	1.001	1,241
16	306	Fort McPherson	3,422,267	3.609	948,301	0.926	878
17	307	Aklavik	2,776,285	3.475	798,914	0.914	730
18	308	Deline	2,658,924	3.546	749,826	1.015	761
19	309	Fort Good Hope	2,874,492	3.576	803,823	1.001	804
20	310	Tulita	2,200,488	3.634	605,551	0.905	548
21	311	Paulatuk	1,350,941	3.492	386,914	1.090	422
22	312	Sachs Harbour	907,022	3.189	284,401	1.075	306
23	313	Tsiigehtchic	864,359	3.537	244,353	0.985	241
24	314	Colville Lake	338,554	2.957	114,488	1.133	130
25	315	Ulukhaktok	1,986,962	3.616	549,489	1.111	610
26	**Subtotal - Diesel**		**44,310,582**	**3.603**	**12,337,411**	**0.931**	**11,491**

NATURAL GAS

Line No.	Plant No.		Generation (kWh)	Plant Efficiency (kWh/L)	Fuel Required (m^3)	Fuel Price (m^3)	Fuel Cost ($000's)
27	301	Inuvik	29,773,906	3.399	8,758,336	0.430	3,769
28	**Subtotal - Natural Gas**		**29,773,906**		**8,758,336**		**3,769**

PURCHASED POWER

Line No.	Plant No.		Generation (kWh)	Price ($/kWh)	Cost ($000's)
29	304	Norman Wells	9,305,234	0.279	2,593
30	**Subtotal - Purch. Power**		**9,305,234**	**0.279**	**2,593**

Northwest Territories Power Corporation
Summary of Generation, Sales, and Revenue
2006/07 and 2007/08
Norman Wells

Description	2006/07 Actual	2007/08 Actual
SALES AND REVENUE		
Residential		
Sales (MWh)	2,914	2,972
Customers	374	384
Average MWh Sales/Customer	7.79	7.74
Revenue (000s)	980	1,052
General Service		
Sales (MWh)	5,689	5,690
Customers	149	147
Average MWh Sales/Customer	38.18	38.71
Revenue (000s)	1,695	2,002
Streetlights		
Sales (MWh)	154	107
Revenue (000s)	50	52
Total Community		
Sales (MWh)	8,757	8,769
Customers	523	531
Revenue (000s)	2,675	3,106
GENERATION		
Source (MWh)		
Hydro		
Gas		
Cubic Metres (000s)		
Diesel	362	127
Purchased Power	9,365	9,556
Total Generation	9,727	9,683
% of Total Generation		
Hydro		
Diesel	4%	1%
Purchased	96%	99%

Appendix 2

Norman Wells diesel displacing wind energy based on HOMER modelling

Norman Wells wind project calculation of net diesel displaced from HOMER model output

Minimum diesel plant load 216 kW (30% of 720 kW smallest generator), wind speed 4.9 m/s @ 37m AGL and 5.5 m/s @ 50m AGL

		Losses from generation				Reductions in surplus			
Project configuration	HOMER generation kWh	Availability 95%	Electrical & other 10%	Net generation	HOMER surplus energy kWh	Availability	Electrical & other losses	Net surplus	Diesel displaced kWh
4 NorthWind 100	617,799	30,890	61,780	525,129	216	0	216	0	525,129
2 Aeronautica 225	784,161	39,208	78,416	666,537	400	0	400	0	666,537
9 NorthWind 100	1,390,046	69,502	139,005	1,181,539	43,656	17,376	26,280	0	1,181,539
4 Aeronautica 225	1,568,322	78,416	156,832	1,333,074	68,635	19,604	31,366	17,665	1,315,409

Assumptions in reductions of surplus		
For 4 Northwind 100s	1	The very small amount of surplus energy would be consumed by electrical & other losses
For 2 Aeronautica 225s	1	The very small amount of surplus energy would be consumed by electrical & other losses
For 9 Northwind 100s	1	Non-coincident downtime reduces surplus to 25% of indicated value
	2	One fifth of losses are systematic like electrical that occur during high output reducing surplus differentially
For 4 Aeronautica 225s	1	Non-coincident downtime reduces surplus to 25% of indicated value
	2	One fifth of losses are systematic like electrical that occur during high output reducing surplus differentially

Appendix 3

Norman Wells wind project capital costs

Norman Wells Project Capital Costs

Project location: Kee Scarp

Cost category	low penetration 4 NW100 turbines	low penetration 2 A225 turbines	medium penetration 9 NW100 turbines	medium penetration 4 A225 turbines
Project Design & Mgmt				
project design	$50,000	$50,000	$75,000	$75,000
environmental assessment & permitting	$25,000	$25,000	$35,000	$35,000
project management	$50,000	$50,000	$75,000	$75,000
Site Preparation				
road construction ($150,000/km) 10 rotor dia/turbine	$13,000	$9,000	$29,000	$18,000
road upgrading ($50,000 per km), 1.5 km	$75,000	$75,000	$75,000	$75,000
site and crane pad construction $15,000/turbine	$60,000	$30,000	$135,000	$60,000
powerline construction ($200,000 per km), 4.5km	$900,000	$900,000	$900,000	$900,000
turbine power collection ($400/m) 10 rotor dia/turbine	$34,000	$24,000	$76,000	$48,000
Wind Equipment Purchase				
wind turbines + towers+ SCADA	$1,436,000	$1,218,000	$3,060,000	$2,316,000
shipping to Hay River	$170,000	$170,000	$370,000	$330,000
shipping Hay River to Norman Wells	$58,000	$56,000	$128,000	$108,000
transformers	$75,000	$75,000	$125,000	$125,000
Installation				
geotehnical $60,000 first + $10k/turbine max +30k	$90,000	$70,000	$90,000	$90,000
foundation design $50,000 first + $10k/turbine max +30k	$80,000	$60,000	$80,000	$80,000
foundation installation	$400,000	$250,000	$900,000	$500,000
crane mob & demob	$100,000	$150,000	$100,000	$150,000
crane on site	$40,000	$30,000	$90,000	$60,000
equipment rental	$40,000	$40,000	$60,000	$60,000
control buildings	$25,000	$25,000	$25,000	$25,000
utility interconnection	$50,000	$50,000	$75,000	$75,000
commissioning	$80,000	$40,000	$205,000	$105,000
labour - assembly & supervision	$110,000	$100,000	$235,000	$180,000
travel and accommodation	$50,000	$50,000	$75,000	$75,000
Diesel Plant Modifications				
high speed comm. & controller	$50,000	$50,000	$50,000	$50,000
dump load			$50,000	$50,000
plant modifications	$50,000	$50,000	$100,000	$100,000
Other				
initial spare parts	$10,000	$10,000	$20,000	$20,000
Insurance	$25,000	$25,000	$50,000	$50,000
other overhead costs (contracts etc)	$50,000	$50,000	$75,000	$75,000
SUBTOTAL CONSTRUCTION	**$4,196,000**	**$3,732,000**	**$7,363,000**	**$5,910,000**
Contingency 10%	**$419,600**	**$373,200**	**$736,300**	**$591,000**
TOTAL CONSTRUCTION	**$4,615,600**	**$4,105,200**	**$8,099,300**	**$6,501,000**
Owners Costs				
manage project organization	$50,000	$50,000	$75,000	$75,000
negotiate agreements	$50,000	$50,000	$75,000	$75,000
staff training	$35,000	$35,000	$35,000	$35,000
TOTAL OWNERS' COSTS	**$135,000**	**$135,000**	**$185,000**	**$185,000**
TOTAL PROJECT COST	**$4,750,600**	**$4,240,200**	**$8,284,300**	**$6,686,000**
Installed capacity kW	400	450	900	900
Installed cost per kW	**$11,877**	**$9,423**	**$9,205**	**$7,429**
Annual O&M costs	$45,000	$50,000	$95,000	$95,000
NW100 base cost CDN$377,000 each	5% discount for 4	$359,000	rounded up to next 000	
	10% discount for 9	$340,000		
Aeronautica 225 base cost CDN$609,000 each	no discount for 2	$609,000	rounded up to next 000	
	5% discount for 4	$579,000		
Shipping to Hay River	NW100 $50,000 first, $40,000 each subsequent			
	A225 $90,000 first, $80,000 each subsequent			
Shipping Hay River to Norman Wells	NW100 $16,000 first, $14,000 each subsequent			
estimates based on 2010 NTCL rates & repacking	A225 $30,000 first, $26,000 each subsequent			

Appendix 4

Norman Wells 400kW wind project of four Northwind 100 turbines

Leading Edge Projects Generation LCOE Economic Model

Project: Norman Wells 4 NorthWind 100 wind turbines

Capital cost	$4,750,600		Capacity	400	kW	Fixed O&M	$45,000	per year	Discount rate	5.39%	
Cost of capital	7.50%	Debt & equity	Annual Energy	525,129	kWh	Variable O&M		per kWh			
Inflation	2.00%	per year	Project life	20	Years	Capacity factor					

Year	Capital	Cost of Cap	Depreciation	Fixed O&M	Variable O&M	Total Ann cost	Ann energy	Cost per kWh	Discounted cost	Discounted energy	Discounted cost per kWh
1	$4,750,600	$356,295	$237,530	$45,000	$0	$638,825	525,129	$1.217	$638,825	525,129	$1.217
2	$4,513,070	$338,480	$237,530	$45,900	$0	$621,910	525,129	$1.184	$590,092	498,262	$1.184
3	$4,275,540	$320,666	$237,530	$46,818	$0	$605,014	525,129	$1.152	$544,689	472,769	$1.152
4	$4,038,010	$302,851	$237,530	$47,754	$0	$588,135	525,129	$1.120	$502,403	448,581	$1.120
5	$3,800,480	$285,036	$237,530	$48,709	$0	$571,275	525,129	$1.088	$463,033	425,631	$1.088
6	$3,562,950	$267,221	$237,530	$49,684	$0	$554,435	525,129	$1.056	$426,392	403,854	$1.056
7	$3,325,420	$249,407	$237,530	$50,677	$0	$537,614	525,129	$1.024	$392,302	383,192	$1.024
8	$3,087,890	$231,592	$237,530	$51,691	$0	$520,813	525,129	$0.992	$360,598	363,587	$0.992
9	$2,850,360	$213,777	$237,530	$52,725	$0	$504,032	525,129	$0.960	$331,125	344,985	$0.960
10	$2,612,830	$195,962	$237,530	$53,779	$0	$487,271	525,129	$0.928	$303,736	327,334	$0.928
11	$2,375,300	$178,148	$237,530	$54,855	$0	$470,532	525,129	$0.896	$278,296	310,587	$0.896
12	$2,137,770	$160,333	$237,530	$55,952	$0	$453,815	525,129	$0.864	$254,676	294,696	$0.864
13	$1,900,240	$142,518	$237,530	$57,071	$0	$437,119	525,129	$0.832	$232,756	279,619	$0.832
14	$1,662,710	$124,703	$237,530	$58,212	$0	$420,446	525,129	$0.801	$212,423	265,313	$0.801
15	$1,425,180	$106,889	$237,530	$59,377	$0	$403,795	525,129	$0.769	$193,573	251,739	$0.769
16	$1,187,650	$89,074	$237,530	$60,564	$0	$387,168	525,129	$0.737	$176,106	238,859	$0.737
17	$950,120	$71,259	$237,530	$61,775	$0	$370,564	525,129	$0.706	$159,930	226,638	$0.706
18	$712,590	$53,444	$237,530	$63,011	$0	$353,985	525,129	$0.674	$144,959	215,043	$0.674
19	$475,060	$35,630	$237,530	$64,271	$0	$337,431	525,129	$0.643	$131,110	204,041	$0.643
20	$237,530	$17,815	$237,530	$65,557	$0	$320,901	525,129	$0.611	$118,308	193,601	$0.611
									$6,455,331	6,673,459	$0.967
Real levelized cost of energy					**$0.967**						

Appendix A

Norman Wells 450kW wind project of 2 Aeronautica 225 turbines

Leading Edge Projects Generation LCOE Economic Model

Project: Norman Wells 2 Aeronautica 225 wind turbines with 50 meter towers

Capital cost	$4,240,200		Capacity	450	kW	Fixed O&M	$95,000	per year	Discount rate	5.39%	
Cost of capital	7.50%	Debt & equity	Annual Energy	666,537	kWh	Variable O&M		per kWh			
Inflation	2.00%	per year	Project life	20	Years	Capacity factor					

Year	Capital	Cost of Cap	Depreciation	Fixed O&M	Variable O&M	Total Ann cost	Ann energy	Cost per kWh	Discounted cost	Discounted energy	Discounted cost per kWh
1	$4,240,200	$318,015	$212,010	$95,000	$0	$625,025	666,537	$0.938	$625,025	666,537	$0.938
2	$4,028,190	$302,114	$212,010	$96,900	$0	$611,024	666,537	$0.917	$579,763	632,435	$0.917
3	$3,816,180	$286,214	$212,010	$98,838	$0	$597,062	666,537	$0.896	$537,530	600,078	$0.896
4	$3,604,170	$270,313	$212,010	$100,815	$0	$583,138	666,537	$0.875	$498,134	569,376	$0.875
5	$3,392,160	$254,412	$212,010	$102,831	$0	$569,253	666,537	$0.854	$461,394	540,245	$0.854
6	$3,180,150	$238,511	$212,010	$104,888	$0	$555,409	666,537	$0.833	$427,141	512,605	$0.833
7	$2,968,140	$222,611	$212,010	$106,985	$0	$541,606	666,537	$0.813	$395,215	486,379	$0.813
8	$2,756,130	$206,710	$212,010	$109,125	$0	$527,845	666,537	$0.792	$365,467	461,494	$0.792
9	$2,544,120	$190,809	$212,010	$111,308	$0	$514,127	666,537	$0.771	$337,757	437,883	$0.771
10	$2,332,110	$174,908	$212,010	$113,534	$0	$500,452	666,537	$0.751	$311,952	415,480	$0.751
11	$2,120,100	$159,008	$212,010	$115,804	$0	$486,822	666,537	$0.730	$287,930	394,222	$0.730
12	$1,908,090	$143,107	$212,010	$118,121	$0	$473,237	666,537	$0.710	$265,575	374,053	$0.710
13	$1,696,080	$127,206	$212,010	$120,483	$0	$459,699	666,537	$0.690	$244,779	354,915	$0.690
14	$1,484,070	$111,305	$212,010	$122,893	$0	$446,208	666,537	$0.669	$225,439	336,757	$0.669
15	$1,272,060	$95,405	$212,010	$125,350	$0	$432,765	666,537	$0.649	$207,461	319,527	$0.649
16	$1,060,050	$79,504	$212,010	$127,857	$0	$419,371	666,537	$0.629	$190,754	303,180	$0.629
17	$848,040	$63,603	$212,010	$130,415	$0	$406,028	666,537	$0.609	$175,236	287,668	$0.609
18	$636,030	$47,702	$212,010	$133,023	$0	$392,735	666,537	$0.589	$160,827	272,950	$0.589
19	$424,020	$31,802	$212,010	$135,683	$0	$379,495	666,537	$0.569	$147,454	258,985	$0.569
20	$212,010	$15,901	$212,010	$138,397	$0	$366,308	666,537	$0.550	$135,048	245,735	$0.550
									$6,579,881	8,470,505	$0.777
Real levelized cost of energy					**$0.777**						

Appendix 4

Norman Wells 900kW wind project of 9 Northwind 100 turbines

Leading Edge Projects Generation LCOE Economic Model

Project: Norman Wells 9 Northwind 100 wind turbines

Capital cost	$8,284,300		Capacity	900	kW	Fixed O&M	$95,000	per year	Discount rate	5.39%	
Cost of capital	7.50%	Debt & equity	Annual Energy	1,181,539	kWh	Variable O&M		per kWh			
Inflation	2.00%	per year	Project life	20	Years	Capacity factor					

Year	Capital	Cost of Cap	Depreciation	Fixed O&M	Variable O&M	Total Ann cost	Ann energy	Cost per kWh	Discounted cost	Discounted energy	Discounted cost per kWh
1	$8,284,300	$621,323	$414,215	$95,000	$0	$1,130,538	1,181,539	$0.957	$1,130,538	1,181,539	$0.957
2	$7,870,085	$590,256	$414,215	$96,900	$0	$1,101,371	1,181,539	$0.932	$1,045,022	1,121,088	$0.932
3	$7,455,870	$559,190	$414,215	$98,838	$0	$1,072,243	1,181,539	$0.907	$965,332	1,063,730	$0.907
4	$7,041,655	$528,124	$414,215	$100,815	$0	$1,043,154	1,181,539	$0.883	$891,094	1,009,307	$0.883
5	$6,627,440	$497,058	$414,215	$102,831	$0	$1,014,104	1,181,539	$0.858	$821,957	957,668	$0.858
6	$6,213,225	$465,992	$414,215	$104,888	$0	$985,095	1,181,539	$0.834	$757,594	908,671	$0.834
7	$5,799,010	$434,926	$414,215	$106,985	$0	$956,126	1,181,539	$0.809	$697,695	862,181	$0.809
8	$5,384,795	$403,860	$414,215	$109,125	$0	$927,200	1,181,539	$0.785	$641,971	818,069	$0.785
9	$4,970,580	$372,794	$414,215	$111,308	$0	$898,316	1,181,539	$0.760	$590,151	776,214	$0.760
10	$4,556,365	$341,727	$414,215	$113,534	$0	$869,476	1,181,539	$0.736	$541,980	736,501	$0.736
11	$4,142,150	$310,661	$414,215	$115,804	$0	$840,681	1,181,539	$0.712	$497,220	698,820	$0.712
12	$3,727,935	$279,595	$414,215	$118,121	$0	$811,931	1,181,539	$0.687	$455,646	663,066	$0.687
13	$3,313,720	$248,529	$414,215	$120,483	$0	$783,227	1,181,539	$0.663	$417,050	629,142	$0.663
14	$2,899,505	$217,463	$414,215	$122,893	$0	$754,571	1,181,539	$0.639	$381,234	596,953	$0.639
15	$2,485,290	$186,397	$414,215	$125,350	$0	$725,962	1,181,539	$0.614	$348,015	566,411	$0.614
16	$2,071,075	$155,331	$414,215	$127,857	$0	$697,403	1,181,539	$0.590	$317,219	537,432	$0.590
17	$1,656,860	$124,265	$414,215	$130,415	$0	$668,894	1,181,539	$0.566	$288,685	509,936	$0.566
18	$1,242,645	$93,198	$414,215	$133,023	$0	$640,436	1,181,539	$0.542	$262,262	483,846	$0.542
19	$828,430	$62,132	$414,215	$135,683	$0	$612,031	1,181,539	$0.518	$237,807	459,091	$0.518
20	$414,215	$31,066	$414,215	$138,397	$0	$583,678	1,181,539	$0.494	$215,187	435,603	$0.494
									$11,503,658	15,015,268	$0.766
Real levelized cost of energy					**$0.766**						

Appendix 4

Norman Wells 900kW wind project of 4 Aeronautica 225 turbines

Leading Edge Projects Generation LCOE Economic Model

Project: Norman Wells 4 Aeronautica 225 wind turbines with 50 meter towers

Capital cost	$6,686,000		Capacity	900	kW	Fixed O&M	$95,000	per year	Discount rate	5.39%	
Cost of capital	7.50%	Debt & equity	Annual Energy	1,315,409	kWh	Variable O&M		per kWh			
Inflation	2.00%	per year	Project life	20	Years	Capacity factor					
Year	**Capital**	**Cost of Cap**	**Depreciation**	**Fixed O&M**	**Variable O&M**	**Total Ann cost**	**Ann energy**	**Cost per kWh**	**Discounted cost**	**Discounted energy**	**Discounted cost per kWh**
1	$6,686,000	$501,450	$334,300	$95,000	$0	$930,750	1,315,409	$0.708	$930,750	1,315,409	$0.708
2	$6,351,700	$476,378	$334,300	$96,900	$0	$907,578	1,315,409	$0.690	$861,143	1,248,109	$0.690
3	$6,017,400	$451,305	$334,300	$98,838	$0	$884,443	1,315,409	$0.672	$796,257	1,184,252	$0.672
4	$5,683,100	$426,233	$334,300	$100,815	$0	$861,347	1,315,409	$0.655	$735,789	1,123,663	$0.655
5	$5,348,800	$401,160	$334,300	$102,831	$0	$838,291	1,315,409	$0.637	$679,457	1,066,173	$0.637
6	$5,014,500	$376,088	$334,300	$104,888	$0	$815,275	1,315,409	$0.620	$626,993	1,011,625	$0.620
7	$4,680,200	$351,015	$334,300	$106,985	$0	$792,300	1,315,409	$0.602	$578,149	959,867	$0.602
8	$4,345,900	$325,943	$334,300	$109,125	$0	$769,368	1,315,409	$0.585	$532,692	910,758	$0.585
9	$4,011,600	$300,870	$334,300	$111,308	$0	$746,478	1,315,409	$0.567	$490,400	864,161	$0.567
10	$3,677,300	$275,798	$334,300	$113,534	$0	$723,631	1,315,409	$0.550	$451,069	819,948	$0.550
11	$3,343,000	$250,725	$334,300	$115,804	$0	$700,829	1,315,409	$0.533	$414,505	777,997	$0.533
12	$3,008,700	$225,653	$334,300	$118,121	$0	$678,073	1,315,409	$0.515	$380,527	738,192	$0.515
13	$2,674,400	$200,580	$334,300	$120,483	$0	$655,363	1,315,409	$0.498	$348,965	700,424	$0.498
14	$2,340,100	$175,508	$334,300	$122,893	$0	$632,700	1,315,409	$0.481	$319,661	664,589	$0.481
15	$2,005,800	$150,435	$334,300	$125,350	$0	$610,085	1,315,409	$0.464	$292,465	630,587	$0.464
16	$1,671,500	$125,363	$334,300	$127,857	$0	$587,520	1,315,409	$0.447	$267,238	598,324	$0.447
17	$1,337,200	$100,290	$334,300	$130,415	$0	$565,005	1,315,409	$0.430	$243,848	567,712	$0.430
18	$1,002,900	$75,218	$334,300	$133,023	$0	$542,540	1,315,409	$0.412	$222,173	538,666	$0.412
19	$668,600	$50,145	$334,300	$135,683	$0	$520,128	1,315,409	$0.395	$202,098	511,107	$0.395
20	$334,300	$25,073	$334,300	$138,397	$0	$497,770	1,315,409	$0.378	$183,515	484,957	$0.378
									$9,557,694	16,716,518	$0.572
Real levelized cost of energy					**$0.572**						

Appendix 5

Norman Wells diesel generation with diesel fuel starting at $1.00 per litre

Leading Edge Projects Generation LCOE Economic Model

Project: Norman Wells incremental diesel generation, 3.7 kWh per litre, fuel at $1.00 per litre, fuel inflation at 3% per year, variable O&M $0.03 per kWh

Capital cost	$0		Capacity		kW	Fixed O&M	$30,000	per year	Discount rate	5.39%	
Cost of capital	7.50%	Debt & equity	Annual Energy	1,000,000	kWh	Fuel	$0.270	per kWh			
Inflation	2.00%	per year	Project life	20	Years	Capacity factor			Fuel inflation	3.00%	

Year	Capital	Cost of Cap	Depreciation	Fixed O&M	Variable O&M	Total Ann cost	Ann energy	Cost per kWh	Discounted cost	Discounted energy	Discounted cost per kWh
1	$0	$0	$0	$30,000	$270,000	$300,000	1,000,000	$0.300	$300,000	1,000,000	$0.300
2	$0	$0	$0	$30,600	$278,100	$308,700	1,000,000	$0.309	$292,906	948,837	$0.309
3	$0	$0	$0	$31,212	$286,443	$317,655	1,000,000	$0.318	$285,982	900,292	$0.318
4	$0	$0	$0	$31,836	$295,036	$326,873	1,000,000	$0.327	$279,225	854,231	$0.327
5	$0	$0	$0	$32,473	$303,887	$336,360	1,000,000	$0.336	$272,629	810,526	$0.336
6	$0	$0	$0	$33,122	$313,004	$346,126	1,000,000	$0.346	$266,191	769,057	$0.346
7	$0	$0	$0	$33,785	$322,394	$356,179	1,000,000	$0.356	$259,907	729,710	$0.356
8	$0	$0	$0	$34,461	$332,066	$366,527	1,000,000	$0.367	$253,774	692,376	$0.367
9	$0	$0	$0	$35,150	$342,028	$377,178	1,000,000	$0.377	$247,788	656,952	$0.377
10	$0	$0	$0	$35,853	$352,289	$388,142	1,000,000	$0.388	$241,944	623,341	$0.388
11	$0	$0	$0	$36,570	$362,857	$399,427	1,000,000	$0.399	$236,241	591,449	$0.399
12	$0	$0	$0	$37,301	$373,743	$411,044	1,000,000	$0.411	$230,673	561,189	$0.411
13	$0	$0	$0	$38,047	$384,955	$423,003	1,000,000	$0.423	$225,239	532,477	$0.423
14	$0	$0	$0	$38,808	$396,504	$435,312	1,000,000	$0.435	$219,934	505,234	$0.435
15	$0	$0	$0	$39,584	$408,399	$447,984	1,000,000	$0.448	$214,756	479,384	$0.448
16	$0	$0	$0	$40,376	$420,651	$461,027	1,000,000	$0.461	$209,702	454,858	$0.461
17	$0	$0	$0	$41,184	$433,271	$474,454	1,000,000	$0.474	$204,768	431,586	$0.474
18	$0	$0	$0	$42,007	$446,269	$488,276	1,000,000	$0.488	$199,951	409,505	$0.488
19	$0	$0	$0	$42,847	$459,657	$502,504	1,000,000	$0.503	$195,250	388,553	$0.503
20	$0	$0	$0	$43,704	$473,447	$517,151	1,000,000	$0.517	$190,660	368,674	$0.517
									$4,827,521	12,708,229	$0.380
Real levelized cost of energy					**$0.380**						

Appendix 5

Norman Wells diesel generation with diesel fuel starting at $1.25 per litre

Leading Edge Projects Generation LCOE Economic Model

Project: Norman Wells incremental diesel generation, 3.7 kWh per litre, fuel at $1.25 per litre, fuel inflation at 3% per year, variable O&M $0.03 per kWh

Capital cost	$0		Capacity		kW	Fixed O&M	$30,000	per year	Discount rate	5.39%	
Cost of capital	7.50%	Debt & equity	Annual Energy	1,000,000	kWh	Fuel	$0.338	per kWh			
Inflation	2.00%	per year	Project life	20	Years	Capacity factor			Fuel inflation	3.00%	

Year	Capital	Cost of Cap	Depreciation	Fixed O&M	Variable O&M	Total Ann cost	Ann energy	Cost per kWh	Discounted cost	Discounted energy	Discounted cost per kWh
1	$0	$0	$0	$30,000	$338,000	$368,000	1,000,000	$0.368	$368,000	1,000,000	$0.368
2	$0	$0	$0	$30,600	$348,140	$378,740	1,000,000	$0.379	$359,363	948,837	$0.379
3	$0	$0	$0	$31,212	$358,584	$389,796	1,000,000	$0.390	$350,930	900,292	$0.390
4	$0	$0	$0	$31,836	$369,342	$401,178	1,000,000	$0.401	$342,698	854,231	$0.401
5	$0	$0	$0	$32,473	$380,422	$412,895	1,000,000	$0.413	$334,662	810,526	$0.413
6	$0	$0	$0	$33,122	$391,835	$424,957	1,000,000	$0.425	$326,816	769,057	$0.425
7	$0	$0	$0	$33,785	$403,590	$437,375	1,000,000	$0.437	$319,157	729,710	$0.437
8	$0	$0	$0	$34,461	$415,697	$450,158	1,000,000	$0.450	$311,679	692,376	$0.450
9	$0	$0	$0	$35,150	$428,168	$463,318	1,000,000	$0.463	$304,378	656,952	$0.463
10	$0	$0	$0	$35,853	$441,013	$476,866	1,000,000	$0.477	$297,250	623,341	$0.477
11	$0	$0	$0	$36,570	$454,244	$490,814	1,000,000	$0.491	$290,291	591,449	$0.491
12	$0	$0	$0	$37,301	$467,871	$505,172	1,000,000	$0.505	$283,497	561,189	$0.505
13	$0	$0	$0	$38,047	$481,907	$519,954	1,000,000	$0.520	$276,864	532,477	$0.520
14	$0	$0	$0	$38,808	$496,364	$535,173	1,000,000	$0.535	$270,387	505,234	$0.535
15	$0	$0	$0	$39,584	$511,255	$550,840	1,000,000	$0.551	$264,064	479,384	$0.551
16	$0	$0	$0	$40,376	$526,593	$566,969	1,000,000	$0.567	$257,890	454,858	$0.567
17	$0	$0	$0	$41,184	$542,391	$583,574	1,000,000	$0.584	$251,863	431,586	$0.584
18	$0	$0	$0	$42,007	$558,662	$600,670	1,000,000	$0.601	$245,977	409,505	$0.601
19	$0	$0	$0	$42,847	$575,422	$618,270	1,000,000	$0.618	$240,231	388,553	$0.618
20	$0	$0	$0	$43,704	$592,685	$636,389	1,000,000	$0.636	$234,620	368,674	$0.636
									$5,930,616	12,708,229	$0.467
Real levelized cost of energy					**$0.467**						

Appendix 6

Norman Wells 900kW wind project of 9 Northwind 100 turbines and NoRWIP subsidy

Leading Edge Projects Generation LCOE Economic Model

Project: Norman Wells 9 NorthWind 100 wind turbines, with NoRWIP at 30% ($2,485,290)

Capital cost	$5,799,010		Capacity	900	kW	Fixed O&M	$95,000	per year	Discount rate	5.39%	
Cost of capital	7.50%	Debt & equity	Annual Energy	1,181,539	kWh	Variable O&M		per kWh			
Inflation	2.00%	per year	Project life	20	Years	Capacity factor					

Year	Capital	Cost of Cap	Depreciation	Fixed O&M	Variable O&M	Total Ann cost	Ann energy	Cost per kWh	Discounted cost	Discounted energy	Discounted cost per kWh
1	$5,799,010	$434,926	$289,951	$95,000	$0	$819,876	1,181,539	$0.694	$819,876	1,181,539	$0.694
2	$5,509,060	$413,179	$289,951	$96,900	$0	$800,030	1,181,539	$0.677	$759,098	1,121,088	$0.677
3	$5,219,109	$391,433	$289,951	$98,838	$0	$780,222	1,181,539	$0.660	$702,427	1,063,730	$0.660
4	$4,929,159	$369,687	$289,951	$100,815	$0	$760,452	1,181,539	$0.644	$649,601	1,009,307	$0.644
5	$4,639,208	$347,941	$289,951	$102,831	$0	$740,722	1,181,539	$0.627	$600,374	957,668	$0.627
6	$4,349,258	$326,194	$289,951	$104,888	$0	$721,032	1,181,539	$0.610	$554,515	908,671	$0.610
7	$4,059,307	$304,448	$289,951	$106,985	$0	$701,384	1,181,539	$0.594	$511,807	862,181	$0.594
8	$3,769,357	$282,702	$289,951	$109,125	$0	$681,777	1,181,539	$0.577	$472,046	818,069	$0.577
9	$3,479,406	$260,955	$289,951	$111,308	$0	$662,214	1,181,539	$0.560	$435,043	776,214	$0.560
10	$3,189,456	$239,209	$289,951	$113,534	$0	$642,693	1,181,539	$0.544	$400,617	736,501	$0.544
11	$2,899,505	$217,463	$289,951	$115,804	$0	$623,218	1,181,539	$0.527	$368,601	698,820	$0.527
12	$2,609,555	$195,717	$289,951	$118,121	$0	$603,788	1,181,539	$0.511	$338,839	663,066	$0.511
13	$2,319,604	$173,970	$289,951	$120,483	$0	$584,404	1,181,539	$0.495	$311,181	629,142	$0.495
14	$2,029,654	$152,224	$289,951	$122,893	$0	$565,067	1,181,539	$0.478	$285,491	596,953	$0.478
15	$1,739,703	$130,478	$289,951	$125,350	$0	$545,779	1,181,539	$0.462	$261,638	566,411	$0.462
16	$1,449,753	$108,731	$289,951	$127,857	$0	$526,539	1,181,539	$0.446	$239,501	537,432	$0.446
17	$1,159,802	$86,985	$289,951	$130,415	$0	$507,350	1,181,539	$0.429	$218,965	509,936	$0.429
18	$869,852	$65,239	$289,951	$133,023	$0	$488,212	1,181,539	$0.413	$199,925	483,846	$0.413
19	$579,901	$43,493	$289,951	$135,683	$0	$469,126	1,181,539	$0.397	$182,281	459,091	$0.397
20	$289,951	$21,746	$289,951	$138,397	$0	$450,094	1,181,539	$0.381	$165,938	435,603	$0.381
									$8,477,765	15,015,268	$0.565
Real levelized cost of energy					**$0.565**						

Appendix 6

Norman Wells 900kW wind project of 4 Aeronautica turbines and NoRWIP subsidy

Leading Edge Projects Generation LCOE Economic Model											
Project: Norman Wells 4 Aeronautica 225 wind turbines with 50 meter towers; with 30% NoRWIP ($2,005,800)											
Capital cost	$4,680,200		Capacity	900	kW	Fixed O&M	$95,000	per year	Discount rate	5.39%	
Cost of capital	7.50%	Debt & equity	Annual Energy	1,315,409	kWh	Variable O&M		per kWh			
Inflation	2.00%	per year	Project life	20	Years	Capacity factor					
Year	**Capital**	**Cost of Cap**	**Depreciation**	**Fixed O&M**	**Variable O&M**	**Total Ann cost**	**Ann energy**	**Cost per kWh**	**Discounted cost**	**Discounted energy**	**Discounted cost per kWh**
1	$4,680,200	$351,015	$234,010	$95,000	$0	$680,025	1,315,409	$0.517	$680,025	1,315,409	$0.517
2	$4,446,190	$333,464	$234,010	$96,900	$0	$664,374	1,315,409	$0.505	$630,383	1,248,109	$0.505
3	$4,212,180	$315,914	$234,010	$98,838	$0	$648,762	1,315,409	$0.493	$584,075	1,184,252	$0.493
4	$3,978,170	$298,363	$234,010	$100,815	$0	$633,188	1,315,409	$0.481	$540,888	1,123,663	$0.481
5	$3,744,160	$280,812	$234,010	$102,831	$0	$617,653	1,315,409	$0.470	$500,624	1,066,173	$0.470
6	$3,510,150	$263,261	$234,010	$104,888	$0	$602,159	1,315,409	$0.458	$463,095	1,011,625	$0.458
7	$3,276,140	$245,711	$234,010	$106,985	$0	$586,706	1,315,409	$0.446	$428,125	959,867	$0.446
8	$3,042,130	$228,160	$234,010	$109,125	$0	$571,295	1,315,409	$0.434	$395,551	910,758	$0.434
9	$2,808,120	$210,609	$234,010	$111,308	$0	$555,927	1,315,409	$0.423	$365,217	864,161	$0.423
10	$2,574,110	$193,058	$234,010	$113,534	$0	$540,602	1,315,409	$0.411	$336,979	819,948	$0.411
11	$2,340,100	$175,508	$234,010	$115,804	$0	$525,322	1,315,409	$0.399	$310,701	777,997	$0.399
12	$2,106,090	$157,957	$234,010	$118,121	$0	$510,087	1,315,409	$0.388	$286,255	738,192	$0.388
13	$1,872,080	$140,406	$234,010	$120,483	$0	$494,899	1,315,409	$0.376	$263,522	700,424	$0.376
14	$1,638,070	$122,855	$234,010	$122,893	$0	$479,758	1,315,409	$0.365	$242,390	664,589	$0.365
15	$1,404,060	$105,305	$234,010	$125,350	$0	$464,665	1,315,409	$0.353	$222,753	630,587	$0.353
16	$1,170,050	$87,754	$234,010	$127,857	$0	$449,621	1,315,409	$0.342	$204,514	598,324	$0.342
17	$936,040	$70,203	$234,010	$130,415	$0	$434,628	1,315,409	$0.330	$187,579	567,712	$0.330
18	$702,030	$52,652	$234,010	$133,023	$0	$419,685	1,315,409	$0.319	$171,863	538,666	$0.319
19	$468,020	$35,102	$234,010	$135,683	$0	$404,795	1,315,409	$0.308	$157,284	511,107	$0.308
20	$234,010	$17,551	$234,010	$138,397	$0	$389,958	1,315,409	$0.296	$143,767	484,957	$0.296
									$7,115,590	16,716,518	$0.426
Real levelized cost of energy					**$0.426**						