Economic Analyses of Independent Power Production and Net Metering - Considerations for Policy Development

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Prepared by

Leading Edge Projects Inc.

John F. Maissan – President
219 Falcon Drive Whitehorse Yukon Y1A 0A2
Phone: (867) 668-3535 Fax: (867) 668-3533
Email: john@leprojects.com Website: www.leprojects.com

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Executive Summary

The Yukon Energy Corporation's planned Aishihik third turbine project (levelized cost of energy – LCOE – of $0.136 per kWh) is likely more cost effective than the technologies available to independent power producers (IPP) that were examined in this report, with the exception of natural gas. However, there are a number of technologies available to IPPs that have the potential to supply energy to our grids cost effectively compared to the planned Mayo B project (LCOE of $0.245 per kWh) and to incremental diesel generation (LCOE of $0.283 per kWh in the hydro zone). These technologies include micro-hydro, forest biomass, wind, natural gas, and binary geothermal. Of these, natural gas would be the cheapest with gas costs starting at about $5.00 per Mcf (thousand cubic feet) delivered to projects. Forest biomass (high cost range) in the hydro zone and small community wind projects in both the large and small diesel zones would produce energy with a higher LCOE than Mayo B and the existing diesel supplies respectively.

IPPs using forest biomass or wind technologies would require projects of about 10MW or larger to achieve the economies of scale required to be cost effective in the hydro zone. Depending on such factors as site characteristics, other technologies identified could be developed cost effectively on a smaller scale.

For the diesel served communities natural gas, if available to these communities, would be the most cost effective electricity source. The LCOE of present diesel supplies are $0.258, $0.323, and $0.567 per kWh in the large, small and Old Crow diesel zones respectively. Micro-hydro and binary geothermal technologies could also be cost effective depending on specific project characteristics.

Most IPP technologies examined produce energy which reduces in cost over time as they involve conversions from no-cost renewable sources, thus no fuel escalation with time. Forest biomass power costs will increase slightly over time as forest harvesting costs increase and natural gas costs will increase with fuel escalation. Micro-hydro and binary geothermal power will cost more in more remote areas for a particular set of circumstances and these additional costs are intended to be captured within the cost range of the variables examined in this report. The estimated costs of energy supply projects are outlined in the table on the next page.

Generally speaking the technologies used in net metering applications cannot produce energy at costs that are competitive with those from planned utility supplies. However, in specific circumstances natural gas (perhaps using micro-turbines), micro-hydro, binary geothermal, or wind may produce cost effective energy – most likely in the context of serving larger General Service (commercial) customers.

Solar PV technology is perhaps the best suited to wide spread residential net metering, but the energy is projected to have an LCOE of $0.875 to $1.510 per kWh depending on system size (larger is cheaper) and customer location (community). In very specific circumstances micro-hydro could be cost effective (in most cases probably resulting from project being installed by the customer them self).

Potential IPP Energy Supply Costs (LCOE), in $ per kWh (rounded) by rate zone (N/A means not applicable) and utility projects for comparison

	Rate Zone			
Technology	**Hydro system**	**Large diesel**	**Small diesel**	**Old Crow**
Micro-hydro	$0.10 to $0.22	$0.10 to $0.22	$0.10 to $0.22	$0.10 to $0.22
Forest biomass - large	$0.22 to $0.34	N/A	N/A	N/A
Wind - large	$0.18 to $0.22	N/A	N/A	N/A
Wind - community	N/A	$0.38 to $0.49	$0.38 to $0.49	$0.49 to $0.65
Natural gas - large	$0.08	N/A	N/A	N/A
Natural gas - small	$0.12	$0.12	$0.12	$0.12
Binary geothermal	$0.12 to $0.18	$0.12 to $0.18	$0.12 to $0.18	$0.12 to $0.18
Utility - diesel	$0.283	$0.258	$0.323	$0.567
Utility - Aishihik	$0.136	N/A	N/A	N/A
Utility - Mayo B	$0.245	N/A	N/A	N/A

Currently Yukon’s hydro zones are almost fully utilizing their hydro energy and new mines scheduled to come on line in the coming months and years will soon drive the requirement for new power supplies. Presently planned hydro projects will provide power at costs starting at an LCOE of $0.136 per kWh (Aishihik third turbine) and $0.245 per kWh (Mayo B without transmission). Existing or new diesel energy supplies are estimated to provide energy at an LCOE of $0.281 to $0.283 per kWh with a fuel increase rate of 3% per year (with inflation at 2% per year).

In the large, small, and Old Crow diesel zones incremental diesel energy are projected to have LCOEs of $0.258, $0.323, and $0.567 per kWh respectively. These LCOEs are based on a fuel inflation rate of 3%, 1% above the rate of inflation of 2%.

The study examined the energy supply projects that Yukon Energy has in development and the default supplies in all rate zones from the perspective of their ability to meet current and future seasonal energy demand patterns. Potential IPP and net metering supply projects were examined on the same basis. Ideal new power supplies will be those that can supply the bulk of their energy during winter when electrical loads are higher and the existing hydro supplies are approaching the low point of their annual cycle.

Net metering is in place in all but one of the provinces, and many provinces have IPP policies. The provincial programs provide a number of examples for the government of Yukon (GY) and other stakeholders to consider in designing IPP and net metering policies best suited to Yukon.

1. Background / Introduction

The GY undertook an in-depth process, including public consultation, which led to the production of the “Energy Strategy for Yukon” released in January 2009. Within this energy strategy GY commits to develop Net Metering and IPP policies. GY is now in the process of developing these policies.

The Yukon Government department of Energy, Mines and Resources (EMR) issued a Request for Proposals (RFP) entitled “Economic Analysis for Independent Power Production and Net Metering Policy” on April 17, 2009. The purpose of the RFP was to have certain economic analyses and related background work prepared for EMR to assist them in their net metering and IPP policy development work. The analyses consider the costs in each of Yukon’s four electrical rate zones.

This report presents the analyses and information prepared for EMR pursuant to the RFP. **Section 1, Background / Introduction** provides the background to this report and introduces each of the report sections. **Section 2, Methodology**, of this report outlines the methodology of the report and also outlines aspects that were beyond the scope of this report. In **Section 3, Present Yukon Power Supply Status**, the present electrical loads, the load patterns, and costs are provided (with details in Attachment A to this report). **Section 4, New Yukon Power Supplies**, presents information on the electrical power supply options presently being developed in Yukon and the diesel generation costs that would be the default option where no other supplies are being developed. **Section 5, Potential Net Metering and IPP Technologies**, presents what in the author’s view are the potential IPP and net metering technologies applicable to Yukon as well as the likely capital and operating costs involved in producing power from these technologies.

Section 6, Provincial Approaches to IPP and Net Metering, provides a description of the approach to IPP and net metering programs in place in various provinces. **Section 7, Considerations for Yukon’s IPP and Net Metering Policy Structure**, identifies economic and technical issues for GY’s consideration in the development of these policies. **Section 8, Considerations for IPP and Net Metering Financial Support**, identifies factors that could be considered by GY in the development of policies. **Section 9, Conclusions**, provides a summary of the author’s conclusions regarding the economic and related matters that could be considered in GY’s development of IPP and net metering policies.

2. Methodology

This report examines in some detail a number of projects and technologies for the purposes of comparing them to each other and to the planned utility projects. It should be understood by the reader that this report is focused on determining project development and operational costs on a consistent basis across technologies, but does not provide an examination of how those costs would or could be allocated. In some cases governments may provide capital subsidies for projects, or allocate costs differently for different customer classes, or may subsidize some customer bills. The examination of such issues is outside the scope of this report.

The main economic analysis tool used in the preparation of this report was a spreadsheet model (created by the author) that calculates on a year by year basis the real levelized cost of energy (LCOE) per kWh of energy produced by a project through its useful life. The calculated LCOE of projects that could be developed is used by utilities and their regulators in selecting which projects are the most appropriate to be developed. In calculating the LCOE future costs and benefits (energy) are discounted by the real discount factor, which in this report would be the cost of capital divided by the inflation factor less 1 (1.0706/1.02 - 1 = 4.96%, rounded to 5.0%). The discounted costs and benefits are summed over the useful life of a project and the LCOE is obtained by dividing the sum of the discounted costs by the sum of the discounted energy.

There are three assumptions used in the model that were applied consistently across all analyses carried out:

- the blended cost of capital (debt and equity) is 7.06%, this is the average of Yukon Energy's and The Yukon Electrical Company's presently approved costs of capital;
- the general rate of inflation is 2%, this is based on the trend of recent years; and
- all energy produced is useful and has the same value.

Two price increase rates for diesel fuel and natural gas (from current price estimates) are used in this report. The lower (base case) is 1% above the assumed general rate of inflation, thus 3% per year, and a high case of 2% above the general rate of inflation, thus 4% per year. These projections are based on the United States Energy Information Administration's ***Annual Energy Outlook for 2010 Reference Case*** which includes projections to 2035, and the associated tables and the World Bank's 2009 ***Global Commodity Markets, Review and price forecast***.

Within each project or within each technology several other variables had to be set in order to run the spreadsheet model. These include the capacity of the project (in kW), the project capacity factor (and from that the annual energy produced in kWh), the project life, the fixed annual operating and maintenance (O&M) cost, and the variable O&M cost. The lives of the various power generation technologies used in this report are 50 years for hydro, 30 years for micro-hydro, and 20 years for all other technologies. These lives may be slightly conservative but they are consistently conservative across the technologies. With regard to O&M costs there was some inconsistency as to how these were used depending on the source information available. In some cases the fixed O&M was based on a per kWh cost reflecting a combination of fixed and variable costs, and in some cases the variable O&M cost was confined to the fuel cost (where appropriate to the technology being examined).

Fixed O&M costs for larger utility hydro projects was based on Yukon Energy's planning projection of 0.5% of capital cost, and the large diesel plant non-fuel O&M cost of $0.02 per kWh was also based on Yukon Energy's planning projections.

This report does not address or evaluate the relative local social benefits of projects or technologies. For instance the local socio-economic benefits of a locally developed and owned renewable energy project would be higher than from a diesel generation project, and for that reason may be preferred by Yukon's utilities, GY, and the Yukon public. This report simply compares the LCOE and leaves it to others to determine the appropriate relative values (financial and/or non-financial) to be assigned to such projects.

Green house gas (GHG) emissions are also not addressed in this report. The renewable energy technologies and projects would produce very limited amounts of GHGs compared to diesel generation projects and natural gas projects would be somewhere in between. Evaluating various project GHG emission footprints, and putting a value on GHG emissions as a cost adder to the LCOE of different generation technologies was beyond the scope of this study. It is very likely, however, that technologies that do not produce GHG will have lower LCOEs relative to GHG producing technologies in the longer term.

The estimates provided in this report assume that the project cost includes the cost to connect it to the power grid. This includes the power line to the grid plus a grid interconnection substation as required. In some provinces high voltage main trunk transmission lines are being provided (or considered) to enable power from regional renewable energy projects (mostly wind projects but also some hydro) to be brought to other parts of the province. Main trunk transmission lines were not considered in this report.

Each project and technology has inherent energy production characteristics such as intermittency or seasonality which need to be considered. Intermittent sources such as wind or solar PV energy require the power system to have other firm capacity sources in place that enable the electrical loads to be met when the intermittent supply is not available. Other supplies (hydro, diesel, biomass, natural gas, geothermal) are much more predictable and steady in their output and would not require the same level of backup. The utilities have models that calculate the reliable capacity of different technologies but such calculations are beyond the scope of this report. In addition to the energy values calculated in this report, some technologies or projects (in part dependent on the characteristics described above as well as location) would have an added value for dependable capacity while others would not.

This report provides a snapshot in time (2009) of the various technologies examined. When comparing projects using technologies with shorter lives to projects using technologies with longer lives, multiple life cycles of the shorter lived technologies using the original capital costs inflated to the future are sometimes used. However, a redevelopment of the shorter lived technology would typically not require all equipment to be replaced or all costs to be re-incurred making the subsequent life cycle to result in a lower LCOE. Similarly some technologies are still maturing and costs over time are trending down, so future developments may yield lower LCOEs. This is especially true of solar PV but also, to a lesser extent, for wind power and binary geothermal technologies. Determining and assigning financial values to these complexities was beyond the scope of this report.

3. Present Yukon Power Supply Status

The Yukon's electrical power supply is provided by a number of power systems. The largest system serves southern Yukon and is generally known as the Whitehorse – Aishihik – Faro (WAF) grid (or system) which is hydro based (principally the Whitehorse Rapids and Aishihik power plants). This grid is supplemented as necessary by diesel generation. The next larger grid is the Mayo – Dawson system which is also hydro based (Mayo hydro plant) and supplemented by diesel. In recent years transmission line development aimed at interconnecting these two hydro based grids into a single grid has been undertaken. This was facilitated by a mining customer that wanted power service and is located roughly half way between these two grids. Both of these grids together are considered the hydro rate zone for electrical rate purposes.

The other rate zones are "large diesel" for diesel generation only served large communities (Watson Lake); "small diesel" which captures all road accessible small communities served by diesel generation only (Swift River, Burwash Landing & Destruction Bay, Beaver Creek); and "Old Crow" which is a small community not accessible by any roads for which diesel fuel has to be brought in by air transport.

In both the hydro zone and the diesel zones, the non-industrial and non-secondary electrical loads (principally residential and general service) follow the weather patterns. The electrical load is highest when temperatures are at their coldest and days are shortest (winter), and lowest in the warm, long daylight period of summer. Secondary sales demand would also follow the weather patterns if the supply was unlimited as it mostly serves heating load. However, given the limited supply of hydro power, secondary sales have to be curtailed in winter. The service of secondary loads is not discussed further in this report. Industrial loads are relatively constant throughout the year.

On a daily basis electrical loads are at their lowest from midnight to about 5AM after which they increase as people get up and begin their daily activities; there is a slight lull after midday, and then there is another peak in late afternoon to early evening around the supper hour.

In the hydro served zone, the hydro plant inflows peak during the spring and early summer snowmelt runoff (Aishihik and Mayo) or during the mid to late summer glacier melt period (Whitehorse Rapids). This is the opposite of the electrical demand which peaks in winter and is at a minimum in summer. The various dams and control structures on these hydro facilities store the water to the extent possible and release it at a later time – during winter peak loads where possible. In the hydro zone, peak winter loads are now being served by a small portion of diesel generation.

In the diesel served zones the diesel generators simply follow the electrical load so there is no excess generation.

Table 1 below summarizes the incremental costs by rate zone and by fuel cost at different time periods, and Table 2 summarizes the total generation costs based on fuel costs forecasted for 2009 (in 2008) and 2008 actual other costs. The June 2009 actual fuel costs used are $0.65 per litre for the large diesel zone (Watson Lake), $0.75 per litre for the small diesel and hydro zones, and $1.45 per litre for Old Crow.

Table 1: Incremental power cost by rate zone and fuel cost at different dates

Rate Zone	2008 peak fuel cost $ per kWh	2009 forecast fuel cost $ per kWh	June 2009 actual fuel cost $ per kWh	June 2009 inflated 20 years at 3% $ per kWh
Large diesel	$0.314	$0.229	$0.170	$0.307
Small diesel (approx avg)	$0.350	$0.243	$0.220	$0.397
Old Crow	$0.618	$0.543	$0.407	$0.735
Hydro – existing hydro	~$0.005	$0.005	$0.005	$0.009
Hydro – YECL stand-by diesel	$0.34	$0.243	$0.214	$0.386
Hydro – all-in peaking diesel		$0.3737	$0.257 est.	$0.464
Hydro – incremental only		$0.337	$0.222	$0.401

Table 2: Generation cost based on 2009 forecast fuel (GRA) and actual 2008 other costs

Rate Zone	Fuel	Variable	Other	Total
Large diesel	$0.229	$0.034	$0.038	$0.301
Small diesel (avg)	$0.243	$0.035	$0.040	$0.309
Old Crow	$0.543	$0.039	$0.042	$0.624
Hydro – Fish Lake plant	$0.000	$0.029	$0.035	$0.064
Hydro – existing hydro (Mayo B other)	$0.000	~$0.005	~$0.016	~$0.021
Hydro – stand-by diesel (YECL)	$0.243	~$0.034	~$0.040	~$0.317
Hydro – large plant peaking diesel	$0.321	$0.016	~$0.049	~$0.386

Attachment A to this report provides additional information on the power supply status, and on the derivations of the figures that are included in the tables above.

4. New Planned Yukon Power Supply Costs

Significant new power supplies are planned for the hydro zone in Yukon as there is a potential for new industrial (mining) electrical loads to be added soon. The largest of these new supply projects is the Mayo B hydro development. This project involves the construction of a new Mayo hydro plant downstream of the existing one to double the head on the plant and thereby approximately double the facility's output. The increased annual energy output will be about 38.4GWh and the added capacity will be about 5 or 6MW (Yukon Energy has not yet indicated a nominal capacity for the expanded plant). The regulation of water levels and releases from Mayo Lake (using facilities already in place for Mayo "A") results in the energy and capacity from this development being available approximately evenly through the year.

The Mayo B project with its even annual output is well suited to serving the industrial load profile which is relatively even throughout the year. However, if the development were to serve non-industrial load, the Mayo B project would be contributing to the surplus energy available in the warmer seasons of the year.

The projected cost of the Mayo B development is $120 million excluding transmission. However, since the project is located on the Mayo-Dawson grid, a transmission line connecting the Mayo-Dawson system with the WAF system will be required to make most of the new power supply useful. This transmission link is projected to cost about $40 million. If this transmission link is attributed to Mayo B the cost of the development would be $160 million.

Economic analysis of the Mayo B project using LCOE economic model indicates that the LCOE would be about $0.245 per kWh. The cost over time is characterized by higher costs early in its life ($0.304 in its first year) and lower costs late in its life ($0.121 per kWh in its last year). This pattern is typical of a capital intensive project, and is the reason why hydro power costs are low in the Yukon today – the existing hydro plants have been substantially depreciated (including some government subsidies and write-offs). If the $40 million transmission link between Pelly Crossing and Stewart Crossing were to be added to the cost of the Mayo B project the LCOE would be $0.324 per kWh ($0.403 per kWh in its first year to $0.157 per kWh in its last year).

The other planned hydro project is the addition of a third turbine (of about 7MW) to the existing Aishihik hydro plant. No other modifications to the plant or its operating licenses are required. This added capacity will enable more of the hydro energy available from this plant to be used in winter thus reducing the diesel peaking generation required in winter – and reducing the surplus hydro available at other times of the year. Because this 7MW turbine would be more efficient than the existing 15MW turbines at lower power plant loads, the average annual energy output of the plant is expected to increase by about 5GWh per year. The cost of this project is estimated at $8.5 million.

The Aishihik third turbine project is thus very well suited to serving the needs of non-industrial load which is higher in winter and lower in summer. The reason for this is that the project better enables the summer water supply which is stored Aishihik Lake to be more fully utilized during the coldest winter weather (offsetting diesel generation). Figure 4 in Attachment A illustrates this effect.

An economic analysis indicates that the Aishihik third turbine project would produce power at a LCOE of $0.136. The cost ranges from $0.168 per kWh in the first year of its life to $0.072 per kWh in its last year. In addition to the benefit of a greater supply low cost energy, more of the existing energy supply can be directed to displacing winter diesel energy (and reduces surplus summer hydro energy by that same amount).

Hydro projects typically have energy outputs that are dictated by the site, and because of their capital intensive nature, most if not all of the energy would have to be required for the power to be economical. The costs of the energy are mostly related to fixed capital cost repayments and thus do not decrease even if the need for the power decreases – in which case the useful power would effectively become more expensive (on a per kWh basis).

New base load diesel generation for the hydro rate zone or for non-grid connected industrial (mining) operations, is an option that is also available. Diesel generation is characterized by low capital costs but high operating costs, primarily the cost of the diesel fuel. Capital costs for new baseload diesel plants are estimated to be about $1.2 million per MW of capacity, and new state-of-the-art generators would get about 4 kWh per liter of diesel fuel. Over an estimated useful life of 20 years the LCOE would be $0.281 per kWh with diesel fuel starting at $0.75 per liter (and increasing at 3% per year – with inflation at 2% per year). Actual cost would range from $0.230 per kWh in year 1 to $0.369 in year 20. With diesel fuel increasing at 4% per year (2% per year above general inflation) the LCOE would be $0.303 per kWh and actual costs would range from $0.230 per kWh in year one to $0.435 per kWh in the twentieth year. Lower initial energy costs that increase over time is typical of generation projects characterized by low capital costs and relatively high and inflating fuel costs.

Diesel generation can be perfectly adjusted to the load – there is no surplus generation (but there is residual heat available). When not needed the remaining costs (capital repayment) are low compared to hydro plants which have very little reduction in cost when the energy is not required.

Table 3 below compares the planned hydro projects and the possible baseload diesel alternative for the hydro zone.

Table 3: Costs of hydro zone planned projects and baseload diesel

Parameter	Mayo B no transmission	Mayo B with transmission	Aishihik third turbine	Diesel, fuel $0.75/l + 3%/yr	Diesel, fuel $0.75/l + 4%/yr
Project life	50 years	50 years	50 years	20 years	20 years
Capital cost	$120 million	$160 million	$8.5 million	$12 million	$12 million
Capacity	5-6 MW	5-6 MW	7 MW	10 MW	10 MW
Annual energy	38.4 GWh	38.4 GWh	5 GWh	65 GWh	65 GWh
Cap factor	88%	88%	8%	75%	75%
Fixed O&M	$600,000 / yr	$800,000 / yr	$42,500 / yr	$1.3 million	$1.3 million
Variable O&M	$0.005 / kWh	$0.005 / kWh	$0.005 / kWh	$0.188/kWh	$0.188/kWh
LCOE	**$0.245**	**$0.324**	**$0.136**	**$0.281**	**$0.303**
kWh cost yr 1	$0.304	$0.403	$0.168	$0.230	$0.230
kWh cost yr 20	$0.229	$0.303	$0.128	$0.369	$0.435
kWh cost yr 50	$0.121	$0.157	$0.072		

In the economic analyses that yielded the data contained in Table 3, the cost of capital is 7.06% (blended debt and equity) and the inflation rate is 2%. Operating and maintenance costs are increased at the rate of inflation. Diesel fuel cost is projected to increase at 3% per year in the base case, 1% above the rate of inflation, but a higher case of 4% per year increase was also prepared. The fixed O&M costs related to the Mayo B hydro project are based on the Yukon

Energy planning estimate of 0.5% of the capital cost. The non-fuel O&M costs for new baseload diesel are also based on Yukon Energy's planning number of $0.02 per kWh.

The incremental cost of energy from existing hydro zone diesel generators is about the same as for new baseload diesels, the variable cost is lower but so is the fuel efficiency. The LCOE for incremental energy is $0.283 at 3% per year fuel increase and $0.307 at 4% per year increase.

In diesel served communities new power supply is achieved by increasing plant capacity as required. This is often done as a matter of routine as engines come to the end of their useful lives. The cost of new energy supply is thus no more than the cost of fuel and the "variable" costs indicated in Table 2. Table 4 below presents this information, the LCOE for a 20 year incremental load, and also projects the costs 20 years out with inflation at 2% per year applying to the variable cost. Fuel is inflated at 3% per year in the base case and 4% per year in a high case.

Table 4: Costs for incremental increased energy supply in diesel rate zones

Parameter	Large diesel	Small diesel	Old Crow
Fuel efficiency kWh/liter	3.8	3.4	3.6
"Variable" costs per kWh	$0.034	$0.035	$0.039
Present fuel cost (+3%/yr)	$0.170 per kWh	$0.220 per kWh	$0.407 per kWh
LCOE	**$0.258**	**$0.323**	**$0.567**
Per kWh cost year 1	$0.204	$0.255	$0.446
Per kWh cost year 20	$0.348	$0.437	$0.770
Present fuel cost (+4%/yr)	$0.30 per kWh	$0.37 per kWh	$0.55 per kWh
LCOE	**$0.278**	**$0.349**	**$0.615**
Per kWh cost year 1	$0.204	$0.255	$0.446
Per kWh cost year 20	$0.408	$0.514	$0.914

The costs outlined in Tables 3 and 4 are the costs against which potential IPP and net metering supplies need to be compared. IPP or net metering generation projects which can supply energy at lower costs than the energy costs presented in the above tables would reduce electricity rates over time.

5. Potential IPP and Net Metering Technologies and Associated Costs

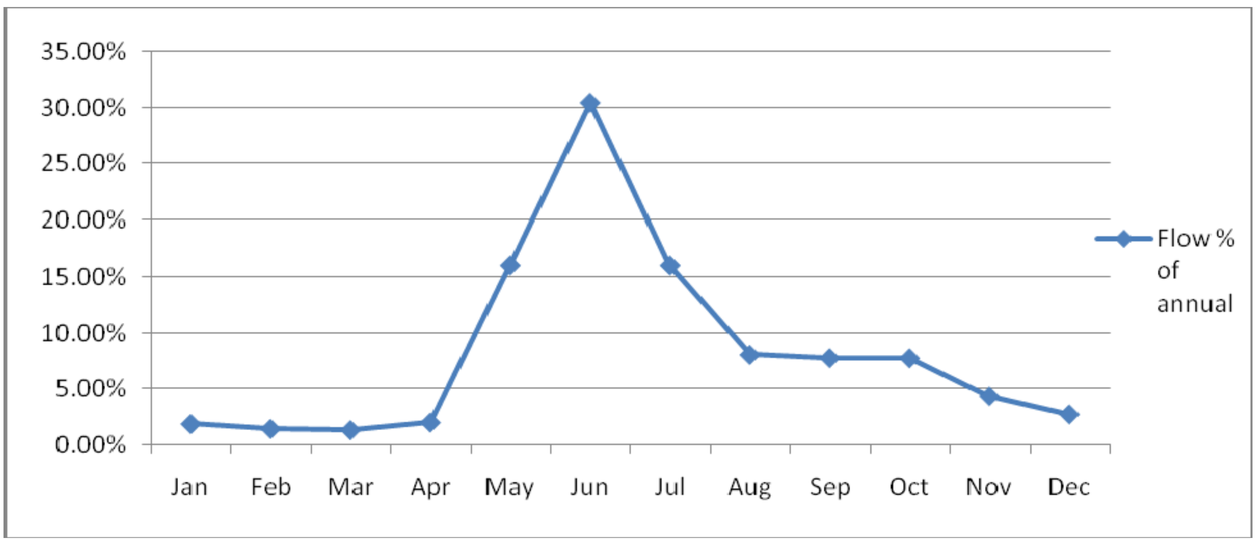
The technologies likely to be considered by IPP proponents are micro-hydro, forest biomass, wind, natural gas, and geothermal. The technologies of potential interest to power system customers interested in net metering include solar PV, wind, natural gas, and micro-hydro. Each of the above technologies and their associated costs are examined below.

Micro-hydro

The potential for micro-hydro in Yukon will be very site dependent. To be effective micro-hydro projects require streams that have a significant "head" (drop in elevation) over a short distance, a year-round water flow, and proximity to existing power lines. In diesel rate zones seasonal only water flow (i.e. none in the depth of winter) may still enable economic projects that displace diesel generation for a portion of the year. For the hydro zone, potential micro-hydro projects will likely be most practical if sized to the winter flows, as there is likely to be some surplus hydro energy in the summer already. This makes the summer energy less valuable than winter energy.

Figure 1 below illustrates the flow pattern of a typical Yukon stream or river fed by snow melt that has limited natural water storage or regulation. The example used is the Nisutlin River above the Wolf River (Water Survey of Canada data). It serves to illustrate how difficult it would be to provide winter (and spring) energy from hydro on similar water courses without storage and regulation, and thus how valuable water storage and regulation is.

Figure 1 Annual flow pattern in a river or stream with limited storage or regulation



Capital costs for micro-hydro are very dependent on specific site geography. The following are examples of cost estimate ranges.

- The Mayo B project, considered a 10MW project by Yukon Energy, will be costing about $12,000 per kW. If considered a 5MW project (the added capacity) the cost would be $24,000 per kW.
- The Atlin micro-hydro project (about 2.4MW) is said to have cost well above the $10 million budget, so it cost well in excess of $4,167 per kW ($15 million would indicate $6,250 per kW).
- A representative of the Independent Power Producers Association of BC indicated that small hydro projects (more than 10MW) would probably average about $3,000 per kW.

- In their Standard Offer Program for projects up to 10MW the Ontario Power Authority suggests that the installed cost is likely in the range of $4,000 to $7,000 per kW.
- Finally, Natural Resources Canada, in their 2004 publication "Micro-Hydro Power Systems A Buyer's Guide", indicates that a 3.5kW system might cost $3,700 per kW, a 10kW system $2,590 per kW, and a 50kW system $1,318 per kW. This information is now dated and actual equipment costs on which this publication was based may well have doubled, and project installation by the builder at no cost is probably assumed.

Depending on circumstances, capital costs could thus range from $5,000 to $15,000 per kW or more in Yukon. For the economic analyses the following assumptions were made:

- O&M costs would be about $0.03 per kWh ($100,000 per year for a 500kW example project);
- the cost of capital is 7.06%;
- the general inflation rate is 2%;
- the project life would be 30 years; and
- the plant would run at an annual capacity factor of 75%.

Table 5 below presents the LCOE as well as the cost of energy in years 1 and 30 for capital costs of $5,000, $10,000, and $15,000 per kW of capacity. As with larger hydro, micro-hydro is characterized by higher energy costs in the earlier years of the project and low energy costs toward the end of the project's life.

Table 5: Cost of micro-hydro energy as a function of capital cost

Parameter	Capital cost		
	$5,000 per kW	**$10,000 per kW**	**$15,000 per kW**
O&M costs $ per kWh	$0.03	$0.03	$0.03
LCOE	**$0.098**	**$0.157**	**$0.217**
Energy cost per kWh year 1	$0.110	$0.189	$0.271
Energy cost per kWh year 30	$0.081	$0.108	$0.136

There are several examples of micro-hydro in and near Yukon that would indicate that in the appropriate circumstances it could be a technology considered for either IPP or net metering. Micro-hydro technology could be applied in any of the rate zones, but from personal knowledge it is unlikely that Old Crow would have suitable projects close enough to be considered.

Forest Biomass

Biomass power production is fairly common throughout the world and encompasses biogas from landfills and farm manure, agricultural wastes of all types from straw to nut shells, municipal solid waste, forest waste, and dedicated forest harvest (dead wood or forest crops). In Yukon's case, forest biomass based on the harvesting of fire killed or beetle killed wood was considered the most likely to be practical. This technology is quite reliable and power production could probably be focused on the winter period and routine shutdowns planned for the summers.

There were three main cost components the author considered in estimating the cost of power. The first was the capital cost of a power plant, the second the cost of the fuel, and the third the operating and maintenance costs. There was limited information available on projects that were of a scale that may be suitable in Yukon. Hence, the author had to extrapolate costs and cost ranges that may be applicable to Yukon.

The following are some of the information sources with respect to capital costs (in $CDN).

- A recent 20MW biomass plant in Germany cost $72 million or about $3,600 per kW.
- A 60MW forest biomass plant in Hanceville, BC cost $260 million or $4,333 per kW.
- The Ontario Power Authority in their Standard Offer Program for projects up to 10MW lists the capital cost range for biomass plants as being $2,400 to $6,200 per kW but that would include landfill and farm manure biogas at the lower end of the range.
- Probably closest to Yukon in size is a 10MW forest biomass project under development in Chapleau, Ontario which is projected to cost $56 million or $5,600 per kW.

Chena Hot Springs in Alaska is said to be working on a 200kW biomass fuelled power plant for remote villages with United Technologies Corporation, but no information with respect to costs and progress could be obtained from either party.

In Yukon, the cost range is would be higher than in either Ontario or BC, so likely in the range of $5,000 to $10,000 per kW.

The possible cost for the dedicated harvesting of forest trees for a power plant and the thermal efficiency that may be achieved (dependent on the moisture content of the wood) was difficult to project, but the author considers that it is likely in the range of $0.10 to $0.15 per kWh. This corresponds to about $100 to $150 per tonne (1000kg), which is roughly a cord of dry wood, delivered to the power plant. A study by Kumar et al in Alberta (undated but no older than 2002) estimated whole forest fuel cost at $72 per MWh or $0.072 per kWh. PriceWaterhouseCoopers' August 2005 report ***Economic Assessment of Forest Industry in Southeast Yukon*** projected harvesting cost for green wood in the order of $65 per cubic meter. When this figure is adjusted for inflation and standing dead wood moisture level the cost would be about $160 per tonne. Present firewood (delivered) prices for logs by the truckload are well below $200 per cord, which provides support for the $100 to $150 per tonne cost range for larger scale dedicated harvesting.

O&M costs were projected to be in the range of $2.5 million to $3.5 million per year for a 10 MW plant, based on web sourced information available on projects. This is roughly equivalent to a range of $0.03 to $0.05 per kWh.

Economic analyses were based on a cost of capital of 7.06%, an inflation rate of 2%, a 20 year project life, operational capacity factor of 85% (74GWh per year from a 10MW plant), and a plant life of 20 years. The lack of economies of scale may make it economically challenging to build and operate a plant much smaller than 10MW. This technology is thus only applicable to IPPs in the hydro zone. Table 6 below outlines the possible range of power costs from biomass plants.

Table 6: Cost of energy from a 10MW forest biomass plant

Parameter	**Low Capital**		**High Capital**	
	Low O&M	**High O&M**	**Low O&M**	**High O&M**
Capital cost per kW	$5,000	$5,000	$10,000	$10,000
Fuel cost $ per kWh	$0.05	$0.10	$0.05	$0.10
O&M cost	$2.5 million	$3.5 million	$2.5 million	$3.5 million
LCOE	**$0.220**	**$0.279**	**$0.283**	**$0.342**
Energy $ / kWh year 1	$0.215	$0.265	$0.297	$0.347
Energy $ / kWh year 20	$0.231	$0.304	$0.267	$0.340

Wind

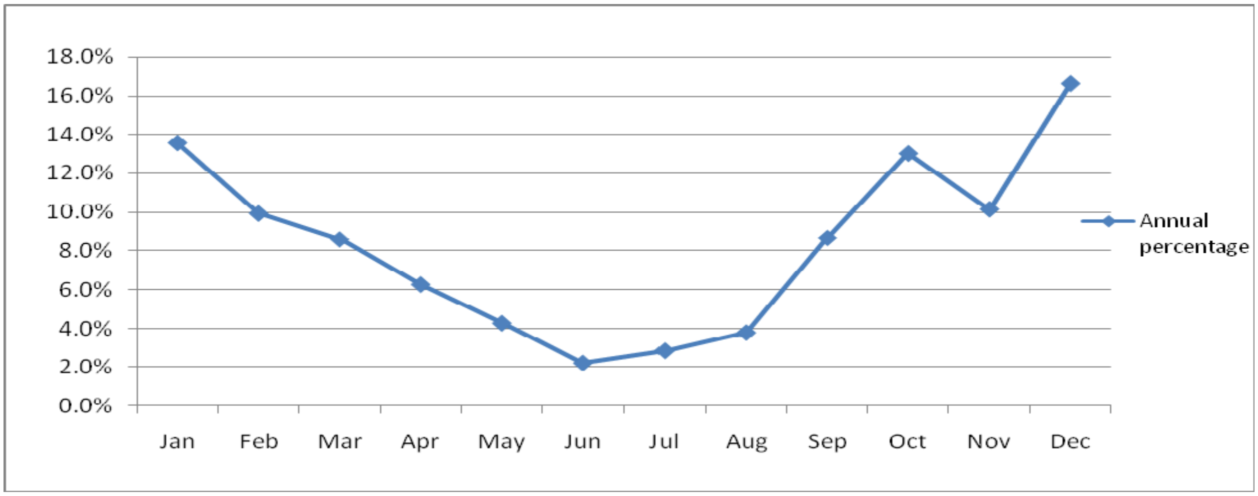
Wind power generation is now common on both a small and large commercial scale in Canada – from a few hundred watts to hundreds of megawatts. Small scale wind generation was used in remote locations (and prairie farms) for battery charging even before solar PV became common. Wind energy development costs are relatively well known for both large and small scale installations. However, construction and operation in Yukon is more difficult and costly than in the southern parts of Canada. Furthermore, the wind resource is very dependent on both geography and location making it difficult to make blanket assumptions that apply everywhere.

Wind resources that would be of interest to larger scale developers (above 6 meters per second) for the hydro rate zone are found at exposed mountain and ridge tops at altitudes of more than 1,000 meters (3,300 feet). However, wind energy is intermittent and a firm back-up power supply (such as hydro) would be required to meet firm loads.

A positive aspect of the wind energy resource at these higher sites is that it is substantially higher in winter than in summer. Figure 2 below illustrates the annual wind energy (the wind speed cubed) available at an altitude of 1200 meters at Whitehorse, based on upper air (radiosonde) data from Environment Canada for the period 1998 to 2007. At this altitude the annual average wind speed is 7.27 meters per second. Another positive aspect of wind patterns is that it tends to be at a daily minimum in the early morning when electrical loads are at their daily minimum and higher at other times of the day when electrical loads are higher. Overall there is a good fit between the wind energy availability pattern and the non-industrial annual load pattern in the hydro zone (see Figure A1 Attachment A).

There are two challenges to wind energy development on a commercial scale. The first is that wind energy is intermittent – the wind does not always blow. This means that wind energy has to be used in combination with one or more other energy sources that can supply the load when the wind is not blowing (and can be turned down or off when the wind is blowing). Generally speaking wind energy fits well with hydro facilities that have storage reservoirs and a relatively high installed capacity. The Aishihik plant with the third turbine installed would be a good example. Alternatively, in diesel served communities, the diesel generation would decrease as wind generation increases.

Figure 2: Wind energy distribution at 1200m above Whitehorse 1998 – 2007



The second challenge is that the higher altitude sites typically suffer from severe rime icing during the winter time causing losses in winter production. While efforts by Yukon Energy over a period of years developed some partial solutions to this problem, there is not yet a commercially available and proven icing mitigation system on the market. There are efforts underway in Scandinavia and, to a lesser degree, in the USA, to develop blade de-icing or anti-icing systems. A developer of a higher altitude site in Yukon would need to be prepared to address the icing issue with appropriate parties.

There are two communities in the diesel rate zones where there is presently a known possibility of small scale wind projects to displace diesel generation. The two communities are Destruction Bay & Burwash Landing (one common diesel plant) and Old Crow. The electrically interconnected communities of Destruction Bay and Burwash Landing have a wind resource of about 6 m/s at 30 meters above ground level, which is marginal but within the realm of possible development. The summit of Crow Mountain near Old Crow is believed to have a better wind resource but it would also have rime icing to deal with.

Wind-diesel systems are becoming common in Alaska and other parts of the world (including Australia and Antarctica), and are increasingly being seriously considered in NWT and Nunavut. The costs for these relatively small scale projects using a small number of 50 to 100kW wind turbines are substantially higher than the large commercial wind farms which use large numbers of 1 to 3MW wind turbines.

The potential for wind generation deployment in net metering applications in Yukon is very limited. Small scale projects installed professionally tend to be expensive. Also, most communities are located in the valley bottoms and are thus relatively sheltered from steady winds. The wind speeds in most communities would be below 4 m/s with the exception of Burwash Landing and Destruction Bay. This modest wind speed would result in annual capacity factors in the order of 5% although specific "good" locations may produce up to twice that amount. Based on the information available, small home systems of no more than a few kW are probably as expensive as solar PV systems and require more maintenance than PV systems.

Table 6 below outlines the range of capital (installed) costs for wind power projects that are likely to be experienced in various areas across Yukon. These costs are based on packaged deals of professionally installed systems that are available in other parts of Canada (with adjustments for higher installation costs in Yukon) and the author's experience from various pre-feasibility studies across northern Canada.

Table 6: Capital cost ranges in $ per kW for IPP and net metering wind projects in Yukon

System size	Whitehorse area	Road connected communities	Old Crow
Less than 10kW	$10,000 to $14,000	$11,000 to $15,000	$12,000 to $16,000
~30kW system	$8,000 to $9,000	$9,000 to $10,000	$10,000 to $11,000
~60kW system	$6,000 to $7,000	$6,500 to $7,500	$8,000 to $10,000
300kW to 1MW	$5,000 to $7,000	$5,300 to $7,300	$7,000 to $10,000
~10MW and up	$3,000 to $4,000	$3,500 to $4,500	Not applicable

Table 7 below outlines the projected the LCOE of a 10MW wind project in the Whitehorse area. The assumptions include a capacity factor of 25% (after icing losses), a fixed O&M cost of $100,000 per year, a variable O&M cost of $0.04 per kWh, a project life of 20 years, and consistent with other economic analyses in this report the assumptions include a cost of capital of 7.06%, and an inflation rate of 2%.

Table 7: Cost of wind energy from a Whitehorse area 10 MW wind farm

Parameter	Capital cost $3,000 per kW	Capital cost $4,000 per kW
Fixed O&M cost	$100,000 per year	$100,000 per year
Variable O&M cost	$0.04 per kWh	$0.04 per kWh
LCOE	**$0.179**	**$0.222**
Energy $ / kWh year 1	$0.210	$0.265
Energy $ / kWh year 20	$0.138	$0.163

Table 8 below presents the results of the economic analyses for a 200 kW wind project located in diesel rate zones. The cost of capital, inflation, and project life assumptions are similar to the large project analyses above, but the capacity factor is assumed to be 20% and the O&M cost are all combined into one variable cost.

Table 8: Cost of wind energy from a diesel zone 200kW wind project

Parameter	Large and small diesel		Old Crow	
	$5,500 per kW	**$7,500 per kW**	**$7,000 per kW**	**$10,000 per kW**
O&M cost / kWh	$0.075	$0.075	$0.100	$0.100
LCOE	**$0.380**	**$0.486**	**$0.488**	**$0.647**
Energy $/kWh yr 1	$0.454	$0.592	$0.582	$0.789
Energy $/kWh yr 20	$0.277	$0.339	$0.360	$0.452

Natural Gas

Yukon has gas production from a field in the south-eastern Yukon which is being "exported" through a pipeline via Ft. Nelson BC, however, Yukon also has confirmed but undeveloped natural gas resources in the Eagle Plain area. There is also potential for gas resources to be found in other areas including the Whitehorse trough. And finally there is the possibility of access to natural gas from the planned Alaska Highway Gas Pipeline.

Natural gas powered electricity generation is mature technology; it can follow the electrical load in the same way that diesel generators can and its capacity would be equally reliable. For larger scale developments gas turbines are typically the technology of choice. These can be configured in a few different ways. The first is a simple cycle arrangement in which the fuel is combusted in the turbine which drives the generator and the exhaust goes out of the stack.

The second way is to recover the turbine exhaust heat to produce high pressure steam to drive an additional steam turbine. These combined-cycle gas turbines typically have higher overall energy efficiencies but cost more to install and operate. The third manner is to recover the exhaust heat from the turbine to satisfy heat requirements that may exist near the installation (space or process heat). The production of combined heat and power also generally results in higher overall energy efficiency.

Information available indicates that the cost of larger turbines can range from $800 to $1,800 per kW of capacity depending on turbine size and how they are set up. A study entitled ***Energy to Mines Report*** prepared for EMR in December 2007 indicated that a General Electric LM6000 42.8 MW turbine would cost about $1,200 per kW.

Smaller scale gas generation installations sometimes use reciprocating engines (similar to diesel generators). Northwest Territories Power Corporation (NTPC) planned for the installation of a

2.8 MW Wartsilla gas generator to their plant in Inuvik in 2006. The projected capital cost, excluding the building related components was about $1,250 per kW. The author will use $1,300 per kW as a reasonable approximation for the 2009 capital cost of smaller scale gas engine generators, excluding building related costs since retrofit projects may be housed in existing diesel plants.

Very small scale installations, of a size appropriate for net metering applications, are also possible. Such installations are typically based on micro-turbines of 60kW or larger. However this technology is not yet fully mature and the author was unable to get appropriate information from suppliers for economic evaluation. The potential here is for these turbines to be designed for combined heat and power production, but controlled by the heat load so that the power production would follow the heat load. The attractiveness of such an arrangement would be that the power production would peak in winter when electrical loads are highest and hydro power availability is at its lowest.

Non-fuel fixed operating costs for large gas turbines were estimated at $0.011 per kWh for the LM6000 turbine operating at 90% capacity factor in the ***Energy to Mines Report***. This figure is used in subsequent analyses. For reciprocating engines, no figures were available so the author used an estimate of $0.03 per kWh for fixed operating and maintenance costs for an engine running at 75% capacity factor. The operating costs for baseload diesels is estimated to be $0.02 per kWh by Yukon Energy, and YECL experiences $0.034 to $0.039 per kWh for their small diesel plants, and it is generally acknowledged that gas fuelled engines cost less than diesels to maintain. Thus a $0.03 per kWh was considered to be appropriate for smaller reciprocating natural gas fuelled engines.

Two levels of fuel costs were considered. The base case is a cost of $5.00 per Mcf (thousand cubic feet) delivered to the plant inflated at 3% per year (1% above inflation at 2%), and the second cost level is a fuel inflation rate of 4%. These costs were assumed to include all delivery costs up to the turbine or engine.

For the purposes of the economic analyses it was assumed that the projects would have a 20 year life, the cost of capital would be 7.06%, and the inflation rate (excluding fuel) 2%. Table 9 below presents the results of the economic analyses.

Table 9: Cost of energy from natural gas projects

Parameter	**Large project**		**Small project**	
	$5.00 / Mcf + 3% PA	**$5.00 / Mcf + 4% PA**	**$5.00 / Mcf + 3% PA**	**$15.00 / Mcf + 4% PA**
LCOE	**$0.081**	**$0.086**	**$0.121**	**$0.127**
Energy $/kWh yr 1	$0.072	$0.072	$0.106	$0.106
Energy $/kWh yr 20	$0.099	$0.114	$0.146	$0.165

Geothermal

Yukon has some potential for geothermal energy which is presently being explored. The presence of warm water springs (Takhini Hot Springs) and warm water wells (Haines Junction) indicates this potential. Geothermal energy would be available on a year-round basis and could probably be turned down to follow the electrical loads as desired. Where geothermal generation plants operate they are known to be reliable.

There are few, if any, geothermal power plants in Canada but there are a number in the USA. The US department of Energy, Geothermal Energy Program, indicates that (conventional) geothermal power plants cost about CDN$2,200 (US$2,000) per kW, and that the cost for plants of less than 1MW would be in the order of CDN$3,300 to $5,500 (US$3,000 to 5,000) per kW.

A more likely type of geothermal power plant for Yukon is a binary power plant – one which can generate power from water that is less than 200°C at which temperature conventional geothermal power plants are less cost effective. A binary power plant uses an intermediate fluid such as a refrigerant with which to drive a turbine. Chena Hot Springs in Alaska installed a 400kW binary geothermal power plant which is powered by 74°C water. The cost for this 2006 project was $2.45 million (US $2.2 million) or about $6,125 per kW.

Binary power systems appear to have become available “off-the-shelf” in modular formats and their popularity seems on the increase. Such systems have the potential to generate power from other sources of residual heat too, so this technology will likely develop further and capital costs will decline as sales volumes increase.

Information from the US available on the web indicates that O&M costs for geothermal plants range from US$0.015 to US$0.045 per kWh. The operators of the Chena hot springs indicate that with their binary geothermal power plant the cost of power has been reduced to US$0.05 per kWh (2006) but there is no detailed breakdown available on this figure. At 100% capacity factor the annual cost of capital (at 7.06%) and depreciation in the early years would be over $0.08 per kWh, thus the author believes that this is the O&M cost of power. We also know that small diesel engines cost in excess of $0.03 per kWh to maintain and that the maintenance of turbines is more particular, specialized, and expensive. An O&M cost of $0.05 per kWh is thus considered to be approximately correct.

While the information base on which to develop capital and operating cost estimates is limited, it is seems likely that capital costs in Yukon will be higher than in the continental USA, and would likely be in the range of $5,000 to $10,000 per kW. For the purpose of economic analyses it was assumed that the operating and maintenance cost of a binary power plant would be $0.05 per kWh, that the capacity factor would be 90%, and that it would have a 20 year life. The cost of capital was assumed to be 7.06% and the inflation rate 2%. Table 10 presents the results of the economic analyses.

Table 10: Cost of energy from a 1MW binary geothermal power plant

Parameter	Capital cost $5,000 per kW	Capital cost $10,000 per kW
Variable O&M cost	$0.05 per kWh	$0.05 per kWh
LCOE	**$0.118**	**$0.176**
Energy $ / kWh year 1	$0.126	$0.203
Energy $ / kWh year 20	$0.107	$0.141

Technologies not analyzed (for IPPs)

There are a few technologies that were not analyzed for IPP power generation. The first is solar PV as the capital cost of solar PV, although decreasing, is still relatively high and the Yukon climate and latitude is not conducive to large scale deployment. However, because solar PV can easily be installed on roof tops and is relatively maintenance free it is well suited to net metering applications. This is explored further in a subsequent section. Gas powered micro-turbines or perhaps even diesel fuelled micro-turbines used for combined heat and power have the potential for IPP scale power generation (in district heating projects for example). However, the author was unable to get the required information from micro-turbine suppliers to analyze this potential.

Solar PV

Photovoltaic (PV) modules convert energy from the sun into electricity. Sunshine is available throughout Yukon but in more northerly locations it is much less available in winter than in summer. Cloud cover will also reduce the solar energy reaching the PV modules so areas that have cloudy conditions more often will have a lower solar power generation potential than less cloudy areas. Ideally arrays of solar modules would be adjusted constantly to directly face the sun, however since tracking systems designed to that do that are expensive, they could simply be faced south at a fixed angle of latitude less 15°, which provides the maximum energy for a fixed orientation, or manually adjusted on a seasonal basis.

Solar arrays can conveniently be located on south facing (or flat) roofs anywhere in Yukon. However, since solar arrays installed at an angle (such as latitude less 15°) will accumulate snow in winter which prevents the sun from reaching the modules, it was decided that to be practical the solar PV arrays should be tilted up to 90° (vertical) for the winter. This has the advantage of having the arrays exposed to a significant amount of sun reflected from the snow, enhancing the output of energy in mid-winter to spring – a time when water flows into our hydro systems are at their annual lows. For the summer time the arrays can then be tilted to the latitude angle which will maximize the summer energy production. Table 11 provides solar PV production per kW of capacity for various community areas based on mapping available from Natural Resources Canada (NRCan). However, solar energy is intermittent (although on a relatively predictable diurnal cycle) and would require a firm back-up supply.

Table 11: Annual solar PV energy production by community area for a 1kW PV array (vertical winter, latitude summer)

Community	Rate zone	Annual Energy kW	Capacity factor %
Beaver Creek & Burwash Landing	Small diesel	960	11.0
Dawson City	Hydro	900	10.3
Mayo	Hydro	880	10.0
Old Crow	Old Crow	840	9.6
Watson Lake	Large diesel	800	9.1
Whitehorse	Hydro	840	9.6

Figure 3 below displays graphically the solar energy that would be produced from solar PV in various community areas throughout Yukon – in all rate zones. The energy produced is from solar arrays in the vertical position for winter and at latitude for summer.

It is very noteworthy that for most communities almost half of the solar energy is produced in the period from January through May at the time when water flows into the hydro systems are at their minimum (see Figures A3, A4, and A5 Attachment A). This suggests that solar PV is at least partly complimentary to the existing hydro plants in the hydro rate zone, and can also displace a significant amount of diesel generation during the winter in the diesel zones. Of note too, would be the fact that solar energy would be produced during the day time when electrical loads are higher. As with wind energy, the supply is intermittent but in this case more predictable.

The convenience of installing net metering solar PV systems on roof tops and the very limited maintenance required is offset by the relatively high cost of purchasing and installing solar PV systems. Table 12 below provides estimates of the cost ranges for professionally installed PV systems of different sizes in various locations in Yukon. These cost ranges are based on the rapidly developing PV market in Ontario where various suppliers have published prices for PV packages of different sizes that can be purchased either for owner installation or professionally installed by the supplier, and very recent experience in Alberta. The capital costs of solar modules have decreased significantly over the latter half of 2009 in particular, and decreasing costs plus an increase in the equipment available will likely continue as world markets expand and production capacity continues to increase.

To estimate the Yukon costs the installation portion of Ontario and Alberta costs were increased by about one third to reflect increased shipping costs and higher labour rates. The Whitehorse area shipping and installation costs range from about 25% of the final installed costs for small systems to 15% for the large systems. The author increased costs for communities outside Whitehorse to cover the additional shipping and installer travel costs. In Ontario net metering customers do not need to pay for a new meter, but those who will be participating in the feed in tariff program (and who will be paid a premium for all energy produced) will be required to pay for their new meter. We do not yet know whether meters will be a cost to net metering participants in Yukon.

Figure 3: Solar PV annual electrical energy distribution by community, from NRCan

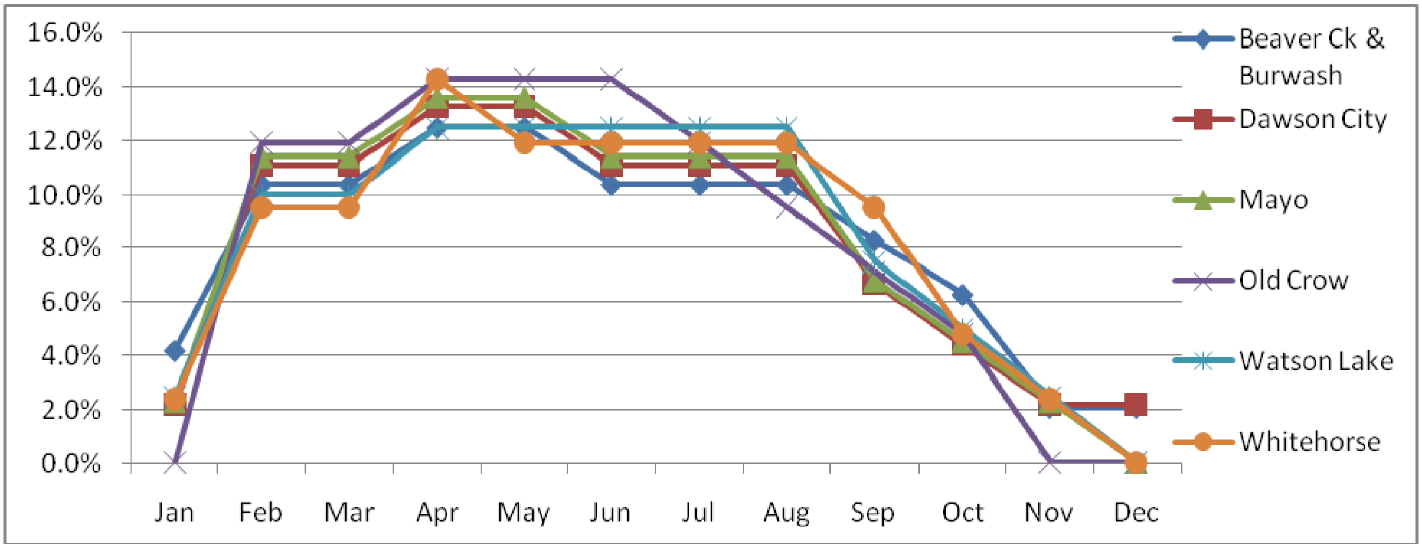


Table 12: Cost ranges for professionally installed net metering PV systems in Yukon communities

System size	Whitehorse area	Road connected communities	Old Crow
Up to 1kW, per kW	$8,000 to $10,000	$9,000 to $11,000	$10,000 to $13,000
2kW to 3kW, per kW	$7,500 to $9,500	$8,500 to $9,500	$9,500 to $11,500
Over 4kW, per kW	$7,000 to $9,000	$8,000 to $10,000	$9,000 to $11,000

The cost of energy produced from net metering PV installations is outlined in Table 13 below. The economic analyses that provided this information assume that PV systems will have a 20 year useful life, will operate at a capacity factor of 10% and will cost $100 per year per kW of capacity to maintain. The cost of capital is assumed to be 7.06% and the inflation rate is assumed to be 2%. As indicated in Table 11, the NRCan information projects capacity factors of about 9% to 11% in Yukon so the actual energy costs will vary somewhat depending on the amount of energy generated (location and site specific).

As can readily be seen from Table 13 the cost of energy from PV systems is high compared to the retail cost of power and also high compared to the cost of new energy supplies throughout the Yukon. Mitigating factors are that potential net metering customers can probably do some of the installation work themselves to reduce cash costs, and that these customers do not always require or expect the same return on capital that a utility would expect. The PV industry is expanding rapidly globally and the costs for solar modules and inverters are trending down steadily (there has been a significant decrease in the cost of solar modules in the latter half of 2009).

Table 13: Cost of energy from net metering PV installations in Yukon

Parameter	$7,000 per kW	$10,000 per kW	$13,000 per kW
Annual O&M per kW	$100	$100	$100
LCOE	**$0.875**	**$1.193**	**$1.510**
Energy $/kW year 1	$1.078	$1.491	$1.904
Energy $/kW year 20	$0.594	$0.777	$0.961

Wind energy net metering

Table 6 on page 18, outlines the installed costs for wind energy systems in Yukon, including net metering scale systems. Annual capacity factors that can be expected from small wind generators located near homes in most regions of Yukon are not likely to be much above 5%. There will, no doubt, be some specific sites where the wind resource is better and annual capacity factors of 10% or possibly more can be achieved. Some sites in the Destruction Bay – Burwash Landing area, that have good wind exposure, would be among these. In reality, though, the cost of providing wind energy to utilities through net metering installations is unlikely be better than the costs listed in Table 13, above, for PV systems. For customers interested in using wind energy in a net metering arrangement, the first priority should be to get a realistic assessment of the wind resource they will be harvesting. The wind generators should be placed on the highest available ground and on the tallest possible tower – at least 25 feet above the surrounding obstructions (trees and buildings).

As with solar PV systems, some potential wind energy net metering customers with appropriate qualifications would be able to do some or all of the installation work themselves and thereby keep cash costs lower than would be the case for third party professionally installed systems.

Summary of IPP and net metering technology suitability

The above sub-sections indicate that the various energy technologies reviewed have varying suitability for IPP and net metering installations. Table 14 below presents a summary of the suitability for IPP and net metering applications of each of the technologies discussed. The cost of electrical energy produced was not taken into account in preparing this table.

Table 14 Energy technologies: summary of their applicability for IPP and net metering

Technology	IPP	Net Metering
Micro-hydro	Fully suitable	Suitability is site specific
Biomass	Fully suitable	Not suitable
Wind	Fully suitable	Suitability is site specific
Natural gas	Fully suitable	May be suitable for larger general service customers
Geothermal	Fully suitable	Suitability is site specific and for larger general service customers
Solar PV	Not suitable	Fully suitable

6. Provincial Approaches to IPP and Net Metering

IPP approaches

Most provinces encourage independent power producers using a variety of approaches. Saskatchewan does not have a policy for projects above 100kW but is considering a standing offer program (SOP) to encompass projects from 100kW to several MW. Only Manitoba and Newfoundland and Labrador (NL) have no specific programs, although Manitoba does have guaranteed open access to transmission for IPP projects of up to 10MW. Quebec and Prince Edward Island (PEI) have no general programs but actively target wind energy development through private producers by request for proposals (RFP).

British Columbia (BC), Alberta, Ontario, New Brunswick (NB), and Nova Scotia (NS) all have SOP or feed in tariff (FIT) programs. BC and Ontario SOP have limits of 10MW (the Ontario FIT program will not have limits), NB has 3MW, and Alberta presently has 1MW although there has been some unhappiness with this level and consideration may be given to a higher threshold. With the exception of Alberta where power pool prices prevail, all provinces with programs have specified tariffs or rates paid to IPPs. Ontario is redesigning their program to become a FIT program with no capacity limits, however, the rates paid to IPPs will vary with project size.

Various provinces (BC, Saskatchewan, NB and others) have, in addition to SOP, issued RFPs targeted at renewable or specific supplies (biomass and wind).

The IPP programs in all provinces target renewable energies and many specify EcoLogo certifiable sources of power as a requirement. BC and Ontario appear to have the most aggressive approaches to IPP development as they will be depending on them to achieve power independence (BC) or to replace coal fired power generation (Ontario), as well as new load growth.

BC and Ontario not only specify fixed rates that apply but have rate structures that encourage generation during higher load periods (winter, and daytime) by having seasonally adjusted and time of day adjusted rates. Premiums are paid for generation during higher electrical load times and reduced payments apply to off-peak generation.

All provinces with IPP or related programs have published interconnection standards that need to be met.

Contract periods are typically 20 years but there are exceptions. BC allows SOP program participants to select contract periods of 20 to 40 years, and RFP respondents may choose contract periods of 5 to 20 years. Ontario's FIT program will offer contracts of 40 years for hydro projects and 20 years for other technologies.

Only BC deals specifically with non-integrated (usually diesel served) communities by having targeted RFPs or other approaches to serve these customers more cost effectively. The Atlin mini-hydro (2.4MW) project is an example of this approach. No other province was determined to have targeted programs for isolated communities but the author has personal knowledge that Quebec (specifically Hydro-Quebec (HQ)) is interested in alternatives to diesel generation in their remote communities. In addition HQ has issued a specific RFP for wind power to be purchased from community and First Nations' projects connected to the grid.

In most jurisdictions, the governments have set the overall policy direction with respect to the objectives and broad parameters of an IPP policy, and have issued directions to the public utility boards (PUB) and utilities to deal with the specifics or details of such things as interconnection standards, rules, processes, and, in some cases, rates. In some of these jurisdictions legislation needed to be changed to enable the government to issue the relevant directions. Thus the PUBs and utilities are both very involved and in are very important participants in the development of fair and appropriate processes for carrying out the government's policies.

In some cases governments provide incentives or general information to assist developers. Examples are reduced water royalty rates in BC, and a wind resource map and developer's guide in NB.

More detailed information on IPP issues by jurisdiction is provided in Attachment B to this report.

Net metering approaches

All provinces with the exception of NL have net metering programs. Neither NWT nor Nunavut has a net metering program although it is not prohibited in NWT, and the author understands that net metering is beginning to be discussed in Nunavut. A PUB ruling (at the request of Northwest Territories Power Corporation (NTPC)) in NWT actually discourages net metering projects larger than 5kW as these customers are required to pay triple the normal monthly demand charge ($24 per kW per month as opposed to $8) as a stand-by fee. Alberta prefers to call their program net billing as net production is metered separately from net consumption (it is actually the same in all provinces).

With the exception of Ontario's pending FIT program in which even net metering scale projects can participate, customers only get "paid" the retail rate for their own generation. This is usually well below the actual cost of the energy generation, and only three provinces will actually pay for excess generation accumulated at the end of the netting period (BC, Alberta, and Manitoba). BC is the only province to pay a premium, albeit small, for excess generation. The Ontario FIT program will pay premium rates for all generation from small scale projects if the clients select the FIT program as opposed to the net metering program (the FIT program requires separate metering of the generation). The netting period is one year in all jurisdictions except in Quebec, where it is 2 years.

In all jurisdictions that have it, net metering appears to be a token program to allow customers who want to self generate to do so. Participation rates have been extremely low; only SaskPower indicated that they had participation rates higher than expected (still only 50-75 for the whole province). None of the provinces expect any meaningful contribution to their energy supplies from net metering. The limited information obtained from the USA indicates that various states are much more aggressive in their pursuit of net metering generation. For example Nevada is targeting 4% of their energy to come through solar net metering arrangements.

The allowable size of net metering projects ranges from 50kW (BC, and Quebec) to a high of 1MW (Alberta). Manitoba is the exception in that they allow up to 10MW because of a history of self generation by industry. Most provinces have lower limits for single phase connections and / or connections at the household voltage level (120/240V single phase) although customers can pay for upgrades to enable larger projects. All provinces also target clean or EcoLogo technologies as a requirement.

All jurisdictions have published interconnection standards and the majority of these have simplified processes for the interconnection of small net metering projects with grid dependent and CSA and or UL approved inverters that have anti-islanding protection and other appropriate features. Most provinces that identify a threshold for this simplified process have it set at 10kW, but BC's limit is 5kW.

In the majority of jurisdictions the utility will pay for (and add to rate base) the cost of the new meter. Only Saskatchewan has a significant financial incentive program that will pay up to 35% of the up-front capital cost of renewable energy net metering (and small power producer) systems. PEI has a specific program that contributes up to $180,000 out of about $250,000 for the installation of a 50kW wind generator at community rinks. Some provinces have exemptions from provincial sales taxes for renewable energy equipment, and for corporations participating in net metering there are some significant federal tax treatment benefits to renewable energy systems.

Of the people the author spoke to, the majority seemed, at least on a personal basis, to be more inclined to capital subsidies if subsidies are to be offered, so that they would not interfere with the established public processes for setting electrical rates and the resulting rate structures. But there was acknowledgement that paying for actual production would encourage owners to keep systems running. Overall there was a concern that significant participation in net metering would drive retail power rates up.

As with IPP policies, the provincial governments have set the overall broad goals with respect to net metering and issued directives to the PUBs and utilities in order to have their objectives carried out. The utilities generally put the details of programs and processes in place and PUBs reviewed these to ensure they were appropriate and fair.

Attachment C to this report provides more detailed information on net metering issues by province.

7. Considerations for IPP and Net Metering policy development

IPP considerations

Section 3 (and Attachment A) of this report outlines the present electrical loads and costs for the existing rate zones of Yukon and section 4 outlines the new supply costs that are planned or expected. In the hydro zone there are two additions planned. The first is the Mayo B hydro project which will generate energy (38.4 GWh per year) at a LCOE of about $0.245 per kWh ($0.324 with transmission). The second is the Aishihik third turbine which will provide energy (5 GWh per year) at a LCOE of $0.136. The existing fleet of diesel generators owned by Yukon Energy produce incremental energy at a LCOE of $0.283 per kWh (fuel at $0.75 per liter, 10% losses, $0.016 variable O&M, and 3% per year fuel inflation) whereas new state of the art baseload diesel generation would produce energy at a LCOE of $0.281 per kWh with fuel inflation at 3% per year (at 4% per year fuel inflation the LCOE is $0.303).

Incremental energy in the large diesel zone has a LCOE of $0.258 per kWh, in the small diesel zone it is $0.323 per kWh, and in Old Crow it is $0.567 per kWh. At 4% fuel inflation the LCOEs would be $0.278, $0.349, and $0.615 respectively. If the cost of diesel generation is the benchmark for alternative energy supplies then there is only a modest difference between any of the zones (a range of $0.06 per kWh) except for Old Crow where the cost of fuel is substantially higher.

The Aishihik third turbine will provide energy at a LCOE substantially lower than that resulting from diesel generation, and the LCOE of the new Mayo B hydro project without transmission will be marginally lower than the LCOE of diesel generation. In the hydro zone incremental diesel generation would be cheaper than Mayo B for about 10 years. If diesel prices go up at rates higher than the assumed 3% per year (general inflation at 2%) this cross-over time will decrease.

Section 5 discusses potential IPP generation technologies and the resultant costs of energy. All the technologies explored in this section applicable to the hydro zone have the potential to be less costly (LCOE) than energy than would be the case from either existing or new baseload diesel generators. Micro-hydro, binary geothermal and natural gas technologies applicable to the large and small diesel zones were also found to have lower LCOEs but small scale wind energy which has a somewhat higher LCOE than the existing diesel supply. In Old Crow all applicable technologies are potentially able to produce energy at a lower LCOE than diesel generation.

Micro-hydro has the potential to produce energy at an LCOE of $0.098 to $0.217 per kWh. The one matter to be explored is whether the plant output will follow the typical water runoff pattern or whether it can be designed to peak in winter to follow the winter peaking electrical loads.

Forest biomass on a fairly large scale for Yukon (10 MW) should be able to produce energy with an LCOE in the range of $0.220 to $0.342 per kWh, which is competitive with diesel generation up to the mid to upper part of this range. Such a plant should be able to be operated at full capacity in winter and could probably be shut down or decreased in output in summer. Because most of the costs are variable – fuel and O&M – the yearly energy costs decrease only modestly over time.

Wind energy from a project of about 10MW should be able to produce energy at an LCOE of $0.179 to $0.222 per kWh, actual annual costs decrease over time. Wind energy is the only energy source identified that peaks in winter when electrical loads are highest. Its disadvantage is that it is intermittent and not dispatchable. This means that another energy source, such as hydro or diesel, will need to be used to provide the system demand when the electrical load is high and the wind is not blowing.

A small scale (200kW) wind project in the small diesel zone is expected to produce energy at an LCOE of $0.380 to $0.488 which is noticeably higher than the diesel generation LCOE of $0.323 ($0.349 at 4% per year fuel inflation). In Old Crow a small scale wind energy project is projected to produce energy at an LCOE of $0.488 to $0.647 per kWh which is somewhat lower to slightly higher than the diesel LCOE of $0.567 ($0.615 at 4% per year fuel inflation).

Large scale natural gas power generation should be able to produce energy at an LCOE of $0.081 ($0.086 per kWh at 4% per year fuel inflation). Small scale natural gas generation using reciprocating engines is expected to produce energy at an LCOE of $0.121 ($0.127 at 4% per year fuel inflation). This is very attractive compared to diesel generation in every rate zone, and even with the Aishihik third turbine in the hydro zone. If and when natural gas becomes available there is virtual certainty that it would be cheaper than diesel generation as well as producing significantly less greenhouse gas emissions.

The final source examined was binary geothermal power plants. Although no source of this geothermal energy has been identified to date, this technology could produce power at an LCOE of $0.118 to $0.176 per kWh.

Table 15 summarizes the present systems projects' LCOEs as well as the potential IPP technology LCOEs.

Table 15 LCOEs of present power systems projects and potential IPP projects

Technology/Project	Parameter description	LCOE
Present Systems		
Mayo B	No transmission	$0.245
Mayo B	With $40 million transmission	$0.324
Aishihik third turbine		$0.136
Hydro zone, new diesel	Baseload diesel, $0.75 / l, fuel inflation 3%	$0.281
Hydro zone diesel	Incremental diesel, $0.75 / l, fuel inflation 3%	$0.283
Large diesel zone	Incremental diesel, $0.75 / l, fuel inflation 3%	$0.258
Small diesel zone	Incremental diesel, $0.75 / l, fuel inflation 3%	$0.323
Old Crow zone	Incremental diesel, $0.75 / l, fuel inflation 3%	$0.567
Potential IPPs		
Micro-hydro	Capital cost $5,000 per kW	$0.098
Micro-hydro	Capital cost $10,000 per kW	$0.157
Micro-hydro	Capital cost $15,000 per kW	$0.217
Forest biomass	Capital $5,000 per kW, wood $0.10 per kWh	$0.220
Forest biomass	Capital $5,000 per kW, wood $0.15 per kWh	$0.279
Forest biomass	Capital $10,000 per kW, wood $0.10 per kWh	$0.283
Forest biomass	Capital $10,000 per kW, wood $0.15 per kWh	$0.342
Wind – large 10 MW	Capital $3,000 per kW	$0.179
Wind – large 10 MW	Capital $4,000 per kW	$0.222
Wind – small 200 kW	$5,500 per kW	$0.380
Wind – small 200 kW	$7,500 per kW	$0.486
Wind – 200 kW Old Crow	$7,000 per kW	$0.488
Wind – 200 kW Old Crow	$10,000 per kW	$0.647
Natural gas 42.8 MW	Gas turbine, $5.00 per Mcf, fuel inflation 3%	$0.081
Natural gas 2.8 MW	Gas engine, $5.00 per Mcf, fuel inflation 3%	$0.121
Binary geothermal	$5,000 per kW	$0.118
Binary geothermal	$10,000 per kW	$0.176

There is thus ample indication that IPP power supplies could provide cost effective energy to Yukon ratepayers in all rate zones compared to diesel generation if given an adequate opportunity to do so. In the hydro zone it appears that only natural gas, a non-renewable energy supply, would be close to competitive with the Aishihik third turbine which is by far the best project today – both from an LCOE and winter peaking perspective. All identified IPP technologies would have a lower LCOE than Mayo B except the higher cost cases of forest biomass power production. The higher cost forest biomass cases would still have a lower LCOE than Mayo B if the transmission cost is included. It would appear that potential IPP developers should be given an opportunity to explore the options available to them and where cost effective encouraged with secure power purchase agreements (PPAs).

Matters to be considered in policy development include: allowable project size, rates at which power is to be purchased, PPA term, and interconnection standards. The first three items on the list will probably need to be varied by rate zone.

Project size

With respect to allowable project size a modest limit of say 1MW would open the door for micro-hydro opportunities through all rate zones, although projects in the diesel zones would need to be scaled to the community load. It is likely that a 1MW limit would preclude forest biomass and wind energy development in the hydro zone as the necessary economies of scale to produce cost effective energy could not be achieved. To effectively open the door to natural gas, wind, or forest biomass generation in the hydro zone the project size would need to be at least 5MW and perhaps 10MW. Wind generation in diesel zones can likely be accommodated within a 1MW limit (perhaps marginal in large diesel – if there is a wind resource of interest in Watson Lake).

The most significant challenge with respect to choosing an IPP size is the amount of generation required in the various zones. With the Aishihik third turbine and the Mayo B projects in operation (they are both in development) there will probably be enough hydro to meet the expected new mining loads (Alexco in Keno City [21-25 GWh per year], and Western Copper near Carmacks [48 GWh per year]) except for winter peaking. The advantage of setting a lower IPP limit is that several new small projects could be added to the hydro system without oversupplying the system, whereas one larger project could oversupply the grid. This could effectively block any new smaller projects for a period of years. A larger energy supply requirement could be dealt with through the issuance of an RFP targeted at the potentially larger projects (biomass, wind, etc.). Or larger projects could be invited and dealt with on a case by case basis. Either way it will be an important consumer cost consideration not to overbuild new energy supplies.

Rates

Rates to be paid to IPP suppliers could be determined in a few ways. They could be specified in a FIT or SOP program. Such a program may specify rates that vary by rate zone and / or season and / or time of day. Such rates could reflect the marginal diesel cost or longer term hydro costs and be essentially the same for the hydro, large diesel, and small diesel zones but higher in the Old Crow zone. For the hydro zone a specific rate structure could be used to encourage winter season and daytime energy production in much the same way as BC does it in their SOP.

PPA term

PPA terms should be in the order of 20 years to allow developers to secure financing. A term consistent with the provinces may also attract some experienced developers to consider projects in Yukon. It may be that if larger IPP hydro projects were to be considered, longer PPA terms would be required as they are typically depreciated over longer periods of time.

There is one risk issue faced by all generation projects in the hydro zone, that of uncertain mining loads which can come and go in time frames of as little as 2 to 5 years. Projects developed by Yukon's utilities deal with these risks and IPP projects will also need this risk to be dealt with. One option would be to develop, within the PPAs, terms which would have the IPPs shutdown their plants to reduce their costs and allow these cost reductions to flow to the consumers while keeping the developer financially whole.

Interconnection standards

Interconnections standards should be developed for Yukon. These could be developed by adapting those of Alberta or any of the other provinces' standards to Yukon's requirements. NWT has interconnection standards that are believed to be a modification of the Alberta standards.

IPPs and isolated industrial customers

With respect to the potential for IPPs to serve isolated industrial customers such as mines, the author sees no issue with this as the ***Public Utilities Act*** in Section 1 Interpretation, exempts, in the author's opinion, any IPP who serves a mine from being considered a public utility. Thus it is a relatively simple matter of negotiation between the two parties. Such an IPP could sell excess power to a public utility and still be exempt.

Net metering considerations

There is only one technology that stands out as being particularly well suited to net metering – solar PV. Small scale versions of wind and micro-hydro, and possibly other technologies, are also possibilities in very specific cases.

Based on information from NRCan, about half of the energy supplied by appropriately situated solar arrays will be available in winter to late spring when water flows into the hydro plants and reservoirs are at their annual lows. This will make a good portion of the solar energy directly useful. The solar energy is also supplied during daytime hours when electrical loads are highest.

Matters that need consideration in the development of a policy include: the allowable project size; the technologies permitted, the interconnection standards, which party pays for the meter, the netting period, and whether excess generation over the netting period is purchased or forfeited.

Allowable project size

Allowable project sizes could be scaled to the customer type – residential or general service. A number of provinces have relatively large maximum sizes but have a simplified process for inverter connected customers who have 10kW or less of generation. Something in the range of 3 to 10kW could be set for a residential limit. General service customers, particularly those with three phase services, likely justify a higher project limit.

Permitted technologies

As with all provinces, the technologies could be limited to renewable power supplies. A possible and reasonable exception might be general service customers who could employ a combined heat and power technology. Such technologies if operated on the basis of heat requirement would be winter peaking – just when the generation is needed.

Interconnection standards

Interconnection standards should be developed and made publicly available. It would be advantageous if such a standard included a simplified process for CSA and / or UL Canada approved grid dependent inverters, with a limit of say 10 kW to be consistent with many provinces.

Meter cost responsibility

Costs for the net metering projects themselves are almost always the responsibility of the net metering customer, but the majority of provinces (or their utilities) will pay for the required bi-directional meter.

Netting period and value of excess generation

The netting period is almost always one year and in many provinces the netting date is specified. There is no need to re-invent this wheel in Yukon. Generation credits in any particular month are carried forward month by month to the netting date at which time they are paid out or forfeited. There are a few provinces that pay for excess generation in a netting period but most do not. It is also important, in the author's view, not to impose a punitive demand charge on these (potential) customers as NWT has done.

8. Considerations for IPP and Net Metering Cost Support

IPP cost support considerations

IPPs are generally expected to pay their own way in all respects, but they do often get some incidental support – besides the favourable federal tax treatment available to corporations. Occasionally they get reduced water rates (micro-hydro in BC) and other indirect support. The only example direct support at present is in Saskatchewan where the government provides a grant of up to 35% of the capital cost of a renewable energy project up to a maximum of $35,000. But in Saskatchewan the Small Power Producer Policy is limited to 100kW – quite small.

Section 7 of this report outlined a number of technologies that have the potential to be more cost effective than utility developed power supplies (whether subsidized by government funds or not). In the author's view a reasonable published rate as part of an SOP or FIT program plus a commitment to a 20 year PPA should be adequate incentive to attract IPP attention. However, the published rate has to reflect the reality of new power supplies in Yukon – i.e. it should be equivalent to the utility developed power projects whether hydro or diesel. If the GY is prepared to subsidize utility projects the GY is probably also prepared to provide an equivalent level of support for IPP projects having exactly the same attributes. PPAs may need to have clauses that deal with the risk of loss of industrial (mining) loads.

In the diesel rate zones where electrical loads are small some government financial support may be required to make the small scale projects economic compared to diesel and thereby reduce or eliminate the diesel generation in those communities.

Net metering cost support considerations

Based on the economic analyses in this report (Section 5) net metering is not likely to result in cost effective new energy supplies. If GY is interested in having net metering customers contribute a meaningful amount of energy to the grid, cost support will need to be provided.

As a first consideration net metering customers could get support for their generation at the marginal cost of utility generation. In diesel zones this would be the existing or projected cost of incremental diesel generation which applies on a year-round basis. In the hydro zone this may be the marginal cost of diesel generation or a new hydro supply. Creativity could also be shown in devising seasonal rates (higher in winter) or time of day rates (higher in the daytime). Time of day rates would require more sophisticated (and probably more expensive) metering and accounting systems and thus their practicality, in comparison to simpler seasonal rates, would need to be considered for that reason.

Alternatively, net metering customers may be provided with a capital subsidy to help purchase and install their systems. This may eliminate the need for a production incentive based system which will require separate metering and a more involved accounting / billing system (for modest amounts of generation). In the capital subsidy case it would also seem reasonable for the utilities to pay for the simpler new meters required or to consider that cost part of the subsidy.

Ontario is going to the extent of setting FIT rates that will allow participants to earn what the province believes is a reasonable return on their project cost. Hence the very high value of $0.802 being placed on generation from home scale solar PV systems. Although this is not strictly a net metering program, customers considering a solar PV system will likely opt to the FIT program rather than for the net metering program. Ontario appears to want a serious amount of generation from small projects.

9. Conclusions

1. Electrical generation LCOE figures (per kWh) in the various rate zones for the present systems, as well as planned new utility supplies and potential IPP supplies, are outlined in table 16 below. The LCOEs are calculated over the expected life of the technologies: 50 years for utility hydro, 30 years for micro-hydro, and 20 years for all other technologies.

Table 16: Energy supply LCOEs in $ per kWh for present systems, planned projects, and potential IPP supply technologies by rate zone (N/A means not applicable)

Technology	Rate Zones			
	Hydro system	**Large diesel**	**Small diesel**	**Old Crow**
Present costs per kWh (not LCOE)	Hydro all-in $0.10 Diesel $0.26	$0.21	$0.26	$0.45
New Energy Projects (LCOE)				
Aishihik 3rd turbine	$0.136	N/A	N/A	N/A
Mayo B no trans	$0.245	N/A	N/A	N/A
Mayo B + trans	$0.324	N/A	N/A	N/A
Existing diesels	$0.283	$0.258	$0.323	$0.567
New baseload diesels	$0.281	N/A	N/A	N/A
IPP projects (LCOE)				
Micro-hydro	$0.157 to $0.217	$0.157 to $0.217	$0.157 to $0.217	$0.157 to $0.217
Forest biomass - large	$0.220 to $0.342	N/A	N/A	N/A
Wind - large	$0.179 to $0.222	N/A	N/A	N/A
Wind - community	N/A	$0.380 to $0.486	$0.380 to $0.486	$0.488 to $0.647
Natural gas - large	$0.081	N/A	N/A	N/A
Natural gas - small	$0.121	$0.121	$0.121	Unsure of availability
Binary geothermal	$0.118 to $0.176	$0.118 to $0.176	$0.118 to $0.176	$0.118 to $0.176

The figures outlined in the above table indicate that the identified IPP technologies can produce electricity at lower costs than diesel generation in all rate zones except for more costly forest biomass cases in the hydro zone and small wind installations in the large and small diesel zones. All technologies appear to be able to produce electricity at costs competitive with Mayo B but with the exception of natural gas, no IPP projects can compete with the LCOE from the Aishihik third turbine.

All projects in remote areas will cost more than in Whitehorse, so while the numbers for some technologies seem to indicate that they would cost no more in remote areas, the cost ranges examined are intended to be broad enough to encompass this cost variation.

2. There are some technologies that appear to be applicable to net metering but these will not be economic on their own in any rate zone except in exceptional circumstances. These are listed below. (Suitably qualified customers may be able to install their systems at lower cost).

- Micro-hydro is likely going to be possible only in specific circumstances and costs are likely as high or higher than those outlined for IPPs above, with an LCOE of up to $0.217 per kWh (or higher). Perhaps most applicable to general service customers;
- Natural gas is a potential energy source when used in micro-turbines to produce heat and electricity and controlled by heat requirement with electricity being the byproduct, however, suppliers did not provide the relevant information to the author to enable an economic analysis;
- Binary geothermal is likely going to be possible only in specific circumstances too, and LCOEs are likely as high or higher than those outlined for IPPs above - $0.176 per kWh and higher. This technology is most applicable to general service customers;
- Wind energy is also likely going to be possible only in specific circumstances and LCOEs are likely as high or higher than those outlined for solar PV below – about $1.00 per kWh and higher; and
- Solar PV is the one technology that would be convenient for all residential and general service customers in all rate zones. Solar arrays can be mounted on south facing roof slopes (or flat roofs) on virtually any home or building. The LCOE range, depending on the size of project and location would be $0.875 to $1.510 per kWh.

3. There are a variety of IPP programs delivered in provinces across Canada that can be used as templates in the design of a Yukon IPP policy. It is recommended that the following attributes be considered when developing an IPP policy:

- Published standard offer or feed in tariff rates;
- Published interconnection requirements (can be taken from another jurisdiction and adapted for Yukon;
- A published list of acceptable technologies;
- 20 year (or more) contract periods;
- A project capacity cap of about 1MW and or a zone specific cap; and
- RFP processes or case by case consideration specifically for larger capacity forest biomass, natural gas, and wind projects.

4. Net metering is in place in all but one province. The existing policies can assist Yukon policy makers in their work. Net metering is appropriate to all rate zones but would provide most value in the three diesel zones. It is recommended that the following attributes be considered when developing a net metering policy:

- If GY wants to have net metering make a meaningful energy contribution to the electrical grid, funding assistance will be required. This could be provided in the form of a capital grant or a higher separately metered feed in tariff. A capital grant would be simpler to administer and would involve minimal ongoing effort but would cost more up-front and may result in a lower customer commitment to ongoing energy production, whereas a feed in tariff would require an ongoing accounting and billing commitment (higher administration cost) but would cost less up-front and would encourage ongoing production;
- A published interconnection standard including a simplified process for connecting CSA or UL Canada approved grid dependent inverters of no more than 10kW capacity;
- The utility to provide the appropriate metering (in rate base);
- A one year netting period;
- Payment for any excess generation; and
- Standardized agreements.

5. The ***Public Utilities Act*** appears to allow for GY to develop the policies it considers appropriate and to provide the necessary direction to the YUB to bring them to fruition. The YUB can provide the necessary direction to the utilities through its orders. GY could also provide direction to Yukon Energy through the Yukon Development Corporation but such directions would not be binding on YECL. The ***Public Utilities Act*** also appears to allow for any IPP to directly serve a single customer (such as a mine) and even to sell excess power to a utility.

6. The existing hydro-electric power plant reservoirs receive the bulk of their water inflows in early summer (Whitehorse Rapids in late summer) and reservoir management enables the water releases into the power plants to be adjusted to match the wintertime high electrical load periods to a reasonable extent. The Aishihik third turbine project will further enhance this ability to use stored water for winter generation.

7. Electrical loads in all rate zones in Yukon peak in winter and are at their minimum in summer. Through all seasons daytime loads (about 6 AM to 11 PM) are higher than during the night. Mining loads tend to be constant throughout the year.

8. Ideal new power supplies are ones that can supply the bulk of their power during the winter when electrical loads are highest and water inflows at their minimums.

Attachment A

Present Yukon Power Supply Status

Electricity is supplied to Yukon's people by a number of non-integrated power systems. The largest system serves southern Yukon and is generally known as the Whitehorse – Aishihik – Faro (WAF) grid (or system) which is hydro based (principally Whitehorse Rapids and Aishihik power plants). This grid is supplemented as necessary by diesel generation. The next larger grid is the Mayo – Dawson grid which is also hydro based (Mayo hydro plant) and is also supplemented by diesel. In recent years transmission line development aimed at interconnecting these two hydro based grids into a single grid has been undertaken. This was facilitated by a mining customer that wanted power service and is located roughly half way between these two systems. These two grids together are considered the hydro rate zone for electrical rate purposes.

The other rate zones are "large diesel" for diesel generation only served larger communities (Watson Lake and formerly Dawson City); "small diesel" (Swift River, Destruction Bay & Burwash Landing, and Beaver Creek) which captures all road accessible small communities served by diesel generation only; and "Old Crow" which is a small community not accessible by roads for which diesel fuel has to be brought in by air transport.

The hydro zone's non-industrial electrical load pattern (excluding the surplus hydro secondary sales) for 2008 is displayed in Figure A1 below. As can be seen, the electrical loads are highest during the colder and darker winter and least during the warmer and lighter summer. The industrial load forecast (the Minto mine) is even throughout the year, and the surplus hydro secondary sales have been much higher in winter than in summer as this is space heating focused and surplus hydro had been available year-round until the winter of 2008-2009. In future secondary sales will be lower (or even nil) winter due to the limited availability of surplus hydro. Figure A2 provides the hydro zone 2008 loads with a full year forecast of the Minto mine added in and secondary sales removed. Potential future mining loads will, like the Minto mine, tend to be flat throughout the year.

Figure A1: Non-industrial electrical load distribution (2008)

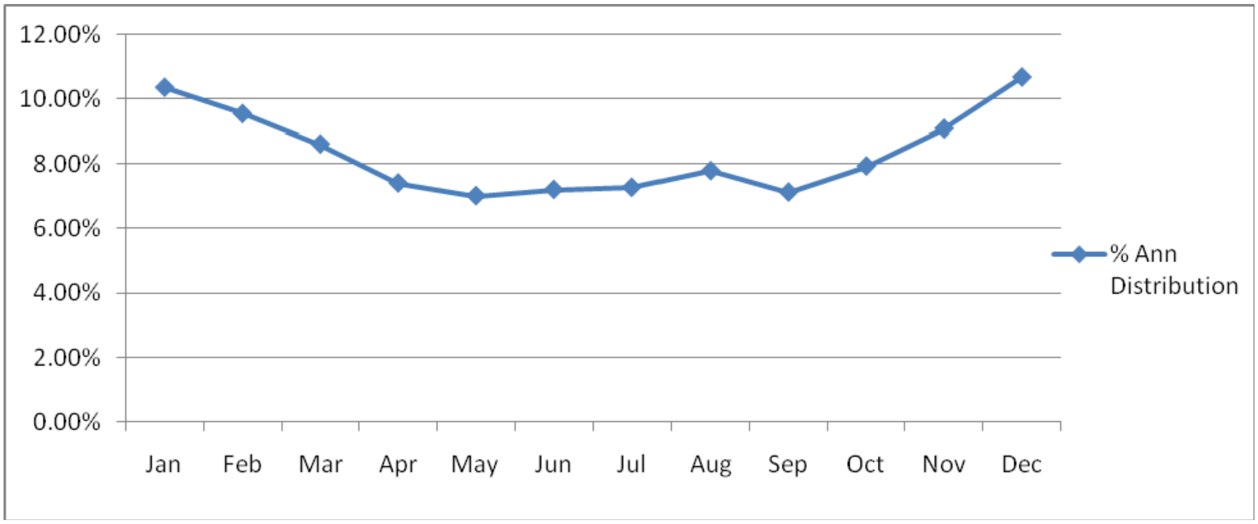
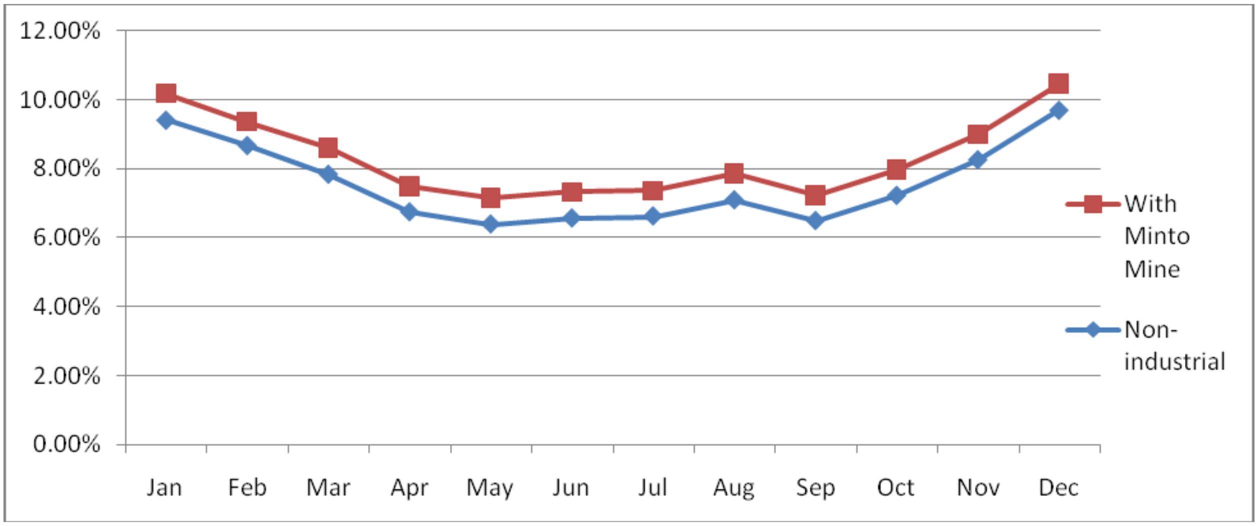
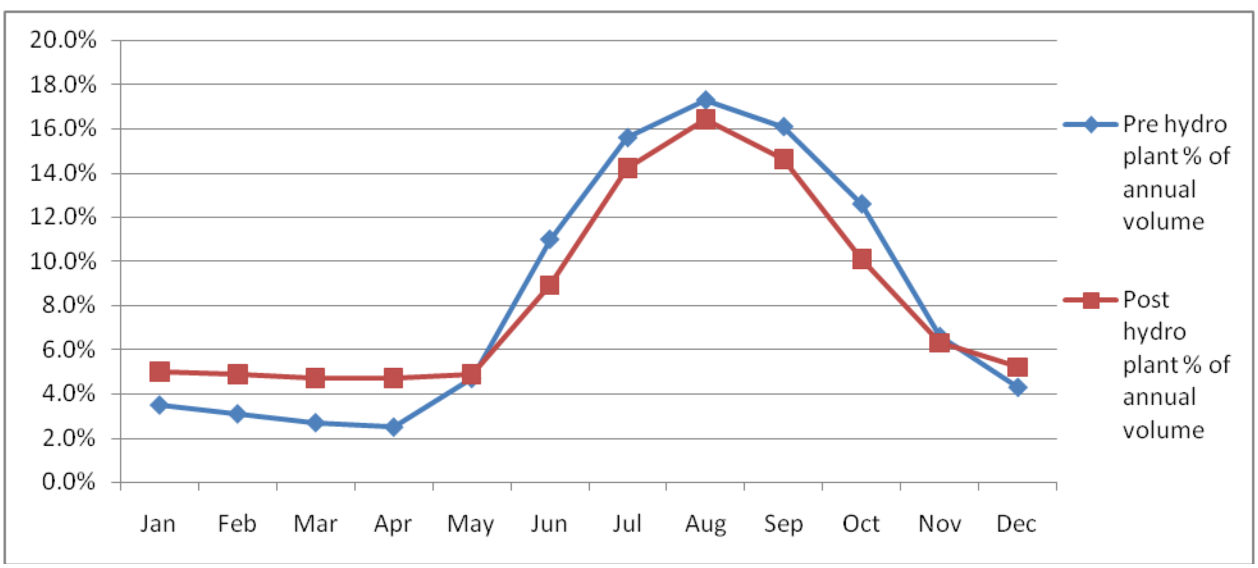


Figure A2: Electrical load distribution with full year Minto mine (2008 + full year mine load forecast)



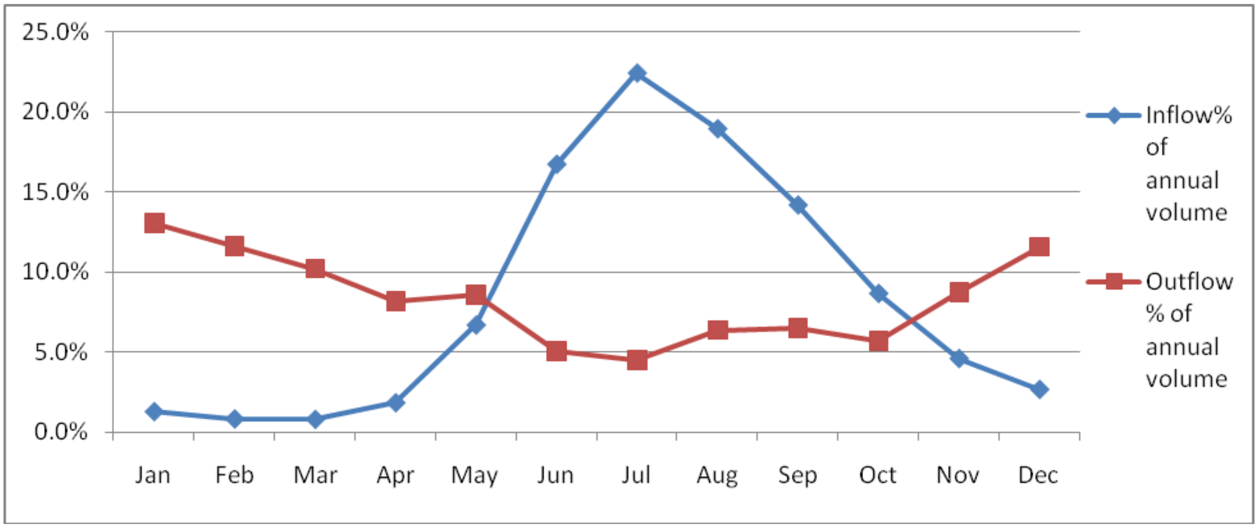
The water flows that supply the hydro generation are described in the following figures. Figure A3 describes the Yukon River flow patters prior to (1944-1967) and following (1968-2007) the development of the Whitehorse Rapids power plant. As can be seen the regulation of the water reduces the flows during spring and summer and increases them during the winter and spring compared to pre-development. The Yukon River is fed principally by melting glaciers in the Coastal Mountains which occurs in the heat of summer rather than by the spring snowmelt that takes place a couple of months earlier in the year. Thus, the peak flows are typically in August. Flows are further attenuated by the large lakes upstream of the hydro plant (Atlin, Tagish, Bennett, and Marsh Lakes).

Figure A3: Yukon River flow pre and post hydro plant development



The principal water flows into Aishihik Lake, which also functions as the reservoir for the Aishihik power plant, is the Sekulmun River and its flows (1981 to 2007) are presented in Figure A4 along with the outflow for a period of five years during which the water was being almost fully utilized and little spillage was necessary (1993-1995 plus 1997-1998; 1996 data is not available). There was some summer spillage in 1994. Its peak inflow is in the month of July and represents the snowmelt at higher elevations attenuated somewhat by Sekulmun Lake (relatively large). The outflow however, has been completely regulated to provide the winter flows necessary to meet peak winter power demand during that period of time.

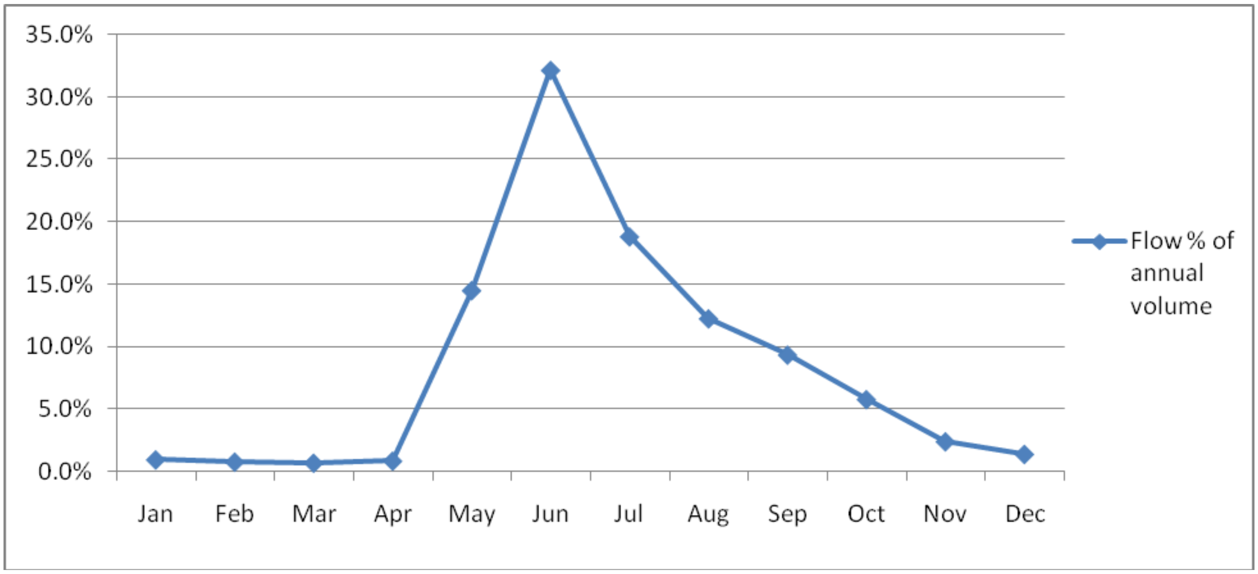
Figure A4: Aishihik Lake inflow and outflow distributions



The Water Survey of Canada Mayo River data is virtually non-existent, thus the Stewart River flow for which some reliable flow data is available (1949-1979) is used to illustrate the pattern of water inflow to Mayo Lake which is regulated for the benefit of the Mayo hydro plant. Figure A5 presents the Stewart River monthly flows as a proxy for the Mayo Lake inflows. These flows are also regulated: storage in the summer in Mayo Lake to the extent permitted and additional discharge in the winter to meet the electrical load requirements. The 5MW Mayo Hydro plant can operate at near full capacity throughout the winter. Surplus summer water is released through the spillway of Wareham Lake – the forebay for the Mayo hydro plant.

Figures A3 through A5 illustrate the actual water inflows and how they are regulated to meet the electrical load profiles illustrated in Figures A1 and A2. The fact that the water supply is out of sync with the electrical load by about 6 months gives rise to the availability of surplus hydro power in summer and gives rise for the need to meet winter peak loads with some diesel generation.

Figure A5: Stewart River flows as proxy for Mayo Lake inflow

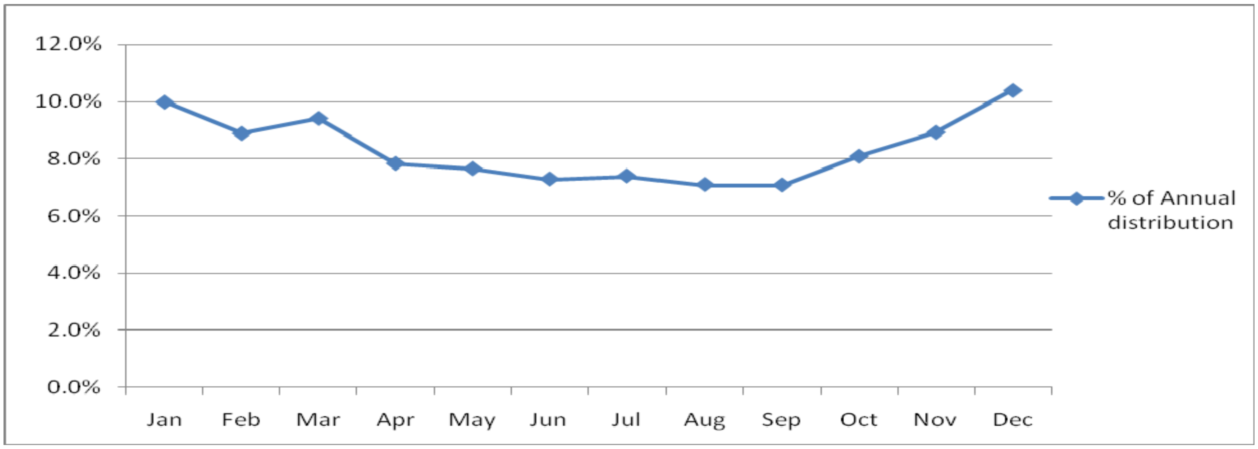


These very same issues are relevant to the technologies and sources of power that would or could be supplied by IPPs and net metering customers on the hydro system. To the extent that power sources are in step with the present water flows for hydro generation they will be of the same value as existing power supplies and contribute to the existing patterns of surplus hydro and diesel peaking. To the extent these new power sources are out of step with water flows and in step with actual electrical loads they will tend to complement the existing power supplies and tend reduce surplus hydro and diesel peaking.

The annual load pattern in the diesel served communities and rate zones is similar to the non-industrial load pattern in the hydro system. Figure A6 presents the annual load distribution in Watson Lake (for 2007), the only community for which this level of detailed information was available to the author. The small diesel served communities probably have very similar distributions. Old Crow might have a slightly lower percentage summer load as many people still follow a traditional lifestyle and spend time on the land away from the community.

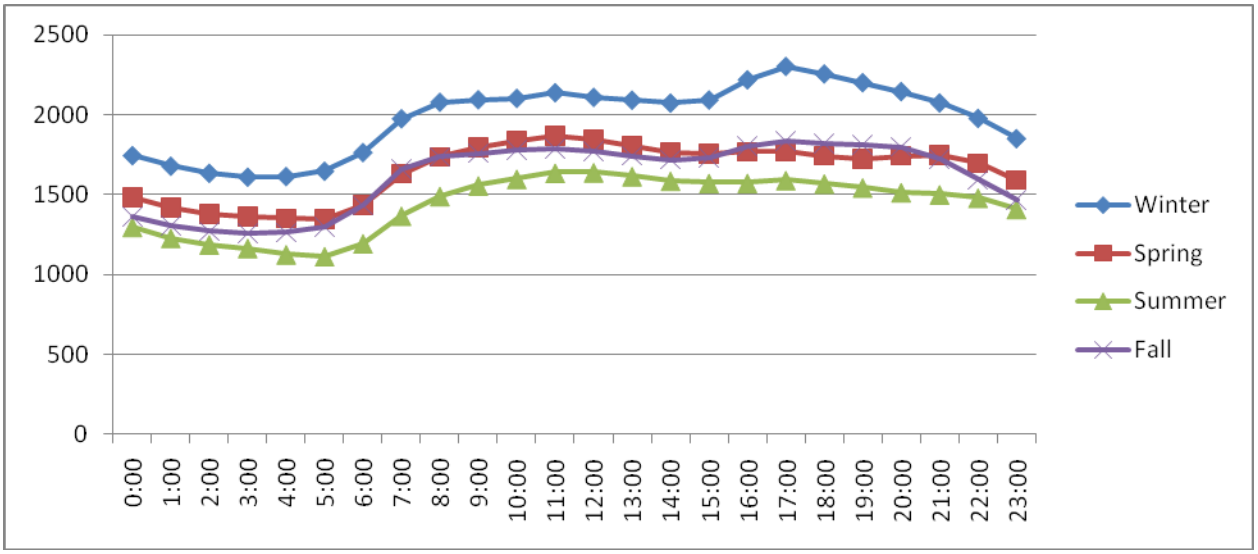
The one significant difference between the three diesel generation served rate zones and the hydro served rate zone is that diesel fuel is always on the margin and can be dispatched as required to meet the loads experienced. Diesel generation would always be displaced by any new marginal source of generation. Unless a significant hydro project or projects are brought to fruition, there will be no “surplus” power available in diesel served communities.

Figure A6: Watson Lake annual load profile



Electrical loads vary by time of day due to our lifestyle pattern and the effect of the daytime sun. Electrical loads increase in the mornings as people start their daily activities, decrease slightly just after midday, the warmest time of the day, and peaks to a daily high in the late afternoon (5 to 6 PM) as people cook supper and do other chores. The electrical loads decrease as people go to bed and cease their daily activities. Electrical loads are at their daily minimum at about 4 to 5 AM. Figure A7 below illustrates the daily load patterns for Watson Lake by season (courtesy of YECL). The hydro rate zone and other rate zones are believed to have very similar patterns but this information was not available for this report.

Figure A7: Typical diurnal electrical load pattern (kW) by season (Watson Lake 2007)



According to information from Yukon Energy the marginal cost of generating additional power when water supply and plant capacity is available is in the order of \$0.005 per kWh (variable O&M). For planning purposes Yukon Energy uses a figure of 0.5% of capital cost as the annual fixed O&M costs for new larger hydro projects. For the Mayo B project this is about \$0.016 per kWh. The total O&M cost of energy production from hydro plants is thus in the order of $0.021 per kWh.

Peaking diesel marginal cost from the large diesel plants on the hydro system is the cost of diesel fuel plus fixed and variable operating and maintenance costs, and the losses experienced in getting the power to Yukon Energy's customers through the power system. This is $0.3737 per kWh according to Yukon Energy's 2008-2009 GRA (based on fuel costs forecasted in 2008). Incremental energy generation with diesel fuel at $0.75 per litre, a fuel efficiency of 3.64 kWh per litre (Yukon Energy GRA page 2-12), and a variable cost of $0.016 per kWh (Yukon Energy GRA page 4-12) would be $0.222 per kWh.

The marginal cost of diesel generation in the three diesel zones is also principally the cost of diesel fuel. In these communities, the diesel plant operations do not change significantly with modest incremental additions or losses of load. The non-fuel variable costs of the diesel plants in diesel zones would not be eliminated unless the diesel plants were shut down and then even some of the cost would not be eliminated as the plant would be kept on stand-by. Fixed and other costs could be somewhat reduced by long term shut-downs but elimination could not occur unless the plant were not even required as a stand-by plant.

Table A1 below summarizes the present incremental costs in all rate zones and Table A2 presents the total generation costs by rate zone. The information in these tables comes from Yukon Energy and YECL either directly or from General Rate Application related documents. In Table A2 the generation cost for existing hydro of $0.021 per kWh is based on Yukon Energy information (GRA and other communications) for present variable costs and the fixed costs for new plants (Mayo B), and the total generation cost for large plant Peaking diesel generation is the author's estimate. Because it was available, the information on YECL's Fish Lake Hydro plant is also inserted into Table A2. The author has used judgment in making some adjustments for (apparently) unusual costs incurred in small diesel zone plants in 2008 and for costs related to the stand-by diesels owned by YECL. The columns in Table A2 provide the components of the generation costs using 2008 GRA fuel forecasts.

The June 2009 actual fuel costs used by the author are $0.65 per litre for the large diesel zone (Watson Lake), $0.75 per litre for the small diesel zone, and $1.45 per litre for Old Crow. The author adopted $0.75 per litre as the base case cost for diesel fuel for the hydro grids as well.

Table A1: Incremental power cost by rate zone and fuel cost at different dates

Rate Zone	2008 peak fuel cost $ per kWh	2009 forecast fuel cost $ per kWh	June 2009 actual fuel cost $ per kWh	June 2009 inflated 20 years at 3% $ per kWh
Large diesel	$0.314	$0.229	$0.170	$0.307
Small diesel (approx avg)	$0.350	$0.243	$0.220	$0.397
Old Crow	$0.618	$0.543	$0.407	$0.735
Hydro – existing hydro	~$0.005	$0.005	$0.005	$0.009
Hydro – YECL stand-by diesel	$0.34	$0.243	$0.214	$0.386
Hydro – all-in peaking diesel		$0.3737	$0.257 est.	$0.464
Hydro – incremental diesel		$0.337	$0.222	$0.401

Table A2: Generation cost based on 2009 forecast fuel cost (GRA) & actual 2008 other costs

Rate Zone	Fuel	Variable	Other	Total
Large diesel	$0.229	$0.034	$0.038	$0.301
Small diesel (average)	$0.243	$0.035	$0.040	$0.309
Old Crow	$0.543	$0.039	$0.042	$0.624
Hydro – Fish Lake plant	$0.000	$0.029	$0.035	$0.064
Hydro – existing hydro (based on Mayo B fixed O&M)	$0.000	~$0.005	~$0.016	~$0.021
Hydro – stand-by diesel (YECL)	$0.243	~$0.034	~$0.040	~$0.317
Hydro – large plant peaking diesel (author's estimate)	$0.321	$0.016	~$0.049	~$0.386

Attachment B - IPP issues review by jurisdiction

Table B.1
IPP - Existence and Nature of IPP Programs

Jurisdiction	IPP Program	Goals of Program	Eligible Technologies	Allowable Size of Projects
British Columbia	Yes, Standing Offer Program (SOP); and RFP calls (Clean Power Call, and Bioenergy Call for Power)	Self sufficiency by 2016; Energy mix 90% renewable; and Zero carbon regulation coming	SOP: clean energy technologies RFPs Clean or targeted like bioenergy; EcoLogo certification implied	SOP 50kW to 10MW
Alberta	All of Alberta power supply is privatized Micro-generation up to 1MW by Regulation Anything larger goes through Hydro and Electric Energy Act process	Micro-generation provides customers an opportunity to generate clean power. Anything above is all private supply	Micro-generation must produce less than 418 kg of GHG per MWh (effectively eliminates oil) and be EcoLogo certifiable	Micro-generation up to 1MW
Saskatchewan	Yes: SaskPower's "Small Power Producers Policy" (SPP) is for ≤100kW only and is focused on meeting own requirements. SaskPower procures generation supply >100kW as needed. There is an Open Access Transmission Tariff for IPPs among others	The SPP was instituted in response to customer demand The OATT can be used by IPPs in Saskatchewan to sell outside the province	No restrictions on SPP. No restrictions on OATT	The interconnection standard to 34.5kV applies to projects of up to 1MW, and a separate interconnection standard for voltages of 72kV and higher

IPP issues review by jurisdiction

Table B.1
IPP - Existence and Nature of IPP Programs

Jurisdiction	IPP Program	Goals of Program	Eligible Technologies	Allowable Size of Projects
Manitoba	Yes, of sorts There is also an Open Access Transmission Tariff	Provide IPPs with access to the grid	All	Up to 10MW OATT depends on transmission capacity
Ontario	Yes, in the process of moving from the Renewable Energy Standing Offer Agreement Program (RESOP) with a 10MW project limit to a Feed In Tariff (FIT) program with no limit	To facilitate the development of significant amounts of renewable energy to meet Ontario's growing needs and to shut down the coal power plants To return a profit to the developers (including to residential roof top solar project owners)	Renewable energies as specified in the Green Energy Act	RESOP had a 10MW limit No limit to FIT but the rates vary with the size and type of generation project
Quebec	No general program. Hydro-Quebec has had 2 major RFPs for wind power (1,000 and 2,000 MW) and an RFP for wind power from community and First Nations projects (250 MW each)	Increase wind power supply on the grid, a (large) portion of which is exported As a result of complaints that smaller projects could not compete with large ones H-Q issued a separate RFP for smaller community and First Nation wind projects	Wind energy only	No limits except the overall RFP

IPP issues review by jurisdiction

Table B.1
IPP - Existence and Nature of IPP Programs

Jurisdiction	IPP Program	Goals of Program	Eligible Technologies	Allowable Size of Projects
New Brunswick	Yes, there is an "Embedded Generation" program with a feed-in tariff. There have also been RFPs targeted to wind energy	To increase the percentage of renewable electrical energy in the provincial grid (RPS standard). Target 400MW wind energy by 2010	FIT program limited to EcoLogo certified renewable energies. RFPs have specifically targeted wind energy development	FIT program 100kW to 3MW June 16, 2009 RFP for wind power was for 100MW
Nova Scotia	Program with a similar effect	To meet the RPS standard of 20% by 2013 (from 10% to 12% in 2008) July 28 NS announced an RPS increase to 25% by 2015	Renewable energies, wind energy targeted in particular	Not specified
Prince Edward Island	Yes, Feed in Tariff RPS standard but it is fully subscribed. PEI had also developed a 10 point plan to significantly increase wind energy generation and export but the economic slowdown put it on hold. Open Access Transmission Tariff in place	To meet an RPS of 15% (actual now at 18%)	Renewable energies, wind energy in particular is targeted as PEI has a good wind resource	Not specified

IPP issues review by jurisdiction

Table B.1
IPP - Existence and Nature of IPP Programs

Jurisdiction	IPP Program	Goals of Program	Eligible Technologies	Allowable Size of Projects
Newfoundland and Labrador	No			
Northwest Territories	No, but considering – and not prohibited			
Nunavut	No			
Canada	Not Applicable			

IPP issues review by jurisdiction

Table B.2
IPP – Rates, Standards, and Participation

Jurisdiction	Applicable Rates	Published Interconnection Standard	Cap on Total Projects or Capacity	Program Participation Rate
British Columbia	SOP: varies by region from \$0.07304 to \$0.08733 per kWh (including environmental attributes) by region. These rates are varied by time of day and time of year from 72% to 125%, and include an inflation adjustment. RFPs bid prices	Yes	None found for SOP. RFPs state overall capacity limits of RFP.	No information on SOP. RFPs have been oversubscribed with proposals
Alberta	Small micro-generators of <150kW retail rates Large micro-generators ≥150kW but ≤1MW get hourly pool price Presumably all larger generators get pool price	Yes for micro-generators	Policy to be reviewed after 25MW of capacity or 300 micro-generators are connected	Rough estimate 65 micro generators totaling about 250kW, but unknown how many are mini micro-generators (small net metering)
Saskatchewan	Retail rates for own use but all monthly export generation purchased at marginal Wholesale rate (about \$0.086 per kWh)	Yes – for lower and higher voltages	Not for SPP The limitation on OATT is the transmission line capacity	Presently there are only about 2 customers as most switched to net metering when available

IPP issues review by jurisdiction

Table B.2
IPP – Rates, Standards, and Participation

Jurisdiction	Applicable Rates	Published Interconnection Standard	Cap on Total Projects or Capacity	Program Participation Rate
Manitoba	Up to Manitoba Hydro to assess, but will depend on on-peak vs. Off-peak supplies	Yes	None found	Unknown
Ontario	The proposed FIT rates vary from a high of \$0.802 per kWh for small solar systems to \$0.103 per kWh for landfill gas >5MW An on-peak incentive is also offered in some cases	Yes	No	The initial RESOP target was 1,000MW but proposals for several thousand MW was received which backlogged the processes for approval and connection. A good participation rate is also expected for FIT
Quebec	Rates competitively bid	Yes	Just the caps in the RFPs	High – the RFPs were all oversubscribed
New Brunswick	FIT rate is \$0.09445 per kWh	Yes	None mentioned for FIT program, but wind RFPs have specified limits	No information on FIT program. Wind RFPs have been fully subscribed
Nova Scotia	Not found, competitive?	Yes	RFPs specify limits	Unknown, but wind energy in Atlantic Canada generally oversubscribes RFPs
Prince Edward Island	The FIT was set at \$0.0775 per kWh but only to the 15% RPS which has been met	Yes	The FIT only applied to the RPS which has been met.	High in wind energy

IPP issues review by jurisdiction

Table B.3
IPP – Incentives and Roles of Parties

Jurisdiction	Incentives	Role of Government	Role of Public Utility Board	Role of Utility
British Columbia	There are a variety of incentives such as adjusted water fee rates, 10 year royalty holiday on wind, tax incentives	Big picture put in place by the BC Energy plan which put a lot of focus on IPP power supplies	BCUC carries out directions from government, regulated BC Hydro	Carries out directions by government and subject to direction from the BCUC
Alberta	No	Set the broad policy direction and enacted legislation (Micro-generation regulation)	The Alberta Utilities Commission sets out the rules and processes for micro-generation (Rule 024) AUC also rules on disputes	Various roles for retailers and Wires Owners pursuant to AUC rules and orders
Saskatchewan	For SPP Yes. Combination of the provincial government and SaskPower – a capital grant of up to 35% of eligible costs to a maximum of $35,000. If other government subsidies apply the maximum is further reduced to limit total support to 100% of cost. Also a SaskPower reduced interest loan through the Banks. For OATT none.	Set broad policy direction	Rates Review Panel ensures that SaskPower's costs and rates are reasonable, and makes recommendations to government	Developed the SPP policy and administers it. OATT is a SaskPower policy

IPP issues review by jurisdiction

Table B.3
IPP – Incentives and Roles of Parties

Jurisdiction	Incentives	Role of Government	Role of Public Utility Board	Role of Utility
Manitoba	No	Unknown	Unknown	IPP and OATT are utility policies
Ontario	An 11% rate of return is built into FIT rates	Enact the Green Energy Act and issue directions to the regulators (and utilities), the appropriate Regulations are also being developed	To carry out the government direction	To implement the programs as per government and Ontario Energy Board instructions
Quebec	No, except the smaller targeted RFP for which higher rates are expected	The Quebec government pushed H-Q into wind energy	Information not obtained	H-Q has driven all the program details in following government direction
New Brunswick	No	Government has set the overall policy direction	Information not obtained	NB Power carried out government direction by developing the programs
Nova Scotia	No	Sets the overall policy direction and the RPS	Regulate the utilities, resolve disputes	Carry out the RFPs to meet the government's requirements
Prince Edward Island	No	Sets overall policy direction and goals	The Island Regulatory and Appeals Commission regulates the utilities	Carry out the government direction subject to the PUB regulation

IPP issues review by jurisdiction

Table B.4
IPP – Other Issues for Consideration

Jurisdiction	Agreement Length	Other issues for Consideration
British Columbia	SOP participants may select contract periods of 20 to 40 years. RFP participants may choose from 5 to 20 years	Remote communities (non-integrated communities) are normally targeted in separate RFPs and local conditions (such as cost of generation) are factored into the agreements. One of the challenges that IPPs have had in BC is negotiating for transmission line right of ways. BC Hydro has expropriation powers. There is thought to government building some power lines into areas where there are multiple potential IPPs and or loads. IPPs have also been frustrated by BC Hydro's sloe review of RFPs and recently, the reduction in the amount of clean power required as a result of an RFP.
Alberta	In-determinant no specific term applies	The Wires Owners are responsible for covering the "reasonable cost" of connecting the micro-generator (meter and perhaps a bit more) There is a possibility that Alberta will review the policy issues related to small to mid scale IPPs (implication to consider situation of those potentially larger than 1MW but smaller than "utility" scale) Consideration being given to power generation from waste heat using, for example, organic Rankin cycle as eligible for micro-generation
Saskatchewan	In-determinant	SaskPower has in the past had two RFPs for environmentally preferred power and has been willing to consider unsolicited proposals (total 42 MW) There are presently 2 RFPs out – one for 100MW of gas peaking and one for 400MW of baseload generation SaskPower is considering a Standard Offer Program for projects of 100kW to several MW, and is also considering an RFP for large wind projects (100s of MW) SaskPower is working on streamlining the administration costs involved in the SPP and net metering programs. SaskPower's one diesel served community does not have any special IPP programming.

IPP issues review by jurisdiction

Table B.4
IPP – Other Issues for Consideration

Jurisdiction	Agreement Length	Other issues for Consideration
Manitoba	None found – perhaps subject to negotiation with Manitoba Hydro	Contact person indicated that there is not much real interest in IPPs as Manitoba Hydro can generate power from hydro very cost effectively, and they have more project that can be developed. However the government did require Manitoba Hydro to issue and RFP for wind power (now operating for a few years) Uncertain how remote communities with diesel generation are treated. Some transmission lines to remote communities were built with considerable government funding
Ontario	FIT contracts will be 40 years for hydro and 20 years for other forms of generation	There will be some rights for generators to connect to power lines (not all transmission owner's discretion) and transmission owner may have to pay for some portion of necessary upgrading There is an effort underway to standardize interconnections more There have been some issues with the performance of smaller wind turbines (see net metering) There is also effort being put into the integration of variable power wind into the power system – even the nuclear plants have had to be turned down on occasion
Quebec	20 years	Even though hydro power is cheaper, the inclusion of wind power which fits well with H-Q's hydro resources (H-Q says that can integrate 4,000MW of wind) and it helps the image of this being "green" power when exported to the USA. The government and H-Q require 60% Quebec content in the wind projects the intent of which is to create wind energy related industry, expertise, and jobs in Quebec. The job creation was targeted to the Gaspe peninsula where unemployment was high and the wind resource is very attractive.

IPP issues review by jurisdiction

Table B.4
IPP – Other Issues for Consideration

Jurisdiction	Agreement Length	Other issues for Consideration
New Brunswick	Information not found	In support of renewable energy the government has developed the "Developer's Guide to Renewable Energy" and a report on model wind turbine provisions and best practices. Information tides and a wind resource map have also been developed by the province. There are also some biomass plants well in excess of the FIT program in operation so there is probably flexibility on a case by case basis.
Nova Scotia	Information not found	The province has created a wind atlas, and appears to be promoting wind energy development as it has good wind resources On July 28, 2009 the government announced an increase in its RPS to 25% by 2015
Prince Edward Island	Information not found, but thought to be 20 years	While PEI has and OATT, the power lines limit exports to about 100MW. Full realization of the wind energy potential would require the installation of additional transmission capacity (submarine cables). The economic downturn has temporarily put the province's 10 point plan for large scale wind energy development on hold. The author was told that renewable energy credits decreased in value from about $100 per MWh to about $50 per MWh (and as low as $20 per MWh), and this also discourages private development.

Attachment C - Net Metering issues review by jurisdiction

Table C.1
Net Metering - Existence of Net Metering Programs

Jurisdiction	Net Metering Program	Goals of Program	Eligible Technologies	Allowable Size of Projects
British Columbia	Yes, since 2004	None specific but loosely part of goal to be energy self sufficient by 2016 and have at least 90% renewables in the mix. Zero carbon regulation also coming.	"BC Clean" micro-hydro, wind, solar, PV, geothermal, tidal, wave, biomass, landfill gas, municipal solid waste, and co-gen of heat and power	Project size limited to 50 kW (and 600V)
Alberta	Yes; Alberta prefers to call it Net Billing as power in and out measured separately; Distributed Generation Interconnection Guide 2002, but more specific micro-generation regulation in 2008	None specific – simply to allow micro-generation	Any Eco-Logo certified technology; also must produce less than 418kg of GHG per MWh. Effectively eliminates oil or diesel (absolute in co-gen) but allows natural gas	Projects of up to 1 MW allowed, but sub-divided into categories of ≤10kW, ≤150kW, and ≤1MW for regulation – see later
Saskatchewan	Yes, since 2007. The net metering program is complimentary to the "Small Power Producers Policy" which is not to be confused with an IPP policy.	None specific – to allow customers to net meter (at the request of government)	Environmentally preferred technologies – the usual renewables but also including flare gas and waste heat recovery	Project limit is 100 kW. For projects connected at 120/240 Volts (i.e. normal households) 5kW is a practical limit above which higher interconnection costs may be incurred.
Manitoba	Yes, since about 1989 as part of Distributed Resources or Customer owned Generation	Initially industrial focused.	No restrictions.	Single phase limit 50kW, three phase limit 10MW.

Net Metering issues review by jurisdiction

Table C.1
Net Metering - Existence of Net Metering Programs

Jurisdiction	Net Metering Program	Goals of Program	Eligible Technologies	Allowable Size of Projects
Ontario	Yes, in 2005 the Ontario government made it a "universal" program	Initially to formalize what a few utilities were doing and to make it universal through the province. See also the Feed in Tariff program goals in Table 2. Also goal is to have these customers contribute to displacing coal generation	Renewable energies (includes agricultural biomass)	Maximum 500 kW
Quebec	Yes, since 2006	To allow residential, farm, and small power business customers to self generate.	Renewable energies.	50kW, but single phase limited to 20kW, maximum voltage 600V
New Brunswick	Yes, since 2005		Renewable Energies EcoLogo compatible	Maximum 100kW
Nova Scotia	Yes, since 2005	To help make renewable energy more accessible.	Renewable energies	Maximum 100kW, but single phase limited to 30kW
Prince Edward Island	Yes	To send a message that people can get involved in renewable energy	Renewable energies	Maximum 100kW
Newfoundland and Labrador	No			

Net Metering issues review by jurisdiction

Table C.1
Net Metering - Existence of Net Metering Programs

Jurisdiction	Net Metering Program	Goals of Program	Eligible Technologies	Allowable Size of Projects
Northwest Territories	No, but considering – and not prohibited			Significant disincentive for projects above 5kW as a stand-by demand charge of $24 per kW per month is added to the customer bill (compared to $8 normal demand charge)
Nunavut	No			
Canada	Not Applicable			
USA	Yes in majority of States		Usually renewable energies	

Net Metering issues review by jurisdiction

Table C.2
Net Metering – Costs and Payment Matters

Jurisdiction	Rates paid to Customer	Who Pays Connection	Netting Period	Excess Paid Out
British Columbia	Retail energy rate	BC Hydro up to $600, customer pays excess.	1 year	Yes, at $0.0816 – BC Hydro's cost of renewable energy generation from RFPs
Alberta	Retail rate for ≤150kW (small micro-generators), and pool price for >150kW but ≤1MW (large micro-generator)	Reasonable costs paid by distribution utility (rate based), any extraordinary costs paid by customer	1 year	Yes (may be offset for any amounts owing by customer)
Saskatchewan	Retail rate	Customer but eligible for financial support. A meter costs about $400	1 year	No
Manitoba	Retail	Customer	Monthly?	Customer option load displacement or load displacement with excess to grid, rates negotiated.
Ontario	Retail (but fairly complex energy & service billing in Ontario)	Less than 10kW utility pays meter, other costs to customer	Effectively 1 year.	No
Quebec	Retail	Customer pays $400 inspection (of installed equipment) fee, H-Q pays for the new meter	2 years	No

Net Metering issues review by jurisdiction

Table C.2
Net Metering – Costs and Payment Matters

Jurisdiction	Rates paid to Customer	Who Pays Connection	Netting Period	Excess Paid Out
New Brunswick	Retail	Customer	1 year	No
Nova Scotia	Retail	Customer	1 year	No
Prince Edward Island	Retail	Utility pays for meter, customer the rest	1 year	No
Northwest Territories	Customers who net meter effectively get the retail rate	Customer	None – presumably cannot be "banked" at all	No
Canada	Not Applicable			
USA				

Net Metering issues review by jurisdiction

Table C.3
Net Metering – Interconnection and Participation

Jurisdiction	Published Interconnection Standard	Simplified Process for Grid Dependent Inverters	Cap on Total Projects or Capacity	Program Participation Rate
British Columbia	Yes	Yes, for generation facilities of not more than 5 kW and CSA Standard C22.2 No. 107.1-01 approved units (anti-islanding and harmonic distortion)	No	No specifics on hand, but believed very low
Alberta	Yes	Yes, for ≤10 kW (Mini micro-generator) using CSA approved inverters (see above).	The policy is to be reviewed when 25 MW of capacity or 300 micro-generators are connected	Rough estimate provided was 250 kW of capacity and about 65 micro-generators
Saskatchewan	Yes	No, but approved inverters are a requirement	Not at present	In 50-75 range
Manitoba	Yes	Yes. Registration process for generators of ≤10kW if the inverter is CSA/UL1741 certified.	None mentioned	No data available but thought to be small.
Ontario	Yes	Yes, for projects of ≤10kW using a grid dependent inverter certified to CSA C22.2 No. 107.1 or UL 1741	Yes, 1% of distributor capacity.	Small: to the end of 2008 260 customers totaling about 3.9MW (25,000 MW peak) but note that the feed in tariff (FIT) program to replace the Standard Offer Program is advantageous to some customers.

Net Metering issues review by jurisdiction

Table C.3
Net Metering – Interconnection and Participation

Jurisdiction	Published Interconnection Standard	Simplified Process for Grid Dependent Inverters	Cap on Total Projects or Capacity	Program Participation Rate
Quebec	Yes	Yes, somewhat. For CSA Standard C22.2 No. 107.1-01 or UL 1741 certified inverters (max 20kW single phase and	None found	No information obtained
New Brunswick	Yes	Yes, for CSA Standard C22.2 No. 107.1-01 or UL 1741 certified inverters	None found	No information obtained
Nova Scotia	Yes	Yes, for CSA Standard C22.2 No. 107.1-01 certified inverters	None found	No information obtained
Prince Edward Island	None found	No information found	None found	No more than 12
Northwest Territories	Yes	No	Not applicable	Few pilot projects
Canada	Not applicable			
USA	The Federal Energy Regulatory Commission (FERC) adopted a "small generator" interconnection standard for distributed energy resources up to 20MW	Yes, for ≤10kW certified inverters		

Net Metering issues review by jurisdiction

Table C.4
Net Metering – Roles of Governments, Public Utility Boards, and Utilities

Jurisdiction	Incentives	Role of Government	Role of Public Utility Board	Role of Utility
British Columbia	None specific but most alternative energy systems are exempt from provincial sales tax (found under energy conservation exemptions)	• Articulated goals in the Energy Plan (2007) • Brought BC Hydro under full regulation • Minister can direct BCUC to carry out its policies	Regulates BCH per gov't direction; sets rates and settles technical issues per normal regulatory process; reviewed and approved the BCH net metering plan;	Conducts itself per gov't direction; proposes rates and interconnection processes and standards for BCUC review; prepared net metering plan for BCUC review;
Alberta	No.	Set the broad policy direction (e.g. the Micro-Generation Regulation pursuant to the Electric Utilities Act)	The Alberta Utilities Commission sets the rules for the utilities (e.g. Rule 024 Rules Respecting Micro-Generation) pursuant to the government regulation	Various utilities have various roles. Retailers must do the tracking and accounting, and the Wires Owners must install and maintain the metering facilities and deal with any technical issues.
Saskatchewan	Yes. Combination of the provincial government and SaskPower – a capital grant of up to 35% of eligible costs to a maximum of $35,000. If other government subsidies apply the maximum is further reduced to limit total support to 100% of cost.	Set out bit picture policy direction	The Saskatchewan Rate Review Panel reviews SaskPower's rate applications, enduring that incurred costs are reasonable, and makes recommendations to government. The Panel was not involved at the detail level such as interconnection standards	SaskPower carries out the broad policy direction of the government

Net Metering issues review by jurisdiction

Table C.4
Net Metering – Roles of Governments, Public Utility Boards, and Utilities

Jurisdiction	Incentives	Role of Government	Role of Public Utility Board	Role of Utility
Manitoba	No.	Does some marketing, ensuring user friendliness.	PUB not involved	Originated the policy
Ontario	No	Changed legislation (Ontario Energy Board Act) to allow government to make regulations for the OEB to carry out.	OEB carries out government regulations by applying these to all utilities. Regulates utilities on a day to day basis. Sets the guidelines such as the Interconnection Guidelines.	Carry out government policies by following OEB regulation (Orders). Prepare, suggest, and discuss interconnection standards through OEB regulation process.
Quebec	No.	Government's energy strategy required H-Q to develop this program	Information not obtained	Develop and implement programs pursuant to government direction.
New Brunswick	No	Implemented a regulation to increase renewable energy sourced electricity by 10% from present level of about 23%. Government has developed renewable energy guide, and provided information of renewable resources (e.g. wind)	Information not obtained	Developed Net Metering and Embedded Generation (IPP) policies.
Nova Scotia	No	Enacted renewable energy standard	Nova Scotia Utility and Review Board regulates Nova Scotia Power	Follow the Utility Board Orders

Net Metering issues review by jurisdiction

Table C.4
Net Metering – Roles of Governments, Public Utility Boards, and Utilities

Jurisdiction	Incentives	Role of Government	Role of Public Utility Board	Role of Utility
Prince Edward Island	RE equipment is Provincial sales tax exempt; community rinks get $180k out of $250k for a wind turbine	Implemented all appropriate legislation; government strongly promotes wind energy	Presumably PUB regulates Maritime Electric, (and Summerside municipal utility) per the Government's orders	Implement the government's programs through PUB orders
Northwest Territories	The Alternative Energy Technologies Program can fund projects which are net metering	At present the government legislation does not permit it to issue direction to the public Utilities Board, but it can issue direction to NTPC, the government owned utility	Regulate the electric utilities	Operate per the PUB Orders, and in the case of NTPC, per government direction
Canada	There are various government programs (for example ecoENERGY) that may fund projects that are net metering			
USA	There are a host of federal and state incentive programs – for residential customers mostly grants and tax rebates; for commercial customers that are also a host of production and tax treatment incentives			

Net Metering issues review by jurisdiction

Table C.5
Net Metering – Other Issues for Consideration

Jurisdiction		Other issues for Consideration
British Columbia		There were initially some technical issues with respect to Smart Meters (see Ontario below). The BC Government and BC Hydro seem much more aggressive on their energy efficiency and conservation plans and goals.
Alberta		The Contact's personal view was that if incentives are to be provided it should probably be in capital cost support so as not to cause market price disruption. Customers in isolated communities served by diesel generation are only paid the retail rate or the pool price depending on size (retail rates are subsidized to general Alberta rates) so there is no reflection of the cost of generation for micro-generators in isolated communities. There has been some dissatisfaction with the interconnection guidelines and some requests for reviews of these.
Saskatchewan		The Small Power Producers Policy (also 100 kW limit) preceded the Net Metering Policy and customers were given the option to switch to net metering. About 8 of the 10 customers did so. Most participants in Net Metering are farm and rural customers and most use wind generation. Cities generally do not allow wind generators. The interest in the program and the number of net metering customers are higher than SaskPower had expected. SaskPower is trying to streamline the administration of the net metering and small power producers policies as this can be fairly costly. SaskPower's one diesel served community has subsidized power and is not treated differently from any other grid connected community
Manitoba		Manitoba had large hydro resources and more projects that can be brought on stream. Power rates are very low.

Net Metering issues review by jurisdiction

Table C.5
Net Metering – Other Issues for Consideration

Jurisdiction		**Other issues for Consideration**
Ontario		The new Feed in Tariff (FIT) program that will be in place this fall will be advantageous to many customers (especially those with solar PV) as the rates will be $0.802 per kWh. The Net Metering, SOP, and FIT programs are not available in diesel served communities because of the rate structures in place there (non-government customers heavily subsidized but government customers not so the fear is that government customers would take advantage of the programs and drive costs up). There have been some power quality issues, primarily with wind turbines having very low power factors
Quebec		Hydro-Quebec prepares a good comparison of electricity prices in major north American cities every year. This is available on their website.
New Brunswick		
Nova Scotia		The government actively promotes renewable energy, particularly wind energy. On July 28, 2009 the government announced an increase in RPS to 25% by 2015
Prince Edward Island		PEI was the first province in Canada to have net metering Net metering does raise a concern about adding costs to non-participating customers A personal opinion indicated that 5MW of net metering may be a practical limit before power quality issues begin to emerge.
Northwest Territories		Effectively NTPC and the PUB discourage the connection of distributed generation by imposing a punitive demand charge of $24 per month per kW of demand on all projects over 5kW. The PUB Order (pursuant to an NTPC request) does not specify this 5kW limit but presumably the rate structures effectively do this. The NWT government would need to change the Act that governs their PUB in order to enable the government to issue instructions to the PUB.
Canada		There are advantageous tax treatment options for corporations purchasing and operating renewable energy systems
USA		Some individual states have aggressive net metering targets (e.g. Nevada is targeting 4% of energy from solar net metering).