

# **DIESEL & THERMAL ELECTRICITY GENERATION OPTIONS**

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## INTRODUCTION

Diesel and thermal electricity generation options generate electricity from converting a solid, gaseous or liquid fuel source to electricity through diesel generators, combustion gas turbines, steam turbines or a combined cycle combination of gas and steam turbines. As such, these options differ from hydro, wind, solar photovoltaic, and fuel cell electricity generation options.

Diesel and thermal electricity generation are discussed in the Yukon context as summarized below and in the attachments, where reliable thermal generation options that can be operated when and as required offer considerable synergies with the current hydro-based generation infrastructure<sup>1</sup>:

- Current Yukon population is almost 35,000, roughly 75% of whom are in Whitehorse.
- Over 94% of Yukoners live in areas served by the internal hydro generation transmission grid (Watson Lake, Destruction Bay, Beaver Creek, Swift River and Old Crow are each served by isolated diesel generation; other than Old Crow, each of these has all weather road access).
- Electricity infrastructure development and loads are materially impacted (i.e., far beyond what would be experienced today in southern provincial jurisdictions), both historically and in the foreseeable future, by mine industrial development, risks and uncertainties.
- There is no electricity grid connection to other jurisdictions, i.e., Yukoners today must rely totally on their own local generation, and have no external market to sell surplus generation.

More specifically, this paper focuses on the following three sets of diesel and thermal generation options:

1. **Diesel Generation Options** – Background on this current “default” generation option in Yukon, its past, current and potential future features as an electricity generation option.
2. **Natural Gas/LNG Thermal Generation Options** – Liquefied natural gas (LNG) thermal generation offers a cleaner and less costly option today in Yukon than diesel generation and could potentially supplant diesel as the “default” option with future sources of natural gas supply from either local resources (e.g., through development of Eagle Plains resources) or access to other local sources (e.g., through development of the Alaska Highway pipeline).
3. **Other Potential Thermal Generation Options** – A high level overview, based primarily on information from the Yukon Energy 2006 Resource Plan, of other potential thermal options in Yukon (municipal waste and biomass, coal, geothermal, solar, and nuclear) to compare and contrast at a broad level with the diesel and natural gas/LNG options. Added information is provided on coal (as this resource is not addressed by other Charrette background papers).

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<sup>1</sup> Attachment 1 provides an overview of the current and committed Yukon bulk power infrastructure (generation and transmission), including projects currently under construction (Stage 2 of Carmacks-Stewart Transmission Project that will connect the Whitehorse-Aishihik-Faro (WAF) and Mayo Dawson (MD) grids before this summer, the Aishihik 3<sup>rd</sup> Turbine hydro enhancement on WAF, and the Mayo B hydro enhancement on MD).

## **1.0 DIESEL GENERATION OPTIONS**

### **1.1 TECHNOLOGY OPTION OVERVIEW**

Diesel generating units offer well established and reliable technology with the following key features relevant to Yukon use:

- Relatively easy access to reliable fuel supplies as required from competitive world markets (i.e., no seasonality or other resource-based limitation on generation capability).
- Relatively low capital costs (approximately \$1 million per MW), with plant location near load centres (minimizes transmission requirements).
- Units that can be permitted, purchased and installed within reasonably short time periods (i.e., usually well under 2 years) and be reliably operated over an economic life of 20 to 25 years.
- Relatively high operating costs, e.g., 2009 approved forecast fuel and operating cost average 26.4 c/kWh for YEC and YECL, excluding Old Crow [where the approved forecast fuel and operating cost was 57.3 c/kW.h]; diesel fuel costs constituted all but 3 c/kW.h of these approved forecasts, and are subject to ongoing inflation and market price uncertainty.
- Environmental impacts related to air emissions (e.g., GHG at approximately 700 tonnes per GWh, and regulated health-related emission effects<sup>2</sup> re: NOx, SO2 and particulates), noise, and potential fuel spills effects (including storage tank leaks).

Diesel unit variations are available for intermittent peaking versus steady base load generation, as well as for other variations (e.g., energy storage benefit options, wind-diesel hybrids, other hybrid variations to facilitate use of other fuels).

In general, diesel units have been well-suited in Yukon to meeting reserve capacity requirements and short-term capacity needs during system peaks (where low capital costs are important). Diesel generation has also been well suited to isolated regions where loads are small (such as the Yukon isolated communities not connected to the grid), to sites away from the grid where loads do not have very long lives (such as temporary applications or short lived mines) or to isolated sites where the heat from the operation of the diesels is of economic value (such as in certain industrial operations). Since diesel units can be turned off when they are not needed (and because of the relatively low capital costs), diesel units also can provide a relatively lower risk source of electricity supply if loads are uncertain (as load decreases can be met with operating cost decreases from putting the unit on standby).

Diesel is expensive for utility "base load" operations that are required to provide sustained energy on a regular basis throughout the year.

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<sup>2</sup> Existing diesel units for YEC require a Permit pursuant to section 12 of the Air Emissions Regulations under the Environment Act and YEC is subject to all applicable requirements and prohibitions under the Environment Act and Air Emissions Regulations; renewal of a Permit for a three year terms requires a YESAA assessment.

- Energy conversion ratios approximate 35% to 37% for reasonably efficient units. Although the most efficient units now in service on WAF have fuel requirements at 3.9 kW.h/litre, new base load diesel unit efficiency would likely approximate 4 to 4.2 kW.h/litre (i.e., at fuel cost of \$1 per litre, fuel cost alone would equal 24 to 25 cents per kW.h). Using existing diesel facilities (which would be a likely situation) would involve lower efficiencies and higher incremental operating costs (approved 2009 average incremental diesel generation costs for the Hydro zone approximated 30 cents per kWh, of which fuel constituted 27 cents).
- Diesel fuel prices are subject to ongoing inflation and market price uncertainty:
  - Diesel fuel prices increased dramatically between the 1996/97 GRA and the recent 2008/2009 GRA, e.g., YEC's approved average GRA fuel price for the Whitehorse-Aishihik-Faro grid was 29.78 c/litre for 1997 and 99.2 c/litre for 2009. Similarly, YECL's approved GRA fuel price for Watson Lake in 2009 was approximately 3 times the price approved for 1997.
  - Future diesel fuel prices are likely to remain closely tied to future oil prices, given the premium use requirements for this liquid (portable and storable) fuel in transportation and other uses. Considerable uncertainty remains as to how future oil prices will change within any specific time period (e.g., next 10, 20 or 50 years) relative to general inflation. Based on the last approved diesel fuel prices in 2009, after the 2008 price peaks but before the full impact of price declines in 2009, longer-term oil price increases might well be expected to exceed inflation rather than to fall below inflation - however, experience over the period since the 1970s demonstrates the material uncertainties applicable to long-term oil price forecasts.

## **1.2 DIESEL AS YUKON DEFAULT OPTION**

Although hydro generation is by far the dominant source of utility-supplied electricity in Yukon, diesel generation facilities account for 57% (44.2 MW) of the reliable capacity to serve the WAF/MD grid winter peak and all of the 8.4 MW of generation capacity (representing about 5% of total Yukon utility electricity generation) to serve five separate "off grid" diesel-served communities as well as any generation currently used to supply "off grid" industrial mine projects. Diesel generation on the WAF grid has fluctuated widely from 1967 to 2010 as the Faro mine load changed and/or new hydro generation was developed. The history of hydro generation development on the WAF and MD grids demonstrates past initiatives to displace diesel generation when the opportunity arose, and the related impacts and risks when mines were shut down (see Attachment 1).

Potential future diesel capacity and generation requirements are reviewed in Attachment 2 assuming that diesel generation today is still the default supply option in Yukon, i.e., the option first selected when current and committed renewable generation infrastructure is not adequate to meet load requirements. These future diesel generation requirements provide the opportunity to develop alternative electricity generation resources to displace the costs and emissions associated with such diesel generation.

Current YEC diesel plant retirement plans and forecast non-industrial load growth together indicate, absent any new infrastructure beyond that currently committed, grid capacity shortfalls emerging in 2013, and expanding to 21 MW by 2020 and 64 MW by 2030. As reviewed in Attachment 2, maintaining

the required quantity of installed reliable capacity is essential to minimize the risk of service disruptions in very cold weather (through unplanned outages or other factors), as well as to supply energy during drought or low water conditions, peak winter periods or (in some instances) during planned system outages. To date, due to low capital cost and ready availability of diesel fuel, diesel generation facilities have been the default option to meet these various capacity-related needs in Yukon.

Although the current diesel infrastructure on the grids is utilized today primarily as reserve capacity to meet peak or short term emergency needs, these facilities remain available as well to provide base load energy as required, i.e., at 90% utilization over a year, the existing 44.2 MW of grid diesel capacity could potentially provide almost 350 GWh per year of electricity or almost as much as the total 2010 utility generation in Yukon (386 GWh).

From a planning perspective, existing and potential new diesel generation plant is used as the “last resort” supply to meet grid generation energy requirements after all available renewable energy generation has been fully utilized.

The predominance of hydro generation on the Yukon system, combined with the fact that Yukon is isolated from other grids outside the territory, means that other forms of backup capacity are required to supplement available Hydro in circumstances of low water or drought. With the diminished surplus hydro generation available today, continued reliance on the existing grid system to deal with load growth will mean an increasing need to rely on more costly diesel generation to meet energy loads over the near term and over the longer term - particularly to meet winter/spring seasonal generation requirements, and to provide reliable energy generation in drought years.

As reviewed in Attachment 2, assessments of diesel displacement opportunities need to fully consider different seasonal and annual water flow conditions.

- **No material diesel displacement opportunity in summer/fall seasons** - Under even a 610 GWh/year “high” load scenario for 2015, over 95% of the average diesel displacement opportunities still occur in the seven month period from November to May and over 75% in the five months from January to May. The isolated nature of the Yukon grid prevents any “export” sale of surplus summer/fall renewable generation.
- **Wide annual variability in water conditions affect diesel displacement opportunities** - “Annual average” diesel energy generation estimates reflect averages of widely varying annual water flow conditions. With loads at a 545 GWh “medium” load scenario for 2015 (approximates current grid loads with one new mine connected of the size of Victoria Gold), “annual average” diesel generation is projected at 101.6 GWh/yr. This “average”, however, includes diesel generation ranging from 13.5 GWh/yr under extreme high water conditions to 199.3 GWh under extreme low water conditions. This annual hydro generation variability needs to be fully considered when assessing the diesel displacement impact that any new renewable resource is expected to achieve. The isolated nature of the Yukon grid prevents any “export” sale of surplus renewable generation during high water years.
- **Load level impacts on diesel displacement opportunities** – Diesel generation requirements on the Yukon grid vary considerably depending on the assumed grid load level. Three loads



reviewed in Attachment 2 reflect 2015 grid load scenarios ranging from “low” to “high”, with resulting “average” diesel generation requirements in 2015 varying from 25 GWh to 161 GWh.

Thermal generation has often been viewed as a good mix to have with hydro generation to provide reliable and cost effective peaking and/or periodic supply during low water conditions. In addition to seasonal supply constraints, systems predominantly based on hydro generation resources such as the Yukon grid are vulnerable to drought (low water) conditions, and in these circumstances hydro generation must be supplemented by other reliable forms of generation. Notably, the requirement for thermal resources to back up hydro resources exists even in interconnected systems such as Manitoba (which continues to include a small amount of thermal generating resources in its power resource plan) and British Columbia (e.g., the Burrard generating station). Conversely, hydro-based systems such as the Yukon grid must also anticipate flood (high water) conditions, and in these circumstances the need to rely on other reliable forms of generation will be greatly diminished and/or eliminated (a factor that may undermine the cost effectiveness of capital-intensive renewable resource options developed to displace diesel generation).

Costs for added diesel generation will have a major impact on future rates in Yukon. By way of example, 101.6 GWh of added base load diesel generation (the 545 GWh load case for 2015) will add \$30.5 million to Yukon costs at 2009 approved Hydro zone average incremental fuel and other operating costs (30 cents per kWh). Based on the forecast Yukon sales of 183 GWh associated with the 545 GWh load case, these added diesel costs would equal approximately 5.9 cents per kWh of customer energy use. Options that could supply this incremental generation at half the cost of diesel would ultimately save customers on average about 2.4 cents per kWh in rates.

Diesel generation’s established position in Yukon testifies to its current default role. A key question is the extent to which this role is challenged today by other available thermal generation options.

## 2.0 NATURAL GAS/LNG THERMAL GENERATION OPTIONS

Liquefied natural gas (LNG) thermal generation offers a cleaner and potentially less costly option today in Yukon than diesel generation, with the potential for future local sources of natural gas supply from either local resources (e.g., through development of Eagle Plains resources, perhaps in conjunction with the Mackenzie Valley Pipeline) or through access to other sources (e.g., through development of the Alaska Highway Pipeline Project).

The Alaska Highway Pipeline Project (AHPP) may bring natural gas along the Alaska Highway by 2020-21, radically changing the default option in Yukon for electricity generation. Accessible natural gas is expected to offer dramatically lower incremental fuel costs than diesel fuel, e.g., 2020-21 (\$2010) fuel costs per kWh of 6-7 cents versus the 24-25 cent range currently applicable for most of Yukon<sup>3</sup>.

Natural gas generating units offer well established and reliable technology with many of the same key features relevant to Yukon use as noted above for diesel generation, including:

- Relatively low capital costs, e.g., approximately \$1.2-1.5 million per MW for simple cycle unit installed) with options for “scalable” generation over a wide range of sizes, as well as options for combined cycle and cogeneration (with associated higher capital costs).
- Units that can be permitted, purchased and installed within reasonably short time periods (i.e., usually well under 2 years) and be reliably operated over an economic life of 20 years; units can also be located at load centres (minimize transmission requirements).
- Operating costs that are mostly composed of fuel cost that is subject to ongoing inflation and market price uncertainty.
  - Simple cycle operation fuel efficiencies of approximately 35% to over 40% (8.5-9.5 Mcf per MW.h), with non-fuel O&M costs at 1-2 cents/kWh; simple cycle operating flexibility (including ability to achieve full production relatively quickly).
  - Combined cycle operation offers higher fuel efficiencies (approximately 48-52% for electricity generation at potentially relevant plant sizes for the Yukon grid), but increases plant capital and non-fuel operating costs; compared to simple cycle, longer start-up times are required for the steam plant in combined cycle options, i.e., this option typically would be limited to continuous base load operation rather than intermittent or peaking operation.
- Cleaner environmental impacts than with diesel generation, e.g., GHG for simple cycle operation at approximately 30-34% less than diesel fuel (about 456 to 500 tonnes per GWh)<sup>4</sup>; regulated health air emission effects re: NO<sub>x</sub>, SO<sub>2</sub> and particulates also typically materially lower than

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<sup>3</sup> At a gas price (2010\$) of \$7 per MMBTU in 2020-21 (i.e., a price consistent with January 2011 BC Hydro mid-price forecasts, taking into account potential impacts of shale gas), natural gas thermal generation fuel costs for simple cycle options could approximate 6 cents/kWh (lower costs would apply to combined cycle options).

<sup>4</sup> 34% estimate (and 456 tonnes per GW.h estimate) per internal working papers prepared for Oil and Gas Resource Branch, Yukon Department of Energy, Mines and Resources.

diesel fuel emissions; reduced potential concerns re: fuel spills effects (including storage tank leaks) compared with diesel fuel.

Natural gas prices are subject to ongoing inflation and market price uncertainty. The following observations derive from BC Hydro's latest (January 2011) Integrated Resource Plan natural gas price forecast<sup>5</sup>:

- Supply softness has driven gas prices to historically low levels; shale gas is expected to contribute to ongoing low prices although uncertainty about environmental issues and timing of development of new shale gas reserves means BC Hydro is considering different scenarios with relatively large price ranges.
- BC Hydro's High gas price scenario assumes prices around \$10/MMBTU escalating to about \$13/MMBTU by 2027 (all in \$2010); assumes shale gas either cannot be developed due to environmental concerns or is very slow to develop.
- BC Hydro's Low gas price scenario assumes prices around \$4/MMBTU escalating to about \$5.5/MMBTU by 2027.
- BC Hydro's Mid gas price scenario assumes prices start around \$4/MMBTU and escalate to about \$7/MMBTU by about 2020 and about \$7.5/MMBTU by 2027.

In Yukon, the developers of the Casino mine project (Western Copper Corporation) have recently identified natural gas/LNG as the likely preferred option for onsite electricity generation by 2018-19 to supply a 1,000 GW.h/year mine load that remains relatively stable throughout the year and is expected to continue for 20+ years<sup>6</sup>. Using combined cycle generation and price forecasts similar to BC Hydro's Mid gas price scenario, electricity generation costs for the Casino mine are expected to be under 10 cents/kWh with access to AHPP natural gas and in the 11-15 c/kWh range prior to AHPP assuming reliance on liquefied natural gas (LNG) imported to Yukon (likely by ship and truck).

Also in Yukon, electricity generation at the Selwyn and MacTung mine projects has been estimated to be more than 10 cents per kWh less costly using LNG from Fort Nelson, BC, rather than diesel fuel<sup>7</sup>.

In summary, LNG import to Yukon has recently been identified as an available near-term gas supply option prior to AHPP or other local Yukon gas supply development - and use of LNG would ensure that the thermal electricity generation so developed could switch to less costly local gas supplies as soon as they become available.

LNG is also being examined as a near-term supply option for Yukon utility thermal electricity generation by as early as late 2013 in the event that new mine loads such as Victoria Gold are to be connected to

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<sup>5</sup> BC Hydro Integrated Resource Plan: "Long-Term Natural Gas Price Forecast" by Dave Ince. BC Hydro notes that natural gas prices are the single biggest variable contributing to spot market electricity prices affecting BC Hydro's market region.

<sup>6</sup> Personal communication with Cameron Brown, V.P. Engineering, Western Copper Corporation.

<sup>7</sup> LNG cost estimated at 17.2 cents/kWh versus diesel cost at 28.6 cents/kWh (internal working papers prepared for Oil and Gas Resource Branch, Yukon Department of Energy, Mines and Resources).

the grid at that time. An LNG supply using a containerized mini-LNG plant would likely need to be developed in the Fort Nelson or south east Yukon area for trucking to Whitehorse. Thermal plant operation to displace diesel generation would typically need to be concentrated almost entirely in seven months (November to May), resulting in an expected capacity factor of less than 40% and suggesting a thermal plant scale of 25 to 40 MW depending on the near term load scenario being addressed. Initial preliminary review using parameters from Casino mine and Yukon Government internal working papers suggests that average unit costs over a 20 year life could potentially be in the 15-20 cents/kWh range (i.e., well below projected costs using diesel). Attractive features of this option include:

- Provision of reliable added capacity to the grid at Whitehorse.
- Far lower incremental operating costs and cleaner emissions than the current diesel generation.
- Opportunities for use of waste heat at Whitehorse, e.g., for district heating.
- Sizeable cost savings, through reduced LNG purchases, in years or seasons with low diesel displacement potential (this provides risk mitigation as regards mine load uncertainties as well ongoing uncertainties related to annual water flow availability).

Alaska has devoted considerable time and energy to natural gas generation given the availability of gas in many key communities. This information and experience could be of value to Yukon should gas become available during the period covered by the Resource Plan.

### 3.0 OTHER THERMAL GENERATION OPTIONS

There are a wide range of other potential thermal options in Yukon using fuel sources other than natural gas or oil, e.g., municipal waste and biomass, coal, geothermal, solar, and nuclear. While there are some common features throughout this range as to the technology for thermal generation of electricity (e.g., using steam turbines, gas turbines or internal combustion engines), each of these resource options tends to offer its own specific parameters (e.g., technologies for collecting and/or processing the resource, resource supplies and reliability throughout the year, emissions-related or other environmental concerns specific to each resource, operating costs, and capital costs).

Yukon Energy's 2006 Resource Plan reviewed at a high level many of these options, noting in many instances (e.g., coal biomass and nuclear) the Alaska Power Association overview of power options titled "New Energy for Alaska" published in March 2004. This Energy Charrette also includes separate expert background papers on thermal generation options involving municipal waste, biomass, geothermal, solar, and nuclear resources.

Coal is reviewed in some detail below, as this resource is not being examined in any other Energy Charrette background papers. A brief overview is provided thereafter of other thermal generation options based primarily on Yukon Energy's 2006 Resource Plan.

#### 3.1 COAL RESOURCES

##### *Yukon Coal Resources*

Prior reviews of coal resources in Yukon (by Energy Mines and Resources (EMR) and others) note a vast potential of coal bearing rocks in Yukon (approximately 37,000 km<sup>2</sup> of Yukon Territory) – with largest deposits within the Bonnet Plume Basin in northeast Yukon.

A 1994 Yukon Coal Inventory notes 103 known coal occurrences in Yukon in 7 different geographical subdivisions<sup>8</sup>. A separate review by EMR "Commodity Brochure on Coal (2008)"<sup>9</sup> provides a review of coal resources in Yukon focusing on 13 separate deposits: 1 deposit (Sulpetro) in Rock River Basin; 7 separate deposits in the Bonnet Plume basin<sup>10</sup> and 5 deposits in the Whitehorse Trough and Tintina Trench.<sup>11</sup>

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<sup>8</sup> Prepared for Energy and Mines Branch, Economic Development (J.A. Hunt, M.Sc., P.Geo, Aurum Geological Consultants Inc (March 31, 1994).

<sup>9</sup> <http://www.geology.gov.yk.ca/pdf/coal.pdf>

<sup>10</sup> Marathon, Pole, Garlic Ring, Illytyd, Pan Ocean, Deslaurier, Spaceship.

<sup>11</sup> Division, Whiskey Lake, Tantalus Mine, South Tantalus and Whitehorse Coal.

The EMR report focuses on ongoing efforts to develop the following four deposits (information provided in the EMR review corresponds with the information provided in the earlier 1994 Yukon Coal Inventory<sup>12</sup>); summary information from both reports is noted below:

- **Division Mountain**<sup>13</sup> - Located 90 km northwest of Whitehorse, approximately 20 km west of the Klondike Highway and the WAF grid. The EMR report notes Cash Minerals has identified a deposit of 52.5 Mt of high-ash, low-sulphur, high-volatile bituminous B. There is probable continuity along the strike for at least 15 km and potential for further deposits of coal in the area. The earlier 1994 Coal Inventory also notes the following characteristic advantages and disadvantages of the deposit:
  - **Advantages:** Occurring in a seam of mineable thickness; accessible by major highway and close to potential markets (90 km from Whitehorse and 22 km from WAF grid), with in situ reserves of 11.1 Mt. Deposit suitable for small-scale thermal plant located in vicinity (exploration at time of 1994 report focused on confirming potential reserves sufficient to support a 10-20 MW thermal plant).
  - **Disadvantages:** Deposit is relatively high in ash, and of limited size, the seam is lenticular and discontinuous, and seams steeply dip to vertical high stripping ratio.
- **Whitehorse Coal** – Located approximately 30 km southwest of Whitehorse and is close to transportation routes and domestic markets. The EMR report indicates seams of mineable thickness, 0.6 to 13 metres that have been identified extending discontinuously for 12 km. Coal in the deposit is a low-sulphur, moderate to high ash anthracite, and is near the surface and highly oxidized. The earlier 1994 Coal Inventory also notes the following characteristic advantages and disadvantages of the deposit:
  - **Advantages:** Close to Whitehorse transportation routes and domestic market; seams of mineable thickness (0.6-13 m) and low sulphur content. Potential for mine mouth power generation station using the fluidized-bed combustion process with local opportunities for domestic and industrial heating.
  - **Disadvantages:** Relatively high ash content and small known deposit size.
- **Rock River** – Located approximately 110 km northeast of Watson Lake in southeast Yukon; the deposit is mostly concealed by a mantle of clay, gravel and sand, locally up to 30 metres thick. The EMR report notes based on five drill holes totalling 720 m, there appears to be approximately

<sup>12</sup> The 1994 Coal Inventory notes occurrences in the following areas: Kluane (Burwash Basin, Bates Lake Basin, White River); Whitehorse Trough (Whitehorse Area, Braeburn Area, Carmack Area, Big Salmon/Laberge Area, and Yukon/Pelly Area; Tintina Trench (Dawson Area, Pelly River Area, Ross River Area, Watson Lake Region); Indian River Area; Rock River; Bonnet Plume Area (Bonnet Plume Basin, individual deposits within the southern Bonnet Plume Basin, Coal showings in the northern Bonnet Plume Basin; Northern Yukon (Mackenzie Delta Area).

<sup>13</sup> Yukon Mining and Exploration website notes that Most Yukon coal occurrences possess historical resource calculations that do not meet National Instrument 43-101 standards. Of all known coal deposits, only Division Mountain has an NI 43-101 resource calculation; see <http://miningyukon.com/miningandexplorationopportunities/mineralexploration/geologicalframework/coal/>

60 Mt of coal within 80 m of the surface. The deposit is classified lignite A to sub-bituminous C, with a thermal content of 3,720 kCal/kg. The EMR report notes a gravity survey outlined anomalous areas indicating a potential for up to 1.5 Bt, and notes the coal is amenable to surface mining at a ratio of approximately 2 to 1, waste to coal by volume. The 1994 Coal Inventory also notes the following characteristic advantages and disadvantages of the deposit:

- **Advantages:** Significant tonnage; suitability for mine mouth coal fired plant; close proximity to Watson Lake; sufficient reserves to sustain a 200 MW power plant for 40 years with coal suitable for uses related to electric power generation, thermal, chemical and production of synthetic fuel.
- **Disadvantages:** High sulphur content; high ash content; lack of nearby infrastructure.
- **Bonnet Plume** – The deposit is located in the northern Yukon approximately 100 km to the east of the Dempster Highway and the EMR report notes the deposit contains the Yukon’s largest resources of coal, with 660 Mt of high volatile bituminous C, in seams of “mineable thickness”. The coal is of low sulphur content and is potentially clean-burning and is potentially suitable for conversion to clean gaseous or liquid fuels. The earlier 1994 Coal Inventory also notes the following characteristic advantages and disadvantages of the deposit:
  - **Advantages:** large reserve potential, seams of mineable thickness, low sulphur content, proximity to Wernecke breccias deposits; ideally situated to provide coal derived electric power south to load centres north of Mackenzie delta, west to provide pumping power to any Dempster pipeline and southeast to supply potential new mines in Yukon and NWT. Sufficient reserves to support any power generation station up to 2000 MW or more; possibility to generate a large amount of power for export to BC and Alaska grids and (possibility to export 10-15 million tonnes per year and ecologically attractive given coal is clean burning<sup>14</sup>. Product may be suitable for mine-mouth generating station or for conversion to gaseous liquid fuels.
  - **Disadvantages:** high ash content, relatively inaccessible and remote from markets (high transportation costs); the report notes that development is unlikely unless the coal were to be used locally. The report also indicates high costs for development and presence of frozen overburden which would render mining difficult.

### ***Yukon Energy 2006 Resource Plan***

Yukon Energy’s 2006 Resource Plan noted that the economics of coal thermal electricity generation are very sensitive to various factors, such as the quality of the coal and emissions standards, which can materially impact the capital costs required for the plant (for example, ash handling and dealing with sulphur in the coal). The following was provided in the 2006 Resource Plan (Chapter 5, page 5-33):

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<sup>14</sup> Indicates coals have high ash content due to discrete bentonite bands but it is possible that a simple washing technique could be designed to separate the coal and bentonite and produce a relative clean coal with a calorific value of approximately 9,000 BTU/lb.

Coal generation has been reviewed a number of times for application in Yukon. Coal in particular as a fuel source has also been examined in many other jurisdictions beyond Yukon, and is a major generation option that is subject to extensive ongoing technology development to address emissions controls as well as other features. Key characteristics of coal relevant to the WAF system are as follows:

- **Economics very sensitive to size of plant:** Repeated assessment of coal potential in Yukon has focused on 20 MW size, as that is the largest single unit that WAF could handle within operating reliability considerations. Economic preference exists for larger plants up to 50 MW or more to secure lower costs per kW.h of output<sup>15</sup>. This size sensitivity extends to capital costs and operating costs (i.e., largely need same material staff complement for 20 MW plant as for 50 MW<sup>16</sup>). However, energy output from larger potential sizes of plant at perhaps 360 GW.h per year (50 MW) are well in excess of most WAF scenario requirements other than the Pipeline.
- **Technologies for use of coal have been advancing at a rapid pace,** particularly with regard to reducing emissions. Any coal generation plant would have to be environmentally sound in order to be considered by Yukon Energy.
- **Facility life of 20-30 years can be well suited to Yukon loads:** The industrial loads in Yukon can allow for large loads of limited life, with risks of major reductions at the end of the life of the mine(s). With a hydro development, the long life of the facility can increase the exposure to this market risk, while the 20-30 year life of coal or other thermal plants is better suited to the timelines of mine life for many developments and to the mitigating of risks of load decreases when the mine closes.

In summary, the practical minimum size coal development considered for Yukon has been at least 20 MW which roughly equates to 144 GW.h/year.

The 2006 Resource Plan also noted that key to development of environmentally sound coal generation in Yukon is the development of indigenous coal deposits independently of power generation requirements (potential development of the Division Mountain Coal project near Braeburn has been discussed from time-to-time).

Yukon Energy's 2006 Resource Plan noted that technologies for use of coal have been advancing at a rapid pace, particularly in regards to reducing emissions, and that a study in Alaska had also summarized

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<sup>15</sup> A 2005 meeting of Yukon Energy with the then developer of Division Mountain presented analysis focused on preferred 50 MW minimum plant scale with expected capacity factor of 80-90% (245-275 GWh/yr for export to the grid). YEC was informed that expected cost of power would be less than 10 cents per kWh, with coal cost at 3.5 cents/kWh based on \$28/tonne of crushed coal.

<sup>16</sup> An earlier study for YDC indicated that 13 staff FTE would be required to operate a 20 MW plant. This number was not sensitive to size (in the extreme, a 1 MW plant was considered and determined to still require 12 staff FTE).



and assessed the potential for small coal developments, including Atmospheric Fluidized Bed Combustion. Although a number of studies were cited, no successful small scale (1-10 MW) electrical utility coal projects are known to be in service in the north.

### ***GHG Emission Issues***

Coal thermal generation using conventional technologies has been associated with materially higher air emissions than occur with diesel generation, including much higher GHG emissions. In BC, where hydro generation is currently the major source of electricity and coal resources are also readily available for power generation, the BC Clean Energy Act directs that BC Hydro generate at least 93% of the electricity in BC from clean or renewable resources (which exclude coal and natural gas); objectives are also set to reduce BC GHG emissions to 6% lower than 2007 by 2012, 18% lower than 2007 by 2016, 33% less than 2007 by 2020, and 80% less than 2007 by 2050. Policy action No. 20 of the BC Energy Plan states that coal-fired generation must meet a zero greenhouse gas emission standard through a combination of 'clean coal' fired generation technology, carbon sequestration and offsets for any residual GHG emissions. BC Hydro's current assessment is that zero or near-zero GHG emission coal generation is not presently commercially viable; BC Hydro references an EPRI 2007 report to note that coal-fired plants with 90% CO2 capture and storage could be commercially available by 2022.

## **3.2 OTHER THERMAL GENERATION RESOURCES**

### ***Biomass Thermal Generation***

Similar to coal options for thermal generation, biomass use for thermal generation is subject to the economic constraints related to fixed costs (including fixed operating and maintenance costs). Biomass generation does not typically become economic unless three key conditions are met (and that to date in Yukon, proposals have not met these three key criteria):

1. The fuel (typically wood) must be available from a source that would otherwise have to pay to dispose of it. Economic biomass generation is not typically possible with a wood product that has a cost to harvest, or even (in at least some cases) that can be delivered to the plant for free; there has to be savings from avoided disposal costs.
2. The wood-fired power actually displaces diesel power.
3. There is a substantial market for power and heat.

### ***Geothermal Generation***

Using heat energy from a geothermal source is practical for electricity generation only if the geothermal occurrence and the energy requirement are located in close proximity, and that the development of geothermal applications in Yukon will therefore first occur where geothermal resources are found close to populated areas and/or the grid. A resource analysis project was being undertaken at the time of the 2006 Resource Plan to assemble existing and available information on groundwater and ground-source heat potential in Yukon communities

### ***Solar***

Solar radiation is greater in Yukon in the summer time, when there is currently a hydro surplus in Yukon grid areas. In isolated areas where grid power is not an option, solar power may be a viable option for residential and small commercial applications for mining camps and lodges, especially those with greater or solely summertime use.

### ***Nuclear***

Yukon Energy's 2006 Resource Plan noted uncertainty about the commercial availability of nuclear generation at the scale required for Yukon, while observing that a nuclear project being considered for Galena, Alaska might be potentially attractive for Yukon. Other relevant considerations also noted as needing substantial further consideration before determining the true potential for nuclear in Yukon included security and waste disposal.

A recent article on nuclear power technology in *The Economist* (December 11, 2010) noted that the number of operating reactors is in decline, and that rather than relying upon huge, traditional reactors costing billions, the nuclear power industry "is turning to small, inexpensive ones, many of which are based on proven designs from nuclear submarines or warships." The potential advantages described for mini-reactors relate to modularity and potential ability to shift much of the building from the field to the factory, with shorter construction time requirements. The article notes as well, however, sources who state that regulatory and licensing procedures are lengthy – these factors mean that little will be built until after around 2017, and that even this timing may be optimistic.

## 4.0 SUMMARY CONCLUSIONS

Diesel and thermal electricity generation options differ from hydro, wind, solar photovoltaic, and fuel cell electricity generation options.

In the Yukon context, diesel generation has constituted the current “default” generation option, offering well established and reliable technology highly suited to intermittent peaking and reserve capacity generation needs as well as “off grid” applications and cases where loads are expected to have a relatively short life. Diesel generation today is expensive, however, for utility “base load” operation required to provide sustained energy on a regular basis throughout the year with utility fuel and operating costs in Yukon averaging 26 cents/kWh; diesel fuel prices are also subject to ongoing inflation and market price uncertainty. Environmental impacts related to air emissions include GHG (about 700 tonnes per GWh) and regulated health-related emissions.

Opportunities to displace diesel generation on the Yukon grid in the foreseeable future are tied specifically to the connection of new industrial loads and the ability of alternative generation sources to provide generation as required in winter/spring seasons and during low water conditions.

In the event that new industrial loads are connected, costs for added diesel generation will have a major impact on future rates in Yukon. Based on the 545 GWh grid load scenario for 2015, options that could supply the forecast incremental diesel generation at half the cost of diesel would ultimately save all Yukon electric utility customers on average about 2.4 cents per kWh in rates.

Liquefied natural gas (LNG) thermal generation offers a cleaner and potentially less costly option today in Yukon than diesel generation, with the potential for future local sources of natural gas supply from either local resources (e.g., through development of Eagle Plains resources, perhaps in conjunction with the Mackenzie Valley Pipeline) or through access to other sources (e.g., through development of the Alaska Highway Pipeline Project). Based on these considerations, LNG could potentially replace diesel as the default option today at least for Yukon grid applications – and, when natural gas becomes locally available for commercial use, natural gas appears virtually certain to displace diesel for Yukon grid applications.

- Natural gas generating units offer well established and reliable technology with many of the same key features relevant to Yukon as noted to date for diesel generation, including low capital costs, flexibility of unit size and application, operating costs that are mostly composed of fuel cost that is subject to ongoing inflation and market price uncertainty, and cleaner environmental impacts than diesel generation (including GHG emissions for simple cycle operation 30-34% less than diesel fuel).
- The Alaska Highway Pipeline Project [AHPP] may bring natural gas along the Alaska Highway by 2020-21, radically changing the default option in Yukon for electricity generation by providing accessible natural gas at potentially much lower incremental fuel costs than diesel fuel, e.g., 2020-21 (\$2010) fuel costs per kWh [based on recent BC Hydro price forecasts reflecting expected shale gas impacts on future market prices] of 6-7 cents versus the 24-25 cent range currently applicable for most of Yukon.

- LNG import to Yukon has recently been identified as an available near-term gas supply option for new mine development in Yukon prior to AHPP or other local Yukon gas supply development - and use of LNG would ensure that the thermal electricity generation so developed could switch to less costly local gas supplies as soon as they become available.
- LNG is also being examined as a near-term supply option for Yukon utility thermal electricity generation by as early as late 2013, at costs potentially in the 15-20 cents/kWh range (i.e., well below projected costs using diesel), in the event that new mine loads such as Victoria Gold are to be connected to the grid at that time.

Other thermal generation options may also offer potential in Yukon to displace diesel generation in the longer term as loads grow and technologies improve for smaller operations suited to Yukon.

- Higher loads and improved technology (to facilitate cost efficient small scale operation as well as 'clean coal' fired generation technology and carbon sequestration) may improve long term opportunities for base load coal generation in Yukon; however, development of indigenous coal deposits independently of power generation requirements may also be required.
- Higher loads (to the point where diesel or gas is required for summer generation) and improved technology may improve opportunities for a limited scale municipal waste and/or biomass electricity base load generation with much reduced GHG emission impacts.
- Geothermal generation is a potentially very attractive source of new base load electricity generation in Yukon; however, timing and success for such development is entirely dependent upon a successful exploration program.
- Solar power may be a viable option in isolated areas where grid power is not an option for residential and small commercial applications for mining camps and lodges, especially those with greater or solely summertime use.
- Similarly, mini nuclear reactors may become an attractive base load generation option in the future through ongoing technology improvements and successful regulatory and licensing initiatives in other markets.

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## ATTACHMENT 1 – CURRENT & HISTORIC YUKON POWER FACILITIES AND GENERATION

### YUKON BULK POWER FACILITIES

Figure 1 shows the current and committed Yukon bulk power (generation and transmission) facilities, including projects currently under construction (including Stage 2 of Carmacks-Stewart Transmission Project to connect the Whitehorse-Aishihik-Faro (WAF) and Mayo Dawson (MD) grids).

The new WAF/MD Integrated System grid to be completed this spring, including the committed new Mayo B and Aishihik 3<sup>rd</sup> Turbine hydro generation enhancement projects to be completed by late 2011, provides approximately 142 MW of installed generation (approximately 92.4 MW YEC hydro, 0.8 MW YEC wind, 38.6 MW YEC diesel, 1.3 MW YECL hydro, and 8.3 MW of YECL diesel).

- **Isolated Grid** - The Integrated System is isolated from grids external to Yukon, in BC or Alaska;
- **Reduced Firm Hydro Capacity for Winter Peak** - Generation capacity planning for the Integrated System focuses on reliable firm capacity required for the winter peak load, including adequate reserve capacity for the largest single contingency (known as "N-1")<sup>17</sup>. The following adjustments apply when assessing firm winter peak capability of the grid generation:
  - Wind and mobile diesel generation are excluded, and firm winter capacity for the Whitehorse, Mayo and Fish Lake hydro plants that can be relied on for peak winter loads is well below the installed capacity due to low winter flows (i.e., reliable firm winter peak capacities during drought condition flows are only 24 MW at the Whitehorse plant, 0.4 MW at the Fish Lake plant, and currently about 10 MW at the enhanced Mayo plant; as load grows, the reliable firm winter capacity at Mayo under lowest-on-record water conditions may be reduced).
  - Firm winter capacity from the Aishihik hydro plant to supply the main load centre in Whitehorse is 100% vulnerable to loss of the transmission line connection (this N-1 event is to be protected against in generation capacity planning).
  - As a result, the load carrying capability of the Integrated System grid that can be relied upon for the winter peak currently approximates 77 MW (the actual peak in 2010 related to this capacity was approximately 67 MW), and this may be reduced as load grows (due to potential reductions in firm capacity at Mayo under lowest flow conditions). Diesel generation accounts for 57% (44.2 MW) of the reliable grid capacity to serve the winter peak.

The balance of the Yukon generation capacity of 8.4 MW is provided in separate diesel-served communities (5.3 MW in Watson Lake, 2.0 MW in three Small Diesel zone communities along the Alaska Highway, and 1.1 MW in Old Crow). For isolated diesel communities the capacity planning criteria requires being able to meet 110% of the community peak with the largest unit out of service.

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<sup>17</sup> The capacity planning criteria for the Integrated System also requires not exceeding Loss of Load Expectation ("LOLE") of 2 hours a year (with LOLE being determined based on all forecast firm loads).

Figure 1: Generation Capacity in Yukon 2011 Current & Committed

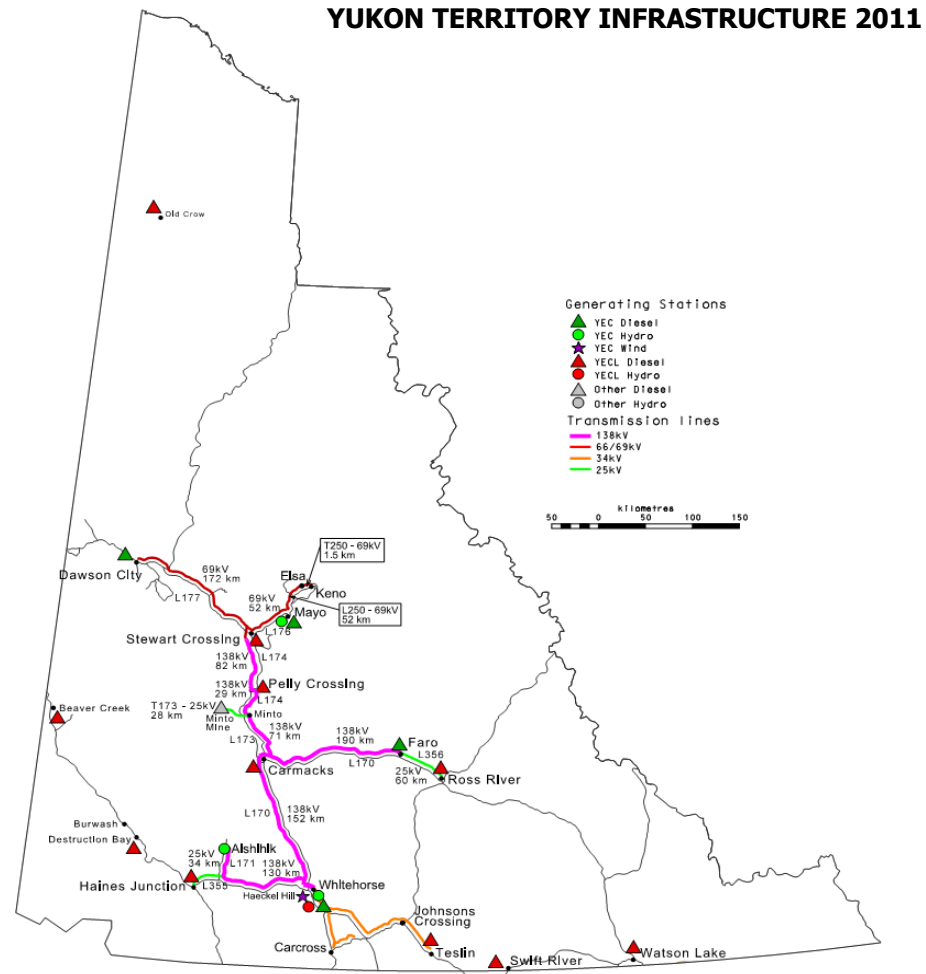
**Yukon Energy Generation Assets**  
(in MW installed & current rating)

Hydro Facilities		
Whitehorse	WAF	40.0
Aishihik	WAF	37.0 *
Mayo	MD	15.4 **
<b>Total Hydro</b>		<b>92.4</b>
Wind Facilities		
Haeckel Hill	WAF	0.8
Diesel Facilities		
Whitehorse	WAF	22.5
Faro	WAF	8.9
Dawson	MD	4.0
Mayo	MD	1.7
Mobile Diesel		1.6
<b>Total Diesel</b>		<b>38.6</b>
<b>TOTAL YUKON ENERGY</b>		<b>131.8</b>

**YECL Generation Assets**  
(in MW installed)

Hydro Facilities		
Fish Lake	WAF	1.3
Base Load Diesel Facilities		
Old Crow	Isolated	1.1
Beaver Creek	Isolated	1.0
Destruction Bay	Isolated	0.9
Swift River	Isolated	0.2
Watson Lake	Watson Lake	5.3
Back-up Diesel Facilities		
Carmacks	WAF	1.6
Pelly Crossing	WAF	1.0
Teslin	WAF	1.5
Haines Junction	WAF	1.8
Stewart Crossing	MD	0.4
Ross River	WAF	1.0
Mobile		1.1
<b>Total Diesel</b>		<b>16.7</b>
<b>TOTAL YECL</b>		<b>18.0</b>
<b>TOTAL YUKON</b>		<b>149.9 (YEC + YECL)</b>

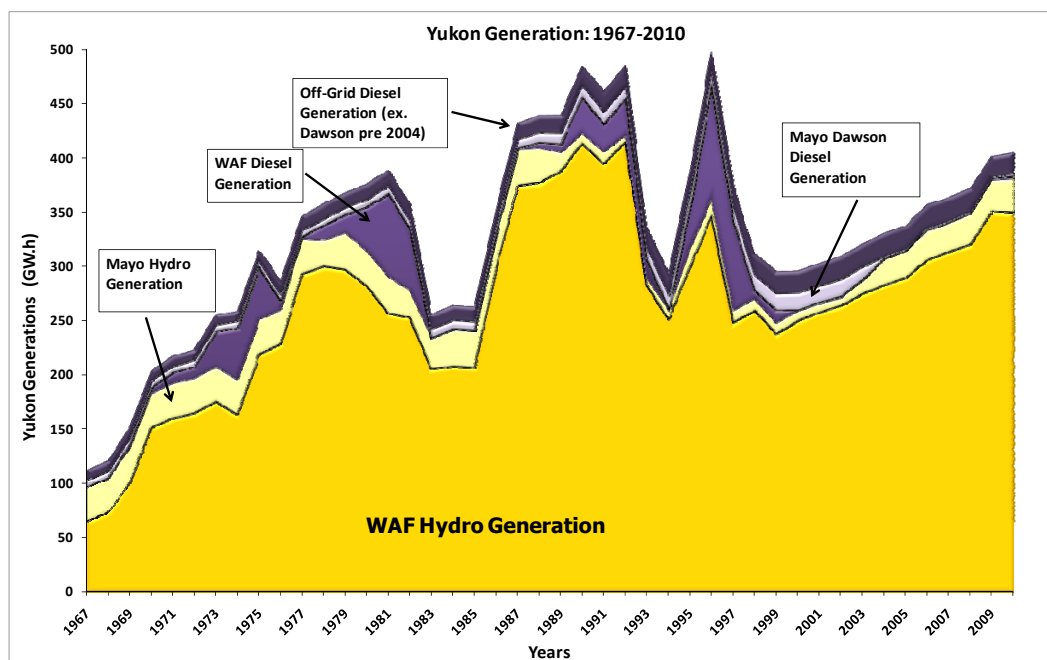
\* Ashihik 3rd Turbine (7MW) committed in 2011  
 \*\* Mayo B (10 MW) committed by end of 2011



## YUKON GENERATION: 1967-2010

Figure 2 below shows Yukon annual electricity generation increasing from 102 GWh in 1967 to 386 GWh in 2010.

**Figure 2: Yukon Generation: 1967-2010**



Hydro renewable generation was the dominant source of Yukon electricity generation throughout this period, with diesel generation fluctuating widely on WAF (i.e., from zero in many years to over 100 GWh/yr in 1996) as the Faro mine load changed and/or new hydro generation was developed.

- Prior to 1967, the initial three Whitehorse Rapids units were developed to supply Whitehorse loads (11 MW in 1956, expanded to approximately 20 MW in 1966 to fully utilize reliable winter flows on the Yukon River); the 1966 development coincided with the initial transmission line from Whitehorse to Faro to service the Faro mine.
- In 1974, the 30 MW Aishihik Lake hydro facility was developed, along with the balance of the WAF 138 kV transmission line, to meet expanding mine and non-industrial loads.
- In 1985, the 20 MW Whitehorse #4 hydro unit was developed to capture the Yukon River summer flows that are in excess of firm winter levels in order to displace summer diesel generation. This enhancement was justified under the assumption that the Faro mine would continue operating – however, during construction of the unit the mine closed and, at the time of commissioning, the 4<sup>th</sup> unit was of no economic value to the system, i.e., it could not displace any diesel generation that was otherwise required. Since that time substantial periods of operation of the Faro mine provided opportunities to capture good economic value from the 4<sup>th</sup> Whitehorse unit – however, had the Faro mine shut for good in the 1980s rather than in early

1998, the unit may not have had any material value to the WAF system for almost three decades after it was commissioned.

- WAF hydro generation was particularly high between 1987 and 1992 (i.e., in excess of 370 GWh), reflecting Faro mine loads (which typically accounted for 40% of all Yukon energy requirements during this period) combined with high water conditions at Aishihik. In contrast, low water conditions on WAF in 1998-1999 fortuitously occurred concurrent with the Faro mine closure.
- After the Faro mine closed permanently in early 1998, there was significant surplus hydro on WAF and new secondary interruptible commercial sales were developed; by late 2008, the first stage of the Carmacks-Stewart Transmission Project was completed to Pelly Crossing (a diesel served community with a 2.2 GWh/yr load), the Minto mine was connected (it was then being supplied by on-site diesel generation at just under 30 GWh/yr), and the WAF hydro surplus was effectively used to reduce diesel generation at Minto and Pelly Crossing.
- In 2010, WAF hydro generation was 348.9 GWh and WAF diesel generation was 2.7 GWh, reflecting considerable non-industrial load growth since the Faro mine era (i.e., mine load in 2010 accounted for only about 30 GWh of the WAF load versus the 180 GWh/yr projected for the Faro mine in the mid-1990s).
- The Mayo A unit operation started in 1952, with the second unit added in 1957, to serve the mines in Keno and Elsa. In the later 1980s these mines closed, and there was considerable surplus hydro at Mayo. Prior to the completion of the Mayo Dawson Transmission Line (MDTL) in September 2003, Dawson City and Stewart Crossing were diesel-served communities - with completion of the MD grid, hydro became the main source of generation for all MD grid communities, i.e., by 2004 only 7% of MD generation (1.9 GWh) was supplied by diesel, as compared to 70% (15.9 GWh) in 2002. With the connection of the Alexco mine and mill in late 2010, the existing hydro capability was largely utilized.
- In 2010, MD hydro generation was 31.5 GWh and MD diesel generation was 2.4 GWh.

The diesel-served community generation was 19.8 GWh in 2010, or about 5% of total Yukon utility generation, with about 70% of this diesel generation being located at Watson Lake. Since 2003, diesel served community generation has been greatly reduced by the hydro grid expansion to Dawson City, Stewart Crossing and Pelly Crossing. Overall load growth in diesel served communities in the last decade has tended to be modest.

Figure 2 excludes non-utility diesel generation. Subsequent to the grid connection of the Minto mine in late 2008, the major current non-utility diesel generation is thought to be at the Wolverine mine (located about 270 km east of the WAF grid) which is increasing production to design capacity in 2011 (about 37 GWh/yr diesel generation estimated to be required on site for over 9 years).



## ATTACHMENT 2 – FUTURE GRID DIESEL CAPACITY & GENERATION

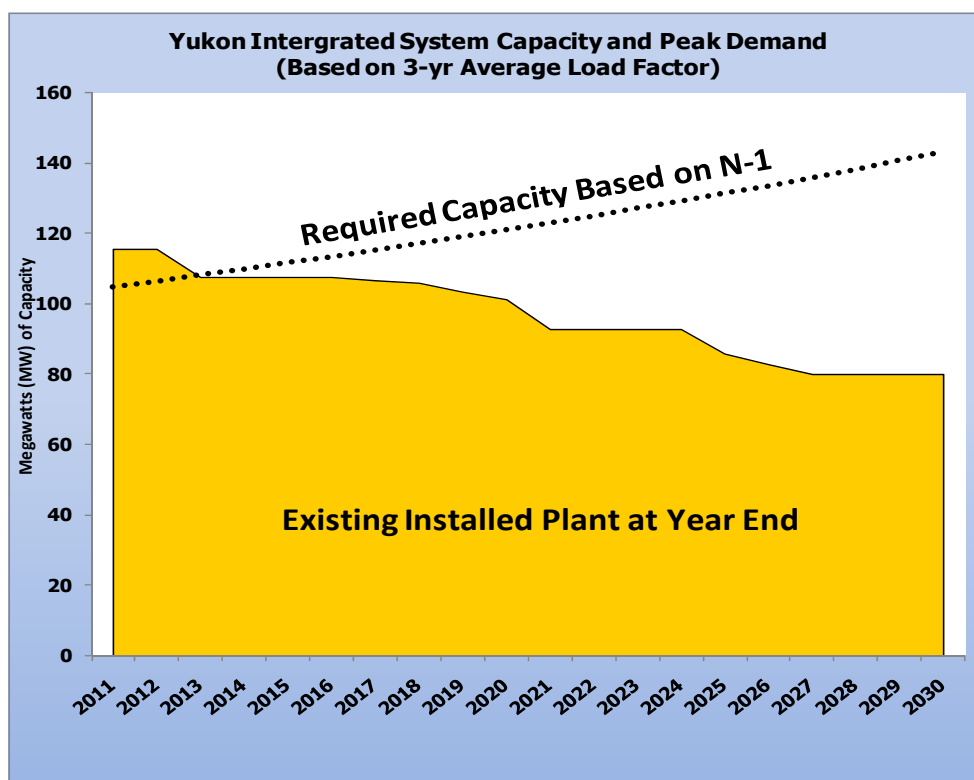
### INTRODUCTION

The integrated WAF/MD hydro grid system in Yukon faces a wide range of potential electricity load scenarios over the next 10 to 40 years. Potential future diesel capacity and generation requirements are reviewed below assuming diesel generation is the default supply option, i.e., the option selected when current and committed renewable generation infrastructure (as described in Attachment 1) is not adequate. These future diesel generation requirements provide the opportunity to develop alternative electricity generation resources to displace the costs and emissions associated with such diesel generation.

### DIESEL CAPACITY REQUIREMENTS - NON-INDUSTRIAL LOADS

Figure 3 shows the forecast capacity surplus or shortfall over the next 20 years on the integrated grid system based on current YEC diesel plant retirement plans, non-industrial load growth assumed at 2.34% per year, and the N-1 capacity planning criteria applicable to non-industrial loads<sup>18</sup>. This assessment shows grid capacity shortfalls emerging in 2013, and expanding to 21 MW by 2020 and 64 MW by 2030<sup>19</sup>.

**Figure 3: Yukon Integrated System Capacity Surplus or Shortfall: 2011-2030**



<sup>18</sup> The N-1 event is the loss of the 37 MW Aishihik generation capacity currently supplied through a single transmission line.

<sup>19</sup> This assessment excludes Loss of Load Expectation capacity planning requirements arising from industrial loads as well as any potential reductions in Mayo hydro plant winter peak capability as load grows.

As reviewed in Attachment 1, diesel generation capacity currently accounts for 57% (44.2 MW) of the reliable Yukon grid capacity to serve the winter peak. This diesel infrastructure is utilized today primarily as reserve capacity to meet peak or short term emergency needs - however, it remains available as well to provide base load energy as required, i.e., at 90% capacity factor the existing 44.2 MW could potentially provide almost 350 GWh per year of electricity.

Under the default option, maintaining the required quantity of installed diesel capacity on the system (and at the right locations on the system), as well as maintaining the ability to operate the diesels, as required, to the full capability of their rated output, is essential in order to minimize the risk of service disruptions due to any of the following events occurring:

- **Interruptions of service on substantial components of the grid due to the inability to meet peak loads on the grid in very cold weather conditions** - (i.e., during times of coincident peak). It is noted that once such outages occur it becomes very difficult to resume service due to a condition known as 'cold load pick-up' where the generation available must be well in excess of the normal average load on a feeder in order to be able to restore service (due, for example, to the fact that after even a brief outage in such weather, basically every furnace fan or heat tape installed on the system will automatically be drawing load when the system is restored).
- **Unplanned system outages (particularly in winter conditions)** - Outages due to this factor could readily be of extended duration, such as the experience of January 29, 2006, where due to a major failure of the power cables at the Aishihik hydro plant, up to 6 WAF diesels operated for 2 days to maintain power to the system. For a further 8 days the WAF system operated in a constrained mode without diesels operating, but needed to be ready to operate at any time. The system was not fully restored to normal status until February 21, more than three weeks after the incident. Diesel generation was similarly used to supply substantial components of the load following the fire at the Whitehorse Rapids hydro plant in October 1997, and to various grid locations during forest fires (when transmission lines are at times required to be de-energized) in recent years.
- **Drought or low water conditions** - Even at the current load levels, the diesel units could be required for energy-related reasons to maintain service to load and ensure the WAF hydro plants can maintain their water levels within licenced ranges. For example, diesel generation for this purpose was required in the late winter of 1999 due to the severe drought conditions experienced at Aishihik in 1998. While this can lead to sustained diesel generation, the output is typically at a low level. For example, during the early part of 1999, the average output of all combined diesel generation on WAF was 3 MW, or less than 10% of the installed diesel capability on WAF.
- **Planned system outages** - During planned outages (e.g., transmission line maintenance), communities such as Faro and Dawson which are located away from the hydro plants require diesel generation to maintain continuity of service.

## DIESEL ENERGY REQUIREMENTS

In addition to providing cost effective reserve and peaking capability, available diesel generation plant also is used as the “last resort” supply to meet grid generation energy requirements after all available renewable energy generation has been fully utilized.

The predominance of hydro generation on the Yukon system, combined with the fact that Yukon is isolated from other grids outside the territory, means that other forms of backup capacity are required to supplement available Hydro in circumstances of low water or drought. With the diminished surplus hydro generation available today, continued reliance on the existing grid system to deal with load growth will mean an increasing need to rely on more costly diesel generation to meet energy loads over the near term and over the longer term - particularly to meet winter/spring seasonal generation requirements, and to provide reliable energy generation in drought years.

- **Winter-summer constraints** - Seasonal water storage is typically needed if hydro facilities are to be fully utilized in winter. In Yukon, controlled seasonal storage exists at Aishihik and to a much lesser extent at Mayo, but is largely not available at Whitehorse. As a result, as grid loads increase there is an increasing need to rely on diesel generation to meet base load energy loads in winter and early spring; however, until loads increase to very much higher levels, little if any grid diesel generation is likely to be required during summer and fall when Whitehorse water supplies tend to sustain surplus hydro generation (a factor that may undermine the cost effectiveness of capital-intensive renewable resource options developed to displace diesel generation, unless these options tend for focus new generation in winter).
- **Drought-flood year constraints** - In addition to seasonal supply constraints, systems predominantly based on hydro generation resources such as the Yukon grid are vulnerable to drought (low water) conditions, and in these circumstances hydro generation must be supplemented by other reliable forms of generation. Notably, the requirement for thermal resources to back up hydro resources exists even in interconnected systems such as Manitoba (which continues to include a small amount of thermal generating resources in its power resource plan) and British Columbia (e.g., the Burrard generating station). Conversely, hydro-based systems such as the Yukon grid must also anticipate flood (high water) conditions, and in these circumstances the need to rely on other reliable forms of generation will be greatly diminished and/or eliminated (a factor that may undermine the cost effectiveness of capital-intensive renewable resource options developed to displace diesel generation).

Table 1 reviews YEC’s power benefit water model analysis of diesel generation displacement opportunities at various grid energy loads that might arise within the next five years, assuming today’s current and committed generation. Due to variability of current hydro generation as reviewed above, assessments of diesel displacement opportunities need to fully consider different seasonal and annual water flow conditions.

- **No material diesel displacement opportunity in summer/fall seasons** - Under even a 610 GWh/year “high” load scenario for 2015, over 95% of the average diesel displacement opportunities (i.e., the average of all water years) still occur in the seven month period from November to May and over 75% in the five months from January to May. The isolated nature of

the Yukon grid prevents any "export" sale of surplus summer/fall renewable generation - accordingly, at these forecast loads the following will occur:

- for five months (June to October) new non-diesel generation has no material diesel displacement value;
  - thermal generation options (e.g., natural gas/LNG combustion turbines) which can be shut down as required during such periods will tend to operate at low (less than 40%) annual capacity factors; and
  - thermal generation options to displace average water year diesel generation will require peak winter diesel generation capacities (based on weekly generation averages) of about 9 MW at the 442 GWh/year "low" load scenario, about 34 MW at the 545 GWh/year "mid" load scenario, and about 48 MW at the 610 "high" load scenario.
- **Wide annual variability in water conditions affect diesel displacement opportunities -** "Annual average" diesel energy generation estimates reflect averages of widely varying annual water flow conditions. With loads at a 545 GWh "medium" load scenario for 2015 (approximates growth to 2015 of current grid loads plus one new mine, i.e., Victoria Gold), "annual average" diesel generation is projected at 101.6 GWh/yr (see Table 1 below). This "average", however, includes diesel generation ranging from 13.5 GWh/yr under extreme high water conditions to 199.3 GWh under extreme low water conditions. Table 1 shows similar variability in annual water conditions at lower and higher grid loads. This annual variability needs to be fully considered when assessing the diesel displacement impact that any new renewable resource is expected to achieve. The isolated nature of the Yukon grid prevents any "export" sale of surplus renewable generation during high water years. At the forecast loads examined for 2015 (ranging from 442 GWh up to 610 GWh/year) the following can be noted:
    - Under even a 610 GWh/year "high" load scenario and the lowest water year at this load (1996), over 90% of the average diesel displacement opportunities in that water year still occur in the seven month period from November to May, i.e., diesel displacement opportunities in summer/fall remain minimal at these loads even in the lowest water year;
    - Peak diesel generation capacities (based on weekly generation averages for each water year) are about 37 MW at the 442 GWh/year "low" scenario, about 55 MW under the 545 GWh/year "mid" load scenario, and about 64 MW under the 610 GWh/year "high" load scenario; and
    - Annual diesel generation for any specific load scenario is "below average" in many (perhaps most) years, e.g., under the 545 GWh/year "mid" load scenario, diesel generation is less than the "average" 101 GWh in 15 of the 28 water years, and less than 86 GWh in 10 of the 28 water years.
  - **Load level impacts on diesel displacement opportunities** – Table 1 demonstrates the extent to which diesel generation requirements on the Yukon grid vary depending on the assumed grid load level. The three loads reviewed in this table reflect 2015 grid load scenarios

ranging from "low" to "high", with resulting "average" diesel generation requirements in 2015 varying from 25 GWh to 161 GWh.

Costs for added diesel generation will have a major impact on future rates in Yukon. By way of example, 101.6 GWh of added base load diesel generation (the 545 GWh load case for 2015 in Table 1) will add \$30.5 million to Yukon costs at 2009 approved Hydro zone average incremental fuel and other operating costs (30 cents per kWh). Based on the forecast Yukon sales of 183 GWh associated with the 545 GWh load case, these added diesel costs would equal approximately 5.9 cents per kWh of customer energy use. Options that could supply this incremental generation at half the cost of diesel would ultimately save customers on average about 2.4 cents per kWh in rates.

The figures that follow Table 1 illustrate, for each of the above three load scenarios for 2015, the generation by source by weeks of the year (season) under average and extreme low water years. These figures use the same assumptions as Table 1, based on the relevant averaged load year estimates.

- 442 Grid Load
  - Figure 4A reviews generation by source by week for under mean water conditions
  - Figure 4B reviews generation by source by week under extreme low water (in this case this occurs in the year with 1999 water flow conditions).
- 545 Grid Load
  - Figure 5A reviews generation by source by week for under mean water conditions
  - Figure 5B reviews generation by source by week under extreme low water (in this case this occurs in the year with 1996 water flow conditions).
  - Figure 5C shows generation by source under water flow in each of the 28 water years.
- 610 Grid Load
  - Figure 6A reviews generation by source by week for under mean water conditions
  - Figure 6B reviews generation by source by week under extreme low water (in this case this occurs in the year with 1996 water flow conditions).

**Table 1 - Yukon Energy Integrated System Capability (GW.h)  
(YEC hydro with Mayo B & Mayo Lake & current Aishihik regulatory regime)**

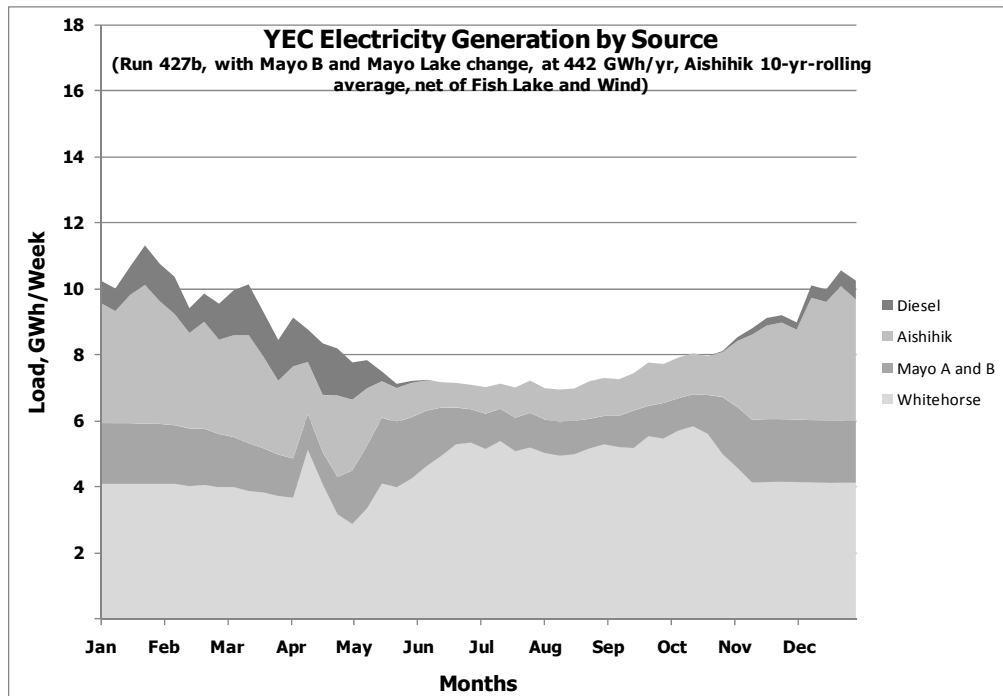
	Firm Load Level (GW.h/year) - Net of Fish Lake and Wind generation		
Total Load	442 GW.h Base Case	545 GW.h Scenario A	610 GW.h Scenario B
<b>Mean Capability</b>			
YEC Hydro Generation (GW.h)	416.9	443.4	449.6
Diesel Generation (GW.h)	25.1	101.6	160.7
<hr/>			
Extreme Low Water			
Extreme Low Water (Extreme Load Year) <sup>1,2</sup>			
YEC Hydro Generation (GW.h)	321.9	345.7	345.9
Diesel Generation (GW.h)	120.2	199.3	264.3
Extreme Low Water (Averaged Load Years) <sup>1,3</sup>			
YEC Hydro Generation (GW.h)	321.9	377.8	380.9
Diesel Generation (GW.h)	120.2	167.2	229.3
<hr/>			
Median Water Conditions			
Median Water Conditions (Median Load Year) <sup>1,2</sup>			
YEC Hydro Generation (GW.h)	427.9	445.9	454.1
Diesel Generation (GW.h)	14.1	99.1	156.2
Median Water Conditions (Averaged Load Years) <sup>1,3</sup>			
YEC Hydro Generation (GW.h)	425.6	445.0	455.0
Diesel Generation (GW.h)	16.5	99.9	155.3
<hr/>			
Extreme High Water			
Extreme High Water (Extreme Load Year) <sup>1,2</sup>			
YEC Hydro Generation (GW.h)	441.5	531.5	563.6
Diesel Generation (GW.h)	0.6	13.5	46.7
Extreme High Water (Averaged Load Years) <sup>1,3</sup>			
YEC Hydro Generation (GW.h)	441.5	510.4	530.1
Diesel Generation (GW.h)	0.6	34.6	80.2

1. The water model develops expected hydro plant capabilities for each load scenario. It reviews, by week, 28 "water years" of record (1981-2008) and 20 "load years" (each examines a different hypothetical scenario to reflect different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this deletes cases where starting or ending year volumes can distort results).

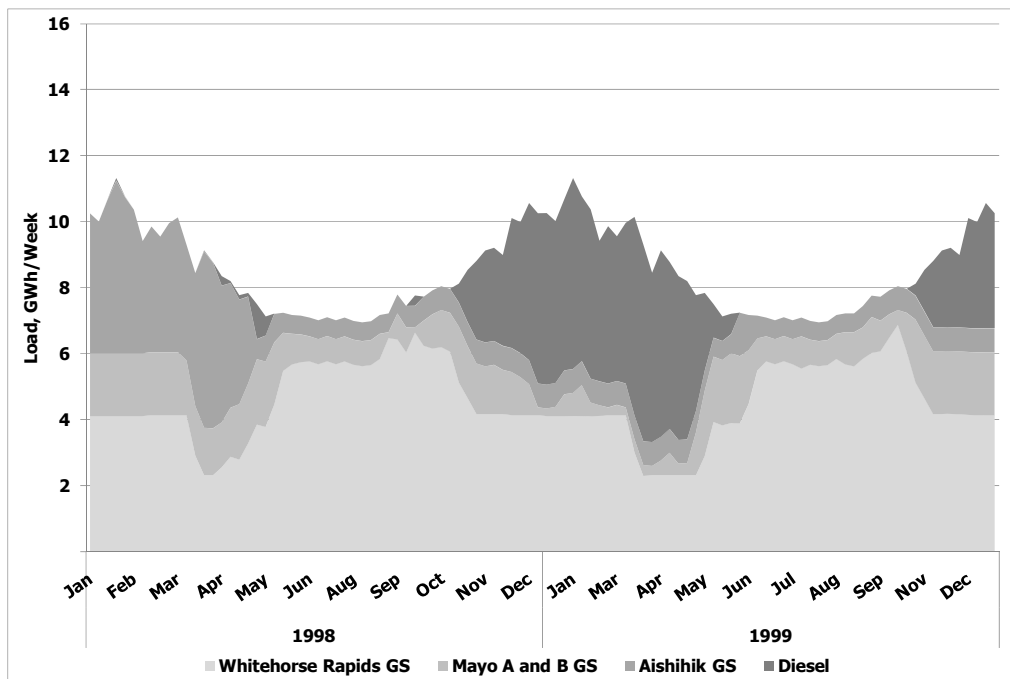
2. "Extreme or Median Load Year" is one year out of the 364 cases examined (28 water years and 13 load years).

3. "Averaged Load Years" is the average annual value for a water year calculated over all 13 load years.

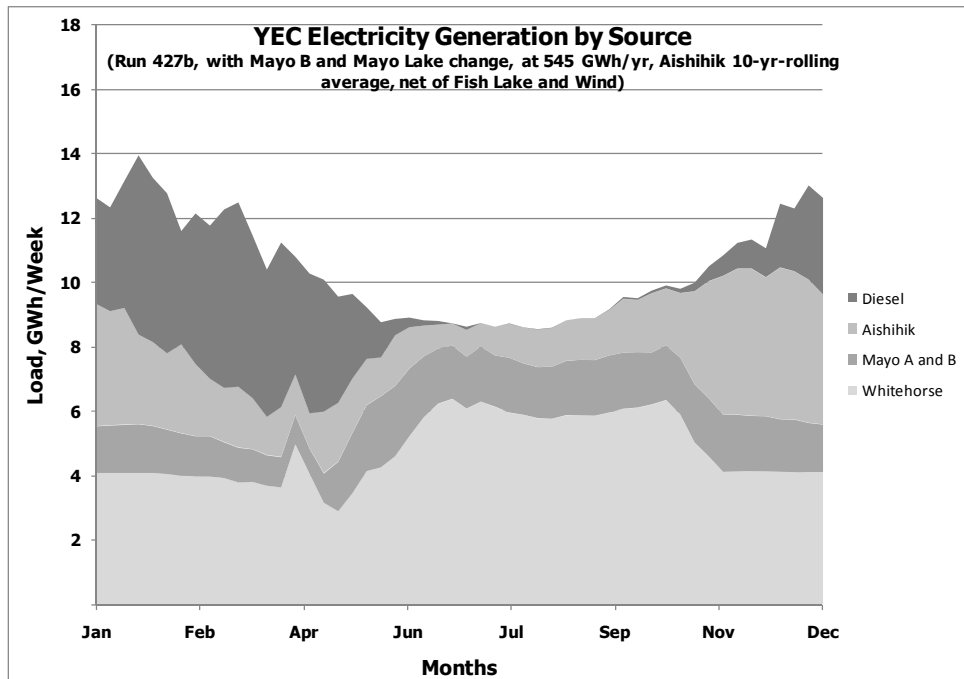
**Figure 4A: YEC Electricity Generation by Source: Mean Flows (average of all water years)  
At 442 GWh/yr Grid load net of Fish Lake and Wind**



**Figure 4B: YEC Electricity Generation by Source: Extreme Low Water (1998-99 water years)  
At 442 GWh/yr net of Fish Lake and wind**



**Figure 5A: YEC Electricity Generation by Source: Mean Flows (average of all water years)  
At 545 GWh/yr Grid load net of Fish Lake and Wind**



**Figure 5B: YEC Electricity Generation by Source: Extreme Low Water (1995-96 water years)  
At 545 GWh/yr net of Fish Lake and wind**

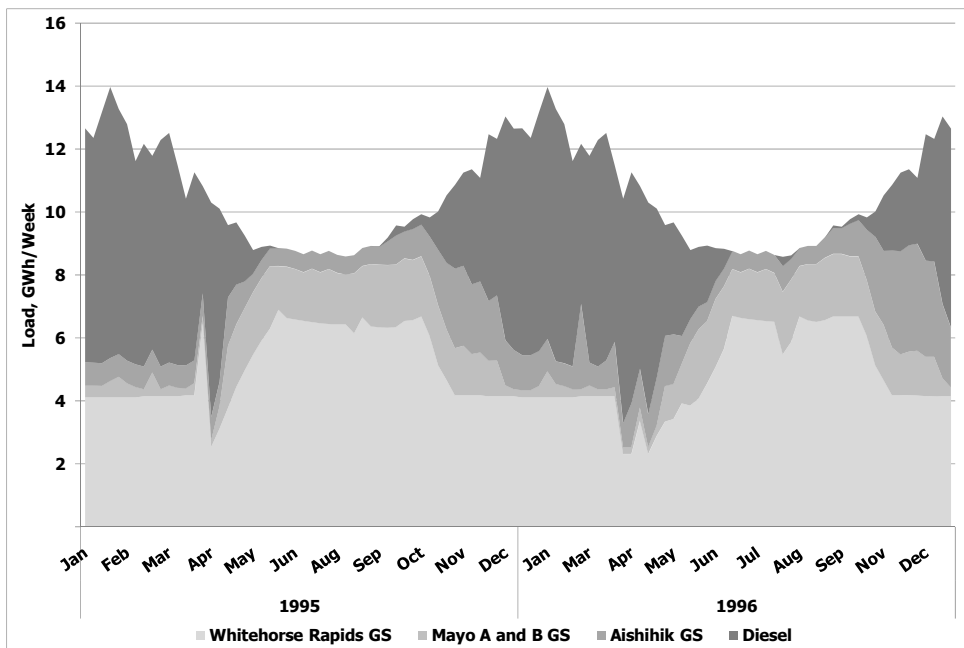
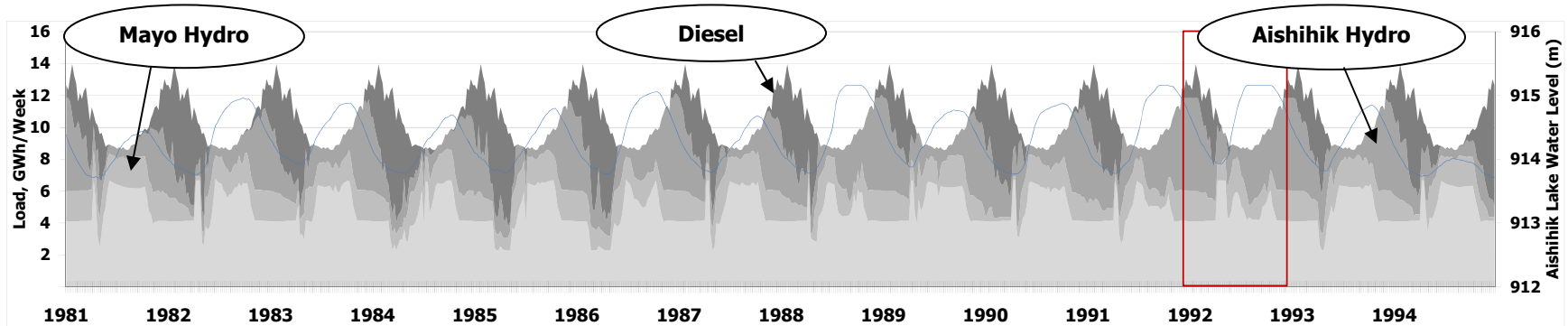
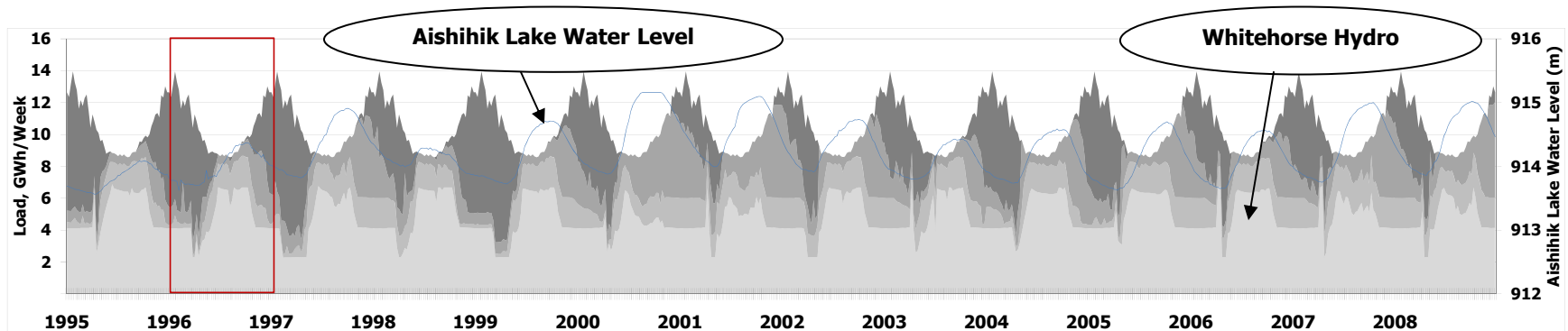




Figure 5C: YEC Generation by Source (Gwh), for all 28 Water Years at 545 Gwh/Yr



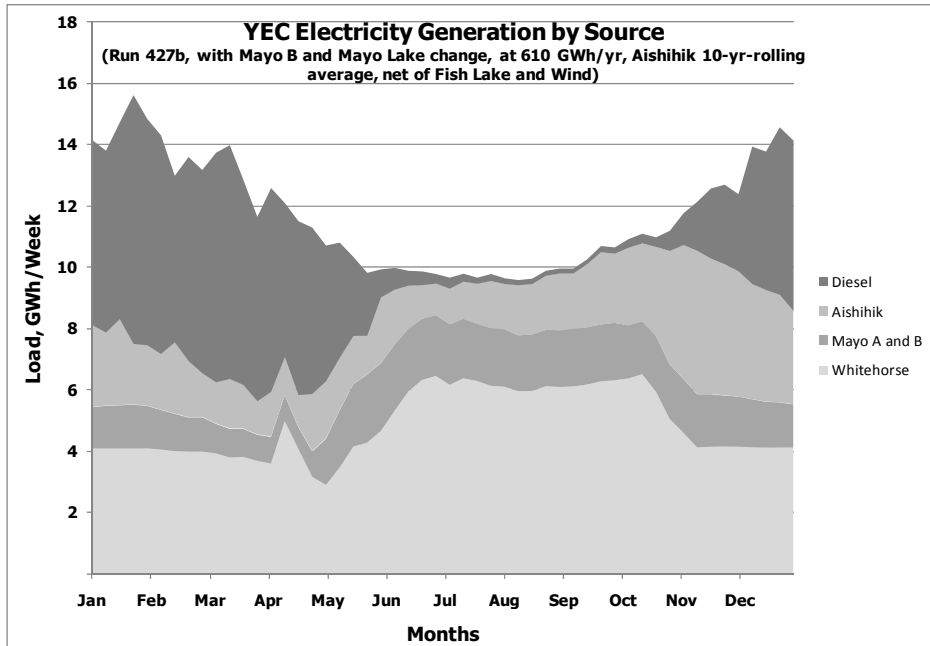
	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
WH	262.0	259.5	254.9	237.1	239.1	224.5	258.0	241.1	269.0	263.0	243.6	246.5	252.4	265.2
Mayo A & B	97.1	74.8	83.9	86.0	85.9	84.4	90.9	77.8	86.3	63.2	70.4	83.9	89.4	69.0
AH	117.6	101.8	119.5	102.5	109.6	137.0	119.8	141.7	136.8	130.7	160.5	179.9	150.1	84.8
Diesel	68.3	108.9	86.7	119.3	110.4	99.1	76.3	84.4	52.8	88.0	70.4	34.6	53.0	126.0



	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
WH	266.4	249.2	232.0	253.1	242.8	228.0	237.2	250.4	253.5	259.3	264.6	260.1	248.5	245.2
Mayo A & B	64.0	61.4	73.4	69.6	67.8	71.8	95.2	94.2	86.0	66.6	72.0	93.5	96.4	96.1
AH	50.9	67.2	98.6	76.9	70.9	134.7	150.1	118.9	85.3	94.0	97.9	90.6	104.6	123.3
Diesel	163.6	167.2	141.0	145.3	163.5	110.4	62.6	81.4	120.1	125.1	110.4	100.8	95.4	80.3

Note: YEC Generation by source (GW.h) with high water year (1992) and low water year (1996) highlighted

**Figure 6A: YEC Electricity Generation by Source: Mean Flows (average of all water years) At 610 GWh/yr Grid load net of Fish Lake and Wind**



**Figure 6B: YEC Electricity Generation by Source: Extreme Low Water (1995-96 water years) At 610 GWh/yr net of Fish Lake and wind**

