10-Year Renewable Electricity Plan Technical Report

DECEMBER 2020

yukon energy

Executive Summary

Demand for electricity is growing in Yukon. There is an existing gap today between the available dependable capacity on the grid and the amount of electricity Yukoners require during a winter peak under emergency conditions. To continue providing most of the territory's energy from renewable sources and to accommodate the increased demand for electricity, Yukon Energy Corporation (YEC, Yukon Energy) must invest in new dependable renewable electricity sources that add firm winter capacity to the grid. This will allow YEC to continue meeting Yukoners' growing demands for renewable electricity – even on the coldest and darkest of days – while also supporting Yukon government's emission reduction targets.

This plan outlines a portfolio of key projects and partnerships needed by 2030 to address the substantial demand for renewable electricity that will result from ongoing economic growth of the Territory, and from the policies and actions outlined in the Yukon government's draft *Our Clean Future: A Yukon strategy for climate change, energy and a green economy*. In this strategy, the government has mandated that an average of 93% of electricity generated on the grid must be produced from renewable sources and includes specific actions to electrify the territory's transportation and heating sectors.

In order to conduct this analysis, YEC updated its load forecast (the projected energy and demand requirements of Yukoners) based on recent learnings from cold weather peaks and incorporated the electrification actions of the Yukon government's *Our Clean Future* strategy to estimate the resulting increased demand. YEC used this load forecast, along with the inventory of existing generation and projects under development, to calculate the gap between the energy and demand requirements and available resources. Using updated technical and cost information on potential resources, the company then conducted a portfolio analysis to evaluate which renewable resource options could best address this gap, across a range of scenarios. The goal of this portfolio analysis was to develop an optimal set of projects capable of addressing both the energy and peak capacity shortfalls over the 10-year planning horizon.

The result is the updated Future-Focused Portfolio. Included in this portfolio are resources which are planned or currently under development. These ongoing projects include: Whitehorse Hydro uprates at WH2 and WH4, the battery energy storage system, renewable energy purchases from Independent Power Producers through the Standing Offer Program, solar energy from the Micro-Generation program, the Southern Lakes and Mayo Lake enhanced storage projects, replacement of diesel generators as they retire, and demand side management programs. The three new projects YEC is proposing are: electricity purchases from the planned Atlin Expansion Project, construction of a pumped storage facility at Moon Lake, and upgrading and expansion of the Southern Lakes Transmission Network. The combination of these three future potential projects not only stores and uses excess renewable power generated in the summer to decrease dependency on fossil fuels during the winter, but also makes connecting potential sources of First Nations-owned renewables in the Southern Lakes region more viable, and creates potential future electricity sales opportunities.

First Nations governments, development corporations and Citizens will have a key role in helping to shape and deliver this plan over the next 10 years. YEC recognizes First Nations as governments and potential energy proponents, partners and investors. In developing this plan, YEC will work pro-actively and collaboratively with First Nations governments and development corporations to forge partnerships and create opportunities for project ownership, investment, contracting, employment and training. First Nations will also be at the forefront of project assessments, permitting and approvals.

The cost of projects in this plan are estimated to be in excess of $500 million, one of the largest investments ever in the Yukon electricity system. Federal funding for the plan will be key to keeping the plan affordable and minimizing risks for Yukon customers.

The 10-Year Renewable Electricity Plan presents a generational opportunity for Yukon to invest in the critical renewable electricity projects needed to fuel Yukoners' lives, work and economy with clean energy. It creates opportunities for Yukon Energy, First Nations governments and development corporations, the Yukon and federal governments, and Yukoners to jointly shape the territory's electricity future.

A clean future lies ahead. Let's work together to meet Yukon's climate goals.

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Glossary of Key Terms

CAPACITY (DEMAND)	The supply (or consumption) of electrical power at a given instant in time. Usually measured in megawatts (MW) in long-term planning context.
DEMAND SIDE MANAGEMENT (DSM)	The attempt to reduce overall electrical consumption at customer sites via initiatives or implementation of codes/standards. Demand side management, if used during peak demand periods, can provide an alternative to supply-side dependable capacity additions.
DEPENDABLE CAPACITY	The maximum generation output that a resource can reliably provide in a specific time frame, expressed in megawatts (MW), typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history. For thermal resources, dependable capacity was assumed to be equal to the installed capacity, since fossil fuels can be stored. For wind resources, dependable capacity is considered zero, as there is no guarantee that there will be the required wind speeds for the two consecutive weeks within the winter period.
DISPATCHABLE GENERATION	Refers to sources of electricity that can be dispatched at the request of power grid operators; that is, generating plants that can be turned on or off, or can adjust their power output on demand. Resource options such as thermal power plants and hydro power plants with reservoirs are dispatchable and they can meet changing electricity loads. In contrast, intermittent resources, such as wind are non-dispatchable because they can only generate electricity while their energy source is available.

ENERGY	The supply (or consumption) of electrical power over a period of time. Usually measured in kilowatt-hours (kWh) for residential usage or gigawatt-hours (GWh) for territorial usage. The annual energy supply must at least cover the annual energy consumption.
GENERATION RESOURCE	Refers to sources of energy that are converted to electrical power and provide energy and/or dependable capacity. Common generation resources include hydro, wind, solar, or thermal (e.g. natural gas or diesel).
INDEPENDENT POWER PRODUCER (IPP)	An energy producer who generates electricity for sale to utilities or consumers.
INSTALLED CAPACITY	The maximum amount of generating capacity that a generation resource is capable of providing, expressed in megawatts (MW).
LOAD	The electrical energy required to power homes, businesses and industrial processes. Sometimes referred to as demand.
N-1 (SINGLE CONTINGENCY) PLANNING CRITERION	A reliability planning criterion used to determine the capacity requirements of the system. YEC's N-1 criterion requires that each part of the YEC transmission grid should be able to carry the forecast peak winter demand, excluding major industrial demand, under the largest single contingency. The single largest contingency is defined as loss of the largest single element which could be either a transmission line or generating station. This criterion considers the ability to interrupt large industrial customers during an emergency event, which is why only non-industrial peak demand is included.
RENEWABLE ENERGY	Energy that comes from sources renewed on an ongoing basis through natural processes. Examples include sun (solar), wind, and flowing water (hydro).

1 Introduction

1.1 Yukon Energy Corporation

Yukon Energy Corporation (YEC) is a public electric utility owned by the Yukon Government through the Yukon Development Corporation (a Crown Corporation). YEC's mandate is to plan, generate, transmit and distribute a continuing and adequate supply of cost-effective, sustainable, clean and reliable electricity for customers in Yukon.

YEC owns and operates the Yukon's integrated transmission system, generating almost 100% of the electricity on this isolated, northern Canadian, electric grid. It is the electric utility with primary responsibility for planning and development of new generation and transmission facilities in Yukon. YEC is incorporated under the Business Corporations Act and regulated by the Public Utilities Act and the Yukon Waters Act.

1.2 Background: Drivers for a 10-Year Renewable Electricity Plan

In July 2019, YEC released its 5-year strategic plan with a bold 10-year vision to be a Canadian leader in sustainable energy by 2030. Later that year, based on the input of Yukoners, YEC's Board of Directors also decided not to move forward with the development of a new 20-megawatt thermal generation facility that would address Yukon's current and forecast capacity shortfall. This decision commenced the re-examination of potential renewable capacity resources.

In November 2019, Yukon government released a draft of its *Our Clean Future* strategy, with a vision for addressing climate change by building thriving, resilient communities powered by clean energy and supported by a sustainable green economy. In it, the government proposed that an average of 93% of electricity generated on the grid be produced from renewable sources and included specific actions to promote the electrification of the territory's transportation and heating sectors. These policy actions triggered the need for an update to YEC's long term load forecast.

These increased electricity requirements to enable a clean Yukon future and the Corporation's commitment to provide renewable capacity solutions to serve this demand formed the need to develop an updated plan for future renewable generation and transmission projects.

1.3 Yukon Integrated System

At present, the Yukon electrical system shown in Figure 1 comprises:

» One (1) large hydroelectric based grid called the Yukon Integrated System (YIS);

» One (1) medium-sized diesel-based grid serving Watson Lake; and

» Three (3) smaller isolated communities with diesel generation (Beaver Creek and Destruction Bay/ Burwash Landing) and solar/diesel generation (Old Crow).

Figure 1: Yukon Electrical Systems

1.4 YEC Resource Planning Criteria

Reliability means that electricity is available when customers demand it. Generation resources exist to supply electricity, and transmission resources exist to move electricity from generators to customers. Planning generation resources involves consideration of two primary supply aspects: energy and capacity. Energy is the total quantity of electricity produced over a period of time (e.g. a day or a year), while capacity is how much electricity can be produced at one time.

Being an islanded system, YEC must ensure there is always an adequate supply of both energy and capacity, including in the event of contingencies (i.e. loss of generation or transmission). Achieving these supply objectives is made more challenging by the islanded nature of the YIS, since YEC cannot rely on its neighbours to provide additional energy and capacity in times of need.

To address YEC's planning requirements, YEC used the following criteria in the resource planning process:

» **Energy Planning Criterion.** This criterion is defined as having firm energy equal to or greater than forecast future energy loads. The energy planning criterion must be met on an annual basis. It should be noted that although YEC plans for firm energy, YEC has excess firm energy available from thermal generation resources to meet the firm energy planning criterion over the planning period. As a result, the 10-Year Renewable Electricity Plan has been modeled on the basis of average energy for renewable generation resources which assumes average water, wind and solar irradiance.

» **Capacity Planning Criterion.** This criterion ensures that the system has sufficient capacity to meet peak demand (peak capacity) for two consecutive weeks under extreme cold winter conditions. The capacity planning criterion is based on the single contingency (N-1) criterion, which states that each part of the YEC transmission grid shall supply the forecast non-industrial peak winter demand, excluding major industrial demand, under the largest single contingency. Yukon's current largest single contingency corresponds to the loss of the 37 MW Aishihik Generation Station, either through an outage of the generating station itself or an outage of the L171 transmission line that interconnects the Aishihik Generating Station to the Takhini Substation.

Please refer to *Section 4.3: Resource Planning and Reliability Criteria* in the 2016 Integrated Resource Plan (IRP) for further details.

2 Context

2.1 Yukon Challenges

» **Islanded Grid.** Yukon cannot rely on adjacent Canadian provinces, territories or the State of Alaska to supply electricity, and must self-supply all its own capacity and energy.

» **Predominantly Hydroelectric Energy Generation.** Most Yukon electricity is generated using renewables, and as recently as 2016 more than 98% of Yukon's electric energy was supplied by renewable (primarily hydroelectric) generation, with the remaining 2% provided by thermal generation (diesel and natural gas fired generation). Hydroelectricity relies on the availability of water to generate electricity, and as a result YEC must anticipate and plan for potential drought conditions.

» **Mismatched Generation Supply and Electricity Demand.** Electricity demand in the Yukon is highly variable, and changes considerably over the course of each day and across seasons. Primarily driven by residential demand for services such as space heating, lighting, cooking and appliance loads, Yukon's electricity demand typically peaks during cold winter days during and shortly after dinner time (typically between 4pm and 6pm). There is a seasonal mismatch between the timing of maximum available electricity production from hydroelectric generation (which peaks in the summer months) and maximum customer demand (which peaks in the winter months). As a result, YEC regularly relies on thermal generation to fill the gap between available hydroelectric generation and electricity demand during the winter peak periods.

» **Industrial Load Changes & Ratepayer Protections.** Yukon's small customer base means that the addition or loss of a major industrial load (e.g. a mine) on the grid has a substantial effect on both overall electricity demand and the total electricity sales volumes. This impacts how YEC's costs are divided amongst ratepayers. This volatility in industrial customer demand makes it challenging for YEC to forecast its future generation supply requirements, or to mitigate potential step changes in electricity rates which can occur with the loss of industrial customer demand.

2.2 Federal Funding to Enable Renewable Capacity

YEC is subject to price regulation and may only charge electricity prices approved by the Yukon Utilities Board (YUB). Since the YUB is an economic regulator, this implies that YEC must select the lowest cost resource options to meet future demand, while still meeting applicable regulations and laws.

Planning for future capacity resource investments is a key outcome of the 2016 Integrated Resource Plan and this current plan. Since thermal generation resources typically offer the lowest cost source of new capacity, this typically leads to the inclusion of new thermal facility investments. For example, a new 20 MW diesel plant was included in the recommended portfolio of the 2016 Integrated Resource Plan.

YEC's 2016 Resource Plan involved a "blank sheet" planning process that evaluated all generation options available to YEC without being constrained or influenced by planning pre-conditions. The 10-Year Renewable Electricity Plan, however, is focused on prioritizing renewable electricity solutions, which strongly influenced the generation resource options that were considered.

Accordingly, in order to meet the objectives of the 5 Year Strategic Plan and the policy objectives set out in the Yukon government's *Our Clean Future* strategy, Federal funding was assumed to support the development of renewable capacity sources that would otherwise not be selected as the lowest cost capacity resources. Federal funding also serves to reduce the impact of large infrastructure development on Yukon electrical rates, thus keeping residential and industrial rates affordable. This will allow Yukon to maintain an affordable quality of life, and ensure Yukon remains a competitive jurisdiction for future industrial development.

In Yukon, there is a long history of the Federal government funding support for large electrical infrastructure development (e.g. Carmacks-Stewart Transmission Project, Mayo B, etc.) to protect ratepayers and keep rates affordable. For the purposes of this plan, it is assumed that new generation and transmission projects will receive Federal funding, to a typical maximum of 75% of total capital cost.

2.3 Relevant Government Policy and Initiatives

YEC is accountable for meeting policy directives issued by the Yukon government and its agencies. Key recent policy developments include:

1) Micro-Generation Policy

2) Independent Power Producer Policy

3) Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy

2.3.1 Micro-Generation Policy

Issued by the Yukon government in October 2013, this policy aims to encourage the small-scale generation of electricity by individuals, small businesses and communities to meet their own needs, as alternatives or supplements to centralized grid-connected power. The policy is applicable to micro-generation projects up to 50 kW. YEC has included micro-generation-sourced energy in its committed resource assumptions for future supply options in the 10-Year Renewable Electricity Plan.

2.3.2 Independent Power Producer (IPP) Policy

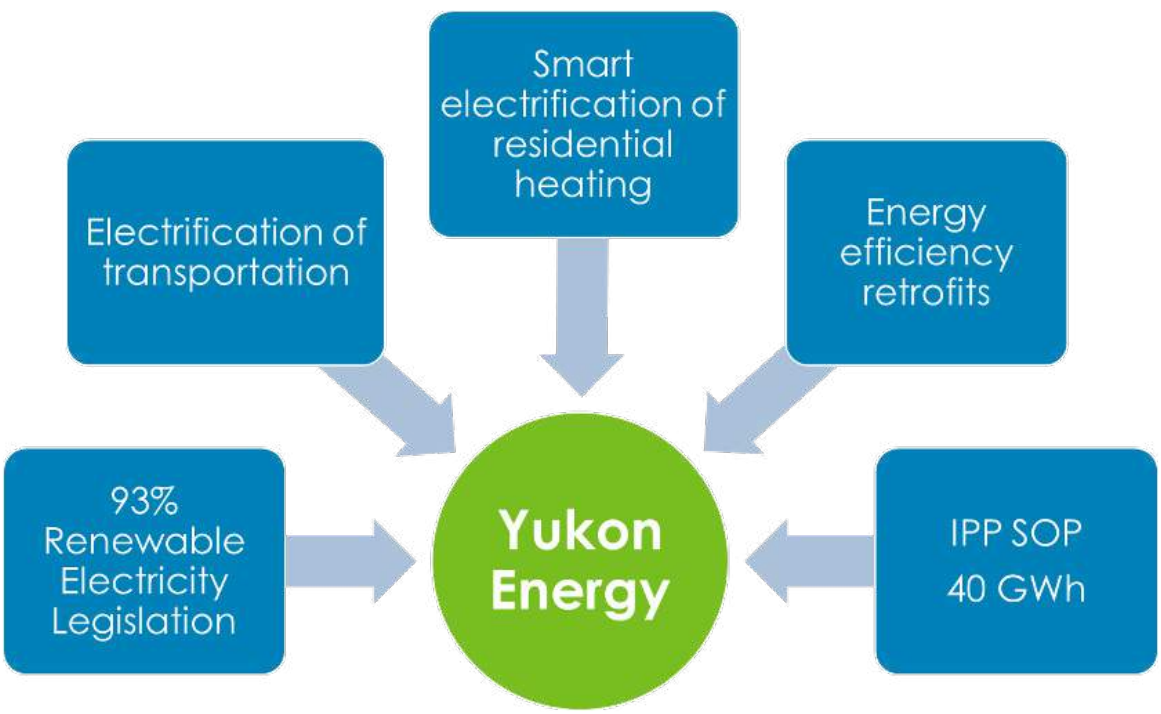
Issued by the Yukon government in October 2015, the IPP policy aims to provide opportunities for non-utility entities to develop new generation resources that can assist the utilities in meeting the demand for affordable, reliable, flexible and clean electrical energy.

YEC and ATCO are actively working with the government to structure a Standing Offer Program (SOP), which is a key element of the IPP Policy. The SOP is intended to provide a standardized technical and commercial framework to facilitate grid connection of new small capacity generation (in the 30 – 2,000 kW range). YEC included 40 GWh of annual IPP-sourced energy in its committed resource assumptions for future supply options in the 10-Year Renewable Electricity Plan.

2.3.3 Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy

Yukon government released a draft of its *Our Clean Future* strategy for public review in November, 2019. The strategy was formally launched in September, 2020. Key goals of the strategy include reducing greenhouse gas emissions, ensuring Yukoners have access to reliable, affordable and renewable energy, adapting to the impacts of climate change, and building a green economy. Figure 2 provides an overview of the various elements of the Yukon government strategy which influenced YEC's expected load and generation requirements.

Figure 2: *Our Clean Future* Strategy Influence on YEC 10-Year Renewable Electricity Plan



The *Our Clean Future* strategy states that Yukon government will develop legislation by 2023 that will require at least 93% of the electricity generated on the Yukon Integrated System to come from renewable sources, calculated as a long-term rolling average, while aiming for an aspirational target of 97% renewable electricity by 2030. This minimum requirement, and the long-term aspirational target, impacted the generation requirements used in the development of the 10-Year Renewable Electricity Plan.

The electrification of transportation and smart heating called for by the strategy is expected to increase the amount of electricity required by Yukoners, while energy efficiency retrofits may reduce or change electricity requirements for some entities. The impact of these actions was reflected in the load forecasts developed for this Plan. The changes to the IPP Standing Offer Program, and the support of Demand Side Management (DSM) programming, were also reflected in the energy portfolio modeling.

The *Our Clean Future* strategy is focused on six priorities: Transportation; Homes and Buildings; Energy Production; Communities; Innovation; and Leadership. Within these priorities, a number of strategies and related actions for energy conservation and the development of renewable energy resources were identified. Table 1 summarizes the key electricity-related initiatives relevant to YEC which were accounted for in the development of the 10-Year Renewable Electricity Plan.

Table 1: Government Energy & Climate Change Strategy: Electricity-Related Initiatives for YEC

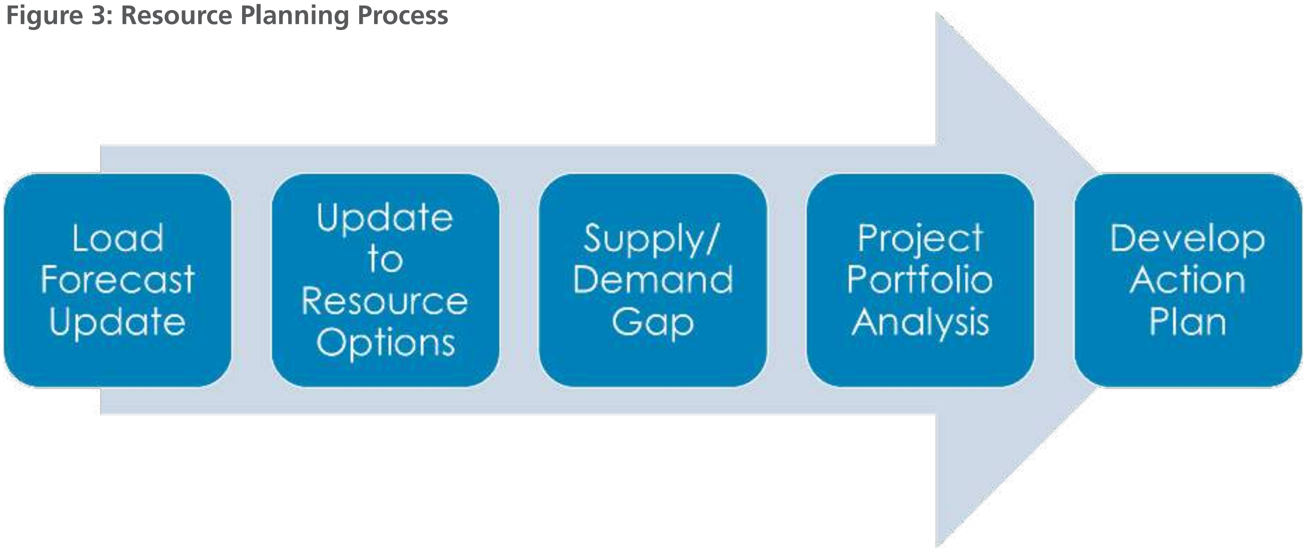
PRIORITY	ACTION NUMBER	ELECTRICITY RELATED INITIATIVE	TARGET	ACCOUNTED FOR IN 10-YEAR RENEWABLE PLAN?
Transportation	Actions #T1, #T2, #T4, and #T6	Increase the availability and use of zero emission vehicles, install fast-charging stations across Yukon, and require new residential buildings in greater Whitehorse area to support Level 2 electric vehicle charging.	4,800 EVs by 2030	Yes (included 5,000 EVs by 2030, based on November 2019 Draft Strategy).
Homes and Buildings	Action #H18, #H21, #H22	Replace residential fossil fuel heating systems with smart electric heating systems.	1,300 buildings over 10 years	Yes
Homes and Buildings	Action #H26, #H27, #H28	Allow Yukon's public utilities to partner with Government of Yukon to pursue cost-effective demand-side-management measures, and collaborate on delivery of capacity and energy DSM programs.	No specific target.	Yes

PRIORITY	ACTION NUMBER	ELECTRICITY RELATED INITIATIVE	TARGET	ACCOUNTED FOR IN 10-YEAR RENEWABLE PLAN?
Energy Production	Action #E7, #E8, #E10	Continue to implement the IPP Policy and the Micro-generation Program and increase the SOP limit to support additional community-based renewable energy projects.	Increase the SOP limit from 20 GWh to 40 GWh, 7 MW of installed Micro-generation capacity by 2030	Yes
Energy Production	Action #E1	While aiming for an aspirational target of 97% by 2030, develop legislation by 2023 that will require at least 93% of the electricity generated on the Yukon Integrated System to come from renewable sources, calculated as a long-term rolling average.	93% long-term rolling average	Yes
Energy Production	Action #E12	Conduct research into the potential to use geothermal energy in Yukon for heating and/or electricity.	No specific target.	No

3 Resource Planning Methodology

The goal of the resource planning process is to develop recommended actions for meeting Yukon's energy and capacity electricity demand requirements over the 10-year horizon.

Figure 3: Resource Planning Process



The planning process was built on the 2016 Resource Plan and followed these steps:

1. **Load Forecast Update**. Forecast future electricity demand for both energy and peak capacity (Section 4);
2. **Supply/Demand Gap.** Create an inventory of existing, committed and planned generation resources (Section 5), then determine potential shortfalls between future demand and generation supply resources in terms of both energy and capacity (Section 6);
3. **Update to Resource Options.** Create an inventory of future potential generation resource options (Section 7);
4. **Project Portfolio Analysis.** Analyze and develop a portfolio of options to address the energy and capacity shortfalls (Section 8); and
5. **Action Plan**. Develop a recommended action plan (Section 9).

It should also be noted that although the planning horizon for the 10-Year Renewable Electricity Plan is from 2020 to 2030, the resource planning process was completed based on a longer timeframe (i.e. 2020 to 2035) to allow for the phased development of certain resource options included in the portfolio analysis. Each step of the planning process is described further in the following sections.

4 Load Forecast

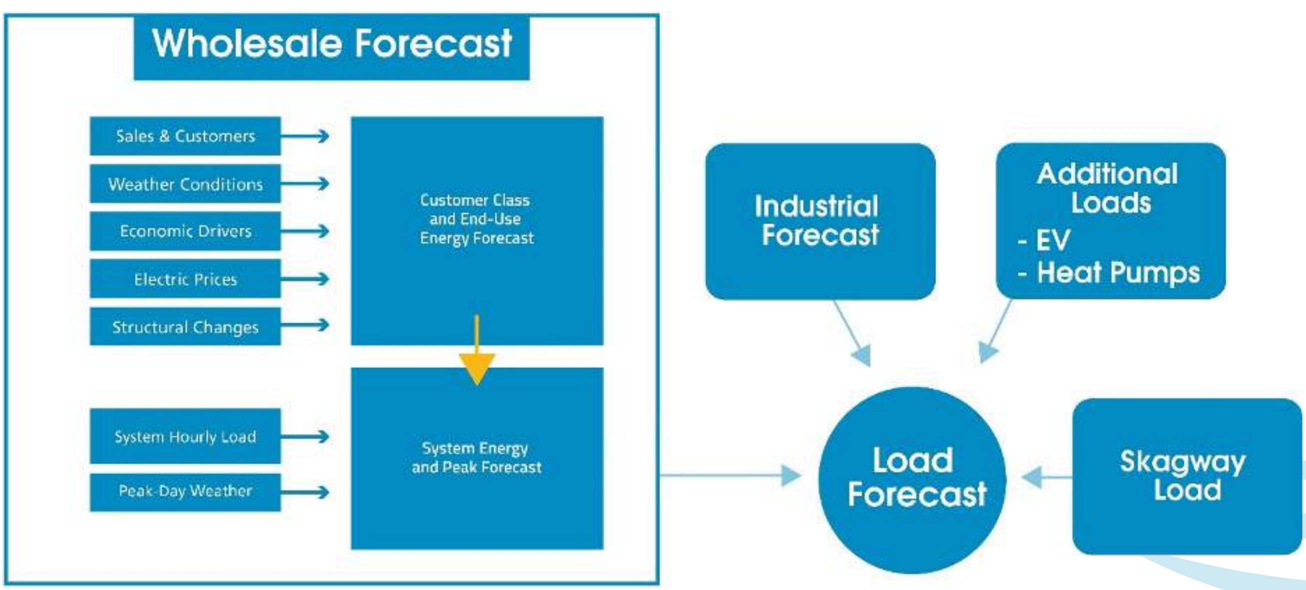
4.1 Load Forecasting Overview

The energy and peak capacity demand forecast estimates YEC's electricity needs over the planning horizon. The forecasting process used multiple inputs provided by external expert sources and inputs from the Yukon government, as well as production forecasts for major industrial customers.

Energy and peak capacity demand forecasts were developed in two parts:

1. **Part 1.** The energy and peak capacity demand forecasts from the 2016 Integrated Resource Plan were updated by Itron using their SAE MetrixND econometric model. The updated forecasts capture a range of input data, including historical sales and energy data by customer class, economic activity, population projections, average expected weather conditions, electricity prices, and improvements in end-use efficiency and standards. The economic activity input assumptions were based on the Yukon government economic model. This included an industrial activity forecast, reflection of the state of the economy in 2019 based on actual population and household numbers, and updated Gross Domestic Product (GDP) statistics.
2. **Part 2.** Additional loads not captured in Part 1 of the demand forecasts were added separately to the demand forecast output. These additional loads included industrial grid-connected mining loads, incremental loads from specific climate policy incentives such as the adoption of electric vehicles and the electrification of space heating in buildings, and the incremental load associated with the potential electrification of cruise ships in Skagway.

Figure 4: Load Forecast - Process Overview



4.2 Load Forecast Scenarios

Yukon's small customer base means that the addition or loss of a major industrial mining load on the grid has a material impact on overall energy requirements. In order to recognize and quantify this volatility, scenarios describing credible potential alternative futures were developed by making specific assumptions concerning the future loads of existing grid-connected mines. Other factors, such as increased loads from the electrification of cruise ships in Skagway and future energy policy actions, were also incorporated into the scenarios.

There are a number of prospective mining projects located far from the Yukon grid (e.g., Coffee Gold Project, BMC Minerals Kudz Ze Kayah project) that could be developed during the planning period. However, since these projects are assumed to be off-grid operations with no direct impact to on-grid electricity demand, and there is limited visibility on the probability or timing of these projects, they were not considered as part of this analysis. The scenarios also did not consider any new large on-grid mining projects being developed in the 10-year planning period as there is limited visibility on the certainty of any of these potential projects coming to fruition. Should new mining developments emerge, future long-term resource plan updates would contemplate how to address the resulting load impact.

The four (4) scenarios considered were:

1. Low Case;
2. Base Case (without Skagway);
3. Base Case (with Skagway); and
4. High Case.

The third scenario in the list, Base Case (with Skagway), represents the expected Base Case for the YEC load forecast, and is referenced as the "Base Case" throughout the remainder of this report. Note that this analysis was conducted prior to the COVID-19 pandemic. YEC will assess the timing and extent of the recovery of the cruise ship industry as part of its evaluation of the Skagway business opportunity.

Table 2: Load Forecast Scenarios - Assumptions

	LOW CASE	BASE CASE (WITHOUT SKAGWAY)	BASE CASE	HIGH CASE
Wholesale Forecast	YG Economic Model Energy Policy Actions	YG Economic Model Energy Policy Actions	YG Economic Model Energy Policy Actions	YG Economic Model Energy Policy Actions
Eagle Gold Load	Operation to 2029 2019 updated forecast	Operation to 2029 2019 updated forecast	Operation to 2029 2019 updated forecast	Operation to 2035 2018 load forecast
Minto Load	None	3 MW average to 2022	3 MW average to 2022	3 MW average to 2031
Alexco Load	None	2.5 MW average to 2035	2.5 MW average to 2035	2.5 MW average to 2035
EV Load	2,000 EVs by 2030; L2 charging; no Time of Use (TOU) rates	6,000 EVs by 2030; L2 charging; no TOU	6,000 EVs by 2030; L2 charging; no TOU	6,000 EVs by 2030; L2 charging; no TOU
Skagway Load	None	None	35 GWh/yr summer demand from 2026 to 2035	35 GWh/yr summer demand from 2026 to 2035

4.3 Energy Forecasts

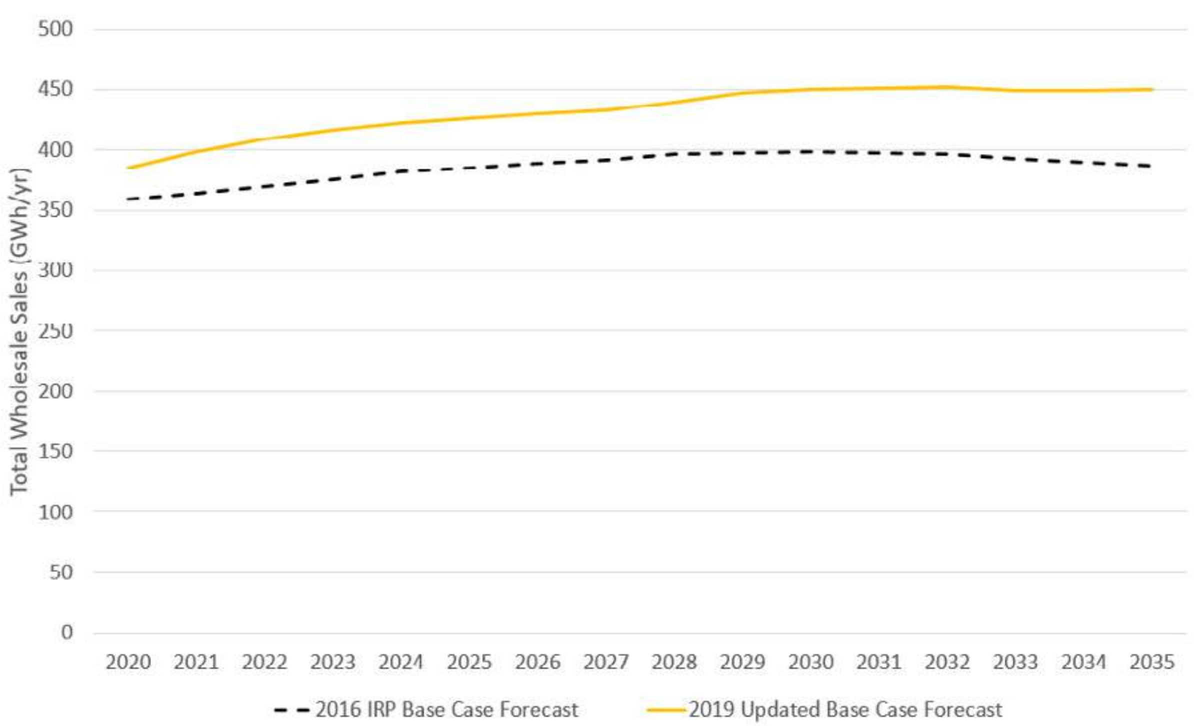
This energy forecast for the Yukon Integrated System (YIS) (see Section 1.3) is for the Base Case scenario. Energy refers to the quantity of electricity, expressed in gigawatt-hours (GWh) that is sold over a specified period of time.

The YIS energy forecast comprises two major elements, wholesale load and industrial (i.e. mining) load, which are combined to produce the total energy forecast. To show how the load forecasts have changed over time, the previous forecast values from the 2016 IRP are included in each of the following graphs.

4.3.1 Annual Energy Forecast

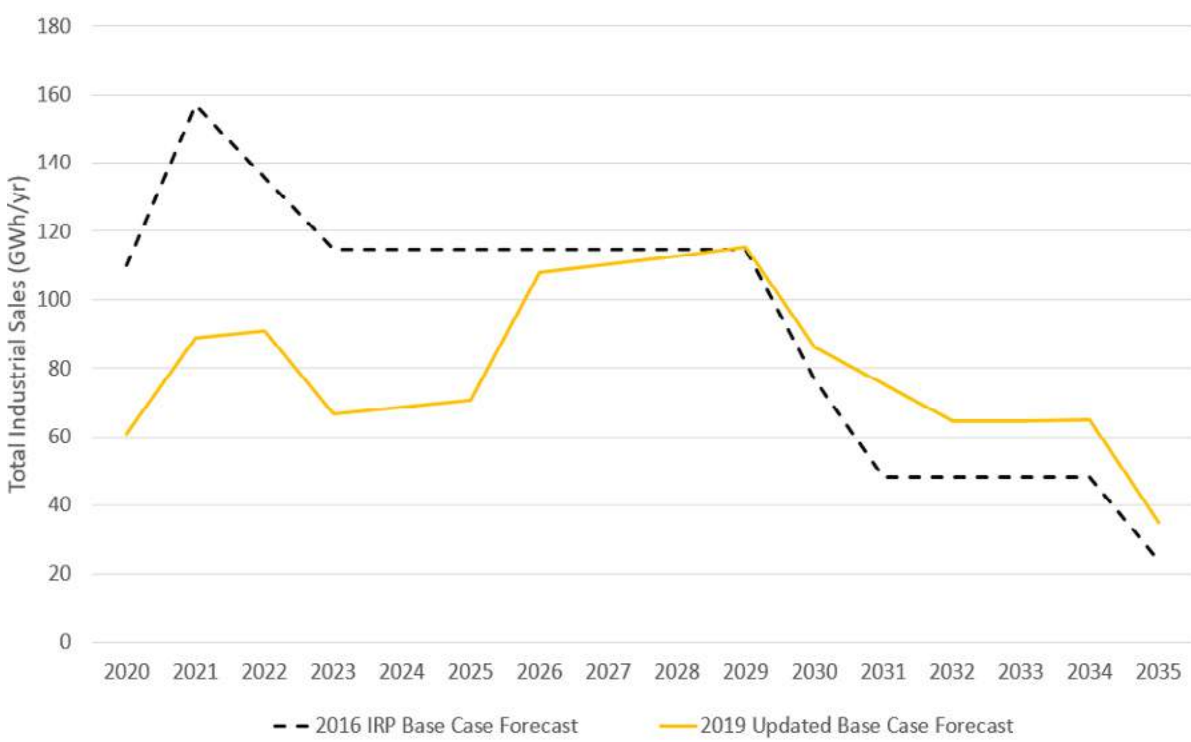
The annual wholesale energy forecast, which includes the incremental Yukon Energy Policy Action loads for the Base Case scenario relative to the 2016 IRP Base Case forecast, is shown in Figure 5. The updated 2019 energy forecast is higher than the 2016 forecast for the entire planning period, including the initial 2020 year. Energy load is higher in 2020 due to higher than forecast economic and population growth over the 2016-2019 period. In addition, the data in Figure 5 illustrates that energy demand is forecast to grow at a higher rate than forecast in the 2016 IRP due to impacts of Yukon government electrification policy actions which include electric vehicles and electrification of space heating.

Figure 5: Base Case - Wholesale Forecast Relative to 2016 IRP Base Case Forecast



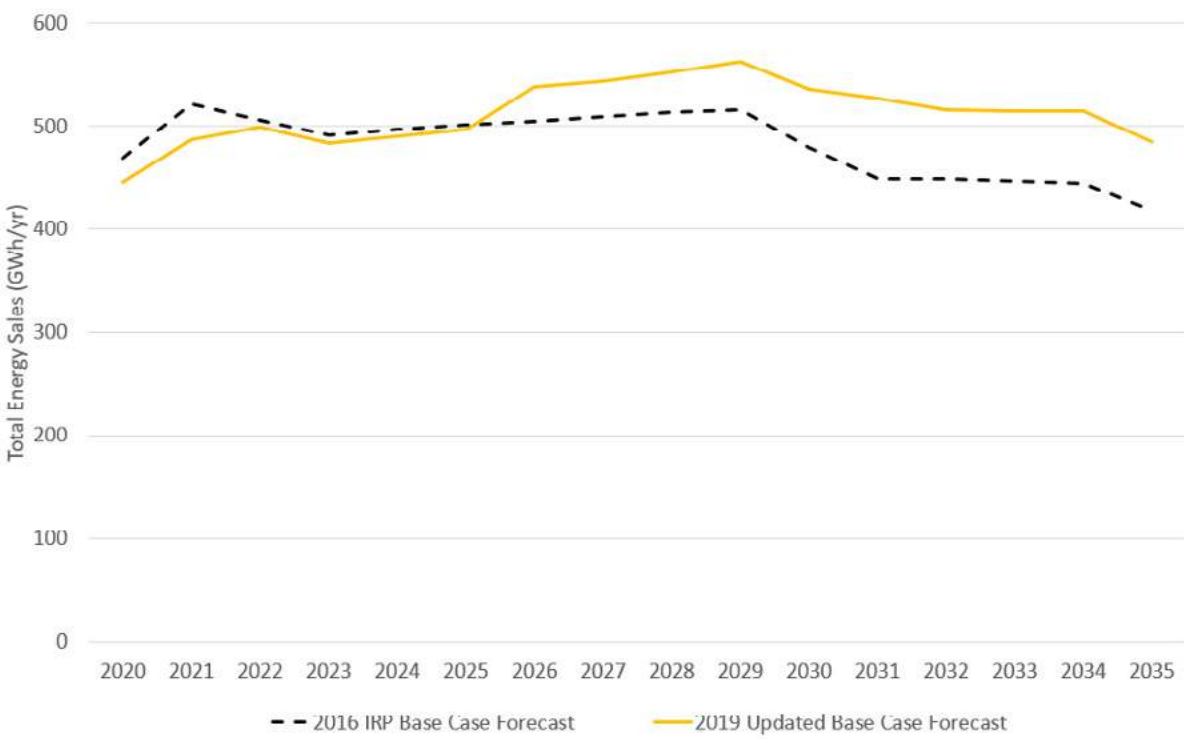
The annual industrial forecast for the Base Case scenario relative to the 2016 IRP Base Case forecast is shown in Figure 6. It should be noted that the 2019 industrial forecast also includes an additional 35 GWh/year load from year 2026 onwards for the assumed electrification of cruise ships in Skagway under this scenario. The observed decrease in forecast industrial load at the start of the planning period (2020-2025) relative to the 2016 forecast is primarily driven by a reduction in the forecast Victoria Gold mining load. The observed increase in forecast industrial load from year 2026 onwards is due to the additional load associated with the electrification of cruise ships in Skagway. Finally, the observed drop-off in industrial load from year 2029 onwards is due to the assumed shut-down of the Eagle Gold mine.

Figure 6: Base Case - Industrial + Skagway Forecast Relative to 2016 IRP Base Case Forecast



The total energy forecast (i.e. wholesale + industrial + Skagway) for the Base Case scenario relative to the 2016 IRP Base Case scenario is shown in Figure 7. The forecast increase in wholesale load is partially offset by the reduction in mining load at the beginning of the planning period, but an increase in total energy is observed from year 2026 onwards due to the addition of the Skagway load. As a result, the updated total energy forecast for the Base Case scenario remains very similar to the 2016 forecast, with slightly lower energy demand in the near-term years, and higher energy demand in the latter years of the planning period.

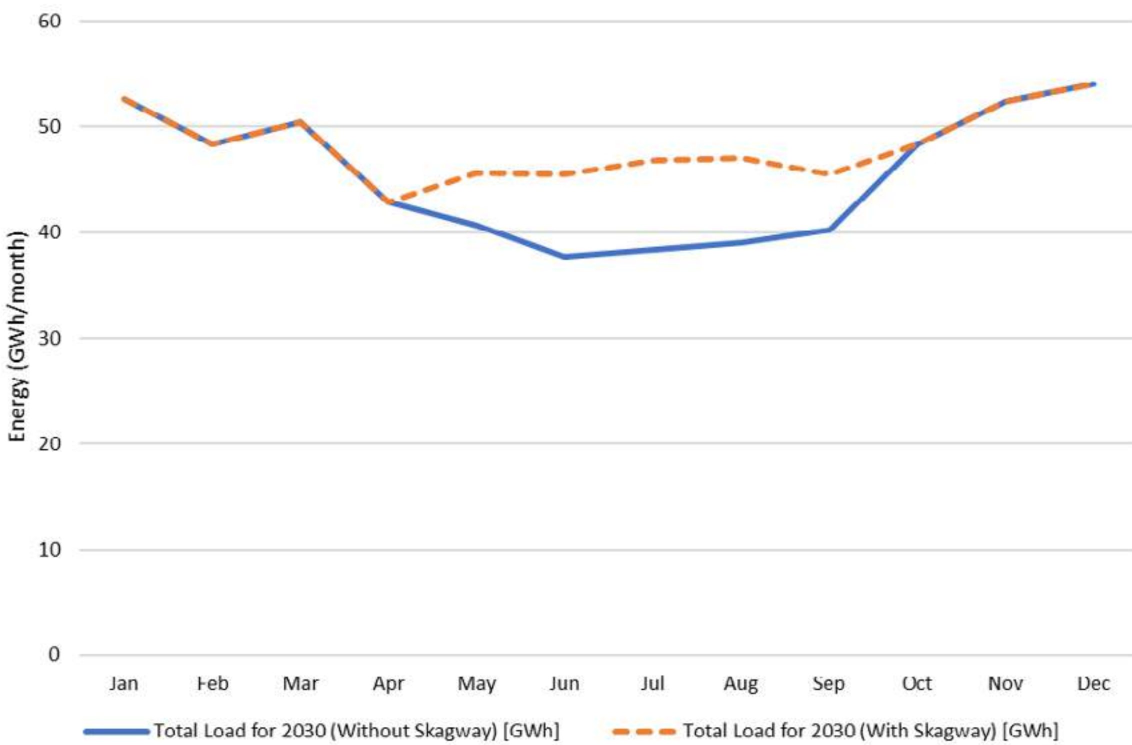
Figure 7: Base Case – Total Energy Forecast Relative to 2016 IRP Base Case Forecast



4.3.2 Seasonal Profiles

Seasonal energy profiles help demonstrate how energy demand changes over the course of a year and identifies which months have the highest and lowest energy demand. Figure 8 shows forecast monthly energy profiles for the year 2030 (with and without Skagway load). The figure does not account for any potential summer "load" from a pumped storage resource (e.g. energy consumption to pump water into the upper storage reservoir). Although the shape of the monthly energy profile will vary over the planning period, the YIS will remain a winter peaking system with maximum energy demand occurring in the winter months and lower energy demand in the summer months. Electricity policy changes in Yukon are not expected to change the fundamental challenge of meeting Yukon's increased energy demand in the winter months.

Figure 8: Monthly Demand Shape for 2030 (With & Without Skagway Load)



4.4 Peak Capacity Demand Forecast

Peak capacity demand is the maximum instantaneous quantity of electricity that customers require (and YEC must supply), expressed in megawatts (MW). For forecasting and planning analyses, which are conducted using the single-contingency (N-1) planning criterion, industrial demand is excluded from the peak capacity demand as it is assumed during an emergency event industrial customers could be interrupted.

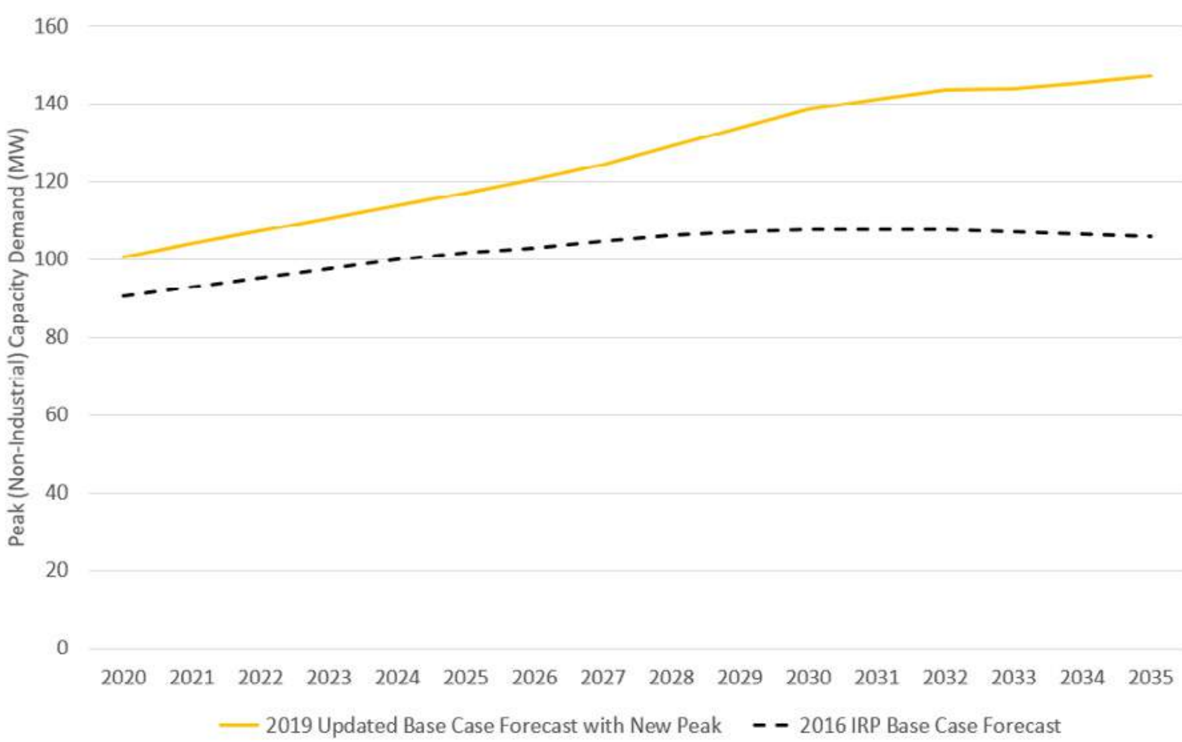
A new peak capacity demand record of 103.84 MW (97.6 MW non-industrial peak) was set on January 14, 2020. The previous record peak was 92.99 MW (90.5 MW non-industrial peak). As a result of this record-breaking peak, YEC was required to update its non-industrial peak capacity demand forecasting model to account for updated information on the actual peak demand of the Yukon system during prolonged cold weather events.

It should be noted that including Skagway in the Base Case does not impact the non-industrial peak capacity demand forecast. Skagway is assumed to add approximately 35 GWh of summer energy per year from year 2026 onwards, but it does not impact the peak capacity demand which occurs in the winter.

The updated non-industrial peak demand for the YIS relative to the 2016 IRP Base Case scenario is shown in Figure 9. The significant growth in the peak non-industrial demand forecast relative to the 2016 IRP Base Case forecast was primarily driven by:

- increased wholesale demand (e.g. population growth) and
- government policy actions related to electrification (e.g. electric heating, electric heat pumps and the adoption of electric vehicles).

Figure 9: Base Case – Updated Peak (Non-Industrial) Capacity Demand Forecast vs. 2016 IRP



5 Update to Resource Options

Generation resources considered as part of the 10-Year Renewable Electricity Plan are described in terms of their average energy and dependable capacity, where:

» **Average Energy**, expressed in GWh/year, is the total quantity of energy that the resource option produces in an average year. An average year is defined as having historically average fuel availability, such as water, wind, or solar irradiance. The fuel supply for a thermal generation station (i.e. diesel or natural gas) is available with a high degree of certainty. Because these fuels can be reliably stored, they are assumed to have 100% fuel availability.

» **Dependable Capacity**, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on fuel availability. For hydroelectric generation this means the average of water inflows for the five driest years in the hydrological record. For thermal resources, dependable capacity is equal to the installed capacity, since fossil fuels can be reliably stored. For wind and solar resources, dependable capacity is considered zero, since there is no guarantee that there will be available fuel (e.g. sun or wind) for the two consecutive weeks within the winter period.

The four (4) categories of generation resources considered as part of the 10-Year Renewable Electricity Plan, and described further in the following sub-sections, are:

1. Existing Resources;
2. Committed Resources;
3. Planned Resources; and
4. Future Potential Resources.

5.1 Generation Resources by Type

5.1.1 Existing Resources

These include YEC's legacy hydroelectric and thermal (diesel-fired and natural gas-fired) generation resources. The thermal diesel-fired resources owned and operated by ATCO in the communities connected to the Yukon Integrated System are also included in the category of Existing Resources. ATCO's generation resources are assumed to contribute to the dependable capacity of the system, with the underlying expectation that ATCO will provide backup power whenever needed.

The retirement of diesel generators that reach end of life over the planning period were also included in this category. Over the planning period, YEC anticipates the retirement of the sole remaining Mirrlees diesel engine in Faro (FD1) and two diesel engines from the Dawson Diesel Plant (DD2 and DD5) in 2023.

The inventory of the existing and retiring YEC and ATCO resources and their technical attributes are presented in Appendix A:.

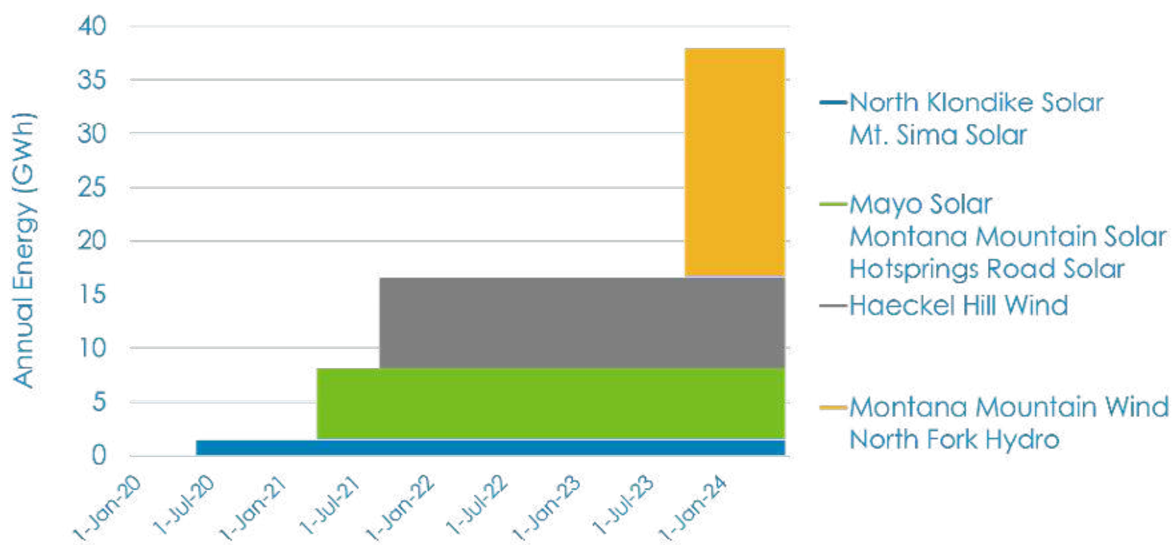
5.1.2 Committed Resources

These include generation resources that have secured YEC Board approvals and for which YEC is in the process of planning and/or constructing. That is, there is no turning back on the commitment to building these generation resources. YEC considers the following as committed resources:

1. **Whitehorse Hydro #2 (WH2) Uprate Project.** The Whitehorse Hydro WH2 Uprate Project will increase the efficiency and maximum capacity of the WH2 generation unit, resulting in more generated electricity for the same water throughput. The WH2 Uprate Project at the Whitehorse generating station will provide 6.2 GWh of annual energy and at least 0.64 MW of dependable capacity.
2. **Battery Storage System.** On September 5, 2019, the Government of Canada committed $16.5 million towards the construction of a new battery storage system in Yukon. The new battery, which is currently projected to be sized at 8 MW/ 40 MWh, will help meet growing peak demands for power while displacing diesel and improving grid reliability.

3. **Standing Offer Program (SOP).** The SOP is outlined in the Independent Power Production (IPP) Policy of the Yukon territorial government issued in 2015. The SOP included in the 10-Year Renewable Electricity Plan envisions 40 GWh/year of energy delivered by the IPP sector by the year 2024 and continuing past the end of the planning period. Figure 10 illustrates the current forecast of the projects anticipated to participate in the program and the resulting expected profile of renewable energy contribution growth from the SOP between 2020 and 2024. Since it is assumed that the SOP projects will most likely be intermittent renewable resources such as wind and solar, no dependable capacity is assigned to these resources.

Figure 10: IPP Standing Offer Program Anticipated Projects



4. **Micro-Generation Program.** The Micro-Generation policy issued by the Yukon government in October 2013 outlines this program. The policy is applicable to projects up to 50 kW. The micro-generation included in the 10-Year Renewable Electricity Plan envisions 6.5 GWh/year of delivered energy by the year 2024 and continuing past the planning period. Similar to the SOP, no dependable capacity is assigned to micro-generation projects because they will be comprised of intermittent renewable resources such as wind and solar.

5.1.3 Planned Resources

These include generation resources which have reached advanced planning stages but have yet to secure all necessary YEC Board approvals. YEC considers the following projects to be Planned Resources:

1. **Whitehorse Unit #4 (WH4) Uprate Project.** This project will increase the maximum water flow at WH4, resulting in an increased maximum output. The WH4 Uprate Project at the Whitehorse generating station will provide 0.9 GWh of annual additional energy. Although this project increases the maximum capacity of the unit, it does not provide additional dependable capacity. This is because water flow in the winter is limited by downstream Yukon River system ice flow restrictions. Subsequent to the completion of this report, the YEC Board of Directors approved the WH4 Uprate Project to proceed in May 2020.

2. **Southern Lakes Enhanced Storage Project (SLESP).** The SLESP will expand the storage range on the Southern Lakes system, which provides water (i.e. fuel) storage for the Whitehorse generating station. This will be achieved by decreasing the licensed Low Supply Level by up to 10 cm and increasing the licensed Full Supply Level by up to 30 cm. Although the SLESP is a water storage project that does not generate electricity itself, it will enable generation of an additional 6.5 GWh of electricity each year at the Whitehorse Hydro facility.

3. **Mayo Lakes Enhanced Storage Project (MLESP).** This project seeks to enhance water storage at Mayo Lake by lowering its current licensed minimum level by up to one metre. The MLESP would generate an additional 4 GWh of electricity each year.

4. **Diesel Replacement.** By replacing retired diesel generator units at existing generation facilities, YEC can reduce the need for rental diesel generators from November through March. The total replacement diesel assumed over the planning period amounts to 12.5 MW.

5. **Demand Side Management (DSM).** DSM involves using incentives, electricity rate structures, and building and appliance codes and standards to encourage customers to reduce the amount of electricity they use. In 2014, YEC and ATCO Electric Yukon jointly launched and operated a DSM program called inCharge which provided rebates and electricity savings kits. However, the YUB denied the costs of this program in its decision on YEC's 2017-2018 General Rate Application. As a result, YEC's DSM activities are on hold pending confirmation that future DSM costs will be allowed. The focus of a relaunched DSM program would be on measures that deliver peak capacity savings (i.e. reductions in peak electricity consumption). A suite of programs has been developed which will be implemented once there is regulatory certainty about allowing of future DSM-related costs. The DSM programming is forecast to provide up to 6.7 GWh of annual energy and 7 MW of dependable capacity by 2030.

For the purposes of this report, it was assumed that Planned Resources will be constructed and operational as planned, and therefore are treated similarly to Committed Resources.

5.1.4 Future Potential Resources

These are potential generation resource options available to meet the needs of YEC's customers over the next 10 years that have not yet advanced into development. These generation resources are described in Section 7.

5.2 Summary: Existing, Committed and Planned Generation Resource Forecast

In Figure 11 and Figure 12, the Existing Resources are shown as blue bars and the Committed and Planned Resources are shown in darker and lighter shades of grey, respectively.

Figure 11: Energy Forecast from Existing, Committed and Planned Resources

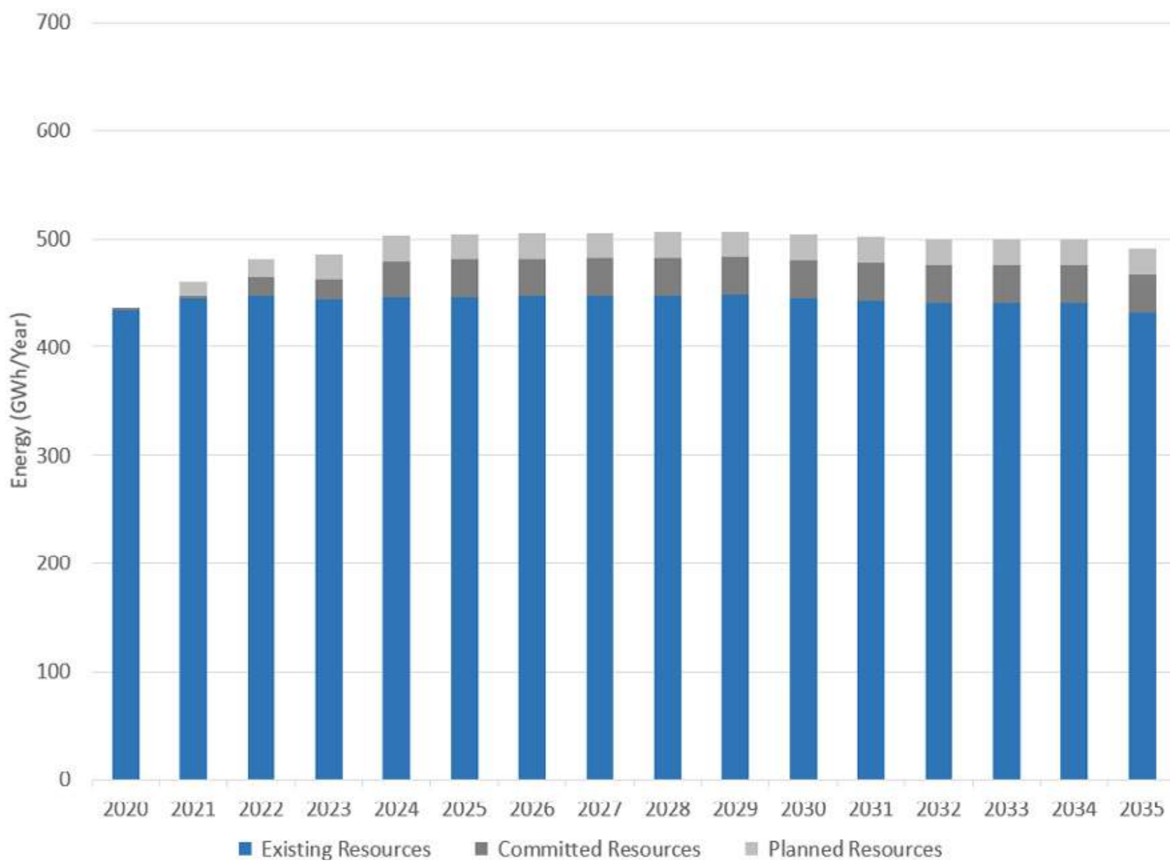
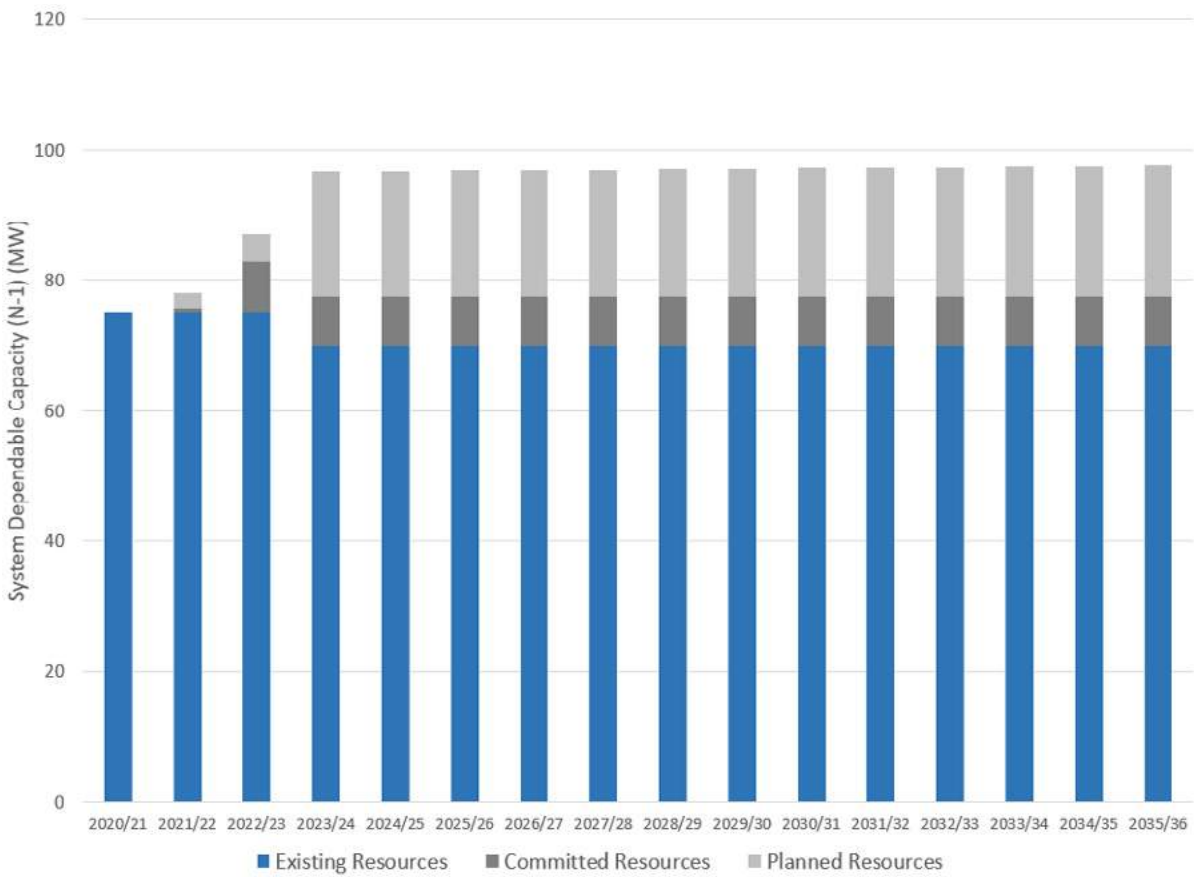


Figure 12: Dependable Capacity (N-1) from Existing, Committed and Planned Resources

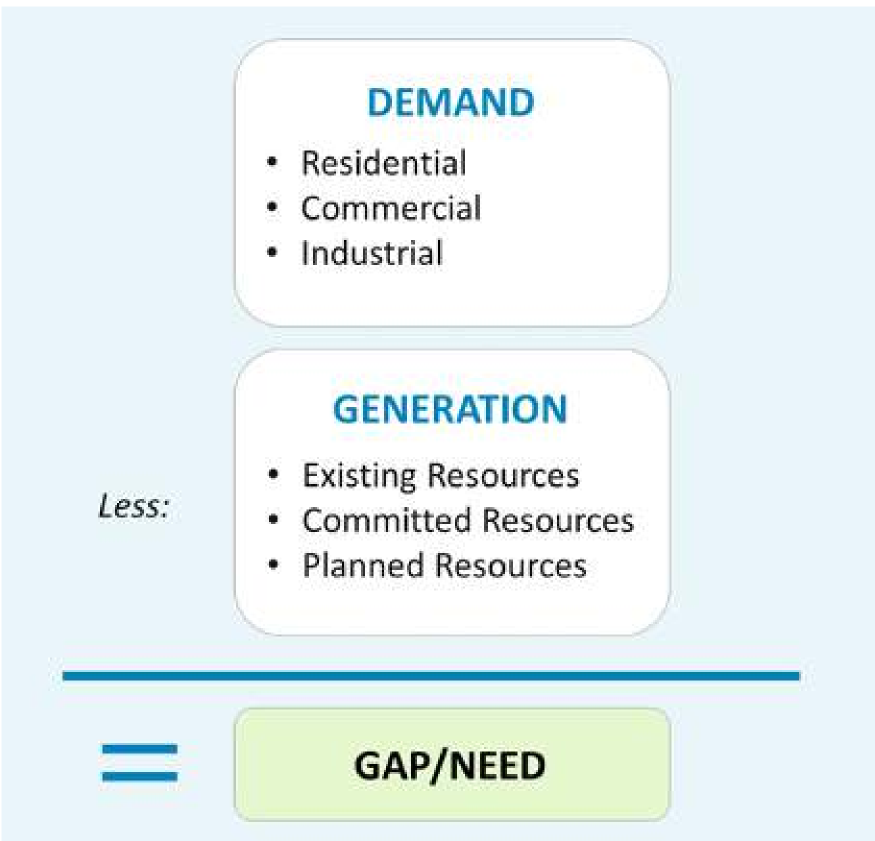


6 Supply & Demand Gap

6.1 Methodology

The goal of the resource planning process was to develop recommended actions for YEC to both meet YIS's electrical energy needs and satisfy the capacity gaps over the 10-year horizon. The difference between electrical demand and generation supply is the gap, or "Need", as shown in Figure 13.

Figure 13: Gap Analysis Overview



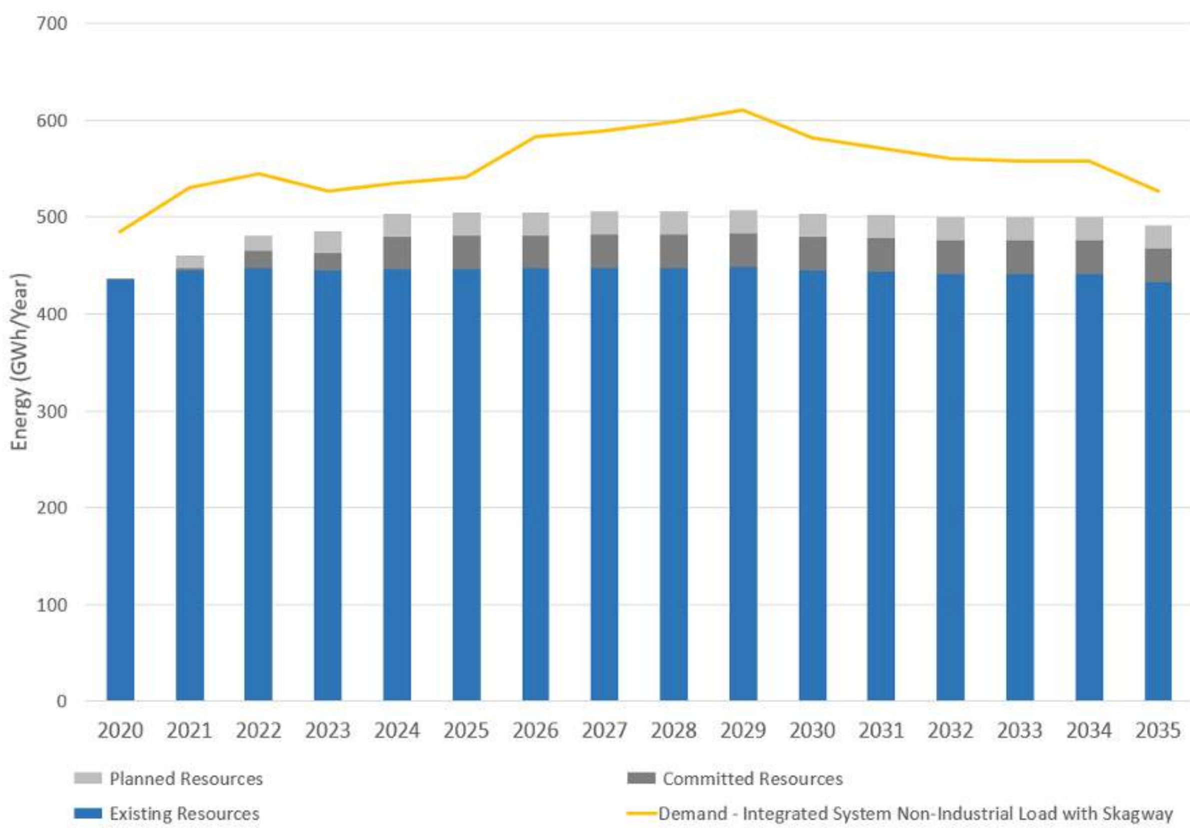
This gap analysis calculates the difference between the forecast energy and peak capacity demand and the expected future resource capability (including Existing, Committed and Planned Resources). The analysis is for the expected Base Case for the 10-Year Renewable Electricity planning evaluations.

6.2 Energy Gap Analysis

6.2.1 Annual Energy Gap

Figure 14 shows the gap between forecast annual energy demand (from Figure 7 in Section 4) and forecast generation (from Figure 11 in Section 5). A detailed breakdown, including individual resources, is included in Appendix A. The annual energy gap increases from 49 GWh in 2020 to 100 GWh in 2029.

Figure 14: Annual Energy Gap Analysis (Base Case)



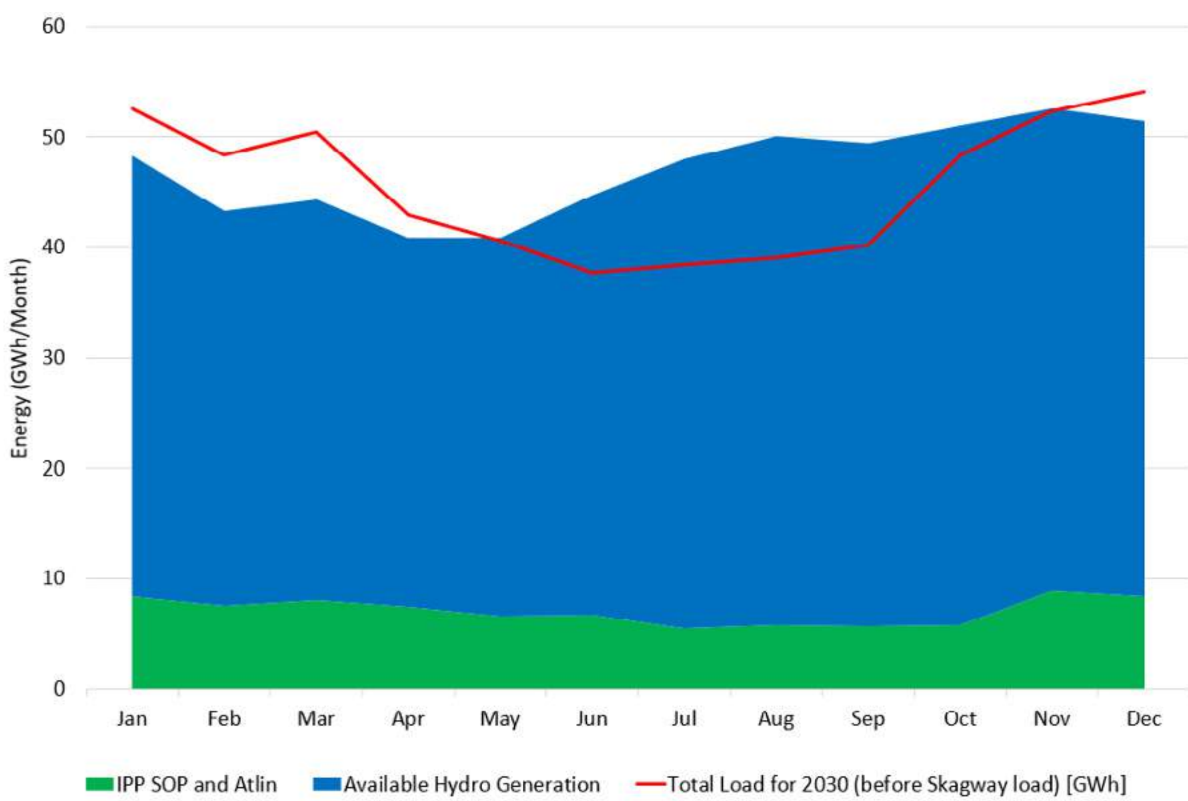
The energy gap between YEC's future expected resource capability and forecast load under average water conditions (as illustrated in Figure 14) implies that in some years YEC will need to utilize thermal resources if it does not develop any new renewable resources. In those years of average or below average water, YEC will need to run LNG, and potentially some diesel, to meet Yukon's energy needs.

This energy gap creates an opportunity for YEC to develop new renewable generation resources. These have the potential reduce reliance on thermal resources (LNG and diesel) to meet the forecast energy gap needs, particularly in low water years. It will be necessary to develop these new renewable energy resources if YEC is to meet the target specified in Yukon government's *Our Clean Future* strategy (a 93% rolling average in renewable energy).

6.2.2 Monthly Energy Gap & Summer Spilled Energy

Figure 15 shows the forecast monthly energy demand compared to the supply of hydroelectric and IPP SOP renewable energy supply for the year 2030.

Figure 15: Monthly Renewable Supply vs Demand (2030)



This figure illustrates that YEC will have surplus energy available during the summer but insufficient energy available during winter months to meet forecast energy demand. Additional data on the monthly and annual energy gap is provided in Appendix B.

Perhaps the most important conclusion to be drawn from Figure 15 is that Yukon is forecast to have surplus energy available in the summer months that will be permanently lost. Typically, this will be in the form of water spilled over the dam at the Whitehorse generating facility. Because other renewables such as solar and wind sourced from IPPs are not dispatchable, their energy must be accepted by YEC. YEC must then use its dispatchable hydroelectric assets (i.e. Whitehorse hydro during the summer) to balance supply and demand. Therefore, YEC will be forced to spill water over the Whitehorse dam whenever excess generation is supplied into the YIS. This seasonal mismatch between potential electricity production from hydro generation and the timing of maximum customer demand is a key planning constraint for YEC.

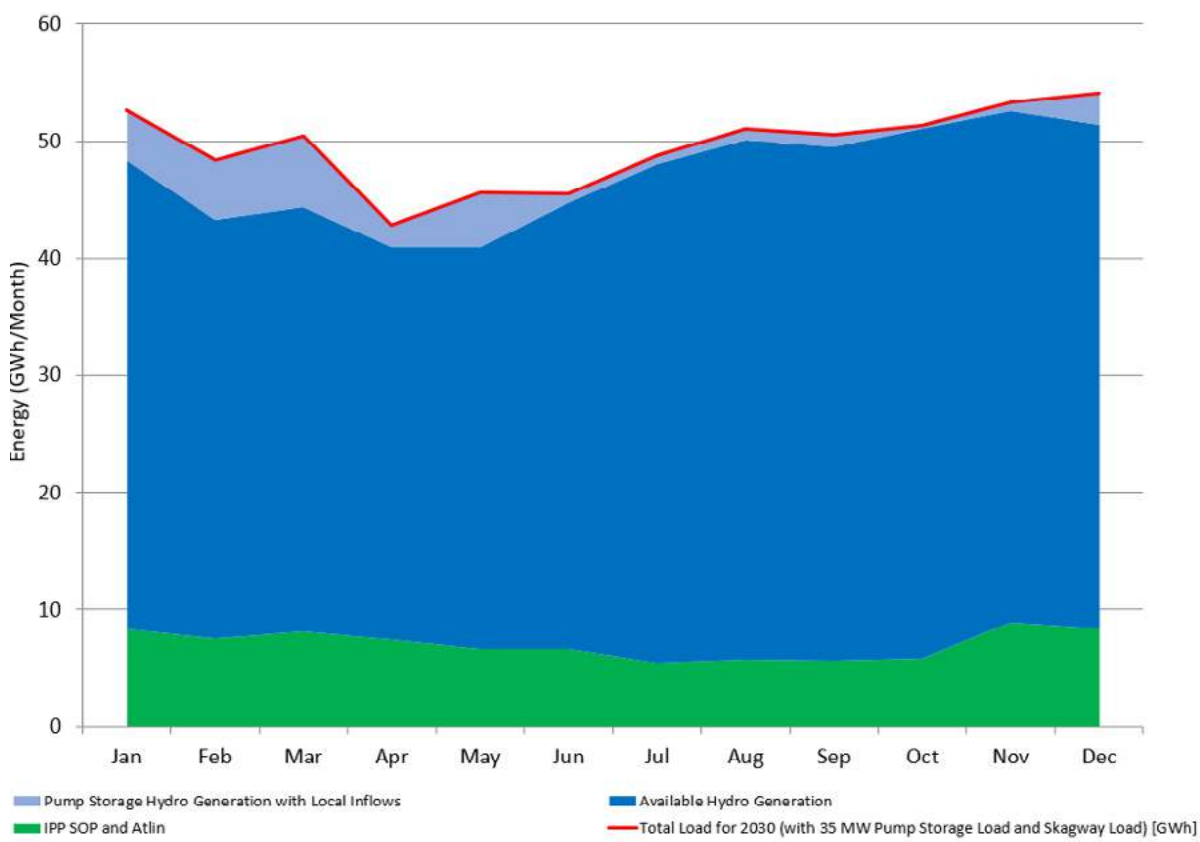
Two development options that would help address this issue are considered in this plan:

1. **Development of Seasonal Storage.** Since YEC has surplus energy available in the summer months and a deficit in winter months, there is a potential to use seasonal storage to store excess summer energy. That is, water spilled at YEC's existing hydro facilities could be stored and used for generation during the winter to meet winter loads. The only commercially available renewable technology for long term fuel storage in the quantities required by YEC (i.e. 40+ GWh) is pumped storage hydro.
2. **Securing New Customers for Summer Energy.** Another option to reduce summertime spilled water (i.e. wasted energy) is to secure new customers looking to purchase summer energy. By developing and investing in the Southern Lakes area as part of the 10-Year Renewable Electricity Plan, YEC has the potential opportunity to sell surplus summer energy to Skagway for the provision of clean shore-side power to cruise ships. The Skagway pier can interconnect up to four (4) cruise ships at once, which can amount to approximately 35 GWh/year of summer energy demand. Currently, cruise ships visiting Skagway in the summer burn diesel to generate shipboard electricity while at port. The electrification of shore-side power is one of the leading strategies that cruise ship operators employ to reduce their greenhouse gas (GHG) emissions while at port. This is an opportunity to utilize YEC's otherwise spilled water (i.e. wasted energy) to increase revenues to offset Yukon electricity costs, while also reducing GHG emissions in Skagway.

By capturing the surplus energy from otherwise spilled water through a combination of seasonal storage development and new summer energy customers, monthly energy supply and demand will be better matched.

This is illustrated in Figure 16 where the increased summer energy demand would reduce the excess amount of hydro generation in the summer months, as demonstrated previously in Figure 8. Additionally, summer demand would be further increased by the pumped storage facility utilizing energy to pump water from the lower reservoir into the upper reservoir. The excess hydro generation would then be available for use in the winter months due to this seasonal storage. The additional energy highlighted in light blue in Figure 16 is the energy provided by the pumped storage facility, which would also help close the energy gap in the winter months. The forecast in this Figure is based on the Tutshi-Moon pumped storage project, which has hydrologic inflows that make it a net energy producer rather than a net energy consumer, as detailed in Section 7.

Figure 16: Monthly Renewable Supply vs Demand – Modified (2030)

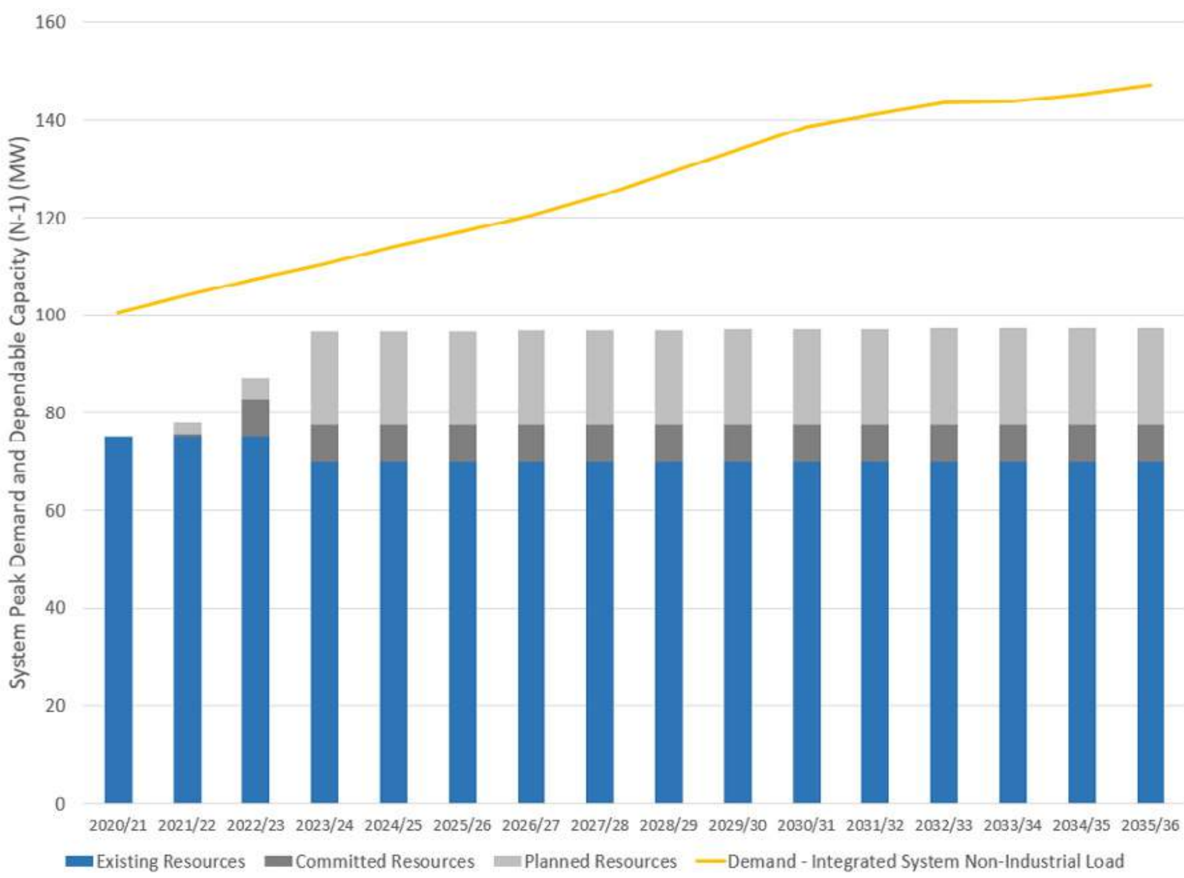


The benefits associated with the productive use of forecast summer surplus energy were the main drivers for incorporating a seasonal pumped storage hydroelectric project and the electrification of Skagway cruise ships as key elements of the 10-Year Renewable Electricity Plan.

6.3 Capacity Gap Analysis

Figure 17 shows the annual gap between the forecasted peak (non-industrial) capacity demand (from Figure 9 in Section 4) and the dependable peak capacity (from Figure 12 in Section 4) under N-1 conditions. The forecast peak capacity gap is significant, growing to approximately 40% of YEC's existing, committed and planned capacity resources. YEC can fill the forecast gap on an interim basis by temporarily renting diesel generators. However, temporary diesel generators have lower reliability and have a higher future availability risk than other resource options. Therefore, finding renewable resource options to fill this peak capacity gap is a priority of the 10-Year Renewable Electricity Plan.

Figure 17: Annual Capacity Gap Analysis under N-1 Conditions (Base Case)



7 Future Potential Resource Options

7.1 Future Potential Resource Options Update Process

The next step in the resource planning process was identifying a list of Future Potential Resource Options to be included in a portfolio that would address the energy and peak capacity gaps identified in Section 6. In order to develop a list of Future Potential Resource Options, the resource options from YEC's 2016 Integrated Resource Plan were updated in three (3) stages:

» **Stage 1:** Refined List of Resources;

» **Stage 2:** Updated Technical Attributes; and

» **Stage 3:** Updated Financial Attributes.

It is important to acknowledge that a comprehensive evaluation of environmental and socio-economic attributes of each resource option was included in the 2016 IRP. Since no showstoppers prohibiting the resource options under consideration in this report were identified during that analysis, these environmental and socio-economic attributes were not re-evaluated as part of the 10-Year Renewable Electricity Plan. If the projects identified in the Plan move forward, detailed environmental and socio-economic analyses and assessments will be carried out as part each project's planning.

7.1.1 Stage 1: Refined List of Resources

In Stage 1, all resource options considered in the 2016 IRP were refined into a subset of preferred resource options. Resource options that were deemed to be fundamentally uneconomic, located too far from existing or proposed transmission infrastructure, too large for the need, or that have been superseded by other options were eliminated from the list. The Committed and Planned Resources described in Sections 5.1.2 and 5.1.3 were also removed from the list because they are assumed to be in operation as per previous plans. The refinement process reduced the 92 resource options evaluated in the 2016 IRP down to 19 resource options (excluding DSM and transmission options).

7.1.2 Stage 2: Technical Attribute Update

In Stage 2, the technical attributes of the refined resource options identified in Stage 1 were updated to reflect current available information. Updates were made to the technical attributes considered in the 2016 IRP such as annual energy, firm energy, installed capacity, dependable capacity, project life, lead time, and resource dispatchability.

The technical attributes from the 2016 IRP were used for the refined list of resource options from Stage 1, except for options which have been studied further since that time. The updated resource options included:

- **Small Hydro.** Knight Piésold Ltd. (KP) was engaged by YEC to update and further develop a desktop review of the potential hydroelectric projects in Yukon and northern BC, provided in Appendix E. This study resulted in a refined and updated list of five (5) small hydroelectric projects of interest, with capacities ranging from 8 MW to 13 MW.
- **Pumped Storage Hydro.** KP was engaged by YEC to update and further develop the Tutshi-Moon pumped storage project. As part of this study, four separate development options with varying levels of installed capacity and winter generating capability were evaluated. The study is provided in Appendix F.
- **Wind.** Although the wind resources have not been studied further since the 2016 IRP, indicative wind sites with varying installed capacities are included in the refined list of resource options. Future wind resources could be implemented either by YEC or by IPPs via a Call for Power.
- **Geothermal.** EAVOR was approached to provide technical and financial details regarding a new geothermal technology being developed in Alberta called the Eavor-Loop technology. The technology was assessed as not being sufficiently mature and commercially proven for consideration as a potential utility resource option. Therefore, an assumption was made that early implementations of the technology would be made via the IPP SOP program. As a result, the technology was excluded from the refined list of resource options.
- **Thermal-Diesel.** Generic permanent and temporary diesel options are included as part of the refined list of resources. They are flexible, scalable, and can be used to help bridge dependable capacity gaps (but not long-term energy gaps). The updated technical attributes associated with these projects were extracted from a series of thermal generation project assessments completed by Midgard Consulting Inc. (Midgard).

7.1.3 Stage 3: Financial Attribute Update

In Stage 3, the financial attributes of the refined list of resource options identified in Stage 1 were updated. The financial attributes considered in the 2016 IRP included the Levelized Cost of Energy (LCOE) and the Levelized Cost of Capacity (LCOC). These were calculated utilizing inputs that include the annualized estimated capital (CAPEX) and operating & maintenance (O&M) costs for each project.

The process for updating these attributes is summarized below:

» **CAPEX Update**. For mature technologies such as hydro and thermal, the CAPEX from the 2016 IRP were inflated to 2019 dollars assuming a 2% inflation rate. The CAPEX for the Small Hydro and Pumped Storage Hydro projects were estimated separately by KP. For maturing technologies including solar and wind, a desktop study was completed to evaluate recent trends in total installed costs. It should be noted that:

- The capital costs of the Atlin Hydro Expansion and the Tutshi-Moon Pumped Storage Hydro Projects were considered with and without Federal funding. Since the completion of this analysis, further work has indicated that additional costs for the Atlin-Jakes Corner transmission must be considered as art of the Atlin Hydro Expansion Project, adding approximately $50 million in capital costs. This will increase the required Federal funding for the project.

- A new 138 kV transmission line from Whitehorse to Skagway (AK) via Carcross (YT), which would be required to connect projects in the Southern Lakes area, was assumed to be supported with up to 75% Federal funding. The transmission cost assumptions associated with projects located near the new transmission line assume an interconnection to this proposed line.

» **O&M Update.** The annualized O&M for the Small Hydro and Pumped Storage Hydro projects in the KP studies were updated. The O&M cost assumptions for all other options were taken from the 2016 Resource Plan, inflated to 2019 dollars assuming a 2% inflation rate.

» **Financial Modelling Update.** Based on the updated set of technical and financial attributes, YEC completed financial modelling to determine the updated LCOE and LCOC associated with the refined list of resource options.

7.2 Future Potential Resource Options

Table 3: Refined List of Future Potential Resource Options

IRP Resource	Options	Installed Capacity (MW)	Dependable Capacity (MW)	Lead Time (Years)
Hydro Uprate	Aishihik Hydro 1 & Hydro 2 Uprate	1.3 MW	1.3 MW	3 Years
Small hydro	Primrose (Storage)	13.0 MW	13.0 MW	6 Years
	Drury (Storage)	10.0 MW	10.0 MW	6 Years
	Tutshi Windy Arm (Storage)	10.0 MW	10.0 MW	6 Years
	Wolf River (ROR)	11.0 MW	4.0 MW	6 Years
	Atlin Hydro Expansion (Storage)	6.0 MW	6.0 MW	5 Years
	Atlin Hydro Expansion (Storage) with Federal funding	6.0 MW	6.0 MW	5 Years
Wind	Wind Resource 1	6.0 MW	0.0 MW	5 Years
	Wind Resource 2	10.0 MW	0.0 MW	5 Years
	Wind Resource 3	20.0 MW	0.0 MW	5 Years
Solar	Whitehorse Solar 1	1.0 MW	0.0 MW	2 Years
	Whitehorse Solar 2	5.0 MW	0.0 MW	2 Years
	Whitehorse Solar 3	10.0 MW	0.0 MW	2 Years
Diesel (Comparator)	Generic Greenfield Permanent @ Takhini	10.0 MW	10.0 MW	4 Years
	Generic Rental @ Whitehorse Substation S150	2.0 MW	2.0 MW	0 Years
Pumped Storage	Tutshi-Moon (15MW-25GWh)	15.0 MW	15.0 MW	6 Years
	Tutshi-Moon (15MW-45GWh)	15.0 MW	15.0 MW	6 Years
	Tutshi-Moon (25MW-50GWh)	25.0 MW	25.0 MW	6 Years
	Tutshi-Moon (35MW-50GWh)	35.0 MW	35.0 MW	6 Years
	Tutshi-Moon (15MW-25GWh with Federal Funding	15.0 MW	15.0 MW	6 Years
	Tutshi-Moon (15MW-45GWh with Federal Funding	15.0 MW	15.0 MW	6 Years
	Tutshi-Moon (25MW-50GWh with Federal Funding	25.0 MW	25.0 MW	6 Years
	Tutshi-Moon (35MW-50GWh) with Federal Funding	35.0 MW	35.0 MW	6 Years
Energy Storage	Lithium-ion	8.0 MW	8.0 MW	2 Years

Table 3 is a summary of the 19 Future Potential Resources considered in the 10-Year Renewable Electricity Plan along with their associated technical and financial attributes.

Annual Energy (MWh/Yr)	CAPEX ($2019)	O&M		LCOC ($/kW-Yr)	LCOE ($/kWh-Yr)
		Fixed ($2019/Yr)	Variable ($2019/ MWh)		
2,700 MWh	$5,300,000	$0	$5.31	$185	$0.09
74,100 MWh	$177,500,000	$3,900,000	$5.00	$797	$0.14
30,600 MWh	$110,500,000	$2,400,000	$5.00	$635	$0.21
49,300 MWh	$135,600,000	$3,700,000	$5.00	$860	$0.17
79,700 MWh	$165,100,000	$3,600,000	$5.00	$2,417	$0.12
44,700 MWh	$131,000,000	$2,900,000	$5.00	$1,270	$0.17
44,700 MWh	$32,750,000	$2,900,000	$5.00	$708	$0.10
18,100 MWh	$39,500,000	$280,000	$27.26	Not supplied	$0.17
29,500 MWh	$49,200,000	$290,000	$21.81	Not supplied	$0.13
57,300 MWh	$73,500,000	$340,000	$21.40	Not supplied	$0.10
1,100 MWh	$2,300,000	$30,000	$0.00	Not supplied	$0.13
5,600 MWh	$8,100,000	$150,000	$0.00	Not supplied	$0.10
11,500 MWh	$16,100,000	$340,000	$0.00	Not supplied	$0.10
2,500 MWh	$25,600,000	$170,000	$22.00	$131	$0.53
2,500 MWh	$0.00	$280,000	$0.00	$243	Not Supplied
19,900 MWh	$182,500,000	$2,020,000	$0.00	$552	$0.42
14,000 MWh	$194,200,000	$2,050,000	$0.00	$581	$0.62
12,000 MWh	$245,000,000	$2,100,000	$0.00	$421	$0.88
10,000 MWh	$280,000,000	$2,150,000	$0.00	$336	$1.18
19,900 MWh	$45,625,000	$2,020,000	$0.00	$239	$0.18
14,000 MWh	$48,550,000	$2,050,000	$0.00	$248	$0.27
12,000 MWh	$61,250,000	$2,100,000	$0.00	$168	$0.35
10,000 MWh	$70,000,000	$2,150,000	$0.00	$130	$0.46
2,800 MWh	$29,500,000	$280,000	$0.00	$280	Not Supplied

7.3 Future Potential Resource Observations

1. **Intermittent renewables do not contribute capacity.** Resources such as wind and solar offer relatively low levelized costs for energy (LCOE), but do not provide dependable capacity to the Yukon system. This is because they can only generate electricity while their energy source is available (e.g. the sun is shining and/or the wind is blowing). As a result, these resources cannot address YEC's key challenge of closing the existing and forecast peak capacity gap. In addition, since solar resources are summer peaking generation resources, integrating more solar resources increases the quantity of surplus summer energy.

2. **Small Hydro.** In general, this is an attractive resource because it offers reasonably priced energy and capacity in a single project. The Atlin Hydro Expansion project is preferred based on its shorter project development timeline when compared to the other small hydro options.

3. **Tutshi-Moon Pumped Storage Hydro Inflows & Seasonal Shifting.** This project would be used for seasonal energy storage, storing excess summer energy (in the form of water held in the upper reservoir) for generation during the winter. This means that pumping water into the reservoir for storage will occur during the summer months when there is surplus energy available, and generation will occur during the winter months when electricity demand increases. In addition, the Tutshi-Moon pumped storage project is expected to have hydrologic inflows that make it a net energy producer. Typical pumped storage hydro projects are net energy consumers due to the energy losses associated with the water pumping process. Since the pumped storage hydro options evaluated are not cost competitive on a LCOC basis compared to greenfield diesel generation or diesel generator rentals without grant funding, Federal funding is required to bring the LCOC of pumped storage hydro in line with that of diesel. Finally, there are economies of scale with regards to the LCOC for the Tutshi-Moon pumped storage project, such that upscaling the project to reduce the project LCOC is justifiable.

4. **Federal Funding**. Securing Federal funding to help finance the Atlin Hydro Expansion and Tutshi-Moon pumped storage hydro projects is required to bring the cost of energy and capacity from these projects down, thereby reducing the impacts of these projects on electricity rates in Yukon. Without Federal funding, these projects are not considered cost-competitive and would most likely not be approved by the Yukon Utilities Board.

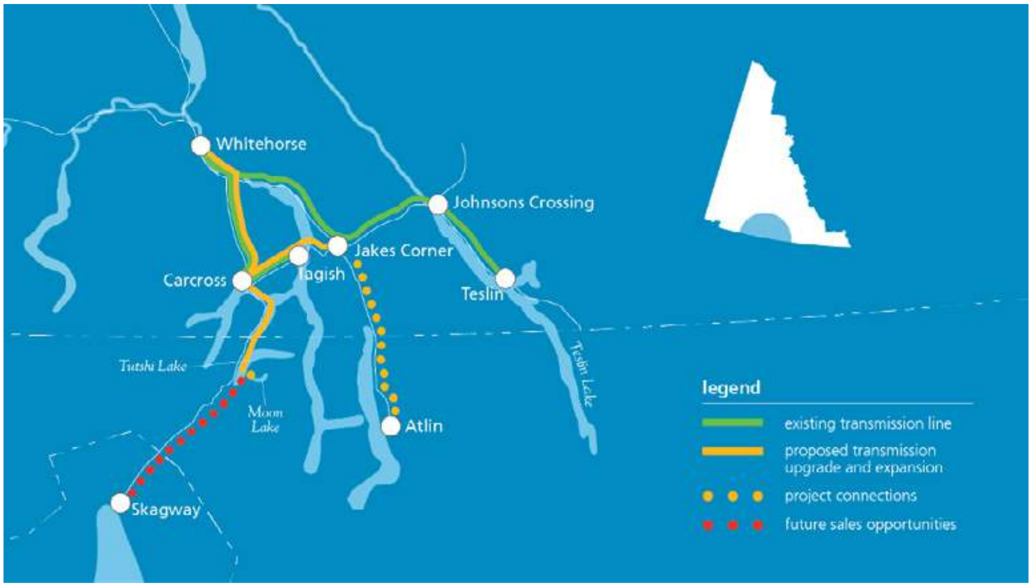
5. **Aishihik Uprate Capacity.** The 1.3 MW dependable capacity associated with the Aishihik Hydro 1 and Hydro 2 uprate projects is only considered available if the loss of Aishihik is no longer the largest single contingency event (N-1 Event) on the YIS.

7.4 Southern Lakes Transmission Project

Given the limitations of existing transmission in the Southern Lakes area and the requirement to connect new projects, upgrading and expanding the transmission infrastructure in the Southern Lakes area is a necessary element of this plan.

This plan assumes that a new transmission line from Skagway (AK) to Whitehorse through Carcross (YT) will be built in a phased manner to support the development of the Southern Lakes area as illustrated in Figure 18. This is a 138 kV transmission line with sufficient transmission capacity to accommodate the full portfolio of future planned projects. In order to minimize intrusion into the natural environment, the proposed line will follow existing rights of way where possible (e.g. highway, transmission or rail).

Figure 18: Southern Lakes Transmission Network



The proposed development of this line follows a phased approach:

- **Phase 1.** This phase includes the construction of the Whitehorse -> Carcross -> Jakes Corner section of the line transmitting power from the Atlin Hydro Expansion project to the load centre at Whitehorse. It should be noted that the viability of connecting the Atlin Hydro Expansion project to the existing ATCO distribution system at Jakes Corner is currently being assessed as an interim measure. By decoupling the timing of the Atlin Hydro Expansion project from that of the Southern Lakes Transmission Project, the Atlin Hydro Expansion project can move forward as soon as possible
- **Phase 2.** This would extend the line from Carcross (YT) to Moon Lake (BC) to interconnect the proposed Tutshi-Moon Pumped Storage Hydro project. The execution of this phase is contingent on the timing and implementation of the proposed Tutshi-Moon Pumped Storage Hydro project.
- **Phase 3.** The final phase of the project would involve an extension of the line from Moon Lake (BC) to Skagway (AK) to complete the 138 kV interconnection from Whitehorse (YT) to Skagway (AK). This final phase will only proceed if and when YEC secures summer energy sales to Skagway for the purposes of providing shore-side power to cruise ships.

Some flexibility is assumed in the sequencing of the transmission construction phases outlined above. For example, it is conceivable that the Whitehorse-Carcross-Skagway line could be constructed in a single step if Yukon Energy is able to advance the business opportunity to sell power to cruise ships in Skagway.

8 Preferred Resource Portfolios

8.1 Portfolio Analysis Methodology

The goal of portfolio analysis is to develop an optimal set of projects capable of addressing both the energy and peak capacity shortfalls over the 10-year planning horizon. YEC's methodology was to follow a directed portfolio development that focused on projects clustered in the Southern Lakes area, facilitated by a Federally supported build-out of transmission infrastructure in that area.

The following assumptions were made in the development of the project portfolio:

1. **Federal Funding.** An assumption was made that Federal funding would be available to protect ratepayers from the impacts of developing significant new infrastructure projects. In order to achieve or exceed the 93% renewable portfolio standard policy objective, Federal funding is also necessary to improve the economics of certain renewable resource options (e.g. pumped storage hydro) relative to the lowest cost fossil fuel-based options.

2. **Committed and Planned Resources Will Happen.** The portfolios assume that the Committed and Planned Resources (previously described in Sections 5.1.2 and 5.1.3), including demand side management programs, are developed and implemented in their respectively planned years.

3. **Atlin Hydro Expansion.** This project is included in the portfolio because of its ability to supply both dependable capacity and firm energy, and because of its significantly shorter project development timeline when compared to other greenfield hydro options.

4. **Tutshi-Moon Pumped Storage Hydro.** This project will provide a significant increase in renewable dependable capacity to address Yukon's existing and forecast capacity shortfall. At the same time, it presents an opportunity to utilize surplus summer energy to meet the forecast winter energy shortfall.

5. **Southern Lakes Transmission build-out.** A new transmission line is required to connect identified projects in the plan (Tutshi-Moon Pumped Storage Hydro; Atlin Hydro Expansion) to the Yukon grid. The development of a new transmission line also facilitates the connection of renewable energy projects developed under the IPP SOP in the Southern Lakes Area, and enables the potential for future sales of surplus summer energy to Skagway for the provision of shore-side power to summertime cruise ships.

6. **Intermittent Renewables (Wind).** These are included as required to meet any residual energy gaps not filled by Tutshi-Moon Pumped Storage Hydro and Atlin Hydro Expansion projects (e.g. in the high load scenario).

7. **Bridging Residual Energy Gaps.** Existing thermal LNG generation is assumed to be available to bridge any small outstanding gaps between average energy and forecast energy demand over the planning period.

8. **Bridging Residual Capacity Gaps.** Temporary rental diesel units are assumed to be available to bridge any outstanding gap between the forecast dependable capacity generation and peak capacity demand over the planning period.

9. **Portfolio Economics Check.** Once the portfolios were built, the Net Present Value of each portfolio was compared to find the lowest cost portfolios which are presented in this report.

The output of the portfolio analysis was an optimum set of resource options that meets the energy and capacity planning criteria under each scenario. The preferred portfolios for the expected Base Case scenario as well as the High Case are presented in the following section. Preferred portfolio analysis results for the Low Case and the Base Case (without Skagway) are provided in Appendix C:

8.2 Preferred Portfolios

The portfolios for the Base Case and High Case scenarios, are presented in the following format:

» **Planning Horizon.** Although the planning horizon for the 10-Year Renewable Electricity Plan is from 2020 to 2030, the annual energy and peak demand forecasts are shown over a longer timeframe (i.e. 2020 to 2035) to show the phased development of certain resource options included in the portfolio (e.g. Tutshi-Moon Pumped Storage Hydro).

» **Annual Energy.** These forecasts show the annual energy demand and average energy generation for Existing, Committed, Planned, and Future Potential Resources over the planning horizon.

» **Peak Capacity Demand.** These forecasts show the peak capacity demand requirement under the N-1 planning criterion, and the dependable capacity for Existing, Committed, Planned, and Future Potential Resources over the planning horizon.

» **Portfolio Summary**. This table lists Future Potential Resources with their respective in-service dates and installed capacities.

» **Portfolio Capital Cost.** This table shows the simple (undiscounted) value of the capital expenditures for Future Potential Resources and the Southern Lakes Transmission Project over the 10-year planning period, both with and without Federal funding (assumed to be the typical maximum 75% of capital cost). For the Base Case and High Case, all three phases of the Southern Lakes Transmission Project are included (e.g. the line extends from Whitehorse, YT to Skagway, AK). These costs include future projects that may be developed by both YEC and/or independent power producers. This does not include the costs of the Committed and Planned Resources in each plan. The Portfolio Capital Cost was presented for illustrative purposes to show the magnitude of undiscounted capital investment over the planning period.

8.2.1 Base Case Portfolio

Figure 19: Base Case Portfolio, Energy

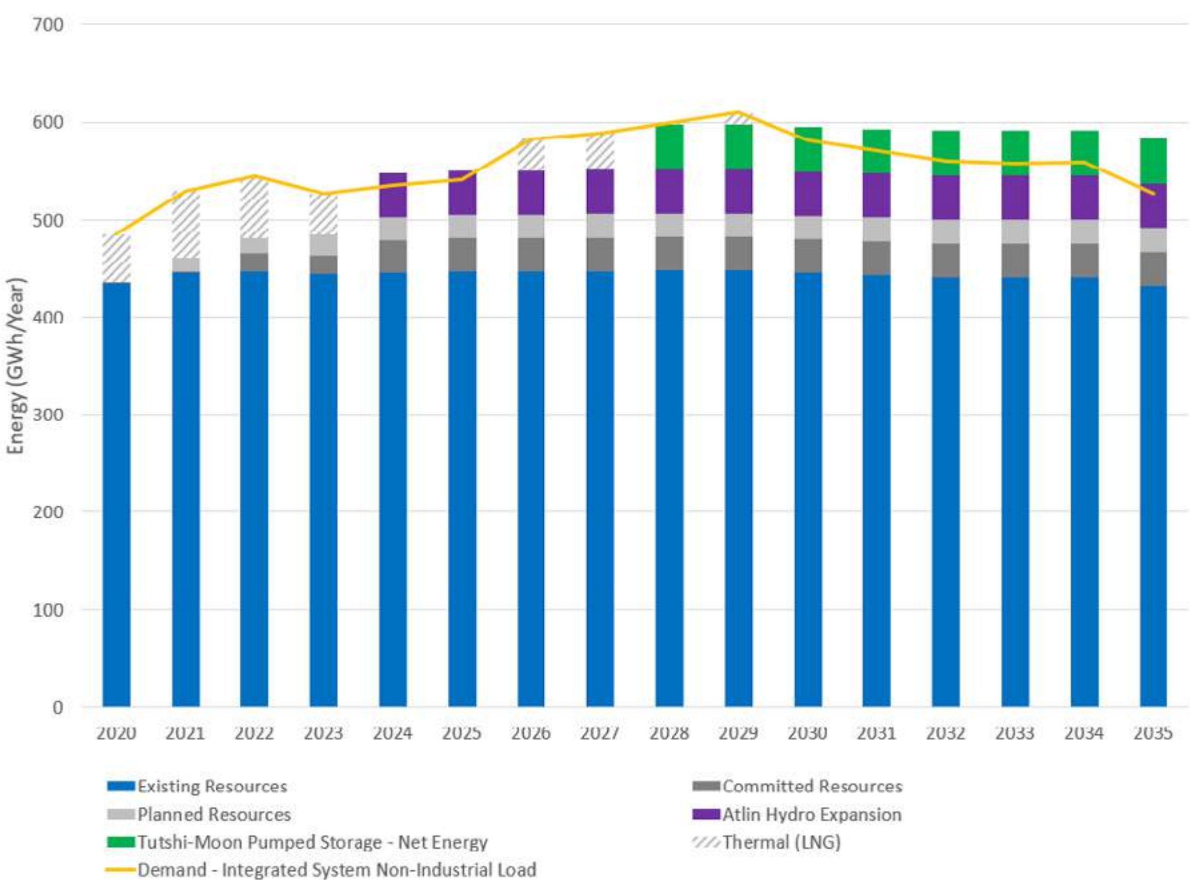


Figure 20: Base Case Portfolio, Capacity

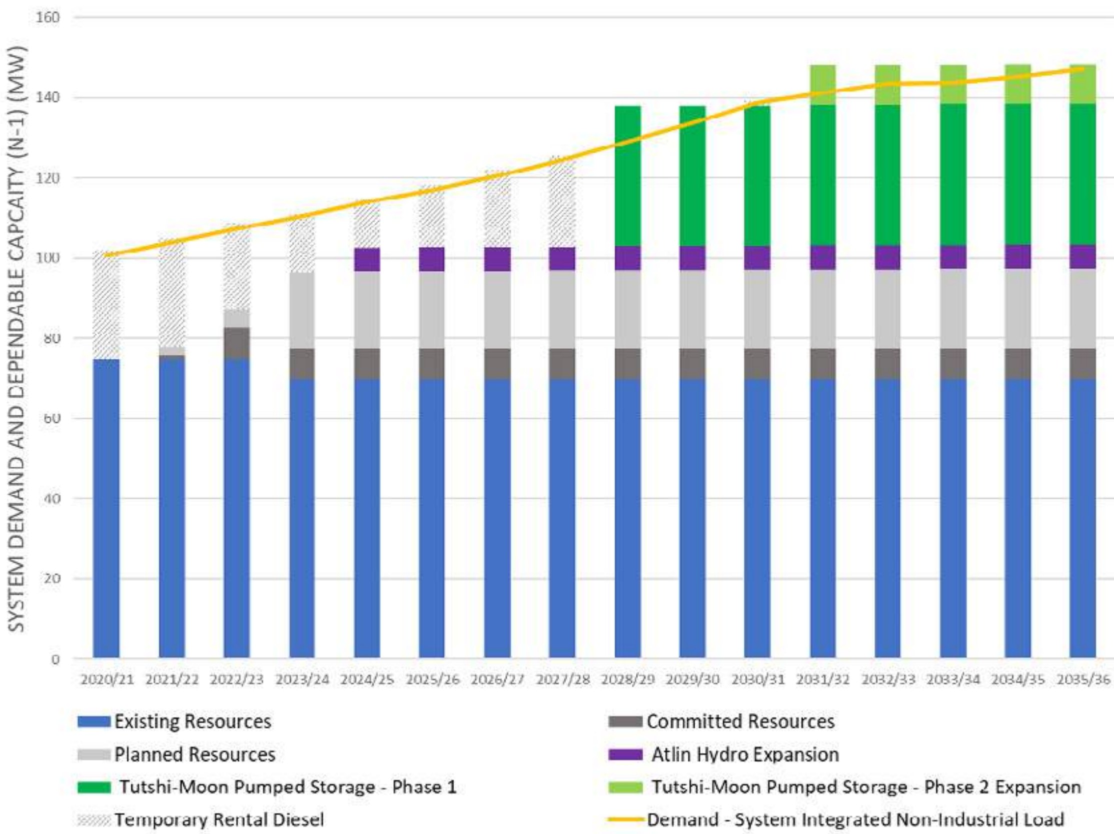


Table 4: Base Case Portfolio Summary (2020 - 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2024/25 Atlin Hydro Expansion Project	6	6
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**41**	**41**
GRAND TOTAL:	**69.9**	**68.1**

Table 5: Base Case Portfolio Cost Summary (2020 – 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 577 million
Portfolio Capital Cost with Federal Funding:	$ 144 million

Appendix D: provides a more detailed breakdown of the cost and capacity components for the Base Case.

8.2.2 High Case Portfolio

Figure 21: High Case Portfolio, Energy

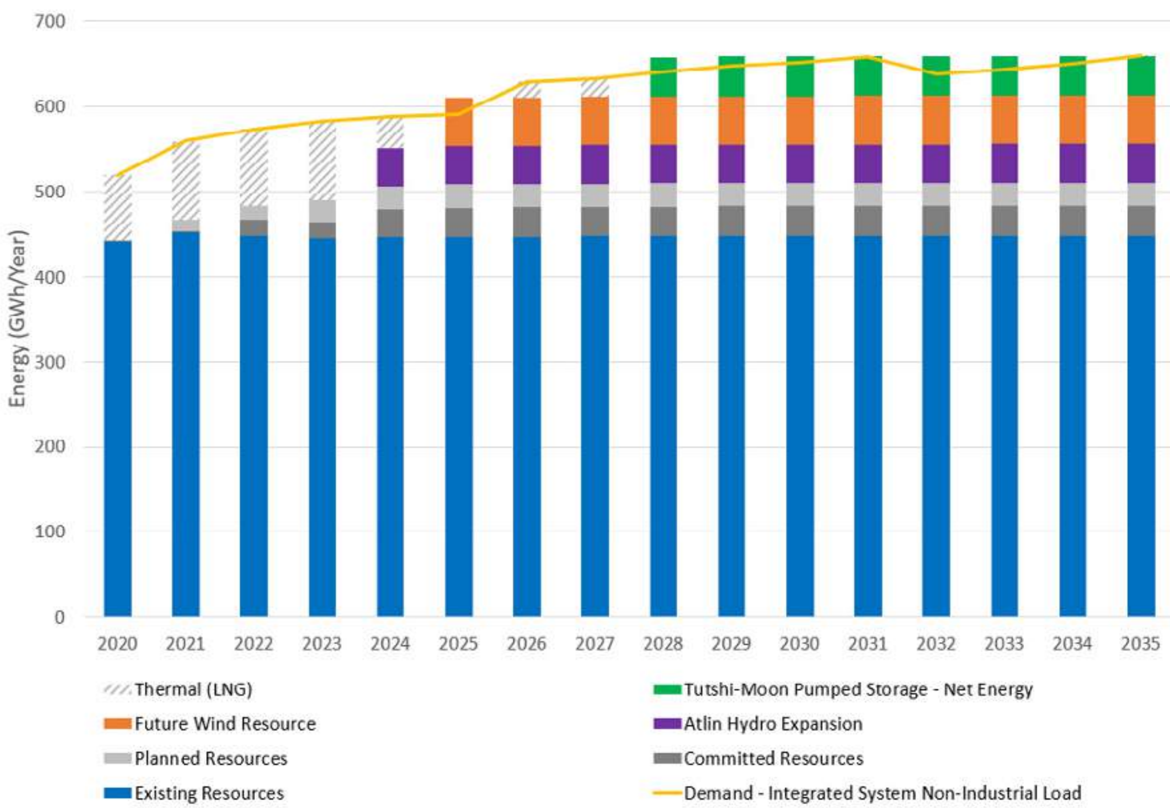


Figure 22: High Case Portfolio, Capacity

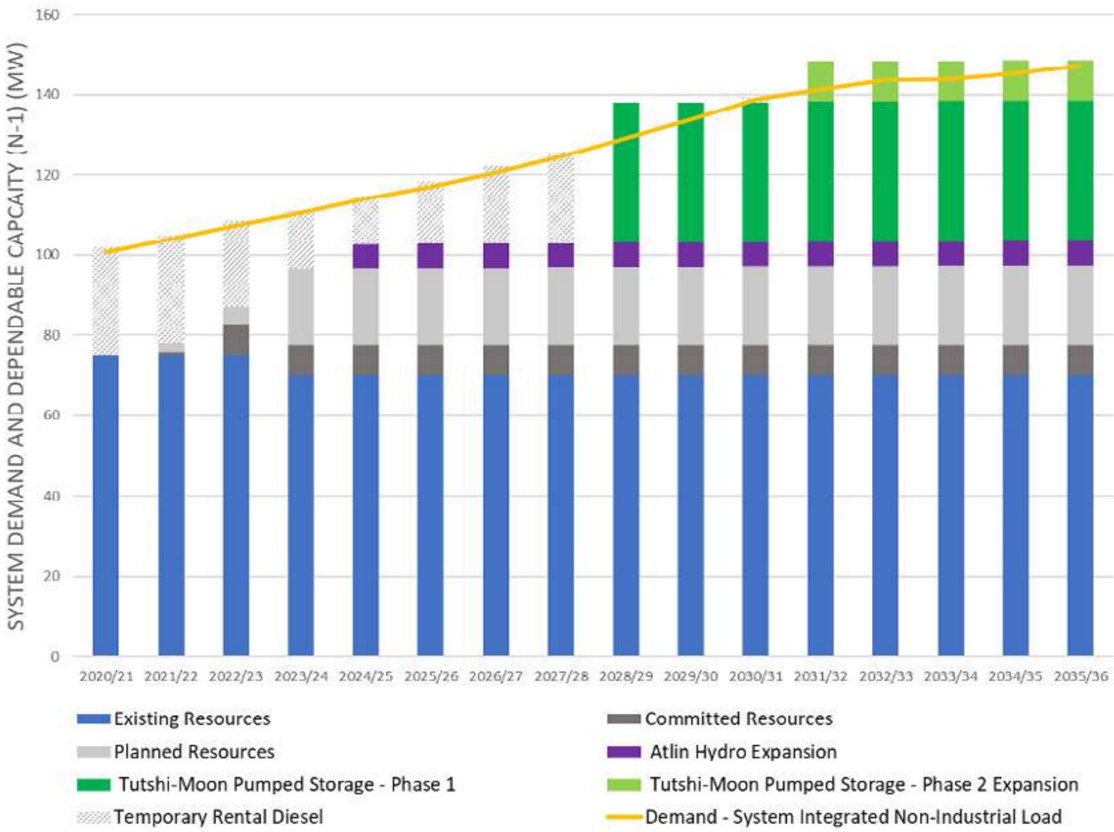


Table 6: High Case Portfolio Summary (2020 – 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2024/25 Atlin Hydro Expansion Project	6	6
2025/26 Wind Resource Project	20	0
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**41**	**41**
GRAND TOTAL:	**89.9**	**68.1**

Table 7: High Case Portfolio Cost Summary (2020 – 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 651 million
Portfolio Capital Cost with Federal Funding:	$ 163 million

Appendix D: provides a more detailed breakdown of the cost and capacity components for the Base Case.

8.3 Portfolio Summary

As a consequence of the long lead times associated with developing generation and transmission, the portfolios show an energy and dependable capacity shortfall over the planning period, especially in the early years. As a result, residual energy and capacity gaps are assumed to be met with LNG generation and temporary diesel generator rentals over the planning period. Conversely, the Base Case scenario shows an energy surplus after 2030 based on the forecast decrease in industrial load, which indicates that the net energy production from the pumped storage facility would be in surplus. Federal funding will be critical in order to protect ratepayers from the financial cost of this potential surplus.

A summary of the resource options comprising the Base Case and the High Case scenario portfolios is presented in Table 8. Implementation of both the Atlin Hydro Expansion project in year 2024/25 and phase 1 of the Tutshi-Moon Lake Pumped Storage Project in year 2028/29 is required for both portfolios. Finally, the High Case scenario also requires a new 20 MW wind resource in 2025/26 to meet the higher energy requirements over the planning period.

Table 8: Future Resources Selected for Key Scenarios

	BASE CASE	HIGH CASE
2024/25	Atlin Hydro Expansion (6 MW)	Atlin Hydro Expansion (6 MW)
2025/26		Wind Resource (20 MW)
2028/29	Tutshi-Moon Pumped Storage Project – Phase 1 (35 MW)	Tutshi-Moon Pumped Storage Project – Phase 1 (35 MW)
Total Portfolio Capital Cost without Federal Funding ($M)	**$577 Million**	**$651 Million**
Total Portfolio Capital Cost with Federal Funding ($M)	**$144 Million**	**$163 Million**

8.3.1 Southern Lakes Geographic Focus

The 10-Year Renewable Electricity Plan's underlying focus on clean energy and capacity resources led to the development of multiple solutions in the Southern Lakes area, the geographical area shown in Figure 23.

Figure 23: Southern Lakes Transmission Network

With its abundance of lakes and proximity to Whitehorse (Yukon's main population and electrical load centre), the Southern Lakes area is well suited for developing hydroelectric resources. Hydroelectric and pumped storage hydro screening studies were completed as part of the 2016 Integrated Resource Plan. These studies identified several potential project sites in the Southern Lakes area, including the Tutshi-Windy Arm and Surprise Lake hydroelectric project sites, as well as the Moon-Tutshi, Racine-Moon, Lindeman-Fraser, Racine-Mount Brown and Atlin-Black Mountain pumped storage hydro sites. These general findings were confirmed in the study updates discussed in Section 7.1. Prospective Independent Power Producer (IPP) projects have also been identified in the Southern Lakes area, including the Atlin Hydro Expansion project and the Montana Mountain Wind and Solar Projects.

Given the limited existing transmission assets in the Southern Lakes area and the requirement to interconnect new projects, upgrading and expanding the transmission infrastructure is a requirement for enabling the projects in the Southern Lakes area. It may also be possible for YEC to take advantage of a potentially attractive business opportunity to supply electricity to cruise ships docking in Skagway during the summer tourist season. Currently, the Skagway pier has the capability to interconnect up to four (4) cruise ships, which can amount to approximately 35 GWh/year of summer energy demand. Cruise ships visiting Skagway today burn diesel fuel to generate shipboard electricity while at the dock. Electrifying cruise ships using surplus energy available during the summer months could lead to increased revenues for Yukoners to offset Yukon electricity costs, and a reduction in GHG emissions in Skagway. As noted in Section 4.2, this analysis was conducted prior to the COVID-19 pandemic; YEC will assess the timing and extent of the recovery of the cruise ship industry as part of its evaluation of the Skagway business opportunity.

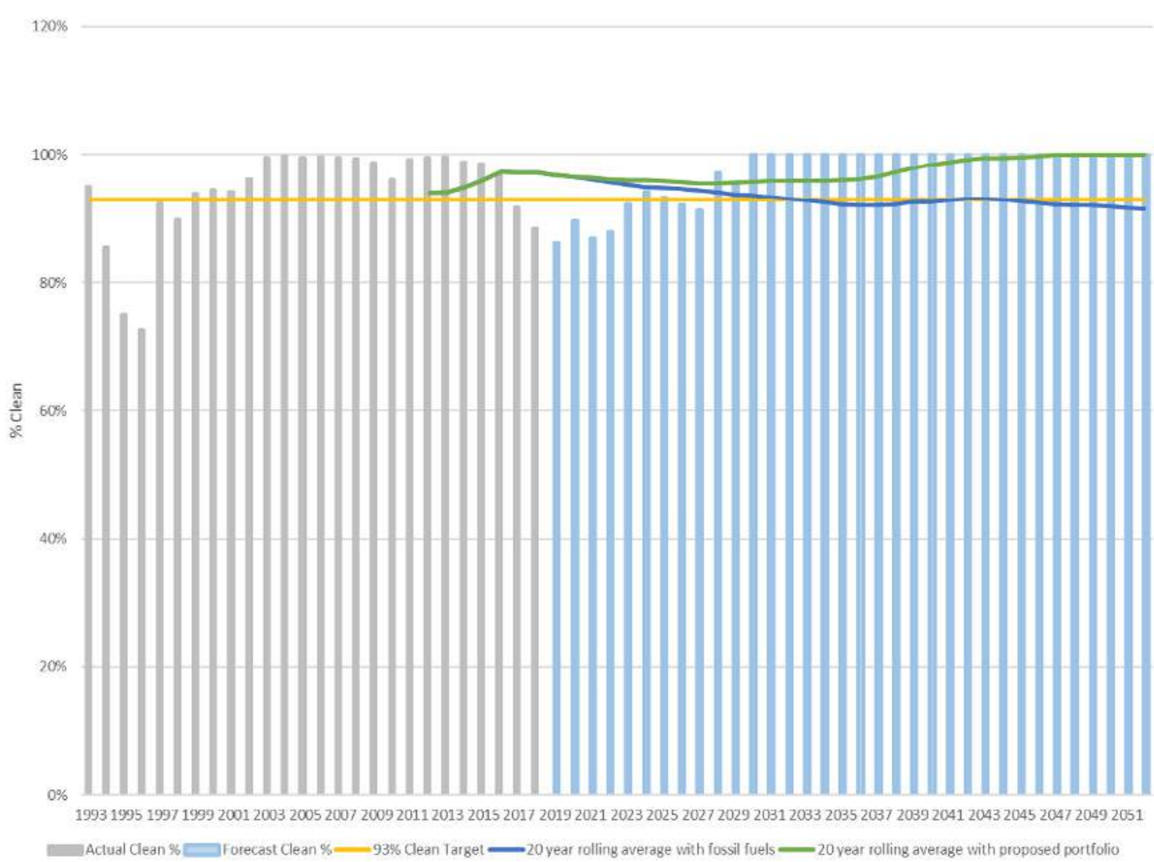
The majority of the new generation in the Plan is located in British Columbia; however, Yukoners will be receiving the benefits of the greenhouse gas emissions reductions and renewable electricity provision. YEC will strive to maximize other benefits to Yukoners via contracting and procurement opportunities and Yukon First Nations benefits agreements. YEC will also continue to work with both the Yukon and BC governments to ensure key stakeholders are engaged appropriately.

8.4 Renewable Portfolio Target

Under the Yukon government's draft Climate Change, Energy and Green Economy strategy, YEC is mandated to meet a renewable portfolio target of 93% on a long-term average basis. This means that at least 93% of the electricity generated on the YIS has to come from renewable sources.

Figure 24 illustrates the forecast percentage renewable generation profile of the electricity mix assuming that the 10-Year Renewable Electricity Plan portfolio is successfully executed. For comparison, the figure also includes a forecast percentage renewable generation profile for an alternate portfolio with a heavy reliance on fossil fuels to meet forecast energy needs (i.e., the portfolio that would be required if the 10-Year Renewable Electricity Plan is not implemented).

Figure 24: Long Term Energy Generation Profile



The bars shown in Figure 24 represent the actual percentage of renewable energy being generated by the system. The gap between the bars and the 100% threshold represents the percentage of energy generated by non-renewable resources (e.g. thermal). The lower percentage of renewable generation observed in recent years (i.e. 2017-2020) was a result of increased thermal generation at the margin given load growth and low hydroelectric resources (drought conditions) in these years.

As new renewable supply projects are developed over the planning period, there is an observed increase in percentage renewables in the energy generation mix. As observed in Figure 24, the 10-Year Renewable Electricity Plan portfolio exceeds the 93% renewable target over the planning period and beyond. The portfolio of projects recommended in the 10-Year Renewable Electricity Plan delivers on Yukon government's commitment for GHG reductions by 2030. It positions YEC favourably to contribute towards achieving the Federal government's "net zero by 2050" target.

9 10-Year Renewable Energy Action Plan

This section presents the key considerations in developing the 10-Year Renewable Electricity Action Plan (Action Plan), and the proposed steps to be undertaken to implement it.

9.1 Project Development Plan

The recommended Action Plan is based on developing the resource portfolio generated for the Base Case scenario, with add-on resources identified for other scenarios. Figure 25 summarizes the Action Plan recommendations.

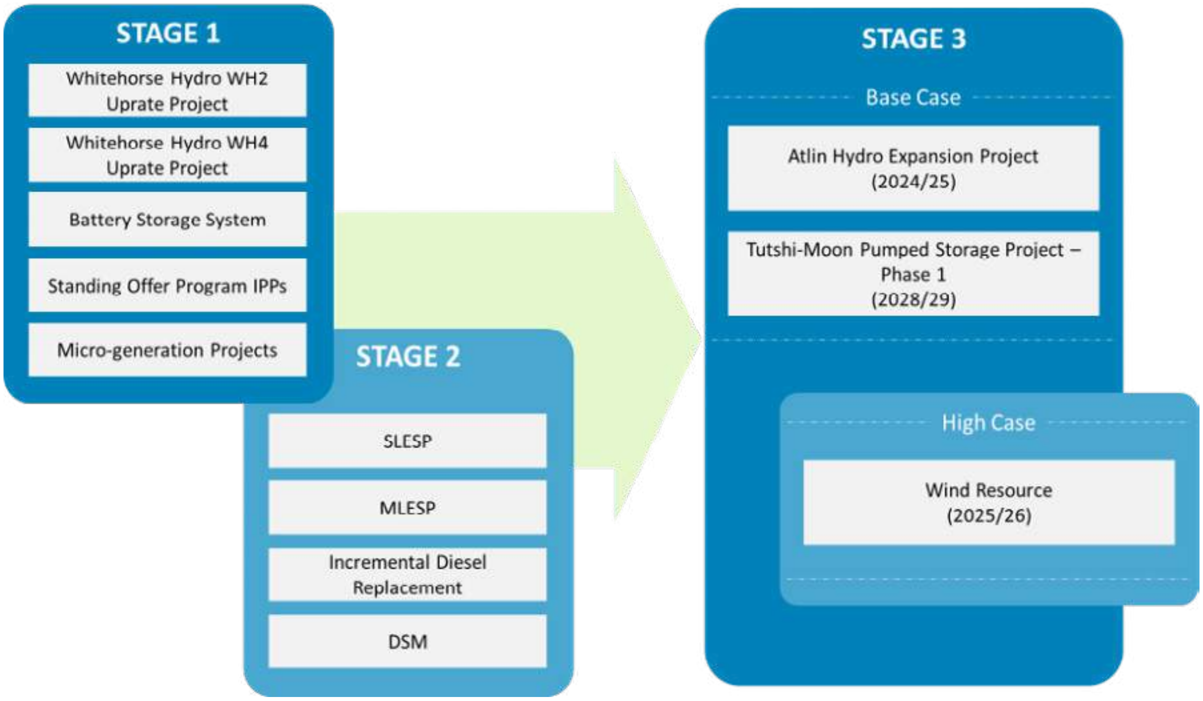
The Action Plan is divided into three stages:

» **Stage 1 – Implementation of the Committed Resources.** These resources are essential in all the portfolios over the planning period. These common resources include the Whitehorse Hydro #2 and #4 (WH2 and WH4) Uprate Projects, Battery Storage System, SOP IPP, and Micro-generation projects.

» **Stage 2 – Completion of Planning Work & Final Decisions to Proceed with Planned Resources.** These common resources include the SLESP, MLESP, the Incremental Diesel Replacement, and DSM.

» **Stage 3 – Development and implementation of the Future Potential Resources.** The options recommended for the expected Base Case scenario are the Atlin Hydro Expansion Project and Phase 1 of the Tutshi-Moon Lake Pumped Storage Project. The additional Future Potential Resource option included in the High Case portfolio (i.e. the Wind Resource) is considered as potential add-on resource to the Action Plan but is ultimately contingent on future growth.

Figure 25: 10-Year Renewable Electricity Action Plan



As with all long-term resource plans, there is the potential for future changes to trigger changes to the path forward. YEC will continue to monitor the key elements that influence the Plan, including the load forecast, progress or obstacles in executing the projects, and developments in emerging or uncertain technologies, and will update the path forward in future long-term resource planning exercises accordingly.

9.2 Key Risks & Uncertainties

The key risks and uncertainties with regard to the 10-year Renewable Electricity Plan are described below. If YEC is unable to move forward with the projects in the Plan, a new plan will be required to address Yukon's load growth and renewable electricity requirements.

» **Federal Funding Uncertainty.** The Action Plan assumes that Federal funding will be secured for the development of the identified generation projects and the supporting Southern Lakes transmission infrastructure. As such, Federal funding is an essential part of the recommended Action Plan as it will help minimize the rate impacts of the plan for Yukoners, and protect ratepayers from contingent risks such as the premature loss of industrial load. However, securing federal funding is not a certainty. To mitigate this risk, options to phase the Federal funding requests, such as focusing on securing funding for project planning first, and only proceeding with project construction once construction funding has been secured, will be explored with Federal funding agencies in order to mitigate risks. YEC will also coordinate closely with Yukon government and potential First Nations project developers and partners in pursuit of this Federal funding. If YEC is unable to secure Federal funding, a new long-term resource plan will need to be developed, as it is a critical requirement for the execution of the 10-Year Renewable Electricity Plan.

» **General Development Risks.** There is always some potential for technical or financial problems during project planning or construction, which could result in abandoning specific lower cost resources in favor of more expensive resources and/or delays. The resulting impacts include higher rates driven by increased portfolio costs and/or insufficient energy and/or capacity supply.

» **Residual Ratepayer Risk (exposure to surplus energy/mismatch).** If the future load projections used to justify capital plans do not materialize, over-building and/or over-production of electricity from the IPP SOP or micro-generation programs could lead to additional surplus energy and a seasonal mismatch between available generation and demand. This poses a financial risk to ratepayers in the form of higher rates.

» **SOP IPP Uncertainty.** The possibility of bankruptcy or failure of contracted generation assets, or the failure of contracted IPPs to reach commercial operation (multiple causes) could result in some IPP projects being delayed or not completed. The resulting risks include the inability to achieve renewable energy targets, increased thermal energy requirements, and/or insufficient energy supply.

» **Regulatory Uncertainties.** These uncertainties could lead to proposed electricity supply projects being disallowed by the regulator or to protracted legal and regulatory processes delaying project approvals or relicensing. If these projects are delayed or canceled, it will result in increased reliance on thermal generation for energy, and ongoing rental of temporary diesel engines for capacity. The resulting risks include the inability to achieve renewable energy targets, and potential rate increases caused by increased portfolio costs due to burning higher cost fossil fuels and introducing more expensive replacement projects.

9.3 First Nations Engagement, Support and Participation

Active First Nations participation in and support for the plan will be vital to the successful execution of the plan. YEC will be actively engaging with those First Nations on whose Traditional Territory the proposed projects are located.

Opportunities exist for First Nations to participate in multiple components of the plan, including the IPP SOP, and by taking an active role as project proponents and/or partners in the 10-Year Renewable Electricity Plan. In addition, First Nations will have contracting and other business opportunities during project planning and construction. These opportunities will be explored in detail during all phases of the project development.

Specific First Nations engagement plans for the two highest priority Future Potential Resources is outlined below:

» **Atlin Hydro Expansion project:** this project is being developed as an Independent Power Producer project by Tlingit Homeland Energy LP (THELP), a corporation owned by the development corporation of the Taku River Tlingit First Nation (TRTFN). As such, THELP will be responsible for all aspects of the project development, including environmental assessment and permitting, engineering design, construction and community and First Nations consultation. Yukon Energy has engaged in negotiations with THELP on a potential Electricity Purchase Agreement (EPA), which will outline the key commercial and operations terms under which YEC would purchase electricity from the Atlin Hydro Expansion project, should the project be approved to proceed. YEC and THELP are actively collaborating on securing government grant funding for the project, which will be critical to supporting the project economics while keeping the price of energy and capacity procured under the EPA affordable to Yukon customers.

» **Moon Lake Pump Storage Project:** this project is located on overlapping Traditional Territory of the Carcross/Tagish First Nation (C/TFN) and the Taku River Tlingit First Nation. As such, YEC plans to actively engage with both First Nations on the development of the Moon Lake Pump Storage project. As of Q4 2020, the project remains in a very early stage of development, and work completed to date has been limited to desk-top engineering and technical studies. YEC plans to engage with both C/TFN and TRTFN to establish a framework agreement covering the initial stages of project assessment and development, with the intent to undertake all field work, environmental assessment and monitoring, engineering design and community engagement in a collaborative, transparent manner. Options for the ultimate ownership structure of the project, including options for either partial of full ownership by First Nations, will also be assessed and negotiated over the initial phase of project planning. YEC will also actively collaborate with C/TFN and TRTFN on securing government grant funding for the project, which will be critical to supporting the project economics while keeping the project affordable for Yukon customers.

Appendix A:
Existing Resources Technical Attributes

Location	Retirement Year	Original Unit #	Current Unit #	Prime Mover Type	Dispatchable	10 Year Renewable Energy Plan Installed Capacity [kW]	10 Year Renewable Energy Plan Dependable Capacity [kW]	2016 IRP Dependable Capacity (IRP Table 4.2.) [kW]
Aishihik								
Hydro	2050	AH1	AH1	Hydro	Yes	15,600	15,000	15,000
	2050	AH2	AH2	Hydro	Yes	15,600	15,000	15,000
	2050	AH3	AH3	Hydro	Yes	7,000	7,000	7,000
					Subtotal	**38,200**	**37,000**	**37,000**
Faro								
Diesel	2023	FD1	FD1	Diesel	Yes	5,150	3,000	4,000
	2050	FD7	FD7	Diesel	Yes	3,000	2,800	2,800
					Subtotal	**8,150**	**5,800**	**6,800**
Dawson								
Diesel	2050	DD1	DD1	Diesel	Yes	800	650	720
	2023	DD2	DD2	Diesel	Yes	1,000	850	920
	2050	DD3	DD3	Diesel	Yes	1,000	850	920
	2050	DD4	FD5	Diesel	Yes	1,440	1,000	1,000
	2023	DD5	DD5	Diesel	Yes	1,500	1,350	1,400
	2050	YM1	FD6	Diesel	Yes	1,440	850	1,000
					Subtotal	**7,180**	**5,550**	**5,960**
Mayo								
Diesel	2050	MD1	FD2	Diesel	Yes	1,000	850	850
	2050	MD2	FD4	Diesel	Yes	1,000	850	850
	2050	MD3	FD3	Diesel	Yes	1,000	850	850
					Subtotal	**3,000**	**2,550**	**2,550**
Hydro	2050	MH1	MH1	Hydro	Yes	2,550	1,500	1,400
	2050	MH2	MH2	Hydro	Yes	2,550		
	2050	MBH1	MBH1	Hydro	Yes	5,310	2,500	3,800
	2050	MBH2	MBH2	Hydro	Yes	5,310	2,500	3,800
					Subtotal	**15,720**	**6,500**	**9,000**
					Total	**18,720**	**9,050**	**11,550**
Whitehorse								
Hydro	2050	WH1	WH1	Hydro	Yes	5,800	3,500	3,000
	2050	WH2	WH2	Hydro	Yes	5,800	3,500	3,000
	2050	WH3	WH3	Hydro	Yes	8,400		
	2050	WH4	WH4	Hydro	Yes	21,327	20,000	18,500
					Subtotal	**41,327**	**27,000**	**24,500**
Diesel	2015	WD1	WG1	Diesel	Yes	N/A	N/A	N/A
	2015	WD2	WG2	Diesel	Yes	N/A	N/A	N/A
	2019	WD3	WD3	Diesel	Yes	N/A	N/A	4,500
	2050	WD4	WD4	Diesel	Yes	2,500	2,250	2,500
	2050	WD5	WD5	Diesel	Yes	2,500	2,250	2,500
	2050	WD6	WD6	Diesel	Yes	2,500	2,250	2,500
	2050	WD7	WD7	Diesel	Yes	3,300	2,800	3,000
					Subtotal	**10,800**	**9,550**	**15,000**
Natural Gas	2055	WG1	WG1	Natural Gas	Yes	4,400	4,200	4,400
	2055	WG2	WG2	Natural Gas	Yes	4,400	4,200	4,400
	2055	WG3	WG3	Natural Gas	Yes	4,400	4,200	N/A
					Subtotal	**13,200**	**12,600**	**8,800**
					Total	**65,327**	**49,150**	**48,300**

Location	Retirement Year	Original Unit #	Current Unit #	Prime Mover Type	Dispatchable	10 Year Renewable Energy Plan Installed Capacity [kW]	10 Year Renewable Energy Plan Dependable Capacity [kW]	2016 IRP Dependable Capacity (IRP Table 4.2.) [kW]
Haeckel Hill								
Wind	2019	WW2	WW2	Wind	No	N/A	N/A	0
						0	**0**	**0**
Mobile Diesels								
Diesel	2050	YM2	YM2	Diesel	Yes	150	0	0
	2050	YM3	YM3	Diesel	Yes	125	0	0
	2050	YM4	YM4	Diesel	Yes	35	0	0
	2050	YM5	YM5	Diesel	Yes	125	0	0
					Subtotal	**435**	**0**	**0**
YECL								
Diesel	2050	CD1	CD1	Diesel	Yes	1,600	1,200	1,206
	2050	TD1	TD1	Diesel	Yes	1,500	1,200	1,130
	2050	RD1	RD1	Diesel	Yes	1,000	750	750
	2050	HD1	HD1	Diesel	Yes	1,750	1,500	1,320
	2050	Pelly G1	Pelly G1	Diesel	Yes	275	200	199
	2050	Pelly G2	Pelly G2	Diesel	Yes	600	400	446
	2050	Pelly G3	Pelly G3	Diesel	Yes	300	200	218
	2050	Stewart G1	Stewart G1	Diesel	Yes	150	100	104
					Subtotal	**7,175**	**5,550**	**5,373**
				YEC	**Hydro**	95,247	70,500	70,500
					Diesel	29,565	23,450	30,310
					Natural Gas	13,200	12,600	8,800
					Wind	0	0	0.0
					Total	**138,012**	**106,550**	**109,610**
				YECL	**Diesel**	7,175	5,550	5,373
					Total	**7,175**	**5,550**	**5,373**
				Yukon Power System	**Hydro**	95,247	70,500	70,500
					Diesel	36,740	29,000	35,683
					Natural Gas	13,200	12,600	8,800
					Wind	0	0	0
					Total	**145,187**	**112,100**	**114,983**
				Single Contingency (N-1) Dependable Capacity	**Hydro**	N/A	33,500	33,500
					Diesel	N/A	27,500	34,363
					Natural Gas	N/A	12,600	8,800
					Wind	N/A	0	0
					Total	**0.0**	**73,600**	**76,663**

Notes:

- *Single Contingency (N-1) scenario dependable capacity excludes the dependable capacity for Aishihik (37 MW) and ATCO's Haines junction diesel generator (1.5 MW) as the community would be isolated by the loss of the transmission line between the Aishihik Generating Station and the Takhini substation.*
- *No dependable capcity assumed for Minto Mine diesel generators and YEC wind turbines and mobile generators with the exception of unit YM1.*
- *Excludes ATCO Fish Lake Hydro. The contribution of the ATCO Fish Lake Hydro plant was not included in the inventory of the existing resources as its contribution was deducted from the load forecast modelling.*

Appendix B: Energy & Capacity Gap

Figure B1: Base Case Energy Gap Analysis: Detailed View

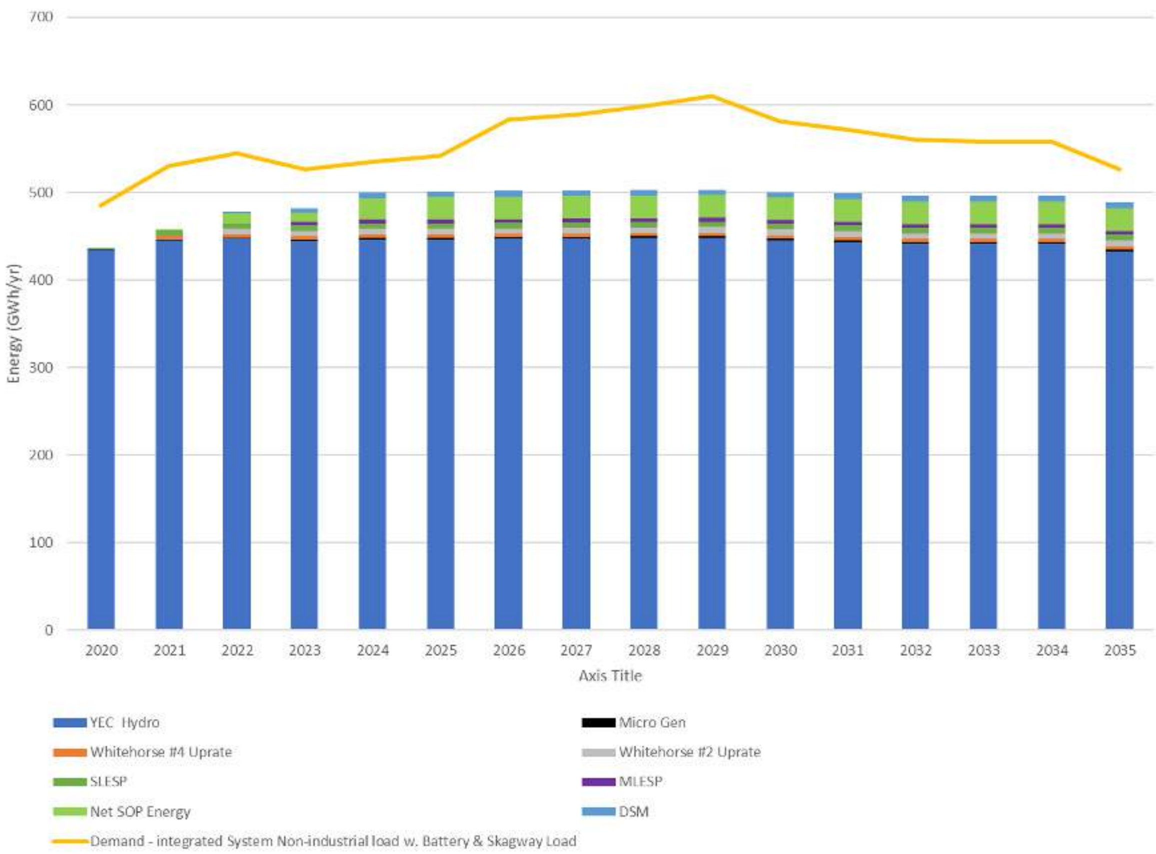


Table B1: Average Annual Energy Surplus/Deficit (Base Case)

YEAR	AVERAGE ENERGY SURPLUS/(DEFICIT) [GWH]	YEAR	AVERAGE ENERGY SURPLUS/(DEFICIT) [GWH]
2020	(49)	2028	(93)
2021	(69)	2029	(103)
2022	(63)	2030	(77)
2023	(42)	2031	(69)
2024	(32)	2032	(60)
2025	(37)	2033	(58)
2026	(78)	2034	(58)
2027	(83)	2035	(35)

Table B2: Average Monthly Energy Gap (Surplus/Deficit)

MONTH	YEAR 2024: AVERAGE ENERGY SURPLUS/ (DEFICIT) [GWH]	YEAR 2030 (BEFORE SKAGWAY LOAD): AVERAGE ENERGY SURPLUS/ (DEFICIT) [GWH]
Jan	(7)	(4)
Feb	(9)	(5)
Mar	(12)	(6)
Apr	(6)	(2)
May	(1)	0
Jun	4	7
Jul	8	10
Aug	10	11
Sep	8	9
Oct	2	3
Nov	(2)	0
Dec	(5)	(3)
Total Surplus [GWh]:	**32**	**40**
Total Deficit [GWh]:	**(42)**	**(20)**

Table B3: Dependable Capacity Surplus/Deficit under N-1 Conditions (Base Case)

YEAR	DEPENDABLE CAPACITY SURPLUS/ (DEFICIT) [MW]	YEAR	DEPENDABLE CAPACITY SURPLUS/ (DEFICIT) [MW]
2020/21	(26)	2028/29	(32)
2021/22	(26)	2029/30	(37)
2022/23	(20)	2030/31	(42)
2023/24	(14)	2031/32	(44)
2024/25	(17)	2032/33	(46)
2025/26	(20)	2033/34	(46)
2026/27	(24)	2034/35	(48)
2027/28	(28)	2035/36	(50)

Appendix C: Additional Scenario Portfolio Results

C.1 Base Case (Without Skagway) Portfolio

Figure C1: Base Case (Without Skagway), Energy

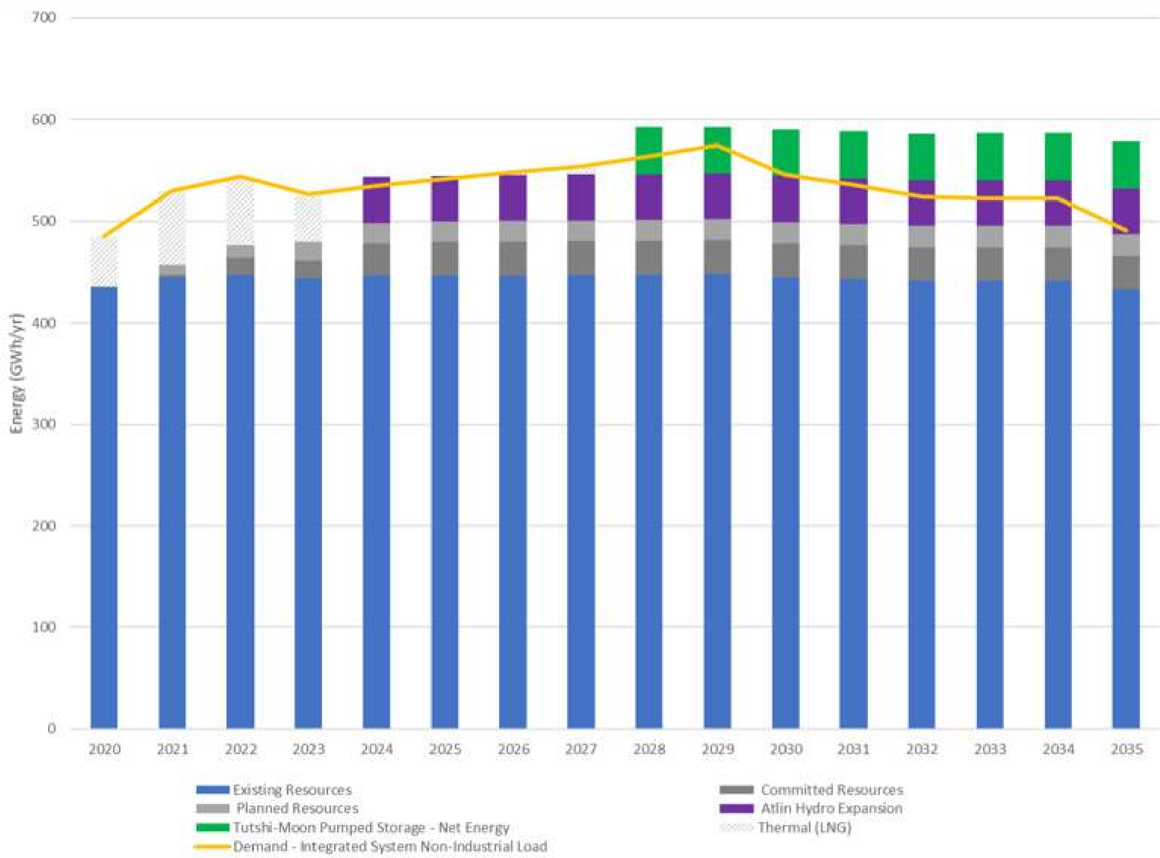


Figure C2: Base Case (Without Skagway), Capacity

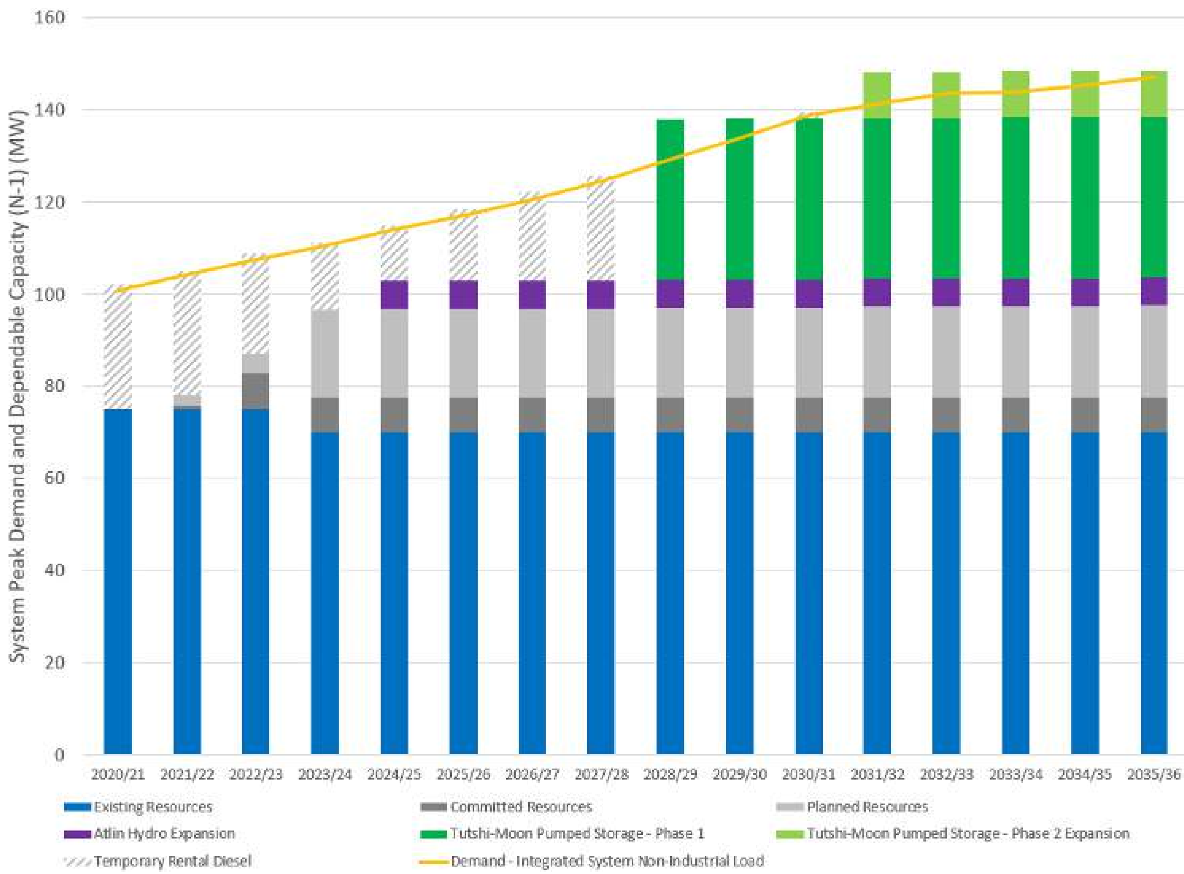


Table C1: Base Case (Without Skagway) Portfolio Summary (2020 - 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2024/25 Atlin Hydro Expansion Project	6	6
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**41**	**41**
GRAND TOTAL:	**69.9**	**68.1**

Table C2: Base Case (Without Skagway) Portfolio Cost Summary (2020 - 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 519 million
Portfolio Capital Cost with Federal Funding:	$ 130 million

C.2 Low Case Portfolio

Figure C3: Low Case, Energy

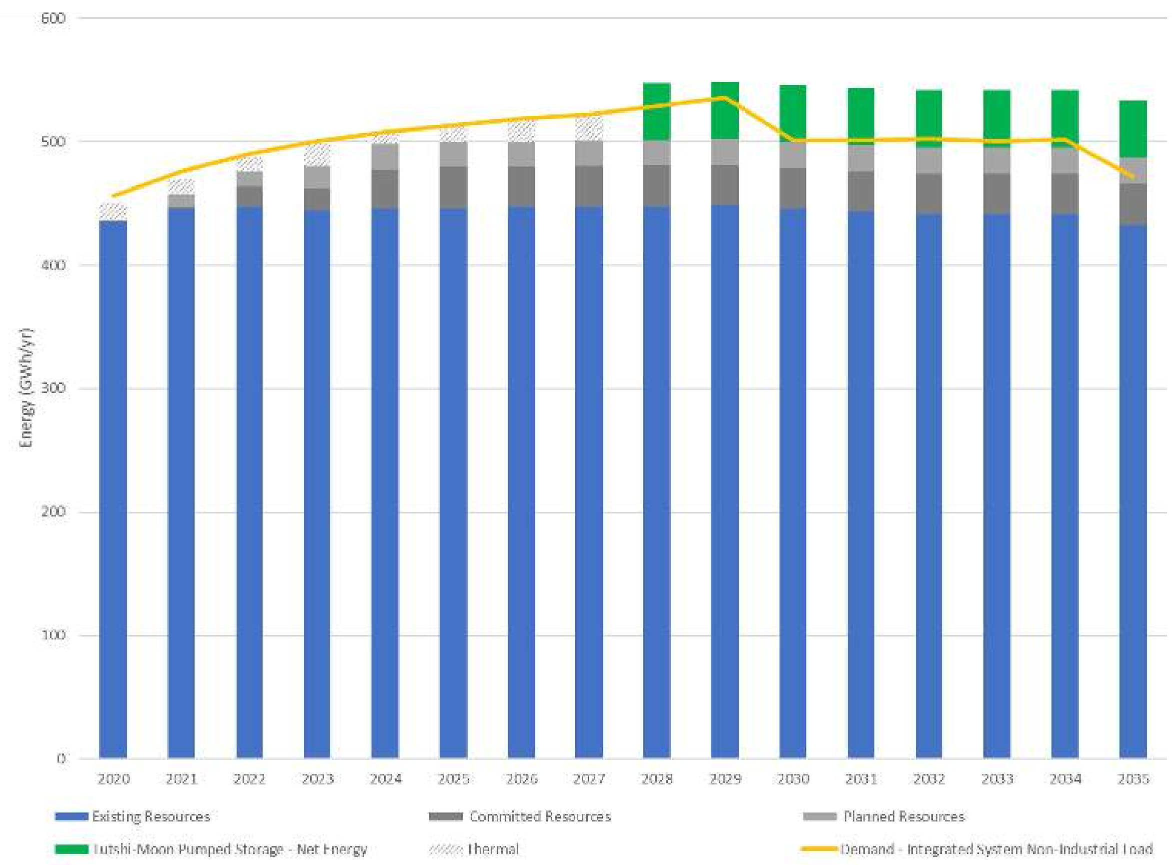


Figure C4: Low Case, Capacity

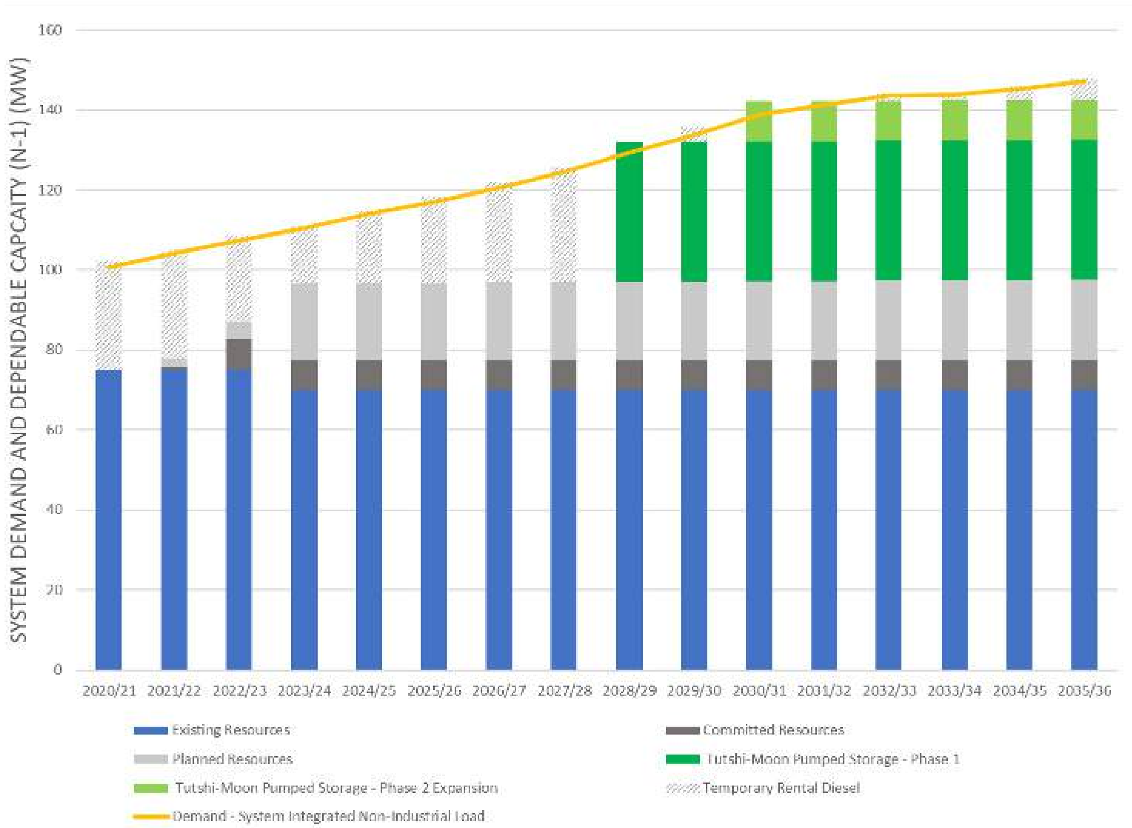


Table C3: Low Case Portfolio Summary (2020 - 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**35**	**35**
GRAND TOTAL:	**63.9**	**62.1**

Table C4: Low Case Portfolio Cost Summary (2020 - 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 388 million
Portfolio Capital Cost with Federal Funding:	$ 97 million

Appendix D: Detailed Scenario Capacity & Capital Costs

D.1 Base Case Portfolio

Table D1: Base Case Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2024/25		
Atlin Hydro Expansion Project	6	6
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	**41**	**41**
TOTAL:	**69.9**	**68.1**

Table D2: Base Case Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Atlin Hydro	$ 131,000,000	$ 98,250,000	$ 32,750,000
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Southern Lakes Transmission Project Phase 1-3 (Whitehorse to Skagway)	$ 166,000,000	$ 124,500,000	$ 41,500,000
TOTAL PORTFOLIO:	**$ 577,000,000**	**$ 432,750,000**	**$ 144,250,000**

[1]The capital costs for the generation projects are from the sources described in Section 7.1.3 and Table 3. The capital costs for the Southern Lakes Transmission Project is based on the 2016 Resource Plan Appendix 5.21: Transmission Options Evaluation study work.

D.2 High Case Portfolio

Table D3: High Case Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2024/25		
Atlin Hydro Expansion Project	6	6
2025/26		
Wind Resource Project	20	0
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	61	41
TOTAL:	**89.9**	**68.1**

Table D4: High Case Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Atlin Hydro	$ 131,000,000	$ 98,250,000	$ 32,750,000
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Wind Resource (20 MW)	$ 73,500,000	$ 55,125,000	$ 18,375,000
Southern Lakes Transmission Project Phase 1-3 (Whitehorse to Skagway)	$ 166,000,000	$ 124,500,000	$ 41,500,000
TOTAL PORTFOLIO:	**$ 650,500,000**	**$ 487,875,000**	**$ 162,625,000**

D.3 Base Case (Without Skagway) Portfolio

Table D5: Base Case (without Skagway) Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2024/25		
Atlin Hydro Expansion Project	6	6
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	**41**	**41**
TOTAL:	**69.9**	**68.1**

Table D6: Base Case (without Skagway) Capital Costs[1] Detail 2020-2030

Cost Component	**Capital Cost (2019$)**	**Federal Funding (2019$)**	**Total Cost with Federal Funding**
Atlin Hydro	$ 131,000,000	$ 98,250,000	$ 32,750,000
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Southern Lakes Transmission Project Phase 1-2 (Whitehorse to Moon Lake)	$ 108,000,000	$ 81,000,000	$ 27,000,000
TOTAL PORTFOLIO:	**$ 519,000,000**	**$ 389,250,000**	**$ 129,750,000**

D.4 Low Case Portfolio

Table D7: Low Case Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	**35**	**35**
TOTAL:	**63.9**	**62.1**

Table D8: Low Case Capital Costs[1] Detail 2020-2030

Cost Component	**Capital Cost (2019$)**	**Federal Funding (2019$)**	**Total Cost with Federal Funding**
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Southern Lakes Transmission Project Phase 1-2 (Whitehorse to Moon Lake)	$ 108,000,000	$ 81,000,000	$ 27,000,000
TOTAL PORTFOLIO:	**$ 388,000,000**	**$ 291,000,000**	**$ 97,000,000**

Appendix E:
Knight Piesold Hydro Options Report

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VA103-556/6-1

SMALL HYDROELECTRIC PROJECTS SCREENING ASSESSMENT (10 MW – 30 MW)

Rev	Description	Date
0	Issued in Final	November 25, 2019

Knight Piésold CONSULTING

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

EXECUTIVE SUMMARY

Yukon Energy Corporation (YEC) engaged Knight Piésold Ltd. (KP) to update and further develop a desktop review of the potential hydroelectric projects in the Yukon and northern British Columbia. This study builds upon KP's 2016 *Small Hydroelectric Projects Screening Assessment,* the Midgard Consulting Inc.'s 2015 *Yukon Next Generation Hydro and Transmission Viability Study - Site Screening Inventory*, and other historic studies. The objectives of the study were to compile a regional assessment of hydropower development sites with installed capacities between 10 MW and 30 MW.

Part I: Screening Assessment

KP completed a screening assessment to progressively eliminate less attractive sites and focus in on the best potential hydroelectric development options. The steps taken in the screening process were:

1. Compilation of a list of 147 sites and alternatives previously considered by Midgard and KP. A handful of additional sites were added for consideration based on proximity to transmission lines and perceived generating potential; however, the review of additional sites should not be considered exhaustive.
2. Screen 1 – Coarse Screening: Projects were grouped by which transmission branch they could be connected to. This included all existing transmission lines in the Yukon as well as a number of proposed lines. With the sites organized, a four-part high-level screen was initiated to eliminate sites that were:
   - Below a 10 MW threshold, or projects not believed to be practical at a 10 MW installed capacity
   - Too distant from transmission (in excess of 50 km from a proposed or existing line)
   - Located in parks (except for Primrose and Tutshi Windy Arm)
   - Affecting the Yukon River or known to flood communities

Sites passing all four of the above criteria, and those sites that were indeterminate on a cursory review, were advanced to Screen 2. A total of 56 sites were advanced.

1. Screen 2 – Quantitative Assessment: KP completed a number of high-level analyses to develop a better understanding of the sites and their hydropower potential. The activities completed in Screen 2 were:
   - Locating sites to best utilize available topographic relief and determining catchment areas
   - Developing conceptual layouts, including intake and powerhouse locations, dam and water conveyance alignments, etc.
   - Reviewing regional hydrological data to establish site-specific estimates for Mean Annual Discharge (MAD) and the seasonal distribution of flow
   - Estimating installed capacity and energy generation profiles
   - Developing indicative capital cost estimates
   - Developing estimates for Levelized Cost of Capacity (LCOC) and Levelized Cost of Energy (LCOE)

Certain sites appeared to have two or more configuration options. KP reviewed these alternatives at a high-level and selected the best option for presentation in this study. In some instances, a run of river and storage option have both been presented.

1. Screen 3 – Final Screening and Selection of Preferred Sites: the results of Screen 2 were presented to YEC for final consideration and selection of the preferred sites. The final screening criteria were applied as follows:
   - Elimination of those sites associated with the proposed Beaver Creek-Hanes Junction and Faro-Watson Lake transmission lines

- Elimination of sites with dams on major rivers due to social risk and high temporary works construction costs
- Elimination of sites with LCOE values exceeding $0.35/kWh

The preferred sites were determined to be Primrose (storage), Drury (storage), Tutshi-Windy Arm (storage), Wolf (as run of river and storage), and Atlin (storage).

Part II: Concept Development for Preferred Sites

KP completed a closer evaluation of the preferred sites to build upon the quantitative results of the screening process and to provide YEC with the basis for planning future studies for these sites. The table below summarizes the key financial and technical attributes for the five preferred sites.

Further evaluations of the preferred sites are recommended to improve the understanding of engineering, economic, environmental, and social factors impacting project development. The first steps would involve discussions with affected First Nations, acquisition of accurate topography to validate elevations, and the initiation of hydrology studies. Should such evaluations indicate that there are no critical barriers to project development, further evaluation of the sites through pre-feasibility and feasibility studies should be pursued to prove economic viability.

Knight Piésold CONSULTING

TABLE 0.1

YUKON ENERGY CORPORATION
HYDROPOWER POTENTIAL ASSESSMENT (10MW-30MW)

PREFERRED SITES
SUMMARY

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DESCRIPTION	Primrose	Drury	Tutshi	Atlin	Wolf	Wolf River & Lake
Installed Capacity (MW)	12.7	10.0	10.0	8.0	11.2	30.0
Dependable Winter Capacity (MW) based on 2 weeks of Winter Production	12.7	10.0	10.0	6.0	4.0	30.0
Average Annual Energy (GWh) x 95% for outages and transmission losses	74.0	30.6	49.3	45.0	79.7	229.5
Average Dec-Mar Energy (GWh) x 95% for outages and transmission losses	33.0	24.9	27.1	20.8	20.1	79.0
Unit Cost of Capacity (M$/MW)	14.0	11.1	16.7	16.4	14.7	15.3
Unit Cost of Energy (M$/GWh)	2.40	3.61	3.39	2.91	2.07	2.00
Levelized Cost of Capacity ($/kW-yr) @4.82%	1,342	673	1,291	1,426	1,780	1,764
Levelized Cost of Energy ($/kWh) @4.82%	0.184	0.277	0.256	0.222	0.160	0.154
Levelized Cost of Winter Energy ($/MWh) @4.82% and 0.19 $/kWh for Non Winter Energy	0.177	0.296	0.311	0.259	0.072	0.086
Project Gross Head (m)	138	100	51	107 and 56	75	100
Design Flow (m^3/s)	11.6	12.7	24.9	7.0	18.8	37.6
MAD (m^3/s)	14.5	4.9	16.2	4.4	75.3	75.3
Design Factor	0.80	2.60	1.55	1.59	0.25	0.50
Dam Height (m)	10	5	5	2.5	-	4
Storable Volume (10^6 m^3)	100	125	265	76	-	350
Water Conveyance Length (m)	4,700	5,200	3,000	4,000	7,400	14,000
Capital Cost Esitmate						
Mod, Demob, Insurance, Bonds, Overheads, Contractor's Profit	$ 29,700,000	$ 18,500,000	$ 27,900,000	$ 1,400,000	$ 27,600,000	$ 57,900,000
Access and Site Preparation	$ 8,000,000	$ 4,600,000	$ 7,900,000	$ 700,000	$ 12,000,000	$ 23,000,000
Intake, Forebay, and Headrace	$ 6,500,000	$ 6,800,000	$ 12,500,000	$ 1,100,000	$ 10,000,000	$ 25,000,000
Water Conveyance System	$ 25,000,000	$ 30,000,000	$ 32,900,000	$ 30,200,000	$ 39,700,000	$ 90,000,000
Powerhouse and Ancilary Services	$ 6,000,000	$ 5,900,000	$ 8,700,000	$ 12,700,000	$ 7,400,000	$ 13,500,000
Power Generation Equipment (Water to Wire)	$ 8,900,000	$ 7,100,000	$ 7,100,000	$ 9,800,000	$ 7,900,000	$ 20,000,000
Switchyward, Transmission and Interconnection	$ 29,500,000	$ 2,700,000	$ 20,200,000	$ 27,100,000	$ 15,000,000	$ 18,000,000
Dams and Reservoirs	$ 15,000,000	$ 4,500,000	$ 3,800,000	$ 1,600,000	$ -	$ 3,500,000
Upgrades to Grid (138 kV 150 km Teslin to Whitehorse)					$ -	$ 82,500,000
SUB-TOTAL	**$ 128,600,000**	**$ 80,100,000**	**$ 121,000,000**	**$ 84,600,000**	**$ 119,600,000**	**$ 333,400,000**
EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 10,300,000	$ 6,400,000	$ 9,700,000	$ 20,300,000	$ 9,600,000	$ 26,700,000
CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 38,600,000	$ 24,000,000	$ 36,300,000	$ 26,100,000	$ 35,900,000	$ 100,000,000
TOTAL ESTIMATED CAPITAL COST	**$ 177,500,000**	**$ 110,500,000**	**$ 167,000,000**	**$ 131,000,000**	**$ 165,100,000**	**$ 460,100,000**

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NOTES:
1. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. DOES NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.
5. ATLIN COSTS ARE BASED COSTS REPORTED BY MORRISON HERSFIELD 2016 ESCALATED AT 2.5%.

0	25NOV19	ISSUED WITH REPORT VA103-556/6-1	BXF	SDR
REV	DATE	DESCRIPTION	PREP'D	CHK'D

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APPENDICES

Appendix A	Historical Documents and Hydropower Project Sites
Appendix B	Site Descriptions

ABBREVIATIONS

C .... loaded capital cost
CFRD .... Concrete Faced Rockfill Dam
DFO .... Fisheries and Oceans Canada
EPCM .... Engineering, Procurement and Construction Management
GWh .... gigawatt hour
IFR .... Instream Flow Requirement
km .... kilometre
KP .... Knight Piésold Ltd.
LC .... levelized capital cost per year
LCOC .... Levelized Cost of Capacityl=
LCOE .... Levelized Cost of Energy
m .... metre
masl .... metre above sea level
m^3 .... cubic metre
Mm^3 .... million cubic metre
m^3/s .... cubic metre per second
MAD .... Mean Annual Discharge
MAUD .... Mean Annual Unit Discharge
MW .... megawatt
MWh .... megawatt hour
Q_d .... design flow
WSC .... Water Survey of Canada
YDC .... Yukon Development Corporation
YEC .... Yukon Energy Corporation
YECL .... Yukon Electrical Company Ltd.
yr .... year

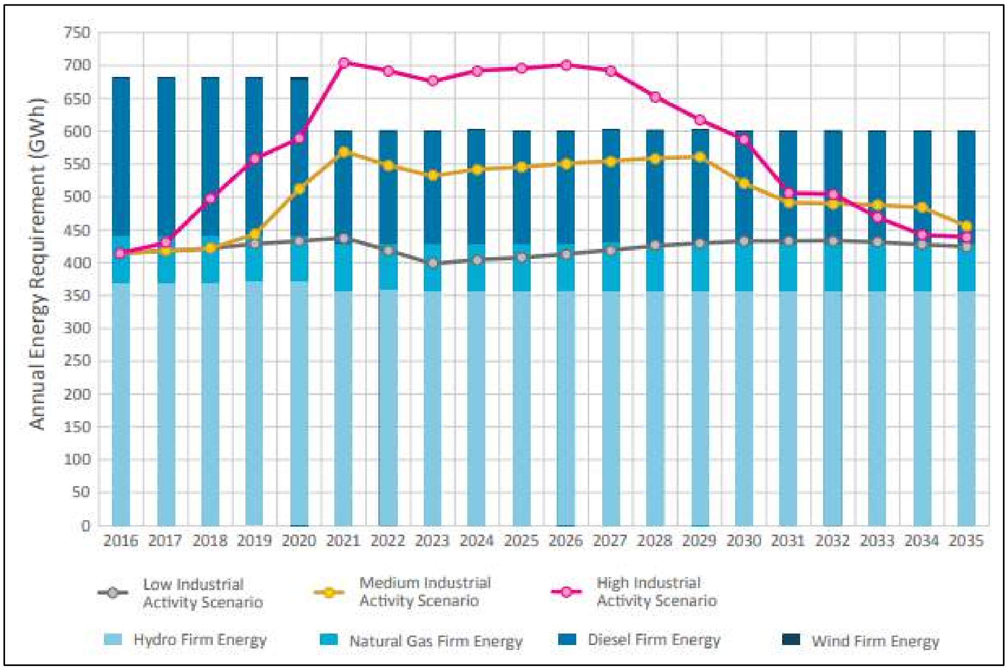
1.0 BACKGROUND

1.1 RESOURCE PLANNING

Yukon Energy Corporation (YEC) and the Yukon government work to ensure that the Yukon's electrical energy needs are met now and in the future, and that future generations can enjoy an energy legacy similar to that provided by the current hydro generation of Whitehorse, Aishihik, Mayo and Fish Lake.

In 2013, the Yukon government issued the Yukon Hydroelectric Power Planning Directive to Yukon Development Corporation (YDC). The directive tasked YDC to plan one or more hydroelectric projects to ensure an adequate and affordable supply of reliable and sustainable electrical power was available in the Yukon.

The 2016 Yukon Energy Resource Plan outlined the energy options that YEC would like to discuss further with the Yukon government, First Nations, stakeholders and the Yukon public. The energy options include small hydro as potential sources of energy to meet future growth. YEC included an investigation of small hydro in its work plan while they monitor how the Yukon load grows over time. Figure 1.1 presents the forecasted energy needs in the Yukon.



NOTES:

1. SOURCE: YUKON ENERGY'S 2016 RESOURCE PLAN (JUNE 2017).

Figure 1.1 Yukon Projected Annual Energy Requirement

The Yukon 2016 Resource Plan states that legally barred and unviable resource options include:

- Generation or transmission options that are located in protected areas or interim protected areas, such as inside a National Park, or projects that would inundate land within a National Park.
- Hydroelectric projects that inundate titled property or a private residence, except for the hydro storage enhancement of existing YEC facilities.
- Projects in remote locations, far from the Yukon transmission grid. The servicing of remote communities is not the focus of the Resource Plan and is covered in specific community planning processes.
- Generation options exceeding 50 MW of installed capacity. Given the YEC demand requirements of the reasonably foreseeable future, and the isolated nature of the Yukon grid, a project beyond this size would exceed domestic requirements, with no ability to sell the surplus.

1.2 ENGAGEMENT

YEC commissioned Knight Piésold Ltd. (KP) in 2019 to update and further develop a desktop review of potential small hydroelectric projects in the Yukon and northern British Columbia. The objectives of the study were to compare technical and economic development criteria and to systematically screen and shortlist development options to provide YEC with the basis to plan future studies on the most attractive sites.

This study is a regional assessment of hydropower development options with capacities between 10 MW and 30 MW, and with estimated transmission line interconnection distances not exceeding 50 km. It builds on KP's 2016 *Small Hydroelectric Projects Screening Assessment*, Midgard Consulting Inc.'s 2015 *Yukon Next Generation Hydro and Transmission Viability Study – Site Screening Inventory*, and other historic studies. It includes a review of all sites previously presented in the 2016 KP study, 2015 Midgard study, and a number of additional sites identified by KP with perceived hydroelectric development potential.

1.3 STUDY LIMITATIONS

The current study is high-level and is based on relatively coarse mapping and hydrology datasets. As such, all results are indicative only and subject to change when better data become available. For example, the publicly available GIS mapping for the Yukon has a contour interval of 20 to 30 metres, and this is restrictive in terms of the identification and evaluation of low-head development sites and low head dams.

The scope of this study is limited to those sites previously identified in the 2016 KP study, the 2015 Midgard study, and a handful of additional sites identified by KP during the current study. There may be other viable sites that have not been considered during previous studies or identified as additional sites in the current study.

The high-level scope and the large number of sites only allowed for limited consideration of alternative configurations at each site. The optimal hydro site will depend on several factors, including capital costs, desired capacity, transmission constraints, environmental impacts, and social conditions.

Finally, the indicative cost estimating performed relies on very generic procedures for estimating quantities (earthworks, concrete, etc.), power equipment types and costs, and transmission line and access road lengths and costs. The values should only be considered as comparative metrics which are used to focus in on the preferred sites. This simplicity is necessary to conduct this type of high-level study, but it may also lead to oversights in terrain hazards, foundation conditions, or other technical challenges that may affect project costs/viability.

2.0 BACKGROUND INFORMATION

2.1 YUKON POWER GRID

YEC provides the power needs for more than 15,000 customers across the Yukon Territory. The Yukon electricity network is an isolated grid, with no connection to other jurisdictions (i.e. BC, Alaska or Northwest Territory). The Yukon grid currently services all Yukon communities except for Watson Lake, Burwash Landing/Destruction Bay, Beaver Creek, and Old Crow.

2.1.1 CURRENT CAPACITY

YEC currently owns and operates approximately 131 MW of installed capacity, consisting of 92 MW of hydro, 0.8 MW of wind, and 37.8 MW of thermal (diesel and natural gas). Yukon Electrical Company Ltd. (YECL), owned by ATCO, supplies approximately 1.3 MW of hydroelectricity and 6.8 MW of diesel power.

YEC's hydroelectric generating capacity is comprised of:

- 37 MW Aishihik Generating Station, 150 km west of Whitehorse
- 15 MW Mayo Generating Station, 450 km north of Whitehorse
- 40 MW Whitehorse Generating Station, located on the Yukon River at Whitehorse
- 1.3 MW Fish Lake Generating Station (YECL)

2.1.2 EXISTING TRANSMISSION LINES

The Yukon power grid is shown on Figure 2.1 and comprises the following major components:

- 138 kV Whitehorse / Aishihik / Faro (WAF) grid
- 69 kV Mayo / Dawson transmission line
- 138 kV Carmacks / Stewart transmission line, connecting the WAF grid and the Mayo / Dawson transmission line

2.1.3 PROPOSED TRANSMISSION LINES

The following major transmission line extensions have also been considered by YEC:

- Skagway (AK) to Whitehorse through Carcross (YK) and British Columbia
- Atlin (BC) to Whitehorse
- Beaver Creek to Hanes Junction (alternatively Destruction Bay to Hanes Junction)
- Faro to Watson Lake, to connect Watson Lake to the Yukon grid

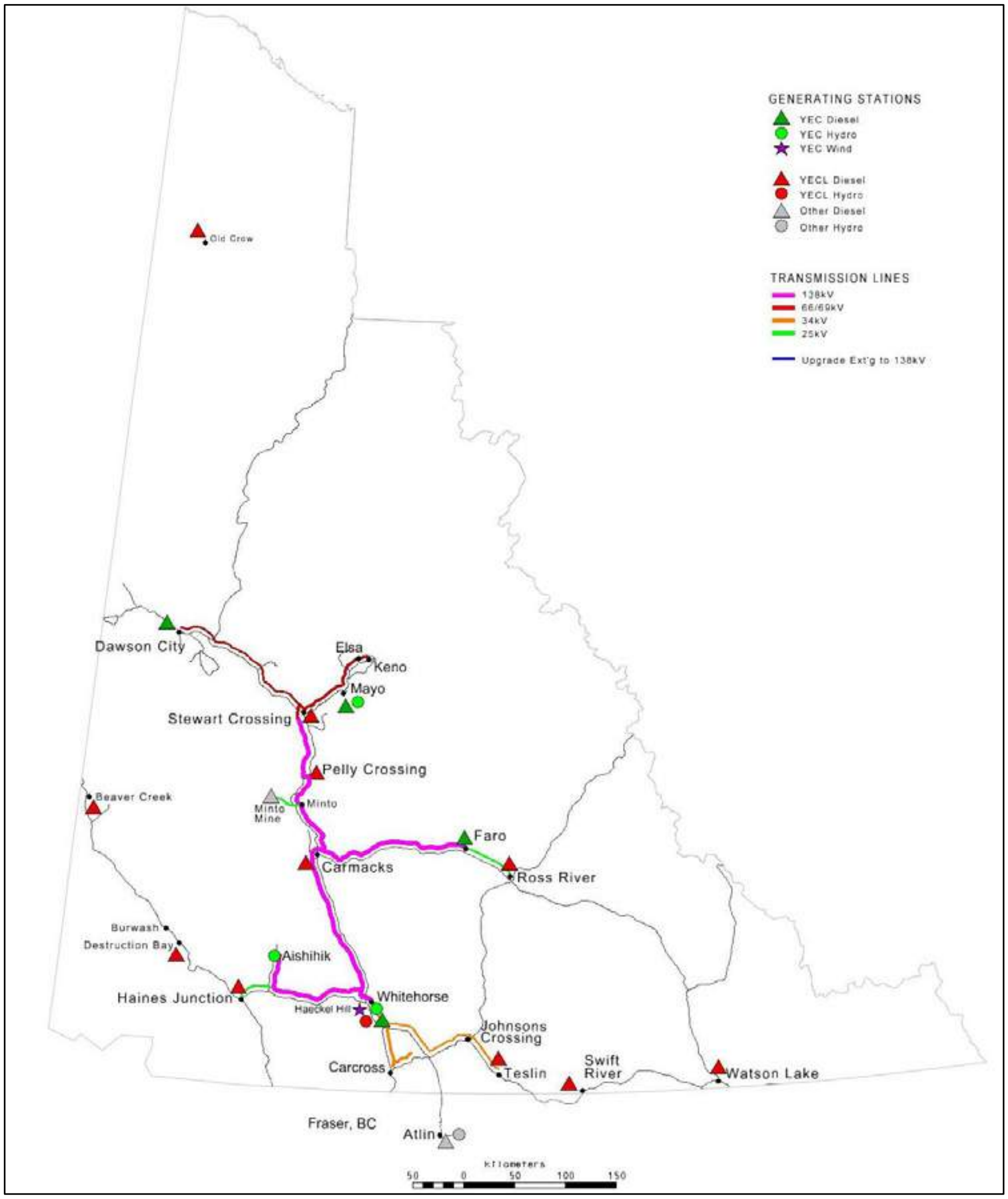


Figure 2.1 Yukon Electricity Network (YEC, 2016)

2.2 OVERVIEW OF HYDROELECTRIC POWER GENERATION

Hydropower is a renewable source of energy with a low carbon footprint. It is a long standing, proven technology that is prevalent worldwide and particularly in regions with high annual precipitation and mountainous terrain.

Conventional hydroelectric power stations can be generally categorized into two types: run of river (RoR) and storage hydro. Storage hydro utilizes water stored behind a dam to generate energy on demand, whereas RoR hydro utilizes the available flows in a river/stream and does not significantly alter natural hydrologic conditions. RoR and Storage hydro are further defined in the sections to follow.

2.2.1 RUN OF RIVER HYDRO

RoR hydroelectric plants utilize the available flow in a river at any given time, with minimal upstream headpond / reservoir live storage. Water is typically diverted at a weir into a water conveyance system (canal, tunnel, and/or penstock), to a powerhouse, and then back into the natural river channel. Very little alteration is made to the natural hydrograph downstream of a run of river project. A conceptual layout of a run of river hydro scheme is provided in Figure 2.2 below.

Electric output is a function of short term (hourly or daily) river discharge, varying daily and seasonally in parallel with the river discharge hydrograph. In the Yukon, run of river generating potential occurs predominantly from May until August, during spring freshet and summer glacial melt.

For the Purpose of this study the run of river projects have been broken down into two categories:

- *"High Head Run of River"* where the projects will divert water away from the main river course, reducing the flow in a portion of the river (i.e. the diversion reach), and then returning the flow to the natural watercourse downstream of the rapids/waterfalls. The project head is generally generated by the natural topographical drop in elevation in the stream over the diversion reach.
- "*Low Head Run of River*" where the project head will principally be generated by the height of the dam/weir in the mainstem of the river. These projects will typically need to handle large flows to generate the required power (i.e. greater than10 MW for the current study). The reservoirs created for these types of dams are not utilized to store the water for electrical generation at select times, but to create the head for power generation. They still operate as run of river facilities utilizing the naturally available flow in the river at any given time.

2.2.2 STORAGE HYDRO

Storage hydroelectric plants utilize an upstream lake or reservoir to store water and to control the outflow and energy output on a daily, monthly, or seasonal basis. This allows for load shaping and winter generation, a times when a run of river hydroelectric facility might not be able to generate a significant amount of energy. A conceptual layout of a storage hydro scheme is provided in Figure 2.2 below.

Storage hydropower configurations vary, from lake/reservoir-controlled High Head RoR style projects, to large dams with built-in generating units where all elevation head is derived from the dam itself, to a combination of both.

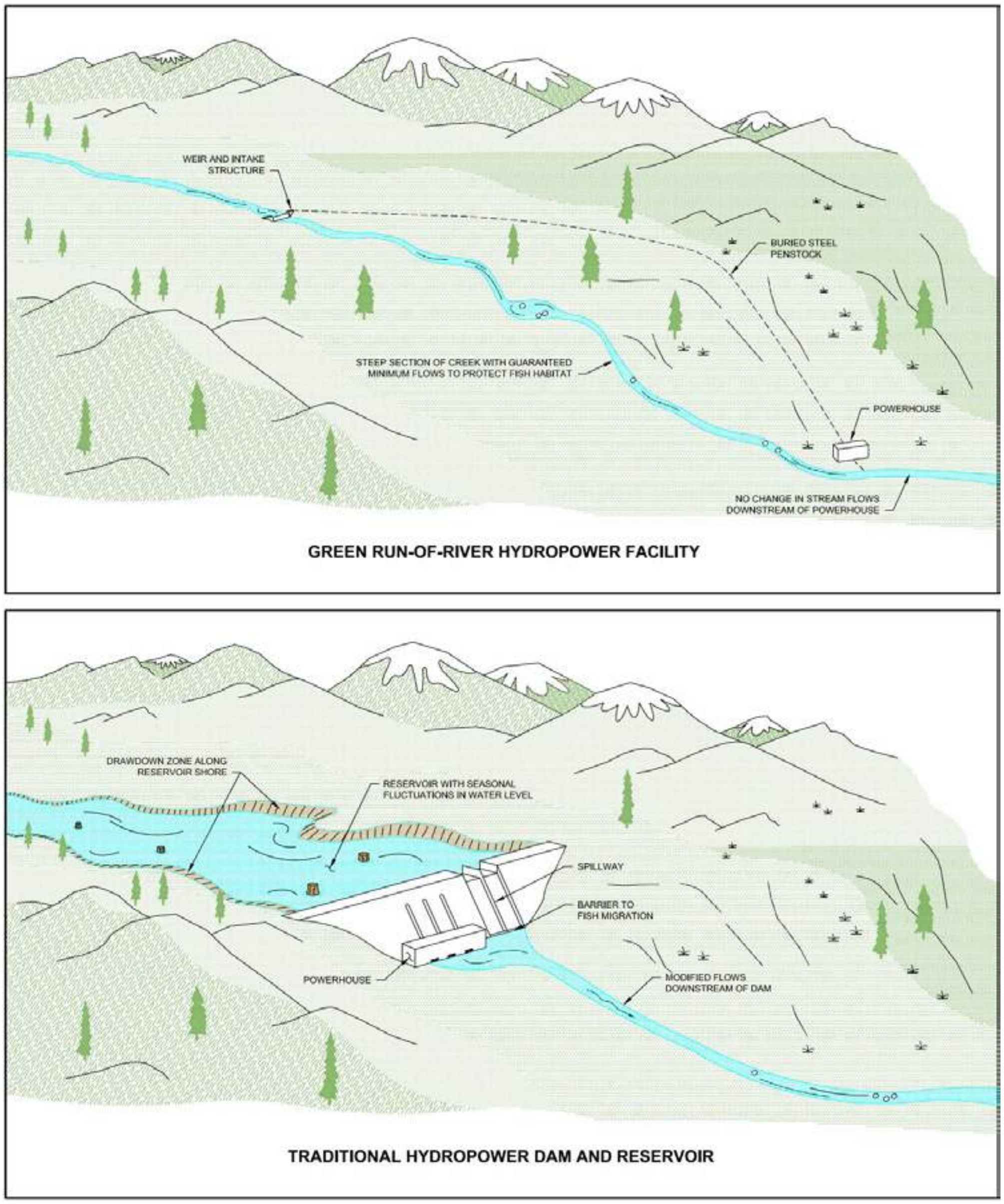


Figure 2.2 Conceptual Hydropower Project Layouts

3.0 SITES AND SCREENING METHODOLOGY

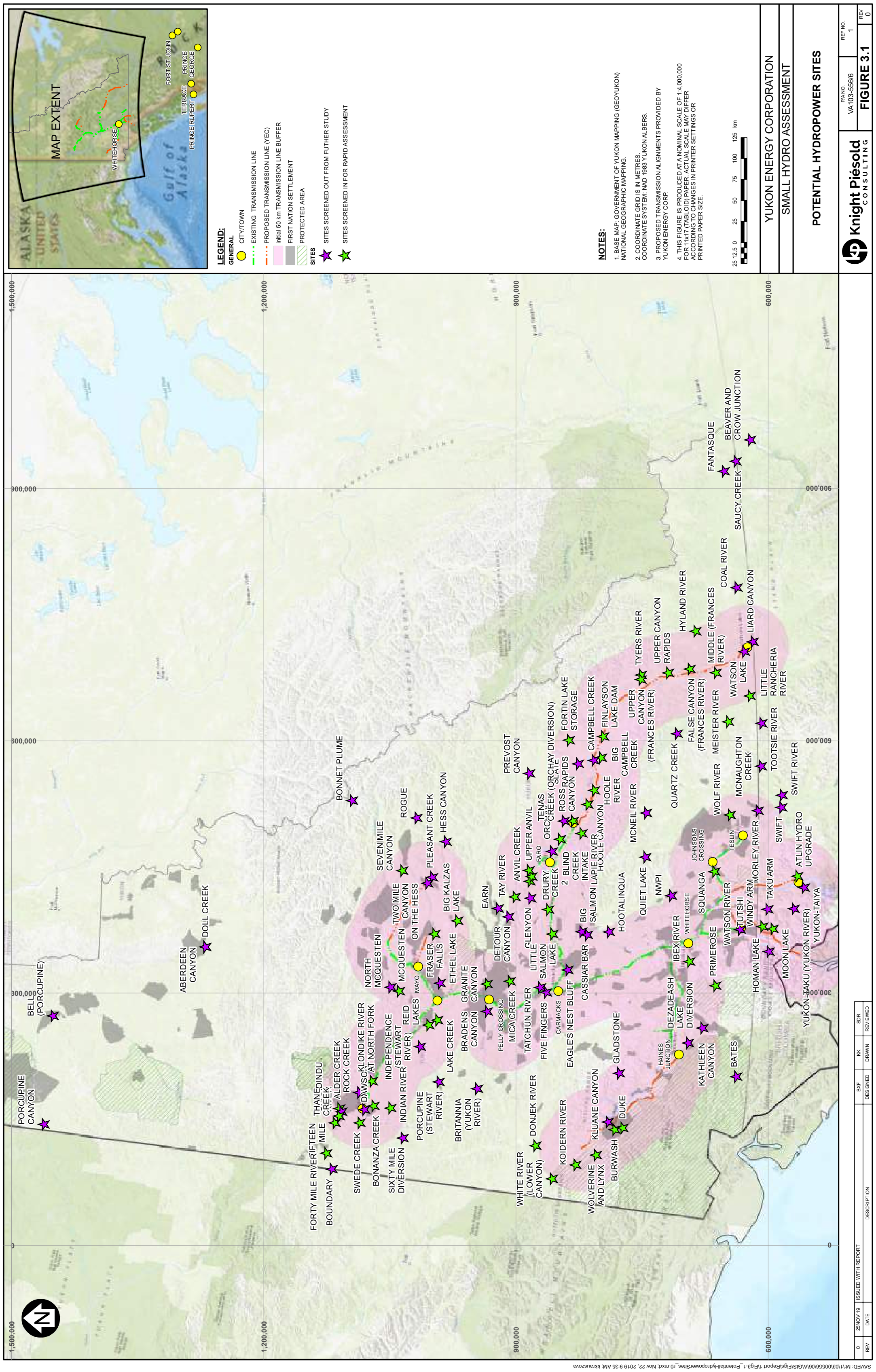
3.1 SITE LIST

KP compiled a list of 147 sites for preliminary review, comprised of the amalgamated set of sites previously considered in the 2016 KP study and 2015 Midgard study, and a number of additional sites which were identified with perceived hydroelectric development potential in close proximity to transmission lines.

Figure 3.1 shows a map of the Yukon with all sites identified. Table 3.1 provides an alphabetical list of sites.

Table 3.1 Site List

Aberdeen Canyon	Fifteen Mile	Lower Canyon on White River	Ross Canyon
Alder Creek	Finlayson	Lynx and Wolverine	Saucy Creek
Anvil Creek	Five Fingers High (150 MW) (Yukon River)	McNaughton Creek	Seven Mile Canyon
Atlin Storage (Yukon River)	Five Fingers High (455 MW) (Yukon River)	McNeil	Site 124
Bates Canyon	Five Fingers Low (75 MW) (Yukon River)	McQuestin	Site 127
Bates Canyon + Dezadeash Diversion	Fortin Lake	Meister River	Sixty Mile River Diversion
Beaver Crow	Forty Mile River	Mica Creek	Slate Rapids (Diversion Scheme)
Bell	Frances River (Lower Canyon)	Middle Canyon (38 MW Version)	Slate Rapids (Powerhouse in Main Dam)
Big Campbell Creek	Frances River (Middle)	Middle Site	Squanga Creek
Big Kalzas Lake	Frances River (Upper Canyon Large)	Moon Lake + Tutshi River Outlet Site A Cluster	Surprise Lake
Big Salmon (Yukon River)	Frances River (Upper Canyon)	Moon Lake + Tutshi Windy Arm Outlet Site B Cluster	Swede Creek
Blind Creek	Frances River (Upper Canyon) - At Rapids or at Francis Lake	Moon Lake A	Swift
Bonanza Creek (Grand Forks)	Fraser Falls (High)	Moon Lake B	Swift River
Bonnet Plume	Fraser Falls (Low)	Moon Lake C	Tatshenshini + Dezadeash / Kusawa Diversion
Boundary	Gladstone Diversion	Morley River	Tatshenshini + Dezadeash Diversion
Bradens Canyon	Glenlyon	North Fork Klondike River	Tay River
Bradens Canyon + Fortin Lake Dam	Granite Canyon (Large)	North McQuesten	Tenas Creek (Orchay Diversion)
Britannia (Yukon River)	Granite Canyon (Small)	NWPI (High)	Thane Creek
Burwash	Hess Canyon	NWPI (Low)	Tootsee River
Campbell Creek	Homan Lake	Ogilvie	Tutshi River Outlet Site A (Lake to Lake)
Cassiar Bar (Yukon River)	Hoole Canyon	Orchay	Tutshi River Outlet Site A (Lake to River)
Chandindu River	Hoole Canyon + Fortin Lake Dam	Pleasant Creek	Tutshi River Outlet Site A (River to Lake)
Coal River	Hoole River	Pleasant Creek with Rogue Diversion	Tutshi River Outlet Site A (River to River)
Dawson	Hootalinqua	Porcupine	Tutshi Windy Arm Outlet Site B (East PH)
Detour Canyon	Hyland River	Porcupine Canyon	Tutshi Windy Arm Outlet Site B (West PH)
Detour Canyon + Fortin Lake Dam	Ibex	Prevost Canyon	Two Mile Canyon
Doll Creek	Independence	Primrose Diversion Scheme (To Takhini Lake)	Tyers River
Donjek to White River Diversion	Indian River	Primrose Lake to Takhini Lake Diversion	Upper & Lower Primrose (2008 Layout)
Drury Creek	Kathleen Canyon	Quartz Creek	Upper Canyon on White River
Duke	Kluane Canyon	Quiet Lake Diversion	Watson Lake
Eagle's Nest Bluff (Yukon River) + Rink Rapids (1 PH)	Koidern	Quiet Lake Diversion + Rose River Diversion	Watson River
Eagle's Nest Bluff (Yukon River) + Rink Rapids (2 PH)	Lake Creek Diversion	Rancheria	Wind
Eagle's Nest Bluff (Alone) (Yukon River)	Lapie	Reid Lakes and Lake Creek	Wolf River
Earn	Liard Canyon	Rock Creek	Wolverine (Yukon River)
Ethel Lake	Little Rancheria River	Rogue	Yukon-Taiya
False Canyon (Frances River)	Little Salmon Dam	Rose Creek	Yukon-Taku (Yukon River)
Fantasque	Little Salmon Diversion	Rose Lake to Kusawa Lake Diversion	


MAP EXTENT
LEGEND:
GENERAL
CITY/TOWN
EXISTING TRANSMISSION LINE
PROPOSED TRANSMISSION LINE (YEC)
initial 50 km TRANSMISSION LINE BUFFER
FIRST NATION SETTLEMENT
PROTECTED AREA
SITES
SITES SCREENED OUT FROM FUTHER STUDY
SITES SCREENED IN FOR RAPID ASSESSMENT
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON MAPPING (GEOYUKON) NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 YUKON ALBERS.
3. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
4. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:4,000,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
POTENTIAL HYDROPOWER SITES
Knight Piésold CONSULTING
VA103-556/6
FIGURE 3.1
0
25NOV'19 ISSUED WITH REPORT

3.2 SCREENING METHODOLOGY

The screening assessment involved several steps to identify, evaluate, and focus in on the preferred hydropower development sites. This process was iterative and included YEC reviews and adjustments to the screening logic throughout the study period. The process was comparable to that used in the 2016 KP study but involved some modifications to the general approach to handle the larger number of sites, modified installed capacity range (between 10 MW and 30 MW), and modified transmission line length restrictions (extended to 50 km).

The process was developed to eliminate sites that are indeterminate, fundamentally flawed, and comparatively expensive or technically unviable, with the overriding objective of providing a focus for future studies on the best development options.

The screening process is described in terms of four main stages:

- Screen 1: Coarse Screening
  - KP applied a coarse screen with four parameters to quickly eliminate many of the less attractive sites which did not warrant an in-depth review. Section 4 describes the coarse screening process.
- Screen 2: Quantitative Assessment
  - KP evaluated a number of quantitative metrics for those sites passing Screen 1 in order to further reduce the site list. Section 5 describes the Screen 2 screening process.
- Screen 3: Final Screening Parameters
  - Those sites passing Screen 2 were presented to YEC for review and feedback, and some final screening criteria were requested by YEC. Section 6 describes the Screen 3 process.
- Assessment of Preferred Options (Top 5 Sites)
  - Screen 3 reduced the site list to the final 5 preferred sites warranting a more detailed assessment. Section 7 describes the final 5 sites.

3.3 DATA COMPILATION

Appendix A summarizes all the previously listed sites and project alternatives in relation to a select number of available reports in which these project sites have been mentioned.

A review of YEC data and a search of publicly available mapping data through the Geomatics Yukon web portal was performed (http://www.geomaticsyukon.ca) to confirm that the data used in the study was as current and comprehensive as possible. In comparison to the 2016 KP study:

- No additional topographical information was available
- Transmission line information was unchanged
- First Nation Settlement Lands were included in the mapping

4.0 SCREEN 1: COARSE SCREENING

4.1 PROJECT GROUPINGS

Projects were first grouped according to the likely transmission line segment (either existing or proposed) that would be used for interconnection. This regional approach helped to streamline the data compilation and review process. The transmission line groupings are:

- Cluster 1: Aishihik-Whitehorse 138 kV (Existing)
- Cluster 2: Carmacks-Whitehorse 138 kV (Existing)
- Cluster 3: Carmacks-Faro 138 kV (Existing)
- Cluster 4: Stewart Crossing-Carmacks 138 kV (Existing)
- Cluster 5: Dawson City-Stewart Crossing 69 kV (Existing)
- Cluster 6: Stewart Crossing-Mayo 69 KV (Existing)
- Cluster 7: Mayo Expansion (Proposed)
- Cluster 8: Faro-Watson Lake (Proposed)
- Cluster 9: Beaver Creek-Hanes Junction (Proposed)
- Cluster 10: Whitehorse-Carcross-Jake's Corner-Johnson's Crossing-Teslin 34 kV (Existing)
- Cluster 11: Carcross-Skagway (Proposed)
- Cluster 12: Jake's Corner-Atlin (Proposed)

4.2 SCREENING ASSESSMENT

With the project sites grouped as discussed above, a coarse screening assessment was undertaken to eliminate undesirable sites and allow the more rigorous Screens 2 and 3 to focus on fewer sites. The coarse screen was implemented with four criteria that could be determined on a cursory review:

- 10 MW minimum installed capacity: sites that were unlikely to meet a minimum installed capacity threshold of 10 MW were eliminated.
- 50 km maximum transmission line length: sites more than 50 km from existing or proposed transmission lines were eliminated.
- Parks and protected areas: sites located in parks or restricted areas were eliminated, except for the Primrose and Tutshi Windy Arm sites (on request by YEC).
- Yukon River and communities: sites affecting the Yukon River or known to flood communities were eliminated.

Table 4.1 presents the full list of sites, grouped according to likely interconnection transmission line. Sites which were not eliminated by any of the four coarse screening parameters are shaded in green and represent the 56 sites that advanced to Screen 2. Figure 4.1 shows a map of the Yukon with the sites that advanced to Screen 2.

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TABLE 4.1

YUKON ENERGY CORPORATION
REGIONAL HYDROPOWER ASSESSMENT

COARSE SITE SCREENING (56 of 147)

Print: Nov/Mon/19 09:40:30

Site Name	Capacity Screen	T-Line Screen	Park Screen	Flood & Yukon Screen	Include in Rapid Assessment	Notes:
Cluster 1: Aishihik-Whitehorse 138 kV (1 of 10)						
Bates Canyon	Pass	Fail	Fail	Pass	No	
Bates Canyon + Dezadeash Diversion	Pass	Fail	Fail	Pass	No	
Gladstone Diversion	NA	NA	Pass	Pass	No	Diversion to Aishihik, Could be looked at further
Kathleen Canyon	Fail	Pass	Pass	Pass	No	
Rose Lake to Kusawa Lake Diversion	Pass	Pass	Fail	Pass	No	
Tatshenshini + Dezadeash / Kusawa Diversion	Pass	Pass	Fail	Pass	No	
Tatshenshini + Dezadeash Diversion	Pass	Pass	Fail	Pass	No	
Primrose Diversion Scheme (To Takhini Lake)	Pass	Pass	Pass	Pass	No	
Primrose Lake to Takhini Lake Diversion	Pass	Pass	Pass	Pass	No	
Upper & Lower Primrose (2008 Layout)	Pass	Pass	TBD	Pass	Yes	Protected Area
Cluster 2: Carmacks-Whitehorse 138 kV (1 of 5)						
Hootalinqua	Pass	Pass	Pass	Fail	No	
Ibex	TBD	Pass	Pass	Pass	Yes	
NWPI (High)	Pass	Fail	Pass	Pass	No	
NWPI (Low)	Pass	Fail	Pass	Pass	No	
Swift	NA	Fail	Pass	Pass	No	
Cluster 3: Carmacks-Faro 138 kV (5 of 14)						
Big Salmon (Yukon River)	Pass	Pass	Pass	Fail	No	Yukon River
Cassiar Bar (Yukon River)	Pass	Pass	Pass	Fail	No	Assumed location on Yukon River
Detour Canyon	Pass	Fail	Pass	Pass	No	Large System, A Bit far from TL
Detour Canyon + Fortin Lake Dam	Pass	Fail	Pass	Pass	No	TL at 80
Eagle's Nest Bluff (Yukon River) + Rink Rapids (1 PH)	Pass	Pass	Pass	Fail	No	Yukon River
Eagle's Nest Bluff (Yukon River) + Rink Rapids (2 PH)	Pass	Pass	Pass	Fail	No	Yukon River
Eagle's Nest Bluff (Alone) (Yukon River)	Pass	Pass	Pass	Fail	No	Yukon River
Earn	Fail	Fail	Pass	Pass	No	Lake capacity can increase but a bit far from TL
Little Salmon Diversion	TBD	Pass	Pass	Pass	No	
Anvil Creek	TBD	Pass	Pass	Pass	Yes	Change location of diversion.
Drury Creek	TBD	Pass	Pass	Pass	Yes	Capacity could be increased to meet the requirement.
Glenlyon	TBD	Pass	Pass	Pass	Yes	
Little Salmon Dam	TBD	Pass	Pass	Pass	Yes	Impact to Camping, Fish Presence
Tay River	TBD	Pass	Pass	Pass	Yes	Actual TL > 50 km
Cluster 4: Stewart Crossing - Carmacks 138 kV (4 of 13)						
Bradens Canyon	Pass	Pass	Pass	Fail	No	
Bradens Canyon + Fortin Lake Dam	Pass	Pass	Pass	Fail	No	
Britannia (Yukon River)	Pass	Pass	Pass	Fail	No	
Five Fingers High (150 MW) (Yukon River)	Pass	Pass	Pass	Fail	No	
Five Fingers High (455 MW) (Yukon River)	Pass	Pass	Pass	Fail	No	
Five Fingers Low (75 MW) (Yukon River)	Pass	Pass	Pass	Fail	No	
Porcupine	Pass	Pass	Pass	Fail	No	
Wolverine (Yukon River)	Pass	Pass	Pass	Fail	No	
Granite Canyon (Large)	Fail	Pass	Pass	Pass	No	
Granite Canyon (Small)	Pass	Pass	Pass	Pass	Yes	
Lake Creek Diversion	Pass	Pass	Pass	Pass	Yes	
Reid Lakes and Lake Creek	TBD	Pass	Pass	Pass	Yes	
Mica Creek	Pass	Pass	Pass	Pass	Yes	
Cluster 5: Dawson City - Stewart Crossing 69 kV (10 of 16)						
Boundary	Pass	Fail	Pass	Fail	No	
Dawson	Pass	Pass	Pass	Fail	No	
Independence	Pass	Pass	Pass	Fail	No	
Ogilvie	Pass	Fail	Pass	Fail	No	
Rock Creek	Fail	Pass	Pass	Pass	No	
Sixty Mile River Diversion	Pass	Fail	Pass	Pass	No	
Alder Creek	TBD	Pass	Pass	Pass	Yes	ROR TBD
Bonanza Creek (Grand Forks)	TBD	Pass	Pass	Pass	Yes	ROR TBD
Chandindu River	TBD	Pass	Pass	Pass	Yes	Try ROR
Fifteen Mile	TBD	Pass	Pass	Pass	Yes	ROR TBD
Forty Mile River	Pass	Pass	Pass	Pass	Yes	
Indian River	TBD	Pass	Pass	Pass	Yes	
McQuestin	TBD	Pass	Pass	Pass	Yes	Large System, Cascade
North Fork Klondike River	Pass	Pass	Pass	Pass	Yes	
Swede Creek	TBD	Pass	Pass	Pass	Yes	ROR TBD
Thane Creek	TBD	Pass	Pass	Pass	Yes	ROR TBD
Cluster 6: Stewart Crossing - Mayo 69 kV (0 of 2)						
Ethel Lake	Fail	Pass	Pass	Pass	No	
North McQuesten	Fail	Pass	Pass	Pass	No	
Cluster 7: Proposed Mayo Transmission Expansions (3 of 9)						
Fraser Falls (Low)	Pass	Pass	Fail	Pass	No	Only one version to be investigated
Hess Canyon	Pass	Fail	Pass	Pass	No	
Pleasant Creek	Fail	Pass	Pass	Pass	No	
Pleasant Creek with Rogue Diversion	Pass	Fail	Pass	Pass	No	
Rogue	Pass	Fail	Pass	Pass	No	Far and Isolated
Two Mile Canyon	Pass	Fail	Pass	Pass	No	
Big Kalzas Lake	Pass	Pass	Pass	Pass	Yes	
Fraser Falls (High)	Pass	Pass	TBD	Pass	Yes	Need to move out of Horshoe Slough Habitat Protection Area
Seven Mile Canyon	Pass	Pass	Pass	Pass	Yes	
Cluster 8: Proposed Faro to Watson Lake (21 of 31)						
Frances River (Upper Canyon Large)	Fail	Pass	Pass	Pass	No	
Frances River (Upper Canyon)	TBD	Pass	Pass	Pass	No	
Middle Canyon (38 MW Version)	TBD	Pass	Pass	Pass	No	No Info
Prevost Canyon	Pass	Fail	Pass	Pass	No	
Rancheria	TBD	Fail	Pass	Pass	No	
Rose Creek	TBD	Pass	Pass	Pass	No	
Slate Rapids (Diversion Scheme)	TBD	Pass	Pass	Pass	No	
Tenas Creek (Orchay Diversion)	TBD	Pass	Pass	Pass	No	
Tootsee River	Fail	Fail	Pass	Pass	No	100 km TL
Watson Lake	Fail	Pass	Pass	Pass	No	

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TABLE 4.1

YUKON ENERGY CORPORATION
REGIONAL HYDROPOWER ASSESSMENT

COARSE SITE SCREENING (56 of 147)

Print: Nov/Mon/19 09:40:30

Site Name	Capacity Screen	T-Line Screen	Park Screen	Flood & Yukon Screen	Include in Rapid Assessment	Notes:
Big Campbell Creek	Pass	Pass	Pass	Pass	Yes	
Blind Creek	TBD	Pass	Pass	Pass	Yes	
Campbell Creek	TBD	Pass	Pass	Pass	Yes	Storage Not Possible, ROR, Mixed with Big Campbell
False Canyon (Frances River)	Pass	Pass	Pass	Pass	Yes	Frances River System
Finlayson	Pass	Pass	Pass	Pass	Yes	
Fortin Lake	TBD	TBD	Pass	Pass	Yes	
Frances River (Lower Canyon)	Pass	Pass	Pass	Pass	Yes	
Frances River (Middle)	Pass	Pass	Pass	Pass	Yes	
Frances River (Upper Canyon)	Pass	Pass	Pass	Pass	Yes	At Rapids or at Francis Lake
Hoole Canyon	Pass	Pass	Pass	Pass	Yes	
Hoole Canyon + Fortin Lake Dam	Pass	Pass	Pass	Pass	Yes	A bit involved, TBD
Hoole River	Pass	Pass	Pass	Pass	Yes	
Hyland River	TBD	TBD	Pass	Pass	Yes	
Lapie	Pass	Pass	Pass	Pass	Yes	Push intake uphill.
Liard Canyon	Pass	Pass	Pass	Pass	Yes	Deemed Urban Flooding - See Note 1.
Little Rancheria River	Pass	Pass	Pass	Pass	Yes	50 km from Watson, 10 MW ROR
Meister River	TBD	Fail	Pass	Pass	Yes	Site of potential but > 50 km TL
Orchay	TBD	Pass	Pass	Pass	Yes	
Ross Canyon	TBD	Pass	Pass	Pass	Yes	
Slate Rapids (Powerhouse in Main Dam)	Pass	Pass	Pass	Pass	Yes	
Tyers River	TBD	Pass	Pass	Pass	Yes	
Cluster 9: Proposed Beaver Creek to Hanes Junction (6 of 8)						
Kluane Canyon	TBD	Pass	Fail	Pass	No	
Upper Canyon on White River	Pass	Pass	Fail	Pass	No	
Burwash	TBD	Pass	TBD	Pass	Yes	
Donjek to White River Diversion	Pass	Pass	Pass	Pass	Yes	
Duke	TBD	Pass	TBD	Pass	Yes	
Koidern	TBD	Pass	TBD	Pass	Yes	
Lower Canyon on White River	Pass	Pass	Pass	Pass	Yes	
Lynx and Wolverine	TBD	Pass	TBD	Pass	Yes	
Cluster 10: Whitehorse-Carcross-Jake's Corner-Johnson's Crossing-Teslin 34kV (2 of 5)						
Morley River	Fail	Pass	Pass	Pass	No	
Swift River	TBD	Fail	Pass	Pass	No	
Watson River	Fail	Pass	Pass	Pass	No	
Squanga Creek	Pass	Pass	Pass	Pass	Yes	Need to Increase Project Head, longer structure (80-100m)
Wolf River	Pass	Pass	Pass	Pass	Yes	
Cluster 11: Proposed Extension from Carcross to Skagway (2 of 13)						
Homan Lake	Fail	Pass	Pass	Pass	No	Increase Project Head, longer structure (80-100m)
Moon Lake A	Fail	Pass	Pass	Pass	No	
Moon Lake C	Fail	Pass	Pass	Pass	No	
Moon Lake B	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (Lake to Lake)	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (Lake to River)	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (River to Lake)	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (River to River)	Fail	Pass	Pass	Pass	No	
Tutshi Windy Arm Outlet Site B (West PH)	Fail	Pass	Pass	Pass	No	
Yukon-Taiya	Fail	Pass	Pass	Fail	No	
Moon Lake + Tutshi River Outlet Site A Cluster	Pass	Pass	Pass	Pass	Yes	
Moon Lake + Tutshi Windy Arm Outlet Site B Cluster	Pass	Pass	Pass	Pass	Yes	
Tutshi Windy Arm Outlet Site B (East PH)	Pass	Pass	Pass	Pass	No	Will need to increase installed Capacity
Cluster 12: Proposed Extension from Jake's Corner to Atlin (1 of 3)						
Yukon-Taku (Yukon River)	Pass	Pass	Pass	Fail	No	
Surprise Lake	Pass	Pass	Pass	Pass	Yes	
Atlin Storage (Yukon River)	Pass	Pass	Pass	Fail	No	
Projects too far from Transmission (18)						
Aberdeen Canyon		Fail			No	
Beaver Crow		Fail			No	
Bell		Fail			No	
Bonnet Plume		Fail			No	
Coal River		Fail			No	
Doll Creek		Fail			No	
Fantasque		Fail			No	
McNaughton Creek		Fail			No	
McNeil		Fail			No	
Middle Site		Fail			No	
Porcupine Canyon		Fail			No	
Quartz Creek		Fail			No	
Quiet Lake Diversion		Fail			No	
Quiet Lake Diversion + Rose River Diversion		Fail			No	
Saucy Creek		Fail			No	
Site 124		Fail			No	
Site 127		Fail			No	
Wind		Fail			No	

M:\1\03\00556\06\A\Report\1 - Yukon Hydropower Potential Assessment (10-30 MW)\Rev 0\Tables and Figures\[Table 4.1.xlsx]Coarse Screen

NOTES:
1. MAY WARRANT A CLOSER LOOK DUE TO THE PRESENCE OF RAPIDS AND TOPOGRAPHIC INACCURACIES AT THE BOUNDARY BETWEEN THE YUKON AND BC.
2. SITES HIGHLIGHTED GREEN HAVE PASSED THE INITIAL COARSE SITE SCREENING.

0	25NOV'19	ISSUED FOR REPORT VA103-556/6-1	BXF	SDR
REV	DATE	DESCRIPTION	PREP'D	CHK'D

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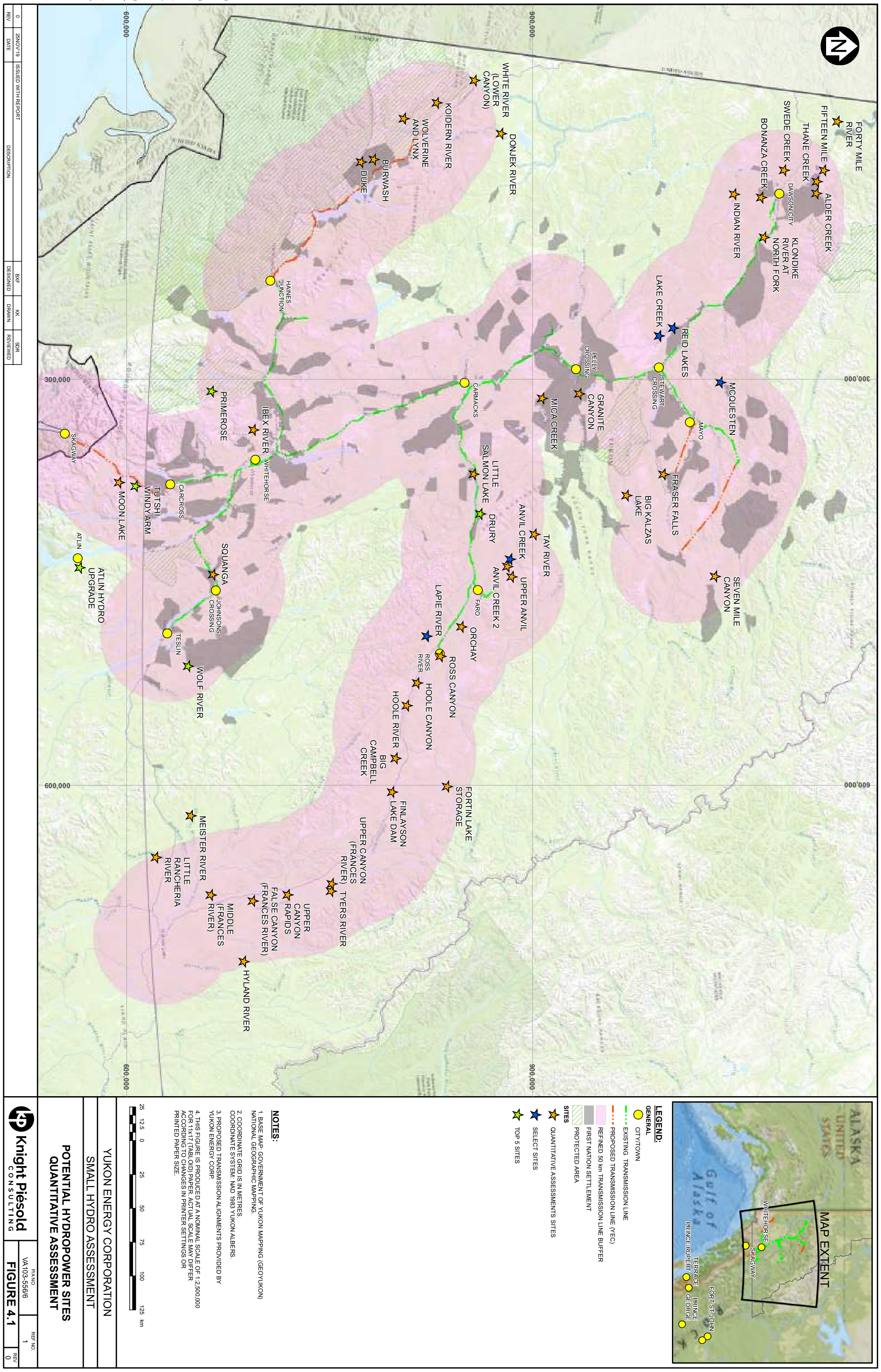


5.0 SCREEN 2: QUANTITATIVE ASSESSMENT

5.1 OVERVIEW

Screen 1 reduced the site list from 147 to 56 sites. Those sites passing Screen 1 were subjected to the Screen 2 process, referred to as the 'Quantitative Assessment'. Screen 2 involved a number of analyses:

- Review of existing information and development of a high-level conceptualization of the projects, including intake and powerhouse location, project head, and potential for reservoir storage.
- Regional hydrological review to develop estimates for Mean Annual Discharge (MAD) and the seasonal distribution of flows.
- Estimation of installed capacity and energy generation profiles.
- Indicative cost estimating.
- Levelized financial comparison, including Levelized Cost of Capacity (LCOC) and Levelized Cost of Energy (LCOE).

The subsequent sections of this report detail the components of the Screen 2 process. A summary of the results can be found in Table 5.2, and details of the review and concept development are presented in Appendix B.

5.2 HYDROLOGY AND DESIGN FLOW ESTIMATES

5.2.1 PREVIOUS ESTIMATES

During the 2016 KP study, flow records were compiled and reviewed from a total of 46 Water Survey of Canada (WSC) gauges with catchment areas between 10 km^2 and 7,000 km^2. This analysis was undertaken to develop an understanding of regional trends in measured runoff for catchments of varying sizes and regions. Monthly average data was used to develop estimates of Mean Annual Discharge (MAD) and Mean Annual Unit Discharge (MAUD) at each stream gauge location. The data were then used to produce generic monthly hydrographs which were scaled and applied to each project site.

1. GAUGES IN YUKON.

Figure 5.1 illustrates the "generic" Yukon hydrographs that were developed. Figure 5.2 illustrates the location of Yukon stream gauges along with indicative unit runoffs.

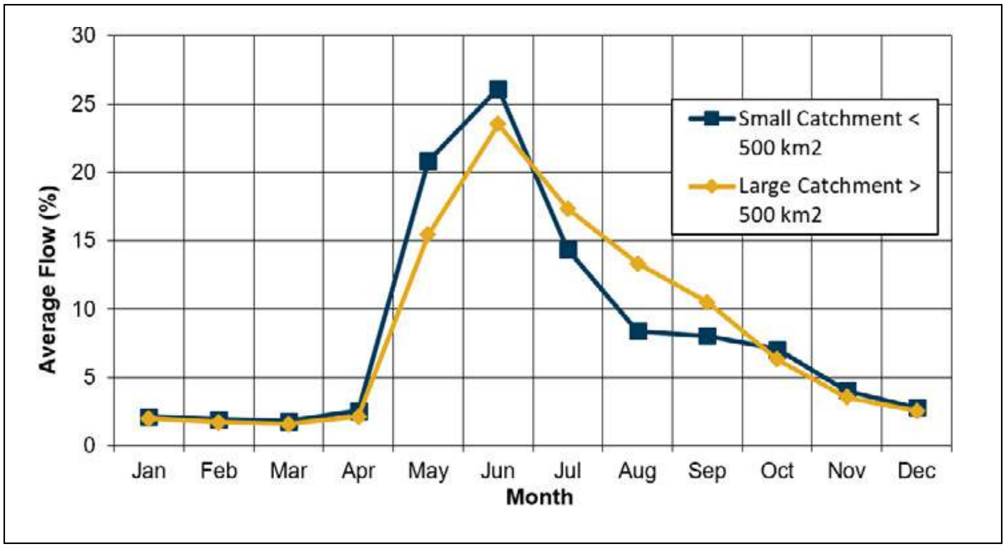
Where no previous hydrology information could be obtained, KP developed estimates based on the MAUD values from the WSC gauges in the region and scaled according to catchment area. These gauges are dispersed across most of the Yukon and provide a reasonable means of assessing hydrologic patterns throughout the region. Some of the basic trends evident in the data are as follows:

- MAUD appears to decrease in a south-westerly direction along the border between the Yukon and the Northwest Territories, with lower unit discharge values evident in the dry, lower relief interior zones versus the mountainous terrain along the eastern provincial border.
- In the south-western corner of the Yukon, MAUD appears to be relatively high due to the onshore movement of moist maritime air from the Pacific Coast. The effects of this moisture influx extend slightly beyond the Coastal Mountain Range, and then drops off markedly due to a 'precipitation shadow' effect that results in a progressive reduction in MAUD moving east.

MAUD values were selected for the project sites based on proximity and similarity of catchment size to the WSC stations. Commonly, there are two to three local gauge stations that provide a basis for estimating unit discharge. Where applicable, consideration was also given to the MAUD values reported for various project sites.

Additional regional considerations when determining a site's MAUD included:

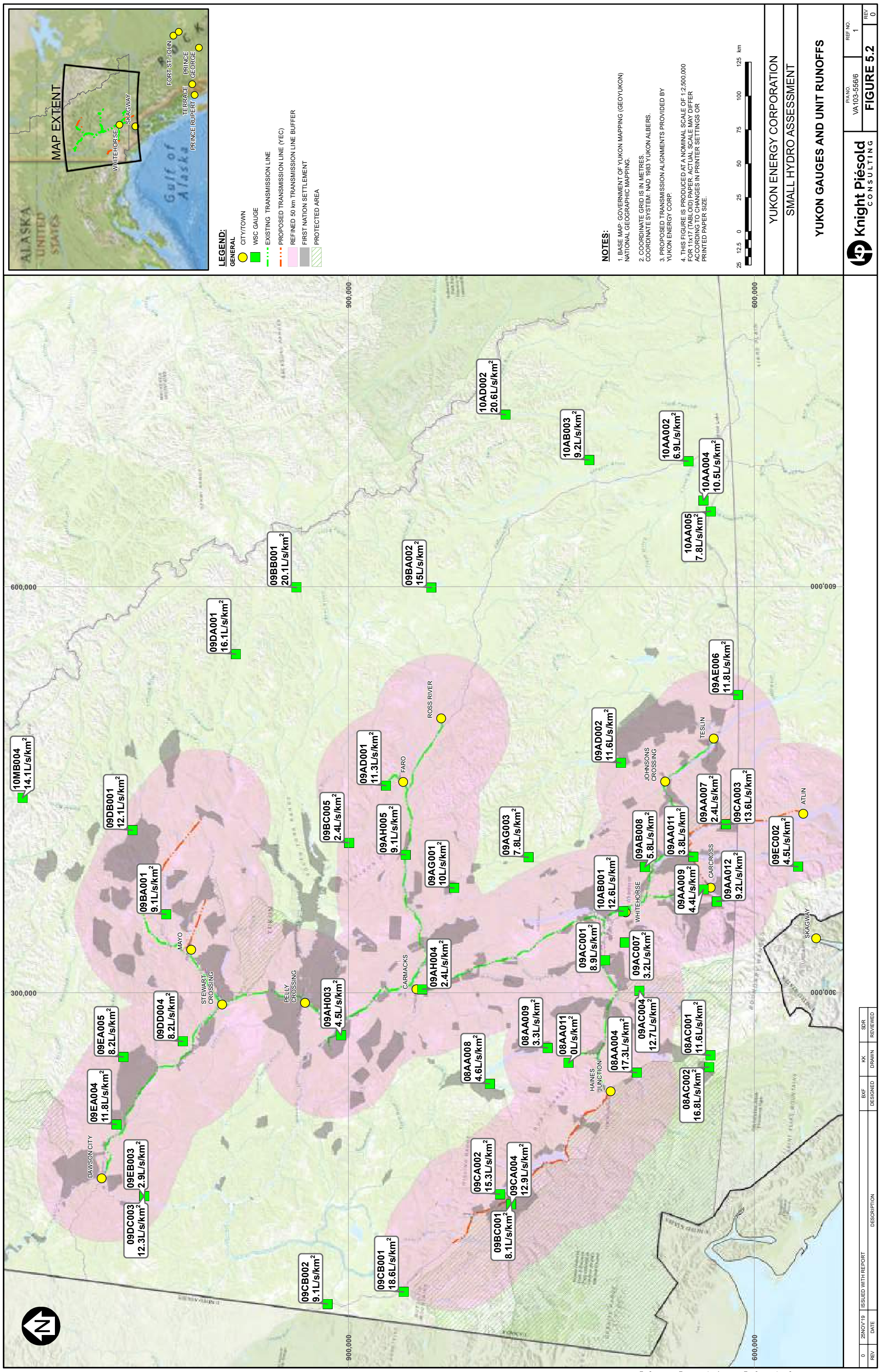
- Glaciers in a watershed, which generally increase MAUD due to melt during the warm summer months
- Lakes in a watershed, which generally decrease MAUD due to greater evaporation
- The local relief, with higher elevation watersheds generally having higher precipitation and correspondingly higher MAUD



NOTES:

2. BASED ON AN EVALUATION OF MONTHLY AVERAGE FLOWS AT 46 WATER SURVEY OF CANADA (WSC) GAUGES IN YUKON.

Figure 5.1 Typical Yukon Hydrograph


MAP EXTENT
LEGEND:
GENERAL
CITY/TOWN
WSC GAUGE
EXISTING TRANSMISSION LINE
PROPOSED TRANSMISSION LINE (YEC)
REFINED 50 km TRANSMISSION LINE BUFFER
FIRST NATION SETTLEMENT
PROTECTED AREA
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON MAPPING (GEOYUKON) NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 YUKON ALBERS.
3. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
YUKON GAUGES AND UNIT RUNOFFS
Knight Piésold CONSULTING
VA103-556/6
FIGURE 5.2

5.2.2 RUN OF RIVER PROJECTS DESIGN FLOW FACTORS AND DESIGN FLOWS

RoR hydroelectric plants utilize the available flow in a river at any given time, with unusable headpond/reservoir storage, and electric output is a function of short-term yield (often evaluated on a daily basis). The optimal installed capacity depends on numerous factors, including constructability, environmental requirements, and the need for and ability to sell seasonal power.

In the previous KP evaluation most of the run-of-river projects evaluated were of the “high-head type”. Based on experience evaluating these types of projects KP made the assumption that the optimal design flow for a run of river plant tends to be in the order of 1.5 to 2 times the MAD value. In contrast KP targeted a design factor 0.5 times MAD for “low-head” storage type projects on large river systems.

In the current evaluation the study aims to target a specific range of capacity and needed the ability to evaluate run-of-river projects located on large river systems. To accomplish this, curves were developed based on a set of assumptions that showed the exchange of capacity factor as a function of the design flow factor. The design flow for the plant is equal to the design factor times the average annual flow. To develop these curves, daily stream flow data for various streams were downloaded from the WSC, with years having incomplete daily records removed. An energy model was then built for a single unit meter of head based on the following assumptions:

- In-stream Flow Requirements (IFR) equal to 5 percent of MAD
- A minimum turbinable flow of 5% of the design flow
- 10 percent head losses through intake and conveyance to the turbine, at maximum design flow, and an exponential decrease in head loss with decreasing flow
- Average efficiency of 90 percent from turbine to the point of sale, to account for turbine – generator losses, transformer losses, transmission losses, station usage, and outages

For a given design flow factor and project head, the resulting design flow, power and energy can be calculated (see Figure 5.3).

To further assess the winter capacity a similar set of curves was developed, combining the energy generated in the months of December, January, February, and March (see Figure 5.4).

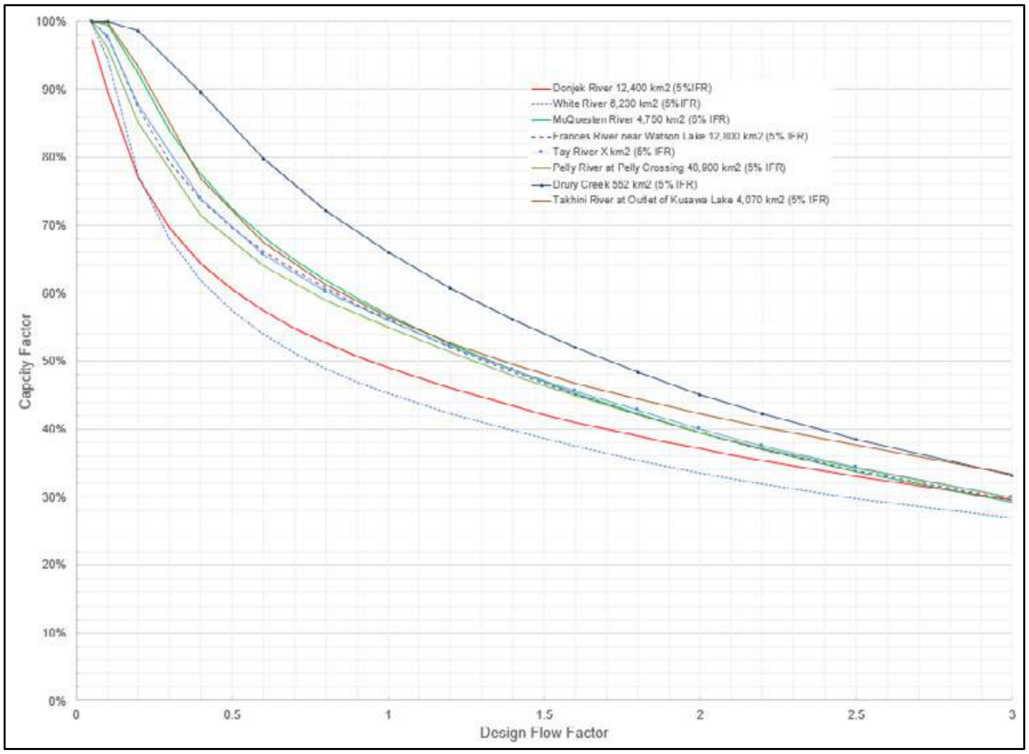


Figure 5.3 Run of River Based Capacity Factors resulting from Design Flow Factors

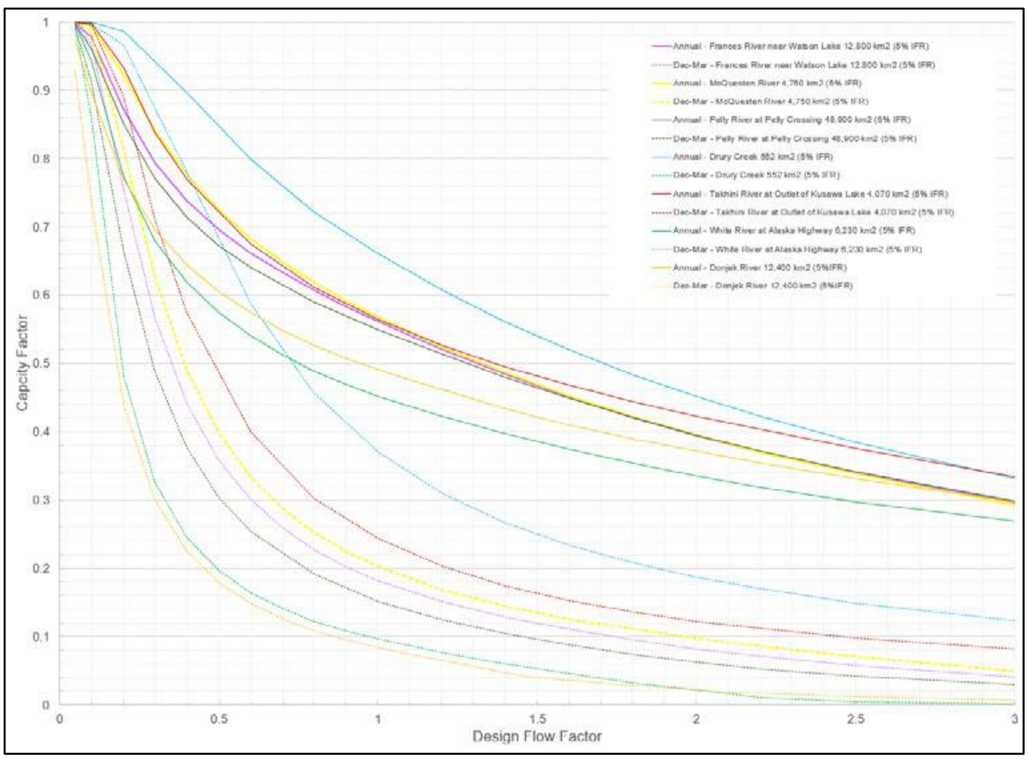


Figure 5.4 Run of River Based Winter Capacity Factors resulting from Design Flow Factors

5.2.3 STORAGE PROJECTS DESIGN FLOW FACTORS AND DESIGN FLOWS

Estimating the design flow factor to be applied in energy modeling for a storage hydroelectric project is inherently more complex than for run-of-river analyses. These complexities lie in the regulation of flows due to the ability to store some volume of water for generation. Individual daily storage regulation models were developed for storage sites making the following assumptions:

- Daily inflows were typically prorated from the nearest stream to the proper unit runoff and drainage area (See Table 5.1).
- Depth capacity curves were assumed to be linear between available topographic contours. This was deemed to be acceptable as, in most instances, the reservoir elevation variations were relatively small.
- Release rules assumed a full day release if water was available in the reservoir during the months of December, January, February or March or if the reservoir volume exceeded 90 percent of its capacity.

All other assumptions were identical to the run-of-river model.

Table 5.1 WSC Gauges for Storage Models

Sites	Surrogate Gauge	Complete Record Period
Drury, Big Kalzas, Finlayson, Glenlyon, Reid Lake (Lake Creek)	Drury Creek (09AH005)	1995-2009 and 2016-2017
Fortin	Pelly River at Pelly Crossing (09BC001)	1960-2017
Wolf River	Nisutlin River (09AD001)	1979-1995
Tushi Windy Arm, Primrose	Takhini River (09AC004)	1954,1959-60, 1965-67, 1969-86

5.2.4 DEPENDABLE CAPACITY

YEC requested that all projects shortlisted during this screening process be assessed for Dependable Capacity. Dependable Capacity, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history. Dependable Capacity was only evaluated for the five preferred sites which are discussed in Section 7.

5.3 INDICATIVE COSTS

Basic indicative cost estimates in $2019 were developed for each project using KP's in-house experience and cost estimating database for projects with comparable characteristics. Where the level of detail in the existing design was insufficient to permit an accurate assessment of site-specific conditions, facility layouts and sizes, costs were scaled according to head, flow, installed capacity, and other key project costing metrics. Cost estimates included the following major components:

- Mobilization, Demobilization, Insurance, Bonds, Overheads, and Contractor's Profits
- Access and Site Preparation
- Dam(s) and Reservoir(s) (if any)

- Intake, Forebay, and Headrace
- Water Conveyance System
- Powerhouse and Tailrace and Ancillary Services
- Power Generation Equipment (Water to Wire)
- Switchyard, Transmission, and Interconnection
- Engineering, Procurement, and Construction Management (EPCM): 8 %
- Contingency: 30 %

5.4 COST TO BENEFIT ANALYSIS

The fair evaluation of alternative hydropower development options requires an assessment of project costs and benefits. The cost to benefit assessment was based on the comparative values for the following financial metrics:

- Unit Cost of Capacity (UCC)
- Unit Cost of Energy (UCE)
- Levelized Cost of Capacity (LCOC)
- Levelized Cost of Energy (LCOE)
- Levelized Cost of Winter Energy (LCOWE)

5.4.1 UNIT COST OF CAPACITY

Unit Cost of Capacity = Capital Cost ($) / Installed Capacity (MW)

This unit of measurement can be useful for gauging project costs in relation to other proposed or existing power projects in a simplistic manner. For instance, YEC's Mayo B Hydroelectric Project was constructed for a cost of roughly $120 million and added 10 MW of power to the Yukon's energy system (YEC, 2016), equating to a UCC of $12 million/MW. The LCOC of the better options in this study are in this order of magnitude, providing some confidence in the underlying quantities and unit rates that have been assumed.

While UCC does have its usefulness, it is not a good measure of the overall project value since capacity is not directly correlated to energy production and revenues.

5.4.2 UNIT COST OF ENERGY

Unit Cost of Energy = Capital Cost ($) / Average Annual Energy Production (GWh/yr).

UCE is a simple and useful financial metric for the determination of a project's value and relative ranking of sites with different installed capacities and hydrology characteristics. Provided that all energy can be sold, UCE is directly correlated with revenue.

UCE in the order of $2.5 million/GWh/yr or less are considered to have development potential.

5.4.3 LEVELIZED COST OF CAPACITY

The loaded capital cost, or net present cost at Commercial Operation Date (COD) is accounts interest accrued during construction, using the following formula:

$$LCOC = \frac{levelized\ cost\ of\ capital + annual\ expenditure}{installed\ capacity}$$

The levelized capital cost per year is calculated using the capital recovery factor formula:

$$LC = \frac{rC(1+r)^n}{(1+r)^n - 1}$$

Where:

LC	levelized capital cost per year
C	Capital Cost
O	Operating and maintenance cost (estimated at 2.2% of Capital Costs + $0.005/kWh)
r	discount rate (assumed 4.82%)
n	expected lifetime of plan + construction period (assuming 3 years of construction and a 65-year design life.)

5.4.4 LEVELIZED COST OF ENERGY

In the energy sector, LCOE is often used as a metric for evaluating energy projects because it allows for an "apples-to-apples" comparison of the costs associated with the generation of energy between different energy sources. For instance, there is a desire to be able to fairly compare hydropower projects with high upfront capital costs, and comparably low operations and maintenance costs (i.e. no fuel cost) with, for instance, thermal generation projects with lower upfront capital costs but relatively high operating costs that include fuel consumption.

The hydroelectric LCOE can be compared against the LCOE of a Yukon based thermal generation asset. If the hydroelectric project's LCOE is higher than the thermal generation LCOE, it is deemed uneconomic.

YEC provided the following information to assist in the hydropower screening evaluation:

- Discount rate for net present valuation: 4.82%
- Yukon grid power: $0.19/kWh
- Diesel generation: $0.33/kWh
- Liquified natural gas (LNG): $0.15/kWh

In order to calculate the LCOE an estimate of the capital and operations and maintenance costs is required. The calculation for LCOE is presented below.

$$LCOE = \frac{sum\ of\ costs\ over\ lifetime}{sum\ of\ energy\ produced\ over\ lifetime}$$

$$LCOE = \frac{\sum_{t=0}^{n} \frac{C^t + O^t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

Ct	Capital Cost in year t

Ot	Operating and maintenance cost in year t (estimated at 2.2% of Capital Costs + $0.005/kWh)
Et	Energy Generated in year t (estimated to be the mean annual energy)
r	discount rate (assumed 4.82%)
n	expected lifetime of plan + construction period (assuming 3 years of construction and a 65-year design life.)

5.4.5 LEVELIZED COST OF WINTER ENERGY (LCOWE)

For the purpose of this study the Levelized Cost of Winter Energy (LCOWE) was calculated as follows to compare the winter generation portfolios:

$$LCOWE = \frac{\sum_{t=0}^{n} \frac{C^t + O^t - R^t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{WE_t}{(1+r)^t}}$$

Where:

Ct	Capital Cost in year t
Ot	Operating and maintenance cost in year t (estimated at 2.2% of Capital Costs + $0.005kWh)
Rt	Revenue from non winter energy at the Yukon grid power rate of $0.19/kWh
WEt	Energy Generated in December, January, February and March of year t
r	discount rate (assumed 4.82%)
n	expected lifetime of plan + construction period (assuming 3 years of construction and a 65-year design life.)

5.5 SCREEN 2 RESULTS

The results of the Screen 2 assessment are presented in Table 5.2. Additional information regarding the background review and development of concepts is presented in Appendix B.

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TABLE 5.2

YUKON ENERGY CORPORATION
YUKON REGIONAL POWER ASSESSMENT

HYDROPOWER POTENTIAL ASSESSMENT (10 MW – 30 MW)
QUANTITATIVE ASSESSMENT PROJECT DATA SUMMARY (56 SITES + 5 ALTERNATIVES)

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Project Name	Evaluated as	Intake Elev.	Tailwater El. (TWL)	Gross Head	Conveyance Length	Transmission Line	Unit Runoff	Drainage Area	MAD	Design Factor	Design Flow	Installed Capacity	Dam Height	Average Annual Capacity Factor	Average Annual Energy	Average Dec-Mar Energy	Capital Cost	Capital Cost to Capacity	Capital Cost to Energy	LCOC	LCOE	Screened Out Due to Discovered Low Capacity	Screened Out Due to Cluster Location	Screened Out Due to Perceived Social Risk	Screened Out Due to Cost	Reviewed for Final Selection	Comments
		masl	masl	m	m	km	l/s/km²	km²	m³/s		m³/s	MW	m	%	GWh/a	GWh/a	M$	M$/MW	M$/GWh/a	$/kW - day	$/kWh @ 4.82%						
Cluster 1: Aishihik-Whitehorse 138 kV (1 of 10 +1 Alternative)																											
Primrose River	HH ROR	878	740	138	4,700	39	12.7	1,138	14.5	1.6	23.1	25.4	NA	46%	102.2	10.3	200	7.9	1.89	1,105	0.151					Yes	Barge Access, Protected Area
Primrose River *	**Storage**	**878**	**740**	**138**	**4,700**	**39**	**12.7**	**1138**	**14.5**	**0.8**	**11.6**	**12.7**	**10**	**70%**	**77.7**	**34.7**	**180**	**14.0**	**2.28**	**1,377**	**0.175**					**Yes**	Barge Access, Protected Area
Cluster 2: Carmacks-Whitehorse 138 kV (1 of 5)																											
Ibex River	HH ROR	880	825	55	5,000	20	12.5	323	4.0	2	8.1	3.5	NA	40%	12.4	0.2	110	30.8	8.79	2,220	0.660	X				No	
Cluster 3: Carmacks-Faro 138 kV (5 of 14 +1 Alternative)																											
Anvil Creek	HH ROR	905	625	280	8,000	28	8.0	657	5.3	2.0	10.5	23.4	NA	40%	82.0	4.8	340	14.6	4.15	1,376	0.315					Yes	Tunnel
Drury Creek	HH ROR	720	620	100	5,200	1	9.1	538	4.9	2.6	12.7	10.1	NA	37%	32.8	4.1	100	10.3	3.19	1,074	0.243					Yes	
Drury Creek *	**Storage**	**720**	**620**	**100**	**5,200**	**1**	**9.1**	**538**	**4.9**	**2.6**	**12.7**	**10.1**	**5.0**	**36%**	**31.9**	**26.2**	**115**	**11.1**	**3.53**	**682**	**0.268**					**Yes**	
Glenlyon	Storage	740	610	130	6,650	50	8.5	396	3.4	2.6	8.8	9.0	15.0	37%	29.3	18.4	230	25.5	7.87	1,527	0.592				X	No	
Little Salmon Lake	HH ROR	565	542	23	8,500	1	9.0	2,607	23.5	2.0	46.9	8.6	NA	45%	33.8	4.7	460	53.2	13.50	3,338	1.011	X				No	Recreational Areas
Tay River	HH ROR	663	600	63	10,000	50	2.4	11,443	27.5	1.0	27.5	13.8	NA	56%	67.5	6.5	330	23.6	4.82	2,053	0.364				X	No	
Cluster 4: Stewart Crossing - Carmacks 138 kV (4 of 13)																											
Lake Creek	HH ROR	620	540	80	6,200	18	10	1,015	10.2	2.00	20.3	12.9	NA	40%	45.2	3.8	170	13.4	3.82	1,300	0.289					**Yes**	
Reid Lakes (if Lake Creek)	Storage	540	480	60	3,700	3	10	1,109	11.1	2.00	22.2	10.6	5	45%	41.7	16.3	140	13.5	3.44	1,156	0.261					**Yes**	Can only be developped with Lake Creek
Granite Canyon	LH ROR	510	485	25	200	15	8	46,204	379	0.25	94.7	18.8	25	81%	133.1	31.0	430	22.6	3.19	2,202	0.243			X		No	
Mica Creek	LH ROR	540	500	40	8,000	2	5	1,291	6.5	2	12.91	4.1	20	40%	14.4	1.2	200	48.4	13.81	3,060	1.035	X				No	
Cluster 5: Dawson City - Stewart Crossing 69 kV (10 of 16)																											
Alder Creek	HH ROR	452	402	50	2,800	28	5	236	1.2	2.00	2.4	0.9	NA	38%	3.1	0.1	80	81.7	24.54	4,742	1.834	X				No	
Bonanza Creek (Grand Forks)	HH ROR	450	340	110	8,000	1	6	184	1.1	2.00	2.2	1.9	NA	38%	6.4	0.1	70	34.9	10.49	2,392	0.787	X				No	
Chandindu River	HH ROR	375	320	55	5,000	30	6	1,231	7.4	2.00	14.8	6.5	NA	38%	21.5	0.4	140	22.5	6.74	1,766	0.508	X				No	
Fifteen Mile	HH ROR	457	319	138	21,000	40	6	1,118	6.7	2.00	13.4	14.7	NA	38%	49.0	0.9	450	30.3	9.09	2,159	0.683				X	No	
Forty Mile River	HH ROR	302	287	15	250	50	5	16,600	74.7	0.70	52.3	6.2	25.0	43%	23.5	0.0	260	41.8	11.09	2,834	0.832	X				No	
Indian River	HH ROR	430	400	30	1,000	30	3	2,210	6.6	2.00	13.3	3.2	15.0	45%	12.5	0.2	110	34.6	8.77	2,495	0.659	X				No	
McQuestin	LH ROR	550	480	70	9,000	45	8	3,769	30.9	1.00	30.9	17.2	10.0	56%	84.3	10.0	330	19.1	3.89	1,806	0.295					**Yes**	
North Fork Klondike River	LH ROR	445	430	15	200	1	12	6,581	77.7	1.10	85.4	10.2	15.0	54%	48.2	4.1	220	21.5	4.55	1,927	0.344			X		No	Will affect existing bridge and roads
Swede Creek	HH ROR	440	340	100	11,500	8	4	356	1.4	2.00	2.8	2.3	NA	38%	7.5	0.1	120	51.8	15.55	3,238	1.164	X				No	
Thane Creek	HH ROR	375	325	50	6,000	30	6	217	1.3	2.00	2.6	1.0	NA	38%	3.4	0.1	100	93.7	28.16	5,348	2.104	X				No	
Cluster 7: Proposed Mayo Transmission Expansions (3 of 9)																											
Big Kalzas Lake	Storage	793	700	93	10,000	45	10	690	6.9	2.00	13.8	10.2	15	45%	40.2	5.6	290	28.7	7.28	2,106	0.548				X	No	
Fraser Falls	LH ROR	530	520	10	200	40	12	30,831	376.1	0.40	150.5	12.0	10	67%	70.2	10.1	550	46.1	7.86	3,301	0.591			X		No	Would flood Horseshoe Slough Habitat Protection Area
Seven Mile Canyon	LH ROR	587	567	20	250	37	10	11,609	116.1	0.80	92.9	14.8	23	51%	65.9	7.3	340	23.2	5.18	1,941	0.391				X	No	
Cluster 8: Proposed Faro to Watson Lake (21 of 31 + 2 Alternatives)																											
Big Campbell Creek	HH ROR	980	860	120	10,000	1	9	563	5.1	2.00	10.1	9.7	NA	40%	33.9	2.0	160	16.5	4.70	1,473	0.356		X			No	
Blind Creek	HH ROR	762	670	92	5,400	1	8	274	2.2	2.00	4.4	3.2	NA	40%	11.2	0.7	70	20.5	5.84	1,673	0.440	X				No	
Campbell Creek	HH ROR	922	891	31	6,500	1	9	175	1.6	2.00	3.2	0.8	NA	40%	2.7	0.2	70	93.8	26.77	5,357	2.000	X				No	
False Canyon (Frances River)	LH ROR	707	692	15	200	7	12.6	12,220	154	0.83	127.8	15.2	15	60%	80.1	9.8	330	21.8	4.14	1,997	0.314		X			No	
Finlayson	HH ROR	840	740	100	6,000	3	11	1,542	16.2	1.50	24.3	19.3	NA	45%	76.0	8.4	170	8.7	2.21	1,124	0.170		X			No	
Finlayson with Lakes	Storage	840	740	100	6,000	3	11	1,542	16.2	1.50	24.3	19.3	5	56%	94.5	15.4	210	10.6	2.17	1,634	0.170		X			No	
Finlayson with Lakes	Storage	840	740	100	6,000	3	11	1,542	16.2	0.95	15.4	12.2	5	70%	74.6	15.1	170	13.5	2.21	1,338	0.167		X			No	
Fortin Lake	LH ROR	895	875	20	250	50	15	5,207	75.5	0.85	64.2	10.2	25.0	70%	62.5	21.1	290	28.6	4.66	2,240	0.353		X			No	
Frances River (Lower Canyon)	LH ROR	Unidentified presumed to be False Canyon																				NA	X			No	
Frances River (Middle)	LH ROR	685	665	20	250	6	13	12,800	161	0.58	93.5	14.9	20.0	66%	85.9	13.0	290	19.7	3.41	1,953	0.259		X			No	
Frances River (Upper Canyon)	LH ROR	The topo around Upper Canyon Rapids is not detailed and a tall structure could backwater onto the Highway																					X			No	
Hoole Canyon	LH ROR	770	745	25	200	3	10	10,192	101.9	0.60	61.1	12.1	25.0	58%	61.5	5.9	210	17.6	3.48	1,782	0.265			X		No	Not revised for absence of Ross River to Watson TL
Hoole Canyon with Fortin*	Storage	770	745	2 x 25	2 x 200	3	10	10,192	101.9	0.50	51.0	10.2+6.5	2 x 25	83%	73.7	43.4	450	27.1	3.71	2,294	0.281		X			No	Not revised for absence of Ross River to Watson TL
Hoole River	LH ROR	801	781	20	200	1	10	9,527	95.3	0.80	76.2	12.1	20.0	52%	55.6	3.8	250	20.7	4.51	1,876	0.342			X		No	Not revised for absence of Ross River to Watson TL
Hyland River	LH ROR	740	680	60	8,800	50	12	6,612	79.3	0.55	43.6	20.8	20.0	68%	123.6	19.8	580	27.6	4.66	2,366	0.352				X	No	
Lapie	HH ROR	850	780	70	6,680	7	9	1,277	11.5	2.00	23.0	12.8	NA	40%	44.8	2.6	170	13.3	3.81	1,315	0.289					**Yes**	
Liard Canyon	LH ROR	Structure would affect Watson Lake																					X			No	
Little Rancheria	HH ROR	840	760	80	11,000	56	8	1,539	12.3	2.00	24.6	15.7	NA	35%	48.0	0.9	340	21.9	7.15	1,689	0.538		X			No	
Meister River	HH ROR	900	800	100	11,000	60	11	1,060	11.7	2.00	23.3	18.5	NA	40%	64.9	3.8	340	18.3	5.22	1,564	0.394	X				No	
Orchay	HH ROR	731	653	78	4,900	4	8	582	4.7	2.00	9.3	5.8	NA	40%	20.2	1.7	90	14.9	4.26	1,377	0.322	X				No	
Ross Canyon	LH ROR	705	665	40	500	5	9	7,310	65.8	0.75	49.3	15.7	40.0	55%	75.6	6.8	240	15.2	3.16	1,621	0.240			X		No	
Slate Rapids	LH ROR	Strictly inferior to Fortin Lake																				NA	X			No	
Tyers River	HH ROR	765	725	40	4,700	11	9	1,367	12.3	2.00	24.6	7.8	NA	40%	27.4	1.8	150	19.2	5.47	1,602	0.413	X	X			No	
Cluster 9: Proposed Beaver Creek to Hanes Junction (6 of 8)																											
Donjek River	LH ROR	648	623	25	200	40	14	12,400	168.0	0.45	75.6	15.0	25	62%	81.6	8.7	330	22.2	4.09	2,064	0.310		X			No	
White River	LH ROR	728	703	25	200	1	19	6,230	117.9	0.65	76.7	15.2	25	53%	70.0	6.7	240	15.7	3.40	1,600	0.259		X			No	
Lynx and Wolverine	HH ROR	875	795	80	5,200	1	18	322	5.8	2.00	11.6	7.4	NA	38%	24.5	0.4	100	13.0	3.92	1,293	0.297		X			No	
Koidern	HH ROR	930	790	140	6,300	21	18	652	11.7	1.40	16.4	18.3	NA	40%	64.0	1.1	170	9.1	2.61	1,131	0.199		X			No	
Burwash	HH ROR	1044	849	195	8,000	1	18	126	2.3	2.00	4.5	7.0	NA	35%	21.5	0.4	100	13.9	4.53	1,284	0.342		X			No	
Duke	HH ROR	985	862	123	9,600	1	18	563	10.1	1.40	14.2	13.9	NA	40%	48.6	2.4	180	13.0	3.70	1,302	0.281		X			No	
Cluster 10: Whitehorse-Carcross-Jake's Corner-Johnson's Crossing-Teslin 34kV (2 of 5 + 1 Alternative)																											
Squanga Creek	HH ROR	769	690	79	8,800	1	4	843	3.0	2.00	6.1	3.8	NA	40%	13.3	1.3	100	27.2	7.77	1,985	0.584	X				No	
Wolf River *	**HH ROR**	**805**	**730**	**75**	**7,400**	**20**	**11**	**6,662**	**75.3**	**0.25**	**18.8**	**11.2**	**NA**	**85%**	**83.5**	**21.2**	**200**	**17.6**	**2.37**	**1,979**	**0.182**					**Yes**	
Wolf River with Wolf Lake *	**Storage**	**805**	**705**	**100**	**12,000**	**150+20**	**11**	**6,662**	**75.3**	**0.50**	**37.6**	**29.9**	**4.0**	**92%**	**241.8**	**83.1**	**670**	**22.3**	**2.76**	**2,171**	**0.211**					**Yes**	
Cluster 11: Carcross to Skagway (2 of 13)																											
Moon Lake	Storage	1121	713.2	408	5,300	2	15	57	0.9	2.57	2.2	7.1	30	32%	20.0	19.9	177	24.8	8.85	1,641	0.864	X				No	B.C.
Tutshi Windy Arm *	**Storage**	**707**	**656**	**51**	**3,000**	**1**	**16**	**992**	**16.1**	**1.55**	**24.9**	**10.1**	**5**	**59%**	**52.2**	**28.5**	**138**	**13.6**	**2.64**	**1,157**	**0.202**					**Yes**	B.C., Located in Tutshi Lake/T'ooch' Áayi Conservancy
Cluster 12: Proposed Extension from Jake's Corner to Atlin (1 of 3)																											
Atlin Hydro	Storage	832	724	107 and 56	4,000	100	8	553 and 678	4.4	1.60	7.0	7.8	2.5	54%	37 (of 46)	17 (of 21)	121	15.5	3.27	1,426	0.222					**Yes**	Reported Values

M:\1\03\00556\06\A\Report\1 - Yukon Hydropower Potential Assessment (10-30 MW)\Rev 0\Tables and Figures\[Table 5.2.xlsx]Summary Table

NOTES:
* Short Listed Sites

REV	DATE	DESCRIPTION	PREP'D	RVW'D
0	25NOV'19	ISSUED WITH REPORT VA103-556/6-1	BXF	SDR

6.0 SCREEN 3: FINAL SCREENING

6.1 ADDITIONAL SCREENING CRITERIA

The Screen 2 results were presented to YEC for review and guidance for the final screening and shortlisting of sites. During this phase, YEC requested the removal of the sites associated with two proposed transmission line segments:

- Cluster 8: Faro-Watson Lake
- Cluster 9: Beaver Creek-Hanes Junction

The removal of the sites associated with these transmission lines was based on low probability of these transmission line segments being developed in the foreseeable future.

Additional final screening criteria were implemented as follows:

- Sites below 10 MW except for Atlin;
- Sites consisting of dams on large river systems were removed due to perceived social risk and high temporary works construction costs
- Sites with a LCOE exceeding $0.35/kWh were removed

Table 6.1 presents the sites remaining for the final selection of the top five preferred sites.

Table 6.1 Sites for Final Selection

Project Name	Evaluated as	Cap.	Avg Energy	Winter Energy	Capital Cost	UCC	LCOE
		MW	GWh/a	GWh/a	M$	M$/MW	$/kWh
Primrose River	RoR	25	102	10	200	7.9	0.15
Primrose River	Storage	13	78	35	180	14.0	0.17
Wolf River	RoR	11	84	21	200	17.6	0.18
Tutshi Windy Arm	Storage	10	52	28	138	13.6	0.20
Wolf River with Wolf Lake	Storage	30	242	83	670	22.3	0.21
Atlin Hydro	Storage	8	37	17	121	15.5	0.22
Drury Creek	RoR	10	33	4	100	10.3	0.24
Reid Lakes & Lake Creek	Storage	11	42	16	140	13.5	0.26
Drury Creek	Storage	10	32	26	115	11.1	0.27
Lapie	RoR	13	45	3	170	13.3	0.29
Lake Creek	RoR	13	45	4	170	13.4	0.29
McQuestin	RoR	17	84	10	330	19.1	0.30
Anvil Creek	Storage	23	82	5	340	14.6	0.31

6.2 SELECTION OF TOP 5 SITES

The selection of the top five sites was made on a combination of comparative LCOE results for the sites presented in Table 6.1, and discussions with YEC for site-specific screening criteria. Four of the shortlisted sites were easily selected for their performance on an LCOE basis and their ability to provide winter energy:

- Primrose
- Drury
- Tutshi-Windy Arm
- Wolf

The fifth site for the shortlist was determined to be Atlin following a detailed conversation with YEC. While Atlin did not offer 10MW of capacity, the following additional considerations ultimately led to the decision:

- Lapie is a RoR project which would not offer any reliable winter generation capacity. Winter capacity is of primary importance to YEC, therefore this site was not selected.
- Reid Lakes and Lake Creek: involves two separate generating stations, with a RoR diversion project feeding a lake storage project. Each on its own is uneconomic, and the combined project is complex and requires an inter-basin transfer of water which is anticipated to pose a significant challenge for development.
- Atlin: while this site offers a lower installed capacity (8 MW), it is optimal for its winter generation potential. It is also considered lower risk than many other sites in terms of the available information supporting its design.

7.0 SHORTLIST CONCEPT DEVELOPMENT

7.1 PRIMROSE

The Primrose River and its tributaries form a hanging valley above Kusawa Lake, which make it a potentially very attractive site. Its presence within the boundaries of Kusawa Territorial Park means it was screened out of the 2016 KP study. The neighbouring drainage of Takhini Lake was also considered as part of proposed schemes in the past.

The Primrose site has been investigated on numerous occasions since 1952. The Demers 1989 Report forms the basis for the project configurations listed in the existing project inventories but were assumed to be using large dams. KP evaluated the project as both a RoR project and a storage project with a 10 m high dam and it is attractive in both instances.

A basic arrangement for the proposed project layout is shown on Figure 7.1. Key project parameters for this layout are as follows:

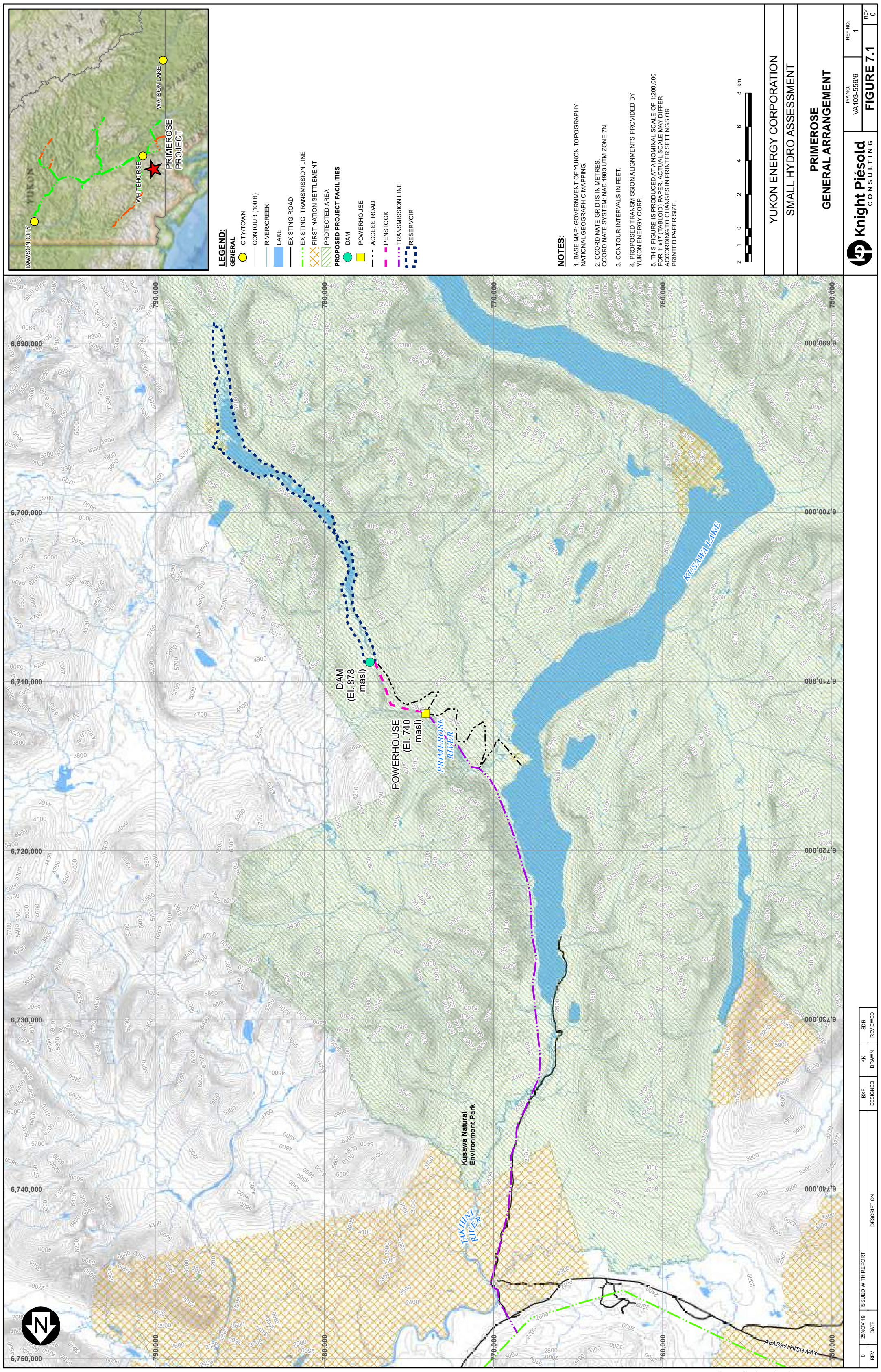
- Design Flow: 11.6 m^3/s.
- Gross Head: 138 m.
- Installed Capacity: 12.7 MW.
- Dependable Capacity: 12.7 MW (during the driest winter of synthetic record 1973-74 the project could generate for 97 continuous days during the winter at 12.7 MW).
- The current access assumes that the project site will require barge access and 20 km of new access roads to reach the proposed dam site from Kusawa Lake. 20 km of additional access road through the Kusawa Territorial Park would be required if the project site is not accessed/accessible by barge.
- A Rose Lake outlet control dam to provide 10 m of lake storage (operating storage of 100 million cubic metres (Mm^3)), equipped with IFR release system and spillway for flood water management.
- A 4,700 m long penstock.
- A Powerhouse (el. 740 masl).
- Substation and a 40 km long transmission line, with a t-tap interconnection to the existing 138 kV line between Aishihik and Whitehorse along Alaska Highway #1.

The project site is attractive but its presence in the Kusawa Territorial Park may be a major obstacle. Only one alternative to lower the powerhouse site to increase the project head at the expense of the increased penstock cost was considered. There could be a more optimal project layout once detailed topography for the site is obtained. Physical considerations at the proposed dam site are also unknown.

Table 7.1 presents the estimated average monthly energy output for the Primrose project. The project layout is shown on Figure 7.1.

Table 7.1 Primrose Average Monthly Energy (GWh)

	Primrose with Storage
Jan	9.0
Feb	8.1
Mar	7.0
Apr	0.0
May	0.0
Jun	0.1
Jul	6.7
Aug	9.0
Sep	8.7
Oct	9.0
Nov	7.6
Dec	9.0
Annual	74.0



LEGEND:
GENERAL
CITY/TOWN
CONTOUR (100 ft)
RIVER/CREEK
LAKE
EXISTING ROAD
EXISTING TRANSMISSION LINE
FIRST NATION SETTLEMENT
PROTECTED AREA
PROPOSED PROJECT FACILITIES
DAM
POWERHOUSE
ACCESS ROAD
PENSTOCK
TRANSMISSION LINE
RESERVOIR
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
DAWSON CITY
WHITEHORSE
WATSON LAKE
PRIMEROSE PROJECT
DAM (El. 878 masl)
POWERHOUSE (El. 740 masl)
PRIMEROSE RIVER
KUSAWA LAKE
Kusawa Natural Environment Park
TAKHINI RIVER
ALASKA HIGHWAY
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
PRIMEROSE
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
VA103-556/6
FIGURE 7.1
ISSUED WITH REPORT

7.2 DRURY

The Drury Lake Project is located on Drury Creek between Drury Lake and Little Salmon Lake, in the Yukon River watershed. The site is approximately 170 km north of Whitehorse and is situated within 1 km of the Robert Campbell Highway and the existing transmission line.

The Drury site was evaluated as both a run of river project and a storage project. The available stream gauge information for Drury seems to indicate some natural flow attenuation from Drury lake offering some winter generation even on a RoR basis.

This project was short listed as it has a relatively low LCOE and offers the opportunity to generate winter energy. It was carried forward as a storage project but may also be valuable as a RoR project.

A variety of studies have previously been commissioned for the Drury site, including high level reconnaissance, geotechnical investigations, and design studies, and these have resulted in several alternative design concepts. The most recent study, apart from the 2016 KP study, was completed by KGS in 2008 and provides basic site layouts, design and geotechnical considerations, and cost estimates for different options.

While earlier studies considered a low gradient canal and a short penstock, geotechnical risk and the presence of permafrost were noted by KGS. At this desktop level, the conveyance alignment and specific constructability concerns cannot be addressed in any detail beyond that reported by KGS, and so the selection of a buried low-pressure penstock instead of a canal has been adopted by KP.

A preliminary general arrangement of the project layout is shown on Figure 7.2. Key project parameters and characteristics for this layout are as follows:

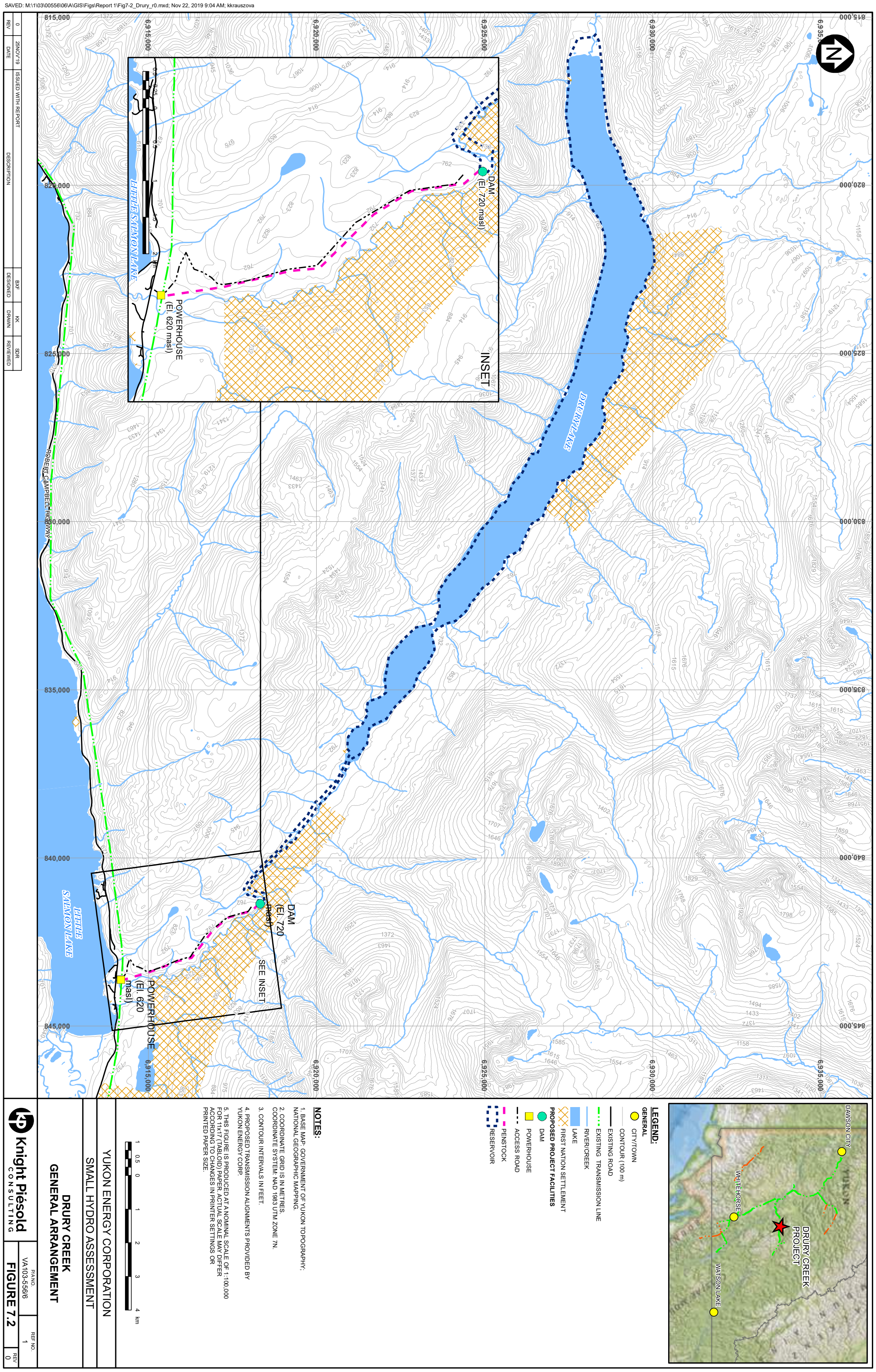
- Design Flow: 12.7 m^3/s.
- Gross Head: 100 m.
- Installed Capacity: 10 MW.
- Dependable Capacity: 10 MW (during the driest winter of synthetic record 1998-99 the project could generate for 63 continuous days during the winter at 10 MW).
- 5.3 km of access roads from the Robert Campbell Highway to the powerhouse, along the water conveyance, and upstream to the outlet of Drury Lake.
- Concrete Faced Rockfill Dam (CFRD) at the outlet of Drury Lake to provide 5 m of storage (operating storage of 130 Mm^3). The dam would be constructed with an IFR discharge system and a spillway to Drury Creek for flood water management.
- An intake structure.
- 4.9 km penstock located on the south side of Drury Creek (alignment as previously indicated by KGS).
- Powerhouse (El. 620 masl) and substation at the edge of Drury Creek, upstream of the Robert Campbell Highway and the river mouth at Little Salmon Lake.
- 0.5 km transmission line, with t-tap interconnection to the existing transmission line.

Note: The lack of detailed topography makes siting the location and configuration of the projects point of diversion difficult. The existing topography shows 5 km of very flat terrain and stream gradient at the outlet of Drury Lake, as such the current option assumes a single structure would be enough to provide impoundment and a penstock offtake.

Table 7.2 presents the average estimated energy output for the Drury project.

Table 7.2 Drury Average Monthly Energy (GWh)

	Drury
Jan	7.2
Feb	6.1
Mar	4.4
Apr	0.0
May	0.0
Jun	0.0
Jul	0.0
Aug	0.2
Sep	1.7
Oct	2.2
Nov	1.6
Dec	7.2
Annual	30.6


SAVED: M:\1\03\00556\06\A\GIS\Figs\Report 1\Fig7-2_Drury_r0.mxd; Nov 22, 2019 9:04 AM; kkrauszova
INSET
DAM
(EL. 720 masl)
POWERHOUSE
(EL. 620 masl)
LITTLE SALMON LAKE
DRURY LAKE
ROBERT CAMPBELL HIGHWAY
SEE INSET
LEGEND:
GENERAL
CITY/TOWN
CONTOUR (100 m)
EXISTING ROAD
EXISTING TRANSMISSION LINE
RIVER/CREEK
LAKE
FIRST NATION SETTLEMENT
PROPOSED PROJECT FACILITIES
DAM
POWERHOUSE
ACCESS ROAD
PENSTOCK
RESERVOIR
DAWSON CITY
WHITEHORSE
WATSON LAKE
DRURY CREEK PROJECT
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:100,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
DRURY CREEK
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
VA103-556/6
FIGURE 7.2
0 25NOV'19 ISSUED WITH REPORT
REV DATE DESCRIPTION DESIGNED DRAWN REVIEWED

7.3 TUTSHI WINDY ARM

The Tutshi – Windy Arm Project is a proposed storage hydropower development located between Tutshi Lake and Windy Arm of Tagish Lake in northern British Columbia. Tutshi and Tagish Lakes are tributaries to the Yukon River. The project site is approximately 45 km to the south of Carcross, Yukon, and the proposed powerhouse location is within 1 km to the east of the Klondike Highway.

Several studies have previously been completed for this site, including geotechnical investigations, design, and cost estimates, resulting in a number of alternative design concepts. This desktop study is based on the most current concepts, presented in the 2008 KGS report.

The Tutshi Lake/T'ooch' Áayi Conservancy was established in 2012 as a result of the Wóoshtin Wudidaa Atlin Taku Land Use Plan and Taku River Tlingit First Nation Strategic Engagement Agreement. The conservancy, located approximately 65 kilometres northwest of Atlin, encompasses the eastern half of Tutshi Lake. Tutshi Lake is culturally significant to the Carcross/Tagish and Taku River Tlingit First Nations. The lake also has high value lake trout habitat. The Tlingit name (T'ooch' Áayi) means "charcoal lake", after the dark colour of the lake water.

A basic arrangement for the proposed project layout is shown on 3. Key project parameters for this layout are as follows:

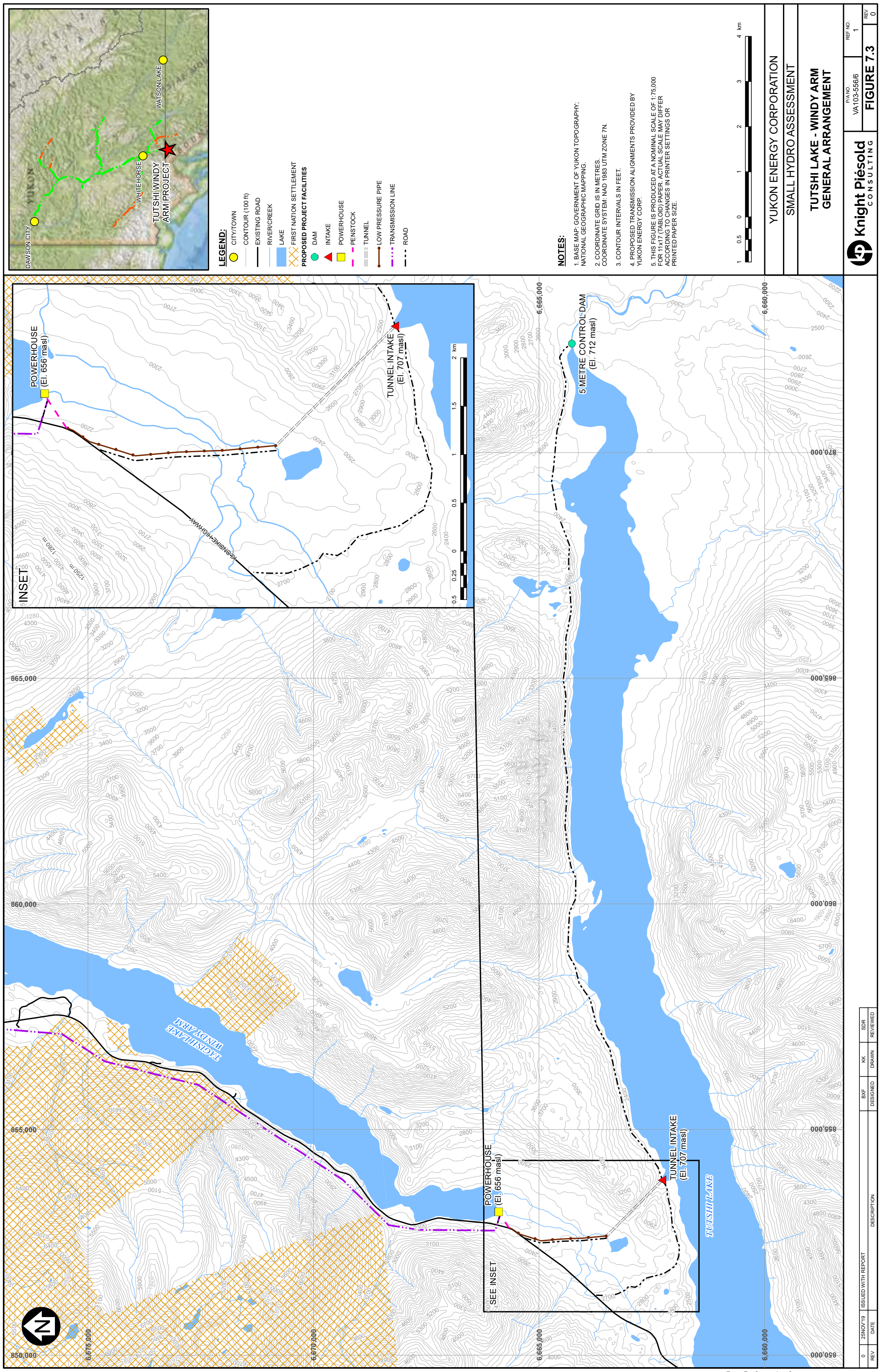
- Design Flow: 25 m3/s.
- Gross Head: 51 m.
- Installed Capacity: 10 MW.
- Dependable Capacity: 10 MW (during the driest winter of synthetic record 1973-74 the project could generate for 108 continuous days during the winter at 10 MW).
- 23.5 km of access roads, to reach the powerhouse, surface conveyance, tunnel intake, and outlet control dam on Tutshi Lake.
- Tutshi Lake outlet control dam to provide 5 m of lake storage (operating storage of 267 Mm3), equipped with IFR release system and spillway for flood water management.
- Tunnel intake and 1.7 km tunnel through the hill separating the north end of Tutshi Lake from Windy Arm of Tagish Lake (Intake El. 707 masl).
- 2.7 km long penstock.
- Powerhouse on the south shore of Windy Arm, Tagish Lake (El. 656 masl).
- Substation and a 1 km long transmission line, with t-tap interconnection to a proposed transmission line along the Klondike Highway between Carcross and Skagway (AK).

The Taku River Tlingit First Nation and Carcross Tagish First Nation would need to be approached prior to any serious consideration of the project site. Site investigations and a more detailed review of site-specific data would be required to confirm project viability and the optimal project size.

Table 7.3 presents the average monthly energy output for the Tutshi-Windy Arm project. The project arrangement is shown on Figure 7.3.

Table 7.3 Tutshi Average Monthly Energy (GWh)

	Tutshi
Jan	7.1
Feb	6.5
Mar	6.2
Apr	0.0
May	0.0
Jun	0.0
Jul	0.4
Aug	5.4
Sep	6.7
Oct	6.4
Nov	3.4
Dec	7.1
Annual	49.3


INSET
POWERHOUSE (El. 656 masl)
TUNNEL INTAKE (El. 707 masl)
SEE INSET
5 METRE CONTROL DAM (El. 712 masl)
TAGISH LAKE WINDY ARM
TUTSHI LAKE
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
EXISTING ROAD
RIVER/CREEK
LAKE
FIRST NATION SETTLEMENT
PROPOSED PROJECT FACILITIES
DAM
INTAKE
POWERHOUSE
PENSTOCK
TUNNEL
LOW PRESSURE PIPE
TRANSMISSION LINE
ROAD
DAWSON CITY
WHITEHORSE
WATSON LAKE
TUTSHI WINDY ARM PROJECT
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:75,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
TUTSHI LAKE - WINDY ARM GENERAL ARRANGEMENT
Knight Piésold CONSULTING
P/A NO. VA103-556/6
REF NO. 1
FIGURE 7.3
REV 0
0 25NOV'19 ISSUED WITH REPORT
REV DATE DESCRIPTION DESIGNED DRAWN REVIEWED

7.4 ATLIN HYDRO

Atlin is an isolated community located approximately 50 km south of the Yukon-British Columbia border. Atlin is only road accessible from the Yukon Territory. On April 1, 2009 the 2.1 MW Atlin Hydro Project began commercial power production (Illustrated in Figure 7.4). The hydropower facility is owned by Xeitl Limited Partnership which is 100% owned by Taku River Tlingit First Nation. The project is located on Pine Creek and is approximately 4 km east of the community of Atlin, BC. The facility overlaps with previously conceived layouts of a Surprise Lake hydroelectric project.

NOTES:
1. PHOTO SOURCE: WWW.WATERPOWERMAGAZINE.COM.

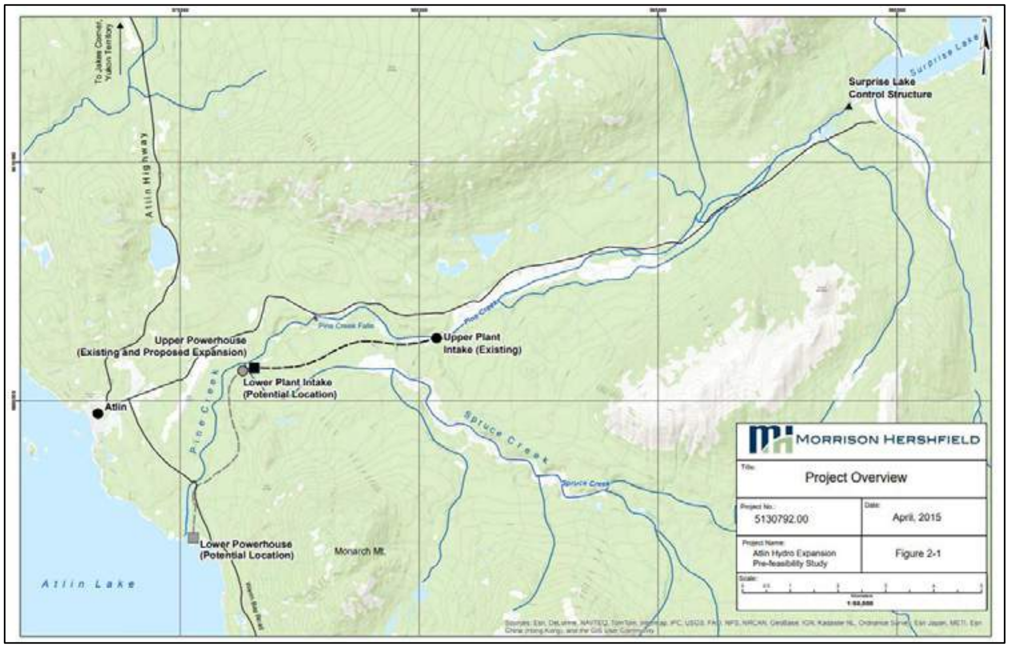
Figure 7.4 Atlin Hydro Project Photos

On June 23, 2016 Morrison Hershfield provided YEC with a detailed report on the Atlin Hydro Expansion Project. The report includes a transmission line options assessment for connection to the Yukon electrical system. The detail provided in this report (good quality topography, complete hydrological assessment, detailed drawings and estimates) means this project has less unknowns and risks than the other projects in this short list.

For the purpose of conciseness, the Morrison Hershfield information will only be repeated here in brief summary. They have completed an alternatives assessment, a hydrological assessment and a Pre-Feasibility Assessment. The proposed general arrangement is shown in Figure 7.5. A summary of the estimated energy is shown in Table 7.4 The conclusion is quoted below.

“It is proposed to develop a total of 7.8 MW at Pine Creek, consisting of expanding the existing (upper) 2.1 MW powerhouse with an additional two turbines to bring the total installed capacity to 5 MW plus the addition of a second, or lower, powerhouse near Atlin Lake with an installed capacity of 2.8 MW. The upper power plant operates under a gross head of approximately 107 m and the lower plant has a gross head of approximately 56 m.”

“For the expansion of the upper power plant, a second 4 km long HDPE penstock will be required to convey a maximum flow of 3.55 m³/s from the existing head pond to the powerhouse. The penstock will require the excavation of a trench, mainly through overburden materials except some limited bedrock excavations near the intake structure. The lower power plant requires 4 km of twin HDPE penstocks to convey a maximum flow of 7 m³/s. A new excavated head pond just downstream of the existing (upper) powerhouse is required to supply the lower penstocks. Spruce Creek would be diverted into the lower head pond such that flows from Spruce Creek can be used to increase electrical generation at the lower power plant.



NOTES:
1. SOURCE: ATLIN HYDRO EXPANSION STUDY.

Figure 7.5 Atlin Hydro Project and Surprise Lake

Increased storage in Surprise Lake to maximize winter electrical generation will be developed by modifying the existing control structure at the lake outlet. It is proposed to increase the storage range from 1.1 m to 2.5 m by increasing both top and bottom storage by approximately 0.7 m. This operating scheme would not require modification of the project's existing Permit Over Crown Land which allows storage of water up to elevation 913.85 masl. The storage of water allows the project to generate approximately 70% of its annual average energy production during winter months (November through April). Winter energy is of highest value to the Yukon's electrical grid.

In consideration of the existing hydropower infrastructure the Atlin Hydro Expansion Project has the potential to produce on average 44.7 GWh/yr of energy, of which at 36 GWh/yr is available for export to the Yukon after the community of Atlin's needs are met. Cost for the hydroelectric development only (without transmission) are estimated at $79.7 million. A total project cost of $120.7 million is estimated, including a 69 kV transmission line to connect with the Yukon's electrical grid at Jakes Corner."

Table 7.4 Atlin Average Monthly Energy (GWh)

	Production	Committed	For Yukon
Jan	5.1	1.0	4.1
Feb	4.9	0.8	4.1
Mar	5.3	0.8	4.5
Apr	4.5	0.8	3.7
May	2.4	0.7	1.7
Jun	3.3	0.6	2.7
Jul	2.2	0.5	1.7
Aug	1.7	0.5	1.2
Sep	2	0.6	1.4
Oct	2.3	0.7	1.6
Nov	5.5	0.7	4.8
Dec	5.5	0.9	4.6
Annual	44.7	8.6	**36.1**

7.5 WOLF RIVER

The Wolf River is a tributary of the Nisutlin River upstream of Teslin Lake, in the headwaters of the Yukon River. The Wolf River Project site is located near the river mouth and approximately 22 km to the northeast of the community of Teslin and the Alaska Highway. First Nation Heritage Routes and First Nation Settlement Lands associated with the Teslin Tlingit Council are visible in the GeoYukon database covering the area adjacent to the north bank of the Wolf River.

The previous KP report and the 1990 and 1991 Hydro Investigations by S. Demers looked at the project site. Little is known of site-specific geotechnical conditions and cannot be confirmed at the desktop level. There are several project configurations possible and the main limitation on the project installed capacity is associated with the capacity of the existing 34 kV transmission line from Teslin. In the current layout the main intake has been placed below the confluence of Caribou Creek and Wolf River (previously the intake was considered a bit higher in the basin missing out on the Caribou Creek catchment.) The 1991 study also noted the potential opportunity for storage in Wolf Lake, which could improve winter generation and the plant capacity factor.

Two project configurations were considered in the first a run-of-river project limited by the existing transmission and capped at 11 MW of installed capacity. A second utilizing the potential of the site at 30 MW with the addition of storage at Wolf Lake to allow for firm winter generation but requiring an additional higher capacity of transmission line to Whitehorse.

A basic general arrangement for the proposed project layout is shown on Figure 7.6.

Key project parameters for this layout are shown below.

Table 7.5 Wolf River Alternatives

Sites	Wolf River	Wolf River and Wolf Lake
Design Flow	18.8	37.6
Gross Head (m)	75	100
Installed Capacity (MW)	11.2	30.0
Dependable Capacity (MW)	4.0	30.0
Canal Length (m)	6,900	11,500
Penstock Length (m)	1,300	900
Transmission Line (km)	20	20+150

Project access should be able to circumvent the Nisutlin River Delta National Wildlife Area. Access to the project site can be done through either or both of the following:

- Upgrades to an existing 34 km trail identified as leaving the Alaska Highway (#1) 20 km east of Teslin.
- A new 23 km access road departing from Teslin, running west of the Nisutlin River Delta National Wildlife Area. This option would require a bridge across the Nisutlin River.
- 73 km of trail upgrades are required to access Wolf Lake from the proposed intake site.

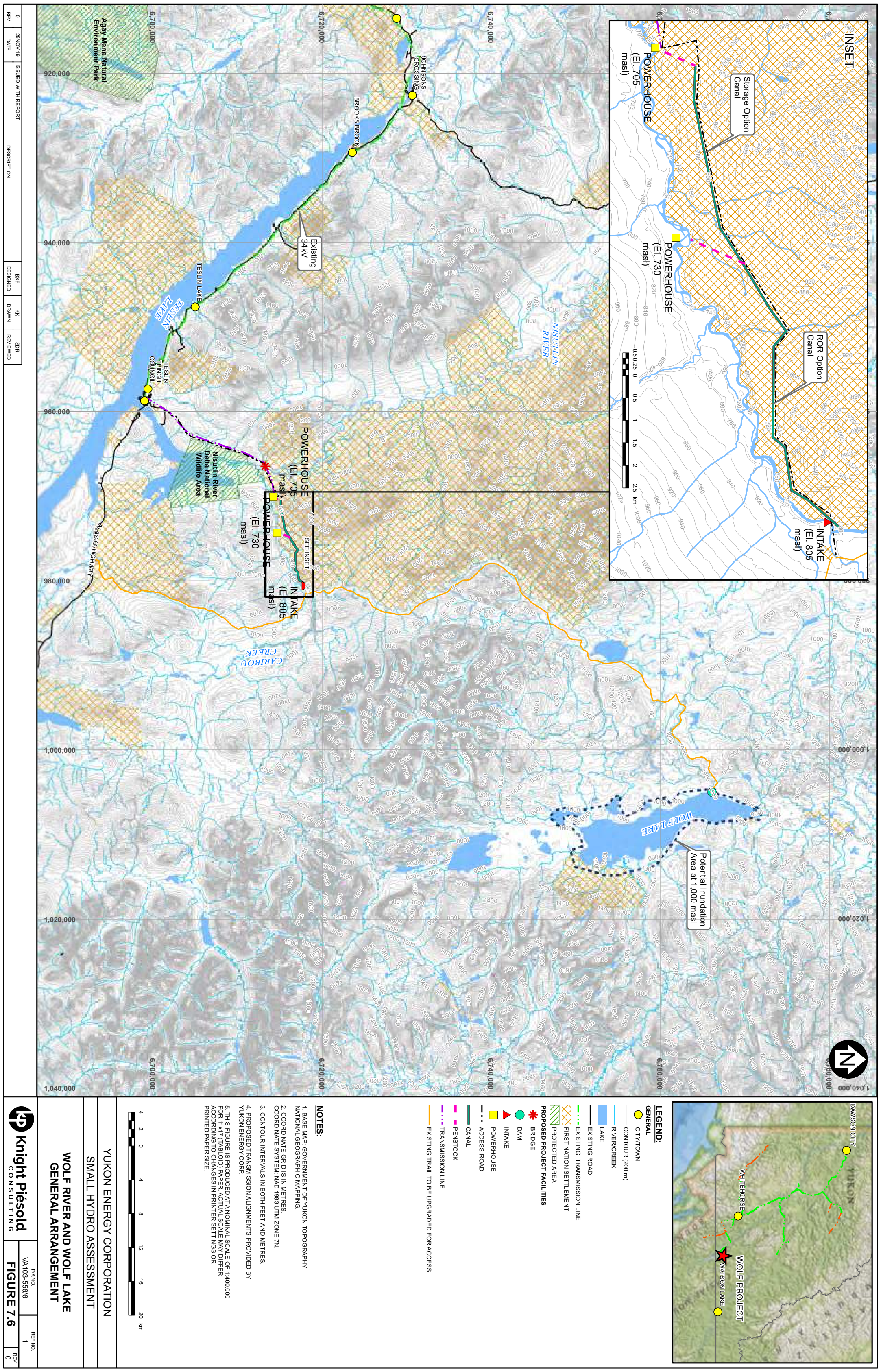
Both project configurations would require a canal diversion and a forebay to the penstock and a powerhouse and a short tailrace channel back to Wolf River.

Both configurations would include a substation and 23 km transmission line to Teslin. Development of a large generating capacity at Wolf River would need a more careful consideration of the transmission line capabilities and energy demand. For the current assessment valuation, it was presumed that 150 km of new line would be needed to connect Teslin to Whitehorse through Jake's Corner to support a 30 MW project site.

Table 7.6 presents the average monthly energy output for the Wolf River project. The project arrangement is shown on Figure 7.6.

Table 7.6 Wolf and Wolf Lake Average Monthly Energy (GWh)

	Wolf	Wolf River and Wolf Lake
Jan	5.7	21.2
Feb	3.9	19.0
Mar	3.9	17.2
Apr	4.8	12.8
May	7.8	19.3
Jun	7.7	20.6
Jul	8.0	21.2
Aug	8.0	21.0
Sep	7.7	20.1
Oct	8.0	20.2
Nov	7.5	15.6
Dec	6.9	21.2
Annual	79.7	229.5



INSET
Storage Option Canal
ROR Option Canal
POWERHOUSE (El. 705 masl)
POWERHOUSE (El. 730 masl)
INTAKE (El. 805 masl)
SEE INSET
TESLIN LAKE
NISUTLIN RIVER
CARIBOU CREEK
WOLF LAKE
Potential Inundation Area at 1,000 masl
Existing 34kV
BROOKS BROOK
JOHNSONS CROSSING
TESLIN
Nisutlin River Delta National Wildlife Area
Agay Mene Natural Environment Park
LEGEND:
GENERAL
CITY/TOWN
CONTOUR (200 m)
RIVER/CREEK
LAKE
EXISTING ROAD
EXISTING TRANSMISSION LINE
FIRST NATION SETTLEMENT
PROTECTED AREA
PROPOSED PROJECT FACILITIES
BRIDGE
DAM
INTAKE
POWERHOUSE
ACCESS ROAD
CANAL
PENSTOCK
TRANSMISSION LINE
EXISTING TRAIL TO BE UPGRADED FOR ACCESS
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN BOTH FEET AND METRES.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:400,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
DAWSON CITY
YUKON
WHITEHORSE
WOLF PROJECT
WATSON LAKE
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
WOLF RIVER AND WOLF LAKE
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
P/A NO. VA103-556/6
REF NO. 1
FIGURE 7.6
REV 0

8.0 CONCLUSIONS AND RECOMMENDATIONS

8.1 CONCLUSIONS

The objectives of the study were to compile a regional assessment of hydropower development sites with installed capacities between 10 MW and 30 MW and within 50 km of existing or proposed transmission lines. KP developed a list of 147 sites and completed a hydropower screening assessment to progressively eliminate the less attractive sites and focus in on the best potential hydroelectric development options. Following a coarse screening of these 147 sites, 56 Sites were selected for a further quantitative assessment. KP performed a quantitative assessment to determine potential layouts, capacity, average annual and winter energy yield and indicative development costs. During a final screening and selection process, the sites were presented to YEC for final consideration and implementation of additional screening criteria. The final screening was based on capacity, location, expected development costs and perceived social acceptability. This narrowed the 56 sites to nine sites, including:

- Primrose (as both ROR and lake storage projects)
- Wolf River (with and without Wolf Lake)
- Tutshi Windy Arm
- Atlin
- Drury Creek (as both ROR and lake storage projects)
- Lake Creek and Reid Lakes
- Lapie
- McQuestin River
- Anvil Creek

These 9 sites were assessed in more detail, and the final 5 preferred sites were selected as:

- Primrose (as a lake storage project)
- Drury (as a lake storage project)
- Tutshi Windy Arm
- Atlin
- Wolf River (with and without Wolf Lake)

A summary of the Financial and Technical attributes of the preferred sites is presented in Table 8.1.

Knight Piésold CONSULTING

TABLE 8.1

YUKON ENERGY CORPORATION
HYDROPOWER POTENTIAL ASSESSMENT (10MW-30MW)

PREFERRED SITES
SUMMARY

Print Nov/25/19 09:00:03

DESCRIPTION	Primrose	Drury	Tutshi	Atlin	Wolf	Wolf River & Lake
Installed Capacity (MW)	12.7	10.0	10.0	8.0	11.2	30.0
Dependable Winter Capacity (MW) based on 2 weeks of Winter Production	12.7	10.0	10.0	6.0	4.0	30.0
Average Annual Energy (GWh) x 95% for outages and transmission losses	74.0	30.6	49.3	45.0	79.7	229.5
Average Dec-Mar Energy (GWh) x 95% for outages and transmission losses	33.0	24.9	27.1	20.8	20.1	79.0
Unit Cost of Capacity (M$/MW)	14.0	11.1	16.7	16.4	14.7	15.3
Unit Cost of Energy (M$/GWh)	2.40	3.61	3.39	2.91	2.07	2.00
Levelized Cost of Capacity ($/kW-yr) @4.82%	1,342	673	1,291	1,426	1,780	1,764
Levelized Cost of Energy ($/kWh) @4.82%	0.184	0.277	0.256	0.222	0.160	0.154
Levelized Cost of Winter Energy ($/MWh) @4.82% and 0.19 $/kWh for Non Winter Energy	0.177	0.296	0.311	0.259	0.072	0.086
Project Gross Head (m)	138	100	51	107 and 56	75	100
Design Flow (m^3/s)	11.6	12.7	24.9	7.0	18.8	37.6
MAD (m^3/s)	14.5	4.9	16.2	4.4	75.3	75.3
Design Factor	0.80	2.60	1.55	1.59	0.25	0.50
Dam Height (m)	10	5	5	2.5	-	4
Storable Volume (10^6 m^3)	100	125	265	76	-	350
Water Conveyance Length (m)	4,700	5,200	3,000	4,000	7,400	14,000
Capital Cost Esitmate						
Mod, Demob, Insurance, Bonds, Overheads, Contractor's Profit	$ 29,700,000	$ 18,500,000	$ 27,900,000	$ 1,400,000	$ 27,600,000	$ 57,900,000
Access and Site Preparation	$ 8,000,000	$ 4,600,000	$ 7,900,000	$ 700,000	$ 12,000,000	$ 23,000,000
Intake, Forebay, and Headrace	$ 6,500,000	$ 6,800,000	$ 12,500,000	$ 1,100,000	$ 10,000,000	$ 25,000,000
Water Conveyance System	$ 25,000,000	$ 30,000,000	$ 32,900,000	$ 30,200,000	$ 39,700,000	$ 90,000,000
Powerhouse and Ancilary Services	$ 6,000,000	$ 5,900,000	$ 8,700,000	$ 12,700,000	$ 7,400,000	$ 13,500,000
Power Generation Equipment (Water to Wire)	$ 8,900,000	$ 7,100,000	$ 7,100,000	$ 9,800,000	$ 7,900,000	$ 20,000,000
Switchyward, Transmission and Interconnection	$ 29,500,000	$ 2,700,000	$ 20,200,000	$ 27,100,000	$ 15,000,000	$ 18,000,000
Dams and Reservoirs	$ 15,000,000	$ 4,500,000	$ 3,800,000	$ 1,600,000	$ -	$ 3,500,000
Upgrades to Grid (138 kV 150 km Teslin to Whitehorse)					$ -	$ 82,500,000
SUB-TOTAL	**$ 128,600,000**	**$ 80,100,000**	**$ 121,000,000**	**$ 84,600,000**	**$ 119,600,000**	**$ 333,400,000**
EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 10,300,000	$ 6,400,000	$ 9,700,000	$ 20,300,000	$ 9,600,000	$ 26,700,000
CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 38,600,000	$ 24,000,000	$ 36,300,000	$ 26,100,000	$ 35,900,000	$ 100,000,000
TOTAL ESTIMATED CAPITAL COST	**$ 177,500,000**	**$ 110,500,000**	**$ 167,000,000**	**$ 131,000,000**	**$ 165,100,000**	**$ 460,100,000**

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NOTES:
1. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. DOES NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.
5. ATLIN COSTS ARE BASED COSTS REPORTED BY MORRISON HERSFIELD 2016 ESCALATED AT 2.5%.

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REV	DATE	DESCRIPTION	PREP'D	CHK'D

8.2 RECOMMENDATIONS

8.2.1 FIRST NATIONS

All 5 of the sites (Primrose, Drury, Tutshi, Atlin, and Wolf River) short listed for concept development will require the involvement of First Nations and other stakeholders to make them a success. In British Columbia, renewable energy has become an important industry for First Nations and it has been an industry First Nations have embraced because projects can be developed with minimal impacts to their rights, environment, and within their values. It is possible the Yukon may experience a similar situation.

Judith Sayers for the BC First Nations Clean Energy Working Group indicates that First Nations with clear Economic Development Plans, Land Use Plans and Community Energy Policies in place before they start involvement with renewable energy projects have an easier time finding an acceptable community direction regarding such projects. Ensuring that renewable energy development is considered in those plans is of key importance. (Source: https://www.cleanenergybc.org/wp-content/uploads/2016/04/BC-FN-Toolkit.pdf).

8.2.2 TECHNICAL EVALUATION

Further evaluation of the preferred sites is recommended, to improve the design basis, project configurations, and understanding of hydrological and geotechnical conditions. The following activities are recommended:

- Set the projects energy objectives, including the required installed capacity and winter energy generation potential to meet the forecasted energy and power demands in the Yukon
- Undertake a screening assessment of social and environmental permitting constraints at each of the five preferred sites
- Obtain accurate mapping (such as satellite topography) for the proposed project areas to confirm project configurations and details including dam sizes, water conveyance routings, available generation head, powerhouse locations, access roads, and transmission lines
- Implement hydrological data collection programs at the preferred sites or reinforce existing programs
- Conduct preliminary site visits to the preferred sites to further evaluate technical viability
- Update energy estimates based on hydrology data and accurate depth-area-capacity curves for reservoirs
- Update quantity and cost estimates

Should the above assessment indicate that there are no critical technical or environmental barriers to development, detailed evaluation of the sites through pre-feasibility and feasibility studies should be pursued to prove economic viability.

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10.0 CERTIFICATION

This report was prepared and reviewed by the undersigned.

PROFESSIONAL ENGINEER
PROVINCE OF BRITISH COLUMBIA
B. S. FICHOT
30575

Prepared: Nov 25, 2019

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Senior Engineer

Reviewed:

Scott Rees, P.Eng.
Senior Engineer

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Approval that this document adheres to the Knight Piésold Quality System: SRM

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

APPENDIX A

Historical Documents and Hydropower Project Sites

(Table A.1)

Knight Piésold CONSULTING

VA103-556/6-1 Rev 0
November 25, 2019

Knight Piésold
CONSULTING

TABLE A.1

YUKON ENERGY
REGIONAL HYDROPOWER ASSESSMENT

HISTORICAL DOCUMENTS AND HYDROPOWER SITES

Print Nov/25/1

Reports	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Date	Aug-66	Jan-68	Dec-69	Feb-70	Jan-75	1977	Nov-80	Oct-80	Nov-80	Aug-81	Oct-82	Mar-82	Feb-82	Feb-82	Feb-82	Jun-82	Sep-82	Mar-83	Oct-83	Dec 1989	Dec 1990	Jun-05	Feb-08	Jan-10	Jan-11	Sep-14	Jan-15	
Author	Department of Mines and	T. Ingledow & Associates Ltd.	Montreal Engineering	T. Ingledow & Associates Ltd.	Sigma Resource Consultants Ltd.	Montreal Engineering	Monenco Consultants Pacific	Shawinigan Engineering	Monenco Consultants Pacific	Shawinigan Stanley	Northwest Hydraulic Consultants Ltd.	Shawinigan Stanley	Acres Consulting Services Ltd.	SNC Consultants Ltd.	Crippen Consultants	Crippen Consultants	Monenco Consultants Pacific	Monenco Consultants Pacific	Monenco Consultants Pacific	A.S. Demers	A.S. Demers	(No Stated Author, Stored in	KGS Group Inc.	AECOM Canada Ltd.	AECOM Canada Ltd.	Marc-Andre Lavigne	Midgard Consulting Inc.	Midgard Consulting Inc
Title	A Preliminary Appraisal of the Yukon-Taiya and Yukon-Taku	Hydro-electric Resources Survey of the Central Yukon Territory	Northern Canada Power Commission - Francis River	Power Survey of the Liard River Basin Yukon and Northwest	The Development of Power in the Yukon (Main Report, Technical	Francis River - Upper Canyon: Preliminary Study of a 25.2 M.W.	Mid-Yukon Feasibility Study: Year 1; Vol 1; Summary Report	Teslin River Hydro Power Study	Yukon Mining Hydro Power Study of Small to Mid- Size	False Canyon Hydro Prefeasibilty Study: Mid-Study Report	Environmental and Socio-Economic Studies of Five Hydro	False Canyon Hydro Prefeasibilty Study	Granite Canyon Development Pre feasibility Study	Prefeasibility Study of a Hydroelectric Site at Ross	Hoole Canyon Hydroelectric Project 1981 Site Investigation	Hoole Canyon Hydroelectric Project Prefeasibility Study	Yukon Hydro Investigations Coordination Conclusions from	Northern Canada Power Commission Slate Rapids	The Inventory of Yukon Hydroelectric Sites: A Review of	Yukon Energy Corporation: 1989 Hydro Investigations	Yukon Energy Corporation: 1990 Hydro Investigations	1991 Hydro Investigations	Assessment of Potential Hydroelectric Sites: Concept	2009 Large Hydro Stage 1: Initial Evaluation Draft Report	Preliminary Power Potential Assessment for Homan Lake	EMAIL: Next Generation Hydro Project	Yukon Next Generation Hydro and Transmission Viability Study:	Yukon Next Generation Hydro and Transmission Viability Study
Reports	1	2		3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Project Name																												
Aberdeen Canyon					x														x					x			x	
Alder Creek																												
Anvil Creek		x			x														x	x						x	x	
Atlin Storage																							x	x		x	x	
Bates Canyon					x																						x	
Bates Canyon + Dezadeash Diversion					x														x					x			x	
Beaver Crow				x															x					x			x	
Bell					x														x					x			x	
Big Campbell Creek																												
Big Kalzas Lake		x			x														x								x	
Big Salmon					x														x					x			x	
Blind Creek																												
Bonanza Creek																												
Bonnet Plume																								x			x	
Boundary					x														x					x			x	
Bradens Canyon		x			x														x					x			x	
Bradens Canyon + Fortin Lake Dam		x			x														x					x			x	
Britannia					x														x					x			x	
Burwash																												
Campbell Creek																								x			x	
Cassiar Bar																								x			x	
Chandindu River		x			x																	x					x	
Coal River																								x			x	
Dawson					x														x					x			x	
Detour Canyon		x			x																			x			x	x
Detour Canyon + Fortin Lake Dam		x			x														x					x			x	x
Doll Creek																												
Donjek to White River Diversion		x			x														x			x		x			x	
Drury Creek		x			x															x	x		x			x	x	
Duke																												
Eagle's Nest Bluff (Alone)							x				x								x					x			x	
Eagle's Nest Bluff + Rink Rapids (1 PH)							x				x								x					x			x	
Eagle's Nest Bluff + Rink Rapids (2 PH)							x				x								x					x			x	
Earn		x			x														x	x							x	
Ethel Lake		x			x														x								x	
False Canyon				x	x				x	x	x	x					x							x			x	x
Fantasque				x															x					x			x	
Fifteen Mile Diversion		x			x														x			x					x	
Finlayson																					x			x		x	x	
Five Fingers High (150 MW)					x														x					x			x	
Five Fingers High (455 MW)					x														x					x			x	
Five Fingers Low (75 MW)					x														x					x			x	
Forty Mile River		x			x														x			x					x	
Frances River (Lower Canyon)				x	x																			x			x	x
Fraser Falls (High)		x			x														x					x			x	x
Fraser Falls (Low)		x			x																			x			x	x
Gladstone Diversion																							x				x	
Glenlyon																												
Granite Canyon (Large)		x			x						x		x						x		x			x			x	x
Granite Canyon (Small)		x			x						x		x						x		x			x			x	x
Hess Canyon		x			x														x								x	
Homan Lake																						x		x	x		x	
Hoole Canyon		x									x									x				x			x	
Hoole Canyon + Fortin Lake Dam		x			x				x		x				x	x	x			x				x			x	x
Hoole River																								x			x	
Hootalinqua					x														x								x	
Hyland Diversion				x															x		x			x			x	
Ibex																												
Independence		x			x														x					x			x	
Indian River		x			x														x			x					x	
Kathleen Canyon																								x			x	
Kluane Canyon		x			x														x	x						x	x	
Koidern																												
Lake Creek Diversion		x			x														x								x	
Lapie																						x				x	x	
Liard Canyon				x	x														x		x			x			x	
Little Rancheria River																								x			x	
Little Salmon Dam									x										x								x	
Little Salmon Diversion		x			x															x							x	
Lower Canyon on White River		x			x														x								x	
Lynx and Wolverine																												
McNaughton Creek																					x		x				x	
McNeil		x			x														x								x	
McQuestin																												
Meister River																								x			x	
Mica Creek		x			x														x								x	
Middle (or Lower) Canyon (Large)					x														x					x			x	x
Middle Canyon (38 MW Version)																								x			x	
Middle Site										x														x			x	
Moon Lake + Tutshi River Outlet Site A Cluster																					x		x	x			x	
Moon Lake + Tutshi Windy Arm Outlet Site B Cluster																					x		x	x			x	
Moon Lake A																					x		x	x		x	x	

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Reports	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Date	Aug-66	Jan-68	Dec-69	Feb-70	Jan-75	1977	Nov-80	Oct-80	Nov-80	Aug-81	Oct-82	Mar-82	Feb-82	Feb-82	Feb-82	Jun-82	Sep-82	Mar-83	Oct-83	Dec 1989	Dec 1990	Jun-05	Feb-08	Jan-10	Jan-11	Sep-14	Jan-15		Oct-16
Author	Department of Mines and	T. Ingledow & Associates Ltd.	Montreal Engineering	T. Ingledow & Associates Ltd.	Sigma Resource Consultants Ltd.	Montreal Engineering	Monenco Consultants Pacific	Shawinigan Engineering	Monenco Consultants Pacific	Shawinigan Stanley	Northwest Hydraulic Consultants Ltd.	Shawinigan Stanley	Acres Consulting Services Ltd.	SNC Consultants Ltd.	Crippen Consultants	Crippen Consultants	Monenco Consultants Pacific	Monenco Consultants Pacific	Monenco Consultants Pacific	A.S. Demers	A.S. Demers	(No Stated Author, Stored in	KGS Group Inc.	AECOM Canada Ltd.	AECOM Canada Ltd.	Marc-Andre Lavigne	Midgard Consulting Inc.	Midgard Consulting Inc.	Kmight Piesold Ltd.
Title	A Preliminary Appraisal of the Yukon-Taiya and Yukon-Taku	Hydro-electric Resources Survey of the Central Yukon Territory	Northern Canada Power Commission - Francis River	Power Survey of the Liard River Basin Yukon and Northwest	The Development of Power in the Yukon (Main Report, Technical	Francis River - Upper Canyon: Preliminary Study of a 25.2 M.W.	Mid-Yukon Feasibility Study: Year 1; Vol 1; Summary Report	Teslin River Hydro Power Study	Yukon Mining Hydro Power Study of Small to Mid- Size	False Canyon Hydro Prefeasibilty Study: Mid-Study Report	Environmental and Socio-Economic Studies of Five Hydro	False Canyon Hydro Prefeasibilty Study	Granite Canyon Development Pre-feasibility Study	Prefeasibility Study of a Hydroelectric Site at Ross	Hoole Canyon Hydroelectric Project 1981 Site Investigation	Hoole Canyon Hydroelectric Project Prefeasibility Study	Yukon Hydro Investigations Coordination Conclusions from	Northern Canada Power Commission Slate Rapids	The Inventory of Yukon Hydroelectric Sites: A Review of	Yukon Energy Corporation: 1989 Hydro Investigations	Yukon Energy Corporation: 1990 Hydro Investigations	1991 Hydro Investigations	Assessment of Potential Hydroelectric Sites: Concept	2009 Large Hydro Stage 1: Initial Evaluation Draft Report	Preliminary Power Potential Assessment for Homan Lake	EMAIL: Next Generation Hydro Project	Yukon Next Generation Hydro and Transmission Viability Study:	Yukon Next Generation Hydro and Transmission Viability Study:	YEC Small Hydroelectric Projects - Screening Assessment
Reports	1	2		3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Project Name																													
Moon Lake C																					x		x	x		x	x		
MoonLake B																							x	x			x		
Morley River																					x	x	x			x	x		x
North Fork Klondike River																						x					x		x
North McQuesten		x			x														x								x		x
NWPI (High)																								x			x		
NWPI (Low)		x			x			x											x					x			x	x	
Ogilvie					x														x					x			x		
Orchay																						x					x		x
Pleasant Creek		x			x														x			x					x		x
Pleasant Creek with Rogue Diversion		x			x																	x					x		x
Porcupine		x			x														x					x			x		
Porcupine Canyon					x														x					x			x		
Prevost Canyon		x			x														x	x							x		x
Primrose Diversion Scheme (To Takhini Lake)																				x							x		
Primrose Lake to Takhini Lake Diversion		x																	x								x		
Quartz Creek				x															x					x			x		
Quiet Lake Diversion		x			x														x								x		x
Quiet Lake Diversion + Rose River Diversion		x																	x								x		x
Rancheria																								x					
Reid Lakes and Lake Creek																													x
Rock Creek																													x
Rogue		x			x														x			x					x		x
Rose Creek																													
Rose Lake to Kusawa Lake Diversion		x			x														x							x	x		x
Ross Canyon		x			x				x		x			x			x		x	x				x			x		
Saucy Creek				x															x					x			x		
Seven Mile Canyon		x			x														x								x		x
Site 124																								x			x		
Site 127																								x			x		
Sixty Mile River Diversion		x			x														x			x					x		x
Slate Rapids (Diversion Scheme)																		x		x				x		x	x	x	
Slate Rapids (Powerhouse in Main Dam)																		x		x				x		x	x		
Squanga Creek																				x		x				x	x		x
Surprise Lake																													
Swede Creek																													
Swift																								x			x		
Swift River																								x			x		
Tatshenshini + Dezadeash / Kusawa Diversion					x														x								x		
Tatshenshini + Dezadeash Diversion					x																			x			x		
Tay River		x			x														x					x			x		
Tenas Creek (Orchay Diversion)																													
Thane Creek																													
Tootsee River																													x
Tutshi River Outlet Site A (Lake to Lake)																					x		x	x			x		
Tutshi River Outlet Site A (Lake to River)																					x		x	x			x		
Tutshi River Outlet Site A (River to Lake)																					x		x	x			x		
Tutshi River Outlet Site A (River to River)																					x		x	x			x		
Tutshi Windy Arm Outlet Site B (East PH)																							x	x			x		x
Tutshi Windy Arm Outlet Site B (West PH)																							x	x			x		
Two Mile Canyon		x			x														x					x			x	x	
Upper & Lower Primrose (2008 Layout)																				x	x		x	x			x		x
Upper Canyon (Large) -Francis River				x	x	x	x												x					x		x	x	x	
Upper Canyon (Medium) -Francis River				x	x	x	x												x					x		x	x	x	
Upper Canyon (Small) -Francis River				x	x	x	x												x					x		x	x	x	
Upper Canyon on White River		x			x														x								x		
Watson Lake																										x	x		x
Watson River		x			x																						x		x
Wind																								x			x		
Wolf River					x														x		x	x		x			x		x
Wolverine					x														x					x			x		
Yukon-Taiya	x				x														x					x			x		
Yukon-Taku	x				x														x					x			x		

M:\1\03\00556\06\A\Report\1 - Yukon Hydropower Potential Assessment (10-30 MW)\Rev 0\Appendix A\[Appendix A.xlsm]Table A.1

REV	DATE	DESCRIPTION	PREP'D	RVW'D
0	25NOV'19	ISSUED WITH REPORT V103-556/6-1	BXF	SDR

APPENDIX B

Site Descriptions

(Pages B-1 to B-9)

APPENDIX B
SITE DESCRIPTIONS

The projects passing the coarse screen have been reviewed below and numeric details about each site can be found in **Error! Reference source not found.** of the main report. On occasion sites previously lacking information have been added to the Table for completeness or a further site-specific review revealed the site should be dismissed from consideration or added for consideration.

1.0 CLUSTER 1 – AISHIHIK-WHITEHORSE 138 KV

1.1 PRIMROSE

This site was short listed. See Section 7.1.

2.0 CLUSTER 2 – CARMACKS-WHITEHORSE 138 KV

2.1 IBEX RIVER

A concept for a 3.5 MW run-of-river on the Ibex River was investigated and dismissed based on size and cost. The site is a bit too far removed from transmission and access to be viable. It does benefit from a nearby stream gauge that could help in refining the energy generation assessment.

3.0 CLUSTER 3 – CARMACKS-FARO 138 KV

3.1 ANVIL

A few run-of-river configurations were considered up and down Anvil Creek. The project location has been previously been associated with Anvil Lake, a site that does not offer the same generating opportunities. The most attractive options for Anvil Creek assume long tunnels, resulting in average to higher LCOE returns, as such the project was not shortlisted. It was only possible to fully regulate the river for winter generation with a very tall dam structure, which proved to be cost prohibitive (i.e. $1 billion for 30 MW of firm winter generation).

3.2 DRURY

This site was short listed. See Section 7.2.

3.3 GLENLYON

Glenlyon offers the opportunity for a lake storage project or a run-of-river project but falls short of the desired installed capacity and is a bit too isolated and costly.

3.4 LITTLE SALMON

The Little Salmon Lake outlet offers little in the way of elevation differential given the current available topography. It is also not believed that it would be an environmentally acceptable site given its use for recreational angling and the name of the lake. It was elected not to consider the site for a high dam.

3.5 TAY RIVER

The Tay River forms a large watershed but it's existing WSC stream gauge indicates (perhaps inaccurately) a very low unit runoff (2.4 l/s/km^2). The gauge information also reveals the site offers a poor winter generation profile even at a low design factor. The site is also a bit too distant from transmission and access increasing its cost.

4.0 CLUSTER 4 - STEWART CROSSING - CARMACKS 138 KV

4.1 LAKE CREEK AND REID LAKES

Lake Creek offered the opportunity for an average run of river project. A Reid Lakes storage project could only be built with a diversion from Lake Creek (through the run of river project). Reid Lakes is a flat system of lakes that appear difficult to keep contained based on the available topographical observations; as a result, it is not able to provide full impoundment for winter generation limiting the concepts value.

Reid Lake was nevertheless a relatively interesting winter energy option, but when averaged with the inclusion of the Lake Creek cost and energy it fell off the project short list, particularly given the requirement for an interbasin transfer.

4.2 GRANITE CANYON

The Granite Canyon project site is located on the Pelly River, approximately 20 km east of Pelly Crossing. It is considered as a small run-over river project on a very large system, the total drainage area is estimated to be 46,200 km^2. The site proved one of the more difficult to evaluate at a very high level as the temporary works costs could outweigh the costs of the permanent works, but this is difficult to evaluate without a detailed assessment.

The Granite Canyon site was previously designed as a potential 254 MW hydroelectric project. The project first appeared in T. Ingledow & Associates Limited's report entitled "Hydroelectric Resources Survey of the Central Yukon Territory" in 1968 and subsequently revisited in Sigma Resource Consultants Limited's 1975 "The Development of Power in the Yukon" report.

KP has not had the opportunity to review the Acres Consulting Services Limited's (Acres) 1982 "Granite Canyon Development Prefeasibility Study" or the AECOM Canada Limited's 2010 "Large Hydro Stage 1" report. The Acres 1982 preliminary project layout included a large facility with a 100 m high concrete arch dam and a smaller 50 m high arch dam configuration with a crest gate spillway structure built into the dam. The water intake, conveyance, powerhouse, and tailrace structures were located on the west abutment of the river. Diversion tunnels were located under the east abutment of the river to facilitate de-watering of the dam site during construction.

KP's rapid assessment assumes a 25 m, concrete faced rockfill dam and a low design flow factor (0.25 x MAD). The initial cost estimate indicates that the project site had a low LCOE and a decent winter energy profile but was not short listed due to perceived social acceptability and permitting risks.

4.3 MICA CREEK

Taltmain Lake offers the ability to regulate the Mica Creek flows however we assume a low unit runoff for the area and there appears to be insufficient drop in elevation to justify a 10 MW project size.

5.0 CLUSTER 5: DAWSON CITY - STEWART CROSSING 69 KV

5.1 ALDER CREEK, BONANZA CREEK, FIFTEEN MILE DIVERSION, FORTY MILE RIVER AND INDIAN RIVER, SWEDE CREEK, AND THANE CREEK

These projects were evaluated on a run-of-river basis as they offered decent drainages or elevation drops but their assumed poor unit runoffs and a lack of winter generating potential make them unsuitable based on current assumptions.

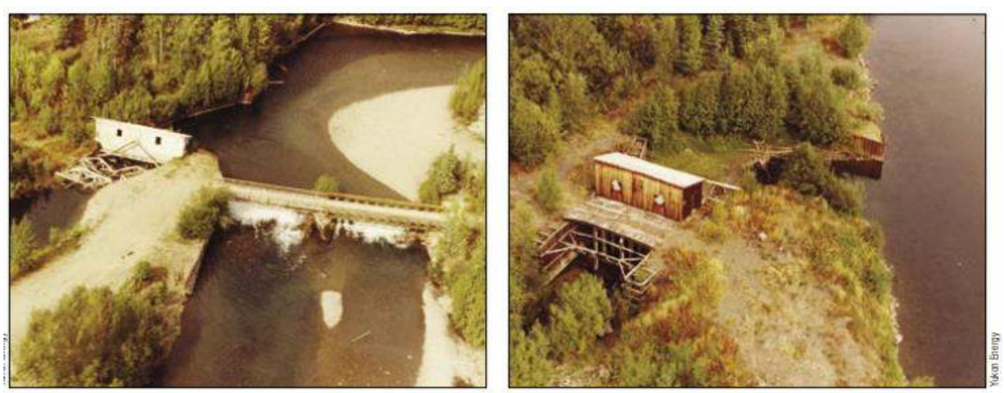
5.2 MCQUESTIN

McQuestin is a sizable river basin (3,769 km^2) and offered some promise as a small section of the river appears on the mapping to show a 60 m drop over a 9 km distance. The existing stream gauge on the river offered some certainty around the unit runoff. The cost estimate puts the project in a high but viable range for further consideration.

5.3 NORTH FORK KLONDIKE RIVER

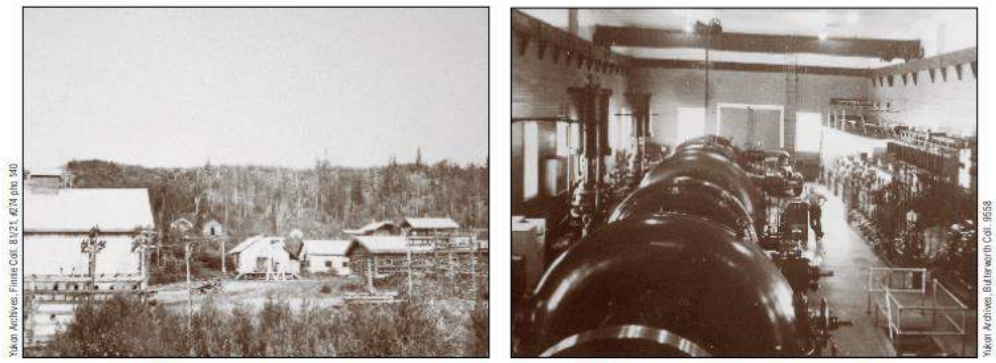
A plant used to exist on the Klondike River at North Fork. YEC information reveals:

“The North Fork plant operated until 1966, when the last Yukon Consolidated Gold Company dredge shut down. A number of studies have been undertaken over the years to explore the feasibility of re-activating the North Fork plant. All have recommended against it, largely because of the difficulty of maintaining power production through the winter months when demand is the highest.”



NOTE:
1. SOURCE: HTTP:/ /WWW.ENERGY.GOV.YK.CA/PDF/POWER_OF_WATER.PDF

Figure 5.1 North Fork Plant (Photos)



Powerhouse at North Fork, (left) 1922 and (right) interior, 1913. In 1935, the building was extended to house a third unit.

NOTE:

2. SOURCE: HTTP:/ /WWW.ENERGY.GOV.YK.CA/PDF/POWER_OF_WATER.PDF

Figure 5.2 North Fork Plant (Photos)

For this review KP considered a 10 MW project with a 10 m dam on the Klondike River at North Fork, elevation was limited due to the presence of bridges and the Klondike Highway.

6.0 CLUSTER 6 - STEWART CROSSING - MAYO 69 KV

No sites investigated.

7.0 CLUSTER 7: PROPOSED MAYO TRANSMISSION EXPANSIONS

7.1 BIG KALZAS LAKE

Big Kalsas Lake offers the opportunity of a 10 MW project with storage and regulation on the lake for winter generation. The cost estimate reveals it is on the higher end of the LCOE.

7.2 FRASER FALLS

A project at Fraser Falls would likely backwater the Horseshoe Slough Habitat Protection Area.

The available topography does not currently allow the identification of any specific drop in elevation at the fall's location. As a result, the project configuration assumed a dam would be the only means of providing any elevation drop. Fraser Falls drain an area in excess of 30,000 km^2. The assumed project costs end up being very high due to the very large temporary work costs.

7.3 PLEASANT CREEK WITH ROGUE DIVERSION

A further look into the access and transmission distances gave reason to remove this site from consideration due to the very high access and temporary works costs.

7.4 SEVEN MILE CANYON

Seven Mile Canyon offer the opportunity for a low head run of river project with a 20 m high structure, but the remoteness and configuration of the project resulted in a higher LCOE.

8.0 CLUSTER 8: PROPOSED FARO TO WATSON LAKE

During the second stage of screening, it was elected not to short list projects along the proposed Faro to Watson route. Lapie and Ross Canyon were still considered due to there proximity to the existing YEC transmission line at Faro.

8.1 BIG CAMPBELL CREEK

The Campbell Creek site was listed in the 2010 AECOM report as “no defined scheme” with a report reference from a 1980 Moneco report. Midgard reviewed the two 1980 Moneco reports available, but neither mentioned the site. The Campbell Creek site was listed in the 1983 Moneco summary report with the statement “not yet studied”. Due to the lack of available site information, it was previously discarded by Midgard. KP had also considered Campbell Creek but Big Campbell Creek is the name of the actual location considered. The site offers the possibility of a 10 MW run of river, but with a high LCOE.

8.2 BLIND CREEK

Small sub 10 MW run of river project that benefits from Anvil Lake.

8.3 CAMPBELL CREEK

In adequate site, possibly confused with Big Campbell Creek in previous studies.

8.4 FALSE CANYON OR FRANCES RIVER (LOWER CANYON)

The site may have been referred to previously as Frances River (Lower Canyon).

False Canyon on the Frances River offers the opportunity for a low head run of river project in a relatively restrained canyon, near the Robert Campbell Highway and the proposed transmission. A 15 m structure would allow for a 15 MW facility.

8.5 FINLAYSON

The Finlayson River is a major tributary to Frances Lake and the Frances River, in the Liard River watershed. The Finlayson River Project is located adjacent to the Robert Campbell Highway and just upstream of Frances Lake, approximately 300 km to the northeast of Whitehorse. The project site was previously short listed by KP.

The current design concept involves a run of river diversion on Finlayson River downstream of the Wolverine River confluence with possible lake storage and flow regulation on Finlayson Lake and Wolverine Lake. The Finlayson site could function as a run of river project on its own merits due to the relatively large drop in elevation. The project could easily be staged as the added controls at Finlayson Lake and Wolverine Lake are distinct sites that simply add value to the run-of-river project.

The site was relatively attractive but was removed from consideration with the removal of the Faro to Watson Lake proposed line.

8.6 FORTIN LAKE DAM

The Fortin Lake site was evaluated as a 6 MW and 10 MW storage site. Its value lies in regulating the Pelly River Flows for the benefit of downstream generation sites. Based on available topography a 25 m structure should offer a large amount of storage without needing to construct multiple saddle dams.

8.7 FRANCIS RIVER (MIDDLE)

On the Frances River, near the Frances River bridge on HWY 4 a narrow portion of the river offers the opportunity for a low head run of river project. A 20 m structure would allow for a 15 MW facility.

8.8 HOOLE CANYON

Hoole Canyon on the Pelly River offers the opportunity for a low head run of river project in a relatively restrained canyon, near the Robert Campbell Highway and the proposed transmission. A 25 m structure would allow for a 12 MW facility.

8.9 HOOLE CANYON + FORTIN LAKE DAM

If the two projects are combined, they offer a firmer winter generation profile for smaller individual installed capacities.

8.10 HOOLE RIVER

The Hoole River site was listed in the 2010 AECOM report but was cut due to having “no defined scheme”. Midgard’s review of all available previous studies revealed no other mention of the Hoole River Project. Due to the lack of available information on the site, it was previously discarded. For the purpose of this study a 12 MW project resulting from a low head 20 m structure is proposed.

8.11 HYLAND RIVER

Hyland River at the Hyland Canyon offer the opportunity for a dam and some drop river elevation. The project site is a bit removed from other infrastructure increasing the potential project cost.

8.12 LAPIE

Lapie is an attractive run of river site and is located close to exiting transmission at Ross River. This study did not evaluate the large number of design permutations that are possible to optimize this site, as the drainage area varies greatly as the potential intake is pushed upstream for greater project head.

8.13 LIARD CANYON

The proper evaluation of Liard Canyon suffers from some topographical and mapping uncertainty at the border between British Columbia and the Yukon. A more detailed look at the site revealed that it is likely that a dam structure would impact the community of Watson Lake, as such the project was removed from further consideration.

8.14 LITTLE RANCHERIA RIVER

The 2010 AECOM report references the 1990 Demers report as a source for the Little Rancheria River site. The Little Rancheria site was listed in the 2010 AECOM report (with no stated capacity or energy) but was cut due to being a "very distant site". Midgard's review reveals the Little Rancheria River site was subject to reconnaissance study only in 1990, and no sites were identified. Due to the lack of available site information, it was previously discarded.

The current evaluation assumes a run-of-river project could be developed at the site with a long penstock, but the project is rather distant from the proposed transmission.

8.15 ROSS CANYON

Ross Canyon on the Ross River offers the opportunity for a low head run of river project in a relatively restrained canyon, near the community of Ross River. A 40 m structure would allow for a 15 MW facility. The site was looked at with a long conveyance system in lieu of a large dam but the capital cost would have increased. The site was removed from further consideration to a perceived lack of social licence. The project would also affect Canol Road #6.

8.16 SLATE RAPIDS

Slate Rapids as previously designed, is a potential 42 MW hydroelectric project on the Pelly River, located in the Pelly River Basin approximately 75 km east of the community of Ross River. The project first appeared in Moneco Consultants Pacific Limited's report entitled "Slate Rapids Hydropower Development" in 1983. It was subsequently revisited in A.S. Demers' 1989 "Yukon Energy Corporation: 1989 Hydro Investigations", and in AECOM Canada Limited's 2010 "Large Hydro Stage 1" report.

Given the range of projects considered 10-30 MW and the fact the Slate Rapids site was difficult to contain requiring multiple saddle dams, the use of Fortin Lake with a smaller structure seemed to be a better option for consideration.

8.17 TYERS RIVER

Tyers River is large drainage tributary of Frances Lake and offers the opportunity for a run of river project, but it is a bit removed from major infrastructure.

9.0 CLUSTER 9 - PROPOSED BEAVER CREEK TO HANES JUNCTION

9.1 LOWER CANYON ON WHITE RIVER

The Lower Canyon on White River is located immediately upstream of the Alaska Highway #1 White River Bridge. The area offers a narrowing of the glacier fed river, creating the potential for a 25 m structure and a 15 MW project.

9.2 DONJEK RIVER

KP Considered a low head run of river project on the Donjek River, it has very similar characteristics to the White River project but with the added costs of being more distant from the proposed transmission line and existing roads. It does drain a slightly larger area.

9.3 KOIDERN

The Koidern Project is a proposed glacier fed run-of-river hydropower development located between Haines Junction and Beaver Creek in southwestern Yukon. The Koidern River is a tributary of the Kluane River. The proposed powerhouse location is within 5 km of the Alaska Highway. It was selected as it is indicative of a more compact and cost-effective type of run-of-river project. It offers lower LCOE despite not offering any dependable capacity.

The project location is outside the bounds of the Asi Keyi Territorial Park, but the intake structure is proposed within the bounds of the Kluane Wildlife Sanctuary. The powerhouse is located outside the area bounds. It is not believed that this particular type of run-of-river development would be in conflict with the objectives of these protected areas, chiefly:

- To provide economic opportunities for Kluane and White River First Nation people.
- To recognize and protect the traditional and current use of the area by Kluane and White River First Nation people.
- To encourage public awareness, appreciation and enjoyment of the natural, historical and cultural resources of the park in a manner that will ensure it is protected for the benefit of future generations.
- To protect, for all time, a natural area of territorial significance, which includes a portion of the Kluane Wildlife Sanctuary, containing physical and biological features of international significance as well as sites of archaeological, historical and cultural value.

It is understood that the management planning for these areas began in April 2015 and is ongoing and that the Government of Yukon and the two affected First Nations will jointly review the plan before it is approved by Yukon's Minister of Environment.

A basic arrangement for the proposed project layout is shown on **Error! Reference source not found.**. Key project parameters for this layout are as follows:

- Design Flow: 16.4 m^3/s
- Gross Head: 140 m
- Installed Capacity: 16 MW
- Dependable Capacity: 0 MW (This project is a glacier fed run-of-river project and does not offer much in the way of winter generation)
- 10 km of access roads, to reach the powerhouse, penstock, and intake
- A run-of-river intake with a small headpond (El. 930 masl.)
- A 7 km long penstock.
- A Powerhouse and tailrace (El. 790 masl)
- A Substation and 20 km long transmission line to a potential transmission line along the Alaskan Highway

9.4 LYNX AND WOLVERINE

Like Koidern, the site offers the opportunity for a high head freshet driven run of river project.

9.5 BURWASH

Like Koidern, the site offers the opportunity for a high head freshet driven run of river project.

9.6 DUKE

Like Koidern, the site offers the opportunity for a high head freshet driven run of river project.

10.0 CLUSTER 10: WHITEHORSE-CARCROSS-JAKE'S CORNER-JOHNSON'S CROSSING-TESLIN 34KV

10.1 SQUANGA CREEK

A development at Squanga Creek would not meet the 10 MW criteria threshold.

10.2 WOLF RIVER

This site was short listed. See Section 7.5.

11.0 CLUSTER 11: PROPOSED EXTENSION FROM CARCROSS TO SKAGWAY

11.1 MOON LAKE

Moon Lake is located roughly 100 km south-southeast from Whitehorse, and 18 km south of the BC Yukon border, and it drains into Tutshi Lake from the south and is ultimately a tributary to the Yukon River, above Whitehorse. While the site was attractive site that had been previously reported in some detail and offered storage capability but was below 10 MW in capacity at a design flow of 2.2 x MAD. The project would also be too small to support a transmission line to Carcross on its own merit.

11.2 TUTSHI LAKE

This site was short listed. See Section 7.3.

12.0 CLUSTER 12 - PROPOSED EXTENSION FROM JAKE'S CORNER TO ATLIN

12.1 SURPRISE LAKE AND THE ATLIN HYDRO PROJECT

This site was short listed. See Section 7.4.

Appendix F: Knight Piesold Pumped Storage Report

Knight Piésold CONSULTING

November 27, 2019

Mr. Hector Campbell
Chair, NNDDC Board
Campbell's North Consulting
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Dear Hector,

RE: Moon–Tutshi Pumped Storage Options

1.0 INTRODUCTION

1.1 REQUEST FOR INFORMATION

YEC (Yukon Energy Corporation) has requested Knight Piésold (KP) to add the Moon-Tutshi pumped storage project to the short-listed sites for its report “Hydropower Potential Assessment (10 MW – 30 MW)”. This letter report has been prepared to provide the relevant information for the Moon-Tutshi pumped storage project separately, as the assessment parameters and characteristics of the proposed pumped storage development are not easily comparable to a traditional hydropower project and are best presented in a separate report.

As requested, KP modeled the proposed Moon-Tutshi Pumped Storage Project, assuming the following development options:

- 15 MW installed capacity and 25 GWh/yr of continuous winter generating capability
- 15 MW installed capacity and 50 GWh/yr of continuous winter generating capability
- 25 MW installed capacity and 50 GWh/yr of continuous winter generating capability
- 35 MW installed capacity and 50 GWh/yr of continuous winter generating capability

1.2 PURPOSE

The proposed purpose of the Moon-Tutshi Pumped Storage Project would be as follows: a pump storage project between Tutshi Lake and Moon Lake designed to seasonally store freshet energy from other Yukon hydropower assets and provide additional winter generation potential to YEC. A pumped storage project would also provide greater flexibility within the YEC grid to allow for easier integration of solar and wind renewables.

1.3 PROJECT SITE AND BASIC CONCEPT

Moon Lake is located in British Columbia (BC) approximately 100km south of Whitehorse, and 20 km south of the BC-Yukon border. Moon Lake drains into Tutshi Lake through Moon Creek at a steep gradient. Existing mapping shows an approximate 390 m drop in elevation between the two lakes. Tutsh Lake drains into Tagish Lake and onwards to the Yukon River.

The Klondike Highway linking Carcross Yukon and Skagway Alaska runs along the western shore of Tutshi Lake. Accessing the Moon Lake site will require either a barge or a new road. If a barge is used, new barge

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landings will need to be constructed at a point along the Klondike Highway and at the foot of Moon Creek. If a new access road is constructed, the shortest and most practical route would be along the southern shoreline of Tutshi Lake.

The 2015 study by Midgard of a proposed pumped storage project at Moon-Tutshi Lakes assumes that flows from Tutshi Lake are pumped into the Moon Lake storage reservoir during high flow - low energy demand periods. The Midgard study had not accounted for a new structure at the outlet of Tutshi Lake, which has now been included. Access to the outlet of Tutshi Lake would require either a new 20 km access road from the Klondike Highway or a new barge landing and access road from Tagish Lake. (See Figure 1.1.)

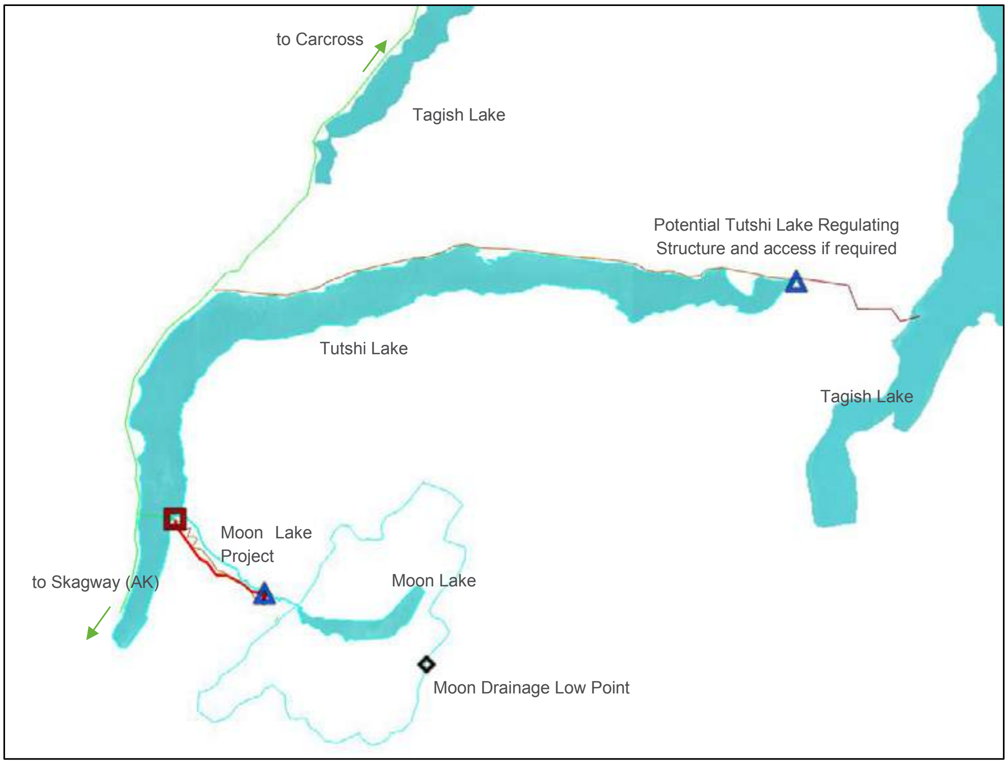

Figure 1.1 Tutshi-Moon Project

The proposed pumped storage project will create a large reservoir for storage on the existing Moon Lake and draw flows as need for generation from this new Moon Lake Reservoir. Water stored in the Moon Lake reservoir will come for two sources, including:

- Natural inflows into the reservoir from the Moon Creek catchment
- Pumped water from the lower Tutshi Lake

The Tutshi Lake/T'ooch' Áayi Conservancy was established in 2012 as a result of the Wóoshtin Wudidaa Atlin Taku Land Use Plan and Taku River Tlingit First Nation Strategic Engagement Agreement. The conservancy, located approximately 65 kilometres northwest of Atlin, encompasses the eastern half of Tutshi Lake. Tutshi Lake is culturally significant to the Carcross/Tagish and Taku River Tlingit First Nations. The lake also has high value lake trout habitat. The Tlingit name (T'ooch' Áayi) means "charcoal lake", after the dark colour of the lake water. Moon Lake is not located within the conservancy, but the outlet of Tushi Lake is.

2.0 CONFIGURATIONS

2.1 PREVIOUS

The 2015 Midgard report proposed a project arrangement comprising the following key components:

- a 31 m high, 700 m long earthfill dam on Moon Lake with a spillway on the south abutment of the dam.
- a low level outlet/intake in both Moon Lake and Tutshi Lake.
- a 5.24 km long, 1.6 m diameter buried steel penstock.
- a powerhouse, with concrete substructure and steel superstructure, containing a 20.2 MW vertical axis Pelton turbine and synchronous generator as well as two 9.4 MW peak power, variable speed drive vertical axis pumps. Flows would be discharged to or drawn from a 7 m deep sump connected to Tutshi Lake.

2.2 PROPOSED

For the purpose of this assessment the layout of the proposed Moon-Tutshi Project has been assumed to be comparable to the Midgard layout, but with differing storage capacities and generation capacities. The Moon Lake dam location and powerhouse location were assumed to be identical; the penstock was assumed to be run on the left bank. The penstock alignment was changed slightly for a more manageable access gradient shortening it by 250m for a total 5km length. These concepts should be further refined if the project is advanced.

The project characteristics for the different development options are presented in Table 2.2 below. The pumping durations presented below were determined based on preliminary modeling of the hydrological system and could be increased in size if desired (i.e. to provide additional flexibility for YEC's Grid for the addition of more renewables such as wind and solar).

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Table 2.1 Moon-Tutshi Project Attributes

	Moon-Tutshi Pumped Storage			
	15 MW	15MW	25MW	35MW
	25 GWh	50 GWh	50 GWh	50 GWh
Moon Lake Minimum Operating Level (masl)	1,114	1,114	1,114	1,114
Moon Full Supply Level (masl)	1,121.5	1,124	1,124	1,124
Tutshi Lake Tail Water Level (masl)	714	714	714	714
Active Storage Variation (m)	7.5	10	10	10
Total Dam Height (m) (assuming 3 m of overburden and 4 m of dead storage and 1 m freeboard)	15.5	18	18	18
Active Storage Volume (x10^6 m^3)	40	59	59	59
Design Flow - Generation (m^3/s)	4.4	4.4	7.35	10.25
Design Flow - Pumping (m^3/s)	1.0	3.0	3.0	3.5
Installed Capacity (MW)	15	15	25	35
Full to Empty Energy Storage (GWh)	38	56	56	56
Generation Duration to Empty Reservoir (Days)	106	156	93	67
Pumping Duration to Fill Reservoir (Days)	460	228	228	196
Average Annual Generating Energy (GWh)	33.4	51.8	54.7	59.1
Minimum Annual Generating Energy (GWh)	25.2	47.6	46.2	51.2
Average Annual Pumping Energy (GWh)	14.8	39.5	44.6	51.2
Average Annual Net Energy (GWh)	18.5	12.2	10.1	7.9
Average Whitehorse Hydro Plant Bonus Winter Yield (GWh) based on 140 kW per m3/s	1.4	1.8	1.9	2.1
Average Total Net Energy (GWh)	19.9	14.0	12.0	9.0

3.0 HYDROLOGY AND ENERGY ASSESSMENT

KP assessed the hydrology of both the Moon Lake and Tutshi Lake catchment areas and then developed a daily energy model using the parameters presented in the sections below (Sections 3.1. through 3.6).

3.1 HYDROLOGY

For the purpose of this study, more effort was placed on the assessment of the Moon Lake catchment area, as it is small when compared to the Tutshi Lake catchment area and would therefore be the more critical water resource in terms of the pumped storage hydro assessment. The natural inflows into Moon Lake would also contribute to the energy generation potential of the project, and therefore have a direct impact on the financial viability of the project.

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Moon Creek has a drainage area of 57.4 km^2 at the proposed dam on Moon Lake. The existing WSC data shown in Table 3.1 was utilised to determine long-term daily inflows into Moon Lake averaging out to 0.8 m^3/s.

Table 3.1 Stream Gauges

Gauge	WSC	Period	Drainage Area (km^2)	Unit Runoff (l/s/km^2)	Complete Years
Moon Creek near the outlet of Moon Lake	09AA018	2012-2017	53	13.5	4
Tutshi River at outlet of Tutshi Lake	09AA013	1956-2017	989	16.2	50

3.2 TUTSHI LAKE STAGE DISCHARGE RELATIONSHIP

For the purpose of this evaluation is was assumed that the Tutshi Lake elevation is naturally maintained at 1,114 masl. This is not an unreasonable assumption given the relative size of Tutshi Lake compared to Moon Lake.

If this project is advanced to the next stage, it is recommended that existing WSC data be utilized to develop a Tutshi Lake stage discharge curve to simulate the natural control of the lake outlet and then perform the appropriate water balance to determine if there is any significant fluctuation in the Tutshi Lake levels that might impact the energy and power generation potential of the proposed project.

3.3 CYCLE EFFICIENCY

A traditional pumped storage hydroelectric project has a roundtrip efficiency of about 70% (i.e. consumes 30% more energy than it generates). As per the previous studies by KP and Midgard, the same 30% losses have been assumed for the Moon-Tutshi Project. This equates to a combined hydraulic, electrical and mechanical efficiency of 87% while generating and 81 % while pumping for the 15 MW, 25 GWh option.

3.4 YEC SYSTEM BENEFIT

YEC has advised KP that the average winter water to kW conversion at the Whitehorse Hydro Plant is 140 kW per m^3/s. The expected additional annual winter energy yield is shown in Table 2.2.

3.5 STORAGE

For the purpose of this assessment the depth area capacity relationship (DAC) provided by the Midgard has been used in the assessment. The corresponding active storage volumes are shown in Table 2.2.

3.6 OPERATING RULES

The Moon Lake Reservoir is operated on a continual generation basis to the extent possible during the months of November-February or if the reservoir is over 95% full. Pumping is triggered in the months of June-September until the reservoir is 95% full. An instream flow release (IFR or ecological flow) of 5% of the Mean Annual Discharge (MAD) is continually released from the Moon Lake Reservoir to sustain the aquatic habitat in Moon Creek.

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3.7 ENERGY ASSESSMENT

A daily flow energy model was developed for the system that accounted for both the pumped flow into Moon Lake plus the natural inflow into Moon Lake. This makes the Moon-Tutshi Pumped Storage Project somewhat unique, as for all four options for the project are net energy generators (i.e. not consumers like traditional closed loop pumped storage hydro facilities). Table 2.2 presents the results of the study, including:

- Energy required for pumping
- Energy generated from a combination of the pumped flows and natural inflows
- Energy generated through benefits to the YEC grid
- Total Net Energy (GWh/year)

4.0 COST ESTIMATE

The capital cost estimates shown in Table 4.1 are based on the project configurations described in Table 2.2 above. These basic project characteristics were used to establish the sizes of the project components and associated quantities. These technical attributes were used to estimate approximate material volumes for excavation, backfill, embankment material and reinforced concrete. Electrical and mechanical equipment requirements were estimated based on empirical data from KP's prior projects and published reports. The capital cost estimate includes an allowance for the Contractor's preliminary and general costs (overheads, insurance, bonus and profit etc.), an allowance for EPCM costs, and a variable contingency.

Unit rates for material production, equipment procurement and installation costs relied on KP's internal costing database including recent, relevant experience with similar sized hydroelectric projects in Western Canada and the Yukon Territory. KP's hydro project cost database also offered an "order of magnitude check of total estimated costs for individual facility components and complete facilities, based on projects with comparable characteristics such as, design flow, penstock pipe characteristics (length, diameter, etc.), gross head, generating capacity, powerhouse area, excavation quantities, reinforced concrete volumes, backfill quantities, switchyard capacity and transmission line capacity and length. Generating equipment costs are based on installed capacity, head and flow, while switchyard costs are interpolated based on installed capacity.

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Table 4.1 Cost Estimate

	Tutshi-Moon			
	15 MW	**15MW**	**25MW**	**35MW**
	25 GWh	**50 GWh**	**50 GWh**	**50 GWh**
Mod, Demob, Insurance, Bonds, Overheads, Contractor's Profit	$30,500,000	$32,500,000	$41,000,000	$46,800,000
Access and Site Preparation	$6,000,000	$6,000,000	$6,000,000	$6,000,000
Intake, Forebay, and Headrace	$3,200,000	$3,200,000	$4,500,000	$5,700,000
Water Conveyance System	$25,000,000	$25,000,000	$37,500,000	$43,400,000
Powerhouse and Ancillary Services	$11,000,000	$11,000,000	$15,500,000	$18,000,000
Power Generation Equipment (Water to Wire)	$15,000,000	$15,000,000	$25,000,000	$35,000,000
Switchyard, Transmission and Interconnection	$4,000,000	$4,000,000	$4,000,000	$4,000,000
Dams and Reservoirs	$22,500,000	$29,000,000	$29,000,000	$29,000,000
Access and Dam on Tutshi	$15,000,000	$15,000,000	$15,000,000	$15,000,000
Sub-Total	$132,200,000	$140,700,000	$177,500,000	$202,900,000
EPCM	$10,600,000	$11,300,000	$14,200,000	$16,200,000
Contingency	$39,700,000	$42,200,000	$53,300,000	$60,900,000
Total Estimated Capital Cost	**$182,500,000**	**$194,200,000**	**$245,000,000**	**$280,000,000**

NOTES:

1. 2019 CANADIAN DOLLARS (CAD)
2. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
3. DOES NOT INCLUDE APPLICABLE SALES TAXES.
4. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
5. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.

5.0 RECOMMENDATIONS

It is recommended that the Taku River Tlingit First Nation and Carcross Tagish First Nation be consulted prior to any serious consideration of the project development. There may be traditional use and cultural values associated with the site that this study does not take into consideration. A more detailed review of site-specific data would be required to confirm project viability and the optimal project size.

Further evaluation of the site is recommended, to improve the design basis, the project configuration, and the understanding of hydrological, topographical and geotechnical conditions. The following activities are recommended:

- Set the project's energy objectives, including the required installed capacity and winter energy generation requirement with a clear purpose for how the plant is envisaged to be utilised.
- Perform a more detailed review of the existing hydrological information.

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- Obtain accurate topographical mapping for the proposed project area to confirm project configurations and details including dam sizes, water conveyance routings, available generation head, powerhouse locations, access roads, and transmission lines. For this project site a LIDAR survey is highly recommended. KP can aide in solicitating contractors to this effect.
- Several existing rights have been previously been identified at the project site and its vicinity. These should be investigated further in order to make sure all potential development barriers have been mitigated.
- Submit a water licence application to Front Counter BC so as to secure the first-in-line water rights to the project ahead of other potential claimants. British Columbia recognizes the rights to water on a first come, first serve basis.
- Complete a feasibility level assessment of the project, including environmental screening.

6.0 CLOSING

Should you require any additional information or clarification on the content of this report, please do not hesitate to contact either of the undersigned.

Yours truly,
Knight Piésold Ltd.

PROFESSIONAL PROVINCE OF B. S. FICHOT # 30575 BRITISH COLUMBIA ENGINEER

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Approval that this document adheres to the Knight Piésold Quality System: SRM

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