NI 43-101 Preliminary Economic Assessment Technical Report – Division Mountain Property

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Effective Date August 1, 2026

Allnorth Consultants Limited EGBC Permit to Practice No. PP 123

DOCUMENT INFORMATION

Project Number:	2602812
File Number:	370
Filename:	260828212-370-RPT-001_Division-Mtn_PEA_Rev 0
Document Revision:	0

REVISION HISTORY

Rev.#	Date of Issue	Prepared By	Reviewed By	Approved By	Description
0	18 Aug 28	MA/TB	SP/KB	KB	Issued for Information

STATEMENT OF QUALIFICATIONS

I, Thomas C. Becker, of Calgary, Alberta, do hereby certify that:

1. I am a geologist living at 135 Edforth Crescent NW, Calgary, Alberta, T3A 3X5.
2. I graduated from the University of Alberta in 1989 with a B.Sc. (Honours) in Geological Sciences.
3. I am a member of the Association of Professional Engineers and Geoscientists of Alberta (registration number 50701).
4. From 1984 to 2001 and from 2004 to present I was actively engaged in mine exploration and development in Alberta, Yukon, China and Mexico.
5. I have read the definition of "qualified person" set out in National Instrument 43-101 ("NI 43-101") and certify that by reason of my education, affiliation with a professional association (as defined in NI 43-101) and past relevant work experience, I fulfill the requirements to be a "qualified person" for the purposes of NI 43-101.
6. I am responsible for the preparation of chapters 1 through 14 and portions of chapters 25 and 26, NI43-101 Preliminary Economic Assessment Technical Report - Division Mountain Property, dated August 17, 2026 (the "Technical Report")
7. I am familiar with the belt of rocks within which the Property lies and the exploration model. I have worked on various aspects of the geology of this Property since 1994 and have contributed to the preparation of geological reports. My last visit to the site was July 1, 2026.
8. I am not aware of any material fact or material change with respect to the subject matter of the Technical Report that is not reflected in the report, non-disclosure of which would make the report misleading.
9. I am independent of the issuer applying all of the tests in Section 1.5 of NI 43-101.
10. I have read NI 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with that instrument and form.

Dated at Calgary, Alberta, this 17th day of August 2026.

Respectively submitted,

Thomas C. Becker, B.Sc., P.Geo

STATEMENT OF QUALIFICATIONS

I, Michael Allen, of Abbotsford, British Columbia, do hereby certify that:

1. I am a mining engineer living at Unit 30 – 3902 Latimer Street Abbotsford, British Columbia.
2. I graduated from the University of British Columbia in 1999 with a BASc. in Mining and Mineral Process Engineering.
3. I am a member of the Engineers and Geoscientists of British Columbia (registration number 3269).
4. From 2001 to present, I was actively engaged in mine development in Alberta, and British Columbia.
5. I have read the definition of "qualified person" set out in National Instrument 43-101 ("NI 43-101") and certify that by reason of my education, affiliation with a professional association (as defined in NI 43-101) and past relevant work experience, I fulfill the requirements to be a "qualified person" for the purposes of NI 43-101.
6. I am responsible for the preparation of Sections 15 through 23, 24, 25 and portions of 26 of the report titled NI43-101 Preliminary Economic Assessment Technical Report - Division Mountain Property dated August 17, 2026 (the "Technical Report").
7. I have experience in both coal mining and coal power plant operations.
8. I am not aware of any material fact or material change with respect to the subject matter of the Technical Report that is not reflected in the report, non-disclosure of which would make the report misleading.
9. I have not completed a site visit.
10. I am independent of the issuer applying all of the tests in Section 1.5 of NI 43-101.
11. I have read NI 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with that instrument and form.

Dated at Abbotsford, British Columbia, this 17th day of August 2026.

Respectively submitted,

Michael Allen, P.Eng.

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LIST OF ACRONYMS AND ABBREVIATIONS - SAMPLE

Acronym	Definition
AACE	Association for the Advancement of Cost Engineering
ACC	Air cooled condenser
ARU	Air replacement unit
ASTM	American Society for Testing and Materials
BF	Belt feeder
BFB	Bubbling Fluidized Bed
CAD	Canadian dollars
CADSIM	CADSIM Plus process simulation software
CAPEX	Capital expenditure
CAT	Caterpillar heavy equipment
CCE	Capital Cost Estimate
CFB	Circulating Fluid Bed
EPCM	Engineering, Procurement, and Construction Management
EU	Engineering Unit
FEED	Front End Engineering Design
FS	Feasibility Study
GHG	Greenhouse gas
GJ	Gigajoule
HGI	Hardgrove Grindability Index
HHV	Higher Heating Value
HMB	Heat and Material Balances
HVAC	Heating, Ventilation, and Air Conditioning
IPP	Independent Power Producer
IRR	Internal Rate of Return
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized Cost of Electricity

LNG	Liquid Natural Gas
MC	Moisture Content
MTPD	Metric Tonnes Per Day
MTPH	Metric Tonnes Per Hour
MW	Megawatt
MWh	Megawatt-hour
NPV	Net Present Value
ODTPH	Oven Dry Tonnes Per Hour
OPEX	Operating Expenditure
PCC	Portland Cement Concrete
PDF	Portable Document Format
PEA	Preliminary Economic Assessment
PF	Pulverized Fuel
PFS	Pre-Feasibility Study
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
RAH	Regenerative Air Heater
RB-C	Babcock & Wilcox subcritical, Carolina style Radiant Boiler
ROW	Right of Way
SC	Surface Condenser
SCR	Selective Catalytic Reactor
SDA	Spray Dryer Absorber
SNC	SNC-Lavalin, now AtkinsRéalis
TIC	Total Installed Capital Costs
UHMW PE	Ultra High Molecular Weight Polyethylene
WACC	Weighted Average Cost of Capital
YEC	Yukon Energy Corporation

1 SUMMARY

This technical report was prepared by Allnorth Consultants Limited ("Allnorth") for Strategic Metals Ltd. ("Strategic"), a mineral exploration and development company with corporate offices in Vancouver, British Columbia. This technical report summarizes the findings of a preliminary economic assessment ("PEA") and presents the mineral resources for Strategic's Division Mountain Coal Project (the Project) in the Yukon. This technical report has been prepared in accordance with National Instrument 43-101 Standards of Disclosure for Mineral Projects ("NI 43-101") and Form 43-101F1.

The Division Mountain coal deposit ("the Property") is located 90 km north-northwest of Whitehorse in southwestern Yukon Territory. Access is by a 31 km four-wheel drive road leaving the Klondike Highway at Braeburn. The Property lies 20 km west of the highway and parallels the Yukon Energy Corporation electrical transmission grid. This point is 290 km by road from a year-round tidewater port at Skagway, Alaska. It lies within the Traditional Territories of Champagne and Aishihik, Little Salmon/Carmacks and Kwanlin Dün First Nations and the Ta'an Kwäch'än Council (collectively "the local First Nations").

The Property is 100% owned by Strategic Metals Ltd. ("Strategic") and is covered by two Territorial Coal Exploration Licences. The licences encompass approximately 37,000 ha of coal-bearing stratigraphy in the Division Mountain area. They were acquired in April and May 2025 and are held under renewable three-year terms.

Exploration on the Division Mountain Property between 1972 and 2018 consisted of 10.4 km of excavator trenching, 72 diamond drill holes totalling 12,230 m, 27 reverse circulation percussion drill holes totalling 2,536 m and 4 rotary air blast ("RAB") drill holes totalling 125 m. Of these, 68 diamond drill holes (11,425 m), 5 reverse circulation percussion (477 m) and 4 RAB drill holes (125 m) were drilled in a 6.5 km by 1.5 km southeast trending area covering the Division Mountain deposit.

Exploration to date has outlined a resource of 52.5 million tonnes (Mt) High Volatile "B" Bituminous coal at the Division Mountain deposit. Calculated weighted average for Division Mountain raw coal, on an air-dried basis, is shown in Table 1.

Table 1: Average Coal Quality

Calorific Value cal/g	Residual Moisture %	Ash %	Volatile Matter %	Fixed Carbon %	Sulphur
5159	2.8	27.6	26.3	43.7	0.45

Allnorth has developed a conceptual surface mine plan for conditions representative of the remote northern climate of Yukon. The mine plan is based on Pit 1, one of the pit areas identified as having potential for surface mining. Pit 1 was selected for this study because it can supply the required coal quantities and has the lowest stripping ratio among the identified mining areas. The mine design project parameters considered in the mine plan, including geologic and geotechnical conditions, mining method, mine layout, equipment requirements, and production/productivity assumptions. For the scoping-level assessment, a pit design with an average strip ratio of approximately 3.5:1 bcm waste to ROM tonnes coal was considered suitable based on the resource size and planned production rate to support a 100MW coal fired power plant.

The proposed coal-fired power plant technology basis was developed around a pulverized fuel boiler, steam turbine generator, air-cooled condenser, boiler feedwater treatment system, and supporting coal offloading and handling infrastructure. Based on vendor discussions, bubbling fluidized bed technology was not considered suitable for the coal due to bed overheating and sintering risk, while circulating fluidized bed technology was considered less favourable due to higher complexity, erosion risk, capital cost, and parasitic load. A pulverized fuel boiler was therefore selected as the preferred technology because it is a proven, commercially available, and cost-effective configuration for the proposed coal characteristics.

The proposed Division Mountain coal mine and associated power generation project is subject to environmental assessment, mine permitting, and First Nations engagement. The Project is located in a largely undeveloped area with important water, fish, wildlife, heritage, and traditional land use values that will require careful assessment and management.

No fatal environmental constraint has been identified based on the information reviewed to date. The principal risks relate to the adequacy of baseline data and the ability to demonstrate effective mitigation for water quality, geochemistry, fish and wildlife habitat, air emissions, reclamation, and Indigenous land use interests. These risks are manageable but will require focused technical work and early integration into project design.

The Project will be assessed under Yukon’s modern treaty and regulatory framework, including review by YESAB before key permits and licences can be issued. Core authorizations are expected to include a Coal Mining Permit, Land Use Permit, Type A Water Licence, air emissions and waste management permits, and potentially federal Fisheries Act authorizations. Yukon has limited recent coal permitting experience, so regulatory expectations may be informed by comparable mining practices in British Columbia.

The Project’s advancement will depend heavily on sustained engagement with affected First Nations and regulators, particularly regarding water protection, fish habitat, wildlife values, heritage resources, and traditional land use. Early, consistent engagement and clear positioning around energy security, economic benefits, environmental controls, and closure commitments will be important to reduce permitting and social licence risk.

The operating cost for the mine average $52/tonne delivered to the power plant. The power plant has a fixed cost of $11.2M per year and a variable cost of $4.8M per year or $6.4 per WMh. This equates to an average total operating cost of $52/WMh.

The capital cost for the mine is $122.0M, including a $ 20.3 M contingency. The capital cost for the power plant is $856.6M with a contingency of $113.6M for a total capital cost of $978.6M. There is also an allowance for a reclamation bond of $20M in the cash flow model.

Calculation of carbon taxes that may be applicable to the Project is difficult to determine because certain mitigations and rulings could significantly reduce or eliminate the amount of payable taxes.

Recent discussions between the Canadian government and certain Provinces also suggest that there may be changes to the industrial carbon tax rates. The extent to which these factors may influence the ultimate carbon pricing treatment for this project would require further discussion with both the Yukon and Federal Governments.

Currently, the federal government mandates a complete phase-out of unabated conventional coal-fired electricity by December 31, 2029. No new coal-fired plants are permitted to join the grid unless they are fully greenhouse gas emissions abated, and so there are no special exemptions for base load coal fired power plants under the federal output-based pricing system for industrial emitters.

The project has not completed an assessment on the inclusion of abatement technology options such as carbon capture and storage and so the potential carbon tax payable for the project has been calculated using the following formula:

Annual Carbon Tax Payable = Annual Coal Tonnes used by Plant × (100% − ash %) × 2.7 t CO_2/t coal × Annual price of carbon

Assuming a base year of 2026, the carbon tax payable would be calculated as follows:

Annual Carbon Tax Payable = 439,000 t coal × (100% − 35%) × 2.7 t CO_2/t coal × \$95/t CO_2 = ~\$73M

A more comprehensive overall project carbon accounting exercise will need to be carried out in the next stages of the project to better understand the implications of carbon pricing on the project. This relatively simplistic approach provides some guidance on the potential impact of carbon pricing on the overall project economics.

For the Base Case capital cost, the project achieves an after-tax IRR of approximately 8% at an electricity sales price of approximately $194/MWh, excluding any carbon taxes that may be payable.

Assuming, the full amount of the projected carbon dioxide emissions from Division Mountain were subject to the carbon tax, the project would achieve an after-tax IRR of approximately 8% at an electricity sales price of approximately $292/MWh.

In addition to the carbon tax, the analysis indicates that project economics are highly sensitive to both electricity sales price and discount rate. Across the evaluated range of power prices, increasing revenue results in significant improvements in both NPV and IRR, demonstrating the potential for improved project economics while highlighting the importance of financing costs, which factor into the discount rate, and long-term power purchase arrangements, as shown in Table 2.

Table 2: Economic Analyses Results without Carbon Tax

Electricity Price	NPV ($M) at Varying Discount Rates with IRR			
	6%	8%	10%	IRR(%)
$200 MWh	228	32	-97	8.4%
$220 MWh	358	135	-18	9.7%
$240 MWh	488	236	64	11.0%

The economic assessment is preliminary in nature and there is no certainty that the results of the preliminary economic assessment will be realized. Mineral resources that are not mineral reserves do not have demonstrated economic viability. No mineral reserves have been estimated for the Property.

The Project would generate several bulk material streams with potential for reuse rather than disposal, principally coal combustion residuals from the power plant, waste rock and overburden from the open pit, salvaged growth media, and process and pit water. Preliminary estimates indicate approximately 138,000 tonnes per year of combustion ash and approximately 70 million bank cubic metres of waste rock over the life of the Pit 1 mine plan. Opportunities to place these materials to beneficial use, including ash as a supplementary cementitious material or structural fill, waste rock as construction aggregate and as progressive in-pit backfill, and recovery of low-grade heat for site and camp heating, have been identified at a conceptual level and are described in Section 24. No capital cost, operating cost, or revenue associated with any of these opportunities has been included in the economic analysis presented in Section 22. Characterisation work to establish whether they are technically and commercially viable is recommended in Section 26.

Prior to starting any additional work on the Project, engagement with the Yukon Government and Yukon Energy should proceed through a structured consultation process to confirm the commercial, technical, and regulatory pathway for a potential future power purchase arrangement. Immediate next steps should include preparation of a preliminary project briefing package, identification of Yukon Energy's applicable interconnection and power procurement contacts, and initiation of a meeting(s) to confirm information requirements, interconnection study scope, grid impact assessment requirements, commercial framework options, and regulatory approval pathways.

Based on the discussions with Yukon Energy/Yukon Government and the past exploration, resource estimates, and engineering studies warrant consideration of a three-phase program. The three proposed phases are independent of each other and could be completed concurrently. Phase 1 would be geotechnical and coal quality studies, with diamond drilling. The Phase 2 study would comprise a capital optimization assessment focused on the two most significant capital cost components: the power plant, specifically the boiler, and the transmission line connecting the Project to the electrical grid. Phase 3 would be the collection of baseline environmental information, completion of desktop studies, and community engagement.

The estimate for Phase 1 is $1,590,000, Phase 2 $590,000, and Phase 3 $1,000,000 for a total of $3,180,000.

2 INTRODUCTION AND TERMS OF REFERENCE

The Division Mountain Property is a coal property located at latitude 61º20' N and longitude 136º05' W, on NTS map sheet 115 H/8, 90 km north-northwest of Whitehorse and 290 km from tidewater at Skagway, Alaska. It is owned 100% by Strategic Metals Ltd.

In the spring of 2005 Mr. Becker, working for Norwest Corporation, was retained by Cash Minerals Ltd. to examine the results of previous exploration conducted on the Property, and update resource calculations for the Property. The assignment included a review of exploration procedures and results; compilation of regional and property-scale geological data and drill data from public sources, assessment reports and company reports. The results of the work were presented in a report titled Geologic Evaluation and Resource Calculation on the Division Mountain Property, Yukon Territory, Canada (Norwest, 2005). The technical report was written to fulfill the requirements of NI 43-101.

Upon completion of the 2005 exploration program Norwest was asked to update the earlier resource estimate. The results of the work were presented in a report titled NI 43-101 Technical Report on the Coal Resources and Reserves of the Division Mountain Property, Yukon Territory, Canada (Norwest, 2008a). The technical report was written to fulfill the requirements of NI 43-101.

In the spring of 2025, Strategic asked the Mr. Becker to update the technical report to present work completed on the Property up to June 1, 2025, which was issued December 11, 2025.

In the spring of 2026, Strategic Metals Ltd. retained Allnorth to complete a preliminary economic assessment for the Division Mountain deposit based on the recommendations put forth in 2025 Resource Report. The basis for the project is the development of a 100 MW coal-fired power plant and associated open-pit coal mine at the Division Mountain Property.

Mr. Becker was responsible for the resource estimate in the 2005, 2008, and 2025 reports. Mr. Becker was not responsible for the reserve estimate in the 2008 report. The Author was not responsible for or involved in any work on the Property or reports related to the Property, after the 2008 report.

Mr. Becker assisted with exploration programs conducted in the fall of 1994, spring of 1995 and last visited the Property on July 1, 2026. The Author’s Statement of Qualifications is provided in this report. This technical report was written to fulfill the requirements of NI 43-101.

3 RELIANCE ON OTHER EXPERTS

This report has been prepared for Strategic Metals Ltd. (Strategic). The findings and conclusions are based on data provided by Strategic as well as site visits and reports prepared by Allnorth and others.

Mr. Becker disclaims information described in the following paragraphs since this information was extracted from sources which may not have been compiled by a qualified person, or by the Mr. Becker and for reasons stated below:

- Claim Information: Information about the location and status of two coal exploration licenses was provided by company documents and the Yukon Government web site of the office of the Whitehorse mining recorder.
- Assessment Reports: Certain assessment reports summarizing exploration programs and used in this report pre-dated the adoption of NI 43-101 reporting standards. As such, and even where the author(s) appear to have been a qualified person(s), these earlier documents do not strictly adhere to the standards required under NI 43-101.
- Purpose of the NI 43-101 Report and Resource Definitions: Under no circumstances is this report to be considered a revision of the previous mineral resources work. This report merely provides a summary of the previous work.
- Qualified Person: The Qualified Person (Author) has not conducted sufficient work to classify the historical mineral reserve as current mineral reserves, and the Author is not treating the historical estimates as current mineral reserves.

Allnorth was provided with a summary of environmental studies as summarized by Ensero Solutions in their report (Division Mountain Coal Project: Environmental Gap Assessment, August, 2026). Allnorth relied upon the conclusions of that work in presenting the status of environmental permitting, as covered in Section 20 of this report.

4 PROPERTY DESCRIPTION AND LOCATION

The Division Mountain Property is located at latitude 61º20' N and longitude 136º05' W on NTS map sheet 115 H/8, 90 km north-northwest of Whitehorse and 290 km from tidewater at Skagway, Alaska, see Figure 1. It lies within the Traditional Territories of Champagne and Aishihik, Little Salmon/Carmacks and Kwanlin Dün First Nations and the Ta'an Kwäch'än Council.

The area of detailed exploration and resource definition at Division Mountain lies largely within 2 coal exploration licences. These are valid for a three-year, renewable term. These licences total approximately 37,000 ha and encompass Upper Jurassic, Lower Cretaceous and Tertiary coal-bearing stratigraphy including several previously known coal occurrences. Figure 2 outlines the general location of the Coal Exploration Licences. Renewal dates are shown in Table 3.

Table 3: Claim List

Licence No.	Mining District	Renewal Date
CYW0166	Whitehorse	2028-04-24
CYW0166	Whitehorse	2028-05-02

Under the Territorial Lands (Yukon) Act, Coal Regulation, exploration licences are currently subject to rental fees of $0.05/ac in the first year, $0.10/ac in the second year and $0.20/ac in the third and final year for each license period. Costs incurred by the license holder on exploration work may be reported to the Yukon Mining Recorder and credited against rental fees. Annual fees for mining leases are currently levied at $1/ac.

Figure 1: Property Location

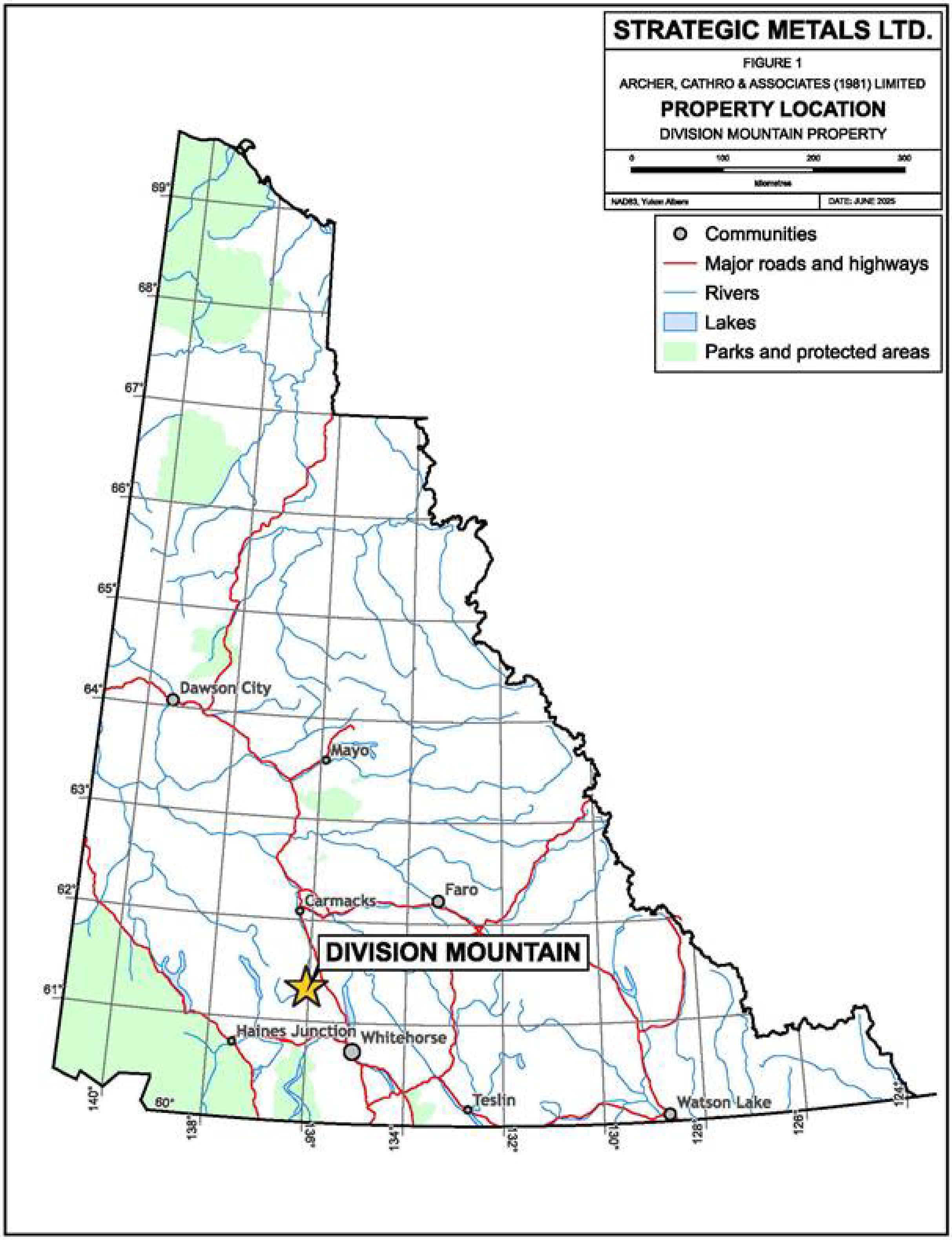
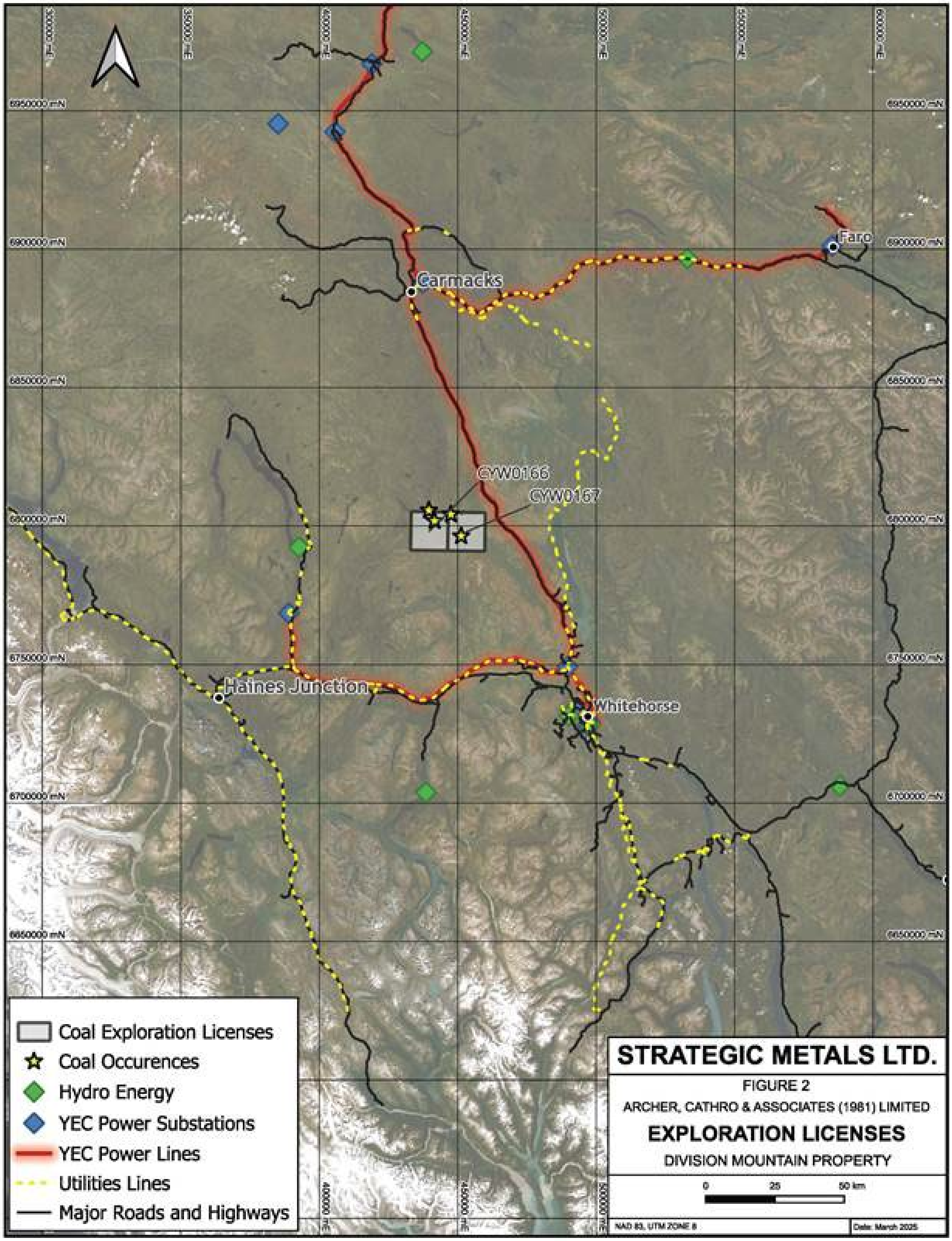


Figure 2: Exploration Licenses



5 ACCESSIBILITY, CLIMATE, LOCAL RESOURCES, INFRASTRUCTURE AND PHYSIOGRAPHY

Access is by 85 km of paved highway from Whitehorse to Braeburn and 31 km all-season four-wheel drive road from Braeburn to Division Mountain, as shown on Figure 2.

Approximately 1 km north of Braeburn Lodge the four-wheel drive road turns into a residential area. The northernmost portion of Braeburn Lake must be forded, and this crossing is generally 50 m wide and approximately 0.5-0.75 m deep. The trail continues to the northwest and eventually joins the historic Dawson Trail stage route, which then extends southward and westward for approximately 22.5 km to a point opposite the northwest end of Corduroy Mountain and approximately due east of the coal occurrences at Division Mountain. From this point, a variety of exploration trails have been constructed over the decades of activity in the area.

The main Property trail extends another 8.5 km westward across Klusha Creek Valley and then climbs up the slopes of Division Mountain to the southernmost portion of the deposit area. There are several short, steep grades (7-15% slope) along the stretch just prior to the trail descending into the Nordenskiold valley.

The nearest permanent buildings are at Braeburn Lake just off the Klondike Highway. The Whitehorse-Aishihik-Faro electrical transmission line parallels the Klondike Highway, 20 km east of the main coal resources.

The area has a continental climate with low levels of precipitation and a wide temperature range. Temperatures range from - 40°C in the winter to 30°C in the summer. Summers are typically pleasant with extended daylight hours, whereas winters are long and cold. Lakes in the area are suitable for float plane use during the ice-free period of early June to late September. Exploration programs are usually conducted between late-May and mid-October, but winter drill programs have been conducted on the Property to take advantage of easier access over frozen ground, which also limits the environmental impact associated with construction of temporary drill access roads.

In the opinion of the Qualified Person, the Property is of sufficient size to accommodate the mining operation, waste rock storage, coal and ash handling and storage, water management structures, the power generation facility, and associated infrastructure described in Sections 16 to 18. Surface rights required for the mine, plant and associated corridors would be obtained through the land use and coal mining permits described in Section 20.2. Water for mine and plant use is expected to be available from on-site wells and pit dewatering, subject to the Water Licence described in Section 20.2. Electrical power for construction would be supplied by diesel generation until the plant is commissioned. A skilled workforce is not resident in the immediate area and would be accommodated in the camp described in Section 18.3, drawing on the Yukon and wider Canadian mining workforce. The Project does not involve tailings or a heap leach facility. Confirmation of surface tenure, of the absence or presence of third-party encumbrances over the licence area, and of access agreements across the Dawson Trail and Braeburn Lake area is recommended in Section 26.

Topography in the Division Mountain region is characterized by rolling hills and broad river valleys with local areas of moderate to steep relief along northerly-trending ridges. Elevations range between 670 and 1680 m. Most of the area is mantled by glacial till and outwash between 1 and 60 m thick. Permafrost is generally restricted to poorly drained areas of moderate to dense vegetation. Natural bedrock exposure is less than 5%, especially within the generally recessive coal measures. Creeks flowing to the north and west off the Property are tributaries of the Nordenskiold River, which is part of the Yukon River watershed, while creeks draining to the south and east flow into Klusha Creek, which joins the Nordenskiold River further to the north.

Tree line in the area is approximately 1300 m on south-facing slopes with willow, alder and black spruce at lower elevations giving way to dwarf birch, alder and stunted spruce at tree line, and finally to grass and lichen at elevations above 1500m. Stands of heavy timber occur at lower elevations near Braeburn Lake.

6 HISTORY

There has been over a century of exploration activity in the Division Mountain area, see Table 4 after Brewer (2017) and Allen (2000). In 1903, J. Quinn and H.E. Porter staked coal near Division Mountain. In 1907, D. Cairnes of the Geological Survey of Canada ("GSC") mapped and sampled three coal seams in Teslin Creek Canyon, north of Division Mountain. An additional coal occurrence was located by Cairnes near the base of Red Ridge, approximately 5 km northwest of the Teslin Creek showings.

In April of 1970, Arjay Kirker Resources Ltd. ("Arjay Kirker"), apparently acting on behalf of Teslin Exploration Ltd., acquired 3 coal exploration licences covering Mount Vowels and Division Mountain areas (Hunt and Hart, 1994). In 1970-1972, they completed geological mapping, bulldozer trenching and diamond drilling. They excavated seven bulldozer pits near the Teslin Creek coal outcrop. Eight seams were exposed ranging in thickness from 0.6 to 4.4 m. A 1047 m, six-hole diamond drill program was conducted in the Teslin Creek area. This work outlined a geological resource of 2.5 Mt (resource estimate was not completed to the standards of NI 43-101). In December 1973, Arjay Kirker staked two coal mining leases covering the thickest coal seams on Division Mountain and one lease covering an exposure on Red Ridge (Hunt and Hart, 1994). These three leases were transferred to Braeburn Coal Ltd. in 1976.

In September of 1970, Norman H. Ursel Associates Ltd. conducted geological mapping of the Cub Mountain area, approximately 4.5 km northeast of Division Mountain (Hunt and Hart, 1994). In 1975, Allen Resource Consultants Ltd. ("Resourcex Ltd.") located coal float in gopher holes on Cub Mountain.

In August 1977, R. Hill visited coal occurrences in the area for Cyprus Anvil Mining and again in August 1978, for Utah Mines (Hunt and Hart, 1994). Apparently, several coal samples were collected for analysis.

Manalta Coal Ltd. acquired two coal exploration licences in 1978 but failed to locate any additional coal seams.

In 1990, one bulldozer trench was remapped and sampled by A.R. Cameron of the GSC (Carne, 1992). Detailed analysis of the trench was carried out in 1991 by the GSC (Beaton et al., 1992).

All-North Resources Ltd. restaked the areas as coal leases in April 1989 (Hunt and Hart, 1994). The W4 Joint Venture restaked the area in April 1990. W4 Joint Venture carried out surface mapping and minor trenching in 1990 and 1991 (Carne, 1992). In August 1992, W4 transferred the two licences to Cash Resources Ltd. ("Cash Resources;" Hunt and Hart, 1994).

In October 1992, Cash Resources purchased four Territorial Coal Exploration Licences enclosing the Division Mountain coal occurrences and later applied for others covering extensions of the favourable rocks to the north. During the 1993 field season, 16 holes totalling 1810 m were drilled to test the Teslin Creek area (Wengzynowski and Carne, 1994). This diamond drilling program defined four seams with an average raw coal aggregate thickness of 10 m over a 1 km strike length forming the eastern limb of the Cairnes Syncline. Measured near-surface resources were calculated at 2.6 Mt to a depth of 200 m, confirming the Arjay Kirker estimate (resource estimate was not completed to the standards of NI 43-101). Hand trenching at Red Ridge 5 km to the north exposed a total thickness of 11.4 m of raw coal in three seams and demonstrated lateral continuity of the coal measures.

In 1994 and 1995, an exploration program consisting of 5.9 km of excavator trenching and 6034 m of HQ-size diamond drilling in 32 holes was carried out to explore a 5 km long southeasterly extension of previously known coal-bearing strata along the limbs of a northerly-plunging syncline-anticline pair (Gish, 1995 and Gish, 1996). This work was successful in discovering a new area of coal deposition with thicker seams than the Teslin Creek area and a dramatically lower strip ratio.

All coal drill intersections greater than 1 m thick were submitted for proximate analysis, generally in samples composed of the entire seam core intersection. In conjunction with the 1994 and 1995 programs, environmental surveys including biological and botanical inventories and water quality assessment were carried out (Gish, 1995 and Gish, 1996) and representative intersections of coal from the 1993 drill program was composited for secondary tests such as grindability, washability, ash chemistry and Ultimate Analysis. The results of the coal quality tests were summarized in an earlier report by the Author (Geologic Evaluation and Resources Calculation on the Division Mountain Property, Yukon Territory, Canada, Becker, March 9, 2005).

Exploration during 1997 consisted of 1667 m of HQ-size diamond drilling in ten holes and twenty-one excavator trenches totalling 2695 m (Gish et al., 1998). The diamond drilling focussed on further delineating west-dipping coal-bearing strata discovered during the 1994-1995 exploration season. More than 900 m of strike length was added to the southwest, while the average aggregate raw coal thickness increased to 24.7 m. The trenching program explored both the Division Mountain Project and Corduroy Mountain, 7 km east of Division Mountain, where an aggregate coal thickness of 23 m was intersected although the most favourable part of the stratigraphy was not tested due to thick overburden cover.

A short excavator trenching program was conducted in early fall 1998 by Cash Resources (Gish, 1998). The work consisted of six excavator trenches totalling 1329 m and was designed to test favourable Tanglefoot Formation stratigraphy in the vicinity of Cub Mountain. No significant coal seams were exposed in any of the trenches.

In November 1998, the Division Mountain Property was optioned to Usibelli Coal Mine, Inc. ("Usibelli;" Sedar, 1998). Exploration in the spring of 1999 consisted of 20 reverse circulation percussion drill holes totalling 1869 m and 4 excavator trenches totalling 315 m (Gish, 2000). The excavator trenches and three of the drill holes were designed as a check of geologic data that formed the basis of the 1998 resource estimate. The bulk of the reverse circulation drilling was carried out to explore the Hull Mountain, Cub Mountain and Corduroy Mountain target areas, all outside the more defined Division Mountain deposit. The program confirmed the results of earlier drilling and outlined several new coal seams on Corduroy Mountain, but Usibelli dropped its option on the Property in May 1999 (Sedar, 1999).

On March 13, 2001, Cash Resources announced a share consolidation and shortly thereafter changed its name to Cash Minerals Ltd. ("Cash Minerals;" Sedar, 2001).

In the spring of 2005, Norwest Corporation ("Norwest") of Salt Lake City, Utah, was contracted by Cash Minerals to complete an initial resource estimate to NI 43-101 standards. A review of all previous assessment work, coal quality tests and a site visit were completed and a report entitled "Geologic Evaluation and Resources Calculation on the Division Mountain Property, Yukon Territory, Canada'' was prepared by Becker, T.C. and published on March 9, 2005.

Later in 2005, Cash Minerals completed four diamond drill holes for a total of 886.57 m on the Division Mountain Property.

The initial 2005 report by Norwest was followed up with a series of reports between 2006 and 2008, all for Cash Minerals, including:

- Norwest Corporation, 2008a. NI 43-101 Technical Report on Coal Resources and Reserves of the Division Mountain Property, Yukon Territory, Canada
- Norwest Corporation, 2008b. Division Mountain Project Pre-Feasibility Study
- SNC-LAVALIN Thermal Power, 2006 Division Mountain Power Project
- The McCloskey Group, Ltd., 2008. The Markets for Division Mountain Steam and PCI

In 2006, Cash Minerals completed 666.9 m of reverse circulation drilling in 7 holes on the Hull Mountain and Cub Mountain areas, located 1 km southeast and 4.5 km northeast, respectively, of the Division Mountain coal deposit (Carne, 2006a).

Also in 2006, Cash Minerals completed 805.9 m of diamond drilling in 4 holes on the Corduroy Ridge prospect (Carne, 2006b).

After 2006, Cash Minerals underwent various changes in management. Then on June 24, 2010, Cash Minerals announced a share consolidation and name change to Pitchblack Resources Inc. (Brewer, 2017).
In 2017, 2560344 Ontario Inc. acquired the Division Mountain Property and related exploration licences. In 2018, they completed 124.7 m of RAB drilling in 4 holes.

In the spring of 2025, Strategic re-staked the Division Mountain Property.

In December of 2025, Strategic issued a 43-101 Resource Report based the previously completed exploration work.

Table 4: Exploration Activity in the Division Mountain Area

Date	Company	Work Preformed and Highlights	Reference
1903	John Quinn and H.E. porter	• staked coal near Division Mountain	Yukon Minfile, 1997
1970	Norman H, Ursel Associates Ltd.	• Cub Mountain area; geological mapping, no coal found (NW comer of NTS block 105E/5)	Hunt and Hart, 1994
1970, 1971	Arjay Kirker Resources Ltd. for Teslin Exploration Ltd.	• Division and Vowel mountains-bulldozer trenching (7 trenches totalling 167 m near Teslin Creek), mapping, sampling and test LP. survey one coal outcrop near Teslin Creek • reconnaissance geological mapping, road building, estimated reserves at 41 Mt • exposed aggregate thickness of 18.6 m of coal over an interval approximately 305 m • explored Corduroy Mountain, no coal located	Kirker, 1971 Craig and Laporte, 1972
1972	Arjay Kirker Resources Ltd.	• drilled 6 diamond drill holes in Teslin Creek area, totalling 1047 m • coal seams intersected vary from 4.6 to 5.9 m • 24.8 m aggregate thickness of coal seams > 0.5 m • reserves calculated as 2.8 Mt	Phillips, 1973
1975	Allen Resource Consultants Ltd. (Resourcex Ltd.)	• located coal float on Cub Mountain in gopher holes, believed to be within the Tantalus formation	Allen, 1975
1977	Hill for Cyprus Anvil Mining Corp.	• collected coal samples for analysis	Hunt and Hart, 1994
1978	Hill for Utah Mines Ltd.	• collected coal samples for analysis	Hunt and Hart, 1994
1978	Manalta Coal Ltd.	• failed to locate any additional coal seams	Hunt and Hart, 1994
1990-1991	All-North Resources Ltd. and W4 Join Venture	• trenching and mapping near Teslin Creek	Yukon Minfile, 1997
1990	Geological Survey of Canada	• one 1972 bulldozer trench was remapped and carefully sampled in the Teslin Creek area for Beaton et al. report	Beaton et al., 1992
1992	Beaton et al, (University of Western Ontario)	• petrography, geochemistry and utilisation potential of the Division Mountain coal occurrence (Cairnes Seam)	Beaton et al., 1992
1993	Cash Resources Ltd.	• drilled 16 holes totalling 1810 m near Teslin Creek • intersected over 28 coal seams > 0.5 m thick • total in situ reserves estimated at 11,139,920 tonnes • hand trenching at Red Ridge exposed 11.4 m coal	Peach, 1993 Wengzynowski and Carne, 1993, 1994

Date	Company	Work Preformed and Highlights	Reference
1994-1995	Cash Resources Ltd.	• 5.9 km of excavator trenching • 6034 m of HQ-size diamond drilling in 32 holes • aggregate coal thickness 10 to 32 m • estimated open pit reserves of 31.7 Mt	Carne and Gish, 1996
1996-1997	Cash Resources Ltd.	• 1667 m of HQ-size diamond drilling in 10 holes • 21 excavator trenches totalling 2695 m at Division and Corduroy mountains • hand trenches southwest of Cub Mountain • raw coal reserves estimated at 54.7 million tonnes	Burke, 1998 Gish and Carne, 1998
1998	Cash Resources Ltd.	• 1329 m of excavator trenching at Cub Mountain • Property optioned to Usibelli Coal Mine Inc.	Burke, 1999
1999	Cash Resources Ltd.	• 1869 m of RC drilling in 20 holes and 4 excavator trenches totalling 315 m at Division Mountain	Gish, 2000
2000	Usibelli Coal Mine Inc.	• Usibelli released option agreement for Division Mountain Property	
2001	Cash Minerals Ltd.	• Cash Resources Ltd. changes name to Cash Minerals Ltd.	SEDAR, 2001
2005	Cash Minerals Ltd.	• Norwest Corporation Ltd. contracted to complete a NI 43-101 Resource Estimate • Cash Minerals completes 866.6 m of diamond drill in 4 holes at Division Mountain	Norwest, 2005
2006	Cash Minerals Ltd.	• SNC Lavalin Ltd. completes a study on thermal power • Norwest completes geotechnical stability analysis of pit walls • Cash Minerals completes 666.9 m of reverse circulation drilling in 7 holes in the Hull Mountain and Cub Mountain areas • Cash Minerals completed 805.9 m of diamond drilling in 4 holes on the Corduroy Ridge coal prospect.	Brewer, 2017 Carne, 2006a Carne, 2006b
2008	Cash Minerals Ltd.	• Norwest completes an updated NI 43-101 Resource and Reserve report • Norwest completes a prefeasibility study for Division Mountain • Mcleskey Group Ltd. completes a market study on steam and pulverized coal injection ("PCI") coals	Norwest, 2008a and b SEDAR, 2008
2010	Pitchblack Resources Ltd.	• Cash Minerals Ltd. changes its name to Pitchblack Resources Ltd.	SEDAR, 2010
2017	2560344 Ontario Inc.	• Pitchblack Resources Ltd sells the Division Mountain Property	SEDAR, 2017 SEDAR, 2019A

Date	Company	Work Preformed and Highlights	Reference
		• 2560344 Ontario Inc. acquires the Division Mountain Property and related Exploration Licences, on February 8, 2017 • 2560344 Ontario Inc. changes its name to Yukoterre Resources Inc	
2018	2560344 Ontario Inc.	• 2560344 Ontario Inc. (Yukoterre Resources Inc) completes 124.7 m of RAB drilling in 4 holes on Division Mountain	Brewer, 2018
2019	Yukoterre Resources Inc	• Yukoterre Resources Inc. completes a NI 43-101 report on February 28, 2019, and an updated NI 43-101 on June 4, 2019	Brewer, 2019A and B SEDAR, 2019B
2024	Yukoterre Resources Inc.	• On August 31, 2024, the 5 coal leases covering the Division Mountain Property expired. The last owner was listed as Yukoterre Resources Inc.	GeoYukon, 2025
2025	Strategic Metals Ltd	• On May 7, 2025, Strategic announced it had acquired two coal licences covering the Division Mountain thermal coal deposit	SEDAR, 2025
2025	Strategic Metals Ltd	Issued and Updated 43-101 Report December 11, 2025	SEDAR, 2025

The tonnage figures reported in Table 4 are historical estimates prepared before the adoption of NI 43-101 and are quoted as reported by the original authors, with sources as shown. The key assumptions, parameters and methods used to prepare those estimates are, in most cases, not stated in the source documents. They are not reported using categories set out in the CIM Definition Standards, and a Qualified Person has not done sufficient work to classify them as current mineral resources or mineral reserves. The issuer is not treating any of these historical estimates as current mineral resources or mineral reserves, and they should not be relied upon. The current mineral resource estimate for the Property is presented in Section 14.

7 GEOLOGICAL SETTING AND MINERALIZATION

This section describes regional geology, stratigraphy and structural geology of the Division Mountain Property.

7.1 Regional Geology

The Division Mountain area lies within the Whitehorse Trough, a northwest-trending, fore-arc basin comprising Mesozoic volcanic and sedimentary rocks. The Whitehorse Trough constitutes the northern end of the Intermontane Belt and is considered part of the Stikinia Terrane. It is bounded by the Yukon-Tanana Terrane to the east and west and by the Cache Creek Terrane to the southeast as shown on Figure 3, and Figure 4, after Hart (1997) and Allen (2000).

During Late Triassic time, an island arc assemblage consisting of a 7000 m thick succession of Lewes River Group aphyric to augite-phyric basaltic andesite flows, breccias and tuff, conglomerate, wacke, limestone and shale was deposited within the Whitehorse Trough. Succeeding Jurassic basin-fill stratigraphy is more complex due to disconformities and hiatus in sedimentation and to diachronous or interfingering relationships in the shallow water and nearshore facies. In general, two sequences are present in the Division Mountain area: 1) Lower to Upper Jurassic conglomerate and sandstone turbidites of the marine to deltaic Laberge Group; and 2) Upper Jurassic to Cretaceous conglomerate, sandstone, mudstone and coal of the largely alluvial Tantalus Formation.

7.2 Stratigraphy

Figure 5 shows a stratigraphic representation of the Whitehorse Trough (Hart, 1997 and Allen, 2000). Figure 6 illustrates regional geology of the Division Mountain area. Figure 7 shows geology with showings (Allen 2000 and Allen et. al. 2001). Figure 8 shows detailed geology with drill holes, section lines and resource blocks.

Legacy geological mapping (Carne and Gish, 1996) in the Division Mountain area had included the coal measures in the Tanglefoot formation, while assigning strata directly underlying the coal measures to the Richthofen formation. However, this interpretation is inconsistent with other reports regarding the Whitehorse Trough (Tempelman-Kluit, 1984; Hart, 1997; and Allen, 2000). The current interpretation is that the coal measures are included in the upper member of the Tanglefoot formation. The underlying strata are included in the lower member of the Tanglefoot formation.

Figure 3: Tectonic Setting

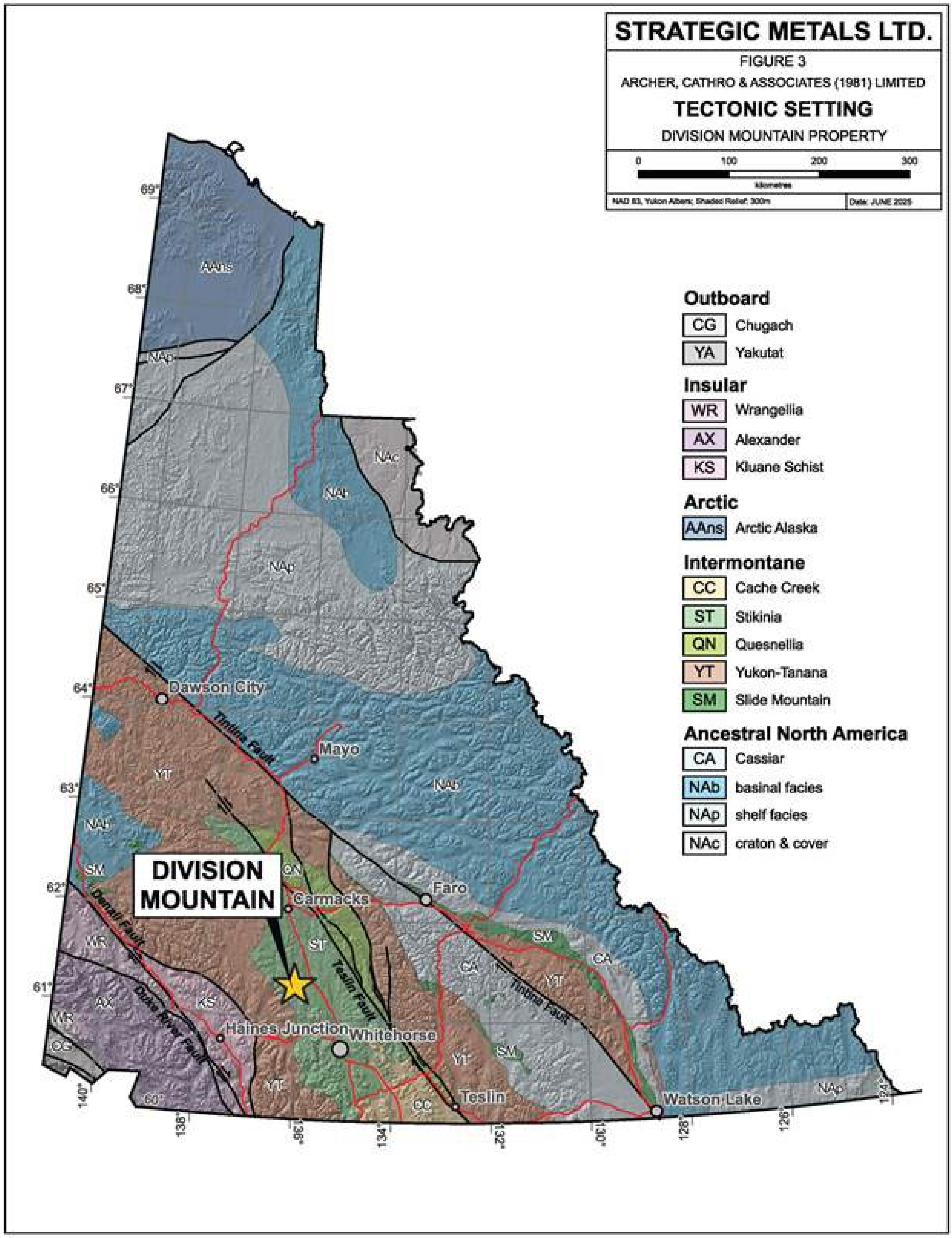


Figure 4: Location of the Whitehorse Trough

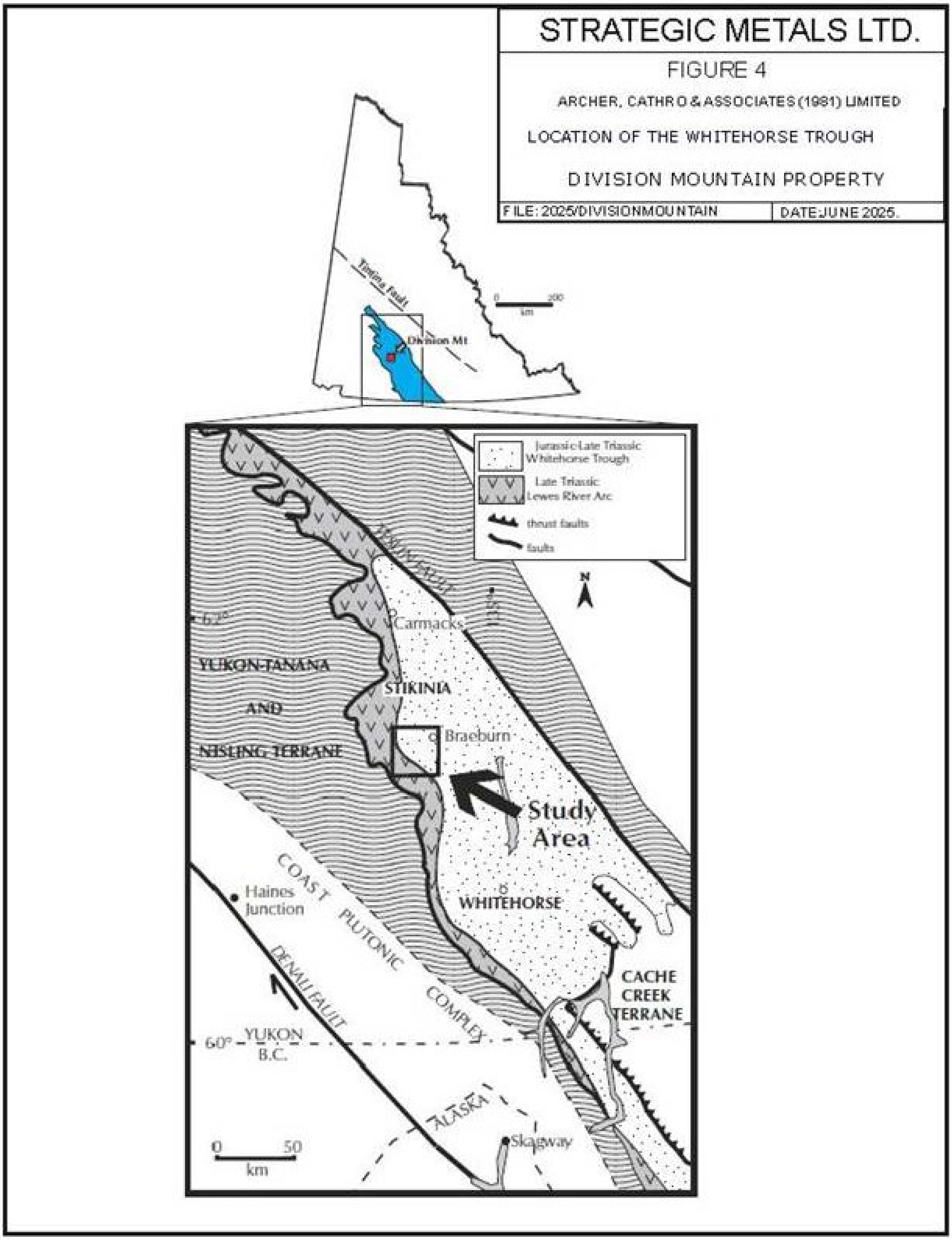


Figure 5: Stratigraphy of the Whitehorse Trough

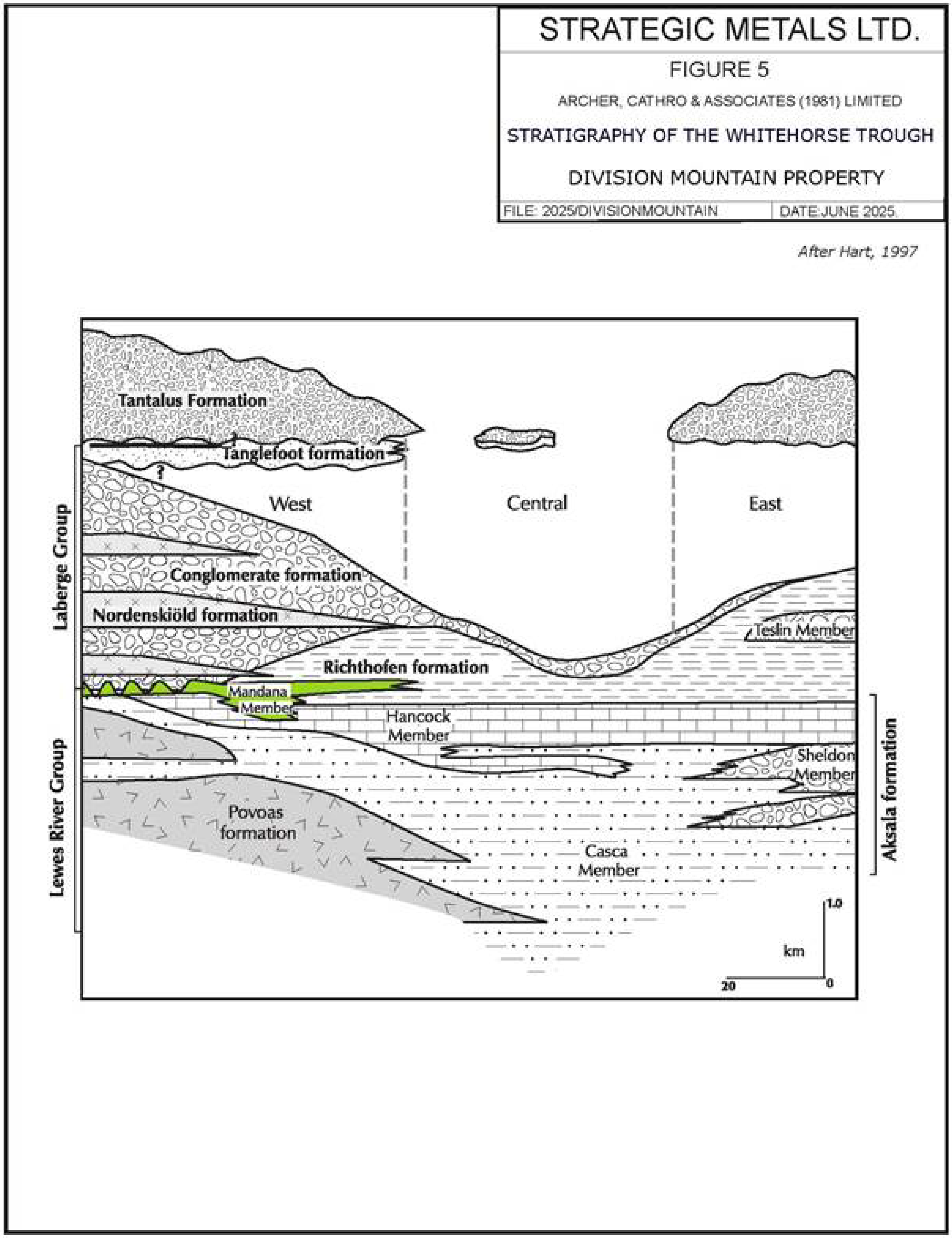


Figure 6: Stratigraphy of the Whitehorse Trough

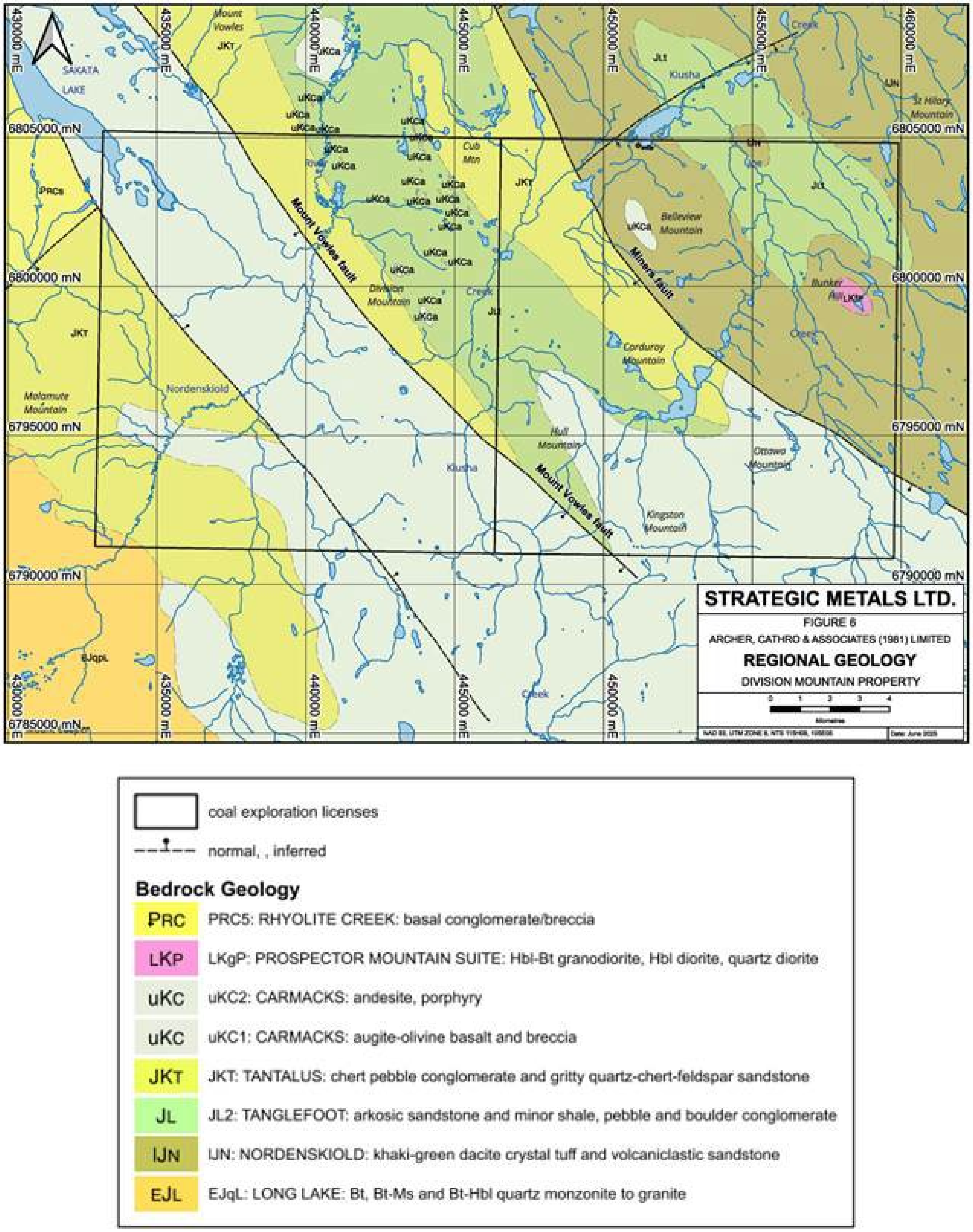
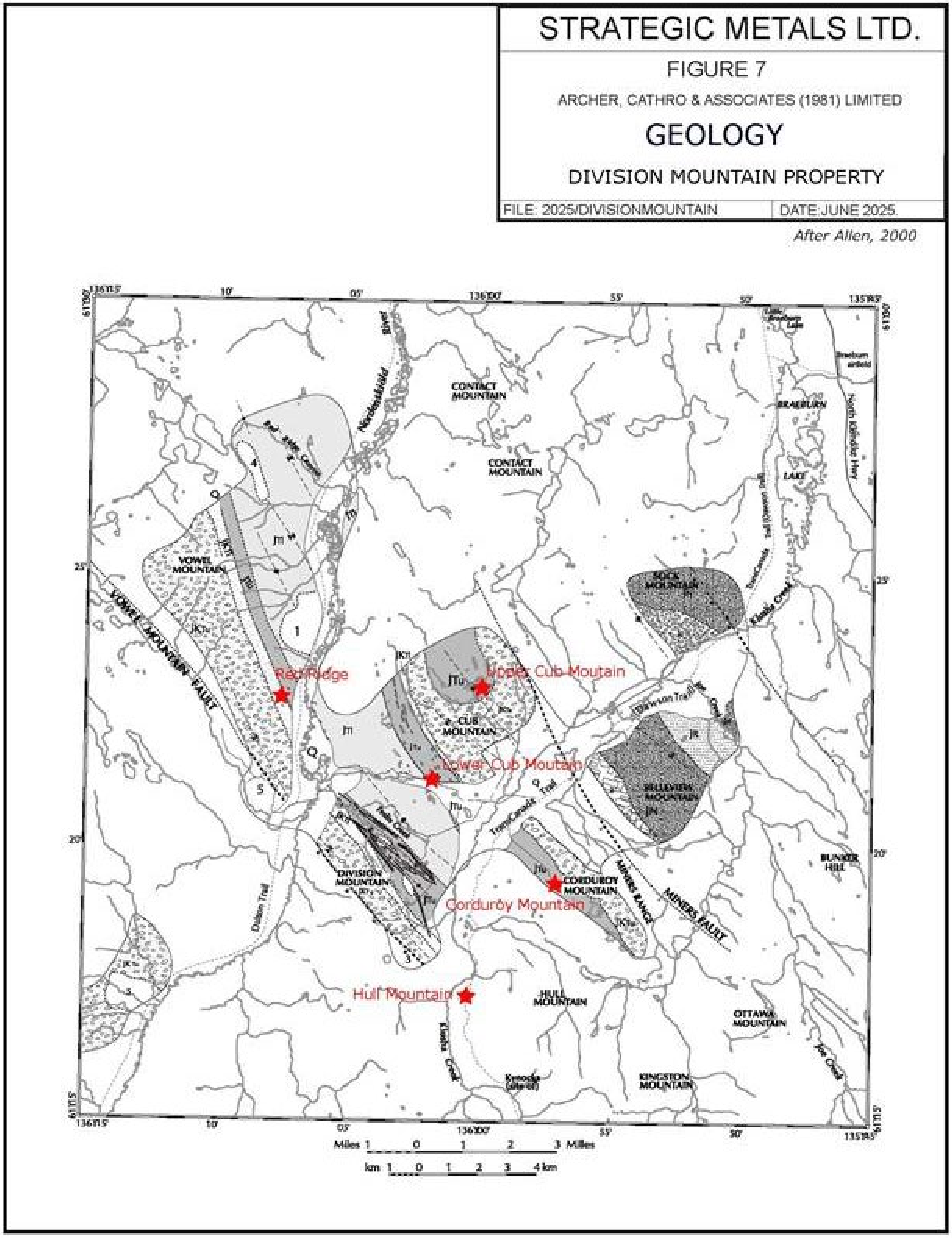


Figure 7: Geology



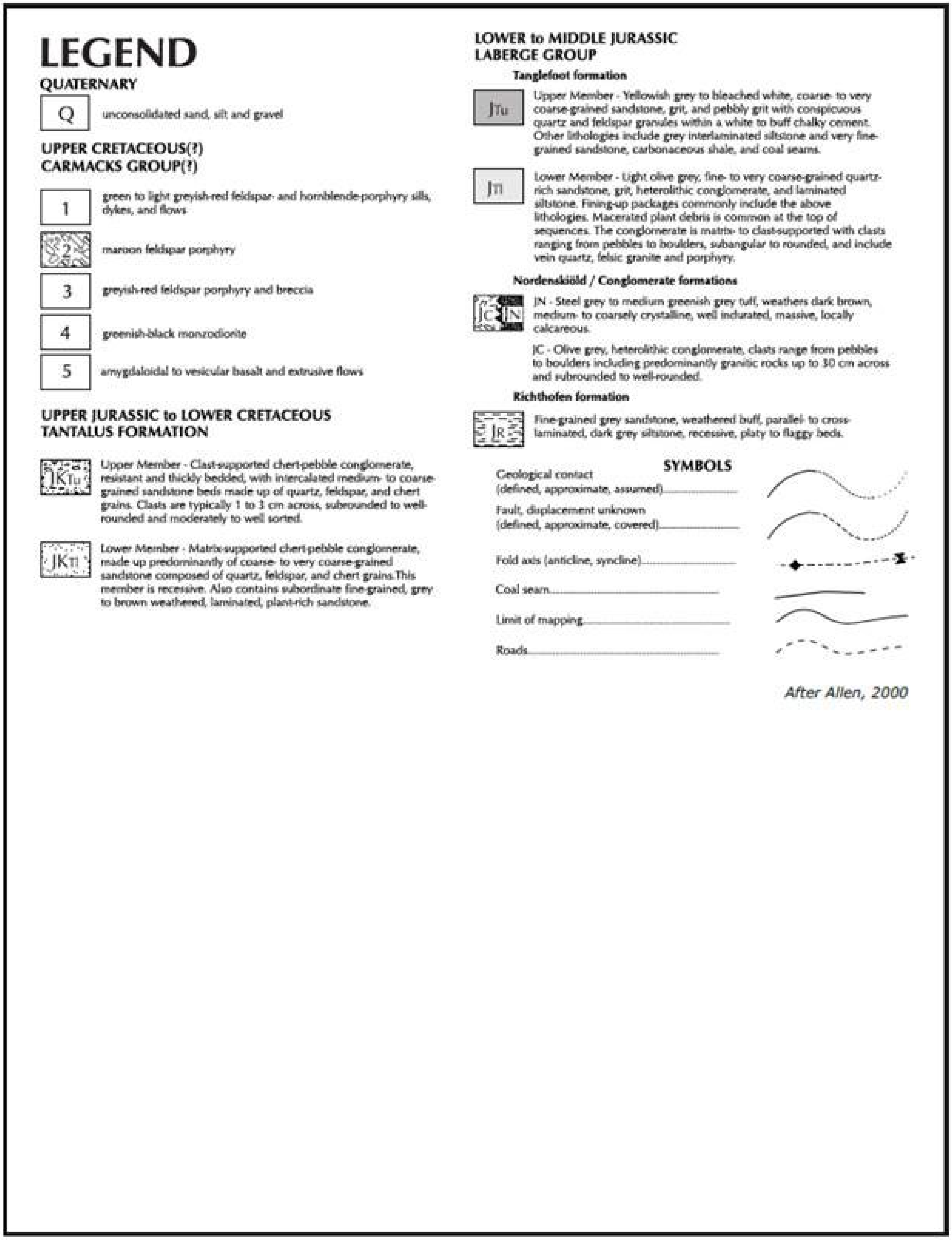
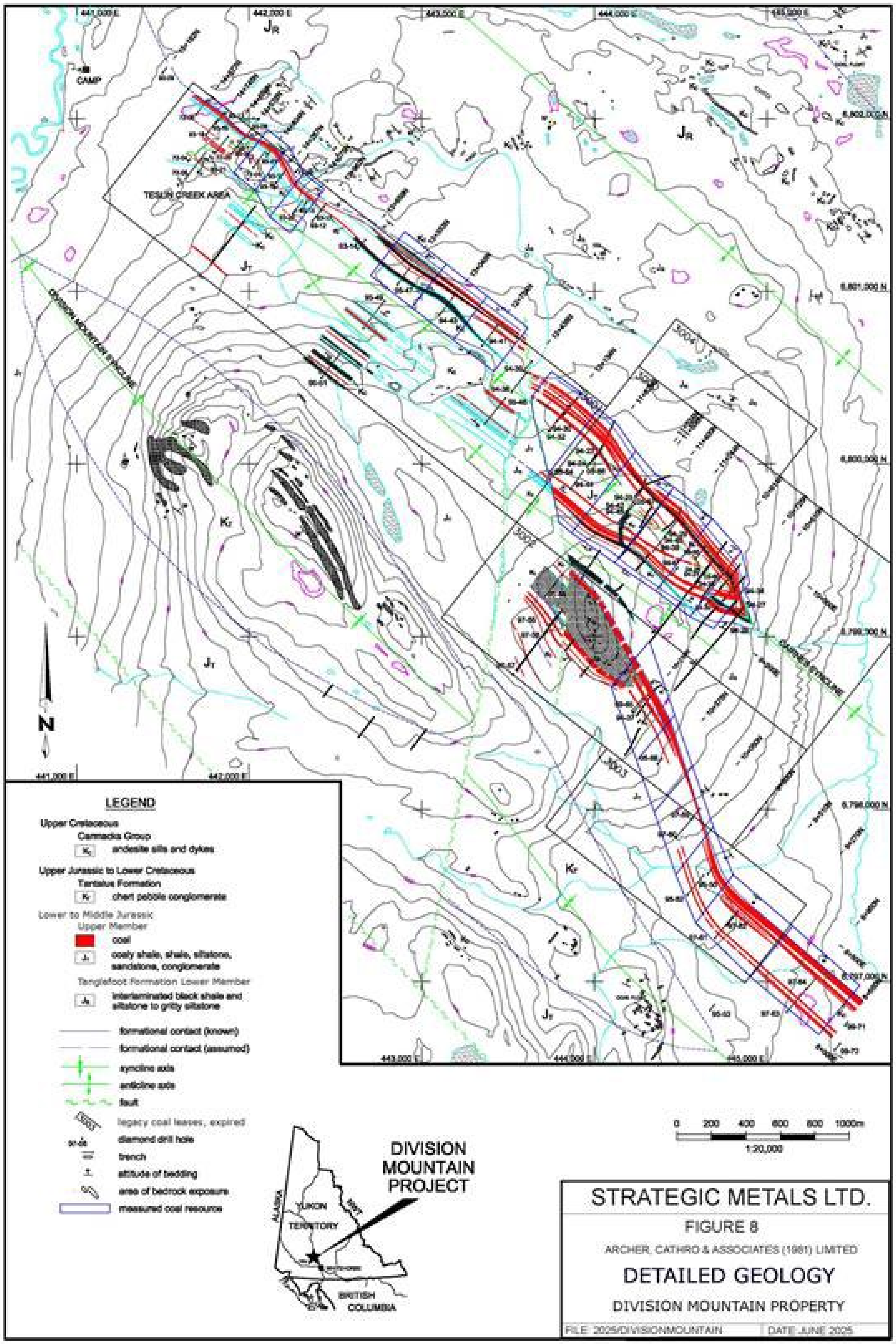

LEGEND
QUATERNARY
Q
unconsolidated sand, silt and gravel
UPPER CRETACEOUS(?)
CARMACKS GROUP(?)
1
green to light greyish-red feldspar- and hornblende-porphyry sills, dykes, and flows
2
maroon feldspar porphyry
3
greyish-red feldspar porphyry and breccia
4
greenish-black monzodiorite
5
amygdaloidal to vesicular basalt and extrusive flows
UPPER JURASSIC to LOWER CRETACEOUS
TANTALUS FORMATION
JKTu
Upper Member - Clast-supported chert-pebble conglomerate, resistant and thickly bedded, with intercalated medium- to coarse-grained sandstone beds made up of quartz, feldspar, and chert grains. Clasts are typically 1 to 3 cm across, subrounded to well-rounded and moderately to well sorted.
JKTl
Lower Member - Matrix-supported chert-pebble conglomerate, made up predominantly of coarse- to very coarse-grained sandstone composed of quartz, feldspar, and chert grains.This member is recessive. Also contains subordinate fine-grained, grey to brown weathered, laminated, plant-rich sandstone.
LOWER to MIDDLE JURASSIC
LABERGE GROUP
Tanglefoot formation
JTu
Upper Member - Yellowish grey to bleached white, coarse- to very coarse-grained sandstone, grit, and pebbly grit with conspicuous quartz and feldspar granules within a white to buff chalky cement. Other lithologies include grey interlaminated siltstone and very fine-grained sandstone, carbonaceous shale, and coal seams.
JTl
Lower Member - Light olive grey, fine- to very coarse-grained quartz-rich sandstone, grit, heterolithic conglomerate, and laminated siltstone. Fining-up packages commonly include the above lithologies. Macerated plant debris is common at the top of sequences. The conglomerate is matrix- to clast-supported with clasts ranging from pebbles to boulders, subangular to rounded, and include vein quartz, felsic granite and porphyry.
Nordenskiöld / Conglomerate formations
JC JN
JN - Steel grey to medium greenish grey tuff, weathers dark brown, medium- to coarsely crystalline, well indurated, massive, locally calcareous.
JC - Olive grey, heterolithic conglomerate, clasts range from pebbles to boulders including predominantly granitic rocks up to 30 cm across and subrounded to well-rounded.
Richthofen formation
JR
Fine-grained grey sandstone, weathered buff, parallel- to cross-laminated, dark grey siltstone, recessive, platy to flaggy beds.
SYMBOLS
Geological contact (defined, approximate, assumed)
Fault, displacement unknown (defined, approximate, covered)
Fold axis (anticline, syncline)
Coal seam
Limit of mapping
Roads
After Allen, 2000

Figure 8: Detailed Geology



The Laberge Group in the Division Mountain area is represented by the shallow marine Lower Member of the Tanglefoot Formation and the fluvial-deltaic, coal-bearing Upper Member of the Tanglefoot Formation (Carne, 2006B). The lithologically distinctive Lower Member serves as an easily recognizable base for the overlying coal measures. Brown weathering black mudstone, with wispy siltstone to fine sandstone laminae in the form of low amplitude cross-stratification, alternates with thick (>l0 m) intervals of massive brown weathering calcareous sandstone. A Lower to Middle Jurassic depositional span is recorded elsewhere in the Whitehorse Trough for the unit but since this sequence is likely diachronous, being a record of a nearshore facies that migrated with basin fill, the precise age of the Lower Member in this area will remain unknown until it can be locally constrained by paleontological data.

Middle to Upper Jurassic Tanglefoot Formation Upper Member strata in the Division Mountain area records a complex fluvial-deltaic depositional environment. In general, the unit consists of upwardly fining sequences of alternating sandstone-conglomerate beds and black shale or shaly mudstone, the latter commonly associated with coaly shale or coal seams. A section measured at Red Ridge, northwest of Division Mountain, consists of 15 sedimentary cycles, each on the order of approximately 10 m thick. A typical cycle consists of:

- A scour-based arkosic pebble conglomerate containing fossils, twigs and branches lying transverse to paleoflow along 1 to 2 m trough foresets;
- Conglomerate lags infilling troughs as lenticular beds;
- A fining-upward zone of medium- to fine-grained arkose containing trough cross-beds which exhibit an upward decrease in set size;
- Grey organic rich shale or shaly mudstone containing leaves, grasses and Metasequoia needles and twigs;
- Coaly shale to shaly coal, commonly rich in coalified twigs and branches;
- Banded coal; and,
- Either a transition back to grey shale or an abrupt termination by the basal pebbly conglomerate bed of the next cycle.

The depositional environment was one of a rapidly aggrading flood-dominated delta. Cross-bedded conglomerate-sandstone cycles represent point-bar deposits from a high energy fluvial system. Paleocurrent variance supports a meandering river interpretation. Of particular interest is that, despite the generally coarse-grained nature of the channel sandstones and conglomerates, the overbank deposits and related coals are relatively thick and demonstrate remarkable lateral continuity. The coal seams were deposited in long-lived delta plain swamps that served as collection sites for transported organic material and for generation of peat bogs. Closer to the Tanglefoot-Tantalus contact, coal becomes less abundant. Instead, grey shale and coaly shale predominates as much thinner beds than the coal seams lower in the succession.

Resistant beds of thick-bedded chert pebble conglomerate of the Upper Jurassic to Lower Cretaceous Tantalus Formation cap the Tanglefoot Formation Upper Member coal-bearing sequence, forming prominent topographic highs in the region. Depositional environment of the Tantalus Formation appears to be one of an active flood plain. Coal has previously been mined within the Tantalus conglomerates 100 km to the north of Division Mountain in the Carmacks region. Coal float has been found in the vicinity of gopher holes in areas underlain by the Tantalus Formation at Division Mountain and Red Ridge but to date none has been found in bedrock.

Small stocks, dykes and sills of porphyritic basalt, andesite and dacite intrude the Tanglefoot Formation coal measures. The presence of glassy chill zones and rare amygdaloidal textures are indicative of emplacement in a near-surface setting. Age of the intrusions is unknown, but they are probably related to regionally extensive volcanic rocks of the Upper Cretaceous Carmacks Group, which unconformably overlie the Laberge and Tantalus stratigraphy in the Division Mountain area.

7.3 Structural Geology

Deformation in the Whitehorse Trough occurred primarily as flexural slip folding during the Middle Cretaceous. Synclinal and anticlinal axes trend north-northwest, parallel to the trough axis. Fold wavelengths are generally between 500 m and 2 km, although complex tight folds with wavelengths less than 3 m have been noted. The coal-bearing Cairnes Syncline, outlined by 1994-95 exploration, trends 310° and plunges 9° to the northwest. The limbs dip between 25 and 72°. Drilling in 1997 and 1999 concentrated on the coal rich east limb of the Division Mountain Syncline about 2 km south of the Cairnes Syncline. This syncline also trends approximately 310° with the east limb dipping 45 to 55° to the southwest. Exploration to date has not yet defined either the fold nose or the western limb of the Division Mountain Syncline.

The folded stratigraphy has only been slightly modified by northwest- and northeast-trending normal faults with minor dip-slip displacements.

7.4 Mineralization

There are no natural exposures of coal in the Division Mountain area. Bedrock occurrences have either been located by hand or machine trenching through glacial till cover in areas of coal float or where coal-bearing stratigraphy has been projected to be present. Coal seams occur throughout the Tanglefoot Formation Upper Member, but the thickest and most continuous accumulations of coal are present near the base of the member.

The Division Mountain coal deposit has been explored over a 6.5 by 1.5 km southeast trending area. Internal stratigraphy and structure of the recessive coal measures is best illustrated on the detailed geology map shown on Figure 8 and on cross sections showing drill hole data in Norwest (2008a). The area of coal resources is discussed in more detail in Sections 9, 10, 13 and 14.

The coal measures have also been identified at the Red Ridge, Upper and Lower Cub Mountain, Corduroy Mountain and Hull Mountain occurrences, all within 7.5 km of Division Mountain.

The Red Ridge coal occurrence was first discovered in 1907 by D.C. Cairnes of the GSC. It lies approximately 5 km along strike to the northwest of the Teslin Creek discovery area. In 1972, Arjay Kirker relocated the coal showing and measured a section from the top of Red Ridge northeast to the Nordenskiold River, which defines approximately 245 m of Tantalus conglomerate overlying finer-grained Tanglefoot sedimentary rocks containing coal and carbonaceous shale. In 1993, a 25 m hand trench was cut near the break-in-slope to the Nordenskiold River valley. A further 15 m was added to this trench in 1997. The trench profile consists of a blanket of glacial soil overlying a series of sub-horizontal layers of arkose-sandstone grit, sand lenses and coal fragment horizons varying in thickness from 20 to 70 cm. Structures within the coal fragment horizon are virtually non-existent. The nature of the stratigraphy in the trench is most likely attributed to downhill creep of a coal horizon uphill at least 10 m from the initial exposure. The probable aggregate true width of bedrock coal may be in the range of 12 to 15 m.

At the Lower Cub Mountain occurrence, the combination of bedrock exposure afforded by the steep southwestern slope of Cub Mountain, results of 1997 and 1998 excavator trenching and the 2006 reverse circulation drill program have provided a reasonably accurate evaluation of the area for its coal potential. A relatively small number of thin coal seams are present within the Upper Member of the Tanglefoot Formation, the host of the nearby Division Mountain coal resource. The only significant intersection is a 1.6 m coal seam with low to moderate apparent ash content and a 20 cm interval (Carne, 2006a).

At the Upper Cub Mountain occurrence favourable stratigraphy was identified but drilling in 1999 suggests that the area lies near the contact of the Tanglefoot and Tantalus formations and maybe higher in the stratigraphy than where coal was found elsewhere. The Upper Cub Mountain occurrence lies north of coal licenses held by Strategic.

At Corduroy Mountain the Tanglefoot Formation Upper Member stratigraphy was explored with a 360 m long trench in 1997. This area is 5 km along strike to the southeast of the same stratigraphy exposed at Lower Cub Mountain. Drilling in 1999 below the excavator trench exposed several additional coal seams, with one hole returning an aggregate thickness of 17.96 m of coal. The four 2006 diamond drill holes provide a complete stratigraphic section across the upper 580 m of the Upper Member of the Tanglefoot Formation (Carne, 2006b). The base of the Upper Member of the Tanglefoot Formation, where the bulk of the Division Mountain resources are located, was not tested by excavator trenches or drill holes.

The Hull Mountain area has coal exploration potential, but no coal has been identified to date. In 1999 and 2006, the area was selected as a target for reverse circulation drilling to assess whether the relatively abundant and thick coal seams that form the Division Mountain coal resource continue beneath the Klusha Creek valley, a distance of 1400 m (Carne, 2006a). Six holes were drilled on the very northern slopes of Hull Mountain, but all ended in overburden that exceeds 20 m depth.

8 DEPOSIT TYPES

As specified in GSC Paper 88-21 (Hughes et al., 1989) coal deposits are commonly classified with respect to their "Geology Type." Coal "Geology Type" is a definition of the amount of geological complexity, usually imposed by the structural complexity of the area. The classification of a coal deposit by "Geology Type" determines the approach to be used for the resource/reserve estimation procedures and the limits to be applied to certain key estimation criteria. The identification of a particular "Geology Type" for a coal property defines the confidence that can be placed in the extrapolation of data values away from a particular point of reference such as a drill hole.

The classification scheme of GSC Paper 88-21 is like many other international coal reserve classification systems but it has one significant difference. This system is designed to accommodate differences in the degree of tectonic deformation of different coal deposits in Canada. Four classes of "Geology Type" are provided for that range from the first, "low," which is for Plains type deposits with low tectonic disturbance; to the fourth, "severe," which is for Rocky Mountains type deposits.

The Division Mountain Property falls within the "moderate" category based on broad open folds (wavelengths from 400 m to well over 1.5 km), relatively uncommon faults (displacements ranging from 10s of metres up to 100 m) and average bedding inclinations of approximately 50º (range from 25 to 72º).

Coal deposits are further classified on the basis "Deposit Type," as defined in GSC Paper 88-21, which refers to the extraction method most suited to the coal deposit. There are four categories, which are:

- Surface
- Underground
- Non-conventional
- Sterilized

The Division Mountain deposit is considered to be a "Surface" mineable deposit.

9 EXPLORATION

This section summarizes excavator trenching, geophysical surveys and environmental surveys performed on the Division Mountain Property during the period 1993 to 2018. The work is described by Wengzynowski and Carne (1994), Gish (1995, 1996and 2000), Gish and Carne (1998), Carne (2006a and 2006b), and Brewer (2018). The 1994 to 2006 work was completed by Cash Minerals, the 1999 program was funded by Usibelli and the 2018 program was completed by 2560344 Ontario Inc. Diamond drilling and borehole geophysical surveys are discussed in Section 10.

The 1994 and 1995 excavator trenching programs utilized a Caterpillar 235 operated under contract by 10983 Yukon Ltd. of Whitehorse. The programs consisted of 30 trenches totalling 5.9 km in length and required 928 hours of excavator time. The 1997 excavator trenching program required 569 hours of Hitachi UH09 excavator time to complete 21 trenches totalling 2695 m in length. The excavator was operated under contract by 15317 Yukon Inc. of Whitehorse. Trenching in 1998 consisted of six trenches totalling 1329 m completed with 116.5 hours of excavator time. In 1999, four excavator trenches totalling 315 m were completed with a Caterpillar 235 excavator operated by Caron Diamond Drilling Ltd. of Whitehorse.

In 1993, VLF-EM, EM-31 and total magnetic field surveys were conducted over 16.5 km on grid crosslines between 10+000N and 15+182N. The readings were taken at 10 m stations by Amerok Geophysics of Whitehorse (Wengzynowski and Carne, 1994).

Geophysical surveys during the 1994 exploration program included 36.9 km of VLF-EM at 10 m intervals on 300 m lines spacing and 576 m of reflection seismic surveys with a constant 4 m geophone interval on selected VLF-EM lines (Gish, 1995). VLF-EM lines were run with 27.4 km orientated at 130° and 9.5 km orientated at 040°. The lines orientated at 130° were intended to test the eastern limb of the Division Mountain Syncline while those orientated at 040° were used to better delineate the nose of the Cairnes Syncline.

Down-hole geophysical logging was performed in 1999 on all reverse circulation drill holes by Amerok Geoscience Ltd. of Whitehorse (Gish, 2000). Resistivity was measured using an IFG BMP-04 galvanic Resistivity tool with 16 inch and 48 inch electrode spacing. Natural radioactivity was quantified with an IFG BSG-01 four channel gamma probe with windows in the 100 KeV to 3 MeV range. Measurement time was constant at one second. The results of these surveys were inconclusive and failed to accurately define the coal seams.

Environmental studies were conducted in 1993, 1994 and 1995. These surveys included a log of wildlife observations made by personnel on the Property and basic meteorological readings recorded when personnel were present on the Property. Hydrology surveys were contracted to J. Gibson & Associates of Whitehorse (Wengzynowski and Carne, 1994 and Gish, 1995). Water samples and flow measurements were taken at five sites located at upper Klusha Creek, upper Nordenskiold River and Teslin Creek.

10 DRILLING

A total of 72 diamond drill holes totalling 12,230 m, 27 reverse circulation percussion drill holes totalling 2536 m and 4 rotary air blast drill holes totalling 124.7 m have been completed on the Division Mountain Property. Of these, 68 diamond drill holes (11,425 m), 5 reverse circulation percussion (477 m) and 4 RAB drill holes (125 m) were drilled in a 6.5 by 1.5 km southeast trending area covering the Division Mountain deposit. The work is described by Wengzynowski and Carne (1994), Gish (1995, 1996 and 2000), Gish and Carne (1998), Norwest (2008a), and Brewer (2018). A list of drill hole location data is provided in Table 5. The location of all drill holes is shown in Figure 9. Cross sections through the coal measures are shown in Norwest 2008a.

Table 5: Drill Hole Survey Data

Drill Hole	UTM Coordinates*		Elevation	Grid Coordinates		Depth	Azimuth Degree	Surface Dip	Final Dip
	x_NAD83	y_NAD83		Northing	Easting				
71-01	441923	6801891	780	14+422	9872	182.88	40	50	-
72-02	442168	6801864	795	14+223	10014	182.88	40	50	-
72-03	441705	6801978	757	14+648	9803	182.88	40	50	-
72-04	441547	6801930	732	14+739	9665	24.99	40	50	-
72-05	441531	6801828	749	14+692	9585	306.33	40	50	-
72-06	441592	6802197	726	14+877	9908	167.03	40	50	-
93-07	442076	6801830	792	14+267	9927	97.84	40	50	-
93-08	441872	6802061	772	14+572	9970	108.5	40	50	-
93-09	441394	6802435	723	15+182	9970	73.46	40	50	-
93-10	442056	6801805	792	14+267	9895	157.3	40	63	60
93-11	441829	6802009	765	14+572	9910	92.66	40	50	55
93-12	442266	6801579	850	13+962	9852	169.16	40	50	57
93-13	442316	6801642	810	13+962	9932	74.37	40	50	54
93-141	442522	6801426	810	13+658	9894	148.13	35	58	62
93-15	442217	6801668	795	14+060	9887	82.6	34	50	54
93-16	441707	6802147	734	14+747	9942	86.56	40	50	54
93-17	441729	6802167	733	14+745	9972	48.77	46	50	53
93-18	441649	6802082	739	14+745	9855	170.38	40	50	56
93-19	441997	6801951	785	14+404	9968	84.1	40	50	-
93-20	441798	6801970	750	14+572	9862	166.12	38	50	58
93-21	441672	6801956	758	14+660	9764	61.87	154	75	78
93-22	442152	6801625	777	14+087	9816	187.5	40	60	65
94-23	443903	6800220	914	11+833	9820	160.02	40	50	46
94-242	443856	6800155	916	11+829	9740	133.81	40	50	48
94-25	444124	6799952	937	11+496	9750	163.98	40	50	45
94-26	444531	6799535	935	10+914	9675	164.9	40	50	50
94-272	444726	6799295	925	10+612	9620	26.52	40	50	-

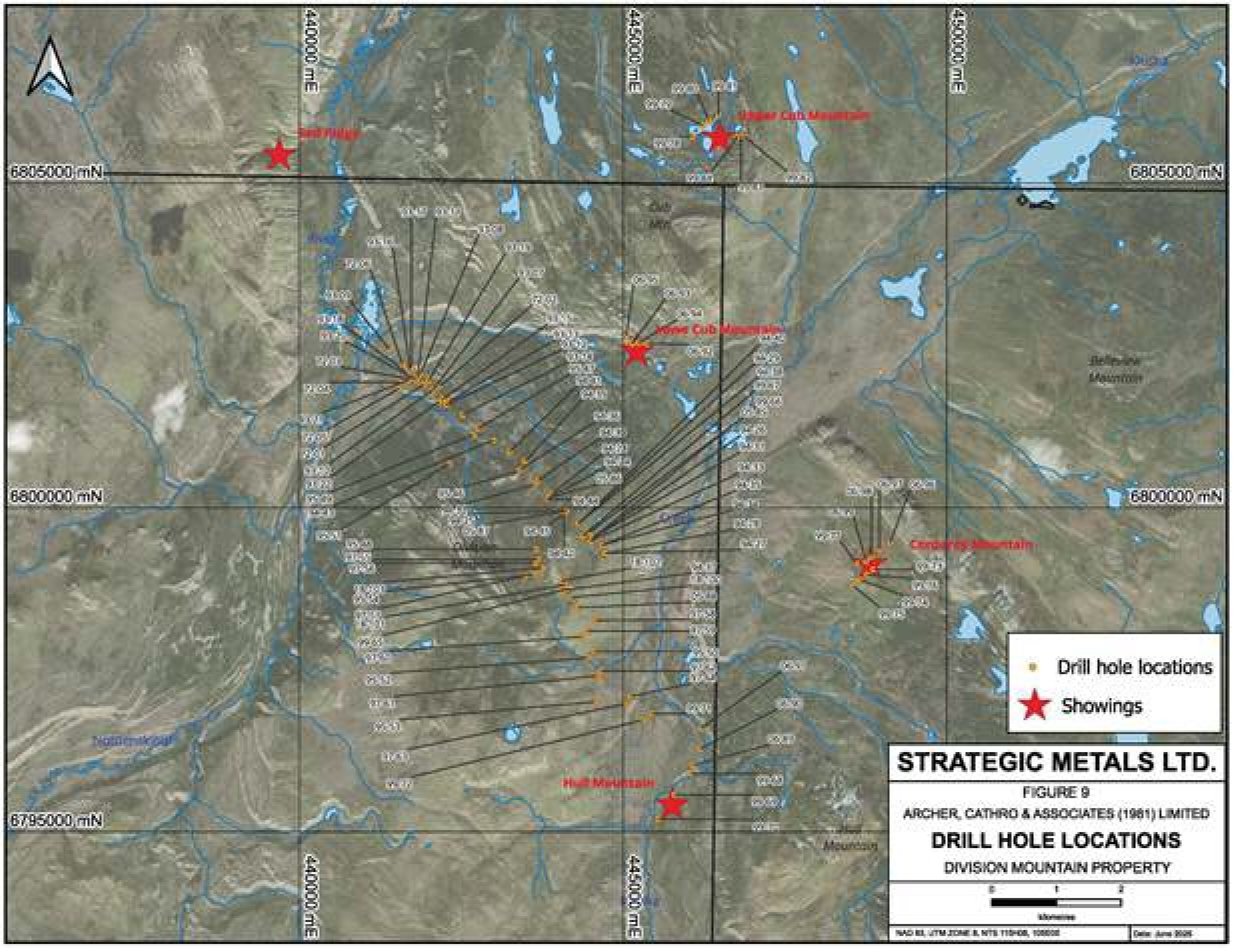
Drill Hole	UTM Coordinates*		Elevation	Grid Coordinates		Depth	Azimuth Degree	Surface Dip	Final Dip
	x_NAD83	y_NAD83		Northing	Easting				
94-28	444728	6799297	925	10+609	9620	78.03	40	50	50
94-29	444310	6799749	939	11+219	9710	188.37	40	50	49
94-30	443684	6800422	906	12+134	9845	178.61	40	50	46
94-31	444534	6799538	934	10+914	9680	178.92	40	70	72
94-32	443635	6800359	898	12+134	9760	252.07	40	60	56
94-33	444503	6799491	935	10+914	9630	109.73	220	50	52
94-34	444678	6799426	930	10+725	9690	145.39	40	70	70
94-35	444678	6799425	930	10+725	9690	129.23	220	50	51
94-36	443419	6800589	887	12+438	9800	229.81	40	50	49
94-37	444126	6798732	958	10+710	8800	206.04	40	50	53
94-38	444308	6799752	940	11+219	9710	178.61	220	50	51
94-39	443489	6800710	877	12+438	9920	117.95	40	50	50
94-40	444307	6799751	940	11+219	9710	268.22	-	90	89
94-41	443248	6800856	890	12+754	9920	239.88	40	50	52
94-42	444087	6799898	948	11+500	9680	273.1	40	70	69
94-43	443000	6801034	876	13+048	9887	252.07	40	50	48
94-44	443834	6800130	918	11+840	9706	215.49	220	50	48
94-45	444088	6799900	947	11+500	9680	163.37	220	60	58
95-46	443383	6800552	895	12+438	9750	306.32	220	50	53
95-47	442758	6801212	883	13+353	9875	224.03	40	50	50
95-48	443653	6799362	992	11+524	9000	274.32	40	50	53
95-49	442683	6801117	840	13+353	9750	325.05	220	50	57
95-50	444551	6797786	845	10+000	8400	100.58	40	50	53
95-51	442318	6800672	929	13+353	9175	315.77	40	50	53
95-52	444452	6797682	841	10+000	8250	245.67	40	50	53
95-532	444568	6797007		9+300	7725	68.28	40	50	-
95-54	443618	6798972	918	12+025	9625	117.65	220	50	48
97-551	443682	6799198	1,002	11+400	8892	175.26	40	55	54
97-561	443642	6799142	1,000	11+400	8824	76.2	40	60	60
97-571	443490	6798947	965	11+400	8570	182.88	40	55	55
97-58	444579	6798261	903	10+305	8876	30.48	40	50	-
97-59	444454	6798097	903	10+050	8580	128.63	40	50	50
97-60	444365	6798009	900	10+050	8460	215.49	40	50	51
97-61	444601	6797405	840	9+510	8141	255.73	40	50	50
97-62	444664	6797479	838	9+510	8240	159.1	40	50	50
97-63	445019	6796970	825	8+950	8040	293.22	40	50	50
97-641	445119	6797088	825	8+950	8220	149.96	40	50	50
99-651,3	444117	6798741	958	10+710	8800	148.13	40	50	-
99-661,3	444487	6799625	935	10+954	9700	129.54	40	50	-

Drill Hole	UTM Coordinates*		Elevation	Grid Coordinates		Depth	Azimuth Degree	Surface Dip	Final Dip
	x_NAD83	y_NAD83		Northing	Easting				
99-671,3	444378	6799567	940	10+979	9620	86.87	220	50	-
99-681,2	446047	6795897		Hull Mountain		44.2	-	90	-
99-691,2	445797	6795572		Hull Mountain		38.1	-	90	-
99-701,2	445547	6795197		Hull Mountain		54.86	-	90	-
99-711,2,3	445447	6796822		8+650	8200	38.1	40	50	-
99-721,2,3	445297	6796722		8+650	8030	74.68	40	50	-
99-731	448867	6799047		Corduroy Mountain		152.4	230	50	-
99-741	448672	6798882		Corduroy Mountain		152.4	230	50	-
99-751	448564	6798792		Corduroy Mountain		91.44	230	50	-
99-761	448769	6798964		Corduroy Mountain		137.16	230	50	-
99-771	448597	6799147		Corduroy Mountain		128.02	230	50	-
99-781,4	446072	6805722		Upper Cub Mountain		91.44	220	50	-
99-791,4	446222	6805897		Upper Cub Mountain		128.02	-	90	-
99-801,4	446322	6805972		Upper Cub Mountain		73.15	-	90	-
99-811,4	446472	6806047		Upper Cub Mountain		60.96	-	90	-
99-821,4	446872	6805722		Upper Cub Mountain		42.67	270	50	-
99-831,4	446822	6805722		Upper Cub Mountain		97.54	270	50	-
99-841,4	446772	6805722		Upper Cub Mountain		99.06	270	50	-
05-851,3,5	444531	6799535		10+914	9676	154.5	40	90	-
05-861,3,5	443856	6800155		11+829	9740	280	40	90	-
05-871,3,5	444124	6799952		11+500	9750	218.2	230	70	-
05-881,3,5	444307	6798457		10+375	8650	231	40	90	-
06-891,2	446086	6796026		Hull Mountain		30.5	40	60	-
06-901.2	446183	6796277		Hull Mountain		32	40	60	-

Drill Hole	UTM Coordinates*		Elevation	Grid Coordinates		Depth	Azimuth Degree	Surface Dip	Final Dip
	x_NAD83	y_NAD83		Northing	Easting				
06-91[1,2]	446202	6796598		Hull Mountain		22.9	40	60	-
06-92[1,4]	445376	6802522		Lower Cub Mountain		142.3	230	60	-
06-93[1,4]	445137	6802522		Lower Cub Mountain		145.4	230	60	-
06-94[1,4]	445239	6802535		Lower Cub Mountain		102.7	230	60	-
06-95[1,4]	445052	6802649		Lower Cub Mountain		191.1	230	60	-
06-96	449125	6799463	1,039.40	Corduroy Mountain		228.6	230	50	-
06-97	448960	6799350	1,015.90	Corduroy Mountain		196.3	230	50	-
06-98	448837	6799244	996.7	Corduroy Mountain		228.6	230	50	-
06-99	448752	6799179	939.4	Corduroy Mountain		152.4	230	50	-
18-100[2,3]	444183	6798612				37.19	40	50	-
18-101[2,3]	444101	6798811				36.58	40	45	-
18-102[2,3]	444045	6798872				35.05	40	45	-
18-103[2,3]	443748	6799072				15.85	40	45	-

*Datum: NAD 1983
[1] approximate UTM coordinates
[2] abandoned in bad ground
[3] approximate grid coordinates
[4] drill hole located outside of coal licenses owned by Strategic Metals Ltd.
[5] estimated drill hole total depth

Figure 9: Drill Hole Locations



The 1993, 1994, 1995 and 1997 diamond drilling programs were contracted to E. Caron Diamond Drilling of Whitehorse and all holes were drilled in the area of the Division Mountain deposit. The drilling was done with one or two skid-mounted Longyear 38 wire-line equipped drills. All holes were drilled with HQ (6.25 cm diameter) equipment; however, badly broken ground necessitated reducing to NQ (4.75 cm diameter) equipment in some holes. Core recovery of the coal intersections averaged about 96%.

In 1999, reverse circulation percussion drilling was carried out by Midnight Sun Drilling Co. Ltd. using a track-mounted Schramm T6585WS drill supported with a Clark skidder. Five of the holes were drilled in the area of the Division Mountain deposit, 3 at Hull Mountain, 5 at Corduroy Mountain and 7 at Upper Cub Mountain.

Three of the 1999 reverse circulation percussion drill holes and 4 excavator trenches were completed in the area of the Division Mountain resource estimate. As part of Usibelli's quality control measures, they selected 5 samples from Trench 04 and sent these for analysis at both the Usibelli Coal Mine, Inc. in Healy, Alaska and the Commercial Testing and Engineering Company in Denver, Colorado.

Down-hole geophysical logging was performed in 1999 on all reverse circulation drill holes by Amerok Geoscience Ltd. of Whitehorse (Gish, 2000). Resistivity was measured using an IFG BMP-04 galvanic resistivity tool, with 16 inch and 48 inch electrode spacing. Natural radioactivity was quantified with an IFG BSG-01 four channel gamma probe with windows in the 100 KeV to 3 MeV range. Measurement time was constant at one second. The results of these surveys were inconclusive and failed to accurately define the coal seams.

In 2005, a total of four diamond drill holes (886.57 m) were completed on the Property. Diamond drilling and bulldozer support was contracted to E. Caron Diamond Drilling. The drilling was done with one skid-mounted Val d'Or wire-line equipped drill and a D7E bulldozer for drill pad construction and drill moves. Holes 05-85, 05-86 and 05-87 were completed with standard HQ equipment while the bottom of holes 05-87 and all of 05-88 were drilled with HQ3 bits and a split core tube

PVC tubing with an inside diameter of 5.08 cm was inserted into drill holes 05-86, 05-87 and 05-88. For each of these holes electrical heat tape was suspended inside the PVC tubing from surface to a depth of 60 m. The completion of these drill holes with PVC tubing and heat tape may enable the permafrost to be thawed when access to the hole is required. Aurora Geosciences Ltd. of Whitehorse was retained to perform down-hole geophysical logging. They attempted to record natural gamma, self-potential ("SP") and resistivity logs in hole 05-85 but due to excessive caving they were not able to log this hole and abandoned any additional surveys. Roke Oil Enterprises Ltd. ("Roke") of Calgary, Alberta was then asked to perform additional logging. Roke arrived on the Property as the final hole of the 2005 program was completed. Roke was unable to perform SP and resistivity surveys since the logging sonde was damaged in transit. They were able to log holes 05-86, -87 and -88 with gamma ray, neutron and electron bulk density equipment. For each of these holes, the HQ rods were lowered to the bottom of the hole then logging was performed through the rods. The rods were then pulled from the hole and the holes logged with a caliper sonde. The results were plotted on strip logs and provided in digital format.

The 2005 drilling program provided large diameter drill core that was used for geotechnical studies. The geotechnical logging of all drill holes was performed by Archer, Cathro & Associates (1981) Limited ("Archer Cathro") of Whitehorse, under instructions and supervision by EBA Engineering Consultants Ltd. of Whitehorse.

In 2006, 3 holes were drilled on Hull Mountain and 4 on Lower Cub Mountain with a Prospector self-propelled, track mounted drill, contracted to Derex Drilling Services Ltd. of Armstrong, BC. Roke was retained to perform down-hole geophysical logging. All drill cutting, sampling and logging was done on site. Drill cutting materials were collected in whole and a 2 kg portion was archived in sample bags that are stored on the Property at the camp.

In 2006, 6 diamond drill holes were completed at Corduroy Mountain. Drilling was contracted to Superior Diamond Drilling Inc. of Peachland, B.C. using a Mandrill 1200 wireline-equipped diamond drill. The holes were drilled with NTW and BTW tools. Helicopter support was provided by Trans North Helicopters and Capital Helicopters from their bases at Whitehorse using a combination of Bell 206, Bell 205 and AStar 350B2 helicopters. All core sampling and core logging was done on site.

In 2018, 4 RAB drill holes were completed on the Division Mountain deposit. The drilling was contracted to Ground Truth Exploration of Dawson City, Yukon.

All drill holes are marked with a 1.5 m long wooden plug bearing an aluminum tag inscribed with hole number, date drilled, azimuth, dip and total depth. Surface inclination of the diamond drill holes was determined using a Brunton compass with downhole inclination determined by acid tests. Results from the downhole surveys show little or no change from surface inclinations.

11 SAMPLE PREPARATION, ANALYSES AND SECURITY

11.1 Sampling Method

This section describes the sampling method followed during the 1993 to 2006 coal quality testing programs. The 2005 and 2006 exploration and sampling programs were carried out under the supervision of a qualified person (Mr. R.C. Carne, M.Sc., P.Geo.).

The following drill core sampling protocol is reported to have been used during the drilling programs:

- Core was lightly washed and measured.
- In 2005, the core was geotechnically logged using a standardized technique defined by EBA Engineering Consultants Ltd.
- Core was geologically logged using a standardized technique defined by Archer Cathro.
- Sample intervals were selected based on coal and parting lithological breaks selected by using geological logs. Top and bottom coal samples for each coal seam were sampled individually with a maximum interval of 30 cm. The minimum coal sample interval for the remainder of the coal seam was approximately 30 cm. Internal partings were sampled separately, with a minimum interval of 10 cm. Roof and floor materials for each coal seam were sampled at approximate 15 to 30 cm intervals, based on lithologic and natural breaks.
- Sample intervals were marked in the wooden core boxes and all core boxes were stored in a secure manner on the Property.
- For each sample interval all the cored material was sent for analysis.
- Sample material was double bagged in 6 mm plastic bags with a sample tag placed between the two sample bags. Two or three samples were placed in a fiberglass bag, sealed with a metal clasp and sample numbers were marked on the outside of the bag with felt pen.

11.2 Sample Security, Preparation and Analysis

As coal samples are a relatively low-value bulk commodity, no extraordinary security procedures were followed. Samples were collected from exploration efforts and submitted for analysis using methods that are consistent with typical industry practices. This section describes the sample handling procedures followed during the 1993 to 1998, 2005 and 2006 exploration programs. The author cannot comment on the procedures followed during the 1972 exploration program but can comment on the 1999 program conducted by Usibelli coal based on the documents provided in an assessment report (Gish 2000).

During the 1993 to 1998 programs, conducted on behalf of Cash Resources Ltd, all samples were transported from the property to Whitehorse by truck, escorted by the geological crew, and then shipped via Canadian Airlines or a local trucking company to either Chemex Labs Ltd. in North Vancouver, B.C. in 1993, 1994 and 1995 or to Loring Laboratories Ltd. of Calgary, Alberta in 1997. Chemex Labs provided proximate analyses as both air dried and dry and for the most part this report was based on the air-dried results.

During the 1999 program Usibelli sent the bulk of their samples to the Usibelli Coal Mine, Inc. in Healy, Alaska but five samples were also sent for check analysis to the Commercial Testing and Engineering Company (CT&E) in Denver, Colorado. The Usibelli lab provided proximate analysis in as received values and dry values. CT&E provided both proximate and ultimate analysis in as received values and dry values plus analysis of ash.

During the 2005 program, conducted on behalf of Cash Minerals, all samples were transported from the Property to Whitehorse by truck, escorted by the geological crew, and then shipped via Greyhound Courier Express to SGS Canada Inc. ("SGS") in Delta, B.C. SGS provided proximate analyses on air-dried, as received and dry bases. The SGS facilities are accredited according to the International Standardization Organization 9001 requirements ("ISO 9001"). For the most part this report was based on proximate analysis as received and air-dried bases.

The 2006 program on Corduroy Mountain was carried out under the supervision of the same qualified person, as was the 2005 program. It is assumed that a similar sample transportation process was followed. The assessment report details that coal intervals were collected in whole and sent to the SGS Mineral Services laboratory in Delta for coal quality analyses.

12 DATA VERIFICATION

The sample data described in this report was collected by Archer Cathro, which conducted the exploration programs on the Division Mountain Property between 1993 and 2008.

In examining and verifying the sample data in this report, the Author performed the following tasks:

- Original assay certificates were reviewed.
- Reported drill core analyses were checked against sample numbers in the drill logs and the original assay certificates to ensure accurate reporting.
- The range of reported results and their geographic distribution were checked against similar ranges and distributions from properties containing similar mineralization.
- The Author personally logged some of the core from the 1994 and 1995 programs and mapped most of the excavator trenches.

13 MINERAL PROCESSING AND METALLURGICAL TESTING

The equivalent terminology, which will be used in this report on coal, is "Coal Quality and Processing".

Prior to 2005, limited studies had been conducted with regards to washability analysis and estimating the potential of the coalbed methane resources. These studies were presented in the earlier report but may not be indicative of the results of more comprehensive and detailed studies. No coking test, long proximate or rank analysis has been performed on samples from the Property.

Calculated average analysis for the Division Mountain raw coal, on an air dried basis, is 2.8% residual moisture, 27.6% ash content, 26.3% volatile matter, 43.7% fixed carbon, 0.45% sulphur and a calorific value of 5159 cal/g as shown in Table 6. The average analysis corresponds to an ASTM rank of High Volatile "B" Bituminous coal.

Table 6: Coal Quality Analyses

Seam	Thickness metres	Calorific Value cal/g	Residual Matter %	Ash %	Volatile Matter %	Fixed Carbon %	Sulphur %	Bulk Density g/cc
5	3.1	4252	2	37.6	16.6	44	0.34	1.59
4	6.2	5390	3.6	24.8	26.7	45.3	0.41	1.5
3e	3.9	5207	3	27.3	24.8	45	0.43	1.52
3d	3.1	5806	2.6	21.3	29.7	46.5	0.48	1.46
3c	3.7	5280	2.6	26.9	27.4	43.1	0.51	1.5
3b	3.4	5006	3.5	29	23.9	44.4	0.47	1.54
3a	4.5	5043	2.9	29.2	26.6	41.7	0.47	1.53
2d	7.7	5310	1.9	25.5	29.7	43	0.39	1.5
2c	2.2	5880	3.2	19.8	29.6	48.1	0.54	1.47
2b	5.4	4852	2.6	29.9	24.3	43.3	0.43	1.54
2a	3.6	5385	3.5	30.2	27.4	40.3	0.53	1.55
1c	1.3	4364	2.1	32.3	26.9	38.7	0.43	1.56
1b	3.3	5422	2.7	22.9	29.3	45.7	0.5	1.49
1a	10.1	5023	3.5	29.8	25.7	43.2	0.44	1.57
Average	**4.4**	**5159**	**2.8**	**27.6**	**26.3**	**43.7**	**0.45**	**1.52**

14 MINERAL RESOURCE ESTIMATES

A resource estimate for the Division Mountain deposit was provided in 2005 (Norwest, 2005) and an updated estimate was provided in 2008 (Norwest, 2008a). This report should not be considered a revision of the previous mineral resources work. This report merely provides a summary of the previous work.

The Author has not conducted sufficient work to classify the historical mineral reserve as current mineral reserves, and the Author is not including an estimate of mineral reserves in this report.

Based on exploration programs conducted between 1993 and 2005, resources were estimated to comply with standards prescribed in NI 43-101. For the classification, estimation and reporting of coal resources for the Division Mountain Property and in accordance with NI 43-101, the Author used the Canadian Institute of Mining ("CIM"), Metallurgy and Petroleum's CIM "Definition Standards on Mineral Resources and Reserves" adopted by CIM Council on November 14, 2004 and referenced the GSC Paper 88-21 "A Standardized Coal Resource/Reserve Reporting System for Canada" (Hughes et al., 1989).

The resource calculation methodology used in the 2005 and 2008 reports approximates that used in 1998 by Mr. R.C. Carne, M.Sc., P.Geo. All resources fall into the Measured category based on the criteria provided in GSC Paper 88-21 and the results of the 2005 drilling, which indicates that seam continuity and geological correlations can be made for distances of over 500 m. The following paragraphs outline the methods used for the resource estimation.

- Reviewed Exploration Data: Verified data as outlined earlier in this report and checked synoptic logs, drill hole locations, geologic model and coal rank.
- Geology Type: Falls within "moderate" category based on broad open folds (wavelengths from 500 to well over 1.5 km), relatively uncommon faults (displacements from 10s m up to 200 m) and average bedding inclinations of 50º (range from 25 to 72º).
- Data Points: Only diamond drill hole data was used. The drill sections are spaced approximately 300 m apart. For coal seams with multiple analyses a weighted average of all samples was taken to represent the seam. For intervals with no analyses due to core loss the interval was assigned a value equal to the arithmetic average of the adjacent intervals.
- Seam Thickness: Seam thicknesses were calculated using trigonometry and confirmed by measurements from drill sections. Minimum allowable coal bed thickness was 0.5 meters. Only five resource blocks were less than 1.0 m thick and the average for all blocks was 4.4 meters.
- Definition of Resource Block: Length defined as horizontal distance, width measured in plan of section and thickness measured as true width. The coal bulk density for work prior to 2005 was based on the rank of coal, ash content and extrapolated from a table provided in GSC Paper 88-21, for the 2005 work this data was provided by SGS.
- Criteria of a Resource: All resources are of immediate interest and fall into the measured categories. Measured resources require the distance from nearest data point to be between 0 and 450 m.
- Method of Estimating Resources:

– On the horizontal plane the length of the measured resource blocks was projected to half the distance between adjacent drill sections. For section 8+950N where there was no adjacent drill section to the southeast the length was projected 225 m from the drill section.

- On the plane of the drill section the width of the measured resource blocks were measured from surface to the first drill hole, this distance never exceeded 225 m. If two or more drill holes existed on the same section then the width was extended down dip to half the distance between the next drill hole, again this distance never exceeded 225 m. The resource block width was then extended down dip to a distance, which represented a 'reasonable' resource depth (see below).
- For this deposit type the maximum depth from surface, as defined in GSC Paper 88-21, is when the ratio of 'bank' cubic meters/tonne of the last tonne exceeds 20:1. This ratio was not approached in these resource calculations instead the bottom of the resource was taken to be a 'reasonable' depth. Along the east limb of the Division Mountain Syncline the depth of the resources ranged from 270 m at the south (8+950N) to 290 m in the middle and 270 m at the north (10+710N). In the area of the Cairnes Syncline it ranged from surface at the south (10+610N) to 300 m at the north (12+124N). In the Teslin Creek area the reasonable depth was taken as 200 m for section line 12+754N to 13+353N and 150 m for section line 14+075N to

A total near-surface resource of 52.5 Mt has been defined (Table 7).

Table 7: Coal Resources Summary

Resource	ASTM Coal Rank	In-Place Resources (Tonnes in Millions)		
		Measured	Indicated	Inferred
Division Mtn.	High Volatile "B" Bituminous	52.493	0	0
Total		52.493		

The Qualified Person is not aware of any environmental, permitting, legal, title, taxation, socio-economic, marketing, political or other factor that would materially affect the mineral resource estimate itself, other than as follows. The Property is held under coal exploration licences that require periodic renewal, as described in Section 4. The Project lies within the Traditional Territories of four Yukon First Nations, and development would be subject to assessment under YESAA and to the authorizations described in Section 20.2. Development of the resource on the basis contemplated in this report would additionally be subject to the federal emissions performance standard for coal-fired electricity generation described in Section 20.2.2, compliance with which has not been demonstrated. These factors bear on the prospects for eventual economic extraction of the resource, and are described in the sections referenced.

15 MINERAL RESERVE ESTIMATES

This report summarizes the findings of a PEA. The work completed today does not support a mineral reserve estimate. There is no certainty that the preliminary economic assessment will be realized. No economically recoverable reserves have been defined in this study.

16 MINING METHODS

To date, mine planning for the Division Mountain project, as summarized in this report, has been performed at a conceptual or 'scoping' level and is considered insufficient as the basis of an estimation of reserves. Mine planning is based on cost inputs as reported in Section 21.

The preliminary economic assessment is preliminary in nature and there is no certainty that the results of the preliminary economic assessment will be realized. Mineral resources that are not mineral reserves do not have demonstrated economic viability. No mineral reserves have been estimated for the Property.

16.1 Introduction

As described previously, the deposit consists of numerous seams, of varying thickness and with some areas of significant dip. In addition, there are known faults. The deposit is therefore considered to be of moderate and complex geology type. There are sufficient quantities of near-surface resources that may support surface mining in the Pit 1 area. A mine plan is presented that examines the economics of a surface mining operation. The term 'mineable' is used in this study to define resources to which mine plans have been applied, but economics have not been considered to a level of accuracy sufficient to define reserves.

The block model was transferred into Hexagon's Mine Plan 3D software for pit shell generation, mine design, and mine scheduling. The model transfer was done using coal solids that were written into a block model.

16.2 Surface Mine Plan

Allnorth has developed a conceptual surface mine plan for conditions representative of the remote northern climate of Yukon. The proposed pit area is shown on **Figure 10**. The mine plan is based on Pit 1, one of the pit areas identified as having potential for surface mining. Pit 1 was selected for this study because it can supply the required coal quantities and has the lowest stripping ratio among the identified mining areas.

The remaining pit areas have been excluded from the current study, as the coal requirements can be met from Pit 1 alone.

The specific project parameters discussed in this section are summarized below as follows:

- Geologic and geotechnical conditions
- Mining method
- Mine layout
- Mining equipment
- Production and productivity levels.

As part of the scoping study evaluation, a series of pit shells were developed for those areas deemed to be of potential for surface mining. These pit shells were used to develop strip ratio – tonnage relationships for estimation of coal tonnages amenable to surface mining at increasing strip ratios. Strip ratio, one of the key constraints involved with surface mining, represents the volume in cubic meters of waste that must be removed to recover one tonne of coal. An average strip ratio range of 3.5 :1 (bcm of waste: ROM tonnes) was selected as being suitable for scoping level evaluation based on the size of the resource and planned production levels for the operation.

16.3 Mining Areas

Using the block model and Lerchs-Grossman algorithm in Hexagon's Mine Plan 3D software, potentially economic mining areas were identified.

As shown in Table 8 below, a substantial amount of coal exists that may be recovered using surface mining techniques. Surface minable locations were defined by analysis of economic strip ratios. Parameters used to develop the surface minable areas include:

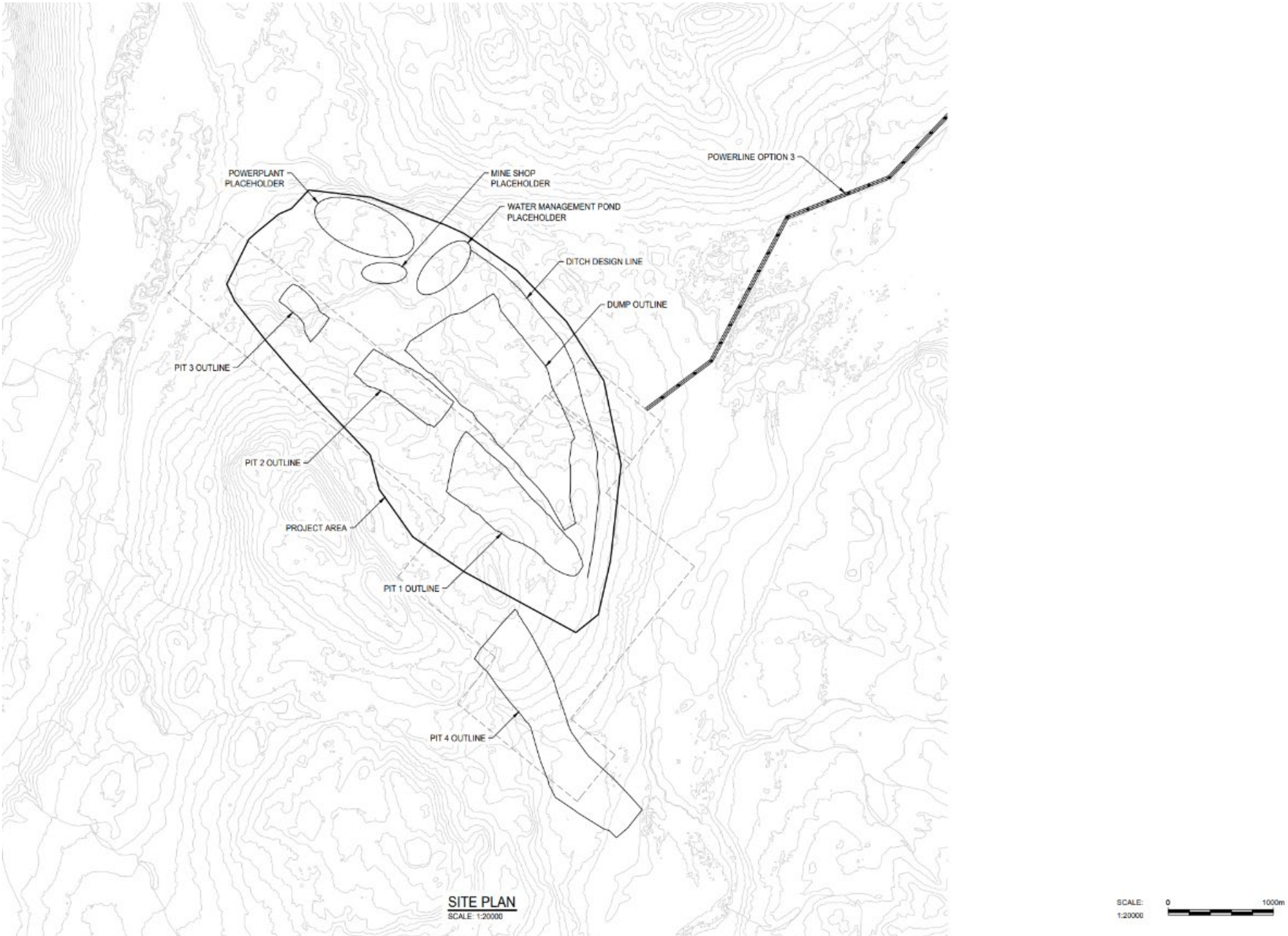
- Target stripping ratio range of 3.5:1 waste volume to ore tonnes
- Overall pit slopes of 45° for endwall
- Overall pit slopes of 38° for the footwall of the syncline
- Dilution of 5%
- Mining recovery of 95%

The surface mineable quantities as identified in Pit 1, Pit 2, Pit 3, and Pit 4 are listed in Table 8. The waste volumes, ROM coal tonnes and stripping ratios are shown for each mining area. Maps detailing the individual mining areas are presented as Figure 10.

Table 8: Surface Mineable Quantities

Area	Included Seam(s)	Waste (M bcm)	ROM Coal (Mt)	Overall Strip Ratio (bcm/tonne)
Pit 1	*Seam 1a-c, Seam 2a-d Seam 3a-e, Seam 4, Seam 5*	*69.75*	*20.25*	*3.1*
Pit 2	Seam 1a-c, Seam 2a-d Seam 3a-e, Seam 4, Seam 5	26.10	4.21	6.2
Pit 3	Seam 1a-c, Seam 2a-d Seam 3a-e, Seam 4, Seam 5	7.58	1.43	5.3
Pit 4	Seam 1a-c, Seam 2a-d Seam 3a-e, Seam 4, Seam 5	145.13	21.99	6.6

Figure 10: Site Plan



16.4 Mining Method

The open pit mining method is a conventional truck and shovel operation utilized at similar coal operations throughout northeastern British Columbia and metals mining operations in the Yukon. The equipment selection centers on coal recovery with the use of relatively small backhoes to clean and mine the coal. This conventional truck and shovel operation consists of four unit operations:

- Drilling
- Blasting
- Loading and hauling waste
- Cleaning, loading and hauling of coal.

16.5 Mine Design Criteria

The pit design criteria is as follows:

- Bench Height 10m
- 20m Between Catch Benches
- Follows Footwall Bedding
- Pit Bottom Operating Width of 25m

The waste dump design is based on a 23-degree overall slope and has enough capacity to store the waste material from the adjacent open pit with 85M LCM of storage.

16.6 Surface Mining Equipment

The equipment selection process assessed the required annual production, haulage distances, mining method, and operational safety. The fleet selected will allow for mining at reasonable unit costs while meeting desired production levels. The use of smaller excavators for coal mining with the same truck fleet for both coal and waste achieves a balance between achieving selectivity of mining smaller seams while trying to maintain low unit costs. Given the life of the surface operation and the production level, it is expected that surface mine operations would be carried out by an owner-operated fleet of mining equipment.

16.6.1 Primary Mining Equipment

The primary mining fleet sizes in order to meet production requirements are proposed as follows:

- Waste Loading: 1 x Hydraulic excavator (CAT 395 or equivalent)
- Coal Loading: 1 x Front end loader (CAT 988 or equivalent)
- Haulage: 7 x 55 tonne capacity rear-dump trucks (CAT 773 or equivalent)
- Drilling: 1 x Rotary blasthole drills 6 inch (155mm) hole diameter, 11m depth.

16.6.2 Support Equipment

Support equipment for the project would be required for the various tasks, including:

- Clean-up and support for in-pit waste and coal loading
- Movement of waste on rock dumps and re-sloping of dumps
- Maintenance of haulroads
- Loading and control of raw and clean coal stockpiles
- Access ramps
- Construction of temporary water management (sumps, ditches etc)
- Maintenance of mining equipment.

The exact size and configuration of the support equipment fleet would be determined at a Feasibility-level study (cost estimates are based on a typical regional spread of support equipment for an operation of this size). It is expected that the fleet would include units of the following type:

- Track-type dozers (CAT 8 equivalent)
- Motor graders (CAT 16M or equivalent)
- Front-end loaders (CAT 988)
- Water truck for road dust control
- Various maintenance vehicles: lube truck, heavy forklifts, tow truck, flat deck truck.

It is assumed that support vehicles required for loading of blastholes would be provided by the blasting contractor.

16.6.3 Production Capacity

Estimates have been prepared for equipment production and productivity based on the scoping level mine layout and Allnorth's current understanding of planned production targets and plant capacity. Productivity levels have been evaluated based on the following parameters:

- Coal seam dip range 35 – 75°
- 24 hour production, two 12 hour shifts, 350 operating days per year
- 83% operational efficiency
- 85 – 90% availability on major equipment
- 70% Overall utilization
- Loading units are assigned sufficient trucks to maintain full production (i.e. loading units are over trucked)
- Generalized waste and coal truck path based on average distances from proposed pits to dumps, facilities, etc.
- Equipment selection as proposed in sections 16.6.1 and 16.6.2.

Based on these assumptions, the estimated monthly production capacity for the primary mining fleet is shown in Table 9 below. It should be noted that the production estimates shown represent production for each fleet and not the combined production of all fleets.

Table 9: Fleet Production Capacity

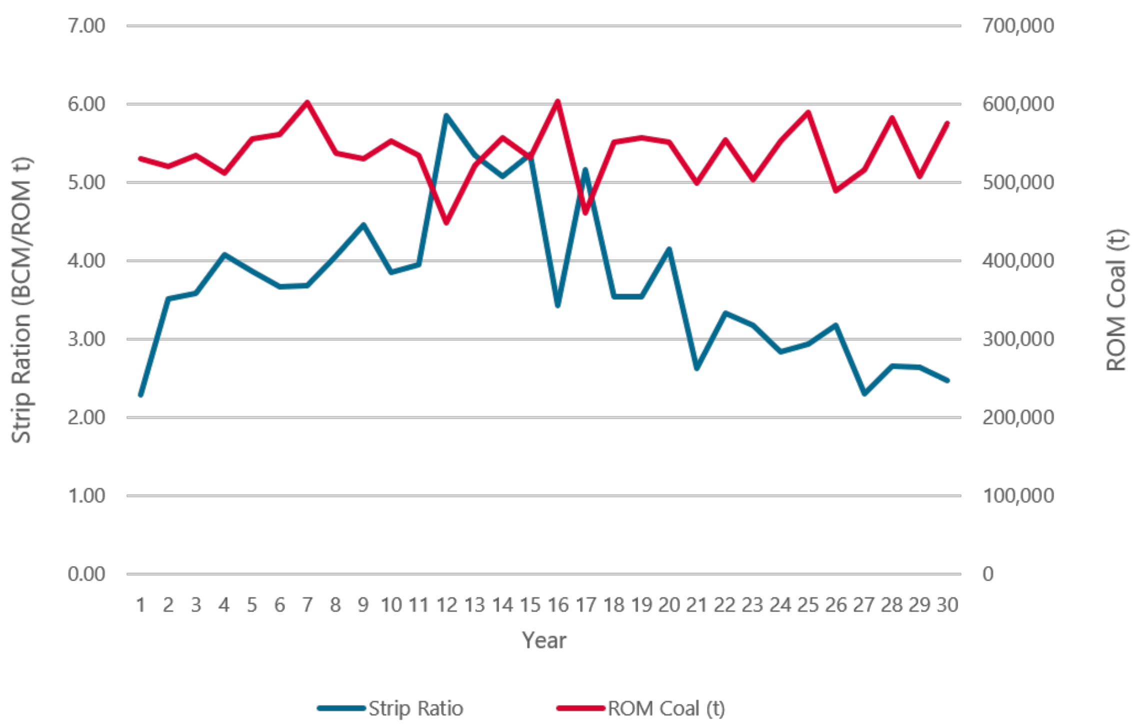
Fleet	Number of fleets at full production	Waste Production per Fleet (Kbcm / month)	Coal Production per Fleet (Ktonnes / month adb)
Waste fleet	1	150 - 225	n.a.
Coal mining fleet	1	n.a.	45 - 50

These production levels represent production capacities based on the scoping level mine plan. As more detailed mine planning and evaluation work is completed, production levels will vary as mining progresses throughout the property due to a number of factors including changing pit geometries, haul distances, production constraints and other factors.

16.7 Production Schedule

The production schedule is based on an annual feed to the coal fired power plant of 0.5 Mtpa of coal from the surface mining operations at a 95% coal recovery rate from the pit (which results in a ROM rate of 0.525 Mtpa). The overall stripping ratio is approximately 3.1 BCM to 1 tonne of ROM coal but fluctuates throughout the mine life. Figure 11 shows the ROM coal mined and overall stripping ratio by year.

Figure 11: LOM Production Summary



Surface mining commences with minimal pre-production in Year 1 due to the near surface nature of the resource, mining then reaches 'steady-state' production (Years 1 through 30). Tables 10 through 12 provide annual mine plan schedule details.

Table 10: Annual Mine Schedule Years 1 to 10

Material	Year 001	Year 002	Year 003	Year 004	Year 005	Year 006	Year 007	Year 008	Year 009	Year 010
Seam 1A	15500	24200	0	1500	18800	0	14700	2000	0	11300
Seam 2A	0	0	1800	500	0	500	300	100	500	1200
Seam 2B	235800	150000	88500	109200	181700	103500	152500	109600	44900	193700
Seam 2C	8200	900	73200	51200	17500	29900	35300	22100	35400	1200
Seam 3A	137900	137400	78600	104600	118800	120600	148500	118200	94000	146200
Seam 3B	84400	107400	151700	132900	119000	136100	117900	134300	101400	111700
Seam 3C	47900	5500	0	0	9700	300	16600	17800	50600	13300
Seam 3E	0	0	0	0	2800	900	10000	11000	33100	8900
Seam 4	900	94600	140300	112600	87400	168300	93700	116600	124400	49300
Seam 5	0	0	0	0	500	500	12900	5500	46600	16600
Grand Total	530500	519900	534200	512500	556400	560600	602400	537100	531000	553400
Waste (BCM)	1218700	1827000	1914100	2092700	2152900	2057700	2216200	2181800	2367900	2133100
Strip Ratio (BCM/t)	2.30	3.51	3.58	4.08	3.87	3.67	3.68	4.06	4.46	3.85

Table 11: Annual Mine Schedule Years 11 to 20

Material	Year 011	Year 012	Year 013	Year 014	Year 015	Year 016	Year 017	Year 018	Year 019	Year 020
Seam 1A	0	9700	0	7400	0	6600	0	5000	0	4500
Seam 2A	0	2800	500	4700	0	7700	300	8800	500	12800
Seam 2B	42600	148800	69800	139800	84500	170200	64000	138600	80400	129800
Seam 2C	35300	0	29100	6400	20700	13600	19600	13500	24800	7200
Seam 3A	104500	91800	114800	111400	115300	120600	100700	97100	130300	89700
Seam 3B	116200	72400	129300	77400	145600	124200	127500	86200	198300	89400
Seam 3C	44700	26600	26500	43200	20300	35600	18500	39500	15700	36600
Seam 3E	25500	24700	22700	32400	25000	18300	19900	22100	14000	25100
Seam 4	132800	45100	117500	85000	109300	76500	89100	97500	85700	109800
Seam 5	32300	27100	11400	48900	11600	30100	21200	42500	7800	47300
Grand Total	533900	449000	521600	556500	532300	603500	460900	550900	557600	552100
Waste (BCM)	2108100	2625300	2789200	2825000	2856000	2071900	2380100	1951100	1977100	2287800
Strip Ratio (BCM/t)	3.95	5.85	5.35	5.08	5.36	3.43	5.16	3.54	3.55	4.14

Table 12: Annual Mine Schedule Years 21 to 30

Material	Year 021	Year 022	Year 023	Year 024	Year 025	Year 026	Year 027	Year 028	Year 029	Year 030
Seam 1A	0	3700	0	3100	3000	0	3200	1100	3900	1500
Seam 2A	1700	15800	2100	28300	31100	2000	32200	29200	34000	43300
Seam 2B	69500	175100	8600	168000	146500	2400	112100	61700	28700	17900
Seam 2C	28700	2000	28900	19400	9100	24500	23100	22800	20900	21100
Seam 3A	117300	90900	110500	109800	99100	98900	110000	111000	107700	109800
Seam 3B	187900	95300	151900	140700	94500	132800	135300	137800	112600	104500
Seam 3C	15700	22800	28200	7900	25900	24100	11600	18500	15100	20400
Seam 3E	5500	18100	14200	6600	16400	15400	7400	14800	13600	12400
Seam 4	71500	87400	124800	59600	119400	146200	81200	141900	131700	190700
Seam 5	1500	43600	35100	9600	43800	43800	200	43500	39100	53700
Grand Total	499400	554500	504300	553000	588900	490000	516100	582400	507300	575300
Waste (BCM)	1311800	1848400	1604700	1569600	1733200	1555500	1189800	1545700	1338800	1427000
Strip Ratio (BCM/t)	2.63	3.33	3.18	2.84	2.94	3.17	2.31	2.65	2.64	2.48

Figures 12 through 15 provide screen shots of the annual mine plan progression along with the approximate location of the primary water management features.

Figure 12: Year 1 Mine Plan

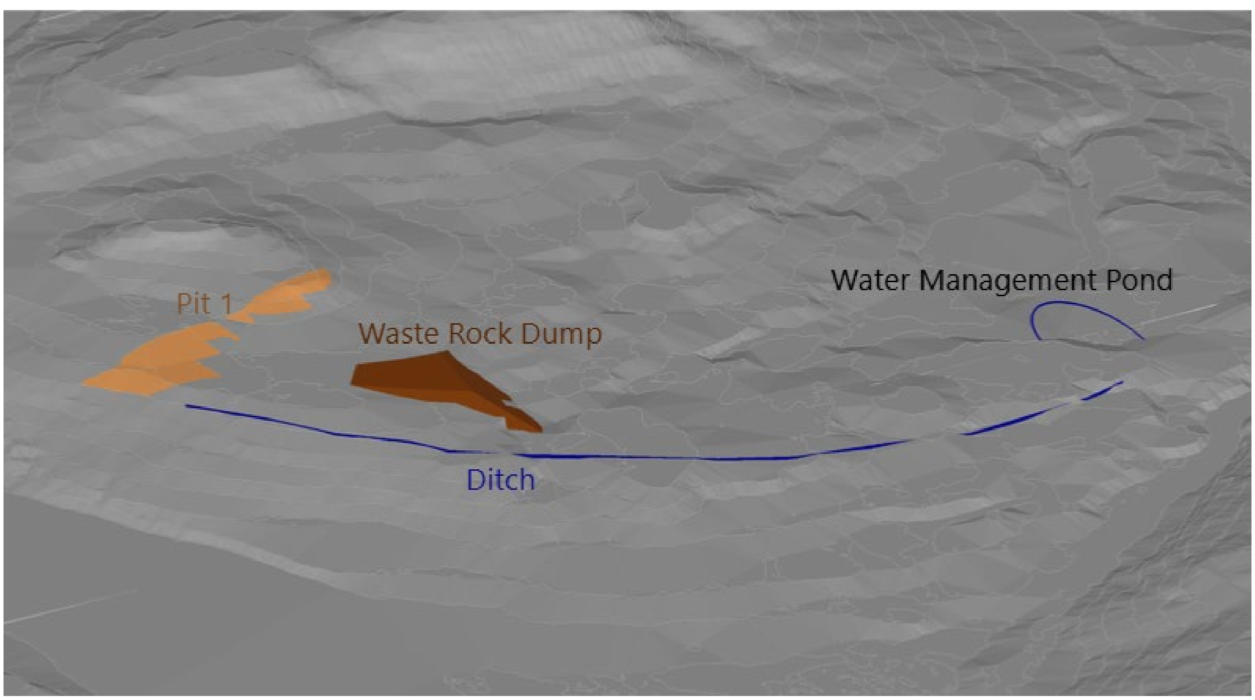


Figure 13: Year 10 Mine Plan

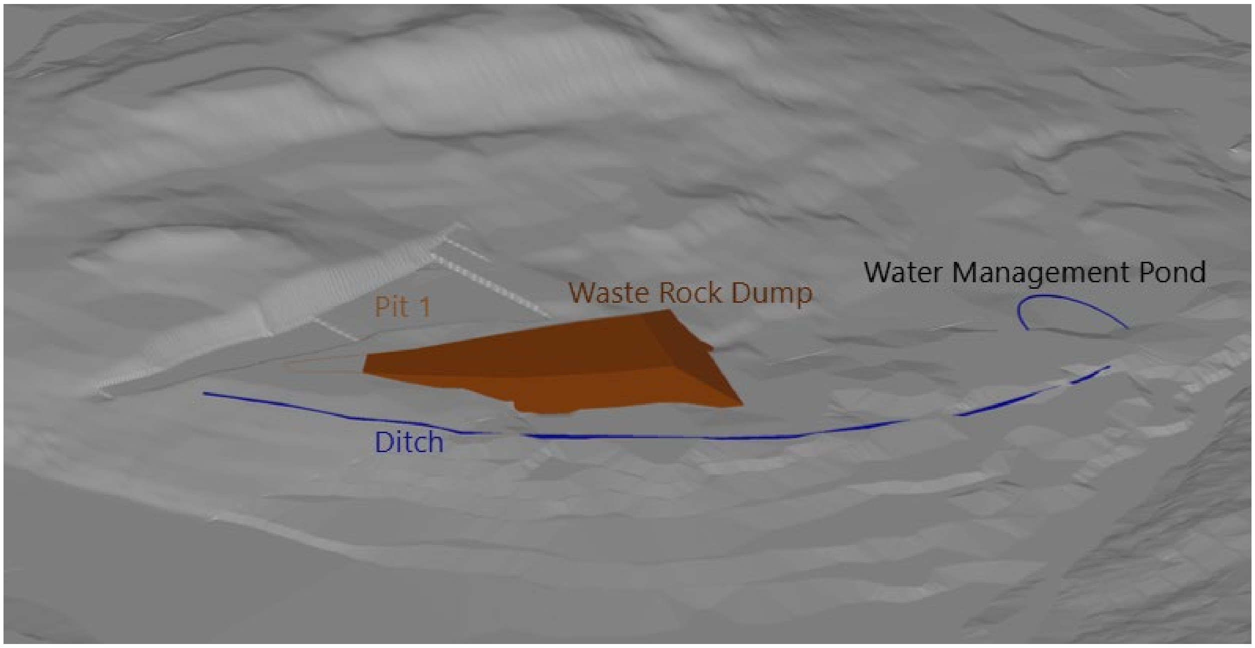


Figure 14: Year 20 Mine Plan

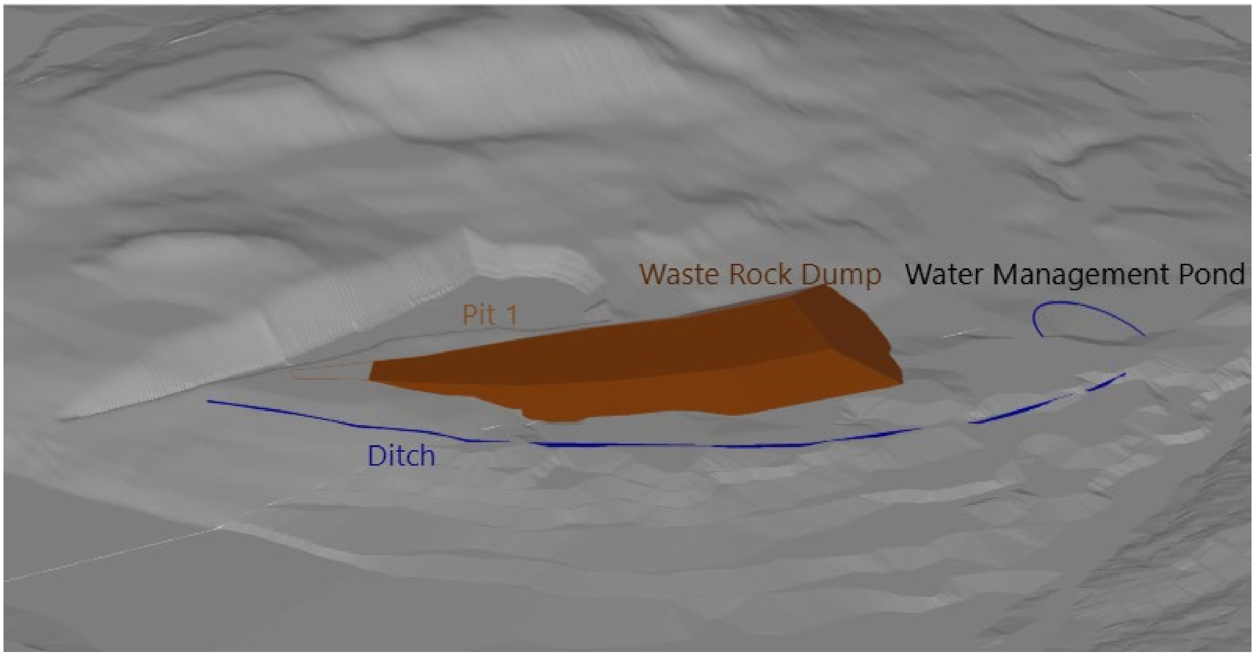
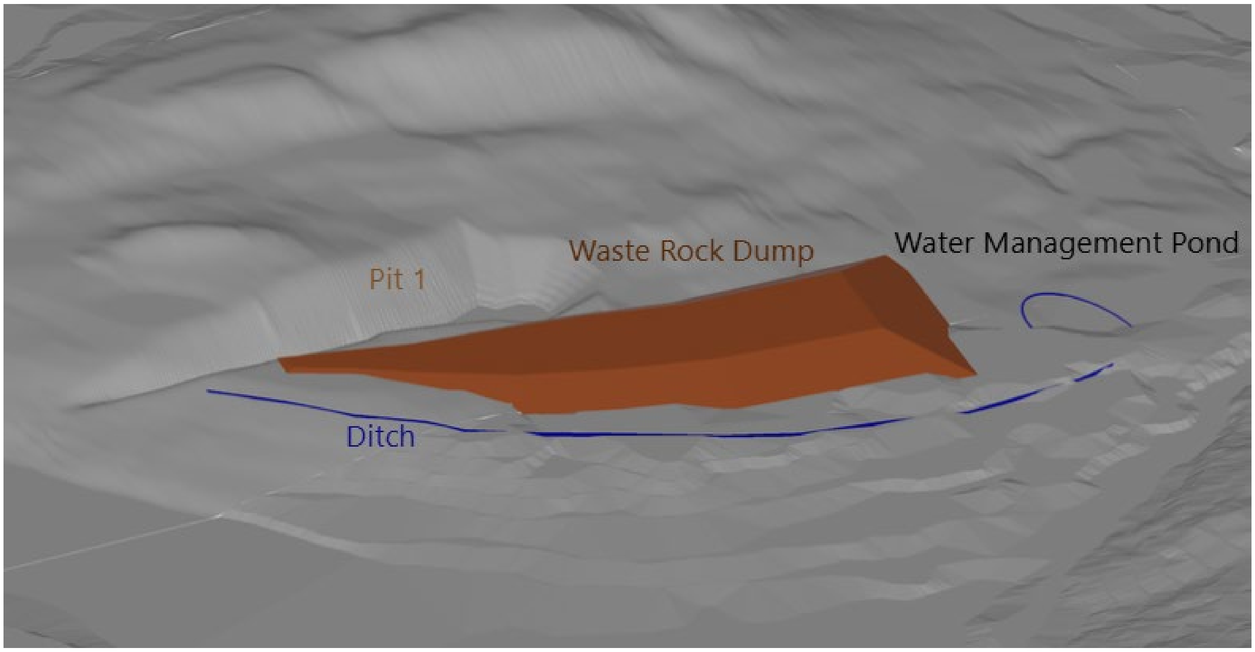


Figure 15: Year 30 Mine Plan



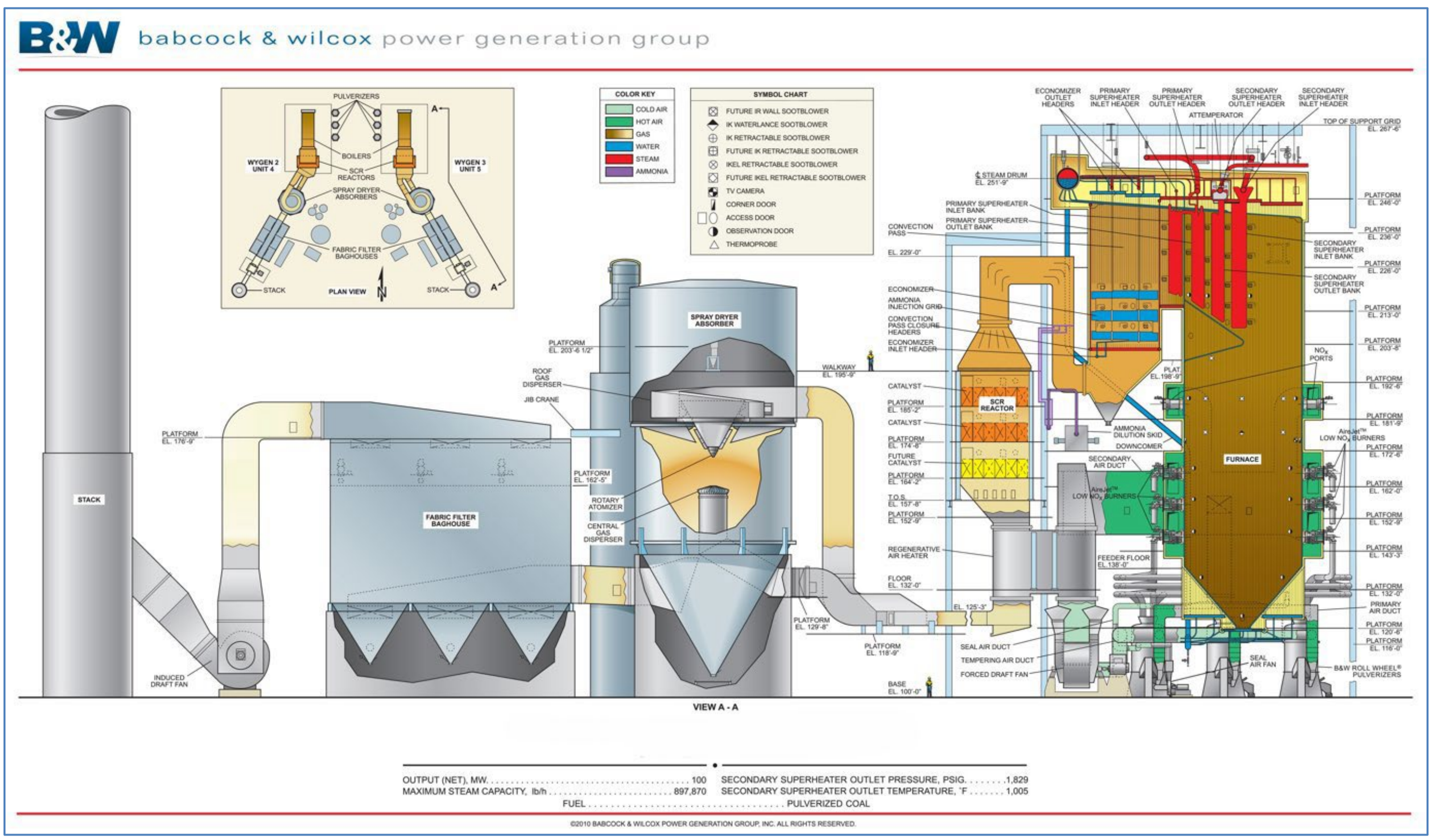
17 RECOVERY METHODS

This section is a summary of the New Coal Fired Power Plant Concept Study Report Division Mountain completed by Allnorth in July 2026.

The proposed coal-fired power plant technology basis was developed around a pulverized fuel boiler, steam turbine generator, air-cooled condenser, boiler feedwater treatment system, and supporting coal offloading and handling infrastructure. Based on vendor discussions, bubbling fluidized bed technology was not considered suitable for the coal due to bed overheating and sintering risk, while circulating fluidized bed technology was considered less favourable due to higher complexity, erosion risk, capital cost, and parasitic load. A pulverized fuel boiler was therefore selected as the preferred technology because it is a proven, commercially available, and cost-effective configuration for the proposed coal characteristics.

The boiler technical description and quote can be found in the Report New Coal Fired Power Plant Concept Study Report Division Mountain. Figure 16 provides a generalised schematic for the PF boiler.

Figure 16 : PF Boiler Schematic



The boiler and steam turbine parameters were selected in consultation with vendors and are based on preliminary mass and heat balances. The 100 MWe design basis considers steam conditions of approximately 126 bar(g) and 540°C, boiler feedwater temperature of 210°C, and condenser pressure of 0.1 bar(a). The steam turbine includes extraction points for feedwater heating and deaeration, supporting overall cycle efficiency. An air-cooled condenser was selected to minimize water consumption, which is advantageous for the project setting, although it requires a relatively large footprint and specific winterization considerations.

Coal quality information from previous studies was incorporated into the design basis, including elemental and proximate analyses adjusted as required for the assumed moisture basis. The coal handling system is designed to receive 50 mm coal from mine trucks, provide short-term and dead storage, reclaim coal using wheeled loaders, manage frozen coal in winter conditions, and deliver coal to the power plant feed system. The material handling concept includes hoppers, feeders, conveyors, a frozen coal crusher, a 24-hour bin, and fire, dust, and cold-weather mitigation measures.

The conceptual plant layout arranges the boiler, steam turbine, air-cooled condenser, flue gas treatment systems, feedwater systems, and coal handling areas to support efficient process flow, minimize piping and ducting complexity, and maintain access for construction and maintenance. The coal stockpile and handling areas are located adjacent to the power plant, with provision for long-term storage to reduce fuel supply disruption risk. Cold climate conditions are a key design consideration, and selected systems are expected to require enclosure, protection, or operational mitigation. The overall conceptual plant footprint is estimated at approximately 5 hectares.

The conceptual design includes ash collection, conditioning and transfer facilities sized for the ash production rate given above. Provision should be made in subsequent design phases for ash to be loaded out for beneficial use as well as for placement in the mine waste storage areas, so that the options described in Section 24.1 are not foreclosed by the layout adopted.

18 PROJECT INFRASTRUCTURE

18.1 Access Road

The proposed access road will generally parallel the proposed power line corridor. Approximately 18.7 km of road upgrades and new road construction will be required to provide access to the site.

The road will be designed to accommodate the transportation of construction materials and equipment to the proposed power plant site.

18.2 Powerline

An option analysis was completed as part of the New Coal Fired Power Plant Concept Study Report Division Mountain. Based on the assessments, the preferred solution is Option 3 consisting of an approximately 18.7 km, 138 kV single circuit transmission line connecting the power facility to the existing YEC network. This option provides the most balanced outcome in terms of technical simplicity, reduced permitting risk, and overall project efficiency.

- Approximate line length: 18.7 km
- Includes a 138 kV switching station
- Avoiding First Nations Settlement Land
- Eliminating the need for a step-up substation
- A switch yard will still be needed; however, it will be at a lower cost than a step-up substation.

18.3 Shop, Offices and Camp

The mine and power plant will require supporting infrastructure and facilities to enable efficient operations. These facilities will include a maintenance shop, warehouse, mine offices, mine dry, fuel depot, and laydown area. Where practical, facilities will be shared between the mining operation and the power plant to maximize the efficient use of available space and resources.

A camp will be developed at a location that provides convenient access to the mine site. It is anticipated that the camp will consist of prefabricated single-storey buildings and will include accommodation facilities, a kitchen and dining hall, and a recreation building.

Construction electrical power for the site facilities will initially be supplied by a diesel generator until the power plant is commissioned. Following commissioning, the diesel generator will be retained on site to provide standby and emergency power. Mine service water, including water for fire protection, dust suppression, equipment washing, and potable use, will be sourced from on-site wells and treated as required to meet operational and regulatory requirements. Sanitary wastewater will be collected and conveyed to a sewage treatment lagoon for treatment and disposal.

18.4 Water Management Structures

A significant component of the mine development cost is the sediment pond and associated ditching. A conceptual sediment pond has been developed based on site topography and the proposed mine layout. Based on the current footprint and anticipated environmental discharge requirements, only one sediment pond is expected to be required.

The main sediment pond will be supported by a primary drainage ditch connecting the pit area to the sediment pond. This ditch will be approximately 3.5 km long and will need to be constructed during the initial pre-production phase of mine development.

As mining progresses, a series of cutoff ditches will also be required to intercept surface runoff and reduce inflows into the Pit 1 area.

Pit 1 will also require groundwater pumping wells to manage groundwater inflows into the pit. These wells will be developed progressively as mining advances, with most installations expected during the later stages of pit development.

19 MARKET STUDIES AND CONTRACTS

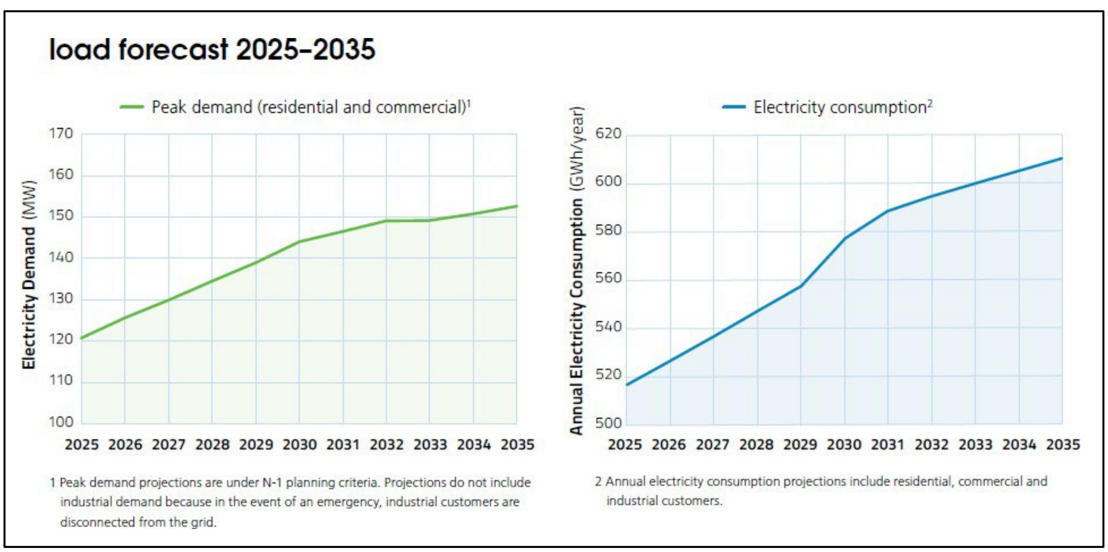
The Yukon's electricity demand (excluding mines) surged by 25% between 2015 and 2020 with a projected non-industrial peak demand projected to rise by 40% by 2030 and 50% by 2035[1] as shown in Figure 17. The peak demand values do not include industrial demand (primarily current or future mining operations). During the winter of 2025, power generation was supplemented with 40 megawatts (MW) of electrical power from 22 rental diesel generators. By 2035 an additional 45 MW is projected to be required.

This will be needed in Whitehorse area, the Yukon's largest and fastest growing electricity load centre.

The capacity (size) of the Yukon electricity system is 162 MW. The dependable capacity in the winter months (due to lower water levels in hydroelectric reservoirs and downstream flow restrictions) is 131 MW. The power limitations in the Yukon are also a limiting factor for mining and industrial development.

This demand outlook indicates that Yukon's electricity system is moving from a period of incremental load growth into a period where new dependable capacity, transmission reinforcement, and demand-side management will be required in parallel. Because the territory operates as an isolated grid, it cannot rely on imports from neighbouring jurisdictions during peak winter conditions; therefore, each additional megawatt of firm load must be matched with local generation or storage that is available when hydro output is constrained. The projected growth in non-industrial demand, combined with potential mining and industrial loads, increases the risk that temporary diesel generation becomes a recurring reliability measure unless new renewable, firm, and flexible resources are advanced ahead of demand.

Figure 17 : Yukon Load Forecast to 2035[1]



[1] Building a Resilient and Renewable Energy Future: Chapter 1

[Link to Yukon]

19.1 Basis of Electricity Price Assumption

No market study, power purchase agreement, term sheet, or independent price forecast has been prepared in support of this assessment. The electricity prices used in the economic analysis presented in Section 22, being $200/MWh, $220/MWh and $240/MWh, are assumptions adopted for sensitivity purposes and do not represent a price that has been offered, negotiated, or independently forecast.

These prices are materially above prevailing Yukon electricity rates. The Project has no contracted offtake, and Yukon Energy Corporation is the only practicable purchaser given the isolated nature of the territorial grid. The commercial framework under which power might be sold, including whether an independent power producer arrangement of this scale and duration is available, has not been established.

The demand outlook described above, and in particular the reliance on rental diesel generation during the winter of 2025 described earlier in this section, indicates a need for new dependable capacity. Need, however, is not the same as price. Establishing the price at which dependable capacity could be sold, benchmarked against the cost of the alternatives available to Yukon Energy, is recommended as part of the structured engagement described in Section 26, and should precede further expenditure on the Project.

The sensitivity of Project economics to this assumption is set out in Section 22.3 and is carried forward as a principal risk in Section 25.2.

20 ENVIRONMENTAL STUDIES, PERMITTING AND SOCIAL OR COMMUNITY IMPACT

As outlined below, information derived from the various studies was compiled and summarized by Ensero Solutions, as presented in Section 3. The principal findings and key considerations from that work are reiterated herein for completeness.

20.1 Environmental Setting

The Project lies within the traditional territories of: Champagne and Aishihik First Nation (CAFN), Little Salmon / Carmacks First Nation (LSCFN), Kwanlin Dun First Nation (KDFN), and Ta'an Kwach'an Council (TKC). The Project location is a largely undeveloped area characterized by glacially derived terrain, extensive wildlife habitat, high-quality aquatic resources, and lands traditionally used by several Yukon First Nations. Baseline environmental studies completed in 1995 identified several physical, biological, and socio-economic features that should be considered during project planning, construction, operation, closure, and reclamation. In this section, environmental considerations identified via the 1995 summary of environmental baseline studies are summarized.

20.1.1 Terrain, Geotechnical and Permafrost Considerations

The project area contains a mixture of colluvial, morainic, glaciofluvial, fluvial, and organic deposits. Morainic and glaciofluvial deposits generally provide the most suitable foundation conditions for mine infrastructure due to their favourable bearing capacity, drainage characteristics, and low susceptibility to frost heaves. Conversely, colluvial fans, steep slopes, gullied terrain, and organic deposits may present stability concerns and require detailed geotechnical assessment before development.

Localized permafrost may occur on north-facing slopes, within organic deposits, and at higher elevations. Disturbance of permafrost-bearing terrain could result in ground settlement, erosion, and infrastructure instability. Project design should therefore minimize vegetation disturbance in sensitive areas and include appropriate engineering measures where frozen ground is encountered.

20.1.2 Geochemistry and Waste Management

Available baseline information indicates that additional rock characterization testing is required to evaluate acid rock drainage (ARD) and metal leaching (ML) potential from waste rock, pit walls, tailings storage facility, construction work areas, topsoil and overburden, and coal-associated materials. Mine planning should incorporate detailed geochemical testing to characterize sulphur content, neutralization potential, paste pH, and metal leachability.

Waste rock storage facilities, coal stockpiles, ash management areas, and tailings or coal processing waste facilities should be designed to limit contamination of groundwater and surface water resources (e.g., source control). A coal-fired power plant would also generate combustion ash and other residual materials. These require geochemical characterization and long-term management and are also a potential resource; options for their beneficial use, and the characterization work needed to evaluate those options, are described in Section 24.1.

20.1.3 Air Quality and Greenhouse Gas Emissions

A coal mine and coal-fired generating station would be significant sources of:

- dust from mining (i.e., wind erosion), crushing, hauling, and coal and waste rock handling;
- combustion emissions including particulate matter (PM_{10} and $PM_{2.5}$), nitrogen oxides (NO_x), sulphur dioxide (SO_2), and greenhouse gases (carbon dioxide [$CO_{2]}$ and methane [CH_4]); and
- vehicle and equipment emissions (i.e., combustion engine emissions).

The Project would require an assessment of cumulative regional air quality impacts and would be expected to develop an air quality management program including emission controls, dust suppression measures, continuous monitoring encompassing all phase of the project.

From a greenhouse gas perspective, coal-fired electricity generation typically exhibits a higher life-cycle carbon intensity than natural gas, nuclear, hydroelectric, wind, or solar generation. Nevertheless, the carbon footprint of modern coal mining operations themselves represents only a portion of the overall life-cycle emissions associated with coal utilization. Contemporary mining projects are increasingly incorporating energy-efficiency measures, emissions monitoring, fleet optimization, methane management, and other carbon-reduction initiatives to minimize operational greenhouse gas emissions. Within the context of existing climate policies and regulatory requirements, these measures support continuous improvement in environmental performance while enabling responsible resource development under a transparent and enforceable regulatory framework.

20.1.4 Vegetation and Reclamation

The area supports mature spruce forests, regenerating post-fire forest communities, peatlands, wetlands, and riparian habitats. Vegetation clearing associated with mining and power generation infrastructure will result in direct habitat loss and soil disturbance. Reclamation planning should:

- Characterize and stockpile valuable topsoil and limit erosion to the extent possible.
- salvage and preserve suitable overburden and growth media,
- use native species for revegetation,
- restore natural drainage patterns, and
- re-establish wildlife habitat and ecosystem function following mine closure.

20.1.5 Water Resources and Hydrology

The project drains to the Klusha Creek–Nordenskiold River watershed, which contains important fish habitat and supports downstream ecological values. Baseline studies indicate generally good water quality, low levels of contaminants, and hydrologic systems influenced by spring snowmelt and seasonal runoff.

Mine development and operation could affect surface water through:

- Changes in runoff patterns caused by mine construction and earthworks, particularly development of mine pit and waste rock dump.
- Increased sediment loading to streams and receiving environments as a result of stripping vegetation, including road construction and the development of mine facilities, including pit, TSF and waste rock dump.
- Potential releases to air, surface water and groundwater from coal handling, coal washing, fuel storage, and power plant and water treatment plant operation.

- Water withdrawals for mine activities (e.g., process water and dust suppression) and power plant and water treatment plant operation.

Comprehensive water management and waste management will be required to manage contaminant transport and protect downstream water quality and aquatic habitat. Water management planning will be required to establish erosion and sediment controls (ESC), clean-water diversions (i.e., limit mine contact water), containment of mine contact water (i.e., potentially contaminated water), and management, including treatment to confirm concentrations of constituents of potential concern (COPC) in the receiving environment remain protective of the broader aquatic and terrestrial community. Water quality treatment needs for mine contact water are complex; the prospective coal mine and power plant will likely need to consider synergistic adverse changes to water quality. For example, in some environments, mine water management, relying on large settling ponds to manage TSS have led to the establishment of habitat with increased productivity and unfavourably the high productivity has resulted in selenium speciation and localized selenium bioaccumulation in aquatic biota.

20.1.6 Fisheries and Aquatic Ecosystems

The Nordenskiold River and Klusha Creek are classified as important fisheries resources and support Arctic grayling, lake trout, lake whitefish, burbot, northern pike, and other resident fish species. The Nordenskiold River also supports Chinook and chum salmon spawning and rearing habitat; Project located in Chinook Salmon Conservation Unit (i.e., CK-71; Nordenskiold Conservation Unit is in Red status, high conservation concern). Relevant potential project effects include:

- Sedimentation of fish habitat,
- Alteration of stream flows,
- Fish passage disruption due to establishment of watercourse crossings and water treatment instream infrastructure,
- Water quality degradation, and
- Habitat loss directly through infrastructure development (e.g., buried by spoils) and indirectly following calcite deposition resulting from water quality changes.

All watercourse crossings, diversions, water management infrastructure, effluent discharge, and water withdrawals should be designed to maintain fish habitat function and meet applicable regulatory requirements. Management becomes increasingly difficult if critical / limited fish habitat is present within the Project area and/or species at risk. Based on the conservation status of the Nordenskiold River Chinook salmon population the focus would need to be on avoiding impacts to fish and fish habitat.

20.1.7 Wildlife and Wildlife Habitat

The Project occurs within habitat used by moose, elk, Dall sheep, waterfowl, furbearers, and numerous other wildlife species. Regional information identified important moose winter range, elk winter range, movement corridors, and harvested wildlife resources within the project area. Concerns include:

- habitat loss and fragmentation,
- direct mortality via collisions with vehicles and powerline or human interactions,

- increased public access resulting in higher hunting pressure,
- disturbance from noise, traffic, lighting, and human activity, and
- restricted wildlife movement around mine and power plant infrastructure.

Mitigation should focus on limiting unnecessary disturbance and access, avoiding and protecting key habitats, maintaining wildlife corridors, and implementing seasonal restrictions where appropriate. Management becomes increasingly difficult if critical / limited wildlife habitat is present within the Project area and/or species at risk. Woodland caribou conservation status in the Project area is Threatened under the SARA; conservation efforts are ongoing, with community involvement playing a significant role in recovery programs. A high priority would be to avoid impacts to seasonal ranges, migration corridors, calving habitat or winter habitat.

20.1.8 Heritage Resource and Traditional Land Use

The study area lies within the traditional territories of the CAFN, LSCFN, KDFN, and TKC. Archaeological sites, historic trails, and traditional land use values have been identified in and around the Project area. Development should:

- avoid heritage sites where possible, by including archaeological assessment consideration during planning (i.e., before construction) to inform the design;
- continue consultation and engagement with affected First Nations on all VESECs, including land use; and,
- incorporate Traditional Knowledge into project planning, including development of environmental management and monitoring programs.

20.1.9 Socio-Economic and Land Use Considerations

The Project has potential to create employment and economic benefits while also affecting existing land uses including trapping, hunting, outfitting, recreation, and seasonal residential use around Braeburn Lake. Increased traffic and road access could alter resource use patterns and increase pressure on wildlife populations. The workforce required as part of mine construction and operation could increase pressure on community infrastructure. As such, careful access management, community engagement, and monitoring of socio-economic effects will be required throughout the life of the project.

20.1.10 Environmental Screening Conclusion

Based on the review of available baseline information, no environmental sensitivities have been identified that would be expected to fundamentally constrain or significantly increase the complexity of developing the Project as a sustainable mining operation. The environmental features identified within the Project area, including water resources, fish and fish habitat, wildlife habitat, vegetation communities, heritage resources, and traditional land use values, are characteristic of the region and represent considerations commonly encountered during mine development in Yukon. These features can be appropriately characterized, assessed, and managed through project design, avoidance and mitigation measures, adaptive management, and regulatory compliance.

While the Project presents several environmental risks that warrant further study, particularly with respect to water management, geochemistry, fisheries, and Indigenous interests, none of the environmental considerations reviewed to date indicate the presence of unique or exceptional constraints that would preclude development. Successful project advancement will depend on collecting sufficient baseline information, incorporating environmental considerations into mine planning and design, and maintaining meaningful engagement with affected First Nations, regulators, and communities.

Accordingly, the primary environmental challenge for the Project is not the presence of significant environmental sensitivities, but rather the collection of adequate baseline data to support informed decision-making, effects assessment, and regulatory approvals. With implementation of the environmental programs and planning recommendations outlined in this report, the Project appears capable of progressing through development while maintaining environmental protection objectives and supporting long-term sustainable mine development.

20.2 Regulatory Framework

In the Yukon, regulatory approvals and permitting for resource developments are governed by a hierarchical legal framework that begins with constitutionally protected modern treaties, followed by federal and territorial legislation, and is implemented through regulations, assessments, and permits. Collectively, this framework is intended to support responsible development, environmental protection, public health and safety, and the consideration of socio-economic and cultural values.

At the highest level, the Umbrella Final Agreement (UFA) and the associated Yukon First Nation Final Agreements and Self-Government Agreements are constitutionally protected under Section 35 of the *Constitution Act*, 1982. The UFA establishes the overarching structure for land ownership, resource management, environmental and socio-economic assessment, and consultation with Yukon First Nations. This structure is further defined and implemented through CAFN, LSCFN, KDFN and TKC Final and Self-government agreements, which allocate lands, define rights and authorities, and confer jurisdiction to First Nations over their Settlement Lands and citizens.

Federal and territorial legislation has been enacted in a manner consistent with these agreements. Key territorial statutes applicable to the Project include the *Territorial Lands (Yukon) Act* (TLYA), *Waters Act, Environment Act, Public Health and Safety Act*, and *Building Standards Act*. Together, these statutes establish regulatory requirements, enforcement mechanisms, and the authorities of oversight bodies. The YESAA, which implements assessment obligations established under the UFA, provides the legal basis for environmental and socio-economic assessment in Yukon and is administered by the Yukon Environmental and YESAB.

Within this legislative framework, the primary regulatory authorization required for the Project is a Type A Water Licence issued by the Yukon Water Board (the Board) under the *Waters Act* and its regulations. A Type A Water Licence is generally required for large, complex industrial projects including water use, including mine dewatering, waste rock management, water treatment and effluent discharge with potential environmental effects.

Projects that require permits or authorizations and are located on, or may affect, Yukon First Nations Settlement Land or Traditional Territories must undergo assessment under YESAA and involve consultation with affected First Nations, as required by the *Yukon First Nations Land Claims Settlement Act* and the applicable Final Agreements. These processes ensure that Indigenous rights, interests, and knowledge are integrated into decision making alongside environmental and socio-economic considerations.

20.2.1 Project-Specific Context

In the Yukon there are no active coal mines and the Yukon's coal sector has historically been limited and largely exploratory. To the north of the Project, about 90 km, the Tantalus Butte Coal Mine was a significant source of coal for the region. The mine was known for its good quality coal and operated for about 58 years, however, the mine faced challenges such as underground fires and environmental concerns, leading to its closure in the late 1970s. The site is now a focus for the Government of Yukon to address safety issues and manage the abandoned mine.

The modern coal mining and coal power generation industry is often viewed through dual lens. On one hand, it is recognized for providing reliable, affordable energy and supporting jobs, economic growth, and energy security in many regions. On the other hand, it faces increasing public scrutiny due to concerns about greenhouse gas emissions, environmental impacts and its role in climate change. As a result, the industry is frequently perceived as being transitioned out with growing pressure to adopt perceived cleaner technologies, reduce emissions, and balance energy demands with environmental sustainability goals. Considering the existing general perception of fossil-fueled energy generation, it is anticipated that early and consistent messaging would be critical regarding the need for the project, industry-wide and mining-wide environmental protection advancements, and project-specific commitments and controls defining the overall sustainability of the proposed project.

At the same time, evolving geopolitical and energy security considerations have renewed discussion in many jurisdictions regarding the role of reliable and affordable energy, dispatchable energy sources and electrical grid stability in supporting economic development and community safety and quality of life (e.g., Saskatchewan's recent funding announcement for coal refurbishment plan [MacPherson 2025]). Volatility in global energy markets, increasing concerns regarding energy sovereignty, and growing recognition of the challenges associated with rapidly transitioning remote and northern regions to alternative energy systems have, in some cases, created a more favourable policy and development context for projects capable of providing secure domestic energy supply. Within Yukon specifically, ongoing concerns regarding electricity system reliability, limited generation capacity, increasing demand associated with population and industrial growth, and constraints on near-term alternative generation options (e.g., hydro power plant shutdowns during critical fish migration windows and low flow conditions) have highlighted the importance of evaluating a broad range of energy supply solutions.

Based on Yukon's current framework for major surface mines, it is expected the Project will be required to obtain a Coal Mining Permit together with a Type A Water License to form the core operating authorization. The Yukon has limited experience permitting coal development activities; however, the application to obtain a Coal Mining Permit is expected to require a level of effort equivalent to that for a Quartz Mining Permit application. It is possible that regulators may need some time to map out the specific regulatory approval process. However, in the Yukon it is common for industry practices in British Columbia to be referred to (e.g., baseline data requirements), and British

Columbia has extensive experience permitting coal development activities and Ensero's experience in BC, both with managing legacy and modern environmental risks, have informed this submission.

Based on the scale and scope of the proposed activities (i.e., open-pit coal mine and power plant) the Project would require various permits to proceed, including:

- Land use permit, mining land use permit and coal mine permit;
- Permits for water use and deposit of waste to water; and
- Permits for air emissions, solid and special waste.

Most of these permits / licenses are issued by the Government of Yukon via the Department of Energy, Mines and Resources (EMR), the regulator for land use, mining land use, etc.; and the Department of Environment (ENV) the regulator, for air emissions and solid/special wastes etc. A Water License would also be required from the Board, the independent regulator for the use of water and deposit of waste to water. Depending on the activities proposed or location of those activities there could be authorizations needed that are issued by the federal government, such as the Fisheries and Oceans Canada (DFO) issuance of a Section 35(2) *Fisheries Act* Authorization [FAA]) or if aspects of the Project are located on First Nation settlement land the issuance of required approvals by self-governing First Nations.

All coal mine projects, power generation projects, and associated activities require an assessment under YESAA before licenses or permits can be issued. YESAA process is administered by YESAB and involves opportunities for First Nations, governments, and the public to provide input on the potential effects of a project. The assessment process ends with a recommendation from YESAB and the issuance of decision document(s) from Decision Bodies (Government of Yukon, Government of Canada, and/or First Nation governments). Regulators can only issue a permit if a decision document allows the project to proceed. Although the information requirements for each regulatory agency are somewhat integrated each decision maker has a distinct process that needs to be followed and requirements to be met. Refer to Table 13: Division Mountain Project Expected Key Regulatory Requirements for a summary.

Table 13: Division Mountain Project Expected Regulatory Requirements

Act	Legislation	Regulatory Approval	Purpose	Responsible Agency
Territorial Lands (Yukon) Act; Lands Act	Coal Regulation	Coal Mining Permit	Allows for the extraction and removal of Coal.	Government of Yukon Department of Energy, Mines and Resources – Lands Branch
Territorial Lands (Yukon) Act; Lands Act	Land Use Regulation	Land Use Permit	Allows for temporary use of public lands	Government of Yukon Department of Energy, Mines and Resources – Lands Branch

Act	Legislation	Regulatory Approval	Purpose	Responsible Agency
Territorial Lands (Yukon) Act; Lands Act	Quarry Regulation	Quarry Permit	Allows for the development of borrow areas	Government of Yukon Department of Energy, Mines and Resources – Lands Branch
Transportation of Dangerous Goods Act	Dangerous Goods Regulation	Transportation of Dangerous Goods	Allows for transportation of dangerous goods to site and special waste from site	Government of Yukon Department of Highways & Public Works – Transport Services Branch
Environment Act	Solid Waste Regulations; Air Emissions Regulations; Special Waste Regulations	Waste Management Permit Air Emissions Permit	Authorizes burning of waste and generation and storage of waste	Government of Yukon Department of Environment - Environmental Protection and Assessment Branch
Waters Act	Waters Regulation	Water License	Authorizes use of and deposition of waste to water	Yukon Water Board
Fisheries Act	Fisheries Act	Section 35 *Fisheries Act* Authorization	Harmful alteration, disruption, or destruction of fish habitat	Department of Fisheries and Oceans
Fisheries Act	Coal Mining Effluent Regulations	Authority to Deposit" deleterious substances to waters frequented by fish	Authority to Deposit" deleterious substances to waters frequented by fish	Environment and Climate Change Canada
Canadian Environmental Protection Act, 1999	Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations (SOR/2012-167)	Unit registration; annual reporting; compliance with emissions performance standard	Limits CO2 emissions intensity of coal-fired generating units to 420 t CO2/GWh	Environment and Climate Change Canada

The reclamation and closure costs are estimated based on Allnorth's internal cost database. The total closure cost and reclamation cost is estimated to be approximately CAD$20.0M. The closure and reclamation cost include the following construction activities:

- Rehandle and placing topsoil on the existing waste dumps, mine roads and platforms.
- Decommissioning water management structures.
- Revegetation/seeding/tree planting.
- Water quality protection measures.
- Long-term monitoring programs.
- Decommissioning and demolition of mine and power plant infrastructure.
- Resloping the waste rock dumps down to 2H:1V slope.

Instead of applying all the closure cost at the end of the mine life, the closure cost is incurred over the life of the Project based on disturbance area. This is done because the regulation requires operations to guaranteed/bond enough money to cover closure costs in any given year.

20.2.2 Federal Greenhouse Gas Regulation of Electricity Generation

In addition to the territorial authorizations described in Section 20.2.1, the Project would be subject to federal regulation of greenhouse gas emissions from coal-fired electricity generation. This regulation applies independently of the YESAA assessment process and of the territorial permits and licenses summarized in Table 13, and compliance with it is a precondition to lawful operation rather than a matter to be resolved through the assessment process.

Applicable Instrument and Performance Standard

The governing instrument is the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, SOR/2012-167, made under the Canadian Environmental Protection Act, 1999 (CEPA). The Regulations establish a performance standard limiting the CO2 emissions intensity of regulated units, and apply to any unit that produces electricity by means of thermal energy using coal as a fuel, whether alone or in conjunction with other fuels. The Regulations contain no minimum capacity threshold.

Section 3(1) of the Regulations provides that a responsible person for a new unit or an old unit must not, on average, emit more than 420 tonnes of CO2 from the combustion of fossil fuels in the unit for each GWh of electricity produced during a calendar year. Three features of the standard are material to the Project:

- Electricity is measured on a net basis. Under section 19, the denominator is gross generation less the electricity consumed by the power plant for generation. Parasitic load, which for a pulverized fuel plant with an air-cooled condenser, flue gas treatment and cold-climate provisions is likely to be significant, therefore worsens the calculated intensity.
- Sorbent emissions are captured by the standard. Under section 3(3), CO2 released from the use of sorbent to control sulphur dioxide emissions is counted toward the limit. The low sulphur content of Division Mountain coal (0.45%) limits, but does not eliminate, this contribution.
- Only biomass is excluded. The limit applies to emissions from the combustion of fossil fuels. CO2 attributable to the combustion of biomass, as defined in section 2(1), is excluded from the numerator, which is the basis on which co-firing could reduce the calculated intensity.

Application to the Project

A "new unit" is defined in section 2(1) as a unit, other than an old unit, whose commissioning date is on or after July 1, 2015, the commissioning date being the day on which the unit begins to produce electricity for sale to the electric grid. The proposed 100 MWe generating unit would therefore be a new unit, and the 420 t CO2/GWh performance standard would apply to it from commissioning. There is no phase-in period, no end-of-useful-life allowance of the kind available to units commissioned before that date, and no grandfathering.

Associated obligations would include registration of the unit with the Minister of the Environment within 30 days of its commissioning date under section 4(1), quantification of emissions by continuous emissions monitoring or by a measured fuel carbon content method under Part 3, and submission of an audited annual report by June 1st each year under section 15.

Project Emissions Intensity

The CO_2 emissions intensity of the proposed generating unit has not been quantified in this study. Two inputs required for a defensible estimate are not yet available. The plant heat and mass balance — including net plant efficiency, auxiliary load, and design capacity factor — has not been finalized at this stage of engineering definition. In addition, no ultimate analysis has been performed on coal from the Property, as noted in Section 13, so the carbon content of the fuel is not established from measured data.

Determination of the Project's emissions intensity, and its comparison against the 420 t CO_2/GWh performance standard, is recommended as part of the next phase of study. That scope should include ultimate analysis for carbon, hydrogen, nitrogen and sulphur on representative coal samples; a finalized heat and mass balance establishing net generation on the basis prescribed by section 19 of the Regulations; and calculation of the resulting emissions intensity using a quantification method consistent with Part 3 of the Regulations. This work is included in the Phase 2 programme described in Section 26.

Notwithstanding that the Project-specific intensity has not been established, it is relevant that the 420 t CO_2/GWh standard was set at approximately the emissions intensity of efficient natural gas combined cycle generation, and was intended to preclude the construction of new unabated coal-fired generating units. Compliance is therefore not expected to be achievable through combustion efficiency alone, and the next phase of work should be directed at identifying and costing a compliance pathway rather than at optimizing plant efficiency against the standard.

Available Flexibilities

The Regulations contain a number of exceptions and exemptions. Their availability to the Project is summarized below.

Table 14: Flexibilities under SOR/2012-167 and their Availability to the Project

Provision	Nature	Availability to the Project
s. 3(5) **Carbon capture and storage**	CO2 that is captured, transported and stored in accordance with applicable law and not subsequently released is excluded from the emissions counted against the limit.	Available in principle. No CCS provision is included in the plant concept described in Section 17, and no capture, transport or storage infrastructure has been identified, costed, or assessed for geological suitability in the region. The degree of capture required cannot be established until the Project's emissions intensity has been determined.
s. 9 **Temporary CCS exemption**	A temporary exemption for a unit designed to be integrated with a CCS system to be constructed.	Not available. The exemption required compliance by 1 January 2025 and, by its terms, remained in effect only until 31 December 2024.
ss. 5 and 6 **Substitution and deferral**	Allows a responsible person to substitute or defer the application of the limit by reference to another unit that is shut down or retired.	Not available. Both mechanisms require a second unit under common ownership located in the same province or territory. Yukon has no operating coal-fired generating units.
ss. 7 and 8 **Emergency circumstances**	Exemption during a disruption, or significant risk of disruption, to electricity supply arising from an extraordinary, unforeseen and irresistible event.	Not a basis for ordinary operation. The exemption runs for 90 days and is extendable only while the emergency persists.
CEPA s. 10 **Equivalency agreement**	The federal Regulations may be declared not to apply in a jurisdiction that has in force provisions the Governor in Council is satisfied achieve equivalent environmental outcomes. Orders of this kind	Theoretically available but speculative. Yukon has no coal-fired generation and no equivalent regulatory scheme, and an agreement would require an initiative of the Government of Yukon rather than of the proponent.

Provision	Nature	Availability to the Project
	are in effect in respect of Saskatchewan and Nova Scotia.	
s. 2(1) **Biomass co-firing**	Emissions attributable to biomass combustion are excluded from the numerator.	Available as a partial measure only. Co-firing rates achievable in a conventional pulverized fuel boiler without major modification are limited, and a secure long-term biomass supply has not been identified. Whether co-firing could contribute materially to compliance cannot be assessed until the Project's emissions intensity has been determined.

Related Federal Instruments

Two further federal instruments were considered and are noted for completeness.

The Clean Electricity Regulations, SOR/2024-263, made under CEPA in December 2024, establish emissions limits applying to fossil-fuelled generating units of 25 MW or greater beginning in 2035. The electricity systems of Yukon, the Northwest Territories and Nunavut are understood not to be subject to those Regulations. This does not affect the application of SOR/2012-167, which is a separate instrument of general application. Federal electricity policy has been under active revision and the current status of both instruments should be confirmed at the time of any subsequent study.

Federal carbon pricing under the Greenhouse Gas Pollution Pricing Act may also apply to the Project through the output-based pricing system for industrial emitters. No carbon price has been applied in the capital cost estimate presented in Section 21.2.1 or in the economic analysis presented in Section 22. Given the scale of the proposed facility, a carbon cost would be expected to represent a material operating expense, and the applicable regime and any output-based allocation for electricity generation in Yukon should be confirmed.

Implications for the Project

The federal performance standard is expected to be the most significant regulatory constraint on the Project. Unlike the territorial authorizations described in Section 20.2.1 — which are directed at how the Project is designed, operated and monitored, and which can be addressed through baseline data collection, mitigation design and engagement — the performance standard is a threshold requirement applying from the commissioning date, and it is not expected to be met by a coal-fired configuration operating without abatement.

Establishing whether and how the Project can comply is therefore a precondition to advancing it beyond the current study stage. The pathways available in principle are:

- Integration of a carbon capture and storage system, together with transport infrastructure and access to a suitable geological storage formation, none of which has been identified in the region;
- Biomass co-firing, alone or in combination with other measures, subject to the boiler and fuel supply constraints noted above; or
- A change in the applicable federal regulatory framework, including through an equivalency agreement between Canada and the Government of Yukon, which would be beyond the control of the proponent.

Each of these carries capital and operating cost implications and, in the case of carbon capture, a reduction in net plant output, that have not been estimated. None is reflected in the capital cost estimate in Section 21, the operating cost estimate in Section 21.2.2, or the economic analysis in Section 22. Accordingly, the economic results presented in Section 22 should be read as applying to an unabated coal-fired configuration, and would require revision if a compliance pathway were adopted. This matter is carried forward as a principal project risk in Section 25.2, and quantification of the Project's emissions intensity together with an assessment of available compliance pathways is recommended as part of the Phase 2 work programme described in Section 26.

21 CAPITAL AND OPERATING COSTS

Costs and revenues have been generated based on information provided from a variety of sources including:

- Allnorth's internal cost database,
- Recently completed projects,
- Vendor-supplied quotations, and
- Published cost data.

Cost Estimate Basis

Capital and operating cost estimates have been prepared for the major cost items and activities associated with the conceptual 100 MW power plant and supporting mine design.

Contingency Allowance

Contingency factors have been applied to all capital cost estimates to reflect the level of uncertainty appropriate for a scoping-level assessment. These allowances also account for cost items or activities that have not been specifically identified at this stage of study.

The treatment of contingency within the economic analysis is discussed in Section 22.

Currency Basis

All cost estimates are presented in constant 2026 Canadian dollars (CAD$).

21.1 Surface Mine Capital and Operating Costs

21.1.1 Capital Requirements Surface Mine

It is assumed that all mining equipment (trucks, loaders, etc.) will be purchased with expenses considered as capital costs (see Section 21.1.2). Capital costs for surface mining are from Allnorth's internal database with adjustments for inflation, site specific conditions, and data from other operations in the region.

Capital requirements for primary project infrastructure (power, water, access roads, etc) are assumed to serve both the surface mining operations and power plant operation and are discussed separately, below (see Section 21.3).

Initial Capital costs are outlines in Table 14 and are pre contingency but include delivery and setup.

Table 15: Surface Mining Capital Cost

Task	CAPEX (M)
Trucks	$10.22
Shovels/Loaders	$6.21
Support/Aux	$17.78
Total Initial Equipment Capex	$34.21
Pre-Development Cost (Roads, Clearing)	$3.3
ROM Pad Construction	$2.0

Task	CAPEX (M)
Mine Infrastructure & Facilities	$22.0
Coal Handling Facilities	$20.0
Water Management	$4.2
Capital Period G&A	$5.0
EPCM	$6.0
Misc. / Spare Parts	$5.0
Total Initial Capital Cost (excluding sustaining capital)	$101.7
Total Initial Capital Cost with 20% Contingency	$122.0
Sustaining Capital Cost*	$18.00

**Sustaining capital is incurred over the life-of-mine and is excluded from the initial capital total. Refer to Section 22 for the treatment adopted in the cash flow model.*

21.1.2 Operating Costs Surface Mine

Operating costs for the surface operation have been based on operating costs from Allnorth's internal database with adjustments for site specific conditions and data from other operations in the region. Hourly wage rates and salaried personnel costs typical of a surface mine in the north of Canada were utilized.

Table 15 shows the overall operating unit costs for the LOM.

Table 16: Mining Operating Cost

Task	Units	Unit Cost
Drilling/Blasting	$/tonne	0.98
Loading	$/tonne	0.81
Hauling	$/tonne	1.21
Dozing & Grading	$/tonne	0.71
Auxiliary Equipment	$/tonne	1.00
Total Mining	$/tonne	4.71
Waste Mining	$/bcm	11.14
Camp Costs	$/tonne	0.43
G&A	$/tonne	0.96
Coal Delivered to Plant	$/tonne	52.32

21.2 CHPP and Power Plant Capital and Operating Costs

21.2.1 Capital Costs – Facilities and CHPP

A PEA-level capital cost estimate was developed for the coal-fired power generation facility. The estimate includes the 1 × 100 MWe development options and has been prepared in accordance with AACE International Class 5 estimating practices.

The estimate is based on a combination of budgetary vendor quotations, historical project data, benchmark unit rates, specialist consultant input, and factored estimating methodologies appropriate for the level of engineering definition available at this stage of study.

Major equipment costs were developed primarily from budgetary quotations obtained from equipment suppliers for key process systems, including:

- Pulverized fuel boiler systems
- Steam turbine generators
- Air-cooled condensers
- Boiler feedwater treatment systems
- Coal receiving and handling equipment

Transmission line and substation costs were developed using conceptual engineering information and specialist consultant input. Balance-of-plant infrastructure, civil works, structural works, piping, electrical systems, and construction support facilities were estimated using benchmarked and factored methodologies derived from comparable mining, power generation, and heavy industrial projects.

The estimate includes allowances for:

- Power generation facilities
- Coal receiving, storage, and handling systems
- Ash handling and storage facilities
- Transmission interconnection infrastructure
- Site development and civil works
- Construction support facilities
- Permanent support buildings
- Utilities and ancillary infrastructure
- EPCM services
- Commissioning and start-up support
- Contingency

A contingency allowance of 15% of direct and indirect costs has been applied to reflect the conceptual level of project definition and associated estimating uncertainty. The estimate is presented in constant Q2 2026 Canadian Dollars and excludes financing costs, escalation beyond the estimate base date, operating costs, carbon pricing, corporate overheads, and transmission upgrades beyond the defined interconnection point.

Table 17: Power Plant Capital Cost Breakdown

Cost Area	($000)
Air Cooled Condenser	$19,432
Boiler	$199,862
Coal Receiving	$11,218
Steam Turbine Generator	$32,295
Insulation and Scaffolding	$10,047
Freight	$15,830

Cost Area	($000)
Access Road	$10,500
Civil, Concrete, and Structural	$58,585
Transmission Line and Electrical	$95,118
Camp and Warehouse/Maintenance Buildings	$37,240
Piping and Cranage	$34,869
EPCM	$78,754
Contractor Indirect	$78,754
Commissioning	$21,002
Spares	$15,751
Catering and bussing	$13,215
Owner's Cost	$10,501
Contingency	$113,597
TOTAL	**$856,570**

21.2.2 Operating Costs – Power Plant

Operating costs include fixed operating and maintenance (O&M) costs, variable O&M costs, and fuel costs. Fixed and variable O&M costs were developed using industry benchmark values appropriate for a 100 MW coal-fired power plant.

Table 18: Power Plant Operating Cost Breakdown

Cost Area	($000)
Annual Fixed Cost	$11,252
Variable (Operating and Maintenance ($6.4/WMH)	$4,765
Total Annual Cost	**$16,017**

22 ECONOMIC ANALYSIS

22.1 Principal Assumptions

The preliminary economic assessment is preliminary in nature and there is no certainty that the results of the preliminary economic assessment will be realized. Mineral resources that are not mineral reserves do not have demonstrated economic viability. No mineral reserves have been estimated for the Property.

The principal assumption capital and operating costs are detailed in Section 21. The preliminary economic assessment is preliminary in nature and there is no certainty that the results of the preliminary economic assessment will be realized. Mineral resources that are not mineral reserves do not have demonstrated economic viability. No mineral reserves have been estimated for the Property.

The project economics are based on an assumed three-year construction period. All capital expenditures incurred prior to the commencement of construction have been treated as sunk capital and are therefore excluded from the forward-looking economic evaluation.

Depreciation has been calculated based on the capital costs presented in Section 21 of this report, using the declining-balance method prescribed by the Canada Revenue Agency. The majority of the capital expenditures are assumed to fall under Class 41(a), which is subject to a 30% depreciation rate.

Yukon coal royalty of $0.28 per tonne has been applied.

Income tax rates of 12% for Yukon and 15% for Canadian Federal have been applied.

A $20M reclamation bond is included in the cash flow model.

22.2 Carbon Tax

Calculation of carbon taxes that may be applicable to the Project is difficult to determine because certain mitigations and rulings could significantly reduce or eliminate the amount of payable taxes. Recent discussions between the Canadian government and certain Provinces also suggest that there may be changes to the industrial carbon tax rates. The extent to which these factors may influence the ultimate carbon pricing treatment for this project would require further discussion with both the Yukon and Federal Governments.

Currently, the federal government mandates a complete phase-out of unabated conventional coal-fired electricity by December 31, 2029. No new coal-fired plants are permitted to join the grid unless they are fully greenhouse gas emissions abated, and so there are no special exemptions for base load coal fired power plants under the federal output-based pricing system for industrial emitters.

The project has not completed an assessment on the inclusion of abatement technology options such as carbon capture and storage and so the potential carbon tax payable for the project has been calculated using the following formula:

Annual Carbon Tax Payable = Annual Coal Tonnes used by Plant × (100% − ash %) × 2.7 t CO_2/t coal × Annual price of carbon

Assuming a base year of 2026, the carbon tax payable would be calculated as follows:

Annual Carbon Tax Payable = 439,000 t coal × (100% − 35%) × 2.7 t CO_2/t coal × \$95/t CO_2 = ~\$73M

A more comprehensive overall project carbon accounting exercise will need to be carried out in the next stages of the project to better understand the implications of carbon pricing on the project. This relatively simplistic approach provides some guidance on the potential impact of carbon pricing on the overall project economics.

22.3 Net Present Value Analysis

For the Base Case capital cost, the project achieves an after-tax IRR of approximately 8% at an electricity sales price of approximately $194/MWhr, excluding any carbon taxes that may be payable.

Assuming, the full amount of the projected carbon dioxide emissions from Division Mountain were subject to the carbon tax, the project would achieve an after-tax IRR of approximately 8% at an electricity sales price of approximately $292/MWhr.

The analysis indicates that project economics are highly sensitive to both electricity sales price and discount rate. For the Base Case capital cost scenario with a discount rate of 8%, the project achieves an after-tax IRR of approximately 8% at an electricity sales price of approximately $194/MWh. Across the evaluated range of power prices, increasing revenue results in significant improvements in both NPV and IRR, demonstrating the potential for improved project economics while highlighting the importance of financing costs, which factor into the discount rate, and long-term power purchase arrangements as shown in Table 19.

Table 19 Economic Analyses Results without Carbon Tax

Electricity Price	NPV ($M) at Varying Discount Rates with IRR			
	6%	8%	10%	IRR(%)
$200/MWh	228	32	-97	8.4%
$220/MWh	358	135	-18	9.7%
$240/MWh	488	236	64	11.0%

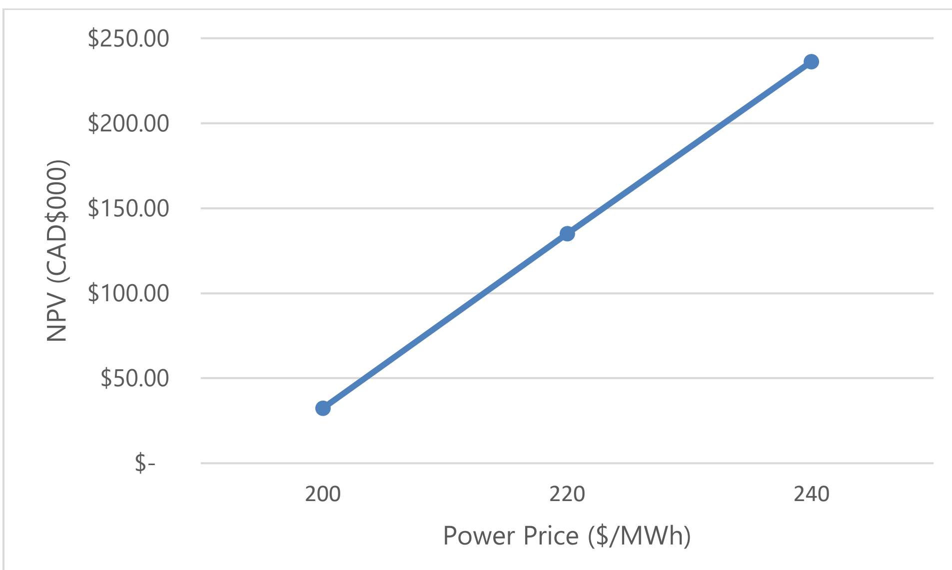
22.4 Sensitivity Analysis

The sensitivity of NPV to discount rate (at a life of project price of $200 per MWh) is shown on Figure 18.

Figure 18: Sensitivity of NPV to Discount Rate

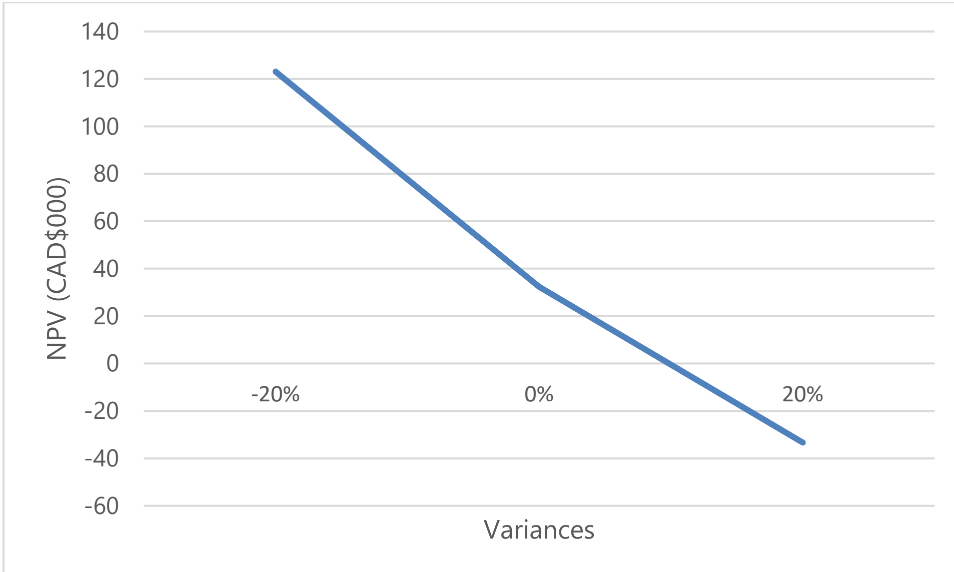
The sensitivity of NPV8% to variances in electricity rate ($ per MWh), at an 8% discount rate, is shown on Figure 19. This analysis suggests that the "break-even" price may be approximately $194 per MWh, or less (depending on contingencies and the discount rate).

Figure 19: Sensitivity of NPV8% to Electricity Rate (Total Cost)



The sensitivity of NPV8% to variations in capital costs is presented in Figure 20. The analysis indicates that project economics are sensitive to changes in capital cost estimates.

Figure 20: Sensitivity of NPV8% to Capital Cost Variances



23 ADJACENT PROPERTIES

This technical report does not utilize any data and/or interpretations from adjacent properties.

24 OTHER RELEVANT DATA AND INFORMATION

There is no other relevant data or information applicable to this report.

25 INTERPRETATION AND CONCLUSIONS

25.1 Interpretation

The Division Mountain Property hosts significant tonnage of High Volatile "B" Bituminous coal. Most of the coal occurs in the Middle to Upper Jurassic Tanglefoot Formation Upper Member, which was deposited in a complex fluvial-deltaic depositional environment. The geology type is "moderate" according to the guidelines set forth in GSC Paper 88-21.

Exploration has focused on a 6.5 by 1.5 km southeast trending area immediately adjacent to Division Mountain. Drilling has outlined a 52.5 Mt resource of High Volatile "B" Bituminous.

A conceptual surface mine plan has been developed for Pit 1 and demonstrates that coal can be delivered at the rate required to supply a 100 MW generating facility over the evaluation period, at a strip ratio consistent with the resource geometry. A pulverized fuel boiler configuration has been selected as the preferred technology for the coal characteristics available. Capital and operating cost estimates have been prepared to AACE Class 5 accuracy.

The economic analysis indicates that Project returns are highly sensitive to the electricity sales price and to the discount rate, and that the Project requires a power price materially above prevailing Yukon rates to generate a positive return. No market study or contracted offtake supports that price, as described in Section 19.1.

No fatal environmental constraint has been identified, but baseline data are dated and incomplete, and water quality, geochemistry, fisheries and Indigenous land use interests will require focused work. The federal emissions performance standard described in Section 20.2.2 is not expected to be met by a coal-fired configuration operating without abatement, and no compliance measure has been engineered or costed.

Opportunities to place the Project's bulk material streams to beneficial use have been identified at a conceptual level in Section 25.3. Salvage value has been credited against the closure estimate, and it assumes that the salvage pays for the site remediation costs.

The preliminary economic assessment is preliminary in nature and there is no certainty that the results of the preliminary economic assessment will be realized. Mineral resources that are not mineral reserves do not have demonstrated economic viability. No mineral reserves have been estimated for the Property.

25.2 Risks and Uncertainties

Risks and uncertainties that may affect the reliability or confidence of the findings of the preliminary economic assessment, as reported in Sections 16 through 22, include the following.

The PEA surface mining plan was not supported by geotechnical information specific to the Division Mountain project site. Rather, the plan was developed using broad assumptions informed by typical geotechnical conditions observed at comparable regional operations. Site-specific geotechnical data should be collected, evaluated, and incorporated into subsequent pre-feasibility and feasibility-level mine planning. Should actual geotechnical conditions prove less favourable than those assumed in this assessment, the open-pit stripping ratio and associated mining costs may increase, with a corresponding adverse effect on project economics.

ML/ARD issues and, more specifically, selenium treatment is a growing concern among regulators in Canada, particularly in BC and AB. Other coal operations in Western Canada are understood to have concerns with selenium treatment, as identified in the Ensero Solutions environmental overview report (see Section 3). Selenium treatment costs were not accounted for in this PEA, but would likely present additional cost if selenium treatment is determined to be required.

Engagement with Yukon Government and Yukon Energy through a structured consultation process represents a key commercial, technical, and regulatory risk to the Division Mountain Project. Without early confirmation of the information requirements, interconnection study scope, grid impact assessment requirements, commercial framework options, and regulatory approval pathway for a potential future power purchase arrangement, the Project may face delays, additional study requirements, misalignment with Yukon Energy procurement expectations, or uncertainty regarding the feasibility of future electricity sales.

The Project would be subject to the federal emissions performance standard of 420 tonnes of carbon dioxide per GWh established under the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations (SOR/2012-167), which applies to a new generating unit from its commissioning date. As set out in Section 20.2.2, the Project's emissions intensity has not yet been quantified, and quantification is recommended as part of the next phase of study. The standard is not expected to be met by a coal-fired configuration operating without abatement, and compliance would require carbon capture and storage, a substantial change in fuel, or a change in the applicable regulatory framework. No such measure has been engineered or costed, and no associated capital cost, operating cost, or reduction in net output is reflected in the estimates presented in Section 21 or the economic analysis presented in Section 22. Section 22 details a carbon tax calculation and the breakeven electricity price required if the full carbon tax is applied to the Division Mountain project. This is considered the principal regulatory risk to the Project, and its resolution is a precondition to advancing the Project beyond the current study stage. An assessment of available compliance pathways is recommended in Section 26.

The economic results presented in Section 22 depend on an assumed electricity sales price of \$200/MWh to \$240/MWh, with a break-even price of approximately \$194/MWh at an 8% discount rate. As described in Section 19.1, no market study, price forecast, or power purchase arrangement supports that assumption, and the assumed prices are materially above prevailing Yukon rates. Yukon Energy Corporation is the only practicable purchaser, and no commercial framework for a transaction of this scale and duration has been established. If a power price at or near the assumed range cannot be secured, the Project as evaluated would not be economic. This is considered the principal commercial risk to the Project.

25.3 Opportunities

The opportunities for a power plant with a 30-year lifespan focus on the circular economy, which describes an approach to industrial design in which materials are kept in productive use for as long as possible, waste streams are treated as inputs to other processes, and the residual burden left at the end of an operation is minimised. Applied to a mining and thermal generation project, the concept does not alter the fundamentally consumptive nature of coal combustion, and it should not be presented as doing so. It does, however, provide a useful framework for identifying material and energy streams that would otherwise be managed solely as waste, and for testing whether those streams can offset costs, reduce disturbance footprint, or lower closure liability.

The discussion in this section is conceptual. No circular economy measure described here has been engineered, costed, or included in the capital cost estimate, the operating cost estimate, or the economic analysis presented in Sections 21 and 22. Each measure identified is accompanied by the work required to establish whether it is viable.

25.3.1 Coal Combustion Residuals

At the design coal feed rate of 0.5 Mtpa and the weighted average ash content of 27.6% reported in Section 13, the power plant would produce on the order of 138,000 tonnes of ash per year, or approximately 4.1 million tonnes over a 30-year operating life. For a pulverized fuel boiler the split is typically in the range of 80% to 85% fly ash and 15% to 20% bottom ash, giving roughly 110,000 to 117,000 tpa of fly ash and 21,000 to 28,000 tpa of bottom ash. Sulphur content of 0.45% is low, so the volume of flue gas desulphurisation residue, if a sorbent-based system is fitted, would be correspondingly modest. These quantities should be confirmed against the heat and mass balance once it is finalised.

Ash is the largest single secondary material stream the Project would produce, and it is the one with the most established markets. Potential beneficial uses, in approximate order of value:

Supplementary cementitious material – Class F fly ash meeting CSA A3001 or ASTM C618 requirements substitutes for Portland cement in concrete at typical replacement rates of 15% to 30%, with both a cost and an embodied carbon benefit to the concrete producer. Suitability depends on loss on ignition, fineness, and the calcium, alkali and sulphate content of the ash, none of which has been measured for Division Mountain coal.

Alkali-activated and geopolymer binders – Where ash does not meet concrete specifications, it may still serve as a precursor in alkali-activated binders for non-structural site applications such as pit floor and haul road stabilisation. This is a developing field and would be treated as a research option rather than a design basis.

Structural fill and road base – Bottom ash is widely used as engineered fill and as a granular base material. On a site requiring road works, a transmission corridor, plant and mine pads, and progressive waste dump construction, internal demand for granular material is substantial, and ash used this way displaces aggregate that would otherwise be quarried under the Quarry Permit contemplated in Table 13.

In-pit and dump co-disposal – Placing ash within the mined-out pit or encapsulated within the waste rock dump avoids a separate ash landfill, its footprint, its liner and cover requirements, and its long-term monitoring obligation. This is likely to be the default disposal route and should be designed as such rather than as a fallback, with the geochemical implications assessed alongside the ARD and metal leaching work already recommended in Section 20.1.2.

Alkalinity for water treatment – Fly ash from bituminous coal is generally alkaline and can be used for pH adjustment in mine water treatment circuits, potentially reducing lime consumption. Whether this is beneficial or harmful depends on the leachable metal content of the specific ash, and it should not be assumed.

Two constraints need to be stated honestly alongside these opportunities. First, the Yukon concrete market is small; annual ready-mix production in the territory is unlikely to absorb more than a fraction of 110,000 tpa of fly ash, and the freight cost to reach a larger market (290 km by road to Skagway, then marine transport) is likely to exceed the value of the material. Realistically, the near-term sinks for the bulk of the ash are on-site construction use and in-pit placement, with cement market sales an upside case rather than a base case. Second, ash marketability depends on properties that have not been measured, because no combustion testing has been carried out on Division Mountain coal. Until it has, any beneficial use claim is speculative.

25.3.2 Waste Rock

The Pit 1 mine plan described in Section 16 is estimated to generate approximately 69.75 million bank cubic metres of waste rock over the planned mine life. Rather than treating this material solely as spoil requiring permanent storage, there is an opportunity to investigate whether a portion of the waste rock could be recovered, processed, and used as construction aggregate for on-site and potentially off-site applications.

Competent waste rock can supply road base, pad construction, sediment pond embankment fill, and transmission line access, reducing or eliminating the need to develop separate borrow areas and the associated permitting, disturbance and reclamation obligation. The suitability of the Tanglefoot Formation clastics for this purpose has not been tested and should be assessed alongside the geotechnical drilling recommended in Phase 1.

25.3.3 Water

The selection of an air-cooled condenser, described in Section 17, is the single most consequential circular decision already embedded in the design. Dry cooling reduces plant water consumption by roughly 90% relative to wet cooling, which is significant in a headwater setting draining to the Klusha Creek and Nordenskiold River system described in Section 20.1.5.

Beyond that, the following should be evaluated:

Reuse of pit dewatering water for dust suppression, equipment wash and, after treatment, boiler makeup, in place of drawing further from on-site wells.

Recycling of treated effluent within the plant rather than discharging it, subject to the accumulation of dissolved constituents.

Recovery of condensate and boiler blowdown heat and water where economic.

Section 20.1.5 already identifies the risk that large settling ponds create productive habitat in which selenium bioaccumulates. Maximising water recycling reduces discharge volume but concentrates dissolved constituents, so the water balance and the water quality objectives need to be developed together.

25.3.4 Energy and Heat Recovery

The Project site has a continuous demand for low-grade heat that is currently unaddressed in the design: camp and office heating over a season with temperatures reaching -40°C, freeze protection for water and slurry lines, coal thaw and frozen coal handling as described in Section 17, and equipment maintenance facilities. Diesel would otherwise supply most of this.

Extracting low-grade heat from the steam cycle for site heating displaces diesel, reduces both cost and emissions, and improves overall fuel utilisation. The air-cooled condenser reduces the availability of waste heat relative to a wet-cooled plant, but turbine extraction and flue gas heat recovery remain available. A district heating tie-in beyond the site is not practical at 90 km from Whitehorse. Suggested scope for the next phase: quantify the site heat demand, evaluate turbine extraction against a dedicated heat recovery loop, and establish the effect on net electrical output.

25.3.5 Fuel Streams

Two fuel-side options bear on circularity and should be assessed together with the emissions compliance work recommended in Section 25.2:

Biomass co-firing – Yukon generates wood residues from forestry, land clearing and wildfire salvage. Co-firing biomass with coal in a pulverized fuel boiler at modest rates is established practice and reduces the fossil carbon intensity of generation proportionally. It requires assessment of fuel supply security, handling and milling, slagging and fouling behaviour, and boiler derating. It should be noted plainly that co-firing at practicable rates would not on its own bring the unit within the federal 420 t CO_2/GWh performance standard discussed in Section 20.2.2.

Coal fines and reject recovery – Recovery of coal fines from handling, stockpile runoff and any future wash plant reject stream keeps saleable energy in the fuel circuit rather than in the waste circuit, and reduces the organic carbon loading on the water treatment system.

25.3.6 Emerging Options

Two further options are noted for completeness. Both are at a research or demonstration stage and neither should be relied upon:

Recovery of critical and rare earth elements from coal ash – Coal ash is under active investigation internationally as a secondary source of rare earth elements, gallium and germanium. Whether Division Mountain ash carries any enrichment is unknown, and the analytical cost of finding out is low. Including a whole-rock and trace element scan in the ash characterisation programme is inexpensive due diligence, whatever the result.

Mineral carbonation of alkaline ash – Calcium- and magnesium-bearing ash reacts with CO2 to form stable carbonates, offering a modest degree of CO2 uptake within the ash disposal stream. Uptake rates are small relative to plant emissions, and this should not be represented as a compliance pathway.

25.3.7 Assets, Consumables, and Closure

Equipment life extension – Section 26 already contemplates evaluating suitable second-hand equipment for the power plant. The same logic extends to the mining fleet: component rebuild and major overhaul programmes, and structured resale of the fleet at closure, retain value that the sustaining capital line otherwise writes off.

Consumables – Off-road tires, used oil, filter, solvent, battery and scrap steel management programmes are standard at northern mine sites and should be described in the waste management plan supporting the Solid Waste and Special Waste permits identified in Table 13.

Decommissioning – Section 20.2 provides for demolition of mine and power plant infrastructure within the $20.0M closure estimate. A 100 MW plant, its boiler structure, transmission line and camp represent a substantial recoverable steel and copper inventory. Salvage value has been credited against the closure estimate, and it assumes that the salvage pays for the remediation costs.

Modular camp reuse – The prefabricated camp described in Section 18.3 is a relocatable asset with residual value at closure.

25.3.8 Regional and Socio-Economic Circularity

Circularity has a regional dimension alongside the material one. Section 20.1.9 identifies employment and economic benefits, and Section 20.2.1 emphasises the importance of early and consistent engagement. The following retain value within the region rather than exporting it, and are the aspects of circularity most likely to matter to the First Nations and communities whose support the Project requires:

Local and First Nations procurement and contracting, including for the aggregate, earthworks, camp services and transport scopes.

Workforce development and training pathways, given that the territory has no operating coal mine and therefore no resident coal mining workforce.

Shared use of the access road and transmission infrastructure by other regional users, subject to the access management constraints identified in Section 20.1.7.

Progressive land return, so that reclaimed areas are handed back during the operating life rather than only at closure.

These commitments should be developed through the engagement process recommended in Phase 3 rather than asserted in advance of it.

25.3.9 Summary of Opportunities and Limitations

Table 20: Circular Economy Opportunity Register

Opportunity	Stream and indicative scale	Maturity	Where addressed
Fly ash as supplementary cementitious material	110–117 kt/a fly ash	Established, but market-limited in Yukon	Phase 2 ash characterization
Bottom ash as structural fill and road base	21–28 kt/a	Established	Phase 2; site earthworks design
In-pit and encapsulated ash co-disposal	Up to 4.1 Mt LOM	Established	Phase 1 geochemistry; Phase 3 permitting
Waste rock as construction aggregate	Subset of 69.75 M bcm	Established, subject to testing	Phase 1 geotechnical programme
Water reuse and closed-loop management	Plant and pit water	Established, constrained by selenium	Phase 3 baseline and water balance
Low-grade heat recovery for site heating	Displaces diesel	Established	Phase 2 plant optimization
Biomass co-firing	Fuel supply dependent	Established, not a compliance solution	Phase 2, with emissions compliance work
Critical element recovery from ash	Unknown	Research stage	Add trace element scan to Phase 2
Ash mineral carbonation	Minor relative to emissions	Research stage	Note only
Equipment rebuild, resale and salvage	Fleet and plant steel	Established	Closure cost review

The opportunities identified in this section are conceptual. None has been engineered or costed, and no capital cost, operating cost saving, or revenue arising from any of them has been included in the estimates presented in Section 21 or the economic analysis presented in Section 22. Quantities cited are derived from the mine plan and coal quality data described elsewhere in this report and are indicative only.

It should further be noted that measures of this kind address the efficiency with which materials and energy are used within the Project. They do not alter the emissions intensity of coal combustion, and they are not a substitute for the greenhouse gas compliance pathway discussed in Section 20.2.2 and Section 25.2.

26 RECOMMENDATIONS

Prior to starting any additional work on the Division Mountain project, engagement with the Yukon Government and Yukon Energy should proceed through a structured consultation process to confirm the commercial, technical, and regulatory pathway for a potential future power purchase arrangement. Immediate next steps should include preparation of a preliminary project briefing package, identification of Yukon Energy's applicable interconnection and power procurement contacts, and initiation of a meeting(s) to confirm information requirements, interconnection study scope, grid impact assessment requirements, commercial framework options, and regulatory approval pathways. A more comprehensive overall project carbon accounting exercise will need to be carried out in the next stages of the project to better understand the implications of carbon pricing on the project based on the discussion with the Yukon Government and Yukon Energy.

Based on the discussions with Yukon Energy and the past exploration, resource estimates, and engineering studies warrant consideration of a three-phase program. The three proposed phases are independent of each other and could be completed concurrently. Phase 1 would be geotechnical and coal quality studies, with diamond drilling. The Phase 2 study would comprise a capital optimization assessment focused on the two most significant capital cost components: the power plant, specifically the boiler, and the transmission line connecting the Project to the electrical grid. Phase 3 would be the collection of baseline environmental information, completion of desktop studies, and community engagement.

The estimate for Phase 1 is $1,590,000, Phase 2 $590,000, and Phase 3 $1,000,000 for a total of $3,180,000.

Table 21: Cost Estimate for Recommendations

Phase	Task	Estimated Cost
1 Engineering Studies	Engineering Studies	160,000
	Lab Analysis	60,000
	Drilling, Coring	1,000,000
	Geophysical Logging	200,000
	Geomatics Survey	40,000
	Consumables	40,000
	Contingency	50,000
	Total Phase 1	**1,550,000**
2 Capital Optimization Studies	Coal Processing Engineering	200,000
	Transmission and Electrical Infrastructure	100,000
	Greenhouse Gas Compliance Pathway Assessment	120,000
	Combustion Testing & Ash Characterization	90,000
	Beneficial Use Market Screening – Ash & Aggregate	35,000
	Heat Demand & Recovery Options	45,000
	Total Phase 2	**590,000**
3 Environmental Baseline Studies	Baseline Data Collection	600,000
	Community Engagement	200,000
	Baseline Studies	200,000
	Total Phase 3	**1,000,000**
	Total	**3,140,000**

Phase 1: geotechnical and coal quality studies. The work should include ten diamond drill holes in the Pit 1 area. The primary purpose of these holes is for geotechnical engineering and collecting coal and waste rock for engineering and environmental analysis.

Detailed engineering studies should be completed during and after the ten holes are completed with the primary focus being geotechnical stability analysis of the pit walls. Coal and wall rocks collected during the coring operations should be submitted for detailed environmental studies, including potential for metal leaching and acid rock drainage (ML/ARD). This work will support future waste rock profiles. Consideration should be given to completion of the holes as ground water monitoring wells;

however, costs for this work are not included in this recommendation. Geological information collected during this work would support future resources modeling.

All ten holes should be logged with downhole geophysical instruments. Some of the preexisting holes and all new holes should be surveyed. All legacy and new drill hole geological should be reviewed and entered in an industry standard modeling software.

The cost estimate for Phase 1 would be $1,550,000.

Capital Optimization

The Phase 2 study should include a targeted capital optimization assessment focused on the principal capital cost drivers, including the power plant and the transmission line connection to the electrical grid. This work should include an evaluation of alternative equipment vendors, including Asian and European suppliers, as well as the potential use of suitable second-hand equipment where technically and commercially appropriate. Additional technical work should include coal combustion and fuel characterization testing, confirmation of boiler performance assumptions, refinement of mass and energy balances, and verification of ash characteristics, including potential beneficial use opportunities.

The Phase 2 study should include an assessment of the Project's greenhouse gas compliance pathway. The scope should confirm the applicability of SOR/2012-167 and any related federal instruments, quantify the Project's emissions intensity from measured coal ultimate analysis and a finalized plant heat and mass balance, compare that intensity against the 420 t CO_2/GWh performance standard, and screen the available compliance options including carbon capture and storage, biomass co-firing, and alternative generation configurations, at a level sufficient to establish order-of-magnitude capital and operating cost implications and the associated effect on net plant output. This work should be completed before further expenditure is committed to the power plant capital optimization scope, as its findings may materially alter the plant configuration under study.

Phase 2 should also include characterisation of coal combustion residuals and screening of beneficial use options for ash and waste rock, as described in Section 24, and a study of site heat demand and heat recovery options.

Transmission and electrical infrastructure work should include confirmation of transmission interconnection requirements and grid impact assessment requirements with Yukon Energy. The study should also include refinement of the proposed transmission line routing, associated design assumptions, and capital cost estimates.

Environmental Studies

Environmental, First Nations, and socio-economic study activities should include the completion of environmental baseline studies and the development of a preliminary permitting strategy. The scope should also include early engagement with affected First Nations, broader community and stakeholder engagement, and socio-economic assessments to evaluate potential regional benefits. Additional work should assess land access requirements, applicable approvals, and considerations related to the Dawson Trail.

This will follow the information requirements detailed in the Ensero Solutions Report. The cost estimate for Phase 3 would be $1,000,000.

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