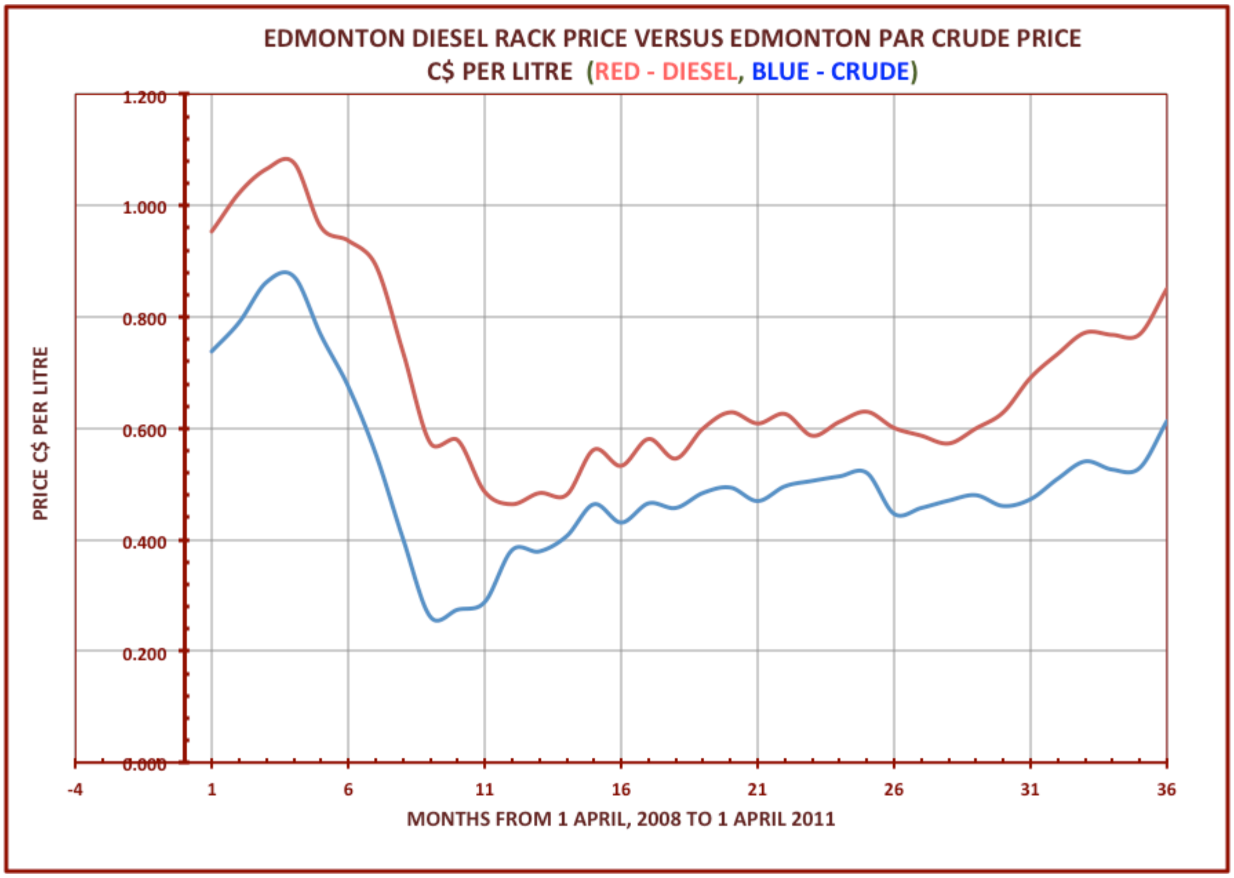
APPENDIX I

ELECTRICAL POWER SUPPLY

W.N. BRAZIER ASSOCIATES INC.

SEABRIDGE GOLD INC.
KSM PROJECT
2012 PFS UPDATE
DIESEL FUEL PRICE



Rev. A – April, 2011
Rev. B – February, 2012
Rev. 0 – April, 2012

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1.0 INTRODUCTION

1.1 General

This report provides projected diesel fuel prices, delivered to site, to be used to establish operating costs for the KSM 2012 PFS update. The following categories of fuel use are included:

Construction Power Generation And heating

- Fuel for construction diesel generators.
- Fuel for building heating.

Mine And Plant Equipment

- Fuel for open pit diesel powered equipment.
- Fuel for ore haulage trucks.
- Fuel for surface fleet (non licenced vehicles).
- Fuel for highway use (concentrate haul, etc.).

The base price of fuel discussed herein is the rack price, which is the wholesale price without Provincial Tax and without Federal Excise Tax. Price discounts on the rack price of several percent may be available for large users of fuel, but any such discounts have not been considered in this evaluation.

As per previous reports, the fuel price as shown herein is based on a three-year average. Current prices and US Energy Information Administration (EIA) crude oil price projections are included for general information, but this report does not include any predictions concerning diesel fuel pricing.

2.0 PRICE SUMMARY

2.1 Taxes

The prices shown herein include all taxes except the 5% Federal GST which may be claimed back as an Input Tax Credit.

2.2 Diesel Fuel Prices

The following table summarizes diesel fuel prices for various uses. These prices are based on the published rack price delivered to site with freight and taxes added as applicable. For very large users there is normally some discount available on the rack price, but this has not been considered in this report.

Of course the highway use price is less the markup as applied by service stations.

Table 2.2 – 1 Site Diesel Fuel Prices, Based On A Three Year Average

END USE	3 YR AVERAGE PRINCE GEORGE RACK PRICE, C$ PER LITRE	FREIGHT, PRINCE GEORGE TO SITE, C$ PER LITRE	FEDERAL EXCISE TAX	BC CARBONE TAX (July 2012)	BC ROAD TAX	TOTAL PRICE PER LITRE C$
POWER GENERATION AND HEATING	$0.6899	$0.0900	$0.0000	$0.0767	$0.0000	$0.8566
OFF ROAD (MINING) USE	$0.6899	$0.0900	$0.0400	$0.0767	$0.0000	$0.8966
HIGHWAY USE	$0.6899	$0.0900	$0.0400	$0.0767	$0.1500	$1.0466

The above prices, as per the basis of this report, are three-year average pieces. The current (Feb 10, 2012) site prices per litre would be:

- Rack price, at site: C$ 1.029
- Power Generation and Heating Price: C$ 1.029
- Off-road price: C$ 1.069
- Highway use: C$ 1.219

3.0 FOUNDATION FOR PRICING

3.1 Base Price

The project Base Case economic evaluation has been undertaken incorporating historical three-year trailing averages for metal prices. The past 3 year average approach has also been taken for diesel fuel pricing. To this end, the average diesel fuel rack price (i.e. the wholesale price excluding all taxes) of diesel in Edmonton for the past three years has been determined (from Natural Resources Canada records). This is then referenced to the rack price of diesel in Prince George in order to arrive at a delivered to site price by adding freight.

In addition to looking at average Canadian dollar prices for diesel, the relationship between rack price and crude in US dollars per barrel has been evaluated such that diesel prices can also be related to crude oil in US dollars per barrel. Several benchmark crude oils indexes are discussed and compared herein. This offers an alternative method of determining the appropriate price of diesel fuel for the feasibility estimates. As the refined cost of diesel has been determined relative to crude oil prices, if diesel fuel prices were to be based on a forecast US dollar crude oil price, the corresponding rack price of diesel may be readily calculated.

The estimated diesel price shown in this report is for ultra low sulphur (ULS) “seasonal” diesel fuel having a winter cloud point of minus 37°C. This is diesel fuel as used in Northern BC and is suitable for project use. The refiners adjust the characteristics of “seasonal” diesel fuel from summer to winter to suit the weather conditions.

There is an empirical relationship between Edmonton rack prices and rack prices in Prince George and Terrace, the two closest cities to the KSM site where rack prices are published.

Note, in Canada the winter months the price of diesel fuel is often relatively high compared to gasoline and summer diesel prices (based on equivalent crude oil prices), because of demand for heating oil, the fact seasonal diesel is lighter in the winter, and other factors. A large purchaser could offset this, with some risk, by buying fuel forward (physical storage is not required).

3.2 Base Fuel Type

The base fuel priced in this report is ultra low sulphur (ULS) “seasonal” diesel.

Fuel refiners, such as Petro-Canada, report that “seasonal” diesel, as their refineries normally produce in the winter in Edmonton, has a guaranteed cloud point of at least minus 37°C which is suitable for most uses in the Yukon, Northern Alberta and at the NWT diamond mines.

All fuel referenced in this study is ultra low sulphur (ULS) diesel. (After Sept. 2010 diesel fuel for off-road use in Canada must be ULSD and by 2012 all diesel fuel in Canada, including for use in locomotives, must be ULSD.)

3.3 Natural Resources Canada Three Year Average ULS Diesel Price

The 3-year average seasonal ULS diesel price at Edmonton, back from Dec. 31, 20011, is C$0.6739 per litre.

Refer to Figure 3.3-1 following.

Figure 3.3 -1 Three Year Average ULS Seasonal Diesel Fuel Pricing

DATE	EDMONTON RACK DIESEL CDN $ PER LITRE	KAMLOOPS RACK DIESEL CDN $ PER LITRE
Jan-09	57.9	59.9
Feb-09	48.6	51.1
Mar-09	46.4	48.9
Apr-09	48.4	50.7
May-09	48.1	50.4
Jun-09	56.2	58.6
Jul-09	53.3	55.4
Aug-09	58.1	59.9
Sep-09	54.6	56.9
Oct-09	60	62
Nov-09	62.9	64.2
Dec-09	60.9	62.2
Jan-10	62.6	65.1
Feb-10	58.7	61
Mar-10	61.2	64
Apr-10	63	65.8
May-10	60.1	63.3
Jun-10	58.7	61.9
Jul-10	57.3	60.4
Aug-10	60	63.3
Sep-10	62.9	66.2
Oct-10	69.1	71.9
Nov-10	73.4	76.2
Dec-10	77.2	80
Jan-11	76.8	80.1
Feb-11	76.9	80.4
Mar-11	85.1	88.5
Apr-11	87.1	90.2
May-11	81.9	83.9
Jun-11	81.2	84.1
Jul-11	81.7	84.5
Aug-11	80.9	83.9
Sep-11	82.6	85
Oct-11	89.7	91.9
Nov-11	94.8	96.9
Dec-11	87.6	89.7
AVERAGE (FOR 3 YEARS)	**67.39** Cents Canadian Per Litre	**69.96** Cents Canadian Per Litre

NOTES
1) SOURCE: NRC, Monthly Average Wholesale (Rack) Prices for Diesel
2) Price differential Edmonton to Prince George: +1.6 cents/L
(NRC Canada does not archive rack diesel prices for Prince George.)

3 YEAR AVERAGE, PRINCE GEORGE:	**68.99** Cents Canadian Per Litre

3.4 Freight Cost To KSM Project Site

The site fuel price is based on future delivery to the mill plantsite up a relatively short road from Highway 37. Delivery over the Coulter Creek Road (after it's complete, but before the tunnel from the mill site to Mitchell is complete) will have an additional freight component not included herein.

The quoted freight rate from Prince George to the KSM mill site is $0.09 per litre. Supply from Prince George is assumed, as there is limited bulk supply out of Terrace. However, there is some upside potential for Terrace supply if additional facilities were built, as fuel could be shipped to Terrace by rail that would save road freight.

3.5 Edmonton Diesel Fuel Price Relative To Crude Oil

The following shows the relationship between diesel fuel and crude oil prices extending back 3 years from the second quarter of 2011. All diesel fuel is ultra low sulphur (ULS) diesel as must be used in Canada.

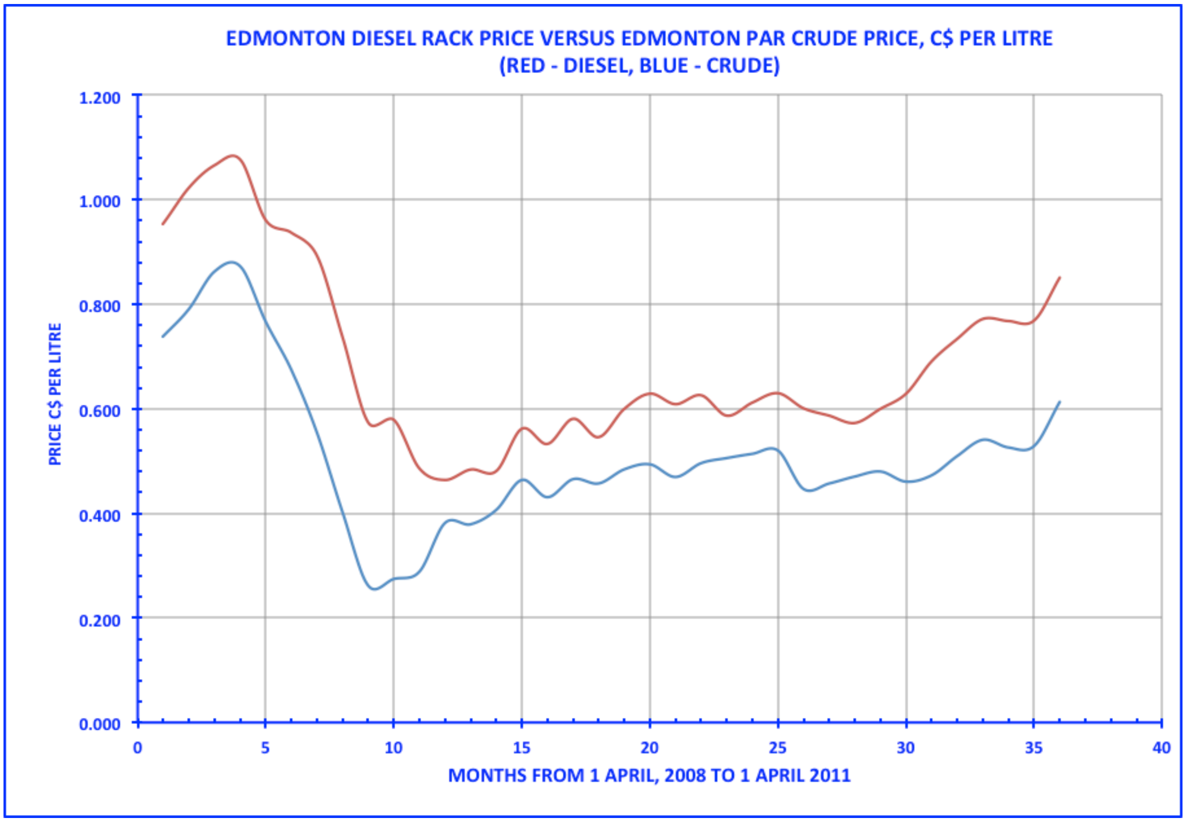
Base average diesel rack price per litre: (ULS Seasonal Diesel, back from April 2011)	C$ 0.689
Corresponding crude oil price per litre:	C$ 0.513
Refining premium, per litre:	C$ 0.176

Refer to Section 4.0 herein for a discussion of diesel fuel taxes.

The diesel fuel refining cost, theoretically, is independent of the price of crude and the refining costs can be roughly determined by matching historical rack prices to crude prices, as these will on average bear a linear relationship, since the variations due to competitive forces should generally average out. A representative of a major refiner in Edmonton has reviewed the methodology used in this report and the resultant estimates of diesel fuel prices relative to crude oil prices and has reported "I would agree with your calculations for budgetary purposes to correlate crude to Edmonton rack."

The table below calculates the average Edmonton rack price for diesel and also correlates historical Edmonton Par crude prices with Edmonton ULS diesel rack prices. Data is generally as per Natural Resources Canada. The empirical relationship as shown agrees well with other industry models and is used herein to arrive at a relationship between crude and diesel rack prices. It also agrees closely with the average rack price in the past 3 years. The reason the rack price has been related to crude prices, rather than only considering the average rack price, is that petroleum prices predictions are usually based on crude oil prices in US dollars per barrel. With the rack price related to crude prices as per the table below, it would be easy to revise the diesel fuel prices if it is desired to base diesel prices and a predicted crude price in US dollars per barrel.

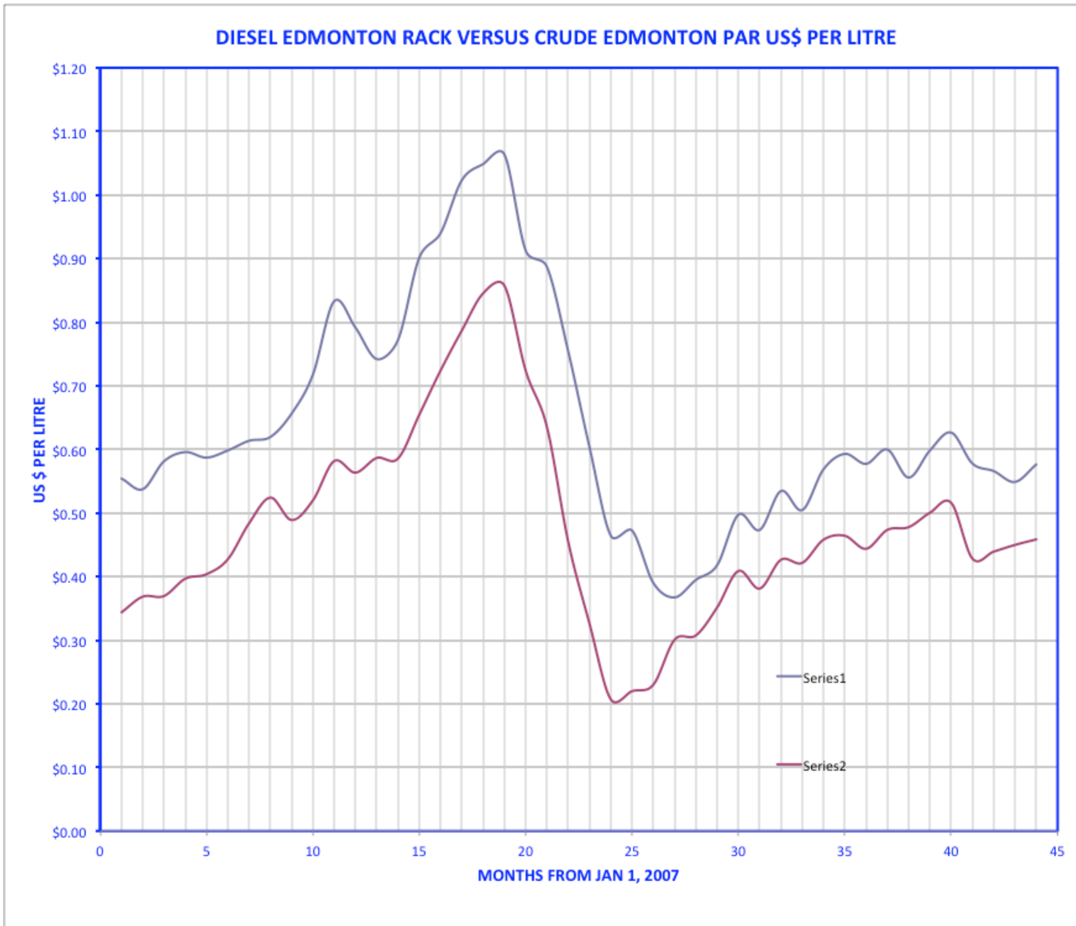
Figure 3.6 – 1 Graph Of Edmonton Par Crude Versus Edmonton Rack Diesel



The above table and graph shows Edmonton diesel rack price in CDN dollars per litre versus Edmonton Par crude prices in CDN dollars per litre, since January, 2008 and illustrates that on average, crude and diesel prices closely track each other.

The average premium of diesel over crude is 17.6 cents CDN per litre. This represents refining cost plus profit.

Figure 3.6 – 2 Edmonton Rack Diesel Fuel Price Versus Crude Oil Price



3.6 Prince George And Terrace Rack Prices

Natural Resources Canada do not archive diesel fuel rack prices for Prince George or Terrace although the Petro-Canada, Shell, etc. publish daily rack prices for these cities. On average, Prince George rack prices are 1.6 cents per litre higher than Edmonton.

3.7 Fuel Storage

The cost of the required fuel storage facilities at the mine site is included in the overall project capital cost and is thus not reflected in the fuel price herein.

3.8 Biodiesel

The Federal Government has mandated that diesel fuel sold in Canada after July 31, 2011 must contain an annual pool average of 2% renewable content. From 2011, biodiesel is available (B5, B10 or B15) from Edmonton in the summer months. Unlike the Vancouver area where biodiesel has been sold for several years, biodiesel will only be available during the summer months, because of its tendency to jell at low temperatures. Current road vehicles all are suited to burn biodiesel (with Ford F350s rated up to B20 for instance). An enquiry has been made concerning power generation and mining equipment but no response has been received to date.

It is assumed the biodiesel blend would be the same cost as regular diesel so this represents an area of possible future environmental credits. With regards to the feasibility study has no impact on equipment or capital costs and is left as an operational issue.

4.0 FUEL TAX

4.1 Summary

Diesel fuel for different uses attracts different taxes. Fuel for power generation and heating in BC has no tax, except the carbon tax, but fuel for general off-road use has a 4 cent per litre Federal Excise Tax. Fuel for highway use of course has the normal road tax applied.

In BC all diesel fuel used for highway vehicles must be clear (taxed). If this fuel is used off-road, a tax rebate must be applied for.

4.2 Federal Excise Tax

Federal excise tax current rates are as follows:

- Leaded aviation gasoline: 11 cents per litre
- Unleaded gasoline: 10¢/L
- Unleaded aviation gasoline: 10¢/L
- Diesel fuel: 4 ¢/L
- Aviation fuel: 4 ¢/L

Federal Excise Tax Exemptions and Rebates are as follows:

- Under the Federal Excise Tax Act, Act, heating (furnace) oil is exempt from excise tax. As well, an exemption of excise tax exists for diesel fuel used in the generation of electricity, except where the electricity so generated is used primarily in the operation of a vehicle (i.e. a diesel electric haulage truck).
- Typically, the excise tax is paid on all the fuel and an exemption is claimed for the fuel used in heating and/or the generation of electricity. (Appropriate fuel metering and end use record keeping is required.)

4.3 BC Taxes Including Carbon Tax

The BC Government currently has a system such that there are point of sale rebates on motor fuels and other gas/biofuels for the provincial portion of the B.C. HST. Thus it (7% provincial portion) does apply to motor fuels in the province. This includes all forms of biofuels, aviation fuel, marine diesel, diesel, as well as car gasoline.

Clear diesel fuel outside the GVRD (for road use) is taxed at

- Motor fuel tax = 15 cents per litre
- Carbon tax (applicable to all diesel fuel) = 6.39 cents per litre. Note as per July 1, 2012 this rises to 7.67 cents.
- Federal excise tax (on all diesel fuel except for power generation and heating) = 4 cents per litre.

Note, off-highway coloured fuel for equipment has a 4 cent Federal tax and a 6.39 cent provincial carbon tax.

4.4 BC Tax On Fuel For Mining

As Per BC Bulletin MFT 010, Fuel Used by the Logging and Mining Industries is taxed as follows:

<u>Summary:</u>

Note, one may use coloured gasoline or coloured diesel fuel only for the purposes authorized under the Motor Fuel Tax Act. Coloured fuel is fuel taxed at a lower rate. The fine or penalty for the unauthorized purchase or use of coloured fuel is equal to three times the tax that would have been payable if the fuel had not been coloured.

<u>You may use coloured fuel (no BC tax except Carbon Tax) in:</u>

<u>General</u>

- stationary or portable engines, such as generators and chainsaws,
- industrial machines when used off-highway, such as bulldozers, backhoes and front-end loaders,
- specific types of equipment, such as tractors and forklifts,
- road building machines, and
- unlicensed vehicles when used off-highway, such as all-terrain vehicles, snowmobiles, unlicensed trucks, etc
- Industrial machines

You may use coloured fuel in industrial machines when the equipment is:
- used off-highway (use on private roads is permitted), or
- travelling to or from a location where the use of coloured fuel in the vehicle is authorized.

But note:

Road-building machines

You may use coloured fuel in road-building machines when the vehicle is:

- used at a highway project area, or
- used, by or for, the government in construction or repair of roads maintained by the government.

You cannot use coloured fuel in road-building machines when:

- the vehicle is used on a highway outside a highway project area for grading, clearing, maintenance etc., or
- the vehicle is not used, by or for, the government in construction or repair of roads maintained by the government. Road-building machines are equipment specifically designed for grading, paving, and constructing roads.

Road building for a mining project is a complicated issue and would need to be investigated in greater detail relative to the details of the intended use.

4.5 BC Provincial PST

Currently (Feb. 2012) in BC there is a 12% HST consisting of a 7% BC portion and a 5% federal GST portion.

B.C. has exempted motor fuels from the HST and the BC Government currently has a system such that there are point of sale rebates on motor fuels and other gas/biofuels for the provincial portion of the B.C. HST. Thus, 7% provincial portion of the HST does apply to motor fuels in the province. This includes all forms of biofuels, aviation fuel, marine diesel, diesel, as well as car gasoline.

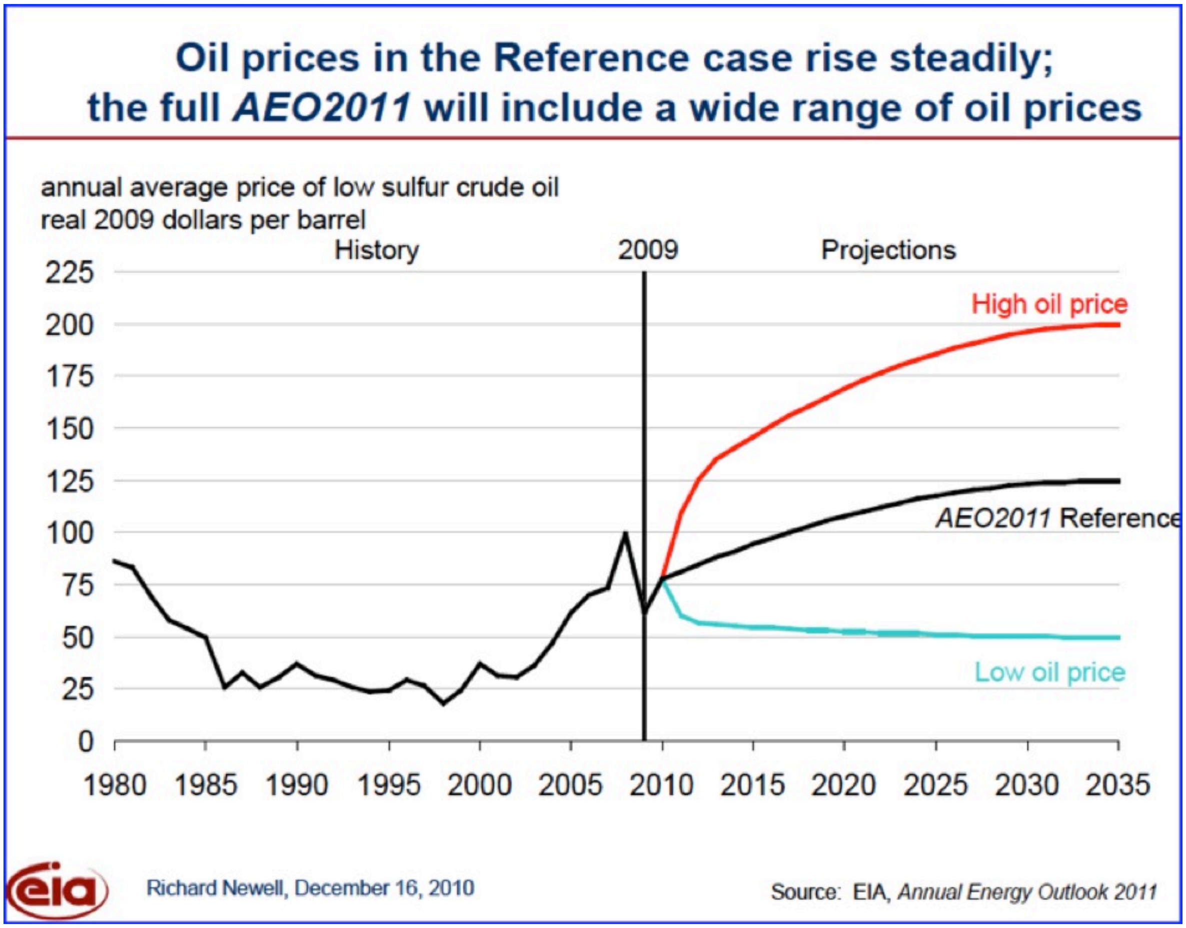
As GST (currently 5%) is an input to the mining operation it is fully recoverable by businesses registered to collect GST or HST as they can claim these as input tax credits (ITC) and is thus this tax need no be considered in a discussion of these taxes for the KSM project. This will continue to be the case when the 7% PST is reinstituted in BC.

5.0 PRICE PROJECTIONS

5.1 General

There are, of course, many divergent views on future oil prices and thus what projected price should be used. The US Department Of Energy (D.O.E.) web site includes projections of future oil prices. The document, authored by the US Energy Information Administration and released in 2011, includes the below graph.

Figure 5.1 – 1 World Crude Oil Price Projections (From US Energy Information Administration)



The EIA expects the price of West Texas Intermediate (WTI) crude oil to average about $100 per barrel in 2012, almost $6 per barrel higher than the average price last year. Based on recent futures and options data, the market believes there is about a one-in-fifteen chance that the average WTI price in June 2012 will exceed $125 per barrel, and about a one-in-fifty chance that it would exceed $140 per barrel. For 2013, EIA expects WTI prices to continue to rise, reaching $106 per barrel in the fourth quarter of next year. EIA's forecast assumes that U.S. real gross domestic product (GDP) grows by 2.0 percent in 2012 and 2.4 percent in 2013, while world real GDP (weighted by oil consumption) grows by 2.9 percent and 3.7 percent in 2012 and 2013, respectively.

Global Crude Oil and Liquid Fuels Overview. Absent a significant oil supply disruption, EIA expects world markets to continue to gradually tighten in 2012 and 2013, as increases in global consumption outpace production growth in countries outside of the Organization of the Petroleum Exporting Countries (OPEC). World liquid fuels consumption grows by an annual average of 1.3 million barrels per day (bbl/d) in 2012 and 1.5 million bbl/d in 2013. Supply from non-OPEC countries increases by 0.8 million bbl/d in 2012 and 0.9 million bbl/d in 2013. EIA expects that the market will rely on both inventories and increases in production of crude oil and non-crude liquids from OPEC members to meet world demand growth. There are many significant uncertainties that could push oil prices higher or lower than projected. Should a significant oil supply disruption occur, and OPEC members do not increase production, or projected non-OPEC projects come online more slowly than expected, oil prices could be significantly higher than projected in this Outlook. If the pace of global economic growth fails to accelerate in Organization for Economic Cooperation and Development (OECD) countries, or if economic growth slows in non-OECD countries, reduced demand could result in lower prices.

Figure 5.1 -2 Current And Project Fuel Prices
(From US Energy Information Administration)

Price Summary

	2010	2011	2012	2013
WTI Crude[a] (dollars per barrel)	79.40	94.86	*100.40*	*103.75*
Gasoline[b] (dollars per gallon)	2.78	3.53	*3.55*	*3.59*
Diesel[c] (dollars per gallon)	2.99	3.84	*3.91*	*3.99*
Heating Oil[d] (dollars per gallon)	2.96	3.71	*3.91*	*4.00*
Natural Gas[d] (dollars per thousand cubic feet)	11.37	10.78	*10.71*	*11.31*
Electricity[d] (cents per kilowatt hour)	11.54	11.79	*11.85*	*11.79*

[a] West Texas Intermediate.
[b] Average regular pump price.
[c] On-highway retail.
[d] U.S. Residential average.

Refining, taxes and freight in total are a significant component of the delivered fuel cost and when doing sensitivity analysis this should be done on the crude oil component of the diesel fuel rack price, not on the delivered price, as freight will rise only slowly with rising crude prices, refining cost should not rise significantly and taxes will rise not at all (baring imposition of any new taxes).

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April 15, 2012

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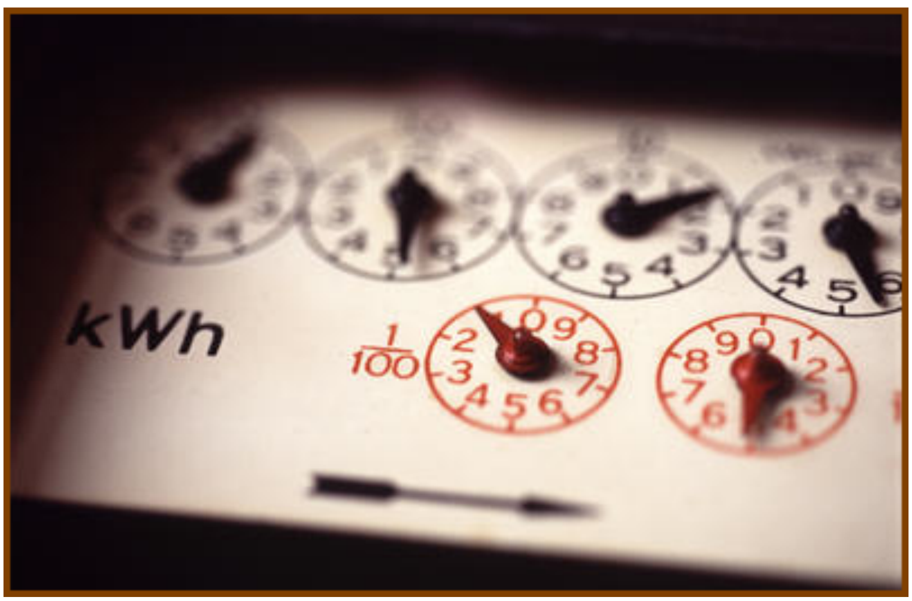
SEABRIDGE GOLD INC.
KSM PROJECT

COST OF ELECTRIC POWER FOR 2012 PFS UPDATE (HPGR MILLING CASE)



Rev. A, January 28, 2012
Rev. 0, March 6, 2012
Rev. 1, May, 2012

INTRODUCTION

This memo provides the cost of power for use in calculating the operating costs for the first quarter 2012 KSM PFS Update for the 130ktpd HPGR case, with BC Hydro "Contract Demand" over 150 MW. Power cost are shown herein only for HPGR milling. The HPGR power costs, which include BC Hydro Power Smart energy savings for the entire consumption, are the costs used in the 2012 PFS update. For the current 130,000 tpd mill, both the SAG and HPGR options have peak power demands over 150 MW, but the HPGR option shows both much lower peak power demand and running load.

Recent discussions with BC Hydro have led to the conclusion that the previously discussed removal of the 150 MW load limit (after which transmission and generation reinforcement charges apply) will not be clarified or the limit removed in the near-term and the KSM PFS Update must assume this remains in place.

If the mine power "Contract Demand" goes over 150 MW, the effective power cost will be higher than the cost of power for the 150 MW SAG mill option with no power savings. One possible solution is to add a combustion turbine to shave the peak off the plant demand, or the other option is to pay a multimillion dollar capital cost contribution for BC Hydro transmission and generation reinforcement. The amount of this contribution cannot be defined at this time by BC Hydro, but for a Contract Demand of 175 MW, a guesstimate would be perhaps in the range of 400 to 500 million dollars.

SUMMARY

The power cost per kW.h in BC has recently rusen significantly due to (a) growing load, (b) the CEA, (c) the required capital expenditures on new transmission, etc. and (d) the re-imposition of of the 7% PST (in the near future). These increases have been and will continue to be higher than the general rate of inflation (CPI).

For the 2012 PFS Updatethe power cost is Canadian **$0.049** per KW.h. Note, this sum includes the local power system losses from the switching station along HW 37, so a separate budget is not required for losses. The above price per KW.h also includes the cost of "Peaking Power" generated by a gas turbine located along HW 16 near the BC Hydro Skeena Substation (to avoid very substantial generation reinforcement charges due to the contract demand being over the current 150 MW limit). The above number includes 7% for PST, as this is being re-introduced. The 5% GST is ignored.

HISTORICAL AND PROJECTED POWER COST

YEAR	HPGR POWER COST	POWER COST SAG	PERCENT INCREASE	HPGR COST WITH 7% PST	SAG POWER COST WITH 7% PST
2009		$0.0410			
2010		$0.0434	5.9%		
2011	0.042	$0.0469	8.1%		
2012	0.046	$0.050	6.4%	0.049	0.053
THE FOLLOWING RATES ARE PROJECTED AT THE CURRENT 8.1% RATE OF INCREASE					
2013	0.049	0.054	8.1%	0.053	0.058
2014	0.053	0.058	8.1%	0.057	0.062
2015	0.058	0.063	8.1%	0.062	0.067
2016	0.062	0.068	8.1%	0.067	0.073

Please note, if the SAG (No energy savings) power costs are used, not only must the higher power draw of the SAG mill be accounted for, but the increased per kW.h power cost applies to the entire mine and plant power bill.

DISCUSSION - REASONS FOR RATE INCREASE

The reasons for the projected increase in electricity costs, over and above what could be anticipated based on inflation, are the same as have been previously reported and include:

- Rates have been essentially constant for a number of years and thus system investment has most probably fallen behind that necessary for transmission and generation to keep pace with growing system load, mainly residential and commercial, but potentially large West Coast LNG plant loads.
- The general load in BC has been growing while of course the amount of old, cheap hydro power remains constant. New hydro power, as always, is relatively costly due to the high capital cost which is reflected in amortization charges per kW.h of electric energy. The government has declared that new electric power will be essentially green power (wind, small hydro, biomass). This means much more costly power. The mix of power is now old cheap hydro power plus new very costly green power. It is thus inevitable that the average cost of electric power will go up.
- In general, energy costs are increasing, in no small part due to the BC Clean Energy Act which requires that at least 93% of new generation must be from much more costly green/renewable energy.

RECENT HISTORICAL RATE INCREASES

In December 2010 the BCUC accepted a negotiated settlement between BC Hydro and intervener groups, including representatives from the main customer groups, which resulted in an overall customer net bill impact of 7.29 per cent. This was in contrast to the BC Hydro request to the BCUC for a 9.23% rate increase.

In early 2011 BC Hydro requested a large rate increase that encountered objections from the B.C. government and BC Hydro responded with a proposed 8.23 %increase. When the power cost memo for the 2011 PFS update was issued in April, 2011 rates had still not been approved by the BCUC. The revised bulk power (transmission service) schedule 1823 tariffs were posted in April, 2011.

As noted above, with the reimposition of the 7% PST it is assumed that, as before, this tax will be applied to industrial accounts and it is NOT deductible as a cost input like the HST is. Thus, power costs due to taxes alone goes up by 7%. This may not actually be implemented until 2013, but it is a known cost and should be accounted for.

DISCUSSION - FORECAST RATE INCREASES

The 2012 BC Hydro tariffs were posted in April and this report has been updated to include these rates. It is believed that for the next several years annual percentage increases will be in the range of 8 %.

KSM MINE AND PLANT LOAD

Since the power cost calculation takes into account reduced rates due to BC Hydro "Power Smart" allowances for energy conservation measures such as use of HPGR grinding and as the power peaks are above 150 MW for the 130,000 tpd operation, the size and load profile play a part in the power cost calculation in addition to the plant load factor and power factor which would normally be the only variables at play for a transmission service customer when calculating power cost.

Based on the Wardrop Load List Rev. D dated March 27/2012 for the 130,000 tpd plant with HPGR grinding with a conveyor to the Teigen mill site from Mitchell, etc. WN Brazier Associates has interpreted the load to be:

Energy Consumption:	1,267,333,352	kW.h/a as per the Load List
Average annual load:	144,673	kW (calculated)
Load Factor	0.85	(Typical for this type of mine)
Peak Load	170,203	kW (Calculated using the Load Factor)
Running Load	151.5	MW (Calculated)

DISCUSSION - BASIS FOR THE ESTIMATED POWER COST

The calculated cost of power is based on the following factors that are unchanged from previous reports except the service point is at Treaty Creek and the grinding mills are at the Teigen plantsite.

1) Rates are BC Hydro's issued tariffs for Schedule 1823 Transmission Service - Stepped Rate. For the purposes of this study, the Point of Delivery will be Treaty Creek. From Treaty Creek to KSM Substation No. 1 is less than 30 km of 287 kV line, so losses are very small. To cover these losses, and the losses in plant step-down transformers, 1% has been added to the cost of power.
2) Power costs are shown both with energy conservation measures in place and approved by BC Hydro.
3) The plant load factor, which effects the power cost due to demand charges, will be 87%
4) The voltage at the Point of Delivery will be 287 kV +/- 10% max. deviation.
5) The power factor (PF) at the point of delivery will be controlled to 100% by the SVC.
6) The Contract Demand will be held to149.9 MW maximum by the peaking gas turbine.
7) The power cost calculated herein includes the small transmission line losses from Treaty Creek to the mine site and also includes the losses in the 287 kV to 25 kV plant substation transformers.
8) Power costs are calculated less taxes, then the estimated 2012 power cost is shown with the 7% PST added as the provincial sales tax is, unfortunately, being reintroduced and it will again, it is assumed, apply to Industrial Power Bills as in years past.
9) The power cost does not include the amortization of the capital expenditures. These are included in the KSM mining project total capital cost.
10) Local power generation, such as from the Mitchell diversion, etc. is assumed to be sold separately to BC Hydro and is not included in power cost calculations. If subtracted from the mine demand, this power would lower the bill but not change the cost per kW.h.

HISTORICAL REFERENCE - POWER COST AS PER 01 MAY 2009 RATE SCHEDULE (NO TAXES)

(SCHEDULE 1823 - TRANSMISSION SERVICE - STEPPED RATE, POSTED APRIL 1, 2009)

The cost of electricity, on a total cost per kilowatt hour basis, is:	C$	$0.0410	per kW.h
(At site, with no special energy savings allowance, includes local system losses such as transformer losses and maintenance of spur transmission line)		(April 2009)	

HISTORICAL REFERENCE - POWER COST AS PER 01 MAY 2010 RATE SCHEDULE (NO TAXES)

(SCHEDULE 1823 - TRANSMISSION SERVICE - STEPPED RATE, POSTED APRIL 1, 2010)

The cost of electricity, on a total cost per kilowatt hour basis, is:	C$	$0.0434	per kW.h
(At site, with no special energy savings allowance, includes local system losses such as transformer losses and maintenance of spur transmission line)		5.9%	Percent Increase over 2009

HISTORICAL REFERENCE - POWER COST AS PER 01 MAY 2011 RATE SCHEDULE (NO TAXES)

A) With No Special Energy Savings Allowance

The cost of electricity, on a total cost per kilowatt hour basi	C$	$0.0469	per kW.h
(At site, with no special energy savings allowance, includes local system losses such as transformer losses and maintenance of spur transmission line)		8.1%	Percent Increase 0ver 2010

B) With Special (Power Smart) Energy Savings (For projects such as HPGR, etc.)

The cost of electricity, on a total cost per kilowatt hour basis, is:	C$	$0.0418	per kW.h

(At site, with special energy savings allowance, includes local system losses such as transformer losses and maintenance of spur transmission line)

It is to be noted that all of the power costs shown that are based on the plant design using energy saving concepts must be approved by BC Hydro then they will, if large enough, essentially eliminate costly Tier 2 powrr. If the HPGR is replaced by a SAG mill, power cost per KW.h will go up, as will total power consumption.

CURRENT POWER COST FOR 2012

B) With Special (Power Smart) Energy Savings (For projects such as HPGR, etc.)

The cost of electricity, on a total cost per kilowatt hour basis, is:	C$	$0.0457	per kW.h
(At site, with special energy savings allowance, includes local		$0.0489	/kW.h with
system losses such as transformer losses and maintenance of spur transmission line)			7% PST

GAS TURBINE POWER COST

The capital cost of the gas turbine has been included in the KSM overall capital cost, thus the turbine power cost only includes natural gas fuel and O&M.

The proposed combustion (gas) turbine would be located in or near Terrace , B.C. and would be supplied by natural gas from the existing Pacific Northern Gas (PNG) line that parallels BC Highway 16. Note PNG is now owned by AltaGas.

The proposed gas turbine is installed to limit power demand peaks to below 150 MW so that the current requirement by the BC Hydro tariffs that for any loads the peak over 150 MW generation and transmission non refundable contributions be made for the entire amount of the load.

Running Load minus 150 MW limit = 151.5 - 150 MW = 1.5 MW
Annual energy shortfall= 8760 hrs by 1.5 13,140 MW.h

Based on 2012 natural gas costs in Terrace from PNG, power cost would be 7 cents per kilowatt hour for fuel. To cover taxes, O&M, etc. assume 10 cents per kilowatt hour. The cost of the shortfall would be:
13,140,000 kW.h $1,314,000 per annum (This assumes plant operates as an IPP generator and earns enough money to pay fixed costs such as taxes, etc.)
Add fixed gas turbine power plant costs covering taxes, etc. $500,000 per annum (Assumed mostly covered by sales to BC Hydro)
This adds $0.0014 per kW.h to the overall power cost.

Hydro generation at site (from other reports): 48,706,000 kW.h
Assume value is BC Hydro tier 2 price less 1 cent for O&M 0.0736 minus 1 cent = $0.064 per kW.h. Annual sales are worth $3,097,701.60

If a new, large, natural gas line to Kitimat is constructed as planned, a lower cost alternative for natural gas supply, relative to the 8 inch PNG line, would be avialable.

APPENDIX B - CALCULATIONS - WITH ENERGY SAVINGS

Power cost calculations follow based on BC Hydro Schedule 1823 - Transmission Service _ Stepped Rate,

Power cost calculations follow:

Year:	April/09	April 1/10	01-May-11	10-Apr-12
Tariff:	0.02608	0.02817	0.03108	0.03261
Energy Cost:		$0.03261	per kW.h up to 90% of CBL in each billing year (TIER 1)	
	0.0736	$0.07360	0.0736	0.0736
		$0.07360	per kW.h above 90% CBL in each billing year (TIER 2)	
Year	April/09	April 1/10	01 May 11	10 April 12
Tariff	5.26	5.581	6.027	6.263
Demand Charge:		$6.2630	per KVA of demand for billing period	

Power Factor:	100.0%	Assume power factor is held at this value or higher at the service point (by a SVC).
Contract Demand:	149.99	MVA (The plant load peak assumed is assumed to be max permitted)
Load Factor	85.0%	Assumed worst case for a mine such as KSM
Average Load:	144.67	MW 144.67 MVA
Monthly MW.h	105,611.1	MW.h (Based on 12 equal months)
Annual GW.h	1,267.3	GW.h/a (From Load List)
10% is Tier 2 energy:	126.7	GW.h/a (Calculated)

HPGR and other energy savings: 16 MW = 131.8 GW.h/a

The energy savings are greater than the Tier 2 energy co all energy is at the low rate, no costly tier 2 power.

Demand Bill:	$939,387	C$ per mth	$11,272,648	C$ per year

For this calculation it is assumed the monthly demand is the same each month and it's also equal to to the Contract Demand.

Energy Bill:	$3,443,978	C$ per mth	$41,327,741	C$ per year

In this calculation, all energy is assumed to be Tier 1 energy, see notes above.

Add 5 % BC Hydro Rate Rider To Energy & Demand: (See BC Hydro Rate Schedule 1901)	$219,168.29	C$ per month
	$2,630,019	C$ per annum
Provincial Government ICE Fund: (As of July 1, 2010 BC Hydro customers no longer pay the Innovative Clean Energy (ICE) Fund levy (0.4%) on electricity.)	$0	C$ per annum (At 0.4% to a max of $100,000/year) (Refund of additional charges must be applied for)
Effective net GST (all assumed refunded):	$0	
Total cost of mine power at Treaty Creek: (This is for an assumed load, when load list final, actual value may be calculated.)	$55,230,409	per annum (excludes losses)
Total cost per kW.h at Treaty Creek:	$0.0436	C$ per kW.h, no tax

Total transmission line and main substation transformer losses: (Based on load flow study)	1.0%	%
	12,673,334	kW.h/a
Cost of Line and transformer losses:	$552,304	C$ per annum
Estimated Cost of 287 kV line maintenance (levelized)	$300,000	C$ per annum
Total Line Losses and maintenance cost:	$852,304	C$ per annum
Total cost of power (based on assumed load used to calculate unit power cost - actual total power cost will be calculated when load list final).	$56,082,713	C$ per annum
Total cost per kW.h at the mine substation (2012 rates, no tax)	$0.0443	C$ per kW.h

(This is to be applied against all power used at the mine and includes an allowance for the cost of line losses, so a separate budget for the cost of transmission line and main transformer losses are not required.)

Note, the cost of transmission and transformer losses are added back into the cost per kilowatt hour, so a separate budget is not required for this.

Add average overall incremental cost of gas turbine power for power:	$0.0014	C$ per kW.h
Grand total power cost, energy savings case, 130,000 tpd:	$0.0457 (No Tax)	C$ per kW.h

W N Brazier

W. Neil. Brazier, P.Eng.

WN BRAZIER ASSOCIATES INC.

SEABRIDGE GOLD INC.
KSM PROJECT

PLANT TAILINGS SYSTEM
ENERGY RECOVERY EVALUATION

Rev. A – March 16, 2010
Rev. 0 – April 3, 2010
Rev. 1 - May 18, 2012

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 General

The KSM process plant tailing system provides an opportunity for energy recovery through hydroelectric type generation. This report evaluates the electric power generation potential and provides an evaluation of the capacity, annual output, economics and also includes basic design criteria for the proposed generation equipment.

The subject of this report is an energy recovery project making use of facilities otherwise required for the process plant. This study only covers the energy recovery electrical equipment. The tailing lines and other works are an integral part of the process plant and are not considered herein.

In general, pumps as turbines can be used over the same head range covered by Pelton and small Francis turbines, for smaller flows within the capacity of available pumps. However, a Pelton impulse turbine or a Francis reaction turbine will have a greater efficiency that a pump acting as a turbine, but at a higher capital cost and cannot handle abrasive slurry flows. In this case in particular, due to the nature of tailings, Pelton or Francis machines cannot be used as their life expectancy would be very short. The proposed installation will utilize standard slurry pumps, modified to run in reverse as power generation turbines. Pumps used as turbines are often referred to as PATs.

The behavior of a pump running as a turbine is generally good, as the power output can be higher than the input for running as a pump. Hydraulically, the pump in turbine mode (PAT) can handle a higher volume of fluid than when in normal pumping mode. There is a higher flow through the pump and this means that the amount of energy that can be generated is higher. Another bonus is that when it is in reverse operation and running as a turbine, the pump will usually run slightly more efficiently than in conventional mode, if the operating point is correctly selected.

The overall economics of the tailings energy recovery scheme will also depend on whether the project supply utility (BC Hydro) 150 MW trigger point for generation reinforcement remains applicable and whether the energy recovery turbines could help bring the project demand down below the 150 MW point. A further consideration when contemplating this installation is whether the design and operation is too complex and technically challenging for (a) typical mine design consultants and (b) typical mine (process plant) operating personnel.

1.2 Study Rationale

The purpose of this study, as part of the KSM prefeasibility study, is to select a configuration for the energy recovery equipment, calculate the power potential of the site, size and cost the major generation equipment, and determine the average annual MW.h of energy production and it's value.

1.3 Reference Documentation

Information concerning slurry pumps and the tailings lines has been provided by Wardrop Engineering and Bosche Ventures Ltd.

1.4 Project Description

The energy recovery system makes use of mine tailings flow from the plant rougher flotation section that will be transported to the tailings pond in 2 separate pipelines, both of which will carry rated flow during normal process plant operation. Only one line will have an energy recovery scheme, as it has a much higher hydraulic head.

As this energy recovery project is part of the process plant, there will be no water licensing requirements.

The following general project information has been provided to the author of this report:

- The tailings line in question will transport 5200m3/hr (1.444 cms) at about 37% solids having an SG of 1.31.
- The tailing viscosity has not been provided (and a value somewhat higher than water has been used, based on typical industry information).
- The high head 40 inch HDPE tailing line (typical Hazen-Williams C-factor of 150) will have two energy recovery stations in series in two separate buildings.
- There will be one emergency pipeline that can be connected to replace either operating line, if a pipeline problem develops.
- The process plant designers have selected Metso 28 x26 metal pumps as typically what would be used for this application. (Pump curves have been provided.)
- Plan drawing No. Dwg 10-10- 1617 Rev 0 was provided that shows the tailing system and the energy recovery equipment locations.
- The flotation plant is at elevation 1070 m and the tailings box operating level will be at 1072m.

Other project information includes:

- The series recovery stations will be at elevations 1040m and 1000m.
- The distance from the flotation plant to the first energy recovery station will be 1800 m.
- Pipeline head loss is shown in the calculations (see Appendix C).
- The distance from the first energy recovery station to the second will be 150 m.

2.0 EXECUTIVE SUMMARY

2.1 General

This energy recovery project, with the output used as load displacement, may be eligible for partial funding under the BC Hydro "Power Smart" program.

However, it must be clearly kept in mind that the energy recovery scheme cannot interfere with mine operations. Hence, any such system must be equipped with a bypass around the energy recovery machine. This would typically consist of air actuated knife gate valves and a ceramic pressure reducing orifice.

2.2 Project Summary

(See Section 4.0 for calculations.)

Project highlights: Refer to Clause 1.4 above.

Turbine Type: Slurry pump, operating in reverse.

Station 1

Installed capacity (turbine and generator): 700 HP (522.2 kW) induction motors or induction generator equivalent (for slightly higher efficiency).

Normal generation (1 machine): 388.5 kW

Station 2

Installed capacity (turbine and generator): 900 HP (671.4 kW) induction motors or induction generator equivalent (for slightly higher efficiency).

Normal generation (1 machine): 578.6 kW

Output For Both Stations

Total generated kW: 967.1

Capacity Factor = 0.92 (allowance made for operation, maintenance and down-time.)

Annual net generation (for two plants): 7,794,060 kW.h/a (for one tailings line)

Electricity price:	7.360 cents Canadian per kW.h (BC Hydro 2012 Tier 2 power cost)
Annual net value of generation:	C$ 573,643 per annum
Less Maintenance Allowance (2 cents per kW.h for O&M)	C$ 155,881 per annum
Net value of generation:	C$ 417,762 per annum

2.3 Capital Cost

Wardrop Engineering estimated the plant capital cost (see Appendix D).

Capital Cost: C$ 3,464,788

3.0 FLOW & FLOW CONTROL

3.1 Rated Tailings Flow

One tailing line: 5200 m3/hr, 1.44 cms, 22,897 USgpm, at an S.G. of 1.31.

It is assumed plant flow will be available 94% of the time and that PATs will operate 92% of the time.

3.2 Slurry Flow

The slurry will, of course, be abrasive, hence the necessity to use of slurry pumps as turbines rather than using say, a Francis turbine, for energy recovery.

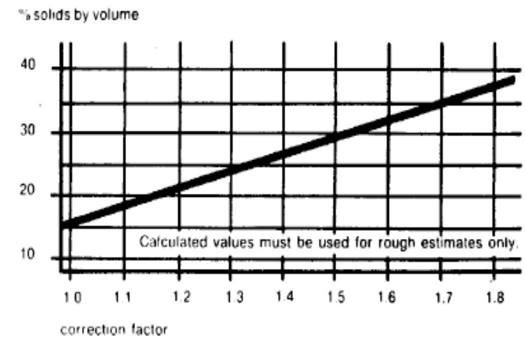
The slurry is assumed to be a low viscosity “settling slurry.”

For correction of friction losses, the following rough guide from Metso is applicable.

Figure 3.2.1 Friction Loss Correction Factors

Pumping of slurries

When calculating the pipe friction losses for a slurry (suspension of solid particles in water) it is advisable to allow for a certain increase when compared with the losses for clean water. Up to concentrations of around 15 percent by volume one may assume that the suspension will behave as water. For higher concentrations friction losses should be corrected by a factor taken from the diagram below.



3.3 Flow Control

A typical hydraulic turbine including Pelton wheels, Francis turbines, etc. all include some form of flow control, operated by the machine's governor, as part of their normal design. In the case of a Francis turbine, which is a reaction machine (in a reaction machine the working fluid changes pressure as it moves through the turbine, giving up its energy) similar to a centrifugal pump, wicket gates (variable guide vanes) are used to control water entry to the machine. (Wicket gates work fine for water control, but of course are not suitable for slurry.) In the case of a Pelton machine, a spear valve controls flow. These flow control mechanisms allow the turbines to run efficiently over a range of flows.

A typical hydro turbine in a run-of-river application uses a level control transmitter in the head pond / forebay to provide a control signal to the turbine governor. The normal operational scheme in these plants is for the governor to control the turbine water flow for maximum power output (assuming a grid connection) until the forebay level drops below a minimum, then the governor throttles back the machine to avoid emptying the penstock (which must be avoided).

In many PAT applications in micro hydro installations there is an excess of water so flow control is not required, or if it is, a simple valve can be used. In other common PAT applications in water works facilities where PATs are used for energy recovery, flow is controlled by an automatic control valve. For water this is a relatively inexpensive and reliable system. For a slurry line the situation is vastly different. The tailing flow will be set (by the process plant) and it will be difficult for the PAT to match this flow. With an oversize unit as has been mandated for this installation, the tailing line will tend to empty, if a smaller PAT was selected, it may not be able to flow enough liquid to match the process plant output.

The total head across a PAT is a fixed number for any given flow (at constant speed). This explains why it's difficult for the PAT to match the tailing flow. Friction head losses are small and so the percentage change in head, which is mostly static head, will be small for a large change in flow, if for instance, the plant output is temporarily decreased. Thus, the head will remain almost constant even though the flow varies.

The above discussion confirms that PAT flow control is required (consisting a flow control valve or variable speed drive), the same as flow control is required for Pelton or Francis turbines. As shown on the general arrangement drawing in Appendix D, a Lorox actuated (proportional) control valve has been included on the inlet to each pump. These valves would be controlled the same as wicket gates for a Francis turbine. These will provide reasonable control over narrow ranges, but to maintain reasonable efficiency over wider flow ranges, a 4 quadrant regenerative variable speed drive is required so that the PAT can be forced to run at different speeds to match the flow requiremets.

Throttling flow by means of a flow control valve in the supply pipe (penstock) is inefficient and only applicable over a small range, as flow control will greatly reduce efficiency, due to the pressure drop across the valve, it would be best to have two or three PATs in parallel with units switched into service as higher flows are required and thus the flow control valves would only have to work across a small range with small consequent energy losses.

To maintain head and prevent emptying of the penstock, the conventional approach for a hydro turbine uses a water level control. The governor senses the water level in the forebay and closes the guide vanes of the (Francis) turbine as soon as the water level drops. In this way, all available water can be used under the nominal turbine head that ensures optimum energy production despite a reduced flow rate (no air is entrained into the penstock and turbine). When using a PAT, such as on the proposed tailings line, which lacks adjustable guide vanes, a similar approach is only possible if the water level control governor acts on a control valve of the penstock. Unfortunately the control valve is an inefficient means of governing since it does not only reduce flow but simultaneously dissipates pressure head. Thus, efficiency drops sharply and the range of flow which can be reasonably accommodated with a control valve as a governing device if the flow range is very limited.

A better method of control is probably to feed the output of the induction generator into the grid via four quadrant VFD so that the PAT can operate at variable speed (as is done with many modern wind turbines). Alternatively, a wound rotor induction generator (sometimes referred to as a double wound machine) can be used. With a small frequency converter (like a VFD) feeding a variable frequency into the machine rotor, the induction generator can operate at various speeds while still supplying power back into the 60 Hz grid. (Both these types of drives are common in the wind turbine industry to feed energy from variable speed turbines into a fixed frequency grid.)

4.0 GENERATION CALCULATIONS

4.1 General

The generation equipment sizing for this energy recovery project is based on the interpretation of the pump curves, for the case when the pump is being used as a turbine. See Appendix B. In this author's judgment, the equipment is over sized, as detailed elsewhere herein.

4.2 Pipeline Head Loss Calculations

For tailing line head loss calculations see Appendix C.

4.3 Power Generation Calculations

Power calculations have been made by determining the pump (turbine) curve intersection with the system curve, noting the power and adjusting by the S.G.

The result is of the above is essentially multiplying the fluid flow by the weight of the slurry moved in a given time frame and thus yields the same result as the standard turbine calculation as shown below. What the curves do is identify the operating efficiency.

Power, P= Q x Hd x Ec x 9.81 x s.g. Kilowatts (kW)

Which is metric format where:

P = Power at the generator terminals, in kilowatts (kW).
Q = Flow in pipeline, in cubic metres per second. (m3/s).
H = The net head in metres (m).
Sg = 1.28 (in this case).
9.81 = The acceleration of gravity.
Ec = Combined turbine and generator efficiency.

The energy output for the normal tailings flow conditions was calculated based on the power generated by the pump (as turbine), based on the operating point and reasonable efficiency.

Energy Recovery Calculations

The below calculations use efficiencies obtained from the pump curves (see Appendix B). The tailings are assumed to be a "settling" slurry and extra viscous affects are assumed not to be great. It is also assumed that in the final design the machine sheave ratio would be adjusted to move the pump as turbine (PAT) to the best efficiency point, which will be at a different speed than it is when running normally as a pump. Note, PAT efficiency will be at least as high as pump efficiency, but it will occur at a different point.

Station 1:

Net slurry head: 85.3 ft., 26.0 m slurry (see Appendix C).
With a slurry s.g of 1.31 head equivalent water = 34.06 m (111.7 ft).

Efficiency (from pump curve): 83%
Power = 1.444 cms * 9.81* 1.31 s.g.*26 m head * 83% pump eff. * 97% gen eff. = 388.5 kW

Station 2:

Net slurry head: 128.7 ft., 39.2 m slurry (see Appendix C)
With a slurry s.g of 1.31 head equivalent water = 51.35 m (168.4 ft).

Efficiency (from pump curve): 82%

Power = 1.444 cms * 9.81* 1.31 s.g.*39.2 m head * 82% pump eff. * 97% gen eff. = 578.6 kW

5.0 MACHINE SELECTION

5.1 General

Rotational fluid machines such as centrifugal pumps are completely reversible and a pump can run effectively as a turbine. However, the characteristics of real fluid flow including friction and turbulence results in different rules for the design of pumps and turbines, as discussed herein.

Pumps are often used as low cost turbines in micro and mini hydro systems. However, in this case, the recovery of energy from the plant tailing flow, slurry pumps are used as no known regular turbine could withstand the highly abrasive tailings slurry flow.

The particular pumps, to be used as turbines for this energy recovery plant, have been selected by the process plant designers. This report discuss, but does not include, the process for generation of a PAT curve and subsequent selection of an appropriate pump. For the design of an actual installation, a slightly different sized pump would probably be selected.

5.2 Equipment Selection Criteria

Actual Equipment

The selection (make and model) of the pumps to be used as turbines (PATs) has been made by others for this project. It is to be noted that without exception, the optimum flow and head of a pump operating in the turbine mode is greater than in pumping mode. In this application once the pump has been selected, the only variable remaining (other than flow control) is operating speed, which can be adjusted by sheave selection in a belt drive application, or by a regenerative VFD.

Design Criteria

The following discussion outlines design factors that would normally be considered when PAT selections are being made. A universal factor is that hydraulically, a pump in turbine mode can handle a higher volume of flow than when in the conventional pumping mode, generally at higher head (when operating at the same rpm). Also, when running as a turbine, a pump often operates at a higher efficiency, or at least at close to equal efficiency as when operated as a pump.

For reasonable operation, the chosen pump (to operate as a turbine) needs to have the head and flow, at the best efficiency point when operating as a PAT, as close as possible to the site conditions (i.e. system curve as normal should intersect the PAT curve at the BEP). The complicating factor is that when operating as a turbine (PAT), the pump has a different performance curve. A centrifugal pump will, of course, operate where the pump curve intersects the system curve. This may bear no relationship to the pump best efficiency point (B.E.P.). The same holds true for a PAT, except the curve is different. In summary, the PAT running conditions in terms of head and flow, for best efficiency as a turbine, are very different from the rated pump output. (Refer to following Clause 5.3 for a discussion of how to determine the PAT curve, as this is not normally available from the pump manufacturer.)

<u>Head</u>

The head available at the turbine is equal to the static head less the head loss in the tailing pipe. The head for a pump in the same situation would be quite different, as it would be the static head plus the pipe head (friction) loss.

<u>Flow</u>

The pump operating conditions in terms of head and flow, for best efficiency as a turbine (PAT), are very different from the rated pump output, although PAT efficiency will be approximately the same as for pump operation. The use of a pump as turbine is limited often by the availability of a fixed flow rate. In this case Lorox (or similar) sleeve type control valves are proposed in order to control flow. However, this control is only practical for small variations in flow. For an efficient installation an electronic coupling between the generator and the grid, allowing variable speed turbine operation, would be the optimum solution.

In turbine mode, the flow increases with increasing head, exactly opposite of the pump case. The head at which a PAT has its best efficiency point (BEP) is considerably higher than its BEP when operating as a pump and it increases to the right (on a standard pump performance graph).

<u>Runaway</u>

Runaway of a regular hydro turbine is always a design and operational issue, and results when the generator load is removed with full fluid flow. The manufacturers advise the maximum runaway speed for each machine, usually based on model tests. For a Francis turbine, which is a reaction machine like a centrifugal pump, the runaway speed is typically 1.8 to 2.1 times normal speed. Turbines are designed to survive the mechanical forces of the runaway speed, although the permitted running time at high speed is often short, due to bearing lubrication issues.

As in the case of a tailings system, like almost any PAT application, flow is not and cannot be controlled by the pump (unlike hydraulic turbines pumps do not have flow control mechanisms), so runaway is a very real consideration. The Pat will have a sleeve type inlet flow control, that can be closed, with air pressure, to prevent runaway, but this system cannot be considered failsafe.

The runaway speed of a PAT can be much higher than the normal speed that the pump was designed to operate at (but typically not as high as say for a Francis turbine). Runaway will occur when the induction generator trips off and thus the load is removed. This is one reason to select an induction generator with significant excess capacity, so that overload trips are not an issue. As also noted in the discussion of the induction generator, as PAT runaway speed is not known, it should be assumed to be 2 times normal speed as a worst case. It is assumed that the low speed pump can withstand this, but this also would need to be conformed with the manufacturer at time of purchase. The induction generator also must be rated for 2 times normal speed.

The design drawing included in Appendix D herewith, includes notes that the PAT is to be equipped with a backup over speed switch. In the event of generator tripping, or power failure (that will amount to the same thing) the over speed switch would be arranged to (a) close the inlet sleeve valve and (b) trip off the remote tailing supply (as it has been advised that the energy recovery station will not have shut-off valves in the tailing line). Alternatively a by-pass around the PAT could be opened. Note, it must be checked with the manufacturer at time of purchase that the pump bearings can sustain the over speed that would result if the inlet valve fails to close and that the pump operates until the line drains out/. It must also be confirmed that the pump will survive the centrifugal forces. Neither of these events are thought to be a major problem in this case, but it is stressed this has not been checked by the author of this report and will be the responsibility of the final process plant designers when the equipment is actually purchased (at some point in the future).

Efficiency & Operating Point

Turbine speed varies according to the load, if the generator is not connected to a utility or if no governor action is included. When the speed changes there is a different efficiency curve for each speed. The best efficiency point occurs at a particular value of flow rate for a given head. The intersection between $H = H(Q)$ turbine performance curve and site curve, gives the head and flow at which the turbine will operate. This is known as the PAT operating point, similar to a pump.

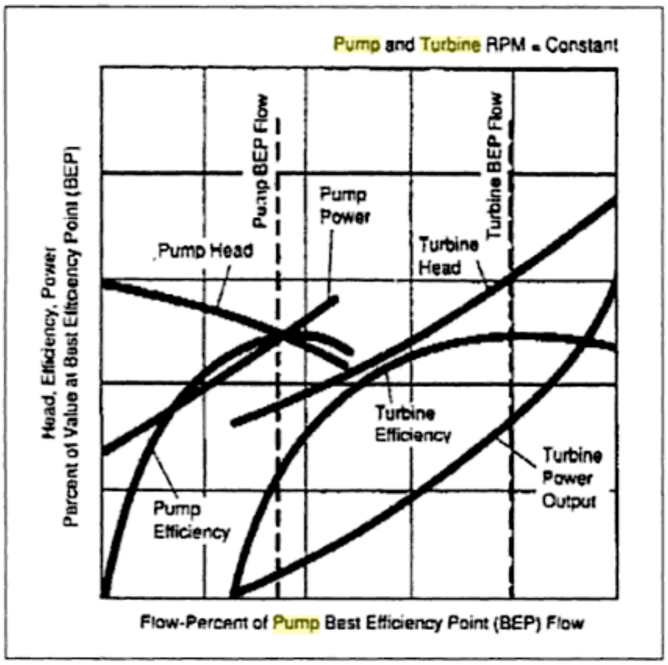
As in the case of pumps, the operation of a Pat should be limited to the centre part of the curve. A PAT does not integrally have the range of flow (and thus power output) control offered by standard hydro turbines. (In our case we are adding a Sleeve type flow control valve.) Once a pump operating as a turbine has been selected for a site, the head, flow, and power output must be held within quite close limits, for a given speed. Thus, the chosen pump needs to have the head and flow, at the best efficiency point, as close as possible to the site conditions. In our case one positive factor is that our selected pump has a relatively low specific speed and as a rule of thumb, lower specific speeds produce flatter curves, which is favourable.

Once a PAT has been selected for a given application, the only variable that can be changed (other than flow if a control valve is added) is speed. When the speed of a centrifugal pump is varied, the best efficiency point comes down at an angle. The affect is almost the same as changing the diameter of the impeller. The same general principle holds true for a PAT.

As discussed in the foregoing, PATs are sometimes connected via four quadrant (regenerative) variable seed drives to allow the optimum PAT rotational speed to be achieved.

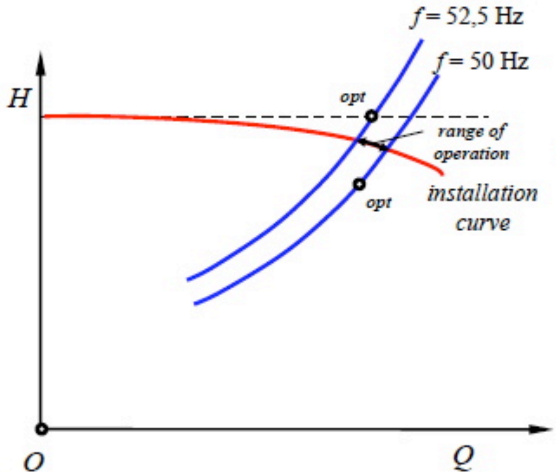
The below Figure 5.1.1 and 5.1.2 illustrate how important it is for the PAT to be operated at the correct conditions. A small change in the operating point can cause a significant drop in efficiency. (Figure 5.1.2 is from Using Standard Pumps As Turbines by Eugen Constantin Isbăşoiu, Diana Maria Bucur, Călin Mihail Ghergu and Georgiana Dunca.)

Figure 5.2.1 Pump Versus PAT Curves

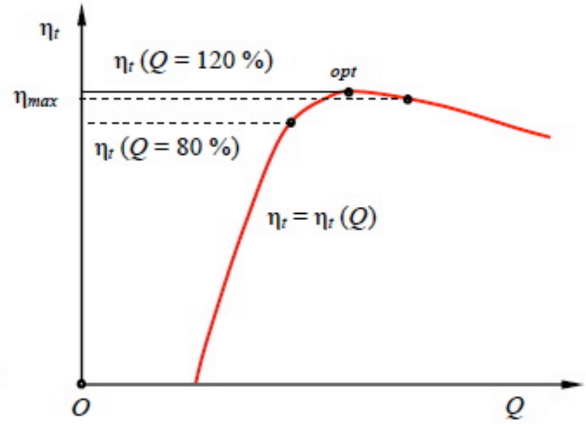


Performance of a pump and a pump-as-turbine (PAT) at identical rotational speeds. (Courtesy *Power & Fluids*, Vol. 10, No. 1)

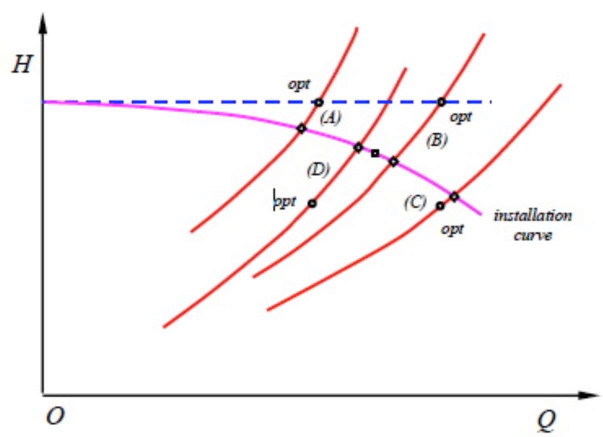
Figure 5.2.2 PAT Performance Curves



Operating range for a pump as turbine



Efficiency curve of pump as turbine



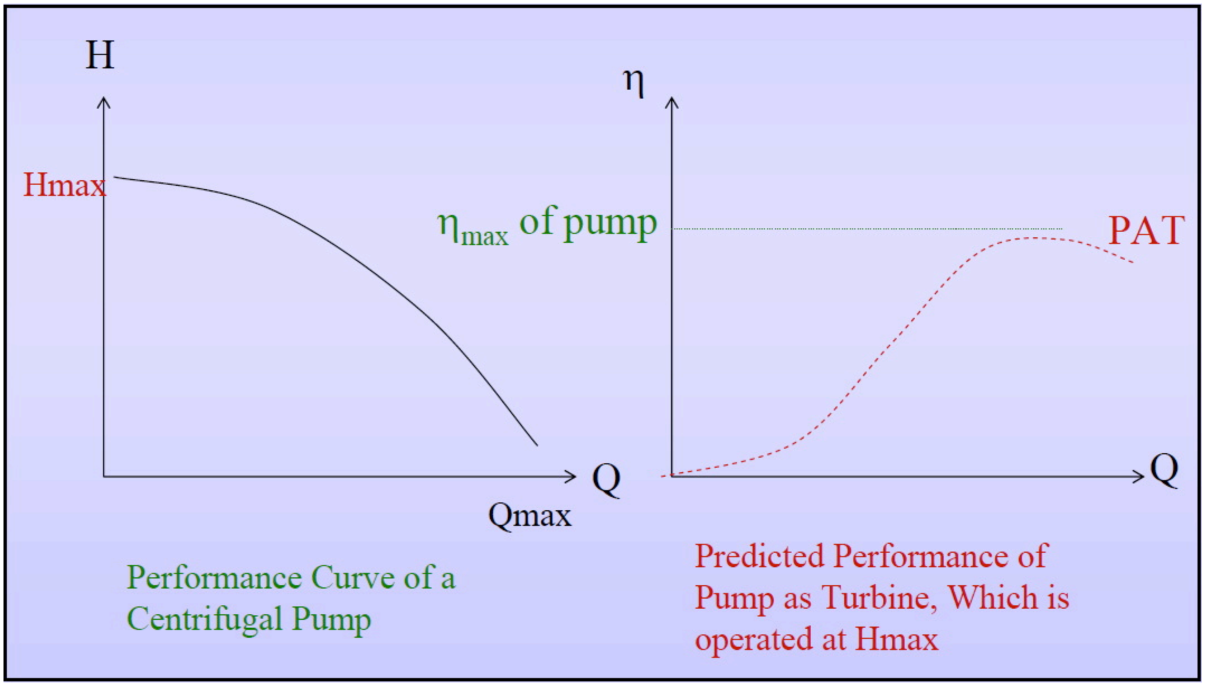
Choosing a pump as turbine

The below table illustrates the typical impact of operating at the wrong point.

Figure 5.2.3 PAT Efficiency And Output

Case:	A	B	C	D (ideal)
P/Pd (Power / design power)	82%	99%	105%	92%
Q/Qd (output /design output)	75%	105%	125%	92%
n/nd (actual speed/design speed)	98%	96%	99%	97%

Figure 5.2.4 Pump Versus PAT Curves



Cavitation

Cavitation can occur in a PAT, just as in a pump. Sufficient back-pressure at the PAT outlet (the inlet when operating as a pump) must be maintained to prevent cavitation. On the other hand, excess pressure may cause pump seal problems.

Vibration

When a pump operates as a turbine, the power output for a given unit can be much higher than when operating at it design point as a pump (not so in our case). Hence, shaft load and deflection could be higher than design and this in turn could affect first critical speed of the unit, etc. and vibration issues could occur. In this case, making use of the large proposed (oversize) low speed pump, problems are not expected. However, in any application this is always a point that should be checked.

Viscosity

The tailing viscosity will effect operation of a PAT. For a pump, as viscosity increases the operational characteristics of a centrifugal pump will change, per the following general rules (a) flow, head and efficiency are reduced and (b) the brake horsepower required is increased. Similar effects on PAT operation can be expected. In the application in question, the tailing viscosity has not been advised, tailings may be a class of fluids where the viscosity actually changes with agitation, and it is a complex matter not considered in detail this report. For this application the tailings is assumed to be a non settling slurry and hence the viscosity effects will not be so great.

5.3 Equipment Selection Calculations

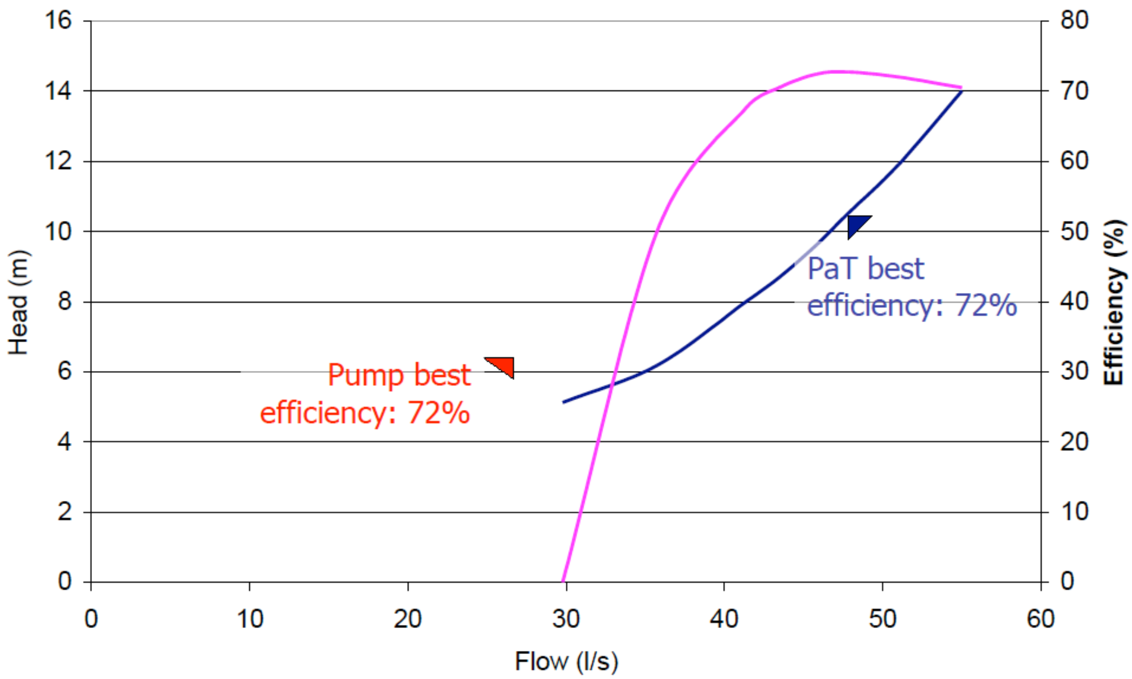
General

The selection of an appropriate PAT requires the correlation between the performance of a pump (direct mode for which we have a curve) and the reverse (turbine) mode, as a performance curve for the pump operating as a turbine is not available. In the case of small units for micro hydro installations, actual tests are often carried out, by connecting the candidate PAT to a supply pump in a flow lab, and simulating operating conditions. In the case at hand this is not practical.

In the case of this project, the tailings line must flow to match the maximum process plant output, hence the selected PAT will be over-sized relative to what would be ideal. Refer to the discussion of control concepts herein.

The figure below illustrates why when used as a PAT, the pump selected should be somewhat smaller than for the pumping situation as a PAT works in higher head and flow rate than those of the pump mode at the same rotational speed.

Figure 5.3.1 PAT Versus Pump Operating Points



PAT Detailed Selection Methods

More exact methods may be based on experimental data from studies that have been carried out on the subject (see Appendix A). These formula/methods are generally correct for pumps of a given specific speed range. The primary documentation concerns low specific speed pumps, which is the case at hand.

There are a number of different calculations of pump specific speed, although of course the basic definition is the same (the specific speed of an impeller is defined as the rpm at which a geometrically similar impeller would run if it were of such a size as to discharge one m3/hr (gpm) against one meter (foot) head.) The acceleration of gravity is sometimes (was originally) included in the formula, some older British results used Imperial gallons, and some metric calculations use cubic metres per second rather than cubic metres per hour. When discussing pump specific speed, it's obviously important agree on the definition. Below is the common definition in US units.

$Ns = N \sqrt{Q} / (H^{0.75})$

Where:
N= pump speed in rpm
Q = capacity in USgpm at the best efficiency point
H = total head at best efficiency point.
G = acceleration of gravity, ft/s/s.

The proposed pump has a specific speed of close to 1500 (Imperial units, 28.1 metric in cms and m) when operating at 350 rpm. This pump falls within the range covered by the selection process used herein. (Note metric specific speed is oten given based on m3/hr, not m3/s (cms).

When a pump is operating as a turbine (PAT), the flow increases with increasing head on the unit, just the opposite of when it operates as a pump. The intersection between the system curve and the PAT curve is the operating point (same concept as a pump) and will show the output power. However, this curve when the unit is operating as a turbine is not the same as the original pump curve. The chosen pump (to be used as a turbine) needs to have the head and flow, at its best efficiency point, as close as possible to the site conditions. The running conditions in terms of head and flow, for best efficiency as a turbine, are very different from the rated pump output, although the pump "as a turbine" efficiency will be approximately the same as it is for pump operation. The experimental data (see Appendix A) showed that, between two pumps with the same specific speeds, the more efficient pump operates as a turbine at greater head and flow.

Experimental data shows that a pump operating as a turbine works at a higher flow rate and head in comparison with its operation in pump mode. The prediction method used is valid in that it has been verified to accurately predict both head ratio and flow rate ratio correctly (between the pump and the pump as a turbine) for the given range of specific speeds. The experimental results also showed that the efficiencies are almost the same in both pump and turbine modes, which is important for the calculations herein.

The BEP head and flow rate for a PAT is greater (by roughly the inverse of the pump BEP efficiency) than the corresponding bep head and flow rate as a pump. For selection of a PAT, the literature (Pumps as Turbines, A User's Guide, Arthur Williams) gives the following relationship that can be used to select the proper pump:

$$Q_t = \frac{Q_{bep}}{\eta_{max}}; \quad H_t = \frac{H_{bep}}{\eta_{max}}; \quad \eta_t = \eta_{max}$$

where Q_{bep} is the flow rate at pump best efficiency point (bep)
H_{bep} is the head at pump bep
η_{max} is the pump maximum efficiency
and Q_t is the flow rate at turbine best efficiency point (bep)
H_t is the head at turbine bep
η_t is the turbine maximum efficiency.

it is noted that the above equations would imply that the ratios of flow and head between pump and turbine operation are equal, but experimental data indicates that the ratio Head(turbine)/Head (pump) is usually greater than the ratio Flow(turbine)/Flow(pump). K.R. Sharma of Kirloskar Co. of India gives the following equations that use different powers of maximum efficiency. For the case where pump and turbine speed are the same:

$$Q_t = \frac{Q_{bep}}{\eta_{max}^{0.8}}; \qquad H_t = \frac{H_{bep}}{\eta_{max}^{1.2}} \tag{9}$$

The following example shows how to calculate the head and flow needed by the turbine when the turbine speed is the same as the pump speed.

***Example 3:** Calculation of turbine best efficiency point (at pump speed).*

The manufacturer of a particular pump gives curves that show that as a pump its maximum efficiency is 62% when delivering 20 l/s at a head of 16 m at 1500 rpm. The pump is required for use as a turbine, driving a synchronous generator at 1500 rpm. The turbine performance at best efficiency predicted from equations (9) will be:

$$Q_t = \frac{Q_{bep}}{\eta_{max}^{0.8}} = \frac{20}{0.62^{0.8}} = \frac{20}{0.682} = 29.3\ l/s;$$

$$H_t = \frac{H_{bep}}{\eta_{max}^{1.2}} = \frac{16}{0.62^{1.2}} = \frac{16}{0.563} = 28.4\ \text{m}.$$

Where the speed are not the same, the pump affinity laws can be used to obtain the following relationship:

$$Q_t = \frac{N_t}{N_p} \times \frac{Q_{bep}}{\eta_{max}^{0.8}}; \qquad H_t = \left(\frac{N_t}{N_p}\right)^2 \times \frac{H_{bep}}{\eta_{max}^{1.2}}$$

The above equations may only be accurate to within 20% so that to correctly pick the pump best efficiency point in the case at hand, the PAT sheave sizes may have to be changed on the field to arrive at the best operating speed to produce best efficiency.

There is a newer selection method, the BUTU method, first developed in Mexico (BUTU = PAT in Spanish) later refined in Great Britain. It uses empirical formula that were found by curve-fitting of experimental data for pump and turbine mode performance of standard pump.

In this proposed installation, a belt driven pump is a better selection than a gearbox or direct connection unit. A directly connected drive will result in a slow induction generator speed (based on large slurry pump operation) and hence the generator will be costly. With a gearbox drive, losses will probably be somewhat less, but adjusting exact pump speed will be costly. With belt drive the motor sheave can be relatively easily changed to make small adjustments in PAT speed as necessary to reach the BEP.

Another factor to keep in mind when selecting a pump as a PAT is the rule of thumb that the impeller diameter should normally be no less than 90% of the casing nominal size, as efficiency will be significantly reduced.

5.4 Efficiency Considerations

Due to the nature of their design, and the fact they "wear" abrasion resistant slurry pumps inherently have lower efficiency than similar water pumps. When used as a turbine they will also, of course, continue the exhibit lower efficiency, but the efficiency as a turbine will be at least as high as it is as a pump. Refer to Appendix A.

For control of the PAT, throttling discharge (e.g. by a control valve) results in a considerable drop of efficiency since, firstly, the pump spiral casing is not designed for flows deviating from design flow and, secondly, the throttling valve dissipates energy, i.e. it reduces the net head on the PAT. Hence the proposed use of a VFD.

5.5 Generator

The generators will be rated:

- Generator KW: to be greater than maximum pump output.
- Generator phase/voltage: 3 phase, 60 Hz, 4160 volts.
- Generator type: Induction generator.
- Generator Power factor (P.F.): lagging, angle depends on output.
- Generator stator insulation: Design B temperature rise, Class F insulation, form wound.
- Rated for an over speed of 2 times normal speed.

It is to be noted that an induction generator will normally produce full power at only 1% over the synchronous speed (in other words the slip is somewhat less than it would be for an induction motor operating as a generator).

Note, for general independent power producers (IPPs) hydro generation applications, BC Hydro has sets limits on the maximum size of induction generators. This is primarily related to the fact that the power system has to provide the leading (magnetizing) vars for an induction generator as, unlike a synchronous generator, an induction machine has no DC exciter to supply magnetizing current for the machine iron. However, in this case, as the induction generators would be connected to the mine distribution system, and the mine will control the system power factor to close to unity, and also as it's an energy recovery scheme, the normal BC Hydro limitations are judged to be inapplicable. Also note, that due to the 138 kV cable connecting the two mine substations, the KSM project has an over supply of leading vars and in fact shunt reactors are applied to absorb vars, so in this case the necessity to supply leading vars from the utility system for generator magnetization is a moot point.

A standard motor is only rated for 125% over speed. As water turbines can runaway (when the generator trips off line but water remains at full flow), a hydro generator is normally rated for the runaway speed of the turbine. For a reaction machine like a Francis turbine, the runaway speed would normally be in the range of 2 times normal. In this case the runaway speed of the proposed PAT is not currently known, so the generator should, to be conservative, ordered suitable for 2 times normal synchronous speed (i.e. designed for 100 percent over-speed).

Standard induction motors can be used as induction generators, but a purpose build induction generator will be more efficient, will only carry a relatively small cost premium in the larger sizes and can be built for more than the normal motor 125% over-speed rating. Also note, a common rule of thumb when using an induction motor as an induction generator is to not operate it at more than 80% of nameplate ratings, so this will tend to make the motor as an induction generator option more costly than expected.

5.6 Installation

The units will be installed on concrete foundations as per standard slurry pumps. Refer to the plant layout drawing in Appendix D.

5.7 By-pass

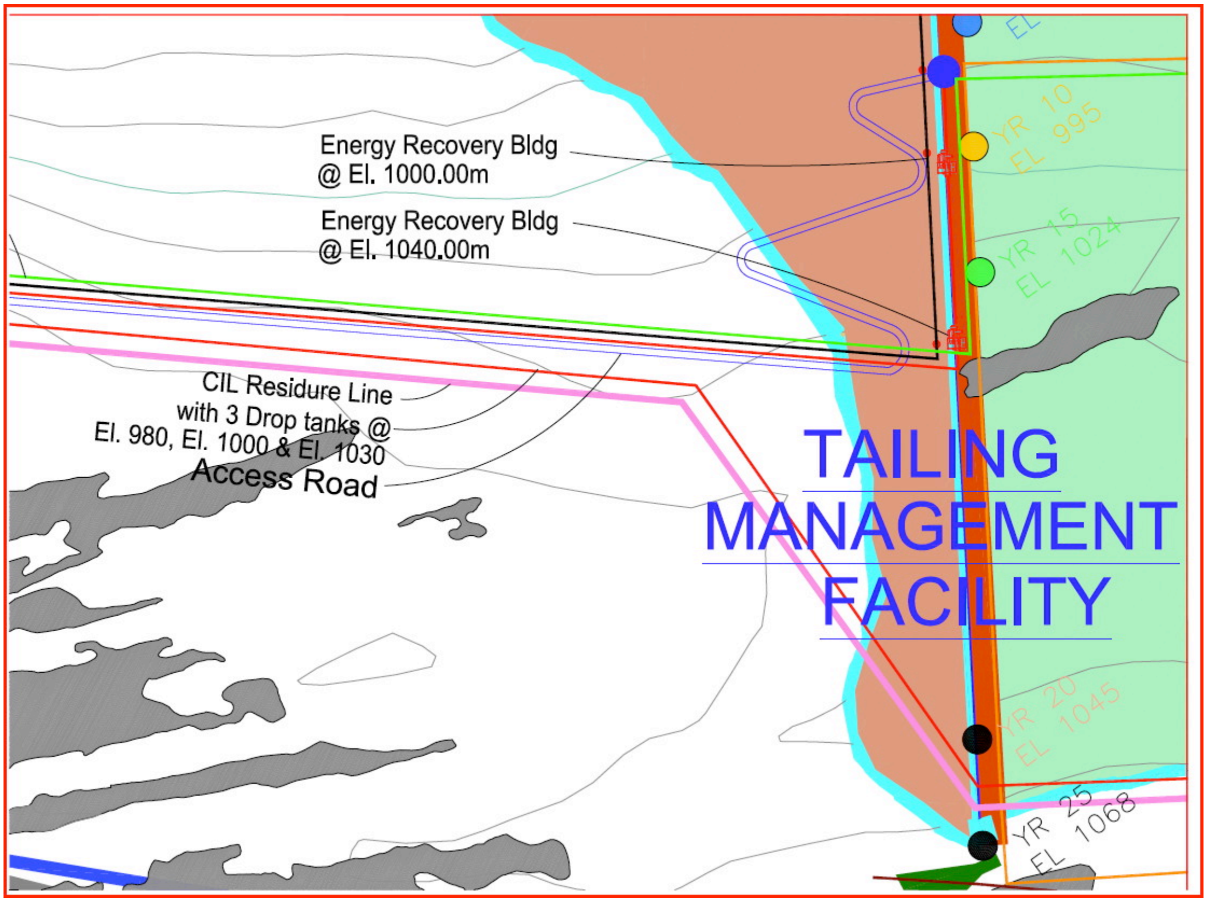
If the PAT is out of service, the entire tailing line can be by-passed, at the flotation plant, with the flow switched over to the spare line. Alternatively, a bypass valve can be installed around the PAT in the station.

6.0 TAILING LINES

6.1 General

The tailing system design and installation is by others. The below plan, taken from Wardrop drawing No. 10-10-1617 Rev 0, illustrates the system general arrangement

Figure 6.1.1 Tailing System Plan



6.2 Surge Tower Or Pressure Relief Valves

As long as there are no fast acting shut-off valves in the system, surge towers, tanks or pressure relief valves will not be required. Note, for a slurry application pressure relief valves would not be a suitable solution.

6.3 Transient Analysis

Note required, based on there being no quick shut off valves in the system and the use of HDPE pipe.

7.0 POWER PLANT DESIGN AND CONSTRUCTION

7.1 General

The energy recovery equipment for the tailing line consists of two series installations installed in two small buildings.

Each “powerhouse” building will be a small pre-engineered, insulated, steel structure. The structure will house the system vales, the pump (as turbine) and induction generators, switchgear, controls, etc. A partition will be provided to separate the electrical equipment from the pumps. Building heating and ventilating equipment will be provided to discharge the heat from the air cooled generators and provide heating in the winter. The powerhouse building will be located on the machine reinforced concrete foundation.

A “shop assembled transportable electrical room has been planned for each energy recovery building.

A 7.5 tonne powerhouse bridge crane would be included in each pump building.

8.0 POWER PLANT CONTROLS

8.1 Automatic PLC Control

The energy recovery plant will be designed for automatic PLC control, with no operators required. Within the power house, basic panel mounted hard-wired manual controls would be provided, plus there would be a flat screen, PC based, operator interface (HMI) that would allow monitoring and/or plant control and would also provide system alarms. Communication provision would also be made to allow a remote HMI at the mill site. (The degree of remote control permitted would require study.) Note, the control system specifically does not include an instrumentation type distributed control system (DCS) as such systems are completely inappropriate for controlling a power plant such as this and are much more costly and harder to maintain than a PLC system.

As the generators are induction generators, no complex generation control system is required. However, as discussed elsewhere herein, runaway is a concern. If a generator trips off line, the energy recovery stations do not have any tailing line valves that may be automatically closed. Instead the interlocks, including PAT over speed switches, will be arranged to close off the supply at the flotation plant, as would a generator trip.

The control system PLC would either be programmed to act as a governor, or a separate digital governor would be used. In either case the “governor” will control the PAT inlet proportional (sleeve type) flow control valve and most probably would also control a VFD that couples the PAT output to the power system. This speed and/or flow control would be based on remote level signals or, as pipe friction loss is low, a pipe pressure signal could be used. In any event, governor action would be the same as per a typical Francis turbine. The controls would also allow the operator to empty the line during shut-downs, etc.

8.2 Generator Control

As the proposed generator is an induction generator, generator control is simple. Because an induction generator is “excited” from the system, until the generator breaker closes it does not generate power. The normal operation with an induction generator is to simply bring the machine up to speed and close the breaker. There is no synchronization required. The system PLC would be programmed to perform the required control functions.

9.0 SUBSTATION AND POWER LINE

9.1 Substation

The energy recovery plant will utilize 4160 volt generation equipment with 4160 volt generator breakers. It is assumed the transmission interconnection will be at 4160 or 25 kV. If the latter, then a step-up transformer would, of course, be required.

The powerhouse will include standard 4160 volt motor starters as generator “breakers.” The switchgear line up will have a main breaker which will be cable connected to the over head pole line. Line terminal lighting arresters and an interlocked air break switch are also required.

The power-plant switchgear would include revenue class generator metering. Note, for power sales to BC Hydro, they normally estimate power system losses from the metering point to the actual point of power purchase, with the estimated cost of such losses being deducted from the power sales.

9.2 Power Lines

It is assumed the hydro plant would be connected to the mine via the distribution system to the TMF. Refer to Wardrop mine electrical drawings and estimates.

10.0 ENVIRONMENTAL

10.1 General

As the project will be all within the mining lease, the environmental considerations will be addressed in the overall KSM project environmental assessment. This assessment is being carried out by Rescan Environmental Services (Rescan) on behalf of Seabridge Gold. This report and all other required information will be forwarded to Rescan.

11.0 POWER SALES

11.1 General

The KSM mine and process plant project energy conservation measures may account for all Rate Schedule 1823 Tier 2 (costly) power. If not, this small machine may displace some remaining tier 2 energy purchases, or if this is not required, the energy may instead be sold to BC Hydro under the “Standing Offer Program.”

For the purposes of this study it is assumed the power sales would be priced at 7.36 cents per kW.h which is the value of Tier 2 energy from BC Hydro, based on their two tier rate schedule 1823 as of April 2012.

11.2 BC Hydro Power Smart Project incentives For Transmission Customers

This incentive applies to customers with projects that:

- Uses more than $50,000 of electricity annually
- The project or group of projects will save at least 300 megawatt hours annually.
- The project is a hard-wired facility upgrade with an expected lifespan of five years or more.
- Will use a technology that has already been successfully implemented in B.C. and is measurable and verifiable.
- The site has been operational for a minimum of six months prior to application.

This avenue would not be available for facilities built as part of the original project.

11.3 BC Hydro Power Smart Project incentives New Plant Design

This incentive applies for customers that have projects:

- In the early stages of planning a new facility or expanding an existing facility.
- That would expect to increase the power load by five per cent or more.
- The facility has a savings potential of more than $9,000 annually (as determined by your free energy study).
- Require funding for incremental costs to improve efficiency, with minimal disruption to your design process.

Power Smart can provide project incentives as much as 75 to 100 per cent of your incremental construction costs (i.e. above standard, inefficient design options).

11.4 BC Hydro Standing Offer Program

BC Hydro has a “Standing Offer Program” to encourage the development of small clean energy projects throughout British Columbia. They state (25 April 2012):

> *The Standing Offer Program is intended to encourage the development of clean or renewable power projects of no more than 15 megawatts throughout British Columbia. The program streamlines the process for small developers selling electricity to BC Hydro, simplifies the contract and decreases transaction costs for developers while remaining cost-effective for rate payers. The Standing Offer Program supports the principles and policies set out in the 2007 BC Energy Plan and the 2010 Clean Energy Act.*

Clean power sources such as run-of –river hydro, energy recovery projects and similar meet the basic requirements. The project generator can be behind a customer load, which means hydro generators connected to the KSM power distribution system are eligible. In these cases the customer's Energy Supply Agreement (ESA) would be modified so that the overall billings to the customer account for the energy generated by the generator that is being sold to BC Hydro under the project Energy Purchase Agreement (EPA). Considerable information is on file concerning the Standing Offer Program (SOP).

BC Hydro will pay for each MW.h of energy delivered based on:

- The base price as determined by the region of the point of interconnection;
- Any CPI escalation applicable to the base price; and
- The time of delivery adjustment factor specified in the EPA.

The following is a typical calculation that illustrates how the SOP Program Rules would be applied to a project located on Vancouver Island, where an EPA is executed in 2012 and COD occurs in 2014. The payment price for energy delivered during Peak Hours in February 2014 is calculated. The price paid would vary over the province but it can be seen that the price is significantly higher than the 7.36 cents per kW.h value of BC Hydro Tier 2 power under rate schedule 1823.

Figure 11.4.1 Typical Energy Sales Value Under SOP

STEP	CALCULATION
Step 1	Determine the applicable Base Price for a project located on Vancouver Island, which is \$102.25/MWh. See *Standing Offer Program Rules, Section 3, Figure 1 – Base Price by Region.*
Step 2	Calculate the escalated Base Price for energy in the year the EPA is signed (2012), which is \$106.45/MWh. = regional price x CPI $_{\text{January 1, 2012}}$ / CPI $_{\text{January 1, 2010}}$ = \$102.25/MWh x 119.2 / 114.5 = \$106.45/MWh *(Note: 100% of the base price is escalated at CPI up to the year the Project EPA is signed.)*
Step 3	Calculate the payment price for energy for 2014 prior to adjusting for the time of day or month when the energy is delivered, which is \$108.60/MWh. = (escalated Base Price * 0.5 * CPI $_{\text{January 1, 2014}}$ / CPI $_{\text{January 1, 2012}}$) + (escalated Base Price * 0.5) = (\$106.45 x 0.5 x 124.0 / 119.2) + (\$106.45 * 0.5) = \$108.60/MWh *(Note: 50% of the escalated Base Price from step 2 is escalated at CPI annually starting the first calendar year after the Project EPA is signed.)*
Step 4	Calculate the payment price for energy delivered in Peak Hours during February 2014, which is \$122.72/MWh. = payment price for 2014 prior to adjusting for the time of day or month when the energy is delivered x Time of Delivery Factor for February Peak Hours = \$108.60/MWh x 113% = \$122.72/MWh

12.0 CAPITAL COST ESTIMATE

12.1 General

Refer to Appendix D for the capital cost estimate.

13.0 PLANT CLOSURE

13.1 General

When the mine is closed at end of life, this energy recovery hydro plant would also be closed.

W N Brazier

W.N. Brazier, P. Eng.

14.0 APPENDIX A – REFERENCE TECHNICAL PAPERS

The following technical papers outline the method of determining the PAT curve, given the pump curve.

- Experimental study of characteristic curves of centrifugal pumps working as turbines in different specific speeds
  Shahram Derakhshan *, Ahmad Nourbakhsh
  (Science Digest)

- Performance of a centrifugal pump running in inverse mode, J Ferna´ndez1, E Blanco2, J Parrondo2, M T Stickland3* and T J Scanlon3
  1Dpto de Electro´nica e Ingenierı´a Electromeca´nica, Universidad de Extremadura, Badajoz, Spain

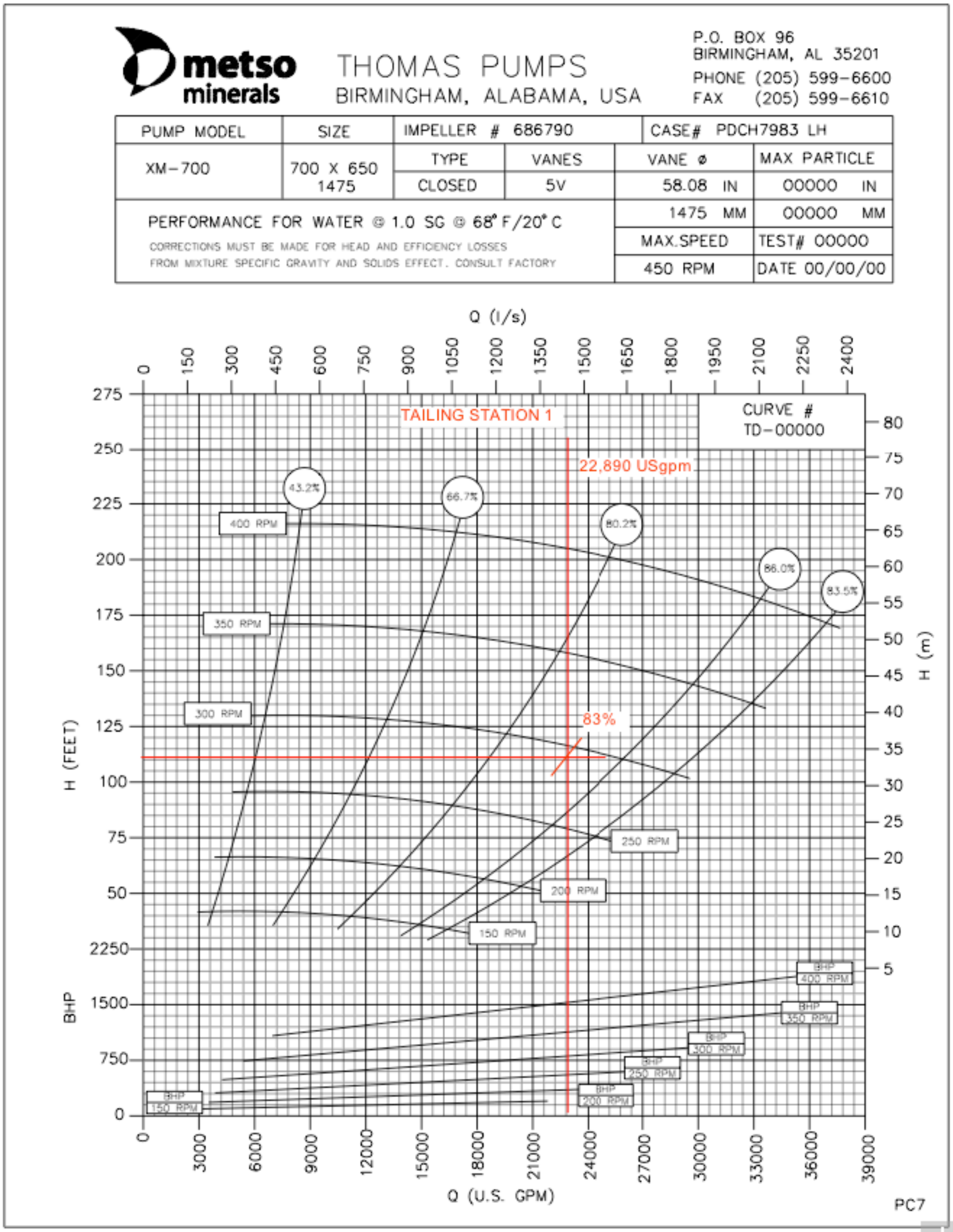
- Pumps As Turbines, A Users Guide by Arthur Williams

- Application Oriented Planning For Pumps As TurbinesKSB pumps

- Experimental Investigation of Centrifugal Pump Working as Turbine for Small Hydropower Systems, Himanshu Nautiyal1, Varun1, Anoop Kumar1 Sanjay Yadav, CS Canada

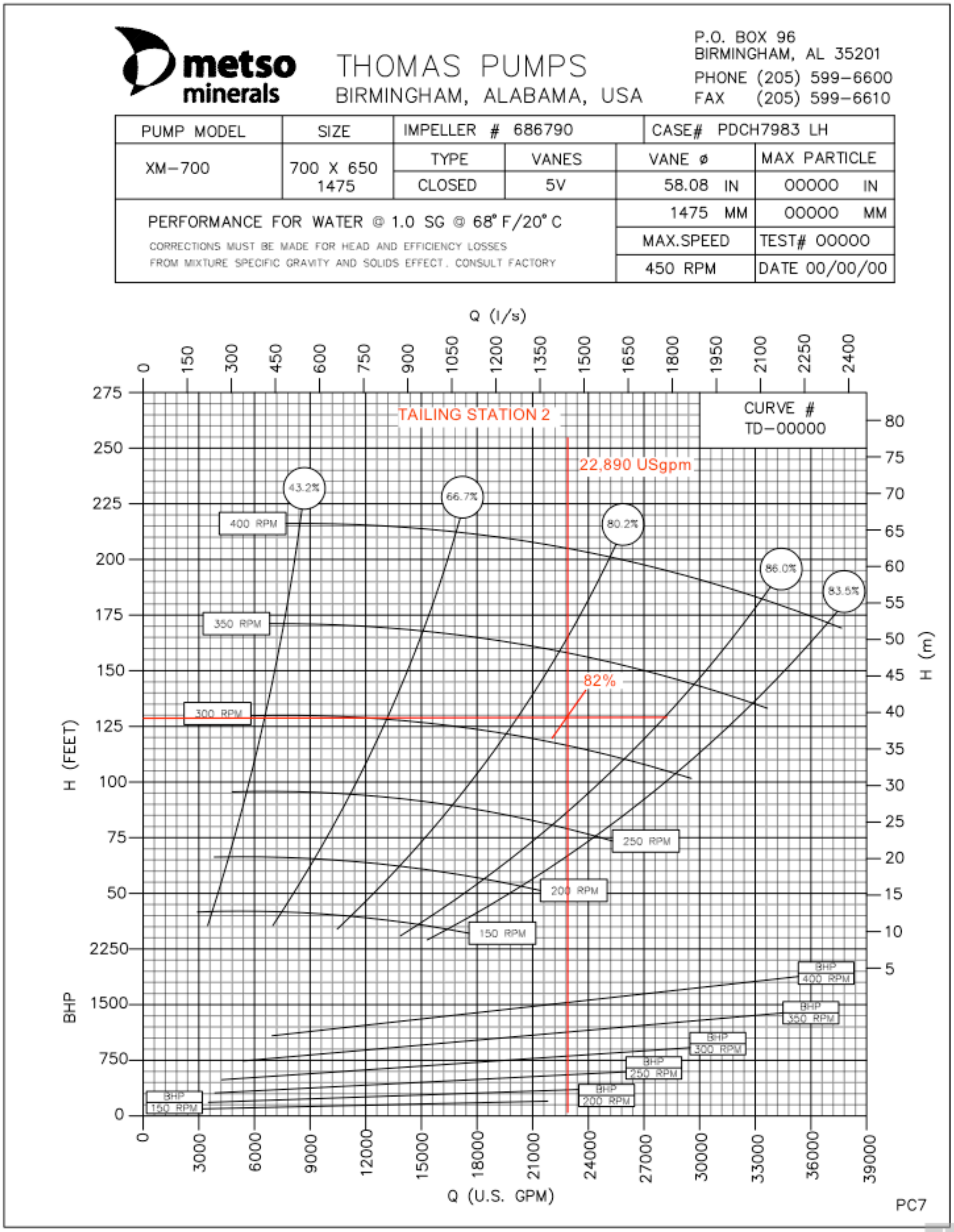
15.0 APPENDIX B - PUMP CURVES

Station 1 - The below pump curve is for the unit (selected by others) for this project.



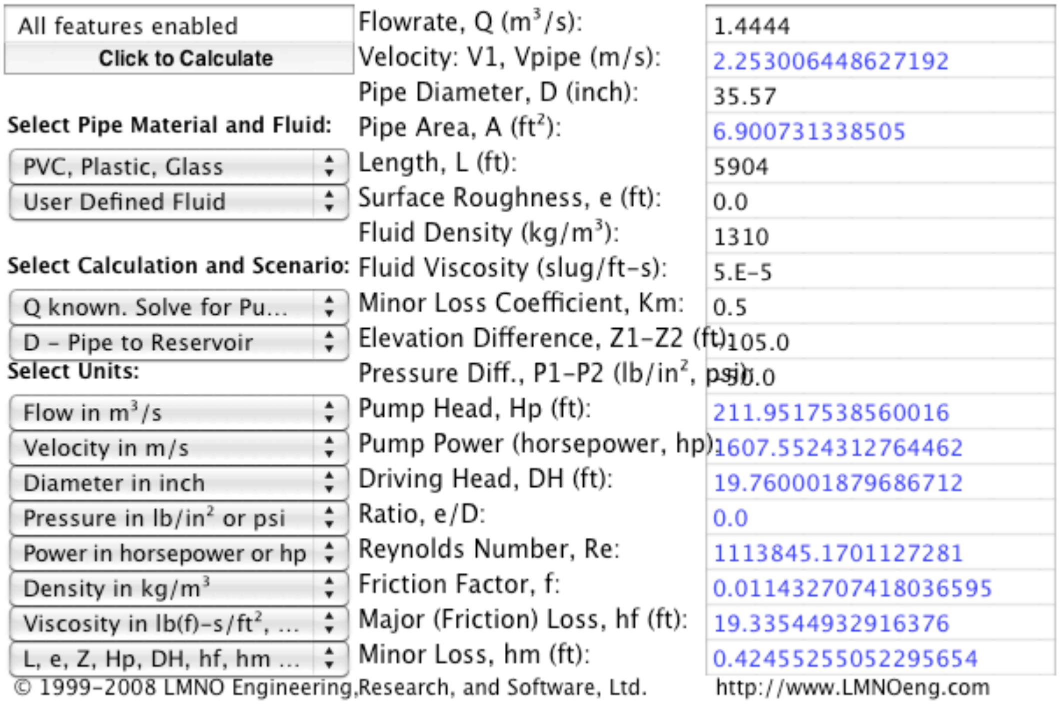
APPENDIX B, PUMP CURVES CONTINUED

<u>Station 2</u> The below pump curve is for the unit (selected by others) for this project.



16.0 APPENDIX C – HEAD LOSS CALCULATIONS

Mill to Station 1 (Head loss = 19.7 ft slurry, net head = 105.0 – 19.7 = 85.3 ft slurry, 111.7 ft water)



All features enabled	Flowrate, Q (m^3/s):	1.4444
Click to Calculate	Velocity: V1, Vpipe (m/s):	2.253006448627192
	Pipe Diameter, D (inch):	35.57
Select Pipe Material and Fluid:	Pipe Area, A (ft^2):	6.900731338505
PVC, Plastic, Glass	Length, L (ft):	5904
User Defined Fluid	Surface Roughness, e (ft):	0.0
	Fluid Density (kg/m^3):	1310
Select Calculation and Scenario:	Fluid Viscosity (slug/ft-s):	5.E-5
Q known. Solve for Pu...	Minor Loss Coefficient, Km:	0.5
D - Pipe to Reservoir	Elevation Difference, Z1-Z2 (ft):	105.0
Select Units:	Pressure Diff., P1-P2 (lb/in^2, psi):	0.0
Flow in m^3/s	Pump Head, Hp (ft):	211.9517538560016
Velocity in m/s	Pump Power (horsepower, hp):	1607.5524312764462
Diameter in inch	Driving Head, DH (ft):	19.760001879686712
Pressure in lb/in^2 or psi	Ratio, e/D:	0.0
Power in horsepower or hp	Reynolds Number, Re:	1113845.1701127281
Density in kg/m^3	Friction Factor, f:	0.011432707418036595
Viscosity in lb(f)-s/ft^2, ...	Major (Friction) Loss, hf (ft):	19.33544932916376
L, e, Z, Hp, DH, hf, hm ...	Minor Loss, hm (ft):	0.42455255052295654

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<u>Station 1 To Station 2 (Head loss = 2.3 ft slurry, net head = 131.0-2.3 ft = 128.7 ft slurry, 168.6 ft water)</u>

All features enabled	Flowrate, Q (m^3/s):	1.4444
Click to Calculate	Velocity: V1, Vpipe (m/s):	2.253006448627192
	Pipe Diameter, D (inch):	35.57
Select Pipe Material and Fluid:	Pipe Area, A (ft^2):	6.900731338505
PVC, Plastic, Glass	Length, L (ft):	492.0
User Defined Fluid	Surface Roughness, e (ft):	0.0
	Fluid Density (kg/m^3):	1310
Select Calculation and Scenario:	Fluid Viscosity (slug/ft-s):	5.E-5
Q known. Solve for Pu...	Minor Loss Coefficient, Km:	0.5
D - Pipe to Reservoir	Elevation Difference, Z1-Z2 (ft):	131.0
Select Units:	Pressure Diff., P1-P2 (lb/in^2, psi):	0.0
Flow in m^3/s	Pump Head, Hp (ft):	220.2275919709348
Velocity in m/s	Pump Power (horsepower, hp):	1670.3206954708992
Diameter in inch	Driving Head, DH (ft):	2.0358399946199413
Pressure in lb/in^2 or psi	Ratio, e/D:	0.0
Power in horsepower or hp	Reynolds Number, Re:	1113845.1701127281
Density in kg/m^3	Friction Factor, f:	0.011432707418036595
Viscosity in lb(f)-s/ft^2, ...	Major (Friction) Loss, hf (ft):	1.6112874440969798
L, e, Z, Hp, DH, hf, hm ...	Minor Loss, hm (ft):	0.42455255052295654

17.0 APPENDIX D - DRAWINGS

Process Plant Tailing System Design

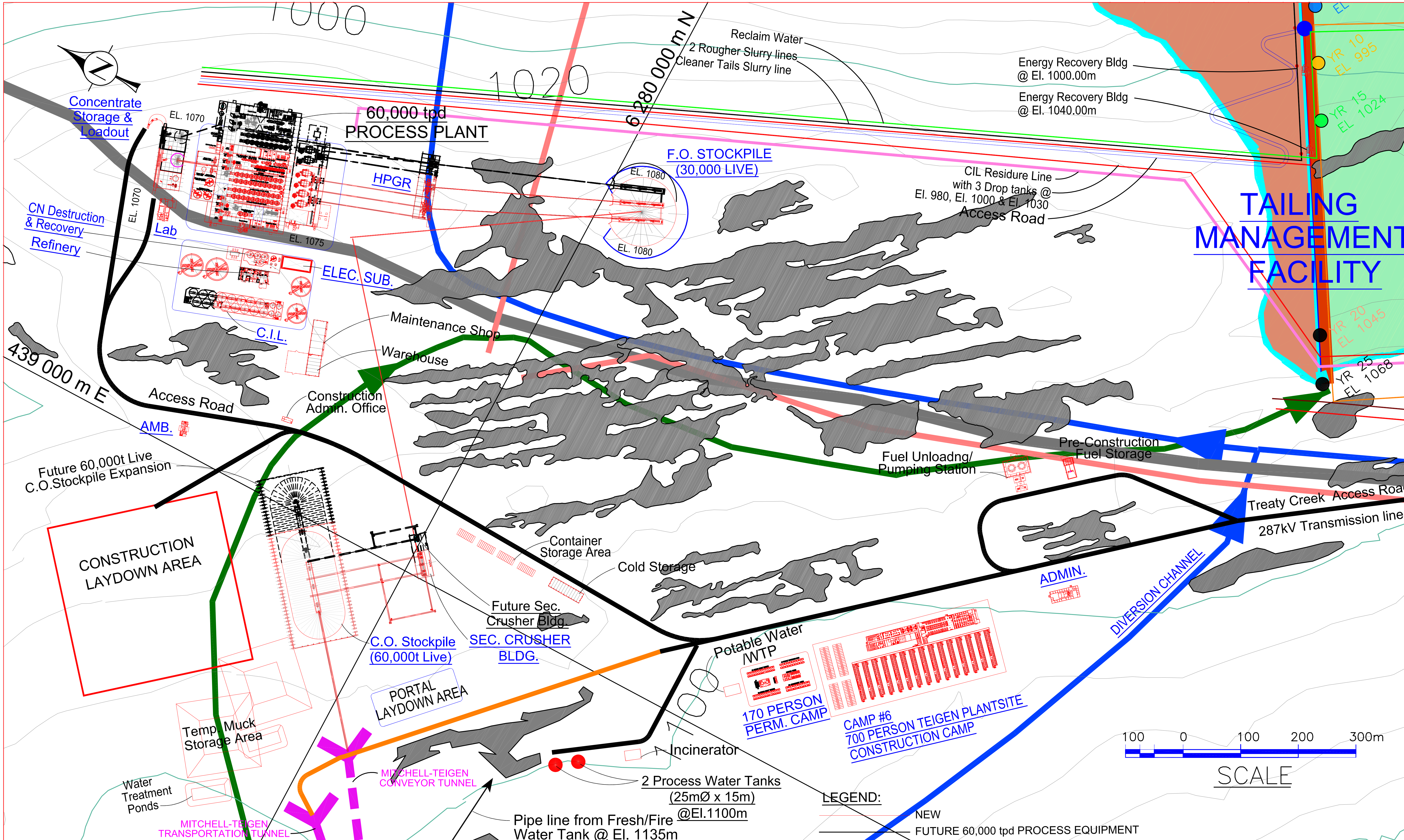
Drawing No. 10 -10 - 1617 Rev 0

Power Plant Drawings

Refer to energy recovery plant General Arrangement drawing No. KSM- 10 - E- 6501 Rev. D.

Power Line Drawings

The power line is shown on Wardrop mine power line plans.



REV. No.	ISSUED FOR	REVISION DESCRIPTION	DR.	CHK.	APP.	DATE
0	ISSUE FOR PFS UPDATE 2012		BW		HB	2012/05/11
A	ISSUE FOR PFS UPDATE 2012		BW		HB	2012-04-02

REFERENCE DRAWING — REF. DWG No.

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SCALE:		DATE:
DESIGNED:	H. Bosche	Mar 17 2012
DRAWN:	B. Wong	Mar 17 2012
CHECKED:		
APPROVED:		

CLIENT: KERR–SULPHURETS–MITCHELL

BOSCHE VENTURES LTD

TITLE: PFS UPDATE 2012 HPGR OPTION HPGR PLANTSITE AT TEIGEN PLAN

PROJECT No. — DRAWING No. 10–10–1617 — REV No. 0

ELECTRICAL DESIGN NOTES

1) PROVIDE HID LIGHTING MINIMUM 350 LUX. PROVIDE HPS WALL MOUNT EXTERIOR LIGHTS (WITH PHOTOCELL CONTROL) OVER DOORS

2) PROVIDE PERIMETER GROUND GRID BONDED TO ALL BUILDING COLUMNS PLUS INTERNAL EQUIPMENT GROUNDING SYSTEM. BOND TO MODULAR ELECTRICAL ROOM INCOMING POWER LINE OVERHEAD GROUND WIRE, ETC. ALL AS PER CEC.

3) PROVIDE HEAVT DUTY GALV. STEEL CABLE TRAY SYSTEM AS REQUIRED.

4) ALL POWER AND CONTROL CABLE SHALL BE TECK 90 TYPE.

5) PROVIDE PLC CONTROL SYSTEM WITH HMI. PROVIDE FIBRE OPTIC LINK BACK TO FLOTATION PLANT CONTROL ROOM. NO DCS JUNK.

6) PROVIDE DIAPHRAGM SEAL TYPE PRESSURE TRANSMITTERS ON INCOMING AND OUTGOING TAILING LINES AND INPUT TO PLC.

7) THE INDUCTION GENERATORS SHALL BE CONTROLLED ESSENTIALLY AS PER INDUCTION MOTORS. PROVIDE MOTOR STARTERS WITH DIGITAL METERING AND DIGITAL MOTOR PROTECTION RELAYS.

8) PUMPS (AS TURBINES) TO HAVE MILTRONICS TYPE SPEED SWITCHES TO ACT AS BACK-UP OVER SPEED SWITCHES (IN CASE STARTER TRIPS BUT TAILINGS CONTINUE TO FLOW).

9) EACH MOTOR STARTER TO HAVE KW TRANSDUCER INPUT TO PLC.

BUILDING DESIGN NOTES

1) PROVIDE PRE-ENGINEERED STEEL STRUCTURE SIZE AS SHOWN, C/W CRANE BEAM AND RAIL FOR 7.5 TONNE CRANE. CRAIN RAIL MINIMUM 5000 ABOVE FLOOR LEVEL.
2) BUILDING ASSUMED TO HAVE SANDWICH PANEL WALL INSULATION.
3) PROVIDE TRUCK AND MAN DOORS AS SHOWN. PROVIDE CANOPIES OVER MAN DOORS.

FOUNDATION DESIGN NOTES

1) SPREAD FOOTINGS, FLOOR SLAB AND PUMP FOUNDATION AS SHOWN ON THE DRAWING. PUMP FOUNDATION MIN. 2500 x 4000 x 1000. BUILDING FLOOR SLAB MINIMUM 200 THICK.

PIPING DESIGN NOTES

1) PROVIDE VALVES, DRAINS, ETC. (Provide a valve to stop the flow, or a smaller 8 - 10 inch drain valve off a tee on the suction of the pump, with a gravity flow 8 - 10 inch pipe and another tee and 8 - 10 inch valve to reroute any line drainage or flush water flow around the pump station to the downstream large tailing line.")
2) PROVIDE PIPE SUPPORTS AS REQUIRED.
3)DIN 600 LAROX AUTOMATIC FLOW CONTROL VALVE, PNEUMATICALLY ACTUATED WITH PNEUMATIC POSITIONER, CAT # PVE-600-AN-6-3-0-L-S COMPLETE WITH 6 BAR SLEEVE FOR SLURRY SERVICE (NATURAL RUBBER, SBRT, ETC.)
4) FIELD RUN AIR PIPING AS REQUIRED.

MECHANICAL DESIGN NOTES

1) BUILDING CRANE SHALL BE 7.5 TONNE.
2) ALL PIPING SHALL BE IN ACCORDANCE WITH ASME B31.3 - 2004 PROCESS PIPING, WHERE APPROPRIATE.
3) PROVIDE VENTILATION FANS AND LOUVRES, ETC. AS SHOWN.
4) AIR COMPRESSOR, 15 SCFM, 120 PSIG, 600 VOLT 3 PHASE

SEABRIDGE GOLD INC.
KERR SULPHURETS MITCHELL PROJECT - PFS
WN BRAZIER ASSOCIATES INC.

TAILING SYSTEM
ENERGY RECOVERY PLANT
GENERAL ARRANGEMENT (TYPICAL FOR 2 BLDGS)

DRAWN BY: WNB DATE: 11 MAR 2010 SCALE: 1:25	DRAWING NO. KSM- 10 - E- 6501	REV. D

18.0 APPENDIX E – WARDROP COST ESTIMATE

The Wardrop cost estimate for the two tailing energy recovery plants is attached. Electrical and controls cost estimate input by WN Brazier Associates Inc.

Area-Sec-Seq	Description	Qty	Labour Unit Mhr	Prod. Factor	Labour Manhour	Labour Rate	Labour Cost	Material Unit Cost	Material Cost	Const Eqt Unit Cost	Const Eqt Cost	Process Eqpt Unit Cost	Process Eqpt Cost	Total Unit Cost	Total Cost (USD)
N32 - Slurry Pipeline Energy Recovery Plant															
N32-1.15-5049.00	Detail Excavation	1,875. m3	0.06	1.30	146.25	107.23	15,683	0.00	0	3.60	6,750	0.00	0	11.96	22,433
N32-1.15-5050.00	Structural Backfill	1,731. m3	0.10	1.30	225.03	107.23	24,130	7.68	13,294	3.84	6,647	0.00	0	25.46	44,072
N32-1.15-5051.00	Concrete work	160. m3	7.00	1.30	1,456.00	107.23	156,130	643.20	102,912	19.20	3,072	0.00	0	1,638.21	262,114
N32-1.15-5052.00	Structural Steel	56. t	22.00	1.30	1,601.60	107.23	171,743	4,608.00	258,048	240.00	13,440	0.00	0	7,914.84	443,231
N32-1.15-5053.00	Wall cladding	322. m2	1.50	1.30	627.90	107.23	67,331	120.00	38,640	14.40	4,637	0.00	0	343.50	110,608
N32-1.15-5054.00	Roof cladding	125. m2	1.00	1.30	162.50	107.23	17,425	105.60	13,200	14.40	1,800	0.00	0	259.40	32,425
N32-1.15-5055.00	Pump	2. lot	170.00	1.30	442.00	107.23	47,397	288.00	576	960.00	1,920	315,193.91	630,388	340,140.18	680,280
N32-1.15-5056.00	induction generator	2. lot	40.00	1.30	104.00	107.23	11,152	0.00	0	96.00	192	67,200.00	134,400	72,872.06	145,744
N32-1.15-5057.00	7.5t overhead crane	2. lot	75.00	1.30	195.00	107.23	20,910	0.00	0	0.00	0	55,680.00	111,360	66,135.12	132,270
N32-1.15-5058.00	piping	2. lot	275.00	1.30	715.00	107.23	76,671	14,400.00	28,800	10.56	21	4,800.00	9,600	57,546.00	115,092
N32-1.15-5059.00	HVAC and building services icdg lighting	2. lot	200.00	1.30	520.00	107.23	55,761	23,040.00	46,080	2.64	5	1,111.98	2,224	52,034.94	104,070
N32-1.15-5060.00	Fire protection (extinguishers only)	2. lot	40.00	1.30	104.00	107.23	11,152	2,400.00	4,800	3,360.00	6,720	0.00	0	11,336.06	22,672
N32-1.15-5061.00	Control and Instrumentation, includes PLC	2. lot	200.00	1.30	520.00	107.23	55,761	7,200.00	14,400	144.00	288	28,800.00	57,600	64,024.32	128,049
N32-1.15-5062.00	25 kV Powerline Terminations only(Fused LB Switch, LA, Cable)	2. lot	68.87	1.30	179.05	107.23	19,200	17,280.00	34,560	14,400.00	28,800	0.00	0	41,280.00	82,560
N32-1.15-5063.00	Transformers (Including Grounding Resistors)	2. lot	125.00	1.30	325.00	107.23	34,850	51,264.00	102,528	11,184.00	22,368	290,495.99	580,992	370,369.19	740,738
N32-1.15-5064.00	Bus/Cable Duct from Transformer Secondaries	2. lot	75.00	1.30	195.00	107.23	20,910	11,520.00	23,040	19.20	38	0.00	0	21,994.32	43,989

Area-Sec-Seq	Description	Qty	Labour Unit Mhr	Prod. Factor	Labour Manhour	Labour Rate	Labour Cost	Material Unit Cost	Material Cost	Const Eqt Unit Cost	Const Eqt Cost	Process Eqpt Unit Cost	Process Eqpt Cost	Total Unit Cost	Total Cost (USD)
N32-1.15-5065.00	4kV MCCs c/w Starters	2. lot	80.00	1.30	208.00	107.23	22,304	2,400.00	4,800	960.00	1,920	18,240.00	36,480	32,752.13	65,504
N32-1.15-5066.00	Cable, Tray & Grounding	2. lot	175.00	1.30	455.00	107.23	48,791	24,000.00	48,000	2,880.00	5,760	6,720.00	13,440	57,995.28	115,991
N32-1.15-5067.00	Terminations	2. lot	130.00	1.30	338.00	107.23	36,244	3,360.00	6,720	960.00	1,920	0.00	0	22,442.21	44,884
N32-1.15-5068.00	Transformer & 600 V MCC (For aux. loads, Includes HVAC)	2. lot	70.00	1.30	182.00	107.23	19,516	9,984.00	19,968	1,536.00	3,072	16,320.00	32,640	37,598.11	75,196
N32-1.15-5069.00	Misc starters & control stations	2. lot	45.00	1.30	117.00	107.23	12,546	9,120.00	18,240	4,320.00	8,640	6,720.00	13,440	26,433.07	52,866
	N32 - Slurry Pipeline Energy Recovery Plant Subtotal				8,818.33		945,607		778,606		118,011		1,622,564		3,464,788

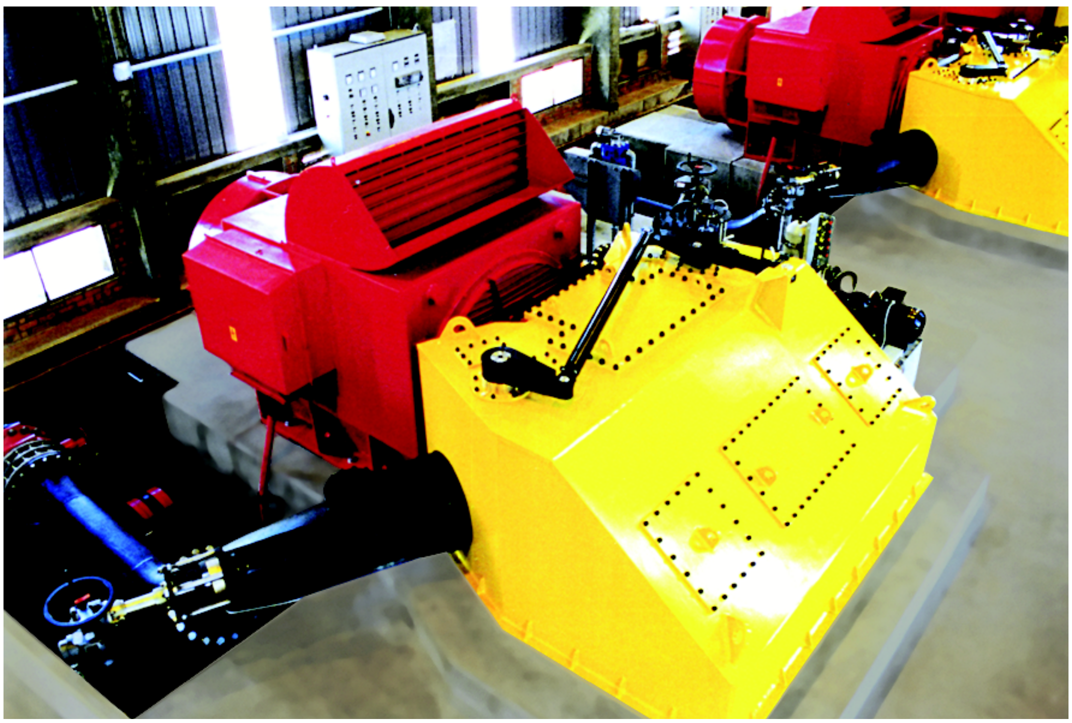
N33 - Water Treatment Energy Recovery Plant

Area-Sec-Seq	Description	Qty	Labour Unit Mhr	Prod. Factor	Labour Manhour	Labour Rate	Labour Cost	Material Unit Cost	Material Cost	Const Eqt Unit Cost	Const Eqt Cost	Process Eqpt Unit Cost	Process Eqpt Cost	Total Unit Cost	Total Cost (USD)
N33-1.15-5071.00	Detailed excavation and backfill	400. m3	0.10	1.00	40.00	107.52	4,301	0.00	0	3.36	1,344	0.00	0	14.11	5,645
N33-1.15-5072.00	Foundations	220. m3	9.00	1.00	1,980.00	107.52	212,890	600.00	132,000	24.00	5,280	0.00	0	1,591.68	350,170
N33-1.15-5073.00	Pre-engineering building with services H&V, lighting, fire alarm system. 12 x 16 m	200. m2	0.00	1.00	0.00	107.52	0	2,976.00	595,200	0.00	0	0.00	0	2,976.00	595,200
N33-1.15-5074.00	7.5 tonne bridge crane c/w bus bars, safety switch, etc.	1. ea	100.00	1.00	100.00	107.52	10,752	1,632.00	1,632	0.00	0	44,160.00	44,160	56,544.00	56,544
N33-1.15-5075.00	Water turbine, Turgo impulse type, Up to 2500 kW, up to 1.7 cms, 133 to 146 m net heat, 201 m gross head withstand (no flow), 4160 volt synchronous generator	1. ea	500.00	1.00	500.00	107.52	53,760	4,800.00	4,800	4,800.00	4,800	1,306,799.97	1,306,800	1,370,159.97	1,370,160
N33-1.15-5076.00	Powerhouse manifold/local hydro piping	20. m	10.00	1.00	200.00	107.52	21,504	216.00	4,320	0.00	0	0.00	0	1,291.20	25,824
N33-1.15-5077.00	Hydraulic power unit (Equipment cost included with with turbine)	1. ea	100.00	1.00	100.00	107.52	10,752	0.00	0	0.00	0	0.00	0	10,752.00	10,752
N33-1.15-5078.00	TIV with bypass and actuator	1. ea	100.00	1.00	100.00	107.52	10,752	0.00	0	0.00	0	52,800.00	52,800	63,552.00	63,552
N33-1.15-5079.00	Allowance for by-pass orifice station	1. lot	200.00	1.00	200.00	107.52	21,504	0.00	0	0.00	0	48,000.00	48,000	69,504.00	69,504
N33-1.15-5080.00	5 kV switchgear, 800 Amp bus, incoming main breaker, generator breaker with integrated gen protective relays, main breaker and cell with fused switch and dry type 4160 -600 volt 45 kva station service transformer.	1. lot	250.00	1.00	250.00	107.52	26,880	4,800.00	4,800	0.00	0	126,720.00	126,720	158,400.00	158,400

WN BRAZIER ASSOCIATES INC.

SEABRIDGE GOLD INC.
KSM PROJECT

WATER TREATMENT PLANT
HYDRO GENERATION REPORT



Rev. A - March 3, 2010
Rev. 0 – March 12, 2010
Rev. 1 – March 26, 2010
Rev. 2 – June, 2012

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1.0 INTRODUCTION

1.1 General

The KSM water treatment plant provides an opportunity for hydroelectric generation as the water flows down from the water treatment storage dam to the treatment plant. This report evaluates the generation potential and provides a preliminary evaluation of the most appropriate plant capacity and includes basic design criteria for the proposed power plant.

This is a hydroelectric project making use of facilities otherwise required for the mine. This study only covers the generation plant. The supply pipe and other works are an integral part of the water storage facilities and the treatment plant and are not considered herein.

The installation will include a Turgo impulse or Francis reaction turbine that will be used to generate power from the water before it enters the treatment plant.

Water treatment plant information, including head and flow, has been provided by Klohn Crippen Berger Ltd. (KCBL).

1.2 Study Rationale

The purpose of this study, as part of the KSM prefeasibility study, is to select a configuration for the energy recovery equipment, calculate the power potential of the site, size and cost the major equipment, and determine the average annual MW.h of energy production and it's value.

As this energy recovery project is part of the process plant, there will be no water licensing requirements.

1.3 Reference Documentation

KCBL provided estimates of flow and head and reference data. See Appendix A.

1.4 Project Description

The water storage and treatment facility has been planned by KCBL. From their description in Section 18.1 of the KSM 2012 PFS update:

- The water storage dam (WSD) “will create the WSF pond, which will be large enough to handle seasonal freshet flows as well as volume accumulated from a 200-year wet year.”
- “Water in the WSF is predicted to be acidic, similar to existing water in Mitchell Creek.”
- “A high-density polyethylene (HDPE) lined steel penstock leads from the outlet of the low-level outlet pipelines to the energy recovery plant and WTP situated below the WSD.”
- “Data taken between 2007 and 2011 combined with regional long term records and water balance calculations indicate that during the various stages of mine life, the WTP will operate year round at a constant rate of 1.9 m^3/s to 2.6 m^3/s.”
- “The WTP also has additional capacity in the form of a spare clarifier and reactors provided to treat up to 3.3 m^3/s to manage system “upsets” that may occur due to natural hazards or extreme events.”

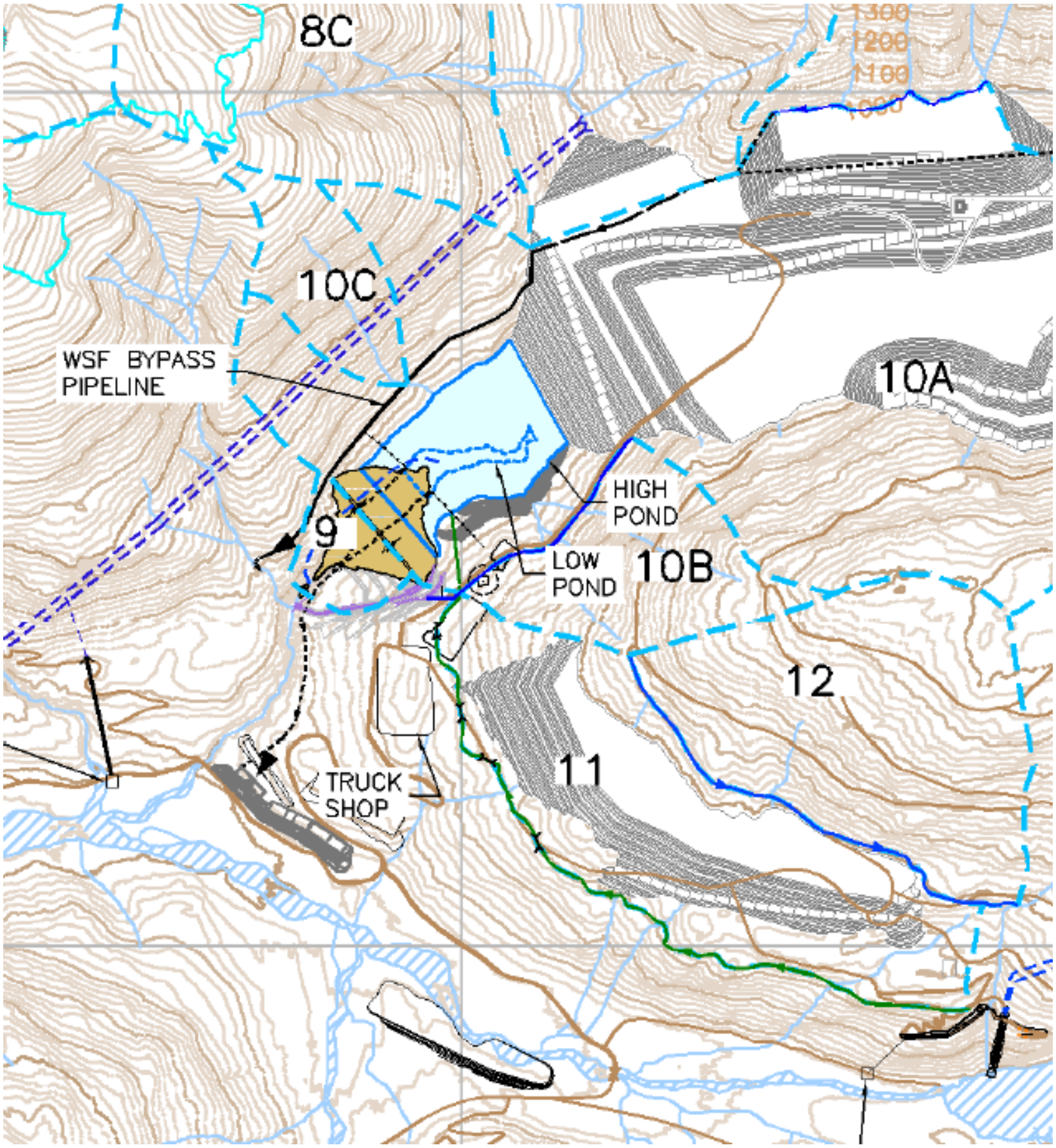
An energy recovery hydro turbine will recover the energy of the water flowing down from the water treatment storage pond through a 0.75 m (29.5 inch) internal diameter, HDPE lined 1360 m log pipeline to the water treatment plant (WTP). The energy recovery facility will consist of a hydro turbine at the end of the water supply conduit. Flow and heat are shown in Figure 2.3.1 in Section 2 herein. A 2,500 kW machine has been selected such that it has adequate capacity to pass flows up to 3 cubic metres per second (cms) without using a turbine bypass system. The bypass system is manually controlled and would normally be reserved for emergency operation. However, if the maximum plant flow of 3.3 cms is required, the manually controlled bypass would be opened.

KCBL has advised, in their April 2012 memorandum:

Analyses of pond water levels and flows resulting from base case diversion efficiencies yield the following conclusions:

- *The ultimate WSF Dam crest elevation required is 710 m.*
- *The maximum water treatment rate is 3.33 m3*
- *The pond will return to average water levels approximately 2 years after a wet year of 200 year return period (time required to treat a 200 year wet event).*
- *A total of 3.0 Bm3 of water will be treated during the 55 year operations phase.*
- *A total of 204 Mm^3 of water will be treated during the 5 year Mine Site initial closure phase.*
- *A total of 204 Mm^3 of water will be treated during the 5 year Mine Site initial closure phase.*
- *A total of 54 Mm^3 of water will be treated annually after closure.*
- *The untreated water will have a pH that may be similar to existing stream water quality and is likely to be acidic.*
- *The Water Treatment plant energy recovery facility would be at 495m.*

Figure 1.4.1 Water Treatment Plant Location (From KCBL Years - 2 to 10)



2.0 EXECUTIVE SUMMARY

2.1 Data

Project highlights (Base Case):

Pipe Size: 32 inch O.D, steel pipe, 0.5 inch wall, with HDPE liner, 29.5 inch I.D. (0.75 m).

Flow (as per KCBL): See Table 2.3.1

Gross Head:	Varies, see Clause 1.4 above and Table 2.3.1. (The pond level varies with the season)
Net Head:	Varies from 107.3 to 110.54 m per Table 2.3.1.
Penstock (pipe) length:	1360 m
Mine Average Treatment Flow:	1.72 m^3/s during operations.
Maximum Treatment (Flow) Rate:	3.3 m^3/s
Turbine Type:	Turgo impulse or Francis reaction turbine.

2.2 Generation And Revenue

Installed capacity (turbine and generator):	2500 kW
Generator:	2,500 kW, 4160 V, 3 ph, 60 Hz, 0.85 PF
Annual generation:	14.639 MW.h/a average years 1-10
(An allowance has been made for operation, maintenance and down-time.)	
Electricity sale price:	7.36 cents Canadian per kW.h (BC Hydro tier 2 energy cost)
Operating cost (O&M):	1.0 cent per kW.h.
Annual net sales value of generation:	C$931,058 per annum years 1 – 10 (Based on 2012 C dollars)

2.3 Plant Output

Plant operation is summarized in the table below, based on flow data from KCBL.

Figure 2.3.1 Annual Generation

WATER TREATMENT PLANT HYDRO GENERATION									
Penstock	1360.0	m (LG)		PIPE I.D.	29.5	inch	0.749 m	(ID)	
Availability	0.980 (Steady)	AV		Friction Factor	150 (HDPE)	(FFC)			
						TURBINE & GENERATOR			
Plant EL.	495	m (PEL)		Power Price	0.0736	/kW.h (PP)	0.010	$/kW.h (O&M)	
YEAR	**AVERAGE FLOW, CMS**	**AVE. EL.**	**GROSS HEAD**	**HEAD LOSS, m**	**NET HEAD, m**	**TURBINE EFFICIENCY**	**MW OUTPUT**	**ANNUAL NET MW.h**	**ANNUAL VALUE $**
0	1.89	620.4	125.4	18.08	107.32	0.84	1.67	14,349	$912,576
1	1.93	621.6	126.6	18.80	107.80	0.84	1.71	14,719	$936,107
2	1.93	621.6	126.6	18.80	107.80	0.84	1.71	14,719	$936,107
3	1.92	621.8	126.8	18.62	108.18	0.84	1.71	14,694	$934,538
4	1.92	621.6	126.6	18.62	107.98	0.84	1.71	14,667	$932,810
5	1.92	622.0	127.0	18.62	108.38	0.84	1.71	14,721	$936,265
6	1.90	621.4	126.4	18.26	108.14	0.84	1.69	14,535	$924,437
7	1.90	621.3	126.3	18.26	108.04	0.84	1.69	14,522	$923,582
8	1.89	621.8	126.8	18.08	108.72	0.84	1.69	14,536	$924,481
9	1.90	621.6	126.6	18.26	108.34	0.84	1.70	14,562	$926,146
10	1.93	621.6	126.6	18.80	107.80	0.84	1.71	14,719	$936,107
11	1.95	622.2	127.2	19.16	108.04	0.84	1.74	14,904	$947,896
12	1.98	622.7	127.7	19.71	107.99	0.84	1.76	15,126	$962,044
13	2.01	623.4	128.4	20.26	108.14	0.84	1.79	15,376	$977,923
14	2.01	623.4	128.4	20.26	108.14	0.84	1.79	15,376	$977,923
15	2.04	623.9	128.9	20.83	108.07	0.84	1.82	15,597	$991,941
16	2.03	624.3	129.3	20.64	108.66	0.84	1.82	15,605	$992,453
17	2.05	625.0	130.0	21.02	108.98	0.84	1.84	15,805	$1,005,203
18	2.04	624.6	129.6	20.83	108.77	0.84	1.83	15,698	$998,365
19	2.03	624.9	129.9	20.64	109.26	0.84	1.83	15,691	$997,933
20	2.02	625.1	130.1	20.45	109.65	0.84	1.83	15,669	$996,540
21	2.05	625.7	130.7	21.02	109.68	0.84	1.85	15,907	$1,011,659
22	2.04	625.3	130.3	20.83	109.47	0.84	1.84	15,799	$1,004,790
23	2.05	625.5	130.5	21.02	109.48	0.84	1.85	15,878	$1,009,815
24	2.07	626.3	131.3	21.40	109.90	0.84	1.87	16,094	$1,023,570
25	2.10	627.0	132.0	21.97	110.03	0.84	1.90	16,345	$1,039,565
26	2.11	627.1	132.1	22.17	109.93	0.84	1.91	16,409	$1,043,623
27	2.13	627.7	132.7	22.56	110.14	0.84	1.93	16,596	$1,055,525
28	2.10	627.3	132.3	21.97	110.33	0.84	1.91	16,390	$1,042,399
29	2.12	627.9	132.9	22.36	110.54	0.84	1.93	16,578	$1,054,342
30	2.09	627.0	132.0	21.78	110.22	0.84	1.90	16,296	$1,036,431

NOTES
1) The annual net MW.h is calculated taking into account the plant availability.
2) Pond elevations and flows provided by KCBL.
3) The power sale price in this case is taken as the BC Hydro rate schedule 1823 tier 2 energy cost.
4) The value of generation is calculated as the sale price minus O&M costs.

2.4 Capital Cost

Plant total Capital Cost: C$4,334,570

The above cost is less contingency and Owner's costs. For details refer to Appendix C herewith.

3.0 HYDROLOGY

3.1 Flow

As water treatment plant flow is a steady process plant flow, the flow duration curve for each year consists of nearly straight sections so is not really applicable.

The factor that is widely variable in this installation is the operating head. The storage dam level varies with the season. However, for energy calculations the average annual flows and heads in Table 2.3.1 have been used based on data from KCBL.

3.2 Water Quality

The water is expected to be sediment free, as it is from a storage dam.

KCBL has advised the untreated water may have a pH that may be similar to the existing stream water quality in the valley and is likely to be acidic.

Impulse machines are readily available with stainless steel runners and spear valve assemblies, whereas other components would normally be steel or cast iron/steel. A proposal has also been received for a Francis (reaction) turbine of all stainless steel construction.

4.0 MACHINE CAPACITY SELECTION

4.1 General

The generation equipment sizing for the energy recovery project is based on the installation of a machine that can handle a treatment (flow) rate of 3.0 m3/s. If the flow increases to the maximum treatment rate of 3.3 m3/s then the manually controlled bypass valve (with orifice pressure reducing station) would be opened. (If the turbine cannot flow enough water, it's not simply a shortfall in generation that results, some other method such as a by-pass pressure reducing valve would be required to handle the required flow to the treatment plant.)

To allow continued flow to the treatment plant if the turbine is out of service, the manual by pass valve and orifice station will be opened. An automatic bypass system could be provided, but at much higher cost.

4.2 Head Loss Calculations

The spreadsheet calculations are based on head loss through the HDPE lined steel pipe as determined by the Hazen –Williams formula. A Hazen Williams friction factor C of 150 has been used (for the HDPE lined pipe).

4.3 Power Calculations

Power calculations have been based on the use of a Turgo impulse or Francis reaction turbine operating at the specified steady flow, for a percentage of time equal to the hydro plant availability. After actual machine selection these calculations would, of course, have to be revised as efficiencies will vary somewhat (the Francis turbine option would be expected to have a slightly higher output due to higher efficiency).

The following standard calculation is embedded in the spreadsheet in Appendix A.

Power, P= Q x Hd x Ec x 9.81 x s.g. Kilowatts (kW)

Which is metric format where:
P = Power at the generator terminals, in kilowatts (kW).
Q = Flow in pipeline, in cubic metres per second (m3/s).
H = The net head in metres (m)
9.81 = The acceleration of gravity
s.g. = 1
Ec = Combined turbine and generator efficiency

It has been assumed the water has a specific gravity of 1.

4.4 Value Of Generated Energy

The energy output for the normal flow conditions was calculated via the spreadsheet. The water treatment plant flow is expected to be almost continuous, but a certain amount of hydro turbine downtime is expected, both scheduled and unscheduled downtime for routine maintenance. However, turbine and generator maintenance, for an installation such as this, is judged to be a relatively infrequent and, on average, a low cost exercise.

In the economic evaluation, an allowance has been made (subtracted from revenues) for both power plant operation and maintenance costs and to account for down time and thus lost power production. See Section 2.0 herein.

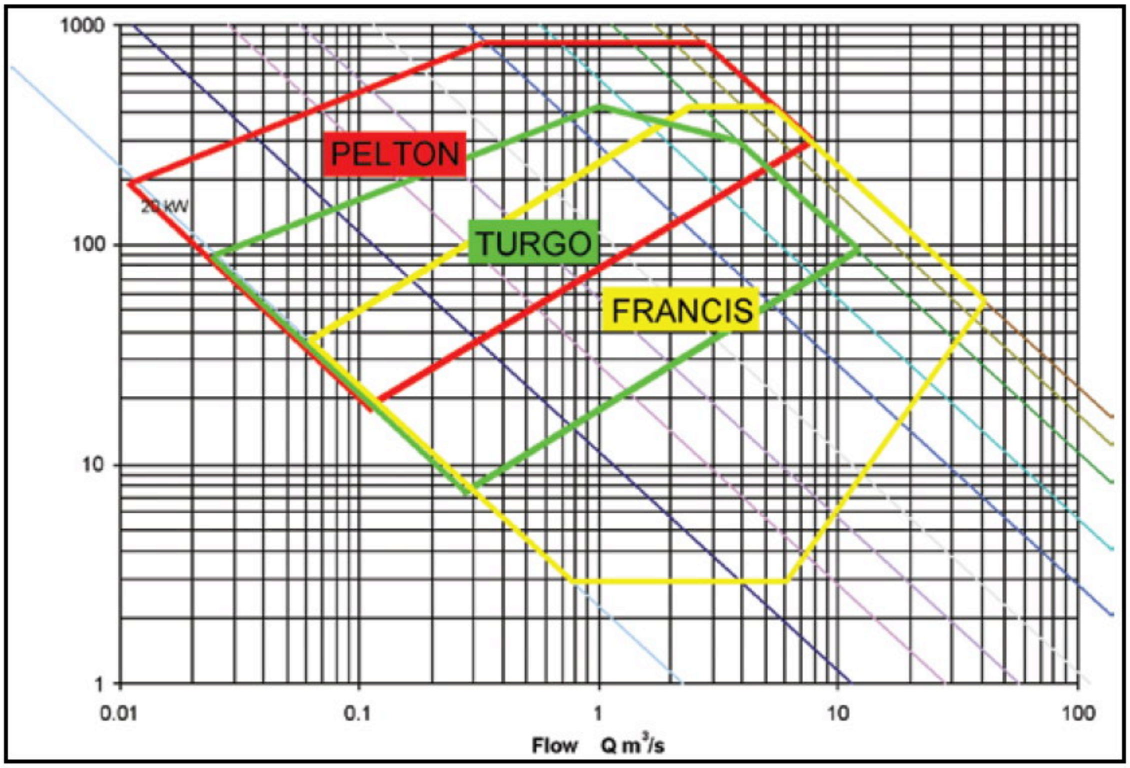
5.0 MACHINE SELECTION

5.1 General

Hydro turbine selection is generally based on its suitability relative to the available head and flow conditions for a project. The chart below from Gilkes shows typical machine selection parameters.

In this case, the governing factors are the acidic (corrosive) water and the highly variable head, due to seasonal pond level variations.

Figure 5.1.1 Turbine Operating Ranges



The above chart shows the typical best operating range of several types of turbines.

From a hydro plant perspective this installation is somewhat unusual in that the head is so variable. The gross head can vary considerably and this wide range in head means a Pelton turbine is not technically suitable.

A Turgo impulse turbine may be suitable for this application as for the same power as a Pelton the Turgo runner is one half the diameter of the Pelton runner, and so twice the specific speed and thus a higher speed and less costly generator can be used. The Turgo, for a given size, can handle a greater water flow than the Pelton because exiting water doesn't interfere with adjacent buckets. A Turgo would have similar issues as a Pelton with regards to variable head. As an impulse turbine it is less sensitive to arenaceous water and water with high debris content. It is thus often the preferred turbine type for applications with highly variable flows and water with significant contamination. A twin jet Turgo would be a better choice than a single jet unit as it could handle the large maximum treatment rates of 3.3 cms while still exhibiting good efficiency at the normal flows in the range of 2 cms. The alternative to a Tugo or Pelton impulse turbine is a Francis turbine. Francis turbines can handle the wide variation in operating head, but there is a cost issue in having a machine fabricated entirely of stainless steel. Another issue with a Francis turbine is that due to the nature of such units, system surge pressure may be greater. Francis turbines cannot have jet deflectors to prevent runaway on sudden 100% load rejection and they do have wicket gates that, due to mechanical failures, can slam shut suddenly and cause penstock pressure surges.

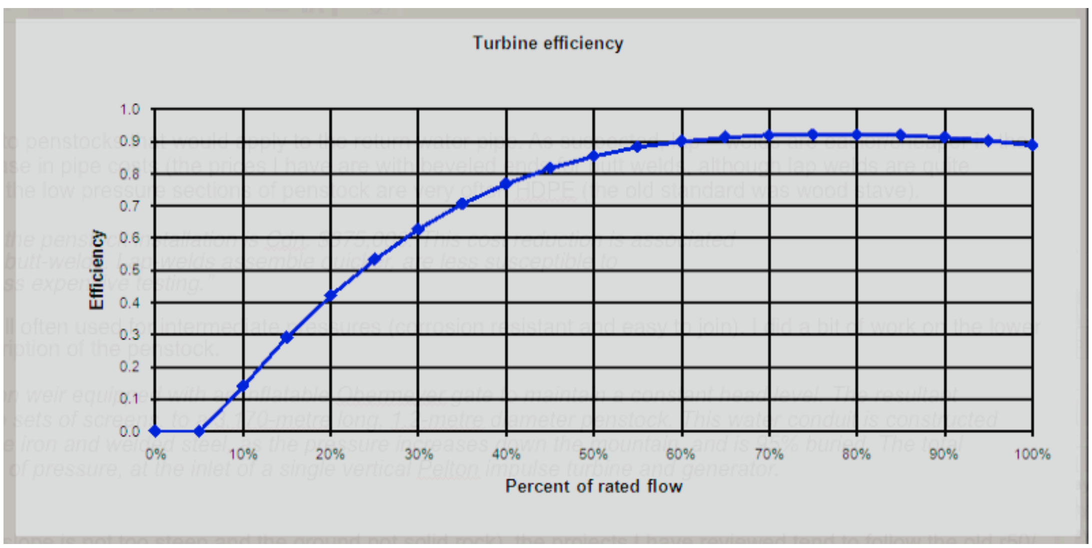
If it turns out the unit was to be a Francis turbine (as a result of the final RFQs), the penstock (supply pipe) rating may have to be reevaluated or a surge relief valve or tank may have to be added.

If the unit is a (twin jet) Turgo impulse turbine, it would be of the horizontal type. Similarly, if the turbine is a Francis unit, it would also be horizontal mount in this small size range.

5.2 Turbine Efficiency

In this application it is believed that proposals will show that a Francis turbine probably has significantly higher efficiency for this variable head application, but its total installed cost will probably be considerably higher than a Turgo, especially if surge control facilities have to be added.

Figure 5.2.1 Typical Francis Turbine Efficiency



For a installation with relatively fixed flow, a Francis turbine will have significantly higher efficiency than a Turgo. On the other hand, in this case with widely varying head, the Francis turbine will have to be designed to work over a wide rage and the efficiency will of necessity be lower than the typical sown above. It's seen that a Francis turbine is at a disadvantage when flows vary (not the case here) and in reality a Francis machine is rarely operated at less than 25% to 30% of rated flow as operation will become unstable.

5.3 Generator

The generators will be rated:

- Generator KW: to match maximum turbine output.
- Generator phase/voltage: 3 phase, 60 Hz, 4160 volts.
- Generator type: Synchronous generator with rotating exciter.
- Generator Power factor (P.F.): 0.85

- Generator stator insulation: Design B temperature rise, Class F insulation, form wound.

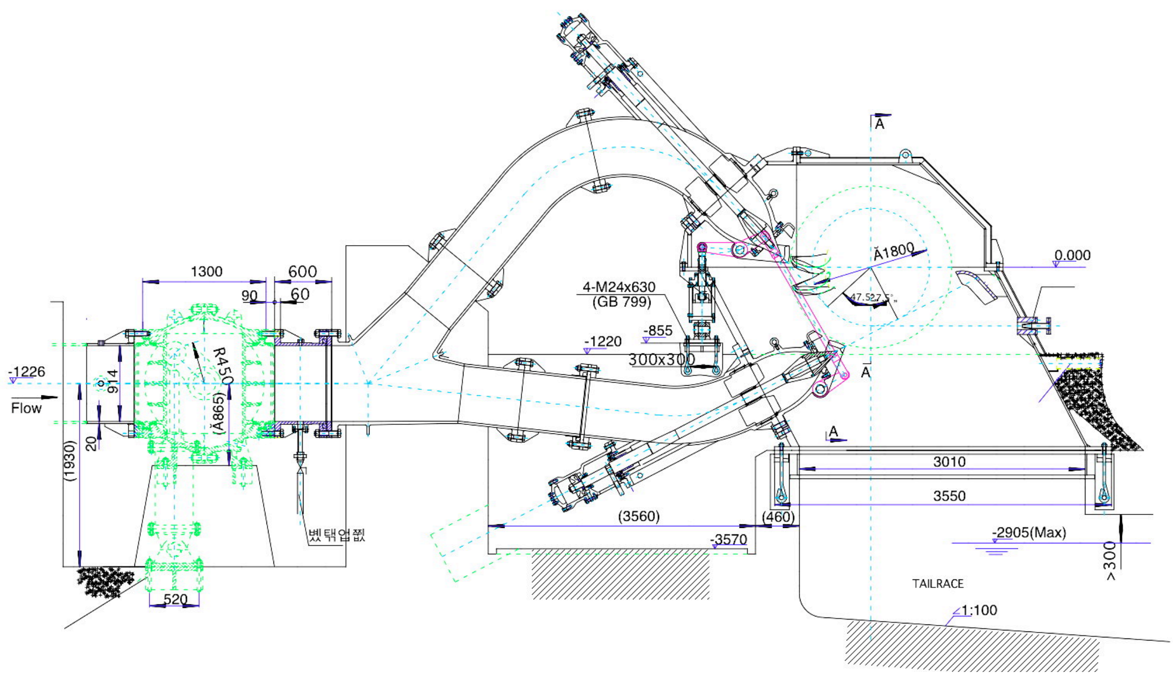
5.4 Alternate Machine Configurations

An impulse turbine has several advantages including (a) easier to obtain a corrosion resistant machine, less water hammer concerns, easier maintenance, etc. Because the operating head is only in the medium range, a two-jet Turgo may be suitable. A Francis machine would be slightly more efficient, but considerably more costly, harder to obtain a corrosion resistant machine, maintenance is more complex, and surge (water hammer) issues are more problematic.

5.5 Installation

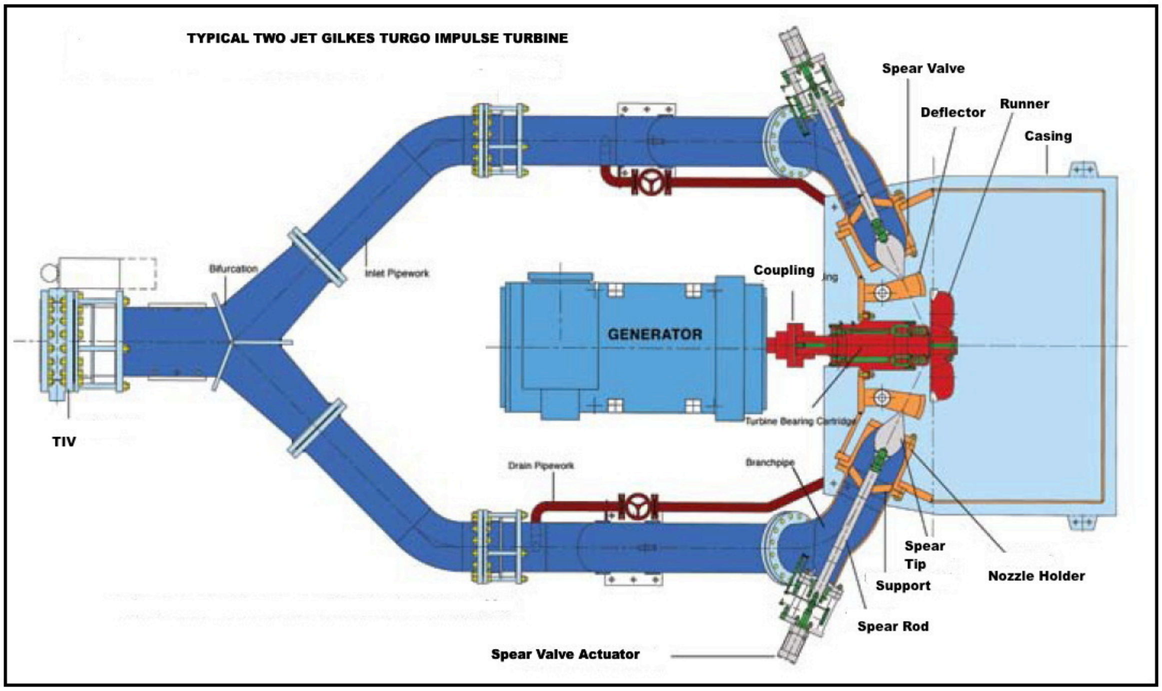
The machine will be a small Turgo or Francis horizontal machine. Both only require relatively simple concrete foundations.

Figure 5.5.1 Typical Twin Jet Horizontal Impulse Turbine Installation



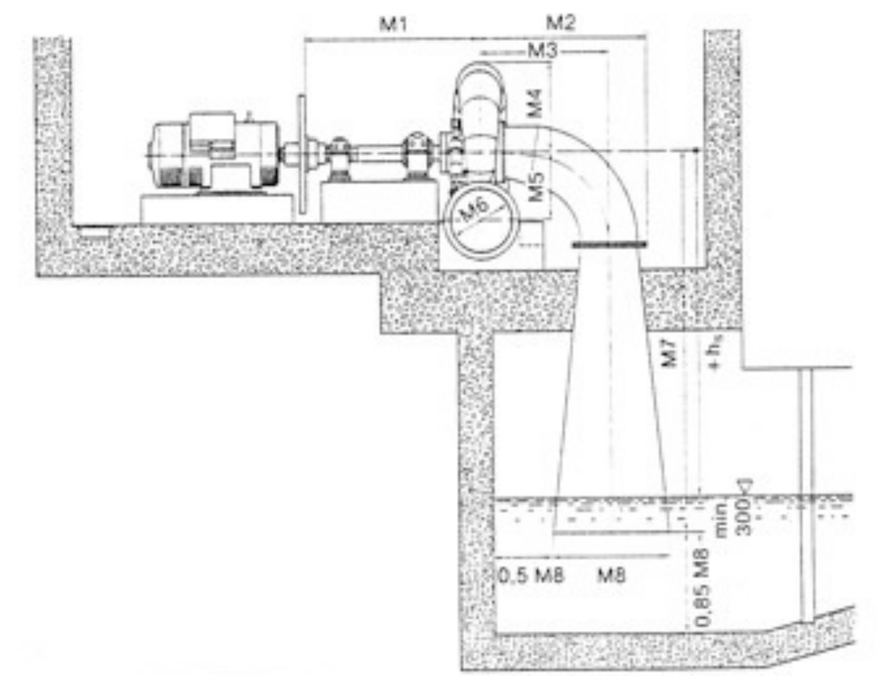
Turgo turbines are also manufactured with piping and jets in a horizontal configuration as shown below.

Figure 5.5.2 Alternate Turgo Configuration With Horizontal Bifurcation



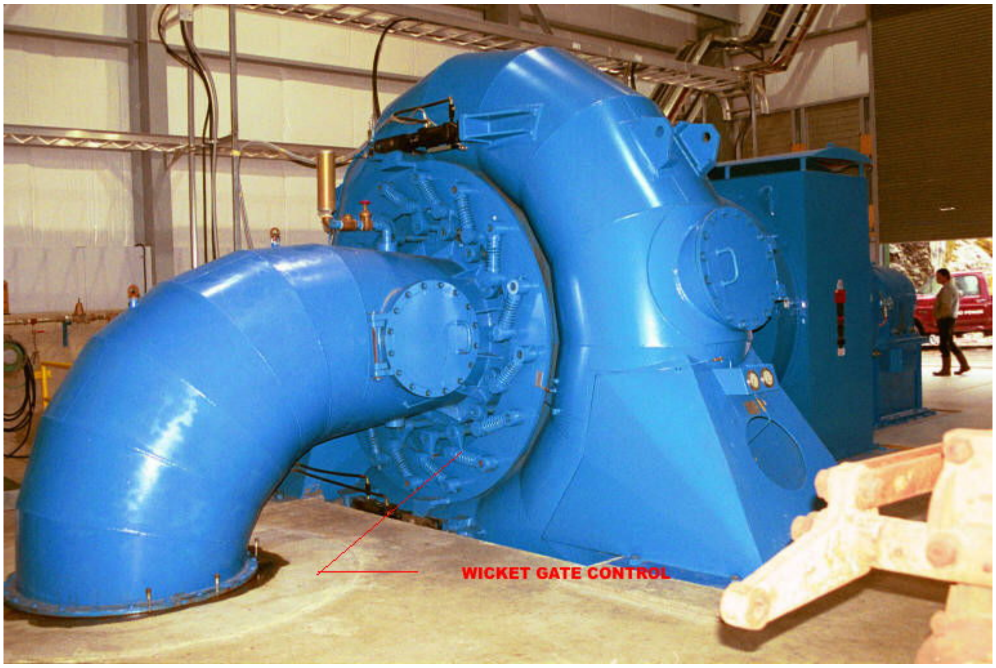
The free flowing water from the runner of an impulse turbine will be directed by a channel to the water treatment plant. If the machine is a Francis turbine, there will be a draft tube extending into the tailrace channel.

Figure 5.5.3 Typical Small Horizontal Francis Turbine Installation



The below photo of a horizontal Francis turbine (Brown Lake Plant) shows a unit that is about 3 times larger than the one in question, but otherwise the installation would be the same as a Francis turbine if used in this plant. Note the runner is overhung on the end of the generator shaft and has no separate bearings.

Figure 5.5.4 Photo Of Typical Francis Turbine (Larger than the proposed unit)



5.6 TIV

At the station operating pressure, standard turbine inlet valves (TIVs) are available. One option is the use of a butterfly valves, but at this head spherical valves are preferable. They should be equipped with a double cylinder hydraulic operator, cast or fabricated steel valve body with forged steel flanges, stainless steel shaft, trunnion bearings, and double retractable seals. A small, actuated, bypass valve will be provided, permitting equalized pressure on both sides of the spherical valve before opening.

Emergency TIV closing will be fail-safe via the typical large counterweights. The system actuator will have an integral orifice that will prevent too rapid closing, even if a hydraulic line ruptures.

Actually two TIVs will be required, one for the turbine and one for the water by-pass pressure reducing orifice station.

5.7 By-pass Orifice Station

If the turbine is out of service, the water will be by-passed through a pressure reducing orifice station to ensure supply to the water treatment plant.

6.0 PENSTOCK (SUPPLY PIPE)

6.1 General

Pipe details have been provided by Wardrop Engineering. Details include:

- 1360 m long.
- 32 inch O.D. steel pipe, 0.5 inch wall, HDPE liner, 29.5 inch I.D.
- Supplied in 20 ft flanged lengths.
- 150 # slip-on flanges (these have been questions by the author of this report).

The pipe with 0.5 inch wall is adequate for the static head, based on standard penstock design criteria, and can withstand the normal design surge levels. However, the ratings of the 150 pound flanges are low in the judgment of this writer. The pipe could be "graded" with upper sections thinner wall or simply HPDE.

When the actual turbine is selected, a detailed transient analysis will be required (planned to be by the water-to-wire equipment supplier). A surge tank or pressure relief valve may be required if a Francis turbine is used.

6.2 Surge Tower Or Pressure Relief Valves

If a Turgo machine is used, with jet deflectors, a penstock surge tower, restricted orifice surge tank, or pressure relief valve would not be required for this particular installation. This follows a common rule of thumb for surge tank or pressure relief valve application, which is that they are primarily required in "isolated" developments and/or where Francis units are used in the power plant. An explanation follows:

The impact of excessive water hammer is, of course, penstock or turbine failure. Water hammer in hydropower plants is the consequence of sudden flow changes that may be caused by:

- Turbine start-up and stop, rapid load acceptance and load reduction,
- Load rejection under governor control, caused by system faults such as transmission line failure, etc.
- Emergency turbine shut-down or incipient machine runaway and subsequent trip.
- Rapid governor action, as could be required of a small plant feeding an isolated load, and rapid closure and opening of safety valves, in particular the turbine inlet valve (TIV).

A discussion of the above issues follows:

- As the plant generation will be interconnected with a utility, BC Hydro, where the generation is literally thousands of times greater than the machine in question, rapid governor response is of no benefit, so machines can be loaded and unloaded at rates slow enough to ensure that penstock water surges are not generated.
- Load rejection of a turbine unit is the most frequent transient regime. When the turbine generator is disconnected from the electrical grid there is a

sudden loss of load and therefore water flow must be interrupted to avoid machine runaway. For a Turgo machine this would, for a basic installation, mean closure of the water inlet (spear) valves. (However, most Turgos have jet deflectors as per blow.)

- With a Turgo turbine, sudden load rejection is normally handled by jet deflectors bypassing the water around the runner, thus rapid flow reductions are not required and the spear valve can close at a suitably slow rate.
- Rapid governor response would be of no advantage to the system, so governor response would be set for slow action, hence no water hammer would be generated. (The spear valve actuator would also be selected so that rapid movement is impossible.)

In summary, in the case where a Turgo impulse machine is being used, the water control spear valve operating mechanism will be equipped with a control actuator that inherently cannot operate very fast, then even in the event of control system problem, the controls cannot possibly cause the water flow to change at a rate fast enough to cause water hammer. The same would also be true of the main (TIV) valve operation.

With no surge tower or pressure relief vales, the result will be a design with a relatively long needle valve opening and closing time. This will be too long for units operating in an isolated mode, but in the this case when operating in parallel with the utility, it's not an issue. Note, due to the very slow opening, synchronizing of the units may have to be accomplished by use of the jet deflectors. This is not an issue as long as the requirement is included in the equipment specifications and as long as governor action is not attempted by use of jet deflectors (which is an invitation for disaster).

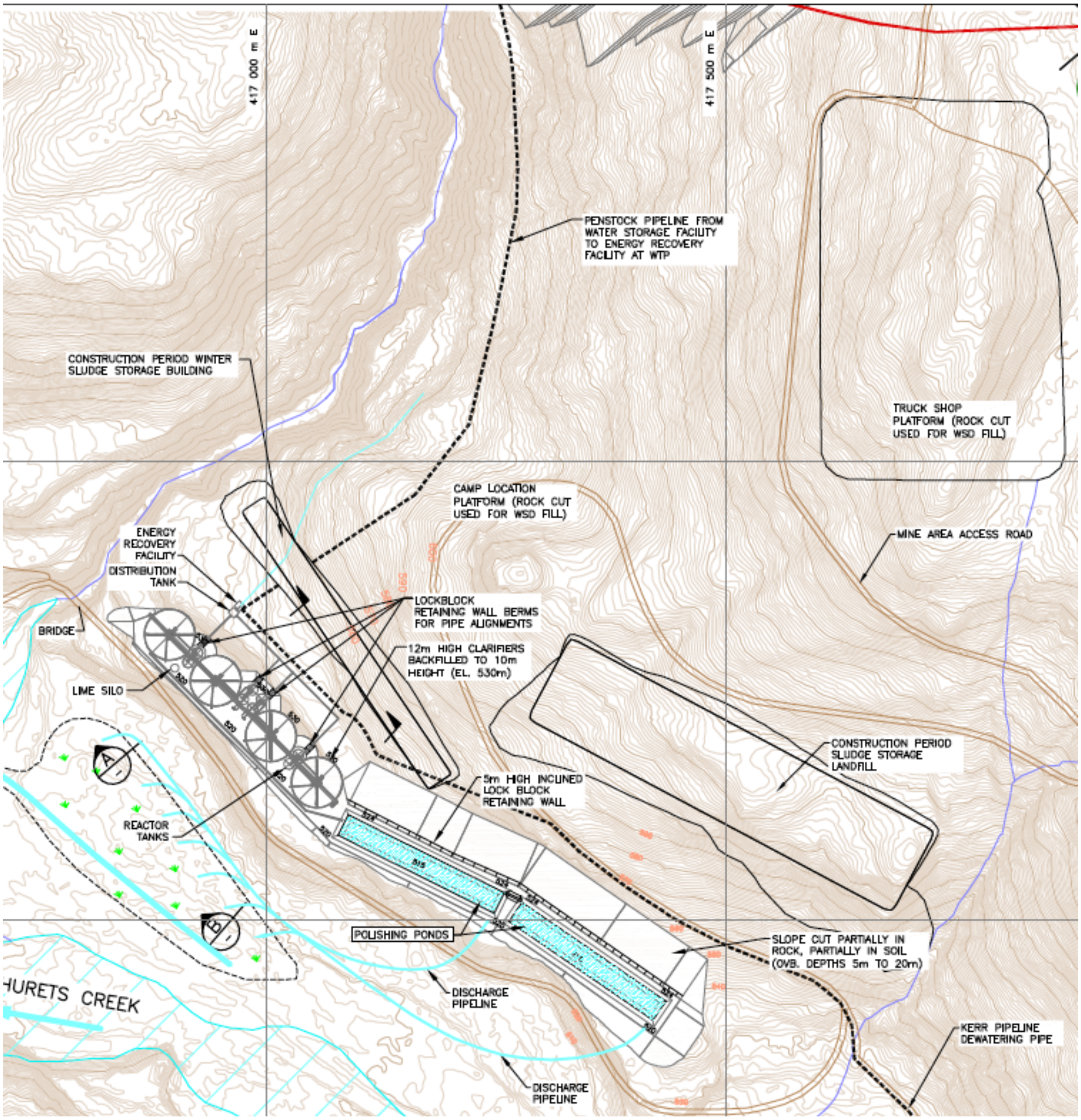
Also, the main turbine shutoff valve (TIV) that is normally closed by a counterweight, will have a hydraulic orifice that in this case will be sized so that the TIV cannot close suddenly.

However, if the final selection is a Francis unit, surge protection may be required. A detailed transient study, which would be specified as part of the "water-to-wire" package, would confirm requirements (see clause below).

6.3 Supply Pipe (Penstock) Route

The supply pipe route is a shown in the following figure (copied from KCBL drawing "Lower Mitchell Water Management Concept.")

Figure 6.3.1 Location Map (From KCBL Drawing D-4207 Rev. A)



6.4 Transient Analysis

Independent specialist consultants that specialize in transient studies could perform a detailed system analysis as part of the final plant design. Alternatively, as planned for this project, the penstock transient analysis can be included as a vendor responsibility in the water-to-wire equipment package. This usually ensures a competitive price for this work and the work can conveniently include the mechanical transient analysis of the turbine generator assembly together with the water conduit study. As these are interrelated subjects and the machine details are well known by

the turbine vendor, a combined approach is efficient and places all of the responsibility with one party.
The results of the water hammer analysis would be the definition of the minimum permissible closing and opening time of the water control of the hydraulic machines (spear valve speed in the case of a Turgo or wicket gate operating speed in the case of a Francis turbine) and main valve closing speed (TIV), to limit pressure surges to small values and to ensure there is no water column separation. Otherwise penstock pressure control (surge tank or pressure relief valve) will be required. Note, even with slow actuator response, and turbine generator lube systems designed to handle run-away speeds, there are still surge pressure issues with Francis turbines, as mechanical failure of the wicket gate mechanism can lead to sudden closure and the generation of significant water hammer. Note, in both the case of a Turgo or a Francis machine, water flow control is a function of governor settings, but the selection of the mechanical actuator operating speed can limit the maximum change in water flow, even if the governor fails. However, in the case of a Francis turbine, the relatively complex wicket gate operating mechanisms have been known to fail, causing sudden water flow shut-off.

The hydro machines (turbines and generators) will be specified to withstand the effects of full runaway speed for a short time. This includes withstand of centrifugal forces plus maintenance of adequate bearing lubrication, usually by use of DC battery powered emergency lube pumps.

To prevent runaway damage, the turbines would be equipped with back-up over speed switches, as is standard practice. If the Pelton/Turgo turbine deflectors fail to work and then the spear valves failed to close, the third back-up activated by the over speed switch would be to close the TIV.

For the purposes of the prefeasibility study, a simple transient analysis has been carried out. It indicates valve closure times must be long (in the order of 100 seconds) to keep transient pressures within the capability of the pipe. This study identified the maximum surge pressure that would be seen at the powerhouse. As this surge travels up the penstock it will decease somewhat in magnitude. However, for this preliminary study it was assumed that the full wave magnitude would be imposed on top of the static head, this being a worst-case conservative approach, used pending more detailed calculations.

6.5 Penstock Diameter And Wall Thickness

The supply pipe is part of the water treatment plant and the design is by others.

It has been advised that the supply pipe is 32 inch O.D. with a 0.5 inch wall thickness and it will have a HPDE liner with a 29.5 inch I.D.

The use of 150 pound slip-on flanges has been proposed. This author has questioned the suitability, in particular to withstand the surge pressure and this is being checked (by others).

It is noted that the penstock wall thickness could be graded, with the use of 3/8 (0.375) inch pipe in the upper section. In addition to evaluating the static pressure along the route, a detailed surge analysis would be required to determine the point where the wall thickness can be reduced.

6.6 Penstock Installation

The penstock is part of the water treatment plant design, by others.

6.7 Air Relief Valves

If the penstock does not have a constant downhill grade, air relief valves are required at all the high spots to allow escape of air. As air relief valves are a maintenance problem isolating gate vales and redundant air valves should be allowed for to facilitate convenient overhaul.

6.8 Leak Detection

Although penstock leaks and failures are rare, detection systems are often requested. Rather than attempting the implementation of an accurate (and costly) differential flow monitoring scheme, leaks can reliably be detected by installation of a simple (and low cost) pressure transmitter on the powerhouse manifold and having the turbine programmable logic controller (PLC) software compare the manifold pressure with what it should be based on generator output, which is, once calibrated, a very accurate indicator of flow. The turbine (and hence penstock) flow will normally have a corresponding head loss (and hence power station pressure reading), any deviation from the norm may be flagged as a problem, typically a penstock leak or equipment failure.

6.9 Cathodic Protection

The penstock (supply pipe) should have an impressed cathodic protection system and thus insulating flanges are to be installed at the powerhouse.

7.0 INTAKE

7.1 General

No information has been provided to date. It is unknown whether there is provision for remote automatic shut-off.

8.0 POWER PLANT DESIGN AND CONSTRUCTION

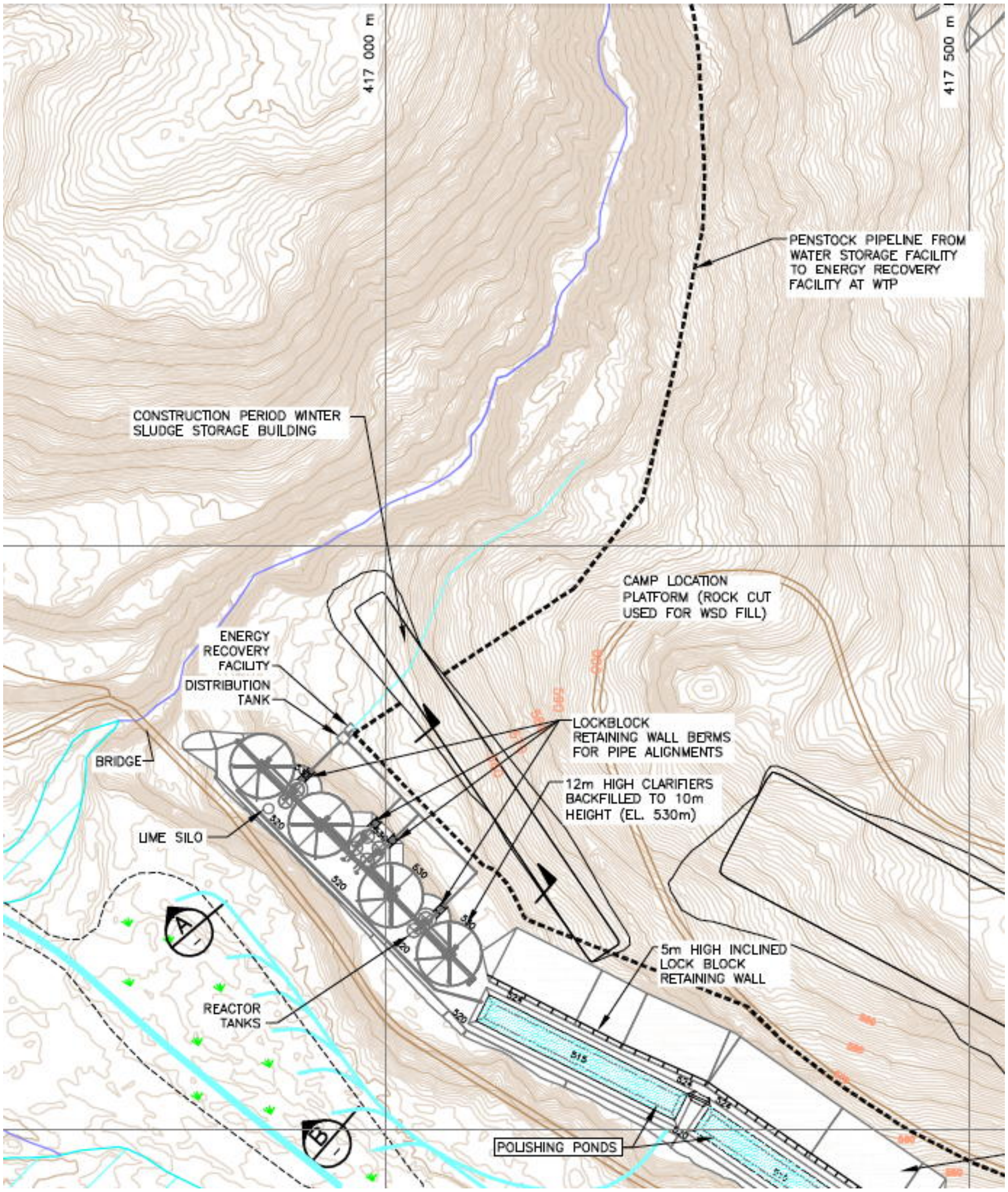
8.1 General

The power plant design and procurement would follow the current industry practice in British Columbia and elsewhere:

- The mechanical electrical turbine, generator, switchgear and controls would be subject to a detailed prescriptive specification covering design and supply. Installation is often requested as a supplemental price.

- The civil works, penstock, building and building services would be designed and constructed separately following conventional principles.

Figure 8.1 – 1 Plant Plot Plan (Form KCBL Drawing 4207)



8.2 Power House Building

The powerhouse building will be a small pre-engineered, insulated, steel structure. The structure will house the inlet valves, turbine and generator, lubrication and hydraulic systems, cooling system, switchgear, and a control / electrical room. Building heating and ventilating equipment will be provided to discharge the heat from the air cooled generators and provide heating in the winter when generator output (and waste heat) is low or non-existent.

The powerhouse will be located on the machine reinforced concrete foundation.

A small 7.5 tonne powerhouse bridge crane or monorail would be included.

8.3 Geohazards

As per the BGG Geohazard Report, Appendix A, Avalanches, has no specific warnings for the water treatment plant area.

9.0 POWER PLANT CONTROLS

9.1 Automatic PLC Control

The power plant will be designed for automatic PLC control, with no operators required. Within the power house, basic panel mounted hard-wired manual controls would be provided, plus there would be a flat screen, PC based, operator interface (HMI) that would allow monitoring and/or plant control and would also provide system alarms. Communication provision would also be made to allow a remote HMI at the mill site. (The degree of remote control permitted would require study.) Note, the control system specifically does not include an instrumentation type distributed control system (DCS) as such systems are completely inappropriate for controlling a power plant such as this and are much more costly and harder to maintain than a PLC system.

The generation evaluation herein assumes that the main turbine, if a Turgo, has a control system that automatically switches jets on and off to match the flow available. It is also assumed that a power plant master PLC system automatically starts, synchronizes and stops the machine.

Machine governor control will be via forebay level, automatically varying power output to maintain the inlet water level.

10.0 SUBSTATION AND POWER LINE

10.1 Substation

The hydro plant will utilize 4160 volt generation equipment with 4160 volt generator breakers. It is assumed the installation would connect at 4160 volts to the adjacent water treatment plant and thus interconnection with the mine 25 kV distribution system would be via the water treatment plant transformer.

Interconnection with the water treatment plant switchgear would be via short run of 5 kV Teck type cable.

The power-plant would include revenue class generator metering. Note, for power sales to BC Hydro, they normally estimate power system losses from the metering point to the actual point of power purchase, with the estimated cost of such losses being deducted from the power sales.

10.2 Power Lines

The hydro plant would be connected to the mine 25 kV distribution system via the water treatment plant. Refer to Wardrop mine electrical drawings and estimates.

11.0 ENVIRONMENTAL

11.1 General

As the project will be all within the eventual mining lease, and as the major component, being the water treatment plant is required for the mining project, the project environmental considerations will be addressed in the overall KSM project environmental assessment. This assessment is being carried out by Rescan Environmental Services (Rescan) on behalf of Seabridge Gold. This report and all other required information will be forwarded to Rescan.

11.2 Emission Reduction Credits

It is to be noted that, if the power is sold under the BC Hydro under their "Standing Offer Program" (Version 2.0, January 2011) as discussed below rather than being used for load displacement, then BC Hydro program rules state:

> *2.4 Environmental Attributes – All Environmental Attributes for the energy delivered to BC Hydro under the Project EPA must be transferred to BC Hydro. The value of the Environmental Attributes is included in the price paid for energy delivered under the SOP and is not paid separately to the Developer.*

12.0 POWER SALES

12.1 General

The KSM mine and process plant project energy conservation measures will most probably account for all Rate Schedule 1823 Tier 2 (costly) power. This small machine may displace some remaining tier 2 energy purchases, or it may instead be sold to BC Hydro under the Standing Offer program.

For the purposes of this study it is assumed the power sales would be priced at 7.36 cents per kW.h which is the value of Tier 2 energy from BC Hydro, based on their two tier rate schedule 1823 as of April 2012.

12.2 BC Hydro Power Smart Project Incentives For Transmission Customers

This incentive applies to customers with projects that:

- Uses more than $50,000 of electricity annually
- The project or group of projects will save at least 300 megawatt hours annually.
- The project is a hard-wired facility upgrade with an expected lifespan of five years or more.
- Will use a technology that has already been successfully implemented in B.C. and is measurable and verifiable.
- The site has been operational for a minimum of six months prior to application.

This avenue would not be available for facilities built as part of the original project.

12.3 BC Hydro Power Smart Project incentives New Plant Design

This incentive applies for customers that have projects:

- In the early stages of planning a new facility or expanding an existing facility.
- That would expect to increase the power load by five per cent or more.
- The facility has a savings potential of more than $9,000 annually (as determined by your free energy study).
- Require funding for incremental costs to improve efficiency, with minimal disruption to your design process.

Power Smart can provide project incentives as much as 75 to 100 per cent of your incremental construction costs (i.e. above standard, inefficient design options).

12.4 BC Hydro Standing Offer Program

BC Hydro has a “Standing Offer Program” to encourage the development of small clean energy projects throughout British Columbia. The program has been updated and the latest issue is Version 2.0, January 2011.

BC Hydro state (25 April 2012):

The Standing Offer Program is intended to encourage the development of clean or renewable power projects of no more than 15 megawatts throughout British Columbia. The program streamlines the process for small developers selling electricity to BC Hydro, simplifies the contract and decreases transaction costs for developers while remaining cost-effective for rate payers. The Standing Offer Program supports the principles and policies set out in the 2007 BC Energy Plan and the 2010 Clean Energy Act.

Clean power sources such as run-of –river hydro, energy recovery projects and similar meet the basic requirements. The project generator can be behind a customer load, which means hydro generators connected to the KSM power distribution system are eligible. In these cases the customer’s Energy Supply

Agreement (ESA) would be modified so that the overall billings to the customer account for the energy generated by the generator that is being sold to BC Hydro under the project Energy Purchase Agreement (EPA). Considerable information is on file concerning the Standing Offer Program (SOP).

BC Hydro will pay for each MW.h of energy delivered based on:

- The base price as determined by the region of the point of interconnection;
- Any CPI escalation applicable to the base price; and
- The time of delivery adjustment factor specified in the EPA.

The following is a typical calculation that illustrates how the SOP Program Rules would be applied to a project located on Vancouver Island, where an EPA is executed in 2012 and COD occurs in 2014. The payment price for energy delivered during Peak Hours in February 2014 is calculated. The price paid would vary over the province but it can be seen that the price is significantly higher than the 7.36 cents per kW.h value of BC Hydro Tier 2 power under rate schedule 1823.

Figure 11.4.1 Typical Energy Sales Value Under SOP

STEP	CALCULATION
Step 1	Determine the applicable Base Price for a project located on Vancouver Island, which is \$102.25/MWh. See *Standing Offer Program Rules, Section 3, Figure 1 – Base Price by Region.*
Step 2	Calculate the escalated Base Price for energy in the year the EPA is signed (2012), which is \$106.45/MWh. = regional price x CPI $_{\text{January 1, 2012}}$ / CPI $_{\text{January 1, 2010}}$ = \$102.25/MWh x 119.2 / 114.5 = \$106.45/MWh *(Note: 100% of the base price is escalated at CPI up to the year the Project EPA is signed.)*
Step 3	Calculate the payment price for energy for 2014 prior to adjusting for the time of day or month when the energy is delivered, which is \$108.60/MWh. = (escalated Base Price * 0.5 * CPI $_{\text{January 1, 2014}}$ / CPI $_{\text{January 1, 2012}}$) + (escalated Base Price * 0.5) = (\$106.45 x 0.5 x 124.0 / 119.2) + (\$106.45 * 0.5) = \$108.60/MWh *(Note: 50% of the escalated Base Price from step 2 is escalated at CPI annually starting the first calendar year after the Project EPA is signed.)*
Step 4	Calculate the payment price for energy delivered in Peak Hours during February 2014, which is \$122.72/MWh. = payment price for 2014 prior to adjusting for the time of day or month when the energy is delivered x Time of Delivery Factor for February Peak Hours = \$108.60/MWh x 113% = \$122.72/MWh

13.0 <u>CAPITAL COST ESTIMATE</u>

13.1 General

Refer to Appendix C

14.0 PLANT CLOSURE

14.1 General

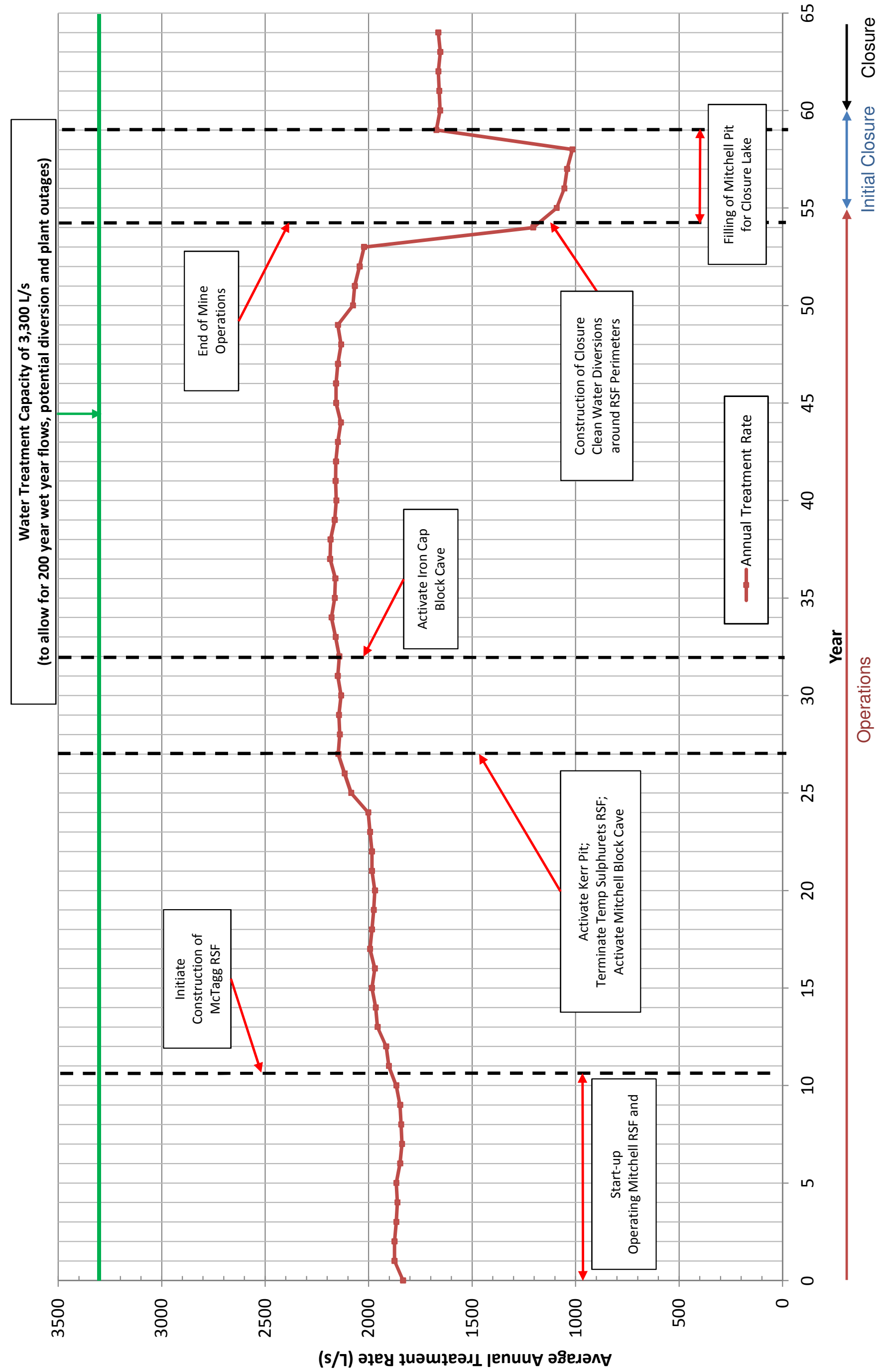
When the mine is closed at end of life, it is understood that the water treatment plant will remain and thus this energy recovery hydro plant would also remain. It could generate power for water treatment operations, and as it is assumed that a utility connection would be maintained, any excess power could be sold.

PROFESSIONAL ENGINEER
PROVINCE OF BRITISH COLUMBIA
W. N. BRAZIER

W N Brazier

W.N. Brazier, P.Eng.
June 26, 2012

15.0 APPENDIX A – KCBL GRAPH



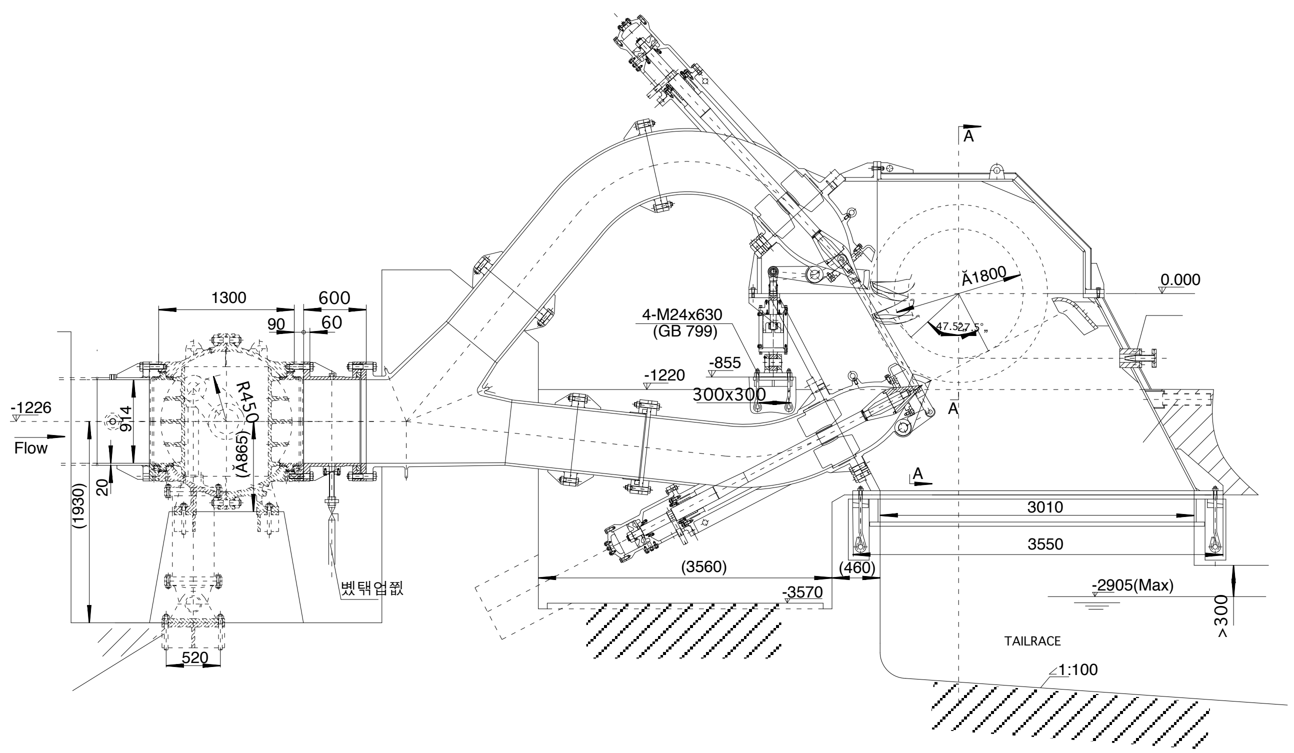
16.0 APPENDIX B - DRAWINGS

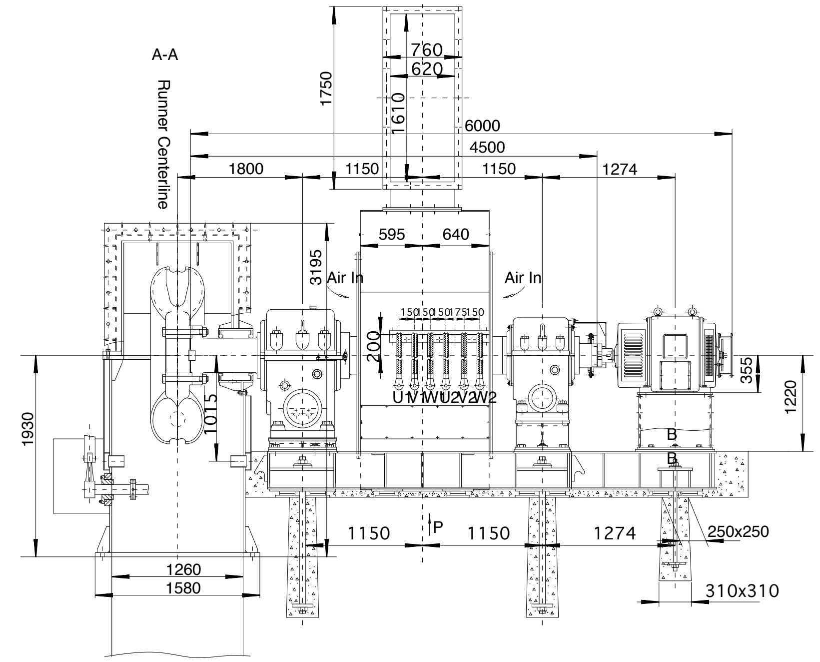
Turbine Drawings

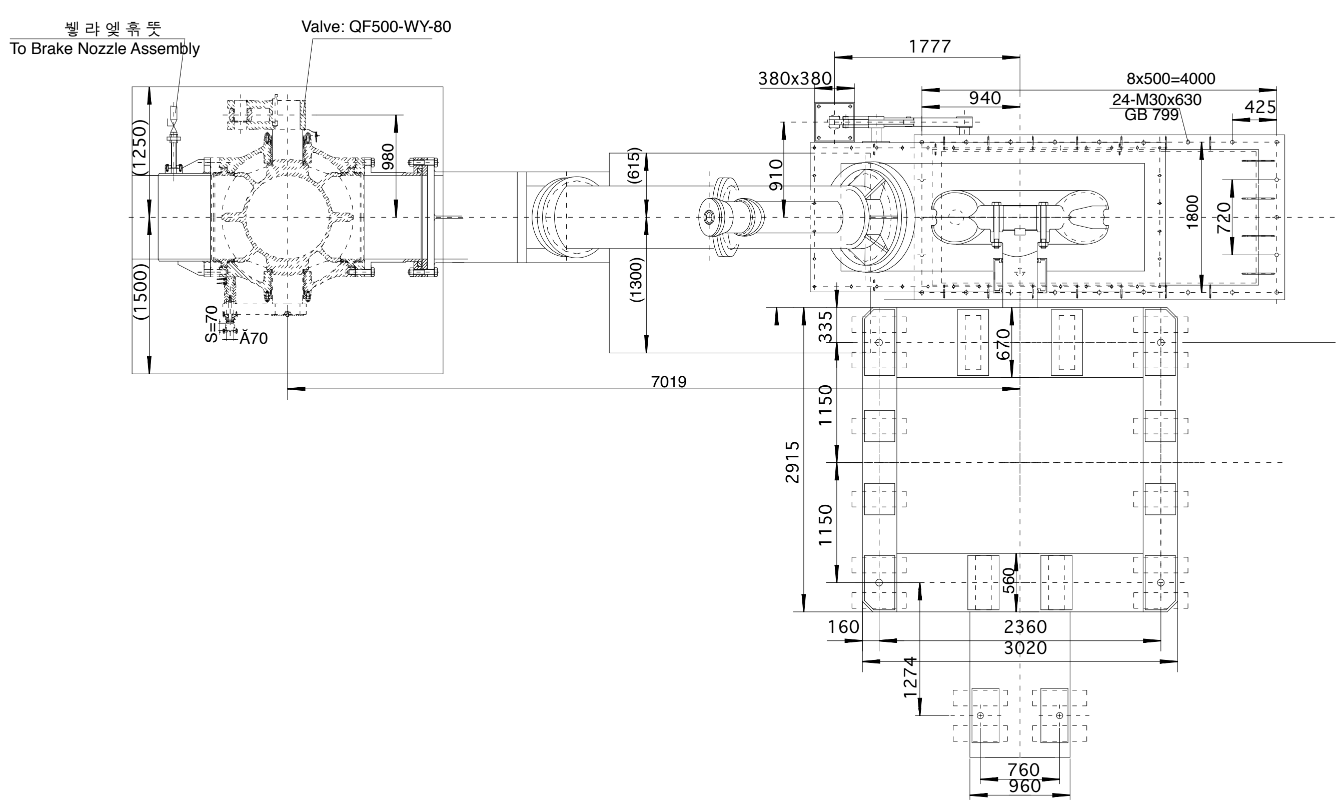
A typical impulse turbine drawing, of a machine size typical for this project, is attached.

Power Line Drawings

The power line will be shown on Wardrop mine power line plans.







P View

KSM PROJECT
RETURN WATER SYSTEM ENERGY RECOVERY
TYPICAL IMPULSE TURBINE
FEBRUARY, 2010

No.	Code No	Description	N.W (kg)	QTY	Remarks
3	Rotary Valve	36" Butterfly Valve			
2	Generator	SFW1750-36/2800			
1	Turbine	CJA237-W-180/2x20			

KSM HYDROELECTIC PROJECT				
Drawing name: GENERAL LAYOUT	Draw. No.	2C 0293		
	Total		Page	
	WT(kg)		Scale	
Model: CJA475-W-180/2X20 SFW2800-16/2150	KUNMING ELECTRICAL MACHINERY Co.Ltd, CHINA			

REV.	MODIFICATION	DATE	SIGN.	STATUS
A	ORIGINAL ISSUE			PREL

Designed by
Checked by
Chief-designed by
Confirmeded by
Stan examined by
Approved by

1:45

17.0 APPENDIX C – COST ESTIMATE

Please refer to the attached cost estimate spreadsheet.

KSM WATER TREATMENT ENERGY RECOVERY CAPITAL COST ESTIMATE FIRST QTR 2012 C$																			
Description	QTY	Units	Unit Weight kg	Unit MH	Labour Rate	Productivity Mult	Equip Rental Unit $	Material Unit Cost $	Equipment Unit Cost $	Subcont. Unit Rate	Weight Total	MHrs Total	Labour Total Cost	Material Total Cost $	Equipment Total Cost $	Equipment Rental Total Cost $	Subcontract Total Cost $	Total Direct Cost	Area Sub-Totals
Capital Cost																			
					112	1.15													
WATER TRATMENT PLANT ENERGY RECOVERY HYDRO					112	1.15													
					112	1.15													
					112	1.15													
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
Detailed excavation and backfill	400	m3		0.10	112	1.15	3.5					40	4,480	-	-	1,400	-	5,880	
					112	1.15						-		-	-	-	-	-	
Foundations	220	m3		9.0	112	1.15	25	$625				1,980	221,760	137,500	-	5,500	-	364,760	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
Pre-engineering building with services H&V, lighting, fire alarm system. 12 x 16 m	200	m2			112	1.15				$3,100.00		-		-	-	-	620,000	620,000	
					112	1.15						-		-	-	-	-	-	
7.5 tonne bridge crane c/w bus bars,	1	ea		100.0	112	1.15													
safety switch, etc.								$1,700	$46,000			100	11,200	1,700	46,000	-	-	58,900	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
Water turbine, Turgo impulse type,	1	ea		500.0	112	1.15	5,000	$5,000	$1,361,250			500	56,000	5,000	1,361,250	5,000	-	1,427,250	
Up to 2500 kW, up to 1.7 cms, 133 to 146 m					112	1.15													
net heat,												-		-	-	-	-	-	
201 m gross head withstand (no flow),					112	1.15						-		-	-	-	-	-	
4160 volt synchronous generator					112	1.15						-		-	-	-	-	-	
Powerhouse manifold/local hydro piping	20	m		10.0	112	1.15		$225				200	22,400	4,500	-	-	-	26,900	
Hydraulic power unit	1	ea		100.0	112	1.15						100	11,200	-	-	-	-	11,200	
(Equipment cost included with with turbine)					112	1.15						-		-	-	-	-	-	
TIV with bypass and actuator	1	ea		100.0	112	1.15			$55,000			100	11,200	-	55,000	-	-	66,200	
					112	1.15						-		-	-	-	-	-	
Allowance for by-pass orifice station	1	ea		200.0	112	1.15			$50,000			200	22,400	-	50,000	-	-	72,400	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
5 kV switchgear, 800 Amp bus,					112	1.15						-		-	-	-	-	-	
incoming main breaker, generator	1	lot		250.0	112	1.15		$5,000	$132,000			250	28,000	5,000	132,000	-	-	165,000	
breaker with integrated gen protective relays, main breaker and cell with fused switch and dry type 4160 -600 volt 45					112	1.15													
kva station service transformer.												-		-	-	-	-	-	
Misc. piping	1	lot		200.0	112	1.15		$12,000				200	22,400	12,000	-	-	-	34,400	
					112	1.15						-		-	-	-	-	-	
Control panel with PLC and HMI with SCADA interface for remote monitoring.	1	lot			112	1.15													
Includes software and programming.								$10,000	$375,000			-		10,000	375,000	-	-	385,000	
Physically install control panel	1	lot		80.0	112	1.15		$2,500				80	8,960	2,500	-	-	-	11,460	
Battery bank charger and DC panel	1	ea		40.0	112	1.15			$25,000			40	4,480	-	25,000	-	-	29,480	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
Ground Grid	1	lot		150.0	112	1.15		$12,500				150	16,800	12,500	-	-	-	29,300	
					112	1.15						-		-	-	-	-	-	
Power and control cables, misc. pilot	1	lot		750.0	112	1.15													
devices, instruments, switches, etc.								$120,000				750	84,000	120,000	-	-	-	204,000	
25 kV, 3c 2/0 Teck, direct burried,	100	m		0.4	112	1.15	10	$125											
includes terminations												40	4,480	12,500	-	1,000	-	17,980	
					112	1.15						-		-	-	-	-	-	

Description	Quantity	Units	Wt	MHr	Labour		Equip Ren	Material	Equipment	Subcont. Unit	Weight	MHrs	Labour	Material	Equipment	Equip Rental	Subcontract	Total	
Power Transformer, 25-4.16 kV, 2.2/3 MVA	1	ea		125.0	112	1.15	1,000	$4,100	$82,000			125	14,000	4,100	82,000	1,000	-	101,100	
ONAN/ONAF, pad mount					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
25 KV Primary recloser, air break switch, terminal pole and lightning arresters	1	lot		80.0	112	1.15		$3,900	$26,000			80	8,960	3,900	26,000	-	-	38,860	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
					112	1.15						-		-	-	-	-	-	
General Equip. Rental (equipment will be readily available from the nearby construction site)	1	lot			112	1.15	30,000					-		-	-	30,000	-	30,000	
Construction Power is from Mitchell portal power plant														-			-	-	Area Subtotal
SUBTOTALS, TOTAL DIRECT COST	Quantity	Units	Wt	MHr	Labour		Equip Ren	Material	Equipment	Subcont. Unit	Weight	MHrs	Labour	Material	Equipment	Equip Rental	Subcontract	Total	$3,700,070
											0.00	4,935.00	$552,720	$331,200	$2,152,250	$43,900	$620,000	$3,700,070	$3,700,070
																			Checksum
Design and Engineering (note, the majority of the design is in the water to wire package which would include the turbine, generator, switchgear, controls, etc.	1	lot			112	1.15				$200,000		-		-	-	-	200,000	200,000	
Construction Office, Abolution, etc. - part of site facilities						1.15						-		-	-	-	-	-	
Construction Management excludes offices, safety & first aid, supplied from plantsite)	1	lot		600.0	$140	1.15	15,000					600	84,000	-	-	15,000	-	99,000	
Vendor reps -(would actually be included in water to wire equipment package)	1	lot		150.0	$140	1.15				$5,000.00		150	21,000	-	-	-	5,000	26,000	
QA/QC, Testing	1	lot		100.0	$140	1.15	5,000			$10,000.00		100	14,000	-	-	5,000	7,500	26,500	
Commissioning	1	lot		200.0	$140	1.15	5,000					200	28,000	-	-	5,000	-	33,000	
					$140	1.15						-		-	-	-	-	-	
Spares	1	lot			$140	1.15			$250,000			-		-	250,000	-	-	250,000	
						1.15						-		-	-	-	-	-	
					$112	1.15						-		-	-	-	-	-	
					$112	1.15						-		-	-	-	-	-	#REF!
					$112	1.15						-		-	-	-	-	-	
					$112	1.15						-		-	-	-	-	-	
												-		-	-	-	-	-	
NOTE												-		-	-	-	-	-	
1) WATER SUPPLY PIPE FROM TREATMENT PLANT, TO HAVE PRESSURE RATING TO MATCH REQIREMENTS OF PLANT REPORT REFERENCED BELOW, BY OTHERS												-		-	-	-	-	-	
2) CLEARING , GRUBBING AND ROUGH GRADING OF SITE, BY OTHERS.												-		-	-	-	-	-	
3) POWER LINES TO AREA BY OTHERS (AS OTHERWISE REQUIRED FOR THE PROJECT).					$112	1.15						-		-	-	-	-	-	
4) GRAVITY FLOW PIPE FROM POWER PLANT TAILRACE TO TREATMENT PLANT INTAKE, BY					$112	1.15						-		-	-	-	-	-	
5) 25 KV TIE-IN WOULD BE AT THE AJACENT TREATMENT PLANT.					$112	1.15						-		-	-	-	-	-	
6) THE ABOVE COSTS ARE LESS CONTINGENCY AND OWNER'S COSTS.					$112	1.15						-		-	-	-	-	-	
PROJECT DESCRIPTION					$112	1.15						-		-	-	-	-	-	-
1) REFER TO THE REPORT "WATER TREATMENT PLANT ENERGY RECOVERY EVALUATION"					$112	1.15						-		-	-	-	-	-	
					$112	1.15						-		-	-	-	-	-	
					$112	1.15						-		-	-	-	-	-	
					$112	1.15						-		-	-	-	-	-	
														-			-	-	Area Subtotal
SUBTOTALS, TOTAL INDIRECT COST	Quantity	Units	Wt	MHr	Labour		Equip Ren	Material	Equipment	Subcont. Unit	Weight	MHrs	Labour	Material	Equipment	Equip Rental	Subcontract	Total	634,500
											0	$1,050	$147,000	$0	$250,000	$25,000	$212,500	Checksum	634,500
TOTAL DIRECT AND INDIRECT COST	Quantity	Units	Wt	MHr	Labour		Equip Ren	Material	Equipment	Subcont. Unit	Weight	MHrs	Labour	Material	Equipment	Equip Rental	Subcontract	Total	4,334,570
											0	$5,985	$699,720	$331,200	$2,402,250	$68,900	$832,500	Checksum	4,334,570