UNIVERSITY OF ALASKA ANCHORAGE
ConocoPhillips Integrated Science Building Combined Heat and Power Upgrades Greenhouse Gas Emissions Reduction Analysis

March 15, 2024

Prepared by:
RSA Engineering, Inc.
670 Fireweed Ln., Suite 200
Anchorage, Alaska 99503

Table of Contents

University of Alaska Anchorage
ConocoPhillips Integrated Science Building
Combined Heat and Power Upgrades
Greenhouse Gas Emission Reduction Analysis

University of Alaska Anchorage
ConocoPhillips Integrated Science Building
Combined Heat and Power Upgrades
Greenhouse Gas Emission Reduction Analysis

Objectives

RSA Engineering has been hired by the University of Alaska Anchorage (UAA) to evaluate the potential for greenhouse gas (GHG) emission reduction if gas-fired microturbines were installed in the ConocoPhillips Integrated Science Building (CPISB) on the UAA campus. The results of the evaluation will be included in a grant application, which could provide UAA with funding to help perform the microturbine work.

Background

A microturbine is a piece of equipment about the size of a commercial heating boiler that burns natural gas to generate electricity. They are typically designed to capture heat from combustion exhaust and transfer it into a fluid-based (i.e. hydronic) building heating system through a built-in heat exchanger. Due to this dual-purpose function, microturbines are often referred to as "combined heat and power" devices, or CHP. Consequently, the terms microturbine and CHP will be used interchangeably in this report. The CHP function typically allows a higher efficiency of natural gas utilization because power and heat are produced simultaneously. Due to their efficiency and relatively compact size, microturbines are sometimes used for site-based power generation, which reduces power consumption from the electric utility. In some circumstances, the financial savings from reduced utility demand can pay for the installation of CHP within a reasonable period of time.

In May 2020, CHP Technical Assistance Partnerships Northwest (TAP) provided a financial analysis of CHP installation in the CPISB, looking at simple payback. The analysis determined that the project would have a simple payback between 5.3 and 5.5 years. The analysis included the existing fuel and power consumption of the building, and projected fuel consumption and power production of the CHP project. This information was used as the basis of the GHG analysis for this report.

Calculations

Existing Conditions

Power and heat for the CPISB are both generated by the combustion of natural gas. Power is produced by Chugach Electric through a combination of gas-fired turbines and renewable energy[1], and delivered through existing distribution infrastructure. Heat is provided using gas-fired cast-iron boilers installed in the CPISB.

The building power utilization and gas consumption data in the 2020 TAP CHP analysis report are used as the baseline consumption data for comparison in this report. Those values are shown in Table 1 along with the approximate amount of GHG emissions created for each. Since heat is produced on-site by burning natural gas, the GHG emissions can be estimated using a value of 117 lbs. of CO_2 per MMBTU (1,000,000 BTU)[2]. Since power is generated off site by Chugach Electric using a combination of gas-fired and renewable production, the GHG emissions were determined by evaluating the total amount of power produced annually (gas-fired and renewable) and calculating a ratio of MMBTU per kilowatt-hour (kWh). This ratio is shown in Table 1.

1 At about 81% and 19% respectively. Based on 2021 data sourced from tariff actions and COPA reports filed with the Regulatory Commission of Alaska, and compiled by the Renewable Energy Alaska Project (REAP). See citation.

Table 1: Existing Energy Consumption

End Use	Annual Consumption	Ratio of MMBTU to kWh	Equivalent BTU Energy Load	Greenhouse Gas Emissions
Power	3,876,100 kWh	0.0071	27,520 MMBtu	3,219,840 lbs CO_2
Heat	133,524 ccf	--	14,020 MMBtu	1,640,340 lbs CO_2
Total	--	--	**41,540 MMBtu**	**4,860,180 lbs CO_2**

<u>Proposed Work</u>

A preliminary design was developed in September of 2020 to install multiple microturbines at the CPISB to generate some of the power used by the facility, to offset power consumption from Chugach Electric. Combustion heat reclaimed by the unit would be used as supplemental building heat. The new units would increase the amount of natural gas consumed on site. The TAP financial analysis utilized two different models for the economic analysis of CHP installation, which provided similar results. This report uses the results from the model that generated less power on site. This is a more conservative approach because power from the utility is generated less efficiently than the microturbines, which would result in higher GHG emissions. The TAP report showed annual on-site power production as 1,746,780 kWh. The resulting building utility power and gas consumption, and their resultant GHG emissions, are shown in Table 2.

Table 2: Proposed Energy Consumption

End Use	Annual Consumption	Ratio of MMBTU to kWh	Equivalent Heating Capacity	Greenhouse Gas Emissions
Power (Utility)	2,129,320 kWh	0.0071	15,118 MMBtu	1,768,806 lbs CO_2
Heat and Power (Site)	221,790 ccf	--	23,288 MMBtu	2,724,696 lbs CO_2
Total	--	--	**38,406 MMBtu**	**4,493,502 lbs CO_2**

<u>GHG Emissions Reduction</u>

The estimated difference between the building's existing power consumption and the proposed power consumption is shown in Table 3.

Table 3: GHG Emissions

GHG Emissions	Existing	Proposed	Reduction
Lbs CO_2 per Year	4,860,180	4,493.502	366,678

There would be an approximate reduction of 366,678 lbs of CO_2 annually. Over a five year period the reduction would be approximately 832 metric tons of CO_2. Over a 25 year period the reduction would be approximately 4,158 metric tons of CO_2.

Conclusion

Based on the information included in the TAP report, the proposed CHP work could reduce the facility GHG emissions by approximately 366,678 pounds per year. Where the TAP analysis indicates that the project could be financially beneficial, the GHG emissions analysis shows that the project could have environmental benefits as well.

Citations

Greenhouse Gas Emissions – U.S. Environmental Protection Agency (EPA). (2023). https://www.epa.gov/ghgemissions/assumptions-and-references-household-carbon-footprint-calculator.

Scott, A. (2023). *Utility Sector Data 2021.* Renewable Energy Alaska Project (REAP). info@realaska.org

APPENDIX A:
CHP Technical Assistance Partnerships Northwest Report

CHP Technical Assistance Partnerships
NORTHWEST

31 May, 2020

Micah K. Chelimo, Facilities Engineer
University of Alaska Anchorage
Facilities Planning & Construction
3211 Providence Drive
GHH Suite106
Anchorage, Alaska 99508

Dear Mr. Chelimo,

Thank you for your recent inquiry regarding a CHP Screening Technical Assistance analysis for a potential Combined Heat and Power (CHP) project at the Conoco Phillips Integrated Science Building (CPISB), part of University of Alaska Anchorage's (UAA) facilities. The UAA is studying a number of selected buildings to assess the feasibility is installing one or more combined heat and power (CHP) projects that could improve UAA energy efficiency, so reducing annual energy use, operating costs and likely net emissions. We understand that the CPISB described in this report currently consumes about 3,876,100 kWh of electrical energy and 14,020 MMBtu of natural gas each year at a total cost of about $666,064 annually.

CHP located at or near the point of consumption, is the concurrent production of electricity and useful thermal energy (heating and/or cooling) from a single source of energy. Instead of purchasing electricity from a local utility and then burning fuel in a boiler to produce thermal energy as the University currently does, consumers use CHP to provide these energy services in one energy-efficient step. As a result, CHP improves efficiency and may reduce greenhouse gas (GHG) emissions as well.

This initial technical/economic screening for CHP viability compares the economics and technical practicality of incorporating a natural gas-fired engine/generator set with heat recovery at CPISB to your current building operations (status quo or "base case"), using gas heating and purchased electricity. UAA supplied four years of monthly gas and electric bills for CPISB, so we averaged the facility's electrical energy and demand and costs from Anchorage Municipal Light & Power (ML&P) as well as natural gas consumption and costs from Enstar, for each month in the four years. We also studied your gas and electrical rate trends and schedules in some detail to ensure that utility electrical energy and demand charges as reflected your University's internal energy cost allocations to CPISB appear to generally reflect the current (2019) rates for both utilities. Analysis of your rates and the Chugach acquisition of ML&P are an essential part of any CHP consideration at UAA.

The annual electrical generation of a potential CHP project at your site is determined in this Screening Technical Assistance analysis for a proposed project that is generally sized to meet annual electrical and thermal loads within practical economic constraints and model limitations. For this analysis, it is assumed that all electrical and thermal energy produced is beneficially used on-site or wasted, based on average consumption of both types of energy in CPISB. No sales to the electrical utility are assumed to occur, nor are any thermal transfers.

Based on our review of the technical and economic data provided, we believe that the CPISB site is a strong candidate for further investigation into the merits of a natural gas-fueled reciprocating engine based CHP system.

The following factors and assumptions form the basis for our CHP system Screening Technical Assistance analysis:

- High Electrical Utility Rates. ML&P has a very unusual electricity rate schedule, as Large Commercial demand charges are relatively quite high at $43.98/kW (2019 averaged for UAA), while energy charges are low at $0.057/kWh (also averaged). Given your internal billing cost allocations based on "melded" electrical costs (combining energy and peak demand charges), we used $0.141/kWh and gas costs of $0.839/CCF (therm) from modeling at CPISB; these are building specific four-year averages, but close to UAA averages. The UAA melded rates appear to representatively cover costs across your campus and also appear reasonably close to applicable (melded) Chugach power rates for this class of account.
- Model Prime Mover Sizing Strategies. Our STA tools size the engine/genset (prime mover) and perform a cost estimate for a CHP project designed to meet average thermal loads, while also incorporating seasonality and power sell-back considerations (modeler may adjust parameters for best economics) . A boiler efficiency of 80% is assumed when converting natural gas consumption into thermal energy availability. An availability factor of 95% is assumed for the engine/generator.
- Low O&M Costs. A maintenance cost of $0.024/kWh is assumed that is consistent with the sizing of the reciprocating engine.

Please see the attachments for the results of our CHP screening analysis. We compared two different models for this analysis, using the same four-year averaged monthly utility energy and cost data: 1) The US Dept. of Energy's CHP screening Technical Assessment Tool model; and 2) WSU Energy Program's CHPSAT model. The models are similar, but differ in their selection of power plants and processing of monthly energy and demand inputs. Comparable results were found in both cases, increasing our confidence in this initial assessment.

DOE CHP TAP Screening Technical Assessment Tool:

- CHP Project Sizing: The CHP project in the DOE STA analysis is sized to meet the average thermal load at the site. A net CHP power of 210 kW is calculated with a natural gas price of $ 8.39/MMBtu.
- Power and Heat Production Rate and Efficiency. The DOE STA analysis assumes an average generating efficiency of 29.6% with a thermal energy recovery of 1.28 MMBtu/hour; loads are assumed to be coincident with generation on a monthly basis.
- Economics: The CHP proposed project would produce about 1,746,780 kWh/year of electrical energy. This is equivalent to about 45% of total current annual CPISB electrical energy use. When maintenance charges are deducted from the estimated annual electrical savings benefits, the net operating cost savings are $115,104 annually. Annual boiler natural gas consumption would decrease by 78%, but with the CHP project installed total on-site natural gas use would increase from 14,020 MMBtu/year to 23,288 MMBtu/year. **Assuming a total installed cost of $608,707 yields a 5.3 year simple payback given current utility rates.**

Washington State University CHPSat Tool:

The WSU CHPSat modeling tool differs from the DOE STA Tool in using a specific prime mover (chosen by modeler) and modeling monthly load variations more closely. They have been cross calibrated continuously for many years.

- CHP Project Sizing: The CHP project in the DOE STA analysis is sized to meet the average thermal load at the site. A net CHP power of 250 kW was selected with a natural gas price of $8.39/MMBtu.
- Power and Heat Production Rate and Efficiency. The DOE STA analysis assumes an average generating efficiency of 29.7%, with a thermal energy recovery of 1.35 MMBtu/hour; loads are assumed to be coincident with generation on a monthly basis. In summer months some heat energy

would be dumped to atmosphere due to operating at full power. This may be adjusted in more detailed studies.

- Economics: The CHP proposed project would produce about 2,054,741 kWh/year of electrical energy. This is equivalent to about 53% of total current annual CPISB electrical energy use. When maintenance charges are deducted from the estimated annual electrical savings benefits, the net operating cost savings are $131,903 annually. Annual boiler natural gas consumption would decrease by 78%, but with the CHP project installed total on-site natural gas use would increase from 14,020 MMBtu/year to 27,079 MMBtu/year. **Assuming a total installed cost of $725,000 yields a 5.5 year simple payback given current utility rates**.

Remember that this is only a preliminary CHP project screening analysis to indicate whether or not your site exhibits potential for installation of a cost-effective generating project. Project sizing, annual generation, energy recovery and total installed cost results should not be used as the basis for seeking project funding. This site has a number of considerations that limit the accuracy of an analysis based on average monthly energy consumption.

Complexity issues that should be resolved in a detailed feasibility study include:

- **Utility Rate Schedule Uncertainty**: Although the current screening economics are based on average ML&P rates over four years, Chugach Electric is in the process of acquiring Anchorage Municipal Light & Power. Current Chugach rates (under their Large General Secondary Service schedule) are $0.11746/kWh and $21.74/kW-mo. While demand charges are still a major cost component, they are less onerous than those imposed under the current Anchorage Municipal Light & Power schedule. During negotiations with Chugach, the potential for application of CHP should be considered to avoid a rate that would make self-generation less attractive.
- **Demand and Possible Backup Charges**: Careful consideration and negotiation of rates (if possible) with Chugach Electric, as well as design for reliability may determine whether the project is economical, depending on the specific energy rates that would be applied to the University facilities individually and as a whole; in aggregate, facilities may “smooth” demand charges, allowing practical application of melded rates, as are currently used internally. However, this should be carefully considered.
- **Coincidence of Electrical and Thermal Loads:** Buildings often set back their occupied space temperatures during the night and on weekends to conserve energy. A “morning warmup” is then required to provide a comfortable environment when teachers and students arrive. Electrical loads might not be high during this warmup period meaning that thermal storage (and electrical battery storage) might be desirable at the school to fully capture CHP project fuel and electrical energy offset capabilities.
- **Sizing of Engine Gensets:** To reliably offset demand charges and allow for islanding of the high school (if desired), the CHP project designer might want to consider multiple reciprocating engines along with a backup reciprocating engine of the same capacity. With this approach, peak demands can be satisfied when one engine is out of service. Dual-fueled engines might also prove desirable should the natural gas supply be lost.
- **Making Use of Energy Efficiency Measures:** The University should deploy energy efficiency measures that would result in demand reductions (such as LED lighting, if they have not already converted to this technology). Demand reductions captured through efficiency measures would occur 100% of the time, ensuring that anticipated savings actually occur. It is likely that efficiency measures would be more cost-effective in terms of capturing demand reduction benefits than the installation of additional CHP generating capacity.

Moving forward, we are available to discuss the potential next steps or additional alternatives with you. If you have any questions or comments, please contact me at 360-956-2071

Regards,

David Van Holde, P.E., CEM

Sr. Energy Systems Engineer
Director, U.S. DOE Northwest CHP TAP
www.northwestCHPTAP.org
WSU Energy Program
905 Plum St. SE, Bldg #3
P.O. Box 43165
Olympia, WA 98504-3165
Ph: 360-956-2071
WASHINGTON STATE UNIVERSITY
EXTENSION ENERGY PROGRAM
www.energy.wsu.edu

CC: Christopher C. McConnell, Director Facilities Planning & Construction, University of Alaska Anchorage; Gil McCoy, WSU-EP

Attachments: *UAA Conoco Phillips Integrated Science Bldg. - DOE CHP TAP Screening Tool_102518.pdf ; CHP20200528~UAA Conoco Phillips Integrated Science~.pdf*

APPENDIX B:
Chugach Electric Power Generation & Gas Consumption Data

Power generation MWh

Description	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
Natural Gas Powered Generation													
Beluga Power Plant													
Unit No. 1	94.3	0.0	0.0	0.0	56.2	0.0	0.0	59.4	0.0	316.4	0.0	0.0	526.4
Unit No. 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unit No. 3	260.5	669.2	967.7	0.0	113.2	0.0	329.5	0.0	6.9	163.2	2.2	0.0	2,512.5
Unit No. 5	0.0	254.0	645.6	0.0	116.2	0.0	201.1	0.0	13.8	135.4	0.0	914.7	2,280.9
Unit No. 6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unit No. 7	0.0	0.0	676.2	0.0	172.8	0.0	0.0	0.0	132.9	0.0	0.0	151.1	1,133.0
Unit No. 8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Generation	354.9	923.2	2,289.5	0.0	458.4	0.0	530.6	59.4	153.7	615.1	2.2	1,065.8	6,452.8
Station Service	(484.8)	(373.0)	(1,869.6)	(336.0)	(234.4)	(158.0)	(214.0)	(234.5)	(157.6)	(467.3)	(215.6)	(209.2)	(4,953.9)
Net Generation	(129.9)	550.2	419.9	(336.0)	224.0	(158.0)	316.6	(175.0)	(3.9)	147.8	(213.4)	856.6	1,498.9
Southcentral Power Project (200.2 MW)													
Unit No. 10 (57.4 MW)	18,373.9	19,870.0	23,423.4	16,760.5	19,370.9	17,200.4	18,260.4	21,704.7	23,730.7	17,282.7	21,731.7	24,169.5	241,878.6
Unit No. 11 (47.6 MW)	22,384.3	24,536.3	27,544.2	23,317.5	27,471.3	25,815.6	13,314.6	25,045.8	26,751.5	23,553.7	30,145.4	30,143.0	300,023.1
Unit No. 12 (47.6 MW)	16,973.6	19,051.8	22,319.0	17,334.8	12,014.8	4,356.1	19,332.6	20,491.3	22,826.3	23,338.6	29,930.4	30,306.9	238,276.2
Unit No. 13 (47.6 MW)	25,442.1	22,999.5	27,184.5	15,688.2	24,824.2	25,594.4	26,984.2	26,979.2	26,529.0	16,217.5	26,650.7	28,733.6	293,826.9
Gross Generation	83,173.9	86,457.5	100,471.1	73,100.9	83,681.2	72,966.5	77,891.8	94,220.9	99,837.5	80,392.4	108,458.1	113,353.0	1,074,004.8
Station Service	(2,633.9)	(2,539.5)	(2,838.7)	(2,039.9)	(2,586.3)	(2,586.3)	(2,636.2)	(2,853.5)	(2,835.1)	(2,545.7)	(2,868.0)	(2,993.3)	(31,956.2)
Net Generation	80,540.0	83,918.0	97,632.4	71,061.0	81,094.9	70,380.2	75,255.6	91,367.5	97,002.4	77,846.8	105,590.1	110,359.7	1,042,048.6
Plant 1 (66.5 MW)													
Unit No. 3 (32.9 MW)	245.5	204.1	1,134.5	1,000.2	160.9	82.2	505.5	2,924.7	0.0	165.1	497.9	2,710.2	9,630.6
Unit No. 4 (33.6 MW)	49.2	0.0	0.0	11.7	0.0	72.1	34.5	0.0	0.0	0.0	0.0	0.0	167.4
Gross Generation	294.7	204.1	1,134.5	1,011.8	160.9	154.3	539.9	2,924.7	0.0	165.1	497.9	2,710.2	9,798.0
Station Service	(45.7)	(50.9)	(60.2)	(51.7)	(37.0)	(29.1)	(105.2)	(214.5)	(86.9)	(119.0)	(277.7)	(461.9)	(1,539.6)
Net Generation	249.0	153.2	1,074.4	960.1	123.9	125.2	434.8	2,710.2	(86.9)	46.1	220.2	2,248.3	8,258.4
Plant 2 (166.8 MW)													
Unit No. 7 (81.8 MW)	935.6	114.7	398.0	207.0	0.0	90.6	472.5	1,432.3	90.4	246.5	2,094.1	455.3	6,536.9
Unit No. 8 (85 MW)	56.9	0.0	0.0	38.1	0.0	104.9	0.0	0.0	0.0	0.0	0.0	0.0	199.9
Gross Generation	992.5	114.7	398.0	245.0	0.0	195.5	472.5	1,432.3	90.4	246.5	2,094.1	455.3	6,736.8
Station Service	(342.2)	(99.6)	(43.2)	(316.8)	(293.0)	(261.2)	(371.8)	(455.9)	(382.2)	(316.5)	(365.0)	(377.6)	(3,625.0)
Net Generation	650.3	15.1	354.8	(71.8)	(293.0)	(65.7)	100.7	976.3	(291.8)	(70.0)	1,729.2	77.7	3,111.8
Plant 2A (126.7 MW)													
Unit No. 9	28,010.1	26,917.3	28,395.8	29,789.1	29,601.5	18,697.0	24,815.9	23,379.8	10,712.1	25,744.0	26,030.7	27,534.5	299,627.9
Unit No. 10	26,998.2	26,152.6	17,547.8	27,635.5	24,193.5	25,397.2	25,915.1	26,490.1	13,828.8	25,982.1	26,065.9	27,144.8	293,351.6
Unit No. 11	18,173.2	16,864.0	13,184.6	18,582.2	15,799.7	13,587.0	16,800.3	17,675.2	6,977.2	17,878.2	17,634.4	17,826.5	190,982.4
Gross Generation	73,181.5	69,933.9	59,128.2	76,006.9	69,594.7	57,681.2	67,531.3	67,545.1	31,518.1	69,604.3	69,731.0	72,505.8	783,962.0
Station Service	(1,939.1)	(1,711.6)	(1,756.7)	(2,661.6)	(2,661.6)	(2,661.6)	(2,662.8)	(2,619.5)	(1,684.4)	(2,552.9)	(2,575.4)	(2,850.6)	(28,337.7)
Net Generation	71,242.4	68,222.3	57,371.5	73,345.3	66,933.1	55,019.6	64,868.5	64,925.6	29,833.7	67,051.4	67,155.6	69,655.2	755,624.3
Total Gas Powered Generation													
Gross Generation	157,997.4	157,633.4	163,421.4	150,364.7	153,895.2	130,997.5	146,966.2	166,182.4	131,599.7	151,023.3	180,783.3	190,090.0	1,880,954.3
Station Service	(5,445.6)	(4,774.6)	(6,568.4)	(5,406.0)	(5,812.3)	(5,696.2)	(5,990.0)	(6,377.8)	(5,146.1)	(6,001.2)	(6,301.7)	(6,892.5)	(70,412.4)
Net Gas Generation	152,551.8	152,858.8	156,853.0	144,958.7	148,082.9	125,301.3	140,976.2	159,804.6	126,453.6	145,022.0	174,481.6	183,197.5	1,810,541.9
Hydroelectric Generation													
Cooper Lake													
Unit No. 1	4,902.2	360.5	1,413.6	775.3	3,657.1	5,193.9	2,676.6	748.5	1,518.9	384.5	781.7	680.4	23,093.1
Unit No. 2	1,780.4	2,565.3	965.9	178.8	2,043.4	3,982.1	1,788.8	518.6	22.2	280.2	188.5	251.2	14,565.2
Gross Generation	6,682.5	2,925.8	2,379.5	954.1	5,700.5	9,176.0	4,465.3	1,267.1	1,541.0	664.6	970.3	931.6	37,658.3
Station Service	(70.8)	(92.3)	(23.2)	(9.8)	(56.7)	(134.1)	(70.7)	(48.7)	(60.7)	(107.2)	(117.7)	(122.1)	(914.1)

Net Generation	6,611.7	2,833.5	2,356.3	944.3	5,643.8	9,041.9	4,394.6	1,218.4	1,480.3	557.4	852.5	809.5	36,744.2
Eklutna [1]													
Eklutna Hydro	7,178.0	6,570.0	10,997.0	11,321.9	6,457.0	7,593.9	4,083.4	1,823.6	4,012.7	7,654.1	4,959.6	7,812.6	80,463.6
Gross Generation	7,178.0	6,570.0	10,997.0	11,321.9	6,457.0	7,593.9	4,083.4	1,823.6	4,012.7	7,654.1	4,959.6	7,812.6	80,463.6
Station Service	(18.9)	(18.7)	(42.0)	(33.5)	(29.3)	(27.2)	(27.5)	(28.5)	87.3	(11.0)	(15.8)	(17.9)	(183.0)
Net Generation	7,159.1	6,551.3	10,955.0	11,288.5	6,427.7	7,566.6	4,055.9	1,795.1	4,100.0	7,643.1	4,943.8	7,794.7	80,280.7
Total Hydro Powered Generation													
Gross Generation	13,860.5	9,495.8	13,376.5	12,276.0	12,157.5	16,769.9	8,548.7	3,090.7	5,553.8	8,318.7	5,929.9	8,744.1	118,121.9
Station Service	(89.7)	(111.0)	(65.2)	(43.3)	(86.0)	(161.3)	(98.2)	(77.2)	26.6	(118.3)	(133.6)	(140.0)	(1,097.1)
Net Hydro Generation	13,770.8	9,384.8	13,311.3	12,232.7	12,071.5	16,608.5	8,450.5	3,013.5	5,580.4	8,200.5	5,796.3	8,604.1	117,024.8
Other Power Purchases													
Purchased Power													
Bradley Lake													
Bradley Lake	22,218.1	20,026.7	19,811.1	19,589.5	16,189.0	19,814.6	23,143.2	22,122.6	22,261.7	15,700.5	14,693.3	15,190.9	230,761.2
Bradley Lake - SES	730.9	658.8	651.7	348.0	287.6	352.0	411.1	392.9	395.4	278.9	261.0	269.8	5,037.9
Total Bradley Lake	22,948.9	20,685.5	20,462.8	19,937.4	16,476.5	20,166.5	23,554.3	22,515.5	22,657.2	15,979.4	14,954.3	15,460.7	235,799.0
Purchases from Other Utilities													
GVEA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEA / AEEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEA (incl. Power Pool)	0.0	0.0	0.0	0.0	0.0	72.0	840.0	0.0	8,240.0	7,884.0	2,911.0	1,882.0	21,829.0
Total Railbelt	0.0	0.0	0.0	0.0	0.0	72.0	840.0	0.0	8,240.0	7,884.0	2,911.0	1,882.0	21,829.0
Renewable Generation													
Fire Island Wind	5,893.2	3,904.8	3,186.3	4,903.7	4,505.1	3,107.2	2,451.5	2,567.9	3,558.8	4,216.0	3,916.2	3,370.8	45,581.5
Qualified Facilities	14.6	22.1	10.8	14.7	19.8	18.8	9.1	9.1	7.7	11.7	14.1	13.9	166.2
Total Renewable	5,907.8	3,926.9	3,197.0	4,918.3	4,524.9	3,126.0	2,460.7	2,576.9	3,566.5	4,227.7	3,930.3	3,384.7	45,747.7
Total Purchased Power	28,856.7	24,612.4	23,659.8	24,855.8	21,001.5	23,364.5	26,855.0	25,092.4	34,463.6	28,091.1	21,795.6	20,727.4	303,375.8
Total Generation and Purchased Power	195,179.3	186,855.9	193,824.1	182,047.2	181,155.9	165,274.4	176,281.6	187,910.5	166,497.5	181,313.6	202,073.5	212,529.0	2,230,942.5
Less Economy Sales	(2,874.0)	(9,932.0)	(6,860.0)	(14,511.0)	(22,455.0)	(12,222.0)	(14,503.0)	(23,883.0)	(6,354.0)	(6,294.0)	(11,657.0)	(7,926.0)	(139,471.0)
Total Net Generation and Purchased Power	192,305.3	176,923.9	186,964.1	167,536.2	158,700.9	153,052.4	161,778.6	164,027.5	160,143.5	175,019.6	190,416.5	204,603.0	2,091,471.5

Non-hydro renewables 13%

Total Net Energy MWh =	2,091,471.5
Total Renewable Energy MWI	398,571.5
% Renewable =	19.06%
% Natural Gas =	81.16%

Source=TA515-530 -8

Natural Gas Usage Mcf

Description		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
Generating Unit														
Beluga Power Plant														
Unit No. 1		2,526	0	0	0	1,135	0	0	2,116	0	18,660	0	25	24,462
Unit No. 2		0	0	0	0	0	0	0	0	0	0	0	0	0
Unit No. 3		6,202	14,190	18,778	0	2,288	0	5,469	0	336	2,993	0	0	50,256
Unit No. 5		0	0	0	0	0	0	0	0	0	0	0	0	0
Unit No. 6		0	5,104	12,816	0	2,516	0	3,631	0	509	2,627	0	15,865	43,068
Unit No. 7		0	0	10,375	0	3,069	0	0	0	3,720	0	0	3,311	20,475
Station Service [1]		61	135	295	0	0	0	0	0	0	0	0	0	491
Subtotal		8,789	19,429	42,263	0	9,008	0	9,100	2,116	4,565	24,280	0	19,201	138,752
Heat Rate		-67.66	35.31	100.65	0.00	40.21	0.00	28.74	-12.09	-1170.51	164.28	0.00	22.42	92.57
Southcentral Power Project[2]														
Unit No. 11		220,892	241,924	269,885	225,187	265,669	249,831	128,758	241,108	257,479	225,184	287,375	288,307	2,901,599
Unit No. 12		167,572	187,532	218,059	167,638	117,350	42,454	186,929	198,199	219,912	223,715	283,631	289,253	2,302,244
Unit No. 13		253,009	229,774	269,348	153,296	242,880	251,079	263,517	262,421	258,416	157,042	253,737	274,730	2,869,249
Subtotal		641,473	659,230	757,292	546,121	625,899	543,364	579,204	701,728	735,807	605,941	824,743	852,290	8,073,092
Heat Rate		7.96	7.86	7.76	7.69	7.72	7.72	7.70	7.68	7.59	7.78	7.81	7.72	7.75
IGT														
Unit No. 1		0	0	0	0	0	0	0	0	0	0	0	0	0
Unit No. 2		0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal		0	0	0	0	0	0	0	0	0	0	0	0	0
Heat Rate														
Plant 1														
Unit No. 3		2,654	2,583	12,828	11,377	1,807	870	5,531	32,058	0	1,886	0	29,515	101,109
Unit No. 4		1,053	38	0	362	184	1,370	759	0	0	0	0	0	3,766
Subtotal		3,707	2,621	12,828	11,739	1,991	2,240	6,290	32,058	0	1,886	0	29,515	104,875
Heat Rate		15	17	12	12	16	18	14	12	0	41	0	13	13
Plant 2														
Unit No. 7		18,700	5,028	7,778	3,515	39	1,252	6,838	18,651	2,137	3,431	28,642	5,895	101,906
Unit No. 8		1,750	0	0	604	0	1,516	0	0	25	156	1,369	897	6,317
Subtotal		20,450	5,028	7,778	4,119	39	2,768	6,838	18,651	2,162	3,587	30,011	6,792	108,224
Heat Rate		31	333	22	-57	0	-42	68	19	-7	-51	17	87	29
Plant 2A														
Unit No. 9		270,315	256,370	264,428	280,518	277,577	178,918	236,928	233,066	105,655	250,523	253,659	268,640	2,876,597
Unit No. 10		261,587	250,977	164,453	265,043	229,743	246,188	255,283	257,735	136,135	255,601	255,882	267,305	2,845,932
Subtotal		531,902	507,347	428,882	545,560	507,320	425,106	492,211	490,801	241,790	506,124	509,541	535,945	5,722,529
Heat Rate		7.47	7.44	7.48	7.44	7.58	7.73	7.59	7.56	8.10	7.55	7.59	7.69	7.57
Total System Natural Gas Mcf		1,206,321	1,193,655	1,249,043	1,107,540	1,144,257	973,478	1,093,643	1,245,354	984,324	1,141,818	1,364,295	1,443,743	**14,147,472**

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
Weighted Avg Heat Rate	7.85	7.81	7.96	7.61	7.73	7.75	7.76	7.78	7.73	7.85	7.82	7.88	7.79
Worst Heat Rate	31.45	332.98	100.65	12.23	40.21	17.89	67.90	19.10	8.10	164.28	17.36	87.41	