2010 Evaluation of Energy Options

Heat and Power

University of Alaska Fairbanks

GLHN Architects and Engineers
0961.01
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Scope of Work

The University of Alaska Fairbanks contracted GLHN A/E to provide first order estimates of the long term performance for a number of alternative campus heat and electric power concepts. Initial evaluation of a broad range of possible technologies lead to a second contract, begun in early 2010, to consider two of the more conventional alternatives in greater technical detail. This report summarizes the combined efforts of both studies, first reviewing the broad initial matrix of possible alternatives, then discussing the methodology, assumptions and results of the more focused work on coal fired steam turbine and natural gas fired combustion turbine technologies.

This report begins with a brief background of the history of campus utility development planning at the University of Alaska Fairbanks, then moves into a discussion of factors that influence decision making for next steps. An immediate need is to plan replacement of the 50 year old steam heat and electric power generation equipment in the Atkinson Plant which form the core of the primary energy infrastructure of campus. Finding an optimal replacement involves evaluating differences in the trade-off between large near term capital outlay and long operating expense. The engineering economics are multidimensional and sensitive to a number of assumptions, projections and variables. Fuel costs and fuel cost projections must include a potential for future shifts in regional energy markets, such as introduction of lower priced pipeline natural gas, along with projections for escalation in energy, operation and maintenance and rate of campus growth. Following discussion on these variables, the report describes the broad range of technologies initially reviewed. Methodology used in a more detailed analysis of two conventional techniques for campus scale combined heat and power is then explained. Results of the spreadsheet modeling effort and a review of the sensitivity of the approach to particular parameters follows. Recommendations for next steps are provided in the final section of the report.

Background

The physical and environmental challenges of operating a university campus in the Interior of Alaska create an intense need for a durable, reliable, energy efficient and low cost utility infrastructure. The university has relied on campus generation of heat (originally wood fired) and electric power (originally diesel engine generated) since its founding in the early 1920s. As campus building area approached 500,000 square feet in the 1960s, a comprehensive analysis of energy options by Bechtel Engineering lead the University to invest in a coal combined heat and power concept. In this system, the energy content of coal, a remarkably inexpensive and abundant local fuel resource, is converted to high pressure steam that expands through a turbine generator before being routed to campus buildings. Because this version of the Rankine power cycle uses the campus heat load as its condenser, it simultaneously provides useful heat and electric power. When compared to alternatives involving purchase of one fuel for a combustion process to generate heat only, and a second fuel to generate electric power, combined heat and power at the UAF Atkinson Power Plant is an energy efficient and low cost endeavor. The primary disadvantages of this concept are the high costs needed to construct and operate the material handling, combustion, ash and particulate emissions of the process. Consideration of trade-offs between initial capital investment and annual operating cost over the life cycle of the system is a classic problem in the field of engineering economics. The 1961 Bechtel Engineering design provided combined heat and power with the two 50,000 lb/hr coal boilers that remain in service. Increasing demand for heat and power driven by campus growth through the 1960s and 1970s forced the University to again consider energy infrastructure alternatives in 1968. It was clear by then that a third unit would be needed for standby purposes. An economic analysis done by Kennedy Engineers compared addition of a third coal fired unit to a new oil fired boiler. Because the third unit would see limited duty through the early years of its useful life, and not be needed as base loaded capacity until campus growth caught up with coal generating capacity, their recommendation was to install the substantially less expensive oil fired unit. In their conclusions, Kennedy Engineers held out the promise of mid-term (15-20 years out) availability of an inexpensive source of natural gas via a proposed regional pipeline. Relatively simple conversion of the new boiler's fuel oil burners to natural gas would then allow the plant to operate at similar cost to coal combustion. Unfortunately, the pipeline has yet to be constructed, and an inexpensive source of natural gas to Fairbanks has not materialized. The University's heat and power demand has continued to grow through construction of new buildings, intensity of ventilation and equipment for scientific research, and computer technology. Reliance on the 1968 oil unit to supplement the 1961 coal units is increasing. A second oil boiler was added early in the 1990s and retrofit to dual fuel in 2007. By 2005, it was recognized that the original 1960s energy infrastructure was in serious need of renewal. Furthermore, it became clear that the annual cost of the relatively small (but far more expensive) fuel oil and electric power purchase needed to supplement the now undersized coal-fired co-generation system would soon exceed the annual cost of the coal purchase.

In 2005, the University commissioned GLHN Architects and Engineers to prepare a Utility Development Plan that collated and prioritized pending costs for system renewal, and compared investment in a new coal combined heat and power system at Atkinson plant to alternatives involving only minimal infrastructure to provide building heat, and purchased electric power. The results, in round numbers, identified over $60 million of infrastructure renewal, in addition to a coal plant improvement and an Atkinson Plant expansion project approaching $150 million. Although the coal plant option would clearly yield lower energy costs over the 20 year period, results of economic life cycle cost comparisons (including debt service) made the comparison closer. It was clear in the results and recommendations of the 2006 Utility Development Plan that the University faces a significant impending problem. S*omething* must be done in the near term to address renewal in the fifty year old infrastructure and its primary equipment. No matter what the solution, significant replacement costs are required. Lead times for equipment replacement, permitting, and infrastructure phasing for a system of this type are on the order of 2-5 years.

The overall range of campus energy options considered in the GLHN 2006 UAF Utility Development Plan was limited to boundary cases of, at one extreme, full investment in a new coal combined heat and power plant and at the other extreme, minimum investment new energy infrastructure with increasing use of stand alone building heating and reliance on purchased electric power. The comparison between these two diverse approaches slightly favored a more energy efficient centralized combined heat and power approach.

A range of alternatives, options and opportunities exist between the extremes considered in the 2006 Utility Development Plan. Alternative technologies using biomass or municipal solid waste, the potential of less expensive pipe line natural gas, or the possibility of an inexpensive regional source of hydro-electric power were not evaluated at that time.

Factors Influencing Decision Making

Technical factors influencing long term campus utility planning at University of Alaska Fairbanks are primarily thermodynamic, economic, and operational. Atkinson Plant converts purchased fuel into heat and power. The prime mover is a set of coal fired boilers that generate steam at sufficient pressure to expand through a turbine that drives an electric generator. The low pressure steam exhausted from this unit provides heat to campus buildings. Campus loads have begun to outgrow the capacity of the Atkinson Plant combined heat and power system, making supplemental purchase of electric power from the utility grid and operation of a fuel oil fired boiler to provide supplemental heat a necessity. Costs to purchase electric power and fuel oil are substantially higher than those associated with coal fired generation. Essential elements of the system are approaching fifty years of age and concern over reliability, maintainability, and safety are mounting. From the thermodynamic perspective, key factors in long term decision making are related to system capacity and process efficiency. The ratio of heat to power is important to maintaining a balance of seasonal performance. Physical characteristics of the different fuel sources create significant difference in the process equipment. A coal fired plant would use a Rankine steam cycle while a natural gas fired plant would use a Brayton cycle used in a combustion turbine with heat recovery strategy.

The economic parameters are equally diverse. Capital costs to install new coal fired equipment are substantially higher than those required to install natural gas fired equipment. The equipment decision may have a fifty year impact on campus operations. Given the large historical differences in the price of coal (at $3.65/million BTU) and the prices of fuel oil (at $20.00/million BTU) and natural gas (at $17.00/million BTU), a switch away from coal would create a large burden on the university's annual energy cost budget. Changes that could reverse this situation include the potential that a pipeline to the vicinity of Fairbanks provides less expensive natural gas and/or the potential that costs associated with CO2 emissions make coal a more expensive fuel. Consideration of factors that adjust fuel costs through the life of the project are important to decision making.

Operational parameters are fairly straight forward and relate to the amount of labor and material that must be applied to maintain the reliability, safety and efficiency of the system installed.

Thermodynamic Factors

- Process type
- Combustion efficiency (steam output to fuel input)

Process heat rate (BTU input to electric power output)
Rate of degredation of equipment efficiency
Plant parasitic losses including station service loads
The match of the process heat-to-power ratio to seasonal campus heat to power demand.
Load growth over time (percentage increase in load per year)

Economic Factors
Capital costs and capital cost phasing over time
Minimum acceptable levels of reliability
Fuel cost and fuel cost escalation
General inflation in construction cost and maintenance labor
Purchased electric power cost and cost escalation
Financing costs (discount rate and interest rate)

Operational Factors
Planned equipment and systems renewal cost
Operation and Maintenance labor
Outages and downtime
Rate of Operation and Maintenance related to equipment degredation

Initial phase

The initial phase of the 2010 study was to prepare a simple calculation tool enabling comparison across a range of alternative campus heat and power options. This tool was intended to provide insight into the more important decision parameters and act as first sieve for comparing new proposals. A second, more detailed tool was developed for comparing two attractive approaches involving conventional fuel sources.

Methodology, Initial Phase

This scope of the first phase was limited to a “first order” estimation of annual energy, operating and debt costs, greenhouse gas emissions and net efficiencies across a range of technical alternatives to provide heat and electric power to the University of Alaska Fairbanks. This was done using a linked pair of Excel spreadsheets. The energy spreadsheet estimated annual energy flow (MMBTU/hr) for each of coal, fuel oil, natural gas, biomass, municipal solid waste, and purchased utility power, for each alternative. The economic spreadsheet computed an estimated cost of fuel and electric power (converted from the energy spreadsheet), operation and maintenance, and loan payment into a single annual cost term. The spreadsheets were set up to model performance over a twenty year period, starting in year 2008. The effect of significant external variables such as fuel cost, interest rate, fuel escalation, construction cost inflation, and campus load growth, over the term of the model were considered by computing performance of each alternative at four year increments, starting with 2008, then 2012, 2016, etc to year 2028. The final product was a graph showing estimated annual cost of the utility system (energy + operations + debt) over the term.

Base Assumptions, Initial Phase

Fuel	*Energy costs*		*Energy Escalation*
Coal	$ 3.65	$/MMBTU	0.25 %/yr
Oil	$20.00	$/MMBTU	1.0 %/yr
Natural Gas	$17.00	$/MMBTU	1.0 %/yr
Biomass/MSW	$ 7.00	$/MMBTU	1.0 %/yr
Elec Power	$ 0.15	$/kWH	1.0 %/yr

Electric Power Growth	*Heat Growth*
1.06 %/yr	0.875 %/yr

Financial Assumptions

interest	*term*	*general inflation*
5.7%	25 yr	3%/yr

Summary of Options, Initial Phase

Option 1: "Do Nothing Different" (DND) models the scenario in which no significant capital investment is made in new heat or electric power. The existing coal fired combined heat and power system continues to operate with increasing supplemental use of GVEA and a combination of fuel oil and natural gas. The fuel-to-steam conversion efficiency at 74% reflecting stoker grate technology. The availability of the coal equipment diminishes (further increasing purchase of supplemental oil, gas and electric power) and operation and maintenance costs are set to increase over time in this model. The model does not consider catastrophic failure or major unplanned outage. The model output for 2008 output closely matches actual documented fuel input to heat and power loads. Although no new investment is made in the production plant, substantial plant maintenance occurs. The economic model does carry capital renewal for the steam distribution system (as do all of the options considered).

Option 2: "Circulating Fluidized Bed" (CFB) This alternative provides a 150,000 #/hr coal fired circulating fluidized bed boiler and a 15 MW steam turbine, and is similar to the concept evaluated in the 2006 Utility development plan. The capital expenditure is on the order of $150 M and includes construction of a new boiler plant, replacement of much of the steam auxiliary system and installation of a new steam turbine in a new plant addition. It is set up to operate in a "heat following" mode, meaning supplemental power is purchased from GVEA. The CFB fuel to steam conversion is estimated at 85%.

Option 3: "Gas Turbine Generator" (GTG)- this concept installs gas turbine generation (several units) of sufficient capacity that no supplemental power is purchased. The cost estimate allocates capital for a new high pressure (+250 psig) gas line to campus, this could alternatively represent low pressure service and a compressor. Supplemental heat is provided with a duct burner (with fuel to steam conversion efficiency of 90%). New turbines and HRSGs are housed in a new turbine building along with electrical switchgear. Existing coal equipment is deactivated. Existing oil and gas boilers remain as standby. This option becomes competitive on a Net Present Value basis with Do Nothing Different if natural gas becomes available at less than approximately $10/MMBTU.

Option 4: “Gas Boiler” (STG)- this concept models the performance of the current Atkinson Plant if the coal units were deactivated and current extraction steam turbine operation proceed with addition of a new 100,000 #/hr gas fired boiler. The new and existing gas boilers would generate 600 psi steam for expansion through a steam turbine to campus heat. The unit would operate in a heat following mode. Fuel to steam efficiency for this boiler is modeled at 0.85% and only natural gas is burned.

Option 5: “All CHP Circulating Fluidized Bed” (CFB all CHP) is a circulating fluidized bed boiler and 20 MW steam turbine with new larger condensers and steam plant auxiliaries. This is an all coal-islanded power station solution- requiring no purchase of utility power or supplemental gas or oil (follows the original Atkinson Plant concept). Construction cost (2010 dollars) is on the order of $180 M. This option, along with the CFB option, could be set up to co-fire Biomass with coal for energy cost reduction or to reduce net greenhouse gas emissions. This option would be capable of exporting power to the electric grid if there were an economic incentive to do so but is not currently set up to do so.

Option 6: “50% Gas Turbine Generator” (GTG)- this concept installs and base loads a single gas turbine generator with heat recovery boiler. Supplemental heat is provided by combination of a duct burner on the turbine generator power train and gas fueled boilers. No coal is burned. Supplemental power is purchased from the Utility. This option requires relatively low capital cost and could be expanded to become Option 3.

Option 7: “Coal Gasifier”- this concept uses a pyrolitic gasifier/oxidizer to convert coal and/or coal co-fired with biomass to steam. Fuel-to- steam conversion efficiency is conservatively set to 70% (research ongoing). A backpressure turbine is installed downstream of the 600 psi heat recovery boiler to reduce pressure to campus distribution. This unit is arranged in a similar fashion to the biomass (wood chip) gasifier recently installed at University of South Carolina which generates up to 60,000 lb/hr at 600 psi and expands steam through a backpressure turbine for campus distribution. More information is needed to model the cost ($/MMBTU) of biomass in Fairbanks- at this point coal is used to compute annual energy cost

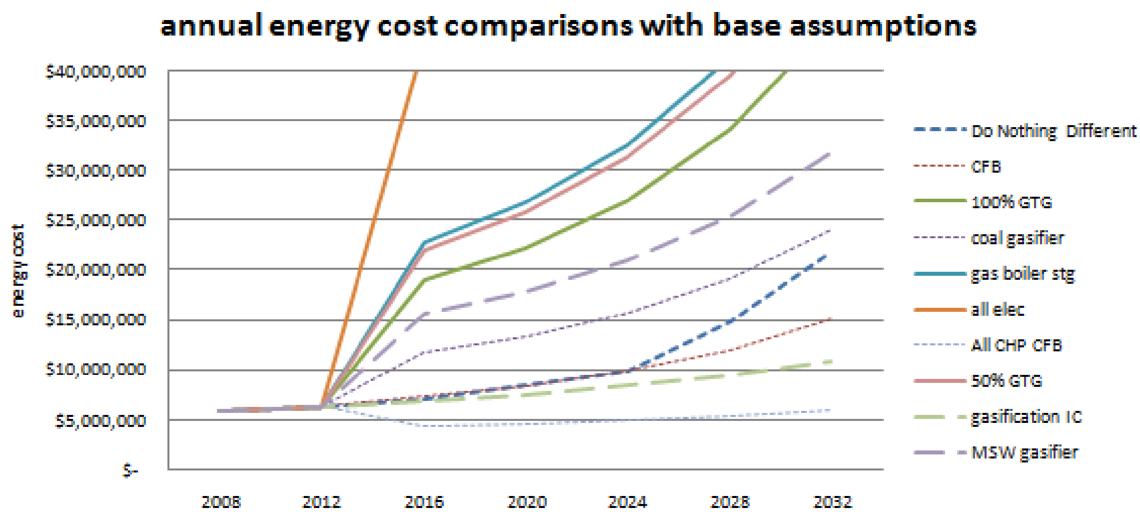
Option 8: “All Electric”- this models the concept of converting the campus heat and power system to all electric in the event of access to a significant source of inexpensive hydro electric power. With hydro power, this concept would achieve a goal of major reduction in campus greenhouse gas emission. Heat would be produced through 12.47 kV electrode boilers in the Atkinson Plant and routed to campus through the existing distribution system. Capital investment in these 125 psi boilers and operating costs are comparatively low. Existing coal units would be removed and the new units installed in their place. Electric generated steam and building condensate return would be routed to campus through the piping in the existing utilidor system. Electric demand quadruples in this option. From an energy cost perspective, this option becomes comparable to “DND” only if electric power became available at roughly $ 0.035/kWh.

Option 9: “MSW IC Internal Combustion” has reciprocating engines fueled with syngas produced from gasification of Municipal Solid Waste or Refuse Derived Fuel (RDF). The units are sized large enough to provide all of the power to meet campus demand. Supplemental heat is provided by natural gas. There are a number of logistical unknowns as this is a developing technology but the promise is that the input fuel cost would be low to free. The model at this point is more speculative than others. Additional research is needed on costs, reliability and efficiency of the gasification process.

Option 10: "MSW Gasifier"- similar technology to the biomass gasifier, this unit would operate with Municipal Solid Waste. This technology has reportedly been used successfully in Canada. The model at this point is more speculative than others. Additional research is needed on environmental issues associated with arctic application and waste handling logistics and costs.

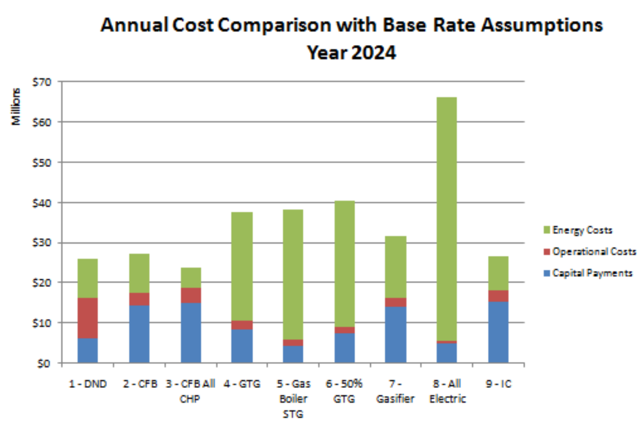
Summary of Results, Initial Phase

The range of estimated annual energy costs is seen in graph below. Given the base assumptions,



options that burn coal or inexpensive biomass/MSW result in less annual expense than those using fuel oil, electricity or natural gas. The lowest cost option with the least escalation is all coal fired co-generation. The highest energy cost option utilizes only purchased electric power.

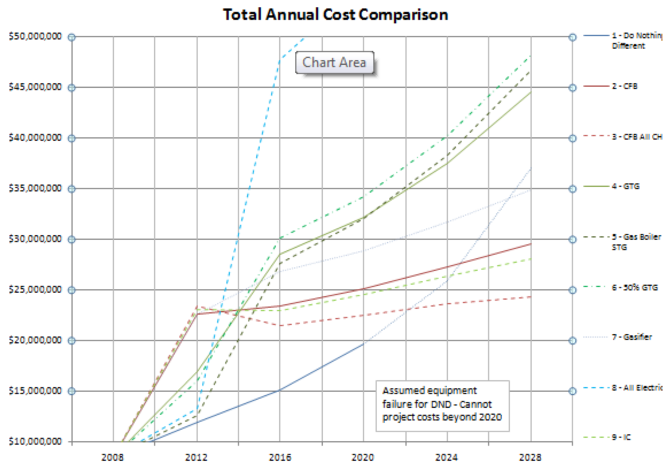
Overall campus utility system costs involve the combination of energy, operations and repayment of the principal and interest on the capital investment in plant. The stacked bar graphic below demonstrates



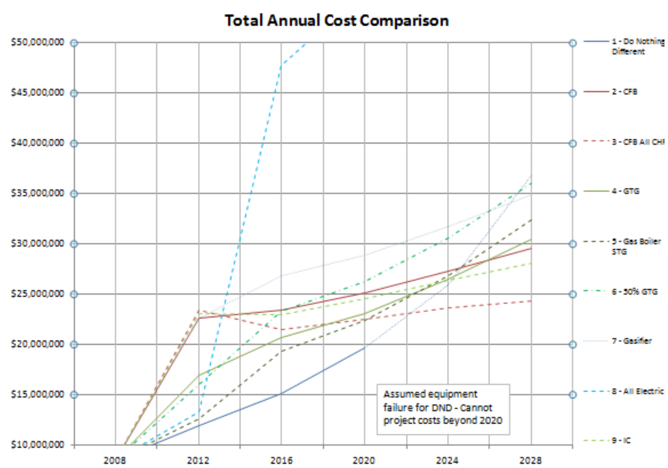
total annual costs across the range of options.

This comparison is a “snapshot” of annual expenses in the year 2024. It shows how capital investment in high efficiency made in 2012 (e.g. CFB all CHP cogeneration system), would lower energy costs enough to yield lowest overall annual cost. An all electric option, which has the lowest capital and operation costs can only make sense as the anticipated cost of electric power is reduced to $0.04/KWh.

A comparison of annual total utility system costs, using the Base Assumptions over the 20 year period is seen below. The magnitude of the spread in annual cost is the “out” years is significant.



A second model, run with the base assumptions modified only by adjusting fuel prices for Natural Gas to $10/MMBTU is shown below. Holding everything else equal, the advent of substantially less expensive source of pipeline natural gas could make near term installation of a gas turbine driven cogeneration process train a better decision. Long a subject of debate and uncertainty, the federal Energy Information Administration (EIA) does not currently project completion of a gas pipeline from the North Slope the Midwest sooner than 2018. To be of any service to UAF, the line would need to follow a southern route. The second phase of this study explored the alternative of natural gas fired combined heat and power in more detail.



Review of Results, Initial Phase

Given the base assumptions, an essential result of this exercise is that overall campus utility costs are projected to more than double over the next twenty years, regardless of which approach is decided (or not) upon. This is driven by a combination of increasing campus load growth, fuel and power costs, and a balance of energy cost, operation and maintenance and bond payment. How much more than double is a function of the decision, and the retrospective quality of the assumptions.

The research to collate data for alternatives demonstrated the relatively narrow range of combined heat and power systems in common use across the United States. Gas turbine cogeneration systems are utilized in a large number of university campus utility systems, coal fired steam cogeneration is typical, particularly in established campuses where access to inexpensive coal made mid 1900 investment in campus scale plants attractive. Use of biomass, either as a primary fuel source or co-fired with coal is less common, but has been in reliable operation at a number of university systems. Beyond these basic technologies, there are few, if any examples of the alternative technologies explored in this study. Municipal Solid Waste as a heat and power production fuel source has had a long history in European utility systems but limited application in the US, particularly on a campus setting. Coal gasification technologies are seeing some application on a larger regional utility scale (the Polk Power Plant in Tampa Fl. Is an example) but have not reached a cost effective level at the size of UAF. Energy systems involving production of syngas to fuel internal combustion or gas turbine engines have been demonstrated and are available, but have not seen wide acceptance as the primary drivers of heat and power systems with the scope or scale of the University of Alaska Fairbanks campus. The concept of a hydro-electric plant that serves the interior of Alaska has great appeal as a “carbon free” energy source, but it is difficult to imagine how the cost of electricity such a major project could be low enough to justify elimination of combined heat and power. The cost and performance of biomass gasification were derived as a first order approximation, with an attempt to use conservative factors to represent the realities of construction in Fairbanks. Costs, availability and environmental mitigation of the biomass and MSW gasification technologies considered here are not well proven in the United States and estimates have been factored up to reflect technology risk.

Significant elements of the decision include financing methodology. Increasing the loan interest rate term (which might serve as a first order model of a third party financing option) tends to make less capital intensive decisions more attractive. Legislation that adds a significant energy cost penalty to annual carbon emission will favor natural gas, biomass, MSW and hydro-electric power options.

Lowest Net Present Value (NPV) is often used in engineering economics as the term that best represents prudent comparative investment decision. A university utility system, historically operated on a year-to-year budget allocation is not necessarily familiar with concepts of comparative rates of return. While information developed in this study is sufficient to perform an NPV analysis, the graphic approach here is intended to demonstrate the more tangible reality of year to year annual utility expense. Although these calculations provide insight into possible long term outcomes of near term decisions, cumulative cost and Net Present Value analysis certainly need to be included in final decision making.

Second Phase

The range of alternatives was narrowed in the second phase to two commonly applied and proven technologies: a coal fired steam cycle using circulating fluidized bed boiler, and a natural gas fired combustion turbines with heat recovery boilers and supplemental firing. More detailed performance analysis, involving performance calculations for each of twelve months, every year was done. The life cycle analysis was extended to thirty years. The effect of differing heat-to-power ratios of the two strategies was analyzed in more detail, and better estimates for ultimate build-out capacity (based on projected peak loads) derived. The more detailed approach allowed inclusion of estimates of operation and maintenance. A central objective of the second phase analysis was to derive of an estimate of the price of natural gas that would represent the “breakpoint” in a comparison of a coal to gas fired cogeneration plant. This analysis needed to recognize that, even if planning approval for a new pipeline was granted immediately, it would be years before less expensive fuel was available in Fairbanks.

Second Phase Methodology

A single spreadsheet was developed for the second phase analysis. Monthly models of current plant performance were calibrated with 2008-2009 PI data and, as before, formed the basis of the Do Nothing Different model. Campus load growth factors and fuel cost factors (based on escalated current costs) were applied for every year from 2010 to 2040. Similar models of monthly behavior of a coal fired steam plant with CFB and a natural gas combustion turbine plant with heat recovery and supplementary firing were developed and run in a similar fashion. Capital cost estimates were updated for each of the Do Nothing Different and alternative strategies. As analysis proceeded, two variations on the basic alternatives were added. Converting electric vapor compression chilling on the West Ridge to steam absorption chilling to improve summertime campus heat to power demand was modeled (CFB Steam Cool), as was the concept of installing additional gas turbine generators with the ability to export electric power (GTG Power Sell) . The concept here was that wintertime campus cogeneration efficiency could be improved by reducing the ratio of supplemental firing to recovered heat. As before, equipment installation costs were factored upward to account for construction difficulty factors, contractor overhead and profit, UAF project management, permitting, design etc. Construction costs were scheduled to occur at appropriate points in the life cycle. A date for the introduction of inexpensive pipeline gas was estimated and a model that considers the alternative of doing no plant improvements inexpensive gas in imminent, then investing in gas turbines was explored.

An annual payments calculation allows input of terms of a loan to repay the capital expense. Interest rate and term are nominally set at 5.7% and 20 years, but can easily be adjusted. When set at 20 years, the dramatic effect of loan repayment on the annual cash flow can be seen in the graph.

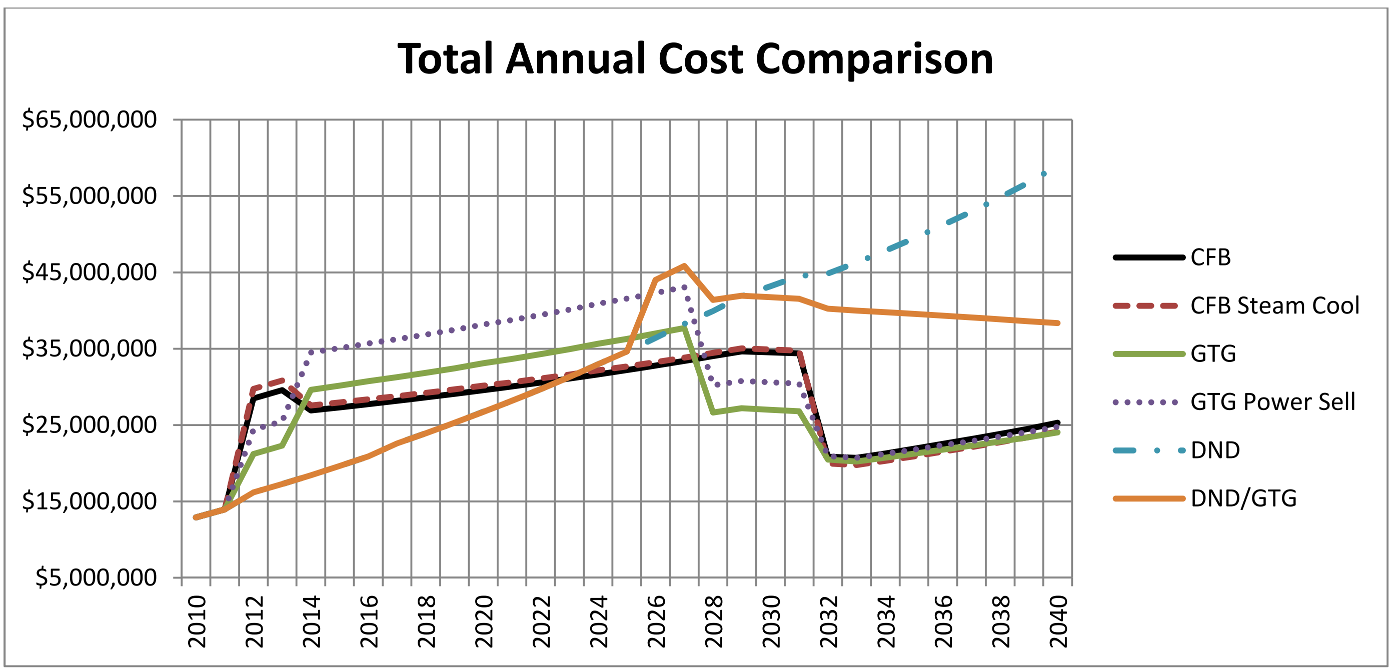
The second phase model includes a calculation to estimate annual operation and maintenance costs. Number of full time equivalent staff is anticipated to be different in a coal plant than a natural gas facility. Annual operation and maintenance is considered with a compounding escalation factor over time. A larger compounding factor is applied to the Do Nothing Different scenario to reflect the increase in maintenance that must be anticipated as the components in the plant exceed their expected useful service lives. The question of how long the existing plant can be sustained without major unplanned outage is not directly addressed in the model. The larger compounding factor provides a means to estimate the cost of mitigating the risk of an unplanned catastrophic failure.

Annual costs for each of the alternatives are summed and compared on a time line. Of interest are the cross-over points at which the annual costs of two options are equal. A net present value calculation is done on the projected cash flow strings and a comparative value derived.

A projection of Greenhouse Gas emissions is derived for each of the options using CO2 equivalencies for coal, natural gas and an estimate of the fuel portfolio of the local electric utility.

Second Phase Results

A graph showing the combination of energy, operations and financing costs provides some insight into the long term performance of the options.

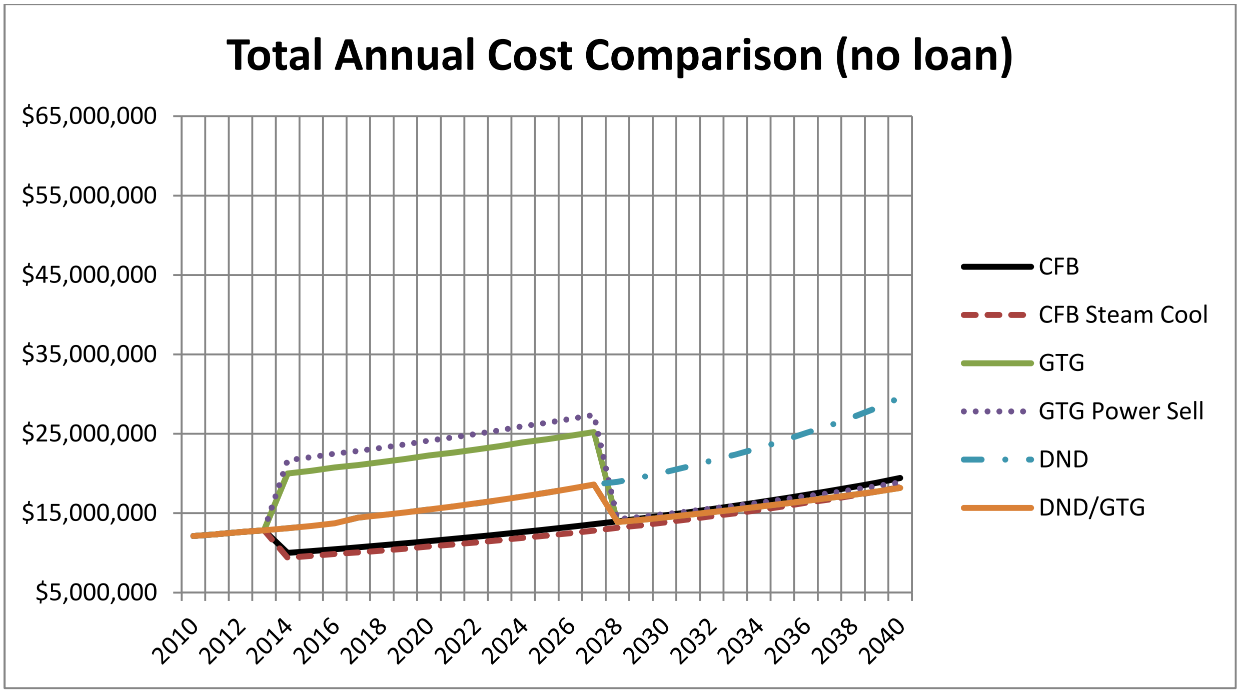


Annual cost for the Do Nothing Different scenario continue to monotonically increase as the aging equipment continues to be repaired and replaced in kind, and increasing amounts of supplemental fuel oil and electric power are purchased. The coal fired CFB options require a substantial capital investment and the benefits of substantially lower fuel are offset by the loan repayment. At the end of the twenty year term, annual costs of the CFB option drop to just energy and operations. The natural gas fired GTG options require less capital, and lower financing costs, but are hampered by high fuel costs until such time as inexpensive pipeline gas becomes available (modeled here as occurring in 2028, and costing $8/MMBTU in 2009 dollars). Deferring the decision to invest in gas turbines until pipeline gas becomes available pushes the problem forward and does not work to lower annual costs in the next forty years. A cross over point at which the annual projected cost of doing nothing different is comparable to those of a new CFB is seen to occur at about 2022 in this model. From that point on, the CFB is a less expensive proposition.

A summary of Net Present Values of the options (in which the lowest NPV represents the best use of capital) is seen below.

Option	NPV (40 yr)
1-CFB	$386,336,411
2- CFB Steam Cool	$391,226,354
3- GTG	$389,215,447
4- GTG Power Sell	$438,712,711
5- DND	$410,671,130
6- DND/GTG	$392,389,688

Consideration of the life cycle costs for this project lead to a question of the validity of the economic terms of the model. Does the University (or the State) make investment decisions based on comparison of potential rates of return? Annual budgets that pay for operations and energy consumed at the Atkinson Plant are typically allotted on a year to year basis. A large part of the current problem is the absence of a renewal fund that could now be tapped to replace and expand the plant. An annual cost comparison that assumes the one time capital cost is “granted” to the university shows the dramatic difference in operating costs alone.



Annual CO2 emissions for the coal fire combined heat and power option are substantially more than those generated from natural gas fired combustion turbines, but can be mitigated, to pre 1990 levels, through co-firing of biomass in the circulating fluidized bed boilers.

Recommendations for Next Steps

Determination of an optimal campus heat and power solution at the University of Alaska is a multi-variable problem, subject to a broad range of assumptions. The spreadsheet model, while a first order approximation, allows consideration of the affect of a number of the central factors. A coal fired solution, while most capital intensive, holds promise of being the least expensive operational solution, provided financial disincentives for carbon emission on this scale do not become onerous over the next twenty years. Certainty of an availability of competitively priced natural gas in the near to mid-term could tip the scales toward installation of gas turbine technology. The central question of when a natural gas pipeline would be a completed and at what price the fuel would be available is beyond the scope of the spreadsheet analysis.

In the absence of a clear understanding of the future of natural gas in Fairbanks, a prudent next step is to advance the conceptual design and permitting efforts to a point where issues related to plant performance, emissions technologies, implementation timing, and construction costs for fuel source alternatives are more completely quantified. Financing options could be explored on a parallel track. More data and detailed analysis will support better decision making. Time is a central issue in solving the complex problems of this aging infrastructure and makes sustained focus essential.