Univ

SIX YEAR IMPLEMENTATION PLAN

Priority	Project Description	

SMALL CRITICAL PROJECTS
(Item 7 from Six Year Implementation Plan)

Priority	Project Description	Project Cost	Capital Request Location
7a	Convert Boiler No. 4 to Natural Gas	$200,000	FY08 R&R Atkinson Revitalization
7b	New Control Room	$260,000	FY08 R&R Atkinson Revitalization
7c	New Turbine controls	$300,000	FY08 R&R Atkinson Revitalization
7d	New Air Compressors	$400,000	FY08 R&R Atkinson Revitalization
7e	Redundant DI water Unit	$110,000	FY08 R&R Atkinson Revitalization
7f	Reconstruct water pumping station Ph. 1	$160,000	FY08 R&R Atkinson Revitalization
7g	Atkinson grading/paving (fugitive dust control)	$130,000	FY08 R&R Atkinson Revitalization
7h	Convert Boiler No. 3 to Natural Gas	$350,000	FY08 R&R Atkinson Revitalization
7i	Replace feedwater heater	$65,000	FY08 R&R Atkinson Revitalization
7j	Utilidor ventilation Phase 1	$130,000	FY08 R&R Atkinson Revitalization
7k	Increase RO water capacity	$195,000	FY08 R&R Atkinson Revitalization
7l	Add Continuous Emissions Monitoring to Boiler No. 4	$250,000	FY08 R&R Atkinson Revitalization
	TOTAL	**$2,550,000**	

Pacific Consulting

APPENDIX A: FINANCIAL APPENDIX

SECTION

THE UNIVERSITY OF ALASKA FAIRBANKS
2005 UTILITY DEVELOPMENT PLAN

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THE UNIVERSITY OF ALASKA FAIRBANKS
2005 UTILITY DEVELOPMENT PLAN
ACKNOWLEDGEMENTS

Utility Development Planning combines elements of the practices of Engineering, Economics, Finance, Accounting, Facility Management and Central Utility Operation. The plan presented in this document was a highly collaborative effort involving the time, energy, knowledge and patience of a diverse group of professionals.

Mike Ruckhaus, P.E., Senior Project Manager, Division of Design and Construction deserves special recognition for his efforts in assembling the UAF working team, coordinating meetings, teleconferences and reviews and assuring university input and feedback into the modeling process. Mike, along with Chilkoot Ward; Facilities Services Director at UAF sustained an intent interest in the planning process and outcome of the work. Their help in informing the consultants and assuring that the data, assumptions, and physics were appropriate was invaluable. Adam Saunders, UAF facilities Services Engineering Assistant is recognized as being a great help to the consultants in the early stages of the process when gathering field data and tracking down fine scale details of the operation were critical.

Key members of the UAF management team whose input in formulating campus strategies, correcting assumptions, and scrutinizing the complex economic and engineering model outputs include:

Kathleen Schedler, P.E. - UAF Associate Vice Chancellor for Facilities and Safety
Steven C. Meckel, CPA-UAF Facilities Services Financial Manger; Division of Budget and Accounting
Linda Zanazzo-UAF Facilities Services Director
Myron J. Dosch, CPA-UAF Assistant Controller, Finance; Statewide Finance-Controller's Office
Richard L. Schointuch, Ph.D., A.I.A.-UAF Associate Vice President for Facilities; Systemwide Facilities Director; SW Finance
Michael Hostina-UAF Associate General Counsel; Office of the General Counsel
Daniel Kaplan-President: Kaplan Financial Consulting, Inc.

The consultant team for the University of Alaska Fairbanks, Utility Development Plan project included:
Design Alaska- Jack Wilbur, Chris Miller, Linda Taylor, Damon Zimmerman
GLHN- Bill Nelson, Henry Johnstone, Megan McGann, Pat Fisher
E3c- John Tysseling, Ben Boersma, Melissa Roberts, Daniel Wright
HRA- Todd Spacek, Scott Lochhead
Pacific Consulting- Jeff Easton

The performance of the existing DES at UAF is excellent. In comparison to regional public utilities, reliability of service is remarkably high. Historically, outages have occurred infrequently and have been of limited duration. With regionally mined coal as the base fuel used to cogenerate steam and electric power, the annual cost to operate the system is extremely attractive when compared to the purchase of liquid or gaseous fuel for boiler heat along with the purchase of electric power from the public utility grid. Coal, purchased by the university under a long-term contract, is a stable, reliable commodity when compared to fuel oil or natural gas alternatives. The return on the 1964 investment decision to construct coal-fired cogeneration has been four decades of reliability, stability

Finally, significant capital renewal issues in the forty-year-old system have surfaced. Among these issues are:

- Electrical distribution safety and reliability;
- Steam equipment reliability and maintainability; and
- Water system reliability and maintainability.

The purpose of the UDP is to enable informed decision making on improvement of campus infrastructure. Construction cost and operating efficiency of alternative engineering approaches to the problem of system growth are formulated, and an economic scenario model that includes operating costs, fuel costs and financing costs over a twenty year period is used to compute net present value by scenario. These net present value calculations, along with less tangible factors that include reliability and fuel market stability, are the critical components needed for the University to arrive at a long-term plan.

A phased capital renewal plan that sustains operation of the existing heating, electric power, water and chilled water infrastructure is presented. Three alternative engineering solutions to the problem of meeting campus load growth are considered. These scenarios are:

- Purchase all additional electric power from the local utility and install individual fuel oil or natural gas building heating boilers as growth occurs;
- Purchase all additional electric power from the local utility and install a new "satellite" fuel oil or natural gas fired heating plant on the West Ridge; or
- Improve the existing steam distribution system and construct a new coal fired steam cogeneration facility capable of serving all electric power and steam heating needs of the campus.

The UDP Project Team strongly recommends that UAF identify and empower a focused Utility Project Team charged with <u>implementation</u> of the UDP Strategy, including an advocacy role seeking to resolve the capital funding issues.

STUDY OVERVIEW

The purpose of this study is to analyze alternative long-term – twenty (20) year – comprehensive utility systems for the University of Alaska Fairbanks' main campus. The University of Alaska Fairbanks, founded in 1917, is the northernmost Land, Sea and Space Grant university and research center in the United States, and this location poses many unique challenges and opportunities for the University. UAF's main campus, the focus of this study, spans nearly 2,250 acres and has an enrollment of over 5,500 students. The campus boasts seven major research units, including the Agricultural and Forestry Experiment Station, the Arctic Region Supercomputing Center, the Geophysical Institute, the Institute of Arctic Biology, the Institute of Marine Science, Institute of Northern Engineering, and the International Arctic Research Center. Graduate enrollment has increased thirteen percent (13%) from 2002-2004, largely due to UAF's ability to attract more than $112.4 million in research funding over the last several years, and UAF remains the only campus in the state to award doctoral degrees.

The growth of UAF, both in terms of student enrollment and physical building square footage, increases its need for reliable utility services. In virtually all campus planning environments, the development and growth of academic, research and community programs impose crucial utility service requirements that must be met to successfully support the broad mission of the university. The utility services infrastructure comprises a fundamental capital asset of the university that must be carefully managed and planned in order to fulfill these service requirements.

In Fiscal Year (FY) 2005, the UAF central campus consumed over 55 million kilowatt hours of electricity and over 275 million pounds of steam used for heating and cooling. Currently, these utility consumption amounts are supplied primarily by the campus' central utility plant; however within the next few years, the increase in campus utility service requirements driven by campus growth will exceed the capacity of the existing utility

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NEED FOR LONG-TERM UTILITY PLANNING

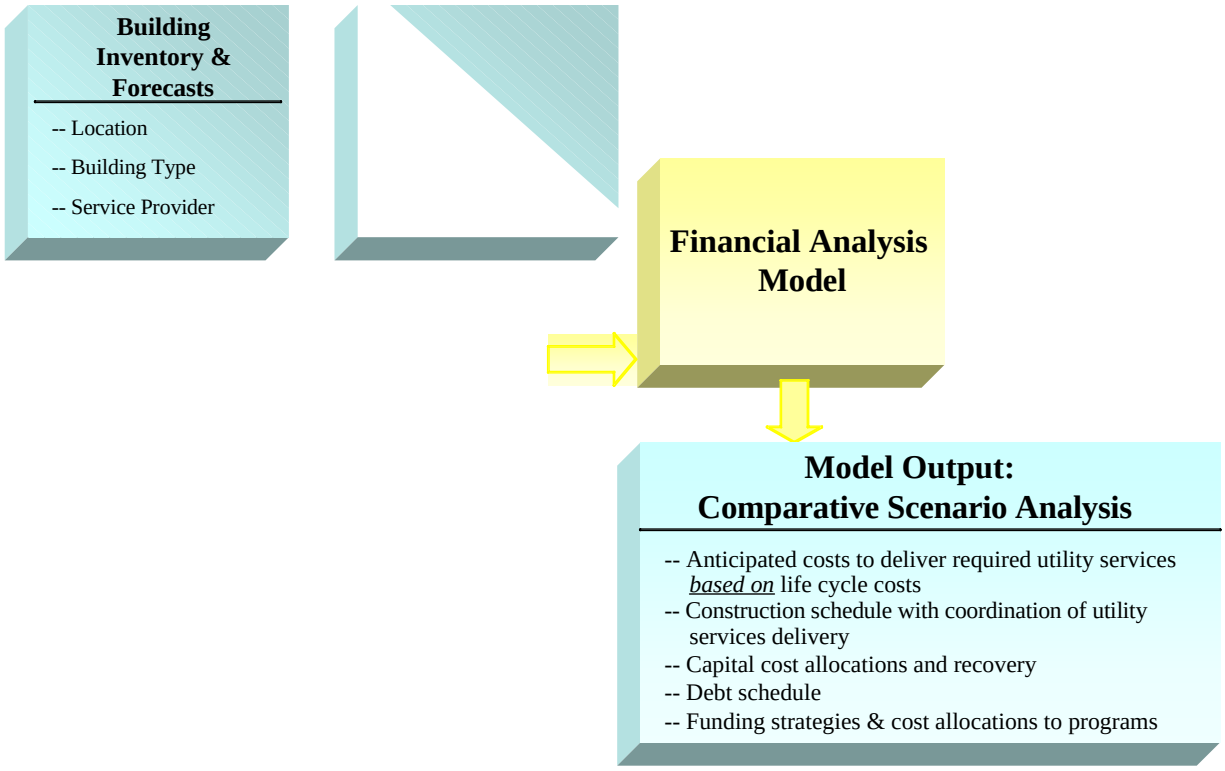
All successful large institutions require a financial plan to conduct their long-term mission requirements. A major component of that plan is the utility infrastructure asset base. Because utility infrastructure is, by nature, a long-term capital-intensive item, it deserves proper attention within the institution's priorities in fiscal and capital planning.

Successful long-term institutional utility services planning requires a comprehensive, strategic and quantitative analysis of various configurations and combinations of utility infrastructure capable of meeting current and future campus utility requirements. Variables such as energy prices, campus growth, and fiscal constraints create complex problems for facilities managers and necessitate the use of comparative analyses in strategic planning evaluations. Equally important is the need for developing a comprehensive funding strategy, which will ensure that the utility project plan chosen can be implemented fully and successfully.

Together, the engineering and economic analyses undertaken for the ***2005 Utility Development Plan*** (UDP) project are capable of addressing the complex nature of such an endeavor. While the engineering analysis addresses the utility infrastructure, system capacity, and efficiency (among other technical matters), the UDP Model utilizes advanced scenario modeling and data analysis methods. The analytical techniques include capabilities to assess life-cycle cost[1] analysis, the ability to perform "what-if" and sensitivity analysis, the ability to allocate costs to responsible entities (e.g., cost centers), and the ability to incorporate long-term trends in forecasted growth, utility load, and energy prices. A graphical description of information flow within the UDP Model is shown below:

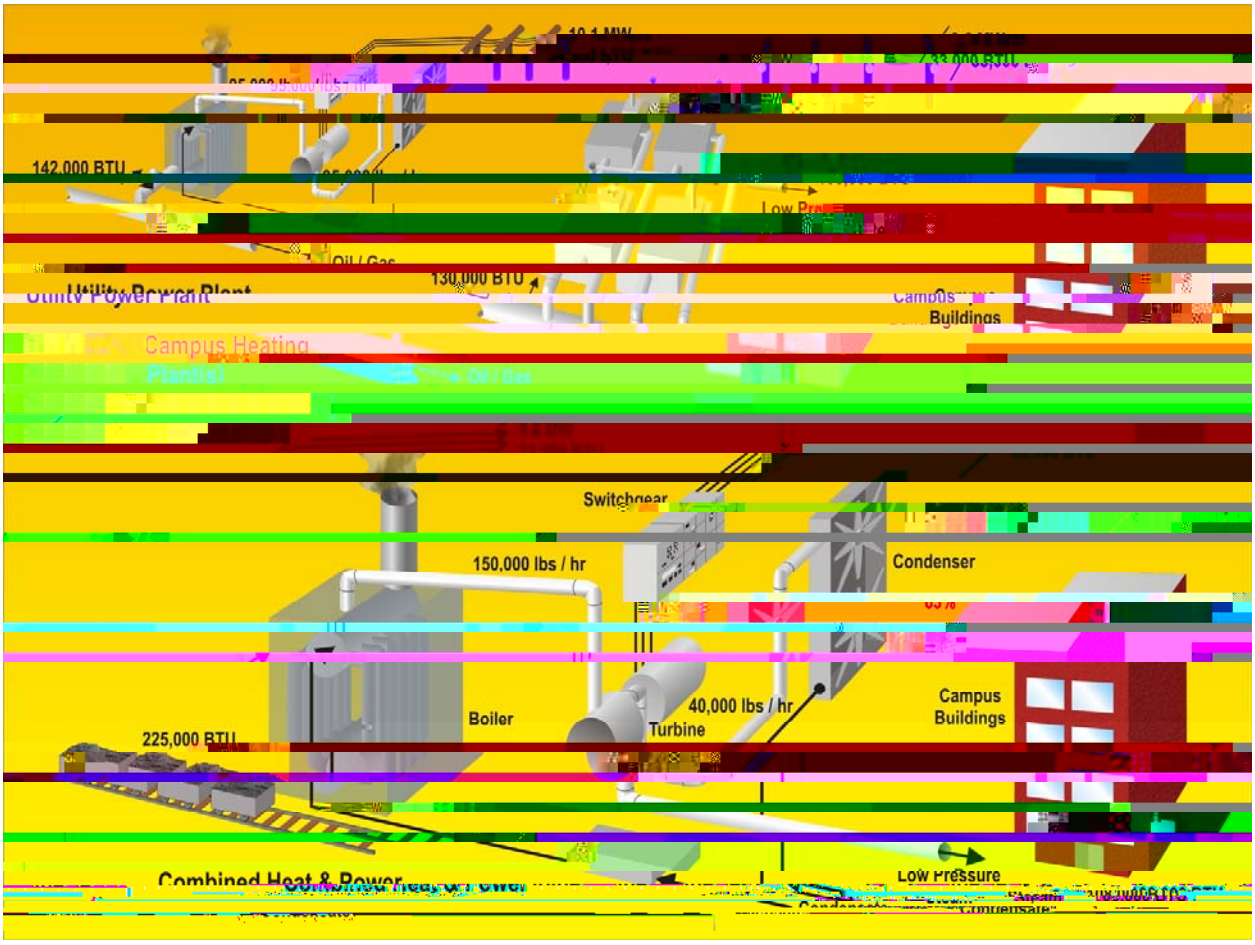
[1] Life-cycle costs are defined as the sum of the present values of:
(a) Investment costs, less salvage values at the end of the study period;
(b) Non-fuel operation and maintenance costs (both annual and major maintenance renewal);
(c) Replacement costs less salvage value of replaced building systems; and
(d) Energy and/or water costs.

Figure 1 UAF UDP Model Information Flow



The UDP Model helps to identify the long-term fiscal implications (costs and benefits) associated with each alternative for serving the utility services demand, and presents comparable economic outputs in the form of net present value analysis for each alternative strategy. The purpose of determining the present value of cash flows stems from the basic finance principle, "a dollar today is worth more than a dollar tomorrow." Performing a net present value analysis is critical for proper comparison of the alternatives in today's dollars — that is, the comparative value of a project if all of the costs and benefits are stated in common terms of present day dollars. When undertaking a long-term project that spans twenty years, the time value of money concept becomes extremely important. This type of economic/financial analysis is a widely accepted methodology in both the corporate and public policy arenas, and has proven invaluable in dealing with the complex nature of utility planning by providing the critical information university administrators need to make well-informed decisions.

Figure 2 UAF District Energy System



The important point to be understood from the diagram is the significant gain in the overall efficiency of energy use for the combined heat and power system at the UAF Atkinson Plant as compared to alternative plant configurations. In particular, the output from the plant is substantially higher than the combination of purchased utility power and alternative plant configurations (with the same level of energy input into the system). Additionally, the primary input fuel (coal) is significantly less expensive on a energy content basis (Btu's) than the alternative plant fuel inputs, thereby further increasing the economic efficiency of the combined heat and power DES plant configuration.

For energy and facilities managers, it is critical to evaluate, through the use of a quantitative, life-cycle analysis, whether the proposed benefits outweigh the costs incurred in

Figure 3 University of Alaska Fairbanks Campus Map Showing Steam Utility System

Significant features of the sub-artic environment of Fairbanks include wintertime low temperatures of negative sixty degrees Fahrenheit (-60° F) and daylight periods ranging from 3.5 hours in December to 22 hours in June. Long periods of sub-zero ambient temperatures over an eight-month heating season amount to 15,000 heating degree days. Long periods of summertime daylight hours combine with high temperatures in the high-nineties degrees Fahrenheit (99° F) to create a significant need for internal cooling in research and academic facilities. Current peak demand statistics are:

Steam:	152,000 lbs/hr
Electric Power:	10 MW
Chilled Water:	3,000 Tons

The campus' central utility system (DES facilities) provides heating, electrical power, water, and, for the lower campus, chilled water for building cooling. A comprehensive history of the University's utilities systems can be found in Appendix C – History of UAF's Utilities Development. Essential elements of the current DES include:

1. A central utility plant facility for fuel transport and storage, steam generation, electrical power generation and transformation equipment, water treatment chilled water production and distribution equipment, auxiliary equipment and systems and administrative offices;

2. Two coal-fired steam generators with the combined ability to generate approximately 100,000 lbs/hr of high pressure steam;

3. Two fuel oil-fired steam generators with the combined ability to generate approximately 200,000 lbs/hr of high pressure steam;

4. A steam turbine generator capable of converting on the order of 130,000 lbs/hr of high pressure steam into 8.5 MW of electric power and 120,000 lbs/hr of low pressure steam for campus heat;

5. A system of subterranean concrete tunnels, known as utilidors connecting the central power plant to essentially all WR and LC buildings. Piping and conduit for low pressure steam, condensate return, water, electric power, communications, compressed air and other utility services are routed within the system of utilidors;

6. A diesel engine generator (DEG) system, originally intended to demonstrate liquefied coal slurry technology, capable of providing approximately 10 MW of electrical power and 20,000 lbs/hr of low pressure steam;

7. A 4,160 Volt electrical distribution system capable of being fed from the steam turbine generator, the local utility (GVEA), or the diesel engine generator;

8. A low pressure steam absorption chilling plant for distribution to buildings on LC; and

9. A set of water wells, a potable water treatment system and a water distribution system that provides potable and fire protection service to both regions of campus.

Central utility services that are not currently provided to the UAF campus via the DES include:

1. Steam, water and electric power to various UAF owned off-campus buildings and facilities;

2. Central cooling to research and academic facilities on the WR, which are currently cooled by means of “stand alone” air-cooled

"primary use" information produced by UAF—and total square footage by building type was summed. Summaries of historical campus square footage by building type and campus location, including forecasts to FY 2012 from the Six-Year Capital Plan, are seen in the two charts below:

Figure 4 Historic & Projected UAF Building (SqFt) Growth 1965-2005, By Building

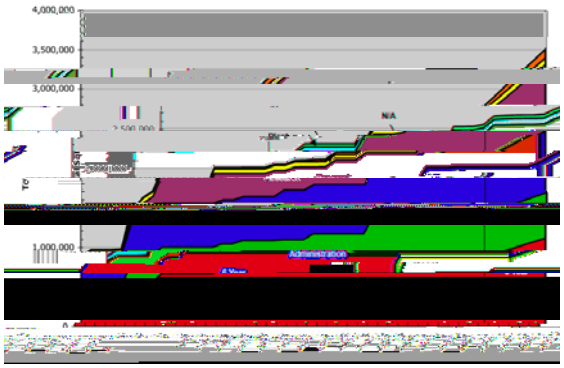
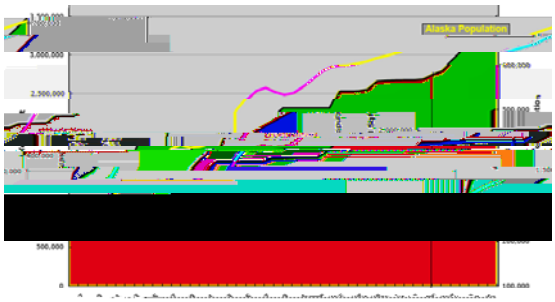


Figure 5 Historic & Projected UAF Building (SqFt) Growth 1965-2005, By Location



The UDP Project Team analyzed UAF's average annual historical growth rates for the campus based on the building inventory data, as well as Alaska state population data. The two graphs demonstrate the uneven pattern of total growth throughout time, including FY2012 square footage growth projections based on the University's Six-Year Capital Plan.

Table 1 summarizes historical building inventories for each ten year increment beginning in FY1965 and also provides the building inventory anticipated to exist in FY 2012 as a result of the Six-Year Capital Plan.

Table 1 Historical Building Inventories

	FY 1965	FY 1975	FY 1985	FY 1995	FY 2005	FY 2012
Lower Campus SqFt	886,187	1,618,781	1,758,188	1,864,219	1,898,616	2,321,116
West Ridge SqFt	5,059	389,580	441,534	667,208	892,759	1,242,611
Total UAF Campus	**891,246**	**2,008,361**	**2,199,722**	**2,531,427**	**2,791,375**	**3,563,726**
Alaska Population	*265,200*	*384,100*	*543,900*	*601,581*	*662,604*	*713,393*

The FY2005 UAF campus square foot calculation of 2.8 million relates to UAF central campus buildings that currently are or could be connected to UAF DES service. Approximately 200,000 square feet of the UAF campus are not served by UAF DES facilities and are ignored by this investigation. To determine appropriate future campus growth, the UDP Project Team first reviewed the University's Six-Year Capital Plan growth prediction. While the Six-Year Plan reflects full implementation of projected growth to FY2012, actual funding and prioritization of building projects constrain current expectations of actual growth. Therefore, to predict more accurate future growth, the UDP Project Team and UAF staff developed a combination of historical growth and expected trends to reach a FY2025 total campus square footage of 3.9 million.

The detailed calculation used to reach the 3.9 million square foot FY 2025 projection assumes:

- Actual build-out of 65% of Six-Year Capital Plan growth projection (i.e., 500,000 square feet of growth) to realistically occur by FY 2016;
- Two percent (2%) annual overall campus growth from FY 2016 to FY 2025; and
- Distribution of campus growth by building type and campus location based on expected specific growth patterns throughout the twenty (20) year study period.

The goal of the growth analysis is to identify a "most likely" strategy for UAF square footage growth, as it relates to delivery of utility services. Within this "most likely" overall campus growth expectation, differing rates are applied to separate areas of campus and individual building types, depending on expected campus trends, priority of program activities within UAF's mission, and physical availability of space. The UDP Project Team believes the estimation of 3.9 million total campus square feet appropriately considers the campus and state's thirty years of past growth, the predicted growth from the University's Six-Year Capital Plan, and the specific campus growth trends expected by UAF staff. This estimation allows for planning of sufficient utility facility capacity to meet future campus needs.

The breakout of percent growth and total forecasted square footages by campus location and building type can be seen in Figure 6, Figure 7, and Table 2 below:

Figure 6 Projected UAF Building (SqFt) Growth 1965-2025, By Building

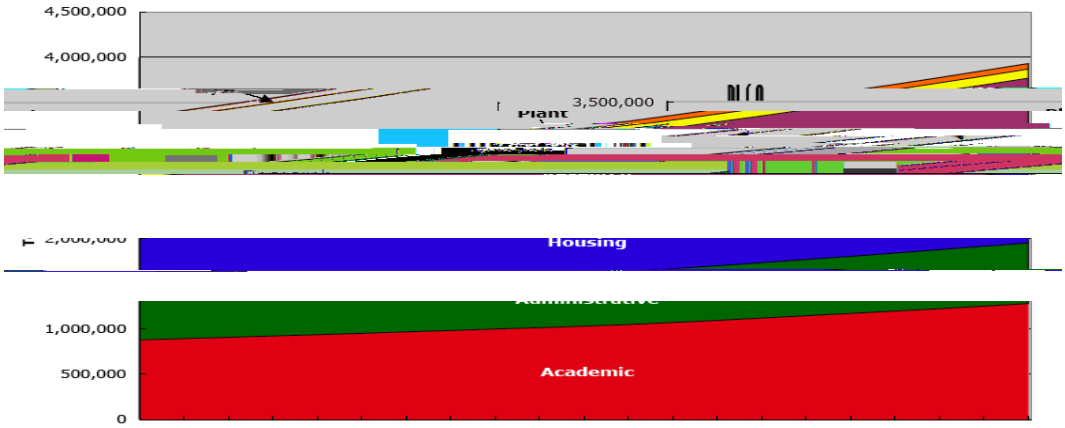


Table 2 Projected UAF Campus Annual Growth Rates

	Lower Campus Growth Rate			West Ridge Growth Rate			UAF Combined Growth Rate		
	Academic	Research	Total	Academic	Research	Total	Academic	Research	Total
FY 2006 - 2016	1.75%	0.30%	1.15%	0.50%	2.93%	2.20%	1.58%	2.84%	1.50%
FY 2017 - 2025	2.25%	1.50%	1.85%	2.00%	2.49%	2.27%	2.22%	2.47%	2.00%

Additional growth strategies derived from the "most likely" case are also analyzed in the UDP Model to provide sensitivity analyses for several campus growth possibilities.

Energy Load Density

When discussing campus growth and future energy use projections for the UAF campus, it is important to also consider trends in projected energy load density throughout the campus. In other words, if the campus were to remain identical in population and building square footage size, how much more energy would be consumed each year as a result of increasing needs for energy per square foot of space. To capture the effects of expected electric load density growth on the UAF campus, a factor of 1.5% is applied to the independent building electrical growth for the first ten years in the UDP Model. The decision to use a factor of 1.5% was arrived through historical analysis of UAF electric consumption data from FY1990 to FY2005. This 1.5% electric load density growth factor is also consistent with other electric consumers of similar size and patterns of electric use—specifically other universities.[4] The electric load density growth factor is not applied in the second ten years of the UDP Model, however. The UDP Project Team and UAF facilities staff decided the increasing efficiency of electrical equipment and the leveling off of the increase of additional personal computers on campus made projecting continued load density growth unrealistic in the model. Electrical loads for lighting and car plugs (block heaters), however, remain in proportion with overall campus square footage growth throughout the twenty-year time span of the UDP Model.

[4] Urso, Jack, "The Energy Crunch," *University Business*, November 2005,

COMMON UTILITY SYSTEM IMPROVEMENTS AND CAPITAL ASSET RENEWALS

The existing utility system infrastructure at UAF requires significant investment in major maintenance and upgrades in order to continue to provide reliable utility services. The maintenance and systems upgrade requirements are common to any and all future strategies the University considers and are incorporated as part of the UDP analyses. Recent studies and investigations of the forty-plus year old steam production and distribution system have identified single point failure reliability issues in plant auxiliaries, facilities, and aged and undersized components of the system that must be replaced.

A large percentage of the physical infrastructure of the existing University's DES was put

In addition to items specifically identified through our 2005 UDP effort, three previous engineering studies were incorporated into this analysis. These include: "*University of Alaska Fairbanks Utility Evaluation Study,"* October 2000 by Coffman Engineers; "*UAF Electrical Distribution System Upgrade Study,"* August 2001 by PDC Consulting Engineers; and "*Water Systems Study,"* 2001. Construction cost estimates from the earlier studies were adjusted to reflect current construction project costs.

Table 3 summarizes the common utility system improvements currently required by UAF. These improvements are described in detail in Appendix A Section A, and their associated time schedules are detailed in Appendix A Section B. **These required upgrades to maintain UAF's utility capabilities and system reliability total approximately $61.7 Million[5] and are a necessity no matter what long-term utility strategy is chosen for UAF.**

Table 3 Common Capital Asset Renewal Expenses by Utility System

Utility System	Estimated 2005 Capital Cost
Electric System	$ 39,489,000
Steam System	$ 14,600,000
Chilled Water System	$ 1,040,000
Domestic Water System	$ 3,022,000
General Plant	$ 3,510,000
Total	**$ 61,660,000**

[5] Total in 2005 dollars.

specific equipment performance and outputs. The UDP Model forecasts life-cycle utility operating and maintenance costs, labor costs, fuel costs, debt (including principal and interest) costs, and capital costs for required new infrastructure and renewal of existing utility service facilities.

The overall project methodology evaluates various strategies capable of meeting these

Once fully allocated between electricity and LP steam, these costs are then combined with any assignable distribution costs (e.g., substation, steam and chilled water distribution systems). Production equipment costs are allocated to the consumable commodities—electricity (kWh), heating (Mlbs), cooling (Ton-Hrs) and domestic water (Gallons). These fully-loaded costs are then divided by the consumed commodities to derive commodity rates.

ENERGY MARKET ANALYSIS

In modeling the University of Alaska Fairbanks' long range utility planning, it is necessary to forecast purchased fuel prices for the University. For the UDP Model, UAF's delivered commodity prices are predicted based on current and expected UAF commodity contracts, locally delivered historical energy price trends, the U.S. Energy Information Administration's (EIA) short and long-range energy price forecasts, Regulatory Commission of Alaska approved tariffs, local market supply

In the Model, expected future fuel oil price fluctuations are derived from the 2004 Energy Information Administration's (EIA) 2004 twenty year forecast for PADD V No. 2 Heating Oil.[7] In the Model, UAF's current actual delivered fuel oil price is trended off percentage price increases of the EIA long-range price to predict the price of delivered purchases for the University.

Coal Price Forecast

UAF's delivered coal price is expected to be the most stable commodity fuel price, with abundant supplies located close to the University and minimal new local demand expected to compete for the supply of reserves. Large reserves also exist in both south-central Alaska and the North Slope, additionally reducing supply pressures.

UAF currently has a ten year contract with the Usibelli Coal Mine to supply coal to the University through FY2011. Coal prices for UAF in the Model are forecasted assuming the University will remain on a similar contract with comparable price adjustment terms for the length of the twenty-year study period.

The purchased price of coal for the University is forecasted using inflationary pricing mechanisms consistent with the existing Usibelli contract. The Model predicts a UAF cost of coal per ton by calculating the percentage change in the Producer Price Index–Industrial Commodities (PPI), plus an adjustment for the coal mine's labor rate. The PPI percentage change is calculated as the simple historical ten year annual average PPI change (+2.9% per annum), and the forecast annually compounds the coal cost component of current pricing by that PPI average increase. To determine an appropriate labor rate adjustment component of prices for the coal mine, the UDP Model assumes labor cost escalation rate of two and one-half percent

[7] Energy Information Administration, Annual Energy Outlook 2005, <http://www.eia.doe.gov/oiaf/aeo/demand.html>, accessed on November 18, 2005.

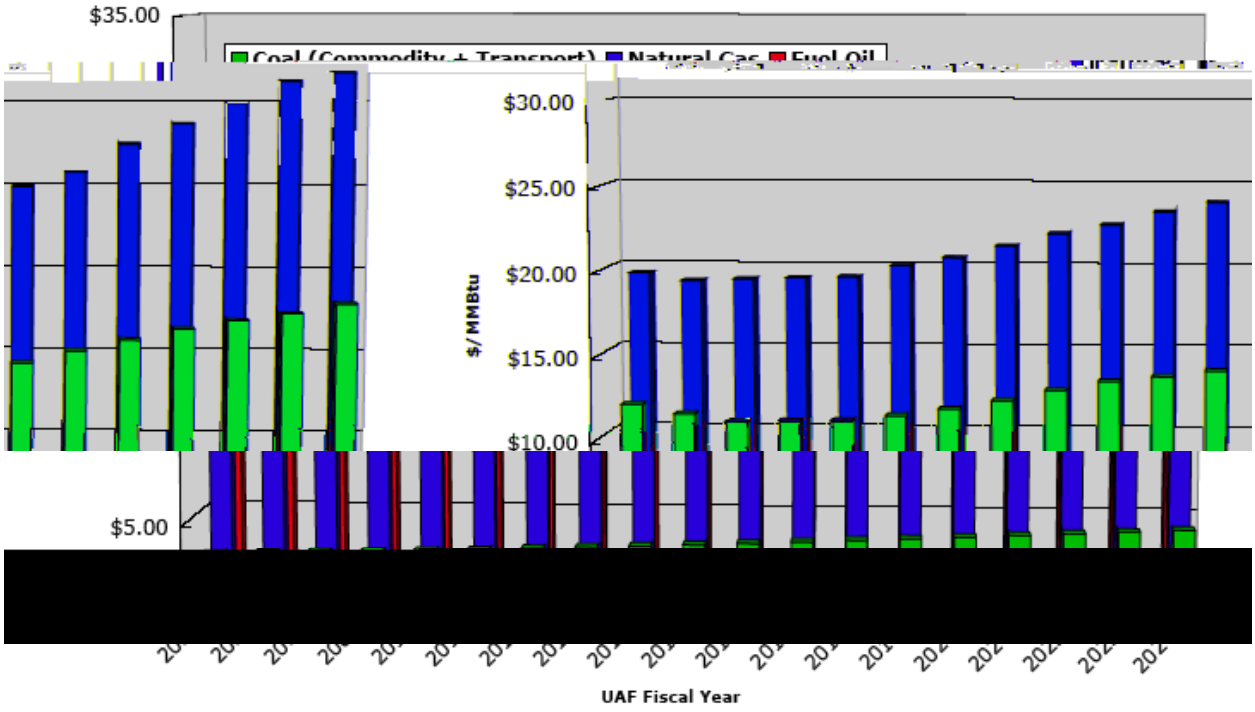
In the Model, the price for natural gas delivered to UAF is calculated using the EIA's 2004 twenty (20) year forecast for natural gas delivered to the East North Central (Chicago) less $1.00. The price in the Model represents the expected long-term price for gas at the expected delivery point of North Slope gas, less $1.00 of transportation differential back to Alaska.[8]

Calculations of the forecast for fuel oil, coal and natural gas commodity delivered to UAF used in the UDP Model, as well as a comparison of the fuel prices, converted into costs per MMBtu are shown in Table 4 and Figure 9 below:

Table 4 UAF Commodity Price Forecasts

	Coal Price per Ton					Price per MMBtu			
FY	Coal Price	Coal Transport	Total Price	Natural Gas per Mcf	Fuel Oil per Gallon	Total Coal	Natural Gas	Fuel Oil	Fuel Oil Less 17%
2006	$40.25	$8.61	$48.86		*$2.23*	$3.13		$18.58	$15.42
2007	$41.34	$8.76	$50.10	$11.89	$2.34	$3.21	$11.83	$19.48	$16.16
2008	$42.45	$8.96	$51.41	$11.33	$2.28	$3.30	$11.28	$19.03	$15.79
2009	$43.60	$9.16	$52.75	$10.89	$2.29	$3.38	$10.83	$19.12	$15.87
2010	$44.78	$9.36	$54.13	$10.94	$2.31	$3.47	$10.88	$19.21	$15.94
2011	$45.99	$9.61	$55.59	$10.99	$2.31	$3.56	$10.93	$19.29	$16.01
2012	$47.23	$9.85	$57.07	$11.32	$2.40	$3.66	$11.26	$19.98	$16.58
2013	$48.50	$10.11	$58.61	$11.75	$2.46	$3.76	$11.69	$20.47	$16.99
2014	$49.81	$10.37	$60.18	$12.25	$2.54	$3.86	$12.19	$21.20	$17.60
2015	$51.16	$10.63	$61.79	$12.90	$2.63	$3.96	$12.83	$21.95	$18.22
2016	$52.54	$10.91	$63.45	$13.48	$2.70	$4.07	$13.41	$22.50	$18.68
2017	$53.96	$11.19	$65.14	$13.76	$2.80	$4.18	$13.69	$23.30	$19.34
2018	$55.41	$11.50	$66.91	$14.14	$2.87	$4.29	$14.07	$23.88	$19.82
2019	$56.91	$11.80	$68.71	$14.75	$3.00	$4.40	$14.68	$24.97	$20.72
2020	$58.45	$12.17	$70.61	$15.49	$3.10	$4.53	$15.42	$25.84	$21.45
2021	$60.02	$12.50	$72.53	$16.17	$3.30	$4.65	$16.09	$27.52	$22.84
2022	$61.64	$12.85	$74.50	$16.83	$3.45	$4.78	$16.74	$28.73	$23.85
2023	$63.31	$13.21	$76.52	$17.35	$3.60	$4.91	$17.26	$29.99	$24.89
2024	$65.02	$13.52	$78.54	$17.79	$3.76	$5.03	$17.70	$31.30	$25.97
2025	$66.77	$13.86	$80.63	$18.38	$3.82	$5.17	$18.29	$31.79	$26.39

Figure 9 UAF Delivered Commodity Price Forecast ($ per MMBtu)



Purchased Electricity Price Forecast (GVEA)

Forecasted prices for purchased electricity in the UDP Model are based on a GVEA tariff rate for General Service customers (GS-2(2)). The GVEA rate applied to electricity pricing in the UBDP Model is based on GVEA's proposed new GS-2(2), which includes a customer charge, a two-tiered energy charge, a power adjustment charge and a demand charge, with a minimum bill equal to the highest demand charge of the past twelve months.[9] The purchased electricity rate is escalated in the Model to reflect expected increases in price associated with

[9] In the matter of the Application of GOLDEN VALLEY ELECTRIC ASSOCIATION, INC. for authority to implement Simplified Rate Filing Procedures and Adjust Rates, Regulatory Commission of Alaska Docket No. U-04-33, "Golden Valley Electric Association, Inc.'s response to the Regulatory Commission of Alaska's Order No. U-04-33(13)," filed October 21, 2005, Exhibit A, pp 2 and 13. The proposed new rate constitutes an approximately 5.1% increase over the current GS-2(2) rate. Additionally, GVEA is required to file a rate case with the Regulatory Commission of Alaska by September of 2007 per Golden Valley Electric Association, Inc.'s Application for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates, (R.C.A. 2005)

In order to better project energy demand in an evolving campus, load factors are developed by building type (i.e., instructional, administrative, research and housing). Metered building steam and electric data, along with consideration of typical building design, served as guides in inferring actual load densities by building type.

The model of annual peak demand for low pressure (distribution) steam was constructed by isolating components of campus steam and electric power and assigning

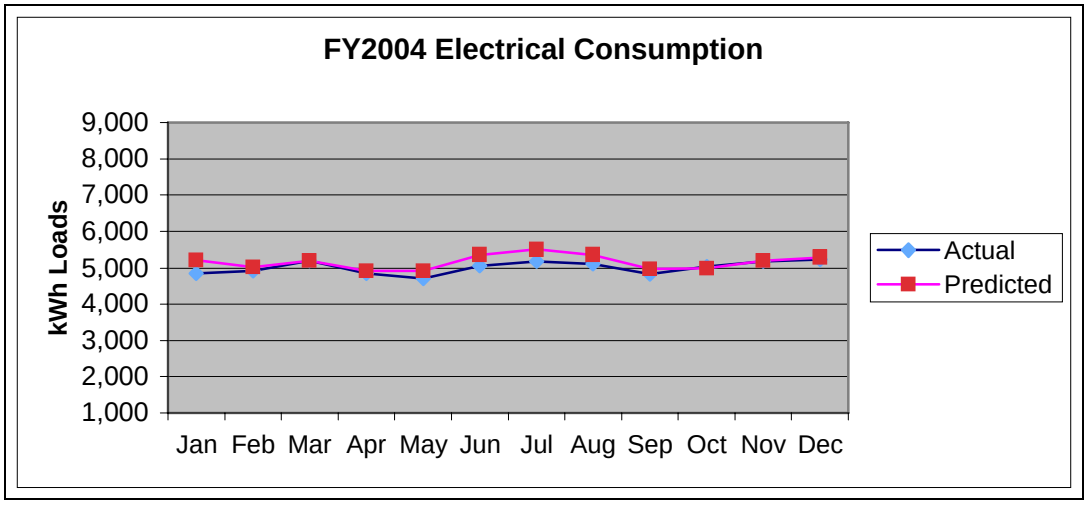
metered loads that are included in the PI database. Engine block heat is a significant component of wintertime electrical demand and is a metered load. The lighting factor was constructed to account for additional campus electric demand that is independent of specific buildings: overall campus lighting of roadways, pedestrian corridors, and building exteriors.

Annual Consumption Model

A quantitative model based on peak historical demand, building square footage by type, heating and cooling degree days, number of daylight hours, and estimated hours of occupancy was constructed to project monthly energy consumption. Model results were compared with historical PI data. Based on these comparisons, both load factors and hours of operation were adjusted to achieve relatively close calibration between the model and actual observed loads. Annual results for steam and electric consumption are shown in Figure 13 and Figure 14 below.

It is important to recognize that the model predicts energy consumption for each hour of an average occupied and unoccupied day of each month. These average days are summed to provide monthly steam Klbs and electric MWH to

Figure 14 UAF Monthly Electrical Consumption, Actual Consumption Comparison to UDP Modeled Consumption



Steam Distribution Model

A model of the pressure drop through the existing utilidor steam piping system at various flow rates was constructed to evaluate the effect of building load growth on campus distribution. Steam flow to the WR was given particular attention given current pressure shortfalls under peak load conditions. The Excel model uses the Babc

STRATEGY FORMULATION AND DEFINITION

The methodology utilized in the ***2005 Utility Development Plan*** considers three distinct strategies (with seven sub-options) to meet the present and future utility demands of UAF. These strategies were defined by the UDP Project Team with the assistance of UAF facilities staff, and differ with respect to specified equipment, timing of installations, purchased fuel commodity used, and physical location of new utility infrastructure development.

The strategies range from a fully centralized plant that maximizes the use of coal for both steam and electric production, to individual building boiler heating systems ("stand alone") that are not connected to the centralized system. Alternative systems are specified to utilize either fuel oil or natural gas for heating, and to supplement UAF's self-generated electricity production capability with purchases from a third-party utility service provider. For each strategy, the engineering analysis defines the utility systems, its components, and associated capital cost (including the cost for each building to convert to DES service). These analyses are driven by the utility service load consumption forecast, which is identical for all strategies. The strategies are then defined, tested, and adjusted accordingly in order to meet these loads forecasted for UAF for the twenty-year study period.

Table 7 shows in general terms how utility services demands for the UAF LC and the WR campus are to be met in each of the strategies. The three strategies are structured to achieve different objectives. The goal in Strategy 1 is to minimize the *upfront initial capital investment* that is required for UAF to be able to satisfy future utility demands of the campus. Strategy 2 is also designed to minimize capital investment, with a simultaneous goal to minimize the number of "stand alone" heating systems that operated independent of the centralized DES system, recognizing the required individual maintenance and operational support and shorted expended

life of the “stand alone” equipment. The goal of Strategy 3 is to construct a durable coal fuel-based DES utility system that will support the demands of the UAF campus for decades to come with little additional future capital investment. All strategies have natural gas fuel as an alternative to retrofit existing fuel oil-burning steam production equipment, and Strategies 2 and 3 also consider the economic advantage of a central chiller plant facility versus “stand alone” cooling facilities in new building construction.

Table 7 Utility Configuration for Strategies

Strategy	Strategy Number	Strategy Name	Lower Campus Utility Services			West Ridge Utility Services		
			Electricity	*Heating*	*Cooling*	*Electricity*	*Heating*	*Cooling*
Minimize *Initial* Capital Investment	**1**	Stand Alone		New loads after 2015 served by individual building boilers			New Heating loads served by individual building boilers	
	1 (NG)	Stand Alone (with Natural Gas)						
	2A							

Strategy 1 - Minimize Capital Investment

Stand Alone Equipment

Strategy 1 is designed to meet future campus utility needs at the lowest initial capital cost outlays to the University. The strategy maximizes the use of existing plant and utility infrastructure to meet campus steam demand, and relies on the University's ability to purchase electricity from a third party (GVEA) to meet growing electric power demands.

Strategy 1 relies on a several primary assumptions (or strategic decisions) in formulating requiremetl25 TD0.0009 T3.3(ulmpus s)8.650.3lmpusl

additional WR heating loads are served by fuel oil (or natural gas) boilers installed in individual buildings.[10] Cooling demands in LC are satisfied through FY2015 by the centralized cooling system and afterwards by chiller equipment installed in individual buildings. New cooling demands in WR are satisfied by "stand alone" chiller equipment installed in individual buildings.

Strategy 1 attempts to minimize initial capital requirements costs, with investment outlays providing for "stand alone" boilers in newly constructed facilities throughout the twenty years modeled. However, there are significant replacement costs of these boiler units (expected after fifteen years of service) included in the life-cycle cost model as well as periodic maintenance costs. Newly installed "stand alone" chiller units are also subject to replacement as are existing "stand alone" chiller units, both new and old will also require periodic maintenance. In the natural gas sub-option, Strategy costs include capital expenditures for a pipeline for natural gas transportation to WR "stand alone" boilers.

Strategy 2 – Minimize Long-Term Capital Cost

West Ridge Satellite Heating Plant

Strategy 2 focuses on efficiently supplying future WR and a portion of LC steam requirements through a new satellite heating plant on the WR. Strategy 2 incurs more initial capital expenditures than Strategy 1, but balances initial capital costs with lower life-cycle production, distribution, maintenance and capital renewal costs. A variant of Strategy 2 considers installation initially of a chiller plant with 2000 tons of single

A new steam line would be installed relatively early in the Strategy 3 plan to solve increasing pressure deficiencies associated with growth on the WR. The UDP proposes construction of a new walking utilidor from the vicinity of Lola Tilly to just west of Student Rec. A new 10" steam line, designed for operation at 125 psi, would be routed from the plant headers to Lola Tilly through the existing utilidor, from Lola Tilly to the Student Rec in the new utilidor and then back into the existing utilidor from Student Rec to a pressure regulating station located at approximately The Geist Museum on the WR. Arrangement of the line so that it can be fed from either the 25 psi turbine backpressure header or from a pressure regulator off the 600 psi boiler header enables supplemental steam to be fed to WR in the near term without diminished turbine output. In Strategy 3, all growth in campus electric demand will be served in the near term by generation from a newly installed 20 megawatt (MW) steam turbine at the Atkinson Plant installed in FY2009. Extraction ports on the new steam turbine will be designed to allow discharge at higher pressure. Upgrades to the existing 25 psi steam distribution system are included in the plan to allow distribution at higher pressure (up to 75 psi) under periods of high winter demand. In this strategy, the backup electric reliability requirements will be provided alternatively by GVEA service or generation from the existing diesel engine generator (DEG), depending on the economically preferred source of supply. A sub-option evaluates installing a new 10 MW steam turbine generator for paralleled operation with the existing steam turbine generator and reducing the size of the coal fired boiler capacity to 100Mlbs/hr instead of the more expensive new 20 MW generator and 150Mlb/hr coal fired steam capacity equipment.

As in Strategy 1 and in Strategy 2, cooling demands in LC are satisfied through FY2015 by the centralized cooling system and afterwards by air-cooled, electric-driven chiller equipment installed in individual buildings. New cooling demands in WR are satisfied by air-cooled, electric-driven chiller equipment in individual buildings. The operating cost of steam absorption chilling is substantially less than air-cooled, electric-driven alternatives due to the use of inexpensive summertime turbine exhaust steam and coincident reduction in expensive campus electric power demand. Absorption chilling is clearly a good match for the UAF campus

For each of the capital items within these groups a useful life is estimated and where required, a period of years after which replacement of the capital asset (i.e., capital renewal) will have to be performed. The useful life estimate is the basis upon which annual depreciation expense is calculated, and also is a basis upon which the financing period is determined. Capital items comprising the Common Capital Asset Renewal and Major Maintenance range from a useful life of ten years to as much as thirty and forty years. For Strategy 1, the useful life of items ranges from ten to fifteen years; Strategy 2, ten to twenty-five years (with the Utilidor Extension being forty years); Strategy 3, ten to forty years. Figure 15 shows the major components of capital costs for the first ten years for the Common Capital investments as well as the particular strategy investments. This chart provides a sense of the duration over which some of these capital investments are expected to occur. The current capital costs are inflation-adjusted for the year in which they are to occur and Financial Appendix - Section B shows the current capital costs as well as the inflation-adjusted costs for the Common and Strategy Capital costs.

Figure 15 UAF UDP Timeline of Major Capital Investments for All Strategies

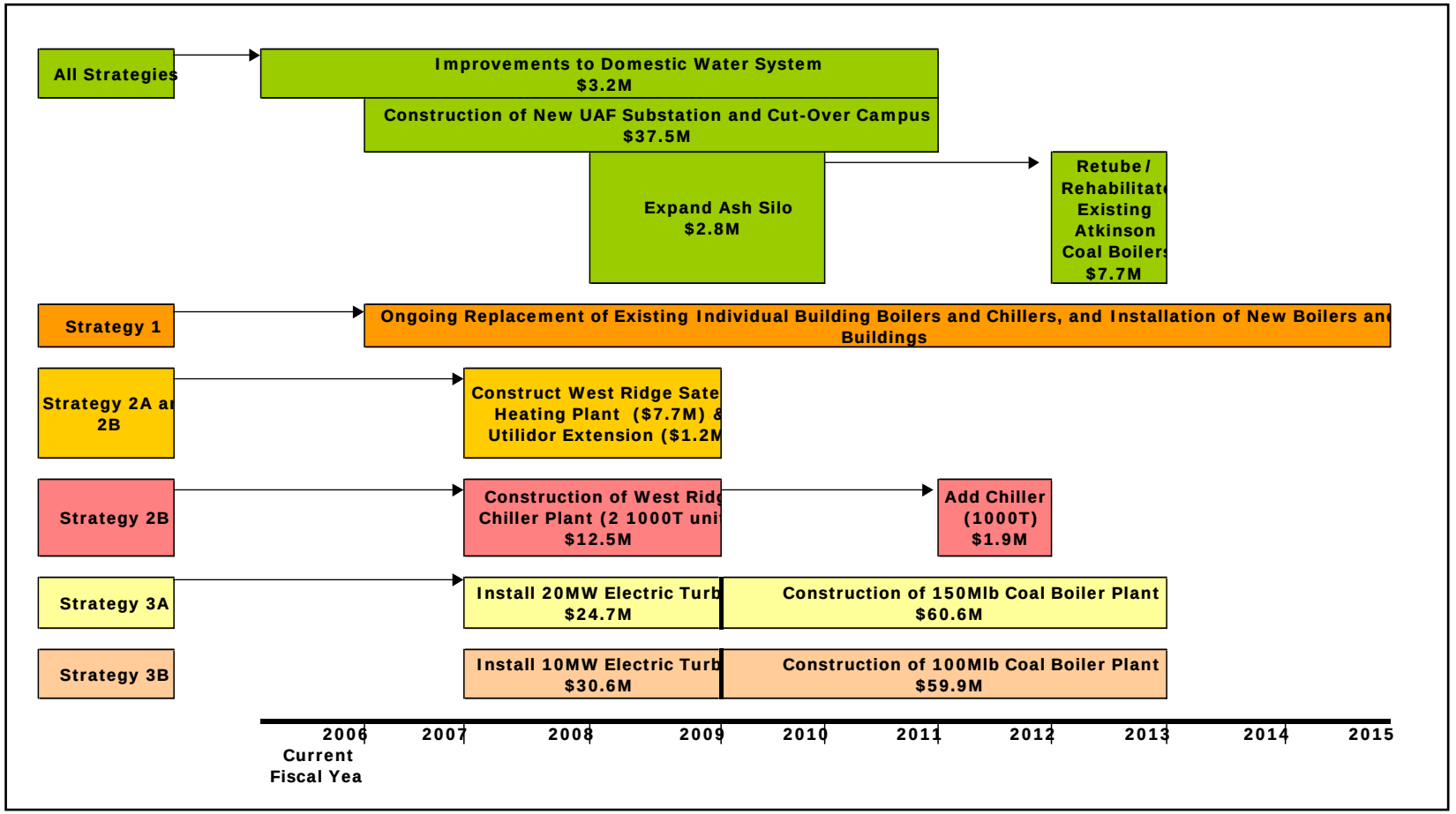


Figure 16 shows the capital expenditures as they occur through time for the common capital investments as well as the particular strategy investments.

Figure 16 UAF Annual Capital Expenditures for Strategies

(*Each Strategy Cost Includes Upgrades and Major Maintenance Costs Common to All Strategies)*

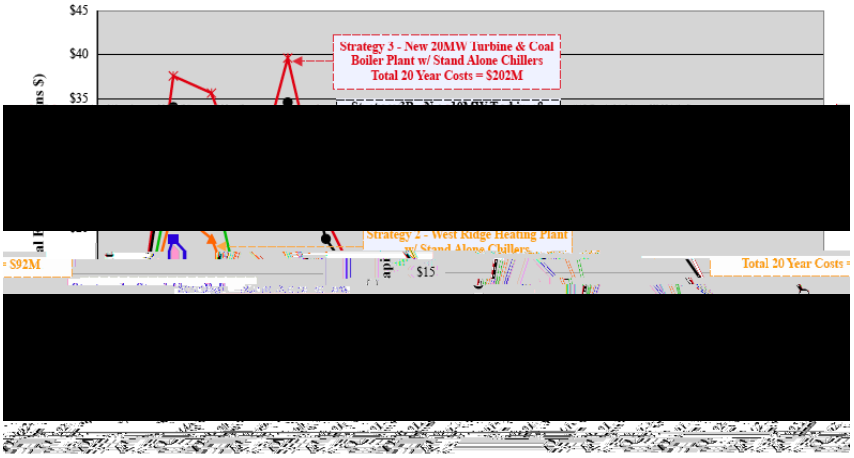
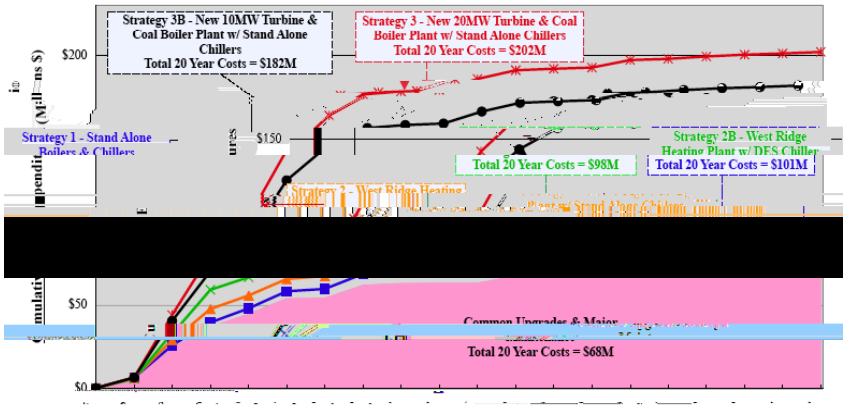


Figure 17 shows the same capital expenditures stated as the cumulative investment expenditures through time.

Figure 17 UAF Cumulative Capital Expenditures for Strategies

(*Each Strategy Cost Includes Upgrades and Major Maintenance Costs Common to All Strategies)*



Financial Appendix - Section C shows the annual depreciation expenses for each of the asset groups. These schedules also include capital renewal/depreciation expenses for current Utilities Division assets that have not previously been included as part of the Utilities Division expenses. These current expenses are included as part of the capital renewal/depreciation expenses in all strategies. Depreciation expenses for the general plant assets are allocated to the final utility commodity products in the same manner as other general operating and maintenance expenses (See Section III for further description of this allocation methodology).

In considering the capital assets' expected useful life associated with the utility infrastructure that composes the Strategy (or Common Improvement/Renewal) investment, the debt financing of the required capital investments is modeled as follows:

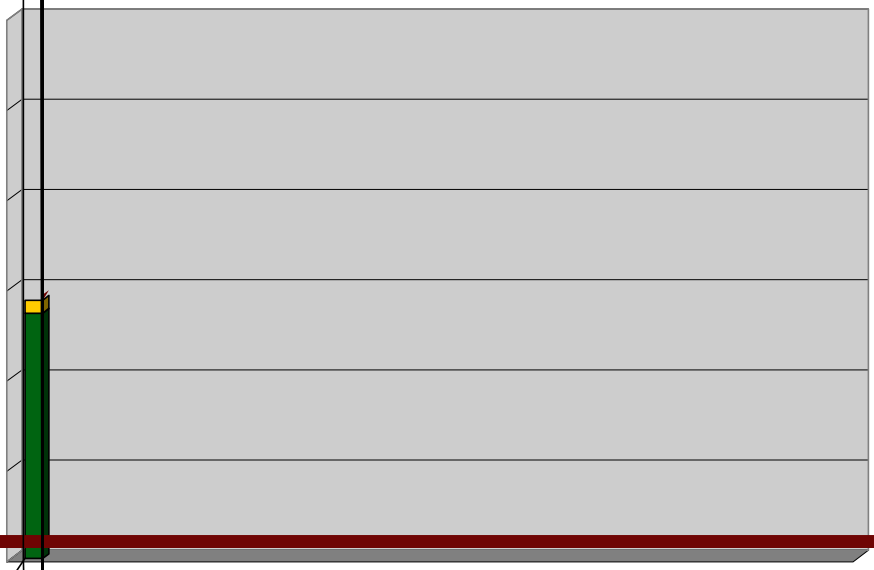
Debt Financing Term (Years)	UAF Utility Systems Investment Strategy
20	Common Improvements and Utility Asset Renewal
15	Strategy 1
20	Strategy 2
30	Strategy 3

It is assumed that bonds are issued for the required capital investments of each Strategy in five-year increments, and bond schedules are calculated separately between the Common Improvements/Renewal capital requirements and the individual capital requirements specified for each Strategy. The necessary debt funding is determined by calculating the interest earned on unexpended bond proceeds (during the five year scheduled capital project expenditure Tw( )sIlef-nsCom6cImds e,ital(he five ca9(ia)4.7(tion2(rategy13)-2(ati5(e)000obta5 0 Tthrough0.25 -1i.068-0

ANNUAL PRODUCTION OUTPUT AND OPERATING COST BY STRATEGY

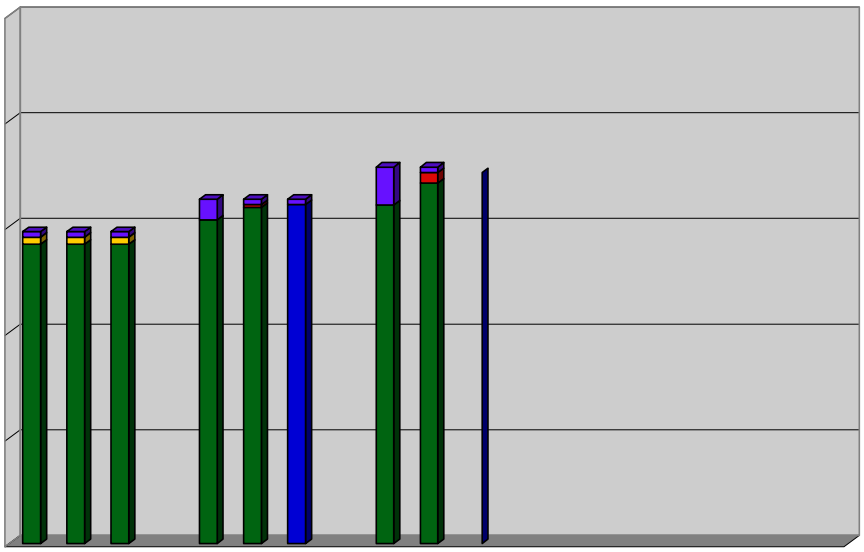
The individual Strategies meet the commodity service requirements of the UAF facilities with different "mixes" of self-production or purchased resources. The production mix associated with each of the different Strategies changes through time as well. Figure 18 demonstrates in five-year increments how the electric service requirements of the UAF campus are met with differing combinations of GVEA purchases, self-generation from the existing Turbine Generator 3 (in the Atkinson Plant), the new 10 MW turbine generator (for Strategy 3 only) and the existing DEG generator. Annual detail of operating costs associated with each of the strategies in implementation years is shown in Financial Appendix - Section E.

Figure 18 Comparative Sources of Electricity Across Natural Gas Strategies



Similarly, Figure 19 demonstrates the differences in the production of the campus' steam service requirements as between DES LP Steam and Stand Alone Steam boilers under the different Strategies through the same twenty-year Model period (in five year intervals). It is apparent that the production strategies will certainly result in different cost implications.

Figure 19 Comparative Sources of Steam Across Natural Gas Strategies



PRO FORMA AND NPV RESULTS

Pro Forma

The UAF Utilities Division, organized as a self-sustaining organization, must track its cash expenditures in order to effectively ascertain its actual cost of providing utility services to the UAF campus. These cash expenditures as well as the non-cash item of depreciation expense are summarized in its financial statements. These statements contain the cost categories that any similar ongoing concern would have and encompass five distinct categories:

1. Purchased Fuel Costs
    a. Coal
    b. Fuel Oil
    c. GVEA Electricity
    d. Natural Gas (*This cost is at present zero*)

2. Operating Expenses related to the production and distribution of electricity, steam, chilled water, and domestic water
3. Personnel Costs
    a. Salaries
    b. Benefits
    c. Travel (This cost is at present negligible)
4. Debt Service
    a. Interest on debt
    b. Principal payments associated with debt
5. Depreciation (non-cash expense)

These operational costs for the Utilities Division are part of the UDP Model and as inflation-adjusted costs are contained within the Pro Forma results shown in Financial Appendix - Section G. Inflation adjustment methods for purchased fuel costs are discussed in Section III, Energy Market Analysis. Production and distribution operating expenses, travel and personnel salaries are inflation-adjusted at a rate of 2.5 percent. Personnel benefits are inflation-adjusted at a rate of twenty-five percent (25%) through FY2009 after which they are inflation-adjusted at a rate of five percent (5%). Debt service payments and depreciation expenses are stated at actual cost.

The actual expenses of the UAF Utilities Division for FY2005 are stated as a part of the Pro Forma in order that a comparison can be made between them and the results obtained by the UAF UDP Model. As can be seen Table 8, the UAF UDP Model closely mirrors the UAF Utilities Division's actual expenses.

Table 8 Comparison of UAF UDP Base Year Costs to Actual Costs

Operating Expenses	Actual 2005	FY 2005	Variance	% Variance
Fuel Cost				
Coal Commodity	$2,538,366	$2,700,786	$162,420	6.4%
Coal Transport	$531,838	$565,747	$33,909	0.06%
Coal Ash Hauling	$83,800	$89,219	$5,419	0.06%
Total Coal Cost	$3,154,004	$3,355,753	$201,749	6.4%
Fuel Oil Commodity	$2,621,563	$1,819,608	($801,955)	30.6%
GVEA Purchased Electricity	$383,632	$294,983	($88,649)	23.1%
Natural Gas Commodity	$0	$0		
Total Fuel Cost	$6,159,199	$5,470,344	($688,855)	11.2%
Operations & Maintenance				
Electric Steam & Chilled Water	$980,064	$1,007,085	$27,021	2.8%
Water & Sewer	$574,878	$570,934	($3,944)	0.7%
Total Operations & Maintenance	$1,554,942	$1,578,019	$23,077	1.5%
Salaries Benefits & Travel				
Electric Steam & Chilled Water	$2,144,735	$2,126,680	($18,055)	0.8%
Water & Sewer	$143,782	$139,469	($4,313)	3.0%
Total Salaries Benefits & Travel	$2,288,517	$2,266,149	($22,368)	1.0%
Debt Service				
Interest Expense				

UAF "transfer" account balances the Utilities Division budget (excluding the non-cash item of depreciation expense), and is essentially the difference between the UAF Utilities Division operating expenses and its directly billed revenues. In FY2005 the "transfer" account revenues were approximately sixty-five percent (65%) of the total operating expenses. By FY2025 in the UAF UDP Model the "transfer" account provides approximately seventy-five percent (75%) of the total operating expenses as new sources of direct billing have not been structured into the Model.

NPV Results

The UDP Model analysis produces results that forecast operating expenses and revenues for each of the Strategies. Those operating expenses and revenues are summarized in the form of a *Pro Forma* statement of annual cashflows for each of the Strategy, which are presented in Financial Appendix - Section G. As was discussed in the preceding section, the revenue requirements for operation of the UAF Utilities Division are balanced each year by "Transfer" account revenues.

The *Pro Forma* analyses adopt this revenue account balancing of cashflow with respect to all forecasted operating expenses including debt costs (principal and interest), but exclude the "depreciation" costs associated with the "fully-loaded life-cycle" cost concepts previously discussed. In the *Pro Forma* presentation these depreciation costs—required for accumulation of an accumulated fund account balance to provide for the replacement and renewal of capital assets at the end of its expected useful life—are shown as a net revenue shortfall in each model year.

Importantly, this treatment of revenue account balancing of cashflow also requires that the Model's analytic results be evaluated in the context of the differences in the *total operating expenses*, rather than net cashflow balances. The economic comparison of each Strategy's

operating expenses can be stated as a total operating cost—but a more useful economic comparison of those operating results is as a *discounted NPV of operating costs*. That is, operating expenses incurred closer to the present time are "weighted" more heavily than those incurred toward the end of the twenty year forecasted time period by a *discount rate* that provides an annual progression that discounts those future expenses. This common financial analysis tool recognizes the time-value of money. The discount rate that is chosen reflects an economic entity's time preference for cash, and it is commonly asserted that a private entity's discount rate will generally be higher than a public entity's.

Thus, Table 9 provides a summary of Strategy results that states the undiscounted total costs and the net NPV of those costs at three different annual discount rates (i.e., 12%, 8% and 5%). Note that because the NPV is presented for operating *expenses*, the economic evaluation is a preference for the ***lowest*** NPV (i.e., exhibiting the minimization of discounted operating expenses). The NPV results are only a *component* of the economic evaluation of these Strategies, as other intangible and exogenous factors that are not captured by the strict financial modeling of costs must also be considered.

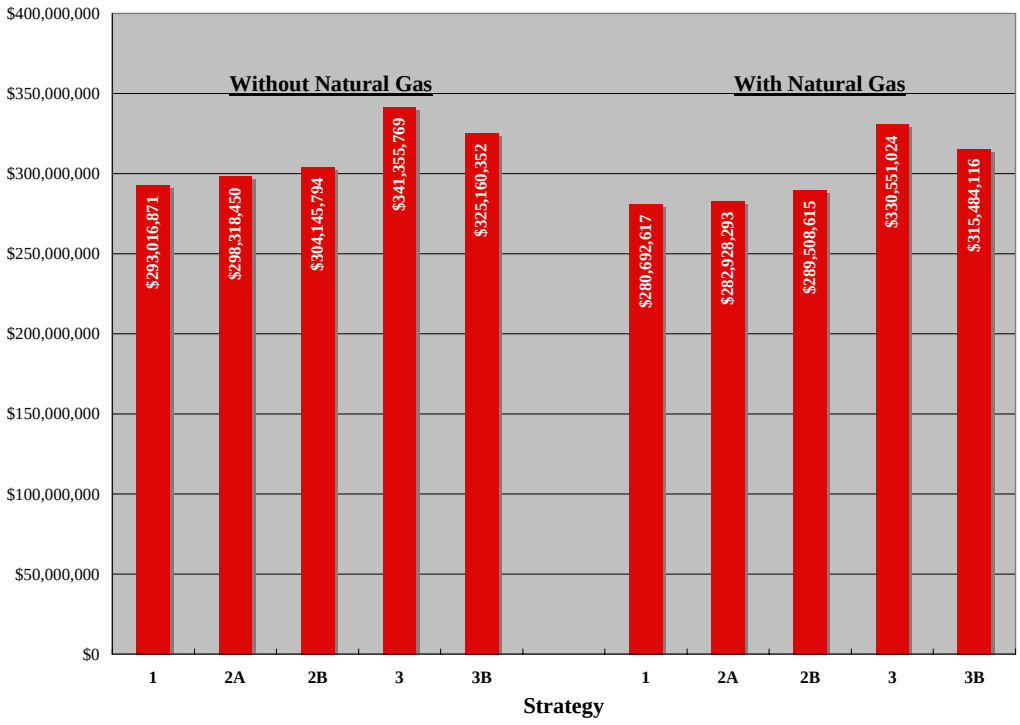
Table 9 UAF UDP Total Operating Expenses and Associated NPVs for All Strategies

Strategy	Total Costs FY2006 – FY2025	NPV of Costs at Selected Rates		
		12%	8%	5%
1 Stand Alone	$511,231,296	$157,657,485	$219,978,647	$293,016,871
$574,581,361 (150 Mlb) Plant & New 20MW Turbine	$191,600,137	$262,347,219		$341,355,769
$551,085,175 (100 Mlb) Plant & New 10MW Turbine	$181,204,707	$248,183,950		$325,160,352
1 Stand Alone (NG)	$488,157,011	$151,647,249	$211,113,127	$280,692,617
2 West Ridge Boiler (NG)	$490,560,103	$153,461,869	$213,171,613	$282,928,293
2B West Ridge Boiler w/ Chiller Plant (NG)	$500,625,643	$157,527,958	$218,448,968	$289,508,615
3 Coal Boiler (150 Mlb) Plant & New 20MW Turbine (NG)	$560,756,966	$183,801,407	$251,978,394	$330,551,024
3B Coal Boiler (100 Mlb) Plant & New 10MW Turbine (NG)	$537,936,720	$174,491,251	$239,871,181	$315,484,116

stated above and discussed subsequently, the strict NPV economic results must also be interpreted in the context of other considerations and risk factors which may suggest that *in spite of the strict NPV evaluation, Strategy 3 may still be a viable long-term utilities system Strategy for UAF.*

Figure 20 summarizes the NPV results (utilizing the 5% discount rate), and groups the Strategies as between those excluding and those implementing the natural gas fuel sub-option.

Figure 20 UAF UDP 20 Year NPV of Operating Expenses by Strategy Discounted at 5%



(principally mines), no energy consumer in the relevant geographic market will impact prices by expansion or reduction in its energy demands for any available fuels (coal, fuel oil, natural gas and electricity).[12]

Coal is projected to have no significant increase in consumption, and the Usibelli Mine is understood to possess adequate long-term supplies to meet all foreseeable local demand requirements. General price inflation, and potentially limited transportation cost increases (likely tied to diesel fuel costs), are the only factors anticipated to influence the delivered price of coal to UAF. Currently, coal transportation costs comprise approximately fifteen percent (15%) of delivered coal costs to the University. Thus, it would require relatively extraordinary changes in diesel fuel costs to influence delivered coal costs.

Moreover, the University has experienced relatively stable coal prices for many years, and currently has a long term contract in place that assures price stability (except with respect to potential transportation cost increases) that allows coal to be an assured "base load" fuel. Stated differently, it is likely that other fuel costs will move relative to coal, not that coal prices will move relative to the other fuels.

The North Pole Refinery (owned by Flint Hills) has executed a long-term contract with the State for its royalty-in-kind oil, assuring that for at least the next decade it will have a stable source of crude for refining. The current State of Alaska fuel purchase contract (under which UAF has been purchasing its fuel oil supplies) ties forecasted price increases to West Coast (lower 48) market price projections, which are driven primarily by international petroleum market conditions. There is no basis to presume that there will be any lessening of the scarcity of petroleum products in these international markets. The only likely scenario is for petroleum prices to increase more rapidly than is anticipated for other commodities over the next twenty (20) years.

[12] It should be noted that UAF has the ability to participate and intervene in all rate case filings GVEA has with the Regulatory Commission of Alaska.

Natural gas prices are understood to be the most uncertain among the energy commodities prices in the Fairbanks geographic markets. The development of the Trans-Alaska Natural Gas Pipeline is looking more likely, but is far from assured. The development of the recently identified Nenana Basin natural gas resources is equally uncertain. UAF's proposed contract with Fairbanks Natural Gas is tied to fuel oil prices, and the ability to consistently deliver liquefied natural gas (LNG) for re-delivery to natural gas consumers is unproven.

Therefore, the primary fuel price "sensitivity" appears to be tied to the relative prices of fuel oil and natural gas, with the price of natural gas potentially "de-coupled" from the price of natural gas in the lower 48.

Likewise, Golden Valley Electric Association (GVEA) has a variety of uncertainties impacting its ability to assure any level of price stability. It currently obtains approximately forty percent (40%) its electricity from Chugach Electric Association under a long-term purchased power agreement (PPA) and delivered through the Northern Intertie. Importantly, those generation resources are principally natural gas fired and located on the State's west coast where available gas supplies are traded in much more competitive market environments.

Of GVEA's 228MW of total owned generation resources, 183MW consist of oil-fired generation (80.3%), 25MW of coal-fired generation (11%), with the remaining 20MW of generation capacity coming from GVEA's share of Bradley Lake's hydroelectric generation capacity.[13] A portion of GVEA's oil-fired generation capacity is provided under a long-term contract with Aurora Energy for electricity from its 27MW Delta Power Plant (formerly Chena Plant) and 36MW Zehnder Plant in Fairbanks. GVEA has also broken ground on an expansion of its North Pole Plant and expects an additional 60MW of naptha-fired combined cycle generation to be online by December 2006.

[13] "GVEA at a Glance," <http://www.gvea.com/about/ataglance.php>, accessed December 8, 2005.

Thus, the preceding discussion of the volatility of fuel oil and natural gas prices vis-à-vis coal prices suggests that the existing generation resources relied on by GVEA are subject to relatively high risk of price variance from the base forecast utilized in the UAF UDP model. Add to this the circumstance that GVEA has thirty

SENSITIVITY CASE 4 — Increasing fuel oil and GVEA electricity costs, with stable coal natural gas costs. The price of fuel oil and GVEA electricity will be increased five, ten and twenty percent (5%, 10 % and 20%) above the original forecast of fuel oil and GVEA electricity prices.

Figure 21 and Figure 22 of the results from each energy price sensitivity case can be seen below. Figure 21 displays the effects of the price sensitivities on the strategies without natural gas, and Figure 22 shows the results on the strategies with natural gas.

Figure 21 Comparison of Price Sensitivity Outcomes (Fuel Oil Strategies without Natural Gas) for Forecasted Operating Expenses (Including Debt) by Strategy

Figure 22 Comparison of Price Sensitivity Outcomes (Fuel Oil Strategies with Natural Gas) for

UAF Growth Sensitivity Analyses

The other primary uncertainty to the fiscal and physical requirements of the UAF utility systems is the assumption as to the pace of campus growth, and corresponding utility service requirements. These growth assumptions can only be tested with respect to the changes in the level of service requirements throughout the twenty-year period modeled, and corresponding levels of capital expenditure on the utility facility required to meet these requirements. That is, the model cannot test the implications of an alternative growth rate for campus facilities utilizing net present value metrics, because the significantly lesser or greater utility service loads would require modeling of differing systems capacity investments and performance—a fundamentally different Strategy to meet different service loads.

SENSITIVITY CASE 5 — Total service load and capacity requirements are compared to the requirements modeled in the three primary Strategies analyzed. The magnitude of differences in these service loads and capacity requirements forecast for the Strategies modeled (i.e., 3.9 million square feet) are compared to alternative twenty-year campus growth projections of 3.6 million square feet and 4.3 million square feet campus build-outs.

The peak demand projections at year twenty for various growth assumptions are as follows:

Table 10 Alternative Forecasted Twenty Year Growth Projection and Associated Peak Utility Service Requirements (FY2026)

Forecasted Campus SF	Peak Distribution System	Peak Electric Demand	Peak Chilled Water
3.6 MSF	176 Mlbs/hr	15.3 MW	5,100 Tons
3.9 MSF	193 Mlbs/hr	16.6 MW	5,500 Tons
4.3 MSF	213 Mlbs/hr	18.8 MW	6,100 Tons

Lower Growth

The lower growth rate sensitivity case (3.6 MSF at year 20) implies for Strategy 1 that fewer individual "stand alone" units would be installed, and would reduce the future cost for equipment replacement as well as reduce the fuel cost differential when compared to Strategies 2 and 3. Lower growth rates make Strategy 1 more attractive. Under Strategy 2, and the further assumption that lower growth projection applies equally to LC and WR, the capital costs associated with installation of Boiler 3 in the WR Plant would be delayed and the installation of Boiler 4 would not be needed until just beyond the 20 year time frame. If instead only LC growth is retarded, and the pace of WR development is as planned, there would be no change in the development of the WR plant. Lower overall consumption of steam and electric power under the lower growth scenario clearly reduces the fuel cost advantages of the coal resource alternative. Capital costs would certainly be reduced by scaling back the capacity of a new boiler and steam turbine generator in Strategy 3. Lesser economies of scale would not improve construction costs on a $/klb or $/MW basis, making the economic comparison of Strategy 3 with alternative Strategies 1 and 2 less attractive.

Higher Growth

A higher than anticipated growth rate would tend to improve the economic comparison of Strategy 3 against Strategies 1 and 2. The capital expenditures for "stand alone" and WR Satellite Heating Plant would be on the order of ten percent (10%) higher than the base case (with more individual boilers, or larger individual units). The fuel and purchased electric costs would increase in similar proportion. Interestingly, additional capital costs for construction to accommodate a higher than modeled growth rate would not be needed under the coal boiler option (Strategy 3). The Atkinson Plant would house either 400 Mlbs/hr or 450 Mlbs/hr (depending on which of the sub-options was implemented) of steam capacity. With the largest

unit offline, firm capacity would be 300 klbs/hr, well in excess of the projected peak campus demand of 213 klbs/hr the plant. The fuel cost differential would improve throughout the planning time frame, although purchase of GVEA supplemental power in the out years would increase under the 100 klbs/hr boiler sub-option specified for Strategy 3.

Capital Funding Sensitivity Analysis

The UAF UDP model analyses evaluate the net economic benefit in terms of *discounted NPV*. The three basic Strategies and the sub-options to those strategies (i.e., alternative configurations of utility equipment and infrastructure required to meet future service requirements) impose differing capital and operating cost outcomes through the twenty-year period that are properly compared on a discounted net present value basis. These comparisons between the scenarios are all performed using the same structuring of debt financing. It is possible that a significant contribution of the initial capital requirements might be available from the State of Alaska, and this contribution is properly considered only with the preferred long-term strategy.

SENSITIVITY CASE 6 — Test the fiscal impact of a $50 million capital contribution from the State of Alaska. The analysis investigates the impact on the level of uti

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RISK ANALYSIS

Risk analysis in the context of the long-term facilities development contemplated in the UAF UDP is a complex and imprecise element of planning. Regardless of the Strategy selected, there are elements of the external environment in which UAF must operate its utility service facilities that are outside its control. These exogenous factors cannot be explicitly modeled within the scope of the UDP, but must be acknowledged and at least identified in the context of the "direction" of impact on the economic evaluations performed by the UDP.

GVEA Electric Service Reliability—A concern that the UDP Project Team has been repeatedly confronted with in its analysis is the reliability of electrical service available from GVEA. With a history of numerous short and longer-term interruptions of power supplies within the GVEA service area, UAF has significant concern that such reliability issue must be evaluated to be a negative attribute of any Strategy that increases the reliance on GVEA electricity supp oe reldS2 105.78 Tmc 1V

decision taken with respect to a particular modeled Strategy is also an operational question. That is, if the modeled growth is overstated, the Strategy 1 infrastructure decision is most prudent in that the operational capacities are most uniformly matched to actual growth, while all other Strategies would provide excess and unutilized operational capacities. Conversely, if the UDP Model understates the actual growth rates for the UAF campus, then the most dramatic impact would be a negative economic result if Strategy 1 were selected, with Strategies 2 and 3 providing sufficient "excess" capacity to handle the unanticipated growth of the campus utility service loads.

Requirement for Capital Investment Beyond Twenty Years—If the UDP were required to anticipate the utility service requirements and associated capital investment for a term greater than the twenty years currently analyzed (e.g., consistent with the forty year expect life of a new coal boiler), greater economic benefit would be obtained from those Strategies that provide the greatest utility service capacity and flexibility in expansion of capacity. This would be consistent with the infrastructure developed in Strategies 2 and 3, where the durable and flexible nature of the utility infrastructure specified would continue to provide economic benefit to UAF, and would serve as a more appropriate foundation for the continued operations of the University's utility systems.

UAF Bonding Constraints—Obviously the lowest initial and total capital cost Strategies are the least impacted by constraints on bonding capacity. Thus, Strategy 1 would be evaluated as least negatively impacted and Strategy 2 could be assessed to be in a relatively neutral economic position with respect to this issue. Strategy 3 is the most capital intensive, and is evaluated with the most negative economic impact as a result of a significant constraint on UAF's ability to issue bond financing to meet the capital construction requirements.

UAF Construction Constraints—The development of the three basic Strategies did not consider any particular construction constraints for the development and installation of the required facilities in Fairbanks. If the requirements for the additional utility systems capacity is being driven by growth in UAF facilities (generally), then it is appropriate to inquire as to the ability to undertake a construction program that is developing tens of millions of dollars of new utility facilities simultaneously with the other UAF construction activities. Put simply, Strategy 1 engenders the least significant construction activities, as the Stand Alone utility solutions are embedded in the construction of the new campus academic and research facilities. Obviously Strategies 2 and 3 impose additional construction beyond the construction of new campus facilities, and at their peaks, could be demanding $30 to $50 million in annual construction *in addition to* other campus construction activities.

Table 11 Impact on UAF of Strategy and Event Combination (for Fiscal Years past 2010)

Strategy Number	Strategy Name	Issues affecting performance of Utilities Division under Strategy							
		GVEA Electric Reliability	Control UAF Electric System	Campus Square Feet Growth Overstated	Campus Square Feet Growth Understated	Requirement for Capital Investment Beyond 20 Years	Regulatory and Permitting Issues	UAF Bonding Constraints	UAF Construction Constraints
1	Stand Alone	—	—	—	—	—	—	+	+
1 (NG)	Stand Alone (with Natural Gas)	—	—	—	—	—		+	+
2A	West Ridge Satellite Heating Plant	—	—	—	+	+	—		

ALTERNATIVE UAF BUSINESS MODEL STRUCTURES AND RATE DESIGN

The UAF UDPB addresses the alternative busi

UAF Utilities Division allocates costs-of-service to several identified users (e.g., research or

existing “Business Model” is structured to meet federal contract and grant utility expense reimbursement requirements, but does not address the long-term sustainability of UAF utilities services in its business practices and (corresponding) rate design.

It is important to note that even with implementation of these expanded concepts of debt expense and accrual of amortized depreciation expense for capital renewal, UAF can continue to calculate a federal utility service reimbursement ra

capital renewal. This is a common element of public (as well as private) utility rate design. The concept is simply that rates charged for utility services must also accumulate a reserve fund for the replacement of the capital assets at the end of its expected useful life.

It is believed that the strictures of the UAF accounting practices *allow* rate designs that would accumulate a reserve fund within the Utilities Division. Such a capital renewal reserve fund would finance the replacement of the capital assets at the time such capital renewal is required. However, it is 6 -1.725 b1T2e

Assuming the University was to choose this independent third-party approach, it must also be assumed that the University would seek to have university-friendly owners in the management and operation of the utility facilities. That is, many of the utility facilities (e.g., steam distribution lines) are—and must be—located contiguous to many other UAF facility assets to which a third-party utility service provider would not be granted operational control. Definition of the relationships and responsibilities between UAF and the third-party utility service provider is but one of the contracting obstacles that must be addressed.

The presumption (for this analysis) is that UAF would participate in the third-party corporation, but would play a minority role. The utility facility assets currently utilized would certainly be part of the third-party facilities, and UAF would either sell or make in-kind contribution of these assets to the third-party corporation. It is assumed for comparative

2. Operations and maintenance (to include supplies and contracts);
3. Labor (salaries and benefits); travel is minimal or separately stated elsewhere;
4. Principal and interest on Utilities Division debt;
5. Depreciation of Utilities Division capital assets; and
6. Profit and Risk Premium

Costs that can be directly assignable to a specific delivered and consumed *utility commodity* (e.g., electricity, steam, chilled water, domestic water) are allocated to those products. This pertains to direct fuel costs as well as other charges such as operations and maintenance, labor, debt, and depreciation.

Allocations of Direct Operating Costs

Costs that cannot be directly assigned to final delivered utility commodities are generally related to the cogeneration facilities of the UAF. By example, the total costs of coal, fuel oil, O&M and labor are first allocated in the model's calculation of costs of production of high pressure steam (HP steam).[18] Total costs, including fuel costs from the HP Steam Boilers 1-4, are then allocated between the steam turbine generator *commodity* outputs of Electricity and Low Pressure Steam (LP Steam) on a Btu-equivalent basis of the consumable products (net kWh and LP Steam). The DEG LP steam and electricity are also allocated in this fashion.

O&M expenses (other than those directly assignable to domestic water[19]) are allocated to the HP steam production equipment—the coal and fuel oil HP steam boilers (1-4)—on a ninety percent (90%) to coal and ten percent (10%) to fuel oil basis. These costs are divided by the boiler fuel inputs (coal and other fuel) to produce O&M rates ($ per unit), which are then used to forecast future O&M costs for various plant and facility production configurations.

[18] Please UAF District Energy System (DES) Model Flows figure in Section I.
[19] Based on information obtained from UAF, it was assumed that three percent (3%) of the gallons of water produced in calendar year 2004 were utilized in utility operations. Therefore, three percent (3%) of domestic water expenses in each year have been re-designated as attributable to general utility expenses.

Once fully allocated between electricity and LP steam, these costs are then combined with any assignable distribution costs (e.g., substation, steam and chilled water distribution systems). Production equipment costs are allocated to the consumable commodities—Electricity (kWh), heating (Mlbs), cooling (Ton-Hrs) and domestic water (Gallons). These fully-loaded costs are then divided by the consumed commodities to derive commodity rates.

UAF Utility Rates and "Sustainable" Rate Design Concepts

Regardless of the business structure in which the utility rates are developed, it is a common component of rate design that the annual operating expense of the utility services be captured in the utility rates. UAF generally accomplishes this task in its current definition of utility rates. Therefore, the most important discussion point to be considered by the UAF UDP is the element of the rate design defining the extent of full *capital cost recovery* in utility rates, and the recovery of "costs" associated with *asset depreciation and renewal*. The following example of future delivered Electricity rates illustrates the point.

Table 12 UAF UDP Strategy 3A Electricity Rates FY 2005 through FY 2010

	FY 2005	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010
UAF Load (kWh)	**58,454,986**	**61,030,610**	**62,968,634**	**65,160,908**	**67,049,772**	**69,198,059**
Electricity Fuel Cost (per kWh)	$0.050	$0.062	$0.054	$0.055	$0.082	$0.087
Electricity O&M Cost (per kWh)	$0.009	$0.007	$0.006	$0.006	$0.008	$0.008
Electricity Labor Cost (per kWh)	$0.018	$0.020	$0.021	$0.023	$0.028	$0.028
Variable Electricity Cost(per kWh)	**$0.077**	**$0.089**	**$0.081**	**$0.084**	**$0.118**	**$0.123**
Electricity Debt Interest Cost (per kWh)	$0.005	$0.005	$0.061	$0.058	$0.063	$0.059
Electricity Debt Principal Cost (per kWh)	$0.000	$0.000	$0.027	$0.030	$0.034	$0.035
"Fully Loaded" Electricity Cost (per kWh)	**$0.082**	**$0.094**	**$0.170**	**$0.172**	**$0.215**	**$0.217**
Electricity Capital Depreciation Cost (per kWh)	$0.022	$0.021	$0.022	$0.027	$0.040	$0.041
"Fully Load Life-Cycle" Electricity Cost (per kWh)	**$0.104**	**$0.115**	**$0.192**	**$0.200**	**$0.255**	**$0.258**

The example provided in the Table 12 is taken from the model outputs for Strategy 3A (with natural gas), but the important point illustrated is the affect of incorporating the capital recovery components in rates. The "variable electricity costs" are a starting point for rates.

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Figure 25 demonstrates the same effects for the overall costs of delivered steam that were just discussed for delivered electricity rates. Note, however, that the advantage of the lower steam rates for Strategy 1 in the first half of the period are overwhelmed by the higher capital and operational costs by the end of the twenty year period for this "stand alone" Strategy.

Figure 25 UAF UDP Structured Blended Steam (DES & Stand Alone) Rate by Strategy *with* Natural Gas

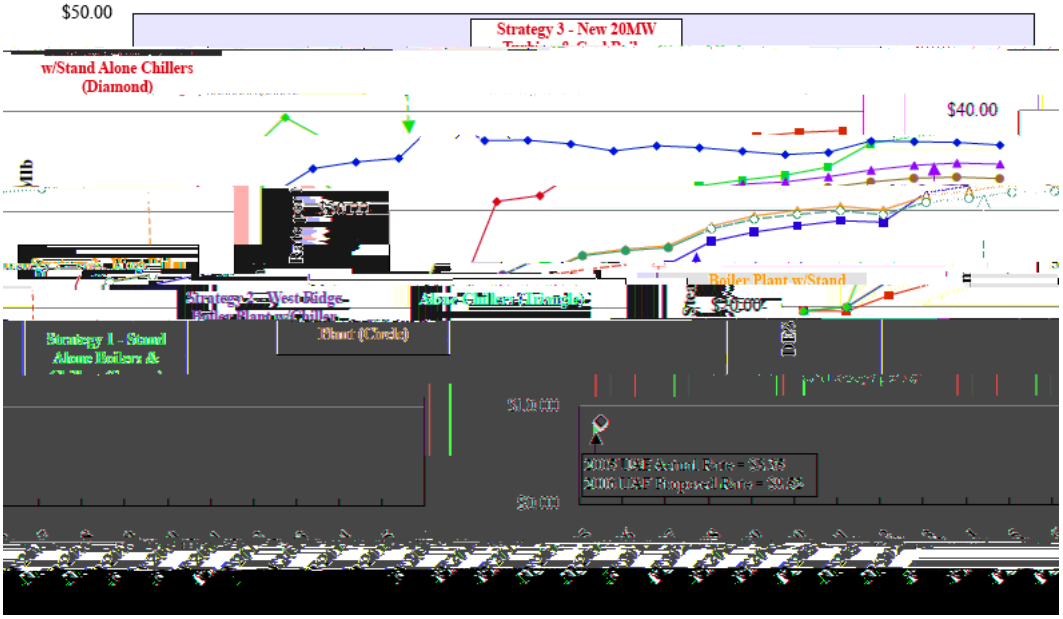
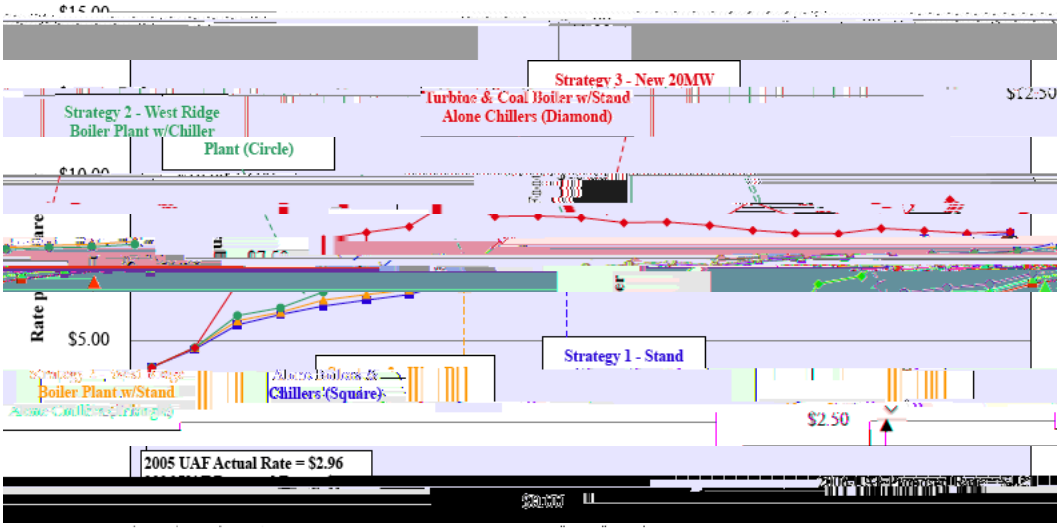


Figure 26 summarizes the forecasted cost of domestic water, which is common to all the Strategies discussed for other utility services.

Figure 26 UAF UDP Structured Domestic Water Rate by Strategy *with* Natural Gas

Figure 27 UAF UDP Structured Square Foot Rate by Strategy *with* Natural Gas



Public Utility Rate Design and a Third-Party Provider

The development of rate designs for utility services provided by a public (or private) utility corporation are significantly more complex as a result of issues related to taxes, cost of capital, and return of and return on capital investments. Although there is no single right or wrong way to define "proper" rate design in a private sector setting, the application of a relatively simplistic public utility rate design model serves to illustrate the impact of providing UAF's required utility services by transfer of the utility assets to a for-profit third-party utility service provider.

This first component of public utility rate design is determination of the "rate base" established (principally) on the un-depreciated book value of the utility's capital assets. The rate base is utilized to determine the "return on equity" to be earned by the utility provider. Rate Base is net of the Accumulated Reserve for Depreciation, which is the accumulation of the full capital Depreciation and Amortization Expense that is treated as an annual Operating Expense.

This first element of the public utility rate design model distinguishes the rates obtained from those specified by the preceding analysis of UAF Utility Division business enterprise utility service rates. In today's capital markets, public utility rate design will generally specify a Return on Equity (ROE) in the range of an eight to twelve percent (8-12%) annual rate. This is a specific addition to rates, which in the context of a UAF new (un-depreciated) capital investment of $50 to $100 million dollars over the next decade could increase cost recovery by $4 to $12 million dollars per year.

In a for-profit business environment, the utility rates must also recover the costs of various taxes (including wage-related, ad valoreum and income taxes), and also account for the various tax benefits (e.g., tax deferrals) that impact private sector utility enterprises. At best, it must be assumed that the consideration of the taxable basis of these utility operations would have no net increase in recoverable costs—however, it is much more likely that these will add to the recovery cost-of-service basis for the utility enterprise.

One final component must be considered in the analysis of a third-party provider of UAF's utility service requirements. Under the current Alaska Public Utility Regulatory Act

Alternative engineering solutions, energy prices, campus growth, capital investment versus long-term operating considerations and fiscal constraints are variables that create complex problems for facilities managers and necessitate the use of comparative analyses in strategic planning evaluations. Equally important is the need for developing a comprehensive funding strategy, which will ensure that the utility project plan chosen can be fully and successfully implemented.

Based on evaluation and consideration of all business and operational parameters discussed in this UDP, UAF has assessed that the "preferred" solution requires development of an implementation plan that focuses on expansion of the central plant facilities (i.e., generally either Strategy 2 or 3), with an emphasis on implementing the coal-fired solution (Strategy 3) if the capital investment constraints can be overcome. The preferred Strategy chosen is expected to become a "guiding principle" for implementation of UAF's utility infrastructure renewal and expansion. However, until capital constraints are resolved, the implementation of the UDP concepts will—of necessity—focus on incremental steps.

The UDP Project Team strongly recommends that UAF identify and empower a focused Utility Project Team charged with implementation of the UDP Strategy, including an advocacy role seeking to resolve the capital funding issues.

EXISTING UTILITY INFRASTRUCTURE RENEWAL REQUIREMENTS

The existing utility system infrastructure at UAF requires significant investment in major maintenance, renewals, and upgrades in order to continue to provide reliable utility services. The maintenance, renewal, and system upgrade requirements are common to any and all future growth strategies the University considers, and are incorporated as part of the UDP analyses. Recent studies and investigations of the forty-plus year old electrical and steam production and distribution system have identified single-point failure reliability issues in plant auxiliaries,

facilities, and aged and undersized components of

Project Team has adopted a Base Case forecast of 3.9 million total campus square feet in FY 2025 as a justified and reasonable estimate of future UAF growth, based on historical campus growth patterns, the University's Six-Year Capital Plan growth projections, and discussions and analysis with UAF staff and administrators.

The UDP Model is largely "driven" by the forecasts of final consumption utility service

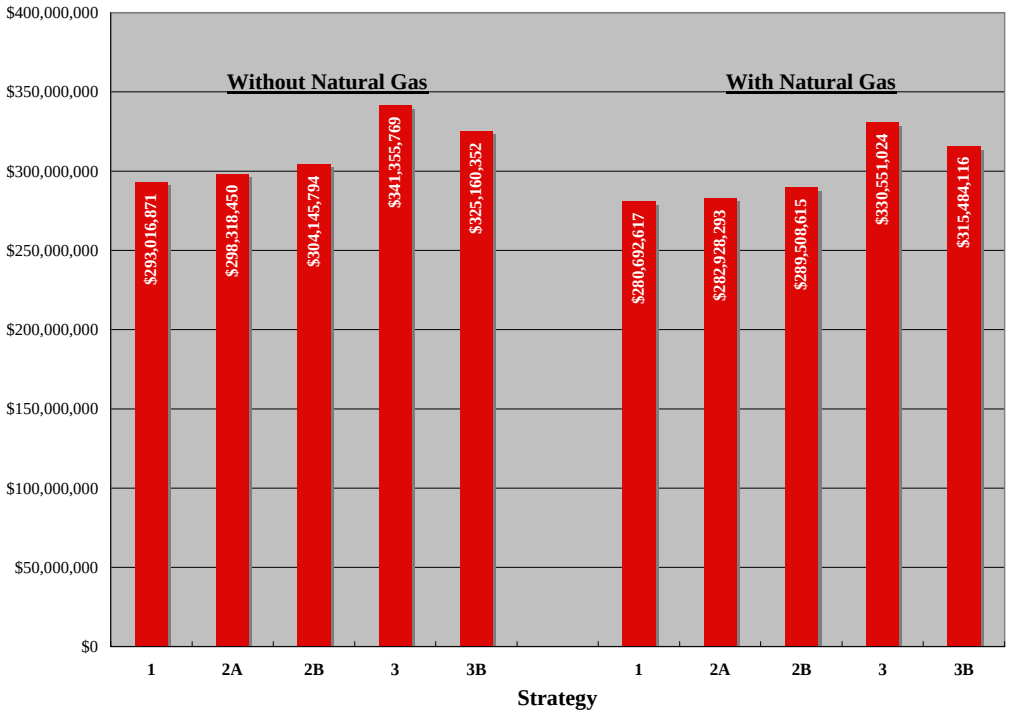
COMPARATIVE ANALYTICAL RESULTS

The UDP Model analysis produces results that forecast operating expenses and revenues for each of the Strategies. Those operating expenses and revenues are summarized as a *Pro Forma* statement of annual cashflows. The *Pro Forma* statements incorporate revenue account balancing of cashflow with respect to all forecasted operating expenses, including debt costs (principal and interest), and depreciation costs associated with the "fully-loaded life-cycle" cost analysis.

To present a fair economic comparison of the modeled Strategies, the UDP compares each Strategy on the basis of its discounted NPV of expenses. Note that, because the NPV is of *operating expenses*, the economic evaluation is a preference for the ***lowest*** NPV.

Figure 28 summarizes the NPV results of each of the Strategies modeled.

Figure 28 UAF UDP 20 Year NPV of Operating Expenses by Strategy Discounted at 5%



These results first demonstrate a consistent preference for each of the Strategies with implementation of the natural gas fuel sub-option. The results also demonstrate a significant

economic preference for Strategies 1 and 2. This means that, *within the time period evaluated*, in spite of the substantially lower annual operating costs of Strategy 3, the expanded coal plant investment will produce higher total operating costs as a result of associated debt service.

The NPV results, however, are only a *component* of the economic evaluation of these Strategies, as other intangible and exogenous factors that are not captured by the strict financial modeling of costs must also be considered. The NPV results must also be evaluated in the context of other considerations and risk factors that may suggest Strategy 3 is still the most strategically sound long-term utilities system investment Strategy for UAF.

FORECASTED UTILITY SERVICE RATES

It is a common component of utility rate design that the annual operating expense of the utility services be captured in the utility rates. UAF generally accomplishes this task in its current definition of utility rates. As a result of UAF's current practice of full recovery of *operating costs* in its current utility rate structures, the most important discussion point to be considered by the UAF UDP is the issue of full *capital cost recovery* in utility rates, and the recovery of "costs" associated with *asset depreciation and renewal*.

This rate design issue arises, as a decision that must be made as to the extent to wSpanenxt28ut1,en r

required to continue the required utility services to the University. *Note that this is <u>exactly</u> the position in which UAF currently finds its utility facilities, which is juxtaposed with the standing of every other campus of the University of Alaska system.*

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university-friendly owners in the management and operation of the utility facilities. Definition of the relationships and responsibilities between UAF and the third-party utility service provider is but one of the contracting obstacles that would need to be addressed.

UDP Sensitivity and Risk Analyses

Risk analysis in the context of the long-term facilities development contemplated in the UAF UDP is a complex and imprecise element of planning. Regardless of the Strategy selected, there are elements of the external environment in which UAF must operate its utility service facilities that are outside its control. These exogenous factors cannot be explicitly modeled within the scope of the UDP, but must be acknowledged and at least identified in the context of the "direction" of impact on the econo