

Study for Shippensburg University

Prime Heating Production
Prime Cooling Production
Heating and Cooling Distribution
Distributed Generation



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SECTION I: ACKNOWLEDGEMENTS, OBJECTIVES

ACKNOWLEDGEMENTS

Abacus would like to acknowledge the support provided by the staff of Shippensburg University during the course of this study. In the Operations and Maintenance Group, Lance Bryson and Bill Lenseie were especially helpful. At the Boiler Plant, Tony Gardner, as well as all the operators and technicians, provided valuable insight into the workings of the plant and the data to document it. The staffs of the HVAC, electrical and control shops were invaluable as well.

OBJECTIVES

Shippensburg University, like many of the facilities in the State System of Higher Education, is faced with a number of issues regarding campus infrastructure. Infrastructure in this report can be taken to mean the production and distribution of prime heat (steam is the primary heat transfer medium), prime cooling (chilled water is primary heat transfer medium), and electricity.

The main issues facing the heating infrastructure are age, new emissions standards, general wear and tear on the system, the physical location of the plant with regard to future campus expansion, and the constraints placed on the distribution system by the physical size of the piping.

The prime cooling production (chillers) is newer, and is more localized (each chiller or bank of chillers generally serves only one building); thus many of the issues facing the heating system do not apply. Instead, the issues facing SU with regard to cooling are mainly due to the decentralized nature of the systems. These include a lack of standard equipment and control schemes, more (and more spread out) maintenance, and the inability to share load among chillers. For the vast majority of the annual operating hours, this inability to share load across buildings results in many chillers running inefficiently at part load, rather than fewer chillers (and pumps and cooling towers) running more efficiently. It also makes it difficult and expensive to adopt new technology in a systematic way.

In terms of electricity, the existing infrastructure is believed to be adequate in capacity and condition; the primary issue is the cost of electrical demand and energy. Therefore, the electrical infrastructure is included only to the extent that is required to determine the capacity of the system to accommodate on-site generation.

The University is aware of these issues, and had taken steps to address them even before Abacus was under contract. Capital Project Justification forms had been submitted to the Commonwealth for \$6.90M worth of repairs to the steam and condensate distribution systems, and \$6.86M for upgrades to the boiler plant. Cooling and electrical infrastructure were not considered in these funding requests.

At this point in the process, Abacus came under contract to provide ESCO services to SU, and as one of the proposed measures, suggested constructing a new heating/cooling plant with new distribution as an alternate to the scope proposed in the two Capital Project Justifications (CPJs). It quickly became apparent that the potential scope of this work would require more study, and to avoid delaying the ESCO project, SU commissioned Abacus to provide this study.

The first objective of the study, as stated in the scoping documents, is to determine the best way for SU to use the funds requested in the CPJs, and to determine if the ESCO process could be used to leverage that money to provide a more comprehensive long term solution than could be achieved with the requested capital alone. A second objective was the need for a Facilities Detailed Project Planning Document in support of the capital projects that are currently approved. Originally, four potential infrastructure solutions were included in the study:

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- Option 1) Spend the money as originally intended; that is, prioritize and upgrade as much of the existing plant and steam distribution system as the capital will allow. If the capital would not cover all the work required to create a "30 year plant", determine how much more money would be required to complete the work.
- Option 2) Construct a new heating plant. The plant would generate high pressure steam, which would be used to generate electricity by means of a backpressure steam turbine. The steam would then be converted to hot water, which would be distributed through a brand new distribution system. The fuels would be coal, gas, and oil.
- Option 3) Same as Option 2, plus centralized cooling. The heating/cogeneration scope of work stays the same as in Option 2. In addition, a central cooling plant would be included, located in the same building as the heating. New chilled water distribution piping would be installed at the same time as the hot water piping. The buildings served by the plant would be limited to those which currently have chillers.
- Option 4) Same as Option 3, with cooling added to those dorms which currently have no cooling. The intent would be to allow the University to host more summer programs, and thus generate more revenue. In this option, the chilled water plant and distribution started under Option 3 would be expanded to allow the dorms to be cooled with chilled water.

Notes on Options:

Any Option other than Option 1 would most likely require that the plant be relocated to a new location. This would greatly simplify construction, by allowing the old plant to continue to function while the new one is being constructed. Proposed locations are shown on the drawings included with this report.

A scenario was considered to put a new plant (Options 2A through 4B) in the same location as the existing plant. This would require a period when the campus was heated with rental boilers. The steam system currently shuts down for about four months in summer – the new plant construction period would be planned to overlap this period as much as possible to minimize the need to rent boilers during the demo period.

This scenario was not the one chosen for analysis in the remainder of the report. One reason is that it added cost and complexity. TAC estimates that demolition and new construction would take 14 months. It would be started as soon as the existing plant was shut down for the summer, and would finish the next year about the time the plant would normally be scheduled to re-start – mid September. Thus SU would need to rent three boilers, and supporting equipment (oil tank, etc) for one heating season. The estimated cost for the rental for this period is \$360,000. However, this is the smaller of the two primary costs associated with this scenario. The larger cost is the premium that would have to be paid to operate on oil rather than coal during the 8 month heating season. Based on the same average fuel consumption data that was used as the Baseline for this study, adjusting for the much greater efficiency of oil-fired boilers than the existing coal boilers, and using the current (very high) cost of No. 2 Oil, SU would pay a premium of just over \$1,000,000 v the cost of providing the same heat with coal. Unlike the proposed new plant, they would not have the Option to fuel switch. The total estimated Adder for this scenario is therefore estimated at \$1,360,000.

The second factor for consideration is that one of the primary reasons for building a new plant was that the existing one is at the far end of the campus, and all future growth is



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projected to be away from the plant. Thus new additions at the opposite end of the campus will eventually require piping upgrades all the way back to the plant. However, should the land acquisition costs for the new plant (see next note) be significantly high, this scenario may become the preferred one.

TAC and SU agreed that no cost of land acquisition was to be included in this study. This was because the possibility exists that some existing SU or SU Foundation land could be swapped for land to build the plant on, or a donor might provide funds for the land, or so on. It was decided not to include these costs at this time because they affect the financials, and yet they may never be incurred. However, if the project progresses and it comes to pass that there is a capital cost associated with land acquisition, it is simple for TAC to re-run the cash flow and financial models to take this into account.

Similarly, the cost of demolishing the existing plant was not included either. It may be done as part of another project, or some other use may be found for it. If it does become part of this project, it is simple to re-run the financials to include this cost.

These were the original Options considered. The use of coal in the proposed plants was considered primarily for two reasons. First, coal was, and is, much cheaper on a BTU basis than any other fuel, although it has recently increased in price significantly. The second reason has to do with labor. The only way that a gas or oil fueled plant can compete with coal on an economic basis is by reducing other operating costs (since the fuel itself is more expensive). These operational costs can include service contracts, parts, repairs, and of course, labor. SU indicated early on that while reducing outside costs was a goal, that it was generally short-handed and fully utilizes the steam plant labor that is available during summer shutdowns for other work.

This led to Options which continued to utilize coal, and to do so in a way which minimized the external costs of coal (emissions control, material handling, etc). The original four Options were intended to utilize coal as cost effectively as possible. In the end, however, gas/oil-only options were included. In our experience with other facilities in the Commonwealth, Owners with gas/oil plants have reduced overall labor costs, primarily in two ways. The most common is through attrition; when plant staff retire, the position is not filled. The second is to re-assign plant personnel to operations tasks elsewhere that were not getting done due to manpower shortages. This does not strictly reduce manpower, but it does eliminate the need to hire additional staff beyond that in the plant, and some Owners have treated this as a reduction in labor costs. In the end, SU will need to determine how to take into account the opportunities that a gas/oil plant provides; technically, such a plant does not need to be manned continuously at all (although Abacus would not recommend running a high pressure steam plant with a steam turbine without staff continuously on hand).

In this report, we have made an assumption on the potential staff "reduction" that could result from attrition or re-assignment. This is only possible, of course, in Options 2, 3, and 4 (since Option 1 retains the coal plant). Therefore, we have renamed Options 2, 3, and 4 to 2A, 3A, and 4A. We have added Options 2B, 3B, and 4B. In each case, the "B" Option is identical to the "A" Option, except the plant is fired on gas and No. 2 oil only, no coal. These are discussed in detail in Section IV, Summary of Options.

Finally, the University asked about the effect of going entirely to electric heat – apparently some members of the SSHE have done so. This was beyond the scope of the study, so it was not fully developed as an "Option". Primarily, a full-blown cost estimate for the work was not completed, because it would require a great deal of effort, and it contains a great deal of unknowns. However, a financial analysis was done for such a scenario, and that financial can be found in Appendix F. The details and implications of the

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systems evaluated can be found in the Executive Summary (it was not developed enough to be counted as an Option, so it is not located in Section IV).

Any Option other than Option 1 would require that the plant be relocated to a new location. This is required so that the old plant can continue to function as the new one is constructed. The new location is envisioned to on land immediately adjacent the campus.

The seven fully developed Options, and the implications of each, are detailed in Section IV, Summary of Options. The intent of this study is to help SU determine which of these Options presents the best long-term campus infrastructure solution for the University for the next 30 years.



SECTION II: EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

As noted in Section I, seven Options were analyzed in detail, and one additional scenario was developed enough to present preliminary data for. A summary of the financial performance of the Options is presented below:

TABLE: Summary of Financials by Option							All Options
	Opt 1	Opt 2A	Opt 2B	Opt 3A	Opt 3B	Opt 4A	Opt 4B
Option Cost :	\$16,182,720	\$22,931,709	\$21,045,672	\$27,106,689	\$25,220,652	\$29,167,614	\$27,281,577
Appropriated Capital :	\$13,760,000	\$13,760,000	\$13,760,000	\$13,760,000	\$13,760,000	\$13,760,000	\$13,760,000
Amount to be Financed :	\$2,422,720	\$9,171,709	\$7,285,672	\$13,346,689	\$11,460,652	\$15,407,614	\$13,521,577
Incremental Cost beyond Opt 1 :		\$6,748,989	\$4,862,952	\$10,923,969	\$9,037,932	\$12,984,894	\$11,098,857
Net Cash Flow over Term :	\$3,687,075	\$5,804,982	\$8,142,180	\$1,455,810	(\$43,030)	\$5,974,955	\$4,570,361
Net Present Value :	\$3,273,695	\$2,148,669	\$3,812,560	(\$1,154,690)	(\$1,258,167)	\$285,887	\$225,831
Year 1 Savings :	\$921,597	\$1,157,065	\$1,152,829	\$1,183,773	\$1,098,906	\$1,337,072	\$1,254,186
Cost of Finance over Term :	\$838,418	\$3,174,004	\$2,521,314	\$4,618,818	\$3,966,127	\$5,332,031	\$4,679,340
Cash Flow over Term/No Debt :	\$6,948,213	\$18,150,695	\$17,949,166	\$19,421,316	\$15,383,749	\$26,714,599	\$22,771,278
NPV/ No Debt :	\$5,530,327	\$10,691,621	\$10,598,771	\$11,277,031	\$9,416,812	\$14,637,249	\$12,820,451
Options				Financial Variables and Assumptions			
1 : Repair, Replace, Renovate Existing Steam Plant				Finance Term: 15			
2A : New Coal/Gas/Oil Steam Plant				Interest Rate: 0.04125			
2B : New Gas/Oil Only Steam Plant				Payments per year: 4			
3A : New Coal/Gas/Oil Steam Plant, New Chiller Plant, existing loads only				Discount Rate: 0.05000			
3B : New Gas/Oil Only Steam Plant, New Chiller Plant, existing loads only				Term of Cash Flow Analysis: 30			
4A : New Coal/Gas/Oil Steam Plant, New Chiller Plant, existing + dorm loads							
4B : New /Gas/Oil Only Steam Plant, New Chiller Plant, existing + dorm loads							
Cash Flow over Term/No debt: This is the Net Cash Flow over the Term of Analysis assuming the entire project was funded with capital, i.e., no money was borrowed. Similarly, NPV/No debt assumed the project is paid for with capital, not debt.							

The Option numbers, 1 through 4, refer to different scopes of work. The "A" and "B" designations on Options 2 through 4 designate a coal/gas/oil fired steam plant ("A") or a gas/oil only plant ("B"). Given the relative cost differential between coal and gas or oil, going to a gas/oil plant actually increases the fuel costs. The only way to show a positive cash flow for the "B" options is to assume that the plant is less heavily manned than the current coal-fired plant is, and that the staff no longer in the plant are lost through attrition, or re-assigned to other unmet needs on campus, eliminating the need to hire for those needs. A complete 30 year cash flow analysis for each Option can be found in Appendix F, and a summary of each financial analysis can be found in Section IV, Summary of Options.

The near total reconstruction of the existing plant and distribution, versus the construction of a totally new plant and associated distribution, is an extremely significant decision for the University to make. In discussing the "value" of each Option, the net present value (NPV) is main variable used in this report. The primary determinant of value, as shown in the Table above, is how the project is financed. SU has \$13,760,000 already appropriated by the Commonwealth for this work. All seven options, however, require more than that amount. How the remainder is obtained will drive the decision SU must make.

If SU is able to obtain the remaining capital without borrowing (borrowing here should be taken to mean any form of finance that requires the repayment of interest, regardless of how it is structured), then the

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sole financial driver of value is the savings generated by the Option. The NPV is simply the discounted present value of the savings stream – the actual cost of the Option does not enter into the valuation (except of course to determine how much money SU must raise). If interest must be paid, then the implementation cost does enter into the NPV as a series of interest payments, and it becomes a major factor. Under the "financed" scenario, therefore, the financials present a more accurate picture of value for money. Unless specifically noted, the remainder of this section assumes that any amount over the \$13.76m already appropriated is being financed at the rate and terms shown in the Table above. A Table containing the complete list of the financial variables and assumptions can be found at the end of this Section.

The most valuable Options are clearly Options 1, 2A, and 2B. While Options 3A through 4B potentially produce more savings, they do so at such a high incremental cost increase that the NPV for these Options is quite small, or even negative. The significant added costs associated with these Options are due to including a new central chilled water plant, in addition to the new steam plant. And while the operational savings produced clearly do not compensate for the added cost, there are additional savings which were not quantified in this report. These are detailed in Section IV; they include the ability to share redundancy across buildings (and thus not have to buy redundancy for each building), the significant reduction in mechanical space required in future buildings (pumps only, no chillers), centralized (and reduced) maintenance, as well as reduction of deferred maintenance and capital (some of the existing chillers are due for replacement). These factors were very well documented and understood for the heating plant, but less so for the cooling plant. However, given the small/negative net present value for these Options, SU would have to base a decision to construct a central chiller plant primarily on these intangibles. Should SU believe that a central chiller plant is desirable, but wish to construct it later, or under another contracting method, then consideration should be given to installing the pipe under this (assuming any Option but Option 1 is chosen). The cost savings would be significant.

Given the nature of the Options, and the savings cash streams they generate, the decision on how to heat the campus going forward boils down to the University's preferences regarding coal, and the assumptions on potential FTE reductions (or re-assignments). The highest NPV is Option 2B, a heating-only, gas/oil fired plant. However, at current fuel costs (and any foreseeable future costs), the savings stream is wholly dependent on the assumptions made regarding wage and benefit reductions. If these are not realistic, or do not occur, then operating costs will rise significantly (the year one fuel-related "savings" for this Option are negative \$40,000). If not for the wage and benefit reductions and the deferred maintenance, this Option would have a negative NPV and a negative cash flow as well.

If SU can commit to these or similar reductions, then Option 2B would appear to be the preferred Option. In addition to having the highest NPV, a gas/oil plant is easier to operate, requires less maintenance, has less support equipment, has lower emissions, is easier to permit, and so on. If SU does not wish to reduce head count, or to count re-assignment of FTEs as a "savings", then Abacus would recommend Option 2A. Although it has a lower NPV than Option 1, it still provides a completely new plant and distribution system, with significant operational advantages, in a better location. A much more complete list of the operational implications of each Option are detailed in Section IV; they support the construction of a new plant and distribution system.

As noted in Section I, SU also asked that an electrically heated campus be considered. This request came late in the study, and would have significantly altered the scope of the study had it been fully developed into an Option. However, it was simple to calculate the potential operational savings of such a system, and therefore a simplified summary of the results is included here. A complete cash flow analysis is included with those of the seven Options in Appendix F.

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Abacus assumed that for any building currently heated with hot water (generated by steam from the central plant, and, in some buildings, by gas-fired "summer" boilers), an electric boiler would be installed. This would reduce the implementation cost; it also would allow SU to continue to use gas in the summer, rather than add to the summer demand peak. In other buildings, electric resistance heat would be used.

Construction costs were not estimated; in general however, the cost of the work in the buildings could well be less than the \$13,760,000 already appropriated. Therefore, in the financial analysis, the cost of the work was set to exactly \$13,760,000. This results in no finance charge being assessed to the work – if the cost were less than that, the result would be the same, and if the cost were higher, the results would be worse. More about construction costs below.

TABLE: Savings/Cost Summary

Electric - Gas

Financial Data			Year 1 Results (1)			Results over Term (2)		
Available Capital:	\$13,760,000		Savings: (\$1,259,045)			Net Cash Flow : (\$26,174,457)		
Cost of this Option:	\$13,760,000		NSP: 1.9 yrs			NPV : (\$9,730,203)		
Amount to Finance:						Investment :		
Cost of Option 1:	\$16,182,720					Net Cash Flow/No debt : (\$26,174,457)		
Incremental Increase:	(\$2,422,720)					NPV/No debt : \$12,820,451		
			Unit Consumption			Cost		
			Modified	This	Unit	Modified	This	TOTAL
Resource Costs			Baseline	Option	Savings	Baseline	Option	SAVINGS
Elec Demand:	\$9.7400	per kW	10,034	70,601	(60,567)	\$97,731	\$687,651	(\$589,920)
On Peak Energy:	\$0.0411	per kWh	1,139,807	9,989,714	(8,849,907)	\$46,823	\$410,377	(\$363,554)
Off Peak Energy:	\$0.0335	per kWh	1,789,509	23,000,517	(21,211,008)	\$59,949	\$770,517	(\$710,569)
Avoided Demand:	\$9.7400	per kW						
Avoided On Peak:	\$0.0411	per kWh						
Avoided Off Peak:	\$0.0335	per kWh						
Coal, barley:	\$87.5600	per ton	3,974		3,974	\$347,963		\$347,963
Coal, buck:	\$116.1600	per ton	491		491	\$57,035		\$57,035
Natural Gas:	\$7.3000	per MBTU	25,725	25,725		\$187,793	\$187,793	
Oil:	\$1.6600	per gal						
			Totals:			\$797,293	\$2,056,338	(\$1,259,045)

Notes: (1) For Options 2 through 4, NSP is based on the Incremental Increase in Cost over Option 1
(2) These results come from the Cash Flow Analysis; they cannot be derived solely from the number in this Table.

As the Table shows, operating costs increase significantly in this scenario, by over \$1.2m in year one. The analysis also indicates that the construction cost is likely to be much higher than the \$13.76m available. This is because peak demand is calculated to rise to over 15 MW, and in fact, is more likely to increase to close to 20 MW. The end-use heating load profile (electricity has none of the losses of the central steam plant) is based on average loads – actual peaks could be 25 – 30 percent higher, thus the estimate of 20 MW.

It is unlikely that the existing electrical transformation and distribution systems could handle these kinds of electrical demands. If not, then rebuilding the electrical systems to do so could easily cost more than all the work in the buildings. Clearly, this scenario seems the least feasible of any detailed in this report.

SECTION II: EXECUTIVE SUMMARY

The remainder of this report is intended to provide supporting information for the data and conclusions in this summary. As noted above, the variables and assumptions that went into the financial summary in this Section is included below:

TABLE: Financial Variables and Assumptions				All Options
Financial Data	30 year term of Analysis		Inflation	
Available Capital: \$13,760,000	Finance Term :	15 years	Fuel/Ops/Maint:	0.0300 per year
Cost of Option 1: \$16,182,720	Interest Rate :	0.04125 per year	Rent:	0.0300 per year
	Payments :	4 per year	Wages/Benefits:	0.0300 per year
	Discount Rate :	0.05000 per year	Construction:	0.0300 per year
Wages & Benefits			unit cost	
FTEs:	11		\$53,000	The unit cost was an average of similar costs Abacus has documented in other SSHE facilities.
potential reduction:	5			
Increased Rents			unit cost	
current room-nights:	13,597 per yr		\$22.00	SU recorded 27,193 "people-nights" in the campus dorm rooms in 2004. Since double occupancy is the norm, this was divided by two to get "room-nights". Unit cost was provided by SU.
Deferred Maintenance Costs (\$000)				
Plant renovations	Year 3:	\$1,639.5	Total deferred maintenance is detailed in Section IV. For the cash flow analysis, it was assumed that the work would not start until year 3 to allow for funding, planning, and design time. The Plant work was assumed to take a maximum of three summers; the distribution work up to five. The cost for each part was divided equally by the number of years, which resulted in the phased costs shown at left. These phased costs were then inflated as shown above, the NPV of the payments calculated over the seven year period at the discount rate shown, and this figure was then divided by seven. This inflated and discounted cash stream was then counted as a savings for years 1 through 7. This represents the amount SU would need to put away/spend each year until the work was done, assuming they invest now and spend as needed.	
phased over	3 yrs	Year 4: \$1,639.5		
		Year 5: \$1,639.5		
Piping renovations	Year 6:	\$676.9		
phased over	5 yrs	Year 7: \$676.9		

The summer dorm room occupancy, measured in "people-nights", was provided by Randy Hammond, the Conference Director, at SU. This figure given (27,193, as shown in the notes in the Table above) was for 2004 and assumes double-occupancy. To convert to "room-nights", this was divided by two to get the 13,597 value shown in the Table above, and in all the subsequent financial models. The assumptions on how many more rooms might be rented in summer if they were air conditioned, and how much more could be charged for the rooms came from Mr Hammond as well.

SECTION III: METHODOLOGY AND BASELINE

METHODOLOGY

The methodology for predicting energy use and therefore cost to operate is straightforward. A mathematical model of the affected systems and their support equipment is created in a spreadsheet. This model is based on the assumption that heating and cooling loads are primarily dependent on outside air temperature (OAT), time of day (TOD), and occupancy (night/day, summer/school year, etc).

The first requirement of the modeling is to relate heating and cooling loads to the three variables (OAT, TOD, and occupancy) they are assumed to be dependent on. To do this, Abacus primarily used data loggers. These devices record or measure information such as temperature, humidity, amps, and motor status. Abacus logged data over a 10 month period, from about July 2003 to February 2004. This logging produced tens of thousands of data points.

The intent was to measure load on a building by building basis. Because the loggers also record the time of the reading (and three dedicated loggers did nothing but measure OAT and humidity), Abacus could relate every data point to the three variables. Heating load (as a function of the three variables) for a building, for instance, could be determined by recording the difference between hot water supply and return temperatures, and knowing the pump flow rate. In buildings with no heat exchanger, load could be determined by logging how many times the condensate pump cycled on and off. Since each cycle pumps the same amount of condensate (within the margin of error), the amount of condensate per hour can be determined. During the summer months, Abacus also measured the heating load in buildings with summer boilers.

Similarly, for cooling, Abacus simultaneously logged the supply/return temperatures, and the chiller amperage. This not only gave us load as a function of the three variables, but also indicated how much power was being used to generate the chilled water. In a chilled water system, the chiller is the dominant consumer of power, by a factor of ten or more. For auxiliary equipment, Abacus took a single power reading using a true RMS kW meter, and then simply monitored whether the equipment was on or off; when on, it was assumed to use the amount of power recorded. The results of this field work can be found in Appendix C. It is presented in the form of schedules. Many of the fields in the schedules are blank; they were created to record basically any type of data that might possibly be obtained about the equipment. Often the data were not available, so the fields are blank.

These data were analyzed statistically to produce load profiles for each building. This was done for both heating cooling. For the same period, Abacus also collected input (fuel) and output (steam) data from the Boiler Plant. At this point, Abacus was able to predict for a given OAT, TOD, and occupancy, what the heating or cooling load would be on the buildings, and how much input (coal, gas or electricity) would be required to meet the load. In the case of heating, Abacus knew both the Plant output and the building end-use. The difference between the two represents the losses in the system that can be attributed to parasitic load, and distribution losses. There is no analog for system losses in the cooling system since it is local.

Equipment behaves in characteristic ways as it loads and unloads. These characteristic "unloading curves" can be obtained from the manufacturers, and/or can be measured directly (as Abacus did with the chiller loggers). These are reproduced mathematically in the models. The models are then capable of predicting load, and how much energy in the form of coal, gas, electricity, etc., must be expended to generate or reject the required heat, as well as the energy cost of transporting the heat transfer media (steam, condensate, and chilled water).

SECTION III: METHODOLOGY AND BASELINE

Having constructed the model, it must be tested against reality. If it cannot "back-predict" known conditions, then it cannot be relied upon to predict future energy consumption. In the predictive mode, the models use weather data that have been averaged out over many years – it is trying to predict long term average energy consumption, not that of a specific and perhaps anomalous year. In the calibration mode, however, the model output is compared to actual energy bills, so it must use the actual weather during the billing period it is being calibrated against.

Abacus started this study back in 2003, so the most current data available at the time was from July 1999 through June 2002 (fiscal years). Abacus calibrated the mode against the known coal, gas, and electrical bills from that period. A summary of the Boiler Plant costs from that period, including both energy and non-energy costs, can be found in Section VI. Likewise, a summary of electrical data from that period, including both consumption and costs, can be found in Section VI. Finally, a series of graphs of Electrical Demand for the months of January 2003 through October 2003, taken at 15 minute intervals, can also be found in this section. These graphs are presented monthly, with two months per page, and are broken out by On Peak, Off Peak - weekend days, and Off Peak - nights. Outside air temperature is also depicted on the graphs. A summary at the top of each graph gives the maximum, minimum, average, and median demand for the month.

The Baseline model, when complete, calibrated to actual energy use to within 2 percent for all forms of energy. Once this calibration is complete, the weather data for the model is changed back to the average data (called TMY, or typical meteorological year data). This average data is used for all further predictions.

The Baseline Model is now complete at this point. However, there are changes anticipated in campus energy consumption. The biggest factors are the ECMs being implemented under Abacus' performance contract, and new buildings coming on line. Therefore, the load profiles in the model must be modified to reflect the expected load after the ECMs, and the new buildings must be added. Once this is done, the model is called the Modified Baseline.

The energy consumption predicted in the Modified Baseline is the basis for all energy savings estimates. Predicted consumption of each type of energy input for each Option is compared to the energy predicted by the Modified Baseline. The difference is the predicted energy savings (positive savings numbers indicate a reduction of energy, negative savings indicate an increase in that particular form of energy input).

A printout of all the models is included in Appendix D.

BASELINE

The Baseline Model predicted the following annual energy inputs. With regard to electricity, the model only predicts that used by the heating system support pieces, and the cooling system. It does not attempt to model lights, fans, plug loads, etc. For this reason, it cannot be calibrated against the meter, which of course does include these other loads. The best means of calibration for cooling power is the demand data mentioned in METHODOLOGY above (and found in Section VI). By comparing the campus demand peaks under varying OATs (which are plotted on the graphs), the magnitude of the effect of the cooling systems on power consumption can be inferred, and a limit placed on it.

Similarly, the natural gas consumption shown is only that for the summer boilers and water heaters. Other end-users such as kitchens and kilns are not included. Again, by comparing data from summer months (months when the gas boilers are being used) vs. winter months (steam plant in use), the amount of gas related to the boilers can be inferred and limits placed on it.

SECTION III: METHODOLOGY AND BASELINE

In addition, the small pie charts give a graphic representation of the relative dollar value of the inputs. If the graphs were by BTU value rather than cost, they would be even more heavily skewed towards coal vs. gas.



SECTION IV: SUMMARY OF OPTIONS

SUMMARY OF OPTIONS

Option 1:

A. Summary Table, Year 1 (see Appendix F for complete cash flow analysis)

TABLE: Savings/Cost Summary							Option 1	
Financial Data		Year 1 Results (1)			Results over Term (2)			
Available Capital:	\$13,760,000	Savings:	\$12,250		Net Cash Flow :	\$3,518,817		
Cost of this Option:	\$16,307,720	NSP:	208 yrs		NPV :	\$3,157,264		
Amount to Finance:	\$2,547,720				Investment :	\$2,547,720		
Cost of Option 1:	\$16,182,720				Net Cash Flow/No debt :	\$6,948,213		
Incremental Increase:	\$125,000				NPV/No debt :	\$5,530,327		
		Unit Consumption			Cost			
		Modified	This	Unit	Modified	This		
Resource Costs		Baseline	Option	Savings	Baseline	Option	TOTAL SAVINGS	
Elec Demand:	\$9.7400 per kW	10,034	10,034		\$97,731	\$97,731		
On Peak Energy:	\$0.0411 per kWh	1,139,807	1,139,807		\$46,823	\$46,823		
Off Peak Energy:	\$0.0335 per kWh	1,789,509	1,789,509		\$59,949	\$59,949		
Avoided Demand:	\$9.7400 per kW							
Avoided On Peak:	\$0.0411 per kWh							
Avoided Off Peak:	\$0.0335 per kWh							
Coal, barley:	\$87.5600 per ton	3,974	3,854	120	\$347,963	\$337,456	\$10,507	
Coal, buck:	\$116.1600 per ton	491	476	15	\$57,035	\$55,292	\$1,742	
Natural Gas:	\$7.3000 per MBTU	25,725	25,725		\$187,793	\$187,793		
Oil:	\$1.6600 per gal							
Totals:					\$797,293	\$785,044	\$12,250	

Notes: (1) For this option only, the NSP is based on the amount above and beyond the Available Capital
(2) These results come from the Cash Flow Analysis; they cannot be derived solely from the number in this Table.

B. Synopsis

Option 1 was the course that SU was undertaking when Abacus came under contract. At that time, SU had already submitted Capital Project Justification forms to the Commonwealth in order to get the money required to do the work. The intent was get as much repair, upgrade, and replacement work done as possible on the steam plant and steam distribution. None of the money was intended for campus electrical distribution or chilled water.

The following are excerpts from the Capital Project Justification form submitted by SU to the Commonwealth for the work in the Steam Plant:

Project Description: Two of the four boilers in the campus coal fired steam generating plant are approaching the half century milestone, and a third is over 35 years old. These boilers and their auxiliary systems require replacement. The design for replacement should incorporate the best available technology from a life cycle standpoint, including dual



SECTION IV: SUMMARY OF OPTIONS

fuel capability for pollution control and economical and cost effective, reliable operation. In addition, the entire plant requires renovation and modernization.

	Base Project	Request (dollars in thousands)		Total
		Land	Design & Cont.	
Bond	5,716		1,144	6,860
Current				
Federal				
Local				
Other				
Total	5,716		1,144	6,860

Project Justification:

Academic program requirements

- This project assures reliable steam energy to support the University’s academic missions
- Identify deficiencies corrected
- Coordinate with DEP to assure the latest environmental requirements are incorporated into the scope
- Boiler plant facility: replace roof; re-point brick; install adequate structural support for induced draft fans; replace windows; install adequate ventilation; renovate toilet room; install emergency lighting; replace existing lighting; replace electrical panels and wiring to meet modern standards and codes. Coal handling equipment: replace elevator and conveyor bearings, belts, and motors; upgrade manpower intensive system for transferring coal from storage pile to elevator hopper. Coal storage facility: Upgrade to meet environmental standards for outdoor stockpiling of coal.
- Modernize coal-weighing system for automation and accuracy.
- Boiler upgrade should include stoker replacement.
- Modernize ash-handling system to meet environmental standards.
- Modernize chemical control system and de-aeration system.
- Replace piping, valves, and appurtenances to the standard and emergency feed water system
- Replace piping, valves, and appurtenances to the steam supply and condensate return system
- Modernize pollution control equipment to meet environmental standards for air and wastewater.
- Perform investigations to determine extent and location of deterioration of systems, the most economical way to replace and improve the operation and maintenance of the system to include consideration of dual fuel capability, and extent and location of any asbestos affecting the work
- Connect boiler controls and administrative functions to the campus-wide building control system and campus network

Revenue potential

- Doing this project will prevent a loss of revenue from unexpected steam heat outages

Matching funds

- None

Cost savings potential

- Correction of deferred maintenance items will reduce maintenance demands, resulting in savings
- Energy performance will be enhanced with new energy envelopes and controls, resulting in savings
- Cost avoidance for downtime due to steam outages

Reduction of Deferred Maintenance Backlog:

- Approximately \$2,000,000 deferred maintenance backlog will be eliminated

Regional economic improvement potential

- Cost avoidance in event of downtime from steam outages

Alternatives considered

- Do nothing (not a satisfactory alternative since not responsive to the facility needs)



SECTION IV: SUMMARY OF OPTIONS

- Interdependency with other capital improvements
 None
- Strategic Plan and Facility Master Plans
 Plans are currently being updated; this project is anticipated to remain consistent with them

Although the Project Description and Project Justification contradict each other on some specifics, they generally define the intended scope. The Description speaks of replacing boilers and auxiliary systems, while the Justification talks only of auxiliary equipment (with regard to the boiler themselves).

There are many references to meeting environmental standards, and this is discussed in great detail below in Subsection F Emissions. SU could easily spend the majority of the \$5.71M worth of construction dollars on emissions controls, but this is probably not the best use of the money. Based on SU's current operating permit, and Abacus' findings to date, Abacus would agree with all of the non-emissions related items listed in the Justification.

The following are excerpts from the Capital Project Justification form submitted by SU to the Commonwealth for the work on the steam distribution:

Project Description: This project provides for renovation of the forty-year old high-pressure steam distribution and condensate systems where required to assure reliable delivery of heat to the campus.

	Request (dollars in thousands)			Total
	Base Project	Land	Design & Cont.	
Bond	5,750		1,150	6,900
Current				
Federal				
Local				
Other				
Total	5,750		1,150	6,900

SECTION IV: SUMMARY OF OPTIONS

Project Justification:

Academic program requirements

- This project assures reliable steam energy to support the University's academic missions
- Identify deficiencies corrected
- Replace high-pressure steam and condensate piping where required, approximately 10,200 linear feet.
- Install approximately 900 feet of new high-pressure steam and condensate piping between manholes 32 and 14 and between manholes 29 and 39 to enable operation of a ring main system to keep buildings in operation in case of a pipe break.
- Perform investigations to determine extent and location of deterioration of steam distribution and condensate collection system, the most economical way to replace and improve the operation and maintenance of the system, and extent and location of any asbestos affecting the work.
- This utility system renovation is urgently required to provide power for almost thirty major facilities.
- Several sections of the campus steam distribution system were installed almost forty years ago and have required numerous repairs for several years in both the high pressure steam and condensate return lines.
- Inspection reveals deterioration, due to corrosion, to the extent that finding sound metal to accept repair welds is difficult, especially in the condensate return lines.
- This utility system renovation is urgently required to heat almost forty major facilities in a region that experienced almost ninety continuous days of snow covered ground in a recent winter.
- The University has experienced failures in the steam distribution system that cause shutdown of the entire system to make repairs, and the risk of catastrophic failure looms.

Revenue potential

- Doing this project will prevent a loss of revenue from unexpected power outages

Matching funds

- None

Cost savings potential

- Correction of deferred maintenance items will reduce maintenance demands, resulting in savings
- Energy performance will be enhanced with new energy envelopes and controls, resulting in savings
- Cost avoidance for downtime due to steam outages

Reduction of Deferred Maintenance Backlog:

- Approximately \$2,000,000 deferred maintenance backlog will be eliminated

Regional economic improvement potential

- Cost avoidance in event of downtime from steam outages

Alternatives considered

- Do nothing (not a satisfactory alternative since not responsive to the facility needs)

Interdependency with other capital improvements

- None

Strategic Plan and Facility Master Plans

- Plans are currently being updated; this project is anticipated to remain consistent with them

Using these CPJs as guideline, and with the help of Tony Gardner at the Plant, a detailed scope of work was developed. Cost estimates were attached to each item. A spreadsheet was developed with all of the potential items required to make the steam plant capable of providing steam efficiently and safely for the next 30 years. In addition, some alternate items were listed. These were primarily items which addressed future concerns. In terms of emissions, for instance, an item was included for sulfur scrubbers. Based on conversations with the State, we believe there is no requirement for scrubbers at this time, regardless of which Option is implemented. However, if coal is included in the final plan, there is a very good chance that the scrubbers would be required within the new life of the plant, so an item was included for scrubbers.

This is one example, there are others. On the spreadsheet below, each item has an ON/OFF toggle. A "1" equals ON, and a zero (a blank) equals OFF. The summary at the top only counts the items toggled ON. The first part is the steam plant, and this is followed by the distribution line items.

SECTION IV: SUMMARY OF OPTIONS

ESTIMATED COSTS: Steam Plant and Distribution Modifications Required for a "30-Year System"

<i>Total, Steam Plant Items Selected</i>	>	\$9,485,181
<i>Total, Steam Distribution Items Selected</i>	>	\$6,697,539
<i>Total</i>	>	\$16,182,720
<i>Total, Steam Plant Deferred Maintenance</i>	>	\$2,887,868
<i>Total, Steam Distribution Deferred Maintenance</i>	>	\$3,384,510
<i>Total</i>	>	\$6,272,379

- Notes: 1 Costs are Total Project costs, and include design, construction, PM, CM, start-up, and commissioning.
 2 Steam Plant numbering starts at 1, Distribution starts at 50 to leave space for additional Steam Plant Items.
 3 "DM" equals Deferred Maintenance. A "1" indicates that this Item represents Deferred Maintenance that will not have to be done if these Items are implemented.

STEAM PLANT		Estimated Cost	On Off	D M
1	Steam Plant Roof:	\$348,717	1	1
	> Replace the entire roof of the steam plant (approx 13,524 sq.ft.) with new composition roof.			
	> The existing roof is 25 years old, and has accumulated tons of ash over the years. In many places, the build-up of ash has sloped the roof away from the drains. Plants are beginning to take root in the ash/dust mixture that has collected.			
	> Minor structural repair is included to repair damage done by leaks over the years.			
	> New insulation is included.			
	> The accumulated ash has changed the drainage, and created areas of ponding.			
2	Steam Plant Roof Drains	\$43,590	1	1
	> Replace the existing rooftop storm drains. This includes only the drains themselves, and the storm leaders in the building.			
	> Item 12 includes re-routing the storm leaders as they exit the building			
3	Repoint and Replace Brick as Required	\$246,659	1	1
	> The horizontal and vertical seals on the coping stones on the top of the parapet have largely failed. This allows water in behind and into the mortar of the bricks, particularly those between the trim piece just below the parapet and the parapet itself.			
	> The resulting freeze/thaw cycling has pushed many of the bricks almost out of the wall.			
	> This includes repointing, and where required, replacing the bricks in the area described as well as the rest of the entire building (approx 30,000 sq.ft.).			
4	Repair and Reseal Coping Stones on Parapet	\$13,155	1	1
	> The seals in most of the coping stones on the parapets have failed (see Item 3).			
	> Similarly, the joints in the watercourse below the parapet have mostly failed also.			
	> This includes resealing the coping stones, all vertical and horizontal joints.			
5	Refurbish Existing Restroom	\$41,110	1	1
	> This includes new WC, new urinal, new shower enclosure, and new DHW heater. All fixtures will be low flow, water saving.			
	> This includes new wall and floor finishes, appropriate for the duty.			
6	Repair Exterior Doors	\$7,893	1	1
	> Replace four in number metal doors and door frames in their entirety. This doors are rusted through, and some of the frames are falling out of the wall.			



SECTION IV: SUMMARY OF OPTIONS

7	Repair/Replace Windows	\$115,108	1	1
	<ul style="list-style-type: none"> > Replace or repair windows, 15 in number, 100" wide by 192" high. Total area approx 2,000 sq.ft. > Repair the operable sections of each window, and re-install the crank actuators where missing. > In some cases, frame and even wall repair will be required - some the window units are being held in by wooden wedges, and would fall out if allowed to. 			
8	Replace Main Electrical Switchgear	\$58,540	1	1
	<ul style="list-style-type: none"> > The existing main switchgear is old, and prone to failure of the breakers. > The handles of the breakers have been known to break off - this is extremely dangerous; a life safety issue. > The existing emergency generator is too close to the switchgear to maintain code-required clearance - this is also a life-safety issue. 			
9	Replace MCCs	\$101,624	1	1
	<ul style="list-style-type: none"> > Most of the buckets and frames in the existing Motor Control Centers are obsolete. > There are three (3) MCCs, with a total of about 45 buckets > Many lack a mechanism for opening the door while leaving the motor running. This means that any work requires a shutdown. > This includes new starters as well as the new MCC frame and buckets. The feeders for this gear are included in Item 10. > Starter will be grouped logically by what they serve - currently, the starter buckets were installed wherever there was room, not by function. > Again, replacing obsolete electrical gear is a life-safety issue. 			
10	Replace Plant Branch Wiring	\$182,750	1	1
	<ul style="list-style-type: none"> > The branch wiring in the plant is obsolete; it still has cloth insulation. > This includes new feeders from the switchgear to the MCCs, and from the MCCs. > This includes new disconnects. > This includes new panels, new branch wiring and conduit, and new outlets. > Like the Main Switchgear and the MCCs, replacement of this wiring should be considered a life safety issue. 			
11	Replace Boiler No. 4 Stoker	\$698,868	1	
	<ul style="list-style-type: none"> > Replace chain grate stoker on Boiler 4 to one suited for smaller (barley) sized anthracite coal. > Move the Stoker drive from the front of the boiler to the back, > This eliminates the need to buy and store two sizes of coal. In effect, it increases the amount of coal storage available, since the other boilers cannot burn the buckwheat coal fired in No. 4. Any coal stored in the buckwheat hoppers cannot be used if No. 4 is not running, yet it takes up hopper space > It also eliminates the worry that operating staff will forget to change the hopper gates on the horizontal conveyor, thus dumping buckwheat coal in the barley hoppers, or vice versa. > The boilers burning barley seem to have lower stack temperatures (i.e., are more efficient). 			

SECTION IV: SUMMARY OF OPTIONS

12	Structural and Operational Upgrades	\$1,475,310	1	1
	<ul style="list-style-type: none"> > These items were grouped together because Shippensburg has received a quote for the combined work. The item is divided into six (6) sub-items, A through F: A > Add two new additional coal hoppers. Within the existing structure, there is room for two (2) more coal hoppers, which will increase storage. B > In order to feed the new hoppers, the existing horizontal conveyor must be extended approx 16 ft. C > The structure holding up the existing bunkers and horizontal conveyor is being corroded by the wet coal and coal dust. This includes repairing and replacing structural elements to bring the structure back to the original strength. D > Install a new DA tank. The existing tank is showing deterioration, and the boiler inspector has suggested that it be replaced. This requires that the roof above the DA tank be removed and then replaced. This should be done coincident with Item 1. E > Install a new ash wash (slurry) tank to improve the function of the existing system. This system washes ash out of the ash removal airstream (the vacuum) to prevent damage to system. The ash/water slurry is pumped to drain. F > Remove the existing ash chute, and extend the ash auger. The chute hangs down at an angle from the end of the existing auger, and hangs so low that only small trucks can be used to haul the ash away. This results in multiple hauling trips per day. If the chute were removed, and the auger extended at the existing angle, a standard truck could be used, and the number of trips reduced. 			
13	Coal Pile and Coal Yard Modifications	\$573,894	1	
	<ul style="list-style-type: none"> > A significant fraction of the coal pile is actually sitting on Rail to Trail property (not SU property). > A significant fraction of the coal pile is outside of the retention wall meant to contain the run-off from the pile. > The water from three sources runs into a surface drainage swale adjacent the coal yard. None of these sources should be run to a surface swale. The sources are the coal pile retention area, the ash hauling retention area, and the storm drains from the Boiler Plant. > All of these sources should be run to the Sanitary System; however, the invert of the new sanitary sewer line installed last year is too high to allow these sources to drain to sanitary by gravity (the line was raised because it was too low to drain to the City system - in the new configuration, it falls less than 1-1/2 feet in 300 feet). > A new retention area with higher walls is required to allow the coal to be properly stored within the area, and entirely on SU property. > The water from the three sources must be collected and pumped to the sanitary system. 			
14	Additional Storage on Grade	\$19,075	1	
	<ul style="list-style-type: none"> > There is limited storage on the main operating floor for storage. Many of the items that must be stocked are far too heavy to move manually (in excess of 800 pounds). Currently, these must be lowered into the basement with heavy equipment, or placed wherever space can be found on the main floor. > These pieces impede movement and operations in the plant. > Directly adjacent the boiler plant is a garage owned by the foundation. According to Plant personnel, people park in front of the garage, but never in it. > This item would add a new roll-up door in the end wall facing the plant, and regrade and pave the approach to the door, allowing access from the plant yard. 			
15	Revise the Coal Service Entrance into the Plant	\$70,709	1	
	<ul style="list-style-type: none"> > Although the hopper which feeds into the elevator is physically close to the coal yard, it can only be reached and fed from the side opposite the yard. > Because of this, operators must load coal into a truck, and drive the truck around the building, then dump it into the intake hopper. > This includes significant re-grading to allow coal to be loaded directly from the coal yard, without driving around the building. It installs new rails for the hopper lid to be drawn away from the hopper to allow this to happen. 			

SECTION IV: SUMMARY OF OPTIONS

16	New Emergency Generator	\$139,774	1	1
	<ul style="list-style-type: none"> > Remove existing emergency generator and install a new one large enough to run the entire boiler plant. > This should be installed outside - the existing unit is too close to the Plant Main Switchgear as it is (it is a code violation). The new, larger unit cannot go in the same spot. 			
17	New Feedwater Pressure Regulator	\$11,511	1	1
	<ul style="list-style-type: none"> > The feedwater pressure regulator keeps the feedwater pressure 20 PSIG higher than the boiler pressure. This ensures that the feedwater can get into the boiler, even as boiler pressure rises. > The existing unit sticks. If the unit were to stick, and the boiler pressure were to rise too high, a low water condition could result in the boilers. This is a life safety issue. 			
18	Add Additional Ventilation Fans	\$22,199	1	1
	<ul style="list-style-type: none"> > There is only one ventilation fan in the roof, just above Boiler No. 2. The heat build-up is significant. This would install three new vent fans to pull air uniformly from the plant. 			
19	Plant Master Steam Meter/Meter Replacement	\$29,928	1	1
	<ul style="list-style-type: none"> > Each Boiler is metered, but there is no Plant Master. In the event that a meter fails, there is no record, and no way to estimate the Plant output. > A Plant Master would allow the operators to calculate the output of any boiler with a failed meter (by subtraction), and to ensure complete record-keeping. > In addition, this includes replacement of two meters in the old plant control panel that contain Mercury. Disposal of the meters is included. 			
20	Re-tube Boiler No. 1	\$641,314	1	
	<ul style="list-style-type: none"> > Boiler No. 1 was installed in 1952. It has never been comprehensively re-tubed. > Boilers 1 and 2 were listed first because they are the oldest. > In a water tube boiler, such as No. 1, the tubes and drums are the pressure vessels. They see the highest pressure, and are subjected to the highest level of corrosion, with hot stack gas on the outside, and water on the inside. > Years ago, before the present operating crew was in place, the water softeners were not used on the boiler make-up. This resulted in very heavy build-up on the tubes. This had to be removed by mechanical scrubbing. > There have been no large-scale tube failures to date, but the intent of this project is to set the plant up for 30-40 years into the future. Some level of re-tubing should be contemplated. > In talking to the EPA and DEP, the consensus was that "major" work on the boiler (generally defined as costing one half or more of the boiler's value) would trigger a requirement to meet current emissions standards. As with the dual-fuel/tri fuel items below, this is assumed to be particulate removal only (a baghouse or electrostatic precipitator), not a scrubber to remove sulfur. Re-tubing was not thought to trigger this requirement, but it is mentioned because there is always a chance the state will require it when it actually happens. At this time, the cost of new emissions controls is not included in the re-tubing items 			
21	Re-tube Boiler No. 2	\$641,314	1	
	<ul style="list-style-type: none"> > Boiler No. 2 was installed in 1952. It has never been comprehensively re-tubed. > See item 20 above. 			
22	Re-tube Boiler No. 3	\$690,646	1	
	<ul style="list-style-type: none"> > Boiler No. 3 was installed in 1964. It has never been comprehensively re-tubed. > See item 20 above. > Boiler No. 3 is newer than 1 or 2, but the intent of this work is to set the plant up for 30 - 40 years, so re-tubing should be considered. 			



SECTION IV: SUMMARY OF OPTIONS

23	Re-tube Boiler No. 4	\$739,978	1
	<ul style="list-style-type: none"> > Boiler No. 4 was installed in 1984. It has never been comprehensively re-tubed. > See item 20 above. > Boiler No. 4 is newer than 1 or 2, but the intent of this work is to set the plant up for 30 - 40 years, so re-tubing should be considered. 		
24	Install Dual-Fuel Capability on Boiler No. 4	\$838,641	1
	<ul style="list-style-type: none"> > Install one or more gas-fired burners in the sidewall of the boiler to allow firing on coal or gas. > Boiler No. 4 was selected first because it is the newest, and has the greatest steam capacity. > Includes a baghouse for particulate removal. If a new burner is added, Abacus' research indicates that this will trigger a requirement to meet current emissions standards. The consensus of the people contacted was that this would require particulate control, but not sulfur removal. > Sulfur removal could add another \$500,000 to the cost. > Boiler No. 4 was selected because it is the newest, and has the greatest steam capacity. > This Item is mutually exclusive with Item 25 - only one can be selected. 		
25	Install Tri-Fuel Capability on Boiler No. 4	\$1,027,747	
	<ul style="list-style-type: none"> > Install one or more gas/oil fired burners in the sidewall of the boiler to allow firing on coal, oil or natural gas. > Unlike Item 24 above, this Item requires new infrastructure for the storage and distribution of No. 2 oil. > Includes a baghouse for particulate removal. If a new burner is added, Abacus' research indicates that this will trigger a requirement to meet current emissions standards. The consensus of the people contacted was that this would require particulate control, but not sulfur removal. > Sulfur removal could add another \$500,000 to the cost. > Boiler No. 4 was selected because it is the newest, and has the greatest steam capacity. > This Item is mutually exclusive with Item 24 - only one can be selected. 		
26	Install Dual-Fuel Capability on Boiler No. 3	\$838,641	1
	<ul style="list-style-type: none"> > Install one or more gas-fired burners in the sidewall of the boiler to allow firing on coal or gas. > Boiler No. 3 was selected second because it is the second newest, and has the second greatest steam capacity. > No. 3 was intended to be chosen only if No. 4 was converted also. No. 4 is the logical choice if only one boiler is done, but by doing No. 4 and No. 3 (combined with the gas-fired No. 5), the Plant should be able to meet load in excess of 95 percent of the time even if coal is not available. This is not the case if only No. 4 is converted. > Includes a baghouse for particulate removal. If a new burner is added, Abacus' research indicates that this will trigger a requirement to meet current emissions standards. The consensus of the people contacted was that this would require particulate control, but not sulfur removal. > Sulfur removal could add another \$500,000 to the cost. > This Item is mutually exclusive with Item 27 - only one can be selected. 		

SECTION IV: SUMMARY OF OPTIONS

27	Install Tri-Fuel Capability on Boiler No. 3	\$879,751		
	<ul style="list-style-type: none"> > Install one or more gas/oil fired burners in the sidewall of the boiler to allow firing on coal, oil or natural gas. > Unlike Item 26 above, this Item requires new infrastructure for the storage and distribution of No. 2 oil. This Item assumes that Boiler 4 was also made tri-fuel, and so only adds an incremental amount of cost to the oil infrastructure > No. 3 was intended to be chosen only if No. 4 was converted also. No. 4 is the logical choice if only one boiler is done, but by doing No. 4 and No. 3 (combined with the gas-fired No. 5), the Plant should be able to meet load in excess of 95 percent of the time even if coal is not available. This is not the case if only No. 4 is converted. > Includes a baghouse for particulate removal. If a new burner is added, Abacus' research indicates that this will trigger a requirement to meet current emissions standards. The consensus of the people contacted was that this would require particulate control, but not sulfur removal. > Sulfur removal could add another \$500,000 to the cost. > Boiler No. 3 was selected second because it is the second newest, and has the second greatest steam capacity. > This Item is mutually exclusive with Item 26 - only one can be selected. 			
28	Install particulate emissions controls on Remaining Boilers	\$772,866	1	
	<ul style="list-style-type: none"> > Install particulate control on remaining boilers (No. 1 and No. 2) 			
29	Install sulfur emissions controls on All Boilers	\$2,959,911		
	<ul style="list-style-type: none"> > Install scrubbers on all four boilers for sulfur removal 			
30	Integrate Boiler Controls into Campus-wide Control System.	\$71,367	1	
	<ul style="list-style-type: none"> > Integrate boiler controls into the campus-wide EMS system. > This allows remote monitoring of the Plant. > It would also automate the recording of fuel use and steam output (and make-up, etc) 			
31	Repair/Replace Valves, Fittings and Appurtenances on Feedwater and Condensate System	\$50,001	1	1
	<ul style="list-style-type: none"> > This is an allowance to remove as much of the remaining deferred maintenance associated with these critical systems as possible. 			

The following distribution line items were identified.

STEAM DISTRIBUTION		Estimated Cost	On Off	
50	Replace Old/Failing Steam and Condensate Piping	\$3,384,510	1	1
	<ul style="list-style-type: none"> > Approx 5,400 linear feet of steam and condensate piping was designated as being most at risk to fail. This includes fittings and expansion loops as required. 			
51	Complete the Ring Main	\$528,344	1	
	<ul style="list-style-type: none"> > Adding approx 850 feet of steam and condensate piping between Manholes 32 and 14, and 29 and 39 will create "rings" in the steam distribution. > These looped systems allow the shutdown of sections of the piping without knocking out service downstream of the shutdown - these areas are backed from the ringed steam mains. 			



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52	Replace Steam Piping to Increase Distribution Capacity	\$2,784,684	1
	<ul style="list-style-type: none"> > The steam distribution system is already fairly constrained in capacity - in winter, the pressure drop from the Plant to the end of the line is 50 PSIG. > The campus is growing away from the Plant. > This will require that some piping be replaced not because of age or service life, but simply to increase capacity. At this time, approx 4,480 feet is included. 		
53	Comprehensive Distribution Master Plan	\$125,000	
	<ul style="list-style-type: none"> > Complete an assessment of the entire system, using both non-destructive and destructive testing to assess the expected remaining service life of the Steam and Condensate Distribution. > Using this information, set out a plan for phased replacement of the systems. 		

In addition to the ON/OFF toggle, there is a Deferred Maintenance toggle (darker field). This toggle indicates which of these items would be considered deferred maintenance. As the CPJs note, these project eliminate a significant amount of work that needs to be done, but has not been funded or implemented yet. By doing any of these Options, either the work is completed as a part of the Option, or the need to do it is eliminated – either way, SU eliminates a little over \$6.27m of deferred maintenance backlog. In the financial analysis, this backlog is spread out over a five year period (starting in year three on the assumption that design and funding must be completed), inflated at assumed rate, and then annualized. This yields an amount that SU would have to put aside each year for the next seven to get this deferred backlog completed. By implementing any of these Options, the need to put this amount aside is eliminated, and thus counts as a savings for the Options

Note that the total project cost, \$16,182,720, is more than the amount requested in the CPJs (by \$2,547,720). Thus, to complete this work, SU would need to request and receive more money, or finance the difference.

C. Drivers

Drivers are factors that would lead SU toward or away from a specific option. These are larger-scale considerations, which must then be backed up by supporting data. The following are some the drivers for Option 1 which must be considered. Positive drivers support this option, while negative drivers suggest reasons for considering other options. The majority of these considerations are expanded upon in the subsections below.

Positive Drivers:

- ◆ The work is almost completely funded by the Commonwealth, SU has the option of cutting back the scope until it matches the budget, requesting more capital from the Commonwealth, or implementing some of all of the scope in an ESCO-type project, thus financing the additional funds required.
- ◆ Done correctly, it should not require re-permitting the steam plant for emissions. Re-permitting represents a significant expense, and would take 4 to 12 months. However, SU may wish to do this anyway, on the assumption that it will be required soon. The intent is to create a 30 year plant, so this must be considered.
- ◆ It has the least visual, acoustical, and access-related impact of any of the options. The majority of the work could be completed in a single summer sessions while the boilers were down for the summer.

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- ◆ The current location of the Plant is remote from most of the campus, and visually screened from it by grade changes. Coal deliveries/ash removal have minimal impact on campus traffic and the visual and acoustical environment.

Negative Drivers:

- ◆ Perhaps the largest negative driver for this option is that while it removes a great deal of deferred backlog and sets up the boiler support systems for many years into the future, it does not address the largest issue facing the distribution of steam. The Plant is located at one end of the campus, and all future growth is projected to be away from Plant. Already, in cold weather, the Plant has trouble maintaining steam pressure at the most remote buildings (Seavers Apartments seems suffer the worst from low pressure). The scope of work assumes that some of the piping is upsized to handle this exact issue. However, the campus will continue to grow away from the plant.
- ◆ Although the Plant work would greatly enhance and upgrade the fuel handling systems and the building itself, they do not address the age of the boilers themselves, and of the building. The boilers were installed in 1952, 1964, and 1984, and the building dates from 1952. Many steam boilers (and many buildings) last longer than this; but at some point investing money in older systems begins to produce diminishing returns.
- ◆ With the addition of Boiler 5, there is no longer any room for expansion. The only way to increase capacity would be to start replacing coal-fired boilers with gas or oil boilers, which require a much smaller footprint per pound of steam.
- ◆ It does not address the inherent disadvantages of a steam distribution system. Steam is a great heat transfer medium; it carries approximately 1,000 BTU/lb of steam, and moves under its own pressure. However, the losses involved in steam system are quite high, as are the ongoing maintenance requirements. As long as fuel (coal) and labor were inexpensive, neither the losses nor the maintenance were significant considerations. Now, however, even coal is becoming a significant expense, and the pool of labor with steam, coal and boiler experience is shrinking. At the same time, all Commonwealth institutions are having to cut maintenance staff due to budget cuts, making the maintenance associated with steam more of a burden. Some additional issues with a steam/condensate system at SU:
 - A steam system is an open-loop system, which means that some of the mass of steam (water) is constantly being lost from the system. This lost mass must be made up with fresh water. This adds up to millions of gallons of water per year.
 - Oxygen and moisture are the main contributors to pipe corrosion. The open-loop nature of the system means that air is constantly introduced into the system. This must be reduced with chemicals. Chemicals are also used to limit scale in the boilers, to control pH, and protect the pipe. Because the system is an open-loop with new water being constantly introduced, chemicals must be added continuously as well. In some cases, depending on water and sewer rates, the chemicals can be more expensive than the water.
 - At SU, the steam plant is shut down from Commencement until the weather gets cold again, generally about the 1st of September. The rationale for doing this is based on the fact that most of the losses in a steam system are constant – that is, they are independent of the mass flow of steam (the load). In winter, the losses may be small compared to the load, but in summer, the losses actually exceed the load; significantly less than half the energy of the fuel is actually making it to end user. Thus, at SU, the Plant is shut down in summer and small, local gas-fired boilers in individual buildings are used as required. This eliminates the losses associated with the steam distribution system, saving money and allowing Plant work do be done without steam shutdowns. However, this also means that the steam and condensate piping are full of air and



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moisture for four months a year with no chemical treatment. This has been going on for about ten years, and although the link cannot be made conclusively, the number of steam leaks has begun to increase. In addition to the corrosion caused by the shutdown, both the shutdown and the re-start in the fall are very maintenance intensive and time consuming.

- After steam transfers its heat, it condenses back to water. This condensate is corrosive (it is hot, oxygenated, and acidic), and hard to deal with. Condensate must be pumped back to the plant, or flows by gravity (one of the reasons the Plant is downhill from the original buildings). Condensate pumps are high maintenance items. The steam and condensate must be kept separate; this is done by steam traps. SU has hundreds of steam traps which require maintenance or replacement on very short cycles; often as little as two years between major maintenance. Traps frequently fail; when they fail open, they are essentially leaks, when the fail closed, no heat transfer takes place.
- A steam/condensate system is very equipment-intensive. Steam is distributed at high pressure, but generally used at low pressure. This requires a pressure reducing station, which requires one or more PRV valves, relief valves, isolation valves, and traps – all maintenance items. And while steam is a great medium for transferring heat through the campus, it is not very good for end-use heat transfer. Water is much easier to deal with, is safer, and offers better temperature control; thus most buildings on the SU campus use water rather than steam inside the building (See the Summary of Building HVAC Characteristics Table in Section VI for individual building heating and cooling characteristics.) This requires that the steam be converted to hot water in a heat exchanger, which in turn requires control valves, isolation valves, relief valves, and steam traps.

D. Operational Considerations

1. Operating costs. The energy-related operating costs for this Option are not expected to vary significantly from the Modified Baseline. None of the improvements to the boilers listed in the CPJ would improve boiler efficiency noticeably. The only energy-related operational savings would come from repairs made to the steam and condensate system. These would result in less heat loss, and fewer leaks. The amount of expected savings is quantified in the table in Sub-section A above.
2. Deferred Maintenance. The deferred maintenance items and the estimated cost of the deferred maintenance eliminated are detailed above in sub-section B. They total \$2,722,379.
3. Reliability. This Option would significantly increase the reliability of the boiler support systems – the coal transportation, the stokers and drives, the weigh lorry, the ash handling, the DA, and the feedwater and chemical feed systems. This is especially important for the coal transportation and stoker systems. As these systems age, parts become much more difficult to find. Many Commonwealth agencies scavenge parts for these systems in particular from other Commonwealth agencies that have converted from coal, and thus no longer need them. By refurbishing or replacing them now, SU is fortifying these critical systems for the next 20-30 years. In terms of the steam and condensate piping, the work is definitely needed, but these systems continue to deteriorate. In particular, this Option does not change the summer shutdown, which lays the pipes up wet and full of air.
4. Spending Priorities. See Sub-section B above.



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E. Financial Considerations

The financial position of each Option depends a great deal on how the project is financed. The analysis assumes that the \$13,760,000 requested in the CPJs is available; however, that amount is not sufficient to pay for any of the Options in its entirety, not even Option 1. Therefore, the analysis looks at making up the difference in two different ways; 1) debt, and 2) capital. The debt is assumed to come from an outside finance company (much like an ESCO project), and the finance term and interest rates used reflect the current offerings in that market. Determining the source of any further capital that might be used to complete the funding of the Options is not within the scope of this report; SU would need to raise that money, or obtain additional money from the Commonwealth.

When evaluating the Options, the nature of the additional money required (typically called "Amount to be Financed", or "Investment" in the spreadsheets) makes a significant difference in the value of the Options over the long term, whether measured by cash flow over the term, or net present value (NPV).

Option 1 is strongest relative to the other options if the project is to be financed with debt. Although it has almost no operational savings, it enjoys the same deferred maintenance savings as the other options, and requires only \$2,547,720 in debt. This amount to be financed is significantly less than any other Option, and because of that, has the second highest NPV of any Option (second only to Option 2B).

If the entire project is capitalized, then the lack of significant operational savings becomes the primary factor in any decision. Without the benefit of the lowest finance costs, this Option has the lowest cash flow and NPV of any Option; in fact the NPV is half or less of most options. This reflects the fact that this Option makes no major changes to the existing systems, other than to put them in order for the next 30 years.

F. Emissions

Abacus talked to eleven different people at the EPA (District 3) and Pennsylvania Department of Environmental Protection (DEP), the primary contacts being Paul Wentworth and Richard Killian at EPA and Leif Ericson and Yasmien Neidlinger at DEP. SU's current Title V operating permit was also obtained. The current Title V permit was issued 24 May 2004 and will expire on 31 May 2009. A copy of SU's current Title V Permit is included in its entirety in Appendix E.

Based on our conversations with these people, Abacus believes that a great deal of the work called for in the CPJs could be done without a New Source Review, and without triggering the need to meet current, stricter environmental standards. The CPJ states the desire to incorporate the latest environmental requirements into the project; it is unclear if that should be taken to mean that they must meet all current requirements for SU (which they do – the Title V permit lists no exceptions taken), or the latest requirements for a New Source.

As currently defined, however, Option1 will require a New Source review, and a new or modified Title V permit. This is due to the dual-fuel burners added to Boilers 3 and 4. In order to ensure that the whole plant is up to current standards, the emission controls on all four boilers are to be upgraded in



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Option 1; thus the cost of the meeting current emissions standards (as Abacus understands them) on all four boilers is included in the estimated project cost.

If SU did wish to avoid having to meet New Source standards, they would have to eliminate the dual-fuel capacity on Boilers 3 and 4, and to use care in how the project is labeled and handled. In trying to avoid the New Source requirements, it is important to understand what actions would trigger them. The first rule of thumb is that the value of the new work cannot exceed 50 percent of the value of the boiler. The second rule is that the work cannot increase the capacity or the emissions of the plant as a whole, or even improve the boiler performance beyond the original specifications. Although it seems strange, one of the most important aspects of this determination is simply what the work is called when it is submitted to the Commonwealth. The DEP and EPA have had negative experiences recently from parties attempting to permit work under existing Title V permits, when in fact the work should have triggered a New Source Review, so they are examining each project closely.

The following words should generally be avoided when referring to the project:

- ◆ Improvement
- ◆ Modification
- ◆ Upgrade
- ◆ Increase (production, capacity, emissions)
- ◆ Redesign
- ◆ Improved
- ◆ Modernization

The following words should not trigger a New Source Review:

- ◆ Maintenance
- ◆ Replacement (like / in-kind is best)
- ◆ Restored to original condition

From a permitting point of view, the agencies involved do not want the user to change the operation; they want it to remain as is, or no better than it originally was when installed.

Abacus does not think the 50 percent rule will apply here, and given reasonable care, SU can avoid triggering a New Source Review. Based on our conversations, we feel certain the following items listed on the CPJ pose no danger of triggering a review:

- ◆ Building upgrades
- ◆ Brick work
- ◆ Electrical replacements
- ◆ HVAC work
- ◆ Plumbing work
- ◆ Work on the DA system
- ◆ Work on any subsystem piping or valving (feedwater, chemicals, etc)
- ◆ Boiler controls
- ◆ Replacement of stokers (as long as style and capacity remain the same)
- ◆ Replacement of grates (as long as style and capacity remain the same)
- ◆ Re-tubing of boilers/refractory work.

The following items, we feel, would be likely to trigger a review:

- ◆ Increase capacity of any boiler
- ◆ Change the combustion, or change the over-fire air system



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- ◆ Add a burner
- ◆ Change fuels or add fuels.

Even if such work did not trigger a New Source Review, it could require a new Title V permit. The Commonwealth can require that this permit be issued before the work starts, and the permit can take 4 to 12 months to obtain.

While avoiding New Source requirements saves significant time and money, it does not provide the significant operational improvements that dual fuel capability would provide. It also does not meet the definition of a "30 year plant", since the new emissions equipment would almost certainly be required in the future in spite of any "grandfathering" that the plant may enjoy now. Therefore, the current scope does include the dual fuel capability, and the upgraded emissions.

No matter what the final scope of work envisioned for the Plant, a Request for Determination for Plan Approval/Operating Permit (RFD) form will need to be filed. A copy of this form is also located in Appendix E. Information about New Source Reviews can be found on the DEP website – the following link is information specifically about NSRs:

<http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/docs/nsr.pdf>

G. Schedule and Impact

All of this work is assumed to be summer work; to be done when the boiler plant and steam system are laid up for the summer. This period is about 15-17 weeks; the fall start-up of the plant being dependent on the weather. Given that some of the work is not urgent, it is assumed that it will be completed over three summer shutdowns. The life safety work and architectural modification would likely be completed the first summer, and then two boilers per summer for the next two summers would complete the work. This work will therefore have little or no visual, acoustical, or access-related impact on the campus operations. This is especially true given the distance of the Plant to the remainder of campus.

The steam and condensate piping work will impact summer programs. The work should be planned to balance the need of the contractor to perform the work in large sections (economy of scale), and the needs of the campus in terms of access. The sections under construction will need to be fenced off, as will the lay-down area and any equipment storage areas. This will disrupt access, which will require an analysis of campus access, especially handicapped access, to be done for each affected building. Temporary ramps and bridges may be required.

There will be visual and acoustical impact as well. These can be minimized by working with the contractors to set acceptable working hours and noise levels.

Scheduling for this work is different from the Plant work, because it cannot be started and completed within the 15-17 week lay-up period. To minimize impact on the campus, Abacus would recommend that the work be phased over three to five summer periods, with the acknowledgement that prep work may begin prior to the summer term, and actual construction may extend slightly beyond the resumption of school in September. The work should be grouped into logical blocks of work, and designed and scheduled far in advance to minimize costs and impact. Abacus has assumed up to five summers to complete the work, but in fact it may require only three.

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Option 2A:

A. Summary Table

TABLE: Savings/Cost Summary							Option 2A
Financial Data		Year 1 Results (1)			Results over Term (2)		
Available Capital:	\$13,760,000	Savings:	\$229,137		Net Cash Flow :	\$5,804,982	
Cost of this Option:	\$22,931,709	NSP:	29.5 yrs		NPV :	\$2,148,669	
Amount to Finance:	\$9,171,709				Investment :	\$9,171,709	
Cost of Option 1:	\$16,182,720				Net Cash Flow/No debt :	\$18,150,695	
Incremental Increase:	\$6,748,989				NPV/No debt :	\$10,691,621	
		Unit Consumption			Cost		
Resource Costs		Modified	This	Unit	Modified	This	TOTAL
		Baseline	Option	Savings	Baseline	Option	SAVINGS
Elec Demand:	\$9.7400 per kW	10,034	10,034		\$97,731	\$97,731	
On Peak Energy:	\$0.0411 per kWh	1,139,807	1,139,807		\$46,823	\$46,823	
Off Peak Energy:	\$0.0335 per kWh	1,789,509	1,789,509		\$59,949	\$59,949	
Avoided Demand:	\$9.7400 per kW		(4,950)	4,950		(\$48,213)	\$48,213
Avoided On Peak:	\$0.0411 per kWh		(898,550)	898,550		(\$36,912)	\$36,912
Avoided Off Peak:	\$0.0335 per kWh		(1,992,100)	1,992,100		(\$66,735)	\$66,735
Coal, barley:	\$87.5600 per ton	3,974	5,775	(1,801)	\$347,963	\$505,659	(\$157,696)
Coal, buck:	\$116.1600 per ton	491		491	\$57,035		\$57,035
Natural Gas:	\$7.3000 per MBTU	25,725	1,350	24,375	\$187,793	\$9,855	\$177,938
Oil:	\$1.6600 per gal						
Totals:					\$797,293	\$568,156	\$229,137

Notes: (1) For Options 2 through 4, NSP is based on the Incremental Increase in Cost over Option 1
(2) These results come from the Cash Flow Analysis; they cannot be derived solely from the number in this Table.

B. Synopsis

This Option would create a completely new means of producing and distributing heat. It does not affect chilled water, but would generate electricity on site, thus avoiding the purchase of that amount of power.

The new Plant would be located closer to the center of campus, to offset the distribution issues that face the current distribution system (campus is growing away from it, and piping appears to be undersized to allow much more expansion). It would use coal as a base-loaded fuel, to take advantage of the low cost per BTU. It would use only a single coal-fired boiler, capable of firing on gas or oil also, to limit the cost of complying with New Source emission standards, and to simplify coal handling and transport. The remaining new boilers would be gas/oil dual fuel boilers.

All of the boilers would be rated to a higher pressure than the existing boilers; no less than 300 PSIG and perhaps as high as 450 PSIG. This allows the economical use of a backpressure steam turbine to generate electricity. Backpressure steam turbines are the most economical means of cogeneration available, and have the lowest maintenance and training costs of any form of cogeneration.

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A backpressure steam turbine simply extracts energy while reducing steam pressure. No steam is ever made simply to make power – at this scale, there is no way to make power for less than you can buy it. Instead, steam is made as required by the load, and the turbine simply extracts electricity from the pressure reduction, rather than heat (as a PRV does). The steam coming out of the turbine has slightly less enthalpy (energy per pound) than steam coming off a PRV, thus slightly more steam must be made when using a turbine. This fuel required to make this incremental amount of steam is the "cost" of operating the turbine. It is worth far less than the power extracted from the turbine.

The output of a steam turbine is extremely dependent on the inlet pressure (thus the higher pressure boilers), and the outlet pressure, or backpressure. The lower, the better. However, it is difficult to distribute low pressure steam; the pipe sizes required are prohibitively expensive. The existing steam distribution, for example, can barely keep up at 70 PSIG. At 5 PSIG, the steam density would be so much less that very little steam would be distributed.

In this case however, low backpressure can be used, because Abacus plans to distribute hot water rather than steam. The reasoning behind this can be found in Subsection C Drivers below. The effect on the turbine is significant; SU cannot distribute 5 PSIG steam, but at 227 deg F, it is more than hot enough under most load conditions to make hot water. The hot water supply temperature would be reset based on load, and the full load temperature differential (supply – return) would be 80 to 100 deg F, to keep the volumetric flow rate down, and with it the pumping costs.

There are other advantages to making steam, but not letting it extend past the Plant; these are detailed below. In general, the boilers are much more efficient, system losses are much less, the effects of corrosion are much easier to control, water consumption is almost zero, and the system is never turned off and laid up wet, as the current distribution piping is – the system would run year round.

Putting a new distribution system in place is estimated to take two years at least (two digging seasons, plus the winter in between). This does imply significant disturbance to the campus. However, because it is completely separate from the existing steam/condensate system, there is no effect on the existing heating, and no need to make temporary connections, etc., as the work progresses.

As the system is extended, new buildings can be switched over to the new system, reducing load on the steam system. Those buildings that already convert to hot water can be tied in to the new system directly. Those buildings still using steam will need to be converted, and the cost of that work included in this Option. The HVAC characteristics of each building can be found in the Summary of Building HVAC Characteristics table in Section VI. Once the new system is completely operational and all buildings are served by it, the gas-fired boiler in the existing Plant would be moved to the new Plant. It is not a high pressure boiler (150 PSIG rated), nor is it dual fuel, so it would likely be used in a back-up role only.

C. Drivers

Positive Drivers:

- ◆ The most obvious driver is that all heating equipment and piping would be new, technologically current, and meet all existing efficiency and emission standards. In Option 1, significant portions of the boiler plant and distribution system would still be 52 years old.



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- Option 2 replaces the entire distribution system rather than patching up the old one. The cost to operate would be much lower than the current costs.
- ◆ The ability to switch fuels, and to generate electricity, gives SU a much better means of managing utility rate volatility, and therefore risk.
 - ◆ It eliminates the issue of the campus growing away from the Plant, with the associated impact on the distribution system sizing.
 - ◆ By keeping all the steam within the Plant, maintenance (and energy loss) would be reduced significantly by the elimination of traps and condensate pumps, except those in the Plant itself. These are visible, and easily monitored and repaired. The difference in the maintenance burden between having hundreds of traps in buildings and manholes, versus perhaps ten traps, all located in the Plant is significant. The same is true of the condensate pumps.
 - ◆ The distribution system (hot water) is a closed loop, which would greatly simplify chemical treatment and reduce the potential for corrosion. The long term chemistry of the piping would be stable, because make-up water would seldom or never be introduced.
 - ◆ The hot water system would run 8,760 hours per year, and would never be laid up full of air. Given care, the expected system useful life would equal or exceed the 50 years that some of the existing piping has provided.
 - ◆ Because of the nature of steam systems, and the age of the plant and distribution at Shippensburg, the overall efficiency of BTUs input to useful BTUs of output barely exceed 50 percent. This is not guesswork. This is what the monthly plant data indicates. Among the losses which would be reduced or eliminated with a hot water distribution system are:
 - Piping heat loss. Steam at 70 PSIG is 316 deg F, and the condensate starts out at 212 deg F. The hot water supply would never exceed 250 deg F, and the return 150 deg F (the insulation would also be much newer and more efficient). Losses would be greatly reduced.
 - Flashing losses. All the flashing occurs in the plant, at very low pressure.
 - Blown traps. All the traps are in the plant, in plain sight. Repair will be prompt.
 - Leaks. The existing system has over 15 percent make-up, much of it due to leaks. The new system is estimated to have 8.5 percent make-up.
 - Boiler combustion efficiency. Judging by the monthly plant data submitted, the existing plant is only about 63 percent efficient. The new plant will be 80 percent or greater.
 - Stack losses. The existing plant cannot recover stack losses. The new plant will use feedwater heaters and, on the gas fired boilers, secondary hot water heaters to recover as much as 6 - 8 percent of input fuel values. Overall boiler efficiency including stack economizer will approach 90 percent.
 - The "banking" of a coal boiler wastes coal, and would be unnecessary in the Proposed Plant.
 - ◆ The Plant could be a public relations plus, because it lowers costs, meets or exceeds current emissions standard, and it complies with Commonwealth Act 28, which requires coal heating unless an exemption is granted. It would be one of the only small, coal-fired heating plants permitted in Pennsylvania in the last couple of decades. Abacus would coordinate with the Pennsylvania Coal Association to ensure that the plant received support at all regulatory levels.
 - ◆ Steam Turbine Generator. The events of the last several years have dramatically demonstrated the volatility of the electrical power market (especially in the 2000-2002 period). Wholesale power prices, which had hovered around \$25 - \$35 per MWh (\$0.025 - \$0.035 per kWh) for years reached levels as high as \$400 per MWh, and in some instances, as high as \$1,000 per MWh for short periods of time. Many utilities were unable to pass some or all of these costs on to the consumers for legal, regulatory, or political reasons;



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however, the reality is that they will have to be allowed to do so to some extent in the future, or they will face bankruptcy (as with Southern Cal Edison). Residential users may be spared by the politicians, but that will only raise the costs for non-residential users, such as Shippensburg. There are many reasons to install on-site generation; one of the most significant is to mitigate the risk of volatile power prices in the future.

Negative Drivers:

- ◆ Cost. This Option requires that the University come up with significantly more money than does Option 1 (beyond that already appropriated), either by issuing debt, or raising or acquiring capital.
- ◆ Disturbance to the campus. For two years, construction would impact the campus visually, acoustically, and affect access as well.
- ◆ Disturbance to buildings. Those buildings that still use steam would have to be converted to hot water (and all steam-fired kitchen equipment be replaced with direct-fired equipment). Many of these buildings are the older buildings of the original campus. However, this would provide a chance to upgrade them, and the work could be done in the summer months.
- ◆ Land. The new Plant would take up land closer to the center of campus, that could potentially be used for academic or housing buildings (i.e. revenue-generating buildings).

D. Operational Considerations

1. Operating costs. As shown in the Table in Subsection A above, these costs decrease by slightly more than \$229,000. Coal consumption actually increases, because the coal boiler is base-loaded, and the Plant would run year-round. The coal displaces natural gas that is currently being used; coal is much cheaper on a per-BTU basis, so there is a net reduction in fuel costs. In addition, net decrease includes the electricity generated by the steam turbine, which avoids the purchase of just over \$151,000 worth of electricity from the utility.
2. Deferred Maintenance. As with Option 1, this Option eliminates \$6,272,379 worth of deferred maintenance.
3. Reliability. The reliability of the new Plant and distribution would be significantly increased. All equipment and materials would be new, and all operators fully trained in the use of the equipment. Because the distribution piping would be new, and is a closed loop, the piping could be treated before use, and the long term chemistry would be stable. This piping should last much longer than the condensate piping currently does.

E. Financial Considerations

As do all options, this Option requires that SU issue bonds, borrow money, enter into a lease-purchase deal, or somehow come up with additional funds. How the Option is evaluated depends heavily on whether the project is financed with debt or with additional capital. If an ESCO-type project approach is envisioned, then the question of how to interface the existing \$13,760,000 of appropriated money into the project becomes a significant issue.

Abacus spoke with Tom Rados of the Department of General Services (DGS) about this project. As long as the Option chosen in essence performs the work defined in the CPJs, DGS has tentatively said they would allow the money to be used for the project. In this case, that is taken to mean that as long as the



SECTION IV: SUMMARY OF OPTIONS

money is used in such a way that it deals with the heating plant and distribution, and no further money would be requested later to repeat scope from the first two CPJs, the \$13,760,000 could be used regardless of which Option was chosen.

However, DGS qualified this by stating that the money would not be turned over directly to the contractor in an ESCO-type project; instead, they proposed that the Commonwealth construct those parts of the project which do not save energy in and of themselves. These could include the actual new Plant building, the distribution piping, the steam to hot water conversions in some buildings, etc. The ESCO would then construct the remaining pieces of the project, using the savings to justify these lower costs in a typical ESCO arrangement.

Abacus has assumed that SU and DGS can work out a way to apply this money to a debt-financed project, and, as with Option 1, has run two financial models: the first assumes debt is used, and the second, that the entire project is paid for with capital. All further Options make this assumption.

Option 2A is a very strong Option regardless of how it is financed. As the Summary Table in Section II shows, when financed with debt, Option 2A has the third highest NPV, behind 2B and 1. It also ranks third when financed solely with capital. This reflects the fact that it produces very high savings for the amount invested, and that among the new plant options (2 through 4), it has the lowest cost.

F. Emissions

The new Plant would be a New Source, and subject to a New Source Review, and a new permit. This would probably require the hiring of a specialized consultant and cost about \$60,000; very few coal-fired plants this small (i.e., smaller than a power plant) have been permitted in the Commonwealth for many years.

Although overall campus emissions would be lower than they currently are, the Title V permit would need to be re-submitted. There is a chance that SU would be classified as a Synthetic Minor Producer, but that has very little advantage. The same review must be done (and the same costs incurred), and it is likely that SU would have to accept limits on the amount of coal burned per year in order to get SM status. It would be more flexible for SU to simply permit the coal-fired unit for full fire, 8,760 hours a year so that the use of the boiler in essence was unlimited. Even under these full-time conditions, it is anticipated that the emissions would not exceed Title V and New Source limits.

Neither the EPA nor the DEP was willing to commit to whether the coal-fired boiler would require a scrubber for sulfur removal, but the unofficial consensus was that it was too small to require one. The primary issues would then become NO_x, particulates (PM₁₀), and fugitive emissions (mostly coal dust and ash).

A baghouse or electrostatic precipitator would be used to remove particulate. The boiler would be inherently low NO_x (and it is a small boiler by most standards). Because there would only be one coal-fired unit, the coal transport system would be simplified, and therefore easier to treat for fugitive emissions. The coal pile, as conceived, will be covered.

SECTION IV: SUMMARY OF OPTIONS

G. Schedule and Impact

This Option would have a significant impact on the campus; visually, acoustically, and in terms of access. Abacus has assumed that the construction would last from the beginning of one digging season, all the way through the end of the subsequent digging season. This is as much as 20 months. During the winter, construction within the new Plant would be the primary work occurring. Work within the buildings to be converted to hot water would be done only during the summer session. All other work would be done as the sequence of construction dictated. This sequence of construction would be completed in conjunction with SU to minimize disturbance to the campus.



SECTION IV: SUMMARY OF OPTIONS

Option 2B

A. Summary Table

TABLE: Savings/Cost Summary							Option 2B
Financial Data		Year 1 Results (1)			Results over Term (2)		
Available Capital:	\$13,760,000	Savings: (\$40,099)			Net Cash Flow : \$8,142,180		
Cost of this Option:	\$21,045,672	NSP: -121.3 yrs			NPV : \$3,812,560		
Amount to Finance:	\$7,285,672				Investment : \$7,285,672		
Cost of Option 1:	\$16,182,720				Net Cash Flow/No debt : \$17,949,166		
Incremental Increase:	\$4,862,952				NPV/No debt : \$10,598,771		
		Unit Consumption			Cost		
Resource Costs		Modified	This	Unit	Modified	This	TOTAL
		Baseline	Option	Savings	Baseline	Option	SAVINGS
Elec Demand:	\$9.7400 per kW	10,034	10,034		\$97,731	\$97,731	
On Peak Energy:	\$0.0411 per kWh	1,139,807	1,139,807		\$46,823	\$46,823	
Off Peak Energy:	\$0.0335 per kWh	1,789,509	1,789,509		\$59,949	\$59,949	
Avoided Demand:	\$9.7400 per kW		(4,950)	4,950		(\$48,213)	\$48,213
Avoided On Peak:	\$0.0411 per kWh		(898,550)	898,550		(\$36,912)	\$36,912
Avoided Off Peak:	\$0.0335 per kWh		(1,992,100)	1,992,100		(\$66,735)	\$66,735
Coal, barley:	\$87.5600 per ton	3,974		3,974	\$347,963		\$347,963
Coal, buck:	\$116.1600 per ton	491		491	\$57,035		\$57,035
Natural Gas:	\$7.3000 per MBTU	25,725	107,500	(81,775)	\$187,793	\$784,750	(\$596,958)
Oil:	\$1.6600 per gal						
Totals:					\$797,293	\$837,392	(\$40,099)

Notes: (1) For Options 2 through 4, NSP is based on the Incremental Increase in Cost over Option 1
(2) These results come from the Cash Flow Analysis; they cannot be derived solely from the number in this Table.

B. Synopsis

The "B" options are variations on the "A" options. The only differences are that coal is eliminated in the "B" options, and as a result, some consideration is given to labor savings. Option 2B, therefore, is exactly the same plant serving exactly the same load as Option 2A, except as noted above.

The use of coal in the proposed Option "A" plants was considered primarily for two reasons. First, coal was, and is, much cheaper on a BTU basis than any other fuel, although it recently increased in price significantly. The second reason has to do with labor. A gas/oil plant is significantly easier to maintain and operate than a coal fired plant, and requires fewer support systems. However, the only way that a gas or oil fueled plant can compete with coal on an economic basis is by reducing other operating costs (since the fuel itself is more expensive). These operational costs can include service contracts, parts, repairs, and of course, labor. SU indicated early on while reducing outside costs was a goal, that it was generally short-handed and fully utilizes the steam plant labor that is available during summer shutdowns for other work.

SECTION IV: SUMMARY OF OPTIONS

As a result, the options assumed the continued use of coal, due to the lower overall cost to operate, while trying to do so in a way which minimized the external costs of coal (emissions control, material handling, etc). The main means of doing this was to include only one coal boiler (and the associated support elements), but to base load it, keeping it running at or near capacity at all times.

The original four Options were thus intended to utilize coal as cost effectively as possible. In the end, however, gas/oil "sub-options" were included. In our experience with other facilities in the Commonwealth, Owners with gas/oil plants have reduced overall labor costs, primarily in two ways. The most common is through attrition; when plant staff retire, the position is not filled. The second is to re-assign plant personnel to operations tasks elsewhere that were not getting done due to manpower shortages. This does not strictly reduce manpower, but it does eliminate the need to hire additional staff beyond that in the plant, and some Owners have treated this as reduced labor costs. In the end, SU will need to determine how to take into account the opportunities that a gas/oil plant provides; technically, such a plant does not need to be manned continuously at all.

Abacus would not recommend running a high pressure steam plant with a steam turbine without staff on hand. In this report, we have made an assumption on the potential staff "reduction" of 5 FTEs that could result from attrition or re-assignment. This is only possible, of course, in Options 2, 3, and 4 (since Option 1 retains the coal plant). Therefore, we renamed Options 2, 3, and 4 to 2A, 3A, and 4A. We have added Options 2B, 3B, and 4B. As noted above, in each case, the "B" Option is identical to the "A" Option, except the plant is fired on gas and No. 2 oil only, and the plant staff is reduced.

In general, the effect of using gas and oil only is that fuel costs increase and first costs decrease. Overall operating costs decrease, if the effect of labor (as described above) is taken into account. There are, however, other external effects that do not show up in a model. No coal would mean no coal pile, no coal trucks, less emission, and less overall environmental impact on the community, which in turn could help with siting issues. These are intangibles that SU must take into account as they go forward.

C. Drivers

In term of steam production and delivery, the drivers for 2B are the same as 2A. As noted above, there are some external factors to consider. A gas/oil plant is likely to be perceived as more environmentally friendly. It will be simpler to operate, and require less parts and maintenance. It will eliminate the need for coal to be delivered, and ash hauled away (although when running on oil, oil deliveries will be required). At the same time, it removes the ability to base load on the cheapest fuel available, coal (and one which is readily available from US sources).

D. Operational Considerations

1. Operating costs. As shown in the Table in Subsection A above, these non-wage operating costs actually increase by slightly more than \$40,000, as gas replaces less expensive coal. The positive NPV of this Option results from a savings in wages and benefits. This can be seen in the summary in Section II, or the Cash Flow in Appendix F.
2. Deferred Maintenance. As with Option 1, this Option eliminates \$6,272,379 worth of deferred maintenance.

SECTION IV: SUMMARY OF OPTIONS

3. Reliability. The reliability of the new Plant and distribution would be significantly increased compared to Option 1, and would be higher even than the associated "A" option (less pieces of support equipment, less emissions control equipment). All equipment and materials would be new, and all operators fully trained in the use of the equipment. Because the distribution piping would be new, and is a closed loop, the piping could be treated before use, and the long term chemistry would be stable. This piping should last much longer than the condensate piping currently does.
4. As with Option 2A, summer shutdowns would be eliminated.

E. Financial Considerations

Options 2A and 2B are unique among the Option pairs; the highest value (measured by NPV) depends on whether the options are financed with debt or additional capital. If the project assumes debt, then Option 2B is the more valuable of the two. If capital is used, then Option 2A is more valuable. As noted above, the value of Option 2B comes solely from deferred maintenance and labor reduction.

In all cases, the "B" options are less expensive – coal fired capacity is replaced with gas/oil capacity, and the emissions requirements are more easily met. In the case of Options 2A and 2B, the savings are the same, within the margin of error (2A has nominally more savings). The deciding factor then becomes the cost of finance, the interest paid over the term of the loan. If money is borrowed, Option 2B "wins" because the amount to be financed is less. The NPV of Option 2B is \$3,812,560 v Option 2A at \$2,148,669. If no money is borrowed, on the other hand, the respective NPVs are \$10,598,771 and \$10,691,621. As mentioned, however, the difference here is so small it is within the margin of error. If a new steam plant is considered, with no attached chiller plant (option 2A or 2B), then the decision should be made based on the use of coal vs gas/oil only - financially, they are the same, given the documented assumptions.

F. Emissions

The new Plant would be a New Source, and subject to a New Source Review, and a new permit. However, it would be much simpler, and therefore less expensive and time consuming, than permitting a plant which burns coal.

G. Schedule and Impact

See Option 2A.

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Option 3A:

A. Summary Table

TABLE: Savings/Cost Summary							Option 3A	
Financial Data			Year 1 Results (1)			Results over Term (2)		
Available Capital: \$13,760,000			Savings: \$255,845			Net Cash Flow : \$1,455,810		
Cost of this Option: \$27,106,689			NSP: 42.7 yrs			NPV : (\$1,154,690)		
Amount to Finance: \$13,346,689						Investment : \$13,346,689		
Cost of Option 1: \$16,182,720						Net Cash Flow/No debt : \$19,421,316		
Incremental Increase: \$10,923,969						NPV/No debt : \$11,277,031		
			Unit Consumption			Cost		
			Modified	This	Unit	Modified	This	TOTAL
Resource Costs			Baseline	Option	Savings	Baseline	Option	SAVINGS
Elec Demand:	\$9.7400	per kW	10,034	3,460	6,574	\$97,731	\$33,700	\$64,031
On Peak Energy:	\$0.0411	per kWh	1,139,807	403,625	736,182	\$46,823	\$16,581	\$30,242
Off Peak Energy:	\$0.0335	per kWh	1,789,509	638,500	1,151,009	\$59,949	\$21,390	\$38,559
Avoided Demand:	\$9.7400	per kW		(6,165)	6,165		(\$60,047)	\$60,047
Avoided On Peak:	\$0.0411	per kWh		(1,228,700)	1,228,700		(\$50,475)	\$50,475
Avoided Off Peak:	\$0.0335	per kWh		(2,501,600)	2,501,600		(\$83,804)	\$83,804
Coal, barley:	\$87.5600	per ton	3,974	7,472	(3,498)	\$347,963	\$654,248	(\$306,285)
Coal, buck:	\$116.1600	per ton	491		491	\$57,035		\$57,035
Natural Gas:	\$7.3000	per MBTU	25,725	1,350	24,375	\$187,793	\$9,855	\$177,938
Oil:	\$1.6600	per gal						
Totals:						\$797,293	\$541,449	\$255,845

Notes: (1) For Options 2 through 4, NSP is based on the Incremental Increase in Cost over Option 1
(2) These results come from the Cash Flow Analysis; they cannot be derived solely from the number in this Table.

B. Synopsis

This Option adds central cooling to the new Plant proposed in Option 2A, and it contains the Scope of Option 2A in its entirety. The amount of heat produced, and therefore the amount of fuel purchased, varies because some of the cooling is produced using absorption chillers (steam powered chillers).

Large scale cooling on campus (cooling produced by chillers as opposed to DX equipment) is currently done at the building level. SU has begun to try to link some buildings together with piping to share capacity, but for the most part, each chiller (or bank of chillers) serves only the building where it is located.

The existing chillers are both air-cooled and water cooled, and range in age from over twenty years old (Huber) to less than five (Heiges). Types vary from reciprocating to centrifugal. Most buildings have only one chiller; some have back-up chillers (Franklin). There are a number of issues related to localized vs. centralized chillers, but the primary issues for SU are the inability of localized chillers to share load, and redundancy.

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Chillers generally operate over 95 percent of the time at less than full load. This is not always an issue; chillers are generally most efficient when operating between about 75 percent and 85 percent. However, below this range, the efficiency falls off quickly. Two buildings of equal size with chillers operating at 50 percent are therefore using significantly more energy than if one chiller could serve them both. Chillers also require support equipment – cooling towers and pumps primarily. Ideally in this scenario, only one set of support equipment would be required as well as only one chiller.

Even in a localized cooling scenario, it is inexpensive to provide redundant pumps, and so many buildings have them. However, it is more expensive to provide redundant cooling towers, and very expensive to provide redundant chillers; thus most buildings do not have these. In a central system, a single redundant piece of equipment (pump, CT or chiller) can serve all buildings; the cost of redundancy is significantly lower.

The unit cost goes down and the unit efficiency of chillers goes up as the size increases (economy of scale). A centralized system allows the deployment of much larger chillers, lowering the cost to operate. This is partly offset by the cost of transporting the chilled water. In a localized scenario, this is very small. Pumping water around a campus incurs a much larger energy penalty. However, the chiller energy required is more than ten times that of the support equipment, so the net effect is still less energy.

In this Option, Abacus proposes to preserve much of SU's capital investment by leaving the newest chillers in place. The central plant would have a limited amount of redundancy because of this. Each building would have the ability to be isolated from the chilled water distribution. This could be done remotely, at the campus control system. In the event of a central chiller failure, the equivalent tonnage of local chillers could be brought on, again remotely. The existing chillers would be prioritized by age, condition, and efficiency. If, for instance, a chiller failed while it was making 350 tons, an operator would select existing chillers from the top of the list down, until at least 350 tons of local chiller capacity was operating. These buildings would be isolated (remotely) from the distribution, physically unable to take water out of the loop. They would continue to run on their local chiller until the Plant chillers were able to take the load.

Distribution would be limited in this Option to those buildings already served by chillers. The piping would be laid in the same trench as the hot water piping, and at the same time. The carrier piping would be steel or plastic, but the outer layer of the piping (the jacketing) would be a type of plastic to avoid the need for cathodic protection.

As currently conceived, the chiller plant uses both absorption and electric chillers to provide maximum operational flexibility. In general, the electric chillers are cheaper to operate; however, using steam powered chillers not only eliminates the energy and demand associated with the electric chiller, the steam passes through the turbine first, producing more electrical energy and reducing demand even further.

C. Drivers

Positive Drivers:

- ◆ Cost to operate is lower than with the existing chilled water systems.
- ◆ This Option allows sharing of capacity across buildings. The absolute minimum amount of capacity can be purchased.

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- ◆ The chillers used will enjoy economy of scale. They will be less expensive and more efficient on a unit basis than the existing chillers, or any smaller chillers SU would buy in the future.
- ◆ Maintenance is reduced; fewer pieces of equipment are required, and they are all in close proximity. Abacus must discuss with SU how much deferred maintenance backlog this Option might eliminate.
- ◆ As new advances in technology arrive, they are easier to implement in a centralized system.
- ◆ Operation and controls logic are simplified.
- ◆ Ability to switch inputs (steam or electric) allows SU to mitigate energy cost volatility.
- ◆ There is no incremental disturbance to the campus beyond that caused by the work of Option 2 – the piping lays along side the new hot water piping.

Negative Drivers:

- ◆ Additional Cost. This Option requires that the University incur debt, enter into leases, or in some way finance the additional cost of the Option above and beyond that of Option 2.
- ◆ Eliminates some of the value of the existing chilled water systems. These systems were capital investments, and they would become back-ups at best, or be demolished at worst under this Option. The newer, better units would be kept in place as back-ups.

D. Operational Considerations

1. Operating costs. As shown in the Table in Subsection A above, these costs decrease by more than \$255,000. Coal consumption actually increases, because the coal boiler is base-loaded, and the Plant would run year-round. The coal displaces natural gas that is currently being used; coal is much cheaper on a per-BTU basis, so there is a net reduction in fuel costs. In addition, the electricity generated by the steam turbine avoids the purchase of just over \$194,000 worth of electricity from the utility.
2. Deferred Maintenance. As with Option 1, this Option eliminates \$6,272,379 worth of deferred maintenance.
3. Reliability. The reliability of the new steam and chilled water plant and distribution would be significantly increased.
4. As with Option 2A, summer shutdowns would be eliminated.

E. Financial Considerations

If the project is financed partially with debt, then Option 3A has a negative NPV. This is because while it adds only marginally to the savings, it significantly increases the cost, to the point where the added interest cost over 15 years overwhelms the added savings over 30 years. On a strictly financial basis, it does not represent a good investment. However, part of the reason is that while the steam plant work has a deferred maintenance aspect to it, no value has been attached to the deferred chilled water maintenance. While not of the magnitude of the heating system maintenance, it not zero; there is a future cost of doing nothing now.

Along with the deferred maintenance aspect, there are other savings associated with central cooling that have not been estimated here. These include

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- ◆ Not having to build space for a cooling plant in future buildings. At \$100/sq.ft. or more, that has value.
- ◆ Built-in redundancy. A central plant requires only one redundant piece of equipment for a whole campus. On a building-by-building basis, redundancy has to be paid for each time – it cannot be shared.

These effects have not been included here – they would require SU to place a monetary value on them before they could be included in a Cash Flow analysis.

On the other hand, if the money is "free" (i.e. no debt need be incurred), then NPV is determined solely a measure of the present value of the savings stream. In this scenario, Option 3A and Option 4A, with the highest annual savings (regardless of cost to implement), are the most valuable options, with virtually the same NPV.

F. Emissions

See Option 2. Option 3 has no further emission issues.

G. Schedule and Impact

See Option 2A. Option 3 has no further schedule of impact issues; it requires no additional digging of pipe trench beyond Option 2A. The minor exception is the work required to hook the buildings into the new chilled water distribution. This would be done in the winter, when cooling is not required, and would be limited to the mechanical spaces in the buildings. Disturbance would be minimal.

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Option 3B:

A. Summary Table

TABLE: Savings/Cost Summary							Option 3B	
Financial Data			Year 1 Results (1)			Results over Term (2)		
Available Capital: \$13,760,000			Savings: (\$94,022)			Net Cash Flow : (\$43,030)		
Cost of this Option: \$25,220,652			NSP: -96.1 yrs			NPV : (\$1,258,167)		
Amount to Finance: \$11,460,652						Investment : \$11,460,652		
Cost of Option 1: \$16,182,720						Net Cash Flow/No debt : \$15,383,749		
Incremental Increase: \$9,037,932						NPV/No debt : \$9,416,812		
			Unit Consumption			Cost		
			Modified	This	Unit	Modified	This	TOTAL
Resource Costs			Baseline	Option	Savings	Baseline	Option	SAVINGS
Elec Demand:	\$9.7400	per kW	10,034	3,460	6,574	\$97,731	\$33,700	\$64,031
On Peak Energy:	\$0.0411	per kWh	1,139,807	403,625	736,182	\$46,823	\$16,581	\$30,242
Off Peak Energy:	\$0.0335	per kWh	1,789,509	638,500	1,151,009	\$59,949	\$21,390	\$38,559
Avoided Demand:	\$9.7400	per kW		(6,165)	6,165		(\$60,047)	\$60,047
Avoided On Peak:	\$0.0411	per kWh		(1,228,700)	1,228,700		(\$50,475)	\$50,475
Avoided Off Peak:	\$0.0335	per kWh		(2,501,600)	2,501,600		(\$83,804)	\$83,804
Coal, barley:	\$87.5600	per ton	3,974		3,974	\$347,963		\$347,963
Coal, buck:	\$116.1600	per ton	491		491	\$57,035		\$57,035
Natural Gas:	\$7.3000	per MBTU	25,725	138,900	(113,175)	\$187,793	\$1,013,970	(\$826,178)
Oil:	\$1.6600	per gal						
Totals:						\$797,293	\$891,315	(\$94,022)

Notes: (1) For Options 2 through 4, NSP is based on the Incremental Increase in Cost over Option 1
(2) These results come from the Cash Flow Analysis; they cannot be derived solely from the number in this Table.

B. Synopsis

This is Option 3A with a gas/oil fired steam plant.

C. Drivers

See Options 3A and 2B (for external considerations related to coal v gas/oil).

D. Operational Considerations

1. Operating costs. As shown in the Table in Subsection A above, these non-wage operating costs actually increase by slightly more than \$94,000, as gas replaces less expensive coal. However, while the wage-reduction benefits of this Option are the same as those of Option 2B, the "negative savings" due to fuel costs increase – thus when financed with debt, Option 3B has a not only a negative NPV, but a negative 30 year cash flow as well – the savings

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- never exceed the cost of finance. This can be seen in the summary in Section II, or the Cash Flow in Appendix F.
2. **Deferred Maintenance.** As with Option 1, this Option eliminates \$6,272,379 worth of deferred maintenance.
 3. **Reliability.** The reliability of the new steam and chilled water plant and distribution would be significantly increased.
 4. As with Option 2A, summer shutdowns would be eliminated.

E. Financial Considerations

If the project is financed partially with debt, then Option 3B has not only a negative NPV, but a negative cash flow as well.

Even if the project is paid for with capital, this project is less valuable than the 3A. This is because the wage-reduction benefits cannot outweigh the increased gas costs.

F. Emissions

See Option 2B. Option 3B has no further emission issues.

G. Schedule and Impact

See Option 2A. Option 3B has no further schedule of impact issues; it requires no additional digging of pipe trench beyond Option 2A. The minor exception is the work required to hook the buildings into the new chilled water distribution. This would be done in the winter, when cooling is not required, and would be limited to the mechanical spaces in the buildings. Disturbance would be minimal.

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Option 4A:

A. Summary Table

TABLE: Savings/Cost Summary							Option 4A	
Financial Data			Year 1 Results (1)			Results over Term (2)		
Available Capital:	\$13,760,000		Savings:	\$169,846		Net Cash Flow :	\$5,974,955	
Cost of this Option:	\$29,167,614		NSP:	76.5 yrs		NPV :	\$285,887	
Amount to Finance:	\$15,407,614					Investment :	\$15,407,614	
Cost of Option 1:	\$16,182,720					Net Cash Flow/No debt :	\$26,714,599	
Incremental Increase:	\$12,984,894					NPV/No debt :	\$14,637,249	
			Unit Consumption			Cost		
Resource Costs			Modified	This	Unit	Modified	This	TOTAL
			Baseline	Option	Savings	Baseline	Option	SAVINGS
Elec Demand:	\$9.7400	per kW	10,034	5,450	4,584	\$97,731	\$53,083	\$44,648
On Peak Energy:	\$0.0411	per kWh	1,139,807	572,100	567,707	\$46,823	\$23,502	\$23,321
Off Peak Energy:	\$0.0335	per kWh	1,789,509	843,800	945,709	\$59,949	\$28,267	\$31,681
Avoided Demand:	\$9.7400	per kW		(7,430)	7,430		(\$72,368)	\$72,368
Avoided On Peak:	\$0.0411	per kWh		(1,355,500)	1,355,500		(\$55,684)	\$55,684
Avoided Off Peak:	\$0.0335	per kWh		(2,639,900)	2,639,900		(\$88,437)	\$88,437
Coal, barley:	\$87.5600	per ton	3,974	7,405	(3,431)	\$347,963	\$648,382	(\$300,418)
Coal, buck:	\$116.1600	per ton	491		491	\$57,035		\$57,035
Natural Gas:	\$7.3000	per MBTU	25,725	12,425	13,300	\$187,793	\$90,703	\$97,090
Oil:	\$1.6600	per gal						
Totals:						\$797,293	\$627,448	\$169,846

Notes: (1) For Options 2 through 4, NSP is based on the Incremental Increase in Cost over Option 1
(2) These results come from the Cash Flow Analysis; they cannot be derived solely from the number in this Table.

B. Synopsis

This Option adds additional central cooling to that proposed in Option 3A, and it contains the Scope of both Option 2A and Option 3A in their entirety. The size of the chiller plant is increased to allow it to provide cooling to the dormitories. Within the dorms, a switchover arrangement in the piping would allow the buildings to distribute chilled water in the summer, and hot water in the winter, but never both.

As the Table shows, this increases both the incremental cost and the cost to operate. This is partially offset by increased revenue that SU could generate with additional summer programs that this Option could enable by cooling the dorms. An assumption has been made regarding how much more SU could charge for air conditioned rooms, as well as how many more they could rent per year. This can be seen in the Cash Flow Analysis in Appendix F.

SECTION IV: SUMMARY OF OPTIONS

C. Drivers

Positive Drivers:

- ◆ See Option 3A.
- ◆ The ability to cool the dorms increase the University's ability to offer summer programs that require on-campus housing. This maximizes the investment in the dorms, and generates revenue.

Negative Drivers:

- ◆ Additional Cost. Adds additional first cost, more than the dollar savings support..

D. Operational Considerations

1. Operating costs. As shown in the Table in Subsection A above, non-wage, non-rent savings are decreased compared to Option 2A or 3A, to just under \$170,000.
2. Deferred Maintenance. As with Option 1, this Option eliminates \$6,272,379 worth of deferred maintenance.
3. Reliability. See Option 3A.
4. As with Option 2A, summer shutdowns would be eliminated.

E. Financial Considerations

Operating costs. As with Option 3B, when financed with debt, Option 4A has a not only a negative NPV, but a negative 30 year cash flow as well – the savings never exceed the cost of finance. This can be seen in the summary in Section II, or the Cash Flow in Appendix F. This is because project adds \$5,000,000 in first cost (and in the amount to be financed), costs more in fuel, and cannot make up the difference in increased rents (estimated at \$149,600 in year one).

F. Emissions

See Option 2A. Option 4A has no further emission issues.

G. Schedule and Impact

See Option 3A. Option 4A has minimal further schedule or impact issues, since the work in the dorms would be done in the summer. Some scheduling of summer programs around the work might be impacted. Disturbance would be minimal.

SECTION IV: SUMMARY OF OPTIONS

Option 4B:

A. Summary Table

TABLE: Savings/Cost Summary							Option 4B	
Financial Data			Year 1 Results (1)			Results over Term (2)		
Available Capital:	\$13,760,000		Savings:	(\$178,040)		Net Cash Flow :	\$4,570,361	
Cost of this Option:	\$27,281,577		NSP:	-62.3 yrs		NPV :	\$225,831	
Amount to Finance:	\$13,521,577					Investment :	\$13,521,577	
Cost of Option 1:	\$16,182,720					Net Cash Flow/No debt :	\$22,771,278	
Incremental Increase:	\$11,098,857					NPV/No debt :	\$12,820,451	
			Unit Consumption			Cost		
Resource Costs			Modified	This	Unit	Modified	This	TOTAL SAVINGS
			Baseline	Option	Savings	Baseline	Option	
Elec Demand:	\$9.7400	per kW	10,034	5,450	4,584	\$97,731	\$53,083	\$44,648
On Peak Energy:	\$0.0411	per kWh	1,139,807	572,100	567,707	\$46,823	\$23,502	\$23,321
Off Peak Energy:	\$0.0335	per kWh	1,789,509	843,800	945,709	\$59,949	\$28,267	\$31,681
Avoided Demand:	\$9.7400	per kW		(7,430)	7,430		(\$72,368)	\$72,368
Avoided On Peak:	\$0.0411	per kWh		(1,355,500)	1,355,500		(\$55,684)	\$55,684
Avoided Off Peak:	\$0.0335	per kWh		(2,639,900)	2,639,900		(\$88,437)	\$88,437
Coal, barley:	\$87.5600	per ton	3,974		3,974	\$347,963		\$347,963
Coal, buck:	\$116.1600	per ton	491		491	\$57,035		\$57,035
Natural Gas:	\$7.3000	per MBTU	25,725	148,900	(123,175)	\$187,793	\$1,086,970	(\$899,178)
Oil:	\$1.6600	per gal						
Totals:						\$797,293	\$975,333	(\$178,040)

Notes: (1) For Options 2 through 4, NSP is based on the Incremental Increase in Cost over Option 1
(2) These results come from the Cash Flow Analysis; they cannot be derived solely from the number in this Table.

B. Synopsis

This is Option 4A with a gas/oil fired steam plant.

C. Drivers

See Options 4A and 2B (for external considerations related to coal v gas/oil).

D. Operational Considerations

1. Operating costs. As shown in the Table in Subsection A above, these non-wage operating costs actually increase by slightly more than \$178,000, as gas replaces less expensive coal. However, while the wage-reduction benefits of this Option are the same as those of Option 2B, the "negative savings" due to fuel costs increase – thus when financed with debt, Option 3B has not only a negative NPV, but a negative 30 year cash flow as well – the savings never

SECTION IV: SUMMARY OF OPTIONS

- exceed the cost of finance. This can be seen in the summary in Section II, or the Cash Flow in Appendix F.
2. **Deferred Maintenance.** As with Option 1, this Option eliminates \$6,272,379 worth of deferred maintenance.
 3. **Reliability.** The reliability of the new steam and chilled water plant and distribution would be significantly increased.
 4. As with Option 2A, summer shutdowns would be eliminated.

E. Financial Considerations

If the project is financed partially with debt, then Option 3B has not only a negative NPV, but a negative cash flow as well.

Even if the project is paid for with capital, this project is less valuable than the 4A. This is because the wage-reduction benefits cannot outweigh the increased gas costs. As with 4A, the cash flow included just over \$149,000 in increased revenue from summer dorm room rentals.

F. Emissions

See Option 2B. Option 4B has no further emission issues.

G. Schedule and Impact

See Option 4A. Option 4B has no further schedule of impact issues; it requires no additional digging of pipe trench beyond that of Option 2A.

SECTION V: SUMMARY OF EXISTING CONDITIONS

SUMMARY OF EXISTING CONDITIONS

A. Heating

Existing Boiler Plant. The existing Boiler Plant consists of four Keeler coal-fired boilers, firing a combination of Buckwheat and Barley sized anthracite coal. The original two boilers, installed in 1952, are rated for 20,000 lbs/hr at 200 PSIG SWP, another was added in 1964 at 25,000 lbs/hr, and a final coal fired boiler was added in 1984, rated at 27,135 lbs/hr. Just recently a fifth boiler, gas fired, was added. This boiler is rated at 15,650 lbs/hr. This should help to eliminate the practice of "banking" a boiler. Because the start-up of a coal fired boiler is a long process, one boiler is always banked. The coal is run into the boiler on the grates, and combustion is started. Once underway, the air to the boiler is severely curtailed. The coal remains hot, but further combustion is almost eliminated. In the event that the banked boiler is needed, air is added and the boiler is on line very quickly. Gas-fired boilers can be started up very quickly, eliminating the need to bank a boiler.

The new boiler will also add needed redundancy. Currently, three boilers are required whenever the outside air temperature drops below 15 to 20 deg F. The fourth boiler is banked. Given the age of the Plant, it is not unlikely that a cold snap could catch the plant with a boiler down, leaving no back-up at all.

Boiler 4 had stoker problems for years, reportedly because the stoker was for the wrong size of coal. This culminated when the stoker finally had to be replaced. Currently the new stoker appears to be working fine.

Maintenance costs for the plant are relatively high, due to age and by the nature of coal fired boilers. See Section VI for a list of annual maintenance costs, and annual Plant Costs.

Existing Support Equipment. The existing deaerator DA tank is a packed column type. The data recorded on the plant summary sheets seems to indicate that it is not functioning correctly. A DA tank removes oxygen by heating boiler feedwater to 227 deg F or more, which reduced the oxygen-carrying capacity of the water to acceptable levels. Sulfite-based chemicals (oxygen scavengers) are also added at the DA to ensure oxygen removal. The data on the plant summary sheets indicate the long-term average feedwater temperature is 212 deg F. At this level, either the feedwater contains excessive O₂, or significant amounts of sulfites must be employed to de-oxygenate the water.

The summary sheets reveal further anomalies that could be harmful to the plant. The recorded amount of make-up water varies greatly from month to month. When asked about it, plant personnel report that they have a large number of heat exchanger (HX) failures over the course of a year. The steam in the HX is at 5-10 PSIG, the water at much higher pressure, so the water actually leaks into the steam system (through the condensate piping). This means the amount of untreated water into the system varies month to month, making water chemistry difficult to maintain. This means major implications for the condition of the distribution system, and the boiler tubes.

Water softeners. Plant personnel report that for many years (prior to most of the existing crew), the water softeners were not used. This resulted in a thick build-up of deposits on the boiler tubes, and, it must be assumed, portions of the distribution system. Any build-up on the boiler tubes significantly affects boiler efficiency. This build-up has long since been cleaned off the tubes, although any damage done still exists (the boilers have not been re-tubed). Likewise, any damage done to the distribution system still exists.

SECTION V: SUMMARY OF EXISTING CONDITIONS

Existing Operating Hours. For the last 10 – 11 years, the existing steam plant has been run about eight months per year (seven full months, and parts of two others). During the summer months, individual boilers located in the building are run on natural gas to provide hot water, and in some cases, steam. This increases costs, as gas is more expensive than coal per BTU delivered, but it also has implication for the distribution system. For the last ten years, the pipes have sat full of air and water for four months per year. This obviously promotes the formation of rust and scale in the pipes. Plant personnel report that up to this period, condensate leaks were not uncommon (condensate is hot, untreated, highly oxygenated water, so leaks are not uncommon), but steam leaks were rare, or non-existent. Only since the plant operations were shifted to school-year hours have steam leaks begun.

Steam and Condensate Distribution. Much of the steam manhole piping was recently upgraded. With the exception of this piping, most of the direct buried system is the same age as the plant (or the building it serves), about 50 years. The information obtained on site and detailed above indicates that some significant degree of corrosion has probably occurred. The fact that the steam piping (as opposed to the condensate piping) has started leaking is an indicator of this.

In order to try to quantify the extent of the corrosion, if any, Abacus paid to have non-destructive testing done by a local company. Tests were done on older pipes, not the recently replaced manhole piping. Two steam pipes, and three condensate pipes were tested using ultrasonic equipment. At each location, wall thickness is measured four times, 90 degrees apart to get a true average thickness. The two steam pipes averaged 24% and 5% loss of wall thickness. The three condensate pipes, which were much thicker to begin with, showed a loss of 6%, 30%, and 25% of wall thickness. Clearly, age and operating conditions have adversely affected the distribution piping. This is expected; the best defense is to minimize the effects through water chemistry and operating practices.

Pipe capacity has not traditionally been a problem, but it will likely be a concern soon. In cold conditions, the operators see a 40 PSI drop in pressure from the Plant (70 PSIG) to the end of the line at Seavers Apartments (30 PSIG). This is a significant drop, but does not affect operations because Seaver can still get the steam it needs. However, a new Performing Arts Center is due to be constructed near Heiges Field House. As with Seavers, this is pretty much the end-of-the-line, for the steam system. By their nature, performance centers require lots of outside air, which in turn requires lots of steam to heat the outside air. This added load could seriously affect the ability of the plant to deliver steam to the farthest reaches of the distribution system. The boiler plant can turn up the pressure at the boilers, but only so far. Fixing the capacity issue would probably entail replacing pipe all the way back to the plant, unless the pressure drop at Seavers is being caused by a very localized condition.

Existing Emissions. The Boiler Plant does include any equipment to mitigate the emission of oxides of nitrogen (NO_x), sulfur dioxide (SO₂), or particulates (PM₁₀). It is therefore very unlikely that they meet the current new source standards for these pollutants. However, due to its age, it is grandfathered under the standards that existed when it was built. In addition to these (mostly) invisible emissions, the plant does produce soot and ash. Soot is especially prevalent when the soot in the boiler is blown down. The neighbors have been known to complain, but the blowdown must be done. The ash is collected by a local builder, who takes it away for free. Finally, dust is an issue. The coal pile is an open pad, with no walls to speak of and no roof. Under current standards, some mitigation of dust potential would have to occur, generally three full walls and roof, or something of that nature. In addition to mitigating dust, an enclosure would keep the coal dry and ice free, raising the average heat content per pound of the coal (as delivered to the boiler).

SECTION V: SUMMARY OF EXISTING CONDITIONS

B. Cooling

Existing Chillers. Currently, twelve buildings have one or more chillers, and a thirteenth building (Shippen) is tied into the chillers from adjacent buildings. Of these, five buildings use air cooled chillers, ranging in age from 33 years to less than a year, and the remainder have water cooled chillers, mostly newer. Air cooled chillers use up to twice as much energy per ton of cooling compared to water cooled units, but they are self contained, and require only a chilled water pump (or pumps). Water cooled are more efficient, but require more support equipment; a cooling tower and condenser water pumps.

There are many arguments both for and against central vs. distributed systems; one of the more compelling arguments against multiple distributed chillers is that you cannot share any redundancy or over-sizing that exists in the chillers, or the support equipment. A perfect example at Shippensburg is the new chiller in Memorial Auditorium. This chiller has a unit mounted control panel with readout, so a great deal of information is available about the chiller. During the walkthrough Abacus observed that the compressor was cycling heavily. Timing with a watch revealed that the compressor would cycle on when the supply / return differential temperature rose to 5 deg F. It would remain on for about 240 seconds, until the differential dropped to 3 deg F. It would take about 90 seconds for the differential to rise to 5 deg F again, at which point, it would start the cycle over. Readouts from the panel confirm that compressor 1 has run for a total of 3,850 hrs, and has started 35,482 times (an average of 9.22 starts per hour, or once every 6.5 minutes). The same numbers for Compressor 2 are: 5,390 hours, 30,212 starts, 5.61 starts per hour, 10.70 minutes per start. Not only is this very inefficient, it is very hard on the equipment. Ideally, a chiller might start once a month, or even once a season and then run continuously.

Chiller noise is another concern that is frequently cited. Air cooled chillers generally sit outside, and can be quite loud. One can easily stand at the door of the campus police station and determine whether or not the Old Main condenser fans are running, and that is just fan noise. In that case, the actual compressor (the noisy part) is inside.

Chilled Water Loop. There has been some discussion at the facilities level of looping buildings together into "mini central plants". This is an attempt to address some of the efficiency, redundancy, and equipment life issues. In one case, Shippen Hall, a building with no chiller is cooled, but this is as far as the concept has gotten to date. Abacus gave thought to extending this system and creating several loops, but the reasoning against ran as such. Creating several small loops helps, but still limits the sharing of load and redundancy, and the ability to benefit from economy of scale. If the intent is that, in time, the small loops are combined into bigger loops, the result will be less than optimal, there is no economy of scale benefit, and one will eventually come to wish that the entire system had been purpose-built as a central system in the first place. Finally, pipe is cheap compared to digging up the campus, so if digging is involved, either minimize the digging, or maximize what goes into the trench once you dig it. In all cases, Abacus felt that a new central heating/cooling plant, using the lessons learned from the existing systems, was a better solution than depending on existing components of unknown reliability and performance.

SECTION V: SUMMARY OF EXISTING CONDITIONS

Electrical

Existing Power. The existing power service for most of the campus comes from a 23 kV pole-mounted service. At the substation, it is transformed to 12.47 kV, and distributed to the campus. This appears to have been fairly robust, although coming from a distribution line means it is inherently less reliable than the same service coming from a transmission line. A redundant main transformer was just added, increasing reliability. Abacus looked at an option that would further increase reliability. This was done as part of the RFP audit, and is included again here.

As noted above, Shippensburg is served off of a 23 kV distribution line. Running across the campus, through the sports fields, is a 115 kV transmission line. The transmission system in the US is extremely robust, much more so (in industry terms) than the various distribution systems. Abacus looked at the possibility of constructing a new substation near the edge of the property, just under the lines. New underground cable would have to be routed to the existing substation, and from there, the existing system re-used. The estimated cost was \$2,000,000; the estimated life span exceeded forty years. Energy savings were negligible, but there were cost savings. The cost (from the utilities) of electrical energy and peak demand generally go down as the delivery voltage goes up. In this case, however, the incentive was not very great, and the savings, at current consumption rates, amounted to \$50,870 per year, a 40 year net simple payback. The primary drivers would not be cost savings, but rather less system maintenance and more reliability.

Additional Information

See the detailed deferred maintenance list in Section IV.

APPENDIX B: ASSESSMENT OF EXISTING CONDITIONS

ESTIMATED COSTS: Steam Plant and Distribution Modifications Required for a "30-Year System"

<i>Total, Steam Plant Items Selected</i>	>	\$9,485,181
<i>Total, Steam Distribution Items Selected</i>	>	\$6,697,539
<i>Total</i>	>	\$16,182,720
<i>Total, Steam Plant Deferred Maintenance</i>	>	\$2,887,868
<i>Total, Steam Distribution Deferred Maintenance</i>	>	\$3,384,510
<i>Total</i>	>	\$6,272,379

- Notes: 1 Costs are Total Project costs, and include design, construction, PM, CM, start-up, and commissioning.
 2 Steam Plant numbering starts at 1, Distribution starts at 50 to leave space for additional Steam Plant Items.
 3 "DM" equals Deferred Maintenance. A "1" indicates that this Item represents Deferred Maintenance that will not have to be done if these Items are implemented.

STEAM PLANT		Estimated Cost	On Off	D M
1	Steam Plant Roof:	\$348,717	1	1
	> Replace the entire roof of the steam plant (approx 13,524 sq.ft.) with new composition roof. > The existing roof is 25 years old, and has accumulated tons of ash over the years. In many places, the build-up of ash has sloped the roof away from the drains. Plants are beginning to take root in the ash/dust mixture that has collected. > Minor structural repair is included to repair damage done by leaks over the years. > New insulation is included. > The accumulated ash has changed the drainage, and created areas of ponding.			
2	Steam Plant Roof Drains	\$43,590	1	1
	> Replace the existing rooftop storm drains. This includes only the drains themselves, and the storm leaders in the building. > Item 12 includes re-routing the storm leaders as they exit the building			
3	Repoint and Replace Brick as Required	\$246,659	1	1
	> The horizontal and vertical seals on the coping stones on the top of the parapet have largely failed. This allows water in behind and into the mortar of the bricks, particularly those between the trim piece just below the parapet and the parapet itself. > The resulting freeze/thaw cycling has pushed many of the bricks almost out of the wall. > This includes repointing, and where required, replacing the bricks in the area described as well as the rest of the entire building (approx 30,000 sq.ft.).			
4	Repair and Reseal Coping Stones on Parapet	\$13,155	1	1
	> The seals in most of the coping stones on the parapets have failed (see Item 3). > Similarly, the joints in the watercourse below the parapet have mostly failed also. > This includes resealing the coping stones, all vertical and horizontal joints.			
5	Refurbish Existing Restroom	\$41,110	1	1
	> This includes new WC, new urinal, new shower enclosure, and new DHW heater. All fixtures will be low flow, water saving. > This includes new wall and floor finishes, appropriate for the duty.			
6	Repair Exterior Doors	\$7,893	1	1
	> Replace four in number metal doors and door frames in their entirety. This doors are rusted through, and some of the frames are falling out of the wall.			



APPENDIX B: ASSESSMENT OF EXISTING CONDITIONS

7	Repair/Replace Windows	\$115,108	1	1
	<ul style="list-style-type: none"> > Replace or repair windows, 15 in number, 100" wide by 192" high. Total area approx 2,000 sq.ft. > Repair the operable sections of each window, and re-install the crank actuators where missing. > In some cases, frame and even wall repair will be required - some the window units are being held in by wooden wedges, and would fall out if allowed to. 			
8	Replace Main Electrical Switchgear	\$58,540	1	1
	<ul style="list-style-type: none"> > The existing main switchgear is old, and prone to failure of the breakers. > The handles of the breakers have been known to break off - this is extremely dangerous; a life safety issue. > The existing emergency generator is too close to the switchgear to maintain code-required clearance - this is also a life-safety issue. 			
9	Replace MCCs	\$101,624	1	1
	<ul style="list-style-type: none"> > Most of the buckets and frames in the existing Motor Control Centers are obsolete. > There are three (3) MCCs, with a total of about 45 buckets > Many lack a mechanism for opening the door while leaving the motor running. This means that any work requires a shutdown. > This includes new starters as well as the new MCC frame and buckets. The feeders for this gear are included in Item 10. > Starter will be grouped logically by what they serve - currently, the starter buckets were installed wherever there was room, not by function. > Again, replacing obsolete electrical gear is a life-safety issue. 			
10	Replace Plant Branch Wiring	\$182,750	1	1
	<ul style="list-style-type: none"> > The branch wiring in the plant is obsolete; it still has cloth insulation. > This includes new feeders from the switchgear to the MCCs, and from the MCCs. > This includes new disconnects. > This includes new panels, new branch wiring and conduit, and new outlets. > Like the Main Switchgear and the MCCs, replacement of this wiring should be considered a life safety issue. 			
11	Replace Boiler No. 4 Stoker	\$698,868	1	
	<ul style="list-style-type: none"> > Replace chain grate stoker on Boiler 4 to one suited for smaller (barley) sized anthracite coal. > Move the Stoker drive from the front of the boiler to the back, > This eliminates the need to buy and store two sizes of coal. In effect, it increases the amount of coal storage available, since the other boilers cannot burn the buckwheat coal fired in No. 4. Any coal stored in the buckwheat hoppers cannot be used if No. 4 is not running, yet it takes up hopper space > It also eliminates the worry that operating staff will forget to change the hopper gates on the horizontal conveyor, thus dumping buckwheat coal in the barley hoppers, or vice versa. > The boilers burning barley seem to have lower stack temperatures (i.e., are more efficient). 			

APPENDIX B: ASSESSMENT OF EXISTING CONDITIONS

12	Structural and Operational Upgrades	\$1,475,310	1	1
	<ul style="list-style-type: none"> > These items were grouped together because Shippensburg has received a quote for the combined work. The item is divided into six (6) sub-items, A through F: A > Add two new additional coal hoppers. Within the existing structure, there is room for two (2) more coal hoppers, which will increase storage. B > In order to feed the new hoppers, the existing horizontal conveyor must be extended approx 16 ft. C > The structure holding up the existing bunkers and horizontal conveyor is being corroded by the wet coal and coal dust. This includes repairing and replacing structural elements to bring the structure back to the original strength. D > Install a new DA tank. The existing tank is showing deterioration, and the boiler inspector has suggested that it be replaced. This requires that the roof above the DA tank be removed and then replaced. This should be done coincident with Item 1. E > Install a new ash wash (slurry) tank to improve the function of the existing system. This system washes ash out of the ash removal airstream (the vacuum) to prevent damage to system. The ash/water slurry is pumped to drain. F > Remove the existing ash chute, and extend the ash auger. The chute hangs down at an angle from the end of the existing auger, and hangs so low that only small trucks can be used to haul the ash away. This results in multiple hauling trips per day. If the chute were removed, and the auger extended at the existing angle, a standard truck could be used, and the number of trips reduced. 			
13	Coal Pile and Coal Yard Modifications	\$573,894	1	
	<ul style="list-style-type: none"> > A significant fraction of the coal pile is actually sitting on Rail to Trail property (not SU property). > A significant fraction of the coal pile is outside of the retention wall meant to contain the run-off from the pile. > The water from three sources runs into a surface drainage swale adjacent the coal yard. None of these sources should be run to a surface swale. The sources are the coal pile retention area, the ash hauling retention area, and the storm drains from the Boiler Plant. > All of these sources should be run to the Sanitary System; however, the invert of the new sanitary sewer line installed last year is too high to allow these sources to drain to sanitary by gravity (the line was raised because it was too low to drain to the City system - in the new configuration, it falls less than 1-1/2 feet in 300 feet). > A new retention area with higher walls is required to allow the coal to be properly stored within the area, and entirely on SU property. > The water from the three sources must be collected and pumped to the sanitary system. 			
14	Additional Storage on Grade	\$19,075	1	
	<ul style="list-style-type: none"> > There is limited storage on the main operating floor for storage. Many of the items that must be stocked are far too heavy to move manually (in excess of 800 pounds). Currently, these must be lowered into the basement with heavy equipment, or placed wherever space can be found on the main floor. > These pieces impede movement and operations in the plant. > Directly adjacent the boiler plant is a garage owned by the foundation. According to Plant personnel, people park in front of the garage, but never in it. > This item would add a new roll-up door in the end wall facing the plant, and regrade and pave the approach to the door, allowing access from the plant yard. 			
15	Revise the Coal Service Entrance into the Plant	\$70,709	1	
	<ul style="list-style-type: none"> > Although the hopper which feeds into the elevator is physically close to the coal yard, it can only be reached and fed from the side opposite the yard. > Because of this, operators must load coal into a truck, and drive the truck around the building, then dump it into the intake hopper. > This includes significant re-grading to allow coal to be loaded directly from the coal yard, without driving around the building. It installs new rails for the hopper lid to be drawn away from the hopper to allow this to happen. 			



APPENDIX B: ASSESSMENT OF EXISTING CONDITIONS

16	New Emergency Generator	\$139,774	1	1
	<ul style="list-style-type: none"> > Remove existing emergency generator and install a new one large enough to run the entire boiler plant. > This should be installed outside - the existing unit is too close to the Plant Main Switchgear as it is (it is a code violation). The new, larger unit cannot go in the same spot. 			
17	New Feedwater Pressure Regulator	\$11,511	1	1
	<ul style="list-style-type: none"> > The feedwater pressure regulator keeps the feedwater pressure 20 PSIG higher than the boiler pressure. This ensures that the feedwater can get into the boiler, even as boiler pressure rises. > The existing unit sticks. If the unit were to stick, and the boiler pressure were to rise too high, a low water condition could result in the boilers. This is a life safety issue. 			
18	Add Additional Ventilation Fans	\$22,199	1	1
	<ul style="list-style-type: none"> > There is only one ventilation fan in the roof, just above Boiler No. 2. The heat build-up is significant. This would install three new vent fans to pull air uniformly from the plant. 			
19	Plant Master Steam Meter/Meter Replacement	\$29,928	1	1
	<ul style="list-style-type: none"> > Each Boiler is metered, but there is no Plant Master. In the event that a meter fails, there is no record, and no way to estimate the Plant output. > A Plant Master would allow the operators to calculate the output of any boiler with a failed meter (by subtraction), and to ensure complete record-keeping. > In addition, this includes replacement of two meters in the old plant control panel that contain Mercury. Disposal of the meters is included. 			
20	Re-tube Boiler No. 1	\$641,314	1	
	<ul style="list-style-type: none"> > Boiler No. 1 was installed in 1952. It has never been comprehensively re-tubed. > Boilers 1 and 2 were listed first because they are the oldest. > In a water tube boiler, such as No. 1, the tubes and drums are the pressure vessels. They see the highest pressure, and are subjected to the highest level of corrosion, with hot stack gas on the outside, and water on the inside. > Years ago, before the present operating crew was in place, the water softeners were not used on the boiler make-up. This resulted in very heavy build-up on the tubes. This had to be removed by mechanical scrubbing. > There have been no large-scale tube failures to date, but the intent of this project is to set the plant up for 30-40 years into the future. Some level of re-tubing should be contemplated. > In talking to the EPA and DEP, the consensus was that "major" work on the boiler (generally defined as costing one half or more of the boiler's value) would trigger a requirement to meet current emissions standards. As with the dual-fuel/tri fuel items below, this is assumed to be particulate removal only (a baghouse or electrostatic precipitator), not a scrubber to remove sulfur. Re-tubing was not thought to trigger this requirement, but it is mentioned because there is always a chance the state will require it when it actually happens. At this time, the cost of new emissions controls is not included in the re-tubing items 			
21	Re-tube Boiler No. 2	\$641,314	1	
	<ul style="list-style-type: none"> > Boiler No. 2 was installed in 1952. It has never been comprehensively re-tubed. > See item 20 above. 			
22	Re-tube Boiler No. 3	\$690,646	1	
	<ul style="list-style-type: none"> > Boiler No. 3 was installed in 1964. It has never been comprehensively re-tubed. > See item 20 above. > Boiler No. 3 is newer than 1 or 2, but the intent of this work is to set the plant up for 30 - 40 years, so re-tubing should be considered. 			



APPENDIX B: ASSESSMENT OF EXISTING CONDITIONS

23	Re-tube Boiler No. 4	\$739,978	1
	<ul style="list-style-type: none"> > Boiler No. 4 was installed in 1984. It has never been comprehensively re-tubed. > See item 20 above. > Boiler No. 4 is newer than 1 or 2, but the intent of this work is to set the plant up for 30 - 40 years, so re-tubing should be considered. 		
24	Install Dual-Fuel Capability on Boiler No. 4	\$838,641	1
	<ul style="list-style-type: none"> > Install one or more gas-fired burners in the sidewall of the boiler to allow firing on coal or gas. > Boiler No. 4 was selected first because it is the newest, and has the greatest steam capacity. > Includes a baghouse for particulate removal. If a new burner is added, Abacus' research indicates that this will trigger a requirement to meet current emissions standards. The consensus of the people contacted was that this would require particulate control, but not sulfur removal. > Sulfur removal could add another \$500,000 to the cost. > Boiler No. 4 was selected because it is the newest, and has the greatest steam capacity. > This Item is mutually exclusive with Item 25 - only one can be selected. 		
25	Install Tri-Fuel Capability on Boiler No. 4	\$1,027,747	
	<ul style="list-style-type: none"> > Install one or more gas/oil fired burners in the sidewall of the boiler to allow firing on coal, oil or natural gas. > Unlike Item 24 above, this Item requires new infrastructure for the storage and distribution of No. 2 oil. > Includes a baghouse for particulate removal. If a new burner is added, Abacus' research indicates that this will trigger a requirement to meet current emissions standards. The consensus of the people contacted was that this would require particulate control, but not sulfur removal. > Sulfur removal could add another \$500,000 to the cost. > Boiler No. 4 was selected because it is the newest, and has the greatest steam capacity. > This Item is mutually exclusive with Item 24 - only one can be selected. 		
26	Install Dual-Fuel Capability on Boiler No. 3	\$838,641	1
	<ul style="list-style-type: none"> > Install one or more gas-fired burners in the sidewall of the boiler to allow firing on coal or gas. > Boiler No. 3 was selected second because it is the second newest, and has the second greatest steam capacity. > No. 3 was intended to be chosen only if No. 4 was converted also. No. 4 is the logical choice if only one boiler is done, but by doing No. 4 and No. 3 (combined with the gas-fired No. 5), the Plant should be able to meet load in excess of 95 percent of the time even if coal is not available. This is not the case if only No. 4 is converted. > Includes a baghouse for particulate removal. If a new burner is added, Abacus' research indicates that this will trigger a requirement to meet current emissions standards. The consensus of the people contacted was that this would require particulate control, but not sulfur removal. > Sulfur removal could add another \$500,000 to the cost. > This Item is mutually exclusive with Item 27 - only one can be selected. 		



APPENDIX B: ASSESSMENT OF EXISTING CONDITIONS

27	Install Tri-Fuel Capability on Boiler No. 3	\$879,751		
	<ul style="list-style-type: none"> > Install one or more gas/oil fired burners in the sidewall of the boiler to allow firing on coal, oil or natural gas. > Unlike Item 26 above, this Item requires new infrastructure for the storage and distribution of No. 2 oil. This Item assumes that Boiler 4 was also made tri-fuel, and so only adds an incremental amount of cost to the oil infrastructure > No. 3 was intended to be chosen only if No. 4 was converted also. No. 4 is the logical choice if only one boiler is done, but by doing No. 4 and No. 3 (combined with the gas-fired No. 5), the Plant should be able to meet load in excess of 95 percent of the time even if coal is not available. This is not the case if only No. 4 is converted. > Includes a baghouse for particulate removal. If a new burner is added, Abacus' research indicates that this will trigger a requirement to meet current emissions standards. The consensus of the people contacted was that this would require particulate control, but not sulfur removal. > Sulfur removal could add another \$500,000 to the cost. > Boiler No. 3 was selected second because it is the second newest, and has the second greatest steam capacity. > This Item is mutually exclusive with Item 26 - only one can be selected. 			
28	Install particulate emissions controls on Remaining Boilers	\$772,866	1	
	<ul style="list-style-type: none"> > Install particulate control on remaining boilers (No. 1 and No. 2) 			
29	Install sulfur emissions controls on All Boilers	\$2,959,911		
	<ul style="list-style-type: none"> > Install scrubbers on all four boilers for sulfur removal 			
30	Integrate Boiler Controls into Campus-wide Control System.	\$71,367	1	
	<ul style="list-style-type: none"> > Integrate boiler controls into the campus-wide EMS system. > This allows remote monitoring of the Plant. > It would also automate the recording of fuel use and steam output (and make-up, etc) 			
31	Repair/Replace Valves, Fittings and Appurtenances on Feedwater and Condensate System	\$50,001	1	1
	<ul style="list-style-type: none"> > This is an allowance to remove as much of the remaining deferred maintenance associated with these critical systems as possible. 			

STEAM DISTRIBUTION		Estimated Cost	On	Off
50	Replace Old/Failing Steam and Condensate Piping	\$3,384,510	1	1
	<ul style="list-style-type: none"> > Approx 5,400 linear feet of steam and condensate piping was designated as being most at risk to fail. This includes fittings and expansion loops as required. 			
51	Complete the Ring Main	\$528,344	1	
	<ul style="list-style-type: none"> > Adding approx 850 feet of steam and condensate piping between Manholes 32 and 14, and 29 and 39 will create "rings" in the steam distribution. > These looped systems allow the shutdown of sections of the piping without knocking out service downstream of the shutdown - these areas are backfed from the ringed steam mains. 			

APPENDIX F: FINANCIAL ANALYSIS

VARIABLES AND ASSUMPTIONS

TABLE: Financial Variables and Assumptions				All Options
Financial Data		30 year term of Analysis		Inflation
Available Capital:	\$13,760,000	Finance Term :	15 years	Fuel/Ops/Maint: 0.0300 per year
Cost of Option 1:	\$16,182,720	Interest Rate :	0.04125 per year	Rent: 0.0300 per year
		Payments :	4 per year	Wages/Benefits: 0.0300 per year
		Discount Rate :	0.05000 per year	Construction: 0.0300 per year
Wages & Benefits		unit cost		The unit cost was an average of similar costs Abacus has documented in other SSHE facilities.
FTEs:	11		\$53,000	
potential reduction:	5			
Increased Rents		unit cost		SU recorded 27,193 "people-nights" in the campus dorm rooms in 2004. Since double occupancy is the norm, this was divided by two to get "room-nights". Unit cost was provided by SU.
current room-nights:	13,597 per yr		\$22.00	
Deferred Maintenance Costs (\$000)				Total deferred maintenance is detailed in Section IV. For the cash flow analysis, it was assumed that the work would not start until year 3 to allow for funding, planning, and design time. The Plant work was assumed to take a maximum of three summers; the distribution work up to five. The cost for each part was divided equally by the number of years, which resulted in the phased costs shown at left. These phased costs were then inflated as shown above, the NPV of the payments calculated over the seven year period at the discount rate shown, and this figure was then divided by seven. This inflated and discounted cash stream was then counted as a savings for years 1 through 7. This represents the amount SU would need to put away/spend each year until the work was done, assuming they invest now and spend as needed.
Plant renovations		Year 3:	\$1,639.5	
phased over	3 yrs	Year 4:	\$1,639.5	
		Year 5:	\$1,639.5	
Piping renovations		Year 6:	\$676.9	
phased over	5 yrs	Year 7:	\$676.9	

APPENDIX F: FINANCIAL ANALYSIS

OPTION 1

TABLE: Financial Analysis/Cash Flow										Option 1		
Financial Data			30 year term of Analysis			Inflation			Results over Term			
Available Capital:	\$13,760,000		Finance Term :	15	years	Fuel/Ops/Maint:	0.0300	per year	Net Cash : \$3,687,075			
Cost of this Option:	\$16,182,720		Interest Rate :	0.04125	per year	Rent:	0.0300	per year	NPV : \$3,273,695			
Amount to Finance:	\$2,422,720		Payments :	4	per year	Wages/Benefits:	0.0300	per year	Investment : \$2,422,720			
Cost of Option 1:	\$16,182,720		Discount Rate :	0.05000	per year	Construction:	0.0300	per year	Yr 1 Savings : \$921,597			
Incremental Increase:									NPV/No debt : \$5,530,327			
Cost of Finance:	\$838,418											
Resource Costs		Year 1 unit Savings	Savings, \$000					Costs		NET CASH FLOW		yr
			Avoided	def	Inc	Wages &	Finance					
			Fuel	Ops	Rent	Benefits						
Elec Demand:	\$9.7400	per kW	\$12.2			\$909.3	(\$217,409)	\$704,188			1	
On Peak Energy:	\$0.0411	per kWh	\$12.6			\$909.3	(\$217,409)	\$704,555			2	
Off Peak Energy:	\$0.0335	per kWh	\$13.0			\$909.3	(\$217,409)	\$704,934			3	
Coal, barley:	\$87.5600	per ton	120	\$13.4		\$909.3	(\$217,409)	\$705,324			4	
Coal, buck:	\$116.1600	per ton	15	\$13.8		\$909.3	(\$217,409)	\$705,725			5	
Natural Gas:	\$7.3000	per MBTU		\$14.2		\$909.3	(\$217,409)	\$706,139			6	
Oil:	\$1.6600	per gal		\$14.6		\$909.3	(\$217,409)	\$706,565			7	
			Year 1				(\$217,409)	(\$202,344)			8	
			Avoided				(\$217,409)	(\$201,892)			9	
Avoided Electrical Costs (turbine output)			units				(\$217,409)	(\$201,426)			10	
Elec Demand:	\$9.7400	per kW		\$16.5			(\$217,409)	(\$200,947)			11	
On Peak Energy:	\$0.0411	per kWh		\$17.0			(\$217,409)	(\$200,453)			12	
Off Peak Energy:	\$0.0335	per kWh		\$17.5			(\$217,409)	(\$199,944)			13	
				\$18.0			(\$217,409)	(\$199,420)			14	
Avoided Operational Costs		per year		\$18.5			(\$217,409)	(\$198,881)			15	
See Annual Lighting/HVAC Expenses				\$19.1				\$19,084			16	
				\$19.7				\$19,657			17	
Deferred Maintenance Costs (\$000)				\$20.2				\$20,247			18	
Plant renovations		Year 3: \$1,639.5		\$20.9				\$20,854			19	
phased over	3 yrs	Year 4: \$1,639.5		\$21.5				\$21,480			20	
		Year 5: \$1,639.5		\$22.1				\$22,124			21	
Piping renovations		Year 6: \$676.9		\$22.8				\$22,788			22	
phased over	5 yrs	Year 7: \$676.9		\$23.5				\$23,472			23	
				\$24.2				\$24,176			24	
Increased Rents		unit cost		\$24.9				\$24,901			25	
current room-nights:	13,597	per yr	\$22.00	\$25.6				\$25,648			26	
Increase in rate:				\$26.4				\$26,417			27	
Increase in rent:				\$27.2				\$27,210			28	
				\$28.0				\$28,026			29	
Wages & Benefits		unit cost		\$28.9				\$28,867			30	
FTEs:	11	\$53,000		\$0.6		\$6.4	(\$3,261,137)	\$3,687,075				
potential reduction:												
			Totals, \$000,000					Totals, \$				

APPENDIX F: FINANCIAL ANALYSIS

OPTION 2A

TABLE: Financial Analysis/Cash Flow										Option 2A	
Financial Data			30 year term of Analysis			Inflation			Results over Term		
Available Capital:	\$13,760,000		Finance Term :	15 years	Fuel/Ops/Maint:	0.0300 per year			Net Cash :	\$5,804,982	
Cost of this Option:	\$22,931,709		Interest Rate :	0.04125 per year	Rent:	0.0300 per year			NPV :	\$2,148,669	
Amount to Finance:	\$9,171,709		Payments :	4 per year	Wages/Benefits:	0.0300 per year			Investment :	\$9,171,709	
Cost of Option 1:	\$16,182,720		Discount Rate :	0.05000 per year	Construction:	0.0300 per year			Yr 1 Savings :	\$1,157,065	
Incremental Increase:	\$6,748,989								NPV/No debt :	\$10,691,621	
Cost of Finance:	\$3,174,004										
Resource Costs		Year 1 unit Savings	Savings, \$000				Costs		NET CASH FLOW		yr
			Fuel	Elec	Ops	def maint	Inc Rent	Wages & Benefits	Finance		
Elec Demand:	\$9.7400 per kW		\$77.3	\$151.9	\$18.6	\$909.3			(\$823,048)	\$334,017	1
On Peak Energy:	\$0.0411 per kWh		\$79.6	\$156.4	\$19.1	\$909.3			(\$823,048)	\$341,449	2
Off Peak Energy:	\$0.0335 per kWh		\$82.0	\$161.1	\$19.7	\$909.3			(\$823,048)	\$349,103	3
Coal, barley:	\$87.5600 per ton	(1,801)	\$84.4	\$165.9	\$20.3	\$909.3			(\$823,048)	\$356,988	4
Coal, buck:	\$116.1600 per ton	491	\$87.0	\$170.9	\$20.9	\$909.3			(\$823,048)	\$365,108	5
Natural Gas:	\$7.3000 per MBTU	24,375	\$89.6	\$176.0	\$21.5	\$909.3			(\$823,048)	\$373,472	6
Oil:	\$1.6600 per gal		\$92.3	\$181.3	\$22.2	\$909.3			(\$823,048)	\$382,088	7
		Year 1 Avoided units	\$95.0	\$186.8	\$22.9				(\$823,048)	(\$518,386)	8
			\$97.9	\$192.4	\$23.5				(\$823,048)	(\$509,246)	9
Avoided Electrical Costs (turbine output)			\$100.8	\$198.1	\$24.2				(\$823,048)	(\$499,832)	10
Elec Demand:	\$9.7400 per kW	4,950	\$103.9	\$204.1	\$25.0				(\$823,048)	(\$490,136)	11
On Peak Energy:	\$0.0411 per kWh	898,550	\$107.0	\$210.2	\$25.7				(\$823,048)	(\$480,149)	12
Off Peak Energy:	\$0.0335 per kWh	1,992,100	\$110.2	\$216.5	\$26.5				(\$823,048)	(\$469,862)	13
			\$113.5	\$223.0	\$27.3				(\$823,048)	(\$459,266)	14
Avoided Operational Costs		per year	\$116.9	\$229.7	\$28.1				(\$823,048)	(\$448,353)	15
See Annual Lighting/HVAC Expenses		\$18,580	\$120.4	\$236.6	\$28.9					\$385,936	16
			\$124.0	\$243.7	\$29.8					\$397,514	17
Deferred Maintenance Costs (\$000)			\$127.7	\$251.0	\$30.7					\$409,439	18
Plant renovations phased over	3 yrs	Year 3: \$1,639.5	\$131.6	\$258.5	\$31.6					\$421,722	19
		Year 4: \$1,639.5	\$135.5	\$266.3	\$32.6					\$434,374	20
		Year 5: \$1,639.5	\$139.6	\$274.3	\$33.6					\$447,405	21
Piping renovations phased over	5 yrs	Year 6: \$676.9	\$143.8	\$282.5	\$34.6					\$460,827	22
		Year 7: \$676.9	\$148.1	\$291.0	\$35.6					\$474,652	23
			\$152.5	\$299.7	\$36.7					\$488,892	24
Increased Rents		unit cost	\$157.1	\$308.7	\$37.8					\$503,559	25
current room-nights:	13,597 per yr	\$22.00	\$161.8	\$318.0	\$38.9					\$518,665	26
Increase in rate:			\$166.7	\$327.5	\$40.1					\$534,225	27
Increase in rent:			\$171.7	\$337.3	\$41.3					\$550,252	28
			\$176.8	\$347.4	\$42.5					\$566,760	29
Wages & Benefits		unit cost	\$182.1	\$357.9	\$43.8					\$583,762	30
FTEs:	11	\$53,000	\$3.7	\$7.2	\$0.9	\$6.4			(\$12,345,713)	\$5,804,982	
potential reduction:			Totals, \$000,000						Totals, \$		

APPENDIX F: FINANCIAL ANALYSIS

OPTION 2B

TABLE: Financial Analysis/Cash Flow										Option 2B				
Financial Data			30 year term of Analysis			Inflation			Results over Term					
Available Capital:	\$13,760,000		Finance Term :	15 years	Fuel/Ops/Maint:	0.0300 per year	Rent:	0.0300 per year	Wages/Benefits:	0.0300 per year	Construction:	0.0300 per year	Net Cash :	\$8,142,180
Cost of this Option:	\$21,045,672		Interest Rate :	0.04125 per year									NPV :	\$3,812,560
Amount to Finance:	\$7,285,672		Payments :	4 per year									Investment :	\$7,285,672
Cost of Option 1:	\$16,182,720		Discount Rate :	0.05000 per year									Yr 1 Savings :	\$1,152,829
Incremental Increase:	\$4,862,952												NPV/No debt :	\$10,598,771
Cost of Finance:	\$2,521,314													
Resource Costs		Year 1 unit Savings	Savings, \$000					Costs		NET CASH FLOW		yr		
			Avoided Fuel	def Elec	Ops	Inc maint	Rent	Wages & Benefits	Finance					
Elec Demand:	\$9.7400 per kW		(\$192.0)	\$151.9	\$18.6	\$909.3		\$265.0	(\$653,799)	\$499,030	1			
On Peak Energy:	\$0.0411 per kWh		(\$197.7)	\$156.4	\$19.1	\$909.3		\$273.0	(\$653,799)	\$506,334	2			
Off Peak Energy:	\$0.0335 per kWh		(\$203.6)	\$161.1	\$19.7	\$909.3		\$281.1	(\$653,799)	\$513,858	3			
Coal, barley:	\$87.5600 per ton	3,974	(\$209.8)	\$165.9	\$20.3	\$909.3		\$289.6	(\$653,799)	\$521,607	4			
Coal, buck:	\$116.1600 per ton	491	(\$216.1)	\$170.9	\$20.9	\$909.3		\$298.3	(\$653,799)	\$529,589	5			
Natural Gas:	\$7.3000 per MBTU	(81,775)	(\$222.5)	\$176.0	\$21.5	\$909.3		\$307.2	(\$653,799)	\$537,810	6			
Oil:	\$1.6600 per gal		(\$229.2)	\$181.3	\$22.2	\$909.3		\$316.4	(\$653,799)	\$546,278	7			
		Year 1	(\$236.1)	\$186.8	\$22.9			\$325.9	(\$653,799)	(\$354,348)	8			
		Avoided	(\$243.2)	\$192.4	\$23.5			\$335.7	(\$653,799)	(\$345,364)	9			
Avoided Electrical Costs (turbine output)	units		(\$250.5)	\$198.1	\$24.2			\$345.8	(\$653,799)	(\$336,111)	10			
Elec Demand:	\$9.7400 per kW	4,950	(\$258.0)	\$204.1	\$25.0			\$356.1	(\$653,799)	(\$326,580)	11			
On Peak Energy:	\$0.0411 per kWh	898,550	(\$265.7)	\$210.2	\$25.7			\$366.8	(\$653,799)	(\$316,764)	12			
Off Peak Energy:	\$0.0335 per kWh	1,992,100	(\$273.7)	\$216.5	\$26.5			\$377.8	(\$653,799)	(\$306,653)	13			
			(\$281.9)	\$223.0	\$27.3			\$389.2	(\$653,799)	(\$296,238)	14			
Avoided Operational Costs	per year		(\$290.4)	\$229.7	\$28.1			\$400.8	(\$653,799)	(\$285,511)	15			
See Annual Lighting/HVAC Expenses	\$18,580		(\$299.1)	\$236.6	\$28.9			\$412.9		\$379,336	16			
			(\$308.0)	\$243.7	\$29.8			\$425.2		\$390,716	17			
Deferred Maintenance Costs (\$000)			(\$317.3)	\$251.0	\$30.7			\$438.0		\$402,438	18			
Plant renovations phased over	3 yrs	Year 3: \$1,639.5	(\$326.8)	\$258.5	\$31.6			\$451.1		\$414,511	19			
		Year 4: \$1,639.5	(\$336.6)	\$266.3	\$32.6			\$464.7		\$426,946	20			
		Year 5: \$1,639.5	(\$346.7)	\$274.3	\$33.6			\$478.6		\$439,755	21			
Piping renovations phased over	5 yrs	Year 6: \$676.9	(\$357.1)	\$282.5	\$34.6			\$493.0		\$452,947	22			
		Year 7: \$676.9	(\$367.8)	\$291.0	\$35.6			\$507.8		\$466,536	23			
			(\$378.8)	\$299.7	\$36.7			\$523.0		\$480,532	24			
Increased Rents	unit cost		(\$390.2)	\$308.7	\$37.8			\$538.7		\$494,948	25			
current room-nights:	13,597 per yr	\$22.00	(\$401.9)	\$318.0	\$38.9			\$554.9		\$509,796	26			
Increase in rate:			(\$414.0)	\$327.5	\$40.1			\$571.5		\$525,090	27			
Increase in rent:			(\$426.4)	\$337.3	\$41.3			\$588.6		\$540,843	28			
			(\$439.2)	\$347.4	\$42.5			\$606.3		\$557,068	29			
Wages & Benefits	unit cost		(\$452.4)	\$357.9	\$43.8			\$624.5		\$573,780	30			
FTEs:	11	\$53,000	(\$9.1)	\$7.2	\$0.9	\$6.4		\$12.6	(\$9,806,986)	\$8,142,180				
potential reduction:	5													
			Totals, \$000,000					Totals, \$						

APPENDIX F: FINANCIAL ANALYSIS

OPTION 3A

TABLE: Financial Analysis/Cash Flow

Option 3A

Financial Data		30 year term of Analysis		Inflation				Results over Term		
Available Capital:	\$13,760,000	Finance Term :	15 years	Fuel/Ops/Maint:	0.0300	per year		Net Cash :	\$1,455,810	
Cost of this Option:	\$27,106,689	Interest Rate :	0.04125 per year	Rent:	0.0300	per year		NPV :	(\$1,154,690)	
Amount to Finance:	\$13,346,689	Payments :	4 per year	Wages/Benefits:	0.0300	per year		Investment :	\$13,346,689	
Cost of Option 1:	\$16,182,720	Discount Rate :	0.05000 per year	Construction:	0.0300	per year		Yr 1 Savings :	\$1,183,773	
Incremental Increase:	\$10,923,969							NPV/No debt :	\$11,277,031	
Cost of Finance:	\$4,618,818									
Resource Costs		Year 1 unit Savings	Savings, \$000				Costs		NET CASH FLOW	yr
			Avoided	def	Inc	Wages &	Finance			
			Fuel	Ops	Rent	Benefits				
Elec Demand:	\$9.7400 per kW	6,574	\$61.5	\$194.3	\$18.6	\$909.3	(\$1,197,700)	(\$13,928)	1	
On Peak Energy:	\$0.0411 per kWh	736,182	\$63.4	\$200.2	\$19.1	\$909.3	(\$1,197,700)	(\$5,695)	2	
Off Peak Energy:	\$0.0335 per kWh	1,151,009	\$65.3	\$206.2	\$19.7	\$909.3	(\$1,197,700)	\$2,785	3	
Coal, barley:	\$87.5600 per ton	(3,498)	\$67.2	\$212.3	\$20.3	\$909.3	(\$1,197,700)	\$11,519	4	
Coal, buck:	\$116.1600 per ton	491	\$69.2	\$218.7	\$20.9	\$909.3	(\$1,197,700)	\$20,515	5	
Natural Gas:	\$7.3000 per MBTU	24,375	\$71.3	\$225.3	\$21.5	\$909.3	(\$1,197,700)	\$29,781	6	
Oil:	\$1.6600 per gal		\$73.5	\$232.0	\$22.2	\$909.3	(\$1,197,700)	\$39,325	7	
		Year 1 Avoided units	\$75.7	\$239.0	\$22.9		(\$1,197,700)	(\$860,192)	8	
			\$77.9	\$246.2	\$23.5		(\$1,197,700)	(\$850,067)	9	
Avoided Electrical Costs (turbine output)			\$80.3	\$253.6	\$24.2		(\$1,197,700)	(\$839,638)	10	
Elec Demand:	\$9.7400 per kW	6,165	\$82.7	\$261.2	\$25.0		(\$1,197,700)	(\$828,896)	11	
On Peak Energy:	\$0.0411 per kWh	1,228,700	\$85.2	\$269.0	\$25.7		(\$1,197,700)	(\$817,832)	12	
Off Peak Energy:	\$0.0335 per kWh	2,501,600	\$87.7	\$277.1	\$26.5		(\$1,197,700)	(\$806,436)	13	
			\$90.3	\$285.4	\$27.3		(\$1,197,700)	(\$794,698)	14	
Avoided Operational Costs		per year	\$93.1	\$293.9	\$28.1		(\$1,197,700)	(\$782,608)	15	
See Annual Lighting/HVAC Expenses		\$18,580	\$95.8	\$302.8	\$28.9			\$427,545	16	
			\$98.7	\$311.8	\$29.8			\$440,372	17	
Deferred Maintenance Costs (\$000)			\$101.7	\$321.2	\$30.7			\$453,583	18	
Plant renovations phased over	3 yrs	Year 3: \$1,639.5	\$104.7	\$330.8	\$31.6			\$467,190	19	
		Year 4: \$1,639.5	\$107.9	\$340.8	\$32.6			\$481,206	20	
		Year 5: \$1,639.5	\$111.1	\$351.0	\$33.6			\$495,642	21	
Piping renovations phased over	5 yrs	Year 6: \$676.9	\$114.4	\$361.5	\$34.6			\$510,511	22	
		Year 7: \$676.9	\$117.9	\$372.3	\$35.6			\$525,827	23	
			\$121.4	\$383.5	\$36.7			\$541,601	24	
Increased Rents		unit cost	\$125.1	\$395.0	\$37.8			\$557,850	25	
current room-nights:	13,597 per yr	\$22.00	\$128.8	\$406.9	\$38.9			\$574,585	26	
Increase in rate:			\$132.7	\$419.1	\$40.1			\$591,823	27	
Increase in rent:			\$136.7	\$431.7	\$41.3			\$609,577	28	
			\$140.8	\$444.6	\$42.5			\$627,865	29	
Wages & Benefits		unit cost	\$145.0	\$457.9	\$43.8			\$646,700	30	
FTEs:	11	\$53,000	\$2.9	\$9.2	\$0.9	\$6.4	(\$17,965,507)	\$1,455,810		
potential reduction:			Totals, \$000,000				Totals, \$			

APPENDIX F: FINANCIAL ANALYSIS

OPTION 3B

TABLE: Financial Analysis/Cash Flow										Option 3B	
Financial Data			30 year term of Analysis			Inflation			Results over Term		
Available Capital:	\$13,760,000		Finance Term :	15	years	Fuel/Ops/Maint:	0.0300	per year	Net Cash : (\$43,030)		
Cost of this Option:	\$25,220,652		Interest Rate :	0.04125	per year	Rent:	0.0300	per year	NPV : (\$1,258,167)		
Amount to Finance:	\$11,460,652		Payments :	4	per year	Wages/Benefits:	0.0300	per year	Investment : \$11,460,652		
Cost of Option 1:	\$16,182,720		Discount Rate :	0.05000	per year	Construction:	0.0300	per year	Yr 1 Savings : \$1,098,906		
Incremental Increase:	\$9,037,932								NPV/No debt : \$9,416,812		
Cost of Finance:	\$3,966,127										
Resource Costs		Year 1 unit Savings	Savings, \$000					Costs		NET CASH FLOW	yr
			Avoided Fuel	def Elec	Ops	Inc maint	Wages & Rent	Benefits	Finance		
Elec Demand:	\$9.7400 per kW	6,574	(\$288.3)	\$194.3	\$18.6	\$909.3	\$265.0		(\$1,028,452)	\$70,454	1
On Peak Energy:	\$0.0411 per kWh	736,182	(\$297.0)	\$200.2	\$19.1	\$909.3	\$273.0		(\$1,028,452)	\$76,141	2
Off Peak Energy:	\$0.0335 per kWh	1,151,009	(\$305.9)	\$206.2	\$19.7	\$909.3	\$281.1		(\$1,028,452)	\$81,998	3
Coal, barley:	\$87.5600 per ton	3,974	(\$315.1)	\$212.3	\$20.3	\$909.3	\$289.6		(\$1,028,452)	\$88,031	4
Coal, buck:	\$116.1600 per ton	491	(\$324.5)	\$218.7	\$20.9	\$909.3	\$298.3		(\$1,028,452)	\$94,245	5
Natural Gas:	\$7.3000 per MBTU	(113,175)	(\$334.3)	\$225.3	\$21.5	\$909.3	\$307.2		(\$1,028,452)	\$100,646	6
Oil:	\$1.6600 per gal		(\$344.3)	\$232.0	\$22.2	\$909.3	\$316.4		(\$1,028,452)	\$107,238	7
			(\$354.6)	\$239.0	\$22.9		\$325.9		(\$1,028,452)	(\$795,319)	8
		Year 1 Avoided units	(\$365.3)	\$246.2	\$23.5		\$335.7		(\$1,028,452)	(\$788,325)	9
Avoided Electrical Costs (turbine output)			(\$376.2)	\$253.6	\$24.2		\$345.8		(\$1,028,452)	(\$781,121)	10
Elec Demand:	\$9.7400 per kW	6,165	(\$387.5)	\$261.2	\$25.0		\$356.1		(\$1,028,452)	(\$773,701)	11
On Peak Energy:	\$0.0411 per kWh	1,228,700	(\$399.1)	\$269.0	\$25.7		\$366.8		(\$1,028,452)	(\$766,059)	12
Off Peak Energy:	\$0.0335 per kWh	2,501,600	(\$411.1)	\$277.1	\$26.5		\$377.8		(\$1,028,452)	(\$758,187)	13
			(\$423.4)	\$285.4	\$27.3		\$389.2		(\$1,028,452)	(\$750,079)	14
Avoided Operational Costs per year			(\$436.2)	\$293.9	\$28.1		\$400.8		(\$1,028,452)	(\$741,728)	15
See Annual Lighting/HVAC Expenses		\$18,580	(\$449.2)	\$302.8	\$28.9		\$412.9			\$295,326	16
			(\$462.7)	\$311.8	\$29.8		\$425.2			\$304,185	17
Deferred Maintenance Costs (\$000)			(\$476.6)	\$321.2	\$30.7		\$438.0			\$313,311	18
Plant renovations phased over	3 yrs	Year 3: \$1,639.5	(\$490.9)	\$330.8	\$31.6		\$451.1			\$322,710	19
		Year 4: \$1,639.5	(\$505.6)	\$340.8	\$32.6		\$464.7			\$332,392	20
		Year 5: \$1,639.5	(\$520.8)	\$351.0	\$33.6		\$478.6			\$342,363	21
Piping renovations phased over	5 yrs	Year 6: \$676.9	(\$536.4)	\$361.5	\$34.6		\$493.0			\$352,634	22
		Year 7: \$676.9	(\$552.5)	\$372.3	\$35.6		\$507.8			\$363,213	23
			(\$569.1)	\$383.5	\$36.7		\$523.0			\$374,110	24
Increased Rents unit cost			(\$586.2)	\$395.0	\$37.8		\$538.7			\$385,333	25
current room-nights:	13,597 per yr	\$22.00	(\$603.7)	\$406.9	\$38.9		\$554.9			\$396,893	26
Increase in rate:			(\$621.8)	\$419.1	\$40.1		\$571.5			\$408,800	27
Increase in rent:			(\$640.5)	\$431.7	\$41.3		\$588.6			\$421,064	28
			(\$659.7)	\$444.6	\$42.5		\$606.3			\$433,696	29
Wages & Benefits unit cost			(\$679.5)	\$457.9	\$43.8		\$624.5			\$446,707	30
FTEs:	11	\$53,000	(\$13.7)	\$9.2	\$0.9	\$6.4	\$12.6		(\$15,426,779)	(\$43,030)	
potential reduction:	5										
			Totals, \$000,000					Totals, \$			

APPENDIX F: FINANCIAL ANALYSIS

OPTION 4A

TABLE: Financial Analysis/Cash Flow

Option 4A

Financial Data		30 year term of Analysis		Inflation			Results over Term		
Available Capital:	\$13,760,000	Finance Term :	15 years	Fuel/Ops/Maint:	0.0300 per year	Net Cash : \$5,974,955			
Cost of this Option:	\$29,167,614	Interest Rate :	0.04125 per year	Rent:	0.0300 per year	NPV : \$285,887			
Amount to Finance:	\$15,407,614	Payments :	4 per year	Wages/Benefits:	0.0300 per year	Investment : \$15,407,614			
Cost of Option 1:	\$16,182,720	Discount Rate :	0.05000 per year	Construction:	0.0300 per year	Yr 1 Savings : \$1,337,072			
Incremental Increase:	\$12,984,894					NPV/No debt : \$14,637,249			
Cost of Finance:	\$5,332,031								

Resource Costs	Year 1 unit Savings	Savings, \$000					Wages & Benefits	Costs	NET CASH FLOW	yr
		Fuel	Elec	Ops	def maint	Inc Rent				
Elec Demand:	\$9.7400 per kW 4,584	(\$46.6)	\$216.5	\$18.6	\$909.3	\$239.3		(\$1,382,643)	(\$45,571)	1
On Peak Energy:	\$0.0411 per kWh 567,707	(\$48.0)	\$223.0	\$19.1	\$909.3	\$246.5		(\$1,382,643)	(\$32,739)	2
Off Peak Energy:	\$0.0335 per kWh 945,709	(\$49.5)	\$229.7	\$19.7	\$909.3	\$253.9		(\$1,382,643)	(\$19,523)	3
Coal, barley:	\$87.5600 per ton (3,431)	(\$51.0)	\$236.6	\$20.3	\$909.3	\$261.5		(\$1,382,643)	(\$5,909)	4
Coal, buck:	\$116.1600 per ton 491	(\$52.5)	\$243.7	\$20.9	\$909.3	\$269.3		(\$1,382,643)	\$8,112	5
Natural Gas:	\$7.3000 per MBTU 13,300	(\$54.1)	\$251.0	\$21.5	\$909.3	\$277.4		(\$1,382,643)	\$22,554	6
Oil:	\$1.6600 per gal	(\$55.7)	\$258.5	\$22.2	\$909.3	\$285.7		(\$1,382,643)	\$37,430	7
	Year 1	(\$57.4)	\$266.3	\$22.9		\$294.3		(\$1,382,643)	(\$856,596)	8
	Avoided	(\$59.1)	\$274.2	\$23.5		\$303.1		(\$1,382,643)	(\$840,815)	9
Avoided Electrical Costs (turbine output)	units	(\$60.9)	\$282.5	\$24.2		\$312.2		(\$1,382,643)	(\$824,560)	10
Elec Demand:	\$9.7400 per kW 7,430	(\$62.7)	\$290.9	\$25.0		\$321.6		(\$1,382,643)	(\$807,817)	11
On Peak Energy:	\$0.0411 per kWh 1,355,500	(\$64.6)	\$299.7	\$25.7		\$331.2		(\$1,382,643)	(\$790,572)	12
Off Peak Energy:	\$0.0335 per kWh 2,639,900	(\$66.5)	\$308.7	\$26.5		\$341.2		(\$1,382,643)	(\$772,810)	13
		(\$68.5)	\$317.9	\$27.3		\$351.4		(\$1,382,643)	(\$754,515)	14
Avoided Operational Costs	per year	(\$70.6)	\$327.5	\$28.1		\$362.0		(\$1,382,643)	(\$735,671)	15
See Annual Lighting/HVAC Expenses	\$18,580	(\$72.7)	\$337.3	\$28.9		\$372.8			\$666,381	16
		(\$74.8)	\$347.4	\$29.8		\$384.0			\$686,372	17
Deferred Maintenance Costs (\$000)		(\$77.1)	\$357.8	\$30.7		\$395.5			\$706,963	18
Plant renovations	Year 3: \$1,639.5	(\$79.4)	\$368.6	\$31.6		\$407.4			\$728,172	19
phased over	3 yrs Year 4: \$1,639.5	(\$81.8)	\$379.6	\$32.6		\$419.6			\$750,017	20
	Year 5: \$1,639.5	(\$84.2)	\$391.0	\$33.6		\$432.2			\$772,518	21
Piping renovations	Year 6: \$676.9	(\$86.8)	\$402.7	\$34.6		\$445.2			\$795,693	22
phased over	5 yrs Year 7: \$676.9	(\$89.4)	\$414.8	\$35.6		\$458.5			\$819,564	23
		(\$92.1)	\$427.3	\$36.7		\$472.3			\$844,151	24
Increased Rents	unit cost	(\$94.8)	\$440.1	\$37.8		\$486.4			\$869,476	25
current room-nights:	13,597 per yr \$22.00	(\$97.7)	\$453.3	\$38.9		\$501.0			\$895,560	26
Increase in rate:	0.2000	(\$100.6)	\$466.9	\$40.1		\$516.1			\$922,427	27
Increase in rent:	0.5000	(\$103.6)	\$480.9	\$41.3		\$531.6			\$950,100	28
		(\$106.7)	\$495.3	\$42.5		\$547.5			\$978,603	29
Wages & Benefits	unit cost	(\$109.9)	\$510.2	\$43.8		\$563.9			\$1,007,961	30
FTEs:	11 \$53,000	(\$2.2)	\$10.3	\$0.9	\$6.4	\$11.4		(\$20,739,645)	\$5,974,955	
potential reduction:										
		Totals, \$000,000					Totals, \$			

APPENDIX F: FINANCIAL ANALYSIS

OPTION 4B

TABLE: Financial Analysis/Cash Flow

Option 4B

Financial Data		30 year term of Analysis		Inflation				Results over Term			
Available Capital:	\$13,760,000	Finance Term :	15 years	Fuel/Ops/Maint:	0.0300	per year	Net Cash : \$4,570,361				
Cost of this Option:	\$27,281,577	Interest Rate :	0.04125 per year	Rent:	0.0300	per year	NPV : \$225,831				
Amount to Finance:	\$13,521,577	Payments :	4 per year	Wages/Benefits:	0.0300	per year	Investment : \$13,521,577				
Cost of Option 1:	\$16,182,720	Discount Rate :	0.05000 per year	Construction:	0.0300	per year	Yr 1 Savings : \$1,254,186				
Incremental Increase:	\$11,098,857						NPV/No debt : \$12,820,451				
Cost of Finance:	\$4,679,340										
Resource Costs		Year 1 unit Savings	Savings, \$000					Costs		NET CASH FLOW	yr
			Avoided Fuel	def Elec	Ops	Inc maint	Wages & Rent	Benefits	Finance		
Elec Demand:	\$9.7400 per kW	4,584	(\$394.5)	\$216.5	\$18.6	\$909.3	\$239.3	\$265.0	(\$1,213,394)	\$40,792	1
On Peak Energy:	\$0.0411 per kWh	567,707	(\$406.4)	\$223.0	\$19.1	\$909.3	\$246.5	\$273.0	(\$1,213,394)	\$51,137	2
Off Peak Energy:	\$0.0335 per kWh	945,709	(\$418.6)	\$229.7	\$19.7	\$909.3	\$253.9	\$281.1	(\$1,213,394)	\$61,792	3
Coal, barley:	\$87.5600 per ton	3,974	(\$431.1)	\$236.6	\$20.3	\$909.3	\$261.5	\$289.6	(\$1,213,394)	\$72,768	4
Coal, buck:	\$116.1600 per ton	491	(\$444.0)	\$243.7	\$20.9	\$909.3	\$269.3	\$298.3	(\$1,213,394)	\$84,072	5
Natural Gas:	\$7.3000 per MBTU	(123,175)	(\$457.4)	\$251.0	\$21.5	\$909.3	\$277.4	\$307.2	(\$1,213,394)	\$95,716	6
Oil:	\$1.6600 per gal		(\$471.1)	\$258.5	\$22.2	\$909.3	\$285.7	\$316.4	(\$1,213,394)	\$107,709	7
		Year 1	(\$485.2)	\$266.3	\$22.9		\$294.3	\$325.9	(\$1,213,394)	(\$789,286)	8
		Avoided	(\$499.8)	\$274.2	\$23.5		\$303.1	\$335.7	(\$1,213,394)	(\$776,563)	9
Avoided Electrical Costs (turbine output)		units	(\$514.8)	\$282.5	\$24.2		\$312.2	\$345.8	(\$1,213,394)	(\$763,458)	10
Elec Demand:	\$9.7400 per kW	7,430	(\$530.2)	\$290.9	\$25.0		\$321.6	\$356.1	(\$1,213,394)	(\$749,960)	11
On Peak Energy:	\$0.0411 per kWh	1,355,500	(\$546.1)	\$299.7	\$25.7		\$331.2	\$366.8	(\$1,213,394)	(\$736,057)	12
Off Peak Energy:	\$0.0335 per kWh	2,639,900	(\$562.5)	\$308.7	\$26.5		\$341.2	\$377.8	(\$1,213,394)	(\$721,737)	13
			(\$579.4)	\$317.9	\$27.3		\$351.4	\$389.2	(\$1,213,394)	(\$706,987)	14
Avoided Operational Costs		per year	(\$596.8)	\$327.5	\$28.1		\$362.0	\$400.8	(\$1,213,394)	(\$691,795)	15
See Annual Lighting/HVAC Expenses		\$18,580	(\$614.7)	\$337.3	\$28.9		\$372.8	\$412.9		\$537,247	16
			(\$633.1)	\$347.4	\$29.8		\$384.0	\$425.2		\$553,365	17
Deferred Maintenance Costs (\$000)			(\$652.1)	\$357.8	\$30.7		\$395.5	\$438.0		\$569,966	18
Plant renovations	Year 3:	\$1,639.5	(\$671.7)	\$368.6	\$31.6		\$407.4	\$451.1		\$587,065	19
phased over	3 yrs	Year 4:	(\$691.8)	\$379.6	\$32.6		\$419.6	\$464.7		\$604,677	20
		Year 5:	(\$712.6)	\$391.0	\$33.6		\$432.2	\$478.6		\$622,817	21
Piping renovations	Year 6:	\$676.9	(\$733.9)	\$402.7	\$34.6		\$445.2	\$493.0		\$641,502	22
phased over	5 yrs	Year 7:	(\$756.0)	\$414.8	\$35.6		\$458.5	\$507.8		\$660,747	23
			(\$778.6)	\$427.3	\$36.7		\$472.3	\$523.0		\$680,569	24
Increased Rents		unit cost	(\$802.0)	\$440.1	\$37.8		\$486.4	\$538.7		\$700,986	25
current room-nights:	13,597 per yr	\$22.00	(\$826.1)	\$453.3	\$38.9		\$501.0	\$554.9		\$722,016	26
Increase in rate:	0.2000		(\$850.8)	\$466.9	\$40.1		\$516.1	\$571.5		\$743,676	27
Increase in rent:	0.5000		(\$876.4)	\$480.9	\$41.3		\$531.6	\$588.6		\$765,986	28
			(\$902.7)	\$495.3	\$42.5		\$547.5	\$606.3		\$788,966	29
Wages & Benefits		unit cost	(\$929.7)	\$510.2	\$43.8		\$563.9	\$624.5		\$812,635	30
FTEs:	11	\$53,000	(\$18.8)	\$10.3	\$0.9	\$6.4	\$11.4	\$12.6	(\$18,200,917)	\$4,570,361	
potential reduction:	5		Totals, \$000,000					Totals, \$			

APPENDIX F: FINANCIAL ANALYSIS

ELECTRIC-GAS SCENARIO

TABLE: Financial Analysis/Cash Flow										Electric - Gas	
Financial Data			30 year term of Analysis			Inflation			Results over Term		
Available Capital:	\$13,760,000		Finance Term :	15 years		Fuel/Ops/Maint:	0.0300 per year			Net Cash :	(\$26,174,457)
Cost of this Option:	\$13,760,000		Interest Rate :	0.04125 per year		Rent:	0.0300 per year			NPV :	(\$9,730,203)
Amount to Finance:			Payments :	4 per year		Wages/Benefits:	0.0300 per year			Investment :	
Cost of Option 1:	\$16,182,720		Discount Rate :	0.05000 per year		Construction:	0.0300 per year			Yr 1 Savings :	\$225,383
Incremental Increase:	(\$2,422,720)									NPV/No debt :	\$10,853,480
Cost of Finance:											
Resource Costs		Year 1 unit Savings	Savings, \$000					Costs		NET CASH FLOW	yr
			Avoided		def	Inc	Wages &				
			Fuel	Elec	Ops	maint	Rent	Benefits	Finance		
Elec Demand:	\$9.7400 per kW	(60,567)	(\$1,259.0)		\$18.6	\$909.3		\$556.5		\$225,383	1
On Peak Energy:	\$0.0411 per kWh	(8,849,907)	(\$1,296.8)		\$19.1	\$909.3		\$573.2		\$204,864	2
Off Peak Energy:	\$0.0335 per kWh	(21,211,008)	(\$1,335.7)		\$19.7	\$909.3		\$590.4		\$183,730	3
Coal, barley:	\$87.5600 per ton	3,974	(\$1,375.8)		\$20.3	\$909.3		\$608.1		\$161,961	4
Coal, buck:	\$116.1600 per ton	491	(\$1,417.1)		\$20.9	\$909.3		\$626.3		\$139,540	5
Natural Gas:	\$7.3000 per MBTU		(\$1,459.6)		\$21.5	\$909.3		\$645.1		\$116,445	6
Oil:	\$1.6600 per gal		(\$1,503.4)		\$22.2	\$909.3		\$664.5		\$92,658	7
			(\$1,548.5)		\$22.9	\$909.3		\$684.4		(\$841,190)	8
			(\$1,594.9)		\$23.5	\$909.3		\$705.0		(\$866,426)	9
Avoided Electrical Costs (turbine output)		Year 1 Avoided units	(\$1,642.8)		\$24.2	\$909.3		\$726.1		(\$892,418)	10
Elec Demand:	\$9.7400 per kW		(\$1,692.1)		\$25.0	\$909.3		\$747.9		(\$919,191)	11
On Peak Energy:	\$0.0411 per kWh		(\$1,742.8)		\$25.7	\$909.3		\$770.3		(\$946,767)	12
Off Peak Energy:	\$0.0335 per kWh		(\$1,795.1)		\$26.5	\$909.3		\$793.4		(\$975,170)	13
			(\$1,848.9)		\$27.3	\$909.3		\$817.2		(\$1,004,425)	14
Avoided Operational Costs		per year	(\$1,904.4)		\$28.1	\$909.3		\$841.8		(\$1,034,558)	15
See Annual Lighting/HVAC Expenses		\$18,580	(\$1,961.6)		\$28.9	\$909.3		\$867.0		(\$1,065,594)	16
			(\$2,020.4)		\$29.8	\$909.3		\$893.0		(\$1,097,562)	17
Deferred Maintenance Costs (\$000)			(\$2,081.0)		\$30.7	\$909.3		\$919.8		(\$1,130,489)	18
Plant renovations	Year 3:	\$1,639.5	(\$2,143.4)		\$31.6	\$909.3		\$947.4		(\$1,164,404)	19
phased over	3 yrs	Year 4:	(\$2,207.7)		\$32.6	\$909.3		\$975.8		(\$1,199,336)	20
		Year 5:	(\$2,274.0)		\$33.6	\$909.3		\$1,005.1		(\$1,235,316)	21
Piping renovations	Year 6:	\$676.9	(\$2,342.2)		\$34.6	\$909.3		\$1,035.3		(\$1,272,375)	22
phased over	5 yrs	Year 7:	(\$2,412.5)		\$35.6	\$909.3		\$1,066.3		(\$1,310,547)	23
			(\$2,484.8)		\$36.7	\$909.3		\$1,098.3		(\$1,349,863)	24
Increased Rents		unit cost	(\$2,559.4)		\$37.8	\$909.3		\$1,131.2		(\$1,390,359)	25
current room-nights:	13,597 per yr	\$22.00	(\$2,636.2)		\$38.9	\$909.3		\$1,165.2		(\$1,432,070)	26
Increase in rate:			(\$2,715.2)		\$40.1	\$909.3		\$1,200.1		(\$1,475,032)	27
Increase in rent:			(\$2,796.7)		\$41.3	\$909.3		\$1,236.1		(\$1,519,283)	28
			(\$2,880.6)		\$42.5	\$909.3		\$1,273.2		(\$1,564,861)	29
Wages & Benefits		unit cost	(\$2,967.0)		\$43.8	\$909.3		\$1,311.4		(\$1,611,807)	30
FTEs:	11	\$53,000	(\$59.9)		\$0.9	\$6.4		\$26.5		(\$26,174,457)	
potential reduction:	11										
			Totals, \$000,000							Totals, \$	