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INTEGRATED ENERGY MASTER PLAN

INDIANA UNIVERSITY - BLOOMINGTON

NOVEMBER 14, 2012

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EXECUTIVE SUMMARY



1 EXECUTIVE SUMMARY

1.1 Overview

1.1.1 In March 2010, Indiana University Issued the "Campus Master Plan". This document focuses on improving the campus grounds, facilities, infrastructure and planning for growth guided by sustainable planning principles. Among these principles is the concept of moving toward a carbon-neutral campus. This report provided broad recommendations for achieving this goal but further investigation was required to identify the specific steps necessary to accomplish this target.

1.1.2 In August of 2010, 8760 Engineering was commissioned to prepare an **Integrated Energy Master Plan** for the Indiana University Bloomington (IUB) campus. The purpose of the Integrated Energy Master Plan is to define and prioritize categories of projects to achieve the most transformative effect on the energy consumption of the IUB campus at the minimum cost and with the highest measure of greenhouse gas emission reduction. This report is to identify a plan for the reduction of energy to best support the ultimate achievement of the goal to move toward a carbon-neutral campus. The Findings, Conclusions and Recommendations of the study that was conducted are summarized in the following paragraphs.

1.2 Findings

1.2.1 Campus Energy Picture and Carbon Footprint

For fiscal year 2010/2011, the total cost of energy consumed on the Indiana University Bloomington campus was $25.6M according to the annual report. This cost includes Electricity, Coal, Natural Gas and Fuel Oil. Carbon emissions released in the generation or combustion of this energy totals 489,895 tons of CO_2.

Table 1.2.1.1: Campus Energy Cost and Carbon Footprint

Energy Source	Energy Cost		Carbon Emissions (tons CO_2)	
Electricity	$18,677,297	73.1%	304,959	62.2%
Coal	$4,263,004	16.7%	165,009	33.7%
Natural Gas	$2,542,489	9.9%	19,623	4.0%
Fuel Oil	$75,282	0.3%	303	0.1%
Total	**$25,558,072**	100%	489,895	100.0%

Through energy simulation and review of building energy metering data, an audit was conducted of a large portion of the Indiana University Bloomington campus. This audit identified that energy is consumed in vastly different ways depending on the building type, age and sources of energy. In general, Table 1.2.1.2 displays the overall splits of energy consumption (by cost and carbon emissions) on campus.

Table 1.2.1.2: Campus Energy Audit by Energy Cost and Carbon Emissions

Energy Load	Cost	Carbon Emissions
Building Lighting	23%	19%
Building Equipment	17%	14%
Building Fans	16%	13%
Heating	17%	26%
Cooling	18%	13%
Heating Losses	7%	10%
Building Losses	4%	5%

While Table 1.2.1.2 suggests that the single largest energy consumer on campus is lighting, other consumers including cooling, heating, fans and building equipment (plug loads, elevators, computers, etc.) are equal players in campus energy consumption. There is no single simple approach to addressing all of these energy demands. Furthermore, overall reduction of energy will require the participation of students and staff to turn lights off and unplug equipment, maintenance personnel to address operation issues and administration to fund projects to bring buildings up to current standards.

1.2.2 Benchmarking of Buildings

When comparing energy metering data and building energy simulation data to the Department of Energy's Commercial Building Energy Consumption Survey (CBECS), it is apparent that buildings on Indiana University Bloomington campus generally utilize more energy on average when compared to similar buildings around the country. These results are not entirely unexpected. While a substantial amount of new construction has been performed in recent years, many of the buildings on campus were constructed in the 1960's and the energy systems serving these buildings are not high performance systems. Furthermore, as part of the survey conducted on this project, 22 buildings were identified that will require capital improvement for building heating and air conditioning systems in the near future.

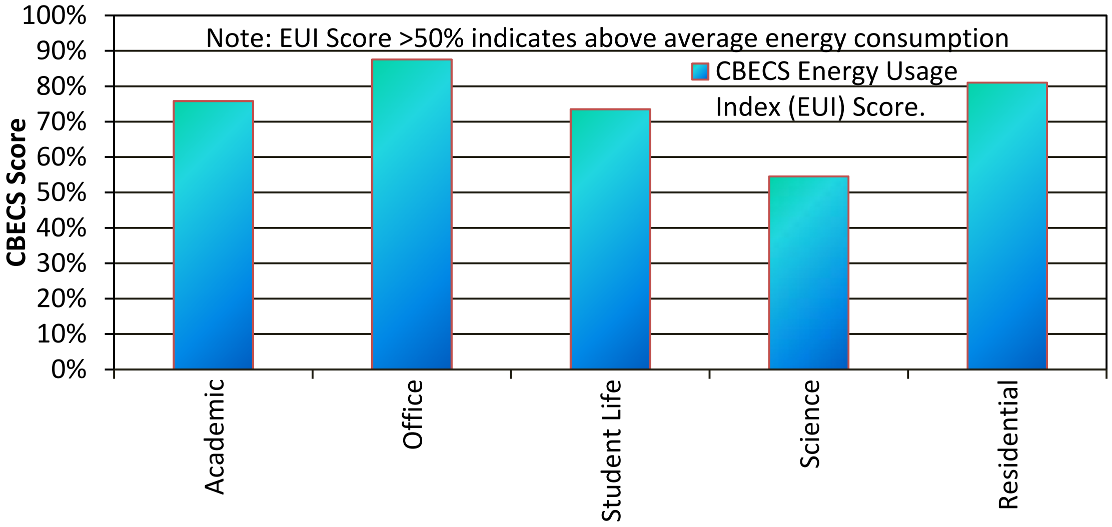


Figure 1.2.2.1: Campus Benchmarking

1.2.3 Utility Distribution

With the exception of the campus steam system, the electric and chilled water distribution systems on campus are in good condition and expected to provide a long service life. However, the campus steam and condensate distribution systems are failing. Review of this system found 4.2 miles of buried piping that is currently in need of replacement. It is estimated that leaks and heat loss associated with these pipes are responsible for $1.8M of energy consumption annually. In order to retain reliable steam service, these piping systems need to be replaced.

1.2.4 Central Plant Age and Condition

The Central Heating Plant is in reasonably good condition considering its age. Substantial investment has been made in the Central Heating Plant in the last few years for the purpose of enabling the plant to operate on either natural gas or coal and to address EPA regulations related to burning coal. During Fiscal Year 2010/2011, coal comprised 92% of fuel burned to generate steam. However, three of the existing boilers (representing more than 50% of the coal boiler capacity) are 50 years old and are nearing the end of their useful life. In February of 2011, the EPA released the Boiler MACT requirements which further restrict allowable emissions from solid fuel fired boilers. Although the timeline of implementation of this regulation is in question, the ultimate cost of complying with these regulations for Indiana University will be in excess of $90 million. Moving forward, we believe the plant will change to a natural gas plant due to both equipment age and the difficulties encountered in replacing coal boilers in compliance with the EPA's rules that exist today.

In general, the majority of the Central Cooling Plant is also in excellent condition. However, there are a number of satellite chillers located around campus that have exceeded their useful life. Although the condition of the central plant chillers is generally excellent, the capacity of the plant has been insufficient to serve the campus peak cooling demand. To address this, additional chillers are being installed such that there will be sufficient cooling capacity during the summer of 2012.

1.3 Conclusions and Recommendations

Based on our observations, calculations, and discussions with IU staff, the following recommendations represent the essence of the Integrated Energy Master Plan identified for the Indiana University Bloomington campus:

1) PREPARE TO STOP BURNING COAL:

a. It is our belief that the Central Heating Plant, either through federal regulatory pressures to limit carbon emissions or tightened EPA requirements on other emissions, will change within the next ten years from a predominately coal fired plant to a plant firing a high percentage or 100% natural gas.

b. It is desirable for the University to retain the multiple fuel sources that they have today to maintain as much operating cost stability as possible. Until a switch has been made at the Central Heating Plant to burn 100% natural gas on a year-round basis, analyze gas and coal costs on a monthly basis to determine which fuel to utilize.

c. When natural gas becomes the prime heating source on campus, the advantages of the large central boiler plant generating steam with coal will largely be eliminated. The campus should plan for replacing the steam system over time with a low temperature heating water system utilizing distributed thermal plants. Such distributed thermal plants should be installed as new buildings are added at the perimeter of the campus, ultimately working inward to sequentially retire buildings from the central steam system. Heat for these thermal plants will be produced utilizing natural gas boilers and technologies including heat and electric cogeneration, geothermal, heat recovery chillers, and solar heating.

d. In lieu of replacing failing steam and condensate distribution piping between the Central Heating Plant and Research Park, implement a phased plan to build a natural gas fired thermal heating plant at Research Park and install building boilers at the Campus View Apartments, Recreational Sports, and the Nelson Halls Residence Administration Building. The design intent of the Research Park plant would be to ultimately convert its operation to both heating and cooling with heat pump chillers to recover the data center heat rejection for providing the heating needs of the other buildings planned for the Research Park Campus as well as the Tulip Tree Apartments.

e. With the exception of the most recently installed gas fired boiler, boiler fuel efficiency at the central plant is less than 70%. When the switch is made to burn 100% natural gas, at least one of the existing boilers will need to be replaced with a more efficient gas fired boiler. The size of this replacement boiler is difficult to predict. As heating load is reduced through energy conservation projects and the construction of satellite heating plants, the appropriate size of this boiler should be determined based on heating needs at that future time.

2) IMPLEMENT ENERGY CONSERVATION PROJECTS

a. Establish a process going forward to make retro-commissioning of the HVAC systems of the major existing buildings on campus a continuous process. Begin the work with the prioritized buildings identified by the report.

b. Aggressively implement energy conservation measures (ECM's) on campus. Utilizing the ECM's described in this report as a guide and target, continue implementing projects through the Qualified Energy Savings Program (QESP) and/or through traditional study/design/bid/build methods. Energy reduction of the existing building stock is essential to making substantial carbon emissions reductions and managing the peak demand on campus infrastructure systems.

c. Even after the implementation of the energy retrofits recommended, a significant electrical base load will exist on the Indiana University Bloomington campus. To offset a portion of this base load, a 7,500 kW gas turbine cogeneration plant with heat recovery boiler should be installed in or near the current Central Heating Plant generating electricity and recovering waste heat from the process to make steam for campus use.

3) REPAIR CAMPUS INFRASTRUCTURE

a. Continue the current effort to selectively replace segments of the existing steam and condensate distribution piping systems due to age and failure potential with new engineered, pre-insulated piping system components. Many of these piping runs are 50 and more years old and should be replaced to reduce distribution heat losses and to improve the reliability of the building systems they serve. Such replacements are necessary because the thermal plants proposed in item 1d above will occur over a period of 15 years or more (with implementation of the Campus Master Plan).

b. Institute a program to survey all steam traps within the buildings on campus. Experience on similar campuses and on the trap surveys conducted on the CHP and the steam distribution systems would indicate that between 10 and 20% of the traps will be malfunctioning and that the cost of the survey and trap replacement will be paid back in less than two years through the energy saved.

c. Continue the current practice of providing metering for the electrical, steam, chilled water, domestic cold water, and natural gas use at each of the major campus buildings. Assemble this data in an energy use database providing rolling annual profiles for benchmarking building consumption against similar buildings and for flagging significant excursions from previous consumption experience.

4) DESIGN MORE EFFICIENTLY

a. Continue requiring LEED certification for all new buildings constructed at the site and for all major renovations (22 buildings were identified as being in need of substantial HVAC capital improvement). Require the building design team to review the first year of actual building energy performance to verify the accuracy of the computer modeling used to achieve the above referenced credits and to identify the source of any significant divergence from predicted consumption.

b. Supplement the current Indiana University Bloomington Design Standards with energy systems requirements for all new buildings and major additions to existing buildings.

c. Although renewable energy implementation opportunities through solar and wind projects are possible, current economics do not support these projects unless other incentives become available. Under best case scenarios, without government incentives, paybacks for photovoltaic are greater than 40 years, paybacks for solar water heating are greater than 20 years and paybacks for large scale wind projects are greater than 12 years. Because the economics of these opportunities are expected to improve, perform an annual analysis of new opportunities for renewable energy implementation for review by the IEMP steering committee with representatives of administration, faculty, staff and students.

d. Continue to monitor the economics of renewable energy technologies in the future and continue to investigate the application of renewable energy technology in new and existing buildings. Consider the inclusion of a renewable energy component into the design of all new projects.

5) ENERGY CONSERVATION THROUGH INVOLVEMENT OF CAMPUS COMMUNITY

a. As indicated in Table 1.2.1.2, the building occupants play a very significant role in energy consumption on campus. Roughly 40% or $10M per year of campus energy consumption can be directly related to the activities and behaviors of the campus community. While eliminating this energy consumption is not possible while continuing the mission of the University, it is certainly possible to reduce this consumption by as much as $3M per year. The University should continue to encourage the behavior changes necessary for the campus community to maximize their role in reducing energy use. Furthermore, the University should support research activities that evaluate the methods of achieving lasting behavioral change for energy conservation.

b. Continue to promote individual and group behaviors in the students, faculty, and staff that reduce energy consumption and promote a sustainable ethic that will permeate the campus community and beyond. Programs such as the Energy Challenge, the Sustainability Internship Program, and the Green Teams have been key elements in these efforts. Continue and expand these functions to include guidelines for sustainable laboratory practices, guidelines for sustainable office practices, and regular re-evaluation of campus IT practices to use the latest technology to minimize energy and paper use.

c. In order to keep energy conservation in the minds of the campus community, prepare an awareness campaign to inform the community. This campaign should include installation of video dashboards at the main entrance of each building on campus to report instant energy usage data as well as display tracking data for the past comparable periods. These dashboards would also educate and inform the community of campus energy initiatives.

6) ACCOUNTABILITY

a. Even with the most aggressive implementation program, achieving the goals identified in this document will require more than 10 years to implement. Tracking the progress to achieving these goals in a systematic way will be necessary to ensure that progress is made over the long term. As part of this plan, an annual report should be issued to the campus community that tracks the progress toward achieving the goals of this plan. This report should summarize the utility consumption (electricity and fuel) on a building by building basis, should track annual carbon emissions, identify renewable energy sources on campus and quantify the energy output of these systems, identify new renewable energy opportunities and economics, and would summarize the activities that are being performed to achieve energy reduction.

Of the recommendations listed above that involve substantial capital investment, Table 1.3.1 summarizes these major Integrated Energy Master Plan initiatives. When completely implemented, these initiatives will cost an estimated $82.6M to implement, reduce annual energy costs by $9.7M per year, and will reduce carbon emissions due to energy use by 52%.

Table 1.3.1: Recommended Integrated Energy Master Plan Initiatives

Project Description		Project Type	Annual Energy, Consumables and Maintenance Cost[1]	Implementation Cost	Annual CO_2 Savings (tons)
Existing Campus		NA	**$ 26,080,000**	**NA**	**496,000**
1	Retro-Commissioning	Energy	$ (910,000)	$ 3,270,000	-27,000
2	Building Energy Conservation Measures	Energy	$ (5,740,000)	$ 44,920,000	-105,000
4A	Selective Retrofit for Central Steam and Condensate Distribution Systems (not including East Main)	Capital Improvement and Energy	$ (950,000)	$ 10,600,000	-28,000
4C	Abandon 10" East 150 psig Steam Main; Replace with Hot Water Boilers and Heating Water Distribution System from the Main Split to Research Park	Capital Improvement and Energy	$ (480,000)	$ 5,310,000[2]	-22,000
9A	Install Natural Gas Cogeneration System at the CHP	Energy	$ (1,790,000)	$ 18,480,000	-58,000
		M&R	$ 310,000		
5B	Revised Central Steam Plant Firing Strategy; 100% Natural Gas with Staff Reductions	Energy	$ 190,000		-20,000
		M&R	$ (360,000)		
Project Subtotals			$ (9,730,000)	$ 82,580,000	-260,000
Existing Campus			$ 26,080,000		496,000
Campus After Implementation of IEMP			**$ 16,350,000** **(37% Reduction)**		**236,000** **(52% Reduction)**

Notes:

[1] Savings based on FY 10/11 estimated average utility costs and carbon emission rates. Annual Cost Reduction includes Energy Cost, Maintenance and Repair Cost and consumables related to the use of coal.

[2] Installing distribution piping in shallow tunnels increases cost by $2,290,000.

DEFINITIONS AND ASSUMPTIONS

2 DEFINITIONS AND ASSUMPTIONS

2.1 Introduction

2.1.1 With the adoption of the 2010 Indiana University Bloomington Master Plan, President McRobbie and the IU Board of Trustees have made energy conservation one of the highest priorities of the University. In response, the University is pursuing efforts to conserve energy through four main approaches, related in outcome but dissimilar in the cost and complexity of implementation. These approaches to saving energy in order of increasing cost and complexity are:

- Energy conservation at the individual personal level. This may range from an individual turning off lights when not in use, to groups of individuals participating in the Energy Challenges, to campus wide policies for reducing the energy consumption of computers, printers, and peripherals when not in use. These initiatives save energy quickly and are low in overall cost to implement, but the persistence of their savings is determined by their degree of acceptance into the University culture.
- Energy conservation from the retro-commissioning of the heating, ventilating and air conditioning (HVAC) systems in campus buildings. This is the arduous process of systematically checking the major energy consuming systems in existing IUB buildings to assure that these systems are functioning as designed and intended. These activities may involve correcting inoperative valves and actuators or altering temperature control sequences that have malfunctioned over time. The energy savings from these changes can be substantial as they often correct the simultaneous use of cooling and heating that may be “silently” wasting energy without the occupant’s knowledge. This process is more expensive than energy conservation at the personal level. Retro-commissioning is time consuming and requires individuals to perform these services that are skilled in the technology of building HVAC systems.
- Energy conservation through Qualified Energy Savings Projects. These are projects that involve basic modifications to the HVAC and electrical systems in existing buildings to reduce energy consumption. Often called Energy Conservation Measures (or ECM’s), these measures may take the form of replacing existing lighting with more efficient lighting, the addition of heat recovery systems to reclaim heat normally lost in the space conditioning process, and basic changes in the arrangement and control of the existing HVAC systems. These changes are significantly more expensive than the previous options and may require up to 10 years of reduced operating costs to offset the initial capital investment.

- Energy conservation through longer term, higher capital cost projects that are more transformative to campus energy consumption. These projects may take the form of utilization of solar energy or biomass fuels for generating heating, solar energy or wind energy for the generation of electricity, or the use of cogeneration facilities on campus to generate electricity, heating, and cooling at lower cost with a more benign impact on the environment.

2.1.2 The purpose of the Integrated Energy Master Plan that is embodied in these pages is to define and prioritize these four categories of projects to achieve the most transformative effect on the energy consumption of the IUB campus at the minimum cost and with the highest measure of greenhouse gas emission reduction. The goals of the Campus Sustainability Report are clear; the purpose of this report is to identify a plan for the reduction of energy to best support the ultimate achievement of these goals.

2.2 Review of Previous Reports

2.2.1 In an effort to understand the characteristics of the existing energy utility systems on campus, the magnitude of use and the conditions and cost of service of the various utilities that serve the campus, the sustainability goals that have been addressed, and the plans for University growth that are envisioned in the future, the following reports were obtained and reviewed. These documents are the basis of our understanding of the existing energy systems, the current cost of operation of these systems, and the greenhouse gas (GHG) emissions impact resulting from energy systems operations.

- Indiana University Bloomington Campus Master Plan, March 2010, prepared by SmithGroup JJR
- The Indiana University Physical Plant Bloomington Annual Reports from 2007-2008, 2008-2009, 2009-2010, and 2010-2011.
- The Indiana University Utility Master Plan, Final Report, February 2003 prepared by Sebesta Blomberg & Associates, Inc.
- The Initial Campus GHG Inventory, Towards Carbon Neutrality at Indiana University, 2008, prepared by Jonathan Brooks Bell
- The updated Campus Greenhouse Gas Inventory, August 2010, prepared by Melissa Greulich

2.2.2 In addition, numerous documents were obtained from the Department of Physical Plant and the Utility Information Group documenting the costs and operating conditions of many of the energy systems serving the campus. This data was invaluable to our understanding of the site and for the preparation of this report.

2.3 Detailed Data Sample Buildings

2.3.1 The Bloomington campus of Indiana University consists of over 500 buildings on almost 2,000 acres. The vast majority of these buildings are conditioned year-round, with either central heating and cooling systems or individual systems housed within the building or building group. The energy consumption of these individual buildings is the key driver of the total campus energy needs and therefore is a significant target of the current study. Yet many of the facilities included on the building list are quite small, with HVAC and electrical systems that are residential in nature.

2.3.2 In an effort to reduce the data from this extensive building portfolio into a more manageable size while still capturing the bulk of the campus energy consumption, the following technique was employed. To capture over 80% of the campus energy use while considering the fewest number of buildings, a small group of buildings was designated as the Detailed Data Sample (DDS) buildings. Such buildings were arbitrarily defined as having the following characteristics:

- Buildings and parking garages of all ages that are served by any of the central plant systems (steam, chilled water, and electricity) having an area greater than 20,000 ft^2
- Buildings and parking garages of all ages over 50,000 ft^2 whether or not they are they are served by any of the central plant systems
- Not scheduled for demolition in the Campus Master Plan
- Does not include the Cyclotron

2.3.3 Review of the campus building list revealed that 104 buildings would be included in this data set based on the characteristics described above. As indicated in Table 2.3.1 below, the DDS Buildings account for just over 82% of the gross campus building area and capture all of the energy intensive buildings on campus except for the Cyclotron. Table 2.3.2 lists the DDS Buildings that were considered.

Table 2.3.1: IUB Building Statistics for the Detailed Data Sample

Indiana University Bloomington - Facts	Indiana University Fact Book 2010-2011	8760 Engineering Building Database	8760 Engineering Detailed Data Sample Buildings
Acreage	1,937	-	-
No. of Buildings	551	554	104
Gross Area (ft^2)	16,249,500	16,870,586	13,840,908
Assignable Area (ft^2)	10,158,205	10,582,250	-

2.3.4 These 104 buildings were studied for current metered energy use as well as modeled to determine an approximate audit of the current energy consumption of these facilities. Using this model, classes of energy conservation measures were simulated to determine the effect on the campus energy needs with the best system arrangement put forward to serve these needs.

Table 2.3.2: Detailed Data Sample Buildings

Building Code	Building Description	Gross Area (ft^2)	Building Code	Building Description	Gross Area (ft^2)	Building Code	Building Description	Gross Area (ft^2)
BL209	Wells Library	557,163	BL009	Poplars Parking	136,402	BL276A	Hickory Hall	63,414
BL601	Memorial Stadium	472,398	BL172	Lee Norvelle Theatre Drama/ Neal&Mars	135,627	BL276D	Linden Hall	63,414
BL053	IN Memorial Union	439,018	BL423	Multi Science 2	131,074	BL276G	Pine Hall	63,414
BL603	Assembly Hall	381,106	BL615	IU Warehouse	130,746	BL316	408 N Union St	60,229

Building Code	Building Description	Gross Area (ft^2)	Building Code	Building Description	Gross Area (ft^2)	Building Code	Building Description	Gross Area (ft^2)
BL227	Read Hall	359,658	BL441	McNutt South	129,665	BL059	Lindley Hall	59,910
BL313	Eigenmann Hall	349,442	BL452	SPEA	128,619	BL141	Memorial Hall	58,578
BL107	Jordan Hall	324,279	BL417	Geological Sciences	126,422	BL147	Merrill Hall	58,322
BL111	Ballantine Hall	305,420	BL148	Music Addition	122,165	BL602	Tennis Center	57,708
BL243	Teter Quad	300,873	BL297	Willkie B	120,091	BL614	ALF-Ruth Lilly Auxiliary Library	55,824
BL237	Wright Quad	295,887	BL301	Willkie A	119,951	BL139	Morrison Hall	53,989
BL257	Forest Quad	289,014	BL153	Art Museum	119,314	BL155	Lilly Library	52,516
BL433	Briscoe Quad	279,424	BL157	Fine Arts	115,554	BL418	Geological Survey	52,361
BL529	Campus View Apartments	267,723	BL453	Harper Hall	109,147	BL005	Bryan Hall	51,436
BL177	Musical Arts Center	267,130	BL072	Chemistry Addition	106,551	BL454	Gresham Dining Hall	50,888
BL555	Tulip Tree Apts	263,003	BL604	Gladstein Fieldhouse	103,427	BL276B	Birch Hall	42,460
BL475	Recreational Sports	253,302	BL150	Music Studio	101,348	BL276E	Cypress Hall	42,460
BL171	Auditorium	238,364	BL595	Mellencamp Pavilion	100,282	BL067	Rawles Hall	42,017
BL451	Business School	238,158	BL158	Radio-TV	99,373	BL455	Shea Hall	42,003
BL181	Simon Msc Lbr Rec	231,539	BL065	Optometry School	94,228	BL463	Nelson RPS Admin.	40,453
BL448	Fee Lane Pkg Garage	223,279	BL276C	Cedar Hall	92,198	BL563	Innovation Center	39,871
BL063	Henderson Parking Garage	205,012	BL299	Willkie C	85,302	BL075	Ernie Pyle Hall	38,292
BL199	Jordan Ave Parking	194,648	BL445	Central Heating	84,020	BL109	Goodbody Hall	37,522
BL069	Atwater Parking	193,084	BL672	Food Storage	81,273	BL461	Magee Hall	37,064
BL450	Godfrey Grad&Exec Ed Ctr	191,743	BL579	Data Center	81,186	BL456	Martin Hall	37,063

Building Code	Building Description	Gross Area (ft^2)	Building Code	Building Description	Gross Area (ft^2)	Building Code	Building Description	Gross Area (ft^2)
BL245	Wendell W. Wright	191,111	BL630	Service Bldg	78,452	BL462	Jenkinson Hall	36,896
BL119	HPER Building	189,776	BL439	McNutt Central	78,264	BL058	Kirkwood Hall	36,450
BL071	Chemistry	183,387	BL101	Myers Hall	76,521	BL061	Swain East	35,609
BL001	Law	170,098	BL149	Sycamore Hall	74,602	BL045	Cravens Hall	35,040
BL419	Psychology	155,246	BL133	Woodburn Hall	73,257	BL057	Wylie Hall	33,513
BL027	Swain West	154,602	BL664	IU Research Park	71,120	BL407	DeVault Alumni Center	32,563
BL437	McNutt North	153,143	BL017	Student Building	69,737	BL033	Maxwell Hall	31,091
BL008	Poplars	150,420	BL607	Cook Hall	69,441	BL304	Mason Hall	24,717
BL091	Wildermuth Center	141,341	BL043	Edmondson Hall	68,588	BL047	Smith Hall	22,621
BL070	Simon Hall (Science)	141,094	BL467	Health Center	64,656	BL055	Owen Hall	20,148
BL007	Franklin Hall	138,149	BL276F	Beech Hall	63,415		Total Area =	13,840,908

2.4 Energy Data Considered

2.4.1 Four years of detailed energy consumption data were obtained for the IUB buildings with one year defined as the University fiscal year of July 1st through June 30th of the following year. The years considered were:

FY 07-08	July 1, 2007 through June 30, 2008
FY 08-09	July 1, 2008 through June 30, 2009
FY 09-10	July 1, 2009 through June 30, 2010
FY 10-11	July 1, 2010 through June 30, 2011

2.4.2 The four years of data obtained were to determine unusual variations that may have occurred in individual buildings throughout this period. The weather in Bloomington for these four years is indicated in Table 2.4.1. Degree Days for both the heating and cooling seasons are relative to a 65° F outdoor air temperature.

Table 2.4.1: Fiscal Year 2007 through 2011 Weather Comparison
Bloomington, Indiana Weather

	ASHRAE Average	FY 07-08	FY 08-09	FY 09-10	FY 10-11
Heating Degree Days	5,322	5,297	5,592	5,553	5,531
Cooling Degree Days	1,055	1,183	1,175	1,107	1,469

2.4.3 Heating degree days for the four years of energy consumption data obtained are relatively constant with the maximum deviation from historical average at + 5.1% in FY 08-09. Cooling degree days varied considerably more with a maximum deviation from historical average of + 39.2% in FY 10-11. Of the four years of detailed energy consumption data obtained, FY 09-10 was closest to the historical average (+ 4.9%).

2.4.4 Coal and natural gas compositions for the actual fuel delivered were obtained during FY 09-10 and these specific characteristics were used in the calculations to determine the rate of greenhouse gas emissions.

2.5 Greenhouse Gas Emissions Considered

2.5.1 Greenhouse gas (GHG) inventories were identified earlier for the Indiana University Bloomington campus in 2008 and again in 2010. These inventories were based on a set of accounting standards jointly established by the World Business Council for Sustainable Development and the World Resource Institute, and embodied in the Cool Air-Cool Planet Campus Carbon Calculator software. These standards divide GHG emissions into the three broad categories enumerated below:

- Scope 1 Direct Emissions – Direct emissions from sources that are owned and/or controlled by the University.
    a) On-Campus Stationary Sources – Emissions from on-campus combustion in boilers, furnaces, and other fossil-fueled combustion processes but not including vehicle fuels
    b) Direct Transportation Sources – Emissions from fuel combustion in vehicles owned by the University
    c) Refrigeration and other Chemical Sources – Emissions from fugitive refrigerant leaks or other chemicals expelled into the atmosphere at the site
    d) Agriculture Sources – Emissions from fertilizer use and methane released from animals housed on site

- Scope 2 Indirect Emissions – Emissions from sources that are neither owned nor operated by the University but that produce a commodity that is linked to on-campus energy use.
    a) Purchased Electricity – Emissions created in combustion processes by power companies off-site to generate electricity for campus use.
    b) Purchased Steam – Emissions created from the production of steam that is purchased from an off campus source (not applicable for IUB since all steam is generated on-campus and appears as a Scope 1 Direct Emission.)
    c) Purchased Chilled Water - Emissions created from the production of chilled water that is purchased from an off campus source (not applicable for IUB since all chilled water is generated on-campus and appears as a Scope 2 Indirect Emission of purchased electricity.)

- Scope 3 Indirect Emissions - Emissions from sources that are neither owned nor operated by the University but that are either financed or otherwise linked to the University.
  a) Solid Waste – Emissions resulting from managing waste produced by the University such as incineration or land filling.
  b) Directly Financed Transportation – Emissions from travel by staff or students financed by the University but not occurring in University owned vehicles such as airline travel and reimbursed travel in personal vehicles.
  c) Commuting – Emissions resulting from regular commuting by faculty, staff, and students to and from campus
  d) Study Abroad Air Travel – Emissions resulting from student travel to study abroad at University designated locations
  e) Transportation and Distribution Losses from Purchased Energy – Emissions associated with losses resulting from the transportation of electricity, steam, or chilled water to the campus (Only losses from purchased electricity apply for IUB.)
  f) Upstream Emissions from Directly Financed Purchases – Emissions associated with paper production, food production, or fuel extraction losses.

2.5.2 The purpose of the Integrated Energy Master Plan was never to duplicate or update the campus GHG inventories developed earlier. Rather, the purpose of the IEMP is to set forth a plan to reduce energy use and cost while simultaneously reducing the carbon impact of campus energy use. With the aggressive carbon reduction goals set forth by the IUB Campus Master Plan, such reductions will represent a critical contributor to the success of these endeavors. For the purposes of this study, our focus was limited to Scope 1a and Scope 2a emissions for the campus. Based on the 2010 GHG Inventory for the campus, these two components represented about 77% of the current campus GHG emissions.

2.5.3 As an engineering study, the approach to GHG emissions in this report is based on the most fundamental engineering concepts and relies to the minimal extent possible on generally accepted emission factors. Emission factors presented here are generally limited to those derived from the most fundamental of scientific principles and calculations. This approach will differ from accepted techniques of GHG measurements in several ways.

2.5.3.1 The study focuses only on carbon dioxide (CO_2) as the greenhouse gas of significance. Often, emissions quoted in the literature are based on equivalent carbon dioxide (eCO_2) from the six greenhouse gases mentioned in the Kyoto Protocol. Such emission values are obtained by multiplying the quantity of the GHG emitted from the particular process multiplied times its global warming potential (GWP) relative to carbon dioxide. For the combustion processes involved in the Scope 1a and 2a emissions considered in this study, the greenhouse gases of concern are limited to carbon dioxide, methane (CH_4) and nitrous oxide (N_2O). The generation of methane and nitrous oxide from combustion occur due to complex factors related to the specifics of the combustion process and cannot generally be calculated from basic principles and fundamental combustion calculations. Table 2.5.1 indicates that the error caused by calculating emissions in terms of CO_2 instead of eCO_2 is less than 1%. Therefore in this study, our measure of GHG emissions will be in units of pounds of CO_2 emitted.

2.5.3.2 Acceptance of item 2.5.3.1 above allows customized combustion calculations based on the fundamental chemical equations of combustion to determine the emissions for the specific composition of the coal and natural gas utilized at the IUB campus (rather than using regional average values). The factors described in this report are therefore specific to the IUB campus.

Scope 2a emissions are likewise calculated from the specific emission factors for Duke Energy Indiana (rather than using regional average values).

2.5.3.3 Emissions are generally presented in units customarily seen in US engineering calculations, e.g., lbs CO_2/MMBtu or lbs CO_2/kWh (where an MMBtu = 10^6 Btu of fuel consumed and a kWh = kilowatt-hours of electricity generated). If tons are referred to, they are in the units of US short tons equal to 2,000 lbs (not MT or metric tonnes of 2,204.6 lbs) unless otherwise noted. Savings will always be stated in customary energy units so that differing units or emission factors may be utilized based on the purpose of future calculations.

Table 2.5.1: Comparison of CO_2 and eCO_2 Emissions Factors

Emission Source	**CO_2 Emission Factors**		**eCO_2 Emission Factors**		**eCO_2 Emission Factors - Consistent Units**		**Error**
Electricity	0.697543	kg CO_2/kWh	0.000702	MT eCO_2/kWh	0.7020	kg CO_2/kWh	-0.63%
Coal	1912.357	kg CO_2/ton	1.927269	MT eCO_2/ton	1927.2690	kg CO_2/ton	-0.77%
Natural Gas	52.75574	kg CO_2/MMBtu	0.052919	MT eCO_2/MMBtu	52.9190	kg CO_2/MMBtu	-0.31%
No. 1 Fuel Oil	9.987005	kg CO_2/gallon	0.010049	MT eCO_2/gallon	10.0490	kg CO_2/gallon	-0.62%

Source: ***Clean Air - Cool Planet, Campus Carbon Calculator, Version 6.6***

FUEL AND ENERGY SOURCES

3 FUEL AND ENERGY SOURCES

3.1 Fuel Characteristics, Cost, Consumption, and CO_2 Emissions

In this section, each of the major fuels utilized on site will be reviewed including their composition, base year cost, current year cost, and projected future costs, as well as the carbon dioxide emissions resulting from their combustion. In addition, the consumption and annual cost for the base year of FY 09-10 will be established. (It should be noted that IUB uses propane in very small quantities at locations off the main campus. Due to its limited use, propane consumption was not considered in our analysis.)

3.1.1 Coal

3.1.1.1 Coal has been used as a primary heating source for the Indiana University Bloomington campus for many years. When the first portion of the Central Heating Plant Building was constructed in 1954, two 64,000 lb/hr coal fired boilers were installed. Though the Central Heating Plant (to be discussed in greater detail in a subsequent section) currently has the capacity to serve the site solely with natural gas, coal has continued to predominate in recent years as the primary source of heat energy for the campus.

3.1.1.2 Coal for the Central Heating Plant is obtained under contract from the Black Beauty Coal Company, a subsidiary of Peabody Energy. The coal that is obtained is a bituminous coal brought in by truck from the Bear Run Mine in Sullivan County, southwest Indiana in an area known as the Illinois Basin. The composition of this coal for the base year of FY 09-10 is indicated in Table A3.1.1.1 in Appendix A. (The software that accompanies this report includes the spreadsheet calculations indicated in this table for future calculations of emissions when coal composition is known). The coal burned is relatively high in sulfur content but the negative aspects of sulfur dioxide (SO_2) in the effluent gases are reduced through the flue gas treatment system installed recently. A summary of the coal data derived from Table A3.1.1.1 for FY 09-10 is summarized below.

- Average Heat Content (HHV) = 11,897 Btu/lb (As-Received)
- Carbon Content = 72.15% (Moisture Free Basis)
- Sulfur Content = 2.44% (Moisture Free Basis)

- Carbon Dioxide Emissions from Combustion = 202.5 lb CO_2/MMBtu Fuel Consumed

3.1.1.3 During FY 09-10, 69,250 tons of coal were consumed with a total heat content of 1,647,734.5 MMBtu. The combustion of this coal released 333,666,236 lb CO_2 into the atmosphere. For FY 09-10, the cost of the coal delivered and consumed at the site was $3,574,685 at a unit cost of $51.62/ton or $2.17/MMBtu. Other plant costs such as ash removal and disposal, chemicals, and supplies are not included in these costs but will also be considered in more detail in a later section. The current, three year contract with Peabody Energy is in its second year with prices for coal, including delivery, set as follows:

Year	**Time Period**	**Delivered Cost/ton**	**Cost Increase vs. FY 09-10 ($51.62/ton)**
Year No. 1	8/1/2010 through 6/30/2011	$60.78	17.70%
Year No. 2	7/1/2011 through 6/30/2012	$62.60	21.30%
Year No. 3	7/1/2012 through 6/30/2013	$64.48	24.90%

For FY 10-11, the delivered cost of coal was $62.24/ton.

3.1.1.4 This rate also has a fuel adjustment charge based on the cost of No. 2 Diesel Fuel used for transporting the coal that goes into effect when No. 2 Diesel Fuel exceeds $2.75/gallon. The fuel adjustment for early 2011 added an additional $4.06/ ton of coal delivered ($60.78 + $4.06 = $64.84/ton of coal delivered).

3.1.1.5 Costs over this three year contract increase at the rate of 3.0% per year. The US Energy Information Administration projects that the cost of coal at the mine mouth will rise relatively slowly through 2035. The average projected growth of delivered coal prices is currently projected at an average increase of 2.0% per year through 2035 with certain geographic areas varying above and below this value based on delivery technique.

3.1.2 Natural Gas

3.1.2.1 Natural gas used at the IUB site is considerably more complex than coal in terms of the rates at which it is purchased and the number of entities involved in obtaining it. In general, pipeline gas is purchased from Energy USA, a natural gas marketer and energy manager. The natural gas is then delivered to the campus by the Indiana Gas Company, Inc. D/B/A Vectren Energy Delivery of Indiana, Inc. or simply Vectren North. The larger users (using 2,000 MMBtu or above per year) receive pipeline gas from Energy USA with delivery by Vectren North. Smaller users obtain both natural gas and delivery service from Vectren North. Based on the magnitude of natural gas consumed and the nature of the facility it is delivered to, a total of four different Vectren North rate structures are involved in providing gas to campus. These are:

Rate 220 – General Sales Service
These are the smaller facilities that receive gas and delivery service from Vectren North only (no Energy USA bill)

Rate 225 – School Transportation Service

This is a school pooling rate with transportation services provided by Vectren North and pipeline gas provided by Energy USA. This is a slightly higher gas rate with most of the gas purchased on the cash market.

Rate 245 – Large General Transportation Service
Rate for larger buildings with an annual usage of 50,000 to 500,000 therms and a maximum daily use of 15,000 therms or less; gas for this rate is purchased on the hedge market from Energy USA but still delivered to the site by Vectren North.

Rate 260 – Large Volume Transportation Service
Rate applicable for only the Central Heating Plant; requires an annual usage of greater than 500,000 therms or a demand of greater than 15,000 therms per day. Gas for this rate is purchased on the hedge market from Energy USA but still delivered to the site by Vectren North. The service is interruptible but IUB pays Vectren North approximately $190,000 annually for a 60,000 MMBtu storage reserve in case of interruption.

3.1.2.2 The cost per MMBtu of these rates vary considerably. For FY 10-11, the campus used 333,161.1 MMBtu of natural gas for a total cost of $2,542,489 and an average cost of $7.63/MMBtu. However, comparing the Central Heating Plant natural gas costs to the remainder of campus for this period show significantly different costs as indicated below:

Portion of Campus	Total Natural Gas Use	Total Cost	Average Cost
Central Heating Plant	140,767.0 MMBtu (42%)	$913,437	$6.49/MMBtu
Remainder of Campus	192,394.1 MMBtu (58%)	$1,629,052	$8.47/MMBtu
Campus Total	333,161.1 MMBtu (100%)	$2, 542,489	$7.63/MMBtu

3.1.2.3 The average cost of natural gas for the Central Heating Plant will be used in the calculation of the marginal cost of steam for FY 10-11 in the energy reduction calculations that follow. For campus buildings not served by campus steam, natural gas costs will be based on the average cost for the remainder of campus.

3.1.2.4 Based on data provided from Vectren North, the natural gas arriving at the IUB campus comes from two main sources:

- Panhandle Eastern Pipeline (Mainline Tuscola East Station)
- Texas Gas Transmission Pipeline (Lebanon Station)

3.1.2.5 For the purpose of the emissions calculations, it was assumed that each of these sources represented 50% of the gas delivered to campus. Thus, the composition of the natural gas for FY 09-10 is indicated in Table A3.1.2.1 in Appendix A reflecting the composition of gas delivered from the two pipeline sources indicated above. (The software that accompanies this report includes the spreadsheet calculations indicated in this table for future calculations of emissions when natural gas composition is known). These calculations indicate that the average carbon dioxide emission factor for the natural gas burned during FY 09-10 was 117.8 lb CO_2/MMBtu.

3.1.2.6 The US Energy Information Administration projects that the cost of natural gas as measured by the Henry Hub Spot Price will increase at an annual average of 4.06% through 2035. The average projected growth of delivered natural gas prices is currently projected at an average increase of 3.13% per year through 2035.

3.1.3 Fuel Oil

3.1.3.1 Fuel oil is used in very limited quantities at the IUB campus and is purchased from the White River Cooperative. It is used as a back-up fuel source for several of the boilers at the Central Heating Plant. The fuel is produced at the County Mark Mount Vernon Refinery with a heat content of approximately 138,000 Btu/gal. For FY 10-11, total campus use was as indicated below:

Location of Use	Quantity Used	Heat Content (MMBtu)	Cost	Average Cost
Central Heating Plant	9,100 gal	1,255.8 MMBtu	$20,930	$16.67/MMBtu
Remainder of Campus	18,440 gal	2,544.7 MMBtu	$54,352	$21.36/MMBtu
Total for Campus	27,540 gal	3,800.5 MMBtu	$75,282	$19.81/MMBtu

3.1.3.2 The average cost of fuel oil for the Central Heating Plant will be used in the calculation of the marginal cost of steam for FY 10-11 in the energy reduction calculations that follow. For campus buildings not served by campus steam, fuel oil costs will be based on the average cost for the remainder of campus.

3.1.3.3 Emissions for the combustion of fuel oil were assumed to be a nominal value of 159.6 lb CO_2/MMBtu.

3.2 Electricity Source, Cost, Consumption, and CO_2 Emissions

3.2.1 For FY 10-11, electrical energy consumption for the IUB main campus is described in the following summary:

Portion of Service	Demand	Energy Use	Cost	Average Cost
Master Meters	42,049 kW	241,000,615 kWh (82%)	$15,026,455	$0.0624/kWh
Isolated Meters	-	51,245,933 kWh (18%)	$3,650,842	$0.0712/kWh
Total Main Campus	42,049 kW	292,246,548 kWh (100%)	$18,677,297	$0.0639/kWh

3.2.2 Electrical demand for the Master Meters in FY 10-11 varied from a monthly maximum peak of 42,049 kW in September 2010 to a monthly minimum peak of 27,223 kW in January of 2011. However, the true minimum demand was measured between 12/24/2010 and 12/26/2010 at 18,857 kW on 12/25/2010.

3.2.3 All electricity for the IUB main campus is obtained from Duke Energy Indiana, Inc. except for:

- A maximum of 250 kW of electrical power obtained through electrical generation at the Central Heating Plant. Electricity is generated here through the use of a steam micro-turbine receiving 150 psig boiler steam and operating at 40 psig back-pressure in parallel with the steam pressure reducing station providing 40 psig steam to a large portion of the campus,

- Approximately 46 kW of electrical power obtained from photo-voltaic collectors on campus at the Tulip Tree Apartments and at Briscoe.

(Several remote buildings are served by Duke Energy Indiana and other utility providers but these are not included in the data presented here.) A large portion of the main campus is served from five high voltage (12.47 kV) Duke Energy master meters with power purchased under a real time pricing tariff designated as Rate HPNO. The letters of the rate indicate it is applicable for High Load Factor, Primary Service Voltage, No Meter Adjustments, and Normal Service. In addition to the master meters, a number of buildings are also served from Duke Energy Indiana but with separate connections and meters that are not a portion of the master meters and their real time summing of demands. These isolated metered buildings fall under several rate classifications depending on their size and the voltage at which they are served, but their costs and consumption were considered part of the main campus.

3.2.4 Electrical costs from Duke Energy Indiana for FY 10-11 were expected to rise by 8% over FY 09-10 but ultimately, the average cost only increased by about 1.6. Similarly, Duke is suggesting a 7% to 12% rate increase for HLF customers like IUB for 2012 relative to 2010. In sharp contrast, the US Energy Information Administration projects that the end use, delivered costs of electric service measured in 2009 dollars will remain flat or even fall by several tenths of a percent through 2035. However, the current Duke Energy Indiana rates are below the national average and thus may be subject to increases beyond those expected for the US average.

3.2.5 Several sources were accessed to determine the emissions that result from the generation of a kWh of electricity delivered to the IUB campus. Based on any of these sources, Scope 2 emissions from the generation of electricity used on site represents the largest single source of carbon emissions for Indiana University Bloomington. Thus the establishment of a proper emission factor for electrical generation will be an important parameter in gauging the success of the campus sustainability effort. This emission factor can be viewed from several perspectives with each yielding a slightly different result. Table 3.2.1 indicates a summary of the resources consulted in pursuit of the proper emission factor to describe electricity for the IUB campus.

3.2.6 Clearly, the simplest approach would be to adhere to the Clean Air – Cool Planet database that was utilized in the preparation of the Campus Carbon Inventories for 2008 and 2010 described earlier with a custom fuel mix selected for electrical generation. However, as can be seen from Table 3.2.1, in 2006 there was a change in the region to which Indiana was assigned by the North American Electrical Reliability Corporation (NERC) essentially reducing the emission factor for electrical generation by over 24%! Since both of the carbon inventories for the IUB campus were completed post 2006, this would appear to be the correct factor to use (1.538 lb CO_2/kWh). However it is clear from every resource consulted that the State of Indiana and Duke Energy Indiana rely very heavily on coal for electric generation. If the State were furnished with electricity generated 100% by coal, the proper theoretical emission factor for electrical generation would be approximately 2.19 lb CO_2/kWh, much closer to the pre 2006 Clean Air – Cool Planet value. After considerable discussion, we recommend for this study that the most current value available from Duke Energy Indiana, 2.087 lb CO_2/kWh be utilized to represent current emissions due to electrical generation. If renewable energy becomes a more prevalent portion of the Duke Energy Indiana source portfolio, then the University should take that reduction into account along with reductions made on campus.

Table 3.2.1: Carbon Dioxide Emissions from Electrical Generation

Date	Source	lbs CO_2/kWh	Website	Software	Comments
2006 and Before	Clean Air - Cool Planet Database	2.028	www.coolair-coolplanet.org	v6.6	Data Based on NERC Zone ECAR Ohio Valley
Post-2006	Clean Air - Cool Planet Database	1.538	www.coolair-coolplanet.org	v6.6	Data Based on NERC Zone RFCW
2009	Energy Information Administration	2.100	www.eia.gov	-	State of Indiana Electricity Profile
2007	Carbon Monitoring for Action	1.965	www.carma.org	-	State of Indiana Electricity Profile
2007	Carbon Monitoring for Action	1.856	www.carma.org	-	Duke Energy Indiana Inc.
2010	Jeff Honaker, Duke Energy Indiana Inc.	1.990	-	-	Duke Energy Indiana Inc.
2011	Duke Energy Carbon Calculator	2.087	www.duke-energy.com/indiana	-	Duke Energy Indiana Inc.

3.3 Comparison of Study Emissions to 2010 IUB Carbon Inventory

3.3.1 The following Tables 3.3.1, 3.3.2, and 3.3.3 compare the emissions calculated for the current study to the results of the 2010 campus carbon inventory. For clarity in these comparisons only, CO_2 emissions are stated in metric tonnes (MT) as opposed to US short tons. The obvious differences are:

- The Scope 1 emissions in the current calculations are based on the actual fuel composition for the coal and natural gas burned on campus and,
- Scope 2 emissions are considerably higher in the current study because of what we believe to be the most accurate emission factor for the generation of electricity used on the IUB campus.

Table 3.3.1: FY 10-11 Emissions Due to Energy Systems Operation

Campus Emissions Sources		Total Consumption		Total CO_2 Emissions		CO_2 Emissions in MT
Scope 1	Coal	1,629,722.4	MMBtu	330,018,786	lbs CO_2	149,695.5
	Natural Gas	333,161.1	MMBtu	39,246,378	lbs CO_2	17,802.0
	Fuel Oil	3,800.5	MMBtu	606,560	lbs CO_2	275.1
Scope 2	Electricity	292,246,548	kWh	609,918,546	lbs CO_2	276,657.2
				979,790,270	lbs CO_2	444,429.8

Table 3.3.2: Emission Factors Used for this Study

Coal	202.5	lbs CO_2/MMBtu	Calculated from FY' 09-10 Coal Analysis
Natural Gas	117.8	lbs CO_2/MMBtu	Calculated from FY' 09-10 Natural Gas Sources
Fuel Oil	159.6	lbs CO_2/MMBtu	Cool Air-Cool Planet, Campus Carbon Calculator V6.6
Electricity	2.087	lbs CO_2/kWh	Duke Energy Carbon Calculator

Table No. 3.3.3: Comparison of Study with IU 2010 Carbon Inventory

Emissions Source	Integrated Energy Master Plan Study		IU 2010 Carbon Inventory	
Scope 1	169,359.70	MT CO_2	179,101	MT eCO_2
Scope 2	267,904.20	MT CO_2	190,367	MT eCO_2
Scope 3	Not Included In Study		109,009	MT eCO_2
Offsets	Not Included In Study		(3,747)	MT eCO_2
Total	437,263.90	MT CO_2	474,730	MT eCO_2

CAMPUS DISTRIBUTED HEATING AND COOLING SERVICES

4 CAMPUS DISTRIBUTED HEATING AND COOLING SERVICES

4.1 High and Medium Pressure Steam

4.1.1 Located on East 11th Street between North Fee and North Walnut Grove is the Central Heating Plant (CHP) – Building BL455, a facility housing the central high pressure steam boiler plant. Built in phases between 1955 and 1971, the building currently houses five boilers generating 150 psig steam for the IUB campus. Steam is distributed from the plant at both 150 psig and at 40 psig through four mains, designated as follows:

- 150 psig North Campus Main
- 40 psig West Campus Main
- 40 psig South Campus Main No. 1
- 40 psig South Campus Main No. 2

4.1.2 Pumped condensate mains return approximately 70% of the steam produced back to the plant. 40 psig steam is obtained through a 150 psig to 40 psig pressure reducing station or through a micro-turbine operating between these two pressures and providing electricity for the plant. Peak steam flow from the plant is approximately 340,000 lbs/hr in the winter and the minimum summer flow is about 70,000 lbs/hr. The plant provides steam for heating and process use to 11,890,974 ft^2 or about 71% of the total campus. The remaining 29% of the campus is served by other local boilers, heaters, or furnaces, generally serving the building in which they are housed and generally fueled with natural gas.

4.1.3 The boilers in the CHP are described in Table 4.1.1 that follows. The boilers vary in the fuels on which they can fire depending on the specific boiler. The CHP boilers were modified significantly in 2007-2008 to reduce pollutants in its effluent gases in order to bring the plant in compliance with the Federal Clean Air Act Rules for Maximum Achievable Control Technology (MACT). The modification included:

- The removal of two aging 1950’s coal boilers (Boiler No. 1 and No. 2),
- The addition of a new, high efficiency natural gas boiler (Boiler No. 7),
- The addition of bag houses to remove particulates from the flue gas of the three remaining coal boilers,

- The installation of lime injection equipment for coal boilers No. 3, 4 and 6 to reduce sulfur dioxide and chlorine in the effluent gases, and
- The installation of activated carbon injection equipment for coal boilers No. 3, 4, and 6 to reduce mercury emissions from the stack gases.

4.1.4 Review of Table 4.1.1 indicates that the firm capacity of the plant (the capacity remaining after the loss of the largest increment of capacity) differs depending on the fuel source considered. If all fuels are considered (any boiler firing on any available fuel), the firm capacity of 460,000 lbs/hr is 35% or 120,000 lbs/hr in excess of the peak flow requirement. Operating on a single fuel only, coal firing does not have the capacity to meet the current peak load requirement either in terms of full capacity or in terms of firm capacity. At times of winter peak loads, coal must be supplemented with another fuel to meet the current campus peak steam needs.

Table 4.1.1: Existing CHP Boilers – Total and Firm Capacity

		Output Capacity				
Boiler Number	**Manufacturer**	**Installed**	**Coal (lbs/hr)**	**Natural Gas (lbs/hr)**	**No. 2 Fuel Oil (lbs/hr)**	**Maximum Capacity (lbs/hr)**
3	Erie City Iron Works	1959	80,000	50,000	50,000	80,000
4	Erie City Iron Works	1959	80,000	60,000	60,000	80,000
5	Union Iron Works	1964	-	150,000	150,000	150,000
6	Riley Stoker Corp.	1970	150,000	130,000	130,000	150,000
7	Nebraska Boiler	2007	-	180,000	180,000	180,000
					Total	640,000

	Total Output Capacity (lbs/hr)	**Firm Capacity (lbs/hr)**
All Fuels	640,000	460,000
Coal	310,000	160,000
Natural Gas	570,000	390,000
Fuel Oil	570,000	390,000

4.1.5 Though the plant is quite flexible in terms of fuel to be utilized, economic pressures remain strong to fire on coal whenever possible. For FY 10-11, the mix of fuels used to generate steam at the CHP was as follows:

Fuel Source	MMBtu of Fuel Consumed	Cost / MMBtu	Total Cost	Percentage of Total
Coal	1,629,722.40	$2.62	$4,263,004	92.0%
Natural Gas	140,767.00	$6.49	$913,437	7.9%
Fuel Oil	1,255.80	$19.80	$20,930	0.1%
Total	1,771,745.20	$2.93	$5,197,371	100.00%

4.1.6 Based on the same time period, the average calculated combustion efficiency of the plant was approximately 70% (actual calculations based on metered flows and enthalpies gives a likely range of efficiencies between 69.8% and 70.8%). Generally, the coal fired boilers are operating at lower than this efficiency while the new natural gas boiler no. 7 is firing at a considerably higher efficiency but on a more expensive fuel.

4.1.7 A more detailed look at the CHP, the steam distribution system, and the condensate return system with a focus on overall losses will be discussed in a later section.

4.2 The Cost of Steam Provided to Campus

4.2.1 The annual report for FY 10-11, and previous years devotes a page to the cost of operation of the Central Heating Plant and to the cost per pound of steam generated. A copy of that analysis for FY 10-11 is included in the Appendix as Table A4.2.1. The conclusion of Table A4.2.1 is that the cost of operation of the Central Heating Plant in FY 10-11 could be expressed as $7.59/thousand pounds of steam produced. As correct as this value is from an accounting standpoint, it overstates value in analyzing energy conservation measures on campus. For example, if an energy conservation measure in Wells Library saves a significant amount of steam in that building, the savings will be less than $7.59/thousand pounds of steam saved. The reason is that in any plant operation, there are fixed costs that are not dependent directly on how many pounds of steam are produced. For instance, Table A4.2.1 indicates that employee costs represent about 17% of the cost of the steam produced. But an energy conservation measure will not affect the employee cost. Therefore, the only valid approach should be to calculate the marginal cost of steam, the portion of the cost that is affected by the consumption of steam. Table 4.2.1 is an example of a calculation of the marginal cost of steam for the IUB campus during FY 10-11. This table format is actually derived from a format used by Charles Matson of the IUB Engineering Services Department with a few slightly altered values.

4.2.2 The table (4.2.1) describes the value of the metered steam produced at the boilers. By this definition, the cost shown represents the marginal cost to produce steam based on only the variable cost parameters related to the generation of the steam. This definition still does not describe the fixed costs (losses) that exist in the system outside the boilers. Such losses would include supply and return piping distribution system losses, losses associated with unreturned condensate, as well as system “losses” in the form of blowdown, radiation, deaerator venting, and feedwater heating. These losses are considered separately in sections that follow.

Table 4.2.1: Steam – Marginal Cost Analysis

Annual Cost Item	**Cost FY 10-11**	**Marginal Cost (%)**	**Marginal Cost (FY 10-11)**
Employee Compensation	$ 1,629,804	0	$ -
Coal	$ 4,263,004	100	$ 4,263,004
Electricity	$ 334,764	100	$ 334,764
Water	$ 112,136	100	$ 112,136
Sewer	$ 140,517	100	$ 140,517
Natural Gas - Local Distribution	$ 261,264	97	$ 253,426
Natural Gas - Gas & Transportation	$ 652,174	97	$ 632,609
Fuel Oil	$ 20,930	100	$ 20,930
Supplies, Chemicals, Other	$ 500,786	49	$ 245,385
Ash Handling	$ 141,655	100	$ 141,655
Maintenance & Repairs	$ 1,597,596	6	$ 95,856
Coal Samples	$ 6,613	100	$ 6,613
Totals	$ 9,661,243		$ 6,246,895
Steam Produced (1,000 lb)	1,273,133		1,273,133
Steam Produced (MMBtu)	1,243,978		1,243,978
Unit Cost (per 1,000 lb)	$ 7.59		$ 4.91
Unit Cost (per MMBtu)	**$ 7.77**		**$ 5.022**

Notes:

1. Costs from FY 10-11 Annual Report of the Physical Plant
2. Marginal Cost Estimate Assumptions
    a. Natural Gas reduced to 97% due to hot standby firing practice.
    b. Consumables related to coal firing 49% of total
    c. Bag replacements for coal firing 6% of total
3. Enthalpy$_{\text{150 psig steam}}$ - Enthalpy$_{\text{feedwater}}$ = 1,196.0 - 218.9 = 977.1 Btu/lb steam

4.3 Chilled Water Systems

4.3.1 Located on East 13th Street between North Woodlawn Avenue and North Forrest Avenue is the central chilled water plant (CCWP) – Building BL411. Built in 1970, the plant houses eight electric centrifugal chillers with a total capacity of 14,596 tons and serves approximately 7,761,451 ft^2 or 46% of the campus including most major campus buildings. Tables A4.3.1 and A4.3.2 in the Appendix indicate the chiller sizes, ages, and refrigerant utilized along with the capacity of support equipment including all associated cooling towers, chilled water pumps, and condenser water pumps. The CCWP Chilled Water System would be generally classified as a primary/secondary/tertiary pumped variable flow chilled water system with the tertiary pumping scheme having been modified from the original and usual design approach. A second variable flow chiller plant at the Forest Quad includes two additional 500 ton chillers and support equipment with room for a third machine of similar size. This system is hydraulically interconnected with the CCWP to function as a base load plant serving the Forest Quad with the ability to also provide chilled water capacity to the campus system. In addition, a 275 ton chiller at Swain West, a 150 ton chiller at Lily Library, and a 100 ton heat pump chiller at the Lee Norvel Theater and Drama Center are connected to the CCWP chilled water loop but can only serve cooling for the building in which they are located. Their use during peak summertime periods does serve to unload the CCWP. The CCWP has the following overall performance and plant efficiency.

Central Cooling Plant Equipment	**Full Load Power (kW)**	**Full Load kW/ton**
Electric Chillers	9,368	0.64
Cooling Auxiliary's		
Chilled Water Pumps	1,056	0.07
Condenser Pumps	1,008	0.07
Cooling Tower Fans	626	0.04
Total Cooling Auxiliaries	2,690	0.18
Totals for Plant	**12,058**	**0.83**

4.3.2 The central chiller plant, the Forest chiller plant, and the Briscoe chiller plant currently act as the three nodes of the existing CCWP. Additional detail on the campus chilled water systems and the correct modifications in design are described in Section 9.3.

4.3.3 From the standpoint of overall campus chilled water system design, the chilled water production (chiller) plants are rated and pumped on the basis of a 55°F return chilled water temperature from the buildings and a 40°F supply chilled water temperature delivered to the buildings, resulting in a 15°F Δt between supply and return. The campus cooling coils have been designed over the years for a variety of different supply and return water temperatures with the median temperatures of the major buildings being 43°F supply water and 55°F return water. The lower chilled water supply temperature from the plants should improve the overall log mean temperature difference (LMTD) between the chilled water system and the campus air systems, likely promoting higher return water temperature and improved variable flow performance.

4.3.4 The CCWP and the associated distributed chiller plants currently have insufficient installed capacity to provide firm cooling capacity for the IUB campus buildings it serves. This assertion was realized during 24 days during the summer of 2010 that campus chilled water curtailment was necessary for all or part of the operating day. A similar experience occurred during the summer of 2011 when a curtailment was required during 12 days. Modifications currently in design to increase campus chilled water capacity are discussed in Section 9.3.

4.4 Cost of Chilled Water Provided by the CCWP

4.4.1 The Physical Plant operating staff prepares an annual summary of the cost of operation of the central chilled water plant (CCWP) and the other chiller plants serving as sources for the loop (Forest Plant and Briscoe Plant). A copy of that analysis for FY 10-11 is included in the Appendix as Table A4.4.1. The conclusion of this table is that the cost of chilled water (cooling energy) generated by the CCWP for FY 10-11 was $0.0568/ton-hour delivered. Unlike the similar data described earlier for the Central Heating Plant, these values should yield a true marginal cost for chilled water that would directly apply for energy conservation measures. Thus for the CCWP for FY 10-11:

Total Cooling Produced	54,773,346 ton-hours
Total Cost of Cooling Provided	$ 3,109,808
Average Cost of Cooling Produced	**$ 0.0568/ton-hour**

4.4.2 However, as the performance of the central chilled water plant (CCWP) and the Forest plant were reviewed and compared to other similar plants, another issue became evident. By dividing the electrical consumption utilized in kilowatt-hours by the metered ton hours produced by the plants, the result is the average kW/ton for the plant during the period documented. The results of this calculation for the central plant and the Forest plant for FY 09-10 are:

Central Chilled Water Plant	0.69 kW/ton
Forest Chilled Water Plant	0.66 kW/ton

4.4.3 Typically we would expect these kW/ton figures to be higher. The operation shown here would be extremely efficient but difficult to achieve with the equipment installed. For the central chilled water plant, the chillers alone at full load require an average of 0.64 kW/ton. The chiller pumps, system chilled water pumps, condenser water pumps, and cooling tower fans together represent an additional 0.19 kW/ton at full load for a total plant performance at full load of 0.83 kW/ton. Chiller kW per ton does drop off somewhat at intermediate loads and many of the auxiliaries are equipped with variable speed drives that also unload at reduced loads. Our first inclination is that the chilled water metering performed at the cooling plant is erroneous, however, analysis of building metered data and the results of the campus energy analysis suggest that the metering is valid. This result, although not expected, may occur because the plant is too small to serve the attached load, which forces the facility chillers to operate for more hours at a high efficiency load point.

Character of Site
Energy Consumption and Cost

5 CHARACTER OF SITE ENERGY CONSUMPTION AND COST

5.1 Overview

5.1.1 In an effort to understand the energy use patterns for a campus like IUB, it is often useful to normalize the metered energy consumption for such a complex facility into uniform graphic representations that can be deconstructed to identify the various components of the total energy use. If such graphs are uniformly presented, the character of use of the energy consumed often yields clues to energy conservation opportunities that should be explored. Our tool for this analysis is to graph the average daily use of each energy form on a monthly basis. For each month, the metered energy consumption is divided by the days in the billing period to arrive at the average daily use of energy for the facility. This variable is graphed on the ordinate of the graph with the month indicated on the abscissa. Several distinct subdivisions of energy use are described and analyzed in the paragraphs that follow. (Note that the use and cost of propane as an energy source has not been included as explained earlier.)

5.1.2 It is also helpful to characterize the total cost of energy for the IUB campus so the contribution of each can be understood in with respect to other energy types. For the fiscal of FY 10-11, energy costs for the portion of campus included in this study were as follows:

Electricity	$18,677,297	73.1%
Coal	$4,263,004	16.7%
Natural Gas	$2,542,489	9.9%
Fuel Oil	$75,282	0.3%
Total	**$25,558,072**	100%

5.1.3 In addition, the average cost of each energy source per unit of consumption for FY 10-11 (for large quantity purchases) was as follows:

Electricity	$ 0.0639/kWh	(or $18.72/MMBtu for heating use)
Coal	$2.62/MMBtu	
Natural Gas	$6.49/MMBtu	(Based on current ratio of gas to coal burning)
Fuel Oil	$19.81/MMBtu	

5.2 Average Daily Use of Fuel

5.2.1 As described in earlier sections, the campus fuel use consists principally of coal, natural gas, and fuel oil. Of the total use of fuel on the campus, approximately 90% of that fuel is consumed at the Central Heating Plant to produce steam for use in approximately 71% of the total campus building area (with coal representing 83% of the total campus fuel consumption). Figure 5.2.1 indicates the average fuel use by month in FY 09-10 for the Central Heating Plant alone.

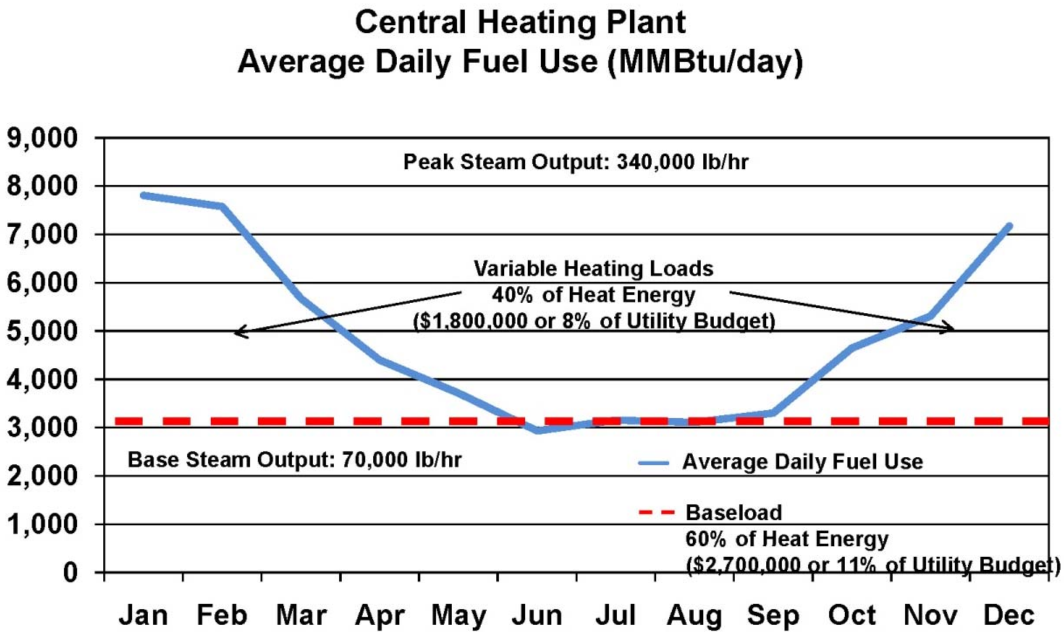


Figure 5.2.1: Central Heating Plant Average Fuel Use

5.2.2 The average daily use graph for fuel in FY 09-10 shows the characteristic shape for a fuel-fired heating system with increased consumption during both “wings” of the winter heating season. The most salient feature of this graph however, is the base use that occurs irrespective of the weather. That base of approximately 3,000 MMBtu/day of fuel, or 60% of the energy annually used to produce steam, has nothing to do with the outside temperature. In terms of cost, about $2.7M or 11% of the overall facilities energy budget occurs due to this base fuel consumption (as compared to the $1.8M of fuel that is truly associated with space heating). This should be a clear target of fuel energy reduction efforts on campus over the coming years. This report will focus in later sections on methods of reducing this base use component.

5.2.3 Figure No. 5.2.2 indicates the same central plant fuel consumption for the identical period but also includes the natural gas and fuel oil used in buildings that are not connected to the campus steam distribution system emanating from the Central Heating Plant. Notice that, although this additional fuel consumption serves about 29% of the campus area, the fuel use per square foot of building area is lower and the summertime base use is significantly smaller for these areas. These observations relate to the type of buildings served in this group and also to the lack of energy distribution losses in this portion of campus (principally served by natural gas fired equipment on a building-by-building or small building group basis). Figure 5.2.3 graphs the non-CHP fuel use separately indicating the much lower base consumption of 34% versus 60% for the CHP fuel use.

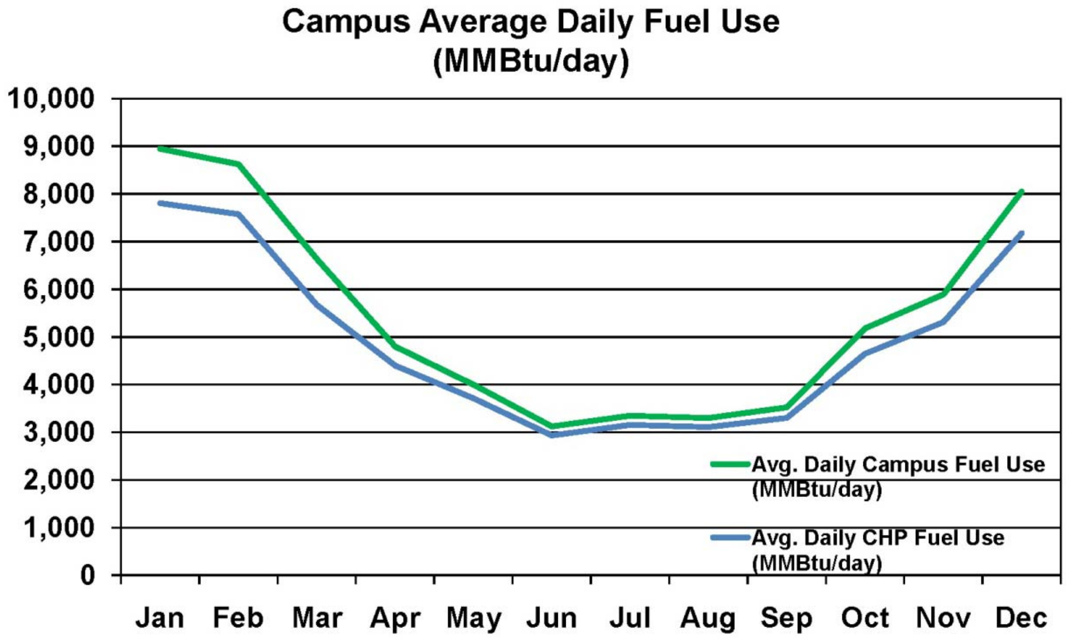


Figure 5.2.2: Campus Average Fuel Use

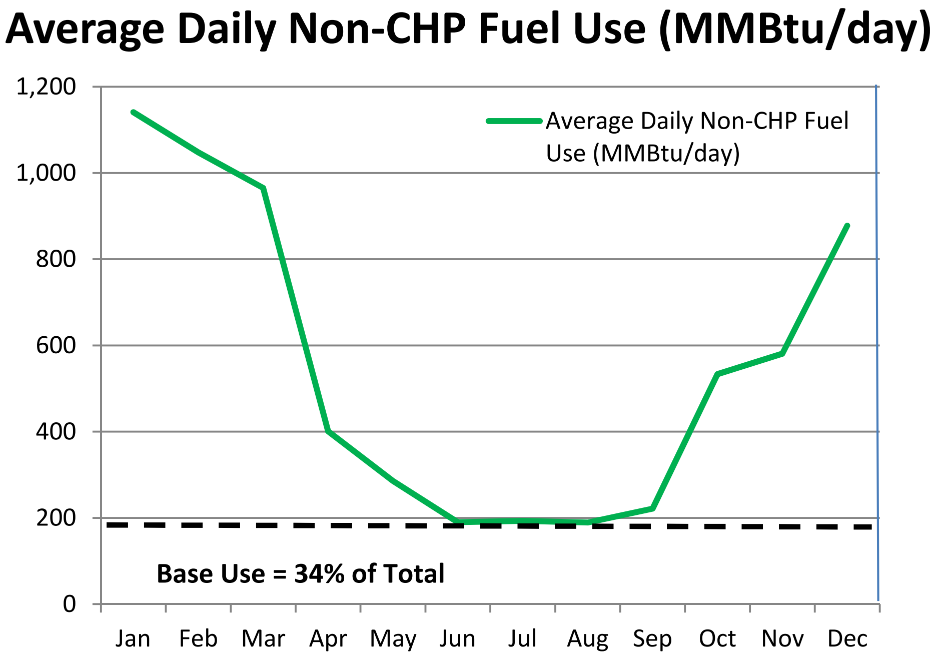


Figure 5.2.3: Non-CHP Fuel Use

5.3 Average Daily Use of Chilled Water

5.3.1 Chilled water use as discussed in this section will be limited to that occurring at the Central Chilled Water Plant. As discussed earlier, this plant and the associated chiller plant at Forest provide chilled water to approximately 47% of the total campus building areas. (The remainder of the campus is cooled by chilled water produced by numerous remote chillers, direct expansion cooling systems, or remains unconditioned during the summer.) This data does not include the Briscoe Chiller Plant that came on line during the summer of 2011. Figure No. 5.3.1 indicates the average daily use of chilled water from the central chilled water system for fiscal year FY 09-10.

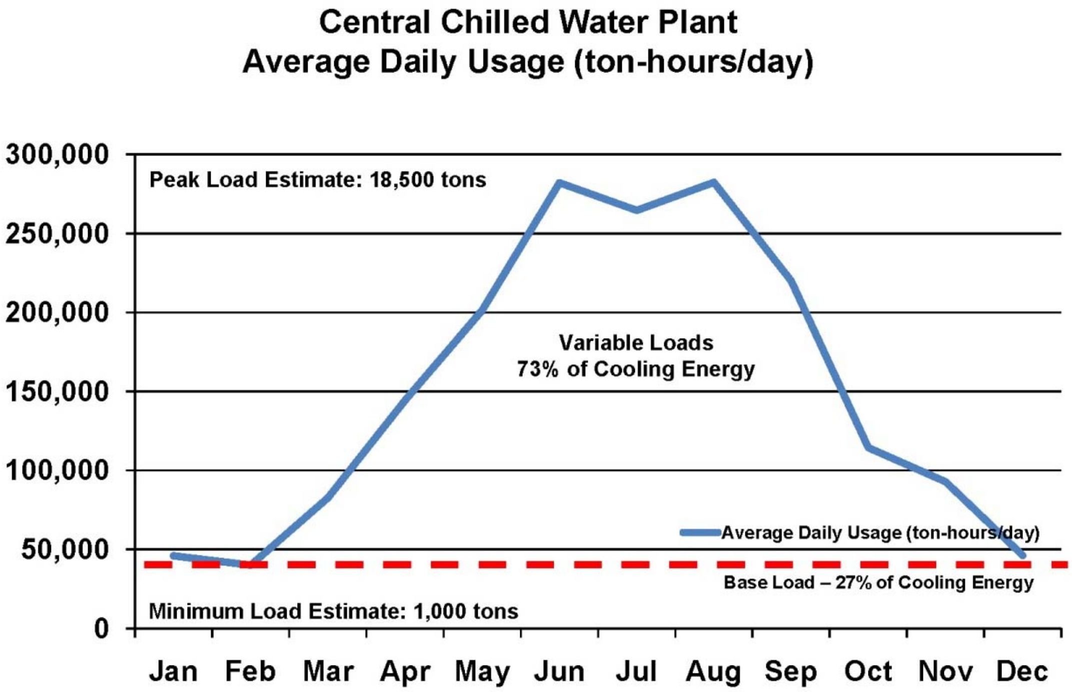


Figure 5.3.1: Average Daily Chilled Water Use

5.3.2 The average daily use curve shows the expected increase in use during the summer months. Since cooling in the system is produced entirely by electrical driven chillers, average daily electrical energy use for this system would have a curve very similar in shape to the average daily ton-hour use.

5.3.3 Of interest again on this graphic is the base use; those ton-hours that are independent of outside weather conditions. In this case, the base load represents approximately 27% of the overall annual consumption of electricity for the central plant. Again, this base load should be the target of energy conservation efforts to identify these base load uses and eliminate them if possible. Examples of such use are chilled water use for condensing water for coolers or lab equipment, chilled water use for interior area fan coil systems, or chilled water use for economizer fan systems whose economizer control systems are not functioning.

5.4 Average Daily Use of Electricity

5.4.1 Electricity as discussed in this section relates to campus electricity provided from the master meters on the high voltage sub-stations. As described in an earlier section, this represents the consumption for over 87% of the IUB campus. The average daily consumption of electricity for FY 09-10 for the master campus high-voltage meters is shown in Figure No. 5.4.1.

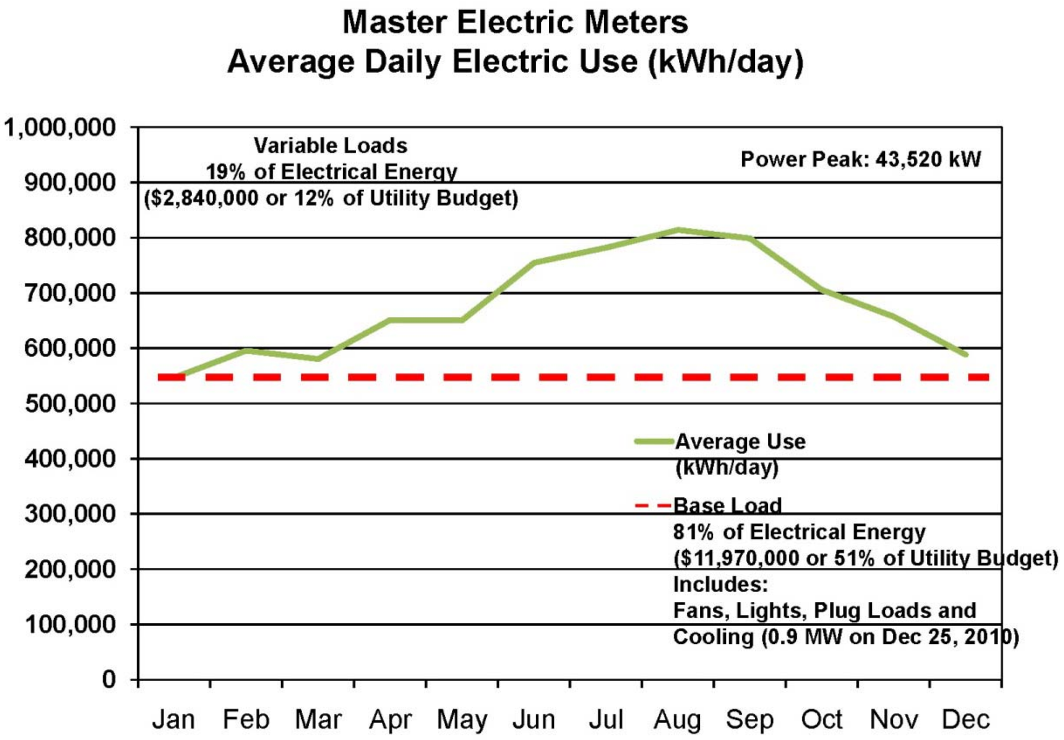


Figure 5.4.1: Average Daily Electric Use

5.4.2 The graph again divides the total consumption into the base and variable components. Obviously, the increase in electrical use during the summertime is the characteristic shape for facilities with electric driven cooling systems. However, looking back at Figure 5.3.1 would indicate that some cooling energy is also in the base electrical load because of the base cooling load needs. Not surprisingly, 81% of the facility electrical energy use is in the base while only 19% is in the variable or weather related portion of the total. Electrical base usage includes energy activities that occur on a regular basis such as lighting, air handling, plug loads, etc. Savings in these areas often target conversion of lighting systems to lower energy luminaires, reducing hours of operation of lights and fan systems, or converting constant volume air moving and pumping systems to variable flow, reducing electrical energy required at part load times. Each of these types of modifications also affect the amount of cooling or heating energy required in the spaces and thus their effects are much more complex than say an increase in the efficiency of a chiller. Often in the case of lighting retrofits, reducing the lighting load and therefore the heat contributed to the space, the summer cooling load for the space may decrease while the winter heating required may actually increase.

5.4.3 Subsequent calculations will further define the character of the energy use and determine the interrelated effects of these energy reduction modifications on the campus overall energy use.

5.5 Average Utility Costs Utilized in Energy Calculations

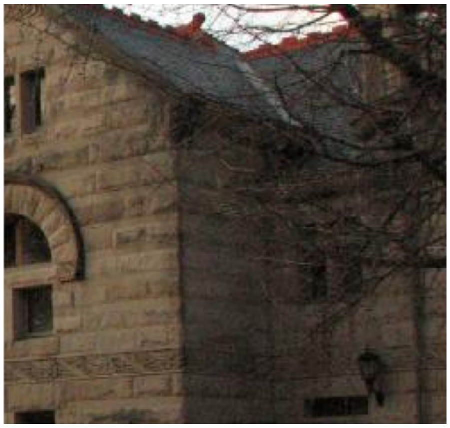
5.5.1 In an effort to utilize the most current energy costs available for evaluation of the energy conservation measures (ECM's) and energy reduction initiatives that follow in this report, annual utility costs for FY 10/11 were obtained. Based on the parameters set forth earlier in the report, and unless stated otherwise, the following average costs of fuel, energy, and water have been used in the ECM calculations that follow.

Electricity	**$0.0639/kWh**
Natural Gas (CHP Only)	**$6.49/MMBtu**
Campus Natural Gas	**$8.47/MMBtu**
Coal (CHP Only)	**$2.62/MMBtu**
Fuel Oil	**$19.80/MMBtu**
Water	**$0.00178/gal**
Sewer	**$0.00419/gal**
Chilled Water (CCWP Only)	**$0.0568/ton-hour (marginal cost)**
Steam (CHP Only)	**$5.022/MMBtu (marginal cost)**

5.5.2 Table A5.5.1 in Appendix A describes the FY 10/11 costs that were used to establish these average costs. Natural gas costs considered for fuel switching and cogeneration options were calculated based on the current Vectren and Energy USA rates.

DEMAND SIDE ANALYSIS





ANALYSIS OF BUILDING AND SITE ENERGY USE

6 DEMAND SIDE ANALYSIS

6.1 Techniques of Analysis, Overview

6.1.1 Central to analyzing the Bloomington campus was developing a fundamental understanding of the campus buildings and how they work. As noted earlier in this report, a total of 104 buildings comprising 82% of the campus gross square footage were included in this analysis. To best understand how the buildings work, a simplified energy model was constructed that enabled simulating building performance utilizing fundamental building data. The building simulation was constructed from survey data, rather than a detailed field investigation or drawing review that is typical of an investment grade energy study. The goals and scope of the Integrated Energy Master Plan dictated a high level approach to the energy modeling effort rather than a detailed study.

6.1.2 This simulation included a number of variables including building skin construction, occupancy, lighting and equipment usage patterns, heating, ventilating and air conditioning system types and source of heating and cooling energy. All of this data was collected in a database and utilized as an input to the energy simulation program. This program constructs an hourly prediction of energy consumption for a typical weather year for each building that is analyzed. From this data, we are able to determine peak heating and cooling demand as well as predict energy usage. Furthermore, utilizing metered utility data for each building (when available), the energy model is validated.

6.1.3 Building Survey for Energy Model: The building energy model accounts for a number of building variables including:

- General building data such a floor area, building type and occupancy
- Building exterior skin construction
- Lighting
- Heating Ventilation and Air Conditioning Systems

Collecting this data involved verbal surveys with key Indiana University staff, field inspections and some review of original building construction drawings. A description of this data collection is included below.

6.1.3.1 General Building Data

Building Gross Square Footage: In general, building floor areas were provided by the Indiana University Space Information Department. In the instance of Memorial Stadium, the building square footage was split between the North End Zone, West Stands and East Stands.

Conditioned Gross Square Footage: For buildings that included floor area that was lighted, but not heated or cooled (such as parking garages), a manual calculation was performed to determine the actual amount of floor area that is heated or cooled. This value is used to calculate HVAC heating and cooling loads.

Building Type: Based on the known usage, each building was split into one of the following use categories: Parking, Single Family, Academic, Laboratory, Theatre/Assembly, Library, Student Life, Office, Museum, Sports / Recreation, Facilities / Service, Dormitory, Data Center, Warehouse, etc. The selection of building type is used to set equipment load densities, equipment load schedules, occupancy schedules, lighting schedules and domestic hot water consumption. For instance, the estimated average peak equipment load density for an academic building is 0.5 Watts / SF versus 2.75 Watt / SF for a laboratory building.

Building Occupancy: Building occupancy is estimated utilizing historical data and data from the Indiana University Residential Programs and Services Department.

6.1.3.2 Building Exterior Skin

Wall, Roof and Window Areas: Estimating the area of building surfaces is necessary for modeling the energy performance of a building. For this study, eight buildings on the IUB campus were analyzed to determine wall, roof and window surface areas. This building data was analyzed to determine ratios for interior floor area versus overall floor area, exterior wall area versus overall floor area, roof area versus overall floor area and window area versus exterior wall area. With this data, the eight buildings were split into three categories of exterior exposure; low, average and high exposure. The ratios displayed in Table 6.1.1.2: Building Skin Model display the values used in analyzing the campus buildings. Using these ratios, wall, roof and window areas are calculated for the energy model. Furthermore, these surface areas are utilized as the basis for the cost estimate for associated energy conservation measures.

Table 6.1.3.2: Building Skin Model

Exterior Exposure Category	Percent Interior SF / GSF	Wall SF / GSF	Roof SF / GSF	Window SF / Wall SF
Low	73%	33%	33%	17.9%
Average	57%	40%	28%	17.9%
High	33%	49%	21%	17.9%

Wall Insulation: Many of the campus buildings were built before the existence of modern energy codes and do not include any significant insulation system. For the energy simulation, walls are considered to be "insulated" or "non-insulated". By surveying the architectural drawings of the buildings in the study, a database was developed to place the buildings in the study into one of the two categories for insulation. Of the 104 Buildings, 67 buildings do not include insulation in the exterior skin of the building. Table A6.1.1 in Appendix A includes a list of buildings that do not have insulation in the exterior skin of the building.

Window Type: Similar to Wall Insulation, many of the older buildings on campus have single pane windows. Buildings constructed today in general have double pane and in some cases, triple pane windows. Furthermore, these windows commonly include a coating or tinting to reduce solar heat gain into the building. For the energy simulation, windows are considered to be "single pane" or "double pane" where single pane windows are clear glass, and double pane windows comply with ASHRAE Standard 90.1. Through a survey conducted in conversation with IUB Facilities Department, a database was assembled to place each building in one of the two categories. At the time of that survey, 47 of the 104 buildings had "single pane" windows. Table A6.1.2 in Appendix A includes a list of buildings that have "single pane" windows.

6.1.3.3 **Lighting:** As part of the Integrated Energy Master Plan, student interns were employed to perform a lighting survey of the 104 buildings included in the detailed study. As part of this survey, the students surveyed 5 to 10 rooms per floor of each building. In each room, the following data was collected:

- room floor area
- number and type of lamps
- tested if fluorescent ballasts were electronic or magnetic
- observed if lighting controls were utilized

Following the survey, this data was compiled and an average building power density (Watts / SF) was calculated and entered into the building database.

6.1.3.4 **Heating, Ventilating and Air Conditioning (HVAC) System Data:** Through a survey and review of building automation graphics with Indiana University Facilities Department, an HVAC survey was conducted for the 104 buildings. This survey focused on determining the following characteristics of the systems serving the buildings:

- HVAC system types
- Are air-side economizers utilized?
- Estimated ventilation air quantity
- Heating, Cooling and Humidification Energy Sources (electric, natural gas, chilled water, steam, etc)
- Building cooling plant description and capacities
- Building heating plant description and capacities
- Fan modulation types (variable speed drives)
- Estimated building supply airflow (per GSF)
- HVAC operating schedule
- Humidification setpoints
- Type of building automation

While some buildings utilized consistent system types throughout, there were a number of buildings that have HVAC systems that exhibit significantly different behaviors (constant volume systems versus variable volume systems for instance). To simulate these buildings, parameters are set to approximate the average building performance.

6.1.4 **Building Metering Data:** As part of the Integrated Energy Master Plan process, utility data for electricity, natural gas, chilled water, steam and coal was collected. This data was entered into the building database to enable retrieving data on a building by building and month by month basis. Where metered data was obviously incorrect or erroneous, the data was removed from the database. Metered data was collected from variety of different sources including the following:

6.1.4.1 Electric Metering: Electric metering data is collected from two sources: Duke Energy bills and Indiana University metering data (for buildings on the IU central electric distribution system). In general, this data appears to be valid. However, our comparisons with the energy model did show abnormalities in the electrical metering of a few buildings. These abnormalities appeared to be the scaling factors were incorrectly applied to the meter output or that meters were not installed on all branches downstream of the main service entrance.

6.1.4.2 Gas Metering: Gas metering data was entirely collected from monthly bills from Vectren (the local natural gas distributor).

6.1.4.3 Steam Metering: Part of the campus metering initiative includes placing positive displacement water meters on the building condensate return piping. These meters are located in various configurations in the buildings, sometimes upstream of condensate return pumps and at times downstream of these pumps. The meters are read on a monthly basis. In general, this system appears to produce reliable results. However, there were a few abnormalities noted during the comparison with the energy model including:

- There are instances when condensate is dumped to the building drain rather than pumped back to the central plant. This occurs when the pump has failed, the condensate return system downstream of the building has failed or the meter has locked up. In general, monthly readings of 0.0 condensate flow were not considered for the validation of the energy model.
- There are instances where metered data appears to include more than one building. These instances are being investigated by IU.

6.1.4.4 Chilled Water Metering: Metering of chilled water is accomplished via the flow meters and temperatures sensors that are wired into the building automation system (Siemens and Johnson Controls). Building chilled water flow meters are high quality ultrasonic flow meters. The building automation systems record chilled water flow, chilled water supply temperature and chilled water return temperature. Simple math is used to calculate chilled water load from these values. There were several abnormalities related to this data:

- There are periods of time during which no data is collected. The data collection for this system is less evolved than the other metering systems.
- There are a number of buildings for which the data collected is obviously erroneous.
- Demand data is collected. Ton-Hour data is not collected or stored and must be manually calculated using the demand data.
- Although demand data is collected, it is virtually impossible to use this data to verify building peak chilled water demand. From review of the data, it appears that peak demands are generally set when a building is taken off of the summertime chilled water curtailment.

6.1.5 **Utility Costs:** The unit costs for electricity, steam, chilled water, natural gas, coal and domestic water are based on marginal costs of these utilities during the IU fiscal year that started in July 2010 and ended in June 2011. This data is discussed in detail in paragraph 5 of this report.

6.1.6 **Building Energy Model:** Following collection of the building data, a computerized energy simulation was performed. For these models, the building floor area is split into an interior zone and exterior zone. All the data collected above in the building database is input into the energy model. Next, a simulation is performed for the interior and exterior zone for every hour of a typical meteorological weather year (8760 hours). Energy demands and usages in terms of electricity, natural gas, steam, chilled water, heating water, domestic cold water and sewer are calculated and stored for totalizing of building, campus and central plant energy demands and usages. Additionally, a degree day fit is performed for the simulation data. This data is plotted on the same graph as actual metered data. This process is used to validate the energy model. If the degree day fit from the energy simulation is similar to the degree day fit of the actual metered data, the energy model is assumed to be valid. Attached below (Figure 6.1.4: Wells Library Chilled Water Simulation Results) is a copy of a graph from the simulation program. In this example, the blue dots represent measured chilled water usage in 2010 and 2011. The red dashed line represents a heating and cooling degree day fit of the data. The green (non-dashed) line represents energy consumption predicted by the energy simulation when corrected for the weather experienced during 2010 and 2011. In this instance, the energy model is slightly under-predicting chilled water consumption, but overall exhibits excellent correlation between the energy model and the actual consumption.

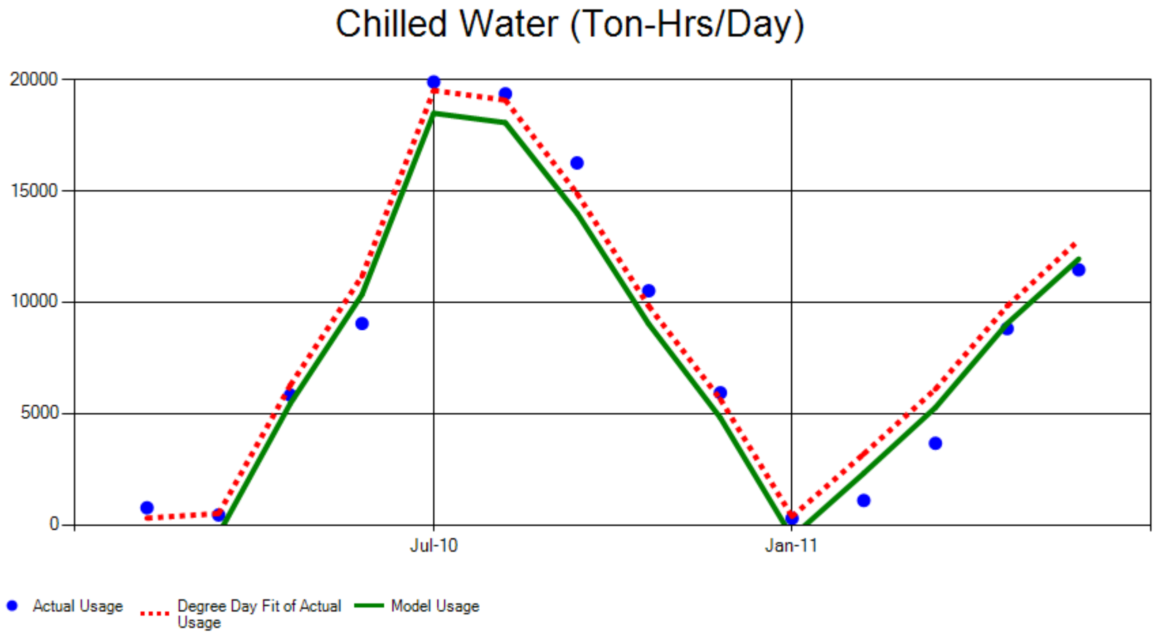


Figure 6.1.4: Wells Library Chilled Water Simulation Results

In the instance where the metered data and model do not exhibit correlation, the energy model parameters are adjusted in an attempt to obtain correlation. In the instances when there is valid energy metering data, the final energy model predicted consumptions are adjusted (up or down) such that annual energy consumption predicted by the model equals the metered data. This adjustment is also applied to the energy conservation measure items described later in this report.

6.2 Building Model Results, Energy and Demand

6.2.1 Campus Buildings, Overall Results: For the purposes of analyzing building performance, energy consumption in terms of electricity, heating (via natural gas and steam) and chilled water were analyzed and summarized. Included in the Appendix A, Tables A6.2.1, A6.2.2 and A6.2.3 of this report are building by building summaries of energy consumption for these three categories.

Listed below is average consumption and demand data for different building types utilizing the data presented in Appendix A6.2. As indicated previously, the Average Annual Consumption values listed include an adjustment to that forces the model to match metered energy data. For technical reasons, a similar adjustment is not made to the demand data. The metering system utilized at IUB presently focuses on collection of consumption data and not on demand data.

Table 6.2.1.1: IUB – Average Energy Consumption and Demand by Building Type – Electric

Building Type	Average Annual Consumption (kWh/SF)	Average Peak Demand (W / SF)
Academic	16.9	3.2
Data Center	158.5	23.1
Facilities	5.1	4.0
Office	14.4	3.0
Parking	2.6	0.3
Residential	10.3	2.2
Science	37.2	5.7
Student Life	18.6	2.8

Table 6.2.1.2: IUB – Average Energy Consumption and Demand by Building Type – Gas and Steam

Building Type	Average Annual Consumption (MMBtu/SF)	Average Peak Demand (Btuh/SF)
Academic	81	27
Data Center	47	17
Facilities	20	8
Office	69	23
Residential	58	24
Science	111	49
Student Life	89	23

Table 6.2.1.3: IUB – Average Energy Consumption and Demand by Building Type – Chilled Water

Building Type	Average Annual Consumption (Ton-Hours/SF)	Average Peak Demand (SF / Ton)
Academic	4.9	447
Office	4.1	454
Residential	2.3	609
Science	12.6	155
Student Life	2.8	417

Note: Averages only includes buildings on central cooling plant

6.2.1.1 Observations from Tables in 6.2.1: Listed below are a few general observations from this data:

- The Data Center exhibits significantly electrical energy consumption (per unit floor area) than all other types of buildings. This result is certainly related to the electrical energy consumption of the computer equipment at the facility.
- Science Buildings exhibit twice the energy consumption and demand (per unit floor area) of other buildings. This result is related to the significantly higher requirements for ventilation, greater intensity of equipment electrical usage and reliance on HVAC systems that utilize reheat energy to control space temperature. Furthermore, the HVAC systems and equipment serving Science Buildings generally cannot be scheduled off during unoccupied hours.
- Residential Buildings exhibit reduced chilled water consumption when compared to other building types. For IUB, this result is not surprising in that a number of the larger residence halls are not fully air conditioned.

6.2.2 Building Benchmarking: One goal of the Integrated Energy Master Plan is to benchmark the performance of the buildings. The source of benchmark data for IUB is data collected by US Energy Information Administration Commercial Buildings Energy Consumption Survey (CBECS). This survey is performed on a regular basis (usually every four years), but was last released in 2003. This data is also used as the basis for benchmarking in the Energy Star program that is administered by the US Department of Energy and US Environmental Protection Agency.

Included in the CBECS database is energy consumption data for a range of building types including many of the types of buildings on the IUB campus including: Education (college or university), Lodging (dormitory, fraternity, or sorority), Office, Laboratory, etc. The CBECS data provides three ways to evaluate building performance against a national average. These methods are described below:

6.2.2.1 Energy Intensity Index (EUI): The first method involves calculating site energy use intensity (EUI). The EUI is calculated by summing all energy consumption utilizing a common unit of kBtu/year/GSF. For electricity, kWh energy is converted to kBtu/year by multiplying kWh by 3.413 kBtu/kWh. For chilled water, the corresponding electrical usage must be calculated by converting ton-hours of cooling to electrical energy (kWh) using the average conversion efficiency (for IUB, we used an average kW/Ton of 0.89). For each building type, a percentile score is assigned based on EUI. A score of 50% indicates that the building is average. A score above 50% indicates that the building uses more energy (has a higher EUI) than the average building.

6.2.2.2 Electricity Use Index: The second method of benchmarking involves calculating site electricity use index. The electricity use index is calculated similarly to the EUI except that fuel sources are not included and units of kWh/year/GSF are utilized. For the IUB, steam and natural gas consumption are not included in the calculation of this index. For each building type, a percentile score is assigned based on electricity use index. A score of 50% indicates that the building is average. A score above 50% indicates that the building uses more electricity (has a higher index) than the average building.

6.2.2.3 Cost Index: The third method of benchmarking involves calculating energy cost per GSF. Because the energy rates present in Indiana are significantly different than the national average, this index was not used in benchmarking IUB.

6.2.2.4 CBECS Benchmarking Graphs: Included below are graphs detailing both EUI and Electricity Use Index for IUB buildings by building type.

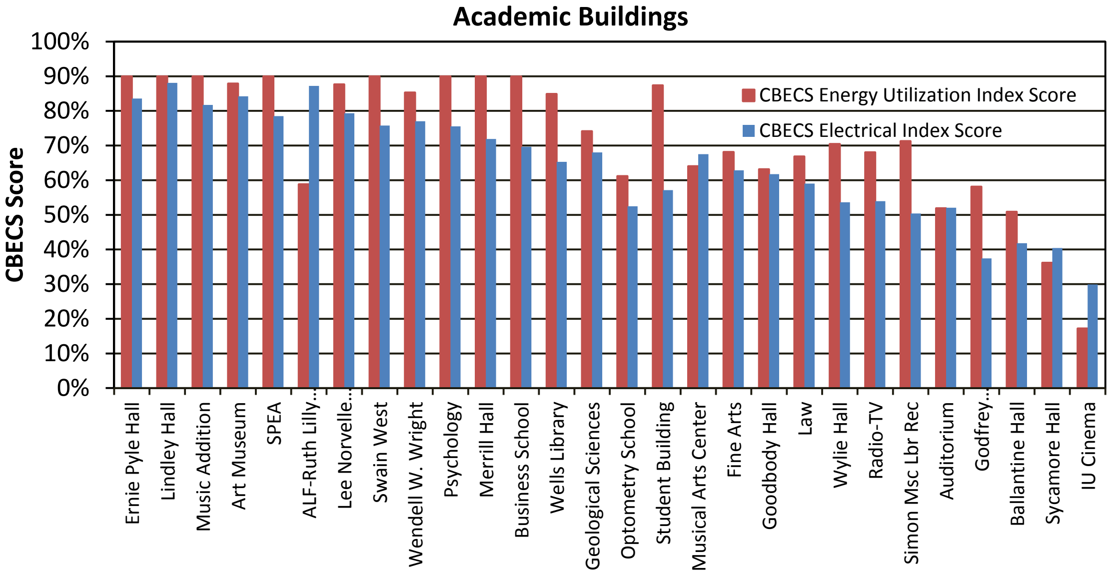


FIGURE 6.2.2.1: CBECS Benchmarking – Academic Buildings

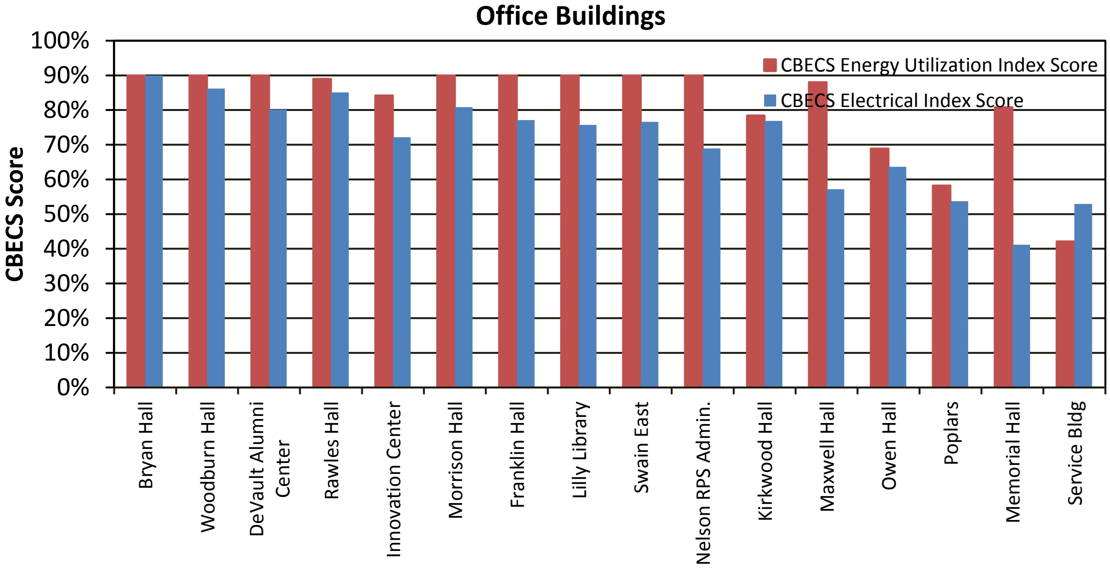


FIGURE 6.2.2.2: CBECS Benchmarking – Office Buildings

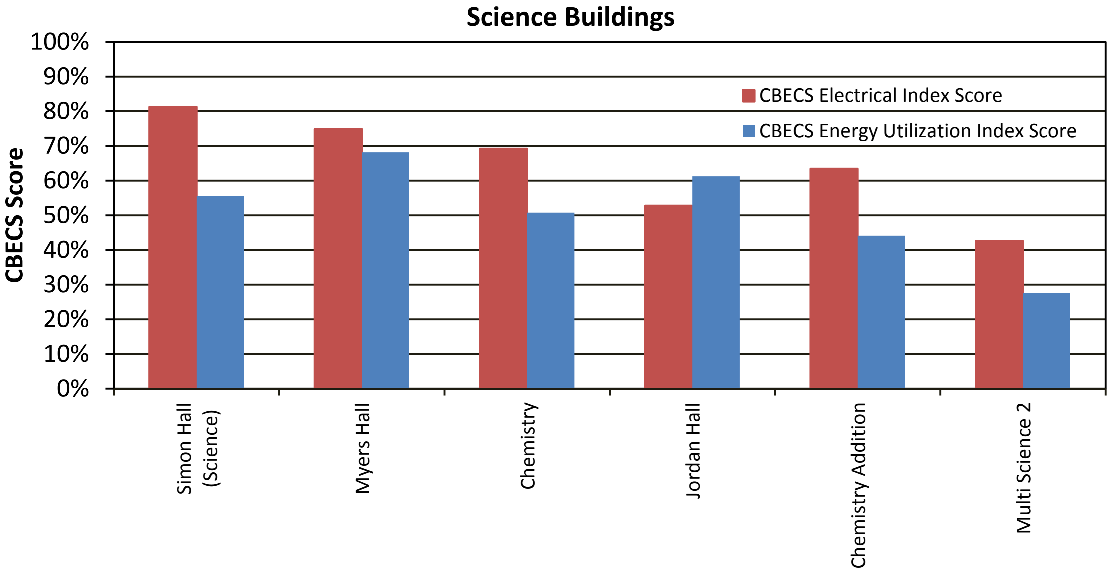


FIGURE 6.2.2.3: CBECS Benchmarking – Science Buildings

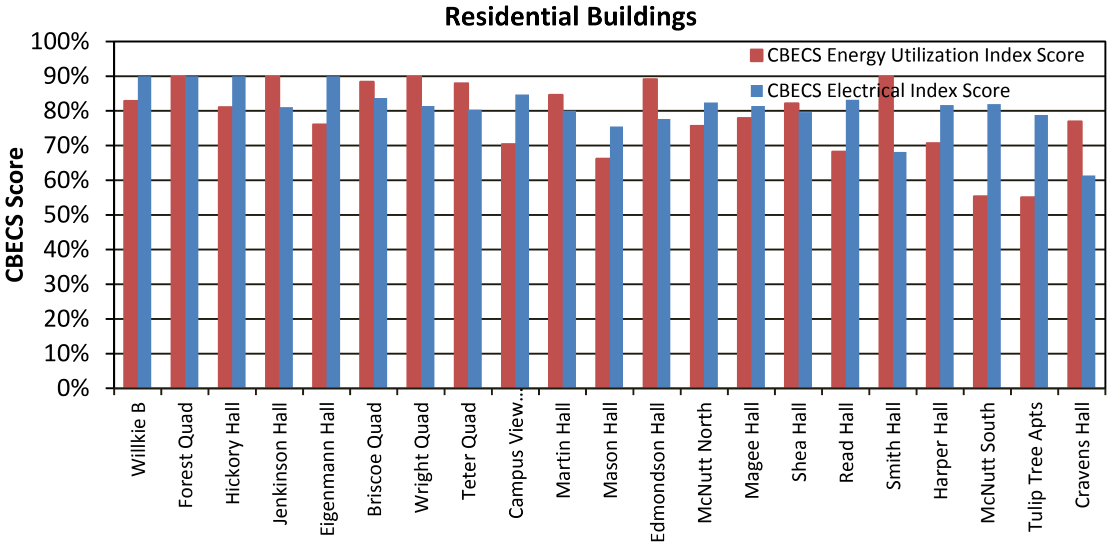


FIGURE 6.2.2.4: CBECS Benchmarking – Residential Buildings

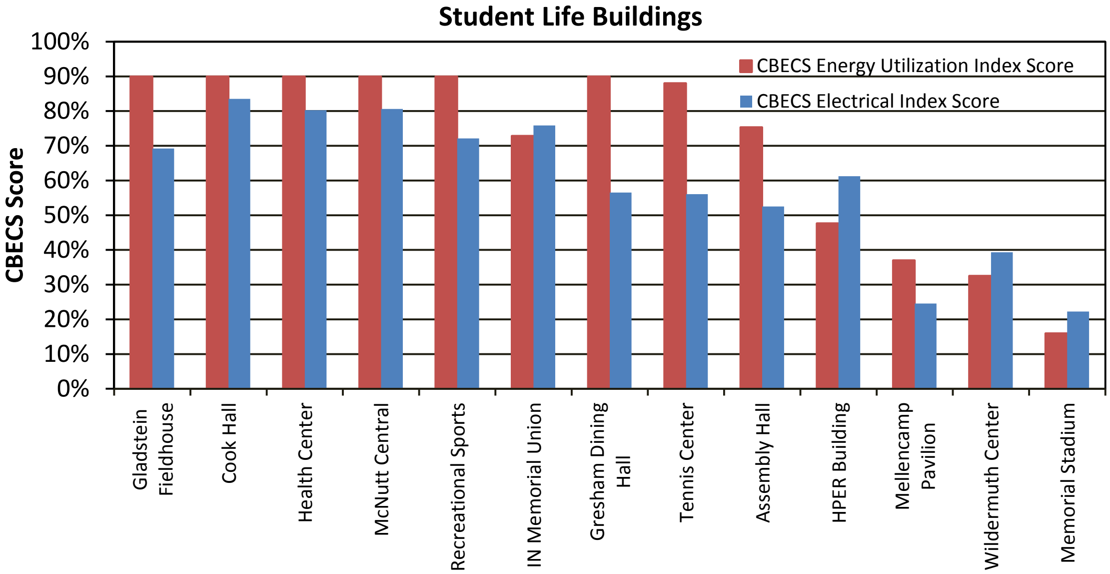


FIGURE 6.2.2.5: CBECS Benchmarking – Student Life Buildings

6.2.2.5 Observations from Figures in 6.2.2.4: Listed below are conclusions from review of CBECS Benchmarking Figures 6.2.3.1, 6.2.3.2, 6.2.3.3, 6.2.3.4 and 6.2.3.5.

- The vast majority of the campus buildings included in this study use more energy and electricity than the average building in the CBECS database.
- Because the CBECS averages are based on a study conducted in 2003, it is possible that a typical 2003 residence hall did not have cooling (where as most of IU residence halls have cooling). This change in residence halls may contribute to higher CBECS scores for this category.
- The CBECS Electrical Index Score is generally lower than the CBECS Energy Utilization Index Score. This trend is likely because more buildings in the CBECS survey were heated by electric than gas or coal.

6.2.2.6 Cost Per Square Foot Analysis: Using both the average CBECS Energy Utilization Index and Electricity Use Index and Indiana University energy costs, we are able to compare the cost of building energy consumption to a CBECS average building and to other building on the IUB Campus. The graphs presented below display this cost information:

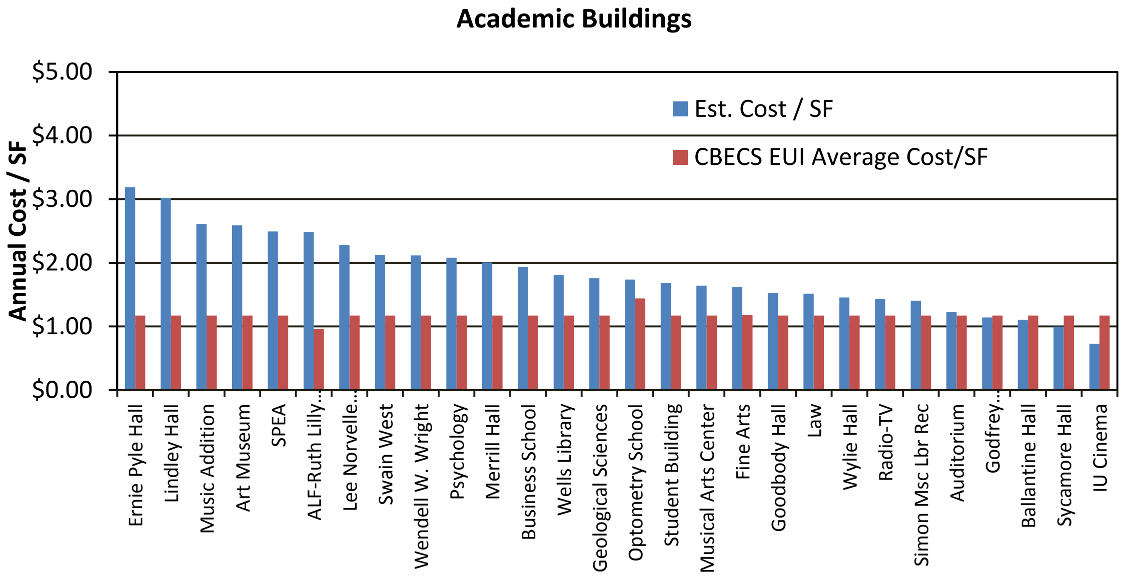


FIGURE 6.2.2.6: Cost / GSF Benchmarking – Academic Buildings

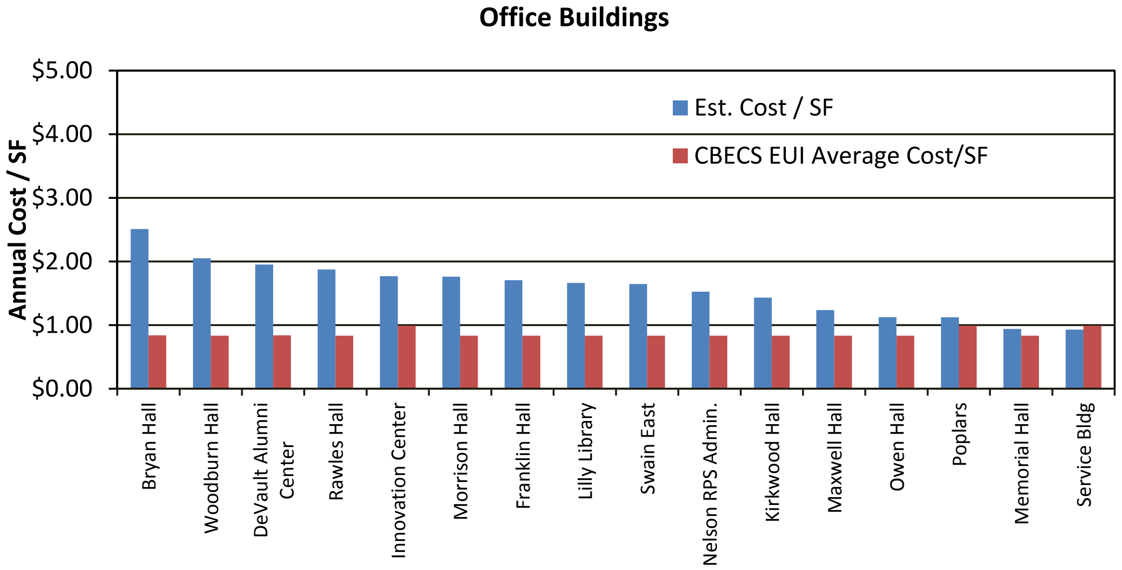


FIGURE 6.2.2.7: Cost / GSF Benchmarking – Office Buildings

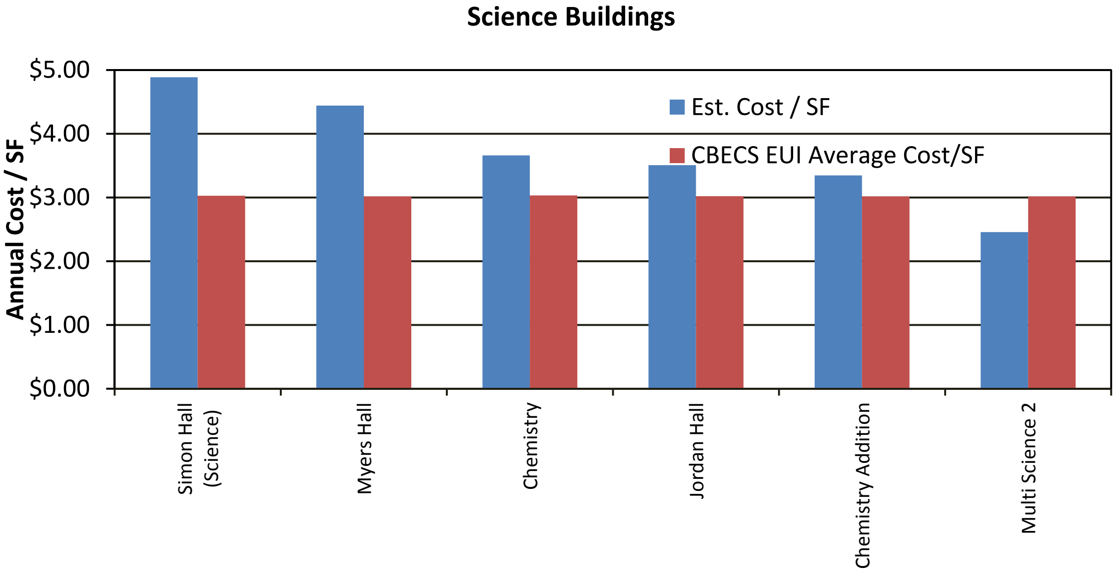


FIGURE 6.2.2.8: Cost / GSF Benchmarking – Science Buildings

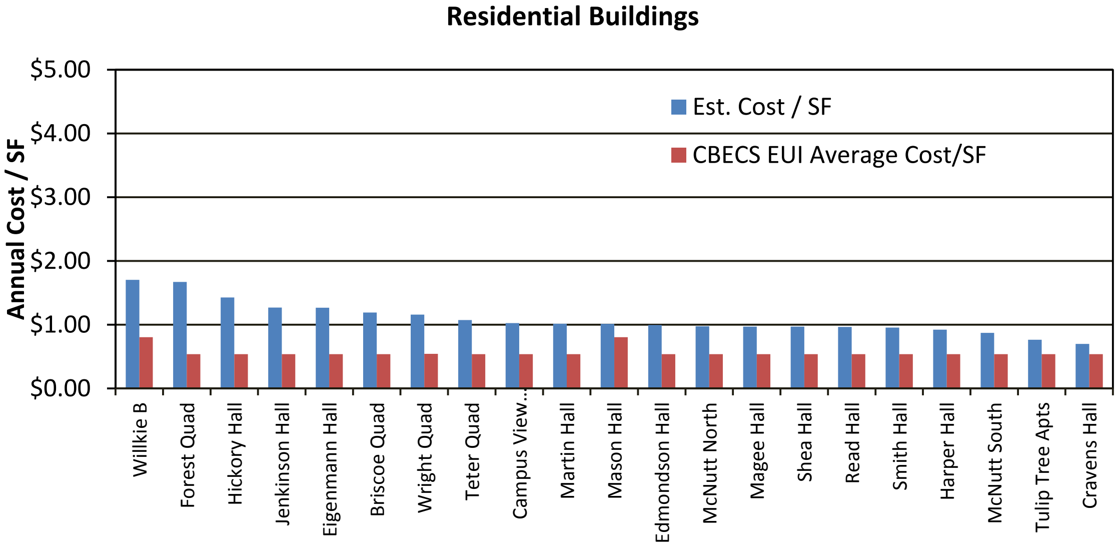


FIGURE 6.2.2.9: Cost / GSF Benchmarking – Residential Buildings

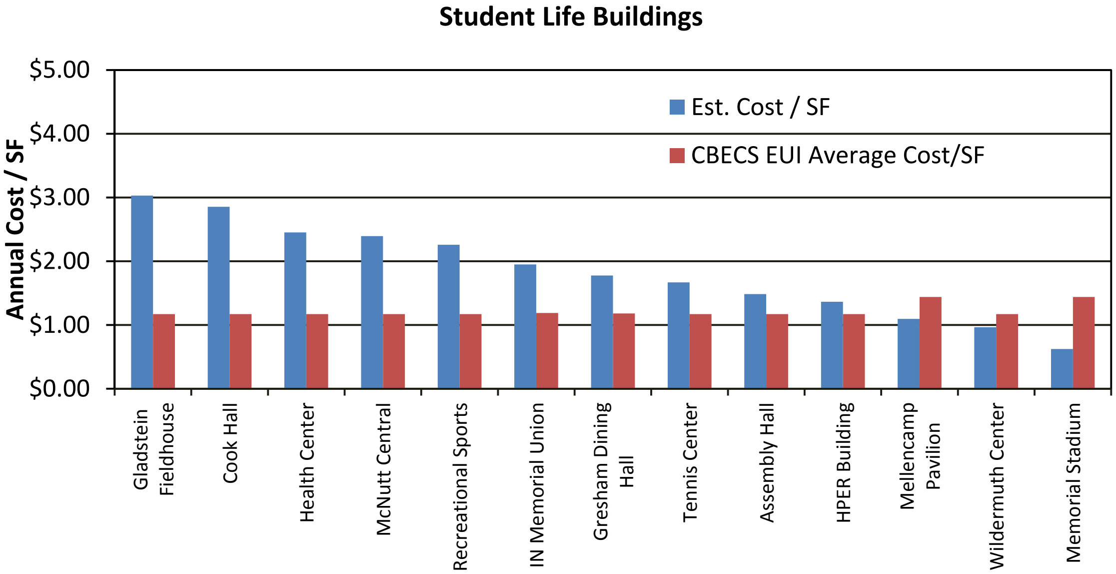


FIGURE 6.2.2.10: Cost / GSF Benchmarking – Student Life Buildings

6.2.2.7 Observations from Figures in 6.2.2.6: Listed below are conclusions from review of Cost Per GSF Benchmarking Figures 6.2.3.6, 6.2.3.7, 6.2.3.8, 6.2.3.9 and 6.2.3.10.

- Not including the data center, the science buildings are the most expensive per GSF for utilities.
- IUB Residential buildings are among the least expensive per GSF for utilities.
- The spread of costs across each category demonstrates that there are significant opportunities to reduce energy consumption on campus.

6.3 Campus Central Plant – Model for Demand Side

6.3.1 **Results:** In addition to providing building by building data, the building energy models are also necessary for understanding how the campus central plants function. Following the validation of the building models, this data is combined with all the buildings to provide usage profiles for the following campus central systems: Steam, Chilled Water and Electric. In the instances where buildings on a central system were not included in the group of 104 buildings, utility usage is estimated based on building type and building size (GSF). This summarized data is described below in Figure 6.3.1, Figure 6.3.2 and Figure 6.3.3. For these graphs, the blue dots represent actual utility measurements, the red dashed line represents a degree-day fit of the data, and the green solid line represents the energy model prediction. In each case, there is excellent correlation between the energy model and actual metered results.

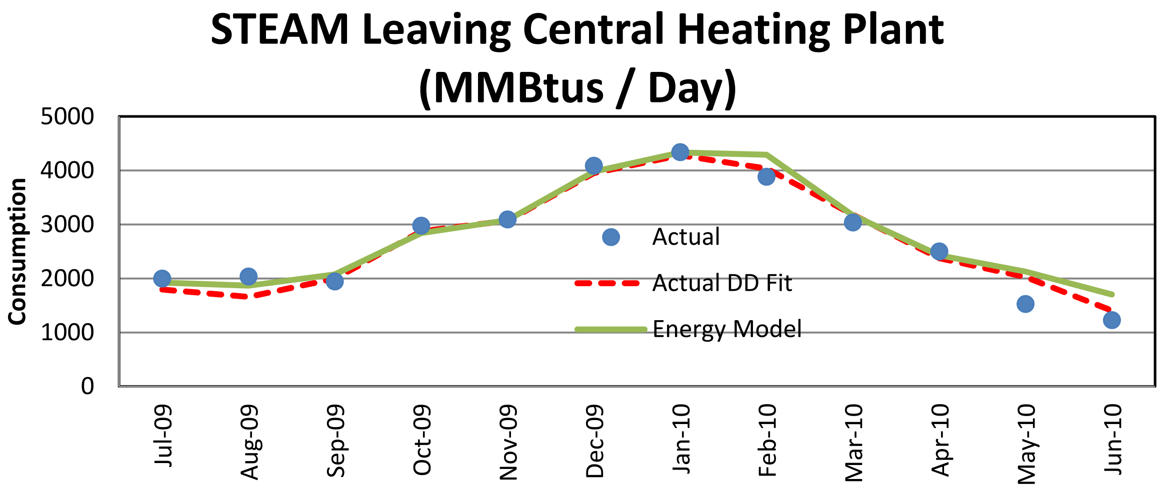


Figure 6.3.1: Demand Side Energy Model – Campus Steam

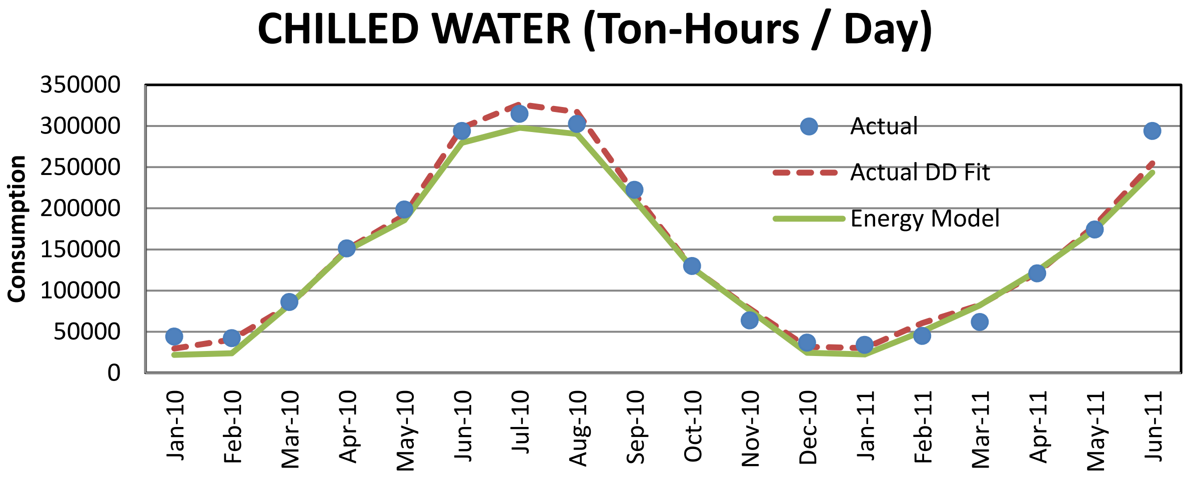


Figure 6.3.2: Demand Side Energy Model – Campus Chilled Water

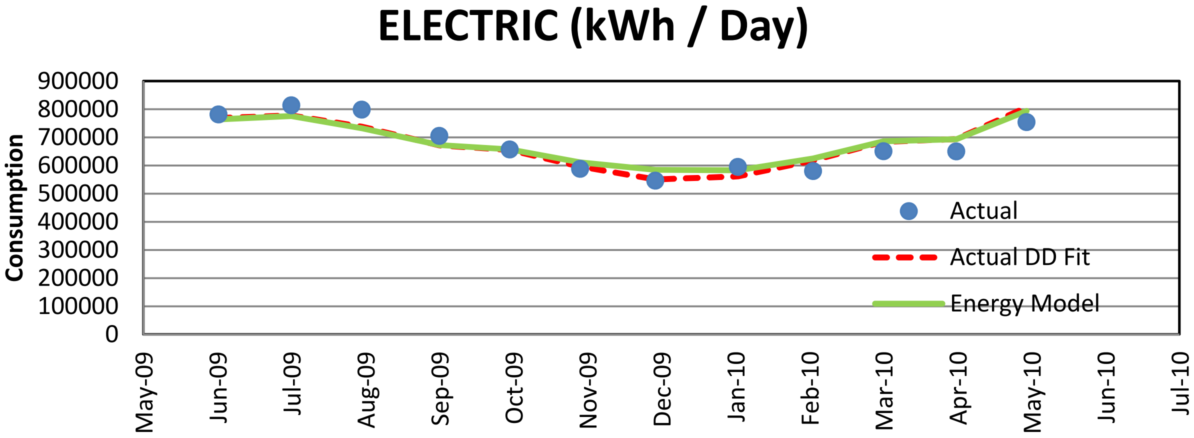


Figure 6.3.3: Demand Side Energy Model – Campus Electric

6.4 Building Utility Audit

6.4.1 **Results:** In addition to determining the overall energy consumption for each building on campus, the energy model data also provides a glimpse of where energy is consumed within the buildings.

6.4.1.1 Energy Audit Graphs: Figure 6.4.1.1 displays an accounting of energy consumption by cost for the various types of buildings at IUB. Energy consumption is grouped in categories including domestic cold water, domestic hot water (including heat energy), fans, lighting, equipment and plug loads, preheat (heating for ventilation air up to 55°F), reheat (heat used to control space temperature), humidification and cooling. It is important to note that this figure does not portray losses within the building resulting from poorly functioning equipment or leaks, but rather the idealized results of the energy model. The difference between the energy model and actual building performance can be attributed to a number of variables which include items that are discussed in the Retro-Commissioning Opportunities section of this report.

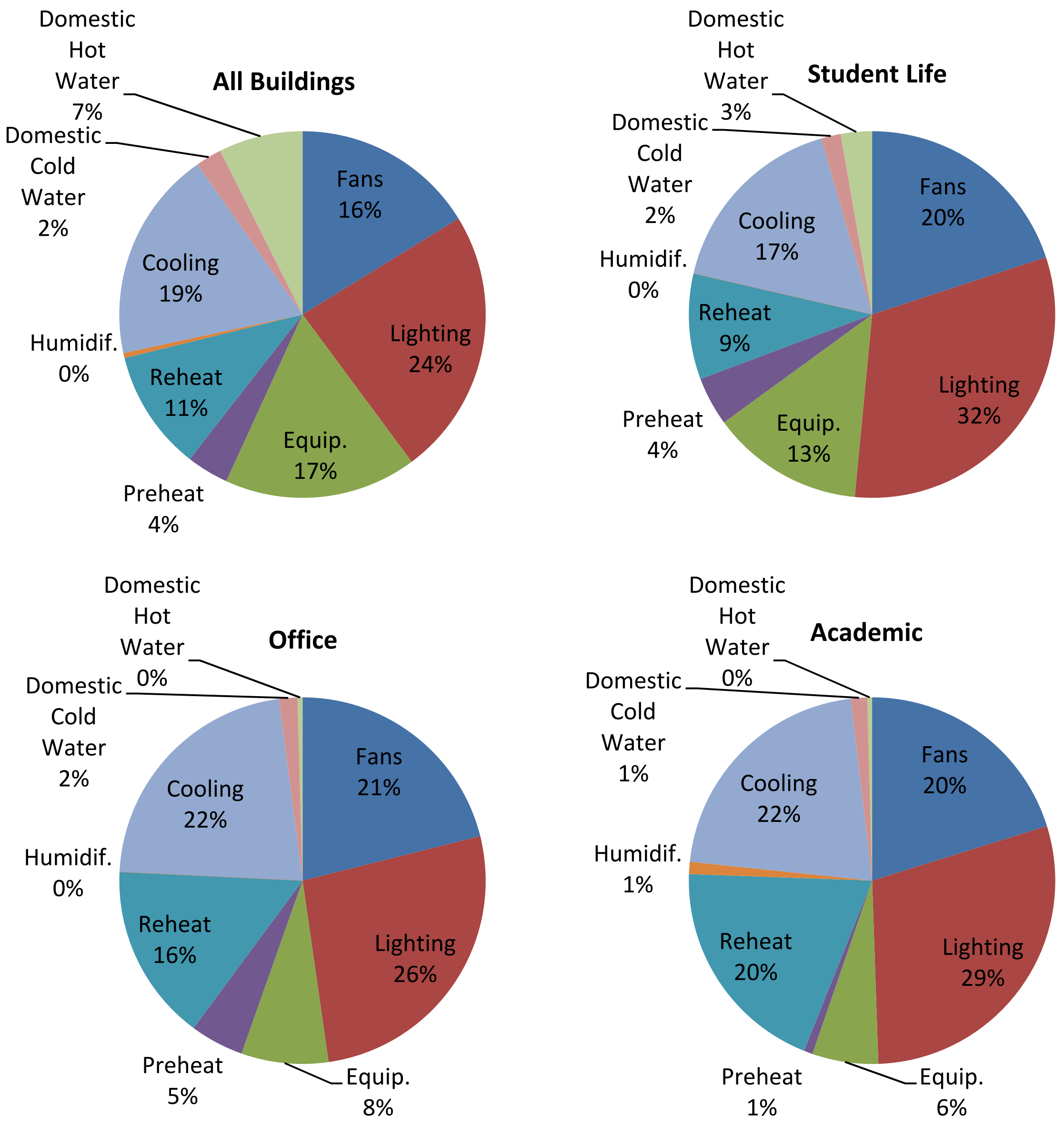


FIGURE 6.4.1.1: Utility Audit by Cost and Type of Building

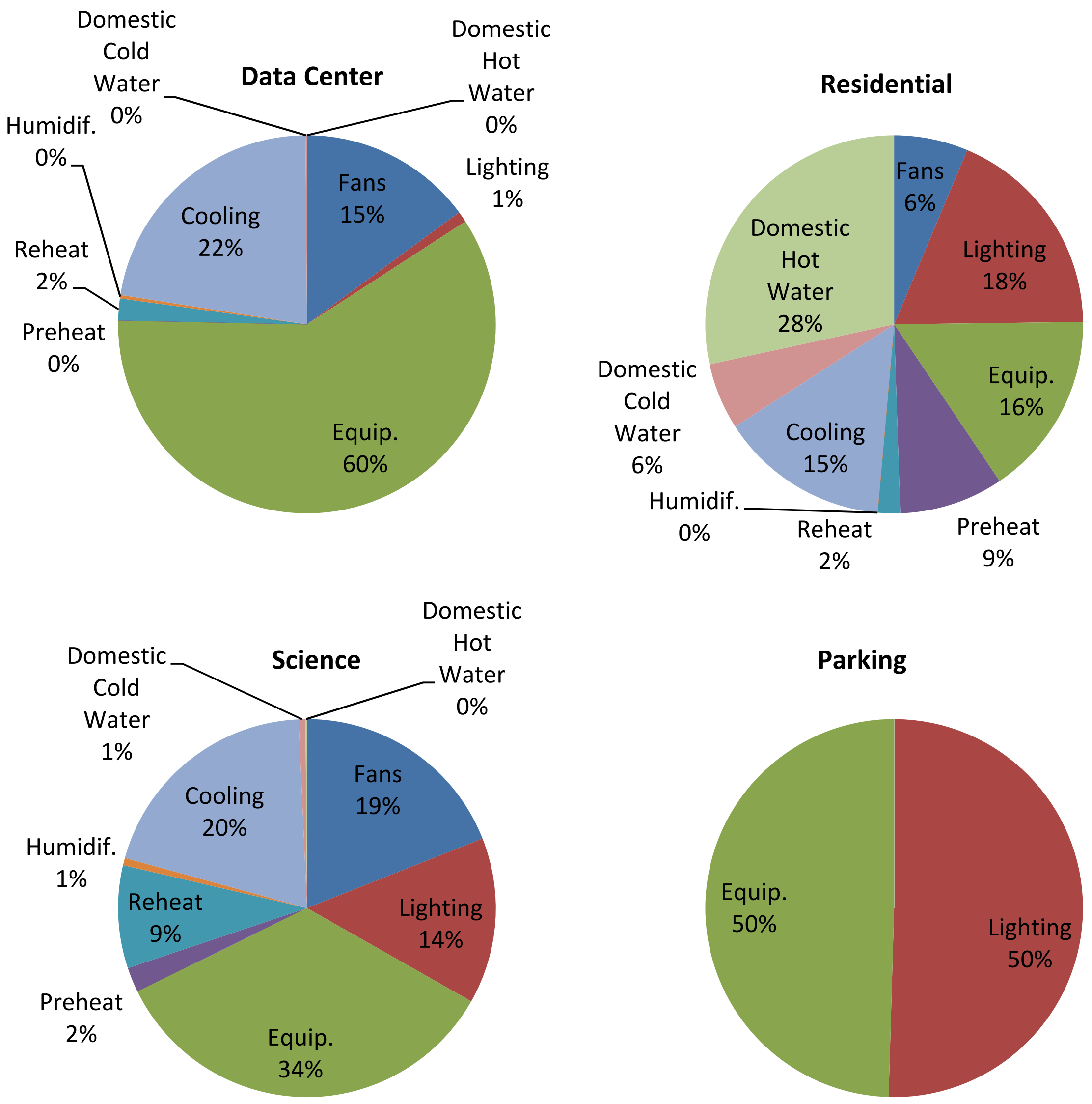


FIGURE 6.4.1.1: Utility Audit by Cost and Type of Building (continued)

6.4.1.2 Observations from Figure in 6.4.1.1: Listed below are conclusions from review of Utility Audit Figure 6.4.1.1.

- Lighting dominates energy consumption cost on the campus. The energy model estimates that 24% of utility consumption on campus is for lighting.
- Cooling is the second most significant energy cost on the campus. Electricity and domestic cold water usage (for the cooling tower) drive the cost of cooling to 19% of the campus utility consumption.
- Heating energy generally doesn't represent a large portion of the overall utility cost. For IUB, the marginal cost of producing heat with the Central Heating Plant is significantly less expensive than for facilities that are heated directly by natural gas or electricity. This comparison could be construed as being erroneous because we know that fixed losses (on

the heating system) that exist outside the buildings drive up the actual cost of heating buildings at IUB.

- Nearly half of the cost of utilities purchased for campus is ultimately used for heating, cooling and ventilating the buildings.
- Utility cost associated with domestic hot water usage is a significant for residence halls.

6.5 Building Retro-Commissioning Opportunities

6.5.1 Definition of Retro-Commissioning: In the facilities engineering and management communities, there are a number of conflicting definitions of retro-commissioning. The scope of this service can include everything from simple tweaks to equipment, energy studies and even major equipment replacement. For the purpose of this study, retro-commissioning has the following definition:

Retro-Commissioning: The service of adjusting, tweaking and repairing mechanical and electrical systems so that performance is returned to the as designed level.

A typical Retro-Commissioning project would identify and repair items such as:

- Control dampers / actuators failed
- Control valves / actuators failed (valves leaking thru)
- Control setpoints are set inappropriately
- Steam traps failed open
- Steam condensate pumps failed
- Insulation is missing

6.5.2 Evaluating Opportunity for Retro-Commissioning at IUB: For a traditional energy study, a basic assumption that is made is that the systems being modeled are fully functional. These studies rely a great deal on review of building drawings and review of building automation shop drawings and schedules of operation. For retro-commissioning, an extensive field investigation phase must be conducted to find how systems have actually broken down. For this reason, it is difficult (with a high level of certainty) to identify the actual economic benefits of retro-commissioning on a particular building without first conducting a detailed survey.

Because the Integrated Energy Master Plan scope of work did not include the exploratory services of retro-commissioning, a more simplistic approach to evaluating the potential for savings was performed.

As noted in paragraph 6.1.4 Building Energy Model, the validation of the energy model included a step of applying an adjustment to the energy model result based on energy metering data. Based solely on our level of understanding of the buildings and confidence in the metering data, we believe that adjustments that increase the amount of energy consumed over the energy model prediction account for retro-commissioning opportunities in the buildings. It is important to note that this method of analysis cannot be as accurate as a formal retro-commissioning study. However, this analysis does provide a glimpse of the scale of savings that are attainable and does identify likely candidates for retro-commissioning.

6.5.2.1 Retro-Commissioning Evaluation Sample: In the analysis for retro-commissioning, the Recreational Sports building appears to be a candidate for retro-commissioning. In this case, there appears to be an excessive consumption of steam. Figure 6.5.2.1 below is a copy of the graph from the energy model. The solid green line represents predicted steam consumption by the energy model and the red dashed line represents a degree day fit of the steam metering data. When this was first observed, we contacted IUB Facilities and discussed the deviation. They had just recently identified that the building heat recovery chiller system was not functioning properly. This improper operation results in direct passage of steam heat through the building heating water system to the building cooling tower. The net result of this failure is that the building uses significantly more heat than a conventional building that does not have heat recovery chillers. For this building, the Integrated Energy Master Plan will claim $116,000 of annual energy savings by retro-commissioning this building.

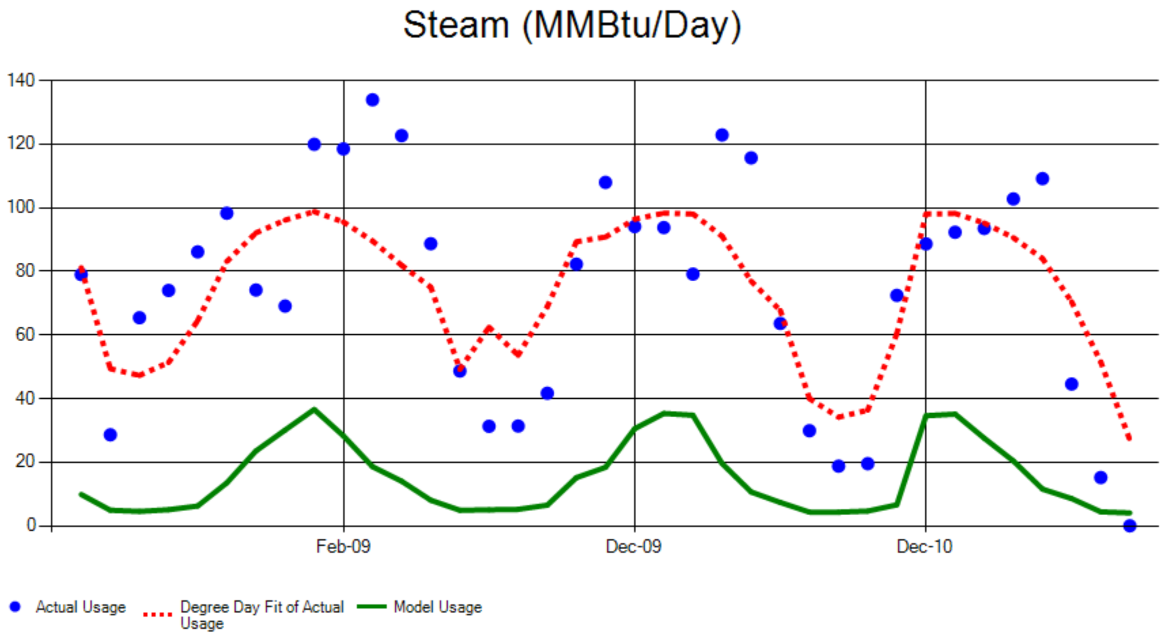


Figure 6.5.2.1: Recreational Sports Steam Consumption

PRIORITIZE BUILDING ENERGY CONSERVATION MEASURES

7 PRIORITIZE BUILDING ENERGY CONSERVATION MEASURES (ECM'S)

7.1 Energy Economics

7.1.1 **Overview:** As part of energy conservation measure planning, a business case that weighs the value of energy saved against the cost of implementing the ECM must be performed. For this study, a Payback Period is calculated to provide an indication of the number of years required to pay back the initial investment in the energy conservation measure. Rather than relying on a simple payback analysis, the analysis utilized on this project includes the time value of money. Additionally, for the parametric analysis in which combinations of ECM's must be compared, a Marginal Payback Period must be calculated. This term provides economic comparison similar to Payback Period, but also allow for determining the relative benefit of each ECM in the recommended group of projects.

7.1.2 **Payback Period:** A typical measure of energy performance that has been used over time is simple payback period. This equation is a described below:

$$Simple\ Payback\ Period\ (years) = \frac{Project\ Cost}{Annual\ Energy\ Cost\ Savings}$$

The simple payback period provides the number of years required to recoup the investment without taking into account the time value of money. This analysis is valid for short payback projects (less than 3 years), but can be inaccurate with longer payback periods because of inflation associated with the cost of energy as well as the internal rate of return of the institution performing the work. To correct for these variables, a present worth escalation factor is applied to the annual cost of energy. This factor is described below:

Given:

$$i = interest\ rate\ (cost\ of\ capital)$$

$$j = energy\ cost\ escalation\ rate$$

$$n = number\ of\ periods\ considered\ to\ evaluate\ the\ investment$$

The present worth escalation factor (PWEF) is calculated below:

$$PWEF = \frac{\left[\frac{1+j}{1+i}\right]^n - 1}{1 - \left[\frac{1+i}{1+j}\right]}$$

Using the PWEF defined above for each utility, Payback Period can be calculated by solving for “n” in the following equation:

Project Cost = Base Year Electric Cost * $PWEF_{elec}$
+ Base Year Natural Gas Cost * $PWEF_{gas}$
+ Base Year Steam Cost * $PWEF_{steam}$
+ Base Year Chilled Water Cost * $PWEF_{chw}$
+ Base Year Coal Cost * $PWEF_{coal}$
+ Base Year Domestic Water Cost * $PWEF_{wtr}$
+ Base Year Sewer Cost * $PWEF_{sewer}$
- Annual Electric Cost After Project * $PWEF_{elec}$
- Annual Natural Gas Cost After Project * $PWEF_{gas}$
- Annual Steam Cost After Project * $PWEF_{steam}$
- Annual Chilled Water Cost After Project * $PWEF_{chw}$
- Annual Coal Cost After Project * $PWEF_{coal}$
- Annual Domestic Water Cost After Project * $PWEF_{wtr}$
- Annual Sewer Cost After Project * $PWEF_{sewer}$

For the Integrated Energy Master Plan, the economic parameters utilized match those that are being used for Indiana University Qualified Energy Savings Projects. These values are listed below:

$$Cost\ of\ capital\ (i) = 4.75\%\ per\ year$$

$$Electric\ Cost\ Escalation\ Rate\ (j_{elec}) = 5.5\%\ per\ year$$

$$Natural\ Gas\ Cost\ Escalation\ Rate\ (j_{gas}) = 5.5\%\ per\ year$$

$$Steam\ Cost\ Escalation\ Rate\ (j_{steam}) = 6\%\ per\ year$$

$$Chilled\ Water\ Cost\ Escalation\ Rate\ (j_{chw}) = 4.5\%\ per\ year$$

$$Coal\ Cost\ Escalation\ Rate\ (j_{coal}) = 5.5\%\ per\ year$$

$$Domestic\ Cold\ Water\ Cost\ Escalation\ Rate\ (j_{wtr}) = 9.8\%\ per\ year$$

$$Sewer\ Cost\ Escalation\ Rate\ (j_{sewer}) = \ 10\%\ per\ year$$

7.1.3 **Marginal Payback Period:** When multiple ECM's are combined into a single project, the economic analysis used in this report lists a marginal payback period (years). The marginal payback calculation is identical to the Payback Period calculation except that the Project and Energy Costs are compared to another project on the same building. Similar to Payback Period, the PWEF is calculated in exactly the same manner. The equations for calculating the Marginal Payback Period are described below:

Given:

$$I_1 = Project\ Cost\ of\ ECM\ No. 1\ (\$)$$

$$I_{1+2} = Total\ Project\ Cost\ of\ both\ ECM\ No. 1\ and\ ECM\ No. 2\ (\$)$$

$$Project\ Annual\ Utility\ Cost_1 = Annual\ Utility\ Cost\ of\ Building\ with\ only\ ECM\ No. 1\ (\$)$$

$$Project\ Annual\ Utility\ Cost_{1+2} = Annual\ Utility\ Cost\ of\ Building\ with\ ECM\ No. 1\ and\ ECM\ No. 2\ (\$)$$

$$Marginal\ Payback\ Period_{1-2} = Marginal\ Payback\ of\ ECM\ No. 2\ after\ Implementation\ of\ ECM\ No. 1$$

Marginal Payback Period$_{1\text{-}2}$ is calculated by solving the equation below for "n" where "n" equals the Marginal Payback Period.

I_{1+2} - I_1 = Annual Electric Cost After Project$_{1+2}$ * PWEF$_{elec}$
+ Annual Natural Gas Cost After Project$_{1+2}$ * PWEF$_{gas}$
+ Annual Steam Cost After Project$_{1+2}$ * PWEF$_{steam}$
+ Annual Chilled Water Cost After Project$_{1+2}$ * PWEF$_{chw}$
+ Annual Coal Cost After Project$_{1+2}$ * PWEF$_{coal}$
+ Annual Domestic Water Cost After Project$_{1+2}$ * PWEF$_{wtr}$
+ Annual Sewer Cost After Project$_{1+2}$ * PWEF$_{sewer}$
- Annual Electric Cost After Project$_1$ * PWEF$_{elec}$
- Annual Natural Gas Cost After Project$_1$ * PWEF$_{gas}$
- Annual Steam Cost After Project$_1$ * PWEF$_{steam}$
- Annual Chilled Water Cost After Project$_1$ * PWEF$_{chw}$
- Annual Coal Cost After Project$_1$ * PWEF$_{coal}$
- Annual Domestic Water Cost After Project$_1$ * PWEF$_{wtr}$
- Annual Sewer Cost After Project$_1$ * PWEF$_{sewer}$

7.1.4 **Value of Carbon Reduction:** The value of any future tax on the cost of carbon dioxide emissions (or any other emission for that matter) is not included in the analysis of the ECM economics. Options for using carbon offsets or renewable energy to meet sustainability goals are discussed later in this report.

7.2 Building Energy Conservation Measures (ECM's)

7.2.1 **Overview:** Included in the following paragraphs are lists of energy conservation measures that were considered for building energy reduction at IUB. This list was developed specifically in response to the general opportunities that were apparent on campus.

These ECM's are simulated as though the work applies to the entire building. In actual practice, this is rarely the case. For this reason, project scope and budget must be validated on a building by building basis prior to final budgeting and implementation.

7.2.2 **Budgeting:** Note that the cost figures listed below are project cost estimates which include a 20% markup for soft costs. In general, cost figures are based on performing the ECM on a building of approximately 127,000 GSF (which corresponds to the average size building in our study). Costs are based on 2011 construction market conditions.

7.2.3 **Energy Conservation Measures (ECM's) Summary:** A listing of the energy conservation measures that were considered for IUB is described in the paragraphs that follow. These descriptions include a brief scope of work and an explanation of how implementation costs were assigned to the projects.

7.2.3.1 ECM: Add Building Insulation

General Description: Many buildings on the IUB campus do not utilize insulation in the exterior wall cavity. This ECM saves energy by increasing the R-Value of exterior walls by an R-Value of 10.0 (°F * ft^2 / Btuh).

Exceptions:

- Assumes scope of work is performed as part of a larger building renovation that includes dismantling finishes inside the building along the perimeter of the building.
- In buildings where humidification is used, considerations must be made to prevent condensation in the new insulation system.

Scope of Work:

- Remove and reinstall ceilings in the vicinity of the exterior wall.
- Remove and reinstall all accessories and fixtures from the exterior wall.
- For stud walls: Remove existing interior drywall partitions from floor to bottom of structure. Install 6 inches of fiberglass insulation between existing studs. Reinstall drywall.
- For masonry walls: Install 3.5" thermally broken studs against the exterior wall (from floor to structural deck). Install 3.5" of fiberglass insulation between the studs. Extend existing power / data outlets to the new wall surface. Reinstall drywall.

Project Cost Allowance: $8.94 / SF of wall area (including windows)

7.2.3.2 ECM: Upgrade Windows

General Description: Change windows to two layers of ¼" glass with low emissivity coating on the exterior that comply with ASHRAE Standard 90.1 (U Value = 0.5 and SHGC = 0.4).

Exceptions:

1. Assumes work is performed as part of a larger building renovation and that work can be performed during normal working hours.

Scope of Work:
1. Remove existing windows and frames.
2. Install new windows.
3. Patch interior walls window/wall interface.
4. Caulk joints between walls and windows on the exterior of the building.

Project Cost Allowance: $43.97 / SF of window area

7.2.3.3 ECM: Lighting Retrofit

General Description: Convert existing fluorescent fixtures to accept T-8 lamps and electronic ballasts.

Scope of Work:
1. Remove existing lamps and ballasts.
2. Install T-8 lamps and electronic ballasts.

Project Cost Allowance: $0.18 / GSF of building floor area + $1.44 / W reduction

7.2.3.4 ECM: Lighting Controls

General Description: Install occupancy sensors to automatically switch lights on and off.

Scope of Work:
1. Replace existing light switches with combination occupancy / light switches.
2. In larger open spaces, install ceiling mounted occupancy sensors.
3. Wiring lighting control relays into existing lighting circuits to control lighting.

Project Cost Allowance: $0.94 / GSF of building floor area

7.2.3.5 ECM: Change HVAC Type

General Description: Change HVAC system type to a more efficient system

Exceptions:
1. These cost estimates assume work would be performed in conjunction with other projects that affect space finishes (ceiling work for instance).
2. Installation of DDC controls on spaces is included under a separate budget.
3. Work would be performed during normal working hours.

Project Cost Allowance: Refer to Table A.

Table A: Change HVAC Type, Cost Model

Proposed HVAC System Type Conversion	Estimated Project Cost / GSF of building floor area
VAV to Fan Coil Units w/ Makeup Air Unit	$ 33.28
CAV to VAV	$ 5.88
CAV to FCU w/ Makeup Air Unit	$ 33.28
Dual Duct VAV to Fan Coil Units w/ Makeup Air Unit	$ 33.16
Dual Duct CAV to Dual Duct VAV	$ 4.84
Dual Duct CAV to Fan Coil Units w/ Makeup Air Unit	$ 33.16
FCU wo/MAU to Fan Coil Units w/ Makeup Air Unit	$ 12.29
Single Zone AHU to Fan Coil Units w/ Makeup Air Unit	$ 22.46
Multi-Zone AHU to VAV	$ 7.10
Multi-Zone AHU to Fan Coil Units w/ Makeup Air Unit	$ 27.14

7.2.3.6 ECM: Install Fan VFD's

General Description: Install variable frequency drives on air handling system that do not currently utilize volume control.

Exceptions:

1. Does not include cost associated with adding VAV boxes or other volume regulating devices.
2. Estimate based on installing VFD's on supply and return fans of 5 AHUs in an average sized building on campus (127,000 gsf)

Scope of Work:

1. Remove existing volume control system (inlet guide vanes, outlet dampers, etc) that exist.
2. Disable existing motor starter.
3. Install variable frequency drive.
4. Install controls to variable frequency drive. Modify programming as required.

Project Cost Allowance: $1.50 / GSF of building floor area

7.2.3.7 ECM: Reduce Max Airflow

General Description: Reduce design airflow quantities in the building. For constant volume systems and 100% outside air systems, there are substantial energy savings available in terms of fan energy and reheat energy (in some cases) by reducing the quantity of air moved in the building.

Exceptions:

1. Does not include cost associated with adding VAV boxes or other volume regulating devices.
2. Estimates assume supply fans would be re-sheaved to revised airflow quantities (VFD's would not be installed as part of this work).
3. Does not include cost associated with adding DDC controls to VAV Boxes.

Scope of Work:

1. Perform additional engineering to determine the proper amount of airflow required.
2. Perform testing and balancing to reduce airflows to new settings.

Project Cost Allowance: $1.14 / GSF of building floor area

7.2.3.8 ECM: Optimize VAV Operation

General Description: Reduce VAV Box minimum airflow setpoints to allow heating to start at lower airflow quantities. This change reduces reheat energy consumption and reduces cooling energy during summer operation.

Exceptions:

1. Does not include cost associated with adding VAV boxes or other volume regulating devices.
2. Cost estimates do not include installation of a variable frequency drive or other volume control device.
3. Does not include cost associated with adding DDC controls to VAV Boxes.

Scope of Work:

1. Perform additional engineering to determine the proper amount of airflow required.
2. Perform testing and balancing to reduce airflows to new settings.

Project Cost Allowance: $1.14 / GSF of building floor area

7.2.3.9 ECM: Reduce Outside Air Quantity

General Description: Reduce minimum outside air quantities to the building air handling system (via scheduling or as a blanket modification).

Exceptions:

1. Does not include cost of occupancy controls.

Scope of Work:

1. Perform testing and balancing to modify outside airflow.
2. Implement any control logic required to reduce outside airflow based on schedule.

Project Cost Allowance: $0.17 / GSF of building floor area

7.2.3.10 ECM: Change AHU Operating Schedule

General Description: Reduce HVAC energy by shutting equipment off during unoccupied hours.

Exceptions:

1. Does not include cost associated with addressing individual rooms that may require year-round cooling
2. Does not include cost of installing full DDC controls on AHU’s that do not have DDC controls.

Scope of Work:

1. Implement any control logic required to change building operating schedule.

Project Cost Allowance: $0.036 / GSF of building floor area

7.2.3.11 ECM: Modify Space Temperature Setpoints

General Description: Revise space temperature setpoints such that the cooling setpoint is 78°F and heating setpoint is 68°F for every hour of the year. Note that this implementation is different than the current system in which building thermostats are manually changed in the spring and fall rather than utilizing a wide deadband.

Exceptions:
1. Does not include cost associated with adding DDC controls to VAV Boxes.

Scope of Work:
1. For buildings with pneumatic thermostats, replace thermostats with deadband thermostats.
2. For buildings with DDC thermostats, modify temperature setpoints to achieve the specified temperature range.

Project Cost Allowance: $0.31 / GSF of building floor area

7.2.3.12 ECM: Implement Air-Side Heat Recovery

General Description: Install air – to – air heat recovery between HVAC supply air and HVAC exhaust.

Exceptions:
1. Pricing assumes that exhaust and outside air ductwork is in close proximity and that existing supply and exhaust systems can handle the additional pressure drop associated with these systems.

Scope of Work:
1. Install heat recovery coils downstream of filterbanks in the air handling unit and exhaust ductwork.
2. Install heat recovery pumps and piping between the heat recovery coils.
3. Install building automation for heat recovery system.

Project Cost Allowance: $15.26 / CFM of outside air

7.2.3.13 ECM: Reduce Humidification Setpoint

General Description: Eliminate humidification in the building.

Scope of Work:
1. Revise controls as required to disable operation of the humidifier.

Project Cost Allowance: $0.036 / GSF of building floor area

7.2.3.14 ECM: Install Zone DDC Controls

General Description: Replace existing pneumatic zone controls with DDC controls. This ECM is automatically included when zone DDC controls are not present and when one of the following ECM's is selected: Change HVAC System Type, Reduce Maximum Airflows, Optimize VAV Operation and Modify Space Temperature Setpoints.

Exceptions:
1. Pricing assumes an average of 1 zone per 800 GSF.

Scope of Work:
1. Demolish existing pneumatic controls.
2. Demolish existing pneumatic reheat control valves.
3. Install electric zone control valves.
4. Install DDC controls on all zone controls.
5. Test and balance to reset VAV Box maximum and minimum airflows.

Project Cost Allowance: $4.58 / GSF of building floor area.

7.2.3.15 Install Pump VFD (Heating Water or Chilled Water)

General Description: Replace existing motor starter with variable frequency drive.

Exceptions:
1. Modifications to AHU and zone control valves (conversion from three-way to two-way valves).

Scope of Work:
1. Demolish existing motor starter.
2. Install variable speed drive.
3. Install DDC controls to modulate speed and monitor.

Project Cost Allowance: For 7.5 HP Motors: $1090/HP, For 75 HP Motors: $382/HP

7.2.3.16 Install Water Side Economizer

General Description: Install plate frame heat exchanger system configured to cool chilled water with condenser water during winter months.

Exceptions:
1. Assumes there is space to install this equipment.

Scope of Work:
1. Install plate frame heat exchanger.
2. Install chilled water and condenser water pump station for system.
3. Install DDC controls to control and monitor.

Project Cost Allowance: For 1200 Tons Cooling: $683 / Ton, For 100 Tons Cooling: $3359/ton

7.2.3.17 Install Heat Recovery Chiller

General Description: Install a building chiller capable of simultaneously producing chilled water and heating water.

Exceptions:

1. Modifications to zone terminal equipment to enable operation with low temperature heating water.
2. Requires installation of water cooled chiller of equal size.
3. Assumes there is space to install this equipment.

Project Cost Allowance: Machine Size – 1200 Tons Cooling: $1057/Ton, 100 Tons Cooling: $1531/Ton

7.3 Methodology For Selecting Applicable ECM's and Parametric Analysis

7.3.1 **Overview:** The following section describes how the various energy conservation measures noted above are selected and analyzed on the building in the study. This analysis balances the economic viability of ECM's, the practicality of implementation and the overall suitability of the ECM's. When analyzing energy savings projects, it is of particular importance to determine how different ECM's interact with each other. For example; there is significant interaction between the Lighting Controls ECM and the Lighting Retrofit ECM. If these two ECM's are analyzed separately, the energy savings of implementing both together will be less than the sum of the ECM savings when considered alone. If more efficient lighting is installed, there is less energy to be saved when utilizing lighting controls (compared to the case in which efficient lighting is not installed). Because this interaction between ECM's is rarely predictable, the analysis of the ECM's must be performed to evaluate the relative performance associated with different combinations of ECM's. This process is referred to as a parametric analysis in this report and is described in more detail below.

7.3.2 **Selecting Applicable ECM's:** Following the validation of the energy model, energy conservation measures (ECM's) that apply to the given building are selected as options for analysis. For this study, the selection of ECM's that were analyzed was performed manually utilizing the survey information collected for lighting and HVAC system types as well as a dedicated review meeting with IUB was conducted specifically to review these selections. In most cases, these ECM's are selected to minimize energy consumption while continuing to maintain occupant comfort. Other guidelines that were followed in selecting applicable ECM's are as follows:

- Air Conditioning is added to buildings that aren't cooled with Change HVAC Type ECM.
- An ECM that would reduce humidification levels is not considered in buildings with art work or musical instruments.
- Laboratory building minimum airflow is not reduced below 4 to 6 air changes per hour.
- Occupancy schedules are not implemented in science buildings.
- Each of the following ECM types are combined into a single ECM's for the parametric analysis:
    - Lighting retrofit ECM and lighting control ECM
    - Change HVAC Type ECM, Reduce Maximum Airflow ECM, Optimize VAV Operation ECM, Install Fan VFD ECM and Modify Space Temperature Setpoints ECM

7.3.3 **Parametric Analysis:** Following the selection of applicable ECM's, a parametric analysis is conducted to determine the order in which the ECM's should be implemented. This process is performed in the following fashion:

- An ECM energy run is calculated that only includes one ECM. If the Payback Period of the ECM energy run is greater than 50 years, it is not considered for further analysis.

- The ECM energy run that provides the shortest Payback Period is selected as the new base case. Each ECM is added to the base energy run (one at a time) and the Payback Period and Marginal Payback Periods are calculated. The energy run that has the shortest Marginal Payback Period is then selected as the new base case and this process is repeated until all ECM's are included in the energy run.

7.3.3.1 Parametric Analysis Example: Included below is an example of the Parametric Analysis for Maxwell Hall. The first table (Table 7.3.3.1) shows the single elimination test. In this instance, the window replacement has a payback period greater than 50 years and automatically eliminated from further consideration. The second table shows the results of the parametric analysis for Maxwell Hall. This analysis begins with the ECM that had the best simple payback in the Elimination Test. Next, the other two remaining ECM's are added in the order that results in best Marginal Payback.

Table 7.3.3.1: ECM Elimination Test - EXAMPLE

Maxwell Hall Elimination Test				
Energy Run	**Included Energy Conservation Measures**	**Estimated Annual Energy Cost Reduction**	**Estimated Implementation Cost**	**Payback Period**
1	Optimize VAV Operation and Space Temp. Setback	$12,747	$45,144	3.5 years
2	Lighting Retrofit and Lighting Controls	$5,944	$43,652	7.2 years
3	Add VFD's to Heating Water	$132	$1,389	7.9 years
4	Replace Windows	$375	$119,900	163

In this example, Replace Windows would be removed from further consideration because simple payback is greater than 50 years.

Table 7.3.3.2: ECM Parametric Analysis - EXAMPLE

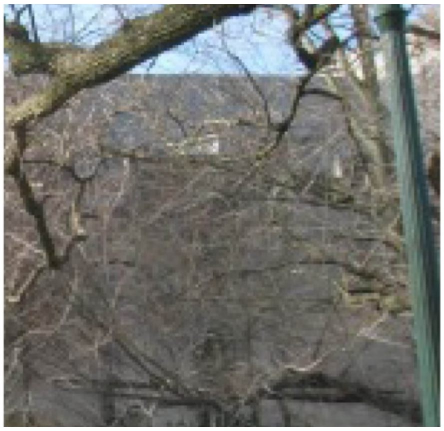
Parametric Run					
Energy Run	**Included Energy Conservation Measures**	**Estimated Annual Energy Cost Reduction**	**Estimated Implementation Cost**	**Payback Period**	**Marginal Payback**
2	Optimize VAV Operation and Space Temp. Setback	$12,748	$45,144	3.5 years	NA
5	Optimize VAV Operation and Space Temp. Setback **+ Lighting Retrofit and Lighting Controls**	$19,746	$88,796	4.5 years	**6.1 years**
7	Optimize VAV Operation and Space Temp. Setback + Lighting Retrofit and Lighting Controls **+ Add VFD's to Heating Water**	$20,438	$90,185	4.6 years	**25.8 years**

In this example, the determination of whether or not to implement the ECM should be based on Marginal Payback rather than Simple Payback.

7.4 Building Energy Run Results

7.4.1 **Results:** The results of the parametric analysis are included in Appendix A, Table A8.2.1. Review and totalization of this data suggests that by implementing all the projects described by the ECM's, a grand total of $6,890,000 per year can be saved through energy conservation. However, the implementation cost to obtain the savings would be $126,476,000 (simple payback period of 18.4 years) and reduce carbon emissions by 129,800 Tons CO_2 per year.

BUILDING INITIATIVES



POTENTIAL COMPONENTS OF THE ENERGY MASTER PLAN

8 BUILDING INITIATIVES

8.1 Building Retro-Commissioning

8.1.1 Opportunities for Retro-Commissioning: Included below are two tables summarizing the opportunities for retro-commissioning at IUB. Our evaluation resulted in two lists of buildings; Strong Candidates and Questionable Candidates. Table 8.1.1.1 summarizes the “Strong Candidates” list. For buildings on this list, there is strong confidence in the metered readings and in our understanding of the building for modeling. Table 8.1.1.2 summarizes the “Questionable Candidates”. For buildings on this list, there is some question as to the accuracy of the metering data and/or our understanding of the building for modeling. For both tables, implementation cost is based on a $0.50 / GSF cost for a retro-commissioning study and an average project simple payback of 1.25 years (based on recent experience).

Table 8.1.1.1: Retro-Commissioning Summary for Strong Candidates

Building		"Strong Candidates" Opportunity for Retro-Commissioning (Potential Annual Savings)	Estimated Implementation Cost
BL604	Gladstein Fieldhouse	$131,361	$215,915
BL475	Recreational Sports	$115,888	$271,511
BL603	Assembly Hall	$114,414	$333,570
BL107	Jordan Hall	$107,771	$296,853
BL237	Wright Quad	$59,946	$222,876
BL209	Wells Library	$60,339	$354,005
BL452	SPEA	$49,297	$125,931
BL451	Business School	$42,942	$172,757
BL243	Teter Quad	$42,038	$202,984
BL111	Ballantine Hall	$40,795	$203,703
BL433	Briscoe Quad	$35,950	$184,649
BL071	Chemistry	$25,363	$123,398
BL027	Swain West	$22,550	$105,489
BL450	Godfrey Grad&Exec Ed Ctr	$10,179	$108,596
BL008	Poplars	$16,776	$96,180
BL462	Jenkinson Hall	$12,298	$33,820
BL155	Lilly Library	$11,355	$40,452
BL017	Student Building	$7,699	$44,492
BL463	Nelson RPS Admin.	$7,242	$29,279
BL059	Lindley Hall	$7,107	$38,839
BL047	Smith Hall	$6,546	$19,493
BL109	Goodbody Hall	$4,601	$24,512
BL033	Maxwell Hall	$4,069	$20,631
Total		**$936,526**	**$3,269,935**

Table 8.1.1.2: Retro-Commissioning Summary for Questionable Candidates

Building		"Questionable Candidates" Opportunity for Retro-Commissioning (Potential Annual Savings)	Estimated Implementation Cost
BL072	Chemistry Addition	$128,686	$53,276
BL119	HPER Building	$62,866	$94,888
BL139	Morrison Hall	$53,558	$26,995
BL157	Fine Arts	$54,713	$57,777
BL453	Harper Hall	$42,207	$54,574
BL257	Forest Quad	$41,422	$144,507
BL602	Tennis Center	$27,050	$28,854
BL461	Magee Hall	$25,089	$18,532
BL149	Sycamore Hall	$21,799	$37,301
BL007	Franklin Hall	$19,167	$69,075
BL454	Gresham Dining Hall	$11,730	$25,444
BL153	Art Museum	$3,453	$59,657
Total		**$491,739**	**$670,878**

8.1.2 **Remarks Concerning Table 8.1.1.1 and Table 8.1.1.2:** As indicated in Paragraph 6.5, the economics presented for retro-commissioning are based on comparisons between building metered usage and the simplified energy model utilized to simulate the building performance. A detailed retro-commissioning study will be required to validate and identify the specific issues that exist at these and other buildings.

8.2 Building Energy Savings Opportunities

8.2.1 **Results:** The results of the parametric analysis are included in Appendix A, Table A8.2.1 and Table A8.2.2 . Review and totalization of this data indicates that by implementing all the ECM's included, a grand total of $6.89M per year can be saved through energy conservation with an implementation cost of $126M. These results are based on marginal utility rates for FY2010-2011 assuming that the existing fuel mix does not change.

8.2.2 **Analysis of Building Energy Conservation Measure Opportunities:** Specific recommendations for how to proceed with the building energy conservation measures are discussed in the recommendations section of this report. Included below is an analysis of the various energy conservation measures that were analyzed and information about the projects that will ultimately reduce energy consumption most effectively.

8.2.2.1 Change HVAC Schedule and Reduce Humidification: The work associated with implementing this ECM's is very little. Even with conservative cost estimates, the average Marginal Payback associated with implementing these projects is 0.2 years. Overall, the Building ECM analysis shows a range of marginal paybacks in the range of 0 to 2 years.

8.2.2.2 Lighting Retrofit and Lighting Controls: Given rising electrical rates, it is not surprising to see that performing lighting retrofits and installing lighting occupancy controls provide reasonable marginal paybacks. For the list of ECM's presented, ECM's for Lighting represent an average marginal payback of 7.6 years with a range of paybacks between 4.3 and 16 years.

8.2.2.3 Air Handling System Modifications: This broad category includes energy conservation measures that change the operation of the air handling systems beyond simple schedule modifications. These modifications include: Install Fan VFD's, Reduce Maximum Airflow, Optimize VAV Operation, Space Temperature Deadbands and complete system change-outs. Because the scopes of work vary widely and are dependent on a large number a parameters, the average marginal payback is 13.3 years with paybacks between 1 year and 47 years.

8.2.2.4 Air-Side Energy Recovery: For the ECM's investigated, the marginal payback associated with installing air to air energy recovery is between 23 and 39 years. This ECM produces poor paybacks because: 1) In a retrofit application, the cost of installing an air to air energy recovery system is very high. Implementing this when first installing a system is substantially less expensive. 2) The marginal cost of steam heat at IUB is low. Because of this, there is less energy cost to save.

8.2.2.5 Replace Windows and Insulate Buildings: For both window replacement and building insulation, the payback periods exceeded 50 years in our model. This result is not unexpected. This result is partly driven by the relatively low marginal cost for heating on campus. This result is also driven by the large cost of implementation. For these types of projects, the business case for performing the project must contain factors in addition to energy savings (such as windows that fail to stop rain intrusion). Similar to Air-Side Energy Recovery, the right time to address these issues (in terms of energy) is when the building is first built.

8.3 Building HVAC Capital Renewal

8.3.1 **Candidates for HVAC Capital Renewal:** As part of the survey that was performed on the buildings, the condition of the HVAC systems was recorded. After reviewing this information, it is apparent that there are many buildings on campus that utilize HVAC systems that have served beyond their expected useful life. For these types of buildings, consideration must be made as to whether it is more prudent to spend capital to improve the overall building rather than improve performance in the short term by placing band-aids on a worn out components.

Listed below are buildings which we believe belong in the "Needs Capital Renewal" category:

Table 8.3.1: Buildings Candidates for HVAC Capital Renewal

Building ID	Building Name
BL008	Poplars
BL027	Swain West
BL043	Edmondson Hall
BL045	Cravens Hall
BL047	Smith Hall
BL055	Owen Hall
BL058	Kirkwood Hall
BL091	Wildermuth Center
BL109	Goodbody Hall
BL111	Ballantine Hall
BL141	Memorial Hall

Building ID	Building Name
BL148	Music Addition
BL149	Sycamore Hall
BL177	Musical Arts Center
BL227	Read Hall
BL237	Wright Quad
BL304	Mason Hall
BL417	Geological Sciences
BL418	Geological Survey
BL467	Health Center
BL602	Tennis Center
BL604	Gladstein Fieldhouse

The typical scope of a HVAC capital renewal would include replacing all or parts of the HVAC system including central station air handling units and terminal units as well as ductwork and piping as applicable.

Similar to the decision to replace windows, the justification for HVAC Capital Renewal needs to extend beyond energy savings. Other justification may include: 1) parts are no longer available, 2) the system is unable to maintain occupant comfort, 3) maintenance costs are too high and 4) cooling is not provided. Energy savings and project costs are included in the results outlined in Tables A8.2.1 and A8.2.2.

CENTRAL PLANT INITIATIVES

9 CENTRAL PLANT INITIATIVES

9.1 Central Steam Heating Plant

9.1.1 Development of Thermal Model

9.1.1.1 An earlier section of the report briefly described the components and capacity of the CHP and the fuels utilized to distribute heating energy in the form of steam to the IUB campus. Figure A9.1.1.1 in the Appendix illustrates the schematic flow diagram of the major components of the steam plant and steam distribution system to and returning from the campus buildings. To analyze fuel use for optional plant operating scenarios such as fuel switching or marginal energy reductions due to reduced campus loads through the initiation of building ECM's and retro-commissioning, a thermal model of the CHP and the distribution system it serves was developed. To develop the model, FY 09-10 plant production data was obtained for all of the major elements of the operation of the CHP including available metered steam, condensate, and make-up water flows, fuel use by service, and electricity generated and purchased to support the steam plant operation. A schematic of the CHP thermal model is indicated on Figure A9.1.1.2 in the Appendix. Operating points and corresponding annual mass flows for FY 09-10 are indicated on Table A9.1.1.3, also in the Appendix. The development of the thermal model of the distribution system and the identification of the thermal requirements of the buildings connected to the steam system are discussed in other sections.

9.1.1.2 The salient features of the thermal model for the CHP and its distribution system based on FY 09/10 data are:

- Overall boiler combustion efficiency of 70.1%
- ASME PTC-4 overall boiler efficiency of 68.6% (considering total heat available for steam production)
- Annual steam distributed to the campus consists of 79% at 40 psig and 21% at 150 psig
- Annual condensate returned to the plant represents 69% of the steam produced with the remaining 31% (plus blowdown) provided by softened and treated make-up water.

- Of the total annual fuel consumed by the plant, 49.4% of the energy is ultimately delivered to the buildings for heating purposes.
- New gas fired boiler No.7 fires at much higher efficiency than the remaining boilers, approaching 88% based on metered fuel use and steam produced.

9.1.1.3 The thermal model was utilized as the basis for all of the CHP calculations that follow.

9.1.2 Energy Conservation/Emissions Reduction Measures

9.1.2.1 Addition of Second Micro-Turbine Generator Set

In 2010, IUB installed a Carrier Micro-Turbine Power System at the CHP. The device is fundamentally a steam turbine generator set installed in parallel with one of the existing plant pressure reducing stations, reducing 150 psig boiler steam generation pressure to 40 psig for distribution to a large portion of the campus. The steam turbine extracts some of the heat content of the entering steam, converting it into shaft energy. This shaft energy spins an electrical generator to provide 480 volt 3 phase electrical energy for the CHP. The energy in the steam extracted by the micro-turbine is by no means free but the value of the electricity produced exceeds the value of the steam used to produce it. Therefore, the micro-turbine generator represents an ECM that saves energy cost. It does not however reduce total energy use or net carbon emissions in that the electricity produced by the micro-turbine is generated mainly by burning coal in coal fired boilers, the same operation that is occurring at the Duke Energy electric power plant generating electricity to serve the IUB campus.

This ECM considers the addition of a second nominal 250 kW micro-turbine generator set in parallel with the first unit. Operating in tandem with the first unit, the system would have the capability of offsetting over 70% of the electricity required by the CHP. Based on our calculations, the installation of a second 250 kW steam micro-turbine generator at the CHP would present the following economic pro forma:

Description of ECM	Annual Cost Savings[1]	Implementation Cost	Payback Period (yrs)	Annual CO_2 Savings (tons)	Percentage of Total CO_2 Emissions from Energy Use[2]
Retrofit of CHP with Additional Micro-Turbine Generator	$88,202[3,4]	$881,910	10.0	0 tons	0.0%

Note 1: Savings based on FY 10-11 estimated average utility costs
Note 2: Based on FY 10-11 energy related emissions of 489,895 tons CO_2 total
Note 3: Based on an annual electrical savings of 1,971,000 kWh based on (250 kW) x (8760 hours/year) x 0.90 Utilization Factor
Note 4: Cost savings are variable based on fuel cost

Though total annual energy use would not be reduced, the operation of the second micro-turbine generator would reduce total energy cost and serve to unload the campus electrical distribution system by a total of 500 kW. If natural gas were being used as the source of steam in the CHP, the annual energy cost savings would be reduced but total carbon emissions would also be reduced (substituting natural gas for coal for that portion of electrical generation).

However, better options are available with similar paybacks that serve both energy cost and carbon emissions. Therefore, we do not recommend this option be implemented.

9.1.2.2 Fuel Source Modifications: Conversion to Full or Partial Natural Gas Use

The emissions benefits of firing on natural gas in lieu of coal are well understood. Combustion of natural gas releases about 58% of the carbon dioxide that is released in the combustion of coal for an equivalent Btu content of fuel burned. Considering the typical efficiency of modern watertube natural gas boilers versus the efficiency of moving grate stoker coal boilers, the actual reduction in carbon dioxide emissions with natural gas is to about 48% looking at the steam produced by each fuel source. From the standpoint of carbon dioxide emissions only, the decision to burn natural gas is simple.

However, the cost per MMBtu for coal has been very stable and inexpensive; with plentiful reserves located close enough to campus that trucking has been a very cost efficient means of delivery for IUB. Coal pricing including delivery is relatively simple with multiple year contracts at relatively fixed prices. Natural gas on the other hand has seen major excursions in cost in the past 5 years and in the current deregulated environment, its purchase is complex, with multiple vendors involved in the purchase and delivery of natural gas with multiple tiers of cost based on the amount of natural gas purchased.

It is our belief that ultimately legislation or operating restrictions imposed by the EPA will limit or prevent the firing of coal at the CHP. But until this becomes the case, we believe it is desirable for the University to retain the multiple fuel sources that they have today to maintain as much operating cost stability as possible. Thus the fuel mix decision must be based on the economics of operation on the comparative fuels available and the stated desire of the University to reduce greenhouse gas emissions. Since there are no present economic drivers in the form of a “carbon tax” on carbon dioxide emissions, it is up to the University to weigh the value of reduced carbon emissions versus the lower cost of operations burning coal at the CHP.

However in the course of our study, it became apparent that the cost of natural gas has been dropping consistently and shows signs of dropping even further. It therefore seemed to make sense to provide the University with an accurate tool to assess the true differential cost between current operations on 90% coal and 10% natural gas and operation on 100% natural gas. Our goal in this effort was threefold.

- To determine the current annual projected operating cost difference between coal and natural gas at the CHP,
- To determine on a month-by-month basis the estimated difference in cost between current operations on 90% coal/10% natural gas and operation on 100% natural gas, and
- To determine the annual cost of base loading the new natural gas boiler no. 7 with the remaining heating needs provided by burning coal.

Given this data, the University can make an informed decision that is based on a combination of the lowest operating cost and the additional cost that would be borne in an operating scenario that defines the resolve of the University to reduce carbon emissions.

To accomplish these tasks, the spreadsheets indicated as Tables A9.1.2.1 thru A9.1.2.5 in the appendix were created. The upper part of the spreadsheet calculates the cost of natural gas for each specific scenario. Each sheet begins with a projected steam load and applies Vectren local delivery charges (Tariff for Gas Service I.U.R.C No. G-19 – effective 2/14/08) and the Energy USA Citygate Gas prices (combining the NYMEX settlement price for past months or NYMEX Futures prices for future months plus the Basis Costs for Vectren North). For the purpose of these comparisons, FY 2010/2011 steam loads were assumed with boiler efficiencies for boiler no. 7, boiler no. 7 and boiler no. 5, or boiler no. 7 and a new higher efficiency boiler no. 8 (replacing boiler no. 5) depending on the scenario considered. The bottom part of the spreadsheet calculates the operating cost of the running on 90% coal and 10% natural gas as is the current technique used at the CHP. Employee costs and differential costs of operating on coal versus natural gas are captured here, with the magnitudes depending on the options considered.

Tables A9.1.2.1 and A9.1.2.5 indicate four options that were considered for the plant and the assumptions that were used, all based on projected operation for FY 11/12. The results of these calculations are indicated below.

1) If operations were switched to 100% natural gas for FY 11/12 and the staff was reduced to accommodate only natural gas, the additional annual cost to operate on natural gas would be $586,314 (Option A).
2) If Boiler No. 5 were replaced with a modern water-tube natural gas boiler of similar size (designated as Boiler No. 8) and efficiency as Boiler No. 7 and with staff reductions as in 1) above, the additional annual cost to operate on natural gas would be reduced to $210,633 (Option B).
3) Without the addition of a new high efficiency Boiler No. 8 but by base loading Boiler No. 7 on natural gas, without any staff reductions, and using coal for the remainder of the steam required, the additional annual cost to operate on in this mode would be $455,622 (Option C). This option would burn approximately 80% natural gas annually.
4) If Boiler No. 7 were base loaded but plant operations were arranged to burn approximately 50% natural gas and 50% coal, the additional annual cost to operate in this mode would be $271,840 (Option E).

Based on these calculations, we would offer several recommendations. These recommendations are based on our assertion that IUB is moving toward firing higher quantities of natural gas in the CHP based on environmental and/or legislative restrictions on the firing of coal, though the timing of these events is yet unknown.

- Using the spreadsheets indicated above, compare the cost of coal versus the cost of natural gas on a month-by-month basis for the CHP to determine the lowest cost fuel choice. If the natural gas cost is higher, determine the monthly premium cost the University is willing to spend for the reduced carbon emissions that will result from this change. (For January of 2012, base loading on natural gas in Boiler No. 7 has yielded favorable results.)
- Assuming favorable natural gas rates continue, revise operations to option (3) indicated above. This would indicate operation on Boiler No. 7 for the months of May through September, with coal and natural gas fired in the remaining months. Such a change would reduce carbon dioxide emissions from the CHP by 71,423 tons of CO_2 per year or a reduction of 40% of present emissions from the CHP.
- Existing Boiler No. 5, capable of firing natural gas or fuel oil but not coal, was installed in 1964 and is currently firing at very low efficiency (63.1% based on FY 09/10 plant production report, even lower in FY 10/11). If increased firing on natural gas is contemplated, we

recommend Boiler No. 5 be replaced with a new high efficiency Boiler No. 8 of the size and efficiency of Boiler No. 7. Such a modification would improve the stability and redundancy of natural gas firing in the plant. If a conversion to 100% natural gas firing occurred, the new boiler would save approximately $376,000 annually (vs. Option A above).

9.1.2.3 Fuel Source Modifications: Conversion to Firing on Biomass

Biomass is an attractive option as a substitute for coal on campuses such as Indiana University Bloomington that are equipped with coal fired boilers but who wish to reduce their carbon emissions. This is possible since at the moment, burning biomass like wood is considered a "Carbon Neutral" process. (Since carbon emitted from the combustion of wood and other biomass materials is recaptured by the growth of replacement wood and crops, it is generally recognized as long term carbon neutral.) The biomass options indicated below were each reviewed for their applicability for IUB. Unfortunately, it is our conclusion that this technology cannot currently compete with natural gas for IUB because of significantly increased biomass fuel costs relative to converting to natural gas. In addition, each of these technologies is proprietary in nature and in the development phase, making true comparisons difficult at this time. This conclusion may change in the future as the technology becomes better developed but for now, it is our recommendation to adopt a "wait and see" posture with respect to the incorporation of biomass in the campus fuel mix. Specifics of our findings are indicated below.

Nu Materials Coal/Biomass Briquettes
(www.numaterials.com).

Nu Materials, a company from Ooltic, Indiana, is marketing a biomass material that is currently composed of 60% coal, 40% biomass, and a binder that holds the product in a briquette form. This mixture has roughly the emissions characteristics of natural gas. This technology and the applicable patents associated with it have just become available for commercial use. Assuming Nu Materials coal biomass briquettes were now available at a cost of $90/ton (their current estimate) and having a heat content of approximately 10,000 Btu/lb (60%coal/40%Biomass designated I-Fuel 60), replacing coal with this fuel based on FY 10-11 stem use would increase the annual operating cost by $3,120,627. Utilizing this technology when it becomes available has the potential to reduce plant emissions by 67,331 tons of CO_2 annually. Initially, the product will be a combination of Peabody coal, wood chips, and a binder. Future materials for binding to coal are paper and various corn or bean products. Nu Materials is working on combining coal with torrefied wood as a biomass option and believes it can be done less expensively than New Biomass but it is still in an experimental stage for them.

New Biomass Torrefied Wood
(www.newbiomass.com)

Torrefaction is the roasting of wood or other biomass to create a product that (1) has increased energy density, (2) have characteristics that make it easy to handle and transport, and (3) is practical to coal fire in existing boilers. The idea would be that the torrefied wood product would be burned in a mix with coal to mimic the emissions characteristics of burning natural gas. This technology is currently available but not in the quantities required by IUB. Based on FY 10-11 fuel costs, burning torrefied wood under a proposed agreement with New Biomass in quantities of approximately 42% torrefied wood/58% coal would displace 70,077 tons of CO_2

emissions annually. The estimated cost of the torrefied wood is $8.00/MMBtu for an estimated additional plant operating cost of $3,723,600 a year.

Nexterra Biomass Gasification Systems
(www.nexterra.ca)

The Nexterra process utilizes wood chips in a fixed bed, updraft gasifier, creating in a proprietary process a synthetic, combustible gas that can be burned in specially designed boilers (but cannot be burned in the existing boilers at the CHP). Such a design would require a significant up-front cost of approaching $7,000,000 for a 40,000 lb/hr boiler plant producing 150 psig steam, significantly smaller than the needs at the CHP except for a partial source. In addition, this would be a turnkey plant addition where Nexterra would design the plant but it would be the responsibility of IUB to procure the biomass materials and set up delivery arrangements for transporting the materials from their point of origin to the CHP. Data that was offered to Nexterra to develop an economic pro forma for the IUB campus CHP have not been responded to as of this date. However our research has led us to believe that the technology is currently not competitive with the option of natural gas combustion.

9.2 Steam and Condensate Distribution Systems

9.2.1 Development of Thermal Model

9.2.1.1 The previous section described the establishment of a thermal model for the CHP and the buildings connected to it. Included in the state points of that model were losses associated with the steam and condensate distribution systems as well as the losses associated with the condensate that does not return to the CHP (being lost from the distribution system). Further, previous sections have indicated that base load steam use (significantly evident in the summertime) should be an important element in reducing energy consumption in the campus thermal systems. By all outward indications, various segments of the steam and condensate distribution piping systems are quite old and, based on repairs undertaken in recent years, have likely lost most of the insulation materials that accompanied their original installation.

9.2.1.2 In an effort to define the losses from the steam and condensate distribution systems at Indiana University Bloomington, a thermal model of the distribution model of the distribution system was developed. The model includes losses for buried piping and piping in tunnels based on algorithms found in the 2008 ASHRAE Handbook – HVAC Systems and Equipment, Chapter 11, "District Heating and Cooling". For existing components of the distribution systems that are more than 15 years old, buried piping was considered uninsulated and piping in tunnels was considered minimally insulated with fiberglass insulation with all service jacket. Sections of the piping that have been recently replaced or that were considered for replacement under this study were considered insulated as per ASHRAE Standard 90.1-2007 requirements. New buried piping was assumed to be in a Multi-Therm 500 Piping System as manufactured by Perma Pipe, Inc. with the insulated steam or condensate pipe centered in an air space surrounded by an insulated steel conduit with fiberglass outer jacket. Soil conditions were varied from dry to very moist with the following values used for soil conductivity k_s:

Soil Type	Soil Conductivity (Btu/hr-ft-°F)
Dry	0.5

Average	1
Moist	1.25
Very Moist	1.7

9.2.1.3 Based on these parameters, Tables A9.2.1.1 through A9.2.1.3 indicate per unit length heat losses expected based on piping insulation system and soil type. Tables A9.2.1.4 through A9.2.1.7 indicate the results achieved from the thermal model of the IUB distribution system. Based on the results of these calculations, the following steady heat losses from the distribution system would be predicted by the model based on the degree of dryness of the soil.

Soil Conditions	Pipe Heat Loss (MMBtu/hr)
Very Moist Soil	**48.1**
Moist Soil	**36.3**
Average Soil	**29.8**
Dry Soil	**16.8**

9.2.1.4 Obviously based on the season and rainfall, the soil conductivity probably varies considerably over the year. Based on the nearly continuous limestone substrate below the campus, moistness is probably often apparent. The model predicts that between dry soil and very moist soil losses would increase by 31,324 MBh or about 32,058 lbs/hr of steam flow. This value roughly matches the experience of the CHP that during a period of heavy rain, the steam load increases by about 35,000 lbs/hr.

9.2.1.5 The thermal model therefore seems accurate at least at its limits. Though the specific variability of weather cannot be definitively determined, what is sure is that losses from the distribution system vary by soil conditions but probably account for at least 50% of the summertime steam load experienced by the CHP. Thus the steam and condensate distribution system is an obvious candidate for any energy conservation measures available.

9.2.2 Energy Conservation/Emissions Reduction Measures

9.2.2.1 Reduction of Plant Steam Generation Pressure to 40 psig

From a theoretical standpoint based on normal boiler design, a 40°F reduction in flue gas temperature for a natural gas fired boiler results in approximately a 1% increase in boiler thermal efficiency. For the same boiler design firing at lower steam pressure, the flue gas temperature reduces in approximately a direct proportion to the temperature reduction of the steam produced by the boiler. For a change in steam pressure from 150 psig saturated to 40 psig saturated, there is a steam temperature drop from 367°F to 287°F. This 80°F drop in temperature will result in a 2.0% increase in boiler efficiency. Based on the FY 10/11 CHP plant production and fuel mix, this change would result in a fuel reduction of about 49,478 MMBtu and a cost reduction of approximately $206,800 annually. In addition, heat losses in the form of radiation and convection from steam piping and vessels that would see this change in pressure would reduce by about 28%.

However, several design issues relative to the existing CHP boilers will make this option difficult to achieve.

- The plant is currently equipped with industrial watertube type boilers that are designed for operation on high pressure steam. Firing these boilers at 40 psig will present several operational issues because of the higher nozzle velocity at the lower pressure steam. Water carryover will almost certainly occur with firing at 40 psig unless the boiler steaming capacities are significantly reduced from their current design capacities.
- The current flue gas economizers on the boilers are effectively reducing the flue gas temperature to attain a large portion of the efficiency benefits that would be achieved by firing the boilers at 40 psig.
- Though the existing micro-turbine does not save energy in the strictest sense, it does reduce plant energy cost, thus reducing again the payback of a reduction in boiler operating pressure since this feature would be lost.

Because of these concerns, we do not recommend the implementation of this option. We believe that a reduction in the operation of the steam main pressure leaving the boiler plant to 40 psig on all of the campus steam mains provides a more viable option to reduce energy as described later.

9.2.2.2 Distribution Steam Pressure Reduction

Energy can be saved through steam pressure reductions in the distribution system serving the campus. The savings can be achieved through related techniques:

- Reduce steam pressure in the 150 psig mains to 40 psig
- Retain the 40 psig steam pressure in all of the mains throughout the year (with no increase in the winter months to serve Jordan Hall)

Our calculations on the heating loads in the various buildings and the sizes of the 150 psig mains lead us to the conclusion that the 150 psig system is oversized for the loads currently connected. Reduction in steam pressure in these mains to 40 psig would save approximately 2,650 lbs/hr of steam flow for an annual savings estimated at the CHP estimated at $102,104 per year (for the existing buried pipe that is in poor condition). These savings would be significantly reduced by simply replacing the existing failed piping. However, additional savings would accrue due to the reduced life of steam traps on the 150 psig system, currently causing frequent replacements. Operation at 40 psig would significantly reduce maintenance and repairs on this part of the piping system.

This work would involve some detailed engineering to verify the extent of the changes required. Though pressure reductions at the boilers may be possible, the simplest approach here would be to utilize a new pressure reducing station in the existing 150 psig main (or possibly reusing one of the existing 150 to 40 psig pressure reducing stations if capacity is available). In addition, the pressure reducing stations in each of the buildings served by the 150 psig mains would require new regulators operating from 40 psig down to the building utilization pressure. The retrofit details vary in each building based on the specific arrangement of the steam system there. However based on the number of buildings connected, we estimate that the costs of this retrofit versus the savings will payback in well less than 10 years.

During the winter months, the steam pressure leaving the plant is raised to 55 to 60 psig to serve the autoclaves located in Jordan Hall. Typically, about 25 psig steam is required to provide the 121°C temperature needed for sterilizing equipment. Analysis of the piping system between the CHP and Jordan hall indicate some pressure loss but significantly less than 15 psig. We believe the issue has to do with the steam distribution and pressure regulation system within Jordan Hall. Our calculations indicate that maintaining 40 psig steam distribution pressure year-round would save approximately $62,500 per year.

To obtain these savings, we recommend a study of Jordan hall be undertaken to identify the true source of the problem. This will require a detailed engineering review of the steam system in Jordan Hall focusing on the actual pressure needs of the autoclaves there, the piping arrangement and size, and the pressure reducing station serving the autoclaves. The fix may involve some piping modifications and retrofit of the pressure regulating valves at the building to operate through an entering pressure of 40 psig maximum to 30 psig minimum. The modification will also permit more electricity to be generated by the CHP micro-turbine generators (since currently output of the micro-turbine generator drops as the exit steam pressure increases during the wintertime to satisfy Jordan Hall).

9.2.2.3 Prioritized Replacement of High Loss Distribution System Piping

The high summer steam demand and the thermal losses that are evident around campus are indications of the large amount of loss occurring in the steam and condensate distribution systems. The thermal model of this system described earlier in this section reinforces and quantifies those losses. In concert with IUB staff, a total of 40 sections of the existing distribution system were identified as areas where high losses were apparent. A distribution system drawing was prepared and is included in the Appendix B as Drawing B9.2.2.1. A spreadsheet was developed and keyed to the above drawing indicating the length and size of the piping from these 40 identified sections. This table appears in Appendix A as Table A9.2.2.1. Next, a second table, Table A9.2.2.2 was developed with the savings prioritized based on the apparent payback for replacing these various segments of the distribution system.

Also in concert with members of the IUB staff and as described later in this report, several sections of the distribution system are not recommended for repair. These segments are:

Section No. 4 – Steam and Condensate Piping to the Tennis Center
The nearly $400,000 cost of this project is not justified for the connected loads. It is a long section of piping at the northern edge of the distribution system that experiences significant losses for the amount of heat required. This facility should be converted to natural gas heat and taken off the central steam distribution system.

Section Nos. 9, 10, 11, 12, 13, 14, 15, 16, 17, and 18 – Steam and Condensate Piping between Central Heating Plant and Research Park
This deletion is described later in this section.

Section Nos. 22, 30, and 31 –Steam and Condensate Piping in Tunnels or Routed Within Buildings
Though these are aging sections of the piping system, their current heat losses do not justify their replacement based on energy economics. Section Nos. 30 and 31 are very old cast iron

threaded piping that probably should be replaced but the replacement would be done more as a capital investment to reduce maintenance costs and prevent future system failures.

Table A9.2.2.3 therefore indicates the recommended segments of the piping system that should be replaced after the deletions indicated above.

9.2.2.4 Initiation of Steam Trap Maintenance Program

Steam traps can be a significant source of energy loss on a campus distribution system such as at Indiana University Bloomington. Traps that are cycling too rapidly or that have failed open admit steam into the condensate return/pump discharge piping, increasing fuel consumption through vented steam loss, interfering with proper condensate return to the boiler plant, and potentially increasing water consumption and chemical treatment. A trap that is cycling too slowly or is failed closed can result in wet steam, water hammer in the steam system with possible resulting damage, increased maintenance, and increased start-up times for morning pickup. To counteract these effects, many campuses have initiated steam trap surveys and then on-going steam trap maintenance programs. To highlight the potential of such a program, the Washington University Medical School in St. Louis presents a good example. A comparison of this steam system with the system at IUB is described below.

Facility	Area Served (ft^2)	Steam Distribution Pressures (psig)
Washington University Medical School	**4,070,000**	**100, 50, 10**
Indiana University Bloomington CHP	**11,890,974**	**150, 40**

The portion of the IUB campus served by the CHP is roughly three times larger than the Washington University Medical School. In 2003, the Medical School contracted with Spirax Sarco to perform a steam trap survey of the campus. In the course of the work, the survey team visited well over 1,000 steam traps. Traps were tagged with location, service, size, type, manufacturer, and status of operation. Spirax Sarco used an ultrasonic testing, recording, and evaluation instrument to perform the survey. The results of the survey were that 181 failed traps were located. Calculations indicated that the faulty traps were wasting a total of 4,800 lbs/hour of steam annually. Replacement and repair of the subject traps resulted in an annual energy cost savings of almost $325,000. The cost of the initial survey and the replacement cost of the traps resulted in a payback of less than 2 years. The traps are now reviewed annually by in-house personnel using test instruments very similar to those employed in the original survey.

IUB initiated such a steam trap maintenance program in 2009 for the steam straps in the central plant and in the distribution system but not within the buildings. Approximately 125 traps were set up in a database with failures located and repaired of 18% of the traps reviewed in 2009. Subsequent years have seen fewer failures but the failure rate is still over 10%.

We recommend that IUB institute a similar steam trap survey to identify failed traps and initiate repairs on the steam systems within the campus buildings. Since these represent continuous losses over the year, payback on investments should be similar to those experienced by the Washington University Medical School.

9.2.2.5 Development of Current and Future Distributed Thermal Plants

We believe that looking into the future, IUB will likely discontinue central steam production, at least on the scale that it is currently employed. There are several reasons for this assertion.

1) Delivering heat to the campus at 366°F (150 psig saturated steam) or 316°F (superheated 40 psig steam) is significantly above the temperature required for heating the buildings. Process steam devices that may require these temperatures represent a tiny fraction of the boiler loads and should be handled separately on a case-by-case basis. Heating water at 130 to 150°F could perform all of the building heating functions required on campus at significantly lower levels of heat loss and therefore lower energy use.
2) The high temperatures indicated in 1) above create significantly higher thermal expansion in the piping system, contributing to failures in the thermal insulation systems, ultimately leading to failure of the piping systems. These effects will continue as long as the higher temperature steam is used.
3) Because of its basic design, a steam system is an “open” system (vented to the atmosphere at various points) where steam can be lost due to vented steam or from steam traps that have failed open. Leaks in the condensate system are often ignored and blow down from the boilers must occur during operation. Because this represents a loss of mass from the system, make-up water must be continually added to the system, increasing heating requirements and requiring significantly more chemical treatment.
4) The coal boilers at the CHP are between 41 and 52 years old and maintenance requirements due to the age of the equipment will continue to increase as time passes. With the permitting and emissions requirements in place for new coal boilers, replacing these boilers will likely be prohibitively expensive. In earlier discussions, it was our thought that at some point, the burning of coal will be phased out at IUB by clean air legislation or the institution of a federally mandated carbon tax. When natural gas becomes the primary campus fuel, the reason for a central boiler facility delivering steam to the campus becomes less important and the high heating system efficiency available with natural gas becomes the key imperative.

We see the conversion to low temperature heating water systems with condensing boilers, possibly combined with geothermal technology, as the system of the future for the IUB campus. With natural gas as the heating source, we see these as distributed thermal plants as indicated on Drawing B9.2.2.2 in the Appendix. Lower temperature heating water systems provide the opportunity of utilizing condensing type natural gas boilers with combustion efficiencies in excess of 90%. In addition, the lower heating water temperature makes heat recovery from cooling system compressors much simpler and less expensive than higher temperature options.

We see this change in heating source occurring from the perimeter of the campus inward, gradually reducing the steam loads on the current CHP over time. A concept for the location of these plants has been indicated on drawing B9.2.2.2 described above. This concept should be considered each time major new buildings or building renovations are considered on the perimeter of the campus. Likewise, heating system renovations of existing buildings anywhere on campus should be arranged for low temperature heating water, making the future conversion of the building to this system arrangement simpler.

The best candidate to initiate this process of conversion to distributed, low temperature thermal plants is the Research Park (or U School), designated as the Research Park Thermal Plant on Drawing B9.2.2.2. At present, most of the direct buried 150 psig high pressure steam and condensate mains extending from the Central Plant to the Tulip Tree Apartments and the Research Park are in very bad condition. Much of the condensate from this section of the campus is not returned to the CHP. Referring to Appendix Table A9.2.2.1 described in an earlier section, these sections of the steam piping system are labeled as Nos. 9, 10, 11, 12, 13, 14, 15, 16, 17, and 18.

Instead of replacing this piping segment, we recommend installing a boiler plant adjacent to the Data Center to serve the Research Park area and the Tulip Tree Apartments and separate boiler plants at Campus View, Recreation Sports and Nelson RPS. These would become the first steps toward initiating the remote distributed thermal plant concept for the campus. This would initially include low temperature condensing boilers and a distribution network to distribute heating water to the Research Park Area and the Tulip Tree Apartments with the provision for expansion as the Research Park development grows. Then in phases over time, similar boiler plants would be installed at Campus View, Recreation Sports, and Nelson RPS. At the completion of these phases, the entire 150 psig east steam main would be retired. At time of the initial phase of the work, Eigenmann would be disconnected from the 150 psig service and connected to the 40 psig service at E. 10th Street. The new system at Research Park and Tulip Tree should be designed to ultimately also serve as the cooling source for Research Park since heat recovery from the cooling required for the IT areas will benefit all of the buildings. Distribution should be arranged in shallow tunnels installed beneath sidewalks or direct buried. Obviously, more engineering work would be necessary to pinpoint the costs and benefits of this option but we believe this work can definitely be done for less than the cost of the replacement of the present underground steam distribution system.

9.3 Campus Chilled Water System

9.3.1 Capacity Limitations and Energy Source Economics

9.3.1.1 A deficiency in peak chilled water capacity has long been a concern to the University. As evidenced by the chilled water curtailments that have been required in recent years, the need for solutions to this issue are both compelling and urgent. Obviously, our current study is focusing on the campus energy needs for cooling as they exist today and as they extend into the future. As part of the overall study, we have focused on means of reducing the energy consumed by this system while providing the additional load necessary to meet a growing campus chilled water demand.

9.3.1.2 One component of this effort has been to quantify the load reductions that are possible at both peak and part load conditions due to modifications in the plant and more importantly, arising from modifications in the buildings that reduce cooling loads. Such load reductions will occur due to the implementation of energy conservation measures, elimination of simultaneous heating and cooling through retro-commissioning, looking toward geothermal systems to replace the aging cooling infrastructure in certain buildings and employing heat recovery chillers at buildings where summer heat is necessary (both thus unloading the CCWP).

9.3.1.3 The following paragraphs summarize our observations and conclusions on the central chilled water system serving the campus.

1) Of the buildings we considered as part of the IU/Bloomington Campus totaling 16,870,586 ft^2, some 7,761,451 ft^2 of these buildings are served by the Central Chilled Water Plant (CCWP). This represents about 46% of the total campus area and includes almost all of the major campus buildings.

2) We would classify the system as a primary/secondary/tertiary pumped variable flow chilled water system with the tertiary pumping scheme having been modified from the original and usual design approach.

3) From the standpoint of overall campus chilled water system design, the chilled water production (chiller) plants are rated and pumped on the basis of a 55°F return chilled water temperature from the buildings and a 40°F supply chilled water temperature delivered to the buildings, resulting in a 15°F Δt between supply and return. The campus cooling coils have been designed over the years for a variety of different supply and return water temperatures with the median temperatures of the major buildings being 43°F supply water and 55°F return water. The lower chilled water supply temperature from the plants promotes higher return water temperature and improved variable flow performance of the system.

4) The CCWP plant (without any contributions from the Forest, Swain West, or Lilly Library chillers) produced 55,087,644 ton-hours of cooling energy during FY2009-2010. Of these ton-hours, about 27% represented a base load that seems to be totally independent of outdoor weather conditions. These ton-hours of cooling energy use would represent a constant load of approximately 1,700 tons. This base load likely represents a large amount of simultaneous cooling and heating that must be a principal target of retro-commissioning efforts as well as process cooling needs such as providing a condensing source for cold rooms and freezers.

5) As of FY 10-11, the CCWP consisted of 10 chillers located at the central plant (14,596 tons) and the Forest plant (1,000 tons), with additional chillers at Swain West (275 tons) and Lilly Library (150 tons) that are operated at times of high campus cooling loads and a heat recovery chiller (100 tons) at the Lee Norvel Theater and Drama Center that is operated as a function of the building reheat load. These additional chillers partially serve the buildings in which they are located, effectively unloading the remainder of the central chilled water system.

6) During FY 10-11, the central chiller plant and the Forest chiller plant acted as the two nodes of the existing CCWP. A third node at the Briscoe chiller plant has recently been completed. The Briscoe plant includes two chillers with a total additional capacity of 1,500 tons including space for the addition of a future 750 ton chiller. The CCWP and associated chillers described above at the conclusion of FY 10-11 had a total current capacity of 17,521 tons. Our computer simulation of the campus cooling loads connected to the plant at that time indicated a peak cooling load of 19,058 tons. A summary of this data is indicated in the table below.

Table 9.3.1: Central Cooling Capacity Summary – FY 10-11

Location of Chiller(s)	Total Capacity (tons)	Function	Chiller Condition - Installation Date	Refrigerant
CCWP	**14,596**	**Central Plant**	**Good, 1984 – 2004**	**HCFC-123, HFC-134A**
Forest	**1,000**	**Central Plant**	**Good, 2007**	**HCFC-123**
Briscoe	**1,500**	**Central Plant**	**Good, 2010**	**HCFC-123**
Lilly Library	**150**	**Building Plant**	**Fair, 1999**	**HCFC-22**
Swain West	**275**	**Building Plant**	**Poor, 1976**	**CFC-11**
Total Capacity	**17,521**			
Calculated Load (2011)	**19,058**			
Current Shortfall	**1,537**			
Current Shortfall w/o Bldg. Chillers	**1,962**			

7) Obviously, the CCWP appears to have insufficient installed tonnage to provide firm cooling capacity for the IU campus. This assertion has been borne out by the 24 days during the summer of 2010 that campus chilled water curtailment was necessary for all or part of the operating day. A similar set of events transpired during the summer of 2011. Further, the aging chillers at Swain West and the Lily Library cannot be considered as firm capacity for the chilled water system moving forward.

8) To address this shortfall, plans are in place to add a third 750 ton chiller and associated equipment at the Forest chiller plant. In addition, a 2,500 ton chiller is planned for installation at the MAC chiller plant including the connection of this plant to the campus chilled water loop as a fourth node. (The chilled water piping infrastructure will be modified to make this capacity more available to serve other campus loads by providing new 16” connections to the existing 24” chilled water mains southwest of the Musical Arts building.) The situation at the conclusion of this work is described in the table below including cooling load increases anticipated by the summer of 2012.

Table 9.3.2: Central Cooling Capacity Summary – With Planned Capacity Increases – Summer 2012

Location of Chiller(s)	Total Capacity (tons)	Function	Chiller Condition - Installation Date	Refrigerant
CCWP	14,596	Central Plant	Good, 1984 - 2004	HCFC-123, HFC-134A
Forest	1,750	Central Plant	Good, 2007-2012	HCFC-123
Briscoe	1,500	Central Plant	Good, 2010	HCFC-123
M100/MAC	2,500	Central Plant	Planned 2012	-
Total Capacity	20,346			
Calculated Load (2012)	19,546			
Excess Capacity	800			

9) If the Energy Conservation Measures described earlier in the report are implemented, the cooling load will drop to a calculated 16,339 tons. Such a change would provide 4,007 tons of excess cooling capacity for the chilled water plant, resulting in a situation of providing firm capacity to the campus (adequate cooling capacity such that if the largest chiller were unavailable, the 4,000 ton chiller at the CCWP, the plant would still have adequate capacity to meet the design loads).

10) As discussed earlier, we have reviewed the performance of the central chilled water plant and the Forest plant to determine their current operating efficiency. By dividing the electrical consumption utilized in kilowatt-hours by the metered ton-hours of cooling produced by the plants, the result is the average kW/ton for the plant. The results of this calculation for the CCWP and the Forest plant for FY 09-10 were 0.69 kW/ton for the CCWP and 0.66 kW/ton for the Forest plant for an average of 0.68 kW/ton for the two plants. For FY 10-11, the combined operating efficiency of the two plants was 0.75 kW/ton. All of these values indicate a very efficiently operated central chilled water facility. Our computer simulations of the cooling required reinforce the ton-hour measurements at the plant, clearly again indicating the very efficient operation of these plants. It is apparent to us that further reductions in energy consumption of these plants will only be obtained by reducing the loads of the buildings connected to the system.

11) Our calculations indicate that with the current prevailing costs for electricity, coal, and natural gas, a high efficiency electric centrifugal chiller is the best current stand-alone option for producing or augmenting the campus cooling needs. At the energy costs experienced for FY 2009-2010, costs of various optional cooling choices available (considering energy costs only) for the production of one ton-hour of cooling were:

Table 9.3.3: Cost Comparison of Chiller Options

High Efficiency Electric Centrifugal Chiller (0.57 kW/ton)	$0.034 / ton-hour
Low Pressure Steam Absorption Chiller (Current Fuel Mix)	$0.064 / ton-hour
High Pressure Steam Absorption Chiller (Current Fuel Mix)	$0.036 / ton-hour
Low Pressure Steam Absorption Chiller (Natural Gas Fuel Only)	$0.137 / ton-hour
High Pressure Steam Absorption Chiller (Natural Gas Fuel Only)	$0.074 / ton-hour
Direct Fired Natural Gas Double Effect Absorption Chiller	$0.076 / ton-hour
Natural Gas Engine Driven High Efficiency Centrifugal Chiller (Without Heat Recovery)	$0.049 / ton-hour
Natural Gas Engine Driven High Efficiency Centrifugal Chiller (With Heat Recovery)	$0.036 / ton-hour

As we look at the cogeneration options in the following section, the economics become more complex when electricity is also a by-product. But as a stand-alone technology, the high efficiency electric chiller is still the least expensive means to obtain ton-hours of cooling.

12) Based on 11) above, the University should purchase all new electric centrifugal chillers based on a life cycle cost bidding approach minimizing energy use for both the direct energy use for the chiller as well as the energy burden that the chiller represents for chilled water and condenser water pumping. The return on investment for reduced energy cost should be based on a minimum of 10 years so that the Owning Cost Index (OCI) for a proposed chiller would be evaluated based on OCI = [First Cost of the Chiller + the Present Worth of Ten Years of Chiller Operating Cost]. The proposed chiller with the lowest OCI would be then be selected.

13) The age of many of the campus chillers is of concern. The latest approach taken by ASHRAE to determine the median life for a centrifugal chiller is to consider the median life a point where 50% of chillers of that age are still in service. Based on this data set, the median life of a centrifugal chiller is 31 years. At 35 years, only slightly more than 25% of centrifugal chillers are still in service. A 31 year old chiller on the IU-Bloomington campus would have been installed in around 1980. Though the chillers at the CCWP, Forest, and Briscoe are in good condition from an age and operational standpoint, the satellite plants around the campus do contain candidates for replacement. Five satellite chillers at a total capacity of 815 tons would meet this parameter. Further, eleven satellite chillers having a total capacity of 3,085 tons are still operating with refrigerant CFC-11. It should be assumed that this capacity must be replaced within the next five to ten years.

14) Additional chiller capacity would also become available through the installation of heat recovery chillers at selected buildings. Such chillers would likely be smaller, incremental chillers installed at buildings that have a summer heating load for reheat, with such chillers being sized based on the anticipated summer heating load. These additional heat recovery chillers would partially serve the buildings in which they are located, effectively unloading the remainder of the central chilled water system while providing a cost effective heating source for summer needs.

15) Another approach to providing additional chiller capacity for the campus would be to consider the construction of a cogeneration plant in the vicinity of the central boiler plant. This option is discussed in greater detail in the next section.

16) Yet another approach to providing additional chiller capacity would be through the utilization of thermal energy storage. The typical scenario would involve generating sub-cooled chilled water at night in a storage tank for subsequent use the next day to offset peak loads. The technique is often considered when the local electric rates reward off-peak nighttime use with a lower demand charge, thus making less expensive ton-hours of cooling during off-peak times. However, the Duke Energy electric rate provided to the master meters offers no time of day demand cost reduction. Thus the nominal of 1,000,000 gallon storage tank required to provide for a 1,000 ton daytime peak would simply compare the cost of the vessel and the system re-piping to the cost of a new chiller and tower. Our experience would indicate the chiller addition to be much simpler and more cost-effective for adding this cooling capacity.

9.3.2 Addressing Campus Cooling Shortfall and Providing for Future Growth

9.3.2.1 Plans already in place for adding cooling capacity at the Forest plant and at the MAC chiller plant (M100) will provide for adequate capacity for the summer of 2012 but without any significant redundant chiller capacity. To provide long term solutions for campus cooling growth, there are several steps that should be taken. Our approach to addressing the long term cooling needs of the campus as loads continue to grow is described in the following summary.

1) Reduce the cooling loads through energy conservation measures and retro-commissioning to reduce simultaneous heating and cooling to a minimum. This step has the potential to remove over 3,200 tons of peak cooling required, providing over 4,000 tons of excess capacity.
2) Add the final 750 tons of chiller capacity to the existing Briscoe chiller plant, increasing the total central chilled water system capacity to 20,846 tons
3) If a cogeneration system is installed at or near the CHP, absorption water chillers may provide additional chilled water capacity to the loop but only if the base steam load is reduced to below the capacity of the cogeneration system heat recovery boiler.
4) As satellite chillers in the buildings are retired, this capacity should be obtained by connecting to the Central Plant or through the implementation of one of the distributed cooling/heating plants described earlier.

9.3.2.2 At this point, two main options remain for the further augmentation of plant capacity

1) Additional chiller capacity could logically be located near the existing CCWP because of proximity of access to the 36” chilled water mains leaving the plant. It is our understanding that such a new chiller plant concept had been set forth for funding consideration to the State of Indiana but with no results as yet. This is a viable option but because of the main sizes leaving the CCWP, adding more than about 5,000 tons at this location will be problematic.
2) Unload the chiller plant by installing new distributed cooling and heating plants around campus as suggested on Drawing B9.2.2.2 in Appendix B. These distributed heating and cooling plants could utilize geothermal well fields to improve cooling efficiency while

significantly reducing distribution losses from the current steam system. We believe this is the better long term investment for the University.

9.3.2.3 The result of these efforts should be to work toward a situation in which firm chiller capacity is available at peak loads for the campus central chilled water system as well as the distributed plants that are developed in the future. Such chiller capacity would be based on current needs, reduced by the implementation of energy reduction measures and retro-commissioning, but augmented by a plan for the additional capacity necessary for future buildings in the master plan and the retirement of aging campus chillers utilizing CFC refrigerants.

9.4 Central Electrical Distribution System

9.4.1 Electrical System Evaluation and Plans for Future Growth

9.4.1.1 Except for isolated buildings that are separately metered by Duke Energy, the bulk of the electric service to the campus is fed by Duke Energy through two distribution points, the University Switching Center located near the CHP and the University Distribution Center located near the Indiana Memorial Union Building. From these points, the University distributes power at 12.47 kV and 4.16 kV to the various campus loads. To date, the capacity of these systems has been adequate to support campus growth. However, new proposed construction on the campus will require the addition of just over 2,000 kW at the University Switching Center, with the attendant needs for new switchgear and bus ducts to carry the additional power needs.

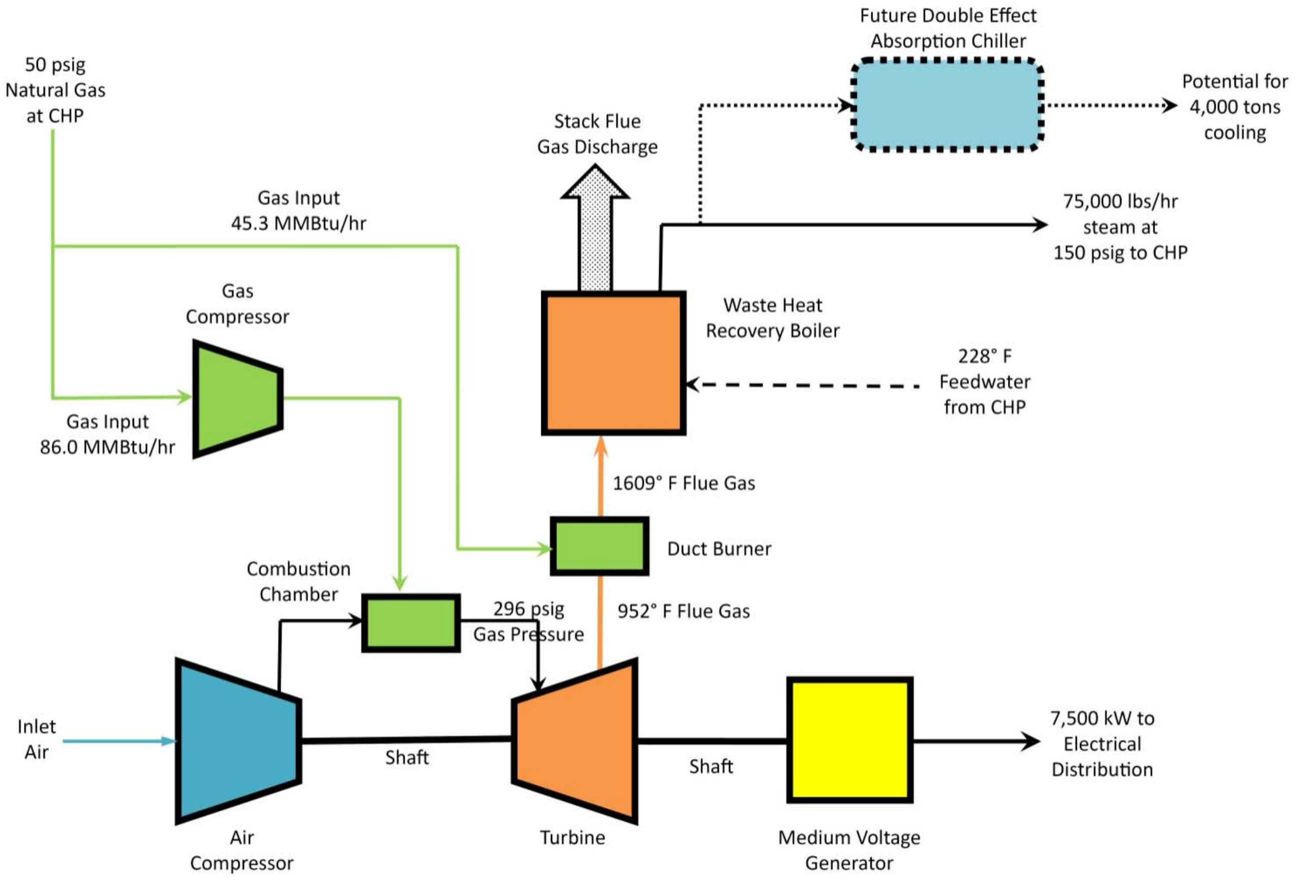
9.4.1.2 It is our position that the current capacity of the electrical distribution need not grow if the energy conservation measures described here are implemented. We estimate that if these ECM's are implemented, the campus load will shrink by an estimated 8600 kW. Further increases in campus demand should be addressed with cogeneration as described in the following paragraphs.

9.4.2 Cogeneration System Option

9.4.2.1 Another more fundamental approach to providing additional electrical capacity for the campus would be to consider the construction of a cogeneration plant in the vicinity of the central boiler plant. The campus base electrical loads, established by meter readings taken during the Christmas week of 2010, indicate that the minimum load is approximately 18,900 kW. Assuming energy conservation efforts could reduce this number by at least 15%, the remaining campus base load might still be in the range of 16,000 kW. As an initial step toward cogenerating the campus base load, a natural gas fired gas turbine generator set with an auxiliary duct burner for co-firing and a heat recovery boiler could be installed with an electrical generating capacity in the range of 8,000 kW. Based on a Solar Turbine Taurus 70 unit with duct co-firing and a heat recovery boiler producing either 150 psig or 40 psig saturated steam, the following performance would be achieved:

Electrical Generation	7,604 kW
Net Electrical Output (less Plant Parasitic Loads)	7,413 kW
150 Psig Steam Generation (with Duct Burner Co-Firing)	75,000 lbs/hr
150 Psig Steam Generation (without operation of Duct Burner Co-Firing)	35,000 lbs/hr
Natural Gas Input at Full Load	131.3 MMBtu/hr

9.4.2.2 Such a plant would reduce energy costs significantly, provide for the option of future additional chilled water capacity needed for the campus, and significantly reduce CO_2 emissions by trading natural gas for coal for some of the campus steam required and trading natural gas electric generation for a large portion of the existing use of coal for electric generation by Duke Energy at the regional level. The general arrangement for such a plant is shown below in Figure No. 9.4.2.1. Duct co-firing of the products of combustion off the gas turbine provides additional heating capacity at a very high fuel-to-steam efficiency.



Natural Gas Turbine Generator

Figure No. 9.4.2.1: Proposed Cogeneration System

9.4.2.3 The analysis of the economics is quite complex and require the insertion of a number of assumptions regarding the operation of the system and, most importantly, on how energy costs, labor costs, and materials costs will increase over the period of the analysis. For this exercise, a software tool from the Department of Energy – Energy Efficiency and Renewable Energy Program of the Federal Energy Management Program (FEMP) was utilized. The Energy Rate Escalation Calculator (EERC 2.0-10) computes an average annual escalation rate for a specified time period (in this case 15 years) specifically for the State of Indiana. This calculator is basically used as a guide for contract payments on Federal Energy Savings Performance Contracts. The annual energy escalation factors from EERC 2.0-10 that were utilized in this analysis are indicated below. The rates identified include inflation.

9.4.2.4

Inflation Rate	3.40%
Escalation Rate for Electricity	4.84%
Escalation Rate for Natural Gas	5.57%
Escalation Rate for Coal	3.40%

(Rates for Electricity, Natural Gas, and Coal all include inflation)

9.4.2.5 These factors were used to set up a 15 year Net Present Value (NPV) matrix for several central plant options including cogeneration. For the cogeneration option, estimated construction costs were prepared for a stand-alone building just north of the existing CHP and utilizing some CHP support services such as softened feedwater and deaeration systems. The cost for such a plant is estimated at $18,480,000. Costs could be reduced somewhat if the equipment could be housed in the CHP but would require the demolition of one of the aging existing boilers. Tables A9.4.2.1 through A9.4.2.6 in the Appendix describe the net present value calculations. The results of these calculations are indicated below in Table 9.4.2.1.

Table 9.4.2.1: Economics of Cogeneration Options

Option	Description	15 Year Total Cost	15 Year Net Present Value	Reduction in CO_2 Emissions (tons)
Base Case	Existing Conditions, 90% Coal, 10% Natural Gas, Existing Boilers, Existing Staff	$ 142,610,174	$ 96,812,185	0
Option A	100% Natural Gas, Existing Boilers, with Staff Reductions	$ 172,446,329	$ 115,709,012	89,784
Option B	100% Natural Gas, New High Efficiency Boiler No. 8, with Staff Reductions	$ 168,220,460	$ 114,407,741	94,698
Option C	80% Natural Gas, 20% Coal, Base Loading Boiler No. 7, Topping with Coal, Existing Boilers, No Staff Reductions	$ 162,292,715	$ 109,171,434	75,300
Gas Turbine Option 1	100% Natural Gas, 7,500 kW Gas Turbine with Duct Burner and 75,000 lbs/hr Heat Recovery Boiler, Existing Boilers, with Staff Reductions	$ 146,444,291	$ 103,044,406	136,860
Gas Turbine Option 2	7,500 kW Gas Turbine with Duct Burner and 75,000 lbs/hr Heat Recovery Boiler, Topping with Coal, Existing Boilers, No Staff Reductions	$ 133,218,007	$ 94,858,140	85,173

9.4.2.6 The theme again is similar to earlier discussions related to utility costs and the Central Heating Plant. Nearly the lowest 15 year net present value of the options considered for the plant is to remain on the current mix of coal and natural gas (90% coal / 10% natural gas). This option also has by far the highest level of carbon emissions of any of the central plant options considered.

9.4.2.7 However as stated earlier, we believe it is inevitable that that University, either through ever stricter emissions standards imposed by the EPA or through the passage of legislation imposing carbon taxation on emissions, will move to burn natural gas in much larger quantities in the years to come. And review of all the options indicated above, the lowest net present value option is the gas turbine with cogeneration and coal used for the remaining heating required. Within the constraints of the assumptions considered, the additional cost of the gas turbine cogeneration plant has paid for its additional investment over 15 years based on the energy cost savings that accrue. This option alone reduces campus emissions by over 28% based on the energy related emissions of FY 09-10.

INCORPORATION OF RENEWABLE ENERGY RESOURCES

10 INCORPORATION OF RENEWABLE ENERGY RESOURCES

10.1 Utilization of Renewable Energy at Indiana University Bloomington

10.1.1 No portion of the energy source equation is receiving more focus than the renewable energy sources – those sources of energy that do not deplete natural resources as they are consumed – sources like hydropower, wind, geothermal systems, biomass, landfill gas, and solar energy. In this section, we will look at renewable energy for IUB in the form of the most practical options currently available – solar energy and wind energy. Our review will include the possible role of legislation and other outside economic drivers on the implementation and economics of renewable energy for the campus. The accomplishment of the reduction milestones for greenhouse gas emissions set forth in the "Campus Master Plan" described earlier will require the deployment of every tool available to the University, both through energy retrofits and behavioral changes on campus as well as through impetus from outside sources of legislation and potential funding.

10.1.2 For renewable energy to play a role in moving the campus toward sustainability, the first element in the puzzle is to reduce the energy needs of campus to the minimum possible level. In existing buildings, this will often require retrofit and periodic retro-commissioning. In new buildings, it will involve not only attaining LEED certification but challenging the designers to creatively achieve minimum energy levels without depending on the acquisition of Renewable Energy Credits (RECs) or Verified Emission Reductions (VERs, sometimes referred to as carbon offsets) to achieve these goals. The basis of this assertion is simple – renewable energy sources are "weak" sources of energy compared to fossil fuel fired power plants generating electricity or massive fossil fuel fired boilers producing steam for heating. Renewable energy by its very nature is generally collected in far lower available energy density than that achieved by large quantities of fossil fuels transported to a point of conversion for the energy required. Thus for renewable energy to play any significant role in the needs of campus, the energy needs of the buildings must be reduced to the absolute minimum. Without such a concerted effort at energy reduction in our buildings, renewable energy will always be relegated to an auxiliary source of building energy rather than a key player in building energy service.

10.2 Solar Energy

10.2.1 Solar Photovoltaic Collectors

10.2.1.1 The installed cost of solar photovoltaic collectors to generate electricity has dropped dramatically in recent years. As recently as 2008, installed costs for photovoltaic systems were in the range of $8.00 to $10.00/watt of installed capacity. Based on late 2011 data, similar costs have dropped into the range of $4.25/watt with prices likely to fall even further. Technology has also continued to increase the energy density that can be recovered from sunlight, now in the range of 14 watts per ft^2 of collector surface. But at IUB, with purchased electricity available in the range of $0.06 to $0.07/kWh and annual sunlight hours of 1,500 or less, current paybacks for such photovoltaic collectors without other funding sources than energy savings exceed 40 years.

10.2.1.2 At IUB, we identified all roof surfaces of the major buildings that would be available to install solar collectors while still providing roof access for any maintenance needed. This total of 493,000 ft^2 were considered covered with solar collectors producing a net output of approximately 6,850 kW of electrical power integrated over the year to produce slightly over 10,000,000 kWh of electricity. The payback on such a project would exceed 40 years without any additional incentives beyond energy cost savings.

10.2.1.3 Obviously, deployment of solar photovoltaic power on any scale will require incentives in terms of utility company rebates, tax incentives, grants, and any other funding mechanisms available to improve the economics to achieve reasonable paybacks. The University must seek out such opportunities as they appear to incorporate innovative financing on solar photovoltaic projects in the future. Without outside incentives, such projects will be difficult to justify. Websites such as www.dsireusa.org should be periodically reviewed for future incentives that may become available for State or Federal sources.

10.2.1.4 As a leader among Midwest Universities in sustainability awareness and education, IUB should be forward leading in its application of renewable energy. However, IUB must maintain a fiscally responsible focus as alternative renewable energy forms are considered. Evaluation should continue going forward to capture changes in cost or technology that may alter the current paybacks available.

10.2.2 Solar Collectors for Space Heating or Domestic Hot Water Heating

10.2.2.1 Here again the installed cost of the systems is the major deterrent to implementation, coupled with the relatively small amount of solar energy available in Bloomington and the high levels of building heat needed during the winter. To establish a test case, a domestic hot water heating system utilizing solar collectors was considered for a location in a dormitory in central Indiana. Assuming that under the base case, such heat was provided by steam from the Central Heating Plant with a marginal cost of $5.022/MMBtu, operation of the solar collection system with 100% coincidence in solar heat available versus heat needed, the system would have a straight line payback period of 20 years. No real system has total coincidence of heat required versus heat available, making the payback always greater than 20 years.

10.2.2.2 Obviously, deployment of solar space heating or domestic hot water heating will require incentives in terms of utility company rebates, tax incentives, grants, and any other funding mechanisms available to improve the economics to achieve reasonable paybacks. The University must seek out such opportunities as they appear to incorporate innovative financing on solar photovoltaic projects in the future. Without outside incentives, such projects will be difficult to justify.

10.2.2.3 In terms of both areas of utilization of recovered renewable solar energy, at best these energy forms are available only while the sun is shining. For example, even if the capacity were available through solar photovoltaic collectors to meet the demand load of the IUB campus, such collectors would occupy over 72 acres of land and could serve only about 17% of the energy consumption of the campus. Thus solar renewable energy, without some effective means of storage, will never offset more than 15 to 20% of the overall electrical needs of the facility it serves no matter what incentives are available.

10.3 Renewable Energy from Wind Power

10.3.1 To assess the economics of renewable energy from wind power, we met with Performance Services, Inc. of Indianapolis who has been involved in the development of several community wind farms in the State of Indiana. All of the facilities that Performance Services have participated in have received a cash grant through the Treasury Grant 1603, found in the American Recovery and Reinvestment Act of 2009 providing nearly 20% of the upfront financing of such a renewable energy project. Unfortunately, only taxable entities are eligible to receive this grant, disqualifying IUB based on its status as a non-profit institution. Table A10.3.1 in the Appendix indicates the financial pro forma for a proposed 12,000 kW wind farm that could be constructed in South Bend, Indiana on land that is owned by the University. (This site was selected due to the more favorable wind conditions that exist there in comparison to Bloomington.) Six – two MW turbines were projected for this project at a total installed cost of $26,191,210 (or $2,180/kW). Based on the economics presented, the average annual cost savings over the 25 year course of the investment is $746,000 with actual cash flow becoming positive after the ninth year of the investment. The project would also provide IUB with 35,740,800 kWh per year of Renewable Energy Credits that could be sold or retained to fund LEED project certification on future projects. Unfortunately, the current value of these credits is only about $0.82/mWh or about $29,308 per year.

10.3.2 Again as in the case of the solar renewable energy options, deployment of wind power will require incentives in terms of Federal or State grants to receive a reasonable return on investment based on other comparative means of reducing energy on campus.

THE INTEGRATED ENERGY MASTER PLAN

11 THE INTEGRATED ENERGY MASTER PLAN

11.1 Overview

As stated earlier, the University is pursuing efforts to conserve energy through four main approaches, related in outcome but dissimilar in the cost and complexity of their implementation. Simply stated, these four approaches in order of increasing cost and complexity are:

- Energy conservation at the individual personal level involving behavioral redirection of the campus community,
- Energy conservation through the retro-commissioning of the heating, ventilating, and air conditioning (HVAC) systems of the campus buildings to achieve efficient operation consistent with the original design intent,
- Energy conservation measures that involve basic modifications to the building HVAC and electrical systems to reduce energy use (as embodied in Qualified Energy Savings Projects), and
- Energy conservation through longer term, even higher capital cost projects that reduce campus energy consumption through modifications to the energy sources and energy distribution models that are currently in place.

Listed below in Table 11.1.1 is a summary of the options presented throughout this report that target one or more of the approaches described above. From a quick review of this list, it is obvious that not all of these projects ultimately make good fiscal sense.

The purpose of the Integrated Energy Master Plan as stated in Section 2.0 of this report was to define and prioritize the four approaches above to achieve the most transformative effect on reducing energy consumption on the IUB campus at the minimum cost but with the highest measure of greenhouse gas emission reduction. It was the intent that the results of this report would become the framework for a long range energy master plan to move toward the achievement of the goals set forth by the 2010 Campus Master Plan.

Table 11.1.1: Possible Components of an Integrated Energy Master Plan

Number	Description of ECM	Annual Energy Cost Savings[1]	Implementation Cost	Payback Period (yrs)	Annual CO_2 Savings (tons)	CO_2 Emissions Reduction[3]
1	Retro-Commissioning	$936,526	$3,269,935	3.5	30,415	6.2%
2	Building Energy Conservation Measures (Marginal Payback < 15 yr)	$5,444,090	$44,916,598	8.3	99,080	20.2%
3A	Retrofit of Central Steam Plant with Additional Micro-Turbine	$88,202[4,6]	$881,910	10.0	0	0.0%
3B	Steam Pressure Reduction in Distribution System from 150 psig to 40 psig	$102,104	$700,000	6.9	1,845	0.4%
4A	Selective Retrofit for Central Steam and Condensate Distribution Systems (not including East Main)	$999,189	$10,510,080	10.5	13,912	2.8%
4B	Retrofit for East Main of Central Steam and Condensate Distribution Systems	$696,000	$6,720,945	9.7	21,282	4.3%
4C	Abandon 10" East 150 psig Steam Main; Replace with Hot Water Boilers and Heating Water Distribution System from the Main Split to Research Park	$480,000	$5,310,000	11.6	25,017	5.1%
5A	Revised Central Steam Plant Firing Strategy; 100% Natural Gas with Staff Reductions and with Existing Boilers	($586,318)	$0	No Payback	84,881	17.3%
5B	Revised Central Steam Plant Firing Strategy; 100% Natural Gas with Staff Reductions and with New High Efficiency Boiler No. 8	($210,633)	$4,650,000	No Payback (12.4 years compared to 5A)	89,795	18.3%
5C	Revised Central Steam Plant Firing Strategy; Base Load Natural Gas, Topping with Coal	($455,262)[2]	$0	No Payback	71,423	14.6%
6	Firing with 40% Torrified Wood at the CHP	($3,723,600)	$0	No Payback	70,077	14.3%
7	Firing Biomass at CHP - Nu Materials I Fuel 60	($3,120,627)	$0	No Payback	67,331	13.7%
8	12,000 kW Wind Farm installed at South Bend Campus	$746,000[8,9]	$26,191,000	35.1	37,296	7.6%
9A	Install Natural Gas Cogeneration System at the CHP; 100% Natural Gas Fired for Remaining Heating	$2,017,000[7] (compared to option 5A)	$18,480,000	6.8[5]	47,076[7] (compared to option 5A)	9.6%
9B	Install Natural Gas Cogeneration System at the CHP; Remaining Heat Furnished by Coal	$2,042,000	$18,480,000	9.1[5]	85,173	17.4%
10	Install PV Collectors on all Campus Buildings	$611,793	$29,104,000	47.6	10,516	2.1%

Note 1: Savings based on FY 10-11 estimated average utility costs

Note 2: Economics based on no staff reductions

Note 3: Based on FY 10-11 energy related emissions of 489,895 tons CO_2 total

Note 4: Based on an annual electrical savings of 1,971,000 kWh based on (250 kW) x (8760 hours/year) x 0.90 Utilization Factor

Note 5: Payback period is based on a net present value calculation that credits the Project Installation Cost by $3,000,000 for cost avoidance associated with adding an additional 75,000 lb/hr boiler at the plant

Note 6: Cost savings reduces dramatically if plant if firing solely on natural gas

Note 7: This option assumes that the CHP has been converted to 100% natural gas in the base case.

Note 8: Annual cost savings based on average savings over the 25 year life; actual cash flow becomes positive at the ninth year of the investment

Note 9: Would provide IUB with 35,740,800 kWh of renewable energy credits annually but the current value of such credits are only $29,308 ($0.82/MWh)

11.2 Recommendations

Based on our observations, calculations, and discussions with IU staff, the following recommendations represent the essence of the Integrated Energy Master Plan identified for the Indiana University Bloomington campus:

1) Continue to promote individual and group behaviors in the students, faculty, and staff that reduce energy consumption and promote a sustainable ethic that will permeate the campus community and beyond. Programs such as the Energy Challenge, the Sustainability Internship Program, and the Green Teams have been key elements in these efforts. Continue and expand these functions to include guidelines for sustainable laboratory practices, guidelines for sustainable office practices, and regular re-evaluation of campus IT practices to use the latest technology to minimize energy and paper use.

2) Continue requiring LEED certification for all new buildings constructed at the site and for all major renovations (22 buildings were identified as being in need of substantial HVAC capital improvement). Such certification process should include as a minimum, attainment of LEED Silver Certification, commissioning and enhanced commissioning providing an independent peer review engineer during the design process, and a minimum of 15 points achieved under Energy and Atmosphere, Credit 1 – Optimize Energy Performance. In addition, the designer should be required to review the first year of actual building energy performance to verify the accuracy of the computer modeling used to achieve the above referenced credits.

3) Supplement the current Indiana University Bloomington Design Standards with energy systems requirements for all new buildings and major additions to existing buildings.

4) Establish a process going forward to make retro-commissioning of the HVAC systems of the major existing buildings on campus a continuous process. Begin the work with the prioritized buildings identified by the report. This process is best accomplished by internal retro-commissioning teams whose main duty is retro-commissioning, supplemented by outside technical support or training on an as-needed basis. This additional operational cost of this effort will be significantly outweighed by the energy cost savings that will accrue through its implementation.

5) Continue the current practice of providing metering for the electrical, steam, chilled water, domestic cold water, and natural gas use at each of the major campus buildings. Assemble this data in an energy use database providing rolling annual profiles for benchmarking building consumption against similar buildings and for flagging significant excursions from previous consumption experience. Such data should be used to inform the internal retro-commissioning teams of prioritized buildings to be addressed.

6) Implement energy conservation measures in the major campus buildings with a marginal payback of 10 years or less. These measures are defined in detail in the body of the report. This is the most important recommendation of the study in that it has the most lasting, transformative effect on the reduction of campus energy use. Since building energy needs determine the “customer” requirements that the energy distribution and source systems must serve, reductions in building energy needs will cascade through the systems, providing for reduced demands on the distribution and source systems as well. Whether these retrofits are undertaken by in-house personnel, through a QESP program, or by means of a traditional design/bid/build approach, the importance of implementing these changes is paramount to the success of the energy conservation program at IUB.

7) Continue the current effort to selectively replace segments of the existing steam and condensate distribution piping systems due to age and failure potential with new engineered, pre-insulated piping system components. Failures and earlier replacements indicate that the aging insulation systems on these lines have repeatedly failed, creating high levels of heat loss from the distribution system. Many of these piping runs are 50 and more years old and should be replaced to reduce these distribution heat losses and to improve the reliability of the building systems they serve.

8) Institute a program to survey all steam traps within the campus and assemble a database indicating location, service, size, type, and manufacturer of each trap. During this survey, observe and record, through visual and ultrasonic testing, the operating status of each trap and systematically repair or replace the faulty traps. (Such a process has already been established for the CHP and the distribution piping.) Experience on similar campuses and on the IUB distribution system would indicate that between 10 and 20% of the traps will be malfunctioning and that the cost of the survey and trap replacement will be paid back in less than two years through the energy saved.

9) Retain the capability to fire coal at the Central Heating Plant but make the operational modifications and capital improvements necessary to convert the Central Heating Plant into a high-efficiency, natural gas fired plant with the infrastructure to reliably fire up to 100% natural gas to meet the campus loads. It is our belief that the Central Heating Plant, either through legislative pressures to limit carbon emissions or tightened EPA requirements on other emissions, will change within the next ten years from a predominately coal fired plant to a plant firing a high percentage or 100% natural gas. To address this upcoming change in plant operations, the aging and inefficient natural gas/oil fired Boiler No. 5 should be replaced with a new high-efficiency Boiler No. 8.

10) Until a switch has been made at the Central Heating Plant to burn 100% natural gas on a year-round basis, utilize and improve the operational gas spreadsheets developed in this report to compare coal costs versus natural gas costs on a monthly or seasonal basis to determine the appropriate fuel choice for the University based on the true operating cost on each fuel. If the natural gas cost is higher, determine the monthly premium cost the University is willing to spend for the reduced carbon emissions that will result from this change. (For January of 2012, base loading on natural gas in Boiler No. 7 has yielded favorable results.)

11) When natural gas becomes the prime heating source on campus, the advantages of the large central boiler plant generating steam with coal will largely be eliminated. Therefore, the long range direction for heating energy conversion and distribution to campus should be modified from the current paradigm of a large Central Heating Plant distributing 300+°F steam to the campus to a model of distributed thermal plants delivering relatively low temperature heating water (160°F or less) for heating smaller clusters of buildings or individual buildings. Such a paradigm switch would significantly limit distribution losses through shorter, lower temperature distribution mains and would permit the application of even higher efficiency natural gas condensing boiler technology with the potential for geothermal energy storage to be utilized. Such distributed thermal plants should be installed as new buildings are added at the perimeter of the campus, ultimately working inward to sequentially retire buildings from the central steam system.

12) The first of the natural gas fired distributed thermal heating plants should be installed at the Research Park/Tulip Tree Apartments with additional incremental gas boilers installed at the Campus View Apartments, Recreational Sports, and the Nelson Halls Residence Administration Building. Due to the poor condition of the 150 psig high pressure steam and condensate piping system serving this part of

the campus and the significant distances involved from the Central Heating Plant, this development makes sense based on the high cost of the replacement of this element of the steam and condensate piping network and the significant losses currently occurring due to its use. The design intent of this plant would be to ultimately convert its operation to both heating and cooling with heat pump chillers to recover the data center heat rejection for providing the heating needs of the other buildings on the Research Park Campus.

13) At present, the economics of firing biomass in the form of torrefied wood or Nu-Materials I Fuel 60 in the IUB coal boilers cannot compete with the economics of firing on natural gas, even when burning the limited quantities of such biomass with coal in quantities to simulate the carbon emission properties of natural gas. In addition, the concept that the burning of biomass such as wood represents a truly carbon neutral process has been challenged in certain areas of the country. Nevertheless, IUB should stay current on this technology including test burns on competing products and identifying any lowering of the price point of these materials if their production mechanisms see more widespread use.

14) Renewable Energy in the form of wind power to generate electricity for the IUB campus cannot currently compete with the cost of purchased electricity from Duke Energy without the assistance of external drivers such as tax incentives, grants, and a firm and consistent market for the renewable energy credits such a wind project could generate. Again IUB should remain cognizant of Federal or State of Indiana grants that may become available for funding wind power projects for public, non-profit entities. However without such incentives, an investment in such a project at this time is not recommended.

15) Even after the implementation of the energy retrofits recommended, a significant electrical base load will exist on the Indiana University Bloomington campus. To offset a portion of this base load, a 7,500 kW gas turbine cogeneration plant with heat recovery boiler should be installed in or near the current Central Heating Plant generating electricity and recovering waste heat from the process to make steam for campus use. The 75,000 lb/hr heat recovery boiler would further cement the reliability of the CHP as a natural gas fired facility and has the capability of utilizing 77% of the entering natural gas fuel to provide useful electrical and heat energy to the campus while significantly reducing carbon emissions.

16) Solar renewable energy in the form of solar photovoltaic collectors has seen dramatic reductions in cost in recent years, with installed costs in 2011 less than 50% of the same costs in 2008. The expectation is that these costs will continue to drop in coming years as technology and greater production allows prices to continue to plummet. However, at current installed costs of approximately $4.25/watt for a photovoltaic system, compared to campus master meter charges (Duke Energy Rate HPNO), with the typical annual incidence of sunlight hours in Bloomington, and without additional grants or incentives, the payback period in terms of cost/savings will exceed 40 years. However, as a leader among Midwest universities in sustainability awareness and education, IUB should be forward leading in the application of solar photovoltaic technology. The University should continue to search for grants, gifts, tax incentives, and other innovative financing techniques that may serve to make the application of these systems more cost effective.

Of the recommendations listed above that involve substantial investment, Table 11.2.1 summarizes these major Integrated Energy Master Plan initiatives. When completely implemented, these initiatives will cost an estimated $82.6M to implement, reduce annual energy costs by $9.7M per year, and will reduce carbon emissions due to energy use by 52%.

Table 11.2.1: Recommended Integrated Energy Master Plan Initiatives

Project Description		Project Type	Annual Energy, Consumables and Maintenance Cost[1]	Implementation Cost	Annual CO_2 Savings (tons)
Existing Campus		NA	**$ 26,080,000**	**NA**	**496,000**
1	Retro-Commissioning	Energy	$ (910,000)	$ 3,270,000	-27,000
2	Building Energy Conservation Measures	Energy	$ (5,740,000)	$ 44,920,000	-105,000
4A	Selective Retrofit for Central Steam and Condensate Distribution Systems (not including East Main)	Capital Improvement and Energy	$ (950,000)	$ 10,600,000	-28,000
4C	Abandon 10" East 150 psig Steam Main; Replace with Hot Water Boilers and Heating Water Distribution System from the Main Split to Research Park	Capital Improvement and Energy	$ (480,000)	$ 5,310,000[2]	-22,000
9A	Install Natural Gas Cogeneration System at the CHP	Energy	$ (1,790,000)	$ 18,480,000	-58,000
		M&R	$ 310,000		
5B	Revised Central Steam Plant Firing Strategy; 100% Natural Gas with Staff Reductions	Energy	$ 190,000		-20,000
		M&R	$ (360,000)		
Project Subtotals			$ (9,730,000)	$ 82,580,000	-260,000
Existing Campus			$ 26,080,000		496,000
Campus After Implementation of IEMP			**$ 16,350,000** **(37% Reduction)**		**236,000** **(52% Reduction)**

Notes:

[1] Savings based on FY 10/11 estimated average utility costs and carbon emission rates. Annual Cost Reduction includes Energy Cost, Maintenance and Repair Cost and consumables related to the use of coal.

[2] Installing distribution piping in shallow tunnels increases cost by $2,290,000.

Appendix A
Supporting Tables and Figures

Table A3.1.1.1: Coal Chemical Composition Analysis
FY 09/10 Delivered Coal

	AR (As-Received)				MF (Dry Basis)			MAF	MF (Dry Basis)				
Sample ID	Moisture (%)	Ash (%)	Sulfur (%)	Btu/lb	Ash (%)	Sulfur (%)	Btu/lb	Btu/lb	Carbon (%)	Hydrogen (%)	Nitrogen (%)	Oxygen (%)	Chlorine (%)
July-09	7.79	7.96	2.66	12,184	8.63	2.89	13,213	14,461	73.33	5.18	1.42	8.55	0.01
August-09	8.08	8.13	2.46	12,188	8.84	2.68	13,259	14,545	73.76	5.13	1.40	8.19	0.01
September-09	9.13	8.84	2.34	11,954	9.73	2.58	13,155	14,573	72.54	5.03	1.47	8.65	0.01
October-09	7.50	9.95	2.37	11,934	10.76	2.56	12,902	14,458	71.31	5.08	1.49	8.80	<0.01
November-09	8.15	9.07	2.38	12,179	9.88	2.59	13,260	14,714	72.66	5.17	1.40	8.30	0.01
December-09	4.48	7.94	2.81	12,940	8.31	2.94	13,547	14,775	73.81	5.24	1.48	8.22	0.01
January-10	11.76	9.35	2.27	11,418	10.60	2.57	12,940	14,474	74.04	5.41	1.54	5.84	<0.01
February-10	9.96	10.53	2.34	11,553	11.70	2.60	12,831	14,531	70.19	4.85	1.53	9.13	0.01
March-10	9.85	10.39	2.46	11,778	11.52	2.73	13,065	14,766	70.96	4.92	1.53	8.34	0.01
April-10	8.82	10.31	2.43	11,706	11.31	2.66	12,838	14,475	71.71	4.99	1.51	7.82	0.01
May-10	8.55	10.71	2.38	11,705	11.71	2.60	12,799	14,497	70.68	5.07	1.48	8.46	0.01
June-10	12.36	10.57	2.37	11,228	12.06	2.70	12,812	14,569	70.80	5.04	1.50	7.90	0.01
FY 2010 Average	8.87	9.48	2.44	11,897	10.42	2.68	13,052	14,570	72.15	5.09	1.48	8.18	0.01

Total Use = 69,250 short tons @ $51.62/ton = $3,574,685 (Source: Annual Report)

($51.62 / 2,000 lb coal) x (1 lb coal / 11,897 Btu) x (1,000,000 Btu / MMBtu) = $ 2.17 / MMBtu (Source: Annual Report)

Component (Dry Basis)	% by Weight	lbs/lb coal	Reaction	Multiplier	lbs Oxygen Required
Carbon	72.15	0.7215	$C + O_2 = CO_2$	2.664	1.922
Hydrogen	5.09	0.0509	$H_2 + 0.5O_2 = H_2O$	7.937	0.404
Sulfur	2.68	0.0268	$S + O_2 = SO_2$	0.998	0.027
Oxygen	8.18	0.0818	Used for Combustion	-1.000	-0.082
Nitrogen	1.48	0.0148	-	-	-
Ash	10.42	0.1042	-	-	-
				Total =	2.271

Therefore, 2.271 lbs oxygen required to burn one lb of coal; air is 23.1% oxygen

Therefore, 9.83 lbs of air required to burn 1 lb of coal

Carbon Dioxide produced in combustion = 0.7215 + 1.922 = 2.644 lbs CO_2 /lb coal

Sulfur Dioxide produced in combustion = 0.0268 + 0.027 = 0.054 lbs SO_2 / lb coal

Composition (Dry)		
	Carbon	72.15%
	Hydrogen	5.09%
	Sulfur	2.68%
	Oxygen	8.18%
	Nitrogen	1.48%
	Ash	10.42%
	Total	100.00%

Accounting for moisture

Both HHV and LHV can be expressed in terms of AR (all moisture counted), MF and MAF (only water from combustion of hydrogen). AR, MF, and MAF are commonly used for indicating the heating values of coal:

AR (As Received) indicates that the fuel heating value has been measured with all moisture and ash forming minerals present.

MF (Moisture Free) or **Dry** indicates that the fuel heating value has been measured after the fuel has been dried of all inherent moisture but still retaining its ash forming minerals.

MAF (Moisture and Ash Free) or **DAF** (Dry and Ash Free) indicates that the fuel heating value has been measured in the absence of inherent moisture and ash forming minerals.

(2.644 lbs CO_2/lb coal) x (2,000 lbs/short ton)/(2.2046 Kg/lb) = 2,398.621 Kg CO_2/short ton coal (Dry Basis)

(2,398.621 Kg CO_2/ short ton coal) x (1.000 - 0.0887) = 2,185.863 Kg CO_2/short ton coal (As Received Basis)

(2,398.621 Kg CO2/2,000 lb coal) x (2.2046 lb CO_2/Kg CO_2) x (1 lb coal/11,897 Btu) x (84.05/84.05) = 202.53 lb CO_2/MMBtu coal (As Received Basis)

Carbon Dioxide Emissions = 202.53 lb CO_2/MMBtu Coal (As Received Basis)

Table A3.1.2.1: Natural Gas Chemical Composition Analysis

Carbon Dioxide Produced by Natural Gas Combustion

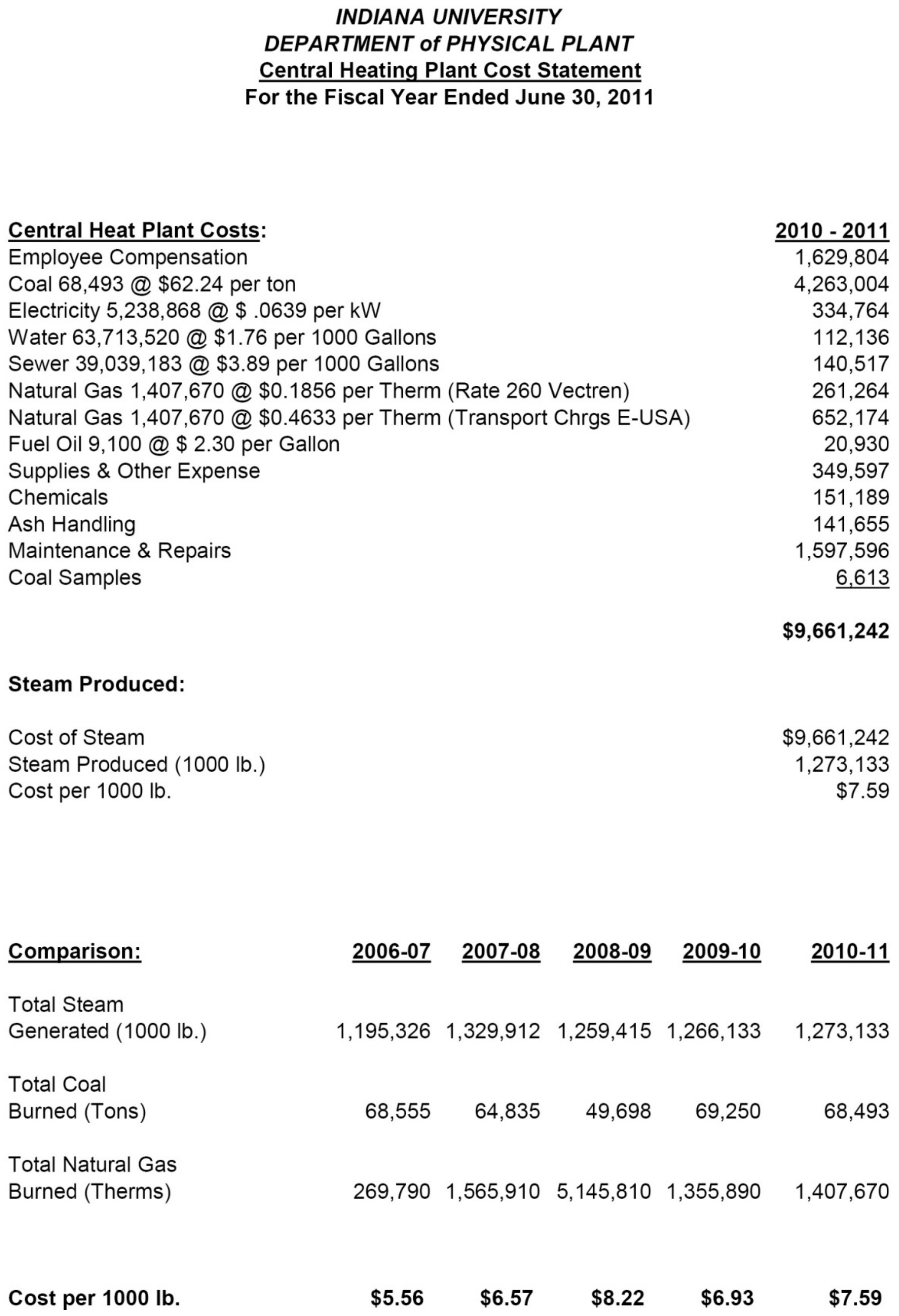
Component	Panhandle Eastern Pipeline Company LP	Texas Gas Transmission LLC	Natural Gas Average
Methane	92.47%	96.43%	94.45%
Ethane	3.18%	1.44%	2.31%
Carbon Dioxide	0.91%	1.69%	1.30%
Propane	0.46%	0.08%	0.27%
Nitrogen	2.83%	0.32%	1.58%
Trace Hydrocarbons	0.15%	0.04%	0.10%
Total by Weight	100.00%	100.00%	100.00%
Higher Htg Value	1,011.9	1,007.2	1,009.5
Specific Gravity	0.60	0.58	0.59

CO_2 Calculation	Lb/lb Burned	lbs CO_2	lbs CO_2/MMBtu	Lb/lb Burned	lbs CO_2	lbs CO_2 / MMBtu	Lb/lb Burned	lbs CO_2	lbs CO_2 / MMBtu
Methane	0.9247	2.5429		0.9643	2.6518		0.9445	2.5974	
Ethane	0.0318	0.0933		0.0144	0.0422		0.0231	0.0678	
Propane	0.0046	0.0138		0.0008	0.0024		0.0027	0.0081	
Carbon Dioxide	0.0091	0.0091		0.0169	0.0169		0.0130	0.0130	
Total		2.6591	118.3		2.7134	117.4		2.6862	**117.8**

Natural Gas Average based on 50% Panhandle Eastern gas (Mainline Tuscola East Station) and 50% Texas Gas Transmission gas (Lebanon Station)

Average Carbon Dioxide Produced per million Btu's burned = 117.8 lbs CO_2/MMBtu

Table A4.2.1: Steam Unit Cost from Annual Report



INDIANA UNIVERSITY
DEPARTMENT of PHYSICAL PLANT
Central Heating Plant Cost Statement
For the Fiscal Year Ended June 30, 2011

Central Heat Plant Costs:	**2010 - 2011**
Employee Compensation	1,629,804
Coal 68,493 @ $62.24 per ton	4,263,004
Electricity 5,238,868 @ $ .0639 per kW	334,764
Water 63,713,520 @ $1.76 per 1000 Gallons	112,136
Sewer 39,039,183 @ $3.89 per 1000 Gallons	140,517
Natural Gas 1,407,670 @ $0.1856 per Therm (Rate 260 Vectren)	261,264
Natural Gas 1,407,670 @ $0.4633 per Therm (Transport Chrgs E-USA)	652,174
Fuel Oil 9,100 @ $ 2.30 per Gallon	20,930
Supplies & Other Expense	349,597
Chemicals	151,189
Ash Handling	141,655
Maintenance & Repairs	1,597,596
Coal Samples	6,613
	$9,661,242

Steam Produced:

Cost of Steam	$9,661,242
Steam Produced (1000 lb.)	1,273,133
Cost per 1000 lb.	$7.59

Comparison:	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**
Total Steam Generated (1000 lb.)	1,195,326	1,329,912	1,259,415	1,266,133	1,273,133
Total Coal Burned (Tons)	68,555	64,835	49,698	69,250	68,493
Total Natural Gas Burned (Therms)	269,790	1,565,910	5,145,810	1,355,890	1,407,670
Cost per 1000 lb.	**$5.56**	**$6.57**	**$8.22**	**$6.93**	**$7.59**

Table A4.3.1: Chilled Water Pumps and Cooling Towers – Central Chilled Water Plant

Central Chilled Water Plant Chillers

Chiller No.	Capacity (tons)	Date Installed	Evaporator Flow (gpm)	Entering Water Temp. (°F)	Leaving Water Temp. (°F)	Electrical Demand (kW)	Electrical Performance (kW/ton)	Condenser Flow (gpm)	Entering Water Temp. (°F)	Leaving Water Temp. (°F)	Refrigerant Used
CH-1	2,500	2004	3,980	55.0	39.9	1,535	0.61	7,500	85.0	94.4	HCFC-123
CH-2	2,500	2004	3,980	55.0	39.9	1,627	0.65	7,500	85.0	94.5	HCFC-123
CH-3	931	1984	1,920	55.0	43.4	576	0.62	3,500	85.0	92.5	HCFC-123
CH-4	931	1984	1,920	55.0	43.4	576	0.62	3,500	85.0	92.5	HCFC-123
CH-5	1,275	1984	2,130	55.0	40.6	786	0.62	3,760	85.0	94.6	HCFC-123
CH-6	1,184	1988	2,130	55.0	41.7	786	0.66	3,760	85.0	94.0	HCFC-123
CH-7	1,275	1988	2,130	55.0	40.6	786	0.62	3,760	85.0	94.6	HCFC-123
CH-8	4,000	1994	6,400	55.0	40.0	2,696	0.67	12,000	85.0	94.5	HFC-134A
Total	14,596		24,590	55.0	40.8	9,368	0.64	45,280	85.0	94.1	

Cooling Towers - Central Chilled Water Plant

Cooling Tower No.	Capacity (gpm)	Wet Bulb Design (°F)	Temperature In (°F)	Temperature Out (°F)	Heat Rejected (MBH)	Date Installed	Variable Speed - Two Speed	Manufacturer	Model No.	Motor Power (HP)
CT-1A	3,750	78	95	85	18,750	2004	VSD	Midwest	CFT-2418-2414-04	75
CT-1B	3,750	78	95	85	18,750	2004	VSD	Midwest	CFT-2418-2414-04	75
CT-2A	3,750	78	95	85	18,750	2004	VSD	Midwest	CFT-2418-2414-04	75
CT-2B	3,750	78	95	85	18,750	2004	VSD	Midwest	CFT-2418-2414-04	75
CT-3	3,500	78	95	85	17,500	1984	Two Speed	Marley	124-102	40
CT-4	3,500	78	95	85	17,500	1984	Two Speed	Marley	124-102	40
CT-5	3,760	78	95	85	18,795	1988	Two Speed	Marley	124-103	60
CT-6	3,760	78	95	85	18,795	1988	Two Speed	Marley	124-103	60
CT-7	3,760	78	95	85	18,795	1988	Two Speed	Marley	124-103	60
CT-8A	4,000	78	95	85	20,000	1994	Two Speed	Marley	Sigma	75
CT-8B	4,000	78	95	85	20,000	1994	Two Speed	Marley	Sigma	75
CT-8C	4,000	78	95	85	20,000	1994	Two Speed	Marley	Sigma	75
Total	45,280				226,385					785

Table A4.3.2: Chilled Water Pumps and Condenser Water Pumps – Central Chilled Water Plant

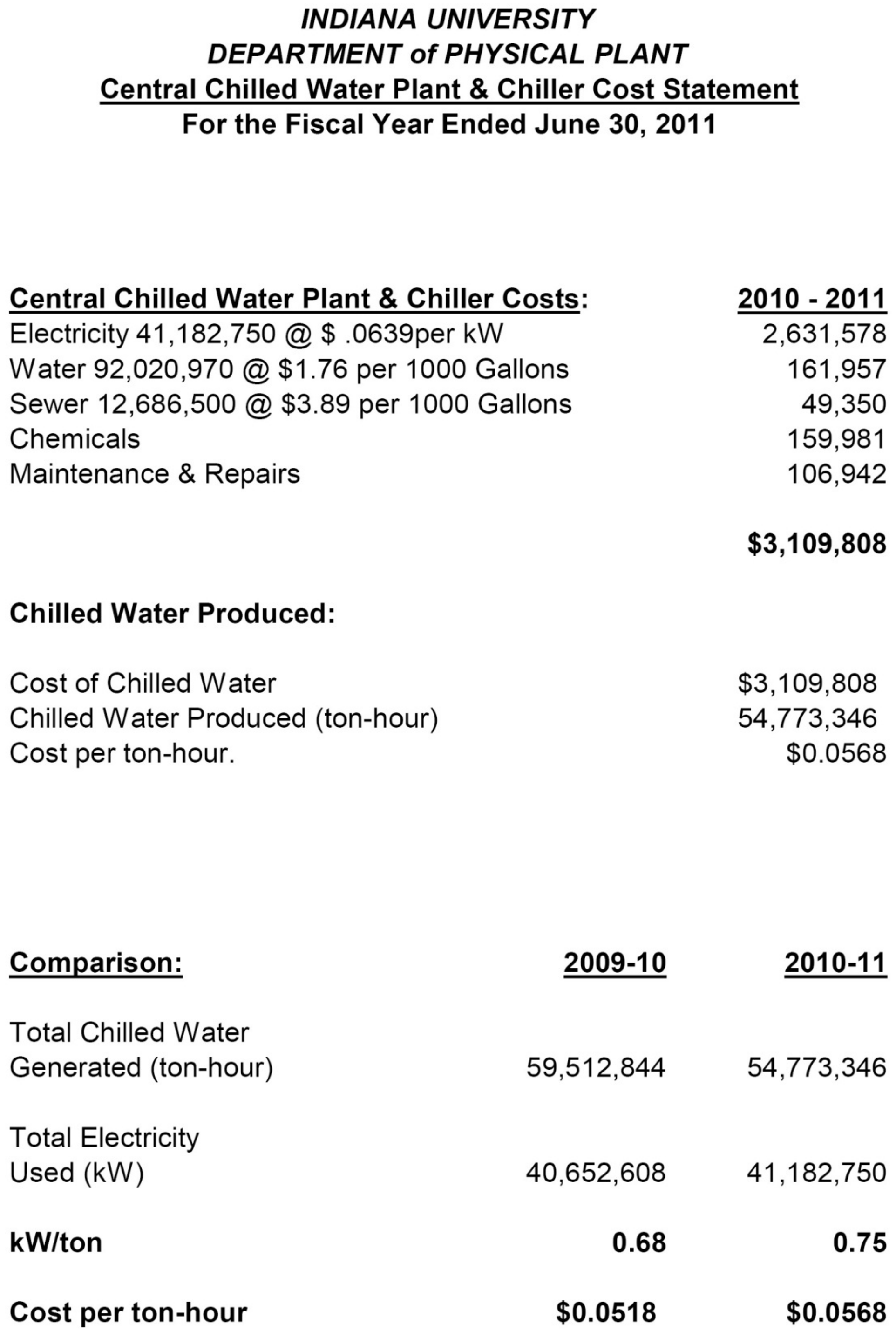
Chilled Water Pumps - Central Chilled Water Plant

Pump No.	Capacity (gpm)	Head (ft)	Power (HP)	Inferred Efficiency	Duty	Variable Speed Drive	Manufacturer	Model No.	Date Installed	Date Rebuilt
PE-1	4,000	40	50	0.81	Chiller No. 1 Chiller Pump	No	Peerless	20HH	2004	
PE-2	4,000	40	50	0.81	Chiller No. 2 Chiller Pump	No	Peerless	20HH	2004	
PE-3	1,920	34	25	0.66	Chiller No. 3 Chiller Pump	No	Peerless	12HXH	1984	
PE-4	1,920	34	25	0.66	Chiller No. 4 Chiller Pump	No	Peerless	12HXH	1984	
PE-5	2,130	52	40	0.70	Chiller No. 5 Chiller Pump	No	Peerless	14HH	1988	2006
PE-6	2,130	52	40	0.70	Chiller No. 6 Chiller Pump	No	Peerless	14HH	1988	
PE-7	2,130	52	40	0.70	Chiller No. 7 Chiller Pump	No	Peerless	14HH	1988	
PE-8	6,400	48	125	0.62	Chiller No. 8 Chiller Pump	No	Peerless	24HXC	1994	
Total	24,630		395							
PS-1	8,000	116	300	0.78	System Pump No.1	Yes	Peerless	20HH	1984	2006
PS-2	4,000	110	150	0.74	System Pump No.2	Yes	Verti-Line	150SW14H2	1967	1991
PS-3	3,200	113	125	0.73	System Pump No.3	No	Peerless	14HH2	1988	
PS-4	2,000	60	50	0.61	System Pump No.4	No	Peerless	14MC	1988	
PS-5	8,000	116	300	0.78	System Pump No.5	Yes	Peerless	24HH	1994	
Total	25,200		925							

Condenser Water Pumps - Central Chilled Water Plant

Pump No.	Capacity (gpm)	Head (ft)	Power (HP)	Inferred Efficiency	Duty	Variable Speed Drive	Manufacturer	Model No.	Date Installed	Date Rebuilt
PC-1	7,500	40	100	0.76	Chiller No. 1 Cond. Pump	No	Peerless	20HH	2004	
PC-2	7,500	40	100	0.76	Chiller No. 2 Cond. Pump	No	Peerless	20HH	2004	
PC-3	3,500	19	30	0.56	Chiller No. 3 Cond. Pump	No	Peerless	16HH	1984	2005
PC-4	3,500	19	30	0.56	Chiller No. 4 Cond. Pump	No	Peerless	16HH	1984	2004
PC-5	3,760	70	100	0.66	Chiller No. 5 Cond. Pump	No	Peerless	16HXB	1988	2006
PC-6	3,760	70	100	0.66	Chiller No. 6 Cond. Pump	No	Peerless	16HXB	1988	2002
PC-7	3,760	70	100	0.66	Chiller No. 7 Cond. Pump	No	Peerless	16HXB	1988	2004
PC-8	12,000	80	300	0.81	Chiller No. 8 Cond. Pump	No	Peerless	26HH	1994	
Total	45,280		860							
PT-1	6,000	54	100	0.82	Tower Pump No.1	VSD	Peerless	20HH	1984	
PT-2	4,500	54	100	0.61	Tower Pump No.2	No	Verti-Line	150SW14H2	1967	2005
PT-3	6,000	54	100	0.82	Tower Pump No.3	No	Peerless	14HH2	1988	
PT-4	6,000	54	100	0.82	Tower Pump No.4	VSD	Peerless	14MC	1988	
Total	22,500		400							

Table A4.4.1: Chilled Water Unit Cost from Annual Report



INDIANA UNIVERSITY
DEPARTMENT of PHYSICAL PLANT
Central Chilled Water Plant & Chiller Cost Statement
For the Fiscal Year Ended June 30, 2011

Central Chilled Water Plant & Chiller Costs:	**2010 - 2011**
Electricity 41,182,750 @ $ .0639per kW	2,631,578
Water 92,020,970 @ $1.76 per 1000 Gallons	161,957
Sewer 12,686,500 @ $3.89 per 1000 Gallons	49,350
Chemicals	159,981
Maintenance & Repairs	106,942
	$3,109,808

Chilled Water Produced:

Cost of Chilled Water	$3,109,808
Chilled Water Produced (ton-hour)	54,773,346
Cost per ton-hour.	$0.0568

Comparison:	**2009-10**	**2010-11**
Total Chilled Water Generated (ton-hour)	59,512,844	54,773,346
Total Electricity Used (kW)	40,652,608	41,182,750
kW/ton	**0.68**	**0.75**
Cost per ton-hour	**$0.0518**	**$0.0568**

Table A5.5.1: Marginal Utility Cost for FY 2010 / 2011

FY 10-11 Fuel, Energy, and Water Estimates

Actual FY 10/11 Costs

Utility	Electricity					Natural Gas						Coal				
	Usage	Units	Cost	Average Cost	Units	Service	Usage	Units	Cost	Average Cost	Units	Usage	Units	Cost	Average Cost	Units
Data	*292,246,548*	kWh	*$18,677,297*	*$0.0639*	*$/kWh*	Total Campus	*3,331,611.0*	therms	*$2,542,489.17*	*$0.763*	*$/therm*	*68,493.00*	tons	*$4,263,004.00*	*$62.24*	$/ton
						CHP only	*1,407,670.0*	therms	*$913,437.00*	*$0.649*	*$/therm*	*16,297,224.4*	therm	*$4,263,004.00*	*$0.262*	*$/therm*
						Campus Only	*1,923,941.0*	therms	*$1,629,052.17*	*$0.847*	*$/therm*					

Utility	Fuel Oil				
	Usage	Units	Cost	Average Cost	Units
CHP	*9,100*	gallons	*$20,930.00*	*$2.30*	$/gallon
Campus	*18,440*	gallons	*$54,351.74*	*$2.95*	$/gallon
Total	*38,005*	therms	*$75,281.74*	*$1.98*	*$/therm*

Water					Sewer				
Usage	Units	Cost	Average Cost	Units	Usage	Units	Cost	Average Cost	Units
623,435	Kgallons	*$1,112,303.46*	*$1.78*	$/Kgallons	*501,972*	Kgallons	*$2,102,113.39*	*$4.19*	$/Kgallons
623,435,000	gallons	*$1,112,303.46*	$0.00178	$/gallon	*501,972,000*	gallons	*$2,102,113.39*	$0.00419	$/gallon

Utility	Chilled Water	Units	Steam	Units
FY 09-10 Rate	*$0.0518*	$/ton-hour	*$0.4489*	$/therm
Factor	*1.0965*	-	*1.1187*	-
FY 10-11 Rate	*$0.0568*	$/ton-hour	*$0.5022*	$/therm

Report Data

					Emissions		Total Emissions	
	kWh	MMBtu	Cost	%	lb CO_2/kWh	lb CO_2/MMBtu	tons CO_2	%
Electricity	292,246,548	-	$18,677,297	73.1%	2.087	-	304,959	62.2%
Coal	-	1,629,722	$4,263,004	16.7%	-	202.5	165,009	33.7%
Natural Gas	-	333,161	$2,542,489	9.9%	-	117.8	19,623	4.0%
Fuel Oil	-	3,801	$75,282	0.3%	-	159.6	303	0.1%
Total Cost	-	1,966,684	$25,558,072	100.0%		Total Emissions =	489,895	100.0%

Table A6.1.1: Building Skin Survey, Buildings without Exterior Insulation

Law	Woodburn Hall	Geological Survey
Bryan Hall	Memorial Hall	Psychology
Poplars	Merrill Hall	Briscoe Quad
Swain West	Music Addition	McNutt North
Maxwell Hall	Sycamore Hall	McNutt Central
Edmondson Hall	Lilly Library	McNutt South
Cravens Hall	Fine Arts	Central Heating
Smith Hall	Auditorium	Business School
IN Memorial Union	IU Cinema	SPEA
Owen Hall	Simon Msc Lbr Rec	Harper Hall
Wylie Hall	Wells Library	Gresham Dining Hall
Kirkwood Hall	Read Hall	Shea Hall
Lindley Hall	Wright Quad	Martin Hall
Swain East	Teter Quad	Magee Hall
Rawles Hall	Forest Quad	Jenkinson Hall
Chemistry	Willkie B	Nelson RPS Admin.
Chemistry Addition	Willkie C	Campus View Apartments
Ernie Pyle Hall	Willkie A	Tulip Tree Apts
Wildermuth Center	Mason Hall	Memorial Stadium
Myers Hall	Eigenmann Hall	Assembly Hall
Goodbody Hall	DeVault Alumni Center	Gladstein Fieldhouse
Ballantine Hall	Geological Sciences	IU Warehouse
HPER Building		

Table A6.1.2: Building Skin Survey, Buildings with Single Pane Windows

Franklin Hall	Morrison Hall	McNutt North
Poplars	Memorial Hall	McNutt Central
Swain West	Merrill Hall	McNutt South
Maxwell Hall	Music Addition	Central Heating
Owen Hall	Sycamore Hall	Business School
Kirkwood Hall	Lilly Library	Harper Hall
Optometry School	Fine Arts	Gresham Dining Hall
Atwater Parking	IU Cinema	Shea Hall
Chemistry	Musical Arts Center	Martin Hall
Chemistry Addition	Wells Library	Magee Hall
Ernie Pyle Hall	Teter Quad	Jenkinson Hall
Wildermuth Center	Forest Quad	Nelson RPS Admin.
Jordan Hall	Geological Sciences	Assembly Hall
Goodbody Hall	Geological Survey	Gladstein Fieldhouse
Ballantine Hall	Psychology	IU Warehouse
HPER Building	Briscoe Quad	

Table A6.2.1: Base Case Energy Model Results for Electricity

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Electrical Usage (kWh)	Estimated Power Usage Density (kWh/SF)	Average Power Demand Usage by Building Type (kWh/SF)	Power Usage on Campus Electrical System (kWh)
BL001	Law	170,098	170,098	2,328,438	13.7	16.9	2,328,438
BL005	Bryan Hall	51,436	51,436	982,133	19.1	14.4	982,133
BL007	Franklin Hall	138,149	138,149	1,891,724	13.7	14.4	1,891,724
BL008	Poplars	150,420	150,420	1,823,574	12.1	14.4	NA
BL009	Poplars Parking	136,402	1	442,109	3.2	2.6	NA
BL009C	International Programs	10,286	10,286	147,879	14.4	14.4	NA
BL017	Student Building	69,737	69,737	821,215	11.8	16.9	821,215
BL021	Kirkwood Observatory	4,297	4,297	72,785	16.9	16.9	72,785
BL027	Swain West	154,602	154,602	3,266,799	21.1	16.9	3,266,799
BL031	Rose Well House	200	0	523	2.6	2.6	523
BL033	Maxwell Hall	31,091	31,091	338,401	10.9	14.4	338,401
BL043	Edmondson Hall	68,588	68,588	566,752	8.3	10.3	566,752
BL045	Cravens Hall	35,040	35,040	202,623	5.8	10.3	202,623
BL047	Smith Hall	22,621	22,621	139,995	6.2	10.3	139,995
BL053	IN Memorial Union	439,018	439,018	8,932,147	20.3	18.6	8,932,147
BL053P	IMU Guard Hut	27	27	138	5.1	5.1	138
BL055	Owen Hall	20,148	20,148	299,554	14.9	14.4	299,554
BL057	Wylie Hall	33,513	33,513	383,320	11.4	16.9	383,320
BL058	Kirkwood Hall	36,450	36,450	705,526	19.4	14.4	705,526
BL059	Lindley Hall	59,910	59,910	1,654,247	27.6	16.9	1,654,247
BL061	Swain East	35,609	35,609	477,255	13.4	14.4	477,255
BL063	Henderson Parking Garage	205,012	1	521,110	2.5	2.6	NA
BL065	Optometry School	94,228	94,228	1,497,378	15.9	16.9	1,497,378
BL067	Rawles Hall	42,017	42,017	877,807	20.9	14.4	877,807
BL069	Atwater Parking	193,084	1	524,345	2.7	2.6	NA
BL070	Simon Hall	141,094	141,094	8,250,356	58.5	37.2	8,250,356

Table A6.2.1: Base Case Energy Model Results for Electricity (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Electrical Usage (kWh)	Estimated Power Usage Density (kWh/SF)	Average Power Demand Usage by Building Type (kWh/SF)	Power Usage on Campus Electrical System (kWh)
	(Science)						
BL071	Chemistry	183,387	183,387	7,455,436	40.7	37.2	7,455,436
BL072	Chemistry Addition	106,551	106,551	3,925,624	36.8	37.2	3,925,624
BL074A	8th St Hut (Hper)	20	20	102	5.1	5.1	102
BL075	Ernie Pyle Hall	38,292	38,292	1,319,630	34.5	16.9	1,319,630
BL091	Wildermuth Center	141,341	141,341	1,848,911	13.1	18.6	1,848,911
BL095	Beck Chapel	2,046	2,046	38,156	18.6	18.6	38,156
BL101	Myers Hall	76,521	76,521	3,122,753	40.8	37.2	3,122,753
BL107	Jordan Hall	324,279	324,279	9,592,417	29.6	37.2	9,592,417
BL109	Goodbody Hall	37,522	37,522	721,435	19.2	16.9	721,435
BL111	Ballantine Hall	305,420	305,420	3,951,453	12.9	16.9	3,951,453
BL119	HPER Building	189,776	189,776	3,222,523	17.0	18.6	3,222,523
BL130A	7th St Hut	16	16	82	5.1	5.1	82
BL133	Woodburn Hall	73,257	73,257	1,285,792	17.6	14.4	1,285,792
BL135	Bryan House	8,188	8,188	117,716	14.4	14.4	117,716
BL139	Morrison Hall	53,989	53,989	764,644	14.2	14.4	764,644
BL141	Memorial Hall	58,578	58,578	534,218	9.1	14.4	534,218
BL143	Music Practice	18,635	18,635	315,650	16.9	16.9	315,650
BL147	Merrill Hall	58,322	58,322	732,587	12.6	16.9	732,587
BL148	Music Addition	122,165	122,165	2,606,871	21.3	16.9	2,606,871
BL149	Sycamore Hall	74,602	74,602	789,078	10.6	16.9	789,078
BL153	Art Museum	119,314	119,314	4,205,194	35.2	16.9	4,205,194
BL155	Lilly Library	52,516	52,516	774,531	14.7	14.4	774,531
BL157	Fine Arts	115,554	115,554	1,735,591	15.0	16.9	1,735,591
BL158	Radio-TV	99,373	99,373	1,122,834	11.3	16.9	1,122,834
BL171	Auditorium	238,364	238,364	2,234,290	9.4	16.9	2,234,290
BL172	Lee Norvelle Theatre Drama/ Neal&Mars	135,627	135,627	3,121,242	23.0	16.9	3,121,242
BL173	IU Cinema	13,506	13,506	116,407	8.6	16.9	116,407
BL177	Musical Arts Center	267,130	267,130	5,690,209	21.3	16.9	5,690,209

Table A6.2.1: Base Case Energy Model Results for Electricity (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Electrical Usage (kWh)	Estimated Power Usage Density (kWh/SF)	Average Power Demand Usage by Building Type (kWh/SF)	Power Usage on Campus Electrical System (kWh)
BL177W	MAC Machine Room 100	2,894	2,894	14,817	5.1	5.1	14,817
BL181	Simon Msc Lbr Rec	231,539	231,539	1,738,794	7.5	16.9	1,738,794
BL197	International Studies	1	0	0	NA	16.9	0
BL197D	316 N Jordan Ave	10,182	10,182	146,384	14.4	14.4	NA
BL198	Admissions	16,525	16,525	237,575	14.4	14.4	NA
BL199	Jordan Ave Parking	194,648	1	494,487	2.5	2.6	494,487
BL207A	324 N Jordan Ave	5,476	5,476	78,727	14.4	14.4	78,727
BL207B	326 N Jordan Ave	3,437	3,437	49,413	14.4	14.4	49,413
BL209	Wells Library	557,163	557,163	8,394,108	15.1	16.9	8,394,108
BL215A	International Center	11,454	11,454	164,671	14.4	14.4	164,671
BL221	University Apt West	69,156	69,156	715,422	10.3	10.3	715,422
BL223	University Apt East	69,157	69,157	715,432	10.3	10.3	715,432
BL227	Read Hall	359,658	359,658	3,663,854	10.2	10.3	3,663,854
BL237	Wright Quad	295,887	295,887	3,109,939	10.5	10.3	3,109,939
BL243	Teter Quad	300,873	300,873	2,141,990	7.1	10.3	2,141,990
BL245	Wendell W. Wright	191,111	191,111	3,823,515	20.0	16.9	3,823,515
BL257	Forest Quad	289,014	289,014	2,249,599	7.8	10.3	2,249,599
BL257C	Forest Quad Chiller	3,816	3,816	2,820,791	739.2	739.2	2,820,791
BL271	Weatherly Hall	37,349	37,349	386,377	10.3	10.3	386,377
BL272	Hershey Hall	36,110	36,110	373,560	10.3	10.3	373,560
BL275	Johnston Hall	36,396	36,396	376,518	10.3	10.3	376,518
BL276	Vos Hall	35,615	35,615	368,439	10.3	10.3	368,439
BL276A	Hickory Hall	63,414	63,414	511,707	8.1	10.3	511,707
BL276B	Birch Hall	42,460	42,460	375,535	8.8	10.3	375,535
BL276C	Cedar Hall	92,198	92,198	815,487	8.8	10.3	815,487
BL276D	Linden Hall	63,414	63,414	554,844	8.7	10.3	554,844
BL276E	Cypress Hall	42,460	42,460	359,072	8.5	10.3	359,072
BL276F	Beech Hall	63,415	63,415	549,416	8.7	10.3	549,416

Table A6.2.1: Base Case Energy Model Results for Electricity (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Electrical Usage (kWh)	Estimated Power Usage Density (kWh/SF)	Average Power Demand Usage by Building Type (kWh/SF)	Power Usage on Campus Electrical System (kWh)
BL276G	Pine Hall	63,414	63,414	535,619	8.4	10.3	535,619
BL276L	Union St Chiller	4,371	4,371	2,194,694	502.1	5.1	2,194,694
BL277	Moffatt Hall	25,769	25,769	266,582	10.3	10.3	266,582
BL278	Griggs Lounge	4,759	4,759	88,752	18.6	18.6	88,752
BL279	Dreiser Hall	2,701	2,701	50,372	18.6	18.6	50,372
BL280	Stempel Hall	40,378	40,378	417,712	10.3	10.3	417,712
BL282	Barnes Lounge	3,892	3,892	72,583	18.6	18.6	72,583
BL297	Willkie B	120,091	120,091	1,341,544	11.2	10.3	1,341,544
BL299	Willkie C	85,302	85,302	2,805,903	32.9	10.3	2,805,903
BL301	Willkie A	119,951	119,951	950,764	7.9	10.3	950,764
BL304	Mason Hall	24,717	24,717	171,405	6.9	10.3	171,405
BL313	Eigenmann Hall	349,442	349,442	6,000,050	17.2	10.3	6,000,050
BL316	408 N Union St	60,229	60,229	NA	NA	14.4	NA
BL404A	Brown Hall	14,653	14,653	151,586	10.3	10.3	151,586
BL404B	Greene Hall	17,294	17,294	178,907	10.3	10.3	178,907
BL404C	Monroe Hall	3,394	3,394	57,490	16.9	16.9	57,490
BL404D	Morgan Hall	19,434	19,434	201,046	10.3	10.3	201,046
BL405	Research Svc. Bldg.	4,126	4,126	21,124	5.1	5.1	21,124
BL407	DeVault Alumni Center	32,563	32,563	536,371	16.5	14.4	536,371
BL411	Chilled Water Plant	38,817	38,817	35,348,099	910.6	739.2	35,348,099
BL411N	N Forrest Ave Chiller	0	0	0	NA	5.1	0
BL413	Arts Annex	25,411	25,411	430,426	16.9	16.9	430,426
BL413A	Graduate Printmaking	6,713	6,713	34,369	5.1	5.1	34,369
BL417	Geological Sciences	126,422	126,422	2,521,325	19.9	16.9	2,521,325
BL418	Geological Survey	52,361	52,361	1,044,516	19.9	16.9	1,044,516
BL419	Psychology	155,246	155,246	2,991,502	19.3	16.9	2,991,502
BL423	Multi Science 2	131,074	131,074	3,439,320	26.2	37.2	3,439,320
BL425C	880 N Walnut Grove	4,189	4,189	43,335	10.3	10.3	43,335

Table A6.2.1: Base Case Energy Model Results for Electricity (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Electrical Usage (kWh)	Estimated Power Usage Density (kWh/SF)	Average Power Demand Usage by Building Type (kWh/SF)	Power Usage on Campus Electrical System (kWh)
BL433	Briscoe Quad	279,424	279,424	2,545,804	9.1	10.3	2,545,804
BL437	McNutt North	153,143	153,143	1,299,989	8.5	10.3	1,299,989
BL439	McNutt Central	78,264	78,264	1,591,464	20.3	18.6	1,591,464
BL441	McNutt South	129,665	129,665	1,051,898	8.1	10.3	1,051,898
BL445	Central Heating	84,020	3,000	1,240,084	413.4	5.1	1,240,084
BL448	Fee Lane Pkg Garage	223,279	1	508,539	2.3	2.6	508,539
BL450	Godfrey Grad&Exec Ed Ctr	191,743	191,743	1,698,131	8.9	16.9	1,698,131
BL451	Business School	238,158	238,158	4,232,737	17.8	16.9	4,232,737
BL452	SPEA	128,619	128,619	3,135,440	24.4	16.9	3,135,440
BL453	Harper Hall	109,147	109,147	894,214	8.2	10.3	894,214
BL454	Gresham Dining Hall	50,888	50,888	526,076	10.3	18.6	526,076
BL455	Shea Hall	42,003	42,003	300,455	7.2	10.3	300,455
BL456	Martin Hall	37,063	37,063	270,964	7.3	10.3	270,964
BL461	Magee Hall	37,064	37,064	299,401	8.1	10.3	299,401
BL462	Jenkinson Hall	36,896	36,896	284,596	7.7	10.3	284,596
BL463	Nelson RPS Admin.	40,453	40,453	529,993	13.1	14.4	529,993
BL465C	Wells House	6,678	6,678	96,008	14.4	14.4	96,008
BL467	Health Center	64,656	64,656	1,966,587	30.4	18.6	1,966,587
BL475	Recreational Sports	253,302	253,302	5,818,687	23.0	18.6	5,818,687
BL489	Rogers HL Elev Pump	388	0	0	NA	149.9	0
BL490	Physical Plt Storage	15,047	0	0	NA	5.1	0
BL493	Hepburn Apartments	26,033	26,033	269,313	10.3	10.3	269,313
BL513	Nutt Apartments	24,520	24,520	253,661	10.3	10.3	253,661
BL519	Bicknell Hall	25,212	25,212	260,819	10.3	10.3	260,819
BL523	Hoosier Courts D/C	6,481	6,481	120,866	18.6	18.6	120,866
BL529	Campus View Apartments	267,723	267,723	3,500,433	13.1	10.3	3,500,433

Table A6.2.1: Base Case Energy Model Results for Electricity (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Electrical Usage (kWh)	Estimated Power Usage Density (kWh/SF)	Average Power Demand Usage by Building Type (kWh/SF)	Power Usage on Campus Electrical System (kWh)
BL539	Banta Apartments	35,904	35,904	371,429	10.3	10.3	371,429
BL543	Evermann Apartments	218,273	218,273	2,258,045	10.3	10.3	2,258,045
BL545	Carillon	943	943	2,466	2.6	2.6	2,466
BL547	Redbud 2 North	49,030	49,030	507,218	10.3	10.3	507,218
BL548	Redbud 1 East	49,029	49,029	507,207	10.3	10.3	507,207
BL549	Botany Greenhouse	3,225	3,225	8,433	2.6	2.6	8,433
BL549A	Junior Gardening	908	908	2,374	2.6	2.6	2,374
BL549B	Pole Barn A	718	0	1,878	2.6	2.6	1,878
BL549C	Pole Barn B	598	0	1,564	2.6	2.6	1,564
BL549G	Botany Field Greenhouse	20,559	20,559	105,257	5.1	5.1	105,257
BL550	Research Lab	693	693	25,755	37.2	37.2	25,755
BL551	Hilltop Garden Center	3,397	3,397	63,351	18.6	18.6	63,351
BL552	Fly Magnetic Center	740	740	3,789	5.1	5.1	3,789
BL555	Tulip Tree Apts	263,003	263,003	2,407,930	9.2	10.3	2,407,930
BL563	Innovation Center	39,871	39,871	686,426	17.2	14.4	NA
BL565	U School E-1	10,151	10,151	145,938	14.4	14.4	145,938
BL566	UITS E-2	15,033	15,033	216,125	14.4	14.4	216,125
BL567	U School E-3	6,512	6,512	93,621	14.4	14.4	93,621
BL568	UITS E-4	8,323	8,323	119,657	14.4	14.4	119,657
BL569	Wrubel Computing Ct	47,248	47,248	679,270	14.4	14.4	679,270
BL570	UITS E-5	12,714	12,714	182,785	14.4	14.4	182,785
BL571	Communication Svcs.	20,028	20,028	287,937	14.4	14.4	287,937
BL572	Intercol. Athl. Gym	35,669	35,669	665,200	18.6	18.6	665,200
BL573	Smith Research Center	56,312	56,312	809,581	14.4	14.4	809,581
BL576	Childrens Center	11,836	11,836	220,732	18.6	18.6	220,732

Table A6.2.1: Base Case Energy Model Results for Electricity (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Electrical Usage (kWh)	Estimated Power Usage Density (kWh/SF)	Average Power Demand Usage by Building Type (kWh/SF)	Power Usage on Campus Electrical System (kWh)
BL577	ROTC Supply Center	10,421	10,421	53,353	5.1	5.1	53,353
BL578	Cyberinfrastructure Bldg (CIB)	131,140	131,140	20,789,342	158.5	158.5	20,789,342
BL579	Data Center	81,186	81,186	12,870,242	158.5	158.5	NA
BL580	Disability & Community	39,419	39,419	566,715	14.4	14.4	566,715
BL595	Mellencamp Pavilion	100,282	100,282	1,034,749	10.3	18.6	NA
BL601	Memorial Stadium	253,872	16,749	473,507	28.3	18.6	473,507
BL601a	Memorial Stadium East Stands	46,384	46,384	699,227	15.1	18.6	699,227
BL601b	Memorial Stadium West Stands	56,223	56,223	1,492,087	26.5	18.6	1,492,087
BL601c	Memorial Stadium North Endzone	115,919	70,000	1,514,833	21.6	18.6	NA
BL602	Tennis Center	57,708	57,708	991,403	17.2	18.6	991,403
BL603	Assembly Hall	381,106	381,106	4,743,415	12.4	18.6	4,743,415
BL604	Gladstein Fieldhouse	103,427	103,427	2,266,366	21.9	18.6	2,266,366
BL605	Outdoor Pool	4,550	4,550	84,854	18.6	18.6	84,854
BL606	Sembwr Concession	1,405	1,405	7,193	5.1	5.1	7,193
BL606A	Sembwr DO 3rd Base	362	0	0	NA	149.9	0
BL606B	Sembwr DO 1st Base	362	0	0	NA	149.9	0
BL606C	Softball DO 3rd Base	242	0	0	NA	149.9	0
BL606D	Softball DO 1st Base	242	0	0	NA	149.9	0
BL606E	Softball Press Box	589	0	0	NA	5.1	0
BL606F	Sembwr Press Box	653	653	3,343	5.1	5.1	3,343

Table A6.2.1: Base Case Energy Model Results for Electricity (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Electrical Usage (kWh)	Estimated Power Usage Density (kWh/SF)	Average Power Demand Usage by Building Type (kWh/SF)	Power Usage on Campus Electrical System (kWh)
BL607	Cook Hall	69,441	69,441	2,387,653	34.4	18.6	2,387,653
BL612	N. Fee Rec. Storage	1,309	1,309	3,423	2.6	2.6	3,423
BL614	ALF-Ruth Lilly Auxilary Library	55,824	55,824	2,170,598	38.9	16.9	NA
BL615	IU Warehouse	130,746	130,746	669,387	5.1	5.1	NA
BL630	Service Bldg	78,452	78,452	934,249	11.9	14.4	NA
BL664	IU Research Park	71,120	71,120	NA	NA	14.4	NA
BL672	Food Storage	81,273	81,273	NA	NA	5.1	NA
BL899	Showalter Fountain	1,500	0	0	NA	149.9	0
BL614	ALF-Ruth Lilly Auxilary Library	55,824	55,824	2,170,598	38.9	16.9	NA
BL615	IU Warehouse	130,746	130,746	669,387	5.1	5.1	NA
BL630	Service Bldg	78,452	78,452	934,249	11.9	14.4	NA
BL664	IU Research Park	71,120	71,120	NA	NA	14.4	NA
BL672	Food Storage	81,273	81,273	NA	NA	5.1	NA
BL990P	Informatics East	39,922	39,922	676,222	16.9	16.9	NA
Total		15,711,983	14,375,252	296,895,893	5,362	5,193	268,721,979

Table A6.2.2: Base Case Energy Model Results for Heating

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Annual Steam and Gas Usage (MMBtu)	Estimated Annual Steam and Gas (MBtu/SF)	Average Steam and Gas Density by Building Type (Mbtu/SF)	Estimated Central Steam Plant Usage (MMBtu)	Basis for Energy Usage
BL001	Law	170,098	170,098	11,859	70	81	11,859	Model Data
BL005	Bryan Hall	51,436	51,436	5,562	108	69	5,249	Meter Data
BL007	Franklin Hall	138,149	138,149	12,611	91	69	12,611	Meter Data
BL008	Poplars	150,420	150,420	6,189	41	69	0	Model Data
BL009	Poplars Parking	136,402	1	0	0	1	0	Model Data
BL017	Student Building	69,737	69,737	7,773	111	81	7,773	Meter Data
BL021	Kirkwood Observatory	4,297	4,297	348	81	81	340	SF Estimate
BL027	Swain West	154,602	154,602	16,332	106	81	16,332	Meter Data
BL033	Maxwell Hall	31,091	31,091	2,483	80	69	2,483	Meter Data
BL043	Edmondson Hall	68,588	68,588	6,293	92	58	6,293	Meter Data
BL045	Cravens Hall	35,040	35,040	2,297	66	58	2,297	Meter Data
BL047	Smith Hall	22,621	22,621	2,525	112	58	2,525	Meter Data
BL053	IN Memorial Union	439,018	439,018	29,025	66	84	26,797	Model Data
BL055	Owen Hall	20,148	20,148	706	35	69	706	Model Data
BL057	Wylie Hall	33,513	33,513	2,758	82	81	2,758	Meter Data
BL058	Kirkwood Hall	36,450	36,450	1,417	39	69	1,417	Model Data
BL059	Lindley Hall	59,910	59,910	5,513	92	81	5,513	Meter Data
BL061	Swain East	35,609	35,609	2,988	84	69	2,988	Model Data

Table A6.2.2: Base Case Energy Model Results for Heating (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Annual Steam and Gas Usage (MMBtu)	Estimated Annual Steam and Gas (MBtu/SF)	Average Steam and Gas Density by Building Type (Mbtu/SF)	Estimated Central Steam Plant Usage (MMBtu)	Basis for Energy Usage
BL063	Henderson Parking Garage	205,012	1	664	3	1	0	Model Data
BL065	Optometry School	94,228	94,228	8,022	85	81	0	Model Data
BL067	Rawles Hall	42,017	42,017	2,146	51	69	2,146	Meter Data
BL069	Atwater Parking	193,084	1	481	2	1	0	Model Data
BL070	Simon Hall (Science)	141,094	141,094	8,272	59	111	8,112	Meter Data
BL071	Chemistry	183,387	183,387	14,244	78	111	13,807	Meter Data
BL072	Chemistry Addition	106,551	106,551	6,648	62	111	6,648	Model Data
BL075	Ernie Pyle Hall	38,292	38,292	7,500	196	81	7,500	Meter Data
BL091	Wildermuth Center	141,341	141,341	3,681	26	84	3,681	Model Data
BL095	Beck Chapel	2,046	2,046	172	84	84	163	SF Estimate
BL101	Myers Hall	76,521	76,521	14,619	191	111	14,619	Meter Data
BL107	Jordan Hall	324,279	324,279	57,515	177	111	57,150	Meter Data
BL109	Goodbody Hall	37,522	37,522	2,233	60	81	2,233	Meter Data
BL111	Ballantine Hall	305,420	305,420	14,735	48	81	14,735	Meter Data
BL119	HPER Building	189,776	189,776	5,575	29	84	5,575	Model Data
BL133	Woodburn Hall	73,257	73,257	5,556	76	69	5,556	Meter Data
BL139	Morrison Hall	53,989	53,989	3,664	68	69	3,664	Model Data
BL141	Memorial Hall	58,578	58,578	4,174	71	69	4,174	Meter Data
BL147	Merrill Hall	58,322	58,322	6,311	108	81	6,311	Meter Data

Table A6.2.2: Base Case Energy Model Results for Heating (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Annual Steam and Gas Usage (MMBtu)	Estimated Annual Steam and Gas (MBtu/SF)	Average Steam and Gas Density by Building Type (Mbtu/SF)	Estimated Central Steam Plant Usage (MMBtu)	Basis for Energy Usage
BL148	Music Addition	122,165	122,165	13,480	110	81	13,480	Model Data
BL149	Sycamore Hall	74,602	74,602	2,239	30	81	2,239	Model Data
BL153	Art Museum	119,314	119,314	8,009	67	81	8,009	Model Data
BL155	Lilly Library	52,516	52,516	5,034	96	69	5,034	Meter Data
BL157	Fine Arts	115,554	115,554	8,064	70	81	7,644	Model Data
BL158	Radio-TV	99,373	99,373	7,643	77	81	7,643	Meter Data
BL171	Auditorium	238,364	238,364	10,666	45	81	10,666	Meter Data
BL172	Lee Norvelle Theatre Drama/ Neal&Mars	135,627	135,627	11,122	82	81	11,122	Meter Data
BL173	IU Cinema	13,506	13,506	7	0	81	0	Model Data
BL177	Musical Arts Center	267,130	267,130	14,943	56	81	14,943	Meter Data
BL177W	MAC Machine Room 100	2,894	2,894	57	20	20	0	SF Estimate
BL181	Simon Msc Lbr Rec	231,539	231,539	20,144	87	81	20,144	Meter Data
BL199	Jordan Ave Parking	194,648	1	0	0	1	0	Model Data
BL209	Wells Library	557,163	557,163	55,317	99	81	55,317	Meter Data
BL215A	International Center	11,454	11,454	792	69	69	652	SF Estimate
BL221	University Apt West	69,156	69,156	4,028	58	58	3,593	SF Estimate
BL223	University Apt East	69,157	69,157	4,029	58	58	3,593	SF Estimate
BL227	Read Hall	359,658	359,658	13,976	39	58	13,976	Meter Data

Table A6.2.2: Base Case Energy Model Results for Heating (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Annual Steam and Gas Usage (MMBtu)	Estimated Annual Steam and Gas (MBtu/SF)	Average Steam and Gas Density by Building Type (Mbtu/SF)	Estimated Central Steam Plant Usage (MMBtu)	Basis for Energy Usage
BL237	Wright Quad	295,887	295,887	27,051	91	58	26,539	Meter Data
BL243	Teter Quad	300,873	300,873	25,250	84	58	25,250	Meter Data
BL245	Wendell W. Wright	191,111	191,111	16,215	85	81	16,215	Model Data
BL257	Forest Quad	289,014	289,014	23,029	80	58	23,029	Meter Data
BL271	Weatherly Hall	37,349	37,349	2,176	58	58	1,940	SF Estimate
BL272	Hershey Hall	36,110	36,110	2,103	58	58	1,876	SF Estimate
BL275	Johnston Hall	36,396	36,396	2,120	58	58	1,891	SF Estimate
BL276	Vos Hall	35,615	35,615	2,075	58	58	1,850	SF Estimate
BL276A	Hickory Hall	63,414	63,414	1,874	30	58	1,874	Meter Data
BL276B	Birch Hall	42,460	42,460	2,500	59	58	2,500	Meter Data
BL276C	Cedar Hall	92,198	92,198	4,460	48	58	4,460	Meter Data
BL276D	Linden Hall	63,414	63,414	3,065	48	58	3,065	Model Data
BL276E	Cypress Hall	42,460	42,460	1,701	40	58	1,701	Meter Data
BL276F	Beech Hall	63,415	63,415	2,832	45	58	2,832	Model Data
BL276G	Pine Hall	63,414	63,414	2,215	35	58	2,215	Meter Data
BL276L	Union St Chiller	4,371	4,371	0	0	20	0	Model Data
BL277	Moffatt Hall	25,769	25,769	1,501	58	58	1,339	SF Estimate
BL278	Griggs Lounge	4,759	4,759	401	84	84	380	SF Estimate
BL279	Dreiser Hall	2,701	2,701	227	84	84	215	SF Estimate
BL280	Stempel Hall	40,378	40,378	2,352	58	58	2,098	SF Estimate

Table A6.2.2: Base Case Energy Model Results for Heating (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Annual Steam and Gas Usage (MMBtu)	Estimated Annual Steam and Gas (MBtu/SF)	Average Steam and Gas Density by Building Type (Mbtu/SF)	Estimated Central Steam Plant Usage (MMBtu)	Basis for Energy Usage
BL282	Barnes Lounge	3,892	3,892	328	84	84	311	SF Estimate
BL297	Willkie B	120,091	120,091	0	0	58	0	Model Data
BL299	Willkie C	85,302	85,302	22,114	259	58	0	Model Data
BL301	Willkie A	119,951	119,951	0	0	58	0	Model Data
BL304	Mason Hall	24,717	24,717	1,662	67	58	0	Model Data
BL313	Eigenmann Hall	349,442	349,442	11,883	34	58	11,883	Model Data
BL316	408 N Union St	60,229	60,229	4,166	69	69	0	SF Estimate
BL404A	Brown Hall	14,653	14,653	854	58	58	761	SF Estimate
BL404B	Greene Hall	17,294	17,294	1,007	58	58	899	SF Estimate
BL404C	Monroe Hall	3,394	3,394	275	81	81	268	SF Estimate
BL404D	Morgan Hall	19,434	19,434	1,132	58	58	1,010	SF Estimate
BL405	Research Svc. Bldg.	4,126	4,126	82	20	20	0	SF Estimate
BL407	DeVault Alumni Center	32,563	32,563	3,527	108	69	3,340	Meter Data
BL411	Chilled Water Plant	38,817	38,817	475	12	0	0	Model Data
BL413	Arts Annex	25,411	25,411	2,060	81	81	2,009	SF Estimate
BL417	Geological Sciences	126,422	126,422	9,474	75	81	9,474	Meter Data
BL418	Geological Survey	52,361	52,361	4,239	81	81	4,239	Model Data
BL419	Psychology	155,246	155,246	15,589	100	81	15,589	Meter Data
BL423	Multi Science 2	131,074	131,074	5,503	42	111	5,503	Model Data

Table A6.2.2: Base Case Energy Model Results for Heating (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Annual Steam and Gas Usage (MMBtu)	Estimated Annual Steam and Gas (MBtu/SF)	Average Steam and Gas Density by Building Type (Mbtu/SF)	Estimated Central Steam Plant Usage (MMBtu)	Basis for Energy Usage
BL433	Briscoe Quad	279,424	279,424	22,226	80	58	22,226	Meter Data
BL437	McNutt North	153,143	153,143	7,240	47	58	7,240	Meter Data
BL439	McNutt Central	78,264	78,264	6,604	84	84	6,604	Model Data
BL441	McNutt South	129,665	129,665	4,011	31	58	4,011	Meter Data
BL448	Fee Lane Pkg Garage	223,279	1	0	0	1	0	Model Data
BL450	Godfrey Grad&Exec Ed Ctr	191,743	191,743	12,551	65	81	12,551	Meter Data
BL451	Business School	238,158	238,158	24,911	105	81	24,911	Meter Data
BL452	SPEA	128,619	128,619	17,674	137	81	17,674	Meter Data
BL453	Harper Hall	109,147	109,147	4,735	43	58	4,735	Model Data
BL454	Gresham Dining Hall	50,888	50,888	6,547	129	84	6,206	Model Data
BL455	Shea Hall	42,003	42,003	2,920	70	58	2,920	Meter Data
BL456	Martin Hall	37,063	37,063	2,798	76	58	2,798	Meter Data
BL461	Magee Hall	37,064	37,064	2,044	55	58	2,044	Model Data
BL462	Jenkinson Hall	36,896	36,896	4,335	117	58	4,335	Meter Data
BL463	Nelson RPS Admin.	40,453	40,453	3,883	96	69	3,883	Meter Data
BL467	Health Center	64,656	64,656	6,555	101	84	6,555	Model Data
BL475	Recreational Sports	253,302	253,302	28,749	113	84	28,749	Meter Data
BL529	Campus View Apartments	267,723	267,723	10,167	38	58	10,167	Meter Data

Table A6.2.2: Base Case Energy Model Results for Heating (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Annual Steam and Gas Usage (MMBtu)	Estimated Annual Steam and Gas (MBtu/SF)	Average Steam and Gas Density by Building Type (Mbtu/SF)	Estimated Central Steam Plant Usage (MMBtu)	Basis for Energy Usage
BL555	Tulip Tree Apts	263,003	263,003	9,479	36	58	9,479	Meter Data
BL563	Innovation Center	39,871	39,871	3,158	79	69	0	Model Data
BL565	U School E-1	10,151	10,151	702	69	69	578	SF Estimate
BL566	UITS E-2	15,033	15,033	1,040	69	69	856	SF Estimate
BL567	U School E-3	6,512	6,512	450	69	69	371	SF Estimate
BL568	UITS E-4	8,323	8,323	576	69	69	474	SF Estimate
BL569	Wrubel Computing Ct	47,248	47,248	3,268	69	69	2,691	SF Estimate
BL570	UITS E-5	12,714	12,714	879	69	69	724	SF Estimate
BL571	Communication Svcs.	20,028	20,028	1,385	69	69	1,141	SF Estimate
BL572	Intercol. Athl. Gym	35,669	35,669	3,002	84	84	2,846	SF Estimate
BL573	Smith Research Center	56,312	56,312	3,895	69	69	3,207	SF Estimate
BL576	Childrens Center	11,836	11,836	996	84	84	944	SF Estimate
BL577	ROTC Supply Center	10,421	10,421	206	20	20	0	SF Estimate
BL578	Cyberinfrastructure Bldg (CIB)	131,140	131,140	6,137	47	47	6,137	SF Estimate
BL579	Data Center	81,186	81,186	3,799	47	47	3,799	Meter Data
BL580	Disability & Community	39,419	39,419	2,726	69	69	2,245	SF Estimate
BL595	Mellencamp Pavilion	100,282	100,282	5,162	51	84	0	Model Data

Table A6.2.2: Base Case Energy Model Results for Heating (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Building Annual Steam and Gas Usage (MMBtu)	Estimated Annual Steam and Gas (MBtu/SF)	Average Steam and Gas Density by Building Type (Mbtu/SF)	Estimated Central Steam Plant Usage (MMBtu)	Basis for Energy Usage
BL601	Memorial Stadium	253,872	16,749	0	0	84	0	Model Data
BL601a	Memorial Stadium East Stands	46,384	46,384	0	0	84	0	Model Data
BL601b	Memorial Stadium West Stands	56,223	56,223	0	0	84	0	Model Data
BL601c	Memorial Stadium North Endzone	115,919	70,000	1,552	13	84	0	Model Data
BL602	Tennis Center	57,708	57,708	6,560	114	84	6,560	Meter Data
BL603	Assembly Hall	381,106	381,106	35,606	93	84	35,606	Meter Data
BL604	Gladstein Fieldhouse	103,427	103,427	33,578	325	84	33,578	Meter Data
BL605	Outdoor Pool	4,550	4,550	383	84	84	363	SF Estimate
BL607	Cook Hall	69,441	69,441	9,107	131	84	9,107	Meter Data
BL614	ALF-Ruth Lilly Auxilary Library	55,824	55,824	0	0	81	0	Model Data
BL615	IU Warehouse	130,746	130,746	2,589	20	20	0	SF Estimate
BL630	Service Bldg	78,452	78,452	1,569	20	69	0	Model Data
BL664	IU Research Park	71,120	71,120	4,919	69	69	0	SF Estimate
BL672	Food Storage	81,273	81,273	1,609	20	20	0	SF Estimate
Total		**14,587,875**	**13,352,413**	**982,243**			**906,947**	

Table A6.2.3: Base Case Energy Model Results for Chilled Water

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Central Cooling Plant Usage (Ton-Hours)	Estimated CHW Use Density (Ton-Hour/SF)	Average CHW Use Density by Building Type (Ton-Hour/SF)
BL001	Law	170,098	170,098	872,739	5.1	4.9
BL005	Bryan Hall	51,436	51,436	658,233	12.8	4.1
BL007	Franklin Hall	138,149	138,149	905,514	6.6	4.1
BL017	Student Building	69,737	69,737	454,379	6.5	4.9
BL021	Kirkwood Observatory	4,297	4,297	20,853	4.9	4.9
BL027	Swain West	154,602	154,602	662,048	4.3	4.9
BL033	Maxwell Hall	31,091	31,091	77,069	2.5	4.1
BL043	Edmondson Hall	68,588	68,588	8,478	0.1	2.3
BL053	IN Memorial Union	439,018	439,018	2,331,360	5.3	2.8
BL057	Wylie Hall	33,513	33,513	183,326	5.5	4.9
BL059	Lindley Hall	59,910	59,910	834,539	13.9	4.9
BL061	Swain East	35,609	35,609	231,192	6.5	4.1
BL067	Rawles Hall	42,017	42,017	209,657	5.0	4.1
BL070	Simon Hall (Science)	141,094	141,094	2,116,972	15.0	12.6
BL071	Chemistry	183,387	183,387	2,144,628	11.7	12.6
BL072	Chemistry Addition	106,551	106,551	1,277,097	12.0	12.6
BL095	Beck Chapel	2,046	2,046	5,641	2.8	2.8
BL101	Myers Hall	76,521	76,521	1,181,127	15.4	12.6
BL107	Jordan Hall	324,279	324,279	4,135,913	12.8	12.6
BL111	Ballantine Hall	305,420	305,420	202,720	0.7	4.9
BL119	HPER Building	189,776	189,776	440,920	2.3	2.8
BL133	Woodburn Hall	73,257	73,257	707,489	9.7	4.1
BL139	Morrison Hall	53,989	53,989	490,925	9.1	4.1
BL147	Merrill Hall	58,322	58,322	676,852	11.6	4.9
BL148	Music Addition	122,165	122,165	1,489,434	12.2	4.9
BL149	Sycamore Hall	74,602	74,602	226,663	3.0	4.9
BL155	Lilly Library	52,516	52,516	223,145	4.2	4.1
BL157	Fine Arts	115,554	115,554	598,960	5.2	4.9
BL158	Radio-TV	99,373	99,373	573,611	5.8	4.9
BL171	Auditorium	238,364	238,364	1,707,487	7.2	4.9
BL172	Lee Norvelle Theatre Drama/ Neal&Mars	135,627	135,627	953,217	7.0	4.9
BL173	IU Cinema	13,506	13,506	42,003	3.1	4.9

Table A6.2.3: Base Case Energy Model Results for Chilled Water (continued)

Building ID and Description		Gross Floor Area (SF)	Conditioned Floor Area (SF)	Estimated Central Cooling Plant Usage (Ton-Hours)	Estimated CHW Use Density (Ton-Hour/SF)	Average CHW Use Density by Building Type (Ton-Hour/SF)
BL181	Simon Msc Lbr Rec	231,539	231,539	1,986,887	8.6	4.9
BL209	Wells Library	557,163	557,163	3,415,935	6.1	4.9
BL215A	International Center	11,454	11,454	47,076	4.1	4.1
BL227	Read Hall	359,658	359,658	755,942	2.1	2.3
BL237	Wright Quad	295,887	295,887	119,912	0.4	2.3
BL243	Teter Quad	300,873	300,873	1,041,154	3.5	2.3
BL245	Wendell W. Wright	191,111	191,111	1,388,687	7.3	4.9
BL257	Forest Quad	289,014	289,014	883,242	3.1	2.3
BL407	DeVault Alumni Center	32,563	32,563	192,683	5.9	4.1
BL413	Arts Annex	25,411	25,411	123,315	4.9	4.9
BL414	Informatics West	28,184	28,184	136,772	4.9	4.9
BL419	Psychology	155,246	155,246	942,692	6.1	4.9
BL423	Multi Science 2	131,074	131,074	1,315,498	10.0	12.6
BL433	Briscoe Quad	279,424	279,424	1,032,086	3.7	2.3
BL437	McNutt North	153,143	153,143	525,560	3.4	2.3
BL439	McNutt Central	78,264	78,264	927,681	11.9	2.8
BL441	McNutt South	129,665	129,665	455,138	3.5	2.3
BL450	Godfrey Grad&Exec Ed Ctr	191,743	191,743	837,278	4.4	4.9
BL451	Business School	238,158	238,158	1,151,762	4.8	4.9
BL452	SPEA	128,619	128,619	558,349	4.3	4.9
BL453	Harper Hall	109,147	109,147	349,861	3.2	2.3
BL454	Gresham Dining Hall	50,888	50,888	402,026	7.9	2.8
BL455	Shea Hall	42,003	42,003	120,958	2.9	2.3
BL456	Martin Hall	37,063	37,063	111,295	3.0	2.3
BL461	Magee Hall	37,064	37,064	116,531	3.1	2.3
BL462	Jenkinson Hall	36,896	36,896	121,400	3.3	2.3
BL463	Nelson RPS Admin.	40,453	40,453	146,974	3.6	4.1
BL601a	Memorial Stadium East Stands	46,384	46,384	254,989	5.5	2.8
BL603	Assembly Hall	381,106	381,106	1,483,692	3.9	2.8
BL990P	Informatics East	39,922	39,922	193,734	4.9	4.9
Totals		8,293,533	8,293,533	47,783,302	5.8	

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Ernie Pyle Hall	$31,276	$1,379	0.0	$31,276	$1,379	0.0	Change HVAC Schedule
Cook Hall	$38,011	$2,500	0.1	$69,287	$3,878	0.1	Change HVAC Schedule
Bryan Hall	$28,180	$1,852	0.1	$97,467	$5,730	0.1	Change HVAC Schedule
Merrill Hall	$27,689	$2,100	0.1	$125,157	$7,830	0.1	Change HVAC Schedule
Gresham Dining Hall	$18,884	$1,832	0.1	$144,040	$9,662	0.1	Change HVAC Schedule
SPEA	$41,018	$4,630	0.1	$185,058	$14,292	0.1	Change HVAC Schedule
Memorial Stadium North Endzone	$14,806	$2,520	0.2	$199,865	$16,812	0.1	Change HVAC Schedule
Law	$31,345	$6,124	0.2	$231,209	$22,935	0.1	Change HVAC Schedule
Simon Msc Lbr Rec	$40,083	$8,335	0.2	$271,292	$31,271	0.1	Change HVAC Schedule
Myers Hall	$10,910	$2,755	0.3	$282,203	$34,026	0.1	Reduce Humidification
Memorial Stadium East Stands	$5,111	$1,670	0.3	$287,314	$35,695	0.1	Change HVAC Schedule
Radio-TV	$9,992	$3,577	0.4	$297,306	$39,273	0.1	Reduce Humidification
Multi Science 2	$10,105	$4,719	0.5	$307,410	$43,992	0.1	Reduce Humidification
Godfrey Grad&Exec Ed Ctr	$8,860	$6,903	0.8	$316,270	$50,894	0.2	Reduce Humidification
Cook Hall	$12,594	$11,666	0.9	$328,864	$62,560	0.2	Reduce Outside Air
Lee Norvelle Theatre Drama/ Neal&Mars	$115,150	$154,615	1.3	$444,014	$217,175	0.5	Optimize VAV Operation

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Myers Hall	$68,108	$111,109	1.6	$512,121	$328,284	0.6	Optimize VAV Operation, Space Temp. Setback
Wendell W. Wright	$3,182	$6,880	2.1	$515,304	$335,164	0.7	Reduce Humidification
Eigenmann Hall	$7,871	$17,441	2.2	$523,175	$352,605	0.7	Add Variable Flow CHW Pumping
Cook Hall	$43,591	$100,828	2.3	$566,766	$453,433	0.8	Optimize VAV Operation, Space Temp. Setback
Willkie A	$15,314	$37,425	2.4	$582,080	$490,858	0.8	Space Temp. Setback
Simon Hall (Science)	$78,061	$204,869	2.6	$660,141	$695,727	1.1	Optimize VAV Operation, Space Temp. Setback
Assembly Hall	$21,225	$64,026	2.9	$681,366	$759,752	1.1	Reduce Outside Air
Chilled Water Plant	$11,274	$36,333	3.2	$692,640	$796,085	1.1	Lighting Controls
Tulip Tree Apts	$24,938	$82,057	3.2	$717,578	$878,142	1.2	Space Temp. Setback
Maxwell Hall	$12,748	$45,144	3.5	$730,325	$923,286	1.3	Optimize VAV Operation, Space Temp. Setback
Ballantine Hall	$71,310	$285,873	3.9	$801,635	$1,209,159	1.5	Lighting Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Gresham Dining Hall	$2,045	$8,549	4.2	$803,680	$1,217,708	1.5	Reduce Outside Air
Myers Hall	$16,586	$71,624	4.3	$820,267	$1,289,332	1.6	Lighting Controls
Central Heating	$18,112	$78,643	4.3	$838,379	$1,367,975	1.6	Lighting Controls
Simon Hall (Science)	$71,702	$326,096	4.5	$910,081	$1,694,071	1.9	Lighting Retrofit, Lighting Controls
Owen Hall	$4,055	$18,859	4.6	$914,135	$1,712,930	1.9	Lighting Controls
Kirkwood Hall	$15,506	$72,171	4.6	$929,641	$1,785,101	1.9	Lighting Retrofit, Lighting Controls
Godfrey Grad&Exec Ed Ctr	$6,987	$32,213	4.6	$936,629	$1,817,314	1.9	Reduce Outside Air
Service Bldg	$14,807	$73,431	4.9	$951,436	$1,890,745	2.0	Lighting Controls
Forest Quad	$18,149	$90,172	4.9	$969,585	$1,980,917	2.0	Space Temp. Setback
Goodbody Hall	$15,777	$79,697	5.0	$985,362	$2,060,614	2.1	Lighting Retrofit, Lighting Controls
Sycamore Hall	$13,724	$69,827	5.0	$999,085	$2,130,441	2.1	Lighting Controls
Poplars	$26,851	$140,793	5.1	$1,025,937	$2,271,234	2.2	Lighting Controls
Poplars Parking	$9,164	$48,123	5.1	$1,035,101	$2,319,357	2.2	Lighting Retrofit
Wendell W. Wright	$1,416	$7,474	5.2	$1,036,517	$2,326,831	2.2	Convert to Variable Volume Heating Water
Optometry School	$687	$3,786	5.4	$1,037,204	$2,330,617	2.2	Convert to Variable Volume Chilled Water
HPER Building	$65,534	$359,360	5.4	$1,102,738	$2,689,977	2.4	Lighting Retrofit, Lighting Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Chemistry	$41,888	$241,631	5.7	$1,144,626	$2,931,608	2.6	Lighting Retrofit, Lighting Controls
Gladstein Fieldhouse	$53,706	$310,529	5.7	$1,198,332	$3,242,137	2.7	Lighting Retrofit, Lighting Controls
Art Museum	$61,436	$356,510	5.7	$1,259,768	$3,598,647	2.9	Lighting Retrofit, Lighting Controls
Memorial Stadium East Stands	$7,415	$43,415	5.7	$1,267,182	$3,642,063	2.9	Lighting Controls
SPEA	$42,622	$254,666	5.9	$1,309,805	$3,896,728	3.0	Lighting Retrofit, Lighting Controls
Lee Norvelle Theatre Drama/ Neal&Mars	$73,907	$444,314	5.9	$1,383,712	$4,341,042	3.1	Lighting Retrofit, Lighting Controls
Lindley Hall	$77,712	$469,023	5.9	$1,461,424	$4,810,066	3.3	Lighting Retrofit, Lighting Controls, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Mellencamp Pavilion	$2,774	$16,847	5.9	$1,464,197	$4,826,913	3.3	Reduce Outside Air
IN Memorial Union	$127,918	$774,428	5.9	$1,592,115	$5,601,341	3.5	Lighting Retrofit, Lighting Controls
Multi Science 2	$20,073	$122,685	6.0	$1,612,188	$5,724,026	3.6	Lighting Controls
Assembly Hall	$57,427	$356,715	6.1	$1,669,614	$6,080,741	3.6	Lighting Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Music Addition	$44,627	$277,070	6.1	$1,714,241	$6,357,812	3.7	Lighting Retrofit, Lighting Controls
Maxwell Hall	$6,998	$43,652	6.1	$1,721,240	$6,401,463	3.7	Lighting Retrofit, Lighting Controls
Geological Survey	$18,030	$113,477	6.2	$1,739,270	$6,514,940	3.7	Lighting Retrofit, Lighting Controls
Cook Hall	$10,193	$64,997	6.2	$1,749,463	$6,579,937	3.8	Lighting Controls
Woodburn Hall	$25,846	$166,147	6.3	$1,775,309	$6,746,084	3.8	Lighting Retrofit, Lighting Controls
Recreational Sports	$148,907	$984,838	6.4	$1,924,216	$7,730,922	4.0	Lighting Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback
Law	$47,399	$314,749	6.5	$1,971,615	$8,045,672	4.1	Lighting Retrofit, Lighting Controls
Bryan Hall	$46,481	$310,468	6.5	$2,018,096	$8,356,139	4.1	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Eigenmann Hall	$81,281	$550,710	6.6	$2,099,377	$8,906,849	4.2	Lighting Retrofit, Lighting Controls
McNutt Central	$10,911	$73,255	6.6	$2,110,288	$8,980,104	4.3	Lighting Controls
DeVault Alumni Center	$4,486	$30,479	6.7	$2,114,774	$9,010,583	4.3	Lighting Controls
Morrison Hall	$15,463	$105,343	6.7	$2,130,237	$9,115,926	4.3	Lighting Retrofit, Lighting Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Nelson RPS Admin.	$9,640	$66,116	6.7	$2,139,878	$9,182,042	4.3	Lighting Retrofit, Lighting Controls
Bryan Hall	$12,703	$87,030	6.7	$2,152,581	$9,269,072	4.3	Lighting Retrofit, Lighting Controls
Art Museum	$123,468	$861,925	6.7	$2,276,048	$10,130,997	4.5	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls
Chemistry Addition	$20,426	$140,392	6.7	$2,296,474	$10,271,389	4.5	Lighting Retrofit, Lighting Controls
Tennis Center	$7,731	$54,015	6.8	$2,304,205	$10,325,403	4.5	Lighting Controls
Swain West	$43,584	$306,112	6.9	$2,347,788	$10,631,515	4.5	Lighting Retrofit, Lighting Controls
Swain East	$7,497	$54,097	7.1	$2,355,285	$10,685,612	4.5	Lighting Retrofit, Lighting Controls
Radio-TV	$12,739	$93,013	7.1	$2,368,024	$10,778,626	4.6	Lighting Controls
Woodburn Hall	$60,482	$442,179	7.1	$2,428,506	$11,220,805	4.6	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Jordan Hall	$63,544	$464,627	7.1	$2,492,050	$11,685,432	4.7	Lighting Retrofit, Lighting Controls
Business School	$30,490	$222,916	7.2	$2,522,540	$11,908,348	4.7	Lighting Controls
Briscoe Quad	$35,593	$261,541	7.2	$2,558,133	$12,169,889	4.8	Lighting Controls
Rawles Hall	$9,897	$72,908	7.2	$2,568,030	$12,242,796	4.8	Lighting Retrofit, Lighting Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Lilly Library	$6,600	$49,155	7.3	$2,574,631	$12,291,951	4.8	Lighting Controls
Merrill Hall	$1,330	$9,798	7.4	$2,575,961	$12,301,750	4.8	Reduce Outside Air
Fine Arts	$25,440	$195,517	7.5	$2,601,402	$12,497,267	4.8	Lighting Retrofit, Lighting Controls
Mellencamp Pavilion	$12,001	$93,864	7.6	$2,613,402	$12,591,131	4.8	Lighting Controls
IU Cinema	$1,634	$12,642	7.6	$2,615,036	$12,603,773	4.8	Lighting Controls
Musical Arts Center	$73,552	$575,078	7.6	$2,688,587	$13,178,850	4.9	Lighting Retrofit, Lighting Controls
Campus View Apartments	$56,719	$449,132	7.6	$2,745,306	$13,627,982	5.0	Lighting Retrofit, Lighting Controls
Willkie B	$39,347	$308,682	7.7	$2,784,653	$13,936,664	5.0	Lighting Retrofit, Lighting Controls
Ernie Pyle Hall	$10,946	$86,846	7.7	$2,795,599	$14,023,510	5.0	Lighting Retrofit, Lighting Controls
Rawles Hall	$25,453	$205,715	7.8	$2,821,052	$14,229,226	5.0	Reduce Max Airflow, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Franklin Hall	$16,062	$129,308	7.9	$2,837,114	$14,358,533	5.1	Lighting Controls
Psychology	$17,865	$145,310	7.9	$2,854,979	$14,503,843	5.1	Lighting Controls
Harper Hall	$12,464	$102,162	8.0	$2,867,443	$14,606,005	5.1	Lighting Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Student Building	$50,071	$420,933	8.1	$2,917,514	$15,026,937	5.2	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Wendell W. Wright	$170,635	$1,440,212	8.2	$3,088,149	$16,467,150	5.3	Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback, Install DDC Zone Controls
Wildermuth Center	$15,496	$132,295	8.3	$3,103,645	$16,599,445	5.3	Lighting Controls
Wendell W. Wright	$33,787	$287,584	8.3	$3,137,432	$16,887,029	5.4	Lighting Retrofit, Lighting Controls
McNutt North	$16,729	$143,342	8.4	$3,154,161	$17,030,371	5.4	Lighting Controls
Tulip Tree Apts	$28,293	$246,171	8.4	$3,182,454	$17,276,542	5.4	Lighting Controls
McNutt South	$13,987	$121,366	8.5	$3,196,440	$17,397,908	5.4	Lighting Controls
Multi Science 2	$4,817	$40,895	8.5	$3,201,257	$17,438,803	5.4	Space Temp. Setback
Forest Quad	$47,680	$414,099	8.5	$3,248,937	$17,852,902	5.5	Lighting Retrofit, Lighting Controls
Memorial Hall	$6,247	$54,829	8.5	$3,255,185	$17,907,731	5.5	Lighting Controls
Read Hall	$37,983	$336,640	8.6	$3,293,168	$18,244,371	5.5	Lighting Controls
McNutt Central	$51,812	$472,402	8.9	$3,344,980	$18,716,773	5.6	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Wylie Hall	$3,322	$31,368	9.2	$3,348,302	$18,748,141	5.6	Lighting Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Health Center	$6,474	$60,518	9.2	$3,354,775	$18,808,659	5.6	Lighting Controls
Lee Norvelle Theatre Drama/ Neal&Mars	$2,436	$22,785	9.3	$3,357,211	$18,831,444	5.6	Reduce Outside Air
Law	$969	$9,471	9.5	$3,358,181	$18,840,916	5.6	Convert to Variable Volume Heating Water
Auditorium	$146,647	$1,438,765	9.5	$3,504,828	$20,279,681	5.8	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Student Building	$6,649	$65,274	9.6	$3,511,477	$20,344,955	5.8	Lighting Controls
Willkie A	$11,295	$112,274	9.7	$3,522,772	$20,457,229	5.8	Lighting Controls
DeVault Alumni Center	$19,128	$196,550	9.9	$3,541,899	$20,653,779	5.8	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Wylie Hall	$19,732	$202,285	9.9	$3,561,632	$20,856,064	5.9	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Innovation Center	$3,635	$37,319	9.9	$3,565,267	$20,893,383	5.9	Lighting Controls
Godfrey Grad&Exec Ed Ctr	$17,560	$179,471	9.9	$3,582,827	$21,072,854	5.9	Lighting Controls
Magee Hall	$3,394	$34,692	10.0	$3,586,221	$21,107,546	5.9	Lighting Controls
Jenkinson Hall	$3,375	$34,535	10.0	$3,589,596	$21,142,081	5.9	Lighting Controls
Martin Hall	$3,369	$34,691	10.0	$3,592,964	$21,176,772	5.9	Lighting Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Memorial Stadium North Endzone	$10,388	$108,500	10.0	$3,603,352	$21,285,272	5.9	Lighting Controls
Wells Library	$50,623	$521,505	10.0	$3,653,975	$21,806,777	6.0	Lighting Controls
Merrill Hall	$5,282	$54,589	10.1	$3,659,258	$21,861,366	6.0	Lighting Controls
Hickory Hall	$5,714	$59,356	10.1	$3,664,972	$21,920,722	6.0	Lighting Controls
Teter Quad	$38,243	$396,430	10.1	$3,703,215	$22,317,152	6.0	Lighting Retrofit, Lighting Controls
Shea Hall	$3,773	$39,315	10.1	$3,706,988	$22,356,467	6.0	Lighting Controls
Swain East	$20,149	$214,936	10.2	$3,727,137	$22,571,403	6.1	Optimize VAV Operation, Space Temp. Setback, Install DDC Zone Controls
Simon Msc Lbr Rec	$20,311	$216,721	10.4	$3,747,448	$22,788,123	6.1	Lighting Controls
Optometry School	$118,198	$1,295,824	10.5	$3,865,646	$24,083,947	6.2	Lighting Retrofit, Lighting Controls, Change HVAC Type, Install DDC Zone Controls, Optimize VAV Operation, Space Temp. Setback
Wells Library	$303,896	$3,363,037	10.6	$4,169,541	$27,446,983	6.6	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
IU Warehouse	$10,669	$117,671	10.6	$4,180,210	$27,564,655	6.6	Lighting Retrofit, Lighting Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Business School	$160,432	$1,794,759	10.7	$4,340,643	$29,359,414	6.8	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Wright Quad	$41,130	$458,033	10.7	$4,381,773	$29,817,447	6.8	Lighting Retrofit, Lighting Controls
Fine Arts	$77,361	$870,815	10.8	$4,459,135	$30,688,261	6.9	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Ernie Pyle Hall	$44,673	$513,726	10.8	$4,503,808	$31,201,987	6.9	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback
Gresham Dining Hall	$4,124	$47,631	11.2	$4,507,932	$31,249,618	6.9	Lighting Controls
Cypress Hall	$3,273	$39,743	11.7	$4,511,206	$31,289,361	6.9	Lighting Controls
Auditorium	$25,978	$314,069	11.7	$4,537,183	$31,603,430	7.0	Lighting Retrofit, Lighting Controls
Willkie C	$35,414	$417,639	11.8	$4,572,598	$32,021,068	7.0	Space Temp. Setback, Install DDC Zone Controls
Willkie C	$6,361	$79,843	11.9	$4,578,959	$32,100,911	7.0	Lighting Controls
Radio-TV	$1,382	$16,695	12.2	$4,580,341	$32,117,606	7.0	Reduce Outside Air

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Gresham Dining Hall	$29,485	$383,492	12.4	$4,609,827	$32,501,098	7.1	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Beech Hall	$4,573	$59,356	12.5	$4,614,399	$32,560,454	7.1	Lighting Controls
Geological Survey	$39,562	$531,344	12.8	$4,653,962	$33,091,798	7.1	Replace Windows, Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
SPEA	$57,099	$776,344	13.0	$4,711,061	$33,868,142	7.2	Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback, Install DDC Zone Controls
Chemistry	$80,332	$1,106,924	13.1	$4,791,393	$34,975,066	7.3	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Pine Hall	$4,298	$59,356	13.3	$4,795,690	$35,034,422	7.3	Lighting Controls
Linden Hall	$4,265	$59,356	13.4	$4,799,956	$35,093,777	7.3	Lighting Controls
Birch Hall	$2,796	$39,743	13.7	$4,802,752	$35,133,520	7.3	Lighting Controls
Memorial Stadium West Stands	$28,709	$423,697	13.8	$4,831,461	$35,557,216	7.4	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Merrill Hall	$47,951	$694,965	13.9	$4,879,412	$36,252,181	7.4	Change HVAC Type, Install DDC Zone Controls, Remove Air Economizer, Optimize VAV Operation, Space Temp. Setback
IN Memorial Union	$223,596	$3,308,440	14.1	$5,103,008	$39,560,621	7.8	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Radio-TV	$39,769	$599,816	14.2	$5,142,777	$40,160,437	7.8	Reduce Max Airflow, Install DDC Zone Controls, Space Temp. Setback
Morrison Hall	$17,517	$264,330	14.3	$5,160,294	$40,424,767	7.8	Space Temp. Setback, Install DDC Zone Controls
Smith Hall	$1,406	$21,173	14.4	$5,161,700	$40,445,940	7.8	Lighting Controls
Cravens Hall	$2,176	$32,797	14.4	$5,163,876	$40,478,738	7.8	Lighting Controls
Edmondson Hall	$4,217	$64,198	14.6	$5,168,093	$40,542,936	7.8	Lighting Controls
Mason Hall	$1,478	$23,135	14.8	$5,169,572	$40,566,071	7.8	Lighting Controls
Jordan Hall	$274,518	$4,350,527	15.0	$5,444,090	$44,916,598	8.3	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Chemistry Addition	$42,319	$681,500	15.0	$5,486,408	$45,598,098	8.3	Install Fan VFD's, Reduce Max Airflow, Space Temp. Setback, Install DDC Zone Controls
Music Addition	$116,157	$1,898,163	15.3	$5,602,565	$47,496,261	8.5	Replace Windows, Change HVAC Type, Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Simon Msc Lbr Rec	$84,144	$1,397,569	15.8	$5,686,709	$48,893,830	8.6	Change HVAC Type, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Psychology	$112,757	$1,920,704	16.0	$5,799,466	$50,814,534	8.8	Change HVAC Type, Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Cedar Hall	$5,151	$86,297	16.2	$5,804,617	$50,900,831	8.8	Lighting Controls
Franklin Hall	$104,159	$1,853,408	16.7	$5,908,776	$52,754,239	8.9	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Law	$47,807	$1,022,521	19.7	$5,956,584	$53,776,759	9.0	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Musical Arts Center	$189,666	$4,304,691	20.3	$6,146,250	$58,081,450	9.4	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Change HVAC Schedule, Space Temp. Setback, Install CHW Pump Variable Speed Drives
Memorial Stadium East Stands	$2,484	$52,878	20.5	$6,148,734	$58,134,328	9.5	Optimize VAV Operation
Memorial Stadium North Endzone	$4,478	$101,640	21.0	$6,153,212	$58,235,968	9.5	Optimize VAV Operation, Space Temp. Setback
Birch Hall	$9,142	$207,884	21.3	$6,162,354	$58,443,852	9.5	Space Temp. Setback, Install DDC Zone Controls
Willkie B	$3,400	$87,987	22.5	$6,165,754	$58,531,839	9.5	Air-Side Heat Recovery
Linden Hall	$12,864	$310,475	22.6	$6,178,618	$58,842,314	9.5	Space Temp. Setback, Install DDC Zone Controls
Beech Hall	$11,662	$310,480	24.8	$6,190,280	$59,152,794	9.6	Space Temp. Setback, Install DDC Zone Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Maxwell Hall	$50	$1,389	25.8	$6,190,330	$59,154,183	9.6	Convert to Variable Volume Heating Water
Health Center	$89,380	$2,790,205	26.7	$6,279,709	$61,944,388	9.9	Change HVAC Type, Install DDC Zone Controls, Space Temp. Setback, Air-Side Heat Recovery, Add Variable Volume CHW Pumping
Nelson RPS Admin.	$18,988	$592,232	27.6	$6,298,697	$62,536,620	9.9	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback
Art Museum	$3,927	$360,000	28.5	$6,302,625	$62,896,620	10.0	Connect to Campus CWP - Variable Flow Pumping
Cedar Hall	$14,057	$451,401	28.5	$6,316,682	$63,348,022	10.0	Space Temp. Setback, Install DDC Zone Controls
Swain West	$40,725	$1,353,144	28.6	$6,357,407	$64,701,166	10.2	Replace Windows, Reduce Max Airflow, Space Temp. Setback, Install DDC Zone Controls
Pine Hall	$9,540	$310,475	30.0	$6,366,947	$65,011,641	10.2	Space Temp. Setback, Install DDC Zone Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Tennis Center	$15,240	$576,203	32.3	$6,382,187	$65,587,844	10.3	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Change HVAC Schedule, Space Temp. Setback, Condensing Water Boiler
Cypress Hall	$5,617	$207,884	34.1	$6,387,804	$65,795,728	10.3	Space Temp. Setback, Install DDC Zone Controls
Willkie B	$14,028	$587,966	36.0	$6,401,832	$66,383,694	10.4	Space Temp. Setback, Install DDC Zone Controls
McNutt South	$1,187	$53,439	36.6	$6,403,019	$66,437,132	10.4	Air-Side Heat Recovery
Jenkinson Hall	$546	$25,343	37.5	$6,403,565	$66,462,475	10.4	Air-Side Heat Recovery
Shea Hall	$619	$28,851	37.6	$6,404,184	$66,491,326	10.4	Air-Side Heat Recovery
McNutt North	$3,351	$157,786	37.9	$6,407,535	$66,649,113	10.4	Air-Side Heat Recovery
Harper Hall	$1,539	$74,971	38.8	$6,409,073	$66,724,083	10.4	Air-Side Heat Recovery
Magee Hall	$519	$25,459	39.0	$6,409,593	$66,749,542	10.4	Air-Side Heat Recovery
Martin Hall	$519	$25,458	39.0	$6,410,111	$66,775,000	10.4	Air-Side Heat Recovery
Teter Quad	$5,788	$286,574	39.4	$6,415,900	$67,061,573	10.5	Air-Side Heat Recovery
Briscoe Quad	$30,323	$1,368,060	40.2	$6,446,223	$68,429,633	10.6	Space Temp. Setback, Install DDC Zone Controls
McNutt North	$16,286	$749,788	40.7	$6,462,509	$69,179,421	10.7	Space Temp. Setback, Install DDC Zone Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Eigenmann Hall	$31,222	$1,706,127	41.1	$6,493,730	$70,885,548	10.9	Space Temp. Setback, Install DDC Zone Controls
Teter Quad	$31,186	$1,473,074	41.7	$6,524,917	$72,358,623	11.1	Space Temp. Setback, Install DDC Zone Controls
Jenkinson Hall	$3,567	$180,643	44.3	$6,528,483	$72,539,265	11.1	Space Temp. Setback, Install DDC Zone Controls
Harper Hall	$10,459	$534,384	44.6	$6,538,942	$73,073,649	11.2	Space Temp. Setback, Install DDC Zone Controls
Campus View Apartments	$21,140	$1,310,772	45.3	$6,560,082	$74,384,421	11.3	Space Temp. Setback, Install DDC Zone Controls
Ernie Pyle Hall	$2,962	$363,163	46.3	$6,563,045	$74,747,584	11.4	Connect to Campus CWP - Variable Flow
Lilly Library	$12,745	$752,449	47.1	$6,575,789	$75,500,033	11.5	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Goodbody Hall	$14,358	$1,068,862	54.8	$6,590,147	$76,568,895	11.6	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Remove Air Economizer, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Air-Side Heat Recovery, Connect to Campus CWP - Variable Flow
Myers Hall	$14,152	$1,121,296	56.9	$6,604,299	$77,690,192	11.8	Air-Side Heat Recovery
Assembly Hall	$37,788	$2,872,015	58.5	$6,642,088	$80,562,207	12.1	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Poplars	$41,669	$3,153,004	60.3	$6,683,756	$83,715,211	12.5	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Air-Side Heat Recovery
Hickory Hall	$3,926	$310,475	63.9	$6,687,683	$84,025,685	12.6	Space Temp. Setback, Install DDC Zone Controls

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Jordan Hall	$45,651	$4,727,036	69.9	$6,733,334	$88,752,721	13.2	Replace Windows, Air-Side Heat Recovery
Optometry School	$2,811	$382,606	77.6	$6,736,145	$89,135,327	13.2	Replace Windows, Reduce Outside Air, Reduce Humidification
Kirkwood Hall	$9,773	$1,802,130	95.1	$6,745,918	$90,937,457	13.5	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Remove Air Economizer, Optimize VAV Operation, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Connect to Campus CWP - Variable Flow Pumping
Forest Quad	$8,662	$1,114,563	96.1	$6,754,580	$92,052,021	13.6	Replace Windows
Teter Quad	$8,946	$1,160,297	96.7	$6,763,526	$93,212,318	13.8	Replace Windows
Briscoe Quad	$8,364	$1,077,580	96.9	$6,771,890	$94,289,898	13.9	Replace Windows

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Read Hall	$32,847	$6,566,475	104.4	$6,804,738	$100,856,373	14.8	Change HVAC Type, Install DDC Zone Controls, Reduce Max Airflow, Reduce Outside Air, Space Temp. Setback, Increase size of CHW Pumping
Franklin Hall	$3,002	$437,337	105.9	$6,807,740	$101,293,710	14.9	Replace Windows
Owen Hall	$4,142	$928,087	106.0	$6,811,882	$102,221,797	15.0	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Remove Air Economizer, Optimize VAV Operation, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Connect to Campus CWP - Variable Flow
Chemistry	$3,988	$611,356	106.0	$6,815,870	$102,833,153	15.1	Replace Windows, Reduce Outside Air

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Memorial Hall	$4,359	$2,684,801	117.6	$6,820,229	$105,517,954	15.5	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Connect to Campus CWP - Variable Flow Pumping
Gladstein Fieldhouse	$12,708	$3,581,725	123.4	$6,832,936	$109,099,679	16.0	Replace Windows, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback, Change FCU Cool Source, Air-Side Heat Recovery, Connect to Campus CWP, Variable Flow
Wright Quad	$12,606	$5,711,646	124.7	$6,845,543	$114,811,325	16.8	Replace Windows, Change HVAC Type, Space Temp. Setback, Install DDC Zone Controls, Air-Side Heat Recovery, Convert to Variable Volume Heating Water

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Chemistry Addition	$1,597	$337,308	126.4	$6,847,140	$115,148,633	16.8	Replace Windows
Maxwell Hall	$642	$119,900	127.2	$6,847,782	$115,268,533	16.8	Replace Windows
Nelson RPS Admin.	$801	$156,004	134.2	$6,848,583	$115,424,538	16.9	Replace Windows
Mellencamp Pavilion	$6,770	$1,539,080	134.8	$6,855,353	$116,963,617	17.1	Change HVAC Type, Space Temp. Setback, Air-Side Heat Recovery
Magee Hall	$1,627	$356,085	150.1	$6,856,980	$117,319,703	17.1	Replace Windows, Reduce Outside Air, Space Temp. Setback, Install DDC Zone Controls
Martin Hall	$1,568	$356,076	151.5	$6,858,548	$117,675,779	17.2	Replace Windows, Reduce Outside Air, Space Temp. Setback, Install DDC Zone Controls
Gresham Dining Hall	$668	$161,096	162.8	$6,859,216	$117,836,875	17.2	Replace Windows
Business School	$3,133	$753,936	165.4	$6,862,349	$118,590,811	17.3	Replace Windows
Psychology	$2,086	$491,462	165.4	$6,864,435	$119,082,273	17.3	Replace Windows
McNutt Central	$907	$247,760	168.8	$6,865,342	$119,330,033	17.4	Replace Windows
Wells Library	$5,495	$1,455,142	176.6	$6,870,837	$120,785,175	17.6	Replace Windows
Fine Arts	$1,408	$365,809	179.3	$6,872,245	$121,150,984	17.6	Replace Windows

Table A8.2.1: Building Energy Conservation Measures, Ordered by Marginal Payback (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Accumulated Annual Energy Cost Savings	Accumulated Implementation Cost	Overall Cumulative Simple Payback	Included Energy Conservation Measures
Assembly Hall	$3,134	$995,335	181.3	$6,875,379	$122,146,319	17.8	Replace Windows, Convert to Variable Volume Heating Water
Shea Hall	$1,347	$405,048	195.3	$6,876,727	$122,551,367	17.8	Replace Windows, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Install DDC Zone Controls
Merrill Hall	$620	$184,630	208.5	$6,877,347	$122,735,997	17.8	Replace Windows
Wildermuth Center	$8,271	$2,959,073	305.3	$6,885,617	$125,695,069	18.3	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Optimize VAV Operation, Space Temp. Setback
McNutt South	$4,383	$781,314	489.3	$6,890,001	$126,476,383	18.4	Install Water Side Economizer

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Law	$31,345	$6,124	0.2	Change HVAC Schedule
Law	$47,399	$314,749	6.5	Lighting Retrofit, Lighting Controls
Law	$969	$9,471	9.5	Convert to Variable Volume Heating Water
Law	$47,807	$1,022,521	19.7	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Bryan Hall	$28,180	$1,852	0.1	Change HVAC Schedule
Bryan Hall	$46,481	$310,468	6.5	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Bryan Hall	$12,703	$87,030	6.7	Lighting Retrofit, Lighting Controls
Franklin Hall	$16,062	$129,308	7.9	Lighting Controls
Franklin Hall	$104,159	$1,853,408	16.7	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback
Franklin Hall	$3,002	$437,337	105.9	Replace Windows
Poplars	$26,851	$140,793	5.1	Lighting Controls
Poplars	$41,669	$3,153,004	60.3	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Air-Side Heat Recovery
Poplars Parking	$9,164	$48,123	5.1	Lighting Retrofit
Student Building	$50,071	$420,933	8.1	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Student Building	$6,649	$65,274	9.6	Lighting Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Swain West	$43,584	$306,112	6.9	Lighting Retrofit, Lighting Controls
Swain West	$40,725	$1,353,144	28.6	Replace Windows, Reduce Max Airflow, Space Temp. Setback, Install DDC Zone Controls
Maxwell Hall	$12,748	$45,144	3.5	Optimize VAV Operation, Space Temp. Setback
Maxwell Hall	$6,998	$43,652	6.1	Lighting Retrofit, Lighting Controls
Maxwell Hall	$50	$1,389	25.8	Convert to Variable Volume Heating Water
Maxwell Hall	$642	$119,900	127.2	Replace Windows
Edmondson Hall	$4,217	$64,198	14.6	Lighting Controls
Cravens Hall	$2,176	$32,797	14.4	Lighting Controls
Smith Hall	$1,406	$21,173	14.4	Lighting Controls
IN Memorial Union	$127,918	$774,428	5.9	Lighting Retrofit, Lighting Controls
IN Memorial Union	$223,596	$3,308,440	14.1	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Owen Hall	$4,055	$18,859	4.6	Lighting Controls
Owen Hall	$4,142	$928,087	106.0	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Remove Air Economizer, Optimize VAV Operation, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Connect to Campus CWP - Variable Flow

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Wylie Hall	$3,322	$31,368	9.2	Lighting Controls
Wylie Hall	$19,732	$202,285	9.9	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Kirkwood Hall	$15,506	$72,171	4.6	Lighting Retrofit, Lighting Controls
Kirkwood Hall	$9,773	$1,802,130	95.1	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Remove Air Economizer, Optimize VAV Operation, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Connect to Campus CWP - Variable Flow Pumping
Lindley Hall	$77,712	$469,023	5.9	Lighting Retrofit, Lighting Controls, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Swain East	$7,497	$54,097	7.1	Lighting Retrofit, Lighting Controls
Swain East	$20,149	$214,936	10.2	Optimize VAV Operation, Space Temp. Setback, Install DDC Zone Controls
Optometry School	$687	$3,786	5.4	Convert to Variable Volume Chilled Water
Optometry School	$118,198	$1,295,824	10.5	Lighting Retrofit, Lighting Controls, Change HVAC Type, Install DDC Zone Controls, Optimize VAV Operation, Space Temp. Setback
Optometry School	$2,811	$382,606	77.6	Replace Windows, Reduce Outside Air, Reduce Humidification

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Rawles Hall	$9,897	$72,908	7.2	Lighting Retrofit, Lighting Controls
Rawles Hall	$25,453	$205,715	7.8	Reduce Max Airflow, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Simon Hall (Science)	$78,061	$204,869	2.6	Optimize VAV Operation, Space Temp. Setback
Simon Hall (Science)	$71,702	$326,096	4.5	Lighting Retrofit, Lighting Controls
Chemistry	$41,888	$241,631	5.7	Lighting Retrofit, Lighting Controls
Chemistry	$80,332	$1,106,924	13.1	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Chemistry	$3,988	$611,356	106.0	Replace Windows, Reduce Outside Air
Chemistry Addition	$20,426	$140,392	6.7	Lighting Retrofit, Lighting Controls
Chemistry Addition	$42,319	$681,500	15.0	Install Fan VFD's, Reduce Max Airflow, Space Temp. Setback, Install DDC Zone Controls
Chemistry Addition	$1,597	$337,308	126.4	Replace Windows
Ernie Pyle Hall	$31,276	$1,379	0.0	Change HVAC Schedule
Ernie Pyle Hall	$10,946	$86,846	7.7	Lighting Retrofit, Lighting Controls
Ernie Pyle Hall	$44,673	$513,726	10.8	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback
Ernie Pyle Hall	$2,962	$363,163	46.3	Connect to Campus CWP - Variable Flow
Ernie Pyle Hall	$52	$127,654	1000.0	#N/A
Wildermuth Center	$15,496	$132,295	8.3	Lighting Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Wildermuth Center	$8,271	$2,959,073	305.3	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Optimize VAV Operation, Space Temp. Setback
Myers Hall	$10,910	$2,755	0.3	Reduce Humidification
Myers Hall	$68,108	$111,109	1.6	Optimize VAV Operation, Space Temp. Setback
Myers Hall	$16,586	$71,624	4.3	Lighting Controls
Myers Hall	$14,152	$1,121,296	56.9	Air-Side Heat Recovery
Jordan Hall	$63,544	$464,627	7.1	Lighting Retrofit, Lighting Controls
Jordan Hall	$274,518	$4,350,527	15.0	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback
Jordan Hall	$45,651	$4,727,036	69.9	Replace Windows, Air-Side Heat Recovery
Goodbody Hall	$15,777	$79,697	5.0	Lighting Retrofit, Lighting Controls
Goodbody Hall	$14,358	$1,068,862	54.8	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Remove Air Economizer, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Air-Side Heat Recovery, Connect to Campus CWP - Variable Flow
Ballantine Hall	$71,310	$285,873	3.9	Lighting Controls
HPER Building	$65,534	$359,360	5.4	Lighting Retrofit, Lighting Controls
Woodburn Hall	$25,846	$166,147	6.3	Lighting Retrofit, Lighting Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Woodburn Hall	$60,482	$442,179	7.1	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Morrison Hall	$15,463	$105,343	6.7	Lighting Retrofit, Lighting Controls
Morrison Hall	$17,517	$264,330	14.3	Space Temp. Setback, Install DDC Zone Controls
Memorial Hall	$6,247	$54,829	8.5	Lighting Controls
Memorial Hall	$4,359	$2,684,801	117.6	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Connect to Campus CWP - Variable Flow Pumping
Merrill Hall	$27,689	$2,100	0.1	Change HVAC Schedule
Merrill Hall	$1,330	$9,798	7.4	Reduce Outside Air
Merrill Hall	$5,282	$54,589	10.1	Lighting Controls
Merrill Hall	$47,951	$694,965	13.9	Change HVAC Type, Install DDC Zone Controls, Remove Air Economizer, Optimize VAV Operation, Space Temp. Setback
Merrill Hall	$620	$184,630	208.5	Replace Windows
Music Addition	$44,627	$277,070	6.1	Lighting Retrofit, Lighting Controls
Music Addition	$116,157	$1,898,163	15.3	Replace Windows, Change HVAC Type, Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Sycamore Hall	$13,724	$69,827	5.0	Lighting Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Art Museum	$61,436	$356,510	5.7	Lighting Retrofit, Lighting Controls
Art Museum	$123,468	$861,925	6.7	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls
Art Museum	$3,927	$360,000	28.5	Connect to Campus CWP - Variable Flow Pumping
Lilly Library	$6,600	$49,155	7.3	Lighting Controls
Lilly Library	$12,745	$752,449	47.1	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation
Fine Arts	$25,440	$195,517	7.5	Lighting Retrofit, Lighting Controls
Fine Arts	$77,361	$870,815	10.8	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Fine Arts	$1,408	$365,809	179.3	Replace Windows
Radio-TV	$9,992	$3,577	0.4	Reduce Humidification
Radio-TV	$12,739	$93,013	7.1	Lighting Controls
Radio-TV	$1,382	$16,695	12.2	Reduce Outside Air
Radio-TV	$39,769	$599,816	14.2	Reduce Max Airflow, Install DDC Zone Controls, Space Temp. Setback
Auditorium	$146,647	$1,438,765	9.5	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Auditorium	$25,978	$314,069	11.7	Lighting Retrofit, Lighting Controls
Lee Norvelle Theatre Drama/ Neal&Mars	$115,150	$154,615	1.3	Optimize VAV Operation
Lee Norvelle Theatre Drama/ Neal&Mars	$73,907	$444,314	5.9	Lighting Retrofit, Lighting Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Lee Norvelle Theatre Drama/ Neal&Mars	$2,436	$22,785	9.3	Reduce Outside Air
IU Cinema	$1,634	$12,642	7.6	Lighting Controls
Musical Arts Center	$73,552	$575,078	7.6	Lighting Retrofit, Lighting Controls
Musical Arts Center	$189,666	$4,304,691	20.3	Replace Windows, Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Change HVAC Schedule, Space Temp. Setback, Install CHW Pump Variable Speed Drives
Simon Msc Lbr Rec	$40,083	$8,335	0.2	Change HVAC Schedule
Simon Msc Lbr Rec	$20,311	$216,721	10.4	Lighting Controls
Simon Msc Lbr Rec	$84,144	$1,397,569	15.8	Change HVAC Type, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Wells Library	$50,623	$521,505	10.0	Lighting Controls
Wells Library	$303,896	$3,363,037	10.6	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Wells Library	$5,495	$1,455,142	176.6	Replace Windows
Read Hall	$37,983	$336,640	8.6	Lighting Controls
Read Hall	$32,847	$6,566,475	104.4	Change HVAC Type, Install DDC Zone Controls, Reduce Max Airflow, Reduce Outside Air, Space Temp. Setback, Increase size of CHW Pumping
Wright Quad	$41,130	$458,033	10.7	Lighting Retrofit, Lighting Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Wright Quad	$12,606	$5,711,646	124.7	Replace Windows, Change HVAC Type, Space Temp. Setback, Install DDC Zone Controls, Air-Side Heat Recovery, Convert to Variable Volume Heating Water
Teter Quad	$38,243	$396,430	10.1	Lighting Retrofit, Lighting Controls
Teter Quad	$5,788	$286,574	39.4	Air-Side Heat Recovery
Teter Quad	$31,186	$1,473,074	41.7	Space Temp. Setback, Install DDC Zone Controls
Teter Quad	$8,946	$1,160,297	96.7	Replace Windows
Wendell W. Wright	$3,182	$6,880	2.1	Reduce Humidification
Wendell W. Wright	$1,416	$7,474	5.2	Convert to Variable Volume Heating Water
Wendell W. Wright	$170,635	$1,440,212	8.2	Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback, Install DDC Zone Controls
Wendell W. Wright	$33,787	$287,584	8.3	Lighting Retrofit, Lighting Controls
Forest Quad	$18,149	$90,172	4.9	Space Temp. Setback
Forest Quad	$47,680	$414,099	8.5	Lighting Retrofit, Lighting Controls
Forest Quad	$8,662	$1,114,563	96.1	Replace Windows
Hickory Hall	$5,714	$59,356	10.1	Lighting Controls
Hickory Hall	$3,926	$310,475	63.9	Space Temp. Setback, Install DDC Zone Controls
Birch Hall	$2,796	$39,743	13.7	Lighting Controls
Birch Hall	$9,142	$207,884	21.3	Space Temp. Setback, Install DDC Zone Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Cedar Hall	$5,151	$86,297	16.2	Lighting Controls
Cedar Hall	$14,057	$451,401	28.5	Space Temp. Setback, Install DDC Zone Controls
Linden Hall	$4,265	$59,356	13.4	Lighting Controls
Linden Hall	$12,864	$310,475	22.6	Space Temp. Setback, Install DDC Zone Controls
Cypress Hall	$3,273	$39,743	11.7	Lighting Controls
Cypress Hall	$5,617	$207,884	34.1	Space Temp. Setback, Install DDC Zone Controls
Beech Hall	$4,573	$59,356	12.5	Lighting Controls
Beech Hall	$11,662	$310,480	24.8	Space Temp. Setback, Install DDC Zone Controls
Pine Hall	$4,298	$59,356	13.3	Lighting Controls
Pine Hall	$9,540	$310,475	30.0	Space Temp. Setback, Install DDC Zone Controls
Willkie B	$39,347	$308,682	7.7	Lighting Retrofit, Lighting Controls
Willkie B	$3,400	$87,987	22.5	Air-Side Heat Recovery
Willkie B	$14,028	$587,966	36.0	Space Temp. Setback, Install DDC Zone Controls
Willkie C	$35,414	$417,639	11.8	Space Temp. Setback, Install DDC Zone Controls
Willkie C	$6,361	$79,843	11.9	Lighting Controls
Willkie A	$15,314	$37,425	2.4	Space Temp. Setback
Willkie A	$11,295	$112,274	9.7	Lighting Controls
Mason Hall	$1,478	$23,135	14.8	Lighting Controls
Eigenmann Hall	$7,871	$17,441	2.2	Add Variable Flow CHW Pumping

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Eigenmann Hall	$81,281	$550,710	6.6	Lighting Retrofit, Lighting Controls
Eigenmann Hall	$31,222	$1,706,127	41.1	Space Temp. Setback, Install DDC Zone Controls
DeVault Alumni Center	$4,486	$30,479	6.7	Lighting Controls
DeVault Alumni Center	$19,128	$196,550	9.9	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Chilled Water Plant	$11,274	$36,333	3.2	Lighting Controls
Chilled Water Plant	$7,027	$2,269,766,656	1000.0	#N/A
Geological Survey	$18,030	$113,477	6.2	Lighting Retrofit, Lighting Controls
Geological Survey	$39,562	$531,344	12.8	Replace Windows, Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Psychology	$17,865	$145,310	7.9	Lighting Controls
Psychology	$112,757	$1,920,704	16.0	Change HVAC Type, Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Psychology	$2,086	$491,462	165.4	Replace Windows
Multi Science 2	$10,105	$4,719	0.5	Reduce Humidification
Multi Science 2	$20,073	$122,685	6.0	Lighting Controls
Multi Science 2	$4,817	$40,895	8.5	Space Temp. Setback
Briscoe Quad	$35,593	$261,541	7.2	Lighting Controls
Briscoe Quad	$30,323	$1,368,060	40.2	Space Temp. Setback, Install DDC Zone Controls
Briscoe Quad	$8,364	$1,077,580	96.9	Replace Windows
McNutt North	$16,729	$143,342	8.4	Lighting Controls
McNutt North	$3,351	$157,786	37.9	Air-Side Heat Recovery

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
McNutt North	$16,286	$749,788	40.7	Space Temp. Setback, Install DDC Zone Controls
McNutt North	$433	$668,910	1000.0	#N/A
McNutt Central	$10,911	$73,255	6.6	Lighting Controls
McNutt Central	$51,812	$472,402	8.9	Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
McNutt Central	$907	$247,760	168.8	Replace Windows
McNutt South	$13,987	$121,366	8.5	Lighting Controls
McNutt South	$1,187	$53,439	36.6	Air-Side Heat Recovery
McNutt South	$4,383	$781,314	489.3	Install Water Side Economizer
Central Heating	$18,112	$78,643	4.3	Lighting Controls
Godfrey Grad&Exec Ed Ctr	$8,860	$6,903	0.8	Reduce Humidification
Godfrey Grad&Exec Ed Ctr	$6,987	$32,213	4.6	Reduce Outside Air
Godfrey Grad&Exec Ed Ctr	$17,560	$179,471	9.9	Lighting Controls
Business School	$30,490	$222,916	7.2	Lighting Controls
Business School	$160,432	$1,794,759	10.7	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Business School	$3,133	$753,936	165.4	Replace Windows
SPEA	$41,018	$4,630	0.1	Change HVAC Schedule
SPEA	$42,622	$254,666	5.9	Lighting Retrofit, Lighting Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
SPEA	$57,099	$776,344	13.0	Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback, Install DDC Zone Controls
Harper Hall	$12,464	$102,162	8.0	Lighting Controls
Harper Hall	$1,539	$74,971	38.8	Air-Side Heat Recovery
Harper Hall	$10,459	$534,384	44.6	Space Temp. Setback, Install DDC Zone Controls
Gresham Dining Hall	$18,884	$1,832	0.1	Change HVAC Schedule
Gresham Dining Hall	$2,045	$8,549	4.2	Reduce Outside Air
Gresham Dining Hall	$4,124	$47,631	11.2	Lighting Controls
Gresham Dining Hall	$29,485	$383,492	12.4	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Gresham Dining Hall	$668	$161,096	162.8	Replace Windows
Shea Hall	$3,773	$39,315	10.1	Lighting Controls
Shea Hall	$619	$28,851	37.6	Air-Side Heat Recovery
Shea Hall	$1,347	$405,048	195.3	Replace Windows, Reduce Outside Air, Change HVAC Schedule, Space Temp. Setback, Install DDC Zone Controls
Martin Hall	$3,369	$34,691	10.0	Lighting Controls
Martin Hall	$519	$25,458	39.0	Air-Side Heat Recovery
Martin Hall	$1,568	$356,076	151.5	Replace Windows, Reduce Outside Air, Space Temp. Setback, Install DDC Zone Controls
Magee Hall	$3,394	$34,692	10.0	Lighting Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Magee Hall	$519	$25,459	39.0	Air-Side Heat Recovery
Magee Hall	$1,627	$356,085	150.1	Replace Windows, Reduce Outside Air, Space Temp. Setback, Install DDC Zone Controls
Jenkinson Hall	$3,375	$34,535	10.0	Lighting Controls
Jenkinson Hall	$546	$25,343	37.5	Air-Side Heat Recovery
Jenkinson Hall	$3,567	$180,643	44.3	Space Temp. Setback, Install DDC Zone Controls
Nelson RPS Admin.	$9,640	$66,116	6.7	Lighting Retrofit, Lighting Controls
Nelson RPS Admin.	$18,988	$592,232	27.6	Change HVAC Type, Install DDC Zone Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback
Nelson RPS Admin.	$801	$156,004	134.2	Replace Windows
Health Center	$6,474	$60,518	9.2	Lighting Controls
Health Center	$89,380	$2,790,205	26.7	Change HVAC Type, Install DDC Zone Controls, Space Temp. Setback, Air-Side Heat Recovery, Add Variable Volume CHW Pumping
Recreational Sports	$148,907	$984,838	6.4	Lighting Controls, Install Fan VFD's, Optimize VAV Operation, Space Temp. Setback
Campus View Apartments	$56,719	$449,132	7.6	Lighting Retrofit, Lighting Controls
Campus View Apartments	$21,140	$1,310,772	45.3	Space Temp. Setback, Install DDC Zone Controls
Tulip Tree Apts	$24,938	$82,057	3.2	Space Temp. Setback
Tulip Tree Apts	$28,293	$246,171	8.4	Lighting Controls

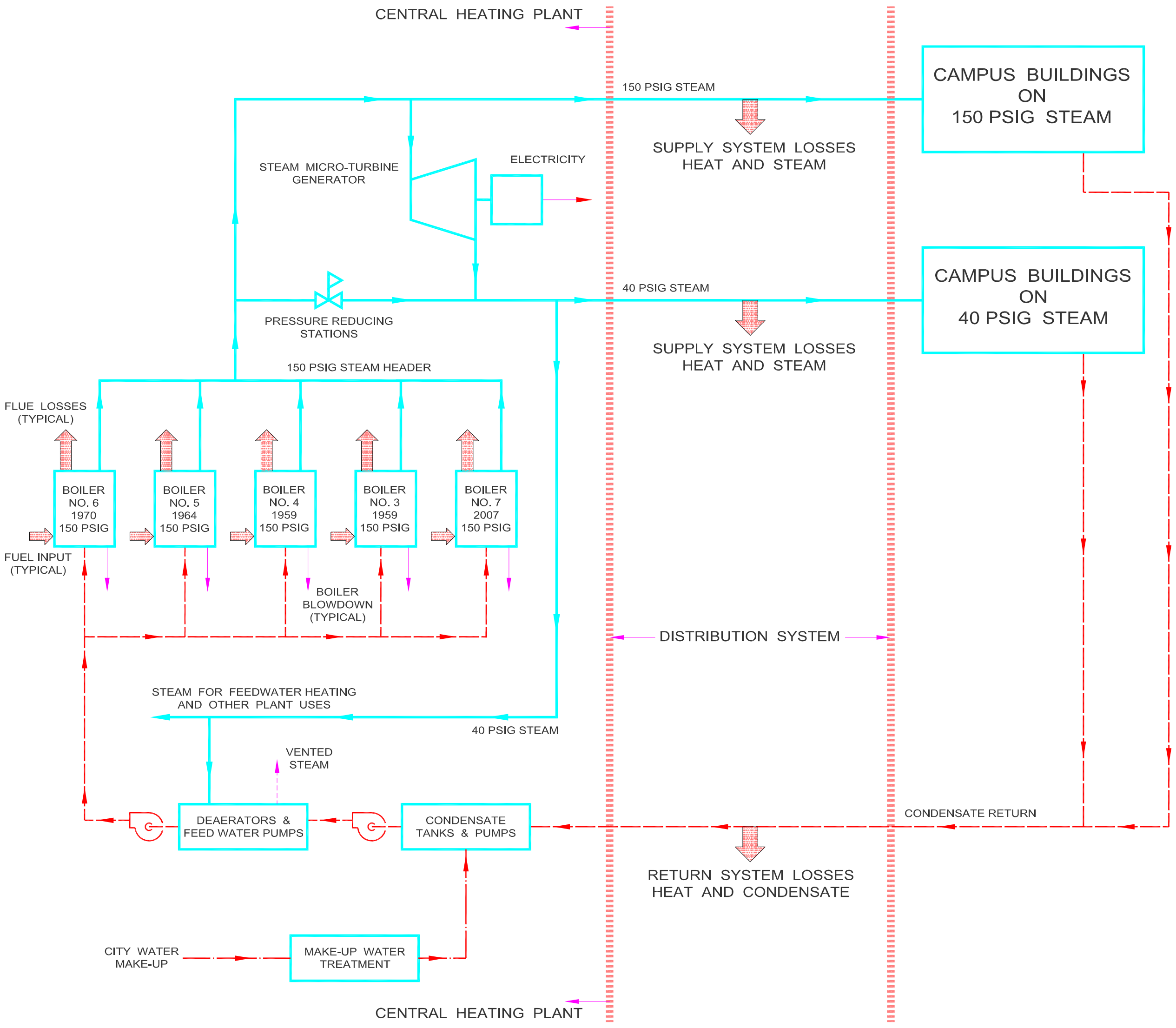
Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Innovation Center	$3,635	$37,319	9.9	Lighting Controls
Mellencamp Pavilion	$2,774	$16,847	5.9	Reduce Outside Air
Mellencamp Pavilion	$12,001	$93,864	7.6	Lighting Controls
Mellencamp Pavilion	$6,770	$1,539,080	134.8	Change HVAC Type, Space Temp. Setback, Air-Side Heat Recovery
Memorial Stadium East Stands	$5,111	$1,670	0.3	Change HVAC Schedule
Memorial Stadium East Stands	$7,415	$43,415	5.7	Lighting Controls
Memorial Stadium East Stands	$2,484	$52,878	20.5	Optimize VAV Operation
Memorial Stadium West Stands	$28,709	$423,697	13.8	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Memorial Stadium North Endzone	$14,806	$2,520	0.2	Change HVAC Schedule
Memorial Stadium North Endzone	$10,388	$108,500	10.0	Lighting Controls
Memorial Stadium North Endzone	$4,478	$101,640	21.0	Optimize VAV Operation, Space Temp. Setback
Tennis Center	$7,731	$54,015	6.8	Lighting Controls
Tennis Center	$15,240	$576,203	32.3	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Change HVAC Schedule, Space Temp. Setback, Condensing Water Boiler
Assembly Hall	$21,225	$64,026	2.9	Reduce Outside Air
Assembly Hall	$57,427	$356,715	6.1	Lighting Controls

Table A8.2.2: Building Energy Conservation Measures, Ordered by Building (continued)

Building Name	Estimated Annual Energy Cost Reduction	Estimated Implementation Cost	Marginal Payback (Years)	Included Energy Conservation Measures
Assembly Hall	$37,788	$2,872,015	58.5	Install Fan VFD's, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback
Assembly Hall	$3,134	$995,335	181.3	Replace Windows, Convert to Variable Volume Heating Water
Gladstein Fieldhouse	$53,706	$310,529	5.7	Lighting Retrofit, Lighting Controls
Gladstein Fieldhouse	$12,708	$3,581,725	123.4	Replace Windows, Optimize VAV Operation, Install DDC Zone Controls, Space Temp. Setback, Change FCU Cool Source, Air-Side Heat Recovery, Connect to Campus CWP, Variable Flow
Cook Hall	$38,011	$2,500	0.1	Change HVAC Schedule
Cook Hall	$12,594	$11,666	0.9	Reduce Outside Air
Cook Hall	$43,591	$100,828	2.3	Optimize VAV Operation, Space Temp. Setback

Figure A9.1.1.1: Central Heating Plant Flow Schematic



STEAM SYSTEM DIAGRAM

Figure A9.1.1.2: Central Heating Plant Thermal Model

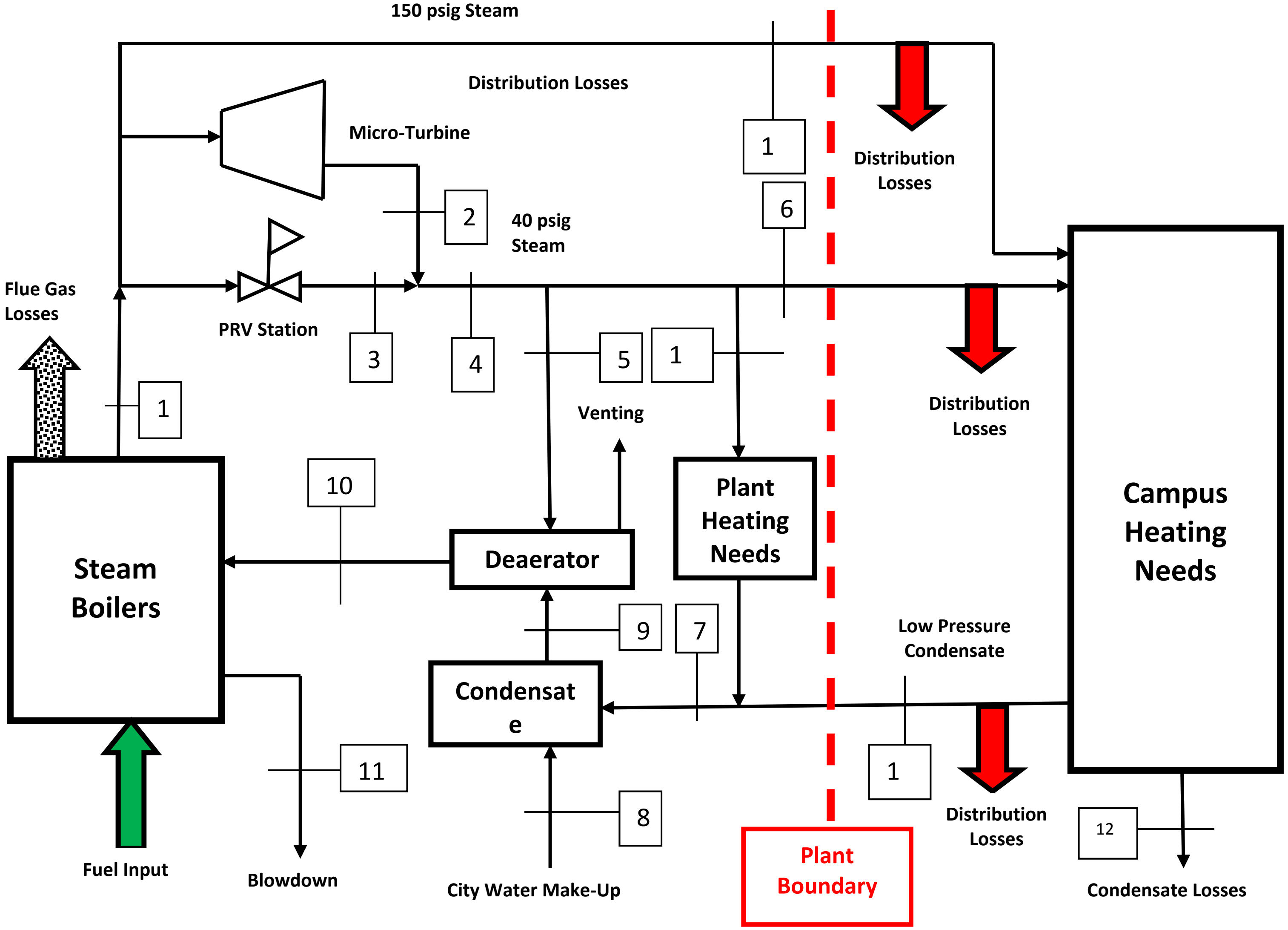


Table A9.1.1.3: FY 09-10 Central Heating Plant Annual Energy Flow

IUB CHP Steam System Flows and State Points

State Point	Description of State Point	Steam Pressure (psig)	Steam Condition	Tempera ture (°F)	Enthalpy (Btu/lb)	Annual Flow (10^3lbs/year)
1	Boiler Discharge	150	Saturated Vapor	366	1,196.0	1,266,133
2	Micro-Turbine Discharge	40	95.5% Quality	287	1,134.4	47,838
3	PRV Station Discharge	40	Superheated Vapor	324	1,196.0	995,399
4	40 psig Steam to Plant	40	Superheated Vapor	319	1,193.2	1,043,237
5	Steam to Deaerator	40	Superheated Vapor	319	1,193.2	131,924
6	40 psig Steam to Campus	40	Superheated Vapor	319	1,193.2	853,515
7	Condensate Returned from Campus and from Plant	0	Subcooled Liquid	171	139.3	743,509
8	Softened Make-Up Water	0	Subcooled Liquid	60	28.1	461,112
9	Feedwater to Deaerator	15	Subcooled Liquid	129	96.7	1,204,621
10	Feedwater to Boiler	165	Subcooled Liquid	250	218.9	1,332,347
11	Boiler Blowdown	150	Saturated Liquid	366	338.5	66,214
12	Unreturned Condensate	0	Saturated Liquid	212	180.2	390,700
13	150 psig Steam to Campus	150	Saturated Vapor	366	1,196.0	222,896
14	Other Plant Steam Needs	40	Superheated Vapor	319	1,193.2	57,798
15	Condensate Returned from Campus	0	Subcooled Liquid	168	135.9	685,711

Boiler Inputs		
Fuel	1,783,503	MMBtu/yr
Feedwater	291,651	MMBtu/yr
Total	2,075,154	MMBtu/yr
Boiler Outputs		
Steam	1,514,295	MMBtu/yr
Blowdown	22,413	MMBtu/yr
Radiation	4,459	MMBtu/yr
Flue Gas Losses	533,986	MMBtu/yr
Total	2,075,154	MMBtu/yr
Combustion Efficiency	70.1%	
Efficiency based on Boiler lbs Produced	68.6%	
Efficiency based on Steam Leaving Plant	66.2%	

Plant Inputs		
Fuel	1,783,503	MMBtu/yr
City Water	12,957	MMBtu/yr
Condensate Return	103,571	MMBtu/yr
Total	1,900,031	MMBtu/yr
Plant Outputs		MMBtu/yr
Flue Gas Losses	533,986	MMBtu/yr
Blowdown	22,413	MMBtu/yr
150 Psig Steam	266,584	MMBtu/yr
40 Psig Steam	1,018,414	MMBtu/yr
Radiation	4,459	MMBtu/yr
DA Venting	4,829	MMBtu/yr
Other Plant Needs for Heat	58,549	MMBtu/yr
Electricity	3,015	MMBtu/yr
Total	1,912,250	MMBtu/yr
Accuracy of Heat Balance	-0.64%	

Total Heat Resulting in Steam Production = Q_{out} - Q_{in} = $(mh)_1$ - $(mh)_{10}$ =	1,222,644	MMBtu/year	
Total Fuel Input =	1,783,503	MMBtu/year	
Implied ASME PTC-4 Boiler Efficiency =	68.6%		
Boiler Combustion Efficiency =	70.1%		
Average Enthalpy of Steam Leaving Plant = $(m_6h_6 + m_{13}h_{13})/(m_6 + m_{13})$ =	1,193.8	(h_{avg}) Btu/lb	
Enthalpy of Condensate at 212°F, 14.7 psia =	180.2	(h_{cond}) Btu/lb	
Heat Available from One LB Steam to Loads and Distribution Losses =	1,013.6	(Δh) Btu/lb	
Average Return Losses = $(m_6 + m_{13})$ h_{cond} - $(mh)_7$ =	100,781	MMBtu/year (Including Heat Loss and Unreturned Condensate)	
Return Losses as % of Total Output =	8.2%		
Enthalpy of 5 psig Saturated Steam =	1,155.9	(h_{supply}) Btu/lb	
Losses from Supply Distribution Analysis as % of Total Output =	209,110	MMBtu/year (Average Soil Conditions)	
Distribution Losses as Percentage of Total Output =	17.1%		
Losses from Supply Distribution Analysis as % of Total Output =	117,410	MMBtu/year (Dry Soil Conditions)	
Distribution Losses as Percentage of Total Output =	9.6%		
Total Distribution Losses as % of Total Output=	25.3%	MMBtu/year (Average Soil Conditions)	
Total Distribution Losses as % of Total Output=	17.8%	MMBtu/year (Dry Soil Conditions)	
Implied Plant Efficiency =	49.4%	(Average Soil Conditions)	
Implied Plant Efficiency =	54.6%	(Dry Soil Conditions)	
Heat Consumed in the Buildings =			
$(m_6h_6 + m_{13}h_{13})$ - Supply Losses - $(m_6 + m_{13})h_{cond}$ =	881,918	MMBtu/year (Average Soil Conditions)	
Percentage Condensate Return from the System =	63.7%	Apparent % Counting Returns from the Plant =	69.1%

For Average Soil Conditions, 49.4% of Heat Input is Used for Heat in the Buildings

Table A9.1.2.1: 100% Natural Gas, Existing Boilers, Reduce Staff with Elimination of Coal Operation

Option A: 100% Natural Gas, Existing Boilers, Staff Reductions

Cost Premium for Operation on 100% Natural Gas in FY 2011/2012

Total Costs for 100% Natural Gas Operation FY 11/12 =	**$7,579,797**
Total Costs for 90% Coal/10% Natural Gas Operation FY 11/12 =	**$6,993,478**
Total Additional Cost for FY 11/12 to Burn 100% Natural Gas =	**$586,318**

FY 2011/2012 Natural Gas Costs

Differential Cost of Operation for 100% Natural Gas Plant Use (with Efficiency of Existing Gas Boilers Considered)

		Vectren Charges (LDC)									**Energy USA Charges**							
Month FY 11/12	**Natural Gas Use (therms)**	**Throughput Charges**	**Customer Facilities Charge (CFC)**	**Capacity Reservation Charge (CRC)**	**Delivery Reservation Charge (DRC)**	**Pipeline Safety Adjustment Charge (PSAC)**	**Universal Service Fund Charge (USFC)**	**Gas Cost Adjustment (GCA)**	**Total Vectren Charges**	**Vectren Line Loss (0.2% of therms used)**	**Energy USA Therms**	**Energy USA Citygate Price/MMBtu**	**Total Commodity Cost**	**Mgmt. Fees**	**Indiana Utilities Receipts Tax**	**Total Energy USA Charges**	**Total Natural Gas Cost**	**Total Natural Gas Cost/MMBtu**
Jul	595,973	$22,472	$1,100	$3,750	$0	$715	$179	$179	$28,395	1,192	597,165	$4.5520	$271,829	$699	$3,806	$276,334	$304,728	$5.113
Aug	663,998	$24,465	$1,100	$3,750	$0	$797	$199	$199	$30,510	1,328	665,326	$4.5800	$304,719	$733	$4,266	$309,718	$340,228	$5.124
Sep	839,451	$29,606	$1,100	$3,750	$0	$1,007	$200	$252	$35,915	1,679	841,130	$4.0870	$343,770	$821	$4,813	$349,403	$385,318	$4.590
Oct	1,117,812	$37,762	$1,100	$3,750	$0	$1,341	$200	$335	$44,489	2,236	1,120,047	$4.0090	$449,027	$960	$6,286	$456,273	$500,762	$4.480
Nov	1,521,713	$49,596	$1,100	$3,750	$26,740	$1,826	$200	$457	$83,669	3,043	1,524,757	$3.7940	$578,493	$1,162	$8,099	$587,754	$671,423	$4.412
Dec	2,361,073	$74,189	$1,100	$3,750	$26,740	$2,833	$200	$708	$109,521	4,722	2,365,795	$4.0815	$965,599	$1,583	$13,518	$980,701	$1,090,222	$4.617
Jan	2,546,209	$79,614	$1,100	$3,750	$26,740	$3,055	$200	$764	$115,223	5,092	2,551,302	$4.1780	$1,065,934	$1,676	$14,923	$1,082,533	$1,197,756	$4.704
Feb	2,165,858	$68,470	$1,100	$3,750	$26,740	$2,599	$200	$650	$103,508	4,332	2,170,190	$4.2010	$911,697	$1,485	$12,764	$925,946	$1,029,454	$4.753
Mar	1,277,512	$42,441	$1,100	$3,750	$26,740	$1,533	$200	$383	$76,147	2,555	1,280,067	$4.1700	$533,788	$1,040	$7,473	$542,301	$618,448	$4.841
Apr	1,171,792	$39,344	$1,100	$3,750	$0	$1,406	$200	$352	$46,151	2,344	1,174,135	$4.1670	$489,262	$987	$6,850	$497,099	$543,250	$4.636
May	1,110,729	$37,554	$1,100	$3,750	$0	$1,333	$200	$333	$44,270	2,221	1,112,950	$4.1875	$466,048	$956	$6,525	$473,529	$517,799	$4.662
Jun	810,024	$28,744	$1,100	$3,750	$0	$972	$200	$243	$35,009	1,620	811,644	$4.1870	$339,835	$806	$4,758	$345,399	$380,408	$4.696
	16,182,143	$534,257	$13,200	$45,000	$133,700	$19,419	$2,378	$4,855	$752,808	32,364	16,214,507		$6,720,001	$12,907	$94,080	$6,826,989	$7,579,797	
	Per MMBtu =	$0.330	$0.008	$0.028	$0.083	$0.012	$0.001	$0.003	$0.465				$4.153	$0.008	$0.001	$4.219	$4.684	

Energy USA Citygate Price = NYMEX Monthly Settlement Price + Vectren North NEC Basis (Historical Summary through November 2011, Futures for Remainder of FY 11/12)

Displays Natural Gas Charges for Heat Necessary to Produce all the Steam that was Generated with the Existing Natural Gas Boilers

Rates Applicable for Energy USA Costs FY 11/12 Only

Table A9.1.2.1: 100% Natural Gas, Existing Boilers, Reduce Staff with Elimination of Coal Operation (Continued)

Costs of Operation for FY 2011/2012 Operating on 90% Coal and 10% Natural Gas

			Vectren Charges (LDC)								Energy USA Charges								Coal and Differential Costs				
Month FY 11/12	Total Steam Consumption (MMBtu)	Natural Gas Use (therms)	Throughput Charges	Customer Facilities Charge (CFC)	Capacity Reservation Charge (CRC)	Delivery Reservation Charge (DRC)	Pipeline Safety Adjustment Charge (PSAC)	Universal Service Fund Charge (USFC)	Gas Cost Adjustment (GCA)	Total Vectren Charges	Vectren Line Loss (0.2% of therms used)	Energy USA Therms	Energy USA Citygate Price/MMBtu	Total Commodity Cost	Mgmt. Fees	Indiana Utilities Receipts Tax	Total Energy USA Charges	Total Natural Gas Cost	MMBtu Coal Required	Differential Costs per MMBtu$^{\text{Note 1}}$	Coal Costs per MMBtu	Total Coal + Differential Cost per MMBtu	Coal and Differential Costs	Total Cost of Coal and Natural Gas Required
Jul	50,062	59,597	$3,222	$1,100	$3,750	$0	$72	$18	$18	$8,180	119	59,716	$4.5520	$27,183	$269	$381	$27,832	$36,012	66,552	$0.900	$2.694	$3.594	$239,188	$275,200
Aug	55,776	66,400	$3,522	$1,100	$3,750	$0	$80	$20	$20	$8,491	133	66,533	$4.5800	$30,472	$299	$427	$31,198	$39,689	74,148	$0.900	$2.694	$3.594	$266,489	$306,178
Sep	70,453	83,872	$4,290	$1,100	$3,750	$0	$101	$25	$25	$9,291	168	84,040	$4.0870	$34,347	$378	$481	$35,206	$44,498	93,660	$0.900	$2.694	$3.594	$336,614	$381,111
Oct	92,334	109,921	$5,437	$1,100	$3,750	$0	$132	$33	$33	$10,484	220	110,141	$4.0090	$44,156	$455	$618	$45,229	$55,713	122,748	$0.900	$2.694	$3.594	$441,159	$496,872
Nov	122,916	146,329	$7,038	$1,100	$3,750	$26,740	$176	$44	$44	$38,892	293	146,622	$3.7940	$55,628	$473	$779	$56,880	$95,772	163,404	$0.900	$2.694	$3.594	$587,276	$683,048
Dec	174,715	207,994	$9,752	$1,100	$3,750	$26,740	$250	$62	$62	$41,716	416	208,410	$4.0815	$85,063	$504	$1,191	$86,758	$128,474	232,265	$0.900	$2.694	$3.594	$834,765	$963,238
Jan	190,145	226,363	$10,560	$1,100	$3,750	$26,740	$272	$68	$68	$42,557	453	226,815	$4.1780	$94,763	$513	$1,327	$96,604	$139,161	252,777	$0.900	$2.694	$3.594	$908,484	$1,047,645
Feb	163,146	194,222	$9,146	$1,100	$3,750	$26,740	$233	$58	$58	$41,085	388	194,610	$4.2010	$81,756	$497	$1,145	$83,398	$124,483	216,886	$0.900	$2.694	$3.594	$779,490	$903,973
Mar	101,930	121,345	$5,939	$1,100	$3,750	$26,740	$146	$36	$36	$37,748	243	121,588	$4.1700	$50,702	$461	$710	$51,873	$89,620	135,505	$0.900	$2.694	$3.594	$487,007	$576,628
Apr	97,184	115,696	$5,691	$1,100	$3,750	$0	$139	$35	$35	$10,749	231	115,927	$4.1670	$48,307	$458	$676	$49,441	$60,190	129,196	$0.900	$2.694	$3.594	$464,333	$524,523
May	93,298	111,070	$5,487	$1,100	$3,750	$0	$133	$33	$33	$10,537	222	111,292	$4.1875	$46,603	$456	$652	$47,711	$58,248	124,030	$0.900	$2.694	$3.594	$445,766	$504,015
Jun	60,082	81,002	$4,164	$1,100	$3,750	$0	$97	$24	$24	$9,160	162	81,164	$4.1870	$33,984	$365	$476	$34,825	$43,984	79,873	$0.900	$2.694	$3.594	$287,063	$331,047
Totals	1,272,042	1,523,812	$74,248	$13,200	$45,000	$133,700	$1,829	$457	$457	$268,891	3,048	1,526,859		$632,964	$5,129	$8,861	$646,955	$915,845	1,691,045				$6,077,633	$6,993,478
	Cost Per MMBtu =		$0.046	$0.008	$0.028	$0.083	$0.001	$0.000	$0.000	$1.765				$4.154	$0.034	$0.001	$4.246	$6.010						

Note 1: Differential Costs Based on $1,418,306/1,575,877 MMBtu = $0.900/MMBtu

(Differential Costs Based on Burning 1,575,877 MMBtu of coal in FY 2010/2011)

Table A9.1.2.2: 100% Natural Gas, High Efficiency Boilers, Reduce Staff with Elimination of Coal Operation

Option B: 100% Natural Gas, High Efficiency Boilers Boilers, Staff Reductions

Cost Premium for Operation on 100% Natural Gas in FY 2011/2012

Total Costs for 100% Natural Gas Operation FY 11/12 = $7,204,111

Total Costs for 90% Coal/10% Natural Gas Operation FY 11/12 = $6,993,478

Total Additional Cost for FY 11/12 to Burn 100% Natural Gas = $210,633

FY 2011/2012 Natural Gas Costs

Differential Cost of Operation for 100% Natural Gas Plant Use (with New High Efficiency Boiler Replacing Boiler No. 5)

		Vectren Charges (LDC)									Energy USA Charges							
Month FY 11/12	Natural Gas Use (therms)	Throughput Charges	Customer Facilities Charge (CFC)	Capacity Reservation Charge (CRC)	Delivery Reservation Charge (DRC)	Pipeline Safety Adjustment Charge (PSAC)	Universal Service Fund Charge (USFC)	Gas Cost Adjustment (GCA)	Total Vectren Charges	Vectren Line Loss (0.2% of therms used)	Energy USA Therms	Energy USA Citygate Price/MMBtu	Total Commodity Cost	Mgmt. Fees	Indiana Utilities Receipts Tax	Total Energy USA Charges	Total Natural Gas Cost	Total Natural Gas Cost/MMBtu
Jul	595,973	$22,472	$1,100	$3,750	$0	$715	$179	$179	$28,395	1,192	597,165	$4.5520	$271,829	$699	$3,806	$276,334	$304,728	$5.113
Aug	663,998	$24,465	$1,100	$3,750	$0	$797	$199	$199	$30,510	1,328	665,326	$4.5800	$304,719	$733	$4,266	$309,718	$340,228	$5.124
Sep	838,724	$29,585	$1,100	$3,750	$0	$1,006	$200	$252	$35,893	1,677	840,401	$4.0870	$343,472	$820	$4,809	$349,101	$384,994	$4.590
Oct	1,099,214	$37,217	$1,100	$3,750	$0	$1,319	$200	$330	$43,916	2,198	1,101,413	$4.0090	$441,556	$951	$6,182	$448,689	$492,605	$4.481
Nov	1,463,392	$47,887	$1,100	$3,750	$26,740	$1,756	$200	$439	$81,872	2,927	1,466,318	$3.7940	$556,321	$1,133	$7,788	$565,243	$647,115	$4.422
Dec	2,120,157	$67,131	$1,100	$3,750	$26,740	$2,544	$200	$636	$102,101	4,240	2,124,397	$4.0815	$867,073	$1,462	$12,139	$880,674	$982,775	$4.635
Jan	2,294,555	$72,240	$1,100	$3,750	$26,740	$2,753	$200	$688	$107,472	4,589	2,299,144	$4.1780	$960,582	$1,550	$13,448	$975,580	$1,083,052	$4.720
Feb	1,980,311	$63,033	$1,100	$3,750	$26,740	$2,376	$200	$594	$97,794	3,961	1,984,271	$4.2010	$833,592	$1,392	$11,670	$846,655	$944,448	$4.769
Mar	1,213,819	$40,575	$1,100	$3,750	$26,740	$1,457	$200	$364	$74,186	2,428	1,216,247	$4.1700	$507,175	$1,008	$7,100	$515,284	$589,469	$4.856
Apr	1,156,956	$38,909	$1,100	$3,750	$0	$1,388	$200	$347	$45,694	2,314	1,159,270	$4.1670	$483,068	$980	$6,763	$490,810	$536,505	$4.637
May	1,110,695	$37,553	$1,100	$3,750	$0	$1,333	$200	$333	$44,269	2,221	1,112,917	$4.1875	$466,034	$956	$6,524	$473,515	$517,784	$4.662
Jun	810,024	$28,744	$1,100	$3,750	$0	$972	$200	$243	$35,009	1,620	811,644	$4.1870	$339,835	$806	$4,758	$345,399	$380,408	$4.696
	15,347,817	$509,811	$13,200	$45,000	$133,700	$18,417	$2,378	$4,604	$727,111	30,696	15,378,513		$6,375,258	$12,489	$89,254	$6,477,000	$7,204,111	
	Per MMBtu =	$0.332	$0.009	$0.029	$0.087	$0.012	$0.002	$0.003	$0.474				$4.154	$0.008	$0.001	$4.220	$4.694	

Energy USA Citygate Price = NYMEX Monthly Settlement Price + Vectren North NEC Basis (Historical Summary through November 2011, Futures for Remainder of FY 11/12)

Displays Natural Gas Charges for Heat Necessary to Produce all the Steam that was Generated with the Existing Natural Gas Boilers

Rates Applicable for Energy USA Costs FY 11/12 Only

Table A9.1.2.2: 100% Natural Gas, High Efficiency Boilers, Reduce Staff with Elimination of Coal Operation (Continued)

Costs of Operation for FY 2011/2012 Operating on 90% Coal and 10% Natural Gas (but with New High Efficiency Gas Boiler)

			Vectren Charges (LDC)									Energy USA Charges								Coal and Differential Costs				
Month FY 11/12	Total Steam Consumption (MMBtu)	Natural Gas Use (therms)	Throughput Charges	Customer Facilities Charge (CFC)	Capacity Reservation Charge (CRC)	Delivery Reservation Charge (DRC)	Pipeline Safety Adjustment Charge (PSAC)	Universal Service Fund Charge (USFC)	Gas Cost Adjustment (GCA)	Total Vectren Charges	Vectren Line Loss (0.2% of therms used)	Energy USA Therms	Energy USA Citygate Price/MMBtu	Total Commodity Cost	Mgmt. Fees	Indiana Utilities Receipts Tax	Total Energy USA Charges	Total Natural Gas Cost	MMBtu Coal Required	Differential Costs per MMBtu Note 1	Coal Costs per MMBtu	Total Coal + Differential Cost per MMBtu	Coal and Differential Costs	Total Cost of Coal and Natural Gas Required
Jul	50,062	59,597	$3,222	$1,100	$3,750	$0	$72	$18	$18	$8,180	119	59,716	$4.5520	$27,183	$269	$381	$27,832	$36,012	66,552	$0.900	$2.694	$3.594	$239,188	$275,200
Aug	55,776	66,400	$3,522	$1,100	$3,750	$0	$80	$20	$20	$8,491	133	66,533	$4.5800	$30,472	$299	$427	$31,198	$39,689	74,148	$0.900	$2.694	$3.594	$266,489	$306,178
Sep	70,453	83,872	$4,290	$1,100	$3,750	$0	$101	$25	$25	$9,291	168	84,040	$4.0870	$34,347	$378	$481	$35,206	$44,498	93,660	$0.900	$2.694	$3.594	$336,614	$381,111
Oct	92,334	109,921	$5,437	$1,100	$3,750	$0	$132	$33	$33	$10,484	220	110,141	$4.0090	$44,156	$455	$618	$45,229	$55,713	122,748	$0.900	$2.694	$3.594	$441,159	$496,872
Nov	122,916	146,329	$7,038	$1,100	$3,750	$26,740	$176	$44	$44	$38,892	293	146,622	$3.7940	$55,628	$473	$779	$56,880	$95,772	163,404	$0.900	$2.694	$3.594	$587,276	$683,048
Dec	174,715	207,994	$9,752	$1,100	$3,750	$26,740	$250	$62	$62	$41,716	416	208,410	$4.0815	$85,063	$504	$1,191	$86,758	$128,474	232,265	$0.900	$2.694	$3.594	$834,765	$963,238
Jan	190,145	226,363	$10,560	$1,100	$3,750	$26,740	$272	$68	$68	$42,557	453	226,815	$4.1780	$94,763	$513	$1,327	$96,604	$139,161	252,777	$0.900	$2.694	$3.594	$908,484	$1,047,645
Feb	163,146	194,222	$9,146	$1,100	$3,750	$26,740	$233	$58	$58	$41,085	388	194,610	$4.2010	$81,756	$497	$1,145	$83,398	$124,483	216,886	$0.900	$2.694	$3.594	$779,490	$903,973
Mar	101,930	121,345	$5,939	$1,100	$3,750	$26,740	$146	$36	$36	$37,748	243	121,588	$4.1700	$50,702	$461	$710	$51,873	$89,620	135,505	$0.900	$2.694	$3.594	$487,007	$576,628
Apr	97,184	115,696	$5,691	$1,100	$3,750	$0	$139	$35	$35	$10,749	231	115,927	$4.1670	$48,307	$458	$676	$49,441	$60,190	129,196	$0.900	$2.694	$3.594	$464,333	$524,523
May	93,298	111,070	$5,487	$1,100	$3,750	$0	$133	$33	$33	$10,537	222	111,292	$4.1875	$46,603	$456	$652	$47,711	$58,248	124,030	$0.900	$2.694	$3.594	$445,766	$504,015
Jun	60,082	81,002	$4,164	$1,100	$3,750	$0	$97	$24	$24	$9,160	162	81,164	$4.1870	$33,984	$365	$476	$34,825	$43,984	79,873	$0.900	$2.694	$3.594	$287,063	$331,047
Totals	1,272,042	1,523,812	$74,248	$13,200	$45,000	$133,700	$1,829	$457	$457	$268,891	3,048	1,526,859		$632,964	$5,129	$8,861	$646,955	$915,845	1,691,045				$6,077,633	$6,993,478
	Cost Per MMBtu =		$0.487	$0.087	$0.295	$0.877	$0.012	$0.003	$0.003	$1.765				$4.154	$0.034	$0.058	$4.246	$6.010						

Note 1: Differential Costs Based on $1,418,306/1,575,877 MMBtu = $0.900/MMBtu

(Differential Costs Based on Burning 1,575,877 MMBtu of coal in FY 2010/2011)

Table A9.1.2.3: Baseload Boiler No. 7, Remaining Load Coal Fired, No Staff Reductions

Option C: Baseload Boiler No. 7, Remaining Load Coal Fired, No Staff Reductions

Cost Premium for Baseload of Boiler No. 7 in FY 2011/2012

Total Costs for 100% Natural Gas Operation FY 11/12 =	**$7,059,782**
Total Costs for 90% Coal/10% Natural Gas Operation FY 11/12 =	**$6,604,520**
Total Additional Cost for FY 11/12 to Burn 100% Natural Gas =	**$455,262**

FY 2011/2012 Natural Gas Costs for Intermittent Gas Operation

Costs of Operation for FY 2011/2012 Operating Base Loaded on Natural Gas, Supplemented with Coal for Topping and with No Staff Changes

			Vectren Charges (LDC)									**Energy USA Charges**								**Coal and Differential Costs**				
Month FY 11/12	**Total Steam Consumption (MMBtu)**	**Natural Gas Use (therms)**	**Throughput Charges**	**Customer Facilities Charge (CFC)**	**Capacity Reservation Charge (CRC)**	**Delivery Reservation Charge (DRC)**	**Pipeline Safety Adjustment Charge (PSAC)**	**Universal Service Fund Charge (USFC)**	**Gas Cost Adjustment (GCA)**	**Total Vectren Charges**	**Vectren Line Loss (0.2% of therms used)**	**Energy USA Therms**	**Energy USA Citygate Price/MMBtu**	**Total Commodity Cost**	**Mgmt. Fees**	**Indiana Utilities Receipts Tax**	**Total Energy USA Charges**	**Total Natural Gas Cost**	**MMBtu Coal Required**	**Differential Costs per MMBtu Note 1**	**Coal Costs per MMBtu**	**Total Coal + Differential Cost per MMBtu**	**Coal and Differential Costs**	**Total Cost of Coal and Natural Gas Required**
Jul	50,062	595,973	$22,472	$1,100	$3,750	$0	$715	$179	$179	$28,395	1,192	597,165	$4.5520	$271,829	$699	$3,806	$276,334	$304,728	0	$0.670	$2.694	$3.364	$0	$304,728
Aug	55,776	663,998	$24,465	$1,100	$3,750	$0	$797	$199	$199	$30,510	1,328	665,326	$4.5800	$304,719	$733	$4,266	$309,718	$340,228	0	$0.670	$2.694	$3.364	$0	$340,228
Sep	70,453	836,528	$29,520	$1,100	$3,750	$0	$1,004	$200	$251	$35,825	1,673	838,202	$4.0870	$342,573	$819	$4,796	$348,188	$384,013	272	$0.670	$2.694	$3.364	$916	$384,930
Oct	92,334	1,043,066	$35,572	$1,100	$3,750	$0	$1,252	$200	$313	$42,186	2,086	1,045,152	$4.0090	$419,001	$923	$5,866	$425,790	$467,977	6,967	$0.670	$2.694	$3.364	$23,436	$491,412
Nov	122,916	1,286,897	$42,716	$1,100	$3,750	$26,740	$1,544	$200	$386	$76,436	2,574	1,289,471	$3.7940	$489,225	$1,045	$6,849	$497,119	$573,556	21,886	$0.670	$2.694	$3.364	$73,625	$647,180
Dec	174,715	1,231,175	$41,083	$1,100	$3,750	$26,740	$1,477	$200	$369	$74,720	2,462	1,233,637	$4.0815	$503,509	$1,017	$7,049	$511,575	$586,295	105,312	$0.670	$2.694	$3.364	$354,271	$940,566
Jan	190,145	1,410,470	$46,337	$1,100	$3,750	$26,740	$1,693	$200	$423	$80,242	2,821	1,413,291	$4.1780	$590,473	$1,107	$8,267	$599,846	$680,089	105,857	$0.670	$2.694	$3.364	$356,103	$1,036,192
Feb	163,146	1,267,020	$42,134	$1,100	$3,750	$26,740	$1,520	$200	$380	$75,824	2,534	1,269,554	$4.2010	$533,340	$1,035	$7,467	$541,841	$617,665	83,777	$0.670	$2.694	$3.364	$281,824	$899,490
Mar	101,930	1,020,053	$34,898	$1,100	$3,750	$26,740	$1,224	$200	$306	$68,218	2,040	1,022,093	$4.1700	$426,213	$911	$5,967	$433,091	$501,308	23,997	$0.670	$2.694	$3.364	$80,724	$582,033
Apr	97,184	1,112,165	$37,596	$1,100	$3,750	$0	$1,335	$200	$334	$44,315	2,224	1,114,389	$4.1670	$464,366	$957	$6,501	$471,824	$516,139	5,558	$0.670	$2.694	$3.364	$18,696	$534,835
May	93,298	1,110,594	$37,550	$1,100	$3,750	$0	$1,333	$200	$333	$44,266	2,221	1,112,815	$4.1875	$465,991	$956	$6,524	$473,472	$517,738	13	$0.670	$2.694	$3.364	$42	$517,780
Jun	60,082	810,024	$28,744	$1,100	$3,750	$0	$972	$200	$243	$35,009	1,620	811,644	$4.1870	$339,835	$806	$4,758	$345,399	$380,408	0	$0.670	$2.694	$3.364	$0	$380,408
Totals	1,272,042	12,387,964	$423,087	$13,200	$45,000	$133,700	$14,866	$2,378	$3,716	$635,947	24,776	12,412,740		$5,151,076	$11,006	$72,115	$5,234,197	$5,870,145	353,638				$1,189,637	$7,059,782
	Cost Per MMBtu =		$0.333	$0.010	$0.035	$0.105	$0.012	$0.002	$0.003	$0.500				$4.158	$0.009	$0.001	$4.225	$4.739						

Note 1: Differential Costs Based on $1,055,413/1,575,877 MMBtu = $0.670/MMBtu

(Differential Costs Based on Burning 1,575,877 MMBtu of coal in FY 2010/2011)

Table A9.1.2.3: Baseload Boiler No. 7, Remaining Load Coal Fired, No Staff Reductions (Continued)

Costs of Operation for FY 2011/2012 Operating on 90% Coal and 10% Natural Gas

			Vectren Charges (LDC)									Energy USA Charges								Coal and Differential Costs				
Month FY 11/12	Total Steam Consumption (MMBtu)	Natural Gas Use (therms)	Throughput Charges	Customer Facilities Charge (CFC)	Capacity Reservation Charge (CRC)	Delivery Reservation Charge (DRC)	Pipeline Safety Adjustment Charge (PSAC)	Universal Service Fund Charge (USFC)	Gas Cost Adjustment (GCA)	Total Vectren Charges	Vectren Line Loss (0.2% of therms used)	Energy USA Therms	Energy USA Citygate Price/MMBtu	Total Commodity Cost	Mgmt. Fees	Indiana Utilities Receipts Tax	Total Energy USA Charges	Total Natural Gas Cost	MMBtu Coal Required	Differential Costs per MMBtu[Note 1]	Coal Costs per MMBtu	Total Coal + Differential Cost per MMBtu	Coal and Differential Costs	Total Cost of Coal and Natural Gas Required
Jul	50,062	59,597	$3,222	$1,100	$3,750	$0	$72	$18	$18	$8,180	119	59,716	$4.5520	$27,183	$269	$381	$27,832	$36,012	66,552	$0.670	$2.694	$3.364	$223,880	$259,892
Aug	55,776	66,400	$3,522	$1,100	$3,750	$0	$80	$20	$20	$8,491	133	66,533	$4.5800	$30,472	$299	$427	$31,198	$39,689	74,148	$0.670	$2.694	$3.364	$249,434	$289,123
Sep	70,453	83,872	$4,290	$1,100	$3,750	$0	$101	$25	$25	$9,291	168	84,040	$4.0870	$34,347	$378	$481	$35,206	$44,498	93,660	$0.670	$2.694	$3.364	$315,071	$359,568
Oct	92,334	109,921	$5,437	$1,100	$3,750	$0	$132	$33	$33	$10,484	220	110,141	$4.0090	$44,156	$455	$618	$45,229	$55,713	122,748	$0.670	$2.694	$3.364	$412,925	$468,639
Nov	122,916	146,329	$7,038	$1,100	$3,750	$26,740	$176	$44	$44	$38,892	293	146,622	$3.7940	$55,628	$473	$779	$56,880	$95,772	163,404	$0.670	$2.694	$3.364	$549,692	$645,464
Dec	174,715	207,994	$9,752	$1,100	$3,750	$26,740	$250	$62	$62	$41,716	416	208,410	$4.0815	$85,063	$504	$1,191	$86,758	$128,474	232,265	$0.670	$2.694	$3.364	$781,341	$909,815
Jan	190,145	226,363	$10,560	$1,100	$3,750	$26,740	$272	$68	$68	$42,557	453	226,815	$4.1780	$94,763	$513	$1,327	$96,604	$139,161	252,777	$0.670	$2.694	$3.364	$850,343	$989,504
Feb	163,146	194,222	$9,146	$1,100	$3,750	$26,740	$233	$58	$58	$41,085	388	194,610	$4.2010	$81,756	$497	$1,145	$83,398	$124,483	216,886	$0.670	$2.694	$3.364	$729,604	$854,087
Mar	101,930	121,345	$5,939	$1,100	$3,750	$26,740	$146	$36	$36	$37,748	243	121,588	$4.1700	$50,702	$461	$710	$51,873	$89,620	135,505	$0.670	$2.694	$3.364	$455,840	$545,460
Apr	97,184	115,696	$5,691	$1,100	$3,750	$0	$139	$35	$35	$10,749	231	115,927	$4.1670	$48,307	$458	$676	$49,441	$60,190	129,196	$0.670	$2.694	$3.364	$434,616	$494,806
May	93,298	111,070	$5,487	$1,100	$3,750	$0	$133	$33	$33	$10,537	222	111,292	$4.1875	$46,603	$456	$652	$47,711	$58,248	124,030	$0.670	$2.694	$3.364	$417,238	$475,487
Jun	60,082	81,002	$4,164	$1,100	$3,750	$0	$97	$24	$24	$9,160	162	81,164	$4.1870	$33,984	$365	$476	$34,825	$43,984	79,873	$0.670	$2.694	$3.364	$268,691	$312,676
Totals	1,272,042	1,523,812	$74,248	$13,200	$45,000	$133,700	$1,829	$457	$457	$268,891	3,048	1,526,859		$632,964	$5,129	$8,861	$646,955	$915,845	1,691,045				$5,688,675	$6,604,520
	Cost Per MMBtu =		$0.584	$0.104	$0.354	$1.051	$0.014	$0.004	$0.004	$1.765				$4.154	$0.034	$0.001	$4.246	$6.010						

Note 1: Differential Costs Based on $1,055,413/1,575,877 MMBtu = $0.670/MMBtu

(Differential Costs Based on Burning 1,575,877 MMBtu of coal in FY 2010/2011)

Table A9.1.2.4: 50% Of Annual Load on Boiler 7, Remaining Load on Coal Boilers, No Staff Reductions

Option E: 50% Load on Boiler No. 7, Remaining 50% Load on Coal, No Staff Reductions

Cost Premium for 50% Natural Gas gand 50% Coal Firing in FY 2011/2012

Total Costs for 50% Natural Gas / 50% Coal Operation FY 11/12 =	**$6,876,360**
Total Costs for 90% Coal/10% Natural Gas Operation FY 11/12 =	**$6,604,520**
Total Additional Cost for FY 11/12 to Burn 100% Natural Gas =	**$271,840**

Energy USA Citygate Price = NYMEX Monthly Settlement Price + Vectren North NEC Basis (Historical Summary through November, Futures for Remainder of FY 11/12)
Displays Natural Gas Charges for Heat Necessary to Produce all the Steam that was Generated with the Existing Natural Gas Boilers
Rates Applicable for Energy USA Costs FY 11/12 Only

Costs of Operation for FY 2011/2012 Operating on 50% Natural Gas and 50% Coal with Existing Boilers and No Staff Changes

			Vectren Charges (LDC)									Energy USA Charges								Coal and Differential Costs				
Month FY 11/12	**Total Steam Consumption (MMBtu)**	**Natural Gas Use (therms)**	**Throughput Charges**	**Customer Facilities Charge (CFC)**	**Capacity Reservation Charge (CRC)**	**Delivery Reservation Charge (DRC)**	**Pipeline Safety Adjustment Charge (PSAC)**	**Universal Service Fund Charge (USFC)**	**Gas Cost Adjustment (GCA)**	**Total Vectren Charges**	**Vectren Line Loss (0.2% of therms used)**	**Energy USA Therms**	**Energy USA Citygate Price /MMBtu**	**Total Commodity Cost**	**Mgmt. Fees**	**Indiana Utilities Receipts Tax**	**Total Energy USA Charges**	**Total Natural Gas Cost**	**MMBtu Coal Required**	**Differential Costs per MMBtu Note 1**	**Coal Costs per MMBtu**	**Total Coal + Differential Cost per MMBtu**	**Coal and Differential Costs**	**Total Cost of Coal and Natural Gas Required**
Jul	50,062	560,343	$21,428	$1,100	$3,750	$0	$672	$168	$168	$27,287	1,121	561,463	$4.5520	$255,578	$681	$3,578	$259,837	$287,124	4,421	$0.670	$2.694	$3.364	$14,872	$301,995
Aug	55,776	623,864	$23,289	$1,100	$3,750	$0	$749	$187	$187	$29,262	1,248	625,112	$4.5800	$286,301	$713	$4,008	$291,022	$320,284	4,980	$0.670	$2.694	$3.364	$16,752	$337,036
Sep	70,453	660,070	$24,350	$1,100	$3,750	$0	$792	$198	$198	$30,388	1,320	661,391	$4.0870	$270,310	$731	$3,784	$274,825	$305,214	22,167	$0.670	$2.694	$3.364	$74,569	$379,783
Oct	92,334	610,624	$22,901	$1,100	$3,750	$0	$733	$183	$183	$28,850	1,221	611,845	$4.0090	$245,289	$706	$3,434	$249,429	$278,279	60,623	$0.670	$2.694	$3.364	$203,935	$482,214
Nov	122,916	665,491	$24,509	$1,100	$3,750	$26,740	$799	$200	$200	$57,297	1,331	666,822	$3.7940	$252,992	$733	$3,542	$257,268	$314,564	98,988	$0.670	$2.694	$3.364	$332,996	$647,561
Dec	174,715	582,601	$22,080	$1,100	$3,750	$26,740	$699	$175	$175	$54,719	1,165	583,766	$4.0815	$238,264	$692	$3,336	$242,292	$297,011	185,785	$0.670	$2.694	$3.364	$624,982	$921,993
Jan	190,145	673,284	$24,737	$1,100	$3,750	$26,740	$808	$200	$202	$57,537	1,347	674,631	$4.1780	$281,861	$737	$3,946	$286,544	$344,081	197,325	$0.670	$2.694	$3.364	$663,800	$1,007,881
Feb	163,146	614,842	$23,025	$1,100	$3,750	$26,740	$738	$184	$184	$55,722	1,230	616,072	$4.2010	$258,812	$708	$3,623	$263,143	$318,865	164,697	$0.670	$2.694	$3.364	$554,040	$872,904
Mar	101,930	531,636	$20,587	$1,100	$3,750	$26,740	$638	$159	$159	$53,134	1,063	532,699	$4.1700	$222,135	$666	$3,110	$225,912	$279,046	84,598	$0.670	$2.694	$3.364	$284,587	$563,633
Apr	97,184	724,953	$26,251	$1,100	$3,750	$0	$870	$200	$217	$32,389	1,450	726,403	$4.1670	$302,692	$763	$4,238	$307,693	$340,081	53,602	$0.670	$2.694	$3.364	$180,316	$520,397
May	93,298	864,749	$30,347	$1,100	$3,750	$0	$1,038	$200	$259	$36,694	1,729	866,479	$4.1875	$362,838	$833	$5,080	$368,751	$405,445	30,516	$0.670	$2.694	$3.364	$102,656	$508,102
Jun	60,082	607,218	$22,801	$1,100	$3,750	$0	$729	$182	$182	$28,744	1,214	608,432	$4.1870	$254,751	$704	$3,567	$259,021	$287,766	13,406	$0.670	$2.694	$3.364	$45,096	$332,862
Totals	1,272,042	7,719,674	$286,306	$13,200	$45,000	$133,700	$9,264	$2,237	$2,316	$492,023	15,439	7,735,114		$3,231,823	$8,668	$45,246	$3,285,736	$3,777,759	921,106				$3,098,601	$6,876,360
	Cost Per MMBtu =		$0.225	$0.010	$0.035	$0.105	$0.007	$0.002	$0.002	$0.387				$4.186	$0.011	$0.001	$4.256	$4.894						

Note 1: Differential Costs Based on $1,055,413/1,575,877 MMBtu = $0.670/MMBtu
(Differential Costs Based on Burning 1,575,877 MMBtu of coal in FY 2010/2011)

Table A9.2.2.3: Steam Distribution System – Piping Repair Priority Ordered by Payback

Costs of Operation for FY 2011/2012 Operating on 90% Coal and 10% Natural Gas

			Vectren Charges (LDC)									Energy USA Charges								Coal and Differential Costs				
Month FY 11/12	**Total Steam Consumption (MMBtu)**	**Natural Gas Use (therms)**	**Throughput Charges**	**Customer Facilities Charge (CFC)**	**Capacity Reservation Charge (CRC)**	**Delivery Reservation Charge (DRC)**	**Pipeline Safety Adjustment Charge (PSAC)**	**Universal Service Fund Charge (USFC)**	**Gas Cost Adjustment (GCA)**	**Total Vectren Charges**	**Vectren Line Loss (0.2% of therms used)**	**Energy USA Therms**	**Energy USA Citygate Price/MMBtu**	**Total Commodity Cost**	**Mgmt. Fees**	**Indiana Utilities Receipts Tax**	**Total Energy USA Charges**	**Total Natural Gas Cost**	**MMBtu Coal Required**	**Differential Costs per MMBtu[Note 1]**	**Coal Costs per MMBtu**	**Total Coal + Differential Cost per MMBtu**	**Coal and Differential Costs**	**Total Cost of Coal and Natural Gas Required**
Jul	50,062	59,597	$3,222	$1,100	$3,750	$0	$72	$18	$18	$8,180	119	59,716	$4.5520	$27,183	$269	$381	$27,832	$36,012	66,552	$0.670	$2.694	$3.364	$223,880	$259,892
Aug	55,776	66,400	$3,522	$1,100	$3,750	$0	$80	$20	$20	$8,491	133	66,533	$4.5800	$30,472	$299	$427	$31,198	$39,689	74,148	$0.670	$2.694	$3.364	$249,434	$289,123
Sep	70,453	83,872	$4,290	$1,100	$3,750	$0	$101	$25	$25	$9,291	168	84,040	$4.0870	$34,347	$378	$481	$35,206	$44,498	93,660	$0.670	$2.694	$3.364	$315,071	$359,568
Oct	92,334	109,921	$5,437	$1,100	$3,750	$0	$132	$33	$33	$10,484	220	110,141	$4.0090	$44,156	$455	$618	$45,229	$55,713	122,748	$0.670	$2.694	$3.364	$412,925	$468,639
Nov	122,916	146,329	$7,038	$1,100	$3,750	$26,740	$176	$44	$44	$38,892	293	146,622	$3.7940	$55,628	$473	$779	$56,880	$95,772	163,404	$0.670	$2.694	$3.364	$549,692	$645,464
Dec	174,715	207,994	$9,752	$1,100	$3,750	$26,740	$250	$62	$62	$41,716	416	208,410	$4.0815	$85,063	$504	$1,191	$86,758	$128,474	232,265	$0.670	$2.694	$3.364	$781,341	$909,815
Jan	190,145	226,363	$10,560	$1,100	$3,750	$26,740	$272	$68	$68	$42,557	453	226,815	$4.1780	$94,763	$513	$1,327	$96,604	$139,161	252,777	$0.670	$2.694	$3.364	$850,343	$989,504
Feb	163,146	194,222	$9,146	$1,100	$3,750	$26,740	$233	$58	$58	$41,085	388	194,610	$4.2010	$81,756	$497	$1,145	$83,398	$124,483	216,886	$0.670	$2.694	$3.364	$729,604	$854,087
Mar	101,930	121,345	$5,939	$1,100	$3,750	$26,740	$146	$36	$36	$37,748	243	121,588	$4.1700	$50,702	$461	$710	$51,873	$89,620	135,505	$0.670	$2.694	$3.364	$455,840	$545,460
Apr	97,184	115,696	$5,691	$1,100	$3,750	$0	$139	$35	$35	$10,749	231	115,927	$4.1670	$48,307	$458	$676	$49,441	$60,190	129,196	$0.670	$2.694	$3.364	$434,616	$494,806
May	93,298	111,070	$5,487	$1,100	$3,750	$0	$133	$33	$33	$10,537	222	111,292	$4.1875	$46,603	$456	$652	$47,711	$58,248	124,030	$0.670	$2.694	$3.364	$417,238	$475,487
Jun	60,082	81,002	$4,164	$1,100	$3,750	$0	$97	$24	$24	$9,160	162	81,164	$4.1870	$33,984	$365	$476	$34,825	$43,984	79,873	$0.670	$2.694	$3.364	$268,691	$312,676
Totals	1,272,042	1,523,812	$74,248	$13,200	$45,000	$133,700	$1,829	$457	$457	$268,891	3,048	1,526,859		$632,964	$5,129	$8,861	$646,955	$915,845	1,691,045				$5,688,675	$6,604,520
	Cost Per MMBtu =		$7.640	$1.358	$4.630	$13.757	$0.188	$0.047	$0.047	$1.765				$4.154	$0.034	$0.001	$4.246	$6.010						

Note 1: Differential Costs Based on $1,055,413/1,575,877 MMBtu = $0.670/MMBtu
(Differential Costs Based on Burning 1,575,877 MMBtu of coal in FY 2010/2011)

Table A9.1.2.5: Assumptions for CHP Fuel Selection Calculation

Assumptions	Description of Assumption
1	**Baseline Assumptions** Fuel Use Based on Metered Steam Loads for FY 2010/2011 FY 2011/12 budget costs based on 90% Coal and 10% Natural Gas Other Natural Gas Boilers = 63.1% (Based on FY 09/10 Boiler No. 5)
2	**Boiler Efficiencies** Coal Boilers = 67.7% Natural Gas Boiler No. 7 = 84.0% Other Natural Gas Boilers = 63.1% (Based on FY 09/10 Boiler No. 5)
3	**Estimated Yearly Plant Operational Savings Using 100% Natural Gas** Wages and Fringes = $255,271 Maintenance and Repair = $350,000 Electrical Savings = $305,409 (4,779,484 kWh) Ash Disposal = $141,655 Coal Sampling = $7,622 Lime = $153,349 Carbon = $105,000 Stack Testing = $10,000 IDEM Emissions Fee=$90,000 **Total Savings = $1,418,306**
4	**Estimated Yearly Plant Operational Savings Using Some Natural Gas** Maintenance and Repair = $350,000 Electrical Savings = $305,409 Ash Disposal = $141,655 Lime = $153,349 Carbon = $105,000 **Total Savings = $1,055,413 (prorated based on 80% Gas / 20% coal)**
5	**Natural Gas Costs** Historical and future gas prices based on November 1, 2011 settlements FY 2011/12 Natural Gas Commodity Prices from Energy USA as City Gate Prices City Gate prices include NYMEX Commodity Charge and the Energy USA Basis Local Distribution Cost = Vectren Rate 260 Large Volume Transportation Service
6	**Coal Costs** 100% Coal Option analyzed at 90% coal and 10% natural gas For FY 09/10 = $62.24/ton, $2.616/MMBtu For FY 10/11 = $64.10/ton, $2.694/MMBtu

Table A9.1.2.5: Assumptions for CHP Fuel Selection Calculation (Continued)

Assumptions	Description of Assumption
7	**Boiler No. 7 Assumptions** Boiler peak capacity for continuous operation set a 150,000 lbs/hr vs. peak capacity rating of 180,000 lbs/hr; Two week boiler operation shut down for maintenance is assumed.
8	**New High Efficiency Boiler No. 8 Assumptions** Boiler peak capacity for continuous operation set a 120,000 lbs/hr vs. assumed capacity rating of 150,000 lbs/hr; Two week boiler operation shut down for maintenance is assumed. Installation requires demolition of existing boiler.
9	**New Gas Turbine and Heat Recovery Boiler Assumptions** 7.5 MW electric generation; 75,000 lbs/hr steam generation Could be located at CHP or remotely and connected to distribution systems

Table A9.2.1.1: Steam System Distribution Thermal Losses Per Unit Length – Very Moist Soil Conditions

40 psig System Losses

		Existing Piping Losses			Perma-Pipe Losses				
Steam Pipe Size (in)	**Condensate Pipe Size (in)**	**Steam Pipe Heat Loss (Btu/hr-ft)**	**Condensate Pipe Heat Loss (Btu/hr-ft)**	**Total Pipe Heat Loss (Btu/hr-ft)**	**Steam Pipe Heat Loss (Btu/hr-ft)**	**Condensate Pipe Heat Loss (Btu/hr-ft)**	**Total Pipe Heat Loss (Btu/hr-ft)**	**Total Heat Loss Savings (Btu/hr-ft)**	**Percentage of Original Loss**
14	6	1,073	428	1,501	93	30	123	1,378	8.2%
12	5	1,036	407	1,443	88	29	116	1,327	8.1%
10	4	975	384	1,359	78	25	103	1,256	7.6%
8	3	905	360	1,265	73	21	94	1,171	7.5%
6	2.5	834	343	1,177	59	21	80	1,097	6.8%
5	2	793	328	1,121	56	19	74	1,047	6.6%
4	2	748	328	1,076	49	19	68	1,008	6.4%
3	1.5	701	312	1,013	42	18	60	954	5.9%

150 psig System Losses

		Existing Piping Losses			Perma-Pipe Losses				
Steam Pipe Size (in)	**Condensate Pipe Size (in)**	**Steam Pipe Heat Loss (Btu/hr-ft)**	**Condensate Pipe Heat Loss (Btu/hr-ft)**	**Total Pipe Heat Loss (Btu/hr-ft)**	**Steam Pipe Heat Loss (Btu/hr-ft)**	**Condensate Pipe Heat Loss (Btu/hr-ft)**	**Total Pipe Heat Loss (Btu/hr-ft)**	**Total Heat Loss Savings (Btu/hr-ft)**	**Percentage of Original Loss**
14	6	1,265	428	1,693	109	30	139	1,554	8.2%
12	5	1,221	407	1,628	103	29	132	1,496	8.1%
10	4	1,149	384	1,533	92	25	117	1,416	7.7%
8	3	1,067	360	1,427	86	21	107	1,320	7.5%
6	2.5	984	343	1,327	70	21	91	1,236	6.8%
5	2	935	328	1,263	65	19	84	1,179	6.6%
4	2	882	328	1,210	58	19	77	1,133	6.4%
3	1.5	827	312	1,139	49	18	67	1,072	5.9%

Table A9.2.1.2: Steam System Distribution Thermal Losses Per Unit Length – Moist Soil Conditions

40 psig System Losses

		Existing Piping Losses			Perma-Pipe Losses				
Steam Pipe Size (in)	**Condensate Pipe Size (in)**	**Steam Pipe Heat Loss (Btu/hr-ft)**	**Condensate Pipe Heat Loss (Btu/hr-ft)**	**Total Pipe Heat Loss (Btu/hr-ft)**	**Steam Pipe Heat Loss (Btu/hr-ft)**	**Condensate Pipe Heat Loss (Btu/hr-ft)**	**Total Pipe Heat Loss (Btu/hr-ft)**	**Total Heat Loss Savings (Btu/hr-ft)**	**Percentage of Original Loss**
14	6	789	315	1,104	89	30	119	985	10.8%
12	5	762	299	1,061	86	28	114	947	10.7%
10	4	717	282	999	76	25	101	898	10.1%
8	3	666	265	931	71	21	92	838	9.9%
6	2.5	614	252	866	58	20	79	787	9.1%
5	2	583	241	824	55	18	73	751	8.8%
4	2	550	241	791	49	18	66	725	8.4%
3	1.5	516	230	746	41	18	59	687	7.9%

150 psig System Losses

		Existing Piping Losses			Perma-Pipe Losses				
Steam Pipe Size (in)	**Condensate Pipe Size (in)**	**Steam Pipe Heat Loss (Btu/hr-ft)**	**Condensate Pipe Heat Loss (Btu/hr-ft)**	**Total Pipe Heat Loss (Btu/hr-ft)**	**Steam Pipe Heat Loss (Btu/hr-ft)**	**Condensate Pipe Heat Loss (Btu/hr-ft)**	**Total Pipe Heat Loss (Btu/hr-ft)**	**Total Heat Loss Savings (Btu/hr-ft)**	**Percentage of Original Loss**
14	6	930	315	1,245	105	30	135	1,110	10.9%
12	5	898	299	1,197	101	28	129	1,068	10.8%
10	4	845	282	1,127	90	25	115	1,012	10.2%
8	3	785	265	1,050	84	21	105	945	10.0%
6	2.5	723	252	975	68	20	89	886	9.1%
5	2	688	241	929	64	18	83	846	8.9%
4	2	649	241	890	57	18	75	815	8.4%
3	1.5	608	230	838	48	18	66	772	7.9%

Table A9.2.1.3: Steam System Distribution Thermal Losses Per Unit Length – Average Soil Conditions

40 psig System Losses

		Existing Piping Losses			Perma-Pipe Losses				
Steam Pipe Size (in)	Condensate Pipe Size (in)	Steam Pipe Heat Loss (Btu/hr-ft)	Condensate Pipe Heat Loss (Btu/hr-ft)	Total Pipe Heat Loss (Btu/hr-ft)	Steam Pipe Heat Loss (Btu/hr-ft)	Condensate Pipe Heat Loss (Btu/hr-ft)	Total Pipe Heat Loss (Btu/hr-ft)	Total Heat Loss Savings (Btu/hr-ft)	Percentage of Original Loss
14	6	631	252	883	87	29	116	767	13.1%
12	5	609	240	849	84	28	111	738	13.1%
10	4	573	226	799	74	25	99	700	12.4%
8	3	533	212	745	70	21	91	654	12.2%
6	2.5	491	202	693	57	20	77	616	11.1%
5	2	467	193	660	54	18	72	588	10.9%
4	2	440	193	633	48	18	66	567	10.4%
3	1.5	413	184	597	40	17	57	539	9.6%

150 psig System Losses

		Existing Piping Losses			Perma-Pipe Losses				
Steam Pipe Size (in)	Condensate Pipe Size (in)	Steam Pipe Heat Loss (Btu/hr-ft)	Condensate Pipe Heat Loss (Btu/hr-ft)	Total Pipe Heat Loss (Btu/hr-ft)	Steam Pipe Heat Loss (Btu/hr-ft)	Condensate Pipe Heat Loss (Btu/hr-ft)	Total Pipe Heat Loss (Btu/hr-ft)	Total Heat Loss Savings (Btu/hr-ft)	Percentage of Original Loss
14	6	744	252	996	102	29	131	865	13.2%
12	5	718	240	958	99	28	126	832	13.2%
10	4	676	226	902	88	25	112	790	12.5%
8	3	628	212	840	83	21	103	737	12.3%
6	2.5	579	202	781	67	20	87	694	11.2%
5	2	550	193	743	63	18	81	662	11.0%
4	2	519	193	712	56	18	74	638	10.5%
3	1.5	486	184	670	48	17	65	605	9.6%

Table A9.2.1.4: Steam System Distribution Thermal Losses – Dry Soil Conditions

Buried 150 Psig Steam (HPS)				*Buried Condensate from HPS*			
Pipe Size (in)	**Length (ft)**	**Heat Loss (Btu/hr-ft)**	**Total Heat Loss (MBh)**	**Pipe Size (in)**	**Length (ft)**	**Heat Loss (Btu/hr-ft)**	**Total Heat Loss (MBh)**
2	481	222	107	1	317	85	27
3	529	243	129	1.5	349	92	32
4	1,886	259	489	2	1,245	97	120
5	600	275	165	2	396	97	38
6	1,317	289	381	2.5	869	101	88
8	5,103	314	1,602	3	3,368	106	357
10	3,818	338	1,290	4	2,520	113	285
12	2,012	359	723	5	1,328	120	159
14	604	372	225	6	399	126	50
	16,350		5,109		10,791		1,156
Buried 40 Psig Steam MPWS)				*Buried Condensate from MPS*			
2	451	188	85	1	298	85	25
3	441	206	91	1.5	291	92	27
4	2,204	220	485	2	1,455	97	140
5	2,739	233	639	2	1,808	97	175
6	3,029	245	743	2.5	1,999	101	202
8	5,451	266	1,452	3	3,598	106	381
10	4,426	287	1,269	4	2,921	113	330
12	878	305	267	5	579	120	69
14	14	316	4	6	9	116	1
16	0	333	0	6	0	126	0
20	881	365	322	8	581	137	79
24	0	400	0	10	0	147	0
	20,514		5,357		13,539		1,430

150 Psig Steam in New Perma-Pipe System				*Condensate from HPS in New Perma-Pipe System*			
Pipe Size (in)	**Length (ft)**	**Heat Loss (Btu/hr-ft)**	**Total Heat Loss (MBh)**	**Pipe Size (in)**	**Length (ft)**	**Heat Loss (Btu/hr-ft)**	**Total Heat Loss (MBh)**
8	2,263	77	174	3	2,263	23	52
4	185	56	10	2	185	19	4
	2,448		185		2,448		56
40 Psig Steam in Tunnels				*Condensate from MPS in Tunnels*			
2	0	66	0	1	0	25	0
3	0	93	0	1.5	0	25	0
4	0	108	0	2	0	25	0
5	0	132	0	2	0	25	0
6	45	156	7	2.5	45	31	1
8	65	137	9	3	65	36	2
10	5,038	159	801	4	5,038	41	207
12	2,618	186	487	5	2,618	48	126
14	1,535	216	332	6	1,535	64	98
16	4,410	246	1,085	6	4,410	64	282
20	0	298	0	8	0	72	0
24	88	357	31	10	88	90	8
	13,799		2,752		13,799		724

Total HPS/Condensate Piping Length =	32,037	ft	34%
Total HPS/Condensate Piping Heat Loss =	6,506	MBh	
Total HPS/Condensate Piping Heat Loss =	6,404	lbs/hr steam (@ 1,015.8 Btu/lb)	

Total MPS/Condensate Piping Length =	61,651	ft	66%
Total MPS/Condensate Piping Heat Loss =	10,263	MBh	
Total MPS/Condensate Piping Heat Loss =	10,132	lbs/hr steam (@ 1,013.0 Btu/lb)	

Total Piping Length =	**93,688**	**ft**
Total Piping Heat Loss =	**16,769**	**MBh**

Table A9.2.1.5: Steam System Distribution Thermal Losses – Average Soil Conditions

Buried 150 Psig Steam (HPS)

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
2	481	443	213
3	529	486	257
4	1,886	519	979
5	600	550	330
6	1,317	579	762
8	5,103	628	3,203
10	3,818	676	2,580
12	2,012	718	1,445
14	604	744	449
	16,350		10,219

Buried Condensate from HPS

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
1	317	170	54
1.5	349	184	64
2	1,245	193	240
2	396	193	76
2.5	869	202	175
3	3,368	212	713
4	2,520	226	569
5	1,328	240	318
6	399	252	100
	10,791		2,312

150 Psig Steam in New Perma-Pipe System

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
8	2,263	77	174
4	185	56	10
	2,448		185

Condensate from HPS in New Perma-Pipe System

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
3	2,263	23	52
2	185	19	4
	2,448		56

40 Psig Steam in Tunnels

2	0	66	0
3	0	93	0
4	0	108	0
5	0	132	0
6	45	156	7
8	65	137	9
10	5,038	159	801
12	2,618	186	487
14	1,535	216	332
16	4,410	246	1,085
20	0	298	0
24	88	357	31
	13,799		2,752

Condensate from MPS in Tunnels

1	0	25	0
1.5	0	25	0
2	0	25	0
2	0	25	0
2.5	45	31	1
3	65	36	2
4	5,038	41	207
5	2,618	48	126
6	1,535	64	98
6	4,410	64	282
8	0	72	0
10	88	90	8
	13,799		724

Buried 40 Psig Steam MPWS)

2	451	376	170
3	441	413	182
4	2,204	440	970
5	2,739	467	1,278
6	3,029	491	1,487
8	5,451	533	2,903
10	4,426	573	2,537
12	878	609	535
14	14	631	9
16	0	665	0
20	881	731	644
24	0	801	0
	20,514		10,715

Buried Condensate from MPS

1	298	170	51
1.5	291	184	53
2	1,455	193	281
2	1,808	193	349
2.5	1,999	202	404
3	3,598	212	762
4	2,921	226	660
5	579	240	139
6	9	116	1
6	0	252	0
8	581	273	159
10	0	294	0
	13,539		2,859

Total HPS/Condensate Piping Length =	32,037	ft	34%
Total HPS/Condensate Piping Heat Loss =	12,771	MBh	
Total HPS/Condensate Piping Heat Loss =	12,572	lbs/hr steam (@ 1,015.8 Btu/lb)	

Total MPS/Condensate Piping Length =	61,651	ft	66%
Total MPS/Condensate Piping Heat Loss =	17,049	MBh	
Total MPS/Condensate Piping Heat Loss =	16,831	lbs/hr steam (@ 1,013.0 Btu/lb)	

Total Piping Length =	**93,688**	**ft**
Total Piping Heat Loss =	**29,820**	**MBh**

Table A9.2.1.6: Steam System Distribution Thermal Losses – Moist Soil Conditions

Buried 150 Psig Steam (HPS)

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
2	481	554	267
3	529	608	322
4	1,886	649	1,223
5	600	688	413
6	1,317	723	952
8	5,103	785	4,004
10	3,818	845	3,225
12	2,012	898	1,806
14	604	930	562
	16,350		12,774

Buried Condensate from HPS

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
1	317	213	68
1.5	349	230	80
2	1,245	241	300
2	396	241	96
2.5	869	252	219
3	3,368	265	892
4	2,520	282	712
5	1,328	299	398
6	399	315	126
	10,791		2,890

150 Psig Steam in New Perma-Pipe System

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
8	2,263	77	174
4	185	56	10
	2,448		185

Condensate from HPS in New Perma-Pipe System

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
3	2,263	23	52
2	185	19	4
	2,448		56

40 Psig Steam in Tunnels

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
2	0	66	0
3	0	93	0
4	0	108	0
5	0	132	0
6	45	156	7
8	65	137	9
10	5,038	159	801
12	2,618	186	487
14	1,535	216	332
16	4,410	246	1,085
20	0	298	0
24	88	357	31
	13,799		2,752

Condensate from MPS in Tunnels

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
1	0	25	0
1.5	0	25	0
2	0	25	0
2	0	25	0
2.5	45	31	1
3	65	36	2
4	5,038	41	207
5	2,618	48	126
6	1,535	64	98
6	4,410	64	282
8	0	72	0
10	88	90	8
	13,799		724

Buried 40 Psig Steam MPWS)

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
2	451	470	212
3	441	516	227
4	2,204	550	1,213
5	2,739	583	1,598
6	3,029	614	1,858
8	5,451	666	3,629
10	4,426	717	3,172
12	878	762	669
14	14	789	11
16	0	831	0
20	881	913	805
24	0	1,001	0
	20,514		13,393

Buried Condensate from MPS

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
1	298	213	63
1.5	291	230	67
2	1,455	241	351
2	1,808	241	436
2.5	1,999	252	505
3	3,598	265	953
4	2,921	282	825
5	579	299	173
6	9	116	1
6	0	315	0
8	581	342	199
10	0	368	0
	13,539		3,573

Total HPS/Condensate Piping Length =	32,037	ft	34%
Total HPS/Condensate Piping Heat Loss =	15,904	MBh	
Total HPS/Condensate Piping Heat Loss =	15,656	lbs/hr steam (@ 1,015.8 Btu/lb)	

Total MPS/Condensate Piping Length =	61,651	ft	66%
Total MPS/Condensate Piping Heat Loss =	20,443	MBh	
Total MPS/Condensate Piping Heat Loss =	20,180	lbs/hr steam (@ 1,013.0 Btu/lb)	

Total Piping Length =	**93,688**	**ft**
Total Piping Heat Loss =	**36,346**	**MBh**

Table A9.2.2.1: Steam Distribution System – Piping Repair Energy Economics

Buried 150 Psig Steam (HPS)

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
2	481	754	363
3	529	827	437
4	1,886	882	1,664
5	600	935	561
6	1,317	984	1,295
8	5,103	1,067	5,446
10	3,818	1,149	4,386
12	2,012	1,221	2,457
14	604	1,265	764
	16,350		17,372

Buried Condensate from HPS

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
1	317	289	92
1.5	349	312	109
2	1,245	328	409
2	396	328	130
2.5	869	343	298
3	3,368	360	1,213
4	2,520	384	968
5	1,328	407	541
6	399	428	171
	10,791		3,930

Buried 40 Psig Steam MPWS)

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
2	451	640	288
3	441	701	309
4	2,204	748	1,650
5	2,739	793	2,173
6	3,029	834	2,527
8	5,451	905	4,935
10	4,426	975	4,313
12	878	1,036	909
14	14	1,073	15
16	0	1,131	0
20	881	1,242	1,094
24	0	1,361	0
	20,514		18,215

Buried Condensate from MPS

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
1	298	289	86
1.5	291	312	91
2	1,455	328	478
2	1,808	328	593
2.5	1,999	343	686
3	3,598	360	1,295
4	2,921	384	1,122
5	579	407	236
6	9	116	1
6	0	428	0
8	581	465	270
10	0	500	0
	13,539		4,859

150 Psig Steam in New Perma-Pipe System

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
8	2,263	77	174
4	185	56	10
	2,448		185

Condensate from HPS in New Perma-Pipe System

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
3	2,263	23	52
2	185	19	4
	2,448		56

40 Psig Steam in Tunnels

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
2	0	66	0
3	0	93	0
4	0	108	0
5	0	132	0
6	45	156	7
8	65	137	9
10	5,038	159	801
12	2,618	186	487
14	1,535	216	332
16	4,410	246	1,085
20	0	298	0
24	88	357	31
	13,799		2,752

Condensate from MPS in Tunnels

Pipe Size (in)	Length (ft)	Heat Loss (Btu/hr-ft)	Total Heat Loss (MBh)
1	0	25	0
1.5	0	25	0
2	0	25	0
2	0	25	0
2.5	45	31	1
3	65	36	2
4	5,038	41	207
5	2,618	48	126
6	1,535	64	98
6	4,410	64	282
8	0	72	0
10	88	90	8
	13,799		724

Total HPS/Condensate Piping Length = 32,037 ft 34%

Total HPS/Condensate Piping Heat Loss = 21,542 MBh

Total HPS/Condensate Piping Heat Loss = 21,207 lbs/hr steam (@ 1,015.8 Btu/lb)

Total MPS/Condensate Piping Length = 61,651 ft 66%

Total MPS/Condensate Piping Heat Loss = 26,550 MBh

Total MPS/Condensate Piping Heat Loss = 26,209 lbs/hr steam (@ 1,013.0 Btu/lb)

Total Piping Length = 93,688 ft

Total Piping Heat Loss = 48,093 MBh

Table A9.2.2.1: Steam Distribution System – Piping Repair Energy Economics

Economics with Very Moist Soil Conditions

(Credit Taken for Distribution Repairs and Condensate Losses from the System)

Pipe Run Number	Pipe Run	Age	Size (in)	Length (ft)	Steam Pressure (psig)	Heat Loss Savings per Unit Length (Btu/hr-ft)	Total Heat Loss Savings (Btu/hr)	Total Annual Heat Loss Savings (MMBtu)	Value of Heat Energy Saved	Replacement Construction Cost	Project Cost (with soft costs)	Payback Period (Years)	Funding	Condensate Return	Piping Location (Buried, Tunnel, ...)
1	Fee Lane (Law to 17th)	1959	8	1,760	150	1,320	2,323,200	20,351.2	$ 141,801	$ 1,232,000	$ 1,478,400	10.4			Buried
2	McNutt Services (2)	1963	4	255	150	1,133	288,915	2,530.9	$ 17,634	$ 127,500	$ 153,000	8.7	100% RPS		Buried
3	Alumni Building	1963	8	750	150	1,320	990,000	8,672.4	$ 60,426	$ 525,000	$ 630,000	10.4			Buried
4	Tennis Center	1987	4	775	150	1,133	878,075	7,691.9	$ 53,595	$ 387,500	$ 465,000	8.7		No	Buried
5	Foster Quad	1962	6	867	150	1,236	1,071,612	9,387.3	$ 65,408	$ 606,900	$ 728,280	11.1	100% RPS		Buried
6	CHP to Law Lane (+ PRV)	1955	14	550	150	1,554	854,700	7,487.2	$ 52,168	$ 385,000	$ 462,000	8.9			Buried
7	Woodlawn Dorms	1961	6	460	40	1,097	504,620	4,420.5	$ 30,800	$ 276,000	$ 331,200	10.8			Buried
8	Research Services	1978	3	300	40	954	286,200	2,507.1	$ 17,469	$ 150,000	$ 180,000	10.3			Buried
9	Fee Lane to Rec Sports	1962	12	2,200	150	1,496	3,291,200	28,830.9	$ 200,884	$ 1,540,000	$ 1,848,000	9.2			Buried
10	Campus View Apartments	1962	8	900	150	1,320	1,188,000	10,406.9	$ 72,512	$ 630,000	$ 756,000	10.4	100% RPS		Buried
11	Eigenmann	1968	4	550	150	1,133	623,150	5,458.8	$ 38,035	$ 275,000	$ 330,000	8.7			Buried
12	Tuliptree Manhole	1964	10	2,000	150	1,416	2,832,000	24,808.3	$ 172,856	$ 1,400,000	$ 1,680,000	9.7			Buried
13	Tuliptree	1965	6	220	150	1,236	271,920	2,382.0	$ 16,597	$ 132,000	$ 158,400	9.5			Buried
14	Tuliptree MH to Bypass	1964	10	150	150	1,416	212,400	1,860.6	$ 12,964	$ 105,000	$ 126,000	9.7			Buried
15	Bypass to Ctr MH	1964	10	600	150	1,416	849,600	7,442.5	$ 51,857	$ 420,000	$ 504,000	9.7			Buried
16	Ctr MH to E Buildings	1964	8	650	150	1,320	858,000	7,516.1	$ 52,370	$ 455,000	$ 546,000	10.4			Buried
17	Ctr MH to IIDC	1969	6	850	150	1,236	1,050,600	9,203.3	$ 64,125	$ 510,000	$ 612,000	9.5			Buried
18	Ctr MH to Smith Res.	1964	8	125	150	1,320	165,000	1,445.4	$ 10,071	$ 87,500	$ 105,000	10.4			Buried
19	Business/SPEA	1982	10	950	40	1,256	1,193,200	10,452.4	$ 72,829	$ 665,000	$ 798,000	11.0			Buried
20	Collins Dorms	1940	6	1,500	40	1,097	1,645,500	14,414.6	$ 100,436	$ 900,000	$ 1,080,000	10.8			Buried
21	HPER/Wildermuth	1961	12	100	40	1,327	132,700	1,162.5	$ 8,100	$ 70,000	$ 84,000	10.4			Buried
22	Fine Arts	1962	8	400	40	224	89,600	784.9	$ 5,469	$ 120,000	$ 144,000	26.3			In Building
23	FA to Auditorium/Lilly	1942	8	700	40	1,171	819,700	7,180.6	$ 50,032	$ 490,000	$ 588,000	11.8			Buried
24	Woodburn	1940	3	120	40	954	114,480	1,002.8	$ 6,987	$ 60,000	$ 72,000	10.3			Buried
25	Ballantine Hall	1959	8	200	40	1,171	234,200	2,051.6	$ 14,295	$ 140,000	$ 168,000	11.8			Buried
26	Presidents Tunnel Conn.	1959	10	375	40	1,256	471,000	4,126.0	$ 28,748	$ 262,500	$ 315,000	11.0			Buried
27	Wells Quad	1936	6	400	40	1,097	438,800	3,843.9	$ 26,783	$ 240,000	$ 288,000	10.8			Buried
28	Music Add. & Simon Lib.	1960	10	500	40	1,256	628,000	5,501.3	$ 38,331	$ 350,000	$ 420,000	11.0			Buried
29	Owen Hall	1937	8	100	40	1,171	117,100	1,025.8	$ 7,147	$ 70,000	$ 84,000	11.8			Buried
30	Dist. To Rowles (tunnel)	1937	10	1,100	40	266	292,600	2,563.2	$ 17,859	$ 440,000	$ 528,000	29.6			In Tunnel
31	Rowles to Swain (tunnel)	1937	10	600	40	266	159,600	1,398.1	$ 9,741	$ 240,000	$ 288,000	29.6			In Tunnel
32	Meyers Hall	1937	10	350	40	1,174	410,900	3,599.5	$ 25,080	$ 245,000	$ 294,000	11.7			Buried
33	Chemistry	1931	10	100	40	1,175	117,500	1,029.3	$ 7,172	$ 70,000	$ 84,000	11.7			Buried
34	Wells Library	1969	12	175	40	1,176	205,800	1,802.8	$ 12,561	$ 122,500	$ 147,000	11.7			Buried
35	North Campbell St.	1949	10	750	40	1,177	882,750	7,732.9	$ 53,880	$ 525,000	$ 630,000	11.7			Buried
36	Weatherly Hall	1956	4	550	40	1,178	647,900	5,675.6	$ 39,546	$ 275,000	$ 330,000	8.3			Buried
37	Old Ashton	1962	6	745	40	1,179	878,355	7,694.4	$ 53,612	$ 447,000	$ 536,400	10.0			Buried
38	International Center	1985	4	180	40	1,180	212,400	1,860.6	$ 12,964	$ 108,000	$ 129,600	10.0			Buried
39	Read Hall	1953	8	160	40	1,181	188,960	1,655.3	$ 11,534	$ 96,000	$ 115,200	10.0			Buried
40	Kirkwood Observatory	1985	2	75	40	1,182	88,650	776.6	$ 5,411	$ 45,000	$ 54,000	10.0			Buried
		-	-	**24,092**	-	-	**28,508,887**	**249,738**	**1,740,089**	**$ 15,225,400**	**$ 18,270,480**	**10.5**			
				feet			**29,177**								
				(4.5 miles)			**lbs/hr**								

Assumptions: Piping Replacement Cost at $700/ft >=8"; $600/ft=6"; $500<=4"; except for pipe in tunnels
Marginal Cost of steam at $5.368/MMBtu with credit for 33% of Maintenance and Repair for the Distribution System
Soil Heat Transfer Condition Assumed to be Very Moist
Condensate Losses evenly distributed by load to the piping sections indicated above

Table A9.2.2.2: Steam Distribution System – Piping Repair Ordered by Payback

Economics with Very Moist Soil Conditions

(Credit Taken for Distribution Repairs and Condensate Losses from the System)

Pipe Run Number	Pipe Run	Age	Size (in)	Length (ft)	Steam Pressure (psig)	Heat Loss Savings per Unit Length (Btu/hr-ft)	Total Heat Loss Savings (Btu/hr)	Total Annual Heat Loss Savings (MMBtu)	Value of Heat Energy Saved	Replacement Construction Cost	Project Cost (with soft costs)	Payback Period (Years)	Funding	Condensate Return	Piping Location (Buried, Tunnel, ...)
36	Weatherly Hall	1956	4	550	40	1,178	647,900	5,675.6	$ 39,546	$ 275,000	$ 330,000	8.3			Buried
4	Tennis Center	1987	4	775	150	1,133	878,075	7,691.9	$ 53,595	$ 387,500	$ 465,000	8.7		No	Buried
2	McNutt Services (2)	1963	4	255	150	1,133	288,915	2,530.9	$ 17,634	$ 127,500	$ 153,000	8.7	100% RPS		Buried
11	Eigenmann	1968	4	550	150	1,133	623,150	5,458.8	$ 38,035	$ 275,000	$ 330,000	8.7			Buried
6	CHP to Law Lane (+ PRV)	1955	14	550	150	1,554	854,700	7,487.2	$ 52,168	$ 385,000	$ 462,000	8.9			Buried
9	Fee Lane to Rec Sports	1962	12	2,200	150	1,496	3,291,200	28,830.9	$ 200,884	$ 1,540,000	$ 1,848,000	9.2			Buried
13	Tuliptree	1965	6	220	150	1,236	271,920	2,382.0	$ 16,597	$ 132,000	$ 158,400	9.5			Buried
17	Ctr MH to IIDC	1969	6	850	150	1,236	1,050,600	9,203.3	$ 64,125	$ 510,000	$ 612,000	9.5			Buried
12	Tuliptree Manhole	1964	10	2,000	150	1,416	2,832,000	24,808.3	$ 172,856	$ 1,400,000	$ 1,680,000	9.7			Buried
14	Tuliptree MH to Bypass	1964	10	150	150	1,416	212,400	1,860.6	$ 12,964	$ 105,000	$ 126,000	9.7			Buried
15	Bypass to Ctr MH	1964	10	600	150	1,416	849,600	7,442.5	$ 51,857	$ 420,000	$ 504,000	9.7			Buried
40	Kirkwood Observatory	1985	2	75	40	1,182	88,650	776.6	$ 5,411	$ 45,000	$ 54,000	10.0			Buried
39	Read Hall	1953	8	160	40	1,181	188,960	1,655.3	$ 11,534	$ 96,000	$ 115,200	10.0			Buried
38	International Center	1985	4	180	40	1,180	212,400	1,860.6	$ 12,964	$ 108,000	$ 129,600	10.0			Buried
37	Old Ashton	1962	6	745	40	1,179	878,355	7,694.4	$ 53,612	$ 447,000	$ 536,400	10.0			Buried
8	Research Services	1978	3	300	40	954	286,200	2,507.1	$ 17,469	$ 150,000	$ 180,000	10.3			Buried
24	Woodburn	1940	3	120	40	954	114,480	1,002.8	$ 6,987	$ 60,000	$ 72,000	10.3			Buried
21	HPER/Wildermuth	1961	12	100	40	1,327	132,700	1,162.5	$ 8,100	$ 70,000	$ 84,000	10.4			Buried
18	Ctr MH to Smith Res.	1964	8	125	150	1,320	165,000	1,445.4	$ 10,071	$ 87,500	$ 105,000	10.4			Buried
1	Fee Lane (Law to 17th)	1959	8	1,760	150	1,320	2,323,200	20,351.2	$ 141,801	$ 1,232,000	$ 1,478,400	10.4			Buried
3	Alumni Building	1963	8	750	150	1,320	990,000	8,672.4	$ 60,426	$ 525,000	$ 630,000	10.4			Buried
10	Campus View Apartments	1962	8	900	150	1,320	1,188,000	10,406.9	$ 72,512	$ 630,000	$ 756,000	10.4	100% RPS		Buried
16	Ctr MH to E Buildings	1964	8	650	150	1,320	858,000	7,516.1	$ 52,370	$ 455,000	$ 546,000	10.4			Buried
7	Woodlawn Dorms	1961	6	460	40	1,097	504,620	4,420.5	$ 30,800	$ 276,000	$ 331,200	10.8			Buried
27	Wells Quad	1936	6	400	40	1,097	438,800	3,843.9	$ 26,783	$ 240,000	$ 288,000	10.8			Buried
20	Collins Dorms	1940	6	1,500	40	1,097	1,645,500	14,414.6	$ 100,436	$ 900,000	$ 1,080,000	10.8			Buried
19	Business/SPEA	1982	10	950	40	1,256	1,193,200	10,452.4	$ 72,829	$ 665,000	$ 798,000	11.0			Buried
26	Presidents Tunnel Conn.	1959	10	375	40	1,256	471,000	4,126.0	$ 28,748	$ 262,500	$ 315,000	11.0			Buried
28	Music Add. & Simon Lib.	1960	10	500	40	1,256	628,000	5,501.3	$ 38,331	$ 350,000	$ 420,000	11.0			Buried
5	Foster Quad	1962	6	867	150	1,236	1,071,612	9,387.3	$ 65,408	$ 606,900	$ 728,280	11.1	100% RPS		Buried
35	North Campbell St.	1949	10	750	40	1,177	882,750	7,732.9	$ 53,880	$ 525,000	$ 630,000	11.7			Buried
34	Wells Library	1969	12	175	40	1,176	205,800	1,802.8	$ 12,561	$ 122,500	$ 147,000	11.7			Buried
33	Chemistry	1931	10	100	40	1,175	117,500	1,029.3	$ 7,172	$ 70,000	$ 84,000	11.7			Buried
32	Meyers Hall	1937	10	350	40	1,174	410,900	3,599.5	$ 25,080	$ 245,000	$ 294,000	11.7			Buried
25	Ballantine Hall	1959	8	200	40	1,171	234,200	2,051.6	$ 14,295	$ 140,000	$ 168,000	11.8			Buried
29	Owen Hall	1937	8	100	40	1,171	117,100	1,025.8	$ 7,147	$ 70,000	$ 84,000	11.8			Buried
23	FA to Auditorium/Lilly	1942	8	700	40	1,171	819,700	7,180.6	$ 50,032	$ 490,000	$ 588,000	11.8			Buried
22	Fine Arts	1962	8	400	40	224	89,600	784.9	$ 5,469	$ 120,000	$ 144,000	26.3			In Building
30	Dist. To Rowles (tunnel)	1937	10	1,100	40	266	292,600	2,563.2	$ 17,859	$ 440,000	$ 528,000	29.6			In Tunnel
31	Rowles to Swain (tunnel)	1937	10	600	40	266	159,600	1,398.1	$ 9,741	$ 240,000	$ 288,000	29.6			In Tunnel
		-	-	**24,092** **feet** **(4.5 miles)**	-	-	**28,508,887** **29,177** **lbs/hr**	**249,738**	**$ 1,740,089**	**$ 15,225,400**	**$ 18,270,480**	**10.5**			

Assumptions: Piping Replacement Cost at $700/ft >=8"; $600/ft=6"; $500<=4"; except for pipe in tunnels
Marginal Cost of steam at $5.368/MMBtu with credit for 33% of Maintenance and Repair for the Distribution System
Soil Heat Transfer Condition Assumed to be Very Moist
Condensate Losses evenly distributed by load to the piping sections indicated above

Table A9.2.2.3: Steam Distribution System – Piping Repair Priority Ordered by Payback – Recommended Segments Only

Economics with Very Moist Soil Conditions After Deletions for Spaces on First Distributed Plant and Longer Payback Spaces

(Credit Taken for Distribution Repairs and Condensate Losses from the System)

Pipe Run Number	Pipe Run	Age	Size (in)	Length (ft)	Steam Pressure (psig)	Heat Loss Savings per Unit Length (Btu/hr-ft)	Total Heat Loss Savings (Btu/hr)	Total Annual Heat Loss Savings (MMBtu)	Value of Heat Energy Saved	Replacement Construction Cost	Project Cost (with soft costs)	Payback Period (Years)	Funding	Condensate Return	Piping Location (Buried, Tunnel, ...)
36	Weatherly Hall	1956	4	550	40	1,178	647,900	5,675.6	$ 39,546	$ 275,000	$ 330,000	8.3			Buried
2	McNutt Services (2)	1963	4	255	150	1,133	288,915	2,530.9	$ 17,634	$ 127,500	$ 153,000	8.7	100% RPS		Buried
11	Eigenmann	1968	4	550	150	1,133	623,150	5,458.8	$ 38,035	$ 275,000	$ 330,000	8.7			Buried
6	CHP to Law Lane (+ PRV)	1955	14	550	150	1,554	854,700	7,487.2	$ 52,168	$ 385,000	$ 462,000	8.9			Buried
40	Kirkwood Observatory	1985	2	75	40	1,182	88,650	776.6	$ 5,411	$ 45,000	$ 54,000	10.0			Buried
39	Read Hall	1953	8	160	40	1,181	188,960	1,655.3	$ 11,534	$ 96,000	$ 115,200	10.0			Buried
38	International Center	1985	4	180	40	1,180	212,400	1,860.6	$ 12,964	$ 108,000	$ 129,600	10.0			Buried
37	Old Ashton	1962	6	745	40	1,179	878,355	7,694.4	$ 53,612	$ 447,000	$ 536,400	10.0			Buried
8	Research Services	1978	3	300	40	954	286,200	2,507.1	$ 17,469	$ 150,000	$ 180,000	10.3			Buried
24	Woodburn	1940	3	120	40	954	114,480	1,002.8	$ 6,987	$ 60,000	$ 72,000	10.3			Buried
21	HPER/Wildermuth	1961	12	100	40	1,327	132,700	1,162.5	$ 8,100	$ 70,000	$ 84,000	10.4			Buried
1	Fee Lane (Law to 17th)	1959	8	1,760	150	1,320	2,323,200	20,351.2	$ 141,801	$ 1,232,000	$ 1,478,400	10.4			Buried
3	Alumni Building	1963	8	750	150	1,320	990,000	8,672.4	$ 60,426	$ 525,000	$ 630,000	10.4			Buried
7	Woodlawn Dorms	1961	6	460	40	1,097	504,620	4,420.5	$ 30,800	$ 276,000	$ 331,200	10.8			Buried
27	Wells Quad	1936	6	400	40	1,097	438,800	3,843.9	$ 26,783	$ 240,000	$ 288,000	10.8			Buried
20	Collins Dorms	1940	6	1,500	40	1,097	1,645,500	14,414.6	$ 100,436	$ 900,000	$ 1,080,000	10.8			Buried
19	Business/SPEA	1982	10	950	40	1,256	1,193,200	10,452.4	$ 72,829	$ 665,000	$ 798,000	11.0			Buried
26	Presidents Tunnel Conn.	1959	10	375	40	1,256	471,000	4,126.0	$ 28,748	$ 262,500	$ 315,000	11.0			Buried
28	Music Add. & Simon Lib.	1960	10	500	40	1,256	628,000	5,501.3	$ 38,331	$ 350,000	$ 420,000	11.0			Buried
5	Foster Quad	1962	6	867	150	1,236	1,071,612	9,387.3	$ 65,408	$ 606,900	$ 728,280	11.1	100% RPS		Buried
35	North Campbell St.	1949	10	750	40	1,177	882,750	7,732.9	$ 53,880	$ 525,000	$ 630,000	11.7			Buried
34	Wells Library	1969	12	175	40	1,176	205,800	1,802.8	$ 12,561	$ 122,500	$ 147,000	11.7			Buried
33	Chemistry	1931	10	100	40	1,175	117,500	1,029.3	$ 7,172	$ 70,000	$ 84,000	11.7			Buried
32	Meyers Hall	1937	10	350	40	1,174	410,900	3,599.5	$ 25,080	$ 245,000	$ 294,000	11.7			Buried
25	Ballantine Hall	1959	8	200	40	1,171	234,200	2,051.6	$ 14,295	$ 140,000	$ 168,000	11.8			Buried
29	Owen Hall	1937	8	100	40	1,171	117,100	1,025.8	$ 7,147	$ 70,000	$ 84,000	11.8			Buried
23	FA to Auditorium/Lilly	1942	8	700	40	1,171	819,700	7,180.6	$ 50,032	$ 490,000	$ 588,000	11.8			Buried
		-	-	**13,522**	-	-	**16,370,292**	**143,404**	**$ 999,189**	**$ 8,758,400**	**$ 10,510,080**	**10.5**			
				feet			**16,754**								
				2.6			**lbs/hr**								
				Miles											

Assumptions: Piping Replacement Cost at $700/ft >=8"; $600/ft=6"; $500<=4"; except for pipe in tunnels
Marginal Cost of steam at $5.368/MMBtu with credit for 33% of Maintenance and Repair for the Distribution System
Soil Heat Transfer Condition Assumed to be Very Moist
Condensate Losses evenly distributed by load to the piping sections indicated above

Table A9.4.2.1: Cogeneration Options – BASE CASE

Base Case - Existing Conditions - 90% Coal/10% Natural Gas
NPV of Current Power Plant Operation
Steam Production = 1,272,042 MMBtu/yr

Year	Total Annual Steam Production (MMBtu)	Coal Use (MMBtu/yr)	Coal Unit Cost ($/MMBtu)	Coal Cost	Natural Gas Use (MMBtu/yr)	Natural Gas Unit Cost ($/MMBtu)	Natural Gas Cost	Electrical Cost	Labor Cost	M&R Costs	Net Annual Cost
Initial Cost			$0.00	$0							$0
1	1,272,042	1,691,045	$2.69	$4,555,675	152,381	$6	$915,811	$305,409	$255,271	$961,278	$6,993,444
2	1,272,042	1,691,045	$2.79	$4,710,568	152,381	$6	$968,012	$320,191	$265,482	$1,021,839	$7,286,092
3	1,272,042	1,691,045	$2.88	$4,870,728	152,381	$7	$1,023,189	$335,688	$276,101	$1,086,214	$7,591,920
4	1,272,042	1,691,045	$2.98	$5,036,332	152,381	$7	$1,081,511	$351,935	$287,145	$1,154,646	$7,911,569
5	1,272,042	1,691,045	$3.08	$5,207,568	152,381	$8	$1,143,157	$368,969	$298,631	$1,227,389	$8,245,713
6	1,272,042	1,691,045	$3.18	$5,384,625	152,381	$8	$1,208,317	$386,827	$310,576	$1,304,714	$8,595,059
7	1,272,042	1,691,045	$3.29	$5,567,702	152,381	$8	$1,277,191	$405,550	$322,999	$1,386,911	$8,960,353
8	1,272,042	1,691,045	$3.40	$5,757,004	152,381	$9	$1,349,991	$425,178	$335,919	$1,474,286	$9,342,378
9	1,272,042	1,691,045	$3.52	$5,952,742	152,381	$9	$1,426,940	$445,757	$349,356	$1,567,166	$9,741,961
10	1,272,042	1,691,045	$3.64	$6,155,135	152,381	$10	$1,508,276	$467,331	$363,330	$1,665,898	$10,159,971
11	1,272,042	1,691,045	$3.76	$6,364,410	152,381	$10	$1,594,247	$489,950	$377,863	$1,770,849	$10,597,321
12	1,272,042	1,691,045	$3.89	$6,580,800	152,381	$11	$1,685,120	$513,664	$392,978	$1,882,413	$11,054,974
13	1,272,042	1,691,045	$4.02	$6,804,547	152,381	$12	$1,781,171	$538,525	$408,697	$2,001,005	$11,533,946
14	1,272,042	1,691,045	$4.16	$7,035,902	152,381	$12	$1,882,698	$564,590	$425,045	$2,127,068	$12,035,303
15	1,272,042	1,691,045	$4.30	$7,275,122	152,381	$13	$1,990,012	$591,916	$442,047	$2,261,074	$12,560,171

Coal increases in cost by 3.40% per year
Electricity Increases at 4.84% per year
Natural Gas increases at 5.57% per year
Labor increases at 4.00% per year
Materials increase at 8.60% per Year; M&R then at average of Labor and Materials - 6.30% per year
University Interest Rate Target of 4.75%
Electrical premium for coal firing based on 4,698,604 kWh/yr

Total Cost =	**$142,610,174**
NPV =	**$96,812,185**
Carbon Dioxide Emissions =	**185,097 tons**
Savings from Base =	**0 tons**

Table A9.4.2.2: Cogeneration Options – Option A (100% Natural Gas Option with No Cogeneration)

NPV of 100% Natural Gas Option A - Existing Steam Boilers - With Staff Reductions
Steam Production = 1,272,042 MMBtu/yr

Year	Total Annual Steam Production (MMBtu)	Coal Use (MMBtu/yr)	Coal Unit Cost ($/MMBtu)	Coal Cost	Natural Gas Use (MMBtu/yr)	Natural Gas Unit Cost ($/MMBtu)	Natural Gas Cost	Electrical Cost	Labor Cost	M&R Costs	Net Annual Cost
Initial Cost											0
1	1,272,042	0	$2.69	$0	1,618,214	$4.68	$7,579,716	$0	$0	$0	$7,579,716
2	1,272,042	0	$2.79	$0	1,618,214	$4.95	$8,011,760	$0	$0	$0	$8,011,760
3	1,272,042	0	$2.88	$0	1,618,214	$5.23	$8,468,430	$0	$0	$0	$8,468,430
4	1,272,042	0	$2.98	$0	1,618,214	$5.53	$8,951,130	$0	$0	$0	$8,951,130
5	1,272,042	0	$3.08	$0	1,618,214	$5.85	$9,461,345	$0	$0	$0	$9,461,345
6	1,272,042	0	$3.18	$0	1,618,214	$6.18	$10,000,641	$0	$0	$0	$10,000,641
7	1,272,042	0	$3.29	$0	1,618,214	$6.53	$10,570,678	$0	$0	$0	$10,570,678
8	1,272,042	0	$3.40	$0	1,618,214	$6.90	$11,173,207	$0	$0	$0	$11,173,207
9	1,272,042	0	$3.52	$0	1,618,214	$7.30	$11,810,079	$0	$0	$0	$11,810,079
10	1,272,042	0	$3.64	$0	1,618,214	$7.71	$12,483,254	$0	$0	$0	$12,483,254
11	1,272,042	0	$3.76	$0	1,618,214	$8.15	$13,194,799	$0	$0	$0	$13,194,799
12	1,272,042	0	$3.89	$0	1,618,214	$8.62	$13,946,903	$0	$0	$0	$13,946,903
13	1,272,042	0	$4.02	$0	1,618,214	$9.11	$14,741,877	$0	$0	$0	$14,741,877
14	1,272,042	0	$4.16	$0	1,618,214	$9.63	$15,582,163	$0	$0	$0	$15,582,163
15	1,272,042	0	$4.30	$0	1,618,214	$10.18	$16,470,347	$0	$0	$0	$16,470,347

Total Cost =	**$172,446,329**
NPV =	**$115,709,012**
Carbon Dioxide Emissions =	**95,313 tons**
Savings from Base =	**89,784 tons**

Table A9.4.2.3: Cogeneration Options – Option B (100% Natural Gas Option with No Cogeneration, High Efficiency Gas Boiler)

NPV of 100% Natural Gas Option B - With Addition of High Efficiency Boiler No. 8 - With Staff Reductions
Steam Production = 1,272,042 MMBtu/yr

Year	Total Annual Steam Production (MMBtu)	Coal Use (MMBtu/yr)	Coal Unit Cost ($/MMBtu)	Coal Cost	Natural Gas Use (MMBtu/yr)	Natural Gas Unit Cost ($/MMBtu)	Natural Gas Cost	Electrical Cost	Labor Cost	M&R Costs	Net Annual Cost
Initial Cost											$4,650,000
1	1,272,042	0	$2.69	$0	1,534,782	$4.68	$7,204,111	$0	$0	$0	$7,204,111
2	1,272,042	0	$2.79	$0	1,534,782	$4.95	$7,598,686	$0	$0	$0	$7,598,686
3	1,272,042	0	$2.88	$0	1,534,782	$5.23	$8,031,811	$0	$0	$0	$8,031,811
4	1,272,042	0	$2.98	$0	1,534,782	$5.53	$8,489,624	$0	$0	$0	$8,489,624
5	1,272,042	0	$3.08	$0	1,534,782	$5.85	$8,973,533	$0	$0	$0	$8,973,533
6	1,272,042	0	$3.18	$0	1,534,782	$6.18	$9,485,024	$0	$0	$0	$9,485,024
7	1,272,042	0	$3.29	$0	1,534,782	$6.53	$10,025,670	$0	$0	$0	$10,025,670
8	1,272,042	0	$3.40	$0	1,534,782	$6.90	$10,597,134	$0	$0	$0	$10,597,134
9	1,272,042	0	$3.52	$0	1,534,782	$7.30	$11,201,170	$0	$0	$0	$11,201,170
10	1,272,042	0	$3.64	$0	1,534,782	$7.71	$11,839,637	$0	$0	$0	$11,839,637
11	1,272,042	0	$3.76	$0	1,534,782	$8.15	$12,514,496	$0	$0	$0	$12,514,496
12	1,272,042	0	$3.89	$0	1,534,782	$8.62	$13,227,823	$0	$0	$0	$13,227,823
13	1,272,042	0	$4.02	$0	1,534,782	$9.11	$13,981,808	$0	$0	$0	$13,981,808
14	1,272,042	0	$4.16	$0	1,534,782	$9.63	$14,778,771	$0	$0	$0	$14,778,771
15	1,272,042	0	$4.30	$0	1,534,782	$10.18	$15,621,161	$0	$0	$0	$15,621,161

Total Cost = $168,220,460

NPV = $114,407,741

Carbon Dioxide Emissions = 90,399 tons

Savings from Base = 94,698 tons

Table A9.4.2.4: Cogeneration Options – Option C (80% Natural Gas Option with No Cogeneration)

NPV of 80% Natural Gas Option C Firing Boiler No. 7 for Base Load - Topping with Coal - Existing Boilers - No Staff Reductions
Steam Production = 1,272,042 MMBtu/yr

Year	Total Annual Steam Production (MMBtu)	Coal Use (MMBtu/yr)	Coal Unit Cost ($/MMBtu)	Coal Cost	Natural Gas Use (MMBtu/yr)	Natural Gas Unit Cost ($/MMBtu)	Natural Gas Cost	Electrical Cost	Labor Cost	M&R Costs	Cost of Coal and Differential Costs	Net Annual Cost
Initial Cost												$0
1	1,272,042	353,638	$2.69	$952,701	1,238,796	$4.74	$5,870,656	$63,868	$255,271	$168,306	$1,440,146	$7,310,802
2	1,272,042	353,638	$2.79	$985,093	1,238,796	$5.01	$6,205,284	$66,959	$265,482	$178,909	$1,496,443	$7,701,726
3	1,272,042	353,638	$2.88	$1,018,586	1,238,796	$5.29	$6,558,985	$70,200	$276,101	$190,181	$1,555,067	$8,114,052
4	1,272,042	353,638	$2.98	$1,053,218	1,238,796	$5.60	$6,932,847	$73,598	$287,145	$202,162	$1,616,122	$8,548,969
5	1,272,042	353,638	$3.08	$1,089,027	1,238,796	$5.92	$7,328,019	$77,160	$298,631	$214,898	$1,679,716	$9,007,735
6	1,272,042	353,638	$3.18	$1,126,054	1,238,796	$6.25	$7,745,716	$80,894	$310,576	$228,437	$1,745,961	$9,491,677
7	1,272,042	353,638	$3.29	$1,164,340	1,238,796	$6.61	$8,187,222	$84,810	$322,999	$242,828	$1,814,977	$10,002,199
8	1,272,042	353,638	$3.40	$1,203,927	1,238,796	$6.99	$8,653,894	$88,914	$335,919	$258,126	$1,886,887	$10,540,781
9	1,272,042	353,638	$3.52	$1,244,861	1,238,796	$7.38	$9,147,166	$93,218	$349,356	$274,388	$1,961,823	$11,108,989
10	1,272,042	353,638	$3.64	$1,287,186	1,238,796	$7.80	$9,668,554	$97,730	$363,330	$291,675	$2,039,921	$11,708,475
11	1,272,042	353,638	$3.76	$1,330,951	1,238,796	$8.25	$10,219,662	$102,460	$377,863	$310,050	$2,121,324	$12,340,986
12	1,272,042	353,638	$3.89	$1,376,203	1,238,796	$8.72	$10,802,182	$107,419	$392,978	$329,584	$2,206,183	$13,008,366
13	1,272,042	353,638	$4.02	$1,422,994	1,238,796	$9.22	$11,417,907	$112,618	$408,697	$350,347	$2,294,656	$13,712,563
14	1,272,042	353,638	$4.16	$1,471,376	1,238,796	$9.74	$12,068,727	$118,069	$425,045	$372,419	$2,386,908	$14,455,636
15	1,272,042	353,638	$4.30	$1,521,402	1,238,796	$10.30	$12,756,645	$123,783	$442,047	$395,882	$2,483,114	$15,239,759

Electrical Cost = $305,409 *(353,638/1,575,877) = $63,868

M&R Costs = 750,004*(353,638/1,575,877) = $168,306

Total Cost =	**$162,292,715**
NPV =	**$109,171,434**
Carbon Dioxide Emissions =	**109,796 tons**
Savings from Base =	**75,300 tons**

Table A9.4.2.5: Cogeneration Options – Gas Turbine Option 1 (Central Plant on 100% Natural Gas Option – Compare with Option A and Option B)

NPV of Turbine Option 1 with Turbine Generator and 75,000 lb/hr Heat Recovery Boiler - 100% Gas - With Staff Reductions
Steam Production = 1,272,042 MMBtu/yr

Year	Total Annual Steam Production Required (MMBtu)	Electrical Savings (kWh)	Unit Cost of Electricity ($/kWh)	Value of Electricity Saved	Natural Gas Use for Cogeneration (MMBtu/yr)	Natural Gas Use for Boilers (MMBtu/yr)	Total Natural Gas Use (MMBtu)	Natural Gas Unit Cost ($/MMBtu)	Natural Gas Cost	Labor Cost	Additional Labor Cost for Gas Tuirbine	Net Annual Cost
Initial Cost												$15,480,000
1	1,272,042	-61,690,986	$0.06	-$3,670,614	1,080,262	831,639	1,911,901	$4.67	$8,924,754	$0	$308,455	$5,562,595
2	1,272,042	-61,690,986	$0.06	-$3,848,271	1,080,262	831,639	1,911,901	$4.93	$9,433,464	$0	$320,793	$5,905,986
3	1,272,042	-61,690,986	$0.07	-$4,034,528	1,080,262	831,639	1,911,901	$5.22	$9,971,172	$0	$333,625	$6,270,269
4	1,272,042	-61,690,986	$0.07	-$4,229,799	1,080,262	831,639	1,911,901	$5.51	$10,539,529	$0	$346,970	$6,656,700
5	1,272,042	-61,690,986	$0.07	-$4,434,521	1,080,262	831,639	1,911,901	$5.83	$11,140,282	$0	$360,849	$7,066,610
6	1,272,042	-61,690,986	$0.08	-$4,649,152	1,080,262	831,639	1,911,901	$6.16	$11,775,278	$0	$375,283	$7,501,409
7	1,272,042	-61,690,986	$0.08	-$4,874,171	1,080,262	831,639	1,911,901	$6.51	$12,446,469	$0	$390,294	$7,962,592
8	1,272,042	-61,690,986	$0.08	-$5,110,081	1,080,262	831,639	1,911,901	$6.88	$13,155,918	$0	$405,906	$8,451,743
9	1,272,042	-61,690,986	$0.09	-$5,357,409	1,080,262	831,639	1,911,901	$7.27	$13,905,805	$0	$422,142	$8,970,538
10	1,272,042	-61,690,986	$0.09	-$5,616,707	1,080,262	831,639	1,911,901	$7.69	$14,698,436	$0	$439,028	$9,520,756
11	1,272,042	-61,690,986	$0.10	-$5,888,556	1,080,262	831,639	1,911,901	$8.13	$15,536,247	$0	$456,589	$10,104,279
12	1,272,042	-61,690,986	$0.10	-$6,173,562	1,080,262	831,639	1,911,901	$8.59	$16,421,813	$0	$474,852	$10,723,103
13	1,272,042	-61,690,986	$0.10	-$6,472,362	1,080,262	831,639	1,911,901	$9.08	$17,357,856	$0	$493,846	$11,379,340
14	1,272,042	-61,690,986	$0.11	-$6,785,625	1,080,262	831,639	1,911,901	$9.60	$18,347,254	$0	$513,600	$12,075,229
15	1,272,042	-61,690,986	$0.12	-$7,114,049	1,080,262	831,639	1,911,901	$10.14	$19,393,047	$0	$534,144	$12,813,142

Total Cost = $146,444,291
NPV = $103,044,406
Carbon Dioxide Emissions = 48,236 tons
Savings from Base = 136,860 tons

(Initial Cost for installation of gas turbine, duct heater, and heat recovery boiler) - (Value of 75,000 lb/hr boiler) =
$18,480,000 - $3,000,000 = $15,480,000

Table A9.4.2.6: Cogeneration Options – Gas Turbine Option 2 (Central Plant on Coal – Compare with Base Case)

NPV of Turbine Option 2 with Turbine Generator and 75,000 lb/hr Heat Recovery Boiler - Coal for Topping - Existing Boilers - With No Staff Reductions
Steam Production = 1,272,042 MMBtu/yr

Year	Total Annual Steam Production Required (MMBtu)	Electrical Savings (kWh)	Unit Cost of Electricity ($/kWh)	Value of Electricity Saved	Total Natural Gas Use for Cogeneration (MMBtu/yr)	Natural Gas Unit Cost ($/MMBtu)	Natural Gas Cost	Coal Use (MMBtu/yr)	Coal Unit Cost ($/MMBtu)	Coal Cost	Electrical Cost	Labor Cost	M&R Costs	Cost of Coal and Differential Costs	Additional Labor Cost for Gas Turbine	Net Annual Cost
Initial Cost																$15,480,000
1	1,272,042	-61,690,986	$0.06	-$3,670,614	1,080,262	$4.80	$5,187,750	994,278	$2.69	$2,678,584	$192,694	$255,271	$473,205	$3,599,754	$308,455	$5,425,345
2	1,272,042	-61,690,986	$0.06	-$3,848,271	1,080,262	$5.08	$5,483,451	994,278	$2.79	$2,769,656	$202,020	$265,482	$503,017	$3,740,175	$320,793	$5,696,149
3	1,272,042	-61,690,986	$0.07	-$4,034,528	1,080,262	$5.37	$5,796,008	994,278	$2.88	$2,863,825	$211,798	$276,101	$534,707	$3,886,431	$333,625	$5,981,536
4	1,272,042	-61,690,986	$0.07	-$4,229,799	1,080,262	$5.67	$6,126,380	994,278	$2.98	$2,961,195	$222,049	$287,145	$568,394	$4,038,782	$346,970	$6,282,334
5	1,272,042	-61,690,986	$0.07	-$4,434,521	1,080,262	$5.99	$6,475,584	994,278	$3.08	$3,061,875	$232,796	$298,631	$604,202	$4,197,505	$360,849	$6,599,417
6	1,272,042	-61,690,986	$0.08	-$4,649,152	1,080,262	$6.34	$6,844,692	994,278	$3.18	$3,165,979	$244,064	$310,576	$642,267	$4,362,886	$375,283	$6,933,709
7	1,272,042	-61,690,986	$0.08	-$4,874,171	1,080,262	$6.70	$7,234,840	994,278	$3.29	$3,273,622	$255,876	$322,999	$682,730	$4,535,228	$390,294	$7,286,191
8	1,272,042	-61,690,986	$0.08	-$5,110,081	1,080,262	$7.08	$7,647,226	994,278	$3.40	$3,384,925	$268,261	$335,919	$725,742	$4,714,847	$405,906	$7,657,898
9	1,272,042	-61,690,986	$0.09	-$5,357,409	1,080,262	$7.48	$8,083,118	994,278	$3.52	$3,500,013	$281,245	$349,356	$771,464	$4,902,077	$422,142	$8,049,928
10	1,272,042	-61,690,986	$0.09	-$5,616,707	1,080,262	$7.91	$8,543,855	994,278	$3.64	$3,619,013	$294,857	$363,330	$820,066	$5,097,266	$439,028	$8,463,442
11	1,272,042	-61,690,986	$0.10	-$5,888,556	1,080,262	$8.36	$9,030,855	994,278	$3.76	$3,742,060	$309,128	$377,863	$871,730	$5,300,781	$456,589	$8,899,669
12	1,272,042	-61,690,986	$0.10	-$6,173,562	1,080,262	$8.84	$9,545,614	994,278	$3.89	$3,869,290	$324,090	$392,978	$926,649	$5,513,006	$474,852	$9,359,911
13	1,272,042	-61,690,986	$0.10	-$6,472,362	1,080,262	$9.34	$10,089,714	994,278	$4.02	$4,000,846	$339,776	$408,697	$985,028	$5,734,346	$493,846	$9,845,544
14	1,272,042	-61,690,986	$0.11	-$6,785,625	1,080,262	$9.87	$10,664,828	994,278	$4.16	$4,136,874	$356,221	$425,045	$1,047,085	$5,965,225	$513,600	$10,358,028
15	1,272,042	-61,690,986	$0.12	-$7,114,049	1,080,262	$10.44	$11,272,723	994,278	$4.30	$4,277,528	$373,462	$442,047	$1,113,051	$6,206,088	$534,144	$10,898,906

Total Cost = **$133,218,007**
NPV = **$94,858,140**
Carbon Dioxide Emissions = **99,924 tons**
Savings from Base = **85,173 tons**

(Initial Cost for installation of gas turbine, duct heater, and heat recovery boiler) - (Value of 75,000 lb/hr boiler) =
$18,480,000 - $3,000,000 = $15,480,000

Table 10.3.1: Wind Energy Economic Analysis

Wind Farm Analysis

University Purchases Six Wind Turbine - Services Loan with Turbine Revenue

Subsidized by Tax Incentives

Performance Park Wind Farm

Six (6) 2 mW turbine

No. of Years	Year	Annual Assumptions			Annual Revenue			Annual Costs			Annual Cash Flow	Cumulative Cash Flow
		kWh Output	PPA Rate	REC Rate	PPA Revenue	REC Revenue	Subtotal	Financed Payment	O&M, Insurance and Repair	Subtotal		
	2010						0			0	0	0
1	2013	35,740,800	0.060	0.000	2,144,448	0	2,144,448	(1,843,328)	(480,000)	(2,323,328)	(178,880)	(178,880)
2	2014	35,740,800	0.062	0.000	2,208,781	0	2,208,781	(1,843,328)	(494,400)	(2,337,728)	(128,947)	(307,827)
3	2015	35,740,800	0.064	0.000	2,275,045	0	2,275,045	(1,843,328)	(509,232)	(2,352,560)	(77,515)	(385,342)
4	2016	35,740,800	0.066	0.000	2,343,296	0	2,343,296	(1,843,328)	(524,509)	(2,367,837)	(24,541)	(409,883)
5	2017	35,740,800	0.068	0.000	2,413,595	0	2,413,595	(1,843,328)	(540,244)	(2,383,572)	30,023	(379,860)
6	2018	35,740,800	0.070	0.000	2,486,003	0	2,486,003	(1,724,803)	(556,452)	(2,281,254)	204,749	(175,111)
7	2019	35,740,800	0.072	0.000	2,560,583	0	2,560,583	(1,724,803)	(573,145)	(2,297,948)	262,635	87,524
8	2020	35,740,800	0.074	0.000	2,637,401	0	2,637,401	(1,724,803)	(590,339)	(2,315,142)	322,259	409,783
9	2021	35,740,800	0.076	0.000	2,716,523	0	2,716,523	(1,724,803)	(608,050)	(2,332,852)	383,670	793,453
10	2022	35,740,800	0.078	0.000	2,798,018	0	2,798,018	(1,724,803)	(626,291)	(2,351,094)	446,925	1,240,378
11	2023	35,740,800	0.081	0.000	2,881,959	0	2,881,959	(1,724,803)	(645,080)	(2,369,882)	512,076	1,752,454
12	2024	35,740,800	0.083	0.000	2,968,418	0	2,968,418	(1,724,803)	(664,432)	(2,389,235)	579,183	2,331,637
13	2025	35,740,800	0.086	0.000	3,057,470	0	3,057,470	(1,724,803)	(684,365)	(2,409,168)	648,302	2,979,939
14	2026	35,740,800	0.088	0.000	3,149,194	0	3,149,194	(1,724,803)	(704,896)	(2,429,699)	719,495	3,699,434
15	2027	35,740,800	0.091	0.000	3,243,670	0	3,243,670	(1,724,803)	(726,043)	(2,450,846)	792,824	4,492,259
16	2028	35,740,800	0.093	0.000	3,340,980	0	3,340,980	(1,724,803)	(747,824)	(2,472,627)	868,353	5,360,612
17	2029	35,740,800	0.096	0.000	3,441,210	0	3,441,210	(1,724,803)	(770,259)	(2,495,062)	946,148	6,306,760
18	2030	35,740,800	0.099	0.000	3,544,446	0	3,544,446	(1,724,803)	(793,367)	(2,518,169)	1,026,276	7,333,036
19	2031	35,740,800	0.102	0.000	3,650,779	0	3,650,779	(1,724,803)	(817,168)	(2,541,970)	1,108,809	8,441,845
20	2032	35,740,800	0.105	0.000	3,760,303	0	3,760,303	(1,724,803)	(841,683)	(2,566,485)	1,193,817	9,635,662
21	2033	35,740,800	0.108	0.000	3,873,112	0	3,873,112	0	(866,933)	(866,933)	3,006,178	12,641,840
22	2034	35,740,800	0.112	0.000	3,989,305	0	3,989,305	0	(892,941)	(892,941)	3,096,364	15,738,204
23	2035	35,740,800	0.115	0.000	4,108,984	0	4,108,984	0	(919,730)	(919,730)	3,189,254	18,927,458
24	2036	35,740,800	0.118	0.000	4,232,254	0	4,232,254	0	(947,322)	(947,322)	3,284,932	22,212,390
25	2037	35,740,800	0.122	0.000	4,359,221	0	4,359,221	0	(975,741)	(975,741)	3,383,480	25,595,870
TOTALS		**893,520,000**			**78,184,996**	**0**	**78,184,996**	**(35,088,679)**	**(17,500,447)**	**(52,589,126)**	**25,595,870**	

COST ASSUMPTIONS:

1. Installed Cost:	$	26,191,210
2. ITC/1603 Cash Grant:	$	(5,048,382)
3. Net installed cost:	$	21,142,828
4. Grant assistance:	$	-
5. Total financed amount:	$	21,142,828
6. Land, O&M, Insurance, repairs:	$	480,000 (years 3 - 25)
7. Financing term:		20
8. Term of taxable financing		5
9. Term of tax exempt financing		15
10. Interest rate - taxable:		6.0%
11. Interest rate - tax exempt:		5.0%
12. Annual service cost inflation:		3.0%

PROJECT ASSUMPTIONS:

1. PSI selected through design build procurement method and constructs wind facility at proposal price
2. University pays PSI on a progress basis to construct wind facility from traditional bond.
3. University receives all wind turbine income years 1-25.
4. University makes annual payment in the amount of $1,843,328 years 1-5.
5. University makes annual payment in the amount of $1,724,803 years 6-20.
6. Bond payments made through revenue generated by turbine.

REVENUE ASSUMPTIONS:

1. Number of turbines:		6	
2. Rated output per turbine		2,000	kW
3. Total rated output for project:		12,000	kW
4. Estimated net capacity factor:		34.00%	
5. Estimated annual electric production		35,740,800	kWh
6. Power Purchase Agreement (PPA) rate:	$	0.060	/ kWh
7. Renewable Energy Credit REC) rate:	$	-	/ kWh
8. Annual PPA Rate increase:		3.00%	
9. Annual REC increase:		3.00%	

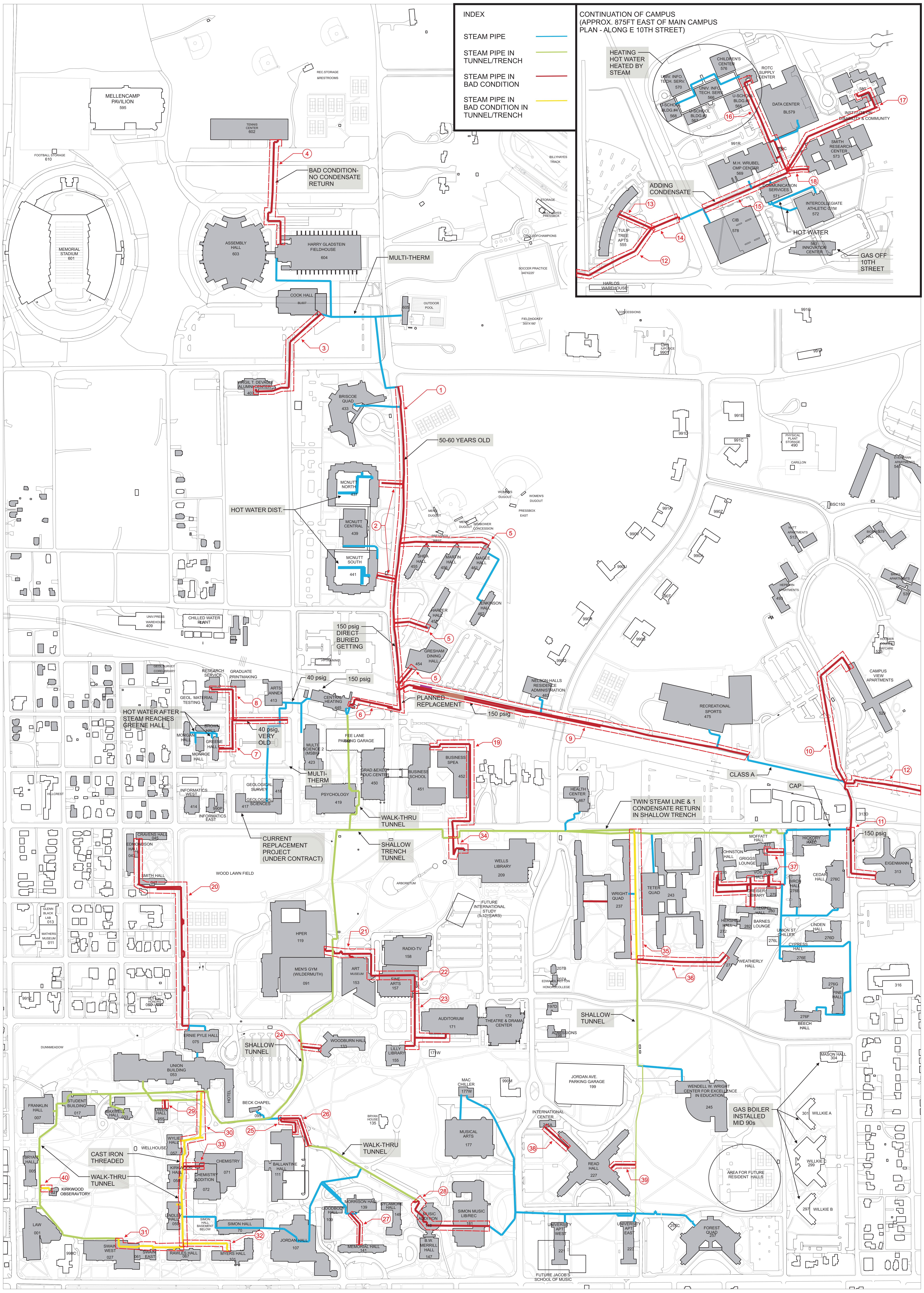
FINANCIAL PERFORMANCE:

1. Installed cost per turbine:	$	3,523,805
2. Net cash flow per turbine:	$	4,265,978
3. Internal Rate of Return:		8.9%

Information Provided By:	Performance Services Indianapolis, IN www.performanceservices.com

Appendix B
Drawings

Figure B9.2.2.1: Steam Distribution System – Piping Condition Assessment



Steam Layout

INDIANA UNIVERSITY

Integrated Energy Master Plan

8760 ENGINEERING

ENGINEERED EFFICIENCY EVERY HOUR

Figure B9.2.2.2: Proposed Distributed Thermal Plants

BRISCOE THERMAL PLANT

HEATING AND COOLING PLANT UTILIZING GROUND SOURCE HEAT EXCHANGER FIELD

DESCRIPTION: 1000 TON HEAT PUMP CHILLER TO PROVIDE SUMMER COOLING AND WINTER HEATING

DISTRIBUTION: ATTACH TO CAMPUS LOW TEMPERATURE HEATING WATER LOOP

CENTRAL CO-GENERATION PLANT

7500KW GENERATION AND 35000MBH OF HEATING. IN SHORT TERM, THIS PLANT WOULD PRODUCE STEAM TO SUPPLEMENT THE CENTRAL PLANT. INTHE LONG TERM, THIS PLANT WOULD SERVE AS THE BASE LOAD HEATING WATER PLANT FOR THE CAMPUS

DESCRIPTION: NATURAL GAS FIRED TURBINE GENERATOR WITH FLUE GAS HEAT RECOVERY. PLANT WOULD INTEGRATE WITH CENTRAL HEATING PLANT FEEDWATER SYSTEM

DISTRIBUTION: CONNECT TO CAMPUS THRU CENTRAL HEATING PLANT

BUILDING LEGEND

🟧	MASTER PLAN PROPOSED BUILDING
🟩	CAPITOL IMPROVEMENT RECOMMENDED
🟨	ON STEAM PLANT, HEATED BY HEATING WATER
🟦	ON STEAM PLANT, AHU'S AND TERMINAL UNITS HEATED BY STEAM

NORTH RESIDENTIAL THERMAL PLANT

IN CONJUCTION WITH CONVERSION OF ASSEMBLY HALL AND THE GLADSTEIN FIELDHOUSE TO HOT WATER HEAT, INSTALL HEATING WATER PLANT

DESCRIPTION: GAS FIRED LOW TEMPERATURE HEATING WATER PLANT.

DISTRIBUTION: UNDERGROUND PIPING TO ASSEMBLY HALL AND FIELDHOUSE, SHALLOW TUNNELS DOWN FEE LANE

RESEARCH PARK THERMAL PLANT

WITH THE PLANNED EXPANSION OF RESEARCH PARK, A THERMAL PLANT WOULD BE INSTALLED TO PROVIDE BOTH HEATING AND COOLING VIA HEAT PUMP CHILLERS AND GEOTHERMAL HEATING

DESCRIPTION: HEAT PUMP CHILLER, PROVIDE COOLING TO DATA CENTER AND SIMULTANEOUSLY HEAT RESEARCH PARK. ADDITIONAL HEAT AND COOLING REQUIRED WOULD BE PROVIDED THROUGH A GEOTHERMAL HEAT PUMP, AND HEAT SUPPLEMENTED BY INNOVATION CENTER BOILERS

DISTRIBUTION: SHALLOW TUNNELS INSTALLED BENEATH SIDEWALKS FOR PIPING DISTRIBUTION

SOUTHEAST QUADRANT THERMAL PLANT

AS PART OF THE MASTER PLAN RESIDENCE HALL EXPANSION, (AT THE FORMER LOCATION OF THE ASHTON CENTER). INSTALL SOUTHEAST QUADRANT THERMAL PLANT.

DESCRIPTION: GAS FIRED LOW TEMPERATURE HEATING WATER PLANT.

DISTRIBUTION: EXTEND SHALLOW TUNNEL TO SERVE EIGENMANN AND UNION STREET RESIDENCE HALLS

HISTORIC CORE THERMAL PLANT

AS PART OF THE MASTER PLAN ACADEMIC EXPANSION, OR CAPITAL IMPROVEMENT OF BALLANTINE, INSTALL HISTORIC CORE THERMAL PLANT.

DESCRIPTION: GAS FIRED LOW TEMPERATURE HEATING WATER PLANT.

DISTRIBUTION: HEATING WATER ROUTED THROUGH EXISTING SHALLOW TUNNEL (AS PRACTICAL) UNDERGROUND WHERE REQUIRED, TO ADJACENT BUILDINGS