CAMPUS WIDE

UTILITIES PRODUCTION AND DISTRIBUTION MASTER PLAN

UIUC PROJECT NO. – U11045

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Foreword

The attached Utility Master Plan document has been developed over the course of the past two years. Within this report, AEI has provided recommendations on how to most effectively meet the anticipated energy demands of the campus in an environmentally responsible manner.

While this effort was started and lead by the Facilities and Services Division, key campus stakeholders have played a critical role in the development and finalization of this report. This effort culminated in the attached report and recommendations, which were formally approved by the Chancellor’s Capital Review Committee on September 23, 2015.

It has been a pleasure to have participated in the development of this important plan, and the collective effort of all parties involved is greatly appreciated.

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1.0 Executive Summary

1.1 Overview

The University of Illinois Urbana Champaign Campus is critically dependent upon its utility systems for daily and ongoing operation. Responsibility for operation and maintenance of these systems resides with the Utilities and Energy Services Division. As such, it is incumbent upon this Division to periodically assess the condition of these assets, identify opportunities for optimization and establish plans for the future. Towards this end, an extensive Utility Master Plan was undertaken. The scope of this study includes generation and distribution of steam, electricity and chilled water over a 35-year timespan (present through 2050).

This Utility Master Plan is a major update of previous Master Plans. The sources used to define the “needs” of the U of I campus include the previous Utility Plans and studies, Illinois Climate Action Plan (iCAP), the Campus Master Plan, and historical energy usage data. University Facility and Services (F&S) also collaborated with university stakeholders to identify issues that needed to be taken into consideration while developing the Master Plan.

A broad array of viable options for satisfying energy needs over this timeframe are identified and evaluated. University stakeholders generated over 200 concepts ranging from individual building-level heating/cooling systems to central cogeneration of steam and electricity using various fuel types. Options for energy generation and delivery include wind, solar, geothermal, heat recovery chillers and even small scale nuclear. Consideration is given to energy production capacity, operability, reliability, adaptability, efficiency, environmental impact and economic viability. The analysis also considers the energy reduction and greenhouse gas reduction targets currently established by the Illinois Climate Action Plan (iCAP). Recommendations are developed for future direction, commitment, and action.

1.2 Utility Demands

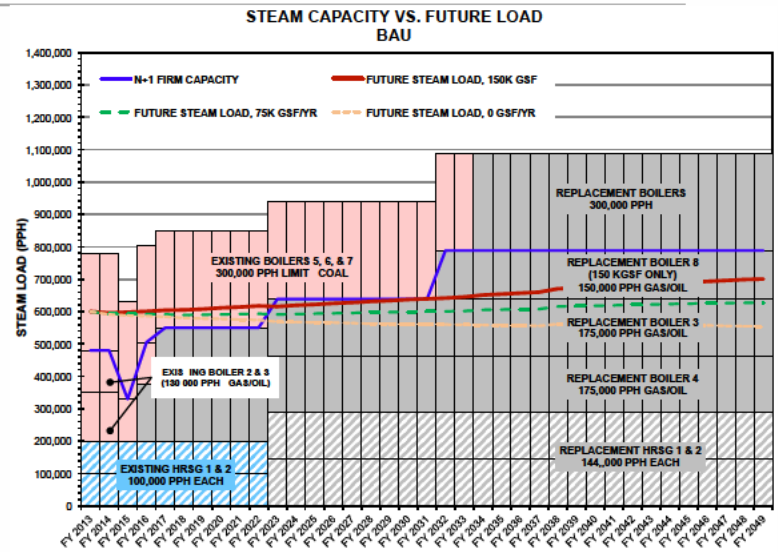
Since the founding of the University of Illinois in 1867, the Urbana-Champaign campus has grown to over 42,000 students and over 10,000 faculty and staff. The campus has more than 320 buildings on the main campus distributed over 2.8 square miles. Including smaller facilities and the south farms, the campus totals more than 660 buildings distributed over 7.1 square miles.

As the university grew, the utility demands of the campus increased to today’s current levels. In the face of such growth, the campus has successfully reduced its energy consumption trend through conservation and retrocommissioning initiatives. Energy consumption per square foot of conditioned space was reduced from 312.3 to 244.2 kBtu/GSF between 2007 and 2014. Continuing these efforts will further reduce campus energy consumption as well as demand.

An essential component of the Utility Master Plan is the projection of the anticipated future utility demand profiles for the campus. These demand profiles are critical to understanding and planning for the infrastructure required to meet these anticipated future utility loads.

The Utility Master Plan presents a forecast of future utility demands for:

- Steam
- Chilled water
- Electricity

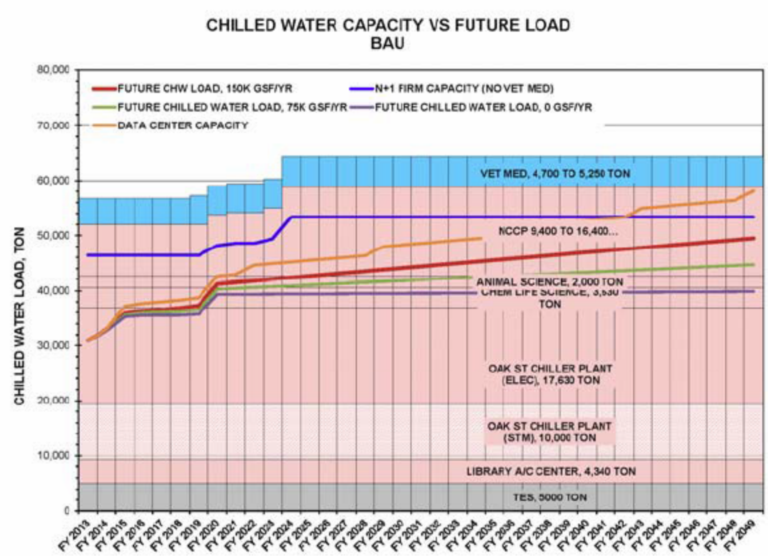


The utility demand forecasts are based on metered building consumption, scheduled building demolitions, anticipated future construction projects, and assumed data center growth. The campus has grown over the past 15 years at a rate close to 300,000 GSF/yr. Given the iCAP target of net zero GSF/yr growth, campus planning has identified three campus growth scenarios that are examined as part of the study.

- iCAP target of net zero gross square feet (GSF)
- Medium growth scenario of 75,000 GSF/yr
- High growth scenario of 150,000 GSF/yr

The campus target is net zero area growth and the medium and high growth scenarios indicate the effect of growth on campus utilities. The Master Plan also examines the impact of data center growth on campus utilities as illustrated in the plots of future load growth. The Data Center future capacity accounts for an additional 5 MW data center being added to campus every seven years.

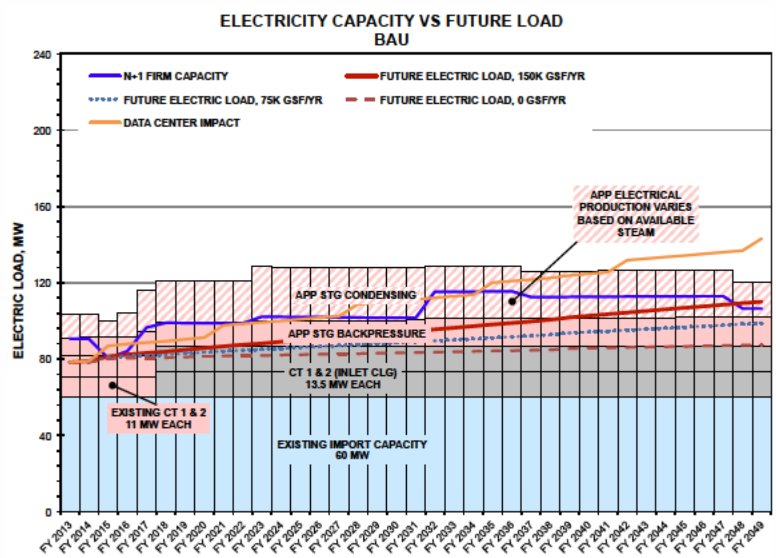
Campus growth has the single greatest impact on greenhouse gas emissions. The campus growth rate, to a high degree, impacts energy and carbon reduction strategies presented in the study. Thus, the campus community must identify an appropriate growth rate to support the campus mission and be committed to restricting expansion to these limits.



In addition to these "demand side" issues, limits will also come into play on the supply side of the utility systems. Regulations and air permitting will limit the allowable size of central plant(s). At some point, if growth is not limited, it will no longer be possible to simply "add one more" load to the system without substantial capital investment and new source air permitting.

1.3 Utility Systems Condition and Planning

Development of the Utility Master Plan requires a detailed condition assessment of existing utility production and distribution systems. Costs to repair, replace, operate and maintain the existing systems are included in the base case for this assessment.



The basic U of I utility infrastructure concept utilizing cogeneration was initiated in the 1940s. The initial cogeneration system incorporated a diversified fuel boiler plant where high pressure steam was expanded through turbine generators producing electricity while simultaneously producing reduced-pressure steam to satisfy campus heating loads. The steam based cogeneration system was expanded in 2003 to include two combustion turbines, two heat recovery steam generators, and an additional three steam turbine generators.

Abbott Power Plant (APP) generates approximately 275,000 megawatt hours (MWH) of electricity each year through the use of a high efficiency cogeneration process. The existing APP operation supplies approximately 50% of the total U of I campus electricity.

The present APP output utilizing the high efficiency cogeneration process and when compared to the regional grid reduces air emissions by:

• Carbon Dioxide	101,000 tons per year
• Oxides of Nitrogen	560 tons per year
• Sulfur Dioxide	1,430 tons per year

The regional carbon dioxide reduction of 101,000 tons per year is equivalent to the removal of 18,000 automobiles off Illinois highways or the reforesting of 21,000 acres of land.

Presently, APP generates electricity at a carbon dioxide rate of 0.87 pounds per kilowatt-hour. This existing rate is **below the proposed EPA standard** of 1.00 pound per kilowatt-hour for new generating equipment. Due to the best-in-class emission control system, APP was recently tested to be **under the new MACT limits by a factor of 15**. The Chiyoda Jet Bubbling Reactor (JBR) not only has maximum scrubbing of sulfur dioxide but also removes mercury emissions to near non-detectable limits.

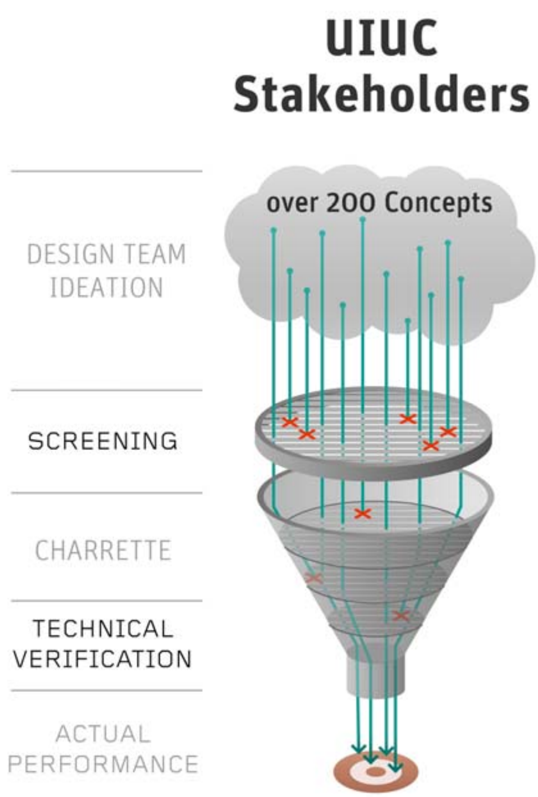
The U of I is actively investigating and implementing various methodologies to reduce campus carbon footprint in the near term. A new 5.8 MW photovoltaic facility is being constructed to serve the campus. Presently, U of I is working with the US Department of Energy to develop a carbon dioxide capture process for APP. Continued investigation, research and receptiveness to emerging technologies is important to meeting the future utility demands for the U of I campus in a sustainable manner.

To optimize heat output while minimizing emissions, many campuses as well as government and industrial facilities are presently converting existing generating plants to match the systems presently operating at U of I APP.

The current campus cooling system meets the chilled water demand with firm capacity generated by electric driven chillers. In addition, the campus cooling system includes a thermal energy storage tank that is utilized to minimize operating costs as well as reduce generating capacity requirements. The campus chilled water growth can be met by replacing existing chillers with larger chillers as equipment reaches the end of its useful life. Chiller replacement should utilize variable speed chillers to continue to improve the overall chilled water system efficiency.

The import capacity of the existing electrical distribution system is limited to 60 MW. The campus peak electrical demand was 80 MW in the summer of 2014 requiring APP to generate any demand above 60 MW. It is recommended to increase the electrical import capacity for increased reliability, utility cost reduction and operational flexibility.

The existing campus utility distribution system includes approximately 300 miles of electrical cable, 30 miles of steam piping and 27 miles of chilled water piping distributed throughout the campus. The existing distribution system allows the campus utility demand to be met through interconnected central plants. In general, central plants require less generating capacity due to load diversity between buildings. The smaller total capacity and the centralized location reduce the cost of maintaining the equipment and allow the campus utility needs be met in a more cost effective manner.



As mentioned, the planning portion of the Utility Master Plan commenced with an inclusive ideation process seeking input from campus stakeholders. This activity resulted in nearly 200 individual concepts for meeting the future utility needs of the campus. Concepts ranged from central multi-fuel cogeneration plant(s) to conventional stand-alone building systems. In addition to conventional energy sources, biomass, solar, wind, geothermal, and small nuclear reactors were included along with heat recovery chillers. Each concept was discussed and refined based on consideration of several factors, including technical viability, scalability, cost and sustainability.

The refinement resulted in multiple viable options that were grouped into four main themes,

Theme 1 – Cogeneration with natural gas (NG) as primary fuel with oil backup and continued power production

Option 1.1 – Increase power import limit and retire coal boilers at Abbott Power Plant (APP). Continue to produce power at APP with combustion turbines (CT) and back pressure (BP) steam turbine generators (STG). Install natural gas boilers at APP to meet campus heating demand and the installation of additional BP STG capacity.

Option 1.2 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CTs and BP STGs. Develop a second cogeneration plant in North Campus using combustion turbines and auxiliary saturated steam boilers at 150 psig. Locate plant to avoid steam piping upgrades.

Option 1.3 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CTs and BP STGs. Develop a second steam heating-only plant in North Campus using natural gas fired saturated steam boilers at 150 psig with oil backup. Locate plant to avoid base case steam piping upgrades.

Theme 2 – NG as primary fuel with no power production (conventional heating only)

Option 2.1 – Increase power import limit and retire coal boilers at APP. Eventually convert APP to a heating-only plant with no power production once the CT and STG equipment reaches the end of its useful life. Install natural gas boilers at APP to meet campus heating demand.

Option 2.2 – Increase power import limit and retire coal boilers. Eventually convert APP to a heating-only plant with no power production once the CT and STG equipment reaches the end of its useful life. Develop a second NG fired heating-only plant on North Campus. Locate plant to avoid base case steam piping upgrades.

Option 2.3 – Increase power import limit and convert entire campus to individual NG fired condensing hot water generators. Eliminate APP and all steam distribution piping. Install new NG piping to all buildings.

Theme 3 – NG as primary fuel with partial renewables (wind, solar, geothermal, biomass)

Option 3.1 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install biomass-fired circulating fluidized bed (CFB) boilers at APP.

Option 3.2 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install natural gas boilers at APP. Install new heat-recovery chiller plant in North Campus.

Option 3.3 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install natural gas boilers at APP. Install wind farm on south campus.

Option 3.4 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install natural gas boilers at APP. Install solar farm on south campus.

Option 3.5 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install syngas/NG fired boilers at APP. Develop gasification plant on South Campus with syngas piping to APP.

Theme 4 – Full renewables and alternative fuels (biomass, geothermal)

Option 4.1 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install syngas/NG fired boilers at APP. Develop gasification plant on South Campus with syngas piping to APP.

Option 4.2 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install natural gas boilers at APP. Add campus-wide geothermal enhanced heat recovery chiller plant and convert entire campus to hot water heating.

Each of the options listed is modeled to calculate the cost of utility services, greenhouse gas emissions, increased land usage required, redundancy of installed capacity (thermal and electric), and capital requirements.

The model is based on assumptions related to campus growth, level of continued energy conservation, data center growth, and financial terms. The model is useful for macro utility planning but is limited as the planning horizon is reduced. The parameters of this interactive model on a global perspective can be modified and the economics revised, as well as risks and opportunities identified.

The following table summarizes the present value life cycle costing of the various options at net zero campus growth and 150,000 GSF per year of campus facility expansion. In addition, the table summarizes each option with and without greenhouse gas charges.

LIFE CYCLE COST SUMMARY ($ MILLIONS)														
	DESCRIPTION				NO CAMPUS GROWTH					150,000 GSF/YEAR GROWTH				
	ABBOTT PP					$0 PER TON GHG		$10 PER TON GHG			$0 PER TON GHG		$10 PER TON GHG	
OPT. NO.	COAL	GAS	BIO	NEW PLANT	PV CAPEX	TOTAL PRESENT VALUE	TPV BAU DIFF.	TOTAL PRESENT VALUE	TPV BAU DIFF.	PV CAPEX	TOTAL PRESENT VALUE	TPV BAU DIFF.	TOTAL PRESENT VALUE	TPV BAU DIFF.
BAU	•	•			269	1,704	---	1,769	---	288	1,842	---	1,919	---
1.1		•			221	1,638	(66)	1,694	(75)	236	1,767	(75)	1,835	(84)
1.2		•		CHP	250	1,720	16	1,768	(1)	255	1,825	(17)	1,884	(36)
1.3		•		BLR	226	1,663	(41)	1,719	(50)	230	1,780	(62)	1,849	(70)
2.1		•			212	1,820	116	1,902	133	223	1,951	109	2,047	127
2.2		•		BLR	216	1,826	123	1,908	140	216	1,946	104	2,041	122
2.3				CBLR	454	2,124	421	2,203	435	454	2,277	435	2,368	449
3.1			•		294	1,726	22	1,779	10	305	1,846	4	1,909	(10)
3.2		•		HRC	266	1,673	(30)	1,729	(39)	281	1,817	(25)	1,884	(35)
3.3		•		WIND	299	1,725	22	1,777	8	314	1,853	11	1,916	(3)
3.4		•		PHV	413	1,851	147	1,906	137	428	1,976	134	2,043	124
3.5		•	•		274	1,793	89	1,842	74	285	1,924	82	1,984	65
4.1			•		265	2,004	300	2,047	278	273	2,137	295	2,189	270
4.2				GHRC	468	1,912	208	1,993	224	476	2,058	215	2,149	230

NOTES 1. CHP - COMBINED HEAT AND POWER
BLR - BOILERS
CBLR - BUILDING CONDENSING BOILERS
HRC - HEAT RECOVERY CHILLERS
GHRC - GEOTHERMAL HEAT RECOVERY CHILLERS
PHV - PHOTOVOLTAIC SOLAR
PV - PRESENT VALUE
TPV - TOTAL PRESENT VALUE
GHG - GREEN HOUSE GAS

As shown in the life cycle cost summary, the most cost effective approach is Option No. 1.1, regardless of campus expansion or greenhouse cost, if any. Option No. 1.1 consists of the following major components

- Retirement of coal operations at the end of the existing equipment useful life (2025 to 2035). The retirement of coal operations could be accelerated.
- Continued operation of existing combined heat and power systems.
- Installation of three new gas boilers (175 kpph).
- Increased electrical import capacity.
- Additional backpressure steam turbine generator capacity.
- Replacement of existing chilled water generating assets at the end of useful life with increased capacity and efficiency units.
- Distribution system upgrades.

1.4 Risk

An assessment is performed for the key risks and reliability considerations associated with the continued utility operations at U of I in its present configuration as well as for each of the developed scenarios. Multiple meetings with key stakeholders identified categories of risks and concerns. The Utility Master Plan assesses impact of each risk on all of the following categories: safety, reliability, institutional mission, economic viability, and reputation.

A risk score is calculated by multiplying the probability of occurrence score by an impact score, resulting in a risk score for each option.

1.5 Recommendations

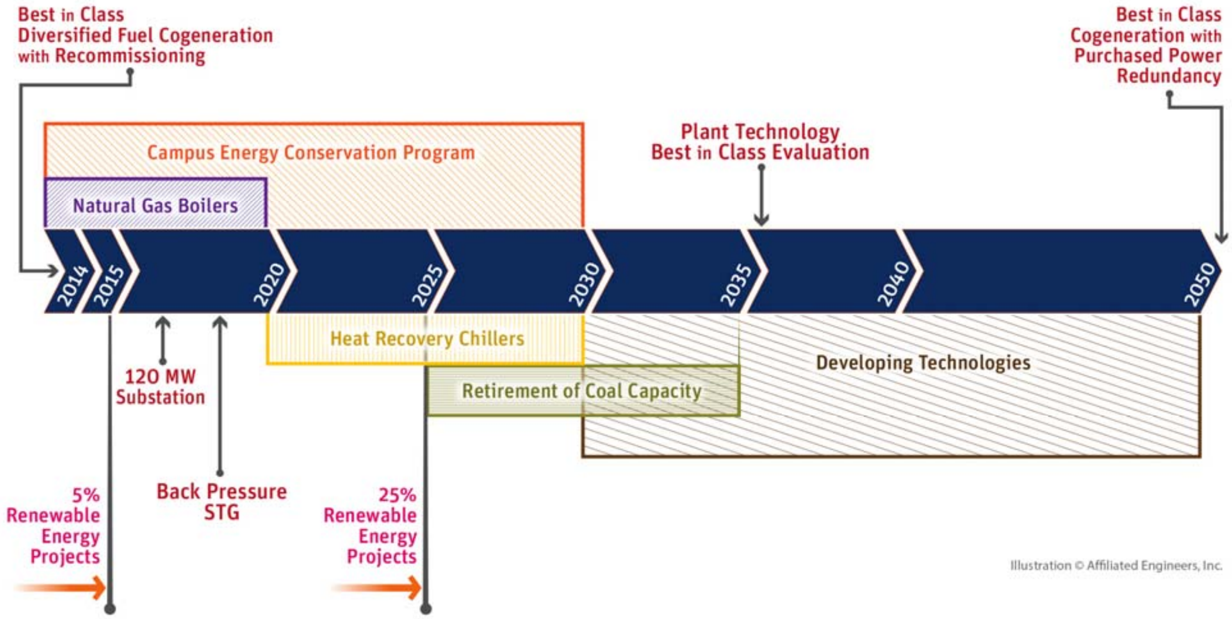
The opportunity index as well as present value life cycle costing reveals that the most effective method to meet the potential load demands of the campus in an environmentally responsible manner is to:

- Expand the current **campus energy conservation program** in conjunction with the **retrocommissioning program** to further reduce campus energy consumption and demand.
- Enhance the existing **best-in-class diversified fuel cogeneration** plant.
- Add **variable-speed chillers** to the existing multi-plant campus cooling system with thermal energy storage.
- Aggressively promote the use of **heat-recovery systems** and **energy reduction strategies** in new capital projects. Ensure full functionality of new systems through **enhanced commissioning**.
- Pursue additional **renewable energy generation** projects (such as the solar farm) as opportunity affords and purchase **renewable energy credits** or develop **renewable power purchase agreements** to achieve campus iCAP targets.
- Limit campus growth to **net zero GSF** as established by the iCAP targets.
- Re-evaluate and apply **best of industry energy supply** utilizing future advanced technology and innovations for plant repowering in the 2030-2040 time frame.
- Apply **heat-recovery chiller** technologies in specific campus regions.
- Increase **electrical import capacity** for increased reliability, enhanced power quality, utility cost reduction and increased opportunity to utilize remote renewable technologies.

Advances in energy technologies and support systems such as carbon dioxide capture are rapidly being developed. Proposed EPA regulations will reduce the carbon dioxide associated with U of I electric purchases by approximately twenty percent. Prior to any major U of I capital expenditure, this Master Plan should be updated to reflect the most current technologies, utility costs, and environmental regulations.

1.6 Implementation

The following figure indicates the general implementation of the major components associated with the Utility Master Plan.


Best in Class
Diversified Fuel Cogeneration
with Recommissioning
Best in Class
Cogeneration with
Purchased Power
Redundancy
Campus Energy Conservation Program
Natural Gas Boilers
Plant Technology
Best in Class Evaluation
2014
2015
2020
2025
2030
2035
2040
2050
Heat Recovery Chillers
Developing Technologies
Retirement of Coal Capacity
120 MW
Substation
Back Pressure
STG
5%
Renewable
Energy
Projects
25%
Renewable
Energy
Projects
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The following table indicates the annual capital expenditures in 2014 dollars for the first ten years of the planning horizon.

OPTION 1.1 INFRASTRUCTURE IMPROVEMENT SCHEDULE (TOTAL PROJECT COSTS in 2014 dollars)
UNIVERSITY OF ILLINOIS - URBANA CHAMPAIGN

SYSTEM	NO.	DESCRIPTION	TOTAL COST ($)	YEAR										
				2014 ($)	2015 ($)	2016 ($)	2017 ($)	2018 ($)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	2024 ($)
STEAM	H 1	ANCILLARY EQUIPMENT REPAIRS	3,375,000	750,000	750,000	650,000	125,000	600,000	500,000					
	H 2	ADDITIONAL BP STG	4,660,000		4,660,000									
	H 3	REPLACEMENT OF HRSG 1 AND 2	27,228,000										27,228,000	
	H 4	THIRD GAS BOILER	9,500,000			9,500,000								
	H 5	COMBUSTION TURBINE INLET COOLING	1,250,000					1,250,000						
	H 6	STEAM TUNNEL AND VAULT REPAIR	8,652,000	1,125,000	105,800	3,695,800	105,800	105,800	2,430,800	1,083,000				
	H 7	REPLACE DISTRIBUTION PIPING	21,418,000		2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800
	H 8	APP CODE AND LIFE SAFETY	2,229,000	557,250	557,250	557,250	557,250							
		SUBTOTAL	78,312,000	2,432,250	8,214,850	16,544,850	2,929,850	4,097,600	5,072,600	3,224,800	2,141,800	2,141,800	29,369,800	2,141,800
CHILLED WATER	C 1	OSCP CODE AND LIFE SAFETY	134,000			18,000								116,000
	C 2	NCCP REPLACEMENT CHILLERS/TOWERS	10,110,000			1,044,000				3,002,000		2,770,000	3,294,000	
	C 3	NCCP HEADER PIPING AND VALVE REPLACEMENT	275,000		275,000									
	C 4	NCCP CODE AND LIFE SAFETY	5,000			5,000								
	C 5	LACC REPLACEMENT CHILLERS/TOWERS	10,300,000	1,728,000	1,728,000	3,754,000					1,589,000	1,501,000		
	C 6	LACC CODE AND LIFE SAFETY	68,000			35,000								33,000
	C 7	ASCP REPLACEMENT CHILLERS/TOWERS	5,090,000			2,088,000							3,002,000	
	C 8	ASCP CODE AND LIFE SAFETY	32,000			18,000	7,000							7,000
	C 9	CLSCP REPLACEMENT CHILLERS/TOWERS	8,506,000	1,742,000	1,742,000	5,022,000								
	C 11	CLSCP CODE AND LIFE SAFETY	22,000			11,000								11,000
	C 12	VMCP REPLACEMENT CHILLERS/TOWERS	4,459,000			576,000			1,159,000				2,724,000	
	C 14	VMCP PIPING/PUMP UPGRADES	65,000				65,000							
	C 15	VMCP CODE AND LIFE SAFETY	6,000			6,000								
	C 16	TES PRESSURE SUSTAINING VALVE MODIFICATIONS	50,000	25,000	25,000									
	C 17	UPGRADE PORTIONS OF DISTRIBUTION PIPING	850,000		400,000	150,000	150,000	150,000						
		SUBTOTAL	39,972,000	3,495,000	4,170,000	12,727,000	222,000	150,000	1,159,000	3,002,000	1,589,000	4,271,000	9,020,000	167,000
ELECT.	E 1	MV DISTRIBUTION EQUIPMENT	9,509,000		1,694,000	391,000	496,000	761,000	391,000	939,000	783,000	1,172,000	2,190,000	692,000
	E 2	MV DISTRIBUTION CABLING	5,533,000		695,000	695,000	695,000	695,000	695,000	411,600	411,600	411,600	411,600	411,600
	E 3	HV TRANSFORMERS, CIRCUIT BREAKERS, RELAYS	927,000						927,000					
	E 4	INCREASE IMPORT CAPACITY TO 120 MW	16,287,000				8,287,000	8,000,000						
		SUBTOTAL	32,256,000		2,389,000	1,086,000	9,478,000	9,456,000	2,013,000	1,350,600	1,194,600	1,583,600	2,601,600	1,103,600
OTHER	O 1	ENERGY EFFICIENCY PROGRAM	22,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
	O 2	RENEWABLE ENERGY PROJECT/PURCHASE	5,500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
		SUBTOTAL	27,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000
TOTAL			178,040,000	8,427,250	17,273,850	32,857,850	15,129,850	16,203,600	10,744,600	10,077,400	7,425,400	10,496,400	43,491,400	5,912,400

2.0 Introduction

2.1 Acknowledgements

The following University of Illinois Urbana-Champaign personnel provided invaluable assistance in obtaining information for and the development of this planning activity

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Mike Bass	Eva Sweeney	Randy Pankau
Robert Bryant	Rick Rundus	Sanja Koric
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2.2 Scope of Study

The U of I at Urbana-Champaign made a commitment to sustainability and proactively addressing climate issues by signing the American College and University Presidents' Climate Commitment with a goal of carbon neutrality by 2050. The first step towards meeting this goal was to develop an action plan and strategies for U of I to move towards a more sustainable campus. The Climate Action Plan (iCAP) identified avenues and actions for reaching carbon neutrality. The Master Plan reviewed and analyzed several of the options presented by iCAP and assesses their efficacy. The Master Plan identifies and outlines projects that best meet the overall goals of the University and the Climate Action Plan.

This comprehensive Master Plan includes an evaluation of the existing utility equipment and distribution systems, based on capacity, condition, and efficiency. The examined services include:

- Steam
- Chilled water
- Electrical
- Natural Gas
- Fuel Oil
- Compressed air

Using information gathered during the equipment assessment and campus utility usage information, a computer based energy model, Utility Master Plan Model (UMP Model), was developed to evaluate options in terms of the goals mentioned above. The resulting system assessments are then used to identify opportunities for meeting capacity, improving efficiency, and developing cost-effective options. System reliability, environmental impacts, permitting, regulations, and budget requirements were also examined for each option.

Implementation timelines and cost estimates are included for options for further consideration, as determined by U of I.

2.3 Background

The University staff maintains and operates Abbott Power Plant (APP), seven chilled water facilities (Oak Street Chiller Plant, North Campus Chiller Plant, Library Chiller Plant, Animal Science Chiller Plant, Chem Life Science Chiller Plant, Veterinary Medicine Chiller Plant and the Thermal Energy Storage Tank and pump building), and over 660 buildings. These facilities provide steam, chilled water and electricity to the University of Illinois Urbana-Champaign campus. Six boilers and two combustion turbines with heat recovery steam generators (HRSG) with a combined capacity of 760,000 pph are located at APP. Steam is not produced at any additional facilities on campus.

Seven chillers with a combined capacity of 27,630 ton are located at the Oak Street Chiller Plant, seven chillers with a combined capacity of 9,400 ton are located at the North Campus Chiller Plant, four chillers with a combined capacity of 4,340 ton are located at the Library Chiller Plant, two chillers with a combined capacity of 2,000 ton are located at the Animal Science Chiller Plant, three chillers are located at the Chem Life Science Chiller Plant with a combined capacity of 3,630 ton, and five chillers are installed at the Veterinary Medicine Chiller Plant with a combined capacity of 3,200 ton. The TES tank is 6.5 million gallons, which provides 50,000 ton-hours of daily cooling capacity.

In total, the heating equipment at APP have a combined capacity of 760,000 pph (460,000 firm capacity), and the cooling equipment at the chilled water plants have a combined capacity of 47,000 ton on the main campus (41,370 ton firm capacity) and 4,700 ton capacity (3,200 ton firm capacity) at the Vet Med complex. APP has two combustion turbines, seven steam turbine generators that can operate in either condensing or backpressure mode, and two steam turbine generators that operate in backpressure mode, and have a nameplate capacity of 81 MW of generating capacity. Actual generating capacity is dependent on available steam production and steam demand on campus and is further discussed in Section 3.

Firm capacity is calculated with the largest piece of equipment (boiler, chiller, generator or single point of failure) not operating. Firm capacity improves the reliability of the system. With firm capacity, one piece of equipment can be maintained, repaired or out of service and the system still has the ability to meet peak loads. The reliability of steam and chilled water supply is critical to U of I operations. An interruption in steam or chilled water supply would affect normal campus operation and impact critical building operations or campus reputation. When firm capacity can meet peak demands, the supply of steam, chilled water and electricity is more reliable.

Peak heating steam demand for campus buildings and in-plant use is 600,000 pph. The peak cooling load in the summer of 2012 was 30,948 ton. The peak electrical demand was 78,437 kW on September 4, 2012. If the air quality control system (AQCS) is considered a single point of failure, firm boiler capacity is not presently available to meet the steam demand since the AQCS system failure would eliminate a total of 300,000 pph of boiler capacity from coal Boilers 5, 6 and 7.

At the peak cooling load, current firm chiller capacity is able to meet the chilled water demand. The current electrical firm capacity is able to meet electrical demand.

The following table summarizes the total and firm chilled water, steam and electrical generating capacities at U of I.

PRODUCTION CAPACITY		
PLANT	GENERATION EQUPMENT EQUIPMENT	CAPACITY 2014
ABBOTT	BOILER 2	130K PPH
	BOILER 3	130K PPH
	BOILER 4	---
	BOILER 5	300K PPH
	BOILER 6	
	BOILER 7	
	HRSG 1	42K PPH
	HRSG 2	42K PPH
	DB 1	58K PPH
	DB 2	58K PPH
TOTAL STEAM GENERATION		760K PPH
FIRM STEAM GENERATION		460K PPH
ELECTRICAL	AMEREN	60.0 MW
	STG CONDENSING	49.0 MW
	STG BACKPRESSURE	10.0 MW
	CT 1	11.0 MW
	CT 2	11.0 MW
TOTAL ELECTRIC GENERATION		141.0 MW
FIRM ELECTRIC GENERATION		79.5 MW
CHILLED WATER	OAK ST	27,630 TON
	NORTH CAMPUS	9,400 TON
	CHEM & LIFE SCIENCE	3,630 TON
	ANIMAL SCIENCE	2,000 TON
	LIBRARY	4,340 TON
	TES	5,000 TON
	VET MED	3,200 TON
TOTAL CHILLED WATER GENERATION		52,000 TON
FIRM CHILLED WATER GENERATION		46,370 TON

NOTE: CHILLED WATER DOES NOT INCLUDE VET MED

3.0 Existing Infrastructure Assessment

A condition assessment of the existing utility production facilities and infrastructure is conducted and a comprehensive analysis is performed to evaluate the existing utility equipment and distribution systems, based on capacity, condition, and efficiency. The examined services include:

- Chilled water
- Electrical
- Steam
- Natural Gas
- Fuel Oil
- Compressed air

Information gathered during the condition assessment is the basis for the business as usual reference case. The assessments are used to develop estimates of probable construction costs for equipment repair and replacement, as well as estimates of equipment efficiencies. The repair and replacement costs, equipment efficiencies and the campus utility usage information form a computer based energy model used to identify opportunities for meeting capacity, improving efficiency, and developing cost-effective options. System reliability, environmental impacts, permitting, regulations, risk and budget requirements are examined for each option.

This section includes the assessment of production facilities including Abbott Power Plant and the Chiller Plants, a discussion of the applicable air regulations, an assessment of the distribution systems, and an update of the campus code and life safety evaluation.

3.1 Abbott Power Plant

General

A comprehensive condition assessment of the Abbott Power Plant steam generation equipment was conducted. The purpose of the site investigations was to initiate a detailed condition assessment of the existing Abbott Power Plant as well as to develop a preliminary understanding of the plant operations and dispatch methodology.

The primary operational mission of the Abbott Power Plant is twofold:

- Supply the campus heating requirements
- Generate electric power when the campus demand exceeds 60 MW.

Abbott Power Plant is configured as a combined heat and power (CHP) plant with the majority of steam exported to the campus passing through backpressure steam turbine generators. This process is the most efficient combined heat and power system as well as electric production cycle using fossil fuels.

In addition, the plant has two combustion turbines with heat recovery steam generation which is an additional highly efficient form of combined heat and power as well as electric production.

From the previous studies as well as discussions with plant managers, the present Abbott Power Plant operation utilizes a cost-effective alignment of steam and electric generating components.

With the University planned replacement of gas/oil Boilers 3 and 4, the Abbott Power Plant will be positioned to serve the campus on either gas/oil or coal for the near-term future (± 10 years). The capability to utilize solid fuel, whether coal, coal-biomass, or enhanced biomass products, should be retained until the long-term cost and availability of natural gas is established.

Global Abbott Operational Analysis

The following table indicates the various fuels available to the Abbott Power Plant and the cost of the University generating electricity in comparison to the average annual marginal cost of purchasing electricity.

PRELIMINARY SCREENING ANALYSIS - ELECTRIC GENERATION					
OPTION NO.	DESCRIPTION	STEAM PRODUCTION	ELECTRIC COST		
			GAS ($/KWH)	COAL ($/KWH)	BIOMASS ($/KWH)
BASE	PURCHASE	—	0.0626	0.0626	0.0626
1	COMBUSTION TURBINE	NONE	0.0707	—	—
1A	COMBUSTION TURBINE	HRSG	0.0365	—	—
1B	COMB. TURB. WITH BP STG	HRSG	0.0349	—	—
1C	COMB. TURB. WITH COND STG	HRSG	0.0515	—	—
2	BACKPRESSURE STG	BOILER	0.0256	0.0135	0.0332
3	CONDENSING STG	BOILER	0.0956	0.0506	0.1242

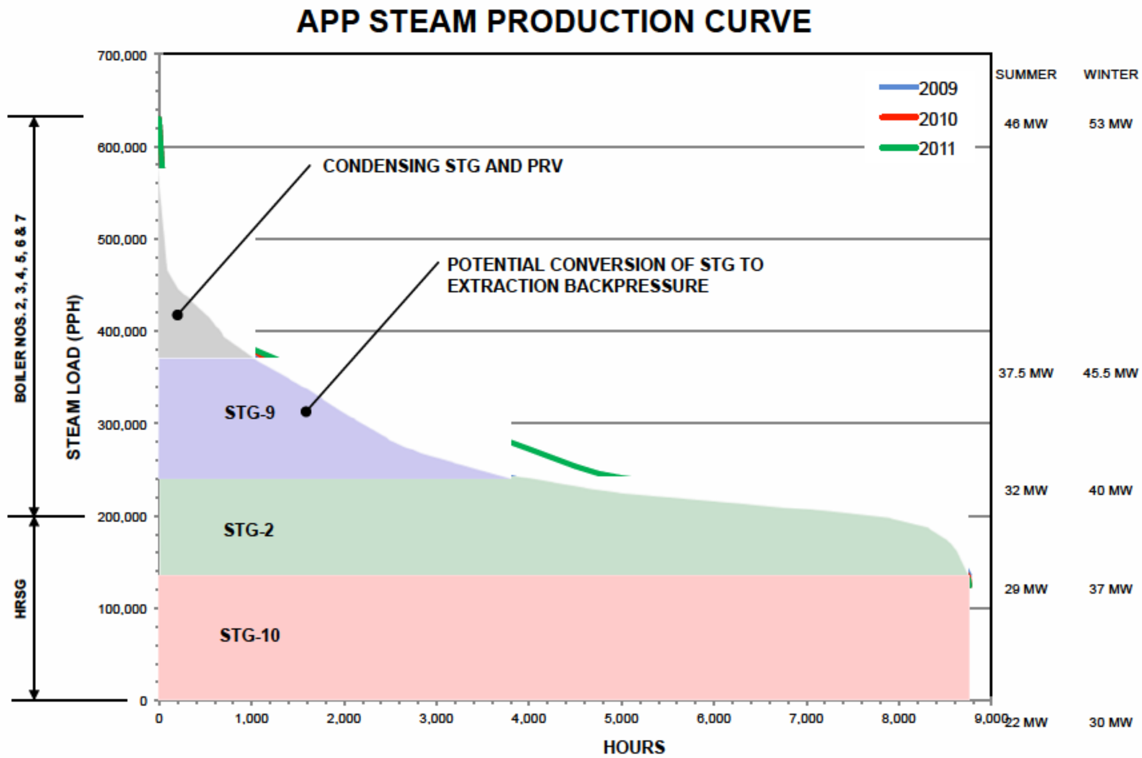
NOTES:
1. GAS COST = $5.89 PER DT
2. CT HR ~ 12,000 BTU/KWH (HHV)
3. CT WITH HRSG HR = 6,200 BTU/KWH (HHV)
4. CT WITH BP STG AND HRSG HR = 5,920 BTU/KWH (HHV)
5. CT WITH COND STG AND HRSG HR = 8,750 BTU/KWH (HHV)
6. BOILER EFFICIENCY - GAS = 82% COAL = 85% BIOMASS = 75%
7. BP STG = 3,413/0.96 = 3,560 BTU/KWH (W/O BOILER EFFICIENCY)
8. COND STG ~ 13,310 BTU/KWH (W/O BOILER EFFICIENCY)
9. "ALL IN" COAL COST = $73.20/TON ($3.23/10^6 BTU)
10. BIOMASS FUEL COST = $7.00/$10^6$ BTU
11. CT ANALYSIS FOR UNFIRED HRSG CONDITION
12. HEAT RATES INCLUDE STANDARD BOILER OFFSET EFFICIENCY OF 83%

INDICATES ON SITE GENERATION OF ELECTRIC POWER IN LIEU OF PURCHASING ELECTRIC POWER

INDICATES ON SITE GENERATION IS NOT COST EFFECTIVE

The table indicates the use of backpressure steam turbine generators is the most cost-effective approach with combustion turbines utilizing heat recovery steam generation also being cost effective. The use of condensing steam turbine generators utilizing steam generated from boilers is not cost effective at the average marginal cost of electricity; however, there are periods when the real-time cost of electricity exceeds the University's condensing electric generation cost and the existing condensing turbines should be energized.

The following figure is the APP steam production curve for calendar years 2009 to 2011. The steam production curve denotes the hourly occurrence of steam generation rates. The area below the steam production curve is the annual steam generated by APP.



The various electric generating assets are indicated on the steam production curve for normal operation. For combined heat and power to be applicable, the steam generated or exhausted needs to be utilized. From the preliminary plant data, Abbott Power Plant base loads with the combustion turbines and additional steam generated is passed through backpressure steam turbine generators. The existing operation utilizes an excellent dispatch strategy, and the electric output of APP can be increased by maximizing the condensing section of the steam turbine generators.

The output of a combustion turbine varies inversely with inlet air temperature. The difference in the listed summer and winter electric output is due to the inlet air temperature variation of the combustion turbine.

Major Equipment Inventory

During the field investigations, the major equipment (boilers, combustion turbines, and steam turbine generators) were reviewed for capacity as well as operating characteristics and efficiency. The following table summarizes the existing steam generation equipment.

STEAM GENERATION EQUIPMENT SUMMARY													
				STEAM GENERATION				OPERATION		HEATING SURFACES			
	YEAR			OUTPUT				CAPACITY	OUTPUT				
UNIT	INSTALL	FUEL	TYPE	DESIGN PPH	ACTUAL PPH	PRESSURE PSIG	TEMP °F	FACTOR %	FACTOR %	BOILER SF	FURNACE SF	SH SF	ECON SF
B2	1972	NG / OIL	WT	175,000	140,000	325	700	25.0	49.0	10,800	INCL.	860	12,540
B3	1972	NG / OIL	WT	175,000	140,000	325	700	13.0	52.0	10,800	INCL.	860	12,540
B4	1972	NG / OIL	WT	---	RTD	325	700	RTD	RTD	10,800	INCL.	860	12,540
B5	1956	COAL	STOKER	150,000	140,000	875	760	17.0	65.0	10,152	1,668	2,610	5,620
B6	1961	COAL	STOKER	150,000	130,000	875	760	17.0	65.0	10,152	1,668	1,670	5,620
B7	1962	COAL	STOKER	200,000	155,000	875	760	31.0	77.0	14,114	2,160	3,671	6,583
HRSG-1	2003	NG CT	HRSG	42,000	42,000	850	750	81.0	100.0	---	---	---	---
DB-1	2003	NG CT	DB	80,000	58,000	850	750	24.0	49.0	---	---	---	---
HRSG-2	2003	NG	HRSG	42,000	42,000	850	750	84.0	100.0	---	---	---	---
DB-2	2003	NG	DB	80,000	58,000	850	750	20.0	38.0	---	---	---	---

The existing coal Boilers 5, 6, and 7 are provided with flue gas economizers as well as air preheaters. The general condition of the coal boilers is good and the gas/oil boilers are fair to poor. Please refer to subsequent sections of this report for evaluations developed to date.

The two Heat Recovery Steam Generators (HRSG) associated with the combustion turbines are experiencing problems with casing expansion and insulation movement. University staff have contacted the HRSG manufacturer for remedial solutions. The HRSGs are provided with duct burners to increase steam output. In addition, the HRSGs include a superheater section to produce 850 psig and 750°F steam.

The following table summarizes the general characteristics of the existing STGs.

SUMMARY OF STEAM TURBINE GENERATORS											
					THROTTLE CONDITIONS		EXTRACTION	EXTRACTION	CONDENSING		
UNIT	INSTALL	MANUFAC.	RECENT OVERHAUL	ELECTRIC CAPACITY (KW)	PRESS. (PSIG)	TEMP (°F)	PRESS. (PSIG)	PRESS. (PSIG)	PRESS. (IN. HG)	CAPACITY FACTOR (%)	OUTPUT FACTOR (%)
STG-1	1940	GE	2009	3,000	300	625	---	70	3	25.0	87.0
STG-2	1940	GE	2009	3,000	300	625	---	70	---	60.0	85.0
STG-3	1947	GE	2010	3,000	300	700	---	70	3	---	---
STG-4	1950	GE	2010	3,000	300	700	---	70	3	---	---
STG-5	1954	GE	---	3,750	RTD	RTD	RTD	RTD	RTD	RTD	RTD
STG-6	1958	GE	2001	7,500	850	750	---	70	3	15.0	42.0
STG-7	1961	GE	N/A	7,500	850	750	---	70	3	15.0	53.0
STG-8	2003	TUTHILL	2010	12,500	840	750	160	0	4	---	---
STG-9	2003	TUTHILL	2010	12,500	840	750	160	0	4	---	---
STG-10	2003	TUTHILL	2010	7,000	840	750	160	50	---	45.0	57.0

The Abbott Plant has ten Steam Turbine Generators (STG) with capacities ranging from 3,000 to 12,500 kW. All of the STGs have a condensing section except STG 2 and 10 (indicated with blue rows in the following table). STG 1 through 4 are supplied from the 325 psig steam system while the remainder of the STGs are served from the 850 psig steam system. All STGs have uncontrolled extraction to provide feedwater heating.

STG 5 has been retired (indicated with a shaded row in the following table) and STG 4 is not presently in operation.

The piping to STGs 8 and 9 has been recently modified to eliminate piping stress and vibrations.

The following table summarizes the approximate operational performance of the STGs at maximum extraction as well as condensing operation.

STEAM TURBINE GENERATOR PERFORMANCE											
UNIT NO.	OPERATION	THROTTLE CONDITIONS			EXTRACTION		EXHAUST		ISENTROPIC TURBINE EFFICIENCY (%)	ELECTRIC OUTPUT (KW)	STEAM RATE (LB/KWH)
		STEAM (PPH)	PRESS (PSIG)	TEMP °F	STEAM (PPH)	PRESS (PSIG)	STEAM (PPH)	PRESS (PSI)			
STG - 1	MAXIMUM EXTRACT.	124,000	300	625	120,000	70	4,000	1.5a	---	3,000	41.3
	MAXIMUM COND.	38,800	300	625	---	70	38,800	1.5a	70.0	3,000	12.9
STG - 2	MAXIMUM EXHAUST	103,200	300	625	---	---	103,200	70.0g	80.0	3,000	34.4
STG - 3	MAXIMUM EXTRACT.	115,000	300	700	110,000	70	5,000	1.5a	---	3,000	38.3
	MAXIMUM COND.	34,200	300	700	---	70	34,200	1.5a	75.0	3,000	11.4
STG - 4	MAXIMUM EXTRACT.	115,000	300	700	110,000	70	5,000	1.5a	---	3,000	38.3
	MAXIMUM COND.	34,200	300	700	---	70	34,200	1.5a	75.0	3,000	11.4
STG - 6	MAXIMUM EXTRACT.	144,000	850	750	120,000	70	24,000	1.5a	---	7,500	19.2
	MAXIMUM COND.	75,000	850	750	---	70	75,000	1.5a	75.0	7,500	10.0
STG - 7	MAXIMUM EXTRACT.	144,000	850	750	120,000	70	24,000	1.5a	---	7,500	19.2
	MAXIMUM COND.	75,000	850	750	---	70	75,000	1.5a	75.0	7,500	10.0
STG - 8	MAXIMUM EXTRACT.	128,000	840	750	100,000	160	28,000	2.0a	---	5,600	22.9
	MAXIMUM COND.	128,000	840	750	---	160	128,000	2.0a	76.0	12,500	10.2
STG - 9	MAXIMUM EXTRACT.	128,000	840	750	100,000	160	28,000	2.0a	---	5,600	22.9
	MAXIMUM COND.	128,000	840	750	---	160	128,000	2.0a	76.0	12,500	10.2
STG - 10	MAXIMUM EXTRACT.	136,000	840	750	100,000	160	36,000	50.0g	---	5,000	27.2
	MAXIMUM EXHAUST	136,000	840	750	---	160	136,000	50.0g	75.0	7,000	19.4

NOTES: 1. OPERATIONAL PERFORMANCES BASED UPON 96% GENERATOR EFFICIENCY

All of the electric generating capacities are based upon 0.8 power factor. Additional electric generating capacity is available depending on the actual power factor.

An interesting observation concerning the GE STG 1 through 7 is that the maximum electric capacity can be obtained by operating at full extraction as well as full exhaust condensing operation.

The existing record and documentation storage system at Abbott Power Plant is excellent and is the best encountered in numerous similar facilities. The STG data even from the late 1930's is extremely comprehensive and could provide the basis for future dispatch optimization programs.

Using the STG record performance data, a preliminary isentropic turbine efficiency was developed for each unit and is listed in the summary table. All of the STGs have good turbine efficiencies.

Using the plant record performance data, the boiler efficiency is developed for each boiler and is listed in the following tables. The operating efficiency of each asset is calculated to determine fuel usage compared to new options for providing steam or HW heating to the campus. Plant performance data used to estimate boiler efficiency is listed in Appendix 3A.

COMBUSTION TURBINE HEAT RATE SUMMARY

MONTH	CY 2009 DATA			CY 2010 DATA			CY 2011 DATA		
	ELECT. PROD. (KWH)	GAS USAGE (THMS)	AVG HR (BTU/KWH)	ELECT. PROD. (KWH)	GAS USAGE (THMS)	AVG HR (BTU/KWH)	ELECT. PROD. (KWH)	GAS USAGE (THMS)	AVG HR (BTU/KWH)
JAN	14,444,214	1,598,772	11,069	15,997,214	1,727,630	10,800	21,214,710	2,273,511	10,717
FEB	17,954,279	1,982,808	11,044	18,704,214	2,022,615	10,814	16,791,968	1,806,739	10,760
MAR	16,443,437	1,827,772	11,116	17,976,511	1,995,502	11,101	17,976,511	1,995,502	11,101
APR	16,978,908	1,886,311	11,110	13,362,073	1,510,234	11,302	13,362,073	1,510,234	11,302
MAY	17,880,582	2,018,106	11,287	18,385,004	2,067,669	11,246	18,385,004	2,067,669	11,246
JUN	7,473,361	860,965	11,520	9,800,361	1,124,052	11,469	9,800,361	1,124,052	11,469
JUL	17,104,076	2,002,137	11,706	15,895,508	1,836,779	11,555	8,552,038	1,092,184	12,771
AUG	17,092,362	1,995,482	11,675	8,771,481	1,001,633	11,419	8,184,000	1,092,184	13,345
SEP	13,360,167	1,546,149	11,573	7,414,442	832,866	11,233	7,920,000	1,056,958	13,345
OCT	18,824,568	2,083,762	11,069	19,325,942	2,138,635	11,066	8,004,000	1,021,721	12,765
NOV	15,330,171	1,703,023	11,109	18,004,966	1,976,708	10,979	18,000,000	2,113,915	11,744
DEC	20,537,684	2,223,486	10,826	21,494,342	2,320,014	10,794	19,344,000	2,184,378	11,292
TOTAL	193,423,809	21,728,773	11,234	185,132,058	20,554,337	11,103	167,534,665	19,339,047	11,543
3-YR AVERAGE HEAT RATE									11,284

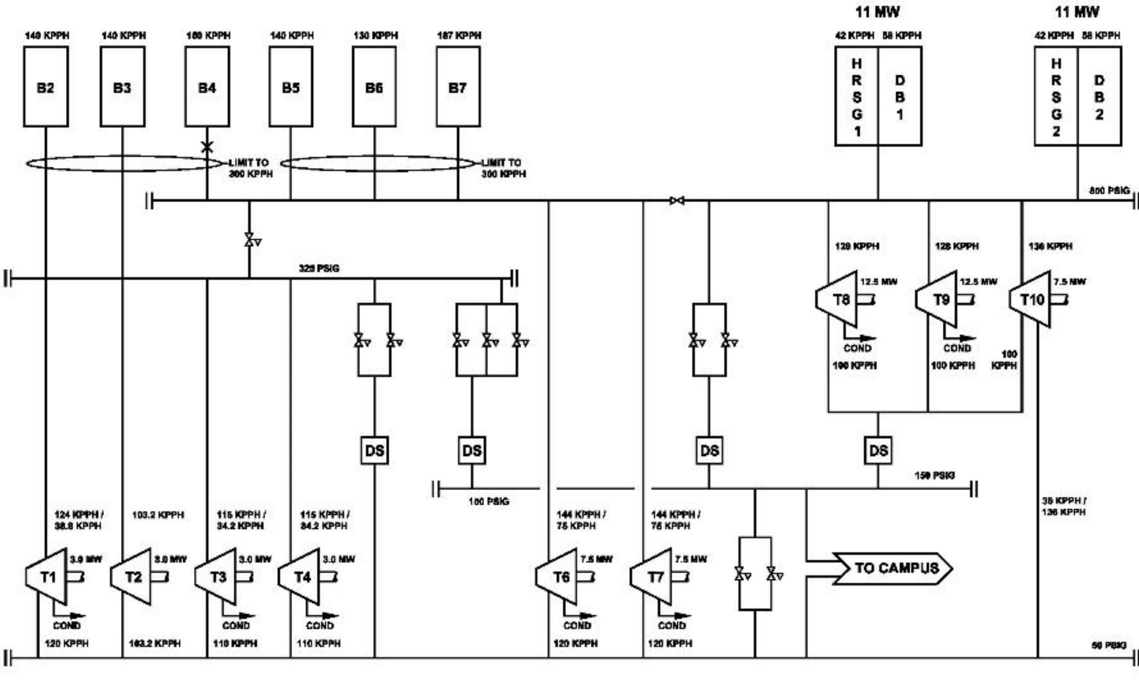
TYPICAL BOILER EFFICIENCY - BOILER NOS. 2 & 3							
PART LOAD (%)	RUN LOAD (%)	O2 (%)	FG TEMP BOILER (°F)	FG TEMP ECON. (°F)	COMB. EFF. (%)	RADIATED & UNACCT LOSSES (%)	BOILER EFF. (%)
10	1.8	10.3	---	325	80.8	10.0	70.8
20	0.1	7.5	---	325	82.5	5.0	77.5
30	0.4	6.1	---	325	83.1	3.3	79.8
40	3.7	6.0	---	325	83.1	2.5	80.6
50	21.7	5.7	---	325	83.2	2.0	81.2
60	21.1	5.7	---	325	83.2	1.7	81.5
70	23.2	5.4	---	325	83.3	1.4	81.9
80	14.8	5.2	---	325	83.4	1.3	82.2
90	12.2	5.1	---	325	83.4	1.1	82.3
100	1.1	5.1	---	325	83.4	1.0	82.4
TOTAL	100.0	---	---	---	---	---	81.5

NOTES:
1. PERCENT LOAD BASED UPON MAXIMUM OUTPUT OF 140,000 PPH
2. O2 BASED UPON COMBUSTION TESTING DATA NOVEMBER 2010
3. ECONOMIZER LEAVING FLUE GAS TEMPERATURE BASED UPON ASSUMED VALUE

TYPICAL BOILER EFFICIENCY - BOILER NOS. 5 - 7								
PART LOAD (%)	RUN LOAD (%)	O2 (%)	FG TEMP BOILER (°F)	FG TEMP ECON. (°F)	FG TEMP AIR PRE-HTR (°F)	COMB. EFF. (%)	RADIATED & UNACCT LOSSES (%)	BOILER EFF. (%)
10	0.6	---	---	---	---	---	---	---
20	1.4	---	---	---	---	---	---	---
30	5.4	10.9	615	372	258	87.8	5.0	82.8
40	0.8	9.4	620	386	270	88.4	3.8	84.6
50	4.5	7.9	635	404	283	88.7	3.0	85.7
60	10.9	6.4	650	422	297	89.0	2.5	86.5
70	21.3	5.5	665	440	310	88.9	2.1	86.8
80	30.2	5.1	693	465	330	88.5	1.9	86.6
90	23.5	4.9	720	490	350	87.9	1.7	86.3
100	1.3	4.8	720	492	372	87.3	1.5	85.8
TOTAL	100.0	---	---	---	---	---	---	86.3

NOTES:
1. PERCENT LOAD BASED UPON MAXIMUM OUTPUT OF 140,000 PPH
2. O2 AND FLUE GAS TEMPERATURES BASED UPON COMBUSTION TESTING DATA JULY 2009 / NOVEMBER 2010

A simplified plant schematic was developed to indicate the boilers and STGs as well as supplemental pressure reducing stations to serve various steam pressures within the system. The following figure presents this general arrangement of components.



LEGEND: # / # = MAXIMUM EXTRACTION / MAXIMUM CONDENSING

External Assessment – Steam Generation

A global business-as-usual, ten-year condition assessment analysis is performed with a focus on the boilers, steam turbines, and other major equipment. The following assessment evaluates the existing equipment and proposes recommendations to modernize equipment.

The global assessment is developed by performing the following tasks:

- Visual assessment of major equipment both idle and operating
- Visual condition evaluation of boiler watersides
- Visual condition evaluation of boiler and HRSG firesides
- Visual inspection and surface temperature measurement of the boiler casings
- Visual inspection of boiler chain grates and ash reinjection systems
- Visual inspection of general plant auxiliary systems
- Review of chemical treatment program
- Review of available operating data and major equipment repair history
- Review of combustion efficiency and emission testing data

The primary purpose of the site investigations is to determine the condition of the existing Abbott Power Plant and estimate useful equipment life, as well as to develop a preliminary understanding of the plant operations and dispatch methodology.

The existing mechanical equipment condition is rated as Poor, Fair, Good, and/or Excellent. The rating system reflects the physical age and condition of the equipment as well as the estimated remaining useful life. The overall assessment process is subjective since equipment was not dismantled. The assessment rating is determined utilizing common industry standards and manufacturers' recommendations.

Equipment Rating	Remaining Useful Life
Poor	<5 years
Fair	10 years
Good	20 years
Excellent	30 years

Equipment Surveyed:

Site Visit No. 1: The first site visit was conducted on August 21st through August 23rd, 2012 and included an assessment of the following equipment:

1. Boiler 5
2. Boiler 6
3. Boiler 7

Boilers 3 and 4 were not evaluated at this time as these units were understood to be scheduled for eventual replacement.

Site Visit No. 2: The second site visit was conducted during the period of December 10th through December 14th, 2012. A brief summary of equipment assessed is as follows:

4. Boiler Feedwater Pumps
5. Condensate Elevation Pumps
6. Condensate Forwarding Pumps
7. Backwash Pumps
8. City Water Booster Pumps
9. Raw Water Pumps
10. Circulating Water Pumps
11. Fuel Oil Pumps
12. DC Heaters
13. Condensate Return Tanks
14. Condensate Polishers
15. Water Softeners
16. Cooling Towers
17. HRSG 1 – Fireside
18. Desuperheater Stations
19. Coal Handling System

Site Visit No. 3: The third site visit was conducted during the period of April 15th through April 19th, 2013, and the respective equipment and systems surveyed at that time are included in this report. A brief summary of equipment surveyed is as follows:

20. Boiler 3
21. Boiler 2
22. Steam Turbine Generator Nos. 1 and 2.

Steam Generation Assessment (Site Visit No. 1)

Assessments of Boilers 5, 6, and 7 were conducted during August of 2012. The APP staff has repaired Boilers 5, 6, and 7 over the past five years as indicated in the table below. The boilers have had repairs to casing, tubes, feeders and chutes. With continued preventive maintenance and proper water treatment, the boilers should provide the University campus with steam generation for the next ten years. Mag-particle testing was completed on Boiler 7 in September 2012. No major areas of concern were identified with the non-destructive testing. Boiler 5 casing was temporarily removed for downcomer repairs and re-installed. Boiler 7 casing was partially repaired when downcomer repairs were made, but further casing repairs are scheduled to be completed by the University.

BOILER NOS. 5, 6 AND 7 RECENT UPGRADES		
BOILER	EQUIPMENT	RECENT REPAIR DATE
BOILER NO. 5	TUBES (REARWALL GEN TUBES, DOWNCOMERS)	2010, 2012
	TUBES (GENERATING BANKS-DRUM TO DRUM)	2005
	ECONOMIZER TUBE SHIELDS	2013
	REFRACTORY (SIDEWALLS, REARWALL)	2013
	CASING (FRONT WALL)	2006
	CASING (SIDEWALLS, REARWALL)	2006
	FEEDERS	2011
BOILER NO. 6	TUBES (REARWALL GEN TUBES, SIDEWALLS)	2009
	TUBES (GENERATING BANKS-DRUM TO DRUM)	2009
	ECONOMIZER TUBE SHIELDS	2013
	REFRACTORY (SIDEWALLS, REARWALL)	2009
	CASING (FRONT WALL)	2009
	CASING (SIDEWALLS, REARWALL)	2009
	FEEDERS	2006
BOILER NO. 7	TUBES (REARWALL GEN TUBES, SIDEWALLS)	2007
	TUBES (NEW DOWNCOMERS)	TBD - 2013
	ECONOMIZER TUBE SHIELDS	2013
	REFRACTORY (SIDEWALLS, REARWALL)	TBD - 2013
	CASING (FRONT WALL)	UNKNOWN
	CASING (SIDEWALLS, REARWALL)	TBD - 2013
	FEEDERS	2008

Boilers 2 and 3 are gas/oil-fired boilers, each with a design capacity of 175,000 PPH at 325 psig and 700°F. Boiler 4 is retired and a project is in progress to replace the unit with a gas/oil fired boiler with a design capacity of 175,000 PPH at 850 psig and 760°F. Repairs have been made over the years to Boilers 2 and 3 to maintain reliability including tube replacements, refractory repairs, and casing patches. The University of Illinois at Urbana - Champaign has indicated that Boilers 2 and 3 cannot be re-tubed to run at 850 psig; therefore, the decision has been made to replace these boilers with new boilers capable of producing higher pressure steam.

Two heat recovery steam generators manufactured by Energy Recovery International (ERI) were installed in 2003 with two combustion turbines manufactured by Solar Turbines. The plant has had extensive problems with these units, and the HRSG manufacturer is in the process of troubleshooting and may possibly implement design changes. Sections of the casing are extremely hot and verified while on-site. It is recommended to utilize the HRSG in the unfired mode (no duct burner) until ERI identifies and corrects these issues. A more detailed theoretical evaluation of the HRSG is included in the additional observations and recommendations portions of this section.

As stated previously, in the past five years, University of Illinois Urbana - Champaign has made repairs to the coal boilers and the gas/oil boilers as needed. The majority of past tube issues were a direct result of poor water treatment. From conversations with plant personnel and the boiler manufacturer, tube failures were frequent ten years ago but have been improving every year since. Chemical injection locations have been corrected. The oxygen scavenger (Erythrobic Acid – Amine) injection location has been correctly relocated from the steam drum to the DC heaters. Injecting oxygen scavenger into the DC heater instead of the steam drum allows the oxygen scavenging reaction to occur prior to the boiler. It is recommended that the plant add a sweetwater system, condensed plant steam, to replace the desuperheating feedwater system. While the existing condensate polishers remove magnesium and calcium from the condensate return, silica is still an issue. Silica is scale-forming and thus can result in local overheating and tube failure. If silica volatilizes and carries over with steam, it can form deposits on steam turbine internals causing blade damage and potential failure. It is recommended that a plan be implemented by the APP to meet with building and distribution personnel to discuss return water chemistry through water sampling results on an annual basis. In addition, the building and distribution staff should work with plant personnel to protect condensate return systems from contamination.

External Assessment – Steam Generation

Photograph 3.1 indicates the casing “patches” on Boiler 3. A detailed assessment will need to be conducted to determine the extent of repairs required and the cost-benefit to implement those repairs. Generally, if the steam drum and mud drum are in good condition, repair over replacement is recommended. Although, if the University has future plans to add Boiler 3 to the 850 psig steam system, replacement is the recommended approach.

Photo 3.1 – Boiler 3 Casing “Patches”

Photograph 3.2 is the external side wall of Boiler 5. Repair on Boiler 5 includes new sidewalls and rear wall casing, refractory, and insulation. New downcomers are also indicated in Photograph 3.2. According to the University, the rear wall casing repair on Boiler 5 will be implemented to match the same configuration on Boiler 6 to improve ease of maintenance and ash management. The U of I has conducted downcomer inspections, and it was determined to replace each due potential failure.

Photo 3.2 – Boiler 5 sidewall & downcomers

Photograph 3.3 indicates the ash reinjection nozzles. The ash reinjection nozzles will be replaced as needed. As part of the repair effort on this boiler, it is recommended that a thorough cleaning of all ash reinjection and overfire air duct and piping be implemented while the boiler is down. Ash reinjection piping can become clogged from ash deposits and “flaking” from the ash hoppers which is not easily detectable from a visual inspection.

Photo 3.3 – Ash Rejection Nozzles

Photograph 3.4 indicates the coal feeders for Boiler 6. These feeders are less than four years old and with proper care, maintenance, and routine inspection by the manufacturer, the remaining useful life of the coal feed system will be extended. Boiler 6 also has four new sootblowers (two on each side of boiler). The University has indicated that the feeders are replaced/rebuilt every 35,000 hours of operation as part of routine maintenance.

Photo 3.4 – Coal Feeders

Photograph 3.5 indicates a portion of the sidewall casing repairs completed on Boiler 7. According to the University, the casing work was done as a retrofit after removal of the sidewall oil burners. This re-work facilitated tube repairs. Downcomer repairs, gas igniter installation and partial casing repairs were performed in 2014. As stated previously, with continued proper maintenance and water treatment, the coal boilers should remain operational for a minimum of ten years.

Photo 3.5 – Boiler 7

Photograph 3.6 highlights one of the HRSGs. The casing on the HRSG was extremely hot during the field visit and verified in the field by AEI. Energy Recovery International is currently troubleshooting and working on possible design changes to correct the current issues with the HRSGs. In addition to operational and financial impacts caused by undesired heat loss, the current condition of specific areas of the HRSG casing presents a safety hazard to operating personnel. The University is of the opinion that the HRSG design does not allow for sufficient thermal expansion, causing cracks at casing corners.

Photo 3.6 – Heat Recovery Steam Generator

Internal Assessment – Steam Generation

Boiler 7's mud drum is shown in Photograph 3.7. The tube projections through the mud drum comply with ASME Code requirements for boiler construction. It is recommended to possibly perform mag-particle or dye-penetrant testing on the mud drum to further determine the condition of the drums. The University indicated that in 2007, the drums were inspected for integrity of the ligaments and a few cracks were repaired.

Photo 3.7 – Boiler 7 Mud Drum

Photograph 3.8 indicates the steam drum for Boiler 7. The drum has some oxygen pitting due to past water chemistry issues. As with the mud drum, it is recommended to possibly perform mag-particle or dye-penetrant testing on the steam drum as well.

Photo 3.8 – Boiler 7 Steam Drum

Photograph 3.9 indicates Boiler 5's superheater tubes. The superheater's tubes have not been replaced within the past 7 to 10 years. New clips were installed in the spring of 2013 to properly support and align the superheater tubes.

Photo 3.9 – Boiler 5 Superheater Tubes

Photograph 3.10 shows the front wall of Boiler 5. The front wall was replaced and new feeders were installed in 2011. The condition and structure of the feeder ports are in very good condition. There are no visual signs of refractory failing or spalling. As expected with a recent replacement, the feeder paddles are in very good condition as well.

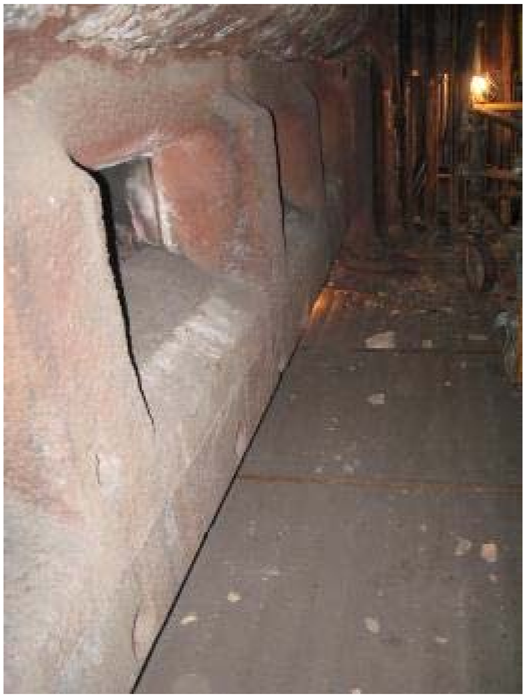


Photo 3.10 – Boiler 5 Front Wall

Photograph 3.11 indicates the grate for Boiler 5. The grate holes were primarily unplugged allowing unobstructed air flow to the coal bed. With continued routine maintenance (such as "punching the grates"), the grate and drives should continue to operate for an additional ten years. Major rebuilds for the grate and drives should be expected every 50,000 to 75,000 run hours. According to the University, this routine maintenance occurs during the spring and fall outages.

Photo 3.11 – Boiler 5 Grates

Steam Generation Assessment (Site Visit No. 2)

Boiler Feedwater Pumps

The Abbott Power Plant is served by ten boiler feedwater pumps. Pumps. 1 through 4 serve the 500 psig feedwater header, and Pumps 5-1, 5-2, and 6 through 9 serve the 1,200 psig feedwater header. Feedwater Pump 4 is abandoned in place and is planned to be removed. Feedwater Pump 5-1 was removed for repair during the time of the assessment. Photograph 3.12 indicates Pump 6 steam turbine drive casing open for maintenance. The turbine blades appeared to be in good condition from a visual assessment. The remaining feedwater pumps appear to be well maintained and in good condition considering the age and operation. The pumps in operation at the time of the assessment were Pumps 3, 5-2, 7, and 9. Of the operating pumps, none appeared to have any visible or audible signs of excessive vibration or uncharacteristic noise. The University indicated that a flow straightener or piping modifications may improve the overall operation of the pumps. More detailed analysis of each feedwater pump is included in the Appendix 3B.

Photo 3.12 – Pump 6 Steam Turbine

Condensate Elevation Pumps

There are currently five condensate elevation pumps that operate. Pumps 1 through 3 take suction from Condensate Return Tanks 1 and 2, and Pumps 6 and 7 take suction from Return Tank 6. The condensate elevation pumps (4 and 5) serving Condensate Return Tanks 3 and 4 are abandoned in place with future plans to be removed. Photograph 3.13 indicates Condensate Elevation Pump 3. Overall, the condensate elevation pumps appear to be in fair condition. The pumps witnessed in operation were Pumps 1, 2, and 6; none of which had signs of excessive vibration or noise. See Appendix 3B for additional analysis.

Photo 3.13 – Condensate Elevation Pump 3

Condensate Forwarding Pumps

Two condensate forwarding pumps take suction from Condensate Return Tank 5 and pump to the condensate polishers which outlet to Condensate Return Tanks 1, 2, and 6. Photograph 3.14 indicates Pump 2 in the foreground and Pump 1 in the background. Only Pump 1 was in operation during the time of the assessment and had no visible or audible signs of excessive vibration or uncharacteristic noise with the exception of some "chattering" of the discharge check valve which can be mistaken for pump cavitation. The pumps appeared to be in an overall good condition from a visual survey. The University indicated that the pump suction strainers are continually and closely monitored as they can quickly clog when the campus changes condensate return procedures. The University has expressed interest in the installation of VFDs on these pumps. This concept should be further investigated and pursued given that condensate return flow is variable depending on load, and flow rate could be controlled to the polishers based on return rate. See Appendix 3B for additional information.

Photo 3.14 – Condensate Forwarding Pumps 1 & 2

Backwash Pumps

Two condensate polisher backwash pumps take suction from Condensate Return Tanks 1, 2, and 6 and pump to the condensate polishers during the backwash cycle of the polisher regeneration process which discharge to drain. Photograph 3.15 indicates Pump 2 in the foreground and Pump 1 in the background. Neither pump was in operation during the time of the assessment, and a polisher regeneration cycle was not witnessed. The pumps appeared to be in an overall fair condition from a visual survey, but the housekeeping pads are in poor condition due to water infiltration in the immediate area. See Appendix 3B for additional information.

Photo 3.15 – Backwash Pumps 1 & 2

City Water Booster Pumps

Photograph 3.16 indicates City Water Booster Pump 1. Both Pumps 1 and 2 are in poor condition, and the University plans to eventually remove and replace these pumps. The pumps are used in case of city water supply pressure drops or fluctuations. Currently, the Abbott Power Plant has two city water feeds, but only the south feed is capable of supplying makeup water to the existing boilers. The University indicated that it is desired to eventually cross-connect the two city water feeds in the plant for redundancy.

Photo 3.16 – City Water Booster Pump 1

Raw Water Pumps

Three raw water pumps serve the makeup water load for the power plant. Photograph 3.17 indicates Pump 1 on the right and Pump 2 to the left. These pumps were not in operation during the time of the assessment. Pumps 1 and 2 appeared to be in an overall fair condition from a visual survey, and Pump 3 was fairly new and in excellent condition. The University indicated the installation of two additional raw water pumps is planned for the near future. See Appendix 3B for additional information.

Photo 3.17 – Raw Water Pumps 1 and 2

Circulating Water Pumps

The Abbott Power Plant has fourteen existing circulating water pumps serving the nine existing condensing steam turbine generators. These pumps circulate water to and from the respective condensing steam turbine hotwells and the outdoor cooling towers. Photograph 3.18 indicates the poor condition of Circulating Water Pump 6-2 bearing housing and pump seal. Overall, the circulating water pumps range in condition from poor to good condition from a visual observation. See Appendix 3B for additional analysis. The only pump witnessed in operation was Pump 6-1, which had no signs of excessive or unusual vibration or uncharacteristic noise.

Photo 3.18 – Circulating Water Pump 6-2

Fuel Oil Pumps

At the time of the assessment, four existing fuel oil pumps are installed to supply the required fuel oil to the plant. Fuel Oil Pumps 1 and 3 supply oil to the boilers, Pumps 4 and 5 supply oil to the combustion turbines, and Pump 2 has been removed. Photograph 3.19 indicates Pump 4, which is equipped with an internal pump pressure relief valve connection directly from pump discharge back to the suction. None of the pumps were in operation during the time of the assessment, as fuel oil was not being used. Pumps 1 and 3 appeared to be in an overall fair condition from a visual survey, as did Pumps 4 and 5. In 2014, a new fuel skid (Pumps 6 and 7) was installed and Fuel Oil Pumps 1 and 3 were removed. The new fuel oil skid will support the new gas boilers. See Appendix 3B for additional information.

Photo 3.19 – Fuel Oil Pump 4

Direct Contact (DC) Heaters

The Abbott Power Plant has six existing DC heaters (deaerators). Heaters 1 and 2 are abandoned in place and will eventually be demolished. Heater 3's make-up water level controller appears to be inoperable, and based on age alone is considered to be in poor condition. DC Heater 4 was not surveyed due to time constraints. Heater 5 is a spray-type deaerator. The overflow level control and make-up level control appear to be in poor condition while the tank appears to be in fair condition having repair work done in 2011. Heater 6 (Photograph 3.20) and its respective controls appear to be in good condition and operating at approximately 11 psig at 244°F, which indicates proper saturated conditions. At the time of the survey, the internal condition and tank metal integrity are unknown. See Appendix 3B for additional information.

Photo 3.20 – DC Heater 6

Condensate Return Tanks

The Abbott Power Plant has six existing Condensate Return Receivers. Tanks 1 and 2 (side by side) are approximately 18,900 gallons each, Tanks 5 and 6 are 18,000 gallons each, and Tanks 3 and 4 are abandoned in place. Tank 5 receives all condensate returns from campus (dirty condensate). Condensate Forwarding Pumps 1 and 2 pump the dirty condensate to the condensate polishers which outlet to Tanks 1, 2, and 6. From there, Condensate Elevation Pumps 1 through 5 pump polished condensate to the DC heaters. Photograph 3.21 indicates the general external condition of Condensate Return Tank 1, where some patching repairs have been made. From an overall external visual assessment, the condensate return tanks appear to be in fair to poor condition with no visible signs of leaks causing damage to the insulation. At the time of the survey, the internal condition and tank metal integrity are unknown. The University stated that future plans include removing all existing condensate return tanks from the basement and replace with outdoor aboveground tanks; one for dirty condensate and one for polished condensate.

Photo 3.21 – Condensate Return Tank 1

Condensate Polishers

The existing polishing system consists of three Condensate Polishers and two backwash pumps. The polishers are fed from Condensate Return Tank 5 (dirty condensate) and outlet to Tanks 1, 2, and 6 (polished condensate). Photograph 3.22 indicates Condensate Polisher 3 and the respective resin trap. Polishers 1 and 2 were in standby and Polisher 3 was in service during the time of the survey. Polisher 3 had a differential pressure of approximately 21 psig (53-32) at 800 GPM, which is typical for this type of equipment. The polisher resin traps and control valves appear to be in good condition, while some of the tank insulation was in poor condition. Overall, the condition of the polishers and the controls appear to be in fair condition. See Appendix 3B for additional information.

Photo 3.22 – Condensate Polisher 3

Water Softeners

The existing water system includes two Water Softeners. The softeners are fed from the existing raw water pumps and feed the Reverse Osmosis (R.O.) system. Photograph 3.23 shows Water Softeners 1 and 2 line-up. The stainless steel piping system appeared to be in good condition. The tanks are approximately ten years old and appear to be in fair condition. Minor leakage was noticed around the tank manway areas. The University indicated that work orders are in to re-paint the tanks. See Appendix 3B for additional information.

Photo 3.23 – Water Softeners 1 & 2

Cooling Towers

Four counter-flow type cooling tower cells serve the cooling water needs of the condensing steam turbine hotwells. These towers were witnessed in operation and appear to have good water distribution across the fill as evidenced by water patterns in the basin areas. The towers require minor repairs to tower internals and field devices. Photograph 3.24 indicates some damaged drift eliminators in the cooling towers. The towers appear to be in overall good condition, and provide sufficient capacity for the existing condensing steam turbines. See Appendix 3B for additional information.

Photo 3.24 – Cooling Tower Drift Eliminators

HRSG-1 – Fireside

The fireside of HRSG 1 was inspected in the furnace areas both upstream and downstream of the radiant superheater. Most areas of the firebox indicate signs of excessive heating. This is evident where many metal surfaces have been warped due to extremely high temperatures. Photograph 3.25.1 indicates overheating at the duct burner assembly. The University has made attempts to prevent the igniters from overheating and failing as indicated with wrapped insulation around each of the three igniters. The photo also indicates bare insulation lining the firebox area with no water-wall or floor tubes to absorb heat and protect the outer boiler casing from hot spots. The first heat transfer surfaces in contact with the flue gases are that of the superheater tubes. The OEM removed four rows of superheater tubes to reduce/control high steam temperatures at the outlet of the superheater. This modification had the desired result, but the overall heating surface has been reduced in the HRSG.

Photo 3.25.1 – HRSG 1 Duct Burner

Photograph 3.25.2 shows the radiant superheater in HRSG 1. The two vertical tube support sheets are deformed as a result of extremely high temperatures in this area. This point of the flue gas stream experiences the highest temperatures which is located just downstream of the duct burner. The deformation of these tube supports could be causing longitudinal stress on the superheater tubes and impacting the integrity of the vertical superheater header external to the furnace.

Photo 3.25.2 – HRSG 1 Superheater

Photograph 3.25.3 indicates the first several rows of generating tubes of the furnace. As indicated, nearly the entire first row and much of the second row of generating tubes has been replaced due to tube failures. The University has replaced the finned tubes in this area with straight tubes as the finned tubes were absorbing too much heat in a very small cross-sectional area of the furnace. The repairs as currently constructed will allow for ease of future repairs and tube replacements if the excessive heating is not immediately rectified. By replacing the finned tubes with straight tubes, the heating surface of the HRSG has again been reduced, thereby derating capacity.

Photo 3.25.3 HRSG 1 Tube Repairs

Photograph 3.25.4 indicates the area of the suspected tube leak. Feedwater spray was evident in this immediate area as well as wet insulation on the furnace floor. HRSG 1 was originally shut down for the purpose of inspecting the failure to determine the location of the leak.

Photo 3.25.4 HRSG 1 Tube Leak

Desuperheater Stations

Five desuperheating stations at the power plant were surveyed for condition and operation. Three of the five appeared to be in good condition utilizing typical piping configurations. Desuperheating feedwater is typically injected several pipe diameters downstream of the steam pressure reducing valve with corresponding temperature transmitters downstream of feedwater injection. The University indicated that three stations used downstream injection effectively. The other two stations utilize combination pressure reducing and desuperheating valves and the University indicated that temperature control was more difficult at these locations. The steam pressure reducing valves and desuperheater feedwater regulating valves appeared to be in fair to poor condition. The piping configurations at these two stations is atypical with feedwater injection directly into the body of the steam reduction valve as indicated in Photograph No. 3.26. The University may want to consider upgrading these two stations to obtain better temperature control. In 2014, the plant repaired the 325 to 50 psig reducing valves and desuperheating station. Repair of the 325 to 150 psig reducing valves and associated desuperheating station is scheduled for 2015. See Appendix 3B for additional information.

Photo 3.26 – Desuperheater Station

Coal Handling System

The existing coal handling system was assessed from the outdoor truck drop hopper grate to the coal feeders serving Boilers 5 through 7. The coal conveying system was witnessed in operation and there were no signs of imminent equipment failure, excessive vibration, or uncharacteristic noise. The handling equipment, including belts, rollers, chutes, hoppers, belt drives, and coal car appeared to be operating satisfactorily and were in fair condition. There were no signs of belt slippage or excessive wear, and coal dust and coal accumulation due to spills were minimal. Photograph 3.27 shows a properly functioning belt magnet that has removed metal debris from the coal stream. The University indicated that the coal conveying structure had recently been inspected and was found to be in poor condition. The inspection of the controls indicated that they are aging, in poor condition, and upgrades should be considered. See Appendix 3B for additional information.

Photo 3.27 – Coal Conveyor Magnet

Steam Generation Assessment (Site Visit No. 3)

Assessments of Boilers 2 and 3 were conducted during April, 2013. Boilers 2 and 3 are gas/oil-fired boilers, each with a design capacity of 175,000 PPH at 325 psig and 700°F. Repairs have been made over the years to Boilers 2 and 3 to maintain reliable service including tube replacements, refractory repairs, and casing patches. From maintenance records, Boiler 2 had furnace tube replacements in 1987 and 1999. Boiler 3 also had furnace tube replacements in 1999.

The steam drums for Boilers 2 and 3 have experienced some minor metal loss due to oxygen pitting. The tubes inside the drum also have some metal loss thus resulting in “knife-edging” on the end of some tubes. As stated previously, the boilers have been re-tubed in different locations at different times. This can be identified from the varying tube penetration distances through the drums.

Boilers 2 and 3 both have casings in poor condition, as indicated by hotspots and holes. The casings have been repaired many times in the past and will need to be monitored and repaired as needed to maintain business-as-usual operation. A rental boiler connection is being installed as a contingency should Boilers 2 and 3 be unable to provide campus heating steam until the new gas boilers are installed.

With proper maintenance, proper water treatment, and associated tube replacements, Boiler Nos. 2 and 3 could last for approximately five years. It is recommended to replace/repair tubes as necessary when they fail over the next five years.

External Assessment – Steam Generation (Boilers 2 and 3)

Photograph 3.28.1 indicates the casing for Boiler 2. The casing has been repaired in certain areas due to the formation of hot spots, causing metal fatigue and eventual failure. Also indicated in this photograph are holes in the casing. The holes should be repaired as soon as possible as part of the next routine boiler maintenance per the Abbott Power Plant schedule.

Photo No. 3.28.1 – Boiler No. 2 Casing

Photograph 3.28.2 indicates another area of the casing on Boiler2. As indicated, the boiler casing is "bowed" outward. The most probable cause of this condition is from over-heating due either poor heat transfer in the furnace to the generating tubes or more likely refractory and/or insulation repairs are required in this area. Another possibility for this condition to have occurred is furnace pressure excursions while fired on fuel oil. The casing is in poor condition; however, with proper repairs and maintenance, the boiler can remain functional for the next five years.

Photo No. 3.28.2 – Boiler No. 2 Casing

Boiler 3 casing is indicated in Photograph 3.28.3. The casing is in poor condition due to multiple "patches" and holes in the casing. Casing stiffeners have broken free from casing and should be re-welded back into place. Similar to that of Boiler 2, with proper repairs and maintenance, the boiler can remain operational for the next five years.

Photo No.3.28.3 – Boiler No. 3 Casing

Internal Assessment – Steam Generation (Boilers 2 and 3)

Photograph 3.29.1 indicates the Boiler 2 mud drum. The tube penetrations are uniform and meet the ASME Code requirements for boiler construction. The top of the drum indicates minor signs of oxidation located around the edges of the tube penetrations.

Photo No. 3.29.1 – Boiler No. 2 Mud Drum

A Boiler 2 steam drum tube penetration is shown in Photograph No. 3.29.2. The tube penetration is “knife-edged” due to metal loss as indicated. The steam drum also has some oxygen pitting inside the tube indicated by small tubercles. The oxygen pitting is likely the result of past water treatment issues that have recently been addressed by current Abbott Power Plant Staff and Management.

Photo No. 3.29.2 – Boiler No. 2 Steam Drum

Photograph 3.29.3 indicates the tube penetrations in the mud drum for Boiler 3. The photograph indicates metal loss on the edge of the tubes causing “knife-edging” in some areas. Similar to Boiler 2, the drum has some minor chemical buildup and oxygen pitting as a result of past water treatment issues.

Photo No. 3.29.3 – Boiler No. 3 Mud Drum

Photograph 3.29.4 indicates the operating waterline of Boiler 3. The steam drum has some oxygen pitting and chemical deposits. The tube penetrations are not uniform throughout the drum likely due to past tube repairs/replacements.

Photo No. 3.29.4 – Boiler No. 3 Steam Drum

Photograph 3.29.5 indicates Boiler 3 steam drum. The edge of the some of the tubes indicates signs of metal loss resulting in "knife-edging" on several tube penetrations. The chemical deposits found were likely iron oxides which usually have a smooth, black, dense magnetite layer forming by the direct reaction of water with the tube and drum metal.

Photo No. 3.29.5 – Boiler No. 3 Steam Drum

Photograph 3.29.6 indicates the tube arrangement located in the furnace of Boiler 2. The tube arrangement is no longer tangent with many tubes protruding out as indicated by the shadows of some tubes over others. The tangent tubes have been welded together using ½" metal spacer strips which was done to fill the gaps between the tubes to prevent short-circuiting of flue gases. This modification affects the radiant heat transfer surface of the generating tubes which can reduce boiler efficiency and capacity. The furnace area also requires some minor refractory work around furnace seals and steam drum to prevent short circuiting of the flue gases. Several floor tiles also need to be replaced. Approximately 60 thickness readings were taken on the furnace tubes. An average thickness of 0.127" was recorded for the vertical sidewall tubes. An average thickness of 0.125” was recorded for the horizontal ceiling tubes. The readings taken do not indicate any metal loss rather some minor buildup of iron oxides. The repair records indicate that the existing nominal tube thicknesses from the most recent repair are tubes of thickness 0.120” which coincide with the readings taken.

Photo No. 3.29.6 – Boiler No. 2 Furnace

Photograph 3.29.7 indicates Boiler 3’s furnace. From the inspection, it appeared that flame impingement may be occurring on the right side and top left of the furnace as indicated in the photograph. This could be a past issue; however, the University should inspect the flame pattern when the burner is in operation or consult with the burner manufacturer representative. Several furnace tubes had weld “patches” indicating past tube failures likely due poor water treatment. The tangent tubes in this boiler were also welded together, but without any metal spacer strips. The concern for this type of repair is welding directing to the tube surfaces and not knowing the depth of the welds; full or partial penetration. Heat transfer is again a concern as well as overheating of the welds themselves. This could cause premature tube failures at the welds. Approximately 50 thickness readings were taken on the furnace tubes. An average thickness of 0.131” was recorded for the vertical sidewall tubes. Similar to boiler No. 2, the readings do not indicate any metal loss rather some minor buildup of iron oxides and other chemicals. The repair records indicate that the existing nominal tube thicknesses from the most recent repair are tubes of thickness 0.120” which coincide with the readings taken.

Photo No. 3.29.7 – Boiler No. 3 Furnace

Steam Turbine Generators 1 and 2

Steam Turbine Generator (STG) 1 is a condensing turbine installed in 1940 and was overhauled in 2009, according to Power Plant personnel. During the April site visit, STG 1 casing was removed allowing for internal inspection of the turbine blades, inner casing, and rotating element.

Steam Turbine Generator 2 is a backpressure turbine installed in 1940 and was also overhauled in 2009. During the April site visit, STG 2 casing was removed allowing for internal inspection as well. The fixed turbine blades were removed from the unit for inspection.

Photograph 3.30.1 indicates STG 1 first stage turbine blades. The blades and turbine wheels appear to be in poor condition. Minor erosion was notable on some blade sections and stages. The University indicated that STG 1 has recently been issued an emergency overhaul for repairs to rotor stages, buckets, diaphragms, and generator.

Photo No. 3.30.1 – STG No. 1

Photograph 3.30.2 indicates STG 2 rotating element. The entire rotating element of the turbine was removed and remotely stored for inspection. The blades and turbine wheels appear to be in poor condition with slightly more and frequent areas of erosion. Both STG 1 and 2 casing appear in fair condition considering their age. Despite the age of the equipment and significant repair history, it is advisable to continue with routine maintenance, frequent mechanical and electrical inspections, and scheduled overhauls. With this plan moving forward, the turbines should remain reliable for another 5-10 years.

Photo 3.30.2

Summary and Recommendations

The Abbott Power Plant (APP) continues to do an excellent job operating and maintaining the vast majority of pertinent equipment and systems given the age of the facility to meet campus demands. During the three site investigations, there continues to be no noticeable signs of imminent failure of any equipment or systems. The life of the heat recovery steam generators (HRSGs. 1 and 2) remain the main concern. A business as usual approach can be safely maintained for the next five years with the exception of the HRSGs.

The University continues to have several projects either planned or underway which include:

- Investigation of HRSG overheating and tube failures; potential modifications or replacements
- Combustion Turbine equipment and controls upgrades; natural gas heating, inlet cooling
- Installation of additional raw water pumps
- Demolition of existing condensate return tanks and replacement with outdoor tanks
- Installation of outdoor raw water storage tanks
- Installation of RO storage tank (completed in 2014)
- City water piping and pumping modifications
- Demolition of abandoned DC heaters
- STG 8-10 general repairs and upgrades
- Coal handling system structural repairs
- Demolition of Boiler 4 and Feedwater Pump 4 and potentially Boiler 3.

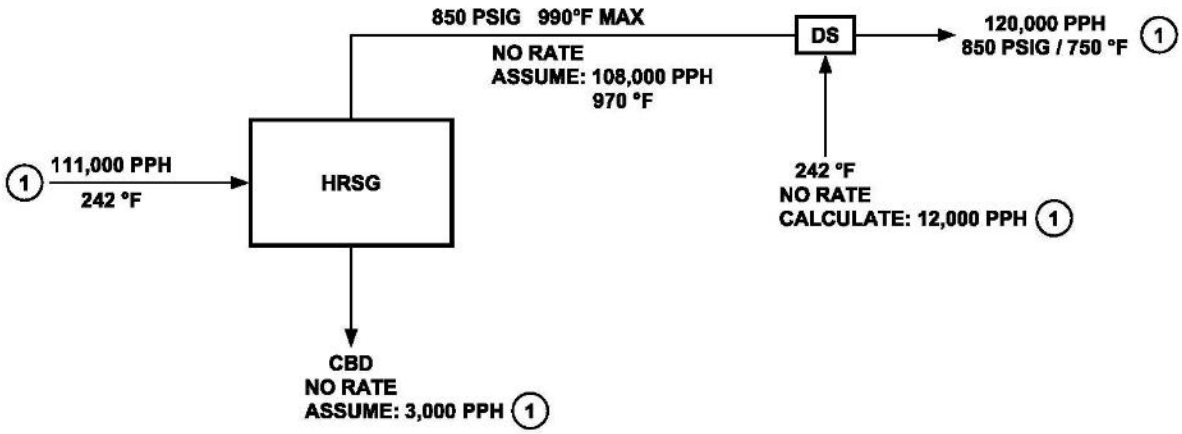
These previously planned projects demonstrate that the University continues to have a high level of understanding of the Plant's immediate and near-term needs.

The following are additional recommendations/observations for the University to consider:

1. The University should consider deferring the hiring of Cleaver Brooks to make modifications to the HRSG and duct burner until the major issues are discussed in greater detail with Cleaver Brooks and CT upgrades are in place through Solar.

2. The HRSG appears to be similar to an ERI slant-tube boiler. With the pressures and temperatures as well as the critical nature of APP, a water-cooled membrane wall boiler would be more appropriate.

3. It appears that approximately 12,000 PPH of generating capacity is added in the HRSG discharge desuperheater. Please see the following sketch for preliminary heat and mass balance.



$$\text{DESUPERHEATER FLOW RATIO (INPUT / INPUT)} = \frac{h_E - h_L}{h_L - h_{242°F}} = \frac{1{,}492.6 - 1{,}365.5}{1{,}365.5 - 210.0}$$

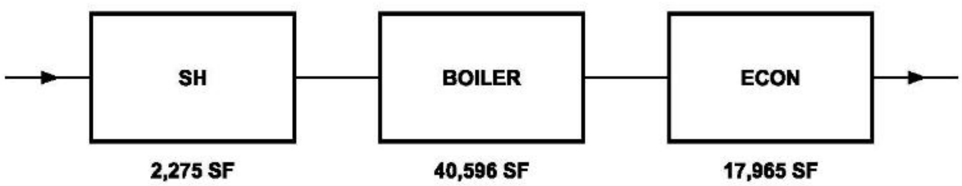
$$= 0.11$$

$$\text{DESUPERHEATER FLOW} = (0.11)(108{,}000) = 11{,}800 \text{ PPH}$$

(USE 12,000 PPH)

NOTES: 1. BASE DATA FROM NATIONAL DYNAMICS 722-3123
2. NATIONAL DYNAMICS SHEET: 108,000 PPH BOILER CAPACITY
120,000 PPH HRSG CAPACITY

4. With the replacement of finned tubes with straight bare tubes, the capacity of the HRSG is reduced. The maximum capacity of the boiler downstream of the desuperheater has been reduced from 120,000 PPH to approximately 104,000 PPH. Please see the following sketch for a preliminary analysis. Surface areas listed are from original design.

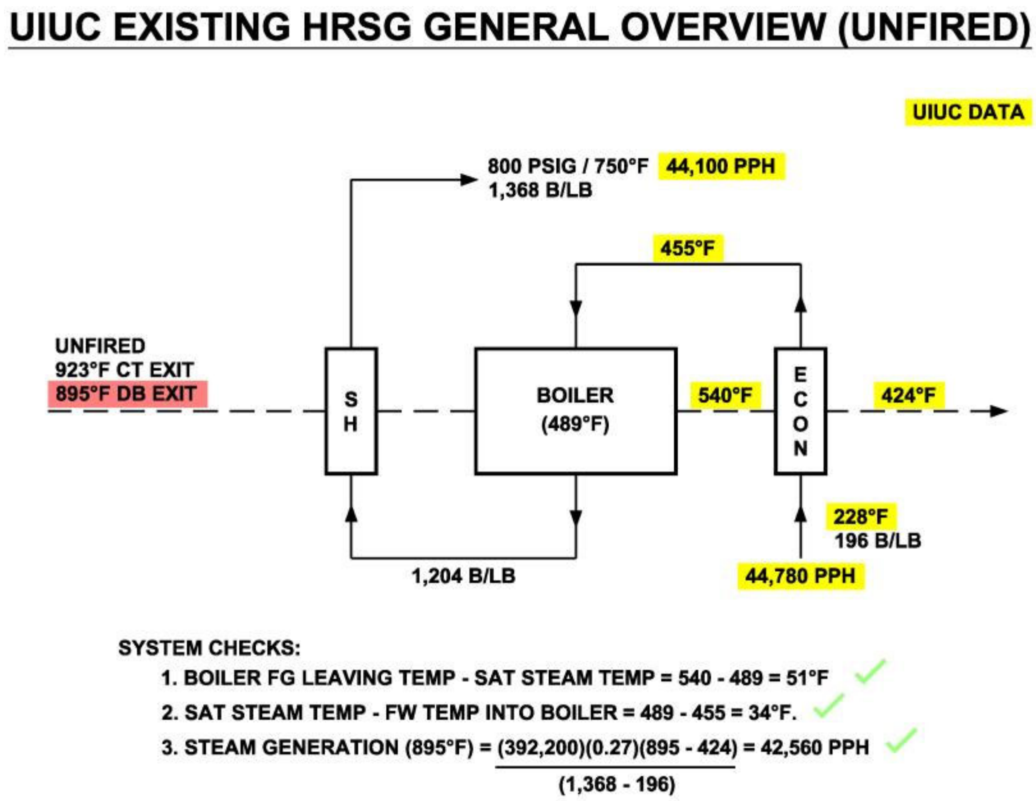


BOILER: 15 VERTICAL TUBES X 50 = 750 TUBES
ASSUME 2 VERTICAL TUBES HAVE FINS REMOVED
APPROXIMATE CORRECTED HEATING SURFACE:
(13/15)(40,596) = 35,183 SF

$$\text{BOILER OUTPUT} = \frac{35{,}183}{40{,}596}(108{,}000) = 93{,}600 \text{ PPH}$$

$$\text{HRSG OUTPUT} = (1.11)(93{,}600) = 104{,}000 \text{ PPH}$$

5. The design of the existing HRSGs was preliminarily reviewed to determine if the typical approach and pinch point temperature ranges were within normal standards. Actual operating data was utilized to check performance. The following figure indicates the results.

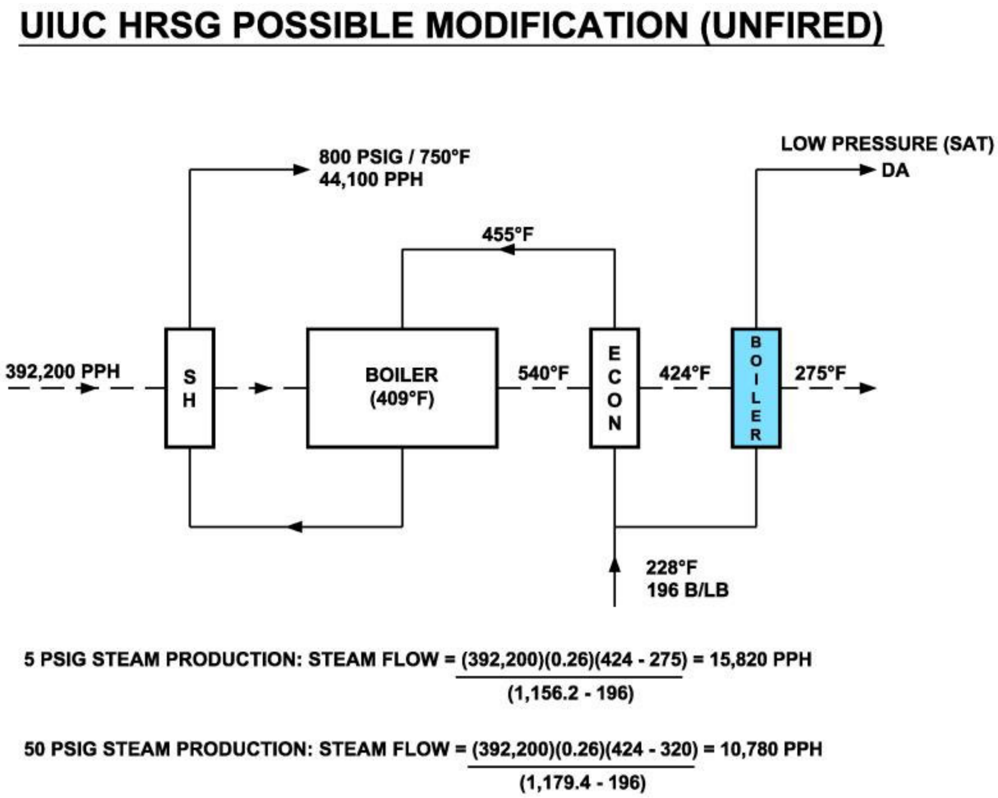


The unfired operating conditions indicate that the approach and pinch point temperature differentials are within normal standards.

The original design leaving ductburner temperature was 1,670°F. This leaving temperature is approaching the upper limit of a non-membrane wall HRSG. The HRSG modifications that APP has implemented such as removing superheater tubes and installing bare tubes in the generator bank has provided a more stable operation.

The two existing HRSGs should be replaced when funding becomes available. Until the HRSG's are replaced, it is recommended that an internal liner be installed between the ductburner and HRSG to eliminate insulation from flaking off and fouling heat transfer tubes. At 1,500°F, metallurgy significantly changes. With the installation of the liner, the ductburner outlet temperature should be limited to approximately 1,400°F. There are a number of available materials that could be used for the liner material including Type 347 stainless steel.

Because the HRSGs generate superheated steam, the flue gas temperature leaving the boiler feedwater economizer is elevated. This elevated flue gas temperature is not caused by a lack of heat transfer surface area but the dynamics (approach and pinch point) of a superheated HRSG. To support the funding of new HRSGs, it may be desirable to add another independent section of heat transfer equipment downstream of the economizer. This additional heat transfer section could be a low-pressure steam generating section or an economizer that elevates the water temperature between the condensate storage tank and deaerator. The following figure indicates the potential of the additional heat transfer unit.



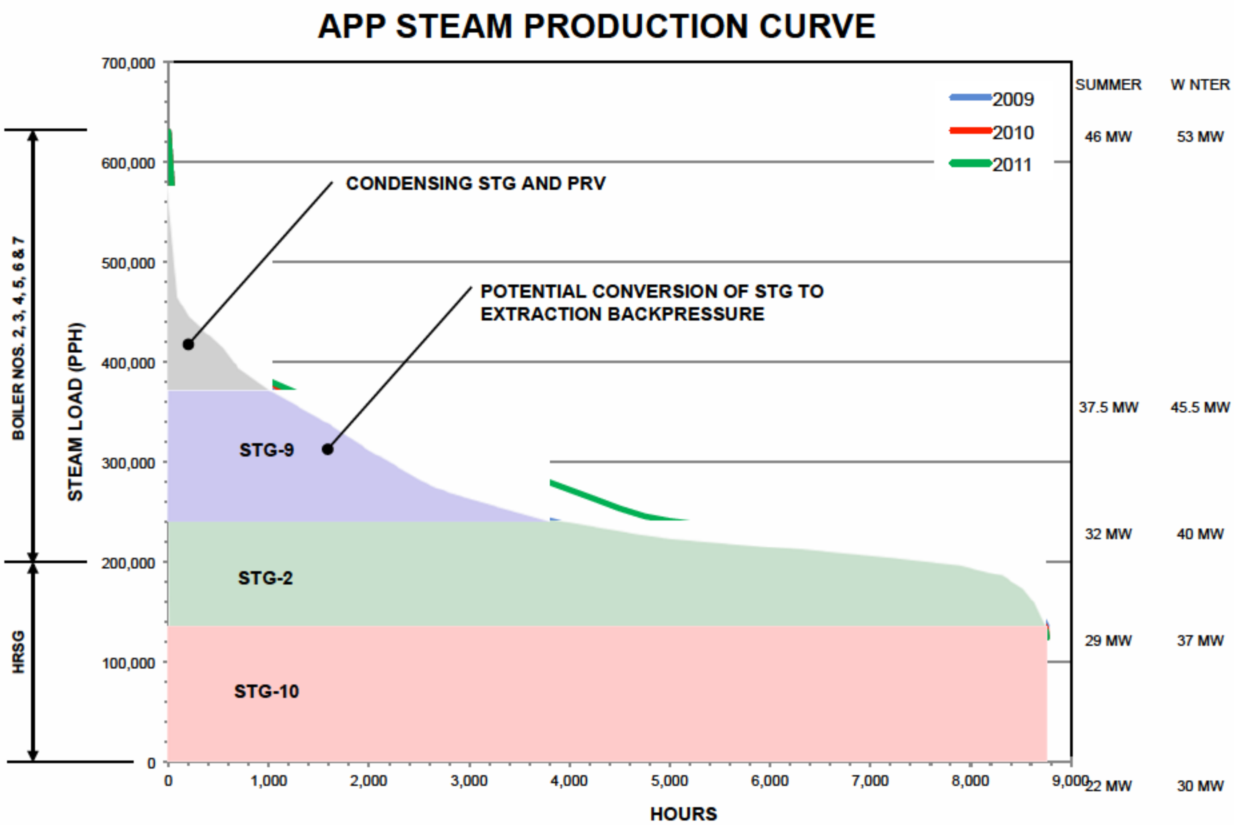
It can be seen from the figure that the gross steam output of the new HRSG is increased by approximately 30% on a mass basis. An optimization of the second economizer should be developed to determine the most cost effective media and associated characteristics at unfired and fired operations.

6. The existing APP is required to generate electric power required by the campus when the demand increases above 60 MW. The CT electric output is critical to meet the self-generated power demands of the campus. If the high pressure (850 psig) steam piping system is out of service for normal maintenance or an unexpected failure, the CT's cannot presently operate. A reconfiguration or supplemental steam piping system should be considered or a HRSG breeching bypass (dump stack) should be possibly investigated.

7. The CTs are not provided with inlet cooling. Inlet cooling will result in higher electrical power outputs and lower heat rates when the ambient temperature is elevated (summer). In addition, the value of the electric power generated is increased as ambient temperatures increase. APP investigated the feasibility of installing CT inlet cooling and has plans to add inlet cooling as an Energy Savings Contract project in 2015/2016.

8. The majority of the steam distributed to campus is correctly passed through a steam turbine generator. The only two steam turbine generators that are extraction/backpressure operation are STGs 2 and 10. Because the campus steam demand far exceeds the throttle rates of these two STGs, additional STGs with condensing sections are operated. The minimum steam flow through the condensing sections of all STGs, except STGs 2 and 10, is elevating the in-plant usage and reducing plant efficiency. APP is investigating the addition of extraction/backpressure STG capacity.

   The following figure indicates the APP steam duration curve and present dispatch of the steam turbine generators.



   The possible conversion of one of the existing STGs from a condensing to a backpressure turbine stage would increase APP efficiency and reduce operating cost. The annual savings of this STG conversion is approximately $230,000 per year.

9. The ongoing maintenance protocol for the feedwater pumps should be maintained by routinely checking vibration through a third party annually. Pump seals should be routinely checked for proper alignment (tightness) and leakage. Some pump seals were in poor condition and should be replaced as identified in the pump summary tables. During a scheduled shutdown, each feedwater pump (and turbine drive) should have the casing cover pulled for a visual inspection of the rotating element.

10. The same routine maintenance (as for feedwater pumps) should be applied to all large pumps in the plant such as the condensate forwarding pumps and circulating water

pumps. Several of the circulating water pump seals and shafts are corroded and should be replaced and/or repaired by a third party.

11. The University should consider internal tank inspections for the DC heaters that are planned for continued operation over the next ten years. It is recommended a third party inspector do a mag-particle or dye-penetrant test on the tank welds and NDT thickness testing of the storage tank to determine any metal loss. The same methodology should be applied to the condensate return tanks to identify immediate repairs unless the tanks are to be replaced within the next five years.

12. Repairing/replacing any damaged drift eliminators and/or tower fill when discovered during internal inspections should be implemented. The towers are critical for continual operation of the condensing steam turbines. Some field devices on the towers require replacement due to the wet operating conditions and outdoor environment. The University should consider a third party to conduct a thorough cooling tower inspection. AEI has been an integral part of these types of tower inspections on other projects.

13. Upgrading several desuperheater stations in the southeast basement area should be initiated. The desuperheating feedwater piping and control valves should be replaced and relocated downstream of the steam pressure regulating valves. The steam pressure reducing valves should also be replaced as part of this modification. These upgrades will provide the required temperature control. The has indicated that a PRV repair project is currently in design with possible implementation in the fall of 2015.

14. In the near future, it is recommended that an automated heat and mass balance be developed for the APP steam and electric generation systems. The model would indicate all system flows and thermodynamic conditions of each major piping system within the plant at any possible operating condition and strategy.

15. On August 30, 2012 the President of the United States issued an Executive Order promoting the use of combined heat and power following the lead taken by the U.S. Environmental Protection Agency (EPA) for the past three years. The University of Illinois at Urbana - Champaign should possibly convey to the campus as well as legislators that the Abbott Power Plant has complied with the intent of the recent 2012 Executive Order for the past 70 years.

16. The supply and availability of natural gas continues to increase in the United States as well as North America. As with coal, the United States is beginning to export natural gas. As demand increases for natural gas through the increased use for utility electric generation as well as the future possibility of vehicular transportation fuel, the present low unit cost of natural gas may increase.

    There is some uncertainty to the continued mass recovery of natural gas from fracking, which has significantly increased the present supply of low cost natural gas. There are actions in both the private and federal sectors to impose strict environmental standards to limit or eliminate fracking.

In the early 1970's, the University switched from coal to an oil based operation. At this time, oil was the lowest cost fossil fuel available in the United States. After a few years of oil operation, the cost of oil escalated and coal was reintroduced to Abbott.

Because of the uncertainty of long term low cost natural gas and the good condition of the Abbott coal systems, from an economic perspective it is recommended to continue to plan to utilize coal for the next ten years. It is very difficult if not impossible from an environmental permitting standpoint to eliminate coal operations and then restart coal operations if natural gas costs increase. This proposed ten-year window will allow for the cost of natural gas to stabilize as well as have existing operational combustion systems that can readily utilize various new fuel sources being developed. Developments in modular nuclear, chemical looping or geothermal may become economically feasible in the next 50 years.

In addition, the time to design, permit and construct new gas/oil boilers would be approximately ten years.

The State of Illinois has the second largest quantity of coal reserves within the United States (100 billion tons). The elimination of coal from Abbott will impact the economy of the state.

The steam being generated from coal in the Abbott Power Plant is utilized in a cogeneration configuration. The steam is passed through extraction/backpressure steam turbine generators to produce electricity prior to being exported to the campus for heating purposes. The use of an extraction/ backpressure steam turbine generator (STG) is the most efficient means of generating electricity from fossil fuels. The exhaust steam from the extraction/ backpressure STG is utilized as useful heat. The only losses of an extraction/ backpressure STG are associated with the electric generator and drive (+/- 4%). The heat rate of an extraction/ backpressure STG including boiler efficiency is approximately 4,340 btu per kilowatt hour compared to a condensing STG heat rate of 10,000 btu per kilowatt hour. Because of the efficiency of the Abbott electric generating systems, the regional carbon footprint from typical coal firing is reduced by approximately 28%.

The combustion of natural gas in comparison to coal will result in less carbon dioxide emissions based upon an equivalent fuel input. Natural gas consists mainly of methane (CH4). The global warming potential of methane is 21 utilizing a carbon dioxide global warming potential of unity. The slippage or leaking of natural gas production and distribution has a significant effect on the gross or actual global warming potential. The natural gas slippage quantity to make the combustion of coal and natural gas equivalent in global warming potential is less than 5%. The gas industry approximates slippage at approximately 2.5%. Very preliminarily and approximate EPA testing is indicating actual slippage greater than initially expected.

17. Abbott Power Plant (APP) generates approximately 275,000 megawatt hours (MWH) of electricity each year through the use of a high efficiency cogeneration process. The existing APP operation supplies approximately 50% of the total U of I campus electricity.

The present APP output utilizing the high efficiency cogeneration process compared to the regional grid reduces air emissions by:

- Carbon Dioxide 101,000 tons per year
- Oxides of Nitrogen 560 tons per year
- Sulfur Dioxide 1,430 tons per year

The regional carbon dioxide reduction of 101,000 tons per year is equivalent to the removal of 18,000 automobiles off Illinois highways or the reforesting of 21,000 acres of land.

Presently APP generates electricity at a carbon dioxide rate of 0.87 pounds per kilowatt-hour. This existing rate is **below the proposed EPA standard** of 1.00 pounds per kilowatt-hour for new generating equipment. Due to the best-in-class emission control system, APP was recently tested to be **under the new MACT limits by a factor of 15**. The Chiyoda Jet Bubbling Reactor (JBR) not only has maximum scrubbing of sulfur dioxide but also removes mercury emissions to near non-detectable limits.

18. Many of the ancillary support systems within the plant correctly utilize backpressure steam turbine drives. As the exhaust steam pressure periodically rises above operating setpoint, the steam turbine devices are secured and alternate electric motor-driven equipment is utilized. A multiport valve installed on the low pressure exhaust header would allow for continued use of backpressure steam turbine driven equipment by exhausting excess steam (pressure) to atmosphere via the multiport valve thus maintaining a constant pressure in the low pressure exhaust system. This enhances plant flexibility and operation. The atmospheric discharge from a multi-port valve is limited and periodic, and provides a short duration period in which non steam driven equipment can be energized.

    According to the University, the plant is considering installing additional 50 psig and 150 psig auxiliary steam systems to more effectively feed steam driven equipment. Utilizing a low pressure steam exhaust header in the plant that ties into low pressure supply to other equipment (DC heaters) is recommended and is in progress by the University. A loop-type auxiliary low pressure exhaust system can be implemented for redundancy utilizing two multi-port valves, one on each side of the loop.

19. There are a number of plant computer control “screens” that should be updated. Typical examples are STGs 2 and 10, which indicate a condenser. It can be a valuable exercise for the plant to audit or review the operating graphic systems periodically.

20. Means for constant boiler feedwater header pressure control for these systems should be investigated. The use of automatic recirculation (ARC) valves or pressure regulating valves through recirculation lines can be utilized on the feedwater pumps and elevation/condensate pumps back to the DC heaters and condensate tanks respectively. Constant header pressure control would be fully automatic and adjustable to operations desired condition.

3.2 Chiller Plants

General

A global ten-year business as usual assessment analysis was performed with a focus on major equipment. The assessment evaluates the existing equipment and proposes recommendations to modernize this equipment.

The global assessment was developed by performing the following tasks:

- Review of past studies and projects
- Interview with plant operators and managers
- Visual assessment of major equipment both idle and operating
- Review of maintenance and operation procedures
- Review of available operating data and major equipment repair history

The University central chilled water system consists of six chiller plants and approximately 23 miles of chilled water distribution piping. Chillers range in age from the oldest being installed in 1993 and the newest in 2012. The chilled water system also includes a 6.5 million gallon thermal energy storage tank with a 12,000 gpm maximum discharge capacity.

The existing plants connected to the central system and respective capacities are indicated in the following table. The Veterinary Medicine Chiller Plant is currently isolated from the central system. The capacity of the Veterinary Medicine Chiller Plant is indicated in the following table.

CAMPUS CHILLED WATER CAPACITY		
CHILLED WATER LOOP	DESCRIPTION	PLANT CAPACITY (TONS)
MAIN CAMPUS	OAK STREET CHILLER PLANT	27,630
	NORTH CAMPUS CHILLER PLANT	9,400
	LIBRARY AC CENTER	4,340
	ANIMAL SCIENCE AC CENTER	2,000
	CHEM LIFE-SCIENCE AC CENTER	3,630
	SUBTOTAL	47,000
VET	VET MED CHILLER PLANT	4,700
TOTAL		51,700

Each of the existing chiller plants is configured to run in either a fixed flow output mode or a differential pressure mode to satisfy campus building loads. The North Campus Chiller Plant is most often operated in differential pressure mode with the remaining plants typically operating in fixed flow output mode. When any plant is operating in differential pressure mode and is not isolated from the loop (i.e. if the CHWS/R isolation valves at the plant entrance are in the open position), the differential setpoint is determined by the Operator, based on the requirements of the buildings. Differential pressure is measured and maintained by the secondary pumps where the chilled water supply and return of the respective operating plant leaves the plant. The system is operated to maintain a 25 psig differential pressure at each of the hydraulically worst buildings in the distribution system. At any given time, several buildings on campus may constitute the worst hydraulic case.

As new buildings are being connected to the central system, some buildings have been equipped with heat recovery equipment that is tied to and contributes chilled water to the central distribution system while serving the heating loads of the respective building. The Electrical and Computer Engineering building as well as the Ikenberry Commons complex have currently implemented this type of heat recovery system. The long-term goal being an investigation as to how heat pump chillers could serve portions of the campus on a larger scale rather than having smaller units spread throughout the campus.

The Thermal Energy Storage system (TES) operates as fixed output by introducing a fixed flow into the system as set by the Operator. The TES may be charged by any plant in the system; however, the University has experienced problems with temperature and pressure when charging from the North Plant with other plants not in operation. These issues include insufficient pressure at the TES to charge the tank and supply water temperatures elevated as much as three degrees above the desired forty degree storage temperature. The TES system is used on a daily basis and the University utilizes the stored thermal energy over a 12hr period each day at an output rate between 6,000 and 8,000 gpm.

The Oak Street, North Campus, Library, Chem Life Sciences and Animal Sciences plants may all be isolated from the chilled water distribution network and still serve either one or more buildings while operating in a differential pressure mode. This mode of operation is implemented only in the event of an emergency if the central distribution system is not available. The building service of each plant under isolation mode is as follows:

- Oak Street Chiller Plant - Physical Plant Services Building (PPSB), future connection to Housing Food Stores.
- North Campus Chiller Plant - Microelectronics Laboratory, Beckman Institute, Computer and Systems Research Laboratory, Civil Engineering Hydrosystems Laboratory, Newmark Civil Engineering Building, Digital Computer Laboratory, future Electrical and Computer Engineering Laboratory.
- Library Air Conditioning Center - Main Library
- Chem Life Sciences Plant - Chem Life Science Building
- Animal Sciences Plant - Animal Sciences Building, Madigan Laboratory, Turner Hall, ACES Library

The winter campus load is 3,000 to 6,000 tons and peak summer peak load exceeds 30,000 tons. The Petascale building is equipped with a cooling tower array for free cooling and will utilize these towers when outdoor temperatures allow. There may be periods during the winter months when the building will continue to rely on chilled water from the central system for cooling if the cooling towers at the building are not available, thereby altering the existing winter load.

The existing chiller plants connected to the central chilled water distribution system are piped in a primary/secondary pumping configuration with a dedicated primary pump per chiller. Installation of variable speed drives on the primary pumps varies depending on the plant, but Oak Street is the only plant in the system that varies the flow of the primary pumps to match secondary flow out of the plant. In the case of the Library Plant and Animal Sciences Plant, the fixed output of the plant is set by the operator to match the primary flow to prevent unnecessary recirculation of chilled water supply within the plant. The North Campus plant contains 2,400 tons of chillers equipped with variable speed drives for reduced energy consumption during low loads. A new 2,800 ton variable speed drive chiller has also been installed in the Oak Street plant to bring the campus wide tonnage on variable speed drives to 5,200 tons.

The chiller plants connected to the central system all utilize a control sequence for the reduction of condenser water supply temperature to maximize system energy savings. In most of the plants, whether the tower fans operate on variable speed drives or are equipped with two speed motors, the condenser water supply setpoint is between 60°F and 75°F. The condenser water setpoint is not modulated and towers operate in an effort to satisfy the setpoint temperature by fan speed modulation or by turning fans on and off. However, the Oak Street Chiller Plant also utilizes a condenser water control sequence to track outdoor wet bulb temperatures.

Oak Street, Library, Chem Life Sciences, Animal Sciences and North Campus Plants are all configured with Emerson Delta V DCS controls and are able to be controlled from either the North Campus or Oak Street Plants.

Summer temperature differential between the 40°F supply temperature and return temperature is normally 16°F. During the winter months, the return water temperature may fall to 44°F causing the operating chillers to run inefficiently. This condition has been reviewed by University staff and they found that in some instances when the freeze control system on the air handling units (AHU) sensed 40°F on the coil, the AHU valve was driven wide open causing an excessive amount of supply water to be blended back into the return water. The University has initiated a procedure that limits the AHU valve in these conditions to 35% open to reduce the flow through the coils while still preventing the coil from freezing. All of the buildings on the chilled water system are metered, and where this method has been implemented, the University has noted a reduction in flow by as much as 80%. The goal is to continue implementation of this method and increase the return water temperature to the plants during winter operation.

The sixth chiller plant on campus, Veterinary Medicine Plant, is not connected to the central system. The plant is configured in a primary/secondary pumping configuration much like the other plants on campus with the secondary pumping system modulating to maintain differential pressure to serve loads. A set of secondary pumps serve loads for the Large Animal and Small Animal buildings and a single secondary pump serves loads for the Basic Sciences Building. There is redundant capacity installed in the plant, but as additional capacity was added to the plant, the header size was not increased. This has resulted in flow issues when multiple chillers are operated. Therefore, the plant is constrained to 3,200 tons due to the existing header.

All of the central plants in the system including Veterinary Medicine are in good condition with most issues being related to the respective cooling towers. The Veterinary Medicine tower, which serves chillers CH-3 and CH-7 being the tower which requires the most attention. Towers at North Plant, Animal Science, Chem Life Sciences and Veterinary Medicine all are observed to have buildup of scale on the fill and in some cases the air pathways of the fill are obstructed. Towers at Veterinary Medicine, Library and Chem Life Sciences are observed to be leaking and in need of repair. At Veterinary Medicine, plans are in place to seal the leaking sump on the cooling tower serving CH-7. There are also projects in progress at both the North Campus and Library chiller plants to replace the most troublesome towers at each location. All of the pumping systems and chillers appear to be in good condition, operating well and are well maintained.

Oak Street Chiller Plant

Description

The Oak Street Chiller plant consists of (2) 5,000 ton York steam driven centrifugal chillers CH-1 and CH-2, (1) 2,000 ton York electric centrifugal chiller CH-3, (1) 2,200 ton York electric centrifugal chiller CH-4, (1) 5,000 ton York electric centrifugal chiller CH-5, (1) 2,800 ton variable speed York electric centrifugal chiller CH-6 and (1) 5,630 ton York electric centrifugal chiller CH-7. The plant piping is arranged in a primary/secondary configuration and each of the chillers are served by a dedicated primary chilled water pump and dedicated condenser water pump. Eight counter flow field erected cooling towers are located in two concrete basins on grade to the west of the plant. Four of the cells are in a common concrete basin to the north and four of the cells are in a common concrete basin to the south with a dedicated underground sump for each basin. Tower fans are equipped with variable speed drives to modulate fan speed to maintain condenser water supply temperature.

Two, 5,000 ton chillers CH-1 and CH-2 are steam turbine driven from steam provided by the Abbott Power Plant and the steam distribution system. These steam turbine chillers are capable of variable speed operation, and are often operated in this manner. The University has indicated that these two chillers are currently utilized when purchased power from Ameren approaches the import limit. However, the chillers are not typically run in the summer to prevent Abbott from specifically running a boiler to produce steam during the warmer months. There are also times when APP is required to generate power, and when this occurs, it is helpful to have a sufficient steam load on the distribution system. The large steam turbine chillers are capable of providing this load if the campus steam demand is minimal during this time period. This condition is based on the fact that with today's electric rates, Abbott can purchase the electrical power to run electric chillers cheaper than the cost associated with making the power and sending excess steam to the steam driven chillers.

Chiller 6 is a 2,800 ton chiller equipped with a variable speed drive and the remaining electric driven centrifugal chillers (Chillers 3, 4, 5, & 7) are constant speed machines and vary load by modulating vanes at the compressor.

Some of the existing condenser water pumps are equipped with variable speed drives; however, the VFDs are used for balancing and do not modulate flow through the chillers. The condenser water system in this plant is setup to operate in two different modes. The first mode uses wet bulb temperature feedback to optimize the condenser water supply setpoint. The second mode sets the condenser water supply temperature at 60°F rather than tracking outdoor wet bulb temperatures, which can lead to unnecessarily operating fans at higher speeds when supply temperature is limited by outdoor wet bulb. Chiller efficiency is increased with lower condenser water supply temperature.

The Oak Street Plant is operated as a fixed flow output plant with the North Plant modulating to maintain differential pressure at the buildings. All of the dedicated primary pumps are equipped with variable speed drives and flow through the chillers is modulated to match the output flow of the plant keeping flow through the primary/secondary bridge to a minimum. Operators indicate that chiller CH-6 is always the first chiller to start in the plant sequence and the last chiller to be turned off due to its efficiency. As with the North Plant, differential pressure is measured in the plant to control pump speed. When charging the Thermal Energy System, the required number of chillers for charging are brought online at the Oak Street Plant. The tank is currently charged and discharged daily for campus energy savings.

Chillers maintain a 40°F supply water temperature to the central chilled water loop when the plant is in operation in either the fixed output mode or the differential pressure mode. In the differential pressure mode, chillers are staged on and off to maintain set point temperature based on kW readings from the chillers. The normal return water temperature during peak load conditions is generally 56°F. As with the North Plant, during winter months of operation, return water temperature can fall to as low as 44°F. The typical campus wintertime load is between 3,000 and 6,000 tons.

When possible, free cooling is utilized as an energy saving measure in the plant. All free cooling is accomplished by natural refrigerant migration in the large chillers with the chiller turned off and the condenser and evaporator pumps in operation. During this mode of operation, the condenser water supply temperature setpoint is typically maintained at 35°F. To date, free cooling has only been accomplished with the steam units, CH-1 and CH-2.

The existing control system is operating on the Emerson Delta V platform. The controls were upgraded in an effort to standardize and have the ability to control all chiller plants across campus from the Oak Street Plant.

Summary of Noted Issues

- There are not considered to be any noteworthy issues or deficiencies at this plant.

Replacement Cost of Existing Equipment

Conceptual capital costs are developed for equipment repair and replacement for the business-as-usual scenario and is listed in the following Table. Detailed estimates are provided in Appendix 3C. The BAU scenario is further described in Section 7.

OAK STREET CHILLER PLANT EQUIPMENT REPLACEMENT SCHEDULE				
EQUIPMENT	CAPACITY (TONS)	YEAR INSTALLED	REPLACE. YEAR	REPLACE. COST ($)
CHILLER 1 (OM)	5,000	2004	2044	6,882,000
CHILLER 2 (OM)	5,000	2004	2044	6,882,000
CHILLER 3 (PACKAGED)	2,000	2004	2034	2,770,000
CHILLER 4 (PACKAGED)	2,200	2005	2035	3,044,000
CHILLER 5 (PACKAGED)	5,000	2007	2037	6,882,000
CHILLER 6 (PACKAGED)	2,800	2008	2038	4,286,000
CHILLER 7 (PACKAGED)	5,630	2012	2042	7,745,000
CT 1	10,000	---	2023	1,629,000
CT 2	10,000	---	2023	1,629,000
CT 3	10,000	---	2023	1,629,000
CT 4	10,000	---	2023	1,629,000
CT 5	10,000	---	2027	1,629,000
CT 6	10,000	---	2027	1,629,000
CT 7	10,000	---	2032	1,629,000
CT 8	10,000	---	2032	1,629,000
TOTAL	27,630	---	---	51,523,000

North Campus Chiller Plant

General

The North Campus Chiller plant consists of (2) 1,200 ton York electrical centrifugal variable speed chillers CH-1 and CH-7, (3) 1,000 ton York electrical centrifugal chillers CH-2, CH-3 and CH-5, and (2) York 2,000 ton York electrical centrifugal chillers CH-4 and CH-6. Each of the chillers are served by a dedicated primary chilled water pump and dedicated condenser water pump. Two cross flow cooling towers are located on the roof of the plant, one five cell tower, CT-1 through CT-5, serves all of the chillers in the plant with the exception of chiller CH-6 which is served by dedicated tower CT-6.

Chillers CH-1 through CH-5 and CH-7 are served by a five cell cross flow tower orientated east/west above the center of the plant. The existing towers are located on the roof such that when chiller CH-6 was installed, the new tower had to be located to the south of the existing towers with its air intakes facing east/west rather than north/south as the five cell tower is configured. More importantly, the current location and configuration of the five cell tower would prohibit the installation of an additional tower lineup without encroaching on the required clearances of both the existing towers and any new towers. It should be noted that there are a total of six towers serving seven chillers. Not all chillers in the plant are capable of running on the six tower cells which currently constrains the plant output to less than full chiller capacity. The five cell tower has two speed fans with temperature modulated by switching fan speeds and turning fans on and off. Two of the five cells are configured to supply condenser water to either the main header, or a separate indoor sump for wintertime operation. However, it is believed that this indoor sump has not been utilized during the last of couple winters. Tower CT-6 is equipped with a VFD for fan modulation but due to vibration issues cannot be run past 42Hz, thereby limiting its capacity.

A project is currently underway to replace CT-6. In this project, CT-6 will be replaced with two 1,300 ton cross flow packaged towers. Along with serving CH-6, these towers will also be tied into the existing condenser water supply and return headers to contribute some additional capacity to the plant. As mentioned above, until the five cell tower is replaced and shifted north, the new towers may experience reduced capacity due to inadequate clearance between them and the existing lineup. Additionally, this project will develop a conceptual plan to replace the remaining towers and add new towers in the remaining free space on the roof. With the full cooling tower build-out, the North Campus Chiller Plant would have the condenser water capacity to support the potential maximum buildout tonnage of this plant. This maximum tonnage is based on the size of the chilled water supply and return headers entering and leaving the plant.

All of the existing centrifugal chillers, with the exception of CH-1 and CH-7, are constant speed machines and vary load by modulating vanes at the compressor. CH-1 and CH-7 are equipped with variable speed drives and modulate load by using a combination of variable compressor speed and vane modulation. Each of the respective primary chilled water and condenser water pumps are currently operated at constant speed. Some of the dedicated evaporator and condenser pumps are equipped with variable speed drives; however, all VFD's are used for balancing only and operate as soft start for the pump motors. Chillers CH-2, CH-3 and CH-5 all have control valves in the evaporator piping that are used to modulate flow through the chiller. The primary pumps for these chillers are constant speed and flow is modulated by the control valve and flow meter for each respective chiller.

The plant is configured in a primary/secondary arrangement with constant primary flow and variable secondary flow. Secondary flow is provided by five distribution pumps that are piped in parallel to serve both the south and north piping loops out of the plant. Flow on both loops is monitored by individual flow meters for each respective loop. The plant is operated year round in differential pressure mode to maintain differential pressure to the buildings on campus. Differential pressure from the buildings is not used to control the speed of the secondary pumps directly. Rather, feedback from a differential pressure sensor located in the plant is used to modulate the secondary pumps and this value is compared with building differential pressure by the Operator to determine the plant setpoint.

Chillers are staged on automatically in order to maintain a 40°F supply water temperature to the buildings. Chillers are staged off by the control system monitoring the kW energy usage of each chiller and adjusting the number of operating chillers to serve the load. The normal return water temperature during peak load conditions is generally 56°F. During winter months of operation, return water temperature can fall to as low as 44°F. The typical campus wintertime load is approximately 3,000 tons, with the maximum wintertime load being approximately 6,000 tons.

The existing control system is operating on the Emerson Delta V platform. The controls were upgraded 3 years ago in an effort to standardize and have the ability to control all of the chiller plants across campus from a central location. Operators indicate that the Emerson Delta V platform has been very reliable.

Summary of Noted Issues

- The installed cooling tower capacity only allows six of the seven chillers to operate simultaneously. The plant was constructed for N+1 chillers but now that there are multiple plants connected to the chilled water distribution system, every plant is not required to have N+1 redundancy provided that there is at least one N+1 chiller connected to the system. A project is currently underway to eliminate this issue.
- The 5 cell cooling tower on the roof is located such that parallel cooling towers cannot be located adjacent to the existing. Any addition of cooling towers on the roof will require that columns be extended to the roof and existing exhaust fans and roof access hatch be relocated. A conceptualization project is currently underway to eliminate this issue. However, the actual implementation of this concept will not occur until a future project is developed.
- The single cooling tower CT-6 that serves chiller CH-6 has damaged fill, vibration issues and is generally not in good condition. The 5 cell cooling tower also has areas of minor fill damage and small holes in side wall casings. A project is currently underway to replace CT-6 with two 1,300 ton cross flow packaged towers, which will eliminate the issues associated with CT-6.
- The five cell cooling tower utilizes 2 speed fans rather than variable speed drives to maintain condenser water supply temperature. The condenser supply temperature is held at 65°F rather than tracking outdoor wet bulb. This condition may result in unnecessarily operating fans when supply temperature is limited by outdoor wet bulb.
- The 24" main chilled water supply and return header which serves both the north and south loops limits the output capacity of the plant to 10,000 tons at 16°F delta T. To upgrade chillers and exceed this capacity in the plant, cooling tower revisions and header revisions would be required. If the 24" header inside of the plant is upsized, the total capacity of the underground 30" and 20" distribution piping would support a plant production of approximately 14,500 tons.
- Primary pumps with VFDs are not used to vary flow through chillers and match secondary flow even though flow meters are installed in the evaporator circuits of all chillers. Rather, flow through the chillers is varied by throttling the pump output with control valves. Regulating the flow rate with the control valves is considerably less efficient than regulating the pump flow with the VFDs on the pump motors.
- The existing chilled water and condenser water systems all have external weight and lever check valves. These valves have high pressure drops and are not typically used for campus chilled water plants.
- Chillers have been installed without reconfiguring existing piping arrangements in the plant. This has caused some issues with accessibility and should be examined with the next chiller replacement.

Replacement Cost of Existing Equipment

Conceptual capital costs are developed for equipment repair and replacement for the business as usual scenario and is listed in the following Table. Detailed estimates are provided in Appendix 3C. The BAU scenario is further described in Section 7.

NORTH CAMPUS CHILLER PLANT
EQIUPMENT REPLACMENT SCHEDULE

EQUIPMENT	CAPACITY (TONS)	YEAR INSTALLED	REPLACE. YEAR	REPLACE. CAPACITY (TONS)	REPLACE. COST ($)
CHILLER 1 (PACKAGED)	1,200	2001	2023	2800	4,286,000
CHILLER 2 (PACKAGED)	1,000	1998	2020	1200	1,674,000
CHILLER 3 (PACKAGED)	1,000	1998	2020	1200	1,674,000
CHILLER 4 (PACKAGED)	2,000	2000	2022	2800	4,286,000
CHILLER 5 (PACKAGED)	1,000	1997	2019	2800	4,286,000
CHILLER 6 (PACKAGED)	2,000	2001	2023	2800	4,286,000
CHILLER 7 (PACKAGED)	1,200	2001	2023	2800	4,286,000
CT 1	3,450	---	2014	---	632,000
CT 2	3,450	---	2014	---	632,000
CT 3	3,450	---	2014	---	632,000
CT 4	3,450	---	2014	---	632,000
CT 5	3,450	---	2014	---	632,000
CT 6	4,400	---	2021	---	750,000
TOTAL	9,400	---	---	16,400	28,688,000

Library A/C Center

General

The Library Air-Conditioning Center consists of (1) 1,000 ton York centrifugal chiller CH-4, (2) 1,100 ton York screw chillers CH-5 and CH-6, (1) 1,140 ton York absorption chiller CH-7. In addition to these operational chillers, there are two abandoned Carrier absorption chillers, along with the associated abandoned pumps and piping. Each of the chillers are served by a dedicated primary chilled water pump and dedicated condenser water pump. The plant is configured in a primary/secondary configuration with a bridge and variable secondary pumps. Four cross flow cooling towers are located on the roof of the building and are dedicated to the respective chillers with the exception of CT-5 and CT-6, which share common piping. Condenser water piping from the abandoned absorption chillers is terminated at the roof level.

Chiller CH-4 is served by a stainless steel Marley tower CT-4 at the north end of the roof with a single fan. Chillers CH-5 and CH-6 are both served by separate two cell cross flow cooling towers located in the center of the roof. Cooling towers for CH-5 and CH-6 are in a two cell configuration, and each tower is constructed with a galvanized steel structure and fiberglass casings. Towers CT-5A, 5B and CT-6A, 6B are configured with common piping to allow CH-5 or CH-6 to utilize all four tower cells. As currently configured, each cell has manual isolation valves, and therefore cannot be automatically isolated from each other. Absorption chiller CH-7 is served by a two cell BAC tower CT-7A, 7B located on the south end of the roof. The tower for CH-7 is constructed with a stainless steel structure and fiberglass casing. The tower for CH-7 was noted to be leaking during the inspection and towers for CH-5 and CH-6 were both noted to have small basin leaks. The leaks appear to be seam leaks and are scheduled for repair.

A project is currently underway to replace towers CT-5A, 5B, 6A and 6B. All cooling tower fans are configured with variable speed drives to modulate fan speed to maintain condenser water supply temperature. Chiller efficiency is increased by setting the condenser supply temperature for all chillers to 70°F regardless of outdoor wet bulb. There is currently no system in place to reduce condenser water temperature setpoint to track outdoor wet bulb.

All of the existing centrifugal chillers are constant speed machines and vary load by modulating vanes at the compressor. Each of the respective primary chilled water and condenser water pumps are currently operated at constant speed. The plant is configured in a primary/secondary arrangement with constant primary flow and variable secondary flow. When in operation, the plant is typically operated in a fixed flow output mode with two of the electric chillers in operation. The secondary flow of the plant is selected to match the primary flow since the primary pumps for the chillers are not equipped with variable speed drives.

Both of the secondary pumps are relatively new and were installed with the capability of adding a future third pump so that capacity from the plant could be further increased. There is significant space that could be recaptured in the plant with the removal of the existing abandoned absorption chillers, associated primary chilled water pumps and condenser water pumps, and all associated abandoned piping. There appears to be adequate space to locate two new towers on the roof to serve new capacity. New towers would require that a complete new tower support structure be constructed. However, further structural analysis would need to be performed to verify that the existing structure could support this additional load on the roof.

Chillers maintain a 40°F supply water temperature to the central loop with the normal return water temperature during peak conditions being 56°F. Two of the chillers are run in fixed output mode during the summer months and plant operation is discontinued during the winter months.

The existing control system is operating on the Emerson Delta V platform. The controls were upgraded in an effort to standardize and have the eventual ability to control all of the chiller plants across campus from the Oak Street Plant.

The chilled water piping has been configured to connect the plant to the central system and feed the Library piping loop from the central system. The chilled water connection for the Library building itself remains connected inside the plant but can be served from the central loop when the Library Plant is not in operation.

Summary of Noted Issues

- The cooling tower serving CH-5, CH-6 and CH-7 are leaking.

- The current Library Master Plan includes a plan to remove the existing cooling towers from the roof and install new towers on the west end of a new addition that will extend further westward. Since it is unknown if the Library Master Plan project will move forward or in what time frame it would occur, a project is underway to replace towers CT-5 and CT-6.
- CT-5 and CT-6 were designed for a CW temperature difference of 15°F. This issue is being addressed in the tower replacement project.
- With the exception of CT-5 and CT-6, cooling towers are dedicated to an individual chiller and chillers cannot utilize various towers.
- CT-5 and CT-6 are connected to a common header, but cannot currently be isolated from one another. This has likely resulted in occasional low flow conditions in the towers that has accelerated scale buildup on the fill. A current project is being conducted to replace CT-5 and CT-6 and will address this issue.
- The condenser supply temperature is held at 70°F rather than tracking outdoor wet bulb. This condition may result in unnecessarily operating fans when condenser supply temperature is limited by outdoor wet bulb conditions.
- The CW pumps serving CH-5 and CH-6 are designed for 2 GPM/ton rather than preferred 3 GPM/ton. These pumps should be upsized.

Replacement Cost of Existing Equipment

Conceptual capital costs are developed for equipment repair and replacement for the business as usual scenario and is listed in the following Table. Detailed estimates are provided in Appendix 3C. The BAU scenario is further described in Section 7.

LIBRARY A/C CENTER
EQUIPMENT REPLACEMENT SCHEDULE

EQUIPMENT	CAPACITY (TONS)	YEAR INSTALLED	REPLACE. YEAR	REPLACE. COST ($)
CHILLER 4 (PACKAGED)	1,000	2000	2023	1,674,000
CHILLER 5 (PACKAGED)	1,100	1993	2016	1,674,000
CHILLER 6 (PACKAGED)	1,100	1993	2016	1,674,000
CHILLER 7 (PACKAGED)	1,100	1999	2020	1,674,000
COOLING TOWER 4 (PACKAGED)	3,000	2000	2025	576,000
COOLING TOWERS 5 (PACKAGED)	2,000	1993	2014	451,000
COOLING TOWERS 6 (PACKAGED)	2,000	1993	2014	451,000
COOLING TOWER 7 (PACKAGED)	4,100	1999	2018	714,000
TOTAL	4,300	---	---	8,888,000

Animal Science Chiller Plant

General

The Animal Sciences plant consists of (2) 1,000 ton York centrifugal chillers CH-3 and CH-4. Two existing carrier chillers CH-1 and CH-2 are also connected to the system but are abandoned and not used. Each of the chillers are served by a dedicated primary chilled water pump and dedicated condenser water pump. The plant is configured in a primary/secondary configuration with a neutral bridge and variable secondary pumps. A five cell cross flow cooling tower is located on the roof of the Animal Sciences Building with one of the cells piped separately to an indoor sump which is currently not in use. The remaining four cells are connected to a common header and serve chillers CH-3 and CH-4.

Both of the existing centrifugal chillers CH-3 and CH-4 are constant speed machines and vary load by modulating vanes at the compressor. Each of the respective primary chilled water and condenser water pumps are operated at constant speed. The dedicated primary pumps are equipped with variable speed drives; however, VFD's are used for balancing only and operate as soft start for the primary pump motors. Condenser pumps are constant speed and not equipped with variable speed drives. The plant is configured in a primary/secondary arrangement with constant primary flow and variable secondary flow. As previously mentioned, the plant is piped so that it can be isolated from the central chilled water distribution system and serve the Animal Sciences, Madigan Lab (previously called the Plant and Animal Biotechnology Lab), ACES Library and Turner Hall buildings.

Under normal conditions, the plant is open to the central chilled water distribution system and when the plant operates it is utilized in a fixed flow output mode. Only when the plant is isolated from the central system is it operated on a variable secondary flow mode with pump speed controlled to maintain differential pressure. When in fixed flow output mode, the secondary pumps vary speed to maintain a fixed flow out of the plant while pressure is variable. The plant currently operates at 100% capacity during the summer months and is turned off during the winter.

Chillers maintain a 40°F supply water temperature to the central system and typical return water temperatures are 56°F during summer operation. Chiller efficiency is increased by setting the condenser supply temperature to 60°F regardless of outdoor wet bulb. There is currently no system in place to track outdoor wet bulb.

The existing control system is operating on the Emerson Delta V platform. The controls allow Operators in the Oak Street Plant to monitor and control the chillers in the Animal Sciences Chiller Plant.

The plant installed capacity is 2,000 ton with a firm capacity of only 1,000 ton. The connected non-diversified load is 4,198 tons in the isolated plant mode. Non-diversified values are used since it is plausible that the four connected buildings would all be at peak load during an outage of the central chilled water loop. This represents a 2,198 ton shortage if the plant had to serve the connected load when isolated from the central chilled water loop and both chillers were functional. The loss of one chiller would result in a 3,198 ton shortage in the isolated mode. This indicates that the Animal Science loop cannot be isolated from the central chilled water loop in order to shed load in an emergency for the majority of the cooling season.

Summary of Noted Issues

- CH-3 and CH-4 were designed for a condenser water temperature difference of 15°F. This will need to be taken into account during a future project to replace these cooling towers.
- The cooling tower on the roof is close to the roof screen south of the tower. Although the roof screen has free area, the tower configuration is not ideal and may cause a reduction in capacity. On the north face of the towers, a rooftop air handling unit is very close to the towers which may inhibit proper airflow to the tower and reduce the tower capacity.
- One cell of the tower is not piped to the other 4 cells and is not currently utilized.
- During a majority of the cooling season, there is a lack of installed capacity if the plant needs to be isolated from the central chilled water distribution loop.
- A project was proposed and developed to add chiller capacity and install additional cooling towers on the open roof area to the east, but was never implemented. This project would include expanding winter operation capability. This may also be a location to add additional chilled water capacity to meet campus growth.

Replacement Cost of Existing Equipment

Conceptual capital costs are developed for equipment repair and replacement for the business as usual scenario and is listed in the following Table. Detailed estimates are provided in Appendix 3C. The BAU scenario is further described in Section 7.

ANIMAL SCIENCES CHILLER PLANT
EQUIPMENT REPLACEMENT SCHEDULE

EQUIPMENT	CAPACITY (TONS)	YEAR INSTALLED	REPLACE. YEAR	REPLACE. COST ($)
CHILLER 3 (PACKAGED)	1,000	2001	2023	1,400,000
CHILLER 4 (PACKAGED)	1,000	2001	2023	1,400,000
CT 1	1,000	---	2018	327,000
CT 2	1,000	---	2018	327,000
CT 3	1,000	---	2018	327,000
CT 4	1,000	---	2018	327,000
CT 5	1,000	---	2018	327,000
TOTAL	2,000	---	---	4,435,000

Chemistry-Life Sciences Chiller Plant

General

The Chem Life Sciences Chiller plant consists of (3) 1,200 ton York centrifugal constant speed chillers CH-1, CH-2 and CH-3. Each of the chillers are served by a dedicated primary chilled water pump and dedicated condenser water pump. A five cell cross flow cooling tower is located on the roof of the building and all five cells can serve any combination of chillers.

The five cell cross flow tower is connected to an indoor sump; however, only two of the five cells are connected to the indoor sump. The existing tower was upgraded with gear boxes, fans, new motors and VFDs in order to increase capacity and allow all chillers to operate simultaneously. Prior to the upgrade, the towers were selected to operate only two of the three chillers with one chiller being redundant but no tower capacity to support the redundant chiller. Operators noted that when trying to reduce condenser water temperature setpoint below 74°F under certain conditions, the upgraded fans and motors are powerful enough to draw water off the fill. Therefore, the condenser water setpoint is consistently held above 74°F.

Each of the primary chilled water and condenser water pumps are currently operated at constant speed. Each primary chilled water pump utilize across the line starting while all of the condenser pumps are equipped with variable speed drives. Variable speed drives on the condenser pumps are used for balancing only and the flow through the chiller condensers is not modulated.

Each of the three chilled water distribution pumps have variable speed drives. Under normal conditions, the plant is open to the central chilled water distribution system and when the plant operates it is utilized in a fixed flow output mode. Only when the plant is isolated from the central system is it operated on a variable secondary flow mode with pump speed controlled to maintain differential pressure in the Chem Life Sciences building. When in fixed flow output mode, the secondary pumps vary speed to maintain a fixed flow out of the plant while pressure is variable. The plant currently operates at 100% capacity during the summer months and is not operated during the winter.

When operating, chillers are staged on automatically in order to maintain a 40°F supply water temperature to the buildings. Chillers are then staged off by the control system monitoring the kW energy usage of each chiller and adjusting the number of operating chillers to serve the load. The normal return water temperature during peak load conditions is generally 56°F.

Chillers maintain a 40°F supply water temperature to the central system and typical return water temperatures are 56°F during summer operation. Chiller efficiency is increased by setting the condenser supply temperature to 74°F regardless of outdoor wet bulb. There is currently no system in place to reduce condenser water temperature setpoint to track outdoor wet bulb. As mentioned above, setpoint is limited to 74°F due to issues with the tower.

The existing control system is operating on the Emerson Delta V platform. The controls were upgraded in 2012 in an effort to standardize and have the eventual ability to control all of the chiller plants across campus from the Oak Street Plant.

Summary of Noted Issues

- The five cell cooling tower on the roof was observed to be leaking during the inspection.
- The five cell cooling tower was upgraded with new fans, motors, nozzles, and gearboxes and can pull water off of the fill if run at full speed.
- The five cell cooling tower utilizes variable speed drives but condenser supply temperature is held at 74°F rather than tracking outdoor wet bulb. This condition may result in the loss of energy savings during shoulder season months when condenser temperatures could be lowered without causing water to be pulled from the fill.

Replacement Cost of Existing Equipment

Conceptual capital costs are developed for equipment repair and replacement for the business as usual scenario and is listed in the following Table. Detailed estimates are provided in Appendix 3C. The BAU scenario is further described in Section 7.

CHEM LIFE SCIENCES CHILLER PLANT EQUIPMENT REPLACMENT SCHEDULE				
EQUIPMENT	CAPACITY (TONS)	YEAR INSTALLED	REPLACE. YEAR	REPLACE. COST ($)
CHILLER 1 (PACKAGED)	1,210	1993	2018	1,674,000
CHILLER 2 (PACKAGED)	1,210	1993	2018	1,674,000
CHILLER 3 (PACKAGED)	1,210	1993	2018	1,674,000
CT 1	2,055	---	2015	459,000
CT 2	2,055	---	2015	459,000
CT 3	2,055	---	2015	459,000
CT 4	2,055	---	2015	459,000
CT 5	2,055	---	2015	459,000
TOTAL	3,630	---	---	7,317,000

Veterinary Medicine Chiller Plant

General

The Veterinary Medicine Chiller plant consists of (1) 650 ton York absorption chiller CH-2, (1) McQuay 800 ton centrifugal chiller CH-4, (1) York 1,500 ton centrifugal chiller CH-5 and (2) York 850 ton centrifugal chillers CH-3 and CH-7. In addition to these operational chillers, there is an abandoned Carrier absorption chiller, along with the associated abandoned pumps and piping. Each of the chillers are served by a dedicated primary chilled water pump and dedicated condenser water pump. The plant is configured in a primary/secondary configuration with a neutral bridge and variable speed secondary pumps. Three cross flow cooling towers are located on the roof of the plant and drain into Sump A, Sump B and Sump C indoor sumps. Sump A is dedicated to chillers CH-4 but interconnected with CH-5 and Sump B. Absorption chiller CH-2 may utilize either tower and both sumps A and B. Sump C and respective tower are dedicated to chillers CH-3 and CH-7. Although not operational the existing abandoned Carrier absorption chiller is piped to sumps A and B.

Chiller CH-4, the 800 ton McQuay chiller, is served by a two cell BAC fiberglass tower which drains in to Sump A on the west end of the plant. Chiller CH-5, the 1,500 ton York chiller, is served by a new two cell BAC cross flow galvanized cooling tower located in the center of the roof which drains into Sump B. As previously mentioned, Sumps A and B are interconnected and the absorption chiller CH-2 is piped such that it can utilize either tower and sump. Chillers CH-3 and CH-7 are served by an all galvanized Marley tower located on the east end of the roof which drains into Sump C. Both BAC towers have fans equipped with variable speed drives for modulation to maintain temperature. The Marley tower serving CH-3 and CH-7 has four cells and four constant speed fans which are turned on and off to maintain condenser water temperature. Chiller efficiency is increased by setting the condenser supply temperature to 70°F regardless of outdoor wet bulb. There is currently no system in place to reduce condenser water temperature setpoint to track outdoor wet bulb.

All of the existing centrifugal chillers are constant speed machines and vary load by modulating vanes at the compressor. Each of the respective primary chilled water and condenser water pumps are currently operated at constant speed. Some of the dedicated condenser water pumps are equipped with variable speed drives; however, the VFDs are used for balancing and operate as soft start for the condenser pump motors. The plant is configured in a primary/secondary arrangement with constant primary flow and variable secondary flow. Primary chilled water pumps are currently being converted to variable speed to allow the primary flow to be matched to the secondary flow. It should be noted that there are no flow meters currently installed in the plant.

Secondary pumps are split between the buildings with a set of secondary pumps serving the Large Animal and Small Animal facilities and a single pump serving the Basic Sciences Building. The secondary pumps vary flow to satisfy load by maintaining a differential pressure setpoint of 15 psig at the respective building(s). Some loads in the buildings are served by small tertiary pumps with the majority of the pumping effort provided by the secondary pumps. The system operates on a water/ethylene glycol mixture, which is connected to a heat recovery system in the buildings. Building air handling units are configured with a mixture of two-way and three-way valves. Where three-way valves have been replaced with two-way valves, pressure independent valves have been utilized.

Chillers are staged on in order to maintain a 40°F supply water temperature to the buildings with the normal return water temperature during peak conditions being 50°F. Chillers are staged off by the Operator monitoring the kW energy usage of each chiller and adjusting the number of operating chillers to serve the load. Chiller plant operation at this plant is discontinued when outside ambient air temperature is 53°F or less.

Existing controls systems have been converted to a single Invensys control system, but the system is independent of the campus Delta V system and the plant cannot be controlled nor monitored from the central control room at the Oak Street Plant.

The anticipated load is 2,000 tons, but under normal conditions the typical load can be served by operating two of the 850 ton chillers. A 2,000 ton load would imply that there is 3,200 tons of firm capacity with the loss of CH-5, the 1,500 ton chiller, and an excess of 1,200 tons assuming that CH-2, the absorption chiller, would operate on the CH-5 tower in the event that CH-5 was not available. Total plant output may be constrained by the fact that as additional capacity has been added to the plant, the headers have not been modified causing increased pressure drops in the primary circuit as multiple chillers are operated. Some changes to header sizes have been made on the secondary side of the piping system but the primary circuit header size may prevent the operation of all chillers in the plant simultaneously. Operators note that when chiller CH-5 is in operation, chillers CH-3 and CH-7 are starved for return chilled water. Operators have also noted that if CH-4 is running and CH-5 is started, CH-4 will drop out.

Summary of Noted Deficiencies

- The Marley cooling tower serving CH-3 and CH-7 has damaged fill and is leaking at several of the piping connections on top of the tower. Where the piping connections are leaking, water is bypassing the fill and or leaking out onto the roof.
- The single Marley tower serving CH-3 and CH-7 is a single point of failure for both chillers. Risk is somewhat lowered since there are 4 fans available and it is unlikely that none of the fans would be available at any given time.
- Support columns for the single Marley tower serving CH-3 and CH-7 are cracked and severely deteriorated. The support members are in need of immediate attention.
- Lack of both total cooling tower capacity and adequate header pipe sizing at the plant will not currently allow the full chiller capacity of the plant to be utilized.
- Inconsistency of pumping with secondary pumps in the building and in the plant. Some branches in buildings have small tertiary pumps.
- Existence of three-way valves at air handlers will bypass flow and reduce delta T at the plant.
- Extensive amount of abandoned piping in the plant has left long dead legs of piping on the condenser side which may contribute to bacterial growth.
- None of the existing chillers are equipped with variable speed drives for low load conditions.
- The Basic Sciences Building is served with a single chilled water pump. A secondary pump should be considered for redundancy.

Replacement Cost of Existing Equipment

Conceptual capital costs are developed for equipment repair and replacement for the business as usual scenario and is listed in the following Table. Detailed estimates are provided in Appendix 3C. The BAU scenario is further described in Section 7.

VET MED CHILLER PLANT EQUIPMENT REPLACEMENT SCHEDULE				
EQUIPMENT	CAPACITY (TONS)	YEAR INSTALLED	REPLACE. YEAR	REPLACE. COST ($)
CHILLER 2 (PACKAGED, ABSORBER)	650	1997	2020	1,674,000
CHILLER 3 (PACKAGED)	850	2001	2024	1,195,000
CHILLER 4 (PACKAGED)	850	2001	2024	1,195,000
CHILLER 5 (PACKAGED)	1,500	2012	2035	2,085,000
CHILLER 7 (PACKAGED)	850	2001	2024	1,195,000
CT 1	1,275	---	2021	658,000
CT 2	1,275	---	2021	658,000
CT 4	4,500	---	2032	763,000
CT 7	5,100	---	2017	837,000
TOTAL	4,700	---	---	10,260,000

Thermal Energy Storage System

General

The Thermal Energy Storage System (TES) consists of a 6.5 million gallon thermal storage tank, three pumps which are used for both charging and discharging, and a system of pressure sustaining valves and control valves. The system is approximately two years of age and is in good condition.

Operators charge the thermal storage tank at 6,000 gpm. When the tank is in recharge mode, chillers are brought on at the Oak Street Plant for charging. The University has experienced a condition where the tank cannot be charged and maintain a 40°F supply water charge when the Oak Street Plant was off and the tank was being charged from the North Plant. Charging at 40°F allows a discharge temperature from the TES of 43°F. The University also noted that the distribution pressure losses will not allow adequate pressure from the North Plant to charge the TES under certain conditions.

University staff indicate that the operation of the Clayton pressure sustaining valves (PSV) have been problematic. Pressures change dramatically when switching between charging and discharging modes which causes issues with adjacent campus buildings. The TES Clayton valves are arranged such that the tank discharge PSV holds a constant return water system pressure. The tank charging Clayton PSV measure supply pressure and try to hold that constant resulting in large pressure swings from charging to discharging.

Two possible solutions have been identified. The recommended solution is to replace the Clayton self-contained valves with high performance butterfly valves. The pump speed could be controlled in both the charging and discharging mode to hold the desired flow rate, charge or discharge. These high performance butterfly valves would be controlled to maintain a set pressure in the return water line as measured by a pressure transmitter. Another, lower cost modification would be to relocate the Clayton PSV pilot sensing line currently located on the tank charging (or supply) pipe and connect it to the return water line. This would then be used to actuate the valve to hold a constant return pressure.

The TES is utilized on a daily basis. A time of use program that watches energy rates to determine when the TES is to be operated is under development, but is not operational. The TES is discharged at a rate of 6,000-8,000 gpm with a targeted 12hr discharge rate. At 8,000 gpm and 12hrs of discharge, approximately 5.76 million gallons of the capacity would be discharged from the TES. The maximum discharge rate that the TES is designed for is 12,000 gpm.

The existing control system is operating on the Emerson Delta V platform. The controls were standardized with North Plant and Oak Street to control all of the chiller plants across campus from the Oak Street Plant or North Plant. Currently, operation of the TES is initiated from the North Plant.

Summary of Noted Deficiencies

- A program that stages the TES into the system based on rate forecasts is under development, but is not currently operational. Tank is providing energy savings by discharging it each day.
- The full capacity of the tank is not utilized every day. With a discharge rate of 8,500gpm, the tank could be fully utilized assuming that 6.1 million gallons would be available for discharge.
- The TES Clayton valves should be replaced or modified to prevent large pressure swings in the system.

Chilled Water Plant Efficiency

Using equipment data sheets and recorded plant performance data, the efficiency of each chilled water plant was developed for the individual plants and is listed in the following tables. The operating efficiency of each asset is calculated for comparisons with new options for providing CHW to the campus. Plant performance data used to estimate efficiency is listed in Appendix 3D.

CHILLER PLANT EFFICIENCY

			EFFICIENCY				AUXILIARY EFFICIENCY				ELECTRIC USAGE			
PLANT	MACHINE TYPE	CAPACITY (TONS)	ELECT. (KW/TON)	STEAM (PPH/TON)	REFRIG. TYPE	INSTALL YEAR	CW PUMP (KW/TON)	CHW PUMP (KW/TON)	CT FAN (KW/TON)	STEAM USAGE (PPH)	CHILLER (KW)	CHILLER AUX. (KW)	STEAM CHILLER (KW)	TOTAL (KW)
OAK STREET CHILLER PLANT														
CHILLER 1	STEAM TURBINE CENTRIFUGAL	5,000	---	*11.0*	R-134a	2004	0.070	0.023	0.044	55,000	---	---	685	685
CHILLER 2	STEAM TURBINE CENTRIFUGAL	5,000	---	*11.0*	R-134a	2004	0.070	0.023	0.044	55,000	---	---	685	685
CHILLER 3	ELECTRIC CENTRIFUGAL	2,000	0.637	---	R-134a	2004	0.076	0.020	0.044	---	1,274	280	---	1,554
CHILLER 4	ELECTRIC CENTRIFUGAL	2,200	0.631	---	R-134a	2005	0.069	0.023	0.044	---	1,388	299	---	1,687
CHILLER 5	ELECTRIC CENTRIFUGAL	5,000	0.615	---	R-134a	2007	0.080	0.032	0.044	---	3,075	780	---	3,855
CHILLER 6	ELECTRIC CENTRIFUGAL	2,800	*0.580*	---	R-134a	2013	0.069	0.023	0.044	---	1,624	381	---	2,005
CHILLER 7	ELECTRIC CENTRIFUGAL	5,630		---	R-134a	2012	0.069	0.023	0.044	---	---	766	---	766
SUBTOTAL		27,630	---	---	---	---	---	---	---	110,000	7,361	2,506	1,370	11,237
PLANT EFFICIENCY (KW/TON)		---	---	---	---	---	---	---	---	---	0.418	0.142	0.137	0.560
NORTH CAMPUS CHILLER PLANT														
CHILLER 1	ELECTRIC CENTRIFUGAL	1,200	0.653	---	R-134a	2001	0.096	0.039	0.041	---	784	211	---	995
CHILLER 2	ELECTRIC CENTRIFUGAL	1,000	0.640	---	R-134a	1998	0.093	0.031	0.041	---	640	165	---	805
CHILLER 3	ELECTRIC CENTRIFUGAL	1,000	0.640	---	R-134a	1998	0.093	0.031	0.041	---	640	165	---	805
CHILLER 4	ELECTRIC CENTRIFUGAL	2,000	0.645	---	R-134a	2000	0.059	0.030	0.041	---	1,290	260	---	1,550
CHILLER 5	ELECTRIC CENTRIFUGAL	1,000	0.651	---	R-134a	1997	0.093	0.031	0.041	---	651	165	---	816
CHILLER 6	ELECTRIC CENTRIFUGAL	2,000	0.676	---	R-134a	2001	0.039	0.039	0.038	---	1,352	232	---	1,584
CHILLER 7	ELECTRIC CENTRIFUGAL	1,200	0.653	---	R-134a	2001	0.096	0.039	0.041	---	784	211	---	995
SUBTOTAL		9,400	---	---	---	---	---	---	---	---	6,140	1,409	---	7,550
PLANT EFFICIENCY (KW/TON)		---	---	---	---	---	---	---	---	---	0.653	0.150	---	0.803
LIBRARY A/C CENTER														
CHILLER 4	ELECTRIC CENTRIFUGAL	1,000	0.595	---	R-134a	2000	0.059	0.033		---	595	92	---	687
CHILLER 5	ELECTRIC SCREW	1,100	*1.200*	---	R-22	1993	0.019	0.034	0.038	---	1,320	100	---	1,420
CHILLER 6	ELECTRIC SCREW	1,100	*1.200*	---	R-22	1993	0.019	0.034	0.038	---	1,320	100	---	1,420
CHILLER 7	STEAM ABSORBER	1,140	---	*18.0*		1999	0.054	0.025	0.104	20,520	---	---	209	209
SUBTOTAL		4,340	---	---	---	---	---	---	---	20,520	3,235	292	209	3,736
PLANT EFFICIENCY (KW/TON)		---	---	---	---	---	---	---	---	---	1.011	0.091	0.000	1.103
ANIMAL SCIENCES A/C CENTER														
CHILLER 3	ELECTRIC CENTRIFUGAL	1,000	0.676	---	R-134a	2001	0.024	0.025	0.042	---	676	91	---	767
CHILLER 4	ELECTRIC CENTRIFUGAL	1,000	0.676	---	R-134a		0.024	0.024	0.042	---	676	90	---	766
SUBTOTAL		2,000	---	---	---	---	---	---	---	---	1,352	181	---	1,533
PLANT EFFICIENCY (KW/TON)		---	---	---	---	---	---	---	---	---	0.676	0.091		0.767
CHEM LIFE SCIENCES CHILLER PLANT														
CHILLER 1	ELECTRIC CENTRIFUGAL	1,210	*0.640*	---	R-134a	1993	*0.093*	*0.031*	*0.041*	---	774	200	---	974
CHILLER 2	ELECTRIC CENTRIFUGAL	1,210	*0.640*	---	R-134a	1993	*0.093*	*0.031*	*0.041*	---	774	200	---	974
CHILLER 3	ELECTRIC CENTRIFUGAL	1,210	*0.640*	---	R-134a	1993	*0.093*	*0.031*	*0.041*	---	774	200	---	974
SUBTOTAL		3,630	---	---	---	---	---	---	---	---	2,323	599	---	2,922
PLANT EFFICIENCY (KW/TON)		---	---	---	---	---	---	---	---	---	0.640	0.165	---	0.805
VET MED CHILLER PLANT														
CHILLER 2	STEAM ABSORBER	650	---	*18.0*		1997	0.039	0.094	0.058	11,700	---	---	124	124
CHILLER 3	ELECTRIC CENTRIFUGAL	850	0.565	---	R-134a	2001	0.049	0.029	0.058	---	480	116	---	596
CHILLER 4	ELECTRIC CENTRIFUGAL	850	0.622	---	R-134a	2001	0.099	0.029	0.074	---	529	172	---	700
CHILLER 5	ELECTRIC CENTRIFUGAL	1,500	0.634	---	R-134a		0.041	0.022	0.058	---	951	182	---	1,133
CHILLER 7	ELECTRIC CENTRIFUGAL	850	0.565	---	R-134a	2001	0.049	0.029	0.058	---	480	116	---	596
SUBTOTAL		4,700	---	---	---	---	---	---	---	11,700	2,440	584	124	3,148
PLANT EFFICIENCY (KW/TON)		---	---	---	---	---	---	---	---	---	0.603	0.144	0.191	0.747
TES TANK														
TES	---	5,000	---	---		2010	---	0.023	---	---	---	---	115	115
PLANT EFFICIENCY (KW/TON)		5,000	---	---	---	---	---	---	---	---	---	---	0.023	---

NOTE: ITALICIZED NUMBERS ARE ESTIMATES BASED ON TYPICAL MACHINE EFFICIENCY. NO NAMEPLATE DATA AVAILABLE

3.3 Steam Distribution Systems

General

The campus steam distribution system was examined to analyze existing conditions in support of the Business As Usual reference case and to create a foundation to evaluate required capital upgrades necessary to support campus load growth over the 35-year growth projections. The analysis included condition assessment and hydraulic simulation of the distribution piping system.

The condition assessment involved onsite walkthrough assessment of portions of the existing tunnel system, combining the observations and conclusions from recent condition assessments completed by outside firms, and providing updated cost assessment of the improvements necessary to improve deficiencies within the distribution system.

The hydraulic model is a software simulation of the entire low pressure (i.e. "Campus Pressure") and high pressure (i.e. "High Pressure" and "Utility Pressure") steam systems from Abbott Power Plant (APP) to each building served by one or both of these systems. The model will indicate distribution bottlenecks and opportunities for improving operational efficiencies, as well as becoming a tool to forecast the implications of future growth scenarios. Building loads for each building were calculated and input into the model.

Condition Assessment Methodology

The University retained Black & Veatch (B&V) to assess the condition of the underground tunnels, piping, and supports of the steam distribution system, Stanley Consultants to evaluate the underground steam tunnel ventilation system, a testing firm was hired to perform non-destructive examination of the piping distribution systems, and AEI performed a visual assessment of the steam manholes. The B&V study was used as a basis for tunnel condition assessment, and is listed in Appendix 3E. Per direction from the University, the ventilation study was not used.

B&V Study Validation

The results of the B&V study were reviewed with the University and it was determined that an entire re-survey of all the tunnels was not required, but a verification of the worst areas identified in the report would be sufficient for validation. These problem areas were identified in the B&V report as "Priority Code D – Major Deterioration" and "Priority Code C – Significant Deterioration" (refer to the B&V Assessment Worksheet and Priority Ratings in Appendix 3E).

Accompanied by University Steam Distribution staff, AEI performed onsite inspections of these areas of the walkable steam tunnels to include visual inspection for conditions of structure, piping, insulation and supports. AEI's lead estimator was part of the survey crew so that firsthand knowledge of the actual conditions could inform the cost estimation.

The B&V report was confirmed to be accurate with respect to tunnel conditions. The total cost to repair all deficiencies identified in the B&V report is $8,123,200. Detailed cost estimates for the steam tunnel repairs are listed in Appendix 3E.

STEAM TUNNEL STRUCTURAL REPLACEMENT		
TUNNEL SECTION	REPLACE. YEAR	REPLACE. COST ($)
GREGORY - I	2014	783,000
6TH ST. - E TUNNEL	2014	263,000
MATHEWS - I1	2014	79,000
PEABODY - II	2016	184,000
PEABODY - IV	2016	220,000
GREGORY - II	2016	286,000
ARMORY AVE - I	2016	101,000
ABBOTT CONN	2016	77,000
OAK ST. - II	2016	342,000
EUCLID	2016	404,000
WRIGHT ST. - I	2016	562,000
DAVENPORT FEED	2016	337,000
MATHEWS - I	2016	561,000
MATHEWS - II	2016	516,000
FLORIDA/KIRBY - I	2019	290,000
PEABODY - I	2019	470,000
PEABODY - II	2019	470,000
ARMORY AVE - II	2019	85,000
FOELLINGER FEED - W SIDE	2019	19,000
ILLINOIS - I	2019	173,000
ILLINOIS - III	2019	71,000
TRANSP BLDG FEED	2019	239,000
6TH ST. - W TUNNEL	2019	13,200
NOYES-UNION SOURCE, E TUNNEL	2019	48,000
NOYES-UNION SOURCE, W TUNNEL	2019	130,000
ENGRG HALL FEED	2019	147,000
GOODWIN - I	2019	170,000
ARMORY AVE - III	2020	93,000
FOELLINGER FEED - E SIDE	2020	32,000
NEVADA - I	2020	25,000
ILLINOIS - II	2020	64,000
GREEN ST. - I	2020	26,000
GREEN ST. - II	2020	81,000
ME LAB FEED	2020	21,000
OAK ST. - I	2020	326,000
ENG LABS & LIBRARY - S END	2020	154,000
ENG LABS & LIBRARY - N END	2020	24,000
GOODWIN - II - S END	2020	29,000
GOODWIN - II - N END	2020	29,000
SSAC FEED	2020	14,000
PAR FEED	2020	66,000
MEMORIAL STADIUM	2020	86,000
COMP LAB/GYMS FEED	2020	13,000
SUBTOTAL EAST-WEST TUNNELS		8,123,200

Non-Destructive Testing

Non-Destructive testing (NDT) of the piping distribution system was conducted to determine wall thickness of the existing piping at multiple locations throughout campus. The age of all piping in the system, see Appendix 3F for pipe age map, as well as feedback from the hydraulic model and University suggestion, informed the locations for the non-destructive testing locations. The NDT was conducted at 11 locations throughout the campus distribution system. Testing results are classified as indicated in the following table and test reports are included in the appendix.

NONDESTRUCTION TESTING RESULTS

LOCATION CODE	YEAR INSTALLED	PIPE SIZE	NDT RESULTS
A	1957-1960	12" CPS	MINOR
		6" PR	MINOR
B	1949-1954	12" CPS	MINOR
		8" UPS	MINOR
		6" HPS	MINOR
		6" PR	MEDIUM
		4" PR	OK
C	1987-2000	12" CPS	MINOR
		8" PR	OK
		6" HPS	MINOR
		6" PR	OK
D	1961-1965	12" CPS	MINOR
E	1917	12" CPS	MINOR
		10" CPS	OK
		8" UPS	OK
		6" PR	OK
F	1917	10" CPS	MAJOR
		6" PR	MINOR
G	1961-1965	12" CPS	MINOR
		6" PR	MINOR
		8" UPS	OK
		6" HPS	OK
H	1966-1971	14" CPS	OK
		12" CPS	MINOR
		8" UPS	MINOR
		6" HPS	MINOR
		6" PR	MINOR
V1	1949	10" CPS	OK
V4	1987-2000	10" HPS	OK

LEVEL OF CONCERN	RECOMMENDED ACTIONS
OK	NO FURTHER ACTION IS REQUIRED. PIPE IS IN GOOD CONDITION.
MINOR	ADDITIONAL GWT INSPECTION POINTS AND/OR TMLS SHOULD BE CONSIDERED FOR THIS PIPE CIRCUIT.
MEDIUM	AREA SHOULD BE INVESTIGATED AT THE NEXT AVAILABLE OPPORTUNITY.
MAJOR	AREA SHOULD BE INVESTIGATED WITHOUT DELAY.
INVALID	GWT SHOT WAS TAKEN BUT THE ANALYSIS COULD NOT BE PERFORMED. I.E. AMBIENT NOISE WAS TOO HIGH; SHOT WAS ATTEMPTED ON TOO ROUGH OF A SURFACE, ETC.

The University is further investigating those locations indicated as either a minor or major concern. NDT results do not show any correlation between approximate pipe age and remaining useful life.

Steam Manholes

Existing steam manholes were visually assessed to determine necessary repairs and upgrades needed to bring the manholes up to current OSHA requirements. Manholes were inspected for structural integrity proper accessibility of manhole sizes and ladder clearances. Twenty-three of the manholes require upgrade at a cost of $529,000. Detailed estimates of the manhole repair are included in Appendix 3C.

Steam System Hydraulic Model

General

A hydraulic model of the campus steam distribution system was developed using programs developed by Applied Flow Technology (AFT). The AFT suite of programs includes a core hydraulic model software, AFT Fathom, and an add-on module for compressible flow analysis (i.e. steam systems), AFT Arrow. AFT Arrow v4.0 was utilized for the steam system hydraulic analysis and the chilled water distribution model, discussed elsewhere in this report, was created using AFT Fathom 7.0.

The campus steam distribution infrastructure consists of three distinct systems: Campus Pressure (CPS), Utility Pressure (UPS) and High Pressure (HPS). The CPS is considered the "low pressure" system, where pressure at APP is controlled between 40 and 55-psig, and it is the primary source of heating distribution to the buildings on campus. The HPS is distributed at 150-psig and it is supplied to buildings with steam process loads that require higher pressure steam (i.e. laboratory, dining and others). Multiple buildings receive both CPS for heating and HPS for process loads.

The UPS system was installed to support the addition of steam driven chillers throughout campus, including extending distribution to the North Campus Chiller Plant and areas north of Springfield Avenue. The UPS system was installed with valves capable of switching the piping system (or sections thereof) between CPS and HPS pressures; allowing the UPS to support the CPS system for additional demand caused by the steam chillers, and to provide redundancy to the HPS system. Additionally, distributed PRV stations were installed to allow the higher pressure systems to supply additional capacity into the CPS system (i.e. when UPS would be valved open to the HPS system). These PRV stations are commonly referred to as Back Pack stations. The University Steam Distribution personnel confirmed that the Back Pack stations have all been disabled (valved closed) and do not operate, however the valves do not close off completely and there is some steam leakage.

The University has opened all of the valves between the UPS and HPS systems, thereby creating a combined High Pressure system that operates at 150 psig leaving APP. Therefore the High Pressure model is a combination of the HPS and UPS systems into a single file. The CPS system is modeled independent of the UPS/HPS analysis as all of the valves from UPS to CPS are closed (hereafter, HPS will be synonymous with the combined HPS/UPS). The Back Pack stations are still included in the model, however the flow is reduced to near-zero numbers (which coincidentally is a reflection of minor valve leakage). A total of four hydraulic models were created to reflect current operation of each steam system (CPS and HPS), along with maximum load growth conditions for each of these systems through the year 2049.

Building loads for each building were estimated and input into the model. The initial output of the model was discussed with the University's Distribution personnel and is validated to the best information available.

For buildings fed both by the HPS and CPS systems, it was not possible to accurately capture the real loads assigned to each of those piping systems because incoming steam is not separately metered. All of the steam within the building is monitored by condensate meters, which involves the following assumptions and limitations: it only captures condensed steam and does not account for wasted steam that is sent to sanitary and it requires calculating the ratio of load between HPS and CPS. The models currently assume a ratio of load between HPS and CPS, based on pipe size and operating pressure.

Observations from the Steam Hydraulic Model

When assessing the hydraulic model, it is critical to note that the load calculation has its inherent assumptions and therefore the hydraulic model is a best-fit representation of the system. The primary implication of the load calculation method is that the individual building loads may be inaccurate while the overall campus consumption is known to be accurate. Therefore one should be careful to not draw conclusions about individual buildings, or small groupings of 2 or 3 buildings, however we can be confident in analysis of the overall system.

The CPS and HPS models were completed and calibration to the best information available in an effort to reflect real world conditions. Observations from the model are as follows, and refer to HPS and CPS model drawings in Appendix 3G.

The HPS system appears to be oversized for both its current usage and usage through 2049. Color charts indicate that pipe velocities are below a recommended maximum velocity of 10,000 feet per minute (FPM) in the tunnel system. It appears that reducing the steam pressure at APP and/or valving some piping offline would be feasible in its current operating state without significant disruption to campus. Another option is to utilize the excess capacity of the HPS system by reconditioning and opening select Back Pack stations to further equalize the load demands between the HPS and CPS systems. The current HPS model in 2049 assumes that only a total of 15,000-PPH of HPS steam is contributed to the CPS system through Back Pack stations. In this case, the HPS is still oversized, however, if additional HPS is contributed to the CPS system via the Back Pack stations as discussed below, then this will affect the operating parameters of the HPS system.

The CPS system is below recommenced velocities in most locations on campus, based on the current maximum load conditions. The majority of the piping system throughout campus is within the 10,000 FPM design value, though much of the piping along Gregory and Peabody is operating at or above 8,000 FPM. Of note in the CPS model, a 14-inch pipe that runs south along Oak Street and then East to Peabody and Euclid is currently valved closed (in the tunnels). This was originally replicated in the model. Through this early analysis, AEI determined that the absence of this pipe in the system had the considerable negative effect of increasing the velocity of other pipes throughout the system. Therefore, after early discussion with the University, it was determined that putting this pipe back into service would become a priority for the University, and that AEI should assume that the pipe is in operating condition for all modeling exercises. Running the same version of the model with the 14-inch open significantly reduced the velocities in the two problematic 12-inch pipes near the Quad and increased the pressure available at Mechanical Engineering Lab (the controlling pressure sensor for APP pressure output to the CPS system) by 4-psig.

- The piping leaving APP has higher velocity until the junctions at Oak and Gregory. This is largely a function of different piping sizes operating at the same pressure, converging at a common junction. The smaller pipes travel a shorter distance and, therefore, carry a relatively larger load.
- A single section along Gregory Drive, north of Ikenberry Dining Hall has increased velocities. This is likely because this pipe is supporting load downstream and, immediately prior to the velocity increase, the pipe has been reduced in size. This condition was exacerbated by the 14-in main that is valved closed.
- A 12-inch pipe originating at Sixth and Gregory which feeds the Library and Undergrad Library and connects to the piping on the south-east side of the Foellinger Auditorium. This pipe has excessive velocities and appears to be undersized. The model suggests that this pipe is carrying 58,000-PPH during peak conditions, with an initial velocity of approximately 14,000-FPM at approximately 25-psig. As the pressure in this pipe decreases, the velocity increases until the final velocity is nearing 18,000-FPM.
- At the northwest side of the Quad, a 12-inch pipe west of Henry Admin, along Wright Street, has excessive velocities. This pipe completes the pipe loop around the north side of the quad, supplying a large load in support of the Engineering Quad. The model suggests that this pipe is carrying 65,000-PPH with a velocity of approximately 14,800-FPM at approximately 27-psig. The primary reason for this increased velocity is the combination of a 16-inch and 12-inch pipe at Daniel and Wright which feed into this 12-inch. There is an abandoned Back Pack station at the southeast corner of Illini Union that could be renewed to alleviate a significant amount of load from this pipe.

Future Loads Modeling

The effects of campus growth on the steam distribution system are examined by modeling the maximum growth scenario through 2049 and examining steam velocity in the piping network. The growth scenarios and where the growth occurs on campus is examined in Section 4. Point loads are connected to steam mains in regions of growth on campus.

At maximum growth, multiple sections of the CPS system will be undersized without the use of the Back Pack stations. The system is undersized enough that AFT is unable to develop a solution.

Setting the Back Pack stations near the Illini Union, Natural History Building, and the Undergrad Library to provide 5,000 PPH flow to the CPS system still results in multiple locations where the CPS system is inadequate. The majority of the piping system throughout campus operates at or above the 8,000 to 10,000 FPM range. The most notable shortcomings of the system in this future scenario are:

- The 12" pipe to the west of the Henry Admin building that runs through the Quad is now experiencing velocities upwards of 20,000 FPM and will need to be replaced with a larger pipe.
- A majority of the piping east of Third Street that runs along Gregory and Peabody Streets has steam velocity in excess of 12,000 FPM in multiple locations. Increased use of the Back Pack stations will reduce the velocity below 10,000 FPM.
- The 12-inch pipe originating at Sixth and Gregory which feeds the Library and Undergrad Library and connects to the piping on the south-east side of the Foellinger Auditorium is now operating in excess of 18,000-FPM and will need to be replaced with a larger pipe.
- The steam velocity through the piping leaving APP has increased to over 16,000 FPM. Using all Back Pack stations on campus reduces the steam velocity close to 10,000 FPM.
- Conceptual capital costs are developed for tunnel structural repair and replacement for the business as usual scenario and is listed in the following Table. Detailed estimates are provided in Appendix 3C.

3.4 Chilled Water Distribution System

General

The distribution system consists of underground direct buried piping constructed from pre-stressed concrete pipe and ductile iron pipe. All of the piping installed in recent years has been configured with restrained joints to allow excavation near the piping without the risk of blowout. The majority of the piping has been installed within the past 15 years with piping in the area of the Library and Animal Sciences exceeding that age.

Chilled Water Hydraulic Model

General

A hydraulic model of the chilled water distribution system was developed using programs developed by Applied Flow Technology (AFT). The AFT suite of programs includes a core hydraulic model software, AFT Fathom, and an add-on module for compressible flow analysis (i.e. steam systems), AFT Arrow. AFT Fathom v7.0 was utilized for the chilled water (CHW) hydraulic analysis, as water is a non-compressible fluid.

As mentioned above, the University central chilled water system consists of six chiller plants with a total capacity of 51,700 tons, a 6.5 million gallon thermal storage tank with a 12,000 gpm maximum discharge capacity, and approximately 23 miles of chilled water distribution piping. The system serves 97 buildings on campus and the University has plans to add an additional 33 existing buildings to the central loop.

The existing chiller plants are configured to run in either a fixed flow output mode or a differential pressure mode. The North Campus Chiller Plant is typically operated in differential pressure mode with all other plants operating in a fixed flow output mode. Differential pressure is measured and maintained by secondary pumps where the chilled water supply and return of the respective operating plant leaves the plant. The system is operated to maintain a differential pressure of 25 psig at the hydraulically worst buildings in the distribution system. The TES system operates as a fixed flow output and is used on a daily basis.

An existing hydraulic model of the chilled water system was updated to reflect current physical configuration and operation of the system. Building loads for each building were estimated by AEI (discussed in Section 4) and input into the model. The initial output of the model was discussed with University Distribution personnel and is validated to the best information available to AEI. An additional model was also created for the CHW system to model the calculated system load growth through 2049.

Observations from the Chilled Water Hydraulic Model

When assessing the hydraulic model, as with the steam models, it is critical to remember that the load calculation has its inherent assumptions and, therefore the hydraulic model is a best-fit representation of the system. The primary implication of the load calculation method is that the individual building loads may be inaccurate while the overall campus consumption is known to be accurate. Therefore one should be careful to not draw conclusions about individual buildings, or small groupings of 2 or 3 buildings, however we can be confident in analysis of the overall system.

Unlike the way that the steam building loads are modeled in AFT Arrow, building loads in AFT Fathom have to be input as designated flow rates (using flow control valves), based on an average system temperature change. Therefore, for the chilled water system, the building flow rates have been calculated using the building load and a 12°F temperature rise. For the existing peak load analysis, the discharge chilled water supply from each of the plants is as follows:

PLANT DISCHARGE CAPACITY	
DESCRIPTION	FLOW (GPM)
THERMAL ENERGY STORAGE TANK	10,000
OAK ST. CHILLER PLANT	32,000
NORTH CAMPUS CHILLER PLANT	16,800
LIBRARY AC CENTER	2,000
ANIMAL SCIENCES CHILLER PLANT	3,700
CHEM LIFE SCIENCES CHILLER PLANT	6,512

In general, the CHW system operates below 8-FPS under peak load conditions, although there are a couple locations where velocity exceeds this velocity:

- A relatively short portion of 10" pipe along Illinois Street just to the east of Goodwin Avenue has velocity exceeding 8-FPS. This appears to be an isolated situation that would not need any immediate attention. There are also much larger mains in this region that can serve any new build out for the near future.

Section 7 describes the business as usual growth scenario used as a base case for comparisons for the future load analysis, the discharge chilled water supply from each of the plants is increased to meet the campus growth:

FUTURE PLANT DISCHARGE CAPACITY	
PLANT	FLOW (GPM)
THERMAL ENERGY STORAGE TANK	10,000
OAK ST. CHILLER PLANT	32,000
NORTH CAMPUS CHILLER PLANT	31,200
LIBRARY AC CENTER	2,000
ANIMAL SCIENCES CHILLER PLANT	3,700
CHEM LIFE SCIENCES CHILLER PLANT	6,512

In general, at full growth the CHW distribution system operates below 8 FPS under peak load conditions, with a few locations where velocity limits exceeds 8 FPS:

- The short portion of 10" pipe along Illinois Street just to the east of Goodwin Avenue has velocity of almost 9-FPS, which is only a small increase of the 8-FPS observed with the existing conditions in this area.
- The largest problem area under this scenario is near the NCCP. It is apparent that this problem stems from an assumed future flow that nearly doubles the existing flow from the plant. Therefore, the existing piping is not sized to handle a flow increase of this magnitude without substantial upsizing. In the current configurations, pipe velocities ranged from 12-FPS to 19-FPS in the pipe closely located to the NCCP.

3.5 Electrical Power Distribution System

Medium Voltage (5kV, 12.5kV AND 13.8kV) System

The following assessment looks at the medium voltage equipment and distribution system on campus. The assessment was developed by reviewing past studies performed for the University, interviewing University utilities distribution staff, visual assessment of major equipment and a review of maintenance and operation procedures.

The campus is served with three distribution voltages through a network of Distributions Centers (DC) and Load Centers (LC) spread throughout the campus. The different LC and DC systems utilize metal enclosed fused switches and metal clad vacuum circuit breakers. The age of the systems varies from the 1950s to 2011. A summary of the condition of each system is indicated below.

Systems with a condition indicated as “Poor” have been identified by physical survey and through recommendation of the Campus Utilities Electricians as needing replacement within the next five years. Systems with a condition indicated as “Fair” have been identified as needing replacement scheduled within the next ten years. Although DC-5 is in good condition, the DC is at rated capacity and would need to be expanded before any additional loads are added. A more detailed description of each system with its ratings is found in the Condition Assessments Appendix 3H.

DC-4 DC-2

DC-7 DC-11

DC-8 DC-10

DC-6 DC-9

DC-1 DC-3

DC-5

Transformers located with the Distribution Centers have all been found to be in "Fair" or "Good" condition. Transformers typically fail without any warning signs so determining useful life is based on age and load. All transformers can be tested for insulation resistance of their windings to make sure they are within industry standards. Transformer monitoring systems are available that continuously test dielectric strength of transformer winding insulation. Winding insulation dielectric strength can be an indicator of transformer useful life.

Air insulated transformers should be cleaned yearly and their cooling fans and controls tested to make sure the transformer is being cooled properly. Oil insulated transformers should have samples taken of their oil every two years to test for dielectric strength and contaminates. Contaminated oil should be replaced. Transformer condition assessments are included in Appendix 3H.

LC-53 “Good”LC-12 “Poor”

LC-7 “Poor”

The underground cables connecting the LC and DC locations to the Abbott power plant vary in age and condition as well. Cables utilizing paper insulated, lead conductor (PILC) and varnished cambric lead (VCL) are the oldest on campus and can be dated back to the 1940s. These cables have a typical useful life of 50 years or longer depending on the load and environment. Most of the cables being recommended for replacement are of these two types and have been in service for 50 or more years. Lead conductor cables require great skill in terminating and splicing making the repair and maintenance requirements much greater than other conductor types, such as copper. Lead conductor maintenance training is rare for new electricians due to its low demand for new installations. New lead conductor cables are still available, but the market for them is not as strong as copper and aluminum cable.

Another cable insulation type used on campus is cross-linked poly ethylene (XLPE) with copper or aluminum conductors. This type of insulation was used later than the lead conductor cables and has a typical useful life of 30 years or more. It is not as robust as some of the other insulation types available and has resulted in numerous faults throughout campus where it has been installed. Some if the more problematic circuits using this insulation have been identified for replacement.

Other less common cable insulation types found on campus are neoprene and butyl rubber. Both of these insulation types have good performance unless they have to be moved or spliced as the insulation becomes rigid and brittle over time.

The preferred cable insulation type used on campus and throughout the world is ethylene-propylene rubber (EPR) with a copper conductor. This cable insulation has a 40 year useful life or more depending on load and environmental conditions. EPR insulated cable with copper conductors is recommended to be used to replace the aging cable on campus.

EQUIPMENT SUMMARY TABLE			
EQUIPMENT	LOAD	ASSESSMENT OBSERVATION	ESTIMATED REMAINING USEFUL LIFE
DC-01	RESERVE 10-0	POOR	< 5 YEARS
DC-01	ADMINISTRATION BUILDING	POOR	< 5 YEARS
LC-15	MATERIAL SCIENCE AND ENGINEERING	POOR	< 5 YEARS
LC-15	ENGINEERING HALL	POOR	< 5 YEARS
LC-1	ICE ARENA	POOR	< 5 YEARS
LC-12	DAVENPORT HALL	POOR	< 5 YEARS
LC-12	FOREIGN LANGUAGE BUILDING	FAIR	5-10 YEARS
LC-8	GEOGRAPHICAL SURVEY LAB AND PERSONNEL SERVICES	POOR	< 5 YEARS
LC-52	MATERIAL RESEARCH LAB	POOR	< 5 YEARS
LC-52	ENGINEERING SCIENCES BUILDING EAST	POOR	< 5 YEARS
LC-52	ENGINEERING SCIENCES BUILDING WEST	POOR	< 5 YEARS
LC-61	PENNSYLVANIA AVENUE RESIDENCE HALL	FAIR	5-10 YEARS
LC-61	FLORIDA AVENUE RESIDENCE HALL	FAIR	5-10 YEARS
LC-36	UNDERGRADUATE LIBRARY	FAIR	5-10 YEARS
LC-36	BEVIER HALL	FAIR	5-10 YEARS
LC-36	FREER GYMNASIUM	POOR	< 5 YEARS
DC-11	ATHELETIC LOOP	POOR	< 5 YEARS
AP-98	DC-2 XFMR #1	POOR	< 5 YEARS
AP-98	DC-2 XFMR #2	POOR	< 5 YEARS
AP-98	RESERVE 51	POOR	< 5 YEARS
DC-2	LC-21 MAIN	FAIR	5-10 YEARS
DC-2	DC-2 AUX	FAIR	5-10 YEARS
DC-2	ROGER ADAMS LAB SOUTH	FAIR	5-10 YEARS
DC-2	STUDENT STAFF A/C CENTER	FAIR	5-10 YEARS
LC-21	DANIELS HALL	FAIR	5-10 YEARS
LC-21	ILLINI UNION WEST	FAIR	5-10 YEARS
LC-21	ILLINOIS STREET RESIDENCE HALL	FAIR	5-10 YEARS
LC-21	MORRILL HALL WEST	FAIR	5-10 YEARS
LC-23	ROGER ADAMS LAB NORTH	FAIR	5-10 YEARS
DC-3	LC-31 MAIN	FAIR	5-10 YEARS
LC-31	DC-3 AUX	FAIR	5-10 YEARS
LC-31	NATURAL RESOURCES BUILDING	POOR	< 5 YEARS
LC-31	SOUTH FARMS	POOR	< 5 YEARS
LC-31	NATURAL RESOURCES BUILDING (2)	POOR	< 5 YEARS
LC-31	INSTITUTE OF GOVERNMENT PUBLIC AFFAIRS	POOR	< 5 YEARS
LC-35	CHILD DEVELOPMENT LAB	POOR	< 5 YEARS
LC-37	ART AND DESIGN BUILDING	FAIR	5-10 YEARS

EQUIPMENT	LOAD	ASSESSMENT OBSERVATION	ESTIMATED REMAINING USEFUL LIFE
LC-37	EDUCATION BUILDING	FAIR	5-10 YEARS
LC-38	SOUTH FARMS EAST	POOR	< 5 YEARS
LC-38	STOCK PAVILION	POOR	< 5 YEARS
LC-38	ART ANNEX & WOOD ENGINEERING LAB	POOR	< 5 YEARS
AP-98	DC-4 XFMR #1	FAIR	5-10 YEARS
AP-98	DC-4 XFMR #2	FAIR	5-10 YEARS
DC-4	LC-41 MAIN	FAIR	5-10 YEARS
LC-41	KENNEY GYM	FAIR	5-10 YEARS
LC-41	STUDENT SERVICES	FAIR	5-10 YEARS
LC-41	SHELFORD VIVARIUM	FAIR	5-10 YEARS
LC-41	TALBOT LAB	FAIR	5-10 YEARS
LC-41	DC-4 AUX	FAIR	5-10 YEARS
LC-41	CIVIL ENGINEERING (STANDBY)	FAIR	5-10 YEARS
LC-42	UNIVERSITY HIGH SCHOOL	POOR	< 5 YEARS
LC-42	DIGITAL COMPUTER LABORATORY NW	FAIR	5-10 YEARS
DC-4	LC-44 MAIN	FAIR	5-10 YEARS
LC-44	PHYSICAL PLANT SERVICES, ATMOSPHERIC SCIENCES, ENVIRONMENTAL HEALTH AND SAFETY	POOR	< 5 YEARS

Cables with a condition indicated as "Poor" have been identified by physical survey and through recommendation of the Campus Utilities Electricians as needing replacement within the next five years. Cables with a condition indicated as "Fair" have been identified as needing replacement scheduled within the next ten years. A more detailed description of each cable with its ratings is found in Appendix 3H.

Cable conditions are difficult to assess by visible inspection alone. A cable that has faulted in the past or has multiple splices within its length is typically a sign the cable is near its end of useful life due to load and environmental conditions. Cables that are not stressed with variable loading cycles and are left untouched in a dry, cool environment will typically last much longer than their predicted useful life. Other methods used to determine cable condition include insulation resistance and high-potential current leakage testing. Both of these testing methods require the cable to be de-energized and disconnected. A current source is injected at one end and the leakage to the surrounding environment is tested to determine if the cable is within industry limits.

Conceptual capital costs are developed for electrical equipment and cable repair and replacement for the business as usual scenario and is listed in the following Table. Detailed estimates are provided in Appendix 3C.

BAU REPAIR & REPLACEMENT COST SUMMARY		
SYSTEM	CONDITION	CONCEPTUAL PROJECT COST ($)
EQUIPMENT	POOR	3,086,000
	FAIR	5,756,000
CABLE	POOR	3,113,000
	FAIR	1,841,000
TOTAL	---	13,796,000

Medium Voltage Planning

The University campus presently distributes multiple levels of medium voltage power throughout the campus. There is an intermixing of 4.16 kV, 12.47 kV, and 13.8 kV voltage levels across geographic boundaries. The University presently does not desire uniformity in a common electric distribution voltage of 13.8 kV primarily due to the excessive costs associated with the voltage conversion effort. The recommended strategy would be to maintain both the 12.47 kV (SECS) and the 13.8 kV (MCS) with the 4.16 kV distribution system being converted to either 15 kV class over time and continue to be served from their respective substation at the higher voltage. The most apparent reason is from efficiency in equipment provisioning in that multiple transformers of the same kVA rating but with different primary voltages would no longer have to be stock-piled for field equipment replacement. The second reason would be the resultant lower line losses and transformer (I2R) loses due to the decrease in amperes to serve the same kVA requirements. It should be noted upgraded voltage conversion typically has no return on investment based on cost of losses alone for urban campus distribution systems. The cost savings is generally realized in the diminished requirement for supplemental quantities of electrical equipment with multiple voltage levels (i.e. 4.16 kV, 12.47 kV, 13.8 kV).

The 12.47 kV and 13.8 kV are of the 15 kV class consequently other than transformation the equipment is the same; however, the 4.16 kV is of the 5 kV class and due to its uniqueness additional equipment stocking is required. Other than single voltage rated transformers, metering, and sectionalizing equipment (due to the increase in amperage for a given kVA), 15 kV electrical equipment is suitable for operation on a 5 kV system. It is prudent to utilize 15 kV conductors (insulation), terminations, and switchgear for replacement of failed 5 kV equipment, if one is anticipating a voltage conversion to the 15 kV class.

The 12.47 kV Distribution Centers (DC's) and Load Centers (LC's) are served from the South East Campus substation. The 13.8 kV DC's and LC's are served from the Main Campus Substation located in the Abbott Power Plant (APP). The 4.16 kV DC's and LC's are served from APP either directly from 4.16 kV switchgear or 13.8 kV step down transformers.

The primary challenges associated with voltage conversion are:

- Multiple buildings are served from a common DC or LC, that are being converted from 4.16 kV to 12.47 kV or 13.8 kV thus requiring multiple dual voltage rated transformers of adequate kva capacity to serve the existing buildings.
- The possible need to provide continuous temporary power for certain loads throughout the duration of voltage conversion due to their mission critical status.
- The need to properly phase the construction to limit unintended consequences of unplanned service outages to adjacent facilities.
- The conversion process typically encompasses several years of construction due the complexity of phased construction.

Obsolescence of multifunction relays cause concern over the future maintainability. A transition to a single vendor would ideally enhance overall system reliability. The primary benefit would be the interchangeability of the individual relays, since they are multifunction in nature, and have the adaptability for arc flash detection as a standard feature. The migration to the newer relays could be phased in over a number of years with the existing PT's and CT's being reused. Furthermore, the newer designed multifunction relays are able to control more than one circuit breaker at a time and preclude the need for a "one-for-one" replacement.

The University's safety officer has stipulated that APP is a power generation facility; consequently, the exceptions outlined in NFPA 70 and 70E, OSHA 1920, and the NESC pertaining to power plants and electrical distribution facilities apply. The hazard exceptions are granted for qualified and authorized personnel only.

High Voltage Electrical System

The following assessment looks at the high voltage equipment located at the Main and South East Campus substations, which includes the 69kV/12.47 kV transformers to the demarcation line of Ameren owned equipment. There were major renovations to these stations in 2002 when all of the current high voltage system equipment was installed. Based upon interviews, there has been little need of maintenance or repair since this installation in 2002. With no documented problems of the major equipment located at these two sites.

Equipment life can vary greatly, but based upon the current use of the equipment, the life expectancy of the breakers and transformers is around 35 years. With a proper maintenance program in place, this could even improve the life expectancy of the equipment. The life expectancy of the microprocessor relays is not as well known since the relatively new entrance into the market. However, in order to keep up with the latest technology and communication standards, the relays should be replaced within 10 years.

Conceptual capital costs are developed for the high voltage electrical system repair and replacement for the business as usual scenario. The costs and is listed in the following Table. Detailed estimates are provided in Appendix 3C.

BAU HIGH VOLTAGE ELECTRIC R&R COST SUMMARY		
SYSTEM	EQUIPMENT	PROBABLE PROJECT COST ($)
MAIN CAMPUS SUB	TRANSFORMER	1,962,000
	CIRCUIT BREAKER	239,000
	RELAYS	613,000
SE CAMPUS SUB	TRANSFORMER	2,412,000
	CIRCUIT BREAKER	463,000
	RELAYS	314,000
TOTAL	---	6,003,000

Preliminary Capacity Review

The purpose of this review is to understand the current system as a whole as it interconnects with Ameren-IP. This will also be reviewed again in further detail in the context of future options when they are developed. This is based upon the review of the Stanley 138kV Electrical Service Study and interviews and site visits with the University.

The following excerpt from the Stanley Study provides insight into the electrical transmission to the campus:

> "The existing Main Campus Substation (MCS) is served by two 69kV transmission lines, one from the Ameren Southwest Campus Substation (SWCS) and one from the North Champaign Substation (NCS). The MCS is constructed with 138kV spacing and insulation and has installed four 69x138kV dual voltage 33 MVA rated transformers at MCS along with two 69x138kV dual voltage 65 MVA transformers at the South East Campus Substation (SECS). The Ameren-IP 69kV system in the area is approaching maximum capacity. Results of discussions with Ameren indicate that the power delivery limit to the campus is 60 MW."

Load data shows that the approximate campus load in 2012 was around 78 MW. The two buses at the Main Substation are rated at 2000A, which would be the limiting factor of the system. At the current 69kV voltage level this indicates that the bus is only loaded approximately a third of the full rating. This will allow for approximately three times the current load for future load growth at a unity power factor for the Main Campus Substation. This also assumes that all of the power is being supplied by Ameren, with no electricity offset by the Abbott Power Plant. However, as stated above, the Ameren system is currently limited to delivering only 60 MW of power. Either additional changes on the Ameren system will need to be completed, or the campus will need to increase the generation capabilities in the future to meet the increased demand of the University campus.

U of I ETAP Model

Introduction

The scope of the ETAP model was to construct, update, and detail the University's existing ETAP model. The scope included entering model data into ETAP from the University's one line documents ED-E1 through ED-E11 which were provided on March 23, 2012. In addition to the model, the deliverables included, a load flow study and a short circuit study, which were run within the model to verify functionality as well as provide a high-level review of the system and potential weak areas.

The ETAP Base Package is a set of core tools, embedded analysis modules, and engineering libraries that allow the user to create, configure, customize, and manage a system model. Core tools allow you to build 3-phase and 1-phase AC and DC network one-line diagrams with unlimited elements including detailed instrumentation and grounding components. The package includes engineering libraries, which provide complete, verified, and validated data based on equipment manufacturers' published data.

Load-flow studies are performed to determine the steady-state operation of an electric power system. ETAP can calculate the voltage drop on each element, the voltage at each bus, and the power flow in all branch and feeder circuits. The load flow study can determine if system voltages remain within specified limits under various contingency conditions, and whether equipment such as transformers and conductors are overloaded.

Load-flow studies are often used to identify the need for additional generation, capacitive, or inductive VAR support, or the placement of capacitors and/or reactors to maintain system voltages within specified limits.

In addition to a load flow study, ETAP is capable of running short circuit studies. The short circuit study will determine the magnitude of currents flowing throughout the power system at various time intervals after a fault occurs. This can be used to evaluate the size and settings of a system's protective devices, such as relays, fuses and circuit breakers, and the circuits they protect.

The goal of a short circuit study is to provide power transformers, switchgear, substations, motor control centers, panel boards and other electrical equipment with the required protection. The study also assists with selecting appropriate types, ampere ratings and device settings to ensure minimum service interruption under overload and short circuit conditions. It also ensures the protective device closest to the overload or short-circuit condition is the one that operates in order to isolate the failure as quickly as possible.

The ETAP model is able to perform detailed studies in several areas and can be used for operating and maintaining an existing system, while also planning for its future expansion. This study, commissioned by the University, was implemented to build their ETAP model, complete a high level load flow analysis, and provide a short circuit report.

Methodology

The University provided a very high level ETAP model that showed block loads for the Distribution Centers (DC). The University requested the model to reflect the detail shown on the prints ED-E1 through ED-E11. This required entering data from the main substation and southeast substation down to each building transformer and a block load representing each building. From the existing model, only the utility supply down to the main substation and southeast substation as well as some power plant and chiller models were able to be used in the new model. The requested studies to be created were load flow and short circuit studies.

The existing model was modified to show the detail for each DC. The existing model had a block load at each DC. The block loads were removed and the building transformer was shown with a block load for each building. The general layout with composite networks was created showing each DC. The skeleton of the model was created as the opening view of the model. Each print was reviewed and the topology of each DC was entered including busses, fuses, transformers, and loads. The busses and fuses were placed in the topology as placeholders to be filled in at a later time. Transformers were entered based on kV and size. Building loads were entered based on meter readings supplied by the University. This continued until all the prints were entered into the model which, in turn, created a topology for the system.

The building loads were entered based on provided data by the University which represented peak loading for each building. Due to scope constraints, only a portion of the fuses and cable information were fully entered into the model. Ultimately, a functioning model was produced capable of running load flow and short circuit studies within ETAP.

Assumptions and Clarifications

While constructing the model, assumptions were made based on the model and documentation provided.

- The ETAP Model provided had correct data from the utility source down to the load side of the main substation bus and southeast substation bus.
- University maps and drawings are correct and prints ED-E1 through ED-E11 show all necessary building details for the ETAP model (provided on 3-23-2012)
- Any generators or motors in the model that were provided were correct and complete unless directed by the University.
- Any future labeled equipment in the model was removed – per University Distribution staff.
- Existing cables in the model are correct. Additional cable lengths and types are estimated by taking the campus map and finding the shortest route. Cables are based on drawings and educated guesses.
- Switches, breakers, and fuses labeled as “reserve” were modeled as normally open.
- Transformers 13.8-4.16kV in the model are correct for DC2, DC3, DC4.
- All fuses are assumed to be S&C SM-5 Standard Speed rated for the kV of the installation.
- Transformer impedances are estimated by ETAP based on size and voltage, when provided.

- The existing model of AP-99, AP-98, CG-01, and CP-41 were used.
- Due to scope constraints and lack of data, not all fuse, breaker, and cable data was entered.

Results and High Level Analysis

The ETAP model was used to conduct a load flow study of the medium voltage distribution systems, the results of which are attached as Appendix 3I. The short circuit study results are attached as Appendix 3I. The study highlights possible overloaded elements and possible low voltage areas. Results outside of normal parameters are highlighted. Results were reviewed for model discrepancies then rerun to filter any overloads due to modeling inputs.

The following Table is a summary of the ETAP Model is listed. The tables that follow show critical voltage and loading levels with a high level analysis of the critical level.

ETAP Case Summary

Study ID	U of I ETAP Load Flow 2-19-2013
Study Case ID	LF
Data Revision	Base
Configuration	Opt1
Loading Cat	Design
Generation Cat	Design
Diversity Factor	Normal Loading
Buses	652
Branches	656
Generators	8
Power Grids	2
Loads	384
Load-MW	110.479
Load-Mvar	74.471
Generation-MW	110.479
Generation-Mvar	74.471
Loss-MW	1.882
Loss-Mvar	12.483
Mismatch-MW	0.002
Mismatch-Mvar	0

Result Summary and Analysis - Bus

Bus ID	Nominal kV	Voltage	MW Loading	% Loading	Analysis
AP60E	4.16	94.99	1.848	0	Load on bus and xfmr looks high, check xfmr size and meter readings.
AP99-WEST	4.16	100.72	8.8	118	Check for actual configuration of Bus.
Bus30	4.16	94.42	0.294	0	Check cable size and length, Field verify configuration. Related to LC-15
Bus394	4.16	94.42	0.501	0	Check cable size and length, Field verify configuration. Related to LC-15
Bus395	4.16	94.42	0.249	0	Check cable size and length, Field verify configuration. Related to LC-15
Bus434	0.208	93.91	0.488	0	Field verify xfmr size and characteristics.
Bus520	4.16	94.79	0.553	0	Verify cable size and length.
Bus537	4.16	94.79	0.337	0	Verify cable size and length.
Bus LC-15	4.16	94.42	1.624	0	Check cable size and length, Field verify configuration.

Result Summary and Analysis – Component

ID	Type	MW Flow	Mvar Flow	Amp Flow	% Loading	Analysis
Cable126	Cable	1.134	0.703	191.4	118	Verify Cable Size and Chiller Loading
Cable127	Cable	1.218	0.755	205.6	126.7	Verify Cable Size and Chiller Loading
Cable169	Cable	1.699	1.397	315.9	170.5	Verify Cable Size and Busey Evans Loading.
T148	Transf. 2W	1.579	1.303	315.9	232.4	Verify Xfmr Size and Busey Evans Loading.
T182	Transf. 2W	0.154	0.105	8.622	158.7	Verify Xfmr Size and Alice Campbell Loading.
T231	Transf. 2W	0.757	0.549	137.5	173.5	Verify Xfmr Size and Eng Hall Remodel Loading.
T249	Transf. 2W	0.42	0.313	74.75	212.9	Verify Xfmr Size and Southeast Building Loading.
T250	Transf. 2W	0.252	0.174	43.71	129.5	Verify Xfmr Size and Upper East Lights Loading.
T251	Transf. 2W	0.235	0.161	40.7	121	Verify Xfmr Size and Lower East Lights Loading.
T253	Transf. 2W	0.151	0.101	26.07	105	Verify Xfmr Size and Admin Building Loading.
T276	Transf. 2W	0.067	0.043	10.97	103.1	Verify Xfmr Size and Tennis Court Lights Loading.
T294	Transf. 2W	0.27	0.188	46.36	138.6	Verify Xfmr Size and Noyes Lab 1 Loading.
T402	Transf. 2W	0.043	0.027	7.146	109.1	Verify Xfmr Size and Wood Engineering Lab 2 Loading.
T430	Transf. 2W	0.755	0.525	133	115.7	Verify Xfmr Size and Art & Design / 4th & Peabody Loading.
T440	Transf. 2W	0.025	0.016	4.144	113.9	Verify Xfmr Size and Surveying Building Loading.
Unit Aux 7	Transf. 2W	1.874	1.23	93.58	106.2	Verify AP-60E Bus loading and Xfmr Size.

3.6 Natural Gas Distribution System

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Once this piping reaches APP, a majority is used for utility purposes (i.e. steam boilers), while a portion is also distributed to campus buildings and research park buildings that are not on the campus steam loop and utilize natural gas for their on-site heating. APP also contains another pressure reducing station, that drops the 400-psig NG down to 40-psig. 40-psig is thus the standard distribution pressure to campus buildings for general usage. The building distribution piping from APP only serves the South end of campus, with a majority of the buildings that utilize NG being located in the research park area to the south of St. Mary's Road and to the west of First Street.

Natural Gas Hydraulic Model

The hydraulic model was developed using programs developed by Applied Flow Technology (AFT). The AFT suite of programs includes a core hydraulic model software, AFT Fathom, and an add-on module for compressible flow analysis (i.e. steam systems), AFT Arrow. AFT Arrow v4.0 was utilized for the natural gas (NG) hydraulic analysis, as NG is a compressible fluid.

Piping layout, sizes, pressures, etc. have been modeled by AEI using the ArcGIS campus utility map, along with supplemental information provided by Distribution staff. Building loads for each building under maximum load conditions were estimated by AEI and input into the model. These load estimates are derived from actual meter data provided by the University. Therefore, the information for which the natural gas model is based is validated to the best information available to AEI.

Observations from the Natural Gas Hydraulic Model

At this point in time the University's natural gas distribution system appears to be considerably oversized for the current utilization and distribution pressure. The total maximum NG demand has been calculated to be approximately 4,260 scfm, and color charts indicate that pipe mass flow rates and velocities are substantially below maximum allowed values. A majority of the distribution system experiences velocities less than 2-FPS under design loads conditions, with a maximum system velocity of just over 10-FPS in a single stretch of pipe. This excess capacity available in the natural gas system would allow for substantial future expansion in the research park area, without the need to provide a considerable amount of new infrastructure to bring the steam system to this region of campus. Given the excess capacity of the University's distribution system, it would also be possible for some of the buildings currently served by Ameren natural gas to be converted to the campus NG distribution, if this would be beneficial for the University.

3.7 Fuel Oil Distribution System

The storage tanks are each 80' diameter tanks that are 28' tall. The rated maximum fill height on each of the tanks is 24'-11", which equates to 22,310 barrels of fuel (937,020 gallons). Based on information provided by U of I, the tanks currently have 12,924 barrels of fuel. The fuel is currently held in the East Tank while inspections and repairs occur in the West Tank. Once repairs are completed the oil will be transferred to the West Tank and the East Tank will be inspected and repaired. During normal operation the oil is assumed to be divided evenly between the two tanks. The tanks were constructed in 1971 and have undergone various repair projects, as deemed necessary through occasional professional analysis of the tank. The tanks are currently being inspected and repaired.

Once inside the lower level (basement) at APP, the fuel oil piping splits to feed two sets of fuel oil pumps. Fuel oil pumps 1 and 3 feed Boilers 2 and 3 and will feed the future Boiler 4. Fuel oil pumps 4 and 5 feed the gas combustion turbines HRSGs 1 and 2. Boilers 2 and 3 both have design fuel flow rates of 11,615-pph. Based on the fuel properties in the table below, this equates to roughly 27-gpm for each boiler under design flow conditions.

Fuel Oil No. 2 Composition	
Nitrogen, % by weight	0.02
Specific Gravity	0.85
Temperature @ Burner	80°F
Viscosity @ Burner	30-40 ssu

The design fuel flow demand of the HRSG combustion turbines has been approximately determined through power output and conversion/efficiency factors. Based on this, the design flow rate of HRSGs 1 and 2 has been determined to be approximately 15 gpm each.

Fuel oil pumps 1 and 3 are a each the same model pump and piped in parallel. It is assumed that they operate in duty/standby configuration, but concurrent parallel operation would also be possible. These pumps are Lonergran Pump System Model P-1532, rated at 32 gpm, 150 psig each on a common control system and skid. Fuel oil pumps 4 and 5 are each the same model pump and also piped in parallel with each other. It is assumed that they operate in duty/standby configuration, but concurrent parallel operation would also be possible. These pumps are Viking

Pumps Model AK4195. Nameplates could not be found on the pumps, but manufacturer's product data regarding the aforementioned model number has a maximum flow rate of 50-gpm at 1200 rpm. The current motors on each of these pumps are 5 HP, 1170 rpm.

Fuel Oil Hydraulic Model

The hydraulic model was developed using programs developed by Applied Flow Technology (AFT). The AFT suite of programs includes a core hydraulic model software, AFT Fathom, and an add-on module for compressible flow analysis (i.e. steam systems), AFT Arrow. AFT Fathom v7.0 was utilized for the fuel oil hydraulic analysis, as fuel oil #2 is a non-compressible fluid.

As mentioned above, the tanks gravity feed the pumps within the basement at APP via the (mostly) 6" pipeline. 12,924 barrels of fuel split between the two tanks equates to approximately 7'-3" of fuel height in each tank. The floor elevation of each tank is 739'-0" and the basement floor elevation of APP is 726'-0". This elevation difference along with the atmospheric pressure, almost negligible vapor pressure, and the low friction loss through the 6" pipeline seems to provide a very adequate NPSHA, although the NPSHR for the pumps is unknown.

Observations from the Fuel Oil Hydraulic Model

The main observation from the hydraulic model is that it seems like the fuel oil system and components are well sized to handle the current maximum possible load. This also seems to coincide with all the information that has been found regarding this system. With Boilers 2 and 3 and HRSGs 1 and 2 running at full capacity continuously, the system should be able to run for just over 15 days, provided the tanks are completely full. The pumps also appear to be designed to flow more fuel than they currently need to. Given that the tanks gravity feed APP, the pipe velocities are also fairly low. The highest velocity in the system under full load is still a little under 1 fps, which is well within acceptable parameters.

3.8 Compressed Air Distribution System

The existing compressed air system has sufficient capacity to serve the University’s compressed air needs. There is currently very little pneumatic load for building pneumatic control systems and University trends are moving from pneumatic controls to building digital controls. A typical university building requires approximately 10 scfm of compressed air. The existing campus distribution system is an 8" compressed air main leaving Abbott Power Plant at 100 psig. The 8" main can support 1650 scfm at 1800 fpm, or approximately 160 buildings.

The remaining buildings using compressed air should be examined further to determine if they can be converted from pneumatic to digital controls and individual compressed air systems added to the chilled water plants that require instrument air.

3.9 Code and Life Safety

A code and life safety analysis was performed to determine any code and life safety impacts on the ability to continue to operate the facilities in a business-as-usual basis over the next 35 years. The analysis included discussions with University code officials and facility operators, reviewing available life safety reports, visual inspections of the existing fire alarm, emergency lighting and means of egress, and an update to previous reports cost estimates for any outstanding items.

The following Reference Materials were reviewed as part of the evaluation

A. International Building Code -2006 Edition.
B. NFPA 101, Life Safety Code-2000 Edition.
C. Asset Summary Report and Requirement List Report from VFA for Abbott Plant. **
D. Requirement Detail Report from VFA for North Campus Chilled Water Plant. ***
E. LSC recommendations of corrective actions from Alan R. Otto to Rick Rundus dated December 9, 2005. *
F. RS Means Electrical Cost Data – 2012 Edition.
G. Chartered Institution of Building Services Engineers -
H. "Indicative Life Expectancy for Building Services Plant, Equipment and Systems."

Reference materials and updated costs for recommended improvements are included in Appendix 3J.

Abbott Power Plant

Status of Items Listed in Report or identified during visual inspection

- Continue to improve coal dust control – Per NFPA 850, coal dust should be controlled by dust collection or dust suppression. Much of the coal train has penetrations open to the rest of the plant. Constructing enclosure hoods at transfer points and patching/eliminating openings can minimize the amount of dust released to surrounding areas, which can reduce the need for dust collection.
- Subdivide plant into separate fire areas – The plant should be subdivided into separate fire areas created by construction of fire rated barriers. The purpose of the barriers is to limit the spread of fire, protect personnel and limit damage occurring as a consequence of fire or explosion within any one area of the plant. The barriers should have a minimum of a 2-hour fire resistance rating. Openings in the barriers should be protected by fire door assemblies, fire dampers, and fire shutters with not less than a 1 and ½ hour fire resistance rating. In addition, duct and pipe penetrations through walls should be caulked with a fire rated caulking.
- Items completed as described in the Used Reference Materials List:
  - Basement lighting is updated.
  - Current office spaces provided with alarm initiating and audio/visual devices.
  - Fire detection in office areas and enclosed stairs 1 and 30.
  - All existing exit paths provided with exit signs.
  - Stair identification signs within Stair 1 and Stair 30 enclosures are provided.
- Items not completed as described in the Used Reference Materials List:
  - The Fire Alarm Control Panel does not have flow monitor modules.
  - The need for additional audible/visible fire alarm notification devices.
  - Emergency lighting illumination levels are inadequate.
  - Emergency lighting for all ways of exit access.
  - All new signs shall be LED type.

- High voltage electrical equipment is not separated from other areas.

Existing Fire Alarm System Description

- The Control Panel is from Cerberus Pyrotronics Model MXL with voice evacuation capability.
- The Control Panel is connected to McCulloh Loop Central System via master box.
- The Control Panel has some space for installation of additional modules.
- All alarm initiating devices quantity and spacing is adequate.
- Audible/visible devices installed on all floors.
- Smoke detectors installed in elevator lobby at each level.
- Manual pull stations installed at all exits from the building.
- Signifire IP camera system is installed.

Proposed modifications for the Existing Fire Alarm System

- Repair or modify existing fire alarm panel to provide all Code required annunciation and monitoring functions.
- Add 6 addressable heat detectors above main switchgear on first floor.
- Add heat detector in oil storage room in the basement.
- Add new alarm causing addressable interface modules for the existing dry pipe sprinkler flow switches and shutoff valve.
- The addition of a more power PA system may not be effective because the existing ambient noise level may be in excess of 120 dB level and require personal protection already; we are proposing installation of an additional 24 visual devices on all floors.
- Replace existing Fire Alarm System in 20 years after original installation.

Existing Emergency Lighting System Description

- The emergency power for emergency lighting system originates from the two following independent sources: (a) central DC batteries providing power at 120 VDC for emergency lights and exit signs in the main building (areas B5 and B7); (b) UPS providing power at 277 VAC for emergency lights and exit signs in the latest building addition.
- All emergency lighting and exit signs circuits are constantly on.
- All emergency lighting in Scrubber Building is battery packs type.
- From the observation it seems that the emergency lighting levels throughout is adequate.

Proposed modifications for the Existing Emergency Lighting System

- Transfer existing emergency and exit signs lighting system to the new emergency generation plant for Abbott Power Plant after the emergency generation plant installation and commissioning.
- Add exit sign at the south stairs in the basement.
- Add exit sign at the exit from room 10C on first floor.

- New Emergency Lighting System will be required after the end of the life expectancy of the existing Emergency Lighting System.

Oak Street Chiller Plant

Status of Items Listed in Report or identified during visual inspection

- The Oak Street Chiller Plant has an existing self-contained breathing apparatus (SCBA) but the University does not have a SCBA program in place. A training program for chilled water staff should be established.
- ASHRAE 15 requires the refrigerant alarm shall annunciate visual and audible alarms inside the refrigerating machinery room and outside each entrance to the refrigerating machinery room. Add alarms outside all entrances to refrigerating machinery room.

Existing Fire Alarm System Description

- Fire Alarm Control Panel is from Siemens, MXL type.
- The Control Panel is connected to McCulloh Loop Central System via master box.
- Alarm initiating devices quantity and spacing is adequate

Proposed modifications for the Existing Fire Alarm System

- Add smoke detectors in offices 2002, 2004, 2006, 2008 located on mezzanine (total four detectors).
- New alarm initiation devices will be required after the end of life expectancy of the existing devices.
- New fire alarm panel and alarm initiating devices will be required after the end of life expectancy of the existing Fire Alarm System.

Existing Emergency Lighting System Description

- The power for the existing emergency system emanates from the emergency generator and is delivered via transfer switch to the following two emergency lighting panels: panel E-LPB-480/277V, 3Ph, 4W for panel E-SPA-120/208V, 3Ph, 4W
- All HID lighting connected to panel E-LPB, all fluorescent, battery pack lighting fixtures and exit signs connected to panel E-SPA
- All emergency lighting and exit signs are constantly on
- Emergency lighting level exceeds 1 foot candle

Proposed modifications for the Existing Emergency Lighting System

- New Emergency Lighting System will be required after the end of life expectancy of the existing Emergency Lighting System.

North Campus Chiller Plant

Status of Items Listed in Report or identified during visual inspection

- The North Campus Chiller Plant has removed the SCBAs, but signs indicating SCBAs still exist. This can create a situation where staff can enter the space expecting SCBA to be present. If a SCBA training program is established, provide SCBAs at North Campus Chiller Plant.
- Items that were completed as described in the Used Reference Materials List from paragraph 2 above: None
- Items that might not be completed as described in the Used Reference Materials List from paragraph 2 above:
    - Lighting: Inefficient Fixtures/Lamps. ***
    - Grounding and Cathodic Protection. ***
    - Replacement of the existing fire alarm system with new addressable fire alarm system. ***
    - Replacement of all existing exit signs with. ***

Existing Fire Alarm System Description

- Fire Alarm Control Panel is Pyrotronic XL3 type.
- The Control Panel is connected to McCulloh Loop Central System via master box.
- The connection between the Fire Alarm Control Panel and the Campus NCC/WAN Control center in the Public Safety Building needs to be verified.
- Alarm initiating devices quantity and spacing is adequate.
- Audible/Visual Devices; strobe lights installed only.

Proposed modifications for the Existing Fire Alarm System

- New Fire Alarm System shall replace the existing system.

Existing Emergency Lighting System Description

- Emergency lighting consisting of three battery packs units and three exit signs.

Proposed modifications for the Existing Emergency Lighting System

- New Emergency Lighting System will be required after the end of life expectancy of the existing Emergency Lighting System.

Library Chiller Plant

Status of Items Listed in Report or identified during visual inspection

- The Library Chiller Plant does not have any SCBA. If a training program is established for chilled water staff, provide SCBAs at the Library Chiller Plant.

Existing Fire Alarm System Description

- Fire Alarm Control Panel is Siemens XLSV located in a closet near main entry in the building.
- The Fire Alarm Control Panel connection to McCulloh Loop Central System needs to be verified.
- The connection between the Fire Alarm Control Panel and the Campus NCC/WAN Control center in the Public Safety Building needs to be verified.
- Alarm initiating devices quantity and spacing is adequate.

Proposed modifications for the Existing Fire Alarm System

- Provide the following after the end of life expectancy of the existing alarm initiating devices:
    - Install new satellite fire alarm panel in the mechanical basement and connect panel to the existing Fire Alarm Control Panel.
    - Replace all existing alarm initiating devices with new and connect all new alarm initiating devices to the new satellite fire alarm panel.

Existing Emergency Lighting System Description

- The emergency lighting system is not adequate.

Proposed modifications for the Existing Emergency Lighting System

- Replace 2 exit signs.
- Add 2 lights in corridor going to electrical room.
- Add 3 lights above the ramp going down.
- Add 4 lights in room west from Room 31
- New Emergency Lighting System will be required after the end of life expectancy of the existing Emergency Lighting System.

Animal Science Chiller Plant

Status of Items Listed in Report or identified during visual inspection

- Means of egress from the Animal Science Chiller Plant are not clearly indicated.
- The Animal Science Chiller Plant does not have any SCBA. If a training program is established for chilled water staff, provide SCBAs.

Existing Fire Alarm System Description

- There is no alarm initiating devices in the upper mechanical room except two temper switches, one pull station and one horn /strobe light.
- There are no alarm initiating devices in the lower mechanical room except one temper, one flow switch and one horn/strobe light.
- The existing fire alarm control panel is in closet 031; fire alarm control panel type XL3

Proposed modifications for the Existing Fire Alarm System

- Add four smoke detectors to be connected to the existing fire alarm control panel.

Existing Emergency Lighting System Description

- There are emergency lighting fixtures in both mechanical rooms connected to emergency lighting panel located between Rooms 15A, 15B and Room 019.

Proposed modifications for the Existing Emergency Lighting System

- Add one emergency lighting fixture above stairs between lower and upper level mechanical rooms.
- Add exit sign at the exit from upper level mechanical room to outside via corridor.
- New Emergency Lighting System will be required after the end of life expectancy of the existing Emergency Lighting System.

Chemistry-Life Sciences Chiller Plant

Status of Items Listed in Report or identified during visual inspection

- The Chemistry-Life Sciences Chiller Plant has an existing self-contained breathing apparatus (SCBA) but the University does not have a SCBA program in place. A training program for chilled water staff should be established.

Existing Fire Alarm System Description

- Existing Fire Alarm Control Panel is from Siemens Pyrotronic, type MCLV; located in closet B108 on first floor.
- The Control Panel is connected to McCulloh Loop Central System via master box 2341
- The connection between the Fire Alarm Control Panel and the Campus NCC/WAN Control center in the Public Safety Building needs to be verified.
- There are no heat or smoke detectors in the room except one smoke detector in the elevator lobby.
- There are two Audible/Visual Devices in room and one flow and temper switches.

Proposed modifications for the Existing Fire Alarm System

- Add two addressable heat detectors

Existing Emergency Lighting System Description

- There are three exit signs and three emergency lighting fixtures connected to the existing emergency lighting panel.

Proposed modifications for the Existing Emergency Lighting System

- New Emergency Lights will be required after the end of life expectancy of the existing Emergency Lighting System.

Vet Med Chiller Plant

Status of Items Listed in Report or identified during visual inspection

- The Vet Med Chiller Plant does not have any SCBA. If a training program is established for chilled water staff, provide SCBAs.
- ASHRAE 15 requires the refrigerant alarm shall annunciate visual and audible alarms inside the refrigerating machinery room and outside each entrance to the refrigerating machinery room. The refrigerant monitor light has been removed from the exterior of the entrance.

Existing Fire Alarm System Description

- Existing Fire Alarm Control Panel is old style and obsolete.
- Heat detectors are old; the detectors quantity in the production area is adequate.
- Auxiliary rooms at lower level do not have alarm initiating devices.

Proposed modifications for the Existing Fire Alarm System

- Replace existing outdated fire alarm panel, alarm initiating and audible visual devices with latest type MXLV fire control panel and associated devices.
- Add smoke detectors in auxiliary rooms

Existing Emergency Lighting System Description

- Exit sign at the west exit stairs is missing.
- The existing emergency lighting area coverage and lighting level is adequate.

Proposed modifications for the Existing Emergency Lighting System

- Add exit sign at the west exit stairs
- New Emergency Lighting System will be required after the end of life expectancy of the existing Emergency Lighting System.

Steam tunnels

A visual inspection of portions of the steam tunnel were conducted during the condition assessment along with an informal polling of peer institutions regarding safety standards and standard operating procedures for entrance into existing steam tunnels. The table shown in Appendix 3K lists a summary of how peer institutions treat occupancy for their steam tunnels. Of the institutions polled, most have identified the tunnels as non-permitted confined spaces. Access to the tunnels is limited to authorized personnel with notification before entry and after leaving a tunnel. The tunnels have means of egress every 300 ft with mechanical lighting.

Ventilation in the tunnels among peer institutions is a mix of natural and mechanical with typical temperatures running ambient plus 10°F.

It is recommended the University institute a similar policy of non-permitted confined space with controlled access, required notification upon entry and exit. Also recommended is the University conduct a survey of the existing tunnels to determine where additional lighting, mechanical or natural ventilation, and means of egress should be added. In addition, the University may examine an energy savings project as a means for re-insulating existing steam piping systems and reducing the heat loss from steam piping systems, resulting in safer temperatures in existing steam tunnels.

4.0 Campus Loads, Projected Growth and Demands

4.1 Overview

Since the founding of the University of Illinois in 1867, the Urbana-Champaign campus has grown to over 42,000 students and over 10,000 faculty and staff. The campus has more than 320 buildings on the main campus spread over 2.8 square miles. Including smaller facilities and the south farms, the campus totals more than 660 buildings spread over 7.1 square miles.

As the University grew, the utility demands of the campus grew to today's current levels. In the face of such growth, the campus has successfully reduced its energy consumption trend through energy conservation and retro-commissioning initiatives. Energy consumption per square foot of conditioned space was reduced from 312.3 to 244.2 kBtu/GSF between 2007 and 2014. Continuing these efforts will further reduce campus energy consumption.

An essential component of the Utility Master Plan is the projection of the anticipated future utility demand profile for the campus. This demand profile is critical to understanding and planning for the infrastructure required to meet these anticipated future utility loads.

The utility demand forecasts are based on current metered building consumption, scheduled building demolitions, anticipated future construction projects, and assumed data center growth. The campus has grown over past 15 years at a rate close to 300,000 GSF/yr. Given the iCAP target of net zero GSF/yr growth, campus planning has identified three campus growth scenarios that were examined as part of the study.

- iCAP target of net zero gross square feet (GSF)
- medium growth scenario of 75,000 GSF/yr
- high growth scenario of 150,000 GSF/yr

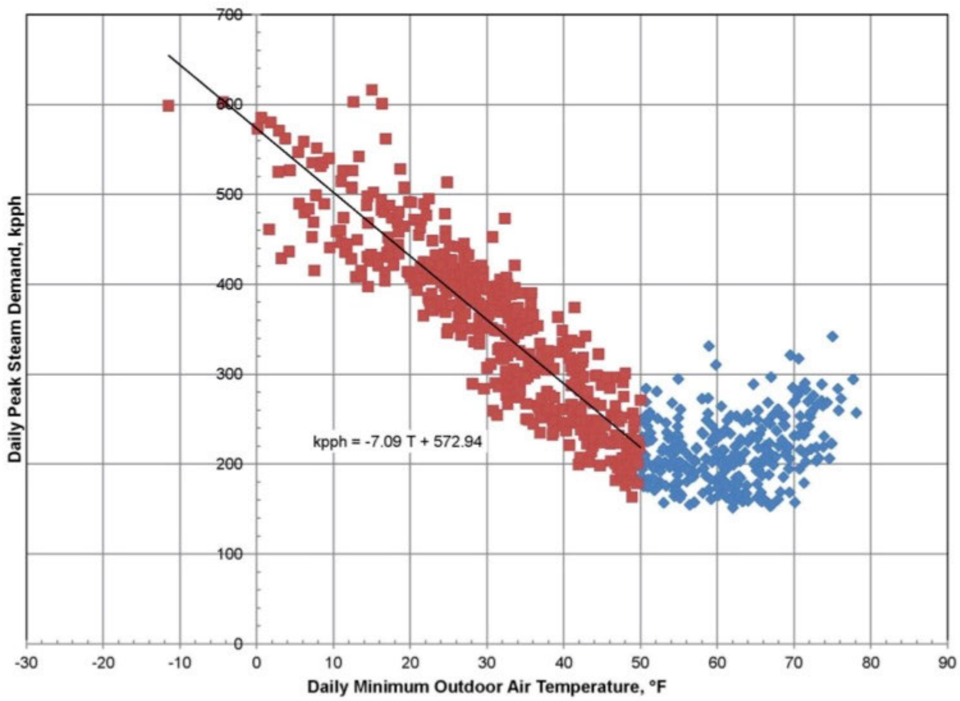
The campus target is net zero area growth and the medium and high growth scenarios show the effect of growth on campus utilities.

4.2 Existing Loads

Utility demands are developed using historical utility demands over five years. A base peak is established, then plans to demolish, renovate, or add buildings to the central systems are accounted for in the campus loads.

The campus future load growth is estimated using diversified peak factors for campus building types.

Central Steam – A plot of measured daily peak steam produced at Abbott Power Plant versus the minimum outdoor air temperature from January 2011 to April 2013 is presented below. The figure indicates steam demand has a linear relationship with outdoor air temperature below 50°F and a constant base usage above 50°F, with increasing steam demand at higher outdoor air temperatures. The increased steam demand at higher outdoor air temperatures (approximately 65°F and above) is caused when steam chillers are brought on-line as the campus chilled water load increases.

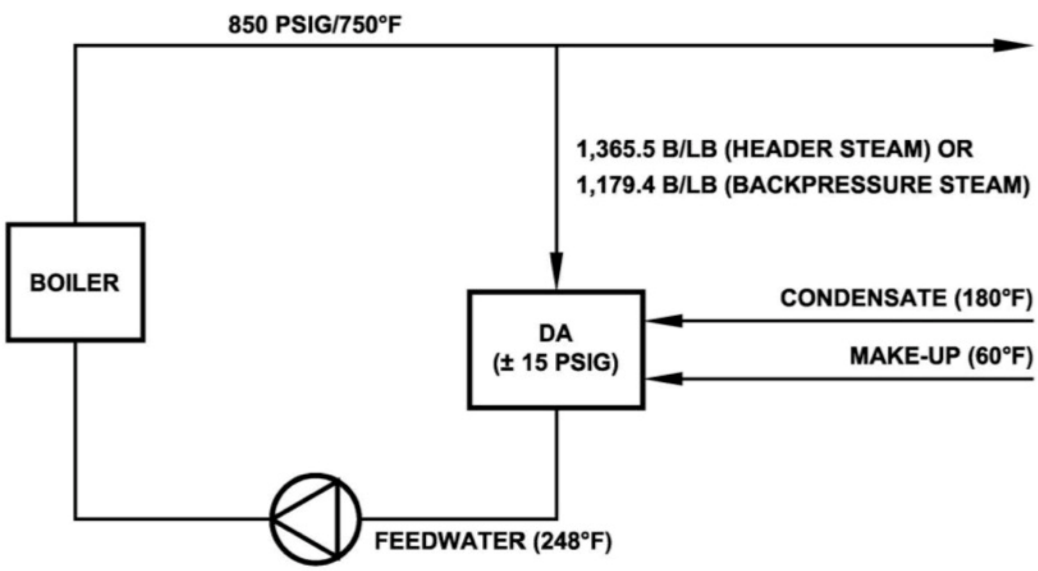


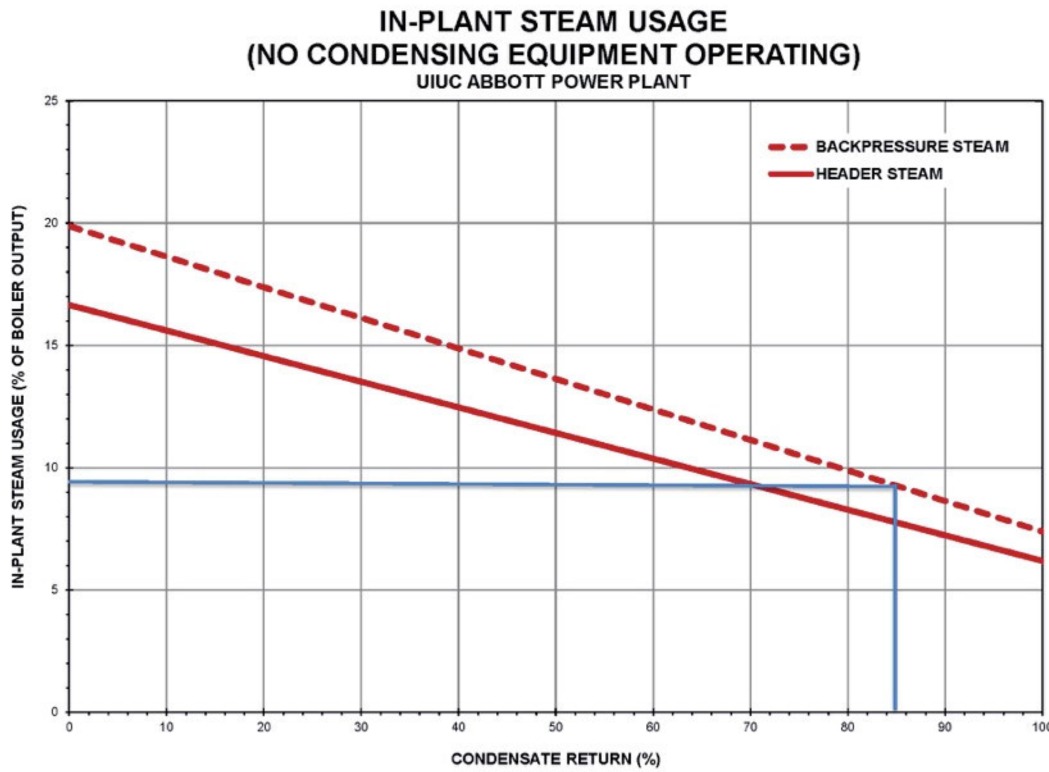
APP Daily Peak Steam vs. Daily Minimum Outdoor Air

The measured peak over this period is 616 kpph and the steam peak at an outdoor air temperature of -11.5°F is 599 kpph. Extrapolating the trend of minimum outdoor air versus peak steam (50°F and lower) to a campus design day at -10°F, the peak plant steam demand is 643.8 kpph.

Campus retro-commissioning efforts have resulted in reduced campus utility consumption and peak demands. Recognizing the trends of reduced peak demands and discussions with U of I staff, 600,000 pph is used as the starting point for peak steam produced at APP. The campus building diversified heating load is estimated by removing the in-plant steam usage and distribution losses from the central plant peak load.

In-plant steam usage as a percentage of boiler output given percentage of condensate return is indicated in the following figure. From discussions with U of I staff, approximately 85% of the campus condensate is returned to APP. This results in 9% of the steam used in-plant for deaerator tanks, make-up water, etc. An additional 50,000 pph is used in the condensing steam turbines, STG Nos. 6 and 7 for a total in-plant steam usage of 107,000 pph. An estimated 9% heat loss in the distribution system leaves a diversified peak campus building heating load of 473,000 pph steam.





Central Chilled Water – The measured peak cooling load, including all buildings connected to the central system as of March, 2011, is 30,948 tons, of which 2,642 tons is associated with the Veterinary Medicine Complex.

Central Power – The peak electrical demand on campus, measured in September 2012 is 78,437 kW. In-plant usage needed to operate Abbott Power Plant during the peak was 1,750 kW.

The electrical demand of the chilled water plants is calculated using average chilled water plant efficiencies per plant as indicated in the table below. Given existing chilled water plant dispatch, it is assumed that 5,000 tons of chilled water is produced using steam driven chillers at the Oak Street Chiller Plant and 5,000 tons are provided from the thermal energy storage (TES) tank during the peak electrical demand. The following table indicates the calculated peak electrical demand required to produce the peak chilled water is 21,450 kW. Measured distribution losses are 6,094 kW, including non-metered loads, leaving a peak campus building electrical demand of 49,143 kW.

PEAK CHILLED WATER PLANT ELECTRICAL DEMAND

PLANT	PLANT LOAD (TONS)	REMAIN. LOAD (TONS)	ELECTRIC DEMAND – CHILLER EFF. (KW/TON)	ELECTRIC DEMAND – CHILLER ELECT. LOAD (KW)	ELECTRIC DEMAND – AUXILIARIES EFF. (KW/TON)	ELECTRIC DEMAND – AUXILIARIES ELECT. LOAD (KW)	ELECTRIC DEMAND – TOTAL PLANT (KW)
VET MED CHILLER PLANT	2,642	33,706	0.603	1,593	0.144	380	1,974
OAK ST CHILLER PLANT (STM)	5,000	28,706	---	---	0.137	685	
OAK ST CHILLER PLANT (ELEC)	9,200	19,506	0.607	5,584	0.144	1,325	7,594
NORTH CAMPUS CHILLER PLANT	8,400	11,106	0.653	5,485	0.150	1,260	6,745
CHEM LIFE SCIENCE CHILLER PLANT	3,256	7,850	0.603	1,963	0.165	537	2,501
LIBRARY A/C CENTER	1,000	6,850	1.011	1,011	0.091	91	1,102
ANIMAL SCIENCE A/C CENTER	1,850	5,000	0.676	1,251	0.091	168	1,419
TES TANK	5,000	---	---	---	0.023	115	115
TOTAL	36,348	---	---	16,888	---	4,562	21,450

The following table summarizes the peak demands measured at the central utility systems and the campus building diversified peak loads. The central steam system serves 148 buildings with a diversified campus peak of 472,600 pph, 90 buildings served by the central chilled water system have a diversified campus peak demand of 30,948 ton (including Vet Med Complex and Petascale), and 193 buildings receive campus electricity and have a diversified campus peak electrical demand of 49,143 kW (including Petascale).

SUMMARY OF PEAK CAMPUS UTILITY DEMAND

DESCRIPTION	STEAM WINTER (PPH)	STEAM SUMMER (PPH)	CHILLED WATER SUMMER (TONS)	CHILLED WATER WINTER (TONS)	ELECTRIC (KW)
AREA SERVED BY UTILITY (SQ FT)	15,876,480	15,876,480	12,300,255	12,300,255	16,340,891
PEAK LOAD ON CENTRAL SYSTEM	630,000	319,000	30,948	6,381	78,437
IN-PLANT DURING PEAK (APP)	107,000	78,863	---	---	1,750
PEAK CAMPUS EXPORT	523,000	240,137	30,948	6,381	76,687
DISTRIBUTION LOSSES	50,400	37,800	---	---	6,094
CHILLER PLANTS @ PEAK	---	---	---	---	21,450
PETASCALE @ PEAK	---	---	---	272	14,414
NET CAMPUS PEAK LOAD	472,600	202,337	30,948	6,109	34,729

4.3 Diversified Building Loads

Individual building diversified loads are estimated using the diversified campus peak loads, up to five years of measured building steam and chilled water consumption data, measured building electrical demand data, and using AEIs experience with similar Midwestern campuses. The purpose of estimating individual building loads is twofold:

- Provide loads to examine campus distribution systems
- Calculate building load factors in order to estimate future growth

The primary implication of the load calculation method is that the individual building loads may be inaccurate while the overall campus peaks are known to be accurate. Therefore, care should be taken not to draw conclusions about individual building, or small groups of 2 or 3 buildings; however there is confidence in the analysis of the overall system or for loads assigned to regions of campus.

Diversified Peak Chilled Water – Five years of monthly chilled water consumption data is separated by season into peak and off-peak seasonal data and converted to an average consumption per hour per season. The buildings that have been retro-commissioned ignore any data before the retro-commissioning when calculating their load profile to determine a more accurate current building peak.

The resulting calculated peak demands are then normalized to the peak production measured at the chilled water plants, resulting in a Diversified Peak Chilled Water Load for each building.

Diversified Peak Steam – Campus steam consumption includes non-weather related loads due to domestic heating and process loads. The non-weather related consumption is removed from the building loads and the remaining steam consumption for the season is reduced to average consumption per hour based on the number of days and hours in the season. The non-weather related loads are added back to the buildings and the resulting peak demands are normalized to the peak production measured at Abbott Power Plant, resulting in a Diversified Peak Steam Load for each building

Diversified Peak Power – Metered electrical demand data is examined for metering anomalies and data prior to retro-commissioning removed for a resulting average peak demand used as the diversified peak campus load.

The following table lists campus buildings served by central utilities and their diversified peak demand.

EXISTING BUILDING UTILITY LOAD SUMMARY

BLDG NO.	BUILDING NAME	ZERO NET BASE (GSF)	PEAK UTILITY LOADS		
			CHW (TONS)	STEAM (PPH)	ELECT. (KW)
0001	DAVENPORT HALL	110,943	166	4,485	142
0002	ART-EAST ANNEX, STUDIO 2	12,182	---	---	---
0003	MCKINLEY HEALTH CENTER	84,225	198	1,657	182
0004	HARDING BAND BUILDING	27,840	---	433	79
0006	ARMORY	260,748	135	3,074	124
0007	FOELLINGER AUDITORIUM	51,765	60	816	87
0008	AGRICULTURAL ENGR SCIENCES BLDG	106,019	188	3,159	436
0010	CHEMISTRY ANNEX	42,466	---	2,025	49
0011	CERAMICS KILN HOUSE	15,697	---	---	63
0012	NOYES LABORATORY OF CHEMISTRY	184,711	310	3,465	199
0013	TALBOT LABORATORY	110,529	---	2,411	128
0014	ICE ARENA	51,676	---	2,378	177
0015	ENGINEERING HALL	93,189	161	1,921	114
0017	ADVANCED COMPUTATION BLDG	45,346	674	899	812
0018	ART-EAST ANNEX, STUDIO 1	47,541	---	726	35
0020	PHYSIOLOGY RESEARCH LABORATORY	4,865	---	---	35
0021	KENNEY GYMNASIUM	49,507	---	1,656	42
0023	ILLINI UNION	305,130	681	7,317	166
0024	NEWMARK CIVIL ENGINEERING BUILDING	186,322	482	6,146	464
0025	HARKER HALL	33,189	59	520	94
0026	ALTGELD HALL	79,721	177	1,494	133
0027	LINCOLN HALL	171,121	---	3,621	---
0028	AERONAUTICAL LABORATORY A	10,443	---	---	32
0029	MECHANICAL ENGINEERING LABORATORY	151,860	326	2,806	723
0031	DYNAMICS TESTING LABORATORY	5,863	---	---	---
0032	NATURAL HISTORY BUILDING	153,284	11	2,066	179
0033	OBSERVATORY	12,528	---	245	41
0034	MATERIALS SCIENCE AND ENG BLDG	101,803	186	3,363	408
0037	EVERITT ELEC & COMP ENGR LAB	124,246	507	4,126	186
0039	MUSIC BUILDING	105,343	251	2,140	267
0040	STOCK PAVILION	43,547	---	1,296	49
0041	LIBRARY	562,532	645	7,668	260
0042	TRANSPORTATION BUILDING	51,445	13	1,872	63
0043	GREGORY HALL	110,044	282	2,090	159
0044	ENGLISH BUILDING	121,013	---	1,950	177
0046	HENRY ADMINISTRATION BUILDING	160,497	335	2,885	204
0048	NUCLEAR RADIATION LABORATORY	9,413	---	---	175
0050	ARCHITECTURE BUILDING	73,845	---	1,302	104
0052	KRANNERT CENTER FOR PERFORMING ARTS	298,293	448	7,289	270
0054	DAVID KINLEY HALL	81,020	124	2,116	105
0055	CERAMICS BUILDING	54,017	---	2,000	131
0056	SHELFORD VIVARIUM	24,278	---	735	107
0058	HUFF HALL	182,536	230	4,907	147
0059	SURVEYING BUILDING	15,024	---	325	30
0060	SMITH MEMORIAL HALL	76,307	149	1,694	98
0061	UNIVERSITY HIGH SCHOOL	53,113	---	1,349	130
0062	CHILD DEVELOPMENT LABORATORY	29,744	---	717	59
0063	UNIVERSITY HIGH SCHOOL GYMNASIUM	5,985	---	---	---
0064	FREER HALL	93,890	60	7,402	285
0065	ILLINI HALL	49,753	---	571	155
0066	SEITZ MATERIALS RESEARCH LAB	123,161	588	9,377	573
0067	LOOMIS LABORATORY OF PHYSICS	175,513	473	3,532	359

EXISTING BUILDING UTILITY LOAD SUMMARY

BLDG NO.	BUILDING NAME	ZERO NET BASE (GSF)	PEAK UTILITY LOADS CHW (TONS)	STEAM (PPH)	ELECT. (KW)
0069	MUMFORD HALL	100,151	15	1,719	144
0070	CHEMICAL & LIFE SCIENCES LABORATORY (NO CHILLERS)	231,316	1,452	11,935	779
0070	CHEMICAL & LIFE SCIENCES LABORATORY (CHILLERS)	---	---	---	2,501
0071	STUDENT SERVICES ARCADE BUILDING	27,525	---	932	60
0072	MEMORIAL STADIUM	771,150	213	5,351	309
0073	AGRICULTURAL BIOPROCESS LAB	24,281	---	695	126
0074	INST GOV & PUBLIC AFFAIRS BLDG	13,526	---	---	35
0075	CHILDREN'S RESEARCH CENTER	46,806	---	---	101
0076	PSYCHOLOGY LABORATORY	154,523	463	4,720	1,070
0077	PLANT SERVICES BUILDING-NORTHEAST	6,315	---	---	24
0078	SNYDER HALL	91,361	---	1,877	178
0079	SCOTT HALL	90,854	---	1,143	151
0080	WESTON HALL	90,900	---	1,269	---
0082	GARNER HALL	83,337	---	735	---
0083	FORBES HALL	83,219	---	682	156
0084	HOPKINS HALL	83,827	---	1,131	---
0087	CLARK HALL	40,266	61	1,936	81
0089	FLAGG HALL	46,933	---	1,467	77
0090	NOBLE HALL	34,098	---	585	64
0091	VAN DOREN HALL	37,529	---	832	67
0094	ALICE CAMPBELL ALUMNI CENTER	68,859	122	1,248	157
0095	SUPERCONDUCTIVITY CENTER	34,081	96	1,551	173
0099	UNDERGRADUATE LIBRARY	95,906	269	1,340	268
0101	BLAISDELL HALL	55,749	---	---	104
0105	PENNSYLVANIA LOUNGE BUILDING	50,928	198	9,169	---
0106	ILLINI UNION BOOKSTORE	96,407	---	1,284	178
0108	COMPUTING APPLICATIONS BUILDING	41,970	---	1,960	271
0109	NATURAL RESOURCES BUILDING	140,587	---	2,296	100
0110	NUCLEAR PHYSICS LABORATORY	36,605	---	1,072	151
0111	BUSEY HALL	59,347	---	2,955	106
0112	MECHANICAL ENGINEERING BUILDING	100,518	191	2,140	370
0115	EVANS HALL	53,352	145	---	---
0116	ROGER ADAMS LABORATORY	268,297	1,509	20,009	1,945
0117	NUCLEAR ENGINEERING LABORATORY	17,861	---	---	80
0118	ACTIVITIES & RECREATION CENTER	442,235	735	6,919	438
0120	ABBOTT POWER PLANT	194,896	---	---	1,750
0122	RADIO TRANSMITTER STATION	726	---	---	2
0124	NATIONAL SOYBEAN RESEARCH CENTER	98,855	260	4,251	610
0125	MUMFORD HOUSE	4,420	---	---	2
0126	LEVIS FACULTY CENTER	35,912	106	902	---
0128	GEOLOGICAL SURVEY LABORATORY	12,938	---	793	41
0130	COBLE HALL	27,738	---	493	89
0131	TURNER HALL GREENHOUSES	67,188	---	5,904	400
0136	STUDENT-STAFF APTS-300 S GOODWIN, U	73,070	---	1,721	---
0137	STUDENT STAFF APTS #2-GREEN/GOODWIN	62,067	---	1,155	---
0138	BURRILL HALL	171,832	753	6,466	893
0141	LINCOLN AVENUE RESIDENCE HALL	150,139	---	3,097	276
0142	ALLEN RESIDENCE HALL	156,131	353	3,085	226
0143	608 S MATHEWS, URBANA	6,765	---	---	---
0144	DALKEY ARCHIVE PRESS (PSSB)	11,100	---	---	11
0145	1205 1/2 W NEVADA, URBANA	5,394	---	89	---
0146	1205 W NEVADA, URBANA	4,825	---	99	---

EXISTING BUILDING UTILITY LOAD SUMMARY

BLDG NO.	BUILDING NAME	ZERO NET BASE (GSF)	PEAK UTILITY LOADS CHW (TONS)	STEAM (PPH)	ELECT. (KW)
0148	COORDINATED SCIENCE LABORATORY	124,008	311	2,597	319
0150	1208 W SPRINGFIELD, URBANA	4,323	---	---	---
0151	1204 W NEVADA, URBANA	4,916	---	---	---
0152	CIVIL ENGINEERING HYDROSYSTEMS LAB	31,847	83	882	169
0154	PERSONNEL SERVICES BUILDING	15,724	---	166	49
0156	LAW BUILDING	189,730	---	3,620	363
0157	AFRICAN AMERICAN STUDIES	5,978	---	---	---
0158	BEVIER HALL	156,771	334	4,558	181
0159	WOHLERS HALL	99,551	203	2,257	315
0160	EDUCATION BUILDING	94,059	317	2,361	393
0161	1401 S MARYLAND, URBANA	5,750	---	---	---
0165	ANIMAL SCIENCES LABORATORY	149,211	485	3,181	1,017
0166	STATE FARM CENTER	315,821	---	6,766	305
0169	BURNSIDES RESEARCH LABORATORY	23,943	---	1,897	83
0171	MEAT SCIENCE LABORATORY	26,277	---	727	105
0172	FOREIGN LANGUAGES BUILDING	117,715	222	2,592	246
0173	AFRICAN AMERICAN CULTURE CENTER	8,294	---	---	---
0174	ENGINEERING SCIENCES BUILDING	107,724	474	6,644	618
0176	REHABILITATION EDUCATION CENTER	42,546	---	996	176
0181	DANIELS HALL	112,091	---	3,436	238
0182	NUCLEAR REACTOR LABORATORY	5,068	---	335	41
0183	WOOD ENGINEERING LABORATORY	10,325	---	310	35
0188	FRED TURNER STUDENT SERVICES BLDG	41,265	81	813	92
0192	MEDICAL SCIENCES BUILDING	114,784	488	3,160	218
0193	SWANLUND ADMINISTRATION BUILDING	33,805	---	---	147
0194	USDA NEMATOLOGY GREENHOUSE	3,787	---	296	12
0196	OPTICAL PHYSICS AND ENGINEERING BLDG	11,182	---	458	---
0197	TURNER HALL	180,003	406	5,570	468
0198	PHYSICAL PLANT SERVICE BUILDING	162,882	40	1,427	146
0201	GARAGE AND CAR POOL	27,395	---	---	105
0208	ATMOSPHERIC SCIENCES BUILDING	11,328	---	---	28
0209	SPEECH AND HEARING SCIENCE	30,211	54	754	124
0210	DIGITAL COMPUTER LABORATORY	194,280	583	3,569	422
0213	ENVIRON HEALTH & SAFETY BLDG	6,079	---	---	11
0215	909 S SIXTH, CHAMPAIGN	4,316	---	---	---
0217	HOUSING FOOD STORES	51,162	---	1,318	346
0218	SCHOOL OF LABOR & EMPLOYMENT RELATIONS	25,258	49	582	75
0219	ART AND DESIGN BUILDING	75,077	---	2,567	163
0220	KRANNERT ART MUSEUM	71,657	---	---	89
0222	PRINTING & PHOTOGRAPHIC SERV BLDG	59,376	---	744	170
0228	BECKMAN INSTITUTE	358,090	1,387	10,046	2,093
0232	NORTH CAMPUS CHILLER PLANT	14,848	---	---	6,745
0235	512 E CHALMERS, CHAMPAIGN	2,455	---	---	---
0237	MICRO AND NANOTECHNOLOGY LABORATORY	147,347	1,119	9,220	845
0238	1207 W OREGON, URBANA	18,054	---	---	---
0242	MORRILL HALL	170,210	719	10,352	792
0243	508 S SIXTH, CHAMPAIGN	7,613	---	---	---
0245	205 S GOODWIN, URBANA	2,207	---	---	---
0250	912 S FIFTH, CHAMPAIGN	3,773	---	---	---
0255	UNIVERSITY PRESS BUILDING	34,294	---	---	98
0256	PLANT SCIENCES LABORATORY	100,848	---	8,394	382
0257	RICHARD T. UBBEN BASKETBALL COMPLEX	39,067	---	---	189

EXISTING BUILDING UTILITY LOAD SUMMARY

BLDG NO.	BUILDING NAME	ZERO NET BASE (GSF)	PEAK UTILITY LOADS		
			CHW (TONS)	STEAM (PPH)	ELECT. (KW)
0258	909 W NEVADA, URBANA	2,980	---	---	---
0262	510 E CHALMERS, CHAMPAIGN	2,534	---	---	---
0267	408 S GOODWIN, URBANA	8,517	---	238	---
0268	DANCE STUDIO	7,592	---	---	---
0272	WARDALL HALL - ISRH - WOMEN'S BLDG	112,616	257	---	---
0274	LOUNGE BUILDING - ISRH	26,340	---	---	26
0275	FOOD SERVICE BUILDING - ISRH	48,015	---	8,892	---
0276	LIBRARY AIR CONDITIONING CENTER	4,311	---	787	1,102
0278	1210 W SPRINGFIELD, URBANA	5,822	---	81	---
0285	912 W ILLINOIS, URBANA	5,059	---	---	---
0287	CLINICAL SKILLS LEARNING CENTER	17,885	78	---	---
0289	WATER SURVEY RESEARCH CENTER #2	10,923	---	---	415
0291	SHERMAN HALL - SINGLE GRAD HOUSING	112,081	260	3,553	---
0292	VETERINARY TEACHING HOSPITAL	233,703	1,026	10,686	165
0297	FOOD SERVICE BUILDING - FARH	81,998	565	10,131	476
0300	ASTRONOMY BUILDING	19,169	---	---	44
0304	TRACK STADIUM	832	---	---	375
0316	ILLINOIS FIELD PRESS BOX	1,153	---	---	45
0323	PUBLIC SAFETY BUILDING	20,729	---	---	62
0324	GRAINGER ENGINEERING LIBRARY	126,838	---	6,249	260
0326	AGRICULTURE SERVICES BUILDING	9,595	---	---	17
0330	ILLINOIS STATE ARCHAEOLOGICAL SURVEY REPOSITORY	4,814	---	---	---
0331	LIBRARY AND INFORMATION SCIENCE BLDG	51,376	---	966	137
0336	MADIGAN LABORATORY, EDWARD R	171,007	873	10,914	888
0338	SOUTH STUDIO 3 (GLASS SCULPTURE BUILDING	4,183	---	---	---
0339	TEMPLE HOYNE BUELL HALL	94,195	---	1,606	127
0350	VET MED BASIC SCIENCES BUILDING	259,413	1,538	13,078	590
0352	VETERINARY MEDICINE CHILLER PLANT	23,088	0	3,551	1,974
0360	ATKINS TENNIS CENTER	68,812	---	---	288
0364	CAMPUS RECREATION CENTER - EAST	104,575	444	1,727	298
0365	907 1/2 W NEVADA, URBANA	4,707	---	---	---
0367	901 W OREGON, URBANA	5,462	---	---	---
0369	INTERNATIONAL STUDIES BUILDING	24,473	---	---	61
0373	SPURLOCK MUSEUM	53,922	116	1,886	176
0376	CAMPBELL HALL	40,731	---	---	97
0377	ACES LIBRARY, INFO. & ALUMNI CENTER	82,742	253	1,516	126
0378	ADMISSIONS AND RECORDS BUILDING	32,930	63	891	104
0379	BIELFELDT ATHLETIC ADMINISTRATION BUILDING	40,084	---	---	100
0380	CAMPUS RECREATION OUTDOOR CENTER	6,533	---	---	130
0381	IRWIN ACADEMIC SERVICE CENTER	25,239	51	---	---
0401	ANIMAL SCIENCE AIR CONDITIONING CTR	10,438	---	---	1,419
0407	IRWIN INDOOR FOOTBALL FACILITY	75,931	---	1,597	248
0506	909 W OREGON, URBANA	11,145	---	---	---
0556	FIRE SUB STATION	11,464	---	---	22
0560	EICHELBERGER FIELD AND PRESS BOX	782	---	---	109
0563	SIEBEL CENTER FOR COMPUTER SCIENCE	266,825	584	3,169	480
0564	NAT CENTER FOR SUPERCOMP APPL	141,708	257	2,310	201
0568	1206 W. NEVADA	2,119	---	---	---
0815	FEED STORAGE PLANT	9,574	---	---	---
0824	AGRONOMY SOUTH FARMS LAB	6,300	---	---	35
0828	ANIMAL SCI SHOP & STOR-HORSE FARM	9,213	---	---	14
0831	ANIMAL SCIENCE K40 FACILITY	12,315	---	---	21

EXISTING BUILDING UTILITY LOAD SUMMARY

BLDG NO.	BUILDING NAME	ZERO NET BASE (GSF)	PEAK UTILITY LOADS CHW (TONS)	STEAM (PPH)	ELECT. (KW)
0842	AGRONOMY SEED HOUSE	13,216	---	---	21
0856	DAIRY EXPERIMENTAL ROUND BARNS	11,336	---	---	12
0857	DAIRY EXPERIMENTAL ROUND BARNS	11,290	---	---	---
0858	1101 WEST ST MARY'S ROAD, U	2,219	---	---	---
0882	STORAGE BUILDING - PELL FARM	247	---	---	---
1000	SUPERVISOR'S RESIDENCE - BEEF	1,680	---	---	8
1037	METAL STORAGE BUILDING	11,192	---	---	3
1042	MODULAR INFECTIOUS DIS CONT BLDG #1	1,092	---	---	---
1043	MODULAR INFECTIOUS DIS CONT BLDG #2	1,092	---	---	---
1071	EARLY CHILD DEVELOPMENT LAB	23,182	84	541	50
1080	INSTITUTE FOR GENOMIC BIOLOGY	219,789	866	19,837	1,142
1085	SOYFACE BARN	1,257	---	---	---
1091	1011 W. UNIVERSITY AVE.	1,700	---	---	---
1093	AERODYNAMICS RESEARCH LABORATORY	6,936	25	440	82
1094	NORTH CAMPUS PARKING DECK	521,441	71	899	131
1096	OAK STREET LIBRARY FACILITY	57,988	---	---	227
1101	PONDS SITE LABORATORY	2,380	---	---	13
1114	1108 W. STOUGHTON	4,384	---	---	---
1133	CHRISTOPHER HALL	26,173	61	513	41
1140	GREGORY PLACE I	4,273	10	352	16
1145	ASIAN AMERICAN HOUSE	6,932	---	---	26
1146	S. FARMS-BEEF CATTLE & SHEEP FIELD LAB	4,774	---	---	42
1148	S. FARMS-SHEEP BARN	3,419	---	---	39
1149	S. FARMS-MANURE SHED	528	---	---	106
1165	BEE RESEARCH FACILITY	3,948	---	---	28
1187	INDOOR GOLF FACILITY	15,262	---	---	58
1188	305 E. CURTIS ROAD		---	---	---
1201	1114 CR, 1200 E		---	---	---
1206	BUSINESS INSTRUCTIONAL FACILITY	162,251	337	2,486	281
1209	ENGINEERING STUDENT PROJECT LABORATORY	7,336	---	---	28
1213	SPEECH LANGUAGE PATHOLOGY CLINIC	3,675	---	---	44
1214	CONFERENCE CENTER	37,960	112	---	144
1216	POULTRY CAGE HOUSE #3	6,776	---	---	46
1233	INTEGRATED BIOPROCESSING RESEARCH LAB	50,000	---	---	---
1241	GREGORY PLACE II	37,200	115	759	72
1244	NATIONAL PETASCALE COMPUTING FACILITY	94,377	5,400	---	14,414
1247	STUDENT DINING AND RESIDENTIAL PROGRAMS BUILDING	139,557	550	18,622	556
1248	TIMOTHY J. NUGENT HALL	57,877	140	---	111
1249	IKENBERRY COMMONS PH2	180,000	---	---	---
1255	IKENBERRY COMMONS PH3	160,000	---	---	---
1258	FRUIT RESEARCH FARM - ADMIN. BLDG.	6,603	---	---	14
1261	FSI - LEARNING RESOURCE RESEARCH CENTER		---	---	142
1267	EBI FARM SHED SOUTH FARMS	11,616	---	---	34
1268	ROBERT A. EVERS LABORATORY		---	---	137
1276	SWINE ISOLATION - OLD CORN CRIB		---	---	---
1494	CENTER FOR WOUNDED VETERENS	32,000	---	---	---
8283	OAK STREET CHILLER PLANT	44,799	---	694	7,709
9999	AREA OF RECENTLY DEMOLISHED BUILDINGS	71,630	---	---	18
	TOTAL	21,750,098	36,348	472,600	78,437

The resulting diversified peak loads are separated by building function and divided by gross area to estimate the diversified building load factors (Btu/sq ft; sq ft/ton; W/sq ft). These factors are used in estimates of future campus growth.

DIVERSIFIED BUILDING LOAD FACTORS			
BUILDING TYPE	HEATING (BTU/SF)	CHW (SF/TONS)	ELECTRIC (W/SF)
ARMORY	12	1,900	0.5
ASSEMBLY / STADIUM / GRANDSTAND	24	667	0.9
BARN / SHED / OUTBUILDING	-	-	5.7
CLASSROOMS / EDUCATIONAL / LIBRARY	23	525	1.9
COMPUTER CENTER	20	34	85.2
DISTRIBUTION	19	-	3.5
DORMITORY / BARRACK / WARD	21	427	1.8
KITCHEN / DINING	87	341	3.4
LABORATORY	50	281	9.4
LECTURE HALL	22	860	1.2
MAINTENANCE SHOP / GARAGE	-	-	3.8
MEDICAL OFFICE / CLINIC	20	425	2.1
MULTI-USE	25	339	2.3
MUSEUM / MONUMENT / MEMORIAL	35	464	2.2
OFFICE	22	474	3.2
OTHER (MECHANICAL BUILDING)	-	-	1.4
PARKING STRUCTURE / GARAGE / PARKING LOT	-	-	1.1
RECREATIONAL / ATHLETIC CENTER / GYMNASIUM	-	597	2.5
RESEARCH PARK	-	-	11.7
RESIDENCE	-	-	1.7
STORAGE / WAREHOUSE	15	-	1.0
SUPPORT FACILITY / PHYSICAL PLANT	27	-	-

4.4 Building Additions and Demolitions

The following table indicates those buildings planned to be added to the central chilled water system. Diversified Building Load Factors and discussions with University staff are used to estimate the added load to the chilled water system in the given year identified in the table. The buildings are currently cooled with a combination of individual air-cooled chillers, partially cooled with window air conditioning units, or are not currently conditioned in the summer. The table identifies an additional 8,108 tons of chilled water that will be added to the peak central cooling system. Similarly, an estimated 5 MW of power associated with the existing cooling system will be removed from the central building peak.

PLANNED ADDITIONS TO CENTRAL CHILLED WATER SYSTEM						
BLDG NO.	BUILDING NAME	ZERO NET BASE (GSF)	CONVERSION YEAR	PEAK CHW LOAD (TONS)	CHW CONSUMP. (TONHR/YR)	REDUCED ELECTRIC LOAD (KW)
0027	LINCOLN HALL	171,121	2012	411	1,033,354	493
0324	GRAINGER ENGINEERING LIBRARY	126,838	2013	317	761,029	380
0044	ENGLISH BUILDING	121,013	2013	291	730,762	349
0013	TALBOT LABORATORY	110,529	2013	265	667,454	319
0219	ART AND DESIGN BUILDING	75,077	2013	138	410,689	166
0071	STUDENT SERVICES ARCADE BUILDING	27,525	2013	80	166,216	79
0059	SURVEYING BUILDING	15,024	2014	38	90,144	46
0166	STATE FARM CENTER	315,821	2015	2,000	2,907,724	50
0010	CHEMISTRY ANNEX	42,466	2015	260	232,299	94
1233	INTEGRATED BIOPROCESSING RESEARCH LAB	50,000	2015	200	425,000	0
0323	PUBLIC SAFETY BUILDING	20,729	2015	53	693,833	280
0004	HARDING BAND BUILDING	27,840	2015	51	152,290	61
1494	CENTER FOR WOUNDED VETERENS	32,000	2015	34	72,000	0
0002	ART-EAST ANNEX, STUDIO 2	12,182	2015	25	0	0
1249	IKENBERRY COMMONS PH2	180,000	2016	193	405,000	0
1255	IKENBERRY COMMONS PH3	160,000	2019	172	360,000	0
0256	PLANT SCIENCES LABORATORY	100,848	2020	406	891,667	0
0109	NATURAL RESOURCES BUILDING	140,587	2020	363	253,447	121
0156	LAW BUILDING	189,730	2020	349	1,037,861	419
0141	LINCOLN AVENUE RESIDENCE HALL	150,139	2020	321	657,438	0
0217	HOUSING FOOD STORES	51,162	2020	256	7,631,330	307
0181	DANIELS HALL	112,091	2020	240	490,833	50
0108	COMPUTING APPLICATIONS BUILDING	41,970	2020	232	582,176	278
0110	NUCLEAR PHYSICS LABORATORY	36,605	2020	203	848,969	50
0106	ILLINI UNION BOOKSTORE	96,407	2020	195	424,191	234
0050	ARCHITECTURE BUILDING	73,845	2020	136	403,950	50
0331	LIBRARY AND INFORMATION SCIENCE BLDG	51,376	2020	128	256,879	154
0065	ILLINI HALL	49,753	2020	119	300,448	143
0040	STOCK PAVILION	43,547	2020	118	134,914	50
0061	UNIVERSITY HIGH SCHOOL	53,113	2020	98	290,539	50
0073	AGRICULTURAL BIOPROCESS LAB	24,281	2020	98	214,683	117
0131	TURNER HALL GREENHOUSES	67,188	2020	67	167,503	50
0369	INTERNATIONAL STUDIES BUILDING	24,473	2020	61	97,894	73
0014	ICE ARENA	51,676	2020	60	126,405	72
0062	CHILD DEVELOPMENT LABORATORY	29,744	2020	55	162,705	66
0154	PERSONNEL SERVICES BUILDING	15,724	2020	38	94,951	45
0338	SOUTH STUDIO 3 (GLASS SCULPTURE BUILDING	4,183	2020	20	25,100	208
0042	TRANSPORTATION BUILDING	51,445	2020	10	11,433	12
0330	ILLINOIS STATE ARCHAEOLOGICAL SURVEY REPOSITORY	4,814	2020	8	310,244	148
	TOTAL	2,952,867	---	8,108	24,523,356	5,014

The following table lists those buildings already planned for construction. The Integrated Bioprocessing Research Lab was included in the original Net Zero Gross square foot calculations. The remaining buildings will be offset with demolitions on campus. The table identifies an additional 599 tons of chilled water, 6,865 pph of steam, and 502 kW of electric power added to the peak central utility systems

PLANNED BUILDING PROJECTS										
BLDG NO.	BUILDING NAME	ZERO NET BASE (GSF)	CONVERSION YEAR	CHILLED WATER		STEAM		ELECTRIC	
				LOAD (TONS)	CONSUMP. (TONHR/YR)	LOAD (PPH)	CONSUMP. (KLBS/YR)	LOAD (KW)	CONSUMP. (KWH)
1233	INTEGRATED BIOPROCESSING RESEARCH LAB	50,000	2015	200	425,000	2,273	9,020	168	1,495,000
1249	IKENBERRY COMMONS PH2	180,000	2016	193	405,000	2,222	8,720	162	1,424,000
1255	IKENBERRY COMMONS PH3	160,000	2019	172	360,000	1,975	7,750	143	1,266,000
1494	CENTER FOR WOUNDED VETERENS	32,000	2015	34	72,000	395	1,550	29	253,000
TOTAL ADDITION TO CENTRAL UTILITY LOAD		422,000	---	599	1,262,000	6,865	27,040	502	4,438,000

The following table indicates those buildings that are planned to be demolished within the next 15 years on campus. The identified buildings represent 553,939 sq ft, 0 tons of chilled water, 6,922 kpph of steam, and 477 kW of power currently on the central utility system. The loads associated with the buildings are removed from the central plant peaks on the identified demolition year.

PLANNED BUILDING DEMOLITIONS								
BLDG NO.	BUILDING NAME	ZERO NET BASE (GSF)	DEMO YEAR	PEAK CHW LOAD (TONS)	PEAK STEAM LOAD (PPH)	AVERAGE ANNUAL CONSUMP. (KLBS/YR)	PEAK ELECTRIC DEMAND (KW)	AVERAGE ANNUAL CONSUMP. (KLBS/YR)
0028	AERONAUTICAL LABORATORY A	10,443	2028	---	---	---	32	65,000
0031	DYNAMICS TESTING LABORATORY	5,863	2028	---	---	---	---	---
0238	1207 W OREGON, URBANA	18,054	2028	---	---	---	---	---
0243	508 S SIXTH, CHAMPAIGN	7,613	2028	---	---	---	---	---
0245	205 S GOODWIN, URBANA	2,207	2028	---	---	---	---	---
0250	912 S FIFTH, CHAMPAIGN	3,773	2028	---	---	---	---	---
0258	909 W NEVADA, URBANA	2,980	2028	---	---	---	---	---
0267	408 S GOODWIN, URBANA	8,517	2028	---	238	569	---	---
0268	DANCE STUDIO	7,592	2028	---	---	---	---	---
0278	1210 W SPRINGFIELD, URBANA	5,822	2028	---	81	178	---	---
0285	912 W ILLINOIS, URBANA	5,059	2028	---	---	---	---	---
0365	907 1/2 W NEVADA, URBANA	4,707	2028	---	---	---	---	---
0882	STORAGE BUILDING - PELL FARM	247	2028	---	---	---	---	---
1043	MODULAR INFECTIOUS DIS CONT BLDG #2	1,092	2028	---	---	---	---	---
1085	SOYFACE BARN	1,257	2028	---	---	---	---	---
1091	1011 W. UNIVERSITY AVE.	1,700	2028	---	---	---	---	---
1114	1108 W. STOUGHTON	4,384	2028	---	---	---	---	---
1145	ASIAN AMERICAN HOUSE	6,932	2028	---	---	---	26	69,960
1188	305 E. CURTIS ROAD		2028	---	---	---	---	---
1201	1114 CR, 1200 E		2028	---	---	---	---	---
1276	SWINE ISOLATION - OLD CORN CRIB		2028	---	---	---	---	---
0084	HOPKINS HALL	83,827	2023	---	1,131	4,441	---	---
0169	BURNSIDES RESEARCH LABORATORY	23,943	2023	---	1,897	8,013	83	332,339
0367	901 W OREGON, URBANA	5,462	2023	---	---	---	---	---
0506	909 W OREGON, URBANA	11,145		---	---	---	---	---
0568	1206 W. NEVADA	2,119	2023	---	---	---	---	---
0815	FEED STORAGE PLANT	9,574	2023	---	---	---	---	---
0828	ANIMAL SCI SHOP & STOR-HORSE FARM	9,213	2023	---	---	---	14	36,470
0857	DAIRY EXPERIMENTAL ROUND BARNS	11,290	2023	---	---	---	---	---
0858	1101 WEST ST MARY'S ROAD, U	2,219	2023	---	---	---	---	---
1042	MODULAR INFECTIOUS DIS CONT BLDG #1	1,092	2023	---	---	---	---	---
0154	PERSONNEL SERVICES BUILDING	15,724	2018	---	166	430	49	407,189
0063	UNIVERSITY HIGH SCHOOL GYMNASIUM	5,985	2018	---	---	---	---	---
0089	FLAGG HALL	46,933	2018	---	1,467	3,047	77	173,256
0143	608 S MATHEWS, URBANA	6,765	2018	---	---	---	---	---
0145	1205 1/2 W NEVADA, URBANA	5,394	2018	---	89	326	---	---
0146	1205 W NEVADA, URBANA	4,825	2018	---	99	297	---	---
0150	1208 W SPRINGFIELD, URBANA	4,323	2018	---	---	---	---	---
0151	1204 W NEVADA, URBANA	4,916	2018	---	---	---	---	---
0157	AFRICAN AMERICAN STUDIES	5,978	2018	---	---	---	---	---
0161	1401 S MARYLAND, URBANA	5,750	2018	---	---	---	---	---
0173	AFRICAN AMERICAN CULTURE CENTER	8,294	2018	---	---	---	---	---
0182	NUCLEAR REACTOR LABORATORY	5,068	2018	---	335	621	41	56,060
0215	909 S SIXTH, CHAMPAIGN	4,316	2018	---	---	---	---	---
0235	512 E CHALMERS, CHAMPAIGN	2,455	2018	---	---	---	---	---
0262	510 E CHALMERS, CHAMPAIGN	2,534	2018	---	---	---	---	---
0083	FORBES HALL	83,219	2014	---	682	3,458	156	2,480,817
0082	GARNER HALL	83,337	2010	---	735	3,408	---	---
TOTAL		553,939	---	---	6,922	24,788	477	3,621,091

4.5 Growth Scenarios

Campus growth scenarios are examined to determine their impact on the campus energy and utilities infrastructure over the next 35 years. The campus has grown over the past 15 years at a rate close to 300,000 GSF/yr. Given the iCAP target of net zero GSF/yr growth, campus planning has identified three campus growth scenarios that were examined as part of the study. 1) the commitments of iCAP set a goal of zero net growth, 2) medium growth (75,000 GSF/year), and 3) high load growth scenario (150,000 GSF/year). Net zero growth suggests that for new buildings to be constructed on campus, the University must provide for the demolition of existing space of equal square footage. For example, the 625,569 sq ft identified as being demolished can be replaced with new buildings on campus.

One third of all growth for each scenario is assumed to occur within Research Park, in non-University buildings. These buildings are currently only served by campus electricity and natural gas and do not receive steam or chilled water from the central campus distribution system. There are no plans to add non-University buildings to the central heating and chilled water distribution systems.

Information provided here describes where the campus growth is assumed to occur. This information is used in the hydraulic models to examine the impact of future growth on the existing campus utility distribution systems.

The Campus Master Plan is used to estimate where future growth would occur for each of the growth scenarios. The following figure presents the campus divided into 11 regions of growth, 9 regions on the main campus, south farms, and growth occurring in the research park.


UIUC Campus Growth Areas
U11045: Utilities Master Plan
12%
26%
2%
9%
18%
1%
4%
18%
10%
Research Park
(Separate from Campus)

Based on the above assumptions the building peak loads, assuming 150k GSF/YR, are projected to grow as listed in the following table. The total area includes those buildings in the research park.

FUTURE CAMPUS UTILITY LOADS AT 150 KGSF/YR				
YEAR	AREA (GSF)	PEAK BOILER OUTPUT (KPPH)	PEAK CHW LOAD (TONS)	PEAK ELECTRIC LOAD (KW)
EXISTING	22,173,000	600	30,948	78,437
2023	23,673,000	616	42,073	88,211
2049	27,573,000	701	49,474	110,100

Current campus conservation efforts are not represented in the growth projections and are treated separately in the utility model.

4.6 Data Center Impact

The impact of continued growth of data centers on the ability of the campus to provide utilities is examined by adding a 5 MW data center every seven years. It is assumed that each 5 MW data center will add 1,400 ton chilled water and 5,500 kW power to the campus peak demands. It is assumed the data centers do not add any significant demand to the campus steam heating system. The following table illustrates the impact of the data center growth on the future campus utility loads at 150 KGSF/yr.

FUTURE CAMPUS UTILITY LOADS AT 150 KGSF/YR IMPACT OF DATA CENTER GROWTH				
YEAR	AREA (GSF)	PEAK BOILER OUTPUT (KPPH)	PEAK CHW LOAD (TONS)	PEAK ELECTRIC LOAD (KW)
EXISTING	22,173,000	600	30,948	78,437
2023	23,673,000	616	44,900	99,200
2049	27,573,000	701	58,100	143,100

5.0 Risk Management and Reliability

5.1 Overview

An assessment was conducted to determine key risks associated with the continued utility operations at U of I in its present configuration as well as each of the scenarios developed.

Key risks considered include energy source and price risks, regulatory risks and risks associated with recommendations from the Illinois Climate Action Plan iCAP as well as what impact these recommendations have on risk. Also included is a comparison of the University to applicable industry standards for energy providers and how existing conditions impact risk to the University.

5.2 Stakeholder Analysis

The following stakeholders were identified and considered:

- Customer Groups
  - Academic
  - Research
  - Student Housing
  - Auxiliaries
  - Commercial Accounts
- Student Groups
- Utility Staff
- Other Staff
- Local Community/Economy
- State Taxpayers
- Legislative
- Governor

Multiple outreach meetings were held to assess the needs and relevant risk concerns of the various stakeholder groups. The meetings primarily focused on the needs of the on-campus customer groups (especially the research community), campus administration, University utilities staff, as well as informing and engaging the student groups, non-utility University staff and the local community.

During the meetings the follow categories of risks and concerns were identified:

- Financial Risk:
  - Capital cost uncertainty, estimation and escalation
  - Cost of capital, i.e. long-term interest rates
  - Revenue and budget uncertainty
- Human Resource Risk:
  - Different/new skill sets required of the utility staff
  - Eventual retirement of key utility staff

- Institutional Risk
    - Institutional governance including concerns with procurement policies, risk responsiveness, insurance policies, the "revolving door" of University leadership and associated priorities. This risk category includes response to environmental, social and political forces including iCAP goals and environmental pressures regarding coal usage as well as the reputational risks associated with current utility configuration.
- Regulatory and Legislative Risk
    - Risk associated with utility regulations, permitting, renewable energy standards as well as carbon legislation and regulation.
- Market Risk
    - Commodity price uncertainty including the risks associated with the price volatility of natural gas, coal, biomass, etc.

The Institute of Risk Management process was used to prioritize the risks. The steps of the process are as follows[1]:

- Recognition or identification of risks
- Ranking or evaluation of risks
- Determine response to significant risks
    - tolerate
    - treat
    - transfer
    - terminate

5.3 Risk Recognition and Identification

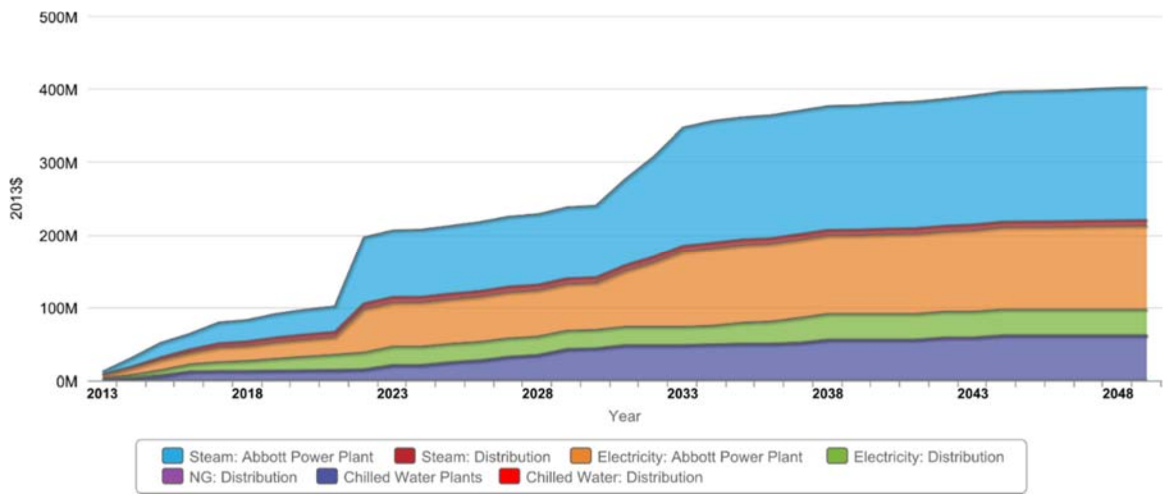
The purpose of this section is to define and describe each of the identified risks and provide background for the second step of the process where the risks will be evaluated and ranked.

[1] A structured approach to Enterprise Risk Management (ERM), IRM, 2010, p. 7.

5.3.1 Financial Risk

Capital Cost Uncertainty

For the purposes of this report, capital cost is defined as any fixed, one-time expense necessary to implement a project to a commercially operable status and/or continue operating a pre-existing asset or project. Future capital expenditures at the University are expected to be significant. Over the forecast period of 35 years, it is expected that the University will be required to spend in the range of $400 million to maintain the utility operations in the current configuration and a growth rate of 150 kGSF/yr (see following graph).



Among other sources, capital cost uncertainty can originate from at least two primary sources; 1) estimation error and 2) capital cost escalation rates that are different than expected due to inflation, technology evolution and other forces.

Estimation Error – In a recommended-practice document published by the Association for the Advancement of Cost Engineering[2], the Association describes the complexity and cautions associated with consuming "engineering, procurement, and construction (EPC) … estimates for process facilities [that] center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved …" such as the systems being considered in this study.

The following table, which was included in the above mentioned study, describes the "expected accuracy range" of cost estimates depending on the "maturity level of project definition deliverables".

[2] COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES, Association for the Advancement of Cost Engineering, November 29, 2011, p. 2.

COST ESTIMATE CLASSIFICATION MATRIX FOR THE PROCESS INDUSTRIES

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

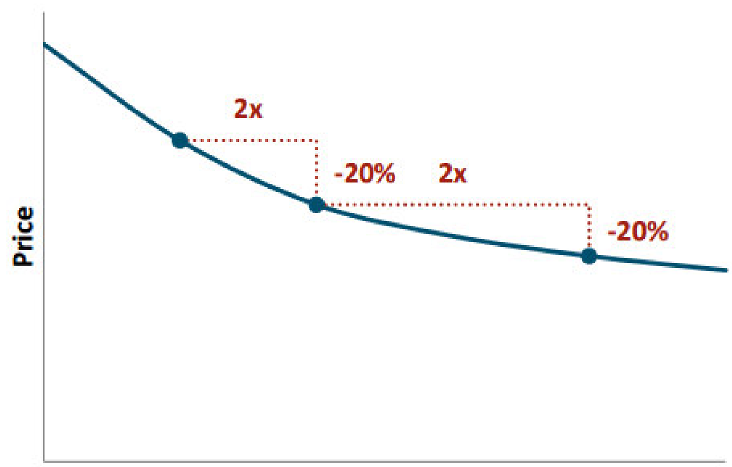
A Class 5 estimate, for example, where the project definition is based on factors and analogies could be associated with an expected accuracy range on the high end of +30% to + 100%; a very broad range. A Class 1 estimate, where the project is almost entirely defined, is still associated with an expected accuracy range on the high end of +3% to +15%. These expected accuracy ranges include the "the application of contingency… [and] represents about 80% confidence that the actual cost will fall within the bounds of the low and high ranges". A more complete description of the defined maturity levels of project definition and the associated estimate classes are included in Appendix 5A of this report.

Capital cost escalation – Capital cost escalation can also be a source of financial risk and uncertainty. The Energy Sector Management Assistance Program published a Study of the Equipment Prices in the Power Sector in 2010[3] describing historical periods of cost escalation for materials and labor required in the energy sector. The study described recent periods of "significant increases in the demand for raw materials and labor associated with the manufacture and fabrication of equipment." The following table, taken from the study, illustrates two contrasting periods; one with stable escalation (1996 – 2003) and one with rapid escalation (2003 to 2007). The study states that "from 2006 to 2008 alone, energy projects financed by the World Bank experienced 30–50 percent increases above the original cost estimates, requiring additional financing, a reduction in scope of the project, or schedule delays." Recent experience has been associated with much more stable, and even negative, capital escalation rates.

[3] Energy Sector Management Assistance Program, Study of Equipment Prices in the Power Sector, 2010, page 5.

Table 2.1	Historical Average Annual Compound Escalation			
Ranking	Plant Equipment and Materials	Jan. 1996–Dec. 2003, % per year	Jan. 2004–Dec. 2007, % per year	Jan. 2004–Dec. 2007, % Increase for Period
	United States			
4	Ready-Mix Concrete	1.9	7.9	36
	Centrifugal Pumps	2.0	4.7	20
	Centrifugal Fans	1.7	4.2	18
	Material Handling Conveyors	1.7	4.7	20
	Pneumatic Conveyors	1.7	3.8	16
	Crushers and Pulverizers	2.9	4.4	19
	Integral Horsepower Motors	0.4	6.4	28
	Fabricated Steel Plates	0.3	10.1	47
2	Structural Steel	0.9	8.0	36
	Steel Pipe and Tubing	NA	7.0	31
	Field Erected Steel Tanks	1.5	5.8	25
3	Heat Exchangers and Condensers	0.8	7.8	35
	Fin Tube Heat Exchangers	1.3	8.4	38
	Industrial Mineral Wool	0.4	3.7	16
	Refractory, Non-Clay	0.4	3.7	16
1	Electric Wire and Cable	1.1	9.1	42
	Power and Distribution Transformers	NA	13.8	68
	Copper Wire and Cable	-0.8	18.7	98
	Industrial Process Control Instruments	NA	3.0	12

Source: U.S. Bureau of Labor Statistics Producers Price Indexes.
NA—Not available.



A potential mitigating factor to general cost escalation is the learning curve associated with technology evolution, depending on the technology. In a study[4] for the Western Electric Coordinating Council (WECC), E3 consulting described that "learning curves capture the well-documented trend that the costs of emerging technologies often drop rapidly as production scales

[4] Cost and Performance Review of Generation Technologies, E3 Consulting, October 2012, p. 11.

up, whereas the costs of more mature technologies are more stable over time." They described, as represented in the figure to the left, a "representative learning curve… where each doubling of cumulative experience results in a cost reduction of 20%."

A National Renewable Energy Lab report described this concept for a set of "focus technologies"[5]. The following figure, taken from that report, illustrates the projected "learning factor" for 11 focus technologies described in the 2009 Annual Energy Outlook. The reader will notice that more mature technologies, such as coal and combined cycle systems, are associated with a fairly stable learning factor while technologies, such as solar PV and Thermal, are associated with a much more dramatic learning curve.

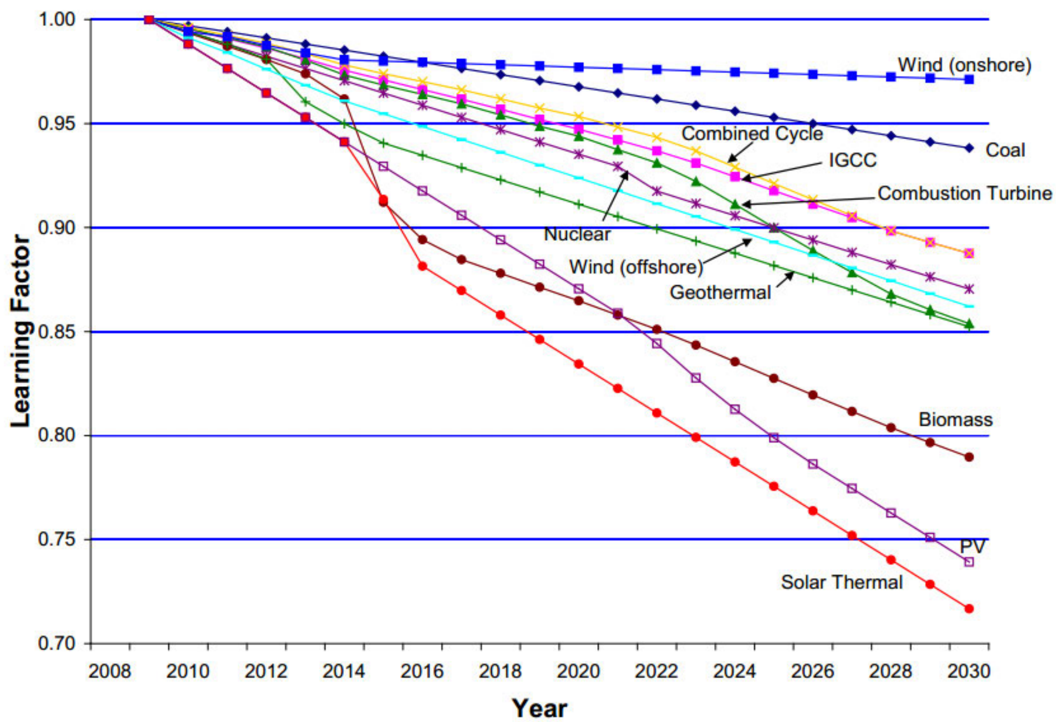


Figure 77. AEO 2009, learning function values for the 11 focus technologies

Long-term Interest Rates

Fluctuations in long-term interest rates can also have significant impact on the cost of providing utilities to the University. As very simple example, the figure below illustrates the history of long-term interest rates since 1976[6]. In 1981, long-term interest rates peaked at just over 14% per annum. At that interest rate the annual interest on a $50 million project funded entirely by debt would have been just over $7 million. Annual interest on a comparable project funded in 2012 would have been less than $2 million. The average nominal interest over this timeframe was approximately 8% equivalent to an annual interest payment of $4 million on our example project.

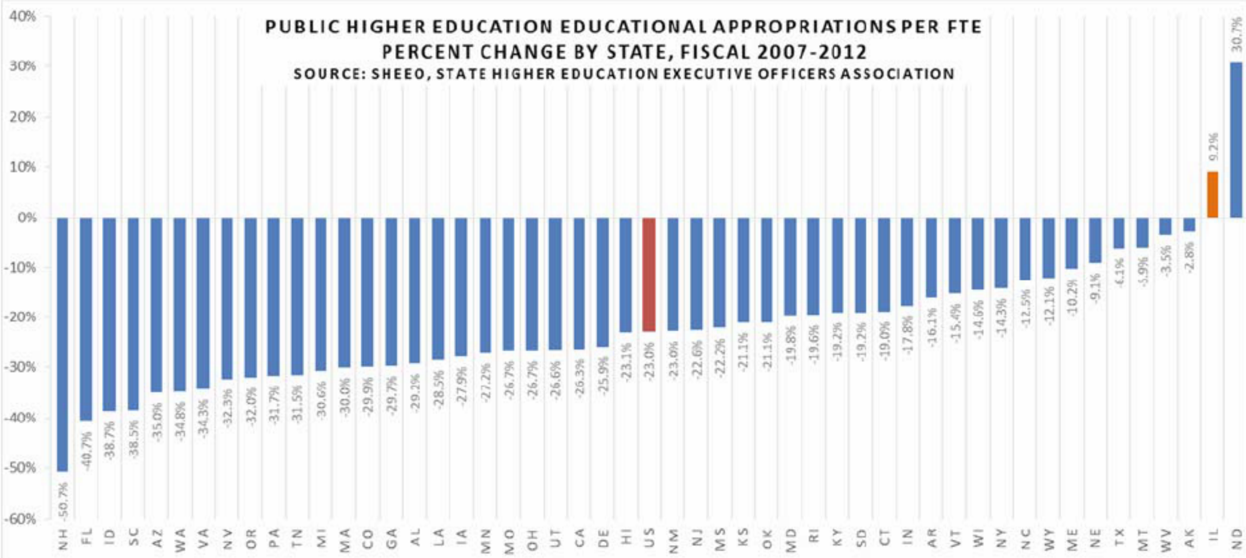
[5] Cost and Performance Assumptions for Modeling Electricity Generation Technologies, ICF International, November 2010, p. 110.
[6] Source: Federal Reserve, http://www.federalreserve.gov/releases/h15/data.htm.

The question at this point becomes what will future interest rates be. The figure below was produced by renowned financial market technical analyst Louise Yamada. She looked at two centuries of US interest rate cycles and argues "we are at a generational bottom and likely to experience increasing rates going forward".[7]

Revenue and Budget Uncertainty

Revenue and budget uncertainty is a valid concern given recent trends in state funding for higher education. The figure below illustrates education appropriations per FTE student since 2007. The trend is dramatically down with an average decrease in appropriations per FTE student of 23%. Illinois is one of two states that did not show a decrease over this time period.

[7] 222 years of interest rate history, September 2013, http://finance.yahoo.com/blogs/talking-numbers/222-years-interest-history-one-chart-173358843.html.



Thousands of $	FY14	FY13	FY12	FY11	FY10	FY9	FY8	FY7
Total University of Illinois Budget	$5,629,364	$5,416,033	$5,032,753	$4,761,314	$4,583,119	$4,164,888	$3,899,682	$3,675,511
Percent Change	*3.9%*	*7.6%*	*5.7%*	*3.9%*	*10.0%*	*6.8%*	*6.1%*	
07-'12 % change			*36.9%*					
Urbana-Champaign Budget	$1,998,503	$2,068,513	$1,893,319	$1,772,611	$1,699,071	$1,615,458	$1,479,940	$1,585,394
Percent Change	*-3.4%*	*9.3%*	*6.8%*	*4.3%*	*5.2%*	*9.2%*	*-6.7%*	
07-'12 % change			*19.4%*					
Energy Services Budget*	$74,262	$74,138	$73,633	$73,081	$71,113			
Percent Change	*0.2%*	*0.7%*	*0.8%*	*2.8%*				
Energy Services as % of UIUC Budget	3.7%	3.6%	3.9%	4.1%	4.2%			

*** Budget information was not broken out for Energy Services specifically prior to FY10.**

Over that same time period, the operating budget for the University of Illinois system has increased nearly 37% (see table below) while the operating budget for the Urbana-Champaign campus has increased nearly 20%[8]. The operating budget for Energy Services has continued to increase as well, but at a much slower rate, even less than inflation. As a percentage of overall Urbana-Champaign campus budget, the budget for Energy services has decreased from 4.2% in FY2010 to 3.7% for FY 2014.

Given the national funding trend illustrated, budget pressures will likely continue to increase, placing even more pressure on the Energy Services organization to become more operationally efficient and require less in real dollar terms.

5.3.2 Human Resource Risk

A common concern at many institutions is the retirement of key utility staff and loss of the "institutional knowledge" these employees have. Developing a succession plan and long-term staffing program will address and offset the challenges of a shrinking pool of qualified candidates and the loss of critical knowledge with the upcoming retirement of many long-term employees.

[8] Source: University of Illinois Budget Summary for Operations, http://www.obfs.uillinois.edu/about-obfs/budget-summary-operations/

5.3.3 Institutional Risk

Another common concern at many institutions of higher education, and one which is shared at U of I, is associated with the "revolving door" of University leadership and the relative commotion associated with seemingly ever-changing priorities. This commotion creates an operational and investment environment filled with uncertainty. This factor includes uncertainty with respect to the possibility of internal mandates to respond to environmental, social and political forces and how to prepare for necessary responses. Internal mandates, including goals contemplated in the iCAP goals, conceived in an effort to respond to environmental pressures regarding coal usage and/or reputational risks associated with the current utility configuration, have the potential to introduce new operational and economic risks.

In a simplified world where the primary objective for Energy Services would be to delivery low-cost, reliable energy supply to the University, deciding to continue to have the ability to utilize coal would be a fairly straightforward decision. First, it provides fuel flexibility, which enables the University to choose to burn coal, natural gas and/or non-coal solid fuels such as biomass. This flexibility provides the University with natural hedging opportunities against price and supply risk. Second, the University, with coal reserves, has a built in back-up supply of fuel to guard against fuel supply interruptions. Third, the University has a utility staff well trained in running an efficiently operated coal-fired plant.

This decision becomes more complicated when social and reputational concerns come into the picture. In an effort to protect the University against current reputational concerns the University may be required to do something with the Energy Services operations that it would not do otherwise. For example, external regulatory forces might ultimately require the University to terminate the use of coal, but absent external mandates the University should be cautious about terminating an operation that provides a valuable level of operational and economic flexibility.

5.3.4 Air Regulatory and Legislative Risk

Air Regulatory Considerations

Regulatory Background – Operators of emissions units, such as boilers, must comply with all applicable air pollution control regulations, in addition to any applicable facility-wide or unit-specific permit conditions. Most applicable regulations are typically documented in a permit, but this is not always the case. It is important to understand that an operator of an emissions unit is responsible for complying with applicable regulations even if those regulations are not specifically called out in an operating or construction permit.

The Illinois Environmental Protection Agency (IEPA) is the lead agency for air pollution permitting, compliance assurance and enforcement in the state of Illinois. Illinois is part of Region V, one of ten administrative regions under the United States Environmental Protection Agency (USEPA). IEPA manages most federal air pollution regulation programs under delegated authority, but USEPA Region V retains oversight over federal programs and can, at its discretion, intervene if it believes the state is deficient in a particular case. IEPA also manages state-only air pollution regulations that are not part of Illinois State Implementation Plan (SIP).

Applicable Regulatory Programs – The following regulatory programs can have an impact on the operation of a power plant in the state of Illinois that utilizes combustion of fossil fuels, biomass, syn-gas or other fuels:

- New Source Performance Standards (NSPS) – These federal regulations have been established to create minimum emissions standards that reflect state of the art technology with respect to emissions of criteria pollutants (nitrogen oxides, carbon monoxide, sulfur dioxide, volatile organic compounds and lead). In general, NSPS standards for boilers do not apply the most stringent emissions limits compared to other programs, thus these rules are not discussed in more detail. However, as part of any new construction project involving power or steam production, the source is required to demonstrate compliance with applicable NSPS standards.
- National Emissions Standards for Hazardous Air Pollutants (NESHAP) – These federal regulations are aimed at controlling emissions of Hazardous Air Pollutants (HAPs). Major sources of HAP emissions must control emissions at a level consistent with Maximum Achievable Control Technology (MACT), which is a high level of control specifically defined in federal regulations for different process types. Boilers that utilize combustion and that are located at either major source or area source of HAP emissions must comply with the recently-promulgated Boiler MACT (BMACT). This rule implies the most stringent controls for many air pollutants and is thus discussed in more detail below.
- Emissions Trading – Many large sources of sulfur dioxide and/or nitrogen oxide emissions are required to participate in emissions trading programs, including the Acid Rain Program and the Clean Air Interstate Rule (the latter of which is expected to be superseded by the Cross State Air Pollution Rule when legal challenges are settled). These trading programs do not necessarily imply the need for more stringent controls, but they can increase the costs associated with emissions and compliance.
- State Rules – Illinois has a variety of applicable state standards that apply to the operation of combustion units. In general, these standards do not imply the need for controls more stringent than what is required under the BMACT or the NSPS and will not be considered further as part of this analysis.

Permit Programs – In the state of Illinois, sources of air pollution emissions are required to obtain a construction permit before constructing a new emissions unit or modifying an existing emissions unit. Certain exemptions to this requirement are codified in Illinois environmental regulations, but the construction or modification of large combustion units are not likely to qualify for an exemption.

Large projects may trigger New Source Review (NSR). In order to determine whether NSR is triggered, the magnitude of potential emissions increases for a variety of pollutants must be determined. If the emissions increase is determined to be greater than the major source threshold, or the major modification threshold, for any pollutant, then NSR requirements are applicable. In the case of U of I, triggering NSR would mean that a construction permit must pass Prevention of Significant Deterioration (PSD) review for all applicable pollutants. Important features of PSD review are as follows:

- The project must involve the use of Best Available Control Technology (BACT) for all applicable pollutants. BACT is a technology level defined in federal rules that accounts for currently-available state of the art control technology and, to a somewhat lesser extent, costs and secondary environmental effects. If PSD review is triggered, BACT requirements may imply more stringent emissions limitations than Boiler MACT.
- Computer dispersion modeling of subject air pollutant emissions must be performed in order to demonstrate that there is no violation of applicable National Ambient Air Quality Standards (NAAQS). Because new, short term NAAQS for sulfur dioxide and nitrogen oxides are much more stringent than previous standards, this requirement could be a concern for certain combustion sources. As such, NAAQS are discussed in more detail in section 7.
- Computer modeling of the effects of emissions on visibility and regional haze in certain protected areas, such as national parks and national wildlife refuges, must be performed if such areas are within approximately 200 km of the project. In addition, Federal Land Managers of potentially-affected protected areas have the opportunity to comment on the project and the proposed permit. Mammoth Cave in Kentucky and the Mingo National Wildlife Refuge in Missouri are the two nearest protected areas to U of I that may be affected by a new project.
- Public participation, in the form of a public comment period and, potentially, a public meeting is required.
- Construction permits that involve PSD review are subject to appeal to the USEPA Environmental Review Board (EAB) for any reason. Opponents of high-profile projects may initiate the EAB appeal process as a means to delay construction of a project. EAB appeals typically take six (6) to twelve (12) months (sometimes longer) to resolve.

NSR permit fees can be significant, anywhere from $10,000 to $100,000 or more, depending on the size of the project. A construction permit of this type will typically take nine (9) to twelve (12) months to obtain, once the application has been submitted to IEPA. Expedited permitting is available in Illinois, although the expedited permit process may not accelerate issuance of an NSR permit substantially and expedited permit fees are five times higher than “normal” permit fees.

If a project does not trigger NSR, then a state minor source construction permit is required. This type of construction permit does not typically require modeling, a BACT analysis or public participation. Fees are substantially lower than permits involving PSD review and IEPA typically issues this type of permit within three (3) to six (6) months following receipt of a complete permit application.

Following construction, a major source (under USEPA’s Title V operating permit program) is required to file for a modification of its operating permit in order to incorporate the new or modified emissions unit(s). U of I currently operates under a Title V operating permit and it is anticipated that the facility would continue to be a Title V major source under any of the currently anticipated future scenarios.

Other Environmental Considerations – In addition to the Illinois Environmental Protection Act, Illinois also has a Solid Waste Act thatprohibits the burning of wastes in boilers. Note that the Solid Waste Act defines the burning of waste as incineration. As interpreted by IEPA’s

Bureau of Land, the definition of "waste" under the Solid Waste Act has been very stringent, significantly more so than in other states or under Federal regulations. As a result, what may be considered biomass fuel in other states can often be considered waste in Illinois. This complication should be taken into account when considering any project that may involve biomass as a fuel or feedstock.

Current Emissions Units

The following table lists the APP units and associated emissions control devices.

CURRENT EMISSION UNITS			
UNIT	SIZE MMBTU/HR	PERMITTED FUEL	EMISSION CONTROL DEVICE
BOILER 2	236	NATURAL GAS AND FUEL OIL	LOW NOx BURNERS
BOILER 3	236	NATURAL GAS AND FUEL OIL	LOW NOx BURNERS
BOILER 4	236	NATURAL GAS AND FUEL OIL	LOW NOx BURNERS
BOILER 5	200	COAL	ESP & COMMON FGD
BOILER 6	200	COAL	ESP & COMMON FGD
BOILER 7	243	COAL	ESP & COMMON FGD
COMBUSTION TURBINE 1 DUCT BURNER 1	134 91	NATURAL GAS AND FUEL OIL	CO CATALYST
COMBUSTION TURBINE 2 DUCT BURNER 2	134 91	NATURAL GAS AND FUEL OIL	CO CATALYST

According to the University of Illinois' Title V permit, there are ten additional boilers throughout the University that were not considered as part of this study. These boilers may also be impacted by existing and future air quality regulations.

Additional Details

Area Source BMACT (40 CFR 63 Subpart JJJJJ). According to APP's operating permit, APP is an "area source" of HAPs emissions since it does not have the potential to emit more than 10 tons of any individual HAP or 25 tons of all combined HAPs. The flue gas desulfuration (FGD) scrubbers installed on the coal units remove a significant percentage of hydrogen chloride (HCl) emitted from the boilers, keeping the facility emissions of HCl under 10 tpy and from being classified a "major source" of HAPs. Not being a HAP Major Source, the APP is subject to the area source version of the BMACT Rule as contained in 40 CFR 63, Subpart JJJJJ.

Note that boilers are exempt if they are:

- Boilers regulated by another MACT rule or Section 129 of the Clean Air Act [40 CFR 63.11195(a), (b), (c) and (g)];
- Boilers or process heaters used for research and development [40 CFR 63.11195(d)];
- Gas-fired boilers defined as any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year [40 CFR 63.11195(e)];
- Hot water heaters, defined as a closed vessel less than 120 gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel [40 CFR 63.11195(f)];
- Temporary boilers [40 CFR 63.11195(h)];
- Residential boilers [40 CFR 63.11195(i)];
- Electric boilers [40 CFR 63.11195(j)]; and
- Electric utility steam generating units (utility boilers greater than 25 MW that burn fossil fuel) [40 CFR 63.11195(k)].

The Area Source BMACT Rule requirements include: emission limitations, operational limitations, work practice standards, compliance demonstration requirements, notifications, recordkeeping, and reporting. APP is required to comply with the applicable requirements of the Area Source BMACT final rule no later than March 21, 2014 for all existing boilers.

Under the Area Source BMACT, coal-fired boilers with a heat input capacity of 10 MMBtu/hr or greater must comply with emission limits for mercury (Hg) and carbon monoxide (CO). There are no emission limits for gas- or oil-fired boilers. The Area Source BMACT Rule allows emissions averaging for similar types of boilers burning similar fuels; however, this averaging is only allowed on Hg for existing boilers.

Presently APP generates electricity at a carbon dioxide rate of 0.87 pounds per kilowatt-hour. This existing rate is **below the proposed EPA standard** of 1.00 pounds per kilowatt-hour for new generating equipment. Due to the best-in-class emission control system, APP was recently tested to be **under the new MACT limits by a factor of 15**. The Chiyoda Jet Bubbling Reactor (JBR) not only has maximum scrubbing of sulfur dioxide but also removes mercury emissions to near non-detectable limits.

The work practice standards for existing coal-fired and oil-fired boilers include requirements for initial and periodic boiler tune-ups and a one-time energy assessment. Additionally, existing coal-fired boilers must minimize the boiler's startup and shutdown periods. Further, startups and shutdowns must be conducted in accordance with the manufacturer's recommended procedures. Note that if manufacturer recommended procedures are unavailable, recommended procedures for a unit of similar design must be followed.

The operational limitations include standards for opacity and air pollution control equipment operation. These standards are based on the type of air pollution control equipment installed.

The compliance demonstration requirements include both initial and continuous requirements to verify that all limits and standards of the Area Source BMACT Rule are met. These compliance demonstration requirements include continuous monitoring system (CMS) installation, stack testing, and/or fuel analysis.

Notifications, recordkeeping, and reporting are required for all compliance demonstration requirements. The notifications, recordkeeping, and reporting requirements are based on boiler size, boiler type, control equipment type, and fuel burned.

Area Source BMACT Rule Applicability

APP has six boilers which require review for applicability of Area Source BMACT Rule requirements: Boilers 2, 3, and 4 which burn natural gas with fuel oil backup and boilers 5, 6, and 7 which burn coal. The BMACT Rule may require APP to install additional pollution controls to meet new emission limits on units and require additional compliance demonstration actions for all of the boilers. The purpose of this Section is to summarize the Area Source BMACT.

The type of fuel burned is an important part of determining the applicability of Area Source BMACT Rule requirements. Per the BMACT rules, a gas-fired boiler is not subject to this rule if it meets the rule's definition of "gas-fired boiler." The definition of a gas-fired boiler is any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year. If boilers 2, 3, and 4 meet this definition then they are classified as "existing" gas-fired boilers and are therefore not subject to the Area Source BMACT. According to plant records in 2011 boilers 2 and 4 did not burn oil and boiler 3 burned 2,264 gallons of oil.

Boilers 5, 6, and 7 are considered "existing" coal-fired boilers under the rule.

Emission Limits

The Area Source BMACT Rule provides Hg and CO emission limits for Boilers 5, 6, and 7. Boilers 2, 3, and 4 are not subject to any emission limits regardless of whether they burn oil or natural gas.

Boilers 5, 6, and 7 will have to meet an Hg emission limit of 22 x 10-6 lb/MMBtu by March 21, 2014. Compliance with this emission limit can be demonstrated by either stack testing or fuel analysis. Based on discussions with the plant the Hg emission rate from these units is undetectable.

Boilers 5, 6, and 7 will have to meet a CO emission limit of 420 ppm (referenced to 3% oxygen) by March 21, 2014. Compliance with this emission limit is demonstrated by stack testing and use of an oxygen analyzer installed at the boiler exit. APP was recently tested to be **under the new MACT limits by a factor of 15.**

Work Practice Standards

As existing coal units, Boilers 5, 6, and 7 must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, recommended procedures for a unit of similar design must be followed.

Affected coal and oil units must have a one-time energy assessment performed by a qualified energy assessor. This seven-part, energy assessment includes [40 CFR 63 Table 2, Condition 16]:

- A visual inspection of the boiler system
- An evaluation of operating characteristics of the facility, specifications of energy using system, operating and maintenance procedures, and unusual operating constraints
- Inventory of major systems consuming energy from affected boilers
- Review available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
- A list of major energy conservation measures that are within the facility's control
- A list of the energy savings potential of the energy conservation measures identified
- Comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments

The owner of existing coal and oil units must conduct an initial tune-up of the affected boilers. Following the initial tune-up, tune-ups must be conducted biennially. These tune-ups include [40 CFR 63.11223(b)]:

- As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the burner inspection may be delayed until the next scheduled unit shutdown but each burner must be inspected at least once every 36 months).
- Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.
- Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly.
- Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available.
- Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made).
- Maintain onsite and submit, if requested by the Administrator: the concentrations of CO in the effluent stream in ppm, by volume, and oxygen in volume percent measured before and after the tune-up of the boiler, a description of any corrective actions taken as part of the tune-up of the boiler, and the type and amount of fuel used over the 12 months prior to the biennial tune-up of the boiler.
- If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

Additional Details

The NAAQS is a USEPA ambient air standard designed to protect public health and welfare. There are primary and secondary standards for six criteria pollutants (Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particulate Matter, and Sulfur Dioxide). The USEPA frequently reviews and if necessary updates these standards to ensure protection of public health and welfare. Recently the USEPA revised the primary SO2, NO2, and ozone standards. The revised NAAQS for SO2 and NO2 could impact the APP facility.

On June 2, 2010, the USEPA established a new one-hour SO2 standard of 75 parts per billion (ppb). This new standard replaced the existing primary standards of 140 ppb (24-hour standard) and 30 ppb (annual standard). Based on a June 2, 2011 Illinois Environmental Protection Agency (IEPA) letter to the USEPA the Urbana-Champaign area was considered unclassifiable in regards to the SO2 NAAQS. The USEPA is potentially allowing the use of a refined air dispersion modeling approach to demonstrate compliance with the standard. Based on the size and fuel burned at the APP, the IEPA may decide to conduct SO2 air dispersion modeling for the facility. If these modeling results show a violation of the standard caused by sources in the Urbana-Champaign area (including the APP), then IEPA may request or require the APP to reduce their SO2 emissions. Although APP already has a scrubber installed for SO2 control on the three coal units and has a 1.20 lbs/MMBtu emission limit, there is a possibility that the combination of stack heights, building heights, and dispersion patterns may result in modeled violations of the SO2 NAAQS standard. If this is the case, a reduction in maximum one-hour SO2 emissions may be required.

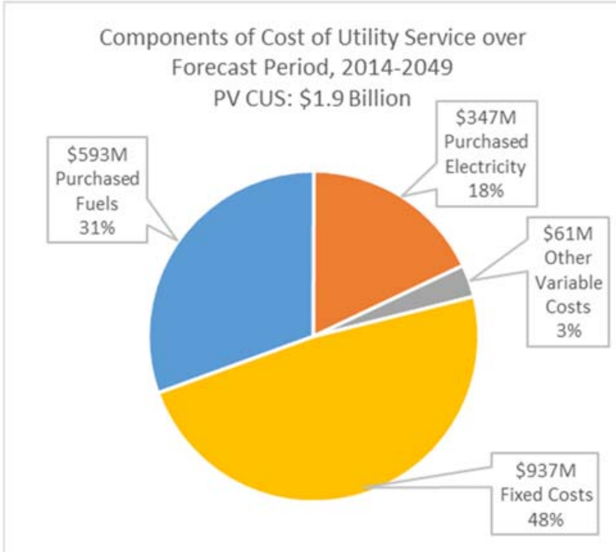
On January 22, 2010, the USEPA established a new one-hour NO2 standard of 100 ppb. The EPA also retained the current annual average NO2 standard of 53 ppb. The USEPA has indicated they will rely on the use of ambient air monitoring (three years) to demonstrate compliance with the standard. If the IEPA monitors the ambient air and detects a violation in the Urbana-Champaign area (including the APP), the IEPA may request or require the APP to reduce their NO2 emission.

The U.S. EPA issued an eight-hour ozone NAAQS in July 1997, based on the average of the highest values measured over the previous three (3) years. The eight-hour ozone standard was 0.08 ppm. However, this standard was essentially 0.084 ppm in practice due to rounding. In 2008 the USEPA lowered the NAAQS for ozone to 0.075 ppm. The USEPA was scheduled to again lower the standard in 2013; however, President Obama has instructed the USEPA to delay plans for this revision. As of August 20, 2013 the Urbana-Champaign area is not in violation of the 2008 ozone NAAQS.

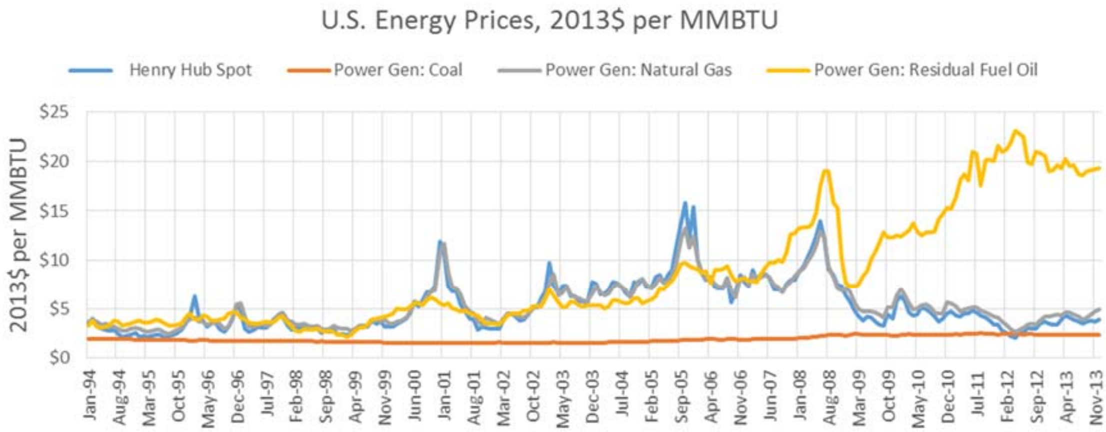
5.3.5 Market Risk

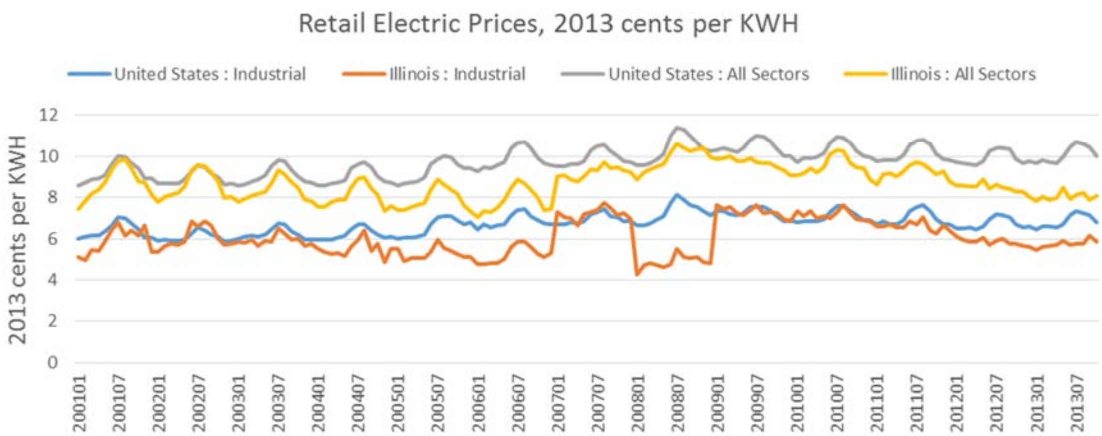
Commodity Price Risk

Purchased fuels and purchased electricity comprise the largest individual cost components associated with providing electric and thermal utilities to the University. Over the 35 year forecast period the University is expected to pay roughly $1.9 billion, in present value terms, to be able to provide utilities to the U of I campus. The figure below illustrates that purchased fuels and purchased electricity constitute 49% of that amount. In 2013, the budgeted amount for purchased fuels and commodities was approximately $35 million.



As illustrated by the energy price figures below, coal and purchased electricity prices have been fairly stable over the past 10 to 20 years. Natural gas, on the other hand, has experienced drastic price fluctuations over time. What impact would this have on U of I? In 2013, as an example, U of I was forecasted to consume approximately 5 trillion BTUs of fuel on campus. In simple terms, if the only source of fuel available were natural gas at 2008 pricing levels the University would have spent $45-$50 million on fuel compared to $20-$25 million with 2013 prices. This example is obviously an oversimplification since the University has a risk management program which attempts to mitigate the impact of these dramatic swings in prices, but the example illustrates the budgetary impact possible in extreme conditions.





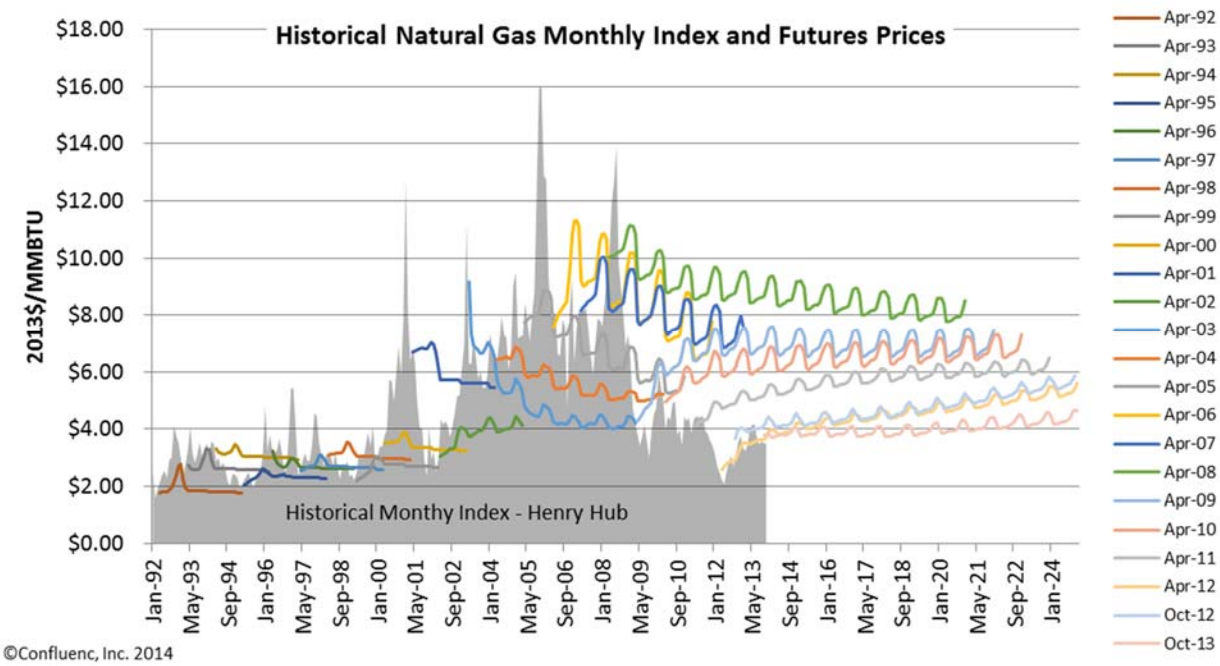
Fellon McCord, a service provider to the University, stated in a report for the University[9] that, “there are several factors that could exert upward pressure on the natural gas market in the coming years.” The report continues:

> “Factors that could influence natural gas prices higher in the coming years include potential regulations on hydraulic fracturing, one of the technology advancements that led to the production boom. The Environmental Protection Agency is currently conducting a lengthy study into possible groundwater contamination associated with “fracking,” and the outcome could influence the use of this practice, or at minimum alter drilling economics. Additionally, demand for natural gas is expected to ramp up considerably in future years, as gas is used to fill the generation gap resulting from increasing nationwide coal retirements. Producers are also looking to higher-priced foreign markets via LNG exports.”

One option to mitigate market price volatility is to enter into futures contracts which will result in budget certainty. This will help protect against price increases, but will also eliminate the opportunity to take advantage of price drops. To illustrate, the following figure indicates historical monthly index prices for Henry Hub back to January 1992 (gray area) as well as reported futures contract transaction prices at sample points in time (colored lines). For example,

[9] Coal Removal Risk Identification, Prepared for Prairieland Energy by Fellon McCord, April 2013, p. 5. See Attachment

the green line starting in April 2008 illustrates that buyers could have locked in future prices in the $8 to $10 per MMBTU range at a time when spot prices were $10 per MMBTU and still going up. Of course, we know the history now of what actually occurred when prices plummeted to less than $4 per MMBTU in less than a year (see gray area for April 2009). A buyer of futures contracts in April 2008 would have had price certainty, but not the lowest price. As a second example, the green line starting in April 2002 illustrates that a buyer of these futures contracts would have locked in price certainty around $4 per MMBTU and would have also shielded themselves from price increases of more than double the April 2002 spot prices.



Commodity Availability

Long-term commodity availability with traditional energy sources, i.e. coal, fuel-oil, natural gas and purchased electricity, is not a significant risk given historical experience. There is a well-established and resilient supply infrastructure for all of these commodities that can respond to supply complexities in the long-term. If U of I were to become heavily dependent on biomass new long-term risks would be introduced since the market infrastructure for biomass is still emerging and not yet proven as to long-term availability and resiliency.

There is some uncertainty to the continued mass recovery of natural gas from fracking, which has significantly increased the present supply of low cost natural gas. There are actions in both the private and federal sectors to impose strict environmental standards to limit or eliminate fracking.

In the early 1970's, U of I switched from coal to an oil based operation. At this time, oil was the lowest cost fossil fuel available in the United States. After a few years of oil operation, the cost of oil escalated and coal was reintroduced to Abbott.

Because of the uncertainty of long-term low cost natural gas and the good condition of the Abbott coal systems, it is recommended to continue to plan to utilize coal for the next ten years. It is very difficult if not impossible from an environmental permitting standpoint to eliminate coal operations and then restart coal operations if natural gas costs increase. This proposed ten year window will allow for the cost of natural gas to stabilize.

The steam being generated from coal in the Abbott Power Plant is utilized in a cogeneration configuration. The steam is passed through extraction/ back-pressure steam turbine generators to produce electricity prior to being exported to the campus for heating purposes. The use of extraction/ back-pressure steam turbine generators is the most efficient means of generating electricity from fossil fuels. Because of the efficiency of the Abbott electric generating systems, the regional carbon footprint from typical coal firing is reduced.

Coal – The State of Illinois has the second largest quantity of coal reserves within the United States (100 billion tons). Presently the United States exports a large quantity of coal. There is and will be an adequate supply of coal to serve U of I.

Natural Gas – The supply and availability of natural gas continues to increase in the United States as well as North America. As with coal, the United States is beginning to export natural gas. The long-term supply of natural gas is adequate for U of I. As demand increases for natural gas through the increased use for utility electric generation as well as the future possibility of vehicular transportation fuel, the supply will be adequate; however, the unit cost may increase.

Biomass – The use of biomass from organic sources such as trees is being considered at many facilities. To contract for a long term supply of biomass (+ 10 years) is difficult. The new University of Wisconsin energy plant was switched from biomass to natural gas because of the inability and/ or uncertainty to obtain a long-term biomass contract.

If a facility is going to consume a large quantity of wood or other materials on an annual basis, the development and management of a dedicated biomass source is generally implemented to insure fuel supply over the life cycle.

Short-term availability of fuel is addressed in the reliability section below.

Campus Load Growth

This Master Plan examines growth scenarios for 0, 75k, and 150k GSF/yr, with only 2/3 of the growth occurring on the main campus and 1/3 in the research park. Historically, the campus has experienced growth rates as high as 300k GSF/yr over 5 to 10 year periods. If growth occurs at a faster pace than planned, the University will experience difficulties responding to needed changes in distribution systems and central utility systems.

Code and Life Safety

Section 3 examines the code and life safety of the existing utility production and distribution systems on campus. The financial and reputational impact that can occur if a serious injury or death occurred due to unsafe working conditions or practice is large. The University is systematically addressing known issues and should continue to inspect, plan, and address code and life safety.

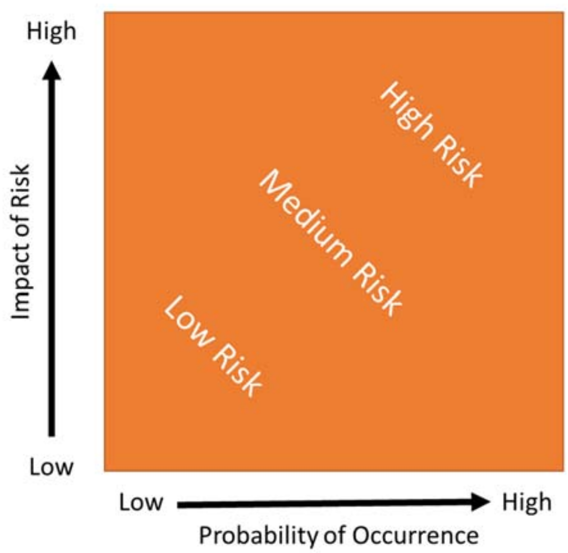
Natural Phenomenon

Universities across the country have experienced significant natural disasters or events including tornadoes, earthquakes, flooding, virus pandemic and sustained heat or cold. How universities have prepared for and responded to those disasters had significant impact on their reputation. For example, when Superstorm Sandy made landfall on the eastern coast of the United States, extended power outages affected the region for days. However, local facilities with cogeneration systems were able to operate in island mode during the event.

5.4 Evaluation and Prioritization of Risk

The University, through the University Office of Enterprise Risk Management[10], collects information about and evaluates risk. A Risk Abstract Form[11] is available for use and utilizes many of the same elements discussed below.

Risk mapping is a common methodology used to assess and prioritize risk. An example used by the University of Illinois system is available from the University Office of Enterprise Risk Management[12]. The intent of risk mapping is to compare the probability of a risk to the potential impact in order to prioritize risks. A risk map helps to organize risks into Low, Medium and High risk categories. The methodology is briefly described below.



[10] http://www.obfs.uillinois.edu/enterprise-risk-management/
[11] http://www.obfs.uillinois.edu/common/pages/DisplayFile.aspx?itemId=1042697
[12] See Blank Risk Map Template at http://www.obfs.uillinois.edu/enterprise-risk-management/resources-tools/

Risk Probability of Occurrence

Various approaches exist to categorize probability, but for our purposes the following table defines the categories we will use for the probability of occurrence.

PROBABILITY OF OCCURRENCE		
PROBABILITY RANGE	DESCRIPTION	NUMERICAL SCORE
91% THROUGH 99%	"VERY LIKELY" TO OCCUR	5
61% THROUGH 90%	"PROBABLE" TO OCCUR	4
41% THROUGH 60%	"MAY OCCUR" ABOUT HALF OF THE TIME	3
11% THROUGH 40%	"UNLIKELY" TO OCCUR	2
1% THROUGH 10%	"VERY UNLIKELY" TO OCCUR	1

Risk Impact

Again, various approaches exist to categorize impact, but the following table outlines how risk impact categories are defined within this Master Plan. Impact of each risk on each of the following categories is assessed; safety, reliability, institutional mission, economic viability, and reputational.

Risk Score

A risk score is calculated by multiplying the probability of occurrence score by the impact score. The table below illustrates a risk score table.

RISK SCORE					
PROBABILITY	IMPACT				
	NEGLIGIBLE	MINOR	MODERATE	SERIOUS	CRITICAL
VERY LIKELY	5	15	25	40	50
PROBABLE	4	12	20	32	40
MAY OCCUR	3	9	15	24	30
UNLIKELY	2	6	10	16	20
VERY UNLIKELY	1	3	5	8	10

The risk score is used to compare risks as part of the risk prioritization process. Based on the risk score the risks are categorized as Low, Moderate, and High are as follows:

- Low Risk: Has little or no potential for increase in cost or degradation of performance. Mitigating actions are normally not considered for risks in this category. These risks are tolerated, monitored and managed as necessary.
- Moderate Risk: May cause some increase in costs or degradation of performance. Mitigating actions may need to be developed in order to treat or transfer these risks.
- High Risk: Likely to cause significant increase in cost or degradation of performance. Significant mitigating actions will likely be required in order to treat, transfer or terminate risks in this category.

U of I Risk Mapping

The U of I risks discussed above have been organized into the following specific risk considerations:

Each of these risks are evaluated according to the process described above comparing probability of occurrence with the possible impact of the risk. The risk map below illustrates the current prioritization of these risks given the current utility configuration. As significant components of the system change in the portfolio evaluations, these risks will be reevaluated.

The specific risk score ranges are as follows:

RISK SCORE RANGES				
LOW RISK	LOW-MODERATE RISK	MODERATE RISK	MODERATE-HIGH RISK	HIGH RISK
1 - 10	11 - 20	21 - 30	31 - 40	41 - 50

Additional detail on the risk assessment is included in Appendix 5B of this report. The calculated risk scores are available in Appendix 5C of this report.

U of I Risk Prioritization and Treatment

The table below shows the prioritization of risks and recommended treatment path.

5.5 Specific iCAP Review

The U of I Office of Sustainability website states, "In 2008, the University of Illinois at Urbana-Champaign signed the American College & University Presidents' Climate Commitment. The Illinois Climate Action Plan (iCAP) makes a commitment to carbon neutrality by mid-century and describes a path toward the fulfillment of this commitment."

The iCAP makes several suggestions that impact the risk profile of the University. The following is a review of these suggestions[13]:

- **Energy Conservation** – Investments in energy conservation is one of the best investments the University could make at the current time to reduce risk. Saving energy

[13] iCAP, a Climate Action Plan for the University of Illinois at Urbana-Champaign, May 15, 2010.

in buildings and other major energy uses saves money, provides reliability benefits, potentially delays necessary investments in infrastructure upgrades and helps the University move toward GHG and other environmental goals. Additionally, risks associated with market price volatility are also mitigated with less energy use.

- **Coal Use at Abbott Power Plant –** The suggestion to eliminate coal use by 2017 increases the risk to the University significantly. The primary financial risk (FR01 and FR03) are amplified with this decision because significant investments will need to be accelerated. Market risk associated with natural gas price volatility (MR02) will be amplified. Market risk associated with biomass availability (MR07), which in the current configuration is not a large concern, suddenly becomes one of the primary risks to the utility operation if a biomass option is chosen as the means to eliminate the use of coal.
- **Renewable Energy –** There are many benefits associated with investments in renewable energy. One of the primary benefits is the opportunity to avoid market risk volatility associated with commodity purchases. This benefit is associated with resources such as wind, solar and geothermal. The primary challenge associated with investments in renewable energy is capital cost risk. Over the past few years, renewable energy investments have become much more cost effective, but often still require significant subsidies to compete with traditional energy sources. Unless cost effective options exist today, or significant subsidies exist, it may be more beneficial to delay investment in significant renewable energy opportunities.
- **Building Standards –** Similar to investments in energy conservation, more stringent building standards can save money, provide reliability benefits, potentially delay investments in infrastructure upgrades and help the University avoid moving further away from GHG and other environmental goals. Risks associated with market price volatility can also be mitigated.
- **Campus Space –** Similar to investments in energy conservation, maintaining a net zero growth policy will help minimize energy spending. A policy such as this can save money, provide reliability benefits, potentially delay investments in infrastructure upgrades and help the University avoid moving further away from GHG and other environmental goals. Risks associated with market price volatility can also be mitigated. The primary challenge associated with limiting campus space is not having the capacity available to meet increased demands if the limits are not maintained.

6.0 Utility Business Model Analysis

6.1 Overview

The purpose of this section is to provide an analysis of the utility business model including an Abbott Power Plant staffing review, structures that might enable the APP to be operated as an independent energy provider, and a description of a budgeting and financing model that has been developed to evaluate investment options considered in the Master Plan.

6.2 APP Staffing Overview

APP current personnel staffing levels and personnel in each staffing designation are evaluated to determine if the current staffing levels are adequate to maintain and operate the plant.

Based on the APP Operation Personnel spreadsheet provided by U of I, the APP is staffed at the following levels:

- Administration – 4
- Engineer – 4
- Instrument Technicians – 3
- Operators – 22
- Mechanic Shop – 7
- Electricians – 7
- Pipefitters – 3
- Extra Help – 4

As noted in the Summary section of the SAIC report dated September, 2009, plant staffing levels appear to be reasonable for a plant of this size. This report heavily recommends cross training between craft designations to realize staff efficiency gains. Even though cross training between craft designations is a reasonable goal in the future, the review did not focus on this major shift in plant maintenance structure due to the difficulty of modifying union jurisdictions.

The plant is well maintained and operated, and provides reliable service to the University. Present operating status indicates that the staffing levels are adequate for the operation and maintenance methods currently used at the plant. Also, the staffing levels are reasonable in comparison to similar sized Power Plant facilities at peer institutions. To optimize the maintenance organization, a mixture of in-plant and contracted resources is used. In-plant forces are best suited for routine preventative maintenance, troubleshooting and small repair work. Their expertise on the total plant system and familiarity with the nuances of the plant is best used in diagnosing and directing the efforts of maintenance resources. The contracted force adds value by bringing in industrial expertise in more specialized fields of knowledge, knowledge that take a craftsman decades to develop. The contract workforce can also mobilize large crews for outages and major repairs to stay focused on task toward a timely completion. Once the task is completed the contractor workforce can be demobilized or reduced to match the work load.

6.3 APP as an Independent Energy Provider

As stated in section 5, one of the key ways to transfer some of the significant financial risks is to operate Abbott as an independent energy provider. While this independent operation may be possible and beneficial, there are associated significant risks and uncertainty. This section describes some of the key elements that should be considered knowing that one of the key considerations is impact on access to capital. Some of the key criteria for consideration of alternative approaches include:

- **Impact on Cost of Service –** This encompasses the cost of service associated with both capital and potentially operation and maintenance. The Business-as-Usual structure is assumed to be tax-exempt debt for construction and permanent financing, as well as the facilities are owned and operated by the University. A specific metric to consider is the present value (PV) of the revenue requirement over the economic life of the facilities.
- **Regulatory/Legal Preclusion and Constraints –** This factor is derived from state and federal regulations and laws.
- **Positive and Recent Precedent –** This is the degree to which recent and successful examples of the implementation of a transaction structure at similar facilities and organizations exist.
- **Ease of Implementation –** Consideration of how easy the structure is to implement.
- **Operational Flexibility –** This is the extent to which the University can be assured that the transaction structure provides sufficient operating flexibility over time including potential modifications to the facility to meet changing circumstances.
- **Reliability/Security –** Consideration of reliability equivalent to or better than the current configuration.
- **Accounting Treatment –** Includes the extent to which the transaction structure would reduce the University bonding capacity.

6.4 Options for Consideration

While there are many variations to obtain capital, most funding methods can be grouped into one of four general strategies: 1) University system financing, 2) Tax- exempt Lease, 3) Non-profit Utility Services Corporation, and 4) Commercial. Each of the general funding strategies is briefly described below.

University System

Many university systems are authorized to issue debt secured by a system-wide pledge of all legally available revenues. The University of Illinois has such a debt program with authorization to issue debt. This is historically how funding has taken place at the University of Illinois.

University system bonds are typically low cost. Interest on the borrowings is tax-exempt and the systems historically have had high credit ratings. This form of funding is the reference to which other options will be compared.

Tax-Exempt Lease

A tax-exempt lease enables tax-exempt entities to obtain use of equipment and pay over time. Under a tax-exempt lease, ownership of the equipment passes to the customer or lessee up front. The title is subject to a lien held by the lessor during the lease term. The lease is referred to as tax-exempt because the "interest" income to the investor is exempt from federal taxes. Tax-exempt leases have been used for a long time to fund energy facilities.

Certificates of Participation (COPs) are a form of fractionalization of a tax-exempt lease. COPs are "an instrument evidencing a pro rata share in a specific pledged revenue stream, usually lease payments by the issuer that are subject to annual appropriation. The certificate generally entitles the holder to receive a share, or participation, in the lease payments from a particular project. The lease payments are passed through the lessor to the certificate holders. The lessor typically assigns the lease and lease payments to a trustee, which then distributes the lease payments to the certificate holders"[1].

There are two ways of accounting for leases, i.e. as an operating or capital lease. In an operating lease, the lessee has the right to use the property during the term of the lease; the property is returned to the lessor at the end of the lease. An operating lease is treated as an operating expense; it does not affect the balance sheet. When a lease is characterized as a capital lease, it shows up as part of the capital of the lessee. The present value of the lease expenses is reflected on the balance sheet of the lessee as debt. A lease is generally treated as a capital lease if it meets any one of the following four conditions:

- The lease life exceeds 75% of the life of the asset
- There is a transfer of ownership to the lessee at the end of the lease
- There is an option to purchase the asset at a "bargain price" at the end of the lease
- The present value of the lease payments exceeds 90% of the fair market value of the asset.

"Non-appropriation" clauses have been used in tax-exempt leases for energy projects in the past to support treatment as operating leases. Under increasingly stringent accounting standards, it is more likely that new, tax-exempt leases will be treated as capital leases.

In states with Energy Service Performance Contracting enabling legislation, state colleges and universities have incorporated 3rd party measurement and verification of savings from energy and other projects to enhance the viability of tax-exempt lease financing.

North Carolina State University (NCSU) is using tax-exempt lease financing to fund the $60 million Cates and Yarbrough Steam Plants Upgrade Project which includes 11 MW of cogeneration. The financing incorporates ongoing third party measurement and verification of savings.

1 Source: Municipal Securities Rulemaking Board

Utility Services Corporation

There is a long history of non-profit utility services corporations being formed for the sole purpose of building, owning, and operating facilities to serve the energy requirements of a discrete set of customers. Municipal utilities fall into this category. Non-profit utility services corporations have also been formed by smaller groups of customers for the purpose of implementing, owning and operating central utility plants.

In some circumstances, the special purpose entity is allowed under state law to arrange financing through the issuance of tax-exempt debt that is supported by long-term services agreements with its customers. Non-profit corporations must apply for tax-exempt status at the federal and sometimes at the state level.

The Medical Center Company of Cleveland, Ohio (MCCo) has been applying this model since 1932. MCCo owns and operates a district energy system for the benefit of its "members". All of its corporate members are also customers and are located within the area designated as University Circle. All members are also tax-exempt institutions operated exclusively for educational, charitable, and religious purposes.

Member and customers of MCCo include Case Western Reserve University, University Hospitals of Cleveland, The Cleveland Museum of Art, The Church of the Covenant, The Musical Arts Association, The Cleveland Botanical Garden, The Cleveland Hearing and Speech Center, The Cleveland Medical Library Association, The Cleveland Institute of Art, and Severance Hall. Capital improvements are financed through the issuance of tax-exempt debt supported by long-term service agreements between MCCo and its members. MCCo is governed by a Board on which the largest customers are represented.

Commercial

In this context, commercial means "for profit". Customers enter into long term agreements with for-profit entities to induce those organizations to build and operate facilities to meet contracted customer requirements. Typically, the assets are held in a taxable entity that is set up for the special purpose of owning and operating them. The capital employed in the special purpose entity is taxable and is comprised of both equity and debt. The capital cost associated with the plant is effectively amortized over of an agreed upon contract term. The charge for capital recovery is converted into a commodity rate typically related to capacity and usage.

This approach is widely used. There are longstanding precedents for the commercial approach in higher education.

The table below describes an example of each of the described funding strategies.

REPRESENTATIVE EXAMPLES OF GENERAL FUNDING STRATEGIES		
Funding Strategy	**Institution**	**Project**
University System Financing	Texas A&M University	CHP plant. 34 MW GE LM2500 +G4 gas turbine, 210 mlb/hr heat recovery steam generator (600 psi), 11 MW back pressure steam turbine, 11 MW emergency generator, extensive electrical and steam system upgrades. ($73 MM)
Tax-exempt Lease	North Carolina State University	CHP plant. Two 5.5 MW combustion turbine generators with 50 mlb/hr heat recovery steam generators, 3 new gas/oil boilers, new transformers, and modifications to substations. ($60 MM)
Non-profit Utility Services Corporation	The Children's Hospital of Alabama	Freestanding central utility plant. ($22 million)
Commercial	University Medical Center of Princeton at Plainsboro (UMCPP)	CCHP plant. 4.6 MW combustion turbine & supplmental-fired heat recovery steam generator, 3000 tons chilled water, 1 million-gal thermal energy storage system (partial funding provided by utility), 6 MW emergency diesel generators, proprietary software dispatch system. ($34 million)

6.5 Summary of Options

Below is a summary of each of the options considered:

- **Non-Profit Utility Services Corporation** – There appears to be a regulatory and legal basis for this approach and longstanding precedent in the U.S. A utility services corporation may receive tax-exempt status and issue tax-exempt debt based on the strength of its off-take contracts. The availability of tax-exempt debt funding will be a major determinant of the cost of utility service. To maintain the tax-exempt status, the customers must be tax-exempt. It is believed that objectives for operational flexibility as well as reliability and security can be met within this framework. In addition, there may be ways for the University to participate in the governance of the special purpose entity. The formation of a new entity and attracting additional customers to that entity adds complexity and likely time over the traditional approach of funding through the University system.
- **Tax-Exempt Lease** – There is certainly regulatory and legal basis for this form of financing in the United States. The most attractive feature of this form of financing is that it preserves the use of low cost, tax-exempt financing. It has apparently been possible to structure tax-exempt leases in the past that did not result in a full credit offset. However, the consensus is that future tax-exempt leases will be treated as capital leases, booked as debt on the balance sheet, and explicitly limit bonding capacity. This optionenables the ability to maintain operational flexibility and assure reliability as well as security as the customer owns and operates the asset from commercial operation. There is likely added complexity to this approach relative to financing through the University system.
- **Commercial** – There are a number of cautionary flags with respect to the commercial financing approach. Foremost is that the taxable capital structure will tend to significantly increase the cost of utility service. The customer is most detached from the

asset under this structure so there are logically concerns about operating flexibility. However, a number of market participants indicate that cost of utility service under a commercial structure may approach costs under tax-exempt structures when the following are considered: 1) tax incentives, 2) locking in the current reduced spread between tax-exempt and taxable interest rates, and 3) larger universe of potential customers including the wholesale electricity market.

Of the three options, the commercial option is likely to increase the cost of utility service significantly unless mitigating options are available to minimize the impact of the higher cost of capital associated with this option.

6.6 Budgeting and Financing Model

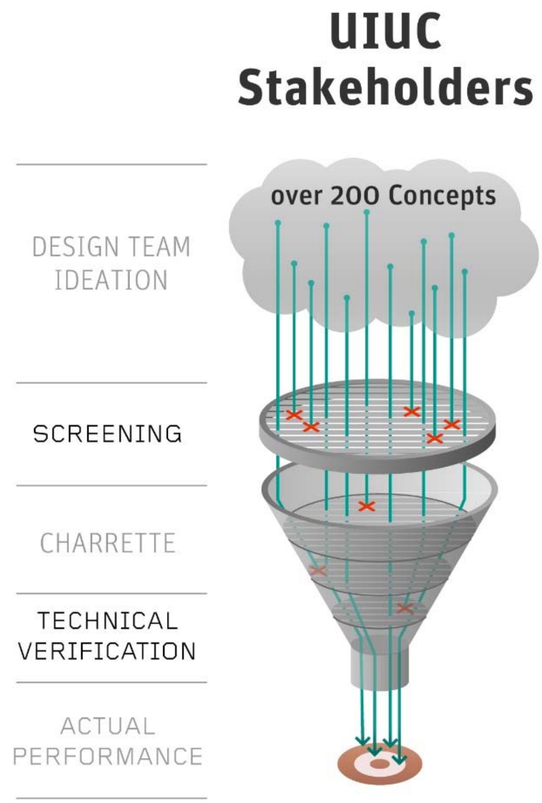
A budgeting and financing model created to evaluate the potential investments recommended as part of the plan is described in Appendix 6-A. The structure of the model was developed after the budget model already in place at the University, in order to retain consistency of language and comparability of metrics. Key metrics that can be compared to historical budgets include total cost of utility service, cost of utility service per unit of energy, required capital, etc.

7.0 Utility Options Analysis

7.1 General

Various options were investigated to provide heating, cooling and electric power to the U of I campus.

Each option is one part of a possible solution to meeting the campus utility requirements. The options are joined together in a computer based business model to develop scenarios. A scenario is any combination of options that provides a viable means of meeting the campus heating, cooling, and power requirements. System reliability, environmental impacts, sustainability, permitting, regulations, and budget requirements are included in the analysis of each scenario.



Nearly 200 individual concepts were identified for consideration and reviewed by the planning team. The initial concepts developed through the engagement process were categorized as follows:

- Improve Reliability
  - General Reliability Issues
  - Second Steam Plant
- Reduce Deficit – Control Utility Rates
  - Alternative Financing
  - Campus User Incentive Programs
  - Real Time Pricing
- Fuel Mix / Fuel Type
  - Coal Alternatives
  - Biomass
  - Methane Opportunities
- Minimize Capital Expenditures
  - Performance Contracting
  - Centralized vs Decentralized Utilities
  - 3rd Party Build, Own, Operate Plants
- Distribution Efficiency Improvements
  - Electrical Distribution Systems
  - Steam Distribution Systems
  - Chilled Water Distribution Systems
  - Heat Recovery
  - Controls Opportunities
  - Alternative Means of Distributing Thermal Utilities

- Plant Optimization
    - Dispatch Model / Algorithm
    - Predictive Controls
    - Optimization of Heat Recovery & Free Cooling
    - Motor Efficiency
    - Staff Training
- Alternative Means of Producing Thermal Utilities
- Renewable Energy Alternatives
    - Wind
    - Geothermal
    - Local Solid Fuels (including biomass)
    - Solar and Solar Thermal
- Operational Models
- Environmental Risk
- Greenhouse Gas Reduction
- Water Efficiency, Specific to Energy Production
- Respond to Growth
    - Smart Buildings
    - Utility Connection Charges
    - Net Zero Energy Requirements
    - Aggressive Building Controls for Occupancy

The preliminary screening process involved discussions with University facilities and services staff on concepts likely to be technically viable, significant in scale, and contribute meaningfully to the University's energy, environmental and operational goals, as well as assessing those concepts that appropriately fit within the known constraints of the University's existing systems and financial realities.

A brief discussion of some of these issues is considered before making economic comparisons.

Conversion to HW – Steam systems have traditionally been used to distribute heat through large campuses because of the inherent advantage of relying on the latent heat of vaporization rather than sensible heat. Saturated steam at 100 psig condensed and cooled to 180°F is approximately 1040 Btu/lb. A hot water system with a 100°F temperature difference is able to transfer approximately 103 Btu/lb, requiring approximately 10 times more mass transfer than a steam system.

Although the steam system requires less mass transfer, it has a much lower density, resulting in similar piping distribution costs as hot water systems. The existing steam system was evaluated (see Section 3, Condition Assessment) to determine the cost of repairing and maintaining the system over the duration of the study. This cost is compared to the cost of installing a entirely new hot water system.

The steam distribution system feeds buildings using steam coils to heat the building and newer building HVAC systems designed for hot water. Buildings using hot water have a steam-to-hot water interface at the building. Those buildings with steam HVAC systems will need to be converted to hot water and the existing hot water systems evaluated to determine if the lower grade heat and smaller temperature differences will require modifications to the existing HVAC systems.

The total capital cost to convert the campus from steam to low temperature hot water was estimated to be $237,672,000. The estimated steam distribution loss is approximately 50,000 pph. A HW distribution system would reduce those losses to the equivalent of approximately 25,000 pph, saving approximately 25,000 pph of heat throughout the year. At a billing rate of $20 per thousand pounds of steam, the approximate annual savings in distribution heat loss with heating water is $ 4.4 million. The simple payback period with the conversion to heating water is approximately 54 years.

Central System versus individual building based systems – U of I currently employs a centralized plant approach to effectively meet the campus utility requirements, rather than operating with dedicated building generated utilities. A central plant localizes heating and cooling sources and distributes steam or heated water and chilled water throughout the campus for individual building consumption.

Many campuses are looking to stay with distributed building systems or move to distributed systems for various reasons, including

- Typically, building based systems require a lower level of sophistication to operate and maintain compared to centralized steam systems.
- The distributed systems are typically financed with each individual building.
- Can have slightly more efficient condensing boilers (86% seasonal efficiency) when compared to centralized steam systems (80 to 85%).
- Centralized utilities have losses in the distribution system that can approach 10% of the peak capacity.
- Distributed systems allow a campus to install newer technology as the campus grows.

Central plants require smaller total boiler and chiller capacity due to load diversity between buildings (as low as 65%) and less firm-capacity equipment. The peak diversified heating demand for the U of I campus is 600 kpph. To provide the same level of redundancy with individual building boilers, an installed capacity of 1,290 kpph would be required. In addition to smaller total capacity, less total space is required for the equipment with the central generation of utilities.

It is more cost effective to add redundancy (firm capacity) to a central plant versus each individual building. Firm capacity in individual buildings requires an additional piece of equipment at each building as opposed to one additional piece of equipment for the entire campus with a central system. Centralized plants typically have industrial equipment compared to commercial equipment for decentralized utility systems, resulting in longer useful life.

Similarly, it is easier to operate and maintain equipment centrally than if the equipment is spread throughout the campus.

Annual operation and maintenance costs for a centralized plant are less than those for a decentralized plant due to the increased number of pieces of equipment and the need to maintain equipment spread across campus[1].

The cost to connect a new building to a centralized plant using direct buried pipe is significantly less than the cost of installing dedicated building equipment that provides firm capacity. Past project have indicated initial costs are roughly 40% lower for connections to existing systems versus an individual building plant.

Centralized systems allow a more flexible building usage. Many times changes in building use or research programs can be met without requiring modifications to equipment in the building.

In addition, centralized systems generally are often multi-fuel plants reducing the risk of sudden increases in energy costs compared to dedicated single fuel building plants.

Fuel – Section 5, Risk Management, examines the availability and cost of fuel choices. The decision to continue to utilize coal and natural gas was examined along with the availability, cost, safety and sustainability of alternative fuels including refuse derived fuel (RDF), urban wood waste, energy crop (switchgrass), forestry biomass (wood chips), liquid biomass, biomass of opportunity and even algae. In a simplified world where the primary objective for Energy Services would be to delivery low-cost, reliable energy supply to the University, deciding to continue the ability to utilize coal would be a fairly straightforward decision. It makes sense on many fronts. First, it provides fuel flexibility, which enables the University to choose to burn coal or natural gas. This flexibility provides the University with natural hedging opportunities against price and supply risk. Second, the University, with coal reserves, has a built in back-up supply of fuel to guard against fuel supply interruptions. Third, the University has a utility staff well trained in running an efficiently operated coal-fired plant.

This decision becomes more complicated when social and reputational concerns come into the picture. In an effort to protect the university against current reputational concerns the University may be required to do something with the Energy Services operations that it would not do otherwise. External regulatory forces might ultimately require the University to terminate the use of coal, but absent external mandates the University should be cautious about terminating an operation that provides a valuable level of operational and economic flexibility.

The campus heating systems provide approximately 2,000,000 klb of steam a year to heat the buildings on campus. Of that heating load, approximately half of the energy is provided by solid

[1] Making Energy Supply Decisions at U.S. Army Installations, Vicki L Van Blaricum, U.S. Army Construction Engineering Research Laboratory.

fuel boilers. To offset the solid fuel boilers, a dedicated energy crop such as switchgrass would require up to 9,000 acres of cropland and 3,600 truck deliveries on campus each year.

Illinois has a Solid Waste Act that prohibits the burning of wastes in boilers. The Solid Waste Act defines the burning of waste as incineration. As interpreted by IEPA's Bureau of Land, the definition of "waste" under the Solid Waste Act has been very stringent, significantly more so than in other states or under Federal regulations. As a result, what may be considered biomass fuel in other states, such as urban wood waste, often is considered waste in Illinois.

As discussed in Section 5, the ability to obtain a long-term contract for biomass fuels such as woody biomass is difficult and is critical before deciding to switch to a biomass fuel.

Electric supply – The campus receives up to 60 MW electrical power from Ameren IP and currently has a peak demand of 80 MW. Any power demands above 60 MW are provided by APP and the campus 5.88 MW solar farm. Options to provide the additional power ranged from increasing the import capacity of renewable technologies such as wind turbines or solar PV, developing a second electrical generating facility on campus, to fuel cells or small nuclear reactors.

There are many benefits associated with investments in renewable energy. One of the primary benefits is the opportunity to avoid market risk volatility associated with commodity purchases. This benefit is associated with resources such as wind and solar through long-term purchases. The primary challenge associated with investments in renewable energy is capital cost risk. Over the past few years renewable energy investments have become much more cost effective, but often still require significant subsidies to compete with traditional energy sources. Unless cost effective options exist today, or significant subsidies exist, it may be more beneficial to delay investment in significant renewable energy opportunities. Issues associated with using wind or solar photovoltaic energy to provide firm capacity to the campus deal with the low capacity factors for renewable energy. According to observations available from NREL the photovoltaic capacity factor for this part of the country is approximately 14-17% and 33 to 38% for wind. Because of the high capital costs and low availability, renewable energy will be used as a supplement.

Fuel Cells: Fuel cell technology has significantly advanced. The high capital cost of fuel cell technology reduces the cost effectiveness of this technology presently, but should be examined again in the future.

Small Scale Nuclear Reactors: The investigation of small-scale nuclear reactors showed promise with regards to providing reliable power with low environmental impact. These technologies are currently not commercially available and should be examined again in the future.

Building Level Steam Turbines – Building level steam turbines (micro turbines) are small scale steam turbines that are used in lieu of or in parallel to building steam pressure reducing (PRV) stations. The concept is to utilize the pressure in the distribution system that is typically reduced through the PRV station and produce usable power. It should be noted that there is no energy loss through a steam pressure reducing station being a constant enthalpy process.

Factors favoring building level steam turbines include:

- High steam distribution pressure. As stated previously, a relatively high PRV station pressure drop is required to make this system economically attractive. Distribution systems typically transport high pressure steam. Typical building pressures required downstream of the PRV station is approximately 15 psig.

Issues that would need to be considered:

- First cost for installing building level steam turbines. The first cost for this technology is approximately $3,500 per KW.
- Building level steam turbine sizing. The steam turbines do not have a high turndown, typically 2:1 or 3:1. Therefore to fully utilize the steam turbines the load either needs to be relatively constant, without major load swings or the steam turbine needs to be sized for a load that is less than the peak of the building to maximize the return on investment. Therefore, this technology will be well suited for laboratory, research and medical buildings requiring a significant amount of heat throughout the course of the year.

Heat Recovery Chillers (HRC) and Geothermal – A HRC can be used to recover heat that is typically rejected to atmosphere through cooling towers, and utilize this heat for building heating systems. Sizing of HRC systems needs to be carefully evaluated so that all of the recovered heat can be utilized. The building heating systems need to be modified to utilize lower temperature hot water systems. Hot water generation temperatures are limited to the size and type of the equipment, and vary from 130 to 170°F depending upon the system selected. The installation of HRC systems can potentially reduce the amount of central cooling and heating plant demands, peak output and related energy consumption and in parts of the country with green electrical supply, lower GHG emissions.

Heat recovery chillers or heat recovery equipment can be used in multiple arrangements to improve the overall system efficiency and meet the thermal needs of the campus. Heat recovery chillers or equipment can be implemented on a small scale or large scale. The small scale would consist of heat recovery equipment being installed inside of new or existing buildings. The large scale would consist of heat recovery equipment being installed in a central plant with both hot water and chilled water distribution systems. In some instances the use of thermal storage (both hot and chilled water) or ground source / sink can be used to mitigate load swings and keep heat recovery equipment active and performing.

Options for implementation of heat recovery chillers are typically restricted to locations where there is a substantial amount of thermal overlap that occurs in large medical or research facilities. From a review of campus development and central plant distribution systems there appear to be opportunities for implementation of HRC systems near the research labs.

Simultaneous heating and cooling demands are required to fully utilize the heat recovery system equipment. Therefore, these systems are best applied in densely developed precincts or individual buildings. Additional building mechanical room space is required for the installation of the HRC system. The HRC system also requires new hot water distribution systems to be installed. As such it is best applied in buildings or precincts that require high levels of outdoor air, such as research or medical buildings.

The successful application of a heat recovery system relates directly to the ability of the campus utility systems to extract "low-grade" heat from one portion of the campus and transfer it to other portions of the campus as efficiently as possible. The characteristics of the heating and cooling over-lap load must be understood and modeled such that it can be best utilized to maximize performance of the heat recovery system equipment.

Heat recovery system equipment is typically evaluated on the following:

Coefficient of Performance: The Coefficient of Performance (COP) is defined as the useful heat generated divided by the energy input (COP = BTUout ÷ BTUin). A typical heat pump is capable of producing approximately 17,000 BTU of hot water (condenser water) per ton (12,000 BTU) of chilled water. The typical heat pump has a heating COP of 3.4 and higher, and a corresponding chiller efficiency of approximately 0.85 ~ 1.1 kW per ton. The coefficient of performance of heat recovery equipment is dependent upon leaving hot water and chilled water temperatures. Lowering the difference between the two water temperatures will result in a higher coefficient of performance

Hot Water Temperature: The leaving hot water temperature is limited by the size / type of heat pump. A centrifugal heat pump is capable of producing a maximum of 155°F leaving hot water temperature and compound centrifugal heat pumps are capable of producing leaving hot water temperatures in excess of 155°F.

The hot water supply temperature range can also limit the available heat recovery equipment manufacturers. JCI/York International offers two models which can produce 170°F hot water with a 40°F rise – the CYK and Titan OM. JCI / York has been able to increase the capability of the CYK from 150°F to 170°F hot water within the past few years through improved compressor technology. Currently, no other domestic manufacturer offers capabilities above 150°F hot water supply temperatures or size above 10 MMBtu / 600 ton. Supply temperatures in excess of 170°F will require hot water boilers to supplement the heat recovery equipment. Conversely, from an energy perspective it is desirable to have as a low as a hot water supply temperature as possible. Therefore, the optimum supply temperature will be determined in conjunction with a building conversion analysis and will need to consider energy consumption, conversion cost, the cost of distribution piping and the net present value. Note that this may involve a seasonal reset of hot water supply temperature.

Biomass Gasification – is a thermal conversion technology where a solid fuel is converted into a combustible gas, also known as synthesis gas (syngas). The process is an extremely efficient means of extracting energy from biomass.

The principle of gasification is to heat biomass materials at low equivalence ratios or in a fully oxygen-starved environment to break the bonds between carbon-hydrogen compounds with high molecular weight and converting them to hydrocarbons with low molecular weight that can be used more conveniently.

Gasification relies on endothermic reactions taking place at elevated temperatures in excess of 1200°F, distinguishing it from the natural biological process of anaerobic digestion that produces biogas. Any biomass can undergo gasification making it attractive when compared to ethanol production or biogas where only selected biomass materials can be used to produce the fuel. This allows the gasification process to utilize feedstock that is not otherwise useful fuels, such as certain recalcitrant feeds and organic waste. Large-scale gasification technologies have been demonstrated using a variety of agricultural and industrial residues such as waste tires and refuse-derived fuel (RDF).

Biomass feed often has a variety of contaminants that can limit its potential as a viable fuel source. The high temperatures in the gasification process help to remove corrosive ash elements such as chloride and potassium, allowing clean gas production from otherwise problematic fuels.

The specific syngas composition depends on the fuel source as well as the gasifier design. The same fuel may offer different heating values and gas qualities when processed in two different gasifiers. Fuel type and downstream gas utilization are the two major factors in determining what type of gasification system best suits a given application. The syngas would have to undergo some degree of cleanup/treatment at the biomass plant to avoid buildup of tar in the pipeline or boilers.

Considerations

- Fuel Supply: As sized for this analysis, it is estimated that some of these options could require very large amounts of biomass fuel. Research would be required to determine the amount of biomass that could be sustainably generated within a reasonable distance from the user.
- Emissions Reduction: As a renewable energy source, the carbon emissions from the use of biomass as a fuel are considered to be zero for greenhouse gas accounting purposes. Also,

the high temperatures and efficiencies achieved by biomass gasification systems produce lower emissions of other air pollutants typically seen from conventional combustion systems.
- Systems Complexity/Compatibility: The systems modeled for these options are based on actual systems that are commercially available. Also, the pairing of certain equipment would need to be verified (e.g., use of syngas in existing and or new boilers).

Biomass combustion – is the direct burning of a biomass in a boiler to produce thermal energy. Facilities can burn many types of biomass fuel, including wood, agricultural residues, wood pulping liquor, municipal solid waste (MSW) and refuse-derived fuel (RDF). Combustion technologies convert biomass fuels into several forms of useful energy for commercial or industrial uses: hot air, hot water, steam and electricity.

A biomass-fired boiler transfers the heat of combustion into steam. Steam can be used for electricity, mechanical energy or heat. Biomass boilers supply energy at low cost for many industrial and commercial uses, although the cost of biomass delivered to Champaign, IL is higher than the cost of existing solid fuels. A boiler´s steam output contains 60 to 85 percent of the potential energy in biomass fuel. The major types of biomass combustion boilers are pile burners, stationary or traveling grate combustors and fluidized-bed combustors.

Pile burners consist of cells, each having an upper and a lower combustion chamber. Biomass fuel burns on a grate in the lower chamber, releasing volatile gases. The gases burn in the upper (secondary) combustion chamber. Operators must shut down pile burners periodically to remove ash. Although capable of handling high-moisture fuels and fuels mixed with dirt, pile burners have become obsolete with the development of more efficient combustion designs with automated ash removal systems.

In a stationary or traveling grate combustor, an automatic feeder distributes the fuel onto a grate, where the fuel burns. Combustion air enters from below the grate. In the stationary grate design, ashes fall into a pit for collection. In contrast, a traveling grate system has a moving grate that drops the ash into a hopper.

Fluidized-bed combustors burn biomass fuel in a hot bed of granular material, such as sand. Injection of air into the bed creates turbulence resembling a boiling liquid. The turbulence distributes and suspends the fuel. This design increases heat transfer and allows for operating temperatures below 972° C (1700° F), reducing nitrogen oxide (NOx) emissions. Fluidized-bed combustors can handle high-ash fuels and agricultural biomass residue.

Conventional combustion equipment is not designed for burning agricultural residues. Straws and grasses contain potassium and sodium compounds. These compounds (called alkali) are present in all annual crops and crop residues and in the annual growth of trees and plants. During combustion, alkali combines with silica, which is also present in agricultural residues. This reaction causes slagging and fouling problems in conventional combustion equipment designed for burning wood at higher temperatures.

Volatile alkali lowers the fusion temperature of ash. In conventional combustion equipment having furnace gas exit temperatures above 1450° F, combustion of agricultural residue causes slagging and deposits on heat transfer surfaces. Specially designed boilers with lower furnace exit temperatures could reduce slagging and fouling from combustion of these fuels. Low-temperature gasification may be another method of using these fuels for efficient energy production while avoiding the slagging and fouling problems encountered in direct combustion.

Considerations

- Fuel Supply: As sized for this analysis, it is estimated that some of these options could require very large amounts of biomass fuel. Additional research would be required to determine the amount of biomass that could be sustainably generated within a reasonable distance to the plant and at what cost.
- Emissions: As a renewable energy source, the carbon emissions from the use of biomass as a fuel are considered to be zero for greenhouse gas accounting purposes. However, direct combustion of biomass may result in significant emissions of some air pollutants that would need to be evaluated further. This is one major difference between direction combustion and gasification of biomass. Gasification systems generally achieve lower emissions compared to direct combustion.
- Systems Complexity: Either of these options would represent an increase in the complexity of the energy production systems. Such changes would need to be further evaluated from an operations and maintenance standpoint.

Cost and emission rates for various heating sources – Often specific heating technologies are considered to be more efficient or have better emissions than traditional boilers or CHP systems due to publicized applications of these technologies. The following table indicates the energy cost required to produce a million Btu of usable thermal heat for the heating methods being considered on the U of I campus.

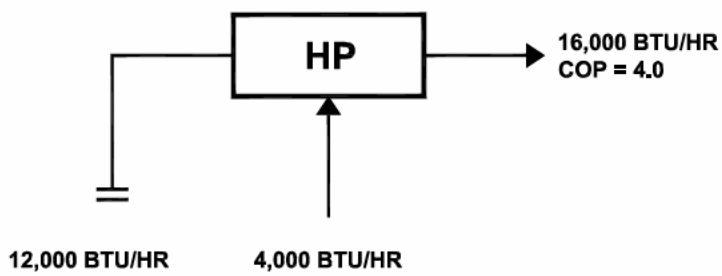
PRELIMINARY SCREENING ANALYSIS - HEATING GENERATION

APPROACH NO.	DESCRIPTION	COST OF HEAT OUTPUT ($\$/10^6$ BTU)
1	GEOTHERMAL HRC	4.58
2	GAS BOILER	7.18
3	COAL BOILER	3.76
4	BIOMASS BOILER	8.75
5	GAS CHP	1.60
6	COAL CHP	1.23

NOTES:

1. ELECTRIC = $0.0626 /KWH
2. GAS COST = $5.89 PER DT
3. "ALL IN" COAL COST = $73.20/TON ($3.23/106 BTU)
4. BIOMASS FUEL COST = $\$7.00/10^6$ BTU
5. GEO HRC COP = 4.0
6. BOILER EFFICIENCY - GAS = 82% COAL = 86% BIOMASS = 80%
7. CT WITH HRSG HR: GROSS = 12,000 BTU/KWH
   NET = 7,000 BTU/KWH

GEO HP



ELECTRIC

$$\text{COST OF HEAT} = \frac{0.0626}{(3413)(4)} \times 10^6 = \$4.58/10^6\ \text{BTU}$$

COAL BOILER

$$\text{COST OF HEAT} = \frac{\$3.23/10^6\ \text{BTU}}{0.86} = \$3.76/10^6\ \text{BTU}$$

BIOMASS BOILER

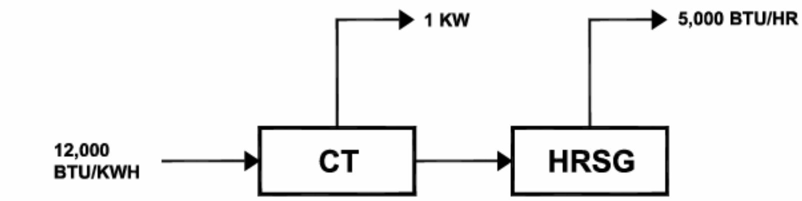
$$\text{COST OF HEAT} = \frac{\$7.00/10^6\ \text{BTU}}{0.80} = \$8.75/10^6\ \text{BTU}$$

(DRY SWITCHGRASS)

GAS BOILER

$$\text{COST OF HEAT} = \frac{\$5.89/10^6\ \text{BTU}}{0.82} = \$7.18/10^6\ \text{BTU}$$

GAS CHP

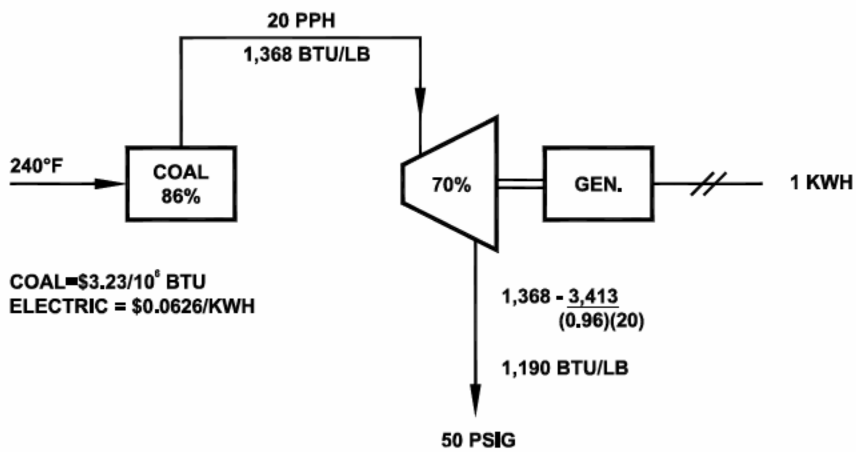


FUEL IN: $(12{,}000)(5.89)/(10^6) = 0.071$

ELECTRIC OUT: 1 KWH @ $\$0.063$/KWH = (0.063)

$\$0.008$ NET FUEL

$$\text{COST OF HEAT} = \frac{\$0.008}{5{,}000} \times 10^6 = \$1.60/10^6 \text{ BTU}$$



$$\text{COAL COST} = \frac{(20)(1{,}368-208)}{0.86}\left(3.23/10^6\right) = \$0.0871$$

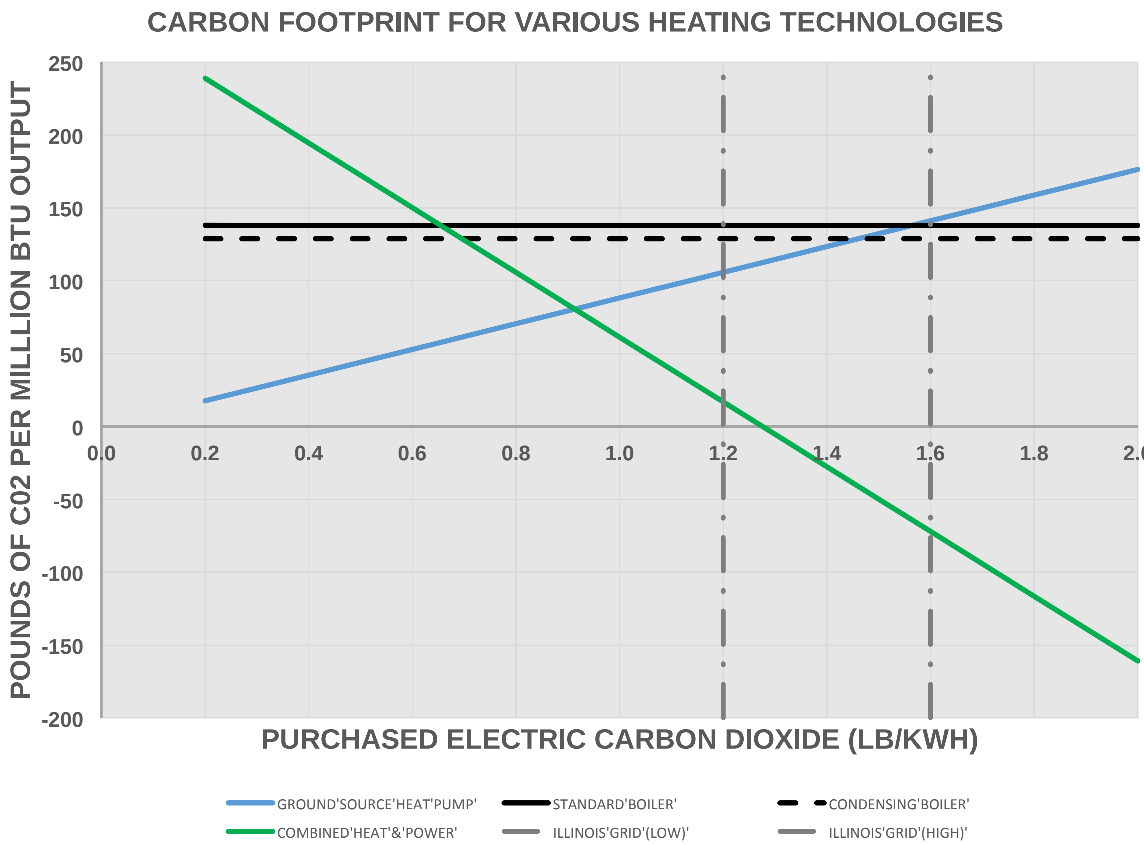
$$\text{ELECTRIC REVENUE} = \langle\$0.0626\rangle$$

$$\text{NET COST} = \$0.0245$$

$$\text{HEAT OUT COST} = \frac{\$0.0245}{(20)(1{,}000)} \times 10^6 = \$1.23/10^6 \text{ BTU}$$

As the table indicates, the most cost effective means to provide heat to the campus buildings is through the use of combined heat and power.

The social impacts of producing heat can be determined by comparing the carbon emissions of each heating method. The following figure indicates the emissions in pounds of CO2 per million Btu of thermal output for various heating sources being considered. When comparing fossil fuels with systems that produce or use electricity such as CHP or electric heating sources such as a heat recovery chiller, the effective emissions must include the emissions associated with the electrical utility grid. CHP systems offset electrical production at an improved efficiency thereby reducing emissions from the utility power plants. Electric heating sources require more electricity to be produced, adding emissions from the power plant. Electricity purchased at the U of I has an emission rate of 1.6 lb CO2 per kWH produced. As the figure indicates, converting from a CHP heat source currently being used to heat the U of I campus to an electric heat source results in increased regional emissions.



In order to develop the options described in this section, several criteria were established with University staff:

- Sufficient chilled water capacity should be provided such that the projected peak chilled water demands would be met with the largest unit out of service, considering all chilled water plants.
- Currently Boilers 5, 6 and 7 share a common air quality control system (AQCS). The AQCS limits the capacity of the coal boilers to 300,000 pph and acts as the largest piece of equipment when determining steam generation firm capacity.
- The University has made the decision to limit the use of the coal boilers to winter months provided adequate gas fired assets are available to serve the campus load.
- Sufficient boiler capacity should be provided such that the projected peak steam demand would be met with the largest unit (or single point of failure) out of service.
- Sufficient electric capacity should be provided such that the projected peak electric demand would be met with the largest single source of power out of service.

The economic performance of each option was evaluated using an integrated energy planning model (IEPM) which valued each option relative to a reference case. The reference case assumes that the University continues to operate and maintain the Abbott Power Plant as a fuel diversified cogeneration facility with continued retrocommissioning in the buildings.

The reference case was modeled in the IEPM incorporating the following elements:

- A 35-year forecast period modeled at monthly intervals
- Forecasted monthly campus energy demands for 35 years
- All central equipment including considerations of useful lives, available capacities, typical operating characteristics, operation and maintenance expenses as well as projected replacement assets.
- Distribution system efficiencies, characteristics, operation and maintenance expenses as well as projected replacement assets.
- Typical central plant fuel mixes forecasted as a result of the current operating philosophy.
- Forecasted energy prices for all fuels and purchased electricity.

Each option was modeled in the IEPM relative to the reference case. Specifically, each option was modeled with the intent to illustrate the incremental impact on each of the elements of the reference case. Incremental capital expenses, operating expenses, efficiencies, fuel mixes and demand profiles were incorporated for each option into the model. The incremental impact on the following key metrics are reported from the model:

- Cost of utility service
- Invested capital
- GHG emissions
- % reliance on coal
- Electric reliability
- Steam reliability
- Chilled water reliability

Many options list assets being replaced at the end of their useful life. The IEMP can be modified to determine the financial impact of replacing assets at an earlier or later date. A more detailed description of the calculations used in the IEMP are provided in Appendix 7A.

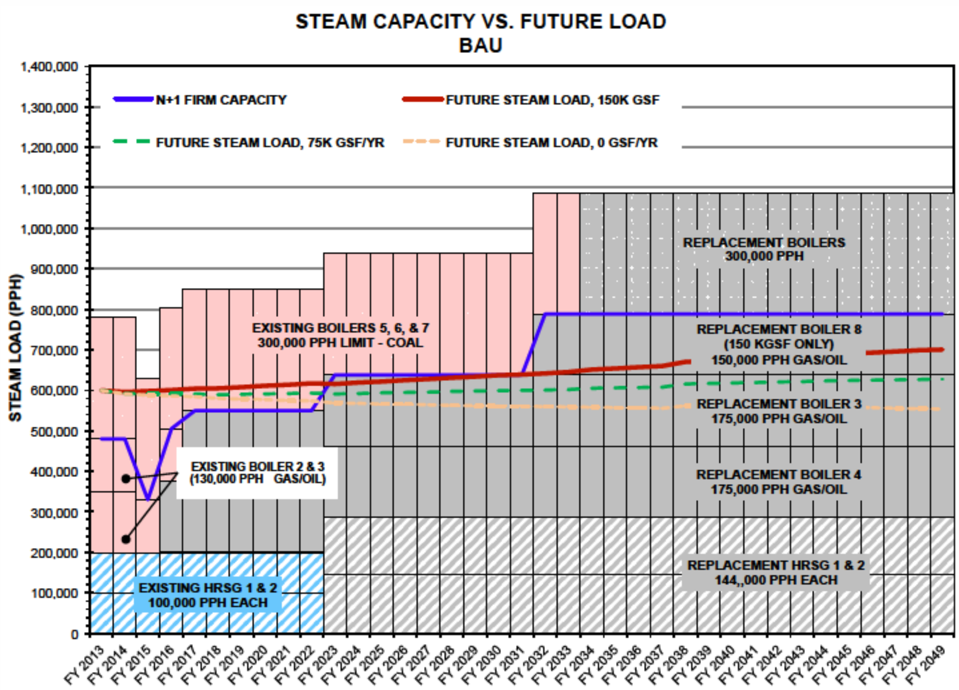
7.2 Business as Usual

The Business as Usual (BAU) case represents the costs to provide utilities on campus if present operations continued. Since the BAU is the reference case against which all other scenarios are compared, it must be a viable solution for meeting the needs of the campus over the next 35 years. Therefore, the capacity of the utility systems in the BAU model are sized to meet the highest campus demand (150k GSF/year growth over 35 years) with firm capacity. The BAU case must have firm capacity able to provide 700 kpph campus send out steam, 49,500 tons firm chilled water capacity and 110 MW firm electric power in 2049.

Heating – Under this approach, Boilers 3 and 4 are replaced with dual fuel (natural gas / fuel oil) boilers at 175 kpph each. Boilers 5, 6 and 7 are replaced with two coal-fired boilers when they reach the end of their useful life, at 150 kpph each. The BAU case assumes continued use of coal during non-summer months and treats Boilers 5, 6, and 7 as a single 300,000 pph asset due to a common air quality control system (AQCS). Combustion Turbines 1 and 2 are equipped with inlet air cooling and continue to be maintained and the heat recovery steam generators (HRSG) and duct burners are replaced with units resulting in 144 kpph of steam each.

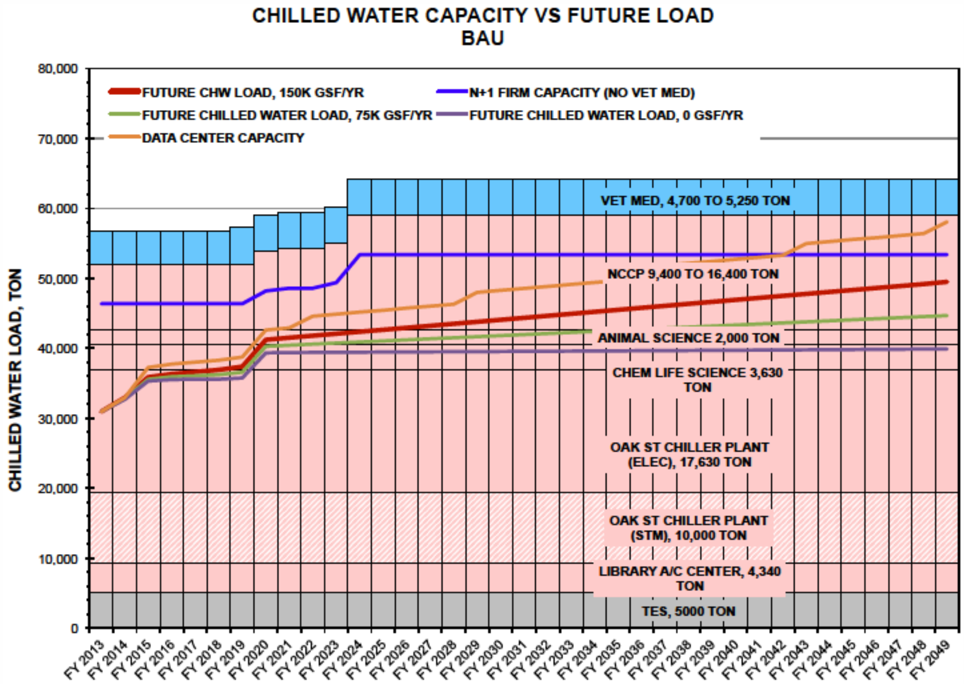
The following figure indicates the BAU heating equipment replacement. Boiler 4 currently is not operational and will be replaced in 2016. Boiler 3 will be removed in 2015 while Boiler 4 is installed and will be replaced in 2017. Boiler 2 will be removed with the installation of Boiler 3 in 2017. **Due to the single point of failure in the AQCS system, there are approximately 200 hours a year when APP does not have adequate firm capacity. The current BAU would not meet firm capacity until 2023 when the HRSGs are replaced.** The lack of firm capacity would necessitate the addition of a rental boiler connection to provide additional steam capacity if required.

At 150 kGSF/yr campus growth rate, the campus load will be greater than the firm capacity of the plant in 2032, and an additional 150,000 pph dual fuel natural gas / fuel oil units at 850 psig will need to be installed. A growth rate of 150 kGSF/yr also results in higher than recommended steam velocities in the distribution system, triggering a steam piping upgrade in 2034.



Cooling – As the campus chilled water loads increase, the BAU model assumes the load is met by replacing chillers in the Vet Med and North Campus Chiller Plant with larger units as the existing chillers reach the end of their useful life.

The following figure indicates the BAU cooling equipment replacement. Chiller 2 in Vet Med is replaced with a 1,200 ton centrifugal electric chiller when it reaches the end of its useful life. Chillers 1, 4, 5, and 6 in the North Campus Chiller Plant are replaced with 2,800 ton variable-speed-drive (VSD) chillers. Chiller 7 is replaced with a 2,000 ton chiller. Chillers 2 and 3 are replaced with 1,200 ton machines.



Power – The BAU case assumes a significant amount of self-generated power with up to 50 MW combined heat and power production and a 5.8 MW solar farm. The campus currently has a contract with Ameren IP to provide 60 MW of power to the campus. The power is supplied to U of I Main Campus Substation (MCS). In the summer, Combustion Turbines 1 & 2 produce 11 MW each until 2018 when inlet air cooling is added and the capacity increases to 13.5 MW each.

Total and Firm Capacity: The electrical capacity of the steam generation equipment at APP is dependent on how much steam is dispatched to campus as well as condensed through a STG. The campus steam demand (send out) in the summer of 2014 was 84,900 pph campus pressure (CP, 50 psig) steam and 160,700 pph high pressure (HP, 150 psig) steam. In plant usage is estimated at 9% of the steam produced, or 41.4 kpph in 2014.

The following lists the heat balance for one typical operating scenario at APP with the intent to maximize electrical production in 2014.

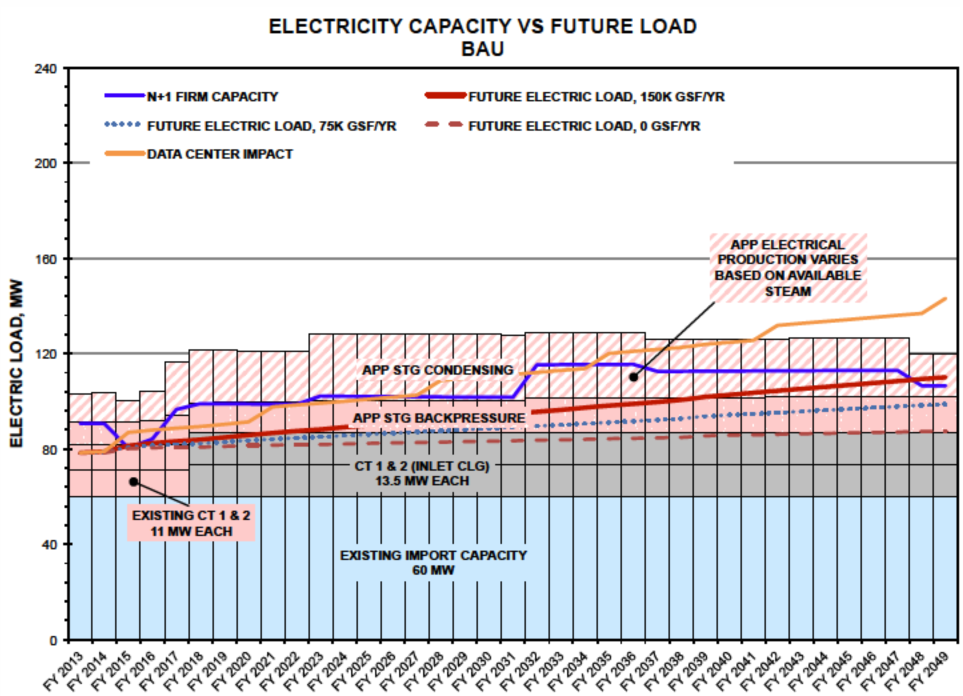
- No Coal usage during the summer, two HRSG/DBs produce 200,000 pph of steam at 850 psig.
- Boilers 2 and 3 produce 260,000 pph of steam at 325 psig.
- 136,000 pph of steam is passed through STG-10 resulting in 7 MW power, 36 kpph of 50 psig (campus pressure – CP) and 100 kpph of 150 psig (high pressure – HP) steam.
- The remaining 64 kpph of 850 psig steam is used to produce power in STG-6 (condensing mode) to produce an additional 6.4 MW of power.

- 48.7 kpph passes through the 325 to 150 pressure reducing valve resulting in 57 kpph HP steam to meet the remaining HP steam requirements.
- 88.4 kpph passes through STG-2 (backpressure) to meet the remaining CP steam requirements, producing 2.6 MW power.
- 73 kpph of the remaining 81 kpph is passes through STG 1 & 3 (condensing) to produce another 6 MW of power.

The resulting production is 84.9 kpph send out at CP, 160.7 kpph at HP, 9.6 MW produced using backpressure steam turbine generators and 12.4 MW produced using condensing steam turbine generators.

The resulting electrical capacity is 104.0 MW. Firm electrical capacity is calculated by assuming one of the CTs is out of service. The reduced electrical capacity is the loss of generation plus the loss of electricity produced from the CT/HRSG/DB generated steam. The resulting firm electrical capacity is 90.7 MW. A similar analysis is conducted for each year of the study to estimate the total and firm capacity of the campus power supply.

The BAU model assumes the STGs are replaced with 850 psig units when they reach the end of their useful life. STGs 2, 9 & 10 are replaced with backpressure units, STG 9 with a 10 MW unit in 2017, STG 2 with a 3 MW unit in 2030, and STG 10 with a 7.5 MW unit in 2048. STGs 1, 3, & 4 are replaced with extraction/condensing STGs, STG 1 with a 3 MW unit in 2030, STG 3 with a 3 MW unit in 2037, and STG 4 with a 3 MW unit in 2017. Remaining useful life of STGs 6, 7 & 8 is beyond the duration of this study.



The effect of continued data center growth on campus is examined by considering the addition of a 5 MW data center every 7 years on campus. Under this condition, the campus demand would exceed the electrical production firm capacity and additional electrical generating assets or additional import capacity would be required.

Estimates of probable cost were developed for the equipment replacements in the BAU and for each option. The detailed estimates are provided in Appendix 7B. The following table indicates the major capital expenditures during the duration of this study in 2014 dollars. The IEMP model inflates the probable costs and then calculates the present value of the capital expenditures using a discount rate. Results shown are based on a fixed inflation rate of 2.5% and a fixed discount rate of 5%. The IEMP model is capable of examining multiple financial scenarios including variable rates.

BAU CAPITAL COSTS

DESCRIPTION		PROJECT COSTS ($)
ABBOTT POWER PLANT		2,229,000
GAS BOILER 3 & 4	175 KPPH @ 850 PSIG	19,006,000
GAS BOILER 2 (150 KGSF ONLY)	175 KPPH @ 850 PSIG	9,503,000
COAL BOILER 5 & 6	150 KPPH @ 850 PSIG	54,152,000
COAL YARD, ASH HANDLING, AQCS		22,855,000
INLET COOLING CT 1 & 2		700,000
HRSG/DB 1 & 2	144 KPPH @ 850 PSIG	27,228,000
STG 1, 3, 4	3 MW	19,926,000
STG 2	3 MW	6,418,000
STG 6	7.5 MW	10,462,000
STG 8 & 9	12.5 MW	26,914,000
STG10	7.5 MW	9,900,000
STEAM DISTRIBUTION		30,070,000
STEAM DISTRIBUTION - (150 KGSF ONLY)		17,780,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES 1. COSTS IN 2014 DOLLARS

2. SOLAR PPA $196/MWH THRU 2024

7.3 Options

The planning portion of the utility master plan commenced with an inclusive ideation process seeking input from campus stakeholders. This activity resulted in nearly 200 individual concepts for meeting the future utility needs of the campus. Concepts ranged from central multi-fuel cogeneration plant(s) to conventional stand-alone building systems. In addition to conventional energy sources, biomass, solar, wind, geothermal, and small nuclear reactors were included. Each concept was discussed and refined based on consideration of several factors including technical viability, scalability, cost and sustainability.

The refinement process resulted in multiple viable options that were grouped into four main themes.

Theme 1 – Cogeneration with natural gas (NG) as primary fuel with oil backup and continued power production

Option 1.1 – Increase power import limit and retire coal boilers at Abbott Power Plant (APP). Continue to produce power at APP with combustion turbines (CT) and back pressure (BP) steam turbine generators (STG). Install natural gas boilers at APP to meet campus heating demand.

Option 1.2 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CTs and BP STGs. Develop a second cogeneration plant in North Campus using combustion turbines and auxiliary saturated steam boilers at 150 psig. Locate plant to avoid steam piping upgrades.

Option 1.3 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CTs and BP STGs. Develop a second steam heating-only plant in North Campus using natural gas fired saturated steam boilers at 150 psig with oil backup. Locate plant to avoid base case steam piping upgrades.

Theme 2 – NG as primary fuel with no power production (conventional heating only)

Option 2.1 – Increase power import limit and retire coal boilers at APP. Eventually convert APP to a heating-only plant with no power production once the CT and STG equipment reaches the end of its useful life. Install natural gas boilers at APP to meet campus heating demand.

Option 2.2 – Increase power import limit and retire coal boilers. Eventually convert APP to a heating-only plant with no power production once the CT and STG equipment reaches the end of its useful life. Develop a second NG fired heating-only plant on North Campus. Locate plant to avoid base case steam piping upgrades.

Option 2.3 – Increase power import limit and convert entire campus to individual NG fired condensing hot water generators. Eliminate APP and all steam distribution piping. Install new NG piping to all buildings.

Theme 3 – NG as primary fuel with partial renewables (wind, solar, geothermal, biomass)

Option 3.1 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install biomass-fired circulating fluidized bed (CFB) boilers at APP.

Option 3.2 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install natural gas boilers at APP. Install new heat-recovery chiller plant in North Campus.

Option 3.3 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install natural gas boilers at APP. Install wind farm on south campus.

Option 3.4 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install natural gas boilers at APP. Install solar farm on south campus.

Option 3.5 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install syngas/NG fired boilers at APP. Develop gasification plant on South Campus with syngas piping to APP.

Theme 4 – Full renewables and alternative fuels (biomass, geothermal)

Option 4.1 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install syngas/NG fired boilers at APP. Develop gasification plant on South Campus with syngas piping to APP.

Option 4.2 – Increase power import limit and retire coal boilers at APP. Continue to produce power at APP with CT and BP STG. Install natural gas boilers at APP. Add campus-wide geothermal enhanced heat recovery chiller plant and convert entire campus to hot water heating.

The options listed were modeled to calculate the cost of utility services, operations, maintenance and repair costs, greenhouse gas emissions, increased land usage required, redundancy of installed capacity (thermal and electric), and capital requirements. Each model was based on assumptions related to campus growth, level of continued energy conservation, data center growth, and financial terms.

It is important to discuss the purpose and limitations of the utility business model. The model is useful for macro utility planning. The parameters of the model can be modified on a global perspective, and the resulting economics as well as risks and opportunities identified. The model examines monthly utility demands and calculates the fuel required to meet these demands. The model is not intended to be used to dispatch equipment.

In addition to the modeled options described in the four themes, the utility business model includes a series of user selections. The selections include

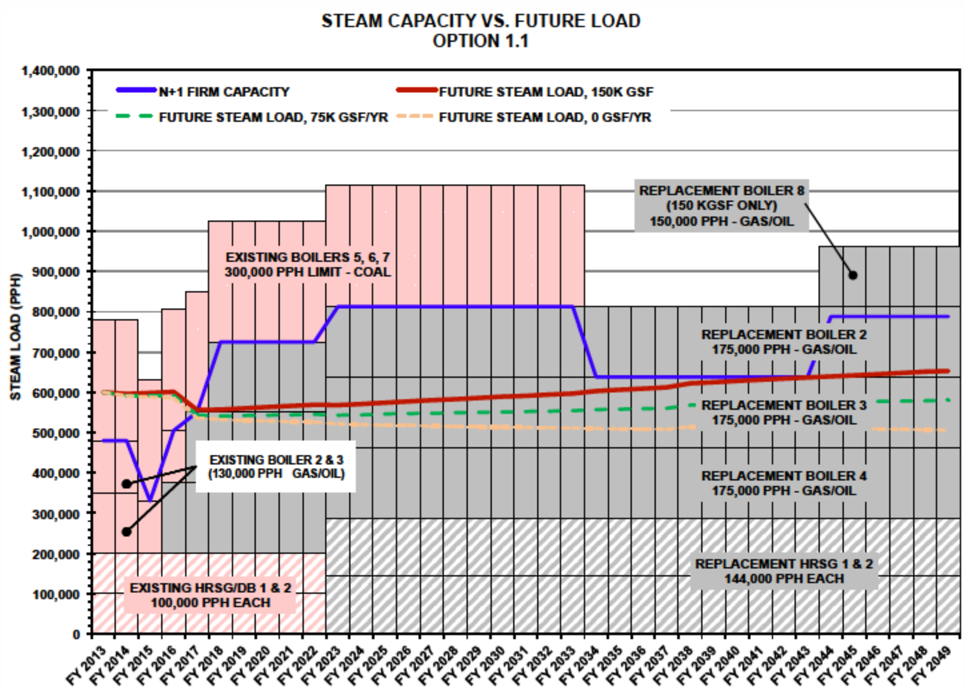
- Campus growth rate – 0 GSF/yr, 75k GSF/yr and 150k GSF/yr
- Additional thermal energy storage – none, 6,000,000 Gal additional TES
- Campus data center growth – none, 5 MW data center every 7 years
- Campus conservation programs – none, Retro-Cx, deferred maintenance, ESCOs, and preventative maintenance
- Standby power generation – none, building generators, regional emergency generation

Results presented in the report include user selections for no thermal storage, no standby power generation, no campus data center growth, and campus conservation as shown in Appendix 7C.

Theme 1 – Cogeneration with natural gas (NG) as primary fuel with oil backup and continued power production

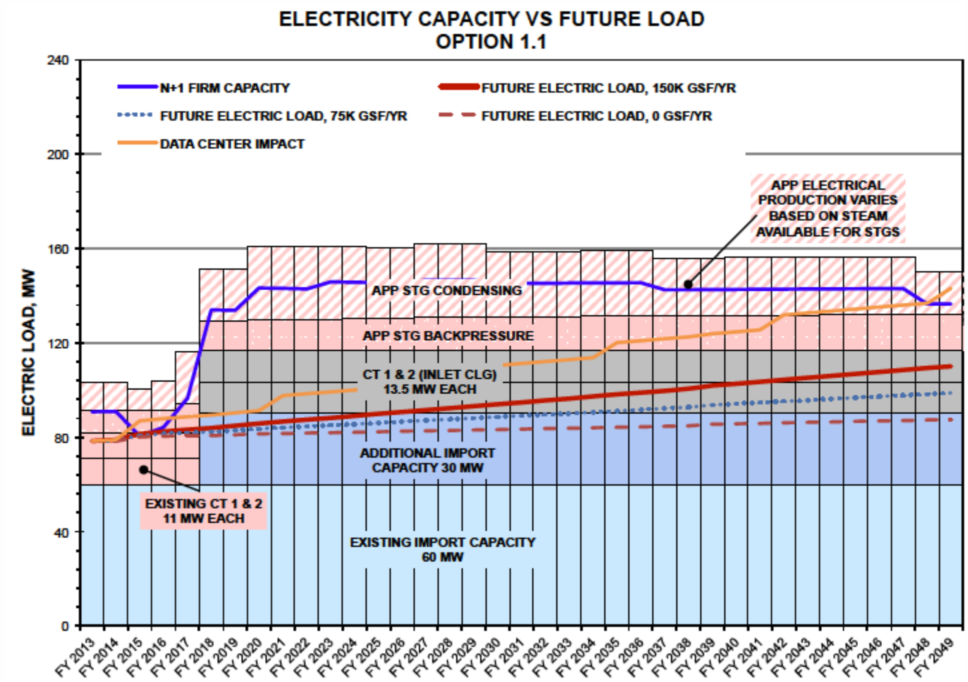
Option 1.1 phases out the use of coal at Abbott Power Plant. The following figure indicates the steam capacity versus future heating load for the study growth scenarios. Boilers 3, 4 and 2 are replaced with natural gas / fuel oil units at 175,000 pph capacity each. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. The combustion turbines continue to be maintained and the HRSG and duct burners are replaced with 144,000 pph units at the end of their useful life. Efficiency of a natural gas boiler is 82% compared with 86% efficient coal boiler.

At a 150 kGSF/yr campus growth rate, the campus heating load will increase beyond the firm capacity of the plant in the year 2044, and an additional 150,000 pph dual fuel natural gas / fuel oil units at 850 psig is installed.



Chilled water production and distribution remain the same as the BAU case.

The following figure indicates the electric capacity versus future electric load for the study growth scenarios. Similar to the BAU, CT 1 and 2 are maintained and the capacity is increased to 13.5 MW each with the addition of inlet air cooling in 2018. The extraction/condensing STGs are retired at the end of their useful life. Backpressure STG 2 is replaced with a 3 MW 850 psig unit in 2030, STG 9 is replaced with a 10 MW 850 psig backpressure unit in 2017 and STG 10 is replaced with a 7.5 MW 850 psig unit in 2048. The power import capacity is increased for improved reliability, utility cost reduction and operational flexibility.



The power import capacity is increased by adding two 69kV feeds to the Southeast Campus Substation as illustrated in the following figure – Campus one-line diagram with increased import.

The location of the new switchyard is identified in the following figure. The switchyard would be built adjacent to the Ameren South Orchard Substation and ductbank and cable routed to the U of I Main Campus Substation and Southeast Campus Substation. System reliability would improve with four 69kV feeds each capable to supply over 35 MW of power each.

The following table indicates estimates of probable project costs for the equipment replacements in Option 1.1. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 1.1 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
GAS BOILER 3, 4 & 2	175 KPPH @ 850 PSIG	28,509,000
INLET COOLING CT 1 & 2		700,000
HRSG/DB 1 & 2	144 KPPH @ 850 PSIG	27,228,000
STG 2	3 MW	6,418,000
STG 9	10 MW	11,210,000
STG10	7.5 MW	9,900,000
STG DEMOLITION		2,628,000
GAS BOILER 8 (150 KGSF ONLY)	150 KPPH @ 850 PSIG	8,695,000
STEAM DISTRIBUTION		30,070,000
STEAM DISTRIBUTION - (150 KGSF ONLY)		17,780,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 1.1 and the BAU cases.

OPTION 1.1 LIFE CYCLE COST SUMMARY ($ MILLIONS)													
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS								
	ABBOTT PP												
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
1.1		•			44	567	—	414	1,025	391	221	1,638
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
1.1		•			49	601	—	480	1,137	393	236	1,767

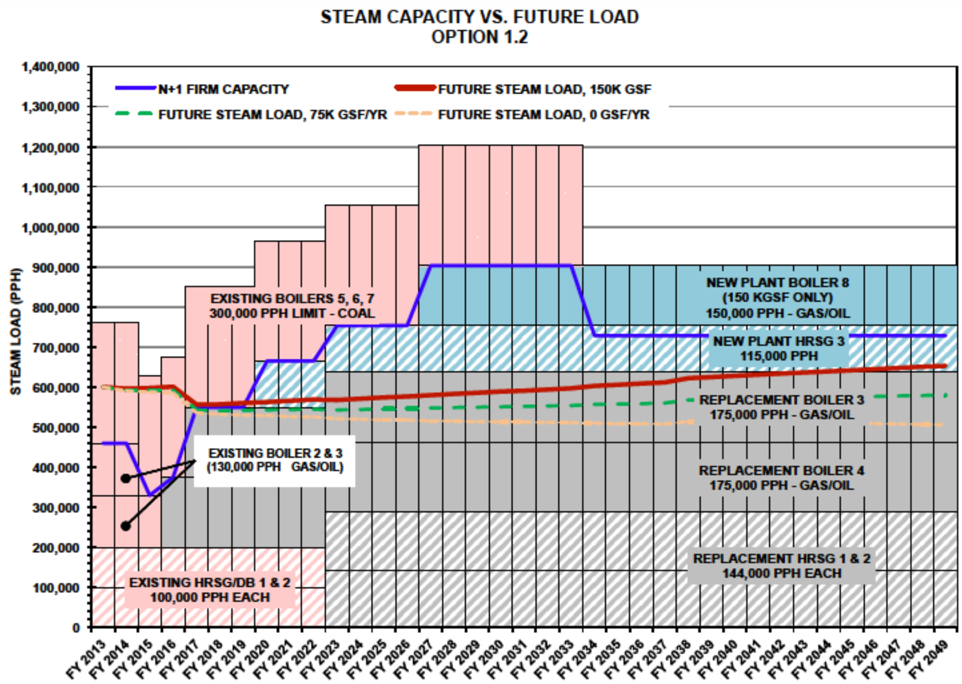
Eliminating the use of condensing STG 6 & 7 as a redundant steam path for campus steam supply significantly reduces the overall steam demand of the campus.

Operations, maintenance and repair costs are estimated from the total value of assets used to produce and distribute utilities to campus. The estimate is based on 3.5% of rotating assets and 1% of stationary assets and is comparable to the existing U of I OM&R budget.

Option 1.1 reduces the total fuel costs, operations, maintenance and repair costs, and capital expenditures compared to the BAU reference case.

Option 1.2 retires coal boilers at Abbott Power Plant and replaces these units with a second CHP plant located in North Campus using 13.5 MW CHP and auxiliary saturated steam natural gas / fuel oil boiler. The following figure indicates the steam capacity versus future heating load for the study growth scenarios. Similar to the BAU, Boilers 3 and 4 are replaced with natural gas / fuel oil units at 175,000 pph capacity each. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. Boilers 5, 6 and 7 are retired at the end of their useful life. The combustion turbines continue to be maintained and the HRSG and duct burner is replaced with 144,000 pph units at the end of their useful life. The new plant includes a 13.5 MW combustion turbine and 115,000 pph HRSG and duct burner.

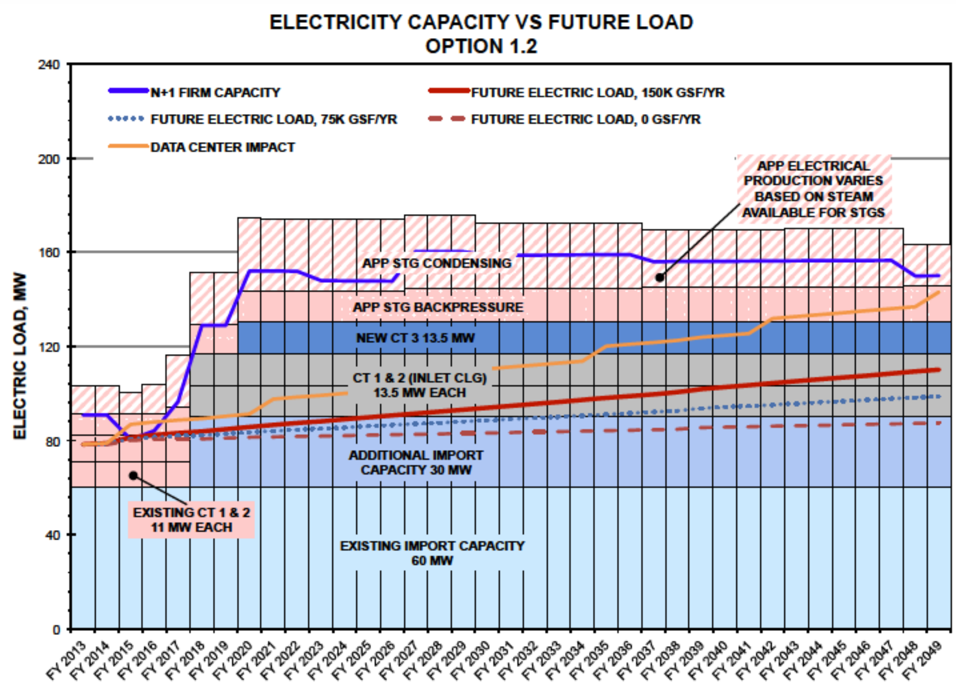
At 150 kGSF/yr campus growth rate, a natural gas / fuel oil boiler at 150,000 pph and 150 psig is installed in 2027 to meet the increased campus heating load.



Chilled water production and distribution remain the same as the BAU case.

The electrical import capacity is increased from 60 to 120 MW for increased reliability, utility cost reduction and operational flexibility. The extraction/condensing STGs are retired at the end of their useful life. Backpressure STG 2 is replaced with a 3 MW 850 psig unit in 2030, STG 9 is replaced with a 10 MW 850 psig backpressure unit in 2017 and STG 10 is replaced with a 7.5 MW 850 psig unit in 2048. The capacity of CT 1 & CT 2 is increased to 13.5 MW each with the addition of inlet air cooling in 2018.

The following figure indicates the electric capacity versus future electric load for study growth scenarios. The electrical import capacity is increased from 60 to 120 MW for increased reliability, utility cost reduction and operational flexibility. The combustion turbines at APP continue to be maintained while the extraction/condensing STGs are retired at the end of their useful life. Backpressure STG 2, 9 and 10 are replaced. The CT at the second plant adds an additional 13.5 MW generating capacity.



The following figure identifies the location of the North Campus Heating Plant as identified in the campus master plan. The location of the plant eliminates the need to implement the base case steam piping upgrades.

The following table indicates estimates of probable project costs for the equipment replacements in Option 1.2. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 1.2 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
GAS BOILER 3 & 4	175 KPPH @ 850 PSIG	19,006,000
INLET COOLING CT 1 & 2		700,000
HRSG/DB 1 & 2	144 KPPH @ 850 PSIG	27,228,000
STG 2	3 MW	6,418,000
STG 9	10 MW	11,210,000
STG10	7.5 MW	9,900,000
STG DEMOLITION		2,628,000
NEW PLANT		6,044,000
CT 3	13.5 MW	23,125,000
HRSG/DB 3	115 KPPH @ 150 PSIG	11,098,000
GAS BOILER 8 (150 KGSF ONLY)	150 KPPH @ 150 PSIG	7,875,000
STEAM DISTRIBUTION		30,070,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 1.2 and the BAU cases.

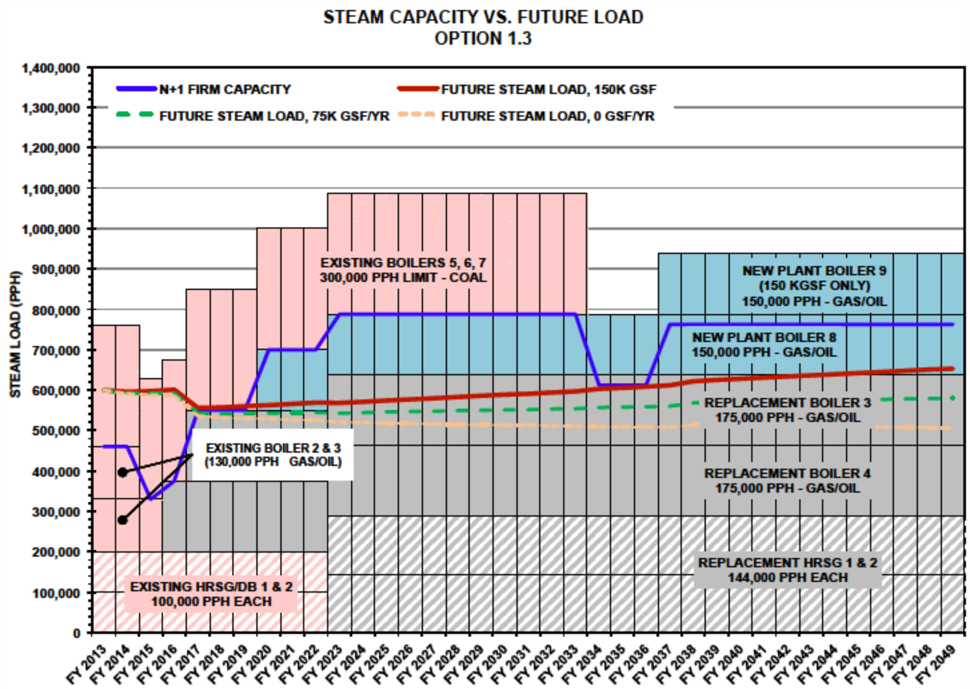
OPTION 1.2 LIFE CYCLE COST SUMMARY ($ MILLIONS)												
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
1.2		•		CHP	29	739	—	292	1,061	410	250	1,720
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
1.2		•		CHP	14	—	—	343	1,156	413	255	1,825

NOTES: 1. CHP - COMBINED HEAT AND POWER

Development of the second plant with increased CHP capacity increases total fuel costs and operations, maintenance and repair costs while reducing the capital expenditures. The total cost of Option 1.2 is greater then the BAU reference case.

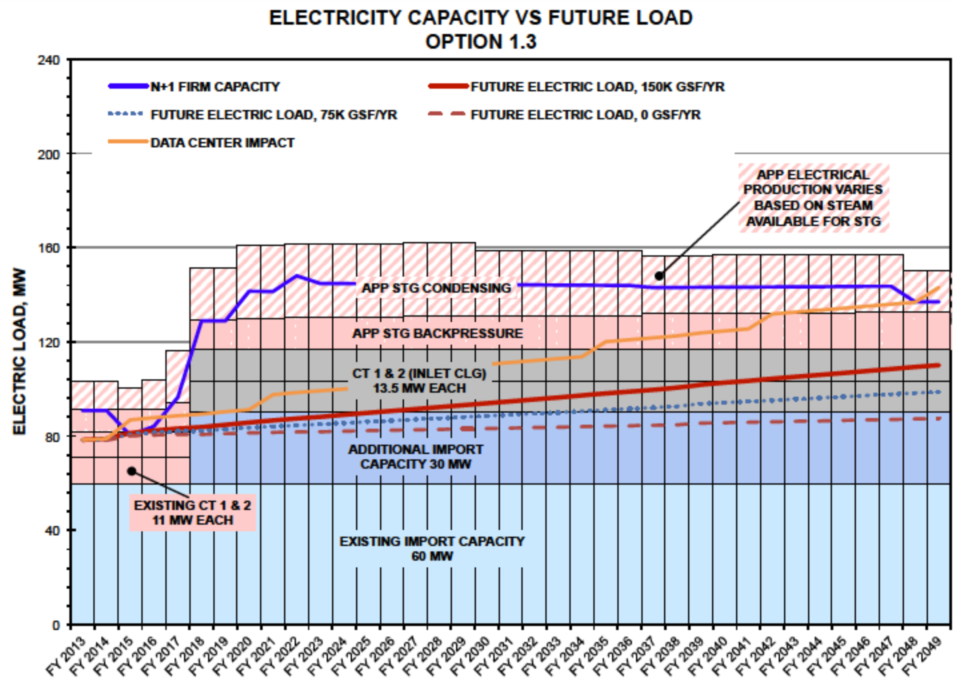
Option 1.3 retires coal boilers at Abbott Power Plant and replaces the units with natural gas / fuel oil units in a second heating only plant. The following figure indicates the steam capacity versus future heating load for the study growth scenarios. Option 1.3 is similar to Option 1.2 except a dual fuel natural gas / fuel oil boiler at 150,000 pph and 150 psig is installed in the new plant in place of a combustion turbine and HRSG. The efficiency of the natural gas boilers is 82% compared with 86% efficient coal boilers.

At 150 kGSF/yr campus growth rate, a natural gas / fuel oil boiler at 150,000 pph and 150 psig is installed in 2037 to meet the increased campus heating load. The location of the eliminates the need to implement the base case steam piping upgrades.



Chilled water production and distribution remain the same as the BAU case.

The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased from 60 to 120 MW for increased reliability, utility cost reduction and operational flexibility. The capacity of CT 1 & CT 2 is increased to 13.5 MW each with the addition of inlet air cooling in 2018. Backpressure STG 2 is replaced with a 3 MW 850 psig unit in 2030, STG 9 is replaced with a 10 MW 850 psig backpressure unit in 2017, STG 10 is replaced with a 7.5 MW 850 psig unit in 2048, and the extraction/condensing STGs are retired at the end of their useful life.



The following table indicates estimates of probable project costs for the equipment replacements in Option 1.3. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 1.3 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
GAS BOILER 3	175 KPPH @ 850 PSIG	19,006,000
INLET COOLING CT 1 & 2		700,000
HRSG/DB 1 & 2	144 KPPH @ 850 PSIG	27,228,000
STG 2	3 MW	6,418,000
STG 9	10 MW	11,210,000
STG10	7.5 MW	9,900,000
STG DEMOLITION		2,628,000
NEW PLANT		4,695,000
GAS BOILER 8	150 KPPH @ 150 PSIG	7,875,000
GAS BOILER 9 (150 KGSF ONLY)	150 KPPH @ 150 PSIG	7,875,000
STEAM DISTRIBUTION		30,070,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 1.3 and the BAU cases.

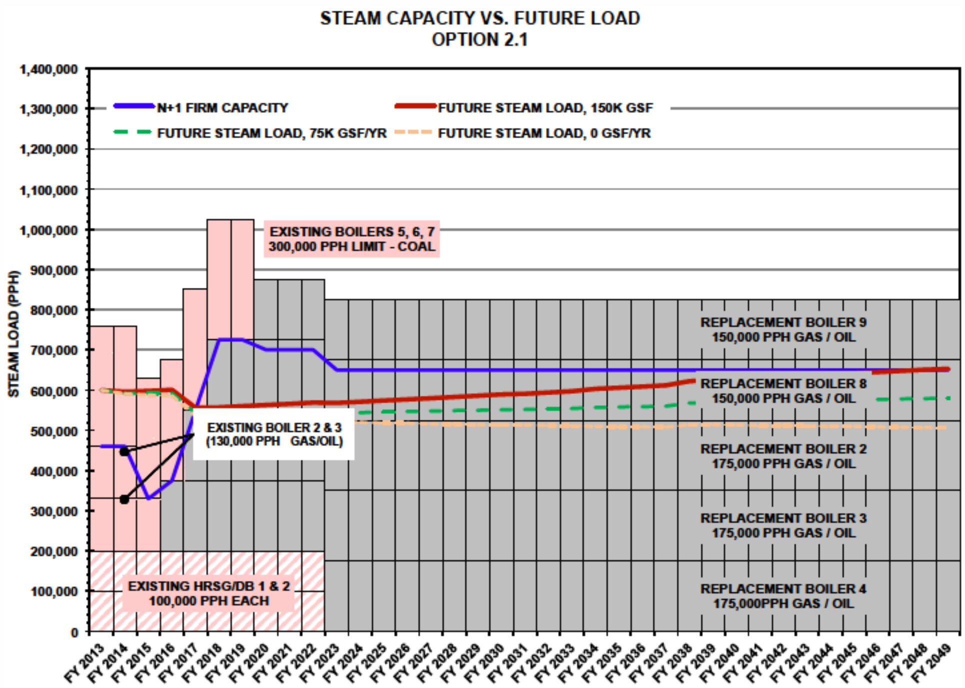
OPTION 1.3 LIFE CYCLE COST SUMMARY ($ MILLIONS)													
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS								
	ABBOTT PP												
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
1.3		•		BLR	31	599	—	415	1,045	392	226	1,663
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
1.3		•		BLR	36	—	—	481	1,156	394	230	1,780

NOTES: 1. BLR - BOILERS

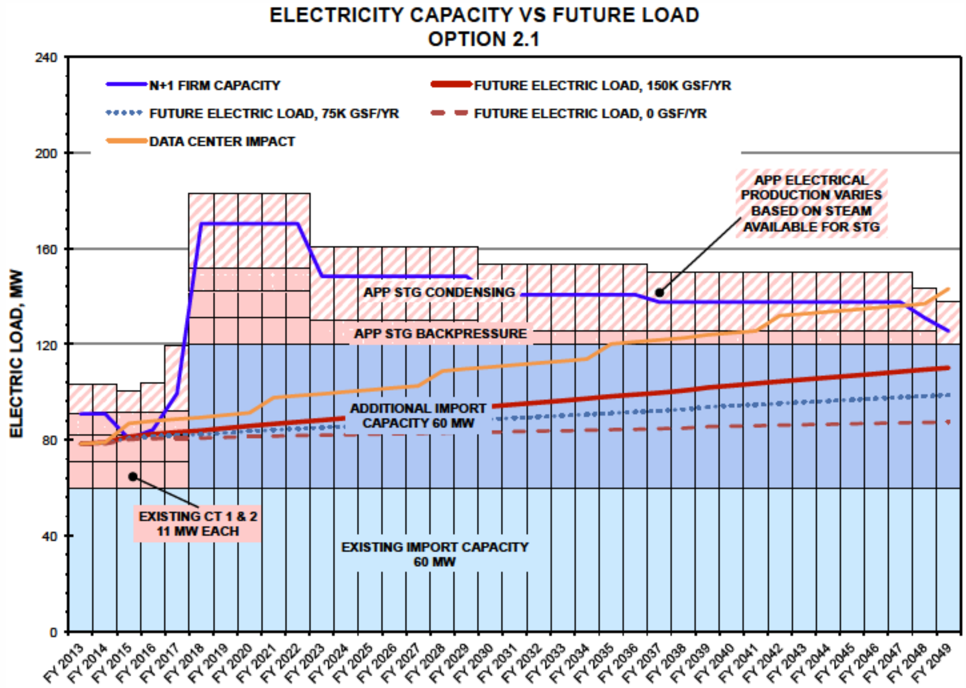
Option 1.3 has in increase in total fuel costs with a reduction in operations, maintenance and repair costs and in capital expenditure. The total cost of Option 1.3 is less then the BAU reference case.

Theme 2 – NG as primary fuel with no power production (conventional heating only)

Option 2.1 increases power import limit to 120 MW, replaces coal boilers with natural gas / fuel oil units and converts Abbott Power Plant to a heating only plant with no power production as the combustion turbines and steam turbine generators reach the end of their useful life. The following figure indicates the steam capacity versus future loads for study growth scenarios. Boilers 3, 4 and 2 are replaced with natural gas / fuel oil units at 175,000 pph capacity each. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. The CTs, HRSGs and DBs are retired at the end of their useful life. Coal boilers 5 & 6 are retired early after Boiler 2 is commissioned and two dual fuel boilers at 150,000 pph capacity and 150 psig are installed to meet campus heating requirements. The efficiency of the natural gas boilers is 82% compared with 86% efficient coal boilers.



The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased for increased reliability, utility cost reduction and operational flexibility. The combustion turbines and STGs are retired at the end of their useful life.



The following table indicates estimates of probable project costs for the equipment replacements in Option 2.1. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 2.1 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	60 MW	29,375,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
GAS BOILER 3, 4 & 2	175 KPPH @ 850 PSIG	28,509,000
CT DEMOLITION		3,752,000
STG DEMOLITION		3,942,000
GAS BOILER 8 & 9	150 KPPH @ 150 PSIG	15,750,000
STEAM DISTRIBUTION		30,070,000
STEAM DISTRIBUTION - (150 KGSF ONLY)		17,780,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

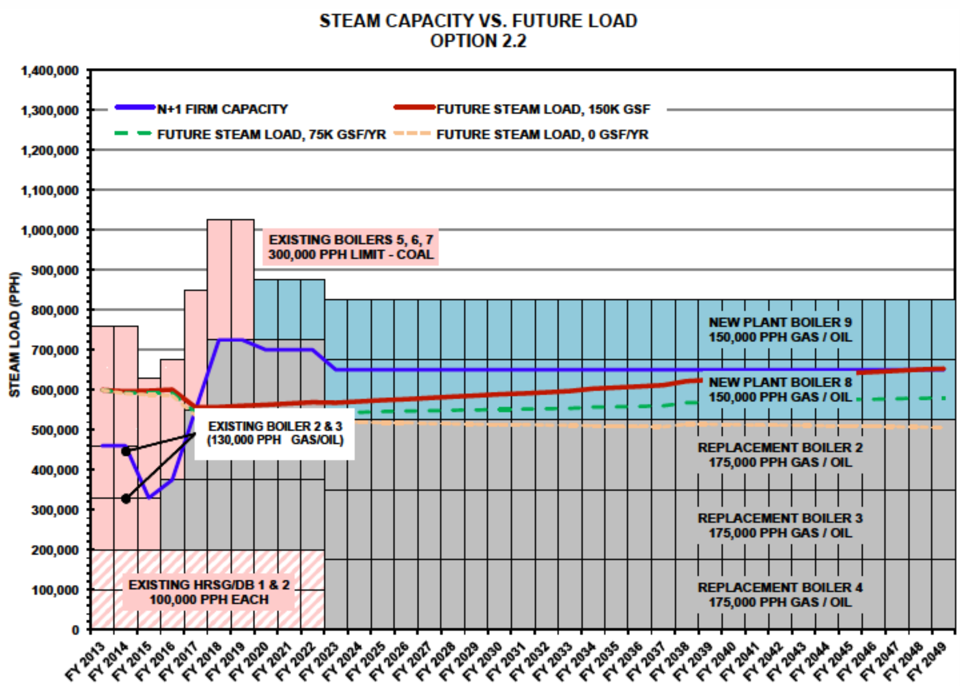
NOTES 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 2.1 and the BAU cases.

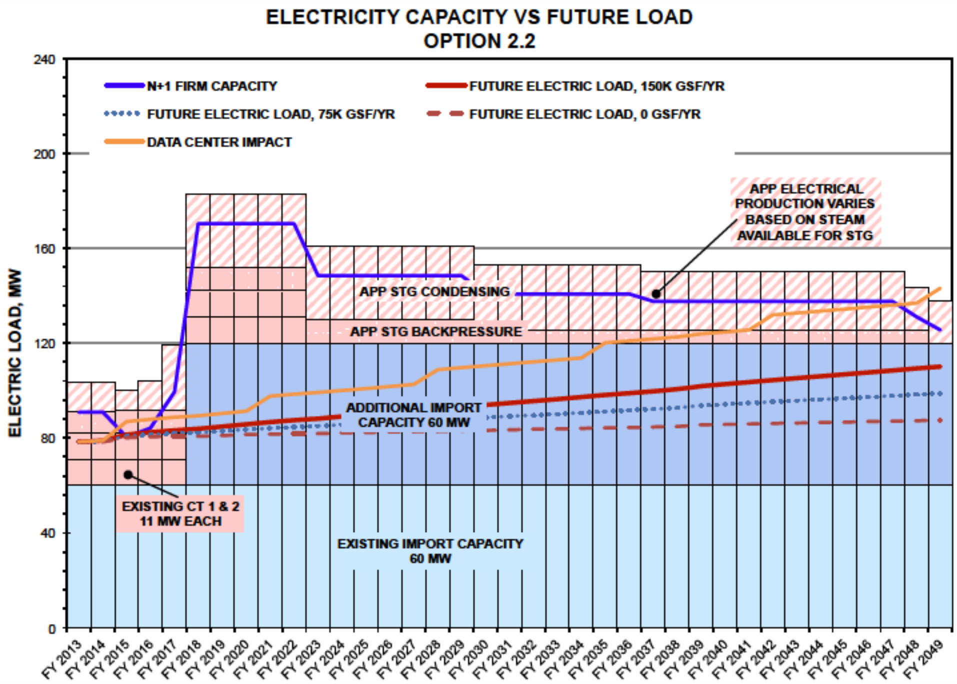
OPTION 2.1 LIFE CYCLE COST SUMMARY ($ MILLIONS)												
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
2.1		•			39	457	—	712	1,208	400	212	1,820
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
2.1		•			44	—	—	786	1,328	401	223	1,951

Eliminating CHP at APP nearly doubles the purchased electrical costs resulting in a greater total cost of Option 2.1 compared to the BAU reference case.

Option 2.2 increases power import limit to 120 MW, replaces coal boilers with natural gas / fuel oil units and converts Abbott to a heating only plant with no power production as the combustion turbines and steam turbine generators reach the end of their useful life. A second plant is developed with natural gas / fuel oil units on the North Campus. Location of the North Campus Heating Plant would avoid the base case steam piping upgrades. The following figure indicates the steam capacity versus future loads for study growth scenarios. Boilers 3, 4 and 2 are replaced with natural gas / fuel oil units at 175,000 pph capacity each. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. The CTs, HRSGs and DBs are retired at the end of their useful life. Coal boilers 5 & 6 are retired early after Boiler 2 is commissioned and two dual fuel boilers at 150,000 pph capacity and 150 psig are installed in the new plant to meet campus heating requirements. The efficiency of the natural gas boilers is 82% compared with 86% efficient coal boilers.



The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is improved for increased reliability, utility cost reduction and operational flexibility. The combustion turbines and STGs are retired at the end of their useful life.



The following table indicates estimates of probable project costs for the equipment replacements in Option 2.2. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 2.2 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	60 MW	29,375,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
GAS BOILER 3, 4 & 2	175 KPPH @ 850 PSIG	28,509,000
CT DEMOLITION		3,752,000
STG DEMOLITION		3,942,000
NEW PLANT		4,695,000
GAS BOILER 8 & 9	150 KPPH @ 150 PSIG	15,750,000
STEAM DISTRIBUTION		30,070,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 2.2 and the BAU cases.

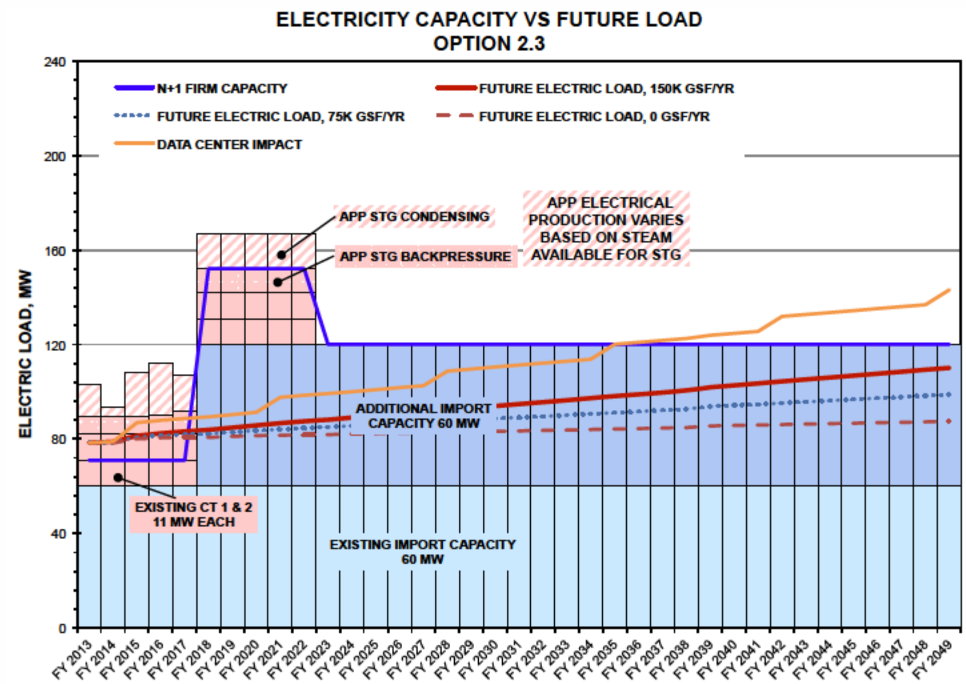
OPTION 2.2 LIFE CYCLE COST SUMMARY ($ MILLIONS)												
OPTION NO.	DESCRIPTION: ABBOTT PP COAL	GAS	BIO	NEW PLANT	INCREMENTAL PRESENT VALUE ANALYSIS: COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
2.2		•		BLR	39	457	—	712	1,208	402	216	1,826
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
2.2		•		BLR	44	—	—	786	1,328	402	216	1,946

NOTES: 1. BLR - BOILERS

Eliminating CHP at APP nearly doubles the purchased electrical costs resulting in a greater total cost of Option 2.2 compared to the BAU reference case.

Option 2.3 increases power import limit to 120 MW, and converts the entire campus to individual natural gas fired condensing hot water generators. Abbott Power Plant and the steam distribution system is retired and natural gas piping is distributed throughout campus to each building. The annual fuel efficiency of the condensing boilers is 87.6% compared with 86% efficient coal boilers and 82% efficient natural gas boilers.

The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased for improved reliability, utility cost reduction and operational flexibility. The CTs and STGs are retired in 2023 and all power is imported from Ameren IP.



The following table indicates estimates of probable project costs for the equipment replacements in Option 2.3. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 2.3 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	60 MW	29,375,000
APP DEMOLITION		17,737,000
NATURAL GAS PIPING		13,400,000
BUILDING CONVERSIONS		252,533,000
CONDENSING BOILERS		185,610,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 2.3 and the BAU cases.

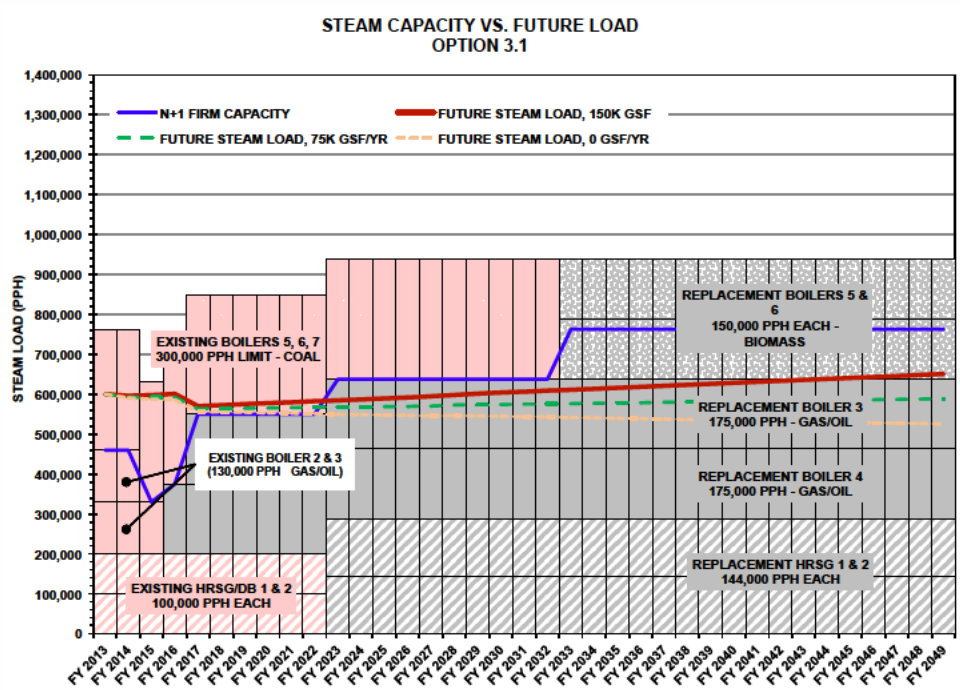
OPTION 2.3 LIFE CYCLE COST SUMMARY ($ MILLIONS)													
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS								
	ABBOTT PP												
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
2.3				CBLR	29	549	—	712	1,289	381	454	2,124
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
2.3				CBLR	30	—	—	786	1,423	400	454	2,277

NOTES: 1. CBLR - BUILDING CONDENSING BOILERS

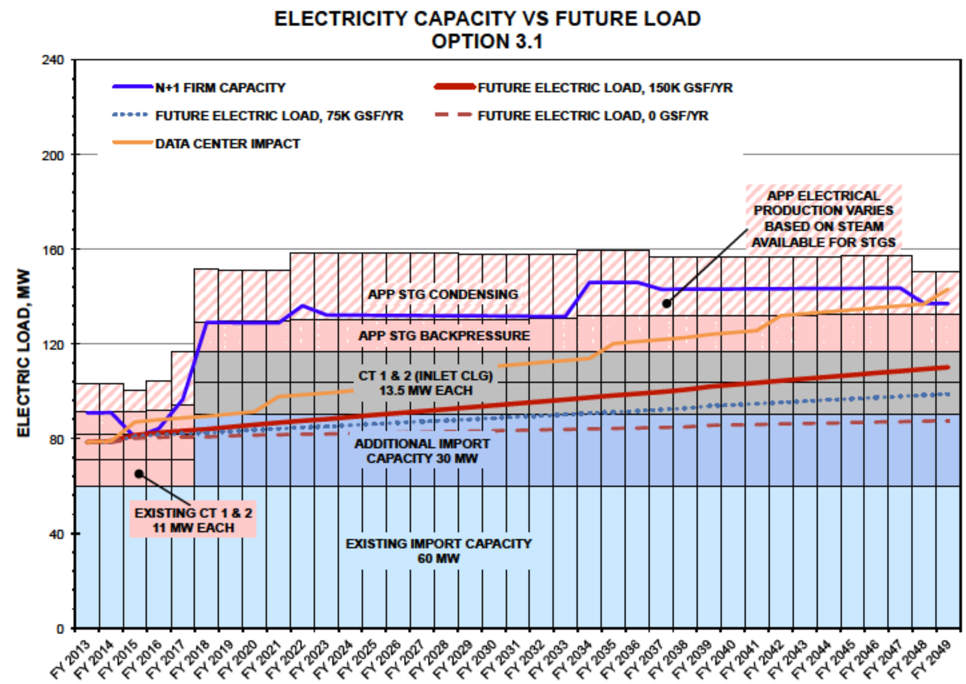
Option 2.3 has higher total fuel costs, higher operations, maintenance and repair costs and higher capital expenditures than the BAU reference case.

Theme 3 – NG as primary fuel with partial renewables (wind, solar, geothermal, biomass)

Option 3.1 replaces the existing coal fired boilers at Abbott Power Plant with biomass circulating fluidized bed (CFB) boilers. The replacement of Boiler 3 and 4 remain dual fuel natural gas / fuel oil fired units at 175,000 pph capacity. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. Boilers 5, 6 and 7 would be replaced with two biomass boilers and new solid fuel and ash handling equipment at 150,000 pph capacity at 850 psig each. The biomass (switch grass) is assumed to have 8,000 Btu/lb energy content and would require 8,050 acres of dedicated land to produce adequate biomass supply to completely offset the university's heating requirements provided by the coal boilers. At a pelletized density of 40 lb/cu. ft., the campus would require 3,220 truck deliveries per year. Switch grass is harvested annually and an adequate storage facility is included in costs for the biomass. The combustion turbines continue to be maintained and the HRSG and duct burners are replaced with 144,000 pph units. The following figures indicate the steam capacity and electric capacity versus future loads for study growth scenarios. The efficiency of the biomass boiler is 80% (maximum, depending on fuel stock) compared with 86% efficient coal boilers.



The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased for improved reliability, utility cost reduction and operational flexibility. The capacity of CT 1 & CT 2 is increased to 13.5 MW each with the addition of inlet air cooling in 2018. Backpressure STG 2 is replaced with a 3 MW 850 psig unit in 2030, STG 9 is replaced with a 10 MW 850 psig backpressure unit in 2017, STG 10 is replaced with a 7.5 MW 850 psig unit in 2048, and the extraction/condensing STGs are retired at the end of their useful life.



The following table indicates estimates of probable project costs for the equipment replacements in Option 3.1. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 3.1 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
BIOMASS BOILER (CFB) 5 & 6	150 KPPH @ 850 PSIG	92,754,000
BIOMASS MATERIAL HANDLING		9,153,000
GAS BOILER 3 & 4	175 KPPH @ 850 PSIG	19,006,000
INLET COOLING CT 1 & 2		700,000
HRSG/DB 1 & 2	144 KPPH @ 850 PSIG	27,228,000
STG 2	3 MW	6,418,000
STG 9	10 MW	11,210,000
STG10	8 MW	9,900,000
STG DEMOLITION		2,628,000
STEAM DISTRIBUTION		30,070,000
STEAM DISTRIBUTION - (150 KGSF ONLY)		17,780,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES
1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 3.1 and the BAU cases.

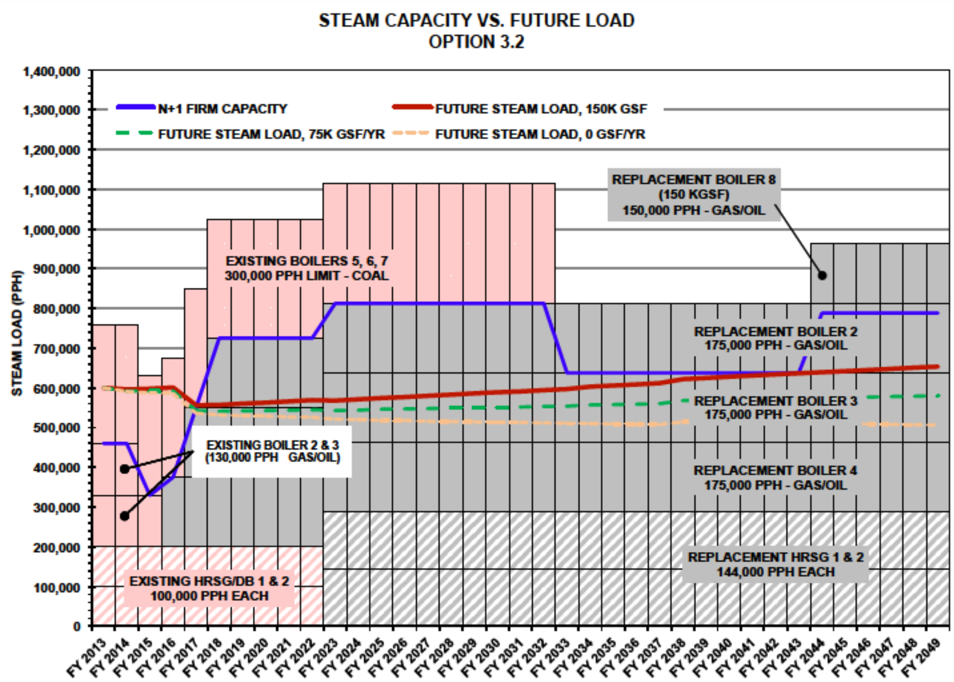
OPTION 3.1 LIFE CYCLE COST SUMMARY ($ MILLIONS)												
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
3.1			•		48	500	53	415	1,015	417	294	1,726
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
3.1			•		54	—	72	481	1,122	419	305	1,846

Option 3.1 reduces the overall fuel costs but increases the operations, maintenance and repair and capital expenditures resulting in and increase in the total present value compared to the BAU reference case.

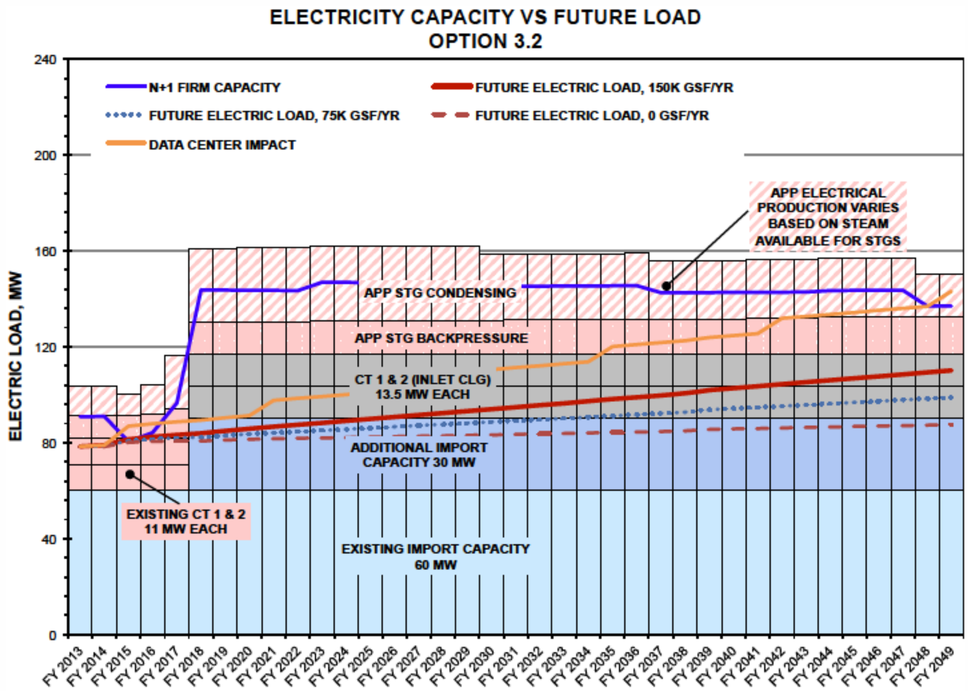
Option 3.2 increases the import limit to 120 MW. A heat recovery chiller plant is installed in the student staff center sized at 4,000 tons. The following figures indicate the steam capacity and electric capacity versus future loads for study growth scenarios. Boilers 3, 4 and 2 are replaced with natural gas / fuel oil units at 175,000 pph capacity each. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. The combustion turbines continue to be maintained and the HRSG and duct burners are replaced with 144,000 pph units at the end of their useful life. Efficiency of a natural gas boiler is 82% compared with 86% efficient coal boiler.

In order to operate, the heat recovery chiller must have a cooling and heating load. The heat recovery chiller plant does not contribute to the heating capacity from December through February and is not included in the following figure.

At a 150 kGSF/yr campus growth rate, the campus heating load will increase beyond the firm capacity of the plant in the year 2044, and an additional 150,000 pph dual fuel natural gas / fuel oil units at 850 psig is installed.



The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased for improved reliability, utility cost reduction and operational flexibility. The capacity of CT 1 & CT 2 is increased to 13.5 MW each with the addition of inlet air cooling in 2018. Backpressure STG 2 is replaced with a 3 MW 850 psig unit in 2030, STG 9 is replaced with a 10 MW 850 psig backpressure unit in 2017, STG 10 is replaced with a 7.5 MW 850 psig unit in 2048, and the extraction/condensing STGs are retired at the end of their useful life.



The heat recovery chiller plant is added to the North Campus and hot water piping distributed to buildings in the region as indicated in the following figure.

The following table indicates estimates of probable project costs for the equipment replacements in Option 3.2. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 3.2 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
GAS BOILER 3, 4 & 2	175 KPPH @ 850 PSIG	28,509,000
INLET COOLING CT 1 & 2		700,000
HRSG/DB 1 & 2	144 KPPH @ 850 PSIG	27,228,000
STG 2	3 MW	6,418,000
STG 9	10 MW	11,210,000
STG10	8 MW	9,900,000
STG DEMOLITION		2,628,000
STEAM DISTRIBUTION		30,070,000
STEAM DISTRIBUTION - (150 KGSF ONLY)		17,780,000
HRC PLANT	4,000 TON	18,930,000
BUILDING CONVERSIONS		13,700,000
DISTRIBUTION PIPING		8,000,000
GAS BOILER 8 (150 KGSF)	150 KPPH @ 850 PSIG	8,695,000
OSCP	27,942 TON	51,523,000
NCPP	12,400 TON	25,198,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 3.2 and the BAU cases.

OPTION 3.2 LIFE CYCLE COST SUMMARY ($ MILLIONS)

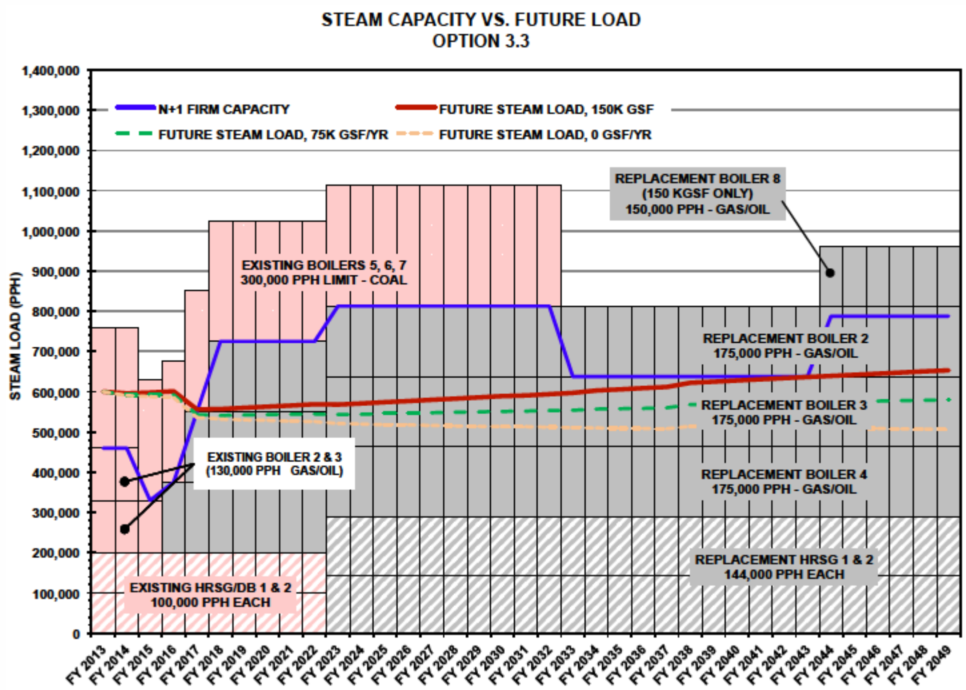
OPTION NO.	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
3.2		•		HRC	43	534	—	433	1,010	398	266	1,673
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
3.2		•		HRC	50	—	72	483	1,136	400	281	1,817

NOTES: 1. HRC - HEAT RECOVERY CHILLERS

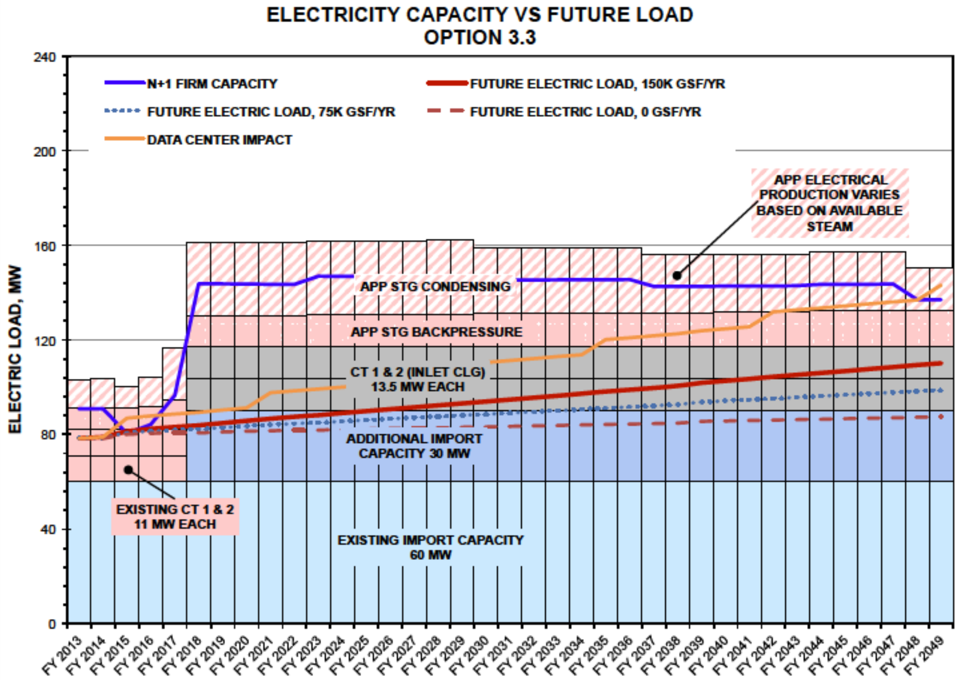
Option 3.2 reduces the overall fuel and operations, maintenance and repair costs with an increase is capital expenditures. The total present value of Option 3.2 is lower than the BAU reference case.

Option 3.3 replaces coal boilers at Abbott with NG fired boilers and adds a wind farm on south campus. The following figures indicate the steam capacity and electric capacity versus future loads for study growth scenarios. Boilers 3, 4 and 2 are replaced with natural gas / fuel oil units at 175,000 pph capacity each. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. The combustion turbines continue to be maintained and the HRSG and duct burners are replaced with 144,000 pph units at the end of their useful life. Approximately 230 acres of land is required to install a 23 MW wind farm sized to offset 70,000 MWh per year. The specific location of the wind farm would be determined with the guidance of the campus architect. Efficiency of a natural gas boiler is 82% compared with 86% efficient coal boiler.

At a 150 kGSF/yr campus growth rate, the campus heating load will increase beyond the firm capacity of the plant in the year 2044, and an additional 150,000 pph dual fuel natural gas / fuel oil units at 850 psig is installed.



The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased for improved reliability, utility cost reduction and operational flexibility. The capacity of CT 1 & CT 2 is increased to 13.5 MW each with the addition of inlet air cooling in 2018. Backpressure STG 2 is replaced with a 3 MW 850 psig unit in 2030, STG 9 is replaced with a 10 MW 850 psig backpressure unit in 2017, STG 10 is replaced with a 7.5 MW 850 psig unit in 2048, and the extraction/condensing STGs are retired at the end of their useful life. In order to provide firm electric capacity, the capacity of the wind farm is not considered.



The following table indicates estimates of probable project costs for the equipment replacements in Option 3.3. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 3.3 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
GAS BOILER 3, 4 & 2	175 KPPH @ 850 PSIG	28,509,000
INLET COOLING CT 1 & 2		700,000
HRSG/DB 1 & 2	144 KPPH @ 850 PSIG	27,228,000
STG 2	3 MW	6,418,000
STG 9	10 MW	11,210,000
STG10	8 MW	9,900,000
STG DEMOLITION		2,628,000
STEAM DISTRIBUTION		30,070,000
STEAM DISTRIBUTION - (150 KGSF ONLY)		17,780,000
GAS BOILER 8 (150 KGSF)	150 KPPH @ 850 PSIG	8,695,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
WIND FARM	23 MW	77,886,000
ELECTRICAL TO SECS		9,265,000
SOLAR PV FARM	5.88 MW	---

NOTES
1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

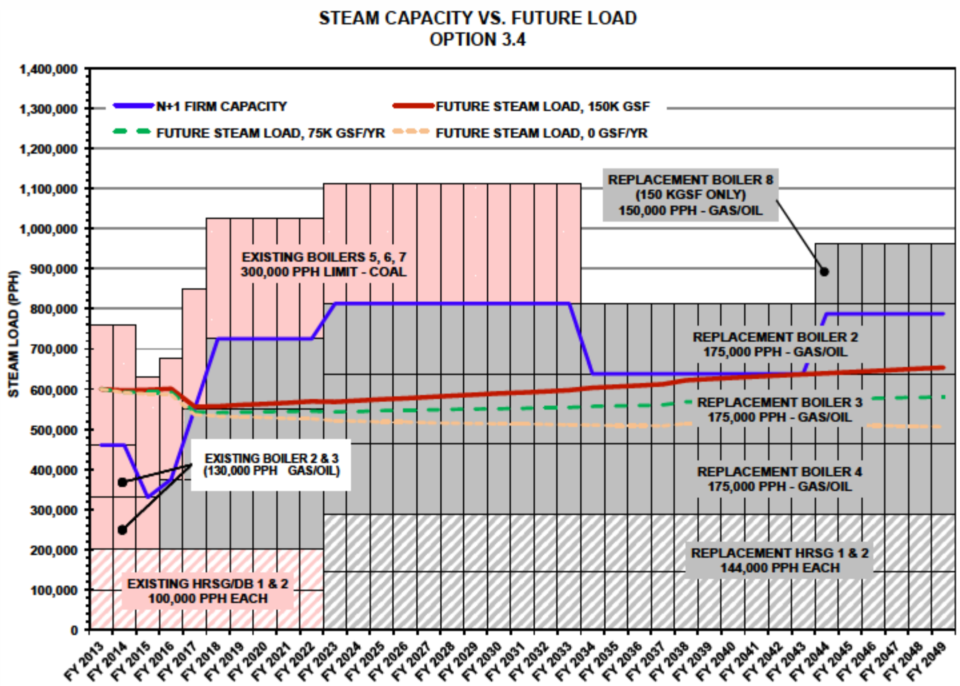
The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 3.3 and the BAU cases.

OPTION 3.3 LIFE CYCLE COST SUMMARY ($ MILLIONS)												
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
3.3		•		WIND	48	559	—	375	982	445	299	1,725
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
3.3		•		WIND	54	—	—	441	1,092	447	314	1,853

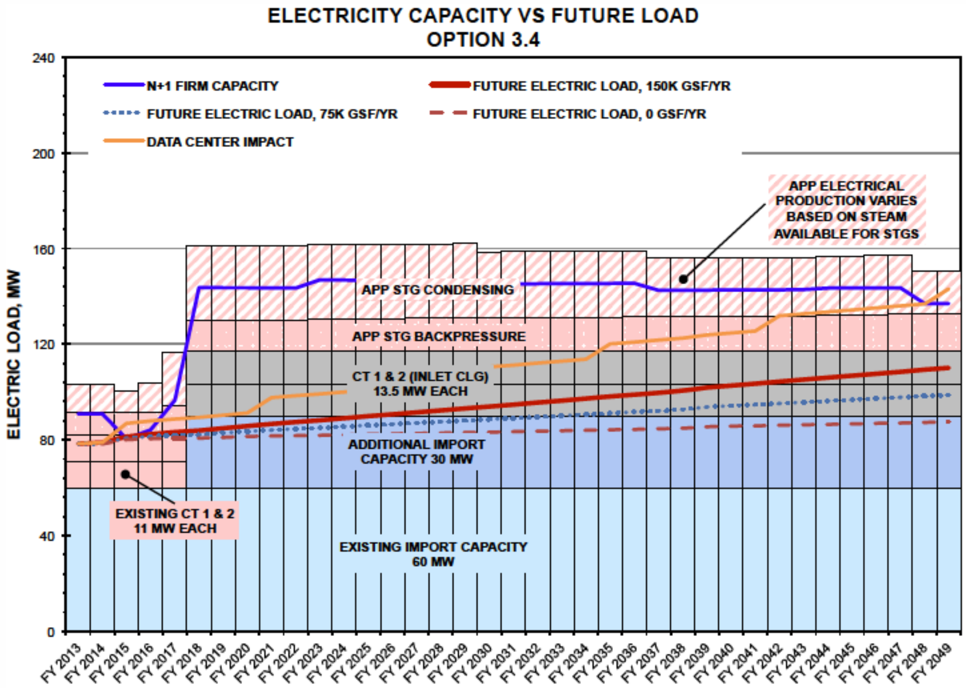
Option 3.3 reduces the overall fuel and operations, maintenance and repair costs with an increase is capital expenditures. The total present value of Option 3.3 is greater than the BAU reference case.

Option 3.4 replaces coal boilers at Abbott with NG fired boilers and adds a solar farm on south campus. The following figure indicates the steam capacity versus future heating load for study growth scenarios. Boilers 3, 4 and 2 are replaced with natural gas / fuel oil units at 175,000 pph capacity each. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. The combustion turbines continue to be maintained and the HRSG and duct burners are replaced with 144,000 pph units at the end of their useful life. Approximately 200 acres of land is required to install a 40 MW solar farm. The specific location of the solar farm would be determined with the guidance of the campus architect. Efficiency of a natural gas boiler is 82% compared with 86% efficient coal boiler.

At a 150 kGSF/yr campus growth rate, the campus heating load will increase beyond the firm capacity of the plant in the year 2044, and an additional 150,000 pph dual fuel natural gas / fuel oil units at 850 psig is installed.



The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased for improved reliability, utility cost reduction and operational flexibility. The capacity of CT 1 & CT 2 is increased to 13.5 MW each with the addition of inlet air cooling in 2018. Backpressure STG 2 is replaced with a 3 MW 850 psig unit in 2030, STG 9 is replaced with a 10 MW 850 psig backpressure unit in 2017, STG 10 is replaced with a 7.5 MW 850 psig unit in 2048, and the extraction/condensing STGs are retired at the end of their useful life. Similar to the wind farm, the capacity of the solar farm is not considered when determining electrical power firm capacity.



The following table indicates estimates of probable project costs for the equipment replacements in Option 3.4. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 3.4 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
GAS BOILER 3, 4 & 2	175 KPPH @ 850 PSIG	28,509,000
INLET COOLING CT 1 & 2		700,000
HRSG/DB 1 & 2	144 KPPH @ 850 PSIG	27,228,000
STG 2	3 MW	6,418,000
STG 9	10 MW	11,210,000
STG10	8 MW	9,900,000
STG DEMOLITION		2,628,000
STEAM DISTRIBUTION		30,070,000
STEAM DISTRIBUTION - (150 KGSF ONLY)		17,780,000
GAS BOILER 8 (150 KGSF)	150 KPPH @ 850 PSIG	8,695,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR FARM	40 MW	210,341,000
ELECTRICAL TO SECS		9,265,000
SOLAR PV FARM	5.88 MW	---

NOTES 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

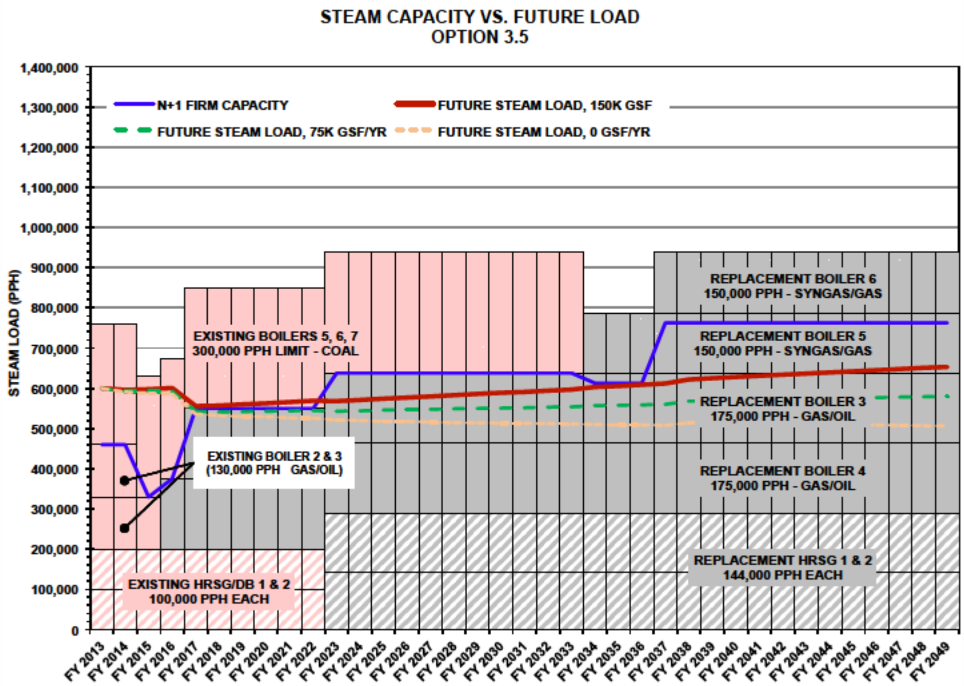
The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 3.4 and the BAU cases.

OPTION 3.4 LIFE CYCLE COST SUMMARY ($ MILLIONS)												
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
3.4		•		PHV	48	559	—	400	1,007	432	413	1,851
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
3.4		•		PHV	54	—	—	466	1,117	432	428	1,976

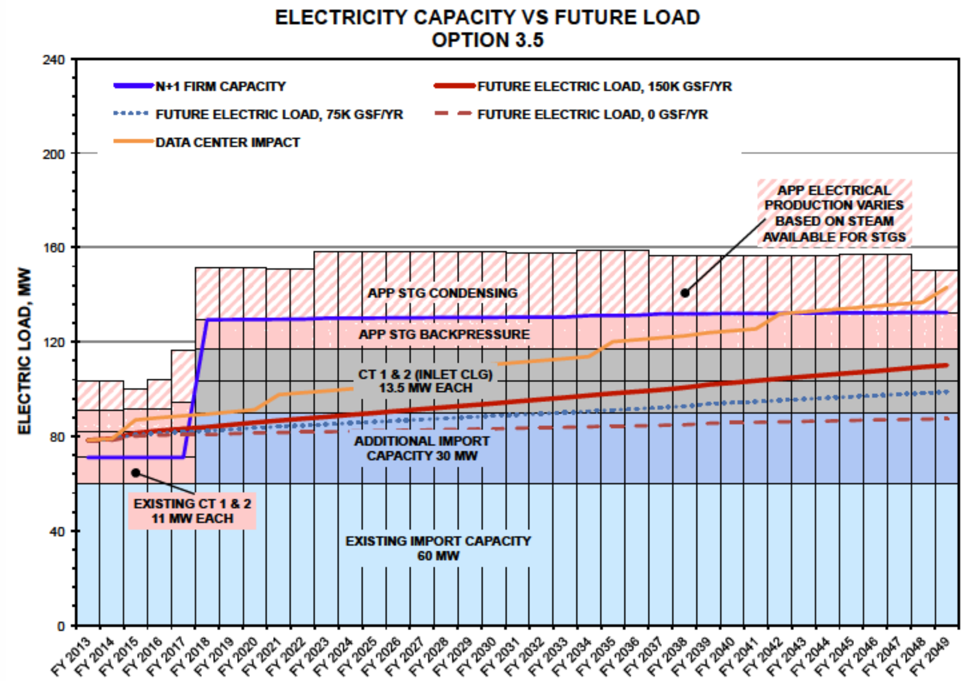
NOTES: 1. PHV - PHOTOVOLTAIC SOLAR

Option 3.4 reduces the overall fuel costs with an increase in operations, maintenance and repair and capital expenditures. The total present value of Option 3.4 is greater than the BAU reference case.

Option 3.5 is based on replacing the coal boilers at Abbott with syngas / natural gas fired boilers at 850 psig. For this analysis, the biomass is assumed to offset the steam heating provided by the coal boilers. The syngas is assumed to have 120 Btu/scf energy content and would require a minimum of 8,950 acres of dedicated land to produce adequate biomass supply. A gasification plant would be built on south campus with syngas piping to Abbott Power Plant. The gasification plant would require an average of 3,580 trucks per year. The following figures indicate the steam capacity and electric capacity versus future loads for study growth scenarios. Similar to the BAU, Boilers 3 and 4 are replaced with natural gas / fuel oil units at 175,000 pph capacity. However, the existing coal fired Boilers 5, 6, and 7 are replaced with two syngas / natural gas units at 150,000 pph at 850 psig. The combustion turbines continue to be maintained and the HRSG and duct burners are replaced with 144,000 pph units. The efficiency of the syngas / natural gas boilers is 80% compared with 86% efficient coal boilers.



The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased for improved reliability, utility cost reduction and operational flexibility. The capacity of CT 1 & CT 2 is increased to 13.5 MW each with the addition of inlet air cooling in 2018. Backpressure STG 2 is replaced with a 3 MW 850 psig unit in 2030, STG 9 is replaced with a 10 MW 850 psig backpressure unit in 2017, STG 10 is replaced with a 7.5 MW 850 psig unit in 2048, and the extraction/condensing STGs are retired at the end of their useful life.



The following table indicates estimates of probable project costs for the equipment replacements in Option 3.5. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 3.5 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
SYNGAS BOILER 5 & 6	150 KPPH @ 850 PSIG	23,892,000
GASIFICATION PLANT		52,203,000
GAS BOILER 3 & 4	175 KPPH @ 850 PSIG	19,006,000
INLET COOLING CT 1 & 2		700,000
HRSG/DB 1 & 2	144 KPPH @ 850 PSIG	27,228,000
STG 2	3 MW	6,418,000
STG 9	10 MW	11,210,000
STG10	8 MW	9,900,000
STG DEMOLITION		2,628,000
STEAM DISTRIBUTION		30,070,000
STEAM DISTRIBUTION - (150 KGSF ONLY)		17,780,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES: 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA: $196/MWH THRU 2024

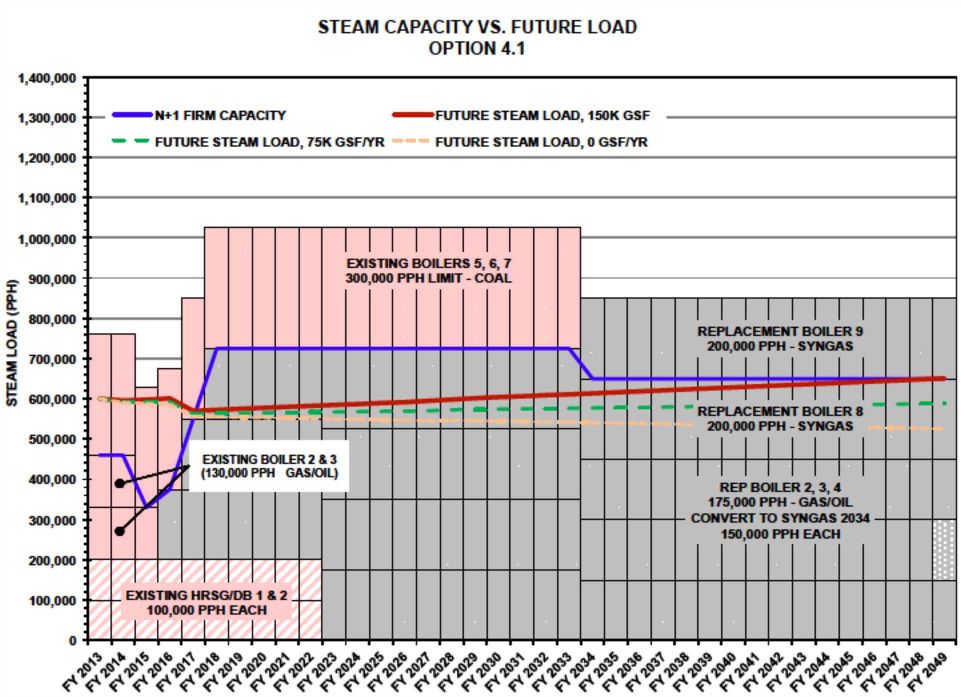
The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 3.5 and the BAU cases.

OPTION 3.5 LIFE CYCLE COST SUMMARY ($ MILLIONS)												
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
3.5		•	•		23	565	76	415	1,078	440	274	1,793
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
3.5		•	•		25	—	90	481	1,197	442	285	1,924

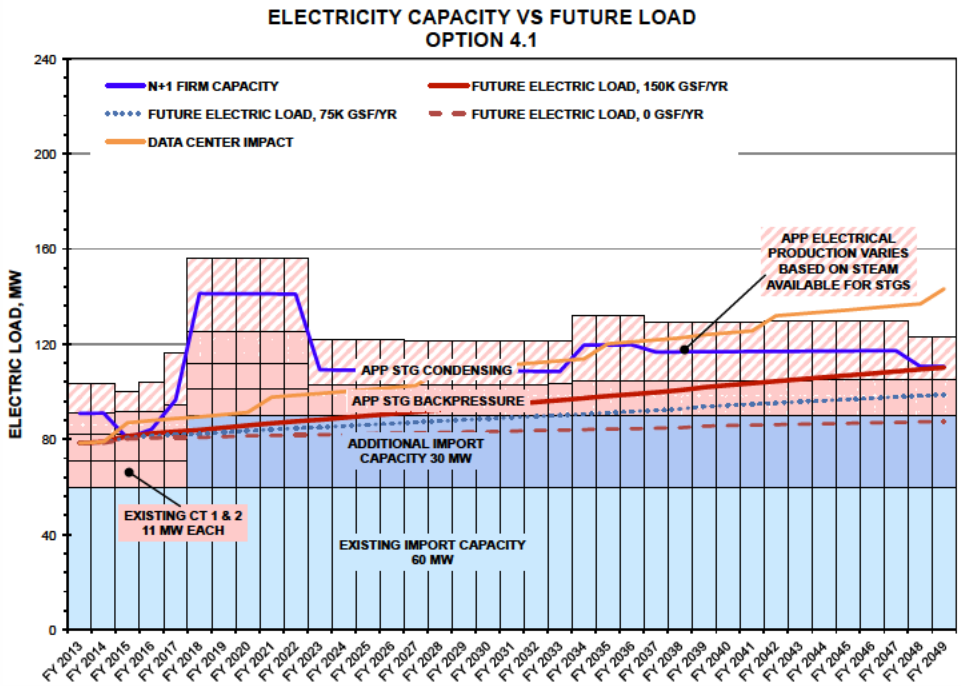
Option 3.5 increases the overall fuel costs, operations, maintenance and repair and capital expenditures resulting in a total present value greater than the BAU reference case.

Theme 4 – Full renewables and alternative fuels (solar, wind, geothermal, nuclear)

Option 4.1 is based on replacing the coal and gas/oil boilers at Abbott with syngas / natural gas fired boilers at 850 psig. The syngas is assumed to have 120 Btu/scf energy content and would require 17,360 acres of dedicated land to produce adequate biomass supply to completely offset the university's heating requirements. A gasification plant would be built on south campus with syngas piping to Abbott Power Plant. The gasification plant would require an average 6,950 trucks per year. The following figures indicate the steam capacity and electric capacity versus future loads for study. Boilers 3, 4 and 2 are replaced with natural gas / fuel oil units at 175,000 pph capacity each. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. Burners in Boilers 3 and 4 are replaced with syngas / natural gas burners and the capacity of the units derated to 150,000 pph capacity. The existing coal fired Boilers 5, 6, and 7 are replaced with two syngas / natural gas units at 200,000 pph at 850 psig. The combustion turbines are retired at the end of their useful life. The efficiency of the syngas / natural gas boilers is 80% compared with 86% efficient coal boilers.



The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased for improved reliability, utility cost reduction and operational flexibility. The combustion turbines at APP are retired at the end of their useful life. Backpressure STG 2 is replaced with a 3 MW 850 psig unit in 2030, STG 9 is replaced with a 10 MW 850 psig backpressure unit in 2017, STG 10 is replaced with a 7.5 MW 850 psig unit in 2048, and the extraction/condensing STGs are retired at the end of their useful life.



The following table indicates estimates of probable project costs for the equipment replacements in Option 4.1. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 4.1 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
GAS BOILER 3, 4 & 2	175 KPPH @ 850 PSIG	28,509,000
SYNGAS BOILER 5 & 6	200 KPPH @ 850 PSIG	26,134,000
BOILER CONVERSION TO SYNGAS		3,584,000
GASIFICATION PLANT		62,494,000
CT DEMOLITION		3,752,000
STG 2	3 MW	6,418,000
STG 9	10 MW	11,210,000
STG10	8 MW	9,900,000
STG DEMOLITION		2,628,000
STEAM DISTRIBUTION		30,070,000
STEAM DISTRIBUTION - (150 KGSF ONLY)		17,780,000
OSCP	27,942 TON	51,523,000
NCPP	16,400 TON	28,688,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES
1. COSTS IN 2014 DOLLARS
2. SOLAR PPA $196/MWH THRU 2024

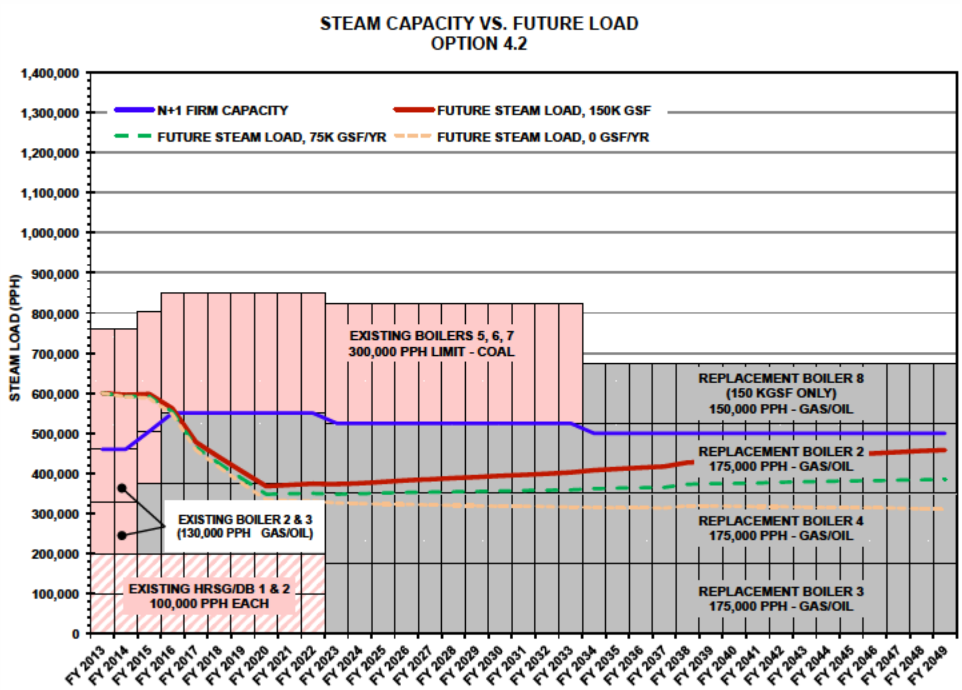
The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 4.1 and the BAU cases.

OPTION 4.1 LIFE CYCLE COST SUMMARY ($ MILLIONS)												
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
4.1			•		24	83	532	660	1,299	439	265	2,004
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
4.1			•		28	—	586	726	1,423	440	273	2,137

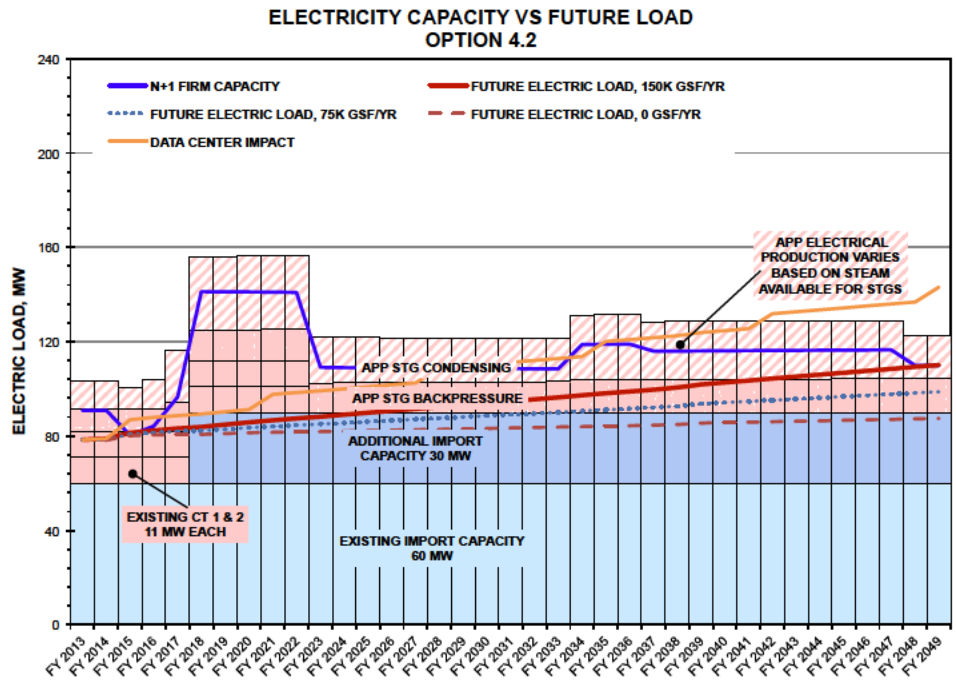
Option 4.1 increases the overall fuel costs, operations, maintenance and repair and capital expenditures resulting in a total present value greater than the BAU reference case.

Option 4.2 increases power import limit to 120 MW, retires all of Abbott Power Plant except three 175,000 pph natural gas / oil boilers and a 150,000 pph natural gas / oil boiler, and converts the entire campus to hot water heating with campus wide geothermal enhanced heat recovery chiller plant. A geothermal bore field of approximately 40 acres is required. The following figure indicates the steam capacity versus future heating load for study growth scenarios. The heating capacity of the heat recovery chiller plant and the reduced distribution losses result in a 195,000 pph reduction in the peak heating demands. Boilers 3, 4 and 2 are replaced with natural gas / fuel oil units at 175,000 pph capacity each. The use of extraction STGs 6 & 7 to provide redundant campus steam is discontinued in 2017 with the gas boiler installation, reducing the steam load by 48,000 pph. The combustion turbines are retired at the end of their useful life.

At a 150 kGSF/yr campus growth rate, a 150,000 pph dual fuel natural gas / fuel oil unit will be installed in 2034 when the coal boilers are retired.



The following figure indicates the electric capacity versus future electric load for the study growth rate scenarios. The electrical import capacity is increased for improved reliability, utility cost reduction and operational flexibility. The combustion turbines and STGs at APP are retired at the end of their useful life.



The following table indicates estimates of probable project costs for the equipment replacements in Option 4.2. Detailed estimates for each piece of equipment are provided in Appendix 7B.

OPTION 4.2 CAPITAL COSTS		
DESCRIPTION		PROJECT COSTS ($)
ADDITIONAL IMPORT CAPACITY	30 MW	15,165,000
ABBOTT POWER PLANT		2,229,000
COAL BOILER DEMOLITION		3,600,000
GAS BOILER 3, 4 & 2	175 KPPH @ 850 PSIG	28,509,000
GAS BOILER 8 (150 KGSF)	150 KPPH @ 850 PSIG	7,875,000
CT DEMOLITION		3,752,000
STG DEMOLITION		3,942,000
BUILDING CONVERSIONS		142,672,000
HW DISTRIBUTION PIPING		95,000,000
HRC PLANT	10,000 TON	47,285,000
BOREFIELD	14,000 TON	57,005,000
OSCP	27,942 TON	51,523,000
NCPP	9,400 TON	19,742,000
LCP	4,300 TON	8,888,000
ASCP	2,000 TON	4,435,000
CLSCP	3,600 TON	7,317,000
VMCP	5,250 TON	10,260,000
TES	5,000 TON	8,928,000
CHILLED WATER DISTRIBUTION		7,589,000
ELECTRICAL DISTRIBUTION		21,933,600
SOLAR PV FARM	5.88 MW	---

NOTES: 1. COSTS IN 2014 DOLLARS
2. SOLAR PPA: $196/MWH THRU 2024

The following table indicates the present value of the fuel costs, the operations, maintenance and repair costs, and capital expenditures for the life of the study for Option 4.2 and the BAU cases.

OPTION 4.2 LIFE CYCLE COST SUMMARY ($ MILLIONS)												
	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
NO GROWTH												
BAU	•	•			92	572	—	363	1,027	407	269	1,704
4.2				GHRC	54	160	—	844	1,058	386	468	1,912
150 KGSF												
BAU	•	•			95	597	—	428	1,142	411	288	1,842
4.2				GHRC	46	—	—	917	1,191	391	476	2,058

NOTES: 1. GHRC - GEOTHERMAL HEAT RECOVERY CHILLERS

Option 4.2 increases the overall fuel costs and capital expenditures while reducing the operations, maintenance and repair costs. The total present value of Option 4.2 is greater than the BAU reference case.

7.4 Results

Each of the options listed was modeled to calculate the cost of utility services, greenhouse gas emissions, increased land usage required, redundancy of installed capacity (thermal and electric), and capital requirements.

The model is based on assumptions related to campus growth, level of continued energy conservation, data center growth, and financial terms. The model is useful for macro utility planning but is limited as the planning horizon is reduced. The parameters of this interactive model on a global perspective can be modified and the revised economics, as well as risks and opportunities identified.

The following tables indicate the present value of the various fuel usages as well as other non-fuel components for the net zero campus growth options and a campus expansion of 150,000 GSF per year.

NO CAMPUS GROWTH LIFE CYCLE COST SUMMARY ($ MILLIONS)

	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP											
OPTION NO.	COAL	GAS	BIO	NEW PLANT	COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
BAU	•	•			92	572	---	363	1,027	407	269	1,704
1.1		•			44	567	---	414	1,025	391	221	1,638
1.2		•		CHP	29	739	---	292	1,061	410	250	1,720
1.3		•		BLR	31	599	---	415	1,045	392	226	1,663
2.1		•			39	457	---	712	1,208	400	212	1,820
2.2		•		BLR	39	457	---	712	1,208	402	216	1,826
2.3				CBLR	29	549	---	712	1,289	381	454	2,124
3.1			•		48	500	53	415	1,015	417	294	1,726
3.2		•		HRC	43	534	---	433	1,010	398	266	1,673
3.3		•		WIND	48	559	---	375	982	445	299	1,725
3.4		•		PHV	48	559	---	400	1,007	432	413	1,851
3.5		•	•		23	565	76	415	1,078	440	274	1,793
4.1			•		24	83	532	660	1,299	439	265	2,004
4.2				GHRC	54	160	---	844	1,058	386	468	1,912

NOTES
1. CHP - COMBINED HEAT AND POWER
BLR - BOILERS
CBLR - BUILDING CONDENSING BOILERS
HRC - HEAT RECOVERY CHILLERS
GHRC - GEOTHERMAL HEAT RECOVERY CHILLERS
PHV - PHOTOVOLTAIC SOLAR
PV - PRESENT VALUE
TPV - TOTAL PRESENT VALUE
GHG - GREEN HOUSE GAS

150,000 GSF/YR CAMPUS GROWTH LIFE CYCLE COST SUMMARY ($ MILLIONS)

OPTION NO.	DESCRIPTION				INCREMENTAL PRESENT VALUE ANALYSIS							
	ABBOTT PP			NEW PLANT								
	COAL	GAS	BIO		COAL	NATURAL GAS	BIOMASS	PURCHASED ELECTRICITY	TOTAL FUEL	FIXED OM&R	CAPEX	TOTAL
BAU	•	•			95	620	---	428	1,142	411	288	1,842
1.1		•			49	609	---	480	1,137	393	236	1,767
1.2		•		CHP	14	800	---	343	1,156	413	255	1,825
1.3		•		BLR	36	639	---	481	1,156	394	230	1,780
2.1		•			44	498	---	786	1,328	401	223	1,951
2.2		•		BLR	44	498	---	786	1,328	402	216	1,946
2.3				CBLR	30	607	---	786	1,423	400	454	2,277
3.1			•		54	516	72	481	1,122	419	305	1,846
3.2		•		HRC	50	531	72	483	1,136	400	281	1,817
3.3		•		WIND	54	597	---	441	1,092	447	314	1,853
3.4		•		PHV	54	597	---	466	1,117	432	428	1,976
3.5		•	•		25	601	90	481	1,197	442	285	1,924
4.1			•		28	83	586	726	1,423	440	273	2,137
4.2				GHRC	46	229	---	917	1,191	391	476	2,058

NOTES 1. CHP - COMBINED HEAT AND POWER
BLR - BOILERS
CBLR - BUILDING CONDENSING BOILERS
HRC - HEAT RECOVERY CHILLERS
GHRC - GEOTHERMAL HEAT RECOVERY CHILLERS
PHV - PHOTOVOLTAIC SOLAR
PV - PRESENT VALUE
TPV - TOTAL PRESENT VALUE
GHG - GREEN HOUSE GAS

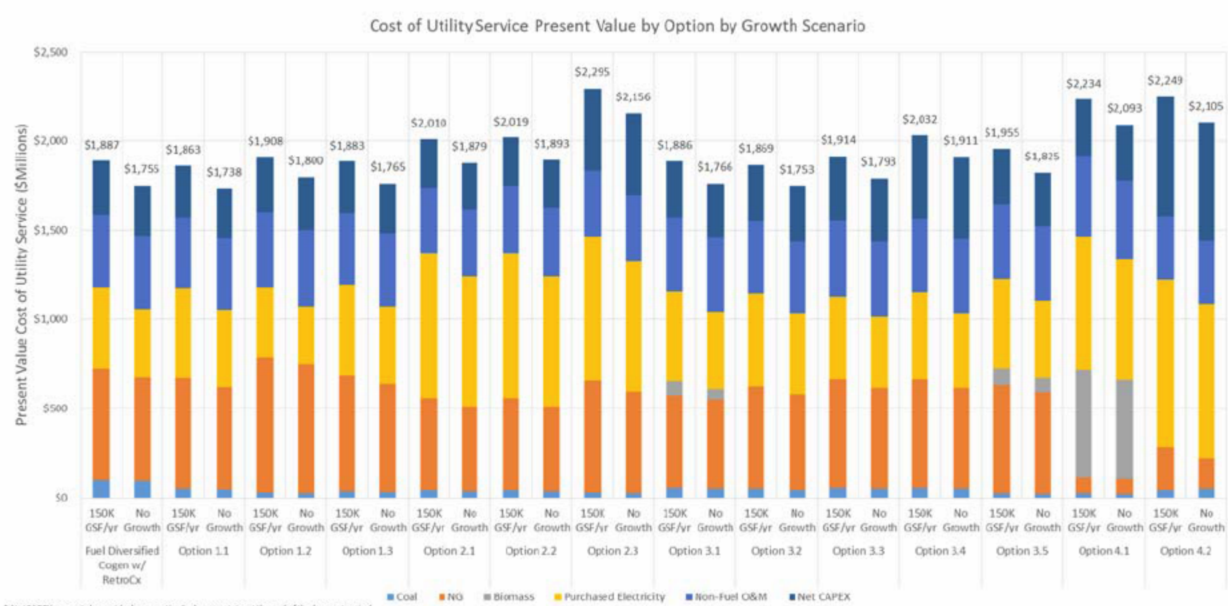
The following table summarizes the present value life cycle costing of the various options at net zero campus growth and 150,000 GSF per year of campus facility expansion. In addition, the table summarizes each option with and without greenhouse gas charges. The blue highlighted cells indicate the best option for that category on a present value of capital basis.

LIFE CYCLE COST SUMMARY ($ MILLIONS)

	DESCRIPTION				NO CAMPUS GROWTH					150,000 GSF/YEAR GROWTH				
	ABBOTT PP					$0 PER TON GHG		$10 PER TON GHG			$0 PER TON GHG		$10 PER TON GHG	
OPT. NO.	COAL	GAS	BIO	NEW PLANT	PV CAPEX	TOTAL PRESENT VALUE	TPV BAU DIFF.	TOTAL PRESENT VALUE	TPV BAU DIFF.	PV CAPEX	TOTAL PRESENT VALUE	TPV BAU DIFF.	TOTAL PRESENT VALUE	TPV BAU DIFF.
BAU	•	•			269	1,704	---	1,769	---	288	1,842	---	1,919	---
1.1		•			221	1,638	(66)	1,694	(75)	236	1,767	(75)	1,835	(84)
1.2		•		CHP	250	1,720	16	1,768	(1)	255	1,825	(17)	1,884	(36)
1.3		•		BLR	226	1,663	(41)	1,719	(50)	230	1,780	(62)	1,849	(70)
2.1		•			212	1,820	116	1,902	133	223	1,951	109	2,047	127
2.2		•		BLR	216	1,826	123	1,908	140	216	1,946	104	2,041	122
2.3				CBLR	454	2,124	421	2,203	435	454	2,277	435	2,368	449
3.1			•		294	1,726	22	1,779	10	305	1,846	4	1,909	(10)
3.2		•		HRC	266	1,673	(30)	1,729	(39)	281	1,817	(25)	1,884	(35)
3.3		•		WIND	299	1,725	22	1,777	8	314	1,853	11	1,916	(3)
3.4		•		PHV	413	1,851	147	1,906	137	428	1,976	134	2,043	124
3.5		•	•		274	1,793	89	1,842	74	285	1,924	82	1,984	65
4.1			•		265	2,004	300	2,047	278	273	2,137	295	2,189	270
4.2				GHRC	468	1,912	208	1,993	224	476	2,058	215	2,149	230

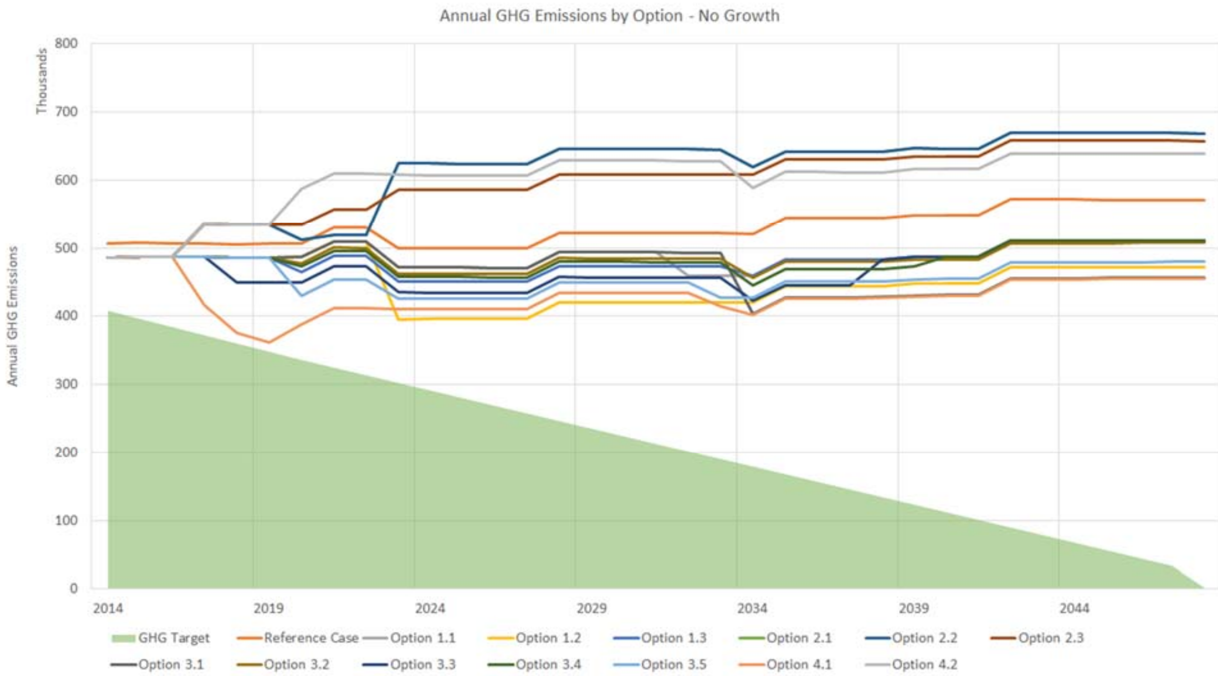
NOTES
1. CHP - COMBINED HEAT AND POWER
   BLR - BOILERS
   CBLR - BUILDING CONDENSING BOILERS
   HRC - HEAT RECOVERY CHILLERS
   GHRC - GEOTHERMAL HEAT RECOVERY CHILLERS
   PHV - PHOTOVOLTAIC SOLAR
   PV - PRESENT VALUE
   TPV - TOTAL PRESENT VALUE
   GHG - GREEN HOUSE GAS

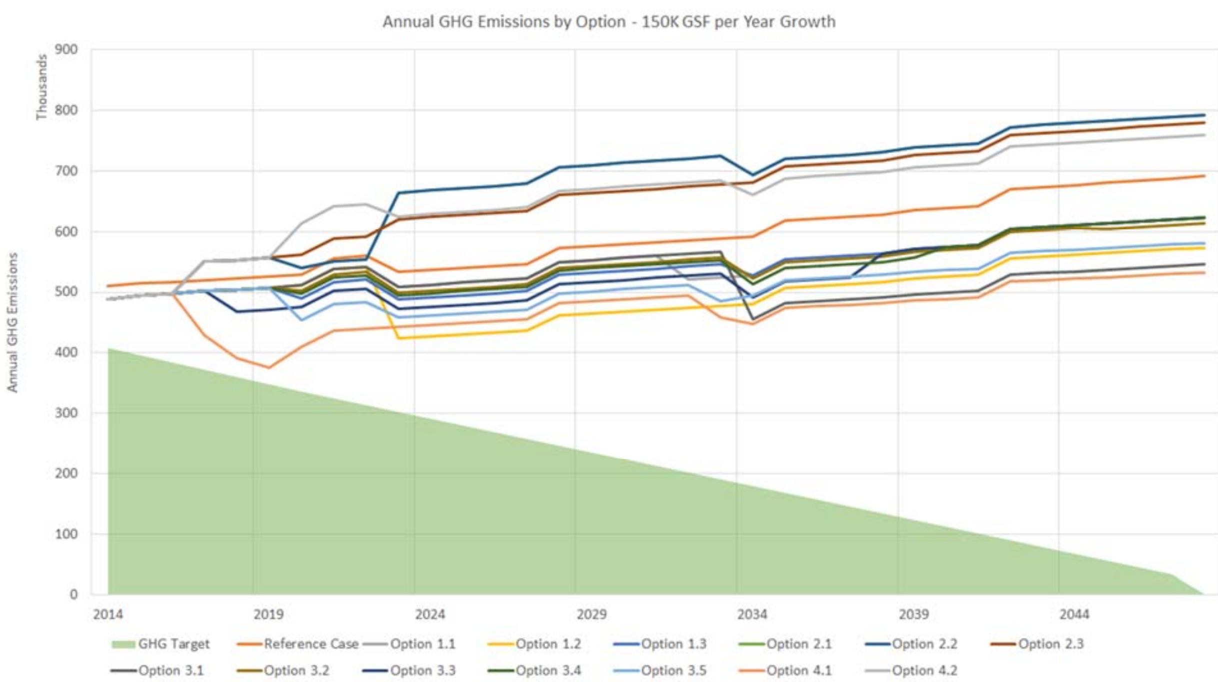
The following figure indicates the breakout of the present value of utility services for each option.



* NetCAPEX accounts for residual unamortized value remaining at the end of the forecast period.

The following figures indicate the annual green house gas emissions for each option over the life of the study for the net zero campus growth options and a campus expansion of 150,000 GSF per year. No combination of current technologies alone results in the iCAP recommended GHG emission levels. In order to meet the recommendations, the campus will need to investigate additional renewable power purchase agreements or purchasing renewable energy credits.





Given the diversified interests on campus, a weighted multi-objective evaluation was used to develop a resulting opportunity score. The present value of capital, the present value of the cost of utility service, the cost to meet the greenhouse goal through purchases, and the risk index are combined to create an opportunity index. The score for each factor is scaled based on the Fuel diversified cogeneration with energy conservation base case where a score of 5.0 is neutral, and greater than 5.0 is a positive result compared to the base case. The resulting Opportunity Index are indicated in the following table where the blue highlighted cell indicates the best value for that category.

MODIFIED OPPORTUNITY INDEX
U of I

OPTION	PV			RISK	PV			RISK SCORE	SIMPLE OPPORTUNITY INDEX
	CAP ($M)	OPER ($M)	GHG ($M)		CAP SCORE	OPER SCORE	GHC SCORE		
BAU	288	1,554	77	100	5.00	5.00	5.00	5.00	5.00
1.1	236	1,531	68	92	6.10	5.08	5.63	5.43	5.57
1.2	255	1,570	59	95	5.65	4.95	6.57	5.26	5.55
1.3	230	1,550	69	96	6.26	5.01	5.62	5.21	5.55
2.1	223	1,728	95	95	6.46	4.49	4.05	5.26	5.15
2.2	216	1,730	95	94	6.67	4.49	4.05	5.32	5.22
2.3	454	1,823	91	126	3.18	4.26	4.21	3.97	3.87
3.1	305	1,541	64	106	4.73	5.04	6.06	4.72	5.09
3.2	281	1,536	68	96	5.14	5.06	5.71	5.21	5.24
3.3	314	1,539	64	95	4.60	5.05	6.05	5.26	5.16
3.4	428	1,549	67	96	3.37	5.02	5.75	5.21	4.71
3.5	285	1,639	61	108	5.06	4.74	6.36	4.63	5.14
4.1	273	1,864	52	109	5.28	4.17	7.43	4.59	5.24
4.2	476	1,582	92	119	3.03	4.91	4.20	4.20	4.06

NOTES OPPORTUNITY INDEX BASED UPON
- 150 KGSF/YR GROWTH RATE
- CAP COST AT 30%
- OPERATING COST AT 30%
- GREENHOUSE GAS AT 20%
- RISK AT 20%

The most cost effective approach is Option No. 1.1 regardless of campus expansion as well as greenhouse cost, if any. Option No. 1.1 consists of the following major components

- Retirement of coal operations at the end of the existing equipment useful life (2025 to 2035).
- Continued operation of existing combined heat and power systems.
- Installation of three new gas boilers.
- Increased electrical import capacity.
- Additional backpressure steam turbine generator capacity.

- Replacement of existing chilled water generating assets at the end of useful life with increased capacity and efficiency units.
- Distribution system upgrades.

8.0 Implementation Plan

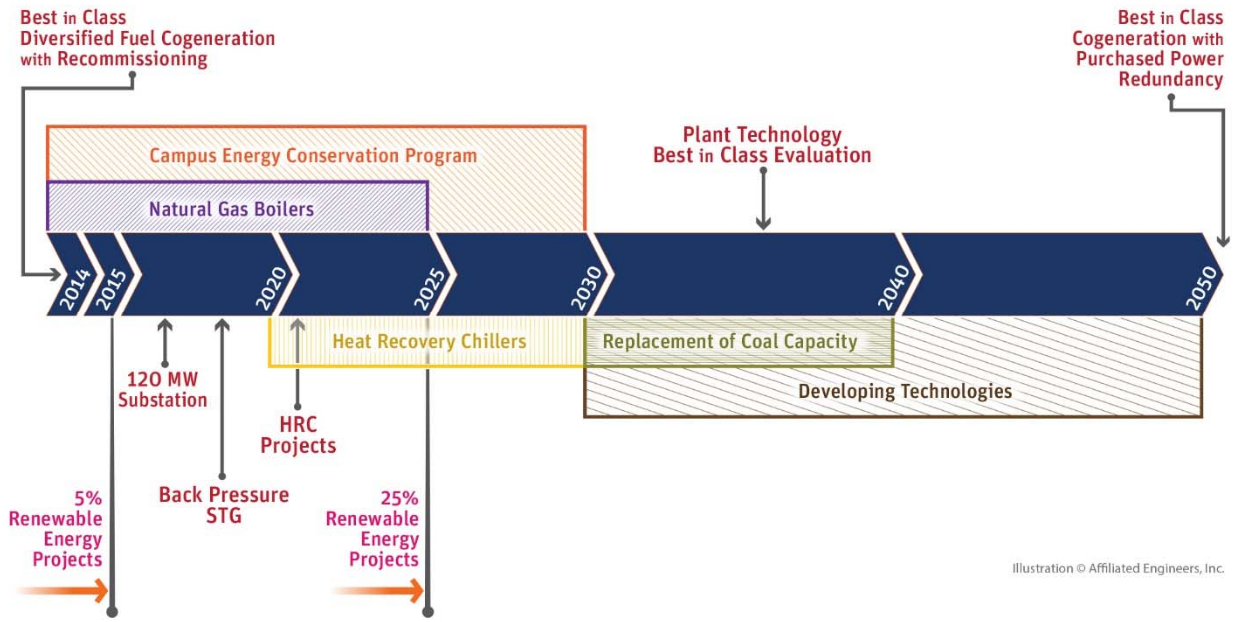
8.1 Recommendation

The analysis revealed that the most effective way to meet the potential load demands of the campus in an environmentally responsible manner is to:

- Expand the current **campus energy conservation program** in conjunction with the **retrocommissioning program** to further reduce campus energy consumption and demand.
- Aggressively promote the use of **heat-recovery systems** and **energy reduction strategies** in new capital projects. Ensure full functionality of new systems via **enhanced commissioning**.
- Pursue additional **renewable energy generation** projects (such as the solar farm) as opportunity affords and purchase **renewable energy credits** or develop **renewable power purchase agreements** to achieve campus iCAP targets.
- Limit campus growth to **net zero GSF** as established by the iCAP targets.
- Maintain the existing **best-in-class diversified fuel cogeneration** plant. Add **variable-speed chillers** to the existing multi-plant campus cooling system with thermal energy storage.
- Evaluate and apply **best of industry energy supply** utilizing advanced technology innovations for plant repowering in the 2030-2040 time frame.
- Apply **heat-recovery chiller** technologies in specific campus regions.
- Increase **electrical import capacity** for increased reliability, utility cost reduction and increased opportunity to utilize renewable technologies remotely via electric power grid.

8.2 Implementation

The following are recommendations for implementation of specific projects to repair deficiencies found during the condition assessment and to plan for future growth. Project construction costs are estimated and prioritized based on input from Facility and Services staff. All costs are in 2014 dollars and include university overhead for items such as design fees, management fees, and appropriate levels of contingency.



OPTION 1.1 INFRASTRUCTURE IMPROVEMENT SCHEDULE (TOTAL PROJECT COSTS in 2014 dollars)
UNIVERSITY OF ILLINOIS - URBANA CHAMPAIGN

SYSTEM	NO.	DESCRIPTION	TOTAL COST ($)	YEAR 2014 ($)	2015 ($)	2016 ($)	2017 ($)	2018 ($)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	2024 ($)
STEAM	H 1	ANCILLARY EQUIPMENT REPAIRS	3,375,000	750,000	750,000	650,000	125,000	600,000	500,000					
	H 2	ADDITIONAL BP STG	4,660,000		4,660,000									
	H 3	REPLACEMENT OF HRSG 1 AND 2	27,228,000										27,228,000	
	H 4	THIRD GAS BOILER	9,500,000			9,500,000								
	H 5	COMBUSTION TURBINE INLET COOLING	1,250,000					1,250,000						
	H 6	STEAM TUNNEL AND VAULT REPAIR	8,652,000	1,125,000	105,800	3,695,800	105,800	105,800	2,430,800	1,083,000				
	H 7	REPLACE DISTRIBUTION PIPING	21,418,000		2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800	2,141,800
	H 8	APP CODE AND LIFE SAFETY	2,229,000	557,250	557,250	557,250	557,250							
		SUBTOTAL	78,312,000	2,432,250	8,214,850	16,544,850	2,929,850	4,097,600	5,072,600	3,224,800	2,141,800	2,141,800	29,369,800	2,141,800
CHILLED WATER	C 1	OSCP CODE AND LIFE SAFETY	134,000			18,000								116,000
	C 2	NCCP REPLACEMENT CHILLERS/TOWERS	10,110,000			1,044,000				3,002,000		2,770,000	3,294,000	
	C 3	NCCP HEADER PIPING AND VALVE REPLACEMENT	275,000		275,000									
	C 4	NCCP CODE AND LIFE SAFETY	5,000			5,000								
	C 5	LACC REPLACEMENT CHILLERS/TOWERS	10,300,000	1,728,000	1,728,000	3,754,000					1,589,000	1,501,000		
	C 6	LACC CODE AND LIFE SAFETY	68,000			35,000								33,000
	C 7	ASCP REPLACEMENT CHILLERS/TOWERS	5,090,000			2,088,000							3,002,000	
	C 8	ASCP CODE AND LIFE SAFETY	32,000			18,000	7,000							7,000
	C 9	CLSCP REPLACEMENT CHILLERS/TOWERS	8,506,000	1,742,000	1,742,000	5,022,000								
	C 11	CLSCP CODE AND LIFE SAFETY	22,000			11,000								11,000
	C 12	VMCP REPLACEMENT CHILLERS/TOWERS	4,459,000			576,000			1,159,000				2,724,000	
	C 14	VMCP PIPING/PUMP UPGRADES	65,000				65,000							
	C 15	VMCP CODE AND LIFE SAFETY	6,000			6,000								
	C 16	TES PRESSURE SUSTAINING VALVE MODIFICATIONS	50,000	25,000	25,000									
	C 17	UPGRADE PORTIONS OF DISTRIBUTION PIPING	850,000		400,000	150,000	150,000	150,000						
		SUBTOTAL	39,972,000	3,495,000	4,170,000	12,727,000	222,000	150,000	1,159,000	3,002,000	1,589,000	4,271,000	9,020,000	167,000
ELECT.	E 1	MV DISTRIBUTION EQUIPMENT	9,509,000		1,694,000	391,000	496,000	761,000	391,000	939,000	783,000	1,172,000	2,190,000	692,000
	E 2	MV DISTRIBUTION CABLING	5,533,000		695,000	695,000	695,000	695,000	695,000	411,600	411,600	411,600	411,600	411,600
	E 3	HV TRANSFORMERS, CIRCUIT BREAKERS, RELAYS	927,000						927,000					
	E 4	INCREASE IMPORT CAPACITY TO 120 MW	16,287,000				8,287,000	8,000,000						
		SUBTOTAL	32,256,000		2,389,000	1,086,000	9,478,000	9,456,000	2,013,000	1,350,600	1,194,600	1,583,600	2,601,600	1,103,600
OTHER	O 1	ENERGY EFFICIENCY PROGRAM	22,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
	O 2	RENEWABLE ENERGY PROJECT/PURCHASE	5,500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
		SUBTOTAL	27,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000
TOTAL			178,040,000	8,427,250	17,273,850	32,857,850	15,129,850	16,203,600	10,744,600	10,077,400	7,425,400	10,496,400	43,491,400	5,912,400