has decreased over the past year from $0.878 per therm to the current price of $0.673 per therm, a 23% decline. Updating the model to incorporate these shifts in the price of fuel will provide more reliable and up-to-date cost savings information and significantly improve the accuracy of savings estimates. Table 4 below shows a summary of fuel cost shifts between 2009 and 2010.

Table 4 - Changes in Fuel Cost, 2009-2010

Fuel Type	2009 Cost Estimate	2010 Cost Estimate	% Change
Diesel ($/gal)	$2.315	$3.020[6]	30.2%
Biodiesel ($/gal)	$2.894	$3.120[6]	7.8%
Natural Gas ($/therm)	$0.878	$0.673[7]	-23.5%

Cost of Distributed Generation Equipment

While the cost of more traditional DG technologies such as diesel and natural gas generators has remained stable since the last review of installed cost, a number of shifts in installed price have occurred in the renewable DG industry. Particularly, the cost of solar photovoltaic (PV) cells has declined dramatically as manufacturer production capacity expands to meet customer demand for solar power. The average installed cost of a 50kW PV, based on review of available sources, is approximately $6,224 per kW, which represents a significant decline from 2009. The cost of PV cells with smaller capacities has also decreased, though to a lesser extent than higher capacity models.

Following the same trends demonstrated by photovoltaic technologies, the installed cost of wind energy has also dropped substantially since 2009, most likely due to the recent expansion of turbine manufacturing facilities in the United States. The installation cost for turbines manufactured by Fuhrlander, a Germany-company, has declined by almost 25% for their 250 kW model and by almost 30% for their 100 kW model. Some turbines have become more expensive however, thus demonstrating that all manufacturers within the industry do not follow uniform trends and underscoring the rapid rate of change within the renewable distributed generation technologies sector.

Contrary to wind and solar power technologies, the installed cost of both bio-gas and natural gas microturbines has increased since the last review of screening model input assumptions. Based on conversations with retailers, the cost of the microturbine equipment greatly exceeds the total estimated installed cost from 2009. In addition, many of the microturbines included in the 2003 screening model have since been discontinued. Allied Signal merged with Honeywell, which resulted in the cancellation of both the Natural Gas and Bio-Gas models of the Allied Signal Turbo generator, a 75 kW microturbine.

Table 5 on the following page presents a summary of major shifts in installed cost estimated between 2009 and 2010.

[6] http://www.afdc.energy.gov/
[7] http://www.centerpointenergy.com/services/naturalgas/business/naturalgasprices/gaspriceupdate/MN/

Table 5 - Distributed Generation Technologies and Associated Shifts in Installed Cost, 2009-2010

DG Manufacturer and Model	2009 Installed Cost Estimate ($/kW)	2010 Installed Cost Estimate ($/kW)	% Change
Solar			
Generic 1kW PV	$10,000	$8,568	-14.3%
Wind Turbines			
Fuhrlander FL100	$5,400	$3,800	-29.6%
Fuhrlander FL250	$2,600	$1,960	-24.6%
Bergey BWC XL.1-24	$7,500	$5,670	-24.4%
Zephyr (GE) 1.5 SLE	$2,600	$1,933	-25.7%
Bio-Gas Microturbines			
Capstone C30	$3,500	$6,600	88.6%
Captstone C60	$2,800	$3,600	28.6%
Natural Gas MicroTurbines			
Capstone C30	$2,200	$2,520	14.5%

State and Federal Incentives

Due to the American Recovery and Reinvestment Act (ARRA) of 2009, numerous incentive, grant, and tax credit programs have been expanded or restructured. After reviewing the legislation and its impacts, GDS has identified a number of key changes that could potentially impact the economics of renewable distributed generation technologies.

In May of 2010, the Minnesota Office of Energy Security (OES) launched a Residential Small Wind Rebate Program. The program closely mirrors the Residential Solar Rebate Program, another buy-down offered by the OES to reduce the initial cost of grid connected photovoltaic technologies. Through the program, residential customers can receive a rebate of 35% of the total installed cost, up to $10,000, of wind turbines with capacity equal or below 35 kW. These rebates are being distributed on a first-come, first-serve basis, and it will therefore be important to continue to monitor their availability.

The Wind and Biomass Renewable Electricity Production Credit (REPC), known also as the Wind Energy Production Tax Credit (PTC) has been significantly restructured as a result of ARRA. Previously through this program, eligible businesses received a federal tax credit of $0.18/kWh produced by a qualified renewable energy resource. However, businesses eligible for the PTC program now have the option of receiving the Business Energy Investment Tax Credit (ITC) *or* a grant from the US Treasury through the Renewable Energy Grant program instead of taking the PTC for new installations.

The ITC allows businesses installing qualified renewable distributed generation technologies to receive a corporate tax credit 30% of installed cost for solar, fuel cells, and small wind, and 10% for geothermal, microturbines and combined heat and power. Since 2009, this program has expanded the incentive for geothermal, microturbine and biomass systems to 30%. These

incentives are available for Commercial, Industrial, and Agricultural customers, as well as utilities. Table 6 below summarizes the tax credit and the maximum incentives available.

Table 6 – Business Energy Investment Tax Credit

Technology	Tax Credit	Maximum Incentive Available
Fuel Cells	30%	$1,500 per 0.5 kW
Solar	30%	No limit
Small Wind (up to 100 MW) - Completed 10/4/08 - 12/31/08	30%	$4,000
Small Wind (up to 100 MW) - Completed after 12/31/09	30%	No limit
Geothermal	30%	No limit
Combined Heat and Power	30%	No limit
Microturbines	30%	$200 per kW

As a result of ARRA restructuring, individuals and businesses eligible for the ITC have the option of receiving a grant through the Renewable Energy Grant program, administered by the Department of treasury, in lieu of the ITC. Much like the ITC program, these grants are available for a large range of technologies, and cover 30% of the equipment cost for solar, fuel cell, and wind projects and 10% of the equipment cost for all other technologies. Commercial, Industrial, and Agricultural customers are eligible through this program to receive funding with relatively few limitations on the size of the grant. However, the grant program is delivered in a different manner than the ITC, and determination of the most appropriate incentive must be examined on a case by case basis.

Since 2009, the Agricultural Improvement Loan Program has expanded as well. This program allows Minnesota residents, Minnesota domestic family-farm corporations or family-farm partnerships to secure loans through the Minnesota Rural Finance Authority (RFA) for improvements to agricultural facilities, including wind energy systems less than 1 MW. The RFA coordinates the loan with individual financial institutions and now lends 45% (up to $300,000) of the principal at a 4.5% interest rate. Previously, RFA participation in the loan was capped at $200,000.

Lastly, it should be noted that, as in 2009, the PV Solar Rebate program offered by the Minnesota Department of Commerce is still active, but all funds have been reserved as of the date of this review. New applications are being placed on a waiting list.

New Technologies

GDS reviewed several distributed generation technologies that were either not included in the 2009 report or have since become commercially available. These technologies are individually described in this section, and summarized in Table 7 on the following page.

Table 7 – New Distributed Generation Technologies

DG Manufacturer and Model	Electrical Output	Variable O&M costs ($/kWh)	Estimated Installed Cost ($/kW)
Biomass CHP			
Emery Energy Company*	75 kW	$0.011	$12,350
Entropic Energy*	250 kW	$0.011	$3,000 to $5,000
Wind Power			
Vestas V90 & V112	3 MW	$0.005	$1,915
Dish/Sterling Concentrated Solar Power			
Infinia PowerDish*	3 kW	$0.04	$4,850
SES Systems*	10 Kw or 25 kW	$0.04	$10,000
Concentrated Photovoltaics			
Cool Earth Solar*	.5 kW	-	$1,000
Soliant Energy SE-500X	0.335 kW	-	$5,500
Combustion Turbines (with Heat Recovery)			
Solar	up to 15 MW	$0.0096	$1,000 to $1,200
Kawasaki Gas Turbines	650 kW to 18 MW	$0.0096	$1,000 to $1,200
Rolls-Royce	2.2 to 51.2 MW	$0.0096	$1,000 to $1,200
Vericor Power Systems	500 kW to 50 MW	$0.0096	$1,000 to $1,200

*Denotes technology note yet commercially available, cost data is based on manufacturers' predictions

Biomass CHP

Biomass combined heat and power generation can offer potential to certain customers. System capacity factors can often be quite high, over 90% in cases where there is a need for year round waste heat. Based on these conditions, woodchip-fired combined heat and power systems could provide excellent benefits to end-use customers from both an operating cost and environmental perspective (including the potential for lowering greenhouse gas emissions). Biomass gasification equipment would likely achieve the highest efficiency levels and lowest greenhouse gas emissions as compared to burner box type units.

Though Biomass CHP technologies were included in the 2003 report as well as the 2009 update, systems with greater output capacity are in development and will soon be commercially available. Emery Energy Company is currently piloting a 75 kW modular biomass gasification system, and Entropic Energy is developing a direct combustion entropic cycle system that capable of generating 250 kW of electricity. This technology is similar to traditional steam-driven combustion cycles, but uses a different working fluid, which increases efficiencies, lowers safety risks, and permits the use of simple and compact equipment. Based on review of available resources, the typical installed cost per kW of these biomass CHP systems will vary substantially depending on the size of the unit installed.

Since the 2009 report, changes enacted by the Energy Improvement and Extension Act of 2008 have taken effect, qualifying biomass CHP systems for federal incentives. The legislation expanded the Business Energy Investment Tax Credit (ITC) to include CHP systems, and businesses paying corporate taxes were eligible to receive a tax credit of 10% of expenditures

for CHP equipment. The American Recovery and Reinvestment Act of 2009 further expanded the incentive program, and now qualified biomass CHP systems are eligible for a 30% ITC through 2013.

Dish/Stirling Concentrated Solar Power (CSP)

This technology differs greatly from traditional solar PV panels, as it uses an array of high-quality mirrors to concentrate the energy from the sun in order to drive a sterling engine. In 2009, the Infinia Powerdish was identified by GDS as a new distributed generation technology capable of producing 3 kW of electricity. Two additional Dish/Stirling Concentrated Solar Power systems developed by SES have since been unveiled, with capacities 25 kW and 50 kW. Though these technologies are relatively expensive, these technologies have higher efficiencies than PV cells and are also projected to have longer lifetimes.

Concentrated Photovoltaics

Like dish/stirling CSP systems, concentrated photovoltaic (CPV) systems use an array of high-quality mirrors to focus the sun's energy. However, instead of driving a sterling engine, these systems concentrate sun up to 1,000 times onto a small, high-efficiency PV cell. This arrangement reduces the need for large areas of expensive PV cells and these systems can therefore be manufactured at a lower cost. CPV systems are easily scalable and require less space than traditional PV panels, thus making them ideal for residential and small business applications. Additionally, as the technology is further developed, the installed cost will continue to decline while efficiencies improve, reducing payback time and increasing energy savings. A particularly inexpensive model is being developed by Cool Earth Solar, utilizing an inflatable chamber with reflective aluminum coating instead of an array of mirrors. The estimated installed cost of this system is projected to be $1,000 per kW.

Combustion Turbines

Combustion turbines are most likely to have financial viability in applications where large year-round system or process heating demands are present, as the technology has reduced efficiencies at part load. These applications typically exist within large commercial or industrial buildings and large institutional campus settings. For the large commercial building and institutional campus systems, absorption chilling is often an integral part of the on-site demand and can help to keep paybacks within a cost-effective range (approximately 5 to 10 years). Additionally, combustion turbines are generally less costly than traditional reciprocating engines at higher output capacities.

A number of viable combustion turbines are currently available over a wide range of power outputs, from 500 kW to 50 MW. Since 2009, they have further penetrated the distributed generation market, as the cost of these systems, including heat recovery equipment, is $1,000 - $1,200 kW.

Thanks for the opportunity to assist with this important effort. If you have any questions or need additional information, please feel free to contact me directly.

Sincerely,

Scott Albert
Principal and Region Manager
GDS Associates, Inc.

Cc: Keith McBrien, GDS Associates, Inc.
Matthew Siska, GDS Associates, Inc.

Attachment 1

Customer Data Profiles – 2003 Model

DISTRIBUTED/ONSITE GENERATION SCREENING MODEL

Prepared by GDS Associates, Inc. for Alliant Energy Corporate Services, Inc. - June 2003

Data - Customer Profiles

Information provided by Alliant Energy Corporate Services, Inc.

0.95 $/therm alternative heating fuel value for customer types where natural gas usage data was n

Code	Customer Type	Rate Class	Natural Gas Avg. Cost ($/therm)	Electricity Avg. Cost ($/kWh)	Peak kW Demand	Annual Therm Consumption	Annual Therms / Peak kw ratio
1	Residential - Electric Heat	Residential	0.900	0.083	0	163	n/a
2	Residential - Gas Heat	Residential	0.900	0.083	0	1,068	n/a
3	Commercial Assembly - Large	Large Power & Lighting Rates	0.958	0.074	152	23,219	153
4	Commercial Assembly - Small	General Demand Metered	0.978	0.087	39	10,040	257
5	Commercial Health Care - Large	Large Power & Lighting Rates	0.612	0.062	1,880	337,344	179
6	Commercial Health Care - Medium	Large Power & Lighting Rates	0.965	0.066	127	20,865	164
7	Commercial Health Care - Small	General Demand Metered	0.950	0.069	15	2,578	172
8	Commercial Hotel/Motel - All Elec	Large Power & Lighting Rates	0.950	0.060	189	14,697	78
9	Commercial Hotel/Motel - Gas	General Demand Metered	0.898	0.064	114	8,865	78
10	Commercial Housing - Aprtmnt Bldgs	Large Power & Lighting Rates	0.944	0.068	180	30,374	169
11	Commercial Office	General Demand Metered	1.213	0.071	15	361	24
12	Commercial Services - Large	Large Power & Lighting Rates	0.950	0.045	1,494	69,319	n/a
13	Commercial Services - Medium	Large Power & Lighting Rates	0.980	0.046	113	5,243	46
14	Commercial Services - Small	General	0.950	0.063	0	524	n/a
15	Commercial Retail - Large	Large Power & Lighting Rates	1.065	0.059	414	14,387	35
16	Commercial Retail - Medium	Large Power & Lighting Rates	0.950	0.061	76	12,450	n/a
17	Commercial Retail - Small	General Demand Metered	1.064	0.075	18	5,272	293
18	Commercial Schools - Large	Large Power & Lighting Rates	0.705	0.054	966	125,748	130
19	Commercial Schools - Medium	Large Power & Lighting Rates	0.950	0.060	184	40,232	n/a
20	Commercial Schools - Small	General Demand Metered	0.705	0.077	111	34,092	307
21	C/I Sewerage System	Large Power & Lighting Rates	0.950	0.049	241	0	n/a
22	C/I Warehouse - Large	Large Power & Lighting Rates	0.950	0.050	946	73,046	77
23	C/I Warehouse - Small	General Demand Metered	0.950	0.074	10	730	73
24	C/I Wholesale Trade - Large	Large Power & Lighting Rates	0.950	0.070	540	16,026	30
25	C/I Wholesale Trade - Medium	Large Power & Lighting Rates	0.950	0.108	750	22,258	30
26	C/I Wholesale Trade - Small	General Demand Metered	0.950	0.076	41	1,217	30
27	C/I Manufacturing - NEC	Large Power & Lighting Rates	0.950	0.039	10,354	307,277	30
28	C/I Manufacturing - Large	Large Power & Lighting Rates	0.977	0.049	963	38,586	40
29	C/I Manufacturing - Medium	Large Power & Lighting Rates	0.950	0.059	298	8,844	30
30	C/I Manufacturing - Small	Large Power & Lighting Rates	1.064	0.063	56	1,080	19
31	Agriculture - Large	Large Power & Lighting Rates	0.950	0.056	170	0	n/a
32	Agriculture - Small	Farm Rates	0.950	0.063	37	0	n/a
33	Government - Large	Large Power & Lighting Rates	0.950	0.046	114	2,744	24
34	Government - Medium	General Demand Metered	0.950	0.061	52	1,251	24
35	Government - Small	General	0.950	0.133	0	626	n/a

RESOURCE ALTERNATIVES

5.0 Supply-Side Alternatives

Many technologies are applicable to supply-side resources. Twenty of these technologies are separately discussed in subsequent sections. For purposes of this report, supply-side technologies are categorized as follows:

Category	Technology
Renewable	Wind Solar-Photovoltaic Solar-Thermal Whole Tree Burning Biomass Geothermal Biogas-Anaerobic Digestion Biogas-Landfill Gas Hydro
Fossil Fuel	Pulverized Coal Fluidized-Bed Combustion Combined Cycle Combustion Turbine Fuel Cell Integrated Gasification Combined Cycle
Purchased Power	Cogeneration/Distributed Generation Independent Power Producer Another Utility MISO Market Energy
Nuclear	Nuclear

The above listing covers all supply-side technologies reviewed for IPL's regulated utility system.

5.0.1 Renewable

Renewable resources refer to resources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy is much more applicable to IPL's utility system and, in addition, has positive environmental benefits. Ten renewable technologies discussed

subsequently are wind, solar-photovoltaic, solar-thermal, whole tree burning, biomass, geothermal, biogas-anaerobic digestion, biogas-landfill gas, ethanol fueled generation and hydro.

5.0.1a Wind

The power of wind has been used for a long time. As examples, wind can power sailboats and run windmills. Wind is also used to drive electric generators, wherein wind turbines capture the wind's energy with blades that operate as airfoils. Wind turbines are commercially available and the technology was evaluated as a supply side resource for IPL's utility system. The results show that wind power is a viable option for IPL and currently IPL has contracted for approximately 250 MW of wind energy, of which almost all is located in Iowa. Furthermore, IPL has recently installed 200 MW of wind in Iowa (Whispering Willow Windfarm - East) to serve IPL's regulated utility customers. Whispering Willow Windfarm - East was put in-service late 2009. Summary historical actual wind data for IPL's wind resources is included in Appendix 5A. For EGEAS modeling, IPL approximates an average capacity factor based on the actual data from a historical year. IPL continues to seek opportunities generated with wind. A study of generating technologies and characteristics, including renewable technologies and characteristics, titled the 2010 Power Station Characterization Study was conducted for IPL by Black & Veatch and finalized in May 2010. Section 9 of the Black & Veatch study focuses on renewable energy technology options. A copy of the Table of Contents from the 2010 Power Station Characterization Study is included in Appendix 5B.

5.0.1b Solar-Photovoltaic

Photovoltaics have achieved more consumer recognition over the last few years. Photovoltaic cells convert sunlight directly into electricity by the interaction of photons and electrons within a semiconductor material. Most photovoltaic applications are smaller than one kW, although

larger utility-scale installations are becoming more prevalent. Current grid-connected PV systems are generally below 100 kW. Solar photovoltaic technologies were investigated in the 2010 Power Station Characterization Study prepared by Black & Veatch dated May 2010. The overnight cost of commercial photovoltaic capacity as developed in this report was estimated to be between $8,000 per kW and $10,500 per kW for a facility less than 100 kW with an approximate capacity factor of 15 percent, and between $3,700 per kW and $5,000 per kW for a facility of approximately 10 MW with an approximate capacity factor of 18 percent. Although solar resources have virtually no emissions after installation, their initial capital cost is significantly more expensive than other resource options. Solar was modeled as a resource option in the EGEAS analysis for this resource plan.

5.0.1c Solar-Thermal

Solar thermal technologies convert the sun's energy to productive use by capturing heat. Early developments in solar thermal technology focused on heating water for domestic use. Advances have expanded the applications to high magnitude energy collection and power conversion on a utility scale. A general feature of solar thermal systems and solar technologies is that peak output typically occurs on summer days when electrical demand is high. However, the costs of this technology are still greater than $5,350 per kW for essentially a peaking type resource and there is a relatively poor potential for utilization of solar thermal energy within IPL's service territory. The costs of this technology are high coupled with a poor potential for utilization makes this technology an unattractive option for IPL at this time.

5.0.1d Whole Tree Burning

One way to generate electrical energy is to burn whole trees. Enormous amounts of land are required for continued operation of a whole tree burning facility. Availability of land within

IPL's service area in the quantities needed presents a problem for this option to be viable for IPL's system.

5.0.1e Biomass

According to the US DOE, there is about 35,000 MW of installed biomass combustion capacity worldwide. The majority of this capacity is in combined heat and power in the pulp and paper industry. By burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Wood and wood waste are the most common biomass fuels. There is reasonable potential for power production from biomass combustion in IPL's service territory. Fuel stream limitations and higher capital costs make this option less attractive; however, biomass was modeled as an option in the EGEAS analysis for this resource plan.

5.0.1f Geothermal

Geothermal power plants use heat from the earth to generate steam and drive turbine generators for the production of electricity. Geothermal power is limited to locations where geothermal pressure reserves are found. Well temperature profiles determine the potential for geothermal development and the type of geothermal power plant installed. The potential for electricity generation from geothermal energy is poor in IPL's service territory. There are no significant geothermal sources in this region.

5.0.1g Biogas-Anaerobic Digestion

Anaerobic digestion is defined as the decomposition of biological wastes by microorganisms, usually under wet conditions, to produce a gas comprising of mostly methane and CO_2. This process occurs in the absence of air (specifically oxygen). The byproduct gas has 50 to 80 percent methane content. The most common applications of anaerobic digestion use industrial

wastewater, animal manure or human sewage. In agriculture applications, anaerobic digesters can be installed where there is a clean, continuous source of manure. For on-farm manure digestion, the resource is readily accessible and only minor modifications are required to the existing manure management techniques. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central digestion facility. IPL's service territory covers vast areas of farm land with large numbers of livestock; therefore, there is good potential for anaerobic digestion within IPL's service territory.

5.0.1h Biogas-Landfill Gas

Landfill gas (LFG) is produced by the decomposition of the organic portion of waste stored in landfills. Landfill gas typically has a methane content between 45 and 55 percent and is considered to be an environmental issue. Methane is a potent greenhouse gas, 25 times more harmful than CO_2. Political and public pressure is rising to reduce air and groundwater pollution. From an energy generation perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines, small combustion turbine generators or other devices. Gas production in a landfill is primarily dependent upon the depth of waste in place, age of waste in place and amount of precipitation received by the landfill. There is good potential for power generation from LFG in IPL's service territory. Currently, landfill gas utilization generates over 125 MW of electricity at landfills in Iowa, Minnesota and Wisconsin.

5.0.1i Hydro

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from one elevation to a lower elevation by passing through a turbine. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. The amount of kinetic energy captured by a turbine is dependent on the head (distance water is falling) and the flow rate of the water.

Another method (run-of-river) of capturing the kinetic energy is to divert the water out of the natural waterway, through a penstock and back to the waterway. Hydroelectric generation is usually regarded as a mature technology that is unlikely to advance. The best sources of hydro generation in IPL's service territory have already been developed. Therefore, additional hydroelectric generation in IPL's service territory is most likely limited to upgrading of existing facilities. Currently, hydroelectric power is a very small percentage of IPL's resource mix.

5.0.2 Fossil Fuel

Fossil fuel refers to any naturally occurring organic fuel such as petroleum, coal or natural gas. Most of the electrical energy generated by IPL's generating facilities is with fossil fuel. The electrical energy purchased utilizes a mix of technologies. However, a significant percentage of this purchased energy is produced from fossil fuel technologies.

5.0.2a Pulverized Coal

Pulverized coal technology is used in many units larger than 20 MW. These units include coal-handling facilities, coal pulverizers, burners, furnaces, air handling facilities, pollution control equipment, water and steam equipment, steam turbines, and related equipment. Due to comparatively low fuel costs and pulverized coal burning being a mature technology, much of the energy generated on IPL's utility system is from units fueled by pulverized coal. The low and relatively more stable operating costs make this a viable option for the future.

5.0.2b Fluidized-Bed Combustion

Fluidized-bed combustion is advantageous in that it has less need for add-on emission control equipment and it can burn extremely low quality fuels. This technology is similar to the pulverized coal technology – the difference is in the combustion process. Coal, along with

crushed limestone, is fed into the furnace and the limestone captures the SO_2 released by the burning mixture. Fluidized-bed combustion is attractive for future units of IPL, since the capital costs are only slightly higher than the pulverized coal technology.

5.0.2c Combined Cycle

Combined cycle refers to the recovery of heat from one turbine, as an example from a combustion turbine, to generate steam to run another generator. Input fuels are oil, natural gas or coal gas. Such units are more efficient than pulverized coal units and can be constructed in stages. Combined cycle units are options to consider for future IPL resources.

5.0.2d Combustion Turbine

Combustion turbine technology is where gaseous or liquid fuel is burned under pressure producing hot gases that pass through an expansion turbine and generates electrical energy. If heat from the turbine is not recovered to run another generation process, it is called a simple cycle technology.

IPL has a number of combustion turbines on its system, but these units are peaking units and generate only a small amount of the total electrical energy produced by IPL. Combustion turbine units continue to be attractive options for meeting system requirements at peak times.

5.0.2e Fuel Cell

Fuel cells directly convert chemical energy into electricity. They offer lower emissions and higher thermal efficiencies than any other fossil fuel based power generation technology. Conceptually, fuel cells are similar to a battery with a continuous addition of chemical energy.

One source of this chemical energy is natural gas. Fuel cells are in commercial service in small installations, but are expensive for central station use.

5.0.2f Integrated Gasification Combined Cycle

The integrated gasification combined cycle (IGCC) application for power generation is relatively new and uses the Shell Coal Gasification Process. Currently, there are four main types of gasifiers; entrained flow, fixed bed, fluidized bed and transport bed. At this time, based on their characteristics and level of development, entrained flow gasifiers are the best choice for high capacity gasification for power generation. The coal will be dried by circulating hot inert gas through a pulverizer. The dried, pulverized coal will be partially oxidized in the entrained flow gasifier to produce raw syngas (synthetic gas produced by the process) with a higher heating value of 250-300 Btu/scf. The raw syngas will be treated to remove particulate, ammonia and sulfur prior to combustion. The clean syngas will then be diluted with nitrogen and water vapor to enhance the combustion turbine generator efficiency and control NO_x to less than 25 ppmv (dry at 15 percent O_2) in the flue gas. The potential environmental advantages of this technology may be offset by a higher capital investment and lower initial plant availability. An IGCC plant takes almost five years to reach full capability. The current uncertainties surrounding IGCC make this technology not as desirable of an option as others today; however, with technological advances and improvements, IGCC may be an option more suitable for future consideration.

5.0.3 Purchased Power

IPL purchases electrical energy from the Midwest Independent Transmission System Operator, Inc. (MISO), other utilities, independent developers and power marketers. The decisions regarding purchased power are primarily functions of need, availability and cost. IPL will continue to purchase power when it makes sense to do so.

5.0.3a Cogeneration/Distributed Generation

Cogeneration refers to facilities that produce electricity as well as other forms of energy. There are a couple of potential cogeneration candidates within the regulated service territory of IPL. Cogeneration will be considered, if feasible. Section 4 of this resource plan details the distributed generation potential.

5.0.3b Independent Power Producer

An independent power producer (IPP) is a non-utility that produces electrical energy for use by electric utilities. IPPs use the same technologies as electric utilities. Capacity and energy from IPPs will continue to be evaluated and used, if available and economical.

5.0.3c Another Utility

IPL routinely purchases power from other utilities on a short-term or seasonal basis. Since the firm load of IPL is growing, additional capacity and energy will be needed in the future. Therefore, if available and economical, purchased power from another utility could be used.

5.0.3d MISO Market Energy

IPL purchases power many hours throughout the year from MISO. In IPL's resource plan modeling, energy from the market can be purchased in every hour of every year of the study period when available and economic.

5.0.4 Nuclear

Nuclear refers to a facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to drive a steam generator. Typical nuclear units are rated at 600 MW or larger and have

high capital requirements. Black & Veatch provided cost and characteristic estimates for a new nuclear generating unit and nuclear was modeled as a resource alternative in the EGEAS analysis for this resource plan.

5.1 Demand-Side Alternatives

DSM programs for this resource plan are categorized into two types of programs: conservation (non-dispatchable) and load management (dispatchable). IPL has achieved considerable demand and energy savings from DSM programs. DSM programs will continue to be a potential resource alternative provided such programs are economical. DSM is discussed further in Section 3 of this resource plan.

5.2 Future Resource Alternatives

Based on the screening of all resource alternatives and the conclusions given in Sections 5.0 and 5.1, Purchased Power, Combustion Turbines, Combined Cycles, Fluidized Beds, Pulverized Coal, IGCC, Wind, Biomass, Biogas, Solar and Nuclear were all evaluated in some form for this resource plan. IPL is committed to meeting the demands of its customers with economic, reliable, safe and environmentally sound resources. Furthermore, IPL's DSM programs and renewable resource portfolio demonstrate IPL's commitment to environmentally sound resources as part of its resource mix.

Information as to the types, sizes and costs for all future units modeled in EGEAS for this resource plan is given in Appendix 5C. With respect to resource costs changing over time, nominal change rates for O&M expenses and capital investment can be found in Appendix 5D. Fuel cost changes are described in Section 6.3.4 and Appendix 6B (Confidential).

APPENDIX 5A

Wind Farm Historical Actual Data Summary

IPL's Major Existing Purchased and Owned Wind Sources

GWH output:

EGEAS Name	MW	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	**average**
WIND IPW CERRO	41.3	101	100	106	101	101	91	103	105	95	84	75	82	**95**
WIND IPW FLYING	43.5					156	151	152	144	141	125	134	142	**143**
WIND IPW BINGHAM	15								43	42	40	41	43	**42**
WIND IPW ADAMS	6					14	13	15	15	14	13	13	13	**14**
WIND IES BEAVER	3.9					11	10	11	11	10	9	9	10	**10**
WIND IES BUENA	78.75	214	206	229	192	180	193	205	185	162	147	167	189	**189**
WIND IES HANCOCK	56.8					156	138	153	148	139	130	139	140	**143**
WIND HARDIN HILL	14.7									29	39	39	47	**39**
WHISP WIL E WIND	200											353	568	**461**

CF % output:

EGEAS Name	MW	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	**average**
WIND IPW CERRO	41.3	28%	28%	29%	28%	28%	25%	28%	29%	26%	23%	21%	23%	**26%**
WIND IPW FLYING	43.5					41%	40%	40%	38%	37%	33%	35%	37%	**38%**
WIND IPW BINGHAM	15								33%	32%	30%	31%	33%	**32%**
WIND IPW ADAMS	6					26%	25%	28%	29%	27%	24%	25%	25%	**26%**
WIND IES BEAVER	3.9					32%	31%	31%	33%	30%	28%	27%	29%	**30%**
WIND IES BUENA	78.75	31%	30%	33%	28%	26%	28%	30%	27%	24%	21%	24%	27%	**27%**
WIND IES HANCOCK	56.8					31%	28%	30%	30%	28%	26%	28%	28%	**29%**
WIND HARDIN HILL	14.7									23%	30%	31%	37%	**30%**
WHISP WIL E WIND	200											20%	32%	**26%**

CERRO = Hawkeye Power Partners
BINGHAM = Windom Wind Farm
ADAMS = G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
BEAVER = Minn Wind I & II
BUENA = Storm Lake Power Partners
WWE = Whispering Willow East Windfarm

APPENDIX 5B

2010 Power Station Characterization Study

May 2010

Prepared by:

Black & Veatch

The following is a copy of only the Table of Contents from the 2010 Power Station Characterization Study prepared by Black & Veatch for IPL.

Table of Contents

1.0 Introduction 1-1
1.1 Technology Descriptions 1-2
1.2 Performance Estimates 1-2
1.3 Power Plant Capital Cost Estimates 1-3
1.4 Power Plant Operating Cost Estimate 1-3
1.5 Preliminary Project Schedule and Durations 1-3
1.6 Preliminary Cash Flow 1-3
2.0 Overall Study Basis Assumptions 2-1
2.1 Plant Site Meteorological Assumptions 2-1
2.2 Plant Site Location and Infrastructure Assumptions 2-2
2.3 Common EPC Capital Cost Estimating Assumptions 2-2
2.3.1 Direct Cost Assumptions 2-3
2.3.2 Indirect Cost Assumptions 2-3
3.0 Rules of Thumb 3-1
3.1 Wet Limestone FGD System 3-1
3.2 Air-Cooled Condenser 3-2
3.2.1 ACC Impact on Combined Cycle Combustion Turbine Capital Costs 3-3
3.2.2 ACC Impact on PC and CFB Capital Costs 3-4
3.2.3 ACC Impact on O&M 3-4
3.3 Potential Cost Reduction Opportunities 3-5
3.3.1 Economies of Scale – Multiple Units 3-5
3.4 Owner's Costs 3-7
4.0 Simple Cycle Combustion Turbine Options 4-1
4.1 Technology Descriptions 4-1
4.1.1 SCCT Operational Description 4-2
4.1.2 GE LMS100PA 4-2
4.1.3 GE 7EA 4-3
4.1.4 GE 7FA.05 4-4
4.2 Performance and Emissions 4-5
4.3 Capital Costs 4-9
4.4 O&M Costs 4-12
4.5 Preliminary Project Schedule 4-12
4.6 Preliminary Cash Flow 4-18
5.0 Combined Cycle Combustion Turbine Options 5-1
5.1 Technology Descriptions 5-1

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5.1.1 CCCT Operational Description 5-1
5.1.2 GE 7FA.05 CCCT 5-4
5.2 Performance and Emissions 5-4
5.3 Capital Costs 5-8
5.4 O&M Costs 5-12
5.5 Preliminary Project Schedule 5-16
5.6 Preliminary Cash Flow 5-19
6.0 Pulverized Coal and Circulating Fluidized Bed Options 6-1
6.1 Technology Descriptions 6-1
6.1.1 Coal Combustion Operational Description 6-1
6.1.2 PC Steam Generators 6-2
6.1.3 CFB Steam Generators 6-6
6.1.4 State-of-the-Art Steam Generator Overview 6-10
6.2 Performance and Emissions 6-11
6.3 Capital Costs 6-15
6.4 O&M Costs 6-21
6.5 Preliminary Project Schedule 6-24
6.6 Preliminary Cash Flow 6-30
7.0 Integrated Gasification Combined Cycle Options 7-1
7.1 Technology Descriptions 7-1
7.1.1 Entrained Flow Gasifiers 7-2
7.1.2 Gasifier Technology Suppliers 7-4
7.2 Performance and Emissions 7-10
7.3 Capital Costs 7-15
7.4 O&M Costs 7-19
7.5 Preliminary Project Schedule 7-21
7.6 Preliminary Cash Flow 7-24
8.0 Nuclear Unit Option 8-1
8.1 Technology Description 8-1
8.1.1 Pressurized Water Reactors 8-1
8.1.2 Westinghouse AP1000 8-1
8.2 Performance and Emissions 8-7
8.2.1 Performance 8-7
8.2.2 Radiological Emissions 8-8
8.2.3 Fossil Fuel Emissions 8-9
8.3 Capital Costs 8-9
8.4 O&M Costs 8-15
8.5 Fuel Cost and Sourcing 8-17

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8.6 Applicable Incentives 8-21
8.6.1 Production Tax Credit Status 8-21
8.6.2 Standby Support Status 8-21
8.6.3 Loan Guarantees Status 8-22
8.7 US NRC Licensing 8-23
8.7.1 Current Delays in Licensing 8-24
8.7.2 Status of AP1000 Construction Worldwide 8-27
8.8 Nuclear Plant Siting 8-30
8.9 Construction Schedule 8-31
8.9.1 Site Preparation 8-31
8.9.2 Construction Phase 8-31
8.9.3 Commissioning Phase 8-33
8.10 Cash Flow Summary 8-33
8.11 Refueling Outages and Maintenance Schedules 8-37
8.12 Spent Fuel 8-37
8.12.1 Yucca Mountain 8-37
8.13 Low Level Radwaste Disposal 8-38
8.14 Decommissioning 8-38
9.0 Renewable Energy Technology Options 9-1
9.1 Solid Biomass 9-2
9.1.1 Direct Fired 9-3
9.1.2 Biomass Integrated Gasification Combined Cycle 9-9
9.1.3 Biomass Co-firing 9-13
9.2 Biogas 9-18
9.2.1 Anaerobic Digestion 9-18
9.2.2 Landfill Gas 9-24
9.3 Biofuels 9-27
9.3.1 Ethanol 9-28
9.3.2 Biodiesel 9-33
9.4 Waste-to-Energy 9-36
9.4.1 Municipal Solid Waste Mass Burn 9-36
9.4.2 Refuse-Derived Fuel 9-39
9.5 Hydroelectric 9-40
9.5.1 Applications 9-41
9.5.2 Resource Availability 9-42
9.5.3 Cost and Performance Characteristics 9-42
9.5.4 Environmental Impacts 9-43
9.5.5 Development Potential 9-43

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9.6 Solar 9-44
9.6.1 Solar Photovoltaic Technologies 9-45
9.6.2 Solar Thermal Technologies 9-54
9.7 Wind 9-58
9.7.1 Applications 9-59
9.7.2 Resource Availability 9-60
9.7.3 Cost and Performance Characteristics 9-61
9.7.4 Environmental Impacts 9-62
9.7.5 Development Potential 9-63
9.8 Geothermal 9-63
9.8.1 Enhanced Geothermal Systems 9-65
9.8.2 Applications 9-66
9.8.3 Resource Availability 9-67
9.8.4 Cost and Performance Characteristics 9-67
9.8.5 Environmental Impacts 9-67
9.8.6 Development Potential 9-68

Appendices

Appendix A. Nuclear Reactor Radionuclide Emissions A-1

List of Tables

Table 2-1. Plant Site Meteorological Assumptions 2-1
Table 3-1. Cost Difference Between SDA and Wet FGD for a PC Unit, 2010$ 3-2
Table 3-2. Cost Difference Between Wet Mechanical Draft Cooling Tower and Dry ACC for a CCCT Unit, 2010$ 3-3
Table 3-3. Cost Difference Between Wet Mechanical Draft Cooling Tower and Dry ACC for a PC and CFB Unit, 2010$ 3-4
Table 3-4. Potential Owners Cost, Fossil/Renewable Technologies 3-8
Table 3-5. Potential Owner's Costs, Nuclear Technologies 3-9
Table 3-6. Typical Owner's Cost, Percent of EPC Cost 3-10
Table 4-1. GE LMS100 Characteristics (GTW-ISO) 4-3
Table 4-2. GE 7EA Characteristics (GTW-ISO) 4-4
Table 4-3. GE 7FA.05 Characteristics (GE-ISO) 4-5
Table 4-4. SCCT Cycle Arrangement Assumptions 4-6
Table 4-5. SCCT Thermal Performance Estimates 4-7
Table 4-6. SCCT Emissions Estimates 4-8

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Table 4-7. SCCT EPC Capital Cost Estimates, 2010$ 4-11
Table 4-8. SCCT O&M Operating Assumptions 4-13
Table 4-9. SCCT Annual O&M Cost Estimates, 2010$ 4-14
Table 4-10. Preliminary SCCT Cash Flow Estimates 4-19
Table 5-1. GE 7FA.05 2x1 CCCT Characteristics (GE-ISO) 5-4
Table 5-2. CCCT Cycle Arrangement Assumptions 5-5
Table 5-3. CCCT Thermal Performance Estimates 5-6
Table 5-4. CCCT Emissions Estimates 5-7
Table 5-5. CCCT EPC Capital Cost Estimates, 2010$ 5-11
Table 5-6. CCCT O&M Operating Assumptions 5-14
Table 5-7. CCCT Annual O&M Cost Estimates, 2010$ 5-15
Table 5-8. CCCT Cash Flow Estimates 5-20
Table 6-1. PC and CFB Cycle Arrangement Assumptions 6-12
Table 6-2. PC and CFB Thermal Performance Estimates 6-13
Table 6-3. PC and CFB Estimated Air Emissions Limits 6-14
Table 6-4. PC and CFB EPC Capital Cost Estimates, 2010$ 6-16
Table 6-5. PC and CFB O&M Operating Assumptions 6-22
Table 6-6. PC and CFB Annual O&M Cost Estimates, 2010$ 6-23
Table 6-7. Preliminary PC Cash Flow Estimates 6-31
Table 6-8. CFB Cash Flow Estimates 6-33
Table 7-1. Comparison of Key Gasifier Design Parameters 7-8
Table 7-2. IGCC Cycle Arrangement Assumptions 7-11
Table 7-3. IGCC Thermal Performance Estimates 7-13
Table 7-4. IGCC Emissions Estimates 7-14
Table 7-5. IGCC EPC Capital Cost Estimates, 2010$ 7-15
Table 7-6. IGCC O&M Operating Assumptions 7-20
Table 7-7. IGCC Annual O&M Cost Estimates, 2010$ 7-21
Table 7-8. Preliminary IGCC Cash Flow Estimates 7-25
Table 8-1. Westinghouse AP1000 Technical Data 8-2
Table 8-2. Nuclear Full Load Performance Estimates 8-8
Table 8-3. Yearly Fossil-Fueled Emissions 8-9
Table 8-4. Nuclear Capital Cost Estimate (2010$) 8-10
Table 8-5. Nuclear O&M Operating Assumptions 8-15
Table 8-6. Nuclear Annual O&M Cost Estimates, 2010$ 8-16
Table 8-7. Nuclear Fuel Costs 8-18
Table 8-8. Status of Westinghouse AP1000 Construction Worldwide 8-28
Table 8-9. Westinghouse AP1000 Siting Requirements 8-30
Table 8-10. AP1000 Cash Flow Estimates 8-34

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Table 9-1. Direct-Fired Biomass Combustion Technology Characteristics 9-6
Table 9-2. Permit Limits for Mancelona (Wood-Fired) Biomass Project. 9-7
Table 9-3. BIGCC Technology Characteristics 9-12
Table 9-4. Co-fired Biomass Technology Characteristics 9-16
Table 9-5. Anaerobic Digestion Technology Characteristics 9-22
Table 9-6. Emissions from Digester Gas-Fired Reciprocating Engines. 9-23
Table 9-7. Emissions from LFG-Fired Reciprocating Engines 9-26
Table 9-8. LFG Technology Characteristics 9-27
Table 9-9. Domestic Fuel Production and Price Comparison 9-28
Table 9-10. MSW Mass Burn Technology Characteristics 9-38
Table 9-11. RDF Technology Characteristics 9-40
Table 9-12. Hydro Technology Characteristics 9-43
Table 9-13. Solar PV Technology Characteristics 9-52
Table 9-14. Solar Thermal Electric Technology Characteristics 9-59
Table 9-15. Wind Power Characteristics 9-61
Table 9-16. Wind Technology Characteristics 9-62
Table 9-17. Geothermal Technology Characteristics 9-68

List of Figures

Figure 4-1. SCCT Schematic Diagram 4-2
Figure 4-2. 1x0 GE LMS100PA SCCT Preliminary Project Schedule 4-15
Figure 4-3. 1x0 GE 7EA SCCT Preliminary Project Schedule 4-16
Figure 4-4. 1x0 GE 7FA.05 SCCT Preliminary Project Schedule 4-17
Figure 4-5. GE LMS100PA SCCT Cast Flow Curves 4-20
Figure 4-6. GE 7EA SCCT Cash Flow Curves 4-21
Figure 4-7. GE 7FA.05 SCCT Cash Flow Curve 4-22
Figure 5-1. 1x1 CCCT Power Plant Schematic Diagram 5-2
Figure 5-2. 2x1 CCCT Power Plant Schematic Diagram 5-3
Figure 5-3. 1x1 GE 7FA.05 CCCT Preliminary Project Schedule 5-17
Figure 5-4. 2x1 GE 7FA.05 CCCT Preliminary Project Schedule 5-18
Figure 5-5. 1x1 GE 7FA.05 CCCT Cash Flow Curves 5-22
Figure 5-6. 2x1 GE 7FA.05 CCCT Cash Flow Curve 5-23
Figure 6-1. Coal Fired Power Plant Schematic Diagram 6-2
Figure 6-2. Typical Arrangement of an SPC Boiler (Source: Babcock & Wilcox) 6-4
Figure 6-3. Typical Arrangement of an SCPC Boiler 6-5
Figure 6-4. Fluidized Bed Technologies 6-7

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Figure 6-5. Typical Arrangement of a CFB Boiler 6-8
Figure 6-6. Environmental Benefits of CFB Combustion Temperatures 6-10
Figure 6-7. 300 MW SPC Preliminary Project Schedule 6-25
Figure 6-8. 600 MW SPC Preliminary Project Schedule 6-26
Figure 6-9. 600 MW SCPC and USCPC Preliminary Project Schedule 6-27
Figure 6-10. 300 MW CFB Preliminary Project Schedule 6-28
Figure 6-11. 600 MW CFB Preliminary Project Schedule 6-29
Figure 6-12. 300 MW SPC Cash Flow Curves 6-35
Figure 6-13. 600 MW SPC Cash Flow Curves 6-36
Figure 6-14. 600 MW SCPC and USCPC Cash Flow Curves 6-37
Figure 6-15. 300 MW CFB Cash Flow Curves 6-38
Figure 6-16. 600 MW CFB Cash Flow Curves 6-39
Figure 7-1. IGCC Schematic Diagram 7-2
Figure 7-2. 1x1 IGCC Preliminary Project Schedule 7-22
Figure 7-3. 2x1 IGCC Preliminary Project Schedule 7-23
Figure 7-4. 1x1 IGCC Cash Flow Curves 7-27
Figure 7-5. 1x1 IGCC Cash Flow Curves 7-28
Figure 8-1. Annual Uranium Production and Requirements 8-19
Figure 8-2. TradeTech's Long-Term Price Indicators - U308 and Conversion 8-19
Figure 8-3. TradeTech's Long-Term Price Indicators - SWU 8-20
Figure 8-4. Typical Fuel Cost Elements 8-20
Figure 8-5. Comparison of Reinforced Concrete Construction 8-25
Figure 8-6. Comparison of Construction Schedules for Reinforced Concrete 8-26
Figure 8-7. Westinghouse AP1000 Construction Schedule 8-32
Figure 8-8. Nuclear Cash Flow Curves 8-36
Figure 8-9. Low Level Waste Compacts 8-40
Figure 9-1. Biomass Sources, Processes, Products, and Markets 9-3
Figure 9-2. 35 MW Biomass Combustion Plant 9-4
Figure 9-3. General Gasification Flow 9-10
Figure 9-4. Coal and Wood Mix 9-13
Figure 9-5. Alholmens Kraft Multi-Fuel CFB 9-15
Figure 9-6. US Biomass Resources per Square Kilometer / yr 9-17
Figure 9-7. Schematic of a Single-Vessel Anaerobic Digester 9-18
Figure 9-8. Diary Manure Digester Facility 9-20
Figure 9-9. Reciprocating Engine Used to Generate Power from LFG 9-24
Figure 9-10. Ethanol Production Facility in Wisconsin 9-28
Figure 9-11. Expansion of US Ethanol Industry since 2000 9-29
Figure 9-12. Crop Density by County 9-31

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Figure 9-13. 3 MW Hydroelectric Plant 9-41
Figure 9-14. Effective Load Carrying Capacity of PV 9-50
Figure 9-15. Solar PV Resource for the US vs. Germany 9-51
Figure 9-16. US Module Costs, $/Watt 9-51
Figure 9-17. Parabolic Trough Installation 9-55
Figure 9-18. Central Receiver Installation 9-56
Figure 9-19. Parabolic Dish Receiver 9-57
Figure 9-20. Linear Fresnel Demonstration Unit 9-57
Figure 9-21. Typical Wind Turbine Design 9-60
Figure 9-22. Iowa Wind Resource Map 9-64
Figure 9-23. Minnesota Wind Resource Map 9-64
Figure 9-24. Basic Geothermal Systems: Simplified Plant Layouts 9-65
Figure 9-25. EGS System Diagram 9-66
Figure 9-26. Geothermal Resource of the United States 9-69

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APPENDIX 5C

Alternative Resource Characteristics

The following is data for future resource alternatives modeled in EGEAS.

Generic Alternative Characteristics
IPL 2012 IRP

EGEAS Unit	Rated Capacity (MW)	Operating Capacity (MW)	Reserve Capacity (MW)	Forced Outage Rate	Full Load Heat Rate (BTU/KWH)	Fuel Price ($/MMBTU)	Fixed O&M Cost ($/KW-Yr)	EGEAS Variable O&M ($/MWH)	Capital Cost ($/KW)	Book Life (Years)	Levelized Carrying Charge Rate	ROE
CT-73	72.895	72.895	67.530	7.36%	12,089	$4.19	$14.83	$20.31	$1,139	27	11.490%	10.000%
CT-88	88.033	88.033	81.554	7.36%	9,073	$4.19	$12.54	$5.01	$1,310	27	11.490%	10.000%
CT-189	188.9	188.9	174.997	7.36%	10,216	$4.19	$6.22	$25.55	$766	27	11.490%	10.000%
CC-288	288.4	288.4	271.298	5.93%	6,837	$4.19	$9.20	$5.19	$1,714	27	12.896%	12.230%
CC-538.9	538.9	538.9	506.943	5.93%	6,960	$4.19	$6.18	$5.14	$1,324	27	12.896%	12.230%
CFB300	300	300	279.660	6.78%	9,966	$2.27	$37.28	$3.93	$4,960	35	12.135%	12.230%
CFB600	600	600	559.320	6.78%	9,928	$2.27	$24.11	$3.83	$3,897	35	12.135%	12.230%
SOLAR10	10	10	10	-	-	-	$28.89	$0.63	$5,973	25	10.892%	11.700%
BIOMASS35	35	35	32.627	6.78%	15,500	$3.14	$102.23	$14.26	$7,662	35	11.781%	11.700%
BIOGAS10	10	10	9.322	6.78%	11,500	$1.57	-	$15.73	$6,106	35	11.781%	11.700%
WIND 50	50	50	6.45	-	-	-	-	$0.00	$2,030	25	10.892%	11.700%
WIND 100	100	100	12.9	-	-	-	-	$0.00	$2,030	25	10.892%	11.700%
PC300	300	300	275.100	8.30%	9,910	$2.27	$37.65	$3.95	$4,888	35	12.135%	12.230%
PC600	600	600	562.560	6.24%	9,290	$2.27	$22.86	$3.89	$3,753	35	12.135%	12.230%
IGCC284	284	284	266.278	6.24%	8,800	$2.27	$46.97	$7.13	$6,177	35	12.135%	12.230%
IGCC568	568	568	532.557	6.24%	8,800	$2.27	$33.87	$6.82	$5,619	35	12.135%	12.230%
PPCT 1YR 50	50	0	50	0.00%	-	ref to CT-189	~$1 initially	-	-	1		-
PPCT 10YR 150	150	150	138.975	7.36%	10,216	ref to CT-189	$103.04	$25.55	-	10		-
PPCC 10YR 150	150	150	141.105	5.93%	6,811	ref to CC-538.9	$201.70	$5.14	-	10		-
PPPC 10YR 150	150	150	140.640	6.24%	9,290	ref to PC600	$524.16	$3.89	-	10		-
NUCLEAR 300J	300	300	288.180	3.94%	10,400	$0.58	$134.86	$0.63	$5,823	35	12.135%	12.230%

Costs are 2012$ unless noted otherwise
Wind Capital Cost is based on $62.50/MWH levelized equivalent in 2010$. Escalation to 2012 is 3.1%/year.
$62.50/MWH x 8760h x 38% CF / 1000 KW per MW / 10.892% LCCR * 1.031^2 = $2030/KW (2012$)
In EGEAS, 10 year PTC impact is modeled using Detailed Capital Costs for Biomass and Biogas:
Biomass $22/MWH x 35 MW x 85% CF x 8760 h / 35,000 KW = -164 $/kW-y over 10 year book life and 100% LFCR (2010$)
Biogas $11/MWH x 10 MW x 85% CF x 8760 h / 10,000 KW = -82 $/kW-y over 10 year book life and 100% LFCR (2010$)
In EGEAS, Solar 25 year ITC impact is modeled using Detailed Capital Costs:
30% of capital inv spread over 25 years, 30% x $5,764/kw / 25 yrs = -69 $/kw-y over 25 year book life and 100% LFCR (2010$)
In EGEAS, CC 538.9 also includes a Transmission cost component in Detailed Capital Costs:
$167.8/kW, 27 year book life, 12.896% levelized carrying charge rate (2012$)

APPENDIX 5D

Change Rates for Key Economic Variables

Interstate Power & Light Company
2012 Resource Plan
Change Rates for Key Economic Variables
West North Central Region

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Consumer Price Index 1)	1.6%	3.0%	1.8%	4.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Capital Investment																		
Combustion Turbine 3)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	1.2%	1.2%	1.2%	1.2%	1.2%	0.5%	0.5%	0.5%	0.5%	0.5%	0.2%	0.2%
Combined Cycle 3)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	1.2%	1.2%	1.2%	1.2%	1.2%	0.5%	0.5%	0.5%	0.5%	0.5%	0.2%	0.2%
Pulverized Coal 3)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	1.2%	1.2%	1.2%	1.2%	1.2%	0.5%	0.5%	0.5%	0.5%	0.5%	0.2%	0.2%
Fluidized Bed 3a)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	1.2%	1.2%	1.2%	1.2%	1.2%	0.5%	0.5%	0.5%	0.5%	0.5%	0.2%	0.2%
IGCC Coal 3)	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	1.0%	1.0%	1.0%	1.0%	1.0%	0.3%	0.3%	0.3%	0.3%	0.3%	-0.1%	-0.1%
Wind 4)	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	0.1%	0.1%
Biomass 4)	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	-0.4%	-0.4%
Photovoltaic 4)	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	-0.9%	-0.9%	-0.9%	-0.9%	-0.9%	-0.9%	-0.9%	-0.9%	-0.9%	-0.9%	-1.7%	-1.7%
Biogas 5)	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Nuclear 6)	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	0.2%	0.2%	0.2%	0.2%	0.2%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.2%	-0.2%
O&M	1.6%	3.0%	1.8%	4.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
MPUC Environmental Costs	1.6%	3.0%	1.8%	4.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Note that these values are the escalation from the previous year, EGEAS convention is that the escalator in a particular year is the escalation from that year to the next year.

1) Wood Mackenzie, "NAGS_LTV_Price_Outlook_Oct_2011.xls", North America Natural Gas Long-Term View, October 2011
Tab "Economic Assumptions", CPI Deflator, US. 2032+ assumes 2% rate similar to 2014-2031
2011=1.000, note that annual escalation percentages match "NAPS_No_Carbon_Case_MacroEconomics_Assumptions_12_15_2011.xls"

3) Assumptions to the Annual Energy Outlook 2011, July 2011
Electricity Market Module, Table 8.11, Cost and Performance Characteristics for Fossil-Fueled Generating Technologies, Reference Case
Total Overnight Cost in 2011 (Reference Case) (2009 $/kW)

3a) Table 8.11 does not provide projected future capital costs for CFB
assumes same escalation as pulverized coal

4) Assumptions to the Annual Energy Outlook 2011, July 2011
Renewable Fuels Module, Table 13.1. Overnight Capital Cost Characteristics for Renewable Energy Generating Technologies, Reference Case

5) Table 13.1 does not provide projected future capital costs for Landfill Gas
2010 costs per Table 8.2 of the Electricity Market Module
assumes flat escalation in real terms

6) Assumptions to the Annual Energy Outlook 2011, July 2011
Electricity Market Module, Table 8.12, Cost Characteristics for Advanced Nuclear Technology, Reference Case
Total Overnight Cost in 2011 (Reference Case) (2009 $/kW)

RESOURCE PLAN

6.0 Overview of Analyses

Initially, IPL creates a chart for the study period comparing the system demand load forecast plus reserve obligations to existing generating capability before resource additions. This chart gives an indication of the amount of new resources required in the future. A graph of this data can be found in Appendix 6A (and numerically in Appendix 10B).

IPL's 2017 shortfall is 346 Planning Resource Credits (PRCs) and increases to 616 PRCs in 2024. After 2024, the modeling represents significant capacity losses such as the expiration of the DAEC PPA and retirement of Burlington and Kapp 2. In 2025 the shortfall is 984 PRCs, in 2026 the shortfall is 1414 PRCs, and in 2027 the shortfall is 1444 PRCs.

To potentially meet future requirements, IPL evaluated many possible resources. On the supply-side, several different technologies are evaluated. Specifically modeled were options such as renewables, fossil-fueled technologies and purchases. The bulk of the analysis is done using EGEAS. In an attempt to reach the best solution, numerous EGEAS runs are made, and each run looked at many plans.

The proposed plan evolved from runs that, along with IPL's existing resources, optionally had available the following resources:

- Wind
- Biomass
- Biogas
- Solar

- Simple Cycle
- Combined Cycle
- Fluidized-Bed
- Integrated Gasification Combined Cycle
- Pulverized Coal
- Nuclear
- Purchased Power

These EGEAS runs looked at many plans and the optimum plan is based on having the lowest cumulative present worth given the assumptions for the 15-year study period plus a 35-year extension period.

As further background and as documented in the 2010 Resource Plan, IPL has subjectively grouped its coal fired generating units into three tiers: Tier 1, Tier 2, and Tier 3.

Tier 1 units are:

- Expected to operate throughout the study period;
- Expected to get full controls for NO_x, SO_2, and Hg;
- Candidates for efficiency upgrades to improve heat rate and lower emissions;
- Tier 1 Units are: Neal Units 3 and 4, Louisa, Ottumwa (OGS), and Lansing Unit 4.

Tier 2 units are:

- Smaller and less efficient than Tier 1 units;
- Not likely to economically withstand full environmental controls;
- Potentially able to withstand low-cost emissions control options;
- Tier 2 Units are:

Tier 3 Units are:

- Not able to withstand any additional emissions control expenditures;

- Not planned to operate throughout the study period;
- All remaining coal units;
- Tier 3 units, with the exception of Sutherland 3, were proposed to be retired in the 2010 Resource Plan.

6.1 Proposed Plan

IPL's plan to meet the demands of its customers requires modification to existing resources, and also new additions. The proposed resource plan includes:

- Using existing owned generation with the exceptions noted below:
  - Retiring [redacted] effective [redacted]
  - Retiring Dubuque Units 3 and 4 effective 1/1/2015, as proposed in the 2010 Resource Plan, [redacted];
  - Retiring [redacted], effective with the addition of a new combined cycle facility in the second quarter of 2017;
  - Retiring [redacted] effective with the addition of a new combined cycle facility in the second quarter of 2017;
  - Retiring [redacted] effective with the addition of a new combined cycle facility in the second quarter of 2017;
  - Retire Fox Lake 3 effective with the addition of a new combined cycle facility in the second quarter of 2017;
  - Retiring Sutherland Units 1 and 3 effective with the addition of a new combined cycle facility in the second quarter of 2017;
  - Retiring [redacted] effective with the addition of a new combined cycle facility in the second quarter of 2017.

- Implementing Ottumwa Generating Station capacity and efficiency upgrades as proposed in the 2010 Resource Plan, as well as a Scrubber and Baghouse installed by 2015;
- Implementing Lansing Unit 4 capacity and efficiency upgrades as proposed in the 2010 Resource Plan, as well as a Scrubber installed by 2016 in addition to the existing SCR and Baghouse installation;
- Modifications at MidAmerican Energy operated units Neal 3, Neal 4, and Louisa as proposed by MidAmerican Energy;
- The installation of "emissions lite" control projects[1] [redacted] by 2015;
- The installation of "emissions lite" control projects [redacted] 2015;
- The installation of "emissions lite" controls projects at [redacted] by 2015;
- The addition of a nominal 600 MW combined cycle plant operational in the second quarter of 2017;
- The purchase of short term capacity in 2016 as needed before the installation of the new combined cycle unit;
- Completing existing purchase power contracts;
- Using forecasted DSM;
- In the long term:
    - Adding incremental renewable generation (for example, the Reference Case selects 1,000 MW of wind in the last 5 years of the study period);
    - Acquiring new purchased power contract(s) (for example, the Reference Case selects several one year peak power purchases at the end of the study period between 2022 and 2027;

[1] "emissions lite" control projects include installing Activated Carbon Injection (ACI) which reduces mercury emissions and upgrading Electrostatic Precipitators (ESPs) which reduces particulate matter for

- Adding new generating units (for example, the Reference Case selects 800 MW of gas fired combustion turbine and combined cycle facilities in the last 3 years of the study period).

IPL will seek MISO approval to remove the proposed retiring generating units from the MISO grid via an Attachment Y filing. For accounting purposes, subsequent to MISO approval to remove the assets from the grid, IPL will retire/remove the assets from its accounting records as prescribed by the FERC Code of Federal Regulations. IPL will potentially incur future removal and environmental costs for the above referenced generating unit assets; the estimated costs and timing of such are uncertain at this time.

6.2 Transmission Congestion

Transmission congestion in the IPL service territory is primarily a result of factors or combination of factors in the operational time frame. These factors include generation and transmission outages, exports from 3rd party generation located in the IPL service territory selling to entities outside of the IPL service territory, and regional power flows through the IPL service territory resulting from short term economy power purchases of entities outside the IPL service territory.

In 2007, the following IPL transmission facilities located in the IPL service territory were congested, requiring reductions of energy in order to alleviate the congestion: Arnold – Vinton 161 kV on one occasion; Fox Lake – Rutland 161 kV on two occasions. On all occasions, congestion relief was accomplished through generation re-dispatch and there was no loss of service to IPL customers.

Utility Mercury and Air Toxics Standard (MATS) compliance

In December 2007, IPL sold its transmission assets to ITC Midwest. As a result of that transaction, IPL no longer owns transmission facilities. For the purpose of that transaction, transmission facilities are defined as all facilities with an operating voltage of 34 kV and above. In 2008, the following ITC Midwest transmission facilities located in the IPL service territory were congested, requiring reductions of energy in order to alleviate the congestion: Fox Lake – Rutland 161 kV on two occasions; Worth County – Hayward 161 kV on one occasion; Hazleton 345/161 kV transformer on one occasion. On all occasions, congestion relief was accomplished through generation re-dispatch and there was no loss of service to IPL customers.

In 2009, the following IPL generators were re-dispatched to a higher or lower output due to transmission system congestion: Lime Creek CT 1, Emery on two occasions, Sutherland Coal Unit 2, Sutherland Coal Unit 3, Sutherland CT 1, Sutherland CT 2, Sutherland CT 3, and Lansing Unit 4. On all occasions the re-dispatch was used to mitigate the transmission congestion, and there was no loss of service to IPL customers.

In 2010, the following IPL generators were re-dispatched on one occasion to a higher or lower output due to transmission system congestion: Prairie Creek Unit 4, Emery, ML Kapp Unit 2, and Ottumwa. On all occasions the re-dispatch was used to mitigate the transmission system congestion, and there was no loss of service to IPL customers.

In 2011, the following IPL generators were re-dispatched to a higher or lower output due to transmission system congestion: Prairie Creek Unit 4 on one occasion, ML Kapp Unit 2 on one occasion, Dubuque 8th Street Unit 4 on one occasion, Marshalltown CT 1 on one occasion, Marshalltown CT 3 on one occasion, Ottumwa on two occasions, and Emery on four occasions.

On all occasions the re-dispatch was used to mitigate the transmission system congestion, and there was no loss of service to IPL customers.

As of July 2012, the following IPL generators were re-dispatched to a higher or lower output due to transmission system congestion: Ottumwa on two occasions, Centerville CT 1 on one occasion, Centerville CT2 on one occasion, ML Kapp Unit 2 on two occasions, Burlington on two occasions, and Sutherland Coal Unit 3 on one occasion. On all occasions the re-dispatch was used to mitigate the transmission system congestion, and there was no loss of service to IPL customers.

IPL continues to work with ITC Midwest through the stakeholder process to insure a reliable supply of energy exists for its customers by continually assessing the current and future needs of the ITC Midwest transmission system. In addition, IPL continues to be active in the MISO Transmission Dependent Utility (TDU) sector of the planning and stakeholder process, as well as various other ad hoc transmission activities. Although past congestion has, on several occasions resulted in IPL having to re-dispatch generation in order to alleviate transmission congestion, IPL has no indication that its generation resources will not be able to meet customer electric demands because of transmission congestion.

6.3 EGEAS Input Assumptions

The following sections highlight the major EGEAS assumptions in the 2012 Electric Resource Plan.

6.3.1 General EGEAS Settings

Highlights of general EGEAS settings include:

- 2012-2027 Study Period with 35 year extension period;
- 8.03% discount rate (After Tax Weighted Allocated Cost of Capital per last approved rate case);
- 2010 Base Year;
- 3.81% Planning Reserve Margin.

6.3.2 Demand and Energy Forecast

See Section 2 for a detailed discussion of the load forecast development. The system demand (MW) modeled in EGEAS is on an Adjusted Firm basis after reducing the system peak by interruptible load, load control, and a Demand Diversity component due to IPL's joint dispatching with Central Iowa Power & Light Cooperative. Note that the forecast assumes loss of a wholesale customer in 2014, which is approximately 65-70 MW.

IPL developed a Base, Low, and High load forecast shown in the tables below. The Base Forecast grows by 350 MW over the study period. The High Forecast grows by 435 MW, and the Low Forecast grows by 267 MW.

Table 6.3.2.1: EGEAS Demand and Energy Forecast, Base Forecast

Year	GWH	Peak (MW)		Inter-ruptible		DLC		Firm Demand		Demand Diversity		EGEAS Demand (MW)
2012	16,612	3,053.5	-	243.0	-	33.0	=	2,777.5	-	16.7	=	2760.8
2013	16,702	3,056.8	-	245.0	-	33.3	=	2,778.5	-	16.7	=	2761.8
2014	16,415	2,999.4	-	247.0	-	33.7	=	2,718.8	-	16.3	=	2702.5
2015	16,554	3,039.4	-	250.0	-	34.0	=	2,755.4	-	16.5	=	2738.9
2016	16,715	3,077.3	-	252.0	-	34.3	=	2,790.9	-	16.7	=	2774.2
2017	16,897	3,114.3	-	255.0	-	34.7	=	2,824.6	-	16.9	=	2807.7
2018	17,056	3,149.2	-	257.0	-	35.0	=	2,857.2	-	17.1	=	2840.1
2019	17,235	3,180.3	-	260.0	-	35.4	=	2,884.9	-	17.3	=	2867.6
2020	17,405	3,216.3	-	263.0	-	35.7	=	2,917.6	-	17.5	=	2900.1
2021	17,572	3,246.4	-	265.0	-	36.1	=	2,945.3	-	17.7	=	2927.6
2022	17,719	3,277.4	-	268.0	-	36.5	=	2,973.0	-	17.8	=	2955.2
2023	17,883	3,311.4	-	271.0	-	36.8	=	3,003.6	-	18.0	=	2985.6
2024	18,068	3,348.4	-	273.0	-	37.2	=	3,038.2	-	18.2	=	3020.0
2025	18,258	3,384.3	-	276.0	-	37.6	=	3,070.8	-	18.4	=	3052.4
2026	18,430	3,417.3	-	279.0	-	37.9	=	3,100.4	-	18.6	=	3081.8
2027	18,614	3,449.4	-	282.0	-	38.3	=	3,129.1	-	18.8	=	3110.3

Table 6.3.2.2: High Forecast

Year	GWH	Peak (MW)		Inter-ruptible		DLC		Firm Demand		Demand Diversity		EGEAS Demand (MW)
2012	16,641	3,058.5	-	243.0	-	33.0	=	2,782.5	-	16.7	=	2765.8
2013	16,752	3,066.7	-	245.0	-	33.3	=	2,788.4	-	16.7	=	2771.7
2014	16,498	3,014.3	-	247.0	-	33.7	=	2,733.6	-	16.4	=	2717.2
2015	16,671	3,058.1	-	250.0	-	34.0	=	2,774.1	-	16.6	=	2757.5
2016	16,866	3,102.9	-	252.0	-	34.3	=	2,816.5	-	16.9	=	2799.6
2017	17,078	3,143.8	-	255.0	-	34.7	=	2,854.1	-	17.1	=	2837.0
2018	17,268	3,184.6	-	257.0	-	35.0	=	2,892.6	-	17.4	=	2875.2
2019	17,479	3,221.6	-	260.0	-	35.4	=	2,926.2	-	17.6	=	2908.6
2020	17,682	3,262.5	-	263.0	-	35.7	=	2,963.7	-	17.8	=	2945.9
2021	17,883	3,298.4	-	265.0	-	36.1	=	2,997.3	-	18.0	=	2979.3
2022	18,064	3,335.4	-	268.0	-	36.5	=	3,030.9	-	18.2	=	3012.7
2023	18,263	3,376.2	-	271.0	-	36.8	=	3,068.4	-	18.4	=	3050.0
2024	18,486	3,419.0	-	273.0	-	37.2	=	3,108.9	-	18.7	=	3090.2
2025	18,717	3,460.9	-	276.0	-	37.6	=	3,147.3	-	18.9	=	3128.4
2026	18,927	3,500.8	-	279.0	-	37.9	=	3,183.8	-	19.1	=	3164.7
2027	19,152	3,538.7	-	282.0	-	38.3	=	3,218.4	-	19.3	=	3199.1

Table 6.3.2.3: Low Forecast

Year	GWH	Peak (MW)		Inter-ruptible		DLC		Firm Demand		Demand Diversity		EGEAS Demand (MW)
2012	16,583	3,048.5	-	243.0	-	33.0	=	2,772.5	-	16.6	=	2755.9
2013	16,652	3,047.9	-	245.0	-	33.3	=	2,769.6	-	16.6	=	2753.0
2014	16,332	2,985.6	-	247.0	-	33.7	=	2,705.0	-	16.2	=	2688.8
2015	16,438	3,019.6	-	250.0	-	34.0	=	2,735.6	-	16.4	=	2719.2
2016	16,566	3,052.7	-	252.0	-	34.3	=	2,766.3	-	16.6	=	2749.7
2017	16,718	3,083.8	-	255.0	-	34.7	=	2,794.1	-	16.8	=	2777.3
2018	16,848	3,113.8	-	257.0	-	35.0	=	2,821.8	-	16.9	=	2804.9
2019	16,997	3,140.0	-	260.0	-	35.4	=	2,844.6	-	17.1	=	2827.5
2020	17,136	3,170.1	-	263.0	-	35.7	=	2,871.4	-	17.2	=	2854.2
2021	17,271	3,194.3	-	265.0	-	36.1	=	2,893.2	-	17.4	=	2875.8
2022	17,387	3,219.5	-	268.0	-	36.5	=	2,915.0	-	17.5	=	2897.5
2023	17,518	3,248.6	-	271.0	-	36.8	=	2,940.8	-	17.6	=	2923.2
2024	18,486	3,419.0	-	273.0	-	37.2	=	3,108.9	-	18.7	=	3090.2
2025	18,717	3,460.9	-	276.0	-	37.6	=	3,147.3	-	18.9	=	3128.4
2026	18,927	3,500.8	-	279.0	-	37.9	=	3,183.8	-	19.1	=	3164.7
2027	19,152	3,538.7	-	282.0	-	38.3	=	3,218.4	-	19.3	=	3199.1

6.3.3 Emission Costs

NO_x and SO_2 emission costs are based on Wood Mackenzie projections, shown below:

Table 6.3.3.1: SO_2 and NO_x Prices

No Carbon Scenario				Carbon Scenario		
	NO_x ($/short ton)	SO_2 ($/short ton)			NO_x ($/short ton)	SO_2 ($/short ton)
2012	$1,467	$129		2012	$743	$121
2013	$827	$98		2013	$65	$35
2014	$1,213	$823		2014	$1,546	$986
2015	$1,578	$134		2015	$1,913	$297
2016	$0	$0		2016	$0	$0
2017	$0	$0		2017	$0	$0
2018	$0	$0		2018	$0	$0
2019	$0	$0		2019	$0	$0
2020	$0	$0		2020	$0	$0
2021	$0	$0		2021	$0	$0
2022	$0	$0		2022	$0	$0
2023	$0	$0		2023	$0	$0
2024	$0	$0		2024	$0	$0
2025	$0	$0		2025	$0	$0
2026	$0	$0		2026	$0	$0
2027	$0	$0		2027	$0	$0

Wood Mackenzie indicated to IPL that the $0 prices in later years are a result of upcoming emission rules, such as MATS, forcing retrofits and retirements of units, which generates an oversupply of allowances for Iowa.

Because there are no Carbon Dioxide (CO_2) regulations that exist today for IPL, potential regulations were considered in sensitivity runs but not included in the Reference Case. Furthermore, three CO_2 cost scenarios were modeled; one based on Wood Mackenzie's CO_2 price projection and the other two from the Commission's Order Establishing 2009 and 2010 Estimate of Future Carbon Dioxide Regulation Costs in Docket No. E-999/CI-07-1199. The CO_2 prices modeled in the three CO_2 scenarios are shown in Table 6.3.3.2 below:

Table 6.3.3.2: CO_2 Prices

Year	Reference Case	Wood Mackenzie CO_2 $/Ton	Minnesota Low CO_2 $/Ton	Minnesota High CO_2 $/Ton
2012	$0.00	$0.00	$9.00	$34.00
2013	$0.00	$0.00	$9.36	$35.36
2014	$0.00	$0.00	$9.55	$36.07
2015	$0.00	$0.00	$9.74	$36.79
2016	$0.00	$0.00	$9.93	$37.52
2017	$0.00	$0.00	$10.13	$38.27
2018	$0.00	$0.00	$10.33	$39.04
2019	$0.00	$0.00	$10.54	$39.82
2020	$0.00	$0.00	$10.75	$40.62
2021	$0.00	$0.00	$10.97	$41.43
2022	$0.00	$16.07	$11.19	$42.26
2023	$0.00	$17.38	$11.41	$43.10
2024	$0.00	$18.79	$11.64	$43.96
2025	$0.00	$20.31	$11.87	$44.84
2026	$0.00	$21.96	$12.11	$45.74
2027	$0.00	$23.75	$12.35	$46.66

6.3.4 Natural Gas, Coal and Market Energy Costs

Natural gas costs are based on Wood Mackenzie projections, which can be found in Appendix 6B (Confidential) for the Carbon and No-Carbon scenarios. Natural Gas prices are shown for Emery, which is the same as a new generic combined cycle or combustion turbine. Pricing for other existing natural gas-fired units use the same trajectory with the starting values noted in Appendix 6C.

Long term coal fuel costs are based on Wood Mackenzie projections. IPL assumed a ramp-up of coal costs between 2011 and 2014, starting with 2010 actuals to 2015 Wood Mackenzie values. This ramp-up acknowledges the transition from expiring legacy contracts. Coal prices are provided in Appendix 6B (Confidential).

Market Economy Energy Costs are also based on Wood Mackenzie projections, and shown in Appendix 6B (Confidential). The EGEAS modeling allows 250 MW of Market Energy at Off Peak prices, and 250 MW of Market Energy at On Peak prices through 2016. In 2017 these values are reduced to 83 MW each (a reduction to one third) to avoid over-reliance on Market Energy and potential fluctuation exposure. This results in Market Energy contributing 5% or less to the long term annual energy portfolio.

6.3.5 Capital and O&M Change Rates

General Capital and Operations & Maintenance (O&M) Change Rates are noted in Appendix 5D.

6.3.6 New Generic Units

New Generic Unit costs and parameters are noted in Appendix 5C. Much of this data comes from the 2010 Power Station Characterization Study performed by Black & Veatch. IPL did not include alternatives for joint owned units in this Resource Plan due to the significant unknowns inherent with other parties such as common timing of need, commitment to participation, and ownership percentage. Further, IPL is a projecting a large shortfall over the planning study when considering assumed unit retirements and the DAEC PPA expiration. Therefore, IPL needs the capacity of full sized units to maintain long term reliability.

6.3.7 Wind Availability

IPL allowed 1,100 MW of new, 38% capacity factor, generic wind to be added in the expansion plan. The new generic wind combined with IPL's existing wind resources allows up to 25% of the energy portfolio to come from wind. In addition, the superfluous unit setting in EGEAS was set to 10 for the generic 100 MW wind alternative.

The 25% wind energy contribution limit is used to acknowledge the significant transmission upgrades needed to support heavy wind penetration, which is supported by other studies. For example, 25% was the upper penetration level used in the 2006 Minnesota Wind Integration Study.[2] Further, the 2011 MISO Transmission Expansion Plan (2011 MTEP) notes "The recent adoption of Renewable Portfolio Standards (RPS) across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers."[3] And also notes, "To meet the various policy objectives, all scenarios … require significant investment in generation and transmission expansion across the 15-year study horizon."[4] However, as shown in the table below, none of the scenarios in the 2011 MTEP accommodate 25% wind penetration. The maximum penetration in the 2011 MTEP is roughly 20%.

Table 6.3.7.1: 2011 MTEP Scenario Results[5]

Scenario	Scenario Renewable Requirements	Renewable / Wind Additions by 2026	Annual Renewable/ Wind Energy Output by 2026	2026 Retail Rate Impact
Business-As-Usual with Mid-low Demand and Energy Growth Rates	State RPS	23,900 MW	16%	-1.2%
Business-As-Usual with Historic Demand and Energy Growth Rates	State RPS	26,800 MW	16%	+2.1%
Carbon Constraint	State RPS	21,000 MW	16%	+14.7%
Combined Energy Policy	Federal 20% RPS	28,800 MW	21%	+18.6%

[2] Prepared for the Minnesota Public Utilities Commission by EnerNex Corporation in collaboration with The Midwest Independent System Operator, http://www.puc.state.mn.us/portal/groups/public/documents/pdf_files/000435.pdf
[3] https://www.midwestiso.org/Library/Repository/Study/MTEP/MTEP11/MTEP11%20Report.pdf page 44
[4] *Ibid*, page 33

6.3.8 Nuclear Purchases

IPL assumed a 400 MW PPA renewal from the Duane Arnold Energy Center for 2014-2025.

6.3.9 Existing Units

Appendix 6C (Confidential) lists IPL's Existing Generating Units, as well as purchases and sales. Appendix 6C also provides the modeled 2012 Planning Resource Credits under the MISO Module E Resource Adequacy construct and dispatch parameters

The following sections highlight changes to existing units such as emission controls[6], upgrades, and retirements. Appendix 6D (Confidential) shows projected cost and operating parameters for the Tier 1 and Tier 2 coal-fired units. Note that the costs shown are in 2009$. IPL will provide the Appendix 6D (Confidential) Microsoft Excel spreadsheet. The Excel file has additional rows to demonstrate how costs are converted to nominal values for EGEAS entry.

6.3.9.1 Ottumwa

The Ottumwa plant was modeled with:

- A Scrubber and Baghouse installed by 2015 to reduce sulfur dioxide (SO2), mercury (Hg), and particulate matter (PM) emissions to comply with the Utility Mercury and Air Toxics Standard (MATS) and a rule similar to the Cross State Air Pollution Rule (CSAPR).
- Selective Catalytic Reduction (SCR) installed by 2021 to reduce nitrogen oxide (NO_x) emissions. This control is a modeling assumption, though not required to comply with existing emission regulations. This assumption was included as a placeholder for

[5] *Ibid*, pages 34-38, and follow-up email between IPL and MISO
[6] Environmental regulations are discussed in section 7.5

compliance with potential emission regulations or resolution to potential Environmental Protection Agency (EPA) issues/concerns.

- Turbine upgrade and capacity/efficiency upgrades by 2015.
- Various other costs to comply with coal combustion residuals (CCR) and water rules (such as 316b and effluent limitation guidelines).

6.3.9.2 Lansing

The Lansing 4 plant was modeled with:

- An SCR and Baghouse installed by 2010 to reduce NO_x, mercury, and particulate matter emissions to comply with MATS and a CSAPR-like rule.
- A Scrubber installed by 2016 to reduce SO2 emissions to comply with a CSAPR-like rule.
- Turbine upgrade and capacity/efficiency upgrades by 2016.
- Various other costs to comply with CCR and water rule 316b and effluent limitation guidelines, and also including a potential cooling tower in 2020 for potential 316a/b compliance.

6.3.9.3 Louisa and Neal Units 3 and 4

IPL is a minority owner to Louisa and Neal units 3 and 4 (4%, 28% and 25.695% respectively), while MidAmerican Energy operates the units. At Louisa, IPL assumed no additional controls. At Neal 3 and 4, the EGEAS modeling assumes a Scrubber, Baghouse and Selective Non-Catalytic Reduction (SNCR) by 2014 as part of MidAmerican Energy's compliance plans.

6.3.9.4 Tier 2 Coal Fired Units

At coal-fired Tier 2 units [redacted] the EGEAS modeling assumes the installation of "emissions lite" control projects by 2015 for MATS compliance. "Emissions lite" control projects include Activated Carbon Injection (ACI) installation and Electrostatic Precipitator (ESP) upgrades. The units also assume various other costs to comply with CCR, water rules and effluent limitation guidelines, and potential 2020 cooling towers. [redacted] are assumed to retire at the end of [redacted], while [redacted] continues into the extension period.

6.3.9.5 Intermediate Unit Retirements

IPL plans to retire several intermediate units, some of which were identified in the 2010 Resource Plan. These units are older, smaller, less-efficient steam units that when constructed, operated on coal and have since been converted to natural gas as their primary fuel. Fox Lake 3 was converted to natural gas in 1996, Dubuque 3 and 4 were converted to natural gas in 2011 and Sutherland 1 and 3 were converted to natural gas in early 2012. Table 6.3.9.5 below summarizes some key information related to the steam units IPL plan to retire.

Table 6.3.9.5 - IPL Intermediate Steam Unit Retirements by End of 2016

Unit Name	Primary Fuel	Age	PRC Capacity	Proposed Retirement, End of Year
Fox Lake 3	Natural Gas	50	81.1	2016
Dubuque 3	Natural Gas	61	28.8	2014
Dubuque 4	Natural Gas	53	31.6	2014
Sutherland 1	Natural Gas	57	28.3	2016
Sutherland 3	Natural Gas	51	58.8	2016

The Dubuque units, as well as Sutherland 1, were assumed to be retired by the end of 2014 in IPL's 2010 Resource Plan. IPL modified the retirement date of Sutherland 1 from the end of 2014 to preserve the generating capacity on this unit for two additional years.

These five steam units are in the range of 50-60 years of age, which is the typical expected life by general industry standards. IPL has maintained the equipment associated with these units for over five decades, but the equipment is showing its age as would be expected. Significant investments would be required to restore the equipment on these units to ensure long-term, reliable operation.

IPL did not conduct a comprehensive review of all projects required to restore these units to long-term reliable operation due to the sheer magnitude of equipment required to operate these units, but rather, developed a high level estimate of the key project investment for Sutherland 1 and 3 and Fox Lake 3. The initial investment to restore these units would be approximately $12M for Sutherland 1, $12M for Sutherland 3 and $10M for Fox Lake 3. A breakdown of the costs is shown on Appendix 6K.

Because these estimates did not include the cost for every component that would need to be replaced or refurbished on these units, has an accuracy of +/-40%. It does summarize what IPL considers to be the most important projects and outlines the magnitude of the investment required to situate these units for long-term operation. Because these are older units and not all issues may be readily visible, IPL cannot easily anticipate any additional costs that could result from issues discovered once work actually begins on the units. This would result in additional expense to repair and refurbish these units.

Also, if the work triggers new source review, it is possible that additional emission control equipment or emission limits could be required, thus resulting in additional expense in addition to the costs to repair and refurbish these units.

6.3.9.6 Peaking Unit Retirements

While IPL's peaking fleet has delivered safe, reliable service to customers for decades, it is an aging fleet. In fact, each of the units was manufactured over 40 years ago, with the exception of which is 38 years old. Based upon general industry standards, a life of 30 to 40 years is a reasonable assumption for peaking units. Table 6.3.9.6 below summarizes some key information relating to the peaking units that IPL plans to retire by the end of 2016.

Table 6.3.9.6 – IPL Peaking Unit Retirements by End of 2016

Unit Name	Primary Fuel	Age	PRC Capacity	Proposed Retirement, End of Year
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2016
[redacted]	[redacted]	[redacted]	[redacted]	2012

* Indicates peaking units purchased used.

Peaking units serve two primary purposes. First, they help ensure IPL has enough planning resource credits, or capacity, to match its customers' peak demand plus a reserve margin on an annual basis. Second, they can provide support for local grid reliability during times of peak load conditions or during times when transmission system conditions dictate local support.

Because these units could be called upon during either high load conditions or for transmission reliability reasons, the units must be sufficiently reliable to perform this intended function, which

requires consistent maintenance of the units. While these units have generally been reliable over the decades, like any piece of equipment, maintaining that reliability continues to be more challenging and cost prohibitive as these units continue to age.

IPL Generation Engineering performed a conditional assessment which evaluated the units as a whole by reviewing the current condition of key system components. IPL's inspection resulted in a determination that the [redacted] will require a significant amount of investment to restore them to a long-term, reliable operating condition. This condition review also supports IPL's position that these peaking units are at or near the end of their useful life.

Further, in the fall of 2011, the [redacted] experienced a control system failure. Subsequent investigation uncovered issues with the turbine blades that would require repair at significant expense before it could be returned to safe, reliable operation. Because IPL was in the process of evaluating the future of its' peaking fleet as a component of its' overall generation plan, a decision was made to delay repairs pending the completion of the peaking fleet plans.

IPL has developed preliminary estimates of the cost to restore its peaking units to a long-term, reliable operating condition. IPL estimates the initial cost to restore the nine peaking units to a long-term reliable operating condition would be approximately $10M per unit (with an accuracy of +/-40%), for a total of $90 million (+/- 40%). Additionally, given that these are older units and not all issues may be readily visible, IPL cannot easily anticipate or estimate additional costs that could result from issues discovered once component repair, refurbishment and replacement actually begins on these aging units. These additional, unanticipated expenses have the potential

to increase the $10M per unit estimate outlined above. Appendix 6L is an estimate of the typical cost to restore each of the nine peaking units.

IPL's experience has also proven that acquiring some of the key replacement components for the old units is quite challenging and in some cases, almost impossible. While it may seem possible to completely repair, replace and refurbish the key components of these units, the reality is that this initiative has the potential to be very challenging.

IPL also understands it could be required to obtain an environmental permit to complete projects to repair and refurbish these peaking units. IPL believes it could be required to install additional emission control equipment on these peaking units if the work triggers new source review requirements. Absent a detailed understanding of the specific work required and an environmental permitting assessment of the required work, it is difficult to estimate the potential costs. However, expense for any additional emission control projects would increase the $10M per unit estimate outlined earlier.

For these reasons IPL did not believe it was reasonable to conduct any further detailed economic analysis associated with the complete refurbishment of these units.

6.4 Scenarios

IPL developed scenarios based on a number of different assumptions. The resulting expansion plan and a cost summary for each of these scenarios are presented in subsequent appendices. Two separate sets of EGEAS runs were performed:

1) Base Set (Plan 1);

2) Tier 2 Retirement Sensitivity Set (Plans 2 and 3).

6.4.1 Base Set Scenarios (Plan 1)

The Base Set (Plan 1) Scenarios take the Reference Case and vary key input assumptions as a sensitivity analysis. Expansion plans and summary costs are presented for 23 scenarios as follows:

- Base Forecast (Reference Case, Proposed Plan)
- High Load Forecast
- Low Load Forecast
- No Economy Energy
- Additional RPS Requirement (IA 15% by 2020, MN 25% by 2025)
- CO_2 Scenario – Wood Mackenzie
- CO_2 Scenario – Minnesota High
- CO_2 Scenario – Minnesota Low
- Higher Natural Gas Fuel Prices ~ +10%
- Higher Natural Gas Fuel Prices ~ +20%
- Higher Natural Gas Fuel Prices ~ +30%
- Lower Natural Gas Fuel Prices ~ -10%
- Lower Natural Gas Fuel Prices ~ -20%
- Lower Natural Gas Fuel Prices ~ -30%
- Higher Coal Fuel Prices ~ +10%
- Higher Coal Fuel Prices ~ +20%
- Higher Coal Fuel Prices ~ +30%
- Lower Coal Fuel Prices ~ -10%
- Lower Coal Fuel Prices ~ -20%

- Lower Coal Fuel Prices ~ -30%
- Higher New Unit Capital Costs ~+10%
- Lower New Unit Capital Costs ~-10%
- Higher Wind Prices ~ +20/MWh

Expansion plans are provided in Appendix 6F. Appendix 6G provides present value cost summaries as well as MW's of 2017 combined cycle capacity additions.

The results of the Base Set (Plan 1) Scenarios indicate that for all 23 cases, a nominal 600 MW combined cycle unit is selected in 2017. Furthermore, all scenarios optimally select additional combined cycle facilities in the 2025-2026 timeframe corresponding with the DAEC PPA expiration and retirement of [redacted], and Sutherland 3.

6.4.1a Reference Case (Proposed Plan / Base Forecast) Scenario

The Reference Case was based on reasonable assumptions and was built to represent a combination of assumptions that was probable at the time of plan development. Annual by-unit production costs for this scenario are shown in Appendix 6E (Confidential).

6.4.1b High Load Forecast Scenario

Starting with the Reference Case assumptions, the high load forecast replaced the load forecast in the Reference Case and then existing and potential future resources were optimized. The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $355 million higher than the Reference Case scenario.

6.4.1c Low Load Forecast Scenario

Starting with the Reference Case assumptions, the low load forecast replaced the load forecast in the Reference Case and then existing and potential future resources were optimized. The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $333 million lower than the Reference Case scenario.

6.4.1d No Economy Energy Scenario

Starting with the Reference Case assumptions, all energy was assumed to be served by IPL resources, that is, no market economy energy was available throughout the study period and then existing and potential future resources were optimized. The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $521 million higher than the Reference Case scenario.

6.4.1e Additional RPS Requirement (IA 15% by 2020, MN 25% by 2025) Scenario

Starting with the Reference Case assumptions an additional renewable portfolio standard (RPS) requirement in Iowa of 10% by 2015 and 15% by 2020 was assumed. The Minnesota requirement of 25% by 2025 was unchanged. Existing and potential future resources were then optimized. The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $54 million higher than the Reference Case scenario.

6.4.1f CO_2 Scenario – Wood Mackenzie Scenario

Starting with the Reference Case assumptions, existing and potential future resources were optimized assuming Wood Mackenzie's 2022 CO_2 price and resulting impacts to natural gas fuel prices, coal fuel prices, market energy prices, SO_2 and NO_x prices. The total cumulative present

worth cost of this scenario for the study period plus the 35-year extension was $2,332 million higher than the Reference Case scenario.

6.4.1g CO_2 Scenario – Minnesota High Scenario

Starting with Wood Mackenzie's 2022 CO_2 case assumptions, existing and potential future resources were optimized assuming a CO_2 price from a Minnesota Order issued October 8, 2009, *Establishing 2009 and 2010 Estimate of Future Carbon Dioxide Regulation Costs* of $34/ton starting in 2012 escalating with the Consumer Price Index (CPI), the general inflation rate assumed in IPL's model runs.

There were no changes to any other inputs, since Wood Mackenzie did not model fuel and market energy price changes corresponding to this specific, accelerated Minnesota CO_2 schedule. This means that a step-change to the fuel and market energy prices as a result of 2012 CO_2 monetization does not occur in 2012, but instead 2022 based on Wood Mackenzie's original CO_2 schedule. Although the timing is not in synch, including the delayed impacts of CO_2 pricing on fuel and market energy pricing is better than excluding such impacts.

The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $4,261 million higher than the Reference Case scenario. Note that of all the scenarios, this has the largest cost impact.

6.4.1h CO_2 Scenario – Minnesota Low Scenario

Starting with the Wood Mackenzie 2022 CO_2 case assumptions, existing and potential future resources were optimized assuming a CO_2 price from a Minnesota Public Utilities Commission Order issued October 8, 2009, *Establishing 2009 and 2010 Estimate of Future Carbon Dioxide*

Regulation Costs of $9/ton starting in 2012 escalating with the CPI, the general inflation rate assumed in IPL's model runs.

There were no changes to any other inputs, since Wood Mackenzie did not model fuel and market energy price changes corresponding to this specific, accelerated Minnesota CO_2 schedule. This means that a step-change to the fuel and market energy prices as a result of 2012 CO_2 monetization does not occur in 2012, but instead 2022 based on Wood Mackenzie's original CO_2 schedule. Although the timing is not in synch, including the delayed impacts of CO_2 pricing on fuel and market energy pricing is better than excluding such impacts.

The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $1,205 million higher than the Reference Case scenario.

6.4.1i Higher Natural Gas Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with natural gas and On Peak Market Economy Energy prices starting 10, 20, and 30 percent higher in the first year, base escalation assumed thereafter. The total cumulative present worth costs of these scenarios for the study period plus the 35-year extension was $325, $636, and $943 million higher than the Reference Case scenario, respectively.

6.4.1j Lower Natural Gas Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with natural gas and On Peak Market Economy Energy prices starting 10, 20, and 30 percent lower in the first year, base escalation assumed thereafter. The total cumulative present

worth cost of these scenarios for the study period plus the 35-year extension was $408, $951, and $1,594 million lower than the Reference Case scenario, respectively.

6.4.1k Higher Coal Fuel Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with coal fuel and Off Peak Market Economy Energy prices starting 10, 20, and 30 percent higher in the first year, base escalation assumed thereafter. The total cumulative present worth cost of these scenarios for the study period plus the 35-year extension was $306, $571, and $797 million higher than the Reference Case scenario, respectively.

6.4.1l Lower Coal Fuel Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with coal fuel and Off Peak Market Economy Energy prices starting 10, 20, and 30 percent lower in the first year, base escalation assumed thereafter. The total cumulative present worth cost of these scenarios for the study period plus the 35-year extension was $336, $683, and $1,036 million lower than the Reference Case scenario.

6.4.1m Higher New Unit Capital Costs ~+10%

Starting with the Reference Case assumptions, existing and potential future resources were optimized with capital costs for new generic units 10 higher in the first year, base escalation assumed thereafter. The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $210 million higher than the Reference Case scenario.

6.4.1n Lower New Unit Capital Costs ~-10%

Starting with the Reference Case assumptions, existing and potential future resources were optimized with capital costs for new generic units 10 lower in the first year, base escalation assumed thereafter. The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $259 million lower than the Reference Case scenario.

6.4.1o Higher Wind Price ~ +20/MWh Scenario

Starting with the Reference Case assumptions, existing and potential future resources were optimized with new wind prices assumed approximately $20 per MWh higher to simulate the loss of the Federal Production Tax Credits. The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $81 million higher than the Reference Case scenario.

6.4.2 Tier 2 Retirement Sensitivity Set (Plan 2 and Plan 3)

The scenarios in this section were performed to determine the cost and expansion plan impact of the Tier 2 units retiring earlier than in the Reference Case (noted in section 6.3.9.4). Expansion plans are given in Appendix 6H. Appendix 6I gives a scenario cost summary that provides the costs of each scenario and MW of short-term gas fired capacity additions. The results of the Tier 2 Retirement Sensitivity Set indicate that earlier retirement of the Tier 2 units increases Present Value Revenue Requirements.

The EGEAS analysis does not include accelerated demolition and site remediation costs of retired Tier 2 units, or the recovery of remaining book value of units. These costs exist in any plan due to the eventual retirement of units; the difference is the timing of recovery.

6.4.2a Tier 2 Staged Gas Conversions and Retirement Plan (Plan 2)

This Plan assumes installation of "emissions lite" control projects by 2015 for MATS compliance, as well as staged gas conversion and retirement of the Tier 2 units:

- [redacted] converted to operate on natural gas by [redacted] and then retired by the end of [redacted]
- [redacted] converted to operate on natural gas by [redacted] and then retired by the end of [redacted]
- [redacted] converted to operate on natural gas by [redacted] and then retired by the end of [redacted]

The EGEAS input cost and operating parameters for these units are provided in Appendix 6D (Confidential). The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $167 million higher than the Reference Case scenario.

6.4.2b Tier 2 Units Retired 12/31/2014 Scenario (Plan 3)

Starting with the Reference Case assumptions, the Tier 2 units are retired by the end of [redacted] This avoids installing "emissions lite" control projects at [redacted] for MATS compliance. The total cumulative present worth cost of this scenario for the study period plus the 35-year extension was $289 million higher than the Reference Case.

6.4.2c Sensitivity Runs for Tier 2 Staged Gas Conversions and Retirements (Plan 2)

The same 22 sensitivities run on the Base Set (Plan 1) were also run on the Tier 2 Staged Gas Conversions and Retirement Plan (Plan 2). The result of this set of runs, similar to the Base Set (Plan 1), indicates the strong need for a nominal 600 MW combined cycle unit in 2017. Only one of the 22 scenarios did not select a 600 MW unit in 2017. This exception was the Minnesota High CO_2 scenario, which selected a nominal 300 MW combined cycle unit in 2017. However, this same scenario selected 1200 MW of combined cycle in the 2024-2026 timeframe.

Furthermore, all scenarios optimally selected additional combined cycle facilities in the 2024-2026 timeframe corresponding with the DAEC PPA expiration and Plan 2 retirement of

6.5 Robustness of Proposed Plan

The proposed plan as supported by the different scenarios is very robust. The load and capability graph after resource additions resulting from the Reference Case (Proposed Plan) can be found in Appendix 6J. A common theme in the scenarios is the need for a 2017 combined cycle addition, further gas fired facility additions in the long term, and wind additions generally later in the study period. The size and timing of the new units may change with different assumptions, but in general, the selected technologies remain the same. Diversity in fuels and technologies insulates against adverse movements in any one particular area which is advantageous when attempting to take a reasonable cost path while maintaining a balanced and reliable portfolio when meeting the needs of IPL's customers. With a diverse and balanced portfolio, IPL can be more flexible in the level of risk assumed in a period of time when there is significant uncertainty facing the electric utility industry.

The planned retirement of the intermediate and peaking units is not detrimental to adequate and reliable electric service, as opposed to a reactionary run to failure approach. IPL determined that an end of year 2016 retirement date was reasonable when coupled with the other components of the IRP which include the proposal to construct a 2017 Combined Cycle plant, the proposed DAEC power purchase agreement as well as planned efficiency improvement and capacity and performance upgrade projects at the Lansing and Ottumwa Generating Stations.

The 2016 retirement date assumption would allow adequate time to effectively and efficiently replace the capacity from these units, resolve any transmission reliability issues associated with unit retirements, and effectively plan for the orderly and effective shutdown and decommissioning of these units, which includes assisting employees impacted by unit retirements. However, since these peaking and steam unit retirement plans are only one component of an overall energy resource plan, they are contingent on approval of other components of IPL's resource plan. Also, before any generating unit can be retired, MISO must conduct a study to determine if there are any adverse effects on the transmission system.

Unplanned failures of generating units expose IPL customers to financial and service related risks such as emergency replacement of generating capacity and the need to address potential grid reliability issues on short notice when units fail. The benefits of this proactive plan, as opposed to a reactive run to failure scenario, include:

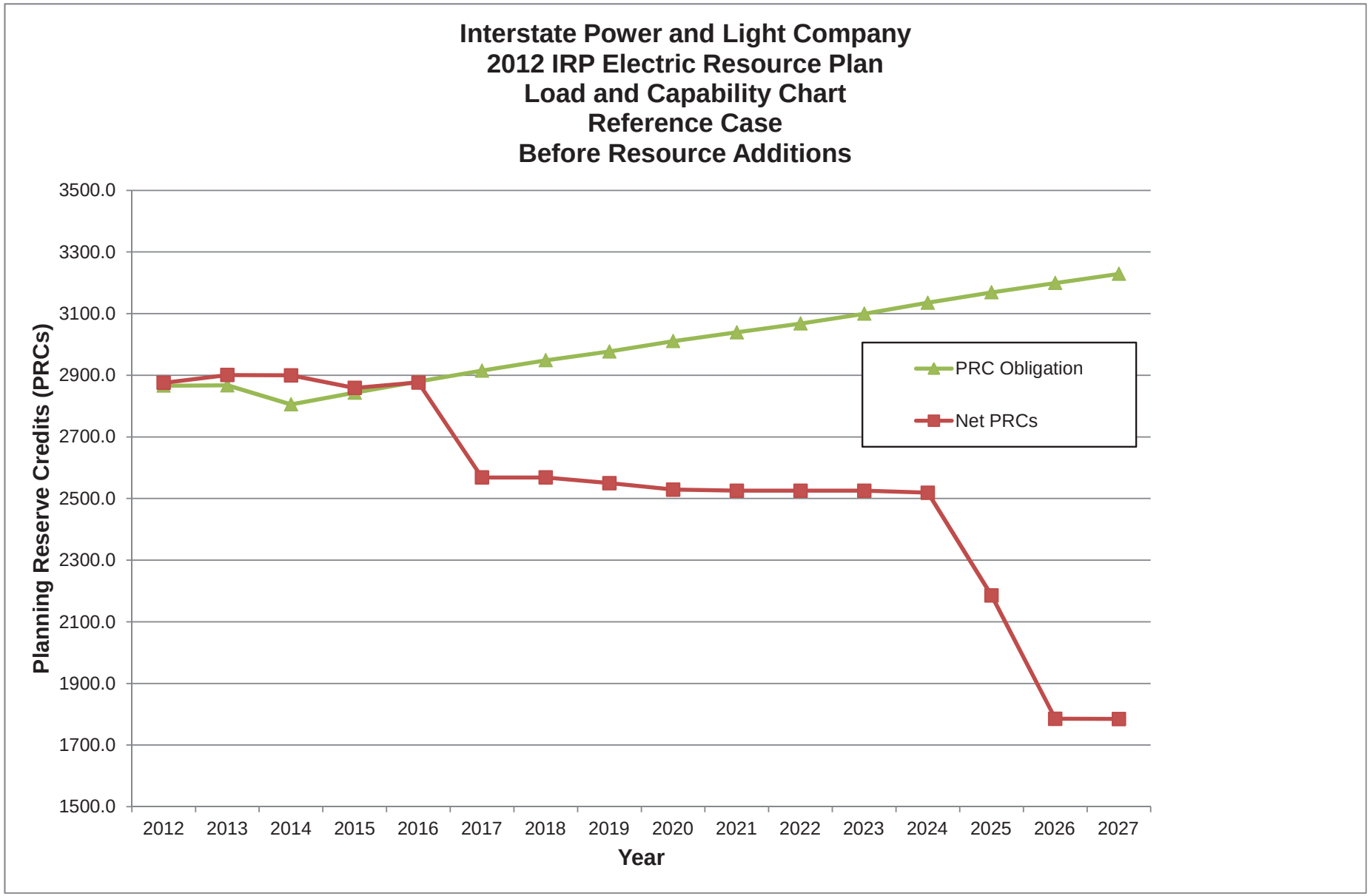
- Adequate time to effectively and efficiently replace the generating capacity on behalf of IPL customers.
- Adequate time to work with MISO and ITC to address any potential grid reliability issues that could adversely impact customers.
- Adequate time to develop and execute an effective plan for shutdown and decommissioning of these units.
- Adequate time to assist employees impacted by the retirement of a unit or entire plant.

APPENDIX 6A

Load and Capability Graph

Reference Case

Before Resource Additions



Appendix 6A
Page 1 of 1

APPENDIX 6B

Fuel Costs

(Confidential)

Exhibit___(BRK-1)
Schedule A
Pages 181-183

Brent R. Kitchen Exhibit

Public notice of additional **confidential** documents included in this filing

APPENDIX 6C

IPL's Existing Generating Units, Purchases and Sales

(Confidential)

Brent R. Kitchen Exhibit

Public notice of additional **confidential** documents included in this filing

APPENDIX 6D

Projected Costs and Operating Parameters of Tier 1 and Tier 2 Units

(Confidential)

Exhibit___(BRK-1)
Schedule A
Pages 187-205

Brent R. Kitchen Exhibit

Public notice of additional **confidential** documents included in this filing

APPENDIX 6E

Reference Case Production Costs

2012 – 2027

(Confidential)

Exhibit___(BRK-1)
Schedule A
Pages 207-232

Brent R. Kitchen Exhibit

Public notice of additional **confidential** documents included in this filing

APPENDIX 6F

Scenario Expansion Plans

Base Set (Plan 1)

IPL's 2012 Integrated Resource Plan
Case: x001 (Plan 1)
Base Forecast (Reference Case)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	200
2025	150	72.895	188.9	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	450	72.895	188.9	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: x002 (Plan 1)
High Load Forecast

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	50	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	50	0	0	0	0	0	0	0
2021	50	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	0
2023	0	0	0	0	0	0	0	100
2024	0	0	0	0	0	0	0	200
2025	150	0	188.9	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	450	0	377.8	0	1077.8	0	0	900

IPL's 2012 Integrated Resource Plan
Case: x003 (Plan 1)
Low Load Forecast

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	100
2024	0	0	0	0	0	0	0	200
2025	150	0	188.9	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	250	0	188.9	0	1077.8	0	0	900

IPL's 2012 Integrated Resource Plan
Case: x004 (Plan 1)
No Economy Energy

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	100
2025	100	0	0	288.4	0	0	0	200
2026	0	0	0	0	538.9	0	0	200
2027	0	0	0	0	0	0	0	200
TOTAL	200	0	0	288.4	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: x005 (Plan 1)
Additional RPS Requirement (10% by 2015, 15% by 2020)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	100
2016	0	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100
2020	0	0	0	0	0	0	0	200
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0
2024	50	0	0	0	0	0	0	100
2025	150	72.895	188.9	0	0	0	0	100
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	300	72.895	188.9	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: x006 (Plan 1)
CO2 Scenario - Wood Mackenzie

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	100
2025	0	0	0	0	538.9	0	0	200
2026	100	0	188.9	0	0	0	0	200
2027	100	0	0	0	0	0	0	200
TOTAL	300	0	188.9	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: x007 (Plan 1)
CO2 Scenario - Minnesota High

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	200
2015	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	200
2018	0	0	0	0	0	0	0	200
2019	0	0	0	0	0	0	0	200
2020	0	0	0	0	0	0	0	100
2021	0	0	0	0	0	0	0	100
2022	0	0	0	0	0	0	0	100
2023	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0
2025	150	0	188.9	0	0	0	0	0
2026	100	0	0	0	538.9	0	0	0
2027	100	0	0	0	0	0	0	0
TOTAL	350	0	188.9	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: x008 (Plan 1)
CO2 Scenario - Minnesota Low

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	100
2025	0	0	0	0	538.9	0	0	200
2026	100	0	188.9	0	0	0	0	200
2027	100	0	0	0	0	0	0	200
TOTAL	300	0	188.9	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: x009 (Plan 1)
Natural Gas Prices +10% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	100
2025	0	0	0	0	538.9	0	0	200
2026	100	0	188.9	0	0	0	0	200
2027	100	0	0	0	0	0	0	200
TOTAL	300	0	188.9	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: x010 (Plan 1)
Natural Gas Prices +20% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	100
2025	0	0	0	0	538.9	0	0	200
2026	100	0	188.9	0	0	0	0	200
2027	100	0	0	0	0	0	0	200
TOTAL	300	0	188.9	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: x011 (Plan 1)
Natural Gas Prices +30% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	100
2025	0	0	0	0	538.9	0	0	200
2026	100	0	188.9	0	0	0	0	200
2027	100	0	0	0	0	0	0	200
TOTAL	300	0	188.9	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: x012 (Plan 1)
Natural Gas Prices -10% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	188.9	0	0	0	0	0
2025	100	0	188.9	0	0	0	0	100
2026	0	0	0	0	538.9	0	0	200
2027	0	0	0	0	0	0	0	200
TOTAL	250	0	377.8	0	1077.8	0	0	500

IPL's 2012 Integrated Resource Plan
Case: x013 (Plan 1)
Natural Gas Prices -20% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	188.9	0	0	0	0	0
2025	50	0	0	288.4	0	0	0	0
2026	0	0	0	0	538.9	0	0	0
2027	0	0	0	0	0	0	0	0
TOTAL	200	0	188.9	288.4	1077.8	0	0	0

IPL's 2012 Integrated Resource Plan
Case: x014 (Plan 1)
Natural Gas Prices -30% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	188.9	0	0	0	0	0
2025	50	0	0	288.4	0	0	0	0
2026	0	0	0	0	538.9	0	0	0
2027	0	0	0	0	0	0	0	0
TOTAL	200	0	188.9	288.4	1077.8	0	0	0

IPL's 2012 Integrated Resource Plan
Case: x015 (Plan 1)
Coal Prices +10% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	200
2025	150	72.895	188.9	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	450	72.895	188.9	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: x016 (Plan 1)
Coal Prices +20% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	200
2025	150	72.895	188.9	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	450	72.895	188.9	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: x017 (Plan 1)
Coal Prices +30% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	200
2025	150	72.895	188.9	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	450	72.895	188.9	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: x018 (Plan 1)
Coal Prices -10% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	200
2025	150	72.895	188.9	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	450	72.895	188.9	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: x019 (Plan 1)
Coal Prices -20% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	188.9	0	0	0	0	100
2025	100	0	188.9	0	0	0	0	200
2026	0	0	0	0	538.9	0	0	200
2027	0	0	0	0	0	0	0	200
TOTAL	250	0	377.8	0	1077.8	0	0	700

IPL's 2012 Integrated Resource Plan
Case: x020 (Plan 1)
Coal Prices -30% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	188.9	0	0	0	0	100
2025	100	0	188.9	0	0	0	0	200
2026	0	0	0	0	538.9	0	0	200
2027	0	0	0	0	0	0	0	200
TOTAL	250	0	377.8	0	1077.8	0	0	700

IPL's 2012 Integrated Resource Plan
Case: x021 (Plan 1)
New Unit Capital Costs +10%

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	188.9	0	0	0	0	0
2025	100	0	188.9	0	0	0	0	100
2026	0	0	0	0	538.9	0	0	200
2027	0	0	0	0	0	0	0	200
TOTAL	250	0	377.8	0	1077.8	0	0	500

IPL's 2012 Integrated Resource Plan
Case: x022 (Plan 1)
New Unit Capital Costs -10%

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	100
2025	0	0	0	0	538.9	0	0	200
2026	100	0	188.9	0	0	0	0	200
2027	100	0	0	0	0	0	0	200
TOTAL	300	0	188.9	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: x023 (Plan 1)
Higher Wind Prices, ~+$20/MWH (no PTC renewal)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	188.9	0	0	0	0	0
2025	50	0	0	288.4	0	0	0	0
2026	0	0	0	0	538.9	0	0	0
2027	0	0	0	0	0	0	0	0
TOTAL	200	0	188.9	288.4	1077.8	0	0	0

APPENDIX 6G

Scenario Cost Summary

Base Set (Plan 1)

IPL's 2012 Integrated Resource Plan			
Plan 1 - No Tier 2 Early Retirments			
Case	Description	PVRR, $M	2017 CC Summer MW
x001	Base Forecast (Reference Case)	14,137.2	539
x002	High Load Forecast	14,492.5	539
x003	Low Load Forecast	13,804.6	539
x004	No Economy Energy	14,658.3	539
x005	Additional RPS Requirement (10% by 2015, 15% by 2020)	14,191.4	539
x006	CO2 Scenario - Wood Mackenzie	16,468.7	539
x007	CO2 Scenario - Minnesota High	18,398.7	539
x008	CO2 Scenario - Minnesota Low	15,341.7	539
x009	Natural Gas Prices +10% (and On Peak Market Energy)	14,462.6	539
x010	Natural Gas Prices +20% (and On Peak Market Energy)	14,772.8	539
x011	Natural Gas Prices +30% (and On Peak Market Energy)	15,080.3	539
x012	Natural Gas Prices -10% (and On Peak Market Energy)	13,729.2	539
x013	Natural Gas Prices -20% (and On Peak Market Energy)	13,186.4	539
x014	Natural Gas Prices -30% (and On Peak Market Energy)	12,542.8	539
x015	Coal Prices +10% (and Off Peak Market Energy)	14,443.3	539
x016	Coal Prices +20% (and Off Peak Market Energy)	14,708.5	539
x017	Coal Prices +30% (and Off Peak Market Energy)	14,933.9	539
x018	Coal Prices -10% (and Off Peak Market Energy)	13,800.9	539
x019	Coal Prices -20% (and Off Peak Market Energy)	13,454.5	539
x020	Coal Prices -30% (and Off Peak Market Energy)	13,101.5	539
x021	New Unit Capital Costs +10%	14,347.1	539
x022	New Unit Capital Costs -10%	13,878.4	539
x023	Higher Wind Prices, ~+$20/MWH (no PTC renewal)	14,217.8	539

APPENDIX 6H

Scenario Expansion Plans

Retirement Sensitivity (Plan 2 and Plan 3)

IPL's 2012 Integrated Resource Plan
Case: x001 (Plan 1 - Tier 2 not retired early)
Reference (Tier 2 not retired early)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	200
2025	150	72.895	188.9	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	450	72.895	188.9	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: v096 (Plan 3 - Tier 2 EOY 2014 retirements)
Tier 2 retired EOY 2014 (no "emissions lite" control projects)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	100	0	377.8	0	0	0	0	0
2016	150	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100
2020	50	0	0	0	0	0	0	0
2021	50	0	0	0	0	0	0	200
2022	100	0	0	0	0	0	0	0
2023	100	0	0	0	0	0	0	100
2024	150	0	0	0	0	0	0	100
2025	150	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	950	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v101 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Base Forecast

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	100
2023	50	0	0	0	0	0	0	100
2024	50	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	300	0	377.8	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: v102 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
High Load Forecast

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	50	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	50	0	0	0	0	0	0	0
2022	100	0	188.9	0	0	0	0	0
2023	100	0	0	0	0	0	0	200
2024	0	0	0	288.4	0	0	0	200
2025	50	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	500	0	188.9	288.4	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: v103 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Low Load Forecast

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	100
2023	0	0	0	0	0	0	0	200
2024	50	72.895	0	0	0	0	0	200
2025	50	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	200	72.895	188.9	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v104 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
No Economy Energy

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	100
2023	50	0	0	0	0	0	0	100
2024	0	0	0	288.4	0	0	0	0
2025	0	0	0	0	0	0	0	200
2026	0	0	0	0	538.9	0	0	200
2027	0	0	0	0	0	0	0	200
TOTAL	100	0	188.9	288.4	1077.8	0	0	800

IPL's 2012 Integrated Resource Plan
Case: v105 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Additional RPS Requirement (10% by 2015, 15% by 2020)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	100
2016	0	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100
2020	0	0	0	0	0	0	0	200
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	0
2023	0	0	0	0	0	0	0	0
2024	0	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	100
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	150	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v106 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
CO2 Scenario - Wood Mackenzie

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	200
2022	0	0	188.9	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	150	0	0	0	0	0	0	200
2025	0	0	0	288.4	0	0	0	0
2026	0	0	0	0	538.9	0	0	100
2027	0	0	0	0	0	0	0	200
TOTAL	200	0	188.9	288.4	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v107 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
CO2 Scenario - Minnesota High

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	200
2015	0	0	0	0	0	0	0	100
2016	0	0	0	0	0	0	0	200
2017	0	0	0	288.4	0	0	0	200
2018	0	0	0	0	0	0	0	200
2019	50	0	0	0	0	0	0	100
2020	100	0	0	0	0	0	0	0
2021	100	0	0	0	0	0	0	0
2022	150	0	188.9	0	0	0	0	0
2023	150	0	0	0	0	0	0	0
2024	0	0	0	0	538.9	0	0	0
2025	0	0	0	0	0	0	0	100
2026	0	0	0	0	538.9	0	0	0
2027	0	0	0	0	0	0	0	0
TOTAL	550	0	188.9	288.4	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v108 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
CO2 Scenario - Minnesota Low

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	0	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	100
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	200	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v109 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Natural Gas Prices +10% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	0	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	100
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	200	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v110 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Natural Gas Prices +20% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	0	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	100
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	200	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v111 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Natural Gas Prices +30% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	200
2022	0	0	188.9	0	0	0	0	100
2023	0	0	0	0	0	0	0	200
2024	0	0	188.9	0	0	0	0	200
2025	0	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	100
2027	50	0	0	0	0	0	0	100
TOTAL	150	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v112 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Natural Gas Prices -10% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	188.9	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	0	288.4	0	0	0	0
2025	50	0	0	0	0	0	0	0
2026	50	0	0	0	538.9	0	0	100
2027	50	0	0	0	0	0	0	200
TOTAL	300	0	188.9	288.4	1077.8	0	0	300

IPL's 2012 Integrated Resource Plan
Case: v113 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Natural Gas Prices -20% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	188.9	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	0	288.4	0	0	0	0
2025	50	0	0	0	0	0	0	0
2026	50	0	0	0	538.9	0	0	0
2027	0	72.895	0	0	0	0	0	100
TOTAL	250	72.895	188.9	288.4	1077.8	0	0	100

IPL's 2012 Integrated Resource Plan
Case: v114 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Natural Gas Prices -30% (and On Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	188.9	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	0	288.4	0	0	0	0
2025	50	0	0	0	0	0	0	0
2026	50	0	0	0	538.9	0	0	0
2027	0	72.895	0	0	0	0	0	100
TOTAL	250	72.895	188.9	288.4	1077.8	0	0	100

IPL's 2012 Integrated Resource Plan
Case: v115 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Coal Prices +10% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	100
2023	50	0	0	0	0	0	0	200
2024	50	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	300	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v116 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Coal Prices +20% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	100
2023	50	0	0	0	0	0	0	200
2024	50	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	300	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v117 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Coal Prices +30% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	0	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	100
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	200	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v118 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Coal Prices -10% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	100
2023	50	0	0	0	0	0	0	100
2024	50	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	300	0	377.8	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: v119 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Coal Prices -20% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	100
2023	50	0	0	0	0	0	0	100
2024	50	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	300	0	377.8	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: v120 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Coal Prices -30% (and Off Peak Market Energy)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	100
2023	50	0	0	0	0	0	0	100
2024	50	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	300	0	377.8	0	1077.8	0	0	1000

IPL's 2012 Integrated Resource Plan
Case: v121 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
New Unit Capital Costs +10%

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	188.9	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	0	288.4	0	0	0	0
2025	50	0	0	0	0	0	0	0
2026	50	0	0	0	538.9	0	0	100
2027	50	0	0	0	0	0	0	200
TOTAL	300	0	188.9	288.4	1077.8	0	0	300

IPL's 2012 Integrated Resource Plan
Case: v122 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
New Unit Capital Costs -10%

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	188.9	0	0	0	0	200
2023	0	0	0	0	0	0	0	200
2024	0	0	188.9	0	0	0	0	200
2025	50	0	0	0	0	0	0	100
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	200	0	377.8	0	1077.8	0	0	1100

IPL's 2012 Integrated Resource Plan
Case: v123 (Plan 2) (Plan 2 - Tier 2 Staged Retirements)
Higher Wind Prices, ~+$20/MWH (no PTC renewal)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	188.9	0	0	0	0	0
2023	50	0	0	0	0	0	0	0
2024	0	0	0	288.4	0	0	0	0
2025	50	0	0	0	0	0	0	0
2026	50	0	0	0	538.9	0	0	0
2027	100	0	0	0	0	0	0	0
TOTAL	350	0	188.9	288.4	1077.8	0	0	0

APPENDIX 6I

Scenario Cost Summary

Retirement Sensitivity (Plan 2 and Plan 3)

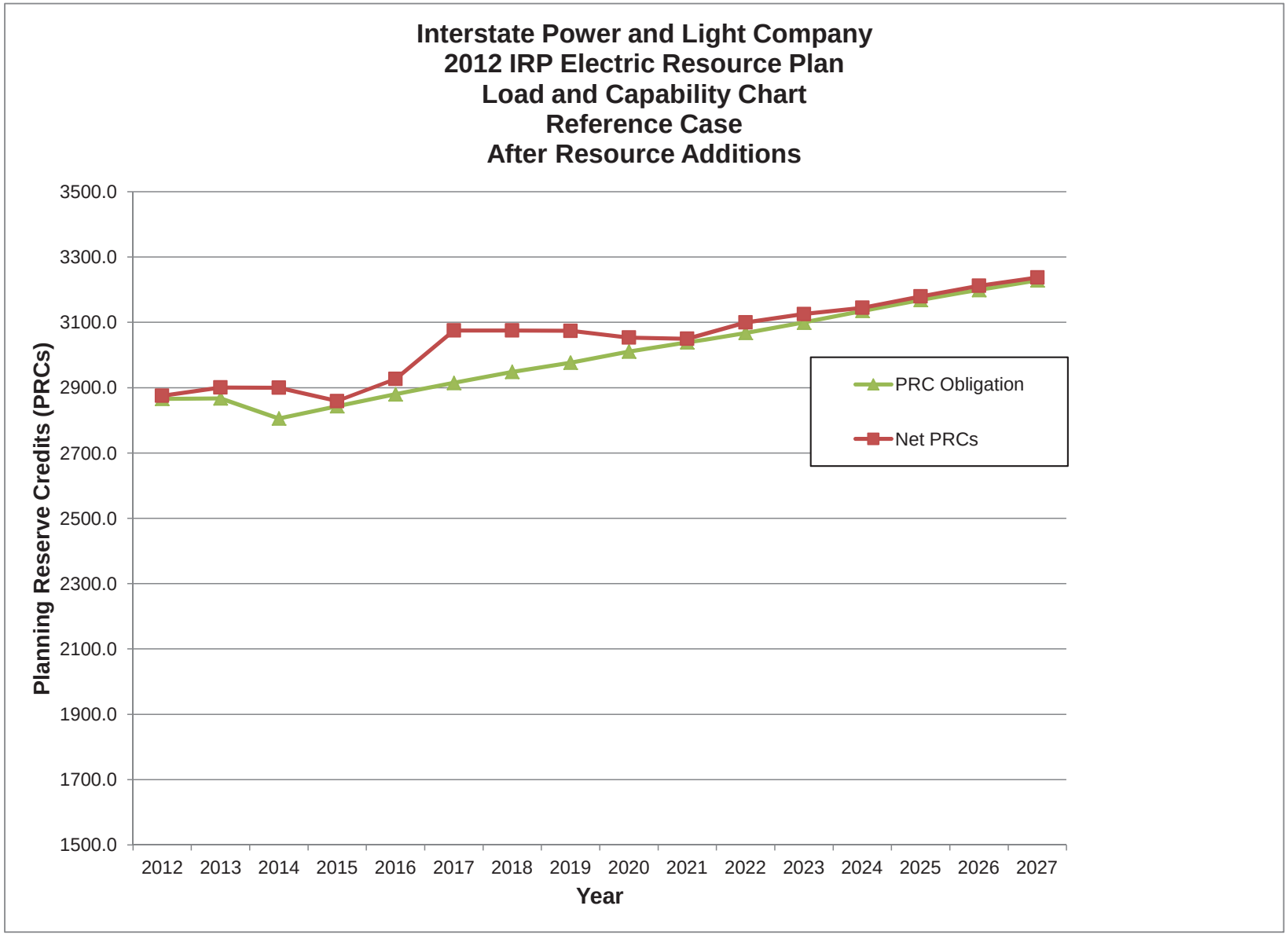
IPL's 2012 Integrated Resource Plan				
Tier 2 Retirement Sensitivies				
Case	**Description**	**PVRR, $M**	**2017 CC Summer MW**	
x001	Reference (Tier 2 not retired early)	14,137.2	539	Plan 1
v101	All Tier 2 Staged gas conversion and retirements	14,304.0	539	Plan 2
v096	Tier 2 retired EOY 2014 (no "emissions lite" control projects)	14,426.6	539	Plan 3
Plan 2 - Tier 2 Staged Gas Conversion and Retirements				
Case	**Description**	**PVRR, $M**	**2017 CC Summer MW**	
v101	Base Forecast	14,304.0	539	
v102	High Load Forecast	14,649.4	539	
v103	Low Load Forecast	13,964.9	539	
v104	No Economy Energy	14,815.7	539	
v105	Additional RPS Requirement (10% by 2015, 15% by 2020)	14,349.0	539	
v106	CO2 Scenario - Wood Mackenzie	16,559.3	539	
v107	CO2 Scenario - Minnesota High	18,442.1	288	
v108	CO2 Scenario - Minnesota Low	15,483.2	539	
v109	Natural Gas Prices +10% (and On Peak Market Energy)	14,662.8	539	
v110	Natural Gas Prices +20% (and On Peak Market Energy)	15,013.4	539	
v111	Natural Gas Prices +30% (and On Peak Market Energy)	15,360.0	539	
v112	Natural Gas Prices -10% (and On Peak Market Energy)	13,853.0	539	
v113	Natural Gas Prices -20% (and On Peak Market Energy)	13,277.1	539	
v114	Natural Gas Prices -30% (and On Peak Market Energy)	12,618.1	539	
v115	Coal Prices +10% (and Off Peak Market Energy)	14,555.1	539	
v116	Coal Prices +20% (and Off Peak Market Energy)	14,771.2	539	
v117	Coal Prices +30% (and Off Peak Market Energy)	14,949.4	539	
v118	Coal Prices -10% (and Off Peak Market Energy)	13,994.1	539	
v119	Coal Prices -20% (and Off Peak Market Energy)	13,674.7	539	
v120	Coal Prices -30% (and Off Peak Market Energy)	13,352.3	539	
v121	New Unit Capital Costs +10%	14,538.9	539	
v122	New Unit Capital Costs -10%	14,032.7	539	
v123	Higher Wind Prices, ~+$20/MWH (no PTC renewal)	14,378.1	539	

APPENDIX 6J

Load and Capability Graph

Reference Case

After Resource Additions



Appendix 6J
Page 1 of 1

APPENDIX 6K

Intermediate Steam Unit Repair Costs

(Confidential)

Exhibit___(BRK-1)
Schedule A
Pages 290-292

Brent R. Kitchen Exhibit

Public notice of additional **confidential** documents included in this filing

APPENDIX 6L

Peaking Unit Repair Costs

(Confidential)

Exhibit___(BRK-1)
Schedule A
Page 294

Brent R. Kitchen Exhibit

Public notice of additional **confidential** documents included in this filing

ACTION PLAN

7.0 General

The resources needed to meet IPL's system capacity and energy requirements come primarily from three types of resources; demand-side, supply-side and renewable resources. During the forthcoming years, IPL will:

- Continue to pursue DSM activities;
- Investigate and pursue renewable energy alternatives;
- Pursue the addition of a 2017 nominal 600 MW combined cycle facility;
- Pursue reasonable emission controls on its remaining coal-fired units;
- Pursue capacity and efficiency upgrades at Tier 1 coal-fired units;
- Retire older peaking units;
- Retire older intermediate steam units;
- Consider all supply-side options and will only commit to resources that are in IPL's and IPL's customers' best interest.

In addition, IPL is engaged in transmission and environmental related activities which are discussed below. The analysis of all options is ongoing.

7.1 Demand-Side Management Activities

IPL's current DSM programs have been aggressively pursued and are continuing to save customers' kilowatts and kilowatt-hours. DSM activity is reported annually in all regulatory jurisdictions in which IPL serves retail customers. These filings on DSM programs to various agencies are expected to continue. IPL will continue to analyze potential demand and energy savings from future DSM activities.

7.2 Supply-Side Activities

IPL is committed to meeting the demands of its customers. In Section 5, the types of resources required to meet IPL's customer needs were identified. Without resource additions, IPL projections show a significant capacity shortfall in 2017. IPL plans to meet its resource needs consistent with the regulations of the governing jurisdictions. Considering the next five years, the immediate incremental capacity and energy needs through 2017 will most likely be met with existing resources, MISO market energy, a MISO market capacity purchase in 2016 (as necessary), and a new nominal 600 MW combined cycle facility in 2017. IPL's future resource requirements will be acquired taking Iowa Code § 476.53(4) and subsequent regulatory rate treatment into consideration.

In this Resource Plan, IPL considered the ongoing viability of its older peaking and intermediate steam units. As discussed in Section 6, as a component of the resource plan, IPL plans to retire Montgomery CT, Dubuque diesel units, Centerville 1 and 2 as well as diesel units, Burlington Units 1-4, Grinnell Units 1 and 2, Fox Lake 3, Hills and Lansing diesel units, Dubuque 3 and 4, and Sutherland Units 1 and 3. Retirements are subject to approval from the MISO through the Attachment Y process.

At its Tier 2 coal-fired units Burlington, Kapp 2, and Prairie Creek, IPL will pursue the addition of "emissions lite" control projects by 2015 for compliance with the Utility Mercury and Air Toxics Standard (MATS).

The proposed resource plan calls for a new nominal 600 MW combined facility in 2017. IPL will seek favorable ratemaking principles for capital investments where Iowa Code § 476.53(4) is applicable and the necessary regulatory and environmental approvals and permits will be

obtained by the appropriate parties. IPL customers' demands will be met, system reliability within the region will be maintained, and customers' rates will be kept as low as reasonably possible.

This action plan will continually be reviewed and revised, as new information with respect to IPL's resource needs becomes available. IPL's resource planning process is continuously iterative and electric resource plans are regularly filed in Minnesota and Iowa. In the interim, all resource options will continue to be considered and evaluated.

7.3 Renewable Activities

IPL continues to consider renewable energy, especially wind energy, a viable option for future resource needs. Currently, IPL purchases capacity and energy from approximately 250 MW of wind turbines. Also, IPL's 200 MW Whispering Willow Windfarm – East came online at the end of 2009. These existing and new resources are expected to allow IPL to obtain a renewable energy portfolio in the range of roughly 6.5% to 9% over the next 15 years. For renewable reporting purposes, IPL allocates this renewable energy between its Iowa and Minnesota jurisdictions.

To satisfy Iowa renewable requirements[1], IPL must secure 49.8 MW of renewable capacity. IPL has assigned this capacity to a 63.2% share of the Storm Lake Power Partners Windfarm. Based on typical capacity factors from Storm Lake Power Partners, this 49.8 MW share equates to approximately 118,000 MWH per year, or 0.8% of annual retail energy sales. As shown in Appendix 7A, IPL is projecting a surplus relative to Iowa's current renewable energy

[1] Iowa Administrative Code 199-15.11(1)

requirements anywhere from approximately 900,000 MWh to 1,100,000 MWh depending on the year.

The Minnesota Renewable Energy Standard[2] sets minimum requirements for renewable energy generation as a percentage of retail energy sales:

- 12% by 2012
- 17% by 2016
- 20% by 2020
- 25% by 2025

As shown in Appendix 7A, IPL has a current "bank" of approximately 71,000 renewable energy credits ("REC" / "RECs"). Even with this REC bank, without further action IPL will fall short of Minnesota's renewable requirements in 2014. The Minnesota shortfall is roughly:

- 15,000 RECs in 2014 and 26,000 RECs in 2015 for the 12% requirement,
- 75,000 RECs per year in 2016 to 2019 for the 17% requirement,
- 120,000 RECs per year in 2020 to 2024 for the 20% requirement,
- 177,000 RECs per year in 2025 to 2027 for the 25% requirement.

When considering IPL collectively, IPL's surplus in Iowa could be used to meet a deficit in Minnesota and then all renewable energy requirements would be met system-wide. Therefore, IPL in total is well positioned to meet both its Iowa and Minnesota renewable energy requirements absent any purchases of Midwest Renewable Energy Tracking System (M-RETS) Certificates.

[2] Minnesota Statutes 216B.1691

Furthermore, IPL's Renewable Energy Production is shown in Appendix 7B and IPL's Annual Community-Based Energy Development (C-BED) Report is included in Appendix 7C. Since IPL's C-BED tariff was approved, IPL has not received any proposals pursuant to its C-BED tariff. In summary, IPL is well positioned to comply with both Iowa's and Minnesota's renewable energy requirements.

7.4 Transmission Activities

On December 20, 2007, IPL sold its transmission assets to ITC Midwest. ITC Midwest is a subsidiary of ITC Holdings. ITC Midwest is an independent transmission company which provides non-discriminatory access to those entities who depend upon the transmission grid. The transaction involved the acquisition of approximately 6,800 miles of 34.5 kV and higher voltage transmission lines in Iowa, Minnesota, Illinois and Missouri. The transaction, Docket Number E-001/PA-07-540, was approved by the Commission in a written order dated February 7, 2008, with an effective date of December 18, 2007. As a result of the transaction IPL status has changed from one of a Transmission Owner (TO) to a Transmission Dependent Utility (TDU).

As a TDU, IPL participates in the planning and stakeholder processes of both MISO and ITC Midwest. In addition, IPL participates in various ad hoc transmission activities. IPL plans to remain active in transmission planning activities as a TDU.

7.5 Environmental Activities

Environmental activities impact many aspects of IPL's business, including our generation planning and energy supply decision-making. IPL must develop plans to make major equipment retrofits and/or add new generation sources many years in advance to allow adequate time to arrange financing, obtain necessary approvals and permits, accomplish engineering design, and

complete the actual construction. Our primary goal in evaluating regulatory developments is to ensure compliance with applicable environmental requirements for air emissions, water and waste management. Furthermore, IPL considers regulatory developments with an objective to select appropriate emissions control technologies that will be highly efficient and cost-effective. Such an approach will achieve environmental objectives while minimizing impacts on our customers' energy costs.

7.5.1 Planning for Environmental Regulations

Environmental planning requires evaluating regulations and understanding associated impacts to IPL's utility operations. The environmental regulatory framework governing air quality requirements is a critical component to developing a flexible emissions strategy that can be changed in response to revisions to existing regulations or issuance of new rules. The framework for implementing rules issued under the authority of the Clean Air Act (CAA) is discussed in Section 7.5.2. Section 7.5.3 provides an overview of the critical air quality rules that IPL is currently considering in its emissions planning efforts. In addition, Section 7.5.4 provides a summary of how proposed water quality regulations are anticipated to impact IPL's power plant operations for cooling water. Section 7.5.5 summarizes potential new or revised waste management regulations that could affect coal combustion byproduct re-use, ash handling or landfill practices at IPL.

IPL monitors the status of environmental rules and regulations that may be subject to change. Additional ambiguity and uncertainty enters the rulemaking process due to litigation of environmental requirements. There is currently significant regulatory uncertainty with respect to the various environmental rules and regulations discussed below. Until litigation on various environmental rules is resolved in the courts or with further action by the EPA, IPL plans to

continue to implement its current multi-emissions compliance plan.

Details of the potential impacts of various environmental regulations and IPL's plan to address the anticipated compliance requirements are provided in IPL's Emissions Plan and Budget (EPB) filing as discussed in section 7.6.1. IPL will closely monitor the future developments of emerging environmental rules as well as associated legal challenges to these requirements and continue to review its multi-emissions compliance plans with regulators to determine if changes are necessary.

7.5.2 Framework Governing Issuance of Air Quality Rules

The federal CAA along with its various amendments provides the framework governing air quality regulations, including emissions compliance requirements for the electric utility industry. The CAA defines the role of federal government and state agencies. Under the CAA, the Environmental Protection Agency (EPA) sets limits on how much of an air pollutant can be in the atmosphere anywhere in the United States. This ensures that all Americans have the same basic health and environmental protections. For IPL, the Iowa Department of Natural Resources (IDNR) and the Minnesota Pollution Control Agency (MPCA), respectively are the state agencies that implement federal environmental rules in Iowa and Minnesota.

The federal CAA along with its various amendments mandate preservation of air quality through existing regulations and periodic reviews to ensure adequacy of these provisions based on scientific data. As part of the basic framework under the CAA, the EPA is required to establish National Ambient Air Quality Standards (NAAQS), which serve to protect public health and welfare. These standards address six "criteria" pollutants. Criteria pollutants are common and found all over the United States. EPA uses criteria pollutants as indicators of air quality. Areas

that comply with NAAQS are considered to be in attainment, whereas routinely monitored locations that do not comply with these standards may be classified by the EPA as non-attainment and require further actions to reduce emissions.

Four of these criteria pollutants are particularly relevant to IPL's electric utility operations: nitrogen oxide (NOx), sulfur dioxide (SO2), particulate matter (PM), and ozone. Ozone is not directly emitted from IPL's generating facilities; however, NOx emissions may contribute to ozone formation in the atmosphere. Fine particulate matter (PM2.5) may also be formed in the atmosphere from SO2 and NOx emissions that react to form sulfate and nitrate aerosols. The CAA also regulates 187 toxic air pollutants, also known as hazardous air pollutants (HAPs), including mercury. In 2009, the EPA commenced regulation of six greenhouse gases (GHGs) including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

State implementation plans (SIPs) document the collection of regulations that individual state agencies will apply to maintain NAAQS and other CAA emissions requirements. The EPA must approve each SIP, and if a SIP is not acceptable to the EPA or if a state chooses not to issue separate state rules, then the EPA can assume enforcement of the CAA in that state (in whole or part) by issuing a federal implementation plan (FIP).

Additional emissions requirements may also be applied under the CAA regulatory framework and are generally implemented using one of two policy approaches, either command-and-control or market-based cap-and-trade. In a command-and-control approach, EPA issues regulations that mandate specific standards of performance, such as achieving a percent of control or a minimum level of emission. These limits are generally applied to each emitting unit individually, although

in some instances, averaging of emissions is allowed at the facility-level in order to provide additional compliance flexibility. In a market-based cap-and-trade approach, an overall limit, or "cap," is set for the allowed emissions level. Regulated facilities receive authorizations to emit in the form of emissions allowances, with the total amount of allowances limited by the cap. Each regulated facility can determine its own compliance strategy to meet the overall reduction requirement, including sale or purchase of allowances, installation of pollution controls, or other operational changes that will reduce emissions. Individual control requirements are not specified under a cap-and-trade program, but each regulated facility must surrender allowances equal to its actual emissions in order to comply.

The CAA also addresses new or modified emissions sources through the New Source Review (NSR) permitting program. NSR permitting ensures that air quality is not significantly degraded in areas that currently achieve the NAAQS, known as Prevention of Significant Deterioration (PSD) permits. It also requires more stringent controls in areas that exceed the NAAQS, known as non-attainment NSR permits. The NSR process requires industry to undergo a pre-construction review for environmental controls when building new facilities or making modifications to existing facilities that would result in a significant increase of a regulated air pollutant.

7.5.3 IPL Planning Considerations for Air Emissions Regulations

The following briefly discusses the primary CAA programs and associated air quality regulatory requirements that IPL is currently considering for its multi-emissions control strategy. Specifically, the federal and state air emission regulations currently applicable to or anticipated to affect IPL's operations include the following: Clean Air Interstate Rule (CAIR), Cross State Air Pollution Rule (CSAPR), and Utility Maximum Achievable Control Technology (MACT)

standards. IPL operations will also comply with the environmental requirements from other CAA rules as they are issued, such as changes to NAAQS, Clean Air Visibility Rule (CAVR) plans including requirements for Best Available Retrofit Technology (BART) on electric generating units constructed between 1962 and 1977, and the Industrial Boiler and Process Heater MACT. However, these currently are not significant drivers of the emissions reductions and air pollution controls that are needed from the IPL generation fleet. The impact of these other regulations will be assessed upon their final issuance and IPL compliance plans adjusted if necessary.

CAIR

CAIR was issued as a market-based cap-and-trade program by the EPA in 2005 to further reduce emissions of SO2 and NOx from electric generating units (EGUs) in the eastern United States (including Iowa and Minnesota). CAIR established new SO2 and NOx (both annual and ozone season) emission caps beginning in 2010 and 2009, respectively, with further reductions in SO2 and NOx emission caps planned to be effective in 2015. CAIR impacts IPL's fossil-fueled EGUs with greater than 25 MW of capacity located in Iowa. In 2008, the D.C. Circuit Court remanded CAIR to the EPA for revision to address flaws identified in a 2008 opinion issued in response to legal challenges to this rule. In the interim, CAIR obligations became effective for NOx on Jan. 1, 2009 and SO2 on Jan. 1, 2010 and remain in place until a final CAIR replacement rule becomes effective.

CSAPR

In August 2011, the EPA published the final CSAPR, as a market-based cap-and-trade program which would include requirements to reduce SO2 and NOx emissions from fossil-fueled EGUs located in 27 states in the eastern half of the U.S. IPL's fossil-fueled EGUs with greater than 25 MW of capacity located in Iowa and Minnesota would be impacted by CSAPR requirements.

CSAPR was expected to replace CAIR and establish annual state emission caps for SO2 and NOx beginning in 2012. These SO2 and NOx emission caps were expected to be lowered further by CSAPR in 2014 for EGUs located in Iowa, but not EGUs located in Minnesota. The CSAPR also includes assurance provisions that would enforce state emission caps. These provisions require regulated EGUs with emissions in excess of the state emission caps to surrender additional penalty emission allowances beginning in 2012. The provisions required to surrender potential additional emission allowances were expected to limit the amount of emissions trading that would be used to meet compliance requirements.

In December 2011, the EPA also issued a final supplemental rule that added Iowa to CSAPR for the ozone season NOx emissions trading program. In February 2012, the EPA issued additional revisions to CSAPR that would delay the effective date of the assurance provisions of CSAPR to 2014, rather than 2012.

However, in December 2011, the D.C. Circuit Court stayed the implementation of CSAPR in response to legal challenges and as a result CAIR obligations remained effective during 2012 pending further review by the D.C. Circuit Court. On August 21, 2012, the D.C. Circuit Court issued its decision vacating and remanding CSAPR to the EPA for further reconsideration. The court ruling also requires that EPA must continue administering CAIR pending the promulgation of a valid replacement. In brief, the court order found that EPA's CSAPR was flawed in two aspects (1) by having upwind states reduce emissions beyond their significant contribution to air pollution in downwind states; and, (2) by not allowing states to have the first opportunity to address needed emissions reductions through rulemaking in state implementation plans. The EPA has 45 days to file a petition seeking rehearing by the same three judge panel or rehearing en banc (this entails review by all of the judges of the D.C. Circuit). If rehearing is denied, then

EPA may file a petition for review of this decision by the Supreme Court. The EPA could also reconsider the CSAPR and address the flaws identified in the court ruling through issuance of a revised rulemaking.

On October 5, 2012, the EPA as well as several states, cities and other organizations, filed petitions for rehearing en banc of the August 2012 decision that vacated the CSAPR. It is anticipated that the D.C. Circuit court will make a determination on whether to grant en banc rehearing by the end of 2012. IPL is unable to predict with certainty the final outcome of the CSAPR vacatur. However, IPL currently anticipates that CAIR will be replaced in the future, either by a modified CSAPR, as currently written, or as modified based upon a ruling from the D.C. Circuit Court, or another rule that addresses the interstate transport of air pollutants, and expect that capital investments and/or modifications to their electric generating facilities to meet the final compliance requirements will be significant.

Utility MACT Rule

In February 2012, the EPA published the final Utility MACT Rule, also referred to as the "Mercury and Air Toxics Standards" (MATS). The MATS rule applies to all IPL coal-fueled EGUs with greater than 25 MW of capacity located in Iowa. The final rule requires compliance with emission limits for mercury, filterable PM as a substitute for non-mercury metal HAPs and hydrogen chloride (HCl) as a substitute for acid gas HAPs. The EPA also proposed alternative standards for total or individual non-mercury metals emissions (instead of filterable PM) and SO2 emissions (instead of HCl for acid gases if air pollution controls for flue gas desulfurization are installed). In addition, work practice standards were proposed for organic HAPs emissions to ensure proper combustion. Compliance for this final rule is required by April 16, 2015. However, an entity can request an additional year for compliance, which may be granted on a

case-by-case basis by state permitting authorities for units that are needed to assure power reliability, units repowering to gas, or units that need additional time to install air emission control technology. The final MATS rule is subject to legal challenge that is pending in the D.C. Circuit Court. In August 2012, the D.C. Circuit Court established its schedule for hearing this case as related to the broader MATS requirements that apply to existing EGUs with final briefs to be filed in April 2013.

7.5.4 IPL Planning Considerations for Water Quality Regulations

Cooling Water Intake Structure Rule – 316(b)

Section 316(b) of the Federal Clean Water Act (CWA) requires the EPA to regulate cooling water intake structures in order to assure that these structures reflect the "best technology available" for minimizing adverse environmental impacts to fish and other aquatic life. More specifically, this rule will require existing power plants to demonstrate how they currently meet or will meet national performance standards to reduce the mortality of fish and shellfish caused by entrainment (taking in of organisms with the cooling water) and impingement (blocking of larger entrained organisms that enter the cooling water intake by some type of physical barrier).

Section 316(b) applies to existing cooling water intake structures at large steam EGUs. In 2007, a court opinion invalidated aspects of Section 316(b), which allowed for consideration of cost-effectiveness when determining the appropriate compliance measures. As a result, the EPA formally suspended Section 316(b) in 2007. In 2009, the U.S. Supreme Court granted the EPA authority to use a cost-benefit analysis when setting technology-based requirements under Section 316(b).

In April 2011, the EPA issued a revised proposed Section 316(b) Rule, which applies to existing and new cooling water intake structures at large steam EGUs. The proposed rule would require that both impingement and entrainment mortality standards be met for power plants that withdraw greater than two million gallons of cooling water per day. Facilities can install technology to meet the impingement standard or reduce the cooling water intake velocity to below a set standard (0.5 feet/second). State agencies will be tasked with determining the best approach to comply with the entrainment standard. Part of this determination will include consideration of a series of factors such as cost and social benefits. Based on the proposed rule, electric generating stations with cooling towers are not anticipated to have significant additional compliance requirements under Section 316(b).

IPL has identified seven electric generating facilities that may be impacted by the revised Section 316(b) Rule, including the following EGUs: [redacted] Of these, [redacted] is located in Minnesota with the others all located in Iowa. The only IPL facility currently equipped with a cooling tower and subject to 316(b) is the [redacted] A final rule is expected to be issued by the EPA mid-2013. The schedule for compliance with this rule has not yet been finalized; however, compliance is currently expected to be required within eight years of the effective date of the final rule.

Effluent Effluent Guidelines

The EPA is required to periodically update the national technology-based regulations to reduce industry discharges of pollutants from effluent wastewater into the waters of the United States. For the electric power sector, the EPA last updated the relevant guidelines for wastewater effluent discharges in 1982. In 2010, the EPA completed an information collection request (ICR)

to gather information from utilities to support a future Effluent Limitation Guideline rulemaking. The proposed rule changes are expected to be issued in November 2012 for public comment and EPA's final rule is expected by April 2014. It is anticipated that this rule will result in new limits and compliance schedules that are incorporated into existing NPDES permits as each comes up for renewal, which typically occurs on a five-year cycle.

The implications of this rulemaking remain uncertain. However, the revisions will likely result in more stringent effluent limits for wastewater discharges associated with plant process wastewaters, particularly those that involve ash management and wet scrubbers. Best Available Technology (BAT) will likely be required to treat wastewater discharges. Early information from the EPA suggests that "no discharge" from ash ponds may be BAT, which suggests that closing ash ponds and converting to "dry" or circulating ash management systems may be necessary or desirable to comply with the effluent limitation guideline requirements. In addition, new effluent guideline requirements could heavily influence or even preclude the selection of certain air emission control technologies (e.g. wet flue gas desulfurization).

7.5.5 IPL Planning Considerations for Solid Waste Management Regulations

Coal combustion residuals (CCR) are what remain after the direct combustion of coal in power plants to generate electricity. There are different types of CCR:

- Fly ash is a very fine powder-like particle, ranging in color from tan to black. It is collected by air pollution controls, such as electrostatic precipitators (ESP) and baghouses, which prevent it from being released through the stacks of the plant.
- Bottom ash is a brown sand-like material collected in the bottom of the boilers.
- Boiler slag is black, shiny and angular. It is coarser than bottom ash and also collected in the bottom of boilers.

Passage of the Resource Conservation and Recovery Act (RCRA) in 1976 delegated the regulation of "non-hazardous" waste to each respective state. CCR's met the definition of a non-hazardous waste; hence, each state developed specific regulations for CCR management for their respective jurisdictions. RCRA was amended in 1980 to include what is referred to as the "Bevill Amendment", which specifically exempted CCR from hazardous waste regulation until further study could be completed by EPA. At this time, CCR remain classified as exempt non-hazardous wastes under RCRA. IPL currently manages CCR to prevent harmful emissions or releases into the environment in accordance with state programs.

In December 2008, national attention was turned to CCR management when a breach in a coal ash impoundment pond occurred at the Tennessee Valley Authority plant located in Kingston, Tennessee. This breach released 1.1 billion gallons of coal ash slurry to the immediate surrounding area and flooded more than 300 acres. In March 2009, EPA declared its intent to move forward with new regulations to address the management of CCRs and potential environmental risks from the disposal of CCRs generated by electric utilities. Consequently, IPL is monitoring potential regulatory changes that may affect the rules for operation and maintenance of coal ash surface impoundments (ash ponds) and/or landfills. In 2009, IPL responded to information collection requests from the EPA for data on coal ash surface impoundments at certain of their facilities. The EPA continues to evaluate the responses and has been conducting site assessments of utilities' coal ash surface impoundments, including certain coal ash surface impoundments operated by IPL.

In June 2010, the EPA issued a proposed rule for all CCR generated by electric utilities that potentially may impact future management of this material. This proposal included two potential

regulatory options for CCR management under RCRA, either: (1) regulate as a special waste under the federal hazardous waste regulations when the CCR is destined for disposal, but continue to allow beneficial use applications of CCRs as a non-hazardous material; or (2) regulate as a non-hazardous waste for all applications subject to new national standards. These proposed regulations include additional requirements with significant impact for CCR management, beneficial use applications and disposal.

IPL has nine current or former coal generating facilities with one or more existing coal ash surface impoundments at each location. In addition, IPL has two active CCR company-owned landfills. All of these CCR disposal units would be subject to the proposed rule currently anticipated to be finalized in the second quarter of 2013. The schedule for compliance with this rule has not yet been established. IPL is currently unable to predict with certainty the impact of these information collection requests, site inspections, or potential future regulations for management of CCRs.

7.6 Environmental Regulatory and Related Initiatives

The following section describes IPL's significant on-going and emerging environmental regulatory initiatives. Section 7.6.1 discusses IPL's recent EPB filing for its coal-fired EGUs. At this time, IPL is not subject to any mandatory regulations to reduce GHG emissions, including CO_2, from existing EGUs. Therefore, IPL's ongoing consideration of potential GHG regulation risk is further discussed in Section 7.6.2 below.

7.6.1 Emissions Plan and Budget (EPB)

IPL is responsible for developing and managing an Emissions Plan and Budget (EPB) filing within the State of Iowa, consistent with the requirements of Iowa Code § 476.6(22). In

accordance with this code section, each rate-regulated public utility that is an owner of one or more electric generating facilities fueled by coal and located in the State of Iowa is required to file an EPB at least every two years. An EPB provides a utility's compliance plan and related budget to meet applicable federal and state environmental requirements. IUB approval demonstrates that IPL's EPB is expected to reasonably achieve cost-effective compliance with applicable environmental requirements.

In April 2012, IPL filed an updated EPB with the IUB that addresses the 2013-2014 period, and provides IPL's understanding of current and emerging air, water and waste environmental compliance requirements that will impact IPL in the near future, and a discussion of how IPL will meet these requirements. IPL currently expects the IUB to issue a decision on IPL's EPB by the end of 2012. The complete filing can be obtained from the IUB (http://www.iowa.gov/iub/).

Section I of this filing describes the specific emission compliance requirements for recently issued regulation and also emerging environmental rules considered in IPL's emission planning efforts. Section II of this filing provides details of the ongoing compliance work and additional investments anticipated for future compliance given IPL's current understanding of potential environmental rule outcomes. More specifically, IPL's Budget Update in Section II provides the particular actions to be taken at IPL coal-fired generation facilities, related costs and timing for each action.

The EPB includes specific details of IPL's multi-emissions plan to be implemented during the 2013 to 2017 timeframe, including:

1) IPL's evaluation of emission control technologies and alternatives to achieve compliance with anticipated environmental requirements; and

2) IPL's specific emission reduction activities and budgets.

IPL's recent EPB includes environmental activities at regulated electric generating stations to reduce emissions of SO_2, NO_x, mercury and particulate matter. This includes installation of air pollution controls at Lansing Generating Station Unit 4 and also the Ottumwa Generation Station Unit 1. The EPB also includes preliminary cost estimates for compliance with water and CCR regulations including studies, engineering evaluations and implementation of control measures.

The Budget Update portion of the recently filed EPB outlines approximately $515 million in environmental capital investments to existing coal-fired generating for the 2013-2017 period. IPL's share of these capital investments is approximately $340 million, with the other joint owner of the Ottumwa Generating Station Unit 1, MidAmerican Energy Company (MidAmerican), responsible for the remaining investments.

IPL plans to continue to execute a long-term, staged environmental compliance strategy that incorporates current regulation and emerging environmental rules. IPL proactively manages the timing, cost and customer rate impact of the actions it entails in the implementation of this strategy. IPL will continue to monitor pending rules, as well as legal challenges that may result in final rules being vacated or stayed and remanded for further reconsideration. In addition to these uncertainties, IPL may not have control over the timing of its planned installation dates, due to the need to coordinate system-wide outages in order to maintain reliability. As necessary, IPL will maintain sufficient flexibility to ensure that environmental compliance requirements are met with sensitivity to minimize the resulting impact on customer rates.

Future updates to the IPL EPB will be performed at least every two years. IPL financial investments for installation of air pollution control technologies discussed in its EPB filing are further updated based on known commitments for engineering, procurement and construction in disclosures to the Securities and Exchange Commission (SEC), Forms 10K and 10Q.

7.6.2 Potential Greenhouse Gas Regulation Risk

In April 2007, the U.S. Supreme Court concluded in *Massachusetts v. EPA* that GHGs meet the CAA definition of an air pollutant. In response to this court decision, the EPA has subsequently issued proposed and final regulations for GHGs under the CAA. These regulations are described in greater detail below, but remain uncertain due to ongoing legal challenge in the D.C. Circuit Court. In June 2012, the D.C. Circuit Court issued its opinion and upheld EPA's rules that impose GHG requirements on certain stationary sources. In August 2012, several industry groups and the Chamber of Commerce filed petitions for rehearing en banc, asking the court to reconsider its opinion upholding EPA's GHG regulations. The outcome of this legal challenge remains pending and will determine if GHG stationary sources, including electric utility operations, will be regulated under the CAA.

Greenhouse Gas Reporting and Permitting

In October 2009, the final EPA Mandatory GHG Reporting rule was issued. The final rule does not require control of GHG emissions; rather, it requires that sources above certain threshold levels monitor and report emissions. The EPA anticipates that the data collected by this rule will improve the United States government's ability to formulate a set of climate change policy options. Emissions of GHGs are reported at the facility level in CO_2-equivalent (CO_2e) and include those facilities that emit 25,000 metric tons or more of CO_2e annually. The CO_2e is an aggregate measure used to compare total GHG impacts by taking into account the relative global

warming potential (GWP) for each individual GHG and adding these contributions into a single value. The final rule applies to electric utility operations at IPL for GHG emissions of CO_2, CH_4, and N_2O from combustion of fossil fuels. IPL submitted its first mandatory GHG annual emissions reports to the EPA for calendar year 2010 by the required due date of September 30, 2011. IPL is maintaining its emissions monitoring methodologies and data collection procedures for ongoing compliance with the EPA's mandatory GHG reporting rule. IPL's annual GHG emissions in terms of total mass as reported to the EPA for 2010 was 12 million metric tons of CO_2e. The CO_2e emissions as reported to the EPA represent all emissions from the facilities operated by IPL and do not reflect their share of co-owned facilities operated by other companies.

In June 2010, the EPA issued the GHG Tailoring Rule with these new permitting requirements commencing as of January 2, 2011. This rule established a GHG emissions threshold for major sources under the PSD permitting program of 100,000 tons per year (tpy) of CO_2e. The rule also established a threshold for what will be considered a significant increase in GHG emissions of 75,000 tpy for CO_2e. New major sources and certain modified existing sources of GHGs will be required to obtain PSD construction permits that demonstrate Best Available Control Technology (BACT) emissions measures to minimize GHGs when the project triggers a significant increase in GHG emissions. IPL is evaluating changes to GHGs resulting from various plant modifications, and submitting PSD air permit applications on a project-specific basis.

EPA NSPS for GHG Emissions from Electric Utilities

In 2010, the EPA announced the future issuance of GHG standards for electric utilities under the CAA. The GHG emission limits are to be established as New Source Performance Standard (NSPS) for new and existing fossil-fueled EGUs. In April 2012, the EPA published a proposed

rule specifically addressing new fossil fuel-fired EGUs larger than 25 MW by establishing an output-based "standard of performance" emissions rate of 1,000 pounds of CO_2 per megawatt-hour gross (lbs CO_2/MWh gross). This emission limit would apply to all new fossil fuel-fired EGUs regardless of fuel type. This emissions rate limitation is expected to be effective upon the EPA's issuance of the final rule, which is currently anticipated in 2013. The proposed NSPS for new EGUs is expected to apply to IPL's potential construction of a new 600 MW natural gas-fired combined-cycle electric generating facility in Iowa, which will be designed to achieve compliance with the proposed CO_2 emissions rate limitation.

The EPA has chosen not to regulate CO_2 emissions from existing modified or reconstructed EGUs at this time. For purposes of NSPS, "modified" means a physical or operational change that increases the source's maximum achievable hourly rate of emissions, excluding pollution control projects. The regulations define "reconstructed" as existing sources that replace components to such an extent that the capital costs of the new components exceed 50% of the capital costs of an entirely new facility, and for which compliance with the NSPS is technologically and economically feasible. According to the EPA, retrofit air pollution control system projects for regulations such as the CSAPR or MATS are to be exempted under this proposed rule. EPA will address the GHG NSPS for modified and reconstructed EGUs in a separate future rulemaking. The proposed GHG NSPS rule is subject to legal challenge that is pending in the D.C. Circuit Court. The EPA has moved to dismiss challenges to the proposed GHG NSPS rule for new EGUs, arguing that the challenges should be dismissed because they seek review of a proposed NSPS that is not a final agency action; since the proposed rule is not a final action, EPA argued, it is not reviewable by the court.

Furthermore, the EPA announced the issuance of proposed regulations for existing EGUs will be delayed and has not yet established a new schedule. For existing EGUs, the NSPS issued by the EPA is expected to include emission guidelines that states must use to develop plans for reducing EGU GHG emissions. The guidelines will be established based on demonstrated controls, GHG emission reductions, costs and expected timeframes for installation and compliance. Under existing EPA regulations, states must submit their plans to the EPA within nine months after publication of the guidelines unless the EPA sets a different schedule. States have the ability to apply less or more stringent standards, or longer or shorter compliance schedules. The implications of the EPA's NSPS rule for GHG emissions from existing EGUs are highly uncertain, including the nature of required emissions controls and compliance schedule for mandating reductions of GHGs.

7.6.3 Environmentally Beneficial Related Initiatives

IPL continues to maintain a number of environmentally-beneficial programs beyond those required for compliance with federal and state regulations, including:

- Seeking renewable energy alternatives that customers can implement voluntarily (such as small-scale wind turbines, biomass, or solar power) and also providing customers the option to subscribe directly through IPL's Second Nature green pricing program;
- Encouraging energy conservation through customer programs like Performance Edge and Shared Savings; and,
- Sponsoring Operating ReLeaf, Branching out and other tree planting programs.

7.7 Other Actions

As in the past, IPL will continue to evaluate the service needs of its customers, the costs of various resources, the applicability of new technologies, and other factors related to resource planning. IPL expects to be adequately flexible so as to accommodate future uncertainties.

APPENDIX 7A

IPL's Renewable Energy Position

IPL Renewable Status

	Retail and Wholesale Energy by State (Note 1)				Retail and Wholesale Demand by State (Note 1)			
Year	MN MWH Retail Sales	IA MWH Retail Sales	MN MWH Wholesale Sales	IA MWH Wholesale Sales	MN MW Retail Demand	IA MW Retail Demand	MN MW Wholesale Demand	IA MW Wholesale Demand
2012	843,107	14,297,477	812	426,056	162.4	2,530.7	0.2	84.2
2013	847,100	14,374,363	818	429,356	162.5	2,531.6	0.2	84.2
2014	852,718	14,478,342	824	50,298	163.3	2,544.3	0.2	11.0
2015	859,960	14,601,304	837	51,087	165.5	2,578.5	0.2	11.2
2016	868,350	14,743,762	850	51,892	167.6	2,611.8	0.2	11.3
2017	877,787	14,904,003	859	52,411	169.7	2,643.3	0.2	11.4
2018	886,112	15,045,351	867	52,914	171.6	2,673.8	0.2	11.6
2019	895,460	15,204,076	875	53,422	173.3	2,699.8	0.2	11.7
2020	904,307	15,354,289	883	53,935	175.3	2,730.3	0.2	11.8
2021	913,027	15,502,338	892	54,453	176.9	2,756.2	0.2	11.9
2022	920,746	15,633,408	901	54,975	178.6	2,782.2	0.2	12.0
2023	929,314	15,778,884	909	55,503	180.4	2,810.8	0.2	12.2
2024	938,963	15,942,700	918	56,036	182.5	2,843.2	0.2	12.3
2025	948,906	16,111,538	927	56,574	184.5	2,873.7	0.2	12.4
2026	957,870	16,263,733	936	57,117	186.2	2,901.4	0.2	12.6
2027	967,467	16,426,671	945	57,665	188.0	2,928.2	0.2	12.7

(Note 1) forecast as of 05/23/2012 (No Jo Carroll)

Tab: Status

IPL Renewable Status

	REC Share Percentages For Sources Other Than Whispering Willow					
Year	MN MWH Retail Sales with 3.15% Distribution Energy Losses (Note 2)	IA MWH Retail Sales with 3.15% Distribution Energy Losses (Note 2)	MWH Wholesale Sales	MN Retail REC Share Ratio (other than Whispering Willow)	IA Retail REC Share Ratio (other than Whispering Willow)	Wholesale REC Share Ratio (other than Whispering Willow)
2012	870,529	14,762,496	426,869	5.4%	91.9%	2.7%
2013	874,652	14,841,882	430,174	5.4%	91.9%	2.7%
2014	880,452	14,949,243	51,122	5.5%	94.1%	0.3%
2015	887,929	15,076,204	51,924	5.5%	94.1%	0.3%
2016	896,592	15,223,296	52,742	5.5%	94.1%	0.3%
2017	906,337	15,388,749	53,269	5.5%	94.1%	0.3%
2018	914,933	15,534,694	53,781	5.5%	94.1%	0.3%
2019	924,585	15,698,581	54,297	5.5%	94.1%	0.3%
2020	933,720	15,853,680	54,818	5.5%	94.1%	0.3%
2021	942,723	16,006,544	55,345	5.5%	94.1%	0.3%
2022	950,693	16,141,877	55,876	5.5%	94.1%	0.3%
2023	959,540	16,292,085	56,412	5.5%	94.1%	0.3%
2024	969,502	16,461,229	56,954	5.5%	94.1%	0.3%
2025	979,769	16,635,558	57,501	5.5%	94.1%	0.3%
2026	989,024	16,792,704	58,053	5.5%	94.1%	0.3%
2027	998,933	16,960,941	58,610	5.5%	94.1%	0.3%

(Note 2) REC Share Ratios adjust for 3.15% reasonable distribution energy losses to put Retail and Wholesale load at equivalent electric system level. Without adjustment, Retail Sales are generally at secondary and distribution level, Wholesale Sales generally at distribution and transmission level.

IPL Renewable Status

	REC Share Percentages For Whispering Willow (Note 3)					
Year	MN MW Retail Demand with 4.01% Distribution Demand Losses (Note 4)	IA MW Retail Demand with 4.01% Distribution Demand Losses (Note 4)	MW Wholesale Demand	MN Retail REC Share Ratio (Whipsering Willow)	IA Retail REC Share Ratio (Whispering Willow)	Wholesale REC Share Ratio (Whispering Willow)
2012	169	2,636	84	5.9%	91.2%	2.9%
2013	169	2,637	84	5.9%	91.2%	2.9%
2014	170	2,651	11	6.0%	93.6%	0.4%
2015	172	2,686	11	6.0%	93.6%	0.4%
2016	175	2,721	11	6.0%	93.6%	0.4%
2017	177	2,754	12	6.0%	93.6%	0.4%
2018	179	2,786	12	6.0%	93.6%	0.4%
2019	181	2,813	12	6.0%	93.6%	0.4%
2020	183	2,844	12	6.0%	93.6%	0.4%
2021	184	2,871	12	6.0%	93.6%	0.4%
2022	186	2,898	12	6.0%	93.6%	0.4%
2023	188	2,928	12	6.0%	93.6%	0.4%
2024	190	2,962	13	6.0%	93.6%	0.4%
2025	192	2,994	13	6.0%	93.6%	0.4%
2026	194	3,023	13	6.0%	93.6%	0.4%
2027	196	3,051	13	6.0%	93.6%	0.4%

(Note 3) Whispering Willow costs, and RECs, are proposed to be allocated by coincident peak.

(Note 4) REC Share Ratios adjust for 4.01% reasonable distribution demand losses to put Retail and Wholesale load at equivalent electric system level. Without adjustment, Retail Sales are generally at secondary and distribution level, Wholesale Sales generally at distribution and transmission level.

Tab: Status

IPL Renewable Status

	REC Shares Other than Whispering Willow				REC Shares for Whispering Willow				Total REC Shares			
Year	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share
2012	676,800	36,686	622,125	17,989	556,000	32,557	507,208	16,235	1,232,800	69,243	1,129,333	34,224
2013	676,527	36,647	621,856	18,024	612,000	35,836	558,294	17,870	1,288,527	72,483	1,180,151	35,894
2014	676,251	37,492	636,582	2,177	662,000	39,772	619,612	2,616	1,338,251	77,264	1,256,194	4,793
2015	675,972	37,476	636,305	2,191	662,000	39,772	619,612	2,616	1,337,972	77,248	1,255,917	4,807
2016	671,941	37,252	632,498	2,191	662,000	39,772	619,612	2,616	1,333,941	77,023	1,252,110	4,807
2017	656,906	36,418	618,348	2,140	662,000	39,772	619,612	2,616	1,318,906	76,190	1,237,960	4,756
2018	648,619	35,959	610,547	2,114	662,000	39,772	619,612	2,616	1,310,619	75,731	1,230,159	4,730
2019	631,929	35,034	594,838	2,057	662,000	39,772	619,612	2,616	1,293,929	74,805	1,214,451	4,673
2020	584,236	32,390	549,945	1,902	662,000	39,772	619,612	2,616	1,246,236	72,161	1,169,557	4,517
2021	580,940	32,207	546,843	1,891	662,000	39,772	619,612	2,616	1,242,940	71,979	1,166,455	4,507
2022	580,641	32,190	546,559	1,892	662,000	39,772	619,612	2,616	1,242,641	71,962	1,166,172	4,508
2023	580,340	32,173	546,275	1,892	662,000	39,772	619,612	2,616	1,242,340	71,945	1,165,887	4,507
2024	515,920	28,602	485,638	1,680	662,000	39,772	619,612	2,616	1,177,920	68,374	1,105,250	4,296
2025	464,559	25,755	437,292	1,511	662,000	39,772	619,612	2,616	1,126,559	65,527	1,056,905	4,127
2026	463,573	25,700	436,364	1,509	662,000	39,772	619,612	2,616	1,125,573	65,472	1,055,976	4,124
2027	463,259	25,683	436,069	1,507	662,000	39,772	619,612	2,616	1,125,259	65,454	1,055,681	4,123

Tab: Status

IPL Renewable Status

	Minnesota Status					Minnesota 4 Year Shelf Life Calculations			
Year	MN % Requirement of retail sales	MN REC Requirement for retail sales	MN Retail REC Share	MN RECs as % of Retail Sales	MN REC Status before 4 Year Shelf Life	4 Year Shelf Life REC balance BOY	4 Year Shelf Life REC balance EOY	REC **req'ts unmet**	4 Year Shelf Life REC's **"Lost"**
2012	12%	101,173	69,243	8.2%	(31,930)	70,947	39,017	0	0
2013	12%	101,652	72,483	8.6%	(29,169)	39,017	9,848	0	0
2014	12%	102,326	77,264	9.1%	(25,062)	9,848	0	-15,215	0
2015	12%	103,195	77,248	9.0%	(25,948)	0	0	-25,948	0
2016	17%	147,619	77,023	8.9%	(70,596)	0	0	-70,596	0
2017	17%	149,224	76,190	8.7%	(73,034)	0	0	-73,034	0
2018	17%	150,639	75,731	8.5%	(74,909)	0	0	-74,909	0
2019	17%	152,228	74,805	8.4%	(77,423)	0	0	-77,423	0
2020	20%	180,861	72,161	8.0%	(108,700)	0	0	-108,700	0
2021	20%	182,605	71,979	7.9%	(110,627)	0	0	-110,627	0
2022	20%	184,149	71,962	7.8%	(112,187)	0	0	-112,187	0
2023	20%	185,863	71,945	7.7%	(113,918)	0	0	-113,918	0
2024	20%	187,793	68,374	7.3%	(119,419)	0	0	-119,419	0
2025	25%	237,227	65,527	6.9%	(171,700)	0	0	-171,700	0
2026	25%	239,468	65,472	6.8%	(173,996)	0	0	-173,996	0
2027	25%	241,867	65,454	6.8%	(176,412)	0	0	-176,412	0

Tab: Status

IPL Renewable Status

	Iowa Status				
Year	IA % Requirement of retail sales (Note 5)	IA REC Requirement for retail sales	IA Retail REC Share	IA RECs as % of Retail Sales	IA REC Status before 4 Year Shelf Life
2012	0.8%	117,833	1,129,333	7.9%	1,011,500
2013	0.8%	117,833	1,180,151	8.2%	1,062,318
2014	0.8%	117,833	1,256,194	8.7%	1,138,361
2015	0.8%	117,833	1,255,917	8.6%	1,138,084
2016	0.8%	117,833	1,252,110	8.5%	1,134,277
2017	0.8%	117,833	1,237,960	8.3%	1,120,127
2018	0.8%	117,833	1,230,159	8.2%	1,112,326
2019	0.8%	117,833	1,214,451	8.0%	1,096,618
2020	0.8%	117,833	1,169,557	7.6%	1,051,724
2021	0.8%	117,833	1,166,455	7.5%	1,048,622
2022	0.8%	117,833	1,166,172	7.5%	1,048,339
2023	0.7%	117,833	1,165,887	7.4%	1,048,054
2024	0.7%	117,833	1,105,250	6.9%	987,417
2025	0.7%	117,833	1,056,905	6.6%	939,072
2026	0.7%	117,833	1,055,976	6.5%	938,143
2027	0.7%	117,833	1,055,681	6.4%	937,848

(Note 5) IPL forecasted requirements based on 199 IAC 15.11(1) = 49.8 MW of capacity. IPL has identified this capacity as 63.2% of the 78.75 MW Buena Vista/Storm Lake Power Partners Wind Farm (117,833 MWH estimated annual energy production).

Tab: Status

APPENDIX 7B

IPL's Renewable Energy Production

IPL Renewable Production in MWH/year

	Allendorf (Sibley) Wind Farm [3]	Buena Vista Wind Farm [4]	Cerro Gordo Wind Farm [5]	Flying Cloud Wind Farm	Hancock Wind Farm	Hancock Second Nature Use	Hancock Sale to CIPCO	Neppel Wind Farm	Hardin Hilltop / Wind[2]	America's Hydro[8]
in M-RETS	No	Yes	Yes	Yes	Yes	-	-	Yes	Yes	Yes
state of location	IA	IA	IA	IA	IA	IA	IA	IA	IA	IA
nameplate MW	1.2	80.3	41.3	43.5	56.8	n/a	-2 (3.52%)	1.5	14.7	2.69
PPA vs owned	PPA	PPA	PPA	PPA	PPA	-	-	PPA	PPA	PPA
renewable type	wind	wind	wind	wind	wind	wind	wind	wind	wind	hydro
2012	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	7,500
2013	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	7,500
2014	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	7,500
2015	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	7,500
2016	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	3,750
2017	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	
2018	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	
2019	900	191,000	99,000	145,000	137,000	-34,250	-4,822	2,400	40,000	
2020	900	191,000	99,000	145,000	137,000	-34,250	-4,822		40,000	
2021	900	191,000	99,000	145,000	137,000	-34,250	-4,822		40,000	
2022	900	191,000	99,000	145,000	137,000	-34,250	-4,822		40,000	
2023	900	191,000	99,000	145,000	137,000	-34,250	-4,822		40,000	
2024	900	191,000	49,500	145,000	137,000	-34,250	-4,822		40,000	
2025	675	191,000		145,000	137,000	-34,250	-4,822		40,000	
2026	0	191,000		145,000	137,000	-34,250	-4,822		40,000	
2027	0	191,000		145,000	137,000	-34,250	-4,822		40,000	

Notes:

1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

Tab: IPL Resources

IPL Renewable Production in MWH/year

	Wind Vision	LJ Trust	Zachary Ridge	Sibley Hills	Whispering Willow Wind Farm	Minn Wind I (Beaver Creek)	Minn Wind II (Beaver Creek)	Sieve Wind Farm	Arnold Wind	Wilmont Hills	Wilmont Hills Second Nature Use
in M-RETS		Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	-
state of location	IA	IA	IA	IA	IA	MN	MN	MN	MN	MN	MN
nameplate MW	*2.1*	2	2	1.2	200	3.8		1	1.65	1.5	n/a
PPA vs owned	*PPA*	PPA	PPA	PPA	owned	PPA	PPA	PPA	PPA	PPA	-
renewable type	*wind*	wind	wind	wind	wind	wind	wind	wind	wind	wind	wind
2012		6,132	6,132	3,679	556,000	5,000	5,000	3,000	6,000	6,000	-6,000
2013		6,132	6,132	3,679	612,000	5,000	5,000	3,000	6,000	6,000	-6,000
2014		6,132	6,132	3,679	662,000	5,000	5,000	3,000	6,000	6,000	-6,000
2015		6,132	6,132	3,679	662,000	5,000	5,000	3,000	6,000	6,000	-6,000
2016		6,132	6,132	3,679	662,000	5,000	5,000	3,000	6,000	6,000	-6,000
2017	*Renewable Attributes retained by seller*	6,132	6,132	3,679	662,000	2,500	2,500	3,000	6,000		-6,000
2018		6,132	6,132	3,679	662,000				6,000		-6,000
2019		6,132	6,132	3,679	662,000				6,000		-6,000
2020		6,132	6,132	3,679	662,000				3,000		-6,000
2021		6,132	6,132	3,679	662,000						-6,000
2022		6,132	6,132	3,679	662,000						-6,000
2023		6,132	6,132	3,679	662,000						-6,000
2024		511	511	307	662,000						-6,000
2025					662,000						-6,000
2026					662,000						-6,000
2027					662,000						-6,000

Notes:

1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
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7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

Tab: IPL Resources

IPL Renewable Production in MWH/year

	Adams Wind Farm[6]	Windom Wind Farm[7]	Additional Second Nature Use	Total MWH Other than Whispering Willow	Whispering Willow MWH	Total MWH With Whispering Willow
in M-RETS	Yes	Yes				
state of location	MN	MN				
nameplate MW	6	19.8				
PPA vs owned	PPA	PPA	PPA			
renewable type	wind	wind				
2012	14,000	42,000	-271	676,800	556,000	1,232,800
2013	14,000	42,000	-544	676,527	612,000	1,288,527
2014	14,000	42,000	-820	676,251	662,000	1,338,251
2015	14,000	42,000	-1,099	675,972	662,000	1,337,972
2016	14,000	42,000	-1,380	671,941	662,000	1,333,941
2017	14,000	42,000	-1,664	656,906	662,000	1,318,906
2018	14,000	42,000	-1,952	648,619	662,000	1,310,619
2019		42,000	-2,242	631,929	662,000	1,293,929
2020			-2,535	584,236	662,000	1,246,236
2021			-2,831	580,940	662,000	1,242,940
2022			-3,129	580,641	662,000	1,242,641
2023			-3,431	580,340	662,000	1,242,340
2024			-3,736	515,920	662,000	1,177,920
2025			-4,044	464,559	662,000	1,126,559
2026			-4,355	463,573	662,000	1,125,573
2027			-4,669	463,259	662,000	1,125,259

Notes:

1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

Tab: IPL Resources

APPENDIX 7C

IPL's C-BED Annual Report

December 22, 2011

ALLIANT ENERGY

Interstate Power and Light Company
An Alliant Energy Company

Alliant Tower
200 First Street SE
P.O. Box 351
Cedar Rapids, IA 52406-0351

Office: 1.800.822.4348
www.alliantenergy.com

Alliant Energy Corporate Service
Legal Department
319.786.4505 – Phone
3193786.4533 – Fax

Paula N. Johnson
Senior Attorney - Regulatory

December 22, 2011

Dr. Burl W. Haar
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

RE: Interstate Power and Light Company
Docket No. E001/M-05-1883
Community-Based Energy Development (C-BED) Annual Report

Dear Dr. Haar:

Enclosed for e-Filing with the Minnesota Public Utilities Commission (Commission), please find Interstate Power and Light Company's Community-Based Energy Development (C-BED) Annual Report pursuant to the Commission's July 28, 2006 Order in Docket No. E001/M-05-1883.

Copies of this filing have been served on the Minnesota Department of Commerce, Division of Energy Resources, the Minnesota Office of Attorney General – Residential and Small Business Utilities Division and the attached service list.

Respectfully submitted,

/s/ Paula N. Johnson
Paula N. Johnson
Senior Attorney - Regulatory

PNJ/tao
Enclosures

cc: Service List

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY'S PETITION FOR APPROVAL OF A COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED) TARIFF	DOCKET NO. E001/M-05-1883

AFFIDAVIT OF SERVICE

STATE OF IOWA)
) ss.
COUNTY OF LINN)

Tonya A. O'Rourke, being first duly sworn on oath, deposes and states:

That on the 22nd day of December, 2011, copies of the foregoing Affidavit of Service, together with Interstate Power and Light Company's Community-Based Energy Development (C-BED) Annual Report, were served upon the parties on the attached service list, by e-filing, overnight delivery, electronic mail, and/or first-class mail, proper postage prepaid from Cedar Rapids, Iowa.

/s/ Tonya A. O'Rourke
Tonya A. O'Rourke

Subscribed and Sworn to Before Me
this 22nd day of December, 2011.

/s/ Wendy E. Howard
Wendy E. Howard
Notary Public
My Commission Expires on September 12, 2012

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_5-1883_1
Lisa	Daniels	lisadaniels@windustry.org	Windustry	2105 First Avenue S. Minneapolis, MN 55404	Paper Service	No	OFF_SL_5-1883_1
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_5-1883_1
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_5-1883_1
Amanda A	James	AmandaJames@alliantenergy.com	Interstate Power & Light Company - Gas	200 First St SE PO Box 351 Cedar Rapids, IA 52401-0351	Paper Service	No	OFF_SL_5-1883_1
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_5-1883_1
Mark	Lindquist		The Minnesota Project	1026 North Washington Street New Ulm, MN 56073	Paper Service	No	OFF_SL_5-1883_1
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_5-1883_1
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	Suite 325 7301 Ohms Lane Edina, MN 55439	Electronic Service	No	OFF_SL_5-1883_1
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	P.O. Box 351 200 First St SE Cedar Rapids, IA 524060351	Paper Service	No	OFF_SL_5-1883_1

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY'S PETITION FOR APPROVAL OF A COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED) TARIFF	DOCKET NO. E001/M-05-1883

INTERSTATE POWER AND LIGHT COMPANY'S C-BED ANNUAL REPORT

COMES NOW, Interstate Power and Light Company (IPL or the Company), and pursuant to the Minnesota Public Utilities Commission's (Commission) Order dated July 28, 2006, files its Community-Based Energy Development Tariff (C-BED Tariff) Annual Report. In support of its annual report, IPL states the following:

1. On December 1, 2005, IPL petitioned the Commission for approval of its proposed C-BED tariff. The Minnesota Department of Commerce (Department), Windustry, the Minnesota Project, Institute for Self-Reliance, and Minnesotans for Energy Efficient Economy (Joint Commentators) filed reply comments on February 2, 2006. IPL and the Joint Commentators filed reply comments on February 21, 2006, and the Department filed supplemental comments on March 29, 2006. On June 7, 2006, IPL filed a reply to the reply comments.

2. On July 28, 2008, the Commission approved IPL's C-BED tariff with modifications. On November 12, 2007, IPL petitioned the Commission to modify its current C-BED tariff (Docket No. E001/M-07-1431) to incorporate the changes from the Next Generation Energy Act of 2007, Article 4, C-BED and Related Issues, approved May 25, 2007. The Commission approved the tariff effective the date of its September 5, 2008 order.

3. In its September 5, 2008, order in Docket No. E001/M-07-1431, the Commission also ordered IPL to file an annual report, either as part of its biennial resource plan or separately. IPL is filing this annual report separate from its biennial resource plan.

4. Since its C-BED tariff was approved, IPL has not received any proposals pursuant to its C-BED tariff. As such, IPL has not rejected any proposals made pursuant to its C-BED tariff. Additionally, IPL has not adopted service for any C-BED proposal under an alternative IPL tariff. Since IPL has not received any proposals, it has not executed any contracts under its C-BED tariff.

5. IPL has participated in planning and educational events with Riverland Community College and the Southwest Initiative Foundation. Additionally, IPL has developed collateral C-BED materials to educate IPL's account management team in Minnesota on the details of the C-BED tariff and to educate C-BED qualified IPL customers in Minnesota on the details of the C-BED tariff. IPL's Key Account Management team uses these collateral materials to discuss the C-BED tariff with potential C-BED candidates. IPL also educates customers on the C-BED tariff and other Minnesota customer-owned generation

options at www.alliantenergy.com/sellmypower. Additionally, customers can call the Alliant Energy Distributed Resources and Renewable Energy Hotline at 1-800-972-5325 to learn more about distributed generation, the interconnection process, fees and tariffs.

WHEREFORE, IPL respectfully requests the Minnesota Public Utilities Commission accept IPL's Annual Report on C-BED projects as in compliance with the Commission's July 28, 2006 Order.

Dated this 22nd day of December, 2011.

Respectfully submitted,

INTERSTATE POWER AND LIGHT COMPANY

By *_/s/ Paula N. Johnson_____*

Paula N. Johnson
Senior Attorney - Regulatory
Alliant Energy Corporate Services, Inc.
200 First Street S.E.
P.O. Box 351
Cedar Rapids, IA 52406-0351
(319) 786-4219

PUBLIC INTEREST CONSIDERATIONS

8.0 Overall Factors

This electric resource plan balances the concerns of many interested parties. A primary concern of IPL is meeting the future energy needs of its customers. These needs are to be met reliably, responsibly, efficiently and flexibly. Numerous factors impact the decisions for which specific resources and/or combinations of resources are selected and these are discussed throughout prior sections of this report. IPL remains flexible when considering all aspects of resource planning.

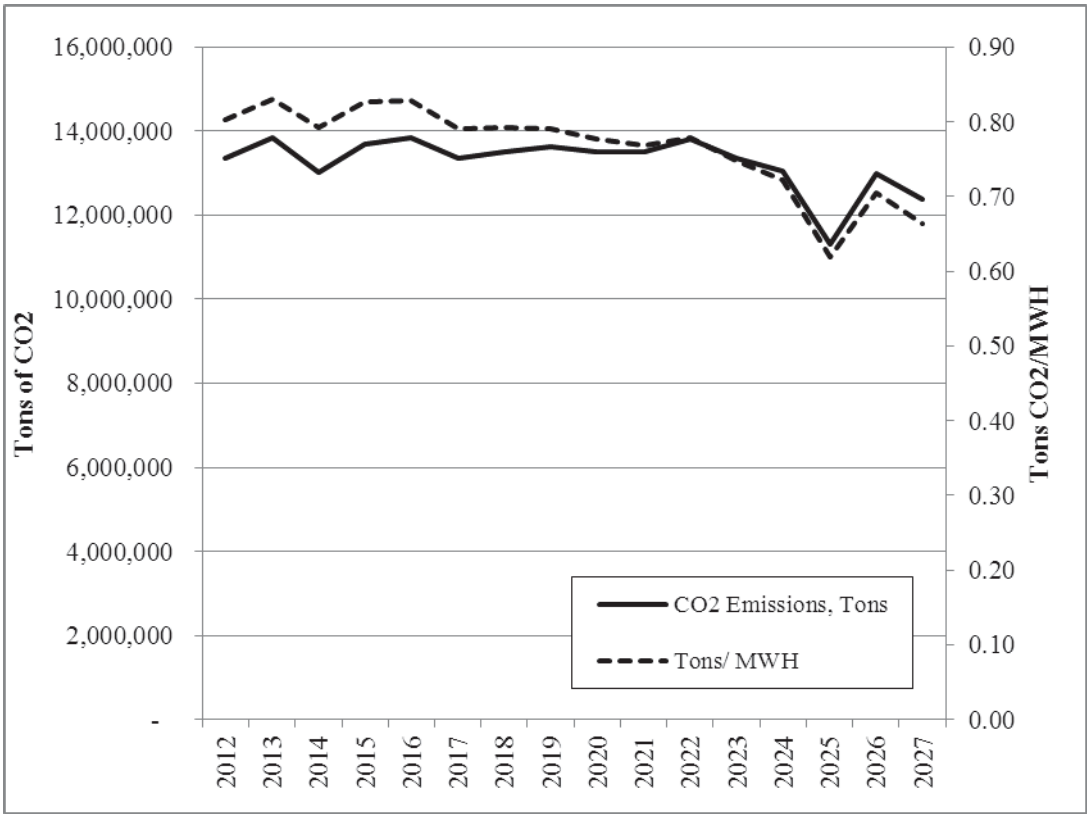
8.0.1 Reliably Meeting Customers' Needs

As a participant of MISO and under the Resource Adequacy (Module E) provisions of the MISO Tariff, IPL has agreed to provide capacity to serve its own load and, in addition, during each calendar month provide a reserve capacity obligation. Controls exist to ensure that each participant provides their share of allocated reserves. Currently, IPL's system meets the MISO requirements and calculations show that it will do so in the future. No capacity deficits are projected at any time and a MISO minimum planning reserve margin of 3.81% is maintained throughout the study period to insure reliable service. An important input to these reserve calculations is the system forecast, which projects the demand and energy for the future. The load forecast is reviewed at least annually to stay current with customers' needs. Refer to Section 2 for a comprehensive discussion of the load forecast.

8.0.2 Responsibly Meeting Customers' Needs

IPL is diligent in using resources wisely, which requires balancing financial impacts with adverse socioeconomic and environmental effects. The actions of IPL relative to these issues are consistent with its institutional responsibilities. Generally, demand-side alternatives reduce emissions into the air, water and land by reducing fossil-fueled supply-side generation. IPL includes DSM throughout the study period in its proposed plan. Furthermore, renewable resources, such as wind generation, also reduce emissions. IPL currently has both owned and purchased wind resources totaling approximately 450 MWs of nameplate generation in its proposed plan. IPL's proposed plan demonstrates IPL is committed to minimizing adverse socioeconomic and environmental effects with financial discipline. In fact, as shown in the chart below, IPL's projected annual CO_2 output (tons) in its Reference Case (proposed plan) is essentially flat through 2022, then declines slightly. This is in contrast to IPL's energy growth. Therefore, IPL's projected CO_2 ton/MWh rate is actually declining over the study period. All reasonable resource plans are developed to minimize the adverse effects, while maintaining the balance of a reliable system with rates as low as practicable.

Chart 8.0.2.1: Reference Case CO2 Emissions and Rate



8.0.3 Efficiently Meeting Customers' Needs

IPL develops resource plans based on the lowest cumulative present worth of revenue requirements, given regulatory and other constraints, yielding a reasonable plan. All reasonable resource alternatives (demand-side and supply-side) are modeled, evaluated and optimized using EGEAS. This insures an optimum plan and, as a result, customers' rates will be as low as practicable. The EGEAS results indicate that IPL's total costs (fuel, operations & maintenance, and new capital fixed charges) per kWh will increase nominally at an average rate of about 5 percent per year over the study period. Assuming an inflation rate of approximately 2 percent per year over that same time period, the change in real terms is approximately 3 percent per year. As a reasonable cost electricity manufacturer, IPL will continue to provide reliable, responsible and affordable electric energy to its customers.

8.0.4 Flexibly Meeting Customers' Needs

The action plan given in Section 7 shows that IPL is continually engaged in planning, and can reasonably respond to unanticipated events. The activities previously discussed and their scheduling permit the timely determination of possible changes to this electric resource plan. This flexibility ensures that customers' needs will be met with no unreasonable increase in costs due to unforeseen changes. Unexpected changes in regulations, customer loads, costs, technology and other parameters can all be accommodated. IPL is not committed to the cost, type, size or timing of any new resources with lead times that allow for further evaluation – this plan is responsive to changes in the load forecast and changes in resource characteristics. The assumptions included in this resource plan were determined by IPL to be reasonable at the time of the analysis.

8.1 Specific Factors

In addition to those topics discussed above, IPL studied some specific assumptions and their impacts on the electric resource plan. The scenarios that were developed and a detailed discussion of each are given in Section 6.

8.2 Considerations of the Proposed Plan

The evaluation of the proposed plan, detailed throughout this document, indicates that the proposed plan is in the public interest. This electric resource plan was developed using the efforts of many company employees and incorporated written reports of several other national consulting firms. The result is a plan that attempted to be responsive to the concerns of all.

SUMMARY

This is a summary of IPL's 2012 Electric Resource Plan filed with the State of Iowa.

9.0 The IPL System

IPL is a regulated utility company that provides electricity and natural gas to retail customers in two mid-western states. Today, IPL serves more than 500,000 electric customers and more than 200,000 natural gas customers in over 100 counties in Iowa and Minnesota. IPL's electric customers currently have an adjusted net internal demand of approximately 2,761 MW, which is projected to grow 350 MW over the next 15 years. Of IPL's electric retail customers, Iowa accounts for approximately 92 percent, and Minnesota approximately eight percent. IPL's Illinois retail load was sold in February 2007 but is still being served today by IPL as a wholesale load to Jo-Carroll Energy. Note that the forecast assumes loss of a wholesale customer in 2014, which is approximately 65-70 MW.

IPL's service territory encompasses approximately 54,000 square miles, including over 22,000 miles of electric distribution line and over 5,000 miles of natural-gas transmission and distribution main. IPL currently owns all or portions of generating facilities located in both Iowa and Minnesota. These owned units are able to produce approximately 2,430 Planning Resource Credits (PRC's) towards The Midwest Independent Transmission System Operator (MISO) Module E Resource Adequacy requirements. IPL's portfolio includes base load plants, which operate year round and are fueled with coal. IPL's portfolio also includes intermediate or combined cycle units, such as the Emery Generating Station, which provide load following capability and are primarily fueled with natural gas. Combustion turbines and diesel generators at various locations throughout IPL's system provide supplemental energy at points throughout the year when demand is highest. IPL also recently installed in late 2009 a 200 MW wind farm,

Whispering Willow Wind Farm - East, in Franklin County, Iowa, which IPL owns and operates. In addition to owned generation, IPL has purchased power contracts for approximately 250 MW from various wind resources as well as for approximately 400 MW from a nuclear plant, the Duane Arnold Energy Center. IPL delivers the energy and exceptional service that our customers and communities count on – safely, efficiently and responsibly.

9.1 Overview of Plan Development

The process used in developing this plan begins with the system load forecast. This forecast includes the needs of all firm IPL customers. The system load forecast plus a reserve requirement is matched against existing capacity to determine IPL's preliminary resource needs. IPL's Load and Capability Table – Before Resource Additions is shown in Appendix 9A. By using the Electric Generation Expansion Analysis System (EGEAS) computer model, all combinations of existing resources and modeled future resource alternatives are considered when determining the optimal expansion plan. Renewable alternatives, Demand-Side Management (DSM) programs and conventional supply-side units are all considered in the resource planning process. The objective function within EGEAS is to minimize the cumulative present worth of revenue requirements for the 15-year planning period plus a 35-year extension period, while maintaining the Midwest Independent System Operator (MISO) planning reserve margin (PRM_{ucap}) of 3.81 percent in each year. However, system reliability and financial risks must also be considered. The ultimate goal is to minimize cost, maximize reliability and minimize risk. Given reasonable assumptions and after careful consideration of costs, reliability and risks, a reference case is constructed.

Once a reference case is determined, IPL develops additional scenarios by changing various input assumptions. Some of the scenarios are regulatory requirements, while IPL creates others

by varying key input assumptions to provide supplemental insight.

9.2 Supply-side Resource Options

In arriving at the proposed plan, IPL considered many different types of resource options. On the supply-side, a broad range of technologies categorized as renewable, fossil fuel, purchased power and nuclear were reviewed.

9.2.1 Renewable

Renewable resources refer to resources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy is much more applicable to IPL's utility system and, in addition, has positive environmental benefits. Ten renewable technologies discussed subsequently are wind, solar-photovoltaic, solar-thermal, whole tree burning, biomass, geothermal, biogas-anaerobic digestion, biogas-landfill gas, ethanol fueled generation and hydro. Wind is the most prevalent renewable technology included in IPL's utility system resource mix. Renewable technologies, especially wind, are continuing to improve in efficiency and will be considered as resource options when applicable. IPL will continue to seek economically competitive renewable opportunities.

9.2.2 Fossil Fuel

Fossil fuel refers to any naturally occurring organic fuel such as petroleum, coal or natural gas. Most of the electrical energy generated by IPL's generating facilities is with fossil fuel. The electrical energy purchased utilizes a mix of technologies. However, a significant percentage of this purchased energy is produced from fossil fuel technologies. Fossil fuel technologies continue to be attractive resource options for IPL.

9.2.3 Purchased Power

IPL purchases electrical energy from the Midwest Independent Transmission System Operator, Inc. (MISO), other utilities, independent developers and power marketers. The decisions regarding purchased power are primarily functions of need, availability and cost. IPL will continue to purchase power when it makes sense to do so.

9.2.4 Nuclear

Nuclear refers to a facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to drive a steam generator. Typical nuclear units are rated at 600 MW or larger and have high capital requirements. Black & Veatch did provide cost and characteristic estimates for a new nuclear generating unit and nuclear was modeled as a resource alternative in the EGEAS analysis for this resource plan.

9.3 Demand-side Resource Options

DSM programs for this resource plan are categorized into two types of programs: conservation (non-dispatchable) and load management (dispatchable). IPL has achieved considerable demand and energy savings from DSM programs. DSM programs will continue to be a potential resource alternative provided DSM is economical.

9.4 Resource Plan

IPL examined many scenarios when developing this resource plan. The cost summaries of the scenario analyses are given in Appendices 9B, 9C. The resulting expansion plan (Reference Case) from this analysis can be found in Appendix 9D.

9.5 Upcoming Resource Activities

The resources needed to meet IPL's system capacity and energy requirements come primarily from three types of resources; demand-side, supply-side and renewable resources. During the forthcoming years, IPL will:

- Continue to pursue DSM activities;
- Investigate and pursue renewable energy alternatives;
- Pursue the addition of a 2017 nominal 600 MW combined cycle facility;
- Pursue reasonable emission controls on its remaining coal-fired units;
- Pursue capacity and efficiency upgrades at Tier 1 coal-fired units;
- Retire older peaking units;
- Retire older intermediate steam units;
- Consider all supply-side options and will only commit to resources that are in IPL's and IPL's customers' best interest.

In addition, IPL is engaged in transmission and environmental related activities which are also discussed below. The analysis of all options is ongoing.

9.5.1 Upcoming Demand-Side Management Activities

IPL's current DSM programs have been aggressively pursued and are continuing to save customers' kilowatts and kilowatt-hours. DSM activity is reported annually in all regulatory jurisdictions in which IPL serves retail customers. These filings on DSM programs to various agencies are expected to continue. IPL will continue to analyze potential demand and energy savings from future DSM activities.

9.5.2 Upcoming Supply-Side Activities

IPL is committed to meeting the demands of its customers. In Section 5, the types of resources required to meet IPL's customer needs were identified. Without resource additions, IPL projections show a significant capacity shortfall in 2017. IPL plans to meet its resource needs consistent with the regulations of the governing jurisdictions. Considering the next five years, the immediate incremental capacity and energy needs through 2017 will most likely be met with existing resources, MISO market energy, a MISO market capacity purchase in 2016 (as necessary), and a new nominal 600 MW combined cycle facility in 2017. IPL's future resource requirements will be acquired taking Iowa Code § 476.53(4) and subsequent regulatory rate treatment into consideration.

In this Resource Plan, IPL considered the ongoing viability of its older peaking and intermediate steam units. As discussed in Section 6, as a component to the resource plan, IPL plans to retire [redacted] Fox Lake 3, Dubuque 3 and 4, and Sutherland Units 1 and 3. Retirements are subject to approval from the MISO through the Attachment Y process.

At its Tier 2 coal-fired units [redacted] IPL will pursue the addition of "emissions lite" control projects by 2015 for compliance with the Utility Mercury and Air Toxics Standard (MATS).

The proposed resource plan calls for a new nominal 600 MW combined facility in 2017. IPL will seek favorable ratemaking principles for capital investments where Iowa Code § 476.53(4) is applicable and the necessary regulatory and environmental approvals and permits will be

obtained by the appropriate parties. IPL customers' demands will be met, system reliability within the region will be maintained, and customers' rates will be kept as low as reasonably possible.

This action plan will continually be reviewed and revised, as new information with respect to IPL's resource needs becomes available. IPL's resource planning process is continuously iterative and electric resource plans are regularly filed in Minnesota and Iowa. In the interim, all resource options will continue to be considered and evaluated.

9.5.3 Upcoming Renewable Activities

IPL continues to consider renewable energy, especially wind energy, a viable option for future resource needs. Currently, IPL purchases capacity and energy from approximately 250 MW of wind turbines. Also, IPL's 200 MW Whispering Willow Windfarm – East came online at the end of 2009. These existing and new resources are expected to allow IPL to obtain a renewable energy portfolio in the range of roughly 6.5% to 9% over the next 15 years. As shown in Appendix 9E, IPL is projecting to be surplus relative to Iowa's current renewable energy requirements anywhere from approximately 900,000 MWh to 1,100,000 MWh depending on the year. Also shown in Appendix 9E, IPL will eventually fall short of Minnesota's renewable requirements which increase to 25% by 2025. The Minnesota shortfall is roughly:

- 15,000 RECs in 2014 and 26,000 RECs in 2015 for the 12% requirement,
- 75,000 RECs per year in 2016 to 2019 for the 17% requirement,
- 120,000 RECs per year in 2020 to 2024 for the 20% requirement,
- 177,000 RECs per year in 2025 to 2027 for the 25% requirement.

When considering IPL collectively, IPL's surplus in Iowa could be used to meet a deficit in Minnesota and then all renewable energy requirements would be met system-wide for IPL.

Therefore, IPL in total is well positioned to meet both its Iowa and Minnesota renewable energy requirements absent any purchases of Midwest Renewable Energy Tracking System (M-RETS) Certificates. Furthermore, IPL's Renewable Energy Production is shown in Appendix 9F. In summary, IPL is well positioned to comply with both Iowa's and Minnesota's renewable energy requirements.

9.6 Effect on Electric Rates

IPL develops resource plans based on the lowest cumulative present worth of revenue requirements, given regulatory and other constraints. All reasonable resource alternatives (demand-side and supply-side) are modeled, evaluated and optimized using EGEAS. This insures an optimum plan and, as a result, customers' rates will be as low as practicable. The EGEAS results indicate that IPL's total costs (fuel, operations & maintenance, and new capital fixed charges) per kWh will increase nominally at an approximate rate of 5 percent per year throughout the study period. Assuming an inflation rate of approximately 2 percent per year over that same time period, the change in real terms is approximately 3 percent per year. As a reasonable cost electricity manufacturer, IPL will continue to provide reliable, responsible and affordable electric energy to its customers.

As IPL has done in the past, IPL will continue to evaluate the service needs of its customers, the costs of various resources, the applicability of new technologies, and other factors related to resource planning. IPL is committed to meeting the demands of its customers with economic, reliable, environmentally sound and safe energy.

APPENDIX 9A

IPL

2012 – 2027 Load and Capability Chart

Before Resource Additions

IPL Projected Load and Generating Capability Data
Reference Case - Before Resource Additions

	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	Summer 2018	Summer 2019	Summer 2020	Summer 2021	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2027
A. Total Internal Demand	3,053.5	3,056.8	2,999.4	3,039.4	3,077.3	3,114.3	3,149.2	3,180.3	3,216.3	3,246.4	3,277.4	3,311.4	3,348.4	3,384.3	3,417.3	3,449.4
B. Demand Resources	292.7	295.0	296.9	300.5	303.1	306.6	309.1	312.7	316.2	318.8	322.2	325.8	328.4	331.9	335.5	339.1
C. Net Internal Demand (A-B)	2,760.8	2,761.8	2,702.5	2,738.9	2,774.2	2,807.7	2,840.1	2,867.6	2,900.1	2,927.6	2,955.2	2,985.6	3,020.0	3,052.4	3,081.8	3,110.3
D. Full Responsibility Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
E. Full Responsibility Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F. Adjusted Net Demand (C + D - E)	2,760.8	2,761.8	2,702.5	2,738.9	2,774.2	2,807.7	2,840.1	2,867.6	2,900.1	2,927.6	2,955.2	2,985.6	3,020.0	3,052.4	3,081.8	3,110.3
G. Planning Reserve Margin	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%
H. PRC Obligation (F * (1 + G))	2,866.0	2,867.0	2,805.5	2,843.3	2,879.9	2,914.7	2,948.3	2,976.9	3,010.6	3,039.1	3,067.8	3,099.4	3,135.1	3,168.7	3,199.2	3,228.8
I. Asset Based PRCs	2,469.4	2,494.7	2,499.7	2,458.9	2,476.6	2,168.4	2,168.4	2,149.7	2,128.9	2,125.4	2,125.4	2,125.4	2,118.9	1,785.2	1,785.2	1,784.6
J. PRC Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
K. PRC Purchases	406.1	406.1	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	0.0	0.0
L. PRC New Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M. Net PRCs (I - J + K + L)	2,875.5	2,900.8	2,899.7	2,858.9	2,876.6	2,568.4	2,568.4	2,549.7	2,528.9	2,525.4	2,525.4	2,525.4	2,518.9	2,185.2	1,785.2	1,784.6
N. Long/(Short) Position (M - H)	9.5	33.8	94.2	15.6	(3.3)	(346.3)	(379.9)	(427.2)	(481.7)	(513.7)	(542.4)	(574.0)	(616.2)	(983.5)	(1,414.0)	(1,444.2)
O. Reserve Percentage (M - F) / F	4.15%	5.03%	7.30%	4.38%	3.69%	-8.52%	-9.57%	-11.09%	-12.80%	-13.74%	-14.54%	-15.41%	-16.59%	-28.41%	-42.07%	-42.62%

IPL Projected Load and Generating Capability Data
Reference Case - Before Resource Additions

	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	Summer 2018	Summer 2019	Summer 2020	Summer 2021	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2027
Committed Purchases and Sales:																
Firm Purchases:																
Total Firm Purchases:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Firm Sales:																
Total Firm Sales:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Participation Purchases:																
DAEC	406.1	406.1	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	0.0	0.0
Total Participation Purchases:	406.1	406.1	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	0.0	0.0
Participation Sales:																
IPL PRC Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Participation Sales:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

IPL Projected Load and Generating Capability Data
Reference Case - Before Resource Additions

	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	Summer 2018	Summer 2019	Summer 2020	Summer 2021	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2027
Proposed New Resources:																
Total Proposed New Resources:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

APPENDIX 9B

Scenario Cost Summary

Base Set (Plan 1)

IPL's 2012 Integrated Resource Plan			
Plan 1 - No Tier 2 Early Retirments			
Case	Description	PVRR, $M	2017 CC Summer MW
x001	Base Forecast (Reference Case)	14,137.2	539
x002	High Load Forecast	14,492.5	539
x003	Low Load Forecast	13,804.6	539
x004	No Economy Energy	14,658.3	539
x005	Additional RPS Requirement (10% by 2015, 15% by 2020)	14,191.4	539
x006	CO2 Scenario - Wood Mackenzie	16,468.7	539
x007	CO2 Scenario - Minnesota High	18,398.7	539
x008	CO2 Scenario - Minnesota Low	15,341.7	539
x009	Natural Gas Prices +10% (and On Peak Market Energy)	14,462.6	539
x010	Natural Gas Prices +20% (and On Peak Market Energy)	14,772.8	539
x011	Natural Gas Prices +30% (and On Peak Market Energy)	15,080.3	539
x012	Natural Gas Prices -10% (and On Peak Market Energy)	13,729.2	539
x013	Natural Gas Prices -20% (and On Peak Market Energy)	13,186.4	539
x014	Natural Gas Prices -30% (and On Peak Market Energy)	12,542.8	539
x015	Coal Prices +10% (and Off Peak Market Energy)	14,443.3	539
x016	Coal Prices +20% (and Off Peak Market Energy)	14,708.5	539
x017	Coal Prices +30% (and Off Peak Market Energy)	14,933.9	539
x018	Coal Prices -10% (and Off Peak Market Energy)	13,800.9	539
x019	Coal Prices -20% (and Off Peak Market Energy)	13,454.5	539
x020	Coal Prices -30% (and Off Peak Market Energy)	13,101.5	539
x021	New Unit Capital Costs +10%	14,347.1	539
x022	New Unit Capital Costs -10%	13,878.4	539
x023	Higher Wind Prices, ~+$20/MWH (no PTC renewal)	14,217.8	539

APPENDIX 9C

Scenario Cost Summary

Retirement Sensitivity (Plan 2 and Plan 3)

IPL's 2012 Integrated Resource Plan				
Tier 2 Retirement Sensitivies				
Case	**Description**	**PVRR, $M**	**2017 CC Summer MW**	
x001	Reference (Tier 2 not retired early)	14,137.2	539	Plan 1
v101	All Tier 2 Staged gas conversion and retirements	14,304.0	539	Plan 2
v096	Tier 2 retired EOY 2014 (no "emissions lite" control projects)	14,426.6	539	Plan 3
Plan 2 - Tier 2 Staged Gas Conversion and Retirements				
Case	**Description**	**PVRR, $M**	**2017 CC Summer MW**	
v101	Base Forecast	14,304.0	539	
v102	High Load Forecast	14,649.4	539	
v103	Low Load Forecast	13,964.9	539	
v104	No Economy Energy	14,815.7	539	
v105	Additional RPS Requirement (10% by 2015, 15% by 2020)	14,349.0	539	
v106	CO2 Scenario - Wood Mackenzie	16,559.3	539	
v107	CO2 Scenario - Minnesota High	18,442.1	288	
v108	CO2 Scenario - Minnesota Low	15,483.2	539	
v109	Natural Gas Prices +10% (and On Peak Market Energy)	14,662.8	539	
v110	Natural Gas Prices +20% (and On Peak Market Energy)	15,013.4	539	
v111	Natural Gas Prices +30% (and On Peak Market Energy)	15,360.0	539	
v112	Natural Gas Prices -10% (and On Peak Market Energy)	13,853.0	539	
v113	Natural Gas Prices -20% (and On Peak Market Energy)	13,277.1	539	
v114	Natural Gas Prices -30% (and On Peak Market Energy)	12,618.1	539	
v115	Coal Prices +10% (and Off Peak Market Energy)	14,555.1	539	
v116	Coal Prices +20% (and Off Peak Market Energy)	14,771.2	539	
v117	Coal Prices +30% (and Off Peak Market Energy)	14,949.4	539	
v118	Coal Prices -10% (and Off Peak Market Energy)	13,994.1	539	
v119	Coal Prices -20% (and Off Peak Market Energy)	13,674.7	539	
v120	Coal Prices -30% (and Off Peak Market Energy)	13,352.3	539	
v121	New Unit Capital Costs +10%	14,538.9	539	
v122	New Unit Capital Costs -10%	14,032.7	539	
v123	Higher Wind Prices, ~+$20/MWH (no PTC renewal)	14,378.1	539	

APPENDIX 9D

Reference Case Expansion Plan

IPL's 2012 Integrated Resource Plan
Case: x001 (Plan 1)
Base Forecast (Reference Case)

YEAR	PPCT 1YR 50	CT-73	CT-189	CC-288	CC-538.9	PC300	PC600	WIND 100
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0
2016	50	0	0	0	0	0	0	0
2017	0	0	0	0	538.9	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	200
2024	50	0	0	0	0	0	0	200
2025	150	72.895	188.9	0	0	0	0	200
2026	50	0	0	0	538.9	0	0	200
2027	50	0	0	0	0	0	0	200
TOTAL	450	72.895	188.9	0	1077.8	0	0	1000

APPENDIX 9E

IPL's Renewable Energy Position

IPL Renewable Status

	Retail and Wholesale Energy by State (Note 1)				Retail and Wholesale Demand by State (Note 1)			
Year	MN MWH Retail Sales	IA MWH Retail Sales	MN MWH Wholesale Sales	IA MWH Wholesale Sales	MN MW Retail Demand	IA MW Retail Demand	MN MW Wholesale Demand	IA MW Wholesale Demand
2012	843,107	14,297,477	812	426,056	162.4	2,530.7	0.2	84.2
2013	847,100	14,374,363	818	429,356	162.5	2,531.6	0.2	84.2
2014	852,718	14,478,342	824	50,298	163.3	2,544.3	0.2	11.0
2015	859,960	14,601,304	837	51,087	165.5	2,578.5	0.2	11.2
2016	868,350	14,743,762	850	51,892	167.6	2,611.8	0.2	11.3
2017	877,787	14,904,003	859	52,411	169.7	2,643.3	0.2	11.4
2018	886,112	15,045,351	867	52,914	171.6	2,673.8	0.2	11.6
2019	895,460	15,204,076	875	53,422	173.3	2,699.8	0.2	11.7
2020	904,307	15,354,289	883	53,935	175.3	2,730.3	0.2	11.8
2021	913,027	15,502,338	892	54,453	176.9	2,756.2	0.2	11.9
2022	920,746	15,633,408	901	54,975	178.6	2,782.2	0.2	12.0
2023	929,314	15,778,884	909	55,503	180.4	2,810.8	0.2	12.2
2024	938,963	15,942,700	918	56,036	182.5	2,843.2	0.2	12.3
2025	948,906	16,111,538	927	56,574	184.5	2,873.7	0.2	12.4
2026	957,870	16,263,733	936	57,117	186.2	2,901.4	0.2	12.6
2027	967,467	16,426,671	945	57,665	188.0	2,928.2	0.2	12.7

(Note 1) forecast as of 05/23/2012 (No Jo Carroll)

Tab: Status

IPL Renewable Status

	REC Share Percentages For Sources Other Than Whispering Willow					
Year	MN MWH Retail Sales with 3.15% Distribution Energy Losses (Note 2)	IA MWH Retail Sales with 3.15% Distribution Energy Losses (Note 2)	MWH Wholesale Sales	MN Retail REC Share Ratio (other than Whispering Willow)	IA Retail REC Share Ratio (other than Whispering Willow)	Wholesale REC Share Ratio (other than Whispering Willow)
2012	870,529	14,762,496	426,869	5.4%	91.9%	2.7%
2013	874,652	14,841,882	430,174	5.4%	91.9%	2.7%
2014	880,452	14,949,243	51,122	5.5%	94.1%	0.3%
2015	887,929	15,076,204	51,924	5.5%	94.1%	0.3%
2016	896,592	15,223,296	52,742	5.5%	94.1%	0.3%
2017	906,337	15,388,749	53,269	5.5%	94.1%	0.3%
2018	914,933	15,534,694	53,781	5.5%	94.1%	0.3%
2019	924,585	15,698,581	54,297	5.5%	94.1%	0.3%
2020	933,720	15,853,680	54,818	5.5%	94.1%	0.3%
2021	942,723	16,006,544	55,345	5.5%	94.1%	0.3%
2022	950,693	16,141,877	55,876	5.5%	94.1%	0.3%
2023	959,540	16,292,085	56,412	5.5%	94.1%	0.3%
2024	969,502	16,461,229	56,954	5.5%	94.1%	0.3%
2025	979,769	16,635,558	57,501	5.5%	94.1%	0.3%
2026	989,024	16,792,704	58,053	5.5%	94.1%	0.3%
2027	998,933	16,960,941	58,610	5.5%	94.1%	0.3%

(Note 2) REC Share Ratios adjust for 3.15% reasonable distribution energy losses to put Retail and Wholesale load at equivalent electric system level. Without adjustment, Retail Sales are generally at secondary and distribution level, Wholesale Sales generally at distribution and transmission level.

IPL Renewable Status

	REC Share Percentages For Whispering Willow (Note 3)					
Year	MN MW Retail Demand with 4.01% Distribution Demand Losses (Note 4)	IA MW Retail Demand with 4.01% Distribution Demand Losses (Note 4)	MW Wholesale Demand	MN Retail REC Share Ratio (Whipsering Willow)	IA Retail REC Share Ratio (Whispering Willow)	Wholesale REC Share Ratio (Whispering Willow)
2012	169	2,636	84	5.9%	91.2%	2.9%
2013	169	2,637	84	5.9%	91.2%	2.9%
2014	170	2,651	11	6.0%	93.6%	0.4%
2015	172	2,686	11	6.0%	93.6%	0.4%
2016	175	2,721	11	6.0%	93.6%	0.4%
2017	177	2,754	12	6.0%	93.6%	0.4%
2018	179	2,786	12	6.0%	93.6%	0.4%
2019	181	2,813	12	6.0%	93.6%	0.4%
2020	183	2,844	12	6.0%	93.6%	0.4%
2021	184	2,871	12	6.0%	93.6%	0.4%
2022	186	2,898	12	6.0%	93.6%	0.4%
2023	188	2,928	12	6.0%	93.6%	0.4%
2024	190	2,962	13	6.0%	93.6%	0.4%
2025	192	2,994	13	6.0%	93.6%	0.4%
2026	194	3,023	13	6.0%	93.6%	0.4%
2027	196	3,051	13	6.0%	93.6%	0.4%

(Note 3) Whispering Willow costs, and RECs, are proposed to be allocated by coincident peak.

(Note 4) REC Share Ratios adjust for 4.01% reasonable distribution demand losses to put Retail and Wholesale load at equivalent electric system level. Without adjustment, Retail Sales are generally at secondary and distribution level, Wholesale Sales generally at distribution and transmission level.

IPL Renewable Status

	REC Shares Other than Whispering Willow				REC Shares for Whispering Willow				Total REC Shares			
Year	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share
2012	676,800	36,686	622,125	17,989	556,000	32,557	507,208	16,235	1,232,800	69,243	1,129,333	34,224
2013	676,527	36,647	621,856	18,024	612,000	35,836	558,294	17,870	1,288,527	72,483	1,180,151	35,894
2014	676,251	37,492	636,582	2,177	662,000	39,772	619,612	2,616	1,338,251	77,264	1,256,194	4,793
2015	675,972	37,476	636,305	2,191	662,000	39,772	619,612	2,616	1,337,972	77,248	1,255,917	4,807
2016	671,941	37,252	632,498	2,191	662,000	39,772	619,612	2,616	1,333,941	77,023	1,252,110	4,807
2017	656,906	36,418	618,348	2,140	662,000	39,772	619,612	2,616	1,318,906	76,190	1,237,960	4,756
2018	648,619	35,959	610,547	2,114	662,000	39,772	619,612	2,616	1,310,619	75,731	1,230,159	4,730
2019	631,929	35,034	594,838	2,057	662,000	39,772	619,612	2,616	1,293,929	74,805	1,214,451	4,673
2020	584,236	32,390	549,945	1,902	662,000	39,772	619,612	2,616	1,246,236	72,161	1,169,557	4,517
2021	580,940	32,207	546,843	1,891	662,000	39,772	619,612	2,616	1,242,940	71,979	1,166,455	4,507
2022	580,641	32,190	546,559	1,892	662,000	39,772	619,612	2,616	1,242,641	71,962	1,166,172	4,508
2023	580,340	32,173	546,275	1,892	662,000	39,772	619,612	2,616	1,242,340	71,945	1,165,887	4,507
2024	515,920	28,602	485,638	1,680	662,000	39,772	619,612	2,616	1,177,920	68,374	1,105,250	4,296
2025	464,559	25,755	437,292	1,511	662,000	39,772	619,612	2,616	1,126,559	65,527	1,056,905	4,127
2026	463,573	25,700	436,364	1,509	662,000	39,772	619,612	2,616	1,125,573	65,472	1,055,976	4,124
2027	463,259	25,683	436,069	1,507	662,000	39,772	619,612	2,616	1,125,259	65,454	1,055,681	4,123

Tab: Status

IPL Renewable Status

	Minnesota Status					Minnesota 4 Year Shelf Life Calculations			
Year	MN % Requirement of retail sales	MN REC Requirement for retail sales	MN Retail REC Share	MN RECs as % of Retail Sales	MN REC Status before 4 Year Shelf Life	4 Year Shelf Life REC balance BOY	4 Year Shelf Life REC balance EOY	REC **req'ts unmet**	4 Year Shelf Life REC's **"Lost"**
2012	12%	101,173	69,243	8.2%	(31,930)	70,947	39,017	0	0
2013	12%	101,652	72,483	8.6%	(29,169)	39,017	9,848	0	0
2014	12%	102,326	77,264	9.1%	(25,062)	9,848	0	-15,215	0
2015	12%	103,195	77,248	9.0%	(25,948)	0	0	-25,948	0
2016	17%	147,619	77,023	8.9%	(70,596)	0	0	-70,596	0
2017	17%	149,224	76,190	8.7%	(73,034)	0	0	-73,034	0
2018	17%	150,639	75,731	8.5%	(74,909)	0	0	-74,909	0
2019	17%	152,228	74,805	8.4%	(77,423)	0	0	-77,423	0
2020	20%	180,861	72,161	8.0%	(108,700)	0	0	-108,700	0
2021	20%	182,605	71,979	7.9%	(110,627)	0	0	-110,627	0
2022	20%	184,149	71,962	7.8%	(112,187)	0	0	-112,187	0
2023	20%	185,863	71,945	7.7%	(113,918)	0	0	-113,918	0
2024	20%	187,793	68,374	7.3%	(119,419)	0	0	-119,419	0
2025	25%	237,227	65,527	6.9%	(171,700)	0	0	-171,700	0
2026	25%	239,468	65,472	6.8%	(173,996)	0	0	-173,996	0
2027	25%	241,867	65,454	6.8%	(176,412)	0	0	-176,412	0

Tab: Status

IPL Renewable Status

	Iowa Status				
Year	IA % Requirement of retail sales (Note 5)	IA REC Requirement for retail sales	IA Retail REC Share	IA RECs as % of Retail Sales	IA REC Status before 4 Year Shelf Life
2012	0.8%	117,833	1,129,333	7.9%	1,011,500
2013	0.8%	117,833	1,180,151	8.2%	1,062,318
2014	0.8%	117,833	1,256,194	8.7%	1,138,361
2015	0.8%	117,833	1,255,917	8.6%	1,138,084
2016	0.8%	117,833	1,252,110	8.5%	1,134,277
2017	0.8%	117,833	1,237,960	8.3%	1,120,127
2018	0.8%	117,833	1,230,159	8.2%	1,112,326
2019	0.8%	117,833	1,214,451	8.0%	1,096,618
2020	0.8%	117,833	1,169,557	7.6%	1,051,724
2021	0.8%	117,833	1,166,455	7.5%	1,048,622
2022	0.8%	117,833	1,166,172	7.5%	1,048,339
2023	0.7%	117,833	1,165,887	7.4%	1,048,054
2024	0.7%	117,833	1,105,250	6.9%	987,417
2025	0.7%	117,833	1,056,905	6.6%	939,072
2026	0.7%	117,833	1,055,976	6.5%	938,143
2027	0.7%	117,833	1,055,681	6.4%	937,848

(Note 5) IPL forecasted requirements based on 199 IAC 15.11(1) = 49.8 MW of capacity. IPL has identified this capacity as 63.2% of the 78.75 MW Buena Vista/Storm Lake Power Partners Wind Farm (117,833 MWH estimated annual energy production).

Tab: Status

APPENDIX 9F

IPL's Renewable Energy Production

IPL Renewable Production in MWH/year

	Allendorf (Sibley) Wind Farm [3]	Buena Vista Wind Farm [4]	Cerro Gordo Wind Farm [5]	Flying Cloud Wind Farm	Hancock Wind Farm	Hancock Second Nature Use	Hancock Sale to CIPCO	Neppel Wind Farm	Hardin Hilltop / Wind[2]	America's Hydro[8]
in M-RETS	No	Yes	Yes	Yes	Yes	-	-	Yes	Yes	Yes
state of location	IA	IA	IA	IA	IA	IA	IA	IA	IA	IA
nameplate MW	1.2	80.3	41.3	43.5	56.8	n/a	-2 (3.52%)	1.5	14.7	2.69
PPA vs owned	PPA	PPA	PPA	PPA	PPA	-	-	PPA	PPA	PPA
renewable type	wind	wind	wind	wind	wind	wind	wind	wind	wind	hydro
2012	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	7,500
2013	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	7,500
2014	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	7,500
2015	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	7,500
2016	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	3,750
2017	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	
2018	900	191,000	99,000	145,000	137,000	-34,250	-4,822	4,800	40,000	
2019	900	191,000	99,000	145,000	137,000	-34,250	-4,822	2,400	40,000	
2020	900	191,000	99,000	145,000	137,000	-34,250	-4,822		40,000	
2021	900	191,000	99,000	145,000	137,000	-34,250	-4,822		40,000	
2022	900	191,000	99,000	145,000	137,000	-34,250	-4,822		40,000	
2023	900	191,000	99,000	145,000	137,000	-34,250	-4,822		40,000	
2024	900	191,000	49,500	145,000	137,000	-34,250	-4,822		40,000	
2025	675	191,000		145,000	137,000	-34,250	-4,822		40,000	
2026	0	191,000		145,000	137,000	-34,250	-4,822		40,000	
2027	0	191,000		145,000	137,000	-34,250	-4,822		40,000	

Notes:

1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

Tab: IPL Resources

IPL Renewable Production in MWH/year

	Wind Vision	LJ Trust	Zachary Ridge	Sibley Hills	Whispering Willow Wind Farm	Minn Wind I (Beaver Creek)	Minn Wind II (Beaver Creek)	Sieve Wind Farm	Arnold Wind	Wilmont Hills	Wilmont Hills Second Nature Use
in M-RETS		Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	-
state of location	IA	IA	IA	IA	IA	MN	MN	MN	MN	MN	MN
nameplate MW	*2.1*	2	2	1.2	200	3.8		1	1.65	1.5	n/a
PPA vs owned	*PPA*	PPA	PPA	PPA	owned	PPA	PPA	PPA	PPA	PPA	-
renewable type	*wind*	wind	wind	wind	wind	wind	wind	wind	wind	wind	wind
2012		6,132	6,132	3,679	556,000	5,000	5,000	3,000	6,000	6,000	-6,000
2013		6,132	6,132	3,679	612,000	5,000	5,000	3,000	6,000	6,000	-6,000
2014		6,132	6,132	3,679	662,000	5,000	5,000	3,000	6,000	6,000	-6,000
2015		6,132	6,132	3,679	662,000	5,000	5,000	3,000	6,000	6,000	-6,000
2016		6,132	6,132	3,679	662,000	5,000	5,000	3,000	6,000	6,000	-6,000
2017	*Renewable Attributes retained by seller*	6,132	6,132	3,679	662,000	2,500	2,500	3,000	6,000		-6,000
2018		6,132	6,132	3,679	662,000				6,000		-6,000
2019		6,132	6,132	3,679	662,000				6,000		-6,000
2020		6,132	6,132	3,679	662,000				3,000		-6,000
2021		6,132	6,132	3,679	662,000						-6,000
2022		6,132	6,132	3,679	662,000						-6,000
2023		6,132	6,132	3,679	662,000						-6,000
2024		511	511	307	662,000						-6,000
2025					662,000						-6,000
2026					662,000						-6,000
2027					662,000						-6,000

Notes:

1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

IPL Renewable Production in MWH/year

	Adams Wind Farm[6]	Windom Wind Farm[7]	Additional Second Nature Use	Total MWH Other than Whispering Willow	Whispering Willow MWH	Total MWH With Whispering Willow
in M-RETS	Yes	Yes				
state of location	MN	MN				
nameplate MW	6	19.8				
PPA vs owned	PPA	PPA	PPA			
renewable type	wind	wind				
2012	14,000	42,000	-271	676,800	556,000	1,232,800
2013	14,000	42,000	-544	676,527	612,000	1,288,527
2014	14,000	42,000	-820	676,251	662,000	1,338,251
2015	14,000	42,000	-1,099	675,972	662,000	1,337,972
2016	14,000	42,000	-1,380	671,941	662,000	1,333,941
2017	14,000	42,000	-1,664	656,906	662,000	1,318,906
2018	14,000	42,000	-1,952	648,619	662,000	1,310,619
2019		42,000	-2,242	631,929	662,000	1,293,929
2020			-2,535	584,236	662,000	1,246,236
2021			-2,831	580,940	662,000	1,242,940
2022			-3,129	580,641	662,000	1,242,641
2023			-3,431	580,340	662,000	1,242,340
2024			-3,736	515,920	662,000	1,177,920
2025			-4,044	464,559	662,000	1,126,559
2026			-4,355	463,573	662,000	1,125,573
2027			-4,669	463,259	662,000	1,125,259

Notes:

1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

Tab: IPL Resources

LOAD & CAPABILITY DATA

10.0 Load & Capability Table

The resulting load and generating capability table after resource additions for IPL can be found in Appendix 10A. In all years, 2012-2027, the reserve margin is at or above the MISO planning reserve margin (PRM_{ucap}) of 3.81 percent. This table is consistent with the EGEAS analysis and the reserve margins match, within rounding, the reserve margins of the Reference Case shown in Appendix 6D. Furthermore, Appendix 10B shows the IPL load and generating capability table before proposed resource additions.

10.1 Capacity Ratings

The generating unit capacity ratings for all IPL facilities can be found in Appendix 10C. Appendix 10C provides the detail for the net Planning Reserve Credit (PRC) line of the load and generating capability chart in Appendix 10B.

10.2 Generating Unit Data

Additional generating unit data from IPL's 2011 FERC Form 1 can be found in Appendix 10D.

APPENDIX 10A

IPL

2012 – 2027 Load and Capability Table

Reference Case

After Resource Additions

IPL Projected Load and Generating Capability Data
Reference Case - After Resource Additions

	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	Summer 2018	Summer 2019	Summer 2020	Summer 2021	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2027
A. Total Internal Demand	3,053.5	3,056.8	2,999.4	3,039.4	3,077.3	3,114.3	3,149.2	3,180.3	3,216.3	3,246.4	3,277.4	3,311.4	3,348.4	3,384.3	3,417.3	3,449.4
B. Demand Resources	292.7	295.0	296.9	300.5	303.1	306.6	309.1	312.7	316.2	318.8	322.2	325.8	328.4	331.9	335.5	339.1
C. Net Internal Demand (A-B)	2,760.8	2,761.8	2,702.5	2,738.9	2,774.2	2,807.7	2,840.1	2,867.6	2,900.1	2,927.6	2,955.2	2,985.6	3,020.0	3,052.4	3,081.8	3,110.3
D. Full Responsibility Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
E. Full Responsibility Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F. Adjusted Net Demand (C + D - E)	2,760.8	2,761.8	2,702.5	2,738.9	2,774.2	2,807.7	2,840.1	2,867.6	2,900.1	2,927.6	2,955.2	2,985.6	3,020.0	3,052.4	3,081.8	3,110.3
G. Planning Reserve Margin	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%
H. PRC Obligation (F * (1 + G))	2,866.0	2,867.0	2,805.5	2,843.3	2,879.9	2,914.7	2,948.3	2,976.9	3,010.6	3,039.1	3,067.8	3,099.4	3,135.1	3,168.7	3,199.2	3,228.8
I. Asset Based PRCs	2,469.4	2,494.7	2,499.7	2,458.9	2,476.6	2,168.4	2,168.4	2,149.7	2,128.9	2,125.4	2,125.4	2,125.4	2,118.9	1,785.2	1,785.2	1,784.6
J. PRC Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
K. PRC Purchases	406.1	406.1	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	0.0	0.0
L. PRC New Additions	0.0	0.0	0.0	0.0	50.0	506.9	506.9	524.2	524.2	524.2	574.2	600.0	625.8	994.2	1,426.9	1,452.7
M. Net PRCs (I - J + K + L)	2,875.5	2,900.8	2,899.7	2,858.9	2,926.6	3,075.3	3,075.3	3,073.9	3,053.1	3,049.6	3,099.6	3,125.4	3,144.7	3,179.4	3,212.1	3,237.3
N. Long/(Short) Position (M - H)	9.5	33.8	94.2	15.6	46.7	160.7	127.0	97.1	42.5	10.5	31.8	26.1	9.7	10.7	12.9	8.5
O. Reserve Percentage (M - F) / F	4.15%	5.03%	7.30%	4.38%	5.49%	9.53%	8.28%	7.20%	5.28%	4.17%	4.89%	4.68%	4.13%	4.16%	4.23%	4.08%

IPL Projected Load and Generating Capability Data
Reference Case - After Resource Additions

	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	Summer 2018	Summer 2019	Summer 2020	Summer 2021	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2027
Committed Purchases and Sales:																
Firm Purchases:																
Total Firm Purchases:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Firm Sales:																
Total Firm Sales:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Participation Purchases:																
DAEC	406.1	406.1	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	0.0	0.0
Total Participation Purchases:	406.1	406.1	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	0.0	0.0
Participation Sales:																
IPL PRC Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Participation Sales:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

IPL Projected Load and Generating Capability Data
Reference Case - After Resource Additions

	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	Summer 2018	Summer 2019	Summer 2020	Summer 2021	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2027
Proposed New Resources:																
One Year Peak Power Purchases					50.0						50.0	50.0	50.0	150.0	50.0	50.0
2017 nominal 600 MW CC						506.9	506.9	506.9	506.9	506.9	506.9	506.9	506.9	506.9	506.9	506.9
Flying Cloud Wind PPA replaced								8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Buena Vista Wind PPA replaced								9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
1000 MW Wind 2023-2027												25.8	51.6	77.4	103.2	129.0
(12.9% Reserve Contribution for Wind)																
2025 73 MW CT														67.5	67.5	67.5
2025 189 MW CT														175.0	175.0	175.0
2026 nominal 600 MW CC															506.9	506.9
Total Proposed New Resources:	0.0	0.0	0.0	0.0	50.0	506.9	506.9	524.2	524.2	524.2	574.2	600.0	625.8	994.2	1,426.9	1,452.7

APPENDIX 10B

IPL

2012 – 2027 Load and Capability Table

Reference Case

Before Resource Additions

IPL Projected Load and Generating Capability Data
Reference Case - Before Resource Additions

	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	Summer 2018	Summer 2019	Summer 2020	Summer 2021	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2027
A. Total Internal Demand	3,053.5	3,056.8	2,999.4	3,039.4	3,077.3	3,114.3	3,149.2	3,180.3	3,216.3	3,246.4	3,277.4	3,311.4	3,348.4	3,384.3	3,417.3	3,449.4
B. Demand Resources	292.7	295.0	296.9	300.5	303.1	306.6	309.1	312.7	316.2	318.8	322.2	325.8	328.4	331.9	335.5	339.1
C. Net Internal Demand (A-B)	2,760.8	2,761.8	2,702.5	2,738.9	2,774.2	2,807.7	2,840.1	2,867.6	2,900.1	2,927.6	2,955.2	2,985.6	3,020.0	3,052.4	3,081.8	3,110.3
D. Full Responsibility Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
E. Full Responsibility Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F. Adjusted Net Demand (C + D - E)	2,760.8	2,761.8	2,702.5	2,738.9	2,774.2	2,807.7	2,840.1	2,867.6	2,900.1	2,927.6	2,955.2	2,985.6	3,020.0	3,052.4	3,081.8	3,110.3
G. Planning Reserve Margin	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%	3.81%
H. PRC Obligation (F * (1 + G))	2,866.0	2,867.0	2,805.5	2,843.3	2,879.9	2,914.7	2,948.3	2,976.9	3,010.6	3,039.1	3,067.8	3,099.4	3,135.1	3,168.7	3,199.2	3,228.8
I. Asset Based PRCs	2,469.4	2,494.7	2,499.7	2,458.9	2,476.6	2,168.4	2,168.4	2,149.7	2,128.9	2,125.4	2,125.4	2,125.4	2,118.9	1,785.2	1,785.2	1,784.6
J. PRC Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
K. PRC Purchases	406.1	406.1	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	0.0	0.0
L. PRC New Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M. Net PRCs (I - J + K + L)	2,875.5	2,900.8	2,899.7	2,858.9	2,876.6	2,568.4	2,568.4	2,549.7	2,528.9	2,525.4	2,525.4	2,525.4	2,518.9	2,185.2	1,785.2	1,784.6
N. Long/(Short) Position (M - H)	9.5	33.8	94.2	15.6	(3.3)	(346.3)	(379.9)	(427.2)	(481.7)	(513.7)	(542.4)	(574.0)	(616.2)	(983.5)	(1,414.0)	(1,444.2)
O. Reserve Percentage (M - F) / F	4.15%	5.03%	7.30%	4.38%	3.69%	-8.52%	-9.57%	-11.09%	-12.80%	-13.74%	-14.54%	-15.41%	-16.59%	-28.41%	-42.07%	-42.62%

File Name: L&C, X series, No additions (2012-09-12).xlsx Sheet Name: IPL 2012 L&C Sheet 1 of 3 Printed: 09/12/2012 1:12 PM

IPL Projected Load and Generating Capability Data
Reference Case - Before Resource Additions

	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	Summer 2018	Summer 2019	Summer 2020	Summer 2021	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2027
Committed Purchases and Sales:																
Firm Purchases:																
Total Firm Purchases:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Firm Sales:																
Total Firm Sales:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Participation Purchases:																
DAEC	406.1	406.1	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	0.0	0.0
Total Participation Purchases:	406.1	406.1	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	0.0	0.0
Participation Sales:																
IPL PRC Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Participation Sales:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

IPL Projected Load and Generating Capability Data
Reference Case - Before Resource Additions

	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	Summer 2018	Summer 2019	Summer 2020	Summer 2021	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2027
Proposed New Resources:																
Total Proposed New Resources:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

APPENDIX 10C

IPL

Planning Resource Credit (PRC) Ratings

IPL's Existing Generating Units, Purchases and Sales
Planning Resource Credits (PRC's)
Reference Case - Before Resource Additions

Resource Description	2012 Summer Reserve Capacity (PRC's)	2013 Summer Reserve Capacity (PRC's)	2014 Summer Reserve Capacity (PRC's)	2015 Summer Reserve Capacity (PRC's)	2016 Summer Reserve Capacity (PRC's)	2017 Summer Reserve Capacity (PRC's)	2018 Summer Reserve Capacity (PRC's)	2019 Summer Reserve Capacity (PRC's)	2020 Summer Reserve Capacity (PRC's)	2021 Summer Reserve Capacity (PRC's)	2022 Summer Reserve Capacity (PRC's)	2023 Summer Reserve Capacity (PRC's)	2024 Summer Reserve Capacity (PRC's)	2025 Summer Reserve Capacity (PRC's)	2026 Summer Reserve Capacity (PRC's)	2027 Summer Reserve Capacity (PRC's)
Dubuque #3	28.8	28.8	28.8	0	0	0	0	0	0	0	0	0	0	0	0	0
Dubuque #4	31.6	31.6	31.6	0	0	0	0	0	0	0	0	0	0	0	0	0
Fox Lake #3G	81.1	81.1	81.1	81.1	81.1	0	0	0	0	0	0	0	0	0	0	0
Kapp #2	176.4	176.4	176.4	176.4	176.4	176.4	176.4	176.4	171.1	171.1	171.1	171.1	171.1	0	0	0
Montgomery CT	13.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesels	9	9	9	5.3	5.3	0	0	0	0	0	0	0	0	0	0	0
Lansing #4	223.8	223.8	223.8	223.8	241.5	241.5	241.5	241.5	234.3	234.3	234.3	234.3	234.3	234.3	234.3	234.3
Louisa	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Neal 25 04	160.2	160.2	157.7	162	162	162	162	162	162	162	162	162	162	162	162	162
Lime Creek 1	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8
Lime Creek 2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2
Wind IPW Cerro Gordo	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	0	0	0	0
Wind IPW Flying Cloud	8.3	8.3	8.3	8.3	8.3	8.3	8.3	0	0	0	0	0	0	0	0	0
Wind IPW Bingham	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	0	0	0	0	0	0	0
Wind IPW Adams	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0	0	0	0	0	0	0	0	0
Wind IES Beaver Creek	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Emery	509.8	548.6	548.6	548.6	548.6	548.6	548.6	548.6	548.6	548.6	548.6	548.6	548.6	548.6	548.6	548.6
Burlington CT1	15.1	15.1	15.1	15.1	15.1	0	0	0	0	0	0	0	0	0	0	0
Burlington CT2	12.6	12.6	12.6	12.6	12.6	0	0	0	0	0	0	0	0	0	0	0
Burlington CT3	14.9	14.9	14.9	14.9	14.9	0	0	0	0	0	0	0	0	0	0	0
Burlington CT4	14.5	14.5	14.5	14.5	14.5	0	0	0	0	0	0	0	0	0	0	0
Grinnell CT1	22.5	22.5	22.5	22.5	22.5	0	0	0	0	0	0	0	0	0	0	0
Grinnell CT2	19.2	19.2	19.2	19.2	19.2	0	0	0	0	0	0	0	0	0	0	0
Centerville Diesel	3.4	3.4	3.4	3.4	3.4	0	0	0	0	0	0	0	0	0	0	0
DAEC Purchase	406.1	406.1	400	400	400	400	400	400	400	400	400	400	400	400	0	0
Ottumwa	295.2	295.2	295.2	310.3	310.3	310.3	310.3	310.3	310.3	308.7	308.7	308.7	308.7	308.7	308.7	308.7
Burlington	167.6	167.6	167.6	167.6	167.6	167.6	167.6	167.6	162.6	162.6	162.6	162.6	162.6	0	0	0
Prairie Creek 1	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Prairie Creek 3	30.7	30.7	30.7	30.7	30.7	30.7	30.7	30.7	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8
Prairie Creek 4	78.5	78.5	78.5	78.5	78.5	78.5	78.5	78.5	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1
Sutherland 1	28.3	28.3	28.3	28.3	28.3	0	0	0	0	0	0	0	0	0	0	0
Sutherland 3	58.8	58.8	58.8	58.8	58.8	0	0	0	0	0	0	0	0	0	0	0
Sutherland CT1	55.3	55.3	55.3	55.3	55.3	55.3	55.3	55.3	55.3	55.3	55.3	55.3	55.3	55.3	55.3	55.3
Sutherland CT2	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5
Sutherland CT3	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6
Centerville 1	12	12	12	12	12	0	0	0	0	0	0	0	0	0	0	0
Centerville 2	20.5	20.5	20.5	20.5	20.5	0	0	0	0	0	0	0	0	0	0	0
Red Cedar Cogen	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Neal #3	140.2	140.2	138	141.9	141.9	141.9	141.9	141.9	141.9	141.9	141.9	141.9	141.9	141.9	141.9	141.9
Whispering Willow East	0	0	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Wind IES Buena Vista	9	9	9	9	9	9	9	0	0	0	0	0	0	0	0	0
Wind IES Hancock	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
Wind Hardin Hilltop	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0
MKT EGY Off Peak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MKT EGY On Peak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Summer Reserve Capacity (PRC's)	2875.5	2900.8	2899.7	2858.9	2876.6	2568.4	2568.4	2549.7	2528.9	2525.4	2525.4	2525.4	2518.9	2185.2	1785.2	1784.6

Appendix 10C
Page 1 of 1

APPENDIX 10D

IPL

Generating Unit Data

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Prairie Creek 123* (b)			Plant Name: *Prairie Creek 4* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1950			1968
4	Year Last Unit was Installed			1997			1968
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			65.00			148.75
6	Net Peak Demand on Plant - MW (60 minutes)			46			126
7	Plant Hours Connected to Load			8383			6414
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			55			143
10	When Limited by Condenser Water			51			137
11	Average Number of Employees			60			60
12	Net Generation, Exclusive of Plant Use - KWh			0			550367000
13	Cost of Plant: Land and Land Rights			8548			160173
14	Structures and Improvements			0			26339624
15	Equipment Costs			62747544			142316212
16	Asset Retirement Costs			3853872			1584691
17	Total Cost			66609964			170400700
18	Cost per KW of Installed Capacity (line 17/5) Including			1024.7687			1145.5509
19	Production Expenses: Oper, Supv, & Engr			0			369546
20	Fuel			0			16128120
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			3531999
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			-3654041
25	Electric Expenses			0			1045202
26	Misc Steam (or Nuclear) Power Expenses			0			605465
27	Rents			0			0
28	Allowances			0			125558
29	Maintenance Supervision and Engineering			0			235227
30	Maintenance of Structures			0			196484
31	Maintenance of Boiler (or reactor) Plant			0			1750165
32	Maintenance of Electric Plant			0			421871
33	Maintenance of Misc Steam (or Nuclear) Plant			0			584257
34	Total Production Expenses			0			21339853
35	Expenses per Net KWh			0.0000			0.0388
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)				Total Prairie	Coal	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				Creek Fuels	Ton	Mcf
38	Quantity (Units) of Fuel Burned	0	0	0	0	391683	261524
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	8402	1013
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	37.380	5.050
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	36.560	5.090
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	2.180	5.020
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.027	0.063
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	12441.000	12441.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Sutherland* (b)	Plant Name: *Marshalltown* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1955	1977
4	Year Last Unit was Installed	1961	1977
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	114.60	202.20
6	Net Peak Demand on Plant - MW (60 minutes)	108	189
7	Plant Hours Connected to Load	6792	368
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	113	208
10	When Limited by Condenser Water	111	0
11	Average Number of Employees	48	48
12	Net Generation, Exclusive of Plant Use - KWh	428667128	14097280
13	Cost of Plant: Land and Land Rights	173560	0
14	Structures and Improvements	13857967	188716
15	Equipment Costs	126195695	25494041
16	Asset Retirement Costs	1596893	0
17	Total Cost	141824115	25682757
18	Cost per KW of Installed Capacity (line 17/5) Including	1237.5577	127.0166
19	Production Expenses: Oper, Supv, & Engr	347709	4420
20	Fuel	11663200	4020584
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	1673556	13719
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	710451	37621
26	Misc Steam (or Nuclear) Power Expenses	591246	9950
27	Rents	0	0
28	Allowances	75657	0
29	Maintenance Supervision and Engineering	360491	3530
30	Maintenance of Structures	400303	5899
31	Maintenance of Boiler (or reactor) Plant	986813	80
32	Maintenance of Electric Plant	949749	41065
33	Maintenance of Misc Steam (or Nuclear) Plant	666699	21010
34	Total Production Expenses	18425874	4157878
35	Expenses per Net KWh	0.0430	0.2949

Line No.	Item (a)	Plant (b)			Plant (c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal		Gas		Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Ton		Mcf		Barrel	
38	Quantity (Units) of Fuel Burned	254659	0	21145	0	35252	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9341	0	1013	0	138500	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	42.090	0.000	6.110	0.000	130.740	0.000
41	Average Cost of Fuel per Unit Burned	41.360	0.000	6.110	0.000	114.050	0.000
42	Average Cost of Fuel Burned per Million BTU	2.210	0.000	6.040	0.000	19.610	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.067	0.000	0.285	0.000
44	Average BTU per KWh Net Generation	11148.000	0.000	11148.000	0.000	14546.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Centerville* (b)			Plant Name: *Burlington* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		Gas Turbine			Steam	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Conventional			Conventional	
3	Year Originally Constructed		1990			1968	
4	Year Last Unit was Installed		1990			1968	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		52.20			211.95	
6	Net Peak Demand on Plant - MW (60 minutes)		25			207	
7	Plant Hours Connected to Load		233			7476	
8	Net Continuous Plant Capability (Megawatts)		0			0	
9	When Not Limited by Condenser Water		49			212	
10	When Limited by Condenser Water		0			212	
11	Average Number of Employees		1			41	
12	Net Generation, Exclusive of Plant Use - KWh		1851900			1202753000	
13	Cost of Plant: Land and Land Rights		19150			81312	
14	Structures and Improvements		262557			12235767	
15	Equipment Costs		5580865			98412682	
16	Asset Retirement Costs		23216			324266	
17	Total Cost		5885788			111054027	
18	Cost per KW of Installed Capacity (line 17/5) Including		112.7546			523.9633	
19	Production Expenses: Oper, Supv, & Engr		4191			202078	
20	Fuel		1184733			19427772	
21	Coolants and Water (Nuclear Plants Only)		0			0	
22	Steam Expenses		1266			1298323	
23	Steam From Other Sources		0			0	
24	Steam Transferred (Cr)		0			0	
25	Electric Expenses		20315			494563	
26	Misc Steam (or Nuclear) Power Expenses		8884			578211	
27	Rents		0			0	
28	Allowances		0			79976	
29	Maintenance Supervision and Engineering		4161			210083	
30	Maintenance of Structures		16781			544840	
31	Maintenance of Boiler (or reactor) Plant		0			783735	
32	Maintenance of Electric Plant		46074			392806	
33	Maintenance of Misc Steam (or Nuclear) Plant		21803			502451	
34	Total Production Expenses		1308208			24514838	
35	Expenses per Net KWh		0.7064			0.0204	
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Oil		Coal	Oil	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Barrel		Ton	Barrel	Mcf
38	Quantity (Units) of Fuel Burned	0	10118	0	772051	0	14367
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	138500	0	8385	0	1033
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	130.390	0.000	24.760	128.990	6.130
41	Average Cost of Fuel per Unit Burned	0.000	117.080	0.000	24.840	0.000	6.130
42	Average Cost of Fuel Burned per Million BTU	0.000	20.130	0.000	1.480	0.000	5.940
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.640	0.000	0.016	0.000	0.064
44	Average BTU per KWh Net Generation	0.000	31780.000	0.000	10777.000	0.000	10777.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Dubuque* (b)			Plant Name: *Lansing* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1904			1948
4	Year Last Unit was Installed			1959			1977
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			66.25			309.80
6	Net Peak Demand on Plant - MW (60 minutes)			61			248
7	Plant Hours Connected to Load			4462			7224
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			64			309
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			16			52
12	Net Generation, Exclusive of Plant Use - KWh			117817300			1365634239
13	Cost of Plant: Land and Land Rights			58147			168534
14	Structures and Improvements			4166183			29035164
15	Equipment Costs			34850660			347121396
16	Asset Retirement Costs			1738524			1868188
17	Total Cost			40813514			378193282
18	Cost per KW of Installed Capacity (line 17/5) Including			616.0530			1220.7659
19	Production Expenses: Oper, Supv, & Engr			186026			433732
20	Fuel			3584657			38741431
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			1051511			1814761
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			441666			593160
26	Misc Steam (or Nuclear) Power Expenses			384732			798254
27	Rents			0			0
28	Allowances			45815			70109
29	Maintenance Supervision and Engineering			181018			376732
30	Maintenance of Structures			54058			111511
31	Maintenance of Boiler (or reactor) Plant			938980			1030882
32	Maintenance of Electric Plant			78300			1427541
33	Maintenance of Misc Steam (or Nuclear) Plant			381090			670912
34	Total Production Expenses			7327853			46069025
35	Expenses per Net KWh			0.0622			0.0337
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal		Gas	Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Ton		Mcf	Ton	Barrel	
38	Quantity (Units) of Fuel Burned	85447	0	249283	919503	7581	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8866	0	1012	8766	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	34.950	0.000	5.018	43.630	132.550	0.000
41	Average Cost of Fuel per Unit Burned	24.240	0.000	5.018	40.140	124.070	0.000
42	Average Cost of Fuel Burned per Million BTU	1.367	0.000	4.959	2.290	21.099	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.021	0.000	0.074	0.027	0.250	0.000
44	Average BTU per KWh Net Generation	15001.000	0.000	15001.000	11837.000	11837.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Montgomery* (b)			Plant Name: *Lime Creek* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Gas Turbine			Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1974			1991
4	Year Last Unit was Installed			1974			1991
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			29.40			82.80
6	Net Peak Demand on Plant - MW (60 minutes)			25			83
7	Plant Hours Connected to Load			8			23
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			22			70
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			-64800			-49100
13	Cost of Plant: Land and Land Rights			14512			0
14	Structures and Improvements			146914			2171344
15	Equipment Costs			2052145			23255690
16	Asset Retirement Costs			54649			49382
17	Total Cost			2268220			25476416
18	Cost per KW of Installed Capacity (line 17/5) Including			77.1503			307.6862
19	Production Expenses: Oper, Supv, & Engr			421			1069
20	Fuel			15705			136998
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			157			9725
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			5577			1807
26	Misc Steam (or Nuclear) Power Expenses			1378			986
27	Rents			0			0
28	Allowances			0			30
29	Maintenance Supervision and Engineering			365			1110
30	Maintenance of Structures			2722			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			27399			3160
33	Maintenance of Misc Steam (or Nuclear) Plant			9284			0
34	Total Production Expenses			63008			154885
35	Expenses per Net KWh			-0.9723			-3.1545
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Oil			Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Barrel			Barrel	
38	Quantity (Units) of Fuel Burned	0	203	0	0	1528	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	140000	0	0	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	77.360	0.000	0.000	89.660	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	13.156	0.000	0.000	15.248	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Red Cedar* (d)			Plant Name: *Sixth Street* (e)			Plant Name: *Emery* (f)			Line No.
		Gas Turbine			Steam			Gas Turbine	1
		Conventional			Conventional			Combined Cycle Steam	2
		1996			1900			2004	3
		1996			1950			2004	4
		22.50			0.00			602.80	5
		20			0			578	6
		333			0			1685	7
		0			0			0	8
		23			0			596	9
		0			0			596	10
		0			0			17	11
		4281600			-9082000			464426655	12
		75177			140303			607541	13
		95587			0			58595309	14
		14061532			0			346189961	15
		0			16582296			52736	16
		14232296			16722599			405445547	17
		632.5465			0			672.6038	18
		10699			37062			1650599	19
		301151			1			28463578	20
		0			0			0	21
		730			19048			52526	22
		0			0			0	23
		0			0			0	24
		47912			-14249			18247	25
		22678			41887			566957	26
		0			0			0	27
		0			0			2601	28
		10740			38814			18250	29
		11793			83633			541	30
		473			25011			2531	31
		21487			11082			4808690	32
		76			15221			0	33
		427739			257510			35584520	34
		0.0999			-0.0284			0.0766	35
		Gas					Oil	Gas	36
		Mcf					Barrel	Mcf	37
0	0	59217	0	0	0	0	595	3573148	38
0	0	1013	0	0	0	0	138500	1009	39
0.000	0.000	5.090	0.000	0.000	0.000	0.000	0.000	7.950	40
0.000	0.000	5.090	0.000	0.000	0.000	0.000	85.040	7.950	41
0.000	0.000	5.020	0.000	0.000	0.000	0.000	14.620	7.880	42
0.000	0.000	0.070	0.000	0.000	0.000	0.000	0.114	0.061	43
0.000	0.000	14012.000	0.000	0.000	0.000	0.000	7773.000	7773.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

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Plant Name: *Ottumwa* (d)			Plant Name: *George Neal # 3* (e)			Plant Name: *Grinnell* (f)			Line No.
Steam			Steam			Gas Turbine			1
Conventional			Conventional			Conventional			2
1981			1975			1990			3
1981			1975			1990			4
387.12			153.95			44.60			5
348			135			0			6
7332			7917			0			7
0			0			0			8
343			144			47			9
338			144			0			10
36			21			1			11
1682322000			917616000			918400			12
856123			331			25000			13
44066325			5013059			235893			14
189906767			52647856			5740633			15
-259434			0			0			16
234569781			57661246			6001526			17
605.9356			374.5453			134.5634			18
198159			715096			403			19
35038284			13397930			130569			20
0			0			0			21
1507868			485925			1090			22
0			0			0			23
0			0			0			24
954503			210567			662			25
396038			877265			419			26
0			0			0			27
112911			76094			0			28
188722			759789			429			29
142163			675354			1681			30
1429924			1274840			366			31
312961			576476			9935			32
877740			321098			5133			33
41159273			19370434			150687			34
0.0245			0.0211			0.1641			35
Coal	Oil		Coal		Gas			Gas	36
Ton	Barrel		Ton		Mcf			Mcf	37
1091169	6338	0	560772	0	29547	0	0	22790	38
8374	140000	0	8580	0	1013	0	0	1011	39
31.350	133.150	0.000	23.240	0.000	5.470	0.000	0.000	5.730	40
30.850	120.580	0.000	23.040	0.000	5.470	0.000	0.000	5.730	41
1.840	20.510	0.000	1.340	0.000	5.400	0.000	0.000	5.670	42
0.020	0.223	0.000	0.014	0.000	0.057	0.000	0.000	0.142	43
10884.000	10884.000	0.000	10519.000	0.000	10519.000	0.000	0.000	25091.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

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Plant Name: *Burlington CT* (d)			Plant Name: *Agency Street* (e)			Plant Name: *M. L. Kapp* (f)			Line No.
		Gas Turbine			Gas Turbine			Steam	1
		Conventional			Conventional			Conventional	2
		1995			1989			1947	3
		1995			1989			1967	4
		92.00			0.00			218.45	5
		0			0			210	6
		0			0			6522	7
		0			0			0	8
		71			0			203	9
		0			0			0	10
		0			0			36	11
		1070000			-134000			899916000	12
		115977			5010			52232	13
		33540			0			10466993	14
		17166379			0			93824357	15
		0			0			911217	16
		17315896			5010			105254799	17
		188.2163			0			481.8256	18
		256			7149			222975	19
		143601			2191			21258038	20
		0			0			0	21
		0			0			1139350	22
		0			0			0	23
		0			0			0	24
		0			0			456311	25
		2147			7560			495283	26
		0			0			0	27
		0			0			53805	28
		273			7596			221877	29
		9480			1231			248681	30
		0			0			1352810	31
		35675			1100			318404	32
		342			161			493272	33
		191774			26988			26260806	34
		0.1792			-0.2014			0.0292	35
		Gas				Coal		Gas	36
		Mcf				Ton		Mcf	37
0	0	24803	0	0	0	603693	0	22906	38
0	0	1035	0	0	0	8471	0	1000	39
0.000	0.000	5.790	0.000	0.000	0.000	37.380	0.000	6.208	40
0.000	0.000	5.790	0.000	0.000	0.000	33.180	0.000	6.208	41
0.000	0.000	5.600	0.000	0.000	0.000	1.958	0.000	6.208	42
0.000	0.000	0.134	0.000	0.000	0.000	0.022	0.000	0.073	43
0.000	0.000	23985.000	0.000	0.000	0.000	11391.000	0.000	11391.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

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Plant Name: *Fox Lake* (d)			Plant Name: *George Neal #4* (e)			Plant Name: *Louisa* (f)			Line No.
		Steam			Steam			Steam	1
		Conventional			Conventional			Conventional	2
		1950			1979			1983	3
		1962			1979			1983	4
		93.10			164.70			32.40	5
		78			163			30	6
		910			8052			6754	7
		0			0			0	8
		86			165			30	9
		81			165			30	10
		13			23			4	11
		31142940			1152069000			181042120	12
		29665			155540			16828	13
		3467298			12838492			12352706	14
		22629687			83673649			22591743	15
		1258385			0			0	16
		27385035			96667681			34961277	17
		294.1465			586.9319			1079.0518	18
		51373			762563			120848	19
		1541209			16349578			2786046	20
		0			0			0	21
		483917			638684			178773	22
		0			0			0	23
		0			0			0	24
		174558			276763			57827	25
		154639			963798			161994	26
		0			0			0	27
		3113			92286			12000	28
		53202			810223			128400	29
		17904			596787			31978	30
		35274			1587641			542386	31
		103413			353900			62848	32
		213187			291045			47934	33
		2831789			22723268			4131034	34
		0.0909			0.0197			0.0228	35
		Gas	Coal	Oil		Coal	Oil	Gas	36
		Mcf	Ton	Barrel		Ton	Barrel	Mcf	37
0	0	381733	677639	3825	0	108447	22	5577	38
0	0	1007	8733	137885	0	8488	138114	1016	39
0.000	0.000	4.339	23.500	127.090	0.000	24.430	0.000	6.439	40
0.000	0.000	4.339	23.230	119.370	0.000	24.100	64.740	6.439	41
0.000	0.000	4.311	1.330	20.610	0.000	1.420	11.161	6.334	42
0.000	0.000	0.053	0.014	0.212	0.000	0.015	0.114	0.065	43
0.000	0.000	12343.000	10293.000	10293.000	0.000	10201.000	10201.000	10201.000	44

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Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Whispering Willow* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Wind Energy			1
Conventional			2
2009			3
2009			4
199.65	0.00	0.00	5
197	0	0	6
7486	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
2	0	0	11
568237000	0	0	12
14326413	0	0	13
58221182	0	0	14
362657025	0	0	15
13713174	0	0	16
448917794	0	0	17
2248.5239	0	0	18
831605	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
68781	0	0	26
709429	0	0	27
0	0	0	28
0	0	0	29
10801	0	0	30
0	0	0	31
87584	0	0	32
8502455	0	0	33
10210655	0	0	34
0.0180	0.0000	0.0000	35
			36
			37
0 0 0	0 0 0	0 0 0	38
0 0 0	0 0 0	0 0 0	39
0.000 0.000 0.000	0.000 0.000 0.000	0.000 0.000 0.000	40
0.000 0.000 0.000	0.000 0.000 0.000	0.000 0.000 0.000	41
0.000 0.000 0.000	0.000 0.000 0.000	0.000 0.000 0.000	42
0.000 0.000 0.000	0.000 0.000 0.000	0.000 0.000 0.000	43
0.000 0.000 0.000	0.000 0.000 0.000	0.000 0.000 0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) X An Original (2) __ A Resubmission	/ /	2011/Q4

FOOTNOTE DATA

Schedule Page: 402 Line No.: 5 Column: e

Sixth Street Generating Station was retired in place 11/1/2010. Installed capacity was 84.75 MW.

Schedule Page: 402 Line No.: 11 Column: b

Employees reported at Prairie Creek 1, 2 and 3 are the same as those reported for Prairie Creek #4, Page 402, Column (c).

Schedule Page: 402 Line No.: 12 Column: b

Generation for Prairie Creek Units 1, 2, and 3 is included in Prairie Creek #4, Page 402, Column (c).

Schedule Page: 402 Line No.: 19 Column: b

Production expenses for Prairie Creek Units 1, 2, and 3 are included in Prairie Creek #4, Page 402, Column (c).

Schedule Page: 402.1 Line No.: 2 Column: d

The Ottumwa Generating Station (OGS) is operated by Interstate Power and Light Company, and owned jointly by the Company and MidAmerican Energy Company with the participants having undivided ownership's of 48% and 52%, respectively.

Schedule Page: 402.1 Line No.: 2 Column: e

George Neal Station Unit #3 is operated by MidAmerican Energy Company and owned jointly by the Company and MidAmerican Energy with the participants having undivided ownerships of 28% and 72%, respectively.

Schedule Page: 402.1 Line No.: 2 Column: f

Grinnell Generating Station was installed for peak load service. Two gas turbines were installed in 1990. Cost of plant (Line 17) includes both turbines.

Schedule Page: 402.1 Line No.: 5 Column: d

Ottumwa installed capacity of 387.12 MW represents Interstate Power and Light Company's 48% interest. Lines 6, and 9 through 44 are also stated in the Company's 48% portion.

Schedule Page: 402.1 Line No.: 5 Column: e

George Neal #3 installed capacity of 153.95 MW represents Interstate Power and Light Company's 28% interest. Lines 6, and 9 through 44 are also stated in the Company's 28% portion.

Schedule Page: 402.1 Line No.: 6 Column: f

Net peak demand for each of the two units at Grinnell Gas Turbine location is as follows: Unit #1 - 20 and Unit #2 - 16.

Schedule Page: 402.1 Line No.: 7 Column: f

Plant hours connected to load for each of the two units at Grinnell Gas Turbine location are as follows: Unit #1 - 60 and Unit #2 - 60.

Schedule Page: 402.1 Line No.: 11 Column: c

Marshalltown Gas Turbine employees are the same as those reported on Page 402.1, Line 11, Column (b), Sutherland.

Schedule Page: 402.2 Line No.: 5 Column: e

All four units at Agency Street Gas Turbine were retired in place 11/1/2010. Installed capacity was 92 MW.

Schedule Page: 402.2 Line No.: 6 Column: d

Net peak demand for each of the four units at Burlington Gas Turbine location is as follows: Unit #1 - 17, Unit #2 - 16, Unit #3 - 15, Unit #4 - 15.

Schedule Page: 402.2 Line No.: 7 Column: d

Plant hours connected to load for each of the four units at Burlington Gas Turbine location are as follows: Unit #1 - 39, Unit #2 - 48, Unit #3 - 57, Unit #4 - 22.

Schedule Page: 402.2 Line No.: 11 Column: b

Centerville Gas Turbine shares an employee that is based at Ottumwa Generating Station, Page 403.1, Column (d).

Schedule Page: 402.3 Line No.: 2 Column: e

George Neal Station Unit #4 is operated by MidAmerican Energy Company. Interstate Power and Light Company has a joint ownership portion of 25.695% of Neal Unit #4.

Schedule Page: 402.3 Line No.: 2 Column: f

Louisa Generating Station is operated by MidAmerican Energy Company. Interstate Power and Light Company has a joint ownership portion of 4.0% of Louisa Generating Station.

Schedule Page: 402.3 Line No.: 5 Column: e

George Neal #4 installed capacity of 164.70 MW represents Interstate Power and Light Company's 25.695% interest. Lines 6, and 9 through 44 are also stated in the Company's 25.695% portion.

Schedule Page: 402.3 Line No.: 5 Column: f

Louisa Generating Station installed capacity of 32.4 represents Interstate Power and Light Company's 4% interest. Lines 6, and 9 through 44 are also stated in the Company's 4% portion.

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FOOTNOTE DATA

Schedule Page: 402 Line No.: 36 Column: c1

Fuels for Prairie Creek Units 1, 2, and 3 are included in Prairie Creek #4, Page 402, Column (c).