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VOLUME 4

SUPPLY-SIDE RESOURCE ANALYSIS

THE EMPIRE DISTRICT ELECTRIC COMPANY

4 CSR 240-22.040

CASE NO. EO-2013-0547

JULY 2013

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SUPPLY-SIDE RESOURCE ANALYSIS

4 CSR 240-22.040 Supply-Side Resource Analysis

PURPOSE: This rule establishes minimum standards for the scope and level of detail required in supply-side resource analysis.

SECTION 1 SUPPLY-SIDE RESOURCE

(1) The utility shall evaluate all existing supply-side resources and identify a variety of potential supply-side resource options which the utility can reasonably expect to use, develop, implement, or acquire, and, for purposes of integrated resource planning, all such supply-side resources shall be considered as potential supply-side resource options. These potential supply-side resource options include full or partial ownership of new plants using existing generation technologies; full or partial ownership of new plants using new generation technologies, including technologies expected to become commercially available within the twenty (20)-year planning horizon; renewable energy resources on the utility-side of the meter, including a wide variety of renewable generation technologies; technologies for distributed generation; life extension and refurbishment at existing generating plants; enhancement of the emission controls at existing or new generating plants; purchased power from bi-lateral transactions and from organized capacity and energy markets; generating plant efficiency improvements which reduce the utility's own use of energy; and upgrading of the transmission and distribution systems to reduce power and energy losses. The utility shall collect generic cost and performance information sufficient to fairly analyze and compare each of these potential supply-side resource options, including at least those attributes needed to assess capital cost, fixed and variable operation and maintenance costs, probable environmental costs, and operating characteristics.

1.1 Existing and Committed Supply-Side Resources

The existing supply-side resources described in this section include those conventional and renewable resources that are in operation on the Empire system or for which Empire has power purchase agreements (PPA). Committed resources include those conventional and renewable resources for which commitments have already been made. Existing and committed as well as future resources were examined in the modeling process for this IRP.

1.1.1 Existing Resources

Empire's existing resources to meet customer obligations include coal-fired units, natural gas-fired combustion turbines (CT), a hydroelectric facility, ownership shares in coal-fired units, an ownership share in a combined cycle (CC) unit, and long-term PPAs for coal and wind. These resources are summarized in *Table 4-1*. All unit ratings and environmental retrofit information described in this IRP represent ratings and assumptions in effect at the time the IRP was in the process of being completed. Units are rerated from time to time and all assumptions are subject to change.

The 2012 Empire net system input by fuel type is shown in *Figure 4-1* and listed in *Table 4-2*. In 2012, 73.1 percent of Empire's total system input (in kWh) was supplied by its steam and thermal generation units, 1.0 percent was supplied by its hydroelectric generation, and the remaining 25.9 percent was purchased power including wind energy. As also shown in this figure and table, coal-fired energy purchased from others under contract constituted 5.2 percent of Empire's 2012 energy profile and wind energy purchases amounted to 15 percent.

Power Plant Resource	Fuel Type	State	Interest (%)	Empire Capacity (MW)	Start Date	Facility Resource Age (Years)
Asbury 1	Coal	MO	100	189[1]	1970	43
Asbury 2[2]	Coal	MO	100	14	1986	27
Iatan 1	Coal	MO	12	85	1980	33
Iatan 2	Coal	MO	12	102	2010	3
Plum Point	Coal	AR	7.52	50	2010	3
Riverton 7[3]	Natural Gas	KS	100	38	1950	63
Riverton 8[3]	Natural Gas	KS	100	54	1954	59
Riverton 9 CT[4]	Natural Gas/Oil	KS	100	12	1964	49
Riverton 10 CT[5]	Natural Gas	KS	100	16	1988	25
Riverton 11 CT[5]	Natural Gas	KS	100	17	1988	25
Riverton 12 CT	Natural Gas	KS	100	142[6]	2007	6
Empire Energy Center 1 CT	Natural Gas/Oil	MO	100	82	1978	35
Empire Energy Center 2 CT	Natural Gas/Oil	MO	100	82	1981	32
Empire Energy Center 3 CT	Natural Gas/Oil	MO	100	49	2003	10
Empire Energy Center 4 CT	Natural Gas/Oil	MO	100	49	2003	10
State Line CT	Natural Gas/Oil	MO	100	94	1995	18
State Line CC	Natural Gas	MO	60	297[7]	1997 & 2001[8]	16 & 12
Ozark Beach	Hydro	MO	100	16	1913	100
Total Empire Installed Capacity				1,388		
Long Term Power Purchases	**Type**				**End Date**	**Term**
Plum Point	Coal			50	2015[11]	
Elk River Wind Farm[9] (150 MW PPA)	Wind			7	2025	20
Meridian Way Wind Farm[10] (105 MW PPA)	Wind			8	2028	20
Capacity Summary						
Total Coal				532		
Total Gas Turbine				543		
Total Combined Cycle				297		
Total Hydro				16		
Total Purchase including Wind				65		
TOTAL				1,453		

[1]Asbury 1 is in the process of an environmental retrofit and turbine project and it is assumed for the IRP that Unit 1 will increase its capacity to 194 MW in 2015 with the project's completion.

[2]It is assumed for this IRP that Unit 2 will retire in 2014 before the completion of the Unit 1 environmental retrofit and turbine project.

[3]For the purposes of this IRP, Unit 7 and 8 are assumed to retire in 2016. Units 7 and 8 last burned coal on September 18, 2012, and will burn natural gas until retirement.

[4]For the purposes of this IRP, it is assumed that Riverton 9 will retire in 2016 with the retirement of Riverton Units 7 and 8.

[5]Riverton 10 and 11 were manufactured in 1967 but were installed at Empire in 1988; they are 43 years old.

[6]For purposes of this IRP, it is assumed that Riverton 12 will be converted to a combined-cycle unit in 2016 with a total capacity of 250 MW.

[7]Represents Empire's 60 percent share of a 500 MW State Line Combined Cycle (SLCC) unit.

[8]One of the gas turbines at State Line CC was installed in 1997 and hence is 13 years old. The other gas turbine and the steam turbine were installed in 2001.

[9]The Elk River Wind Farm consists of 100 1.5 MW turbines for a total of 150 MW. For purposes of the IRP, 7 MW of its installed capacity is counted toward the Company's reserve margin. Although the term of the PPA is 20 years, the term can be extended once for a period of 5 years at Empire's option. For this IRP, 7 MW of wind capacity is assumed but is likely subject to rerating in the future.

[10]The Meridian Way Wind Farm began commercial operation on December 15, 2008. The facility is rated at 105 MW and approximately 8 MW is counted toward the Company's reserve margin. For this IRP, 8 MW of wind capacity is assumed but is likely subject to rerating in the future.

[11]Empire owns an undivided ownership interest of 7.52 percent (approximately 50 MW) in Plum Point and has signed a PPA for an additional 50 MW. Empire has the right to convert the PPA to an undivided ownership interest in 2015.

Table 4-1 - Empire Supply-Side Resources - Existing and Committed

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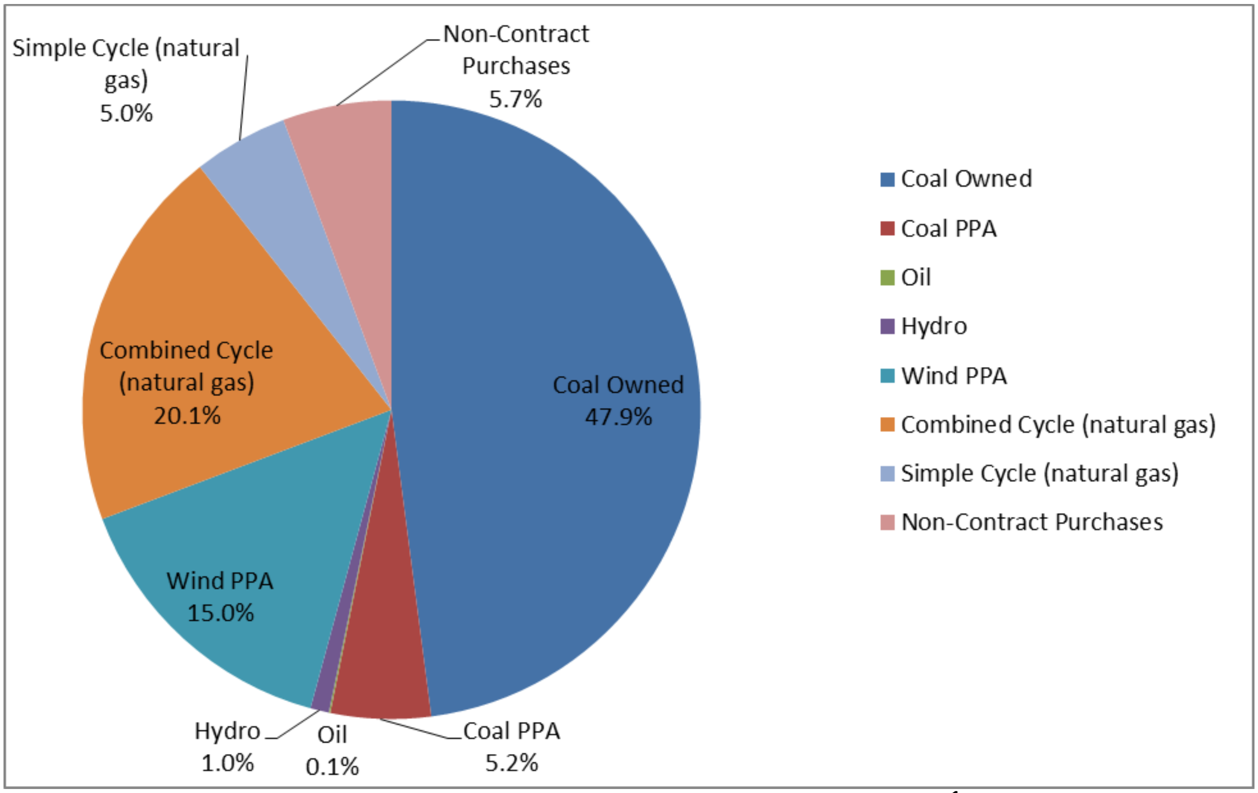


Figure 4-1 - Generation Mix by Fuel Type for 2012[1]

	MWh in 2012	%	
Coal Owned	2,854,682	47.9%	
Coal PPA	311,472	5.2%	(53.17% Total Coal (Own + PPA))
Oil	4,842	0.1%	
Hydro	57,719	1.0%	
Wind PPA	895,238	15.0%	
Combined Cycle (natural gas)	1,197,335	20.1%	
Simple Cycle (natural gas)	294,821	5.0%	(25.1% Total Natural Gas (CC + SC))
Non-Contract Purchases	338,530	5.7%	
Total MWH NSO	5,954,639	100.0%	

Table 4-2 - Generation by Type for 2012 - Total System MWH (Net System Output)

[1] Renewable energy attributes are sold as renewable energy credits (RECs).

1.1.2 Compliance Plan

In order to comply with forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). While the Cross State Air Pollution Rule (CSAPR) that was to take effect on January 1, 2012 was stayed in late December 2011 then vacated in August 2012 by the District of Columbia Circuit Court of Appeals, the Mercury Air Toxics Standard (MATS) was signed by the Environmental Protection Agency (EPA) Administrator on December 16, 2011 and became effective on April 16, 2012. MATS requires compliance by April 2015 (with flexibility for extensions for reliability reasons).

This Compliance Plan largely follows the preferred plan presented in the most recent IRP. The Compliance Plan calls for the installation of a scrubber, fabric filter, and powder activated carbon injection system at Unit 1 of the Asbury plant (collectively referred to as the Asbury AQCS) by early 2015 at a cost ranging from $112 million to $130 million. The Asbury AQCS project is currently under construction. The addition of this air quality control equipment will require the retirement of Asbury Unit 2, a 14-MW steam turbine that is currently used for peaking purposes. The Compliance Plan also calls for the transition of the Riverton Units 7 and 8 from operation on coal to full operation on natural gas which was completed in September of 2012. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 for startup, will be retired upon the conversion of Riverton Unit 12, a recently installed simple cycle CT, to a combined cycle unit. This conversion is currently scheduled for the 2016 timeframe.

1.1.2.1 Asbury

The Asbury plant, located near Asbury, Missouri consists of two coal-fired units totaling 203 MW. Unit 1 was installed in 1970. Unit 2 was installed in 1986.

Many modifications have been made to the Asbury Plant since Unit 1 achieved commercial operation in 1970. The precipitators were upgraded in 1977. The generator was rewound in 2007. A new state-of-the-art coal unloading facility was completed in 1990. In 1999, a new fiberglass cooling tower was installed, replacing the previous wood one. The cyclones were replaced in 2001, after they had operated for 30 years. Also in 2001, a distributed control system was installed. Selective catalytic reduction (SCR) for nitrous oxides (NO_X) control was completed in 2008; equipment to overfire air (also for NO_X control) was installed in 2001 and 2004. Routine maintenance, annual maintenance, and long-term maintenance is conducted on each of the units reflecting short-term and long-term cycles. As an example, the turbines are torn down approximately every five to six years (depending on hours of operation and the number of starts) and blades are replaced periodically as necessary. The rotor, valves, and bearings are inspected regularly and are in reasonable condition. In the next 10 to 20 years, the floor tubes will need to be replaced and a section of the reheater will need to be replaced as well.

In the September 2010, IRP Empire studied various scenarios related to the Asbury coal-fired plant. This included the potential retrofitting of the plant to include installation of additional environmental equipment so the plant would be in compliance with prospective environmental regulations that could require maximum achievable control technologies (MACTs) in the 2015 timeframe for compliance with the EPA's MATS rule as discussed above in the Compliance Plan at the end of Section 1.1.1. Asbury has already installed SCR equipment in 2008. Several IRP plans, including the preferred plan, proposed the installation of a scrubber to reduce sulfur dioxide (SO_2), a fabric filter to reduce particulate matter (PM), and a powder activated carbon injection system to reduce mercury at the Asbury plant (collectively referred to as the Asbury air-quality control system or AQCS). Empire's Compliance Plan does include the Asbury AQCS project in the 2015 timeframe and the retirement of Unit 2 in the 2014 timeframe. In Empire's last IRP a commitment was made to investigate permitting requirements, issue a request for proposal (RFP) for the project, and evaluate the RFP bids.

In October 2010, Black & Veatch (B&V) completed the Asbury AQCS study that was under way at the time that Empire filed its September 2010 IRP. In January 2011, Empire's Asbury AQCS team began working with B&V to develop technical specifications based on the recommendations of the Asbury AQCS study. These technical specifications were delivered to Empire in May 2011, at which time Empire began working with Sega, Inc. to issue an RFP and to evaluate the resulting proposals. The RFP was issued on June 17, 2011 with bids due to Empire by September 15, 2011. Empire spent approximately two months evaluating the five proposals before selecting the proposal submitted by a joint venture of Alberici Constructors (St. Louis, Missouri) and Stanley Consultants (Muscatine, Iowa). Empire executed a contract with the joint venture on January 16, 2012, requiring completion of the project by February 1, 2015 which will allow the Asbury Plant to comply with the MATS rule. The AQCS will also enable Empire to comply with the Clean Air Interstate Rule (CAIR) and/or the CSAPR as is described in Section 2.2.1. The environmental compliance derived from this project will allow Empire to continue to meet customer's future demand for electricity with a diversified mix of resources. Empire now expects the cost for the Asbury AQCS to range from $112 million to $130 million as compared to the $158 million estimate in the last IRP.

Associated with the Asbury AQCS project and other pending environmental regulations is the potential need for an ash landfill and bottom ash conveyance equipment at the Asbury Plant as a result of expected changes to the Federal Resource Conservation and Recovery Act (RCRA) as discussed in Section 2.2.3.

1.1.2.2 Riverton

Empire's Riverton Generating Plant located at Riverton, Kansas, has two steam-electric generating units (Riverton 7 and 8) with an aggregate generating capacity of 92 MW and four natural gas-fired CT units (Riverton 9, 10, 11, and 12) with an aggregate generating capacity of 187 MW. Riverton Units 7 and 8 transitioned to burning solely natural gas after a long run of coal operation at the site. Over the coal burning life of these units, they produced reliable power for Empire's customers for approximately 60 years, with the last date to burn coal being September 18, 2012. These steps were taken to allow Empire to comply with regulations from the EPA and continue to generate reliable power for Empire's customers.

Unit 7 is rated at 38 MW burning 100-percent natural gas; it was installed in 1950. Unit 8 is rated at 54 MW burning 100-percent natural gas; it was installed in 1954. In the September 2010 IRP, Empire affirmed that it would monitor the Riverton Units 7 and 8 coal-fired units for environmental compliance to determine at what point the units should be retired or transitioned to natural gas operation, if needed, prior to their retirement. The Compliance Plan that is introduced at the end of Section 1.1.1 calls for the transition of the Riverton Units 7 and 8 from operation on coal to full operation on natural gas. This took place in September 2012. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 for startup, will be retired upon the conversion of Riverton Unit 12, a simple cycle combustion turbine installed in 2007, to a combined cycle unit. This conversion is currently scheduled for the 2016 timeframe.

Riverton Unit 12 is a natural gas-fired Siemens V84.3A2 combustion turbine that was installed at the Riverton power plant in Riverton, Kansas in 2007. It is currently rated at 142 MW for the summer peak season and it is primarily used as a peaking unit. When this unit was originally constructed, adequate natural gas piping and electric transmission were designed and built to accommodate its conversion to a combined cycle (CC) unit at some point in the future. The potential Riverton 12 conversion to a CC unit (Riverton combined cycle conversion) was considered as a candidate resource in the most recent IRP (September 2010 IRP). In all 17 plans that were studied, including the preferred plan, the Riverton combined cycle conversion was selected as the first supply-side resource addition for the 2015 timeframe. This project is assumed to add about 100 additional MW to the system, making the Riverton combined cycle a roughly 250 MW unit upon completion. The Riverton combined cycle conversion will utilize existing site infrastructure and will incorporate the existing Riverton Unit 12 CT into a CC unit. A heat recovery steam generator (HRSG) will be installed along with a new steam turbine and a cooling tower to provide cooling water for the condenser. A new control room and control system will also be installed to operate the unit. Upon completion of the project, Riverton Units 7, 8, and 9 will retire.

As noted above, this project has shifted about one year making it a 2016 timeframe project. Thus, all of the implementation plan schedules for this project from the last IRP have shifted accordingly. In September 2012, an internal team was assembled and began working on operating and construction permitting; water rights issues; and RFP development. An RFP was issued on January 3, 2012 with proposals to be returned by April 9, 2013. This same team will be responsible for evaluation of the proposals, contractor selection, and project oversight.

1.1.2.3 Iatan

Empire owns a 12-percent undivided interest in the nominal 670-MW, coal-fired Iatan 1 located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3-percent interest in the site and a 12-percent interest in certain common facilities. Empire is entitled to 12 percent of the unit's available capacity and is obligated to pay for that percentage of the operating costs of the unit. For the purposes of this IRP, it is assumed that Empire's share of the Iatan 1 capacity Is 85 MW.

AQCS additions at Iatan 1 included an SCR for the removal of NO_X, a wet scrubber for the removal of SO_2, a fabric filter baghouse for the removal of PM, and a powder activated carbon system for the removal of mercury. These additions, made in order to comply with EPA regulations and to meet the requirements for an air permit for Iatan 2, were completed in 2010.

Empire also owns a 12-percent undivided interest in the Iatan 2 unit, which for purposes of this IRP is assumed to be 102 MW (Empire's share). The AQCS (SCR, scrubber, fabric filter) constructed with the new Iatan 2 unit complies with the recent and anticipated air quality regulations.

1.1.2.4 State Line

Empire's State Line Power Plant, located west of Joplin, Missouri, presently consists of State Line Unit 1, a CT with generating capacity of 94 MW and a CC unit (State Line CC) with generating capacity of 500 MW, of which Empire is entitled to 60 percent, or 297 MW. All units at the State Line Power Plant burn natural gas as a primary fuel, with State Line Unit 1 having the ability to also burn fuel oil as a backup fuel. Burning fuel oil requires water injection for emissions control. The CC consists of two CTs with a HRSG on the back of each CT. Steam from the HRSGs is fed to the steam turbine. The CC can operate in two modes:

1. 1 x 1 mode (one CT and the steam turbine) with capacity of 150 MW (Empire's share).
2. 2 x 1 mode (two CTs and the steam turbine) with total capacity of 297 MW (Empire's share).

The total State Line CC heat rate is roughly 7,400 Btu/kWh.

No major upgrades or additional environmental equipment are expected for any unit at the State Line facility during the planning horizon. Routine maintenance will be conducted. The State Line CC CTs have dry low NO_X burners, and there is an SCR on each HRSG.

1.1.2.5 Empire Energy Center

Empire has four CT peaking units at the Empire Energy Center in Jasper County, Missouri (near the town of La Russell), with an aggregate generating capacity of 262 MW. Energy Center

Units 1 and 2 were installed in 1978 and 1981. They are simple cycle frame CTs. Energy Center Units 3 and 4 are aeroderivative CTs installed in 2003. These two newer units have the ability to be on line in 10 minutes or less and are thus considered quick-start units. For purposes of this IRP, Unit 1 is assumed to retire near the end of the planning horizon in 2032.

These peaking units operate on natural gas as well as fuel oil. All units undergo routine maintenance with inspections on a regular cycle and equipment is refurbished as needed. All of the CTs use water injection to control NO_X.

1.1.2.6 Ozark Beach

Empire's hydroelectric generating plant, located on the White River at Ozark Beach, Missouri, has a generating capacity of 16 MW (four 4-MW units). Empire recently celebrated this facility's 100-year anniversary from when the unit was put into service in 1913. This centurion unit has been updated periodically as needed for its continuing contribution to Empire's renewable portfolio.

The hydroelectric generating plant (FERC Project No. 2221) has a long-term license from FERC to operate this plant which forms Lake Taneycomo in southwestern Missouri. As part of the Energy and Water Development Appropriations Act of 2006 (the Appropriations Act), a new minimum flow pattern was established with the intent of increasing minimum flows on recreational streams in Arkansas. To accomplish this, the level of Bull Shoals Lake will be increased an average of 5 feet. The increase at Bull Shoals will decrease the net head waters available for generation at Ozark Beach by 5 feet and, thus, reduce Empire's electrical output. Empire estimates the lost production to be up to 16 percent of the average annual energy production for this unit. The loss in this facility would require Empire to replace it with additional generation from gas-fired and coal-fired units or with purchased power. The Appropriations Act required the Southwest Power Administration (SWPA), in coordination with Empire and Empire's relevant public service commissions, to determine Empire's economic detriment assuming a January 1, 2011 implementation date. On June 17, 2010, the SWPA posted a revised Final Determination that Empire's customers' damages were $26.6 million. On September 16, 2010, Empire received a $26.6 million payment from the SWPA, which was deferred and recorded as a non-current liability. Empire originally increased Empire's current tax liability by approximately $10.0 million recognizing that the $26.6 million payment might have been considered taxable income in 2010. During the first quarter of 2011, Empire submitted a pre-filing agreement with the Internal Revenue Service (IRS) requesting that a determination be made regarding whether or not the payment could be deferred under certain sections of the Internal Revenue code. The IRS accepted Empire's position that the payment be deferred for tax purposes and recognized over the next 20 years. As such, Empire reduced the current tax liability in accordance with this deferral. The SWPA payment, net of taxes, is being used to reduce fuel expense for Empire's customers in all of Empire's jurisdictions. In addition, it is Empire's current understanding that the SWPA has delayed the implementation of the new minimum flows until 2016.

1.1.2.7 Plum Point

The Plum Point Energy Station is a new 665-MW, sub-critical, coal-fired generating facility built near Osceola, Arkansas. Empire owns 7.52 percent (approximately 50 MW) of the project. In addition, Empire has a 30-year PPA for an additional 50 MW of capacity and an option to purchase an undivided ownership share of the 50 MW covered by the PPA beginning in 2015 (refer to Volume 1: Executive Summary for more information on the Plum Point PPA option to convert to ownership).

Plum Point is equipped with an SCR for NO_x removal, a dry scrubber for SO_2 control, combustion controls for volatile organic compounds (VOC) mitigation, and a fabric filter baghouse for the removal of PM.

1.1.2.8 Purchased Power

Empire has existing PPAs for both conventional and renewable resources during the planning horizon.

In addition to its undivided ownership share of 7.52 percent (approximately 50 MW) in the Plum Point Energy Station, Empire entered into a PPA for an additional approximate 50 MW of capacity. Empire has the option to convert this PPA into an undivided ownership interest of approximately 50 MW in 2015 (refer to Volume 1: Executive Summary for more information on the Plum Point PPA option to convert to ownership).

On December 10, 2004, Empire entered into a 20-year contract with PPM Energy to purchase all of the energy generated at the Elk River Wind Farm located in Butler County, Kansas. The wind farm began commercial operation on December 15, 2005. This facility consists of 100 1.5-MW turbines. Empire also has the ability to extend the contract term for five years after the end of the 20-year contract period. Empire has contracted to purchase all of the output of the project which is estimated to be approximately 550,000 MWh of energy per year. Seven (7) MW of the 150 MW of installed capacity is counted toward the Company's reserve margin. This is the actual current rating of the facility calculated per SPP criteria, but it is subject to rerating in the future A 5% accredited rating was utilized for the load and capability tables in this IRP.

In June 2007, Empire signed a contract with Horizon Wind Energy to buy wind energy from the Cloud County Wind Farm, LLC which receives energy from the 105-MW Meridian Way Wind Farm located in Cloud County, Kansas near Concordia. The contract expires in December of 2028. The facility is expected to generate approximately 350,000 MWh per year. The facility began commercial operation on December 23, 2008. Eight (8) MW of the 105 MW of installed capacity is counted toward the Company's reserve margin. This is the actual current rating of the facility calculated per SPP criteria, but it is subject to rerating in the future. A 5% accredited rating was utilized for the load and capability tables in this IRP.

1.1.2.9 Retirements

Empire's generating resources as shown in *Table 4-1* include units that have been in operation for over 50 years.

Barring significant changes in environmental regulations at the State or Federal level, retirements of units other than those modeled in the IRP over the planning horizon would occur only in the case of a catastrophic equipment failure where it would not be economically feasible for the unit to continue operation.

1.1.2.10 Emission Controls on Existing Units

AQCS equipment is being added to the Asbury Plant Unit 1 as described in Section 1.1.1.1.

1.1.2.11 Existing Plant Upgrades

An examination of recent and possible upgrades at existing plants was conducted by Empire during the development of this IRP.

1. New pollution control systems have recently been installed at the coal-fired Asbury and Iatan 1 units. Asbury Unit 1 was retrofitted with an SCR in 2008. A scrubber, SCR, fabric filter, and powder activated carbon system were installed at the jointly owned Iatan Unit 1 coal-fired unit in 2009.

2. New pollution control systems are being installed at the Asbury 1 unit. Unit 1 is being retrofitted with a scrubber, fabric filter, and a powder-activated carbon injection system. This AQCS project and steam turbine project is planned for completion in 2015. Unit 2 will be retired prior to this in 2014.

3. The conversion of Riverton 12 (a CT) to a CC unit is to take place by 2016.

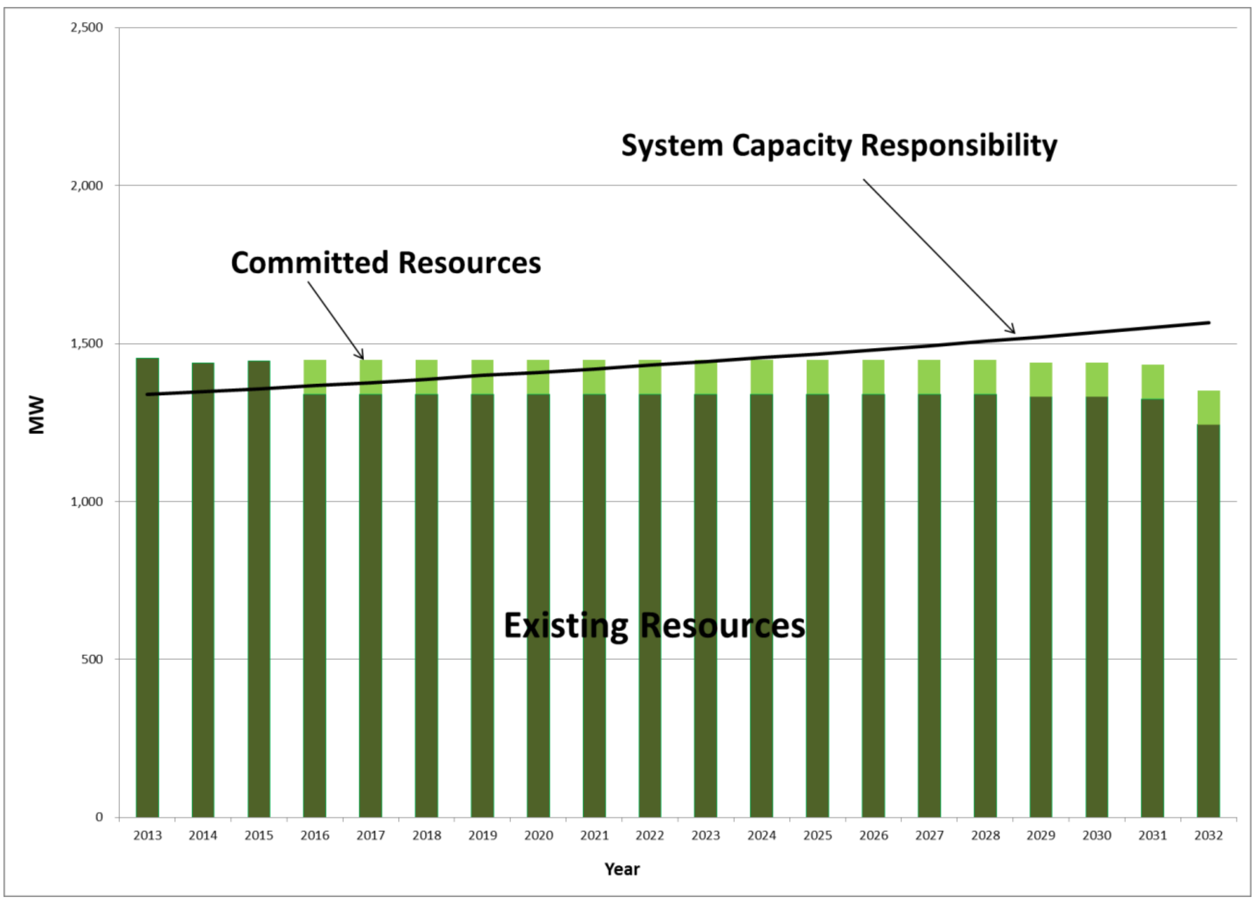
4. Empire's normal, ongoing maintenance program at each of its plants, addresses critical operational and mechanical issues to ensure the longevity of the units.

1.1.3 Committed Resources

As detailed in Section 1.1.1.2, Empire is committed to the conversion of the Riverton Unit 12 from simple cycle CT to a CC unit to increase its capacity from 142 MW to approximately 250 MW by 2016.

1.1.4 Resource Deficit

After accounting for all existing resources (including increased ratings and retirements) and all planned resources, Empire faces a resource deficit around the 2024 timeframe based on the base load forecast for this IRP as shown in *Figure 4-2* and *Table 4-3*. This does not account for implementation of new demand-side management measures.



Note: We are assuming for this IRP that EC1 would retire in 2032 but this is not a commitment.

Figure 4-2 - Load and Capability Summary

[redacted]

****Highly Confidential in its Entirety****

Table 4-3 - Load and Capability Summary 2013 to 2032 with Existing Resources, Committed Resources, and Potential Retirements with Base Load Forecast for this IRP and no Contemplated Additions (MW) and no DSM

1.1.5 Capacity Margin

As a member of the SPP, Empire is required to maintain a minimum 12-percent capacity margin which is approximately equivalent to a 13.7-percent reserve margin. This value was used as the minimum reserve margin value for capacity planning in this IRP.

1.2 Potential Supply-Side Resource Options

Empire initially considered a wide range of supply-side resource technologies with varying levels of technology development, feasibility, and size. After considering Empire's size, location, and interconnections, the potential supply-side resource options selected for further investigation are shown below:

1. Super-critical coal (joint-ownership with and w/o CCS and PPA).
2. Combustion Turbines (Aero-derivative CT and frame CT).
3. Combined cycle (with and w/o CCS).
4. Integrated gasification combined cycle (IGCC).
5. Reciprocating internal combustion engine (RICE).
6. Distributed generation (DG).
7. Small modular nuclear (SMN).
8. Traditional nuclear (PPA).
9. Wind (ownership and PPA).
10. Biomass.
11. Landfill gas.

12. Utility scale solar PV.

    a. All of the potential options above were screened and are considered feasible, thus were passed on to the next analysis as supply-side candidate resource options.

Based on a definition of combined heat and power (CHP) that was provided by The Missouri Department of Natural Resources (MDNR) at an Empire Stakeholder Advisory Group meeting, CHP is a form of distributed generation in which generation of electricity is part of an integrated energy system in which (a) the same energy source is used for the simultaneous or sequential provision of useful thermal energy and on-site electric generation; and (b) at least some of the useful thermal energy or electricity that is produced in this integrated energy system is used to meet on site energy needs. Under this definition, a cogeneration system in which waste heat captured from electric generation is used exclusively to generate more electricity is not an example of CHP. CHP is not a single technology, but an integrated energy system that can be modified depending upon the needs of the energy end user. CHP systems are found in the industrial sector, the commercial sector (including institutional end users such as college campuses, hospitals and office buildings) and multifamily residential buildings. Examples of thermal load served in CHP system include space heating, cooling or dehumidification and industrial process heating and cooling needs. Examples of the generation technologies used in CHP systems include steam turbines, gas turbines, microturbines, reciprocating engines, and fuel cells.

CHP has been a topic in several of Empire's Stakeholder Advisory Group meetings. CHP requires a partnership such as with a sewage treatment plant, hospital, nursing home, or college. A generator supplies power to the grid and the waste heat can be utilized by the CHP partner. With regards to potential CHP in the Empire service territory, Empire reported to the Advisory Group that some poultry processing plants within the service territory were potential candidates. One of the larger poultry processing plants in Empire's service territory has analyzed CHP potential, but decided that the project was not economically feasible. It would be difficult to evaluate a generic CHP project since costs and other project details are very project specific and require a CHP partner. The Advisory Group suggested a periodically monitoring system to check for CHP opportunities. It was discussed among the Advisory Group that Empire can continue to monitor CHP for the next IRP, but CHP cannot be a resource that Empire can reasonably be expected to use, develop, implement or acquire since costs and other project details are very project specific and requires a CHP partner. The IRP rule states that the utility must evaluate existing and potential supply-side resource options that can reasonably be expected to use, develop, implement, or acquire. Therefore, Empire will continue to look for CHP opportunities, but it will not be considered as a potential supply-side resource option in this IRP.

SECTION 2 ANALYSIS OF POTENTIAL SUPPLY-SIDE RESOURCE OPTIONS

(2) *The utility shall describe and document its analysis of each potential supply-side resource option referred to in section (1). The utility may conduct a preliminary screening analysis to determine a short list of preliminary supply-side candidate resource options, or it may consider all of the potential supply-side resource options to be preliminary supply-side candidate resource options pursuant to subsection (2)(C). All costs shall be expressed in nominal dollars.*

2.1 Cost Rankings of Potential Options

(A) Cost rankings of each potential supply-side resource option shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the potential supply-side resource option using the utility discount rate. The utility shall include the costs of ancillary and/or back-up sources of supply required to achieve necessary reliability levels in connection with intermittent and/or uncontrollable sources of generation (i.e., wind and solar).

Costs and analysis descriptors of the potential supply-side resource options listed in Section 1.2 that are conventional technologies are presented in *Table 4-4*. *Table 4-5* presents this same information but for renewable technologies.

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	Supercritical Coal			Combustion Turbine		Combined Cycle	
	No CCS	With CCS	PPA-No CCS	Aeroderivative CT	Frame-Type CT	No CCS	With CCS
Online Year	2023	n/a	2020	2015	2015	2017	n/a
Size, MW (net)	50[1]	50[1]	50	50	87	250	250
Full load heat rate, Btu/kWh	8,800	11,200	8,800	9,200	11,400	7,050	8,250
Lead time, months	60	72	-	36	36	42	48
Capital Cost, $/kW (2012 $)	2,988	5,716	-	992	980	1,026	2,258
Fixed O&M, $/kW-year	31.17	33.78	449.19[2]	12.47	12.2	15.12	23.22
Variable O&M, $/MWh	4.47	6.46	4.47	3.18	2.12	3.60	3.31
Equivalent Forced Outage Rate, %	6	7	6	3.6	3.6	5.5	5.5
Maintenance Outage Rate, %	6.5	7.5	6.5	4.1	4.1	7	6
SO_2 Emissions, lbs/MMBtu	0.03	0.03	0.03	-	-	-	-
NO_x Emission, lbs/MMBtu	0.05	0.05	0.05	0.05	0.03	0.01	0.01
CO_2 Emissions, lbs/MMBtu	210	21	210	120	120	120	12
Mercury Emissions, lbs/MMBtu	0.0002	0.0002	0.0002	-	-	-	-

	RICE	SMN	DG	IGCC		Traditional Nuclear PPA
				No CCS	With CCS	
Online Year	2014	2024	2014	2023	n/a	[redacted]
Size, MW (net)	75	300	5	50[1]	50[1]	
Full load heat rate, Btu/kWh	8,600	9,500	9,050	8,700	10,700	
Lead time, months	24	180	12	48	60	
Capital cost, $/kW (2012 $)	1,150	10,000	1,507	3,383	5,619	
Fixed O&M, $/kW-year	14.57	74.12	17.63	51.38	72.81	
Variable O&M, $/MWh	3.18	0.58	7.84	7.22	8.45	
Equivalent Forced Outage Rate, %	2	3.5	0	6	7	
Maintenance Outage Rate, %	2	5.5	0	6.5	7.5	
SO_2 Emissions, lbs/MMBtu	-	-	-	0.02	0.02	
NO_x Emissions, lbs/MMBtu	0.01	-	-	0.01	0.01	
CO_2 Emissions, lbs/MMBtu	120	-	-	210	21	
Mercury Emissions, lbs/MMBtu	-	-	-	0.0005	0.0005	

[1]Ownership share of a larger unit.

[2]Monthly capacity payment x12 months. Includes capital and fixed O&M.

Note:
CCS - Carbon Capture and Sequestration
PPA - Power Purchase Agreement
CT - Combustion Turbine (Simple Cycle)
RICE - Reciprocating Internal Combustion Engine
SMR - Small Modular Nuclear
DG - Distributed Generation
IGCC - Integrated Gasification Combined Cycle

Table 4-4 - Costs and Analysis Descriptors of Potential Supply-Side Resource Options - Conventional Technologies

	Wind PPA	Wind PPA w/ PTC	Wind Own	Biomass	Landfill Gas	Solar-PV
Online Year	2014	2014	2014	[redacted]		
Size, MW (net)	10	10	10			
Full load heat rate, Btu/kWh	0	0	0			
Lead time, months	0	0	12			
Capital Cost, $/kW (2012 $)	0	0	1,800			
Fixed O&M, $/kW-year	0	0	0			
Variable O&M, $/MWh	53.756[1]	30.73[1]	12.00			
Equivalent Forced Outage Rate, %	0	0	0			
Maintenance Outage Rate, %	0	0	0			
SO_2 Emissions, lbs/MMBtu	0	0	0			
NO_x Emission, lbs/MMBtu	0	0	0			
CO_2 Emissions, lbs/MMBtu	0	0	0			
Mercury Emissions, lbs/MMBtu	0	0	0			

[1]Monthly capacity payment x 12 months. Includes capital and fixed O&M.

Table 4-5 - Costs and Analysis Descriptors of Potential Supply-Side Resource Options - Renewable Technologies

Figures 4-3 through *4-6* depict the levelized busbar costs of the potential supply-side resource options under the "base environmental" cost scenario. These figures are presented by category of resource in terms of base load (*Figure 4-3*), intermediate load (*Figure 4-4*), peaking (*Figure 4-5*), and intermittent load (*Figure 4-6*).

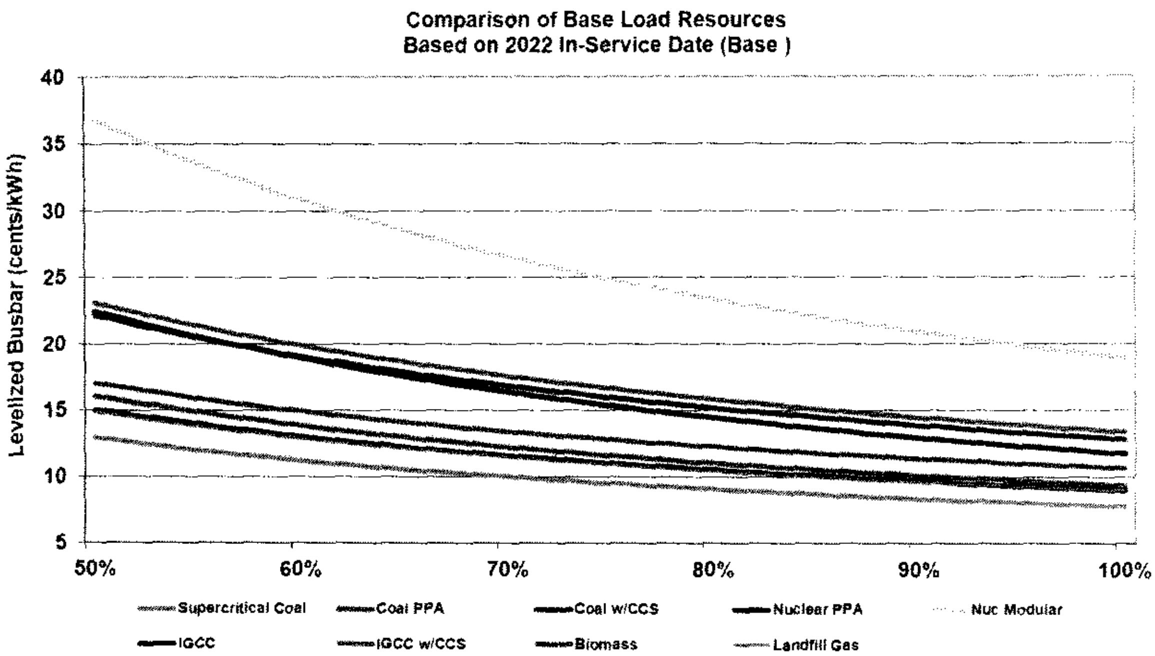

Figure 4-3 - Levelized Busbar Costs Comparison for Base Load Potential Supply-Side Resource Options

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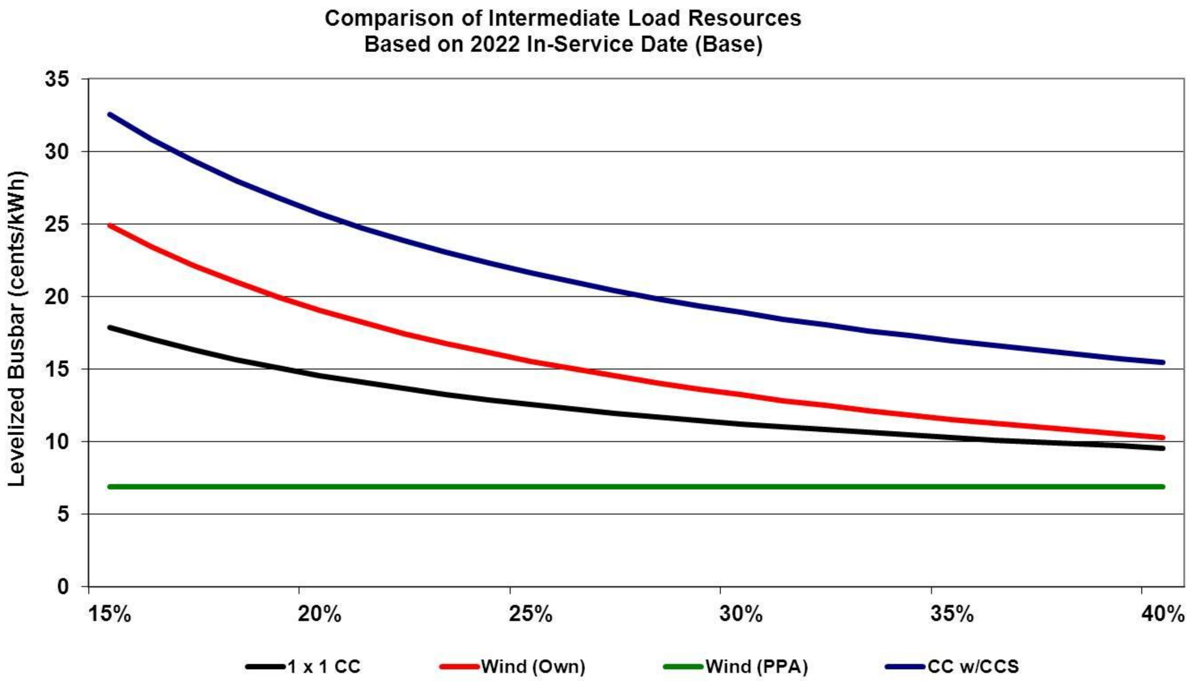

Figure 4-4 - Levelized Busbar Costs Comparison for Intermediate Load Potential Supply-Side Resource Options

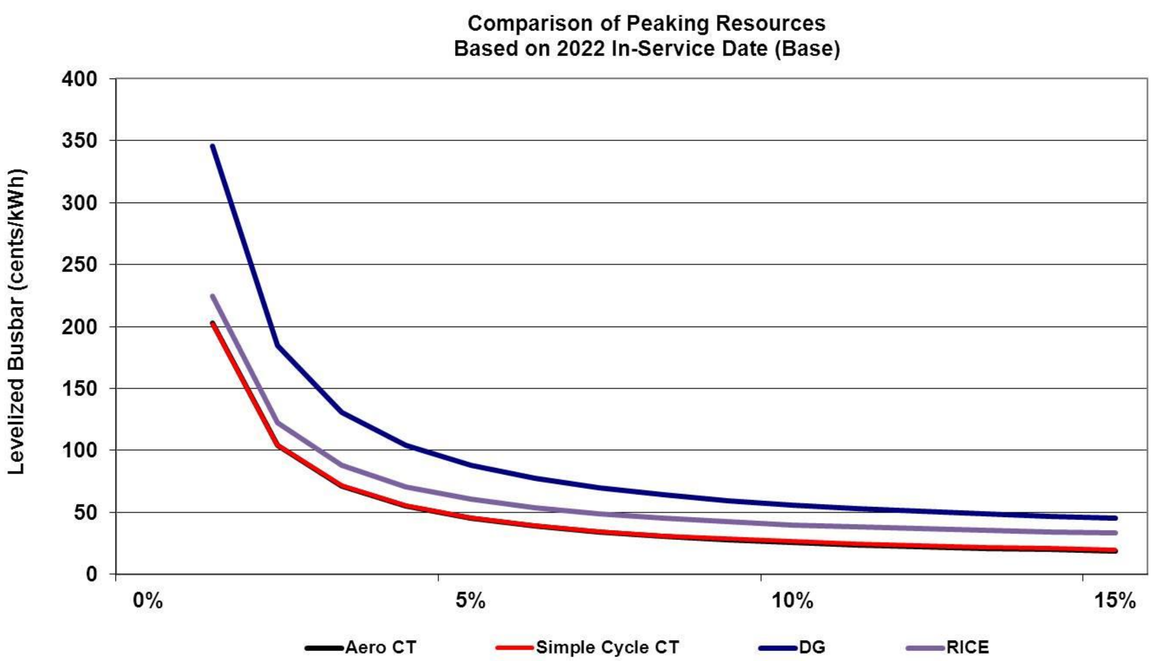

Figure 4-5 - Levelized Busbar Costs Comparison for Peaking Potential Supply-Side Resource Options

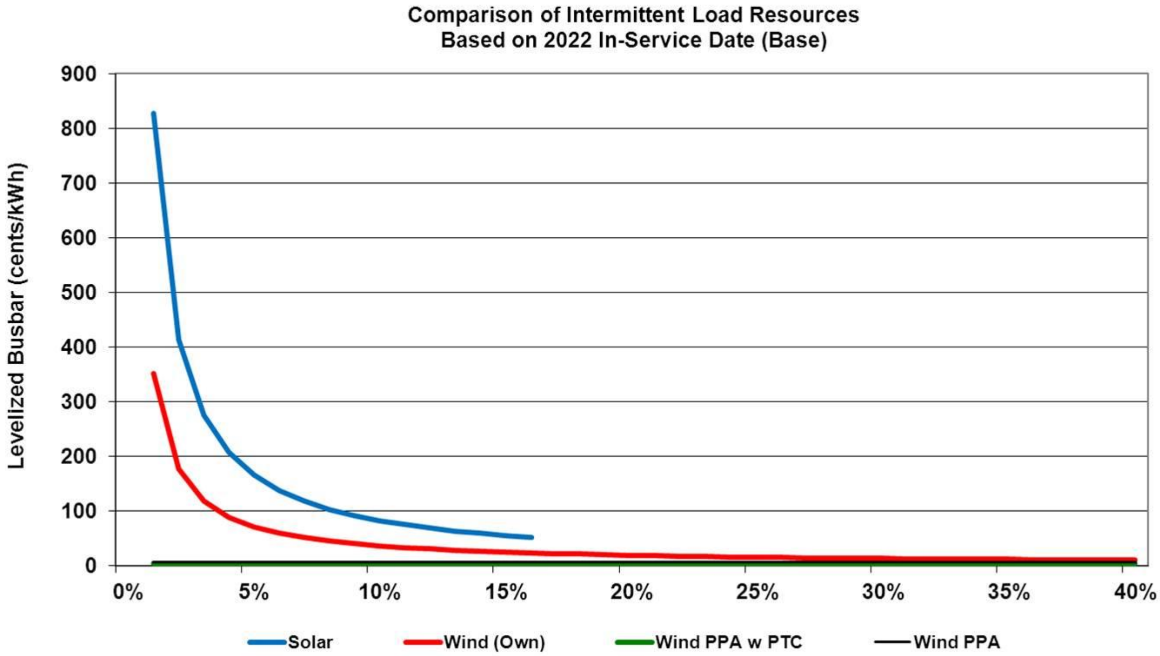

Figure 4-6 - Levelized Busbar Costs Comparison for Intermittent Load Potential Supply-Side Resource Options

2.2 Probable Environmental Costs of Potential Supply-Side Resource Options

(B) The probable environmental costs of each potential supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental legal mandates that may be imposed at some point within the planning horizon. The utility shall identify a list of environmental pollutants for which, in the judgment of the utility decision-makers, legal mandates may be imposed during the planning horizon which would result in compliance costs that could significantly impact utility rates. The utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that legal mandates requiring additional levels of mitigation will be imposed at some point within the planning horizon. The utility, based on these probabilities, shall calculate an expected mitigation cost for each identified pollutant.

Empire is subject to various Federal, State, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes including their identification, transportation, disposal, record-keeping, and reporting as well as remediation of contaminated sites and other environmental matters. Empire believes its operations are in material compliance with present environmental laws and regulations. Environmental requirements have changed frequently and become more stringent over time.

Empire expects this trend to continue. While Empire is not in a position to accurately estimate compliance costs for any new requirements, it expects any such costs to be material, although recoverable in rates.

In summary, some of the newly proposed and developing environmental regulations that could impact resource planning include the following:

1. MATS standards rule.
2. CSAPR/CAIR.
3. Cooling water intake structure issues.
4. Federal RCRA governing the management and storage of coal combustion residuals (CCR), often referred to as coal ash.
5. Greenhouse gas (GHG) legislation/regulations.

Empire continues to monitor these and other potential environmental issues that could impact the Company's operations.

Compliance Plan

In order to comply with forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). While the CSAPR that was to take effect on January 1, 2012 was stayed in late December 2011 then vacated in August 2012 by the District of Columbia Circuit Court of Appeals, the MATS was signed by the EPA Administrator on December 16, 2011 and became effective on April 16, 2012. MATS requires compliance by April 2015 (with flexibility for extensions for reliability reasons).

This Compliance Plan largely follows the preferred plan presented in the most recent IRP. The Compliance Plan calls for the installation of a scrubber, fabric filter, and powder activated carbon injection system at Unit 1 of the Asbury plant (collectively referred to as the Asbury

AQCS) by early 2015 at a cost ranging from $112 million to $130 million. The Asbury AQCS project is currently under construction. The addition of this air quality control equipment will require the retirement of Asbury Unit 2, a 14-MW steam turbine that is currently used for peaking purposes. The Compliance Plan also calls for the transition of the Riverton Units 7 and 8 from operation on coal to full operation on natural gas which was completed in September of 2012. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 for startup, will be retired upon the conversion of Riverton Unit 12, a recently installed simple cycle CT, to a combined cycle unit. This conversion is currently scheduled for the 2016 timeframe.

2.2.1 Air Emission Impacts

The Federal Clean Air Act (CAA) and comparable State laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control and related requirements. These requirements include maximum emission limits on our facilities for SO_2, PM, NO_x, and mercury. In the future they are also likely to include limits on other hazardous air pollutants (HAPs) and GHG such as carbon dioxide (CO_2) and methane.

In the September 2010 IRP filing, the environmental analysis assumed three levels of future CO_2 (carbon) costs within a potential cap and trade future and one case with no future carbon costs. The base case assumed that a cap and trade system for carbon would be in place by year 2015. Empire's current five-year business plan, which covers the period 2012 through 2016, does not include any carbon costs.

In addition to carbon, all of the alternate plans in the September 2010 IRP filing assumed costs for other emissions such as SO_2, NO_x, and mercury. However, in the most recent five-year business plan, which assumes a normalized operating scenario, Empire does not anticipate the need to purchase any allowances for these pollutants in the period 2012 through 2016.

A major environmental factor that was addressed in the September 2010 IRP was based on the EPA's regulation of mercury standards for electric generating units (EGU) requiring MACT. The last IRP referred to this as EGU MACT, which has also been referred to as Utility MACT or HAPS MACT within the industry. Most recently, it has become known and published as the MATS rule. With the official publication of the final rule, the effective period began on April 16, 2012. Applicable to Empire's existing coal-fired electric generating units, the MATS rule establishes limitations based on MACT for mercury, non-mercury heavy metals, acid gas, and organic hazardous air pollutants.

An environmental regulation that has further developed since the last IRP filing in September 2010 is the CSAPR - formerly the Clean Air Transport Rule. On December 23, 2008 the Court remanded CAIR back to the EPA without vacating it until the EPA issued a new rule to replace CAIR. CSAPR is the EPA's response to the court's remand of CAIR. CSAPR is designed to reduce ozone and fine particulate emissions from power plants by setting standards for SO_2 and NO_x. CSAPR was finalized by the EPA in July 2011 requiring a reduction in NO_x and SO_2 levels starting in 2012 with further reductions starting in 2014. This rule was scheduled to take effect January 1, 2012. However, the District of Columbia Circuit Court of Appeals issued a last-minute stay in late December 2011 in response to legal challenges. Forty-five (45) plaintiffs, including numerous "upwind" states and power companies brought litigation to challenge the rule. On August 21, 2012, the Court of Appeals vacated the CSAPR. On October 5, 2012, the EPA filed a petition seeking en banc rehearing of the Court's decision and on January 24, 2013, the Court of Appeals denied EPA's petition for rehearing. As previously mentioned, this rule was designed to replace EPA's 2005 CAIR. With the vacating of CSAPR, Empire is still subject to the requirements of CAIR. In the meantime, Empire is moving forward with the aforementioned Compliance Plan to meet the MATS rule, which will assist in meeting final CSAPR requirements.

The following sections describe how Empire's emissions of SO_2, NO_x, PM, mercury, and greenhouse gases are affected by the Federal and State air pollution rules.

2.2.1.1 SO_2 Emissions

The CAA regulates the amount of SO_2 an affected unit can emit. Currently SO_2 emissions are regulated by the Title IV Acid Rain Program and CAIR. On January 1, 2012, CAIR was to have been replaced by the CSAPR. As noted above, the District of Columbia Circuit Court of Appeals (Court of Appeals) issued a stay of the CSAPR and CAIR will remain in effect until the EPA develops a valid replacement for CAIR.

MATS, discussed further below, was signed on December 16, 2011, and will affect SO_2 emission rates at Empire's facilities. In addition, the compliance date for the revised SO_2 National Ambient Air Quality Standards (NAAQS) is August of 2017; this will also affect SO_2 emissions from Empire's facilities. The SO_2 NAAQS is discussed in more detail below.

2.2.1.1.1 Title IV Acid Rain Program

Under the Title IV Acid Rain Program, each existing affected unit has been allocated a specific number of emission allowances by the EPA. Each allowance entitles the holder to emit one ton of SO_2. Covered utilities, such as Empire, must have emission allowances equal to the number of tons of SO_2 emitted during a given year by each of their affected units. Allowances in excess of the annual emissions are banked for future use. In 2011 and 2012, Empire SO_2 emissions exceeded the annual allocations. This deficit was covered by Empire's banked allowances. Empire estimates that their Title IV Acid Rain Program SO_2 allowance bank plus annual allocations will be more than their projected emissions through 2016. Long-term compliance with this program will be met by the Compliance Plan along with possible procurement of additional SO_2 allowances. Empire expects the cost of compliance to be fully recoverable in the rates.

2.2.1.1.2 Clean Air Interstate Rule

In 2005, the EPA promulgated CAIR under the CAA. CAIR generally calls for fossil-fueled power plants greater than 25 MW to reduce emission levels of SO_2 and/or NO_x in 28 eastern states and the District of Columbia, including Missouri, where Empire's Asbury Energy Center, State Line, and Iatan Units 1 and 2 are located. Kansas was not included in CAIR and the Riverton Plant was not affected. Arkansas, where Plum Point Plant is located, was included for ozone season NO_x, but not for SO_2.

In 2008, the Court of Appeals vacated CAIR and remanded it back to EPA for further consideration, but also stayed its vacatur. As a result, CAIR became effective for NO_x on January 1, 2009 and for SO_2 on January 1, 2010 and required covered states to develop State Implementation Plans (SIPs) to comply with specific SO_2 state-wide annual budgets.

SO_2 allowance allocations under the Title IV Acid Rain Program are used for compliance in the CAIR SO_2 program. Beginning in 2010, SO_2 allowances were utilized at a 2:1 ratio for Empire's Missouri units. As a result, based on current SO_2 allowance usage projections, Empire expects to have sufficient allowances to take them through 2016.

In order to meet CAIR requirements for SO_2 and NO_x emissions (NO_x is discussed below in more detail) and as a requirement for the air permit for Iatan 2, an SCR system, a flue-gas desulfurization (FGD) scrubber system and baghouse were installed at the jointly owned Iatan 1 plant and an SCR was installed at the Asbury plant in 2008. The jointly owned Iatan 2 and Plum Point plants were originally constructed with the above technology.

2.2.1.1.3 Cross-State Air Pollution Rule - Formerly the Clean Air Transport Rule

On July 6, 2010, the EPA published a proposed CAIR replacement rule entitled the Clean Air Transport Rule (CATR). As proposed and supplemented, the CATR included Missouri and Kansas under both the annual and ozone season for NO_x as well as the SO_2 program while Arkansas remained in the ozone season NO_x program only. The final CATR was released on July 7, 2011 under the name of the CSAPR, and was set to become effective January 1, 2012. However, as mentioned above, the Court of Appeals vacated CSAPR on August 21, 2012, and CAIR will be in effect until a valid replacement for CAIR is developed by the EPA. When it was published, the final CSAPR required a 73-percent reduction in SO_2 from 2005 levels by 2014. The SO_2 allowances allocated under the EPA's Title IV Acid Rain Program cannot be used for compliance with CSAPR but would continue to be used for compliance with the Title IV Acid Rain Program. Therefore, new SO_2 allowances would be allocated under CSAPR and retired at one allowance per ton of SO_2 emissions emitted. Based on current projections, Empire would receive more SO_2 allowances than would be emitted. Long-term compliance with this rule will be met by the Compliance Plan along with possible procurement of additional SO_2 allowances. A number of states, including Kansas, various electric utilities, and industrial organizations commenced litigation in the Court of Appeals and challenged the CSAPR, resulting in the August 2012 vacatur of the rule. Empire anticipates compliance costs associated with CAIR or its subsequent replacement to be recoverable in the rates.

2.2.1.1.4 Mercury Air Toxics Standard

The MATS standard was fully implemented and effective as of April 16, 2012, thus requiring compliance by April 16, 2015 (with flexibility for extensions for reliability reasons). The MATS regulation does not include allowance mechanisms. Rather, it establishes alternative standards for certain pollutants, including SO_2 (as a surrogate for hydrogen chloride), which must be met to show compliance with hazardous air pollutant limits (see additional discussion in the MATS section below).

2.2.1.1.5 SO_2 National Ambient Air Quality Standard

In June 2010, the EPA finalized a new 1-hour SO_2 NAAQS which, for areas with no SO_2 monitor, originally required modeling to determine attainment and non-attainment areas within each state, but in April 2012, the EPA announced that it is reconsidering this approach. The modeling of emission sources was to have been completed by June 2013 with compliance with the SO_2 NAAQS required by August 2017. Because the EPA is reconsidering the compliance determination approach, the compliance time-frame may be pushed back. Draft guidance for 1-hour SO_2 NAAQS has been published by the EPA to assist states as they prepare their SIP submissions. The EPA is also planning a rulemaking to address some of the 1-hour SO_2 NAAQS implementation program elements. It is likely coal-fired generating units will need scrubbers to be capable of meeting the new 1-hour SO_2 NAAQS. In addition, units will be required to include SO_2 emissions limits in their Title V permits or execute consent decrees to assure attainment and future compliance.

2.2.1.2 NO_X Emissions

The CAA regulates the amount of NO_X an affected unit can emit. As currently operated, each of Empire's affected units is in compliance with the applicable NO_X limits. Currently, regulated NO_X emissions are limited by the CAIR as a result of the vacated CSAPR rule and by ozone NAAQS rules (discussed below) which were established in 1997 and in 2008.

2.2.1.2.1 Clean Air Interstate Rule

The CAIR required covered states to develop SIPs to comply with specific annual NO_X state-wide allowance allocation budgets. Based on existing SIPs, Empire had excess NO_X allowances during 2011 which were banked for future use and will be sufficient for compliance at least through the end of 2016. The CAIR NO_X program also was to have been replaced by the CSAPR program

January 1, 2012, but because the Court of Appeals vacated CSAPR, CAIR will remain in effect until the EPA develops a valid replacement for CAIR.

2.2.1.2.2 Cross-State Air Pollution Rule

As published, the CSAPR would have required a 54-percent reduction in NO_X from 2005 levels by 2014. The NO_X annual and ozone season allowances that were allocated and banked under CAIR could not be used for compliance under CSAPR. New allowances would have been issued under CSAPR. However, as discussed above, CSAPR was vacated by the Court of Appeals on August 21, 2012.

2.2.1.2.3 Ozone National Ambient Air Quality Standard

Ozone, also called ground level smog, is formed by the mixing of NO_X and VOCs in the presence of sunlight. On January 6, 2010, the EPA proposed to lower the primary NAAQS for ozone designed to protect public health to a range between 60 and 70 parts per billion (ppb) and to set a separate secondary NAAQS for ozone designed to protect sensitive vegetation and ecosystems.

On September 2, 2011, President Obama ordered the EPA to withdraw proposed air quality standards lowering the 2008 ozone standard pending the CAA 2013 scheduled reconsideration of the ozone NAAQS (the normal five-year reconsideration period). States will move forward with area designations based on the 2008 75 ppb standard using 2008 to 2010 quality assured monitoring data. Empire’s service territory will be designated as attainment, meaning it will be in compliance with the standard. In the interim, the 1997 ozone NAAQS will remain in effect.

2.2.1.3 Particulate Matter Emissions

PM is the term for particles found in the air which comes from a variety of sources.

2.2.1.3.1 Particulate Matter National Ambient Air Quality Standard

On June 14, 2012, the EPA proposed the following actions: 1) to strengthen the annual $PM_{2.5}$ (particle size (microns)) NAAQS, also known as fine particulate matter and 2) set a separate 24-hour $PM_{2.5}$ standard to improve visibility primarily in urban areas. On December 14, 2012, the EPA revised only the primary annual standard to 12 ug/m^3 and states are required to meet the primary standard in 2020.

Currently, the proposed standards should have no impact on Empire's existing generating fleet because the $PM_{2.5}$ ambient monitor results are below the level required by these proposed standards. However, the proposed standards could impact future major modifications/ construction projects that require a Prevention of Significant Deterioration (PSD) permit.

2.2.1.4 Mercury and Air Toxics Emissions

Mercury and air toxics emissions have been impacted by the Clean Air Mercury Rule and the MATS rule.

2.2.1.4.1 Clean Air Mercury Rule

In 2005, the EPA issued the Clean Air Mercury Rule (CAMR) under the CAA. It set limits on mercury emissions by power plants and created a market-based cap and trade system expected to reduce nationwide mercury emissions in two phases. New mercury emission limits for Phase 1 were to go into effect January 1, 2010. On February 8, 2008, the Court of Appeals vacated CAMR. This decision was appealed to the U.S. Supreme Court which denied the appeal on February 23, 2009.

2.2.1.4.3 Mercury Air Toxics Standard

The EPA issued Information Collection Requests (ICRs) for determining the National Emission Standards for Hazardous Air Pollutants (NESHAP), including mercury, for coal and oil-fired electric steam generating units on December 24, 2009. The ICRs included the Iatan, Asbury, and Riverton plants. All responses to the ICRs were submitted as required. The EPA ICRs were intended for use in developing regulations under Section 112(r) of the CAA maximum achievable emission standards for the control of the emission of HAPs including mercury. The EPA proposed the first ever national MATS in March 2011, which became effective April 16, 2012. MATS establishes numerical emission limits to reduce emissions of heavy metals, including mercury, arsenic, chromium, and nickel, and acid gases, including hydrogen chloride and hydrogen fluoride. For all existing and new coal-fired EGUs, the proposed standard will be phased in over three years, and allows states the ability to give facilities a fourth year to comply.

The MATS regulation of HAPs in combination with CAIR/CSAPR is the driving regulation behind Empire's Compliance Plan and its implementation schedule. Empire expects compliance costs to be recoverable in the rates.

2.2.1.5 Greenhouse Gases

Empire's coal and gas plants, vehicles, and other facilities, including EDG (Empire's gas segment), emit CO_2 and/or other GHGs which are measured in carbon dioxide equivalents (CO_2e).

On September 22, 2009, the EPA issued the final Mandatory Reporting of Greenhouse Gases Rule under the CAA which requires power generating and certain other facilities that equal or exceed an emission threshold of 25,000 metric tons of CO_2e to report GHGs to the EPA annually commencing in September 2011. Empire and EDG's GHG emissions for 2010 and 2011 have been reported as required to the EPA.

On December 7, 2009, responding to a 2007 U.S. Supreme Court decision that determined that GHGs constitute “air pollutants” under the CAA, the EPA issued its final finding that GHGs threaten both the public health and the public welfare. This “endangerment” finding did not itself trigger any EPA regulations, but was a necessary predicate for the EPA to proceed with regulations to control GHGs. Since that time, a series of rules including the PSD and Title V GHG Tailoring Rule (Tailoring Rule) have been issued by the EPA and several parties have filed petitions with the EPA and lawsuits have been filed challenging these rules. On June 26, 2012, the D.C. Circuit Court issued its opinion in the principal litigation of the EPA GHG rules (endangerment, the Tailoring Rule, GHG emission standards for light-duty vehicles, and the EPA’s rule on reconsideration of the PSD interpretive memorandum). The three-judge panel upheld the EPA’s interpretation of the CAA provisions as unambiguously correct. This opinion solidifies the EPA’s position that the CAA requires PSD and Title V permits for major emitters of greenhouse gases, such as Empire. Empire’s ongoing projects are currently being evaluated for the projected increase or decrease of CO_2e emissions as required by the Tailoring Rule.

As the result of an agreement to settle litigation pending in the Court of Appeals, on March 27, 2012, the EPA proposed a carbon pollution standard for new power plants. This action is designed to limit the amount of carbon emitted by electric utility generating units. The New Source Performance Standard (NSPS) would require all new power plants to meet a CO_2 emissions limit of 1,000 pounds per megawatt hour (lbs/MWh). This is equal to a coal-fired power plant capturing 50 percent or more of its emissions. The rule does offer some flexibility but would still require an average of 1,000 lbs/MWh over a 30-year period. It is expected that most new natural gas-fired combined cycles will meet the new standard. The proposed rule would apply only to new fossil-fuel fired electric utility generating units. The proposal would not apply to existing units, including modifications such as changes needed to meet other air pollution standards such as is currently being undertaken by the Asbury facility. Comments for the proposed regulation are currently under consideration by the EPA, and Empire will determine the impact on the Riverton Unit 12 conversion after the final rule is released. Final standards are expected in 2013. At this time, the regulation does not propose a standard of performance for modifications, and Empire does not expect the Riverton 12 combined cycle permitting to be affected. Proposed EPA NSPS regulations (through state guidelines) for existing plants are expected in late 2013.

A variety of proposals has been and is likely to continue to be considered by Congress to reduce GHGs. Proposals are also being considered in the House and Senate that would delay, limit, or eliminate EPA's authority to regulate GHGs. At this time, it is not possible to predict what legislation, if any, will ultimately emerge from Congress regarding control of GHGs.

Certain states have taken steps to develop cap and trade programs and/or other regulatory systems which may be more stringent than Federal requirements. For example, Kansas is a participating member of the Midwestern Greenhouse Gas Reduction Accord (MGGRA), one purpose of which is to develop a market-based cap and trade mechanism to reduce GHG emissions. The MGGRA has announced, however, that it will not issue a CO_2e regulatory system pending Federal legislative developments. Missouri is not a participant in the MGGRA.

The ultimate cost of any GHG regulation cannot be determined at this time. However, Empire expects the cost of complying with any such regulations to be recoverable in the rates.

2.2.2 Water Related Impacts

Empire operates under the Kansas and Missouri Water Pollution Plans that were implemented in response to the Federal Clean Water Act (CWA). Their plants are in material compliance with applicable regulations and have received necessary discharge permits.

2.2.2.1 Clean Water Act Section 316(b)

Riverton Units 7 and 8 and Iatan Unit 1, which utilize once-through cooling water, were affected by regulations for Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) Phase II. The regulations became final on February 16, 2004. In accordance with these regulations, Empire submitted sampling and summary reports to the Kansas Department of Health and Environment (KDHE) which indicate that the effect of the cooling water intake structure on Empire Lake's aquatic life is insignificant. KCP&L, who operates Iatan Unit 1, submitted the appropriate sampling and summary reports to the Missouri Department of Natural Resources (MDNR).

In 2007 the U.S. Court of Appeals for the Second Circuit remanded key sections of these CWA regulations to the EPA. As a result, the EPA suspended the regulations and revised and signed a pre-publication proposed regulation on March 28, 2011. The EPA has secured an additional year to finalize the standards for cooling water intake structures under a modified settlement agreement. The EPA is obligated to finalize the rule by July 27, 2013. Empire will not know the full impact of these rules until they are finalized. If adopted in their present form, Empire expects regulations of Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) to have a limited impact at Riverton. The retirement of Units 7 and 8 are scheduled in 2016. Impacts at Iatan 1 could range from intake flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. Empire's new Iatan Unit 2 and Plum Point Unit 1 are covered by the proposed regulation but were constructed with cooling towers, the proposed Best Technology Available. When Riverton 12 undergoes its conversion to combined cycle operation, it also will be constructed with a cooling tower. Empire expects these units to be unaffected or minimally impacted by the final rule.

2.2.2.2 Surface Impoundments

Empire owns and maintains coal ash impoundments located at the Riverton and Asbury Power Plants. Additionally, Empire owns a 12-percent interest in a coal ash impoundment at the Iatan Generating Station and a 7.52-percent interest in a coal ash impoundment at Plum Point. The EPA has announced its intention to revise its wastewater effluent limitation guidelines under the CWA for coal-fired power plants. The final rule is expected to be published in 2013. Once the new guidelines are issued, the EPA and states would incorporate the new standards into wastewater discharge permits including permits for coal ash impoundments. Empire does not have sufficient information at this time to estimate additional costs that might result from any new standards. All of the coal ash impoundments are compliant with existing State and Federal regulations.

2.2.3 Waste Material Impacts

2.2.3.1 Coal Combustion Residuals

On June 21, 2010, the EPA proposed a new regulation pursuant to the Federal RCRA governing the management and storage of CCR. In the proposal, the EPA presents two options: (1) regulation of CCR under RCRA Subtitle C as a hazardous waste and (2) regulation of CCR under RCRA Subtitle D as a non-hazardous waste. The public comment period closed in November 2010. It is anticipated that the final regulation will be published in 2014. Empire expects compliance with either option as proposed to result in the need to construct a new landfill and the conversion of existing ash handling from a wet to a dry system(s) at a potential cost of up to $15 million at their Asbury and Riverton Power Plants. This preliminary estimate will likely change based on the final CCR rule and its requirements. Empire expects resulting costs to be recoverable in the rates.

On September 23, 2010 and November 4, 2010, EPA consultants conducted on-site inspections of the Riverton and Asbury coal ash impoundments, respectively. The consultants performed a visual inspection of the impoundments to assess the structural integrity of the berms surrounding the impoundments, requested documentation related to construction of the impoundments, and reviewed recently completed engineering evaluations of the impoundments and their structural integrity. In response to the inspection comments, the recommended geotechnical studies have been completed and new flow monitoring devices and settlement monuments at both coal ash impoundments have been installed. Final geotechnical engineer report documents for both site impoundments have been received. As a result of the transition from coal to natural gas, initial planning for the closure of the Riverton impoundment is in progress in coordination with the KDHE Bureau of Waste Management. Empire expects to close it this year. The final design for additional recommendations that will improve safety for slope stability at the Asbury impoundment is under review. The site assessment project has complied with all corrective measures and recommendations made by the EPA in the initial site assessment reports.

2.3 Selection of Preliminary Supply-Side Candidate Resource Options

(C) The utility shall indicate which potential supply-side resource options it considers to be preliminary supply-side candidate resource options. Any utility using the preliminary screening analysis to identify preliminary supply-side candidate resource options shall rank all preliminary supply-side candidate resource options based on estimates of the utility costs and also on utility costs plus probable environmental costs. The utility shall—

2.3.1 Potential Supply-Side Resource Option Table

1. Provide a summary table showing each potential supply-side resource option and the utility cost and the probable environmental cost for each potential supply-side resource option and an assessment of whether each potential supply-side resource option qualifies as a utility renewable energy resource; and

The list of potential supply-side resource options - both conventional and renewable were listed in Section 1.2. The costs were shown in *Tables 4-4* and *4-5*, and comparison busbar costs were shown in *Figures 4-3* through *4-6*.

2.3.2 Elimination of Potential Supply-Side Resource Options

2. Explain which potential supply-side resource options are eliminated from further consideration and the reasons for their elimination.

None of the potential supply-side resource options have been eliminated from further consideration as candidate resource options.

SECTION 3 INTERCONNECTION AND TRANSMISSION REQUIREMENTS OF PRELIMINARY CANDIDATE OPTIONS

(3) The utility shall describe and document its analysis of the interconnection and any other transmission requirements associated with the preliminary supply-side candidate resource options identified in subsection (2)(C).

3.1 Interconnection and Transmission Constraints Analysis

(A) The analysis shall include the identification of transmission constraints, as estimated pursuant to 4 CSR 240-22.045(3), whether within the Regional Transmission Organization's (RTO's) footprint, on an interconnected RTO, or a transmission system that is not part of an RTO. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the preliminary supply-side candidate resource options under consideration, that the costs of the transmission system investments associated with preliminary supply-side candidate resource options, as estimated pursuant to 4 CSR 240-22.045(3), are properly considered and to provide an adequate foundation of basic information for decisions to include, but not be limited to, the following:

1. Joint ownership or participation in generation construction projects;

2. Construction of wholly-owned generation facilities;

3. Participation in major refurbishment, life extension, upgrading, or retrofitting of existing generation facilities;

4. Improvements on its transmission and distribution system to increase efficiency and reduce power losses;

5. Acquisition of existing generating facilities; and

6. Opportunities for new long-term power purchases and sales, and short-term power purchases that may be required for bridging the gap between other supply options, both firm and nonfirm, that are likely to be available over all or part of the planning horizon.

3.1.1 Background

Empire is a member of the Southwest Power Pool (SPP) and, as such, is now reliant on the SPP's determination of which transmission lines will be built and on what schedule. As a member of SPP, Empire is assigned a cost sharing allocation of all lines that are built in the SPP. That cost allocation varies per line.

The SPP conducts three studies directly associated with transmission planning: large generation interconnect studies, aggregate transmission service studies, and the SPP transmission expansion plan (STEP). The large generation interconnect study determines all of the modifications needed to connect a new generator into the transmission system. The aggregate transmission service studies determine system upgrades required to grant transmission service from a generation source to a load. The STEP determines upgrades required for a reliable transmission system and provides a screening of potential economic projects. Until a specific line is submitted to the SPP, it is not possible to estimate what the actual cost to Empire will be. Therefore, Empire modeled a generic transmission cost adder for each alternative resource examined in this IRP.

As of January 2005, the SPP uses a FERC-approved process called an aggregate transmission service study. In this process, SPP combines all long-term, point-to-point and all long-term network resource transmission service requests received during a sequential four-month open season into a single aggregate transmission service study. Such an aggregated analysis should result in a more optimal expansion of the SPP transmission system than occurred previously with less aggregated analyses.

Empire actively participates in transmission planning in the SPP through committee membership, attending meetings, participation as a customer and a transmission owner in the development and implementation of all of SPP's transmission studies, and other methods. In two recent cases involving the Open Access Transmission Tariff in the SPP, Empire filed protests with the FERC. These cases involved the OATT "Highway/Byway" cost allocation methodology and the modified transmission planning process referred to as the Integrated Transmission Plan (ITP).

For the purposes of Empire's 2013 IRP, Empire did assign transmission costs on a $/kW basis for each candidate resource examined in this IRP. The cost was $82.73/kW in 2013 dollars, escalating at 2.5 percent per year.

Empire is providing information in this IRP on future transmission projects within Empire's control area that are planned by the SPP in the STEP (see Volume 4.5 of this IRP). This information has been approved by the SPP Board of Directors.

Since not all of Empire's planned construction projects are accounted for in the STEP, details from Empire's 2013 to 2017 Construction Budget for planned transmission and distribution projects are presented in Volume 4.5 of this IRP. Empire's 2013 to 2017 Transmission and Construction Budget includes transmission system additions, transmission system rebuilds, distribution system additions, distribution system rebuilds, and distribution system extensions and service.

Plans for transmission projects within the SPP change frequently as conditions on utility systems, including Empire's, change.

3.1.2 Losses

Empire works to reduce system losses in a variety of ways. One is by evaluating losses of power transformers at the time of purchase. As old transformers are replaced, newer transformers have lower levels of losses. Another is by strategically installing capacitor banks on the distribution system. In the late 1990s, Empire undertook a power factor campaign targeting installation of capacitor banks around the system. As can be seen in *Table 4-6*, Empire's total system losses have decreased over time; its 2011 electric system losses were less than 7 percent as compared to losses of over 8 percent in 2000.

Year	Firm Sales	Total Losses	Annual Losses	5-Year Rolling Average Losses
	(MWh)	(MWh)	%	%
1998	4,162,607	303,175	7.28	
1999	4,163,824	304,747	7.32	
2000	4,424,768	366,028	8.27	
2001	4,494,199	304,067	6.77	
2002	4,566,262	334,287	7.32	7.39
2003	4,594,856	347,676	7.57	7.45
2004	4,628,759	338,035	7.30	7.45
2005	4,923,486	361,858	7.35	7.26
2006	5,049,599	273,483	5.42	6.99
2007	5,118,460	356,396	6.96	6.92
2008	5,124,277	353,204	6.89	6.78
2009	4,901,435	349,647	7.13	6.75
2010	5,202,277	363,250	6.98	6.68
2011	5,082,772	351,949	6.92	6.98

Table 4-6 - Historical System MWh Losses

3.2 New Supply-Side Resources Output Limitations

(B) This analysis shall include the identification of any output limitations imposed on existing or new supply-side resources due to transmission and/or distribution system capacity constraints, in order to ensure that supply-side candidate resource options are evaluated in accordance with any such constraints.

Empire has not identified any transmission system capacity constraints that would limit the output of the new supply-side resource of Riverton 12 CT to CC conversion. When this unit was originally constructed adequate natural gas piping and electrical transmission were designed and built to accommodate its conversion to a combined cycle unit at some point in the future. There are no other new resources planned.

SECTION 4 SUPPLY-SIDE CANDIDATE RESOURCE OPTIONS

(4) All preliminary supply-side candidate resource options which are not eliminated shall be identified as supply-side candidate resource options. The supply-side candidate resource options that the utility passes on for further evaluation in the integration process shall represent a wide variety of supply-side resource options with diverse fuel and generation technologies, including a wide range of renewable technologies and technologies suitable for distributed generation.

4.1 Identification Process for Potential Supply-Side Resource Options

(A) The utility shall describe and document its process for identifying and analyzing potential supply-side resource options and preliminary supply-side candidate resource options and for choosing its supply-side candidate resource options to advance to the integration analysis.

Future supply-side resources available to Empire over the 20-year planning horizon include both conventional and renewable resources. The conventional resources considered in the IRP are described in Section 4.1.1 of the report. The renewable resources considered in the IRP are described in Section 4.1.2 of the report.

4.1.1 Conventional Resource Options

A variety of conventional resources were examined in the course of preparing this IRP. These resources included supercritical pressure coal-fired steam generating units (supercritical coal), simple cycle CT, CC CT, reciprocating internal combustion engines (RICE), small modular nuclear (SMN), distributed generation, integrated gasification combined cycle (IGCC), and traditional nuclear.

Empire also investigated CHP as a potential supply-side resource to include. As discussed in Section 1.2 with regards to potential CHP in the Empire service territory, Empire reported to the Advisory Group that some poultry processing plants within the service territory were potential candidates. It would be difficult to evaluate a generic CHP project since costs and other project details are very project specific and require a CHP partner. CHP cannot be a resource that

Empire can reasonably be expected to use, develop, implement, or acquire since costs and other project details are very project specific and requires a CHP partner. The IRP rule states that the utility must evaluate existing and potential supply-side resource options that can reasonably be expected to use, develop, implement, or acquire. Therefore, Empire will continue to look for CHP opportunities, but it will not be considered as a potential supply-side resource option in this IRP.

Following is a discussion of the preliminary supply-side candidate resource options that were advanced to the integration analysis.

4.1.1.1 Coal Technology

The newest and most efficient coal-fired steam electric units are supercritical pressure. In a supercritical pressure coal-fired unit, chunks of coal are crushed into fine powder in the pulverizer and are fed into a combustion unit (boiler or furnace) where it is burned. Heat from the burning coal is used to generate steam that is used to spin one or more turbines to generate electricity. The percentage of the electricity produced annually in the U.S. by coal-fired units has been decreasing in recent years, dropping from 53 percent in 2007 to 42 percent of the country's electricity production in 2011.

4.1.1.2 Combustion Turbine Technologies

CTs typically burn natural gas and/or No. 2 fuel oil, and are available in a wide variety of sizes and configurations. In this process air is compressed and then fuel is combusted, after which the hot compressed exhaust gas is expanded through a turbine which spins an electrical generator. CTs are generally used for peaking and reserve purposes because of their relatively low capital costs, higher full load heat rate, and the higher cost of fuel when compared to conventional coal-fired base load capacity. CTs are generally classified as either aeroderivative or frame type (also known as "heavy duty"). Aeroderivatives have the added benefit of providing quick-start capability in certain configurations.

4.1.1.3 Combined Cycle Technologies

In a CC facility, the hot exhaust gases from one or more CTs pass through a HRSG. The steam generated by the HRSG is expanded through a steam turbine which, in turn, drives an additional generator. Combustion turbine combined cycle systems typically burn natural gas and are available in a wide variety of sizes and configurations.

4.1.1.4 Reciprocating Internal Combustion Engine Technologies

Large RICE used for stationary electric power production typically burn natural gas and/or No. 2 fuel oil and are available in a wide variety of sizes and configurations. The engine process is similar to that associated with a vehicle engine, except much larger and the drive shaft spins an electrical generator. RICE are generally used for peaking and reserve purposes because of their relatively low capital costs and the higher cost of fuel when compared to conventional coal-fired base load capacity. RICE can be either compression ignition (such as a diesel engine) or spark ignition (similar to gasoline powered engines in vehicles). Natural gas-fired spark ignition RICE have the added benefit of using lower cost fuel available by pipeline and no need for No. 2 fuel oil as an igniter fuel as is required by compression ignition engines burning natural gas.

4.1.1.5 Small Modular Nuclear Technology

Small modular reactors (SMRs) are receiving much attention and interest as well. These are new reactor designs for which each module is much smaller than the typical approximate 1,000 MW associated with the nuclear units designed and built in the 1970s and 1980s. The development of a SMR design suitable for the initiation of the licensing process is at least five years off. Including this time, the licensing time, and the construction time, an operational SMR is beyond the planning horizon of this IRP.

4.1.1.6 Distributed Generation Technologies

Distributed generation (DG) refers to small-scale power plants that differ from traditional electricity supply due to their small size, location, and grid connection. DGs are located at or near the point at which the power is used. Such installations relieve congestion in power lines during periods of peak demand, helping to defer investments in additional transmission and distribution capacity. DG facilities are often installed on the distribution system as opposed to on the transmission system, where generation is typically connected. DG facilities may also be used to boost the quality and reliability of local electricity service by providing voltage control and backup power to customers who require such "premium" service.

4.1.1.7 Integrated Gasification Combined Cycle Technology

Coal gasification is a process that converts solid coal into a synthetic (syn) gas composed mainly of carbon monoxide and hydrogen. IGCC combines both steam and combustion turbines (combined cycle). The fuel gas leaving the gasifier must be cleaned (to very high levels of removal efficiencies) of sulfur compounds and particulates in order to be a suitable fuel for combustion turbines. After the fuel gas has been cleaned, it is burned and expands in the combustion turbine to generate electricity. Steam is generated in the HRSG and superheated in both the gasifier and the HRSG unit downstream from the combustion turbine. The steam is then directed through a steam turbine to produce additional electricity. IGCC plants can achieve up to 45-percent efficiency depending on the level of integration of the various processes, greater than 99-percent SO_2 removal, and NO_x below 50 parts per million (ppm). Because of the nature of the process, CO_2 is already separated from the syn gas produced by the coal gasifier. This leaves some additional cleanup, compression, and transportation for CO_2 sequestration. Compared to new coal-fired boilers or combined cycle combustion turbines, application of carbon capture and sequestration (CCS) to the IGCC plant is viable within the IRP planning horizon.

4.1.1.8 Traditional Nuclear

New nuclear units are currently being pursued around the country at brownfield sites, meaning additional units are being planned at sites with operating units. New nuclear unit designs have been submitted to the U.S. Nuclear Regulatory Commission (NRC) and have received or are awaiting design approval.

These units are 1,000 MW or greater in size. For purposes of this IRP, Empire considered participating in traditional nuclear through a PPA.

4.1.2 Renewable Resource Options

The regulatory requirements for renewable resources in certain Empire jurisdictions are discussed first in the section on Renewable Portfolio Standards (RPS). The second section contains a discussion of the renewable resources considered in this IRP.

4.1.2.1 Renewable Portfolio Standards

RPS or Renewable Energy Standards (RES) have been established by the voters or the legislature in Missouri, Kansas, and Oklahoma. The requirements for each are provided below. In addition, there are several proposals currently before the U.S. Congress to adopt a nationwide RPS.

4.1.2.1.1 Missouri

On November 4, 2008, Missouri voters approved the Clean Energy Initiative (Proposition C). This initiative requires Empire and other investor-owned utilities (IOUs) in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass, and hydro power, or purchase renewable energy credits (RECs), at the rate of at least 2 percent of retail sales by 2011, and increasing to at least 15 percent by 2021. Two (2) percent of this amount must be solar. However, Empire has an exemption from the solar requirement. A challenge to this exemption, brought by two customers and Power Source Solar, Inc., was dismissed on May 31, 2011 by the Missouri Western District Court of Appeals. The plaintiffs filed in the Missouri Supreme Court for transfer of the case from the Missouri Western District to the Missouri Supreme Court, but the transfer was denied. On January 30, 2013, a complaint was filed with the Missouri Public Service Commission (MPSC) by Renew Missouri regarding several points of Empire's 2011 RES Compliance Report and the 2012 to 2014 Compliance Plan. Included in this complaint are challenges to the use of Ozark Beach Hydroelectric as a renewable energy resource, Empire's exemption from solar requirements, and the use of vintage RECs for compliance. The complaint is currently under consideration by the MPSC.

The Missouri Renewable Energy Standard (MORES) compliance rules were published by the MPSC on July 7, 2010. Missouri IOUs and others initiated litigation to challenge these rules. On June 30, 2011, a Cole County Circuit Court judge ruled that portions of the rules were unlawful and unreasonable, in conflict with Missouri statute and in violation of the Missouri Constitution. Subsequent to that decision, a portion of the appeal was dropped and the entire order was stayed. On December 27, 2011, the judge issued another order that was identical to the stayed order with the constitutionality issue omitted. The MPSC appealed this decision and in November of 2012 the court dismissed lawsuits brought against the RES and affirmed the MPSC rules that were finalized in July 2010.

Empire has satisfied the current compliance requirements of the rule which requires the generation or purchase of electricity from RESs of at least 2 percent of retail sales by 2011, increasing to at least 15 percent by 2021.

However, there have been proposed changes to the MORES. Currently there is an initiative petition approved for circulation in Missouri which proposes a statutory amendment to RSMo Chapter 393, relating to renewable energy. The proposed changes would prescribe by rule a portfolio requirement far exceeding the current requirements.

Table 4-7 below shows the timing and energy requirements for both the existing MORES and the proposed initiative petition:

Current Dates	Current RES Percentage (no less than)	Proposed Dates	Proposed Percentage (no less than)
2011-2013	2	2014-2016	5
2014-2017	5	2017-2019	10
2018-2020	10	2020-2022	15
Beginning 2021	15	2023-2025	20
		2026 and thereafter	No less than 25 each year

Notes:
1. Percentage of an electric utility's sales
2 Some or all of the requirement may be satisfied by the purchase of RECs.
3. Each kWh of eligible energy generated within Missouri will count as 1.25 kWh.
4. The proposed initiative petition also requires solar rebate incentives to be provided by each utility beginning in 2014
5. Proposed columns are purely informational and Empire did not include these in its modeling.

Table 4-7 - Missouri Renewable Energy Standard Comparison

Under the initiative petition, the definition of "renewable energy" would no longer include Empire's Ozark Beach hydro facility. In order to meet the 2011 Missouri RPS, RECs from Ozark Beach generation were retired, and the additional 0.25 bonus credits for Missouri-generated energy were claimed. If the pending initiative petition passes, Empire would not be able to use the energy credits from Ozark Beach for compliance.

In addition, if the proposed MORES initiative petition were to pass, Empire would have to make significant changes to its current renewable energy Compliance Plan, which uses Empire's Ozark Beach hydro facility in conjunction with existing wind PPAs for compliance. Empire's current Compliance Plan also takes into consideration that its existing wind farm PPAs, Elk River and Meridian Way, expire in 2025 (with a one-time five year extension option) and 2028, respectively. As a result, Empire does not expect additions to its renewable portfolio and associated costs directly attributable to the current MORES until the 2026 timeframe.

Under the new MORES initiative petition, Empire would see the cost increases associated with the solar rebate program as soon as 2014. In addition, Empire would see changes to its existing renewable energy portfolio beginning in 2024 and escalating substantially through 2032. The anticipated rate impact as a result of the pending initiative petition would begin in 2014, holding through 2023 and increasing from 2024 through 2026. During this period, Empire would be restricted on the amount of incremental renewable energy due to the proposed rate cap which limits rate increases to 3 percent on an annual basis for residential customers. The initiative petition did not appear on the November 2012 ballot.

4.1.2.1.2 Kansas

Kansas established a renewable energy standard effective November 19, 2010 based on the state legislature passed HB 2369 in 2009. Utilities are required to generate or purchase a certain amount of their electricity peak demand for Kansas-only customers from eligible renewable resources as shown in *Table 4-8*.

Years	Percentage of Utility Peak Capacity Demand
2011-2015	10 percent
2016-2019	15 percent
2020 and onward	20 percent
Note: Percent calculated based on the average demand of the prior three years	

Table 4-8 - Kansas Renewable Portfolio Standard

Renewable energy resources are defined by the statute to include:

1. Wind.
2. Solar thermal sources.
3. Photovoltaic cells and panels.
4. Dedicated crops grown for energy production.
5. Cellulosic agricultural residues.
6. Plant residues.

7. Methane from landfills or from wastewater treatment.

8. Clean and untreated wood products such as pallets.

9. Existing hydropower.

10. New hydropower, not including pumped storage, which has a nameplate rating of 10 MW or less.

11. Fuel cells using hydrogen produced by one of the above-named renewable energy resources.

12. Other sources of energy, not including nuclear power, that become available after the legislation becomes effective, and that are certified as renewable by rules and regulations of the Kansas Corporation Commission.

Renewable resources installed in Kansas qualify for a 1.1 multiplier for the purpose of compliance. The RPS will apply to all power sold to Kansas retail customers whether the power they consume is generated or purchased inside or outside of the state.

4.1.2.1.3 Oklahoma

In May 2010, Oklahoma enacted HB 3028 that established a renewable energy goal for electric utilities operating in the state. The goal is "that 15 percent of all installed capacity of electricity generation within the state by the year 2015 be generated from renewable energy sources". Qualifying renewable energy resources include:

1. Wind.

2. Solar.

3. Photovoltaic.

4. Hydropower.

5. Hydrogen.

6. Geothermal.

7. Biomass including agricultural crops, wastes, and residues, wood, animal and other degradable organic wastes, municipal solid waste, and landfill gas.

8. DG from an eligible renewable energy resource less than 5 MW.

9. Other renewable energy resources approved by the Commission.

10. Demand-side management and energy efficiency.

The percentage of renewable energy shall be determined by dividing all installed capacity of renewable electricity generation in Oklahoma by the total installed capacity of all electricity generation in Oklahoma.

Empire has no electric generating resources in Oklahoma.

4.1.2.2 Renewable Resources

Empire examined a range of renewable resources in this IRP. These include wind, biomass (chicken/turkey waste, landfill gas, and others), and solar (PV and solar thermal). Empire has burned fuel derived from tires (tire-derived fuel, TDF) at its Asbury station. Empire is currently between contracts for TDF supply and anticipates using TDF again later in 2013. During tire collections, Empire has helped clean up over 24,000 tires in the service territory. To date over 4.5 million equivalent passenger tires (EPTs) have been used at Asbury.

As previously discussed, Empire has PPAs with Cloud County Wind Farm, LLC, located in Cloud County, Kansas and Elk River Wind Farm, LLC, located in Butler County, Kansas. Empire does not own any portion of either wind farm. More than 15 percent of the energy Empire puts into the grid comes from these long-term PPAs. Through these PPAs, Empire generates about 900,000 RECs each year. A REC represents 1 MWh of renewable energy that has been delivered into the bulk power grid and “unbundles” the renewable attributes from the associated energy.

This unbundling is important because it cannot be determined where the renewable energy is ultimately delivered once it enters the bulk power grid. As a result, RECs provide an avenue for renewable energy tracking and compliance purposes.

Empire has been selling the majority of the RECs it receives from the previously mentioned wind PPAs, and plans to continue to sell all or a portion of them moving forward. As a result of these REC sales, Empire cannot claim that all the underlying energy is renewable. Once a REC has been claimed or retired, it cannot be used for any other purpose. At the end of 2012, sufficient RECs, including hydro, were retired to comply with the Missouri and Kansas requirements through the end of November 2012. Additional RECs were retired in January of 2013 to complete the process for 2012. In the future, Empire will continue to retain a sufficient amount of RECs to meet any current or future RPS.

4.1.2.2.1 Wind

Wind energy systems for utility applications transform the kinetic energy of the wind into electrical energy. Horizontal-axis turbines (propeller-style machines) are the most common wind turbine configuration today, constituting almost all of the utility-scale (greater than 100 kW) applications. *Figure 4-7* shows this typical wind turbine configuration.

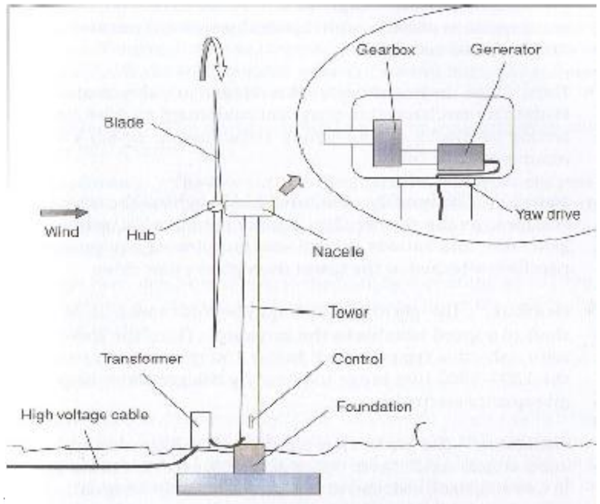

Figure 4-7 - Wind Turbine Configuration

Turbine subsystems include:

1. A rotor, or blades, that convert the wind's energy into rotational shaft energy.
2. A nacelle (enclosure) containing a drive train, usually including a gearbox (not all turbines require a gearbox) and a generator.
3. A tower to support the rotor and drive train.
4. Electronic equipment such as controls, electrical cables, ground support equipment, and interconnection equipment[2].

The American Wind Energy Association (AWEA) reported as of the end of 2012 that the U.S. had 60,007 MW of installed wind energy capacity. The installed wind energy capacity by state, as reported by AWEA as of the end of 2012 are shown in *Figure 4-8*. 13,131 MW of additional wind capacity was added in the U.S. in 2012, which represents 42 percent of all new electricity capacity additions in the U.S. Kansas and Oklahoma were in the top five states for adding new wind capacity in 2012.

[2] Figure, general information and state project information from web site of the American Wind Energy Association www.awea.org.

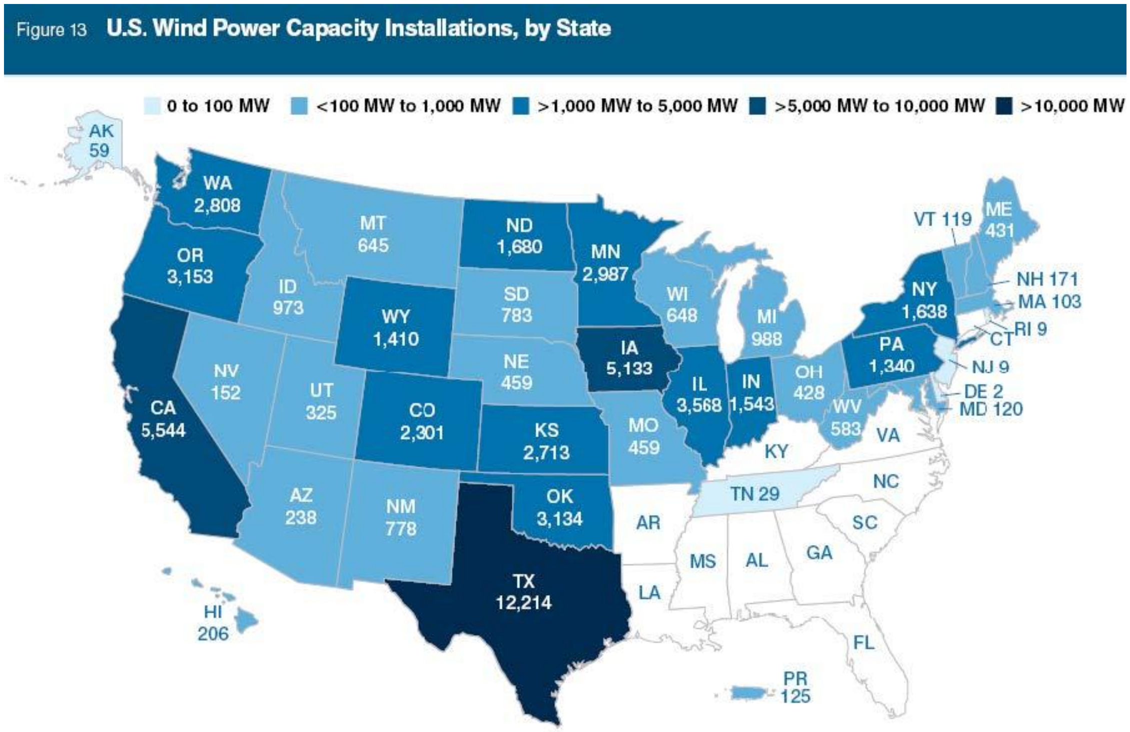

Figure 4-8 - U.S. Wind Power Capacity Installation by State, 2012

Wind - Missouri

The profile of wind resources shown on *Figure 4-9* reveals that Class 3 or lower wind resources exist in Empire's Missouri service territory. Generally wind resources need to be at least Class 3 (the highest wind ranking is Class 7) in order to be considered suitable for wind energy development. This map shows some suitable resources in the Ozark Plateau. Wind resource maps from other sources have indicated that the northwest corner of the State has the highest class wind rankings.[3] The resources that AWEA reports to be online in Missouri are shown in *Table 4-9*.

[3] Figure 3-44, "Missouri annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-44m.html.

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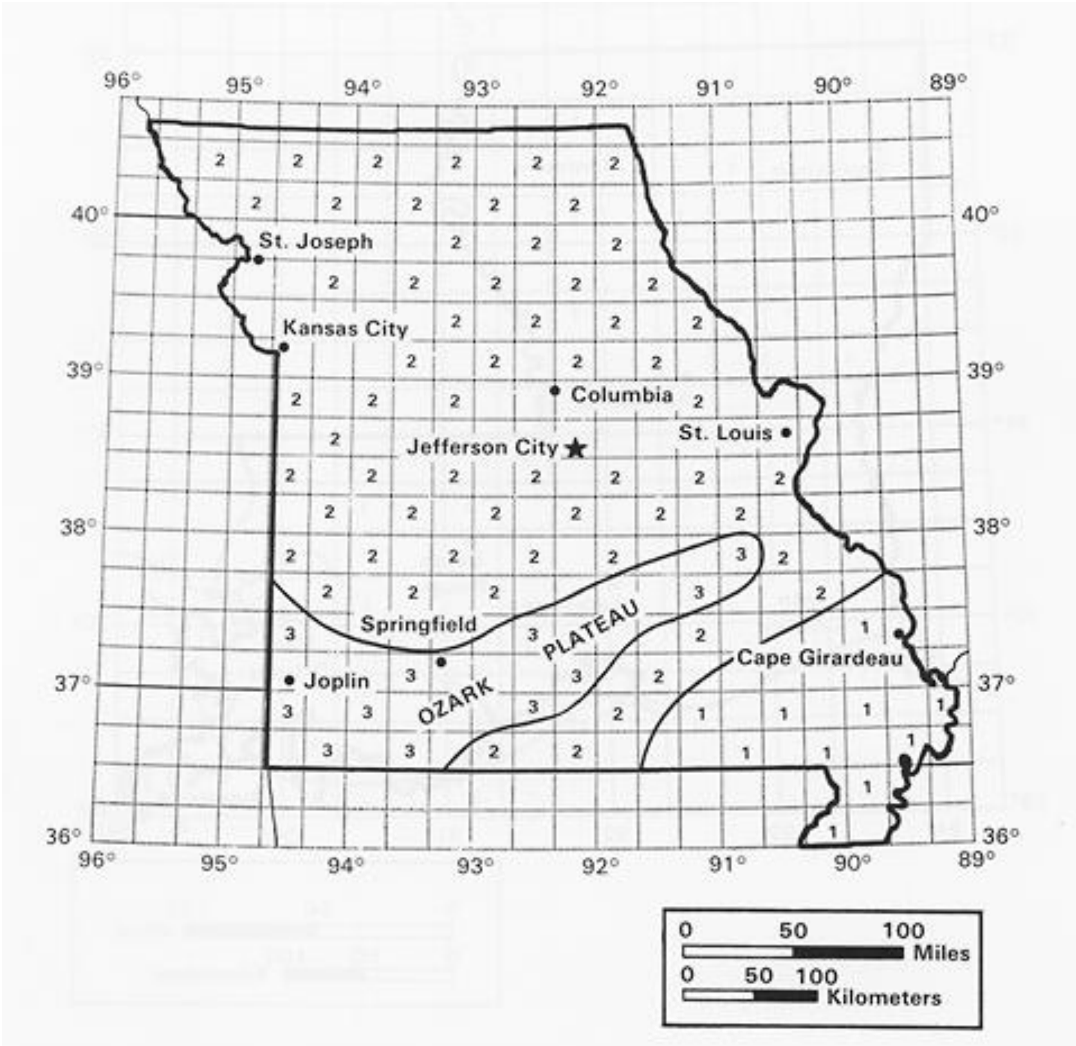

Figure 4-9 - Wind Resources in Missouri (a)

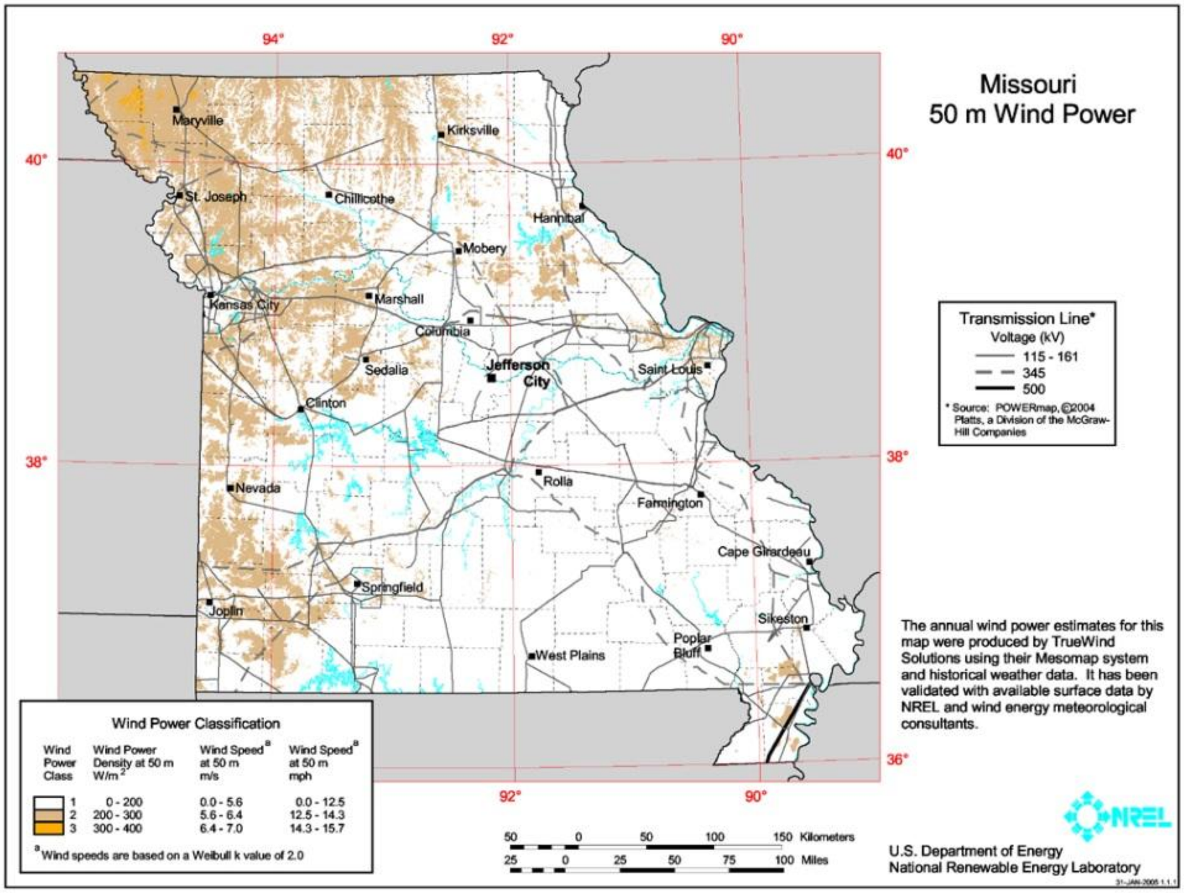

Figure 4-10 - Wind Resources in Missouri (b)

Year of Operation	Size (MW)	Name	Developer	Utility Purchaser
2007	56.7	Bluegrass Ridge Wind energy project	Wind Capital Group/John Deere Capital	Associated Electric Cooperative (AECI)
2008	5	Loess Hills Wind Energy Center	Wind Capital Group/John Deere Capital	Missouri Joint Municipal Electric Utility Commission
2008	50.4	Cow Branch Wind Energy Center	Wind Capital Group/John Deere Capital	AECI
2008	50.4	Conception Wind Project	Wind Capital Group/John Deere Capital	AECI
2009	146	Farmers City	Iberdrola Renewables	
2010	150	Lost Creek Wind Farm	Wind Capital Group	AECI

Table 4-9 - Wind Energy Projects in Missouri

Wind - Kansas

The AWEA ranks Kansas third in the nation (behind North Dakota and Texas) in potential wind energy production. The resource map in *Figures 4-11* and *4-12* shows the Classes 3 and 4 wind resources in Kansas.[4] The resources that AWEA reports to be online in Kansas are shown in *Table 4-10*. This list includes the Elk River and Meridian Way wind energy projects which are part of Empire's existing supply-side resources through PPA. The SPP has certified the capacity that Empire counts for both Elk River (7 MW) and Meridian Way (8 MW). For purposes of planning in the IRP, 5 percent of the nameplate of any new wind resource counts toward the capacity margin calculation.

[4] Figure 3-42, "Kansas annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-42m.html.

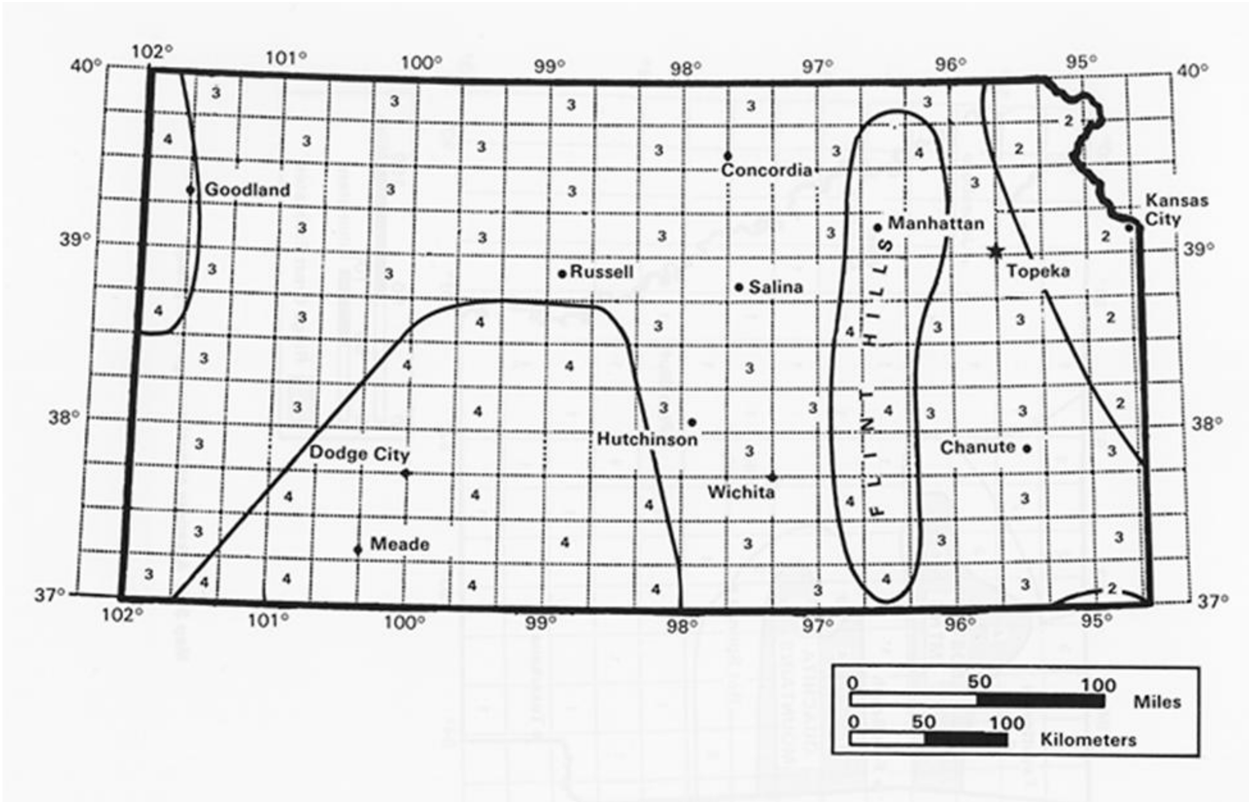

Figure 4-11 - Kansas Wind Resource Map (a)

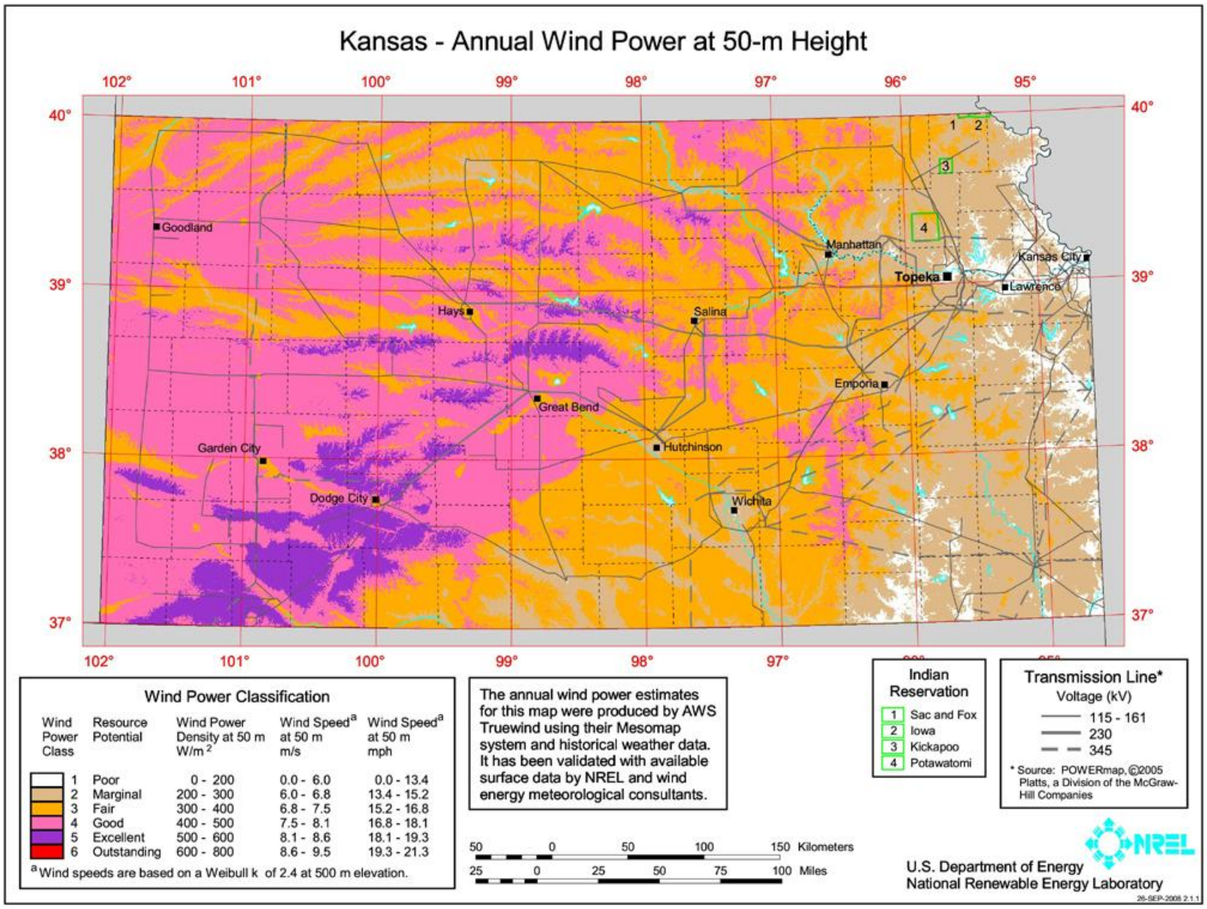

Figure 4-12 - Kansas Wind Resource Map (b)

Year of Operation	Size (MW)	Name	Developer	Utility Purchaser
2001	112.2	Gray County Wind Farm	NextEra Energy Resources	Aquila and Mid-Kansas Electric Company
2005	150	Elk River Wind Farm	PPM Energy[1]	Empire
2006	100.5	Spearville Wind Energy Facility	Kansas City Power & Light	Kansas City Power & Light
2008	100.8	Smoky Hills Wind Farm	Tradewind Energy	Sunflower Electric /Midwest Energy /Kansas City BPU
2008	148.5	Smoky Hills II	Tradewind Energy	Sunflower Electric /Midwest Energy /Kansas City BPU
2008	105	Meridian Way	Horizon Wind Energy	Empire
2008	96	Meridian Way II	Horizon Wind Energy	Westar
2009	100	Flat Ridge Wind Farm	BP Alternative Energy/Westar	Westar
2009	99	Central Plains	Westar	Westar
2010	12.5	Greensburg	John Deere Renewables	Unknown
2010	48	Spearville II	Kansas City Power & Light	Kansas City Power & Light
2011	200	Caney River	Tradewind Energy	Tennessee Valley Authority
2012	201	Post Rock	Wind Capital Group	Westar
2012	167.9	Ironwood I	Duke Energy/Westar	Westar
2012	104	Shooting Star	WindPower[2]	Sunflower Electric
2012	165	Cimarron I	CPV Renewables[3]	Tennessee Valley Authority
2012	100.8	Spearville 3	EDF Renewables	Kansas City Power & Light
2012	131	Cimarron II	CPV Renewables[3]	Kansas City Power & Light
2012	99	Ensign	NextEra Energy Resources	Kansas City Power & Light
2012	419	Flat Ridge 2	BP Wind	Associated Electric/Southwestern Electric Power

[1]Elk River Wind Farm is now owned by Iberdrola Renewables.
[2]Now owned by Exelon.
[3]Now owned by NextEra Energy Resources.

Table 4-10 - Wind Energy Projects in Kansas

Wind - Oklahoma

Oklahoma ranks eighth nationwide in potential wind energy production with most Class 3 and higher wind resources located in the western portion of the state. The resource map in *Figures 4-13* and *4-14* shows the Classes 3 and 4 wind resources in Oklahoma.[5] The resources that AWEA reports to be online and under construction in Oklahoma are shown in *Table 4-11.*

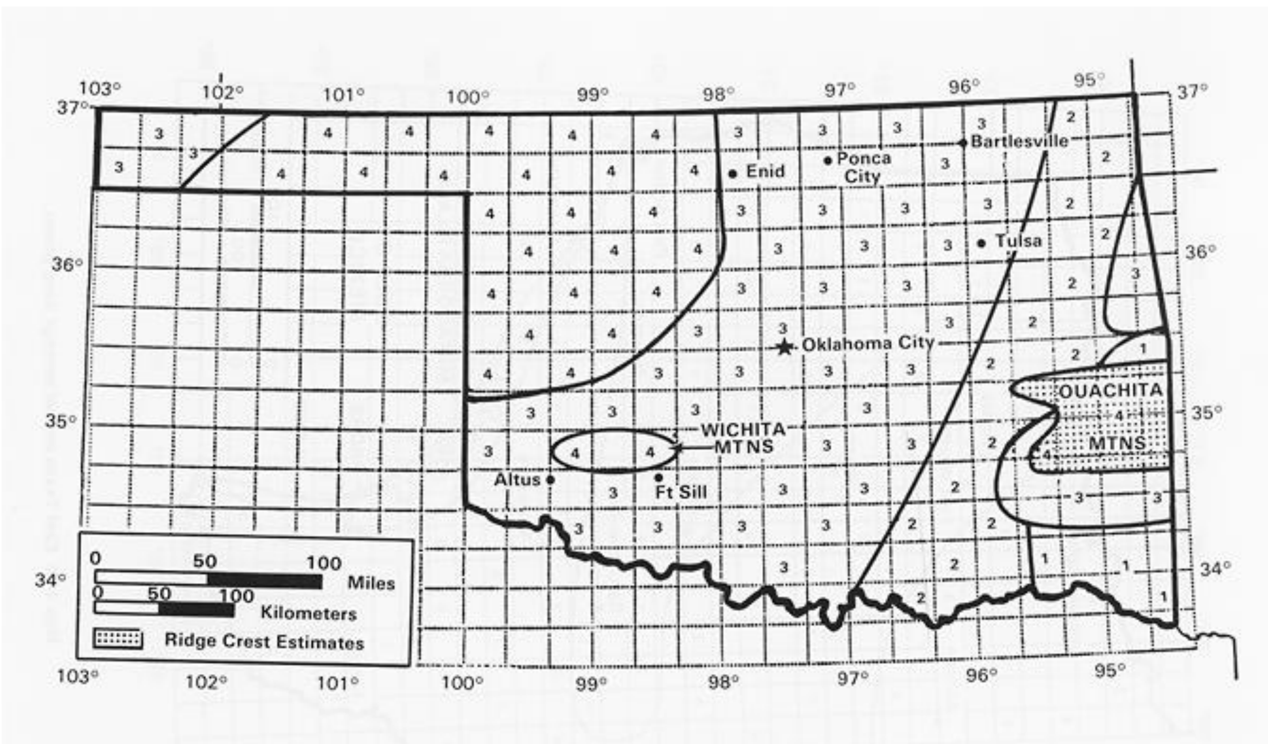

Figure 4-13 - Oklahoma Wind Resource Map (a)

[5]Figure 3-45, "Oklahoma annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-45m.html.

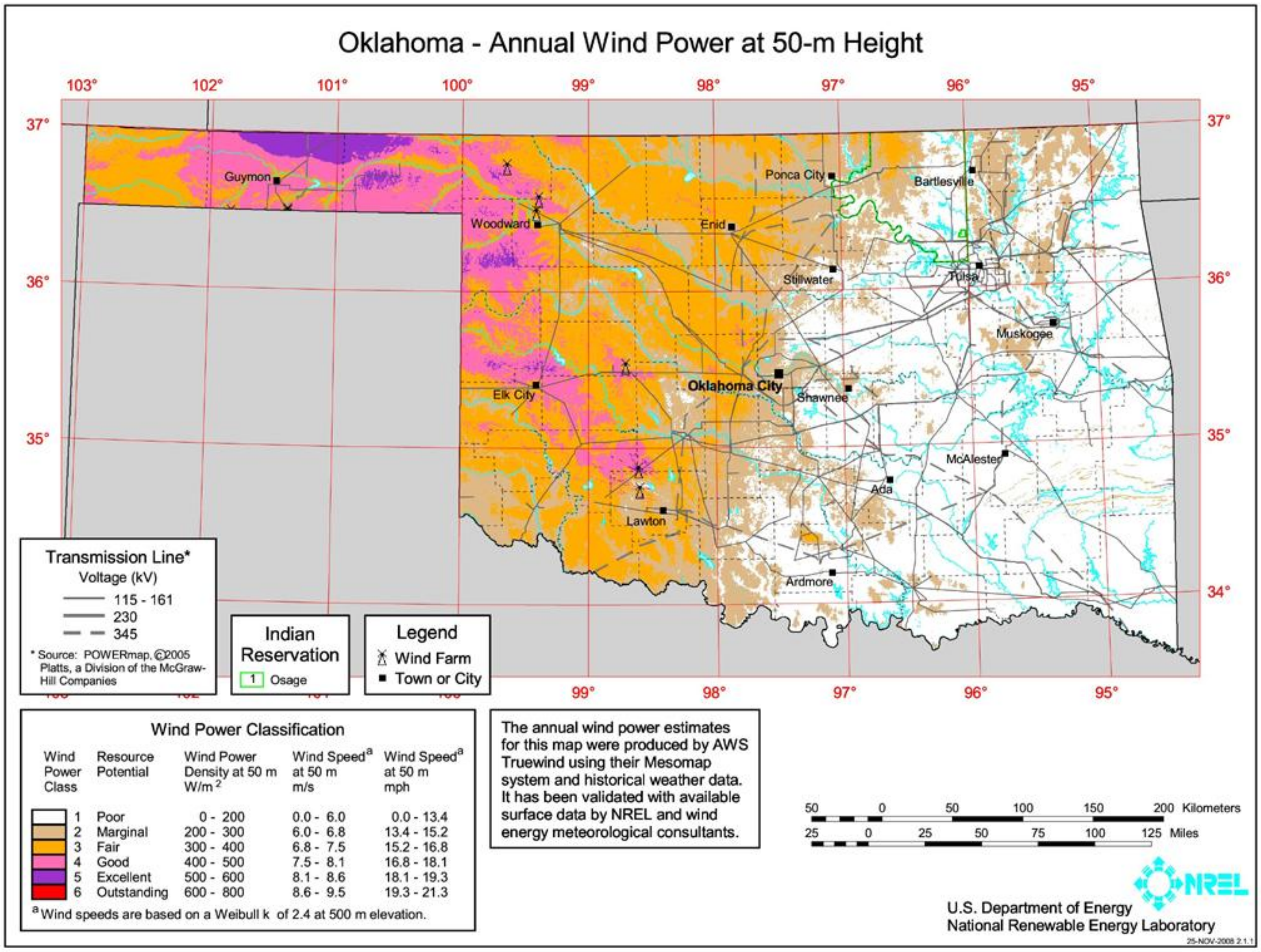

Figure 4-14 - Oklahoma Wind Resource Map (b)

Year of Operation	Size (MW)	Name	Developer	Utility Purchaser
		Operational		
2003	102	Oklahoma Wind Energy Center	FPL Energy[1]	Oklahoma Municipal Power Authority; Oklahoma Gas & Electric
2003	74.25	Blue Canyon	Horizon Wind Energy[2]	Western Farmers Electric Coop
2005	147	Weatherford	FPL Energy[1]	Public Service Company of Oklahoma (AEP)
2005	151.2	Blue Canyon II	Horizon Wind Energy[2]	Public Service Company of Oklahoma (AEP)
2006	60	Centennial	Invenergy	Oklahoma Gas & Electric (OG&E)
2007	94.5	Sleeping Bear	Chermac Energy Corp/Edison Mission Group	Public Service Company of Oklahoma (AEP)
2007	60	Centennial	Chermac Energy /Invenergy	OG&E
2008	18.9	Buffalo Bear	Edison Mission Group	Western Farmers Electric Coop
2009	123	Red Hills	Acciona North America	Western Farmers Electric Coop
2009	34.5 + 64.5	Blue Canyon V	Horizon Wind Energy[2]	Public Service Company of Oklahoma
2009	98.9	Elk City 1	NextEra Energy Resources	Unknown
2010	101.2	OU Spirit (formerly Keenan I)	CPV Renewables	OG&E
2010	151.8	Keenan II	CPV Renewables	OG&E
2010	99.2	Minco	NextEra Energy Resources	Unknown
2010	100.8	Elk City II	NextEra Energy Resources	Unknown
2011	100.8	Minco II	NextEra Energy Resources	Unknown
2011	99	Blue Canyon VI	Horizon Wind Energy[2]	Western Farmers Electric Coop
2012	129.6	Taloga	Edison Mission Group	OG&E
2012	150	Rocky Ridge	Tradewind Energy/Enel	Unknown
2012	227.5	Crossroads	RES Americas	OGE
2012	132	Big Smile at Dempsy Ridge	Acciona North America	Unknown
2012	235	Chisholm View	Tradewind Energy Enel Green Power	Alabama Power
2012	295	Canadian Hills	Apex Wind Energy/Atlantic Power Corp.	Southwester Power; Grand River Dam Authority
2012	60	Blackwell	Next Era Energy Resources	Oklahoma State University

[1]Now known as NextEra Energy Resources.
[2]Now known as EDP Renewables.

Table 4-11 - Wind Energy Projects in Oklahoma

Wind - Arkansas

The resource map in *Figures 4-15* and *4-16* shows the Classes 3 and 4 wind resources in Arkansas.[6] Only one very small wind resource is reported to be operational by AWEA, 0.1 MW at the Bitworks Prairie Grove Industrial Park. AWEA reports no proposed projects.

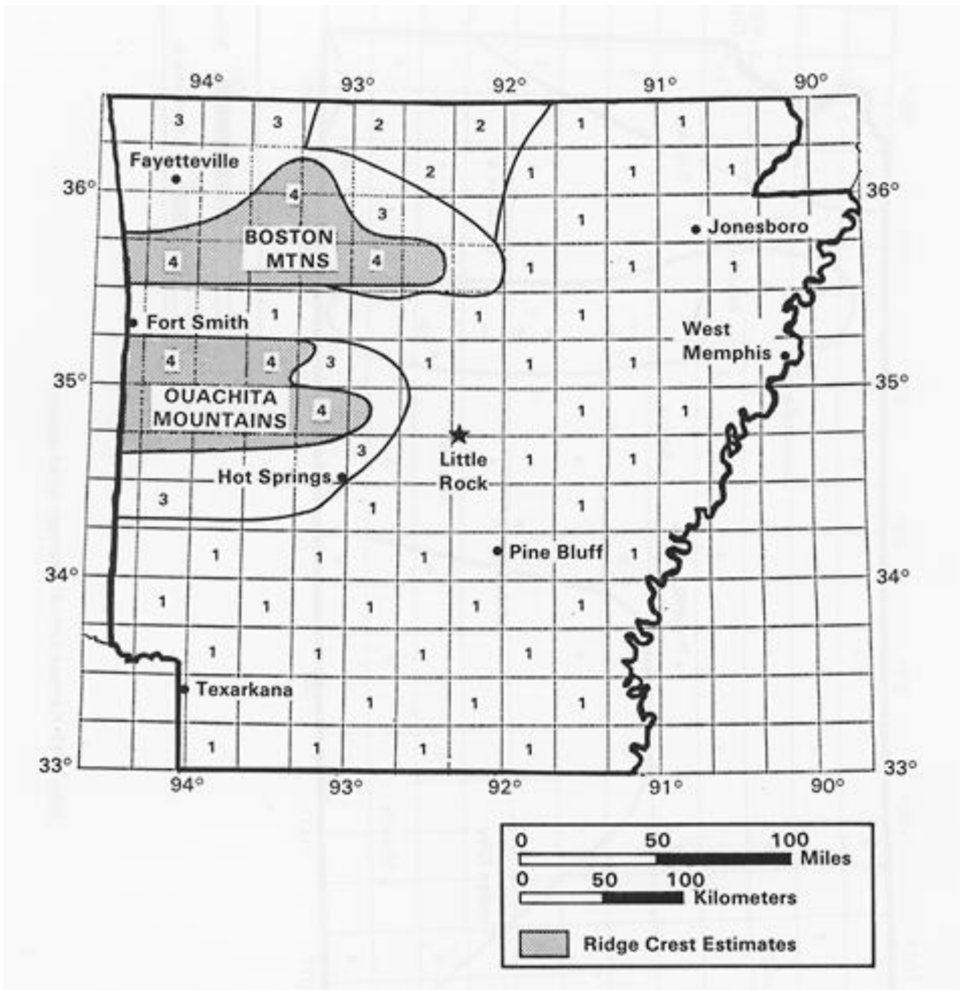

Figure 4-15 - Arkansas Wind Resource Map (a)

6 Figure 3-41, "Arkansas annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-41m.html.

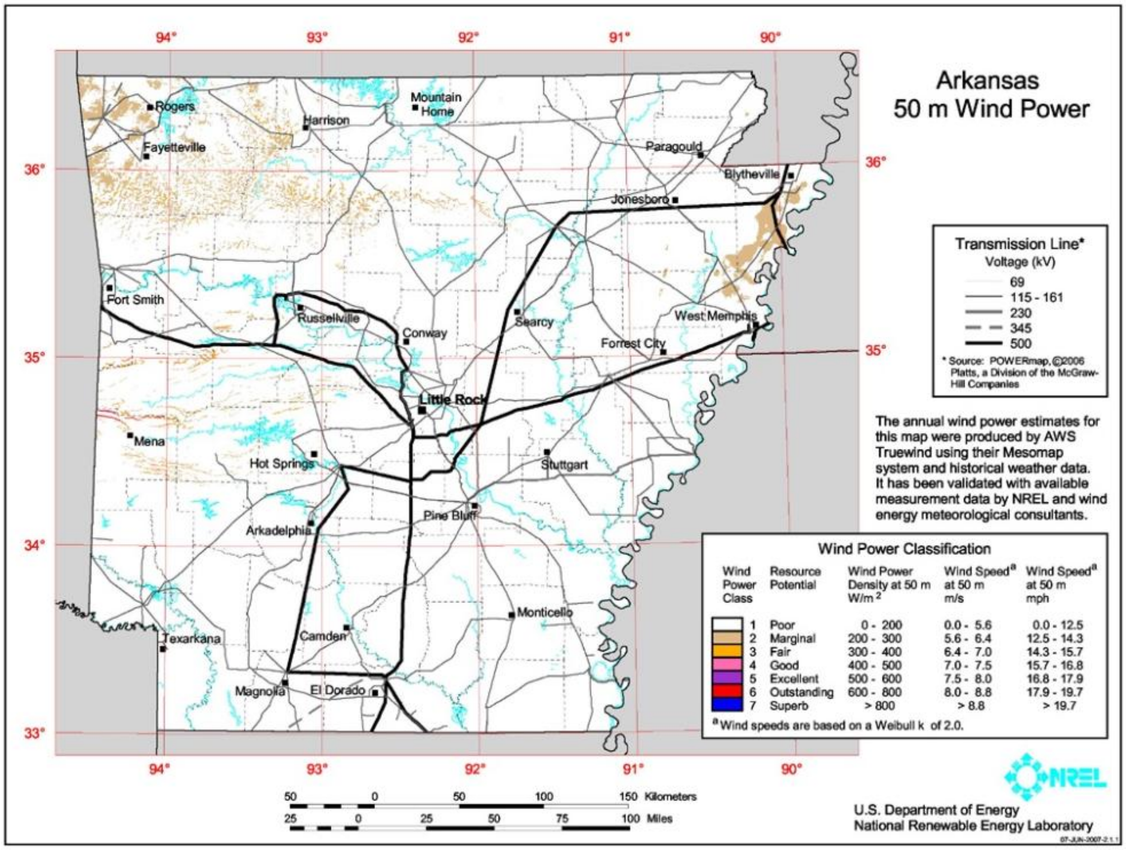

Figure 4-16 - Arkansas Wind Resource Map (b)

4.1.2.2.2 Biomass

Biomass electric generation is currently the largest source of renewable energy other than hydroelectric in the U.S. Biomass means any plant-derived organic matter available on a renewable basis including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, aquatic plants, animal wastes, municipal wastes, and other waste materials. Waste energy consumption generally falls into categories that include municipal solid waste, landfill gas, and other. Other biomass includes agriculture byproducts/crops, sludge waste, tires, and other biomass solids, liquids, and gases. Biofuels being developed from biomass resources include ethanol, methanol, biodiesel, Fischer-Tropsch diesel, and gaseous fuels such as hydrogen and methane. [7]

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[7] U.S. Department of Energy, Energy Efficiency and Renewable Energy, "Biomass Topics," http://www.eere.energy.gov/RE/biomass.html.

Biomass resources available in Missouri, as reported by the National Renewable Energy Laboratory, are shown on *Figure 4-17*. For the 16 counties[8] that comprise the Empire service territory, the biomass resource potential is quite small.

Biomass - Chicken/Turkey Waste

Chicken and/or turkey wastes represent a form of biomass that is prevalent in Empire's service territory.

Biomass - Landfill Gas

The U.S. Energy Information Administration (EIA) describes landfill gas as follows[9]:

> Municipal solid waste contains significant portions of organic materials that produce a variety of gaseous products when dumped, compacted, and covered in landfills. Anaerobic bacteria thrives in the oxygen-free environment, resulting in the decomposition of the organic materials and the production of primarily carbon dioxide and methane. Carbon dioxide is likely to leach out of the landfill because it is soluble in water. Methane, on the other hand, which is less soluble in water and lighter than air, is likely to migrate out of the landfill. Landfill gas energy facilities capture the methane (the principal component of natural gas) and combust it for energy.

[8] Barry, Barton, Cedar, Christian, Dade, Dallas, Greene, Hickory, Jasper, Lawrence, McDonald, Newton, Polk, St. Clair, Stone, and Taney.

[9] "Landfill Gas," U.S. Department of Energy - Energy Information Administration, http://www.eia.doe.gov/cneaf/solar.renewables/page/landfillgas/landfillgas.html.

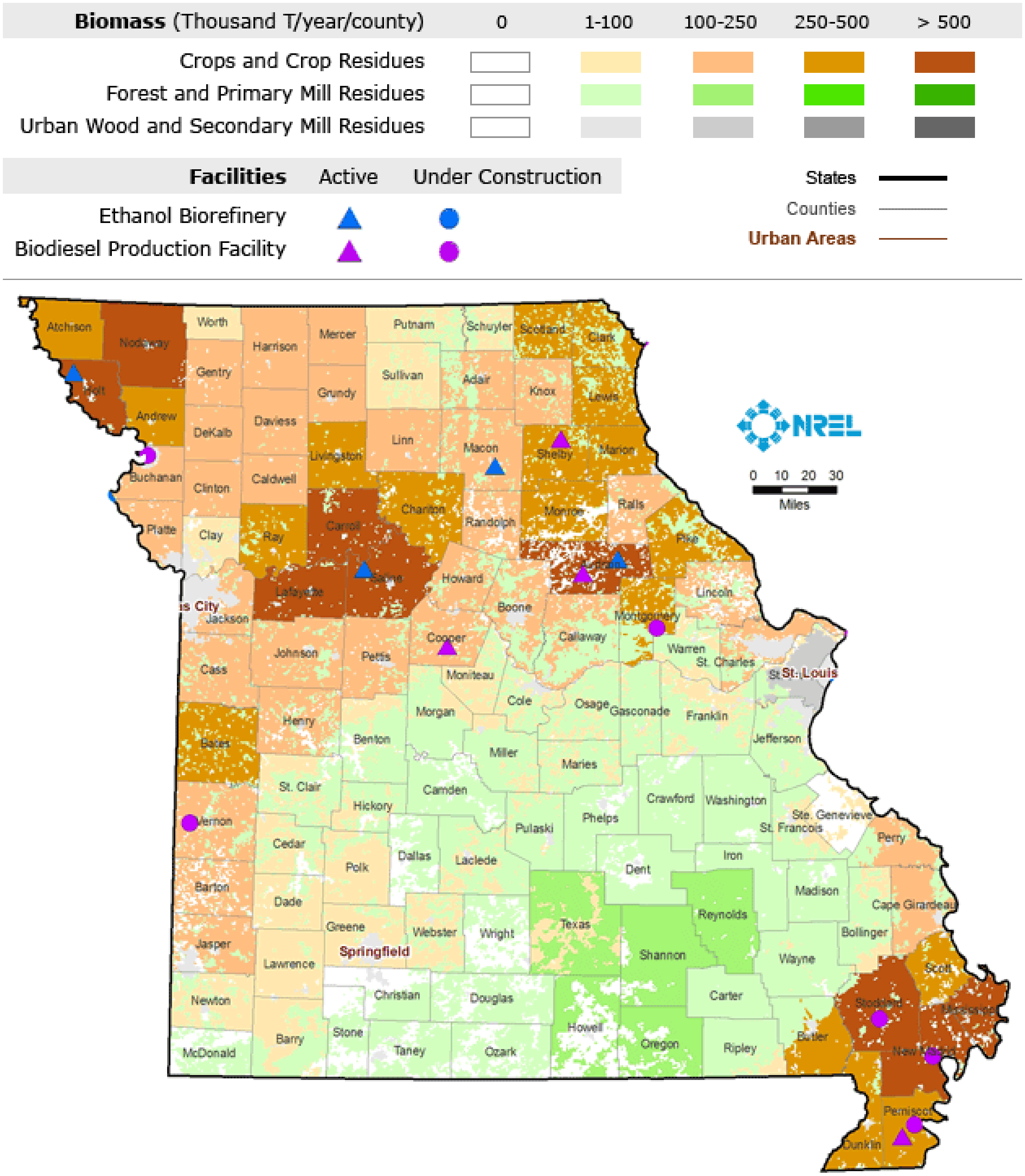

Figure 4-17 - Biomass Resources in Missouri[10]

[10] Source: National Renewable Energy Laboratory.

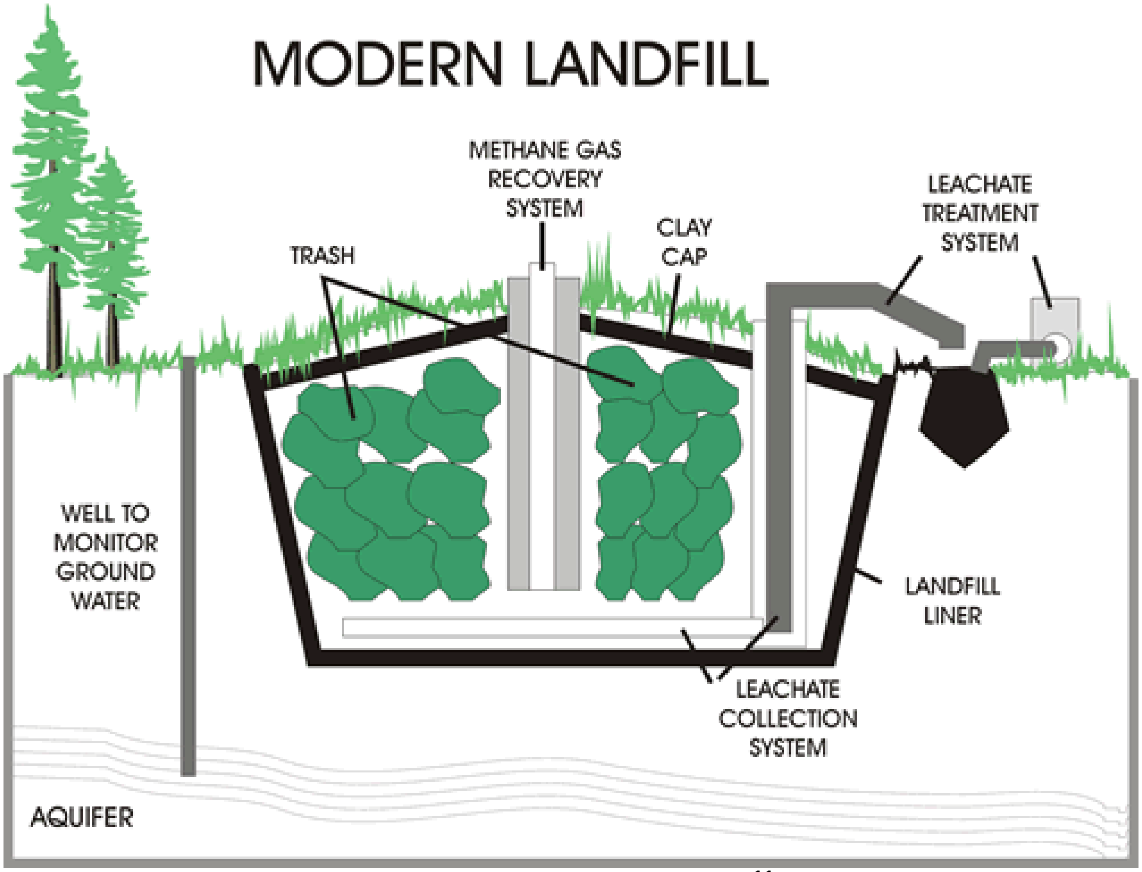

Figure 4-18 - Modern Landfill[11]

[11] Source: The National Energy Education Project.

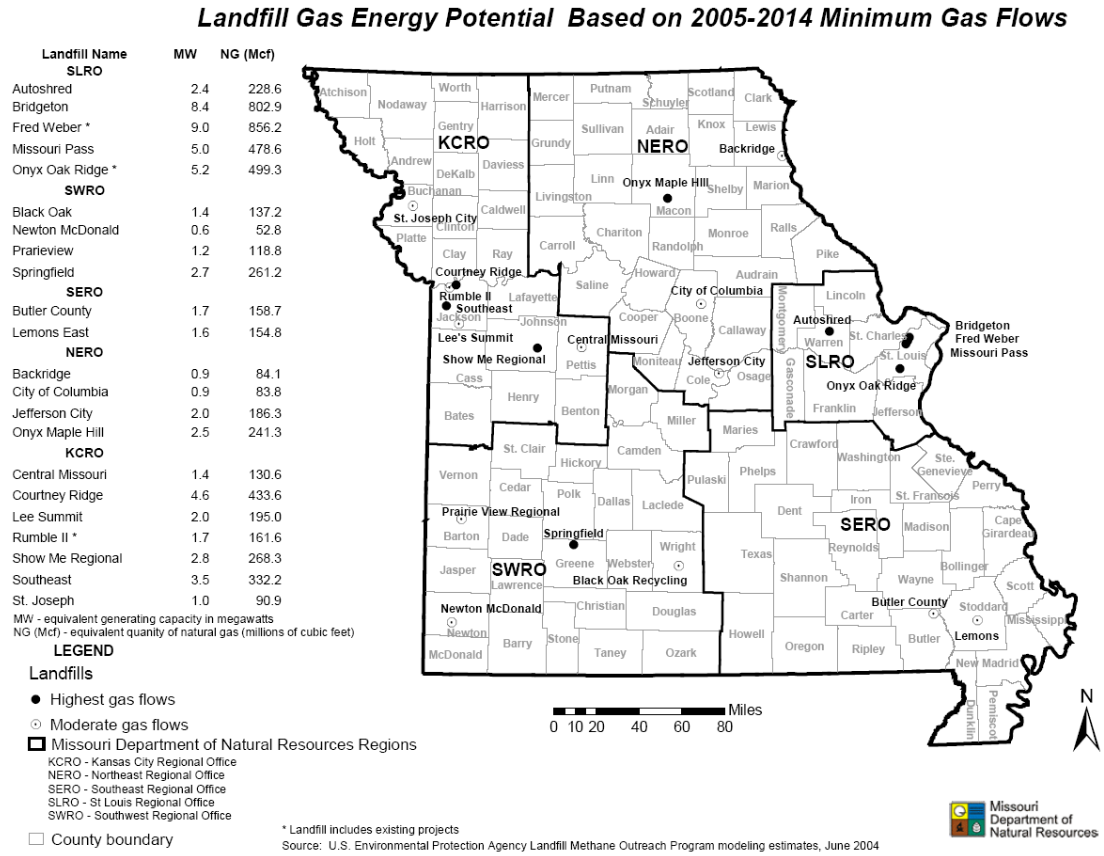

Figure 4-19 - Landfill Gas Energy Potential Based on 2005-2014 Minimum Gas Flows

Biomass - Additional Biomass

Additional biomass has been interpreted by Empire to mean wood waste and municipal solid waste. The U.S. Department of Energy - EIA reports that wood waste, consisting of forest lands, private land clearing, urban tree and landscape residues, manufacturing and wood processing wastes, as well as construction and demolition debris, can serve as a source of fuel to generate electricity. Municipal solid waste (garbage) can be sorted and the combustible products that are not recycled can be used to generate electricity.

Figure 4-20 - Biomass - Wood Waste Facility

4.1.2.2.3 Solar

The solar radiation that comes from the sun can be harnessed and converted to electricity in two primary ways: solar PV and concentrating solar power (CSP). PVs or solar cells change sunlight directly into electricity. A typical PV cell is shown in *Figure 4-21*. The potential for PV applications as reported by the National Renewable Energy Laboratory is shown in *Figure 4-22*.

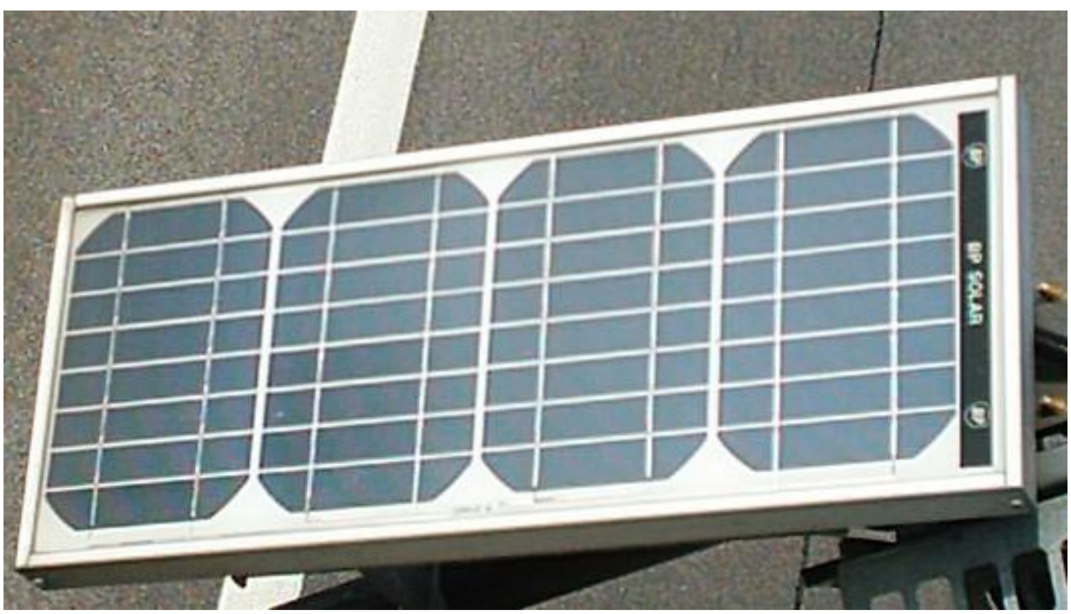

Figure 4-21 - Photovoltaic Cell

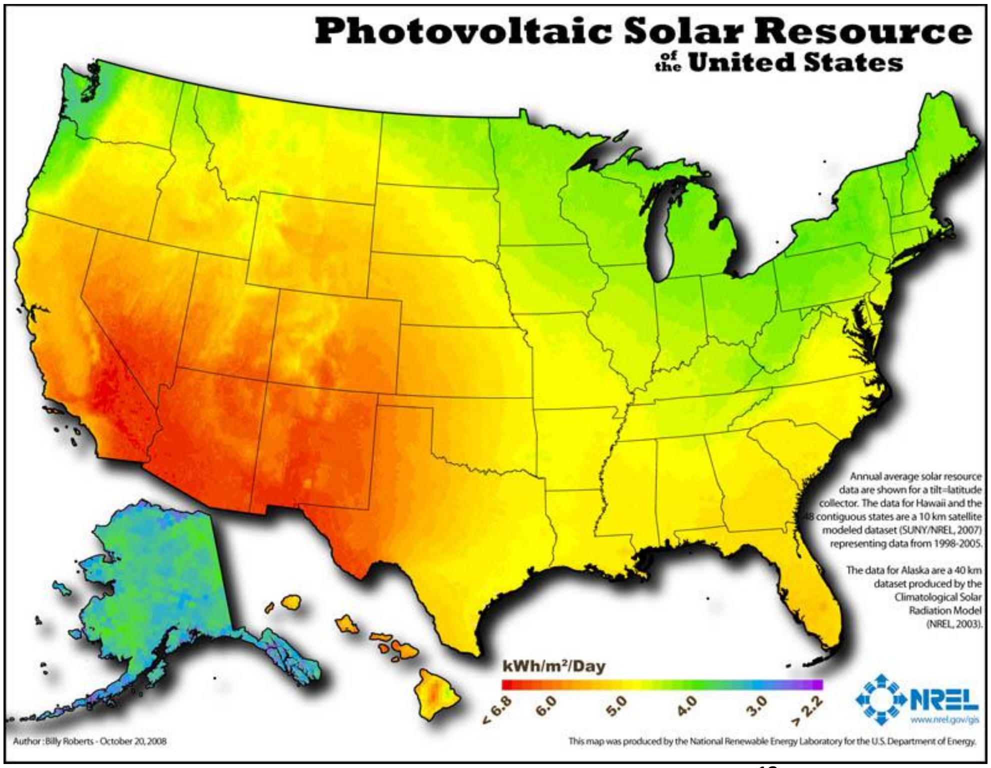

Figure 4-22 - Photovoltaic Solar Resource[12]

CSP is one of the technologies classified as solar thermal. Any solar thermal technology involves a process where the solar energy is used to heat a fluid thereby creating steam that drives a turbine to generate electricity. The existing CSP facilities in the U.S. are found in California, Arizona, and Nevada. An example of a CSP facility is shown in *Figure 4-23.*

[12] Source: National Renewable Energy Laboratory.

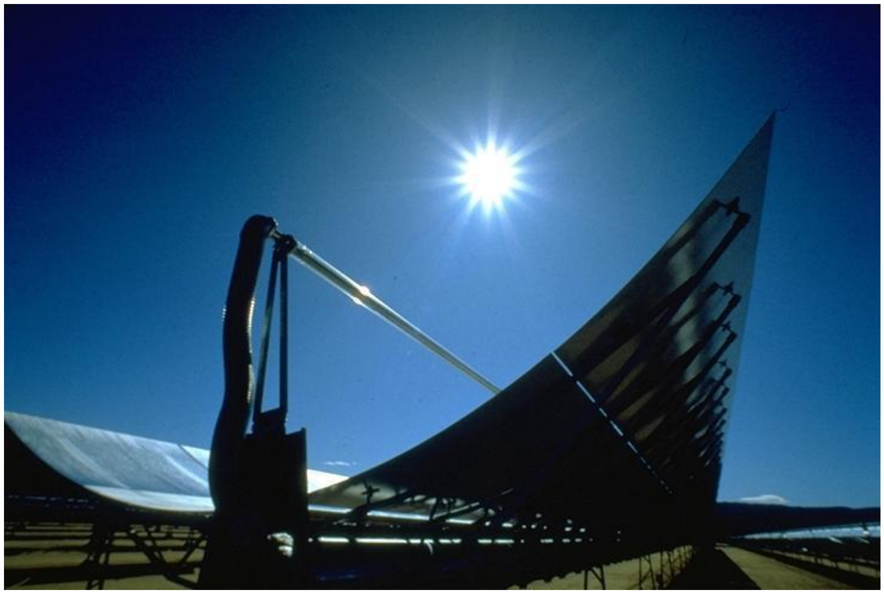

Figure 4-23 - Concentrating Solar Power Facility

The potential for CSP as developed by the National Renewable Energy Laboratory is shown in *Figure 4-24*. Missouri has lower CSP potential than the potential for PV applications.

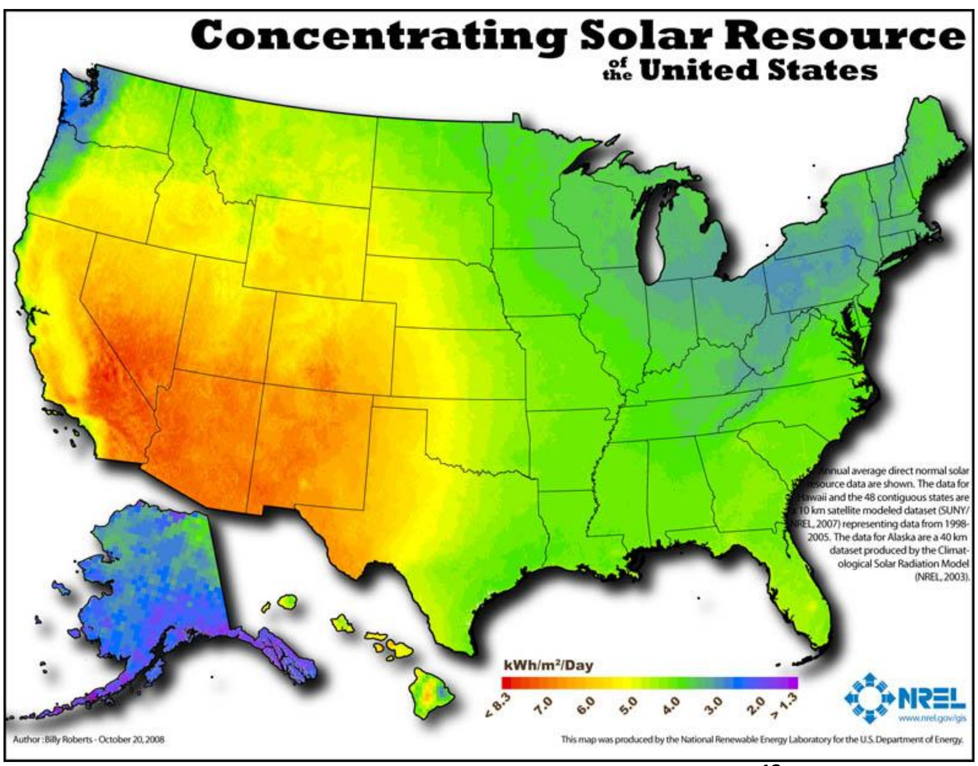

Figure 4-24 - Concentrating Solar Resource[13]

[13] Source: National Renewable Energy Laboratory.

Residential solar PV was considered as a potential program in the DSM analysis. In the demand-side resource analysis it was screened out as not being cost effective, but it was utilized in the most aggressive DSM portfolios.

4.2 Elimination of Preliminary Supply-Side Resources Due to Interconnection or Transmission

(B) The utility shall indicate which, if any, of the preliminary supply-side candidate resource options identified in subsection (2)(C) are eliminated from further consideration on the basis of the interconnection and other transmission analysis and shall explain the reasons for their elimination.

None of the preliminary supply-side candidate resource options were eliminated from consideration based on interconnection or transmission analysis.

4.3 Interconnection Cost for Supply-Side Resource Options

(C) The utility shall include the cost of interconnection and any other transmission requirements, in addition to the utility cost and probable environmental cost, in the cost of supply-side candidate resource options advanced for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3).

The interconnection cost assumed for the Riverton 12 CT to CC conversion was zero since the additional capacity for the CC was already planned for and built. The interconnection cost for all supply-side candidate resource options was $82.73/kW (2013$).

SECTION 5 SUPPLY-SIDE UNCERTAIN FACTORS

(5) The utility shall develop, and describe and document, ranges of values and probabilities for several important uncertain factors related to supply-side candidate resource options identified in section (4). These cost estimates shall include at least the following elements, as applicable to the supply-side candidate resource option:

5.1 Fuel Forecasts

(A) Fuel price forecasts, including fuel delivery costs, over the planning horizon for the appropriate type and grade of primary fuel and for any alternative fuel that may be practical as a contingency option;

Table 4-12 shows a comparison of historical fuel costs, including transportation and other fuel-related costs, for Empire's facilities:

Fuel Type	2012	2011	2010	2009	2008	2007
Coal - Iatan	1.760	1.603	1.193	1.186	1.070	0.978
Coal - Asbury	2.395	2.315	1.877	1.763	1.577	1.432
Coal - Riverton	2.541	2.314	1.833	1.768	1.724	1.548
Coal - Plum Point	1.804	1.858	1.799	-	-	-
Natural Gas	4.493	5.475	6.061	7.376	6.909	7.050
Oil	20.291	21.304	15.443	14.318	16.721	14.870

Source: Empire.

Table 4-12 - Empire's Historical Delivered Fuel Costs ($/MMBTu)

Empire's weighted cost of fuel burned per kWh generated was 2.6742 cents in 2012, 2.9558 cents in 2011, 2.9936 cents in 2010, and 3.1698 cents in 2009. These costs have been dropping as a result of incorporating the new coal-fired units and favorable natural gas and market purchase prices.

The Asbury Plant is fueled primarily by coal with oil being used as the start-up fuel and TDF being used as a supplemental fuel. (Empire is currently between TDF supply contracts and anticipates using TDF again later in 2013. Since Empire began burning TDF at Asbury, the equivalent of nearly 4.5 million passenger tires have been consumed as fuel.) In 2012, Asbury burned a coal blend consisting of approximately 92.7-percent Western coal (referred to in this report as either Western or Powder River Basin (PRB) coal) and 7.3-percent local coal (so-called blend coal) on a tonnage basis. All of the Western coal for Asbury is shipped by rail, a distance of approximately 800 miles.

The Riverton Plant fuel requirements are primarily now met by natural gas (Units 7 and 8 no longer burn coal as of September 2012). A Siemens V84.3 A2 CT (Unit 12) was installed at the Riverton plant in 2007. Riverton 12 and three other smaller units are fueled by natural gas.

Units 1 and 2 at the Iatan Plant are jointly owned coal-fired generating units. Empire's ownership share is 12 percent (approximately 85 MW of Unit 1 and 102 MW of Unit 2). KCP&L is the operator of this plant and is responsible for arranging its fuel supply. The PRB coal burned at Iatan is transported by rail by the Burlington Northern and Santa Fe (BNSF) Railway Company.

The coal-fired Plum Point Energy Station met the in-service criteria on August 12, 2010. Empire owns, through an undivided interest, 7.52 percent (approximately 50 MW) of the project's capacity. Plum Point Services Company, LLC (PPSC), the project management company acting on behalf of the joint owners, is responsible for arranging its fuel supply. PPSC has secured contracts for low sulfur Western coal in quantities sufficient to meet approximately 86 percent of Plum Point's requirements for 2013, 86 percent for 2014, 86 percent for 2015 and 94 percent for 2016. Empire has a 15-year lease agreement, expiring in 2024, for 54 railcars for Empire's ownership share of Plum Point. In December 2010, Empire entered into another 15-year lease agreement for an additional 54 railcars associated with the Plum Point PPA.

The Energy Center and State Line simple cycle CT facilities are fueled primarily by natural gas with fuel oil available for use as backup. During 2012, fuel consumption at the Energy Center was 99-percent natural gas on a kWh-generated basis. Essentially all of the State Line Unit 1 generation came from natural gas in 2012. The State Line CC unit is fueled 100 percent by natural gas.

Empire has firm transportation agreements with Southern Star Central Pipeline, Inc. for the transportation of natural gas to the State Line Power Plant for the jointly owned combined cycle unit. This transportation agreement can also supply natural gas to State Line Unit 1, the

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Energy Center, or the Riverton Plant, as elected by Empire on a secondary basis. In 2002, Empire signed a precedent agreement with Williams Natural Gas Company (now Southern Star Central), that provides additional transportation market zone capability through 2022. This contract provides firm market zone transport to the sites that previously were only served on a secondary basis. The majority of Empire's physical natural gas supply requirements will be met by short-term forward contracts and spot market purchases. Forward natural gas commodity prices and volumes are hedged in accordance with Empire's Risk Management Policy in an attempt to lessen the volatility in the Company's fuel expense and gain predictability.

5.1.1 Coal Forecast

Figure 4-25 depicts and *Table 4-13* lists the forecasted generic coal prices for the base, high, and low scenarios.

[redacted]

****Highly Confidential in its Entirety****
Figure 4-25 - Generic Coal Price Forecast for Base, High, and Low Scenarios[14]

[14] Source for the high, low and annual escalation factors: EIA Annual Energy Outlook, June, 2012, Other Sets of coal prices have also been developed for the other environmental cases.

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Year	Base	High	Low
[redacted]			

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Table 4-13 - Forecasted Generic Coal Prices for Base, High, and Low Scenarios ($/MMBtu)

The first five years of the coal price forecasts used for the Asbury, Riverton, Iatan, and Plum Point facilities were derived by Empire fuels personnel and reflect contract knowledge over those years. The values for subsequent years use escalators based on the U.S. EIA May 2012 projections. Ventyx produces coal price forecasts using its coal sub-module. The coal sub-module utilizes a network LP that satisfies, at least possible cost, the demand for coal at individual power plants with supply from existing mines using the available modes of transportation. For each year and iteration, the sub-module executes in the following manner:

1. For each iteration, demand by each power generating plant is taken from the prior iteration of the power module. The sub-module takes into account the potential to switch or blend coals at each plant, where and to the extent such potential exists.

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2. Supply is represented by mine-level short- and long-run marginal cost curves, maximum output, and developable reserves.

3. Transportation is represented as the minimum cost rate for each mine-plant pairing, taking into account the modes of transportation that are possible, e.g., rail, truck, barge.

4. The network LP generates forecasts of annual FOB prices by mine, delivered prices by plant, and the characteristics of the coal delivered to each plant, e.g., sulfur and heat content.

5. Known contracts between specific mines and power plants are represented. These contracts influence the forecast of spot coal produced at each mine.

Coal price projections for Asbury are shown in *Table 4-14*, those for Iatan 1 and 2 are shown in *Table 4-15*, and Plum Point's coal price projections are found in *Table 4-16*. Many utilities that consume coal have recently experienced cost increases due to increases in the cost of coal transportation.

Year	Western Base	Blend Base
[redacted]		

Table 4-14 - Asbury Coal Price Forecast ($/MMBtu)
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Year	Western Base
[redacted]	

Table 4-15 - Iatan Coal Price Forecast ($/MMBtu)
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Year	Western Base
[redacted]	

Table 4-16 - Plum Point Coal Price Forecast ($/MMBtu)
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5.1.2 Natural Gas Forecast

Figure 4-26 depicts and *Table 4-17* lists the forecasted natural gas prices (Henry Hub) for the base, high, and low scenario no CO_2 case. *Figure 4-27* depicts and *Table 4-17* lists the forecasted natural gas prices (Southern Star Delivered) for the base, high, and low scenario no CO_2 case.

[redacted]

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Figure 4-26 - Forecasted Base, High, and Low Natural Gas Prices (Henry Hub) - No CO_2 Case[15]

[15] Other Sets of natural gas prices have also been developed for the other environmental cases.

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[redacted]

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Figure 4-27 - Forecasted Base, High, and Low Natural Gas Prices (Southern Star Delivered) - No CO_2 Case ($/MMBtu)

HENRY HUB PRICES			
	Base	Low	High
[redacted]			

SOUTHERN STAR DELIVERED PRICES			
	Base	Low	High
[redacted]			

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Table 4-17 - Forecasted Base, High, and Low Natural Gas Prices (Henry Hub and Southern Star Delivered) - No CO_2 Case (\$/MMBtu)

The natural gas price forecast used for this IRP is based on the Ventyx Spring 2012 Power Market Advisory database modified by Ventyx. Natural gas prices were developed for three carbon scenarios: base (No CO_2), moderate CO_2, and high CO_2 (carbon tax) assumptions. Any carbon tax would start no earlier than 2015. The natural gas prices are correlated to the CO_2 prices and are shown on *Table 4-18* and *Figure 4-28*.

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Figure 4-28 - Forecasted Base Natural Gas Prices (Henry Hub) with CO_2 Scenarios

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Year	Base No CO_2 Scenario	Moderate CO_2 Scenario	High CO_2 Scenario
[redacted]			

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Table 4-18 - Forecasted Base Natural Gas Prices (Henry Hub) with CO_2 Scenarios

5.1.2.1 Natural Gas Price Forecasting Methodology

Ventyx produces natural gas price forecasts for each month at individual pricing hubs using its natural gas sub-module. The natural gas sub-module produces forecasts of monthly natural gas prices at individual pricing hubs. The Operations Component consists of a model of the aggregate U.S. and Canadian natural gas sector. For each month and iteration, it executes in the following manner:

1. The Operations Component includes an econometric model of Lower 48 and Canadian demand in each of the sectors other than power, relating monthly consumption to the Henry Hub price.

2. For each iteration of the Operations Component, natural gas demand by the power sector is taken from the prior iteration of the Power Module.
3. LNG supply is forecast using proprietary global LNG model and Henry Hub prices from the previous iteration. This model utilizes forecasts of global LNG demand and supply.

4. North American production is represented in the Operations Component by a series of Lower 48 and Canadian supply curves. These relate production at a wellhead to the wellhead price of natural gas for each basin and geology in each year. Then, an annual production algorithm identifies the relative prices at each of the supply basins to the basin production necessary to meet annual gas demand. Regional storage is based upon a schedule of injections and withdrawals required to balance monthly demand and production. Then, monthly gas production, transportation, and demand after storage are simulated within a gas network optimization model to provide both gas flows and prices at each point within the gas network. Prices at each point in the topology are determined based upon wellhead prices plus transportation costs.

5. From this solution, the monthly Henry Hub price is identified directly from its geographic point within the gas network.

5.1.2.2 Natural Gas Risk Management Policy

Empire works diligently to mitigate the price volatility associated with changes in natural gas pricing. Empire developed and implemented a Risk Management Policy (RMP) during 2001 to manage this volatility. The RMP outlines the instruments that may be used to help manage volatility. In general terms, Empire's RMP allows the use of NYMEX Futures, Swaps, and Physical purchases to help manage price volatility. The RMP includes a minimum annual quantity of natural gas whose price must be established in advance through either a financial instrument and/or physical gas contract. For example, Empire has currently established the price on the following quantities of natural gas for the upcoming calendar years (as of December 2012).

Year	Hedge Percentage	Dekatherms	Average Price
2013	60%	5,680,000	$5.14
2014	40%	4,000,000	$4.74

Year	Hedge Percentage	Dekatherms	Average Price
2015	20%	1,910,000	$4.93
2016	10%	1,000,000	$4.41

The RMP serves to minimize the exposure that Empire has to the impacts of fluctuating natural gas prices.

5.1.3 Fuel Oil Forecast

U.S. crude oil prices are based on conditions in the world oil market. Based on extensive prior analysis, Ventyx believes that the feedback to the world oil market from the markets represented in the North American forecast, i.e., power, natural gas, coal, and emissions, is extremely weak. Moreover, the effects on the world oil market of the types of policies or exogenous events that might be modeled, such as a CO_2 cap-and-trade program, are also very weak. As a result, Ventyx believes it is appropriate to treat the world oil market - and more specifically U.S. crude oil prices - as an exogenous input, as opposed to modeling it explicitly. Ventyx currently uses the forecast of West Texas Intermediate (WTI) price from the U.S. EIA most recent Annual Energy Outlook. We generate forecasts of region-specific prices for refined oil products burned in power plants, e.g., diesel and residual, based on an analysis of historical relationships between these prices and the WTI price.

5.1.4 Renewables Forecast

The Ventyx renewables module simulates the market reaction to the imposition of state RPS. The module simulates annual additions of renewable capacity that will be made in each zone, by technology type, given 1) the total potential capacity for each technology for each area, and 2) the relevant RPS. The module also simulates the annual REC prices for each jurisdiction that imposes an RPS.

The module considers zone-specific supply curves for renewable additions. Each supply curve is expressed in terms of the amount of capacity that would be constructed, measured in MWh of renewable energy generated, at various REC prices. These supply curves are adjusted to take into account zonal energy and capacity prices. The module then identifies the renewable capacity additions that 1) together satisfy the RPS, and 2) require the lowest first-year REC price. In such instances, the REC price is set as the additional payment, measured in dollars per MWh, that the marginal capacity addition requires to break even financially, taking into account the energy market revenues, variable and fixed O&M expenses, and amortized capital costs.

5.2 Capital Costs of Supply-Side Candidate Options

(B) Estimated capital costs including engineering design, construction, testing, startup, and certification of new facilities or major upgrades, refurbishment, or rehabilitation of existing facilities;

The capital costs modeled for each resource option include only generic costs for new transmission required; not those costs expected at any specific location due to the current methods that the SPP uses to plan and cost out new transmission projects. Costs are included for the switching station at the power plant.

5.2.1 Supercritical Coal Technology

As modeled, the coal option available to Empire represents its ownership share of a larger unit. As larger units benefit from economies of scale, this modeling choice was made to ensure Empire was able to take advantage of the cost effectiveness represented by the larger units. However, the actual timing and ownership share of units that Empire might be able to participate in will be dependent on plans of other utilities in the region and are expected to be largely out of Empire's control. The data used in the modeling are shown in *Table 4-19*.

Cost data are based on information from The U.S. EIA "Assumptions to the Annual Energy Outlook 2012". Emissions of SO_2 and NO_X are estimated for a newly permitted coal-fired unit. Mercury emissions are as stated in the February 16, 2012 release of the final MATS regulation for new coal-fired units. U.S. EPA has issued a reconsideration of this limit. Supercritical coal units with carbon capture and sequestration are not assumed to be commercially viable within the planning horizon modeled in this IRP. Costs were developed for a coal unit equipped with

CCS prior to making a judgment on the earliest feasible year of installation. The data are presented to show the estimated cost and efficiency differences between a traditional coal-fired unit and one equipped with CCS.

Parameter	No CCS	With CCS	PPA - No CCS
Earliest feasible year of installation	2023	Outside of planning horizon	2020
Size, MW (net)	50[1]	50[1]	50
Full load heat rate, Btu/kWh	8,800	11,200	8,800
Lead time, months after permit	60	72	-
Capital cost, $/kW (2012 $)	2,988	5,716	-
Fixed O&M, $/kW-year	31.17	33.78	449.19[2]
Variable O&M, $/MWh	4.47	6.46	4.47
Equivalent Forced Outage Rate, percent	6	7	6
Maintenance Outage Rate, percent	6.5	7.5	6.5
SO_2 Emissions, lbs./MMBtu	0.03	0.03	0.03
NO_x Emissions, lbs./MMBtu	0.05	0.05	0.05
CO_2 Emissions, lbs./MMBtu	210	21	210
Mercury Emissions, lbs./GWhr[3]	0.0002	0.0002	0.0002
[1]Ownership share of a larger unit. [2]Monthly capacity payment x 12 months. Includes capital and fixed O&M. [3]Regulatory limit in Utility MATS. This limit is being reconsidered by U.S. EPA.			

Table 4-19 - New Supercritical Coal Performance Parameters

With the assumption that CO_2 may eventually be regulated (either cap and trade or a tax) with an associated requirement to significantly reduce CO_2 emissions in the future, CCS may need to be proven as a viable technology in order for coal-fired generation to continue to be a future new resource option. For purposes of this IRP, Empire assumed CCS has not progressed enough to be a viable alternative for this IRP during the entire twenty-year planning horizon.

Combustion Turbine Technologies

In this IRP, both frame-type and aeroderivative CTs were options in the optimization modeling with data used as shown in *Table 4-20*. Capital and O&M costs are based on estimates prepared by Sega, Inc. (Sega). Sega's capital cost analysis was performed using actual project cost data and Thermoflow Inc.'s thermal engineering software that includes a Plant Engineering and Construction Estimator (PEACE) module for determining capital costs. Thermoflow uses information from original equipment manufacturers (OEMs), material suppliers, engineering firms, and contractors to determine the cost indices contained in the PEACE module. The cost indices are refreshed on a routine basis (typically bi-annual) to reflect current market conditions. The PEACE costs are based on site works, foundations, mechanical installation and materials, electrical installation and materials, and engineering design and startup for specific models of CTs. The aeroderivative costs are based on a GE LM6000PF and the frame-type costs are based on a GE 7EA.

Parameter	Aeroderivative CT	Frame-Type CT
Earliest feasible year of installation	2015	2015
Size, MW (net)	50	87
Full load heat rate, Btu/kWh	9,200	11,400
Lead time, months	36	36
Capital cost, $/kW (2012 $)	992	980
Fixed O&M, $/kW-year	12.47	12.20
Variable O&M, $/MWh	3.18	2.12
Equivalent Forced Outage Rate, Percent	3.6	3.6
Maintenance Outage Rate, Percent	4.1	4.1
NO_X Emissions, lbs./MMBtu	0.05	0.03
CO_2 Emissions, lbs./MMBtu	120	120

Table 4-20 - Combustion Turbine Performance Parameters

5.2.2 Combined Cycle Technologies

In this IRP, a new unsited 250-MW CC facility is assessed with data used as shown in *Table 4-21*. Capital and O&M costs are based on estimates prepared by Sega and were derived from Thermoflow software as described in Section 5.2.2 for CTs. The development of CCS to apply to a CC facility is considered outside of the planning horizon.

Parameter	No CCS	With CCS
Earliest feasible year of installation	2017	Outside of planning horizon
Size, MW (net)	250	250
Full load heat rate, Btu/kWh	7,050	8,250
Lead time, months	42	48
Capital cost, $/kW (2012 $)	1,026	2,258
Fixed O&M, $/kW-year	15.12	23.22
Variable O&M, $/MWh	3.60	3.31
Equivalent Forced Outage Rate, percent	5.5	5.5
Maintenance Outage Rate, Percent	7	6
NO_X Emissions, lbs./MMBtu	0.01	0.01
CO_2 Emissions, lbs./MMBtu	120	12

Table 4-21 - Combined Cycle Performance Parameters

5.2.3 Reciprocating Internal Combustion Engine Technologies

In this IRP, spark ignition natural gas-fired RICE was the option in the optimization modeling with data used as shown in *Table 4-22*. Capital and O&M costs are based on estimates prepared by Sega. Sega's capital cost analysis was performed using actual project cost data. Data for capital costs for the RICE are based on manufacturers' information provided by Caterpillar and Wartsila for a new, multi-unit, 75-MW unsited facility.

Parameter	RICE
Earliest feasible year of installation	2014
Size, MW (net)	75
Full load heat rate, Btu/kWh	8,600
Lead time, months	24
Capital cost, $/kW (2012 $)	1,150
Fixed O&M, $/kW-year	14.57
Variable O&M, $/MWh	3.18
Equivalent Forced Outage Rate, percent	2
Maintenance Outage Rate, percent	2
NO_X Emissions, lbs./MMBtu	0.01
CO_2 Emissions, lbs./MMBtu	120

Table 4-22 - Reciprocating Internal Combustion Engine Performance Parameters

5.2.4 Small Modular Nuclear Technology

Empire is not aware of any opportunities for it to become a joint owner of a nuclear unit in the region. For purposes of the IRP, an SMR was the option in the optimization modeling with data used as shown in *Table 4-23* for a new, 300-MW SMR unit. Capital cost data for the SMR is based on an assessment of a report prepared by the University of Chicago for the Department of Energy. Operating cost data for the SMR are based on information provided by Ventyx.

Parameter	Value
Earliest feasible year of installation	2024
Size, MW (net)	300
Full load heat rate, Btu/kWh	9,500
Lead time, months	180
Capital cost, $/kW (2012 $)	10,000
Fixed O&M, $/kW-year	74.12
Variable O&M, $/MWh	0.58
Equivalent Forced Outage Rate, percent	3.5
Maintenance Outage Rate, percent	5.5
	None

Table 4-23 - Small Modular Nuclear Performance Parameters

5.2.5 Distributed Generation Technologies

Data used to model distributed generation are shown in *Table 4-24.* Cost data are based on information from U.S. EIA "Assumptions to the Annual Energy Outlook 2012".

Parameter	Value
Earliest feasible year of installation	2014
Size, MW (net)	5
Full load heat rate, Btu/kWh	9,050
Lead time, months	12
Capital cost, $/kW (2012 $)	1,507
Fixed O&M, $/kW-year	17.63
Variable O&M, $/MWh	7.84
Equivalent Forced Outage Rate, percent	0
Maintenance Outage Rate, percent	0

Table 4-24 - Distributed Generation Performance Parameters

5.2.6 Integrated Gasification Combined Cycle IGCC

The analysis assumes that Empire would participate in a share of a larger jointly owned unit. Data used to model IGCC are shown in *Table 4-25*. Cost data are based on information from U.S. EIA "Assumptions to the Annual Energy Outlook 2012".

Parameter	No CCS	With CCS
Earliest feasible year of installation	2023	N/A
Size, MW (net)	50[1]	50[1]
Full load heat rate, Btu/kWh	8,700	10,700
Lead time, months	48	60
Capital cost, $/kW (2012 $)	3,383	5,619
Fixed O&M, $/kW-year	51.38	72.81
Variable O&M, $/MWh	7.22	8.45
Equivalent Forced Outage Rate, percent	6	7
Maintenance Outage Rate, percent	6.5	7.5
SO_2 Emissions, lbs./MMBtu	0.02	0.02
NO_x Emissions, lbs./MMBtu	0.01	0.01
CO_2 Emissions, lbs./MMBtu	210	21
Mercury Emissions, lbs./MMBtu	0.0005	0.0005
[1]Represents a share of a larger jointly-owned unit.		

Table 4-25 - IGCC Performance Parameters

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5.2.7 Traditional Nuclear Technology

Empire is not aware of any opportunities for it to become a joint owner of a nuclear unit in the region. For purposes of the IRP, a 1,000-MW PPA was the option in the optimization modeling with data used as shown in *Table 4-26*. Cost data for the traditional nuclear PPA option is based on information provided by Ventyx.

Parameter	Value
Earliest feasible year of installation	[redacted]
Size, MW (net)	
Full load heat rate, Btu/kWh	
Lead time, months	
Capital cost, $/kW (2012 $)	
Fixed O&M, $/kW-year	
Variable O&M, $/MWh	
Equivalent Forced Outage Rate, percent	
Maintenance Outage Rate, percent	
Emissions	
[1]Monthly capacity payment x 12 months. Includes capital and fixed O&M.	

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Table 4-26 - Traditional Nuclear Performance Parameters

5.2.8 Wind

Future wind capacity was considered as a PPA beginning in 2014 at the performance shown in *Table 4-27*. The forecasted cost is highly dependent on whether there is a production tax credit (PTC). Therefore, the costs are shown with and without the PTC. In addition, a candidate supply-side resource option of Empire owning a wind facility was considered at the performance also shown in *Table 4-27*.

Parameter	PPA	PPA With PTC	Own
Earliest feasible year of installation	2014	2014	2014
Size, MW (net)	10	10	10
Full load heat rate, Btu/kWh	0	0	0
Lead time, months	0	0	12
Capital cost, $/kW (2012 $)	0	0	1,800
Fixed O&M, $/kW-year	53.756[1]	30.73[1]	12.00
Variable O&M, $/MWh	0	0	0
Equivalent Forced Outage Rate, percent	0	0	0
Maintenance Outage Rate, Percent	0	0	0
Emissions	0	0	0
[1]Monthly capacity payment x 12 months. Includes capital and fixed O&M.			

Table 4-27 - Wind Performance Parameters

5.2.9 Biomass

The biomass characteristics modeled in the optimization planning are shown in *Table 4-28*.

Parameter	Value
Earliest feasible year of installation	[redacted]
Size, MW (net)	
Full load heat rate, Btu/kWh	
Lead time, months	
Capital cost, $/kW (2010 $)	
Fixed O&M, $/kW-year	
Variable O&M, $/MWh	
Equivalent Forced Outage Rate, percent	
SO_2 Emissions, lbs./MMBtu	
NO_x Emissions, lbs./MMBtu	
CO_2 Emissions, lbs./MMBtu	

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Table 4-28 – Biomass Performance Parameters

5.2.10 Landfill Gas

The landfill gas characteristics modeled in the optimization planning are shown in *Table 4-29*.

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Parameter	Value
Earliest feasible year of installation	[redacted]
Size, MW (net)	
Full load heat rate, Btu/kWh	
Lead time, months	
Capital cost, $/kW (2010 $)	
Fixed O&M, $/kW-year	
Variable O&M, $/MWh	
Equivalent forced outage rate, percent	
SO_2 emissions, lbs./MMBtu	
NO_x emissions, lbs./MMBtu	
CO_2 emissions, lbs./MMBtu	

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Table 4-29 - Landfill Gas Performance Parameters

5.2.11 Solar

The data used for modeling solar photovoltaic (PV) in the IRP are shown in *Table 4-30.*

Parameter	Solar PV
Earliest feasible year of installation	[redacted]
Size, MW (net)	
Full load heat rate	
Lead time, months	
Capital cost, $/kW (2010 $)	
Fixed O&M, $/kW-year	
Equivalent forced outage rate	
Emissions	

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Table 4-30 - Solar Performance Parameters

5.3 Fixed and Variable Costs of Supply-Side Candidate Options

(C) Estimated annual fixed and variable operation and maintenance costs over the planning horizon for new facilities or for existing facilities that are being upgraded, refurbished, or rehabilitated;

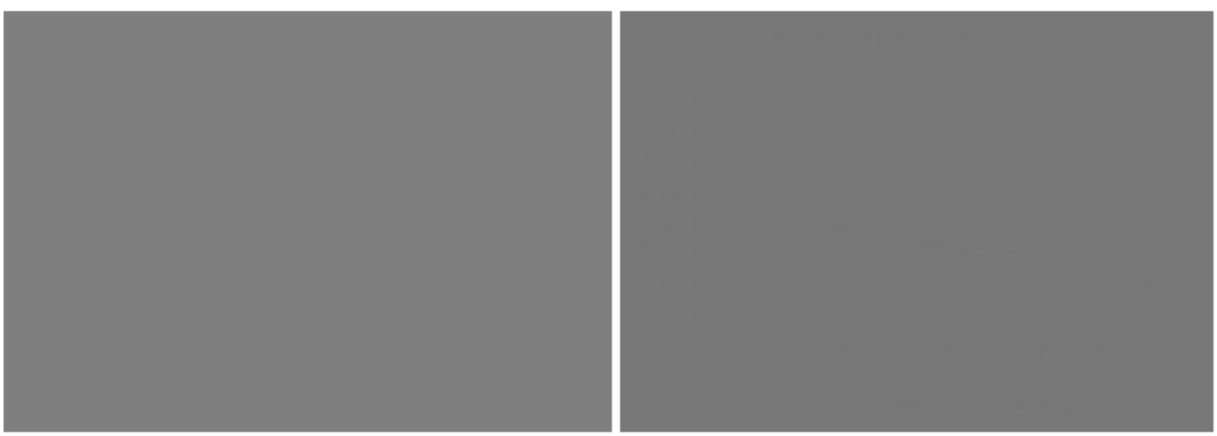
Fixed and variable costs for the candidate options are included in the tables in the previous Section 5.2.

Operation and maintenance (O&M) cost estimates are provided. Empire believes the uncertainty that surrounds the O&M costs for any future power plant is significantly overshadowed by the uncertainty related to any of natural gas prices, market prices, and the level of carbon taxes. Thus, the uncertainty associated with O&M costs is not considered further in this IRP.

5.4 Emission Allowance Forecasts

> *(D) Forecasts of the annual cost or value of emission allowances to be used or produced by each generating facility over the planning horizon;*

NO_X and SO_2, along with many other pollutants, are regulated by a number of State and Federal statutes that complicates price projections for the costs of emissions, the limits on the emissions themselves, and the projected future levels of emissions. The emissions costs assumed in the analysis, reflecting a combination of State and Federal requirements, are shown in *Figure 4-29.*



NP

[redacted]

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Figure 4-29 - SO_2 and NO_X Emission Cost Forecasts Under Three Scenarios

Three levels of CO_2 regulation were examined including a case in which no CO_2 regulation was enacted. *Figure 4-30* shows the projected CO_2 costs ($/ton) in a cap and trade system (referenced as a carbon tax in this IRP), assumed to be applicable no earlier than 2015. Because the optimization models are capable of expressly modeling allowance costs and impacts of carbon taxes, no separate environmental mitigation costs needed to be calculated for the supply-side resources enumerated in this Volume of the IRP report.

[redacted]

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Figure 4-30 - Forecasted CO_2 Prices Under Three Scenarios[16]

5.5 Leased or Rented Facilities Fixed Charges

(E) Annual fixed charges for any facility to be included in the rate base, or annual payment schedule for leased or rented facilities; and

There are no leased or rental facilities.

5.6 Interconnection or Transmission Costs for Supply-Side Candidates

(F) Estimated costs of interconnection or other transmission requirements associated with each supply-side candidate resource option.

The interconnection cost assumed for the Riverton 12 CT to CC conversion was assumed to be zero since the additional capacity for the CC was already planned for. The interconnection cost for all supply-side candidate resource options was $82.73/kW (2013$).

[16] Base: No CO_2 costs (50 percent), Moderate: CO_2 costs begin 2021 (40 percent), High: CO_2 costs begin 2015 (10 percent).

5.7 Market Price Forecast

Another uncertain factor to consider when modeling supply-side candidate resources is power market price. Market prices for the SPP were projected by Ventyx for use in the modeling. These prices reflect conditions in the market expected to be experienced by Empire and use the most recent market information available. Market prices were determined for each of the carbon tax scenarios. The projected on-peak market prices used for the modeling in this IRP are shown in *Figure 4-31.*

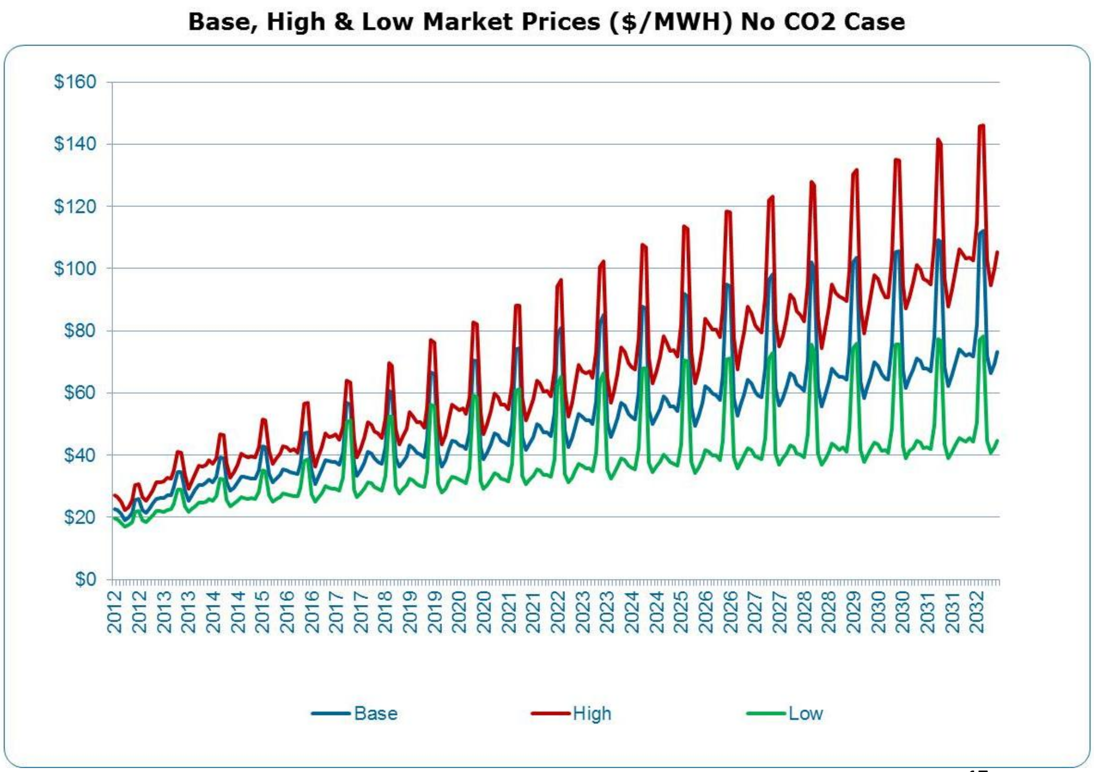

Figure 4-31 - Forecasted Market Price for SPP for Three Scenarios[17]

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[17] Other Sets of market prices have also been developed for the other environmental cases.