HC

# VOLUME 4

# SUPPLY-SIDE RESOURCE ANALYSIS

# THE EMPIRE DISTRICT ELECTRIC COMPANY

# 4 CSR 240-22.040

# FILE NO. EO-2016-0223

# APRIL 2016

****HIGHLY CONFIDENTIAL****

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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.

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.*

The unit ratings below represent Empire's share for jointly owned units. All unit ratings described in this IRP report represent summer ratings (unless otherwise specified). Units are rerated from time to time and all assumptions are subject to change.

| Power Plant Resource | Fuel Type | State | Interest (%) | Empire Capacity (MW) | Start Date | Facility Resource Age (Years) |
|---|---|---|---|---|---|---|
| Asbury 1 | Coal | MO | 100 | 194 | 1970 | 45 |
| Iatan 1 | Coal | MO | 12 | 85 | 1980 | 35 |
| Iatan 2 | Coal | MO | 12 | 105 | 2010 | 5 |
| Plum Point | Coal | AR | 7.52 | 50 | 2010 | 5 |
| Riverton 10 CT | Natural Gas | KS | 100 | 16 | 1988 | 27 |
| Riverton 11 CT | Natural Gas | KS | 100 | 17 | 1988 | 27 |
| Riverton 12 CC | Natural Gas | KS | 100 | 250 | 2007 | 8 |
| Empire Energy Center 1 CT | Natural Gas/Oil | MO | 100 | 82 | 1978 | 37 |
| Empire Energy Center 2 CT | Natural Gas/Oil | MO | 100 | 82 | 1981 | 34 |
| Empire Energy Center 3 CT | Natural Gas/Oil | MO | 100 | 49 | 2003 | 12 |
| Empire Energy Center 4 CT | Natural Gas/Oil | MO | 100 | 49 | 2003 | 12 |
| State Line CT | Natural Gas/Oil | MO | 100 | 94 | 1995 | 20 |
| State Line CC | Natural Gas | MO | 60 | 297 | 1997 & 2001 | 18 & 14 |
| Ozark Beach | Hydro | MO | 100 | 16 | 1913 | 102 |
| Total Empire Installed Capacity | | | | 1,386 | | |
| **Long Term Power Purchases** | **Type** | | | | **End Date** | **Term** |
| Plum Point | Coal | | | 50 | 2040 | |
| Elk River Wind Farm[4] (150 MW PPA) | Wind | | | 17 | 2025 | 20 |
| Meridian Way Wind Farm (105 MW PPA) | Wind | | | 19 | 2028 | 20 |
| **Capacity Summary** | | | | | | |
| Total Coal | | | | 434 | | |
| Total Gas Turbine | | | | 389 | | |
| Total Combined Cycle | | | | 547 | | |
| Total Hydro | | | | 16 | | |
| Total Purchase including Wind | | | | 86 | | |
| TOTAL | | | | 1,472 | | |

1. Riverton 10 and 11 were manufactured in 1967 but were installed at Empire in 1988; they are 48 years old.
2. Represents Empire's 60 percent share of a 495 MW State Line Combined Cycle (SLCC) unit.
3. One of the gas turbines at State Line CC was installed in 1997 and hence is 18 years old. The other gas turbine and the steam turbine were installed in 2001.
4. The Elk River Wind Farm consists of 100 1.5 MW turbines for a total of 150 MW. For purposes of the IRP, 17 MW of its installed capacity is counted toward Empire's reserve margin. This firm capacity is subject to rerating in the future. 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.
5. The Meridian Way Wind Farm began commercial operation on December 15, 2008. The facility is rated at 105 MW and approximately 19 MW is counted toward Empire's reserve margin. This firm capacity is subject to rerating in the future.

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

Empire's generation by fuel type for 2014 is shown in *Figure 4-1* and listed in *Table 4-2*. In 2015, 50 percent of Empire's generation was supplied by coal, 25 percent from natural gas, and 18 percent was provided by renewable sources. The remaining generation was provided by non-contract purchases. As of March 1, 2014, the Southwest Power Pool Integrated Marketplace (SPP IM) allows Empire to buy generation from and sell generation to participants throughout the SPP region.

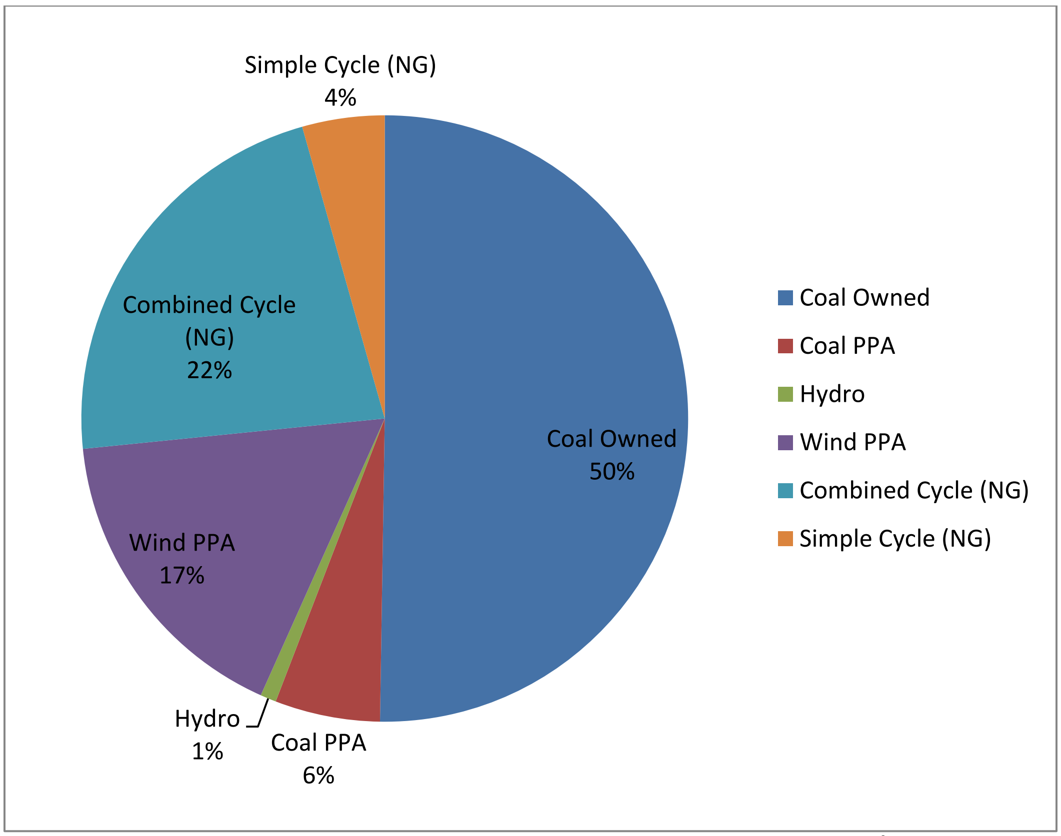


**Figure 4-1 - Empire Generation by Fuel Type for 2015[1]**

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

| Type | MWh in 2015 | % |
|---|---|---|
| Coal Owned | 2,480,453 | 50% |
| Coal PPA | 276,550 | 6% |
| *Total Coal* | *2,757,003* | 56% |
| Hydro | 41,927 | 1% |
| Wind PPA | 824,493 | 17% |
| *Total Renewable* | *866,420* | 18% |
| Combined Cycle (NG) | 1,096,386 | 22% |
| Simple Cycle (NG) | 216,534 | 4% |
| *Total Natural Gas* | *1,312,920* | 27% |
| ***Total System MWh (Net System Output)*** | ***4,936,343*** | ***100%*** |

**Table 4-2 - Empire Generation by Type for 2015**

### 1.1.1 Compliance Plan

In order to comply with current and forthcoming environmental regulations, Empire continues to implement its compliance plan and strategy (Compliance Plan). The Mercury Air Toxic Standards (MATS) and the Clean Air Interstate Rule (CAIR), replaced by the Cross State Air Pollution Rule (CSAPR), which Empire discusses further below, are the drivers behind its Compliance Plan and its implementation schedule. The MATS requires reductions in mercury, acid gases and other emissions considered hazardous air pollutants (HAPS). They became effective in April 2012 and required full compliance by April 16, 2015. Empire is currently in material compliance with MATS, although the regulation has been remanded to the D.C. Circuit Court for further consideration (discussed below). The CSAPR was first proposed by the Environmental Protection Agency (EPA) in July 2010 as a replacement of CAIR and came into effect on January 1, 2015. Empire anticipated compliance costs associated with the MATS, CAIR and CSAPR regulations to be recoverable in its rates.

Empire's Compliance Plan largely follows the preferred plan presented in the company's Integrated Resource Plan (IRP), filed in mid-2013 with the MPSC. In addition to the Riverton

Unit 12 project, the process of installing a scrubber, fabric filter, and powder activated carbon injection system at Asbury plant has been completed and the equipment placed in service in December 2014. This addition required the retirement of Asbury Unit 2, a steam turbine rated at 14 megawatts that was used for peaking purposes. Asbury Unit 2 was retired on December 31, 2013.

#### 1.1.1.1 Asbury

The Asbury plant, located near Asbury, Missouri, consists of one coal-fired unit totaling 194 MW. Unit 1 was installed in 1970.

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 over-fire air (also for $NO_X$ control) was installed in 2001 and 2004. The Asbury Air Quality Control System (AQCS) project, as described in the 2013 IRP, has been completed. The project included the addition of a Dry Circulating Fluidized Bed Scrubber for sulfur dioxide removal; a Powder Activated Carbon Injection system for mercury removal; and a pulse jet filter fabric baghouse for removal of particulate matter from the flue gas. The AQCS project also included a conversion from a forced draft boiler to a balanced draft; a turbine upgrade; and retirement of Unit 2. The upgrades to the Unit 1 Turbine included new rotor and inner casings for efficiency gains. The AQCS project brought Asbury from 189 MW to 194 MW (net generation) and compliant with MATS regulations. 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 8 to 10 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.

Associated with the Asbury AQCS project, new regulations, and other pending environmental regulations is the need to construct a coal combustion residual landfill and modify the bottom ash conveyance equipment at the Asbury Plant. These changes are a result of expected changes to the Federal Resource Conservation and Recovery Act (RCRA) as discussed in Section 2.2.3and the recent Effluent Limit Guidelines discussed in section 2.2.2.

#### 1.1.1.2 Riverton

Empire’s Riverton Generating Plant located at Riverton, Kansas, has three natural gas-fired CT units (10, 11, and 12) with an aggregate generating capacity of 175 MW. Riverton Units 7 and 8 transitioned to burning solely natural gas after a long run of coal operation at the site, and were retired in 2014 and 2015 respectively. 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.

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 Riverton 12 conversion to a CC unit (Riverton combined cycle conversion) will add about 100 additional MW to the system, making the Riverton combined cycle a roughly 250 MW unit upon completion in early to mid-2016. Once in service, this will become Empire’s most efficient unit. 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.

#### 1.1.1.3 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 2009.

Empire also owns a 12-percent undivided interest in the Iatan 2 unit, which for purposes of this IRP is assumed to be 105 MW (Empire's share). The AQCS (SCR, scrubber, fabric filter) constructed with the relatively new Iatan 2 unit complies with the recent and anticipated air quality regulations.

#### 1.1.1.4 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 495 MW, of which Empire is entitled to 60 percent, or 297 MW. All of the 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.

#### 1.1.1.5 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.

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 $NO_X$.

#### 1.1.1.6 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). In 2013 Empire celebrated this facility's 100-year anniversary from when the unit was put into service in 1913. This centurion unit has been updated periodically so that it will continue contributing to Empire's renewable portfolio. Empire plans to begin the relicensing process at Ozark Beach in the third or fourth quarter of 2016. The relicensing process takes about five years to complete and does not expire for thirty years.

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), the new minimum flow pattern was established to increase minimum flows on recreational streams in Arkansas. To accomplish this, the level of Bull Shoals Lake was increased an average of 5 feet. The increase at Bull Shoals decreased the net head waters available for generation at Ozark Beach by 5 feet and, thus, reduced Empire's electrical output. The lost production represented about 16 percent of the average annual energy production for the unit. The Appropriations Act required Southwest Power Administration (SWPA), in coordination with Empire and Empire's relevant public service commissions, to determine Empire's economic detriment from the lost production. On June 17, 2010, 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.

#### 1.1.1.7 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 that began on September 1, 2010.

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.

#### 1.1.1.8 Generating Plant Efficiency Improvements to Reduce Energy Use

Empire is continually evaluating generating resource efficiency improvement opportunities in which it can reduce its overall auxiliary load at existing power plants to reduce its own use of energy. As described above, Empire's power supply portfolio is diverse in the type of power plants (such as coal, gas, and renewables). Potential improvement projects for reducing auxiliary loads are dependent on the type of power plant. Provided below are few examples of projects that provide opportunities for reducing the utility's own use of energy at existing power plants:

- On-line condenser cleaning system
- Intelligent soot blower controls
- Fabric filter modification
- Boiler feed pump/turbine rebuild
- Air Heater and duct leakage reduction

- DSC control neural network
- Dry FGD system modification
- Cooling tower advanced mist eliminators and heat transfer fill
- Economizer replacement
- Combined VFD and axial flow ID fan
- HP/IP/LP turbine overhaul

Several of the coal-fired power plants within Empire's power supply portfolio just underwent plant upgrades (such as Iatan 1 and Asbury) or are newly constructed (such as Iatan 2 and Plum Point). New coal plants are typically designed to reduce auxiliary load consumption in order to make the unit significantly more efficient. During upgrade projects (such as Iatan 1 and Asbury), utilities typically take the opportunity to implement additional efficiency projects. Due to the age of the newly constructed units and the recent upgrades at Iatan 1 and Asbury, it is anticipated that few plant efficiency projects remain that have not already been implemented.

Empire does not specifically operate all of the units within its power supply portfolio and does not control the improvements implemented at those plants. For the plants which Empire does operate, as part of its regular operations and maintenance program for the plants, Empire evaluates potential improvement projects. Below provides a list of the plant improvement projects that Empire has implemented over the years at its existing power plants:

- Plant Asbury: Increased insulation on exposed boiler and ductwork; upgraded feedwater heaters and lube oil coolers; upgraded forced draft fan rotors; and replaced motors with VFDs
- Plant Energy Center: Upgraded controls systems; replaced motors with VFDs

Empire will continue to explore cost effective generating plant efficiency improvements which reduce the utility's own use of energy in the future. The timing of these improvements may be better suited to correspond with the implementation of the Clean Power Plan in order to capture any potential carbon reductions that may result due to efficiency gains.

#### 1.1.1.9 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 long-term PPA for an additional approximate 50 MW of capacity on September 1, 2010.

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. Seventeen (17) 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.

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. Nineteen (19) 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.

#### 1.1.1.10 Retirements

*For the purposes of this IRP*, Empire assumed that Asbury 1 retires in 2035, Riverton 10 and 11 retire in 2033, Empire Energy Center 1 retires in 2023, and Empire Energy Center 2 retires in 2026. Under normal conditions, Empire has no further plans of retiring additional units. However, due to recent changes in environmental regulations, specifically the Clean Power Plan (which was stayed in February of 2016), retirement of some units may be accelerated depending on impact to current resources. For example, Plan 16 in this IRP considers an earlier retirement date for the Asbury unit in 2022 for planning purposes. The evaluation of retirements was considered within the resource planning process. 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.

#### 1.1.1.11 Emission Controls on Existing Units

Emission controls on existing units are described above in sections 1.1.1.1 through 1.1.1.7.

#### 1.1.1.12 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 are installed at the Iatan 1 unit. 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 installed at the Asbury 1 unit. Unit 1 is retrofitted with an SCR, scrubber, fabric filter, and a powder-activated carbon injection system. This AQCS project and steam turbine project was completed in 2015. Unit 2 was retired in 2013.

3. The conversion of Riverton 12 (a CT) to a CC unit is currently under construction and will be completed early to mid-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.

### 1.1.2 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. The conversion process is currently underway with a contractual in-service date of June 1, 2016.

### 1.1.3 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 13.6-percent reserve margin. This value was used as the minimum reserve margin value for capacity planning in this IRP. SPP's current reserve margin requirement has been in place since about 1998. SPP may review the required reserve margin level periodically, and it is possible that it could change at some point in the future.

### 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 2029 timeframe based on a summer peak, and the 2033 timeframe based on a winter peak. The summer peaking base load forecast for this IRP is shown in *Figure 4-2* and *Table 4-2*. The winter peaking base load forecast for this IRP is shown in *Figure 4-3* and *Table 4-3*. The following figures and tables do not account the implementation of new demand-side management measures. Winter capacity ratings for thermal generation resources are higher than summer capacity ratings.

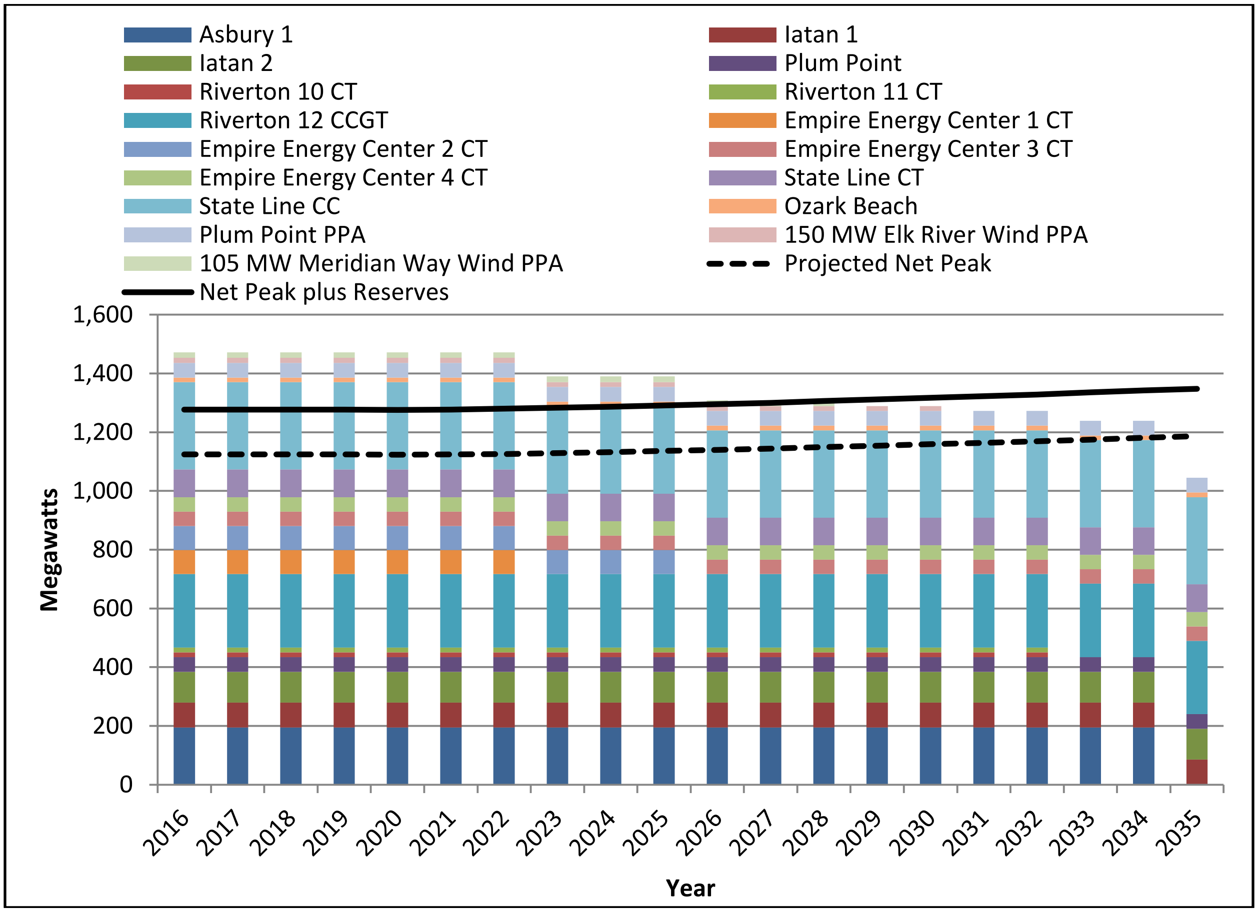


**Figure 4-2 - Summer Peaking Load and Capability Summary Chart**

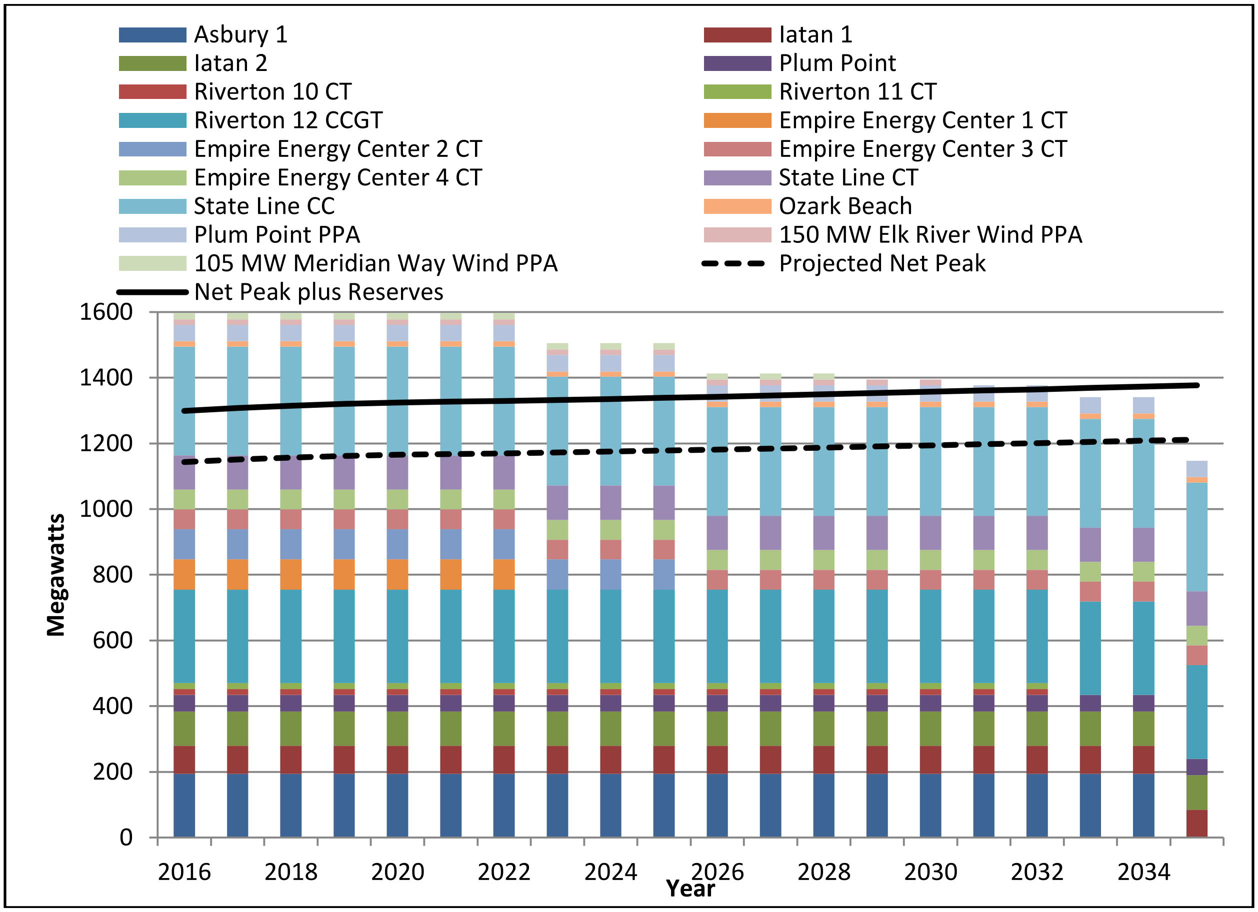


**Figure 4-3 - Winter Peaking Load and Capability Summary Chart**

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**Table 4-2 - Summer Peaking Load and Capability Summary Table**

**Highly Confidential in its Entirety**
**Table 4-3 - Winter Peaking Load and Capability Summary Table**

## 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 (with carbon capture and sequestration (CCS))
2. Simple cycle (Aero-derivative CT, E-class frame CT, F-class frame CT)
3. Combined cycle (unfired and fired)
4. Reciprocating engines
5. Small modular nuclear reactor
6. Distributed generation (microturbine and CHP)
7. Integrated gasification combined cycle (with CCS)
8. Traditional nuclear
9. Wind
10. Biomass (poultry waste)
11. Landfill gas (recip engine)
12. Utility scale solar PV
13. Battery storage

Each of the above options was screened assuming 100 percent ownership by Empire. While partial ownership or a PPA might offer advantages over full ownership, screening each option in this manner allows for a direct comparison of the different technologies.

## 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 and storage technologies.

| | Supercritical Coal | Combustion Turbine | | | Combined Cycle | |
|---|---|---|---|---|---|---|
| | With CCS | Aeroderivative CT | E-Class Frame-Type CT | F-Class Frame-Type CT | Unfired | Duct Fired |
| Availability Factor | 90.0% | 87.8% | 91.5% | 95.0% | 89.5% | 89.5% |
| ISO Net Output, Full Load kW | 425,000 | 46,400 | 90,100 | 213,700 | 346,000 | 441,800 |
| Full Load Net Heat Rate, Btu/kWh | 10,500 | 9,620 | 11,310 | 9,720 | 6,520 | 7,010 |
| Capital Cost, $/kW (2015 $) | 5,520 | 1,780 | 1,110 | 650 | 980 | 860 |
| Fixed O&M, $/kW-year | 31.90 | 31.70 | 15.83 | 7.30 | 12.26 | 12.26 |
| Variable O&M, $/MWh | 11.80 | 7.10 | 3.37 | 0.90 | 1.76 | 1.86 |

| | Reciprocating Engines | Small Mod. Nuke | Distributed Generation | | IGCC | Traditional Nuke |
|---|---|---|---|---|---|---|
| | | | Microturbine | Turbine CHP | With CCS | |
| Availability Factor | 97.1% | 83.0% | 99.0% | 95.0% | 80.0% | 83.0% |
| ISO Net Output, Full Load kW | 110,300 | 160,000 | 1,000 | 5,100 | 525,000 | 1,117,000 |
| Full Load Net Heat Rate, Btu/kWh | 8,350 | 10,130 | 6,510 | 4,790 | 10,500 | 10,130 |
| Capital Cost, $/kW (2015 $) | 1,230 | 4,130 | 4,700 | 5,690 | 7,450 | 5,470 |
| Fixed O&M, $/kW-year | 9.50 | 89.64 | 180.30 | 173.20 | 36.30 | 89.64 |
| Variable O&M, $/MWh | 3.00 | 1.38 | Included in FOM | Included in FOM | 17.10 | 1.38 |

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

| | Wind | Biomass | Landfill Gas | Solar | Battery Storage |
|---|---|---|---|---|---|
| | | Poultry Waste | Recip Engine | Photovoltaic | |
| Availability Factor | 95.0% | 90.0% | 91.8% | 98.0% | N/A |
| ISO Net Output, Full Load kW | 50,000 | 5,000 | 5,000 | 10,000 | 10,000 |
| Full Load Net Heat Rate, Btu/kWh | N/A | 14,100 | 10,500 | N/A | N/A |
| Capital Cost, $/kW (2015 $) | 2,020 | 5,890 | 4,200 | 2,410 | 4,370 |
| Fixed O&M, $/kW-year | 24.48 | 120.00 | 180.00 | 19.50 | 59.60 |
| Variable O&M, $/MWh | Included in FOM | 10.00 | 20.00 | Included in FOM | Included in FOM |

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

*Figure 4-4* through *Figure 4-7* 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 4-4*), intermediate load (*Figure 4-5*), peaking load (*Figure 4-6*), and intermittent load (*Figure 4-7*).

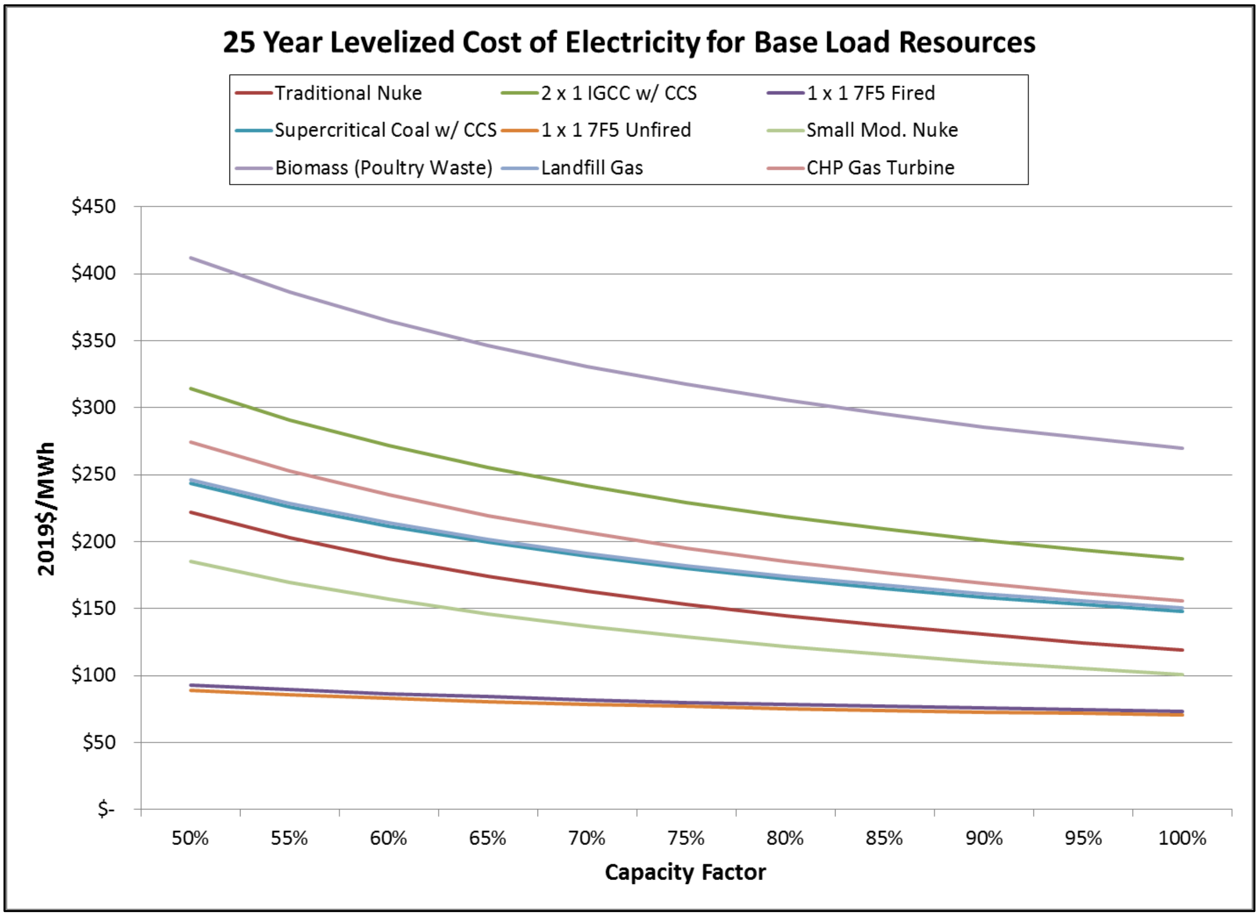


**Figure 4-4 - Levelized Busbar Costs Comparison for Potential Base Load Supply-Side Resource Options**

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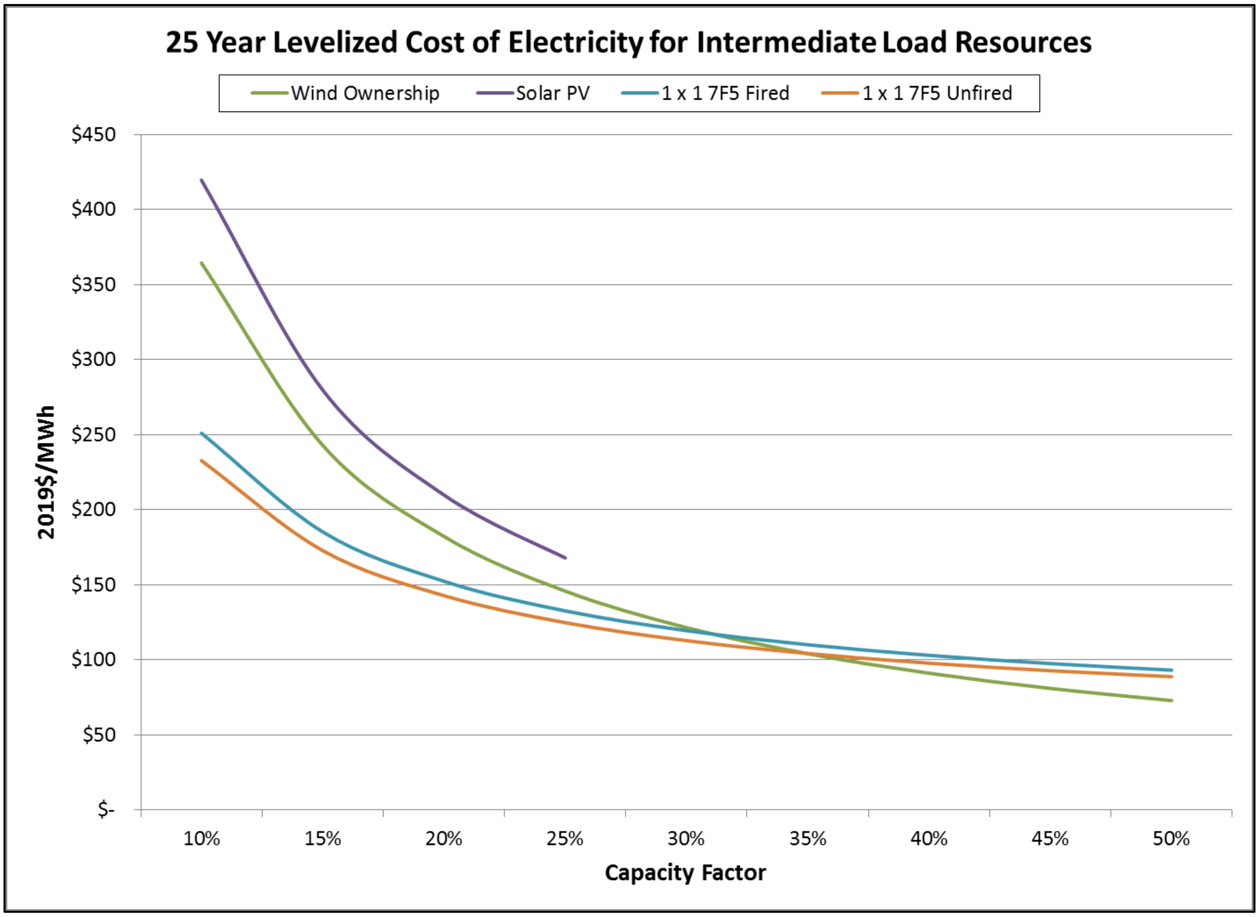


**Figure 4-5 - Levelized Busbar Costs Comparison for Potential Intermediate Load Supply-Side Resource Options**

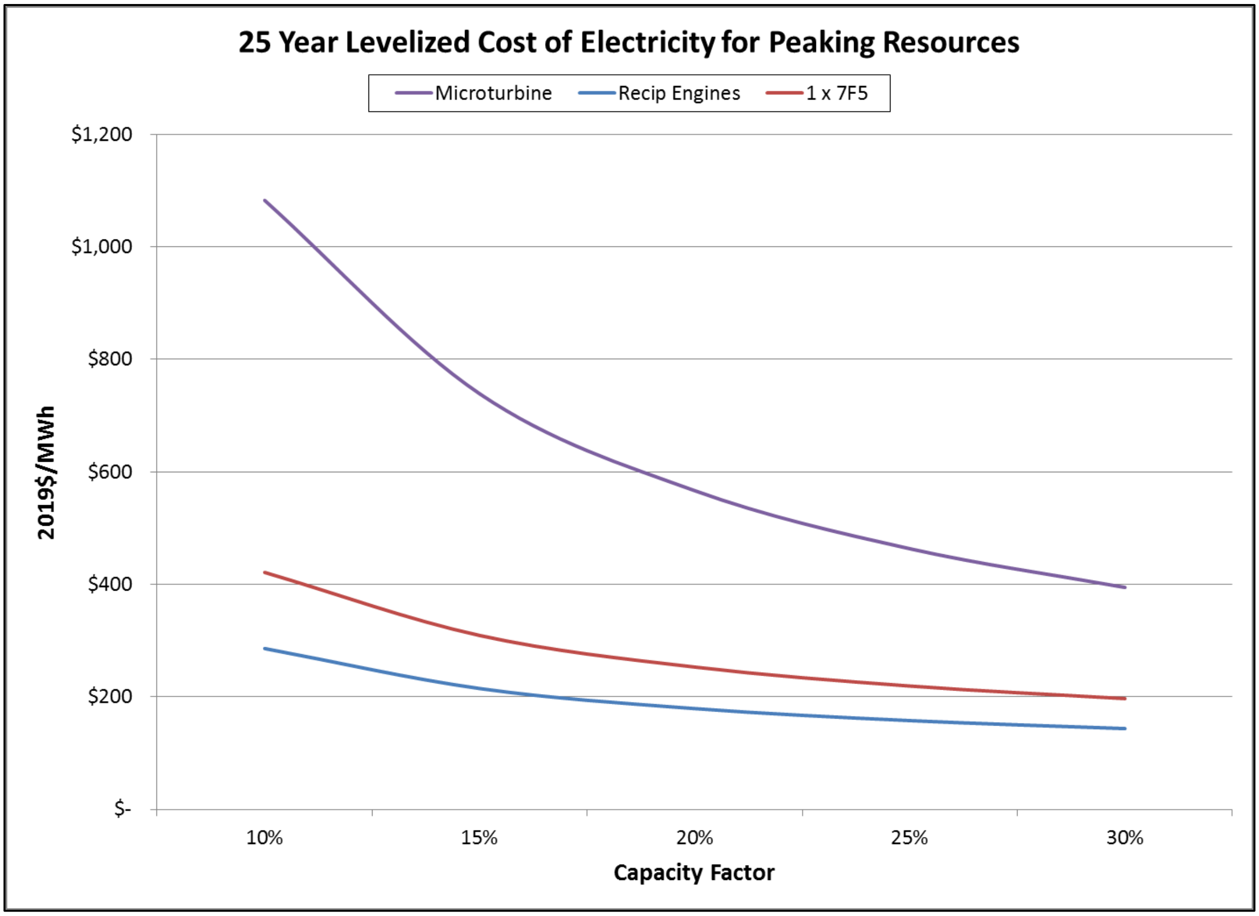


**Figure 4-6 - Levelized Busbar Costs Comparison for Potential Peaking Load Supply-Side Resource Options**

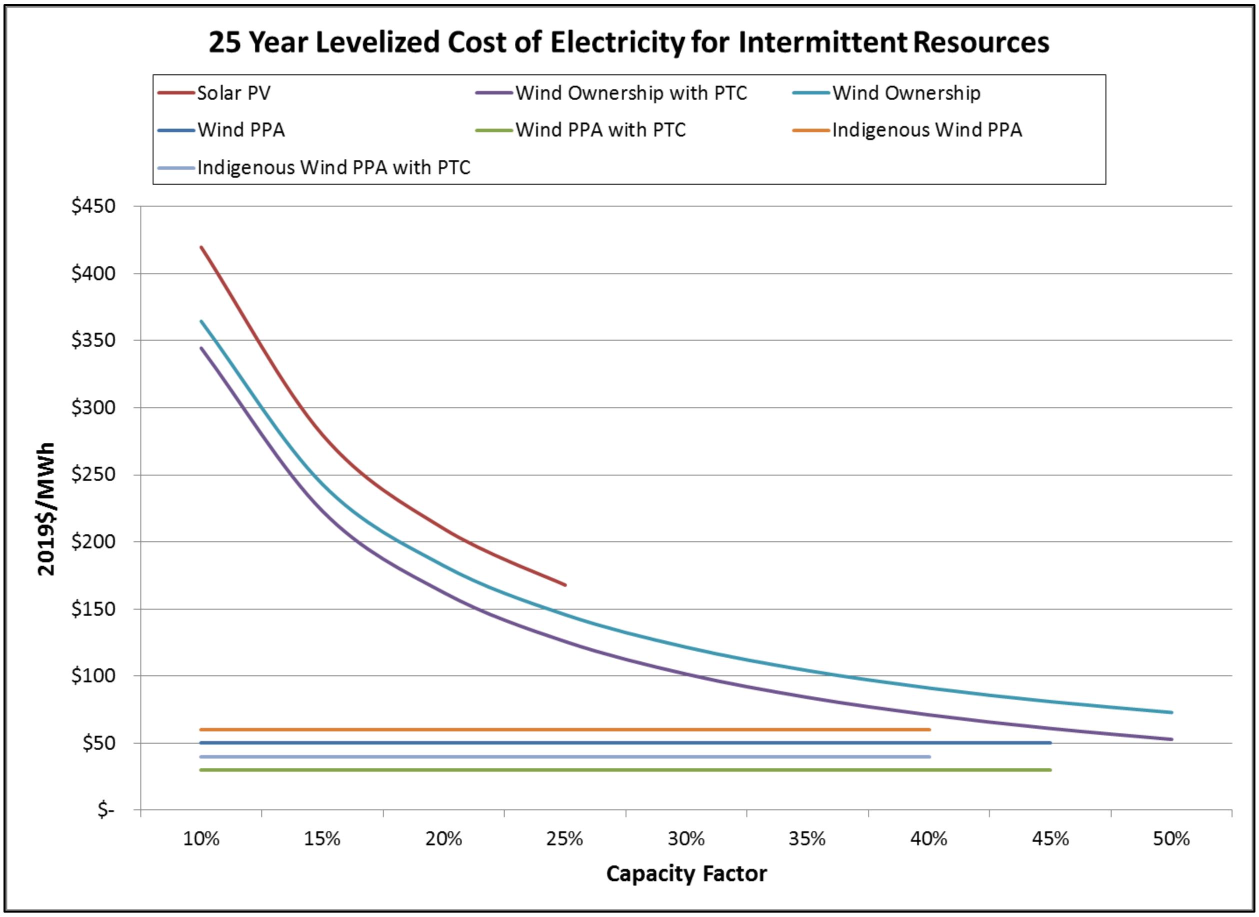


**Figure 4-7 - Levelized Busbar Costs Comparison for Potential Intermittent Load Supply-Side Resource Options**

## 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 (Clean Water Act Section 316(b))
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 (e.g., The Clean Power Plan (CPP))
6. Effluent Limit Guidelines (ELGs)
7. $SO_2$, $NO_2$, ozone, PM National Ambient Air Quality Standards (NAAQS)
8. Clean Water Act Section 316(a)

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

In order to comply with forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). The Mercury and Air Toxics Standards (MATS) and the Clean Air Interstate Rule (CAIR), replaced by the Cross State Air Pollution Rule (CSAPR), which is discussed further below, are drivers behind Empire's

Compliance Plan and its implementation schedule. The MATS requires reductions in mercury, acid gases and other emissions considered hazardous air pollutants (HAPS). The rule became effective in April 2012 and required full compliance by April 16, 2015. Empire is currently in material compliance with MATS, although the regulations have been remanded to the D.C. Circuit Court for further consideration (discussed below). The CSAPR was first proposed by the Environmental Protection Agency (EPA) in July 2010 as a replacement of CAIR and came into effect on January 1, 2015. Portions of CSAPR have been remanded back to EPA for further consideration. Empire is in material compliance with CSAPR. The Clean Power Plan requires a 32% carbon emission reduction from 2005 baseline levels by 2030 and requires fossil fuel fired power plants across the nation, including those in Empire's fleet, to meet state specific goals to lower carbon levels. On August 3, 2015, the EPA released the pre-published final rule; however in February of 2016 a stay of the pre-published final rule was issued by the US Supreme Court (discussed below).

This Compliance Plan largely follows the preferred plan presented in the most recent IRP filed in mid-2013 with the MPSC. The Compliance Plan called 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). This project was completed and the equipment placed in service in December 2014. The addition of this air quality control equipment required the retirement of Asbury Unit 2, a 14-MW steam turbine that was used for peaking purposes. Asbury Unit 2 was retired on December 31, 2013. In September 2012, Empire completed the transition of Riverton Units 7 and 8 from operation on coal and natural gas to operation solely on natural gas. Riverton 7 was permanently removed from service on June 30, 2014. Riverton Unit 8 and Unit 9 were retired June 30, 2015. Empire is converting Riverton Unit 12, a recently installed simple cycle CT, to a combined cycle unit. This conversion is currently scheduled for completion in 2016.

### 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 Empire's facilities for $SO_2$, PM, $NO_X$, $CO_2$ and hazardous air pollutants including mercury.

Since Empire's last IRP filing, CSAPR has been re-instated. Under the CSAPR Program, in Empire's most current five-year business plan (2015-2019), which assumes normal operation while maintaining compliance with permit conditions, Empire anticipates that it may be economically beneficial to purchase allowances for some of these pollutants, if needed, but at the time of this writing, the allowance markets have not been fully developed. Empire is currently in material compliance with CSAPR and Empire expects be able to meet all applicable, future CSAPR requirements.

As described above, the MATS rule required compliance by April, 2015. Following the completion of the Asbury Air Quality Control System (AQCS) project and the demonstration of continuous compliance as required by the regulation, Empire is in material compliance with MATS.

In June, 2015, the US Supreme Court remanded the MATS rule back to the D.C. Circuit Court, holding that the EPA must consider cost (including cost of compliance) before deciding whether regulation is appropriate and necessary. The court noted that it will be up to the EPA to decide within the limits a reasonable interpretation how to account for cost. MATS remains in effect until the D.C. Circuit Court acts. Accordingly, Empire and other entities subject to MATS must comply with its terms absent further relief granted.

On August 3, 2015, the EPA released the pre-published final rule for limiting carbon emissions from existing power plants. The CPP requires a 32% carbon emission reduction from 2005 baseline levels by 2030 and requires fossil fuel fired power plants across the nation, including those in Empire's fleet, to meet state specific goals to lower carbon levels. States will choose between a rate and mass based program. Furthermore, the state will use either an emission standards plan which includes source-specific requirements or a state measures plan which includes a mixture of measures implemented by the state.

By September 6, 2016, according to the pre-published final rule, each state must submit its initial plan with a request for an extension or a final plan to the EPA. If the state receives an extension, the final plan must be submitted by September 6, 2018. States will then implement plans to achieve the progressive $CO_2$ emissions over the period of 2022 to 2029 with the final $CO_2$ goal accountability by 2030. Empire continues to evaluate potential paths forward on the final rule released by the EPA. In February of 2016, a stay of the pre-published final rule was issued by the US Supreme Court. The timeline above may be impacted based on the Court's findings.

On August 3, 2015, EPA also released a pre-published final rule for limiting carbon emissions from new, reconstructed, or modified fossil fuel fired sources. New fossil fuel fired combustion turbines and coal-fired unit will also have annual carbon limits on a lb/MW-hr or lb/MMBtu basis.

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, CSAPR, MATS, and NAAQS.

MATS, which is discussed below, regulates acid gases. This can require regulation of either Hydrochloric acid (HCl) or $SO_2$.

#### 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 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

The CAIR generally called for fossil fuel fired power plants greater than 25 MW to reduce emission levels of $SO_2$ and/or NOx in 28 eastern states and the District of Columbia, including Missouri, where Asbury Energy Center, State Line and Iatan Units No. 1 and No. 2 are located. Kansas was not included in CAIR and Riverton Plant was not affected. Arkansas, where Plum Point Plant is located, was included for ozone season NOx but not for $SO_2$. Empire was in full compliance with CAIR, which ended December 31, 2014.

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

CSAPR replaced CAIR beginning in 2015. The CSAPR requires 23 states to reduce annual $SO_2$ and NOx emissions to help downwind areas attain NAAQS for fine particulate matter. Twenty five states are required to reduce ozone season NOx emissions to help downwind states attain NAAQS for ozone. The CSAPR NOx annual program impacts Empire’s Missouri and Kansas units with the CSAPR NOx ozone season program impacts Empire’s units in Missouri and Arkansas.

The CSAPR divides the states required to reduce $SO_2$ into two groups. Both groups must reduce their $SO_2$ emissions in Phase I. Group 1 states, which include Empire's sources in Missouri and Arkansas, must make additional $SO_2$ reductions for Phase 2 in order to eliminate their significant contribution to air quality problems in downwind areas. Empire's units in Kansas are in Group 2 of the CSAPR $SO_2$ program. Empire's five year business plan anticipates that the system may not have sufficient allowances to cover emissions generated. If that is the case, Empire believes it may be economically beneficial to purchase allowances for compliance. Empire anticipates compliance costs associated with CSAPR or its subsequent replacement to be recoverable in the rates.

#### 2.2.1.1.4 Mercury Air Toxics Standard

As discussed above, MATS was remanded back to the D.C. Circuit Court for reconsideration. Until the Court decision, Empire must comply with its terms absent further relief granted. The original 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. On August 10, 2015, EPA finalized the Data Requirement Rule (DRR). Under this rule, facilities that emit 2,000 tons/year or more of $SO_2$ will be required to demonstrate compliance with the NAAQS through either air dispersion modeling or ambient air monitoring. Additionally, some facilities with emissions below 2,000 tons/year of $SO_2$ could also require NAAQS compliance if the state or

EPA believes their facility's dispersion characteristics raise the risk of non-compliance. By January 15, 2016, the states will be required to identify sources that will require an analysis. If a facility plans to demonstrate compliance by air dispersion modeling, that analysis will required completion by January 13, 2017. If monitoring is performed, it must begin by January 1, 2017 and be completed by early 2020. For facilities not complying with the NAAQS $SO_2$ standard, additional compliance requirements will be mandated. Based on 2014 $SO_2$ emissions, both Plum Point and Asbury Plants had $SO_2$ emissions above 2,000 tons/year. However, until the state develops their list of affected sources, it is unknown, what, if any facilities will be required to perform a NAAQS demonstration. Additionally, at this time, it is too early to determine what, if any additional compliance costs will be required

#### 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 CSAPR 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 Clean Air Interstate Rule (CAIR) program ended in 2014. Empire's facilities meet compliance with the CAIR program. The CAIR program was replaced by CSAPR beginning in 2015.

##### 2.2.1.2.2 Cross-State Air Pollution Rule

The CSPAR rule, which began in 2015, issues allowances to each of Empire's affected units. If emissions are greater than allowances, then Empire will be required to purchase allowances. At this time, it is unknown if Empire's CSAPR emissions will exceed allowances in 2015.

Although this is a new program, it is expected that allowances will be available and will be a cost effective compliance strategy, if required.

#### 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 December 17, 2014, the EPA proposed to lower the primary NAAQS for ozone designed to protect public health to a range between 65 and 70 parts per billion (ppb). A final standard is expected in October, 2015. The current standard is 75 ppb. Based on the current standard, Empire's service territory is in compliance with the standard. Empire believes the revised ozone could impact Empire's region but at this time, it is too early to determine what, if any, impact it would have on Empire's generation fleet.

### 2.2.1.3 Particulate Matter Emissions

Particulate Matter (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. In January, 2013, 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 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 standards could impact future major modifications and/or 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

The Clean Air Mercury Rule was ultimately replaced by the MATS rule in 2012.

#### 2.2.1.4.2 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.

Since the rule was finalized in 2012, numerous court cases were filed. One of the cases was heard by the U.S. Supreme Court. The court remanded MATS back to the D.C. Circuit Court to require cost to be part of the “appropriate and necessary” analysis performed by EPA. Empire is still subject to MATS unless the court rules otherwise. The MATS regulation of HAPs in combination with 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 2013 and 2014 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.

On August 3, 2015, the EPA released the pre-published final rule for limiting carbon emissions from existing power plants. The CPP requires a 32% carbon emission reduction from 2005 baseline levels by 2030 and requires fossil fuel fired power plants across the nation, including those in Empire's fleet, to meet state specific goals to lower carbon levels. States will choose between a rate and mass based program. Furthermore, the state will use either a emission standards plan with includes source-specific requirement impacting affected power plants or a state measures plan which includes a mixture of measures implemented by the state.

By September 6, 2016, each state must either submit to the EPA its initial plan with a request for an extension or final plan. If the state receives an extension, the final plan must be submitted by September 6, 2018. States will then implement plans to achieve the progressive $CO_2$ emissions over the period of 2022 to 2029 with the final $CO_2$ goal accountability by 2030. Empire continues to evaluate potential paths forward on the final rule released by the EPA. In February of 2016, a stay of the pre-published final rule was issued by the US Supreme Court. The timeline above may be impacted based on the Court's findings.

New fossil fuel fired units will be subject to annual emission limits. For a base loaded combustion turbine, the annual limit is 1,000 lb $CO_2$/MW-hr. For non-base loaded combustion turbines the annual limit is between 120 to 160 lb $CO_2$/MMBtu depending on the natural gas/fuel oil operating hours. A new coal-fired plant must meet an annual limit of 1,400 lb $CO_2$/MW-hr.

There are also $CO_2$ limits for modified or reconstructed units as well.

In addition to the new unit limits, a state can include an emissions cap for both new (sources commencing construction after January 8, 2014) and existing sources. At this time, it is unknown what the state programs will and will not include.

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.

The EPA proposal was introduced in June 2014 and the pre-published final version was unveiled on August 3, 2015 after Empire's IRP process was underway. Empire has attended CPP meetings in each of the states that it serves. However, at this time there are no state approved implementation plans in the states that Empire serves. Environmental uncertainty was discussed during Empire's pre-integration meeting with Missouri Stakeholders on November 20, 2015. During the November 20, 2015 Stakeholder discussions, it was agreed that CPP state and/or regional compliance plans are currently unknown, but, to move forward, Empire would need to make assumptions about the future to continue with the development of the 2016 IRP in order to meet its April 2016 IRP filing deadline. The annual update process and future triennial compliance filings could then be utilized to update environmental analyses as new information becomes known. Further, following the pre-integration meeting, on February 9, 2016, just months before Empire's 2016 IRP filing date, the U.S. Supreme Court issued a stay of the CPP in a 5-4 decision. Contributing to the uncertainty, the court's decision does not overturn the CPP, nor decide the legal merits of the challenges brought against the U.S. EPA for issuing the CPP. Rather, the court's decision stalls the implementation of the CPP while lawsuits challenging the legality of the plan are adjudicated by the D.C. Circuit Court of Appeals.

While there is much uncertainty surrounding the CPP timing and potential compliance, Empire did address environmental costs in its 2016 IRP filing. Although the CPP is unclear, based upon industry knowledge and where it seems likely states may be headed with respect to each state compliance plan from preliminary meetings, Empire modeled various carbon scenarios with some sensitivity around certain key aspects of the CPP.

As highlighted below, Empire modeled four future carbon cases and one alternate plan related to environmental compliance:

1. No carbon rule during the study period
2. Cap and Trade – Low allowance cost Case
3. Cap and Trade – Mid allowance cost Case
4. Cap and Trade – High allowance cost Case
5. Alternate Environmental Plan: Retire Asbury early in 2022 (Asbury's assumed retirement for other plans is 2035)

Along with a no carbon cost future, carbon allowance costs per ton were studied at three levels based on publicly available data from a CO2 price forecast published by Synapse Energy Economics, Inc., a research and consulting firm specializing in energy, economic and environmental topics. The annual CO2 price per ton, which is assumed to begin in year 2022, is shown in the table below.

| Year | 1<br>No<br>Carbon | 2<br>Synapse<br>Low | 3<br>Mid (based on EPA<br>BB) | 4<br>Synapse<br>High |
|---|---|---|---|---|
| 2022 | - | 19.84 | 26.84 | 33.84 |
| 2023 | - | 21.43 | 29.16 | 36.9 |
| 2024 | - | 23.07 | 31.57 | 40.07 |
| 2025 | - | 24.77 | 34.06 | 43.35 |
| 2026 | - | 26.53 | 37.77 | 49.01 |
| 2027 | - | 28.35 | 41.62 | 54.89 |
| 2028 | - | 30.23 | 45.61 | 60.98 |
| 2029 | - | 32.17 | 49.74 | 67.3 |
| 2030 | - | 34.19 | 54.01 | 73.84 |
| 2031 | - | 36.26 | 58.44 | 80.62 |
| 2032 | - | 38.41 | 63.02 | 87.64 |
| 2033 | - | 40.63 | 67.77 | 94.9 |
| 2034 | - | 42.92 | 72.67 | 102.42 |
| 2035 | - | 45.29 | 77.75 | 110.21 |

**Table 4-7 - CO2 $/Ton 2016 IRP Costs**

Empire will continue to monitor the status of the CPP and will provide updates in subsequent IRP filings to the extent any material changes have occurred.

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.

#### 2.2.1.6 Startup/Shutdown/Malfunctions (SSM)

In a petition filed by the Sierra Club in 2011 to EPA, they claimed that recent court decisions require EPA to review any state implementation plan (SIP) that exempts emission limits during SSM. EPA agreed with the Sierra Club, that most SIPs would need to be revised to exclude SSM emission exemptions. On May 22, 2015, EPA finalized an action requiring 36 states, including Missouri, Kansas and Arkansas, to revise their SIPS by November 22, 2016. It is unknown, what if any changes to Empire's current emissions will be required as a result of the new SIPs.

### 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 (now retired) 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.

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. Following a series of court approved delays; the EPA published the final rule on August 15, 2014 with an effective date of October 14, 2014. An industry coalition has filed an appeal of the rule in the Fifth Circuit and additional court challenges are expected. Empire expects the regulations to have a limited impact at Riverton given the retirements of Units 7 and 8. A new intake structure design and cooling tower will be constructed as part of the Unit 12 conversion at Riverton. Impacts at Iatan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. Iatan Unit 2 and Plum Point Unit 1 are covered by this regulation, but were constructed with cooling towers, the proposed Best Technology Available. Empire expects them to be unaffected or minimally affected 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.

On November 3, 2015, EPA finalized the Effluent Limit Guidelines. The rule requires control of units 50 MW or greater. The new limits addresses waste streams from FGD blowdown, fly ash transport water, bottom ash transport water, combustion residual leachate, non-chemical metal cleaning, and gasification wastewater. For FGD blowdown, best available technology is physical, chemical, and biological treatment of FGD streams. Numerical limits were set for Arsenic, Mercury, Selenium and Nitrates. Fly Ash Transport Water has a zero discharge standard, unless used as FGD scrubber makeup in which case any blowdown must meet the FGD discharge standards. Flue Gas Mercury Control Wastewater has a zero discharge standards. Bottom Ash Transport Water has a zero discharge standard, unless used as FGD scrubber makeup in which case any blowdown must meet the FGD discharge standards. Combustion Residual Leachate can continue to be discharged with existing best practicable control technology (BPT) limits for TSS and oil and grease. New sources, potentially including horizontal landfill expansions at sites that currently do not collect and/or discharge leachate, would be subject to new source performance standards including arsenic and mercury limits on the discharge of this wastewater. For Nonchemical Metal Cleaning Wastewater, EPA has reserved the right to add limits on this waste stream in the future but is encouraging state permit writers to evaluate each site on a case by case basis to establish appropriate limits. Gasification Wastewater has new limits on Arsenic, Mercury, Selenium and Total Dissolved Solids imposed on discharges.

Facilities will be required to meet the new limits as soon as practicable which would be defined as between November, 2018 to December, 2023. The timeframe will depend on the state review process.

Impacts to the facilities have not been quantified at this time. Since the rule was just published in the Federal Register, additional time will be required to address what, if any impacts the rules will have on the facilities.

### 2.2.3 Coal Combustion Residuals

On April 17, 2015, the EPA published the final rule to regulate the disposal of coal combustion residuals (CCRs) as a non-hazardous solid waste under subtitle D of the Resource Conservation and Recovery Act (RCRA). Empire expects compliance to result in the need to construct a new landfill and conversion of existing bottom ash handling from a wet to a dry system at a potential cost of up to $15 million at Empire's Asbury Power Plant. This preliminary estimate was developed before the rule was finalized and will be updated to conform to the final rule. Empire also has a $5.5 million asset retirement obligation for the pond closure costs. Empire expects resulting costs to be recoverable in the rates. Final closure of the existing ash impoundment, for which an asset retirement obligation of $4.4 million has been recorded for Empire's interest in the coal ash impoundment at the Iatan Generating Station, has been accounted for in Empire's ARO.

Empire has received preliminary permit approval in Missouri for a new utility waste landfill adjacent to the Asbury plant. Empire's Detailed Site Investigation (DSI) has been completed and was submitted to MDNR for review and approval in on January 21, 2015. Receipt of the final construction permit for the waste landfill is expected in late 2016 or 2017. The Riverton ash landfill was closed in place prior to the deadlines contained within the rule and will not be under the purview of the new CCR regulations. The Riverton landfill was closed and approved under KDH&E regulations.

## 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, are listed in Section 1.2. The costs are shown in *Table 4-4* and *Table 4-5*, and comparison busbar costs are shown in *Figure 4-4* through *Figure 4-7*.

### 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.*

The list of potential supply-side resource options, both conventional and renewable, are listed in Section 1.2. The costs are shown in *Table 4-4* and *Table 4-5*, and comparison busbar costs are shown in *Figure 4-4* through *Figure 4-7*.

## 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 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 footprint. That cost allocation varies per line.

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 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.

Currently 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 six-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 footprint 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 2016 IRP, Empire did assign transmission costs on a $/kW basis for each candidate resource examined in this IRP. The cost was $62.98/kW in 2016 dollars, escalating at 2.5 percent per year.

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

Since not all of Empire's planned construction projects are accounted for in the STEP, details from Empire's 2016 to 2020 Construction Budget for planned transmission and distribution projects are presented in Appendix H to Volume 4.5 of this IRP. Empire's 2016 to 2020 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 4-8*, Empire's total system losses have decreased over time; its 2015 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 | 7.3 | 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 |
| 2012 | 4,914,783 | 318,528 | 6.48 | 7.26 |
| 2013 | 4,966,280 | 348,358 | 7.01 | 7.19 |
| 2014 | 5,030,148 | 340,802 | 6.78 | 7.04 |
| 2015 | 3,410,519 | 237,222 | 6.96 | 6.93 |

**Table 4-8 - 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. There are no other new resources planned at this time.

## 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 coal, simple cycle combustion turbines, combined cycle combustion turbines, reciprocating engines, small modular nuclear reactors, distributed generation, integrated gasification combined cycle, and traditional nuclear.

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

For purposes of this IRP, only coal units with carbon capture and a sequestration (CCS) technology was considered for a potential resource candidate. CCS is the process of capturing waste $CO_2$ from large point sources, such as fossil fuel power plants, transporting it to a storage site, and depositing it where it will not enter the atmosphere, normally an underground geological formation. The aim is to prevent the release of large quantities of $CO_2$ into the atmosphere from fossil fuel use in power generation and other industries.

Pulverized Coal (PC) steam generators are characterized by the fine processing of coal for combustion in a suspended fireball. Coal is supplied to the boiler from bunkers that direct coal into pulverizers, which crush and grind the coal into fine particles. The primary air system transfers the pulverized coal from the pulverizers to the steam generator's low $NO_x$ burners for combustion. Two types of burner arrangements for pulverized coal units are wall fired and tangentially fired (T-fired). Wall fired burners are more common and involve multiple burners arranged in rows up the side of a boiler wall. In T-fired burner arrangements, rows of burners are located in the corners of a boiler. Each type of arrangement burns the coal in the middle elevation of the boiler in suspension. This is also referred to as a suspended fireball and, along with the fine coal particle size, is characteristic of pulverized coal combustion. PC technology is a mature and reliable energy production technology used around the world.

The steam generator produces high-pressure steam that expands in the steam turbine generator to produce electricity. A portion of the steam exits the turbine through extractions and flows to the feedwater heaters and may feed boiler feedwater pump turbines.

The power industry typically classifies conventional coal fired power plants as subcritical, supercritical, and ultra-supercritical based on the steam operating pressure. Subcritical units operate below the critical point of water, which is 3,208 psia and 705°F, supercritical units operate above the critical point of water. Ultra-supercritical units operate at even higher pressures or temperatures in order to increase efficiency. While efficiency is increased, higher grade and thicker materials must be used, which increase costs.

At pressures above the critical point of water, heat addition no longer results in the typical boiling process in which there is an exact division between steam and water. The fluid becomes a composite mixture throughout the heating process. Due to the increased steam pressures and temperatures, supercritical units are generally more efficient than subcritical units of the same size resulting in fuel savings and decreased emissions.

Most modern coal PC plants are operated at supercritical steam conditions because of the efficiency and emissions improvements compared to subcritical plants. If PC technology is chosen as the best technology to further develop, a more detailed study shall be performed to evaluate the optimal steam cycle.

Evaluations have shown that there are technical and economic constraints to supercritical PC unit minimum size. Units near 400 MW and below typically incur undesirable tube velocities and require prohibitively expensive materials to handle stress and erosion issues. The PC plant evaluated for this assessment is a supercritical unit with carbon capture capability. The addition of carbon capture technology is expected to reduce the net output by approximately 15 percent. It is assumed that the unit will burn Powder River Basin (PRB) coal and reject heat with wet cooling towers. Units in this size range would typically consist of one boiler and one steam turbine.

Proposed greenhouse gas (GHG) regulations will limit $CO_2$ emissions to 1,400 lbs/MWh, a level which would require carbon capture on PC plants or co-firing. Carbon capture on PC plants has been demonstrated in the field, and as the technologies mature, they will likely become more technically and financially feasible, especially if markets emerge for the captured gases.

The PC plant in this assessment includes $CO_2$ capture using the advanced amine process. The advanced amine process is an enhancement on the Monoethylamine (MEA) process that was developed over 60 years ago, and has been adapted to treat flue gas streams for $CO_2$ capture. Other organic chemicals belonging to the family of compounds known as “amines” are now being used to reduce cost and power consumption as compared to the traditional MEA solvent.

In the advanced amine process, a continuous scrubbing system is used to separate $CO_2$ from the flue gas stream. The system consists of two main elements: an absorber where $CO_2$ is removed from the flue gas and absorbed into an amine solvent, and a regenerator (or stripper), where $CO_2$ is released (in concentrated form) from the solvent and the original solvent is then recovered and recycled. Cooled flue gases flow vertically upwards through the absorber countercurrent to the absorbent (amine in a water solution, with some additives). The amine reacts chemically with the $CO_2$ in the flue gas to form a weakly bonded compound, called carbamate. The scrubbed gas is then washed and vented to the atmosphere. The $CO_2$-rich solution leaves the absorber and passes through a heat recovery exchanger, and is further heated in a reboiler using low-pressure steam. The carbamate formed during absorption is broken down by the application of heat, regenerating the sorbent and producing a concentrated $CO_2$ gas stream. The hot $CO_2$-lean sorbent is then returned to the opposite side of the heat exchanger where it is cooled and sent back to the absorber. Fresh reagent is added as make up for losses incurred in the process.

#### 4.1.1.2 Simple Cycle Technologies

A simple cycle gas turbine (SCGT) plant utilizes natural gas to produce power in a gas turbine generator. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Also, gas turbine manufacturers continue to develop high temperature materials and cooling techniques to allow higher firing temperatures of the turbines, resulting in increased efficiency.

Typically, SCGTs are used for peaking power due to their fast load ramp rates and relatively low capital costs. However, the units have higher heat rates compared to combined cycle and coal-fired technologies. SCGT generation is a widely used, mature technology.

Typical simple cycle plants operate with natural gas as the operating fuel. Often, the ability to operate on fuel oil is also required in case the demand for power exists when the natural gas supply does not. This assessment does not include dual fuel capability as an option for any technologies.

Evaporative coolers are often used to cool the air entering the gas turbine by evaporating additional water vapor into the air, which increases the mass flow through the turbine and therefore increases the output. Evaporative coolers are included as an optional component on all SCGT technologies in this assessment.

While this is a mature technology category, it is also a highly competitive marketplace. Manufacturers are continuously seeking incremental gains in output and efficiency while reducing emissions and onsite construction time. Frame unit manufacturers are striving to implement faster starts and improved efficiency. Advances in combustor design allow improved ramp rates, turndown, fuel variation, efficiency, and emissions characteristics. Aeroderivative turbines also benefit from the R&D efforts of the aviation industry, including advances in metallurgy and other materials. Aeroderivative gas turbine technology is based on aircraft jet engine design, built with high quality materials that allow for increased turbine cycling. The output of commercially available aeroderivative turbines ranges from less than 20 MW to approximately 100 MW in generation capacity. In simple cycle configurations, these machines typically operate more efficiently than larger frame units and also exhibit shorter ramp up and turndown times, making them ideal for peaking and load following applications. Aeroderivative units typically require fuel gas to be supplied at higher pressures (i.e. 675 psig to 960 psig for many models) than more traditional frame units.

Aeroderivative turbines are considered mature technology and have been used in power generation applications for decades. These machines are commercially available from several vendors, including General Electric (GE), Siemens, Rolls Royce, and Mitsubishi-owned Pratt & Whitney. This assessment bases aeroderivative performance estimations on the GE LM6000 turbine, which is well-established in the marketplace.

Frame engines are industrial engines, more conventional in design, that are typically used in intermediate to baseload applications. In simple cycle configurations, these engines typically have higher heat rates when compared to aeroderivative engines. The smaller frame units have simple cycle heat rates around 11,000 Btu/kWh (HHV) or higher while the largest proposed units will have heat rates approaching 9,250 Btu/kWh (HHV). However, frame units have higher exhaust temperatures (≈1,100°F) compared to aeroderivative units (≈850°F), making them more efficient in combined cycle operation because exhaust energy is further utilized. Frame units typically require fuel gas at lower pressures than aeroderivative units (i.e. ~500 psig).

Frame engines are offered in a large range of sizes by multiple suppliers, including GE, Siemens, Mitsubishi, and Alstom. Commercially available frame units range in size from approximately 50 MW up to 350 MW. This assessment evaluates "E-Class" and "F-Class" frame options, based on the representative GE turbines.

#### 4.1.1.3 Combined Cycle Technologies

The basic principle of the Combined Cycle Gas Turbine (CCGT) plant is to utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the gas turbine to produce steam in a heat recovery steam generator (HRSG). This steam is then used to drive a steam turbine and generator to produce electric power. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing. The heat rate will increase during duct fired operation, though this incremental duct fired heat rate is generally less than the resultant heat rate from a similarly sized SCGT peaking plant.

The use of both gas and steam turbine cycles (Brayton and Rankine) in a single plant to produce electricity results in high conversion efficiencies and low emissions. Combined cycle facilities have efficiencies typically in the range of 52 percent to 58 percent on an LHV basis. Gas turbine manufacturers continue to develop high temperature materials to raise the firing temperature of the turbines and increase the efficiency. They are also developing cooling techniques to allow higher firing temperatures.

#### 4.1.1.4 Reciprocating Engine Technologies

The reciprocating, or piston, engine operates on the four-stroke Otto cycle for the conversion of pressure into rotational energy. Fuel (No. 2 fuel oil or diesel) and air are injected into a combustion chamber prior to its compression by the piston assembly of the engine. A spark ignites the compressed fuel and air mixture causing a rapid pressure increase that drives the piston downward. The piston is connected to an offset crankshaft, thereby converting the linear motion of the piston into rotational motion that is used to turn a generator for power production. By design cooling systems are typically closed-loop, minimizing water consumption. Emission control is generally accomplished via lean cycle combustion through fuel to air ratio control, although traditional secondary control options are available, such as SCR equipment.

Many different vendors, such as Wärtsilä, Fairbanks Morse, Caterpillar, Kawasaki, Mitsubishi, etc. offer reciprocating engines and they are becoming popular as a means to follow wind turbine generation with their quick start times and operational flexibility. There are slight differences between manufacturers in engine sizes and other characteristics, but all largely share the common characteristics of quick ramp rates and quick start up.

The Wärtsilä 18V50SF (single fuel) reciprocating engine was evaluated in this assessment as potential candidate for a peaking facility. The Wärtsilä 18V50SF engine can achieve stable, high efficiency across the ambient range. These heavy duty, medium speed, four-stroke combustion engines are easily adaptable to grid-load variations, such as wind and solar generation fluctuation.

#### 4.1.1.5 Small Modular Nuclear Technology

Manufacturers are designing small modular reactors (SMR) to create a smaller scale, completely modular nuclear reactor. These modular reactors are on the order of 30 feet in diameter and 300 feet high. The conceptual technologies are similar to advanced pressurized water reactors

(APWR), and the entire process and steam generation is contained in one, modular vessel. The steam generated in this vessel is then tied to a steam turbine for electric generation.

According to these manufacturers, the benefit of these SMRs is two-fold: the smaller unit size will allow more resource generation flexibility and the modular design will reduce overall project costs while providing increased benefits in the areas of safety, waste management, and the utilization of resources. Due to the design's modularity, most of the fabrication is planned to be done in the manufacturing facility before the vessel is shipped to the site. The goal is to reduce field labor and construction schedule.

This assessment includes the evaluation of a 160 MW SMR facility, based on current designs supported by government grants. Currently, SMRs are considered conceptual in design and are developmental in nature. Several manufacturers have completed conceptual design of these modular units to target lower output and costs, and are in various stages of permitting applications with the Department of Energy. However, there is currently no industry experience with developing this technology outside of the conceptual phase. Therefore, the information provided in this assessment for the SMR option is based on feedback and initial indications from SMR manufacturers.

#### 4.1.1.6 Distributed Generation Technologies

Combined Heat and Power (CHP) technology is used in a variety of applications where host facilities see an efficiency, cost, or reliability advantage from CHP over purchasing power from their utility and meeting their thermal needs through on-site generation. CHP allows the facility to meet all or part of their thermal and electric needs through a single fuel source. A CHP system consists of a prime mover, generator, heat recovery and electrical interconnection. Typical prime movers used in CHP systems include reciprocating internal combustion engines, combustion turbines, microturbines, or fuel cells. A generator coupled to the prime mover produces electric power that serves the host facility's power demand. The hot exhaust from the prime mover is recovered and used to serve the host facility's thermal demand. This can be in the form of steam for process use, building heating, or building cooling in the summer. The electrical distribution system is interconnected to the utility which provides the balance of the facilities electric load and serves as a back-up power source.

CHP plants offer an efficiency benefit compared to simple cycle units of comparable size. In addition to the electrical output, the work from the exhaust energy is also produced with the same amount of inlet fuel.

A Solar turbine was selected as the representative technology for the 5 MW CHP option. Currently Solar turbines have over an 80 percent market share for this size range, and have historically been selected the most frequently for CHP projects utilizing combustion turbine technology as the prime mover. However, other OEMs also provide turbines in this size range that can be competitive. Reciprocating engines are also used in a variety of CHP applications as a substitute to gas turbines. A reciprocating engine offers better simple cycle efficiency, but less exhaust energy for steam production. A reciprocating engine selection may make sense in an application where the facility has higher electrical demand relative to its thermal demand.

#### 4.1.1.7 Integrated Gasification Combined Cycle Technology

The Integrated Gasification Combined Cycle (IGCC) technology produces a low calorific value synthesis gas (syngas) from coal that can be fired in a combined cycle power plant. The gasification process itself is a proven technology used extensively for chemical production of products such as ammonia for fertilizer. Integrating proven gasifier technology with gas turbine combined cycle technology is fairly new and continues to improve with additional project experience. There are currently six IGCC plants that have either been built, are in construction, or are in the development phase within the United States. Summit Power – Texas Clean Energy Project and Hydrogen Energy California are in the development stages, Mississippi Power – Kemper Co. is under construction, and Duke Energy – Edwardsport, Tampa Electric – Polk and Wabash Valley Power – Wabash River have been completed. IGCC is considered beneficial because it can remove certain pollutants prior to combustion resulting in lower emissions compared to other coal technologies.

Gasifiers designed to accept coal as a solid fuel generally fall into three categories: fluidized bed, moving bed, and entrained flow.

Fluidized bed reactors efficiently mix feed particles with coal particles already undergoing gasification. They accept a wide range of solid fuels including low rank coals with high moisture and ash content, but are not suitable for liquid fuels. The Kellogg-Brown-Root (KBR), Kellogg-Rust-Westinghouse (KRW), and High Temperature Winkler designs use fluidized bed technology.

In moving-bed reactors, large particles of coal move slowly down through the bed while reacting with oxygen moving up through the bed. Moving-bed gasifiers are also not suitable for liquid fuels. The Lurgi Dry Ash gasification process is a moving bed design used at both the Dakota Gasification plant for production of substitute natural gas (SNG) and the South Africa Sasol plant for production of liquid fuels. The BGL gasification process also includes a moving bed gasifier design.

The entrained flow gasifier reactor design converts coal into molten slag. This gasifier design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. GE, Phillips 66, Siemens, and Shell produce entrained flow gasifiers.

Pulverized coal in conjunction with oxygen from an air separation unit (ASU) feed into the gasifier at around 600 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exits at around 2400°F where it then cools to less than 400°F in a syngas cooler. The heat recovery process generates a large quantity of steam. Steam is used within the gasification block and for integration with the combined cycle power block, where additional power is produced by the steam turbine. Reliability issues associated with fouling and/or tube leaks within the syngas cooler have challenged existing IGCC installations. The syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system, typical of those utilized in chemical production gasifiers.

Upon exiting the syngas cooler, the syngas enters scrubbers which remove particulates, mercury, ammonia ($NH_3$), hydrogen chloride and other alkali components. Hydrogen sulfide ($H_2S$) is removed from the syngas stream by conventional acid gas removal (AGR) technologies, such as a SELEXOL scrubbing unit explained in the next section. The removed acid gas stream is processed in a sulfur recovery unit (SRU), such as a standard Claus unit, which produces elemental sulfur. The cooled, cleaned, sweet syngas flows into a modified combustion chamber of a gas turbine specifically designed to accept the low calorie syngas. Combustion in the turbine generates hot exhaust gas. This hot exhaust gas enters a heat recovery steam generator which recovers excess heat from the gas turbine exhaust to produce steam for the steam turbine and gasification process.

A benefit of IGCC is that $CO_2$ can be captured from the syngas leaving the gasifier before it is mixed with air in a combustion turbine. The $CO_2$ is relatively concentrated (50 percent volume) and at high pressure, offering the opportunity for a lower capture cost. $CO_2$ capture in an IGCC facility is accomplished by first shifting the syngas to convert CO and $H_2O$ into $CO_2$ and $H_2$. The $CO_2$ is then absorbed in the AGR unit, resulting in a hydrogen rich fuel.

Solvents such as SELEXOL and RECTISOL are typically used in the pre-combustion $CO_2$ capture process. The IGCC option in this study is evaluated utilizing the SELEXOL scrubbing process to accomplish pre-combustion carbon capture. The SELEXOL solvent is a dimethyl of ether and polyethylene glycol. It is a physical solvent selective to both $H_2S$ and $CO_2$ and therefore makes an excellent choice for the IGCC technology. In the AGR, the syngas is routed through both an $H_2S$ absorber and a $CO_2$ absorber. The $H_2S$ is removed from the solvent by heat, and the $CO_2$ rich solvent is run through flash tanks, where the $CO_2$ is released by reduction in pressure. The $CO_2$ is captured at relatively low pressure and temperature, so this evaluation assumes that compression is required. Additional treatment and drying of the $CO_2$ may be required for transportation and sequestration depending on the final purity requirements.

#### 4.1.1.8 Traditional Nuclear

In pressurized water reactors, water is heated by the nuclear fuel but the water is kept under pressure to prevent it from boiling. Instead, the hot water is pumped from the reactor pressure vessel to a steam generator. There the heat of the water is transferred to a second, separate supply of water, which boils to produce steam. The coolant in the advanced pressurized water reactor is contained in the pressurized primary loop and does not pass through the steam turbine. This plant will utilize a dual, spherical design containment building with larger maintenance areas. Also, greater redundancy and diversity will exist in the electrical distribution and support systems.

### 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) which currently requires Empire and other investor-owned utilities 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), in amounts equal to at least 5 percent of retail sales in 2014, increasing to at least 15 percent by 2021. Empire is currently in compliance with this regulatory requirement as a result of generation from Empire's Ozark Beach Hydroelectric Project and purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC. Proposition C also requires that 2 percent of the energy from renewable energy sources must be solar; however, Empire believed that it was exempt by statute from the solar requirement. On January 20, 2013 the Earth Island Institute, d/b/a Renew Missouri, and others challenged Empire's solar exemption by filing a complaint with the MPSC. The MPSC dismissed the complaint and Renew Missouri filed a notice of appeal seeking review by the Missouri Supreme Court. On February 10, 2015 the Missouri Supreme Court issued an opinion holding that the legislature had the authority to adopt the statute providing the exemption but reversed the MPSC's holding that the two laws could be harmonized. The statute providing the exemption (which was enacted in August 2008) was impliedly repealed by the adoption of proposition C because it conflicted with the latter law. On May 6, 2015, the MPSC approved tariffs Empire filed on May 5, 2015 to establish solar rebate payment procedures and revise Empire's net metering tariffs to accommodate the payment of solar rebates. As of December 31, 2015, Empire had processed 236 solar rebate applications resulting in solar rebate-related costs totaling approximately $3.5 million under the new tariff. Empire recorded the $3.5 million as a regulatory asset. The law provides a number of methods that may be utilized to recover the associated expenses. Empire expects any costs to be recoverable in rates.

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 4-9* 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 the entire 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 4-9 - Missouri Renewable Energy Standard Comparison**

#### 4.1.2.1.2 Kansas

Legislation was recently adopted that altered the Kansas renewable portfolio standard (RPS), ending all mandatory requirements in 2015. The mandate, which required 20 percent of Empire's Kansas retail customer peak capacity requirements to be sourced from renewables by 2020, has been changed to a voluntary goal. One of the reasons for the change is that Kansas utilities have certified that they are already meeting the 20 percent target. Empire is currently in compliance as a result of purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC.

#### 4.1.2.1.3 Oklahoma

Empire is not subject to the Oklahoma renewable energy goal since it does not own electric generating resources in 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.

**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's current contracts expire at the end of 2015. After expiration, Empire will commence annual bidding to renew the contracts. During tire collections, Empire has helped clean up over 32,800 tires in the service territory. To date approximately 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 2015, sufficient RECs, including hydro, were retired to comply with the Missouri requirement through the end of November 2015. Additional RECs were retired in January of 2016 to complete the process for 2015. In the future, Empire will continue to maintain a sufficient amount of RECs to meet any current or future RPS requirements.

#### 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 4-8* shows this typical wind turbine configuration.

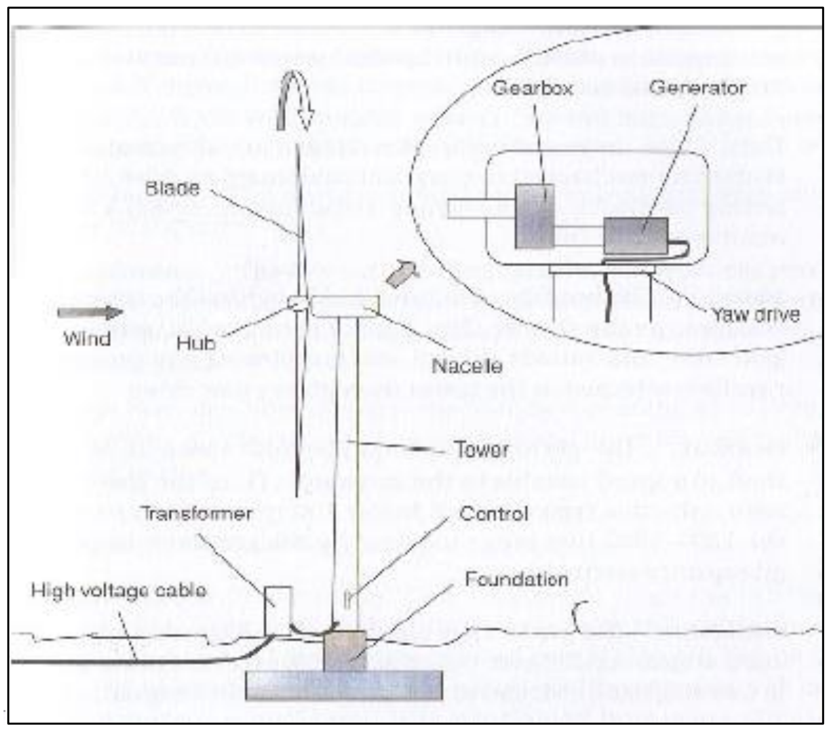


**Figure 4-8 - Wind Turbine Configuration**

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 2015 that the U.S. had 74,472 MW of installed wind energy capacity. The installed wind energy capacities by state, as reported by AWEA as of the end of 2015, are shown in *Figure 4-9*.

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

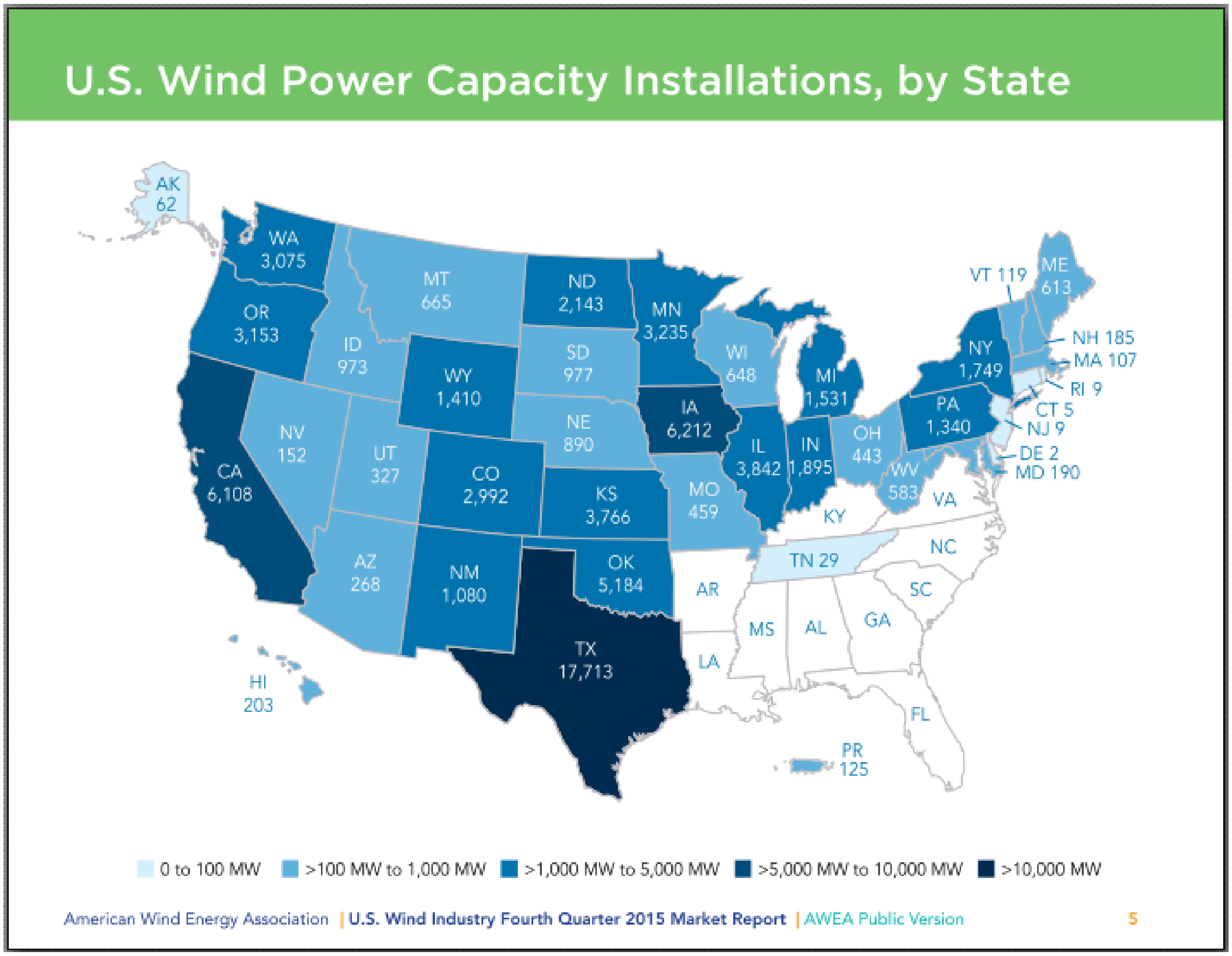


**Figure 4-9 - U.S. Wind Power Capacity Installation by State, 2015**

**Wind - Missouri**

The profile of wind resources shown on *Figure 4-10* **r**eveals 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. The resources that AWEA reports to be online in Missouri are shown in *Table 4-10*.

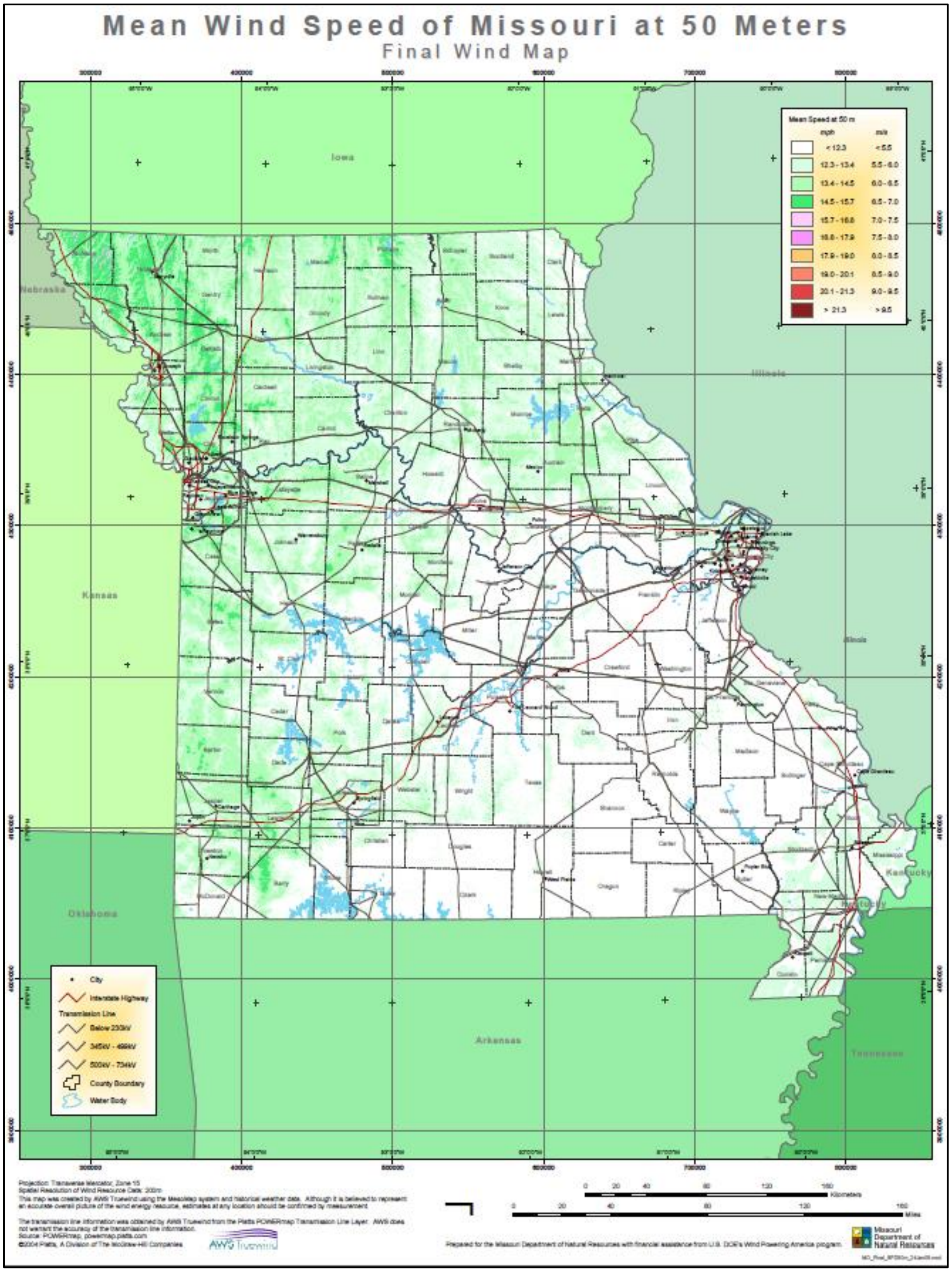


**Figure 4-10 - Wind Resources in Missouri**

| 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 4-10 - Wind Energy Projects in Missouri**

**Wind - Kansas**

The resource map in *Figure 4-11* shows the classes of wind resources in Kansas. The resources that AWEA reports to be online in Kansas are shown in *Table 4-11*. 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 (17 MW) and Meridian Way (19 MW). For purposes of planning in this IRP, 5 percent of the nameplate capacity of any new wind resource counts toward the capacity margin calculation for the first 3 years of its operation, based on SPP wind accreditation criteria. Then it is assumed to increase to 15 percent of its nameplate capacity for the remaining life of the wind farm.

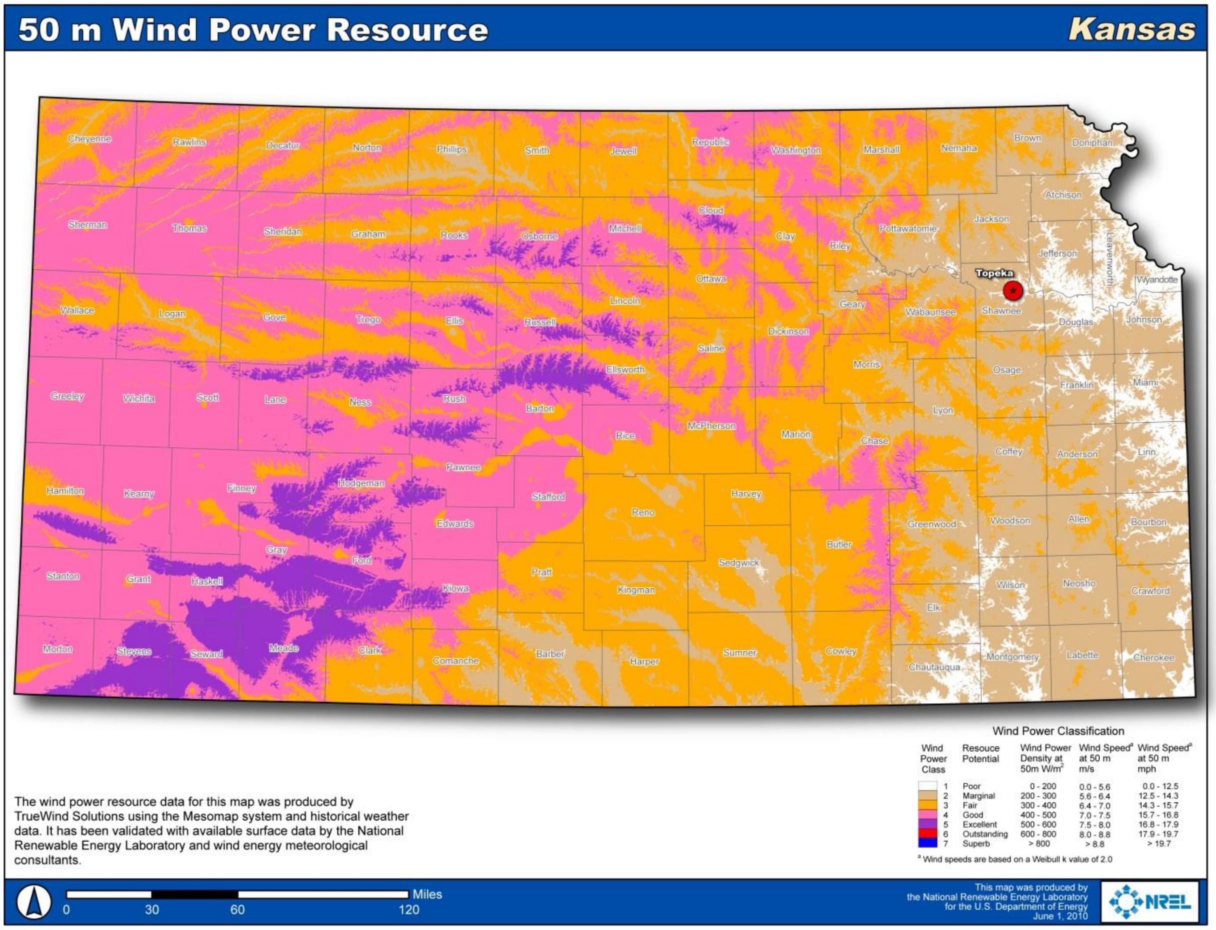


**Figure 4-11 - Kansas Wind Resource Map**

| 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 |
| 2013 | 4 | Fort Hays State University | Fort Hays State University | Fort Hays State University |
| 2014 | 250 | Buffalo Dunes | Tradewind Energy | Enel Green Power North America and Stamford, Conn.-based GE Energy Financial Services |
| 2015 | 72 | Marshall Wind | RPMA Access | Unknown |
| 2015 | 200 | Buckeye Wind | Invenergy | Unknown |
| 2015 | 400 | Western Plains | Infinity Wind Power | Unknown |
| 2016 | 200 | Ninnescah | NextEra Energy | Westar |
| 2015 | 49.5 | Alexander Wind | New Jersey Resources | Kansas City Board of Public Utilities |
| 2016 | 200 | Waverly Wind | EDP Renewables | Kansas City Power and Light |
| 2015 | 150 | Slate Creek Wind | EDF Renewables | Great Plains Energy |
| 2015 | 200 | Cedar Bluffs Wind | NextEra Energy | Unknown |

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

**Table 4-11 - 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 *Figure 4-12* shows the classes of wind resources in Oklahoma. The resources that AWEA reports to be online and under construction in Oklahoma are shown in *Table 4-12.*

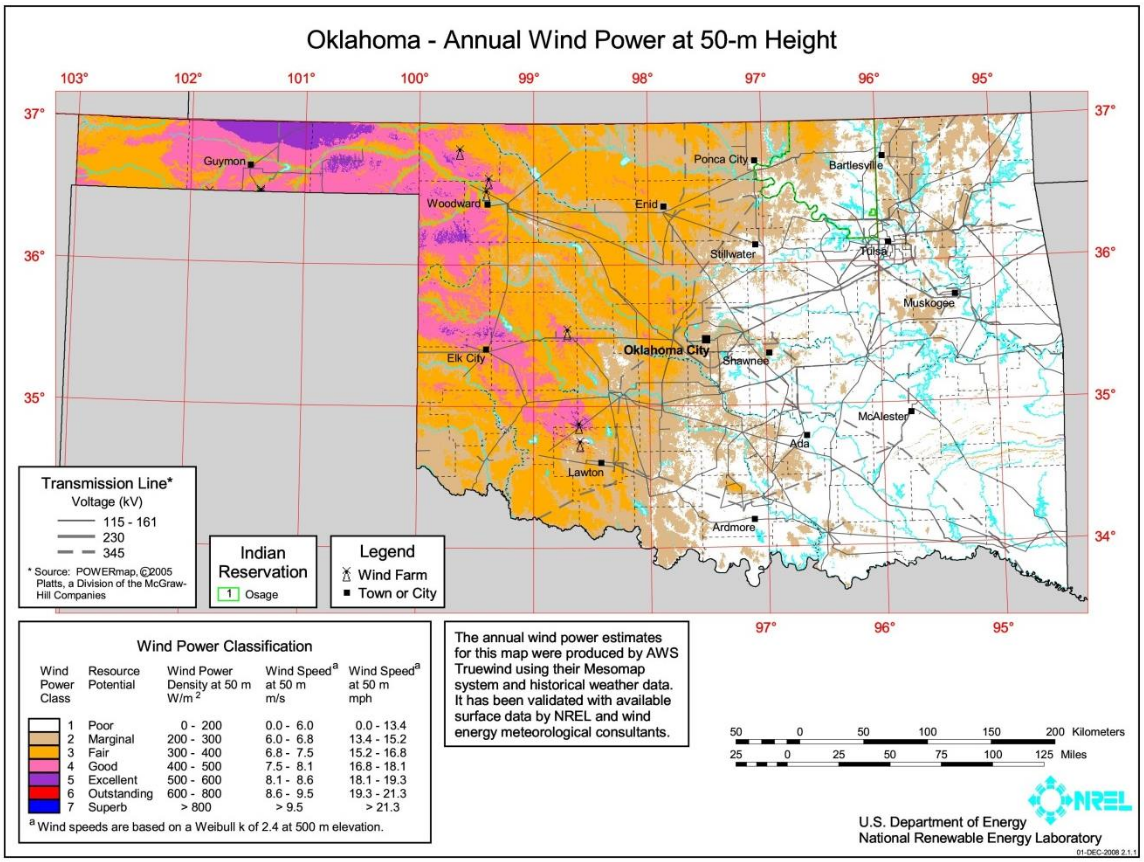


**Figure 4-12 - Oklahoma Wind Resource Map**

| Year of Operation | Size (MW) | Name | Developer | Utility Purchaser |
|---|---|---|---|---|
| 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 |
| 2012 | 80 | DeWind Novus | DeWind | Unknown |
| 2012 | 80 | DeWind Novus II | DeWind | Unknown |
| 2012 | 101 | Minco 3 | NextEra Energy Resources | Unknown |

| | | | | |
|---|---|---|---|---|
| 2015 | 150 | Osage County Wind | Tradewind Energy Enel Green Power | Associated Electric |
| 2014 | 150 | Origin | Enel Green Power | Arkansas Electric Cooperative |
| 2015 | 300 | Balko Wind | | Unknown |
| 2016 | 100 | Arbuckle Wind | Lincoln Electric | EDP Renewables |
| 2015 | 298 | Kindfisher Wind | Apex Clean Energy | Gulf Power |
| 2015 | 98 | Breckenridge | NextEra Energy | Grand River Dam Authority |
| 2015 | 200 | Goodwell | Tradewind Energy | Unknown |
| 2015 | 299 | Kay County Wind | Apex Clean Energy | Westar |
| 2016 | 150 | Grant Wind | Apex Clean Energy | Western Farmers, NTEC[3], and ETEC[3] |

[1]Now known as NextEra Energy Resources.
[2]Now known as EDP Renewables.
[3]Northeast Texas Electric Cooperative, Eastern Texas Electric Cooperative

**Table 4-12 - Wind Energy Projects in Oklahoma**

**Wind - Arkansas**

The resource map in *Figure 4-13* shows the classes of wind resources in Arkansas. 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.

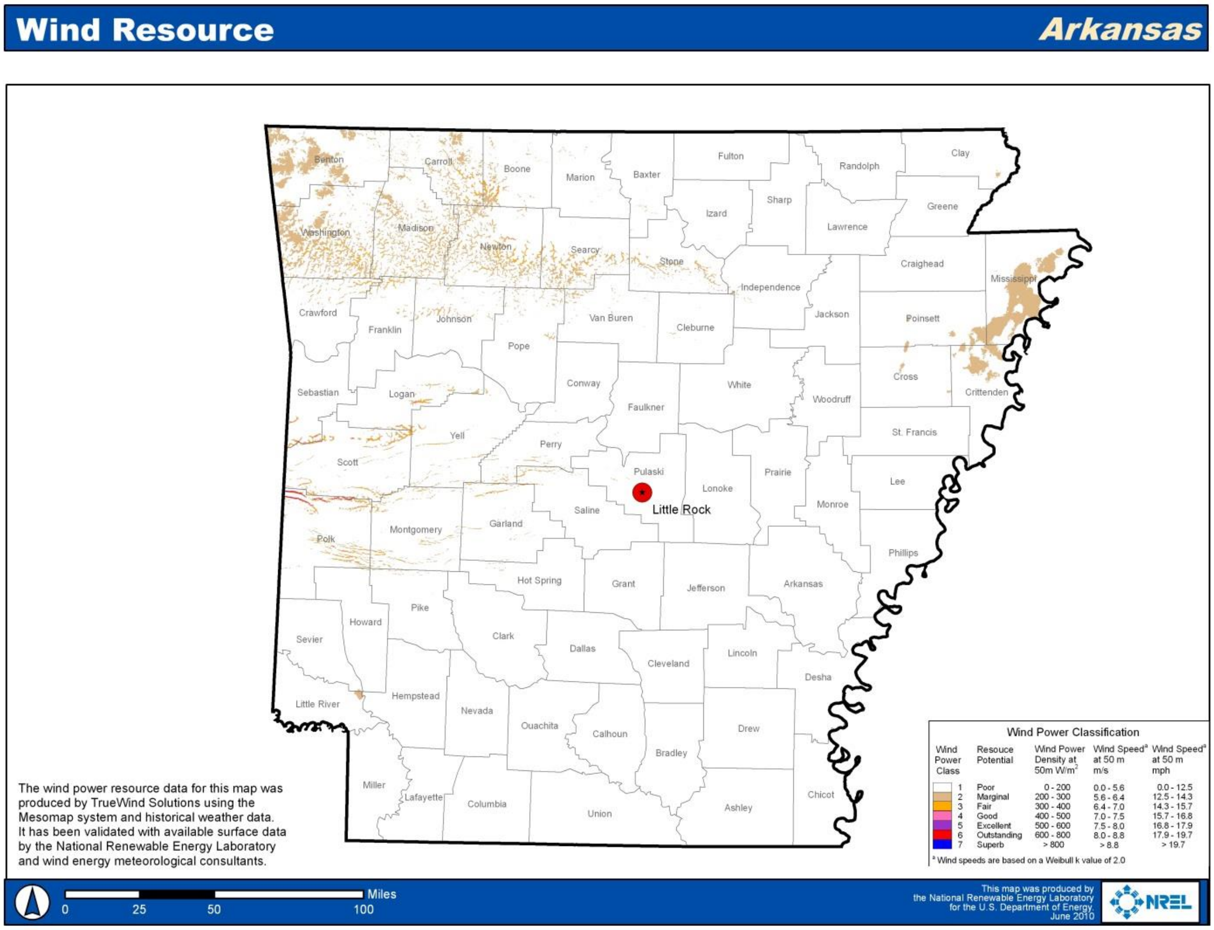


**Figure 4-13 - Arkansas Wind Resource Map**

#### 4.1.2.2.2 Biomass

Biomass electric generation is currently the third largest source of renewable energy behind hydroelectric and wind 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.

Biomass resources available in Missouri, as reported by the National Renewable Energy Laboratory, are shown on *Figure 4-14*. For the 16 counties[3] that comprise the Empire service territory, the biomass resource potential is quite small.

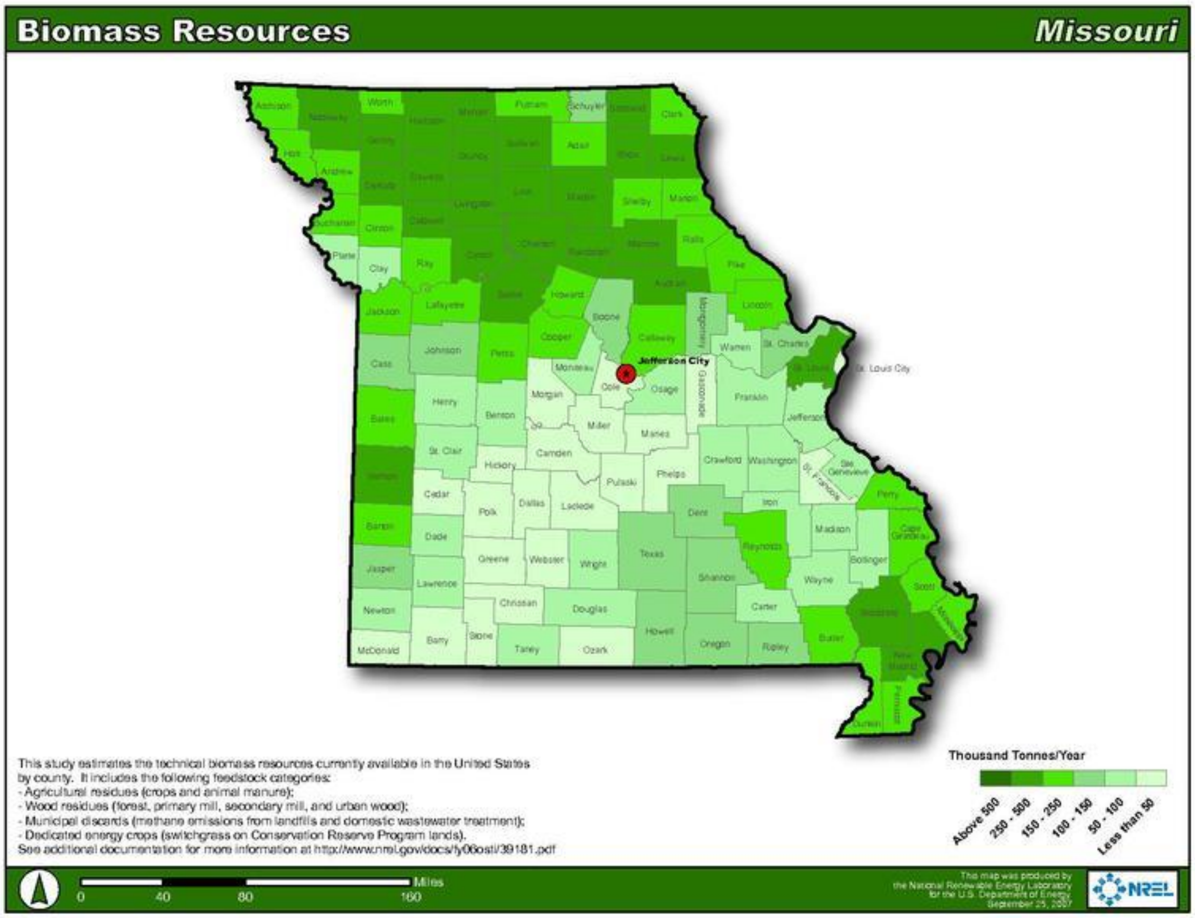


**Figure 4-14 - Biomass Resources in Missouri**

**Biomass - Chicken/Turkey Waste**

Poultry waste was analyzed as a form of biomass in Empire's territory. The assumptions used are presented in *Table 4-13*.

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

| Poultry Waste Assumptions | |
|---|---|
| Daily chicken manure output per 100 birds | 27 lbs |
| Heat rate of plant | 14,000 Btu/kW-hr |
| Waste heat capacity | 4,500 Btu/lb |
| Tons per year of waste required for 5 MW | 61,320 |
| Average number of chickens per farm in MO | 40,000 |
| Fuel cost in 2015$ | $6.05 |

**Table 4-13 - Biomass Poultry Waste Assumptions**

In order for Empire to receive 5 MW (at 90 percent capacity factor) of power from poultry waste it would require approximately 61,000 tons of litter. Industry research indicated that 100 birds collectively produce an average of 27 lbs of waste per day[4]. There are approximately 50 chicken farms within a 100 mile radius of Empire.[5] USDA's 2012 Census of Agriculture indicates that there are approximately 40,000 chickens in inventory per farm in the state of Missouri. Based on Empire's annual fuel needs to power a 5 MW unit, approximately 60 percent of all poultry waste within 100 miles would need to be procured. Poultry litter also has other uses, such as fertilizer applications, which may introduce competition for Empire to secure adequate supply. The cost of transporting the waste was assumed to be 40 cents per ton-mile and the overall cost was calculated based on coordinate data from Hoover Database. Although these results suggest that poultry waste as a form of energy is feasible, more investigation would be required to obtain exact pricing.

**Biomass - Landfill Gas**

The U.S. Energy Information Administration (EIA) describes landfill gas as follows[6]:

[4] "Poultry Manure Management And Utilization Problems And Opportunities," Ohio State University
[5] Source: Hoover Database
[6] "Landfill Gas," U.S. Department of Energy - Energy Information Administration, http://www.eia.doe.gov/cneaf/solar.renewables/page/landfillgas/landfillgas.html.

> 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 thrive 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.

All of the landfills in Empire's service territory already utilize landfill gas-to-energy projects, which limits Empire's opportunity to produce additional renewable energy utilizing landfill gas. *Figure 4-15* presents an illustration of a modern landfill. *Figure 4-16* demonstrates the landfill gas energy potential for the state of Missouri.

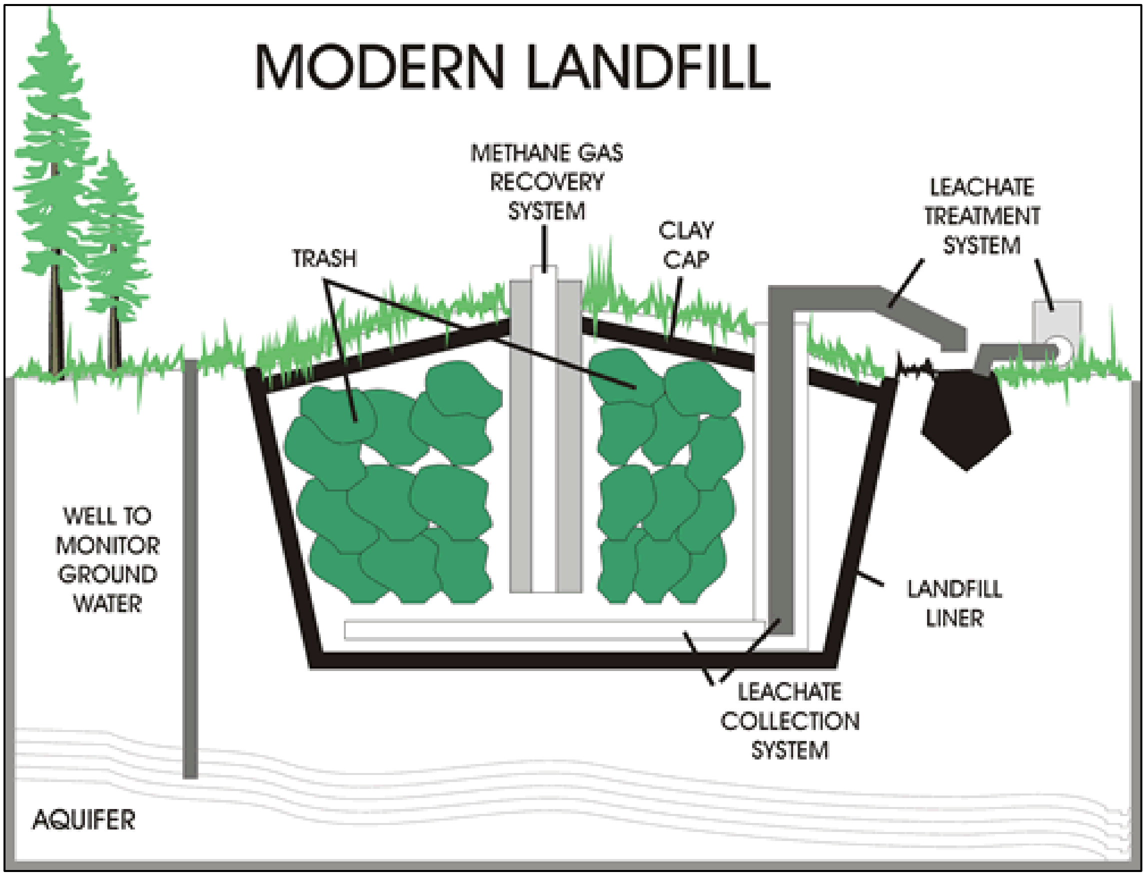


**Figure 4-15 - Modern Landfill**[7]

[7] Source: The National Energy Education Project

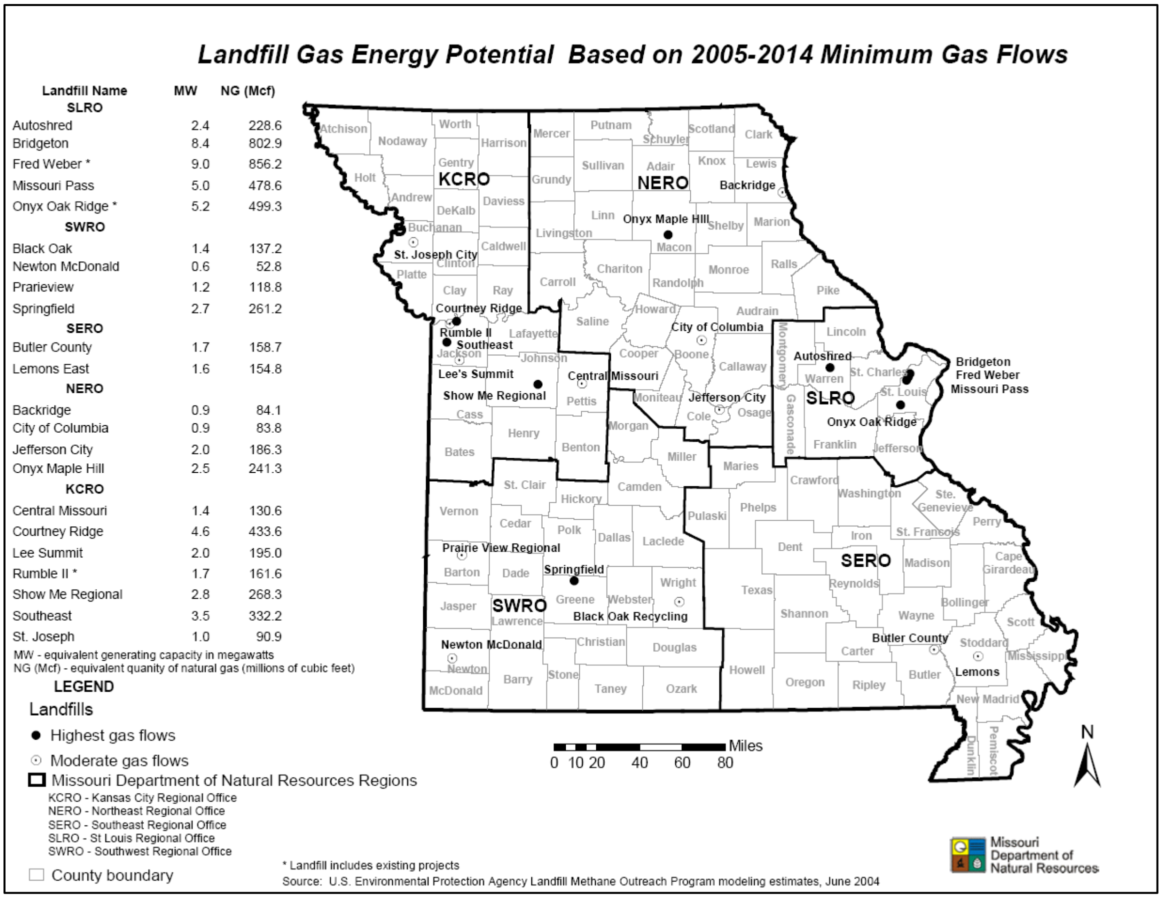


**Figure 4-16 - Landfill Gas Energy Potential**
**Based on 2005-2014 Minimum Gas Flows**

## Biomass - Additional Biomass

Additional biomass has been interpreted by Empire to mean wood waste, agricultural crops and waste, and municipal solid waste. The U.S. Department of Energy - EIA reports that wood waste from forest or 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. Biomass fuels can come from agriculture sources that include both dedicated crops, such as switchgrass, or from crop residuals leftover from primary farming, such as corn waste. Municipal solid waste (garbage) can be sorted and the combustible products that are not recycled can be used to generate electricity. The biomass fuels described above can be utilized in a variety of operations including both stand-alone boilers designed for 100 percent biomass fuel and scenarios in which coal is the primary fuel and the biomass fuel is co-fired. When biomass fuel is co-fired, biomass typically accounts for 5 percent to 20 percent of the total fuel content.

*Figure 4-17* presents a photograph of a wood waste biomass facility.

**Figure 4-17 - 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 4-18*. The potential for PV applications as reported by the National Renewable Energy Laboratory is shown in *Figure 4-19.*

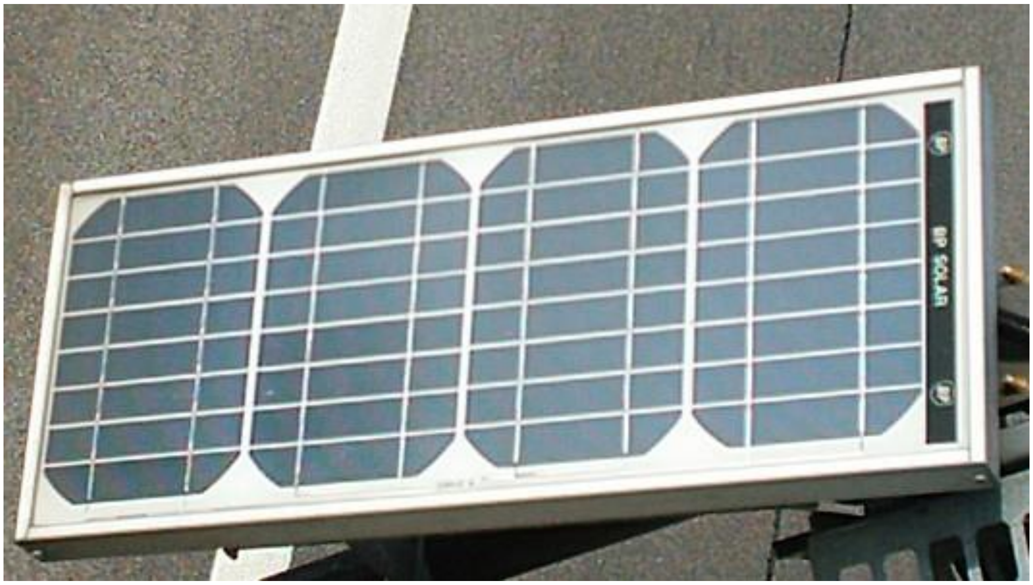


**Figure 4-18 - Photovoltaic Cell**

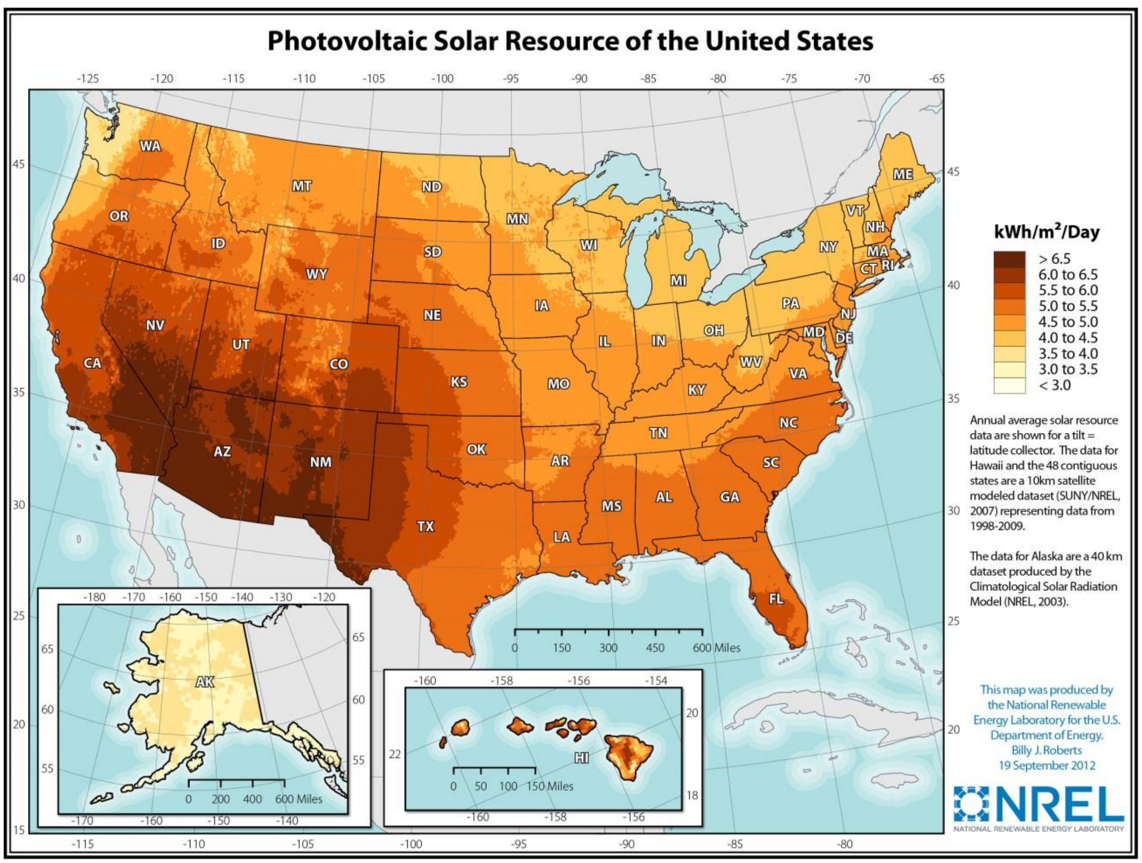


**Figure 4-19 - Photovoltaic Solar Resource**

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 4-20.*

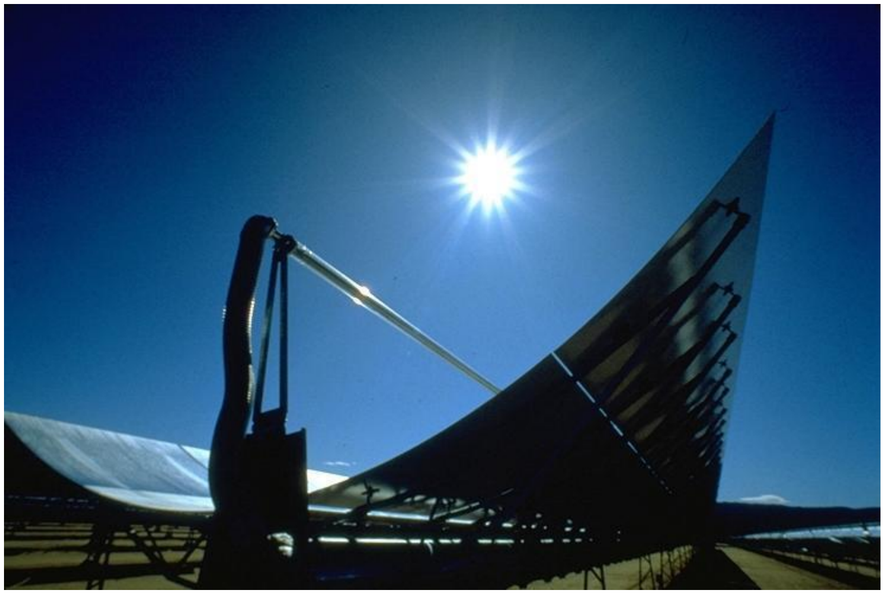

**Figure 4-20 - Concentrating Solar Power Facility**

The potential for CSP as developed by the National Renewable Energy Laboratory is shown in *Figure 4-21*. Missouri has lower CSP potential than the potential for PV applications.

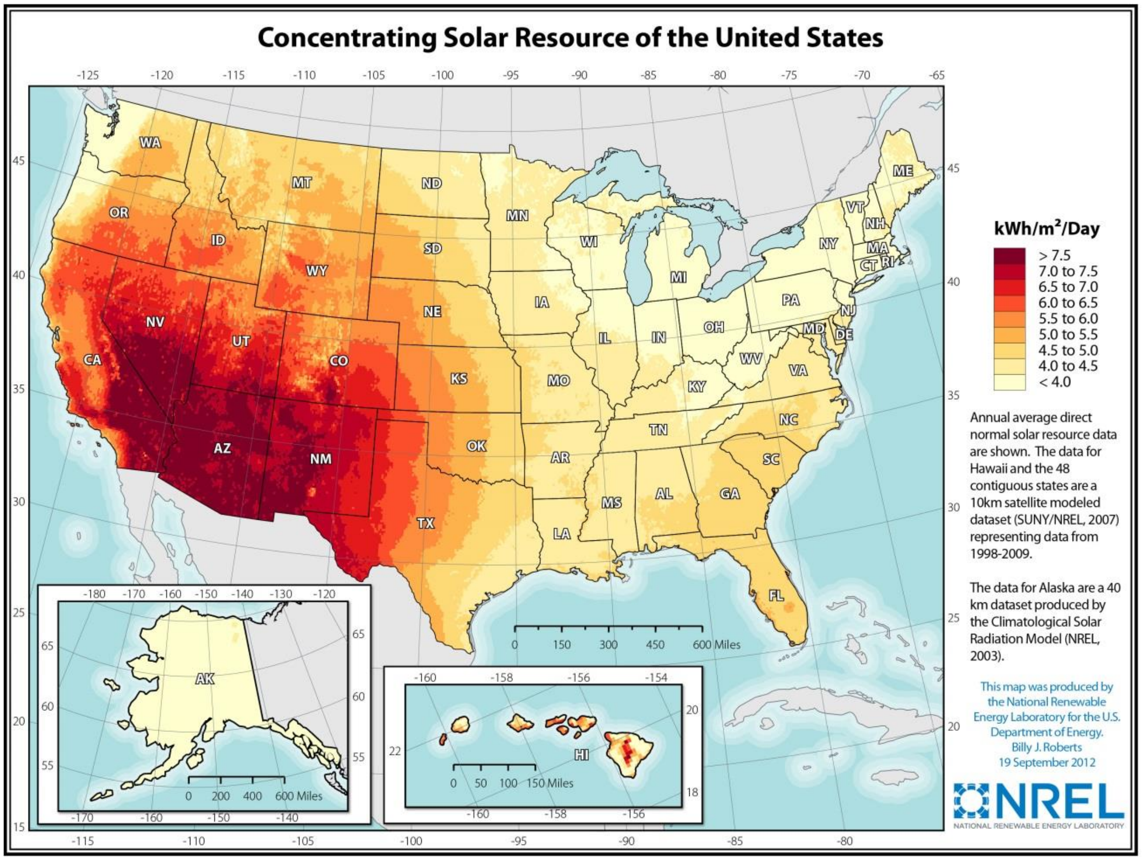


**Figure 4-21 - Concentrating Solar Resource**

Residential solar PV was considered as a potential program in the demand-side analysis.

## 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 $62.98/kW (2016$).

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

| Fuel Type | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 |
|---|---|---|---|---|---|---|
| Coal - Iatan | 1.63 | 1.74 | 1.76 | 1.76 | 1.6 | 1.19 |
| Coal - Asbury | 2.29 | 2.36 | 2.43 | 2.4 | 2.32 | 1.88 |
| Coal - Riverton | - | - | - | 2.54 | 2.31 | 1.83 |
| Coal - Plum Point | 2.12 | 2.31 | 2.12 | 1.8 | 1.86 | 1.8 |
| Natural Gas * | 3.64 | 4.67 | 4.36 | 3.94 | 4.9 | 5.61 |
| Natural Gas with FT ** | 4.27 | 5.27 | 4.95 | 4.51 | 5.48 | 5.97 |
| Oil | 15.46 | 17.52 | 21.87 | 20.29 | 21.3 | 15.44 |

* Natural gas includes commodity, commodity charges, derivative gain/loss and excludes firm transportation

** Natural gas includes commodity, commodity charges, derivative gain/loss and firm transportation

**Table 4-14 - Empire's Historical Delivered Fuel Costs ($/MMBtu)**

Empire's weighted cost of fuel burned per kWh generated was 2.5461 cents in 2015, 2.9700 cents in 2014, 2.8070 cents in 2013, 2.6742 cents in 2012, 2.9558 cents in 2011, and 2.9936 cents in 2010. These costs dropped from 2010 to 2012 as a result of incorporating 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. Since Empire began burning TDF at Asbury, the equivalent of nearly 5.0 million passenger tires have been consumed as fuel. In 2015, Asbury burned a coal blend consisting of approximately 92.6-percent Western coal (referred to in this report as either Western or Powder River Basin (PRB) coal) and 7.4-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 now met by natural gas (Units 7, 8, and 9 are all retired as of June 2015). A Siemens V84.3 A2 CT (Unit 12) was installed at the Riverton plant in 2007 and is in the process of being converted to a one-on-one combined cycle unit. Riverton 12 and two 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 105 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 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 2014, fuel consumption at the Energy Center was 96.1-percent natural gas on a kWh-generated basis and 65-percent of the State Line Unit 1 generation came from natural gas in 2014. The State Line CC unit is fueled 100 percent by natural gas.

Empire has firm transportation agreements with Southern Star Central Pipeline, Inc. with current expiration dates of July 30, 2017, for the transportation of natural gas to the SLCC. This date is adjusted for periods of contract suspension by Empire during outages of the SLCC. Empire has reached agreement with Southern Star to replace these firm transportation agreements effective April 1, 2016 with a new agreement that runs through October 2022. Empire has additional firm transportation agreements that provide firm transportation to Riverton plant sufficient to supply Riverton Unit 12 through August, 2019. These transportation agreements can also supply natural gas to State Line Unit No.1, the Empire Energy Center or the Riverton Plant, as elected by Empire on a secondary basis. Empire expects that these transportation agreements will serve nearly all of Empire's natural gas transportation needs for Empire's generating plants over the next several years. Any remaining gas transportation requirements, although small, will be met by utilizing capacity release on other holder contracts, interruptible transport, or delivered to the plants by others.

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 several years into the future in accordance with Empire's Risk Management Policy in an attempt to lessen the volatility in Empire's fuel expenditures and gain predictability. In addition, Empire has an agreement with Southern Star to purchase one million decatherms of firm gas storage service capacity for a period of five years, expiring in 2016. The reservation charge for this storage capacity is approximately $1.1 million annually. Once this contract expires, Empire does not plan to replace the firm gas storage.

### 5.1.1 Coal Forecast

*Figure 4-22* depicts and *Table 4-15* lists the forecasted generic coal prices for the base, high, and low scenarios.

****Highly Confidential in its Entirety****
**Figure 4-22 - Generic Coal Price Forecast for Base, High, and Low Scenarios[8]**

[8] Source for the high, low and annual escalation factors: U.S. EIA Annual Energy Outlook (May 2015). Other Sets of coal prices have also been developed for the other environmental cases.

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**Table 4-15 - 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 Annual Energy Outlook (May 2015) projections. ABB 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.

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 4-16*, those for Iatan 1 and 2 are shown in *Table 4-17*, and Plum Point's coal price projections are found in *Table 4-18*. Many utilities that consume coal have recently experienced cost increases due to increases in the cost of coal transportation.

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**Table 4-16 - Asbury Coal Price Forecast ($/MMBtu)**

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**Table 4-17 - Iatan Coal Price Forecast ($/MMBtu)**

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**Table 4-18 - Plum Point Coal Price Forecast ($/MMBtu)**

### 5.1.2 Natural Gas Forecast

*Figure 4-23* depicts and *Table 4-19* lists the forecasted natural gas prices (Henry Hub) for the base, high, and low scenario no $CO_2$ case. *Figure 4-24* depicts and *Table 4-19* lists the forecasted natural gas prices (Southern Star Delivered) for the base, high, and low scenario no $CO_2$ case.

****Highly Confidential in its Entirety****
**Figure 4-23 - Forecasted Base, High, and Low Natural Gas Prices (Henry Hub) - No $CO_2$ Case[9]**

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

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**Figure 4-24 - Forecasted Base, High, and Low Natural Gas Prices (Southern Star Delivered) - No $CO_2$ Case**

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**Table 4-19 - 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 ABB Power Market Advisory database modified by ABB. 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 2022. The natural gas prices are correlated to the $CO_2$ prices and are shown on *Table 4-20* and *Figure 4-25*.

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**Figure 4-25 - Forecasted Base Natural Gas Prices (Henry Hub) with $CO_2$ Scenarios**

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**Table 4-20 - Forecasted Base Natural Gas Prices (Henry Hub) with $CO_2$ Scenarios**

### 5.1.2.1 Natural Gas Price Forecasting Methodology

ABB 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. For each iteration of the Operations Component, natural gas demand by the power sector is taken from the prior iteration of the Power Module. The Power Module is a zonal model of

the North American interconnected power system spanning 73 zones. The Module simulates separate hourly energy and annual capacity markets in all zones. The Module simulates the operations of individual generating units, i.e., not aggregations of units. The Power Module comprises two components, which simulate 1) operations; and 2) conventional power plant capacity additions.

2. Canadian and L48 U.S. residential, commercial, and industrial (RCI) demand forecasts are treated as exogenous inputs to the natural-gas sub module. RCI demand is forecast based on an analysis of RCI demand in the EIA Annual Energy Outlook (AEO) and the National Energy Board of Canada (NEBC) 25 year outlook. ABB also conducts its own research and analysis of industrial demand based on publically available analysis of forecast industrial demand. Historical data from the ABB Velocity Suite product are used as a starting point for demand growth applied based on growth rates taken from EIA and NEBC forecast and to add monthly seasonal shape to annual forecasts.
3. Imports and Exports of LNG as well as pipeline exports to Mexico (outside CA connected Baja California) are also treated as exogenous demand sources drawing on the combined Canadian and L48 gas system. These forecasts are created based on analysis of: historical data for individual pipelines and import terminals, individual pipeline and LNG export projects, projected supply and demand for global LNG, and projected demand for natural gas in Mexico. 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.
4. From this solution, the monthly Henry Hub price is identified directly from its geographic point within the gas network.

*Table 4-21* delineates the three phases of the Reference Case long term natural gas price forecast.

| Forecast Phase | Period Length | Data Source | Forecast Technique |
|---|---|---|---|
| Futures Driven | First 24 Months | NYMEX Henry Hub futures and market differentials | Calculated Henry Hub and liquid market center differentials |
| Blend | Months 25-48 | ABB Advisors and NYMEX/Velocity Suite | Linear process to gradually equate near-term to long-term fundamentals |
| Long-term Fundamentals | Remaining forecast period (to 2039) | ABB Advisors | Fundamental supply and demand analysis modeling |

**Table 4-21 - ABB Reference Case Gas Price Forecasting Phases**

To derive the burner tip forecasts used, ABB Advisors first aggregates regional prices and basis swaps at major trading hubs. Using this historical data for the first 24 months of the forecast, ABB Advisors developed a differential price between the appropriate market center nearest to the power plant and the Henry Hub. Natural gas prices for the first 24 months of the forecast were driven by Henry Hub futures market prices plus a basis differential. For the following 24 months of the forecast period (months 25-48), ABB Advisors blends the futures market price expectations with Empire's long-term fundamental forecast so that by the end of this period the gas price forecasts are consistent with Empire's fundamental view. To forecast future burner tip gas prices beyond the initial 48-month period, ABB Advisors utilized a cost-minimization linear program model of gas supply and demand.

#### 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 various instruments including but not limited to 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 31, 2015) in *Table 4-22*.

| Year | Hedge Percentage | Dekatherms | Average Price |
|---|---|---|---|
| 2015 | 61% | 8,646,000 | $3.37 |
| 2016 | 41% | 5,992,900 | $3.34 |
| 2017 | 20% | 3,025,000 | $3.33 |
| 2018 | 10% | 1,460,000 | $2.95 |

**Table 4-22 - Empire Natural Gas Hedges[10]**

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, ABB Advisors 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 CO2 cap-and-trade program, are also very weak. As a result, ABB Advisors 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.

[10]December 31, 2015 Natural Gas Position Report

ABB's oil forecast is based on a survey of other long term oil price forecasts (EIA, IEA etc.). ABB use the same methodology for blending the NYMEX as for natural gas: For months 1-24, ABB is 100 percent dependent on NYMEX while for months 24-48, ABB uses a blend of NYMEX and the long term forecast, and for months 49+ ABB uses the long term forecast. ABB generates 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 West Texas Intermediate (WTI) price.

#### 5.1.4 Renewables Forecast

The ABB Renewables Module simulates the market reaction to the imposition of state renewable portfolio standards (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 renewable energy certificate (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 assumes an EPC contracting strategy. Each option includes an allowance for typical owner's costs, an on-site switchyard, transmission interconnect, natural gas interconnect, and water interconnect as applicable. Representative distances for interconnects were assumed for the various plant types and sizes.

### 5.2.1 Supercritical Coal Technology

The supercritical PC option is based on engineering experience by Burns & McDonnell and publically available information. Carbon capture is assumed to be required for any new coal construction. The data used in the modeling are shown in *Table 4-23*.

| Parameter | With CCS |
|---|---|
| Earliest Feasible Year of Installation | 2023 |
| Lead Time in Years (includes development and construction) | 7.5 |
| Availability Factor | 90.0% |
| Equivalent Forced Outage Rate | 5.2% |
| Scheduled Outage Days per Year | 25 |
| ISO Net Output, Full Load kW | 425,000 |
| Full Load Net Heat Rate, Btu/kWh | 10,500 |
| ISO Net Output, Minimum Load kW | 149,000 |
| Minimum Load Net Heat Rate, Btu/kWh | 12,800 |
| Capital cost, $/kW (2015 $) | 5,520 |
| Fixed O&M, $/kW-year | 31.90 |
| Variable O&M, $/MWh | 11.80 |
| $SO_2$ Emissions, lbs./MMBtu (HHV) | 0.02 |
| $NO_X$ Emissions, lbs./MMBtu (HHV) | 0.02 |
| CO Emissions, lbs./MMBtu (HHV) | 0.15 |
| $CO_2$ Emissions, lbs./MMBtu (HHV) | 105 |
| Mercury Emissions, lbs./GWh | 0.003 |

**Table 4-23 - New Supercritical Coal Performance Parameters**

Variable O&M costs include major maintenance costs associated with the supercritical PC plant. Emissions assume activated carbon injection, SCR, spray dry absorber, fabric filter baghouse, wet flue gas desulfurization, and approximately 50 percent carbon capture are used at the plant.

### 5.2.2 Simple Cycle Technologies

In this IRP, both frame-type and aeroderivative combustion turbines were evaluated with data used as shown in *Table 4-24*. Capital and O&M costs are based on EPC experience by Burns & McDonnell as well as OEM input and quotes. Performances were modeled using OEM provided modeling software. The aeroderivative costs are based on a GE LM6000PC and the frame-type costs are based on a GE 7EA, and a GE 7F5.

| Parameter | Aeroderivative CT | E-Class Frame-Type CT | F-Class Frame-Type CT |
|---|---|---|---|
| Earliest Feasible Year of Installation | 2019 | 2019 | 2019 |
| Lead Time in Years (includes development and construction) | 3.0 | 3.0 | 3.0 |
| Availability Factor | 87.8% | 91.5% | 95.0% |
| Equivalent Forced Outage Rate | 30.8% | 34.5% | 10.2% |
| Scheduled Outage Days per Year | 9 | 9 | 9 |
| ISO Net Output, Full Load kW | 46,400 | 90,100 | 213,700 |
| Full Load Net Heat Rate, Btu/kWh | 9,620 | 11,310 | 9,720 |
| ISO Net Output, Minimum Load kW | 23,200 | 45,100 | 102,600 |
| Minimum Load Net Heat Rate, Btu/kWh | 11,410 | 14,640 | 12,470 |
| Capital cost, $/kW (2015 $) | 1,780 | 1,110 | 650 |
| Fixed O&M, $/kW-year | 31.70 | 15.83 | 7.30 |
| Variable O&M, $/MWh | 7.10 | 3.37 | 0.90 |
| Major Maintenance, $/CT hour | 20 | 300 | 400 |
| Major Maintenance, $/CT start | N/A | 7,700 | 15,000 |
| $NO_X$ Emissions, lbs./MMBtu (HHV) | 0.092 | 0.033 | 0.033 |
| CO Emissions, lbs./MMBtu (HHV) | 0.027 | 0.056 | 0.020 |
| $CO_2$ Emissions, lbs./MMBtu (HHV) | 120 | 120 | 120 |

**Table 4-24 - Combustion Turbine Performance Parameters**

Major maintenance costs are based on LTSA pricing from the OEM. For aeroderivative turbines this will be determined by the operating hours. For frame units the major maintenance cost will be based on either hours or starts of the turbine depending on the annual hours per start operating profile. No SCR or CO catalyst is assumed for the simple cycle units. This is consistent with plants currently being permitted based on BACT practices.

### 5.2.3 Combined Cycle Technologies

In this IRP, a greenfield 1x1 F-class combined cycle in both fired and unfired configurations is evaluated with data used as shown in *Table 4-25*. Capital and O&M costs are based on estimates prepared by Burns & McDonnell based on past experience, and vendor quotes.

| Parameter | F-Class Unfired Plant | F-Class Fired Plant |
|---|---|---|
| Earliest Feasible Year of Installation | 2020 | 2020 |
| Lead Time in Years (includes development and construction) | 4.0 | 4.0 |
| Availability Factor | 89.5% | 89.5% |
| Equivalent Forced Outage Rate | 9.1% | 9.1% |
| Scheduled Outage Days per Year | 14 | 14 |
| ISO Net Output, Full Load kW | 346,000 | 342,500 |
| Full Load Net Heat Rate, Btu/kWh | 6,520 | 6,590 |
| ISO Incremental Fired Output, kW | N/A | 99,300 |
| ISO Incremental Fired Heat Rate, Btu/kWh | N/A | 8,460 |
| ISO Net Output, Minimum Load kW | 187,500 | 185,300 |
| Minimum Load Net Heat Rate, Btu/kWh | 7,440 | 7,520 |
| Capital cost, $/Unfired kW (2015 $) | 980 | 1,100 |
| Capital cost, $/Fired kW (2015 $) | N/A | 860 |
| Fixed O&M, $/kW-year | 12.26 | 12.26 |
| Variable O&M, $/MWh | 1.76 | 1.81 |
| Incremental Fired Variable O&M, $/MWh | N/A | 2.04 |
| Major Maintenance, $/CT hour | 400 | 400 |
| Major Maintenance, $/CT start | 15,000 | 15,000 |
| $NO_X$ Emissions, lbs./MMBtu (HHV) | 0.007 | 0.007 |
| CO Emissions, lbs./MMBtu (HHV) | 0.004 | 0.004 |
| $CO_2$ Emissions, lbs./MMBtu (HHV) | 120 | 120 |

**Table 4-25 - Combined Cycle Performance Parameters**

Incremental duct firing performances represent the additional output, and the associated heat rate, of the extra megawatts produced by burning natural gas in the duct burners. This estimate assumes a duct burner temperature of 1,600°F. A SCR and CO catalyst were assumed for both combined cycle options.

### 5.2.4 Reciprocating Internal Combustion Engine Technologies

In this IRP, a power plant consisting of six (6) 18 MW Wärtsilä reciprocating engines were selected as the representative reciprocating engine technology and screened to provide the data shown in *Table 4-26*. Capital and O&M costs are based on estimates prepared by Burns & McDonnell. Burns & McDonnell's capital cost analysis was performed using actual project cost data.

| Parameter | Recip Engines |
|---|---:|
| Earliest Feasible Year of Installation | 2019 |
| Lead Time in Years (includes development and construction) | 3.0 |
| Availability Factor | 97.1% |
| Equivalent Forced Outage Rate | 2.5% |
| Scheduled Outage Days per Year | 0 |
| ISO Net Output, Full Load kW | 110,300 |
| Full Load Net Heat Rate, Btu/kWh | 8,350 |
| ISO Net Output, Minimum Load kW | 9,200 |
| Minimum Load Net Heat Rate, Btu/kWh | 9,160 |
| Capital cost, $/kW (2015 $) | 1,230 |
| Fixed O&M, $/kW-year | 9.50 |
| Variable O&M, $/MWh | 3.00 |
| Major Maintenance, $/CT hour | 50 |
| Major Maintenance, $/CT start | N/A |
| $NO_X$ Emissions, lbs./MMBtu (HHV) | 0.019 |
| CO Emissions, lbs./MMBtu (HHV) | 0.035 |
| $CO_2$ Emissions, lbs./MMBtu (HHV) | 130 |

**Table 4-26 - Reciprocating Engine Performance Parameters**

### 5.2.5 Small Modular Nuclear Technology

Performance and cost data used for the SMR is shown in *Table 4-27* for a new, 160-MW unit. Capital cost data for the SMR is based on publically available information on Holtec's unit. Holtec has received Department of Energy funding for their design.

| Parameter | Small Modular Nuke |
|---|---|
| Earliest Feasible Year of Installation | 2023 |
| Lead Time in Years (includes development and construction) | 7.0 |
| Availability Factor | 83.0% |
| Equivalent Forced Outage Rate | 8.0% |
| Scheduled Outage Days per Year | 25 |
| ISO Net Output, Full Load kW | 160,000 |
| Full Load Net Heat Rate, Btu/kWh | 10,130 |
| Capital cost, $/kW (2015 $) | 4,130 |
| Fixed O&M, $/kW-year | 89.64 |
| Variable O&M, $/MWh | 1.38 |

**Table 4-27 - Small Modular Nuclear Performance Parameters**

### 5.2.6 Distributed Generation Technologies

Data used to model distributed generation is shown in *Table 4-28*. Cost and performance estimates are based on in house experience from Burns & McDonnell. Both options represent technologies designed to deliver 100 percent of their power and heat/steam to their host. As such, no allowances for transmission interconnection or distribution were included.

| Parameter | Microturbine | Combined Heat & Power |
|---|---|---|
| Earliest Feasible Year of Installation | 2016 | 2019 |
| Lead Time in Years (includes development and construction) | 0.5 | 3.0 |
| Availability Factor | 99.0% | 95.0% |
| Scheduled Outage Days per Year | 3 | 14 |
| ISO Net Output, Full Load kW | 1,000 | 5,100 |
| ISO Full Load Steam Production, lbs./hr | 2,580 | 29,370 |
| Full Load Net Heat Rate, Btu/kWh | 6,510 | 4,790 |
| Capital cost, $/kW (2015 $) | 4,700 | 5,690 |
| Fixed O&M, $/kW-year | 180.30 | 173.20 |
| Variable O&M, $/MWh | Included in FOM | Included in FOM |
| Major Maintenance, $/CT hour | Included in FOM | Included in FOM |
| Major Maintenance, $/CT start | Included in FOM | Included in FOM |
| $NO_X$ Emissions, lbs./MMBtu (HHV) | 0.035 | 0.005 |
| CO Emissions, lbs./MMBtu (HHV) | 0.096 | 0.005 |
| $CO_2$ Emissions, lbs./MMBtu (HHV) | 120 | 120 |

**Table 4-28 - Distributed Generation Performance Parameters**

### 5.2.7 Integrated Gasification Combined Cycle IGCC

Cost and performance data used to model a 2x1 IGCC with CCS is shown in *Table 4-29*. As with the supercritical coal option, carbon capture is assumed to be required for this option at approximately 50 percent.

| Parameter | 2x1 IGCC with CCS |
|---|---|
| Earliest Feasible Year of Installation | 2023 |
| Lead Time in Years (includes development and construction) | 7.5 |
| Availability Factor | 80.0% |
| Equivalent Forced Outage Rate | 12.0% |
| Scheduled Outage Days per Year | 25 |
| ISO Net Output, Full Load kW | 525,000 |
| Full Load Net Heat Rate, Btu/kWh | 10,500 |
| ISO Net Output, Minimum Load kW | 183,800 |
| Minimum Load Net Heat Rate, Btu/kWh | 12,500 |
| Capital cost, $/kW (2015 $) | 7,450 |
| Fixed O&M, $/kW-year | 36.30 |
| Variable O&M, $/MWh | 17.10 |
| $SO_2$ Emissions, lbs./MMBtu (HHV) | 0.01 |
| $NO_X$ Emissions, lbs./MMBtu (HHV) | 0.033 |
| CO Emissions, lbs./MMBtu (HHV) | 0.049 |
| $CO_2$ Emissions, lbs./MMBtu (HHV) | 95 |
| Mercury Emissions, lbs./GWh | 0.003 |

**Table 4-29 - IGCC Performance Parameters**

### 5.2.8 Traditional Nuclear Technology

Cost and performance estimates for a traditional nuclear plant option are shown in *Table 4-30*. Cost data is based on in house Burns & McDonnell experience from previous studies.

| Parameter | Traditional Nuke |
|---|---|
| Earliest Feasible Year of Installation | 2025 |
| Lead Time in Years (includes development and construction) | 9.0 |
| Availability Factor | 83.0% |
| Equivalent Forced Outage Rate | 8.0% |
| Scheduled Outage Days per Year | 25 |
| ISO Net Output, Full Load kW | 1,117,000 |
| Full Load Net Heat Rate, Btu/kWh | 10,130 |
| Capital cost, $/kW (2015 $) | 5,470 |
| Fixed O&M, $/kW-year | 89.64 |
| Variable O&M, $/MWh | 1.38 |

**Table 4-30 - Traditional Nuclear Performance Parameters**

### 5.2.9 Wind

Cost and performance estimates for the wind option are shown in *Table 4-31*. Wind that is indigenous to the state of Missouri is assumed to have a lower capacity factor than wind that could be sited in other states with more wind potential, such as Kansas. At the end of 2015, Congress extended the federal production tax credit (PTC) that will help reduce the energy cost of wind generation by providing a tax credit that offsets the energy cost for wind farms. The production tax credit is assumed to be approximately $23/MWh in 2016 and decreases over time based on the current tax credit. The specific schedule for the PTC is accounted for within the economic dispatch modeling.

| Parameter | Wind Ownership | Wind Ownership with PTC | Wind PPA | Wind PPA with PTC | Indigenous Wind | Indigenous Wind with PTC |
|---|---|---|---|---|---|---|
| Earliest Feasible Year of Installation | 2018 | 2018 | 2016 | 2016 | 2016 | 2016 |
| Lead Time in Years (includes development and construction) | 2.5 | 2.5 | N/A | N/A | N/A | N/A |
| Availability Factor | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% |
| Equivalent Forced Outage Rate | 7.0% | 7.0% | 7.0% | 7.0% | 7.0% | 7.0% |
| Scheduled Outage Days per Year | 0 | 0 | 0 | 0 | 0 | 0 |
| ISO Net Output, Full Load kW | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 |
| Typical Capacity Factor | 35-45% | 35-45% | >40% | >40% | 35% | 35% |
| Capital cost, $/kW (2015 $) | 2,020 | 2,020 | N/A | N/A | N/A | N/A |
| Fixed O&M, $/kW-year | 24.48 | 24.48 | N/A | N/A | N/A | N/A |
| Energy Cost, $/MWh | 0.00 | - 23.00[11] | 50.00 | 27.00[11] | 60.00 | 37.00[11] |

**Table 4-31 - Wind Performance Parameters**

### 5.2.10 Biomass

Cost and performance estimates for the biomass option are shown in *Table 4-32*. This option assumes a stoker unit fed with poultry waste.

[11] Energy cost reflects PTC of $23.00/MWh in 2016. The PTC decreases to $18.40/MWh in 2017, $13.80/MWh in 2018, $9.20/MWh in 2019, and $0.00/MWh in 2020.

| Parameter | Biomass |
|---|---|
| Earliest Feasible Year of Installation | 2019 |
| Lead Time in Years (includes development and construction) | 3.5 |
| Availability Factor | 95.0% |
| Equivalent Forced Outage Rate | 6.0% |
| Scheduled Outage Days per Year | 25 |
| ISO Net Output, Full Load kW | 5,000 |
| Full Load Net Heat Rate, Btu/kWh | 14,100 |
| ISO Net Output, Minimum Load kW | 3,500 |
| Minimum Load Net Heat Rate, Btu/kWh | 18,300 |
| Capital cost, $/kW (2015 $) | 6,860 |
| Fixed O&M, $/kW-year | 200.00 |
| Variable O&M, $/MWh | 10.00 |
| NOX Emissions, lbs./MMBtu (HHV) | 0.10 |
| CO Emissions, lbs./MMBtu (HHV) | 0.15 |
| CO2 Emissions, lbs./MMBtu (HHV) | 205 |

**Table 4-32 - Biomass Performance Parameters**

### 5.2.11 Landfill Gas

Cost and performance estimates for the landfill gas option are shown in *Table 4-33*. The landfill gas is assumed to be combusted in a reciprocating engine.

| Parameter | Landfill Gas Recip Engine |
|---|---|
| Earliest Feasible Year of Installation | 2018 |
| Lead Time in Years (includes development and construction) | 2.5 |
| Availability Factor | 91.8% |
| Equivalent Forced Outage Rate | 27.4% |
| Scheduled Outage Days per Year | 25 |
| ISO Net Output, Full Load kW | 5,000 |
| Full Load Net Heat Rate, Btu/kWh | 10,500 |
| ISO Net Output, Minimum Load kW | 2,500 |
| Minimum Load Net Heat Rate, Btu/kWh | 11,500 |
| Capital cost, $/kW (2015 $) | 4,200 |
| Fixed O&M, $/kW-year | 180.00 |
| Variable O&M, $/MWh | 20.00 |
| $NO_X$ Emissions, lbs./MMBtu (HHV) | 0.02 |
| CO Emissions, lbs./MMBtu (HHV) | 0.50 |
| $CO_2$ Emissions, lbs./MMBtu (HHV) | 180 |

**Table 4-33 - Landfill Gas Performance Parameters**

### 5.2.12 Other Biomass

Other biomass resource options were considered within this resource plan; however they were not specifically evaluated in regards to cost and performance for a variety of reasons. A robust supply of fuel is required to support a long-term biomass facility. Based on biomass surveys (as presented in *Figure 4-14)*, wood waste, agriculture waste, and municipal solid waste do not appear to provide a robust fuel supply compared to the other biomass resources evaluated within this study, especially for a stand-alone biomass resource.

Co-firing biomass in an existing coal-fired power plant is a potential option. However, converting a unit to co-burn biomass does not increase the overall output of the facility, and can actually decrease the output due to increased auxiliary loads for additional biomass handling equipment and decreased boiler efficiencies. Co-firing biomass resources may provide energy for renewable energy requirements; however these resources will still produce $CO_2$

emissions. Therefore, utilities in the Midwest have focused more on wind energy for meeting renewable energy requirements.

For these reasons, additional biomass resources were not carried forwarded for detailed analysis within the economic dispatch modeling.

### 5.2.13 Solar

Cost and performance estimates for the solar option are shown in *Table 4-34*. Solar costs assume photovoltaics are used to produce power as opposed to a solar thermal plant.

At the end of 2015, Congress extended the federal investment tax credit (ITC) that will help reduce the energy cost of solar generation by providing a tax credit that offsets the energy cost for solar facilities. The investment tax credit is assumed to be in approximately 30 percent from 2016 to 2019 and decrease over time afterwards. For the purposes of this evaluation, *Table 4-34* does not include the ITC. The specific schedule for the ITC is accounted for within the economic dispatch modeling.

| Parameter | Solar PV |
|---|---:|
| Earliest Feasible Year of Installation | 2018 |
| Lead Time in Years (includes development and construction) | 2.0 |
| Availability Factor | 98.0% |
| Scheduled Outage Days per Year | 0 |
| ISO Net Output, Full Load kW | 10,000 |
| Full Load Net Heat Rate, Btu/kWh | N/A |
| Capital cost, $/kW (2015 $) | 2,410 |
| Fixed O&M, $/kW-year | 19.50 |
| Variable O&M, $/MWh | Included in FOM |

**Table 4-34 - Solar Performance Parameters**

### 5.2.14 Battery Storage

Cost and performance estimates for the battery option are shown in *Table 4-35.* Plant costs were estimated in order to represent a battery storage unit used for peak shaving or grid VAR support.

| Parameter | Battery Storage |
|---|---|
| Earliest Feasible Year of Installation | 2017 |
| Lead Time in Years (includes development and construction) | 1.5 |
| Scheduled Outage Days per Year | N/A |
| ISO Net Output, Full Load kW | 10,000 |
| Full Load Net Heat Rate, Btu/kWh | N/A |
| Capital cost, $/kW (2015 $) | 4,370 |
| Fixed O&M, $/kW-year | 59.60 |
| Variable O&M, $/MWh | Included in FOM |

**Table 4-35 - Battery Storage 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;*

O&M costs for the candidate options are included in the tables in the previous Section 5.2. Costs are broken out by fixed costs, variable costs, and major maintenance costs depending on the type of technology being evaluated.

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 the following figures. *Figure 4-26* and *Figure 4-27* present $SO_2$ price forecasts for varying levels of $CO_2$ for the state of Missouri and Kansas respectively. *Figure 4-28* displays an annual price forecast for $NO_x$ for varying levels of $CO_2$.

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**Figure 4-26 - $SO_2$ Group 1 (MO) Price Forecast Under Four Scenarios**

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**Figure 4-27 - $SO_2$ Group 2 (KS) Price Forecast Under Four Scenarios**

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**Figure 4-28 - $NO_X$ Annual Price Forecast Under Four Scenarios**

Four levels of $CO_2$ regulation were examined including a case in which no $CO_2$ regulation was enacted. *Figure 4-29* shows the projected $CO_2$ costs ($/ton) in a cap and trade system assumed to be applicable no earlier than 2022. The Mid case represents the base case assumption, with Low and High based on the Synapse 2014 Report. 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.

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**Figure 4-29 - $CO_2$ Price Forecast Under Four Scenarios**

## 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.*

For information about the interconnection costs and other transmission requirements for each supply side candidate resource option please refer to Section 4.3.

## 5.7 Market Price Forecast

Another uncertain factor to consider when modeling supply-side candidate resources is power market price. Market prices for market area SPP-KSMO were projected by ABB 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. The projected on-peak market prices for the gas scenarios used for the modeling in this IRP are shown in *Figure 4-30*. Market prices were also developed for each of the carbon tax scenarios.

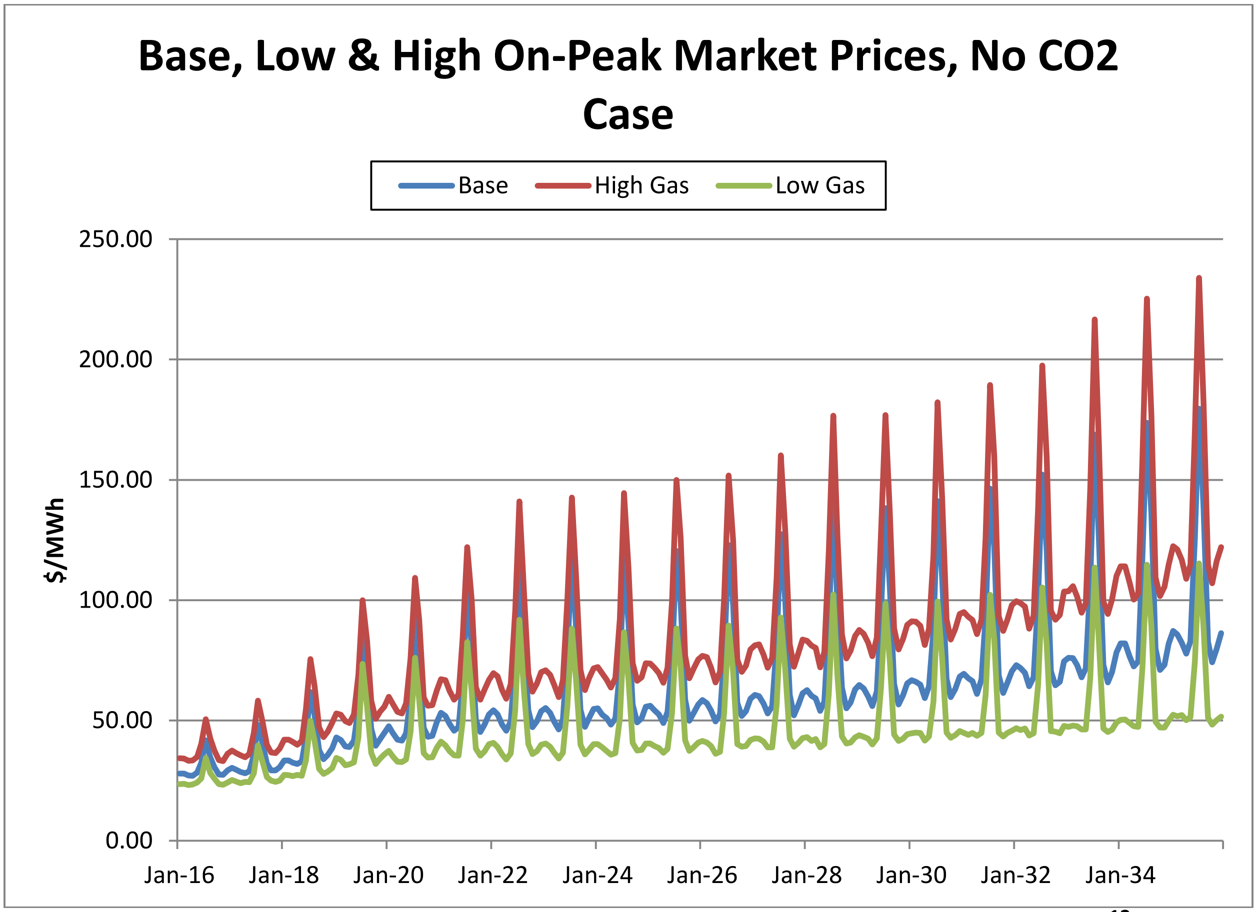


**Figure 4-30 - Forecasted On-Peak Market Price for SPP for Three Scenarios**[12]

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