EXHIBIT

334

INVESTING IN MISSOURI // 2014 INTEGRATED RESOURCE PLAN

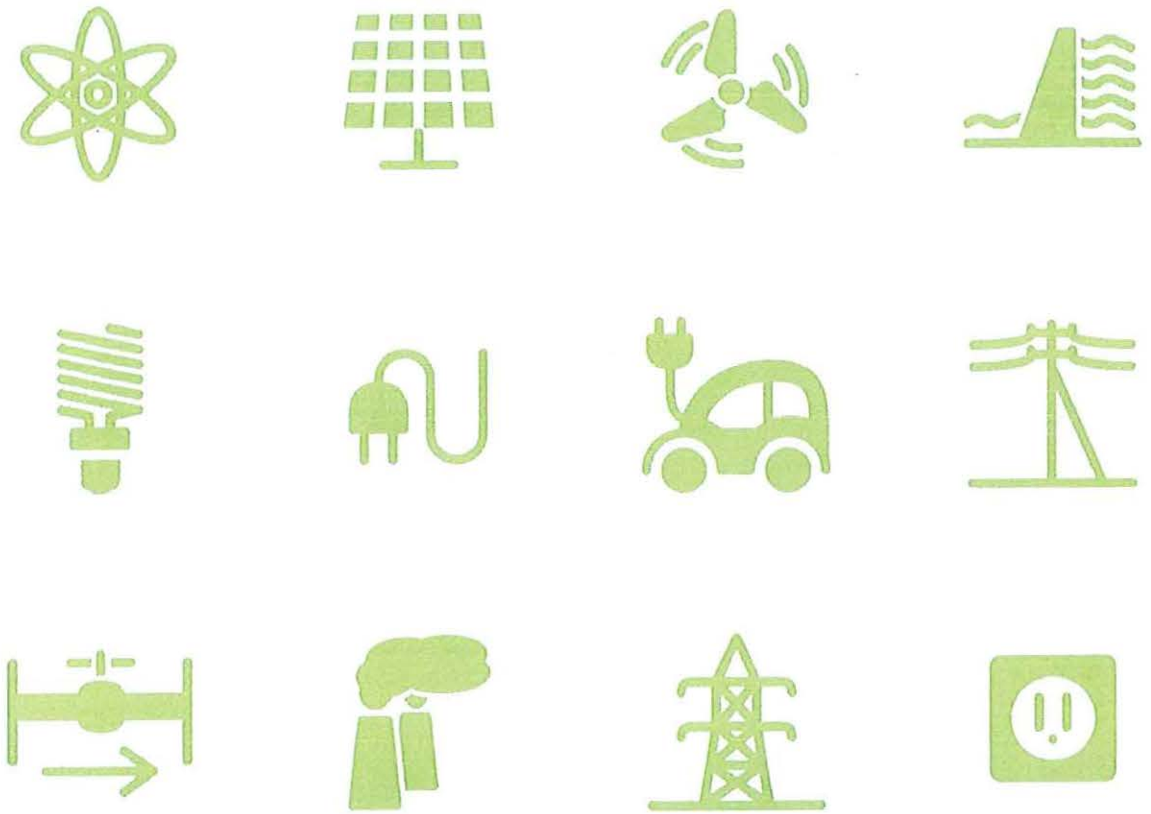

Exhibit No. 334

Date 11-14-14 Reporter KF

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Ameren
MISSOURI

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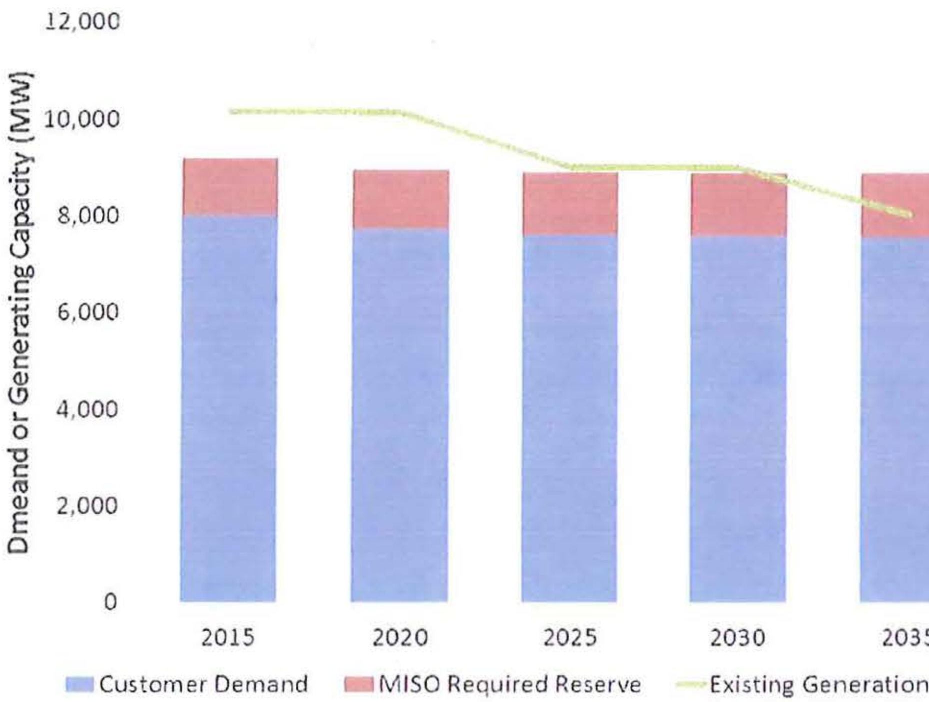
Figure 1.2 Customer Demand, Reserve and Generation

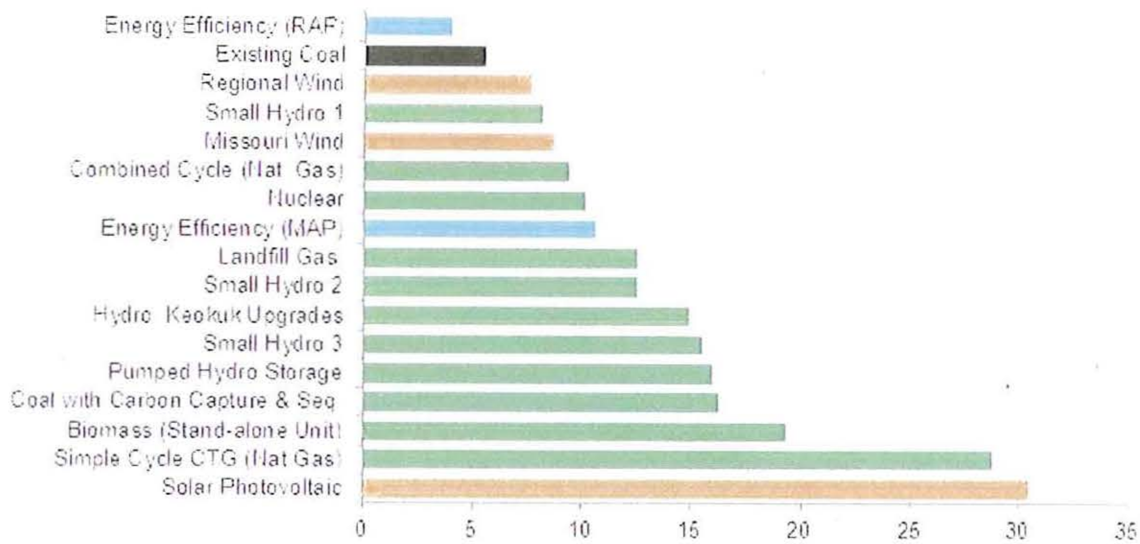


Note: Does not include addition of new generation sources

Ameren Missouri produces over 70% of the electricity it generates from coal. Ameren Missouri's existing fleet of coal-fired generating units are all between 37 and 61 years old, as shown in Table 1.1. Through diligent maintenance and cost-effective equipment replacement we have been able to maintain the efficiency and production capability of our low-cost coal-fired energy centers while also maintaining high standards of safety and reliability. Eventually though, such coal-fired units will be retired and, if necessary, replaced at the end of their useful lives. Retirement of our Meramec Energy Center can be carried out without creating a need for new generating capacity, primarily as a result of the continuation of our cost-effective customer energy efficiency programs. However, retirement of additional coal generation beyond Meramec is expected to result in a need for new generation. As Table 1.1 shows, we expect to retire our Sioux Energy Center by the end of 2033. Upon the retirement of Sioux we expect to need to add new generating capacity to meet customer demand and MISO reserve margin requirements for reliability.

the same level of service, convenience and comfort. They also include new generating resources such as renewable, natural gas, or nuclear powered generation. We have taken a fresh look at these and many other options for meeting customers' future needs.

Figure 1.3 LCOE for Resource Options (cents/kWh)



Note: Does not reflect inclusion of tax incentives. Blue denotes energy efficiency. Black denotes existing coal. Orange denotes intermittent resources. MAP energy efficiency reflects costs and energy savings incremental to RAP.

One way to compare these different resource options is to look at the levelized cost of energy for each option. The levelized cost of energy, or LCOE, is a measure of the per-unit cost of energy produced by a resource over its expected useful life expressed in cents per kilowatt-hour (cents/kWh). It includes all of the costs of construction and ownership, such as the recovery of the capital investment and a fair return for investors, and all of the costs of operations, such as the people, fuel, and other resources needed to operate and maintain the facilities in a safe and reliable manner. Figure 1.3 shows a comparison of the LCOE for some of the most promising resource options. It also includes the LCOE for our existing coal-fired resources. As the graphic shows, the more cost-effective resources include energy efficiency, natural gas-fired combined cycle turbines, nuclear, and renewables such as wind, hydro and landfill gas. It also shows that our existing coal generators remain low-cost sources of energy for meeting our customers' needs for the duration of the generators' expected useful lives.

It is important to recognize that while the LCOE provides a useful measure of the cost of energy from various resource options, it is not the only factor that must be considered in making resource decisions. The additional advantages of resources that can provide generation on demand and with short notice, such as simple cycle combustion turbine

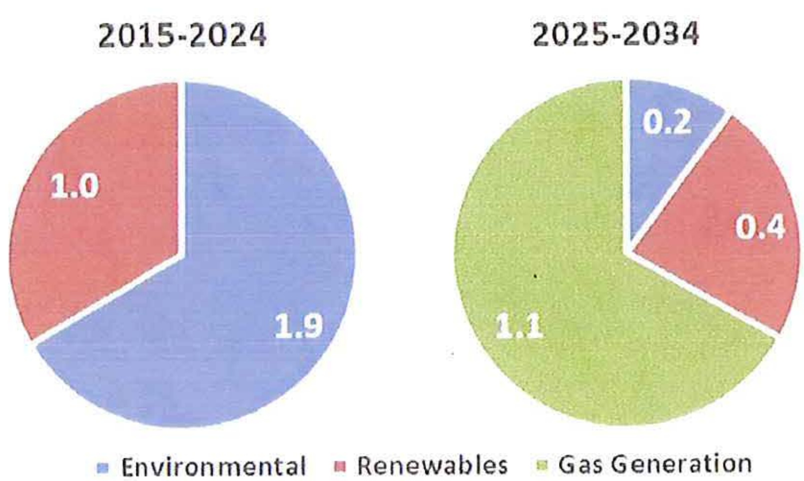
The development of our plan focused on several key elements, including optimizing the use of our existing low-cost generation resources through their normal life expectancy to minimize the cost to our customers, preserving Missouri's economic competitiveness and avoiding unnecessary investments. By 2035, our plan would result in a diverse mix of coal, nuclear, natural gas and renewable energy resources that would in turn allow us to achieve a reduction in carbon dioxide emissions of 30 percent below 2005 levels. It also allows us to comply with the requirements of Missouri's RES.

Our plan systematically incorporates generation resources with lower levels of carbon dioxide and other emissions. It also provides for flexibility in addressing environmental regulations, including those associated with greenhouse gases, while mitigating the potential for unnecessary investments. Because our plan is based on small incremental capital investments over time, it also allows us to effectively manage the risks associated with the development and adoption of distributed generation. In short, our plan allows us to responsibly transition to cleaner, more diverse sources of energy in a way that is beneficial to customers, shareholders, the environment and our communities.

Generation Investments

Our preferred resource plan includes investments in new renewable and gas-fired generation and in environmental controls on our existing generation fleet, as well as ongoing investments to ensure the safe, reliable and cost-effective operation of our existing fleet. Figure 1.5 shows our expected investment in new generation and environmental controls over the next twenty years.

Figure 1.5 Generation Investments ($Billions)



Note: Reflects known and expected future environmental regulations

Implementation

Over the next three years, Ameren Missouri's implementation plan will be focused on several key elements:

- ✓ Securing approval for our next three-year cycle of energy efficiency programs and implementing those programs starting in 2016 will allow us to continue to provide customers options for reducing their energy usage and their electric bills and defer the need for new sources of generation.
- ✓ Completion of our O'Fallon Renewable Energy Center solar facility and development of additional renewable resources, including a subsequent solar project to be completed in 2016, will allow us to comply with the requirements of the Missouri RES and also begin to expand our portfolio of renewable generation.
- ✓ Conversion of Meramec units 1 and 2 from coal to natural gas-fired operation will allow us to begin the managed transition of our coal-fired fleet.
- ✓ Reducing emissions of our existing coal fleet by continuing to make investments in pollution-control equipment
- ✓ We will be working to identify and evaluate sites for new generation such as wind, solar and natural gas combined cycle.
- ✓ Securing an extension of our operating license for our existing Callaway nuclear facility from the Nuclear Regulatory Commission will allow us to continue to rely on low-cost nuclear generation for the next 30 years.
- ✓ Continuing our efforts to support the development of new nuclear generation in Missouri, including the preservation of an option for reliable carbon-free generation and the associated economic development benefits for the state of Missouri.

Contingencies

Because the conditions and circumstances that affect our resource decisions are ever-changing, we must also be prepared for changes in circumstances that warrant a re-evaluation of our plan. There are a few key considerations that may result in a need for such a re-evaluation.

First, the implementation of customer energy efficiency programs requires that our interests are aligned with our customers' interests in using energy more efficiently. The Missouri Energy Efficiency Investment Act (MEEIA), passed and signed into law in 2009, requires that the Missouri Public Service Commission (PSC) provide cost recovery and incentive mechanisms that align our interests with those of our customers. In 2012, the PSC approved energy efficiency programs and associated cost recovery and incentive mechanisms that have allowed us to successfully implement those rapid deployment of distributed technologies could offset the energy consumption driven by economic forces for a considerable period of time under the right circumstances.

2.4 Reliability Requirements

Ameren Missouri is a member of the Midcontinent Independent System Operator (MISO) and participates in its capacity and energy markets. MISO has established a process to ensure resource adequacy through Module E of its FERC tariff. Module E establishes an annual resource adequacy construct which requires load-serving entities to demonstrate adequate resource capacity to satisfy expected load and reserve margins. MISO establishes its planning reserve margin (PRM) requirements annually through its loss of load expectation (LOLE) study process. MISO's last LOLE study report, published in late 2013, indicates a planning reserve margin requirement of 14.9% (applied to peak demand) in 2015, increasing to 17.3%. Table 2.3 shows the year-by-year PRM through 2023. Ameren Missouri has assumed that the PRM beyond 2023 remains at 17.3%.

Table 2.3 MISO System Planning Reserve Margins 2015 through 2023

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023
PRM $_{\text{Installed Capacity}}$	14.9%	15.0%	15.1%	15.1%	15.6%	16.0%	16.4%	16.8%	17.3%

In addition to establishing the PRM requirements, MISO also establishes a capacity credit for wind generation. The capacity credit is applied to the net output capability (in MW) of a wind farm to determine the amount of capacity that can be counted toward the PRM for resource adequacy. The MISO's value for wind capacity credit based on the 2013 Resource Adequacy report is 14.1%.

2.5 Energy Markets

Energy market conditions that may affect utility resource planning decisions include prices for natural gas, coal, nuclear fuel, and electric energy and capacity. Natural gas prices in particular have a strong influence on energy prices as on-peak wholesale prices are often set by gas-fired generators. Ameren Missouri has updated its assessment of these key energy market components to serve as a basis for analysis of resource options and plans.

Table 6.15 Utility-Scale vs. Customer-Owned Solar Analysis

Assumptions	Utility-Scale	Customer-Owned
Size (kW-DC)	5,745	5,745
(kW-AC)	4,500	4,500
Capacity Factor (%)	15.5%	14.4%
Annual Output Degradation Factor (%)	0.7%	0.7%
Fixed O&M ($/kW-AC)	$25	$29
Economic Life (Years)	20	20
Installed Price ($/W-DC)	$2.96	$4.00
Installed Price ($/W-AC)	$3.78	$5.11
Direct Project Cost	$16,996,500	$22,980,000
RESULTS		
With 30% ITC		
NPV Cost ($)	$15,528,289	$16,792,684
NPV Output (MWh)	86,224	76,067
LCOE with 30% ITC ($/MWh)	$180	$221
With 10% ITC		
NPV Cost ($)	$20,154,189	$21,109,798
NPV Output (MWh)	86,224	76,067
LCOE with 10% ITC ($/MWh)	$234	$278
Without ITC		
NPV Cost ($)	$23,352,222	$26,150,807
NPV Output (MWh)	86,224	76,067
LCOE without ITC ($/MWh)	$271	$344

In addition to the cost advantage, utility-scale solar projects offer benefits that are shared by all customers, rather than just those customers whose premises are favorable to the installation of solar generation and are able to afford the significant up-front costs.

6.2.6 Potential Wind Resources[8]

Black & Veatch performed a high level wind project siting analysis to identify priority multi-county development areas in a study region consisting of the following states: Montana, North Dakota, South Dakota, Kansas, Nebraska, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Michigan, Illinois, Indiana and Kentucky. Analysis was based on a Geographic Information Systems (GIS) siting model developed to estimate the LCOE for wind projects across these states. The GIS model estimates project capital cost and net capacity factor for three representative 100 MW wind project configurations. The three wind project types were identified, as follows:

- Type 1: A moderate to high wind speed, conventional wind project using proven wind turbine technology at the current industry normal 80 meter hub height.

[8] EO-2007-0409 14

- Type 2: A low wind speed project using newer technology built on a well-proven wind turbine platform at the increasingly common 100 meter hub height.
- Type 3: A low to medium wind speed project at a 120 meter hub height, using newer wind turbine technology in the early stages of commercialization.

Based on the LCOE results, Black & Veatch identified a set of 23 promising high-value development areas. Black & Veatch identified potential wind development areas by overlaying maps of wind energy potential with the existing and planned transmission system. Identifying development areas near existing or planned transmission lines minimizes the expected cost of interconnection. A discussion of the transmission system build out that supports expanded renewable energy, and associated cost allocation methods, is included in Chapter 7. At least one high value area was identified in each state, and two or three areas were identified in several states. Each identified area consists of several contiguous counties with low estimated LCOE, significant land available for additional development and no known major environmental barriers. Figure 6.7 shows the entire study area with the lowest calculated LCOE of the three project types. Table 6.16 shows the results for the 80 meter hub height Black & Veatch analysis. Table 6.17 shows the results for the 100 meter hub height Black & Veatch analysis. Table 6.18 shows the results for the 120 meter hub height Black & Veatch analysis.

Figure 6.7 Wind Analysis Identified Development Areas and LCOE

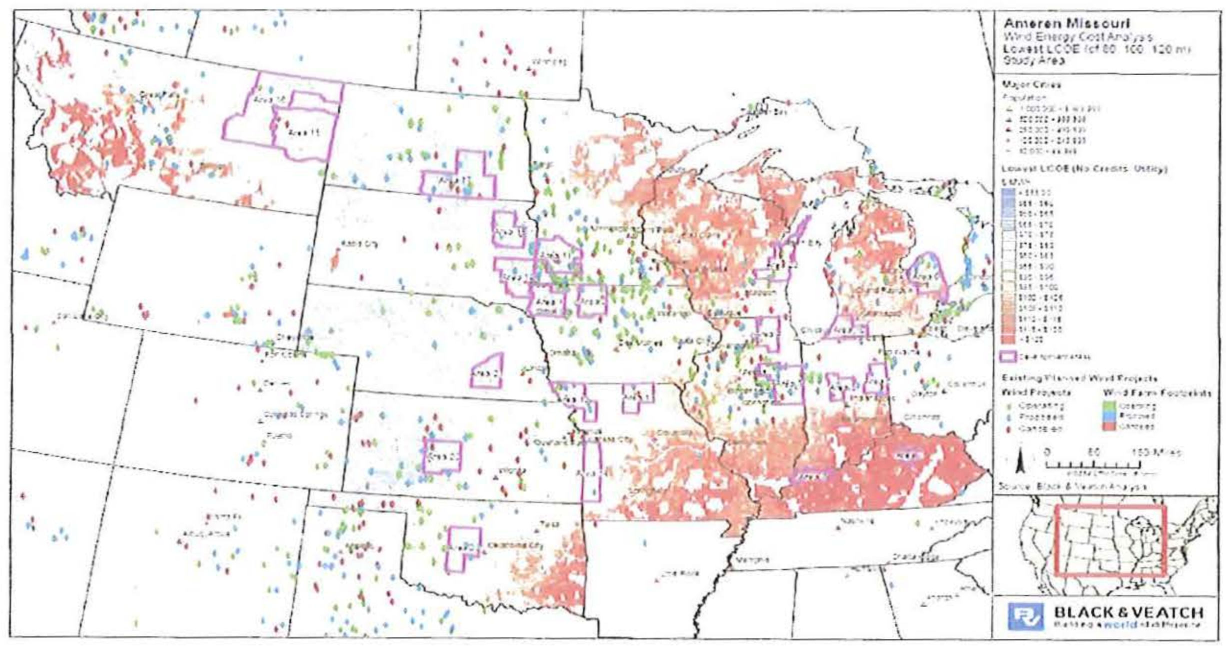


Table 6.16 Priority Development Areas, 80 Meter Results

Area	State	Capital Cost, ($/kW)	Capacity Factor (%)	LCOE without Incentives (¢/kWh)
1	IA	$2,030	40.0%	7.30
2	IA	$2,029	37.9%	7.70
3	IL	$2,025	33.4%	8.80
4	IL	$2,020	31.3%	9.30
5	IN	$2,024	33.3%	8.80
6	IN	$2,021	30.7%	9.50
7	KY	$2,021	21.9%	13.50
8	KY	$2,019	21.7%	13.60
9	MI	$2,020	28.9%	10.20
10	MI	$2,020	27.0%	10.90
11	MN	$2,030	39.3%	7.50
12	MO	$2,022	33.5%	8.70
13	MO	$2,032	30.9%	9.50
14	MO	$2,024	30.4%	9.60
15	MT	$2,039	36.6%	8.10
16	MT	$2,091	37.1%	8.10
17	ND	$2,031	40.0%	7.30
18	SD	$2,031	40.3%	7.30
19	SD	$2,031	39.8%	7.40
20	WI	$2,020	31.3%	9.30
21	NE	$2,021	40.1%	7.30
22	KS	$2,023	40.9%	7.10
23	OK	$2,023	36.2%	8.10

Table 6.17 Priority Development Areas, 100 Meter Results

Area	State	Capital Cost, ($/kW)	Capacity Factor (%)	LCOE without Incentives (¢/kWh)
1	IA	$2,385	41.0%	8.10
2	IA	$2,370	41.1%	8.10
3	IL	$2,370	40.0%	8.30
4	IL	$2,365	37.9%	8.70
5	IN	$2,369	39.8%	8.30
6	IN	$2,366	37.3%	8.90
7	KY	$2,366	28.4%	11.70
8	KY	$2,364	28.3%	11.80
9	MI	$2,365	35.5%	9.40
10	MI	$2,365	33.6%	9.90
11	MN	$2,371	41.0%	8.10
12	MO	$2,368	39.8%	8.30
13	MO	$2,377	37.5%	8.90
14	MO	$2,369	37.0%	9.00
15	MT	$2,381	38.9%	8.60
16	MT	$2,424	39.5%	8.60
17	ND	$2,375	40.9%	8.10
18	SD**	-	-	-
19	SD	$2,373	41.0%	8.10
20	WI	$2,365	37.9%	8.80
21	NE	$2,366	41.0%	8.00
22	KS**	-	-	-
23	OK	$,2367	40.5%	8.20

Note: ** The wind turbines used in the 100 and 120 meter cases are intended for low wind sites. All land in these identified areas is predicted to be above design conditions for these machines.

Table 6.18 Priority Development Areas, 120 Meter Results

Area	State	Capital Cost, ($/kW)	Capacity Factor (%)	LCOE without Incentives (¢/kWh)
1	IA	$2,791	37.6%	10.10
2	IA	$2,772	37.7%	10.00
3	IL	$2,773	36.5%	10.40
4	IL	$2,768	34.5%	10.90
5	IN	$2,772	36.4%	10.40
6	IN	$2,769	34.0%	11.10
7	KY	$2,769	25.2%	15.20
8	KY	$2,767	25.0%	15.20
9	MI	$2,768	32.2%	11.80
10	MI	$2,768	30.3%	12.50
11	MN	$2,773	37.6%	10.00
12	MO	$2,771	36.4%	10.40
13	MO	$2,779	34.1%	11.10
14	MO	$2,772	33.7%	11.20
15	MT	$2,786	35.5%	10.70
16	MT	$2,828	36.1%	10.70
17	ND	$2,778	37.4%	10.10
18	SD**	-	-	-
19	SD	$2,777	37.6%	10.10
20	WI	$2,767	34.5%	10.90
21	NE	$2,769	37.5%	10.00
22	KS**	-	-	-
23	OK	$2,770	37.0%	10.20

Note: ** The wind turbines used in the 100 and 120 meter cases are intended for low wind sites. All land in these identified areas is predicted to be above design conditions for these machines.

Based on the Black & Veatch analysis, cost assumptions were developed for Missouri Wind and Regional Wind for compliance with the Missouri RES. Missouri Wind cost and performance characteristics assumptions are based on the average 100 meter results for Priority Development Areas 12 and 13 located in Missouri. Regional Wind cost and performance characteristics are based on the average 80 meter results for Iowa, Illinois, Minnesota, and South Dakota (i.e., Priority Development Areas 1, 2, 3, 11, 18, and 19) and were selected based on deliverability to MISO, expected cost performance, and relative geographic proximity. Approximately 500 MW of Missouri Wind is assumed to be available for RES Compliance and additional wind for RES compliance or for other resource needs could be supplied by Regional Wind.

Cost assumptions were reviewed with internal subject matter experts and revised as appropriate. Table 6.19 list primary characteristics for potential wind resources. Chapter 6 – Appendix C contains more detailed information.

Table 6.19 Potential Wind Resources

Resource Option	Plant Output (MW)	Total Project Cost Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	LCOE without Incentives (¢/kWh)
Missouri Wind 100 meter Hub Height	100	$2,197	$29	$0	38.7%	8.75
Regional Wind 80 meter Hub Height	101	$1,879	$29	$0	38.5%	7.67

6.2.7 Renewable Supply

Black & Veatch developed a supply curve for the aggregate mix of renewable energy projects considered in the Ameren Missouri service territory. Supply curves are used in economic analyses to determine the quantity of a product that is available for a particular price (e.g., the amount of renewable energy that can be generated within a utility system for under $150/MWh).

The supply curve in Figure 6.8 was constructed by plotting the amount of generation added by each project against its corresponding levelized cost. For this study, the renewable generation added by each project class is plotted against its levelized cost of electricity in ascending order. In this case, generation (GWh/yr) is on the x-axis and levelized cost ($/MWh) is shown on the y-axis. Every "step" on the graph represents an individual project color-coded by its technology type. The curve compares the quantities and costs for the renewable resources and shows which products can be brought to market at the lowest cost (resources toward the left side). Note: the LCOE of wind in the Missouri MISO region (development area 13), with no incentives included, is indicated by a dashed line on the supply curve. Because potential available wind energy is much greater than that from other resources, it has not been incorporated into the supply curve. By comparing the cost of other resources to the cost of wind resources, we can get an idea of their relative competitiveness as a renewable energy resource. With so much potential, it was assumed that enough wind would be available to meet Ameren Missouri's renewable energy requirements.

Biomass co-firing appears to be a cost-effective renewable resource compared to other renewable resources in Figure 6.8. However, the potential for co-firing is much smaller when considering the fuel supply constraints. Although the region is flush with biomass materials, their use as feedstock for power plant operations is highly dependent on the emergence of sustainable fuel supply. It is important to note that biomass co-firing is a fuel substitute and therefore adds no additional energy or capacity benefits. Incorporating the expected energy and capacity benefits would indicate wind, hydroelectric, and landfill gas are more cost-effective resources than biomass co-firing

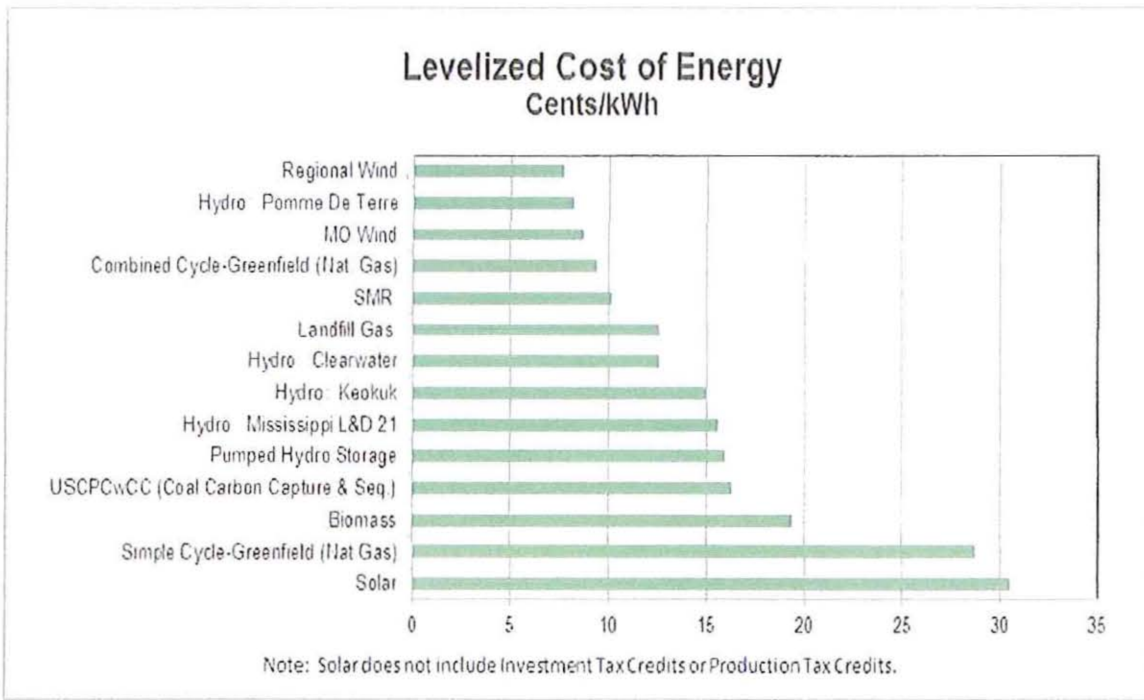
6.4 Power Purchase Agreements

After discussions with Ameren Missouri's Asset Management and Trading organization it was determined that there were no pending potential long-term power purchases for consideration at the time of the analysis. Furthermore, Ameren Missouri learned from its experience in developing the 2008 and 2011 IRPs that soliciting the market for long-term power purchases or sales is not productive for bidders given the data at this stage of the analysis is generic, and potential respondents are reluctant to share information on potential agreements without a high expectation for an executed contract. Evaluation of generic power purchase agreements would not be expected to yield different results in terms of relative performance of resource types, as the only reasonable assumption that could be made absent specific information would be that such an agreement would be cost-based.

6.5 Final Candidate Resource Options[10]

Figure 6.9 shows the LCOE without incentives (e.g., Investment Tax Credits or Production Tax Credits) for a range of potential supply side resources.

Figure 6.9 Levelized Cost of Energy



It is important to note that levelized cost of energy figures, while useful for convenient comparisons of resource alternatives, do not fully capture all of the relative strengths

[10] 4 CSR 240-22.040(4); 4 CSR 240-22.040(4)(C)

and challenges of each resource type. For example, wind resources are intermittent resources and therefore cannot be counted on for meeting peak demand requirements in the same way a nuclear or gas-fired resource can. Similarly, using an energy cost measure to evaluate peaking resources such as simple cycle CTGs does not fully reflect their value as a capacity resource. The levelized cost of wind resources presented in Figure 6.9 also does not reflect the full cost of transmission infrastructure needed to integrate wind and other intermittent resources into the electric grid. Such costs are allocated to members of the MISO based on methods approved by the FERC. Based on the screening analysis, it was concluded that USCPC was selected to represent the coal resource type. However, USCPC was not considered further in the alternative resource plans because of its cost and the uncertainty of CCS technology.[11] Table 6.21 shows the component analysis for the levelized cost of energy figures.

Table 6.21 Levelized Cost of Energy Component Analysis[12]

Resource	Levelized Cost of Energy (¢/kWh)									
	Capital	Fixed O&M	Variable O&M	Fuel	Pump Cost	Decommission	CO2	SO2	NOx	Total Cost
New Resources										
Regional Wind	6.66	1.00	0.00	--	--	--	--	--	--	7.67
Hydro: Pomme De Terre	7.44	0.00	0.74	--	--	--	--	--	--	8.18
MO Wind	7.75	1.00	0.00	--	--	--	--	--	--	8.76
Combined Cycle	3.87	0.24	0.49	4.71	--	--	0.15	0.00	0.00	9.46
Nuclear: SMR	6.63	2.03	0.28	1.18	--	0.07	--	--	--	10.18
Landfill Gas	5.89	1.64	1.35	3.64	--	--	--	0.00	0.00	12.53
Hydro: Clearwater	11.85	0.00	0.74	--	--	--	--	--	--	12.59
Hydro: Keokuk Option 3	14.69	0.20	0.07	--	--	--	--	--	--	14.96
Hydro: Mississippi L&D 21	14.82	0.00	0.74	--	--	--	--	--	--	15.56
Storage: Pumped Storage	9.50	0.23	0.51	--	5.76	--	--	--	--	16.00
Coal (USCPC w CCS)	8.93	0.59	2.57	4.18	--	--	0.06	0.00	0.00	16.33
Biomass	10.39	2.66	1.40	4.92	--	--	--	0.00	0.00	19.38
Simple Cycle	19.94	2.11	1.72	5.34	--	--	0.17	0.00	0.00	29.28
Solar	28.61	1.90	0.00	--	--	--	--	--	--	30.51

The LCOE for future resource options is an important measure for assessing these options. However, it is not the only factor that must be considered in making resource decisions. Facts and conditions surrounding future environmental regulations, commodity market prices, economic conditions, economic development opportunities, and other factors must be considered as well. A robust range of uncertainty exists for many of these factors, all of which leads to one overriding conclusion – maintaining effective options to pursue alternative resource options in a timely fashion is a prudent course of action.

[11] 4 CSR 240-22.040(2)(C)2
[12] 4 CSR 240-22.040(2)(C)1

With the approval of MTEP13, a total of 11 transmission projects have been approved by the MISO Board of Directors for construction in Missouri before 2019. A summary of the projects is shown in the table below. Table 7.1 also includes the proportion of transmission service charges arising from the projects that Ameren MO Load is expected to pay.[5] The costs of these projects are not impacted by whether the project is constructed by Ameren Missouri or an affiliate.

Table 7.1 MTEP Transmission Projects in Missouri - Summary

Transmission Projects with a Portion in Missouri in MTEP13 or Prior MTEPs in Service in Late 2013 or Not Yet in Service			
Project Type	Number of Projects	Estimated Total Project Cost ($Million)	Estimated Percentage of Transmission Service Charges Arising From the Projects to be Paid by Ameren Missouri Load
Baseline Reliability or Reliability/Other Projects Not Cost Shared	7	46.3	100%
Baseline Reliability Projects - Cost Shared	1	30.8	86.90%
MVPs 7, 8, & 9	3	784.9	Approximately 8.9%

A brief description of the 11 transmission projects can be found in Appendix A.

A key component of fulfilling Ameren Missouri's obligation of continuing to provide safe and reliable service is the identification of potential future needed transmission upgrades. A list of projects that are under consideration by Ameren and MISO and that are located totally or partially in Missouri is provided in Appendix A in Table 7A.2. [6]

Current and previous transmission system expansion plans can be found on MISO's website:
https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx[7]

[5] 4 CSR 240-22.045(3)(A)4
[6] 4 CSR 240-22.045(6)
[7] 4 CSR 240-22.045(3)(C)

Revenue Credits from Previously Constructed Regional Transmission Upgrades[8]

Regional transmission upgrades, such as Multi-Value Projects and Market Efficiency Projects, are eligible for cost sharing under Attachment GG or MM of the MISO Tariff. Ameren Missouri does not have any such projects which receive revenue credits through this process.

7.1.3 Ameren Missouri Transmission Planning[9]

Ameren Missouri's transmission strategy is centered upon meeting the evolving needs of its customers for safe and reliable energy. Each year the Ameren Missouri transmission system is thoroughly examined and studied to verify it will continue to provide Missouri customers with reliable and safe service through compliance with all applicable North American Electric Reliability Corporation (NERC) standards as well as Ameren's Transmission Planning Criteria and Guidelines.

The studies identify potential system conditions where reduced reliability may occur in the future. Additional studies are then performed to evaluate all practical alternatives to determine what, where and when system upgrades are required to address the future reliability concern. This annual review identifies any transmission system reinforcements necessary to provide reliable and safe service in response to changing system conditions. These studies consider the effects of overall system load growth, the adequacy of the supply to new and existing substations to meet local load, the expected power flows on the bulk electric system (BES) and the resulting impacts on the reliability of the Ameren Missouri transmission system.

In order to successfully achieve the goal of a safe and reliable transmission system, Ameren Missouri participates in a multitude of transmission planning activities including:

- MISO Transmission Expansion Plan (MTEP) development
- MISO regional generation interconnection studies
- NERC reliability standards development,
- Participation in SERC regional planning and assessment activities,
- Participation in the Eastern Interconnection Planning Collaborative (EIPC)

This high level of involvement affords the opportunity to supply comments and provide input to these many transmission planning processes which supports the goal of

[8] 4 CSR 240-22.045(3)(A)5

[9] 4 CSR 240-22.045(3)(B)1; 4 CSR 240-22.045(3)(B)2; 4 CSR 240-22.045(3)(B)3; 4 CSR 240-22.045(3)(B)4; 4 CSR 240-22.045(4)(A)

maintaining a reliable and safe transmission system which will meet the current and future needs of our Missouri customers.

As part of the Ameren Missouri Transmission Planning Process the ability of transmission system improvements to reduce transmission system losses is considered. A major aspect of Ameren Missouri's focus of providing continued safe and reliable service to our customers is maintaining transmission equipment and replacing aging infrastructure when it approaches the end of its operational life. The Ameren Missouri area experienced rapid economic growth and substantial investment in transmission infrastructure during the 1960s and 70s. Considerable portions of the transmission system are now over forty years old and are reaching the end of their operational life with a commensurate increased risk of failure and higher maintenance expense. The existing equipment is also less efficient than comparable modern equipment. Ameren Missouri is working to address the most critical issues by making targeted investments to replace its aging grid infrastructure to maintain system reliability.

7.1.4 Avoided Transmission Cost Calculation Methodology[10]

The methodology that was used during the development of the previous Integrated Resource Plan was again used in the 2014 Plan. Avoided transmission costs are based upon integrated system effects and are difficult to quantify, as opposed to energy and capacity costs where there are markets that provide specific prices. As part of integration modeling, Ameren Missouri estimated the MW impacts of DSM programs and a corresponding reduction in transmission capital expenditures.

The first step is to identify the transmission projects that are related to serving customer load and their associated cost. An estimated generic marginal cost of system transmission capacity is then calculated and adjusted by applying the following factors:

- Usage Growth-Related Factor - This factor captures the effect that some of the transmission projects cannot be deferred by DSM because they are not driven by usage growth but rather by load relocating to different areas with Ameren Missouri. This causes a local load increase but not a net system load increase.
- Location-specific Factor/Deferrable Factor - This factor accounts for the fact that Ameren analyzes the transmission system in aggregate and it is not possible to determine with certainty which load increase will be deferred by DSM programs. DSM programs are not being designed to avoid or offset specific transmission projects; therefore it is not possible to identify the specific transmission projects which would be deferred.

[10] 4 CSR 240-22.045(2); 4 CSR 240-22.045(3)(A)3

Potential Keokuk Expansion

A potential Keokuk Energy Center expansion project was evaluated in the capacity planning process. As discussed in Chapter 4, Option 3 (3-5k)---the addition of five units to the spare bays---was the least cost option and was evaluated further in the integration analysis. The Keokuk expansion would provide 50 MW of additional capacity.

DSM Portfolios

DSM portfolios were included in capacity planning separately as energy efficiency and demand response. Energy efficiency (EE) and demand response (DR) programs not only reduce the peak demand but also reduce reserve requirements associated with those demand reductions. The following combinations of DSM portfolios were evaluated: 1) RAP EE and DR, 2) RAP EE Only, 3) MAP EE and DR, 4) MAP EE Only and 5) MEEIA Cycle 1 Only[2]. The MEEIA Cycle 1 Only DSM portfolio reflects completion of Ameren Missouri's current three-year program cycle with no further energy efficiency during the planning horizon and does not include DR.

Renewable Portfolios

Compliance with Missouri's renewable energy standard (RES) was updated to reflect current assumptions, including baseline revenue requirements, and an updated 10 year forward looking methodology which impacts the calculation of a 1% rate cap.

Ameren Missouri performed its RES compliance analysis with the *2014 IRP RES Compliance Filing Model* (model). The model is designed to calculate the retail rate impact, as required by the Commission's RES rules[3]. This model determines the quantity of renewable energy needed to meet both the overall RES portfolio standard and the solar portfolio standard "carve-out" absent any rate impact constraints. The model then determines the amount of renewable energy, both solar and non-solar that can be built without exceeding an average 1% revenue requirement increase over a ten-year period. Ameren Missouri's expected renewable energy credit (REC) position is presented in Figure 9.3.

[2] EO-2012-0142 12

[3] 4 CSR 240-20.100(5)

Figure 9.3 Ameren Missouri's RES REC Positions

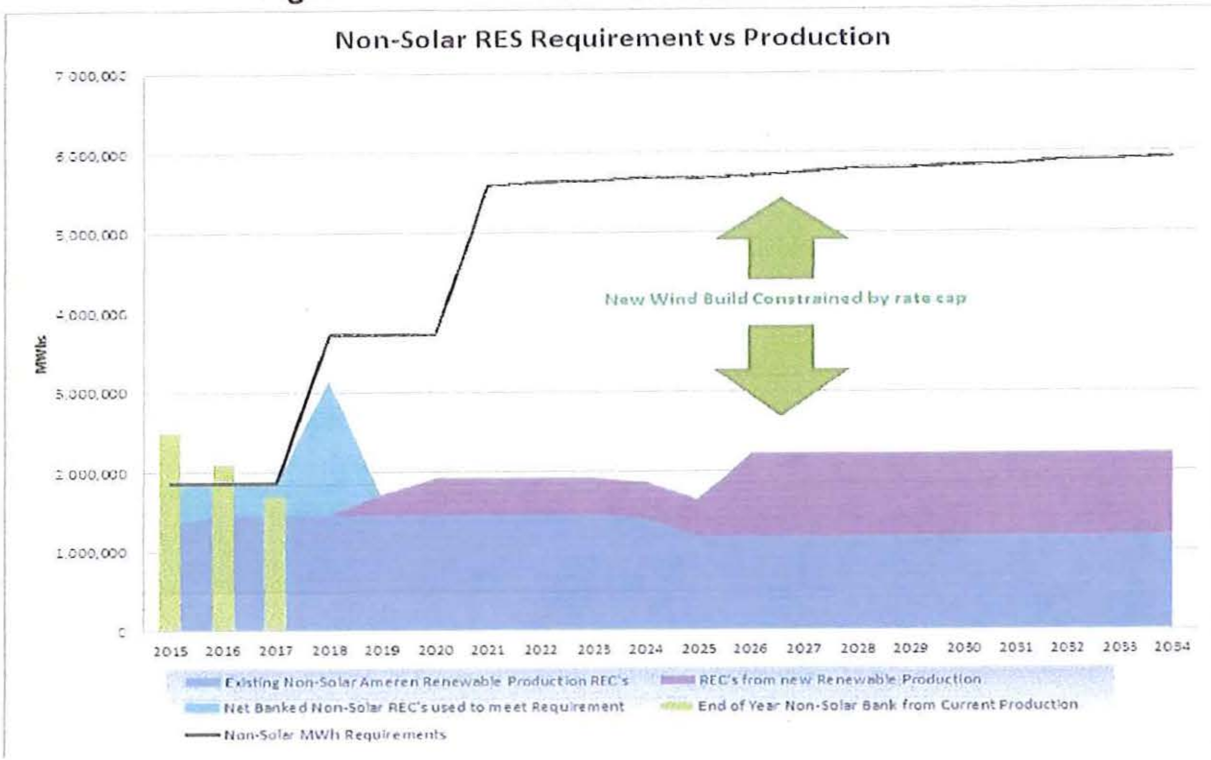


Figure 9.3 shows that Ameren Missouri expects to meet the overall REC requirement until 2018, without being constrained by the 1% rate impact limitation. Ameren Missouri is able to meet the overall standard until 2018 using RECs generated by its existing qualifying resources, including hydro, wind, and landfill gas, and banked RECs from prior years.

Once the standard increases to 10% in 2018, Ameren Missouri exhausts its remaining REC bank then places new wind generation into service starting in 2019. The model shows the amounts of planned new wind and solar resources needed to meet the standard subject to the 1% rate cap. In addition, the model is used to provide a view on RES compliance for both an unconstrained and constrained (i.e., 1% rate impact cap) view of compliance. Table 9.2 shows the unconstrained and constrained amounts of wind, landfill gas (LFG), and solar resources needed. This model was used to develop the RES compliance portfolios for the alternative resource plans. Appendix A shows the unconstrained and constrained amounts of wind, LFG, and solar resources needed in Term 1 (2014-2023) and Term 2 (2025-2034) by year.

Table 9.2 2014 IRP Compliance Filing Model

Description	10 Year Sum TERM 1 (2015-2024)	10 Year Sum TERM 2 (2025-2034)	20 Year Sum (2015-2034)
Unconstrained Full RES REC Requirement met with new builds			
MW's Installed New Solar	5	54	59
MW's Installed New LFG	5	0	5
MW's Installed New Wind	1,003	110	1,114
RES Requirement within 1% Rate Cap Limit			
MW's Installed New Solar	16	10	26
MW's Installed New LFG	5	0	5
MW's Installed New Wind	100	142	242

Several renewable portfolios were evaluated in the capacity planning process using *2014 IRP RES Compliance Filing Model*: 1) RES compliance with RAP or MAP, 2) RES Compliance with MEEIA Cycle 1 Only, and 3) Balanced (i.e., 400 MW Wind, 45 MW Solar, and 20 MW Small Hydroelectric). The RES portfolios were developed using the described in Section 9.2.

When developing the RES compliance investment needs, consideration was given to the potential difference between RAP DSM investment vs a MAP DSM investment due to their differing impacts on customer sales, which is used as the basis for determining the amount of renewable energy needed to comply with the RES portfolio requirements. After modeling both, the difference in the level of renewable generation added was determined to be insignificant, primarily because of the effect of the 1% rate impact limitation on investment levels. Specifically, the difference was less than 1 MW of investment in solar for Term 1 and less than 4 MW's of wind investment for Term 2. Therefore MAP and RAP portfolios are accompanied by the same level of renewable investment when included in alternative resource plans.

Table 9.3 shows the timing of resources for renewable portfolios included in the alternative resource plans.

Table 9.3 Alternative Resource Plans - Renewable Portfolios

Renewable Portfolios		Nameplate Capacity (MW)																				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	TOTAL
RES with RAP or MAP	Wind	0	0	0	0	50	50	0	0	0	0	0	142	0	0	0	0	0	0	0	0	242
	Solar	5	10	0	0	0	0	2	0	0	0	10	0	0	0	0	0	0	0	0	0	28
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RES with MEEIA Cycle 1	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	5	10	0	0	0	0	2	0	0	0	10	0	0	0	0	0	0	0	0	0	26
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Balanced	Wind	0	0	0	0	50	50	0	100	0	100	0	100	0	0	0	0	0	0	0	0	400
	Solar	5	10	0	0	0	0	10	0	0	0	10	0	10	0	0	0	0	0	0	0	45
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	10	0	0	0	20