Chapter 6 - Appendix A

Characterization – Thermal Resources

6.1 Coal and Natural Gas Options[1]

Preliminary Screening Analysis[2]

Option	Description	Candidate Option
Coal	Greenfield - USCPC with Amine-Based Post-Combustion with CC	✔
Gas	Greenfield - Molten Carbonate Fuel Cell	✘
Gas	Greenfield - 2-on-1 GE7FA CCCT	✔
Gas	Greenfield – 2-on-1 Wartsila 20V34SG Combined Cycle Reciprocating Engine	✘
Gas	Greenfield - Twelve Wartsila 20V34SG Simple Cycle Reciprocating Engines	✘
Gas	Greenfield - Two 501F SCCTs (5% CF)	✔
Gas	Mexico - One GE LM6000 Sprint SCCT (5% CF)	✘

6.1.1 Technology Characterization

Cost, performance, and operating characteristics were developed for each of the seven coal and natural gas options in support of the Preliminary Screening with input from Ameren Missouri's internal resources. .

All performance and cost estimates were based on technologies fueled by the following design fuels:

- Coal - The coal option is characterized such that it can operate on 100 percent Powder River Basin (PRB) coal.
- Natural Gas - All gas-fueled options would be designed to operate on pipeline quality natural gas, assumed to be 100 percent methane with 0.2 grain of sulfur per 100 standard cubic feet, unless specified otherwise.

6.1.1.1 Capacity Ranges

Each of the generation technologies identified in the evaluated options list has sizing limitations. The selection of practical size ranges for each of the technologies is based on Ameren Missouri's ability to plan for and reasonably implement the technology. Table 6A.1 provides a summary of approximate size limitations for new generation units.

[1] 4 CSR 240-22.040(1)
[2] 4 CSR 240-22.040(2)

Table 6A.1 Capacity Ranges

Technology Description	Single Unit Size Lower Range (MW)	Single Unit Size Upper Range (MW)
Ultra-Supercritical PC	500	1,000
Simple Cycle Combustion Turbine	20	270
Combined Cycle Combustion Turbine	25	1,200
Molten Carbonate Fuel Cells	<1	3
Simple Cycle Reciprocating Engine	<1	17
Combined Cycle Reciprocating Engine	18	37

Full load thermal performance and emissions were developed for all evaluated options. Thermal performance was estimated for a 95° F day and a 20° F day. Site conditions were selected to reflect Ameren Missouri's service area. The following elevation and ambient conditions were assumed for all performance estimates:

- Elevation--500 feet above mean sea level.
- 20° F day ambient conditions:
  - Dry bulb temperature--20° F.
  - Relative humidity--60 percent.
- 95° F day ambient conditions:
  - Dry bulb temperature--95° F.
  - Relative humidity--60 percent.

Capacity and performance data for each evaluated option are presented in Table 6A.11 and Table 6A.12 under the Supporting Tables section.

6.1.1.2 Commercial Availability

The commercial status of each of the evaluated technologies was qualitatively assessed. Technology maturity was assessed as either "mature" or "developing." Technologies defined as mature were those that are proven and well established within the electric power generation industry; e.g., combined cycle. Developing technologies consist of all other technologies that may have limited experience, have been utilized in demonstration projects, or consist of laboratory-tested conceptual designs; e.g., coal with carbon capture.

6.1.1.3 Capital Cost Estimates

Screening level, overnight EPC capital cost estimates were developed for all evaluated options and expressed in 2016 dollars. The values presented are reasonable for today's market conditions, but, as demonstrated in recent years, the market is dynamic and unpredictable. Power plant costs are subject to continued volatility and the estimates in this report should be considered primarily for comparative purposes. The EPC costs presented in this report were developed in a consistent manner and are reasonable relative to one another.

The EPC estimates include costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis and are representative of “inside the fence” project scope. The overall capital cost estimates consist of three main components: EPC Capital Cost, Owner’s Cost (excluding AFUDC [Allowance for Funds Used during Construction]), and Owner’s AFUDC Cost. Capital costs for all evaluated options are presented in Table 6A.12.

An allowance has been made for Owner’s costs (excluding AFUDC). Items included in the Owner’s costs include “outside the fence” physical assets, project development, and project financing costs. These costs can vary significantly, depending upon technology and unique project requirements. Owner’s costs were developed as a percentage of the EPC capital cost as shown in the tables referenced above. Owner’s costs are assumed to include project development costs, interconnection costs, spare parts and plant equipment, project management costs, plant startup/construction support costs, taxes/advisory fees/legal costs, contingency, financing and miscellaneous costs. Table 6A.2 shows a more detailed explanation of potential owner’s costs.

For the purposes of characterizing all of the evaluated options, the AFUDC was calculated by applying the Present Worth Discount Rate (PWDR) over half of the construction duration, with the construction duration being defined as the time period from Notice to Proceed (NTP) to Commercial Operation Date (COD).

Table 6A.2 Potential Items Included In Owner's Costs

Project Development: Site selection study Land purchase/options/rezoning Transmission/gas pipeline rights of way Road modifications/upgrades Demolition (if applicable) Environmental permitting/offsets Public relations/community development Legal assistance **Utility Interconnections:** Natural gas service (if applicable) Gas system upgrades (if applicable) Electrical transmission Supply water Wastewater/sewer (if applicable) **Spare Parts and Plant Equipment:** Air quality control systems materials, supplies, and parts Acid gas treating materials, supplies and parts Combustion turbine and steam turbine materials, supplies, and parts HRSG materials, supplies, and parts Gasifier materials, supplies, and parts Balance-of-plant equipment materials, supplies and parts Rolling stock Plant furnishings and supplies Operating spares **Owner's Project Management:** Preparation of bid documents and selection of contractor(s) and suppliers Provision of project management Performance of engineering due diligence Provision of personnel for site construction management	**Plant Startup/Construction Support:** Owner's site mobilization O&M staff training Supply of trained operators to support equipment testing and commissioning Initial test fluids and lubricants Initial inventory of chemicals/reagents Consumables Cost of fuel not recovered in power sales Auxiliary power purchase Construction all-risk insurance Acceptance testing **Taxes/Advisory Fees/Legal:** Taxes Market and environmental consultants Owner's legal expenses: • Power Purchase Agreement (PPA) • Interconnect agreements • Contracts--procurement & construction • Property transfer **Owner's Contingency:** Owner's uncertainty and costs pending final negotiation: • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreement (e.g., interconnection contract costs) **Financing:** Development of financing sufficient to meet project obligations or obtaining alternate sources of funding Financial advisor, lender's legal, market analyst, and engineer Interest during construction Loan administration and commitment fees Debt service reserve fund **Miscellaneous:** All costs for above-mentioned Contractor-excluded items, if applicable

6.1.1.4 Non-Fuel O&M Costs

Non-fuel O&M cost estimates were developed for each of the evaluated options. All O&M cost estimates are presented in Table 6A.12. First year O&M costs (in 2016 $s) were estimated, and for future years a 2% escalation rate was used.

The modes of dispatch used to establish maintenance intervals for many of the options are as follows:

<u>Baseload Dispatch Profiles</u> – Options evaluated at a baseload dispatch mode were assumed to operate at full load at a capacity factor of 85 percent. The coal resource with Carbon Capture and Compression (CCC) was assumed to operate at the same dispatch profile as its non-carbon capture counterparts.

<u>Intermediate Load Dispatch Profiles</u> – Two operating profiles were used for the intermediate load technologies.

- **Profile 1 – Cycling Operation – Off Nights/Off Weekends**: 6 months per year operation at 5 days a week, 8 hours per day in 2x1 combined cycle mode, off-line 16 hours per day and on weekends. Shut down and laid up for 6 winter months per year. Total full load operation of 1,043 hours per year and a capacity factor of about 12 percent.
- **Profile 2 –** Based on the production cost model results from the 2014 IRP, a 45% capacity factor was used for the 2-on1 combined cycle option.

<u>Peaking Load Dispatch Profiles</u> – All new unit combustion turbine options were evaluated at a peaking dispatch mode, with a capacity factor of 5 percent. It was assumed that 90 starts were associated with a 5 percent capacity factor.

Reciprocating engines operating in simple cycle were evaluated at a 5 percent capacity factor as well.

6.1.1.5 Scheduled and Forced Outages

Scheduled maintenance intervals were obtained from original equipment manufacturers (OEMs) or estimated on the basis of Black & Veatch experience for each of the technologies. Where information was not available, maintenance intervals were estimated using data gathered from comparable technologies. These scheduled maintenance patterns were assumed to be the same for technologies employing CCC equipment. The maintenance patterns are presented in Table 6A.3.

Table 6A.3 Scheduled Maintenance Outage Patterns

Technology Description	Weeks/Year
Ultra-Supercritical PC (Note 1)	1-1-3-1-1-6
Molten Carbonate Fuel Cells (Note 2)	1
Combined Cycle Combustion Turbine (Note 3)	1-1-2-1-1-6
Combined Cycle Reciprocating Engine (Note 4)	2-3-2-3-2-4
Siemens 501F (Note 5)	1-2-1-4
GE LM6000 Sprint (Note 6)	1-10
Simple Cycle Reciprocating Engine (Note 4)	2-3-2-3-2-4

Notes:
(1) 1 week boiler/AQS inspection annually, 3 week boiler cleaning/SCR catalyst change at 3 year intervals, and a 6 week STG major outage every 6 years.
(2) Short outages required every 2,000 to 3,000 hours of operation.
(3) 1 week combustion inspection every 8,333 eq. hours, 2 week hot gas path inspection every 25,000 eq. hours, and a 4 week major inspection every 50,000 eq. hours for the combustion turbine.
(4) 2 week per 8,000 hours, 3 weeks per 16,000 hours, and 4 weeks per 48,000 hours.
(5) Siemens recommends the following: 1 week combustion inspection every 400 starts, 2 week hot gas path inspection every 800 starts, and a 4 week major inspection every 1,600 starts.
(6) GE recommends the following: 1 week hot section rotable exchange every 25,000 hours and a 10 week (nominal) engine overhaul every 50,000 hours.

Where available, generic equivalent forced outage rate (EFOR) and equivalent demand forced outage rate (EFORd) data were gathered for each of the technologies. The EFOR and EFORd data are presented in Table 6A.4. The information was taken from the NERC GADS database and published literature to the extent that data were available. When information was not available, values were estimated using data gathered from comparable technologies. EFOR and EFORd were not estimated for technologies employing CCC equipment. For this effort and at this stage of planning, it is assumed that the availability of CCC equipment is independent of the generating facility availability and does not affect EFOR and EFORd. The information is generic, but representative for screening-level supply-side resource analyses.

Table 6A.4 Forced Outage Rates

Technology Description	EFOR, %	EFORd, %
Ultra-Supercritical PC	8%	8%
Molten Carbonate Fuel Cells	2%	2%
Combined Cycle Combustion Turbine	3%	2%
Combined Cycle Reciprocating Engine	3%	2%
Siemens 501F	17%	5%
GE LM6000 Sprint	11%	6%
Simple Cycle Reciprocating Engine	23%	4%

6.1.1.6 Waste Generation

Wastewater and waste solids must be processed and properly disposed. Technologies fueled by natural gas produce negligible solid waste, but can produce wastewater streams. Coal-fueled technologies produce both wastewater and waste solids. Table 6A.5 presents a summary of the production of wastewater and solid wastes for the evaluated options.

Table 6A.5 Waste Generation

Technology Description	Wastewater, gpm	Solid Waste, tons/year
679 MW - Ultra-Supercritical PC with 90% Post CCC	3,300	274,000
100 MW - Molten Carbonate Fuel Cells	Negligible	Negligible
600 MW - Combined Cycle Combustion Turbine	750	Negligible
17.8 MW - Combined Cycle Reciprocating Engine	10	Negligible
346 MW - Siemens 501F	Negligible	Negligible
39.3 MW - Mexico - GE LM6000 Sprint	Negligible	Negligible
99 MW - Wartsila 20V34SG Simple Cycle Reciprocating Engine	Negligible	Negligible

6.1.1.7 Coal Technology Option[3]

Ultra-Supercritical (USC) Pulverized Coal (PC)

The following assumptions have been made for the ultra-supercritical PC option:

1. Single unit site, with a capacity of 900 MW net (nominal).
2. USC TC4F STG and USC PC boiler.
3. AQCS:
    - Low nitrogen oxide (NO_x) burners and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control.
    - Wet flue gas desulfurization (FGD) for sulfur dioxide (SO_2) control.
    - Activated carbon injection for mercury control.

[3] 4 CSR 240-22.040(1)

- Pulse-jet fabric filter for particulate matter (PM10) control.
- Sorbent injection for sulfur trioxide (SO_3) control.

4. Turbine driven boiler feed pumps.
5. Throttle conditions – 3,800 psia (pounds per square inch absolute)/1,110° F main steam/1,110° F reheat.
6. Single reheat steam cycle.
7. Eight feedwater heaters – Three high-pressure (HP), four low-pressure (LP), and one deaerator (DA).
8. Employs carbon dioxide (CO_2) capture and compression (CCC) that utilizes an amine-based chemical solvent to remove 90 percent of the CO_2 from the flue gas stream. Staged compression would deliver the CO_2 to the site boundary at a pressure of 2,200 psig (pounds per square inch gauge). CO_2 transportation and sequestration are evaluated separately.
9. Costs based on PRB coal capability only.

6.1.1.8 Natural Gas Technology Options[4]

Combined Cycle

Performance, emissions, and cost estimates were prepared for the following combined cycle technology:

- 2-on-1 GE combined cycle based on a 7FA.05 CTG.

The following assumptions have been made for all combined cycle options:

1. Two CTGs, two HRSGs, and one TC2F STG.
2. AQCS:
    - Dry low NO_x burners and SCR for NO_x control.
    - CO oxidation catalyst for CO and VOC controls.
3. Inlet air evaporative cooling above 59° F.
4. Duct firing during hot day conditions to match 600 MW net plant output.
5. Triple-pressure HRSGs.
6. A mechanical-draft, counterflow, cooling tower assumed for heat rejection.
7. No HRSG bypass dampers and stacks.

(Note: High efficiency “H” and “J” Class turbines will likely be available in the future. Ameren Missouri is continually evaluating new technologies.)

Fuel Cell

Performance, emissions, and cost estimates were prepared for the following fuel cell technology:

[4] 4 CSR 240-22.040(1)

- Generic, molten carbonate fuel cells.

The following assumptions have been made for the gas-fueled fuel cell facility:

1. Thirty-six (36) 2.8 MW (net, nominal) fuel cell packages.

Combined Cycle Reciprocating Engines

Performance, emissions, and cost estimates were prepared for the following reciprocating engine technology:

- Wärtsilä 20V34SG

The following assumptions have been made for the gas-fueled combined cycle reciprocating engine facility:

1. NO_x reduction would be achieved through use of a urea-based SCR system located in the HRSGs.
2. The power block would consist of two 20V34SG engines, one nonreheat STG, and two HRSGs.
3. A mechanical-draft, counterflow cooling tower would be included.

Simple Cycle

Performance, emissions, and cost estimates were prepared for the following simple cycle technologies:

- Large Frame – Siemens 501F.
- Aeroderivative – GE LM6000 SPRINT.

The following assumptions have been made for all simple cycle options:
1. Dry low NO_x (DLN) burners would be included for NO_x control.
2. Units that are dispatched at a capacity factor of 5 percent would not include an SCR system or CO oxidation catalyst.

(Note: High efficiency “H” Class turbines will likely be available in the future. Ameren Missouri is continually evaluating new technologies.)

Reciprocating Engines (Simple Cycle)

Performance, emissions, and cost estimates were prepared for the following reciprocating engine technology:

- Wärtsilä 20V34SG

The following assumptions have been made for the gas-fueled reciprocating engine facility:

1. Units would be dispatched at a low capacity factor that would preclude SCR.
2. The power block would consist of twelve 20V34SG engines, for a 100 MW net (nominal) output.

No additional operational characteristics, constraints or siting impacts that could affect the screening results were identified. By the same token, no other technology characteristics were identified that may make the technology particularly appropriate as a contingency option under extreme outcomes.

6.1.2 Preliminary Screening Analysis

Preliminary Screening Methodology[5]

After each evaluated option was characterized, each was subjected to a preliminary screening analysis. The preliminary screening analysis provided an initial ranking of the technologies. A scoring methodology was developed to compare the different options within their fuel group by an overall weighted score. This score was developed for each option by comparing the following categories: levelized cost of energy, environmental cost, risk reduction, planning flexibility, and operability. Criteria within those categories were established, and numerical scores were assigned on the basis of the differentiating qualitative technology characteristics. Criteria were established on the basis of Black & Veatch's experience with consideration of Ameren Missouri's known planning requirements. For the 2017 IRP, Ameren Missouri subject matter experts reviewed the scoring criteria and the technology scores were revised as needed. Categories and criteria, along with their assigned weightings, are presented in Table 6A.6.

[5] 4 CSR 240-22.040(2)

Table 6A.6 Scoring Criteria

Category/Criteria	Category/Criteria Weighting	Scoring Basis Guidelines
Utility Cost	**35**	
Levelized cost of energy	90	100 - Lower 5 percentile. 90 to 10 - 5 to 95 percentile, linearly scaled. 0 - Upper 5 percentile.
Specificity of location	10	100 - Within Ameren Missouri service territory. 50 - Within MISO 0 - Outside MISO
Environmental Cost	**20**	
Currently meets regulated emissions limits	60	100 - Produces no emissions. 85 - Ability to meet emissions limits. 0 - Inability to meet emissions limits.
Potential for future addition of more stringent control technologies and level of control	40	100 - Would not require any future controls for any major pollutants. 75 - May require controls for 2 major pollutants. 50 - May require controls for 3 major pollutants. 25 - May require controls for 4 major pollutants. 0 - May require controls for 5 or more major pollutants.
Risk Reduction	**15**	
Technology status	60	100 - Commercially proven. 50 - Demonstration. 25 - Developmental with positive trend. 0 - Developmental with negative trend.
Constructability	20	100 - Less labor, material and equipment risk. 50 - Moderate labor, material & equipment risk. 25 - More labor, material and equipment availability risk.
Safety training requirements	20	100 - Minimal requirement & hazards. 50 - Industry standard for baseload generation in safety training and hazards. 0 - Unique requirements and/or hazards.
Planning Flexibility	**15**	
Permitting	10	100 - Less extensive permitting. 50 - Moderate permitting. 25 - More extensive permitting.
Schedule Duration	10	100 - Lower 5 percentile. 90 to 10 - 5 to 95 percentile, linearly scaled. 0 - Upper 5 percentile.
Fuel Flexibility	25	100 - No fuel required. 50 - Multiple fuels, multiple sources. 25 - Multiple fuels and single source or single fuel and multiple sources. 0 - Single fuel, single source.
Scalability/Modularity/Resource Constrained	20	100 - Has no constraints. 75 - Has one constraint. 25 - Has two constraints. 0 - Is constrained by scalability, modularity, and resource availability.
Transmission Complexity	15	100 - Requires less redundancy, less planning. 50 - Require more redundancy, more planning
Construction Schedule and Budget Risk	20	100 - Cost or schedule uncertainty. 75 - Cost and schedule uncertainty. 50 - Cost and schedule uncertainty with limited industry experience. 25 - Major cost and schedule uncertainty. 0 - Major cost and schedule uncertainty with limited industry experience.
Operability	**15**	
Availability	50	100 - Equivalent Availability factor ≥ 85% 50 - Equivalent Availability factor ≤ 85%
Technical Operability Training	15	100 - Minimal technical operability management (TOM). 50 - Moderate TOM 25 - Moderate TOM and advanced technology. 0 - Unique experience and management requirements for operation.
Load-Following/VAR Support	35	100 - Load-following and reactive power support capabilities. 50 - Load-following or reactive power support capabilities. 25 - Moderate load-following or reactive power support capabilities. 0 - Inability or constraints to load-following and reactive power support capabilies.

Risk Reduction – The scoring of the various options took the amount of risk associated with development and operations into account. An option's commercial status, constructability, and potential hazards were all evaluated.

Planning Flexibility – The time required to construct a resource option, the fuels an option could burn to produce electricity, and Ameren Missouri's ability to properly plan and integrate an option into its current service network were evaluated for this category.

Operability – An option's availability, load-following capability, and complexity of operation were reviewed and scored accordingly.

Environmental Cost – A resource option's ability to meet current and potential future environmental regulations was incorporated into the ranking process. Emissions constituents considered for this category include, but are not limited to, CO_2, particulate matter, sulfur oxides (SO_x), NO_x, Hg, and CO. A schedule of emission costs used in the utility cost estimates for screening is presented in Table 6A.7.

Table 6A.7 Emissions Costs and Escalation Rates[6]

	SO_2	NO_X Annual	NO_X Seasonal	CO_2*
2016 $/ton	$6.00	$7.50	$200.00	$2.23
Escalation	0.0%	0.0%	0.0%	2.00%
Source	Internal Subejct Matter Experts based on CSAPR			IHS CERA-North American Power Market Fundamentals: Rivalry, April 2016 (CO2 Prices begin in 2025)

* Probability-weighted average

It was assumed that new resources would be required to meet more stringent environmental regulations and, therefore, would not incur any additional mitigation costs. For example, any new coal unit would include a scrubber for SO_2, an SCR for NO_x, activated carbon injection for mercury, and in some cases carbon capture and compression technology.

Levelized Cost of Energy – One of the more significant criteria in the scoring was the levelized cost of energy (LCOE). Financial factors, such as fuel costs, tax life, economic life, escalation rates, present worth discount rate (PWDR), levelized fixed charge rate (LFCR) that were used in the LCOE estimates in the screening in addition to other costs presented earlier are listed in Table 6A.8 and Table 6A.9.

[6] 4 CSR 240-22.040(5)(D)

Table 6A.8 Fuel Prices for LCOE Estimates

Delivered	Greenfield		Greenfield	
Type	PRB Coal		Natural Gas	
2017 $/MMBtu	$1.88	(Varies)	$3.45	(Varies)
Escalation	2.0%	(Varies)	2.0%	(Varies)

Table 6A.9 Financial Inputs for LCOE Estimates

Technology	Tax Life Years	Economic Life Years	LFCR Percent	PWDR Percent
Coal - USCPC	20	40	9.53	5.95
Simple Cycle (SCCT)	15	30	9.94	5.95
Combined Cycle (CCCT)	20	30	10.25	5.95
Fuel Cells	15	20	11.65	5.95
Gas Reciprocating	15	30	9.94	5.95

Annual costs for the LCOE estimates include levelized annual capital cost, fixed and variable O&M, fuel cost, and emissions allowances if applicable; LCOE estimates were developed in three different ways: without emission costs, with emissions costs for SO_2 and NO_x, and with emissions costs for SO_2, NO_x and CO_2.

Preliminary Screening Results[7]

The levelized costs of energy and overall scorings of the evaluated options are presented in Table 6A.15a and Table 6A.15b. All levelized costs of energy and overall scorings are presented with and without SO_2, NO_x, and CO_2 price forecasts included. The following figures show the LCOE and total screening scores.

[7] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(B)

Figure 6A.1 LCOE for Coal and Gas Options[8]

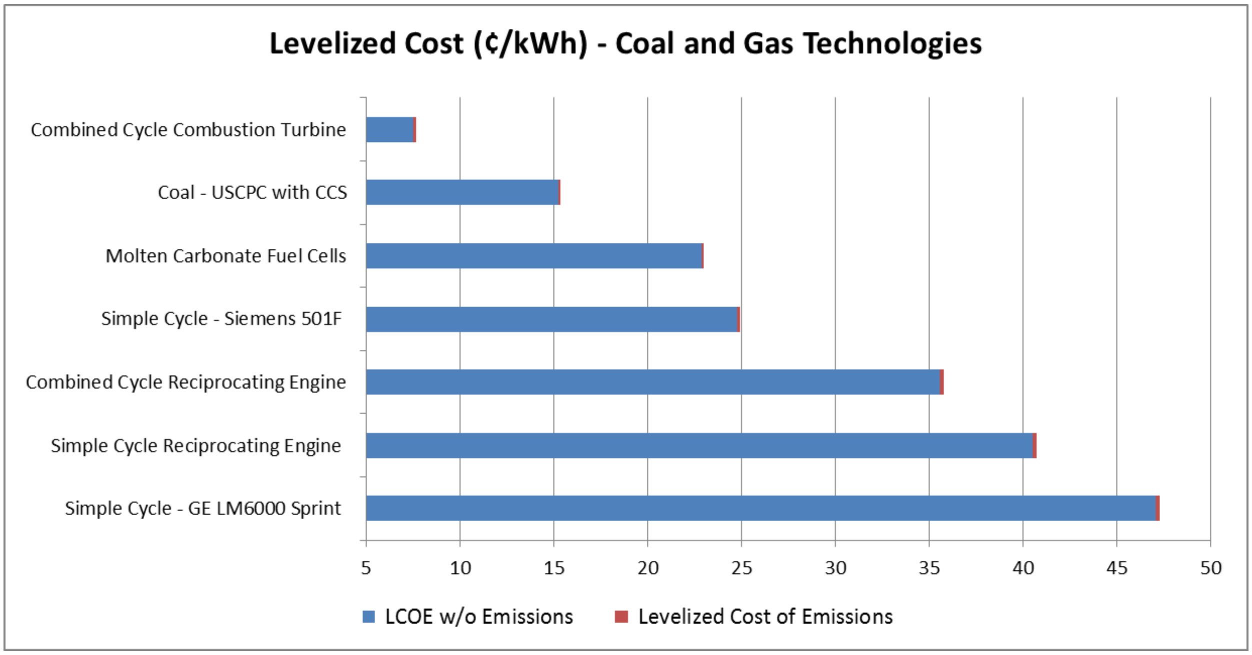
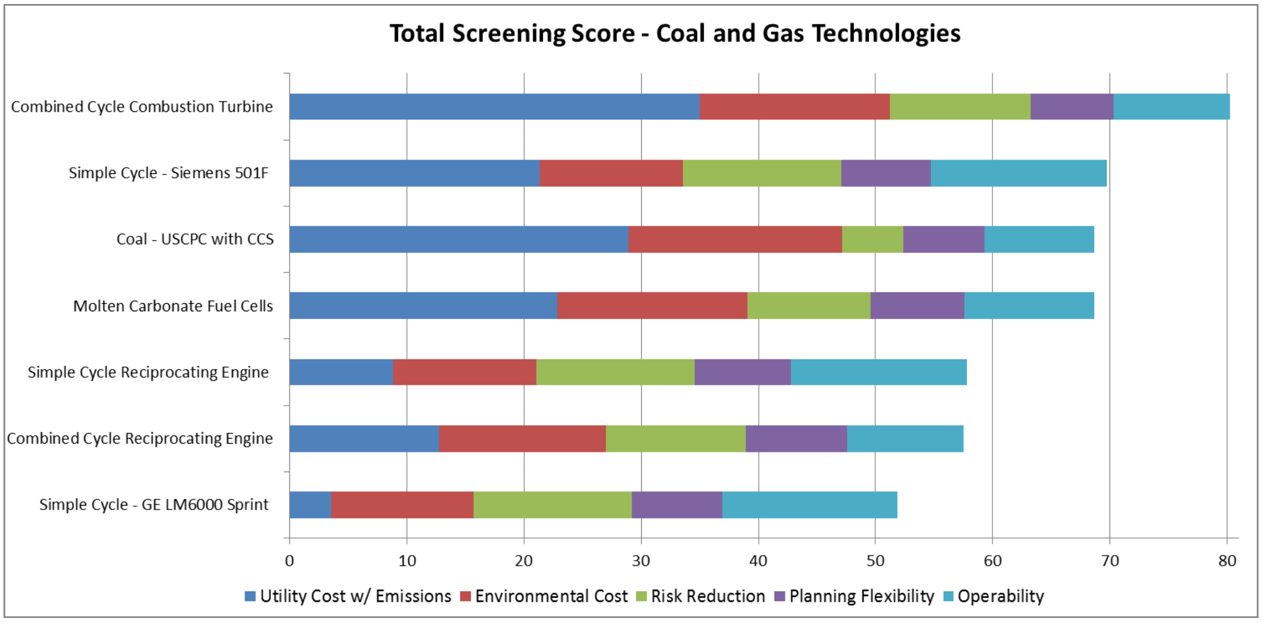


Figure 6A.2 Total Screening Score for Coal and Gas Options[9]



[8] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(C)
[9] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(C)

6.1.3 Candidate Options

Using the preliminary screening results as a tool, Ameren Missouri selected three technologies to be characterized further. Table 6A.10 presents a listing of the potential candidate options.[10]

Table 6A.10 Candidate Options[11]

Technology Description	Load Type	Fuel Type
Greenfield - USCPC w/ Carbon Capture	Base	Coal
Greenfield - Combined Cycle	Intermediate	Gas
Greenfield - Simple Cycle	Peaking	Gas

6.2 Nuclear Options[12]

6.2.1 AP1000 Characterization

Design Parameters

Key AP1000 design parameters include the following:

Design life - 40 years
- Thermal Output - 3,451 MW
- Electrical Output - 1,100 MW
- Number of fuel assemblies - 157
- Fuel lattice - 17 ft x 17 ft
- Active Fuel Length - 12.0 ft
- Refueling Frequency - 18 month Refueling Interval

The reactor can use Uranium dioxide fuel rods.

Decommissioning Cost

After a nuclear energy center is closed and removed from service, it must be decommissioned. Decommissioning includes removal and disposal of radioactive components and materials at the nuclear energy center. The U.S. Nuclear Regulatory Commission (NRC) requires licensees to put aside funds for the eventual decommissioning throughout the energy center's operating life.

The reductions in building volumes, number of buildings, and number of components have a direct effect on the decommissioning costs of the AP1000 units. The AP1000 has 40% less building volume, 80% less piping, 50% fewer valves, and 85% less cable

[10] 4 CSR 240-22.040(2)(C)2
[11] 4 CSR 240-22.040(4)(A)
[12] 4 CSR 240-22.040(1)

than a typical Generation II plant. Based upon the substantial reduction in volume of material to be disposed of, decommissioning costs are likely less than existing nuclear facilities in the U.S. Based on licensing documents submitted to the NRC, over $400 million dollar per unit decommissioning estimate (2007 dollars) was reported as part of the twin unit AP1000 project under construction at the Vogtle Site in Georgia. These estimates were reviewed and approved by the NRC.

Annual decommissioning fund contributions were estimated using the same inflation and fund return assumptions as in Ameren Missouri's 2014 triennial funding update filing for Callaway Energy Center.

Scheduled Outage

The refueling cycle requirements control the scheduled routine and maintenance outages for nuclear units. Current enrichment limits of 5 percent prevent fuel cycle lengths longer than 24 months. Ameren Missouri assumed an 18 month refueling schedule; scheduled maintenance would occur in a 24 day period (3.43 weeks) every 18 months.

Forced Outage Rate and Availability

Based on an expected forced outage rate of 2.0% and scheduled maintenance of 24 days every 18 months, annual availability is estimated to be approximately 94%.

Waste Generation

Based on the South Carolina Electric & Gas Combined License (COL) Application for Summer 2&3, Westinghouse estimates that one AP1000 would generate approximately 5,760 cubic feet of low-level radioactive waste annually. Following volume reduction and compaction, the estimated low-level radioactive waste disposal volume is 1,960 cubic feet per year for each new unit.

Water Impacts

Consumptive use of water is primarily attributable to evaporation losses from cooling water systems, blowdown, and cooling tower drift. The AP1000 will utilize two natural-draft cooling towers with evaporative losses of approximately 14,550 gallons per minute (gpm). Blowdown from the new cooling towers will be approximately 4,850 gpm each. The unit will consume a total of approximately 19,413 gpm including estimated cooling tower drift (12.5 gpm).

In comparison to average annual flow of the Missouri River over 50 years, such losses are estimated to require less than 0.1 percent of river flow. The water resources so committed for plant operation will have no material effect on other users downstream from the plant.

6.3 Supporting Tables

Table 6A.11 Coal and Gas Options – Capacity and Performance[13]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Gross Plant Output, MW (20 F)	Full Load Auxiliary, MW (20 F)	Full Load Net Plant Output, MW (20 F)	Full Load Net Plant Heat Rate HHV, Btu/kWh (20 F)	Full Load Gross Plant Output, MW (95 F)	Full Load Auxiliary, MW (95 F)	Full Load Net Plant Output, MW (95 F)	Full Load Net Plant Heat Rate HHV, Btu/kWh (95 F)	Assumed Annual Capacity Factor	Forced Outage Rate
Greenfield - Amine-Based Post Combustion with CCS	Coal	Baseload	USCPC	860	174	686	12,200	852	173	679	12,300	85%	8%
Greenfield - Molten Carbonate	Gas	Baseload	Fuel Cell	N/A	N/A	100	8450	N/A	N/A	100	8450	80%	2%
Greenfield - 2-on-1 GE7FA	Gas	Intermediate	CCCT	661	20	641	6655	617	17	600	6661	45%	2%
Greenfield - 2x1 Wartsila 20V34SG	Gas	Intermediate	Recip	18.3	0.57	17.8	8,100	18.3	0.57	17.8	8,100	12%	2%
Greenfield - Two 501Fs	Gas	Peaking	SCCT	443	1	436	10,020	358	1	352	10,530	5%	5%
Mexico - One LM6000 Sprint	Gas	Peaking	SCCT	48.5	1.2	47.3	9,180	40.7	1.0	39.7	9,690	5%	6%
Greenfield - Twelve Wartsila Recip. Engines	Gas	Peaking	Recip	101.2	2.2	99.0	8,740	101.2	2.2	99.0	8,740	5%	4%

Table 6A.12 Coal and Gas Options – Cost Estimates[14]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	EPC Capital Cost, $1,000	EPC Capital Cost, $/kW	Owner's Cost, $1,000	Project Cost - with Owner's Cost, $1,000	Project Cost - with Owner's Cost, $/kW	Total Project Cost - with Owner's Cost and AFUDC, $1,000	First Year Fixed O&M Cost, $1,000/yr	First Year Fixed O&M Cost, $/kW-yr	First Year Variable O&M Cost, $1,000/yr	First Year Variable O&M Cost, $/MWh	Owner's Cost, percent	AFUDC Cost, percent
Greenfield - Amine-Based Post Combustion with CCS	Coal	Baseload	USCPC	679	3,495,450	5,148	433,436	3,928,886	5,786	4,814,998	24,459	36.0	33,940	6.91 12.725*	12.4%	23%
Greenfield - Molten Carbonate	Gas	Baseload	Fuel Cell	100	687,714	5,743	34,386	722,100	7,221	866,520	0	0.0	29,936	40.20	5%	20%
Greenfield -2-on-1 GE7FA	Gas	Intermediate	CCCT	600	631,542	1,053	137,866	769,407	1,282	797,783	4,852	8.1	9,917	4.19	12%	4%
Greenfield - 2x1 Wartsila 20V34SG	Gas	Intermediate	CC Recip	17.8	36,873	2,072	9,587	46,460	2,610	48,354	725	40.8	164	8.76	26%	4%
Greenfield - Two 501Fs	Gas	Peaking	SCCT	352	209,039	594	29,265	247,067	702	257,141	2,786	7.9	2,692	17.46	14%	4%
Mexico - One LM6000 Sprint	Gas	Peaking	SCCT	39.7	43,352	1,092	11,272	54,624	1,376	56,851	1,257	31.7	116	6.69	26%	4%
Greenfield - Twelve Wartsila Recip. Engines	Gas	Peaking	SC Recip	99.0	97,437	984	13,641	111,078	1,122	115,607	2,975	30.1	407	9.40	14%	4%

* Carbon transportation and storage cost

[13] 4 CSR 240-22.040(1)
[14] 4 CSR 240-22.040(5)(B); 4 CSR 240-22.040(5)(C)

Table 6A.13 Coal and Gas Options – Commercial Status, Construction Duration and Environmental Characteristics[15]

Resource Option	Fuel Type	Operations Mode	Technology Description	Fuel Flexibility	Technology Maturity	Permitting & Development, months	NTP to COD, months	NOx, lbm/MBtu	SO2, lbm/MBtu	CO2, lb/MMBtu	CO, lbm/MBtu	PM10, lb/MWh	Hg Removal Percentage	Water Usage, gal/min
Greenfield - Amine-Based Post Combustion with CCS	Coal	Baseload	USCPC	Yes	Developing	24 to 36	64	0.050	0.06	21	0.120	0.012	90%	4,150 to 7,700
Greenfield - Molten Carbonate	Gas	Baseload	Fuel Cell	Limited	Developing	14 to 18	60	0.009	0.0006	117	0.009	0.004	0%	2,500 to 4,600
Greenfield -2-on-1 GE7FA	Gas	Intermediate	CCCT	No	Mature	14 to 18	38	0.009	0.0006	117	0.009	0.004	0%	2,500 to 4,600
Greenfield - 2x1 Wartsila 20V34SG	Gas	Intermediate	Recip	No	Mature	14 to 18	38	0.032	0.0006	117	0.570	0.024	0%	10 to 100
Greenfield - Two 501Fs	Gas	Peaking	SCCT	No	Mature	14 to 18	27	0.033	0.0006	117	0.009	0.003	0%	25 to 46
Mexico - One LM6000 Sprint	Gas	Peaking	SCCT	No	Mature	14 to 18	27	0.054	0.0006	117	0.120	0.005	0%	15 to 29
Greenfield - Twelve Wartsila Recip. Engines	Gas	Peaking	Recip	No	Mature	14 to 18	30	0.318	0.0006	117	0.570	0.018	0%	0 to 100

Table 6A.14 Coal and Gas Options – Economic Parameters and LCOE[16]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Debt Term, years	Economic Life, years	FOM Escalation Rate	VOM Escalation Rate	Present Worth Discount Rate	Fixed Charge Rate	LCOE w/o Emissions, ¢/kWh	Levelized Cost of SO2 & NOx, ¢/kWh	Levelized Cost of CO2, ¢/kWh	LCOE w/ Emission Costs & CO2, ¢/kWh
Greenfield - Amine-Based Post Combustion with CCS	Coal	Baseload	USCPC	679	20	40	2.0%	2.0%	5.95%	9.53%	15.24	0.00	0.06	15.30
Greenfield - Molten Carbonate	Gas	Baseload	Fuel Cell	100	15	20	2.0%	2.0%	5.95%	11.65%	22.87	0.00	0.11	22.98
Greenfield - 2-on-1 GE7FA	Gas	Intermediate	CCCT	600	20	30	2.0%	2.0%	5.95%	10.25%	7.50	0.00	0.14	7.64
Greenfield - 2x1 Wartsila 20V34SG	Gas	Intermediate	Recip	17.8	15	30	2.0%	2.0%	5.95%	9.94%	35.57	0.00	0.17	35.73
Greenfield - Two 501Fs	Gas	Peaking	SCCT	352	15	30	2.0%	2.0%	5.95%	9.94%	24.72	0.00	0.17	24.89
Mexico - One LM6000 Sprint	Gas	Peaking	SCCT	39.7	15	30	2.0%	2.0%	5.95%	9.94%	47.07	0.00	0.20	47.27
Greenfield - Twelve Wartsila Recip. Engines	Gas	Peaking	Recip	99	15	30	2.0%	2.0%	5.95%	9.94%	40.49	0.01	0.18	40.68

15 4 CSR 240-22.040(1)
16 4 CSR 240-22.040(2)(C)1

Table 6A.15a Coal and Gas Options – Scoring Results[17]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Levelized Cost of Energy w/o Emissions Score	Levelized Cost of Energy w/ SO2, NOx Score	Levelized Cost of Energy w/ SO2, NOx & CO2 Score	Speficity of Location Score	Utility Cost w/o Emissions Total Score	Utility Cost with SO2 & NOx Total Score	Utility Cost with Emissions & CO2 Total Score	Currently Meets Regulated Emission Limits Score	Potential for Future Addition of More Stringent Controls Score	Environmental Cost Total Score	Technology Status Score	Constructability Score	Safety Training Requirements Score	Risk Reduction Total Score
Greenfield - Amine-Based Post Combustion with CCS	Coal	Baseload	USCPC	679	81	81	81	100	**29**	**29**	**29**	85	100	**18**	25	50	50	**5**
Greenfield - Molten Carbonate	Gas	Baseload	Fuel Cell	100	61	61	61	100	**23**	**23**	**23**	85	75	**16**	50	100	100	**11**
Greenfield - 2-on-1 GE7FA	Gas	Intermediate	CCCT	600	100	100	100	100	**35**	**35**	**35**	85	75	**16**	100	50	50	**12**
Greenfield - 2x1 Wartsila 20V34SG	Gas	Intermediate	Recip	17.8	29	29	29	100	**13**	**13**	**13**	85	50	**14**	100	50	50	**12**
Greenfield - Two 501Fs	Gas	Peaking	SCCT	352	57	57	57	100	**21**	**21**	**21**	85	25	**12**	100	100	50	**14**
Mexico - One LM6000 Sprint	Gas	Peaking	SCCT	39.7	0	0	0	100	**4**	**4**	**4**	85	25	**12**	100	100	50	**14**
Greenfield - Twelve Wartsila Recip. Engines	Gas	Peaking	Recip	99	17	17	17	100	**9**	**9**	**9**	85	25	**12**	100	100	50	**14**

Table 6A.15b Coal and Gas Options – Scoring Results

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Permitting Score	Schedule Duration Score	Fuel Flexibility Score	Scalability/ Modularity/ Resource Constrained	Transmission Complexity Score	Construction Schedule and Budget Risk Score	Planning Flexibility Total Score	Availability Score	Technical Operability Training Score	Load Following/ VAR Support Score	Operability Total Score	Total Score w/o Emissions	Total Score w/ SO2 & NOx	Total Score w/ SO2, NOx & CO2
Greenfield - Amine-Based Post Combustion with CCS	Coal	Baseload	USCPC	679	25	0	25	100	50	50	**7**	100	25	25	**9**	**69**	**69**	**69**
Greenfield - Molten Carbonate	Gas	Baseload	Fuel Cell	100	100	11	0	100	50	75	**8**	100	100	25	**11**	**69**	**69**	**69**
Greenfield - 2-on-1 GE7FA	Gas	Intermediate	CCCT	600	50	50	0	75	50	75	**7**	100	50	25	**10**	**80**	**80**	**80**
Greenfield - 2x1 Wartsila 20V34SG	Gas	Intermediate	Recip	17.8	50	75	0	75	100	75	**9**	100	50	25	**10**	**58**	**58**	**58**
Greenfield - Two 501Fs	Gas	Peaking	SCCT	352	50	13	0	75	100	75	**8**	100	100	100	**15**	**70**	**70**	**70**
Mexico - One LM6000 Sprint	Gas	Peaking	SCCT	39.7	50	13	0	75	100	75	**8**	100	100	100	**15**	**52**	**52**	**52**
Greenfield - Twelve Wartsila Recip. Engines	Gas	Peaking	Recip	99.0	50	0	0	100	100	75	**8**	100	100	100	**15**	**58**	**58**	**58**

[17] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(C)1

6.4 Compliance References