5.0 CAPACITY ALTERNATIVES

Several alternatives to the construction of new capacity were considered. The other options to provide energy or reduce the need include: load management, renewable energy utilization, distributed generation, central station generation, repowering of existing units, participation in other units, or purchase power options. The internet Web site for Associated Electric Cooperative, Inc. (http://www.aeci.org/index.html), presents information concerning their plans to build new generation, including consideration of conservation and renewable energy resources. This information is highlighted under the topic of "Building for Tomorrows Energy Needs."

5.1 LOAD MANAGEMENT

As a cooperative, AECI's primary purpose is to provide low cost energy to meet the needs of its members. Consumer/members serve on the management team for the distribution cooperatives, the G&Ts, and on the Board for AECI. In the year 2000, AECI modified its rate structure to have both a peak and base demand billing component. This kind of demand billing structure sends appropriate price signals to and encourages the G&T members to take any cost-effective action possible to lower their peak demand at the time of AECI's summer and winter peak. As discussed in Section 4, implementation of DSM or other load management policies is the responsibility of individual distribution cooperatives. Beyond providing information and sending appropriate price signals in its rates, there is little else AECI can do that would have a significant effect on the projected load growth in their system.

As noted earlier, the major load growth is associated with residential growth, and this category has already experienced some conservation measures and efficiency improvements. Although additional improvements to efficiency and improved load management are anticipated, these are already incorporated in the load forecast.

5.2 RENEWABLE ENERGY SOURCES

AECI is in a similar situation with respect to renewable resources as it is with load management. AECI exists for the sole purpose of providing all the energy demanded by its member owners reliably and at the lowest cost possible. Therefore, absent specific requirements from our members, renewable resources can only be incorporated into AECI's generation mix when they are the lowest cost alternative. Every quarter AECI provides its members the opportunity to purchase energy from renewable resources. To date, this demand has been very limited and AECI has been able to supply it through its own renewable generation resource.

In general, renewable technologies hold promise for certain applications, and in certain locations, but the available renewable energy sources are not compatible with the need for this project. For the projected baseload energy needs of AECI, renewable energy technologies, while often innovative and in some aspects environmentally preferable, do not yet provide a reliable generation source for meeting baseload requirements. This is due in large part to their dependence on uncontrollable factors (i.e. the wind and sun) and the relatively large land requirement per MW of capacity of these technologies. As the technologies mature, and the development costs become more competitive with conventional generation alternatives, the use of renewable energy sources will increase.

5.2.1 Wind Energy

Wind energy has developed rapidly during the past decade due in part to Federal supporting grants. Fuel costs are non-existent and the only costs are the capital costs associated with the initial installation of the equipment, including the transmission lines, and maintenance costs.

The 1.5-Megawatt series turbines are the largest wind turbines manufactured in the United States and are among the most widely utilized worldwide with more than 1,000 in operation today. The turbine rotor diameter is about 230 feet (10 percent longer than the wingspan of a Boeing 747), and the rotor height, at its tallest point, is about 330 feet. Each machine requires space for the 230-foot blades to spin freely, and optimal spacing is required to assure minimal interference between turbines. According to a publication from the American Wind Energy Association (AWEA) entitled "The Most Frequently Asked Questions About Wind

Energy," in open flat terrain, the land area required is approximately 50 acres per MW (AWEA, 2005). Therefore, to produce 660 MW of power would require approximately 433 of the 1.5 MW turbines, or over 21,000 acres of land. Also, due to the intermittent nature of wind, capacity factors, even in high wind resource areas, are no more than about 30 percent. To be comparable to a 660 MW baseload plant, over 2,000 MW of widely dispersed wind generation would be required.

Some larger turbine systems are under development, including a 3.6 MW system, which is the industry's highest capacity operating prototype to date. The continuing development of larger and more efficient wind power systems is expected to make the technology an even more cost-competitive power generation option in the years ahead. As mentioned above, it is important to note that since the wind does not blow all of the time, it cannot be the only power source for that many households without some form of power storage system or grid backup.

As a renewable resource, wind is classified according to wind power classes, which are based on typical wind speeds. These classes range from class 1 (the lowest) to class 7 (the highest) Wind resources in Missouri are classified by the National Renewable Energy Laboratory (NREL) as Class 2 and Class 3 (Elliott, et al., 1986). Wind power classes and their respective power and speeds are provided in Table 5-1. According to the Missouri Department of Natural Resources (MDNR):

> "Generally speaking, utility-scale wind power projects using large turbines that service the electrical grid require an average wind speed of at least 7 meters per second (15.7 miles per hour) or average power of at least 400 Watts per square meter (NREL class 4). Small-scale turbines such as those used by farmers and homeowners are designed to operate at lower wind speeds, and may be useful at average speeds as low as 5-6 meters per second (11.2 to 13.4 miles per hour, NREL class 2 to 3)." (MDNR, 2005)

MDNR is working with several utilities to study winds at high elevations to determine whether large commercial wind farms are possible in the state. Kansas City-based Aquila Inc. and St. Louis-based AmerenUE are funding a yearlong study through the University of

Table 5-1 Classes of Wind Power

Wind Power Class	Wind Power	Speed, m/s (mph)[a]
1	1<200	5.6 (12.5)
2	200-300	5.6-6.4 (12.5-14.3)
3	300-400	6.4-7.0 (14.3-15.7)
4	400-500	7.0-7.5 (15.7-16.8)
5	500-600	7.5-8.0 (16.8-17.9)
6	600-800	8.0-8.8 (17.9-19.7)
7	>800	>8.8 (19.7)

[a] Mean wind speed is based on the Rayleigh speed distribution of equivalent wind power density. Wind speed is for standard sea-level conditions. To maintain the same power density, speed increases 3%/1000 m (5%/5000 ft) of elevation. (from the Battelle Wind Energy Resource Atlas)
Source: AWEA, 1998.

Missouri-Columbia to look at six locations. The NREL has recently provided new maps of the state's wind speeds indicating the windiest part of the state is in extreme northwest Missouri, rather than in the southwest as previously shown on a 1980's map (Kansas City Star, 2005). Statewide wind resource maps are available online at http://www.eere.energy.gov/windandhydro/windpoweringamerica/wind_maps.asp.

Based on this information, the wind resources in Missouri may be adequate for small scale applications, but would not offer the average wind power required for utility scale wind power projects.

In addition, very good wind generation resources generally achieve a capacity factor of about 25 to 35 percent. In other words, although the wind speed may be within the range required to produce power approximately 65 to 80 percent of the time, it will only be able to achieve between 25 to 35 percent of maximum capacity on an annual average (AWEA, 2004). This is not compatible with a baseload requirement, and would need to be supplemented with energy resources that can be scheduled to provide "firm" energy. There are some wind generation facilities that have included natural gas fired combustion turbines to supplement the wind powered generation and therefore can offer "firm" energy. In this type of installation, the high costs of the natural gas fuel are offset somewhat by the low costs of the wind generation. The total cost however, including the capital costs for both, plus the operation and maintenance is not as cost effective as other options for firm baseload generation capacity even with wind's current production tax credit.

In addition, numerous environmental issues have been raised concerning wind turbine installation including: potential impacts to migrating waterfowl, raptors, and bats; visual impacts; and noise. Small wind energy systems are a feasible component of load management, and can be used to reduce energy usage requirements within residential, commercial, and agricultural categories. The consumers/members of AECI can, and do, implement small wind energy projects as determined individually to be appropriate.

In summary, wind is an improving generation technology that can contribute to a systems energy supply. However, until significant advances in storage technology are realized, wind will continue to need substantial subsidy, such as the federal production tax credit, to be economically viable. At this time it has been estimated that two-thirds of the economic value of wind projects comes from tax benefits (Feo, 2004). Therefore, unless and until this changes or AECI's members begin to demand a renewable resource, wind is not a viable alternative to the proposed project.

5.2.2 Solar

The solar powered systems for potential power generation include both direct conversion, using photovoltaic (PV) cells, and indirect conversion using concentrated solar power (CSP) system to create steam. There are two primary obstacles to solar energy development for AECI's need for central power generation; the space required and the energy storage requirement.

According to the NREL, Missouri has a good useful resource throughout the state for flat-plate collectors using PV cells. In one of the state's better locations, a PV array with a collector area equal to the size of a football field (1.3 acres) can produce around 957,000 kWh per year. This is enough to power 96.1 average homes (NREL, 2005). Using the example above, approximately 7,900 acres or 12 square miles would be needed for this technology to produce the 660 MW projected for this project.

The Department of Energy (DOE) has established a partnership between Sandia National Laboratory and the NREL to investigate and encourage the development of solar energy (DOE, April 2005). Within this program the DOE researches and develops various CSP systems including: trough systems, dish/engine systems, and power towers. These technologies are used in CSP plants that use different kinds of mirror configurations to convert the sun's energy into high-temperature heat. The heat energy is then used to generate electricity in a steam generator.

CSP demonstration projects have shown the ability to deliver power during periods of peak demand by using thermal storage systems. Land requirements for CSP plants vary with generating capacity and technology. Generally four to five acres are required for each megawatt of installed capacity. To serve the planned 660 MW for AECI, this would require at least 2,600 acres.

According to the NREL, for concentrating collectors, Missouri could pursue some type of technologies, but large scale thermal electricity systems are not effective with these resources. In the state's best areas, a current PV solar concentrator system with a collector area of 200,000 square meters, a system covering roughly 200 acres, could produce about 35,011,000 kWh per year—enough to power 3,513.4 homes. This correlates to approximately 32,500 acres or 50 square miles that would be needed to produce the 660 MW projected form this project.

Most of these studies and solar energy demonstration plants have been accomplished in the southwest United States where conditions are ideal for solar power. The NREL has developed maps of solar resources for the United States and many other regions, to allow precise assessment of potential sites. No solar sites have been identified in AECI’s service area that would be suitable for the large scale generation required to satisfy their loads. Nonetheless AECI continues to follow commercial advances in solar photovoltaic technology.

Solar heating and photovoltaic energy systems are a feasible component of load management, and can be used to reduce energy usage requirements within residential, commercial, and agricultural categories. The consumers/members of AECI can, and do, implement solar technologies as determined individually to be appropriate.

Solar is a resource similar to wind in that it is intermittent, and requires large land areas, and advanced storage technologies to provide a baseload resource. However, the solar technology is not as advanced and costs are higher than wind. Solar is not a viable alternative for this project.

5.2.3 Hydroelectric

Hydroelectric resources can be more dependable, but are commonly used to supplement baseload generation when water is available, and there is a peak demand. There are several hydroelectric generating sources in the region. None of these existing facilities or planned hydroelectric generation resources would be able to meet the baseload need of 660 MW. In addition, both the construction of a new dam and the operation of a hydroelectric facility can result in unacceptable environmental impacts. In fact, it is questionable whether another hydroelectric facility will ever be permitted in the U.S.

5.2.4 Biomass

Biomass is the renewable resource of highest potential in the AECI service area. Conventional steam electric generation is capable of using biomass fuels to provide some or all of the energy requirements. Due to the fact that the biomass fuels usually contain less heat per pound and more water per pound than coal, using biomass fuels can require substantially greater material handling. In some cases, treating the fuels (crushing, drying, pelletizing, etc.) is beneficial to the combustion process, but adds to the fuel preparation costs. AECI operates the Chamois plant and uses biomass fuels for a portion of that plant's heat input. AECI does not intend to design the proposed new AECI baseload plant to utilize biomass fuels for a portion of the heating requirements for the following reasons:

- Capacity is available at the Chamois plant to burn additional biomass fuels.
- Other existing units in the AECI system are better suited to biomass co-firing than the proposed unit.
- Availability of biomass fuels in large quantities are seasonal and subject to frequent interruptions and variability in both quality and quantity.

- The use of biomass fuels is best suited to combustion processes such as circulating fluidized bed or stoker firing. These combustion processes are not typically available above a single unit size of 250 MW, and have a lower efficiency than some other combustion processes.
- The proposed unit will be a pulverized coal unit which does not lend itself to biomass co-firing.
- Biomass fuels can reduce the potential for recycle (sales) of ash.

5.3 DISTRIBUTED GENERATION

Fuel cells, micro-turbines, internal combustion engines and battery energy storage systems were briefly considered to meet AECI's needs. Fuel cells are not currently economical on a commercial electric generation basis. Micro-turbines, while increasingly becoming an element of resource planning strategy, are not cost effective as a primary source of meeting overall customer requirements. Micro-turbines will continue to provide an option for niche power requirements where lack of transmission access, footprint limitations, and low load factor situations exist. Internal combustion engines (i.e. diesels) are used throughout the country for smaller generation needs. A large engine could produce approximately 15 MW of power, which means that over 40 such engines would need to be distributed throughout the service territory to replace the planned centralized generation of 660 MW. This source would have the disadvantage of higher fuel prices and greater emissions of some pollutants. For the reasons above, none of the distributed generation alternatives are appropriate for AECI's proposed baseload plant.

5.4 CENTRAL STATION GENERATION

The following sections apply to central station projects as opposed to distributed generation. Fossil fuels are the most cost effective fuel source for the centralized energy demand. The only alternative to fossil fuels that has been successfully demonstrated to provide the capacity and firm power required for large dependable and continuously operated centralized generation is nuclear.

5.4.1 Nuclear

The Nuclear Energy Institute provides a substantial amount of information on its website (http://www.nei.org/) related to the re-emergence of nuclear technology. Prominent among this information is the recent bill referred to as the Climate Stewardship and Innovation Act of 2005 (*Introduction of S. 1151 on May 26; Congressional Record, page S6046*). This bill, introduced by Senators McCain and Lieberman, strongly supports additional development of nuclear technology to help respond to the global climate change issues.

As evidence of the growing recognition of the need to reconsider the potential for nuclear energy, three industry consortia applied in 2004 to the DOE to test the new combined construction and operating license (COL) for new nuclear power plants. The consortia include NuStart Energy Development LLC, a partnership of 11 leading energy companies, a group led by Dominion, and another led by the TVA. The three consortia will partner with DOE to test the Nuclear Regulatory Commission's new COL process and DOE will provide funding to the groups to assist in the development of advanced technology reactors.

Nuclear energy is currently our nation's largest source of emission-free electricity and our second largest source of power overall. The 103 U.S. nuclear units supply about 20 percent of the electricity produced in the United States. A total of 441 nuclear power plants are operating around the world in 31 countries, and supply approximately 16 percent of the world's electrical energy. Currently 25 new nuclear plants are under construction worldwide. Although there are some problems, including the long term disposal of nuclear waste material that need to be resolved, it is likely that nuclear energy will have a significant role in the energy future of the United States and the world.

Further information concerning nuclear energy can be found through the DOE, the Nuclear Regulatory Commission (NRC), the Nuclear Energy Institute (NEI), the American Nuclear Society (ANS), the World Nuclear Association, the Nuclear Energy Agency (NEA) and the International Atomic Energy Agency (IAEA).

AECI believes nuclear power will be a critical component of the U.S.'s energy future. However, the risks and costs associated with the next generation of nuclear plants will be large. As noted above, even large utilities are forming consortia to deal with these potential risks and costs. While AECI believes nuclear power may be an option for its future generating needs, it is simply far too small for nuclear power to be a viable option for this project.

5.4.2 Natural Gas

Natural gas-fired generation was evaluated and determined to not be a preferred option to meet the baseload energy requirements due to the higher fuel costs and volatility of natural gas prices. Natural gas-fired generation can be developed using internal combustion, typically either simple-cycle or combined-cycle combustion turbine technology, or using external combustion such as direct firing in a boiler.

Direct firing in a boiler was rejected due to the current and projected cost of natural gas and this technology does not offer a higher efficiency than other fuels using the same type of process.

Combined-cycle plants do provide a higher level of efficiency. The basic principle of the combined-cycle plant is to utilize the natural gas to produce power in a gas turbine - which can be converted to electric power by a coupled generator—and then 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 create electric power with a coupled steam turbine and generator. The use of both gas and steam turbine cycles in a single plant to produce electricity results in high conversion efficiencies and low emissions. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gas fuels to mechanical power or electricity. Modern combined-cycle plants utilizing the steam produced by the HRSG increases the efficiencies up to and in some cases exceeding 58 percent. Gas turbine manufacturers are continuing to develop high temperature materials and improved cooling to raise the firing temperature of the turbines and further increase the efficiency. This combined-cycle system offers high efficiency, but because of the high fuel costs, this type of system is best suited to supply intermediate electrical demands, rather than baseload capacity. AECI currently owns, or is acquiring, over 1,500 MW of combined-cycle generation, adequate to meet its intermediate capacity needs.

Simple-cycle combustion turbine technology offers an even lower capital cost, but also has the fuel cost disadvantages associated with natural gas and lower overall efficiency. This technology is primarily used to meet peak electrical demands.

The price and volatility of natural gas is problematic in using this fuel for baseload generation. Natural gas prices for electrical generation have recently increased from a low of $2.86 per thousand cubic feet in February of 2002 to a high of $6.85 per thousand cubic feet in December of 2004 with short term spikes of over $12 (EIA, May 2005). Both simple-cycle and combined-cycle options were considered for this project. However, they are not well-suited for baseload capacity and, with the relatively high and volatile cost of fuel, these options did not compare favorably with the solid fuel options for the proposed project.

5.4.3 Oil

Similarly, oil could theoretically be used in the simple-cycle and combined-cycle facilities described above under natural gas, and as boiler fuel. According to a report by the DOE's Electric Power Monthly for May of 2005, the average price of fuel oil in January of 2005 was $5.63 per million British Thermal Units (BTU) compared to $1.44 for Coal and $6.64 for Natural Gas (EIA, May 2005). Although the cost of energy from fuel oil is slightly less than natural gas, the cost for environmental controls for burning fuel oil would be higher that the controls required for natural gas. While generally cleaner burning that coal, oil can result in significantly greater emissions of some pollutants than natural gas. Oil-fired generation was not considered as a viable option, based on the high cost of the fuel, combined with concerns related to availability, energy independence, and environmental controls

5.4.4 Coal

Coal is the most abundant fuel resource in the United States. The DOE has identified coal reserves underground in this country to provide energy for the next 200 to 300 years. There are three primary technologies identified for generating electrical energy from coal: fluidized bed (FB), integrated gasification combined-cycle (IGCC) and pulverized coal (PC). As part of the alternatives evaluation, all three technologies (FB, IGCC, and PC) were evaluated. A PC unit was found to have the lowest installed cost, the lowest fixed operations and maintenance costs and is the most proven technology of the three options, and was selected as the preferred coal technology.

5.4.4.1 Fluidized Bed

The combustion process within a fluidized bed boiler occurs in a suspended bed of solid particles in the lower section of the boiler. The bed is fluidized by air drawn through the bed from underneath. Some incombustible material is placed in the bed to help control the combustion process. Using limestone and flyash re-injection for this incombustible material helps to reduce the emissions of acid gases. A refinement to this design collects and returns material to the bed. This is referred to as a circulating fluidized bed (CFB) system. Generally, combustion within the bed occurs at a slower rate and lower temperature than a pulverized coal boiler. The result is that a fluidized bed boiler can burn a lower quality fuel and remove 90 percent or more of the sulfur products and produce less nitrogen pollutants.

Fluidized bed boilers can also burn just about anything that is combustible — wood, ground-up railroad ties, seeds, hulls and other waste materials. This technology is well suited to burn fuels with large variability in constituents. Within a reasonable range, deviations in fuel type, size or Btu content have minimal effects on the furnace performance characteristics.

Currently, fluidized bed units are limited to a maximum size of approximately 250 MW. Although a multi-unit facility could be built, this would not be able to benefit from the economies of scale associated with a 660 MW project. Also, because of the lower operating temperature of the CFB system, it doesn't achieve the higher efficiency levels achieved by pulverized coal boilers, especially supercritical boilers.

A new type of fluidized bed boiler is being proposed to improve on the basic system. It encases the entire boiler inside a large pressure vessel. Burning coal in a pressurized fluidized bed boiler (PFBC) results in a high-pressure stream of combustion gases that can spin a gas turbine to make electricity, then boil water for a steam turbine. The PFBC technology offers higher thermal efficiency. It is estimated that boilers using this system will be able to generate 50 percent more electricity from coal than a regular power plant from the same amount of coal. Because it uses less fuel to produce the same amount of power, this technology would result in less carbon dioxide (a greenhouse gas) being produced per MW generated. This technology is currently in the demonstration phase and is not feasible for the proposed project.

5.4.4.2 Integrated Gasification Combined-cycle (IGCC)

Integrated Gasification Combined Cycle (IGCC) is emerging as one of the most promising technologies in power generation. AECI thoroughly evaluated this technology and considers it very promising. The primary concern is its stage of development. There is not yet an IGCC unit in the 600 MW range operating commercially; much less with an extended operating history. AECI is simply too small to accept the risk of a first-of-a-kind technology that an IGCC unit would constitute at this time.

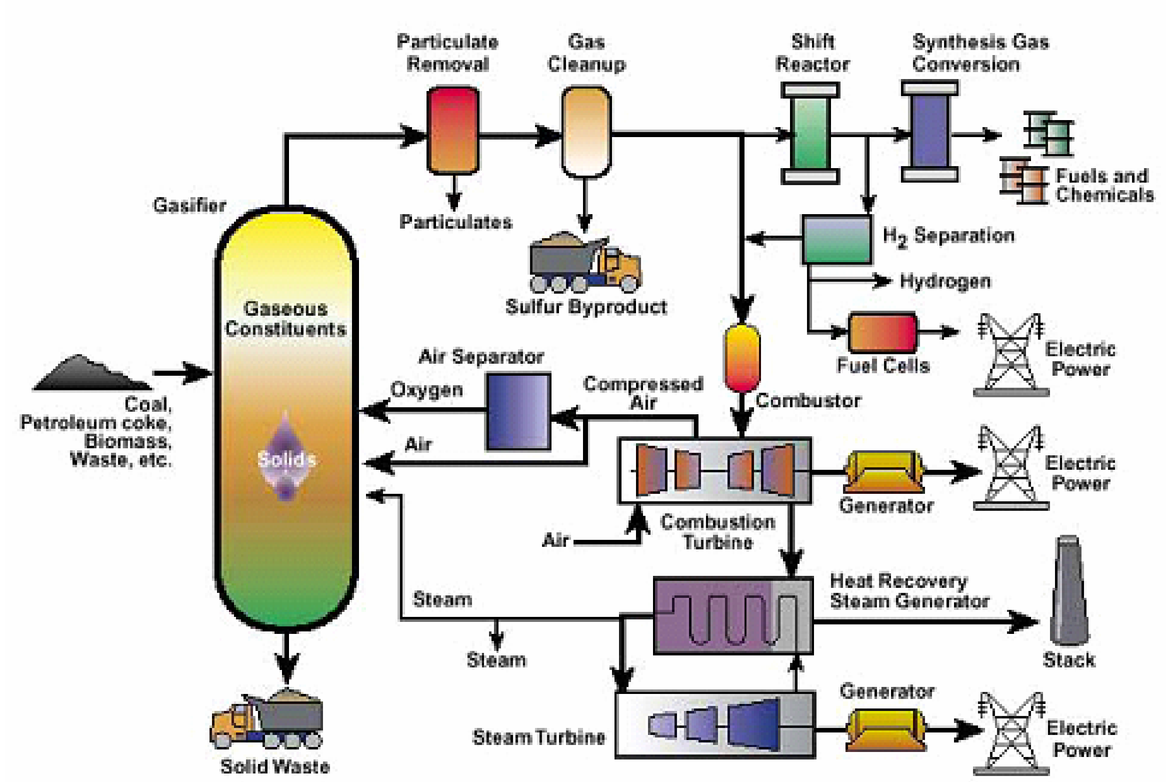
This technology can utilize low-quality solid and liquid fuels, and is able to meet stringent emissions requirements. Rather than burning coal directly, gasification breaks down coal or virtually any carbon-based feedstock into its basic chemical constituents. In a modern gasifier, coal is typically exposed to hot steam and carefully controlled amounts of air or oxygen under high temperatures and pressures. Under these conditions, carbon molecules in coal break apart, typically producing a mixture of carbon monoxide, hydrogen and other gaseous compounds.

Currently demonstration projects in Tampa, Florida, and West Terre Haute, Indiana, are generating electricity by gasifying coal, rather than burning it. At a plant in Kingsport, Tennessee, the Eastman Chemical Company has been using coal gas to make methanol and plastics.

In the simplest of terms, an IGCC power plant consists of a “gasification island” and a combustion turbine combined-cycle power block. IGCC involves the integration of the following technologies: cryogenic oxygen production, gasification (coal conversion to raw syngas), heat recovery, syngas scrubbing and desulfurization processes, sulfur recovery, and a syngas-fired combined-cycle power block.

The gasification island includes the entire coal receiving, handling, preparation, gasification, heat recovery, and syngas cleanup facility—up to delivery of the syngas to the power block. Figure 5-1 provides a schematic of a generic IGCC process.

Figure 5-1 IGCC Schematic



Source: National Energy Technology Laboratory (NETL), December 2002

Only oxygen-blown gasification has been successfully demonstrated for IGCC. Oxygen-blown gasification avoids the large gas (nitrogen) flows and very large downstream equipment sizes and costs that air-blown gasification (discussed below) would otherwise impose. However, the trade-off is that an expensive cryogenic oxygen plant (with a large auxiliary power demand) is required. Pressurized oxygen-blown gasification reduces equipment sizes and enables the delivery of syngas at the fuel pressure required by combustion turbines.

Saturated steam is routed to the HRSG of the combined cycle, where it is superheated and used to augment steam turbine power generation. The steam required for gasification is also supplied from the steam circuit.

The environmental benefits of coal gasification stem from the ability to clean as much as 99 percent of the pollutant-forming impurities from coal-derived gases. Sulfur in coal, for example, emerges as hydrogen sulfide, and can be captured and, in some cases, extracted in a form that can be sold commercially. Likewise, nitrogen typically forms ammonia and can be scrubbed from the coal gas. Again, in some cases the scrubber can yield by-products that can be used to produce fertilizers or other ammonia-based chemicals.

Generally cyclones and/or ceramic, sintered metal hot filters, and water scrubbing are employed for particulate removal. Water scrubbing removes ammonia (NH_3), hydrogen cyanide (HCN), and hydrochloric acid (HCl) from the syngas. Following cooling and particulate removal, a chemical process like Rectisol or Claus is used to remove most of the sulfur constituents from the syngas.

As part of the Air Quality Construction Permit process, a few states have elected to review IGCC as a viable process alternative for electrical generation. In response to a request from the IEPA, Prairie State prepared an analysis of the development status, performance (thermal, environmental, operational), and economics of IGCC. As part of the analysis, the carbon dioxide (CO_2) emission rates for the pulverized-coal (PC) option and the two potential IGCC technologies were normalized to the same equivalent net power output (1,599 MW). The results of this study indicated that the CO_2 output of a 1,599 MW (equivalent) IGCC plant may be lower or higher than that of the 1,559 MW Prairie State proposed PC design, depending on which gasification process is selected for comparison and the ultimate optimization of those IGCCs (Prairie States 2003).

Table 5-2 Comparison of Estimated CO_2 Emissions from the Prairie State PC and IGCCs

1,559 MW	PC Plant	ChevronTexaco-Q	Global E-Gas-HR
Coal required, tons/day	20,287	22,532	20,178
Estimated Heat Rate, Btu/kWh	9,521	10,576	9,451
Estimated carbon conversion, %	99.9	97.0	99.0
CO_2 output, tons/day	36,019	38,844	35,503
tons/year	11.83 MM	12.76 MM	11.66 MM
tons/MWh	0.963	1.038	0.949

Coal carbon content = 48.5% as received
90% capacity factor IGCC plants (Normalized to 1,559 MW equivalent)
Source: Prairie States 2003.

IGCC technology does offer an increased opportunity for CO_2 removal. A study prepared by DOE/ National Energy Technology Laboratory (NETL)-EPRI reported that CO_2 scrubbing could capture about 90 percent of the uncontrolled CO_2 for any combustion technology. Since any coal-based technology will produce approximately twice as much CO_2 as natural gas technology, scrubbing coal-fired plants results in capturing about twice as much CO_2 as from natural gas-fired power plants (DOE 2002). This can be beneficial if there is a use for the captured CO_2. Currently, there are few practical ideas for carbon sequestration, and it is possible that captured CO_2 may eventually be released back into the environment. For example, CO_2 that is used by plants through photosynthesis to create biomass can sequester CO_2, but the CO_2 can eventually be released back into the environment should the biomass be burned.

The same DOE study of CO_2 capture indicated the addition of technology to remove up to 90 percent of the CO_2 would result in a capital cost increase of approximately 30 percent for the IGCC technology, while the additional cost to a PC system would be approximately 73 percent. In addition to lower capital cost, because IGCC produces a more concentrated CO_2 stream at higher pressure that other technologies, the energy consumption associated with the CO_2 scrubbing is lower. Even though scrubbing of CO_2 emissions from IGCC can reduce the amount released to the atmosphere, the emissions would still be about twice that of a gas-fired combined-cycle plant (DOE 2002).

There are less costly options envisioned, but they typically achieve less removal. An engineering study, performed for ChevronTexaco by Jacob's Engineering in cooperation with General Electric, evaluated the design concept of incorporating the option of approximately 75 percent CO_2 capture into a new IGCC facility. Their evaluation was based on the logic that IGCC units built today may not have a commercial need to capture CO_2, unless there was the potential for using enhanced oil recovery (EOR) through CO_2 injection or a future regulatory requirement for sequestration in a suitable repository (e.g., an aquifer). The engineering study developed a process flow scheme that used ChevronTexaco Quench gasifers followed by syngas shift reactors, physical absorption acid gas removal (e.g. Selexol), a sulfur recovery system, and a combined cycle unit consisting of two gas turbines, a HRSG and a single steam turbine. The unit design they evaluated would be capable of capturing 75 percent of the feed carbon as CO_2 (DOE 2002).

The IGCC emission information in Table 5-3 is based on a Final Report Prepared for the Gasification Technologies Program, National Energy Technology Laboratory, entitled "Major Environmental Aspects of Gasification-Based Power Generation Technologies." (DOE, 2002)

Table 5-3 Comparison of IGCC Technology Criteria Pollutant Emission Levels

Criteria Pollutant	Projected IGCC Emission Levels[a]	Recent BACT Permit Limits for Conventional Coal Combustion	Polk IGCC Operating Permit Limit[b]	Wabash River IGCC Operating Permit Limit[c]
Sulfur dioxide (SO_2)	0.08 lb/10^6 Btu 0.7 lb/MWh	0.1 lb/10^6 Btu, 30-Day average, 0.09 lb/10^6 Btu annual average	0.166 lb/10^6 Btu 1.43 lb/MWh	0.145 lb/10^6 Btu 1.25 lb/MWh[e]
Nitrogen oxides (NO_x) (as NO_2)	0.09 lb/10^6 Btu 0.77 lb/MWh	0.07 lb/10^6 Btu, 30 day, normal operation NOx - 0.06 lb/10^6 Btu, annual	0.06 lb/10^6 Btu 0.53 lb/MWh	0.157 lb/10^6 Btu 1.35 lb/MWh
Particulate (PM_{10}) and Sulfuric Acid (H_2SO_4) Mist	0.011 lb/10^6 Btu 0.10 lb/MWh	PM10 - 0.018, 3-hour (Method 202 or alternative)	0.033 lb/10^6 Btu 0.288 lb/MWh[d]	0.029 lb/10^6 Btu 0.25 lb/MWh[f]
Carbon monoxide (CO)	0.033 lb/10^6 Btu 0.29 lb/MWh	0.15 lb/10^6 Btu, 24-hour average	0.045 lb/10^6 Btu 0.392 lb/MWh	0.256 lb/10^6 Btu 2.2 lb/MWh[g]

[a] Basis: Heat rate equals 8,600 Btu/kWh. SO_2 emissions are based on 2.5 percent sulfur, 12,000 Btu/lb coal, and 98 percent reduction. NO_x emissions are based on a turbine combustor that emits 15 ppm NO_x (15 percent O_2, dry). CO, PM_{10}, and H_2SO_4 emissions are based on 1998 Wabash River plant experience.
[b] Values provided by TECO Energy
[c] Basis: permit limits specified in final technical report for Wabash River Coal Gasification Repowering Project.
[d] Basis: 0.068 lb/MWh for particulate-only (17 lb/hr, excluding H_2SO_4 mist) and 0.22 lb/MWh (55 lb/hr H_2SO_4)
[e] Basis: 252 MWe @ 6,000 hrs/year, 1,512,000 MWh/year
[f] Basis: limits specified for combustion turbine (20 percent max opacity, 0.01 lb/10^6Btu H_2SO_4) and tail gas incinerator (6.8 tons/yr)
[g] Based on limits specified for flare, combustion turbine, and tail gas incinerator.

The emission rates in Table 5-3 represent permitted emissions during normal operation, and do not include emissions during start-up and shutdown of the system and upset conditions. The IGCC demonstrations (all partly supported by government and/or R&D consortia funding) have been largely successful and have shown that coal gasification is technically feasible and the systems are capable of meeting current emissions regulations for new coal-fired plants.

Efficiency gains are another potential benefit of coal gasification. In a typical coal combustion plant (supercritical plant), approximately 40 percent of the energy value of coal is actually converted into electricity, the rest is lost as waste heat.

A coal gasification power plant, however, typically gets dual duty from the gases it produces. First, the coal gases, after being cleaned to remove sulfur, particulate and nitrogen pollutants, (and possibly carbon dioxide), are fired in a gas turbine - much like natural gas - to generate electricity. The hot exhaust of the gas turbine is then used to generate steam to power a conventional steam turbine-generator. Similar to the natural gas combined cycle, this system converts much more of coal's inherent energy value into useable electricity. The thermal efficiency of a coal gasification power plant can be boosted to 40 percent or more.

Future concepts are being investigated that may incorporate a fuel cell or fuel cell-gas turbine hybrid that could achieve even higher efficiencies, perhaps in the 60 percent range, or nearly 50 percent above today's typical coal combustion plants. Higher efficiencies can translate into more economical electric power and potential savings for ratepayers. A more efficient plant also uses less fuel to generate power, meaning that less carbon dioxide is produced.

However, in its present state of development and demonstration, IGCC is still encumbered by lower reliabilities, and higher capital and electricity production costs than modern PC boiler power plants with state-of-the art emissions controls.

“Availability” is the measure commonly used to represent the reliability of a power plant and component sections of or equipment in the plant. Availability is a measure of the percentage of the time in a period during which the plant was actually running, operable at full capacity, and—if not operating—was fully available to be operated. Annual availabilities (12 month periods) are commonly reported, since short-term availabilities are not very meaningful. The IGCC availability data generally show a pattern of gradual improvements in most of the demonstrations. Despite the success of the demonstration projects, significant design issues have limited coal gasification units from achieving acceptable availability levels. Some of the design issues include fouling within the syngas cooler, design of the pressurized coal feeding system, molten slag removal from the pressurized gasifier, durability of gas clean-up equipment and solid particulate carryover resulting in erosion within the combustion turbine. The complexity of the combined-cycle unit in conjunction with the reliability of numerous systems including the gasifier, O_2 generator, air separation unit and multiple scrubbers tends towards reduced plant availability. The current generation of IGCC plants has demonstrated operational availability of around 75 percent compared to typical availability of greater than 90 percent for conventional pulverized coal units.

While conceptual “optimized” designs are now emerging, none have been built. One approach to ensuring high availability is the use of a spare gasifier. Having a spare gasifier enables higher availability, since the operation and maintenance of the units can be alternated. For example, Eastman Chemical Company has been operating a ChevronTexaco coal gasification system at its chemical plant in Kingsport, Tennessee since 1983. Operations are alternated between two 1,250 ton/day (bituminous coal) 1,000 psig gasifiers. The reported on-stream factor for September 2000 - September 2002 was 97 percent. However, this has an unfavorable impact to the capital cost. Another approach, which supports high power block availability, is to fire natural gas in the combustion turbines to replace the loss of syngas when gasifier capacity is reduced or lost. Unfortunately, the economics of this approach are subject to the volatility of natural gas prices—and possibly also to gas supply interruptions or unavailability.

Continuing efforts of the existing demonstration plant owners/operators and most of the gasification technology vendors have led to improvements in operations, maintenance, and design concepts. However, presently, gasification process reliability issues remain. IGCC plant availabilities are not yet comparable to the 90+ percent availabilities expected and required by modern electric power generating companies for competitive operation in the United States power market. Although the availabilities to date of the various IGCC demonstration projects reflect progress, long-term availabilities over 90 percent for single-train systems have not yet been achieved and remain to be demonstrated.

It is potentially feasible that multiple train IGCC plants could be constructed to produce approximately 660 MW—and some economies of scale should be realized with a large plant. However, such multi-train plants have not been demonstrated and, at this stage of the development and evolution of IGCC technology, the financial risks of building an IGCC plant have thus far prevented the project from proceeding beyond the planning stages. The addition of spare gasifiers to allow the IGCC to operate with 90+ percent availability and approach the standard of 90 percent annual capacity factor results in estimated capital costs and costs of producing electricity of about 30-35 percent higher than those estimated for PC plants.

Because of the availability and reliability concerns, and the fact that no coal-based IGCCs larger than the single-train 250-265 MW demonstration plants have been built in the United States, some financial institutions have been unwilling to finance IGCC projects. Recently, the Public Service Commission of Wisconsin ruled against a proposed IGCC plant (Wisconsin Energy Corporation, Elm Road) as being too expensive and unreliable to impose on the rate payers.

The ability to finance a project, and to obtain commercial performance and cost guarantees from the system providers has been a major hurdle. Over the past 2-3 years, the major gasification process vendors, and at least a few engineering/plant construction companies have been collaborating with the objective of developing improved IGCC designs, which address the above availability and cost issues. No gasification process vendors or IGCC suppliers have yet offered written guarantees regarding availability, however discussions are underway about how to structure a commercial IGCC package bid with the necessary guarantees/warranties. The complexity of IGCC makes this challenge very formidable.

Some in the utility industry, anticipate that a 2-year record (at least) of 92+ percent availabilities (plus demonstrated economics comparable to PC power plants) will be required to convince financial institutions that the risk in financing IGCC projects is comparable to that of PC projects.

A recently published review of DOE's Vision 21 Research and Development Program (Phase I) by the National Research Council (NRC—of the National Academies) came to a very similar conclusion about IGCC (DOE, May 2005). Specifically, the NRC concluded that "even if the projected cost of these plants reach the required levels, investors need confidence that these plants will run as designed, with availability levels in excess of 90 percent. The only way to achieve this is to build additional plants incorporating the necessary lower cost improvements and to allow extended periods for start up so the improved technologies can mature sufficiently to meet their goals. The pace of development and demonstration appears to be too slow to meet the goal of having coal gasification technology qualified for the placement of commercial orders by 2015" (NRC, 2003).

In its review, the NRC noted recent DOE/ NETL surveys of the market for gasification technologies which indicate that plant owners will require 90 percent availability for power production plants and 97 percent availability for chemical production plants. The DOE/NETL survey referred to reliability as gasification's "Achilles' Heel" (NRC, 2003).

Coal-fueled IGCC technology offers some potential advantages relative to environmental impacts and energy efficiency, and has a potential to be part of the long-term future for clean-coal generation within the United States. For this project, these perceived benefits do not offset the disadvantages of this technology associated with the reduced availability combined with the increased cost, increased financing difficulty, and the risks associated with initial application of a new technology.

IGCC offers some potential advantages relative to environmental impacts and energy efficiency. At the current stage of development however, the systems do not offer adequate reliability and are too costly on the basis of total cost ($/MWh) to meet AECI's needs.

5.4.4.3 Pulverized Coal (PC)

Conventional PC technology is a reliable energy producer around the world and can be characterized by the maximum operating pressure of the cycle. Coal is supplied to the unit through coal bunkers, then to the feeders and into the pulverizers where the coal is crushed into fine particles. The primary air system transfers the coal from the pulverizers to the steam generator burners for combustion. Flue gas is transferred from the steam generator, through a selective catalytic reducer (SCR) for nitrogen oxides (NO_x) reduction and into an air heater. From the air heater the flue gas flows to a sulfur dioxide (SO_2) scrubber system and a particulate removal system.

The operating pressure of conventional coal-fired power plants can be classified as subcritical and supercritical. Subcritical and supercritical technology refers to the state of the water and steam that is used in the steam generation process. Subcritical power plants utilize pressures below the critical point of water in which there is a distinct difference in the state of the liquid. The majority of the steam generators built in the United States utilize subcritical technology. These units utilize a steam drum and internal separators to separate the steam from the water. In general, the steam cycle consists of one steam generator and one steam turbine generator. The balance of plant equipment consists of a condenser, condensate pumps, low-pressure feedwater heaters, deaerating feedwater heater, boiler feedwater pumps and high-pressure feedwater heaters.

The critical point of water is 3,208.2 pounds per square inch (psi) and 705.47 degrees Fahrenheit (°F). At this critical point, there is no difference in the density of water and steam. At pressures above 3,208.2 psi, 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. Supercritical units, which are slightly more expensive, are somewhat more efficient than subcritical units. AECI currently is proposing a supercritical boiler for this project.

The steam turbine exhausts to a condenser where the steam is condensed. The heat load of the condenser is typically transferred to a wet cooling tower system. The condensed steam is then returned to the steam generator through the condensate pumps, low-pressure feedwater heaters, deaerating heater, boiler feed pumps and high-pressure feedwater heaters. Some operating units utilize a closed feedwater system in lieu of a deaerating feedwater heater with a deaerating condenser included in the system.

5.5 REPOWERING/UPRATING OF EXISTING GENERATING UNITS

Repowering and uprating of existing generation units owned or operated by AECI is not practical or feasible. Each operating unit has been reviewed, and there is not a potential to uprate an existing plant or to repower an existing facility that would result in the required additional capacity. In addition, under EPA's current regulatory interpretations, repowering or up-rating a unit would potentially subject the facility to review in accordance with the New Source Review requirements. This reduces the potential economic advantages associated with improving existing facilities.

There are no repowering or up-rating opportunities on the AECI system that have the potential to satisfy the need for an additional 660 MW of capacity.

5.6 PARTICIPATION IN ANOTHER COMPANY'S GENERATION PROJECT

AECI considered participation in other units including one proposed by Kansas City Power and Light (KCP&L, a subsidiary of Great Plains Energy) referred to as Iatan 2, and Peabody Coal's Prairie State plant in Illinois. Participation in these units was thoroughly evaluated by AECI and considered by their Board of Directors. However, based on their determination that the "self build" option provided significant advantages regarding future dispatch requirements, compliance with future environmental regulations, and also offered better security for future energy prices and availability, the AECI Board rejected participation in these projects. No other projects were known to AECI where participation was an option and adequate generating capacity was available.

5.7 PURCHASED POWER

AECI continuously evaluates the power market for cost effective opportunities to meet the power supply obligations to its members. Historically, AECI did rely on long-term power purchase contracts as part of its resource mix. However, as wholesale electricity markets have become more deregulated, transmission constraints have increased and prices have become more volatile, purchase power has become increasingly less viable.

As noted, AECI's mission is to provide the lowest cost reliable power supply, with as much stability as possible, to its member owners. AECI has experienced situations where power supplied under long term contracts has not been reliable. Furthermore, "long term" in this market is less than 10 years and costs are high.

Additionally, as part of its planning process to meet its growing loads, AECI issued a Request for Proposal (RFP) to supply its needed capacity and energy. Only a few responses were received and none of them were as cost effective as the proposed project.

AECI has and continues to evaluate power markets for opportunities to supplement its generation portfolio. However, long term power supply agreements are too costly and too unreliable to be a viable alternative to the proposed project.

5.8 NEW TRANSMISSION CAPACITY

AECI has an excellent transmission system with a large number of interconnections with regional power suppliers. There are now new transmission capacity additions that in and of themselves would provide the needed power and energy. Furthermore, new transmission capacity was evaluated as part of the RFP mentioned in the previous section, which resulted in offers that were not competitive with the proposed project.

5.9 CAPACITY ALTERNATIVES SUMMARY

As part of its planning to meet the increasing capacity and energy demand on its system, AECI evaluated numerous supply alternatives. As a member-owned cooperative with contractual obligations to meet its member's requirements, certain options have very limited applicability. Of the potential capacity supply options, AECI considers IGCC and nuclear very promising but with far too much risk for a company of its size at this time. Renewable options are currently too costly, are not available in the AECI service territory, and are not viable for the needed capacity. Other options, such as purchased power and transmission capacity additions, are too costly and unreliable. The best alternative at this time for AECI to meet its growing loads is a 660 MW supercritical pulverized coal generating unit.