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Integrated Resource Plan

Integrated Resource Analysis Appendices

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Integrated Resource Plan

Integrated Resource Analysis

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Environmental Issues

Air Quality Issues

The most significant environmental control costs facing the Company will result from the myriad of air pollution regulations stemming from the Clean Air Act Amendments of 1990 and recent rulemaking for control of mercury and reduction of transported pollutants. The Company has met and exceeded compliance with the Title IV Acid Rain provisions of this Act, by switching a number of power plants from Illinois basin bituminous coals to western low-sulfur sub-bituminous coals and installing advanced low NO_X burners and overfire air systems as well as utilizing neural-net-based combustion control and post-combustion control systems to significantly lower NO_X emissions. However, additional significant pollution control costs are anticipated in order to comply with the following Clean Air Air requirements:

- Title I NO_X controls to help achieve the existing ozone standards in St. Louis, Chicago and other metropolitan areas in the eastern United States;
- Additional SO_2 and NO_X controls as a result of the recent EPA (Environmental Protection Agency) Clean Air Interstate Rule;
- Additional SO_2 and NO_X controls as a result of new national ambient air quality standards (NAAQS) for ozone and fine particulate matter ($PM_{2.5}$);
- Mercury controls as a result of the recent EPA Clean Air Mercury Rule to reduce mercury emissions from coal-fired power plants;
- Additional SO_2 and possibly NO_X controls under the Regional Haze program;
- Control of other air toxics.

In addition, it is possible that some form of CO_2 controls or offsets will be necessary to address the Climate Change issue over the next 5 to10 years.

Each of these issues are discussed briefly in this section. Also, an effort is underway to craft new Federal legislation to consolidate these numerous air pollution control regulations facing the utility industry. This will be discussed as well.

Title I NO_X Controls

The St. Louis area, along with many other major metropolitan areas, has been a "nonattainment" area for ozone since monitoring for the pollutant began back in the 1970s. A nonattainment area means the area includes monitors which record ozone levels that exceed the national ambient air quality standard for ozone. Numerous regulations have been developed to control emissions of Nitrogen Oxides (NO_X) and Volatile Organic Compounds (VOCs) which are the primary precursors to ozone formation.

In 1998, the State of Missouri promulgated regulations to control NO_X emissions from power plants and many other sources in the State. The Missouri regulations require utility sources to be in compliance with the regulations during the ozone season beginning in May 2004. Through the development of advanced NO_X controls on many of the Company's generating units, AmerenUE has already installed sufficient NOx controls to comply with the new State of Missouri NO_X rules. Low NO_X burner systems were installed on Meramec units 1 and 2 in 2004 and further development of controls at the Sioux plant, and additional refinements of the NO_X control systems at Rush Island plant have been completed to meet the Missouri NO_X rules with some margin of compliance.

The Federal EPA also issued what is referred to as the "NO_X SIP Call" regulations.[1] These rules require significant (roughly 75 percent) reductions in NO_X emissions from utility boilers in most states east of the Mississippi River. As a result of various court challenges, the NO_X SIP Call regulations were remanded back to EPA as they apply to Missouri. The Court ruled that EPA did not have sufficient evidence to include all of Missouri in the rule – just the eastern third of the State. The EPA re-proposed the NO_X SIP Call for Eastern Missouri in February 2002 and issued a final rule on April 21, 2004. The State of Missouri promulgated regulations to implement the Federal requirements that are effective October 1, 2005. The rule establishes an emission cap for utility units located in the eastern third of Missouri beginning in May 2007. This rule will likely require AmerenUE to install Selective Catalytic Reduction (SCR) or similar technology on one or two units at the Sioux power plant. It is anticipated that these controls would take roughly three years to fabricate and install, at a cost of approximately $110 million. Research into a promising new technology is underway that may delay the requirement to install SCR on the units at Sioux. A new low NO_X burner system will also be installed on Meramec unit 3 to meet the new Missouri NO_X rules with some margin of compliance.

Because the St. Louis area failed to attain the ozone standard by the deadlines established in the Clean Air Act, the EPA took action to "bump up" the area to a "Serious" ozone nonattainment area in January 2003. The "bump up" required the State of Missouri to either implement additional emission reductions or demonstrate attainment with the ozone standard by January 2004. In May 2003, the EPA determined that the St. Louis area had attained the one-hour ozone standard and redesignated the area to attainment.

[1]SIP refers to State Implementation Plan. Under the Clean Air Act, the Federal EPA can issue a "SIP Call" if they determine that a State's air pollution regulations are not sufficiently stringent to prevent long-range transport of air pollution from within that State from contributing to downstate nonattainment areas. The NO_X SIP Call was originally issued against 22 states by EPA to help areas like Chicago, Atlanta and cities along the Eastern Seaboard attain the ozone standards.

Clean Air Interstate Rule

In January 2005, the EPA issued the Clean Air Interstate Rule (CAIR). The rule requires reductions in nitrogen oxides and sulfur dioxide from electric generating units through implementation of a cap-and-trade based system. The intent of the rule is to reduce long range transport of air pollution from upwind sources that are thought to contribute to downwind nonattainment areas. The rule applies to 28 eastern and Midwestern states and the District of Columbia and includes Missouri. The EPA determined that emissions from electric utilities in Missouri have a significant impact on nonattainment areas for ozone and fine particulate matter in the St. Louis and Chicago areas. The rule requires both ozone season and annual emission caps for NOx in a phased approach with Phase 1 beginning in 2009 and Phase 2 beginning in 2015. The rule also requires a reduction in SO_2 emissions by requiring a change in the way Acid Rain Program allowances are surrendered. The current Acid Rain Program requires the surrender of one SO_2 allowance for every ton of SO_2 that is emitted. The CAIR program will require that SO_2 allowances be surrendered at a ratio of two allowances for every ton of emission in 2010 through 2014. Beginning in 2015, SO_2 allowances will be surrendered at a ration of 2.86 allowances for every ton of emission. States are required to develop regulations to implement the rule and submit final regulations to the EPA for approval by September 11, 2006. The new Clean Air Interstate Rule will require significant additional reductions in NO_X and SO_2 emissions from the Company's power plants by 2009 and 2010 respectively.

New Ambient Air Quality Standards for Ozone and Fine Particulates

In July 1997, the EPA issued regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. The standards were challenged by industry and some States, and arguments were eventually heard by the U.S. Supreme Court. On February 27, 2001, the Supreme Court upheld the standards in large part, but remanded a number of significant implementation issues back to EPA for resolution. Additional challenges to the rules made their way through the courts and were ultimately upheld by a legal process that ended in March 2002. The EPA completed rulemaking to address the issues raised by the Court and established a standard for ozone on an eight-hour basis to replace the one-hour standard and a new standard for fine particulate matter. The St. Louis area was designated as nonattainment for both the ozone and fine particulate standards. The State of Missouri is required to develop a state implementation plan (SIP) to attain the standards. The SIP plans must be submitted to the EPA by June 2007 for ozone and April 2008 for fine particulate matter. The new eight-hour ozone and fine particulate matter ($PM_{2.5}$) ambient standards will require significant additional reductions in SO_2 and NO_x emissions from the Company's power plants by 2009.

Mercury

In December, 2000, EPA issued a decision under the Clean Air Act to regulate mercury emissions from coal-fired power plants. In January 2005, the EPA reversed its decision to regulate mercury from coal-fired power plants by requiring Maximum Achievable Control Technology (MACT). At the same time, the EPA issued the Clean Air Mercury Rule (CAMR) that will establish a nationwide cap-and-trade program to control mercury from coal-fired power plants. CAMR establishes a two-phase emission cap with the first phase in 2010 and the second phase in 2018. The State of Missouri is required to develop regulations to implement the mercury control program by November 2006. The rules will require the installation of continuous emission monitoring systems for mercury on all of the Company's coal-fired power plants by 2009. We anticipate that controls will be required to comply with both phases of the regulations however it is not determined what controls will be installed on each unit. The necessary controls will be installed prior to January 2010 for Phase 1 and prior to January 2018 for Phase 2. At this time, it is believed that Flue Gas Desulfurization (scrubbers), which control SO_2, combined with Selective Catalytic Reduction (SCR), which control NOx, may be sufficient to achieve a 90 percent reduction in mercury emissions at utility boilers burning bituminous coal, although this remains unproven over sustained periods of time on commercial units. For utility boilers which burn sub-bituminous coal – such as the AmerenUE generating units – there is no proven technology to achieve mercury reductions beyond forty to seventy percent for a sustained period. Various technologies are currently being tested at the pilot scale, but at this time, the type and cost of mercury controls that might be needed on the AmerenUE boilers is unknown. It is anticipated, however, that the cost of these controls will be significant.

Regional Haze

EPA is in the process of developing a program to bring visibility levels in pristine areas of the United States back to "natural" conditions by the year 2064. On July 20, 2001, EPA took a major step in this process by proposing "Best Available Retrofit Technology" (BART) Guidelines. The guidelines were finalized in a rule that was effective September 6, 2005. These guidelines are to be used by Regional Planning Organizations to direct States to require the installation of various pollution controls, primarily for SO_2, and to a lesser degree, NOx. The State must determine the appropriate level of BART control. BART controls would require SO_2 scrubbers on most large coal-fired generating units, including most of AmerenUE's power plants, by 2012. Smaller generating units would also require controls, and some degree of NOx controls is also anticipated under this program. Recently, EPA has indicated that the schedule to require these controls may be accelerated in conjunction with controls required to attain the new fine particulate standard discussed above. The State of Missouri is required to develop a state implementation plan to implement BART controls by April 2008. At this time, the degree and extent of controls that might be required on AmerenUE's power plants under this program is still uncertain. However, the costs are expected to be significant.

Air Toxics

Title III of the Clean Air Act requires EPA to assess the risks to public health from hazardous air pollutants emitted by utility boilers after implementation of the other Titles in the Act. The EPA is required to describe alternative control strategies for pollutants which warrant regulation. In addition, EPA has been working towards an agreement with the Canadian government to eliminate man-made bio-accumulating toxins.

The possibility of regulatory-required controls for additional toxics from utility emission sources is highly uncertain. It is possible that EPA or the states may be forced by Clean Air Act provisions to define Maximum Achievable Control Technology (MACT) requirements for toxic emissions in the coming years. Formaldehyde has been identified in recent permitting of combustion turbines, combined-cycle units and reciprocating internal combustion engines as an emission of concern. Nickel is the primary toxic compound emitted from oil-fired units. Dioxins, furans, poly-aromatic hydrocarbons, arsenic, chromium, cadmium, vanadium, selenium and benzene have been identified as potential control candidates for coal-fired boilers. Because these compounds are emitted in such minute quantities, and control requirements for other regulatory programs are believed to be effective in reducing a portion of these emissions, it is unknown what, if any, future additional control requirements might be necessary.

Carbon Dioxide

Continuing congressional and international interest in managing CO_2 emissions in the United States represents a critical uncertainty factor that could significantly affect supply-side costs. Burning fossil fuels produces relatively large amounts of CO_2, a natural by-product of combustion. Presently, there is no known economically practical way to remove and dispose of CO_2 from a flue-gas stream.

AmerenUE has been participating with other utilities in a Climate Challenge program established by the DOE under Section 1605(b) of the Energy Policy Act. Activities included in this program include demand side initiatives, efficiency improvements at power plants, community lighting programs, contributing to the development of efficient electro-technologies and participation in Utilitree Carbon Company and Power Tree Carbon Company, a consortium of energy companies which invest in the reforestation of domestic and foreign lands as a means of sequestering carbon.

The Bush Administration is working on the development of a program to provide incentives to utilities and other industries to curb or offset carbon emissions. DOE is working on a revision to their current voluntary reporting program which will stay voluntary, but will include a registry and other programs to document carbon reductions and offsets. Meanwhile, some U. S. Senators have proposed various legislation which would require significant reductions in CO_2 emissions over the next five to ten years (discussed in the New Clean Air Legislation section below).

New Clean Air Legislation

A number of congressmen and senators have proposed new Clean Air legislation in the past few years. Many of these bills would require drastic reductions in power plant emissions over the next five to ten years. In addition, because of the numerous regulatory programs that will require extensive emission reductions from utility boilers – often for the same pollutant – under different timetables and at different emission levels discussed above, the utility industry has been working with the Bush Administration and members of Congress on revisions to the Clean Air Act. These proposals, often referred to as "multi-emissions legislation," would reduce SO_2, NO_x, mercury and possibly CO_2 from utility boilers under one set of provisions. Reductions range from 50 percent to 90 percent from existing levels, and compliance years range from 2009 to 2018.

Because the emission targets and compliance timetables being debated are so diverse at this time, it is not possible to determine the cost or impact on existing or future supply-side options. While the cost of such legislation to AmerenUE and other utilities is expected to be significant, it is anticipated that it will be in the range of the cumulative costs of all the regulatory programs discussed above. A key element of such legislation is to ensure regulatory relief from the pollution control programs in the current Clean Air Act.

The possibility that CO_2 controls may be part of such legislation – or even part of a new Administration program – must be considered in the development of supply side options. Since coal-fired generation produces massive CO_2 emissions, AmerenUE needs to take this into account as it evaluates its resource options.

WATER QUALITY ISSUES

Clean Water Act Priority Pollutants

The Missouri Department of Natural Resources (MDNR) regulates wastewater discharges from generating facilities through both a construction and an operating permit program. Standards for allowable discharge are guided by federally promulgated effluent guidelines and by state-established limits either by rule or by source-specific permit limitation.

As part of this overall process, EPA has identified 126 priority pollutants upon which it has focused regulatory attention. Two groups of priority pollutants are important relative to discharges from utility generating facilities. They are: 1) toxic metals and 2) organic toxic pollutants.

Process wastewater from the AmerenUE's existing coal-fired power plants may contain trace levels of some of these pollutants. To date current treatment processes have been determined to be adequate in addressing these trace pollutants.

Total Maximum Daily Load (TMDL) Program

Under the federal Clean Water Act, the TMDL program provides a framework for identifying and cleaning up "impaired" waters. Section 303(d) of the Clean Water Act requires states to establish TMDLs for all waters that do not meet water quality standards. This is done by determining the total pollutant loading (or assimilative capacity) for individual pollutants (including heat), that a particular water body can accept without violating applicable water quality standards. The waste load allocation must account for both point source discharges of pollutants and non-point source pollution, as well as a margin of safety to deal with uncertainties. TMDLs are applied to a specific reach of water body for a specific pollutant.

As waste load allocations for point sources are implemented, more stringent effluent limitations might be required in a National Pollutant Discharge Elimination System (NPDES) water discharge permit for a facility. States periodically develop lists of impaired water bodies for public notice. TMDLs have the potential to affect both new and existing sources through more stringent effluent limitations. Since TMDLs are established on a location (reach of water body) and pollutant specific basis, it would be important to review state impaired water lists as part of any plant siting process to evaluate potential impacts to any new source construction.

Cooling Water Intake Structure Impacts

Section 316(b) of the Clean Water Act requires cooling water intake structures to reflect the "best technology" available for minimizing adverse environmental impact to aquatic organisms. Cooling water intakes can adversely impact aquatic organisms basically in two ways. The first is entrainment, which is the taking of small-size organisms such as phyto- and zooplankton, fish eggs and larvae. The second is through entrapment/impingement of larger fish on traveling screens within the intake structure.

On November 29, 2001, EPA issued the final new facility rule for section 316(b) of the Clean Water Act. The rule applies to all facilities that 1) are required to have an NPDES permit, 2) have at least one cooling water intake structure that uses 25 percent of the water it withdraws for cooling purposes; and 3) have a design flow of greater than 2 million gallons per day.

The new rule has two basic technology tracks. Track I is the "fast track" option. Under this alternative the facility must meet the following requirements if intake flows are equal to or greater than 10 million gallons per day:

1) Intake flow must be reduced to a level commensurate with what could be achieved with a closed cycle recirculating cooling system.

2) The maximum through-screen design intake velocity is 0.5 feet per second

3) The facility total design intake flow must be less than or equal to 5 percent of the source water annual mean flow (freshwater river or stream criteria).

4) The permittee must select and implement technologies or operation measures to minimize impingement mortality of fish and shellfish if:

    a. there are threatened, endangered or otherwise protected species or critical habitat within the hydraulic zone of influence of the intake; or

    b. there are migratory or sport or commercial species of impingement concern which pass through the intake hydraulic zone of influence; or

    c. it is determined by EPA or a fishery management agency that, after meeting the technology requirement outlined above, the facility would still contribute unacceptable stress to the protected species or other species of concern.

5) The permittee must select and implement technologies or operational measures to minimize entrainment if:

    a. there are threatened, endangered, or otherwise protected species or critical habitat within the hydraulic zone of influence of the intake; or

    b. there are, or would be, undesirable cumulative stressors affecting possible entrained species of concern, and it was determined that the proposed facility would contribute unacceptable stress to these species.

The permittee may choose Track II instead of Track I, but there appears to be little advantage to doing so since EPA requires a facility to meet the basic performance standards of Track I. Under Track II the permittee is obligated to meet a "comparable level" requirement that the facility will reduce both impingement mortality and entrainment of all life stages by 90 percent or greater than that which could be achieved by a flow commensurate with closed-cycle cooling and an intake velocity of 0.5 feet per second. Although the permittee can request less stringent requirements than those provided, the variance provision is likely to be very difficult to satisfy and may not be of any practical benefit.

In summary, the 316(b) new facility rule will make it more difficult, if not impossible, to construct once-through cooling systems, even on large rivers such as the Missouri and the Mississippi.

On July 9, 2004, EPA published final Phase II 316(b) rules for cooling water intakes at existing power plants. These regulations require comprehensive environmental, technology and economic studies to characterize and mitigate adverse impacts to aquatic organisms for intakes at most of our major power plants. This information is compiled into a comprehensive demonstration study that must be submitted to MDNR by January 2008. This rule has the potential to increase future expenditures for fish protection at existing facilities.

Missouri River Master Manual

The Missouri River Master Water Control Manual (Master Manual), which was implemented in the late 1960's, manages how the U.S. Army Corps of Engineers (Corps) operates the six dams on the mainstem of the Missouri River -- Fort Peck, Garrison, Oahe, Big Bend, Fort Randall and Gavins Point. Due to a wide variety of Missouri River management concerns, the Corps in 1989 set out to revise the current Master Manual in an attempt to balance congressionally mandated purposes of the reservoir system such as flood control, navigation, water supply, water quality and protection of endangered species. In general, many of plans put forward by the Corps reduced the amount of water released into the Missouri River mainstem channel.

In March 2004, the Corps adopted a new Master Manual that generally reduces the amount of water released to the river and holds more water in conservation in the upper reservoirs. The reduced water flow has the potential to impact Labadie Plant's ability to comply with water quality-based thermal effluent limits. Alternatives to comply with thermal limits include plant load reductions or partial or full conversion to open or closed cycle cooling system utilizing cooling towers. It is still too early in the implementation of the new Master Manual to determine the full extent of impacts to the plant.

ASH DISPOSAL ISSUES

Coal combustion by-products (CCB) generated at coal-fired power plants contain many trace metal constituents. As a result of more than 20 years of EPA studies and through various regulatory and legislative initiatives, CCB has been exempted from the hazardous waste disposal programs. However, new ponding facilities must meet a number of requirements, including the lining of ponds, in order to properly store flyash. Some existing facilities, such as the Labadie plant, have also lined existing ponds to maintain flyash and bottom ash storage capability. AmerenUE does not have sufficient onsite storage capability to keep up with the flyash produced by many of the generating units Even though much of the flyash is sold and recycled for use primarily in the road construction and concrete making industries.

EPA continues to evaluate and revise rules pertaining to the onsite storage and disposal of CCB. The potential remains that in some future year, major reconstruction of ash ponds, the construction of onsite landfills or offsite disposal options for CCB may become necessary. In addition, there is a concern that some potential mercury emission control options may result in flyash contamination with excessive carbon. This could potentially make the flyash unusable by the concrete and/or construction industries and may also lead to the need for alternative disposal options.

Analysis and Valuation of
Ameren's Planning Reserve Margins
Final Report

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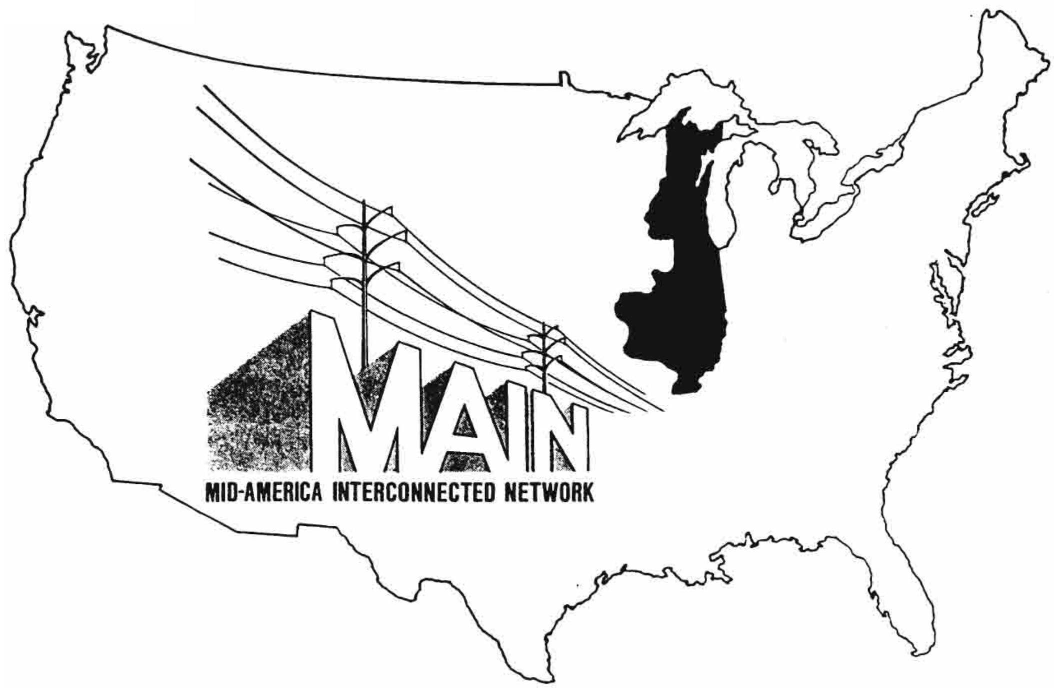

Prepared by the MAIN Reserve Margin Working Group

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Introduction

This report was prepared to fulfill the directive given in MAIN Guide #6 to annually determine generation reserve requirements for MAIN as a whole, as an aid for resource planning and assessment.. The study, based on calculations using Loss of Load Probability (LOLP) / Loss of Load Expectation (LOLE) calculations, covers the years 2005 through 2009 and 2014. The LOLE for a study year is the sum of daily LOLP values for each workday during the year. The adequacy criterion used by MAIN is an annual LOLE of no more than 0.1 day per year. A composite system size of MAIN times four (MAIN x 4) was used to represent MAIN and the neighboring interconnected systems. This study assumes that no transmission limitations to deliverability exist, either within MAIN or from neighboring systems. Transmission assessments are performed by MAIN in other studies.

The calculations consider the population of existing and future generation units, both those owned by utilities and those owned by Independent Power Producers (IPPs), expected generator availability, firm and nonfirm net scheduled imports, and the emergency support anticipated being available from other regions. They also consider load forecast uncertainty (LFU) at two levels: uncertainty attributable to weather conditions only and uncertainty due to all factors. The latter includes uncertainty due to economic conditions and random variability in addition to weather uncertainty. A Load Forecast Uncertainty multiplier reflects some independence of load forecast uncertainties among regions.

Generation reserve goals are expressed as percentages on two bases in this report. The traditional method expresses reserves using adjusted demand as a base (reserve margin). A newer method expresses reserves using adjusted capability as a base (capacity margin). This report does not attempt to determine the projected reserve margin in future years; rather, it establishes the range of minimum reserve margins required to maintain the 0.1 day per year LOLE.

Partial and complete forced generation outage data for this study has been generated by the NERC pc-GAR program, which accesses the NERC Generator Availability Data System (NERC-GADS).The NERC-GADS database is populated with information from generating companies throughout the US and Canada. The NERC GADS program is recognized as the standard for the power generation industry with respect to unit availability and outage data reporting and tracking.

This study report contains several cases examining the sensitivity of generation reserve goals to particular study assumptions, based on the fifth year of the study horizon. Four cases examine factors contributing to change from one year to the next:

- Annual updates of the time period used to develop the load profile.
- Change in the generating unit mix.
- Updated Load Forecast Uncertainty values.
- Updated Load Forecast Uncertainty multiplier.

Another case explores whether maintenance schedules materially affect generation goals. Eight more cases examine the impact of alternative assumptions regarding generator performance, load forecast uncertainty, and the LFU multiplier.

Executive Summary

The Working Group continues to recommend that Generation Reserve Goals remain at a minimum reserve margin of 14% for the short-term (up to one year ahead). The Working Group further recommends that the minimum planning reserve margin be reduced to a range of 15% to 18% (from 16% to 19%) for long-term resource planning and assessment.

A minimum short-term reserve margin of 15% was informally observed for many years and was formally adopted in December 2002; this was reduced to 14.12% in June 2003, and to 14% in September 2004 based on studies performed by this working group. A minimum planning reserve margin of 17% to 20% was recommended from 1996 to 2002, and 16% to 19% in 2003 and 2004. Over the past several years, improvements in the performance of nuclear units have slightly reduced the Generation Reserve Goals.

Methodology and Study Assumptions

The LOLE program utilized for this study considers forced outages of each generating unit to occur randomly, independent of the forced outages of all other units, and at a uniform rate through the year. Common mode outages, whether due to incidents such as tornadoes and floods affecting multiple units at a given site, failures of fuel supply affecting units at various sites, or even terrorism, were not considered. This was because (1) they occurred infrequently and (2) the capacity at a single site was a small fraction of total regional reserves. Furthermore the NERC GADS data collection does not provide a basis for estimating the frequency and duration of such events for any site or class of generating units.

Since its inception this study has been based on units sited within the MAIN region, regardless of ownership, except that the shares of Quad Cities and Joppa owned by utilities outside MAIN are excluded. Known future transactions reported in the EIA-411 are netted for each summer and winter season. Net firm purchases are treated as a reduction in load, while net non-firm purchases are treated as additional generation; see assumption 11 on page 5 for further details. Since the intent of this study is to determine what reserve margin is needed to achieve the desired level of reliability (rather than expected reserve margins based on resource plans) the performance of those IPP and other generators not currently committed to serve load are included in the analysis. The following assumptions were used for the Base Scenario. Appendix I identifies sources of these values.

1. A composite system size of MAIN x 4 was used to represent MAIN and neighboring interconnected systems (refer to the MAIN Guide #6 Special Report June, 1978.)
2. Unit net generating capabilities, fuel types, installation and retirement dates were based on data supplied in items 2.1, 2.2, 3.3, and 3.4 of the April 1, 2005 MAIN report to the Energy Information Administration (EIA) and data provided by MAIN member utilities. Summer and winter capabilities were used during appropriate weeks.
3. Unit availability for nuclear, hydro, and fossil-fired steam units was projected using partial and complete outage probabilities generated by the NERC pc-GAR program, which accesses the Generating Availability Data System (NERC-GADS). For the base case, availability was projected based on 1999-2003 performance of similar units located in the

MAIN, MAPP (US), SPP, SERC, and ECAR reliability councils. Browns Ferry Unit 1, which has been shut down for a number of years, was excluded. Table 1 summarizes generating unit performance in terms of equivalent forced outage rates (EFOR) data for 1999-2003.

Annual EFOR values for classes of nuclear units represented in MAIN are shown in Figure 1. In some cases values have been restated from previous reports based on the most current version of the NERC pc-GAR program. While the improved performance since 1999 is apparent, this trend appears to have "bottomed out" and further improvement cannot reasonably be extrapolated.

4. Certain sensitivity cases considered other unit populations or time frames, as noted.

5. Based on a survey of MAIN member companies' experience, combustion turbine (CT) and aero-derivative (jet) units placed in service since 1990 were assumed to have equivalent forced outage rates (EFOR) of 5%. For lack of other information, combined cycle units were also assumed to have (EFOR) of 5%. Older CT's and jets, and internal combustion (IC) units were assumed to have (EFOR) of 10%.

6. Maintenance schedules submitted by the MAIN member utilities were used in the study. It should be noted that these schedules are considered proprietary and are seen only by the MAIN staff. No generation was planned to be out for maintenance during the predominant LOLE contributing week of any year in the study. Sensitivity case 5 examines the impact of disregarding planned maintenance.

7. Load Forecast Uncertainty is expressed as the standard deviation σ of the distribution of loads divided by the expected value, or coefficient of variation. The MAIN Coordination Center staff computed values of LFU considering only weather, and considering all factors (weather, economic activity, technology change and substitution), using methods determined by the former MAIN Load Forecast Working Group.

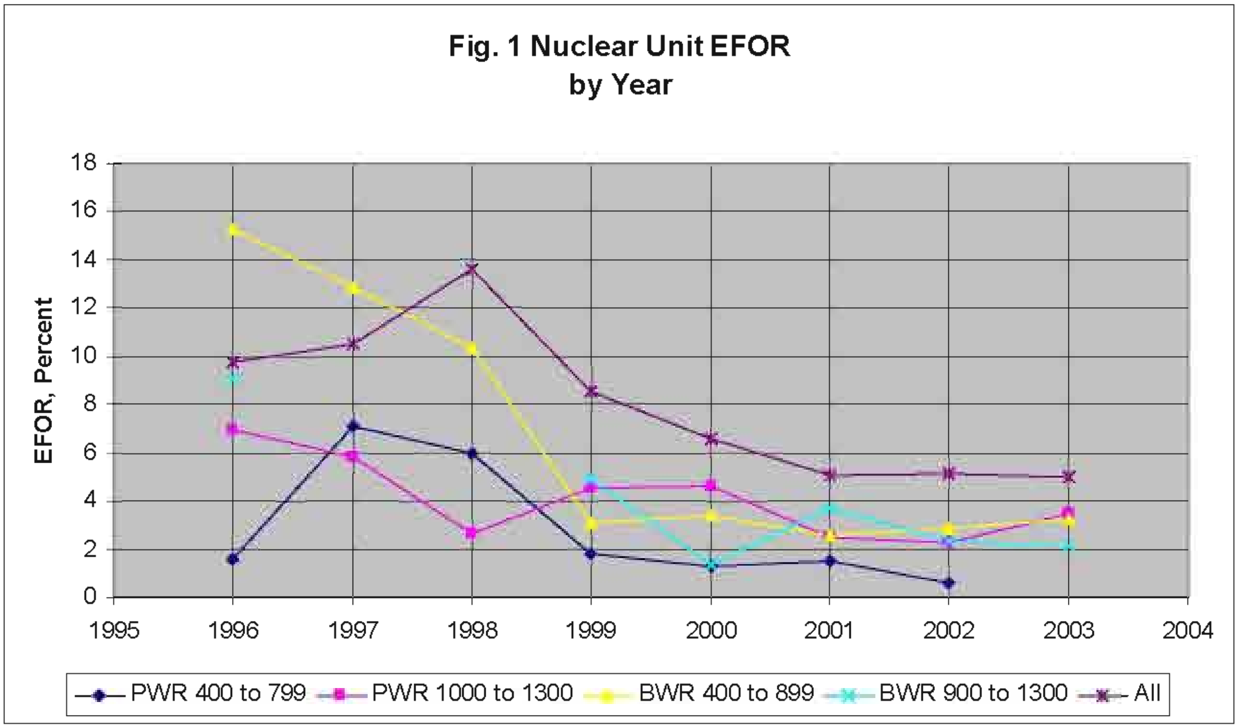
	Load Forecast Uncertainty	
	Weather Only	All Factors
2005	3.34%	4.99%
2006	3.34%	5.89%
2007	3.34%	6.14%
2008	3.34%	6.14%
2009 - 2014	3.34%	6.31%

8. The LFU values listed in assumption 7 were adjusted by an LFU multiplier of 0.953 to recognize a degree of non-correlation of load forecast uncertainty among regions. This LFU multiplier is computed as the correlation between MAIN peak load and the total of peak loads for MAIN, MAPP, SPP, SERC and ECAR. In studies prior to 2004 the LFU multiplier was computed as the average correlation between peak loads of MAIN, MAPP, SPP, SERC and ECAR. The former value was heavily impacted by changes in regional boundaries during the period. In addition, the new calculation focuses more on correlations between MAIN and the aggregate of its neighbors, and less on correlations between those neighbors. Sensitivity case 6 examines the impact of the LFU multiplier.

Table 1
Equivalent Forced Outage Rate (EFOR)

Unit Type:		PWR	BWR	COAL	MBLR	OIL [1]	GAS [1]	HYDR	PUMP	NNFP*	WIND	I.C.	COMB	JET	C.T.	TOTAL
MW	(2005)	7353	6822	28232	3162	186	414	684	440	450	4	355	5613	322	16535	70876
	(2009)	7353	6822	30101	3162	186	414	684	440	1041	4	355	9011	626	17843	78043
	(2014)	7353	6822	32976	3162	186	414	684	440	2587	4	355	9611	626	17843	83064
Source:		NERC pc-GAR: 1999-2003									Estimated from MAIN Survey					
Size Range																
0	30			5.06	3.69	1.86	3.52	3.72								
31	99															
100	199			5.49					1.78							
200	299			5.25	3.84											
300	399			5.61												
400	599	1.65%	3.38%	6.99		(1)	(1)									
600	799			6.90												
800	899															
900	999		2.86%													
1000	UP	6.82%														
Vintage																
To 1989														10.0	10.0	
1990 and later														5.0	5.0	
All										5.62	10.0	10.0	5.0			
2005 Weighted Avg.		5.71	2.90	6.13	3.81	1.86	3.52	3.72	1.78	5.79	10%	10%	5%	5.80	5.66	5.43

* NNFP = net non-firm purchased power – a weighted average of fossil steam plant performance is used as a proxy..
(1) Due to retirement of Collins Station, no longer considered.



9. A 98.63% peak load coincidence factor among MAIN subregions was used, based on 2000 through 2004 data.

10. A load profile based upon 1999 through 2004 load data was used to extend seasonal peaks to all workdays for this year's study.

11. Bulk power transactions scheduled for summer and non-summer months of each year were modeled based on data supplied in items 2.1 and 2.2 of the April 1, 2005 MAIN report to the EIA. Net full responsibility (firm) imports were accounted for by adjusting demand. Other (non-firm) net imports were represented by proxy units with availabilities equal to the average for all fossil fired steam units in NERC-GADS. Separate values were used during the summer (June-September) and winter (October-May) seasons. The assumed non-firm net imports for each season were as follows.

Non-Firm Net Imports into MAIN (MW)

	Jan-May	*June-Sept*	*Oct-Dec*
2005	0	450	436
2006	436	878	804
2007	804	1059	1048
2008	1048	1058	840
2009	840	1041	1001
2014	2800	2587	2486

12. This study assumes that no transmission limitations to deliverability exist, either within MAIN or from neighboring systems. Transmission assessments are performed by MAIN

in other studies.

Results

The results of the analysis are contained in Tables 2 through 5 and Figures 2 and 3. The contents of these tables and figures are described in the following sections.

Generation Reserve Goals to Achieve an LOLE of 0.1 Day per Year

Table 2 shows the reserve margins required to achieve an LOLE of 0.1 day per year for the no LFU, weather only LFU and the all factors LFU scenarios in 2005-2009 and 2014.

Table 2
Required MAIN Reserve Margins
To Achieve an LOLE of 0.1 Day Per Year

Year	2005	2006	2007	2008	2009	2014
No LFU	5.29%	5.28%	5.26%	5.24%	5.25%	5.42%
Weather Only LFU	9.35%	9.34%	9.31%	9.33%	9.34%	9.46%
All Factors LFU	12.40%	14.14%	14.55%	14.64%	15.02%	15.12%

2009 Reserves Supplied from Interconnections

Table 3 shows the reserve levels required to achieve an LOLE of 0.1 day per year for the MAIN times four and MAIN times one systems in 2009. The difference, times the 2009 adjusted capability, reflects reserves supplied from neighboring regions through transmission interconnections. Results for weather LFU only and for all LFU factors are shown on this table.

Table 3
2009 Reserves Supplied from Interconnections

	Adjusted Reserve Margin		Adjusted Capability	Reserves Supplied from Interconnections, MW[2]
	MAIN x 4[1]	MAIN x 1		
Weather Only LFU	9.34%	10.25%	78075	589
All Factors LFU	15.02%	15.67%		381

[1] An LFU multiplier of 0.953 is applied only to the MAIN x 4 system.
[2] These reserves are in addition to scheduled imports listed in assumption 11.

Loss of Load Expectation versus Reserve and Capacity Margin

Figures 2 and 3 present the relationship between expected LOLE and reserve levels in the year 2009. Conditions of LFU due only to weather and LFU due to all factors are presented. The relationship is plotted in Figure 2 measuring reserve levels in terms of reserve margin and in Figure 3 measuring reserve levels in terms of capacity margin.

Figure 2
Loss of Load Expectation versus Adjusted Reserve Margin

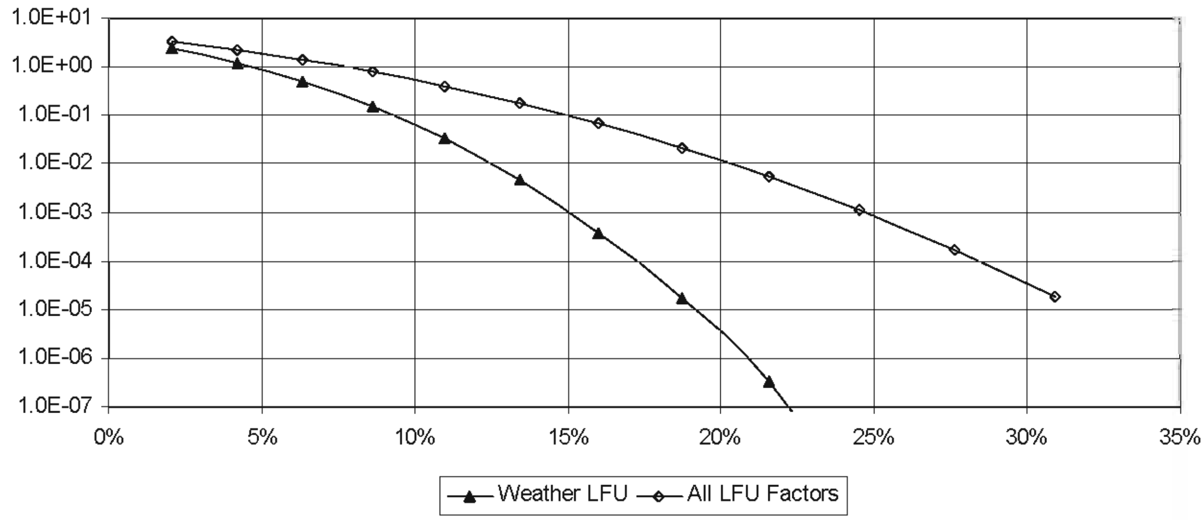
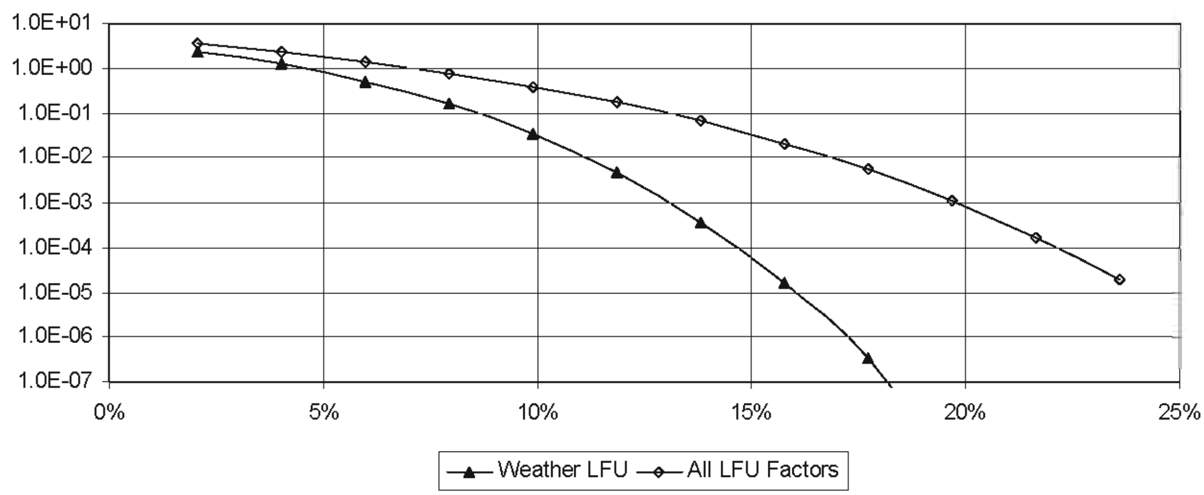


Figure 3
Loss of Load Expectation versus Adjusted Capacity Margin



Historical Trend in Generation Reserve Goals

The minimum reserve levels required to achieve an LOLE of 0.1 day per year, as computed by the annual studies of the last ten years, are shown in Tables 4A, 4B and 4C. These tables compare Generation Reserve Goals assuming, respectively, no LFU, weather LFU only, and all LFU. This comparison is based on the tenth year considered in each study.

Table 4A

Historical Trends in Generation Reserve Goals with No LFU

10th Year of Study

Report Year	Years Studied	NERC-GADS Availability Data (Regional** in all years)	MAIN Reserve Margin Policy	Reserve Margin*	Reserve Margin Change	Primary Reason(s) for Reserve Change
1996	1996-1999 & 2005	1990-1994	18 - 22%	8.9%		
1997	1997-2000 & 2006	1991-1995	17 - 20%	8.8%	-0.1%	Improved availabilities offset by reduced maintenance
1998	1998-2001 & 2007	1992-1996		8.1%	-0.7%	Improved availabilities
1999	1999-2002 & 2008	1993-1997		7.7%	-0.4%	Change in load shape
2000	2000-2004 & 2009	1994-1998		7.4%	-0.3%	Change in load shape. Improved availabilities offset somewhat by a change in load shape and unit mix
2001	2001-2005 & 2010	1995-1999		6.7%	-0.7%	Improved availabilities, revised approach to estimating CT availability
2002	2002-2006 & 2011	1996-2000		7.5%	+0.8%	Lower availabilities
2003	2003-2007 & 2012	1997-2001	16% ***	7.2% / 5.9%	-0.3% / -1.6%	Improved nuclear availabilities after 1998
2004	2004-2008 & 2013	1998-2002	16 - 19%	5.7%	-1.5%	Improved availabilities and lower LFU
2005	2005-2009 & 2014	1999-2003	15 – 18%	5.4%	-0.3%	Continuing improvement in availabilities.

*- Reserve margin required to achieve an LOLE of 0.1 day per year

** - Regional is defined as MAIN, MAPP (US), SPP, SERC, and ECAR. All TVA nuclear units were excluded in 1998 and previous years. TVA BWR units were excluded in 1999, 2000 and 2001. Browns Ferry Unit 1 was excluded in 2002 and subsequent years.

*** - 16% to 19% was recommended by the RMWG; the Board did not specifically adopt an upper limit.

Table 4B

<u>Historical Trends in Generation Reserve Goals with Weather LFU Only</u>

10th Year of Study

Report Year	Years Studied	NERC-GADS Availability Data (Regional** in all years)	Weather Only LFU	MAIN Reserve Margin Policy	Reserve Margin*	Reserve Margin Change	Primary Reason(s) for Reserve Change
1996	1996-1999 & 2005	1990-1994	3.28%	18 - 22%	11.8%		
1997	1997-2000 & 2006	1991-1995	3.25%	17 - 20%	11.7%	-0.1%	Improved availabilities offset by LFU reductions and reduced maintenance
1998	1998-2001 & 2007	1992-1996	3.21%		10.8%	-0.9%	Improved availabilities and lower LFU multiplier
1999	1999-2002 & 2008	1993-1997	3.15%		11.5%	+0.7%	LFU multiplier of 0.947 and change in load shape
2000	2000-2004 & 2009	1994-1998	3.18%		11.5%	0.0%	Improved availabilities offset somewhat by a change in load shape and higher LFU multiplier
2001	2001-2005 &2010	1995-1999	3.22%		10.9%	-0.6%	Improved availabilities, revised approach to estimating CT availability
2002	2002-2006 & 2011	1996-2000	3.16%		11.2%	+0.3%	Lower availabilities, offset by lower weather uncertainty (LFU) and LFU multiplier
2003	2003-2007 & 2012	1997-2001	3.16%	16% ***	10.9% / 9.7%	-0.3% / -1.5%	Improved nuclear availabilities after 1998
2004	2004-2008 & 2013	1998-2002	3.05%	16 - 19%	9.4%	-1.5%	Improved availabilities and lower LFU
2005	2005-2009 & 2014	1999-2003	3.34%	15 – 18%	9.5%	+0.1%	Improved availabilities offset by higher weather uncertainty (LFU)

*- Reserve margin required to achieve an LOLE of 0.1 day per year

** - Regional is defined as MAIN, MAPP (US), SPP, SERC, and ECAR. All TVA nuclear units were excluded in 1998 and previous years. TVA BWR units were excluded in 1999, 2000 and 2001. Browns Ferry Unit 1 was excluded in 2002 and subsequent years.

*** - 16% to 19% was recommended by the RMWG; the Board did not specifically adopt an upper limit.

Table 4C

Historical Trends in Generation Reserve Goals with All LFU

10th Year of Study

Report Year	Years Studied	NERC-GADS Availability Data (Regional** in all years)	All Factors LFU	MAIN Reserve Margin Policy	Reserve Margin*	Reserve Margin Change	Primary Reason(s) for Reserve Change
1996	1996-1999 & 2005	1990-1994	6.51%	18 - 22%	16.8%		
1997	1997-2000 & 2006	1991-1995	6.45%	17 - 20%	16.7%	-0.1%	Improved availabilities offset by LFU reductions and reduced maintenance
1998	1998-2001 & 2007	1992-1996	6.31%		15.4%	-1.3%	Improved availabilities and lower LFU multiplier
1999	1999-2002 & 2008	1993-1997	6.21%		17.3%	+1.9%	LFU multiplier of 0.947 and change in load shape
2000	2000-2004 & 2009	1994-1998	6.34%		17.9%	+0.6%	Improved availabilities completely offset by a change in load shape and higher LFU multiplier and LFU
2001	2001-2005 &2010	1995-1999	6.44%		17.4%	-0.5%	Improved availabilities, revised approach to estimating CT availability
2002	2002-2006 & 2011	1996-2000	6.32%		17.2%	-0.2%	Lower weather uncertainty (LFU) and LFU multiplier, offset by lower availabilities
2003	2003-2007 & 2012	1997-2001	6.32%	16% ***	16.8% /15.6%	-0.4% / -1.6%	Improved nuclear availabilities after 1998
2004	2004-2008 & 2013	1998-2002	6.20%	16 - 19%	15.5%	-1.3%	Improved availabilities and lower LFU
2005	2005-2009 & 2014	1999-2003	6.31%	15 – 18%	15.1%	-0.4%	Improved availabilities partially offset by higher weather component of LFU

*- Reserve margin required to achieve an LOLE of 0.1 day per year

** - Regional is defined as MAIN, MAPP (US), SPP, SERC, and ECAR. All TVA nuclear units were excluded in 1998 and previous years. TVA BWR units were excluded in 1999, 2000 and 2001. Browns Ferry Unit 1 was excluded in 2002 and subsequent years.

*** - 16% to 19% was recommended by the RMWG; the Board did not specifically adopt an upper limit.

Sensitivity Analysis

Twelve sensitivity cases were run for 2009, the fifth year studied, each modifying one assumption from for the Base Scenario. Table 5 compares the Generation Reserve Goals to achieve a LOLE of 0.1 day per year. These cases fell into three categories: (1) to assess the impact of updated input values from last year's study, (2) to examine the impact of planned maintenance schedules, the collection of which is relatively burdensome to both members and MAIN staff, and which involve commercially sensitive information, and (3) to determine how sensitive the results were to alternative assumptions. These sensitivities are described below; the change from Base Scenario assumptions is underlined.

Sensitivity Cases examining effect of study input values changed from prior year

1. 1998-2002 NERC-GADS data for units located in the MAIN, MAPP (US), SPP, SERC and ECAR reliability councils, excluding Browns Ferry 1, was substituted for the Base Scenario values.

2. An LFU multiplier value of 0.963, which was used in last year's study, was used.

3. The load profile used in last year's study, based on 1998-2002 data, was utilized.

4. LFU values of 3.05% (weather) and 6.20% (all factors) were used.

Sensitivity Case examining impact of planned maintenance

5. The effect of maintenance was disregarded: no unit maintenance outages were considered.

Sensitivity Cases examining effect of alternative assumptions

6. An LFU multiplier value of 1.0 was used to represent four regions that are perfectly correlated.

7. Combustion Turbine (CT) and jet unit EFOR was modeled at 7.5% regardless of vintage.

8. 1999-2003 pc-GAR national data, excluding Browns Ferry 1, was substituted for the Base Scenario values.

9. 1999-2003 pc-GAR data for units located in the MAIN region only was substituted for the Base Scenario values.

10. The equivalent forced outage rates of generation units were increased from the Base Scenario values by 5%.

11. 1999-2003 pc-GAR data for units located in the MAIN, MAPP (US), SPP, SERC and ECAR reliability councils, excluding Browns Ferry 1 and disregarding reserve shutdown hours, were substituted for the base values. This increased the EFOR of unit types that are frequently in reserve.

12. Load Forecast Uncertainty was increased by 10%, to 3.67% for LFU due to weather only and 6.94% for LFU due to all factors.

Table 5
Sensitivity Analysis for 2009

		Generation Reserve Goals to Achieve LOLE of 0.1 Day Per Year		
		No LFU	Weather LFU Only	All LFU Factors
Base Scenario for 2009		5.25%	9.34%	15.02%
Sensitivity Cases examining effect of study input values changed from prior year				
1.	1998-2002 NERC-GADS availabilities, MAIN & surrounding regions (from pc-GAR)	5.05%	9.20%	14.88%
2.	LFU multiplier = 0.963 (last year's value)	5.25%	9.41%	15.15%
3.	1998-2002 load profile	5.25%	9.41%	15.17%
4.	LFU =3.05% (weather) and 6.20% (all factors)	5.25%	8.84%	14.79%
Sensitivity Case examining significance of planned maintenance				
5.	Planned maintenance disregarded	5.25%	9.35%	15.02%
Sensitivity Cases examining effect of alternative assumptions				
6.	LFU multiplier = 1.0	5.25%	9.63%	15.60%
7.	CT and jet EFOR = 7.5% regardless of vintage	5.97%	10.06%	15.71%
8.	1999-2003 NERC-GADS national availabilities	5.27%	9.39%	15.07%
9.	1999-2003 NERC-GADS availabilities; MAIN units only	5.46%	9.61%	15.29%
10.	All unit EFOR increased by 5%	5.50%	9.58%	15.25%
11.	Reserve shutdown hours excluded from availabilities	6.22%	10.31%	15.94%
12	LFU increased by 10% to 3.67% (weather) and 6.94% (all factors)	5.25%	9.93%	16.19%

Range of Reserve Margin Goals

Prior to 2002 a range of reserve margin goals was set by the Board. The lower and upper limits of the range set in 1992, 18% to 22%, were determined by alternative scenarios using hypothetical values of the Load Forecast Uncertainty multiplier ranging from 0.707 to 1.0. In 1997 the range was lowered to 17 to 20%, taking into account scenarios with a narrower range of LFU multiplier of 0.854 to 1.0. At the time the 2003 interim report was prepared attention was focused on the minimum value and while a range of 16% to 19% appears in the report text the Board did not specifically adopt an upper limit.

Consideration of all of the sensitivity cases examining the effects of alternative assumptions (cases 6 through 12) would indicate a range of 15.0% to 16.2%. The lower value is now based on five years of NERC GADS data and it now appears reasonable to depend on sustaining this level of unit performance. Variations in unit performance have become the driving force behind changes in the reserve margin target, as LFU and LFU multiplier fluctuations have been modest over the last ten years. Such variations, of course, are influenced by management decisions and regulatory actions impacting the units involved.

In the 2004 and 2003 studies some weight was given to the base case values calculated in previous studies, justifying caution in reducing the range too quickly. As recently as 2000, a reserve margin of 17.9% was calculated to obtain LOLE of 0.10 under "base" assumptions. Selected sensitivity cases in the 2000 and 2001 studies gave reserve margins over 19%.

The Reserve Margin Working Group acknowledges that, while its best estimate of the required reserve margin is approximately 15%, a combination of adverse changes could increase that by as much as three percentage points. Accordingly they now recommend a reserve margin range of 15% to 18%, reduced one percentage point from the range recommended last year.

Conclusions

The Working Group recommends that Generation Reserve Goals remain at a minimum reserve margin of 14% for the short-term (up to one year ahead). The Working Group recommends a minimum planning reserve margin of 15% to 18% for long-term resource planning and assessment.

A minimum short-term reserve margin of 15% was informally observed for many years and was formally adopted in December 2002; this was reduced to 14.12% in June, 2003. A minimum planning reserve margin of 16% was recommended in 2003 and 2004.

A downward trend in generator forced outage rates, particularly nuclear, that began in 1999 is a major driving force behind this trend. Several nuclear units with chronic problems have been retired and significant improvements have been made at those that remain. It appears reasonable to assume that this good performance will be sustained, but further improvement will not be readily attained.

MAIN Guide No. 6, which mandates this study, has been revised by the MAIN Planning, Operating and Market Interface Committees and is awaiting Board approval as this study is prepared. Among other changes it makes participation in NERC GADS, including reporting of generator performance and event data, mandatory for generating units 10 MW and larger. Anticipating this mandate, a number of generation owners within MAIN began reporting during 2004. The Working Group feels this substantially fulfills its self-assigned task in the 2003 report to "Investigate how to obtain valid and comparable unit performance data in a competitive marketplace."

Year to year comparisons should be based on year 5 for future studies. The ten-year planning horizon required by NERC Planning Standards is substantially greater than the lead time for combustion turbines, which predominate among units being built currently.

Recommendations for Future Studies by Reliability First

It is anticipated that this is the final Reserve Margin study to be conducted by MAIN. Some members of MAIN are expected to join MRO, while others, together with ECAR and MAAC, will form Reliability First, a new NERC region. Reliability First will combine the methodologies of its predecessor regions to evolve a methodology for its combined footprint. In doing so, issues which need to be addressed include

- Review of LFU calculation methodology, particularly for short-term studies
- Incorporate consideration of common-mode events, including terrorism and fuel supply disruption, into its methodology
- Clarify the distinction between short term and long-term generation reserve goals
- Develop a more comprehensive methodology for determining the upper limit of the recommended reserve margin bandwidth.

Sensitivity case 5 demonstrates that current maintenance schedules have very little impact on LOLE and hence on Generation Reserve Goals. Obviously this is a consequence of generation owners not performing maintenance during the summer months when loads are high. This indicates that in future studies consideration should be given to doing the study in two parts: a first pass disregarding maintenance, in which critical weeks for each of the first two or three years studied are determined. (Maintenance schedules are generally tentative or "typical" beyond three years.) Generation owners would then be polled to determine if they plan any maintenance during those weeks, and cases could be redone as necessary if any is identified. This would eliminate submission of commercially sensitive information that will not significantly impact the outcome of the study.

Appendix I

Study Data Sources

Source	Item(s)
MAIN Report to the EIA April 1, 2005	Generating Unit Size and Fuel Type Seasonal Peak Demand Power Transactions
NERC pc-GAR (GADS data base)	Generating Unit Forced Outage Rates -- Full and Partial
MAIN Member Utilities (survey)	Generating Unit Maintenance Schedule CT and Jet Forced Outage Rates
NERC Hourly Load Data 1999-2004	Load Profile
NERC Electric Supply and Demand	Load Forecast Uncertainty Multiplier
Records of MAIN Load Forecast Working Group	Weather Adjusted Loads, LFU values Peak Load Coincidence Factor

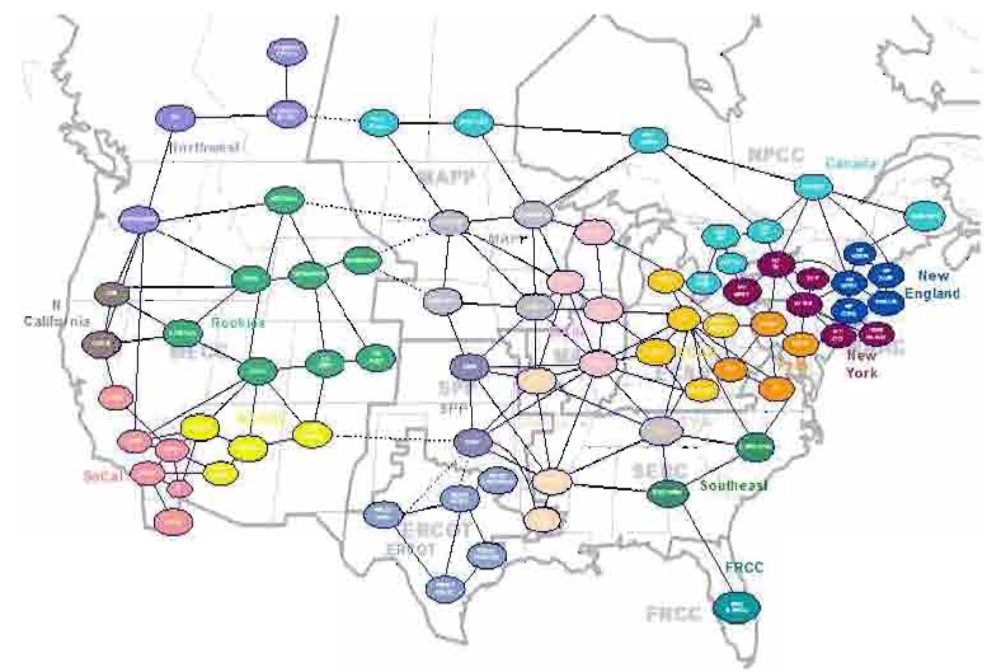
COST ANALYSIS MODEL

EnerPrise Strategic Planning *powered by* MIDAS Gold® is an integrated, fast, multi-scenario zonal market model capable of capturing many aspects of regional electricity market pricing, resource operation and asset and customer valuation. It is comprised of four modules: markets, portfolio, financial and risk. The markets and portfolio modules are hourly, multi-area, chronologically correct, market production costing modules used to derive market prices, evaluate power contracts and develop regional or utility-specific resource plans. The financial and risk modules provide full financial results and statements and decision-making tools necessary to value customers, resource portfolios and business unit profitability. Each module is discussed separately.

Markets Module

The markets module generates zonal electric market price forecasts for single- and multi-area systems by hour and chronologically correct for 30 years. Prices may be generated for energy only, bid- or ICAP-based bidding processes (ICAP is the world's largest voice and electronic interdealer broker.). Prices generated reflect trading between transaction groups where transaction group may be best defined as NERC (North American Electric Reliability Council) sub-regions. Trading is limited by transmission paths and constraints quantities.

Market Areas



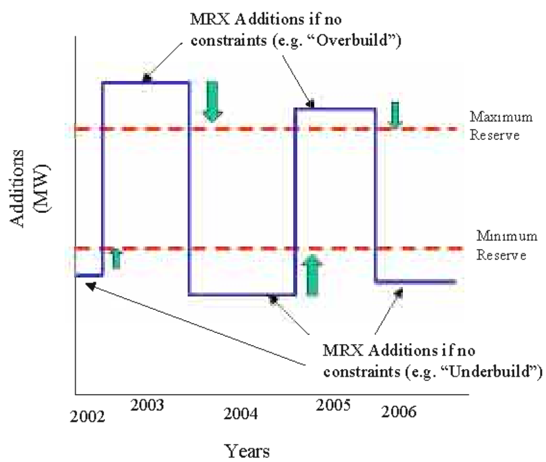
Some of the data used to populate the module are as follows:

- Operational information for more than 10,000 generating units
- Load forecasts by zone (where zone may be best defined as utility level) and historical hourly load profiles
- Transmission capabilities
- Coal price forecast by plant with delivery adders from basin
- Gas price forecast from Henry Hub (the pricing point for natural gas future contracts traded on the New York Mercantile Exchange), with LDC (Local Distribution Companies) and basis adders for delivery points

When running the markets module, the main process of the simulation is to determine hourly market prices. Plant outages are based on a unit derate, and maintenance may be specified as a number of weeks of scheduled outages.

The market based resource expansion algorithm (MRX) builds resources by planning region based on user-defined profitability and/or minimum and maximum reserve margin requirements in determining prices. In addition, strategic retirements are made of non-profitable units based on user-defined parameters.

MRX Decision Basis



The markets module simulation process performs the following steps to determine price:

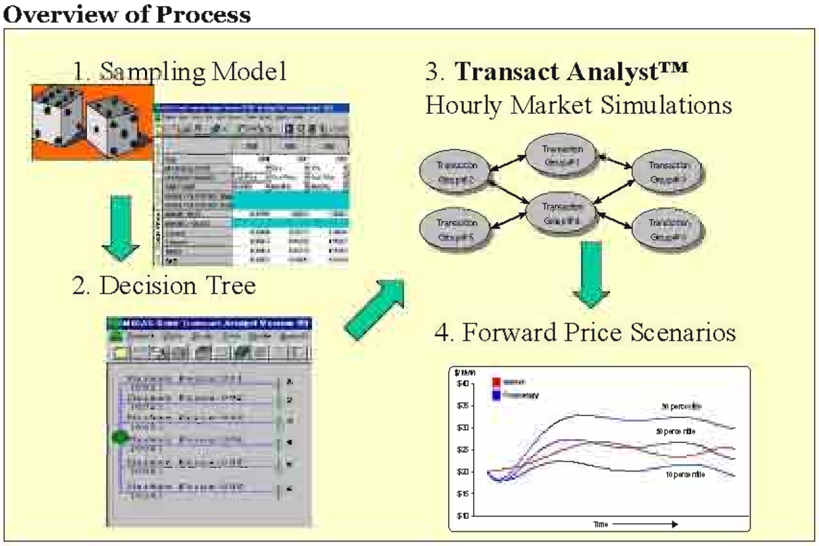
- Hourly loads are summed for all customers within each Transaction Group.
- For each Transaction Group in each hour, all available hydro power is used to meet firm power sales commitments.
- For each Transaction Group and Day Type, the model calculates production cost data for each dispatchable thermal unit and develops a dispatch order.
- The model calculates a probabilistic supply curve for each Transaction Group considering forced and planned outages.
- Depending on the relative sum of marginal energy cost + transmission cost + scarcity cost between regions, the model determines the hourly transactions that would likely occur

among Transaction Groups.

- The model records and reports details about the generation, emissions, costs, revenues, etc., associated with these hourly transactions.

Strategic Planning has the functionality of developing probabilistic price series by using a four-factor structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission. Using a Latin Hypercube-based sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price "drivers" (e.g. demand, fuel price, availability, hydro year, capital expansion cost, transmission availability, market electricity price, reserve margin, emission price, electricity price and/or weather) and take into account statistical distributions, correlations and volatilities for three time periods (i.e. Short-Term *hourly*, Mid-Term *monthly*, and Long-Term *annual*) for each transaction group. By allowing these uncertainties to vary over a range of possible values a range or distribution of forecasted prices are developed.

Overview of Process



Portfolio Module

Once price discovery has been completed in the markets module the portfolio module may be used to perform utility or region specific portfolio analyses. Simulation times are faster and it allows for more detailed operational characteristics for a utility specific fleet. The generation fleet is dispatched competitively against pre-solved market prices from either the markets module or other external sources. Native load may also be used for non-merchant/regulated entities with a requirement to serve.

Portfolio module operates generation fleet based on unit commitment logic which allows for plant specific parameters of:

- Ramp rates
- Minimum/maximum run times
- Start up costs

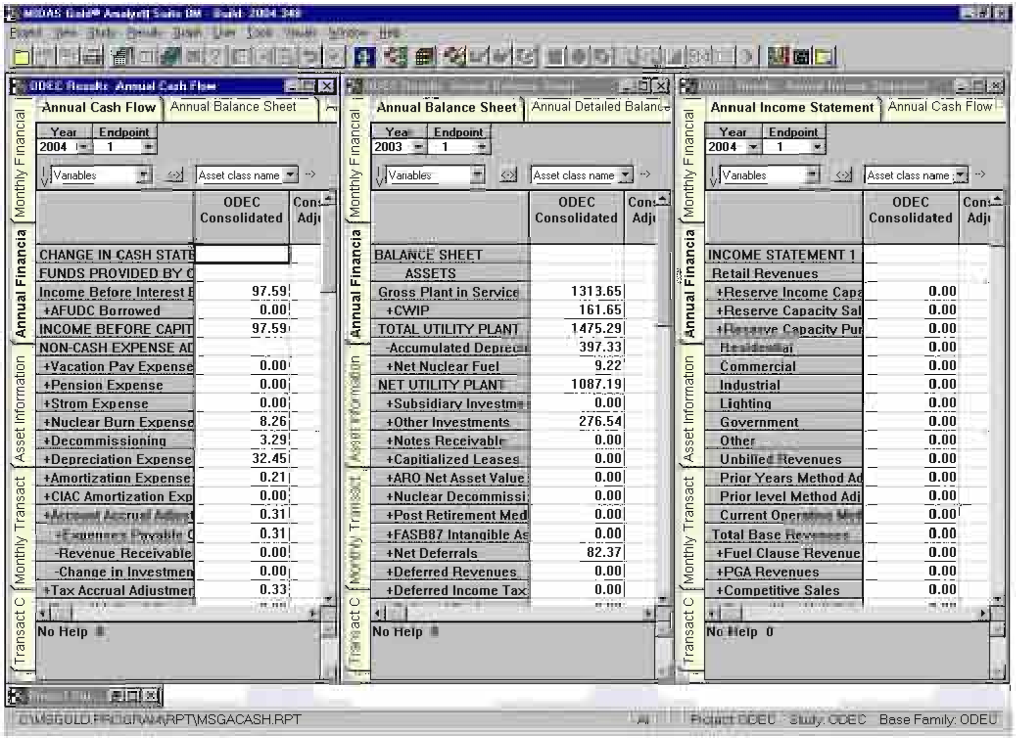
The decision to commit a unit may be based on one-day, three-day, seven-day and month criteria. Forced outages may be based on Monte-Carlo techniques or frequency duration with the capability to perform detailed maintenance scheduling. Resources may be de-committed based on transmission export constraints.

Portfolio module has the capability to operate a generation fleet against single or multiple markets to show interface with other zones. In addition, physical, financial and fuel derivatives with pre-defined or user-defined strike periods, unit contingency, replacement policies or load following for full-requirement contracts are active.

Financial Module

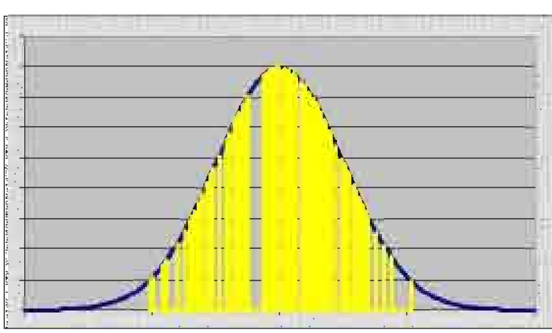
The financial module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts.

Sample Reports

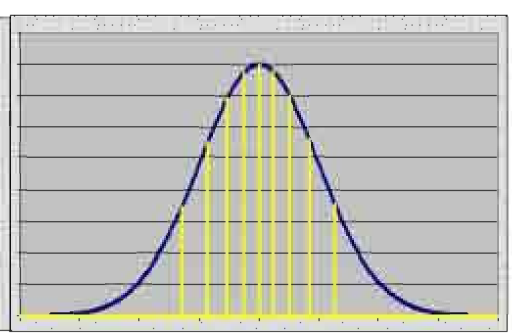


Risk Module

Risk Module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables providing flexibility not available in other models. This functionality is through the use of Latin HyperCube sampling which is a stratified sampling program similar to Monte-Carlo random sampling technique.



Monte Carlo Sample



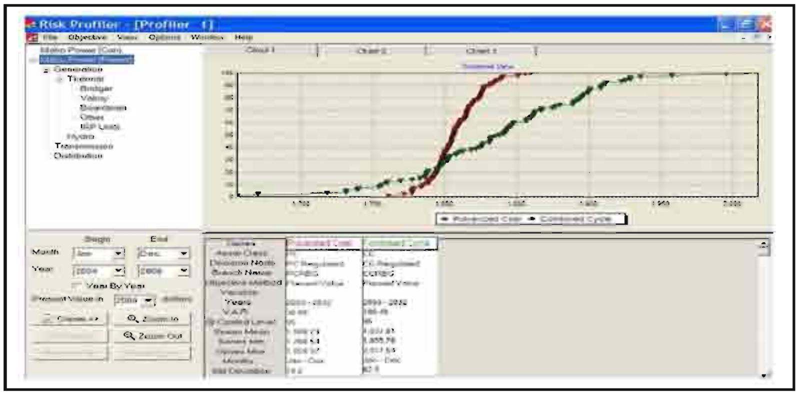
Latin HyperCube Sample

- Generate random variability
- Variables may be defined as:
    - Constant
    - Random walking
    - Mean reverting
- Distributions may be defined as:
    - Normal
    - Log-normal
    - Uniform
- Eliminates the need to use exterior programs to perform risk analytics
- Statistical parameters are user-defined by variable and provide for a four-factor modeling of variability based on:
    - Short-term (hourly, daily, weekly)
    - Mid-term (monthly)
    - Long-term (quarterly, annual, semi-annual)
    - Multi-year (by year)
- Single and multiple correlations are user-defined between variables
- Stochastics may be performed on both production and financial variables providing flexibility not available in other models

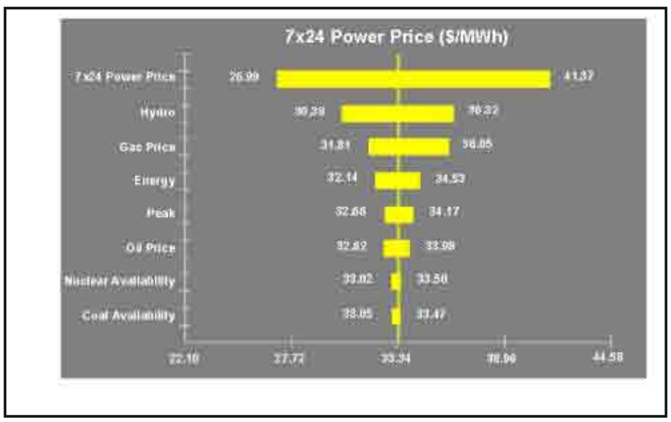
Risk Module Reporting & Tools for Data Analysis

- Reports are generated providing the monthly multipliers by variable, including volatility and standard deviation
- Scenario Viewer™ provides a graphical view of multipliers to ascertain a view of modifications made by product by time frame
- Risk Profiler™ generates cumulative probability distribution curves and includes statistics related to:
    - User defined measurements
    - VaR
    - Mean, minimum and maximum values
    - Standard deviation
    - Skewness and kurtosis
- Risk Profiler provides the capability to:
    - Drill down by business unit to determine which business unit drives probability distribution curves
    - Change business structure with drop and drag of organization chart to revise results

- Drill down capability to identify which endpoint is represented to determine specifics of drivers



- Tornado Chart Builder™ may be used to determine effective hedging strategies by identifying drivers of:
  - Market prices generated in the Markets Module
  - Drivers of user-defined dependent variables produced by stochastic analyses



- Efficient Frontier™ allows users and management to quickly assess the levels of risk associated with multiple decisions
- Value at Risk Optimization™ is another tool available to assist management in determining which decision, given uncertainty, attains pre-determined earnings goals, given user-defined levels of earnings-at-risk or other user-defined objectives

Common Functionality of All Modules

- Input information organized in logical tables by type of information in a format similar to spreadsheets for ease of use
- Operates as a desk-top application without the need for servers
- Fully integrated and seamless to user with no additional installation or IT support required
- Results are presented in a pivot-table spreadsheet format
- Internal graphics capability available on results
- User-defined customization of results exported
- Information available to the lowest level defined by user
- May roll up results to mid levels to group assets
- Multi-tool applications available to:
  - Run multiple studies
  - Convert files from multiple formats
  - Manage results

EnerPrise Strategic Planning *powered by* MIDAS Gold® documentation is available for review in the Company's Corporate Planning Department or may be obtained from Global Energy Decisions subject to appropriate licensing restrictions imposed by them.