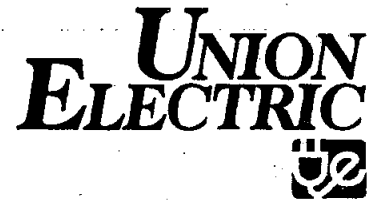


# **ENERGY RESOURCE PLAN**

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**FILED**  
JUL 10 1995  
MISSOURI  
PUBLIC SERVICE COMMISSION

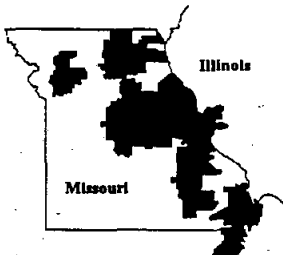
**RESOURCE PLANNING COMMITTEE**

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June 1995

## COMPANY BACKGROUND

Union Electric Company (UE) is an independent, investor-owned utility headquartered in St. Louis, Missouri. UE currently supplies electric service to territories in Missouri and Illinois having an estimated population of 2,600,000 within an area of approximately 24,500 square miles. The population and electrical load is concentrated in the Metropolitan St. Louis Area.



Natural gas purchased from non-affiliated pipeline companies is distributed in 90 Missouri communities and the City of Alton, Illinois.

The Company employed 6,266 persons as of December 31, 1994. UE's highest gross instantaneous peak electrical load was 7,540 megawatts in the summer of 1993.

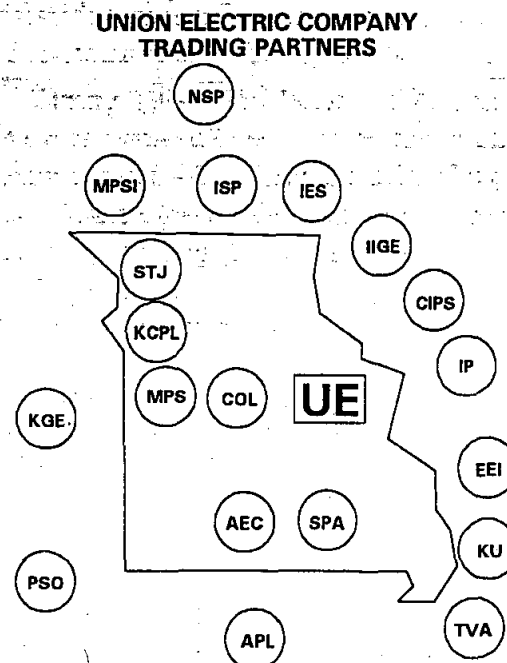
During 1994, 95.8% of total operating revenues was derived from the sale of electricity and 4.2% from the sale of natural gas. Approximately 89% of the Company's electric operating revenues was based on rates regulated by the Missouri Public Service Commission in 1994. The balance was regulated by the Illinois Commerce Commission (8%) and the Federal Energy Regulatory Commission (3%).

UE operates one nuclear-fueled and five fossil-fueled steam generating plants containing a total of 19 units with a net summer generating capacity of 6,758 megawatts. In addition, two hydroelectric plants, one pumped storage plant, nine combustion turbine units, and several small diesel units

provide an additional net summer generating capacity of 1,067 megawatts. The Company's aggregate net summer generating capacity is 7,825 megawatts. In addition, UE owns 40% of Electric Energy Incorporated, providing 405 megawatts of capacity from the Joppa Plant which is located on the Ohio River, in Joppa, Illinois.

The Company is strategically located in the center of the United States and conducts interchange transactions directly with nineteen surrounding utilities. These numerous links give UE the flexibility to meet system requirements with the lowest cost power available. As of December 31, 1994, the Company owned approximately 3,315 circuit miles of electric transmission lines.

The following figure provides a pictorial representation of UE and the companies it can directly transact with.



## **2 Company Background**

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The Company faces issues common to the electric and gas utility industries which have emerged during the past several years. These include: changes in the structure of the industry as a result of amendments to federal laws regulating ownership of generating facilities and access to transmission systems; the potential for more intense competition; continually developing environmental laws, regulations, and issues; public concern about the siting of new facilities; magnetic fields emanating from power lines and other electric sources; proposals for demand-side management programs; and public concerns about the disposal of nuclear wastes and about global climate issues. The Company is monitoring these issues.

## INTRODUCTION

### SECTION 1

#### 1.1 PURPOSE

The resource planning objective at Union Electric is to develop a plan that provides our customers high quality service at the lowest possible cost, consistent with paying a fair return to our investors and maintaining the welfare of our employees.

This Energy Resource Plan (ERP), which documents the process used to pursue this objective, is a snapshot of an ongoing planning process at UE. The plan continuously evolves as new information is received, economic conditions change, new technologies emerge, legislation changes, and the planning process itself improves.

The planning process focuses on identifying future system requirements and developing a flexible resource strategy to meet those requirements. This ERP provides the results of the planning process for the twenty-year planning horizon through 2014.

#### 1.2 PLAN SUMMARY

This ERP updates the December 1993 ERP and addresses issues which will likely affect UE's future capacity and energy requirements. The load forecast used in the development of this ERP was prepared in October, 1994 and indicates that system resource requirements are not expected to exceed available resources before 2000.

The demand forecast, in conjunction with system reliability requirements, determines when additional resources — supply-side and demand-side management (DSM) — are required to meet customer demand. After the timing of future resource needs is determined, the preferred resource mix is developed.

Based on assumptions developed for this ERP, the preferred resource plan for the

twenty-year planning horizon includes an economic combination of supply-side and demand-side resources as follows:

<u>Additional Generation</u>	<u>Capacity</u>
Sioux Operating Improvement	16 MW
Taum Sauk Runner Replacement	80 MW
Combustion Turbines	825 MW
Combined Cycle Units	180 MW
Venice Repowering	510 MW
Capacity Purchases	200 MW
150 MW 1998-2004	
50 MW 2000-2013	
Renewables	2 MW

<u>Demand Reduction</u>	<u>Capacity Equivalence</u>
Eliminate 25 Hz Losses	20 MW
DSM Programs (by June 2000)	133 MW
DSM Programs (by June 2014)	268 MW

This ERP relies on relatively small, short lead time resources to meet projected load growth. These qualities provide flexibility to meet the constantly changing external forces facing UE.

UE recognizes that purchases from independent power producers (IPPs) and competitive bidding programs may provide for a portion of these future resources. These options will be used to the extent they are economically justified when decisions are required.

Even though the plan calls for 1,515 megawatts of new dual fuel (gas and oil)

## 4 Introduction

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generation, the Company's fuel mix changes only slightly over time. UE will remain heavily dependent on coal and nuclear generation.

This ERP does not require a substantial commitment for new supply-side resources over the next several years. UE has contracted for the purchase of 150 MW from Central Illinois Public Service Co. for the period June 1, 1998 through May 31, 2005.

The following programs will be initiated or continued over the next three years to provide more information for future decisions.

- Demand-Side Management (DSM) program development will continue in order to gain additional experience in implementing and marketing DSM strategies.
- Combustion turbine (CT) technology and siting will be reviewed and updated as conditions change, to minimize combustion turbine costs and construction lead time requirements.
- The Clean Air Act compliance study will be reviewed and updated as regulations are written and conditions change to yield the least-cost compliance strategy.
- All demand-side and supply-side resource options will be monitored for changes which could affect the preferred resource plan.
- Prior to proceeding with the Keokuk rewind project, the current preliminary estimates of project cost and efficiency gains will be reviewed and updated. In addition, the company will determine if there is a market for 25 Hz generation before a decision is made to proceed with project implementation.
- Engineering, design and procurement of the equipment necessary for the Taum

Sauk runner replacement project will proceed.

- The wind analysis study that was initiated in 1995 will be continued to determine wind availability in the UE service area.
- The Meramec Unit 3 repowering study that was initiated in 1995 will be completed to determine the economics of repowering vs. rehabilitating the boiler.
- Studies will be initiated to evaluate the economics of potential upgrades at several coal-fired units and combustion turbines.

Demand-side options will be phased in over several years so they will be in place when needed. The Company is conducting pilot programs to help guide demand-side program selection and implementation. System-wide programs are scheduled to start in 1997 and gradually build toward a substantial demand reduction. The DSM program phase-in allows the Company to determine more accurately the expected demand reduction. Supply-side measures can be advanced if demand-side programs fail to meet expectations.

Varying degrees of uncertainty exist in the assumptions required to develop the preferred resource plan. Fuel prices, load growth, future legislation, econometric forecasts, new plant costs, and numerous other inputs cannot be predicted with certainty. Various risk analysis techniques, including sensitivity analysis, probabilistic decision trees, and scenario analysis were used to address these uncertainties.

In addition to the expected forecast scenario, the following alternative scenarios were created to investigate the effect of changing the assumptions.

- Low Forecast – Lower than expected peak and energy growth due to unfavorable economic conditions.
- Competition — Assumes a phased in competitive environment where industrial rates are deregulated in 1998, commercial rates in 2000, and retail rates in 2002.
- Environmental Regulation — Assumes a significant increase in environmental regulation beginning in 2000 and extending throughout the planning horizon.
- High Forecast – Higher than expected peak and energy growth due to favorable economic conditions.

This ERP identifies a resource plan that is robust across all of the scenarios. The scenarios do not affect the selection of DSM programs, however they do impact resource timing. The low forecast and environmental regulation scenarios delay the CT decision date. The high forecast scenario may advance the need for additional capacity. This scenario requires additional power purchases for several years and advances the required date for the first CT.

### 1.3 PLAN DEVELOPMENT

A Resource Planning Committee, chaired by the Manager - Resource Planning, is responsible for coordinating the information needed to prepare the ERP. This committee reviews the ERP prior to its submission to upper management for approval.

Members of this committee represent the following functions and departments:

- |                      |                            |
|----------------------|----------------------------|
| • Corporate Planning | • Distribution Engineering |
| • Division Marketing | • Energy Supply            |

- |                          |   |
|--------------------------|---|
| • Environmental Services | • Financial Planning and Investments      |
| • Fossil Fuel            | • General Counsel                         |
| • Mechanical Engineering | • Power Plant Maintenance and Engineering |

Numerous functions supply information to develop the ERP and participate in its review. A brief description of responsibilities follows:

#### Fossil Fuel Supply

The Fossil Fuel and Energy Services Departments maintain up-to-date information on fossil fuel price and availability (coal, oil, natural gas and propane). These departments also maintain information on fuel transportation from origin to UE generating facilities. The departments forecast fossil fuel prices and availability.

#### Nuclear Fuel Supply

The Nuclear Licensing & Fuels Department maintains up-to-date information on uranium price and availability. This department also maintains information on uranium, conversion, enrichment, and fabrication services. The department forecasts uranium prices and availability.

#### Generation Capacity

The Mechanical Engineering (Engineering & Construction) and Power Plant Maintenance and Engineering (Power Plants) Departments develop and maintain information on long-term, supply-side resource options. Mechanical Engineering is responsible for new facilities and major modifications or major improvements to existing facilities. Power Plant Maintenance and Engineering is responsible for existing unit

## 6 Introduction

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performance ratings, capacity ratings, and improvements.

The Mechanical Development group of the Mechanical Engineering Department evaluates emerging generation technologies, renewables, near commercial technologies, and existing commercial technologies. These evaluations consider technical feasibility, commercial viability, costs, performance, and environmental concerns. Technologies include those appropriate for new generation capacity additions as well as retrofit technologies.

The Power Plant Maintenance and Engineering Department monitors existing plants for achieving performance and emissions requirements.

Studies by both departments are conducted to evaluate potential enhancements and improvements to existing facilities. These studies may result in operating improvements and/or plant modifications.

### **Purchased Power**

The Energy Services Department maintains and develops information on the long-term, purchased power market.

### **Transmission**

The Transmission Planning Department maintains and develops information regarding long-term transmission resource options. The Transmission and Interconnections group evaluates the transmission system considering feasibility, economics, reliability, and performance. These studies aid in developing long range plans for the utilization and optimal expansion of the transmission system.

### **Environmental**

The Environmental Services Department maintains and develops information on environmental standards. It also actively supports the environmental permitting and regulatory process.

### **Cogeneration; Renewables; Demand-Side Management**

The Mechanical Engineering and Corporate Planning Functions develop information on these resource options.

### **Regulatory Issues**

The General Counsel Function monitors legislation and regulatory proceedings to determine impacts on the resource plan or the planning process. This function also develops information on possible future regulatory issues.

### **Financial Data**

The Controller's Function annually develops the ten-year budget. The budget information and financial parameters developed by the Financial Planning and Investments Department are used in the planning process.

### **Distribution**

Distribution Engineering develops information on loss reduction in the distribution system.

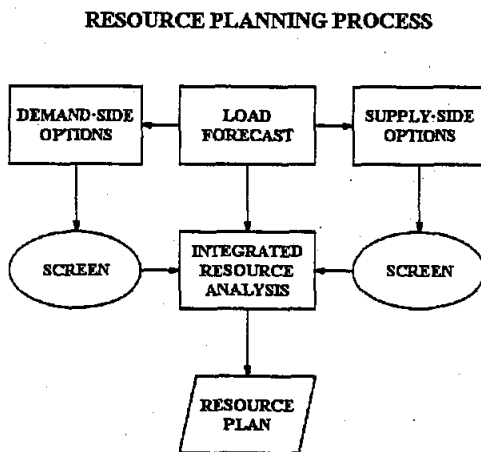
### **Plan Development**

Corporate Planning is responsible for aggregating the data, modeling the UE system, analyzing resource options, and making recommendations to the Resource Planning Committee.

The plan development within Corporate Planning is divided between two groups:

- Demand-Side Planning — Forecast, DSM Screening, Non Utility Generators (NUGs), Cogeneration
- Corporate Analysis — Supply-Side Screening & Optimization, Integration, Risk Analysis, Reliability Analysis

The following figure portrays the process used to develop this ERP.



#### 1.4 PLANNING ENVIRONMENT

A number of regulatory and legislative requirements affect the Company's energy resource planning, and other developments will potentially affect the Company in the future.

##### Power Plant and Industrial Fuel Act of 1978

Substantial amendments to the Power Plant and Industrial Fuel Act of 1978 became effective in 1987. The basic result of these amendments was to remove restrictions on the use of natural gas and petroleum for the generation of electricity, except with respect to new power plants designed to operate as base load units.

Current regulations define base load units as power plants where the kilowatt-hour output exceeds the plant's design capacity multiplied by 3500 hours for any twelve calendar month period. The restrictions on new base load units are not onerous since oil and natural gas units must simply be capable of being converted to coal use in the future. Combined cycle units meet this requirement if they can be converted to burn gasified coal at

a future date. Rules designed to implement the amendments to the Fuel Use Act became effective December 22, 1989.

##### Public Utility Regulatory Policies Act of 1978

The purpose of the Public Utility Regulatory Policies Act of 1978 (PURPA) was to encourage conservation of energy and efficient use of energy resources. PURPA encouraged production of electricity by cogeneration and small power production. This introduced a new form of competition for electric generation by:

- Requiring utilities to interconnect with qualifying facilities (QFs),
- Requiring utilities to buy power from qualifying facilities at the utility's avoided cost,
- Requiring utilities to provide qualifying facilities with supplemental, backup, maintenance, and interruptible power.

Purchasing power from qualifying facilities can reduce the amount of new generation required by a company. A Missouri statute enacted in 1986 requires electric suppliers to purchase the electrical output of municipally owned waste-to-energy facilities at the price they sell electricity to the municipality. However, contrary to a similar Illinois law, no tax credits are given to the utility for the difference, if any, between the rate and the utility's avoided cost.

UE currently purchases about 2.5 MW of waste-to-energy generation from facilities in Illinois and Missouri that use landfill gas.

##### Nuclear Waste Policy Act of 1982

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the permanent storage and disposal of spent nuclear fuel. DOE currently charges one mill per nuclear kilowatt-hour

## 8 Introduction

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generated and sold for future disposal of spent fuel. DOE is not expected to have its permanent storage facility for spent fuel available until at least 2010. UE has sufficient storage capacity at the Callaway Plant site until 2005, and has viable storage alternatives under consideration. Each alternative will likely require Nuclear Regulatory Commission approval, and may require other regulatory approvals. The National Association of Regulatory Utility Commissioners has been active in trying to facilitate an early resolution to the fuel storage issue. The delayed availability of DOE's disposal facility is not expected to adversely affect the continued operation of the Callaway Plant.

### **Energy Policy Act of 1992**

While the Energy Policy Act of 1992 (EPAct) contains numerous electricity-related provisions, few of these provisions establish direct requirements for electric utilities. Most of EPAct sets policy for federal agencies — primarily the Department of Energy (DOE). However, some sections of EPAct will affect the electric utility industry:

- Promotion of Energy Efficiency
- Promotion of Renewable Energy Sources
- Provisions on Nuclear Licensing, Waste and Uranium Enrichment
- Increased Research on Environmental Issues
- Increased Competition in Electric Generation

### Energy Efficiency

The EPAct promotes energy efficiency by setting equipment and appliance efficiencies, and requiring federal and state agencies to assess and revise standards for building codes. The net effect of these provisions on utilities will be to reduce the cost-effectiveness of

some electric utility demand-side programs, as energy efficiency measures will be implemented without utility intervention. REEPS and COMMEND, the forecasting models used by Union Electric, now include the effects of EPAct standards for the residential and commercial classes.

### Renewable Energy

The EPAct promotes renewable energy sources, like biomass and wind power, by requiring DOE research and development, and by creating a 1.5 ¢/kWh tax credit for electricity produced with wind and closed loop biomass resources installed between December 1, 1994 and July 1, 1999. The EPAct requires an inflation adjustment for this incentive, and the Internal Revenue Service announced on March 21, 1995 that the credit for 1995 will be 1.6 ¢/kWh.

This credit may encourage use of renewable resources by utility customers or utilities themselves, particularly where marginal energy costs are high.

### Nuclear Power

The EPAct attempts to encourage the nuclear power option by streamlining the plant licensing process and moving toward a solution to long-term waste storage. EPAct also created the United States Enrichment Corporation to manage operation of the U.S. uranium enrichment plants.

### Environmental Provisions

The EPAct requires the DOE to conduct research into environmental issues related to energy production and delivery, including EMF and coal. The most important provision is for global climate change research. DOE is required by EPAct to conduct global warming studies, assess alternative policies, and report its findings to Congress. DOE also must

develop a greenhouse gas inventory and guidelines for voluntarily reporting data.

While carbon dioxide (CO<sub>2</sub>) is a major focus of EPAct, it does not require CO<sub>2</sub> emission reductions. It does direct DOE to assess the feasibility and economic, energy, social, environmental, and competitive implications of reducing CO<sub>2</sub> emissions by 20 percent by 2005. See further discussions below under "Environmental Legislation and Regulation."

#### Competition in Electric Generation

Two EPAct provisions create greater competition for electric generation:

- The EPAct creates a new category of electric power supplier called an Exempt Wholesale Generator (EWG). EWGs, and their affiliates, are exempted by the EPAct from regulation under the Public Utility Holding Company Act.
- The EPAct grants the Federal Energy Regulatory Commission (FERC) expanded authority to order electric utilities to provide wholesale transmission access.

The magnitude of the effect of these provisions remains to be seen and could vary from region to region, based upon relative costs and transmission capacity. Union Electric has not seen any EWG development in its territory since the passage of EPAct.

Prior to EPAct, FERC had granted waivers to some regulations for "power marketers," entities included under the definition of electric utilities in the Federal Power Act. Power marketers do not need to own any generation facilities, which is a requirement for EWGs, but may request transmission service under Section 211 of the Federal Power Act. FERC may impose conditions relating to transmission access on utilities that form power marketing affiliates.

Union Electric has seen considerable activity with marketers and brokers.

The development of rules and standards implementing EPAct is being closely monitored and results have been, and will continue to be, incorporated into the Company's resource planning process.

#### **FERC Orders and Rulings**

In October 1994, FERC issued a policy statement on pricing both firm and non-firm transmission services provided by public and transmitting utilities. This policy statement sets forth that transmission pricing must adhere to the Federal Power Act requirement that transmission rates be just and reasonable, and not unduly discriminatory or preferential. In addition, transmission pricing should follow five principles:

- **Transmission Pricing Must Meet the Traditional Revenue Requirement** - In the aggregate, rates must be designed so that a transmission owner meets, but does not exceed, its revenue requirement.
- **Transmission Pricing Must Reflect Comparability** - Transmission customers should receive access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmitting utility uses for its system.
- **Transmission Pricing Should Promote Economic Efficiency** - Pricing should promote efficient expansion of transmission capacity, efficient location of new generation and load, efficient use of existing transmission facilities, and efficient dispatch of existing generating resources.
- **Transmission Pricing Should Promote Fairness** - Existing wholesale, retail, and transmission customers should not pay for the costs incurred to provide

wholesale wheeling services ordered under Section 211, and third-party customers should not subsidize existing customers.

- **Transmission Pricing Should Be Practical** - Pricing should be as easy to understand and administer as appropriate given the other pricing principles.

FERC distinguished between "conforming" and "non-conforming" pricing proposals. Non-conforming proposals are those which exceed traditional revenue requirements (the first principle listed above.) While FERC clearly indicated it prefers conforming proposals, it will accept non-conforming proposals that meet certain filing requirements and additional evaluation criteria.

At the same time it issued its new pricing policy, FERC also issued orders regarding two Regional Transmission Groups (RTG) and a notice of inquiry and request for comments regarding alternative power pooling institutions under the Federal Power Act. The RTG orders established criteria for approval of RTG organizations, requiring that all RTG members offer transmission services on a comparable basis to other members through a single RTG tariff or individual transmission tariffs. RTGs also must provide for the development of a single regional transmission plan. The alternative power pooling notice of inquiry stated FERC's belief that these pools have a great potential for addressing many barriers to transmission access and requested comments on the concept to allow FERC to better understand the merits of such arrangements. Comments on the proposal were received from many parties. As of this writing, FERC has not taken any additional action in this docket.

In March 1995 FERC issued a Notice of Proposed Rulemaking (NOPR) on open transmission access. The NOPR would impose two tariffs on all transmission providers, one for network service and one for point-to-point service. In addition, the NOPR establishes requirements for minimum ancillary services and procedures for obtaining services. Related dockets on real-time information networks (RIN) and stranded investment have been established. FERC is hosting a series of technical conferences and workshops to discuss components of the RIN, and interested parties are being given the opportunity to file initial and reply comments on this and other elements of the NOPR.

UE will continue to monitor and participate in FERC activities related to transmission access.

### Other

In addition to the above, several other areas directly impact the planning environment, including:

- Resource Planning Legislation and Regulation
- Missouri Statewide Energy Planning and Global Warming Studies
- Illinois Legislation and Related Activities
- Environmental Legislation and Regulation

### Resource Planning Legislation and Regulation

Both state jurisdictions in which Union Electric operates, Missouri and Illinois, have legislation and/or regulations which require resource planning. Illinois has established rules to implement amendments to the Illinois Public Utilities Act in the area of "Least-Cost Planning for Electric Utilities." The Missouri Public Service Commission has enacted rules for "Electric Utility Resource Planning".

In December 1988 the Illinois Commerce Commission adopted "Least-Cost Planning" rules, implementing Section 8-402 of the Illinois Public Utilities Act. UE filed resource plans under these rules in July 1989 and July 1992. These plans were accepted by the Illinois Commerce Commission with only minor modifications.

In May 1993 the Missouri Public Service Commission adopted "Electric Utility Resource Planning Rules". UE filed its first electric resource plan under these rules in December 1993. In early 1994 a series of workshops with interested parties was held to review the filing. These parties developed a "Joint Agreement" that established actions UE would take to provide supplemental information through additional filings or in future resource plans. In July 1994 the Commission issued an order accepting the Joint Agreement.

#### Missouri Statewide Energy Planning and Global Warming Studies

In 1991 the Missouri Department of Natural Resources (DNR), in conjunction with the Missouri Environmental Improvement and Energy Resources Authority, commissioned a statewide energy planning study. This study was to "provide recommendations to promote energy self-sufficiency as a means to enhance economic growth for the state of Missouri, while at the same time assuring environmental protection and sustained quality of life." Results of the study, issued in 1992, include a number of recommendations on energy use in the state. For electric utilities, emphasis is placed on using least-cost planning processes.

Partially in response to this study, Missouri Governor Mel Carnahan established a "Missouri Energy Futures Coalition" of key Missouri energy stakeholders in March 1994. The initial focus of the coalition is to perform "a thorough analysis of the Statewide Energy

Study to identify long-term energy requirements and opportunities." The Coalition plans to issue a report to the General Assembly and governor in late 1995.

A report has also been developed by the Missouri Commission on Global Climate Change which recommends several policies related to demand-side management and least-cost planning.

Policy recommendations from the Energy Futures Coalition and Global Climate Change studies may generate additional legislative proposals in upcoming Missouri legislative sessions. It appears the goals of these policies and recommendations are already addressed through Union Electric's resource planning process.

#### Illinois Legislation and Related Activities

In April 1994 the Illinois Commerce Commission passed a resolution setting forth its intent to examine changes in the structure of the electric energy industry and the resulting implications for regulation of that industry. The Center for Regulatory Studies was selected to facilitate this examination. A task force of interested stakeholders formed the Regulatory Initiatives Task Force (RITF). Two working groups were established from this task force.

The Competition Group examined the existing legislative and regulatory framework for the Illinois electric utility industry, the change in the structure of that industry, and the implications of those changes for the various stakeholders. The Policy Group developed alternative scenarios for the future of the industry and potential legislative and regulatory responses to those scenarios. Over the remainder of 1994 and early 1995 the working groups met to develop and review sections of the RITF report, which was issued in final form in May 1995. It is anticipated

this report will be used in additional policy review activities.

In the last Illinois legislative session several proposals were considered that deal with the structure of the Illinois electric utility industry and its regulation:

- Senate Joint Resolution 21 - This resolution establishes a special legislative committee to examine competition in the electric utility industry, with the support of a non-voting technical assistance group. The scope of the examination is roughly equivalent to the work of the RITF. SJR 21 requires the committee to consider the report of the RITF, and other industry studies and reports. It also requires that the proposed amendment to SB 1058 (see below) be used as a "key element for developing legislative proposals". The first meeting of the committee and the assistance group was held on June 15, 1995.
- Senate Bill 232 - This legislation allows any public utility to propose experiments in alternative regulation before the Illinois Commerce Commission. As of this writing, SB 232 is awaiting the Governor's signature.
- Amendment to Senate Bill 1058 - An amendment to SB 1058 was considered by the Senate Energy Committee in April 1995. This amendment, supported by Illinois Power Company, the Illinois Industrial Energy Consumers, and the Illinois Manufacturers' Association, includes provisions that would: (1) Allow utilities to lease generating plant to subsidiaries without ICC approval, in exchange for a freeze in certain retail rates; (2) Allow utilities to classify customers based upon their access to competitive services; (3) Require a

phase-in of open retail transmission access; and (4) Provide for recovery of "stranded investment" over a specified time period. The Energy Committee passed Senate Bill 1058 to the Senate floor without this amendment. However, the proposal is referenced in SJR 21 (see above).

UE will participate in the work of the joint committee.

### Environmental Legislation and Regulation

Several regulatory and legislative issues pertaining to the environment may affect the energy planning process. Air quality, water quality, solid waste, and hazardous waste regulations must be taken into account when planning facility modifications, improvements, and relocation's. These regulations can significantly affect project cost and scheduling. A combustion turbine at a new site may require as much as three to four years of lead time to perform adequate siting studies, complete environmental monitoring programs, and acquire the environmental permits before beginning onsite construction.

The appendix of the *Integrated Resource Analysis* (IRA) report provides a detailed discussion of environmental issues. The following is a summary of existing and potential environmental legislation.

Future supply-side resources included in this ERP are designed to meet or exceed New Source Performance Standards (NSPS). The estimated cost of future compliance with currently regulated emissions is included in the base resource cost estimates.

The Clean Air Act Amendments of 1990 (CAAA) require major Sulfur Dioxide (SO<sub>2</sub>) and Nitrous Oxide (NO<sub>x</sub>) emissions reductions from the UE system in steps. The first reductions began in 1995 and the second will start in 2000. The emission reduction

requirements will increase beyond the year 2000 as load growth and new fossil-fired capacity require additional SO<sub>2</sub> allowances.

The CAAA established a market based approach for controlling SO<sub>2</sub> emissions. The estimated market value for SO<sub>2</sub> allowances is included in the Company's analysis of resource alternatives. The Company's estimate for the market value of allowances used in developing this ERP was \$150/ton in 1995 nominal dollars, escalating to approximately \$181/ton in 2000 nominal dollars. Escalation after 2000 is assumed to be 4% a year. The low and high estimates for allowances beginning in 2000 were \$159/ton and \$201/ton respectively. These values were also assumed to escalate at 2% and 6% a year respectively.

Information from the SO<sub>2</sub> allowance auction held by the EPA in March, 1995 and from recent activity in the allowance market indicates a 1995 allowance price on the order of \$132/ton in 1995 nominal dollars, escalating at a rate slightly higher than the rate used in the Company's analysis. Based on these updated parameters, future prices should be within the bounds of the low and high estimates used in the analysis.

Considerable uncertainty remains in the environmental legislative and regulatory arenas. Key issues include:

- Global warming - which may lead to CO<sub>2</sub> emissions reductions,
- Air toxics - which could lead to additional particulate and flue gas controls,
- Ozone nonattainment - which could require accelerated NO<sub>x</sub> controls on all fossil-fired units, and
- The operating permit program - which could reduce the Company's flexibility with regard to physical modification and fuel use.

Although future NO<sub>x</sub> requirements are uncertain at this time, the estimates for pulverized coal plants include low NO<sub>x</sub> burner systems which are expected to meet future requirements.

President Clinton's October 1993 Climate Action Plan sets a goal to reduce U.S. greenhouse emissions to 1990 levels by 2000. Unlike SO<sub>2</sub> and NO<sub>x</sub>, CO<sub>2</sub> is a gas which cannot be economically reduced or removed and disposed of by existing technologies. However, this may not be the perception of current administration decision-makers and influential lobbyists.

"Some industry observers are convinced that the nation cannot meet Clinton's commitment without levying a tax on CO<sub>2</sub> emissions or imposing a tough and costly regulatory scheme. However, others in the industry, as well as some administration officials and environmentalists, believe it is possible to meet and possibly exceed the emission-reduction goal without imposing significant new costs on utilities and other U.S. businesses."<sup>1</sup>

UE is participating with the Department of Energy and the electric utility industry in the Climate Challenge Program, which is designed to develop voluntary, cost-effective limitations on greenhouse gas emissions.

Although the current effort to reduce greenhouse gas emissions is voluntary, international activities could lead to less flexible requirements. The first meeting of the "Conference of the Parties" that signed the 1992 "Framework Convention on Climate Change" was held in Berlin in late March and early April 1995. The Framework Convention required the Conference of the Parties to take up a number of matters at its first meeting, one of which was to determine if actions and

<sup>1</sup> Electrical World, September 1993, pg. 18.

measures specified to be taken by nations beyond the year 2000 were adequate to reduce emissions of greenhouse gases to levels considered necessary to protect against global warming. The initial goal specified by the Convention was that developed nations would institute actions and measures with the aim of reducing emissions of greenhouse gases to 1990 levels by 2000.

The Conference of the Parties agreed that negotiations should begin without delay and be conducted as a matter of urgency to strengthen the commitments of the developed nations with the stated aim to elaborate policies and measures, as well as to set quantified limitation and reduction objectives within specified time-frames, such as 2005, 2010, and 2020, with respect to greenhouse gas emissions.

Because the objectives and limitations may not apply to developing countries like China and India, concerns have been raised that U.S. industrial competitiveness could be severely hampered. The U.S. Senate will have to ratify any protocol or amendment, and opposition is already lining up against such actions.

### 1.5 DOCUMENTATION

This ERP, which summarizes the preferred resource plan, and its development, is supported by three separate reports with associated appendices and references:

- *Load Forecast Data and Methodology* – Details and models used to determine the forecast.
- *Demand-Side Management Analysis (DSMA)* Report – Details and models used to develop and screen DSM programs.
- *Integrated Resource Analysis (IRA)* Report – Details and models used to identify the optimal supply-side plan and integrate with the demand-side options.

The balance of this document describes the planning process at UE. Section 2 summarizes the forecasting effort and results. Section 3 describes the demand-side planning process. Section 4 reviews the supply-side screening and optimization analysis. Section 5 delineates the integration process and results. Section 6 summarizes the scenario analysis, risk analysis, and preferred plan selection. Section 7 reviews the Company's Clean Air Act compliance strategy. Section 8 summarizes the preferred resource plan and describes the implementation plan associated with the results.

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**FUTURE REQUIREMENTS**  
**SECTION 2**

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**2.1 ENERGY AND DEMAND FORECAST**

The 1995-2004 load forecast, prepared in the fall of 1994, provides the basis used to develop this ERP. The energy and demand forecasts do not include the effects of programs UE may institute in the areas of marketing, demand-side management, cogeneration, or new uses of electricity. These programs are discussed in other ERP sections.

The ten-year forecast of summer peak demand growth is 1.1% (80 MW/YR) and is lower than the 1.5% (100 MW/YR) experienced over the 1985-1993 period. The principal reasons for a lower forecast include air conditioning saturation on the UE system and air conditioning efficiency improvements.

The ten-year forecast of winter peak demand growth is 2.1% (130 MW/YR), consistent with historical growth. Winter peak demand growth is forecasted to continue, primarily due to residential heating growth and growth in electrically heated commercial developments.

The ten-year forecast of annual sales growth is 1.8% (659 GWh/YR), consistent with historical growth. The individual ten-year class forecasts are discussed below.

**Residential**

The residential sales forecast is 1.6% (191 GWh/YR), lower than the 2.3% (220 GWh/YR) experienced over the 1985-1993 period. The decrease mainly results from continued improvements in appliance efficiencies and the saturation of growth in major energy-using appliances.

**Commercial**

The commercial class continues to be the fastest growing class, forecasted to grow at 2.4% (315 GWh/YR), consistent with historical growth. The fastest growing sectors are forecasted to be the health and lodging sectors. The fastest growing electric end-uses are forecasted to be electric heating and electric water heating.

**Industrial**

The industrial sales forecast is 1.4% (126 GWh/YR), consistent with historical growth. Although employment in the industrial sector continues to decline, some growth is expected due to increased automation, electrotechnologies usage, new capacity additions, and environmental regulation compliance.

**Wholesale**

The wholesale sales forecast is 1.5% (27 GWh/YR), consistent with historical growth.

The following tables provide the annual sales and peak demand forecasts for the 1995-2004 period. The 1995-2004 Load Forecast represents UE's assessment of the most likely future growth pattern.

## 16 Future Requirements

### 1995-2004 Sales Forecast

Year	Sales (GWh)	Annual Change
1994	32,100	
1995	32,991	2.8%
1996	33,735	2.3%
1997	34,455	2.1%
1998	35,068	1.8%
1999	35,643	1.6%
2000	36,276	1.8%
2001	36,876	1.7%
2002	37,544	1.8%
2003	38,297	2.0%
2004	38,926	1.6%
Compound Growth Rate (CPG) — 1995-2004 1.8%		

### 1995-2004 Peak Demand Forecast

Year	Summer (MW)	Winter (MW)	Net Output (GWh)	Load Factor
1995	7,200	5,750	35,589	56.4%
1996	7,290	5,880	36,392	56.8%
1997	7,380	6,010	37,168	57.5%
1998	7,460	6,140	37,831	57.9%
1999	7,540	6,270	38,450	58.2%
2000	7,620	6,400	39,133	58.5%
2001	7,700	6,530	39,779	59.0%
2002	7,780	6,660	40,500	59.4%
2003	7,860	6,790	41,313	60.0%
2004	7,940	6,920	41,991	60.2%
Compound Growth Rate (CPG) — 1995-2004 1.1%      2.1%      1.9%				

The *1994 Load Forecast Data and Methodology* report provides additional details regarding the 1994 Load Forecast.

## 2.2 RESERVE REQUIREMENTS

System reserve capacity provides for such uncertainties as random unit outages,

abnormal weather and unanticipated load growth. UE has developed an extensive transmission system that provides the capability to interchange power with most major utility systems in the Midwest. The interconnections allow the Company to plan for future resource needs on a regional basis and provide opportunities to make economic capacity and energy interchanges with other utilities.

UE is a member of both the Mid-America Interconnected Network (MAIN) and the Illinois-Missouri Power Pool. UE participates with the other MAIN companies to annually assess the adequacy of MAIN's generation system reliability.

The results of the 1994 assessment are contained in an August 10, 1994 report entitled, *MAIN Guide #6 Generation Reliability Study, 1994-2003*. This report indicates that MAIN has adequate reserves planned during the period analyzed. The assessment is based on calculations made using the Loss of Load Probability (LOLP) methodology. This methodology is also referred to as Loss of Load Expectation (LOLE) by some companies.

The adequacy criterion adopted by MAIN is generally used throughout the power industry and is an LOLP of 0.1 day per year (equivalent to 1 day in 10 years) or better.

MAIN's LOLP calculations consider both expected generator availability and emergency support available from other regions. Two levels of load forecast uncertainty are evaluated: (1) uncertainty due to weather only and (2) uncertainty due to all factors including weather.

The MAIN Engineering Committee reviews the work of the MAIN Guide No. 6 Working Group and recommends generation reserve goals for MAIN. The MAIN

Executive Committee recommends a minimum 18% to 22% reserve margin for planning future unit additions. UE uses a minimum 18% reserve margin for planning new resources. However, for near-term planning of approximately one year or less, uncertainties in variables such as load forecasts are reduced. As a result, a reduced reserve margin of 15% is considered adequate for a planning horizon of approximately one year.

The Company reviews its system reserve forecast before each peak season to determine if power purchases will be required to supplement existing resources to provide a minimum 15% short-term reserve margin.

The potential for purchasing power from other utilities is discussed in Section 4. The Company believes that economic, short lead time purchases will be available to allow it to maintain a minimum short-term reserve margin of 15% through at least 1999. Also, a purchase commitment should not be needed until a few months prior to power being required. The availability of interchange purchases allows the Company to plan for reliable power at the lowest reasonable cost to its customers.

The Company analyzes the interchange market and estimates when economic short-term interchange purchases will no longer be available. For purposes of this ERP, the Company plans to meet its minimum 18% reserve margin for planning future resources with owned resources or long-term resource commitments beginning in the year 2000.

### DEMAND-SIDE RESOURCES

#### SECTION 3

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##### 3.1 IDENTIFYING ENERGY EFFICIENCY MEASURES

Results from an earlier Barakat and Chamberlin, Inc. (BCI) study were used to identify energy efficiency measures for the commercial, industrial, and residential sectors. The BCI work was originally done for the development of the December 1993 ERP.

In order to ensure that economic screening was manageable, measures were first subjected to a qualitative screen by considering several non-economic factors (e.g. technological maturity). Measures passing this qualitative screen were passed to the next level, the Measure Level Screening Analysis (MLSA).

##### 3.2 MEASURE LEVEL SCREENING ANALYSIS

The Measure Level Screening Analysis (MLSA) is a per-unit life cycle analysis using annual avoided energy and capacity costs. "Per-unit" means the analysis considers only the impact of a single device or a single program participant. For example, room air conditioners are analyzed on a per-device basis, without developing assumptions concerning the average number of room air conditioners per customer, or the number of participating customers.

Avoided energy costs were calculated for six costing periods including summer on-peak, summer off-peak, winter on-peak, winter off-peak, transitional on-peak, and transitional off-peak, both with and without probable environmental costs. Avoided capacity costs were calculated based on levelized expected supply-side generation costs, including generation-related

transmission costs and fixed operating and maintenance costs. These costs were then distributed across the three on-peak costing periods based on loss of load probabilities. Benefit-cost ratios were calculated based on annualized values. Two ratios were calculated, the utility test and the probable environmental test.

For the commercial sector, thirty-two building prototypes were developed based on the results of a commercial end use survey. Screening each measure for every building type resulted in over 1400 benefit to cost calculations for this sector alone.

Residential results covered all major electric end uses including air conditioning, heating, refrigeration, water heating and lighting. In order to evaluate building shell measures, three building prototypes were developed — single family, small multi-family, and large multi-family. Each building prototype had up to six HVAC system combinations. In total, the MLSA resulted in nearly 500 benefit to cost calculations for the residential sector.

Industrial measures were not analyzed through the MLSA because the diversity of industrial activities and the narrowness of process populations and measure applications in the Union Electric service territory prevent accurate generalizations. For example, previous industrial MLSAs found that motor downsizing was highly uneconomical; however, Union Electric's MotorMiser audits have uncovered several cost-effective opportunities to downsize motors. As such, generalization made within the complex industrial sector could prematurely exclude some cost-effective opportunities. Rather than exclude these

opportunities, all applicable measures were passed directly to the program level analysis where they were incorporated into programs tailored to meet customers' specific energy and process efficiency needs.

### 3.3 DSM PROGRAM DEVELOPMENT

The MLSA results were used to assemble potential demand-side programs. Results of pilot programs, either completed or on-going, were used extensively during this assembly. Pilot program results were used in order to incorporate actual field experience in the development of this ERP.

### 3.4 PROGRAM LEVEL SCREENING ANALYSIS

Program Level Screening Analysis (PLSA) was performed using the Electric Power Research Institute (EPRI) DSManager model. DSManager uses hourly system load profiles, system avoided energy cost, and program load impacts to calculate program benefits. The user provides annual cost assumptions for each program, including all costs incurred by either the utility or the participating customer. The model calculates five benefit-cost tests using California Standard Practice procedures. These include the Participant Test, the Utility Test, the Ratepayer Impact Test, the Total Resource Cost Test, and the Societal Test.

The Participant Test was used as an indicator of acceptable program design. The discount rate used to calculate benefits and costs reflected implicit discount rates observed in the marketplace. A 33% rate was assumed for commercial and industrial customers. Residential programs assumed a 20% rate. Programs were designed so that the Participant benefit-cost ratio was at least 1.0.

The expected discount rate for the Utility Test, Ratepayer Impact Test, Total Resource Cost Test, and Societal Test was 10.46%.

The PLSA used thirty-six day types to represent program load impacts and calculate program benefits. These day types for each month of the year were — Peak Weekday, Typical Weekday, and Typical Weekend. Typical load and avoided energy costs were determined for each hour of each day type. Avoided energy costs were developed using hourly data from the Company's Fall 1994 Forecast and Fuel Budget.

Annual avoided capacity costs were based on levelized avoided generation costs.

Additional information concerning the screening process is contained in the *Demand-Side Management Analysis* (DSMA) report. Information regarding capacity equivalence is contained in the *Integrated Resource Analysis* (IRA) report.

### 3.5 POTENTIAL DEMAND-SIDE RESOURCES

A brief description of each program identified as a demand-side resource follows. All programs were assumed to start enlisting participants in 1997 and stop receiving new participants after 2006 (except to maintain a constant impact level through the end of the planning horizon).

#### Residential Audit & Financing – Water Heating and Lighting Measures

This program would target single-family residential customers with central electric heating and air conditioning or heat pump, and electric water heaters. The basic program would provide a comprehensive home energy audit to eligible customers for a price of \$50. Those responding to the offer would receive a free package of measures including: a water heater blanket, pipe insulation, and one compact fluorescent bulb.

### **Residential Audit & Financing – Building Shell Measures**

Residential customers receiving a comprehensive home energy audit would be eligible to participate in this program. Qualified specialists would perform blower door and duct blasting testing in order to identify the potential for infiltration reduction. At the customer's expense, improvements would be achieved by implementing several measures including: duct sealing, window caulking, weather stripping, and basement wall insulation.

### **Residential Audit & Financing – Central A/C and Heat Pump Shading – Incentives**

Residential customers receiving a comprehensive home energy audit would be eligible to participate in this program. Where opportunities have been identified to cost-effectively shade air conditioner (A/C) units, Union Electric would provide limited incentives for landscaping used to shade the units.

### **Residential Setback Thermostats – Gas Heating Customers**

This program would educate customers with central gas heating about the benefits of electronic setback thermostats. Participants would pay retail store prices for thermostats.

### **Residential Low Income – Water Heating and Lighting Measures**

Residential customers with electric water heaters, who received free building shell measures, would be eligible to participate in this program. Qualified specialists would audit water heater systems and install packages of water heater measures, including water heater blankets and pipe insulation. Each customer would also receive one compact fluorescent bulb. Additionally, UE would assist the Community Action

Agencies in conducting educational seminars on ways to reduce customers' energy costs.

### **Residential Low Income – Building Shell Measures**

Low income residential customers in poorly weatherized multi-family dwellings with central electric heat would be targeted for this program. Qualified specialists would perform blower door and duct blasting testing to identify opportunities for infiltration reduction. Improvements would be achieved by implementing several measures including duct sealing, window caulking, and weather stripping. Energy service organizations would perform most of the marketing and administration of this program. Additionally, UE would assist the Community Action Agencies in conducting educational seminars on ways to reduce customers' energy costs.

### **Residential Low Income – Water Bed Measures**

Residential customers with electrically heated water beds, who received free building shell measures, would be eligible to participate in this program. Qualified specialists would install foam mattress pads. Additionally, UE would assist the Community Action Agencies in conducting educational seminars on ways to reduce customers' energy costs.

### **Residential Appliance Cycling Program – Central A/C and Heat Pump Cycling**

This program would target single-family residential customers with central air conditioning or heat pumps. Qualified contractors would install and service load management devices on outdoor cooling units. The normal operation of cooling units would be limited on the hottest days. Participants would receive limited summer

bill credits and access to a free 24-hour emergency diagnostic service.

#### **Residential Appliance Cycling Program – Water Heater Cycling**

Residential customers with electric water heaters would be eligible to participate in this program. Similar incentives to the Central Air Conditioner and Heat Pump Cycling program would be offered.

#### **Residential Appliance Removal Program – Refrigerator Removal**

This program would remove old and inefficient refrigerators that operate on the UE system. PCBs would be removed from any oils and the metal and refrigerant would be recycled. UE would hire a contractor to provide turn-key services encompassing all program aspects. Such services would include: appointment scheduling, appliance removal, and proper recycling and reclaiming of environmentally hazardous materials.

#### **Residential Appliance Removal Program – Freezer Removal**

This program would remove old and inefficient freezers that operate on the UE system in the same fashion as the Refrigerator Removal program.

#### **Residential New Construction – Building Shell Measures**

This program would provide incentives to builders to encourage more efficient home construction. Reimbursement of qualified expenses would be provided to builders for the installation of several measures including duct sealing, window caulking, weather stripping, and basement wall insulation. Only builders installing high efficiency heating and cooling, water heating and specific environmental measures would be eligible.

#### **Residential New Construction – Central A/C and Heat Pump Shading – Incentives**

Builders that install high-efficiency end-use equipment would be eligible to participate in this program. Where opportunities are identified to cost-effectively shade A/C units, Union Electric would provide limited rebates for landscaping used to shade these units.

#### **Commercial Audits – Level I: Walk Through Audit and Analysis**

This program would provide a walk-through audit and follow-up energy analysis to large commercial customers. Energy services would consist of analyzing the customer's billing history, disaggregating consumption by end-use, and recommending energy efficiency improvements. Life cycle cost analysis would be provided for recommended measures. The audit would be provided at no cost to the customer.

#### **Commercial Audits – Level II(a): Engineering Study With Lighting Emphasis**

This program would provide follow-up service to customers participating in the Level I audit. Such services would provide a more focused analysis through computer modeling of electric loads, calibration to whole building metered data, and modeling of energy efficiency measures. Interactive effects would be considered by modeling the measures one at a time as well as bundled. Customers would initially split the audit cost with UE. If the customer chose to implement the recommendations, the audit cost would be refunded.

### **Commercial Audits – Level II(b): Comprehensive Building Modeling For All Major Systems (HVAC, Refrigeration, Lighting)**

This program would provide follow-up service to customers participating in the Level I audit (and not participating in Level II(a) Lighting Emphasis). Such services would provide a more focused analysis through computer modeling of electric loads, calibration to whole building metered data, and modeling of energy efficiency measures. Interactive measure effects would be considered in order to optimize building efficiency. Customers would split the audit cost with UE. However, the audit cost would be refunded if the customer implements the audit recommendations.

### **Small Commercial Energy Services – Do It Yourself Audit**

This program would provide small commercial establishments a survey to perform a simple audit. Customers would walk through their facility recording information on sources of energy use. When completed, the customer would return the audit to be scanned into a computer, where the audit responses would be matched with actual historical energy usage. A report would be returned to the customer. Included in this report would be a disaggregation of past energy use by end-use and recommendations for improvement including simple payback analysis. The audit would be provided at no cost to the customer. A list of contractors and institutions providing installations and financing would be made available at no charge.

### **Small Commercial Energy Services – Walk Through Audit**

This program would provide small commercial establishments the services of an expert auditor who would enter information on sources of energy use into a computer. When the analysis was complete, the customer would receive a disaggregation of past energy use by end use and recommendations for improvement including simple payback analysis. The audit, analysis and recommendations would all be provided in one visit. The audit would be provided at a small fee to participating customers (well below the actual cost of the audit). A list of contractors and institutions providing installations and financing would be made available at no charge.

### **Commercial New Construction Design Assistance and Incentives (Financing or Reimbursement)**

This program would provide design assistance to large commercial customers before they construct new facilities. In addition, the program would seek to identify institutions that provide low cost financing. Design assistance and low cost financing may not be enough to overcome barriers often associated with maximizing the efficiency of new construction. As such, the program may require reimbursement of the incremental cost of efficiency upgrades in order to be successful.

### **Thermal Storage – Off-Peak Cooling**

This program would provide design assistance to customers considering installing thermal storage systems. In addition, a bill credit would be made to customers based on the avoided cost of on-peak demand. Because of the cost associated with these systems, customers would likely seek attractive financing. If the design assistance,

bill credit, and financing were not enough to avoid lost opportunities in this market, reimbursement of the incremental cost of efficiency upgrades would be considered.

#### **Customized Industrial Process Audits**

This program would provide a free walk through audit and follow-up energy analysis to medium and large industrial customers. Energy services would consist of analyzing the customers' billing history, evaluating process, energy, and materials handling efficiencies, and recommending process/energy efficiency improvements. Simple payback analysis would be provided for recommended measures.

For customers with significant demand and/or energy reduction opportunities, Union Electric would offer to co-fund additional engineering analyses in order to encourage implementation. If measures are installed the customer would then be eligible to receive reimbursement for his audit costs.

#### **Demand and Energy Control Informational Program**

This program would provide free information and seminars to larger industrial customers. The program would make actual metering data, local energy control successes, and trade allies in efforts to encourage the installation of demand and energy monitoring equipment at industrial sites. Trade allies would be relied on to deliver the program to the greatest extent possible.

#### **Energy Efficient Motors – MotorMaster Software**

This program would provide industrial customers with the *MotorMaster* software for evaluating options when purchasing or replacing three-phase motors. The software assists the user in choosing the most cost-

effective and energy efficient option. The software would be provided free of charge.

#### **Energy Efficient Motors – MotorMiser Audits**

This program would provide qualified industrial customers with a free on-site evaluation of selected motor applications by a local motor expert/consultant. The purpose of the evaluations would be to identify cost effective opportunities for: upgrading to energy-efficient motors, installing adjustable speed drives, or improving drive train efficiencies.

#### **Standby Generation/Curtailable Power Program**

This program would supplement UE's power system during periods of stress. Customers that are willing to curtail load or use standby generation would receive a special rate discount. In return, UE would be allowed to curtail power as needed to maintain a firm power supply, deliver contractual power obligations to other utilities, and maintain the integrity of the interconnected system.

The following five DSM programs failed the Program Level Screening Analysis:

- Residential Audit & Financing - Central A/C and Heat Pump Shading - Incentives
- Residential Low Income - Water Heating and Lighting Measures
- Residential Appliance Cycling Program - Water Heater Cycling
- Residential New Construction - Central A/C and Heat Pump Shading - Incentives
- Commercial New Construction Design Assistance and Incentives (Financing or Reimbursement)

### SUPPLY-SIDE RESOURCES SECTION 4

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#### 4.1 EXISTING RESOURCES

The UE system relies on a diverse mix of generating technologies to supply electrical power. The vintage of the plants range from 1913 for the Keokuk Hydroelectric Plant to 1984 for the Callaway Nuclear Plant. Sufficient capital and maintenance work is planned for all units to provide for continued operation for an indefinite period.

Tables 4-1 and 4-2 list the existing units and summarize their capabilities.

Power plants are generally categorized by the type of load they serve; base, intermediate, or peaking.

##### **Base Capacity**

Base capacity for the UE system is provided by the Callaway, Keokuk, Labadie, Rush Island, and Sioux power plants. These plants represent 68% of the total system-owned capacity.

##### Callaway

The Callaway Plant, located in central Missouri, was placed in service in 1984. It consists of one pressurized water reactor nuclear power unit. The net capacity of the plant varies from 1,125 MW in the summer to 1,177 MW in the winter. Refueling of the unit occurs approximately every 18 months. The most recent refueling was completed in the spring of 1995.

##### Keokuk

The Keokuk Hydroelectric Plant, located on the Mississippi River in the vicinity of Keokuk, Iowa, was placed in service in 1913. The facility includes fifteen run-of-river hydroelectric generators that have a total net capacity of 119 MW, during expected summer river conditions. Eight of

the fifteen units generate power at a frequency of 25 Hz. The 25 Hz power is currently sold to Iowa Electric Light & Power (IELP) or converted to 60 Hz and integrated into the UE System. The plant is not subject to license renewal requirements under the Federal Power Act.

##### Labadie

The Labadie Plant, located on the Missouri River in eastern Franklin County, Missouri, consists of four pulverized coal-fired units placed in service from 1970 to 1973. Each unit has a summer net rating of 559 MW, with a total plant rating of 2,236 MW. Coal for the plant is delivered by two rail lines.

These units were identified in the Clean Air Act Amendments of 1990 (CAAA) as Phase I affected units. Modifications have been implemented to achieve compliance with the Act and to allow the flexibility to burn low sulfur coal. All four units have been fitted with low NO<sub>x</sub> burners.

##### Rush Island

The Rush Island Plant is composed of two pulverized coal-fired units, each with a summer net capacity of 581 MW. Rush Island Plant is located on the Mississippi River near Festus, Missouri. These units were placed in service in 1976 and 1977. Coal for the plant is delivered by rail.

Both units, although designated as Phase II units, have received Phase I permits as substitution units. Low NO<sub>x</sub> burners have been installed on one of the units. Installation of low NO<sub>x</sub> burners on the remaining unit is scheduled to be completed by the end of 1995.

Planned low sulfur coal modifications are scheduled to be completed in 1996.

### Sioux

The two Sioux units use cyclone boilers and have a summer net capacity of 463 MW each. A restoration of net capacity to 471 MW is expected in 1997 as a result of improvements in plant equipment and operation. Sioux Plant is located on the Mississippi River in eastern St. Charles County, Missouri. The units were placed into service during 1966 and 1968. Coal is delivered to the plant by rail.

The Sioux units are also designated as Phase I affected units according to the CAAA. Modifications are currently being implemented to enhance the flexibility to burn low sulfur coal. These planned modifications are scheduled to be completed in 1997. As with all units, there are continuing investigations of compliance alternatives to optimize the operation of the plant. In addition, a long-range utilization planning study has identified modifications that are being incorporated in the budgeting and maintenance planning process.

UE began an experiment to burn used tires in the Sioux Plant in 1992. The results showed that a mixture of tires and coal could be economically burned in the boilers without adversely impacting compliance with environmental regulations. The Company is presently burning a mixture of chipped tires with the coal. When the project is fully implemented, the Sioux Plant is expected to burn a mixture composed of approximately 2% chipped tires and 98% coal. The plant is expected to burn approximately 2 million used tires each year. This is equivalent to 25,000 tons of coal.

### **Intermediate Capacity**

The Meramec Plant and purchases of up to 405 MW from the Joppa Plant provide the Company's intermediate capacity requirements. These resources account for about 16% of the Company's capacity.

### Meramec

The four-unit Meramec Plant is located in southern St. Louis County, Missouri on the Mississippi River. Two units, each with a net summer capacity of 131 MW, were placed in service in 1953 and 1954. The third unit has a summer net capacity of 280 MW and was placed in service in 1959. Unit 4, rated at 338 MW, was placed in service in 1961.

The primary fuel for all four units is coal, which is delivered by barge. Units 1 and 2 have the ability to achieve full rated capacity on either coal or natural gas. Up to 30% of Unit 3's output can be fueled by natural gas.

The units at the Meramec Plant, which are designated as Phase II units according to the CAAA, have received Phase I permits as substitution units.

Low NO<sub>x</sub> burners are planned to be installed on Meramec Unit 4 in 1996, in conjunction with a planned major boiler rehabilitation. Meramec Unit 3 is a possible candidate for repowering and a final decision on low NO<sub>x</sub> burner installation for this unit will not be made until an in-depth repowering study is completed. A site specific study is currently in progress, to identify costs for use in the further evaluations.

Implementation of projects identified in the Meramec long-range planning program continues.

### **Peaking Capacity**

Peaking capacity is supplied by a variety of technologies that utilize oil, natural gas, hydroelectric, and pumped storage. Approximately 16% of the Company's total capacity is considered peaking capacity.

### **Combustion Turbine Generators**

The Company's nine CTs have a total net summer capacity of 381 MW. The units were installed from 1967 through 1978. All of the units, except the Viaduct and Kirksville units, are fired with distillate fuel oil. The Viaduct and Kirksville units, with a combined net summer capacity of 38 MW, are fueled with natural gas.

### **Diesels**

Approximately 5 MW of diesel engine capacity exists on the system.

### **Venice**

The Venice Plant, located in Venice, Illinois, east of downtown St. Louis, is the oldest fossil-fueled plant on the UE system and is composed of eight boilers that supply steam to a header system for six generating units. The plant was originally built to fire coal and was placed in service from 1942 through 1950. In the mid-1970s, the first six boilers were converted to fire distillate fuel oil and natural gas. The remaining two boilers were converted to fire only distillate fuel oil. The six generating units have a combined net summer rating of 429 MW.

### **Osage**

The Osage Hydroelectric Plant is located at Bagnell Dam on the Lake of the Ozarks, in central Missouri. The first six units were placed in service in 1931, and units 7 and 8 were placed in service in 1953. The eight hydroelectric generators result in a total plant capability of 212 MW. The Osage Plant is licensed until 2006 under the Federal

Power Act, but the plant is expected to be available indefinitely.

### **Taum Sauk**

Taum Sauk Plant is a pumped-storage facility located 90 miles southwest of St. Louis, Missouri. The plant has a net summer rating of 350 MW and includes two reversible pump-turbine units and upper and lower reservoirs. Both units were placed in service in 1963. The plant operates by pumping water from the lower reservoir to the upper reservoir during times of low system load and low energy cost. During peak demand periods the water is released from the upper reservoir for generation by the two water turbines.

Although the Federal Power Act license for the Taum Sauk Plant expires in 2010, it is assumed to be available indefinitely.

### **Power Plant Long Range Planning**

Long range planning for existing power plants has been implemented by the Company.

Evaluations of the Venice, Meramec and Sioux units indicate that the overall condition of each plant is good. However, a number of major modifications and repairs are necessary to assure reliable generation in the future. Completed and planned projects include replacement of major boiler components, heat exchangers, controls, and others.

### **Interchange Purchases And Sales**

### **Joppa**

The Joppa Plant, located on the Ohio River in Joppa, Illinois, is owned by Electric Energy, Inc., which is jointly owned by four utilities. Union Electric owns 40% of Electric Energy, Inc. and is entitled to receive as much as 405 MW of capacity for a limited time each year. Union Electric can

currently take 10% of the Joppa Plant available generation during a calendar year, and with a five year notice can increase its take to 40%.

Before August 1st of each year, Union Electric provides a schedule to Electric Energy, Inc. indicating the time periods and amounts of Joppa Plant's capacity that should be reserved for Union Electric during the following calendar year.

#### Arkansas Power and Light (AP&L)

UE agreed to purchase unreserved capacity from AP&L as part of the agreement to buy portions of AP&L's service territory in southern Missouri. The contract specifies the purchase of capacity until March 2002 with an option to extend the purchase for six years. The purchase amount was increased to 160 MW beginning in 1995. Provisions exist to extend the contract beyond 2008.

#### Iowa Electric Light & Power Co. (IELP) and Central Illinois Public Service (CIPS)

As a result of the sale of the Company's Iowa and Northern Illinois service territories, which included both 60 Hz and 25 Hz loads, UE supplies 60 Hz power to the purchasing companies according to the following schedule:

Year	IELP	CIPS	Total
1995	100 MW	5 MW	105 MW
1996	80 MW		80 MW
1997	60 MW		60 MW

In addition, 54 MW of 25 Hz power is contracted to be sold to IELP on an interruptible basis so they may supply existing 25 Hz customers.

#### Associated Electric Cooperative (AEC)

UE and Associated Electric Cooperative have an existing interchange agreement. In exchange for use of available transmission capability on UE's system, Associated Electric Cooperative is expected to provide UE with 21-31 MW of capacity during the months of March through October. Similarly, UE is expected to provide 15 MW of capacity to Associated Electric Cooperative during the months of October through May in return for UE's use of Associated Electric Cooperative's transmission system. The capacity and energy that can be scheduled under this arrangement is limited and based on the peak demand and energy transmitted by the other party during the previous April through March period.

#### **4.2 FUELS**

The electricity generated by company-owned units is derived primarily from coal (65%) and nuclear (30%) with the remainder coming from hydroelectric, oil and natural gas.

The UE system depends on four coal-fired power plants to produce over 65% of the total energy. Currently, these plants consume about 11 million tons of coal annually. Small changes in the delivered price of coal significantly affect electricity production costs. Consequently, UE continually monitors transportation costs and various coal markets to assess changes and evaluate their impact on future conditions. Oil, natural gas, and nuclear fuel markets are also continually monitored and evaluated.

The Company's forecasts of fuel prices are based on many information sources, including published data, various forecasting organizations, and in-house fuel market knowledge. The forecasted prices of coal, oil, natural gas, and nuclear fuel used to

develop this Energy Resource Plan were developed in the fourth quarter of 1994 and embody the best information available at that time. Further information on the forecasts and forecasted fuel prices is included in Section 4 of the *Integrated Resource Analysis* (IRA) report.

### Existing Coal Contracts

Long-term contracts cover approximately 80% of the Company's 1996 coal requirements. No coal is under contract after 2001. Current contracts provide both low sulfur and high sulfur coal. Additional low sulfur coal will be required to meet the Company's long-range requirements and its compliance program under the CAAA.

## 4.3 SYSTEM IMPROVEMENTS

### Power Plant Improvements

Changes in unit efficiency occur over time for various reasons, such as the requirement to burn coal of a different quality than the coal for which the boiler was originally designed, new governmental regulations, etc. UE continually reviews its existing units to determine the economies of improving plant efficiency.

A wide array of projects are either planned, or are being evaluated, for maintaining and improving availability and efficiency. Large boiler components, heat exchangers, controls, etc., are systematically evaluated and replaced, or improved, if justified.

### Sioux Plant

Each Sioux unit currently has a summer net capacity of 463 MW. An additional 8 MW (net) increase in the capacity rating for each of the two units is anticipated in 1997 due to further improvements in plant equipment and operation. By 1997 the

rating of each of the units is expected to be 471 MW (net).

### Osage

An increase in rated capability of the Osage Plant may be achievable by replacing the existing runners with new more efficient runners.

### Keokuk

The overall economics of rewinding the existing 25 Hz generators at Keokuk will be dependent on the future needs of Iowa Electric Light & Power (IELP). UE has a contract to supply as much as 54 MW of IELP's 25 Hz requirements, on an interruptible basis, until the end of 1998. This contract can be extended beyond 1998 if both parties agree. If an agreement cannot be reached with IELP, this ERP shows that it would be beneficial to rewind the 25 Hz generators for 60 Hz service. Operation at 60 Hz would reduce system losses by as much as 19.5 MW at maximum loading conditions. If a 25 Hz customer is not available, savings in losses of about 103,000 MWh per year are estimated.

### Taum Sauk Plant

The Taum Sauk Plant rating was increased to 350 MW (net) in the summer of 1991 to match the amount of system peak the plant is expected to carry. The rating is based on the amount of water expected to be discharged over a typical summer day to meet system load requirements. A 430 MW (net) rating may be achieved by increasing efficiency of the existing turbines by replacing the runners.

### Controls Replacements

Modern control technology is being installed/planned at Meramec, Sioux, Labadie, and Rush Island. The new technology is expected to improve unit

reliability, efficiency and safety as well as improve operator training and effectiveness.

#### Plant Auxiliary Power Reductions

Adjustable and two speed motors have been installed at Labadie, Meramec, Rush Island and Sioux to reduce station auxiliary power requirements. New energy saving static exciters have been installed at Sioux. More efficient lighting has been installed throughout Meramec Plant and other facilities.

#### Venice Plant Repowering

The Company participated with EPRI and Sargent & Lundy in a project to develop a workstation for utility repowering evaluations. As part of the project, a site specific study was performed for the Venice Plant. Although a generic workstation for this project is not available, the results for Venice Plant were available for use in the development of this ERP.

#### Meramec Plant Unit 3 Repowering Study

The Company is participating in a project with EPRI and Sargent & Lundy to identify site specific costs for repowering Meramec Plant Unit 3. This study is in progress and sufficient information was not available to include this option in the development of the ERP. The economics of this option will be analyzed when the data is received.

#### T&D System Improvements

Ongoing assessments of the age, condition, and efficiency level of UE's transmission and distribution facilities require daily decisions regarding implementation of cost-effective measures to ensure reliable service. These assessments would include the benefits of DSM and distributed generation targeted for specific T&D areas.

### 4.4 PROBABLE ENVIRONMENTAL COSTS

For planning purposes, probable environmental costs are defined as the expected cost to the utility of complying with new or additional environmental laws, regulations, taxes or other requirements that utility decision makers judge may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates.

In order to develop resource plans, and test their robustness to more stringent environmental regulations than currently envisioned, three levels of mitigation more stringent than 1995 requirements were hypothesized. Fixed and variable costs to comply with regulations for those emissions that can be controlled were developed by Burns & McDonnell for use in the development of this ERP.

Estimates of CO<sub>2</sub> adders, ranging from \$1.45 to \$11.40 per ton of CO<sub>2</sub> (1995 dollars), were developed by the Company to serve as proxies for possible future regulations on greenhouse emissions. Every incremental dollar of adder per ton of CO<sub>2</sub> adds about \$0.48/MWh to the cost of a combined cycle unit operating on natural gas. About \$1/MWh would be added to the cost of operating a pulverized coal plant.

Subjective probabilities were assigned to each of the three mitigation levels.

The Burns & McDonnell estimates of costs to comply with regulations for those emissions that can be controlled are contained in a report entitled *Environmental Costs at Existing and Future Fossil Fuel Fired Units For Union Electric*. This report, and the IRA report, provide further details regarding the development and application of environmental control costs, and resultant

probable environmental costs used in the development of this ERP.

### 4.5 FUTURE RESOURCES

The magnitude and timing of resource needs were established using the Company's 1994 peak demand and energy forecasts which indicate that the Company will require approximately 385 MW of new resources by the year 2000. Approximately 1,860 MW of new resources are required by the end of the 20 year study period.

Although capacity can be added to the system by improvements at existing units, new facilities will be required to satisfy future load growth. Power purchases, and a number of generation technologies, offer potential supply-side resource options for capacity additions. The options range from mature technologies, similar to existing units, to new technologies in various levels of development. In addition, the resources may be utility owned or purchased from another party.

#### Interchange Purchases

Future supply-side additions may be achieved through new generation resources or the purchase of power. In order to assess the availability and feasibility of employing purchased power in the development of this ERP, UE requested proposals from 65 parties for the supply of power. The parties included all the systems that have interchange agreements with UE as well as most of the systems that are one system removed. Based on the responses, there appears to be over 600 MW of purchased capacity available to UE near the end of the decade. Although some of the capacity may have already been committed to other purchasers, there should be sufficient capacity available to make economic short lead time purchases to meet system reserve

requirements and to provide an alternative to building new generation capacity through at least the year 2000.

Future transactions in the generation market may be constrained by transmission line limits due to wheeling requirements that may be imposed on utilities in the future and actions resulting from the Federal Energy Regulatory Commission Notice of Proposed Rulemaking (NOPR) on transmission access and pricing. Thus, some purchase power sources may not be accessible when required in the future due to reasons other than generation unit outages.

The current analysis of the UE transmission system indicates that UE has adequate transmission capability to import several hundred megawatts of capacity from several directions. Based on current transmission system plans and the Company's anticipated capacity needs, UE does not foresee the need for additional transmission facilities to accommodate capacity purchases.

More specific studies will be undertaken when definitive resource opportunities are examined. Such studies will also take into account other transactions occurring on the interconnected system that affect UE's transmission system and may reduce the ability to transact with other systems.

Union Electric has contracted with Central Illinois Public Service Co. (CIPS) for the purchase of 150 MW of power from June 1998 to May 2005. This purchase was made recognizing that the power could be marketed or incorporated into the UE System.

UE also has the opportunity to purchase additional energy from the Joppa plant and to extend the existing contract for wholesale power with Arkansas Power and Light (AP&L).

### Future Technologies

A qualitative screening review was performed to evaluate the future generation technologies and determine those that should be removed from further review at this time. Technologies considered significantly inferior in development potential, cost, performance, or applicability were eliminated from further quantitative evaluation.

The following is a summary of the potential technologies considered:

#### New Resources

- Conventional Pulverized Coal
- Super Critical Pulverized Coal
- Advanced Pulverized Coal
- Fluidized Bed Combustion
- Coal Gasification Combined Cycle
- Magnetohydrodynamics
- Simple Cycle Combustion Turbine
- Combined Cycle Combustion Turbine
- Compressed Air Energy Storage
- Fuel Cells
- Battery Energy Storage
- Super Conducting Magnetic Energy Storage
- Pumped Hydro
- Low-Head Hydro
- Wind Power
- Biomass
- Geothermal
- Solar
- Nuclear

The *Generation Technologies for Integrated Resource Planning* report provides a detailed discussion of each of these technologies, including ranges of costs, emissions and performance data.

In addition to the new technologies, descriptions of the following unit upgrade technologies are included in the report.

### Existing Unit Potential Upgrades and Repowering

- Venice Repowering
- Taum Sauk Runner Replacement
- Osage Runner Replacement
- Inlet Air Cooling — Existing Combustion Turbines

The following additional resource opportunities, including power purchases, were considered as future resources in the development of this ERP. These resources are described in Section 3 of the IRA report and include:

#### Possible Additional Resource Opportunities

- Keokuk 25 Hz Generator Rewind
- Amorphous Transformers
- Iatan Jointly Owned Plant
- Alton Lock & Dam 26R
- Extension of the AP&L Purchase
- Additional Joppa Energy
- CIPS Peaking Capacity Purchase
- Intermediate Capacity Purchase #1
- Intermediate Capacity Purchase #2
- Base Capacity Purchase
- KLT - Iatan - Base Capacity Purchase

### Cogeneration, IPPs, NUGs and QFs

The potential for development of cost effective non-utility generation in the UE service area appears to be limited. In general, UE rates are lower than the cost of non-utility generation options. Customers with steam loads that can justify the investment in cogeneration equipment have been cogenerating since the early 1960's. No new steam loads large enough to warrant cogeneration have been added to the UE service area.

There are 88 MW of non-utility generation, excluding emergency diesel backup generators, in the UE service area. Of the 88 MW, 14 MW have come on-line after PURPA became law in 1978. Included in the 14 MW are 6 MW of peak shaving diesel generators, 4 MW of either landfill gas or methane fueled generation, and 4 MW of peak shaving generation fueled by either coal or natural gas.

UE has either evaluated or reviewed several site specific studies on the feasibility of non-utility generation in the UE service area. UE's rates are lower than the costs of the alternatives considered in each study.

Even though none of the non-utility generation options reviewed are lower cost than the Company's current rates, generation fueled by certain types of waste resources may have economic potential by the end of this decade. The total capacity that may be available from generation fueled by these types of waste resources is in the 10 to 20 MW range.

Other than limited potential from non-utility generation fueled by waste resources, there does not appear to be significant potential for customer on-site generation in the future. The cost differential between UE rates and the cost of non-utility generation is projected to be greater than UE's avoided costs.

The mix of resources identified in the preferred resource plan is based on UE estimates of resource costs and the information available at this time. UE will continue to study these options as new information becomes available.

### 4.6 SCREENING RESULTS

The potential supply-side resource options eliminated through the qualitative screening review include:

- Magnetohydrodynamics
- Super Conducting Magnetic Energy Storage
- New Pumped Hydro
- New Low-Head Hydro
- Advanced Battery Energy Storage
- Geothermal
- Nuclear - Advanced Light Water (Passive Safety)
- Solar - Thermal
- Nuclear - Advanced Liquid Metal Reactor
- Fuel Cells - Molten Carbonate

The remaining options were quantitatively screened at two levels, both with and without probable environmental costs. The first level involved a one-on-one comparison of costs over each resource option's operating range. Levelized annual costs for capital charges, fixed and variable O&M, fuel, emissions, and environmental costs were compared for each option at various capacity factors. Resources that produced the lowest cost for any of the ranges of capacity factor were considered for further review. Some options were only marginally higher in cost than the lowest cost options. To avoid excluding any attractive options, those within 20% of the lowest cost option were included in the second level screening review.

Although wind energy passed the first level of screening analysis, it will not be practical to commit to reliance on wind energy until its capacity equivalence and wind energy availability can be accurately evaluated. At present, there is insufficient wind energy resource data available for the UE service area to support operation in the 30% capacity factor range. Wind monitoring stations were installed in early 1995 and data will be collected for at least one year. A

further assessment of wind energy and its potential contribution to the UE system will be made when this data is available.

Due to the environmental benefits of wind, this option is included in the renewable energy scenario, based on an assumed capacity factor of 30%.

The resource options that passed the first level of screening were then screened at the system level to determine which options would best satisfy UE system needs. The dominant options from the first level of screening, along with power purchases, were modeled with the Electric Power Research Institute (EPRI) developed Electric Generation Expansion Analysis System (EGEAS) optimization model.

The evaluations produced a group of resources that satisfied system needs at the lowest cost. The following resource options emerged from the system level screening analysis as future resource candidates:

- Combustion Turbines
- Combined Cycle
- Taum Sauk Runner Replacement
- Keokuk Generator Rewind
- Additional Joppa Energy Purchase
- Extension of AP&L Purchase 2002 -- 2007
- Venice Repowering
  - Phase 1 - Units 5&6
  - Phase 2 - Units 3&4
- CIPS Peaking Capacity Purchase - 1998-2004
- Intermediate Capacity Purchase #2 - 2000-2013

The following seven resource options failed the system level screening analysis:

- CAES

- Jointly Owned Iatan Unit
- Osage Runner Replacement
- Full Venice Repowering (all six units)
- Intermediate Capacity Purchase #1 — 1997-2013
- Base Capacity Purchase — 1998-2013
- KLT-Iatan Base Capacity Purchase

The details and results of the quantitative screening analysis are included in Section 5 of the IRA report.

Table 4-3 shows the preferred all supply-side resource plan resulting from the quantitative screening analysis. The results of the quantitative screening analysis were incorporated in the resource integration analysis described in Section 5.

**Table 4-1**  
**Generating Capability - Existing Units**  
**1995 Unit Ratings**

Station Unit	Type	Net Capability (MW)		Fuel Type	Transportation Method
		Summer	Winter		
Callaway	Nuclear	1125	1167	Uranium	Truck
Rush Island 1	Steam	581	583	Coal	Rail
Rush Island 2	Steam	581	583	Coal	Rail
Labadie 1	Steam	559	561	Coal	Rail
Labadie 2	Steam	559	561	Coal	Rail
Labadie 3	Steam	559	561	Coal	Rail
Labadie 4	Steam	559	561	Coal	Rail
Sioux 1	Steam	463	470	Coal	Rail
Sioux 2	Steam	463	470	Coal	Rail
Meramec 1	Steam	131	134	Coal/NG	Barge,RR/PL
Meramec 2	Steam	131	134	Coal/NG	Barge,RR/PL
Meramec 3	Steam	280	282	Coal/NG	Barge,RR/PL
Meramec 4	Steam	338	347	Coal	Barge,RR
Venice (6 Units)	Steam	429	439	NG/#2 Oil	Truck/PL
Total Steam Turbine		6758	6853		
Osage (8 Units)	Hydro	212	205	Water	
Keokuk (15 Units)	Hydro	119	122	Water	
Total Hydro		331	327		
Taum Sauk (2 Units)	PS	350	275	Water	
Total Pumped Storage		350	275		
Venice	CT	25	31	#2 Oil	Truck
Howard Bend	CT	43	48	#2 Oil	Truck
Meramec	CT	55	64	#2 Oil	Truck
Mexico	CT	55	64	#2 Oil	Truck
Moberly	CT	55	64	#2 Oil	Truck
Moreau	CT	55	64	#2 Oil	Truck
Fairgrounds	CT	55	64	#2 Oil	Truck
Kirksville	CT	13	15	Nat Gas	Pipeline
Viaduct	CT	25	31	Nat Gas	Pipeline
Total Combustion Turbine		381	445		
Canton (5 Units)	Diesel	4	4	#2 Oil	Truck
Portable	Diesel	1	1	#2 Oil	Truck
Total Diesel		5	5		
Total Company		7825	7905		
Joppa <sup>(1)</sup>	Steam	405	405	Coal	Rail,Barge
Grand Total		8230	8310		

(1) Amount of Joppa capacity scheduled according to the EEI/DOE contract. Union Electric's 40% share of the 6-unit Joppa Plant is 405 MW.

Table 4-2  
**1995 Capacity Mix**  
 (Megawatts)

<u>Station/Unit</u>	<u>Base</u>	<u>Intermediate</u>	<u>Peak</u>	<u>Total</u>
Callaway	1125			1125
Rush Island 1	581			581
Rush Island 2	581			581
Labadie 1	559			559
Labadie 2	559			559
Labadie 3	559			559
Labadie 4	559			559
Sioux 1	463			463
Sioux 2	463			463
Keokuk (15 Units)	119			119
Meramec 1		131		131
Meramec 2		131		131
Meramec 3		280		280
Meramec 4		338		338
Venice (6 Units)			429	429
Osage (8 Units)			212	212
Taum Sauk (2 Units)			350	350
Venice			25	25
Howard Bend			43	43
Meramec			55	55
Mexico			55	55
Moberly			55	55
Moreau			55	55
Fairgrounds			55	55
Kirksville			13	13
Viaduct			25	25
Canton (5 Units)			4	4
Portable			1	1
Joppa		405 <sup>(1)</sup>		405
<b>Total</b>	<b>5568</b>	<b>1285</b>	<b>1377</b>	<b>8230</b>
<b>Percent</b>	<b>67.7%</b>	<b>15.6%</b>	<b>16.7%</b>	

(1) Amount of Joppa capacity scheduled according to the EEI/DOE contract.  
 Union Electric's 40% share of the 6-unit Joppa Plant is 405 MW.

**Table 4-3**  
**All Supply-Side Resource Plan**  
**1995 - 2014**  
**Nominal Forecast**

Year		MW Added Net
1995	Venice Restaffing	92
1996		
1997	Sioux Improvement	16
1998	CIPS Purchase <sup>1</sup>	
1999	Eliminate 25 Hz Losses <sup>2</sup>	20
2000	Taum Sauk Improvement ..... 80 MW	282
	Power Purchase ..... 50 MW	
	Renewables ..... 2 MW	
	CTs - 2 ..... 150 MW	
2001	CT	75
2002	CT ..... 75 MW	75
	Extend AP&L Purchase ..... —	
2003	CT	75
2004	CTs - 2	150
2005	CTs - 3 ..... 225 MW	75
	End CIPS Purchase ..... -150 MW	
2006	CT	75
2007	CT ..... 75 MW	75
	Joppa Additional Energy ..... —	
2008	Venice 5 & 6 Repowering ..... 248 MW	88
	End AP&L Purchase ..... -160 MW	
2009	Combined Cycle	180
2010		
2011	Venice 3 & 4 Repowering	262
2012		
2013	Combined Cycle	180
2014	End 50 MW Purchase	-50

Joppa      405 MW - 1995 - 2014

AP&L      160 MW - 1995 - 2007

Approximately 50 MW of unidentified purchases are assumed to be available after 2000 for future reliability, if required.

<sup>1</sup> CIPS Purchase Availability For UE System: 1998 - 80 MW, 1999 - 75 MW, 2000 Through May, 2005 - 150 MW

<sup>2</sup> Keokuk Generator Rewind

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**RESOURCE INTEGRATION**  
**SECTION 5**

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**5.1 OVERVIEW**

Integrated resource analysis identifies alternative strategies consisting of both demand-side and supply-side resources which meet future peak demand and energy requirements in a cost effective manner. This analysis develops the preferred resource strategy that provides reliable service at the lowest practicable cost, is equitable to customers, and provides flexibility to respond to changing conditions.

The Company used the EGEAS model to perform the integrated analysis. The analysis addressed the twenty-year planning period 1995-2014, with a 10 year extension period to account for end effects. All results are reported in terms of 1995 present value of revenue requirements (PVRR) over this 30 year period.

The EGEAS screening work discussed in Section 4 identified the supply-side options to be considered at integration. Likewise, the DSManager screening work discussed in Section 3 identified the demand-side programs to be considered at resource integration.

The demand-side screening effort identified 9 residential, 6 commercial and 5 industrial programs as potential resource options. These individual programs were combined into two integrated DSM programs — DSM-14 and DSM-20 — which are shown in Table 5-1.

The database underlying the integration analysis was developed using sources throughout the Company. The Company's "experts" in each area developed cost estimates, operational parameters, and subjective probabilities associated with their particular expertise. Thus, Financial

Planning and Investments supplied cost of capital data, Energy Supply developed plant operating parameters, etc. The IRA report describes the data development responsibilities and data assumptions in greater detail.

**5.2 ANALYSIS**

The Company established three levels of environmental mitigation beyond 1995 requirements — Green, Greener and Greenest — for use in evaluating the potential impact of possible future regulations on resource plans. Optimal schedules of resources for the all supply-side and the two demand-side management strategies were developed for the three levels of mitigation.

The capacity equivalence and system load impact for the DSM measures included in the two demand-side management strategies were developed. The system adjusted demand, which is used for reserve calculations, was changed to account for the capacity equivalence of each strategy. System loads were adjusted for each of the DSM programs and the supply-side units were reoptimized using the EGEAS model.

A total of nine resource schedules for the following three strategies were developed.

**All Supply-Side** — This strategy does not include any DSM programs.

**DSM-14** — This strategy includes the fourteen DSM programs which had a benefit/cost ratio greater than 1.0 for the total resource cost test performed without probable environmental costs.

**DSM-20** — This strategy includes the twenty DSM programs which had a benefit/cost ratio of at least 0.95 for the total resource cost test performed with probable

environmental costs. Participation levels and load impacts for the programs included in this strategy are higher than those used in the development of the DSM-14 strategy due to the addition of probable environmental costs in program development.

The nine resource schedules are shown on Table 5-2. In all cases, the optimal all supply-side schedules rely on a sequence of CTs, combined cycle units, and unit repowering to meet the expected load growth forecast.

The optimal schedules for the Green and Greener environmental cases require CTs beginning as early as 2000, followed by combined cycle units after 2006. The Greenest case advances combined cycle units to 2000. The early addition of combined cycle units in the Greenest case is due to capacity reductions on existing base load units to provide for the energy requirements of the additional environmental control equipment.

### 5.3 SENSITIVITY ANALYSIS

The sensitivity of several parameters was evaluated for the all supply-side strategy to determine which assumptions had the largest impact on resource selection. These included forced outage rates of existing base load units, reduced economy coal purchases, construction and O&M costs, fuel costs, and SO<sub>2</sub> allowance costs.

It was determined *a priori* that risk analysis would be performed for the following factors, therefore they were not included in the sensitivity analysis.

- Environmental Cost
- Construction and O&M Cost (Renewable Technologies)
- Load Forecast

The following paragraphs describe the sensitivities. The base case conditions

included expected values for all parameters including probable environmental costs.

**Fuel Prices** – Base case conditions assumed that Powder River Basin (PRB) coal would escalate annually at approximately 3% during the study period. This sensitivity assumed that PRB coal would escalate each year at approximately 1.5% (low) and 4.75% (high).

The base case conditions assumed that oil and natural gas prices would escalate at approximately 3.5% and 4.75% per year, respectively. This sensitivity assumed oil and natural gas price escalation rates would increase to approximately 4.5% and 6.0% (high) and decrease to approximately 1.0% and 2.0% (low), respectively.

**Construction and O&M Costs** – Capital and O&M cost estimates were varied based on the assumptions contained in the *Generation Technologies for Integrated Resource Planning* report. This resulted in costs being varied by as much as  $\pm 15\%$  from nominal values, depending on the technology, to arrive at high and low cost estimates.

**Economy Coal Purchase** – Base case conditions assumed a varying level of economy coal purchase power availability during the study period. The level was held constant over the second ten-year period. This sensitivity assumed that economic coal purchase power would be reduced by 50% after 1999, and would be eliminated in 2005. Thus, this sensitivity resulted in replacing economic coal purchases with internal generation or oil and natural gas purchases starting in 2000.

**Equivalent Forced Outage Rate** — The base case conditions assumed forced outage rates consistent with the Company's ten-year fuel budget. This sensitivity assumed that existing coal and nuclear units would experience an increase in equivalent forced

outage rate (EFOR) of 0.5 percentage points each year over the period 2005-2014 for a total increase of five percentage points by 2014.

**SO<sub>2</sub> Allowance Costs** — The allowance cost for SO<sub>2</sub> emissions included in base case conditions was \$150 per ton of SO<sub>2</sub> in 1995 escalating at 4% per year thereafter. For this sensitivity, high and low escalation rates of 6% and 2% respectively were applied to the \$150 per ton base condition value for 1995.

### Results

The sensitivity analysis shows that three of the factors do not significantly change resource selection. The factors that are not critical for decision making include:

- Construction and O&M Costs
- Increased Forced Outage Rates (Existing base load units)
- SO<sub>2</sub> Allowance Costs

These factors were removed from the list of uncertainties to be considered in the risk analysis discussed in Section 6.

The remaining uncertain factors were examined from the standpoint of their impact on resource timing and selection as well as other issues. The following factors were found to have a significant impact on the selection or timing of resources and were selected for risk evaluation:

- Economy Coal Purchases
- Fuel Cost

Table 5-3 shows the results of the sensitivity analysis for resource selection and timing for the all supply-side strategy. Although resource timing changes based on the sensitivities considered, CTs are selected to meet future requirements through at least 2004. This is also true for the Green and Greener environmental mitigation levels selected for analysis, as shown in Table 5-1.

Thus, based on the integration analysis, a resource plan calling for CTs in the early years of the planning period is robust for all but the Greenest level of environmental mitigation. This level is considered an extreme case and results in significant reductions in the output of existing units due to the addition of environmental controls.

A more detailed discussion of the sensitivity analysis is contained in Section 6 of the IRA report.

Table 5-1

**Individual DSM Programs Included in  
DSM-14 and DSM-20  
Integrated Programs**

	DSM-14		DSM-20	
	Capacity Equivalence (MW)		Capacity Equivalence (MW)	
	2000	2014	2000	2014
<b>Commercial Programs:</b>				
Audits-Level I - Walk Through Audit	6.7	16.7	10.0	25.0
Audits-Level IIA - Engrg Study Lighting Emphasis	6.7	16.7	10.0	25.0
Audits-Level IIB - Comprehensive Bldg Modeling	13.1	32.8	19.7	49.2
Small Comm Do-it-Yourself Audit	1.7	4.2	2.5	6.3
Small Comm Walk-Thru Audit	3.2	8.1	4.8	12.1
Thermal Storage - Off-Peak Cooling			2.2	5.6
<b>Industrial Programs</b>				
Customized Process Audit Program	3.9	9.7	4.9	12.2
Demand & Energy Control Info Program	4.6	11.4	5.0	12.6
MotorMaster Software Subprogram	0.1	0.3	0.2	0.4
MotorMiser Audit Subprogram	1.5	3.7	2.3	5.7
Standby Generation/Curtailable Power Rate	40.4	40.4	44.4	44.4
<b>Residential Programs</b>				
Water Heater and Lighting Measures			0.3	0.6
Building Shell Measures			0.1	0.3
Setback Thermostats - Gas Heating Cust	0.5	1.0	0.6	1.2
Low Income Building Shell Measures	0.3	0.8	0.5	1.1
Low Income Water Bed Measures				0.1
Central Air Conditioner/Heat Pump Cycling			18.8	46.1
Refrigerator Removal	1.5	4.0	5.3	13.9
Freezer Removal			0.8	2.8
New Construction Building Shell Measures	0.4	2.0	0.6	3.1
<b>Total</b>	<b>84.6</b>	<b>151.8</b>	<b>133.0</b>	<b>267.7</b>

**Table 5-2**  
**Optimized Expansion Plans**  
**Green, Greener and Greenest Levels of Environmental Control**

Year	Level of Environmental Control								
	Green			Greener			Greenest		
	All Supply	DSM 14 152 MW	DSM 20 268 MW	All Supply	DSM 14 152 MW	DSM 20 268 MW	All Supply	DSM 14 152 MW	DSM 20 268 MW
1995									
1996									
1997	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux
1998	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP
1999	KGR	KGR	KGR	KGR	KGR	KGR	KGR	KGR	KGR
2000	TS 1 CT 50 MW PP	TS 50 MW PP	50 MW PP	TS 2 CT 50 MW PP	TS 1 CT 50 MW PP	TS 50 MW PP	TS 1 CT 2 CC 50 MW PP	TS 2 CC 50 MW PP	TS 1 CT 1 CC 50 MW PP
2001	1 CT	1 CT	TS	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT
2002	Extend AP&L 2 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT
2003	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CC	1 CT	1 CC
2004	1 CT	1 CT	1 CT	2 CT	1 CT	1 CT		1 CT	
2005	3 CT	3 CT	3 CT	3 CT	3 CT	3 CT	1 CT 1 CC	1 CT 1 CC	1 CC
2006	2 CT	2 CT	1 CT	1 CT	1 CT	1 CT	1 CC	1 CT	1 CC
2007	Extra Joppa 1 CT	Extra Joppa 1 CT	Extra Joppa 1 CT	1 CC	1 CC	1 CT		1 CT	
2008	Repower V5&6	Repower V5&6	Repower V5&6	Repower V5&6 Extra Joppa	Repower V5&6 Extra Joppa	Repower V5&6 Extra Joppa	Repower V5&6	Repower V5&6	Repower V5&6
2009	1 CT	1 CT	1 CT			1 CT	2 CT	1 CT	1 CC
2010	1 CT	1 CT	Repower V3&4	1 CC	1 CC	Repower V3&4	1 CT	Repower V3&4	
2011	Repower V3&4	Repower V3&4					1 CT		1 CC
2012			1 CT	Repower V3&4	Repower V3&4		1 CT	1 CT	
2013			1 CC			1 CC	Repower V3&4	1 CC	Repower V3&4
2014	2 CT	2 CT		1 CT	1 CT	1 CT			
CT (MW)	1200	1050	750	900	750	825	675	675	225
CC (MW)	0	0	180	360	360	180	900	720	1080
Repower (MW)	528	528	528	510	510	510	510	510	510
Upgrades (MW)	116	116	116	116	116	116	116	116	116
Total - Supply (MW)	1844	1894	1574	1886	1736	1631	2201	2021	1931
DSM (MW)	0	152	268	0	152	268	0	152	268
Total (MW) - 2014	1844	1846	1842	1886	1888	1899	2201	2173	2199

Sioux	Sioux 16 MW Improvement
CIPS PP	CIPS 150 MW Power Purchase
KGR	Keokuk Generator Rewind 20 MW Capacity Equivalence
50 MW PP	50 MW Intermediate Power Purchase
Repower V3&4	Repower Venice Units 3 & 4
Repower V5&6	Repower Venice Units 5 & 6
Extra Joppa	Increased Utilization Of Joppa Energy
Extend AP&L	Extend The Present Purchase Contract With AP&L As Provided For In The Contract
TS	Taum Sauk Runner Replacement - 80 MW
DSM	Demand-Side Management Capacity Equivalence

**Table 5-3**  
**Optimal All Supply-Side Expansion Plans - Sensitivities**  
**Probable Environmental Costs — Included**

Year	Case								
	Base	Sensitivity							
	Nominal Conditions	Increased F.O.R	Reduced Economy Purchases	High Const. and O&M Costs	Low Const. and O&M Costs	High Fuel Costs	Low Fuel Costs	High SO2 Costs	Low SO2 Costs
1995									
1996									
1997	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux
1998	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP
1999	KGR	KGR	KGR	KGR	KGR	KGR	KGR	KGR	KGR
2000	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP
2001	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT
2002	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT
2003	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT
2004	2 CT	2 CT	2 CT	2 CT	2 CT	2 CT	2 CT	2 CT	2 CT
2005	3 CT	3 CT	Extra Joppa Repower V 5&6	3 CT	3 CT	3 CT	Repower V 5&6	3 CT	3 CT
2006	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT
2007	1 CT Extra Joppa	1 CT Extra Joppa	1 CT	1 CT Extra Joppa	1 CT Extra Joppa	1 CT Extra Joppa	1 CT	1 CT Extra Joppa	1 CT Extra Joppa
2008	Repower V 5&6 1 CC	Repower V 5&6 1 CC	Repower V 3&4 1 CT	Repower V 5&6 1 CC	Repower V 5&6 1 CC	Repower V 5&6 1 CC	Repower V 3&4 1 CT	Repower V 5&6 1 CC	Repower V 5&6 1 CC
2009			1 CT				1 CT Extra Joppa		
2010									
2011	Repower V 3&4	Repower V 3&4	1 CC	Repower V 3&4	Repower V 3&4	Repower V 3&4	2 CT	Repower V 3&4	Repower V 3&4
2012							1 CT		
2013	1 CC	1 CC	1 CC	1 CC	1 CC	1 CC	1 CT	1 CC	1 CC
2014			1 CT				2 CT		
CT (MW)	900	900	900	900	900	900	1275	900	900
CC (MW)	360	360	360	360	360	360	0	360	360
Repower (MW)	512	512	512	512	512	512	512	512	512
Upgrades (MW)	116	116	116	116	116	116	116	116	116
Total - Supply (MW)	1888	1888	1888	1888	1888	1888	1903	1888	1888
DSM (MW)	0	0	0	0	0	0	0	0	0
Total (MW) - 2014	1888	1888	1888	1888	1888	1888	1903	1888	1888

Sioux	Sioux 16 MW Improvement
CIPS PP	CIPS 150 MW Power Purchase
KGR	Keokuk Generator Rewind 20 MW Capacity Equivalence
50 MW PP	50 MW Intermediate Power Purchase
Repower V3&4	Repower Venice Units 3 & 4
Repower V5&6	Repower Venice Units 5 & 6
Extra Joppa	Increased Utilization Of Joppa Energy
Extend AP&L	Extend The Present Purchase Contract With AP&L As Provided For In The Contract
TS	Taum Sauk Runner Replacement - 80 MW
DSM	Demand-Side Management Capacity Equivalence

## PLAN SELECTION

### SECTION 6

#### 6.1 SCENARIO DEVELOPMENT

For this ERP, a new scenario analysis methodology was developed by a team consisting of forecasting, DSM analysis, and supply-side analysis personnel. The first step consisted of interviewing senior management about what issues or trends they thought would impact the electric utility industry. The two theme areas that senior management believes will impact the industry are competition and the environment. Based on these results, the team decided to analyze a competition scenario and an environmental scenario, along with the usual base, high, and low forecast scenarios. Each scenario was generated using the 1995-2014 sales and peak demand forecasts developed in the fall of 1994 as a starting point. A brief summary of the five scenarios follows.

**Base Forecast Scenario** – The base forecast scenario represents the Company's assessment of the most likely growth pattern for the future. It assumes no exogenous shocks (e.g., recession, deregulation, etc.) to the system. The twenty-year forecasted peak demand growth under this scenario is 1.0%, or 82 MW, per year.

**Low Forecast Scenario** – This scenario is the lower band of a 75% confidence interval around the base forecast. This scenario is attributed to lower population growth and household formation, a smaller rise in labor force participation rates, lower labor productivity growth, more rapidly rising energy prices, slower foreign growth, and a slower increase in government purchases than the expected forecast. The result is higher inflation and lower real GNP growth due to reduced levels of industrial production and personal consumption. The

twenty-year peak demand growth under this scenario is reduced to 0.4%, or 31 MW, per year.

**Competition Scenario** – This scenario assumes an aggressive deregulation schedule. Industrial rates are assumed to be deregulated in 1998, commercial rates in 2000, and residential rates in 2002. After deregulation, prices in each market class are assumed to achieve the market clearing price for that market class. The market clearing prices for each market class were determined by surveying experts within the Company. The twenty-year forecasted peak demand growth under this scenario is 1.0%, or 82 MW, per year, which is the same as the "Base Forecast Scenario".

**Environmental Scenario** – This scenario is based on extreme environmental regulations being imposed on the electric utility industry. It assumes Maximum Available Control Technology for new units and existing units. In addition it assumes a CO<sub>2</sub> tax of \$11.40 per ton of CO<sub>2</sub> for all emissions in excess of 1990 levels. Environmental compliance is assumed to begin in 2000 and extend throughout the planning horizon. The twenty-year forecasted peak demand growth under this scenario is 0.7%, or 51 MW, per year.

**High Forecast Scenario** – This scenario is the higher band of a 75% confidence interval around the base forecast. The high forecast scenario is attributed to higher population growth, increased household formation, higher labor force participation rates, higher labor productivity growth, slower energy price growth, increased foreign economic growth and increased government purchases. Increased industrial

production and personal consumption levels result in lower inflation and higher real GNP growth. The twenty-year peak demand growth under this scenario increases to 1.6%, or 132 MW, per year. A 15% planning margin was used to determine resource needs to avoid double counting forecast uncertainty. The 18% margin used in other scenarios accounts for forecast uncertainty due to weather and non-weather related factors.

These five scenarios set reasonable bounds on what might occur over the next twenty years. Other scenarios could be developed that would result in conditions outside the bounds. However, every conceivable future cannot be modeled in a timely manner. The five scenarios selected were judged to be inclusive of most realistic assumptions.

Optimal supply-side and integrated resource expansion plans were developed for each scenario.

## 6.2 SCENARIO ANALYSIS

The various scenarios were modeled with the EGEAS program. An optimal expansion plan was developed for each scenario. The resource options for the expansion plans included the Taum Sauk runner replacement, Keokuk generator rewind, Venice Repowering, CTs, CC units, additional Joppa energy purchase, and the extension of the AP&L purchase. Wind generation was included as a candidate resource in the environmental scenario.

The low load growth and environmental scenarios result in lower demand and delay the need for additional capacity. The competition scenario does not change resource timing or selection. With the high growth scenario, the first resource need is advanced to 1996. Based on current

information, there is adequate generation in the midwest to cover this need, through economical purchases until at least 1999 or 2000. The high growth scenario advances the need for the first CT to 1999 or 2000.

The DSM-20 strategy was preferred over the all supply-side strategy, based on the utility cost test, for all of the scenarios that were evaluated.

Table 6-1 shows the optimal integrated resource plan for each scenario. All scenarios include the Taum Sauk runner replacement project and the Keokuk generator rewind project in the expansion schedule. The Keokuk generator rewind option is always selected in the first year available, *i.e.*, 1999. The Taum Sauk runner replacement is also selected as the first addition to satisfy capacity needs. CTs are added as necessary until about 2005 or 2008, when the CIPS and AP&L purchases are tentatively scheduled to end. The low growth scenario does not include any CC units.

The scenario analysis produced results similar to the results of the sensitivity analysis described in Section 5. In general, the strategy of implementing unit improvements and installing CTs is robust across most scenarios through 2005. Only in the high growth scenario are intermediate load units added prior to 2005. Furthermore, all of the resource additions included in the strategy are relatively low cost and have short lead times.

The high growth scenario is considered an extreme event which could be met through power purchases until new CTs can be installed.

The optimum resource plan developed by EGEAS for each scenario was simulated using the MIDAS model. The results of that analysis are shown in Table 6-2. This table

provides a comparison of the all supply-side strategy to the DSM-20 strategy based on three evaluation criteria: levelized average system rates, utility cost, and total resource cost. In general, the DSM-20 strategy is preferred for all of the evaluation criteria over all the futures considered. Slightly higher levelized average system rates are shown for the low and high forecast scenarios. These results indicate that the DSM-20 strategy is a robust strategy across the futures considered.

### 6.3 RISK ANALYSIS

The results of the sensitivity analysis discussed in Section 5 indicate that UE is faced with two major resource decisions at the current time. The Company needs to decide what level of DSM to implement in 1997. In addition, it must decide whether to plan on installing peaking or intermediate resources in the early and mid 2000's. These decisions may be impacted by the following five uncertainties:

- Load Forecast
- Fuel Cost
- Future Availability of Economy Coal Energy for Purchase
- Future Environmental Costs
- Construction and Fixed O&M Cost for Wind Generation

The EPRI developed Multiobjective Integrated Decision Analysis System (MIDAS) model was used for the risk analysis. In order to limit the size of the decision tree being analyzed, it was decided to use two expansion strategies for the risk analysis, one consisting of all CTs and the second consisting of all CCs. This decision was based on a review of the results of the system integration analysis discussed in Section 5.

Figure 6-1 depicts the decision tree that was developed. The risk analysis results are contained in Table 6-3 and show that the outcomes, using expected values, are very close for the two DSM strategies. Also, both DSM strategies are preferred to the all supply-side strategy based on the Utility Cost Test and the Total Resource Cost Test. Further, the results support a decision to delay installation of intermediate resources to the late 2000's.

An expansion strategy of DSM and CTs plus power purchases appears to be the most economic choice through the early and mid 2000's.

An Expected Value of Perfect Information (EVPI) analysis was performed to determine the value of resolving the uncertainties considered in the decision tree. The results of the EVPI analysis are shown in Table 6-4. If the value of resolving the uncertainty is zero, then the preferred strategy remains preferred for all modeled values of the uncertainty. If the preferred strategy would change for one or more of the uncertainty values modeled, then the value of resolving the uncertainty is not zero.

As shown in Table 6-4, the expected savings that would result from having perfect information is very small on a percentage basis for the variables analyzed. The uncertainty in future environmental costs is the most significant, followed by uncertainty in availability of economy coal energy for purchases, and uncertainty in the load forecast.

The savings shown in Table 6-4 would be expected if perfect information were available. They do not reflect the savings, if any, from decreasing the uncertainty in these variables. In fact, the uncertainties may not be able to be resolved, even with additional research and investment. The data highlights

where uncertainty would have a significant impact on expected outcomes.

Section 7 of the IRA report contains a more complete discussion of the risk analysis performed.

#### 6.4 PLAN SELECTION

The sensitivity, scenario and risk analyses show that the DSM-20 plan is preferred. The DSM-20 plan is composed of a menu of cost effective DSM programs; Venice repowering; Sioux, Taum Sauk and Keokuk plant improvements; combustion turbines; combined cycle units; an extended AP&L contract; additional Joppa energy and economic power purchases. It includes 825 MW of combustion turbines, 180 MW of combined cycle capacity, 510 MW of Venice Repowering and 268 MW of equivalent DSM capacity.

Both the DSM-20 plan and the all supply-side plan provide for system reliability and flexibility. Tables 6-5 and 6-6 show the timing of resources for these plans. Both plans utilize combustion turbines in the early years, with the DSM-20 plan substituting demand-side resources for some of the early combustion turbine additions. Combustion turbines and demand-side resources can be added in increments to closely match forecasted load growth. Thus, from the perspective of reliability and flexibility, either plan would perform well. Likewise, neither plan should be difficult to finance due to the relatively small capital expenditures required for resource additions in any given year.

The DSM-20 plan provides for maximum annual energy savings of nearly 0.9 million MWh over the all supply-side plan. As such, it would likely perform better for futures with increased emphasis on the environment.

The levelized system rates test yielded results for the DSM-20 plan that were

approximately equal to the all supply-side plan for the expected forecast scenario. Given no average rate impact and the fact that the DSM-20 plan contains programs directed at each of the three major retail rate classes, the Company does not believe that the DSM-20 plan should be rejected based on equity considerations.

The DSM-20 plan provides the maximum insurance against actions in the environmental area.

The Company's preferred resource plan is shown in Table 6-7 and is based on the DSM-20 plan. The DSM-20 plan was developed for the Greener environmental mitigation level discussed in Section 5. The Greener mitigation level represents most likely conditions, based on the probabilities developed for this ERP, except for the installation of environmental controls on existing units. The level of environmental controls on existing units included in the Greener mitigation level has only a 15% probability of occurrence based on Company estimates. The level of environmental controls for existing units, included in the Green mitigation level, has a 80% probability of occurrence and is the most likely level.

The DSM-20 plan, shown in Table 6-5, includes a 48 MW reduction in existing system capability and a 3 MW reduction in the EEInc. purchase beginning in the year 2000. However, based on most likely conditions, these reductions would not be required. Therefore, the capacity and reserve values shown in Table 6-5, have been adjusted to eliminate the 51 MW reduction for the preferred resource plan shown in Table 6-7. This additional capacity may allow the Company to delay the first CT and the Taum Sauk runner upgrade projects by one year.

Figure 6-1

## Risk Analysis Decision Tree

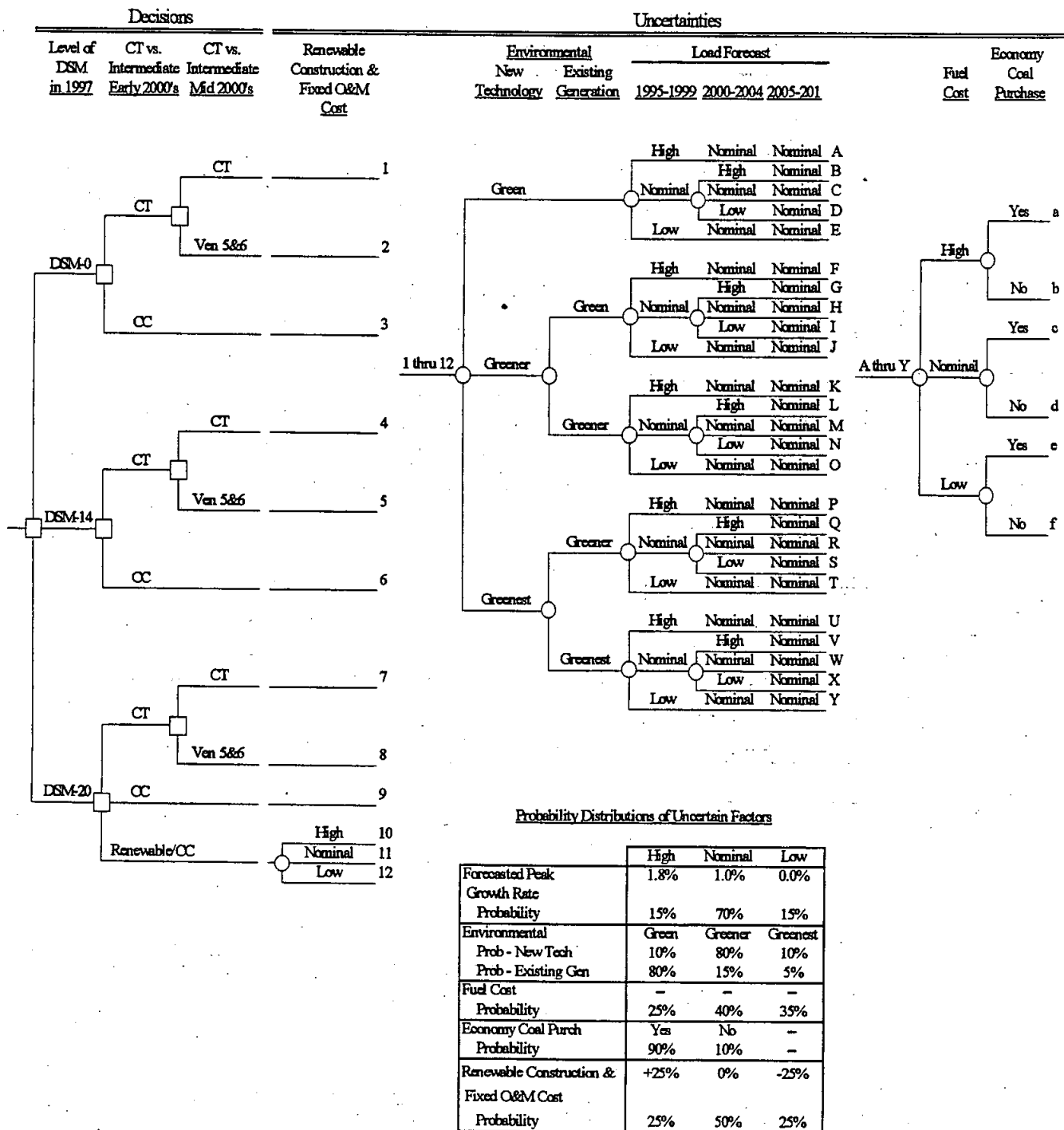


Table 6-1

**Optimal Integrated Resource Plans for Each Scenario  
(Probable Environmental Costs — Included)  
DSM-20 Plan**

Year	Scenario				
	Nominal	Low Growth	High Growth	Environmental	Competition
1995					
1996					
1997	Sioux	Sioux	Sioux	Sioux	Sioux
1998	CIPS PP		CIPS PP	CIPS PP	CIPS PP
1999	KGR	KGR	KGR 4 CT	KGR	KGR
2000	TS 50 MW PP		50 MW PP	TS 50 MW PP	TS 50 MW PP
2001	1 CT		TS 1 CT		1 CT
2002	Extend AP&L 1 CT		Extend AP&L 1 CT	Extend AP&L	Extend AP&L 1 CT
2003	1 CT	TS	Repower V 5&6	1 CT	1 CT
2004	1 CT			1 CT	1 CT
2005	3 CT		Repower V 3&4	Repower V 5&6	3 CT
2006			1 CC		
2007	2 CT	1 CT	1 CT	1 CT	2 CT
2008	Repower V 5&6 Extra Joppa	Extra Joppa	2 CC	Repower V 3&4	Repower V 5&6 Extra Joppa
2009	1 CT	1 CT	1 CC		1 CT
2010	1 CT		1 CT Extra Joppa	1 CC	1 CT
2011	Repower V 3&4	1 CT	1 CC		Repower V 3&4
2012			1 CC	1 CC	
2013	1 CT	1 CT	1 CT		1 CT
2014	1 CT		1 CC		1 CT
CT (MW)	975	300	675	225	975
CC (MW)	0	0	1260	360	0
Repower (MW)	512	0	512	510	512
Upgrades (MW)	116	116	116	116	116
Total - Supply (MW)	1603	416	2563	1211	1603
DSM (MW)	268	268	268	268	268
Total (MW) - 2014	1871	684	2831	1479	1871

Sioux

CIPS PP

KGR

50 MW PP

Repower V3&amp;4

Repower V5&amp;6

Extra Joppa

Extend AP&amp;L

TS

DSM

Sioux 16 MW Improvement

CIPS 150 MW Power Purchase

Keokuk Generator Rewind 20 MW Capacity Equivalence

50 MW Intermediate Power Purchase

Repower Venice Units 3 &amp; 4

Repower Venice Units 5 &amp; 6

Increased Utilization Of Joppa Energy

Extend The Present Purchase Contract With AP&amp;L As Provided For In The Contract

Taum Sauk Runner Replacement - 80 MW

Demand-Side Management Capacity Equivalence

Table 6-2

**Scenario Analysis  
Strategy Comparison**

Levelized Average System Rates ( $\text{\$/kWh}$ )

Strategy	Scenario				
	Base	Low	High	Environmental	Competition
All Supply	0.001	0	0	0.001	0.014
DSM-20	0	0.026	0.029	0	0

Utility Cost (\$ in Millions)

Strategy	Scenario				
	Base	Low	High	Environmental	Competition
All Supply	303.72	179.69	214.58	392.41	303.72
DSM-20	0	0	0	0	0

Total Resource Cost (\$ in Millions)

Strategy	Scenario				
	Base	Low	High	Environmental	Competition
All Supply	212.89	108.84	102.04	301.59	212.89
DSM-20	0	0	0	0	0

\* The results shown for each scenario are the differences between the strategy cost and the low cost strategy expressed in either present value of revenue requirements or levelized rates over the period, 1995-2024.

**Table 6-3**  
**Risk Analysis**  
**Expected Values for Strategies Evaluated**

Strategy	Levelized Average System Rate	Utility Cost	Total Resource Cost
	Levelized ¢/kWh	30 Yr PVR \$ in Millions	30 Yr PVR \$ in Millions
DSM20; All CT Expansion; Ven 5&6 Repower 2008	7.458	26,040.05 *	26,125.82 *
DSM20; All CT Expansion; Ven 5&6 Repower 2005	7.458	26,040.37	26,126.14
DSM14; All CT Expansion; Ven 5&6 Repower 2008	7.456 *	26,042.25	26,126.45
DSM14; All CT Expansion; Ven 5&6 Repower 2005	7.457	26,046.95	26,131.14
DSM20; All CC Expansion; Ven 5&6 Repower 2008	7.471	26,085.52	26,171.29
DSM14; All CC Expansion; Ven 5&6 Repower 2008	7.471	26,094.04	26,178.24
DSM20; All CC Expansion; Ven 5&6 Repower 2008 Renewables in 2000	7.478	26,110.16	26,195.94
No DSM; All CT Expansion; Ven 5&6 Repower 2008	7.464	26,363.71	26,363.71
No DSM; All CT Expansion; Ven 5&6 Repower 2005	7.464	26,364.30	26,364.30
No DSM; All CC Expansion; Ven 5&6 Repower 2008	7.483	26,430.01	26,430.01

\* Lowest Value

**Table 6-4**  
**EVPI Results**

Evaluation Criteria: Levelized Average System Rates

Expected Value: 7.456 ¢/kWh

<u>Uncertainty</u>	<u>EVPI ¢/kWh</u>
Load Forecast	0.000
Fuel Cost	0.001
Future Availability of Economy Coal Energy for Purchase	0.001
Future Environmental Costs	0.002
Capital and Fixed O&M Cost for Renewables	0.000

Evaluation Criteria: Utility Cost

Expected Value: \$26,040.05 Mil

<u>Uncertainty</u>	<u>EVPI \$ Millions</u>
Load Forecast	1.58
Fuel Cost	0.92
Future Availability of Economy Coal Energy for Purchase	2.87
Future Environmental Costs	5.35
Capital and Fixed O&M Cost for Renewables	0.00

Evaluation Criteria: Total Resource Cost

Expected Value: \$26,125.82 Mil

<u>Uncertainty</u>	<u>EVPI \$ Millions</u>
Load Forecast	2.60
Fuel Cost	0.92
Future Availability of Economy Coal Energy for Purchase	2.87
Future Environmental Costs	5.73
Capital and Fixed O&M Cost for Renewables	0.00

Table 6-5

**DSM-20 Resource Plan**  
**Greener Environmental Mitigation Level - Controls On New and Existing Units**

YEAR	UNIT	RESOURCE ADDITION (REDUCTION)				UE CAPACITY MW	EEINC PURCHASE MW	PURCHASE (SALE) MW	ADJUSTED CAPACITY MW	ADJUSTED DEMAND MW	RESERVE %
		UE CAPACITY			PUR						
		DSM MW	SUP MW	Total MW	MW						
1995	Venice Restaffing		92	92		7,825	405	155	8,385	7,143	17.4
1996				0		7,825	405	155	8,385	7,199	16.5
1997	DSM, SX Improvement	44	16	60		7,885	405	155	8,445	7,268	16.2
1998	DSM, CIPS Purchase	22		22	150	7,907	405	240	8,552	7,288	17.3
1999	DSM, Keokuk Generator Rewind	22	20	42		7,949	405	235	8,589	7,367	16.6
2000	DSM, Taum Sauk Runners Renewables 50 MW Purchase	45	80	125	2 50	8,026	402	362	8,790	7,447	18.0
2001	DSM, CT	23	75	98		8,124	402	362	8,888	7,527	18.1
2002	DSM, CT Extend AP&L Purchase	23	75	98	—	8,222	402	362	8,986	7,606	18.1
2003	DSM, CT	22	75	97		8,319	402	362	9,083	7,686	18.2
2004	DSM, CT	23	75	98		8,417	402	362	9,181	7,765	18.2
2005	DSM, CT-3 End CIPS Purchase	22	225	247	(150)	8,664	402	212	9,278	7,845	18.3
2006	DSM, CT	22	75	97		8,761	402	212	9,375	7,925	18.3
2007	CT		75	75		8,836	402	212	9,450	8,004	18.1
2008	Repower Venice Units 5&6 End AP&L Purchase Additional Joppa Energy		248	88	(160) —	9,084	402	52	9,538	8,084	18.0
2009	CT		75	75		9,159	402	52	9,613	8,163	17.8
2010	Repower Venice Units 3&4		262	262		9,421	402	52	9,875	8,243	19.8
2011				0		9,421	402	52	9,875	8,322	18.7
2012				0		9,421	402	52	9,875	8,402	17.5
2013	CC		180	180		9,601	402	52	10,055	8,481	18.6
2014	CT End 50 MW Purchase		75	75	(50)	9,676	402	2	10,080	8,561	17.7

Table 6-6

**All Supply-Side Resource Plan  
Greener Environmental Mitigation Level - Controls On New and Existing Units**

YEAR	UNIT	RESOURCE ADDITION (REDUCTION)				UE CAPACITY MW	EEINC PURCHASE MW	PURCHASE (SALE) MW	ADJUSTED CAPACITY MW	ADJUSTED DEMAND MW	RESERVE %
		UE CAPACITY			PUR MW						
		DSM MW	SUP MW	Total MW							
1995	Venice Restaffing		92	92		7,825	405	155	8,385	7,143	17.4
1996				0		7,825	405	155	8,385	7,199	16.5
1997	SX Improvement		16	16		7,841	405	155	8,401	7,268	15.6
1998	CIPS Purchase			0	150	7,841	405	240	8,486	7,288	16.4
1999	Keokuk Generator Rewind		20	20		7,861	405	235	8,501	7,367	15.4
2000	Taum Sauk Runners		80	230		8,043	402	362	8,807	7,447	18.3
	CT-2		150								
	Renewables				2						
	50 MW Purchase				50						
2001	CT		75	75		8,118	402	362	8,882	7,527	18.0
2002	CT		75	75		8,193	402	362	8,957	7,606	17.8
	Extend AP&L Purchase				—						
2003	CT		75	75		8,268	402	362	9,032	7,686	17.5
2004	CT-2		150	150		8,418	402	362	9,182	7,765	18.2
2005	CT-3		225	225		8,643	402	212	9,257	7,845	18.0
	End CIPS Purchase				(150)						
2006	CT		75	75		8,718	402	212	9,332	7,925	17.7
2007	CC		180	180		8,898	402	212	9,512	8,004	18.8
2008	Repower Venice Units 5&6		248	248		9,146	402	52	9,600	8,084	18.7
	End AP&L Purchase				(160)						
	Additional Joppa Energy				—						
2009				0		9,146	402	52	9,600	8,163	17.6
2010	CC		180	180		9,326	402	52	9,780	8,243	18.6
2011				0		9,326	402	52	9,780	8,322	17.5
2012	Repower Venice Units 3&4		262	262		9,588	402	52	10,042	8,402	19.5
2013				0		9,588	402	52	10,042	8,481	18.4
2014	CT		75	75		9,663	402	2	10,067	8,561	17.6
	End 50 MW Purchase				(50)						

Table 6-7

**Preferred Resource Plan**  
**Greener Environmental Mitigation Level - Controls On New Units**

YEAR	UNIT	RESOURCE ADDITION (REDUCTION)				UE CAPACITY MW	EEINC PURCHASE MW	PURCHASE (SALE) MW	ADJUSTED CAPACITY MW	ADJUSTED DEMAND MW	RESERVE %
		UE CAPACITY			PUR MW						
		DSM MW	SUP MW	Total MW							
1995	Venice Restaffing		92	92		7,825	405	155	8,385	7,143	17.4
1996				0		7,825	405	155	8,385	7,199	16.5
1997	DSM, SX Improvement	44	16	60		7,885	405	155	8,445	7,268	16.2
1998	DSM, CIPS Purchase	22		22	150	7,907	405	240	8,552	7,288	17.3
1999	DSM, Keokuk Generator Rewind	22	20	42		7,949	405	235	8,589	7,367	16.6
2000	DSM, Taum Sauk Runners Renewables 50 MW Purchase	45	80	125	2 50	8,074	405	362	8,841	7,447	18.7
2001	DSM, CT	23	75	98		8,172	405	362	8,939	7,527	18.8
2002	DSM, CT Extend AP&L Purchase	23	75	98	—	8,270	405	362	9,037	7,606	18.8
2003	DSM, CT	22	75	97		8,367	405	362	9,134	7,686	18.8
2004	DSM, CT	23	75	98		8,465	405	362	9,232	7,765	18.9
2005	DSM, CT-3 End CIPS Purchase	22	225	247	(150)	8,712	405	212	9,329	7,845	18.9
2006	DSM, CT	22	75	97		8,809	405	212	9,426	7,925	18.9
2007	CT		75	75		8,884	405	212	9,501	8,004	18.7
2008	Repower Venice Units 5&6 End AP&L Purchase Additional Joppa Energy		248	88	(160) —	9,132	405	52	9,589	8,084	18.6
2009	CT		75	75		9,207	405	52	9,664	8,163	18.4
2010	Repower Venice Units 3&4		262	262		9,469	405	52	9,926	8,243	20.4
2011				0		9,469	405	52	9,926	8,322	19.3
2012				0		9,469	405	52	9,926	8,402	18.1
2013	CC		180	180		9,649	405	52	10,106	8,481	19.2
2014	CT End 50-MW Purchase		75	75	(50)	9,724	405	2	10,131	8,561	18.3

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**CLEAN AIR ACT COMPLIANCE REVIEW**  
**SECTION 7**

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**7.1 SULFUR DIOXIDE – SO<sub>2</sub>**

In February, 1992, the Company completed its first comprehensive review of alternative strategies for complying with the Clean Air Act Amendments of 1990. That review recommended that the Company initially switch to low sulfur fuel. This provides the flexibility to install scrubbers or other control technologies in the future, if warranted. Four key uncertainties which could impact the compliance strategy were identified. They include:

- Scrubber cost
- Fuel price differential between Illinois and PRB coal
- SO<sub>2</sub> emission credit value
- Derate level, if any, from operating units on PRB coal

The review outlined the magnitude of change to the first three uncertain variables which would be necessary before the recommended strategy would change. The fourth uncertainty — derate level from operating units on PRB coal — provided an advantage to the scrub strategies in the 1992 review. A 400 MW system derate was assumed based on initial coal test burn results — 50 MW per unit for the eight units at Labadie, Rush Island, and Sioux when operating on 100% PRB coal. Any reduction in the derate level when operating on 100% PRB coal from that used in the review would increase the savings identified for the fuel switch strategy.

The 1992 review also recommended that the assumptions used in the analysis be reexamined periodically to identify any significant changes which would require a new review to determine whether the Company's preferred compliance strategy

should be changed. The Company reviewed the planning assumptions included in the February 1992 review for both the July 1992 and December 1993 ERPs and for the development of this ERP.

The unit deratings assumed in the initial study amounted to approximately 400 MW when operating on 100% PRB coal. Work performed since that time and current operation, maintenance, and construction budgets reflect plans for plant investments and major projects that address the unit deratings. While the long-term impacts of PRB coal on unit capability, availability and efficiency are not known at this time, scheduled plant modifications and operating strategies are expected to eliminate the deratings while maximizing use of PRB coal.

Estimates for scrubber retrofits at the Company's existing facilities have not changed from those used in the 1992 study, other than for inflation.

The initial study assumed a fuel premium for PRB coal over Illinois coal of approximately 10¢/MMBtu in the year 2000. The expected fuel price differential is now projected to be lower than this value. It also assumed a value for Phase II SO<sub>2</sub> credits of approximately \$625/ton in the year 1995 (1993 dollar's) escalating at 5¼% per year. The estimate used for developing this ERP was \$150/ton in 1995, escalating at 4% per year. As discussed in Section 1, information from the SO<sub>2</sub> allowance auction held by the EPA in March, 1995 and from recent activity in the allowance market indicates a 1995 allowance price on the order of \$132/ton in 1995 nominal dollars, escalating at a rate slightly higher than the rate used in the development of this ERP.

Current assumptions all favor the Company's original fuel switch strategy. Union Electric will continue to monitor the SO<sub>2</sub> allowance market.

## 7.2 NITROGEN OXIDES – NO<sub>x</sub>

The Environmental Protection Agency (EPA) published final rules on NO<sub>x</sub> emissions in the March 22, 1994 Federal Register (Vol. 57, No. 228). As a result of these rules, the Company revised its NO<sub>x</sub> compliance strategy. This revised strategy is documented in a July 1994 report entitled *NO<sub>x</sub> Compliance Strategy*.

The July 1994 report recommends a strategy which involves averaging system units for NO<sub>x</sub> compliance. Averaging will allow the company to minimize cost by only requiring controls on those units where it is most cost effective. Specifically, the study recommends:

- Installation of low NO<sub>x</sub> burners at Labadie, Rush Island and Meramec 3 and 4.
- Substituting the two Rush Island units, and four Meramec units in 1995 and 1996. Investigate continued substitution at these units in 1997, 1998 and 1999 when Phase II NO<sub>x</sub> limits are established.
- Avoiding expensive options at Sioux and Meramec 1&2 by utilizing more cost effective options at other units.
- Avoiding additional controls at Venice, existing combustion turbines and diesels.

The U. S. Court of Appeals for the District of Columbia vacated Section 407 of the EPA NO<sub>x</sub> rules on November 29, 1994. The major reason for vacating the EPA rule was the definition of low NO<sub>x</sub> burners. Although a change in definition may raise the

NO<sub>x</sub> requirements for Phase II units from the values that might have been determined using the original definition, the overall impact on the Company's July, 1992 strategy is not believed to be significant — other than to change the initial compliance date. An agreement was reached on a direct final EPA rule on March 28, 1995. This direct final rule establishes a compliance date of January 1, 1996 for Phase I units and defines low NO<sub>x</sub> burner technology as "burners only."

Further changes in rules and additional regulations could require modifications to the recommended plan. Maintaining options and flexibility are important characteristics of the Company's preferred NO<sub>x</sub> strategy as the key uncertainties are resolved over the next several years. The flexible strategy outlined above is designed to address potential regulatory changes in a least cost manner.

## 7.3 TITLE III – AIR TOXICS

Air toxic regulations are still in the formative stages and are addressed in detail in the IRA report and its appendices. The Company considered potential impacts of possible future regulations on existing and future generation requirements in the development of this ERP. The Company will follow developments in this area closely to further address potential impacts on existing and future generation.

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**PLAN SELECTION AND IMPLEMENTATION**  
**SECTION 8**

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**8.1 PLAN SUMMARY**

The Company's preferred resource plan (see Table 6-7) involves low cost, incremental capacity additions that can be adapted to changing conditions. Demand-side and supply-side options have been selected so as to minimize future revenue requirements. The Company has contracted for the purchase of 150 MW from Central Illinois Public Service Co. for the period 1998 to 2004 and the Sioux capacity restoration is currently planned for 1997. DSM implementation is planned to commence in 1997 and continue to grow into the early 2000's. The actions should allow the Company to delay the need for supply-side additions until 2001. The Keokuk generator rewind project depends on future 25 Hz generation requirements. The IELP contract expires on December 31, 1998. Prior to that date the company will determine if there is a market for 25 Hz generation and whether these generators should be rewound.

Additional peaking resources, including a 80 MW improvement at Taum Sauk, several new CTs, and additional DSM are required during the period 2003 to 2014. Repowering of Venice Units 5&6 is planned in 2008. Venice Units 3&4 are planned to be repowered in 2010. One combined cycle unit is planned for 2013. A decision to proceed with CTs, at an existing site, is expected to require two years lead time. Thus, under expected conditions, a decision would not be required until 1999 for the first CT installation. Repowering Venice Units 5&6 requires a decision by 2004, based upon a lead time of four years for that project.

The Company investigated each plan's potential impact on the environment using scenario and risk analysis. Since the preferred plan described in Section 6 relies on cost effective DSM programs and relatively low environmental impact resources — oil and/or natural gas-fired CTs and combined cycle units — it is also preferred when environmental impacts are considered. Thus, this plan is robust across most of the planning assumptions used in this study.

The financing requirements for resources included in the preferred resource plan should not have a significant impact on the Company. This assumes that reasonable rate treatment for both supply-side and demand-side resources will be provided.

Construction expenditures for the new resources included in the plan are expected to average approximately \$120 million per year over the planning period with no one year exceeding \$250 million. This relatively smooth pattern of expenditures is due to the phased installation of demand-side programs, the relatively short construction time for the supply-side facilities and the magnitude of the capital investment required for 75 MW combustion turbines and 180 MW combined cycle units.

Table 8-1 compares the preferred resource plan with the plan that would be preferred if probable environmental costs were not considered. This table shows that the need for the first combustion turbine is advanced one year by the preferred resource plan. Although the timing of unit additions differs between the two plans, they both include the same resource additions over the twenty year planning horizon — except for

one additional combustion turbine in the preferred resource plan.

If the units in the preferred resource plan were all acquired with the controls necessary to meet the increased environmental mitigation requirements assumed in the development of the plan, the additional equipment costs would result in a 30 year 1995 PVRR of \$61.5 million over the equipment costs for a plan based on existing environmental requirements. The 30 year PVRR includes the 20 years of the planning horizon and the additional 10 years used to account for end effects. This is the expected amount that would be required to provide for the uncertainties of future environmental regulation. It only accounts for added control equipment expenditures.

The likelihood of changes in environmental regulations will be assessed prior to each future unit commitment. The \$61.5 million PVRR calculated in this plan as the cost to insure against an uncertain environmental future, assumes that all future unit purchases will be made without additional information.

The preferred resource plan is somewhat insensitive to assumptions on probable environmental costs due to its reliance on combustion turbines and combined cycle units operating on natural gas. If the Company needed base type capacity at this time, instead of peaking and intermediate capacity, probable environmental costs would have had a greater impact on resource selection.

The average system rates (as calculated by MIDAS) for the preferred resource plan increase at approximately 63% of the inflation rate used in the analysis. This value increases to about 67% of the inflation rate when probable environmental costs are considered. Thus, in real terms, electric

rates are expected to decrease over the planning horizon. This moderate growth in nominal average system rates should not have an adverse impact on utility customers.

## 8.2 IMPLEMENTATION RESPONSIBILITIES

The following departments are responsible for performing the detailed work of planning, scheduling, and implementing projects associated with acquiring resources once they are included in an ERP.

**Resource Planning** – Design and analyze demand-side programs, forecast customer energy and peak demand requirements, plan future resource additions.

**Transmission Planning** – Plan and schedule major transmission, subtransmission and major substation facilities.

**E&C Electrical Engineering** – Schedule, design, and procure transmission and substation facilities.

**E&C Mechanical Engineering** – Plan, schedule, design, and procure new generation facilities and improvements and modifications to existing generation facilities.

**E&C Construction & Services** – Manage outside construction labor and provide drafting and clerical support services.

**Power Plant Maintenance and Engineering** – Plan and schedule improvements and modifications to existing facilities. These projects are generally smaller in scope than projects carried out by the Mechanical Engineering Department.

**Fossil Fuel** – Procure fossil fuels, other than natural gas, for Company facilities.

**Nuclear Licensing & Fuels** – Procure Callaway Plant nuclear fuel.

**Environmental Services** – Conduct environmental impact studies and obtain

permits for continued operation of existing facilities as well as new facilities.

**Energy Services** – Evaluate and acquire long-term purchased power. Procure Natural gas for Company facilities.

**Division Marketing** – Perform market research, program design, schedule, and implement demand-side management programs.

**Distribution Engineering** – Implement loss reductions on the distribution system if cost justified.

The responsible departments are charged with reviewing the parameters used in the development of the ERP for their specific areas and notifying Corporate Planning if any parameter changes would warrant an early plan review.

### 8.3 DEMAND-SIDE IMPLEMENTATION

Over the past few years, UE has made considerable progress in building the capability to evaluate demand-side resources. The Company has implemented several pilot programs in addition to conducting market and end use research.

This ERP has identified several new, potentially cost-effective, opportunities. These opportunities will be carefully evaluated by using pilot programs to test their effectiveness. Critical uncertainties include customer response, load impacts, and costs to manage and verify demand-side resources. UE expects the pilot phase of demand-side resource development to extend at least through the end of 1996.

Programs will be expanded to larger scales over time as they are determined to be cost-effective and the mechanisms necessary for effective implementation, management and evaluation are in place. For planning purposes, the Company has assumed that full-scale implementation of cost-effective

programs will occur in 1997. Actual full-scale implementation of individual programs could occur before or after this date depending on the progress of capability building and the need for additional resources.

The following is a discussion of the major activities UE has recently completed, or is currently undertaking, to build its capability to implement cost-effective demand-side resources.

#### Pilot Programs

##### "Cold Cash"

This program offered residential customers a free removal and recycling service for old, inefficient refrigerators and freezers. In addition, a \$50 savings bond was provided as an added incentive. Program evaluation suggests that the savings bond is unnecessary and that free riders need to be minimized if the program is to be cost-effective. The program design used in this ERP reflects the experience gained by the Company through "Cold Cash." The pilot results were used in the screening analysis of the Residential Refrigerator and Freezer Removal programs.

##### In Concert With The Environment®

The goal of *In Concert* is to provide cost-effective demand-side management through education. The program uses an energy survey to educate high school students and their families about household energy usage. In addition to teaching the importance of efficiency and environmental awareness, the program provides customers with a bill disaggregation and customized recommendations for a variety of energy efficiency measures. The program has reached thousands of students across numerous school districts over the past three

years. Process evaluation and impact evaluation are currently underway. The pilot is testing the assumptions used in the screening of the Residential Water Heater and Lighting Measures, Building Shell Measures, and Setback Thermostats - Gas Heating Customers programs.

#### "No Sweat" Residential Energy Management Program

During the summers of 1993-94, residential customers received bill credits in return for allowing UE to cycle their air conditioners during peak times. Additional participation is being solicited in 1995; the final year of the pilot. Program evaluation will include a detailed analysis of load impacts, free riders, and reasons for participation. Preliminary data suggests that customers have not experienced significant discomfort during cycling periods and continuous financial incentives may not be required for prolonged participation, which could help the program become cost-effective. The pilot is testing the assumptions used in the screening of the Residential Central Air Conditioner/Heat Pump Cycling program.

#### "Green Key"

Through this pilot program, UE will investigate the cost-effectiveness of providing builder reimbursement to encourage the installation of specified energy efficiency measures in the residential new construction market. The reimbursement will be equal to the incremental cost of the specified energy efficiency measures for electrically heated homes. These measures include higher levels of ceiling insulation, low emissivity windows, basement wall insulation, programmable thermostats (single-family only), duct sealing, and building sealing to reduce air infiltration.

The program will involve up to 500 units in the UE Missouri territory, with 100 units being targeted for low income housing. The pilot is scheduled to begin upon Missouri Public Service Commission approval of tariffs. The pilot will test the assumptions used in the screening of the Residential New Construction Building Shell Measures program.

#### Energy Savings Partnership Program

This pilot program was implemented in August 1993. The program is intended to reduce the energy and/or demand requirements of existing commercial buildings and to provide insight into the energy use and technical service needs of the customer. The program design calls for the Company to provide a variety of technical and administrative services to encourage commercial customers to implement electric efficiency measures. Examples include lighting retrofits, more efficient HVAC equipment and energy management systems. In addition, the Company may provide loans to customers who qualify for such services. Several audits are currently under way. The pilot is testing the assumptions used in the screening of the Commercial Audits programs — Level I - Walk Through Audit, Level IIA - Engineering Study Lighting Emphasis, and Level IIB - Comprehensive Building Modeling.

#### "MotorMiser" Information Campaign

Begun in mid-1993, this program encourages industrial customers to install high efficiency motors when they replace failed or existing motors. The program uses informational brochures and software to assist the customer with motor purchases. Interested customers will be given assistance in analyzing the economics and application of high efficiency motors and drives.

Preliminary information suggests that the program has successfully influenced customers to avoid making motor purchase decisions solely on initial cost. The program also offers a free on-site efficiency evaluation of selected motor applications for those customers having qualified demand/energy reduction opportunities. The pilot is testing the assumptions used in the screening of the Industrial MotorMaster Software and MotorMiser Audit programs.

#### Customized Industrial Process Audits

This pilot program began in the summer of 1993. Its purpose is to encourage industrial customers to make process-oriented efficiency and demand control improvements. Industrial customers are being offered the opportunity to have their production processes evaluated by a nationally recognized expert in their specific industrial field. Recommendations have included: replacing existing electric motors with high efficiency motors or adjustable speed drives, improving compressed air and refrigeration systems, installing heat recovery systems, insulating energy intensive processes, and deploying energy-saving technologies. Recommendations on how to best use existing curtailable and off-peak power rates are also provided. The pilot is testing the assumptions used in the screening of the Industrial Customized Process Audit program.

#### Demand and Energy Control Information Program

This pilot program was kicked off with an informational seminar in February of 1995. The purpose of the program is to encourage industries to install demand and energy monitoring equipment at their plants. The program supplies each participant with: their load profile, strategies and reasons for

monitoring their electric usage, local energy control successes, and an opportunity to view currently commercially available equipment. Trade allies would be relied on to deliver the program to the greatest extent possible.

The pilot is testing the assumptions used in the screening of the Industrial Demand & Energy Control Information program.

#### "Rider G" Curtailable Power Pilot Project

This pilot program was fielded in Union Electric's Missouri service territories in September of 1994. The purpose of the program is to encourage larger customers to curtail demand during periods of system stress. The pilot provides a performance-based bill credit to participants who curtail demand during requested periods. The pilot is available to customers with curtailable loads as low as 1,000 kW and allows some compliance flexibility.

This pilot will test the assumptions used in the screening of the Standby Generation/Curtailable Power Rate program.

#### Small Commercial Walk Through Audit

This program would provide small commercial establishments an expert auditor who would enter information on sources of energy use into a computer. When the analysis was complete, the customer would receive a disaggregation of past energy use by end use and recommendations for improvement, including simple payback analysis. The audit recommendations would be expected to primarily address lighting measures. The audit would be provided at a small fee to participating customers (well below the actual cost of the audit). A list of contractors and institutions providing installations and financing would be made available at no charge. A pilot is scheduled to begin during 1995. This pilot will test the

assumptions used in the screening of the Small Commercial Do-it-Yourself Audit and Walk-Thru Audit programs.

### **End-Use and Market Research Projects**

#### Commercial End Use Research

This project included on-site surveys of 800 commercial buildings throughout the UE service area. As a result, hourly end-use load profiles for 32 commercial building prototypes have been developed. This database was used in the commercial sector load forecast, as well as in demand-side resource analysis. Data from the project has also been provided to Missouri and Illinois state agencies studying the economics of improved building codes.

#### Industrial Market Research Project

In order to better position industrial DSM programs to meet customer needs, UE conducted a survey of its larger industrial customers in 1993. A total of 122 large industrial customers were surveyed.

The survey found that:

- Barriers to energy-efficiency vary with the industrial segment. Major barriers include first cost and lack of personnel and time.
- Industries are most concerned with increasing productivity and product quality and are not overly concerned about fuel costs when making equipment purchases.
- Industries need relatively quick paybacks to perform energy-efficiency improvements (<2 years).
- The majority of those industries surveyed were interested in participating in Union Electric's Industrial Process Audit and MotorMiser pilot programs.

The study suggests that industries are interested in energy-efficiency as it pertains to increased productivity, quality, or environmental compliance. This finding strengthens Union Electric's belief that energy-efficiency should be marketed to manufacturers as a part of process improvements.

#### 1993 Residential Market Segmentation Study

The objective of this research was to investigate residential customers' attitudes toward energy usage, conservation, and efficiency. The data was acquired using geodemographic techniques so that the Company could better target its marketing of energy-efficiency messages and programs. Some of the findings were that:

- Customer attitudes toward conservation are not strong predictors of their likelihood to take such actions.
- UE conservation efforts need not exceed the customers' own level of effort in order to achieve high favorability and loyalty ratings.
- Customer attitudes toward Union Electric and their conservation efforts do not appear to be a function of demographics.

The study's findings will impact how Union Electric communicates and delivers efficiency programs to residential customers.

#### Residential End-Use Research

This project included on-site surveys of 511 residential homes throughout the UE service area. As a result, hourly end-use load profiles for 15 residential building prototypes have been developed. The load and energy impacts of 29 demand-side measures were also evaluated. This database was used in the residential sector load

forecast, as well as the demand-side resource analysis.

### Future Programs

The Energy Resource Plan has identified several potential demand-side resources that need further evaluation over the next few years. Potential pilot programs in the residential sector include a low income program and a new construction program. A pilot program is needed in the commercial sector to address thermal storage. Potential pilots in the industrial sector include a more detailed analysis of rate incentives for dispatchable standby generation and an investigation into the economics of providing real-time load information to customers for load management and process control.

### 8.4 SUPPLY-SIDE IMPLEMENTATION

The first year the UE system is expected to need new supply-side capacity based on the preferred resource plan is 2001. CT installation requires a minimum of two years advance notice for an existing site. Thus, this decision would not be required until 1999. However, under the high load growth scenario the need for new peaking capacity is advanced to 1999, based on planning assumptions for that scenario.

Recognizing the possible need to install future CTs on short notice, the Company has taken steps to assure minimum lead time.

A CT site selection study which was completed in 1990 was updated in 1992. The study identified the Meramec plant as the best site for the next CT, and sites at two other Company owned substations as locations for subsequent CTs. In addition to site selection, work on identifying key issues which affect CT procurement and engineering has also been completed. This advance work will help reduce CT lead time. Although a lead time greater than two years

would be required for a new site, it could be shortened by obtaining a *de minimis* permit, as allowed for in Missouri 10 CSR-6.060, and then pursuing full environmental permitting during unit installation. The risk involved in pursuing this option would not be taken unless absolutely necessary to provide for system reliability. The availability of interchange power in the Midwest makes this an unlikely event.

The lead time for installation of evaporative cooling or thermal storage equipment on existing CTs is approximately one year. These options may provide 22 to 65 MW of the Company's new CT requirement. These technologies will continue to be reviewed in order to obtain better operating and cost data.

The Keokuk rewind project requires about three years to implement. This includes one year for preliminary design work and two years for generator procurement and installation.

The Taum Sauk runner replacement project requires approximately three years lead time, two years for runner procurement and one year for construction. The model testing and preliminary engineering work required prior to runner procurement is expected to take one year and is included in the current budget. A decision to proceed with this project is needed in May, 1997.

Intermediate and base type capacity decisions are not required until approximately 2004. As part of the Company's normal planning process, the load forecast and capacity addition needs are reviewed annually.

New resource options will continue to be evaluated as information becomes available. In addition, the Company's current efforts to assess the viability of wind resources in the UE service area will continue.

## **64 Plan Selection and Implementation**

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The Company will consider competitively bidding future supply-side resources prior to making a unit commitment.

The preferred resource plan is shown in Table 6-7.

**Table 8-1**  
**Comparison**  
**Preferred Resource Plan**  
**and**

**DSM-20 Plan W/O Probable Environmental Costs**

Year	Preferred Resource Plan DSM 20	Plan Without Probable Environmental Costs DSM 20
1995		
1996		
1997	Sioux Improvement	Sioux Improvement
1998	CIPS PP	CIPS PP
1999	KGR	KGR
2000	Taum Sauk 50 MW PP	50 MW PP
2001	1 CT	Taum Sauk
2002	Extend AP&L 1 CT	Extend AP&L 1 CT
2003	1 CT	1 CT
2004	1 CT	1 CT
2005	3 CT	3 CT
2006	1 CT	1 CT
2007	1 CT	1 CT
2008	Repower V5&6 Extra Joppa	Extra Joppa Repower Ven 5&6
2009	1 CT	1 CT
2010	Repower Ven 3&4	Repower Ven 3&4
2011		
2012		1 CT
2013	1 CC	1 CC
2014	1 CT	
CT (MW)	825	750
CC (MW)	180	180
Repower (MW)	510	528
Upgrades (MW)	116	116
Total - Supply (MW)	1631	1574
DSM ( MW)	268	268
Total (MW)	1899	1842
Environmental Cost Premium 20 Yr + 10 Yr Ext. PVRR (Million)	\$61.5	Base

Sioux

CIPS PP

KGR

50 MW PP

Repower V3&amp;4

Repower V5&amp;6

Extra Joppa

Extend AP&amp;L

TS

DSM

Sioux 16 MW Improvement

CIPS 150 MW Power Purchase

Keokuk Generator Rewind - 20 MW Capacity Equivalence

50 MW Intermediate Power Purchase

Repower Venice Units 3 &amp; 4

Repower Venice Units 5 &amp; 6

Increased Utilization Of Joppa Energy

Extend The Present Purchase Contract With AP&amp;L As Provided For In The Contract

Taum Sauk Runner Replacement - 80 MW

Demand-Side Management Capacity Equivalence