FEDERAL ENERGY REGULATORY COMMISSION'S DEMAND RESPONSE TECHNICAL CONFERENCE JANUARY 25, 2006

REGIONAL PERSPECTIVE PANEL

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➢ GENERAL INFO AND DISCLAIMERS

- MoPSC regulates 4 investor-owned utilities ("IOUs") - AmerenUE, Kansas City Power & Light ("KCPL"), Aquila-MPS & L&P, Empire Electric
- Regions of participation include:
  - Midwest ISO ("MISO" - AmerenUE)
  - Southwest Power Pool ("SPP" - KCPL & Empire)
- Did not survey utilities in MISO nor SPP regions, rather these comments are based upon Missouri's experience.

➢ HIGHLIGHTS

- While time-of-use ("TOU") rate designs (such as inverted block, seasonal or time-of-day rates) can alter energy usage somewhat without significant investment in metering equipment:
  - *Demand Response Programs* are not aimed at overall reduction in energy use, but rather at having customers move their usage from an on-peak to an off-peak period. This requires some form of Dynamic Pricing such as offering customer incentives for reducing demands during Critical Peak Pricing periods.
  - TOU rates alone have not proven to be an effective means for moving usage from on-peak to off-peak periods.
  - Since *Energy Efficiency Programs* are aimed at reducing energy use on a year-around basis, those programs do generally result in some reduction in demand during on-peak periods.
- To be effective, demand response must provide a way for bundled retail load to respond to wholesale price signals without being exposed to the high costs and volatility that exist in the wholesale spot-market.
- For small customers (residential and small commercial and industrial), the programs must be simple to understand & easy to implement (likely to require automation) and they must be properly compensated for actually reducing their demand.
- While interruptible rates for large industrial customers currently provide the largest demand response, this demand response is limited to those customers who can afford to be interrupted.

I. WHAT IS THE STATUS OF DEMAND RESPONSE PROGRAMS AND TIME-BASED RATES IN YOUR REGION?

Missouri has not "restructured" and there is no movement to do so. We have some of the lowest residential and commercial rates in the country. Missouri consumers have grown accustomed to cheap electricity and many of them are very resistant to conservation efforts.

A. **Time-of-Use ("TOU") Pricing** whereby electricity prices are set for a specific time period on an advanced or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

1. **Seasonal Rates** - All 4 Missouri IOUs have seasonal rates, i.e. higher in the summer (June-Sept)
   - Street and outdoor lighting services do not have seasonal rates

2. **Optional Time-of-Day ("TOD") Rates -** All 4 Missouri IOUs offer optional time-of-day rates with higher rates on peak and lower rates off peak to all of their customers. Larger non-residential customers typically have 3 rates (on-peak, shoulder, off-peak).
   - **There has been very little interest.**
     - AmerenUE, our largest IOU, has only 40 out of more than 1,000,000 residential customers currently served under TOD rates
     - Non-residential – less than 1% participation
     - Large non-residential – 5% participation
   - **The current slim differential between on-peak and off-peak rates (because of current low generation costs) does not justify customers choosing these programs.**

3. **Mandatory Time-of-Day Rates -** Only one of our small systems (Aquila-L&P) has this for Large Power Service.
   - Has been effective since it is mandatory.
     - <u>Note</u>: Since we do not have "retail choice" in Missouri, this Commission is still able to "mandate" certain programs or rate design.
     - However, wide-spread implementation of mandatory cost-based TOU energy rates may not be cost effective because of current low generation costs and the slim differential between on-peak and off-peak rates.

While AMR arguably provides the potential for widespread application of TOU programs, there is concern regarding:

- **cost** (need for additional investment in communication and data storage equipment for "mass market" programs),
- **reliability** (need more consistent and reliable communication between meter and network on a sub-hourly basis), and
- **accuracy** (problems with estimation routines to fill data gaps and reflect change in customer behavior) of the system for the accumulation of hourly data for numerous customers.

Studies from the 70-80's (discussed in *The Electricity Journal*, July 2002), showed that:

- better demand response results from TOU rates came from households having more and larger electric appliances
- price responsiveness was found to be significantly less for small and medium C&I customers than for residential customers.

Several studies during the 90's have shown **"dynamic" pricing (critical or real-time pricing), when combined with enabling technology, can produce much larger reductions in peak demand than traditional TOU rates**. For example, devices on major appliances are programmed to modify usage when prices exceed a certain level. (*The Electricity Journal*, July 2002.)

B. Critical Peak Pricing ("CPP") whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption.
Note: the timing and/or the price are not known until "day before."

1. **Time-of-Day Rates with Critical Peak Pricing –** AmerenUE had a 2 summer (6/04 thru 9/05) small-scale pilot/test program to determine the effectiveness of day-ahead notification of residential customers of a Critical Peak Pricing Period and the benefits of using a "smart" thermostat in conjunction with the program.

   - Residential customers with the largest power use were recruited into 3 pilot groups:

     (1) "TOU Only" – 3-part rate, ie. on-peak (4 hrs), shoulder and off-peak pricing. This group was discontinued after the 1st year b/c the TOU rate alone did not appear to motivate customers to shift load from the on-peak to off-peak or mid-peak periods.

     (2) "CPP" – critical peak pricing applied for a total of 10-days during the summer when forecasted temperature above 90°. Customer was allowed 1 day off if too many days in a row.

(3) "CPP-Thermostat" – same as CPP but with pre-programmed thermostat

- The pilot started with 280 high usage residential customers; in April'05 there were 217 customers still participating, 77 of whom were in the TOU Only group and were returned to the standard rate when this group was discontinued. An additional 120 customers were recruited into the remaining two pilot groups, for a total 260 participants. At the end of the pilot, 233 customers were still participating.

- Incentive payments of up to $100 and $50 were given to the customers in 2004 and 2005, respectively, for their participation in the pilot. The CPP-Thermostat group participants were also given programmable thermostats with a value of $190.

C. Real-Time Pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly.
<u>Note</u>: the time periods, timing, and the price are variable.

1. **Real Time Pricing -** Hourly day-ahead prices are transmitted to large non-residential customers (i.e., large industrial and commercial customers) based on expected load and market conditions. These prices apply to increases and decreases in a customer's load relative to the customer's baseline load.
   - Only two IOUs have (Aquila-MPS & KCPL)
     - Initially popular with customers, but now have fewer participants
     - Concerned that costs are greater than value provided to customers
     - **Minimal evidence of customers changing behavior at current cost level**s
   - Empire and AmerenUE – No customers/**insufficient interest** by larger non-residential customers

D. Load Management - Credits for consumers who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

1. **Interruptible/Curtailable Rates for large customers are the most effective demand response tool used by Missouri utilities.** Customers are paid to reduce load during the highest cost hours of the summer. All four Missouri IOUs offer some form of interruptible/curtailable rates to large customers.
   - **Voluntary programs** where the customer is offered a price per kWh to reduce its load during the curtailment period, and the customer may either accept or reject the offer. (AmerenUE, Aquila-MPS, Aquila-L&P)
     - From 1983-2000, AmerenUE's calls for interruption were primarily driven by the Company's system load conditions as opposed to economic (power price) conditions.
     - Since 2000, 20-25% of AmerenUE customers enrolled in curtailment programs have curtailed when requested.

- Well received by Aquila customers due to the non-mandatory aspect.
- Aquila has typically obtained the necessary load reduction when requested, even when only a few of the available customers chose to participate.

- **Mandatory programs** where the customer receives a credit per kW of curtailable demand and must reduce load whenever a curtailment is called. (Empire, KCPL)
  - KCPL requests participating customers curtail load for a max. of 8 hrs/day, but no more than 120 hrs/year or 25 days/year. A 4-hour curtailment notice is given. Currently 12 customers with 24 MW of load reduction are participating. Curtailments are called for operational and economic reasons.
  - Empire – requests participating customers to curtail demand for a max. of 6 hrs/day, but no more than 200 hrs/year. The request notice is provided at least 1 hr prior to demand reduction, and will occur when Empire anticipates new summer or winter peak demands to be set and/or energy prices are anticipated to exceed $100/MWh. Participants are provided credits on demand reduction based upon type of metering (substation, primary or secondary).

- **Hybrid programs** where the customer receives an "Option Premium Payment" per MW of curtailable demand and a $/MWh "Strike Price" payment for each MWh of load reduction. If the customer fails to reduce load to the agreed level when a curtailment is called, the customer must pay the Company the "Passthrough Market Price" for each MWh it uses in excess of the contracted level. (AmerenUE, Aquila-MPS & L&P)
  - AmerenUE customers can select from a menu of strike prices, number of days of curtailment/week and curtailment durations of 8 or 16 hrs/day. Min. curtailment required is 1,000 kW/hour. Was last utilized in 2000-2001 with 6 customers participating. Prevailing power market prices since that time have not warranted calling for curtailments.
  - Aquila says only a few customers on this schedule in the St. Joseph area. The rate was once fairly popular; however most customers left the program when the Company began calling for curtailments.

2. **Voluntary Air Conditioning Cycling for residential and small commercial customers** and other high-usage appliances, such as water heaters and swimming pool pumps---possibly offering some choice as to which ones will be cycled.

   - AmerenUE's Optional Residential Central Air Conditioner Cycling Program (1993-1997)
     - Company paid a limited number of residential customers for control of their air cooling equipment. This program was applicable to single-family homeowners allowing AmerenUE to control their air conditioning compressors or heat pumps during summer cooling periods.
     - Certain incentives, such as free diagnostic service of participant's A/C equipment, were utilized to encourage sign up.
     - Satisfactory participation rates, up to 27% of eligible customers
     - However, the cost/benefit analysis didn't justify continuing the program.
       - A better screening process would have eliminated households who turned the thermostat up during the day, or those with older, under-sized and

under-maintained units who quit the program after the first hot cycling day.

- KCPL's A/C Cycling (Energy Optimizer) Program
    - Residential and small commercial customers
    - Air conditioning load is reduced when KCP&L sends signal to thermostat
    - Temperature ramping and compressor cycling strategies, pre cooling
    - Use CellNet for evaluation and verification
    - Free thermostat, installation and replacement
    - No annual incentive
    - 14,400 installations by June 1, 2007

II. What have been the successes, challenges and barriers associated with demand response and time-based rates in your region?

A. Successes

1. Interruptible rates, when they're voluntary, work well for some sophisticated industrial and large commercial users.

2. Curtailment programs which are structured to provide individual customers some flexibility and choice.

3. Newer A/C cycling programs with programmable thermostats show some promise.

B. Barriers

1. Interruptible Rate Offerings

- **Few customers can afford to be interrupted – e.g. they may need to be up & running 24-7.**
  - Requires that electricity is major component of cost and labor is a minor component of cost.
  - Requires flexibility in manufacturing process to be able to curtail production.
  - Customers do not want to be curtailed more than 3 days in a row.
- **If customers cannot afford to be interrupted, then in order to take advantage of interruptible rates, customers must have expensive, back-up generation.**

2. Real-Time Pricing Tariffs

- **Lack of customer perception of options for demand reductions**
  - Customers don't think in terms of electricity use as an option, rather electricity use is viewed as a necessity.
  - Customers don't want to invest in the skills and devices needed to make demand response an option. The cost of using electricity has to be a major budget item before this investment is seen as cost effective.
- **Customers do not want to be exposed to real-time prices.**
  - Customers want the protection of a fixed price for electricity.
  - Customers are not used to making a calculation of what they are willing to pay in order to have the protection of a fixed electricity price.
- **Utilities must be able to determine a customer's base-line use.**
  - The customer is not exposed to real-time prices for its base-line use, but the customer is paid/pays real-time prices for differences in actual usage that is below/above base-line use.
  - Determining base-line use can be a highly complex process for customers whose usage is affected by external forces that are not under their control (e.g., weather, economic conditions, major equipment outages, etc.)

3. Critical Peak Pricing

- **Customers' desire for saving money with relatively little effort.**
  - Customers do not want to dramatically change their home comfort level.
  - Customers' dissatisfaction from saving less than expected.

4. **Load Management**
   - **Some customers are concerned about rising temperatures within their homes**
     - If A/C units are sized properly, there will be little, if any, cycling on and off during peak hours of the hottest days. Thus, cycling imposed by the utility will result in some level of increased temperatures within the house.
   - **Some customers are concerned about giving up control of a major household appliance to the utility**
     - In order for A/C cycling to be an effective tool, the utility must have the ability to shut air conditioning units off for a period of time.
     - Part of the concern is with the reliability of the utility's control devices, where a failure may result in the air conditioner being shut down for a much longer period than expected.
     - Additionally, some customers have alleged premature failure of air conditioning unit as a result of frequent cycling.
   - **Complexity of programming device**
   - **In home installation requires customer to be home**

C. Major Challenges

1. **Customer Education** - It will be an incremental (long-term) process to convince customers that they should invest the time and effort needed to participate in demand response programs. If existing programs fail to meet the concerns of customers, it will be extremely difficult to get customers to consider even newly redesigned programs. This puts a high premium on **getting it right the first time**.

2. **Simplicity and ease for the customer vs. high cost of technology –** It is critical to the success of demand response programs for customers to understand their options and to be able to easily implement these options. For example, the new programmable thermostats have the following features:
   - New A/C load reduction strategies include pre-cooling, offering customers the opportunity to limit temperature drift.
   - The new programmable thermostat offers customer the opportunity to save energy all year long with the effective use of the programming feature.
   - The programmable thermostat also gives customer the opportunity to program and set their thermostat over the Internet.

   While devices such as programmable thermostats help to overcome customer barriers, the downside may be the high cost of such devices when compared to the benefits from associated demand savings.

3. **Utility Base-Line Use Determination -** In order to protect large use customers from real-time prices the utility must provide a reasonable estimate of base-line use. This determination can become complex when external factors (e.g., weather or economics) impact the base-line use. The greater the impact of external factors on a large customer's use, the more difficult it becomes to make a reasonable estimate of that use, and the less likely for the customer to be willing to participate in a demand response program.

4. **Design demand response programs that effectively address customers' needs and at the same time remain cost effective.** For example, large customers who potentially would take interruptible/curtailment services may express concerns about being interrupted several days in a row, the high cost they incur from having to interrupt their production processes, having their level of interrupted demands cut back to the actual level when they fail to fully interrupt, or the one size fits all nature of the interruptible program. In order to attract large use customers, demand response programs need to focus on specific concerns of large customers that are barriers to participation and add design elements to attract these customers, yet remain cost-effective.

III. WHAT IS THE ROLE OF DEMAND RESOURCES IN REGIONAL PLANNING AND TRANSMISSION EXPANSION PLANNING IN YOUR REGION? WHAT STEPS HAVE BEEN TAKEN TO INCORPORATE DEMAND RESOURCES INTO THESE PLANS?

A. Regions of participation include:

- Midwest ISO ("MISO" : AmerenUE)
- Southwest Power Pool ("SPP" : KCPL & Empire)

Therefore, regional planning for Missouri requires coordination between two RTOs, MISO and SPP. The highly interconnected rural electric cooperatives have not joined either RTO. Also, there are small pockets of municipal utilities all over the state. The good thing about this system is that we get to compare and contrast the different approaches of the two RTOs. More importantly, we're not dependent upon the proposals of any one RTO.

B. Regional Transmission Planning in MISO and SPP

Both the Midwest ISO and the Southwest Power Pool have regional planning that includes different planning tools for:

1) Reliability, involving peak load flow evaluations; and
2) Transmission congestion, involving estimates of production costs savings.

Demand response can be included in both types of evaluations.

For peak load flow evaluations, the demand reductions from demand response resources should be used at a reliability level demonstrated by the program. The primary question is the extent to which utilities can rely on these resources being available when called upon. Moreover, this is more of an issue with real-time pricing demand response, where the customer can decide not to respond by decreasing demand when prices are high.

In evaluation of production cost savings from reductions in transmission congestion, the primary issue is a cost-benefit evaluation of which projects provide a load-serving entity with the most cost-effective means of reducing congestion. In this context, demand response resources should be viewed as an alternative means of reducing production costs to the load-serving entity. In this context, the issue is one of comparing estimates of transmission expansion costs and production cost savings to the expected costs and benefits from demand response resources along with the uncertainties associated with these various alternatives.

C. Limited Role of Demand Response Resources in Resource Planning

It is Missouri's experience that without a requirement to include demand-side resources as a part of integrated resource planning, the tendency is for utilities to view resource planning primarily as an exercise in determining capacity additions that will meet a given level of demand at the minimum expected costs. Moreover, reduced usage of a product is not generally considered to be a goal for business, and developing expertise in this area is not seen as a valuable area of endeavor. If new demand response programs offer utilities the opportunity to meet customer demand requirements at a lower cost than the cost of generation, then there is an opportunity for demand response programs to become cost effective. Thus, it is prudent planning for utilities to become increasingly involved in demand response programs.

Aggregate of the Capacity and Load Forecasts of the Missouri IOU Electric Utilities

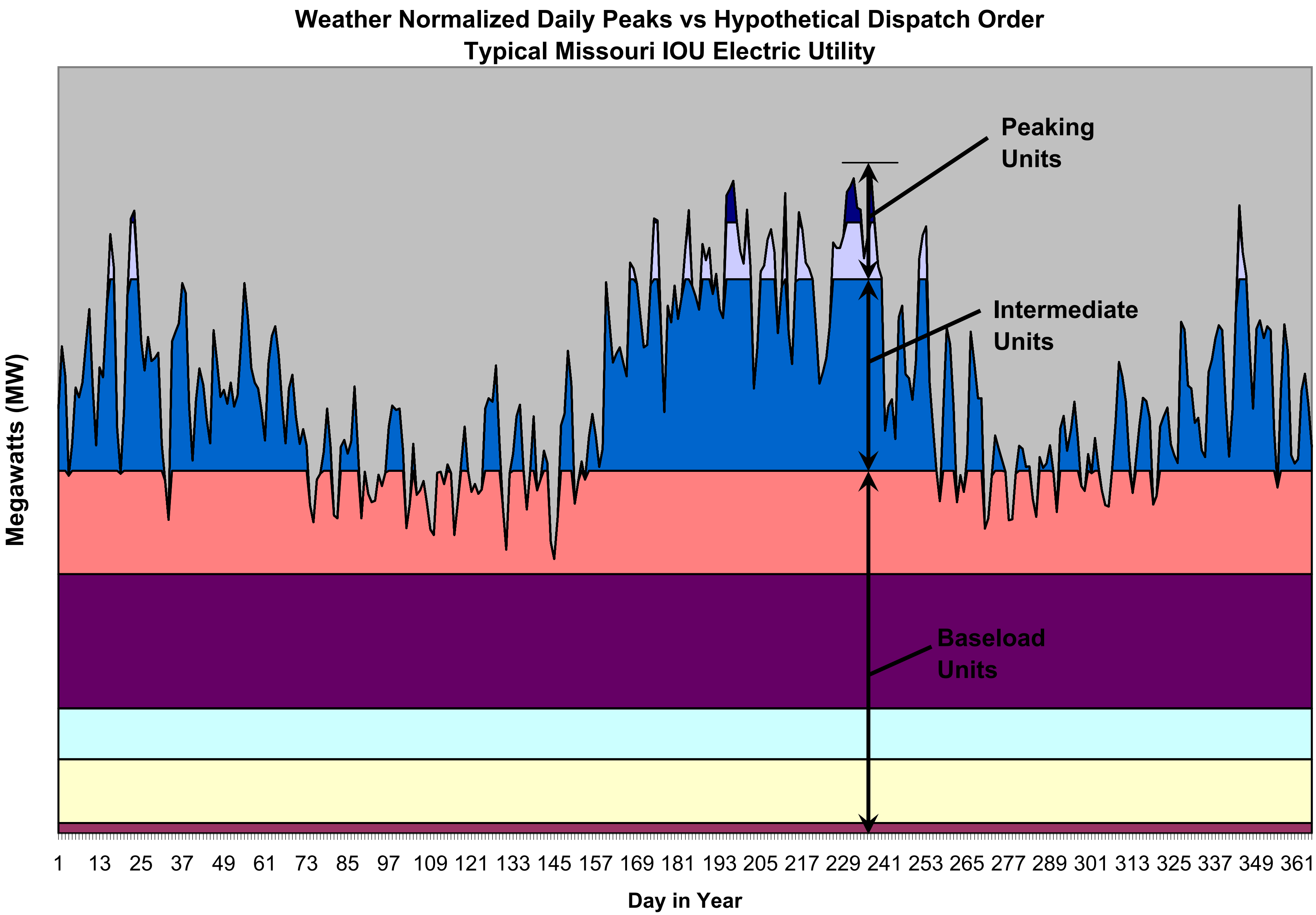
	2006	2007	2008	2009	2010
Existing Capacity					
Generation	16,056	16,240	16,249	16,249	16,949
Net Purchases	542	542	541	450	128
Capacity Available	**16,598**	**16,782**	**16,790**	**16,699**	**17,077**
Forecasted Peaks with DSM	14,973	15,225	15,492	15,613	15,839
Required Reserves	2,154	2,190	2,228	2,246	2,278
Capacity Required	**17,127**	**17,415**	**17,720**	**17,859**	**18,117**
Excess (Shortage) Capacity	**(529)**	**(633)**	**(930)**	**(1,160)**	**(1,040)**

Western Missouri

	2006	2007	2008	2009	2010
Existing Capacity					
Generation	6,895	7,061	7,070	7,070	7,770
Net Purchases	373	373	372	281	119
Capacity Available	**7,268**	**7,434**	**7,442**	**7,351**	**7,889**
Forecasted Peaks with DSM	6,577	6,736	6,910	7,070	7,203
Required Reserves	895	917	940	964	982
Capacity Required	**7,472**	**7,653**	**7,850**	**8,034**	**8,185**
Excess (Shortage) Capacity	**(204)**	**(219)**	**(408)**	**(683)**	**(296)**

Eastern Missouri

	2006	2007	2008	2009	2010
Existing Capacity					
Generation	9,161	9,179	9,179	9,179	9,179
Net Purchases	169	169	169	169	9
Capacity Available	**9,330**	**9,348**	**9,348**	**9,348**	**9,188**
Forecasted Peaks with DSM	8,396	8,489	8,582	8,543	8,636
Required Reserves	1,259	1,273	1,287	1,281	1,295
Capacity Required	**9,655**	**9,762**	**9,869**	**9,824**	**9,931**
Excess (Shortage) Capacity	**(325)**	**(414)**	**(521)**	**(476)**	**(743)**



Weather Normalized Daily Peaks vs Hypothetical Dispatch Order
Typical Missouri IOU Electric Utility
Peaking Units
Intermediate Units
Baseload Units
Megawatts (MW)
1 13 25 37 49 61 73 85 97 109 121 133 145 157 169 181 193 205 217 229 241 253 265 277 289 301 313 325 337 349 361
Day in Year