FORTNIGHTLY'S

SPARK

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Economic dispatch of electric generation will be a hot topic in 2006 thanks to the requirement by EPACT 2005 that FERC convene joint federal-state boards to figure out how to maximize efficient and money saving dispatch. Commissioner Nora Brownell already headed up one exploratory meeting with PJM/MISO to help flesh out the issues. But FERC has a long way to go.

Are you ready for the new breed of mobile asset management technologies available from vendors? Hart Levy, an expert at Indus International helps sort through the difficulties facing utilities and explains how to choose the right tools to manage the asset life-cycle.

Lori A. Burkhart
Editor

GENERATION EFFICIENCIES

The Delicate Balance of Economic Dispatch

By Lori A. Burkhart

Getting electricity from the generating plant to the end user is not easy. The vexing job of getting electric reliably where it is needed, while increasingly up to RTOs and ISOs, still involves numerous other players. And all of them are faced with rising fuel prices, making it even more important to try to move energy in a cost-effective manner.

That is why the Energy Policy Act of 2005 directs the U.S. Department of Energy (DOE) to issue a report and an annual report thereafter on economic dispatch of electric generation. It also requires FERC to convene joint federal-state boards not only to understand how dispatch works in various parts of the county, but also to examine what works, what barriers exist, and how to improve it.

On November 21, 2005, FERC commissioner Nora Mead Browenell presided over the first PJM/MISO joint board meeting on security constrained economic dispatch (SCED), noting a need to "wring all the efficiencies that we can out of the system." The meeting raised numerous issues requiring further exploration in order further to improve power plant dispatch in the U.S.

The ultimate goal of the meeting, which will be followed up by a series of four other meetings in February, is to make recommendations to Congress as to how to improve on economic dispatch of electricity. (A Jan. 6 announcement by FERC says it set two meetings on Feb. 12 for the South and PJM/MISO regions, and on Feb. 13 for the West and Northeast regions, *Docket No. AD05-13-000*.)

The Nov. 21 meeting started with the basics. Thanh Luong, a senior electrical engineer in FERC's Office of Electricity Delivery and Energy Reliability, set forth the definition of economic dispatch as provided for in EPACT 2005: "The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing »

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any operational limits of generation and transmission facilities." (*For more on SCED, see Box, What is SCED, p.6.*) Economic dispatch is referred to as "constrained" because it requires a further balancing of efficiency, reliability and other factors.

There are two types of economic dispatch. The "unit commitment" is made on the day-ahead, and then the actual "unit dispatch" is done in near real time. Security constrained generation unit commitment is based on factoring in of supply offers, load forecasts, and demand bids from market participants including non-utility generation units. Simultaneous consideration of both cost and reliability limits occur, which then produces hourly prices for the day ahead.

Although definitions and SCED methods make sense on paper, problems often occur in practice. Despite all the planning that goes into SCED, for example, load forecasts can change, generation can trip off, or transmission lines can fail.

To counter potential problems, plant dispatch usually is managed using SCED software, which runs every five minutes and considers both generation and transmission reliability limits simultaneously.

Pluses and Minuses

The November conference took aim at what is working with SCED and what needs improvement. Numerous issues were raised, and at this point, solutions offered are few, but are sure to come as the debate continues.

Some speakers pointed out that geographic size can be an important plus for SCED, which is a benefit of the large-sized RTOs and ISOs.

An example of when bigger is better for economic dispatch concerns time zones. For instance, an RTO operating in the Eastern and Midwestern time zones can take advantage of time differences and varying system peaks to help save money. So if the most expensive system peak is reached at 11 p.m. in the East, but it is 10 p.m. in the West, the dispatcher can send electricity back and forth across the zones, saving money by dispatching power based on the time difference.

James P. Torgerson, president and CEO of PJM points out in his testimony that one reason utility mergers are successful is they are able to increase the area of dispatch. "That is where significant savings come from, from economic dispatch over a broader area," he explains.

The potential down side of large geographic scope, however, is that the bigger footprint can increase the risk of the single point of failure. If the centralized economic dispatch fails, it makes more clear the need for a robust back-up software system.

Merit order of economic dispatch is another important consideration discussed at the meeting. Simply put, the most economic plants are expected to be dispatched first. When that doesn't happen, parties will complain that uneconomic plants are being dispatched out of the merit order queue. But numerous factors also go into deciding which plants are the most economic.

Merit-order issues also arise regarding protection of native load. FERC's Dave Meyer, with the Office of Electricity Delivery and Energy Reliability, says that of the comments reviewed by FERC so far in the proceeding, one of the principal issues

concerns assertions by non-utility generators (NUGs) that some vertically integrated utilities use dispatch to favor their own generation. He also notes that such favoring may not be done with malicious intent, but may in fact result from the operating rules and practices in place for economic dispatch.

"If the rules and practices have the effect of excluding non-utility generation capacity from what's called the economic dispatch stack—that is when you put these plants into merit order—the rules and practices used may either exclude capacity from that stack altogether or it may affect the position of a particular generation resource in the stack," Myer says.

Such practices or rules also include rules for determining whether NUGs receive long-term contracts for their output or for the use of transmission facilities. Myer explains they further affect whether NUGs provide sufficient operational flexibility to qualify for economic dispatch. Being able to qualify for economic dispatch means a plant has to be responsive to changing conditions, and some *(Cont. on p. 5)*

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TECHNOLOGY

Mobile Asset Management Makes its Mark

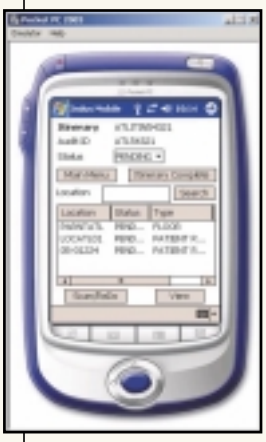
By Hart A. Levy

Utilities today face increasing challenges from customers' requirements, new and increasingly complex regulations, cost pressures, and the drive to continually increase operational excellence. In order to survive in this brave new world, utilities must revisit and rethink many of their existing business processes. In particular, critical areas such as customer service and asset maintenance and repair require significant change, and a new breed of solutions from technology vendors to empower this change. The days of paper-based communication and manual processes are over, and a new era of automation and wireless communication has arrived.

One area where this change is especially striking is in enterprise asset management (EAM). As populations grow and new business spring up in their service areas, utilities find themselves managing a burgeoning set of widely dispersed assets that often are associated with locations and customers. The growing trend of mergers and acquisitions places an added strain on utilities as they race to bring an even broader and more diverse multitude of plants and infrastructure within a common view. As a result, utilities are now looking for new EAM solutions that extend asset management and maintenance capabilities in order to help extend the life of the asset, as well as to increase the uptime and reliability of their infrastructure.

The Growing Role of Mobile Asset Tracking in Service Management

Utilities face unique challenges in managing their wealth of physical assets. Yet, like many other industries, they are confronted with the growing requirement to track and maintain mobile and dispersed assets, particularly in the transmission and distribution (T&D) environment. Assets such as meters, power lines and transformers—or pipes and valves—are largely dispersed across various physical locations, including customer premises. Replacement parts for these assets provide an additional element of complexity, as they must be tracked from premises to premises in the trucks of numerous field service technicians.



Utilities have a critical need to track these mobile and dispersed assets in order to:

- Comply with Sarbanes-Oxley and other industry regulations by maintaining a complete audit trail of assets.
- Increase customer loyalty and generate new revenue streams by transforming traditional service activities into integrated profit-making operations.
- Reduce costs by outsourcing non-core activities such as equipment maintenance and making service operations improvements.
- Extend best-practice maintenance approaches to assets dispersed outside normal organizational boundaries.

However, utilities have long struggled to adopt traditional work-management solutions precisely because their asset base includes numerous and diverse assets, much of which are not contained within the four walls of a plant or building. Managing assets that are so widely dispersed and frequently changed out for repair creates an intensive process to ensure that assets can be tracked. This struggle has come to the forefront for many utilities, because knowing exactly where assets are located —not to mention their status and maintenance history—is now required by new industry regulations and policies.

In order to meet these challenges, some utilities have turned to outsourcing the maintenance of infrastructure assets. This growing practice allows utilities quickly to scale resources while simultaneously reducing overhead, without disrupting or degrading key services to customers. However, outsourcing brings its own set of challenges. Outsourced service organizations require tools that enable them to analyze the reliability and performance of the assets they maintain. Similar to preventive and predictive maintenance approaches offered by traditional EAM software solutions such as Indus, solutions that analyze asset performance are a critical tool for these service providers. »

Some service offerings include entitlements, such as service calls and replacement parts for the assets these service providers maintain. These entitlements often are tied to service level agreements (SLAs) which require that service providers ensure assets maintain a certain level of uptime and/or performance. Therefore, in order to offer these services and remain profitable, these companies must closely track failure rates and causes against the assets. The ability to track performance and reliability of dispersed assets is not only important in meeting SLAs; it helps to set realistic SLA parameters in the first place. Therefore, understanding the life expectancy and reliability of an asset is an integral part of defining service coverage for the asset.

Know Thy Constituent(s)

One you have implemented a system that allows you to track the location of mobile assets, you are only part of the way there. As assets move from location to location, there will often be different permutations of asset owners, asset operators and asset service providers. Consequently, next-generation asset-tracking systems also need to allow the definition and association of multiple constituents.

Take for example a meter. As the asset owner, the utility essentially leases or loans the meter to a customer either on a home or a place of business. The home or business who uses the power that flows through the meter becomes the asset operator. When service is needed to repair or replace the meter, the utility may use an outsourced service provider to provide the repair service, making that company the service provider. Each of these constituents —owner, operator, and service provider —have activities, costs, and return on investment related to the asset. And, this information must be tracked, stored, and managed distinctly for each constituent based on their individual business and security needs. For this requirement to be met efficiently, any system tracking the asset must be able to dynamically recognize the constituents based on the assets' location, type of work being performed, and other variables. The system must also be able to provide information on the asset performance, history and failure rates to assist the service provider in maximizing the life of the asset.

New Realities Require New Technology

Dealing with the new reality of multi-constituent, dispersed assets requires more than the traditional EAM approach to asset management. It requires companies to change the way they perform, measure and optimize the delivery of services — the cornerstone of customer satisfaction and incremental service revenue. And, EAM technologies must evolve in kind to support the tracking of dispersed assets and enable dynamic functionality which intelligently reflects multiple locations and owners for each asset.

Many EAM solutions already offer a mobile capability, enabling field technicians to access work orders and related information from their laptop or PDA at the point of service and providing real-time update of work status. In addition, new technologies such as automated meter reading (AMR), radio frequency identification (RFID), and global positioning systems (GPS) are also becoming widely adopted so that asset tracking becomes immediate and automated, no longer requiring field technicians to manually inventory and verify assets at each location. Both local and global positioning systems can now support movement of assets, as well as maintain a history of location and usage.

Next-generation EAM solutions must enable these advanced positioning and other mobile tracking technologies. They must also incorporate preventive and condition-based maintenance and integrate routing information, real-time inventory data

and service requests. As a result, organizations will be able to track mobile and dispersed assets from one location to another, return the assets to inventory, and issue them directly to customers while also having multiple-party ownership, operation and service.

In Summary …

In the world of T&D utilities, most assets are not confined to within the four walls of a plant, but extend out geographically to other parts of the country and to the customers that the organization serves. As utilities progress to meet the demand for management of dispersed assets, they need new tools to manage the asset lifecycle. These organizations should seek out solutions that offer location- or customer-based asset tracking, asset location history, stationary vs. moveable equipment, preventive and predictive capabilities, local and global positioning enablement for automated tracking of asset movement, and the definition of multiple ownership and constituents. They will find that the payback on these solutions will make them well worth the investment. ■

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Generation Efficiencies

(Cont. from p. 2)

NUG generation perhaps doesn't provide such flexibility.

Economic dispatch versus efficient dispatch also is an area of concern. Myer acknowledges that economic dispatch doesn't always run high-efficiency gas units before it runs lower efficiency units. "DOE is skeptical of the merits of efficiency dispatch because we think it would increase consumers' electricity costs for benefits that are at best uncertain," Myer warns.

Testimony at the meeting raises questions over how MISO treats jointly owned units. That issue is further confused by some jointly owned units in the western part of MISO being owned not only by market participants, but also by entities located outside the MISO market. Those rules need »

The DOE Report—First Solutions Suggested

"Economic dispatch is a straightforward concept: costs to serve a given level of electricity demand are minimized by dispatching lower-cost generation before dispatching higher-cost generation."

So explains the U.S. Department of Energy (DOE) in its study required by EPACT 2005 on procedures used by electric utilities to perform economic dispatch. It is charged with analyzing possible revisions to such procedures to improve the ability of non-utility generation resources to include their output in that dispatch, while analyzing potential consumer benefits.

Although acknowledging it does not yet have all the answers, and that future annual reports will improve on initial results, DOE's first, but somewhat hurried report to Congress, *The Value of Economic Dispatch*, released Nov. 7, 2005, gives a number of proposed suggestions to improve dispatch. But the findings open up other questions related to, at a minimum, load-forecasting methods, transmission-grid development, contracting practices and native-load protection.

For example, if a generator is included in the dispatch stock, there is a presumption that it can deliver its production to loads. But DOE says many respondents reiterate the need for enhanced transmission planning processes that address long-term economics as well as reliability, and of building a more robust transmission network allowing customers to save money by accessing more efficient generations than is possible with today's transmission system. One non-utility generator (NUG) recommends that every transmission upgrade that enables access to low-cost generation resources should be built if the upgrade's cost is less than the savings achievable by the dispatch of the lower-cost supply.

But with suggestions made that are too numerous to mention, the DOE report merely makes an initial stab at finding ways to improve plant dispatch.

The report recommends that DOE and FERC explore the following:

- Proposals by the Electric Power Supply Association and Edison Electric Institute for more standard contract terms and conditions for NUG-to-buyer contracting;
- Implementation of uniform dispatch rules by conducting in-depth review of various dispatch entities (RTOs, utilities, federal agencies) and documenting rationale for all deviations from pure least-cost, merit-order dispatch, in terms of procurement, utility commitment and real-time dispatch;
- Issues surrounding lack of NUG provision of instantaneous load-following regulation service under automatic generation control (AGC);
- Studies comparing market clearing price outcomes and total costs against the true production costs of the actual units dispatched—(1) how NUG bids in regulated utility dispatch and utility owned generator bids in centralized markets compare to actual production costs; and (2) how total electricity costs in centralized markets compare to total costs of the same production priced at actual production cost; and
- Scrutinizing technical quality of economic dispatch technology tools such as software, data, algorithms and assumptions to ensure any enhancements will improve reality and affordability of electricity.

DOE acknowledges the analyses of economic dispatch impacts conducted to date do not fully address Congress' directives. DOE said it would be useful to improve both the modeling and availability of data before attempting a new study to answer the questions asked in EPACT 2005 on the impacts of economic dispatch on different regions and customer classes across the U.S. It does plan to address those matters in next year's report to Congress on economic dispatch.

*Re The Value of Economic Dispatch: A Report to Congress Pursuant to Section 124 of the Energy Policy Act of 2005, Nov. 7, 2005 (U.S.D.O.E.).—**LB***

What is Security-Constrained Economic Dispatch?

Calling its performance "often considered one of the most important functions performed by all system operators," MISO describes security constrained economic dispatch (SCED) as having been used by utility system operators for decades, and as essential for ensuring reliable operations in any system with multiple generators and a network of interconnected transmission and distribution facilities.

"As this term is used throughout the industry, and applied to the Midwest ISO, the 'dispatch' is the set of procedures the system operator uses to instruct generators as to when and how much energy to inject at their respective locations. [The dispatch may also include instructions to specific "loads" (*i.e.*, energy consumers) that have the ability to adjust their energy withdrawals from the grid in direct response to the system operator's dispatch instructions.) For most system operators, including the Midwest ISO, these dispatch instructions are given to generators every five minutes, although there are still some system operators that use a somewhat longer dispatch interval. In each dispatch interval, the system operator gives those generators subject to the dispatch specific instructions regarding the need to increase or decrease energy output from their respective units. These instructions change dynamically as the need for energy output varies throughout the hour and day. In the Midwest ISO, generators may "self-schedule" in order to limit dispatch flexibility or account for limited dispatch ability, such as that of a nuclear power plant. Self-scheduling allows the generator to provide a specified output to the system operator at which the generators will operate. This self-scheduled output is accepted as a given, and the dispatch takes into account these fixed generation resource schedules when providing the dispatch signal to other participating generators."

Re Response of MISO Inc., to Questions Regarding Security-Constrained Economic Dispatch, submitted to PJM/MISO Joint Board Meeting, held Nov. 21, 2005 in Docket No. AD05-13-000.—**LB**

clarification, argues Doug Collins, speaking on behalf of the MISO Vertically Integrated Transmission Owners.

Load forecasting methods also need improvement. Because economic dispatch is very dependent on accuracy of load forecasts, improvements in accuracy obviously will lead to improvements in dispatch.

The question of fuel diversity also comes into play. SCED is supposed to be neutral as to fuel diversity, yet questions were raised at the meeting concerning the social value of fuel diversity. Some argue that perhaps there is a need for regulatory action to ensure that fuel diversity stays in place over the long term, in order to avoid problems posed by the recent over-reliance on natural gas and related troublesome gas price increases.

A larger issue surrounds the integrity of the interstate transmission system as a whole. The state of the electric transmission system plays a large part in determining the success or failure of SCED. Markets are hampered by the simple fact there is not enough transmission. The resulting congestion can create system imbalances. Also, the generation owners often own transmission, which leads to imbalances when native load is protected.

RTO Balance Sheets

Because RTOs and ISOs handle so much dispatch, evidence was presented aimed at proving they save money. Many studies and findings of cost savings resulting from SCED were presented at the conference (*see chart, pgs. 7, 8, 9, 10)*. MISO's Torgerson points to such savings as one reason RTOs are needed. Those savings are weighed against the cost of an RTO to the average residential customer. He says the cost of supporting an RTO averages about 44 cents per MWh, which amounts to about $3 to $5 per year to each customer.

According to FERC's Meyer, previous studies made by RTOs on the benefits of economic dispatch found cost savings in the range of one to five percent of total wholesale electricity costs. Other studies by independent power producers (IPPs) found benefits of 8 percent to over 30 percent of total variable production costs.

Economics aside, for now, it can be said that the first proceeding on SCED raises more questions than provides answers. It marks the start of a much-watched case during 2006 as more information is gathered and solutions are suggested on how to improve SCED. ■

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Summary of Key Midwest ISO Benefit –Cost Studies related to Regional Security-Constrained Economic Dispatch

Study	Geographic Scope	Quantitative Analysis – Items Covered	Key Quantitative Findings	Key Qualitative Findings
Wisconsin – March 26, 2004	Wisconsin Investor Owned Utilities	The study compared participation of Wisconsin Midwest ISO members participation in the Midwest Energy Market to a continuation of Day 1 operations,taking into consideration: • Production and purchased power costs; • Revenues from off-system sales; • FTR Revenues from projected Tier 1 & 2 allocations; • Congestion Costs; and • Schedule 16 & 17 Market Implementation Costs.	• During 198 Level 3 and higher TLR events in Wisconsin during 2003, constrained flowgates were under utilized by 11.4% on average without regional economic dispatch. This was significantly higher degree of under utilization than in other less constrained portion of the Midwest ISO. • Implementation of Midwest ISO energy markets would result in a net savings $51.2 million / yr.	Development of transparent and efficient spot markets will change economic incentives and produce significant intermediate and long-term efficiency benefits.
GFA – June 25, 2004	MISO Member Control Areas	The study quantified: • The historical impacts of 2003 Level 3 and higher TLRs on transmission utilization; • Cost of service benefits from managing congestion through security-constrained unit commitment and economic dispatch taking into consideration production and purchased power costs, off-system sales revenues, and the cost of market implementation; • Costs to serve load at market prices; and • In an illustrative analysis, the potential impacts of a carve-out of GFAs.	• During 926 Level 3 and higher TLRs the constraining transmission facilities were under utilized by 12.9% on average due to the imprecision of the TLR process. • Regional unit commitment and dispatch could produce benefits in production costs, purchased power costs, and off-system sales of $255 million / yr. After deducting the cost of market implementation, this represents a net benefit of $128 million / yr. • Security-constrained unit commitment and economic dispatch would reduce the cost of power at market prices to Midwest ISO members by $713 million / yr. Taking into the cost of market implementation, this equals a net benefit of $586 million / yr. • A carve-out of GFA contracts could raise peak prices in the Wisconsin Public Service load zone by 52%, in the Wisconsin Power & Light area by 20.9%, and by substantial amounts in other control areas.	• Use of TLRs to manage transmission congestion is economically inefficient–TLR curtailments do not reflect the then current value of transactions curtailed. • Reliance on TLRs to manage congestion makes it difficult to system reliability. • The economic benefits of regional dispatch quantified in this analysis were exclusive of potentially larger benefits of transparent markets related to improved investment decisions, lower forced outage rates, and enhanced demand management.

Source: MISO Response to Questions, *Docket No. AD05-13-000*

(Cont. on p. 8)

Summary of Key Midwest ISO Benefit –Cost Studies related to Regional Security-Constrained Economic Dispatch

Study	Geographic Scope	Quantitative Analysis – Items Covered	Key Quantitative Findings	Key Qualitative Findings
LG&E/KU III – March 3, 2005	LG&E / KU control area	The study examined the total costs of continued membership in the Midwest ISO compared to a non-specific LG&E / KU proposal for independent transmission operations with a contract for reliability coordination services. Costs and benefits considered in the study included: • Production and purchased power costs; • Transmission payments associated with off-system sales; • Congestion costs; • Uplift charges; • LG&E / KU administrative costs; • RTO charges; • Off-system sales revenue; • Transmission revenues; and • Financial Transmission rights related costs and revenues.	Withdrawal from the Midwest ISO in favor of stand alone transmission operations and contracting for reliability coordination services would: • Impose a net recurring cost on LG&E / KU customers of $46.2 million / yr.; • LG&E / KU would be responsible for paying an exit fee of $40.2 million; • Under a broad range of assumed futures, there would be significant net recurring costs to LG&E / KU, ranging from $7.3 million per year to $52.9 million per year; and • For the period 2005 – 2010, the net present value cost to LG&E / KU of leaving the Midwest ISO (after taking into consideration all costs of Midwest ISO membership) would be $276.1 million.	The study identified economic incentives for more efficient location of generation, including that locating a single combustion turbine downstream for frequently occurring transmission constraints instead of near LG&E / KU's major load center where the Companies have sited generation could save consumers $2.2 million / yr. This study updates earlier testimony that had identified additional benefits of transparent markets based on regional dispatch,including: • Meeting LG&E / KU merger requirements related to the mitigation of market power; • Incentives to reduce LG&E/KU forced outages to provide the equivalent of more than 170 MW of capacity; • Price signals that if made available to consumers might reduce peak demand by 100 MW or more and enhance choice; • Incentives for improved generator efficiency; • Enabling regulators to benchmark utility costs; and •Facilitating the allocation of capital investment risks through liquid wholesale markets.

(Cont. on p. 9)

Summary of Key Midwest ISO Benefit –Cost Studies related to Regional Security-Constrained Economic Dispatch

Study	Geographic Scope	Quantitative Analysis – Items Covered	Key Quantitative Findings	Key Qualitative Findings
Aquila – October 2005	Aquila Missouri Operating Companies	The study compares the benefits and costs of the Aquila operating companies participating in the Midwest ISO, participating in an efficient SPP Energy Imbalance Service (EIS) market, or operating on a Stand Alone basis outside of the two RTOs. The comparison was made based on the following four perspectives: • Production & Purchased Power Costs to serve Aquila Missouri native load; • Benefit to Aquila Missouri taking into consideration Production Costs, Purchased Power Costs, and Off- system Sales Revenue Net of Transmission Charges; • Congestion Costs associated with use of transmission to serve Aquila Missouri native load customers; and • Costs to serve Aquila Missouri native load at Wholesale Power Prices.	Aquila-MO participation in the Midwest ISO results in: • The lowest production and purchased power costs for serving Aquila native load – at least $5.7 million / yr. below the cost of the SPP EIS market and $6 million / yr. less than the cost of Stand Alone Operations • The greatest benefit to Aquila-MO taking into consideration net off- system sales revenues – $3.3 million / yr. greater than for SPP EIS participation and $6.4 million / yr. more than under Stand Alone Operation. • The lowest congestion costs $5.7 million / yr. less than in SPP and $6 million / yr. less than operation on a Stand Alone basis; and • The lowest cost to serve native load at wholesale prices – $38.5 million / yr. less than in SPP and $26.8 less than with Stand Alone Operations.	• SPP's EIS combines elements of traditional transmission rights with locational pricing when an "imbalance" is created. Differences between this approach and the LMP markets used in the Midwest ISO and other RTOs could facilitate strategic behavior to degrade the efficiency of economic dispatch and under some circumstances expand high price load pockets. • SPP's EIS proposal would not implement a regional security constrained economic dispatch that takes into consideration potentially impacted constraints such as that implemented for reliability purposes in other RTOs. • Transparent energy markets provide incentives for improved generator efficiency and availability, identify efficient locations for generation and transmission investments, permit regulators to benchmark utility costs, facilitate allocating capital investment risks through liquid wholesale markets,and enhance consumer choice.

(Cont. on p. 10)

Summary of Key Midwest ISO Benefit –Cost Studies related to Regional Security-Constrained Economic Dispatch

Study	Geographic Scope	Quantitative Analysis – Items Covered	Key Quantitative Findings	Key Qualitative Findings
Value Review – Analysis of pre-Midwest ISO to post Midwest IOS Market **Presented October 19, 2005**	Midwest ISO Region	This analysis involves a simulation based on a relative review of publicly available data in which the same dispatch optimization algorithm was used in all cases. The models used in this analysis were statistical and cost based. The analysis provides results that are representative of the total benefits available to the market. The analysis was performed by: • Developing costs of control areas as islands • Developing a best case bilateral market • Blend first to scenarios to develop a representative bilateral market view • Comparing these three scenarios to the Midwest ISO market to see relative cost differences	The results of this analysis varied depending on assumptions, but were bounded by the examples analyzed: • Production cost savings range between $59 million and $154 million per month producing a benefit / cost ratio of between 5/1 and 14/1 • Taking into account both market and reliability administration costs, the net benefit / cost ratios are between 2.5/1 and 7/1 • Optimization of the market reduced the effects of net fuel inflation from an approximate 30% to an approximate 25% increase	
Analysis of the Benefits of the Midwest ISO's Day- 2 Markets **Preliminary results of study conducted by ICF Consulting, LLC October 31, 2005**	Midwest ISO Region	This analysis compares an actual Midwest ISO Day- 2 operation to a simulated Midwest ISO Day- 1 operation for a single peak hour and for the entire 24- hour period of July 7, 2005. This analysis also estimates the maximum benefits achievable from an optimal Day- 2 operation to reflect the potential to increase savings to Midwest ISO consumers from incremental operational improvements to current Midwest ISO Day- 2 operations.	This study estimates that roughly, between $0.6 million to $1.0 million in maximum benefits from production costs savings over the 24- hour period of July 7, 2005. Annualized over a year, this amounts to approximately $220 million to $365 million in potential gross savings to consumers.	Additional savings are possible from potential improvements in Midwest ISO operations. For example, improvements in load forecasting could have a direct impact on improving unit commitment.