Demand Response

Market Participation vs. Subsidized Programs

Alice K. Jackson
Occidental Energy Ventures Corp.

Current and Near Future Demand Response Opportunities

- New York ISO
- PJM Interconnection
- Electric Reliability Council of Texas
Demand Response in the NYISO

• **Current Market Design:**
  – Voluntary Emergency Demand Response (EDRP)
  – Installed Capacity from Demand Response, i.e. ICAP (SCR)
  – Day-Ahead Demand Response (DADRP)
  – Real-Time Voluntary Demand Response

• **Near Future:**
  – 10 and 30 Minute Non-Synchronized Reserves
  – 10 Minute Spinning Reserves

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**NYISO Participation**

![Chart showing EDRP & SCR Growth](chart.png)
PJM

• **Current Market Design:**
  – Voluntary Emergency Demand Response
  – Day-Ahead or Real-Time Demand Response
  – Real-Time Voluntary Demand Response
  – Synchronized Reserves

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**PJM Participation**

2006 Active Participants
PJM Load Response Program
11/30/2006

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<td>1,462,205</td>
<td>4,427</td>
<td>1,081,025</td>
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**PJM Synchronized Reserves**

- **Current Market Design:**
  - Responsive Reserve Service (similar to Spinning Reserves in other markets)
    - Under Frequency Relay/Manual Dispatched Resources
    - Automatic Generation Control (AGC) Dispatched Demand Resources
  - Non-Spinning Reserves
  - Regulation
    - AGC Dispatched Demand Resources
  - Balancing Up Loads (BULs)*
  - Real-Time Voluntary Demand Response

- **Near Future:**
  - Replacement Reserve Service

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**ERCOT**

- **Current Market Design:**
  - Responsive Reserve Service (similar to Spinning Reserves in other markets)
    - Under Frequency Relay/Manual Dispatched Resources
    - Automatic Generation Control (AGC) Dispatched Demand Resources
  - Non-Spinning Reserves
  - Regulation
    - AGC Dispatched Demand Resources
  - Balancing Up Loads (BULs)*
  - Real-Time Voluntary Demand Response

- **Near Future:**
  - Replacement Reserve Service
ERCOT Participation

AGC Dispatched Demand Resources

- October 2006 – Pilot started in ERCOT
- October 2006 through January 2007 – data collected for analysis
- Results of the pilot filed in the PUCT Project No. 31575 stated:
  “In summary, the Controllable Loads that participated in the pilot program performed at least as well as generation resources in providing regulation service.”
- January 25, 2007 – PUC made AGC Dispatched Demand Resources (i.e. Controllable Loads) a permanent option in the ERCOT market.
Market Participation vs. Subsidized Programs

• Participation in existing Ancillary Services by demand side responders is favorable over special programs.
  – Less administration
  – No subsidies!

• ISO/RTO should determine what response characteristics they need for reliability, so that suppliers (Loads or others) can compete to provide those response characteristics; versus, suppliers deciding what they want to sell and lobbying the stakeholder process to force the ISO/RTO to purchase what they want to sell.

• Important to maintain the integrity and quality of demand response by implementing market based solutions.

In Short

Allowing Demand Side Resources to participate in existing markets is a proven way of achieving Demand Response.

Subsidized programs are not necessary in order to get substantial demand response.
Southwest Power Pool Regional
State Committee
San Antonio, Texas

AEP’s Energy Efficiency Programs

Billy G. Berny
January 28, 2007
Texas Energy Efficiency Policy
PURA §39.905/§ SR 25.181

• Standard Offer (SOP) and Market Transformation (MTP)
  Programs are to be implemented through Retail Electric
  Providers (REPS) and Energy Efficiency Service Providers
  (EESPs).

• Programs are to be available to all customers, in all
  customer classes.
  − Large Commercial & Industrial defined as customers with
    maximum demands of 100 kW and above.
  − Residential & Small Commercial defined as customers with
    maximum demands less than 100 kW
  − Hard-to-reach (Lower-income) customers at total household
    incomes < 200% of federal poverty level.

• All programs are designed to reduce system peak demand,
  energy consumption and energy costs.

Texas Incentive Payments

• Under Commission-approved programs, the T&D
  utility pays all incentives directly to the Project
  Sponsor, not to the customer.

• The Project Sponsor is not required to pass any
  incentive payment along to the host customer.

• Customer protection rules require that the Project
  Sponsor must disclose to the host customer that
  incentives are being made available to the Project
  Sponsor “through a ratepayer-funded program,
  manufacturers, or other entities.”
Typical Project Sponsors

- National energy efficiency services providers
- HVAC dealers/installers
- Insulation contractors
- Not-for-profit housing agencies
- Lighting contractors
- Retail Energy Providers (REPs)
- Large Commercial/Industrial customers may serve as their own Project Sponsor

AEP Energy Efficiency Programs in Texas

- Residential and Small Commercial SOP
- Hard-To-Reach SOP
- Commercial and Industrial SOP
- Emergency Load Mgmt. SOP (So. Texas only)
AEP Energy Efficiency Programs in Texas (continued)

- Low-income Weatherization Program (TDHCA)

- Texas SCORE for Public Schools and Texas CitySmart for Local Governments

- Energy Efficiency Improvement SOP (specifically for not-for-profit agencies)

AEP 2007 Energy Efficiency Incentive Budget

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<th>TNC</th>
<th>SWEPCO</th>
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<td>1.63 MW</td>
<td>1.70 MW</td>
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<td>Budgets</td>
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<td>$1.228 million</td>
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<td>Customers</td>
<td>675,000</td>
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<td>190,000 (Tex)</td>
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Texas Energy Efficiency Issues

- In the aggregate the statutory demand goal for energy efficiency is being met;
- Most utilities are generally meeting their demand reduction goals on an annual basis;
- Some individual utilities have difficulty meeting annual goals;
- Cost recovery on a timely basis is essential and critical.
- 2006 approximate results: 148 MW demand reduction, nearly $80 million incentives paid for savings achieved.

SWEPCO Arkansas

- APSC Energy Efficiency 06-004-R Final Order issued January 11, 2007
- Produced as a result of a statewide collaborative approach
- Proposed 2007 programs must be filed not later than July 1, 2007
- APSC review and programs implemented not later than October 1, 2007
- Annual reporting requirements, cost-benefit tests, and other administrative functions are outlined.
SWEPCO Arkansas

APSC Docket No. 06-004-R, Order 12:
• Allows DSM/energy efficiency program costs to be recovered concurrently through a surcharge or rider.
• Demand response mechanisms to be established through utility-specific rate/tariff proceedings.
• Calls for statewide customer education campaign.

SWEPCO Louisiana

• No statewide legislation nor regulatory requirements for energy efficiency exist.
• Traditional vertically-integrated utility structure continues.
PUBLIC SERVICE COMPANY OF OKLAHOMA

Residential/Commercial Tariff offerings to enable Demand Response:

- Time of Use features - seasonal rates with inclining block structure in summer months
- Optional General Service Time of Day rate
- Real Time Pricing - 5 commercial customers
- Proposed TOD pilot for Residential, Low Use General Service and Modified TOD for GS customers (100 participants per rate - best rate option)

PUBLIC SERVICE COMPANY OF OKLAHOMA

Industrial Tariff Offerings to enable Demand Response:

- Mandatory TOD demand ratchet (summer months 1-9 pm) for all primary & transmission customers
- RTP - 30 participating customers
- Energy Price Curtailable Rider - (filed revisions in current case to encourage participation)
- Proposed Interruptible Power Service Rider - proposed demand credit for enrolled interruptible load
- Proposed Emergency Curtailable Rider - for short term load curtailments
In Summary

**Texas** – TDU-provided, comprehensive programs, all customer classes, in a restructured market. Must revise for concurrent cost recovery through a surcharge or factor, instead of base rates.

**Arkansas** – traditional utility structure, new energy efficiency rules for defined programs for all customer classes; headed in the right direction.

**Louisiana** – traditional utility structure, no mandated programs.

**Oklahoma** – traditional utility structure, multiple tariffs for demand response. Will incorporate DSM/EE into IRP process.
Agenda

• Current State of Demand Response and Energy Efficiency Programs

• Arkansas Energy Efficiency Guidelines

• Program Expansion Plans

Current State of Programs

• Demand response programs
  – Load curtailment, energy curtailment tariffs

• Demand side management programs
  – Time of use rates available for all classes
  – Real time pricing tariff for large industrials

• Energy efficiency programs
  – Energy Star® homes
  – Geothermal heating and cooling
  – RateTamer® energy information service
Current State of Programs

• Energy Star® homes program
  – Provide builder education through homebuilders associations
  – Co-operative advertising and promotion with builder partners

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<th>Year</th>
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<td>331</td>
<td>366</td>
<td>416</td>
<td>960</td>
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<td>MWh’s Saved</td>
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<td>561</td>
<td>1,155</td>
<td>1,812</td>
<td>2,558</td>
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• Geothermal heating and cooling
  – Address residential and commercial (new and replacement) markets
  – Provide builder and contractor education
  – Co-operative advertising and promotion with partners
  – Offer financing through a partner agreement
  – Estimated reduction of 2,100 MWh’s in 2005

<table>
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<th>Year</th>
<th>2001</th>
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<td>276</td>
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Arkansas Guidelines

- Final order issued on January 11th
- “Quick start” program filing for plan years 2007-2009 due July 1
- Program implementation required no later than October 1
- Annual reporting required April 1st of each year
- Comprehensive program plan filings due April 1st, 2009

Program Expansion Plans

- “Severely Inefficient Housing” program in Arkansas
- Statewide education program through the Arkansas Energy Office
- Expand Arkansas TOU offerings to all customer classes
- Add Load Curtailment tariff in Arkansas
Program Expansion Plans

- Pilot Living Wise® program in schools
- Develop targeted marketing campaigns to increase customer program participation
- Perform market study to determine potential of direct load control programs and commercial and industrial prescriptive incentive programs
In 2005, KCP&L reached Stipulations and Agreements with both Kansas and Missouri regulators for a Comprehensive Energy Plan

**The Benefits:**

- Collaborative process that included all constituents
- Affordable energy to fuel long-term growth
- Environmental improvements to keep our area's air clean
- Jobs plus affordable energy to support economic growth
One goal is to have programs for customers in all markets.

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<th>Program</th>
<th>Type</th>
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<td>✔</td>
<td>✔</td>
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Efficiency and Affordability Programs will help customers save energy and money.

Programs Already Available:

- **Energy Optimizer** (AC cycling)
- **Energy Analyzer** (online analysis)
- **Change a Light, Change the World**

Programs in Development:

- Energy Star® Homes
- Cool Homes Program
- Rebates for Commercial/Industrial Custom Efficiency Retrofits
- Rebates for Commercial/Industrial Efficient New Construction
- Many more!
Weatherization assistance will help those who need it most

Low-Income Weatherization for Existing Homes
(Increased funding to KCMO plus expanded funding to other communities)
• Low-Income New Construction
(In cooperation with Local Initiatives Support Corporation - LISC)

Demand response programs let customers partner with KCP&L to control growth in peak demand

• Demand Response Programs
• Energy Optimizer - AC cycling for residential and small business customers
• MPower for larger businesses
Dynamic Voltage Control
The Circuit of the Future uses automation and monitoring to improve reliability and provide data to manage our system more effectively.

Circuit of the Future Plans Include:
1. Automated substations
2. Automated switches
3. Power quality monitoring through sensors
4. Automated capacitors
5. Distributed generation
6. Load control devices
7. Automated metering
8. Wireless communication to devices

Dynamic Voltage Control

- Without Cap Automation
- With Cap Automation
Regional Issues for Energy Efficiency and Demand Response

- Rules do not address energy efficiency or demand response
- Only benefit with demand response is to reduce net system load
- No planning criteria
- No market rules

www.kcpl.com
Questions and Answers
SPP Regional State Committee
Technical Conference

Generation and Transmission Planning-
Predicting the Future....

Mark Rossi
January 28, 2007
Is Transmission Being Built?

• Recent Projects Summarized in EEI January 2007 Report
  - Summarizes over 60 major recent transmission projects from around the country totaling over $10B in investments
  - Planned spend up $31.5B over next five years when compared to previous five years
  - Activity in both RTO and non-RTO regions of the country

Source: EEI Survey of Transmission Investment May 2005

PJM Results

Data Valid as of March 1, 2006

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<th>In-Service</th>
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<td>$590</td>
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<td>$74</td>
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<td>$534</td>
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Source: PJM RTEP May 2006
## ISO-NE Results

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<th>Estimate Range Minimum</th>
<th>Estimate Range Maximum</th>
<th>Estimated Costs Minimum ($millions)</th>
<th>Estimated Costs Maximum ($millions)</th>
<th>Range Minimum ($millions)</th>
<th>Range Maximum ($millions)</th>
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<td>Concept</td>
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<td>-50% 200%</td>
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<td>145 72</td>
<td>435</td>
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<tr>
<td>Proposed</td>
<td>49</td>
<td>-25% 50%</td>
<td></td>
<td>324 243</td>
<td>486</td>
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<tr>
<td>Planned</td>
<td>80</td>
<td>-25% 25%</td>
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<td>1859 1395</td>
<td>2324</td>
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<tr>
<td>Under Construction</td>
<td>37</td>
<td>-10% 10%</td>
<td></td>
<td>995 895</td>
<td>1094</td>
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<tr>
<td>Total October 2006 Plan</td>
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<td></td>
<td>3323 2605</td>
<td>4339</td>
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<tr>
<td>In-Service</td>
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<td>75 68</td>
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<td>9.9</td>
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</table>

(1) All costs provided by Transmission Owners
(2) Not included here is the cost of 88 reliability projects for which no estimates have been provided. Estimates for these projects are noted as TBD in the Project Listing.

Source: ISO-NE RTEP October 2006

## What’s Driving These Recent Projects

- **Most, if not all, are reliability driven**
  - Correct long-term known reliability concerns
  - Replace old infrastructure
  - Serve new growth

- **Not one, but two crisis happened**
  - Western prices skyrocket
  - 2004 Blackout

- **Political will was there**

- **Potential for financial incentives have been created**
  - More favorable regulatory policy with passage of EPAct 2005
Incorporating Generation Planning into Long-Term Transmission Planning

Factors under all scenarios:
- Load forecast, including demand response potential
- Known generation additions
- Retirements
- Fuel diversity (depends on perspective)
- Proximity
- Location of proposed new assets or retirements
- Purchase and sale obligations
- Neighboring jurisdictions

Other Factors:
- Orders 679, 889, and new NOPR proposed on January 17, 2006
- State IRP process requirements
- Long-term capacity obligations

CAISO’s New Planning Process

Source: CAISO Presentation on website www.caiso.com
NYISO's Planning Process

INITIAL PHASE

NYISO Performs Reliability Needs Assessment (RNA)

NYISO to Publicize Reliability Needs Assessment

NYISO Issues Request for Solutions

Market-Based Responses
- Generation
- DSM
- Merchant Transmission

Regulated Responses
- Transmission
- May consider alternatives
- TO & non-TO proposals

NYISO Evaluates Market-Based Responses and Regulated Responses To Ensure They Will Meet the Identified Reliability Needs
DPS screens non-TO alternative regulated proposals

NYISO Formulates Comprehensive Reliability Plan (CRP)

Board Approval of Plan

COMPREHENSIVE PHASE

No viable/timey mkbl or reg solution to an identified need

“Gap” Solutions by TOs

Board Approval of Plan

Source: NYISO Presentation August 2006 on website www.nyiso.com

PJM's Reliability Planning Process

Reliability

Apply sensitivity analyses to reliability criteria

5 year 10 year 15 year

Include all required upgrades at all voltage levels in RTEP

Identify 230-345 kV new construction requirements and continue to re-evaluate each year

500-765 kV upgrades included in RTEP

Pursue Right-of-way acquisition for 500-765 kV projects

230-345 kV new construction included in RTEP
PJM’s Process for Economic Projects

- Proposes to create portfolio of projects over certain time horizon
- Objective function is to “equalize” net benefits (costs) over the time period for participating members
- Observations
  - Innovative approach towards addressing cost allocations
  - Timing of benefits and costs will be important to participating members
  - Commitments by all interested stakeholders, particularly the state commissions, will be critical to success
  - Aligning approval processes and showing progress for each phase

Core economic analyses related to:
- Production cost
- Transmission congestion
- Other econometric factors

Evaluate additional infrastructure requirements based on impact of market efficiency analysis assumptions
Establish stakeholder committee to recommend scope of analysis and assumptions, as well as to review results and make upgrade recommendations to the Board

SPP Proposed Portfolio Approach
General observations

- The best planning process in the world still cannot overcome lack of political will to execute the plan
  - Siting facilities
  - NIMBY
- Encouraging transparency works and helps support point 1 above
- FERC NOPR on separation of duties
- Industry has small base of experience with economic upgrades but processes are being put in place and experience is being gained

Is Transmission Being Built?

- Recent Projects Summarized in EEI January 2007 Report
  - Summarizes over 60 major recent transmission projects from around the country totaling over $10B in investments
  - Planned spend up $31.5B over next five years when compared to previous five years
  - Activity in both RTO and non-RTO regions of the country

Source: EEI Survey of Transmission Investment May 2005
### PJM Results

**Source:** PJM RTEP May 2006

<table>
<thead>
<tr>
<th>Project Stage (Status)</th>
<th>Project Count</th>
<th>Estimate Range Minimum (%)</th>
<th>Estimate Range Maximum (%)</th>
<th>Estimated Costs Minimum ($millions)</th>
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<tbody>
<tr>
<td>Concept</td>
<td>87</td>
<td>-50%</td>
<td>200%</td>
<td>145</td>
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<td>Proposed</td>
<td>49</td>
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<td>324</td>
<td>243</td>
<td>486</td>
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<tr>
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<td>1395</td>
<td>2324</td>
</tr>
<tr>
<td>Under Construction</td>
<td>37</td>
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<td>10%</td>
<td>995</td>
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<td>1094</td>
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<tr>
<td><strong>Total October 2006 Plan</strong></td>
<td><strong>253</strong></td>
<td></td>
<td></td>
<td><strong>3323</strong></td>
<td><strong>2605</strong></td>
<td><strong>4339</strong></td>
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</table>

**Notes:**
- (1) All costs provided by Transmission Owners
- (2) Not included here is the cost of 88 reliability projects for which no estimates have been provided. Estimates for these projects are noted as TBD in the Project Listing

**Source:** PJM RTEP May 2006

----

### ISO-NE Results

**Source:** ISO-NE RTEP October 2006

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**Source:** ISO-NE RTEP October 2006
What’s Driving These Recent Projects

- **Most, if not all, are reliability driven**
  - Correct long-term known reliability concerns
  - Replace old infrastructure
  - Serve new growth
- **Not one, but two crisis happened**
  - Western prices skyrocket
  - 2004 Blackout
- **Political will was there**
- **Potential for financial incentives have been created**
  - More favorable regulatory policy with passage of EPAct 2005

Incorporating Generation Planning into Long-Term Transmission Planning

- **Factors under all scenarios**
  - Load forecast, including demand response potential
  - Known generation additions
  - Retirements
  - Fuel diversity (depends on perspective)
  - Proximity
  - Location of proposed new assets or retirements
  - Purchase and sale obligations
  - Neighboring jurisdictions
- **Other Factors**
  - Orders 679, 889, and new NOPR proposed on January 17, 2006
  - State IRP process requirements
  - Long-term capacity obligations
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PJM’s Process for Economic Projects

Market Efficiency

Current Economics

Core economic analyses related to:
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Demand Response and Resource Planning

Randy Gunn
Summit Blue Consulting
January 2007

Agenda

- Introduction and definitions
- DR requirements of EPACT
- Residential demand response potential and program results
- Commercial/industrial demand response potential and program results
- ISO DR results
- How utilities integrate demand response with resource planning
- Conclusions
Demand Response Definition

- Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

- Encompasses traditional utility DR programs and ISO programs

Traditional DR Programs and ISO Programs

<table>
<thead>
<tr>
<th></th>
<th>Traditional Utility Program</th>
<th>ISO Program</th>
</tr>
</thead>
<tbody>
<tr>
<td>Program Use</td>
<td>Last resort</td>
<td>Grid mgmt; market price mitigation</td>
</tr>
<tr>
<td>Compensation</td>
<td>Generally Static ($/kW)</td>
<td>Dynamic based on market price</td>
</tr>
</tbody>
</table>
DR Program Types

- **Reliability / Emergency** is focused on programs where someone has a "call option" on a resource.

- **Economic/Demand Bidding:** programs where a consumer (or its agent) bids in a price at which they are willing to sell their reduction.

- **Pricing Based:** programs are focused on commodity pricing that has incentives for consumers to use power based on market conditions.

How is DR Used?
EPACT—Federal Encouragement of DR

"It is the policy of the United States that”:

- Time-based pricing and DR shall be encouraged

- Deployment of enabling technology shall be facilitated

- Unnecessary barriers to DR participation in markets be eliminated

- Benefits of DR shall accrue to non-participants within the same regional entity

---

EPACT (2)

- Several major drivers for advanced metering and demand response:
  - Requirement that all federal building have advanced metering by 2012
  - Requirement that utilities offer dynamic pricing and provide advanced metering
  - Requirement that states investigate advanced metering
  - Requirement that DOE make recommendations to Congress
  - Requirement that FERC conduct annual assessments
EPACT—Smart Meters and DR

- Time-based Metering and Communications Requirement:
  - Utility Requirement: By 02/08/07, Utilities must offer time based rate schedule and provide metering to customers requesting such
  - State Regulatory Requirement: By 02/08/07, States must conduct an investigation whether it is appropriate to implement the new requirement

EPACT—Smart Meters and DR (2)

- Utility Requirement
  - Rates must vary according to wholesale costs
  - Rates shall enable consumer to manage use and costs through advanced metering and communications technology
  - Types to be offered include: TOU, CPP & RTP and credits for large customers in peak reduction agreements

  Must provide customers requesting the rate with a time-based meter that will enable the rate
Utility DR Benchmarking Project

- Summit Blue surveyed 40 larger US and Canadian utilities to gauge the "state of the practice" regarding demand response (DR) there. This was part of a DR project for the International Energy Agency.
- The primary purpose was to determine DR program impacts obtained by top-performing US programs, and features of such programs. These results are used to provide benchmarks for top-performing DR programs.
- A secondary purpose was to investigate the methods and models currently used for DR potential studies, and how they compare to DSM potential studies.

DR Potential Benchmarks Developed

- Residential direct load control (DLC)
- Commercial/industrial interruptible rates (IR)
- C/I demand bidding/buyback (DBB)
- Only 1 significant impact program found for each of residential TOD rates, C/I DLC, and C/I RTP programs. Limited applicability to other utilities currently.
- Data presented was self-reported by utilities, and checked for reasonableness, but not independently verified due to budget constraints.
Residential Direct Load Control

- Through these programs, utilities control one or more of customers’ air conditioners, water heaters, space heating systems, or pool pumps.
- Central air conditioners (CACs) are most commonly controlled. Typical control is 15 minute on-off cycling during peak demand periods.
- Control devices used most frequently are FM radio signals and paging signals.
- Many utilities have been offering these programs for 10 or more years.
- About 1/3 of utilities surveyed offer this type of program.

Residential DLC Program Impacts

<table>
<thead>
<tr>
<th>Percentage of Utilities</th>
<th>% Residential Peak Demand Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-5%</td>
<td>60%</td>
</tr>
<tr>
<td>6-10%</td>
<td>10%</td>
</tr>
<tr>
<td>10% or more</td>
<td>10%</td>
</tr>
</tbody>
</table>
Residential DLC Participation

Top Res DLC Program Features

- Longevity: all of the top-performing programs have been operating for at least 14-15 years.
- DSM requirements: Two of top three utilities based in states where law or regulations require electric utilities to spend significant money on “conservation” programs. DR programs that result in customers using less electricity overall qualify as conservation programs there.
- Economic factors of limited importance. All top performing programs conducted by low-cost utilities, and program incentives offered by top-performing programs not larger than average.
Residential DR Pricing Programs

- Participation in residential Time-of Day (TOD), Critical Peak Pricing (CPP), and Real-Time-Pricing (RTP) programs is generally low, 3% or less for almost all the utilities surveyed.
- For CPP and RTP programs, this is not surprising, since these programs have all been offered for 4 years or less. Most of these programs have also been pilot programs, not full scale efforts to date.
- About 1/3 of utilities offer TOD rates, 14% offer CPP, and 5% offer RTP programs

Chicago Energy Smart Pricing Plan Evaluation

- Voluntary residential real-time-pricing program. The Community Energy Cooperative implements the program for Commonwealth Edison. Summit Blue evaluated the program.
- In operation from 2003-2006. More than 1,000 program participants.
- ESPP participants have an overall price elasticity of -4.7%. This means that a doubling of electricity prices results in a decrease in their hourly electricity use by nearly 5%.
- Participants continue to show a significant response to the high-price notifications (i.e., when prices exceed $0.10/kWh). Participants reporting successful notifications essentially double their average response to changes in electricity prices
- ESPP participants’ overall monthly summer energy (kWh) usage suggests a conservation effect, that is a reduction in usage of 3% to 4%, relative to what their usage was estimated to be had they not received hourly electricity prices.
Commercial/Industrial Interruptible Rates

- Through these programs, utilities offer customers (usually) fixed price discounts for reducing their loads during peak periods.
- Customers usually are given 1-2 hours notice before a control period starts.
- Utilities often penalize customers if they don’t reduce their loads to the contracted levels.
- Most utilities require customers to commit to minimum load reductions, which vary from as little as 50 kW up to 5,000 kW.
- Slightly more than half of utilities surveyed offer IR programs. Many utilities have offered these rates for 20 years or more.

C/I Interruptible Rate Impacts

![Bar chart showing the percentage of utilities with different peak demand reduction percentages.]

- 4% or less: 45%
- 5% - 9%: 35%
- 10% - 14%: 15%
- 15% or more: 10%
Top IR Program Features

- Longevity: the top IR programs have been in operation for an average of 24 years, with a range of 14 to 37 years.
- Steel plants and other heavy industry participation. Several top performing programs get most of their demand reduction for these programs from steel plants.
- Limited customer participation: from the IEA survey, 2% of C&I customers at most participate in IR programs. Many utilities with large program impacts only have 10-30 large participating customers.
- DSM requirements and incentives. Three of top five utilities are based in Minnesota and Iowa, where utilities are required to invest in DSM.

C/I Demand Bidding/Buyback Programs

- These programs are similar to IR programs, but are newer programs designed to be more flexible for customers. They generally eliminate mandatory demand reductions and penalties to customers.
- Utilities’ load reduction discounts are usually tied to spot market electric prices in some manner.
- Utilities notify customers about a high electric price period, then customers declare how much they will reduce their load for the discount offered by the utility. This is usually done through a web site.
- Slightly less than half of utilities surveyed offer DBB programs.
C/I DBB Program Impacts

- Reported program impacts were realized several years ago when spot market electric prices were high. Most utilities have not used these programs much in the last few years when spot market prices have been lower.
- Program participation rates are low for top programs: .05% and .08% of all C/I customers.
C/I Direct Load Control Programs

- These programs are very similar to residential DLC programs.
- About 25% of utilities surveyed offer this type of program.
- Almost 40% of utilities that offer a residential DLC program do not offer a C/I version.
- Average program impacts per customer are 4 kW, four times as large as average residential impacts.
- However, all but one utility reported program impacts of 1% of their C/I peak demands or less.
- Participation varies widely, from 1 to 10,000 customers per utility.

C/I Pricing Programs

- Almost half of utilities surveyed offer C/I TOD rates.
- About 30% of utilities surveyed offer C/I RTP rates.
- Approximately 15% of utilities surveyed offer C/I CPP rates.
- Utilities reported very limited peak demand reduction impact data for these programs.
- Almost all the impact data that was reported amounted to 1% or less of utilities C/I peak demands.
ISO DR Program Results and Potential

Available Technical Market Potential

<table>
<thead>
<tr>
<th>Market</th>
<th>System Peak (MW)</th>
<th>Current DR (MW)</th>
<th>Remaining Available Potential (MW)*</th>
<th>Penetration % **</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISO-NE</td>
<td>28,021</td>
<td>681</td>
<td>2,121</td>
<td>24%</td>
</tr>
<tr>
<td>NYISO</td>
<td>33,879</td>
<td>1,837</td>
<td>1,551</td>
<td>54%</td>
</tr>
<tr>
<td>PJM</td>
<td>144,796</td>
<td>2,275</td>
<td>12,204</td>
<td>16%</td>
</tr>
<tr>
<td>ERCOT</td>
<td>63,056</td>
<td>1,800</td>
<td>4,506</td>
<td>29%</td>
</tr>
</tbody>
</table>

* Available Potential = (System Peak * 10%) – Current DR
** Penetration = Current DR / (System Peak * 10%)

Current ISO DR Programs and Payments

<table>
<thead>
<tr>
<th>MARKET</th>
<th>PROGRAM</th>
<th>ESTIMATED VALUE Per MW-Year</th>
<th>2006 Total Market Payments (est.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISO-NE</td>
<td>Real Time 30-Min DR</td>
<td>$45,000 – region $150,000 – SWCT RFP**</td>
<td>$23,490,000 $31,650,000</td>
</tr>
<tr>
<td>NYISO</td>
<td>ICAP SCR</td>
<td>$63,000 – Long Island $109,000 – NYC</td>
<td>$16,443,000 $46,868,250</td>
</tr>
<tr>
<td>PJM</td>
<td>Economic DR</td>
<td>$7,800</td>
<td>$9,249,405*</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Responsive Reserve</td>
<td>$88,000</td>
<td>$158,158,800</td>
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Total for 4 regions $289,859,455

CA Demand Reserve Partnership Not available
MISO Under construction Not applicable

* actual
** SWCT Request for Proposal: In December 2003 ISO-NE issued an RFP for DR in Southwest Connecticut to address a dangerous transmission congestion issue.
SPP Long-Term DR Potential

- Total SPP peak demand is currently about 43,000 MW. The load breakdown between residential and commercial and industrial is currently uncertain.
- Based on the DR potential estimates from the IEA project, we estimate that about 10% of system peak demand, or 4,300 MW, could be reduced by DR in the long run. This should be considered at least a 10 year goal, and will require a considerable collaborative effort with utilities and customers.
- The NY ISO currently has DR impacts that total about 5% of system peak demand. That’s the highest for the systems we have data on.

Demand Response and IRP

- Many states that have not implemented restructuring still require utilities to conduct integrated resource plans (IRPs). IRPs common in the southeast, midwest, and western US.
- Main objective of IRPs is to identify the lowest cost electric system expansion plan.
- Options that are usually considered as part of IRPs include new generation, energy efficiency, demand response, renewables, and power purchases.
- Planning periods for most IRPs are at least 15-20 years, with additional years often analyzed to account for “end effects”.

- 2000 base or gross peak demand = 8,409 MW.
- Xcel already had achieved about 700 MW of DR impacts by 2000, which reduced the net summer peak to about 7,700 MW.
- “Gross” resource needs range from 4,650 to 7,500 MW, excluding energy efficiency (EE) and DR.
- Base case DSM plan totaled 910 MW of EE and DR. DR impacts totaled 217 MW. Alternative DSM scenarios had impacts between 691 MW and 1,210 MW.
- EGEAS model and T&D analysis selected optimal DSM scenario as 1,174 MW of peak demand reduction, the second largest DSM scenario. This scenario’s cost of $974 million was almost double that of the base case scenario ($515 million).

Conclusions

- Simple estimate of long-term DR potential is about 10% of peak demand.
- Largest impact DR programs across the country include ISO DR bidding programs of varying types, utility interruptible rates, and utility direct load control.
- Reasonably priced DR impacts are usually selected as low-cost resources through IRP analyses.
Factoring Modern Grid Principles into Integrated Resource Planning

Southwest Power Pool
SPP RSC Technical Conference
28-29 January 2007

Steve Pullins, President, Horizon Energy Group

Burning Questions

• What will the future size and profile of demand be like in 5, 10, and 20 years?
• Are there other viable resource and delivery options available today and in the future?
• Are these options cost effective?
• How do we plan for such options?
• What are the prerequisite elements for the RTO to facilitate integrated resource planning in consultation with state regulators?
Outline

- Robust Trends and Vectors
- The Industry is Changing
- Systems Approach to IRP
- Expected Benefits of the Approach (offsets by Smart Grid strategies)
- Actionable Steps a Regional IRP Team Could Take

What is happening in the Grid today?

- There are Robust Trends at work in many of the key functions of the nation’s electric system.
- Alone, they are interesting and sometimes alarming
- Together, they seem to be pointing us in a worrisome direction
- We see these as industry “vectors” indicating the direction of how current pressures will drive future performance…or lack thereof
Robust Trends

- Electric Reliability
- Generation Mix Movement
- Market Movement
- Electric Consumer GDP Loss
- Getting Over the Deployment Hump
- Renewables Growth
- 12M DG Poised for Grid Influence
- Loss of Skills & Experience
- Effects of Grid Divorce

Electric Infrastructure – Growing Crisis?

Transmission problems rocketed when generation additions outdistanced transmission additions.
Generating Nodes on the Grid

Change in Generation Mix Connected to the Grid

Exponential increase

Electricity Market Paradigm Shift
Annual Business Loss from Grid Problems

*Prime Study: $150B annually for power outages and quality issues*

Do we have “Pilot-its”?

*Example:*

- **Pilot** = <5% deployment into the field (substations and feeders).
- **Deployment** = >25% deployment into the field.
Renewables Growth

**12M DG Poised for Grid Influence**

- Growth in number and capacity is steady
- Regulated / intercom.
  - Municipal: 965 MW
  - IOU: 238 MW
- Unregulated / intercom.
  - Private: 21,800 MW
- Non-intone. Base load, CHP, & Peaking
  - Private: 21,700 MW
- Utilities use ~ 1,300 MW and useful private use ~43,000 MW (unreg.)
- 33X could be used by Municipal / Coop with adequate comm./control
Loss of Skills and Experience

- Utility downsizing has reduced senior staff
- Experienced staff in the power industry is aging
- Enrollment in power engineering at universities is small
- Complexity of modern grid requires skills in advanced power system and IT
- Perceived value of technical skills has been reduced over the past 15 years
- Fundamental understanding of the power systems has been replaced by advancements in technology
- Graduating < 60,000 engineers annually (China at 300,000; India at 200,000)

Effects of Grid Divorce

- 40 states now have Net Metering laws
- 20 states with RPS
- 37 states with incentives for small-scale renewables
- If the trend over the last 10 years holds for the next, by 2016 over 4 million consumers will be off-grid
Today’s Industry Vectors

- Industry Vectors drive change….or not
- Using the Robust Trends, we can plot the Industry Vectors in relation to the state of stakeholder groups
  - Consumer State
  - Grid Operator State
  - Generator State
  - Regulatory State
- The RED arrow in each of the following 4 charts represents the direction into the future state from the current stakeholder drivers

Consumer State Vector

**Context:** Cost and reliability of service are important to consumers

**Vector into the Future:** High cost; low reliability

Robust Trends:
- Electric Reliability
- Generation Mix Movement
- Market Movement
- Electric Consumer GDP Loss
- Getting Over the Deployment Hump
- Renewable Growth
- 13M DG Panel for Grid Influence
- Loss of Skills & Experience
- Effects of Grid Divorce
Grid Operator State Vector

**Context:** Cost and flexibility of providing bulk power transmission are important to grid operators

**Vector into the Future:** Moderate cost; low flexibility

Generator State Vector

**Context:** Cost of providing wholesale power and hours of operation are important to generation providers

**Vector into the Future:** High cost; low hours
Regulatory State Vector

Context: Providing policy and rules that positively affect change and benefit the public trust are important to state regulators

Vector into the Future: Low affect on change; low benefit to society

Summary of Current State & Vectors of the Grid

*Given the current path*....

- The consumer sees high cost of service and low reliability; the vector is for higher costs and lower reliability in the future
- The grid operator sees high cost of delivery and some flexibility; the vector is for slightly decreasing cost of delivery and more constraints
- The generator sees high cost to provide service and low hours of operation; the vector is for more of the same
- The regulator sees low affect on change and low realized benefit to society; the vector is for less affect on change and lower realized benefits
The times, they are a changin’ ….

What Business Models Are Emerging

Drivers

- The Future Utility
- The Future Consumer
- The Future Vendor / Service Provider

Increasing Complexity

Exploding Options

Increasing Bandwidth and Nodes

Values

- More consumer options
- Real-time pricing
- More control nodes
- Reliability pressure
- Information security
- Self-provisioning
- Self-healing

33X
- More self-directed consumers
- More independent data users
- More private fleets

Technology Needs
- Communications

The Value Proposition Needs
- Technology
Timing of These Changes

2007 – 2011
- PSC’s go for total benefits picture
- Enforced reliability
- AMI widely used
- Several Smart Grid deployments underway
- Expanded DR programs

2012 – 2016
- Multi-svcs model common in Munis / CoOps
- IOUs invest in tech subs

2017 – 2021
- National RPS hits 25%
- Deploy 2G HTS wire
- No. of grid generators tops 1M
- Wide use of grid agents
- R&D reaches 4%
- Home / last mile merge
- Intelligent consumer energy app’s
- Divorced consumers hit 4M

Systems Approach to Modernize the Grid

Needed leadership in the electricity delivery vision and operating model; industry too fractured to form a consensus in this area; Federal / States must take the lead – industry expects/needs this

Tradition focus is in the technology development arena; this area is mature in assuring technologies streams

Integration – identified gap in today’s science and technology development
Integrated Resource Planning

It’s not about throwing out established processes, it’s about adding options.

Systems Approach to IRP

Integrated Plans may now include smart grid, green utility, and multiple markets elements.
Expected Benefits of a Systems Approach to IRP

<table>
<thead>
<tr>
<th>Case 1 – San Diego Region</th>
<th>Case 2 – Confidential Utility</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Annual Benefits</td>
<td>$141M</td>
</tr>
<tr>
<td>System Benefits (20-years)</td>
<td>$1,433M</td>
</tr>
<tr>
<td>Societal Benefits (20-years)</td>
<td>$1,396M</td>
</tr>
<tr>
<td>Total Capital Cost</td>
<td>$490M</td>
</tr>
<tr>
<td>Annual O&amp;M Cost</td>
<td>$24M</td>
</tr>
</tbody>
</table>

* Includes 2 large wind farm additions

From 4 studies, we see a change in capital planning of roughly +6% to – 20% over 20 years.

San Diego Region Benefits Profile

- Job Creation & Increased GDP
- Increased capital investment efficiency
- Increased security
- Increased integration of distributed generation
- Tax gain from Depreciation Increase
- Environmental benefits
- Reduction in congestion cost
- Reduced blackout probability
- Reduction in forced outages
- Reduction in peak demand
- Reduction in restoration time
- Other benefits
Potential Regional IRP Steps to Take

• Self-assess regional open-thinking on resources
• Self-assess regional benefits considerations
• Assess Future Operating Model Options
  – Smart Grid
  – Green Utility / Region
  – Multiple Markets
• Benchmark Future Probable States with others
• Document Options process and Scenarios process
Peak Generation Resource Trend

Adding generation to address the peak forces average asset utilization downward.

Source: Pete Brandien, VP System Operations, ISO-NE
The Financial Electric System

Fuel Purchased: $78B/year

- Robust Trends (2004)
- Additions for Growth (2005–24)
- Retirement (2005-24)
- Smart Grid Avoidance (2005 – 24)

Load Purchased: $260B/year

Planned capital influx: $936B

Effective Cost of Generation

- Hydro
- Nuclear
- Natural Gas Base
- Natural Gas Peaker
- Utility-owned Wind Farm
- Consumer-owned DG
- DR as Gen
- Utility-owned DG Wind
- Consumer-owned DG Solar

Load Purchased:
- $300B
- $80B
- $240B
- $110B
- $730B
- $206B
- $156B
- $12B
- $36B
- $57B ($46-117B)

Outages / PQ: $150B/year

Generation
- $480B (53%)
- $80B (50%)
- $240B (30%)
- Consumer Systems $220B (<1%)

Transmission
- $80B

Distribution
- $90B

Consumer Systems
- $110B
- $33B
- $73B

Load Purchased:
- $260B/year

Planned capital influx: $936B

Effective Cost of Generation

- $25,000
- $20,000
- $15,000
- $10,000
- $5,000
- $0

- Nuclear
- Fossil
- Natural Gas Base
- Natural Gas Peaker
- Hydro
- Utility-owned Wind Farm
- Corporate-owned DG
- DR as Gen
- Utility-owned DG Wind
- Consumer-owned DG Solar
### Generation Cost Matrix

<table>
<thead>
<tr>
<th></th>
<th>Nuclear</th>
<th>Fossil</th>
<th>Natural Gas Base</th>
<th>Natural Gas Peaker</th>
<th>Hydro</th>
<th>Utility-owned Wind Farm</th>
<th>Consumer-owned DG</th>
<th>DR as Gen</th>
<th>Utility-owned DG Wind</th>
<th>Consumer-owned DG Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capex ($/kw)</strong></td>
<td>$1,600</td>
<td>$1,168</td>
<td>$900</td>
<td>$980</td>
<td>$1,600</td>
<td>$1,150</td>
<td>$75</td>
<td>$75</td>
<td>$2,100</td>
<td>$2,800</td>
</tr>
<tr>
<td><strong>Availability</strong></td>
<td>93%</td>
<td>85%</td>
<td>85%</td>
<td>4%</td>
<td>67%</td>
<td>30%</td>
<td>4%</td>
<td>4%</td>
<td>30%</td>
<td>15%</td>
</tr>
<tr>
<td><strong>Transmission capex</strong></td>
<td>$210</td>
<td>$210</td>
<td>$210</td>
<td>$210</td>
<td>$210</td>
<td>$210</td>
<td>$210</td>
<td></td>
<td>$210</td>
<td></td>
</tr>
<tr>
<td><strong>Distribution capex</strong></td>
<td>$85</td>
<td>$85</td>
<td>$85</td>
<td>$85</td>
<td>$85</td>
<td>$85</td>
<td>$85</td>
<td></td>
<td>$85</td>
<td></td>
</tr>
<tr>
<td><strong>Transmission losses</strong></td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td></td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td><strong>Distribution losses</strong></td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td></td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td><strong>Effective capex ($/kw)</strong></td>
<td>$2,053</td>
<td>$1,739</td>
<td>$1,423</td>
<td>$24,744</td>
<td>$2,850</td>
<td>$4,866</td>
<td>$3,750</td>
<td>$1,675</td>
<td>$7,000</td>
<td>$18,667</td>
</tr>
</tbody>
</table>

2005 fuel cost ($/MMBTU)

|                               | $2.60   | $6.00  | $6.00            | $6.00             |       |                        | $0.00            |           | $0.00               | $0.00                  |
| **Heat rate (BTU/kwh)**       | 9000    | 9000   | 9000             | 9000              |       |                        | $0.00            |           | $0.00               | $0.00                  |
| **Transmission losses**       | 5%      | 5%     | 5%               | 5%                | 5%    | 5%                     | 5%               |           | 5%                  |                        |
| **Distribution losses**       | 5%      | 5%     | 5%               | 5%                | 5%    | 5%                     | 5%               |           | 5%                  |                        |
| **Effective capex ($/kw)**    | $2,053  | $1,739 | $1,423           | $24,744           | $2,850| $4,866                 | $3,750           | $1,675    | $7,000              | $18,667                |

**Asset Utilization (AU)** is a more complete financial measure.

\[
AU = \frac{\text{MWH delivered} \times \text{Hours in a year}}{\text{Nameplate capacity}}
\]

### Denmark Changed in Two Decades

**Centralized System of the mid 1980’s**

- Small CHP
- Large CHP
- Wind

**More Decentralized System of Today**

- Small CHP
- Large CHP
- Wind

Source: Danish Energy Center
Wind Resource

Typically not coincident with peak demand.

Solar Resource

Coincident with peak demand!
Conclusions

• Broadening the generation portfolio beyond the traditional resource base may stem the tide on peak to average ratio and drive better asset utilization.
• Renewables can play an effective role in the generation portfolio, while, at the same time, providing a distributed “hedge” against large events.
• Demand Response and Consumer-owned DG are more cost effective at addressing peak demand than using natural gas-fired generation.
CapX 2020 Transmission Initiative

Progress Through An Alliance Approach

Southwest Power Pool
Technical Conference on Regional Resource Planning
San Antonio, Texas
January 29, 2007
Laura McCarten, CapX Utilities

CapX 2020 Transmission Initiative

- Current CapX Projects
- Alliance Approach to Project Implementation
- Minnesota Renewable Energy Portfolio
- Planning for Future
**CapX 2020**

**Capacity Expansion Needed by 2020**

- Formed Spring 2004
- Alliance of 11 electric cooperatives, municipal and investor-owned utilities
- Why new transmission?: reliability; implement state and federal energy policies; long term economic vitality
- CapX Mission: Collaborative approach to assure timely and efficient projects; influence state and federal policy; and coordinate common efforts

**Participating utilities**
- Dairyland Power Cooperative
- Great River Energy
- Midwest Municipal Transmission Group
- Minnesota Power
- Minnkota Power Cooperative
- Missouri River Energy Services
- Otter Tail Power Company
- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- Wisconsin Public Power Incorporated
- Xcel Energy

---

**Customer Use Is Growing**

- Historical growth from 2000-2004: 2.64%/year
- Projected future growth to year 2020: 2.5%/year

![Customer Use Graph](chart_image)
CapX 2020 Utilities Serve Minnesota and the Region

6,300 MW of load growth in the region through 2020

Rigorous Process Yielded Flexible Plan

Process
- Modeled three potential future generation development scenarios
- Assessed transmission required under each scenario
- Many facilities were common to all three scenarios
Initial Vision Study - Need for 345-kV Backbone System by 2020

CapX Project Groups

<table>
<thead>
<tr>
<th>Project Group</th>
<th>Desired In-Service</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Group I</strong> – Est. $1.3 billion, 600+ miles of new lines</td>
<td></td>
</tr>
<tr>
<td>SE Twin Cities-Rochester-LaCrosse, WI 345kV</td>
<td>2012-2014</td>
</tr>
<tr>
<td>Bemidji-Grand Rapids 230 kV</td>
<td>2012-2014</td>
</tr>
<tr>
<td>Fargo, ND-St. Cloud/Monticello 345kV</td>
<td>2012-2014</td>
</tr>
<tr>
<td>Brookings, SD-SE Twin Cities 345 kV</td>
<td>2012-2014</td>
</tr>
<tr>
<td><strong>Group II</strong> – Additional 345 kV facilities in Twin Cities area, and possibly to west</td>
<td>2014 to 2020</td>
</tr>
<tr>
<td><strong>Group III</strong> – Remote Generation Outlet</td>
<td></td>
</tr>
<tr>
<td><em>Timing and characteristics of Group II and Group III will be defined by generation development and further studies</em></td>
<td></td>
</tr>
</tbody>
</table>

Total cost of all Groups est. to exceed $3.5 billion
Group I Projects Underway

- Four lines work together to ensure regional reliability
- Enables 1,000+ MW renewable energy
- Lines are essential building blocks for any future generation or energy policy scenario
- 3-5 year review & permitting period; and multi-year construction period if approved

Project Participants and Development Managers

Fargo ND / St. Cloud / Monticello
- Xcel Energy
- Great River
- Missouri River
- MN Power
- Otter Tail Power

Bemidji / Grand Rapids
- Otter Tail Power
- Great River
- Minnkota
- MN Power
- Xcel Energy

Brookings SD / SE Twin Cities
- Great River
- Missouri River
- MMTG
- Otter Tail Power
- Xcel Energy

SE Twin Cities / Rochester / LaCrosse WI
- Xcel Energy
- Dairyland
- Rochester Public Utilities
- SMMPA
- WI Public Power
Regional Cost Recovery

- Cost allocation methodology for reliability projects is now set
  - MISO members – tariff-based allocation
  - Non-members – negotiated benefit area
- Regional pricing methodology continues to progress
  - MISO filing on economic projects, other initiatives in progress
- Group 1 projects submitted to MISO for classification, decision expected March ’07

Uncertainty in classification affects who pays, not whether costs will be recovered.

Regulatory Plan: Projected Timeline

<table>
<thead>
<tr>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exemption Filing</td>
<td>MN Certificate of Need – 345kV Projects</td>
<td>Routes Analyses</td>
<td>Public Meetings</td>
<td>MN Route Permits</td>
</tr>
</tbody>
</table>
Assuring Efficiency and Consistency Across Multiple Projects

Inter-utility teams develop strategies, analysis, techniques & templates that become “standards”

- **Regulatory**: state Certificate of Need-type and federal permits
- **Planning**: project details, regional & Group 2 and 3 plans
- **Communications**: key messages, outreach process, media
- **Standards**: design standards, new technology, sourcing
- **Governmental Affairs**: legislative and local government
- **Agreements**: interim and long-term contractual agreements

CapX 2020 Networked Organization
Support & Project Team Coordination

CapX2020 Vision Team
CapX2020 Staff
- Regulatory
- Planning
- Communications
- Standards
- Government Affairs
- Agreements

M.C. - LaCrosse
M.C. - Fargo
M.C. - Brookings
Management Committee
Bemidji
LaCrosse
Fargo
Brookings
Bemidji Project
- Project Management
- Routing
- Project Communications
- Right-of-Way
- Engineering
- Construction Management
- Accounting
Analysis Starting for “Build” Phase Issues

- Plan for sequencing construction of individual segments
- Choose model for project management, engineering, procurement, construction
- Define sourcing strategies
- Develop human resources, especially skilled trades

Broad Array of Interested Parties

- Fargo
- Bemidji
- Brookings
- LaCrosse
- Reg
- Leg
- UGPTC
- NDTA
- SDIA
- NDIC
- MISO
- MAPP
- ATC
- NDTA
- MISO
- MAPP
- ATC
Policy Issues

- Generation choices, policies
- Renewable Energy Objective
- Transmission as “non-denominational”
- Cost allocation, recovery
  - State regulators allow “real-time” cost recovery
  - FERC incentives
  - MISO RECB I and II - uncertainties
- National level – energy security, reliability, siting
- Long time horizon of plan and solution

Minnesota Renewable Portfolio
Standard – Role of Transmission

- Wind Integration Study completed late 2006 – incremental integration costs of 25% wind by 2020
  - Costs to schedule & operate conventional resources to accommodate variability and uncertainty of wind
  - Key assumptions: consolidated balancing over MISO area, needed transmission in place, geographic dispersion of wind installations
  - Costs range from $2.11 - $4.41 per MWh
- CapX Transmission Consortium providing transmission information, considerations
  - Uncertainty in getting needed transmission in place by 2020
  - CapX continue to lead planning effort, with MISO and stakeholder involvement
  - CapX lead future transmission implementation
- State PUC oversight role, may reduce a utility's RPS for specific reasons
- Legislative action soon
Implications of 25% Renewable Portfolio Standard by 2020

- Renewable Portfolio Standard (RPS) of 25% by 2020 equals about 5,700 MW wind capacity statewide
- Current efforts will result in Xcel Energy having about 1,500 MW wind installed by 2010, about 700 MW counts towards RPS
- CapX Group 1 transmission projects will enable additional 1,000+ MW new wind

Approximately 4,000 MW additional wind resources by 2020 to meet 25% RPS

Planning For the Future

- Update Vision study, reflecting state Renewable Portfolio Standard
- Analyze Minnesota-wide penetration of Community Based Energy Development (CBED) projects
- Reconcile plans with MISO and other transmission providers
- Define Group 2 & 3 individual projects
Ensuring a Successful CapX Collaboration

“When organizations do establish a strong, collaborative working relationship with a partner, they realize an average of 73% more value from the alliance.”

“More than half of alliance managers report their companies under-invest in working relationships with partners”

Harvard Study “Managing Alliances for Business Results”
Lessons Learned from 350 companies

Thank you!
SPP Planning Overview

RSC SPP Technical Conference
January, 2007
Overview

SPP Transmission Expansion Plan (STEP)

Highlights of other planning studies
Tools for economic analyses

Supply Adequacy Audit

EHV Overlay Study

STEP Overview

Open and transparent process

Comprehensive reliability assessment for 2006 – 2016 including steady-state, dynamic, as well as reactive reserve margin analyses and recommendations

$1.4 billion of transmission projects for the years 2006 through 2016

Appendix A in the SPP Transmission Expansion Plan (STEP) report provides a detailed summary of every transmission project planned or needed in SPP through the planning horizon

Transmission reliability planning is based on expected total loads using approved resources for any combination of firm, confirmed transmission service sold based on traditional deterministic NERC and SPP Criteria
2006-2016 STEP EHV

2006-2016 STEP Transmission Projects

Project Cost by Project Type
Total $1.4 billion

- New Lines: 47%
- Line Rebuilds/Upgrades: 29%
- New Transformers: 14%
- Transformer/Substation Upgrades: 6%
- New Caps/Reactors/Devices: 4%

www.spp.org
STEP Recommendations

1. The SPP Board of Directors (BOD) approves this 2006-2016 SPP Transmission Expansion Plan. The TWG and MOPC support this SPP RTO Staff recommendation.

2. The SPP BOD authorizes and directs the start of construction of projects listed in Appendix 'B' in this 2006 SPP Transmission Expansion Plan. The TWG supports this SPP RTO Staff recommendation. MOPC approved Recommendation #2 with a remand to the TWG to consider extending Appendix B beyond a 2 year commitment window for reliability projects through the entire planning horizon in the next STEP.

In response to MOPC direction, Staff has initiated project tracking with TWG members on all STEP projects to ensure that TOs “work the plan” and are taking steps to get reliability projects in long term capital budgets, work plans for permitting, ROW acquisition, etc. Quarterly status reports forthcoming with tracking metrics which will focus on status and costs.

2006-2016 STEP
Appendix B Projects

<table>
<thead>
<tr>
<th>Project Type</th>
<th>Cost Percentage</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Lines</td>
<td>35%</td>
<td>$71.8 million</td>
</tr>
<tr>
<td>Line Rebuilds/Upgrades</td>
<td>29%</td>
<td>$58.7 million</td>
</tr>
<tr>
<td>New Transformers</td>
<td>8%</td>
<td>$16.2 million</td>
</tr>
<tr>
<td>Transformer/Substation Upgrades</td>
<td>22%</td>
<td>$44.5 million</td>
</tr>
<tr>
<td>New Capacitors/Reactors/Devices</td>
<td>8%</td>
<td>$16.2 million</td>
</tr>
</tbody>
</table>
Lessons Learned in Expansion Planning

SPP Transmission Expansion Plan Process and the SPP Aggregate Study Process needed to be better synchronized

Better project tracking is required

Need to clearly identify projects that are required for reliability

Need to clear up some confusion about how the Economic Planning assessment fits into the Expansion Plan

SPP Economic Modeling Process needs improved documentation and stakeholder involvement

Base Plan Upgrades

Base Plan Guidelines Task Force (BPGTF)

MOPC approved recommended guidelines in April 2006 which included potential base plan funding of projects driven by member standards/procedures, not SPP Criteria, through 2007.

Staff has recommended, and MOPC has approved, base plan funding for 53 projects and $113M of E&C investment in the STEP. Cost allocations will be determined and shared with stakeholders after BOD approval.

Recommendations regarding cost recovery for projects associated with ineffective Transmission Operating Directives are being reviewed.

BPGTF is still formulating position on cost recovery for projects associated with NERC standard TPL-003.
SPP Tariff Studies

Aggregate Transmission Service Request Studies
  Lots of learning by staff and stakeholders
  Study scopes keep expanding
  Latest studies evaluate in excess of 10,000 MW of new service simultaneously with cost sharing for more regional transmission upgrades
  Service agreements being executed and transmission improvements being implemented

Generation Interconnection Studies
  14,000 MW + of new generators being evaluated
  Mostly wind farms, although several major coal units have come under study recently

Wind Potential

UNITED STATES ANNUAL AVERAGE WIND POWER

Diagram Courtesy of rredc.nrel.gov
Economic Planning

Economics Modeling and Methods Task Force documented process, assumptions, and expected results

Screens in STEPs continue to identify several promising economic expansion projects within the SPP footprint

GED enhancing MarketSYM/PowerWorld to include Security Constrained Unit Commitment logic

SPP Staff evaluating PROMOD IV and GridView packages now under 90 day trials with training as well as benchmarking analysis in process
Other Transmission Expansion Studies

Texas CREZs
- SPP proposing 3rd leg of “X” plan with 345 kV line and new 345 kV line & 600MW HVDC tie into DFW
  - 20% cost of ERCOT panhandle loop
  - Save $50M+/year in congestion costs

Other ERCOT Studies
- 200-600 MW HVDC ties in West Texas & Panhandle areas look very promising
- Entergy QPRs with 450 – 1,050 MW HVDC
- Hugo II outlet and 400 MW HVDC
SPP DRAFT CREZ Solution

SPP 765 kV Supporting 9-10 GW of Texas Wind Development in CREZs 2, 3 & 4
Other Transmission Expansion Studies (cont.)

LPSC studies with support of Entergy ICT

Joint planning studies for TX/OK, as well as TX/LA/AR

Ozarks

KETA

500 kV Overlay for the Ozarks
Joint Planning

MISO/SPP Joint Study
- JOA Requirement
- Scope being finalized in 1Q07

Support of DOE Congestion Studies and NIETC designations
- Significant support provided to DOE/CRAI/LBL
  - SPP comments filed October 2006
    - Supportive of screening analyses, but ISO/RTOs need to identify solutions as part of existing planning processes
    - Shouldn’t focus only on flowgates, need to look at LMP contours
    - Asset management & coordinated planning are key
    - No NIETCs in SPP yet, but we may need help in getting transmission built/upgraded through national forests, etc.
- ISO/RTO Council Planning Committee
  - ERAG to improve modeling & studies
Supply Adequacy Audit

Last performed in 1999

SPP Staff will perform again in first quarter of 2007, coincident with EIA-411 data collection efforts

SPP staff must be able to rely on EIA-411 data to determine compliance against SPP capacity margin requirements, as well as calculations based on safe harbor provisions for Base Plan funding for new DRs under the SPP OATT

Careful review of EIA-411 data
  * Net Dependable Capacity for wind can not be 100% of its total capacity
  * Jointly owned generation must not be double counted
  * All resources have long-term firm deliverability under SPP OATT
  * All transactions match internal and external to SPP
  * TDU's like AECC, KEPCO, etc. needs to be distributed properly
  * Data needs to be compared with last year for any major changes/errors

Provide good foundation for new LOLE study to determine supply adequacy metrics
Background

SPP Transmission Expansion Planning process in place and effective in identifying reliability needs, least cost solutions and potential economic upgrades through the 10 year planning horizon

Desire by Staff and others to identify long range vision for bulk power transmission network in SPP with input from independent entities with EHV experience

Monies budgeted and approved for consulting services to help with long range planning in SPP Engineering
Request for Proposal

Strawman drafted by Staff in 3rd Quarter 2006

Discussed at TWG meetings

Approved by TWG in November

Issued Dec 1st to dozen A/E firms

4 comprehensive proposals received by Dec 29th deadline

SPP EHV Overlay Contractors Selected

![InfraSource Technology](image)

![PowerWorld Corporation](image)
EHV Overlay Objectives

Create a blueprint for 345, 500, 765 kV or higher overlay needs in and around SPP

- Identify an approach to determine impacts on existing SPP Criteria, e.g., reliability margins

Approach to optimize existing assets in footprint

Recommendations on increased ties or synchronous operations with ERCOT and WECC

Next Steps

Statement of Work being finalized
White paper issued to outline objectives, as well as stakeholder feedback process and issues
Major agenda items at TWG meeting on February 7-8 in Tulsa
Completion slated for mid-2007 with interim milestones coordinated with SPP calendars
Appreciate support of members and stakeholders throughout the assessment
Questions/comments to EHVOverlay@spp.org
EHV Overlay White Paper

EHV Overlay planning process will be transparent and deliver a plan that is traceable, defendable and dynamic.

Process: Timeline and milestones

Need input on “futures” scenarios

Concepts: Transmission as an “enabler” and “hedge” that provides “flexibility”, as well as “reliability”