Emerging Issues &
Basic Concepts
Emerging Issues

1. Rate Case Trends
2. Demand Side Management (DSM)
3. Decoupling
4. Renewable Portfolio Standards
5. Climate Change/Greenhouse Gases
6. Interruptible Credits
7. Riders/Automatic Price Adjustment Clauses
8. Nuclear Generation
9. Other Issues
Rate Case Trends

- Large capital investments by utilities
- Increasing fuel costs
- Smart grid cost recovery
Fuel Price Forecasts

Source: 2011 EIA Annual Energy Outlook
Smart Grid

- Transmission plant upgrade
- Smart metering
- Information back and forth between the generator and the user
- Not fully developed
- Objective -- maximize efficiencies in generation and usage
- Rate Impact → $
Demand Side Management (DSM)

- Changes on customer side of the meter that reduces utility consumption costs
- Utility sponsored and funded
- Customer peak use and costs
Demand Side Management

Pros and Cons

**FOR**
- Market imperfections
- Knowledge of customers
- Central planning preferable to free market

**AGAINST**
- DSM is not a monopoly, therefore no need to regulate it
- Utilities may have conflicted incentives
- Free Riders
- More Overhead
Decoupling

- Fundamental rate setting change
- Revenues of utility are made independent of sales levels
- Rate change not tied to cost change
PROS and CONS of Decoupling

**PROS:**
- Removes disincentives for utility to pursue DSM
- Increased stability
- Lower risk for utility
- Moderates impact of abnormal weather for residential customers

**CONS:**
- Utility has less interest in providing good service
- Removes incentive for customer to conserve
- Erodes correct price signal to customers
- Shifts risk from utility to customers
**RPS Policies**

<table>
<thead>
<tr>
<th>State</th>
<th>RPS Goal</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>30% by 2020 (IOUs)</td>
<td>10% by 2020 (co-ops &amp; large munis)*</td>
</tr>
<tr>
<td>ID</td>
<td>105 MW</td>
<td></td>
</tr>
<tr>
<td>IA</td>
<td>10% &amp; 1,100 MW x 2015*</td>
<td></td>
</tr>
<tr>
<td>IL</td>
<td>25% x 2025</td>
<td></td>
</tr>
<tr>
<td>IN</td>
<td></td>
<td></td>
</tr>
<tr>
<td>KY</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ME</td>
<td>30% x 2000</td>
<td>New RE: 10% x 2017</td>
</tr>
<tr>
<td>MA</td>
<td>22.1% x 2020</td>
<td>New RE: 15% x 2020 (+1% annually thereafter)</td>
</tr>
<tr>
<td>MI</td>
<td>25% x 2025</td>
<td></td>
</tr>
<tr>
<td>MN</td>
<td>25% x 2025</td>
<td>(Xcel: 30% x 2020)</td>
</tr>
<tr>
<td>NV</td>
<td>25% x 2025*</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td>25% x 2025 (large utilities)*</td>
<td>5% - 10% x 2025 (smaller utilities)</td>
</tr>
<tr>
<td>PA</td>
<td>~18% x 2021†</td>
<td></td>
</tr>
<tr>
<td>PR</td>
<td>20% x 2035</td>
<td></td>
</tr>
<tr>
<td>RI</td>
<td>16% x 2020</td>
<td></td>
</tr>
<tr>
<td>SC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SD</td>
<td>10% x 2015</td>
<td></td>
</tr>
<tr>
<td>UT</td>
<td>20% by 2025*</td>
<td></td>
</tr>
<tr>
<td>VA</td>
<td>15% x 2025*</td>
<td></td>
</tr>
<tr>
<td>VT</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WI</td>
<td>Varies by utility; 10% x 2015 statewide</td>
<td></td>
</tr>
<tr>
<td>WV</td>
<td>25% x 2025*</td>
<td></td>
</tr>
<tr>
<td>WY</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
- *Minimum solar or customer-sited requirement
- **Extra credit for solar or customer-sited renewables
- †Includes non-renewable alternative resources

[29 states + DC and PR have an RPS (7 states have goals)]

www.dsireusa.org / April 2011
Green House Gas Price Impact on Electricity

Natural Gas and Motor Fuel at the Pump

Source: Southern Company
Interruptible Credits

- Recent trend among utilities to under-value credits paid to interruptible load
- Long term avoided resource costs vs. short term avoided costs of market purchases
- Short term valuation does not properly reflect capacity value of interruptible load
- Short term approach may be appropriate in certain circumstances
- One reasonable approach to long term valuation is the cost of a combustion turbine peaking unit
Riders/Automatic Price Adjustment Clauses

- Riders are designed to track changes in only a single cost item
  - Most common riders: fuel and purchased power adjustment mechanisms
  - DSM costs and/or lost revenues are becoming more common for rider recovery
- Intended for significant, volatile cost items beyond utilities’ control
- Riders often misused by utilities
- Utilities attempt to shift risk to customers
**Rider Advantages / Disadvantages**

**ADVANTAGES**
- Matches cost with revenue of covered item
- Can reduce the need for frequent rate cases

**DISADVANTAGES**
- Constitutes single-issue ratemaking
- Can increase utilities revenues
- Provide no incentive for cost control
Automatic Price Increase

- Proposed Illinois Legislation
  - House Bill 14
  - Formula ratemaking allows for automatic yearly price increase
  - Less oversight than current regulatory process
  - After-the-fact review shifts burden of proof to consumers
Nuclear Generation

• Provides approximately 20% of electricity in U.S.
• U.S. has not approved new nuclear plant in 30 years
• Large capital costs vs. low fuel costs
• Recent legislation proposed in Iowa for recovery of costs for construction work in progress (CWIP) for nuclear generation
• Nuclear generation’s future - ???
• Small modular reactors (SMR)
Other Issues

• Allocation of wind direct costs
  – Capital cost and fixed O&M
  – Energy resource vs. traditional fixed cost
  – Energy resource basis penalizes large users of electricity
Other Issues

• FERC Order 745
  - Demand response resources compensated for services provided to energy market at market price for energy or locational marginal price (LMP)
  - Helps to ensure competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.
Emerging Issues

Questions
Basic Concepts
Electric System Functions

- Generation
- Transmission
- Distribution
- Customer
Electric System Functions
Functional Components of an Integrated Electric Utility Company

Network Transmission Service
- Power Plant
- Main Power
- Transformer: Voltage: 13.2 – 23.0 kV
- Switching Equipment
- Voltage: 69 – 765 kV

Transformation Service
- Substation Transformer
- Circuit Breaker
- Voltage: <69 kV

Distribution Wires Service
- Distribution Pole
- Capacitor

Customer
- Meter

ABC Power & Light Company
Energy vs. Demand

- Energy = Work (light, heat, motion)
- Demand = Rate of Work
- Energy ~ Distance
- Demand ~ Speed
- Energy = Demand Summed (integrated) over time
Measuring Energy

- 1,000 watt-hours = 1 kilowatt-hour (kWh)
- 1,000 kWh = 1 megawatt-hour (MWh)
- 1,000 MWh = 1 gigawatt-hour (GWh)
Measuring Demand

• 1,000 watts = 1 kilowatt (kW)
• 1,000 kW = 1 megawatt (MW)
• 1,000 MW = 1 gigawatt (GW)
Do Not Confuse the Two

- Energy in Megawatthours
- Billed no matter when you use it.
- Demand in Kilowatts
- Billed based on Peak (maximum) demand in month
Relationship Between Energy and Demand

Energy: 500 watts x 2 hours = 1000 watthours = 1.0 kWh
Demand: 500 watts = 0.5 kW

Energy: 200 watts x 5 hours = 1000 watthours = 1.0 kWh
Demand: 200 watts = 0.2 kW
Daily Demand Pattern

Demand kW

<table>
<thead>
<tr>
<th>Time</th>
<th>4:00</th>
<th>8:00</th>
<th>12:00</th>
</tr>
</thead>
<tbody>
<tr>
<td>2:00</td>
<td>1 kWh</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

500 watts x 2 hrs

Demand kW

<table>
<thead>
<tr>
<th>Time</th>
<th>4:00</th>
<th>8:00</th>
<th>12:00</th>
</tr>
</thead>
<tbody>
<tr>
<td>5:00</td>
<td>1 kWh</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

200 watts x 5 hrs
Load Factor

• Relationship between demand and energy usage
• Measures how efficiently you are using your electricity
• Average Demand / Peak Demand
• Average Demand = Energy Usage / Time of Consumption
Load Factor

**Monthly Load Factor (LF)**

\[
LF = \frac{\text{kWh consumed in month}}{\text{Peak kW of Month} \times \sim 730 \text{ Hours}}
\]

**Annual Load Factor (LF)**

\[
LF = \frac{\text{kWh consumed in year}}{\text{Peak kW of Year} \times 8,760 \text{ Hours}}
\]
Why is Load Factor Important?

- Load factor measures how efficiently a class utilizes facilities installed to meet maximum demand
- Most fixed costs related to demand
- In general, a higher load factor suggests more energy is taken off-peak
It Costs Less (per MWh) to Serve a High Load Factor Customer!!!

• High Load Factor customer spreading fixed costs over a larger number of MWh
Two Measures of Demand

- **Coincident vs. Non-Coincident**
  - Depends upon time of peak demand
  - Coincident demand looks at time when system is peaking (monthly or annually)
  - Non-Coincident looks at individual customer or class
CP and NCP Demands

- **Coincident Peak**

  - NCP of A
  - CP of A
  - NCP of B
  - CP of B

Demand vs. Time

A | B
Reactive Power

- Occurs when voltage and current are out of phase
- Real power (kW) flows from generator to load
- Reactive power (kVAR) flows back and forth and supplies no energy
- Reactive power has a cost and contributes to losses
Power Factor Triangle

Real power = 100 kW
and
Apparent power = 142 kVA
then
Power Factor = 100/142 = 0.70 or 70%
Why Improve Your Power Factor?

Utilities usually charge a penalty for power factors less than 0.95 or 95%
QUESTIONS?