Energy Industry Update

Highlights of Recent Significant Events and Emerging Trends in the Energy Industry

Fall 2004
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Keeping your eye on the ball for the greatest comeback ever
(Red Sox rout Yankees in game 7, American League)

“We stuck together, and erased history”

Mired in a slump at the absolute worst of times, Red Sox centerfielder Johnny Damon got aggressive in Game 7 of the American League Championship Series, helping his team to win entry into the 2004 World Series … which, incidentally, they won.

Source of photo and caption: www.sportsillustrated.cnn.com, 10/04
## Executive Summary

Fall 2004 finds the energy industry focused and, for the most part, financially healthy. Today’s industry themes are neither as dramatic nor rapid as the bold trends of 1999-2003. However, subtle changes are impacting our industry. This Energy Industry Update provides a snapshot of where we find ourselves today and where we are likely to go tomorrow. We hope you find this document useful and informative.

### Theme 1
2010 planning with 2020 vision

Where you will be in 2010 depends heavily on how you view, and adapt to, today’s uncertain drivers of industry structure. For example: Will FERC become more, or less, adamant about market power and RTO development? Will deregulation remain stalled? Will high fuel prices and environmental concerns continue driving new generation technology to fruition? Will natural gas generation become stranded? Will capacity expansion be driven regionally? Will pressure for EPS growth foster more outsourcing of non-core operations? Your answers to these, and other, questions will drive your unique strategy and profitability.

### Theme 2
The search for growth continues

Energy companies, along with most other U.S. companies, have spent the last three to five years cutting costs and improving core operations. Now, however, as cost cutting opportunities diminish, growing the top line has, once again, come back into focus.

Many utilities have become aggressive in their search for new products and services. For example: PPL has an award-winning AMR program; Narragansett Electric has achieved record penetration with “clean energy”; National Grid has profited from cell phone tower siting, installation, and maintenance; and, Cinergy has a joint venture with local municipalities for BPL commercialization.

### Theme 3
Outsourcing of all non-core functions

To reduce costs, capture economies of scale and skill, and ensure “best of breed” services, utilities have been outsourcing specific functions (e.g., IT, HR, supply chain, facilities management, customer services, etc.) for quite some time.

However, the outsourcing of all, or nearly all, non-core functions to a “partner provider” is a new trend.

TXU Energy, Dynegy, BC Hydro, and others have all recently entered into such long-term, billion-dollar agreements in hopes of better aligning their support costs with their more core-focused business operations.

### Theme 4
SOX is impacting organizational structure

The financial reporting and certification requirements of the Sarbanes-Oxley Act (SOX) are mandated for most public companies filing year-end financial statements after 11/15/04. By now, most companies have developed cross-functional compliance teams and, through a tremendous effort and great expense, have ensured adequate internal controls.

The more subtle trend, however, is the impact SOX is having upon organizational structure (e.g., appointment of divisional CFOs; centralizing of communication channels; and, applying the lessons learned from SOX to enterprise risk management processes across the organization).

### Theme 5
Financial traders marginalize utility trading

The energy trading landscape has changed dramatically in the last few years. Energy companies have exited, or scaled back, speculative and physical wholesale trading; and financial institutions and sophisticated hedge funds have stepped up to fill the void.

The new entrants have reduced counterparty risk, added liquidity and enhanced market stability. However, they have also introduced non-transparent pricing, through long-term, complex structured products, and possibly even exacerbated price volatility as some players deliberately seek market inefficiencies. Both the CFTC and the SEC are increasing surveillance of this market sector.

Stock Price History by Class

September 15, 2001 to November 15, 2004
Normalized Stock Price Averaged by Class

The word “merchants” is used to describe those engaged in merchant generation and/or merchant trading.

Sources: Stock prices from nasdaq.com. All stock prices on graph are mid-month. NE=no earnings; N/A=not available
## Analysts Comment On State of Industry

### What Wall Street Analysts are Saying About Various Companies, by Industry Segment

<table>
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<tr>
<th>Remaining Merchant Traders and/or Generators</th>
<th>Ex-Merchants Who Returned to Core Operations in 2003</th>
<th>Integrated Utilities (Some With Merchant Activity)</th>
<th>Stand-Alone T&amp;D Entities</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Comex Workers</strong></td>
<td><strong>Stable, but Limited Growth</strong></td>
<td><strong>Blazing Saddles</strong></td>
<td><strong>Low Risk, Stable</strong></td>
</tr>
<tr>
<td><em>Significant progress restoring stable platform for growth; refinancing has reduced credit risk; free cash flow modest relative to debt (AES)</em></td>
<td><em>Earnings growth low; flat return on net operating assets; limited cash flow; few catalysts for upside surprises; CEO sees industry consolidation (AEP)</em></td>
<td><em>Solid balance sheet, with potential to get stronger (CIN)</em></td>
<td><em>Low risk operations; high dividend payout ratio supports the share price; seeking rate increase by 2005 for infrastructure (ED)</em></td>
</tr>
<tr>
<td><em>Earnings leverage heavily dependent on higher spark spreads; LT contracts back remaining projects; close to reaching liquidity goals (CPN)</em></td>
<td><em>Financial crisis has passed; debt maturity schedule manageable; much simpler company (ILA)</em></td>
<td><em>Robust cash flow; strong balance sheet; successful electricity trading and marketing; may expand commodities trading (CEG)</em></td>
<td><em>Stability provided by long term PBR plans at all of company’s utilities; realized significant synergies from integrating super-regional T&amp;D; limited organic growth (EAS)</em></td>
</tr>
</tbody>
</table>
| *Asset sales provided 2004 financial flexibility; respected management team; potential for material cash flow if power market improves; debt maturities timed to allow market recovery (DYN)* | *Restructuring continues; limited growth in current form, transformation likely; E&P providing strength (DUK)* | *Strength from increasing E&P volumes/pricing, and expiring hedges; above average EPS growth prospects (DOM)* | *
| *Reorganization plan by 12/04; asset value can cover debt; may do stock for debt swap; recovery hopeful (MIR)* | *Commendable recovery; still financially constrained; may have to sell more core assets, issue equity or merge (EP)* | *Cash rich; strong balance sheet; likely to pursue acquisitions and/or increase dividend (ETR)* | *
| *Impressive ability to generate cash flow at bottom of wholesale cycle; credit quality improving (RRI)* | *Value climbing as restructuring effort continues; LT growth will come from regulated utility (PCG)* | *Strong cash and balance sheet position; great progress on cost cutting (EXC)* | *
| **Solid balance sheet; above average EPS growth prospects (DOM)** | *Balance sheet weak but improving; E&P will provide strength (WMB)* | *Strong international contribution; POLR security; strong liquidity (PPL)* | *
| **Cash rich; strong balance sheet; likely to pursue acquisitions and/or increase dividend (ETR)** | **Strong balance sheet, with potential to get stronger (CIN)** | **Solid balance sheet; 4-5% EPS growth expected (SO)** | **Strong balance sheet; 4-5% EPS growth expected (SO)** |
| **Important to note:** *Company ticker symbol follows analyst comment* |

2010 Planning with 2020 Vision

Where you are in 2010, depends on how you view, and adapt to, the uncertain drivers of industry structure today

- Will Pat Wood be re-nominated?
- Will RTOs continue to develop?
- Will transmission companies proliferate?
- Will transmission be able to generate enough return to gain access to capital for expansion?
- Will POLR auctions become standardized?
- Will retail rate setting depend upon power procurement methodology?
- Will consumer interest in "clean power" wane as prices differentiate?
- Can new products and services create substantial revenue growth?
- Will U.S. continue to be bifurcated into regional markets and territorial markets?
- Will market power issues cause divestitures or just mitigation activity?
- Will capacity expansion be driven regionally?
- Will small retail customers remain increasingly happy with auction-bid POLR solutions?
- Will renewables incentives be enough to satisfy state renewables requirements?
- Will fuel prices and environmental constraints strand some assets and speed development of new technologies?
- Is outsourcing the best way to cut costs and improve efficiency?
- Is divestiture, consolidation, or both the best option?
- Is it possible to grow revenues both organically and non-organically?
- Can we make Sarbanes-Oxley pay off through better risk management?
- Are our risk-adjusted opportunities compatible with our desired credit rating and EPS growth?
- What strategy will get us where we want to be in 2010?

Is this just election politics … or is it truth?

"Enthusiasm at the FERC for reform may cool now that FERC Chairman Pat Wood appears to be headed out of office in 2005."
Alex Flint, Staff Director of the Senate Energy and Natural Resources Committee, 10/27/04

Source: Scott, Madden analysis; Platts Electric Power Daily; T&D=transmission and distribution; RTO=regional transmission organization; ITC=Independent transmission company; POLR=provider of last resort; LNG=liquefied natural gas; EPS=earnings per share; PPA=purchase power power agreement
## Generation and Trading Models 2004

### Six Generation Models (Example companies may fit into one or more categories)

| Core Oriented | Very focused on existing portfolio cost, performance, emissions expenditures, and service to incumbent customers. Generation may be regulated or unregulated. *Examples: AEP, Cinergy, PG&E, Progress Energy, Southern Co., TVA, and others* |
| Contracted to T&D Buyers | Deregulated generation but have strong contractual ties to T&D buyers through auction or assignment. *Examples: Constellation Energy, Pepco, PSEG, TXU Energy, and others. FirstEnergy intends to be in this category* |
| Portfolio Strategists | Strong incumbent position in both regulated utility sector and unregulated markets. Will acquire and/or divest select assets as appropriate. Value chain can stretch from natural gas E&P to energy retail. *Examples: Dominion, Duke Energy, Entergy, Exelon, FPL Group, PPL, and others* |
| Acquisition Oriented | Focus on scale and scope of portfolio. Will buy or build to achieve goal in target markets. *Examples: Ameren, Calpine, Reliant Energy, Sempra, Constellation Energy, and others* |
| Generation is a Sideline | Primary business is trading commodities or financing power plants. Generation assets acquired to: strengthen trading position; wring value out of long-term, above-market contracts; or, to protect financial investment. *Examples: Goldman Sachs, GE Energy, Merrill Lynch, Morgan Stanley, private unregulated hedge funds acting like day traders, and others* |
| Opportunists | This group sees future profits in acquiring troubled generation plants. May retain, run, and sell capacity and power into niche markets and/or may sell assets when market turns. *Examples: Bear Stearns & The Houston Energy Group, Carlyle Riverstone, Kohlberg Kravis Roberts, MMC & Wood Power, Panda Acquisitions & Carl Icahn, Texas-Pacific Group, and others* |

### The Rise of Financial Entity Trading

“Traditional energy companies, such as utilities, are either exiting or being marginalized in this emerging, more sophisticated financial-entity trading environment. ... There are now some 100-150 hedge funds involved in a major way in trading gas and power. There should be some concern about the volatility which they can create.” Peter Fusaro, Chairman, Global Change Associates, 10/04

“I predict that utilities will increasingly outsource the asset optimization task to the banks.”

David Owens, Sr. VP Entergy-Koch Trading, 10/04

- Financial players have improved overall counterparty credit profiles
- Liquidity seems to have improved, but market remains far from robust
- Financial players are creating LT complex products that are more profitable than standard products, but also more difficult to unwind. Market transparency may suffer
- Dramatic increase in hedge fund trading activity may exacerbate market volatility & instability
- Hedge funds could default without warning

E&P = exploration and production of natural gas. LT = long term
Trends in T&D Asset Management

“Asset management has become a major competitive skill for utilities eager to control costs, meet performance-based rate regimes and, in the process, maximize their returns.”
GF Energy, Survey of Asset Management in T&D, July 2004

Survey Statistics *

- **Participation:** 65% of large U.S. utilities have set up a formal asset management program
  - In 25% of these cases, asset management has remained decentralized with the various departments implementing their own programs under their respective vice presidents
  - Overall, 50% of utilities have set up asset management groups. 40% of these groups were created less than two years ago

- **Timeframe:** Asset management cannot be implemented overnight. Most utilities surveyed indicated a five-year timeframe to properly implement asset management

- **Cost:** The yearly cost of an asset management program is about 0.3%-0.5% of the asset base involved, plus the equivalent of roughly 0.7 to 1.0% for program set up

- **Payback:** Many asset management initiatives have a payback period of less than 2-3 years

- **Condition-based maintenance (CBM):** U.S. utilities are progressively using CBM. CBM means customizing O&M on the basis of equipment condition, past failure, and comparison to history of similar equipment. The adoption rate for CBM is about 35% of U.S. utilities, with a growth rate of 4-6% per year. GF Energy forecasts that most utilities will have converted to CBM by 2006

Best Practices *

- Set up benchmarking program by asset class and region
- Implement unique and comprehensive equipment tagging
- Practice cluster-based asset management (cluster by similar types of equipment characteristics, conditions, manufacturer types)
- Use more real-time data and on-line non-disruptive testing and monitoring
- Improve data management (data capture, test quality, and data mining)
- Monitor “critical assets” – 15-20% of all assets – critical not only in terms of potential failures and operational grid impacts, but also revenue and customer satisfaction impact

- Broaden on-line condition monitoring of equipment
- Roll-out condition-based maintenance (CBM)
- Extend preventive maintenance cycles on non-critical assets
- Apply cross-training and maintenance shift rotations when possible
- Adopt multi-rule condition-based overhaul programs
- Consider selective specialty outsourcing
- Re-engineer or adopt new O&M practices based on lessons learned
- Develop pilot programs for early wins

Asset management practices are starting to influence the way equipment is being replaced. GF Energy found that close to 30% of the equipment replacement decisions are now CBM-driven, compared to none about 6-7 years ago. This means that less equipment is run to failure and/or that fewer assets are replaced on a purely time-based approach

Source: **“Asset Management in Transmission and Distribution,”** GF Energy, July 2004; T&D=transmission and distribution
The Heart of Planned Outage Management

Effective and efficient outage management is a source of strategic, competitive advantage

Whether it's a nuclear, fossil, or T&D outage

A large percentage of non-fuel O&M is spent on outages …

… and, the vast majority of capital expenditures occur during outages

The question is … Are you reaping the best value for every dollar spent?

The key is to execute every outage as efficiently and effectively as possible

So … how e-x-a-c-t-l-y do you do that?

Characteristics and trends of companies that have the most effective outage management procedures and processes

- Have a thorough understanding of the material condition of each piece of equipment
- Have a robust condition-based maintenance, or reliability-centered maintenance program
- Centralize the outage management function to standardize practices and procedures across the fleet
- Develop and implement a “system owner” (e.g., subject matter experts) program that is a key driver in work scope determination
- Leverage technical knowledge across the fleet
- Elevate the skills of outage managers and encourage them to earn Project Manager Professional certifications

Successful execution of any planned outage requires disciplined management controls in eight key areas

1. Business planning and budgeting
2. Timing and duration optimization
3. Organization structure
4. Goal setting and analysis
5. Defined accountability and responsibility for results
6. Pre-outage planning and milestone management
7. Ability to communicate direction, issues and status
8. Cost accounting and management

Source: Scott, Madden analysis; O&M=operations and maintenance expense; T&D=transmission and distribution
On 1/1/07, Illinois will end its mandatory deregulation transition period and its freeze of bundled electric rates. The Illinois Commerce Commission is currently investigating the issues which need to be resolved prior to full competition on 1/1/07. One of the major issues is the methodology for power procurement for load serving entities (e.g., T&D utilities).

This page summarizes some of the pros/cons of these options:

- **Vertical Auction**
  - LSEs vertically divide load obligation into tranches, each having the same load shape. Prospective suppliers bid to serve full-requirements products.
  - **Pros** – Transparent, competitive, prudent for cost recovery, prudent for cost recovery, track record from other states.
  - **Cons** – May limit number of players who can offer full-requirements products.

- **Full Requirements RFP Process**
  - Same as option one except, instead of auction, commission approves and monitors a utility-designed RFP process.
  - **Pros** – Transparent, competitive, prudent for cost recovery, track record from other states.
  - **Cons** – May limit number of players who can offer full-requirements products.

- **Horizontal Procurement**
  - LSEs horizontally divide load according to resource type (baseload, intermediate, peaking) or by weekday/hour. Auction or RFP process conducted for each segment.
  - **Pros** – Product flexibility, may dilute exposure to volatility or market power, small suppliers can participate.
  - **Cons** – Significant complexity for PUC prudency reviews.

- **Affiliate Purchases**
  - LSE contracts with generating affiliate for all of its load obligation. Affiliate can acquire power on market.
  - **Pros** – Utilizes legacy portfolio and risk management expertise, may provide stable rates.
  - **Cons** – Not a competitive approach, may be inconsistent with FERC affiliate rules, does not facilitate participation by non-affiliates.

- **Traditional Utility Resource Planning + Competition**
  - This approach is consistent with traditional utility resource planning, but is adapted to consider competitive supply. LSE periodically assesses demand/supply, commission approves utility supply plan.
  - **Pros** – Can be structured in favor of competitive procurement.
  - **Cons** – Judgment-based review, methodologies not standard.

- **Transition Period Extension or Expiration**
  - Utility rates remain subject to a bundled rate “freeze”, or to traditional rate regulation. Utility would be free to acquire power by any means. Cost recovery limited to current rates.
  - **Pros** – May be favorable for consumers in short run, could be compatible with wholesale procurement process.
  - **Cons** – LSEs absorb volatility of wholesale power prices.

- **Integrated Utility Supply or Re-regulation**
  - Retail load which is not served by competitive suppliers is served by integrated utility, as always. PUC regulates rates for these customers.
  - **Pros** – Preserves multi-jurisdictional operational efficiencies (e.g., generation in non-dereg state).
  - **Cons** – May preclude competitive suppliers.

Source: “Post 2006 Initiative,” Final report to the IL Commerce Commission, Procurement Working Group, 10/18/04; IL Commerce Commission website. LSE=load serving entity; PUC=public utility commission; RFP=request for proposal.
Retail Rate Setting Policy Options
Under Full Competition

The Illinois electric utilities were legally prevented from seeking rate increases during the transition to competition. It is likely that new rate cases will be initiated for most, or perhaps even all, Illinois utilities during 2006, with rates becoming effective in 2007. Some of the major rate setting policy options presented to the IL Commerce Commission by the Post-2006 Initiative, Rates Working Group, are presented here.

**Recommended treatment of rates under various procurement options** (see prior page)

<table>
<thead>
<tr>
<th>Power Procurement Method</th>
<th>Vertical Auction</th>
<th>Full Requirements RFP Process</th>
<th>Horizontal Procurement</th>
<th>Affiliate Purchases</th>
<th>Traditional Utility Resource Planning + Competition</th>
<th>Transition Period Extension or Expiration</th>
<th>Integrated Utility Supply or Re-regulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Treatment</td>
<td>Utilities should pass through, with no mark-ups or return on, the costs of acquiring the commodity itself</td>
<td>Utilities’ rates should include their cost of acquiring the capacity and energy and the costs of hedging, if any</td>
<td>Utilities’ rates should include their costs of acquiring the capacity and energy and the costs of hedging, assuming legal test supports no affiliate abuse</td>
<td>Same as under horizontal procurement. Utilities’ rates should include their cost of acquiring the capacity and energy and the costs of hedging, if any</td>
<td>Utilities should recover their commodity costs, in whole or part, through existing, frozen bundled rates and through just/reasonable rates for other commodity components</td>
<td>Utilities will recover their production costs under traditional ratemaking principles or an alternative regulatory structure, as allowed by law</td>
<td></td>
</tr>
</tbody>
</table>

**Other select, rate policy issues which received Rate Working Group consensus**

- When filing bundled service tariffs, utilities should separately determine the cost of the commodity component and provide unbundled price information to customers
- Prices related to services which can be provided by a competitive metering service provider should be unbundled, even in tariffs where the services remain bundled
- A single proceeding should be used by each utility to determine the unbundled delivery services rate and the distribution components of the bundled rates
- Utilities should endeavor to synchronize the delivery charges in their unbundled rates with the delivery price components of their bundled rates
- Utilities should at least partially hedge against variation in market prices included in the commodity portion of rates for residential and small commercial customers
- If the prudence of the procurement plan is reviewed and approved in advance by the PUC, it should not be re-examined again, after the fact, unless absolutely necessary

Source: “Post 2006 Initiative,” Final report to the IL Commerce Commission, Rates Working Group, 10/18/04; IL Commerce Commission website; PUC=public utility commission; RFP=request for proposal
# Utility Outsourcing – Select Examples

**Same motivation for all:** Cut costs, improve service, increase employee opportunities

<table>
<thead>
<tr>
<th>Vendor and Initiation</th>
<th>Functions (all or in part)</th>
<th>Employee Transfer</th>
<th>Terms</th>
<th>Expected Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>BC Hydro</td>
<td>Accenture 4/03</td>
<td>IT, HR, financial, purchasing, CIS, facilities management</td>
<td>Yes</td>
<td>10-year $1.3B (C)</td>
</tr>
<tr>
<td>Dynegy</td>
<td>Accenture 10/03</td>
<td>IT, HR, procurement, financial</td>
<td>Yes</td>
<td>Multi-year Multi-million</td>
</tr>
<tr>
<td>Entergy</td>
<td>SAIC 10/99</td>
<td>IT</td>
<td>Yes</td>
<td>7-year $580M</td>
</tr>
<tr>
<td>Enbridge</td>
<td>Accenture 7/02</td>
<td>Customer services</td>
<td>Yes</td>
<td>N/A</td>
</tr>
<tr>
<td>Hydro One</td>
<td>Cap Gemini 3/02</td>
<td>IT, HR, supply chain, financial, customer care</td>
<td>Yes</td>
<td>10-year $90M-$130M per year (C)</td>
</tr>
<tr>
<td>Ontario Power</td>
<td>Cap Gemini 2/01</td>
<td>IT</td>
<td>Yes</td>
<td>10-year $1B (C)</td>
</tr>
<tr>
<td>PSEG &amp; PPL</td>
<td>EDS 1/01, 4/00</td>
<td>IT</td>
<td>Yes</td>
<td>8-10 year $135-$137M Total</td>
</tr>
<tr>
<td>TXU Energy</td>
<td>Cap Gemini 7/04</td>
<td>IT, HR, supply chain, financial, customer services</td>
<td>Yes</td>
<td>10-year $3.5B</td>
</tr>
<tr>
<td>Williams</td>
<td>IBM 6/04</td>
<td>IT, HR, finance, accounting</td>
<td>Yes</td>
<td>7.5-year $320M</td>
</tr>
</tbody>
</table>

**Don’t forget your SOX!**
(Compliance with Sarbanes-Oxley)

When outsourcing or off-shoring, it is critical to understand the vendor’s business and the extent to which the vendor uses subcontractors. Your outsourcing contract should state the vendor’s scope and timing for reviewing its system of internal controls, and those of its subcontractors, and for reporting back to you in the form of a SAS #70 audit report. Contract should also state who is responsible for the cost of compliance.

Sources: Various company websites and press releases. (C)=Canadian dollars
# Sarbanes-Oxley, Section 404 Compliance: Lessons Learned

<table>
<thead>
<tr>
<th>Planning and Project Management</th>
<th>Process and Policy</th>
</tr>
</thead>
</table>
| ◆ Form a CEO-empowered project management office to: monitor project progress; align methodologies; coordinate multiple groups, schedules and resources; control quality; and, manage across organizational boundaries | ◆ Acknowledge that controls may not be as good as we think  
  — What we say we do vs. what we actually do  
  — Tolerance for errors vs. new regulatory scrutiny and auditor conservatism  
  — Effects of reduced staff  
  — Utility conservatism and “lagging practices” |
| ◆ Understand that “SOX fatigue” will overtake process owners and will continue as processes change and future SOX testing is required | ◆ Understand auditor views on control objectives, rigor of assessment, and best practices  
  ◆ Form model of ideal process and control evidence before assessing control adequacy  
  ◆ Use Section 404 compliance as an opportunity to:  
    — Document and provide platform for common understanding of controls, both within and outside organization  
    — Improve processes, adding structure or streamlining and reducing complexity |
| ◆ Provide incentives and milestones, but ensure quality isn’t subordinated to speed |  |
| ◆ Ensure review and testing of processes begins early enough in audit cycle to allow time for remediation of any exceptions |  |
| ◆ Apply the 80/20 rule – focus on those processes that pose the most risk or are unmanageable through compensating controls |  |
| ◆ Make control gaps transparent, monitor and consistently follow up on remediation |  |

<table>
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<tr>
<th>Skills and Knowledge</th>
<th>Systems and Infrastructure</th>
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<tr>
<td>◆ Hire, develop and train staff with good foundation in accounting and audit skills</td>
<td>◆ Address IT controls early and continually. IT controls permeate the organization and are often the last to be scrutinized, however, they could be the most complex to fix</td>
</tr>
<tr>
<td>◆ Leverage subject-matter expertise and knowledge of leading practices, which can be as valuable as accounting or audit expertise</td>
<td>◆ Establish a methodology and a templated approach. Stick with your approach, but be flexible enough to accommodate anomalies</td>
</tr>
<tr>
<td>◆ Employ internal audit, or objective inside organization, to review management assessments to help control extent, and cost, of testing by external auditors</td>
<td>◆ Leverage technology for compliance wherever possible (e.g., to reduce paper intensity)</td>
</tr>
<tr>
<td>◆ Maintain continuity—same resources should be involved in designing and testing of control processes</td>
<td></td>
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<tr>
<th>2004</th>
<th>2005 and Beyond</th>
<th>Issues on the Horizon</th>
</tr>
</thead>
</table>
| Tier 1 company initial management assessments and auditor reviews | ◆ Ongoing compliance and certification  
  ◆ Tier 2 company initial assessments | ◆ Ongoing SOX compliance monitoring and management  
  ◆ Records management  
  ◆ Automation / IT-enabled compliance  
  ◆ Leading practice reviews and adoption  
  ◆ Audit/accounting training  
  ◆ Migration from spreadsheets to automated accounting tools |

Source: Scott, Madden analysis
Form Follows Function – Impact of Sarbanes-Oxley on Structure

Who would have thought that Sarbanes-Oxley, which focuses heavily on corporate governance and accounting practices, would have such an impact on organizational structure?

Finance and Accounting (F&A)

- Are your F&A functions organized around a unified service delivery model, or do you have multiple “islands” of F&A working independently?
- Do your various F&A functions have well-defined responsibilities, compatible systems, and consistent processes?
- Are your decision-making processes enabled by efficient communications between the various F&A functions?
- Does your F&A organization structure (e.g., centralized or semi-decentralized) ensure data integrity and reliable accounting controls?
- Does the structure of your F&A organization facilitate the implementation of best practices?
- Are your F&A functions organized into transaction processing and the more corporate/divisional analytical planning, forecasting and decision-making functions?
- Does your F&A organization have the right number of layers and the most appropriate-size spans of control?

Information Technology (IT)

- Is your Chief Information Officer on the Sarbanes-Oxley (SOX) steering committee?
- Do the IT department and all those involved in processing financial IT systems understand their roles? Do they possess the skills necessary to perform their job responsibilities relating to internal control?
- Is IT risk assessment aligned with corporate risk assessment?

Is your organization structured for success in the post-Enron/SOX world? What small steps are others taking?

Microsoft

Microsoft recently appointed divisional CFOs for each of its major business units, with dual-reporting to the corporate CFO and business heads.

“Five years ago, we established a very strong role for operating-group and divisional CFOs in our organizations. We installed them and then grew the talent of a “new age” CFO in each of our groups. Today, this structure enables us to cut costs further by centralizing our controllership function. In only seven months, we have reduced total F&A costs by 10%. Our three-year goal is to reduce these costs by 25%.”

Martyn Redgrave, Executive VP and CFO (8/04)

Carlson Companies

At Carlson Companies, a leader in the hotel, resort, and restaurant industry, the burning platform for F&A re-organization was a tremendous pressure regarding profit margins.

“Five years ago, we established a very strong role for operating-group and divisional CFOs in our organizations. We installed them and then grew the talent of a “new age” CFO in each of our groups. Today, this structure enables us to cut costs further by centralizing our controllership function. In only seven months, we have reduced total F&A costs by 10%. Our three-year goal is to reduce these costs by 25%.”

John Connors, CFO and Sr. VP of Finance and Administration (8/04)

Sources: “Finance’s Big Leap Forward,” Business Finance magazine, Eric Kress, 8/04; “The Sarbox Conspiracy,” CIO Magazine, 7/1/04; Scott, Madden analysis
Sarbanes-Oxley Meets Enterprise Risk Management

What is Enterprise Risk Management?

- It is a process, ongoing and flowing through an entity
- It is effected by people at every level of the entity
- It is applied in a strategy setting, across the entity, at every level and business unit
- It encompasses a portfolio view of risk
- It identifies potential events to be managed within the entity's risk appetite
- It provides reasonable assurance to management and the board
- It is structured to achieve objectives in one or more separate, but overlapping, categories

Enterprise risk management is a multidirectional, iterative process in which almost any component can and does influence another

Components of Enterprise Risk Management (ERM)

**Internal Environment** – Consider the tone of the entity and establish how risk is viewed, including integrity, ethics, risk philosophy, and risk appetite

**Objectives** – Align with the entity's mission and risk appetite

**Event Identification** – Identify internal and external risks and opportunities with potential to affect objectives, positively or negatively

**Risk Assessment** – Consider likelihood and impact

**Risk Response** – Develop a response (avoid, accept, reduce, or share) that aligns with risk tolerance and appetite

**Control Activities** – Develop policies and procedures to carry out risk responses

**Information and Communication** – Identify, capture, communicate in an effective format and timeframe

**Monitoring** – Monitor the system through ongoing management activities and separate evaluations

Everyone in an entity has some responsibility for ERM

How Does ERM tie to SOX?

- About 35% of SOX compliance is ERM
- Many of the controls being documented and tested for compliance fall under the ERM umbrella
- SOX compliance must stop being a "finance project" and become a part of an entity's day-to-day activities
- The knowledge gained by the SOX assessment of all the processes which affect the financial statements can also help improve an array of ERM processes
- SOX implementation has begun a flow of communication and role definition for ERM in finance, risk management, operations, audit, and other functions

## Growth Opportunities

- Better profit management of the basic utility
  - Automated meter reading
  - E-billing
  - Builder installs
- Growth through customer addition
  - Privatization (e.g., federal military base)
  - Municipal/coop acquisition and/or retention
  - Economic development
- Leverage existing core products and customers
  - Differentiated core
    - Green power / Clean energy
    - Flat bill / time of season pricing
  - Restructure regulatory model
    - Performance-based rates
    - Cost pass-throughs
- Leverage existing assets
  - Broadband over power lines
  - Attachments / rights of way
  - Call centers
- Provide services to new customers
  - Services to: Upstream providers, munis, RTOs, etc.
    - T&D services
    - Load management
    - Demand-side management
    - Maintenance
  - Outdoor lighting
  - Premium power
  - Distributed generation
  - Home wiring / surge protection
  - Energy management
- Add new value-added products

## Mini Profiles of Select Opportunities

### Flat Billing
- Fixed annual bill provides 12 equal payments with no year-end settlement. Utility must build a risk premium into the bill
  - IPALCO has now; Nicor has seasonal flat bill; Georgia Power is running pilot

### Green Power or “Clean Energy”
- Studies in New England have found that consumers respond better to the term “clean energy” than to “green power.” The National Grid’s Narragansett Electric in Rhode Island recently ran such a promotion and achieved a U.S. record penetration rate of 24% in 100 days

### Attachments – Right of Way
- Substation maintenance; overhead line maintenance; cell phone tower siting, installation, maintenance
  - National Grid USA has GridCom subsidiary; Puget Energy has InfrastruX subsidiary

### Munis & Coops
- Solid financial performance of some munis & coops make them attractive acquisition targets
  - On the flip side, retention of municipal wholesale business is also worth the effort

### Premium Power
- 24 X 7 dependence upon IT systems has made many corporations anxious about having 99.9% system availability
  - Each additional “9” added to 99.9% uptime yields price premiums for you

### Automated Meter Reading
- AMR eliminates estimated bills, aids customer service reps. Will eventually lead to new rate options and power outage reporting
  - PPL has industry’s most extensive AMR program (1.1 million meters installed, intent is for all customers to have AMR)
**Broadband Over Power Lines (BPL)**

“We urge utilities to pursue new and developing technologies, like BPL, that will foster greater customer options in broadband, provide more efficient management of the power supply system, and ensure increased operational reliability.”

Joint statement from FERC Chairman Pat Wood and FCC Chairman Michael Powell, 10/14/04

<table>
<thead>
<tr>
<th>BPL Vendors and Partners</th>
<th>Utilities with Commercial BPL</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>Central Virginia Electrical Coop</td>
</tr>
<tr>
<td>Alliant</td>
<td>Cinergy</td>
</tr>
<tr>
<td>Ameren</td>
<td>City of Manassas</td>
</tr>
<tr>
<td>AZ Public Service</td>
<td>PPL (in advanced preparation stage)</td>
</tr>
<tr>
<td>Avista</td>
<td></td>
</tr>
<tr>
<td>Bowling Green, OH</td>
<td></td>
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<tr>
<td>Chelan PUD, WA</td>
<td></td>
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<tr>
<td>City of Salem, VA</td>
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<tr>
<td>Clyde, OH</td>
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<tr>
<td>Conectiv</td>
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<tr>
<td>ConEd</td>
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<tr>
<td>Consumers Energy</td>
<td></td>
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<tr>
<td>Cowetta Fayette EMC</td>
<td></td>
</tr>
<tr>
<td>Dominion Resources</td>
<td></td>
</tr>
<tr>
<td>Douglas PUD, WA</td>
<td></td>
</tr>
<tr>
<td>Duke Energy</td>
<td></td>
</tr>
<tr>
<td>Fayetteville, TN</td>
<td></td>
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<tr>
<td>Idaho Power</td>
<td></td>
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<tr>
<td>Indianola Municipal</td>
<td></td>
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<tr>
<td>IDACORP</td>
<td></td>
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<tr>
<td>Kissimmee, FL</td>
<td></td>
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<tr>
<td>New Horizon, GA</td>
<td></td>
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<tr>
<td>Orange and Rockland</td>
<td></td>
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<tr>
<td>Pepco</td>
<td></td>
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<tr>
<td>Penn Yan, NY</td>
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<tr>
<td>PG&amp;E</td>
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<tr>
<td>Progress Energy</td>
<td></td>
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<tr>
<td>RPU, WI</td>
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<tr>
<td>Santee Cooper</td>
<td></td>
</tr>
<tr>
<td>Southern Co.</td>
<td></td>
</tr>
<tr>
<td>Sierra Pacific</td>
<td></td>
</tr>
<tr>
<td>TECO</td>
<td></td>
</tr>
<tr>
<td>and others</td>
<td></td>
</tr>
</tbody>
</table>

**Utilities with BPL Pilots**

- AEP
- Alliant
- Ameren
- AZ Public Service
- Avista
- Bowling Green, OH
- Chelan PUD, WA
- City of Salem, VA
- Clyde, OH
- Conectiv
- ConEd
- Consumers Energy
- Cowetta Fayette EMC
- Dominion Resources
- Douglas PUD, WA
- Duke Energy
- Fayetteville, TN
- Idaho Power
- Indianola Municipal
- IDACORP
- Kissimmee, FL
- New Horizon, GA
- Orange and Rockland
- Pepco
- Penn Yan, NY
- PG&E
- Progress Energy
- RPU, WI
- Santee Cooper
- Southern Co.
- Sierra Pacific
- TECO
- and others

**The Business Case**

- Projected cost is $100-$200 per home passed, depending on density
- Fees depend on speed
  - $30-$40 residential
  - $60-$360 business
- Internal benefits for system monitoring, load-control technologies, automated meter reading. *This might be the key driver for utilities*
- One more way to maintain customer loyalty
- Supports economic development plans, especially for municipals
- Two monkey wrenches:
  - In an recent survey, Platts Research discovered that only 9% of 1,000 residential customers were very interested in utility-provided BPL if it was priced at $29.95/month, a price that is below the typical charge from cable or other broadband providers
  - The utility-provided BPL market may be limited by the strong incumbency of DSL and cable

**Investor-owned utility model**

- Joint venture with vendor
- Target markets: businesses; residential; munis and coops in areas with limited broadband access, but networks that can support BPL; long-distance phone companies and internet-service providers

**Municipal utility model**

- Franchise out BPL and collect percentage of all revenues generated
- Receive distribution grid monitoring service for free from franchisee

Clean Coal Technology

“It is my belief that the IGCC cost structure is coming down and eventually will be equal to or lower than more conventional pulverized coal technology.” James Rogers, CEO, Cinergy, 9/28/04

“Clean coal is a cornerstone of our current energy portfolio, particularly for power generation, and it will continue to be so for the long-term future.” Spencer Abraham, Secretary of Energy, 11/03

Integrated gasification combined cycle (IGCC)
Domestic coal is treated to remove its sulfur and convert it to a gas. Oxygen is mixed with the gasified coal and then burned.
Benefit: Less fuel, more efficiency

<table>
<thead>
<tr>
<th>Technology cost comparison from EPRI</th>
<th>(500 MW plants, with 80% capacity factor)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total plant cost $/kW</td>
</tr>
<tr>
<td>IGCC</td>
<td>$1,250-$1,350</td>
</tr>
<tr>
<td>Pulverized coal</td>
<td>$1,230-$1,290</td>
</tr>
<tr>
<td>Natural gas, CC</td>
<td>$440</td>
</tr>
</tbody>
</table>

NARUC identified barriers to IGCC commercialization
- Higher capital cost than NGCT
- Chance of low plant availability
- Doubts about commercial viability
- Increased risk due to higher development costs
- Skepticism regarding IGCC technology and reliability
- Lack of turnkey vendors
- Permitting problems
- Failure of some IGCC projects
- Uncertainty about emissions regulation
- Lack of purchase power agreements
- Uncertainty about tax credits

Benefits of Integrated Gasification Combined Cycle

<table>
<thead>
<tr>
<th>Environmental</th>
<th>Technology</th>
<th>Economic</th>
<th>Security</th>
</tr>
</thead>
<tbody>
<tr>
<td>IGCC would dramatically reduce emissions of SO₂, NOₓ, mercury, particulates, and CO₂ as compared to conventional coal plants</td>
<td>IGCC facilities can be used to co-produce liquid fuels (e.g., diesel fuel), commodity chemicals, and even hydrogen</td>
<td>IGCC would provide an opportunity to cost-effectively re-power older, conventional coal plants</td>
<td>IGCC would be valuable in reducing reliance on imported fuels from unstable regions. The coal supply chain is less vulnerable than the oil/gas infrastructure</td>
</tr>
</tbody>
</table>

Sampling of planned or operating IGCC plants

<table>
<thead>
<tr>
<th>AEP</th>
<th>First Energy</th>
<th>Cinergy</th>
<th>TECO</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP plans to construct the first commercial-scale base-load IGCC in 2010. Four 250-MW units. Cost $1.3B. Part of emissions mitigation plan</td>
<td>First Energy and Consol Energy, a large eastern coal company, have formed a task force to evaluate the commercial viability of baseload IGCC</td>
<td>Cinergy is negotiating with GE and Bechtel about potential IGCC conversion of its existing 160-MW Edwardsport coal-fired plant in Indiana</td>
<td>Tampa Electric has had an operating IGCC plant since 1996. 250-MW, 3 units. Built with a $120M grant from the DOE</td>
</tr>
</tbody>
</table>

Federal tax credit renewed

On 10/4/04, President Bush signed legislation containing a 10-year extension of the federal tax credit for energy from wind and biomass. The credit applies to qualifying turbines built by year-end 2005 and is retroactive to 1/1/04. The tax credit is 1.8 cents/kWh produced.

When the credit expired in 12/03, the growth in the wind industry stalled, but investment is now expected to resume.

When the wind is blowing, a new wind turbine can produce electricity at a cost of 2.5 to 4 cents per kWh vs. 5.5+ cents at a new gas-fired generator.

Note: Wind is an intermittent source of power

FERC sees four challenges

- Uniform national standards for grid interconnection
- Tariff issues when generators do not produce preset quota of power
- Lack of regional grid capacity
- Value of installed-capacity market for wind

“As wind continues to expand, we at FERC are trying to remove as many barriers as possible. We have been working on these issues for about a year in a focused way, and we’ve made a lot of progress. The ball is in the industry’s court. After AWEA, working with FERC, comes up with the rules, FERC will propose a final rule.”

Rob Gramlich, FERC, 9/28/04

Eighteen states now require utilities to obtain set percentages of electricity from renewable sources by various target dates. The wind industry hopes to provide 6% of the nation’s power by 2020

Total installed U.S. wind energy capacity as of 1/22/04: 6,400 MW

<table>
<thead>
<tr>
<th>States with &gt;200 MW</th>
<th>CA</th>
<th>TX</th>
<th>MN</th>
<th>IA</th>
<th>WY</th>
<th>OR</th>
<th>WA</th>
<th>CO</th>
<th>NM</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW Installed</td>
<td>2,051</td>
<td>1,293</td>
<td>580</td>
<td>472</td>
<td>285</td>
<td>260</td>
<td>244</td>
<td>229</td>
<td>205</td>
</tr>
<tr>
<td>MW Proposed or Under Construction</td>
<td>337</td>
<td>92</td>
<td>111</td>
<td>420</td>
<td>0</td>
<td>0</td>
<td>645</td>
<td>0</td>
<td>80</td>
</tr>
</tbody>
</table>

Sources: American Wind Energy Association (AWEA); news and quotes from Platt's Electric Power Daily, "Not Just Tilling Anymore," WSJ, 10/14/04
**Federal/State Environmental Incentives**

“The States do not have consistent incentives to encourage the environmental upgrading of base-load generators (mainly coal-fired). However, many states do allow the recovery of such costs through rates.”

NARUC, 2004

“Coal-based utilities face significant economic hardship without certain, timely, and full recovery processes for emission control expenditures.”

AEP, 2004

**Federal Incentives for Environmental Investments**

<table>
<thead>
<tr>
<th>Initiative</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Plant Improvement Initiative</td>
<td>Provides $95 million for partial funding of clean energy projects. DOE has selected 8 projects for funding in the program’s initial phase.</td>
</tr>
<tr>
<td>IRS permits 60-month amortization</td>
<td>IRS permits 60-month amortization of certain qualified pollution control facility additions to plants placed in service prior to 1/1/76. Can provide approximately a 6% NPV benefit over life of project.</td>
</tr>
<tr>
<td>IRS section 29 synthetic fuels tax credits</td>
<td>IRS section 29 synthetic fuels tax credits is a good deal. However, no new Section 29 credits can be granted until Congress enacts and the President signs new legislation into law.</td>
</tr>
</tbody>
</table>

**Proposed Federal Environmental Rules**

- **Clear Skies bills** include a cap and trade program that provides incentives for improved environmental performance of base-load generation. Sets strict, mandatory caps for SO$_2$, NO$_x$, and mercury.
- **EPA’s Clean Air Interstate Rule** focuses on 29 Eastern states and the District of Columbia. Each state must revise its SIP to include control measures that meet state-wide emission reduction requirements.
- **EPA’s Utility Mercury Reductions Rule** has two alternatives: cap and trade program or rule requiring installation of “maximum achievable control technologies” (MACT).

**State incentive programs in states with substantial coal-fired generation**

<table>
<thead>
<tr>
<th>State</th>
<th>% Coal-based generation</th>
<th>Cost Recovery*</th>
<th>Regulatory Incentives</th>
<th>Tax Incentives</th>
<th>Finance Mechanisms</th>
<th>Ratemaking Treatments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Georgia</td>
<td>65%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indiana</td>
<td>94%</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Kentucky</td>
<td>97%</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Michigan</td>
<td>68%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North Carolina</td>
<td>62%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North Dakota</td>
<td>92%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Jersey</td>
<td>17%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ohio</td>
<td>87%</td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>59%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>South Carolina</td>
<td>42%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>South Dakota</td>
<td>35%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>West Virginia</td>
<td>99%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wisconsin</td>
<td>71%</td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

Barriers to increased environmental investment for base-load plants as identified by each state commission:

- Cost of CCT
- Cost / lack of tax incentives
- Stranded costs / lost sales
- Excessive cost / plant ages
- CO$_2$ from out of state plants
- Regulatory/market uncertainty
- Cost recovery in open market
- Federal policy uncertainty
- Increased costs and rates
- None reported


CCT=clean coal technology; NPV=net present value; SIP=State Implementation Plan. *Cost recovery may be full or limited to accelerated depreciation policies.*
"In Fitch’s view, natural gas prices are currently above the long-term trend, and over time, prices are expected to decline, reverting to a long-term trend at around $3.60-$3.70/MMBtu in constant dollars. Factors that could cause prices to decline include: demand destruction, more LNG imports, new construction of clean coal technologies or nuclear plants. However, these forces are unlikely to reduce price pressure in the near term. Until 2008 or later, natural gas prices will be high and volatile.” FitchRatings, 10/26/04

“The higher and more volatile gas prices are not a fault of markets. Rather, they are the result of a disappointing geological experience over the last several years, compounded by issues involving access to resources. Eventually, enough LNG imports will be available to meet rising U.S. demand for natural gas. But, LNG won’t be available in healthy volumes until 2009 or 2010. In the interim, we predict natural gas prices will exceed $5/MMBtu for the next few years; and, abnormal weather could push prices into the $8-$10/MMBtu range.”
Daniel Yergin, Chairman, Cambridge Energy Research Associates 10/11/04 (in testimony before Congress)

Sources: “Electric Fuels Outlook,” FitchRatings, 10/18/04; “The Next Big Thing,” FitchRatings, 10/26/04; “Natural Gas, Heating Oil Rise Amid Fears of Tight Supplies,” Wall Street Journal, 10/21/04; “Congress Warned High Gas Prices Will Persist Next Five Years,” Natural Gas Week, 10/11/04; Natural gas chart from oilnergy.com; Coal chart from EIA weekly coal news and markets
**LNG Update**

### Key LNG Issues

**Regulatory Jurisdiction**
- In June 2004, the DOE told a Congressional committee that FERC, and not the states, should have exclusive regulatory authority over the siting, construction, and operation of LNG terminals. The FERC and California currently disagree about on-shore LNG jurisdiction. Siting of off-shore LNG terminals currently falls under the jurisdiction of the DOT, through the Coast Guard and the Maritimes Administration.

**Overcapacity vs. Supply**
- In July 2004, analysts at Deutsche Bank (DB) said that re-gasification capacity will not be a problem in the future. Instead, the primary hurdle will be finding dedicated LNG supply to fill those terminals as global demand for LNG increases. DB says the number of proposed re-gasification projects proposed in N. America (40) is ludicrous given the market needs. Only 2-3 new terminals expected by 2010.

**Security and Supply Fears**
- Local politicians and residents in many coastal towns are rejecting proposals for LNG terminals based on fears that the terminals could become terrorist targets.
- Exxon Mobil believes that the diversity of the world’s LNG suppliers will help stop the development of an OPEC-style cartel.

**Gas Interchangeability**
- The burn “quality” of natural gas depends upon how and where it is gathered and the ratio of its chemical components. Imported LNG is generally of a higher quality than domestic natural gas and, therefore, can adversely impact the end usage. In September 2004, the NAESB proposed a set of standards whereby pipeline operators will inform power plant owners of the quality of the natural gas they are transporting.

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**Existing and approved U.S. LNG terminals, as of 9/04**

<table>
<thead>
<tr>
<th>Existing</th>
<th>Approved</th>
<th>Proposed (not shown on map)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. Everett, MA: 1.035 Bcfd</td>
<td>1. Hackberry, LA: 1.5 Bcfd</td>
<td>7. Fall River, MA: 0.8 Bcfd</td>
</tr>
<tr>
<td>B. Cove Point, MD: 1.0 Bcfd</td>
<td>2. Port Pelican: 1.6 Bcfd</td>
<td>8. Long Beach, CA: 0.7 Bcfd</td>
</tr>
<tr>
<td>C. Elba Island, GA: 1.2 Bcfd</td>
<td>3. Bahamas*: 0.84 Bcfd</td>
<td>9. Corpus Christi, TX: 2.6 Bcfd</td>
</tr>
<tr>
<td>D. Lake Charles, LA: 1.2 Bcfd</td>
<td>4. Gulf of Mexico: 0.5 Bcfd</td>
<td>10. Sabine, LA: 2.6 Bcfd</td>
</tr>
</tbody>
</table>

**In Perspective:**
- LNG satisfied only about 2% of U.S. natural gas demand in 2003. Growth of this percentage depends upon economics of LNG vs. domestic natural gas.

**“Access to world supplies will require a major expansion of LNG terminal import capacity and the development of offshore re-gasification technologies.”**
- Alan Greenspan, 4/04

**“There was a time when America produced everything it needed. That is not the case today, and it won’t ever be the case again with natural gas.”**
- Scott Nauman, Exxon Mobil, 5/04

**“Even a moderate terminal construction schedule provides enough capacity to cover likely available LNG import supply as soon as 2007.”**
- George Beranek, PFC Energy, 10/04

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Sources: “Existing and Proposed N. American LNG Terminals,” FERC Office of Energy Projects, 9/04; “LNG Boom? What Boom?”, Deutsche Bank, 7/04; Industry news; NAESB=N. American Energy Standards Board (NAESB to vote on interchangeability rule in Fall 2004, if approved, it will be filed with FERC) *U.S. pipeline approved, LNG terminal pending in Bahamas
Canadian Energy Activities in a Nutshell

**British Columbia +**

Wholesale market open in BC, Saskatchewan, and Manitoba.

- BC government maintains ownership of BC Hydro and has established a “heritage pool” (just like Quebec) whereby retail customers have access to cheap power from plants built before 2002.

*(Heritage assets are those which customers have already paid for)*

**Alberta**

Competition began for all customers in 2001. As of 2004, competition is working well for large industrial customers, but the majority of residential and small business customers have chosen to remain on regulated default rates. The default rates will continue until July 1, 2006, after which time these customers will receive a pass-through market price from their incumbent utility.

**Ontario**

The new Liberal Party government introduced controversial legislation to replace the current competitive wholesale market with a hybrid market of regulated baseload prices, LT PPAs, and a much smaller competitive market. Small customers on default rates, large customers on market rates. Possible closure of 5 coal plants (7,500 MW). Vote in Fall 2004.

**Quebec**

Wholesale market open. In 2000, the government established a “heritage pool” whereby Quebec retail customers have access to 165 Twh per year at 2.79 cents/kWh, the lowest rate in North America. No intent to open retail market.

Government-owned Hydro Quebec projects an 11% ROE for years 2004-2008. 50% net income goes to government annually.

Hydro-Quebec and Enbridge, a major Canadian NG mid-stream player, each own substantial stakes in Noverco, parent of Gaz Metropolitan, which is the 3rd largest LDC in Canada and serves both Quebec and Vermont.

Two LNG terminals have been proposed in Quebec on the St. Lawrence river.

**Nova Scotia +**

Nova Scotia will open its wholesale market to municipal utilities by 2005. Legislation being considered to make rest of wholesale market competitive. Retail will remain regulated and receive standard offer from a “heritage pool.”

New Brunswick opened its wholesale market in 4/04 to large industrials and municipal utilities.

Newfoundland and Labrador considering merits of competition.

**Sources:** Industry news; “Natural Gas Markets in Transition, Looking Ahead to 2010,” National Energy Board, 8/04; Alberta Energy and Utilities Board; Ontario Energy Board; Nova Scotia Department of Energy. Notes: LT PPAs=long-term purchase power agreements; NG=natural gas; LDC=local distribution company.
“Day One” RTO Estimated Costs

On 10/6/04, the FERC staff released a report which assesses the costs of getting RTOs to a "Day One" stage. The report was developed with the input of current RTO/ISO participants.

Key findings
- Cost of Day One RTO to typical retail customer is $0.19 per month
- Typical investment outlay is $38-$117 million
- Typical annual revenue requirement is $35-$78 million
- Many costs are reliability-related
- Cost data is not accounted for in a standardized way. FERC intends to standardize RTO cost reporting
- Many costs are reliability-related
- Incomplete market design and changing plans at mid-course
- Poor project management
- Extensive delays resulting in cost overruns and increased interest on debt prior to actual operations
- Lack of an existing power pool and established working relationships
- Not moving from Day One to Day Two in incremental stages

Primary cost drivers
- Lack of clear business plan and good project management
- Incomplete system design
- Over-customization of software
- Excessive changes during development
- Implementation delays
- Incompatibility of member IT and communications systems

IT is largest expense due to:
- Tariff admin and design
- Congestion management (redispatch only)
- Parallel path flow
- Ancillary services
- OASIS
- Market monitoring
- Transmission planning
- Interregional coordination

“Day One” RTO Functions (costs are estimated below)
- Tariff admin and design
- Congestion management (redispatch only)
- Parallel path flow
- Ancillary services
- OASIS
- Market monitoring
- Transmission planning
- Interregional coordination

“Day Two” RTO Functions (these costs were not estimated)
- All of the Day One functions, with market-based congestion management instead of redispatch; PLUS
- Day-ahead energy market
- Same-day energy market
- Ancillary services market
- Capacity market

(Dollars are rounded in millions)

<table>
<thead>
<tr>
<th></th>
<th>PJM</th>
<th>MISO</th>
<th>ERCOT</th>
<th>SPP*</th>
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<tbody>
<tr>
<td>Full time employees</td>
<td>263</td>
<td>187</td>
<td>188</td>
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<tr>
<td>RTO Investment Costs</td>
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<tr>
<td>Transmission Service Provider</td>
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<td>Transmission Support</td>
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<td>Reliability</td>
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<td>Management</td>
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<td>Building</td>
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<td>Total RTO Investment Costs</td>
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<td>Est. Annual Operating Expense</td>
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<tr>
<td>Est. Labor Cost (salaries, benefits, taxes)</td>
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<td>$22</td>
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<tr>
<td>Depreciation</td>
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<td>O&amp;M</td>
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<tr>
<td>Other Expenses</td>
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<tr>
<td>Interest Expense</td>
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<tr>
<td>Total Est. Annual Operating Expense</td>
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<td>$64</td>
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Consensus response from over 50 market participants: FERC’s assessment of costs to operate within an RTO are skewed because of the differing accounting methods used. New accounting standards for RTOs/ISOs are needed.

Source: “FERC Staff Report on Cost Ranges for the Development and Operation of a Day One RTO,” 10/04; cost table from Exhibit 3; “Parties weigh in on FERC financial rules for RTOs, ISOs,” Platts Electric Power Daily, 11/11/04; “SPP provided its cost estimates as if it was near Day One functionality.”
Regional Transmission Organization Activity

### Grid West
- **10/04** – Members to vote on bylaws in November. WA and OR Congressmen and 13 munis and coops urge caution until questions about FERC jurisdiction and BPA’s costs & benefits are resolved.

### CA ISO
- **10/04** – Successful implementation of market redesign phase 1B. This phase includes real-time economic dispatch, and penalties for generators who deviate from expected production.

### SPP
- **10/04** – FERC granted SPP full RTO status, subject to submission of certain revisions. SPP/MISO continue to work out the details of their joint operating agreement to be submitted to FERC.

### ERCOT
- **10/04** – TX legislators are considering giving the TX PUC more authority over ERCOT after they were “shocked” to learn of ERCOT’s high levels of debt and severe governance problems.

### MISO
- **10/04** – Goal is to have a 3/1/05 market launch. Working on resolving technology issues, stakeholder participation in testing, and seams agreements with neighboring systems. Will tie to PJM by 2006.

### GridFlorida
- **7/04** – GridFlorida hired ICF Consulting to conduct a study on the costs and benefits of an RTO and the impact of a wholesale competitive market upon consumers. Study to be completed in late 2004.

### PJM
- **10/04** – FERC conditionally approved Virginia Power’s application to create PJM South. AEP and DPL integrated into PJM. PJM generating capacity is now about 134,000 MW.

### ISO New England
- **11/04** – FERC accepted a final RTO agreement filed by Nepool and ISO New England. FERC imposed a few minor conditions which must be met soon. This RTO will facilitate trading with NY and Canada.

### NY ISO
- **7/04** – NERC assessed the readiness and reliability of NY ISO and said the ISO was well equipped to handle the day-to-day operation of the control area, including emergency situations. High praise.

Sources: Map from www.FERC.gov; IE Energy’s Electric Transmission Week; Platts Electric Power Daily; RTO websites; WestConnect and the proposed Entergy RTO not shown.

DPL=Dayton Power and Light; PUC=public utilities commission; Nepool=New England Power Pool

This map was created using Platts POWERrap September 1, 2004