Gas-Electric Coordination in PJM: Trends, Issues, Interactions, and Looking Ahead

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PRELIMINARIES: COMPARING PIPELINE AND ELECTRIC TRANSMISSION
## Gas Pipeline vs. Electricity Transmission: Similarities

### Gas Pipelines
- Transportation network
- Multiple owners
- Sell firm and interruptible service
- Pre-defined receipt and delivery points

### Electricity Transmission
- Transportation network
- Multiple owners
- Sell firm and non-firm service
- Point-to-point and network service

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Gas Pipeline vs. Electricity Transmission: Differences

**Gas Pipelines**
- Each owner operates its own assets. No RTO/ISO concept
- No single market operator
- Each pipeline owner responsible for reliable operation
- Expansion is market driven
- Costs allocated to those who use pipeline in proportion to their use
- Expansion siting and permitting FERC jurisdictional

**Electricity Transmission**
- RTOs/ISOs system in aggregate for multiple, passive owners
- RTOs operate centralized, bid-based markets that account and operate for reliability
- Expansion is reliability driven
- Costs allocated pro rata and beneficiary/cost causer pays
- Expansion siting and permitting subject to multiple state, local, and/or federal jurisdictions
ELECTRICITY AND GAS MARKET TRENDS
Gas in PJM is now Lower Cost than Henry Hub

**SHALE GAS!**

- Low commodity prices, translating to dramatically increased gas consumption for power generation—Marcellus is the cheapest gas in North America!

![Graph showing gas prices from Tennessee Gas Pipeline Zone 4 Marcellus and Henry Hub trading points, 2012](image-url)
Combined Cycle Gas is Leading the Way as Gas Prices Fall

Capacity Factors of Natural Gas Combined Cycle and Combustion Turbine Generation

- **Combined Cycle**
- **Combustion Turbine**
- **Natural Gas Price**

Graph showing capacity factors and natural gas prices from January 2011 to June 2012.
Low Natural Gas Prices into the Future

Average Monthly Natural Gas Prices, 2006–16

Source: IHS CERA
20706-11
Trend of Increasing Coal Prices Forecast to Continue

- Central Appalachian (12,500; 1.5)
- Northern Appalachian (13,000; 4.0)
- Illinois Basin (11,800; 5.0)
- Powder River Basin (8,800; 0.8)

FOB Price
(US dollars per short ton)

Source: IHS CERA, ICAP.
Notes: (t$/#) = (Btu per pound (lb); lbs sulfur dioxide (SO₂) per MMBtu. FOB = free on board.
Generation Resource Retirement Status

Nearly 18 GW of Actual & Announced Deactivations
Decline in Coal-Fired Generation
Natural Gas Generation in the Queue Doubles since 2010

- Wind derated to 13% UCAP
Evolving Resource Mix in the Capacity Market

MW

Capacity Auction Delivery Year

- COAL
- GAS
- NUCLEAR
- DEMAND RESPONSE
- WIND
Maintaining Resource Adequacy over the Summer Peak

Cleared Reserve Margin

Target Installed Reserve Margin

ISSUES: COORDINATION TODAY
Issue: Timely gas nominations are due at 10AM the day before (Day 1); electric “awards” are made at 4PM the day before (Day 1) = 6 hours later; actual gas flow occurs starting at 10AM on Day 2

Source: NERC report on Gas Electric Interdependency
...but the timely nomination is the most important—later nominations are based on the availability of “leftovers” and are meant to address adjustments to an initial timely nomination.
Power Generation is Not the Ideal Gas Customer!

- Power generation gas use does not fit neatly into the gas contractual construct
  - Electricity demand, like gas demand, fluctuates and is subject to steep ramps, especially in winter
  - Increased wind and other intermittent resources don’t help
  - Fastest starting generation resources, generally are gas-fired combustion turbines which can go to full output in about 10 minutes or less
  - Combined cycle resources are developing fast start capabilities
  - Need for quick ramping to respond to forced outages.
  - As wind is to power….power is to gas!
Managing Load Variability is a Gas and Electric Issue Now

**Summer Load Shape**

Slow, gradual increase in load throughout the day. Gas-fired units can be more carefully planned and sequentially brought into service.

**Winter Load Shape**

Very steep load pickup (5AM-8AM) in the morning, followed by an immediate stop and gradual decline during the day.
ISSUES: INCENTIVES AND MARKET RULES
Electricity Market Rules Provide Incentives for Gas-fired Generation to Manage Fuel Risks

- Currently no market or reliability requirement to have firm fuel
- Generation has an incentive to be available to run for energy
  - Earn energy market rents in day-ahead or real-time energy markets
  - Avoid buying back day-ahead commitments at higher real-time prices
- RPM capacity market provides incentives to be available
  - Minimize forced outage rate (EFORd) and to maximize UCAP available for sale in future years
  - Minimize peak period forced outages (EFORp) to avoid peak period penalties
Incentives for “Firm vs. Interruptible”

- Low gas prices are changing the basic dispatch of the system
  - Combined-cycle plants are running like base load plants (>80% capacity factor)
  - Low capacity factor units like CTs are still there and needed to handle the occasional high load or forced outage situation (<5% capacity factor)

- Gas-fired generation can avail themselves of the capacity release markets to secure firm transportation when needed
  - Often at a discount
  - Can be bundled with commodity gas
Filed Tariff Rates Provide Little Incentive for Firm Transportation

- At high capacity factors, the costs of firm and interruptible delivery service start to converge:

<table>
<thead>
<tr>
<th></th>
<th>Firm (FT-1)</th>
<th>Interruptible (IT-1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservation</td>
<td>$3,257,402</td>
<td>$3,282,848</td>
</tr>
<tr>
<td>Usage</td>
<td>$681,783</td>
<td>$3,282,848</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$3,939,186</td>
<td>$3,282,848</td>
</tr>
</tbody>
</table>

or

- If electricity is $50/MWh, then gas transportation is 6.4% of energy offer 5.3% of energy offer

  - So, high capacity factor units can begin to “afford” firm service, but the low capacity factor units cannot!

- Electricity market rules
  - FT cannot be included in cost-based energy offers, but IT can
  - FT is not precluded from inclusion in the RPM offers in the avoidable cost rate component.
Prevalence of Interruptible Delivery Service

Majority of power plants are using interruptible gas transmission service!

New England Gas-fired Power Generation (>100 MW)
ISSUES: COORDINATING RELIABILITY AND OPERATIONS GOING FORWARD
• Improved Communication and Data Exchange
  – Give Gas Control a fighting chance to anticipate what we are going to do!
Coordinating Needed Gas Pipeline Additions

• Market driven expansion is occurring:
  – Producers in what have otherwise been bottled up production regions are subscribing for transportation in open seasons
    • REX bringing Rockies gas east to Ohio
    • Expansions in the Marcellus region
  – Change from the “demand-pull”, LDC driven expansions
  – Generation-owning shippers will need to effectively use the secondary capacity release market at times, if relying on interruptible service
  – Producers and generators may need to team up in open season processes to ensure delivery under peak conditions
Coordination on the Electric Side

Existing Procedures

- **Synchronized reserve**
  - Can manage the loss of the largest generator
  - Energy and reserve prices will rise

- **Shortage pricing and emergency procedures**
  - Allows DR to set price if needed to maintain energy balance and reserves
  - Prices rise to reflect shortages of synchronized and primary reserve

Do we need additional rules??

- Why are current market incentives not enough to get the desired economic and reliability outcome?
- Can we move the electric day to more closely align with the gas day?
- Limits on quick start generation?
- Mandate firm transportation or duel fuel?
- Rethink the use of hydro and pumped storage?
PJM at the Crossroads of Major Interstate Pipelines
PJM at the Center of New Shale Production and Storage
PJM could have up to 21,000 MW of gas capacity unavailable in the winter when heating load peaks and still be at the target IRM of 15.4%.
Coordination on the Gas Side

Existing Procedures

• Capacity Release
  – Allows for short-term, just-in-time purchases of transportation
  – Marketers may bundle transportation with commodity gas

• Operational Flow Orders (OFOs)
  – Can interrupt IT customers
  – How often is this done to gas generation, especially in areas where multiple options exist?

Possible new rules, procedures or products??

• Can we move the gas day to more closely align with the electric day?

• Demand response for gas customers
  – LDCs could sell transportation or bundled product in something akin to a real-time balancing market?

• Differing rate designs for pipeline imbalance charges that reflect increasing operational difficulties
  – Analogous to operating reserve demand curves in RTO markets?
Moving Forward toward Better Coordination

• Trust that the gas industry market forces will add capacity as needed, based on the existing paradigm
  – In areas where there is high reliance on gas, e.g. New England, require firm gas service or dual fuel capability for a substantial portion of the capacity (ISO-determined)

• Develop understanding on both sides of the limitations that exist
  – How much “instantaneous capacity” is available on each pipeline?
  – Share operational information to minimize surprises
Concluding Thoughts

• Power generation is a “double edged sword” for the gas business
  – Largest growth market
  – Potential to cause problems in operations

• Working together, we can minimize the operational problems
  – Awareness of the limitations on each side
  – Increased real time communications across the aisle
  – Use of the demand side resources on each side