



2008 Summer Market and Reliability Assessment

Item No.: A-3
May 15, 2008

Mr. Chairman and Commissioners, good morning. We are here to present the Summer Market and Reliability Assessment for 2008. This presentation will be posted on the Commission's Web site today.

Key Results

- The electric system should be reliable this summer, with some local issues
- Electric prices likely to rise
- Gas infrastructure supports growing electric markets

Today, we will emphasize three main points:

1. Overall the reliability of the bulk power system for this summer should be adequate. But there are some areas of concern that require close monitoring.
2. Wholesale electric prices are likely to be considerably higher than they were a year ago.
3. In the fastest growing regions – Florida and Arizona, for example – the continuing robustness of the natural gas infrastructure plays a crucial role in meeting growing electric power demand.

National Reliability Issues

- Overall Reliability Assessment
- Demand Forecast
- Capacity Margins
- Demand Response
- New Generation
- Regional Highlights

The reliability and adequacy of the bulk power system this summer, as forecasted by the planning authorities and reviewed by the Regional Entities and NERC is projected to be adequate. Extreme weather conditions and major outages of generation and transmission pose risks to reliability and where these risks are significant, contingency plans, including operating procedures, are expected to be in place to manage these risks.

Overall non-coincident peak demand this summer, assuming normal weather and 50% load forecast probability, is forecasted to be 1.3% higher than the actual demands of last summer with some regions showing an increase in demand while others a reduction. While the capacity margins to supply this increased demand are forecasted to be sufficient, there are concerns for supply reliability due to deliverability of reserves. In particular, these concerns manifest themselves in Southern California due to constraints on imports from the north and outside California, and in the Southeast should the drought conditions persist, coupled with any major transmission and/or generation outages.

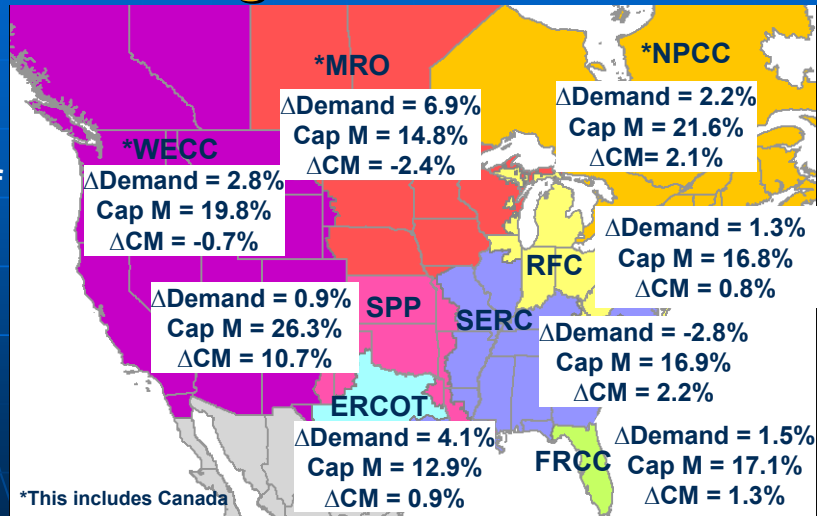
Demand response has increased both as a means to reduce peak demand and to provide ancillary services for operating flexibility.

These issues and regional highlights will be explored in the remainder of the presentation.

Demand and Capacity Margin, 2007-2008

Comparison of 2008 vs 2007 Demand and Capacity Margin

Source: Derived from NERC data and Energy Velocity



Demand Forecast

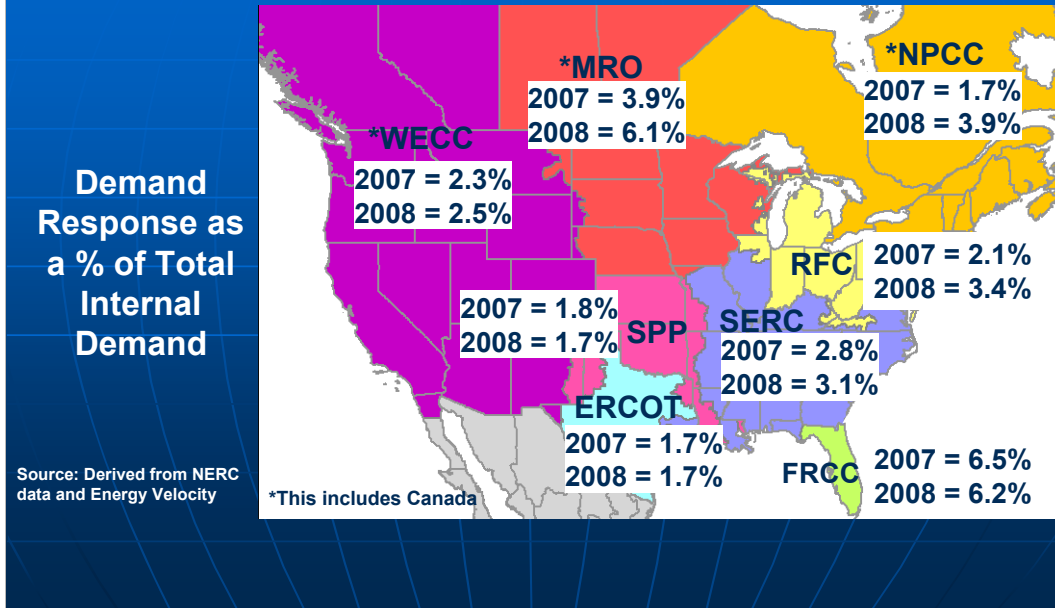
Demand forecasters use generalized assumptions about weather, economic activity and other factors. Therefore, predicting abnormal conditions that create record peaks are difficult.

Overall, the non-coincident peak-demand forecast is 867,525 MW, which represents a 1.3% increase from the actual demand of last summer. On this map, which shows 2008 summer forecasts compared with 2007 summer actual peak by region, we see that assuming normal conditions, the forecast peak demand is expected to grow from a low of 0.9% in SPP to a high of 6.9% in MRO. The exception is the SERC region, which is projecting a demand reduction of 2.8%. This bears scrutiny as past forecasts for the SERC region have been consistently lower than actual demands for the last few years, when all-time peaks have been repeatedly set.

Capacity Margins

Capacity margins are indicative of the amount of reserve capacity that is available to avert the risk to reliability from a number of uncertainties such as load forecasting errors and outages of bulk power system equipment among other factors. The map shows the capacity margins and the change in projected capacity margins for the coming summer compared with last summer. Because of different generation mixes, unit sizes, deliverability and other factors required reserve margins will vary to achieve the same reliability performance. In and of themselves, the capacity margins cannot be compared across regions. However, the change in capacity margin within a region, relative to historically achieved capacity margins, is an appropriate measure of the resource adequacy of the same region. On that basis, the capacity margins shown appear to be on par with prior years.

Demand Response 2007-2008



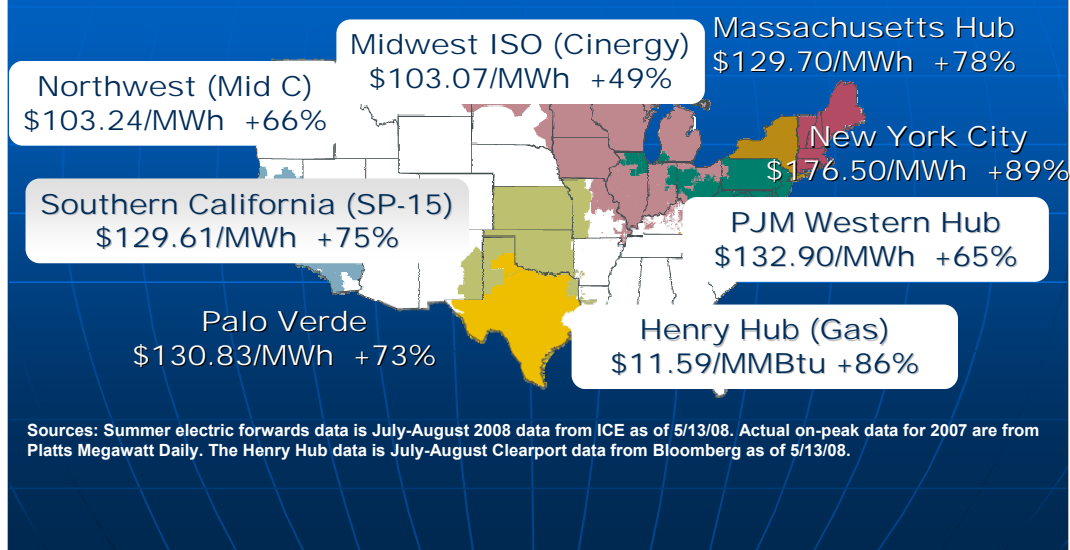
Demand Response

This summer, demand response resources have increased to manage peak loads across the United States. The amount of dispatchable demand response available to reduce peak load is forecast to increase significantly in NPCC from just under 2% of internal demand to 4% and in MRO from 4% to 6%. This resource can play an important part in reducing the stress on the grid at the time of system peak.

New Generation

Over 10,000 MW of new generating resources have been added to the US power system over the past year. Not all of the new capacity will have a direct impact on capacity margins due to issues such as deliverability and coincidence of availability during peak demand periods.

Forward Markets Suggest Higher Electric Prices

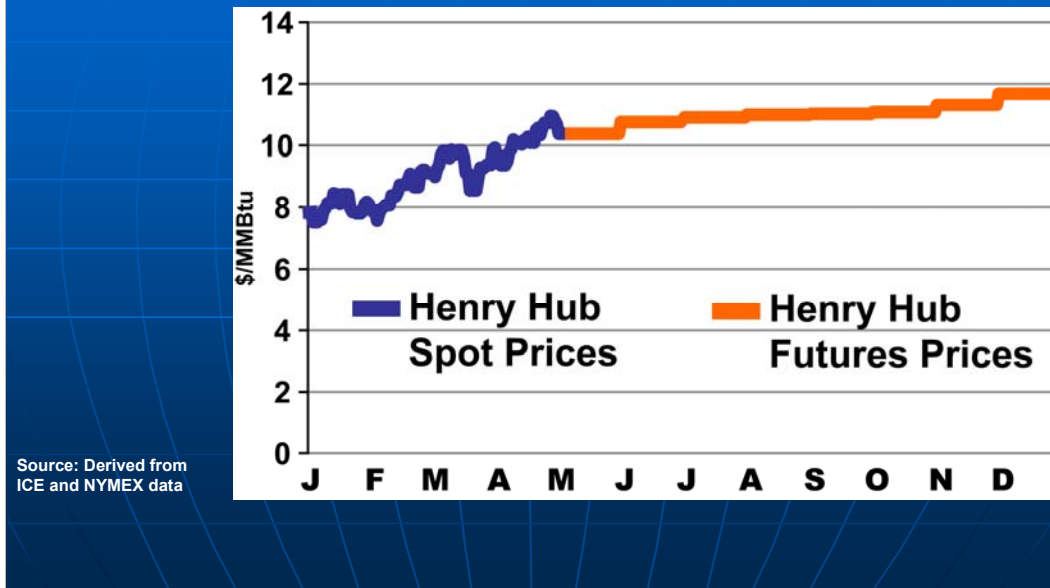


The most important aspect of electric power markets this summer is that wholesale prices are likely to be quite a bit higher than last year. Forward prices from the InterContinental Exchange are 50 to 90 % higher than last summer's prices. They are higher almost everywhere, in both RTO and non-RTO regions. The degree of increase depends on how often natural gas is the marginal fuel being burned, not on whether a region is part of an RTO. Thus, the largest increases appear in the Northeast where gas is almost always on the margin. The lowest appear in the Midwest, where coal is more often on the margin.

These prices are important, but I need to give you two cautions in using them. First, forward prices are not predictions of the future. They are the price that willing buyers are paying – right now – to willing sellers for deliveries this summer. That may or may not be where the prices end up. In any case, they are already affecting eventual costs – those who hedge their positions with forward transactions are locking in this price already as part of their summer portfolio.

Second, there is no direct relationship between wholesale and retail electric prices. The effect of higher wholesale prices in short-term markets on retail prices varies based on the reliance on short-term purchases.

Gas Prices Higher in 2008



Why are forward electric prices so high for this summer?

Let's look at natural gas prices first. The slide shows that the American natural gas price has been rising rapidly since the start of the year. Forward prices are also higher for the rest of the year, even though American gas production is rising. Why?

First, last winter was a roughly normal winter, but that was considerably cooler than the two previous winters. So natural gas storage levels are lower going into this summer. Market participants need to buy more gas through the summer to make up the difference.

Second, demand is rising, especially for electric power. Given today's generation fleet, natural gas will fuel most of the increase in electric power demand around the country. Last year, generators burned about 10 % more gas than in 2006. So far this year, it is up again – 11 % compared to last year.

Third, imports will probably fall. Canadian imports are down a little so far this year. LNG imports are likely to be down as well. In the first four months of the year, they were down by 62 %. In the spring and summer of last year, British gas prices were \$3 to \$4 per MMBtu. We imported record volumes with an American price in the \$6 to \$8 range. This year, the British price is above \$11, about at parity with the Henry Hub price. So we will probably import more than the first four months would suggest, but still less than last year – especially to Gulf Coast ports.

Finally, there appears to be global commodities boom in most raw materials.

All these factors tend to increase gas price for the summer. The increase in domestic production is substantial and works the other way. Overall, gas prices are rising – but for the same heat content, they remain at only about half of current oil prices.

Continued on next page

Continued from previous page

Natural gas is the most influential factor affecting electric power prices, because in the summer natural gas is on the margin more often and in more places than any other fuel. But other factors also matter. For example, last summer wholesale electric prices went up faster than fuel prices, especially natural gas. That could happen again. The United States has added little baseload capacity over the last few years. As a result, if loads continue to rise, the electric system must use generators that cost progressively more to run. The market clearing price should normally rise enough to make it worthwhile to run those generators. The shift of what is on the margin can be from coal-fired units to gas-fired ones, or from combined cycle units to combustion turbines. Either way, the result is normally higher prices, even if fuel prices stayed the same.

Regional Reliability Highlights

- **West** – Southern California Concerns
- **ERCOT** – Wind Operational Challenges
- **Southeast** – Drought and Demand Forecast

West

While the reserve margins in WECC look sufficient, transmission limitations continue to constrain the ability to deliver these reserves from northern to southern California. Under normal conditions, it is expected that demand response, voluntary conservation and use of interruptible loads may be required this summer in southern California. The risk assessed by CAISO for a Stage 3 Emergency this year is greater than last year.

Hotter than forecasted temperatures, as has occurred the previous two years, coupled with major generation and or transmission outages in southern California, could result in rolling blackouts due to shrinking operating reserves. This remains a concern, despite the implementation of demand response of more than 1400 MW.[1]

ERCOT

Wind generation in Texas is expected to increase by over 3,700 MW this summer compared to last summer. This increase in variable generation will present additional operational challenges and may result in congestion, limiting the available wind output and requiring more frequent reliance on demand response.

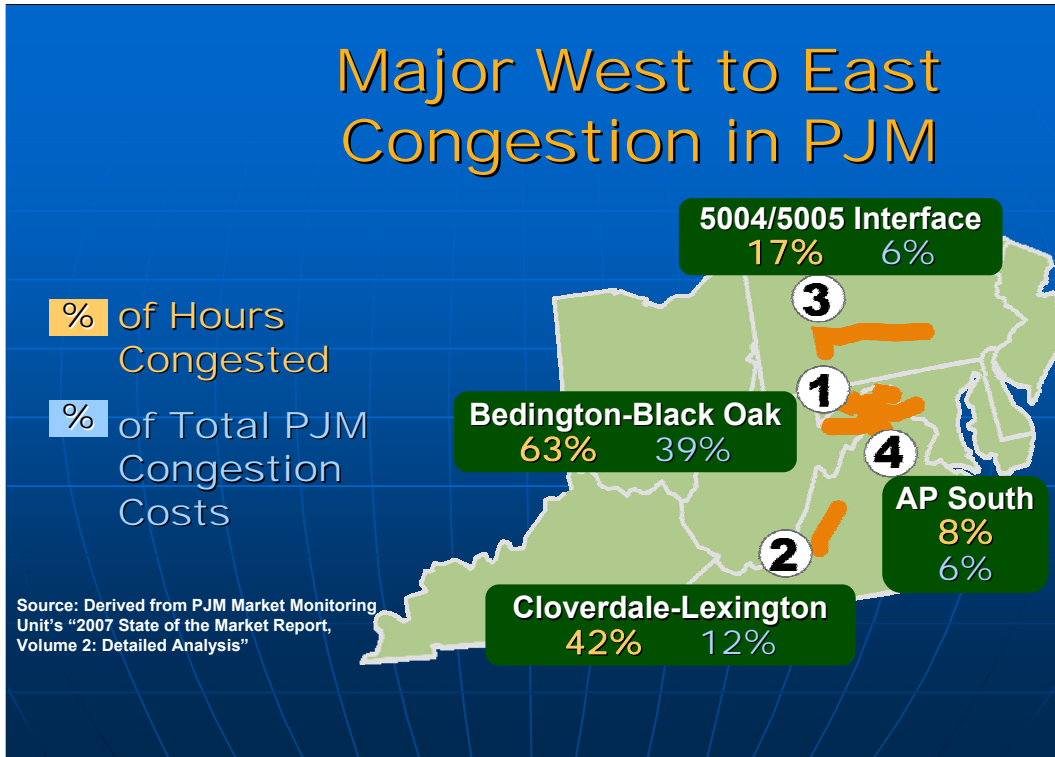
Southeast

At the present time, the drought conditions in the southeast are improving in many areas. All sub-regions performed studies and identified no significant reliability issues for this summer based on continued spring rains.

The Regional demand for SERC was under forecasted in each of the prior two consecutive summers close to 10,000 MW. For 2008 the demand is again projected to decrease, in this case, by 2.8% from the actual demand of summer 2007.

The low demand forecast, coupled with the drought conditions, require close monitoring of reliability risks and mitigation plans this summer.

[1] CAISO 2008 Summer Loads and Resources, April 28, 2008, Table 16, Page 24.



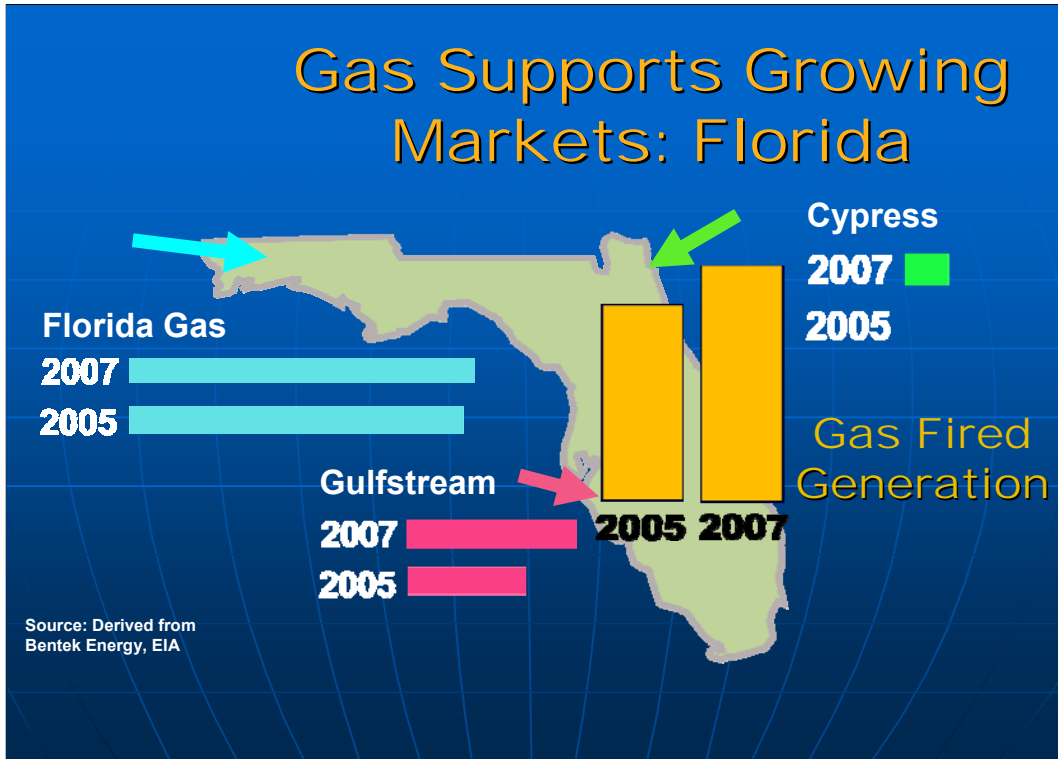
I'll start in the Northeast.

In 2007, New York and New England alleviated the most acute sources of congestion on the East Coast. The Neptune line greatly reduced congestion into Long Island. Transmission upgrades in Connecticut and Boston reduced congestion in New England. However larger, though less acute, issues remain.

For example, in PJM, West to East congestion is increasing. In 2007, the overall incidence of congestion in the day-ahead market increased by about 11 %, and it's up again this year so far. The congestion is increasingly concentrated in four major bottlenecks - shown on the slide - that limit flows from West to East. As you can see from the peach colored numbers on the slide, Bedington-Black Oak was congested 63 % of the time in 2007. Together, these four constraints accounted for over 60 % of all congestion in PJM in 2007 – the blue numbers on the slide.

West to East congestion affects prices. In 2007, wholesale power prices averaged \$66/MWh for PEPCo in the mid-Atlantic, and only \$46 for AEP in Ohio.

PJM has been working hard to alleviate the congestion. For example, PJM estimates that the TrAIL project would add about 5,300 MW of West to East transfer capability. The line could be in service as soon as the summer of 2011, if it receives needed permits later this year. But until upgrades come on line, increasing loads are likely to increase both the incidence and cost of congestion.

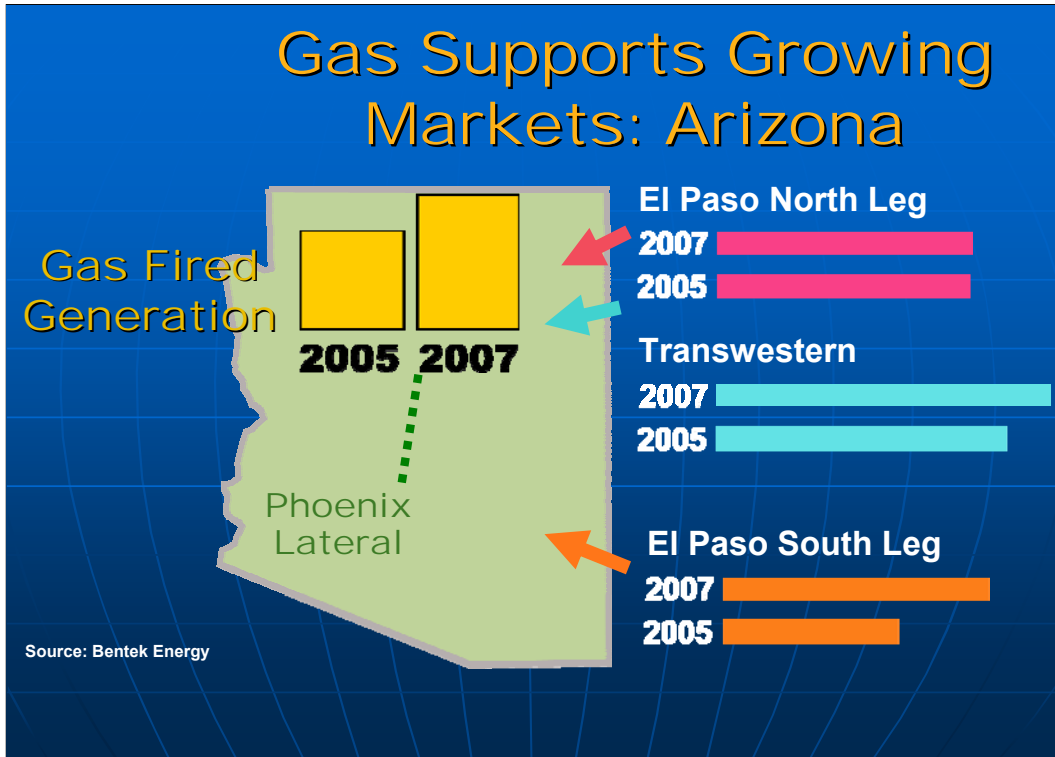


Turning to the Southeast, Florida is the fastest-growing energy market in the region. Electrically, Florida has relatively sparse connections with the rest of the Southeast. The state depends heavily on natural gas for both existing and new power generation. The yellow bars on the slide show that Florida's gas-fired generation has increased by 19 % between 2005 and 2007. So far in 2008, it's up again, 11 % higher than the same period last year. The smaller bars show how throughput has increased to meet demand on the three major gas pipelines serving Florida.

Reporting of market prices for gas is sporadic for peninsular Florida; power prices are even less transparent. The indications we can see suggest that in the summer, Florida often places a higher value on natural gas than any other part of the country, including New York and New England. This is symptomatic, in part, of being at the end of the pipelines.

Fortunately, Florida has been able to add new gas pipeline capacity. Last year, the Cypress Pipeline added 265MMcf per day of capacity. This year that has expanded by a further 116 MMcf per day. Later this year Gulfstream is scheduled to increase capacity by 500 MMcf per day.

Gas Supports Growing Markets: Arizona



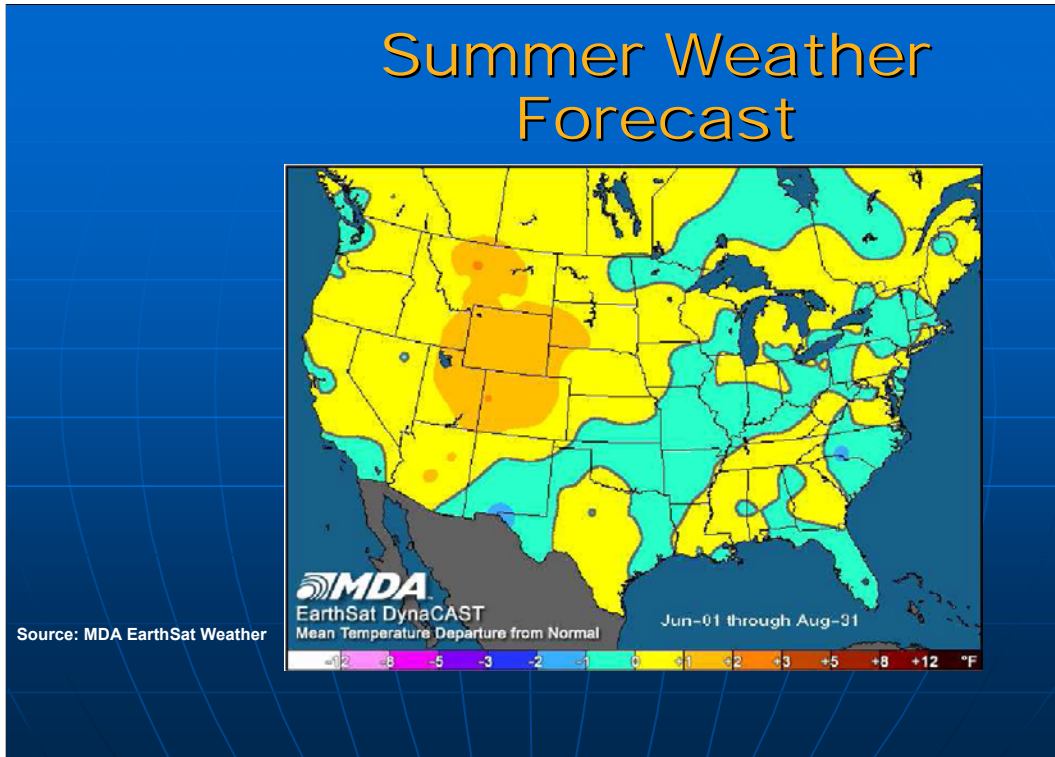
In the West, Arizona is a rapidly growing market - Phoenix is now larger than Philadelphia, and Maricopa County, outside Phoenix, is the fastest growing county in the country. Electric power demand is rising quickly – and that means rapidly increasing use of natural gas.

In 2007, Arizona consumed 113 TWh, an increase of 11 % over 2005. Almost all of that increase came from greater use of natural gas. Natural gas used for electric power was up by 32 %. You can see on the slide how gas usage in generators grew in the state, and how utilization rose for pipelines entering the state. Indeed, this April, for the first time, all three of the major pipelines entering the state operated at 95 % of capacity.

Unlike Florida, Arizona is not at the end of the line for natural gas. As a result, there are many ways to meet increasing Arizona demands, not just the option of increasing mainline capacity from points further East. For example, when more Rockies gas reaches Southern California through El Paso's 1903 line, that frees up pipeline capacity to add service to Arizona. For example, Transwestern Pipeline is adding the Phoenix lateral you can see on the slide to take gas that would have gone to California to the Phoenix area instead.

The American pipeline industry has proven adept at adding this sort of flexibility over the years. As things stand now, Arizona has met and is meeting its growing needs without seeing its natural gas prices rise any faster than in other parts of the country.

Summer Weather Forecast



What are the biggest unknowns in looking at the summer? The biggest variable is the weather. A cool summer could keep electric prices far below the levels that many people expect, as they did last year in Texas. Conversely, a hot summer could raise prices and reliability concerns even more.

The slide shows the current forecasts for the summer.

The other major weather factor is hurricanes. So far, forecasters say that we can expect a more active year than normal. They are guessing that we will see about 15 named storms, 8 of which will become hurricanes. They say there is a 69 % chance that a major storm will make landfall in the United States. We saw in 2005 what badly placed hurricanes could do to energy prices. Indeed, one of the forces that may be keeping gas prices relatively high is the fear of hurricanes.



2008 Summer Market and Reliability Assessment

Item No.: A-3

May 15, 2008

Thank you very much. We welcome your questions.