

Slide 1



FEDERAL ENERGY REGULATORY COMMISSION

## Winter 2011-12 Energy Market Assessment

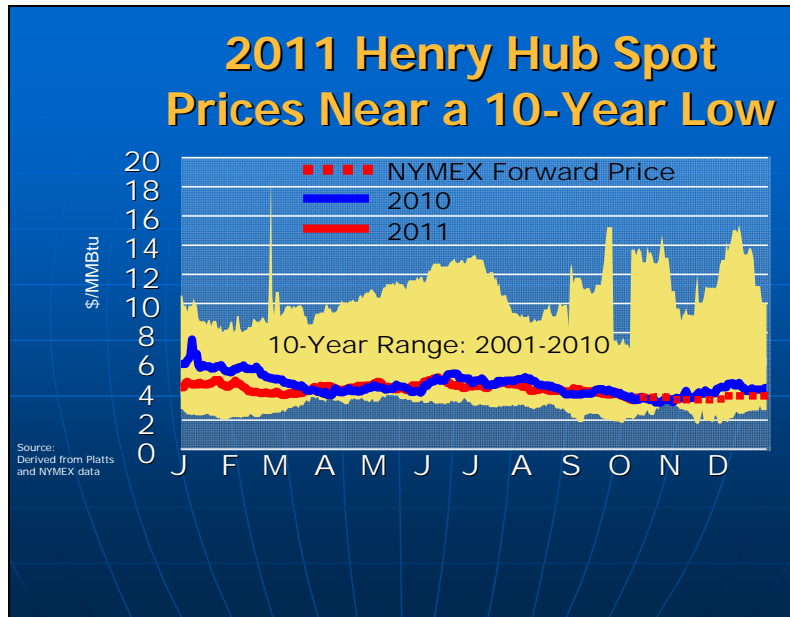
Item No: A-3  
October 20, 2011

The Winter Assessment provides forward prices for both electric and natural gas markets. These forward prices are not projections of what winter prices may be. No such analysis has been conducted by staff.

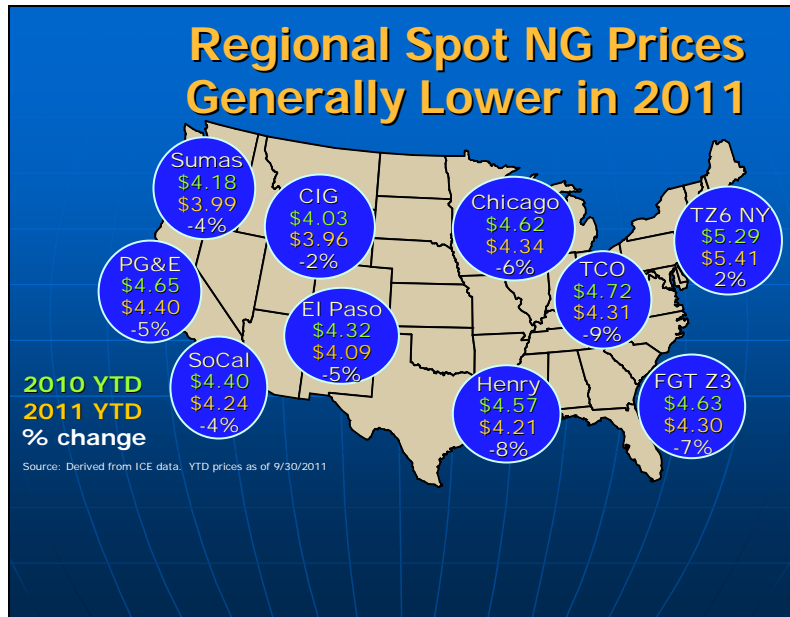
Mr. Chairman, Commissioners. Today I am pleased to present the Office of Enforcement's Winter 2011-2012 Energy Market Assessment. The Winter Energy Assessment is staff's opportunity to share observations about natural gas, electricity and other energy markets as we enter the winter.

Market conditions going into the winter are generally positive. Despite a 2.6% increase in natural gas demand this year, prices remain among the lowest in the past decade, due to continued production growth and new pipelines transporting gas from the producing areas to consumers. Gas-fired electric generation is benefiting from the lower gas prices, raising expectations for continued demand growth from this sector in the upcoming winter. As has been the case in past years, we can expect localized pipeline constraints in the Northeast during extreme cold weather periods, as growing gas power generation adds to peak gas demand for space heating.

I will begin by discussing the natural gas markets, and talk about the electric markets later in the presentation.



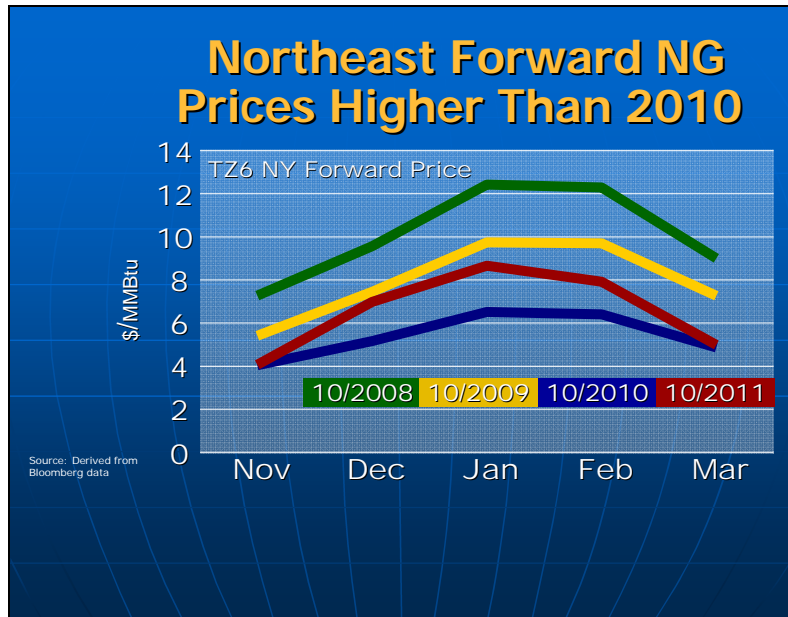
Despite record-cold temperatures at the end of the 2010-2011 winter heating season and strong demand for electric generation for air conditioning needs this past summer, U.S. natural gas prices in 2011 have remained near the bottom of the 10-year range. The average forward Henry Hub price for the upcoming winter, November through March, is currently \$3.87/MMBtu. These price levels are due to record setting production, robust storage levels, and pipeline projects that have allowed additional supplies to flow out of the production areas, helping moderate regional transportation constraints, and get natural gas to markets.



Year-to-date prices in 2011 are below 2010 levels in most regions. The exception is in the Northeast, where prices are up for the year due to price spikes in January.

Additional pipeline capacity has helped moderate prices across the country. According to FERC's Office of Energy Projects, 8.2 Bcfd of pipeline capacity went into service from January through August of this year. In the West, the new Ruby and Bison pipelines are providing additional supplies from the Rockies to Western and Midwestern markets. The increased supply from the Rockies helped reduce prices in Northern California and the upper Midwest. In the Southeast, the Florida Gas Transmission Phase VIII mainline expansion entered service on April 1, increasing capacity from 2.3 to 3.1 Bcfd. The additional supply of Gulf Coast natural gas helped moderate price spikes in Florida this past summer. Between June and August, Florida gas demand peaked at 4.5 Bcfd, a 22% increase from last year's peak, and gas prices reached a high of \$5.23/MMBtu. In contrast, during the summer of 2010 constraints on the pipeline resulted in frequent price spikes over \$7.00/MMBtu and a high price of \$12.84/MMBtu.

Access to new production and added natural gas transportation capacity has contributed to a trend towards the convergence of prices between regional markets. During 2011, there were fewer incidences of spikes in basis between regional natural gas hubs and the Henry Hub benchmark price. This trend is expected to continue throughout the winter, as additional pipeline infrastructure comes into service and provides access to new low cost gas supplies.



Forward prices for winter natural gas in the Northeast are significantly higher than they were last year. On October 11 the winter contract forward price, November to March, at New York's Transco Zone 6 was \$6.52/MMBtu, 21% higher than last winter's forward contract price on the same date in 2010. The increase reflects the low forward price expectations leading into last winter. Last year, added pipeline capacity in the Northeast raised expectations for lower winter prices. Despite the additional infrastructure, the region experienced occasional pipeline constraints and price spikes during the cold snaps in January and February. This year the markets seem to be accounting for the possibility of similar spikes, but overall, forward prices remain at moderate levels.

Weather is a key factor in winter gas demand and prices. In its most recent winter forecast, the National Oceanic and Atmospheric Administration (NOAA) calls for average temperatures in the Northeast.

Forward winter prices in the rest of the country are relatively flat, except at the Northwest Sumas Hub, which is 15% below 2010 levels. This is due to lower natural gas demand for power generation resulting from high hydropower output, and also the additional supply of Rockies gas via the new Ruby pipeline.

### Electric Wholesale On-Peak Forward Winter Prices

(\$/Mwh) FOR JANUARY AND FEBRUARY

| Location                    | 2011    | 2012    | % Change |
|-----------------------------|---------|---------|----------|
| New York City               | \$65.75 | \$85.13 | 29%      |
| Massachusetts Hub           | \$56.02 | \$73.25 | 31%      |
| PJM Western Hub             | \$47.71 | \$55.25 | 16%      |
| Midwest ISO (Cinergy)*      | \$36.93 | \$43.25 | 17%      |
| Northwest (Mid C)           | \$37.02 | \$33.10 | -11%     |
| Southern California (SP-15) | \$38.41 | \$37.65 | -2%      |
| Henry Hub (Gas) \$/MMBtu    | \$4.31  | \$4.18  | -3%      |

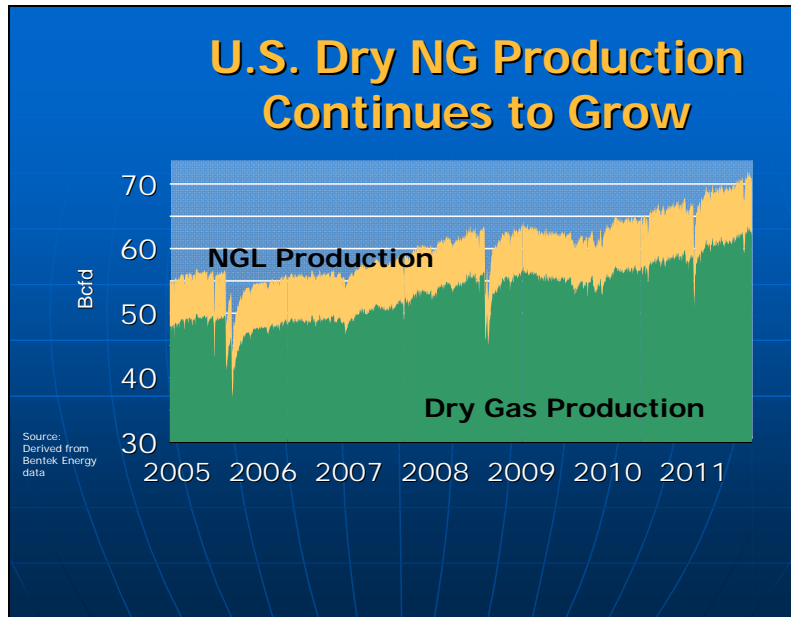
Source: Derived from ICE data as of 09/30/11 for 2012 contracts and as of 09/30/10 for 2011 contracts.  
\* The Midwest ISO (Cinergy) Hub will become the MISO Indiana Hub at the start of 2012.

I will now turn to the outlook for electricity prices this winter. For the purpose of this slide, winter peak electricity demand is defined as January and February.

Forward winter prices are generally mixed compared to last year. In the Northeast, forward winter prices are higher than they were at this time last year. The Massachusetts Hub has the largest increase, up 31%, and New York City is 29% above last year's price, reflecting the outlook for local natural gas prices. This is important because gas is typically the marginal, or price setting, fuel in this region. Unlike the Henry Hub in Louisiana, which is slightly down, Northeast gas prices are, as previously indicated, significantly higher than last year.

Forward winter prices are also higher for MISO and PJM, with the Cinergy Hub up 17% and the PJM Western Hub up 16%. These increases may reflect higher demand from industrial power customers, which at the end of the second quarter was 2.5% higher than in 2010. In addition, the weather forecast from both NOAA and AccuWeather call for colder than average weather for the Great Lakes, the Midwest, and northern plain states, which may also be influencing the forward electric prices. Despite the increase from last year, prices for this winter are at the same level as 2010 winter prices, and are significantly below 2009 winter levels.

In the West, prices are generally unchanged, except for the Mid-Columbia Hub, which is 11% lower than last year. This is consistent with winter forward natural gas prices in the Northwest, which are 9.3% lower than last year. Additionally, NOAA is forecasting above average precipitation in the Northwest this winter, which could have a positive effect on hydroelectric production.



Natural gas production continued to grow in 2011, setting records throughout the year and averaging 60.3 Bcfd through September, a 6% increase over 2010. Shale gas now accounts for more than 25% of U.S. production, up from 5% in 2007. There has also been an increase in production of associated gas from oil shale wells, as high oil prices led to the acceleration in drilling for shale oil. The Baker Hughes gas-directed rig count remained relatively flat this year, but oil-directed rigs increased from 777 at the beginning of the year to 1080 on October 14.

Production growth brings its own challenges, such as insufficient infrastructure to move natural gas, natural gas liquids (NGLs) and shale oil to markets. Also, higher on-shore production in areas prone to cold weather increases the likelihood of well freeze-offs, which in past winters temporarily affected regional supplies.

In some regions, the rush to extract oil from oil rich shale formations has also resulted in high levels of flaring, or burning of natural gas. In the Bakken shale formation in North Dakota, for example, the natural gas gathering system is struggling to keep pace with growing production, and an estimated 25% of the natural gas produced, as much as 100 MMcfd, has been flared this year. However, major gatherers and pipelines are expanding their systems, and adding storage and gas processing capability to get the gas to markets.

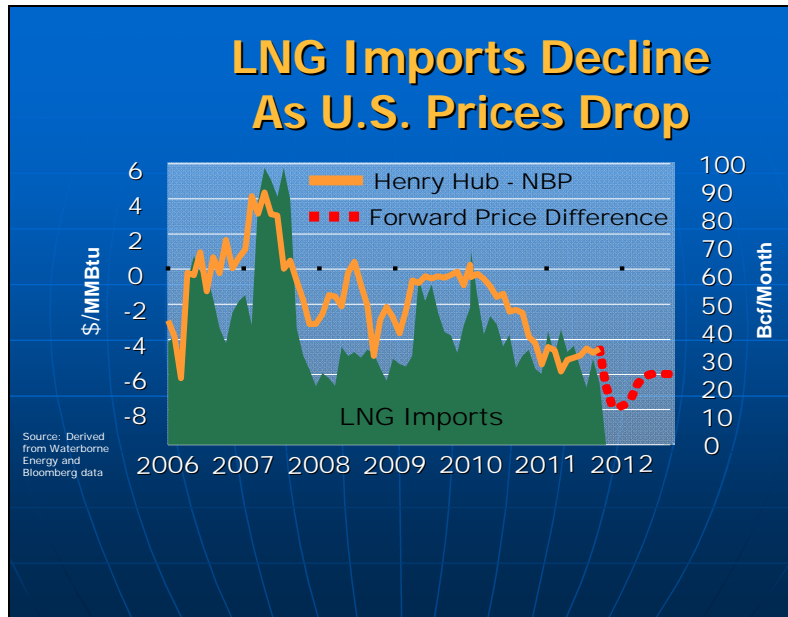
## New Infrastructure for Rising Marcellus Production

| Company/Project Name                  | Capacity (Mmcf/d) | Projected In-service Date |
|---------------------------------------|-------------------|---------------------------|
| 1 Central NY Oil & Gas Mark I Project | 550               | Summer 2012               |
| 2 Dominion Appalachian Gateway        | 484               | Fall 2012                 |
| 3 Tennessee 300 Line Expansion        | 350               | Fall 2011                 |
| 4 Empire Tioga Line Extension         | 350               | Fall 2011                 |
| 5 National Fuels Gas Northern Access  | 320               | Fall 2012                 |
| 6 Equitrans Sunrise Project           | 314               | Summer 2012               |

Source: Derived from FERC & industry sources. Note: FERC-Approved or Pending Projects Over 300 MMcf/d Going In-service in the Next Year

Marcellus Shale production has increased from 2.7 to 4.7 Bcfd in the past year alone. In Northeast Pennsylvania, where production is up 1.3 Bcfd from 2010 levels, pipeline constraints have led to natural gas prices in the \$2.00/MMBtu range, the lowest in the country. New expansion projects should help relieve constraints in the Marcellus producing region this winter, and stabilize prices in areas with high levels of constrained take-away capacity.

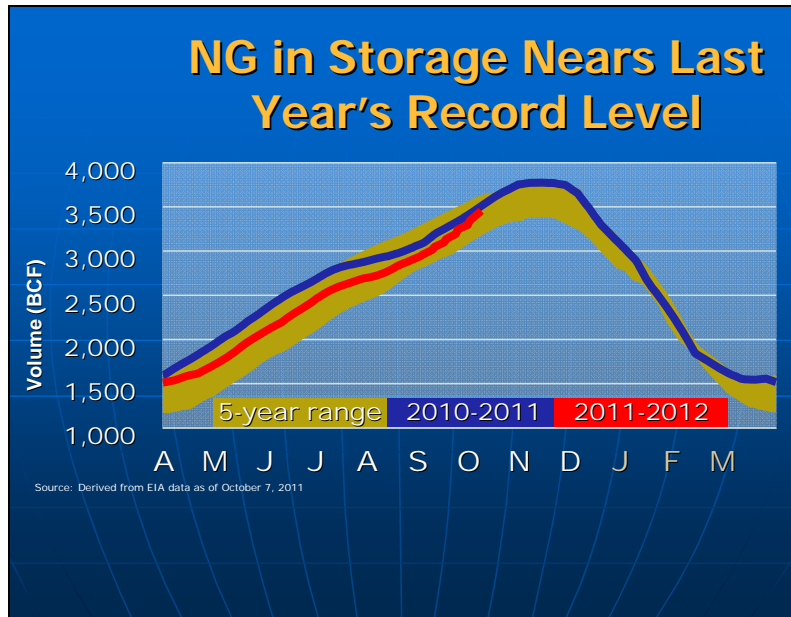
At this time there are over 6 Bcfd of FERC-approved and proposed pipeline projects designed to provide additional takeaway capacity for Marcellus shale gas. In Northern Pennsylvania, the Tennessee Gas 300 Line Expansion project will add 350 MMcf/d of capacity starting this fall. The Empire Tioga Line Extension will connect Pennsylvania Marcellus production to the Empire Connector Pipeline in New York, for an additional 350 MMcf/d of takeaway capacity, also starting this fall. In the southwestern Marcellus area, Dominion's Appalachian Gateway will help move gas from Pennsylvania and West Virginia to eastern markets starting fall 2012.



Growing shale gas production has had a significant impact on liquefied natural gas imports. Year-to-date, the eight active U.S. LNG terminals have operated at only 5% of capacity. Some Gulf Coast terminals have managed to extract value from their underutilized facilities by providing temporary storage of landed LNG before sending it to higher priced destinations around the world. These LNG re-exports amounted to 45 Bcf through the first nine months of 2011, about 19% of total U.S. LNG imports over the same period.

Decreasing LNG imports are due to the low price of natural gas in the United States compared to world markets. In 2007, U.S. natural gas prices commanded a \$4/MMBtu premium over the National Balancing Point in the United Kingdom, and LNG imports peaked at almost 100 Bcf/month. Since the fall of 2007, U.S. prices have generally been at a substantial discount to world LNG prices, and LNG imports have tumbled. Current winter forward natural gas prices at Henry Hub are \$6 to \$8/MMBtu lower than comparable European prices. LNG does continue to play a role in the Northeast, where imports through Everett in Boston and Canaport in New Brunswick, Canada, are underpinned by long-term contracts.

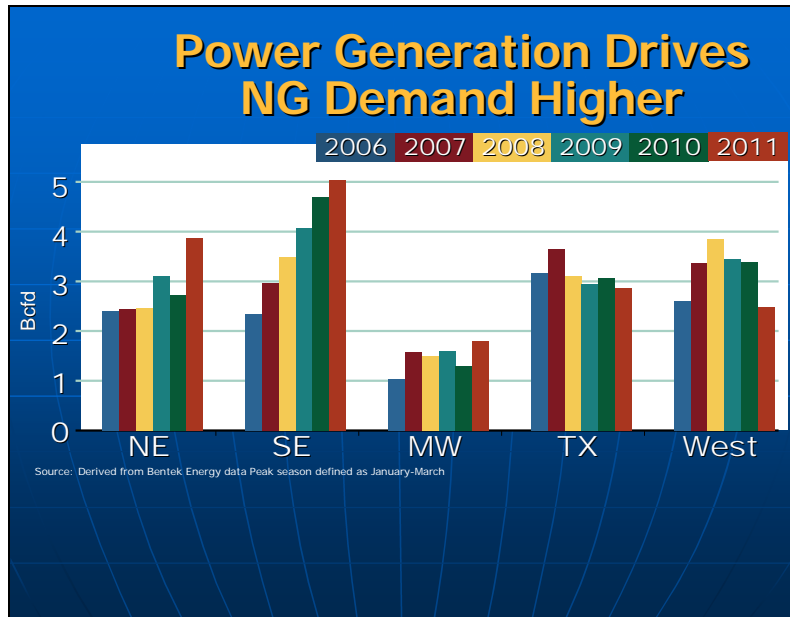




Natural gas storage levels are an important indicator of the industry's ability to meet winter demand. As of October 7, 2011, U.S. working gas in storage was 2% above the 5-year average, and is expected to end the injection season near or above the record set last year.

This year's injection season began slowly, due to high temperatures and robust use of natural gas as an electric generation fuel. Record heat in the Gulf Coast and Midwest led to a 5% increase in summer power burn, resulting in lower injections in those regions. Also, Rockies natural gas, which in the past would have flowed to fill Western storage, flowed east to meet the high demand.

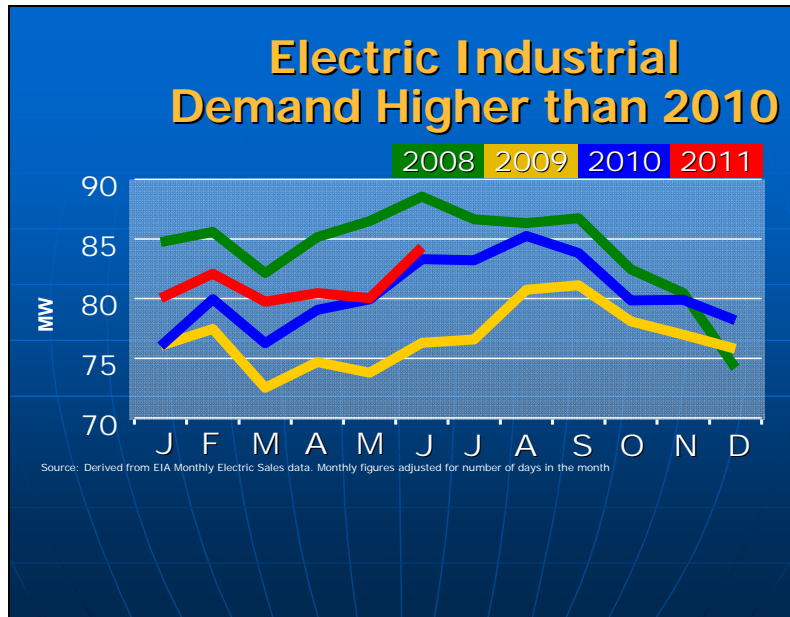
Since August, however, injections have been strong as demand moderated with the end of the summer cooling season. Currently, the East region is 1% below the 5-year average, the West is 3% higher and the producing region is up 7%. At the current injection rates, natural gas in storage should be sufficient to meet winter demand.



U.S. natural gas demand for power generation is up 3.6% through October 14, driven by high summer electricity demand. In addition, natural gas continues to displace some coal used for electric generation, particularly in the east, due to rising coal prices and lower natural gas prices. In 2011, the central Appalachian coal price is 21% higher than in 2010, and Powder River coal is up 7%.

In some regions, gas-fired power generation for the peak winter months, January through March, has been increasing for the past few years, due to new gas-fired units and greater utilization of existing ones. This is of special interest in the Northeast, where generation demand on peak days can coincide with heating load demand. These coinciding peak events can strain the pipeline delivery system and lead to fuel supply restrictions on natural gas-fired units, as regional gas pipelines prioritize deliveries to customers holding firm transportation rights. In recent winters these coinciding peaks have led to occasional price spikes but no major reliability issues.

In other sectors, year to date residential and commercial demand rose 3.5%, mostly due to the cold temperatures in the first quarter. This growth is offset by the small uptick in industrial gas demand, up only 0.2% due to the slow pace of the economic recovery. U.S. natural gas demand for all sectors is up 2.6% from last year.



Two prime factors that influence the level of electric consumption from year to year are the economy and weather. The level of economic activity is reflected primarily in industrial electric consumption, which is largely immune to weather effects. By contrast, electric demand in the residential sector is more sensitive to weather.

The industrial sector makes up 25-30% of total electric consumption. At the trough of the recession in 2009, annual demand by industrial users was the lowest in ten years. Industrial demand has grown steadily since then. As the chart shows, industrial electric use, when compared to the same month a year earlier, has grown each month of 2010 and so far in 2011. These levels, however, are still below the industrial consumption prior to the recession.

## **Southwest Outage and Curtailments Follow-up**

- February 2011, the Southwest region experienced 5–days of unusually cold weather
- 3.7 million electric customers affected
- Natural gas service to over 50,000 customers in New Mexico, Texas and Arizona interrupted
- FERC and NERC initiated an inquiry, and issued recommendations in August
- State led initiatives are already underway to address the problems encountered

As reported to the Commission in August, during the first week of February 2011, the Southwest region experienced unusually cold weather that resulted in the widespread loss of electric and gas service. Over 3.7 million electricity customers were affected, as utilities were forced to initiate rolling blackouts totaling over 6,000 MW. At the same time, local distribution companies interrupted gas service to more than 50,000 customers in New Mexico, Texas and Arizona.

A joint inquiry by the Federal Energy Regulatory Commission and the North American Energy Reliability Corporation looked into the causes of the outages and made recommendations. The recommendations, released in August 2011, included measures that electric and natural gas companies can take to reduce the chances of similar events in the future, such as steps to weatherize equipment, and adopt procedures to prevent similar problems in the future. Additional inquiries and recommendations were launched by the industry and by state regulators.

At this time, there are several state level initiatives underway to address the issues. On the electric side, the Salt River Project in Arizona has made infrastructure and procedural improvements to better handle cold weather events. Staff of the New Mexico Public Utilities Commission is preparing a report on the outages to include recommendations for weatherization and other infrastructure improvements. Under new state legislation, the Texas Public Utility Commission has directed its electric utilities to update their emergency plans and recommend improvements.

On the gas side, the New Mexico legislature and PUC are awaiting a formal report and recommendations from the state task force established to investigate the event. However, the New Mexico Gas Company has begun installing additional gas valves to better control their system and procured additional storage capacity at the Chevron Keystone Storage field. The Arizona Corporation Commission (ACC) reviewed the circumstances surrounding the gas outages. The ACC has said it would like to see underground natural gas storage developed in the state.

This concludes the 2011-2012 winter assessment. We will answer any questions you may have.

Slide 13



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