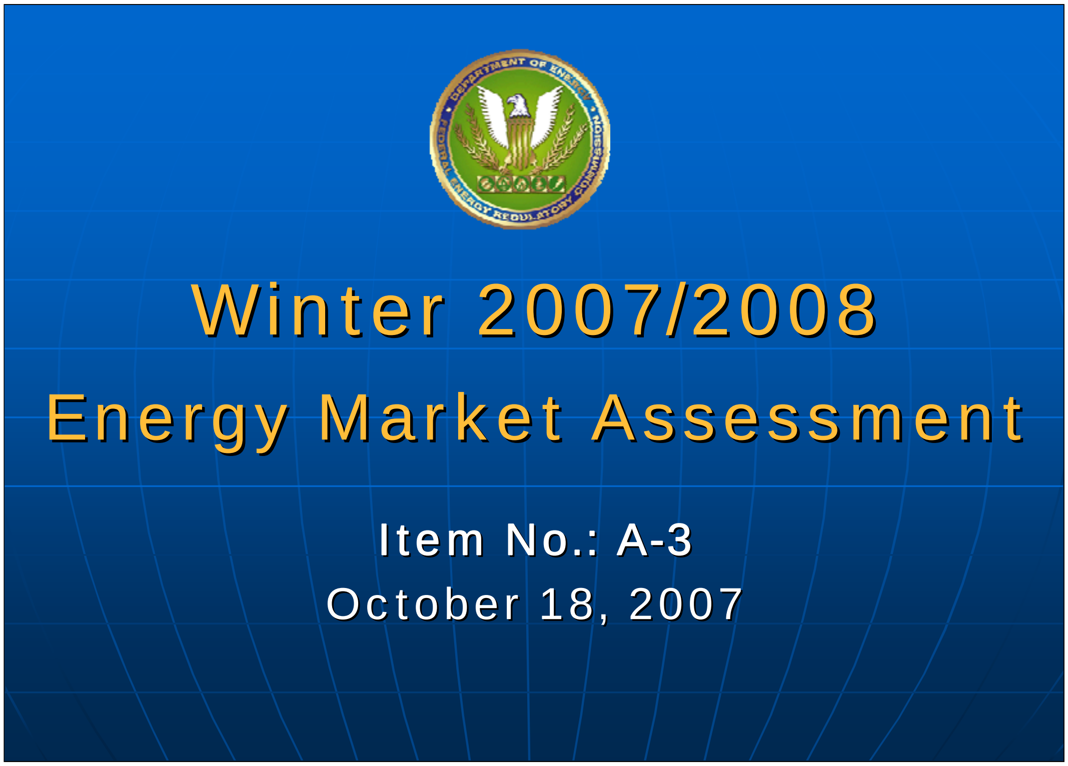


Mr. Chairman, Commissioners. Today I'm pleased to present the Office of Enforcement's *Winter 2007-2008 Energy Market Assessment*. With me is Chris Peterson, who recently took on acting leadership of the Division of Energy Market Oversight's Natural Gas Group.

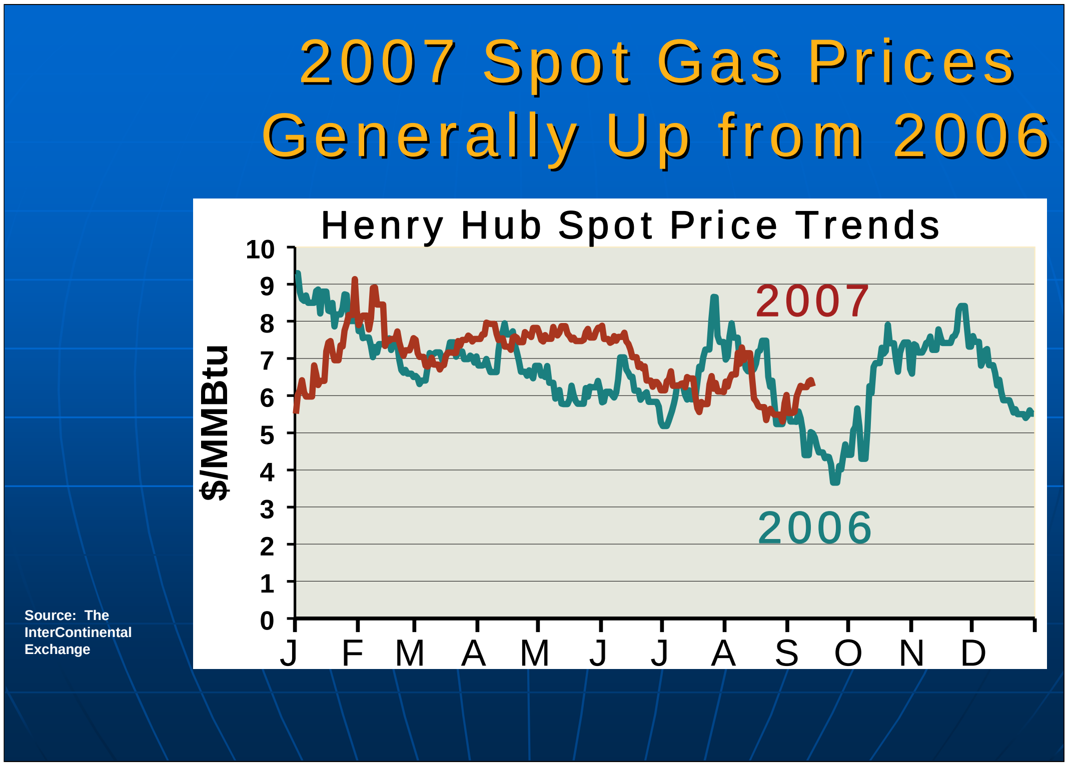
After I'm finished with the Winter Assessment, I'll turn it over to Jeff Wright of the Office of Energy Projects to discuss infrastructure.

The *Winter Assessment* is staff's annual opportunity to share observations about natural gas, electric and other energy markets into the winter.

For a second year, the prospects for natural gas markets as we head into this winter are very good. Though spot prices have been a bit higher this year than last, reflecting increased use of gas, they have not moved up as strongly as oil. Current gas prices reflect robust storage inventories and predictions for generally mild winter weather. I will begin the presentation by reviewing key national and international conditions affecting U.S. gas markets.

New capacity additions in the form of pipelines and liquefied natural gas (or "LNG") facilities may change some regional pricing dynamics late in the winter, and I will spend a few minutes discussing some of those changes this morning as well.

Overall, current conditions for natural gas demonstrate significant flexibility to deal with most challenges that might arise through the winter.

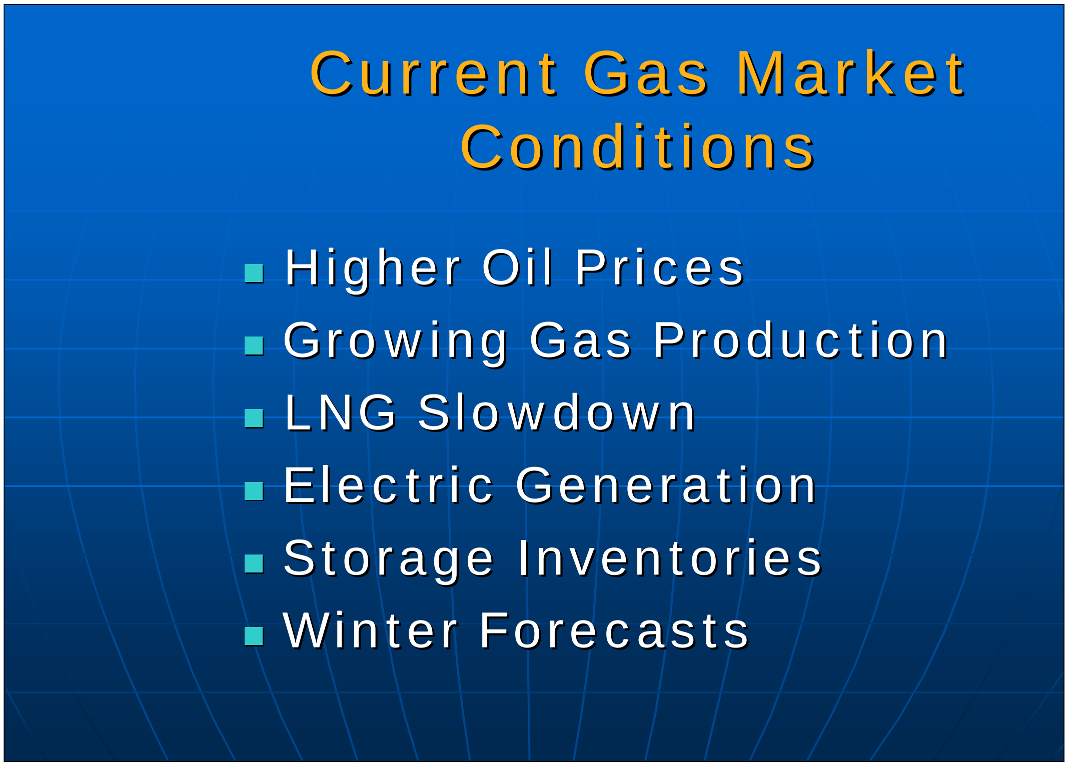


Natural gas prices are up slightly this year compared to last.

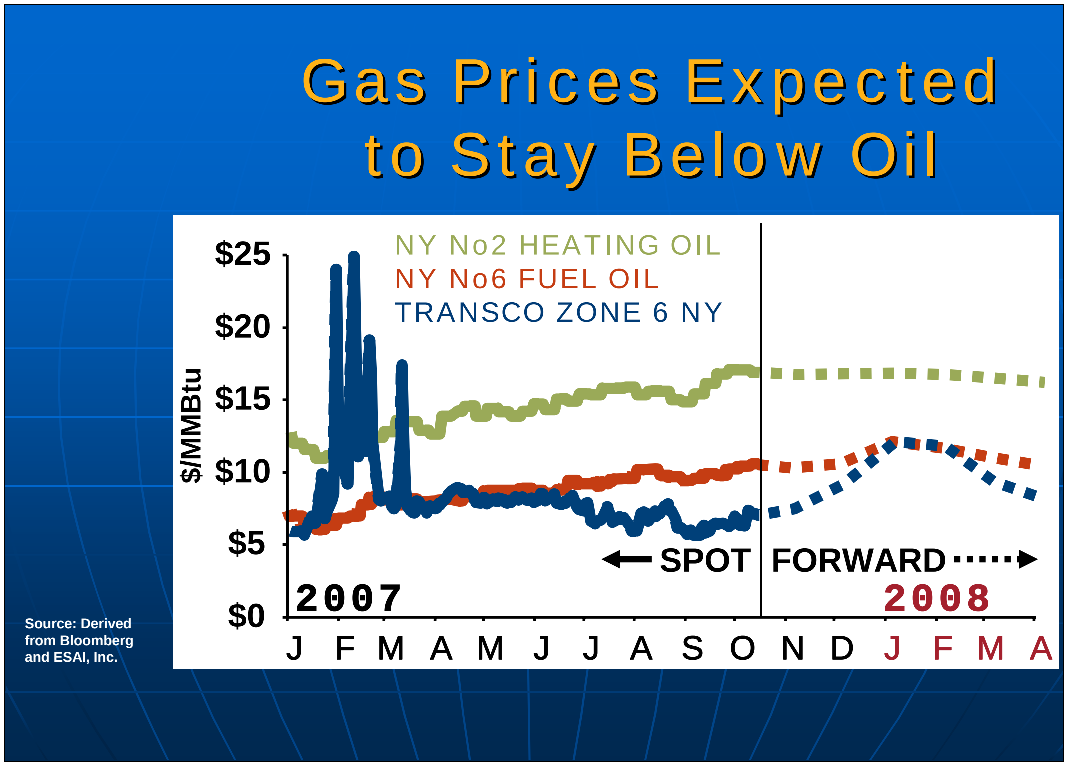
This graph compares next-day spot natural gas prices traded at Henry Hub, Louisiana, on the IntercontinentalExchange (or "ICE") in 2007 and 2006. Henry Hub spot prices so far this year – shown in red – have averaged almost $6.95 per million British thermal units (or MMBtus) – up between 20 and 25¢ from last year – shown in blue.

Warm weather late in 2006 continued into the first half of January, only to see a colder-than-normal February in the United States. The graph shows how low early January spot gas prices gave way to weather-driven increases in February. Prices remained above 2006 levels from February through June. Summer weather in 2007, though hotter-than-normal, did not reach the same temperatures as in 2006. Summer 2006 in the United States (defined by the National Climactic Data Center as June through August) was the hottest since 1900; summer 2007 was only the 6th hottest. Consequently, July and August 2006 natural gas price increases were not matched in 2007.

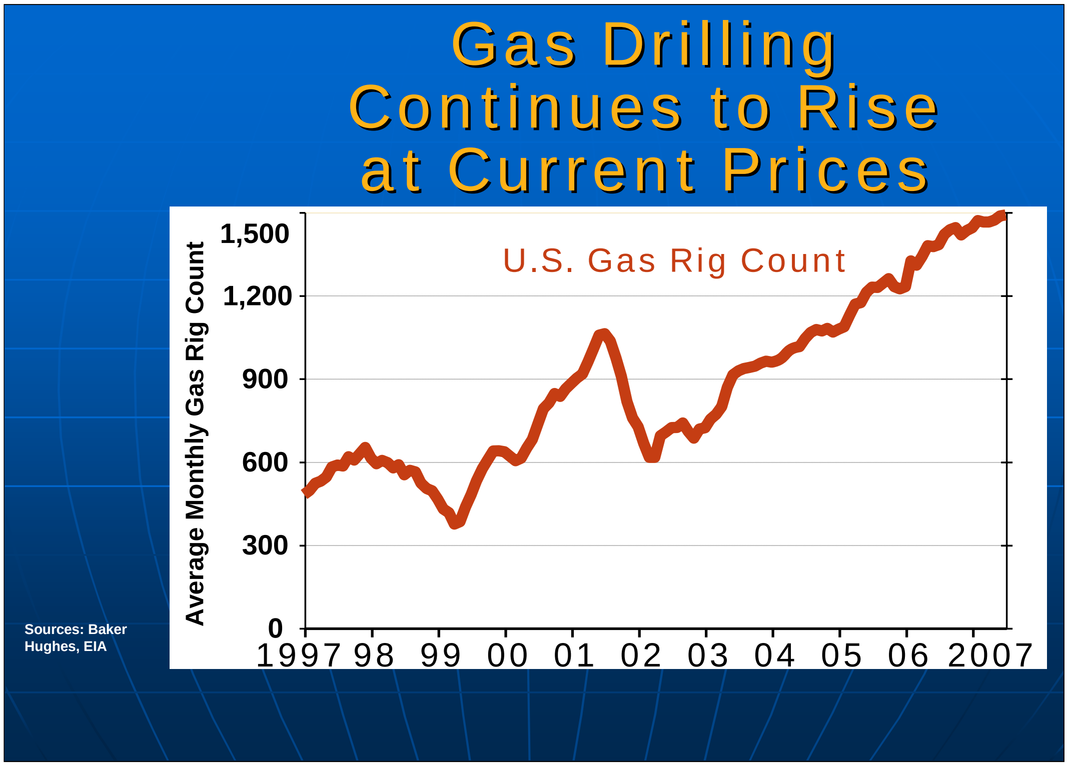
Meanwhile, much of the United States has seen unseasonably warm weather into September and October; increasing natural gas burn for electric generation well into what we generally consider the "shoulder period" when nuclear and coal plants are down for planned maintenance in preparation for the winter. Consequently, Henry Hub spot prices have not declined as much as in the autumn of 2006.



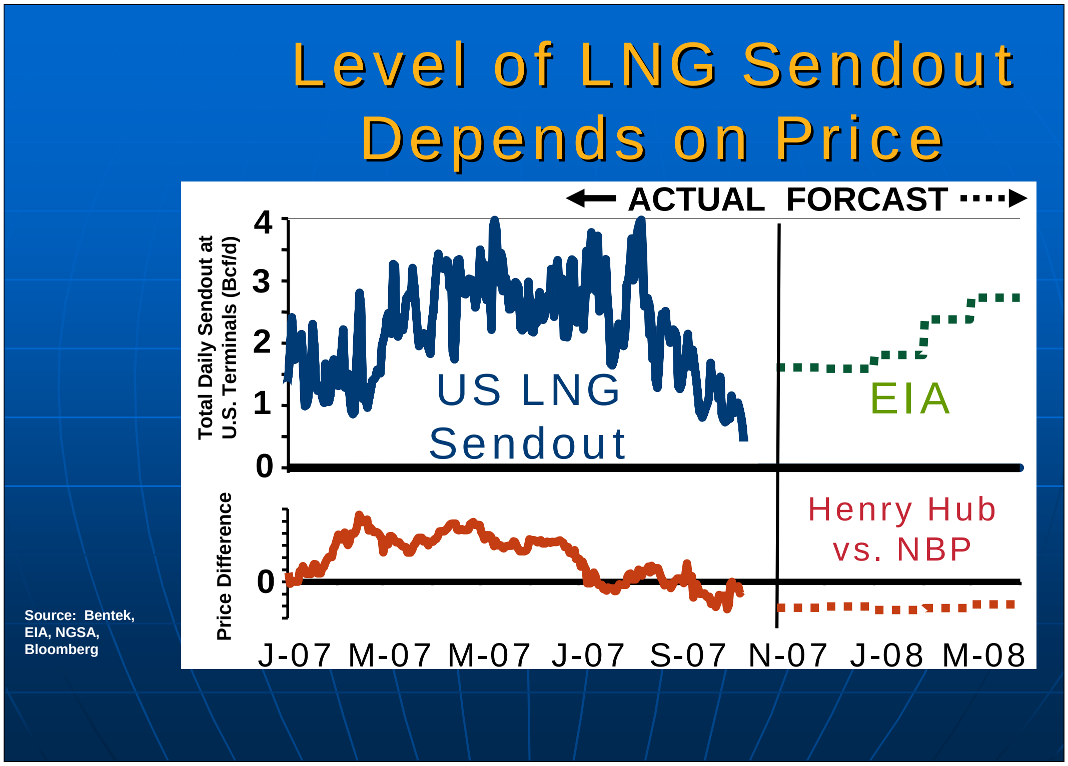
Current natural gas market conditions are the result of a variety of national and international factors. I will review these next, including high oil prices, growing domestic gas production, record LNG deliveries that have begun to slow, increasing use of gas in electric generation, strong storage inventories and current winter weather forecasts.



One of the most dramatic changes in energy market conditions has been the increase in oil prices. The spot West Texas Intermediate crude oil price averaged about $66/barrel in 2006 and has averaged only about a dollar higher this year. Oil prices reached a new record – if we don't adjust for inflation – briefly above $88/barrel this week, representing an almost 50% increase in price over the same week in 2006. Last year, I pointed out that gas prices had fallen below competing oil product prices for longer in the summer of 2006 than we had seen in some time. This graph of gas and oil product prices into New York City in 2007 shows that, starting mid-summer, gas prices have been much lower than Number 6 fuel oil (known as residual fuel oil or "resid"). For many years prior to 2006, New York gas prices traded between resid and heating oil prices, with occasional exceptions when gas prices rose on weather. We can see some of these weather-related increases on the graph in February and March. This winter, we are likely to see these kinds of prices again in the northeast during cold spells. Sustained, relatively-lower gas prices and is expected to continue into early 2008, as represented in the forward prices on the graph. Apparently natural gas has been able to capture the remaining competitive fuel-switching consumption without driving prices up – at least compared to oil. The change may reflect a new relationship between gas and oil prices. In effect, gas and oil price competition may be dead – at least for now.

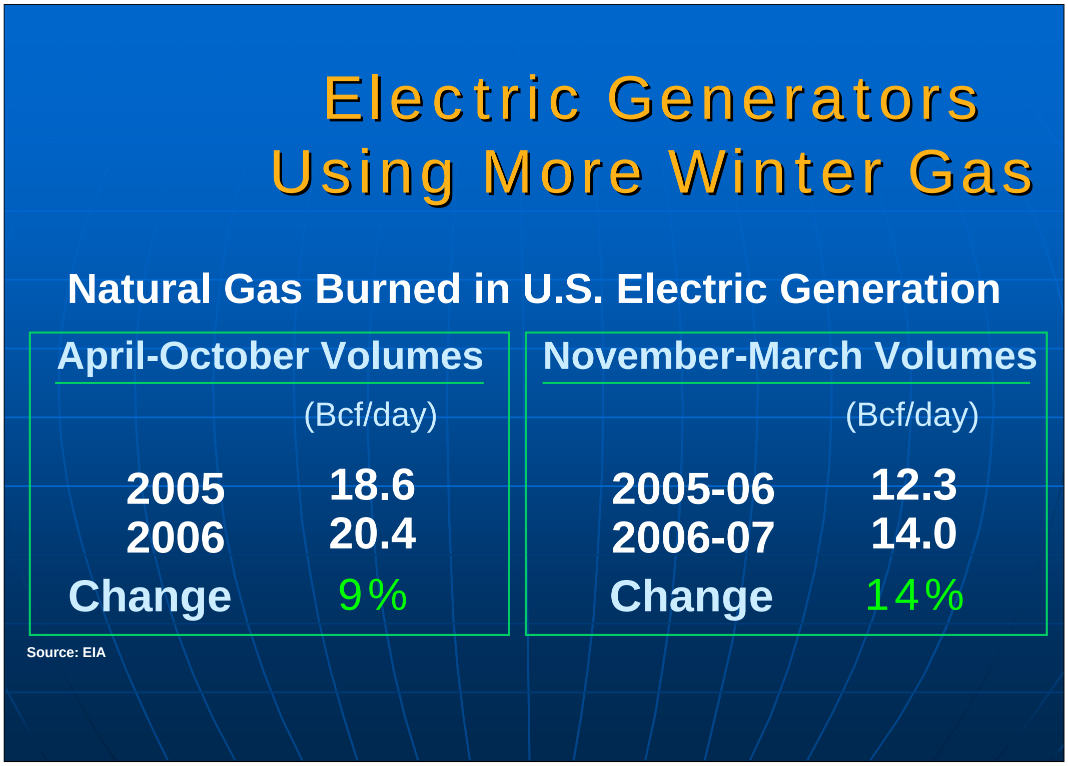


In part, gas prices have remained lower because of increases in production due to new gas wells. Realized gas production is, in part, a function of drilling activity and the yield or productivity of new wells. This graph of drilling rig use collected by Baker Hughes shows that current prices continue to support growth in drilling for natural gas. How this affects the overall supply situation is less clear, because we know that, on average, the productivity of wells drilled has declined. Nevertheless, the Energy Information Administration (or EIA) reports that total marketed U.S. production in 2007 through July was up over the same period in 2006 by a little over 2%. Overall, EIA estimates that 2007 marketed production will be 19.6 trillion cubic feet, about a 1.3% increase.

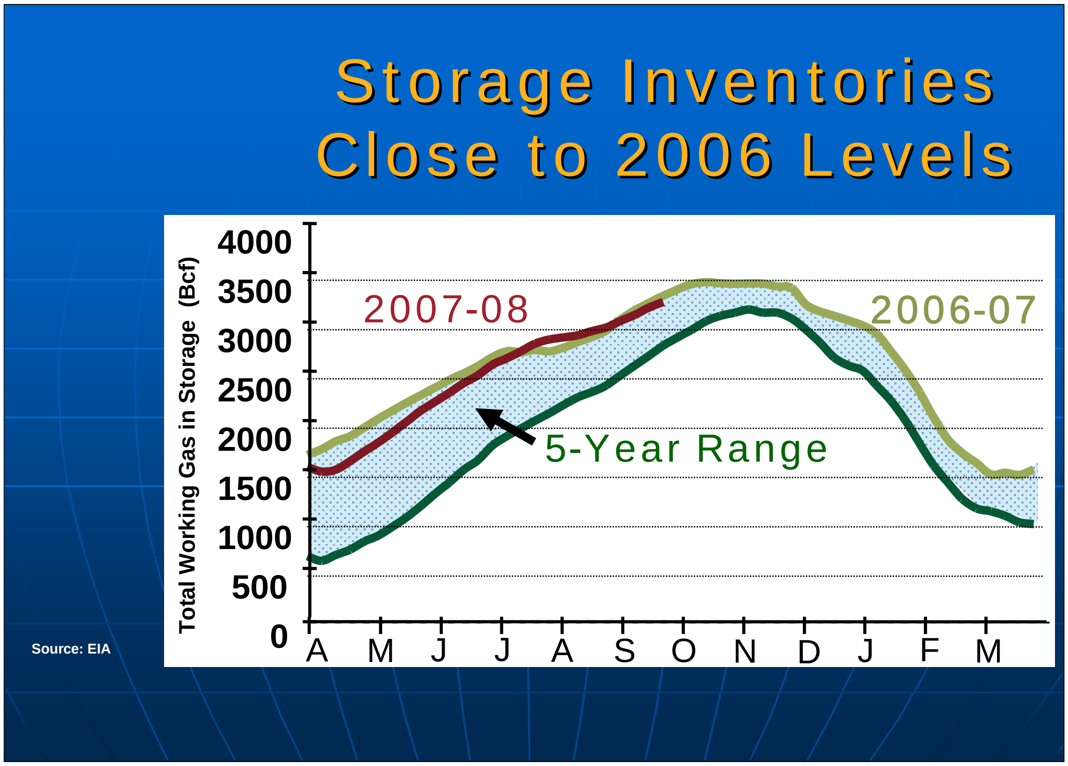


In addition to production increases, the United States enjoyed record LNG deliveries during the first part of 2007. Through mid-October, 2007 U.S. LNG sendout averaged 2.5 billion cubic feet (or Bcf) per day, up 50% from the same period in 2006. First-half of 2007 deliveries largely coincided with reduced demand in Europe, improved global liquefaction plant use, and new supplies from the Middle East. During the summer, with hot weather and pipeline outages in northern Europe and the July shutdown of Tokyo Electric Power Co.'s Kashiwazaki-Kariwa nuclear plant after an earthquake, international prices rose and U.S. LNG sendout levels began to drop. We see that response on this graph; at the top is total U.S. sendout this year, with EIA's winter forecast of LNG imports. On the graph, we can see that sendout is somewhat correlated to whether and how much spot Henry Hub prices exceed those at, in this example, the United Kingdom's National Balancing Point.

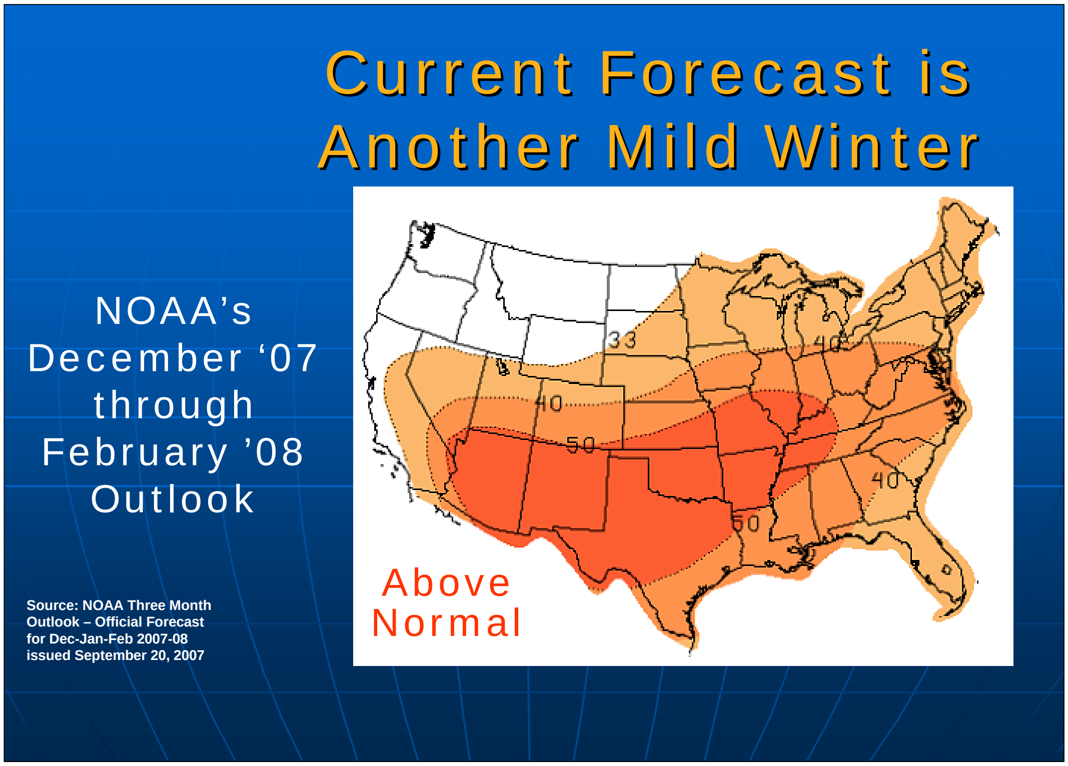
Given the forward projection of higher European prices compared to the United States, EIA's current projections may be optimistic, which underscores an important point. LNG will be available when U.S. prices are relatively high – basically, times of more stress in energy markets here than abroad. Consequently, expanding LNG capacity serves as a sort of insurance policy – not used much when times are good, but very helpful if times get bad. That leads to the apparent dichotomy that *not* using the new capacity will signal a better domestic supply/demand balance than using it will.



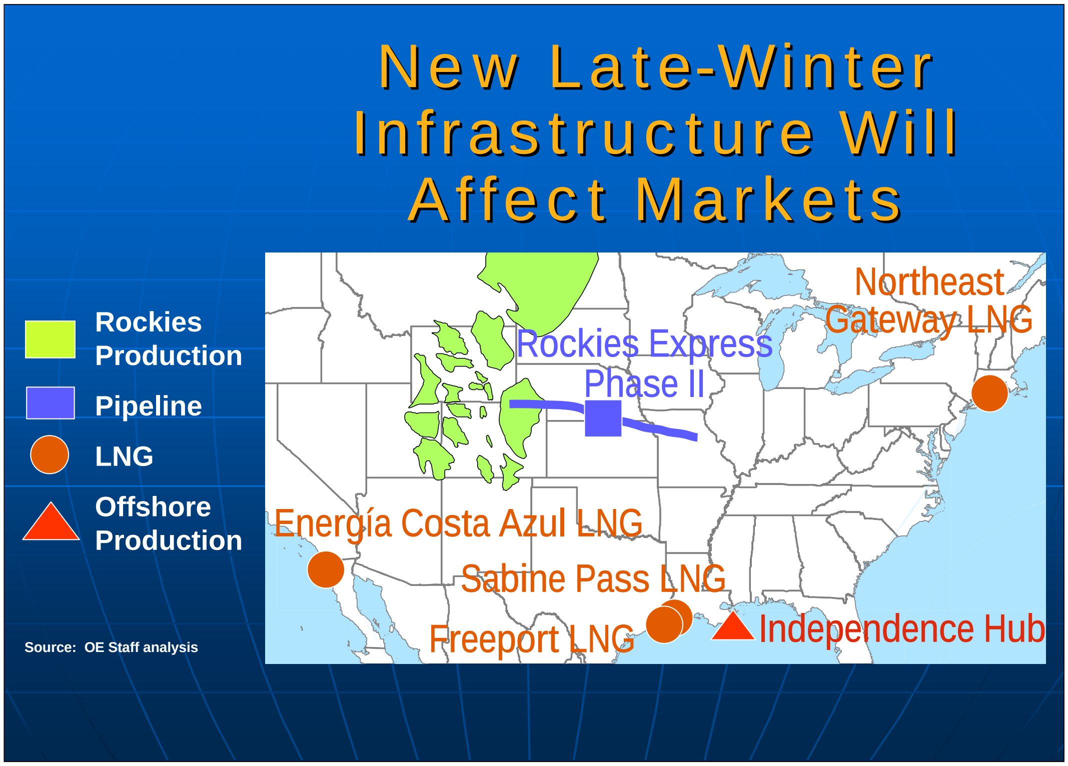
An important change in natural gas consumption in the United States has been increased demand by electric generation. According to EIA, in the first half of the decade, net U.S. generating capacity increased by about 20 percent, of which 97% of the added generation was gas-fired. As electricity demand grows, much of the available incremental capacity is gas-fired, resulting in significant increases in gas use. Between 2005 and 2006, consumption of gas in electric generation outside the winter months leapt 9%. So far this year, analysis by Bentek of interstate pipeline flows indicates another increase of around 10%. Winter consumption of gas in electric generation has been growing even faster; 14% between last winter and the winter before. Growth in demand generally keeps upward pressure on gas prices and indicates that any disruptions to gas supply in the winter – and, right now, we don't anticipate any of those – would affect electricity markets significantly.



Our best way of assessing the net effects of supply and demand factors in U.S. natural gas is to look at storage inventories. At this point, the United States appears to be heading towards another near-record level of storage. In April, at the beginning of the "injection season," inventories were below last year's level. Early in the summer, inventories grew in comparison to last year, surpassing last year's level in July. Starting in July 2006, fierce heat across the United States actually resulted in a two weeks of net national storage withdrawals. Since July, storage inventories have fallen slightly below last year's level, though we should recall that last year's peak inventory was greater than any since November 1990. Basically, we expect to see full storage this year. Effectively full storage goes a long way toward protecting the country from the disruptions and price spikes associated with tight supply-demand balances in the winter.



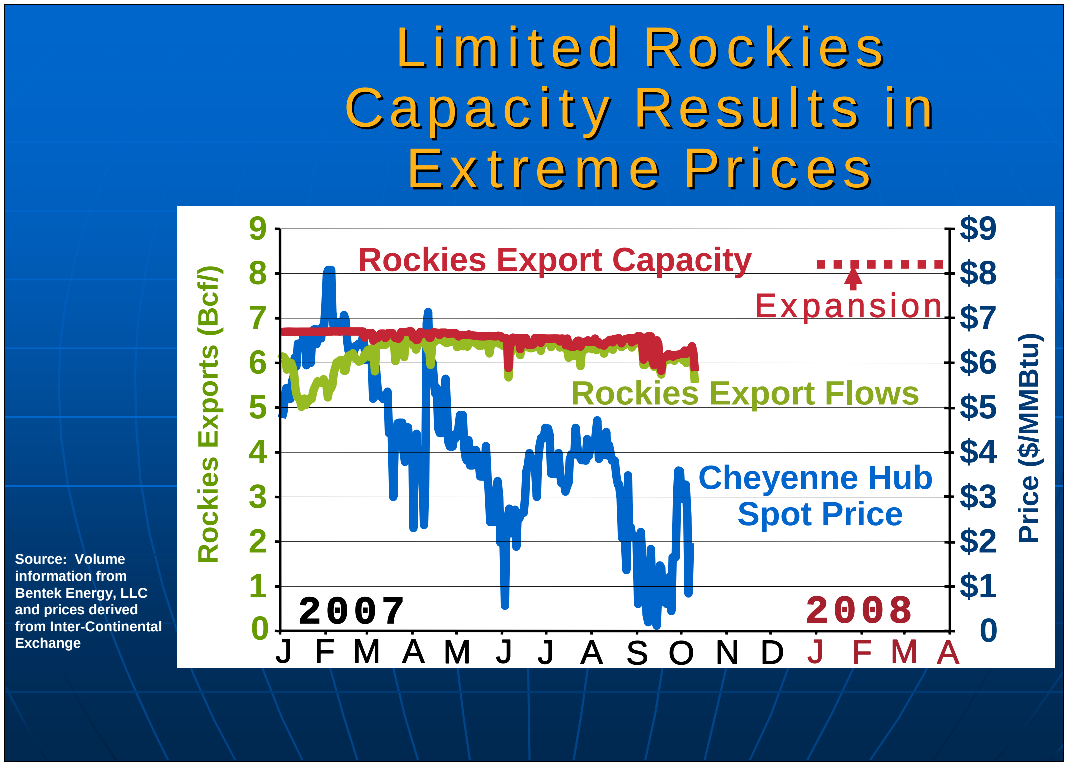
Ultimately, the performance of natural gas markets next winter will be driven by weather. Weather forecasting into the next season is notoriously difficult, though energy traders review carefully and often act on their beliefs regarding weather forecasts. The current winter forecast from the National Oceanic and Atmospheric Administration, published almost a month ago, indicates warmer-than-normal winter temperatures across much of the United States, driven by La Niña conditions in the Pacific Ocean. If true, gas prices could remain stable or even see some downward pressure.



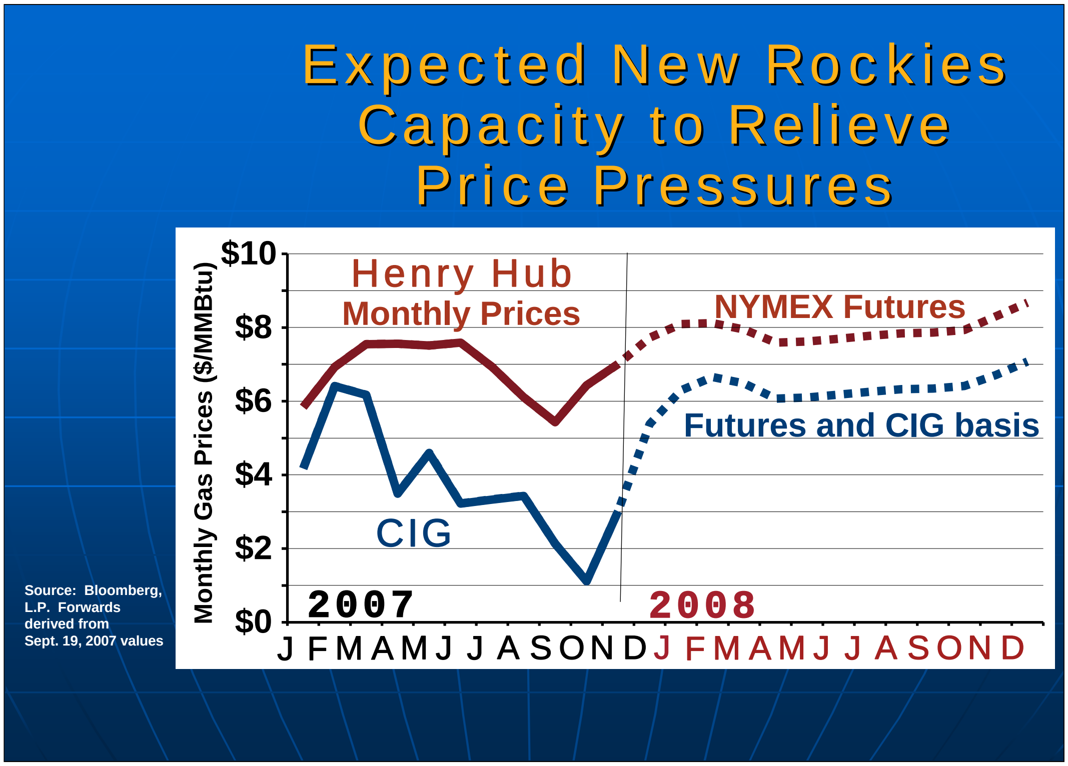
U.S. gas market dynamics are likely to change late in the winter this year as new infrastructure becomes available. Major pipeline projects include the Independence Trail Pipeline, designed to bring more gas onshore from the Gulf of Mexico, which is already transporting about six-tenths of a Bcf/day on its way to a Bcf, and the next phase of the Rockies Express Pipeline which will transport gas from the Cheyenne Hub to mid-continent pipeline interconnects in Missouri in early 2008. In addition, several new North American LNG terminals are expected to begin at least limited operations before or during the first quarter of 2008, including Freeport for 1.5 Bcf/day, Northeast Gateway for 0.8 Bcf/day and the Sabine Pass terminal for 2.6 Bcf/day. Sempra's terminal in Baja, Mexico – the 1.0 Bcf/day Energía Costa Azul facility – is also expected to begin operations sometime early next year.

As we've seen, new LNG terminals do not mean additional *supply* so much as they mean additional *capacity*. Depending on international gas prices, the supply may or may not be available to U.S. markets.

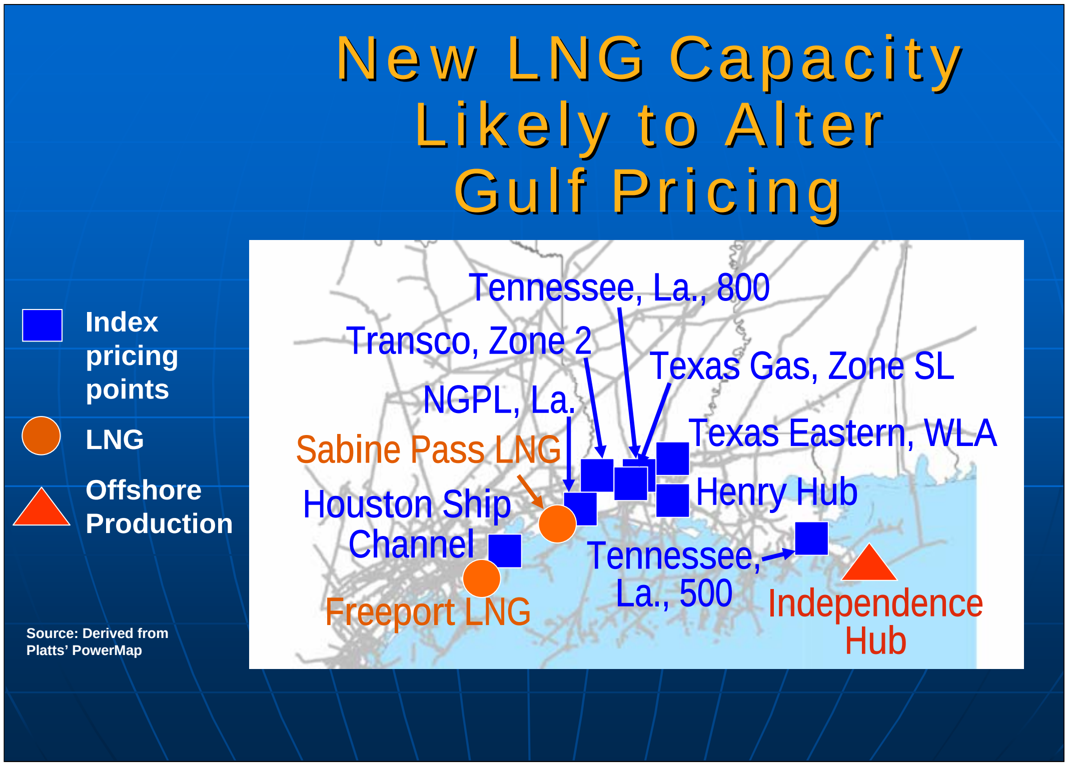
I'd like to look in a little more detail at the dynamic we've seen this year in the Rockies.



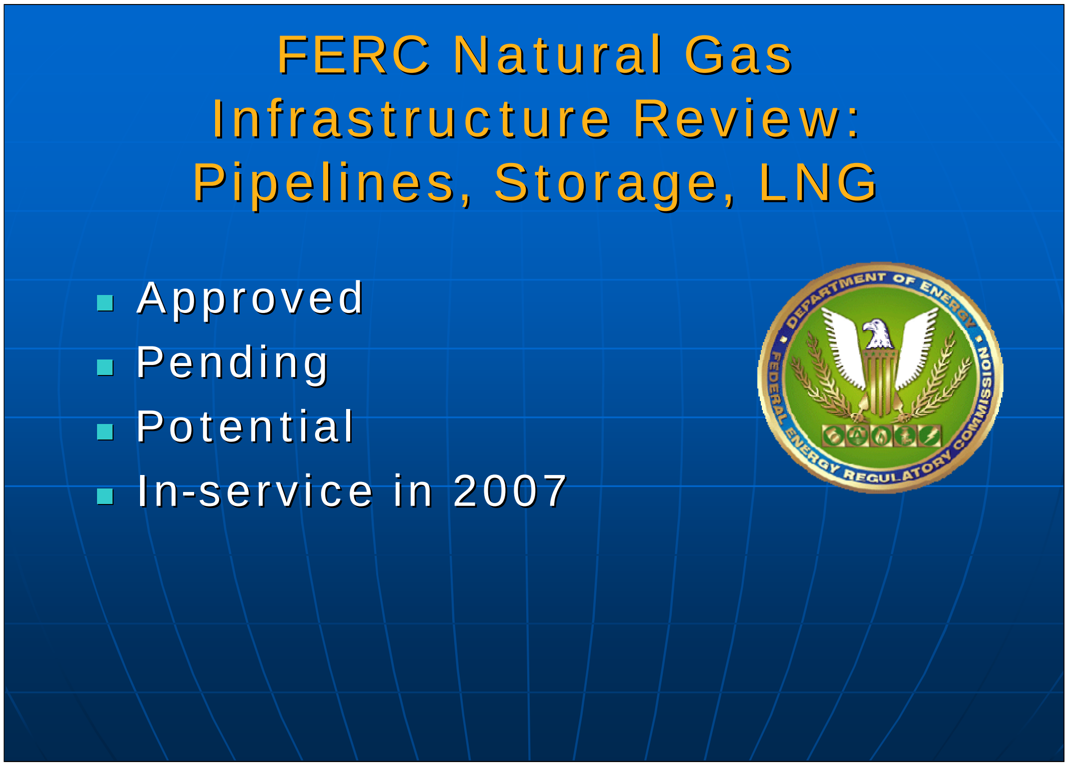
On September 14, the natural gas market in the Rockies produced a documented transaction for natural gas sold on ICE for only one penny per MMBtu. The same day, the price at Henry Hub averaged $6.23/MMBtu. The difference in prices nationally and in the Rockies is further evidence of the extreme price volatility that can result from constraints on the interstate pipeline system. As we can see on this graph of both Cheyenne Hub gas prices and of export capacity use out of the Rockies, producers have been producing effectively as much as can be used or delivered from the Rockies since early in 2007. When there simply isn't anywhere else to take the gas, prices will respond, even to extremes. For a small decrease in capacity, the price effect is large. On the graph you can see that when the red capacity line goes down, the price falls as well – even to one penny. The dichotomy is that gas prices across the rest of the country remain high, and are driven down only where the supply is bottled-up. The fix for this kind of price volatility is infrastructure.



Forward markets are reflecting the expectation that, with its expected early 2008 completion, Phase II of the Rockies Express Pipeline will reduce the difference between Rockies prices and those to the east and west. This graph of historical and forward prices indicates that the average difference between Henry Hub and the Colorado Interstate Gas Pipeline pricing point (or CIG) is expected to narrow somewhat with the capacity addition – though not disappear. CIG is broadly representative of other points in the Rockies. The market signals – while definitely painful in the short term for producers and western state tax revenues – do appear to be attracting investment in infrastructure.



Back in the Gulf of Mexico, new LNG terminals at Sabine Pass and Freeport will add 4.1 Bcf/day of new sendout capacity to an area well-interconnected with existing pipelines. Still, depending on the vagaries of the international LNG market, those terminals may attract few cargoes this winter or they may temporarily overwhelm the existing pipeline network. In the unhappy event that U.S. gas prices become relatively high in international terms, heavy deliveries into the area could overload the system for some periods – depressing prices locally at the index points on the map. In the short term, local, supply-oriented prices could get quite low – though I'd hope not the one penny we saw in the Rockies under similar conditions. Such prices could reduce drilling. In the long term, low and volatile supply-area prices would be a strong incentive to further develop pipeline infrastructure along the Gulf coast. We will see what, if anything, these new terminals do to market performance in the area.



Thank you, Steve. Good morning Mr. Chairman and commissioners.

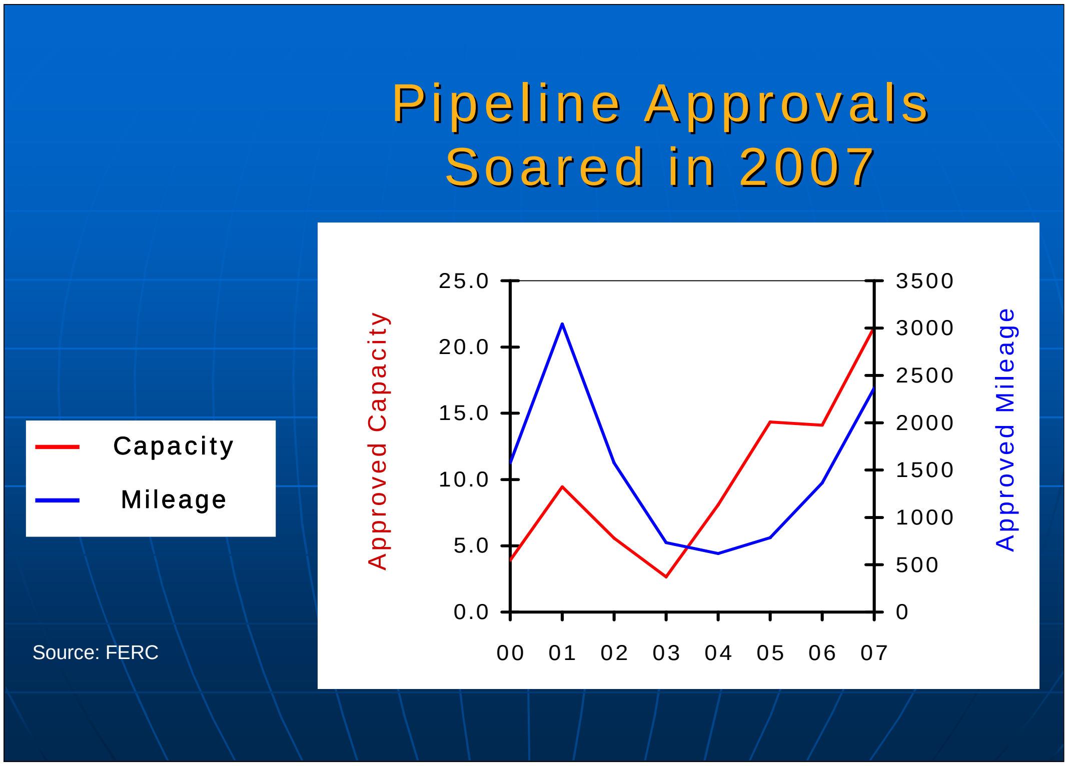
This morning I would like to take a look at the natural gas infrastructure – pipelines, storage and LNG terminals – that the Commission has approved in 2007 and, in addition, what projects are currently being analyzed at the Commission as well as projects that may be expected to be filed with the Commission in the not too distant future. Further, I will touch upon what gas infrastructure has actually gone into service this past year.

Pipeline Approvals 2000-2007 (Oct)

	Capacity (Bcf/day)	Miles of Pipe	Compression (HP)	Cost (Billions)
2000	2.2	1,102.8	151,096	0.8
2001	8.8	2,700.3	870,767	4.4
2002	5.8	1,590.0	560,064	3.1
2003	1.7	352.4	221,545	1.0
2004	8.1	619.3	83,538	1.2
2005	14.3	785.1	123,036	1.9
2006	14.1	1,363.6	329,657	4.2
2007 (Oct)	21.5	2,365.7	746,180	7.0
TOTAL	76.5	10,879.2	3,085,883	23.6

Source: FERC

The table on the slide before you presents a summary of the pipeline facilities that the Commission has approved from 2000 up to this meeting. These approvals totaled over 76 billion cubic feet per day of capacity, nearly 11,000 miles of pipeline, over 3 million horsepower of compression at an estimated cost of close to $24 billion.

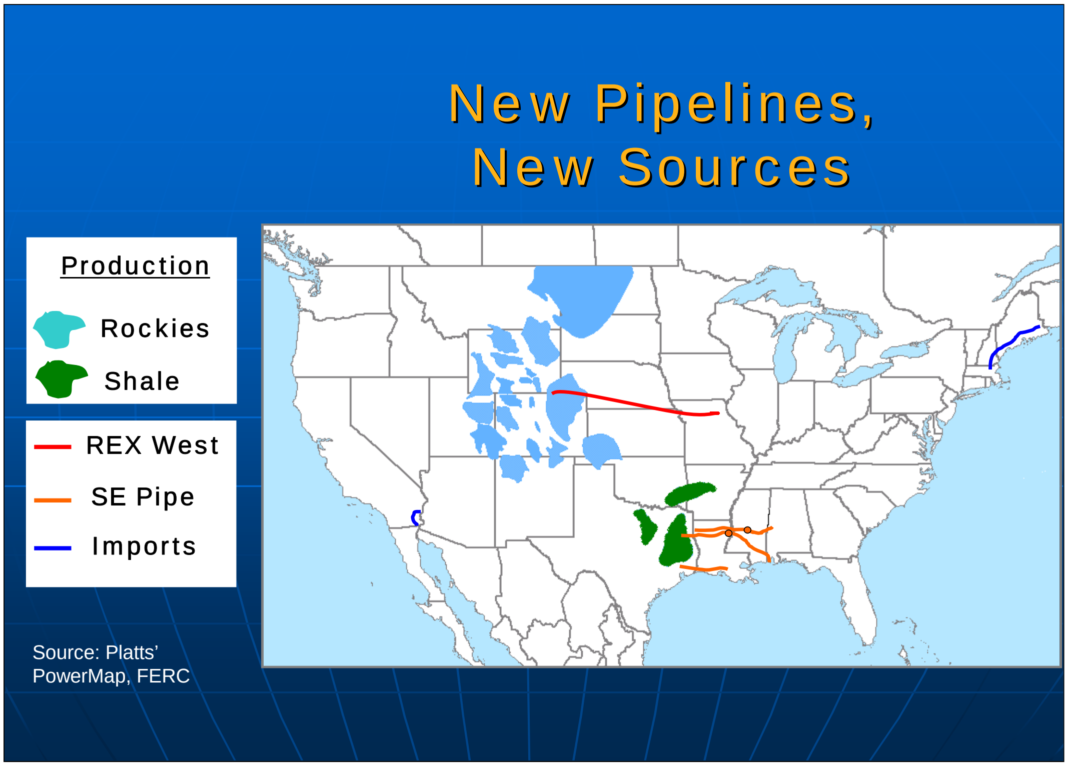


Using the information from the previous slide, this slide shows the dramatic increase in both the capacity and mileage approved by the Commission. In fact, the approval of 21.5 billion cubic feet of capacity per year represents a 50 percent increase over the capacity approved the previous year and constitutes over 28 percent of the capacity approved since the beginning of 2000.

The increase in approved mileage was even more dramatic, nearly a 75 percent increase over 2006 and over 20 percent of the mileage approved in this decade.

We have definitely moved out of the trend of recent years which was characterized by the approval of high-capacity, short mileage pipelines that are associated with LNG terminals to effect the delivery of the regasified LNG to the existing transmission system. In the past two years, and this year in particular, we have seen the trend move back to the more traditional long-line pipelines.

This trend is exemplified by the Rockies Express, or REX, West pipeline and the pipelines leading from east Texas to interconnections with existing long-line pipelines headed to load centers.



On this map, we can see some of the major projects approved in 2007. The projects have highlighted here will help the U.S. obtain gas supplies from areas and sources that will help to replace traditional supply areas such as the offshore Gulf of Mexico and the Western Canadian Sedimentary Basin. In 2001, the Gulf accounted for about one-quarter of U.S. production at 5.1 trillion cubic feet, but has declined to where it's only about 17 percent of U.S. production, or 3.1 Tcf. Meanwhile, net imports from Canada, primarily from the Western Canadian Sedimentary Basin, have declined from a high of almost 9.9 billion cubic feet per day in 2002 to less than 9 Bcf per day so far this year. By 2025, EIA projects that net imports from Canada will average less than 3.8 billion cubic feet per day.

While the Rocky Mountain area has been an important supply region in the past, its importance is increasing. In 2001, the Rockies accounted for 19.8 percent of the U.S. proven reserves. By the end of 2005, proven reserves in the Rockies accounted for about 22.3% of total U.S. proven reserves. Still, not enough supplies are getting out of the Rockies to the markets that value it the most due to the lack of pipeline capacity, resulting in the dramatic price drop that Steve illustrated earlier. One cure for this is the REX West pipeline which will take Rocky Mountain supplies in an easterly direction. Customarily, western sources of gas have headed to the Southwest and to California. Ultimately, if REX East is approved, natural gas will, for the first time, be transported from the Rocky Mountain region to eastern Ohio in one pipeline, for ultimate consumption in the northeast U.S., a region traditionally served by Gulf volumes.

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If we look to east Texas, we see much development in the shale fields, notably the Barnett Shale near the Dallas-Fort Worth area. The pipes approved this year will transport in excess of 3 billion cubic feet per day to interconnections with pipelines headed to demand centers in the Northeast and Florida.

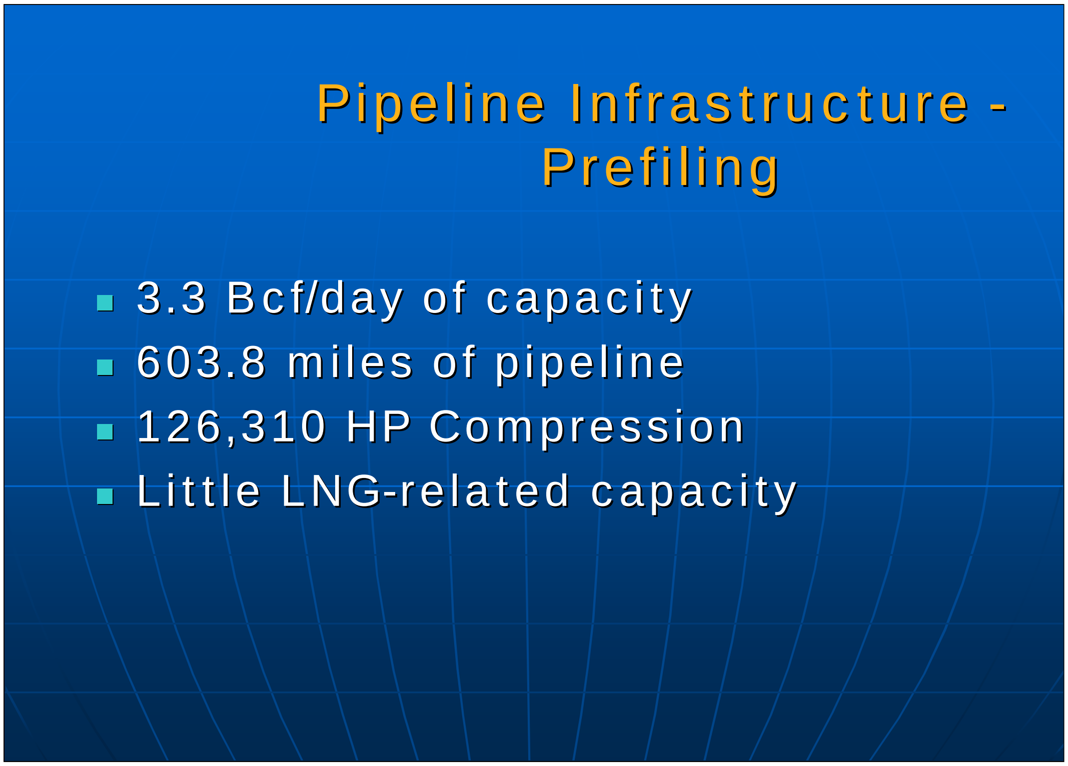
Two other pipelines of note, while not lengthy, are important nonetheless. I would first direct your attention to the short pipeline in the Southwest. This is the North Baja pipeline. This year the Commission approved its proposal to reverse flow so that gas flows from Mexico to the U.S. and to increase its capacity via pipeline looping to 2.7 billion cubic feet per day. This major expansion is to accommodate the regasified LNG that will flow from the Costa Azul LNG terminal near Ensenada on Mexico's Baja coastline. Initially, Costa Azul will have an initial flow of 1 billion cubic feet per day commencing early next year. Costa Azul already has approval to expand its facility by another 1.6 billion cubic feet per year and is expected to start construction on the expansion next year.

The final pipeline approval I would like to note is the expansion of the Maritimes and Northeast pipeline, crossing from Canada into Maine and terminating in Massachusetts. The Commission approved an expansion of the Maritimes facilities by over 0.4 billion cubic feet per day to accommodate the importation of regasified LNG from the Canaport LNG import terminal in Canada to supply the U.S. Northeast. The Canaport terminal in St. John, New Brunswick is expected to have a regasification capacity of 1 billion cubic feet per day, most of which will be exported to the U.S. This supply is expected to come on line in late 2008.

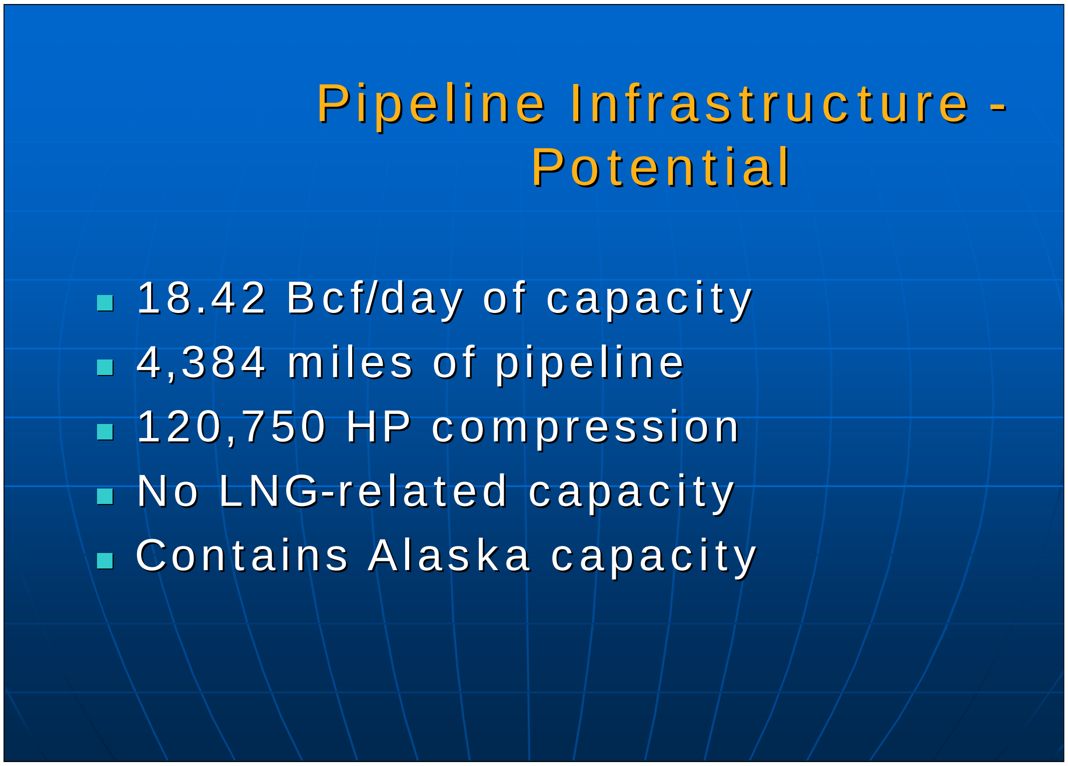
Pipeline Infrastructure - Pending Applications

- 17.97 Bcf/day of capacity
- 2,804.0 miles of pipeline
- 575,891 HP compression
- 47% of capacity - LNG related
- Gas source for projects slowly changing

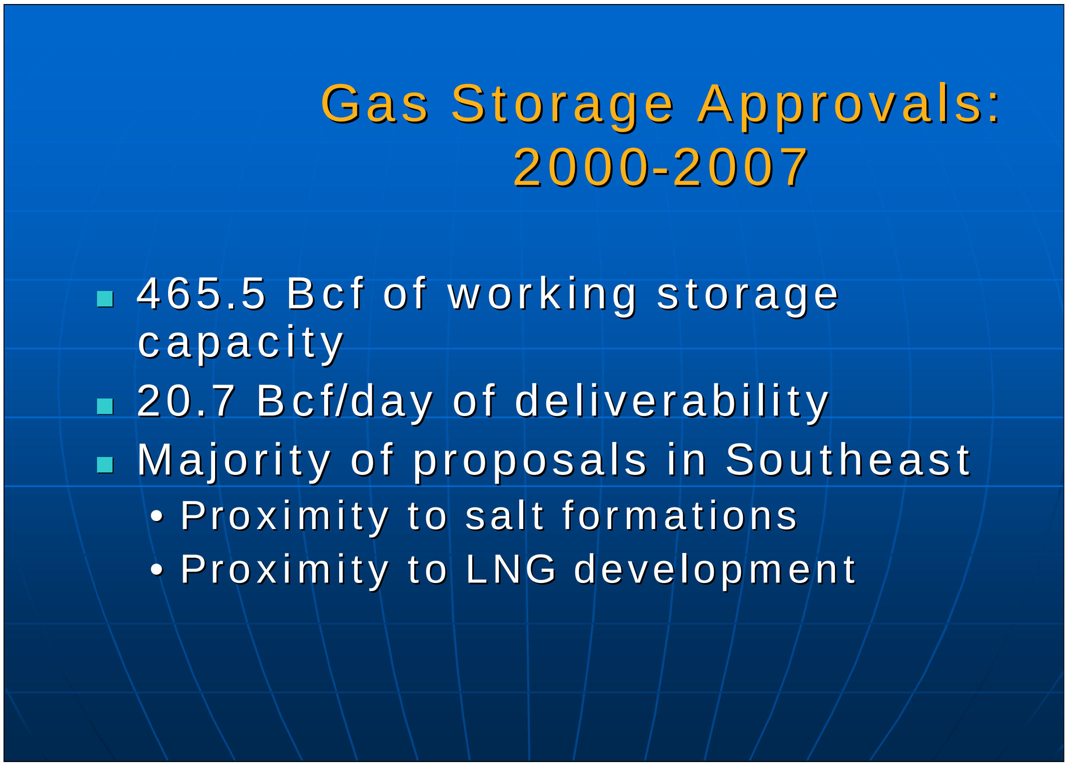
Currently, there are numerous projects before the commission totaling almost 18 Bcf per day of capacity and 2,800 miles of pipeline. While there are still pipeline projects dedicated to LNG projects – approximately 47% of the capacity – there are major projects to transport North American production – the Rockies Express East project from the terminus of the Rockies Express West in Missouri to eastern Ohio, as well as various other proposals to transport gas from the Barnett Shale and Fayetteville Shale in east Texas, Oklahoma and Arkansas, and an expansion of the Transwestern Pipeline to bring more gas to the growing Phoenix area.



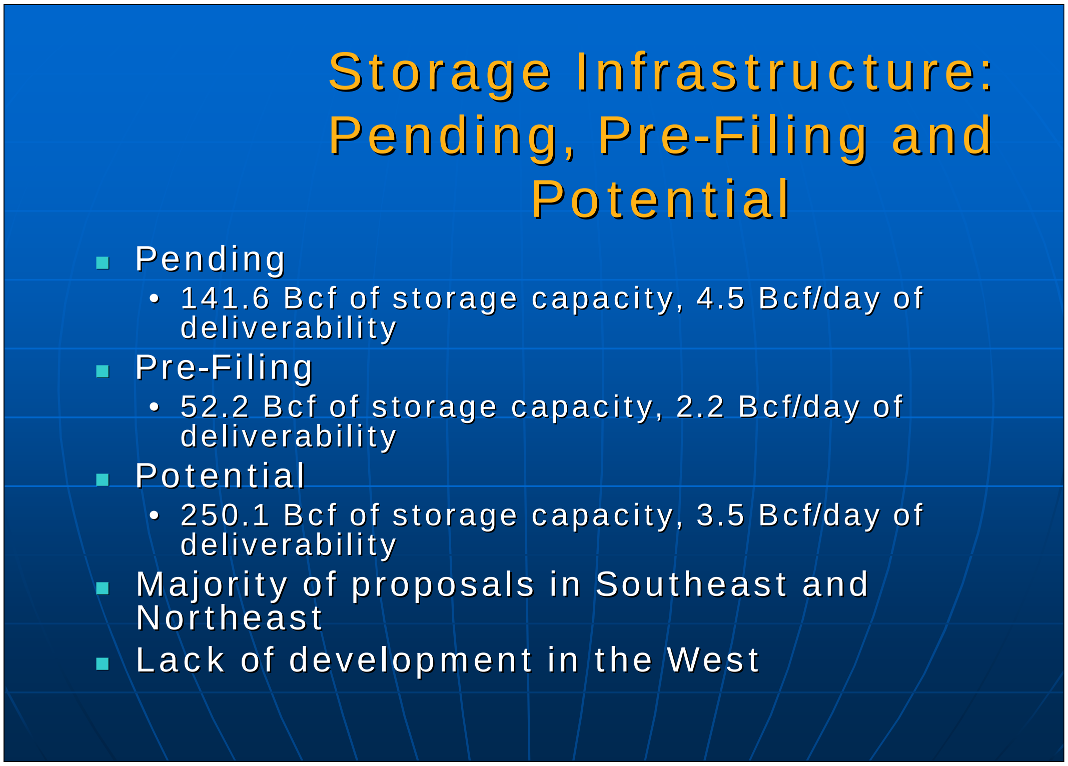
In our prefiling category – those cases that are beginning their environmental review prior to making a formal filing with the commission – we see very little LNG-related pipeline activity. Much of the 3.3 billion cubic feet per day of capacity and 600 miles of pipe is spread about the country.



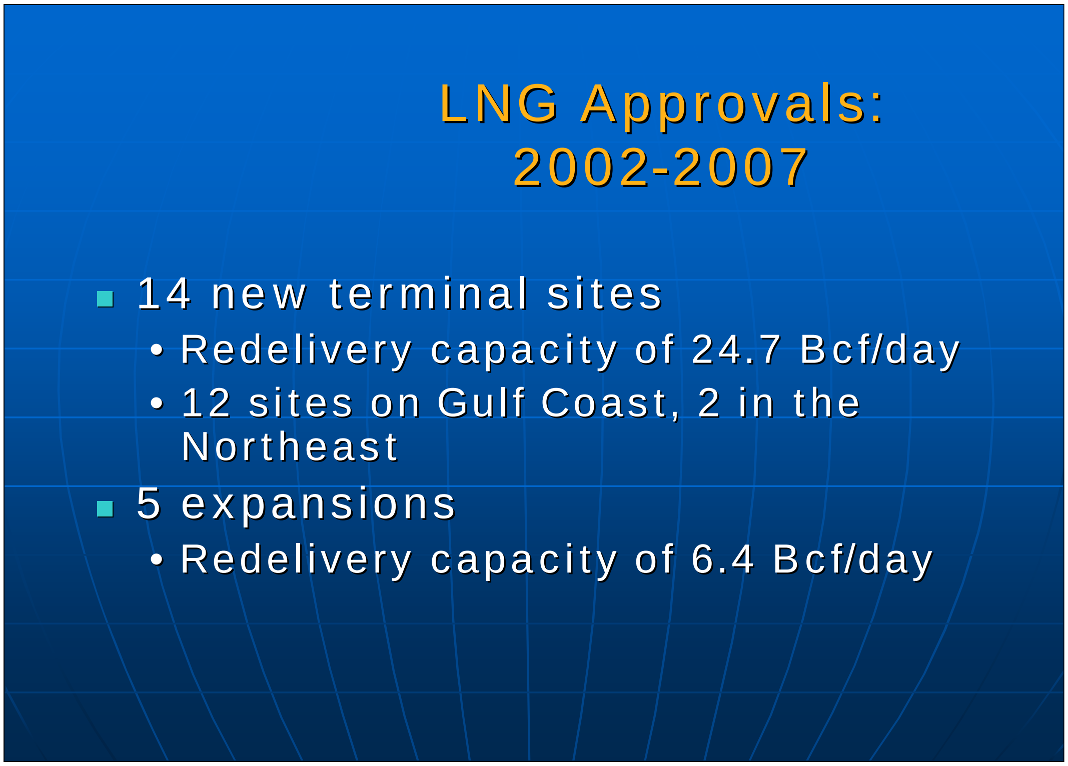
Taking a quick look at potential projects that may be filed within the next couple of years, we see the potential for over 18 Bcf per day of capacity and over 4,000 miles of pipeline. None of these potential projects are directly related to LNG terminals. I do note that these totals contain an amount for the transportation of Alaskan North Slope gas to the Lower 48. Currently, under the state's Alaska Gasline Inducement Act there is a request for applications that closes on November 30th. If everything goes according to schedule, the state could issue a license to a potential applicant by April of next year.



Changing the focus to storage, I would note that since 2000, the Commission has approved 265.5 Bcf of storage capacity and daily delivery from storage of 20.7 Bcf. Storage proposals, especially in recent years, have centered around the Southeast/Gulf Coast area where high delivery salt formations can be utilized to store regasified LNG in addition to traditional gas production from this region.

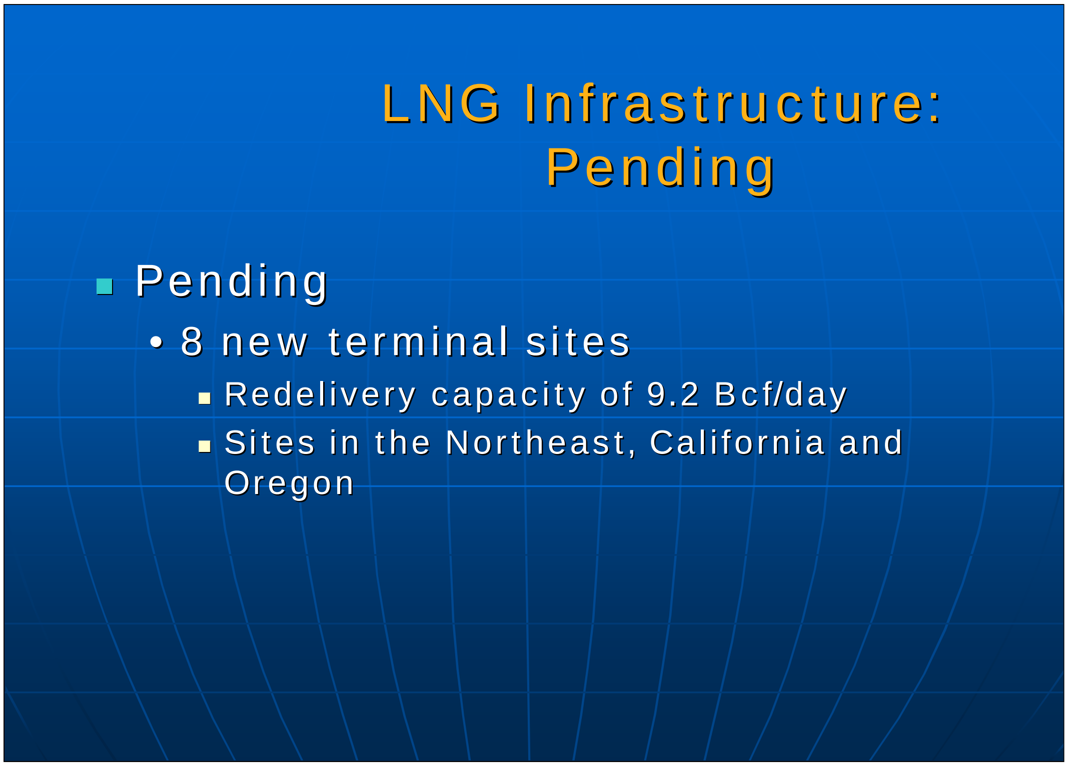


The Commission has several storage projects that are pending and in the pre-filing program that total close to 200 Bcf of capacity and 6.7 Bcf per day of deliverability. Over 60 percent of this capacity is located in Texas and the Gulf Coast states. There are potential projects totaling about 250 Bcf of capacity and 3.5 Bcf per day of deliverability. The majority of these possible projects appear to be located in the Southeast with several other potential projects in the Northeast. As has been the case for the last several years, there a lack of storage development in the western U.S.

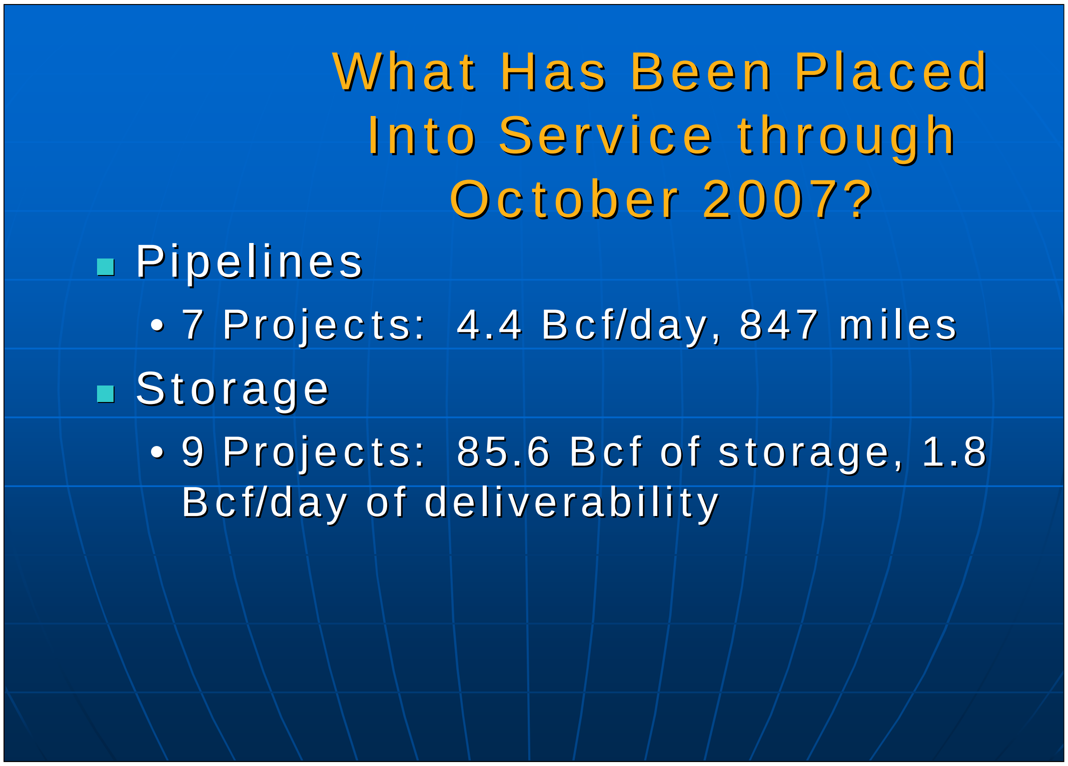


Switching to LNG, we see that that since December 2002, the Commission has approved 14 new terminal sites – three this year. All except for two, are located on the Gulf Coast. The total sendout of the approved terminals is 24.7 Bcf per day. In addition, the Commission has approved expansions at five locations that total 6.4 Bcf per day in new sendout capacity. The total approved sendout capacity exceeds 31 Bcf per day.

Currently, there are four new terminals and two expansions under construction that total 10.1 Bcf per day in sendout capacity.



The Commission is currently processing applications for eight new LNG terminals with a combined redelivery capacity of 9.2 Bcf per day. These proposed terminals are located in Oregon (3), California (1), in Maine near the Canadian border (2), in Long Island Sound (1), and near Baltimore, Maryland (1).



In conclusion, I would note that up to this point in 2007, we have seen 7 pipeline projects place in service with a capacity of 4.4 Bcf per day. This includes CenterPoint's Carthage to Perryville project that will transport over 1.2 Bcf per day of east Texas gas to interconnections in Louisiana and Southern Natural's Cypress Pipeline that will move 0.5 Bcf per day of regasified LNG to Florida – a major new source of gas for Florida.

There have been nine storage projects that commenced service this year with a combined capacity of over 85 Bcf and about 1.8 Bcf per day of deliverability.

While no LNG facilities have gone into service this year, we should expect to see new sites and expansions commence service next year.

This concludes the presentation. Steve and I will be happy to answer any questions you may have.