North American Natural Gas Fundamentals: Do They Matter and Does Anyone Know What They Are?

Deutsche Bank

March 9, 2005

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Outline

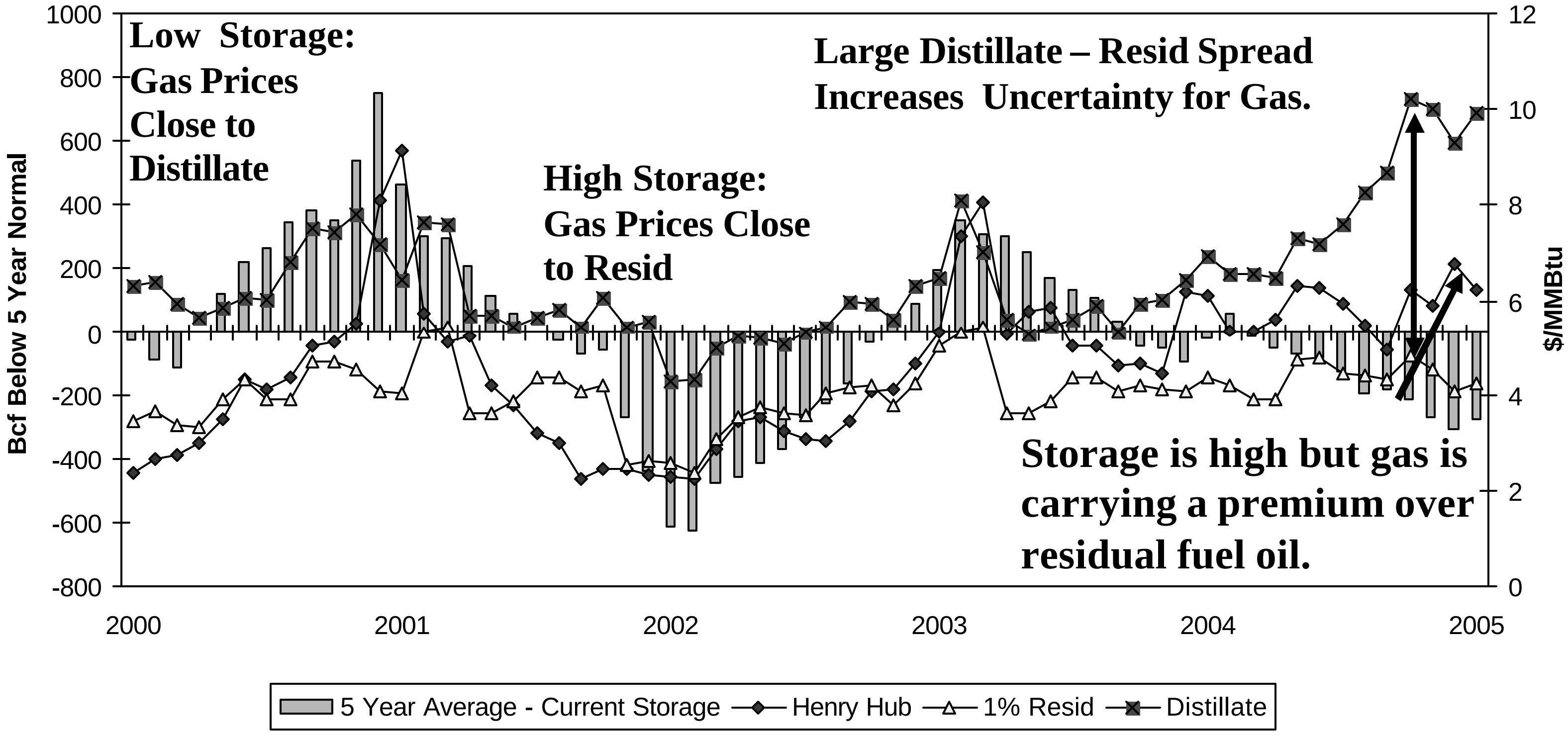
- **What are fundamentals and when do they matter?**
- **Demand response to price**
- **Production**
- **Outlook**
  - Non-heating season
  - Long term

There is a need for more clarity about what is meant by fundamentals. Often the term fundamentals is used to refer to the most likely price. However, risk and uncertainty are key factors driving the market.

- **Within price bands, short term supply and demand are not very responsive to price. This is an important aspect of risk assessment. For example, gas has lost most of its market to residual fuel oil. Consequently, a surge in gas demand or loss of supply is likely to cause sharp price increases.**
- **Prices can diverge substantially from the level that would balance the market for a long time. Sooner or later the market returns to fundamentals, but you could go bankrupt waiting.**
- **A small error in projecting supply and demand can make the difference between $3.00 and $7.00 per MMBtu gas.**
- **Fundamentals have their greatest downside impact when working gas storage is close to capacity. Three out of the last four years, forward prices have surged in the spring and fallen by September.**
- **Weather adjusted working gas storage withdrawals/injections is a key market signal.**

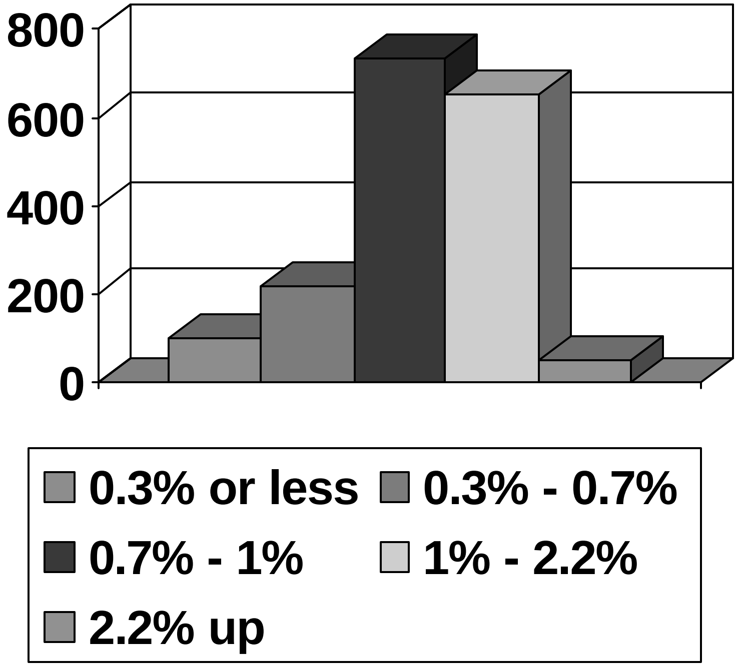
Henry Hub prices tend to be closer to residual fuel oil when storage is higher than normal and to distillate when storage is below normal.

Henry Hub Prices vs Working Gas Storage



Electric power fuel switching capability is complex. It depends upon the season and location. Peak switching to resid 2.7 Bcfd, average 1.8 Bcfd during a cold winter, .5 Bcfd summer, very little during shoulder months. (Distillate 1 Bcfd peak, .6 Bcfd during winter).

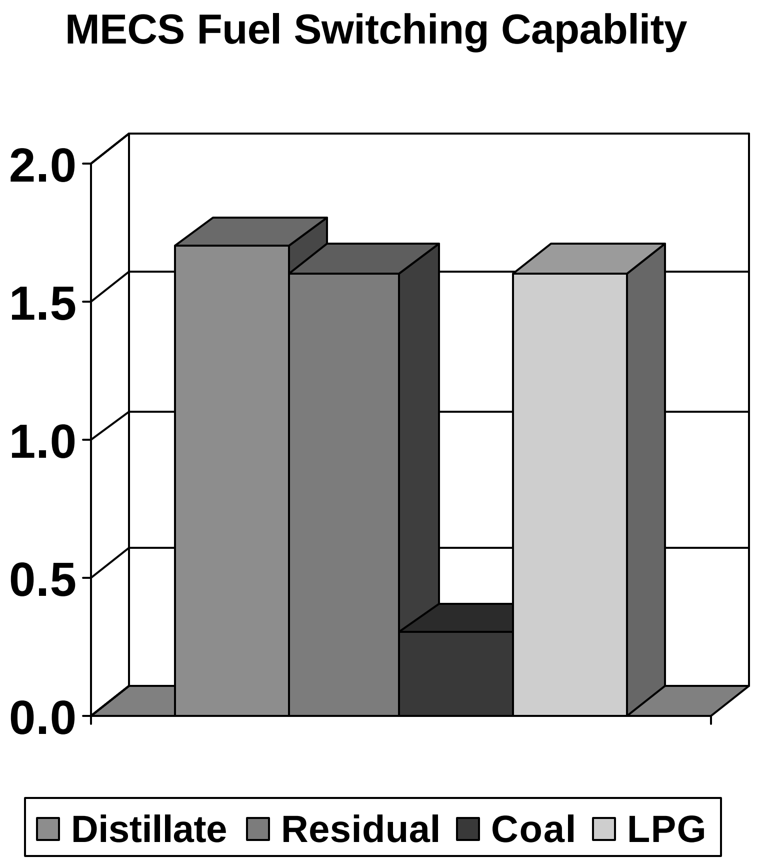
Electric Power Residual Fuel Oil (MMcfd)



Northeast Fuel Switching Prices

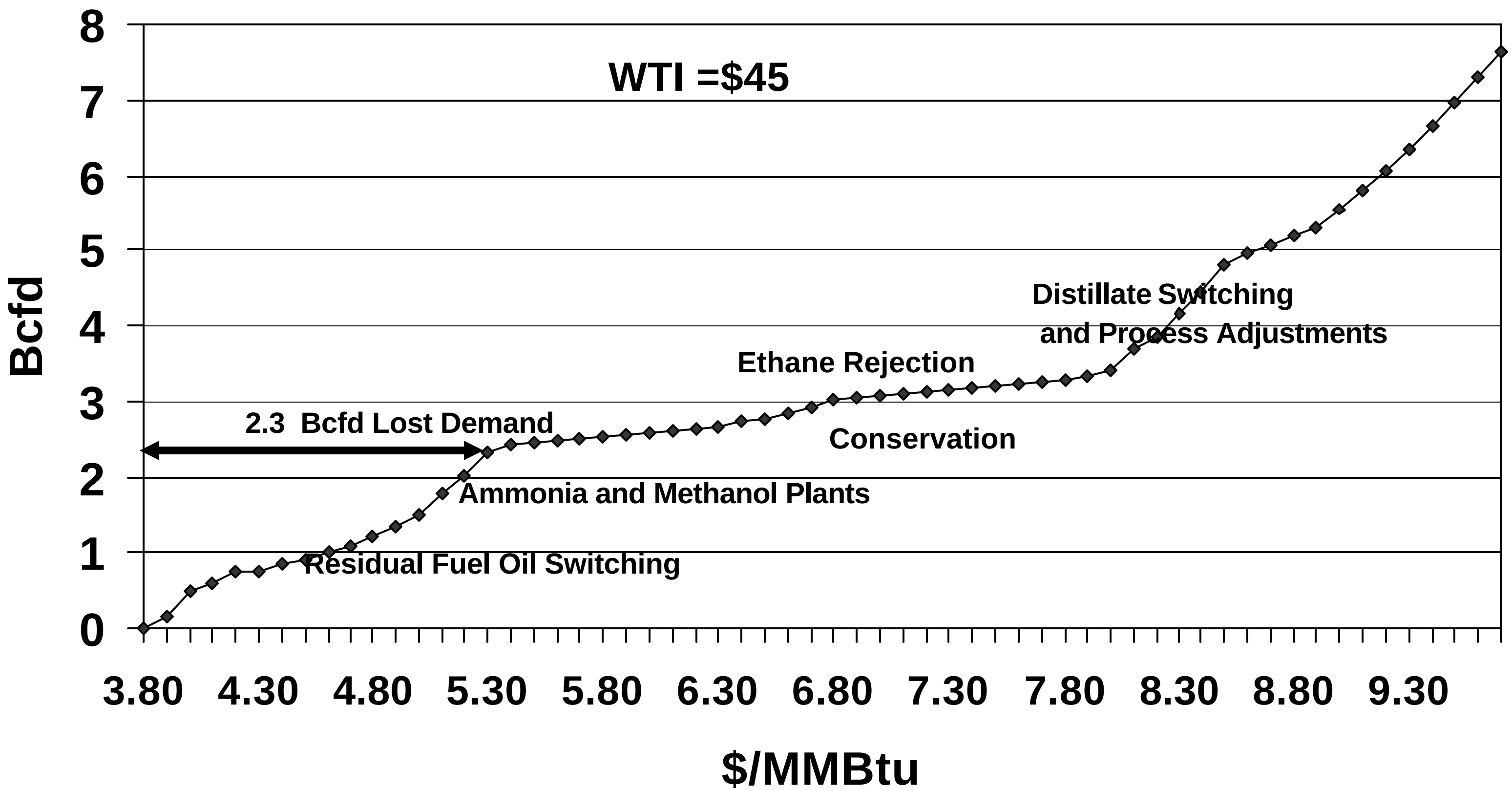
WTI = $30/ bbl	$/MMBtu SEP	JAN
1% Resid NY	3.65	3.65
Taxes & Shipping	0.45	0.45
Delivered NY	4.10	4.10
Basis	0.30	1.00
Henry Hub (Steam)	3.80	3.10
Henry Hub (CC)	5.68	4.98

The information on industrial fuel switching capability is very limited. SEER estimates there is about .5 Bcfd residual and between 1 and 1.5 Bcfd distillate switching capability.



- The 1998 MECS study switching capability is much higher than actual switching.
- Annual residual fuel oil consumption in the industrial sector is only about .5 Bcfd.
- A Department of Commerce study indicated about 500 Bcf per year of boiler switching capability during 1994-98.
- NPC study suggests boiler switching capability of approximately 200 Bcf per year or less.

Most of the "easy" short term demand reductions have taken place. With current distillate prices, it would take substantial gas price increases to reduced demand.



North American natural gas production – who do you believe?

- **Raymond James – expects YOY declines in US production of 2% to 4% per year for the foreseeable future. (August 2004) Raymond James assumes that quarterly financial report data is a good indicator of US production. SEER has shown that company report data understates production growth.**
- **BENTEK's model of North America supply and demand predicts a gas surplus of almost 1.9 BCFD by late 2005. With normal weather, BENTEK expects to see gas prices in the low $3.00s by fall of 2005. (December, 2004)**
- **EIA shows 2004 production down 1.5% after adjustment for Hurricane Ivan. Flat after adjustment for "Balancing Item". Recent TRRC data indicates sharp decline in Texas production (about 25% of US total).**

The Deepwater and Rockies will be the primary sources of US production growth.

	US Production Bcf/d					Change	
	2003	2004	2005	2006	2007	03-04	04-05
Gulf Deepwater	3.9	3.8	4.1	4.6	4.7	-0.1	0.3
Gulf Shelf	9.5	8.4	7.6	6.8	6.1	-1.1	-0.8
Gulf Onshore	12.1	12.1	11.8	11.6	11.6	0.0	-0.3
Mid-Continent	7.3	7.4	7.6	7.3	6.9	0.1	0.2
Permian	4.5	4.5	4.6	4.6	4.6	0.0	0.1
Rockies	7.2	7.5	8.1	8.8	9.5	0.4	0.6
SJ	3.3	3.3	3.4	3.4	3.4	0.0	0.0
Other	4.1	4.2	4.3	4.9	5.0	0.1	0.1
Total	51.8	51.2	51.5	52.0	51.8	-0.6	0.3
%Change	-0.3%	-1.1%	0.5%	1.0%	-0.4%		

Increased production will come from tight gas, coal bed methane, shale and deepwater.

- **Tight Gas (3 Bcf/d): Green River tight gas in WY (Jonah and Pinedale), Mamm Creek and Rulison in Colorado, Natural Buttes in Utah, Bossier (TX) and Vernon (LA).**
- **Coal Bed Methane (5 Bcfd): Deeper Big George coals in the Powder River will offset declines in Wyodak coals.**
- **Shale gas production will grow from 1.5 to 2.0 Bcfd by 2006 (primarily Barnett shale in North Texas).**
- **Substantial deepwater additions in late 2004 and early 2005.**

Major pipeline expansions are coming from the Rockies. Over 2 Bcfd is targeted for eastern markets. Encana’s tight gas play in the Pieance Basin is expected to be a major supply source.

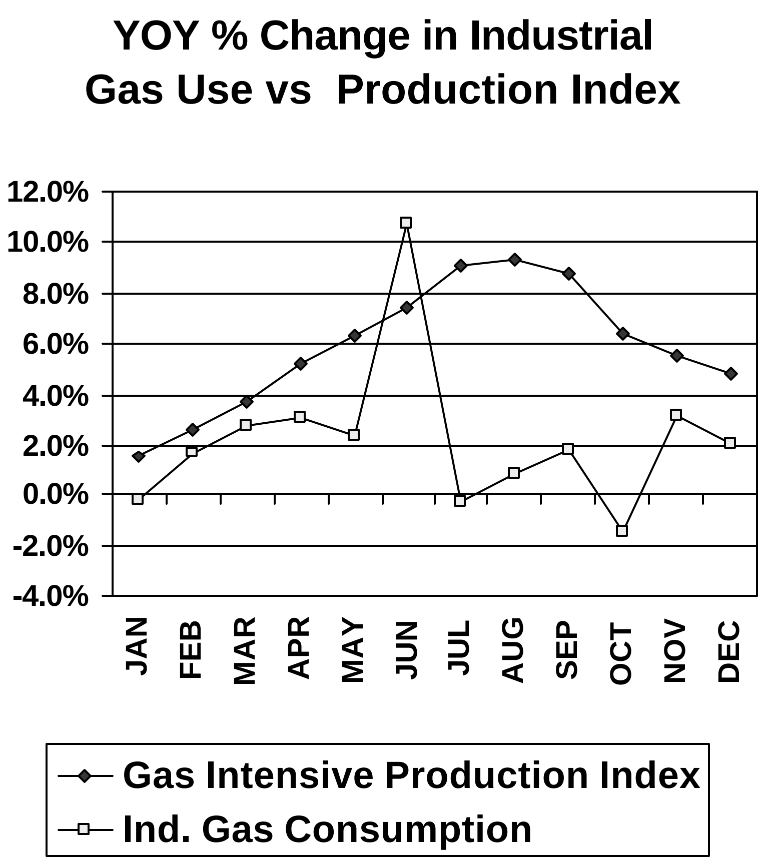
Pipeline	Origin	Destination	Capacity Addition (MMcfd)	Date	Status
Cheyenne Plains	Cheyenne, WY	Greensburg, KA	576	Dec-04	Operating
Cheyenne Plains	Cheyenne, WY	Greensburg, KA	179	Mar-06	Applied
Entrega	Pieance Basin, NW CO	Northeast CO	1300	Fall 2005	Applied
Ken River	Opal WY	S. CA	500		Under Consideration

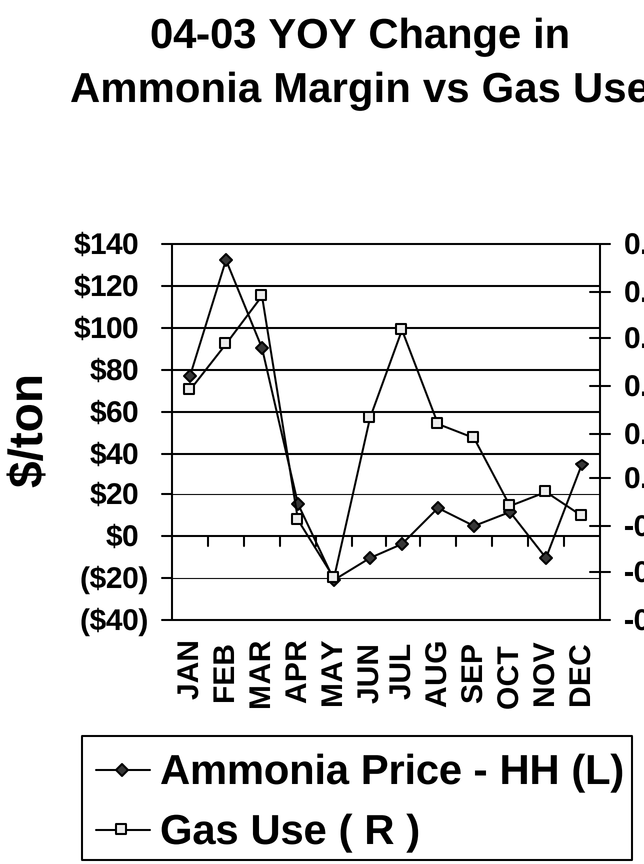
Production growth, increased imports should provide supply growth. Additional LNG, primarily from Nigeria and Trinidad, will be a major source of supply growth.

	US Supply (Billon Cubic Feet / Day)					Change	
	2003	2004	2005	2006	2007	03-04	04-05
LNG (1)	1.2	1.6	1.7	2.4	3.3	0.5	0.2
Canada	8.6	8.9	9.1	9.0	9.1	0.3	0.2
Mexico	-1.1	-1.1	-1.0	-1.1	-0.9	0.0	0.1
Net Imports	8.6	9.3	10.0	10.3	11.7	0.8	0.5
US Production	51.8	51.2	51.5	52.0	51.8	-0.6	0.3
Total Supply	60.4	60.6	61.4	62.3	63.5	0.2	0.8
%Change in Supply		0.3%	1.3%	1.5%	1.9%		

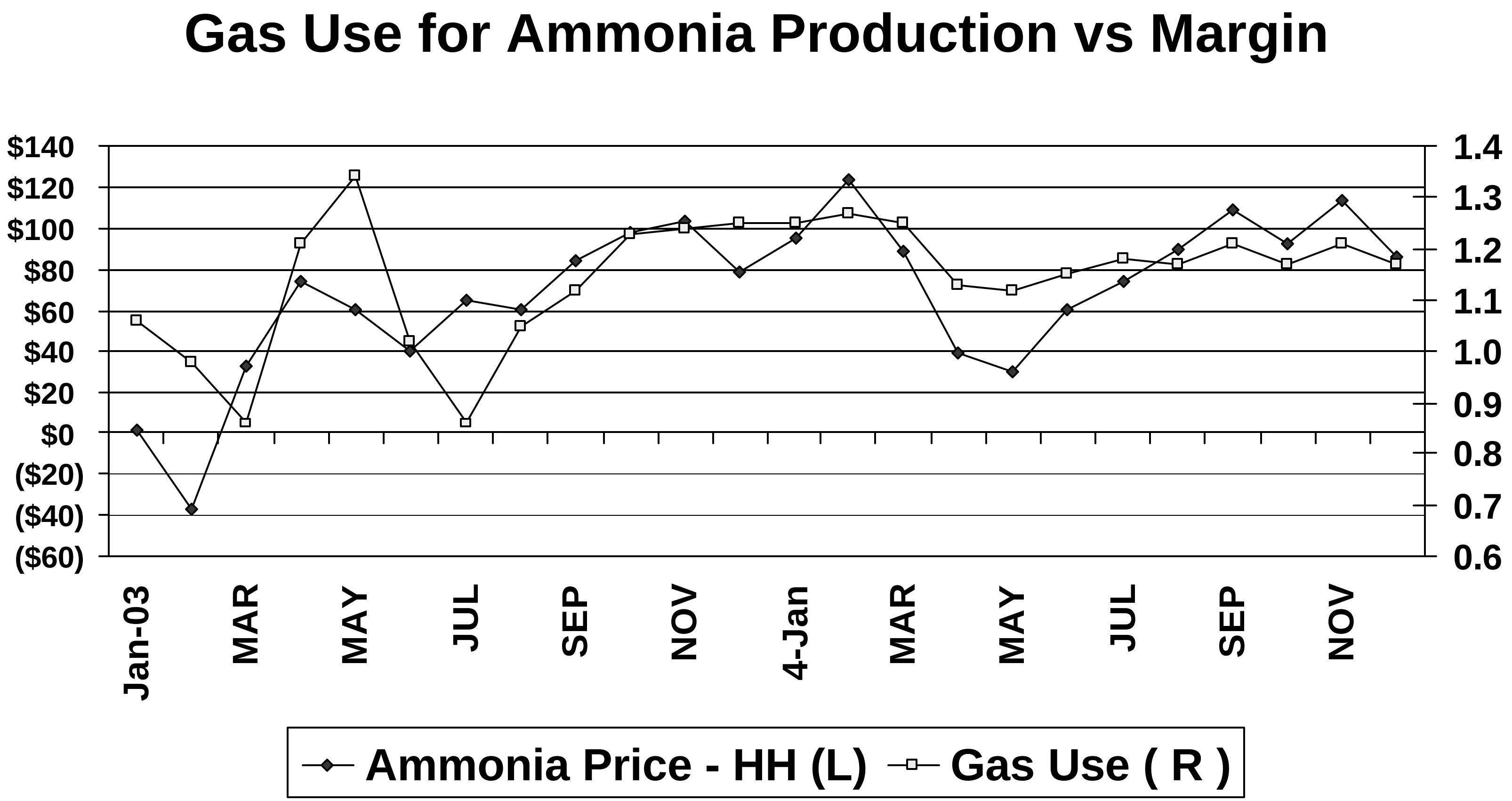
(1) Net of Alaska exports

The gas weighted index of industrial production increased by 8% in 2004 but EIA reported industrial gas consumption only increased by 2%. Gas consumption per output has decreased in all gas intensive industries.





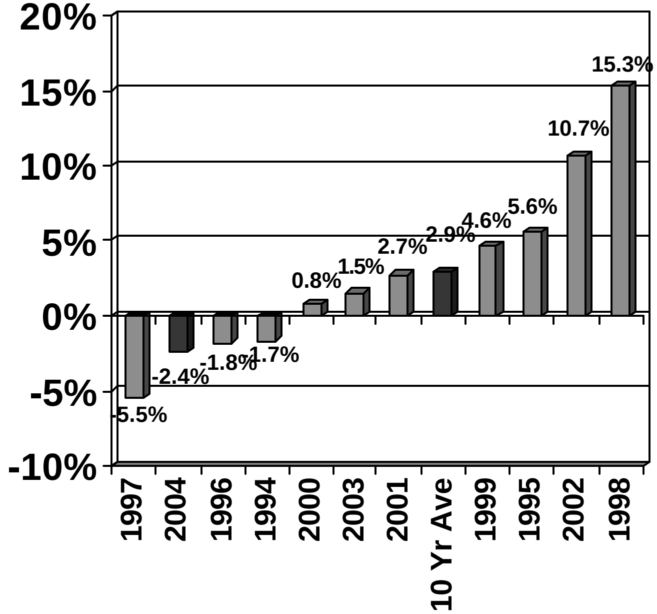
Gas use for the production of anhydrous ammonia production was up 8% in 2004.



During the non-heating season a 10% change in CDD would cause electricity demand to increase about 2% and gas consumption for power generation about 5% (.8 Bcfd).

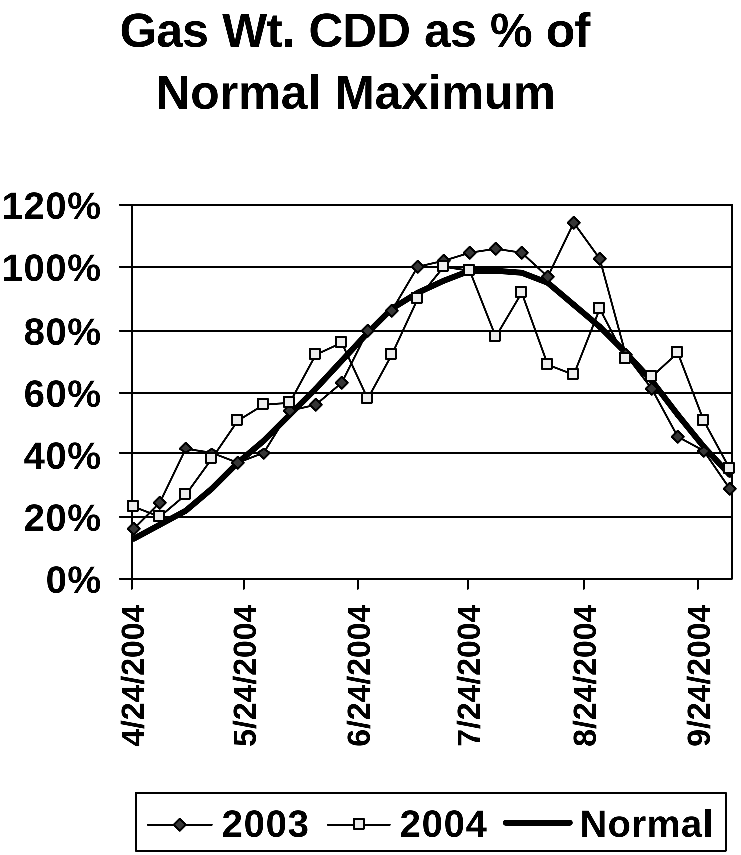
- **During the last ten years CDDs have averaged 2.9% higher than the 30 year normal**
- **2004 was 2.4% below the 30 year normal.**
- **The chances of exceeding normal CDDs by 5% or more is about 1/3.**

Population Wt. CDD (% of 30 Year Normal)



In the summer a 10% increase in CDD causes about a 3% increase in electricity consumption and a 7% increase in gas consumption for power generation (1.2 Bcfd).

- **The crucial period is July and August (7/10 – 8/14).**
- **Gas is on the margin and inefficient units dispatch.**
- **<u>During the peak demand period in 2003 gas weighted degree days were 9% below normal. In 2003 they were 6% above normal.</u>**



Weather, coal and hydro generation could sharply change gas consumption for power generation.

- **Coal supply to the east is expected to gradually improve this year.**
- **A repeat of last year's hydro would add .5 Bcfd to gas demand and a normal hydro year would reduce gas demand by 1 Bcfd.**
- **Total demand could be 1 Bcfd higher or 1.5 Bcfd lower because of weather and hydro.**

Bcfd Equivalent Generation
Non-Heating Season

Fuel	Ave.	05-04	% Ch
Coal	47.5	1.1	2.4%
Petroleum	2.8	0.0	0.0%
Natural Gas	16.8	1.0	5.8%
Nuclear	18.9	0.0	0.0%
Hydro (1)	10.6	0.5	4.7%
Total	**96.6**	**2.6**	2.7%

(1) Includes Geothermal and other

With normal weather, working gas storage injections should be approximately 2025 Bcf during the non-heating season. Working gas storage levels should end October about the same level as last year.

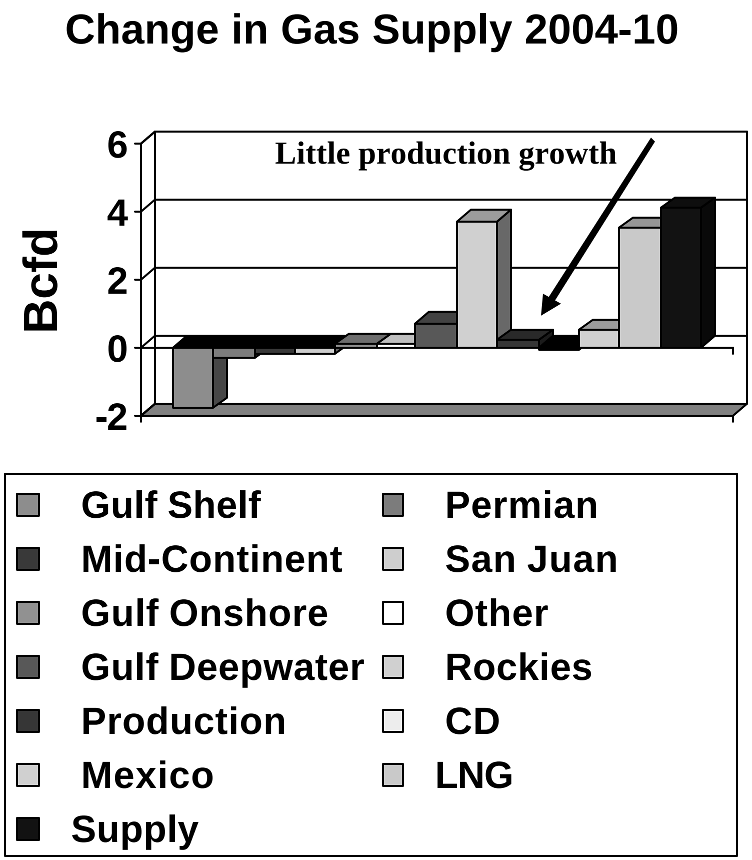
- **The major near term downside risk is oil prices and the major upside is weather.**
- **Weather adjusted storage withdrawals indicate the supply-demand balance is looser than last year.**
- **Watch weather adjusted storage injections.**

Non-Heating Season Supply-Demand

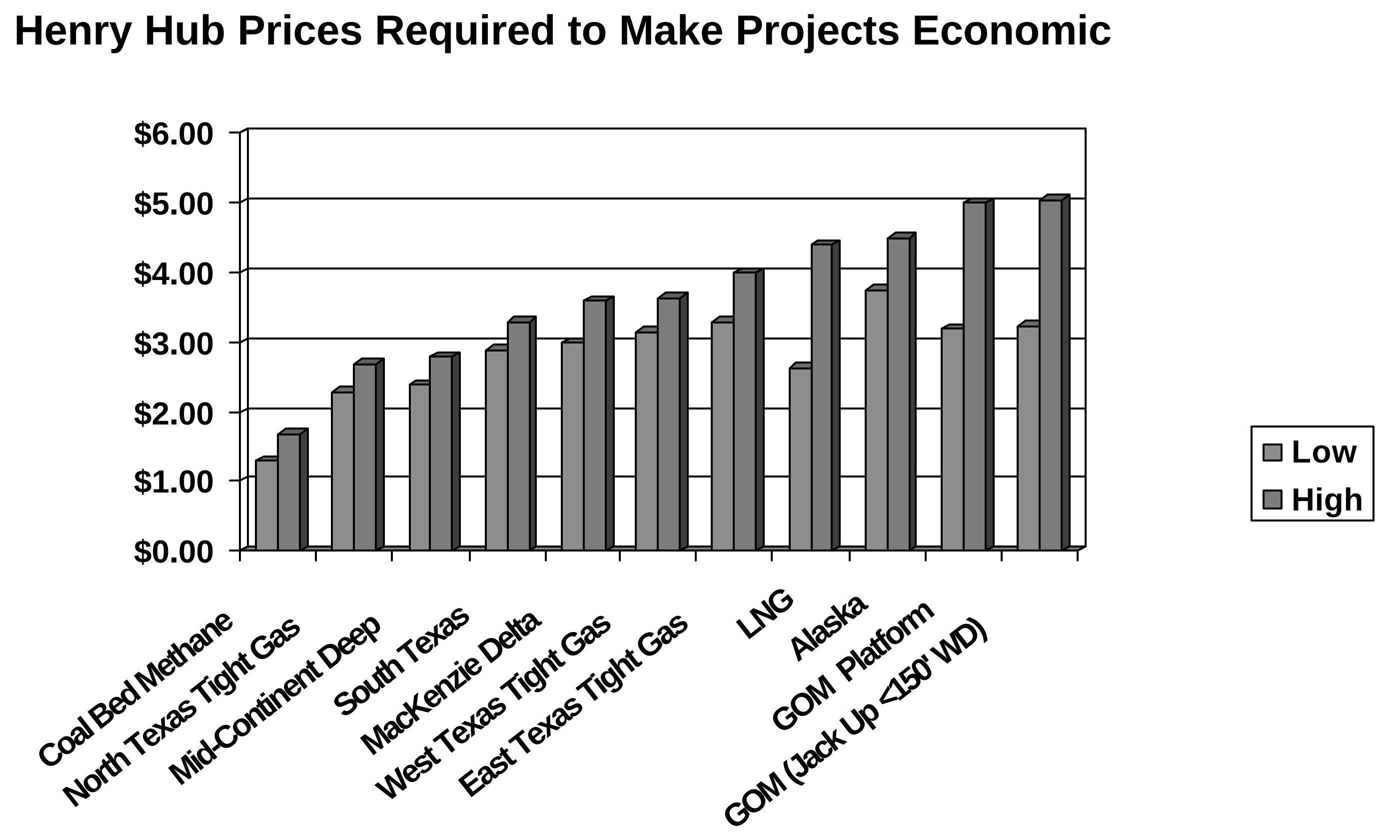
Sector	2005	05-04 (Bcfd)	05-04 %Change
Residential	6.2	0.05	0.9%
Commercial	5.1	0.05	0.9%
Industrial	18.8	0.28	1.5%
Electric Power	16.8	1.10	7.0%
Other	4.5	-0.01	
Total Deliveries	51.4	1.47	2.9%
Production	51.3	0.14	0.3%
LNG	1.9	0.28	14.5%
Canada & Mexico	7.9	0.12	1.5%
Total New Supply	61.1	0.54	0.9%

US supply growth is expected to be about 1% per year. High prices will be required to keep demand growth to this rate.

- **US LNG projections range from 4.2 Bcfd to 11 Bcfd. SEER reference is 5.5 Bcfd.**
- **Rockies growth expected to be about 4 Bcfd with a downside 1.5 Bcfd up side 1 Bcfd. The key driver is litigation by environmentalist and the speed at which permits are issued.**
- **Deepwater and deep shelf has great potential but it remains to be seen how much will be realized.**



What is the marginal cost of supply? Near term, constraints on rigs, experienced workers, and lack of prospects attractive to majors limits production growth.



There is substantial disagreement about long term U.S gas prices. Price projections continue to be revised upward. The issues include environmental regulations, the cost of coal gasification, the loss of gas intensive industrial production, capital allocation, available rigs and geologists etc.

- **ICF has an extremely detailed supply model. They have been calling for prices close to $4.50 /MMBtu by 2006 and below $4.00 by 2015.**
- **Economy.com forecasts the dollar will decline another 10% this year and many analysts think the US dollar has to decline another 20%. The long term exchange rate could have a significant impact the economics of LNG.**